LARGE FILING SEPERATOR SHEET

CASE NUMBER: 03-93-EL-ATA
03-2079-EL-AAM
03-2080-EL-ATA
03-2081-EL-AAM
05-724-EL-UNC
05-725-EL-UNC

FILE DATE: 11-10-08

SECTION: 15 of 17

NUMBER OF PAGES: 200

DESCRIPTION OF DOCUMENT: Conf. Release

		CGE On Syst	- Purch				
5	Reliant Energy Services, Inc. (RES M)	1,600	0.00	0.00	56,000.00	56,000.00	
7	Select Energy, Inc. (Select Energy Inc E)	350	0.00	0.00	22,000.00	22,000.00	
3	South Carolina Electric & Gas Company (South Carolina E&G E)	3,200	0.00	0.00	126,960.00	126,960.00	
9	Southern Company Services, Inc. (SWE M)	873	0.00	0.00	41,516.00	41,516.00	
0	Southern Indiana Gas & Electric Company (Southern IN G&E E)	3,770	0.00	0.00	143,840.00	143,840.00	
1	Split Rock Energy LLC (Split Rock Energy)	600	0.00	0.00	39,600.00	39,600.00	
2	Strategic Energy, LLC (SEL M)	240	0.00	0.00	12,240.00	12,240.00	
3	Tenaska Power Services Co. (Tenaska Power Serv E)	475	0.00	0.00	26,650.00	26,650.00	
4	Tennessee Valley Authority (TVAPT M)	39,805	0.00	0.00	1,388,275.00	1,388,275.00	
5	The Energy Authority (The Energy Auth E)	1,058	0.00	0.00	29,660.00	29,660.00	
6	Tractebel Energy Marketing, Inc. (TEMI M)	11,200	0.00	0.00	451,240.00	451,240.00	
7	TransAlta Energy Marketing (US) Inc. (TransAlta Energy M E)	5,865	0.00	0.00	255,370.00	255,370.00	
8	UBS AG (UBS AG)	9,600	0.00	0.00	460,800.00	460,800.00	
9	Virginia Electric and Power Company (Virginia Elec&Pwr E)	10,400	0.00	0.00	454,760.00	454,760.00	
0	Wabash Valley Power (Wabash Valley PowerE)	1,020	0.00	0.00	22,260.00	22,260.00	
1	Westar Energy, Inc. (Westar Energy E)	1,800	0.00	0.00	107,400.00	107,400.00	
2	Williams Energy Marketing & Trading Company (Williams Engy M&Tr E	1,600	0.00	0.00	46,400.00	46,400.00	
3	PSI generation for CGE's trading sales	49,172	0.00	0.00	1,465,891.70	1,465,991.70	381.56
4	Adjustment to Tie	(71,961)	0.00	0.00		0.00	
	ection Totals	664,552	$403,000.00	$1,037,910.05	$27,887,620.70	$29,328,530.75	381.56
	ff-System Energies transferred to On-System Report						
5	Cinergy Capital & Trading, Inc. (CCT)	10	0.00	0.00	678.30	678.30	
5	BP Energy Company (AMCO M)	17,600	0.00	0.00	545,600.00	545,600.00	
	ection Totals	17,610	$0.00	$0.00	$546,278.30	$546,278.30	-
	rand Totals	682,162	$403,000.00	$1,037,910.05	$28,433,899.00	$29,874,809.05	381.56

CONFIDENTIAL PROPRIETARY
TRADE SECRET

02785

Of the purchased power above the following is the breakdown	MWHS	DEMAND	OPTIONS	ENERGY	TOTAL
Purchases for Load excluding Intercompany Transfer					
Forwards					
	-	0.00		-	0.00
Total Forward Purchases On System	-	0.00	0.00	0.00	0.00
Forward Book Outs					
Dynegy Power Mktg	-	0.00	0.00	-	0.00
Edison Mission	-	0.00	0.00	-	0.00
Total Forward *Book Out Purchases*	-	0.00	0.00	0.00	0.00
Total Forward Purchases	-	0.00	0.00	0.00	0.00
Hourly					
OVEC	98,019	0.00	0.00	2,407,628.10	2,407,628.10
American Electric Power Co	263	0.00	0.00	26,300.00	26,300.00
CCT	350	403,000.00	0.00	15,608.10	418,608.10
Dayton Power & Light	7	0.00	0.00	700.00	700.00
East Kentucky Power Coop	7	0.00	0.00	700.00	700.00
Hoosier Energy	1	0.00	0.00	100.00	100.00
Indianapolis Power & Light	7	0.00	0.00	700.00	700.00
Louisville Gas & Electric	17	0.00	0.00	1,700.00	1,700.00
Northern Indiana Public Service Co	15	0.00	0.00	1,500.00	1,500.00
Southern Indiana Gas & Electric	2	0.00	0.00	200.00	200.00
Adj to tie to Prelim Pace	7,441	0.00	0.00	133,284.90	133,284.90
Total Hourly Purchases	106,129	403,000.00	0.00	2,588,421.10	2,991,421.10
Hourly Transfer from Off System					
Cinergy Capital & Trading	10	0.00	0.00	678.30	678.30
Total Hourly Transfer Purchases	10	0.00	0.00	678.30	678.30
Total Hourly Purchases	106,139	403,000.00	0.00	2,589,099.40	2,992,099.40
Transfer from PSI					
Psi generation		0.00	0.00		0.00
	-	0.00	0.00	-	0.00
Total Purchases for Load	106,139	$403,000.00	$0.00	$2,589,099.40	$2,992,099.40

664,552	3,033,086	O&D
	(2,355,360)	generation
	(13,174)	loop
	664,552	
	0	

CONFIDENTIAL PROPRIETARY
TRADE SECRET

02786

02787

E Schedule 4 Report
termination of Net Energy Costs incurred and KWhr Purchases
al for the month of July 2003

Company Name	MWhrs	Demand	Option Premium	Fuel W Trans	Other	EA Cost	Energy Charge	Total	EA Tons
-System Energy									
Alcoa Power Generating Inc. d/b/a APG Trading (APGT M)	228	$0.00	$0.00	$9,600.00	$0.00	$0.00	$9,600.00	$9,600.00	0.00
Allegheny Energy Supply Company LLC (AETS M)	10,550	0.00	0.00	419,450.00	0.00	0.00	419,450.00	419,450.00	0.00
Ameren Energy as Agent (Ameren Energy E)	4,875	0.00	0.00	219,525.00	0.00	0.00	219,525.00	219,525.00	0.00
American Electric Power Service Corporation (American Elec Powr E)	183,496	0.00	0.00	6,859,300.00	0.00	0.00	6,859,300.00	6,859,300.00	0.00
American Electric Power Service Corporation trans	1,918	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Aquila Merchant Services, Inc. (Aquila Merchant E)	15	0.00	0.00	301.50	0.00	0.00	301.50	301.50	0.00
Associated Electric Cooperative, Inc. (AECI M)	200	0.00	0.00	13,000.00	0.00	0.00	13,000.00	13,000.00	0.00
Big Rivers Electric Corporation (Big Rivers Elec Co E)	645	0.00	0.00	29,735.00	0.00	0.00	29,735.00	29,735.00	0.00
Brascan Energy Marketing Inc. (Brascan Energy E)	2,400	0.00	0.00	88,000.00	0.00	0.00	88,000.00	88,000.00	0.00
Blue Ridge transmission	2	0.00	0.00	0.00	0.00	0.00		0.00	0.00
Buckeye Power (BUCKM M)	9,281	0.00	0.00	398,623.00	0.00	0.00	398,623.00	398,623.00	0.00
Cargill Power Markets, LLC (Cargill Pow Mar E)	7,089	0.00	0.00	264,820.00	0.00	0.00	264,820.00	264,820.00	0.00
Central Illinois Light Company (CILMAR M)	1,644	0.00	0.00	52,314.75	0.00	0.00	52,314.75	52,314.75	0.00
Cinergy Capital & Trading, Inc. (CCT)	346	0.00	403,000.00	15,834.00	0.00	0.00	15,834.00	418,834.00	0.00
Conectiv Energy Supply, Inc. (CNCT M)	100	0.00	0.00	6,000.00	0.00	0.00	6,000.00	6,000.00	0.00
Constellation Power Source, Inc. (Constellation Powr E)	7,271	0.00	0.00	282,270.00	0.00	0.00	282,270.00	282,270.00	0.00
Consumers Energy Co. (Consumers Energy E)	5,052	0.00	0.00	274,820.00	0.00	0.00	274,820.00	274,820.00	0.00
Coral Power, L.L.C. (CORP M)	4,035	0.00	0.00	185,400.00	0.00	0.00	185,400.00	185,400.00	0.00
DTE Energy Trading, Inc. (DTEET M)	75,965	0.00	0.00	3,707,760.00	0.00	0.00	3,707,760.00	3,707,760.00	0.00
Dayton Power & Light Company (Dayton Power&Light E)	4,985	0.00	0.00	186,275.00	0.00	0.00	186,275.00	186,275.00	0.00
Dayton Power & Light Company trans	4	0.00	0.00	0.00	0.00	0.00		0.00	0.00
Detroit Edison Company (The) (Detroit Edison Co E)	1,477	0.00	0.00	74,450.00	0.00	0.00	74,450.00	74,450.00	0.00
Duke Energy Trading and Marketing LLC (DETM M)	13,414	0.00	0.00	597,506.50	0.00	0.00	597,506.50	597,505.50	0.00
Duke Energy Trading and Marketing trans	7	0.00	0.00	0.00	0.00	0.00		0.00	0.00
Duke Power Company (Duke Power Co E)	2,444	0.00	0.00	118,768.00	0.00	0.00	118,768.00	118,768.00	0.00
Dynegy Power Marketing, Inc. (Dynegy Power Mktg E)	50	0.00	0.00	1,800.00	0.00	0.00	1,800.00	1,800.00	0.00
East Kentucky Power Cooperative, Inc. (EKPCPM M)	38	0.00	0.00	2,025.00	0.00	0.00	2,025.00	2,025.00	0.00
Edison Mission Marketing & Trading Inc. (Edison Mission M&T E)	8,624	0.00	0.00	272,846.00	0.00	0.00	272,846.00	272,846.00	0.00
El Paso Merchant Energy, L.P. (El Paso Merchnt En E)	2,385	0.00	0.00	96,400.00	0.00	0.00	96,400.00	96,400.00	0.00
EnergyUSA-TPC Corp. (EnergyUSA TPC E)	14,000	0.00	0.00	508,880.00	0.00	0.00	508,880.00	508,880.00	0.00
Exelon Generation Company, LLC (ExelonGenerationCo E)	2,368	0.00	0.00	94,640.00	0.00	0.00	94,640.00	94,640.00	0.00
FirstEnergy Solutions Corp. (FirstEnergySolut E)	4,800	0.00	0.00	187,600.00	0.00	0.00	187,600.00	187,600.00	0.00
Hoosier Energy Rec, Inc. (Hoosier Energy Rec E)	736	0.00	0.00	10,985.00	0.00	0.00	10,985.00	10,985.00	0.00
Indianapolis Power & Light Company (Indianapls Pwr&Lt E)	11,848	0.00	0.00	392,723.50	0.00	0.00	392,723.50	392,723.50	0.00
J Aron & Company (J Aron & Company E)	36,785	0.00	1,021,680.00	1,783,520.00	0.00	0.00	1,783,520.00	2,805,200.00	0.00
LG&E Energy Marketing Inc. (LG&E Energy Mktg E)	3,770	0.00	0.00	172,328.50	0.00	0.00	172,328.50	172,328.50	0.00
LGE/KU (LGE/KU E)	19,433	0.00	0.00	893,035.00	0.00	0.00	893,035.00	893,035.00	0.00
Lebanon, OH - City of (LEBANON OH E)	0	0.00	16,230.00	0.00	0.00	0.00		16,230.00	0.00
Mirant Americas Energy Marketing, L.P. (MAEM M)	7,855	0.00	0.00	183,953.00	0.00	0.00	183,953.00	183,953.00	0.00
Morgan Stanley Capital Group Inc. (Morgan Stanley E)	800	0.00	0.00	28,400.00	0.00	0.00	28,400.00	28,400.00	0.00
Northern Indiana Public Service Company (NIPSGE M)	3,462	0.00	0.00	156,795.00	0.00	0.00	156,795.00	156,795.00	0.00
Northern Indiana Public Service Company transmission	52	0.00	0.00	0.00	0.00	0.00		0.00	0.00
Northern States Power Co. (Northern State Pwr E)	5,870	0.00	0.00	195,250.00	0.00	0.00	195,250.00	195,250.00	0.00
Ohio Valley Electric Corporation-Power Scheduling (OVEC Power Sch E)	99,398	908,077.67	0.00	2,023,604.48	0.00	0.00	2,023,604.48	2,931,682.15	0.00
PPL Energy Plus Co LLC (PPL Energy Plus Co E)	560	0.00	0.00	30,800.00	0.00	0.00	30,800.00	30,800.00	0.00
PSEG Energy Resources & Trade LLC (PSET M)	1,100	0.00	0.00	50,800.00	0.00	0.00	50,800.00	50,800.00	0.00
Progress Ventures, Inc. dba Progress Energy Ventur (Progress Ventures E)	113	0.00	0.00	6,424.00	0.00	0.00	6,424.00	6,424.00	0.00
Public Service Company of Colorado (Public Serv Co CO E)	3,800	0.00	0.00	127,200.00	0.00	0.00	127,200.00	127,200.00	0.00
RWE Trading Americas Inc. (RWE Trading Americ E)	18,312	0.00	0.00	888,560.00	0.00	0.00	888,560.00	888,560.00	0.00
Rainbow Energy Marketing Corporation (REMC M)	785	0.00	0.00	24,800.00	0.00	0.00	24,800.00	24,800.00	0.00
Reliant Energy Services, Inc. (RES M)	1,800	0.00	0.00	58,000.00	0.00	0.00	58,000.00	58,000.00	0.00
Select Energy, Inc. (Select Energy Inc E)	335	0.00	0.00	22,000.00	0.00	0.00	22,000.00	22,000.00	0.00
South Carolina Electric & Gas Company (South Carolina E&G E)	3,200	0.00	0.00	128,960.00	0.00	0.00	128,960.00	128,960.00	0.00
Southern Company Services, Inc. (SWE M)	873	0.00	0.00	41,516.00	0.00	0.00	41,516.00	41,516.00	0.00
Southern Indiana Gas & Electric Company (Southern IN G&E E)	3,586	0.00	0.00	143,840.00	0.00	0.00	143,840.00	143,840.00	0.00
Split Rock Energy LLC (Split Rock Energy)	800	0.00	0.00	39,800.00	0.00	0.00	39,800.00	39,800.00	0.00
Strategic Energy, LLC (SEL M)	0	0.00	0.00	12,240.00	0.00	0.00	12,240.00	12,240.00	0.00
Tenaska Power Services Co. (Tenaska Power Serv E)	475	0.00	0.00	28,850.00	0.00	0.00	28,850.00	28,850.00	0.00
Tennessee Valley Authority (TVAPT M)	39,805	0.00	0.00	1,388,275.00	0.00	0.00	1,388,275.00	1,388,275.00	0.00
The Energy Authority (The Energy Auth E)	529	0.00	0.00	16,335.00	0.00	0.00	16,335.00	16,335.00	0.00
Tractebel Energy Marketing, Inc. (TEMI M)	10,353	0.00	0.00	419,000.00	0.00	0.00	419,000.00	419,000.00	0.00
TransAlta Energy Marketing (US) Inc. (TransAlta Energy M E)	5,850	0.00	0.00	255,370.00	0.00	0.00	255,370.00	255,370.00	0.00
UBS AG (UBS AG)	9,568	0.00	0.00	460,800.00	0.00	0.00	460,800.00	460,800.00	0.00
Virginia Electric and Power Company (Virginia Elec&Pwr E)	10,400	0.00	0.00	454,760.00	0.00	0.00	454,760.00	454,760.00	0.00
Wabash Valley Power (Wabash Valley PowerE)	1,011	0.00	0.00	22,280.00	0.00	0.00	22,280.00	22,280.00	0.00
Westar Energy, Inc. (Westar Energy E)	1,800	0.00	0.00	107,400.00	0.00	0.00	107,400.00	107,400.00	0.00
Williams Power Company, Inc. (Williams Power E)	1,600	0.00	0.00	48,400.00	0.00	0.00	48,400.00	48,400.00	0.00
Psi Based on the Scheduled Interchange 0 Mwhs		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Psi related to Psi Gen to Cge Native per Prel. PACE		0.00	0.00	0.00	0.00	0.00		0.00	0.00
Psi re:Psi Gen to Cge Accrual Trading Sales per EITF 02-03 file	49,172	0.00	0.00	1,089,493.75	306,479.16	60,018.79	1,465,991.70	1,485,991.70	381.56

