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AUG 31 2009

PUBLIC SERVICE
COMMISSION

VERIFICATION

State of Ohio)
)
County of Hamilton)

The undersigned, Julia S. Janson being duly sworn, deposes and says that I am employed by the Duke Energy Corporation affiliated companies as President – Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc.; that on behalf of Duke Energy Kentucky, Inc., I have supervised the preparation of the responses to the foregoing responses to information requests; and that the matters set forth in the foregoing response to information requests are true and accurate to the best of my knowledge, information and belief after reasonable inquiry.

Julia S. Janson, Affiant

Subscribed and sworn to before me by Julia S. Janson on this 27th day of August, 2009.

NOTARY PUBLIC

My Commission Expires:

NOTARY PUBLIC
STATE OF OHIO

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

VERIFICATION

State of Ohio)
)
County of Hamilton)

The undersigned, William Don Wathen Jr., being duly sworn, deposes and says that I am employed by the Duke Energy Corporation affiliated companies as Director - Rates; that on behalf of Duke Energy Kentucky, Inc., I have supervised the preparation of the responses to the foregoing responses to information requests; and that the matters set forth in the foregoing response to information requests are true and accurate to the best of my knowledge, information and belief after reasonable inquire.

D M Wathen

William Don Wathen Jr., Affiant

Subscribed and sworn to before me by William Don Wathen Jr. on this 18th day of August 2009.

Patty A. Selm

NOTARY PUBLIC

My Commission Expires:

PATTY A. SELM
Notary Public, State of Ohio
My Commission Expires 09-15-2014

257522

<u>VERIFICATION</u>

State of North Carolina)
)
County of Mecklenburg)

The undersigned, Stephen G. De May, being duly sworn, deposes and says that I am employed by the Duke Energy Corporation affiliated companies as Vice President and Treasurer of Duke Energy Corporation; that on behalf of Duke Energy Kentucky, Inc., I have supervised the preparation of the responses to the foregoing responses to information requests; and that the matters set forth in the foregoing response to information requests are true and accurate to the best of my knowledge, information and belief after reasonable inquire.

Stephen G. De May, Affiant

Subscribed and sworn to before me by Stephen G. De May on this 19th day of August, 2009.

Kathy S. Moraleda
NOTARY PUBLIC Kathy S. Moraleda

My Commission Expires: 12/13/2013

252695

VERIFICATION

State of Ohio)
)
County of Hamilton)

The undersigned, Stephen R. Lee being duly sworn, deposes and says that I am employed by the Duke Energy Corporation affiliated companies as Director, Financial Forecasting; that on behalf of Duke Energy Kentucky, Inc., I have supervised the preparation of the responses to the foregoing responses to information requests; and that the matters set forth in the foregoing response to information requests are true and accurate to the best of my knowledge, information and belief after reasonable inquire.

Stephen R. Lee, Affiant

Subscribed and sworn to before me by Stephen R Lee on this 26th day of August, 2009.

NOTARY PUBLIC

My Commission Expires:

NOTARY PUBLIC STATE OF OHIO

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

269137 v.8

<u>VERIFICATION</u>

State of North Carolina)
)
County of Mecklenburg)

The undersigned, David L. Doss being duly sworn, deposes and says that I am employed by the Duke Energy Corporation affiliated companies as Director of Accounting; that on behalf of Duke Energy Kentucky, Inc., I have supervised the preparation of the responses to the foregoing responses to information requests; and that the matters set forth in the foregoing response to information requests are true and accurate to the best of my knowledge, information and belief after reasonable inquire.

David L Doss

David L. Doss, Affiant

Subscribed and sworn to before me by David L. Doss on this 25th day of August, 2009.

Elizabeth Love Rothrock

NOTARY PUBLIC

My Commission Expires: 12/7/2013

VERIFICATION

State of Ohio)
)
County of Hamilton)

The undersigned, Timothy A. Phillips being duly sworn, deposes and says that I am employed by the Duke Energy Corporation affiliated companies as Lead Forecaster; that on behalf of Duke Energy Kentucky, Inc., I have supervised the preparation of the responses to the foregoing responses to information requests; and that the matters set forth in the foregoing response to information requests are true and accurate to the best of my knowledge, information and belief after reasonable inquire.

Timothy A. Phillips, Affiant

Subscribed and sworn to before me by Timothy A. Phillips on this 24th day of August, 2009.

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

<u>VERIFICATION</u>

State of Ohio)
)
County of Hamilton)

The undersigned, Jay R. Alvaro being duly sworn, deposes and says that I am employed by the Duke Energy Corporation affiliated companies as Vice-President – Total Rewards; that on behalf of Duke Energy Kentucky, Inc., I have supervised the preparation of the responses to the foregoing responses to information requests; and that the matters set forth in the foregoing response to information requests are true and accurate to the best of my knowledge, information and belief after reasonable inquire.

Jay R. Alvaro

Jay R. Alvaro, Affiant

Subscribed and sworn to before me by Jay R. Alvaro on this 19TH day of August, 2009.

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

<u>VERIFICATION</u>

State of Ohio)
)
County of Hamilton)

The undersigned, James E. Ziolkowksi being duly sworn, deposes and says that I am employed by the Duke Energy Corporation affiliated companies as Rates Manager; that on behalf of Duke Energy Kentucky, Inc., I have supervised the preparation of the responses to the foregoing responses to information requests; and that the matters set forth in the foregoing response to information requests are true and accurate to the best of my knowledge, information and belief after reasonable inquire.

James E. Ziolkowski

James E. Ziolkowski, Affiant

Subscribed and sworn to before me by James E. Ziolkowski on this 20th day of August, 2009.

Patty A. Selm

NOTARY PUBLIC

My Commission Expires:

PATTY A. SELM
Notary Public, State of Ohio
My Commission Expires 09-15-2014

269137 v 6

VERIFICATION

State of Ohio)
)
County of Hamilton)

The undersigned, Donald L. Storck being duly sworn, deposes and says that I am employed by the Duke Energy Corporation affiliated companies as Director of Rate Services; that on behalf of Duke Energy Kentucky, Inc., I have supervised the preparation of the responses to the foregoing responses to information requests; and that the matters set forth in the foregoing response to information requests are true and accurate to the best of my knowledge, information and belief after reasonable inquire.

Donald L. Storck
Donald L. Storck, Affiant

Subscribed and sworn to before me by Donald L. Storck on this 18th day of August, 2009.

Patty A. Selm
NOTARY PUBLIC

My Commission Expires: PATTY A. SELM
Notary Public, State of Ohio
My Commission Expires 09-15-2014

<u>VERIFICATION</u>

State of Ohio)
)
County of Hamilton)

The undersigned, Robert M. Parsons being duly sworn, deposes and says that I am employed by the Duke Energy Corporation affiliated companies as Rates Manager; that on behalf of Duke Energy Kentucky, Inc., I have supervised the preparation of the responses to the foregoing responses to information requests; and that the matters set forth in the foregoing response to information requests are true and accurate to the best of my knowledge, information and belief after reasonable inquire.

Robert M. Parsons

Robert M. Parsons, Affiant

Subscribed and sworn to before me by Robert M. Parsons on this 18th day of August, 2009.

Patty A. Selm

NOTARY PUBLIC

My Commission Expires:

PATTY A. SELM
Notary Public, State of Ohio
My Commission Expires 09-15-2014

<u>VERIFICATION</u>

Commonwealth of Pennsylvania)
)
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 says that he has supervised the preparation of the responses to the foregoing responses to information requests; and that the matters set forth in the foregoing response to information requests are true and accurate to the best of his knowledge, information and belief after reasonable inquire.

John J. Spanos

John J. Spanos, Affiant

Subscribed and sworn to before me by John J. Spanos on this 20th day of August, 2009.

NOTARY PUBLIC

My Commission Expires: February 20, 2011

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Cheryl Ann Rutter, Notary Public
East Pennsboro Twp., Cumberland County
My Commission Expires Feb. 20, 2011
Member, Pennsylvania Association of Notaries

VERIFICATION

State of Ohio)
)
County of Hamilton)

The undersigned, Gary J. Hebbeler being duly sworn, deposes and says that I am employed by the Duke Energy Corporation affiliated companies as General Manager, Gas Engineering; that on behalf of Duke Energy Kentucky, Inc., I have supervised the preparation of the responses to the foregoing responses to information requests; and that the matters set forth in the foregoing response to information requests are true and accurate to the best of my knowledge, information and belief after reasonable inquire.

Gary J. Hebbeler

Gary J. Hebbeler, Affiant

Subscribed and sworn to before me by Gary J. Hebbeler on this 21st day of August, 2009.

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

VERIFICATION

State of Ohio)
)
County of Hamilton)

The undersigned, Brenda R. Melendez being duly sworn, deposes and says that I am employed by the Duke Energy Corporation affiliated companies as Manager, Accounting; that on behalf of Duke Energy Kentucky, Inc., I have supervised the preparation of the responses to the foregoing responses to information requests; and that the matters set forth in the foregoing response to information requests are true and accurate to the best of my knowledge, information and belief after reasonable inquire.

Brenda R. Melendez

Brenda R. Melendez, Affiant

Subscribed and sworn to before me by Brenda R. Melendez on this 21st day of July, 2009.

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

VERIFICATION

Province of Nova Scotia)
)
County of Halifax)

The undersigned, Dr. Roger A. Morin, being duly sworn, deposes and says that he has supervised the preparation of the responses to the foregoing responses to information requests; and that the matters set forth in the foregoing response to information requests are true and accurate to the best of his knowledge, information and belief after reasonable inquire.

Dr. Roger A. Morin, Affiant

Subscribed and sworn to before me by Dr. Roger A. Morin on this 21st day of August, 2009.

NOTARY PUBLIC

MICHAEL R. CROWELL
A Commissioner of the Supreme Court of Nova Scotia

My Commission Expires:

269137 v.16

STAFF-DR-02-001

REQUEST:

Refer to Volume I of the application, Tab 33.

a. Refer to FR 10(9)(h)(1), the Projected Income Statement 2009-2011. Explain the large decrease in Other Revenue from 2009 to 2010.

b. Refer to 10(9)(h)(8), the Mix of Gas Supply 2009-2011.

(1) Explain why lines 2 and 10 are labeled "Undetermined".

(2) Explain why the amounts on line 13, Total Cost, do not reconcile with line 8, Gas Purchased, on the Projected Income Statement 2009-2011.

c. Explain the disparity between the increase in gas retail customers shown in the Customer Forecast 2009 – 2011, 10(9)(h)(14), and the decrease in sales volumes shown in the MCF Sales Forecast 2009 – 2011 on the following page, 10(9)(h)(15).

RESPONSE:

a. 2009 includes actual revenues related to MISO RSG/make whole payments for generating units dispatched. These types of revenues are not assumed in the forecast.

b. (1) At the time the forecast is prepared, providers of gas supply are not known. In addition, these providers of gas supply will change during forecasted periods.

b. (2) - The difference in the gas purchased on the totals is due to the income statement line including change in deferred gas costs while the supply forecast does not.

c. Increased number of customers does not always translate into a corresponding increase in gas sales due to influences on customer behavior such as increased equipment efficiencies, conservation, and price increases. Use per customer has also been declining. For example, Kentucky residential gas use per customer (on a weather normal basis) shows an annual rate of decline of 1.6% over the 2001-2008 period.

PERSON RESPONSIBLE: Stephen G. De May / Stephen R. Lee

STAFF-DR-02-002

REQUEST:

Refer to Volume IV, Tab 47.

a. Provide a copy of the cost of service study, Exhibits FR-10(9)v-1 through FR-10(9)v-6, electronically on CD-ROM in Microsoft Excel format with all formulas intact and unprotected.

b. Refer to FR-10(9)v-1, page 10 of 23. Explain why the two rows titled "Elim Other Than DE-KY Portion" are allocated using different allocation factors.

c. Refer to FR-10(9)v-1, page 15 of 23. Explain why Misc. Service Revenue is allocated to the rate classes based on total customer number rather than directly assigned for items such as bad check and reconnection charges.

d. Refer to FR-10(9)v-2 through FR-10(9)v-5. Provide these schedules on a total basis as opposed to the rate class basis provided in the application.

e. Refer to FR-10(9)v-2, page 2 of 20.

(1) Under "Distribution Plant", explain why the division of Mains into the demand and customer portion is 78.2 and 21.8 percent, respectively, rather than 85 and 15 percent as calculated on WPFR-9v-6, page 16 of 27.

(2) Under "General & Intangible Plant" and "Common & Other Plant", provide the basis for the percentage allocations among the six items listed under each category, stated below, and explain why these allocations do not match those on WPFR-9v-6, page 5 of 27.

Production Plant	3.76%
Production Plant Commodit	4.63%
Distribution Plant	50.84%
Customer Accounting	34.42%
Customer Service & Information	6.35%
Sales	0%

f. Refer to FR-10(9)v-2, page 5 of 20. Explain why it is reasonable to allocate "Misc Deferrals" using the KA&G_CA allocator.

g. Refer to FR-10(9)v-2, page 7 of 20. Under "Distribution O&M", explain why the division of Mains into the demand and customer portion is 78.2 and 21.8 percent, respectively, rather than 85 and 15 percent as calculated on WPFR-9v-6, page 16 of 27.

h. Refer to FR-10(9)-2, page 19 of 20.

(1) In the first column, there are two allocators titled "Distr Land, Struc & Equp Dem" and "Distr Land, Struc & Equp Cust." Explain how the amounts in these accounts were classified as demand-related versus customer-related.

(2) Explain how the allocator "Present Revenues by Function" was derived.

i. Refer to WPFR-9v-6, page 1 of 27. This page states that the Average and Excess Demand-Peak Day ratios were calculated based on 2007 Mcf and load research data. Explain why 2008 data was not used.

j. Refer to WPFR-9v-6, pages 17 and 18 of 27. Describe the "Handy Whitman Index for Gas Utility Construction, Northern Central Region" and why it is being used in the minimum size study rather than actual cost data.

RESPONSE:

a. An electronic copy is provided on CD-ROM. See Staff-DR-02-002a COSS.xlsm.

b. The two rows titled "Elim Other Than DE-KY Portion" are allocated using different allocation factors because they are different types of costs. The first, ($4,440) reflects the elimination of Social Security Taxes on labor expenses related to facilities devoted to other the Duke Energy Kentucky customers (Erlanger Gas Plant). It is allocated based on allocator K411, A&G factor. The second, ($67,616), is elimination of property tax related to facilities devoted to other than Duke Energy Kentucky customers (Erlanger Gas Plant) and is based on allocator K901, present revenues.

c. Miscellaneous Service revenue is allocated to rate class based on total customer rather than direct assigned for items such as bad check and reconnection charges because miscellaneous revenues are not available in our accounting system by rate class.

d. Please see ATTACHMENT STAFF-DR-02-002 COSS Class Totals.

e.

(1) The cost of mains were classified prior to allocating to rate class. On FR-10(9)v-1, page 2, the demand portion of mains of $196,666,446 represents 85% of the total cost of mains. The customer portion of mains, $34,705,843, represents 15% of the total cost of mains. The **demand** portion was allocated to class using **demand** allocator K203, resulting in the $115,285,871 shown

on FR-10(9)v-2, page 2. The **customer** portion was allocated to class using **customer** allocator K401, resulting in the $32,145,246 shown on FR-10(9)v-2, page 2.

(2) General and Intangible Plant and Common & Other Plant were first functionalized on WPFR-9v-6, page 5 prior to classifying and allocating. For example, the production plant portion of General and Intangible Plant of $142,219 is 4.298% of total General and Intangible Plant of $3,308,961 on WPFR-9v-6, page 5. The 4.298% comes from the functional allocators derived on WPFR-9v-6, page 5 of 27. The $142,219, classified as demand, is allocated to class using allocator K419, A&G PROD-DEMAND EXCL REG EXP, resulting in the $90,854 shown on WP-10(9)v-2, page 2.

f. "Misc Deferrals", classified as a customer cost using the KA&G_CA factor on FR-10(9)v-2, page 5, is allocated to rate class on WP-10(9)v-1, page 5 using allocation factor K411, A&G factor. It is appropriate to classify and allocate "Misc Deferrals" in this manner because this amount is comprised of various accumulated deferred income taxes includable in Account 283 – Accumulated Deferred Income Taxes - Other. This includes items such as loss on reacquired debt, asset retirement obligation, regulatory asset accrued pension, decommissioning liability, etc.

g. Please see the response to 2.e(1).

h.

(1) The allocator KDIST_STR_D titled "Distr Land, Struc & Equip Demand" indicates that the account was classified as 100% demand. This includes System Measuring & Regulating Equipment and Distribution Regulators (278), and Land, Rights of Way, and Structures and Improvements (various accounts). According to the Gas Distribution Rate Design Manual, prepared by the National Association of Regulatory Utility Commissioners ("NARUC"), demand or capacity costs vary with the quantity or size of plant and equipment. They are related to the maximum system requirements which the system is designed to serve and do not vary with the number of customers or their annual usage. The NARUC manual goes on to state that included in these costs are: the capital costs associated with producton, transmission and storage plant their related expenses; the demand cost of gas; and most of the capital costs and expenses associated with that part of distribution plant not allocated to customer costs, such as the costs associated with distribution mains in excess of the minimum size. The accounts listed above meet that criteria – they do not vary with the number of customers or their annual usage and are related to maximum system requirements. The allocator KDIST_STR_C, titled"Dist Land, Struc, & Equip Cust" indicates the account was classified as 100% customer. KDIST_STR_C was not used in this study.

(2) The allocator "Present Revenues by Function" was derived from present revenues appearing on Schedule M-2.2, page 2 of 7 (12 mos forecasted). See Volume VI, tab M.

i. 2007 Load Research and 2007 Mcf was used to develop demand allocators because 2008 load research data was not available at the time these demand allocators were prepared. For consistency 2007 Mcf was used with the 2007 load research data to develop the demand allocators.

j. The "Handy Whitman Index" is published for the electric, gas and water industries. Each set of indexes are maintained for general items of construction, such as reinforced concrete, and specific items of material or equipment, such as pipe or turbo-generators. These publications are used by regulatory bodies, operating utilities, valuation engineers and equipment industries. Handy-Whitman numbers are widely used to trend original cost at prices prevailing at a certain date.

The Handy Whitman Index was used in the cost of service study to calculate the amount of investment that would be required if all mains were comprised of 1" plastic mains (the minimum size in this study). The actual installed book cost of 1" plastic mains is \$5.30 per foot. It would not be correct to apply this cost to all plastic mains installed in every vintage (from 1965 – 2008). Plastic mains installed in 1965 were priced much lower cost than the average installed cost. Therefore, the Handy Whitman Index was used to calculate the cost per foot of 1" plastic mains in each vintage year. These calculations are shown on WPFR-9v-6, which calculates the minimum size cost of plastic mains by year.

As an example, the 1965 cost per foot of 1" of plastic main was calculated as follows:

$$\frac{\text{Handy Whitman Factor 1965 } 71}{\text{Handy Whitman Factor 2008 } 467} \times \$5.30 = \$0.81 \text{ per foot}$$

The calculated \$0.81 1965 cost of 1" plastic main multiplied times the 592 feet of plastic main installed in 1965 (all sizes) equal \$480 minimum size cost in 1965. This process was used for each year for which plastic main was installed to arrive at the total minimum size cost of plastic mains.

PERSON RESPONSIBLE: Donald L. Storck

DUKE ENERGY KENTUCKY
COST OF SERVICE STUDY
TWELVE MONTHS ENDING JANUARY 31, 2011
GAS CASE NO: 2009-00202

ATTACHMENT STAFF-DR-02-002 COSS CLASS TOTALS
FR-10(9)v-CLASS TOTALS
WITNESS RESPONSIBLE:
DONALD L. STORCK

	ITEM	ALLO	TOTAL GAS ALL CLASSES	COMMODITY	DEMAND	CUSTOMER	TOTAL AT ISSUE
SUMMARY OF RESULTS	Schedule 1						
NET INCOME COMPUTATION							
GROSS GAS PLANT IN SERVICE	GP11		388,986,305	672,114	211,428,149	176,886,042	388,986,305
TOTAL DEPRECIATION RESERVE	DR11		(106,403,991)	(380,064)	(58,549,920)	(47,474,007)	(106,403,991)
TOTAL RATE BASE ADJUSTMENTS	RB71		(29,456,349)	477,437	(16,690,583)	(13,243,203)	(29,456,349)
TOTAL RATE BASE	RB91		253,125,965	769,487	136,187,646	116,168,832	253,125,965
CAPITALIZATION ALLOC TO GAS OPER	GCAP		253,750,235	770,560	136,523,506	116,456,169	253,750,235
OPERATING EXPENSES							
TOTAL O&M EXPENSE	OM31		97,956,713	73,957,738	12,867,604	11,131,371	97,956,713
TOTAL DEPRECIATION EXPENSE	DE41		11,657,827	50,612	6,173,863	5,433,352	11,657,827
TOTAL OTHER TAX & MISC EXPENSE	L591		4,089,172	11,902	2,113,503	1,963,767	4,089,172
TOTAL OP EXP EXC INC & R TAX	OP61		113,703,712	74,020,252	21,154,970	18,528,490	113,703,712
NET FED INCOME TAX EXP ALLOWABLE	I879		7,848,516	(14,780)	4,249,329	3,613,966	7,848,515
NET STATE INCOME TAX EXP ALLOWABLE	J979		1,447,800	(2,351)	782,161	667,990	1,447,800
AFUDC OFFSET	LO33	KNET_CWIP	(289,745)	0	(158,493)	(131,252)	(289,745)
TOTAL OPERATING EXPENSE	OPEX		122,710,283	74,003,121	26,027,967	22,679,194	122,710,282
RETURN ON CAPITALIZATION	RC51		19,465,181	59,110	10,472,718	8,933,353	19,465,181
TOTAL OTHER OPERATING REVENUES	QO27		(743,924)	(472,916)	(173,581)	(97,427)	(743,924)
TOTAL GAS COST OF SERVICE	CS05		141,431,540	73,589,315	36,327,104	31,515,120	141,431,539
PROPOSED REVENUES	R602		141,431,759	78,905,519	25,766,615	36,759,625	141,431,759
EXCESS REVENUES	XREV		219	5,316,204	(10,560,489)	5,244,505	220
TOTAL RETURN EARNED	RETE		19,465,316	3,307,312	4,020,259	12,137,747	19,465,318
RATE OF RETURN EARNED ON CAP	RORE		0.076710	4.292090	0.029450	0.104230	0.07671
TOTAL RATE OF RETURN ALLOWABLE	RORA		0.076710	0.076710	0.076710	0.076710	0.07671
RETURN EARNED ON COMMON EQUITY	REOE		0.11000	8.55750	0.01530	0.16515	0.11000
ALLOWED RETURN ON COMMON EQUITY	AROE		0.11000	0.11000	0.11000	0.11000	0.11000
PRESENT REVENUES	R600		123,937,423	78,905,519	29,062,916	15,968,988	123,937,423
REVENUE INCREASE JUSTIFIED	RIJD		17,494,117	(5,316,204)	7,264,188	15,546,132	17,494,116
PER UNIT PRES REV	RIJP		0.14115	(0.06737)	0.24995	0.97352	0.14115
REVENUE INCREASE REQUESTED	RIRD		17,494,336	0	(3,296,301)	20,790,637	17,494,336
PER UNIT PRES REV	RIRP		0.14115	0.00000	(0.11342)	1.30194	0.14115

