VERIFICATION

STATE OF OHIO)
) **SS:**
COUNTY OF HAMILTON)

The undersigned, Lisa Steinkuhl, Rates & Regulatory Strategy Manager, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of her knowledge, information and belief..

Lisa D Steinkuhl
Lisa Steinkuhl, Affiant

Subscribed and sworn to before me by Lisa Steinkuhl on this 5TH day of June, 2014.

Adele M. Frisch
NOTARY PUBLIC

ADELE M. FRISCH
Notary Public, State of Ohio
My Commission Expires 01-05-2019

My Commission Expires: 1/5/2019

VERIFICATION

STATE OF NORTH CAROLINA	)	
	)	**SS:**
COUNTY OF MECKLENBURG	)	

The undersigned, Joseph McCallister, Director of Natural Gas Oil & Emissions, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Joseph McCallister, Affiant

Subscribed and sworn to before me by Joseph McCallister on this 5 day of June, 2014.

Rita G Kale
NOTARY PUBLIC

RITA G KALE
NOTARY PUBLIC
CATAWBA CO., NORTH CAROLINA

My Commission Expires: 6/17/2017

VERIFICATION

STATE OF NORTH CAROLINA	)	
	)	**SS:**
COUNTY OF MECKLENBURG	)	

The undersigned, John D. Swez, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

John D. Swez, Affiant

Subscribed and sworn to before me by John D. Swez on this 28 day of May, 2014.

Rita G Kale

NOTARY PUBLIC

RITA G KALE NOTARY PUBLIC CATAWBA CO., NORTH CAROLINA

My Commission Expires: 6/17/2017

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Duke Energy Kentucky
Case No. 2014-00078
Staff's Second Set of Data Requests
Date Received: May 23, 2014

STAFF-DR-02-001

REQUEST:

Refer to the response to Item 1 of Commission Staff's First Request for Information ("Staff's First Request"). In response to Item 1.a. of the request, Duke Kentucky states, in relevant part, that its affiliates have experienced numerous circumstances in which natural gas was purchased to meet forecasted generation needs and subsequently sold in the spot market, and that the regulatory treatment in the jurisdictions in which the affiliates operated allowed recovery through the various fuel adjustment clauses.

a. State whether such jurisdictions had an off-system sales rider in effect. If so, identify the jurisdiction and provide a copy of the relevant tariff.
b. If the answer to Item 1.a. is affirmative, state whether the affiliate(s) have ever recovered costs through the off-system sales rider and explain the procedure used to determine the amount of the costs to be recovered.
c. Identify the jurisdictions referenced in the response which had a fuel adjustment clause and provide a copy of the relevant fuel adjustment tariffs.
d. Provide printed copies of the testimony referenced in the response to Item 1.a. of Staff's First Request.

RESPONSE:

a. The following jurisdictions have an off-system sales rider: Duke Energy Carolinas (DEC) – North Carolina and Duke Energy Indiana (DEI). Please see Staff-DR-02-001a Attachment 1a and 1b for DEC's tariffs and Attachment 1c for DEI's tariff. Duke Energy Florida (DEF) has an off-system sales profit sharing mechanism embedded in its FAC rider.

b. Yes. Costs offset the revenue to derive the margin to flow through these riders. For example, total gas expense is allocated (FAC) native or non-native (off-system) sales based on an after-the-fact costing model to determine the net profit from off-system sales to be shared.

c. The following jurisdictions have a fuel adjustment clause:

Jurisdiction	Tariff
Duke Energy Carolina – North Carolina	Staff-DR-02-001c Attach 1
Duke Energy Carolina – South Carolina	Staff-DR-02-001c Attach 2
Duke Energy Progress – North Carolina	Staff-DR-02-001c Attach 3
Duke Energy Progress – South Carolina	Staff-DR-02-001c Attach 4
Duke Energy Progress - Florida	Staff-DR-02-001c Attach 5
Duke Energy Indiana	Staff-DR-02-001c Attach 6

d. Please see Staff-DR-02-001 Attachments d1, d2 and d3.

PERSON RESPONSIBLE: (a-c) Lisa Steinkuhl
(d) Legal

APPLICABILITY (North Carolina Only)
Service supplied under the Company's rate schedules is subject to the approved BPM Prospective Rider to share Bulk Power Marketing (BPM) Net Revenues and short-term Non-Firm Point-to-Point (NFPTP) Transmission Revenues with customers.

The Commission has ordered effective for service rendered on and after September 25, 2013 that the BPM Prospective Rider amounts be set at decrements of 0.0664 ¢/kWh for BPM Net Revenues and 0.0069 ¢/kWh for Non-Firm Point-to-Point Transmission Revenues for a total decrement of 0.0733¢/kWh including revenue-related taxes and regulatory fee .

The BPM Prospective Rider is a continuing decrement rider which shall be subject to modification in each annual BPM True-up Rider adjustment proceeding for the purpose of estimating actual BPM Net Revenues and NFPTP Transmission Revenues expected to be experienced during the rate period for that proceeding.

Duke Energy Carolinas, LLC

Amended
Electricity No. 4
North Carolina Original Leaf No 106

BPM TRUE-UP RIDER (NC)

APPLICABILITY (North Carolina Only)
Service supplied under the Company's rate schedules is subject to approved Bulk Power Marketing (BPM) net revenues and short-term non-firm point-to-point transmission revenues adjustments, if any, over or under the BPM Prospective Rider.

BPM PROSPECTIVE RIDER
The BPM Prospective Rider established September 25, 2013 in Docket E-7, Sub 1026 includes a BPM Net Revenues decrement of 0.0642 ¢/kWh and a Non-Firm Point-to-Point Transmission Revenues decrement of 0.0067 ¢/kWh. These decrements will be subject to modification, as approved by the Commission, in each annual proceeding to adjust the BPM True-up Rider.

BPM NET REVENUES AND NON-FIRM POINT-TO-POINT TRANSMISSION REVENUES ADJUSTMENT FACTOR
A rider adjustment will be applied to the energy charges of all NC Retail rate schedules in an amount to the nearest one ten-thousandth of a cent, as determined by the following formula, to the extent determined reasonable and proper by the Commission. This adjustment is not included in the rate schedules of the Company and therefore, must be applied to the bill as calculated under the applicable rate.

$$A = ((((B - BB) + (P - BP)) + R) / S)$$

Where:

A = BPM Net Revenues and Non-Firm Point-to-Point Transmission Revenues Rate Adjustment per kilowatt hour applied to the applicable base rates rounded to the nearest one ten-thousandths of a cent

B = Net Revenues from Certain Wholesale Sales for the period calculated as [(WR – IC) X 90% X NC Allocation Factor)]

Where:

WR = Revenues from Bulk Power Marketing (BPM) Sales, defined as non-firm wholesale sales made by Duke Energy Carolinas under its market-based rate authority and sales made under Duke Energy Carolinas, LLC Wholesale Cost-Based Rate Tariff Providing for Sales of Capacity and Energy within the Duke Energy Carolinas, LLC Control Area.

NC Allocation Factor = NC Retail kWh sales / Total kWh sales from current Cost of Service Study

IC= Incremental Costs, defined as incremental costs associated with the wholesale sales (WR above), as determined by a post event dispatch model that assigns the lowest cost generation to serve retail and cost-based wholesale load. The incremental costs shall include the fuel costs and variable O&M costs as determined by the post event dispatch model, emissions allowance costs using the methodology proposed by the Public Staff and approved by the Commission in its June 28, 2006 Order in Docket No. E-7, Sub 751, the transmission costs associated with said sales, an allocation of wholesale business personnel costs, and the net impact of any hedges entered into on behalf of said transactions.