CONFIDENTIAL PROPRIETARY
TRADE SECRET

1 Adjust to tie CGE Purchase. eduled on PSI lines	-36,627	0.00	0.0.	0.00	0.00	0.00		0.00	
ection Totals	684,393	$908,077.67	$1,448,910.00	$26,672,321.01	$308,479.16	$60,018.76	$27,038,818.83	$29,357,806.80	361.56
ff-System Energies transferred to On-System Report									
2 BP Energy Company (AMCO M)	17,600	$0.00	$0.00	$545,600.00	$0.00	$0.00	$546,600.00	$546,600.00	0.00
3 Cinergy Capital & Trading, Inc. (CCT)	10	0.00	0.00	$452.40	$0.00	$0.00	452.40	452.40	0.00
ection Totals	17,610	$0.00	$0.00	$546,052.40	$0.00	$0.00	$546,052.40	$546,052.40	0.00
urchased Transmission related to Purchases									
4 Ameren Transmission re: Central Illinois Light Company July 2003 541 mwhs		895.78	0.00	249.65	0.00	0.00	249.65	1,145.81	0.00
5 Ameren Transmission re: Edison Mission Marketing & Trading Inc. July 2003 2,144 mwhs		4,456.78	0.00	990.13	0.00	0.00	990.13	5,446.91	0.00
6 Ameren Transmission re: Northern States Power Co. July 2003 186 mwhs		562.73	0.00	85.90	0.00	0.00	85.90	648.63	0.00
7 Ameren Transmission re: AEC - July 2003 289 mwhs		907.30	0.00	133.46	0.00	0.00	133.46	1,040.76	0.00
8 Ameren Transmission re: The Energy Authority July 2003 76 mwhs		3.16	0.00	35.10	0.00	0.00	35.10	38.26	0.00
9 American Electric Power re: Duke Energy Trading and Marketing July 2003 500 mwhs		2,682.16	0.00	680.00	0.00	0.00	680.00	3,342.16	0.00
0 American Electric Power re: Duke Power Company July 2003 1,980 mwhs		13,223.08	0.00	3,128.40	0.00	0.00	3,128.40	16,351.48	0.00
1 Northern Indiana Public Service Co. Transmission re: Consumers Energy Co. July 2003 1,812 mwhs		4,568.43	0.00	761.04	0.00	0.00	761.04	5,329.47	0.00
2 Tennessee Valley Authority Transmission re: Cinergy Capital & Trading, Inc. July 2003		1,856.29	0.00	0.00	0.00	0.00	0.00	1,856.29	0.00
3 Tennessee Valley Authority Transmission re: Duke Power Company July 2003		841.40	0.00	0.00	0.00	0.00	0.00	841.40	0.00
4 Tennessee Valley Authority Transmission re: Southern Company Services, Inc. July 2003		3,864.37	0.00	0.00	0.00	0.00	0.00	3,864.37	0.00
ection Totals	0	$33,861.46	$0.00	$6,043.85	0.00	0.00	$6,043.85	$39,905.34	0.00
rand Totals	702,003	$941,939.13	$1,449,910.00	$27,224,417.29	$308,479.16	$60,018.76	$27,690,915.21	$29,973,764.34	361.56

Of the purchased power above the following is the breakdown Purchases for Load excluding Intercompany Transfer	MWHS	DEMAND	ENERGY	TOTAL
Forwards On System				
Cinergy Capital & Trading				0.00
Total Forward Purchases On System	0	0.00	0.00	0.00
Forwards Off System				
Cinergy Capital & Trading		0.00		0.00
Total Forward Purchases Off System	0	0.00	0.00	0.00
Total Forwards	0	0.00	0.00	0.00
Hourly				
OVEC	99,398	908,077.67	2,023,804.48	2,931,882.15
American Electric Power Co	263	0.00	26,300.00	26,300.00
CCT	348	403,000.00	15,834.00	418,834.00
Dayton Power & Light	7	0.00	700.00	700.00
East Kentucky Power Coop	7	0.00	700.00	700.00
Hoosier Energy	1	0.00	100.00	100.00
Indianapolis Power & Light	7	0.00	700.00	700.00
Louisville Gas & Electric	17	0.00	1,700.00	1,700.00
Northern Indiana Public Service Co	15	0.00	1,500.00	1,500.00
Southern Indiana Gas & Electric	2	0.00	200.00	200.00
Adj to tie to Prelim Pace	8,066	0.00	517,308.52	517,308.52
Total Hourly Purchases	108,129	1,311,077.67	2,588,847.00	3,899,724.67
Hourly Transfer from Off System				
Cinergy Capital & Trading	10	0.00	452.40	452.40
Total Hourly Transfer Purchases	10	0.00	452.40	452.40
Transfer from PSI generation	0	0.00	0.00	0.00
Total Hourly Purchases	108,139	1,311,077.67	2,589,099.40	3,900,177.07
Total Purchases for Load	108,139	$1,311,077.67	$2,589,099.40	$3,900,177.07

684,393

3,056,127	total purchases
-2,355,360	generation
(16,374)	loop
684,393	

CONFIDENTIAL PROPRIETARY TRADE SECRET

02788

GE Schedule 4 Report
Determination of Net Energy Costs Incurred and KWHr Purchases
Preliminary Estimate for the month of August 2003

Company Name	MWHrs	Demand	Option Premium	Energy Charge	Total	EA Tons
n-System Energy						
Allegheny Energy Supply Company LLC (AETS M)	5,887	$0.00	$0.00	$297,830.00	$297,830.00	
Ameren Energy as Agent (Ameren Energy E)	10,850	0.00	0.00	531,475.00	531,475.00	
American Electric Power Service Corporation (American I	73,892	0.00	0.00	3,175,660.00	3,175,660.00	
Aquila Merchant Services, Inc. (Aquila Merchant E)	1,819	0.00	0.00	36,551.85	36,551.85	
Associated Electric Cooperative, Inc. (AECI M)	904	0.00	0.00	51,937.00	51,937.00	
BP Energy Company (AMCO M)	2,400	0.00	0.00	96,000.00	96,000.00	
Big Rivers Electric Corporation (Big Rivers Elec Co E)	1,767	0.00	0.00	93,563.00	93,563.00	
Buckeye Power (BUCKM M)	12,875	0.00	0.00	572,980.00	572,980.00	
Cargill Power Markets, LLC (Cargill Pow Mar E)	4,876	0.00	0.00	240,540.00	240,540.00	
Central Illinois Light Company (CILMAR M)	6,269	0.00	0.00	233,680.00	233,680.00	
Cinergy Capital & Trading, Inc. (CCT)	22,561	403,000.00	0.00	1,203,925.05	1,606,925.05	
Conectiv Energy Supply, Inc. (CNCT M)	3,300	0.00	0.00	176,550.00	176,550.00	
Constellation Power Source, Inc. (Constellation Powr E)	5,421	0.00	0.00	252,885.00	252,885.00	
Consumers Energy Co. (Consumers Energy E)	4,764	0.00	0.00	263,964.00	263,964.00	
Coral Power, L.L.C. (CORP M)	2,400	0.00	0.00	99,200.00	99,200.00	
Covert Generating Company, LLC (Covert Generating E)	1	0.00	0.00	9.00	9.00	
DTE Energy Trading, Inc. (DTEET M)	23,117	0.00	0.00	1,010,981.00	1,010,981.00	
Dayton Power & Light Company (Dayton Power&Light E)	9,029	0.00	0.00	329,655.00	329,655.00	
Detroit Edison Company (The) (Detroit Edison Co E)	920	0.00	0.00	38,060.00	38,060.00	
Duke Energy Trading and Marketing LLC (DETM M)	41,509	0.00	0.00	1,988,155.00	1,988,155.00	
Duke Power Company (Duke Power Co E)	200	0.00	0.00	12,300.00	12,300.00	
East Kentucky Power Cooperative, Inc. (EKPCPM M)	2	0.00	0.00	200.00	200.00	
Edison Mission Marketing & Trading Inc. (Edison Missior	10,709	0.00	0.00	308,420.00	308,420.00	
El Paso Merchant Energy, L.P. (El Paso Merchnt En E)	4,000	0.00	0.00	243,920.00	243,920.00	
EnergyUSA-TPC Corp. (EnergyUSA TPC E)	7,200	0.00	0.00	190,320.00	190,320.00	
Entergy-Koch Trading, LP (EntergyKochTrading E)	2,097	0.00	0.00	136,481.00	136,481.00	
Exelon Generation Company, LLC (ExelonGenerationCo I	11,360	0.00	0.00	370,605.00	370,605.00	
FirstEnergy Solutions Corp. (FirstEnergySolut E)	1,794	0.00	0.00	70,610.00	70,610.00	
Hoosier Energy Rec, Inc. (Hoosier Energy Rec E)	1,191	0.00	0.00	35,625.00	35,625.00	
Indianapolis Power & Light Company (Indianaplis Pwr&Lt	11,879	0.00	0.00	360,238.00	360,238.00	
J Aron & Company (J Aron & Company E)	8,000	0.00	1,021,680.00	261,740.00	1,283,420.00	
Kansas City Power & Light Company (KCPLPS M)	2,949	0.00	0.00	156,395.50	156,395.50	
LG&E Energy Marketing Inc. (LG&E Energy Mktg E)	16,711	0.00	0.00	685,779.00	685,779.00	
LGE/KU (LGE/KU E)	15,660	0.00	0.00	762,287.50	762,287.50	
Lebanon, OH - City of (LEBANON)	0	0.00	16,230.05	0.00	16,230.05	
Magnolia Energy LP (Magnolia Energy E)	23,409	0.00	0.00	1,335,302.00	1,335,302.00	
Mirant Americas Energy Marketing, L.P. (MAEM M)	39,447	0.00	0.00	1,674,461.50	1,674,461.50	
Northern Indiana Public Service Company (NIPSGE M)	12,287	0.00	0.00	501,632.00	501,632.00	
Northern States Power Co. (Northern State Pwr E)	4,175	0.00	0.00	105,700.00	105,700.00	
Occidental Power Services, Inc. (Occidental Pwr Svc E)	350	0.00	0.00	22,923.00	22,923.00	
OVEC	125,044	0.00	0.00	2,826,628.10	2,826,628.10	

CONFIDENTIAL PROPRIETARY
TRADE SECRET

02789

U2790

l2	PPL Energy Plus Co LLC (PPLEP M)	760	0.00	0.00	54,200.00	54,200.00	
l3	PSEG Energy Resources & Trade LLC (PSET M)	2,210	0.00	0.00	133,285.00	133,285.00	
l4	Public Service Company of Colorado (Public Serv Co CO	800	0.00	0.00	6,400.00	6,400.00	
l5	RWE Trading Americas Inc. (RWE Trading Americ E)	520	0.00	0.00	34,710.00	34,710.00	
l6	Reliant Energy Services, Inc. (RES M)	957	0.00	0.00	65,076.00	65,076.00	
l7	Sempra Energy Trading Corp. (SETC M)	800	0.00	0.00	46,000.00	46,000.00	
l8	Southern Company Services, Inc. (SWE M)	1,994	0.00	0.00	97,809.00	97,809.00	
l9	Southern Illinois Power Cooperative (Southern Illin Pwr E)	45	0.00	0.00	2,880.00	2,880.00	
i0	Southern Indiana Gas & Electric Company (Southern IN (	6,254	0.00	0.00	249,274.50	249,274.50	
i1	Strategic Energy, LLC (SEL M)	1,276	0.00	0.00	50,114.00	50,114.00	
i2	Tenaska Power Services Co. (Tenaska Power Serv E)	2,007	0.00	0.00	95,005.00	95,005.00	
3	Tennessee Valley Authority (TVAPT M)	25,305	0.00	0.00	1,005,940.00	1,005,940.00	
4	The Energy Authority (The Energy Auth E)	1,739	0.00	0.00	55,370.50	55,370.50	
5	Tractebel Energy Marketing, Inc. (TEMI M)	4,800	0.00	0.00	193,320.00	193,320.00	
6	TransAlta Energy Marketing (US) Inc. (TransAlta Energy	800	0.00	0.00	6,360.00	6,360.00	
7	Virginia Electric and Power Company (Virginia Elec&Pwr	6,400	0.00	0.00	309,680.00	309,680.00	
8	Wabash Valley Power (Wabash Valley PowerE)	380	0.00	0.00	18,745.00	18,745.00	
9	Westar Energy, Inc. (Westar Energy E)	2,505	0.00	0.00	149,930.00	149,930.00	
0	Williams Power Company, Inc. (Williams Power E)	2,400	0.00	0.00	82,400.00	82,400.00	
1	PSI generation for CGE's trading sales	7,213	0.00	0.00	340,102.75	340,102.75	53.04
2	Adjustment to Tie	(226,079)	0.00	0.00		0.00	
ection Totals		376,131	$403,000.00	$1,037,910.06	$23,751,770.26	$25,192,680.30	53.04
ff-System Energies transferred to On-System Report							
3	American Electric Power Service Corporation (American I	4,814	$0.00	$0.00	$318,200.00	$318,200.00	
4	BP Energy Company (AMCO M)	16,800	0.00	0.00	520,800.00	520,800.00	
5	Cinergy Capital & Trading, Inc. (CCT)	298	0.00	0.00	20,284.46	20,284.46	
6	Coral Power, L.L.C. (CORP M)	800	0.00	0.00	53,200.00	53,200.00	
7	Dayton Power & Light Company (Dayton Power&Light E)	6	0.00	0.00	600.00	600.00	
8	East Kentucky Power Cooperative, Inc. (EKPCPM M)	1	0.00	0.00	100.00	100.00	
9	EnergyUSA-TPC Corp. (EnergyUSA TPC E)	800	0.00	0.00	50,400.00	50,400.00	
0	Hoosier Energy Rec, Inc. (Hoosier Energy Rec E)	1	0.00	0.00	100.00	100.00	
1	Indianapolis Power & Light Company (Indianaplis Pwr&Lt	2	0.00	0.00	200.00	200.00	
2	LGE/KU (LGE/KU E)	2	0.00	0.00	200.00	200.00	
3	Mirant Americas Energy Marketing, L.P. (MAEM M)	1,600	0.00	0.00	101,600.00	101,600.00	
4	Northern Indiana Public Service Company (NIPSGE M)	2	0.00	0.00	200.00	200.00	
5	Southern Indiana Gas & Electric Company (Southern IN (	2	0.00	0.00	200.00	200.00	
6	Wabash Valley Power (Wabash Valley PowerE)	800	0.00	0.00	52,800.00	52,800.00	
7	PSI re: ICT related to trading	8,800	0.00	0.00	516,360.00	516,360.00	
ection Totals		34,728	$0.00	$0.00	$1,636,244.46	$1,636,244.46	0.00
rand Totals		410,859	$403,000.00	$1,037,910.06	$25,387,014.71	$26,827,924.76	53.04

CONFIDENTIAL PROPRIETARY
TRADE SECRET

Of the purchased power above the following is the breakd	MWHS	DEMAND	OPTIONS	ENERGY	TOTAL
Purchases for Load excluding Intercompany Transfer					

Forwards On System					
CCT	0	0.00		-	0.00
Total Forward Purchases On System	0	0.00	0.00	0.00	0.00
Forwards Off System					
CCT	0	0.00		-	0.00
Total Forward Purchases Off System	0	0.00	0.00	0.00	0.00
Forward Book Outs					
Dynegy Power Mktg	0	0.00	0.00	-	0.00
Edison Mission	0	0.00	0.00	-	0.00
Total Forward Book Out Purchases	0	0.00	0.00	0.00	0.00
Total Forward Purchases	**0**	**0.00**	**0.00**	**0.00**	**0.00**
Hourly					
OVEC	125,644	0.00	0.00	2,826,628.10	2,826,628.10
American Electric Power Co	12	0.00	0.00	1,200.00	1,200.00
CCT	16,242	403,000.00	0.00	1,100,740.64	1,503,740.64
Dayton Power & Light	4	0.00	0.00	400.00	400.00
Louisville Gas & Electric	1	0.00	0.00	100.00	100.00
Northern Indiana Public Service Co	1	0.00	0.00	100.00	100.00
Adj to tie to Prelim Pace	365	0.00	0.00	(135,111.58)	(135,111.58)
Total Hourly Purchases	**141,669**	**403,000.00**	**0.00**	**3,794,057.16**	**4,197,057.16**
Hourly Transfer from Off System					
American Electric Power Co	14	0.00	0.00	1,400.00	1,400.00
Cinergy Capital & Trading	298	0.00	0.00	20,284.46	20,284.46
Dayton Power & Light	6	0.00	0.00	600.00	600.00
East Kentucky Power Coop	1	0.00	0.00	100.00	100.00
Hoosier Energy	1	0.00	0.00	100.00	100.00
Indianapolis Power & Light	2	0.00	0.00	200.00	200.00
Louisville Gas & Electric	2	0.00	0.00	200.00	200.00
Northern Indiana Public Service Co	2	0.00	0.00	200.00	200.00
Southern Indiana Gas & Electric	2	0.00	0.00	200.00	200.00
Total Hourly Transfer Purchases	**328**	**0.00**	**0.00**	**23,284.46**	**23,284.46**
Total Hourly Purchases	**141,997**	**403,000.00**	**0.00**	**3,817,341.62**	**4,220,341.62**
Transfer from PSI					
Psi generation	0	0.00	0.00	-	0.00
	0	**0.00**	**0.00**	**-**	**0.00**
Total Purchases for Load	**141,997**	**$403,000.00**	**$0.00**	**$3,817,341.62**	**$4,220,341.62**

