RECEIVED
JUL 12 2006
PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF THE UNION LIGHT, HEAT AND POWER COMPANY D/B/A DUKE ENERGY KENTUCKY TO INCREASE ITS ELECTRIC RATES	)))	CASE NO. 2006-00172

ATTORNEY GENERAL'S INITIAL REQUEST FOR INFORMATION TO
THE UNION LIGHT, HEAT AND POWER COMPANY D/B/A DUKE ENERGY KENTUCKY

Comes now the intervenor, the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention, and submits this First Request for Information to Union Light, Heat and Power Company d/b/a Duke Energy Kentucky to be answered by the date specified in the Commission's Order of Procedure, and in accord with the following:

(1) In each case where a request seeks data provided in response to a staff request, reference to the appropriate request item will be deemed a satisfactory response.

(2) Please identify the witness who will be prepared to answer questions concerning each request.

(3) These requests shall be deemed continuing so as to require further and supplemental responses if the company receives or generates additional information within the scope of these requests between the time of the response and the time of any hearing conducted hereon.

(4) If any request appears confusing, please request clarification directly from the Office of Attorney General.

(5) To the extent that the specific document, workpaper or information as requested does not exist, but a similar document, workpaper or information does exist, provide the similar document, workpaper, or information.

(6) To the extent that any request may be answered by way of a computer printout, please identify each variable contained in the printout which would not be self evident to a person not familiar with the printout.

(7) If the company has objections to any request on the grounds that the requested information is proprietary in nature, or for any other reason, please notify the Office of the Attorney General as soon as possible.

(8) To the extent that the company has objections to any request for the provision of information on the grounds that doing so would violate Copyright laws, in lieu of the information requested, please state for the answer what efforts have been made by the company to secure permission to provide copies of the information requested for use in this case only. The response should include the name of the person to whom the request for permission to provide a copy of the document for use in this case was made, the date of the request, a copy of all documentation of the request and response, and the means by which the Attorney General might contact that person directly via telephone or electronically together with how and when the company will make the information available for inspection.

(9) For any document withheld on the basis of privilege, state the following: date; author; addressee; indicated or blind copies; all persons to whom distributed, shown, or explained; and, the nature and legal basis for the privilege asserted.

(10) In the event any document called for has been destroyed or transferred beyond the control of the company, please state: the identity of the person by whom it was destroyed or transferred, and the person authorizing the destruction or transfer; the time, place, and method of destruction or transfer; and, the reason(s) for its destruction or transfer. If destroyed or disposed of by operation of a retention policy, state the retention policy.

(12) Please provide written responses, together with any and all exhibits pertaining thereto, in one or more bound volumes, separately indexed and tabbed by each response.

Respectfully submitted,

GREGORY D. STUMBO
ATTORNEY GENERAL OF KENTUCKY

DENNIS G. HOWARD II
ELIZABETH BLACKFORD
LAWRENCE W. COOK
ASSISTANT ATTORNEYs GENERAL
FRANKFORT KY 40601-8204
(502) 696-5453
FAX: (502) 573-8315

NOTICE OF FILING AND CERTIFICATION OF SERVICE

I hereby give notice that I have filed the original and five true copies of the foregoing with the Executive Director of the Kentucky Public Service Commission at 211 Sower Boulevard, Frankfort, Kentucky, 40601 this the 12th day of July, 2006, and certify that this same day I have served the parties by mailing a true copy, postage prepaid, to the following:

SANDRA P MEYER
PRESIDENT
DUKE ENERGY KENTUCKY INC
139 EAST FOURTH STREET
CINCINNATI OH 45202

JOHN J FINNIGAN JR ESQ
DUKE ENERGY SHARED SERVICES INC
139 EAST FOURTH STREET
CINCINNATI OH 45202

MICHAEL L KURTZ
BOEHM KURTZ & LOWRY
36 E SEVENTH ST SUITE 1510
CINCINNATI OHIO 45202

Case No. 2006-00172
Attorney General's Request for Information
To Duke Energy Kentucky

1. With regard to the Trial Balance for the March 31, 2006 balance sheet in the response to PSC-1-30, please provide the following information:

   a. The balance sheet Trial Balance provided by the Company in its response to PSC-1-30 in the prior gas rate case shows significantly more detailed FERC sub-accounts, particularly with regard to ADIT accounts 190, 282, 283 and 284. Please provide a more detailed version of the March 31, 2006 balance sheet Trial Balance in the same detail as per the Trial Balance in the response to PSC-1-30 in the prior gas rate case.

   b. Provide similar balance sheet Trial Balances (in the detail as requested in part a above) for the months of February 2006, April 2006, May 2006 and June 2006. In addition, continue to update this request as additional actual monthly Trial Balances become available.

2. With regard to helicopter usage and expenses, please provide the following information:

   a. Which DEK employees are eligible for helicopter usage?

   b. Provide a detailed description of the reasons why helicopter usage is necessary for the provision of electric service.

   c. Provide the helicopter expenses included in the above-the-line Base Year and Forecasted Period operating expenses.

3. With regard to footnotes (1) and (2) on Schedule A, please provide the following information:

   a. Explain why the sales from RTP sales are excluded in the determination of the annualized fuel costs for the Forecasted Period.

   b. Provide a worksheet showing how the formula described in footnote (2) [Schedule M-2.3 total sales less RTP sales, times $0.021619/kwh] produces annualized fuel costs of $85,741,667.

4. Provide a worksheet showing the components of, and explaining the reasons for, the Non-Jurisdictional plant in service balance of $24,089,143 and the Non-Jurisdictional depreciation reserve balance of $8,748,625 for the Forecasted Period shown on WPA-1d.

5. Schedule C-2, line 23 and WPC-2e show that the adjusted annualized Pro Forma Forecasted Period depreciation expenses amount to $32,810,000 ($32,582,234 + $227,766). In this regard, please provide the following information:

   a. Schedule B-3.2, pages 1-6 show the calculation of this pro forma annualized deprecation expense number of $32,810,000. The data in column F on this schedule indicate that the depreciation accrual rates used in the annualized depreciation expense calculations are the current depreciation rates that have previously been approved by the PSC. In this regard, on page 8 of his direct testimony, Mr. Davey confirms that the depreciation rates used are the "rates currently in effect and approved by this Commission in Case No. 91-370." Mr. Davey also confirms that the depreciation rates used for the three transferred plants are the same as the depreciation rates used prior to the transfer. Yet, Mr. Wathen states on page 19 of his testimony that the depreciation expenses projected for the test year are based on "accrual rates proposed by Mr. Spanos and reflected in Schedule B-3.2…" Similarly, Mr. Council states on page 6 of his testimony that the proposed depreciation expenses in this case are based on the depreciation rates proposed by Mr. Spanos. Please provide a detailed explanation of these seemingly contradictory facts and statements.

   b. If the calculated depreciation amount of $32.810 on Schedule B-3.2 is based on Mr. Spanos' proposed depreciation rates (not the currently authorized depreciation rates), provide the comparable annualized depreciation expenses for the Forecasted Period using the currently authorized depreciation rates. Provide these calculations in the same format and detail as shown on Schedule B-3.2, pages 1-6.

   c. Provide a worksheet showing all detailed calculations and explanations in support of the pro forma depreciation expense adjustment of $227,766 shown on Schedule D-2.23, page 1.

6. The Gas cash working capital allowance of $2,388,409 shown on WPA-1d suggests total pro forma adjusted gas operation and maintenance expenses (net of purchased gas costs) of $19,107,272. Provide a worksheet showing all of the projected gas O&M expense components for the Forecasted Period, and explain the source of these projected gas expenses for 2007.

7. In the same format as shown on WPB-5.1d, pages 1 and 2, WPB-5.1h, WPB-5.1i and WPB-5.1j, provide the actual monthly balances for the M&S, prepayments, fuel and emission allowance components for the 12-month period ended June 30, 2006.

8. Please update the monthly balance sheet data on WPB-6a for actual balances for the months of February through June 2006.

9. Please provide a breakout of the Forecasted Period 13-month average electric ADIT balances in accounts 190, 282, 282 liberalized depreciation, and 283 shown on WPB-6b

by FERC sub-account components (i.e., in the same Trial Balance detail as requested in AG-1-1(a)).