BB = BPM Prospective Rider Net Revenues collected based on decrement of 0.0642 ¢/kWh established September 25, 2013 in Docket No. E-7, Sub 1026

P = Revenues from Non-Firm Point-to-Point Wholesale Transmission Service provided under the Open Access Transmission Tariff for the period calculated as [WT X 100% X NC Allocation Factor]

BPM TRUE-UP RIDER (NC)

Where:

WT =	Revenues from Non-Firm Point-to-Point Transmission Sales, defined as short-term non-firm wholesale transmission sales made by Duke Energy Carolinas under its Open Access Transmission Tariff.
NC Allocation Factor =	NC Retail Transmission Plant / Total Transmission Plant from current Cost of Service Study
BP =	BPM Prospective Rider Non-Firm Point-to-Point Transmission Revenues collected based on decrement of 0.0067 ¢/kWh established September 25 2013 in Docket No. E-7, Sub 1026
R =	Return calculated by applying, on a monthly basis, 50% of the net-of-tax overall rate of return approved in the last general rate case.
S =	Projected Sales, defined as projected North Carolina Retail jurisdictional kilowatt hour sales from all classes of customers for the applicable July 1 – June 30 rider period.

The following shows the calculation of the BPM Net Revenues and Non-Firm Point-to-Point Transmission Revenues Adjustment:

	Effective September 25,2013
BPM Prospective Rider Net BPM Revenues and Non-Firm Point-to-Point Transmission Revenues Rate Established September 25, 2013 in Docket No. E-7, Sub 1026	-0.0709 ¢/kWh
BPM Net Revenues and Non-Firm Point-to Point Transmission Revenues Rate Adjustment	0.0659 ¢/kWh
Gross Receipts Tax and Regulatory Fee Multiplier	X 1.034554
Total Adjustment	0.0682 ¢/kWh

The appropriate revenue-related tax factor is applicable to rate adjustments approved under this Rider. The rider calculation will be subject to appropriate modification to reflect changes in income tax laws or regulations, subject to Commission approval.

Beginning in 2009, the Company files the BPM Net True-up Rider on May 1 of each year following the calendar year under consideration, to be effective July 1 of that year. The procedure followed with respect to the review and implementation of each BPM True-Up Rider shall be the same as that established in Docket No. E-7, Sub 751.

IURC No. 14
Thirteenth Revised Sheet No. 70
Cancels and Supersedes
Twelfth Revised Sheet No. 70
Page 1 of 3

Duke Energy Indiana, INC.
1000 East Main Street
Plainfield, Indiana 46168

STANDARD CONTRACT RIDER NO. 70
RELIABILITY ADJUSTMENT
APPLICABLE TO ALL RETAIL RATE SCHEDULES

A. The applicable charges for electric service to the Company's retail electric customers shall be increased or decreased, to the nearest 0.001 mill ($0.000001) per kWh to recover and/or credit the net jurisdictional cost of reliability purchases, peak load management costs, and net profits from non-native sales, in accordance with the following formula:

Reliability Adjustment Factor:

$$= \left\{(a*c)d+(b*d)-\left[\frac{(e*c)-\$14,747,000}{2}\right]d\right\}*\left(\frac{1}{s}\right)$$

where:

1. "a" equals year-round purchased power capacity costs (i.e., total cost of purchases, less fuel costs attributable to such purchases recoverable via Standard Contract Rider No. 60) associated with reliability purchases as approved by the Commission. The total cost of reliability purchases shall include all charges relating to such purchases including, but not limited to, transmission, demand, capacity, reservation, and/or, option payments, or other equivalent charges, including profits thereon.
2. "b" is the total year-round amount of bill credit provided to customers under the Company's PowerShare® program including any additional demand response amounts determined to be includable by the Commission, less the annual level built into base rates in Cause No. 42359 ($1,023,000).
3. "c" is the total retail rate group's allocated percentage share of the Company's average twelve monthly coincident system peak demands as developed for cost of service purposes in Cause No. 42359.
4. "d" is the individual retail rate group's allocated percentage share of the Company's average twelve monthly coincident retail peak demands as developed for cost of service purposes in Cause No. 42359.
5. "e" represents actual net profits realized from non-native sales which shall not be less than zero. Actual non-native sales revenues shall be reduced by a fixed trading expense value of $3,953,000.
6. "s" represents actual monthly kilowatt-hour sales by individual retail rate groups for the twelve months ending September of each year.

B. The factor as computed above shall be modified to allow for the recovery of utility receipts taxes and/or other similar revenue based taxes incurred due to the recovery of net reliability costs.

C. The factor shall be further modified to reflect the reconciliation of annual net costs approved for recovery, by retail rate group, and actual annual amounts billed customers.

D. The reliability factor by rate group is as follows:

Issued:
June 19, 2013

Effective:
The First Billing Cycle
of July 2013

Duke Energy Indiana, INC.
1000 East Main Street
Plainfield, Indiana 46168

STANDARD CONTRACT RIDER NO. 70
RELIABILITY ADJUSTMENT
APPLICABLE TO ALL RETAIL RATE SCHEDULES

Line No.	Rate Groups	Estimated Reliability Factor Per kWh to be Applied to Customer Bills (A)	Line No.
1	Rate RS	$0.000576	1
2	Rates CS and FOC	$0.000640	2
3	Rate LLF	$0.000437	3
4	Rate HLF	$0.000471	4
5	Customer L	$0.000242	5
6	Customer D	$0.000674	6
7	Customer O	$0.000367	7
8	Rate OL	$0.000216	8
9	Rate WP	$0.000413	9
10	Rate SL	$0.000161	10
11	Rate AL	$0.000141	11
12	Rate MHLS	$0.000160	12
13	Rates MOLS and UOLS	$0.000014	13
14	Rates TS, FS and MS	$0.000524	14

Duke Energy Indiana, INC.
1000 East Main Street
Plainfield, Indiana 46168

STANDARD CONTRACT RIDER NO. 70
RELIABILITY ADJUSTMENT
APPLICABLE TO ALL RETAIL RATE SCHEDULES

ALLOCATED SHARE OF THE AVERAGE MONTHLY COINCIDENT SYSTEM PEAK DEMANDS (12 CP) APPLICABLE TO COMPANY'S RETAIL CUSTOMERS, BY RATE GROUP, AND WHOLESALE ELECTRIC CUSTOMERS, EXPRESSED AS A PERCENTAGE OF THE COMPANY'S AVERAGE TWELVE MONTHLY COINCIDENT SYSTEM PEAK DEMANDS DEVELOPED IN CAUSE NO. 42359

Line No.	Rate Groups	kW Share of System Peak (12CP) (A)	Percent Share of System Peak (B)	Percent Share of Retail Peak (C)	Line No.
1	Rate RS	1,582,005	33.713%	36.727%	1
2	Rates CS and FOC	224,244	4.779%	5.206%	2
3	Rate LLF	628,152	13.386%	14.583%	3
4	Rate HLF	1,808,886	38.547%	41.994%	4
5	Customer L	10,481	0.223%	0.243%	5
6	Customer D	7,860	0.167%	0.182%	6
7	Customer O	19,045	0.406%	0.442%	7
8	Rate OL	4,855	0.103%	0.113%	8
9	Rate WP	17,235	0.367%	0.400%	9
10	Rate SL	2,185	0.047%	0.051%	10
11	Rate AL	272	0.006%	0.006%	11
12	Rate MHLS	282	0.006%	0.007%	12
13	Rates MOLS and UOLS	69	0.001%	0.002%	13
14	Rates TS, FS and MS	1,893	0.040%	0.044%	14
15	TOTAL RETAIL	4,307,464	91.791%	100.00%	15
16	WHOLESALE	385,190	8.209%	-	16
17	TOTAL COMPANY	4,692,654	100.00%	-	17

Issued:
June 19, 2013

Effective:
The First Billing Cycle
of July 2013

Duke Energy Carolinas, LLC

Electricity No. 4
North Carolina Twenty-Seventh Revised Leaf No. 60
Superseding North Carolina Twenty-Sixth Revised Leaf No. 60

FUEL COST ADJUSTMENT RIDER (NC)

APPLICABILITY (North Carolina Only)

Service supplied under the Company's rate schedules are subject to approved fuel charge adjustments, if any, over or under the Rate set forth in the approved rate schedules. Adjustments are made pursuant to North Carolina General Statute 62-133.2 and North Carolina Utilities Commission Rule R8-55 as ordered by the North Carolina Utilities Commission.