CONFIDENTIAL PROPRIETARY
TRADE SECRET

02791

376,131	2,946,628	O&D
	(2,531,471)	generation
	(39,026)	loop
	376,131	
	0	

CONFIDENTIAL PROPRIETARY
TRADE SECRET

02793

CGE Schedule 4 Report
Determination of Net Energy Costs Incurred and KWHr Purchases
Final for the month of August 2003

	Company Name	MWHrs	Demand	Option Premium	Fuel W Trans	Other	EA Cost	Energy Charge	Total	EA Tons
	On-System Energy									
1	Allegheny Energy Supply Company LLC (AETS M)	6,659	$0.00	$0.00	$298,330.00	$0.00	$0.00	$298,330.00	$298,330.00	0.00
2	Ameren Energy as Agent (Ameren Energy E)	10,850	0.00	0.00	531,475.00	0.00	0.00	531,475.00	531,475.00	0.00
3	American Electric Power Service Corporation (American Elec Powr E)	72,305	0.00	0.00	3,094,660.00	0.00	0.00	3,094,660.00	3,094,660.00	0.00
4	Aquila Merchant Services, Inc. (Aquila Merchant E)	29	0.00	0.00	603.00	0.00	0.00	603.00	603.00	0.00
5	Associated Electric Cooperative, Inc. (AECI M)	854	0.00	0.00	48,937.00	0.00	0.00	48,937.00	48,937.00	0.00
6	BP Energy Company (AMCO M)	1,600	0.00	0.00	64,000.00	0.00	0.00	64,000.00	64,000.00	0.00
7	Big Rivers Electric Corporation (Big Rivers Elec Co E)	1,766	0.00	0.00	93,563.00	0.00	0.00	93,563.00	93,563.00	0.00
8	Buckeye Power (BUCKM M)	12,875	0.00	0.00	572,980.00	0.00	0.00	572,980.00	572,980.00	0.00
9	Cargill Power Markets, LLC (Cargill Pow Mar E)	4,052	0.00	0.00	195,140.00	0.00	0.00	195,140.00	195,140.00	0.00
10	Central Illinois Light Company (CILMAR M)	1,281	0.00	0.00	47,757.00	0.00	0.00	47,757.00	47,757.00	0.00
11	Cinergy Capital & Trading, Inc. (CCT)	22,581	0.00	403,000.00	1,213,554.85	0.00	0.00	1,213,554.85	1,616,554.85	0.00
12	Conectiv Energy Supply, Inc. (CNCT M)	2,500	0.00	0.00	133,550.00	0.00	0.00	133,550.00	133,550.00	0.00
13	Constellation Power Source, Inc. (Constellation Powr E)	5,100	0.00	0.00	236,405.00	0.00	0.00	236,405.00	236,405.00	0.00
14	Consumers Energy Co. (Consumers Energy E)	3,914	0.00	0.00	224,534.00	0.00	0.00	224,534.00	224,534.00	0.00
15	Coral Power, L.L.C. (CORP M)	2,400	0.00	0.00	99,200.00	0.00	0.00	99,200.00	99,200.00	0.00
16	DTE Energy Trading, Inc. (DTEET M)	20,994	0.00	0.00	927,581.00	0.00	0.00	927,581.00	927,581.00	0.00
17	Dayton Power & Light Company (Dayton Power&Light E)	8,235	0.00	0.00	293,273.40	0.00	0.00	293,273.40	293,273.40	0.00
18	Dayton Power & Light trans)	24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19	Detroit Edison Company (The) (Detroit Edison Co E)	881	0.00	0.00	38,060.00	0.00	0.00	38,060.00	38,060.00	0.00
20	Duke Energy Trading and Marketing LLC (DETM M)	40,439	0.00	0.00	1,943,915.00	0.00	0.00	1,943,915.00	1,943,915.00	0.00
21	Duke Power Company (Duke Power Co E)	200	0.00	0.00	12,300.00	0.00	0.00	12,300.00	12,300.00	0.00
22	East Kentucky Power Cooperative, Inc. (EKPCPM M)	3	0.00	0.00	300.00	0.00	0.00	300.00	300.00	0.00
23	Edison Mission Marketing & Trading Inc. (Edison Mission M&T E)	9,345	0.00	0.00	272,004.00	0.00	0.00	272,004.00	272,004.00	0.00
24	El Paso Merchant Energy, L.P. (El Paso Merchnt En E)	3,200	0.00	0.00	202,320.00	0.00	0.00	202,320.00	202,320.00	0.00
25	EnergyUSA-TPC Corp. (EnergyUSA TPC E)	5,600	0.00	0.00	117,120.00	0.00	0.00	117,120.00	117,120.00	0.00
26	Entergy-Koch Trading, LP (EntergyKochTrading E)	2,097	0.00	0.00	136,481.00	0.00	0.00	136,481.00	136,481.00	0.00
27	Exelon Generation Company, LLC (ExelonGenerationCo E)	11,360	0.00	0.00	370,605.00	0.00	0.00	370,605.00	370,605.00	0.00
28	FirstEnergy Solutions Corp. (FirstEnergySolut E)	994	0.00	0.00	39,810.00	0.00	0.00	39,810.00	39,810.00	0.00
29	Hoosier Energy Rec, Inc. (Hoosier Energy Rec E)	1,009	0.00	0.00	28,190.00	0.00	0.00	28,190.00	28,190.00	0.00
30	Indianapolis Power & Light Company (Indianaplis Pwr&Lt E)	11,322	0.00	0.00	357,238.00	0.00	0.00	357,238.00	357,238.00	0.00
31	J Aron & Company (J Aron & Company E)	5,600	0.00	1,021,680.00	148,940.00	0.00	0.00	148,940.00	1,170,620.00	0.00
32	Kansas City Power & Light Company (KCPLPS M)	2,949	0.00	0.00	156,395.50	0.00	0.00	156,395.50	156,395.50	0.00
33	LG&E Energy Marketing Inc. (LG&E Energy Mktg E)	16,311	0.00	0.00	677,979.00	0.00	0.00	677,979.00	677,979.00	0.00
34	LGE/KU (LGE/KU E)	14,175	0.00	0.00	727,039.50	0.00	0.00	727,039.50	727,039.50	0.00
35	Lebanon, OH - City of (LEBANON OH E)		0.00	16,230.00	0.00	0.00	0.00	0.00	16,230.00	0.00
36	Magnolia Energy LP (Magnolia Energy E)	23,405	0.00	0.00	1,335,302.00	0.00	0.00	1,335,302.00	1,335,302.00	0.00
37	Mirant Americas Energy Marketing, L.P. (MAEM M)	34,398	0.00	0.00	1,425,686.50	0.00	0.00	1,425,686.50	1,425,686.50	0.00
38	Northern Indiana Public Service Company (NIPSGE M)	11,459	0.00	0.00	464,632.00	0.00	0.00	464,632.00	464,632.00	0.00
39	Northern States Power Co. (Northern State Pwr E)	3,891	0.00	0.00	93,200.00	0.00	0.00	93,200.00	93,200.00	0.00
40	Occidental Power Services, Inc. (Occidental Pwr Svc E)	350	0.00	0.00	22,923.00	0.00	0.00	22,923.00	22,923.00	0.00
41	Ohio Valley Electric Corporation-Power Scheduling (OVEC Power Sch E)	129,828	901,393.27	0.00	2,142,106.97	0.00	0.00	2,142,106.97	3,043,500.24	0.00
42	PPL Energy Plus Co LLC (PPL Energy Plus Co E)	750	0.00	0.00	54,200.00	0.00	0.00	54,200.00	54,200.00	0.00
43	PSEG Energy Resources & Trade LLC (PSET M)	2,210	0.00	0.00	133,285.00	0.00	0.00	133,285.00	133,285.00	0.00
44	Public Service Company of Colorado (Public Serv Co CO E)	800	0.00	0.00	6,400.00	0.00	0.00	6,400.00	6,400.00	0.00
45	RWE Trading Americas Inc. (RWE Trading Americ E)	520	0.00	0.00	34,710.00	0.00	0.00	34,710.00	34,710.00	0.00
46	Reliant Energy Services, Inc. (RES M)	957	0.00	0.00	65,076.00	0.00	0.00	65,076.00	65,076.00	0.00
47	Southern Company Services, Inc. (SWE M)	1,994	0.00	0.00	97,809.00	0.00	0.00	97,809.00	97,809.00	0.00
48	Southern Illinois Power Cooperative (Southern Illin Pwr E)	42	0.00	0.00	2,880.00	0.00	0.00	2,880.00	2,880.00	0.00
49	Southern Indiana Gas & Electric Company (Southern IN G&E E)	5,911	0.00	0.00	249,474.50	0.00	0.00	249,474.50	249,474.50	0.00
50	Strategic Energy, LLC (SEL M)	290	0.00	0.00	19,772.00	0.00	0.00	19,772.00	19,772.00	0.00
51	Tenaska Power Services Co. (Tenaska Power Serv E)	1,953	0.00	0.00	95,005.00	0.00	0.00	95,005.00	95,005.00	0.00
52	Tennessee Valley Authority (TVAPT M)	25,305	0.00	0.00	1,005,940.00	0.00	0.00	1,005,940.00	1,005,940.00	0.00
53	The Energy Authority (The Energy Auth E)	915	0.00	0.00	33,022.00	0.00	0.00	33,022.00	33,022.00	0.00
54	Tractebel Energy Marketing, Inc. (TEMI M)	4,785	0.00	0.00	193,320.00	0.00	0.00	193,320.00	193,320.00	0.00
55	TransAlta Energy Marketing (US) Inc. (TransAlta Energy M E)	800	0.00	0.00	6,360.00	0.00	0.00	6,360.00	6,360.00	0.00
56	Virginia Electric and Power Company (Virginia Elec&Pwr E)	5,388	0.00	0.00	309,680.00	0.00	0.00	309,680.00	309,680.00	0.00
57	Wabash Valley Power (Wabash Valley PowerE)	485	0.00	0.00	26,280.00	0.00	0.00	26,280.00	26,280.00	0.00
58	Westar Energy, Inc. (Westar Energy E)	2,505	0.00	0.00	149,930.00	0.00	0.00	149,930.00	149,930.00	0.00
59	Williams Power Company, Inc. (Williams Power E)	2,400	0.00	0.00	82,400.00	0.00	0.00	82,400.00	82,400.00	0.00
60	Psi Based on the Scheduled Interchange 0 Mwhs		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	Psi related to Psi Gen to Cge Native per Prel. PACE		0.00	0.00	0.00	0.00	0.00		0.00	0.00

CONFIDENTIAL PROPRIETARY
TRADE SECRET

62 Psi re:Psi Gen to Cg... ...rual Trading Sales per EITF 02-03 file	7,213	0.00	0.00	255,077.06	75,744.25	9,281.43	340,102.75	34...76	53.04
63 Adjust to tie CGE Purchases scheduled on PSI lines	(196,714)	0.00	0.00	0.00	0.00	0.00		0.00	0.00
Section Totals	376,584	$901,393.27	$1,440,910.00	$21,608,711.28	$75,744.25	$9,281.43	$21,693,738.97	$24,036,040.24	53.04
Off-System Energies transferred to On-System Report									
64 American Electric Power Service Corporation (American Elec Powr E)	4,800	$0.00	$0.00	$316,800.00	$0.00	$0.00	$316,800.00	$316,800.00	0.00
65 BP Energy Company (AMCO M) re: ULH&P	16,800	0.00	0.00	520,800.00	0.00	0.00	520,800.00	520,800.00	0.00
66 Cinergy Capital & Trading, Inc. (CCT)	298	0.00	0.00	17,043.14	0.00	0.00	17,043.14	17,043.14	0.00
67 Coral Power, L.L.C. (CORP M)	800	0.00	0.00	53,200.00	0.00	0.00	53,200.00	53,200.00	0.00
68 EnergyUSA-TPC Corp. (EnergyUSA TPC E)	800	0.00	0.00	50,400.00	0.00	0.00	50,400.00	50,400.00	0.00
69 Mirant Americas Energy Marketing, L.P. (MAEM M)	1,600	0.00	0.00	101,600.00	0.00	0.00	101,600.00	101,600.00	0.00
70 Wabash Valley Power (Wabash Valley PowerE)	800	0.00	0.00	52,800.00	0.00	0.00	52,800.00	52,800.00	0.00
71 PSI re:sales bookouts tied to PSI's native load purchases	8,800	0.00	0.00	516,360.00	0.00	0.00	516,360.00	516,360.00	0.00
Section Totals	34,698	$0.00	$0.00	$1,629,003.14	$0.00	$0.00	$1,629,003.14	$1,629,003.14	0.00
Purchased Transmission related to Purchases									
72 Ameren Transmission re: AEP - August 2003, 69mwhs		$211.23	$0.00	$36.20	$0.00	$0.00	$36.20	$247.43	0.00
73 Ameren Transmission re: Associated Electric Cooperative, Inc. August 2003, 662mwhs		$1,037.79	$0.00	$347.10	$0.00	$0.00	$347.10	$1,384.89	0.00
74 Ameren Transmission re: Central Illinois Light Company - August 2003, 184mwhs		551.03	$0.00	$96.54	$0.00	$0.00	96.54	$647.57	0.00
75 Ameren Transmission re: Edison Mission Marketing & Trading Inc. - August 2003, 3,022mwhs		5,182.84	$0.00	$5,543.81	$0.00	$0.00	5,543.81	$10,726.65	0.00
76 Ameren Transmission re: Kansas City Power & Light Company - August 2003, 2,679mwhs		5,663.46	$0.00	$1,405.68	$0.00	$0.00	1,405.68	$7,069.14	0.00
77 Ameren Transmission re: Northern States Power Co. - August 2003, 186mwhs		569.41	$0.00	$97.60	$0.00	$0.00	97.60	$667.01	0.00
78 Ameren Transmission re: The Energy Authority - August 2003, 154mwhs		413.27	$0.00	$80.80	$0.00	$0.00	80.80	$494.07	0.00
79 American Electric Power Service Transmission re: Duke Power Company - august 2003, 200MWHS		1,051.31	$0.00	$322.69	$0.00	$0.00	322.69	$1,374.00	0.00
80 American Electric Power Service Transmission re: PPL Energy Plus Co LLC- August 2003, 160mwhs		841.05	$0.00	$252.80	$0.00	$0.00	252.80	$1,093.85	0.00
81 American Electric Power Service Transmission re: PSEG Energy Resources & Trade LLC- August 2003, 50mwh		262.83	$0.00	$155.18	$0.00	$0.00	155.18	$418.01	0.00
82 Dayton Power & Light re: FirstEnergy Solutions Corp. august 2003		400.00	$0.00	$0.00	$0.00	$0.00	0.00	$400.00	0.00
83 Northern Indiana Public Service Co. Transmission re: Consumers Energy Co. - August 2003, 1,787mwhs		4,798.80	$0.00	$682.08	$0.00	$0.00	682.08	$5,480.88	0.00
84 Northern Indiana Public Service Co. Transmission re: DTE Energy Trading, Inc. August 2003, 672mwhs		1,595.88	$0.00	$240.24	$0.00	$0.00	240.24	$1,836.12	0.00
85 Tennessee Valley Authority Transmission re: Cinergy Capital & Trading, Inc. - August 2003		335,241.50	$0.00	$0.00	$0.00	$0.00	0.00	$335,241.50	0.00
86 Tennessee Valley Authority Transmission re: Associated Electric August 2003		1,431.49	$0.00	$0.00	$0.00	$0.00	0.00	$1,431.49	0.00
87 Tennessee Valley Authority Transmission re: Magnolia Energy LP - August 2003		188,031.92	$0.00	$0.00	$0.00	$0.00	0.00	$188,031.92	0.00
88 Tennessee Valley Authority Transmission re: Southern Company Services, Inc. - August 2003		11,993.52	$0.00	$0.00	$0.00	$0.00	0.00	$11,993.52	0.00
Section Totals	0	$559,277.33	$0.00	$9,280.72	0.00	0.00	$9,280.72	$568,558.05	0.00
Grand Totals	411,282	1,460,670.60	1,440,910.00	23,246,975.14	75,744.25	9,281.43	23,332,000.83	26,233,631.43	53.04