10. Please indicate whether the Forecasted period 13-month average electric ADIT balance in account 283 includes ADIT associated with unbilled revenues. If so, indicate the 13-month average balance and explain whether this is a positive (prepayment ADIT) or a negative ADIT balance.

11. Provide a worksheet showing the calculations and calculation components in support of the statement on page 5 of Mr. Smith's direct testimony that the difference between the revenue requirement related to owning and operating "the Plants" versus the Company's previous wholesale power contract with Duke Energy Ohio is approximately $34 million.

12. With regard to WPA-1d, please provide the following information:

    a. For each of the rate base components in the Electric Jurisdictional column, provide the impact of including the transfer of the three plants.

    b. For the rate base components shown in the Non-Jurisdictional (last) column, provide the impact of including the transfer of the three plants.

13. Please provide the impact of the transfer of the three plants on the 13-month average capital balances (common equity, long-term debt, short-term debt) and the Account 255 ADITC balances shown on Schedule J-1, page 2.

    In addition, show what the allocated electric jurisdictional capitalization amount of $550,186,484 shown on WPA-1c would be without the impact of the reflection of the three transferred plants.

14. With regard to the operating expenses, taxes other than income taxes and depreciation associated with the reflection of the three transferred plants, please provide the following information:

    a. For each of the Base Year and Forecasted Period operating expense accounts and taxes other than income taxes accounts shown on Schedule C-2.1, provide the impact of the reflection of the three transferred plants.

    b. For the depreciation expenses on Schedule B-3.2, provide the impact of the reflection of the three transferred plants.

15. With regard to the income tax adjustment D-2.14 shown on Schedule D-1, page 4 (last column), please provide the following information:

    a. Provide a worksheet showing supporting calculations for each of the dollar amounts shown in this column.

b. Explain whether this net operating income adjustment is the result of restating the unadjusted Base Year income taxes and the income taxes associated with all Base Period adjustments based on the use of a 5.8% state income tax rate rather than a 7.0% income tax rate.

16. With regard to the pro forma Forecasted Period income tax calculations on Schedule E-1, pages 1-3, please provide the following information:

a. What is the basis for the interest expense deduction amount of $16,237,028? If this is calculated through the interest synchronization method, reconcile this amount to the $16,211,048 that results from applying the proposed weighted debt cost of 2.910% to the pro forma electric capitalization of $557,080,702.

b. What does the Kentucky Income Tax Adjustment – Misc Base Year amount of $6,045,379 represent and why has it been reduced by $4,936,379 going from the Base Year to the Forecasted Period?

c. Dividing the current Kentucky income tax amount of $142,796 for the pro forma Forecast Period into the total Kentucky taxable income of $2,369,904 results in a tax rate of 6.025%. Please reconcile this derived tax rate to the Forecasted Period Kentucky income tax rate of 5.8% that has been assumed by the Company in this case.

d. From the other data shown on Schedule E-1, provide a worksheet showing the derivation of Pro Forma Forecast Period deferred state income tax amount of $394,834 and the deferred federal income tax amount of $1,874,337.

e. The Base Year ITC amortization is $163,857, as shown in the first column of Schedule E-1, page 3. Please provide the following information:

   1) What were the actual corresponding electric ITC amortization amounts for the year 2005 and for the most recent 12-month period (e.g., year ended 6/30/06)?
   2) What is the reason for the $20,011 reduction from the Base Year to the Forecasted Period?

17. With regard to the IRC Section 199 Manufacturing shown on Schedule D-2.29 and described on page 3 of Mr. Butler's direct testimony, where is the impact of this tax deduction reflected in the income tax calculations on Schedule E-1, pages 1-3?

18. Schedule G-1 shows total payroll taxes for the Base Year of $1,475,118 and for the Forecasted Period of $2,117,099. In this regard, please provide the following information:

a. Reconcile these Base Year and Forecasted Period payroll taxes to the corresponding Base Year and Forecasted Period "Payroll Taxes Expensed – Electric amounts of $504,727, and $852,213, respectively.

b. Dividing the total Base Year payroll taxes of $1,475,118 into the Base Year labor expenses indicates a ratio of 8.50%. For the Forecasted Period, this ratio is 9.38%. Please provide the reasons why the ratio of payroll taxes to total payroll is so much higher for the Forecasted Period.

19. With regard to the State and Other Taxes for the Base Year and Forecasted Period shown on Schedule C-2.1, pages 6 and 13, please provide the following information:

a. Provide the actual electric property taxes in accounts 408020, 408025, 408055, 408065 and 408150 for the years 2003, 2004, 2005 and the most recent available 12-month period ending in 2006.

b. Explain why the Company has not included any property taxes for account 408150 for the Forecasted Period.

c. Provide detailed reasons and support for the proposed increase of $250,000 from the Base Year to the Forecasted Period for the East Bend property taxes.

d. The Base Year property taxes for the property taxes in accounts 408020, 408025 and 408055 amount to $3,027,448 and the corresponding taxes for the Forecasted Period amount to $4,875,540, or 61% higher than the Base Year taxes. In the same detail and format as per the Company's response to AG-DR-01-187 in the 2005 gas rate case, provide detailed explanations for this large projected property tax increase. In addition, identify the portion of the Base Year to Forecasted Period property tax increase that is caused by the Company's assumption that it will no longer receive assessment values lower than net book value in its negotiations with the KDR.

20. On page 10 of his direct testimony, Mr. Butler states: "As in past years, Duke Energy Kentucky will attempt to negotiate proper assessment values with the KDR." In this regard, please provide the following information in the same format and detail as per the Company's response to AG-DR-02-013 in the 2005 gas rate case:

a. For each of the last 4 tax years (2002, 2003, 2004 and 2005), provide details as to how successful the Company has been in its negotiations with the KRD to obtain assessment values that are below the net book value of the Company. To quantify this success, please provide, for each of these 4 years, the actual property taxes paid by the Company as compared to the property taxes it would have had to pay without the successful negotiations with the KRD to obtain assessment values below the net book value of the Company.

b. Assuming that the Company will be equally successful in its negotiations with the KRD to obtain assessment values below the net book value of the Company as it has been in recent years, how would this impact the Forecasted Period property taxes in accounts 408020, 408025 and 408055 that total $4,875,540?

21. Reference page 10, lines 6-9 of Mr. Butler's direct testimony; please indicate when the result of the Company's negotiations with the KDR for the 2006 tax year will become available. In addition, provide a copy of these results to the AG as soon as they are available, along with an analysis showing how the Forecasted Period property taxes currently reflected on Schedule C-2.1, page 13 would be impacted if the Commission were to adjust these property taxes for the results of the 2006 tax year KDR negotiations.

22. WPC-2b shows that the Forecasted Period includes total fuel revenues (w/o consideration of the OSS sharing of $2,190,184) of $102,961,803. Explain why this is so much higher than, and why this amount does not reconcile to, the pro forma Forecasted Period fuel revenues of $85,741,667 shown on Schedule A, Line 13.

23. With regard to the Off-System sales margin sharing, please provide the following information:

a. Confirm that the pro forma Forecasted Period fuel costs/revenues of $85,741,667 implicitly include an Off-System margin sharing credit of $2,306,284, which amount is shown on a projected monthly basis on Attachment WDW-1, page 2. If this is not correct, provide the correct answer.

b. In each monthly FAC filing, starting in January 2007, will the Company compare the actual Off-System margin number for that month to the projected Off-System margin number for January 2007 shown on Attachment WDW-1, page 2, and so on? Please provide a detailed explanation of how this process will work.

24. With regard to the proposed new Miscellaneous Charges discussed on page 34 of Mr. Bailey's testimony, provide the following information:

a. What is the projected annualized revenue amount associated with the new miscellaneous charge for the Reconnections at the Pole, what is the basis for this revenue projection, and where are these annualized revenues reflected in the Forecasted Period filing Schedule C-2.1, page 8 and Schedule M?

b. What is the projected annualized revenue amount associated with the new miscellaneous charge for the After-Hours Reconnection, what is the basis for this revenue projection and where are these annualized revenues reflected in the Forecasted Period filing Schedule C-2.1, page 8 and Schedule M?

c. What is the projected annualized revenue amount associated with the new miscellaneous charge for the Field Collections, what is the basis for this revenue projection and where are these annualized revenues reflected in the Forecasted Period filing Schedule C-2.1, page 8 and Schedule M?