ATTACHMENT STAFF-DR-02-002 COSS CLASS TOTALS
FR-10(9)v-CLASS TOTALS
WITNESS RESPONSIBLE:
DONALD L. STORCK

DUKE ENERGY KENTUCKY
COST OF SERVICE STUDY
TWELVE MONTHS ENDING JANUARY 31, 2011
GAS CASE NO: 2009-00202

	ITEM	ALLO	TOTAL GAS ALL CLASSES	COMMODITY	DEMAND	CUSTOMER	TOTAL AT ISSUE
GROSS GAS PLT IN SERVICE	Schedule 2						
PRODUCTION PLANT							
PRODUCTION PLANT	P100	KPROD	2,094,949	0	2,094,949	0	2,094,949
PRODUCTION PLANT IN SERVICE	P121		2,094,949	0	2,094,949	0	2,094,949
TRANSMISSION PLANT							
TRANSMISSION PLANT	T100						
TRANSMISSION PLANT IN SERVICE	T121		0	0	0	0	0
TOTAL PROD & TRANS PLANT	PT21		2,094,949	0	2,094,949	0	2,094,949
DISTRIBUTION PLANT							
SYSTEM M&R - (2780, 2781)	D100	KDIST_STR_D	4,272,913	0	4,272,913	0	4,272,913
DIST REG - 2782	D102	KDIST_STR_D	1,107,447	0	1,107,447	0	1,107,447
LARGE IND M&R - (2850, 2851)	D104	KDIST_LRGIND_D	504,476	0	504,476	0	504,476
MAINS - (2761, 2762, 2763, 2765, 2767, 2768) Dema	D106	KDIST_MA_D	196,666,446	0	196,666,446	0	196,666,446
MAINS - (2761, 2762, 2763, 2765, 2767, 2768) Cust	D107	KDIST_MA_C	34,705,843	0	0	34,705,843	34,705,843
SERVICES - (2801, 2802, 2803, 2804, 2805-2807)	D108	KSERV_CUS	101,262,272	0	0	101,262,272	101,262,272
MTRS & MTR INST (2810, 2811, 2820, 2821)	D110	KMTRS_CUS	21,006,025	0	0	21,006,025	21,006,025
LAND, R OF W STRUCT & IMPROV, OTH, SL	D112	KDIST_STR_D	1,126,490	0	1,126,490	0	1,126,490
HOUSE REG & INSTALL (2830-2831, 2840-2841)	D114	KMTRS_CUS	12,534,431	0	0	12,534,431	12,534,431
GAS DISTRIBUTION - COMPLETED NOT CLASS	D118	KDIST_MA_D	1,014,039	0	1,014,039	0	1,014,039
DISTRIBUTION PLANT IN SERVICE	D141		374,200,382	0	204,691,811	169,508,571	374,200,382
TOTAL TRANS & DIST PLANT	TD21		374,200,382	0	204,691,811	169,508,571	374,200,382
TOTAL GROSS PTD PLANT	PD21		376,295,331	0	206,786,760	169,508,571	376,295,331
GENERAL & INTANGIBLE PLANT							
PRODUCTION PLANT	G100	KA&G_PROD	142,219	0	142,219	0	142,219
PRODUCTION PLANT COMMODITY	G102	KA&G_PROD_C	175,243	175,243	0	0	175,243
DISTRIBUTION PLANT	G104	KA&G_DIST	1,869,166	(0)	1,067,947	801,219	1,869,166
CUSTOMER ACCOUNTING	G106	KA&G_CA	956,786	0	0	956,786	956,786
CUSTOMER SERVICE & INFORMATION	G108	KA&G_CS_INF	165,547	0	0	165,547	165,547
SALES	G110	KA&G_SALES	0	0	0	0	0
GEN & INTANG PLANT IN SERVICE	G121		3,308,961	175,243	1,210,166	1,923,552	3,308,961
COMMON & OTHER PLANT							
PRODUCTION PLANT	C100	KA&G_PROD	403,239	(0)	403,239	0	403,239
PRODUCTION PLANT COMMODITY	C102	KA&G_PROD_C	496,871	496,871	0	0	496,871
DISTRIBUTION PLANT	C104	KA&G_DIST	5,299,712	(0)	3,027,984	2,271,728	5,299,712
CUSTOMER ACCOUNTING	C106	KA&G_CA	2,712,809	0	0	2,712,809	2,712,809
CUSTOMER SERVICE & INFORMATION	C108	KA&G_CS_INF	469,382	0	0	469,382	469,382
SALES	C110	KA&G_SALES	0	0	0	0	0
COMMON & OTHER PLT IN SERVICE	C121		9,382,013	496,871	3,431,223	5,453,919	9,382,013
GROSS GAS PLT IN SERVICE	GP11		388,986,305	672,114	211,428,149	176,886,042	388,986,305

ATTACHMENT STAFF-DR-02-002 COSS CLASS TOTALS
FR-10(9)v-CLASS TOTALS
WITNESS RESPONSIBLE:
DONALD L. STORCK

DUKE ENERGY KENTUCKY
COST OF SERVICE STUDY
TWELVE MONTHS ENDING JANUARY 31, 2011
GAS CASE NO: 2009-00202

	ITEM	ALLO	TOTAL GAS ALL CLASSES	COMMODITY	DEMAND	CUSTOMER	TOTAL AT ISSUE
DEPRECIATION RESERVE	Schedule 3						
PRODUCTION PLANT							
PRODUCTION PLANT	P150	KPROD	1,215,841	0	1,215,841	0	1,215,841
TOTAL PROD DEPREC RESERVE	P171		1,215,841	0	1,215,841	0	1,215,841
TRANSMISSION PLANT							
TRANSMISSION PLANT	T168						
TOTAL TRANS DEPREC RESERVE	T171		0	0	0	0	0
DISTRIBUTION PLANT							
SYSTEM M&R - (2780, 2781)	D150	KDIST_STR_D	1,800,852	0	1,800,852	0	1,800,852
DIST REG - 2782	D152	KDIST_STR_D	564,368	0	564,368	0	564,368
LARGE IND M&R - (2850, 2851)	D154	KDIST_LRGIND_D	355,267	0	355,267	0	355,267
MAINS - (2761, 2762, 2763, 2765, 2767, 2768) Dema	D156	KDIST_MA_D	51,715,904	0	51,715,904	0	51,715,904
MAINS - (2761, 2762, 2763, 2765, 2767, 2768) Custc	D157	KDIST_MA_C	9,126,336	0	0	9,126,336	9,126,336
SERVICES - (2801, 2802, 2803, 2804, 2805-2807)	D158	KSERV_CUS	27,067,013	0	0	27,067,013	27,067,013
MTRS & MTR INST (2810, 2811, 2820, 2821)	D160	KMTRS_CUS	5,057,978	0	0	5,057,978	5,057,978
LAND, R OF W STRUCT & IMPROV, OTH, SL	D162	KDIST_STR_D	593,117	0	593,117	0	593,117
HOUSE REG & INSTALL (2830-2831, 2840-2841)	D164	KMTRS_CUS	2,373,116	0	0	2,373,116	2,373,116
GAS DISTRIBUTION - RWIP	D168	KGROS_DIST	(751,231)	0	(410,932)	(340,299)	(751,231)
TOTAL DIST DEPREC RESERVE	D191		97,902,720	0	54,618,576	43,284,144	97,902,720
GENERAL & INTANGIBLE PLANT							
PRODUCTION PLANT	G150	KA&G_PROD	69,755	(0)	69,755	0	69,755
PRODUCTION PLANT COMMODITY	G152	KA&G_PROD_C	85,952	85,952	0	0	85,952
DISTRIBUTION PLANT	G154	KA&G_DIST	900,951	0	514,758	386,193	900,951
CUSTOMER ACCOUNTING	G156	KA&G_CA	477,002	(0)	0	477,002	477,002
CUSTOMER SERVICE & INFORMATION	G158	KA&G_CS_INF	87,895	(0)	0	87,895	87,895
SALES	G160	KA&G_SALES	1,402	0	0	1,402	1,402
TOTAL GEN DEPREC RESERVE	G171		1,622,957	85,952	584,513	952,492	1,622,957
COMMON & OTHER PLANT							
PRODUCTION PLANT	C150	KA&G_PROD	347,680	(0)	347,680	0	347,680
PRODUCTION PLANT COMMODITY	C152	KA&G_PROD_C	294,113	294,113	0	0	294,113
DISTRIBUTION PLANT	C154	KA&G_DIST	3,121,226	(1)	1,783,310	1,337,917	3,121,226
CUSTOMER ACCOUNTING	C156	KA&G_CA	1,613,513	0	0	1,613,513	1,613,513
CUSTOMER SERVICE & INFORMATION	C158	KA&G_CS_INF	284,539	0	0	284,539	284,539
SALES	C160	KA&G_SALES	1,402	0	0	1,402	1,402
TOTAL COM & OTHER PLT RESERVE	C171		5,662,473	294,112	2,130,990	3,237,371	5,662,473
DEPRECIATION EXPENSE ANNUALIZATION ADJUSTMENT		KDEPREC_EXP	0	0	0	0	0
TOTAL DEPRECIATION RESERVE	DR11		106,403,991	380,064	58,549,920	47,474,007	106,403,991

DUKE ENERGY KENTUCKY
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ATTACHMENT STAFF-DR-02-002 COSS CLASS TOTALS
FR-10(9)v-CLASS TOTALS
WITNESS RESPONSIBLE:
DONALD L. STORCK

	ITEM	ALLO	TOTAL GAS ALL CLASSES	COMMODITY	DEMAND	CUSTOMER	TOTAL AT ISSUE
NET GAS PLANT	Schedule 4						
PRODUCTION PLANT							
PRODUCTION PLANT IN SERVICE	P121		2,094,949	0	2,094,949	0	2,094,949
TOTAL PROD DEPRC RESERVE	P171		(1,215,841)	0	(1,215,841)	0	(1,215,841)
NET PRODUCTION PLANT	P221		879,108	0	879,108	0	879,108
TRANSMISSION PLANT							
TRANSMISSION PLANT IN SERVICE	T121		0	0	0	0	0
TOTAL TRANS DEPREC RESERVE	T171		0	0	0	0	0
NET TRANSMISSION PLANT	T221		0	0	0	0	0
DISTRIBUTION PLANT							
DISTRIBUTION PLANT IN SERVICE	D141		374,200,382	0	204,691,811	169,508,571	374,200,382
TOTAL DIST DEPREC RESERVE	D191		(97,902,720)	0	(54,618,576)	(43,284,144)	(97,902,720)
NET DISTRIBUTION PLANT	D241		276,297,662	0	150,073,235	126,224,427	276,297,662
NET PTD PALNT	NT31		277,176,770	0	150,952,343	126,224,427	277,176,770
NET TRANS & DIST PLANT	NT21		276,297,662	0	150,073,235	126,224,427	276,297,662
GENERAL & INTANGIBLE PLANT							
GEN & INTANG PLANT IN SERVICE	G121		3,308,961	175,243	1,210,166	1,923,552	3,308,961
TOTAL GEN & INTG DEPREC RESERVE	G171		(1,622,957)	(85,952)	(584,513)	(952,492)	(1,622,957)
NET GENERAL & INTANG PLANT	G221		1,686,004	89,291	625,653	971,060	1,686,004
COMMON & OTHER PLANT							
COMMON & OTH PLT IN SERVICE	C121		9,382,013	496,871	3,431,223	5,453,919	9,382,013
TOTAL COM & OTH DEPREC RESERVE	C171		(5,662,473)	(294,112)	(2,130,990)	(3,237,371)	(5,662,473)
NET COMMON & OTHER PLANT	C221		3,719,540	202,759	1,300,233	2,216,548	3,719,540
NET GAS PLANT IN SERVICE	NP21		282,582,314	292,050	152,878,229	129,412,035	282,582,314

DUKE ENERGY KENTUCKY
COST OF SERVICE STUDY
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ATTACHMENT STAFF-DR-02-002 COSS CLASS TOTALS
FR-10(9)v-CLASS TOTALS
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DONALD L. STORCK

	ITEM	ALLO	TOTAL GAS ALL CLASSES	COMMODITY	DEMAND	CUSTOMER	TOTAL AT ISSUE
RATE BASE	Schedule 5						
RATE BASE ADJUSTMENTS							
SUBTRACTIVE ADJUSTMENTS							
ACCUM DEF INC TAXES (282)							
LIBERALIZED DEPRECIATION	B200	KNET_PLNT	42,242,421	43,728	22,853,384	19,345,309	42,242,421
OTHER - CIAC, CAP INT	B202	KNET_PLNT	1,566,332	1,621	847,394	717,317	1,566,332
TOTAL ACCOUNT 282	B221		43,808,753	45,349	23,700,778	20,062,626	43,808,753
ACCUM DEF INC TAXES (283)							
MISC DEFERRALS	B222	KA&G_CA	2,942,665	0	0	2,942,665	2,942,665
UNRECOVERED PURCHASED GAS COST	B224	KPROD_COM	295,400	295,400	0	0	295,400
TOTAL ACCOUNT 283	B243		3,238,065	295,400	0	2,942,665	3,238,065
OTHER SUBTRACTIVE ADJUSTMENTS							
CUSTOMER ADV FOR CONSTR (ACCT 252)	B244	KNET_PLNT	1,638,646	1,697	886,516	750,433	1,638,646
ITC (ACCT 255)	B246	KNET_PLNT	8,280	8	4,480	3,792	8,280
TOTAL OTHER SUBTRACTIVE ADJS	B285		1,646,926	1,705	890,996	754,225	1,646,926
TOTAL SUBTRACTIVE ADJUSTMENTS	B287		48,693,744	342,454	24,591,774	23,759,516	48,693,744
ADDITIVE ADJUSTMENTS							
ACCUM DEF INC TAXES (190)							
VAC PAY ACC, POST RET, PEN BEN, DEF COMP	V200	KA&G_FUNCT	12,828,932	679,427	4,691,796	7,457,709	12,828,932
TOTAL ACCOUNT 190	V221		12,828,932	679,427	4,691,796	7,457,709	12,828,932
OTHER							
OTHER	V233		0	0	0	0	0

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FR-10(9)v-CLASS TOTALS
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DONALD L. STORCK

	ITEM	ALLO	TOTAL GAS ALL CLASSES	COMMODITY	DEMAND	CUSTOMER	TOTAL AT ISSUE
RATE BASE	Schedule 5 2						
CONSTRUCTION WORK IN PROGRESS							
PRODUCTION - CWIP	V234	KGROS_PROD	0	0	0	0	0
DISTRIBUTION - CWIP	V236	KGROS_DIST	3,777,154	0	2,066,149	1,711,005	3,777,154
COMMON - CWIP (GAS)	V238	KGROS_COM	0	0	0	0	0
GENERAL - CWIP	V240	KGROS_GEN	0	0	0	0	0
TOTAL RATE BASE CWIP	V255		3,777,154	0	2,066,149	1,711,005	3,777,154
TOTAL ADDITIVE ADJUSTMENTS	V289		16,606,086	679,427	6,757,945	9,168,714	16,606,086
NET ORIGINAL COST RATE BASE	RB21		250,494,656	629,023	135,044,400	114,821,233	250,494,656
WORKING CAPITAL							
MATERIALS & SUPPLIES							
FUEL SUPPLIES							
TOTAL FUEL STOCKS	W641		0	0	0	0	0
PLANT MATERIALS & SUPPLIES							
GAS ENRICHER LIQUID	W642	KPROD	355,804	0	355,804	0	355,804
OTHER SUPPLIES	W644	KNET_PLNT	(95,694)	(100)	(51,771)	(43,823)	(95,694)
TOTAL PLANT MATS. & SUPPLIES	W659		260,110	(100)	304,033	(43,823)	260,110
TOTAL MATERIALS & SUPPLIES	W661		260,110	(100)	304,033	(43,823)	260,110
PREPAYMENTS							
KY. PSC MAINTENANCE TAX	W674	KFUNC_REV	0	0	0	0	0
TOTAL PREPAYMENTS	W687		0	0	0	0	0
CASH WORKING CAPITAL							
TOTAL GAS, PP & OTHER	W705		0	0	0	0	0
AUTO CALC (O&M-GAS COST)/8	W711		2,371,199	140,564	839,213	1,391,422	2,371,199
TOTAL WORKING CASH	W721		2,371,199	140,564	839,213	1,391,422	2,371,199
MISCELLANEOUS WORKING CAPITAL							
GAS STORED UNDERGROUND	W730	KPROD	0	0	0	0	0
TOTAL MISC WORK CAPITAL	W747		0	0	0	0	0
TOTAL WORKING CAPITAL	WC71		2,631,309	140,464	1,143,246	1,347,599	2,631,309
PRELIMINARY SUMMARY							
TOTAL SUBTRACTIVE ADJUSTMENTS	B287		(48,693,744)	(342,454)	(24,591,774)	(23,759,516)	(48,693,744)
TOTAL ADDITIVE ADJUSTMENTS	V289		16,606,086	679,427	6,757,945	9,168,714	16,606,086
TOTAL WORKING CAPITAL	WC71		2,631,309	140,464	1,143,246	1,347,599	2,631,309
TOTAL RATE BASE ADJUSTMENTS	RB71		(29,456,349)	477,437	(16,690,583)	(13,243,203)	(29,456,349)
RATE BASE CALCULATION							
NET GAS PLANT IN SERVICE	NP21		282,582,314	292,050	152,878,229	129,412,035	282,582,314
TOTAL RATE BASE ADJUSTMENTS	RB71		(29,456,349)	477,437	(16,690,583)	(13,243,203)	(29,456,349)
TOTAL RATE BASE	RB91		253,125,965	769,487	136,187,646	116,168,832	253,125,965
CAPITALIZATION ALLOC TO GAS OPER	GCAP	KRATE_BASE	253,750,235	770,560	136,523,506	116,456,169	253,750,235
TOTAL RATE OF RETURN ALLOWABLE	RORA		0.0767100000	0.0767100000	0.0767100000	0.0767100000	0.0767100000

DUKE ENERGY KENTUCKY
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ATTACHMENT STAFF-DR-02-002 COSS CLASS TOTALS
FR-10(9)v-CLASS TOTALS
WITNESS RESPONSIBLE:
DONALD L. STORCK

	ITEM	ALLO	TOTAL GAS ALL CLASSES	COMMODITY	DEMAND	CUSTOMER	TOTAL AT ISSUE
RETURN ON CAPITALIZATION	RC51		19,465,181	59,110	10,472,718	8,933,353	19,465,181

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DUKE ENERGY KENTUCKY
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	ITEM	ALLO	TOTAL GAS ALL CLASSES	COMMODITY	DEMAND	CUSTOMER	TOTAL AT ISSUE
	Schedule 6						
O&M EXPENSES							
PRODUCTION O&M							
COMMODITY RELATED O&M							
ANNUALIZED GAS COST - COMMODITY	P300	KPROD_COM	72,785,458	72,785,458	0	0	72,785,458
PURCHASED GAS & OTHER	P302	KPROD_COM	589,496	589,496	0	0	589,496
TOTAL ENERGY RELATED	P341		73,374,954	73,374,954	0	0	73,374,954
DEMAND RELATED PROD O&M							
ANNUALIZED GAS COST - DEMAND	P352	KPROD	6,153,909	(0)	6,153,909	0	6,153,909
TOTAL DEMAND RELATED	P391		6,153,909	(0)	6,153,909	0	6,153,909
OTHER THAN COM/DEM RELATED							
PRODUCTION EXPENSES	P400	KPROD	350,697	0	350,697	0	350,697
ELIM OTHER THAN ULH&P PORTION	P402	KPROD	(32,821)	0	(32,821)	0	(32,821)
TOTAL PROD OTHER THAN COM/DEM	P441		317,876	0	317,876	0	317,876
TOTAL PRODUCTION O&M	P451		79,846,739	73,374,954	6,471,785	0	79,846,739
TRANSMISSION O & M							
TRANSMISSION O & M	T318						
TOTAL TRANSMISSION O & M	T341		0	0	0	0	0
DISTRIBUTION O & M							
LOAD DISPATCH, RENTS	D300	KNET_PLNT_DIST	494,675	0	311,691	182,984	494,675
MAINS & SERVICES OPER	D302	KDIST_MA_D	1,643,396	0	1,643,396	0	1,643,396
M & R STATION	D304	KDIST_STR_D	87,270	0	87,270	0	87,270
CUSTOMER INST & OTHER	D306	KMTRS_CUS	1,439,732	0	0	1,439,732	1,439,732
METERS & HOUSE REG	D308	KMTRS_CUS	192,641	0	0	192,641	192,641
MAINS	Dema D310	KDIST_MA_D	837,340	0	837,340	0	837,340
MAINS	Custo D311	KDIST_MA_C	147,766	0	0	147,766	147,766
SERVICES	D312	KSERV_CUS	708,338	0	0	708,338	708,338
SUPV, ENG & OTHER	D314	KNET_PLNT_DIST	153,640	0	83,450	70,190	153,640
M & R, INDUSTRIAL	D316	KDIST_LRGIND_D	236,847	0	236,847	0	236,847
ELIM OTHER THAN ULH&P PORTION	D318	KNET_PLNT_DIST	(239,604)	0	(130,185)	(109,419)	(239,604)
TOTAL DISTRIBUTION O & M	D341		5,702,041	0	3,069,809	2,632,232	5,702,041
CUSTOMER ACCOUNTING							
TOT CUST ACCT EXP EXCLUD UNCOLL EXP	C300	KCUST_ACCTG	2,714,400	0	0	2,714,400	2,714,400
UNCOLLECTIBLE EXP	C302	KFUNC_REV	1,403,255	876,522	310,109	216,624	1,403,255
ANNUALIZED UNCOLL EXP ADJ	C304	KFUNC_REV	(1,280,335)	(799,742)	(282,945)	(197,648)	(1,280,335)
UNCOLLECTIBLES ON INCREASE		KFUNC_REV	47,758	29,832	10,554	7,372	47,758
TOTAL CUSTOMER ACCT EXPENSE	C317		2,885,078	106,612	37,718	2,740,748	2,885,078

DUKE ENERGY KENTUCKY
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ATTACHMENT STAFF-DR-02-002 COSS CLASS TOTALS
FR-10(9)v-CLASS TOTALS
WITNESS RESPONSIBLE:
DONALD L. STORCK

	ITEM	ALLO	TOTAL GAS ALL CLASSES	COMMODITY	DEMAND	CUSTOMER	TOTAL AT ISSUE
O&M EXPENSES	Schedule 6 2						
CUSTOMER SERVICE & INFORMATION							
TOTAL CUST SERVICE & INFO	C320	KCUST_INFO	532,529	0	0	532,529	532,529
ELIMIN OTHER THAN ULH&P PORTION	C322	KCUST_INFO	(855)	0	0	(855)	(855)
TOTAL CUSTOMER SERV. & INFO.	C331		531,674	0	0	531,674	531,674
SALES							
SALES EXPENSE	S300	KCUST_SALES	0	0	0	0	0
ELIMINATION OF EXPENSE	S302	KCUST_SALES	0	0	0	0	0
TOTAL SALES EXPENSE	S317		0	0	0	0	0
ADMINISTRATIVE & GENERAL							
ADMINISTRATIVE & GENERAL							
PRODUCTION PLANT	A300	KA&G_PROD	423,843	0	423,843	0	423,843
PRODUCTION PLANT COMMODITY	A302	KA&G_PROD_C	522,260	522,260	0	0	522,260
DISTRIBUTION PLANT	A304	KA&G_DIST	5,570,510	(1)	3,182,706	2,387,805	5,570,510
CUSTOMER ACCOUNTING	A306	KA&G_CA	2,851,425	0	0	2,851,425	2,851,425
CUSTOMER SERVICE & INFORMATION	A308	KA&G_CS_INF	493,366	0	0	493,366	493,366
SALES	A310	KA&G_SALES	0	0	0	0	0
TOT ADMIN & GEN LESS REG EXP	A312		9,861,405	522,260	3,606,549	5,732,596	9,861,405
RATE CASE EXPENSE	A314	KA&G_FUNCT	86,667	4,590	31,695	50,382	86,667
ELIMINATE VARIOUS EXPENSES	A316	KA&G_FUNCT	(2,139)	(114)	(781)	(1,244)	(2,139)
INCENTIVE COMPENSATION	A318	KA&G_FUNCT	(616,501)	(32,651)	(225,466)	(358,384)	(616,501)
ANNUALIZE KYPSC MAINT TAX	A319	KA&G_FUNCT	(48,067)	(2,545)	(17,579)	(27,943)	(48,067)
ELIM MERGER CREDITS & AMORT	A320	KA&G_FUNCT	(290,184)	(15,368)	(106,126)	(168,690)	(290,184)
TOTAL ADMIN. & GENERAL	A337		8,991,181	476,172	3,288,292	5,226,717	8,991,181
TOTAL O & M EXPENSE	OM31		97,956,713	73,957,738	12,867,604	11,131,371	97,956,713

DUKE ENERGY KENTUCKY
COST OF SERVICE STUDY
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ATTACHMENT STAFF-DR-02-002 COSS CLASS TOTALS
FR-10(9)v-CLASS TOTALS
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DONALD L. STORCK

	ITEM	ALLO	TOTAL GAS ALL CLASSES	COMMODITY	DEMAND	CUSTOMER	TOTAL AT ISSUE
DEPRECIATION EXPENSE	Schedule 7						
PRODUCTION DEPRECIATION							
PRODUCTION DEPRECIATION	P460	KNET_PLNT_PROI	41,775	0	41,775	0	41,775
TOTAL PRODUCTION DEPREC EXP.	P481		41,775	0	41,775	0	41,775
TRANSMISSION DEPRECIATION			0	0	0	0	0
TOTAL TRANSMISSION DEP. EXP.	T481		0	0	0	0	0
DISTRIBUTION DEPRECIATION							
DISTRIBUTION DEPRECIATION	D460	KNET_PLNT_DIST	8,621,123	0	4,682,586	3,938,537	8,621,123
DISTRIBUTION DEPRECIATION EXP ADJ	D462	KNET_PLNT_DIST	2,061,951	0	1,119,955	941,996	2,061,951
TOTAL DIST. DEPREC EXP.	D481		10,683,074	0	5,802,541	4,880,533	10,683,074
GENERAL DEPRECIATION							
GENERAL DEPRECIATION	G460	KNET_PLNT_GEN	158,383	8,388	58,774	91,221	158,383
GENERAL DEPRECIATION EXP ADJ	G476	KNET_PLNT_GEN	0	0	0	0	0
TOTAL GENERAL DEPREC EXP.	G481		158,383	8,388	58,774	91,221	158,383
COMMON AND OTHER DEPRECIATION							
COMMON DEPRECIATION	C460	KNET_PLNT_COM	774,595	42,224	270,773	461,598	774,595
COMMON DEPRECIATION EXP ADJ	C476	KNET_PLNT_COM	0	0	0	0	0
TOTAL COM & OTHER DEPREC EXP.	C481		774,595	42,224	270,773	461,598	774,595
TOTAL DEPRECIATION EXPENSE	DE41		11,657,827	50,612	6,173,863	5,433,352	11,657,827