BASE FUEL COSTS

Effective September 25, 2013, the Base Fuel Cost established in Docket No. E-7, Sub 1026 is 2.3182 ¢ per kilowatt hour which is included in energy charges of the Company's rate schedules.

FUEL COST ADJUSTMENT AND EXPERIENCE MODIFICATION FACTOR

All service supplied under the Company's rate schedules is subject to an increment per kilowatt hour as set forth below. This adjustment is not included in the Rate Schedules of the Company and therefore, must be applied to the bill as calculated under the applicable rate.

RESIDENTIAL SERVICE	Fuel and Fuel Related Costs September 25 2013
Adjustment to Residential	-.0.0876¢/kWh
Experience Modification Factor & Interest	-0.0534 ¢/kWh
Net Fuel Rider Factor	-0.1410 ¢/kWh
Gross Receipts and Regulatory Fee Multiplier	X 1.034554
Fuel Cost Adjustment Factor	-0.1459¢/kWh

GENERAL SERVICE AND LIGHTING	Fuel and Fuel Related Costs September 25, 2013
Adjustment to General Service and Lighting	0.0384 ¢/kWh
Experience Modification Factor & Interest	-0.1371 ¢/kWh
Net Fuel Rider Factor	-0.0987 ¢/kWh
Gross Receipts and Regulatory Fee Multiplier	X 1.034554
Fuel Cost Adjustment Factor	-0.1021¢/kWh

INDUSTRIAL SERVICE	Fuel and Fuel Related Costs September 25, 2013
Adjustment to Industrial	0.0798 ¢/kWh
Experience Modification Factor & Interest	-0.1510 ¢/kWh
Net Fuel Rider Factor	-0.0712 ¢/kWh
Gross Receipts and Regulatory Fee Multiplier	X 1.034554
Fuel Cost Adjustment Factor	-0.0737¢/kWh

Duke Energy Carolinas, LLC

Electricity No. 4
South Carolina Twenty-Seventh Revised Leaf No. 50B
Superseding South Carolina Twenty-Sixth Revised Leaf No. 50B

ADJUSTMENT FOR FUEL COSTS

APPLICABILITY

This adjustment is applicable to and is a part of the Utility's South Carolina retail electric rate schedules.

The Public Service Commission has determined that the costs of Fuel in an amount to the nearest one ten-thousandth of a cent, as determined by the following formula, will be included in the base rates to the extent determined reasonable and proper by the Commission.

$$F = E / S + G / S_1$$

Where:

F = Fuel cost per kilowatt-hour included in base rate, rounded to the nearest one ten-thousandth of a cent.

E = Total Projected system Fuel costs:

(A) Fuel consumed in the Utility's own plants and the Utility's share of fuel consumed in jointly owned or leased plants plus the following variable environmental costs: (a) the cost of ammonia, lime, limestone, urea, dibasic acid, and catalysts consumed in reducing or treating emissions, and (b) the cost of emission allowances, as used, including allowance for SO2, NOx, mercury, and particulates. These environmental costs are reduced by the net proceeds of any sales of emission allowances.

Plus

(B) Fuel costs related to purchased power such as those incurred in unit power and limited term power purchases where the fossil fuel associated with energy purchased are identifiable and are identified in the billing statement. Also the cost of 'firm generation capacity purchases' which are defined as purchases made to cure a capacity deficiency or to maintain adequate reserve levels. "Costs of firm generation capacity purchases" include the total delivered costs of firm generation capacity purchased and excludes generation capacity reservation charges, generation capacity option charges and any other capacity charges.

Plus

(C) Fuel costs related to purchased power (including transmission charges), such as short term, economy and other such purchases, where the energy is purchased on an economic dispatch basis, including the total delivered cost of economy purchases of electric power defined as purchases made to displace higher cost generation at a cost which is less than the purchasing utility's avoided variable costs for the generation of an equivalent quantity of electric power. Energy receipts that do not involve money payments such as Diversity energy and payback of storage energy are not defined as purchased or interchange power relative to this fuel calculation.

Minus

(D) The cost of fuel and applicable environmental costs recovered through intersystem sales including the fuel costs and applicable environmental costs related to economy energy sales and other energy sold on an economic dispatch basis.
Energy deliveries that do not involve billing transactions such as Diversity energy and payback of storage energy are not defined as sales relative to this fuel calculation.

S = Projected system kilowatt-hour sales excluding any intersystem sales.

G = Cumulative difference between jurisdictional fuel revenues billed and fuel expenses at the end of the month preceding the projected period utilized in E and S.

S_1 = Projected jurisdictional kilowatt-hour sales for the period covered by the fuel costs included in E.

Environmental costs reflected in the fuel cost are allocated between customer classes based on firm coincident peak demand.

The appropriate revenue-related tax factor is to be included in these calculations.

The fuel cost F as determined by SCPSC Order No. 2013- 696 for the period October 2013 through September 2014 is 2.0653 cents per kilowatt-hour for residential customers, 2.0446 cents per kilowatt-hour for general service and lighting customers and 2.0337 cents per kilowatt hour for industrial customers.

Duke Energy Progress, Inc.
(North Carolina Only)

RR-1

ANNUAL BILLING ADJUSTMENTS
RIDER BA-7

APPLICABILITY – RATES INCLUDED IN TARIFF CHARGES

The rates shown below are included in the MONTHLY RATE provision in each schedule identified in the table below:

Billing Adjustment Factors (¢/kWh)*					
Rate Class	Fuel and Fuel-Related Adjustment		DSM/EE Adjustment		Net Adjustment
	Rate[(1)]	EMF[(2)]	Rate[(3)]	EMF[(4)]	
Residential	-0.201	0.041	0.307	-0.010	0.137
Applicable to Schedules: RES, R-TOUD, R-TOUE & R-TOU					
Small General Service	-0.096	-0.039	0.235	0.012	0.112
Applicable to Schedules: SGS, SGS-TOUE, SGS-TOU-CL (constant load), TSF & TSS					
Medium General Service	-0.067	-0.042	0.235	0.012	0.138
Applicable to Schedules: MGS, SGS-TOU, SI, CH-TOUE, GS-TES, APH-TES, CSG, CSE					
Large General Service	-0.039	-0.131	0.235	0.012	0.077
Applicable to Schedules: LGS, LGS-TOU, LGS-RTP					
Lighting	0.110	-0.754	0.105	-0.007	-0.546
Applicable to Schedules: ALS, SLS, SLR & SFLS					

* Billing Adjustment Factors, shown above, include North Carolina gross receipts tax and regulatory fee.

Billing Adjustment Factors Description:

(1) The Fuel and Fuel-Related Adjustment Rate is adjusted annually to reflect incremental changes in the costs of fuel and fuel-related costs from the rates approved in the last general rate case.

(2) The Fuel and Fuel-Related Adjustment Experience Modification Factor (EMF) is adjusted annually to reflect the difference between reasonable and prudently incurred fuel and fuel-related costs and the fuel and fuel-related revenues realized during a test period under review and shall remain in effect for a fixed 12 month period.

(3) The Demand Side Management/Energy Efficiency (DSM/EE) Rate is adjusted annually to reflect the costs and incentives associated with demand side management and energy efficiency measures and programs approved by the North Carolina Utilities Commission.

(4) The Demand Side Management/Energy Efficiency Experience Modification Factor (DSM/EE EMF) is adjusted annually to reflect the difference between reasonable and prudently incurred DSM/EE costs and incentives and DSM/EE revenues realized during the period under review and shall remain in effect for a fixed 12 month period.