25. Please provide a detailed reconciliation between the Forecasted Period Other Revenues shown on Schedule C-2.1, page 8 and the Forecasted Period Other Revenues that are included on Schedule M, page 1.

26. In the same format and account detail as shown on Schedule C-2.1, page 1 of 14, provide the actual Other Revenue components and associated revenues for each of the years 2003, 2004 and 2005 and for the most recent available 12-month period ended in 2006.

27. Please provide a worksheet comparing each of the Other revenue components and associated revenues for the Base Year on Schedule C-2.1, page 1 to the Other revenue components and associated revenues for the Forecasted Period on Schedule C-2.1, page 8, and explain and justify all of the adjustments made to arrive at the Forecasted Period revenue amounts totaling $1,557,765, representing a substantial reduction from the Base Year revenue total of $11.3 million.

28. With regard to the Merger Savings Credit for the electric operations, please provide the following information:

   a. Is it correct to state that, through the pro forma revenue adjustment of $2,044,825 on Schedule D-2.32, the pro forma adjusted Forecasted Period operating revenues no longer include the impact of the Merger Savings Credit? If this is not correct, provide the correct answer.

   b. Is it correct to state that the customers of the Company receive the Merger Savings Credit by way of a separate Rider rather than through a base rate credit?

   c. Provide the level of electric Merger Savings Credits that will flow to the ratepayers through the Rider in each year from 2006 through 2011.

29. With regard to the base revenue adjustment of $2,255,960 shown and described on Schedule D-2.34, please provide the following information:

   a. Where in the direct testimony of Mr. Bailey is there a "detailed explanation" for this revenue adjustment?

   b. Provide a more detailed explanation and a worksheet showing supporting calculations for this $2,255,960 reconciliation between the Forecasted Period Schedule M base revenues and the Forecasted Period revenues calculated in the budget.

30. Please provide the impact on the Company's proposed pro forma adjusted Forecasted Period base revenues of $172,138,103 by using the 1980-2004 25-year average normalized Heating and Cooling Degree Days of 5,047 and 1,099, respectively, rather

than the Company's proposed 10-year average Heating and Cooling Degree Days of 5,018 and 1,048, respectively.

31. Please expand the Degree Day data currently shown on Attachment RGS-2 by including actual heating and cooling degree data for the year 2005 and re-calculate the 10-year, 25-year and 30-year normalized averages through the year 2005 rather than the year 2004.

32. Please provide the impact on the Company's proposed pro forma adjusted Forecasted Period base revenues of $172,138,103 by using the 1986-2005 25-year average normalized Heating and Cooling Degree Days to be provided in response to the prior data request rather than the Company's proposed 10-year average Heating and Cooling Degree Days of 5,018 and 1,048, respectively.

33. Provide comparisons of the Company's actual versus originally budgeted annual electric operating revenues, expenses and taxes other than income taxes, by USOA account number (i.e., in the same account no. and account title detail and format as shown for the base period on Schedule C-2.1, pages 1 through 6 of 14), for each of the 3 years 2003 through 2005. In addition, show the annual variances and explain in detail any annual variances greater than 10%.

34. In the same format and detail as per Schedule C-2.2, pages 1-2, provide the actual O&M expenses (starting with account 500 and ending with account 935) for each of the years 2003, 2004 and 2005 and for the12-month period ended May or June (if available) 2006.

35. Please provide a side-by-side comparison, by detailed FERC plant account, of the John Spanos proposed depreciation rates in this case versus the existing PSC-approved depreciation rates.

36. Please provide a listing and description of any large commercial and industrial customers that were or are expected to be added as customers of DEK or were lost or are expected to be lost as customers of DEK that have become known since the time the Company prepared its filing in this case and that, therefore, are not reflected in the Forecasted Period electric sales and revenues. If so, provide full details and a description of how the annualization of such changes would impact the Forecasted Period revenue requirement.

37. Please identify any expenses, taxes and/or capitalization investments included in the Forecasted Period associated with the Company's Hartwell Recreation Center.

38. Please provide any changes affecting the Forecasted Period revenue requirement that should be made to the filing results based on information that has become available since the preparation of the filing.

39. Please provide a listing of all amortization expenses (other than the two amortization expenses shown on Schedule D-2.15) included in the Forecasted Period above-the-line operating expenses. For each amortization expense, provide the unamortized balance at the beginning of the Forecasted Period, the authorized amortization period, the Forecasted

Period amortization expense, the amortization expiration date, and an indication as to whether the cost deferral and amortization was authorized by the PSC.

40. With regard to the transaction costs associated with the transfer of the Plants shown on WPD-2.15a, please provide the following information:

a. On page 13 of the PSC's Order in Case No. 2003-00252, the Commission states that "ULH&P has estimated that the total transaction costs would be $4.9 million…." Please provide a worksheet showing the total actual transaction costs incurred to date and additional costs projected to be incurred. Provide these actual and projected costs in total and broken out by cost category. In addition, indicate whether all of these costs are allocated to DEK's electric operations or whether a portion of these costs are allocated to DEK's gas or other operations.

b. Explain and reconcile the difference between the originally estimated total transaction cost number of $4.9 million and the actual/projected cost number of $1,478,571 shown on WPD-2.15a.

c. Provide the basis for, and all actual source documentation in support of, the estimated transaction costs of $187,000. In addition, provide the actual amount that has been booked to date for these costs.

41. With regard to Mr. Wathen's testimony, page 15, lines 20 – 22, please provide a copy of the relevant section of the PSC Order in Case No. 92-346 in which it discusses its findings and conclusions regarding the Work Force Reduction program.

42. With regard to the Work Force Reduction – Electric deferred cost balance of $1,530,917 shown on WPD-2.15a, please provide the following information:

a. Provide a worksheet showing the derivation of this deferred cost and explain whether this balance represents the total unamortized Work Force Reduction cost amount allocated to electric operations and deferred by the Company in 1992.

b. Explain why the Company did not start amortizing this deferred cost balance (starting in 1992) in order to match the electric cost savings experienced by the Company as a result of the Work Force Reduction program.

c. Did the Company experience electric cost savings from the implementation of the Work Force Reduction program during the period 1992 – 2006?

d. If so, has the Company quantified these cost savings and would the Company agree that these cumulative cost savings exceed the deferred cost balance of approximately $1.5 million the Company is now proposing to charge to the ratepayers on a going forward basis?

43. Please provide, by specific expense component and in total, the actual expenses incurred for the current case through June 30, 2006. Continue to update this response once additional actual monthly expenses become available.

44. With regard to Regulatory Commission expenses, please provide a breakout of the Forecasted Period account 928 Regulatory Commission expenses of $390,780 by regulatory activity and case number. In addition, provide a similar account 928 breakout for the years 2003, 2004 and 2005 and for the most recent 12-month period ended in 2006.

45. With regard to PSC assessment fees, please provide the following information:

   a. Provide a worksheet showing the total PSC assessment fees included in the Forecasted Period and the calculations made to determine these projected fees, showing the assessment rate used and the revenue base to which this rate was applied.

   b. Provide the pro forma PSC assessment fees, and the underlying calculations and calculation components that would result from applying the PSC assessment rate of .1670% to the appropriate Forecasted Period revenues subject to these fees.

   c. Is the rate of .1670% the currently effective rate or the projected rate for the Forecasted Period? When will the rate to be effective during the Forecasted Period become available?

46. WPF-5b shows annual Forecasted Period "Other" (professional services) expenses of $1,894,366, broken out by specific components. In the same format and detail as per WPF-5b, provide the corresponding actual annual Other professional services expenses, in total and by specific component, for the years 2003, 2004, 2005 and the most recent available 12-month period ended in 2006.