Of the purchased power above the following is the breakdown Purchases for Load excluding Intercompany Transfer	MWHS	DEMAND	ENERGY	TOTAL
Forwards On System				
Cinergy Capital & Trading				0.00
Total Forward Purchases On System	0	0.00	0.00	0.00
Forwards Off System				
Cinergy Capital & Trading		0.00		0.00
Total Forward Purchases Off System	0	0.00	0.00	0.00
Total Forwards	0	0.00	0.00	0.00
Hourly				
OVEC	129,828	901,393.27	2,142,106.97	3,043,500.24
American Electric Power Co	26	0.00	2,600.00	2,600.00
CCT	16,242	403,000.00	882,148.30	1,285,148.30
Dayton Power & Light	6	0.00	600.00	600.00
East Kentucky Power Coop	1	0.00	100.00	100.00
Hoosier Energy	1	0.00	100.00	100.00
Indianapolis Power & Light	2	0.00	200.00	200.00

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TRADE SECRET

02794

Louisville Gas & Elec.	3	0.00	300.00	300.00
Northern Indiana Public Service Co	3	0.00	300.00	300.00
Southern Indiana Gas & Electric	2	0.00	200.00	200.00
Adj to tie to Prelim Pace	(4,675)	0.00	768,257.39	768,257.39
Total Hourly Purchases	141,439	1,304,393.27	3,796,912.66	5,101,305.93
Hourly Transfer from Off System				
Cinergy Capital & Trading	298	0.00	17,043.14	17,043.14
Total Hourly Transfer Purchases	298	0.00	17,043.14	17,043.14
Transfer from PSI generation	0	0.00	0.00	0.00
Total Hourly Purchases	141,737	1,304,393.27	3,813,955.80	5,118,349.07
Total Purchases for Load	141,737	$1,304,393.27	$3,813,955.80	$5,118,349.07

376,584	2,949,627	total purchases
	-2,531,471	generation
	(41,572)	loop
	376,584	
	0	

CONFIDENTIAL PROPRIETARY
TRADE SECRET

02795

:GE Schedule 4 Rep..t
ietermination of Net Energy Costs incurred and KWHr Purchases
reliminary Estimate for the month of September 2003

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TRADE SECRET

02796

	Company Name	MWHrs	Demand	Option Premium	Energy Charge	Total	EA Tons
	n-System Energy						
	Alcoa Power Generating Inc. d/b/a APG Trading (APGT I	240	$0.00	$0.00	$6,720.00	$6,720.00	
	Allegheny Energy Supply Company LLC (AETS M)	40	0.00	0.00	800.00	800.00	
	Ameren Energy as Agent (Ameren Energy E)	6,950	0.00	0.00	240,575.00	240,575.00	
	American Electric Power Service Corporation (American I	116,637	0.00	0.00	2,299,539.00	2,299,539.00	
	American Municipal Power - Ohio, Inc. (AMPOHI M)		60,880.90	0.00	0.00	60,880.90	
	Aquila Merchant Services, Inc. (Aquila Merchant E)	200	0.00	0.00	4,020.00	4,020.00	
	Associated Electric Cooperative, Inc. (AECI M)	250	0.00	0.00	3,900.00	3,900.00	
	Big Rivers Electric Corporation (Big Rivers Elec Co E)	970	0.00	0.00	28,000.00	28,000.00	
	Buckeye Power (BUCKM M)	5,827	0.00	0.00	209,505.00	209,505.00	
0	Cargill Power Markets, LLC (Cargill Pow Mar E)	10,022	0.00	0.00	228,640.00	228,640.00	
1	Carolina Pwr & Lt dba Progress Enrgy Carolinas Inc (Car	455	0.00	0.00	12,810.00	12,810.00	
2	Central Illinois Light Company (CILMAR M)	4,551	0.00	0.00	128,377.00	128,377.00	
3	Cinergy Capital & Trading, Inc. (CCT)	0	403,000.00	0.00	0.00	403,000.00	
4	Constellation Power Source, Inc. (Constellation Powr E)	1,137	0.00	0.00	27,565.00	27,565.00	
5	Consumers Energy Co. (Consumers Energy E)	1,188	0.00	0.00	52,900.00	52,900.00	
6	Covert Generating Company, LLC (Covert Generating E)	32	0.00	0.00	268.00	268.00	
7	DTE Energy Trading, Inc. (DTEET M)	400	0.00	0.00	4,100.00	4,100.00	
8	Dayton Power & Light Company (Dayton Power&Light E)	1,805	0.00	0.00	55,384.60	55,384.60	
9	Detroit Edison Company (The) (Detroit Edison Co E)	525	0.00	0.00	18,525.00	18,525.00	
0	Duke Energy Trading and Marketing LLC (DETM M)	5,867	0.00	0.00	96,415.00	96,415.00	
1	Duke Power Company (Duke Power Co E)	675	0.00	0.00	24,400.00	24,400.00	
2	Dynegy Power Marketing, Inc. (Dynegy Power Mktg E)	100	0.00	0.00	3,100.00	3,100.00	
3	East Kentucky Power Cooperative, Inc. (EKPCPM M)	3	0.00	0.00	300.00	300.00	
4	Edison Mission Marketing & Trading Inc. (Edison Missior	2,045	0.00	0.00	80,230.00	80,230.00	
5	EnergyUSA-TPC Corp. (EnergyUSA TPC E)	24,800	0.00	0.00	361,900.00	361,900.00	
6	Exelon Generation Company, LLC (ExelonGenerationCo I	1,050	0.00	0.00	30,080.00	30,080.00	
7	FirstEnergy Solutions Corp. (FirstEnergySolut E)	630	0.00	0.00	17,736.00	17,736.00	
8	Hoosier Energy Rec, Inc. (Hoosier Energy Rec E)	850	0.00	0.00	17,480.00	17,480.00	
9	Indianapolis Power & Light Company (Indianaplis Pwr&Lt	17,068	0.00	0.00	365,875.00	365,875.00	
0	J Aron & Company (J Aron & Company E)	4,320	0.00	0.00	67,088.00	67,088.00	
1	Kansas City Power & Light Company (KCPLPS M)	50	0.00	0.00	1,500.00	1,500.00	
2	LG&E Energy Marketing Inc. (LG&E Energy Mktg E)	6,842	0.00	0.00	142,421.00	142,421.00	
3	LGE/KU (LGE/KU E)	9,208	0.00	0.00	266,675.00	266,675.00	
4	Lebanon, OH - City of (LEBANON OH E)	0	0.00	16,230.05	0.00	16,230.05	
5	Northern Indiana Public Service Company (NIPSGE M)	1,314	0.00	0.00	35,850.00	35,850.00	
6	Northern States Power Co. (Northern Stats Pwr E)	2,075	0.00	0.00	62,625.00	62,625.00	
7	OVEC	90,609	0.00	0.00	2,131,628.10	2,131,628.10	
8	RWE Trading Americas Inc. (RWE Trading Americ E)	800	0.00	0.00	26,320.00	26,320.00	
9	Southern Indiana Gas & Electric Company (Southern IN (	2,185	0.00	0.00	60,867.00	60,867.00	
0	Strategic Energy, LLC (SEL M)	100	0.00	0.00	3,200.00	3,200.00	
1	Tenaska Power Services Co. (Tenaska Power Serv E)	9	0.00	0.00	153.00	153.00	

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32	Tennessee Valley Authority (TVAPT M)	3,750	0.00	0.00	111,875.00	111,875.00	
3	The Energy Authority (The Energy Auth E)	854	0.00	0.00	16,858.00	16,858.00	
4	TransAlta Energy Marketing (US) Inc. (TransAlta Energy	400	0.00	0.00	6,000.00	6,000.00	
5	UBS AG (UBS AG)	800	0.00	0.00	28,800.00	28,800.00	
6	Virginia Electric and Power Company (Virginia Elec&Pwr	895	0.00	0.00	14,045.00	14,045.00	
7	Westar Energy, Inc. (Westar Energy E)	200	0.00	0.00	3,700.00	3,700.00	
8	Williams Power Company, Inc. (Williams Power E)	1,440	0.00	0.00	24,160.00	24,160.00	
9	Wisconsin Public Service Corporation (WPSM M)	650	0.00	0.00	14,300.00	14,300.00	
0	PSI generation for CGE's Native Load	3,596	0.00	0.00	49,472.82	49,472.82	26.46
1	PSI generation for CGE's Trading Sales	328,250	0.00	0.00	5,169,937.50	5,169,937.50	
2	Adjustment to Tie	(264,249)	0.00	0.00		0.00	
ection Totals		398,417	$463,880.90	$16,230.05	$12,556,620.02	$13,036,730.97	26.46
ff-System Energies transferred to On-System Report							
3	BP Energy Company (AMCO M)	16,800	$0.00	$0.00	$520,800.00	$520,800.00	0.00
ection Totals		16,800	$0.00	$0.00	$520,800.00	$520,800.00	0.00
rand Totals		415,217	$463,880.90	$16,230.05	$13,077,420.02	$13,557,530.97	26.46
		675,968					

Of the purchased power above the following is the breakd Purchases for Load excluding Intercompany Transfer	MWHS	DEMAND	OPTIONS	ENERGY	TOTAL
Forwards On System					
CCT	0	0.00		-	0.00
Total Forward Purchases On System	0	0.00	0.00	0.00	0.00
Forwards Off System					
CCT	0	0.00		-	0.00
Total Forward Purchases Off System	0	0.00	0.00	0.00	0.00
Forward Book Outs					
Dynegy Power Mktg	0	0.00	0.00	-	0.00
Edison Mission	0	0.00	0.00	-	0.00
Total Forward Book Out Purchases	0	0.00	0.00	0.00	0.00
Total Forward Purchases	0	0.00	0.00	0.00	0.00
Hourly					
OVEC	90,809	0.00	0.00	2,131,628.10	2,131,628.10
American Electric Power Co	200	0.00	0.00	20,000.00	20,000.00
CCT		403,000.00	0.00	0.00	403,000.00
Dayton Power & Light	4	0.00	0.00	400.00	400.00
East Kentucky Power Coop	3	0.00	0.00	300.00	300.00
Louisville Gas & Electric	8	0.00	0.00	800.00	800.00

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TRADE SECRET

Northern Indiana Public Service Co	8	0.00	0.00	800.00	800.00
Adj to tie to Prelim Pace	16,800	0.00	0.00	520,459.25	520,459.25
Total Hourly Purchases	**107,832**	**403,000.00**	**0.00**	**2,674,387.35**	**3,077,387.35**
Hourly Transfer from Off System					
American Electric Power Co		0.00	0.00		0.00
Southern Indiana Gas & Electric		0.00	0.00		0.00
Total Hourly Transfer Purchases	**0**	**0.00**	**0.00**	**0.00**	**0.00**
Total Hourly Purchases	**107,832**	**403,000.00**	**0.00**	**2,674,387.35**	**3,077,387.35**
Transfer from PSI					
Psl generation	3,598	0.00	0.00	49,472.82	49,472.82
	3,598	**0.00**	**0.00**	**49,472.82**	**49,472.82**
Total Purchases for Load	**111,430**	**$403,000.00**	**$0.00**	**$2,723,860.17**	**$3,126,860.17**
	3,598			(49,472.82)	

398,417	2,466,894	O&D
	(2,057,542)	generation
	(10,935)	loop
	398,417	
	0	

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TRADE SECRET

02798

0.00
0.00

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TRADE SECRET

02799

CINCINNATI GAS & ELECTRIC COMPANY
ON SYSTEM PURCHASES
Determination of Net Energy Costs Incurred and KWHr Purchases
ALLOCATED TO CGE"S NATIVE LOAD AND NON-TRADING SALES
FOR THE MONTH OF SEPTEMBER 2003
FINAL PER PACE DATED NOVEMBER 21, 2003

LINE NO.	Company Name	MWHrs	Demand	Option Premium	Fuel W Trans	Other	EA Cost	Energy Charge	Total	EA Tons
1	Alcoa Power Generating Inc. d/b/a APG Trading (APGT M)	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00
2	Allegheny Energy Supply Company LLC (AETS M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	Ameren Energy as Agent (Ameren Energy E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	American Electric Power Service Corporation (American Elec Powr E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	Aquila Merchant Services, Inc. (Aquila Merchant E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	Associated Electric Cooperative, Inc. (AECI M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	Big Rivers Electric Corporation (Big Rivers Elec Co E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	Buckeye Power (BUCKM M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	Cargill Power Markets, LLC (Cargill Pow Mar E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	Carolina Pwr & Lt dba Progress Enrgy Carolinas Inc (Carolina Powr & Lt E	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	Central Illinois Light Company (Central Illinois Lt E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	Cinergy Capital & Trading, Inc. (CCT)	0	0.00	403,000.00	0.00	0.00	0.00	0.00	403,000.00	0.00
12	Constellation Power Source, Inc. (Constellation Powr E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	Consumers Energy Co. (Consumers Energy E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	Dayton Power & Light Company (Dayton Power&Light E)	4	0.00	0.00	400.00	0.00	0.00	400.00	400.00	0.00
15	Detroit Edison Company (The) (Detroit Edison Co E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	Duke Energy Trading and Marketing LLC (DETM M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	Duke Power Company (Duke Power Co E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	Dynegy Power Marketing, Inc. (Dynegy Power Mktg E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19	East Kentucky Power Cooperative, Inc. (EKPCPM M)	3	0.00	0.00	300.00	0.00	0.00	300.00	300.00	0.00
20	Edison Mission Marketing & Trading Inc. (Edison Mission M&T E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	EnergyUSA-TPC Corp. (EnergyUSA TPC E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	Exelon Generation Company, LLC (ExelonGenerationCo E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	FirstEnergy Solutions Corp. (FirstEnergySolut E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	Hoosier Energy Rec. Inc. (Hoosier Energy Rec E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
25	Indianapolis Power & Light Company (Indianaplis Pwr&Lt E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
26	J Aron & Company (J Aron & Company E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	Kansas City Power & Light Company (KCPLPS M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
28	LG&E Energy Marketing Inc. (LG&E Energy Mktg E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29	LGE/KU (LGE/KU E)	8	0.00	0.00	800.00	0.00	0.00	800.00	800.00	0.00
30	Northern Indiana Public Service Company (NIPSGE M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
31	Northern States Power Co. (Northern Stats Pwr E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
31	Ohio Valley Electric Corporation	91,517	741,962.91	0.00	1,451,377.35	0.00	0.00	1,451,377.35	2,193,340.26	0.00
32	RWE Trading Americas Inc. (RWE Trading Americ E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33	Southern Indiana Gas & Electric Company (Southern IN G&E E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34	Strategic Energy, LLC (SEL M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
35	Tenaska Power Services Co. (Tenaska Power Serv E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36	Tennessee Valley Authority (TVAPT M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
37	The Energy Authority (The Energy Auth E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
38	TransAlta Energy Marketing (US) Inc. (TransAlta Energy M E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
39	UBS AG (UBS AG)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40	Virginia Electric and Power Company (Virginia Elec&Pwr E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
41	Westar Energy, Inc. (Westar Energy E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42	Williams Power Company, Inc. (Williams Power E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
43	Wisconsin Public Service Corporation (WPSM M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
44	Psl Based on the Scheduled Interchange 304,492 Mwhs	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
45	PSI re: PSI Generation to CGE's Native Load	83	0.00	0.00	1,089.42	(175.15)	124.06	1,038.33	1,038.33	0.78
46	PSI re: PSI Generation to CGE's Trading Sales	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47	PSI re: PSI Generation to CGE's Non-Trading Sales	69	0.00	0.00	1,383.63	93.02	219.49	1,696.14	1,696.14	1.38
48	Adjust to tie CGE Purchases scheduled on PSI lines		0.00	0.00	0.00	0.00	0.00		0.00	0.00
	SUBTOTAL	91,684	$ 741,962.91	$ 403,000.00	$ 1,455,350.40	$ (82.13)	$ 343.55	$ 1,455,611.82	$ 2,600,574.73	2.16

CONFIDENTIAL PROPRIETARY
TRADE SECRET

CINCINNATI GAS & ELECTRIC COMPANY
ON SYSTEM PURCHASES
Determination of Net Energy Costs Incurred and KWHr Purchases
ALLOCATED TO CGE"S NATIVE LOAD AND NON-TRADING SALES
FOR THE MONTH OF SEPTEMBER 2003
FINAL PER PACE DATED NOVEMBER 21, 2003

LINE NO.	Company Name	MWHrs	Demand	Option Premium	Fuel W Trans	Other	EA Cost	Energy Charge	Total	EA Tons
	Off-System Energies transferred to On-System Report									
49	BP Energy Company (AMCO M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
50	PSI re:sales bookouts tied to PSI's native load purchases	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SUBTOTAL	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00
	Accrual Trade non-Native load Energies and Bookouts									
72	Lebanon, OH - City of (LEBANON OH E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SUBTOTAL	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00
	Purchased Transmission related to Purchases									
51	Ameren Trans re: Associated Electric - Sept 21003 48mwhs		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
52	Ameren Transmission re: Central Illinois Light Sep 2003- 436mwhs		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
53	Ameren Transmission re: Edison Mission Marketing & Trading - Sept 2003 1,229mwhs		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
54	Ameren Transmission re: Northern States Power - Sept 2003 182mwhs		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
55	Ameren Transmission re: The Energy Authority - Sept 2003 48mwhs		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
56	Ameren Trans re: Wisconsin Public Service - Sept 2003 613mwhs		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57	American Electric Power Service Trans re: - Sept 2003 VEPCO 700mwhs		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
58	Dayton Power & Light re: FirstEnergy Solutions Sept 2003 - demand		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
59	Midwest Independent System Operator re: CPMT's MidWest Region			0.00	0.00	0.00	0.00	0.00	0.00	0.00
60	Midwest Independent System Operator re: Southern Indiana Gas & Electric Company			0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	Northern Indiana Public Service Co. Trans re: Consumers Energy Sept 2003 - 273mwhs		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SUBTOTAL	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00
	TOTAL	91,684	$ 741,962.91	$ 403,000.00	$ 1,455,350.40	$ (82.13)	$ 343.65	$ 1,455,611.82	$ 2,600,574.73	2.16