DUKE ENERGY KENTUCKY
COST OF SERVICE STUDY
TWELVE MONTHS ENDING JANUARY 31, 2011
GAS CASE NO: 2009-00202

ATTACHMENT STAFF-DR-02-002 COSS CLASS TOTALS
FR-10(9)v-CLASS TOTALS
WITNESS RESPONSIBLE:
DONALD L. STORCK

	ITEM	ALLO	TOTAL GAS ALL CLASSES	COMMODITY	DEMAND	CUSTOMER	TOTAL AT ISSUE
OTHER TAXES & MISC EXPENSES	Schedule 8						
TAXES OTHER THAN INC & REV							
REAL ESTATE & PROPERTY TAX							
REAL ESTATE & PROPERTY TAX	L500	KNET_PLNT	4,390,640	4,545	2,375,362	2,010,733	4,390,640
ANNUALIZE PROPERTY TAX	L502	KNET_PLNT	(894,566)	(926)	(483,965)	(409,675)	(894,566)
TOTAL REAL EST & PROP TAX	L521		3,496,074	3,619	1,891,397	1,601,058	3,496,074
MISCELLANEOUS TAXES							
PAYROLL & HIGHWAY	L560	KA&G_FUNCT	637,163	33,745	233,022	370,396	637,163
ANNUALIZED PAYROLL TAXES	L562	KA&G_FUNCT	(4,440)	(235)	(1,624)	(2,581)	(4,440)
KYPSC MAINTENANCE ADJ	L564	KFUNC_REV	(67,616)	(43,048)	(15,856)	(8,712)	(67,616)
TOTAL MISCELLANEOUS TAXES	L581		565,107	(9,538)	215,542	359,103	565,107
MISCELLANEOUS EXPENSES							
KYPSC ON INCREASE	L560	KFUNC_REV	27,991	17,821	6,564	3,606	27,991
TOTAL MISCELLANEOUS EXPENSES	L581		27,991	17,821	6,564	3,606	27,991
TOTAL OTHER TAX & MISC EXPENSE			4,089,172	11,902	2,113,503	1,963,767	4,089,172
PRELIMINARY SUMMARY							
TOTAL O&M EXPENSE	OM31		97,956,713	73,957,738	12,867,604	11,131,371	97,956,713
TOTAL DEPRECIATION EXPENSE	DE41		11,657,827	50,612	6,173,863	5,433,352	11,657,827
TOTAL OTHER TAX & MISC EXPENSE	L591		4,089,172	11,902	2,113,503	1,963,767	4,089,172
TOTAL OP EXP EXC IT & REV TAX	OP61		113,703,712	74,020,252	21,154,970	18,528,490	113,703,712

ATTACHMENT STAFF-DR-02-002 COSS CLASS TOTALS
FR-10(9)v-CLASS TOTALS
WITNESS RESPONSIBLE:
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DUKE ENERGY KENTUCKY
COST OF SERVICE STUDY
TWELVE MONTHS ENDING JANUARY 31, 2011
GAS CASE NO: 2009-00202

	ITEM	ALLO	TOTAL GAS ALL CLASSES	COMMODITY	DEMAND	CUSTOMER	TOTAL AT ISSUE
INCOME TAX BASED ON RETURN	Schedule 9						
FEDERAL INCOME TAX DEDUCTIONS							
AUTOMATIC INTEREST CALCULATION							
AUTO PROC INTEREST DED	Y751	KRATE_BASE	4,388,840	13,328	2,361,297	2,014,215	4,388,840
TOTAL INTEREST EXPENSE	Y783		4,388,840	13,328	2,361,297	2,014,215	4,388,840
OTHER DEDUCTIONS							
DEPREC EXCESS TAX-BOOK	Y790	KDEPREC_EXP	5,349,903	23,245	2,833,240	2,493,418	5,349,903
AMORT OF LOSS ON REACQUIRED DEBT	Y792	KNET_PLNT	(122,590)	(127)	(66,322)	(56,141)	(122,590)
DEFERRED FUEL COST - PGA	Y794	KPROD_COM	68,552	68,552	0	0	68,552
ADJUSTMENT FOR NON JURISDICTIONAL ACCT	Y796	KNET_PLNT	(1,311,530)	(1,358)	(709,545)	(600,627)	(1,311,530)
TOTAL OTHER DEDUCTIONS	Y823		3,984,335	90,312	2,057,373	1,836,650	3,984,335
NET DEDUCTIONS AND ADDITIONS	Y871		8,373,175	103,640	4,418,670	3,850,865	8,373,175
FEDERAL INCOME TAX ADJUSTMENTS							
FED PROV DEF INC TAX (410.1)							
LIB DEPRECIATION	Z750	KDEPREC_EXP	1,277,249	5,549	676,415	595,285	1,277,249
AMORT OF LOSS ON REACQUIRED DEBT	Z752	KNET_PLNT	0	0	0	0	0
DEFERRED FUEL COST - PGA	Z754	KPROD_COM	0	0	0	0	0
TOTAL FED PROV DEF IT (410.1)	Z781		1,277,249	5,549	676,415	595,285	1,277,249

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ATTACHMENT STAFF-DR-02-002 COSS CLASS TOTALS
FR-10(9)v-CLASS TOTALS
WITNESS RESPONSIBLE:
DONALD L. STORCK

	ITEM	ALLO	TOTAL GAS ALL CLASSES	COMMODITY	DEMAND	CUSTOMER	TOTAL AT ISSUE
INCOME TAX BASED ON RETURN	Schedule 9 2						
FED PROV DEF INC TAX (411.1)							
TOTAL FED PROV DEF IT (411.1)	Z811		0	0	0	0	0
AMORT INV TAX CREDIT & SERV CO. ALLOC TAX CR.		KNET_PLNT	72,657	75	39,308	33,274	72,657
TOTAL AMORTIZED ITC & SERV CO ALLOC	Z815		72,657	75	39,308	33,274	72,657
TEST YEAR INV TAX CREDIT							
TEST YEAR INV TAX CREDIT	Z823		0	0	0	0	0
PRELIMINARY SUMMARY							
TOTAL FED PROV DEF IT (410.1)	Z781		1,277,249	5,549	676,415	595,285	1,277,249
TOTAL FED PROV DEF IT (411.1)	Z811		0	0	0	0	0
TOTAL AMORTIZED ITC & ALLOC SERV CO CR	Z815		(72,657)	(75)	(39,308)	(33,274)	(72,657)
TOTAL FEDERAL TAX ADJUSTMENTS	Z863		1,204,592	5,474	637,107	562,011	1,204,592
FEDERAL INCOME TAX COMPUTATION							
RETURN ON CAPITALIZATION	RC51		19,465,181	59,110	10,472,718	8,933,353	19,465,181
NET DEDUCTIONS AND ADDITIONS	Y871		(8,373,175)	(103,640)	(4,418,670)	(3,850,865)	(8,373,175)
TOTAL FEDERAL TAX ADJUSTMENTS	Z863		1,204,592	5,474	637,107	562,011	1,204,592
TOTAL STATE PROV DEF IT (410.1 & 411.1)	Z911		331,863	1,442	175,751	154,670	331,863
AFUDC OFFSET	Z933		(289,745)	0	(158,493)	(131,252)	(289,745)
BASE FOR FIT COMPUATION	I865		12,338,716	(37,614)	6,708,413	5,667,917	12,338,716
FIT FACTOR K190/(1-K190)	I867		0.53846	0.53846	0.53846	0.53846	0.53846
PRELIM FED INCOME TAX	I869		6,643,924	(20,254)	3,612,222	3,051,955	6,643,923
TOTAL FEDERAL TAX ADJUSTMENTS	Z863		1,204,592	5,474	637,107	562,011	1,204,592
NET FED INCOME TAX ALLOWABLE	I879		7,848,516	(14,780)	4,249,329	3,613,966	7,848,515

DUKE ENERGY KENTUCKY
COST OF SERVICE STUDY
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ATTACHMENT STAFF-DR-02-002 COSS CLASS TOTALS
FR-10(9)v-CLASS TOTALS
WITNESS RESPONSIBLE:
DONALD L. STORCK

	ITEM	ALLO	TOTAL GAS ALL CLASSES	COMMODITY	DEMAND	CUSTOMER	TOTAL AT ISSUE
INCOME TAX BASED ON RETURN	Schedule 9 3						
FEDERAL INCOME TAX PAYABLE							
PRELIM FEDERAL INCOME TAX	I869		6,643,924	(20,254)	3,612,222	3,051,955	6,643,923
TEST YEAR INV TAX CREDIT	Z823		0	0	0	0	0
NET FED INCOME TAX PAYABLE	I889		6,643,924	(20,254)	3,612,222	3,051,955	6,643,923
STATE INCOME TAX							
KY TAXABLE INCOME ADJUSTMENT		KNET_PLNT	1,499,627	1,551	820,210	677,866	1,499,627
DEDUCTIONS IN ADD TO Y871	Y911		1,499,627	1,551	820,210	677,866	1,499,627
STATE INCOME TAX ADJUSTMENTS							
STATE PROV DEF INC TAX (410.1)							
LIB DEPRECIATION	Z890	KDEPREC_EXP	331,863	1,442	175,751	154,670	331,863
AMORT OF LOSS ON REACQUIRED DEBT	Z892	KNET_PLNT	0	0	0	0	0
DEFERRED FUEL COST - PGA	Z896	KPROD_COM	0	0	0	0	0
TOT STATE PROV DEF IT (410.1)	Z915		331,863	1,442	175,751	154,670	331,863
STATE PROV DEF INC TAX (411.1)							
TOT STATE PROV DEF IT (411.1)	Z939		0	0	0	0	0
OTHER SIT ADJUSTMENTS							
OTHER SIT ADJUSMENTS	Z941		0	0	0	0	0
TOTAL STATE INC TAX ADJUSTMENT	Z951		331,863	1,442	175,751	154,670	331,863

DUKE ENERGY KENTUCKY
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FR-10(9)v-CLASS TOTALS
WITNESS RESPONSIBLE:
DONALD L. STORCK

	ITEM	ALLO	TOTAL GAS ALL CLASSES	COMMODITY	DEMAND	CUSTOMER	TOTAL AT ISSUE
INCOME TAX BASED ON RETURN	Schedule 9 4						
SUMMARY OF SIT CALCULATION							
RETURN ON CAPITALIZATION	RC51		19,465,181	59,110	10,472,718	8,933,353	19,465,181
NET FED INCOME TAX ALLOWABLE	I879		7,848,516	(14,780)	4,249,329	3,613,966	7,848,515
NET FED. AND STATE DED. AND ADDITIONS	Y871		(9,872,802)	(105,191)	(5,238,880)	(4,528,731)	(9,872,802)
AFUDC OFFSET	Y911		(289,745)	0	(158,493)	(131,252)	(289,745)
TOTAL STATE INC TAX ADJ	Z957		331,863	1,442	175,751	154,670	331,863
BASE FOR SIT COMPUTATION	J965		17,483,013	(59,419)	9,500,425	8,042,006	17,483,012
SIT FACTOR K192/(1-K192)	J967		0.063830	0.063830	0.063830	0.063830	0.063830
PRELIMINARY STATE INCOME TAX	J969		1,115,937	(3,793)	606,410	513,320	1,115,937
TOTAL STATE INCOME TAX ADJ.	Z957		331,863	1,442	175,751	154,670	331,863
NET STATE INC TAX EXP ALLOWABLE	J979		1,447,800	(2,351)	782,161	667,990	1,447,800
STATE INCOME TAX PAYABLE							
PRELIMINARY STATE INCOME TAX	J969		1,115,937	(3,793)	606,410	513,320	1,115,937
OTHER SIT ADJUSTMENTS	Z955		0	0	0	0	0
NET STATE INCOME TAX PAYABLE	J989		1,115,937	(3,793)	606,410	513,320	1,115,937
COMPOSITE TAX RATE	CTAX		0.38900	0.38900	0.38900	0.38900	0.38900

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ATTACHMENT STAFF-DR-02-002 COSS CLASS TOTALS
FR-10(9)v-CLASS TOTALS
WITNESS RESPONSIBLE:
DONALD L. STORCK

	ITEM	ALLO	TOTAL GAS ALL CLASSES	COMMODITY	DEMAND	CUSTOMER	TOTAL AT ISSUE
COST OF SERVICE COMPUTATION	Schedule 10						
OTHER OPERATING REVENUES							
LATE PAYMENT CHARGES	Q000	KFUNC_REV	43,376	27,615	10,172	5,589	43,376
MISC SERVICE REVENUE	Q002	KFUNC_REV	0	0	0	0	0
BAD CHECK & RECONNCTION CHARGES	Q004	KFUNC_REV	35,832	22,427	7,930	5,475	35,832
OTHER MISC REV	Q006	KFUNC_REV	29,844	18,680	6,604	4,560	29,844
REVENUE TRANSP OF GAS ASSOC COS	Q008	KFUNC_REV	600,696	382,436	140,861	77,399	600,696
INTERDEPARTMENTAL	Q024	KFUNC_REV	34,176	21,758	8,014	4,404	34,176
TOTAL OTHER OPERATING REVS	Q027		743,924	472,916	173,581	97,427	743,924
COST OF SERVICE COMPUTATION							
TOTAL OP EXP EXC INC & REV TAX	OP61		113,703,712	74,020,252	21,154,970	18,528,490	113,703,712
RETURN ON CAPITALIZATION	RC51		19,465,181	59,110	10,472,718	8,933,353	19,465,181
NET FED INCOME TAX ALLOWABLE	I879		7,848,516	(14,780)	4,249,329	3,613,966	7,848,515
NET STATE INCOME TAX ALLOWABLE	J979		1,447,800	(2,351)	782,161	667,990	1,447,800
TOTAL OTHER OPERATING REVENUES	Q027		(743,924)	(472,916)	(173,581)	(97,427)	(743,924)
SUBTOTAL B	CS03		141,721,285	73,589,315	36,485,597	31,646,372	141,721,284
TOTAL OTHER OPERATING REVENUES	Q027		743,924	472,916	173,581	97,427	743,924
LESS: REVS EXCL FROM REV TAX CALC	REXC		0	0	0	0	0
OTHER OPERATING REVS TO BE TAXED	OORT		743,924	472,916	173,581	97,427	743,924
REVENUE TAX FACTOR	L030		0.00000	0.00000	0.00000	0.00000	0.00000
REVENUE TAX ON OTHER OPER. REVS	L031		0	0	0	0	0
AFUDC OFFSET	L032		(289,745)	0	(158,493)	(131,252)	(289,745)
OTHER DEDUCTION COST TO SERVICE	L033		(289,745)	0	(158,493)	(131,252)	(289,745)
TOTAL GAS COST OF SERVICE	CS05		141,431,540	73,589,315	36,327,104	31,515,120	141,431,539
PROPOSED REVENUES	R602		141,431,759	78,905,519	25,766,615	36,759,625	141,431,759
TOTAL GAS COST OF SERVICE	CS05		(141,431,540)	(73,589,315)	(36,327,104)	(31,515,120)	(141,431,539)
EXCESS REVENUES	XREV		219	5,316,204	(10,560,489)	5,244,505	220
COMPOSITE TAX RATE	CTAX		0.38900	0.38900	0.38900	0.38900	0.38900
EXCESS TAX	XTAX		85	2,068,002	(4,108,030)	2,040,113	85
EXCESS RETURN	XRET		135	3,248,202	(6,452,459)	3,204,394	137

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FR-10(9)v-CLASS TOTALS
WITNESS RESPONSIBLE:
DONALD L. STORCK

	ITEM	ALLO	TOTAL GAS ALL CLASSES	COMMODITY	DEMAND	CUSTOMER	TOTAL AT ISSUE
ROR, TAX RATES & SPEC FACTORS	Schedule 11						
RATE OF RETURN							
CAPITALIZATION AMOUNTS				RATIO	RATIO	RATIO	RATIO
LONG TERM DEBT	K100		367,408,791	0.4459	0.4459	0.4459	0.4459
PREFERRED STOCK	K102		0	0.0000	0.0000	0.0000	0.0000
COMMON STOCK	K104		411,218,278	0.49901	0.4990	0.4990	0.4990
SHORT TERM DEBT	K106		45,441,090	0.05514	0.0551	0.0551	0.0551
UNAMORTIZED DISCOUNT	K108		0	0.0000	0.0000	0.0000	0.0000
TOTAL	K115		824,068,159	1.0000	1.0000	1.0000	1.0000
COST OF CAPITAL							
LONG TERM DEBT	K120		0.04657	0.04657	0.04657	0.04657	0.04657
PREFERRED STOCK	K122		0.00000	0.00000	0.00000	0.00000	0.00000
COMMON STOCK	K124		0.11000	0.11000	0.11000	0.11000	0.11000
SHORT TERM DEBT	K126		0.01928	0.01928	0.01928	0.01928	0.01928
UNAMORTIZED DISCOUNT	K128		0.00000	0.00000	0.00000	0.00000	0.00000
WEIGHTED COST OF CAPITAL							
LONG TERM DEBT	K141		0.02076	0.02076	0.02076	0.02076	0.02076
PREFERRED STOCK	K143		0.00000	0.00000	0.00000	0.00000	0.00000
COMMON STOCK	K145		0.05488	0.05488	0.05488	0.05488	0.05488
SHORT TERM DEBT	K147		0.00106	0.00106	0.00106	0.00106	0.00106
UNAMORTIZED DISCOUNT	K149		0.00000	0.00000	0.00000	0.00000	0.00000
TOT RATE OF RETURN ALLOWABLE	HARI	RORA	0.076710	0.07671	0.07671	0.07671	0.07671
TAX RATES AND SPECIAL FACTORS							
SHORT TERM DEBT COST	K180		0.00000	0.00000	0.00000	0.00000	0.00000
FEDERAL INCOME TAX RATE	K190		0.35000	0.35000	0.35000	0.35000	0.35000
STATE INCOME TAX RATE	K192		0.06000	0.06000	0.06000	0.06000	0.06000
REVENUE TAX RATE	K196		0.00000	0.00000	0.00000	0.00000	0.00000

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	ITEM	ALLO	TOTAL GAS ALL CLASSES	COMMODITY	DEMAND	CUSTOMER	TOTAL AT ISSUE
INCOME TAX BASED ON REVENUES	Schedule 12						
NET INCOME COMPUTATION							
TOTAL GAS COST OF SERVICE	CS05		141,431,540	73,589,315	36,327,104	31,515,120	141,431,539
TOTAL OTHER OPERATING REVENUES	Q027		743,924	472,916	173,581	97,427	743,924
TOTAL GAS REVENUE	CS07		142,175,464	74,062,231	36,500,685	31,612,547	142,175,463
TOTAL OP EXP EX INC & REV TAX	OP61		(113,703,712)	(74,020,252)	(21,154,970)	(18,528,490)	(113,703,712)
FIRM SERVICE REVENUE TAX	RTXP		0	0	0	0	0
NET INCOME	NI01		28,471,752	41,979	15,345,715	13,084,057	28,471,751
ADJUSTMENTS TO NET INCOME							
TOTAL INTEREST EXPENSE	Y783		(4,388,840)	(13,328)	(2,361,297)	(2,014,215)	(4,388,840)
TOTAL OTHER DEDUCTIONS	Y823		(3,984,335)	(90,312)	(2,057,373)	(1,836,650)	(3,984,335)
PRELIMINARY TAXABLE INCOME	TI01		20,098,577	(61,661)	10,927,045	9,233,192	20,098,576
STATE INCOME TAX COMPUTATION							
PRELIMINARY TAX ABLE INCOME (INCL AFUDC)	TI01		20,098,577	(61,661)	10,927,045	9,233,192	20,098,576
DEDUCTIONS IN ADD TO Y871	Y911		(1,499,627)	(1,551)	(820,210)	(677,866)	(1,499,627)
STATE TAXABLE INCOME	SI01		18,598,950	(63,212)	10,106,835	8,555,326	18,598,949
STATE INCOME TAX PAYABLE							
STATE INCOME TAX RATE	K192		0.06000	0.06000	0.06000	0.06000	0.06000
PRELIM SIT = SI01 * K192	ST01		1,115,937	(3,793)	606,410	513,320	1,115,937
OTHER SIT ADJUSTMENTS	Z955		0	0	0	0	0
STATE INCOME TAX PAYABLE	SP01		1,115,937	(3,793)	606,410	513,320	1,115,937
SIT ALLOWABLE							
STATE INCOME TAX PAYABLE	SP01		1,115,937	(3,793)	606,410	513,320	1,115,937
TOTAL STATE PROV DEF IT(410.1)	Z911		331,863	1,442	175,751	154,670	331,863
TOTAL STATE PROV DEF IT(411.1)	Z933		0	0	0	0	0
NET STATE INC TAX ALLOWABLE	SA01		1,447,800	(2,351)	782,161	667,990	1,447,800

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WITNESS RESPONSIBLE:
DONALD L. STORCK

	ITEM	ALLO	TOTAL GAS ALL CLASSES	COMMODITY	DEMAND	CUSTOMER	TOTAL AT ISSUE
INCOME TAX BASED ON REVENUES	Schedule 12 2						
FEDERAL INCOME TAX COMPUTATION							
PRELIMINARY TAXABLE INCOME (INCL AFUDC)	TI01		20,098,577	(61,661)	10,927,045	9,233,192	20,098,576
STATE INC TAX PAYABLE	SP01		(1,115,937)	3,793	(606,410)	(513,320)	(1,115,937)
NET FEDERAL TAXABLE INCOME	FI01		18,982,640	(57,868)	10,320,635	8,719,872	18,982,639
FEDERAL INCOME TAX RATE	K190		0.35000	0.35000	0.35000	0.35000	0.35000
PRELIMINARY FIT = FI01 * K190	FT01		6,643,924	(20,253)	3,612,222	3,051,955	6,643,924
TOTAL FED PROV DEF IT (410.1)	Z781		1,277,249	5,549	676,415	595,285	1,277,249
TOTAL FED PROV DEF IT (411.1)	Z803		0	0	0	0	0
TOTAL AMORTIZED ITC & SERV CO ALLOC CR	Z813		(72,657)	(75)	(39,308)	(33,274)	(72,657)
NET FED INC TAX ALLOWABLE	FA01		7,848,516	(14,779)	4,249,329	3,613,966	7,848,516
FEDERAL INCOME TAX PAYABLE							
PRELIM FIT	FT01		6,643,924	(20,253)	3,612,222	3,051,955	6,643,924
TEST YEAR INV TAX CREDIT	Z823		0	0	0	0	0
FED INC TAX PAYABLE	FP01		6,643,924	(20,253)	3,612,222	3,051,955	6,643,924
PRELIMINARY SUMMARY							
NET INCOME (EXCL AFUDC OFFSET)	NI01		28,761,497	41,979	15,504,208	13,215,309	28,761,496
NET FED INC TAX ALLOWABLE	FA01		(7,848,516)	14,779	(4,249,329)	(3,613,966)	(7,848,516)
NET STATE INC TAX ALLOWABLE	SA01		(1,447,800)	2,351	(782,161)	(667,990)	(1,447,800)
OVERALL RETURN EARNED-SCH 12	RETU		19,465,181	59,109	10,472,718	8,933,353	19,465,180
RATE OF RETURN EARNED-SCH 12	RORX		0.07671	0.07671	0.07671	0.07671	0.07671

STAFF-DR-02-003

REQUEST:

Refer to Volume V, Tab C, Schedule C-2.1.

a. Refer to page 1 of 16. Line 3, Gas Cost Revenue, and Line 15, Purchased Gas, are both shown as $78,939,367. The amount for Other Gas Supply Expenses, Line 16, is $589,496. Describe the nature of this account and state whether any of the amounts recorded therein would have been recovered through Duke Kentucky's gas cost adjustment ("GCA").

b. Refer to page 2 of 16.

   (1) Although Duke Kentucky's tariff lists a late payment charge, Account 487001, Late Payment Charges, has a zero balance. Explain whether or not Duke Kentucky currently charges a late payment penalty.

   (2) Provide the detail of Account 496017, Provision for Rate Refunds.

c. Refer to page 13 of 16. Provide work papers supporting the $1,403,255 balance in Account 904000, Uncollectible Accounts.

RESPONSE:

a. Other Gas Supply Expense includes expenses incurred directly in connection with the purchase of gas for resale. This expense would include operation and maintenance of gas measuring stations, operation and maintenance of odorization equipment, supervisory, administrative and clerical personnel directly engaged in the calculation and checking of purchased natural gas deliveries and cost, supervisory, administrative, and clerical personnel indirectly involved in matters relating to purchased natural gas operations, and customer transportation charges for Kentucky volumes moved through the Duke Energy Ohio system. These expenses are not recovered through Duke Kentucky's GCA.

b.

   (1) Under the Cinergy Accounts Receivable Purchase and Sales Agreement, Duke Energy Kentucky ("DEK") does not retain the right to keep revenues received from customers due to late payments. DEK has transferred that right to the purchaser of the receivables. Since DEK has passed the risk of late payment to the purchaser of its accounts receivables, it is appropriate that the purchaser receive the late payment revenues.