47. With regard to the Other professional services of $1,894,366 and $1,052,644 for the Forecasted Period and Base Year, respectively, please provide the following information:

   a. What expense portions of the total annual expenses of $1,894,366 and $1,052,644 would not have been incurred were it not for the transfer of the three Plants? In addition, indicate the specific line item expense items that were impacted by the transfer of the Plants.

   b. Explain why the majority of the Other professional services expenses for the Base Year have no monthly expense bookings for the actual first 6 months of the Base Year, but show monthly expense bookings for the projected 6 months of the Base Year.

   c. Provide an updated WPF-5a with actual monthly expense data for September 2005 through June 30, 2006.

d. With regard to the WPF-5b, line 32 ("Duke-Cinergy") expense credit of ($765,059), please provide the following information:

   1) Explain what the expenses and expense credits (particularly the large credit in December 2005) in this line item represent.
   2) Provide the corresponding monthly expenses and expense credits for the years 2003, 2004 and 2005.
   3) Explain why the Company has assumed that such expenses and expense credits will not be booked in the Forecasted Period.

48. With regard to the Forecasted uncollectible expenses in the Forecasted Period, please provide the following information:

   a. On WPD-2.31a, the Company has removed from its unadjusted Forecasted Period uncollectible expenses an amount of $2,289,942 for the Time Value of Money portion of the total uncollectible expense. Please provide the total unadjusted uncollectible expenses in the Forecasted Period and the amount of uncollectible expenses that will remain in the pro forma adjusted Forecasted Period after reflecting the $2,289,942 adjustment. In addition, indicate where on Schedule C-2.1, pages 6 – 14 these unadjusted uncollectible expenses for the Forecasted Period are reflected.

   b. Schedule C-2.1, page 11, line 7 shows Loss on Sale of A/R Forecasted Period expenses of $3,157,234. Please reconcile this expense number to the unadjusted Forecasted Period uncollectible expenses to be provided in response to part a above and provide a worksheet showing the derivation of the $3,157,234.

49. As stated on page 49 of the PSC's Order in Case No. 2005-00042, the Commission in the recently concluded DEK gas rate case ruled that no uncollectible expenses in the Forecasted Period and in the gross revenue conversion factor should be reflected for ratemaking purposes for DEK. In the instant electric rate case, the Company is not following this recent PSC ruling and has reflected an adjusted level of uncollectible expenses in the Forecasted Period operating expenses and gross revenue conversion factor. Please explain this inconsistency and provide the reasons why the Company believes that this recent PSC ruling is not applicable to the Company's electric operations.

50. As described on page 44 of the PSC Order in Case No. 91-370, the PSC in that case disallowed various institutional/promotional advertising expenses included in account 912. Are any expenses for the same 912 account and sub-account items (or similar expenses that are now booked in a different account) as listed in the 91-370 PSC Order included in the Forecasted Period expenses in the instant case? If so, provide a detailed listing and quantification of all such expense items.

51. With regard to the Company's Account 916 – Miscellaneous Sales expenses, please provide the following information:

   a. Actual Account 916 expenses for the years 2004 and 2005 and for the most recent available 12-month period ended in 2006, in total and as broken out by detailed expense component.

   b. Breakout of the projected Forecasted Period Account 916 expenses of $2,020,000 by detailed expense component.

   c. Basis for the projected expense level of $2,020,000.

52. With regard to the Company's EEI membership dues, please provide the following information:

   a. Dues included in the Forecasted Period.

   b. EEI-issued documentation (and any other available documentation) describing the nature and purpose of the EEI's activities.

   c. Copy of the most recent study conducted by the Company to quantify the ratepayer benefits of the Company's EEI membership.

53. With regard to the Company's electric EPRI membership dues, provide the actual electric EPRI expenses booked in 2003 and 2004 and the projected EPRI dues included in the Forecasted Period.

54. Do the Company's Forecasted Period operating expenses include any allocated expenses from gas related memberships, such as, for example, AGA dues? If so, quantify these allocated Forecasted Period expenses.

55. Appendix D of the PSC Order in Case No. 91-370 identifies a number of miscellaneous expenses that were disallowed for ratemaking purposes in that case. Are any of these expenses, or similar type expenses, still included in the pro forma adjusted Forecasted Period expenses? If so, please describe and quantify these expense items.

56. In the same format and detail as per the response to AG-DR-01-216 in the 2005 gas rate case, provide a detailed breakout and listing of all of the expense components making up the Forecasted Test Period expense account 910000 – Miscellaneous Customer Service and Info of $499,355.

57. In the same format and detail as per the Company's response to AG-DR-01-217 in the 2005 gas rate case, provide a detailed breakout and listing of all of the expense components making up the Forecasted Test Period expense account 930202 – Miscellaneous General expenses of $602,868 and compare it to the actual account 930202 expenses for the year 2005 and the most recent available 12-month period ended in 2006.

Provide explanations for any major variances between the Forecasted Period expenses and the actual expenses.

58. In the same format as per your response to AG-DR-01-219 in the 2005 gas rate case, provide a detailed breakout of the expense components making up the total Forecasted Period electric Account 921 - Office Supplies and Expense amount of $2,530,853 and compare it to the corresponding actual Account 921 expense components for the year 2005 and the most recent available 12-month period ended in 2006. Provide explanations for any major variances between the Forecasted Period expenses and the actual expenses.

    In addition, if this account includes Community Outreach Dinner, Miscellaneous Event and Government Affairs expenses, please provide detailed breakouts of these expense types.

59. With regard to the Government Affairs expenses included in the pro forma adjusted Forecasted Period above-the-line operating expenses, please provide the following information:

    a. Does the Company have employees whose main function is to address Governmental Affairs matters? If so, identify these employees, describe the nature and purpose of their responsibilities, and provide the total compensation, payroll tax and employee benefit expenses associated with these employees that are included in the Forecasted Period above-the-line operating expenses.

    b. Provide all other Governmental Affairs expenses included in the Forecasted Period, similar to what the Company provided in its response to PSC-DR-03-057 in the 2005 gas rate case.

60. Do the Forecasted Period above-the-line expenses include Corporate Sponsorship expenses? If so, provide a listing, description, and quantification of these expenses and explain why these expenses should be included for ratemaking purposes in this case.

61. With regard to the Back-Up PSA costs reflected in this case, please provide the following information:

    a. Attachment WDW-1, page 1 shows that, without considering the Back-Up PSA update adjustment addressed in Schedule D-2.25, the Forecasted Period unadjusted Back-Up PSA expenses amount to $11,365,778. Is this correct and does this mean that, *with* the consideration of the Back-Up PSA update adjustment of $10,431,923 addressed in Schedule D-2.25, the Company is requesting rate recovery for a total cost amount of $21,797,701? Please provide a detailed explanation and confirmation with regard to this question.

    b. What would the total Forecasted Period Back-Up PSA cost be under the assumption that the costs would be as per the current terms of the PSA that was approved by the PSC in Case No. 2003-00252.

c. Under the assumption that the PSC rejects the Company's request in this case to update the current PSC terms based on current market prices, is the Company required to reflect in this case the PSA cost calculated based on the current terms of the PSA that was approved by the PSC in Case No. 2003-00252? If not, what would be the alternative scenario(s)?

d. With regard to the delays in the transfer of the Plants described in Mr. Esamann's testimony starting on page 6, line 14 and ending on page 7, line 5, isn't it true that even if the delays had not occurred and the transfer of Plants had taken place earlier (say 2004), the capacity charge prices for the Back-Up PSA would not have changed and would have remained at the level that was originally negotiated and approved by the PSC in Case No. 2003-00252? If this is not correct, provide a detailed explanation of why not.

62. With regard to the Company's Network Integration Transmission Service ("NITS") costs, please provide the NITS costs included in the unadjusted Forecasted Period expenses and show in which account(s) on Schedule C-2.1, pages 9 – 13 these costs are included.

63. FR 10(9)(h)(10) shows that for the 2007 Forecasted Period, the Company projected total electric labor costs of $28,554,063, of which $22,578,629 (79.07%) was determined to be labor O&M expense. In this regard, please provide the actual total electric labor costs for the years 2003, 2004 and 2005 and for the most recent available 12-month period ended in 2006, as well as the percentages and dollar amounts of these total actual labor costs that were charged to O&M expense.