The fuel rate included in base tariff rates was adjusted pursuant to Base Rate Rider BR-1 effective December 1, 2013 to 3.120¢/kWh for RES, 3.109¢/kWh for SGS, 3.025¢/kWh for MGS, 3.062¢/kWh for LGS and 3.789¢/kWh for Lighting, including North Carolina gross receipts tax and regulatory fee.

Demand Side Management/Energy Efficiency "Opt-Out" Option

North Carolina Utilities Commission Rule R8-69(e) allows commercial customers with annual consumption of 1,000,000 kWh or greater in the billing months of the prior calendar year and all industrial customers to elect to not participate in any utility-offered DSM/EE program and, after written notification to the utility, not be subject to the DSM/EE Rate and EMF, shown above. For purposes of application of this option, a customer is defined to be a metered account billed under a single application of a Company rate tariff. For commercial accounts, once one account meets the opt-out eligibility requirement, all other accounts billed to the same entity with lesser annual usage located on the same or contiguous properties are also eligible to opt-out of the DSM/EE Rider and DSM/EE EMF. Since these rates are included in the rate tariff charges, Customers electing this option shall receive the following DSM/EE Credit on their monthly bill statement:

DSM/EE Credit = DSM/EE Rate Credit plus DSM/EE EMF Credit

Where:
DSM/EE Rate Credit = Billed kWh times DSM/EE Rate*
DSM/EE EMF Credit = Billed kWh times DSM/EE EMF Rate*

* The DSM/EE Rate and EMF shall be as shown in the above table for the schedule applicable to Customer's monthly bill.

Following the December bill each year, usage for commercial accounts electing to "opt-out" of the DSM/EE rates shall be reviewed and the customer shall be notified and removed from the "opt-out" option if annual consumption is less than 1,000,000 kWh in the prior twelve months.

APPLICABILITY – RATES NOT INCLUDED IN TARIFF CHARGES

The rates shown below are not included in the MONTHLY RATE provision of the applicable schedule used in billing and shall therefore be added to Customer's monthly bill statement:

Billing Adjustment Factors Per Customer ($/month)*			
Revenue Class	REPS Rate[5]	REPS EMF[6]	Net Billing Rate
Residential	$ 0.33 per month	-$0.13 per month	$ 0.20 per month
Commercial/Public Streets and Highways	$ 7.74 per month	-$0.36 per month	$ 8.10 per month
Industrial/Public Authority	$33.13 per month	-$2.48 per month	$30.65 per month

* Billing Adjustment Factors, shown above, include North Carolina gross receipts tax and regulatory fee.

For purposes of the applicability of the REPS-related Billing Adjustment Factors, a "Customer" is defined as all accounts (metered and unmetered) serving the same customer of the same revenue classification located on the same or contiguous properties. If a customer has accounts which serve in an auxiliary role to a main account on the same premises, no REPS charge should apply to the auxiliary accounts, regardless of their revenue classification. Upon written notification from Customer, accounts meeting these criteria shall be coded in the billing system to allow Customer to receive only one monthly REPS charge for all identified accounts.

Billing Adjustment Factors Description:

(5) The Renewable Energy Portfolio Standard (REPS) Rate is adjusted annually to reflect research and development costs and incremental costs incurred to comply with the state's Renewable Energy and Energy Efficiency Portfolio Standard (REPS).

(6) The Renewable Energy Portfolio Standard Experience Modification Factor (REPS EMF) Rate is adjusted annually to recover the difference between reasonable and prudently incurred REPS costs and REPS revenues realized during the period under review and shall remain in effect for a fixed 12 month period.

SALES TAX

To the above charges will be added any applicable North Carolina Sales Tax.

The DSM/EE EMF, Fuel and Fuel-Related Adjustment EMF and REPS EMF are effective for service rendered through November 30, 2014.

Supersedes Rider BA-6A
Effective for service rendered on and after December 1, 2013
NCUC Docket No. E-2, Subs 1030, 1031, and 1032

RIDER NO. 39D
ADJUSTMENT FOR FUEL AND VARIABLE ENVIRONMENTAL COSTS

APPLICABILITY

This adjustment is applicable to and is a part of the Utility's South Carolina retail electric rate schedules.

The costs of fuel shall be recovered from Utility's Customers through a charge billed on a kilowatt-hour basis in an amount rounded to the nearest one-thousandth of a cent. The variable environmental cost shall be recovered from each Customer Class through a charge rounded to the nearest one-thousandth of a cent when billed on a kilowatt-hour basis and rounded to the nearest cent when billed on a kilowatt basis. Such charges shall be determined by the following formulas, and will be included in the base rates to the extent determined reasonable and proper by the Commission:

$$F_1 = \frac{E}{S} + \frac{G}{S_1}$$

$$F_2 = \frac{R + G_2}{S_2}$$

Where:

F_1 = Fuel cost per kilowatt-hour included in base rate, rounded to the nearest one-thousandth of a cent.

E = Total projected system fuel costs:

(A) Fuel consumed in the Utility's own plants and the Utility's share of fuel consumed in jointly owned or leased plants. The cost of fossil fuel shall include no items other than those listed in Account 151 of the Commission's Uniform System of Accounts for Public Utilities and Licensees. The cost of nuclear fuel shall be that as shown in Account 518 excluding rental payments on leased nuclear fuel and except that, if Account 518 also contains any expense for fossil fuel which has already been included in the cost of fossil fuel, it shall be deducted from this account.

Plus

(B) Fuel costs related to purchased power such as those incurred in unit power and limited term power purchases where the fossil fuel costs associated with energy purchased are identifiable and are identified in the billing statement. Also the cost of "firm generation capacity purchases," which are defined as purchases made to cure a capacity deficiency or to maintain adequate reserve levels. Costs of "firm generation capacity purchases" includes the total delivered costs of firm generation capacity purchased and excludes generation capacity reservation charges, generation capacity option charges and any other capacity charges.

Plus

(C) Fuel costs related to purchased power (including transmission charges), such as short term, economy and other such purchases, where the energy is purchased on an economic dispatch basis, including the total delivered cost of economy purchases of electric power defined as purchases made to displace higher cost generation at a cost which is less than the purchasing Utility's avoided variable costs for the generation of an equivalent quantity of electric power.

Energy receipts that do not involve money payments such as Diversity energy and payback of storage energy are not defined as purchased or interchange power relative to this fuel calculation.

Minus

(D) The cost of fuel and applicable allowance cost recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

Energy deliveries that do not involve billing transactions such as Diversity energy and payback of storage are not defined as sales relative to this fuel calculation.

S = Projected system kilowatt-hour sales excluding any intersystem sales.

G = Cumulative difference between jurisdictional fuel revenues billed and fuel expenses for the period ending the last day of the month preceding the projected period utilized in E and S.

S_1 = Projected jurisdictional kilowatt-hour sales for the period covered by the fuel costs included in E.

F_2= Variable environmental cost expressed on either a per kilowatt-hour or kilowatt basis and recoverable in base rate, rounded to the nearest one-thousandth of a cent if recovered on a kilowatt-hour basis or cent if recovered on a kilowatt basis.

R = The projected allocated cost of ammonia, lime, limestone, urea, dibasic acid and catalysts consumed in reducing or treating emissions recorded in FERC Account 502 plus the projected allocated cost of SO_2 and NO_X emission allowances, mercury and particulates recorded in FERC Account 509. The cost shall include purchased power and intersystem sales costs related to environmental compliance provided they are identifiable and identified in the billing statement. These variable environmental costs shall be allocated to each Customer Class based upon the Customer Class firm peak demand contribution to the Utility's annual peak demand from the prior year. If a curtailment period coincides with the peak hour, the firm peak demand contribution shall be the class demand at the time of the peak. If a curtailment period does not coincide with the peak hour, the firm peak demand contribution shall be the class demand reduced by the difference between the sum of the registered demands of curtailable customers during the peak hour minus the sum of their contracted Firm Demands.