(2) The provision for rate refunds represents the revenues billed through the AMRP rider from the inception of the rider until the rider was declared invalid by the Kentucky Circuit Court in 2005. The Company reserved these amounts in December 2008 subsequent to the Kentucky Circuit Court's November 7, 2008 decision. The Company has appealed this decision.

Year	Amount
2002	$214,477
2003	$1,420,358
2004	$3,431,314
Through June 19, 2005	$2,451,479
Total	$7,517,628

c. See Attachment Staff-DR-02-003(c).

PERSON RESPONSIBLE: Robert M. Parsons

Duke Energy Kentucky, Inc.
Account 904 - Uncollectible Accounts

Line No.	Description	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Forecasted Period
1	Monthly Sales Data	45,749,067	46,631,046	33,210,112	33,991,643	36,503,606	42,933,229	42,337,760	37,708,213	41,403,608	47,661,586	59,547,523	59,768,509	527,445,902
2	Late Charges	(323,174)	(330,736)	(224,464)	(225,973)	(238,540)	(280,521)	(276,677)	(251,212)	(286,434)	(341,510)	(429,879)	(429,960)	(3,639,080)
3	Adjusted Total	45,425,893	46,300,310	32,985,648	33,765,670	36,265,066	42,652,708	42,061,083	37,457,001	41,117,174	47,320,076	59,117,644	59,338,549	523,806,822
4	Discount on receivables sold	1.19%	1.19%	1.19%	1.19%	1.19%	1.19%	1.19%	1.19%	1.19%	1.19%	1.19%	1.19%	
5	Loss on Sale of AR (Line 3 * Line 4)	$540,568	$550,974	$392,529	$401,811	$431,554	$507,567	$500,527	$445,738	$489,294	$563,109	$703,500	$706,129	$6,233,301
6	Collection Agent Revenue	($22,713)	($23,150)	($16,493)	($16,883)	($18,133)	($21,326)	($21,031)	($18,729)	($20,559)	($23,660)	($29,559)	($29,669)	($261,905)
7	Total	$517,855	$527,824	$376,036	$384,928	$413,421	$486,241	$479,496	$427,009	$468,735	$539,449	$673,941	$676,460	$5,971,396
8	% Allocated to Uncollectible Accounts	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	
9	904 Account Total	$413,733	$421,697	$300,429	$307,533	$330,297	$388,476	$383,087	$341,153	$374,490	$430,985	$538,436	$540,448	$4,770,765
10	Allocated to Gas													
11	% Allocated to Gas	29.41%	29.41%	29.41%	29.41%	29.41%	29.41%	29.41%	29.41%	29.41%	29.41%	29.41%	29.41%	
12	904 Account Allocated to Gas	$121,694	$124,037	$88,367	$90,457	$97,152	$114,265	$112,680	$100,346	$110,151	$126,768	$158,373	$158,965	$1,403,255

STAFF-DR-02-004

REQUEST:

Refer to Volume V, Tab D, Schedule D-2.4. Explain how the $146,105 adjustment was calculated.

RESPONSE:

The source of the adjustment is Schedule C-2, line 16, Other Gas Supply Expenses – Other. The difference between the forecasted period amount of $589,496 and the base period amount of $443,391 is $146,105. Other Gas Supply Expenses – Other on Schedule C-2 is the sum of accounts 807000 and 813000 on Schedule C-2.1.

PERSON RESPONSIBLE: Robert M. Parsons

STAFF-DR-02-005

REQUEST:

Refer to Volume V, Tab I. Explain why residential revenue, line 4, Schedule I-2.1, decreases from $93,979,581 in 2008 to $80,925,193 in the base period when Schedule I-4, line 4, shows residential sales increasing, over this same period, from 6,653,731 to 6,747,636 Mcf.

RESPONSE:

The decrease is the result of the cost of gas declining from an average of approximately $10.00 per MCF in 2008 to $7.50 per MCF in the base period.

PERSON RESPONSIBLE: Stephen R. Lee

STAFF-DR-02-006

REQUEST:

Refer to Volume VI, Tab L.

a. Refer to page 1 of 5. For Rate RS, Duke Kentucky states that a customer charge of $25.11 would be required for full recovery of customer-related costs but that the $30.00 proposed recovers all of the customer-related costs plus some of the fixed costs necessary to serve these customers. Provide the calculation for the customer charge and volumetric charge that would be required if the customer charge fully recovered all fixed costs necessary to serve these customers.

b. Explain why Duke is proposing a $30 per month customer charge for Rate RS when it calculated customer-related costs to be $25.11 per customer.

c. Compare the proposed Rate RS customer charge to the proposed Rate GS customer charge; Duke states that its calculation of the customer charge required for the full recovery of customer-related costs for Rate GS would result in a customer charge of $47.82 per customer, and "Accordingly", it is proposing to set the customer charge at $47.50. Explain the difference in treatment of these two classes.

d. Refer to page 1 of 5. For Rate GS, Duke Kentucky states that a customer charge of $47.82 would be required for full recovery of customer-related costs, and therefore, the company is proposing a customer charge of $47.50. Provide the calculation for the customer charge and volumetric charge that would be required if the customer charge fully recovered all fixed costs necessary to serve these customers.

e. Refer to page 2 of 5. For Rate IT, Duke Kentucky states that a customer charge of $784.74 would be required for full recovery of customer-related costs, but that the company is proposing to maintain its current customer charge of $430.00. Provide the calculation for the customer charge and volumetric charge that would be required if the customer charge fully recovered all fixed costs necessary to serve these customers.

f. Refer to page 2 of 5. For Rate FT-L, Duke Kentucky states that a customer charge of $305.17 would be required for full recovery of customer-related costs, but that the company is proposing to maintain its current customer charge of $430.00. Provide the calculation for the customer charge and volumetric charge that would be required if the customer charge fully recovered all fixed costs necessary to serve these customers.

g. Refer to page 2 of 5. Duke Kentucky states that, in the past, it has set the customer charge for Rate IT and FT-L at the same level and is proposing to maintain the current customer charge for the two classes. Explain in detail why Duke Kentucky desires to set the customer charges for these two classes at the same level rather than increase the IT customer charge and reduce its FT-L customer charged based on its calculations of customer-related costs to serve these customers. Include in the response an explanation of whether Duke Kentucky believes Rate FT-L customers are subsidizing Rate IT customers.

RESPONSE:

a. Please see STAFF-DR-02-006 Attachment.xls.

b. The Company proposes to move toward a Modified Straight Fixed Variable rate design for Rate RS. The $30 charge recovers all of the customer-related costs plus some of the fixed costs necessary to these customers.

c. The Company does not propose to move Rate GS toward a Modified Straight Fixed Variable Rate because of the large diversity in sizes of non-residential customers. The proposed Rate GS customer charge of $47.50 recovers essentially all of the customer costs associated with Rate GS.

d. Please see STAFF-DR-02-006 Attachment.xls.

e. Please see STAFF-DR-02-006 Attachment.xls.

f. Please see STAFF-DR-02-006 Attachment.xls.

g. The Company sets the customer charges for Rate IT and Rate FT-L at the same level because some customers receive a portion of their gas under IT and a portion under FT-L at the same time. In this situation, the customer pays only one customer charge. The Company does not believe that FT-L customers are subsidizing IT customers because the FT-L and IT rates are designed to meet the revenue targets as specified in the cost of service study.

PERSON RESPONSIBLE: James E. Ziolkowski

Duke Energy Kentucky

Calculation of Monthly Charge To Recover All Fixed Costs and Volumetric Charge

STAFF-DR-02-006 Attachment

Rate RS	**Amount**
Total Proposed Revenues From FR-10(9)v-2 page 1	$95,387,592
Less: Proposed Revenues (Commodity) From FR-10(9)v-2 page 1 and Sch M-2.3	-$49,819,246
Total Fixed Cost	$45,568,346
Annual Number of Bills	1,073,044
Monthly Charge To Recover All Fixed Costs	$42.47
Volumetric Rate Per MCF	$0.00

Rate GS	**Amount**
Total Proposed Revenues From FR-10(9)v-3 page 1	$42,005,213
Less: Proposed Revenues (Commodity) From FR-10(9)v-3 page 1 and Sch M-2.3	-$29,086,273
Total Fixed Cost	$12,918,940
Annual Number of Bills	84,334
Monthly Charge To Recover All Fixed Costs	$153.19
Volumetric Rate Per MCF	$0.00

Rate FT-L	**Amount**
Total Proposed Revenues From FR-10(9)v-4 page 1	$2,669,206
Less: Proposed Revenues (Commodity) From FR-10(9)v-4 page 1 and Sch M-2.3	$0
Total Fixed Cost	$2,669,206
Annual Number of Bills	1,020
Monthly Charge To Recover All Fixed Costs	$2,616.87
Volumetric Rate Per MCF	$0.00

Rate IT	**Amount**
Total Proposed Revenues From FR-10(9)v-5 page 1	$1,369,748
Less: Proposed Revenues (Commodity) From FR-10(9)v-5 page 1 and Sch M-2.3	$0
Total Fixed Cost	$1,369,748
Annual Number of Bills	288
Monthly Charge To Recover All Fixed Costs	$4,756.07
Volumetric Rate Per MCF	$0.00

STAFF-DR-02-007

REQUEST:

Provide, as of December 31, 2008, or the most recent date for which the information is available, the number of Duke Kentucky's residential customers that do not use gas for space heating purposes. In addition, provide the average monthly usage of Duke Kentucky's non-space-heating residential customers for 2008, or for the 12 months ended as of the date used in response to the first part of this request item.

RESPONSE:

As of December 31, 2008, Duke Energy Kentucky had 2,836 non-space heating customers that used an average of 43.3 CCF per month.

PERSON RESPONSIBLE: Timothy A. Phillips

Duke Energy Kentucky, Inc.
Case No. 2009-00202
Second Set Staff Data Requests
Date Received: August 17, 2009

STAFF-DR-02-008

REQUEST:

Has Duke Kentucky performed any kind of sensitivity analysis to determine the customer charge level that would result in fuel-switching by 1) non-space-heating residential and 2) space-heating residential customers? If yes, provide the results of the analysis.

RESPONSE:

The Company has not performed sensitivity analyses to determine customer charge levels that would result in fuel-switching.

PERSON RESPONSIBLE: James E. Ziolkowski

Duke Energy Kentucky, Inc.
Case No. 2009-00202
Second Set Staff Data Requests
Date Received: August 17, 2009

STAFF-DR-02-009

REQUEST:

Refer to Volume VI, Tab L-2 page 70 of 70.

a. Provide detailed cost justification information for the Installation of Meter Pulse Equipment of $500, the replacement of Meter Index charge of $155, and the additional trip charge of $60.

b. State whether the meter pulse equipment will be owned by the customer or Duke Kentucky.

c. Which customer classes are targeted by the proposed Rate MPS, Meter Pulse Service?

d. Have customers requested this service?

e. How many customers, broken down by customer class, does Duke Kentucky expect to take advantage of this service?

RESPONSE:

a. Following are the estimated costs:

<u>Installation</u>	
Electronic Pulser:	$100
Auxiliary pulser board, wiring, etc.:	$45
Intrinsically safe electronic switch, box, and wiring:	$225
4 hrs. install incl. 1 hr. travel @ $25.50 labor, $7.00 truck (Total $32.50/hr.)	<u>$130</u>
	$500
<u>Meter Index Charge</u>	
2 hrs. install incl. 1 hr. travel @ $25.50 labor, $7.00 truck (Total $32.50/hr.)	$65
Materials	<u>$90</u>
	$155
<u>Additional Trip Charge</u> (e.g., lightning strike, calibration check, etc. ~ 2hrs.)	$60

b. The meter pulse equipment will be owned by Duke Energy Kentucky.

c. Rate MPS applies mainly to non-residential customers that have energy management systems in their facilities. Installation of the equipment is by customer request.

d. Yes.

e. The Company expects ten to twenty non-residential customers to participate each year. Requests for this service have come from schools, federal government buildings, and commercial/ industrial customers. No residential customers have requested this service.

PERSON RESPONSIBLE: James E. Ziolkowski

STAFF-DR-02-010

REQUEST:

Refer to Volume VI, Tab M.

a. Provide a copy of this response electronically on CD-ROM in Microsoft Excel format with all formulas intact and unprotected.

b. List and explain all differences in methodology between this cost of service study and the one filed by Duke Kentucky in its most recent gas rate case.

c. Refer to Schedule M-2.2, page 1 of 7. Column M is calculated by subtracting column K from column F. Explain what is contained in column F and the purpose of column M.

RESPONSE:

a. Please see STAFF-DR-02-010 Attachment Base.xlsm and STAFF-DR-02-010 Attachment Forecasted.xlsm.

b. Listed below are the differences in methodology between this cost of service study and the one filed in the most recent gas case:

   1. A minimum size study to determine the customer portion of mains was performed in this case, resulting in 85% classified as demand, 15% classified as customer. The demand portion allocated to class using demand allocator K203; the customer portion was allocated to class using customer allocator K401. A minimum intercept study was performed in the last case, resulting in 78% classified as demand, 22% classified as customer. In that case, total mains (demand and customer portions) were allocated to class using "blended allocator" K415.
   2. On page 15 of 23 of FR-10(9)v-2, the Kentucky Taxable Income Adjustment was allocated to rate class using allocator NP29, weighted net plant ratios. This line item was not in the most recent gas case.
   3. Non-weather-normalized calendar month (billed + unbilled) mcf was used to calculate peak day demands on WPFR-10(9)v-6, pages 6 and 7. In most recent case weather-normalized billed mcf was used.
   4. On WPFR-10(9)v-6, page 22 number of customers was used as the weighting factor for services Account 380. In the most recent gas case number of services was used as the weighting factor.

c. Column M on Schedule M-2.2, page 1 shows the proposed revenue increases associated with each rate. The values in column M were calculated as the difference in column F (Schedule 2.3) minus column K (Schedule 2.2).

PERSON RESPONSIBLE: James E. Ziolkowski (a. and c.). Donald S. Storck (b.)

Duke Energy Kentucky, Inc.
Case No. 2009-00202
Second Set Staff Data Requests
Date Received: August 17, 2009

STAFF-DR-02-011

REQUEST:

Refer to Volume VII of the application, Tab C, Exhibit WPC-2b. For each item listed under "Other Revenue," provide the annual amount for the years 2004 through 2008.

RESPONSE:

See Attachment Staff-DR-02-011.

PERSON RESPONSIBLE: Robert M. Parsons

DUKE ENERGY KENTUCKY, INC.
OTHER REVENUE
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2004 THROUGH DECEMBER 31, 2008

		Twelve Months Ended December 31,				
Account	Description	2004	2005	2006	2007	2008
487000	Late Payment Charge	0	0	0	0	0
488060	Bad Check Charges	9,798	10,725	12,942	10,839	11,086
488020	Reconnection Charges	12,753	12,530	27,898	21,739	26,822
488070	Field Collection Charges	0	0	0	2,103	2,969
488100	Erlanger Gas Plant	639,746	438,628	639,469	460,306	514,092
489010	Transp of Gas for Others - Inter Co.	657,936	652,698	595,080	595,080	597,526
493040	Rent Land & Buildings - Assoc.	34,176	34,176	34,176	34,176	34,176
496017	Provision for Rate Refunds	0	1,245,000	(1,245,000)	0	(7,517,628)
484400	Interdepartmental Sales	60,044	68,785	28,632	40,966	53,843
Various	Other Gas Revenues	(18,420)	41,854	6,854	5,526	19,538
	Total Other Revenue	1,396,033	2,504,396	100,051	1,170,735	(6,257,576)

Duke Energy Kentucky, Inc.
Case No. 2009-00202
Second Set Staff Data Requests
Date Received: August 17, 2009

STAFF-DR-02-012 PUBLIC

REQUEST:

Refer to page 9 of the Direct Testimony of Julia S. Janson ("Janson Testimony"), specifically, the reference to the December 2008 Bill Comparison Report provided by the American Gas Association ("AGA"), which indicated that Duke Kentucky's delivery rates for residential, commercial, and industrial customers "were lower than all other Kentucky investor-owned utilities reported in the survey." Provide the referenced AGA report.

RESPONSE:

CONFIDENTIAL PROPRIETARY TRADE SECRET

This response has been filed with the Commission under a Petition for Confidential Treatment.

PERSON RESPONSIBLE: N/A

Duke Energy Kentucky, Inc.
Case No. 2009-00202
Second Set Staff Data Requests
Date Received: August 17, 2009

STAFF-DR-02-013

REQUEST:

Refer to lines 19 – 23 on page 12 of the Janson Testimony. Provide the surveys and survey results which show that local economic development officials have a 100 percent satisfaction rate with Duke Kentucky's economic development efforts and services.

RESPONSE:

See Attachment STAFF-DR-02-013.

PERSON RESPONSIBLE: Julia S. Janson

Duke Energy

Duke Energy Economic Development 2006 Survey

Prepared by Market Analysis
December 2006

Executive Summary

Overall satisfaction with the Duke Energy's Economic Development Department is at 83% of LEDOS indicated they were very satisfied and an additional 17% said they were somewhat satisfied. On a 4.0 scale, the mean satisfaction score decreased slightly from 2005 at 3.8. When comparing service quality levels with last year, 27% said that service was better today and 73% indicated it was about the same. No one said it was not as good.

When rating the staff on service quality attributes, the percentage who said they strongly agree increased for all services expect *communicates effectively* and *staff involvement*. These decreases were not statistically significant.

Similar to last year, LEDOs said that attraction of new business, direct financial assistance and electric/gas availability information were the most important services. Scholarships, information on Duke Energy policy and procedures and educational opportunities regarding Duke Energy's operations were rated the least important.

Duke Energy®

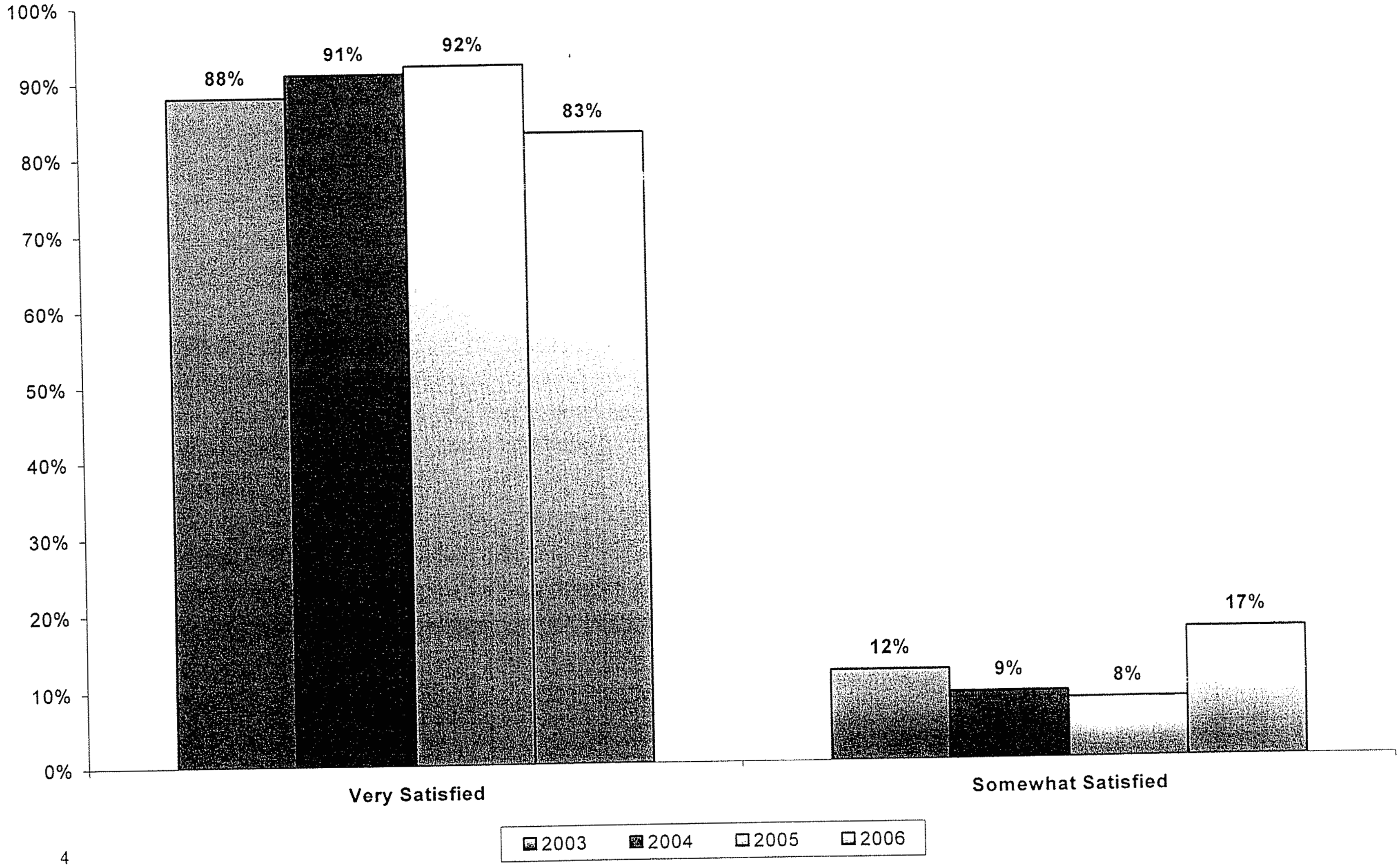
Introduction

In a continual effort to improve services, the Duke Energy Economic Development Department has commissioned Market Analysis to conduct an annual survey. Research objectives include measuring:

- Overall level of satisfaction associated with the services provided by Duke Energy Economic Development
- What LEDOs think Duke Energy Economic Development could do to provide better service
- Service quality comparison with previous year
- LEDO perceptions of the Economic Development staff across a number of service attributes
- What Economic Development services LEDOs expect to be the most and least important to them in the future

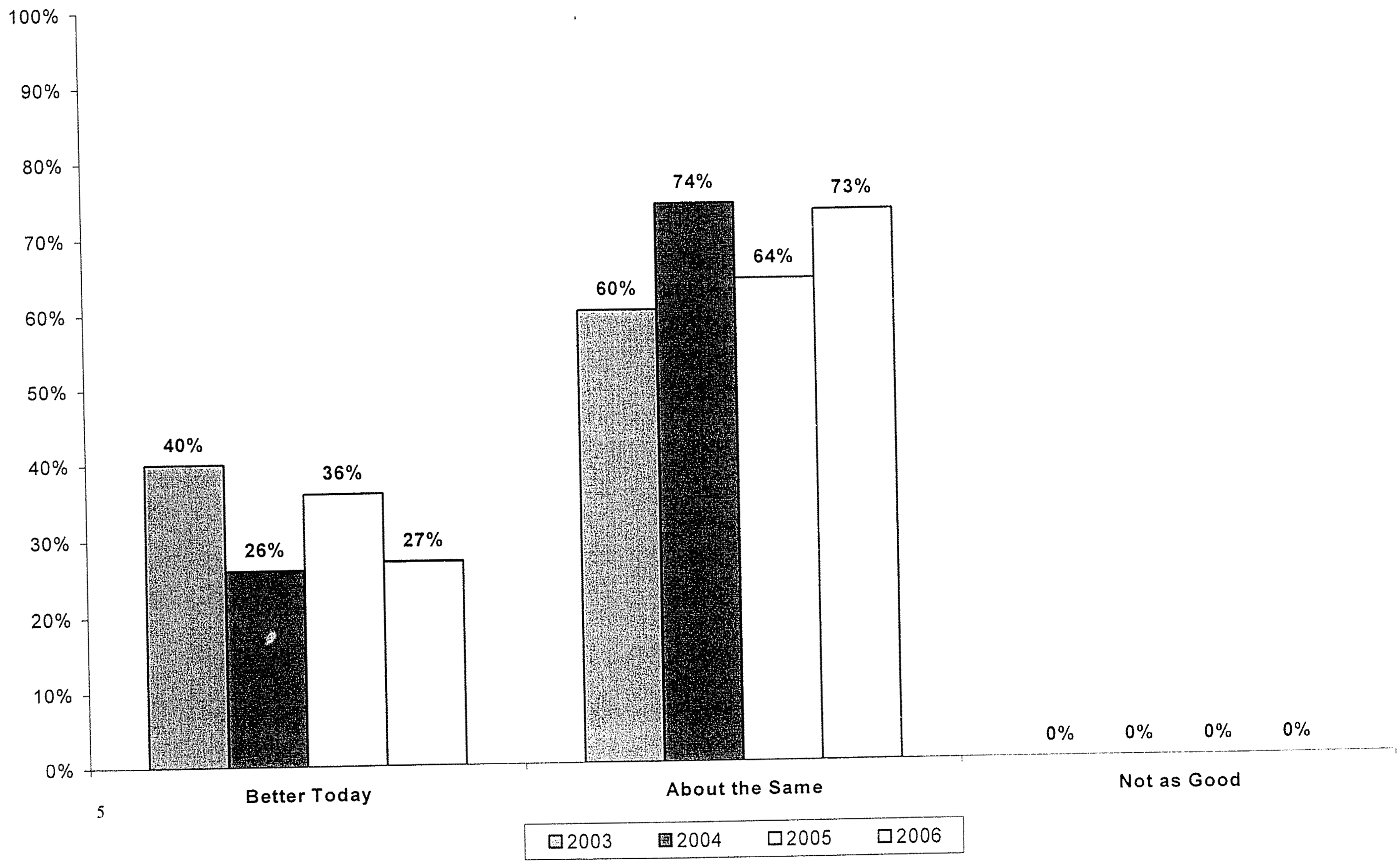
On November 6, 2006 an online survey was sent via email to 55 LEDOs. Thirty surveys were returned, for a response rate of 55%. In the following presentation, the results are compared with previous years. The Appendix contains open ended comments and more detailed data for each of the charts.