64. With regard to the Company's total number of employees, please provide the following information:

a. Total actual number of employees for each month from January 2003 through June 2006 and the corresponding total projected number of employees for the remaining months of 2006 and the 2007 Forecasted Period.

b. Of the total number of monthly actual and projected employees to be provided in part a above, indicate the monthly actual and projected employees allocated to the electric operations and forming the basis for the determination of the Company's actual labor costs for its electric operations.

c. What are the monthly number of total company and (electric allocated) employees underlying the requested Forecasted Period labor expense of $22,578,629. In addition, indicate how many of these employees are not currently on the Company's payroll (i.e., are projected to be hired between now and the 2007 Forecasted Period).

65. Schedule G-2, page 1 shows that for the Forecasted Period, the total labor dollars are $21,571,735 and the portion of these costs charged to O&M expense amounts to

$11,362,849. Please reconcile these total labor costs and total labor O&M expenses to the Forecasted Period total labor costs and total labor O&M expenses of $28,554,063 and $22,578,629, respectively, shown on FR 10(9)(h)(10) and Schedule G-1, page 1.

66. Please provide the actual number of vacancy positions carried by the Company in each of the years 2003, 2004 and 2005 and in 2006 to date.

67. With regard to the Company's Employee Benefit expenses, please provide the following information:

   a. Reconcile the Base Year and Forecasted Period total employee benefit O&M expenses shown on Schedule G-1 to the Base Year and Forecasted Period total employee benefit expense shown on Schedule G-2, page 2.

   b. For the same employee benefit O&M expense components as shown on Schedule G-1, provide actual expenses for the year 2004, 2005 and the most recent available 12-month period ended in 2006. In addition, provide explanations for any major variances between actual and projected expenses.

68. Please provide the revenue requirement increase caused by the Company's proposal to add $6,195,185 to the capitalization for the AMI project. Provide all calculations and calculation components.

69. On page 20 of his direct testimony, Mr. Stanley claims that the Company projects that "the AMI system will allow us to realize approximately $34 million in savings through 2020." In this regard, please provide the following information:

   a. Provide a worksheet showing all of the calculations, calculation components and assumptions in support of this statement.

   b. Does the cumulative $34 million savings amount include the cumulative impact of the annual revenue requirements associated with the capital investments associated with this project? If not, why not?

70. With regard to the Forecasted Period transmission costs, please provide the following information:

   a. Total MISO transmission costs (and any other transmission costs) included in the Forecasted Period. Provide these transmission costs in total and broken out by specific transmission cost component (e.g. MISO Schedule 10, Schedule 16, Schedule 17, etc.).

   b. For each of the transmission cost categories to be provided in response to part a above, indicate in which FERC account on Schedule C-2.1 these costs are included.

c. Are all of the transmission costs to be identified in the response to part a eligible for inclusion in the proposed Rider TCRM? If not, explain which costs are and which aren't.
d. Schedule L-2.2, page 71 of 88 shows that the Rider TCRM-eligible transmission costs included in the Base Year are $12,047,693. What are the Rider TCRM-eligible transmission costs included in the Forecasted Period?

e. In the Company's opinion, which of the transmission cost categories identified in the response to part a above, are extremely volatile and difficult to forecast?

f. For each of the transmission cost categories to be identified in the response to part a above, provide the actual annual costs for 2003, 2004, 2005 and the most recent available 12-month period ended in 2006.

71. In the PSC's data request 4-1(b) in the prior gas rate case, the Company was asked to provide the 10-year average slippage factor for its electric operations. In this regard, please provide the following information:

a. Confirm that the 10-year average slippage factor (1995 – 2004) for the electric operations that was provided by the Company and accepted for ratemaking purposes by the PSC was 100.6 percent.

b. Confirm that the 100.6 percent 10-year average (1995 – 2004) electric plant slippage factor of 100.6 percent was for the Company T&D plant only and did not include the slippage factor for the Company's production plant.

c. Explain why the Company only calculated the electric plant slippage factors in the prior gas rate case based on the T&D plant slippage and not the production plant slippage.

d. The AG has calculated from the response to PSC-1-12(b) in the instant case that the 10-year average electric T&D plant slippage factor for the years 1996 – 2005 is 98.3%. Please confirm this. If you do not agree, explain your disagreement.

e. The AG has calculated from the response to PSC-1-12(b) in the instant case that the 10-year average electric production plant slippage factor for the years 1997 – 2005 is 136.1%. Please confirm this. If you do not agree, explain your disagreement.

72. The electric slippage factor of 107.533% calculated by the Company in the response to PSC-1-12(b) is based on a combination of the 10-year average (1996 – 2005) electric T&D plant slippage factor and the 9-year average (1997 – 2005) electric production plant slippage factor. Please confirm this. If you do not agree, explain your disagreement.

73. The response to PSC-1-12(b) shows that the slippage factors for the Company's electric production plant were as follows for the following years: 209.5% in 2004; 255.8% in

2003, 145.9% in 1998 and 128.9% in 1997. In this regard, please provide the following information:

a. Explain the reasons for the very large variances (actual higher than budgeted plant construction) for each of these years.

b. Confirm that all of the plant construction variances shown in the response for the years 1997 – 2005 were incurred by DE Ohio prior to the transfer to DE Kentucky.

74. With regard to the response to PSC-1-19 (employee benefits), please provide the following information:

a. Reconcile the Forecasted Period total employee benefit O&M expenses of $9,410,155 to the corresponding O&M expenses of $9,483,024 on Schedule G-1.

b. In the same format and detail as per the employee benefit O&M expenses shown in the response to PSC-1-19, provide the actual *monthly* employee benefit O&M expenses for the 12-month period ended June 30, 2004.

c. The Forecasted Period total employee benefit O&M expenses of $9,410,155 are 3 times as high as the actual 2005 employee benefit O&M expenses. For each employee benefit expense components provide an explanation for the increase of the projected Forecasted Period expense over the actual 2005 expense and the actual expense for the 12-month period ended June 30, 2006.

75. With regard to the operating income information in the response to PSC-1-30, please provide the following information:

a. The response states that the electric operating income statements are shown on pages 24 through 38. However, the electric operating income statements only show data for accounts 403 through 547. Please expand these operating income statements by providing electric operating income statement data for accounts 548 through 935.

b. In the completed format as requested in part a above, update the response to PSC-1-30 by providing actual electric operating income statements for the months of April through June 2006.

c. In the same completed format as requested in part a above, provide the actual annual.

76. Which classes in the ACOS are allocated (a) primary and secondary distribution costs, and (b) only primary distribution costs?

77. Please provide, for each class in the ACOS, the contributions to the 12 coincident peaks and the work papers which develop the same.

78. Please provide for the Summer and Non-Summer months in the ACOS the work papers which develop the same.

79. Please explain how the S/NS method is time differentiated? Is the time differentiation between peak and off-peak months and/or time of day?

80. Please provide, for each class in the ACOS, the contributions to the non-coincident peaks and average demand used in the average and excess study and the work papers which develop the same.

81. Please provide the work papers which develop the 12CP and S/NS class capacity cost switching to be about 1.1%. (See the testimony of P. Ochsner, page 7, lines 7-8).

82. Please provide the work papers which develop the 12 CP and A&E class capacity cost switching to be about 7.6%. (See the testimony of P. Ochsner, page 7, lines 9-12).

83. Please explain why the Company has not calculated class rates of return on a 12 CP and Average Demand methodology.

84. Please provide an ACOS run using the 12 CP and Average Demand method weighting the Average Demand by the system load factor and the 12 CP by 1 minus the load factor.

85. Was a coincident demand and average demand methodology explicitly rejected in the last case? If so, please provide documentation.

86. Have the regulatory commissions with jurisdiction over any of Duke's retail electric utilities approved any methods other than the 12 CP. (See the testimony of P. Ochsner, page 7, lines 16-20).

87. Please provide for the test year the kilowatt-hour sales from generation fired by gas, oil, coal, nuclear, hydro and other sources.

88. Please provide for the test year the purchased power kilowatt-hours from generation fired by gas, oil, coal, nuclear, hydro and other sources.

89. Which accounts in the distribution ACOS include a customer component.

90. Please explain why the production function was classified into demand and energy functions for functionalization purposes, but not in the allocation of production capacity costs in the ACOS.