G_2= The allocated cumulative difference between jurisdictional variable environmental revenues billed and variable environmental costs for the period ending the last day of the month preceding the projected period utilized in R and S_2.

S_2 = Each schedule and rider shall be assigned to the Customer Class shown in the table below for recovery of variable environmental cost on either a kilowatt-hour or kilowatt basis. For schedules and riders to be recovered on a kilowatt-hour basis, S_2 shall be the projected jurisdictional Customer Class kilowatt-hour sales for the period covered by the variable environmental costs included in R. For schedules and riders to be recovered on a kilowatt basis, S_2 shall be the projected jurisdictional Customer Class Firm kilowatt demand billing units for the period covered by the variable environmental costs included in R. The Firm billing demand units shall include the on-peak billing demands only for customers served under time-of-use schedules and firm billing demands only for customers served under curtailable tariffs.

The appropriate revenue-related tax factor is to be included in these calculations.

CUSTOMER CLASS FUEL RATES

The fuel cost as determined by Public Service Commission of South Carolina for each Customer Class is as shown in the following table, which shall remain in effect until superseded by a subsequent Commission order; Provided that the terms of S.C. Code Ann. Section 58-27-865 shall govern this calculation, and in case of any conflict this statute shall control.

Customer Class	**Applicable Rate Schedules**	**F_1 Rate**	**F_2 Rate**
Residential	RES, R-TOUD, R-TOUE and Plan E**	2.934¢/kWh	0.054¢/kWh
General Service (non-demand)	SGS, SGS-TOU*, SI, CSG, CSE, GS, TSS and TFS	2.910¢/kWh	0.047¢/kWh
General Service (demand) *(applicable only to firm billing demands)*	MGS, SGS-TOU*, SGS-TES, LGS, LGS-TOU, LGS-RTP, LGS-CUR-TOU and Rider SS	2.910¢/kWh	$0.12/kW
Lighting	ALS, SLS, SLR, and SFLS	2.910¢/kWh	0.000¢/kWh

* Customers billed under the constant load provision of Schedule SGS-TOU shall be billed in accordance with the General Service (non-demand) Customer Class.

** The Revenue Credit stated in Line Extension Plan E reflects the Fuel Rate (F_1) of the applicable customer class and the residential class Variable Environmental Rate (F_2).

Supersedes Rider No. 39C
Effective for bills rendered on and after July 1, 2013
SCPSC Docket No. 2013-001-E, Order No. 2013-486

DUKE ENERGY

RATE SCHEDULE BA-1
BILLING ADJUSTMENTS

Applicable:

To the Rate Per Month provision in each of the Company's filed rate schedules which reference the billing adjustments set forth below.

COST RECOVERY FACTORS								
Rate Schedule/Metering Level	**Fuel Cost Recovery[1]**			**ECCR[2]**		**CCR[3]**		**ECRC[4]**
	Levelized ¢/ kWh	**On-Peak ¢/ kWh**	**Off-Peak ¢/ kWh**	**¢/ kWh**	**$/ kW**	**¢/ kWh**	**$/ kW**	**¢/ kWh**
RS-1, RST-1, RSL-1, RSL-2, RSS-1 (Sec.)		5.627	3.740	0.402	-	1.644	-	0.243
< 1000	4.077							
> 1000	5.077							
GS-1, GST-1								
Secondary	4.364	5.634	3.744	0.345	-	1.303	-	0.235
Primary	4.320	5.577	3.707	0.342	-	1.290	-	0.233
Transmission	4.277	5.522	3.670	0.338	-	1.277	-	0.230
GS-2 (Sec.)	4.364	-	-	0.266	-	0.897	-	0.205
GSD-1, GSDT-1, SS-1*								
Secondary	4.408	5.691	3.782	-	1.18	-	4.26	0.220
Primary	4.364	5.634	3.744	-	1.17	-	4.22	0.218
Transmission	4.320	5.577	3.707	-	1.16	-	4.17	0.216
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3*								
Secondary	4.408	5.691	3.782	-	0.87	-	3.13	0.293
Primary	4.364	5.634	3.744	-	0.86	-	3.10	0.290
Transmission	4.320	5.577	3.707	-	0.85	-	3.07	0.287
IS-1, IST-1, IS-2, IST-2, SS-2*								
Secondary	4.408	5.691	3.782	-	1.07	-	3.61	0.201
Primary	4.364	5.634	3.744	-	1.06	-	3.57	0.199
Transmission	4.320	5.577	3.707	-	1.05	-	3.54	0.197
LS-1 (Sec.)	4.139	-	-	0.144	-	0.239	-	0.183
*SS-1, SS-2, SS-3								
Monthly								
Secondary	-	-	-	-	0.116	-	0.418	-
Primary	-	-	-	-	0.115	-	0.414	-
Transmission	-	-	-	-	0.114	-	0.410	-
Daily								
Secondary	-	-	-	-	0.055	-	0.199	-
Primary	-	-	-	-	0.054	-	0.197	-
Transmission	-	-	-	-	0.054	-	0.195	-
GSLM-1, GSLM-2	See appropriate General Service rate schedule							

(1) Fuel Cost Recovery Factor:
The Fuel Cost Recovery Factors applicable to the Fuel Charge under the Company's various rate schedules are normally determined annually by the Florida Public Service Commission for the billing months of January through December. These factors are designed to recover the costs of fuel and purchased power (other than capacity payments) incurred by the Company to provide electric service to its customers and are adjusted to reflect changes in these costs from one period to the next. Revisions to the Fuel Cost Recovery Factors within the described period may be determined in the event of a significant change in costs.

(2) Energy Conservation Cost Recovery Factor:
The Energy Conservation Cost Recovery (ECCR) Factor applicable to the Energy Charge under the Company's various rate schedules is normally determined annually by the Florida Public Service Commission for twelve-month periods beginning with the billing month of January. This factor is designed to recover the costs incurred by the Company under its approved Energy Conservation Programs and is adjusted to reflect changes in these costs from one period to the next. For time of use demand rates the ECCR charge will be included in the base demand only.

(Continued on Page No. 2)

DUKE ENERGY.

RATE SCHEDULE BA-1
BILLING ADJUSTMENTS
(Continued from Page 1)

(3) Capacity Cost Recovery Factor:

The Capacity Cost Recovery (CCR) Factors applicable to the Energy Charge under the Company's various rate schedules are normally determined annually by the Florida Public Service Commission for the billing months of January through December. This factor is designed to recover the cost of capacity payments made by the Company for off-system capacity and is adjusted to reflect changes in these costs from one period to the next. For time of use demand rates the CCR charge will be included in the base demand only.

(4) Environmental Cost Recovery Clause Factor:

The Environmental Cost Recovery Clause (ECRC) Factors applicable to the Energy Charge under the Company's various rate schedules are normally determined annually by the Florida Public Service Commission for the billing months of January through December. This factor is designed to recover environmental compliance costs incurred by the Company and is adjusted to reflect changes in these costs from one period to the next.

Gross Receipts Tax Factor:

In accordance with Section 203.01 of the Florida Statutes, a factor of 2.5641% is applicable to electric sales charges for collection of the state Gross Receipts Tax.

Right-of-Way Utilization Fee:

A Right-of-Way Utilization Fee is applied to the charges for electric service (exclusive of any Municipal, County, or State Sales Tax) provided to customers within the jurisdictional limits of each municipal or county governmental body or any unit of special-purpose government or other entity with authority requiring the payment of a franchise fee, tax, charge, or other imposition whether in money, service, or other things of value for utilization of rights-of-way for location of Company distribution or transmission facilities. The Right-of-Way Utilization Fee shall be determined in a negotiated agreement (i.e., franchise and other agreements) in a manner which reflects the Company's payments to a governmental body or other entity with authority plus the appropriate Gross Receipts Taxes and Regulatory Assessment Fees resulting from such additional revenue. The Right-of-Way Utilization Fee is added to the charges for electric service prior to the application of any appropriate taxes.