Overall Satisfaction



Service Quality Comparison

with last year



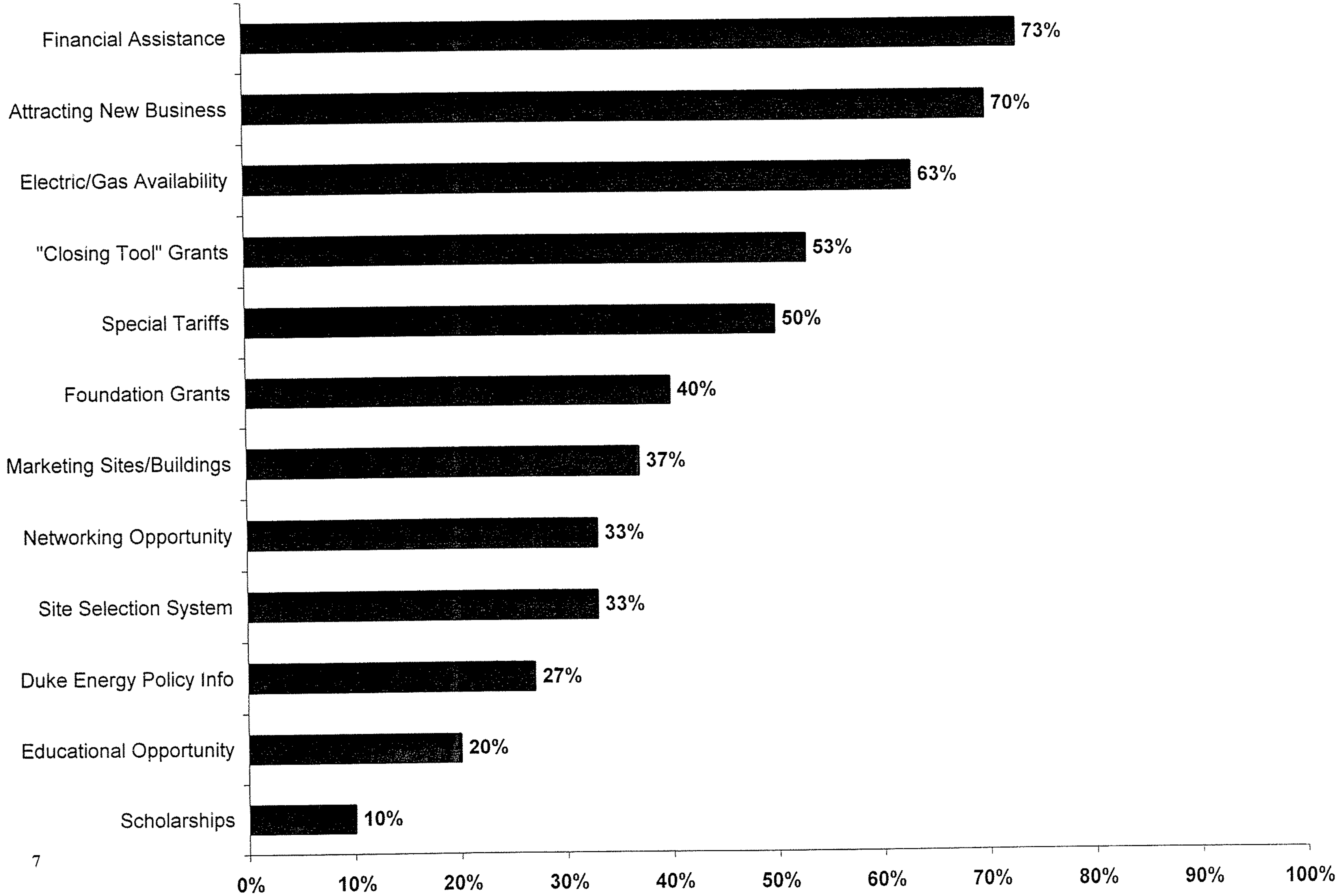
Service Attributes

% strongly agree

Service Attribute	2004	2005	2006	Change from 2005
Services are provided and completed on time.	86	92	93	+1
The staff is knowledgeable.	86	88	93	+5
I have confidence in their work.	95	92	100	+8
The staff communicates effectively.	81	96	90	-6
The service provided by the staff meets my expectations.	86	84	93	+9
The staff is respected by others in the economic development community.	81	88	93	+5
The staff's involvement in projects is valuable to my community's efforts.	67	84	80	-4
I trust the staff to represent the region fairly.	86	84	93	+9

Service Importance

% very important



Service Importance (continued)

LEDOs were asked to rate what three Duke Energy Economic Development services would be the most and least important to their organizations over the next few years.

The three ***most important*** services were:

1. Attraction of new business
2. Direct financial assistance for economic development efforts
3. Information about electric/gas availability within community

The three ***least important*** services were:

1. Scholarships
2. A source of information about Duke Energy policies and procedures
3. Educational opportunities regarding Duke Energy operations

Appendix

What additional services should the Duke Energy Economic Development Department offer that are not currently available?

Duke Energy

- Targeted investment in extending gas/electric capacity to potential new industrial/office parks without having a tenant already identified.
- Not aware of anything at this time
- None that I can think of.
- I have found the Economic Development team at Duke Energy to be extremely helpful. Redevelopment is becoming more of an issue for communities in Greater Cincinnati. Pulling resources together to help first ring suburbs revitalize older, vacant and/or underutilized properties would be extremely helpful.
- Helping to facilitate relationships with site location consultants
- Energy demand-reduction incentives to existing businesses in our region
- Duke Energy has been very responsive in looking at ways the company can play a roll in offering financial incentives (ED Grant Prgram) to projects that absolutely need the gap funding to bring the investment into the region (Duke Territory). Continued focus on the options for financial partnership to leverage companies should be paramount, especially in light of State of Ohio law changes that make tax abatement less attractive.
- Assistance with utility extensions for office/industrial park development
- Assist in the coordination /facilitation of services by Duke operations.

What could the Duke Energy Economic Development Department do to provide better service?

Duke Energy

- Their service is excellent now
- Publicy support Procure and help educate economic development orgs as well as chambers on its benefits as a whole. By example, educate and express the value to the individual as welll as the state as a whole.
- Nothing that I can think of.
- More networking & outreach
- I would be interested in seeing a mechanism developed to communicate information, trends, etc developed to share the knowledge learned during business recruitment travel. How can we take the info learned on site location consultant trips and bring more value-add back to our Regional ED Colleagues?
- Frustrated by inadequate/unreliable electric capacity to my community, which is seriously inhibiting our ability to attract and retain businesses.
- Duke ED staff are a great asset to the State of Ohio's business attraction and marketing efforts.

Additional Comments or Suggestions

Duke Energy®

- The Duke Energy Economic Development Department is knowledgeable, involved and supportive in local ED initiatives. They play a vital role in promoting the area by participating and supporting OEDA, CoreNet, tradeshows and local chambers of commerce. They are all very well respected in the ED community. The region is a better place because David, Nancy and Karen.
- Staff could be increased to provide a Duke representative to assist with large projects where a large amount of electricity and gas consumption is requested, preferably it would be nice to have a Duke representative on site visits.
- Our community was the recipient of a DUke Energy Community grant. Those monies helped us develop a much needed marketing piece.
- One the ranking pages, top 3 most least important services, all of those services are extremely important. I can not rank any as least useful, we use all of them. Duke's ED team is quick and efficient with their business attraction assistance on utility specifics. This can make or break a deal. Duke ED could do more on its website and work to collaborate info with the developing CintiUSA partnership site locator project with GIS Planning. We also should consider ways to minimize duplication as it pertains to ProCure. These information consolidation efforts will help us at the local level and beyond. Overall, Duke's ED team is an essential part of the efforts put into marketing our local position, our Region's competitiveness as well as nationally and internationally. Great Job.
- None
- I value the professional relationship we have cultivated with Duke Energy ED Staff and really value when you bring your technical engineers to prospect meetings.
- I can always count on representatives from Duke to be professional, knowledgable, and willing to help.

Table 1: Taking everything into consideration, how satisfied are you with the Duke Energy Economic Development services that you have used in the past 12 months?

Total	Very Dissatisfied	Somewhat Dissatisfied	Somewhat Satisfied	Very Satisfied	Mean
30	0 0%	0 0%	5 17%	25 83%	3.8

Table 2: Compared with last year, is the service you now receive from the Duke Energy Economic Development Department. . .

Total	Better Today	About the Same	Not as Good as in the Past	Not Applicable
30	8 27%	22 73%	0 0%	0

For all tables in this Appendix, the top number represents the number of responses, the bottom number the percentage.

Table 3: Regarding the Duke Energy Economic Development staff, please indicate your level of agreement or disagreement with the following statements.

Duke Energy

Attribute	Total	Strongly Agree	Somewhat Agree	Somewhat Disagree	Strongly Disagree	Mean
Services provided/completed on time.	30	28 93%	2 7%	0 0%	0 0%	3.9
The staff is knowledgeable.	30	28 93%	2 7%	0 0%	0 0%	3.9
I have confidence in their work.	30	30 100%	0 0%	0 0%	0 0%	4.0
The staff communicates effectively	30	27 90%	3 10%	0 0%	0 0%	3.9
The service provided by the staff meets my expectations	30	28 93%	2 7%	0 0%	0 0%	3.9
Staff is respected by economic development community.	30	28 93%	2 7%	0 0%	0 0%	3.9
Staff involvement in projects is valuable to community efforts	30	24 80%	4 13%	2 7%	0 0%	3.7
I trust the staff to represent the region fairly	30	28 93%	2 7%	0 0%	0 0%	3.9

Table 4: Please indicate how important or unimportant you expect the following services to be to your organization in the next few years.

Duke Energy

Service	Total	Very important	Somewhat important	Somewhat unimportant	Very unimportant	Mean
Scholarships	30	3 10%	7 23%	9 30%	11 37%	2.1
Attraction of new business	30	21 70%	8 27%	1 3%	0 0%	3.7
Special tariffs	30	15 50%	11 37%	2 7%	2 7%	3.3
Direct financial assistance	30	22 73%	6 20%	2 7%	0 0%	3.7
Educational forum for site selection system	30	10 33%	12 40%	3 10%	5 17%	2.9
Assist in marketing sites & buildings	30	11 37%	14 47%	4 13%	1 3%	3.2
Electric/gas availability info	30	19 63%	8 27%	1 3%	2 7%	3.5
Foundation grants	30	12 40%	15 50%	2 7%	1 3%	3.3
Networking opportunity	30	10 33%	15 50%	4 13%	1 3%	3.1
Educational opportunity	30	6 20%	14 47%	7 23%	3 10%	2.8
Grants that could be used as a "closing tool" to attract targeted industries	30	16 53%	9 30%	4 13%	1 3%	3.3
Duke Energy policy & procedure	30	8 27%	14 47%	5 17%	3 10%	2.9

Table 5: LEDO ranking for most important services

Service	Most important
Attraction of new business	18 60%
Direct financial assistance	16 53%
Electric/gas availability info	14 47%
Grants that could be used as a "closing tool" to attract targeted industries	9 30%
Special tariffs	8 27%
Foundation grants	8 27%
Educational forum for site selection system	6 20%
Assist in marketing sites & buildings	4 13%
Networking opportunity	4 13%
Educational opportunity-Duke Energy operations	2 7%
Duke Energy policy & procedure	1 3%
Scholarships	0 0%

Duke Energy®

Table 6: LEDO ranking for least important services

Service	Least important
Scholarships	24 80%
Duke Energy policy & procedure	16 53%
Educational opportunity-Duke Energy operations	10 33%
Networking opportunity	8 27%
Education forum for site selection system	8 27%
Assist in marketing sites & buildings	7 23%
Special tariffs	6 20%
Foundation grants	4 13%
Direct financial assistance	3 10%
Electric/gas availability info	1 3%
Grants that could be used as a "closing tool" to attract targeted industries	1 4%
Attraction of new business	0 0%

Duke Energy Economic Development 2007 Survey

Prepared by Market Analysis
November 2007

Executive Summary

When rating the staff on service quality attributes, all the respondents strongly agreed or somewhat agreed for all services expect *the staff's involvement in projects is valuable to my community's efforts*. Only one LEDO responded somewhat disagree to this service.

Similar to last year, LEDOs said that attraction of new business, direct financial assistance were the most important services along with grants that could be used as a "closing tool" to attract industries. Scholarships, information on Duke Energy policy and procedures, special tariffs, and networking opportunities were rated the least important.

An additional question was added to the survey this year. On a scale of 1 to 10, where 1 means "Very Dissatisfied" and 10 means "Very Satisfied" Overall, how satisfied are you with Duke Energy? Eighty-three percent of respondents are satisfied with Duke Energy, giving a rating of 8 or higher.

Introduction

In a continual effort to improve services, the Duke Energy Economic Development Department has commissioned Market Analysis to conduct an annual survey. Research objectives include measuring:

- Overall level of satisfaction associated with the services provided by Duke Energy Economic Development
- What LEDOs think Duke Energy Economic Development could do to provide better service
- Service quality comparison with previous year
- LEDO perceptions of the Economic Development staff across a number of service attributes
- What Economic Development services LEDOs expect to be the most and least important to them in the future

On November 12, 2007 an online survey was sent via email to 46 LEDOs. Twenty-four surveys were returned, for a response rate of 52%. In the following presentation, the results are compared with previous years where applicable. The Appendix contains open ended comments and more detailed data for each of the charts.

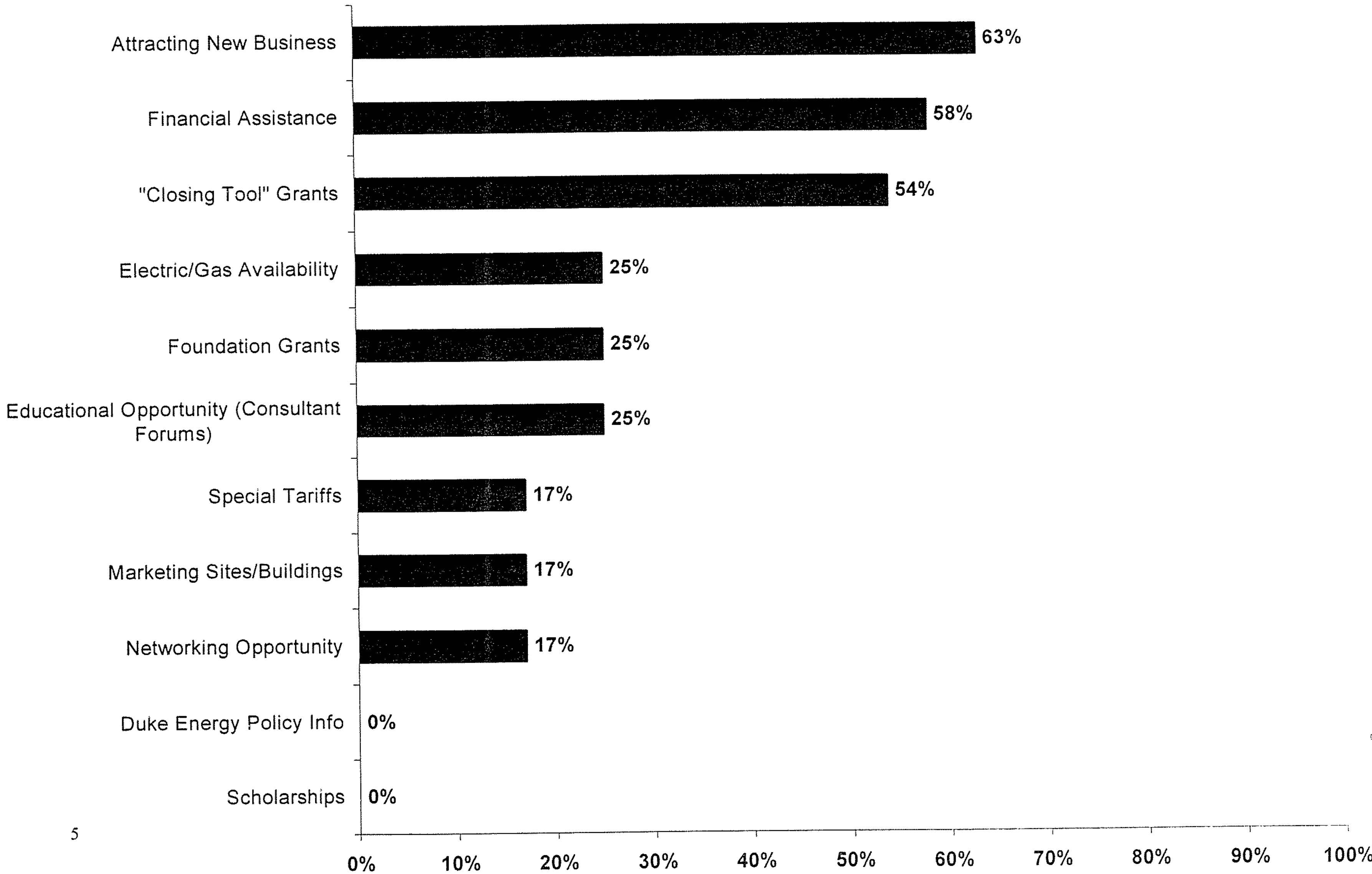
Service Attributes

% strongly agree

Service Attribute	2005	2006	2007	Change from 2006
Services are provided and completed on time.	92	93	83	-10
The staff is knowledgeable.	88	93	83	-10
I have confidence in their work.	92	100	88	-12
The staff communicates effectively.	96	90	79	-11
The service provided by the staff meets my expectations.	84	93	83	-10
The staff is respected by others in the economic development community.	88	93	83	-10
The staff's involvement in projects is valuable to my community's efforts.	84	80	75	-5
I trust the staff to represent the region fairly.	84	93	96	+3

Service Importance

% very important



Service Importance (continued)

LEDOs were asked to rate what three Duke Energy Economic Development services would be the most and least important to their organizations over the next few years.

The three ***most important*** services were:

1. Attraction of new business
2. Direct financial assistance for economic development efforts
3. Grants that can be used as a "closing tool" to attract targeted industries

The three ***least important*** services were:

1. Scholarships
2. A source of information about Duke Energy policies and procedures
3. Special tariffs for chronically late vacant industrial buildings and Brownfield development (tie)
3. Facilitate networking opportunities among economic development organizations. (tie)

Appendix

What additional services should the Duke Energy Economic Development Department offer that are not currently available?

Duke Energy®

- I'd be interested in a "Utility 101" type of course, to explain how energy is created, stored, delivered to customers, types of lines, what terms mean, how prices are determined, etc...
- Services provided by Duke Energy are excellent. If any changes were to be made, possibly holding outside agencies who are recipients of Duke Energy cash accountable for the money received.
- None that are more important than the ones currently provided

What are the three things Duke Energy Economic Development Department could do to help make your organization or community more successful in attracting or retaining companies?

Duke Energy

- 1-3)Provide assistance in extending electric & gas infrastructure to targeted sites for new business park development.
- Provide digital mapping of utilities. Provide education on utility rate incentives.
- I've had some experience trying to organize streetscape projects. Getting preliminary and later more detailed information about relocating utilities underground has been difficult. It's been hard to find the right person, then hard to get the information in a timely manner, etc...
- Assist with Brownfields redevelopment 2. Provide economic development funding 3. Assisting us with answers regarding rates, availability, etc.
- None that I am aware.
- continue regional marketing efforts, continue statewide marketing efforts, continue and expand educational programs
- Not Applicable
- More grants for Marketing Monies to "close the deal"
- Clear communication of services available to help with attraction and retention efforts 2) Aggressive lead generation program 3) Participation of niche marketing areas in various communities (example Northern Kentucky- data center focus)
- Utility comparisons with other communities competing for a project; continue your high level of service to existing companies; be a sounding board for projects
- . Provide financial assistance for targeted industries to locate here . Advertise the merits of Greater Cincinnati vs. other regions we compete with (Columbus, Indianapolis, Louisville, Nashville)
- 1)Cooperative meetings with local firms regarding power/energy related matters 2)Better programs that reward energy conservancy by business 3)Continued participation in regional economic development by Duke.
- continued help in attracting new investment help or "cash grants" for companies that are expanding help address rising energy costs

Additional Comments or Suggestions

- My comments relative to the Foundation grants is that they have a pre-determined timeframe. ED is very market driven and the foundation dollars could be better utilized in project development vs. studies, infrastructure development etc.
- I believe the Duke Energy Economic Development professionals are well respected in the ED community, their participation in trade shows, consultant forums and site selection visits are a valuable asset to the Greater Cincinnati area. I have worked with David, Nancy and Karen on numerous occasions; their knowledge, experience and professionalism have represented Duke Energy very well
- We have started to see more leads in the tech sector from Duke Energy. The group does a good job with consultant outreach for the region through their annual consultant forum and event.
- Whether Duke, Cinergy or CG&E...always an asset in economic development. On site services during development have declined however.

Table 1: Regarding the Duke Energy Economic Development staff, please indicate your level of agreement or disagreement with the following statements.

Attribute	Total	Strongly Agree	Somewhat Agree	Somewhat Disagree	Strongly Disagree	Mean
Services provided/completed on time.	24	20 83%	4 17%	0 0%	0 0%	3 8
The staff is knowledgeable.	24	20 83%	4 17%	0 0%	0 0%	3.8
I have confidence in their work.	24	21 88%	3 12%	0 0%	0 0%	3.9
The staff communicates effectively	24	19 79%	5 21%	0 0%	0 0%	3 8
The service provided by the staff meets my expectations	24	20 83%	4 17%	0 0%	0 0%	3 8
Staff is respected by economic development community.	24	20 83%	4 17%	0 0%	0 0%	3.8
Staff involvement in projects is valuable to community efforts	24	18 75%	5 21%	1 4%	0 0%	3 7
I trust the staff to represent the region fairly	24	23 96%	1 4%	0 0%	0 0%	3.9

Table 2: Please indicate how important or unimportant you expect the following services to be to your organization in the next few years.

Duke Energy®

Service	Total	Very important	Somewhat important	Somewhat unimportant	Very unimportant	Mean
Scholarships	24	0 0%	5 21%	11 46%	8 33%	1.9
Attraction of new business	24	17 71%	5 21%	2 8%	0 0%	3.6
Special tariffs	24	11 46%	5 21%	7 29%	1 4%	3.1
Direct financial assistance	24	15 63%	7 29%	1 4%	1 4%	3.5
Grants that can be used as "closing tools"	24	14 58%	8 33%	1 4%	1 4%	3.5
Assist in marketing sites & buildings	24	11 46%	6 25%	7 29%	0 0%	3.2
Electric/gas availability info	24	16 67%	4 17%	2 8%	2 8%	3.4
Foundation grants	24	7 29%	13 54%	4 17%	0 0%	3.1
Networking opportunity	24	10 42%	10 42%	4 17%	0 0%	3.3
Educational opportunity	24	10 42%	11 46%	3 13%	0 0%	3.3
Duke Energy policy & procedure	24	3 13%	14 58%	4 17%	3 13%	2.7

Table 3: LEDO ranking for most important services

Service	Most important
Attraction of new business	15 63%
Direct financial assistance	14 58%
Grants that could be used as a "closing tool" to attract targeted industries	13 54%
Educational opportunity-Duke Energy operations	6 25%
Foundation grants	6 25%
Electric/gas availability info	6 25%
Special tariffs	4 17%
Assist in marketing sites & buildings	4 17%
Networking opportunity	4 17%
Duke Energy policy & procedure	0 0%
Scholarships	0 0%

Table 4: LEDO ranking for least important services

Duke Energy®

Service	Least important
Scholarships	20 83%
Duke Energy policy & procedure	14 58%
Networking opportunity	7 29%
Special tariffs	7 29%
Assist in marketing sites & buildings	6 25%
Educational opportunity-Duke Energy operations	5 21%
Foundation grants	5 21%
Electric/gas availability info	3 13%
Attraction of new business	2 8%
Direct financial assistance	1 4%
Grants that could be used as a "closing tool" to attract targeted industries	0 0%

Duke Energy Kentucky, Inc.
Case No. 2009-00202
Second Set Staff Data Requests
Date Received: August 17, 2009

STAFF-DR-02-014

REQUEST:

Refer to page 19 of the Janson Testimony. Explain how the J.D. Power 2008 study of residential customer satisfaction for the country's 60 large gas utilities specifically captures the satisfaction level of the customers of Duke Kentucky.