91. Were the class revenue requirements at proposed rates based upon the ACOS or the functionalized cost of service? (See the testimony of P. Ochsner, page 9, lines 6-10).

92. Please define and explain the difference between Diversified Class Peak data and Non-Coincident Peak data (See the testimony of P. Ochsner, page 10, lines 16-17).

93. Please provide the coincident peak load factor and line loss factor for each class in the ACOS.

94. Please explain why it is appropriate to use the average demand ratio developed from the diversified class peak demands to allocate substations. (See the testimony of P. Ochsner, page 13, lines 7-9).

95. Please explain why it is appropriate to use weighted distribution line allocation factor K205 to allocate poles, towers, & fixtures and conductors. (See the testimony of P. Ochsner, page 13, lines 10-13).

96. Please explain why it is appropriate to use weighted average number of customers to allocate services to secondary voltage customers. (See the testimony of P. Ochsner, page 13, lines 20-22).

97. Please provide the service drop costs for each voltage level that customers take service and the number of customers at each voltage level.

98. Why did the Company allocate common and general plant on functionalized salaries instead of functionalized net plant in service?

99. Were transmission costs allocated on the same basis as production capacity costs?

100. Please provide the work papers which develop the proposed class revenue requirements.

101. Please provide the work papers which develop the class allocation of capitalized costs with references to the cost of service study.

102. Do the proposed revenue requirements reflect any non-cost criteria? If so, please identify and explain the application of the non-cost criteria.

103. Please list the demand and energy relationships and explain how those relationships were pertinent to the design of the Company's rates. (See the testimony of J. Bailey, page 7, lines 6 -8).

104. Please provide any reports in the possession of the Company or its consultants that evaluate the load research for use in the design of rates.

105. Please provide documentation that the underlying load research supporting the production capacity and distribution demand allocation factors are statistically significant?

106. Please provide the work papers which extrapolate statistically significant load research data for the 210 residential customers from the entire population of the residential class.

107. Please provide work papers and explain how the residential load research data was used to develop production capacity and distribution demand allocation factors in the ACOS. Please provide references to the ACOS.

108. Please identify the load characteristics and explain how these characteristics might impact operating costs during seasonal and time of use periods. (See the testimony of J. Bailey, page 8, lines 14 - 17).

109. Does the polynomial expression fail to explain 26% of the variability between Kwh and KW? (See the testimony of J. Bailey, page 9, line 15 to page 10 line 2).

110. Please provide a bill frequency report showing the number of customers at each of the usage intervals on Table 3. (See the testimony of J. Bailey, page 10, line 4).

111. Please provide the analysis of cost differences between summer and winter periods and for peak and off-peak periods. (See the testimony of J. Bailey, page 13, lines 8 - 14).

The following interrogatories reference the testimony and schedules of Lynn J. Good.

112. With reference to page 4, lines 13-18, please provide copies of all reports written by the three major credit rating agencies on ULHP, Cinergy, and Duke Energy in the past two years (2005-2006).

113. With reference to page 6, lines 1-6, please provide copies of all presentations and/or reports made by executives of UHLP, Cinergy, or Duke Energy to the three major credit rating agencies in the past two years (2005-2006).

114. With reference to page 6, lines 1-6, please provide documentation of the concerns expressed by rating agencies.

115. With reference to page 9, lines 1-11, please provide copies of the documentation associated with the private placement of $155m of senior unsecured notes.

116. With reference to page 10, lines 1-9, please provide a list of assumptions as well as copies of all workpapers, documents, and electronic spreadsheets used in the calculation of the 6.090% debt cost rate.

117. With reference to page 10, lines 13-21, please provide a list of assumptions as well as copies of all workpapers, documents, and electronic spreadsheets used in the calculation of the 5.138% short-term debt cost rate. In this case, please provide all documentation supporting the basis of the pricing of the short-term debt, the use of Bloomberg's Implied Forward Curve to price the short-term debt, and the basis and justification for the 20 basis point credit spread.

118. With reference to page 10, lines 1-9, please provide copies of all workpapers, documents, and electronic spreadsheets used in the calculation of the 6.090% debt cost rate.

119. Please provide electronic copies (Microsoft Excel) of the following schedules, with all data and formulas left intact: Schedules J-1, J-1.1, J-1.2, J-2, and J-3.

120. With reference to Schedules J-1.1 and J-1.2, please provide the projected monthly capitalization figures that comprise the 13-month moving average. Please provide the data in hard copy and electronic forms (in Microsoft Excel Worksheet format), with all data and formulas left intact.

The following interrogatories reference the testimony and schedules of Dr. Roger A. Morin.

121. With reference to page 26, lines 13-14 and Exhibit RAM-2, please indicate (1) the definition of beta as employed in the analysis, (2) the exact methodology employed in computing the beta.

122. With reference to page 29, line 9 to page 30, line 32, please provide (1) a detailed summary of the methodology employed, as well as the associated work papers, in estimating the equity risk premium on the aggregate equity market, (2) the individual company as well as the overall stock market price and dividend data, as well as the earnings and dividend growth rate data used in estimating the equity risk premium, and (3) a hard copy and an electronic copy (Microsoft Excel) of all spreadsheets and data employed, with all data and equations intact.

123. With reference to page 29, lines 5-8, please provide (1) a definition of the 'market price of risk' and 'the amount of risk in common stocks,' and (2) copies of all studies performed indicating that these factors have not changed.

124. With reference to page 30, footnote 7, please provide a copy of the paper cited.

125. With reference to page 31, line 13, please provide a copy of the book chapter.

126. With reference to page 32, line 1, please provide a copy of the data used to construct the graph. Please provide the data in hard copy and electronic formats.

127. With reference to page 32, lines 1-14, please provide copies of all studies that indicate a weighting of .25/.75 is appropriate.

128. With reference to page 34, line 13 to page 35, line 17, and Exhibit RAM-3, please provide the methodology used to construct the Moody's Electric Utility Index including the following: (1) the weights applied to the stock prices and dividends of each company in arriving at the index values, (2) how adjustments are made to the Index when companies are added to or deleted from the Index, (3) how adjustments are made to the

Index in the event of stock splits and stock dividends, and (4) the number of companies in the Index each year.

129. With reference to page 35, line 18 to page 37, line 9, please provide (1) the raw data used to construct the Allowed Risk Premium graphs, (2) the summary regression statistics, and (3) copies of the Regulatory Research Associates quarterly reports from which the allowed returns were obtained.

130. With reference to page 45, lines 1-23 and Exhibit RAM-5, please (1) indicate the universe of integrated electric utility companies which were considered in constructing the combination group, (2) list the companies eliminated by the 'investment-grade' screen, (3) provide the appropriate ratings for DEK and Duke Energy, and (4) provide the investment-grade ratings for the companies in the group as well as for those excluded from the group.

131. With reference to page 45, lines 1-23 and Exhibit RAM-5, please provide copies of all empirical studies performed which compare the riskiness of the group of integrated electric utilities and Moody's Electrics with DEK.

132. With reference to page 53, lines 12-22, please provide details (date, amount, and costs) of all equity infusions into DEK made by Duke Energy (1) over the past five years, and (2) any planned infusions in the future.

133. With reference to page 56, lines 6-19, please provide copies of all empirical studies performed which compare the fuel adjustment clauses of DEK relative to those in the group of integrated electric utilities or with Moody's Electrics.

134. With reference to page 57 line 14 to page 63, line 2, please provide (1) a copy of Chapter 19 of your book, (2) all data in hard copy and electronic formats used to do the optimal capital structure study on page 60, (3) copies of source documents that indicate DEK has a business risk position of 5.0 and the appropriate debt ratio benchmarks, (4) a copy of the study performed which supports the statement that large institutional investors are precluded from investing in bonds rated below 'A', and (5) a copy of the study performed which supports the statement that DEK's financial condition is not consistent with a single 'A' credit rating.

135. With reference to Exhibit RAM-10, do the common equity ratios shown include or exclude short-term debt?

136. With reference to page 63, lines 15-20, please provide (1) copies of all empirical studies performed which demonstrated the stated benefits of the acquisition by Duke Energy, and (2) the reasoning as to which these purported benefits have no 'discernable impact on the rate of return on equity' for DEK.