Municipal Tax:

A Municipal Tax is applied to the charge for electric service provided to customers within the jurisdictional limits of each municipal or other governmental body imposing a utility tax on such service. The Municipal Tax shall be determined in accordance with the governmental body's utility tax ordinance, and the amount collected by the Company from the Municipal Tax shall be remitted to the governmental body in the manner required by law. No Municipal Tax shall apply to fuel charges in excess of 0.699¢/kWh.

Sales Tax:

A State Sales Tax is applied to the charge for electric service provided to all non-residential customers and equipment rental provided to all customers (unless a qualified sales tax exemption status is on record with the Company). The State Sales Tax shall be determined in accordance with the State's sales tax laws. The amount collected by the Company shall be remitted to the State in the manner required by law. In those counties that have enacted a County Discretionary Sales Surtax, such tax shall be applied and paid in a like manner.

Governmental Undergrounding Fee:

Applicable to customers located in a designated Underground Assessment Area within a local government (a municipality or a county) that requires the Company to collect a Governmental Undergrounding Fee from such customers to recover the local government's costs of converting overhead electric distribution facilities to underground facilities. The Governmental Undergrounding Fee billed to a customer's account shall not exceed the lesser of (i) 15 percent of a customer's total net electric service charges, or (ii) a maximum monthly amount of $30 for residential customers and $50 for each 5,000 kilowatt-hour increment of consumption for commercial/industrial customers, unless the Commission approves a higher percentage or maximum monthly amount. The maximum monthly amount shall apply to each line of billing in the case of a customer receiving a single bill for multiple service points, and to each occupancy unit in the case of a master metered customer. The Governmental Undergrounding Fee shall be calculated on the customer's charges for electric service before the addition of any applicable taxes.

Duke Energy Indiana, Inc.
1000 East Main Street
Plainfield, Indiana 46168

IURC No. 14
Fortieth Revised Sheet No. 60
Canceling Thirty-ninth Revised Sheet No. 60

STANDARD CONTRACT RIDER NO. 60
FUEL COST ADJUSTMENT APPLICABLE
TO ALL RETAIL RATE SCHEDULES

A. The applicable charges for electric service to the Company's retail customers shall be increased or decreased, to the nearest 0.001 mill ($0.000001) per kWh to recover and/or credit the cost for fuel in accordance with the following formula:

Fuel Cost Adjustment Factor = F/S - $0.014484

where:

1. "F" is the estimated expense of fuel based on a three-month average cost beginning with the first month of the billing cycle and consisting of the following costs:

   (a) the average cost of fossil fuel consumed due to the operation of Company's own generating units incurred to serve native load customers, including only those items listed in Account 151, of the Federal Energy Regulatory Commisssion's Uniform System of Accounts for Class A and B Public Utilities and Licensees (FERC US of A);

   (b) the actual identifiable fossil and nuclear fuel costs, or, if fuel costs are not specifically identified, costs computed in accordance with applicable Commission Orders, associated with energy purchased or transferred to serve native load customers for reasons other than identified in (c) below;

   (c) the net energy cost, exclusive of capacity or demand charges, of energy purchased or transferred to serve native load customers on an economic dispatch basis, and energy purchased or transferred to serve native load customers resulting from the scheduled outage of a Company owned generating unit, when the costs thereof are less than the Company's fuel costs of replacement net generation from its own system, as computed in accordance with applicable Commission Orders,

2. "S" is the estimated kilowatt-hour sales as recorded on the Company's books and records in accordance with the FERC US of A for the same estimated period set forth in "F,"

B. The factor as computed above shall be modified to allow the recovery of utility receipts taxes and/or other similar revenue based taxes incurred due to the recovery of fuel costs.

C. The factor shall be further modified commencing with the fifth succeeding billing cycle month to reflect the difference between the estimated incremental fuel cost billed and the incremental fuel cost actually incurred during the first and succeeding billing cycle month(s) in which such estimated incremental fuel cost was billed.

D. Effective for all bills rendered beginning with and subsequent to the later of the effective date of the Commission's Order or the first billing cycle of April 2014 the fuel cost adjustment shall be $0.019311 per kilowatt-hour.

E. From time to time, and subject to approval of the Commission, the factor shall be further modified to include the separate recovery, pursuant to Ind. Code 8-1-2-42(a), of costs applicable to certain power purchases in excess of the monthly purchased power benchmark.

ISSUED:

April 2, 2014

EFFECTIVE:

April 3, 2014

DE-Ohio Exhibit____

FILE

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of The Cincinnati Gas & Electric Company to Modify its Quarterly Fuel and Purchase Power Component of its Market Based Standard Service Offer.	)	Case No. 05-725-EL-UNC
In the Matter of the Application of The Cincinnati Gas & Electric Company to Adjust and Set its System Reliability Tracker Market Price	)	Case No. 05-724-EL-UNC
In the Matter of the Application of Duke Energy Ohio, Inc. to Modify its Quarterly Fuel and Purchase Power Component of its Market Based Standard Service Offer	)	Case No. 06-1068-EL-UNC
In the Matter of the Application of Duke Energy Ohio, Inc. to Adjust and Set its System Reliability Tracker	)	Case No. 06-1069-EL-UNC

DIRECT TESTIMONY OF

CHARLES R. WHITLOCK

ON BEHALF OF

THE CINCINNATI GAS & ELECTRIC COMPANY

D/B/A DUKE ENERGY OHIO, INC.

DATE: September 1, 2006

TABLE OF CONTENTS

I. INTRODUCTION

Q. **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Charles R. Whitlock, and my business address is 139 East Fourth Street, Cincinnati, Ohio 45202.

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

A. I am employed by Duke Energy Americas, an affiliate of Duke Energy, as President, Commercial Asset Management ("CAM").

Q. **PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.**

A. I am a graduate of the University of Alaska at Anchorage with a Bachelor of Business Studies Degree in Accounting. I am also a graduate of the Mahler School Advanced Management Skills Program and the Center for Creative Leadership Developing Strategic Leadership Program. I have also taken advanced course work in the area of business management at Harvard University. I joined Cinergy in May 2000 as a power trader for Cinergy Services. Prior to joining Cinergy, I was a Senior Power Trader with Statoil Energy. I also held various positions with Vitol Gas and Electric which included responsibilities for energy trading, marketing and risk management. I was named to my current position in April 2006.

Q. **PLEASE DESCRIBE YOUR RESPONSIBILITIES AS PRESIDENT, COMMERCIAL ASSET MANAGEMENT.**

A. I am responsible for the commercial asset management operations. Specifically, I have responsibility to maintain the safe, reliable and economic supply of fuel, power, emission allowances and capacity to Duke Energy Ohio's (DE-Ohio) Market Based Standard Service Offer ("MBSSO") consumers. I also have responsibility for the commercial risk management of all components of DE-Ohio's non-MBSSO generation which includes risk associated with power prices, fuel prices, emission allowance ("EA") prices, congestion and weather.

II. PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to provide an overview of how DE-Ohio manages its resource requirements associated with the Fuel and Purchase Power Rider ("Rider FPP") and the System Reliability Tracker ("Rider SRT"). I will provide testimony regarding the basis for the costs provided to Mr. Wathen for inclusion in Rider FPP and address some of the issues raised in the 2005 Audit of Rider FPP. In the next section of my testimony, I will discuss the Company's plans for meeting its obligations under Rider SRT. Then, I will make some recommendations with respect to the Company's future resource purchases. Finally, I am sponsoring Attachment CRW-1.

III. PORTFOLIO OPTIMIZATION

Q. ONE OF THE AUDITOR'S RECOMMENDATIONS IN THE 2005 AUDIT WAS THAT DE-OHIO "ECONOMICALLY MANAGE FUEL, POWER, AND EMISSION ALLOWANCES FORWARD FOR THE BALANCE OF THE RSP PERIOD." IS THE COMPANY FOLLOWING THIS RECOMMENDATION?