RESPONSE:

The 2008 study ranks the 60 largest Local Distribution Companies (LDC) in the United States andcollectively represents over 48.6 million households.

J.D. Power and Associates worked with Western Wats (Orem, UT) to target two separate residential
panels:
Opinion Outpost (Orem, UT)
Survey Sampling International (Fairfield, CT)

The question set was developed based on input from J.D. Power and Associates' research professionals, interviews with gas utilities, consumer survey and focus group research, as well as findings from six earlier J.D. Power and Associates Gas Utility Residential Customer Satisfaction Studies.

The overall experience of residential customers is measured using 38 satisfaction attributes within six factors: Company Image, Communications, Price & Value, Billing & Payment, Customer Service, and Field Service.

A total of 29,943 online interviews with gas residential customers were conducted in four waves - from September 21, 2007 through July 25, 2008.

The results for the industry are reported across four regions within the United States: East, Midwest, South and West.

PERSON RESPONSIBLE: Julia S. Janson

STAFF-DR-02-015

REQUEST:

Refer to page 4 of the Direct Testimony of Stephen R. Lee, specifically, the response starting on line 14, which states that the weather normalization methodology used in developing Duke Kentucky's projected sales and revenues is "the same methodology that management incorporates for preparing budgets and forecasts and for presentations of financial projections to the Board of Directors, credit ratings agencies and the investment community." Explain whether the methodology is identical to what is described in the Direct Testimony of Timothy A. Phillips ("Phillips Testimony").

RESPONSE:

Yes, the methodology is identical in both testimonies.

PERSON RESPONSIBLE: Stephen R. Lee / Timothy A. Phillips

STAFF-DR-02-016

REQUEST:

Refer to page 11 of the Direct Testimony of Brenda R. Melendez and Volume IV of Duke Kentucky's application, at Tab 42, which contains its independent auditor's annual opinion report, which consists of a one-page letter from Deloitte & Touche, LLP, to its board of directors. Provide the full audit report, including, but not limited to, the audited financial statements and the notes to those statements.

RESPONSE:

The one-page letter from Deloitte & Touche, LLP is the full audit report. The audited financial statements and the notes to those statements have been provided in FR 10(9)(p).

PERSON RESPONSIBLE: Brenda R. Melendez

STAFF-DR-02-017

REQUEST:

Refer to the Direct Testimony of Roger A. Morin ("Morin Testimony"), page 29, and Attachments RAM-2 and RAM-3.

a. Provide the most recent company profiles as reported by Value Line for each of the companies in each of the proxy groups listed in RAM-2 and RAM-3.

b. Describe the criteria used to select the companies and explain how those criteria were applied in the selection of the companies in each proxy group.

c. Identify the gas utilities and combination electric and gas utilities not selected for the respective proxy groups and explain why they were not selected.

RESPONSE:

a. Dr. Morin does not fully understand what is meant by the general term "most recent company profiles". Since the question refers to Exhibits RAM-2 and RAM-3, Dr. Morin presumes that the question refers to the most recent data of those two exhibits. Updated versions of those two exhibits is Attachment STAFF-DR-02-017a using the most recent data. If the question is meant to provide the Value Line sheets for each of the companies in those exhibits, Dr. Morin relies on the Value Line Investment Analyzer software, which is available by commercial paid subscription only and protected by copyright. The formal Value Line copyright notification in the software is shown below.

b. and c. See responses to AG-DR-01-073 and AG-DR-01-074.

PERSON RESPONSIBLE: Roger A. Morin

Duke Energy Kentucky, Inc.
Case No. 2009-00202
Second Set Staff Data Requests
Date Received: August 17, 2009

STAFF-DR-02-018

REQUEST:

Refer to the Morin Testimony, page 31. Provide a copy of the Harris, Marston, Mishra and O'Brien article, "Ex Ante Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM."

RESPONSE:

See Attachment STAFF-DR-02-018.

PERSON RESPONSIBLE: Roger A. Morin

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Ex Ante Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM

Robert S. Harris, Felicia C. Marston, Dev R. Mishra, and Thomas J. O'Brien*

We estimate ex ante expected returns for a sample of S&P 500 firms over the period 1983-1998. The ex ante estimates show a better overall fit with the domestic version of the single-factor CAPM than with the global version, but the difference is small. This finding has no trend in time and is consistent across groups formed on the basis of relative foreign sales. The findings suggest that for estimating the cost of equity, the choice between the domestic and global CAPM may not be a material issue for many large US firms.

The estimation of a firm's cost of equity capital remains one of the most critical and challenging issues faced by financial managers, analysts, and academicians. Although theory provides several broad approaches, recent survey evidence reports that among large US firms and investors, the capital asset pricing model (CAPM) is by far the most widely used model.

Among the variety of decisions to be made in implementing the CAPM is the choice between a domestic or global index for the market portfolio. Although theory suggests that using a domestic market index is appropriate only for an asset traded in a closed, national market, empirical research has thus far failed to establish whether a global or domestic pricing model performs better with US stocks.

We study the choice between the global and domestic CAPM by examining which of the two models provides the better fit with a sample of *ex ante* expected equity return estimates for large US companies. In contrast to many prior studies that use realized returns, we estimate implied expected returns based on the theory's call for a forward looking measure. The question we ask is whether the domestic or the global version of the single-factor CAPM provides the better fit with the dispersion of the *ex ante* expected return estimates for a sample of S&P 500 equities. Our study period covers 1983 to 1998.

We find that the domestic US CAPM fits the *ex ante* expected return estimates better than does the global CAPM. This result shows no trend over time. We also find that except for a few years in the early 1990s, the better fit of the domestic CAPM holds consistently across subsamples formed on the basis of the relative levels of the firms' foreign sales. However, the difference in fit of the two versions of the CAPM is small.

We also find a positive and significant empirical relation between *ex ante* risk premium estimates and systematic risk estimates. Moreover, we find that the *ex ante* risk premium estimates for

For helpful discussions and comments, the authors thank anonymous referees, the workshop at the University of Cincinnati (especially Steve Wyatt), participants at the 2002 Eastern Finance Association meeting (especially Erasmo Giambona, Walt Dolde, and the discussant, Steve Ciccone), the participants at the 2002 FMA European meeting (especially Steve Christophe and the discussant, Ricardo Leal), Greg Nagel, and Mo Rodriguez. The authors also acknowledge the contribution of Thomson Financial for I/B/E/S earnings data. These data have been provided as part of a broad academic program to encourage earnings expectations research.

**Robert S. Harris is Professor and Dean at the University of Virginia. Felicia C. Marston is an Associate Professor at University of Virginia. Dev R. Mishra is an Assistant Professor at Memorial University of Newfoundland in St. John's, NF, Canada. Thomas J. O'Brien is Professor of Finance at the University of Connecticut.*

broad industry groups have a high correlation with the corresponding Fama-French (1997) estimates from the CAPM, but not with the estimates from their three-factor model.

The study's practical implications are based on the widespread use of the CAPM in cost of capital estimation by large US firms and investors, where the traditional use of the S&P 500 index as the "market portfolio" continues to be the standard. Our findings support the use of the domestic CAPM to estimate the cost of equity of large US firms. However, finding a relatively small difference in the overall fit of the two CAPM versions suggests that the choice between applying the domestic CAPM and the global CAPM may not be a critical issue for many large US firms.

The paper is organized as follows. Section I reviews related literature. This review includes the domestic and global versions of the single-factor CAPM and why the two models are theoretically likely to result in different expected rates of return for a given asset. Section II discusses the methodology and data for the empirical analysis. Section III reports the results of the empirical comparison of the *ex ante* expected return estimates with the estimates of the two CAPM versions and with corresponding measures of risk. Section IV provides a brief summary and conclusion.

I. Review of Related Literature

Recent survey evidence (Bruner, Eades, Harris, and Higgins, 1998) and Graham and Harvey, 2001) reports that the capital asset pricing model (CAPM) is widely used by large US firms and investors. The CAPM also continues to have wide popularity in academic textbooks and applied articles (e.g., Kaplan and Peterson, 1998 and Ruback, 2002).

These applications use the traditional domestic CAPM, $k_i = r_f + \beta_{iD}[k_{MD} - r_f]$; where k_i is the equilibrium expected rate of return for asset i; r_f is the risk-free rate; β_{iD} is the beta of asset i against the domestic market portfolio returns; k_{MD} is the equilibrium required rate of return on the domestic market portfolio; and $k_{MD} - r_f$ is the risk premium on the domestic market portfolio.

A. Global CAPM and Domestic CAPM

Stehle (1977) and Stulz (1995a, 1995b, 1999) argue that using a domestic market index is only appropriate for an asset traded in a closed, national financial market. Although equilibrium international asset pricing models are multifactor in general, if the purchasing power parity (PPP) condition holds, then the single-factor CAPM equation can be adapted to a international context for assets in the global market portfolio, as discussed in Stulz (1995c). We emphasize the difference between the domestic and global CAPMs by Equation (1).

$$k_i = r_f + \beta_{iG}[k_{MG} - r_f] \quad (1)$$

where k_i is the equilibrium expected rate of return for asset i in a specific pricing currency, r_f is the nominal rate of return on an asset that is risk-free and denominated in the pricing currency, β_{iG} is the beta of asset i's returns against the unhedged global market index returns, with returns computed in the pricing currency, k_{MG} is the equilibrium required rate of return in the pricing currency on the unhedged global market portfolio, and $k_{MG} - r_f$ is the risk premium on the unhedged global market portfolio. As in Grauer, Litzenberger, and Stehle (1976), under the assumption of logarithmic utility the global CAPM in Equation (1) holds

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with any numeraire currency. Ross and Walsh (1983) show that when log utility is not assumed, Equation (1) holds for at most one currency. We assume that currency is the US dollar.

Karolyi and Stulz (2003) point out that only in the special case in which β_{iG} equals $\beta_{iD}\beta_{DG}$ does the global CAPM result in the same expected return as the domestic CAPM, i.e., when an asset's global beta is equal to its domestic beta times the global beta of the domestic market portfolio. Generally, this condition does not hold. Instead, when β_{iG} is greater than $\beta_{iD}\beta_{DG}$, the domestic CAPM is likely to underestimate the asset's expected return relative to the global CAPM, because there is more global systematic risk in the asset's returns than is accounted for by the domestic market index. Similarly, when β_{iG} is less than $\beta_{iD}\beta_{DG}$, the domestic CAPM is likely to overestimate the asset's expected return relative to the global CAPM, because the asset has less global systematic risk in its returns than is accounted for by the domestic market index.

Stehle (1977) reports empirical support for the global CAPM over the domestic version in realized returns for US stocks from 1956 to 1975. Harvey's (1991) study provides further empirical support of global pricing of US equities. Black (1993) asserts that the issue of whether a global or domestic index should be used in CAPM applications is not yet settled. However, given the significant globalization of the world financial markets, Stulz (1995a, 1995b, 1999) advocates the use of the global version. In contrast to Stehle's (1977) findings, Griffin (2002) reports that for the period between 1981 and 1995, a three-factor (Fama-French) domestic model had lower pricing errors for US firms than did an analogous three-factor world version. His results indicate that a domestic pricing model is a better fit with realized return data than a global pricing model.

Campbell's (1996) empirical analysis of a multifactor domestic pricing model finds that the single-factor domestic "... CAPM is a good approximate model for stock and bond prices," since the additional factors (returns to human capital and changes in expected market return) are highly correlated with the market index returns. Ng (2003) reaches a similar conclusion in the context of the global CAPM, with the additional factors of FX risk and shifts in both expected market returns and expected FX changes. Therefore, we only examine the two single-factor CAPMs. Griffin (2002) does not report results on domestic compared to world single-factor (market index) models. However, in private correspondence after our study was completed, Griffin reported to us that the domestic version of the single-factor model had lower pricing errors than did the world model.

For large US companies like those in the S&P 500, there are arguments why choosing a domestic or a global index for CAPM applications could be a non-issue. One argument is that a US index will closely track a global index, especially as markets have become more integrated and since the market value of US stocks is a substantial proportion of the market value of a global index. However, the data show that the beta of the S&P 500 compared to the MSCI World Index has been substantially less than one in the past. Another argument is that S&P 500 companies are often global in scope, which makes the S&P 500 something of a global index in its own right. However, Jacquillat and Solnik (1978) and Christophe and McEnally (2000) report evidence that a portfolio of US multinationals is an ineffective vehicle for international diversification. Even if the choice between a global and a domestic index does not matter much for large US firms in general, it might make a difference for US firms with very high (or low) levels of foreign involvement. However, this empirical question is unanswered. Older studies by Hughes, Logue, and Sweeney (1975) and Agmon and Lessard (1977) suggest this possibility, reporting that global (domestic) betas increased (decreased) with the level of US firms' foreign-to-total sales ratio. However, more recent results in Diermeier and Solnik (2001) do not find this effect to be strong for US firms.

A domestic index could be the preferred benchmark for US investors with a significant "home bias", as in the Cooper and Kaplanis (2000) model of partially integrated world markets. However, we do not know whether the popularity of the domestic CAPM among US firms is for this reason.

B. *Ex Ante* Expected Return Estimates

Empirical tests comparing global to domestic pricing models usually rely on realized returns. However, Elton (1999) points out that *ex ante* estimates of expected returns are more desirable. We obtain *ex ante* expected return estimates through analysts' growth forecasts and discounted cash flow (DCF) models, as in a number of prior studies, including Claus and Thomas (2001), Fama and French (2002), and others discussed below.

In contrast to research that uses realized returns, almost all of the studies using *ex ante* expected return estimates find an empirical relation between expected return and beta risk, despite differences in approaches and time periods. For example, using the constant dividend growth model, Harris and Marston (1992) and Marston and Harris (1993) report a significant relation between *ex ante* expected return estimates and (domestic) betas for a sample of US stocks in the 1982-1987 period. At the same time they confirm the findings of previous empirical studies of no significant relation between realized returns and betas.

When they apply a DCF model to 51 highly leveraged transactions (mostly management buyouts) in the period 1980-1989, Kaplan and Ruback (1995) find that implied costs of capital estimates are related to beta but not to the size and book-to-market factors. Using IBES forecasts, Gordon and Gordon (1997) and Gode and Mohanram (2003) also observe a significant relation between *ex ante* expected equity return estimates and domestic US betas. Gordon and Gordon use a finite horizon dividend discount model and the time period 1985-1991. Gode and Mohanram use the Ohlson-Juettner (2000) valuation model for the period 1984-1998. Also, Brav, Lehavy, and Michaely (2003) find a positive empirical association between analysts' direct return forecasts and beta for US stocks, but not between the return forecasts and the size and book-to-market factors.

The results of Gebhardt, Lee, and Swaminathan (2001) provide the only exception that we know of to a positive empirical relation between *ex ante* expected return and beta risk estimates. Their study, which uses IBES forecasts and a clean-surplus residual income valuation model, reports no significant association between their *ex ante* expected return estimates and domestic betas for a sample of US stocks from the period 1979-1995.

There is some controversy about IBES forecasts. La Porta (1996) asserts that analysts' growth forecasts tend to be too extreme, but Lee, Myers, and Swaminathan (1999) find that IBES forecasts improve their intrinsic value estimates over forecasts based on a time series model.

II. Methodology and Data

In this section, we discuss our approach for estimating *ex ante* expected returns using the constant dividend growth model and the consensus of financial analysts' five-year earnings growth forecasts available through IBES. In addition, we explain our criteria for comparing the global and domestic CAPMs.

A. *Ex Ante* Expected Return Estimation

For each month from January 1983 through August 1998, we calculate an *ex ante* expected

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return estimate for each dividend-paying US stock in the S&P 500 index for which data are available. We eliminate a firm in a given month if there are fewer than three analysts' forecasts, if the standard deviation around the mean forecast exceeds 20%, or if there are not sufficient historical returns for the prior 60 months to perform beta estimations. The analysis comprises 65,154 expected return estimates for the months from January 1983 to August 1998. We obtain dividend and other firm-specific information from the Compustat files.

We estimate *ex ante* expected rates of return by using the constant dividend growth model.

$$k_i^a = \frac{D_{1i}}{P_{0i}} + g_i \tag{2}$$

where k_i^a is the *ex ante* expected rate of return (cost of equity) estimate for company i, D_{1i} is the dividend per share expected to be received at time 1, P_{0i} is the current price per share, and g_i the expected long term growth rate in dividends per share, which we assume is equal to the consensus of the analysts' growth forecasts. See Timme and Eisemann (1989) for a review of the benefits of analysts' forecasts over historical growth estimates.

We recognize that our study, like any study of asset pricing relations, is a joint "test" of the underlying model and the empirical constructs used. Therefore, like other studies, we cannot conclude whether rejection is due to failure of the model or of the empirical proxies. With this standard caveat, our method for estimating *ex ante* expected returns, which uses IBES growth forecasts and the dividend growth model, has several strengths. First and foremost, theory suggests that measures of return should be those that investors expect to prevail over some future time horizon. Although many empirical tests rely on realized returns, there is no necessary relation between the investors' expected returns suggested by theory and subsequently realized returns, except under strong assumptions.

Second, as noted earlier, and in contrast to studies that use realized returns, the results of studies that use *ex ante* expected return estimates are robust across time periods and DCF models in finding a positive empirical relation between expected return and systematic risk. Since we find that our *ex ante* expected return estimates behave similarly to those of other empirical studies, we believe that our *ex ante* estimates are representative.

Third, our approach should not bias the outcome of this study toward one version of the CAPM over the other. That is, there is no reason to think that the relative fit of the two CAPM versions with the *ex ante* expected return estimates depends on a particular DCF valuation model or source of growth forecasts.

Finally, given the widespread use of the CAPM, the conflicting empirical results on the impact of using a domestic or global index warrants additional study using a variety of approaches. Furthermore, additional empirical results on the constant growth model, given its longstanding history and continued use, could be useful.

B. Global CAPM Compared to Domestic CAPM

To use either the global or the domestic CAPM to estimate a firm's cost of equity, we use a time-varying approach to estimate betas and market risk premia. We estimate the firms' equity betas for a particular month with monthly excess returns (the stock return minus 20-year Treasury bond (T-bond) return) for five years prior to the month for which we estimate the cost of equity. We estimate equity betas for all companies by using an ordinary least squares (OLS) of excess stock returns on excess market index returns. We obtain monthly stock returns in US dollars from January 1978 through August 1998 from the CRSP files. We obtain T-bond returns from the website of the Federal Reserve Bank of St. Louis. We use the S&P 500 Index as the domestic US index. (We also use the CRSP Value-Weighted Index in a robustness check.) We use the Morgan Stanley Capital International (MSCI) World Index with gross dividend reinvestment as the global market index. The monthly data for the global index is from the website of MSCI: www.mscidata.com. This index is unhedged and thus, when reported in US dollars, reflects exchange rate changes in currencies against the US dollar.

The question we investigate is which of the two CAPM versions, if we assume that version is the "correct" model, has less variation in its fit with the *ex ante* expected return estimates for the individual firms. To implement this investigation, we "back out" the estimated *market* risk premia (domestic and global) for each month from the *ex ante* expected returns of the individual stocks. To do so, for a given month, we first turn each stock's *ex ante* expected return estimate into an *ex ante* risk premium estimate by subtracting the yield on the 20-year T-bond. Then we aggregate the stocks' *ex ante* risk premia estimates with value weighting, producing an *ex ante* portfolio risk premium estimate for the month. For the domestic CAPM, we value-weight the firms' domestic beta estimates into a portfolio domestic beta estimate for the month. Since the portfolio risk premium should be equal to the portfolio beta times the market risk premium, the domestic market risk premium estimate for the month is found implicitly by dividing the portfolio risk premium estimate by the portfolio domestic beta estimate. For example, if the value-weighted portfolio of eligible stocks has an *ex ante* risk premium estimate of 6% and a domestic beta estimate of 0.9, then the implicit domestic market risk premium estimate (for that month) is 6% divided by 0.9, which equals 6.67%. To ensure a fair comparison between the domestic CAPM (DCAPM) and the global CAPM (GCAPM), we use an analogous procedure (each month) to estimate the implicit global market risk premium from the *ex ante* portfolio risk premium estimate and the portfolio's global beta estimate. In other words, we estimate the domestic market risk premium by assuming that the domestic CAPM is valid for the average stock, and estimate the global market risk premium by assuming that the global CAPM is valid for the average stock. By design, this approach implies that the average difference between the model estimates and the *ex ante* estimates is zero for both CAPM versions.

We then investigate how much variation exists for individual firms between the *ex ante* risk premium estimates and the corresponding estimates of each of the two CAPM versions. For each month from January 1983 until August 1998, we analyze each available stock as follows. We begin by using the stock's domestic beta and the domestic market risk premium estimates to find the firm's risk premium estimate under the DCAPM. We also estimate the stock's risk premium under the GCAPM with the stock's global beta and the global market risk premium estimates. We then compare the *ex ante* risk premium estimate for the stock with the risk premium estimates of both CAPM versions.

For a given stock and month, there will generally be differences between all three risk premium estimates. For example, a stock in June 1989 might have an *ex ante* risk premium estimate of 5%, a DCAPM estimate of 4%, and a GCAPM estimate of 7%. In this hypothetical example, the DCAPM would be considered as the better fit because it provides a risk premium estimate that is closer to the *ex ante* estimate.

We use three metrics to assess which of the two CAPM versions has the better overall fit with the *ex ante* estimates. First, we examine the average of the absolute differences between the model estimates and the *ex ante* estimates. We decide that the model with the lower overall average of absolute differences across all observations for the individual firms is the better-fitting model for this metric. Second, we determine the percentage of the *ex ante* estimates for which the DCAPM provides a closer fit than the GCAPM. In the third metric, we compare the results of cross-sectional OLS of *ex ante* risk premium estimates for the individual stocks against both the estimated domestic betas and the estimated global betas. Whichever regression has the higher r-squared indicates the better-fitting CAPM version with this approach. We also examine the regression results for relative consistency with the theory: an intercept of zero and a positive slope.

Further, we investigate whether the fit of the *ex ante* estimates with those of the two CAPM versions is related to the ratio of foreign sales to total sales, which we use here as a proxy for international exposure. Although we understand that the relative level of foreign sales does not completely capture a firm's international exposure, its use is standard in many empirical studies, including Fatemi (1984), Jorion (1990), Miller and Reuer (1998), and Doidge, Griffin, and Williamson (2002), who contend that a good rationale for using relative foreign sales as a proxy for international exposure is the high correlation with other measures of firms' international operations.

Of the 489 firms used in the study, 253 firms have a reported foreign sales entry (including 76 firms reporting zero foreign sales) for the period 1994 to 1998. The overall average ratio of foreign to total sales is approximately 20% for the 253 firms. Using the eligibility criteria discussed above, we use the data for the 253 firms from 1983 to 1998 to construct a subsample of 36,580 observations (out of the 65,154 total observations), an average of about 194 firms per month. Of these observations, 11,053 involve a firm reporting zero foreign sales during 1994-1998, an average of about 59 firms per month. We divide the remaining observations, involving firms reporting non-zero foreign sales during 1994-1998, into three equal-sized groups of 8,509 observations based on the magnitude of relative foreign sales. Each group had an average of about 45 firms per month. The high foreign sales group has an average ratio of foreign to total sales of 53%, and the medium and low groups had ratios of 27% and 7%, respectively.

III. Results

This section describes in detail the results of the study, as reported in the tables.

A. Summary of Risk Premium Differences for DCAPM and GCAPM

Table I summarizes the average absolute differences between the *ex ante* risk premium estimates and the DCAPM and GCAPM estimates, and the percentage of instances in which the *ex ante* estimates are closer to the DCAPM estimate than to the GCAPM estimate. For all the observations in the sample, over all years from 1983 through 1998, the DCAPM's estimated expected return differs in absolute terms from the corresponding *ex ante* estimate by an average of 0.027, or 270 basis points. The GCAPM's estimated expected return differs in absolute terms from the corresponding *ex ante* estimate by an average of 0.029, or 290 basis points.

For every year except 1992, the average absolute difference between the DCAPM estimates and the *ex ante* estimates is less than or equal to the average absolute difference between the GCAPM estimates and the *ex ante* estimates. Based on the average absolute difference criterion, we find that the DCAPM has a better overall fit with the *ex ante* risk premium estimates.

However, the overall margin of difference, 270 basis points compared to 290 basis points, is not dramatic. The difference is the closest in the early 1990s. In contrast, in the 1980s and late 1990s, the DCAPM is the better fit by a wider margin. In a robustness check, we obtain

Table I. Summary of Risk Premium Differences For DCAPM and GCAPM

The columns show, respectively, the average number of firms per month (#Firms), the value-weighted averages of the estimated *ex ante* risk premia (*Ex Ante*), average domestic beta estimates (β_{iD}), the average domestic market risk premium estimates (RP_D), the average absolute differences between the *ex ante* estimates and those of the DCAPM (*Ex*-D), the average global beta estimates (β_{iG}), the average global market risk premium estimates (RP_G), the average absolute differences between the *ex ante* estimates and those of the GCAPM (*Ex*-G), and the percentage of cases in which the *ex ante* estimate is closer to the DCAPM estimate than to GCAPM estimate (%DCAPM Closer). The numbers in parenthesis are corresponding *t*-statistics.