137. Please provide electronic copies (Microsoft Excel) of all spreadsheets and data employed, with all data and equations intact, for all pages of the following Exhibits: RAM-3, RAM-5, RAM-6, RAM-7, RAM-8, and RAM-9.

General

138. Provide hard copies of all workpapers underlying the Depreciation Study prepared by Mr. John Spanos of Gannett Fleming.

139. Provide all information obtained by Mr. Spanos and Gannett Fleming from Company operating personnel, and separately, financial management personnel relative to current operations and future expectations in the preparation of the study.

140. Please provide all notes taken during any meetings with Company personnel regarding the study. Identify by name and title, all Duke Energy Kentucky ("DEK"), previously Union Light, Heat and Power Company ("ULH&P") personnel who provided the information, and explain the extent of their participation and the information they provided.

141. Identify all plant tours taken during the preparation of the Depreciation Study.

a. Identify those in attendance and their titles and job descriptions.
b. Provide all conversation notes taken during the tour.
c. Provide all photographs and images taken during the tour.

142. Provide all internal and external audit reports, management letters, consultants' reports etc. which address in any way, the Company's property accounting and/or depreciation practices.

143. Please provide copies of all Board of Director's minutes and internal management meeting minutes in which the subject of the Company's depreciation rates or retirement unit costs were discussed.

144. Provide copies of all internal correspondence which deals in any way with the Company's retirement unit costs, electric depreciation rates, and/or the Depreciation Study.

145. Provide copies of all external correspondence, including correspondence with Mr. Spanos and Gannett Fleming, which deals in any way with the Company's retirement unit costs, electric depreciation rates, and/or the Depreciation Study.

146. Provide copies of all industry statistics available to Mr. Spanos and/or the Company relating to electric company depreciation rates.

147. Identify all industry statistics upon which Mr. Spanos relied in formulating the depreciation proposals.

148. Which accounting method is reflected in the life studies; "location-life" or "cradle-to-grave"?

149. What is impact of the accounting method used, i.e., "location-life or "cradle-to-grave" on the lives calculated in the Depreciation Study?

150. Provide explanatory examples of the debits and credits relating to customer advances and contributions-in-aid of construction.

151. Provide explanatory examples of the debits and credits relating to the accounts for which depreciation is charged to clearing accounts.

152. Provide a copy of the Company's capitalization policy.

153. Identify and explain the Company's (including its parent and all affiliates) plans for the provision of Broadband Over Power Lines ("BPL"). Identify and explain all BPL trials in which the Company (including its parent and all affiliates) is involved.

154. Please explain what impact BPL will have upon the following, by FERC USOA account.

    a. Plant lives
    b. Plant retirement patterns (Iowa Curves)
    c. Gross salvage
    d. Cost of removal
    e. Retirement units
    f. Accounting under FERC Uniform System of Accounts
    g. Accounting under GAAP
    h. Accounting under SEC rules

Data

155. Please provide on diskette or CD all tabulations included in the Depreciation Study and all data necessary to recreate in their entirety, all analyses and calculations performed for the preparation of the study. Please provide this and all electronic data in Excel (or .txt format if appropriate), with all formulae intact. Please provide any record layouts necessary to interpret the data. Please include in the response electronic spreadsheet copies of all of the schedules and/or tables included in the Depreciation Study, with all formulae intact.

156. If not provided elsewhere, please provide Mr. Spanos's amortization calculations and workpapers for general plant accounts in electronic format (Excel) with all formulae intact.

157. For each plant account (including ***all*** production, transmission, distribution, general and common general accounts), and for each year since the inception of the account up to and including 2005, please provide the following standard depreciation study data as identified at pages 30-33 of the August 1996 NARUC Public Utility Depreciation Practices Manual ("NARUC Manual"). Provide the data in electronic format (Excel or .txt). Provide aged vintage data if available. Use the codes identified for each type of data, unless the Company regularly uses other codes. In those circumstances, identify and explain the Company's coding system.

Code	Data Type
9	Addition
0	Ordinary Retirement
1	Reimbursement
2	Sale
3	Transfer – In
4	Transfer – Out
5	Acquisition
6	Adjustment
7	Final retirement of life span property (see NARUC Manual, Chapter X)
8	Balance at Study Date
	Initial Balance of Installation

158. If the depreciation study data provided in response to the preceding question is not the exact set of data used for the depreciation study submitted in this case (for the accounts included in the study), explain all differences and reconcile the amounts provided to those used in the case.

159. If not provided elsewhere, provide the cost of removal and gross salvage data used in the Depreciation Study net salvage analyses. If this data differs from that reflected on the Company's books, please explain the differences and provide a reconciliation. Please provide this data in electronic (Excel or .txt) format.

160. Provide the following annual accumulated depreciation amounts for all plant accounts (including ***all*** production, transmission, distribution, general and common general accounts) for the last 20 years (up to, and including, 2005). If the requested data is not available for the last 20 years, provide the data for as many years as are available. Also, if the data is not available at the plant account level, please provide the data at the level it is available. Please provide data in both hard copy and electronic format (Excel or .txt).

a. Beginning and ending reserve balances,
b. Annual depreciation expense,
c. Annual retirements,
d. Annual cost of removal and gross salvage,
e. Annual third party reimbursements.

161. Please provide a comparison of the annual cost of removal and gross salvage amounts shown on ULH&P's federal tax returns with the corresponding book amounts, for the last 5 years. Provide the annual deferred tax expense associated with each of the differences. Also, provide the beginning and ending accumulated deferred tax balances and state whether they are rate base additions or rate base deductions.

162. Provide a summary of annual maintenance expense by USOA account (for all accounts) for the last 20 years. If the requested data is not available for the last 20 years, provide the data for as many years as are available. Please provide data in both hard copy and electronic format.

163. Explain what consideration, if any, was given to annual maintenance expense data in Mr. Spanos's estimation of service lives, dispersion patterns and net salvage.

Depreciation Rate Calculations

164. If not provided elsewhere, provide the calculation of the rates proposed in the Depreciation Study in electronic format (Excel) with all formulae intact.

165. Please provide the proposed depreciation rates, split into three separate components: capital recovery, gross salvage and cost of removal.

166. Does the Company maintain its book reserve by plant account? If not, explain why not.

167. If the Company does not maintain its book reserve by plant account, provide the calculation of the book reserve shown in the depreciation study.

168. Was reciprocal, harmonic, or ELG weighting used in any of the depreciation rate calculations? If yes, please provide all calculations using direct weighting. Also, provide this in hardcopy and electronic format (Excel).

169. If applicable, calculate all depreciation rates using the same weighting procedure used in the current depreciation rates, i.e., the same procedure used the last time depreciation rates were calculated.

170. If not provided elsewhere, please provide all remaining life calculations resulting from the depreciation study in electronic format (Excel) with all formulae intact.

Net Salvage

171. If not provided elsewhere, provide electronic (Excel) versions of the net salvage studies included in the depreciation study, with all formulae intact.

172. If not provided elsewhere, please provide the Sargent and Lundy decommissioning cost study that formed the basis for Mr. Spanos's terminal net salvage estimates. Also, provide on diskette or CD all workpapers supporting his terminal net salvage estimates for each account for which terminal net salvage is a factor, specifically showing how they

relate to the Sargent and Lundy study. Please include all calculations in electronic format (Excel), with all formulae intact.

173. Other than the existence of the Sargent and Lundy study (which presumably provides the cost of dismantlement), does ULH&P have any specific plans to actually retire and dismantle any of its production plants? If so, please provide all such plans.

174. Do Mr. Spanos's net salvage recommendations, including his terminal net salvage estimates, incorporate inflation expected to be incurred in the future? If yes, please explain fully how this inflation is factored into each recommendation, and provide supporting calculations in electronic format (Excel). If not, please provide support showing no future inflation was included.

175. If Mr. Spanos's net salvage recommendations include inflation expected to be incurred in the future, please provide the net present value of Mr. Spanos's net salvage recommendations.

176. Does Mr. Spanos agree that including inflation expected to be incurred in the future in net salvage estimates results in charging today's ratepayers for tomorrow's inflation? Please explain why or why not.