02801

CONFIDENTIAL PROPRIETARY
TRADE SECRET

CGE Schedule 4 Report
Determination of Net Energy Costs incurred and KWHr Purchases
Preliminary Estimate for the month of October 2003

CGE On System-PURCH

02802

	Company Name	MWHrs	Demand	Option Premium	Energy Charge	Total	EA Tons
	System Energy						
	Alcoa Power Generating Inc. d/b/a APG Trading (APGT M)	320	$0.00	$0.00	$6,080.00	$6,080.00	
2	Allegheny Energy Supply Company LLC (AETS M)	1,794	0.00	0.00	33,214.50	33,214.50	
3	Ameren Energy as Agent (Ameren Energy E)	5,200	0.00	0.00	150,300.00	150,300.00	
4	American Electric Power Service Corporation (American Elec Powr I	65,958	0.00	0.00	1,918,340.00	1,918,340.00	
5	Associated Electric Cooperative, Inc. (AECI M)	40	0.00	0.00	1,520.00	1,520.00	
6	Big Rivers Electric Corporation (Big Rivers Elec Co E)	539	0.00	0.00	13,540.00	13,540.00	
7	Brascan Energy Marketing Inc. (Brascan Energy E)	95	0.00	0.00	2,123.25	2,123.25	
8	Buckeye Power (BUCKM M)	3,030	0.00	0.00	116,295.00	116,295.00	
9	Cargill Power Markets, LLC (Cargill Pow Mar E)	375	0.00	0.00	10,677.00	10,677.00	
10	Central Illinois Light Company (Central Ilinois Lt E)	2,920	0.00	0.00	87,932.00	87,932.00	
11	Cinergy Capital & Trading, Inc. (CCT)	0	0.00	403,000.00	0.00	403,000.00	
12	Constellation Power Source, Inc. (Constellation Powr E)	1,600	0.00	0.00	40,100.00	40,100.00	
13	Consumers Energy Co. (Consumers Energy E)	230	0.00	0.00	12,440.00	12,440.00	
14	Covert Generating Company, LLC (Covert Generating E)	42,359	0.00	0.00	461,848.00	461,848.00	
15	DTE Energy Trading, Inc. (DTEET M)	4,880	0.00	0.00	67,360.00	67,360.00	
16	Dayton Power & Light Company (Dayton Power&Light E)	2,946	0.00	0.00	77,320.40	77,320.40	
17	Dayton Power & Light Company adj related to Maimi Fort 5	0	0.00	0.00	80,000.00	80,000.00	
18	Detroit Edison Company (The) (Detroit Edison Co E)	975	0.00	0.00	35,587.50	35,587.50	
19	Dominion Energy Marketing, Inc. (Dominion Enrgy Mar E)	2,400	0.00	0.00	65,000.00	65,000.00	
20	Duke Energy Trading and Marketing LLC (DETM M)	34,048	0.00	0.00	1,055,344.50	1,055,344.50	
21	Duke Power Company (Duke Power Co E)	2,325	0.00	0.00	85,900.00	85,900.00	
22	Edison Mission Marketing & Trading Inc. (Edison Mission M&T E)	680	0.00	0.00	16,261.00	16,261.00	
23	Exelon Generation Company, LLC (ExelonGenerationCo E)	690	0.00	0.00	24,436.00	24,436.00	
24	FirstEnergy Solutions Corp. (FirstEnergySolut E)	1,850	0.00	0.00	49,425.00	49,425.00	
25	Hoosier Energy Rec, Inc. (Hoosier Energy Rec E)	805	0.00	0.00	18,135.00	18,135.00	
26	Indianapolis Power & Light Company (Indianaplis Pwr&Lt E)	13,042	0.00	0.00	278,185.50	278,185.50	
27	J Aron & Company (J Aron & Company E)	50	0.00	0.00	687.50	687.50	
28	Kansas City Power & Light Company (KCPLPS M)	471	0.00	0.00	15,598.00	15,598.00	
29	LG&E Energy Marketing Inc. (LG&E Energy Mktg E)	1,358	0.00	0.00	26,930.00	26,930.00	
30	LGE/KU (LGE/KU E)	7,700	0.00	0.00	232,050.00	232,050.00	
31	Lebanon, OH - City of (LEBANON OH E)	0	0.00	16,230.05	0.00	16,230.05	
32	Mirant Americas Energy Marketing, L.P. (MAEM M)	4,050	0.00	0.00	69,337.50	69,337.50	
	Morgan Stanley Capital Group Inc. (Morgan Stanley E)	800	0.00	0.00	22,640.00	22,640.00	
	Northern Indiana Public Service Company (NIPSGE M)	3,750	0.00	0.00	82,625.00	82,625.00	
35	Northern States Power Co. (Northern Stats Pwr E)	150	0.00	0.00	3,300.00	3,300.00	
36	OVEC	108,469	0.00	0.00	2,544,628.10	2,544,628.10	
37	Sempra Energy Solutions (Sempra Enrgy Soltn E)	720	0.00	0.00	10,080.00	10,080.00	
38	Sempra Energy Trading Corp. (SETC M)	800	0.00	0.00	21,320.00	21,320.00	
39	Southern Indiana Gas & Electric Company (Southern IN G&E E)	4,260	0.00	0.00	99,405.00	99,405.00	
40	Split Rock Energy LLC (Split Rock Energy)	649	0.00	0.00	14,278.00	14,278.00	
41	Strategic Energy, LLC (SEL M)	70	0.00	0.00	1,400.00	1,400.00	
42	Tennessee Valley Authority (TVAPT M)	3,375	0.00	0.00	95,550.00	95,550.00	
43	The Energy Authority (The Energy Auth E)	3,784	0.00	0.00	114,768.50	114,768.50	
44	Wabash Valley Power (Wabash Valley PowerE)	45	0.00	0.00	810.00	810.00	
45	Westar Energy, Inc. (Westar Energy E)	1,010	0.00	0.00	35,000.00	35,000.00	
46	PSI generation for CGE's Native Load	0	0.00	0.00	0.00	0.00	0.00
47	PSI generation for CGE's Trading Sales	202,751	0.00	0.00	4,197,869.44	4,197,869.44	1,457.33
48	Adjustment to Tie	(286,234)	0.00	0.00	0.00	0.00	
	Section Totals	247,129	$0.00	$419,230.05	$12,295,641.69	$12,714,871.74	$1,457.33
	Off-System Energies transferred to On-System Report						
49	American Electric Power Service Corporation (American Elec Powr I	3,200	$0.00	$0.00	$115,200.00	$115,200.00	
50	BP Energy Company (AMCO M)	18,400	0.00	0.00	570,400.00	570,400.00	
51	PSI re: purchases for native load	3,200	0.00	0.00	97,000.00	97,000.00	
	Section Totals	24,800	$0.00	$0.00	$782,600.00	$782,600.00	$0.00
	Grand Totals	271,929	$0.00	$419,230.05	$13,078,241.69	$13,497,471.74	$1,457.33
		352,212					

Of the purchased power above the following is the breakdown Purchases for Load excluding Intercompany Transfer	MWHS	DEMAND	OPTIONS	ENERGY	TOTAL
Forwards On System					
CCT	0	0.00	403,000.00	-	403,000.00
Total Forward Purchases On System	0	0.00	403,000.00	0.00	403,000.00
Forwards Off System					
CCT	0	0.00		-	0.00
Total Forward Purchases Off System	0	0.00	0.00	0.00	0.00
Forward Book Outs					

CONFIDENTIAL PROPRIETARY
TRADE SECRET

CINCINNATI GAS & ELE[illegible]IC COMPANY
ON SYSTEM PU[illegible]SES
Determination of Net Energy Costs in[illegible]red and MWHS Purchased
ALLOCATED TO CGE's NATIVE LOAD AND CGE NON-TRADING SALES
FINAL PER PACE DATED DECEMBER 9, 2003
FOR THE MONTH OF OCTOBER 2003

CONFIDENTIAL PROPRIETARY
TRADE SECRET

LINE NO.	Company Name	MWHS	DEMAND	OPTION PREMIUM	FUEL	OTHER	EA COSTS	TOTAL ENERGY CHARGE	TOTAL CHARGE	EA TONS
1	Alcoa Power Generating Inc. d/b/a APG Trading (APGT M)	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00
2	Allegheny Energy Supply Company LLC (AETS M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	Ameren Energy as Agent (Ameren Energy E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	American Electric Power Service Corporation (American Elec Powr E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	Associated Electric Cooperative, Inc. (AECI M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	Big Rivers Electric Corporation (Big Rivers Elec Co E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	Buckeye Power (BUCKM M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	Cargill Power Markets, LLC (Cargill Pow Mar E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	Central Illinois Light Company (Central Illnois Lt E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	Cinergy Capital & Trading, Inc. (CCT)	0	0.00	403,000.00	0.00	0.00	0.00	0.00	403,000.00	0.00
11	Constellation Power Source, Inc. (Constellation Powr E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	Consumers Energy Co. (Consumers Energy E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	Covert Generating Company, LLC (Covert Generating E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	DTE Energy Trading, Inc. (DTEET M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	Dayton Power & Light Company (Dayton Power&Light E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	Dominion Energy Marketing, Inc. (Dominion Enrgy Mar E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	Duke Energy Trading and Marketing LLC (DETM M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	Duke Power Company (Duke Power Co E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19	Edison Mission Marketing & Trading Inc. (Edison Mission M&T E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	Exelon Generation Company, LLC (ExelonGenerationCo E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	FirstEnergy Solutions Corp. (FirstEnergySolut E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	Hoosier Energy Rec, Inc. (Hoosier Energy Rec E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	Indianapolis Power & Light Company (Indianaplis Pwr&Lt E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	Kansas City Power & Light Company (KCPLPS M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
25	LG&E Energy Marketing Inc. (LG&E Energy Mktg E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
26	LGE/KU (LGE/KU E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	Mirant Americas Energy Marketing, L.P. (MAEM M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
28	Morgan Stanley Capital Group Inc. (Morgan Stanley E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29	Northern Indiana Public Service Company (NIPSGE M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30	Northern States Power Co. (Northern Stats Pwr E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
31	Ohio Valley	108,469	808,615.45	0.00	1,725,935.37	0.00	0.00	1,725,935.37	2,534,550.82	0.00
32	Ohio Valley Sept adj	0	0.00	0.00	(113,287.84)	0.00	0.00	(113,287.84)	(113,287.84)	0.00
33	Sempra Energy Trading Corp. (SETC M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34	Southern Indiana Gas & Electric Company (Southern IN G&E E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
35	Split Rock Energy LLC (Split Rock Energy)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36	Strategic Energy, LLC (SEL M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
37	Tennessee Valley Authority (TVAPT M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
38	The Energy Authority (The Energy Auth E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
39	Wabash Valley Power (Wabash Valley PowerE)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40	Westar Energy, Inc. (Westar Energy E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
41	PSI related to PSI Generation allocated to CGE's Native Load	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42	Psi re:Psi Gen to Cge Accrual Trading Sales per EITF 02-03 file	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
43	Adjust to tie CGE Purchases scheduled on PSI lines	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SUBTOTAL	108,469	$ 808,615.45	$ 403,000.00	$ 1,612,647.53	$ -	$ -	$ 1,612,647.53	$ 2,824,262.98	0.00
	Off-System Energies transferred to On-System Report									
44	American Electric Power Service Corporation (American Elec Powr E)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
45	BP Energy Company (AMCO M)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SUBTOTAL	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00
	Accrual Trade non-Native load Energies and Bookouts									
46	Lebanon, OH - City of (LEBANON OH E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SUBTOTAL	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00

02803

ON SYSTEM P ASES
Determination of Net Energy Costs I..urred and MWHS Purchased
ALLOCATED TO CGE's NATIVE LOAD AND CGE NON-TRADING SALES
FINAL PER PACE DATED DECEMBER 9, 2003
FOR THE MONTH OF OCTOBER 2003

.INE NO.	Company Name	MWHS	DEMAND	OPTION PREMIUM	FUEL	OTHER	EA COSTS	TOTAL ENERGY CHARGE	TOTAL CHARGE	EA TONS
	Purchased Transmission related to Purchases									
47	Ameren Transmission re: Central Illinois Light 488mwhs		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
48	Ameren Transmission re: Edison Mission Marketing & Trading 298mwhs		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
49	Ameren Transmission re: Kansas City Power & Light 471mwhs		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
50	Ameren Transmission re: Northern States Power Co.		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
51	Ameren Transmission re: The Energy Authority 178mwhs		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
52	American Electric Power Trans re: Duke Power 2,325mwhs		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SUBTOTAL	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00
	TOTAL	108,469	$ 808,615.45	$ 403,000.00	$ 1,612,647.53	$ -	$ -	$ 1,612,647.53	$ 2,824,262.98	0.00
	CONTROL TOTAL FROM 1003PACE File	108,469							$ 2,824,262.98	

CONFIDENTIAL PROPRIETARY
TRADE SECRET

02804

02805

CONFIDENTIAL PROPRIETARY
TRADE SECRET

CGE Schedule 4 Report
Determination of Net Energy Costs incurred and KWHr Purchases
Preliminary Estimate for the month of November 2003

	Company Name	MWHrs	Demand	Option Premium	Energy Charge	Total	EA Tons
1	Ameren Energy Marketing Company (Ameren En Mk Co I	1,575	$0.00	$0.00	$44,340.00	$44,340.00	
2	Ameren Energy as Agent (Ameren Energy E)	4,350	0.00	0.00	159,475.00	159,475.00	
3	American Electric Power Service Corporation (American I	67,123	0.00	0.00	1,685,282.80	1,685,282.80	
4	Associated Electric Cooperative, Inc. (AECI M)	1,405	0.00	0.00	68,225.00	68,225.00	
5	Big Rivers Electric Corporation (Big Rivers Elec Co E)	400	0.00	0.00	12,300.00	12,300.00	
6	Buckeye Power (BUCKM M)	3,018	0.00	0.00	101,493.50	101,493.50	
7	Cargill Power Markets, LLC (Cargill Pow Mar E)	348	0.00	0.00	10,676.00	10,676.00	
8	Carolina Pwr & Lt dba Progress Enrgy Carolinas Inc (Car	250	0.00	0.00	8,450.00	8,450.00	
9	Cinergy Capital & Trading, Inc. (CCT)	87	0.00	403,000.00	2,803.83	405,803.83	
10	Constellation Power Source, Inc. (Constellation Powr E)	1,200	0.00	0.00	44,200.00	44,200.00	
11	Consumers Energy Co. (Consumers Energy E)	3,915	0.00	0.00	122,320.00	122,320.00	
12	Covert Generating Company, LLC (Covert Generating E)	58,874	0.00	0.00	691,288.25	691,288.25	
13	DTE Energy Trading, Inc. (DTEET M)	178	0.00	0.00	5,128.00	5,128.00	
14	Dayton Power & Light Company (Dayton Power&Light E)	2,530	0.00	0.00	76,245.00	76,245.00	
15	Detroit Edison Company (The) (Detroit Edison Co E)	800	0.00	0.00	29,200.00	29,200.00	
16	Duke Energy Trading and Marketing LLC (DETM M)	5,631	0.00	0.00	193,605.00	193,605.00	
17	Duke Power Company (Duke Power Co E)	400	0.00	0.00	16,300.00	16,300.00	
18	East Kentucky Power Cooperative, Inc. (EKPCPM M)	5	0.00	0.00	500.00	500.00	
19	Edison Mission Marketing & Trading Inc. (Edison Missior	3,071	0.00	0.00	98,863.50	98,863.50	
20	EnergyUSA-TPC Corp. (EnergyUSA TPC E)	2,950	0.00	0.00	49,662.50	49,662.50	
21	Entergy-Koch Trading, LP (EntergyKochTrading E)	319	0.00	0.00	12,176.00	12,176.00	
22	Exelon Generation Company, LLC (ExelonGenerationCo I	1,250	0.00	0.00	31,875.00	31,875.00	
23	FirstEnergy Solutions Corp. (FirstEnergySolut E)	350	0.00	0.00	14,300.00	14,300.00	
24	Hoosier Energy Rec, Inc. (Hoosier Energy Rec E)	474	0.00	0.00	15,650.00	15,650.00	
25	Indianapolis Power & Light Company (Indianaplis Pwr&Lt	10,017	0.00	0.00	260,663.00	260,663.00	
26	Kansas City Power & Light Company (KCPLPS M)	420	0.00	0.00	10,840.00	10,840.00	
27	Lebanon, OH - City of (LEBANON OH E)	0	$0.00	$16,230.00	$0.00	$16,230.00	
28	LG&E Energy Marketing Inc. (LG&E Energy Mktg E)	1,563	0.00	0.00	43,064.50	43,064.50	
29	LGE/KU (LGE/KU E)	4,230	0.00	0.00	150,146.00	150,146.00	
30	Mirant Americas Energy Marketing, L.P. (MAEM M)	800	0.00	0.00	22,600.00	22,600.00	
31	Morgan Stanley Capital Group Inc. (Morgan Stanley E)	800	0.00	0.00	23,000.00	23,000.00	
32	Northern Indiana Public Service Company (NIPSGE M)	7,192	0.00	0.00	209,599.00	209,599.00	
33	Northern States Power Co. (Northern Stats Pwr E)	750	0.00	0.00	25,950.00	25,950.00	
34	Ohio Valley	85,763	0.00	0.00	2,345,628.10	2,345,628.10	
35	PSEG Energy Resources & Trade LLC (PSET M)	825	0.00	0.00	19,850.00	19,850.00	
36	Public Service Company of Colorado (Public Serv Co CO	800	0.00	0.00	22,800.00	22,800.00	
37	Sempra Energy Trading Corp. (SETC M)	1,600	0.00	0.00	41,000.00	41,000.00	
38	Southern Company Services, Inc. (SWE M)	400	0.00	0.00	14,400.00	14,400.00	
39	Southern Indiana Gas & Electric Company (Southern IN (	782	0.00	0.00	21,150.00	21,150.00	
40	Strategic Energy, LLC (SEL M)	1,058	0.00	0.00	25,344.00	25,344.00	
41	Tennessee Valley Authority (TVAPT M)	2,200	0.00	0.00	82,900.00	82,900.00	
42	The Energy Authority (The Energy Auth E)	2,658	0.00	0.00	69,881.50	69,881.50	