Year	#Firms	*Ex Ante*	β_{iD}	RP_D	*Ex*-D	β_{iG}	RP_G	*Ex*-G	%DCAPM Closer
1983	285	0.066	0.883	0.075	0.030	0.864	0.077	0.031	0.573(8.489)***
1984	300	0.053	0.915	0.058	0.026	0.897	0.059	0.027	0.581(9.777)***
1985	314	0.057	0.925	0.062	0.026	0.915	0.062	0.028	0.561(7.524)***
1986	320	0.074	0.985	0.075	0.028	0.890	0.084	0.030	0.580(9.931)***
1987	327	0.061	1.024	0.060	0.024	0.941	0.065	0.027	0.618(14.76)***
1988	335	0.064	1.000	0.064	0.024	0.969	0.066	0.026	0.589(11.28)***
1989	352	0.066	0.982	0.067	0.023	0.890	0.073	0.025	0.601(13.08)***
1990	357	0.071	0.972	0.073	0.025	0.797	0.089	0.026	0.531(4.108)***
1991	363	0.075	0.976	0.077	0.027	0.723	0.104	0.027	0.482(-2.409)**
1992	370	0.078	0.990	0.079	0.030	0.723	0.109	0.028	0.440(-8.002)***
1993	374	0.082	1.018	0.080	0.029	0.576	0.142	0.029	0.490(-1.299)
1994	375	0.073	1.038	0.070	0.025	0.576	0.126	0.026	0.515(2.012)**
1995	370	0.077	1.039	0.074	0.028	0.579	0.133	0.031	0.538(5.118)***
1996	379	0.078	1.008	0.077	0.027	0.604	0.129	0.035	0.632(17.83)***
1997	383	0.082	1.005	0.081	0.029	0.650	0.127	0.037	0.616(15.73)***
1998	388	0.092	1.010	0.091	0.031	0.793	0.116	0.035	0.575(7.826)***
Avg.	349	0.072	0.986	0.073	0.027	0.774	0.097	0.029	0.556(28.57)***

***Significant at the 0.01 level.
**Significant at the 0.05 level.

similar results (not reported here) when we use the CRSP Value-Weighted Index instead of the S&P 500 Index for the domestic US market portfolio.

We make two observations about the magnitudes of the market risk premium estimates. First, the global market risk premium estimates are higher than the local US market risk premium estimates. Although this observation may seem counterintuitive, it is a logical consequence of the fact that the global beta of the US market has historically been less than one. (See, for example, Karolyi and Stulz, 2003). Our second observation is that market risk premium estimates are higher than those reported in studies by Claus and Thomas (2001) and Fama and French (2002), but have a similar magnitude to that observed by Kaplan and Ruback (1995) and to the long-term unconditional estimates of Constantinides (2002). Regardless, these estimates should not bias the results in favor of one CAPM version over the other.

When we examine the percentage analysis reported in Table I, we see that with the exception of the three consecutive years from 1991 through 1993, in the majority of the cases the *ex ante* risk premium estimate is closer to the DCAPM estimate than to the GCAPM estimate. Overall, the *ex ante* estimates are closer to the DCAPM estimate 56% of the time. Given the large sample, this percentage is significant in a statistical sense.

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B. Cross-Section Regressions On Systematic Risk

Table II reports the results of the cross-section regression of the firms' *ex ante* risk premium estimates on the beta estimates. Overall, the cross-section regressions provide further evidence that consistently throughout the time period 1983-1998, the *ex ante* estimates have a better fit with those of the DCAPM than with the GCAPM. Table II shows that the r-squares of all of the regressions are higher when we use the domestic beta as the independent variable than with the global beta. Moreover, the DCAPM regression results are consistently better aligned with the theory. The regression intercepts are closer to zero for the DCAPM than for the GCAPM, and the *t*-statistics on the slope coefficients are more significant for the DCAPM than for the GCAPM. These observations apply to the entire period, to all four individual sub-periods, and to each of the 16 years covered in the study.

The findings of significant, positive slope coefficients in each of the 16 years' cross-section regressions appear to strongly confirm the basic asset pricing theory prediction that expected returns are positively related to beta risk. We note that we are using individual stock parameters, not portfolios, and we use no control variables in the cross-section regressions. However, the positive regression intercepts suggest the possible omission of risk factor(s) or systematic optimism in the analysts' growth forecasts. Further exploration of this issue is beyond the scope of this study and is a topic for future research.

Together, Tables I and II lead us to conclude that using all three metrics (average absolute differences, percentage of cases with the better fit, and cross-section regression results), the domestic CAPM fits the dispersion of *ex ante* risk premium estimates better than does the global CAPM. This finding surprised us, in light of the continuing integration of world financial markets and international diversification by investors. However, this finding is consistent with the Cooper and Kaplanis (2000) model of partially segmented global capital markets and home bias.

C. Impact of Foreign Sales

We hypothesize that the global CAPM provides the better fit for companies with a relatively higher level of foreign sales, or that at least we observe a trend toward this relation over time. Table III shows this expectation is not the case. Only in the 1990-1994 period the GCAPM is the better fit for the high and medium foreign sales groups, and the DCAPM is the better fit for the low and zero foreign sales groups. However, after 1994, the pattern is generally the same for all four foreign sales groups, and there is no longer a better fit by the GCAPM for firms in the high and medium relative foreign sales groups.

Looking at all the years together, the average absolute differences between the *ex ante* risk premium estimates for the individual stocks and those of the two CAPM versions are about the same for each foreign sales level group, and the DCAPM estimates are slightly closer to the *ex ante* estimates in all four groups. Thus, we conclude that the relative level of foreign sales does not indicate when the *ex ante* expected returns are more closely related to the GCAPM than the DCAPM, except possibly during times when the US and global economies are not in sync.

D. Risk Premium Estimates and Differences by Industry

Given the potential for measurement error at the company level, there are benefits from looking at industry aggregates. Table IV breaks down the full-period risk premium estimates by broad industry groups. The results weight each firm in the industry equally. We obtain similar results

Table II. Cross-Section Regressions

The table presents the results of cross-section regressions of *ex ante* risk premium estimates and systematic risk estimates for individual firms. We use ordinary least squares, with *ex ante* risk premium estimates as the dependent variable and firm beta against indicated market portfolio as independent variable The numbers in parenthesis are the corresponding *t*-statistics.

	Versus Domestic Beta			Versus Global Beta			
Year	Intercept	Slope	R-Sq	Intercept	Slope	R-Sq	#Obs
1998	0.062 (35.07)***	0.025 (13.73)***	0.065	0.065 (38.39)***	0.025 (12.45)***	0.054	2718
1997	0.059 (46.08)***	0.020 (15.45)***	0.050	0.067 (62.89)***	0.026 (10.99)***	0.026	4590
1996	0.053 (43.91)***	0.023 (19.79)***	0.079	0.063 (65.33)***	0.021 (14.87)***	0.046	4544
1995	0.053 (45.99)***	0.020 (20.74)***	0.088	0.059 (57.29)***	0.027 (17.04)***	0.061	4439
1994	0.043 (35.78)***	0.026 (25.85)***	0.129	0.05 (40.52)***	0.037 (18.69)***	0.072	4503
1993	0.048 (38.14)***	0.028 (25.43)***	0.126	0.056 (44.79)***	0.039 (18.99)***	0.074	4489
1992	0.041 (27.73)***	0.027 (20.57)***	0.087	0.042 (28.77)***	0.037 (20.38)***	0.086	4437
1991	0.036 (22.29)***	0.031 (21.99)***	0.100	0.043 (27.05)***	0.034 (17.61)***	0.067	4357
1990	0.035 (20.00)***	0.033 (20.86)***	0.092	0.047 (28.44)***	0.026 (13.99)***	0.044	4287
1989	0.039 (25.59)***	0.025 (17.87)***	0.070	0.049 (35.32)***	0.017 (11.97)***	0.038	4222
1988	0.039 (24.17)***	0.023 (15.60)***	0.057	0.048 (31.53)***	0.016 (11.29)***	0.031	4015
1987	0.037 (23.05)***	0.024 (16.90)***	0.068	0.048 (32.75)***	0.016 (10.88)**	0.029	3929
1986	0.057 (42.63)***	0.017 (14.19)***	0.050	0.065 (49.90)***	0.011 (8.33)***	0.018	3835
1985	0.045 (40.69)***	0.012 (12.06)***	0.037	0.051 (45.47)***	0.007 (6.96)***	0.013	3770
1984	0.045 (38.79)***	0.008 (7.27)***	0.015	0.05 (43.15)***	0.003 (2.67)***	0.002	3605
1983	0.053 (45.93)***	0.011 (10.23)***	0.030	0.057 (50.04)***	0.007 (6.87)***	0.014	3414
1995-1998	0.058 (88.77)***	0.020 (32.61)***	0.061	0.063 (113.76)***	0.023 (29.25)***	0.050	16,291
1991-1994	0.042 (61.55)***	0.028 (46.34)**	0.108	0.054 (82.29)***	0.027 (29.93)***	0.048	17,786
1987-1990	0.038 (46.83)***	0.026 (35.09)***	0.070	0.051 (68.49)***	0.016 (21.31)***	0.027	16,453
1983-1986	0.049 (79.50)***	0.013 (22.82)***	0.034	0.057 (92.38)***	0.006 (10.27)***	0.007	14,624
1983-1998	0.049 (138.64)***	0.020 (64.27)***	0.059	0.065 (215.79)***	0.006 (18.81)***	0.005	65,154

***Significant at the 0.01 level.

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Table III. Impact of Foreign Sales

The table displays the results of our analysis of the average absolute risk premium differences for individual firms for four groups, sorted by the ratio of foreign sales to total sales. The average ratio of foreign-to-total sales for the HIGH (MEDIUM, LOW) Foreign Sales Group is 53% (28%, 7%), respectively. Each group shows three columns, the average absolute differences between the *ex ante* estimates and those of the DCAPM (*Ex*-D), the average absolute differences between the *ex ante* estimates and those of the GCAPM (*Ex*-G), and the percentage of cases in which the *ex ante* estimate is closer to the DCAPM estimate than to GCAPM estimate (%DCAPM Closer). The numbers in parenthesis are corresponding *t*-statistics.

	High Foreign Sales			Medium Foreign Sales		
Year	*Ex*-D	*Ex*-G	%DCAPM Closer	*Ex*-D	*Ex*-G	%DCAPM Closer
1983	0.025	0.029	0.707(9.76)***	0.029	0.031	0.585(3.73)***
1984	0.021	0.024	0.723(10.69)***	0.027	0.028	0.620(5.36)***
1985	0.021	0.023	0.571(3.14)***	0.027	0.027	0.513(0.58)
1986	0.023	0.026	0.613(5.14)***	0.028	0.029	0.517(0.72)
1987	0.021	0.022	0.605(4.75)***	0.027	0.029	0.574(3.47)***
1988	0.023	0.024	0.561(2.76)***	0.027	0.028	0.560(2.84)***
1989	0.023	0.024	0.571(3.30)***	0.026	0.028	0.555(2.65)***
1990	0.024	0.024	0.476(-1.12)	0.028	0.027	0.519(0.89)
1991	0.031	0.030	0.443(-2.71)***	0.028	0.028	0.549(2.33)**
1992	0.029	0.026	0.353(-7.38)***	0.029	0.029	0.487(-0.62)
1993	0.028	0.024	0.405(-4.74)***	0.032	0.030	0.525(1.22)
1994	0.024	0.020	0.409(-4.55)***	0.027	0.024	0.499(-0.04)
1995	0.027	0.028	0.464(-1.79)*	0.026	0.029	0.544(2.058)**
1996	0.022	0.032	0.664(8.50)***	0.025	0.040	0.702(10.42)***
1997	0.025	0.037	0.664(8.57)***	0.025	0.047	0.788(16.91)***
1998	0.026	0.034	0.627(5.28)***	0.029	0.041	0.749(11.44)***
Average	0.025	0.027	0.546(8.55)***	0.028	0.031	0.578(14.51)***
	Low Foreign Sales			**Zero Foreign Sales**		
Year	*Ex*-D	*Ex*-G	%DCAPM Closer	*Ex*-D	*Ex*-G	%DCAPM Closer
1983	0.036	0.036	0.499(-0.04)	0.027	0.029	0.518(0.88)
1984	0.029	0.028	0.530(1.27)	0.025	0.026	0.54(2.01)**
1985	0.028	0.030	0.639(6.31)***	0.029	0.031	0.585(4.48)***
1986	0.032	0.032	0.532(1.41)	0.028	0.032	0.649(8.11)***
1987	0.027	0.027	0.579(3.59)***	0.026	0.031	0.682(10.27)***
1988	0.025	0.026	0.511(0.49)	0.024	0.027	0.611(6.01)***
1989	0.026	0.027	0.579(3.82)***	0.022	0.024	0.579(4.19)***
1990	0.027	0.028	0.559(2.80)***	0.026	0.027	0.482(-0.97)
1991	0.025	0.027	0.533(1.59)	0.026	0.025	0.414(-4.66)***
1992	0.029	0.030	0.526(1.24)	0.026	0.025	0.484(-0.85)
1993	0.030	0.031	0.542(2.04)**	0.026	0.032	0.551(2.80)***
1994	0.025	0.024	0.503(0.17)	0.024	0.029	0.57(3.92)***
1995	0.026	0.027	0.506(0.29)	0.031	0.036	0.634(7.55)***
1996	0.026	0.027	0.554(2.66)***	0.033	0.040	0.611(6.19)***
1997	0.027	0.031	0.557(2.80)***	0.034	0.038	0.534(1.89)*
1998	0.030	0.032	0.512(0.49)	0.033	0.033	0.526(1.22)
Average	0.028	0.029	0.541(7.67)***	0.027	0.030	0.561(12.99)***

***Significant at the 0.01 level.
**Significant at the 0.05 level.
*Significant at the 0.10 level.

Table IV. Risk Premium Estimates and Differences by Industry

The table shows the breakdown of the full-period risk premium estimates by broad industry groups. The reported results weight each firm in the industry equally. Columns two to nine, respectively, show the total number observations (#Obs), the average *ex ante* risk premia (*Ex Ante*), the average domestic beta estimates (β_{iD}), the average global beta estimates (β_{iG}), the average DCAPM industry risk premium estimate (RP_D), the average GCAPM industry risk premium estimate (RP_G), the average absolute differences between the *ex ante* estimates and those of the DCAPM (*Ex*-D), and the average absolute differences between the *ex ante* estimates and those of the GCAPM (*Ex*-G), and the percentage of cases in which the *ex ante* estimate is closer to the DCAPM estimate than to GCAPM estimate (%DCAPM Closer). The numbers in parenthesis are the corresponding *t*-statistics. Rows in italics indicate *Ex*-G lower than *Ex*-D.

Industry	#Obs	Ex Ante	β_{iD}	β_{iG}	RP_D	RP_G	Ex-D	Ex-G	%DCAPM Closer
Aero	738	6.63	1.15	0.90	7.86	7.97	0.031	0.033	0.52(0.96)
Autos	1546	5.29	1.15	0.89	7.94	7.69	0.033	0.037	0.54(3.52)***
Banks	4004	7.16	1.21	0.85	8.58	7.96	0.027	0.026	0.49(-0.82)
Beer	1264	6.60	0.87	0.69	6.07	6.25	0.024	0.028	0.64(10.25)***
BldMt	1298	6.84	1.27	1.01	8.74	8.51	0.026	0.029	0.64(10.84)***
Books	1291	7.64	1.07	0.80	7.37	6.86	0.021	0.023	0.52(1.48)
Boxes	626	8.39	1.04	0.85	7.15	7.27	0.027	0.029	0.52(1.04)
BusSv	1374	8.15	1.07	0.82	7.49	7.24	0.023	0.028	0.60(7.77)***
Chems	2451	6.49	1.16	0.94	7.99	8.14	0.024	0.026	0.57(7.50)***
Chips	1414	8.11	1.28	0.96	8.93	8.53	0.026	0.028	0.57(5.70)***
Clths	562	7.74	1.37	0.93	9.69	8.74	0.030	0.030	0.47(-1.44)
Cnstr	_989_	_7.70_	_1.54_	_1.18_	_10.68_	_10.33_	_0.046_	_0.039_	_0.39(-7.14)***_
Comps	_1281_	_9.42_	_1.19_	_0.90_	_8.31_	_8.09_	_0.032_	_0.037_	_0.53(2.27)**_
Drugs	2098	8.29	0.99	0.78	6.91	7.09	0.023	0.023	0.50(0.00)
ElcEq	1246	6.89	1.08	0.89	7.46	7.63	0.017	0.019	0.55(3.65)***
Energy	3487	6.29	0.88	0.87	5.99	7.63	0.032	0.035	0.57(8.12)***
Fin	657	8.38	1.76	1.13	12.87	11.89	0.056	0.053	0.49(-0.74)
Food	_2588_	_7.02_	_0.86_	_0.65_	_5.99_	_5.77_	_0.019_	_0.025_	_0.69(20.71)***_
Fun	183	9.98	1.19	0.95	8.25	8.40	0.020	0.018	0.33(-4.78)***
Gold	588	4.59	0.57	0.85	3.76	7.48	0.050	0.051	0.61(5.50)***
Hlth	432	10.4	1.29	1.05	8.99	9.83	0.026	0.024	0.49(-0.48)
Hshld	2368	6.77	1.02	0.77	7.10	6.92	0.021	0.022	0.51(1.11)
Insur	4992	7.46	1.03	0.72	7.23	6.45	0.024	0.024	0.51(1.95)*
LabEq	1280	7.31	1.10	0.92	7.48	7.92	0.020	0.020	0.48(-1.40)
Mach	_2683_	_7.32_	_1.20_	_0.98_	_8.36_	_8.86_	_0.027_	_0.032_	_0.57(7.75)***_
Meals	561	7.98	1.06	0.79	7.35	7.18	0.024	0.028	0.63(6.53)***
MedEq	1334	8.80	1.03	0.77	7.18	6.86	0.029	0.032	0.52(1.70)*
Paper	2969	6.14	1.13	0.89	7.79	7.59	0.024	0.025	0.59(9.48)***
PerSv	453	9.12	0.95	0.76	6.61	6.95	0.028	0.028	0.58(3.28)***
Retail	_4380_	_9.27_	_1.12_	_0.76_	_7.74_	_6.65_	_0.031_	_0.038_	_0.62(16.24)***_
Rubber	524	7.06	1.22	0.88	8.55	8.14	0.025	0.027	0.55(2.19)**
Ships	187	1.95	0.95	0.65	6.39	4.75	0.046	0.041	0.27(-6.98)***
Stee	1510	4.96	1.13	0.97	7.76	8.18	0.041	0.044	0.61(8.92)***
Telcm	1553	6.12	0.83	0.61	5.91	6.08	0.020	0.023	0.56(4.42)***
Toys	_447_	_7.42_	_1.24_	_0.93_	_8.70_	_8.54_	_0.028_	_0.035_	_0.69(8.63)***_
Trans	1651	5.70	1.14	0.87	7.90	7.67	0.029	0.031	0.50(0.37)
Txtls	374	6.52	0.95	0.74	6.50	6.53	0.022	0.024	0.58(3.14)***
Util	6189	4.15	0.57	0.48	3.95	4.38	0.017	0.019	0.57(10.79)***
Whlsl	1582	8.29	0.92	0.75	6.41	6.77	0.028	0.025	0.45(-4.40)***

***Significant at the 0.01 level.
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with value weighting. Also, the DCAPM industry risk premium estimates with the CRSP Value-Weighted Index are very close to the estimates we report for the S&P 500 Index.

Since the DCAPM provides the better overall fit, the DCAPM will have the better fit for many industries. The GCAPM provides a slightly better fit for a few of the industry groups, Banks, Construction, Finance, Health, and Wholesale. For industry groups such as Computers, Food, Machines, Retail, and Toys, the DCAPM provides a significantly better overall fit with the *ex ante* estimates than does the GCAPM.

E. Further Analysis of Industry Risk Premium Estimates

Table V reports the results of cross-section regressions using the industry risk premium estimates for the period 1983-1998, and estimates obtained from other approaches by Fama and French (1997) and Gebhardt et al. (2001). We excluded the Ships and Fun industries, which only had one firm each in our sample.

The most striking result in Table V is that the *ex ante* industry risk premium estimates have an r-square of 31.6% (a correlation of about 0.56) with the Fama-French DCAPM estimates. The Fama-French DCAPM industry estimates even outperform our own DCAPM industry estimates in explaining our *ex ante* industry estimates, even though the Fama-French time span is different, 1963-1994. Perhaps the explanation has to do with investors using more than five years of realized returns as the basis for expectations, or viewing the one-month Treasury bill (used by Fama and French) as the risk-free security instead of the 20-year T-bond used in this study. Both of the DCAPM industry estimates outperform the GCAPM industry estimates.

The r-square of the *ex ante* industry risk premium estimates and the Fama-French (1997) industry risk premium estimates for the 3-Factor Model is only 5.79% (a correlation coefficient of 0.24). Thus, the *ex ante* industry risk premium estimates have a much better fit with the Fama-French DCAPM industry estimates than with those of the 3-Factor Model. This finding is consistent with similar findings reported by Kaplan and Ruback (1995) and Brav et al. (2003). The results with the CRSP Value-Weighted Index as the DCAPM benchmark are very close to those reported with the S&P 500 Index.

Gebhardt et al. (2001) determined their *ex ante* risk premium estimates by using the residual income model from the full period 1979-1995, with the ten-year T-bond serving as the risk-free security. The Gebhardt-Lee-Swaminathan industry risk premium estimates have a very low correlation with our DCAPM and GCAPM estimates, with the Fama-French (1997) DCAPM and 3-Factor Model estimates, and with our *ex ante* industry estimates.

IV. Conclusion

We compare *ex ante* expected return estimates, which are implicit in share prices, analysts' growth forecasts, and the dividend growth model, with expected return estimates from the global CAPM and the domestic (US) CAPM. We use the MSCI World Index as the market benchmark for computing betas for the global CAPM, and both the S&P 500 Index and the CRSP Value-Weighted Index as the market benchmark for computing betas for the domestic CAPM. Our sample comprises S&P 500 companies over the period 1983-1998. We find that the domestic CAPM has a better fit with the dispersion of *ex ante* expected return estimates, overall and for all subsamples, based on the ratio of foreign sales to total sales. We observe no trend in this fit over time. While the domestic model provides a better fit of our data, the relatively small empirical difference between the models suggests that for estimating the

Table V. Cross-Section Regressions with Industry Risk Premium Estimates

Panel A displays the results of cross-section regressions. We use our industry *ex ante* risk premium estimates for the period 1983-1998 compared to industry average risk premium estimates from the DCAPM, the GCAPM, and estimates reported in Fama and French (1997) and Gebhardt, Lee, and Swaminathan (2001). Panel B shows the results of cross-section regressions using the Gebhardt, Lee, and Swaminathan (2001) *ex ante* risk premium estimates (from the residual income model for the overall time period 1979-1995) compared to industry average risk premium estimates from the DCAPM, the GCAPM, and estimates reported in Fama and French (1997). The numbers in parenthesis are the corresponding *t*-statistics.

Panel A. Dependent Variable: Ex Ante Industry Risk Premium Estimate			
Independent Variable	**Intercept**	**Slope**	**R- Square**
Industry Risk Premium Estimates:			
--Our DCAPM	4.442(4.51)***	0.370(2.92)***	19.58%
--GCAPM	4.775(3.73)***	0.325(1.96)**	9.99%
--Our Fama-French DCAPM	2.861(2.58)***	0.773(4.02)***	31.60%
--Fama-French 3-Factor	8.218(11.86)***	-0.154(-1.47)	5.79%
--Gebhardt-Lee-Swaminathan	7.241(17.03)***	0.005(0.04)	0.00%
Panel B. Dependent Variable: Industry Risk Premium Estimate of Gebhardt-Lee-Swaminathan			
Industry Risk Premium Estimates:			
-- Our DCAPM	0.863(0.65)	0.237(1.38)	5.13%
-- Our GCAPM	2.287(1.36)	0.050(0.23)	0.15%
-- Fama-French DCAPM	1.305(0.79)	0.240(0.83)	1.93%
-- Fama-French 3-Factor	1.343(1.56)	0.212(1.62)	6.97%

***Significant at the 0.01 level.
**Significant at the 0.05 level.

cost of equity, the choice between the domestic and global CAPM may not be a material issue for many large US firms.

The consistently better performance of the domestic CAPM surprises us, given the extensive integration in the world financial markets and arguments for the global CAPM over the domestic CAPM. Perhaps the explanation is that US practitioners apply the domestic CAPM, as suggested in standard textbooks when they should be using the global CAPM. An alternative explanation is that US practitioners believe a domestic market index is a better benchmark for their investment decisions than is a global index. By extending our study to smaller US companies and to non-US companies, we might be able to shed more light on this question. We leave this possibility to future research.