177. Does Mr. Spanos believe that including future inflation in net salvage estimates falls under the "known and measurable" standard usually followed in rate cases? Please explain why or why not.

178. On an account-by-account basis, for each of the five years ending 2005, explain whether the gross salvage and cost of removal incurred was normal or abnormal and why.

179. Explain, and provide examples of, the Company's retirement unit cost procedures for each account. Identify all changes to retirement unit costs which have occurred over the years.

180. Were any retirements, classified as sales or reimbursements, excluded to the extent to which the salvage receipt represents recovery of original cost? If yes:

    a. Provide, by account, the annual retirements and the related salvage that has been excluded for the 10 years ending 2005.
    b. Provide the Commission Orders and Decisions approving this practice.
    c. Demonstrate that the retirements were excluded from the life studies.

181. Explain the Company's procedures for gross salvage and cost of removal.

182. Explain how cost of removal relating to replacements is allocated between cost of removal and new additions. Provide copies of actual source documents showing this allocation.

183. Does ULH&P/DEK agree that, in the case of a replacement, ULH&P/DEK has control over how much of the cost of the replacement is assigned to the retirement as cost of removal, and how much is capitalized to plant-in-service? Please explain the answer fully.

184. Please provide all manuals, guidelines, memoranda or other documentation that deal with the Company's policies on the assignment of capital costs and net salvage with regard to the replacement of retired plant. Also, please provide a sample workorder for a replacement project, showing these cost assignments.

185. Provide narrative explanations of the Company's aging and pricing procedures.

186. Identify and explain the Company's expectations with respect to future removal requirements and markets for retired equipment and materials. Please provide the basis for these expectations.

187. Provide the retirements cost of removal reflected in the Company's construction budget for the years 2005-2009 inclusive. Provide by account.

188. Explain how the Company accounts for third party reimbursements and how they are reflected in the depreciation study.

189. If third-party reimbursements were excluded from the net salvage studies, was the related retirement also excluded from the life studies?

190. Provide the Company's capital budget for the next five years. Identify all retirements, replacements, new additions and cost of removal reflected in this budget. Provide by account where available and explain how the cost estimates are derived for these items.

191. Please refer to the net salvage study of Account 1900 on page III-139 of the Study. Provide an explanation for the large amount of cost of removal in 2002 and 2003.

192. Please refer to the net salvage study of Account 3120 on page III-141 of the Study. Provide an explanation for the large amount of cost of removal in 2003.

193. Please refer to the net salvage study of Account 3532 on page III-146 of the Study. Provide an explanation for the large amount of cost of removal in 2004.

194. Please refer to the net salvage study of Account 3550 on page III-147 of the Study. Provide an explanation for the large amount of cost of removal in 2001 and 2005.

195. Please refer to the net salvage study of Account 3620 on page III-151 of the Study. Provide an explanation for the large amount of cost of removal in 2003 and 2005.

196. Please refer to the net salvage study of Account 3640 on page III-153 of the Study. Provide an explanation for the large amount of cost of removal in 2003.

197. Please refer to the net salvage study of Account 3700 on page III-159 of the Study. Provide an explanation for the large amount of cost of removal in 2003.

Service Lives

198. If not provided in the workpapers, please provide the retirement rate analysis ranking of best-fit life/curve combinations for each account. If the service life indications resulting from the analyses are not the best-fit life/curves, please explain how they were selected.

199. For any accounts where Mr. Spanos did not base his service life/curve selection on the results of his retirement rate analysis, explain why he did not. Also, explain in detail how those service live/curve combinations were selected.

200. Provide copies of any and all actuarial and semi-actuarial studies prepared by the Company since the last depreciation study.

201. Provide the Company's most recent Integrated Resource Plan dealing with plant lives.

202. Identify and explain all Company programs which might affect plant lives.

203. Provide all internal life extension studies prepared by the Company. Life extension refers to any program, maintenance or capital, designed to extend lives and/or increase capacity of its existing plant-in-service. Identify the functions to which these studies relate.

204. Provide the following information for all final retirements for the last 15 years. If requested data is not available for the last 15 years, provide the data for as many years as are available.

    a. Date of retirement
    b. Amount of retirement
    c. Account
    d. Reason for retirement
    e. Whether or not retirement was excluded from historical interim retirement rate studies.

205. Please provide the ARO/ARC calculations for each of DEK's/ULH&P's mass property accounts assuming that DEK/ULH&P has legal AROs for all of its plant.

206. Refer to page II-19 of the Depreciation Study, where it states "For 18 of the 40 plant accounts and subaccounts for which survivor curves were estimated, the statistical analyses resulted in good to excellent indications of the survivor patterns experienced." Please provide a full explanation of how Mr. Spanos determined this. In other words, what are the criteria Mr. Spanos uses to determine that a statistical analyses "results in good to excellent indications of survivor patterns experienced."

Life Span

207. Was the life span methodology utilized in the prior studies? If so, please provide a comparison, by account and location, of the probable retirement year forecasted in the prior studies, with the probable retirement year forecasted in the Depreciation Study.

208. Please provide the specific calculation of each probable retirement year used in Mr. Spanos's study.

209. Please explain in detail the reason for implementing an after hours reconnection charge of $50 for any request for same-day reinstatement of service if the Company receives notice after 12:30 p.m. and provide all data relied upon and all workpapers, calculations and assumption used to determine the amount of the fee.

210. Please explain in detail the reason for imposing an after hour reconnection charge of $50 plus an additional $25 in the after hours fee (moving from $65 to $90) for reconnection at the pole and provide all data relied upon and all workpapers, calculations and assumption used to determine the amount of the fees.

211. Please provide a load and resource schedule, for as long a time period as is available, showing the Company's peak day forecast, capacity available to meet the forecasted peak loads and the amount of any excess or deficiency in peak day capacity.

212. Please describe and provide the capacity of all planned generating additions and retirements included in the load and resource schedule.

213. Please provide the Company's most recent FERC Form 1.

214. Please provide, for the time period covered by the load and resource schedule, capacity broken down by fuel source.

215. Please provide the Company's most recent Integrated Resource Plan and power supply capacity plan.

216. Please provide the Company's reserve margin requirement and indicate whether the reserve margin is self imposed or imposed by the Midwest ISO.

217. Please describe the Midwest ISO's day ahead and day 2 energy markets.

218. Please describe the pricing basis for sales to and purchases to the Midwest ISO Day ahead and Day 2 energy market.

219. Please provide a comparison of avoided cost and market price of generation for the past 3 years.

220. Does the Company have a forecast of market prices? If so, please provide.

221. In the region, does the marker price of capacity and energy exceed the cost of service price? If so, please provide documentation and any studies supporting the same.

222. Has the Company sold power at market prices in the past? If so, was any revenue credited to ratepayers? Please explain.

223. Please define locational marginal price for power purchased through the Midwest ISO day ahead energy market and distinguish the locational marginal price from market price.

224. What is the reason for the shift from high historic PowerShare credits and recent low credits?

225. Please describe the PowerShare CallOption program.

226. How much is the proposed material increase related to the proposal to re-price the PowerShare program? Is the proposed price more or less than market value? Please explain.

227. With respect to Rider GP, why is it in the customers' best interest to acquire RECs and Carbon Credits?

228. Should the RECs and Carbon credits be sold into the market, how will the revenue be treated for ratemaking?

229. With respect to the Customer Service office. Are service offices available in each county served by DEK or is the Covington office the only office? Has Union always had only one service office? If not, where were other offices located and when were they closed?

230. With reference to the "nominal transaction fee" assessed by the third party vendor for the BillPayer 2000 option:

    a. Is this bill payment option newly offered with this filing? If not, when was it first offered and did the PSC approve it as an offering?

    b. What is the transaction fee?

    c. Is the transaction fee paid by Duke or by the customer?

    d. If the transaction fee is paid by the customer, does Duke also pay the vendor something to provide the service? If so, how does the amount paid by Duke compare to that paid by the customer?

    e. Is the risk of non-payment or late payment reduced for billing that automatically deducts amounts owing on a pre-approved basis from a customer account from that experienced for billing that requires customer response through mailing a check or otherwise actively paying? If so, by what amount is the risk reduced?