CGE On Syst PURCH

Dayton Power & Light	0	0.00	0.00	0.00	0.00
East Kentucky Power Coop	0	0.00	0.00	0.00	0.00
Louisville Gas & Electric	0	0.00	0.00	0.00	0.00
Northern Indiana Public Service Co		0.00	0.00		0.00
Adj to tie to Prelim Pace	(86)	0.00	0.00	(2,713.78)	(2,713.78)
Total Hourly Purchases	**85,993**	**0.00**	**0.00**	**2,368,618.15**	**2,368,618.15**
Hourly Transfer from Off System					
American Electric Power Co	0	0.00	0.00	0.00	0.00
East Kentucky Power Coop	0	0.00	0.00	0.00	0.00
Hoosier Energy Rec	0	0.00	0.00	0.00	0.00
Indianapolis Power & Light	0	0.00	0.00	0.00	0.00
LGE/KU	0	0.00	0.00	0.00	0.00
Northern Indiana Public Service Co	0	0.00	0.00	0.00	0.00
Southern Indiana Gas & Electric	0	0.00	0.00	0.00	0.00
Total Hourly Transfer Purchases	**0**	**0.00**	**0.00**	**0.00**	**0.00**
Total Hourly Purchases	**85,993**	**0.00**	**0.00**	**2,368,618.15**	**2,368,618.15**
Transfer from PSI					
Psi generation		0.00	0.00		0.00
	0	**0.00**	**0.00**	-	**0.00**
Total Purchases for Load	**85,993**	**$0.00**	**$403,000.00**	**$2,368,618.15**	**$2,771,618.15**

294,050	2,601,896	O&D
	(2,296,760)	generation
	(11,086)	loop
	294,050	
	0	

02806

CONFIDENTIAL PROPRIETARY
TRADE SECRET

02807

CGE Schedule 4 Report
Determination of Net Energy Costs Incurred and MWHS of Purchases
Final Per PACE Dated January 19, 2004
Allocated to CGE's Native Load
For the Month of November 2003

LINE NO.	Company Name	MWHrs	Demand	Option Premium	Fuel W Trans	Other	EA Cost	Energy Charge	Total	EA Tons
	On-System Energy									
1	Ameren Energy Marketing Company (Ameren En Mk Co E)	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00
2	Ameren Energy as Agent (Ameren Energy E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	American Electric Power Service Corporation (American Elec Powr E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	Associated Electric Cooperative, Inc. (AECI M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	Big Rivers Electric Corporation (Big Rivers Elec Co E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	Buckeye Power (BUCKM M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	Cargill Power Markets, LLC (Cargill Pow Mar E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	Carolina Pwr & Lt dba Progress Enrgy Carolinas Inc (Carolina Powr & Lt E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	Cinergy Capital & Trading, Inc. (CCT)	87	0.00	403,000.00	2,878.83	0.00	0.00	2,878.83	405,878.83	0.00
10	Constellation Power Source, Inc. (Constellation Powr E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	Consumers Energy Co. (Consumers Energy E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	Covert Generating Company, LLC (Covert Generating E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	City of Covington (Covington) - 31 mwhs Manual Adjustment	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	DTE Energy Trading, Inc (DTEET M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	Dayton Power & Light Company (Dayton Power&Light E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	Duke Energy Trading and Marketing LLC (DETM M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	Duke Power Company (Duke Power Co E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	East Kentucky Power Cooperative, Inc. (EKPCPM M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19	Edison Mission Marketing & Trading Inc. (Edison Mission M&T E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	Entergy-Koch Trading, LP (EntergyKochTrading E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	Exelon Generation Company, LLC (ExelonGenerationCo E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	FirstEnergy Solutions Corp. (FirstEnergySolut E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	Hoosier Energy Rec, Inc. (Hoosier Energy Rec E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	Indianapolis Power & Light Company (Indianaplis Pwr&Lt E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
25	Kansas City Power & Light Company (KCPLPS M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
26	LG&E Energy Marketing Inc. (LG&E Energy Mktg E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	LGE/KU (LGE/KU E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
28	Mirant Americas Energy Marketing, L.P. (MAEM M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29	Morgan Stanley Capital Group Inc. (Morgan Stanley E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30	Northern Indiana Public Service Company (NIPSGE M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
31	Northern States Power Co. (Northern Stats Pwr E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	Ohio Valley Power	86,449	820,237.79	0.00	1,677,800.40	0.00	0.00	1,677,800.40	2,498,038.19	0.00
33	PSEG Energy Resources & Trade LLC (PSET M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34	Public Service Company of Colorado (Public Serv Co CO E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
35	Sempra Energy Trading Corp. (SETC M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36	Southern Company Services, Inc. (SWE M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
37	Southern Indiana Gas & Electric Company (Southern IN G&E E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
38	Tennessee Valley Authority (TVAPT M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
39	The Energy Authority (The Energy Auth E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40	TransAlta Energy Marketing (US) Inc. (TransAlta Energy M E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
41	Wabash Valley Power (Wabash Valley PowerE)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42	Westar Energy, Inc. (Westar Energy E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
43	PSI related to PSI Generation allocated to CGE's Native Load	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
44	PSI related to PSI Generation allocated to CGE's Trading Sales	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
45	Adjust to tie CGE Purchases scheduled on PSI lines	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Section Totals	86,536	$ 820,237.79	$ 403,000.00	$ 1,680,679.23	$ -	$ -	$ 1,680,679.23	$ 2,903,917.02	0.00
	Off-System Energies transferred to On-System Report									
46	BP Energy Company (AMCO M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

CONFIDENTIAL PROPRIETARY
TRADE SECRET

47	Cinergy Capital & Trading, Inc. (CCT)	3	0.00	0.00	99.27	0.00	0.00	99.27	99.27	0.00
	Section Totals	3	$ -	$ -	$ 99.27	$ -	$ -	$ 99.27	$ 99.27	0.00
	<u>**Accrual Trade non-Native load Energies and Bookouts**</u>									
48	Lebanon, OH - City of (LEBANON OH E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Section Totals	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00
	<u>**Purchased Transmission related to Purchases**</u>									
49	Ameren Transmission re: Ameren - Nov 2003 47mwhs		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
50	Ameren Transmission re: Associated Electric Cooperative - Nov 2003 192mwhs		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
51	Ameren Transmission re: Northern States Power - Nov 2003 138mwhs		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
52	Ameren Transmission re: The Energy Authority - Nov 2003 114mwhs		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
53	Ameren Transmission re: Wabash Valley Power - Nov 2003 140mwhs		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
54	AEP Service Transmission re: Carolina Pwr & Lt Nov 2003 250mwhs		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
55	AEP Service Transmission re: Duke Power Company - Nov 2003 400mwhs		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
56	AEPService Transmission re: PSEG Energy Resources & Trade - Nov 2003 25mwhs		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Section Totals	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00
	TOTAL	86,539	$ 820,237.79	$ 403,000.00	$ 1,680,778.50	$ -	$ -	$ 1,680,778.50	$ 2,904,016.29	0.00
	CONTROL TOTAL FROM 1103 PACE File	86,539							$ 2,904,016.29	

CONFIDENTIAL PROPRIETARY
TRADE SECRET

02809 CONFIDENTIAL PROPRIETARY
TRADE SECRET

GE Schedule 4 Report
etermination of Net Energy Costs incurred and KWHr Purchases
reliminary Estimate for the month of December 2003

Company Name	MWHrs	Demand	Option Premium	Energy Charge	Total	EA Tons
n-System Energy						
1 Ameren Energy Marketing Company (Ameren En Mk Ci	8,808	$0.00	$0.00	$269,684.75	$269,684.75	
2 Ameren Energy as Agent (Ameren Energy E)	13,725	0.00	0.00	398,000.00	398,000.00	
3 American Electric Power Service Corporation (Americar	116,529	0.00	0.00	3,820,226.00	3,820,226.00	
4 Aquila Merchant Services, Inc. (Aquila Merchant E)	1,590	0.00	0.00	31,959.00	31,959.00	
5 Associated Electric Cooperative, Inc. (AECI M)	450	0.00	0.00	22,700.00	22,700.00	
6 BP Energy Company (AMCO M)	5,600	0.00	0.00	176,920.00	176,920.00	
7 Big Rivers Electric Corporation (Big Rivers Elec Co E)	175	0.00	0.00	7,350.00	7,350.00	
8 Brascan Energy Marketing Inc. (Brascan Energy E)	5,600	0.00	0.00	180,400.00	180,400.00	
9 Buckeye Power (BUCKM M)	4,448	0.00	0.00	167,772.50	167,772.50	
10 Cargill Power Markets, LLC (Cargill Pow Mar E)	17,892	0.00	0.00	533,522.00	533,522.00	
11 Cinergy Capital & Trading, Inc. (CCT)	0	0.00	403,000.00	0.00	403,000.00	
12 City of Hamilton (Hamilton E)	1,000	0.00	0.00	23,475.00	23,475.00	
13 Conectiv Energy Supply, Inc. (CNCT M)	7,200	0.00	0.00	162,000.00	162,000.00	
14 Constellation Power Source, Inc. (Constellation Powr E)	5,675	0.00	0.00	156,250.00	156,250.00	
15 Consumers Energy Co. (Consumers Energy E)	850	0.00	0.00	42,750.00	42,750.00	
16 Coral Power, L.L.C. (CORP M)	800	0.00	0.00	37,600.00	37,600.00	
17 Covert Generating Company, LLC (Covert Generating E	83,304	0.00	0.00	2,219,507.00	2,219,507.00	
18 DTE Energy Trading, Inc. (DTEET M)	11,650	0.00	0.00	322,437.50	322,437.50	
19 Dayton Power & Light Company (Dayton Power&Light E	59,450	0.00	0.00	1,878,940.00	1,878,940.00	
20 Detroit Edison Company (The) (Detroit Edison Co E)	250	0.00	0.00	11,650.00	11,650.00	
21 Dominion Energy Marketing, Inc. (Dominion Enrgy Mar	1,600	0.00	0.00	45,440.00	45,440.00	
22 Duke Energy Trading and Marketing LLC (DETM M)	27,649	0.00	0.00	887,104.25	887,104.25	
23 Duke Power Company (Duke Power Co E)	150	0.00	0.00	7,800.00	7,800.00	
24 Eagle Energy Partners I, L.P. (Eagle Energy E)	456	0.00	0.00	15,930.00	15,930.00	
25 East Kentucky Power Cooperative, Inc. (EKPCPM M)	50	0.00	0.00	1,150.00	1,150.00	
26 Edison Mission Marketing & Trading Inc. (Edison Missi	6,129	0.00	0.00	187,480.00	187,480.00	
27 EnergyUSA-TPC Corp. (EnergyUSA TPC E)	6,925	0.00	0.00	174,112.50	174,112.50	
28 Entergy-Koch Trading, LP (EntergyKochTrading E)	7,600	0.00	0.00	298,400.00	298,400.00	
29 Exelon Generation Company, LLC (ExelonGenerationC	450	0.00	0.00	18,650.00	18,650.00	
30 FirstEnergy Solutions Corp. (FirstEnergySolut E)	100	0.00	0.00	2,000.00	2,000.00	
31 Hoosier Energy Rec, Inc. (Hoosier Energy Rec E)	1,595	0.00	0.00	31,330.00	31,330.00	
32 Indianapolis Power & Light Company (Indianaplis Pwr&	10,430	0.00	0.00	262,888.00	262,888.00	
33 J Aron & Company (J Aron & Company E)	12,045	0.00	0.00	324,938.75	324,938.75	
34 Kansas City Power & Light Company (KCPLPS M)	100	0.00	0.00	5,050.00	5,050.00	
35 LG&E Energy Marketing Inc. (LG&E Energy Mktg E)	1,750	0.00	0.00	62,050.00	62,050.00	
36 LGE/KU (LGE/KU E)	7,975	0.00	0.00	229,787.50	229,787.50	
37 Lebanon, OH - City of (LEBANON OH E)	0	0.00	16,230.00	0.00	16,230.00	
38 Manitoba Hydro Electric Board (The) (Manitoba Hydro E	50	0.00	0.00	800.00	800.00	
39 Mirant Americas Energy Marketing, L.P. (MAEM M)	3,200	0.00	0.00	68,700.00	68,700.00	
40 Northern Indiana Public Service Company (NIPSGE M)	6,015	0.00	0.00	174,857.50	174,857.50	
41 Northern States Power Co. (Northern Stats Pwr E)	200	0.00	0.00	9,600.00	9,600.00	
42 Ohio Valley	127,945	0.00	0.00	2,903,628.10	2,903,628.10	
43 PSEG Energy Resources & Trade LLC (PSET M)	14,120	0.00	0.00	457,830.00	457,830.00	
44 Public Service Company of Colorado (Public Serv Co C	1,600	0.00	0.00	63,600.00	63,600.00	
45 Select Energy, Inc. (Select Energy Inc E)	1,600	0.00	0.00	60,800.00	60,800.00	
46 Sempra Energy Trading Corp. (SETC M)	800	0.00	0.00	38,000.00	38,000.00	
47 South Carolina Electric & Gas Company (South Carolin	800	0.00	0.00	14,800.00	14,800.00	
48 Southern Indiana Gas & Electric Company (Southern IN	3,323	0.00	0.00	113,770.00	113,770.00	
49 Split Rock Energy LLC (Split Rock Energy)	800	0.00	0.00	31,600.00	31,600.00	
50 Strategic Energy, LLC (SEL M)	1,408	0.00	0.00	33,792.00	33,792.00	
51 Tenaska Power Services Co. (Tenaska Power Serv E)	522	0.00	0.00	24,773.00	24,773.00	
52 Tennessee Valley Authority (TVAPT M)	23,450	0.00	0.00	803,950.00	803,950.00	
53 The Energy Authority (The Energy Auth E)	2,469	0.00	0.00	76,943.00	76,943.00	
54 TransAlta Energy Marketing (US) Inc. (TransAlta Energ	103	0.00	0.00	5,665.00	5,665.00	
55 WPS Energy Services, Inc. (WPS Energy Service E)	6,450	0.00	0.00	144,500.00	144,500.00	
56 Wabash Valley Power (Wabash Valley PowerE)	850	0.00	0.00	40,120.00	40,120.00	
57 Westar Energy, Inc. (Westar Energy E)	1,960	0.00	0.00	93,200.00	93,200.00	
58 Williams Power Company, Inc. (Williams Power E)	4,800	0.00	0.00	141,800.00	141,800.00	
59 PSI generation for CGE's Native Load	0	0.00	0.00	0.00	0.00	0.00
60 PSI generation for CGE's Trading Sales	6,737	0.00	0.00	122,702.36	122,702.36	49.54
61 Adjustment to Tie	(151,052)	0.00	0.00	0.00	0.00	
ection Totals	488,150	$0.00	$419,230.00	$18,442,685.71	$18,861,915.71	49.54
ff-System Energies transferred to On-System Report						
62 BP Energy Company (AMCO M)	17,600	$0.00	$0.00	$545,600.00	$545,600.00	0.00