We also find significant and consistently positive associations between our *ex ante* risk premium and beta estimates. These findings are consistent with the reports in a number of other studies that use *ex ante* return estimates.■

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STAFF-DR-02-019

REQUEST:

Provide Attachment RAM-4 electronically on CD-ROM in Microsoft Excel format with all formulas intact and unprotected.

RESPONSE:

See attached CD for Attachment RAM-4.

PERSON RESPONSIBLE: Roger A. Morin

STAFF-DR-02-020

REQUEST:

Refer to page 14 of the Direct Testimony of Robert M. Parsons ("Parsons Testimony"), Schedule D-2.11 and Workpaper WPD-2.11a. Identify and describe the specific items and/or reasons for Other Operating Expenses being $362,672 greater in the forecasted period than in the base period.

RESPONSE:

The amount on Schedule D-2.11 is to adjust the base period to the forecasted level per Kentucky Administrative Regulations. Other Operating Expenses in the base period includes $362,672 of negative amortization expense that is nearly offset by related DSM revenues during the six months of actual activity. This amortization and revenue was not budgeted since the net income result is zero.

PERSON RESPONSIBLE: Robert M. Parsons

STAFF-DR-02-021

REQUEST:

Refer to page 14 of the Parsons Testimony, Schedule D-2.13 and Workpaper WPD-2.13a. Identify and describe the specific items and/or reasons for Taxes Other than Income Taxes being $2,761,119 greater in the forecasted period than in the base period.

RESPONSE:

The primary expense contributing to the increase in Taxes Other than Income Taxes is property tax expense. In December 2008, a period that is included in the base period, an adjustment was made to property tax expense in the amout of ($2,141,801) as a result of the final Property Valuation received from the Kentucky Revenue Cabinet. Other increases in the forecasted period property tax expense are due to additions to plant in-service, assessment valuations, and increased property tax rates. The total increase in property tax expense is $2,810,362.

PERSON RESPONSIBLE: Robert M. Parsons

STAFF-DR-02-022

REQUEST:

Refer to pages 15 and 27 of the Parsons Testimony. Page 15 indicates that the adjustment related to the company's proposal to move the portion of bad debt charge offs associated with gas cost revenue to its GCA is $255,116. On page 27, the difference between the total uncollectible expense of $338,344 and the portion related to the cost of delivering gas to customers, $122,920, is $215,424. Explain whether the $255,116 and $215,424 represent different costs and, if not, why the two amounts should not be the same.

RESPONSE:

The $255,116 is the amount required to adjust the forecasted uncollectible expense to the annualized uncollectible expense for delivery only (Base Revenue.) The $215,424 is the annualized uncollectible expense on Fuel only. Detailed calculation of these amounts is included on attachment STAFF-DR-02-022.

PERSON RESPONSIBLE: Robert M. Parsons

DUKE ENERGY KENTUCKY

Explanation of Uncollectible Expense Annualization Adj.

Line No.		Amount (1)	
1	Forecasted Period Uncollectible Expense (WPD-2.15a, line 9)	378,036	
2	Annualized Uncollectible Expense -		
3	Base (WPD-2.15a, line 7)	122,920	
4	Fuel (WPD-2.15a, line 8)	215,424	(2)
5	Total (WPD-2.15a, line 6)	338,344	
6	Annualization Adj. Excluding Fuel (line 1 - line 3)	255,116	(3)

(1) Excluding Time Value of Money.
(2) This is the annualized uncollectible expense on Fuel only.
(3) This is the amount required to adjust the forecasted uncollectible expense to the annualized uncollectible expense on Delivery only.

Duke Energy Kentucky, Inc.
Case No. 2009-00202
Second Set Staff Data Requests
Date Received: August 17, 2009

STAFF-DR-02-023

REQUEST:

Refer to pages 17 – 18 of the Parsons Testimony. Explain whether the proposed methodology for calculating property tax expense has been used by Duke Kentucky in any of its previous forecasted test year rate cases.

RESPONSE:

No. In previous forecasted test year rate cases, the Company has included the forecasted expense in its revenue requirement calculation. Staff has taken issue with this forecasted expense in those cases. The methodology used in this case for calculationg property tax expense was developed to alleviate the disagreement over the amount of property tax expense allowed in the forecasted test year.

PERSON RESPONSIBLE: Robert M. Parsons

STAFF-DR-02-024

REQUEST:

Refer to page 28 of the Parsons Testimony, which indicates that the amount of uncollectible expense in Duke Kentucky's base rates and in the gas commodity component would have to be adjusted if the Commission does not approve its proposed treatment of uncollectible expense. Provide the amount of such adjustments along with revised versions of all schedules, exhibits and work papers that will be affected by these adjustments.

RESPONSE:

If the Commission does not approve the Company's proposed treatment of uncollectible expense, the uncollectible expense adjustment on Schedule D-2.18 will increase by $215,424 resulting in an increase in the revenue requirement of $218,330. See attachment STAFF-DR-02-024 for the revised versions of all schedules and workpapers.

PERSON RESPONSIBLE: Robert M. Parsons

DUKE ENERGY KENTUCKY, INC.
CASE NO. 2009-00202
OVERALL FINANCIAL SUMMARY
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2009
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2011

DATA: "X" BASE PERIOD "X" FORECASTED PERIOD
TYPE OF FILING: "X" ORIGINAL UPDATED REVISED
WORK PAPER REFERENCE NO(S).: SEE BELOW

SCHEDULE A
PAGE 1 OF 1
WITNESS RESPONSIBLE:
R. M. PARSONS

LINE NO.	DESCRIPTION	SUPPORTING SCHEDULE REFERENCE	JURISDICTIONAL REVENUE REQUIREMENTS BASE PERIOD	FORECAST PERIOD
1	Capitalization Allocated to Gas Operations	WPA-1a. 1c	243.125.397	253,767,597
2	Operating Income	C-2	6,172,247	8,690,942
3	Earned Rate of Return (Line 2 / Line 1)		2 54%	3 42%
4	Rate of Return	J-1	7.199%	7 671%
5	Required Operating Income (Line 1 x Line 4)		17,502,597	19,466,512
6	Operating Income Deficiency (Line 5 - Line 2)		11,330,350	10,775,570
7	Gross Revenue Conversion Factor	H	1.6437800	1.6437800
8	Revenue Deficiency (Line 6 x Line 7)		18,624,603	17,712,666
9	Revenue Increase Requested	C-1	N/A	17,712,666
10	Adjusted Operating Revenues	C-1	N/A	124,681,347
11	Revenue Requirements (Line 9 + Line 10)		N/A	142,394,013

DUKE ENERGY KENTUCKY, INC.
GAS DEPARTMENT
CASE NO. 2009-00202
DATA: BASE PERIOD "X" FORECASTED PERIOD
CALCULATION OF JURISDICTIONAL CAPITALIZATION

WPA-1c
WITNESS RESPONSIBLE:
R. M. PARSONS

Line No.	Description		Capitalization Total	Capitalization Gas
1	Total Forecasted Period Capitalization	(1)	824,068,159	
2				
3	Less: Gas Non-jurisdictional Rate Base	(2)	7,311,037	
4	Electric Non-jurisdictional Rate Base	(2)	(4,341)	
5	Non-jurisdictional Rate Base	(2)	(51,332,129)	
6				
7	Jurisdictional Capitalization		868,093,592	
8				
9	Gas Jurisdictional Rate Base Allocation %	(3)	29.108%	252,684,683
10				
11	Plus: Jurisdictional Gas ITC	(4)		1,082,914
12				
13	Total Allocated Capitalization			253,767,597
14				
15				
16				To Sch. A

Notes:
(1) Schedule J-1, page 2.
(2) Source: WPA-1d.
(3) Allocation percentage from WPA-1d.
(4) Schedule B-6, page 2.

WPA-1d
WITNESS RESPONSIBLE:
R. M. PARSONS

DUKE ENERGY KENTUCKY, INC.
GAS DEPARTMENT
CASE NO. 2009-00202
TO DETERMINE THE FORECAST PERIOD RATIO OF KENTUCKY JURISDICTIONAL GAS OPERATIONS
TO JURISDICTIONAL TOTAL COMPANY OPERATIONS
DATA: BASE PERIOD "X" FORECASTED PERIOD

Line No.	Description	Schedule Reference	Total Company	Gas Excl. of Facil Dev. to Other Than DE-Ky Custs.	Gas Non-Juris.	Elec Excl. of Facil Dev. to Other Than DE-Ky Custs.	Electric Non-Juris.	Non-Jurisdictional
1	Total Utility Plant in Service (Accts 101 & 106)	Sch B-2	1,611,086,666	388,986,305	12,357,099	1,185,654,914	0	24,088,348
2								
3	Additions:							
4	Construction Work in Progress (Account 107)	Sch B-4	19,852,896	3,777,154	0	16,075,742	0	0
5								
6	Fuel Inventory	WPB-5.1i	23,784,532	0	0	23,784,532	0	0
7								
8	Materials & Supplies -							
9	Propane Inventory (Account 151)	WPB-5.1b	1,016,582	355,804	660,778	0	0	0
10	Other Material and Supplies (Accts. 154 & 163)	WPB-5.1c	10,653,895	(95,694)	0	10,749,589	0	0
11	Total Materials & Supplies		11,670,477	260,110	660,778	10,749,589	0	0
12								
13	Gas Stored Underground (Account 164)	WPB-5.1g	2,308,330	0	2,308,330 (E)	0	0	0
14								
15	Prepayments (Account 165)	WPB-5.1e	2,080,109	0	121,240	1,657,228	301,641	0
16								
17	Emission Allowances (Account 158)	WPB-5.1j	4,252,584	0	0	4,252,584		
18								
19	Cash Working Capital Allowance	WPB-5.1a	17,192,737	2,398,127	0	14,794,610	0	0
20								
21	Other Rate Base Items	Sch B-6	0	0	0	0	0	0
22	Total Additions		81,141,665	6,435,391	3,090,348	71,314,285	301,641	0
23								
24	Deductions:							
25	Reserve for Accumulated Depreciation (Acct 108)	Sch B-3	692,147,793	104,342,038 (A)	7,896,329	571,538,510	0	8,370,916
26								
27	Accum. Deferred Income Taxes (Accts 190, 282, & 283)	Sch B-6	168,930,460	36,021,577 (B)	(842,963) (C)	68,260,647	0	65,491,199
28								
29	Customer Advances for Construction (Account 252)	Sch B-6	1,638,646	1,638,646	0	0	0	0
30								
31	Investment Tax Credits - 3%	Sch B-6	2,955,668	8,280	1,083,044 (D)	0	305,982	1,558,362
32	Total Deductions		865,672,567	142,010,541	8,136,410	639,799,157	305,982	75,420,477
33								
34	Net Original Cost Rate Base		826,555,764	253,411,155	7,311,037	617,170,042	(4,341)	(51,332,129)
35								
36	Jurisdictional Rate Base Ratio		100.000%	30.659%	0.885%	74.668%	-0.001%	-6.210%
37								
38	Jurisdictional Rate Base Ratio - Excluding Non-Jurisdictional		100.000%	29.108%		70.892%		

Notes:
(A) Does not include depreciation annualization adjustment per Commission precedent.
(B) Adjusted for non-jurisdictional gas plant.
(C) WPB-6d. Includes Liberalized Depreciation of $665,328, and Unbilled Revenue - Fuel of ($1,508,291).
(D) WPB-6b and WPB-6d.
(E) Treatment of Gas Stored Underground as a non-jurisdictional item is conditional on the Commission approving the request to recover carrying costs in the GCA rider.

DUKE ENERGY KENTUCKY, INC.
GAS DEPARTMENT
CASE NO. 2009-00202
CASH WORKING CAPITAL

WPB-5.1a
WITNESS RESPONSIBLE:
R. M. PARSONS

LINE NO.	DESCRIPTION	WORK PAPER REFERENCE	JURISDICTIONAL BASE PERIOD	JURISDICTIONAL FORECASTED PERIOD
1	Gas Cash Working Capital			
2	Total Jurisdictional O & M Expense	Sch C-2	101,961,952	98,124,379
3				
4	Less: Purchased Gas Cost	Sch C-2	81,058,949	78,939,367
5				
6	Net Operation & Maintenance Expense		20,903,003	19,185,012
7				
8	Cash Working Capital			
9				
10	1/8 of Net Operation & Maintenance Expense	To Sch B-5.1 <---	2,612,875	2,398,127
11				
12				
13	Electric Cash Working Capital			
14	Total Jurisdictional O & M Expense	Company Records	105,690,022	118,356,881
15				
16	Less: Fuel and Purchased Power Expense	Company Records	0	0
17				
18	Net Operation & Maintenance Expense		105,690,022	118,356,881
19				
20	Cash Working Capital			
21				
22	1/8 of Net Operation & Maintenance Expense		13,211,253	14,794,610
			To WPA-1b	To WPA-1d

DUKE ENERGY KENTUCKY, INC
CASE NO 2009-00202
JURISDICTIONAL OPERATING INCOME SUMMARY
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2011

DATA: BASE PERIOD "X" FORECASTED PERIOD
TYPE OF FILING: "X" ORIGINAL UPDATED REVISED
WORK PAPER REFERENCE NO(S): SCHEDULE C-2, WPC-1a

SCHEDULE C-1
PAGE 1 OF 1
WITNESS RESPONSIBLE:
R M PARSONS

LINE NO	DESCRIPTION	FORECASTED RETURN AT CURRENT RATES	PROPOSED INCREASE		FORECASTED RETURN AT PROPOSED RATES
		($)	($)		($)
1	Operating Revenues	124,681,347	17,712,666	(1)	142,394,013
2					
3	Operating Expenses				
4	Operation & Maintenance	98,124,379	48,355		98,172,734
5	Depreciation	11,657,827	0		11,657,827
6	Taxes - Other	4,061,181	28,340		4,089,521
7	Operating Expenses before Income Taxes	113,843,387	76,695		113,920,082
8					
9	State Income Taxes	389,771	1,058,158		1,447,929
10	Federal Income Taxes	2,046,992	5,802,235		7,849,227
11					
12	Total Operating Expenses	116,280,150	6,937,088		123,217,238
13					
14	AFUDC Offset	289,745	0		289,745
15					
16	Income Available for Fixed Charges	8,690,942	10,775,578		19,466,520
17					
18	Capitalization Allocated to Jurisdictional Gas Operations	253,767,597			253,767,597
19	Rate of Return on Capitalization	3.42%			7.67%
20					
21	Jurisdictional Rate Base	253,152,895			253,152,895
22	Rate of Return on Rate Base	3.43%			7.69%

(1) Source: Schedule M

DUKE ENERGY KENTUCKY, INC.
CASE NO. 2009-00202
JURISDICTIONAL ADJUSTED OPERATING INCOME STATEMENT
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2009
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2011

DATA: "X" BASE PERIOD "X" FORECASTED PERIOD
TYPE OF FILING: "X" ORIGINAL UPDATED REVISED
WORK PAPER REFERENCE NO(S).: SCHEDULE C-2.1, SCHEDULE D-1, WPC-2a through WPC-2e

SCHEDULE C-2
PAGE 1 OF 1
WITNESS RESPONSIBLE:
R. M. PARSONS

LINE NO.	MAJOR ACCOUNT OR GROUP CLASSIFICATION	BASE PERIOD	ADJUSTMENTS TO BASE PERIOD AMOUNT	ADJUSTMENTS TO BASE PERIOD SCHEDULE REFERENCE	FORECASTED PERIOD	PRO FORMA ADJUSTMENTS TO FORECASTED PERIOD AMOUNT	PRO FORMA ADJUSTMENTS TO FORECASTED PERIOD SCHEDULE REFERENCE	PRO FORMA FORECASTED PERIOD
1	OPERATING REVENUE							
2	Base	43,927,668	890,725	D-2.1	44,818,393	223,039	WPC-2e	45,041,432
3	Gas Cost	82,329,395	(2,543,805)	D-2.1	79,785,590	(846,223)	D-2.24	78,939,367
4	Other Revenue	(6,301,866)	7,516,506	D-2.1	1,214,640	(514,092)	WPC-2e	700,548
5	Total Revenue	119,955,197	5,863,426		125,818,623	(1,137,276)		124,681,347
6								
7	OPERATING EXPENSES							
8	Operation and Maintenance Expenses							
9	Production Expenses							
10	Liquefied Petroleum Gas	100,086	(17,311)	D-2.2	82,775	0		82,775
11	Other	227,559	40,363	D-2.3	267,922	(32,821)	D-2 19	235,101
12	Total Production Expense	327,645	23,052		350,697	(32,821)		317,876
13								
14	Other Gas Supply Expenses							
15	Purchased Gas	81,058,949	(1,273,359)	D-2.2	79,785,590	(846,223)	D-2.24	78,939,367
16	Other	443,391	146,105	D-2.4	589,496			589,496
17	Total Other Gas Supply Expenses	81,502,340	(1,127,254)		80,375,086	(846,223)		79,528,863
18	Transmission Expense	0	0	D-2.5	0	0		0
19	Distribution Expense	5,626,174	316,688	D-2.6	5,942,862	(240,821)	WPC-2e	5,702,041
20	Customer Accounts Expense	3,811,654	306,001	D-2.7	4,117,655	(1,064,911)	D-2 15	3,052,744
21	Customer Service & Information Expense	542,651	(10,122)	D-2.8	532,529	(855)	D-2 22	531,674
22	Sales Expense	0	0	D-2.9	0	0	D-2.22	0
23	Administrative & General Expense	10,514,160	(652,755)	D-2.10	9,861,405	(870,224)	WPC-2e	8,991,181
24	Other	(362,672)	362,672	D-2.11	0	0		0
25	Total Operation and Maintenance Expense	101,961,952	(781,718)		101,180,234	(3,055,855)		98,124,379
26								
27	Depreciation Expense	8,838,161	757,715	D-2.12	9,595,876	2,061,951	D-2.23	11,657,827
28								
29	Taxes Other Than Income Taxes							
30	Other Federal Taxes	530,251	106,912	D-2.13	637,163	(4,440)	D-2.19	632,723
31	State and Other Taxes	1,736,433	2,654,207	D-2.13	4,390,640	(962,182)	WPC-2e	3,428,458
32	Total Taxes Other Than Income Taxes	2,266,684	2,761,119		5,027,803	(966,622)		4,061,181
33								
34	State Income Taxes							
35	State Income Tax - Current	415,004	(482,695)	D-1, E-1	(67,691)	125,599	D-1, E-1	57,908
36	Provision for Deferred Income Taxes - Net	(130,836)	551,604	D-1, E-1	420,768	(88,905)	D-1, E-1	331,863
38	Total State Income Tax Expense	284,168	68,909		353,077	36,694		389,771
39								
40	Federal Income Taxes							
41	Federal Income Tax - Current	464,651	(310,951)	D-1, E-1	153,700	688,700	D-1, E-1	842,400
42	Provision for Deferred Income Taxes - Net	29,337	1,735,405	D-1, E-1	1,764,742	(487,493)	D-1, E-1	1,277,249
43	Amortization of Investment Tax Credit	(62,003)	(10,654)	D-1, E-1	(72,657)	0	D-1, E-1	(72,657)
44	Total Federal Income Tax Expense	431,985	1,413,800		1,845,785	201,207		2,046,992
45								
46	Total Operating Expenses and Taxes	113,782,950	4,219,825		118,002,775	(1,722,625)		116,280,150
47								
48	AFUDC Offset	0	0		0	289,745	D-2.20	289,745
49								
50	Net Operating Income	6,172,247	1,643,601		7,815,848	875,094		8,690,942

DUKE ENERGY KENTUCKY, INC.
CASE NO. 2009-00202
ADJUST UNCOLLECTIBLE EXPENSE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2011

DATA: BASE PERIOD "X" FORECASTED PERIOD
TYPE OF FILING "X" ORIGINAL UPDATED REVISED
WORK PAPER REFERENCE NO(S).: WPD-2.15a

SCHEDULE D-2.15
PAGE 1 OF 1
WITNESS RESPONSIBLE:
R. M. PARSONS

PURPOSE AND DESCRIPTION			AMOUNT

PURPOSE AND DESCRIPTION: To reflect the reclassification of the "time value of money" portion of the total discount expense from uncollectible expense to interest expense and to annualize uncollectible expense based on adjusted forecasted period revenue.

Time Value of Money Reclassification		$	(1,025,219)
Uncollectible Expense Annualization			(39,692)
Total Uncollectible Expense Adjustment		$	(1,064,911)
Jurisdictional allocation percentage (A)			100.000%
Jurisdictional amount	To Sch D-1 Summary <---	$	(1,064,911)

(A) Allocation Code - DALL

DUKE ENERGY KENTUCKY. INC
GAS DEPARTMENT
CASE NO 2009-00202
ANNUALIZE UNCOLLECTIBLE EXPENSE
FOR THE TWELVE MONTHS ENDED JANUARY 31. 2011

WPD-2 15a
WITNESS RESPONSIBLE:
R M PARSONS

Line No.	Description	Source	Total Amount	Base / Fuel Ratio	Charge-offs	Collection Costs	Late Payment Charges	Time Value of Money	
1	Base Revenue	Sch C-2	45.041.432	36 33%					
2	Fuel Revenue	Sch C-2	78.939.367	63 67%					
3	Less: Interdepartmental Revenues	Sch C-2 1	43,376						
4	Revenue Subject to Uncollectible Ratio (1) + (2) - (3)		123 937.423						
5	Uncollectible Expense Factor	WPH-a			0.9140%	0.0500%	-0.6910%		
6	Annualized Uncollectible Expense (4) * (5)				1.132,779	61.969	(856.404)		
7	Annualized - Base (6) * Base Revenue %				411,539	22,513	(311,132)		
8	Annualized - Fuel (6) * Fuel Revenue %				721,240	39.456	(545.272)		
9	Forecasted Period Uncollectible Expense (A)	Sch C-2 1	1,403,255		1,265,736	69,180	(956,880)	1,025,219	(B)
10	Adjustment to Uncollectible Expense (6) - (9)		(1,064,911)		(132,957)	(7,211)	100,476	(1,025,219)	(C)

(A) Forecasted Period Uncollectible Expense is split using the following ratio developed from WPH-a:

	WPH-a	Ratio
Charge-off's	0 9140%	90 20%
Collection Costs	0 0500%	4 93%
Late Charges	-0 6910%	-68 19%
Time Value	0.7403%	73.06%
	1 0133%	100.00%

(B) The time value of money is eliminated because the sale of accounts receivable is included in short-term debt on Schedule J-2
(C) This adjustment is conditional upon the Commission approving the Company's request to recover the annualized uncollectible expense related to fuel revenue through its GCA rider

DUKE ENERGY KENTUCKY, INC.
CASE NO. 2009-00202
ADJUSTED JURISDICTIONAL FEDERAL AND STATE INCOME TAXES
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2009
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2011

DATA: "X" BASE PERIOD "X" FORECASTED PERIOD
TYPE OF FILING: "X" ORIGINAL UPDATED REVISED
WORK PAPER REFERENCE NO(S).: WPE-1a WPE-1b

SCHEDULE E-1
PAGE 1 OF 3
WITNESS RESPONSIBLE:
R. M. PARSONS

		AT CURRENT RATES					AT PROPOSED RATES	
LINE NO.	DESCRIPTION	BASE PERIOD (1) ($)	ADJUSTMENTS (2) ($)	FORECASTED PERIOD (3) ($)	PRO FORMA ADJ. TO FORECASTED ($)	PRO FORMA FORECASTED PERIOD ($)	ADJUSTMENTS (4) ($)	ADJUSTED (5) ($)
1	Operating Income before Federal							
2	and State Income Taxes	6,888,400	3,126,310	10,014,710	823,250	10,837,960	17,635,971	28,473,931
3								
4	Reconciling Items:							
5	Interest Charges	(4,967,514)	790,334	(4,177,180)	(211,679)	(4,388,859)	0	(4,388,859)
6	Net Interest Charges	(4,967,514)	790,334	(4,177,180)	(211,679)	(4,388,859)	0	(4,388,859)
7								
8	Permanent Differences	(54,403)	(14,149)	(68,552)		(68,552)		(68,552)
9								
10	Tax Depreciation	(17,992,799)	719,053	(17,273,746)	266,016	(17,007,730)	0	(17,007,730)
11	Book Depreciation	8,838,161	757,715	9,595,876	2,061,951	11,657,827	0	11,657,827
12	Excess of Tax over Book Depreciation	(9,154,638)	1,476,768	(7,677,870)	2,327,967	(5,349,903)	0	(5,349,903)
13								
14	Other Reconciling Items:							
15	Amortization of Loss on Reacquired Debt	175,048	(52,458)	122,590	0	122,590	0	122,590
16	Deferred Fuel Cost - PGA	(7,647,986)	7,647,986	0	0	0	0	0
17	Unbilled Revenue - Fuel	(3,879,447)	4,725,670	846,223	(846,223)	0	0	0
18	Other	20,383,117	(19,071,587)	1,311,530	0	1,311,530	0	1,311,530
19	Total Other Reconciling Items	9,030,732	(6,750,389)	2,280,343	(846,223)	1,434,120	0	1,434,120
20	Total Reconciling Items	(5,145,823)	(4,497,436)	(9,643,259)	1,270,065	(8,373,194)	0	(8,373,194)