A. Yes. A significant area of my responsibility is to "economically manage" the portfolio of resources used to meet the Company's MBSSO load obligation through 2008.

Q. **PLEASE EXPLAIN THE TERM "ECONOMIC MANAGEMENT."**

Economic management refers to the way CAM manages market risk for our MBSSO consumers. This management consists of CAM using the transactable forward markets in power, fuel and emission allowances to meet our forecasted load obligation under the MBSSO. Purchasing or contracting for enough resources to meet our MBSSO load requirements is sometimes referred to as being "balanced."

Both Rider FPP and Rider SRT are impacted by our ability to economically manage our resources. Volatility in the price of resources and volatility in MBSSO load affect the costs we include in Rider FPP. As forecasts of demand and prices for energy, fuel, and emission allowances change, the expected least cost mix of generation and purchased power required to serve the Rider SRT and Rider FPP load changes. Changes in prices and load result in the buying or selling of the fuel, emission allowances, and contracts for power. The mix of generation and purchased power is monitored daily and adjusted subject to the ability to transact in the market. We continue to refine our portfolio of resources through this buying and selling up to the date for physical delivery of the contracted resource (*i.e.*, fuel, emission allowances, or power). Any gains or losses on the fuel, emission allowances, and energy will be tracked for the benefit of the consumer. This active portfolio management results in the least cost supply to our Rider SRT and Rider FPP consumers. We manage our non-MBSSO commitments in the same manner.

IV. RIDER FPP DISCUSSION

Q. WHAT IS RIDER FPP?

A. The Commission approved Rider FPP as the mechanism that facilitates the direct pass through of the Company's fuel costs needed to power its generation plants, the cost of energy bought on the open market, and the cost of emission allowances. I am responsible for acquiring the fuel, energy, and emission allowances that are included in the Rider FPP.

Q. AT THE TIME OF THE 2005 AUDIT, CERTAIN DE-OHIO PLANTS WERE BEING TRANSFERRED TO DE-KENTUCKY. THE ORDER IN THE LAST AUDIT INDICATED THAT THE METHODOLOGY FOR THE ALLOCATION OF FUEL COSTS AND/OR FUEL CONTRACTS WERE TO BE REVIEWED IN THIS AUDIT. PLEASE EXPLAIN THAT METHODOLOGY.

A. On January 1, 2006, Miami Fort Unit 6, East Bend Unit 2, and the Woodsdale Units 1-6 were transferred from DE-Ohio to Duke Energy Kentucky (DE-Kentucky).

No coal contracts were transferred with Miami Fort 6 as a result of this transaction. Miami Fort Station has two inventories one for Miami Fort Unit 8 and another for Miami Fort Unit 5, Unit 6, and Unit 7. Miami Fort Unit 6 pays for fuel consumed at Miami Fort station based on the weighted-average cost of inventory related to the pile maintained for Units 5, 6, and 7.

At East Bend, certain coal contracts were transferred from DE-Ohio to DE-Kentucky. The contracts were allocated based on projected burns of scrubber coal. Criteria utilized to split the coal were 1) avoidance of re-pricing, and 2) unit compatibility. Coal from Oxford Mining was appropriate to burn at East Bend, so those scrubber coal contracts were allocated for use at East Bend. High sulfur coal contracts of Peabody Arclar mine and Foundation Cumberland mine were also assigned to DE-Kentucky on a pro rata basis.

Q. WERE THERE ANY CONTRACTS RELATED TO WOODSDALE?

A. No. Woodsdale is a gas unit and no contracts were assigned as part of the transfer to DE-Kentucky.

Q. THE ORDER IN CASE NO. 05-806-EL-UNC SETTLING THE AUDIT ALSO ADDRESSED THE ALLOCATION OF MARGINS ON COAL SALES. PLEASE EXPLAIN THE CRITERIA USED FOR ALLOCATING THE COAL MARGIN FOR TRANSACTIONS MADE AFTER JANUARY 1, 2005.

A. The Order directed the parties to the last Audit to discuss the "criteria for the equitable assignment of benefits and costs of coal contract sales margins for contracts executed on or after January 1, 2005." The criteria being used to incorporate margins on coal sales in Rider FPP is to subtract the gain or loss associated with contracts for coal sales made after January 1, 2005, from the monthly fuel cost in the Rider FPP calculation. In this way, the average fuel cost included in the Rider FPP market price incorporates the gain or loss on the sale of coal contracts executed after January 1, 2005.

V. RIDER SRT DISCUSSION

Q. PLEASE DECRIBE RIDER SRT.

A. Rider SRT allows the Company to track and collect costs associated with meeting its MBSSO load obligation plus a fifteen percent (15%) reserve margin. The Company is the sole holder of the provider of last resort ("POLR") obligation and, consequently, must have the resources to stand ready to serve all retail load in its service territory. Rider SRT includes costs incurred by DE-Ohio to ensure that we can provide safe and reliable service to all consumers in our service territory. The expectation for safe and reliable service should be no different than if we were still under traditional regulation.

Q. PLEASE EXPLAIN THE 2007 RIDER SRT PLAN.

A. DE-Ohio proposes to maintain a reserve margin of 15 percent of the projected retail load served in its certified territory by any entity for 2007. DE-Ohio agrees to make purchases to achieve that reserve, keeping records sufficient for Commission staff audit, and will recover the associated costs from consumers that do not avoid the Rider SRT. The management of this reserve will include the purchase and sale of capacity for non-residential consumers that leave or return to the MBSSO at the higher of the MBSSO price or the monthly-average hourly LMP price.

As in previous years, the estimate of purchases required to meet our reserve margins begins with our capacity position which is shown on the last page of Attachment CRW-1. This calculation compares the load in our service territory, switched and non-switched, plus 15% for reserves, to our generation capacity. To the extent that the load plus reserves exceeds capacity, this excess is the amount of capacity we need to purchase in order to meet our reserve margin requirements for 2007.

The remaining pages of Attachment CRW-1 are a summary of the products that we have purchased or expect to purchase to meet the 2007 requirements.

Q. DO YOU BELIEVE THAT THE COMMISSION SHOULD ENCOURAGE THE COMPANY TO MAKE RELIABILITY PURCHASES FOR MORE THAN ONE YEAR?

Yes. As I discussed earlier regarding economic management and balancing our resources earlier, DE-Ohio believes that it is beneficial to purchase capacity instruments for periods longer than a year and to do so would enable DE-Ohio to take advantage of reliability and pricing opportunities in the market that would accrue to the benefit of MBSSO consumers. Purchasing products over various periods of time creates a reliability hedge for MBSSO consumers. It also permits MBSSO consumers to benefit from low prices in the market that may not be available at a later date. There is no economic reason to restrict capacity purchases to a single calendar year. DE-Ohio is asking the Commission to approve this approach in this proceeding.

Q. YOUR ESTIMATED COST FOR RESERVE PURCHASES IN 2006 HAS FALLEN SIGNICANTLY SINCE THE COMPANY MADE ITS INITIAL 2006 RIDER SRT FILING. WILL YOU EXPLAIN WHAT CHANGED?

A. Clearly, the estimated costs for 2006 were much higher than we actually experienced. We originally estimated that reliability purchases for the year would be $24 million. In our filing for the fourth quarter of 2006, our most recent estimate is approximately $4 million. The primary reasons for this difference are a change in both products and prices of products needed to obtain the reserve margin. Product changes include the elimination of the Daily Fixed Call Option with Unit Contingency (outage insurance), base-load, and mid-merit tolls from the plan. This change accounts for $16 million of the variance. The Fixed Strike Energy Options procured were bought for less than originally estimated. For example, the summer daily $100 call options were valued at $14.50/MW in the original plan but our actual costs were $5.25/MW. We were also able to purchase Capacity at prices lower than we anticipated in the original filing.

With the ability to true-up these costs, the total costs incurred and revenue collected from consumers should be nearly even with consumers by the end of year.