Section Totals	17,600	$0.00	$0.00	$545,600.00	$545,600.00	0.00
d Totals	505,750	$0.00	$419,230.00	$18,988,285.71	$19,407,515.71	49.54

Of the purchased power above the following is the breal Purchases for Load excluding Intercompany Transfer	MWHS	DEMAND	OPTIONS	ENERGY	TOTAL
Forwards On System					
CCT	0	0.00	403,000.00	-	403,000.00
Total Forward Purchases On System	0	0.00	403,000.00	0.00	403,000.00
Forwards Off System					
CCT	0	0.00	0.00	-	0.00
Total Forward Purchases Off System	0	0.00	0.00	0.00	0.00
Forward Book Outs					
Dynegy Power Mktg	0	0.00	0.00	-	0.00
Edison Mission	0	0.00	0.00	-	0.00
Total Forward Book Out Purchases	0	0.00	0.00	0.00	0.00
Total Forward Purchases	0	0.00	403,000.00	0.00	403,000.00
Hourly					
OVEC	127,945	0.00	0.00	2,903,628.10	2,903,628.10
American Electric Power Co		0.00	0.00		0.00
CCT		0.00	0.00		0.00
East Kentucky Power Coop		0.00	0.00		0.00
Hoosier Energy Rec		0.00	0.00		0.00
Indianapolis Power & Light		0.00	0.00		0.00
LGE/KU		0.00	0.00		0.00
Northern Indiana Public Service Co		0.00	0.00		0.00
Southern Indiana Gas & Electric		0.00	0.00		0.00
American Electric Power Co		0.00	0.00		0.00
Dayton Power & Light	0	0.00	0.00	0.00	0.00
East Kentucky Power Coop	0	0.00	0.00	0.00	0.00
Louisville Gas & Electric	0	0.00	0.00	0.00	0.00
Northern Indiana Public Service Co		0.00	0.00		0.00
Adj to tie to Prelim Pace		0.00	0.00	(555.92)	(555.92)
Total Hourly Purchases	127,945	0.00	0.00	2,903,072.18	2,903,072.18
Hourly Transfer from Off System					
American Electric Power Co	0	0.00	0.00	0.00	0.00
East Kentucky Power Coop	0	0.00	0.00	0.00	0.00
Hoosier Energy Rec	0	0.00	0.00	0.00	0.00
Indianapolis Power & Light	0	0.00	0.00	0.00	0.00
LGE/KU	0	0.00	0.00	0.00	0.00
Northern Indiana Public Service Co	0	0.00	0.00	0.00	0.00
Southern Indiana Gas & Electric	0	0.00	0.00	0.00	0.00
Total Hourly Transfer Purchases	0	0.00	0.00	0.00	0.00
Total Hourly Purchases	127,945	0.00	0.00	2,903,072.18	2,903,072.18
Transfer from PSI					
Psi generation		0.00	0.00		0.00
	0	0.00	0.00	-	0.00
Total Purchases for Load	127,945	$0.00	$403,000.00	$2,903,072.18	$3,306,072.18

505,750	3,033,999	O&D
	(2,517,465)	generation
	(10,784)	loop
	505,750	
	0	

CONFIDENTIAL PROPRIETARY
TRADE SECRET

CGE Schedule 4 Report
Determination of Net Energy Costs Incurred and MWHs Purchased for Native Load
FINAL FOR THE MONTH OF DECEMBER 2003
PER PACE DATED FEBRUARY 19, 2004

LINE NO.	Company Name	MWHrs	Demand	Option Premium	Fuel W Trans	Other	EA Cost	Energy Charge	Total	EA Tons
	On-System Energy									
1	Ameren Energy Marketing Company (Ameren En Mk Co E)	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00
2	Ameren Energy as Agent (Ameren Energy E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	American Electric Power Service Corporation (American Elec Powr E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	Aquila Merchant Services, Inc. (Aquila Merchant E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	Associated Electric Cooperative, Inc. (AECI M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	BP Energy Company (AMCO M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	Big Rivers Electric Corporation (Big Rivers Elec Co E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	Brascan Energy Marketing Inc. (Brascan Energy E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	Buckeye Power (BUCKM M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	Cargill Power Markets, LLC (Cargill Pow Mar E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	City of Hamilton (Hamilton E)	68	0.00	0.00	660.00	0.00	0.00	880.00	660.00	0.00
12	Cinergy Capital & Trading, Inc. (CCT)	0	0.00	403,000.00	0.00	0.00	0.00	0.00	403,000.00	0.00
13	Conectiv Energy Supply, Inc. (CNCT M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	Constellation Power Source, Inc. (Constellation Powr E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	Consumers Energy Co. (Consumers Energy E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	Covert Generating Company, LLC (Covert Generating E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	DTE Energy Trading, Inc. (DTEET M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	Dayton Power & Light Company (Dayton Power&Light E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19	Detroit Edison Company (The) (Detroit Edison Co E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	Dominion Energy Marketing, Inc. (Dominion Enrgy Mar E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	Duke Energy Trading and Marketing LLC (DETM M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	Duke Power Company (Duke Power Co E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	Eagle Energy Partners I, L.P. (Eagle Energy E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	East Kentucky Power Cooperative, Inc. (EKPCPM M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
25	Edison Mission Marketing & Trading Inc. (Edison Mission M&T E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
26	Entergy-Koch Trading, LP (EntergyKochTrading E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	Exelon Generation Company, LLC (ExelonGenerationCo E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
28	FirstEnergy Solutions Corp. (FirstEnergySolut E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29	Hoosier Energy Rec. Inc. (Hoosier Energy Rec E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30	Indianapolis Power & Light Company (Indianaplis Pwr&Lt E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
31	J Aron & Company (J Aron & Company E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	Kansas City Power & Light Company (KCPLPS M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33	LG&E Energy Marketing Inc. (LG&E Energy Mktg E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34	LGE/KU (LGE/KU E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
35	Manitoba Hydro Electric Board (The) (Manitoba Hydro E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36	Northern Indiana Public Service Company (NIPSCGE M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
37	Northern States Power Co. (Northern Stats Pwr E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
38	Ohio Valley Power	129,046	0.00	0.00	2,858,628.10	0.00	0.00	2,858,628.10	2,858,628.10	0.00
39	PSEG Energy Resources & Trade LLC (PSET M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40	Public Service Company of Colorado (Public Serv Co CO E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
41	Select Energy, Inc. (Select Energy Inc E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42	Sempra Energy Trading Corp. (SETC M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
43	South Carolina Electric & Gas Company (South Carolina E&G E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
44	Southern Indiana Gas & Electric Company (Southern IN G&E E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
45	Tenaska Power Services Co. (Tenaska Power Serv E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
46	Tennessee Valley Authority (TVAPT M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47	The Energy Authority (The Energy Auth E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
48	TransAlta Energy Marketing (US) Inc. (TransAlta Energy M E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
49	WPS Energy Services, Inc. (WPS Energy Service E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
50	Wabash Valley Power (Wabash Valley PowerE)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
51	Wester Energy, Inc. (Wester Energy E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
52	Williams Power Company, Inc. (Williams Power E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
53	PSI related to PSI Generation allocated to CGE's Non Trading Sales	1,689	0.00	0.00	85,564.20	3,019.64	5,477.45	94,061.29	94,061.29	26.82

CONFIDENTIAL PROPRIETARY
TRADE SECRET

CGE Schedule 4 Report
Determination of Net Energy Costs Incurred and MWHs Purchased for Native Load
FINAL FOR THE MONTH OF DECEMBER 2003
PER PACE DATED FEBRUARY 19, 2004

LINE NO.	Company Name	MWHrs	Demand	Option Premium	Fuel W Trans	Other	EA Cost	Energy Charge	Total	EA Tons
	On-System Energy									
54	PSI related to PSI Generation allocated to CGE's Trading Sales	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
55	PSI related to PSI Purchases allocated to CGE's Trading Sales	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
56	Adjust to tie CGE Purchases scheduled on PSI lines	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Section Totals	130,803	$ -	$ 403,000.00	$ 2,944,872.30	$ 3,019.64	$ 5,477.45	$ 2,953,369.39	$ 3,356,369.39	25.82
	Off-System Energies transferred to On-System Report									
57	BP Energy Company (AMCO M)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Section Totals	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00
	Accrual Trade non-Native load Energies and Bookouts									
58	Lebanon, OH - City of (LEBANON OH E)	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Section Totals	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00
	Purchased Transmission related to Purchases									
59	TVA re: CCT - November 2003 - Demand		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60	TVA re: Southern Company Svcs - November 2003 - Demand		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	American Electric Power Service Transmission re: Duke Power- 150mwhs		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Section Totals	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00
	TOTAL	130,803	$ -	$ 403,000.00	$ 2,944,872.30	$ 3,019.64	$ 5,477.45	$ 2,953,369.39	$ 3,356,369.39	25.82

CONFIDENTIAL PROPRIETARY
TRADE SECRET

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CGE Schedule 4 Report
Determination of Net Energy Costs incurred and KWHr Purchases
Preliminary Estimate for the month of January 2004

CONFIDENTIAL PROPRIETARY
TRADE SECRET

Company Name	MWHrs	Demand	Option Premium	Energy Charge	Total	EA Tons
On-System Energy						
1 Alcoa Power Generating Inc. d/b/a APG Trading (APGT I	90	$0.00	$0.00	$1,440.00	$1,440.00	
2 Ameren Energy Marketing Company (Ameren En Mk Co I	2,457	0.00	0.00	93,768.50	93,768.50	
3 Ameren Energy as Agent (Ameren Energy E)	5,590	0.00	0.00	198,325.00	198,325.00	
4 American Electric Power Service Corporation (American I	658,155	0.00	0.00	22,986,300.00	22,986,300.00	
5 American Municipal Power - Ohio, Inc. (AMPOHI M)	720	0.00	0.00	21,600.00	21,600.00	
6 Aquila Merchant Services, Inc. (Aquila Merchant E)	5,388	0.00	0.00	113,137.50	113,137.50	
7 Associated Electric Cooperative, Inc. (AECI M)	544	0.00	0.00	29,098.00	29,098.00	
8 Big Rivers Electric Corporation (Big Rivers Elec Co E)	65	0.00	0.00	2,875.00	2,875.00	
9 Buckeye Power (BUCKM M)	3,335	0.00	0.00	143,232.50	143,232.50	
10 Cargill Power Markets, LLC (Cargill Pow Mar E)	9,970	0.00	0.00	208,789.00	208,789.00	
11 Carolina Pwr & Lt dba Progress Enrgy Carolinas Inc (Car	1,592	0.00	0.00	70,300.00	70,300.00	
12 Cinegry Capital & Trading	28	0.00	0.00	1,877.40	1,877.40	
13 Conectiv Energy Supply, Inc. (CNCT M)	4,700	0.00	0.00	167,100.00	167,100.00	
14 ConocoPhillips Company (ConocoPhillips Co E)	200	0.00	0.00	12,800.00	12,800.00	
15 Constellation Power Source, Inc. (Constellation Powr E)	4,270	0.00	0.00	103,190.00	103,190.00	
16 Consumers Energy Co. (Consumers Energy E)	1,804	0.00	0.00	83,036.00	83,036.00	
17 Covert Generating Company, LLC (Covert Generating E)	31,733	0.00	0.00	675,493.00	675,493.00	
18 DTE Energy Trading, Inc. (DTEET M)	9,798	0.00	0.00	264,286.00	264,286.00	
19 Dayton Power & Light Company (Dayton Power&Light E)	2,538	0.00	0.00	89,272.00	89,272.00	
20 Detroit Edison Company (The) (Detroit Edison Co E)	325	0.00	0.00	15,050.00	15,050.00	
21 Dominion Energy Marketing, Inc. (Dominion Enrgy Mar E)	8,400	0.00	0.00	417,332.80	417,332.80	
22 Duke Energy Trading and Marketing LLC (DETM M)	18,960	0.00	0.00	495,051.00	495,051.00	
23 Duke Power Company (Duke Power Co E)	1,767	0.00	0.00	81,225.00	81,225.00	
24 Edison Mission Marketing & Trading Inc. (Edison Missior	18,811	0.00	0.00	542,466.00	542,466.00	
25 EnergyUSA-TPC Corp. (EnergyUSA TPC E)	10,000	0.00	0.00	306,340.00	306,340.00	
26 Entergy-Koch Trading, LP (EntergyKochTrading E)	3,405	0.00	0.00	68,422.00	68,422.00	
27 Exelon Generation Company, LLC (ExelonGenerationCo I	26,639	0.00	0.00	538,446.20	538,446.20	
28 Hoosier Energy Rec, Inc. (Hoosier Energy Rec E)	2,804	0.00	0.00	80,436.00	80,436.00	
29 Indianapolis Power & Light Company (Indianaplis Pwr&Lt	16,158	0.00	0.00	536,874.00	536,874.00	
30 J Aron & Company (J Aron & Company E)	3,250	0.00	0.00	91,700.00	91,700.00	
31 Kansas City Power & Light Company (KCPLPS M)	515	0.00	0.00	25,685.00	25,685.00	
32 LG&E Energy Marketing Inc. (LG&E Energy Mktg E)	1,446	0.00	0.00	42,595.00	42,595.00	
33 LGE/KU (LGE/KU E)	7,475	0.00	0.00	298,325.00	298,325.00	
34 Mirant Americas Energy Marketing, L.P. (MAEM M)	9,400	0.00	0.00	382,250.00	382,250.00	
35 Morgan Stanley Capital Group Inc. (Morgan Stanley E)	7,700	0.00	0.00	172,700.00	172,700.00	
36 Northern Indiana Public Service Company (NIPSGE M)	7,585	0.00	0.00	331,030.00	331,030.00	
37 Northern States Power Co. (Northern Stats Pwr E)	50	0.00	0.00	2,600.00	2,600.00	
38 Occidental Power Services, Inc. (Occidental Pwr Svc E)	15	0.00	0.00	900.00	900.00	
39 Ohio Valley	132,882	0.00	0.00	3,145,316.94	3,145,316.94	
40 PSEG Energy Resources & Trade LLC (PSET M)	2,357	0.00	0.00	21,061.00	21,061.00	
41 Progress Ventures, Inc. dba Progress Energy Ventur (Pr	800	0.00	0.00	26,920.00	26,920.00	

42 Public Service Company of Colorado (Public Serv Co CO	800	0.00	0.00	34,000.00	34,000.00	
43 Rainbow Energy Marketing Corporation (REMC M)	800	0.00	0.00	21,200.00	21,200.00	
44 Reliant Energy Services, Inc. (RES M)	1,600	0.00	0.00	48,000.00	48,000.00	
45 Sempra Energy Trading Corp. (SETC M)	3,600	0.00	0.00	153,000.00	153,000.00	
46 Southern Company Services, Inc. (SWE M)	2,775	0.00	0.00	148,736.00	148,736.00	
47 Southern Indiana Gas & Electric Company (Southern IN (	4,125	0.00	0.00	151,100.00	151,100.00	
48 Tenaska Power Services Co. (Tenaska Power Serv E)	623	0.00	0.00	37,606.00	37,606.00	
49 Tennessee Valley Authority (TVAPT M)	4,775	0.00	0.00	199,125.00	199,125.00	
50 The Energy Authority (The Energy Auth E)	1,767	0.00	0.00	61,611.00	61,611.00	
51 Virginia Electric and Power Company (Virginia Elec&Pwr	200	0.00	0.00	12,300.00	12,300.00	
52 WPS Energy Services, Inc. (WPS Energy Service E)	800	0.0C	0.00	29,200.00	29,200.00	
53 Wabash Valley Power (Wabash Valley PowerE)	665	0.00	0.00	35,915.00	35,915.00	0.00
54 Westar Energy, Inc. (Westar Energy E)	4,359	0.00	0.00	200,040.00	200,040.00	
55 Williams Power Company, Inc. (Williams Power E)	800	0.00	0.00	20,000.00	20,000.00	
56 PSI generation for CGE's Native Load	0	0.00	0.00	0.00	0.00	0.00
57 PSI generation for CGE's Accrual trades	1,836	0.00	0.00	30,373.83	30,373.83	13.50
58 *PSI additional generation for CGE's Trading Sales*	186,735	0.00	0.00	3,675,582.25	3,675,582.25	1,373.05
59 Adjustment to Tie	(327,152)	0.00	0.00	0.00	0.00	0.00
Section Totals	**912,829**	**$0.00**	**$0.00**	**$37,746,434.92**	**$37,746,434.92**	**$1,386.55**
Off-System Energies transferred to On-System Report						
60 Cargill Power Markets, LLC (Cargill Pow Mar E)	800	$0.00	$0.00	$20,800.00	$20,800.00	
61 DTE Energy Trading, Inc. (DTEET M)	800	0.00	0.00	12,400.00	12,400.00	
62 Dominion Energy Marketing, Inc. (Dominion Enrgy Mar E;	800	0.00	0.00	20,800.00	20,800.00	
63 LGE/KU (LGE/KU E)	800	0.00	0.00	20,800.00	20,800.00	
64 South Carolina Electric & Gas Company (South Carolina	800	0.00	0.00	20800.00	20800.00	
Section Totals	**4,000**	**$0.00**	**$0.00**	**$95,600.00**	**$95,600.00**	**$0.00**
Accrual Trade non-Native load Energies and Bookouts						
65 Lebanon, OH - City of (LEBANON OH E)	0	$15,810.05	$0.00	$0.00	$15,810.05	
Section Totals	**0**	**$15,810.05**	**$0.00**	**$0.00**	**$15,810.05**	**$0.00**
Grand Totals	**916,829**	**$15,810.05**	**$0.00**	**$37,842,034.92**	**$37,857,844.97**	**$1,386.55**