VI. MISCELLANEOUS ISSUES

Q. DO YOU HAVE ANY COMMENTS ON THE PURCHASING OF RESOURCES BEYOND 2008?

A. Yes, DE-Ohio filed an application on August 2, 2006, in Case No. 06-986-EL-UNC, to extend the MBSSO beyond December 31, 2008. Extending the MBSSO through 2010 will enable DE-Ohio to update the Rider FPP market price so that reliable service at a stable price can continue to be offered to consumers of DE-Ohio.

At the present time, we are not actively managing our position beyond 2008, subject to the outcome of the extension or Commission approval in this case. With Commission approval, the Company will begin to purchase fuel and the other components of Rider FPP and Rider SRT beyond 2008 at current market prices to the benefit of MBSSO consumers.

Q. **PLEASE EXPLAIN ANY NEW DEVELOPMENTS WITH REGARD TO THE LEGACY DUKE ENERGY NORTH AMENRICA ("DENA") ASSETS.**

The legacy DENA assets, now owned by DE-Ohio, are located in MISO and PJM. There has been no change regarding their disposition and they are being dispatched into the market by MISO and PJM, as appropriate. In the previous SRT case, DE-Ohio agreed not to include the legacy DENA assets as capacity instruments to satisfy SRT reserve margin capacity absent Commission approval. DE-Ohio requests such approval in this case to the extent that capacity purchases from legacy DENA assets are purchased at the market price and represent a benefit to MBSSO consumers. There is no reason to treat the legacy DENA assets in a different manner than any other generating capacity available in the market. The MBSSO consumer should expect that we pursue all economic means of obtaining generating capacity to meet their needs. Excluding viable assets because they are DENA legacy assets is illogical and would be imprudent.

VII. CONCLUSION

Q. **DO YOU HAVE ANY FINAL COMMENTS REGARDING RIDER FPP OR RIDER SRT BEING ADDRESSED IN THIS FILING?**

A. I believe that DE-Ohio is prudently obtaining and utilizing its resources to meet its MBSSO obligations for the Rider FPP and the Rider SRT. We have complied with all of the applicable directives included in the Order settling the Audit of the Rider FPP, in Case No. 05-806-EL-UNC, and with the directives included in the Order approving the Stipulation reached in Case No. 05-724-EL-UNC. We use reasonable methods for allocating costs and have mechanisms in place to ensure that consumers are paying only for the Company's actual costs.

Q. **WAS ATTACHMENT CRW-1 PREPARED BY YOU OR UNDER YOUR SUPERVISION?**

A. Yes.

Q. **DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A. Yes.

CONFIDENTIAL PROPRIETARY
TRADE SECRET

DUKE ENERGY OHIO

Summary of Projected 2007 Capacity and Purchased Power Costs Incurred to Serve SRT Customers

Total Estimated Capacity Costs and Jurisdictional Allocation

Line No.	Description	January (A)	February (B)	March (C)	April (D)	May (E)	June (F)	July (G)	August (H)	September (I)	October (J)	November (K)	December (L)	Total (M)	Line No.
1	Daily Fixed Strike Energy Firm LD Call Option	[redacted]													1
2	Mit-Mark Gas Tolling Agreement														2
3	Regulatory Capacity Purchase														3
4	Existing Henry County Capacity Purchase														4
5	Total Applicable to Retail Customers														5

CONFIDENTIAL PROPRIETARY
TRADE SECRET

DUKE ENERGY OHIO

Projected Purchased Capacity

Line No.	Description (A)	Amount (B)	Description (C)	Amount (D)	Line No.	March
	February	[redacted]	July	[redacted]		
1	MWs		MWs		1	April
2	Capacity Charge/Kw/Month		Capacity Charge/Kw/Month		2	
3	CG&E's Capacity Charge		CG&E's Capacity Charge		3	
4	Estimated Monthly Costs Recoverable Via System Reliability Tracker - Rider SRT		Estimated Monthly Costs Recoverable Via System Reliability Tracker - Rider SRT		4	May
	March		August			April
5	MWs		MWs		5	
6	Capacity Charge/Kw/Month		Capacity Charge/Kw/Month		6	
7	CG&E's Capacity Charge		CG&E's Capacity Charge		7	
8	Estimated Monthly Costs Recoverable Via System Reliability Tracker - Rider SRT		Estimated Monthly Costs Recoverable Via System Reliability Tracker - Rider SRT		8	May
	April		September			June
9	MWs		MWs		9	
10	Capacity Charge/Kw/Month		Capacity Charge/Kw/Month		10	
11	CG&E's Capacity Charge		CG&E's Capacity Charge		11	July
12	Estimated Monthly Costs Recoverable Via System Reliability Tracker - Rider SRT		Estimated Monthly Costs Recoverable Via System Reliability Tracker - Rider SRT		12	
	May		October			August
13	MWs		MWs		13	
14	Capacity Charge/Kw/Month		Capacity Charge/Kw/Month		14	September
15	CG&E's Capacity Charge		CG&E's Capacity Charge		15	
16	Estimated Monthly Costs Recoverable Via System Reliability Tracker - Rider SRT		Estimated Monthly Costs Recoverable Via System Reliability Tracker - Rider SRT		16	October
	June		November			November
17	MWs		MWs		17	
18	Capacity Charge/Kw/Month		Capacity Charge/Kw/Month		18	
19	CG&E's Capacity Charge		CG&E's Capacity Charge		19	
20	Estimated Monthly Costs Recoverable Via System Reliability Tracker - Rider SRT		Estimated Monthly Costs Recoverable Via System Reliability Tracker - Rider SRT		20	
			Total Purchased Capacity Charge		21	

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TRADE SECRET

DUKE ENERGY OHIO

Projected Daily Fixed Strike Energy Firm Liquidated Damages Call Option

Line No.	Description (A)	Amount (B)	Description (C)	Amount (D)	Line No.
	May	[redacted]	July	[redacted]	
1	Days		Days		1
2	Daily Hours		Daily Hours		2
3	MWs Optioned		MWs Optioned		3
4	MWHs Subject to Reservation Charge		MWHs Subject to Reservation Charge		4
5	Charge Per MWH		Charge Per MWH		5
6	Cost per kW-month Capacity		Cost per kW-month Capacity		6
7	Capacity Charge		Capacity Charge		7
	June		August		
8	Days		Days		8
9	Daily Hours		Daily Hours		9
10	MWs Optioned		MWs Optioned		10
11	MWHs Subject to Reservation Charge		MWHs Subject to Reservation Charge		11
12	Charge Per MWH		Charge Per MWH		12
13	Cost per kW-month Capacity		Cost per kW-month Capacity		13
14	Capacity Charge		Capacity Charge		14
			SUMMARY		
			Total Daily Call Options Capacity Charge		15

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DUKE ENERGY OHIO

Henry County Capacity Purchase

Purchase of PJM Capacity from PSEG

Line No.		January	February	March	April	May	June	July	August	September	October	November	December	Total
1	MWs	[redacted]												
2	Cost per KW/Month													
3	Total Cost													

Case No. 05-724-EL-UNC
Case No. 05-725-EL-UNC
Case No. 06-1068-EL-UNC
Case No. 06-1069-EL-UNC
Attachment CRW-1
Schedule C
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TRADE SECRET

DUKE ENERGY OHIO
Capacity Position for 2007

Updated on August 14, 2006 [illegible]

Native	2007 January	February	March	April	May	June	July	August	September	October	November	December
Supply	[redacted]											
Maintenance *												
Supply with Maintenance Considerations												
Native and Switched Peak Demand												
Call Option & RTP												
Purchases												
CG&E Native Load Capacity Position												
Margin												
Capacity Position @ 15% Reserve Margin												

(*) - represents the maintenance schedule based upon economics and resource constraints. Also this uses the highest weekly volume during the month. The schedule has some flexibility and might be adjustable for peak days.

Please note: All residential customers and non-residential customers who have not opted-out are included in this analysis.