Of the purchased power above the following is the breakd Purchases for Load excluding Intercompany Transfer	MWHS	DEMAND	OPTIONS	ENERGY	TOTAL
Forwards On System					
CCT	0	0.00	0.00	-	0.00
Total Forward Purchases On System	0	0.00	0.00	0.00	0.00
Forwards Off System					
CCT	0	0.00	0.00	-	0.00
Total Forward Purchases Off System	0	0.00	0.00	0.00	0.00

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CONFIDENTIAL PROPRIETARY
TRADE SECRET

CGE On Syst— PURCH

Forward Book Outs					
Dynegy Power Mktg	0	0.00	0.00	-	0.00
Edison Mission	0	0.00	0.00	-	0.00
Total Forward Book Out Purchases	0	0.00	0.00	0.00	0.00
Total Forward Purchases	**0**	**0.00**	**0.00**	**0.00**	**0.00**
Hourly					
OVEC	132,882	0.00	0.00	3,145,316.94	3,145,316.94
American Electric Power Co		0.00	0.00		0.00
Northern Indiana Public Service Co		0.00	0.00		0.00
Adj to tie to Prelim Pace	17,150	0.00	0.00	214,395.12	214,395.12
Total Hourly Purchases	**150,032**	**0.00**	**0.00**	**3,359,712.06**	**3,359,712.06**
Hourly Transfer from Off System					
American Electric Power Co	0	0.00	0.00	0.00	0.00
Southern Indiana Gas & Electric	0	0.00	0.00	0.00	0.00
Total Hourly Transfer Purchases	**0**	**0.00**	**0.00**	**0.00**	**0.00**
Total Hourly Purchases	**150,032**	**0.00**	**0.00**	**3,359,712.06**	**3,359,712.06**
Transfer from PSI					
Psi generation	0	0.00	0.00	-	0.00
	0	**0.00**	**0.00**	**-**	**0.00**
Total Purchases for Load	**150,032**	**$0.00**	**$0.00**	**$3,359,712.06**	**$3,359,712.06**

916,829	3,377,393	O&D
	(2,451,633)	generation
	(8,931)	loop
	916,829	
	0	

CONFIDENTIAL PROPRIETARY
TRADE SECRET

02815

02816

CONFIDENTIAL PROPRIETARY
TRADE SECRET

CGE Schedule 4 Rep...
Determination of Net Energy Costs incurred and KWHr Purchases
Preliminary Estimate for the month of February 2004

Company Name	MWHrs	Demand	Option Premium	Energy Charge	Total	EA Tons	per mwh cost
On-System Energy							
1 Ameren Energy Marketing Company (Ameren En Mk Cc	4,340	$0.00	$0.00	$146,675.00	$146,675.00		33.80
2 Ameren Energy as Agent (Ameren Energy E)	28,372	0.00	0.00	1,091,610.00	1,091,610.00		38.47
3 American Electric Power Service Corporation (Americar	414,182	0.00	0.00	15,987,415.30	15,987,415.30		38.60
4 Aquila Merchant Services, Inc. (Aquila Merchant E)	6,600	0.00	0.00	138,600.00	138,600.00		21.00
5 Associated Electric Cooperative, Inc. (AECI M)	1,285	0.00	0.00	61,720.00	61,720.00		48.03
6 BP Energy Company (AMCO M)	1,600	0.00	0.00	77,600.00	77,600.00		46.50
7 Big Rivers Electric Corporation (Big Rivers Elec Co E)	382	0.00	0.00	12,340.00	12,340.00		32.30
8 Buckeye Power (BUCKM M)	14,028	0.00	0.00	518,491.00	518,491.00		36.96
9 Cargill Power Markets, LLC (Cargill Pow Mar E)	8,735	0.00	0.00	337,592.00	337,592.00		38.65
10 Carolina Pwr & Lt dba Progress Enrgy Carolinas Inc (Ca	250	0.00	0.00	9,250.00	9,250.00		37.00
11 Citadel Energy Products LLC (Citadel Energ Prod E)	13,600	0.00	0.00	599,136.00	599,136.00		44.05
12 Conectiv Energy Supply, Inc. (CNCT M)	2,400	0.00	0.00	92,400.00	92,400.00		38.50
13 Constellation Power Source, Inc. (Constellation Powr E)	3,040	0.00	0.00	111,050.00	111,050.00		36.53
14 Consumers Energy Co. (Consumers Energy E)	1,374	0.00	0.00	65,258.00	65,258.00		47.49
15 Covert Generating Company, LLC (Covert Generating E	650	0.00	0.00	18,955.00	18,955.00		29.16
16 DTE Energy Trading, Inc. (DTEET M)	9,108	0.00	0.00	337,348.00	337,348.00		37.04
17 Dayton Power & Light Company (Dayton Power&Light E	3,156	0.00	0.00	129,080.00	129,080.00		40.90
18 Detroit Edison Company (The) (Detroit Edison Co E)	525	0.00	0.00	25,225.00	25,225.00		48.05
19 Dominion Energy Marketing, Inc. (Dominion Enrgy Mar	7,200	0.00	0.00	318,507.25	318,507.25		44.24
20 Duke Energy Trading and Marketing LLC (DETM M)	20,888	0.00	0.00	832,384.50	832,384.50		39.85
21 Duke Power Company (Duke Power Co E)	3,297	0.00	0.00	138,901.00	138,901.00		42.13
22 Eagle Energy Partners I, L.P. (Eagle Energy E)	800	0.00	0.00	36,280.00	36,280.00		45.35
23 East Kentucky Power Cooperative, Inc. (EKPCPM M)	1,296	0.00	0.00	48,756.00	48,756.00		37.62
24 Edison Mission Marketing & Trading Inc. (Edison Missio	56,377	0.00	0.00	1,397,331.00	1,397,331.00		24.79
25 EnergyUSA-TPC Corp. (EnergyUSA TPC E)	7,600	0.00	0.00	316,200.00	316,200.00		41.61
26 Entergy-Koch Trading, LP (EntergyKochTrading E)	1,850	0.00	0.00	82,200.00	82,200.00		44.43
27 Exelon Generation Company, LLC (ExelonGenerationCc	30,340	0.00	0.00	600,020.00	600,020.00		19.78
28 FPL Energy Power Marketing, Inc. (FPL Energy Pow Mi	1,600	0.00	0.00	47,120.00	47,120.00		29.45
29 FirstEnergy Solutions Corp. (FirstEnergySolut E)	10,300	0.00	0.00	442,950.00	442,950.00		43.00
30 Hoosier Energy Rec, Inc. (Hoosier Energy Rec E)	2,607	0.00	0.00	80,495.00	80,495.00		30.88
31 Indianapolis Power & Light Company (Indianaplis Pwr&l	33,060	0.00	0.00	1,167,927.00	1,167,927.00		35.33
32 J Aron & Company (J Aron & Company E)	5,600	0.00	0.00	186,800.00	186,800.00		33.36
33 Kansas City Power & Light Company (KCPLPS M)	2,360	0.00	0.00	111,545.00	111,545.00		47.26
34 LG&E Energy Marketing Inc. (LG&E Energy Mktg E)	3,041	0.00	0.00	95,327.00	95,327.00		31.35
35 LGE/KU (LGE/KU E)	27,985	0.00	0.00	1,034,966.00	1,034,966.00		36.98
36 Mirant Americas Energy Marketing, L.P. (MAEM M)	800	0.00	0.00	41,600.00	41,600.00		52.00
37 Morgan Stanley Capital Group Inc. (Morgan Stanley E)	3,400	0.00	0.00	130,012.50	130,012.50		38.24
38 Northern Indiana Public Service Company (NIPSGE M)	8,457	0.00	0.00	286,968.00	286,968.00		33.93
39 Northern States Power Co. (Northern Stats Pwr E)	1,292	0.00	0.00	43,825.00	43,825.00		33.92
40 Ohio Valley	109,554	0.00	0.00	2,875,792.70	2,875,792.70		26.25
41 PJM Interconnection, L.L.C. (PJM M)	7	0.00	0.00	243.04	243.04		34.72
42 PSEG Energy Resources & Trade LLC (PSET M)	7,200	0.00	0.00	239,450.00	239,450.00		33.26
43 Progress Ventures, Inc. dba Progress Energy Ventur (P	35	0.00	0.00	1,575.00	1,575.00		45.00
44 Select Energy, Inc. (Select Energy Inc E)	14,100	0.00	0.00	259,325.00	259,325.00		18.39

45 Sempra Energ, Trading Corp. (SETC M)	4,400	0.00	0.00	159,500.00	159,500.00		36.25
46 South Carolina Electric & Gas Company (South Carolin	800	0.00	0.00	34,400.00	34,400.00		43.00
47 Southern Company Services, Inc. (SWE M)	1,287	0.00	0.00	53,316.00	53,316.00		41.43
48 Southern Illinois Power Cooperative (Southern Illin Pwr	80	0.00	0.00	3,475.00	3,475.00		43.44
49 Southern Indiana Gas & Electric Company (Southern IN	14,165	0.00	0.00	523,190.00	523,190.00		36.94
50 Tenaska Power Services Co. (Tenaska Power Serv E)	2,065	0.00	0.00	91,298.00	91,298.00		44.21
51 Tennessee Valley Authority (TVAPT M)	1,250	0.00	0.00	42,750.00	42,750.00		34.20
52 The Energy Authority (The Energy Auth E)	2,671	0.00	0.00	100,587.00	100,587.00		37.66
53 TransAlta Energy Marketing (US) Inc. (TransAlta Energ	4,000	0.00	0.00	176,200.00	176,200.00		44.05
54 Wabash Valley Power (Wabash Valley PowerE)	112	0.00	0.00	3,135.00	3,135.00		27.99
55 Westar Energy, Inc. (Westar Energy E)	7,208	0.00	0.00	337,917.00	337,917.00		46.88
56 Williams Power Company, Inc. (Williams Power E)	14,400	0.00	0.00	325,600.00	325,600.00		22.61
57 Move to off system	-65,000	0.00	0.00	(2,310,750.00)	(2,310,750.00)		35.55
58 PSI generation for CGE's Native Load	0	0.00	0.00	0.00	0.00	0.00	#DIV/0!
59 PSI generation for CGE's Accrual trades	42,385	0.00	0.00	966,632.97	966,632.97	311.65	22.81
60 PSI additional generation for CGE's Trading Sales		0.00	0.00		0.00	0.00	#DIV/0!
61 Adjustment to Tie	(314,345)	0.00	0.00	0.00	0.00	0.00	-
Section Totals	590,151	$0.00	$0.00	$31,083,497.26	$31,083,497.26	311.65	
Off-System Energies transferred to On-System Report							
62 American Electric Power Service Corporation (Americar	13,600	$0.00	$0.00	$611,600.00	$611,600.00		44.97
63 Cargill Power Markets, LLC (Cargill Pow Mar E)	5,200	0.00	0.00	230,300.00	230,300.00		44.29
64 Constellation Power Source, Inc. (Constellation Powr E)	6,000	0.00	0.00	304,000.00	304,000.00		50.67
65 DTE Energy Trading, Inc. (DTEET M)	11,600	0.00	0.00	448,960.00	448,960.00		38.70
66 Dominion Energy Marketing, Inc. (Dominion Enrgy Mar	800	0.00	0.00	43,800.00	43,800.00		54.75
67 East Kentucky Power Cooperative, Inc. (EKPCPM M)	800	0.00	0.00	28,800.00	28,800.00		36.00
68 Edison Mission Marketing & Trading Inc. (Edison Missio	3,200	0.00	0.00	165,600.00	165,600.00		51.75
69 EnergyUSA-TPC Corp. (EnergyUSA TPC E)	1,600	0.00	0.00	84,000.00	84,000.00		52.50
70 Entergy-Koch Trading, LP (EntergyKochTrading E)	3,200	0.00	0.00	124,400.00	124,400.00		38.88
71 Mirant Americas Energy Marketing, L.P. (MAEM M)	800	0.00	0.00	44,000.00	44,000.00		55.00
72 Occidental Power Services, Inc. (Occidental Pwr Svc E)	1,600	0.00	0.00	72,400.00	72,400.00		45.25
73 PSEG Energy Resources & Trade LLC (PSET M)	600	0.00	0.00	15,950.00	15,950.00		26.58
74 Rainbow Energy Marketing Corporation (REMC M)	1,600	0.00	0.00	88,000.00	88,000.00		55.00
75 Tenaska Power Services Co. (Tenaska Power Serv E)	800	0.00	0.00	40,600.00	40,600.00		50.75
76 TransAlta Energy Marketing (US) Inc. (TransAlta Energ	1,200	0.00	0.00	43,700.00	43,700.00		36.42
77 WPS Energy Services, Inc. (WPS Energy Service E)	800	0.00	0.00	40,200.00	40,200.00		50.25
78 Wabash Valley Power (Wabash Valley PowerE)	2,800	0.00	0.00	123,600.00	123,600.00		44.14
Section Totals	56,200	$0.00	$0.00	$2,509,910.00	$2,509,910.00	0.00	
Accrual Trade non-Native load Energies and Bookouts							
79 Lebanon, OH - City of (LEBANON OH E)	0	$15,810.00	$0.00	$0.00	$15,810.00		
Section Totals	0	$15,810.00	$0.00	$0.00	$15,810.00	0.00	
Grand Totals	646,351	$15,810.00	$0.00	$33,593,407.26	$33,609,217.26	311.65	
	1,025,696				35,919,967.26	35.02	

02817

CONFIDENTIAL PROPRIETARY
TRADE SECRET

Of the purchas... power above the following is the breal	MWHS	DEMAND	OPTIONS	ENERGY	TOTAL
Purchases for Load excluding Intercompany Transfer					
Forwards On System					
CCT	0	0.00	0.00	-	0.00
Total Forward Purchases On System	0	0.00	0.00	0.00	0.00
Forwards Off System					
CCT	0	0.00	0.00	-	0.00
Total Forward Purchases Off System	0	0.00	0.00	0.00	0.00
Forward Book Outs					
Dynegy Power Mktg	0	0.00	0.00	-	0.00
Edison Mission	0	0.00	0.00	-	0.00
Total Forward Book Out Purchases	0	0.00	0.00	0.00	0.00
Total Forward Purchases	0	0.00	0.00	0.00	0.00
Hourly					
OVEC	109,554	0.00	0.00	2,875,792.70	2,875,792.70
American Electric Power Co		0.00	0.00		0.00
Northern Indiana Public Service Co		0.00	0.00		0.00
Adj to tie to Prelim Pace	14,867	0.00	0.00	191,933.23	191,933.23
Total Hourly Purchases	124,421	0.00	0.00	3,067,725.93	3,067,725.93
Hourly Transfer from Off System					
American Electric Power Co	0	0.00	0.00	0.00	0.00
Southern Indiana Gas & Electric	0	0.00	0.00	0.00	0.00
Total Hourly Transfer Purchases	0	0.00	0.00	0.00	0.00
Total Hourly Purchases	124,421	0.00	0.00	3,067,725.93	3,067,725.93
Transfer from PSI					
Psi generation	0	0.00	0.00	-	0.00
	0	0.00	0.00	-	0.00
Total Purchases for Load	124,421	$0.00	$0.00	$3,067,725.93	$3,067,725.93

646,351	2,662,826	O&D
	(2,009,042)	generation
	(7,433)	loop
	646,351	
	0	

02818

CONFIDENTIAL PROPRIETARY
TRADE SECRET

Ohio Energy Group First Set Data Requests
CG&E Case No. 03-93-EL-ATA
Date Received: February 25, 2004
Response Due: March 8, 2004

OEG-DR-01-015

REQUEST:

15. For each month January 2005 through December 2005, please provide the Company's budget/projection of RTC revenues assuming CG&E's Electric Reliability and Rate Stabilization Plan is approved.

RESPONSE:

Following are the Company's budgeted RTC revenues (in thousands) by month for 2005:

Jan	11,339
Feb	10,456
Mar	10,140
Apr	9,196
May	9,260
Jun	10,856
Jul	12,319
Aug	12,502
Sep	11,652
Oct	9,569
Nov	9,445
Dec	10,659
2005	127,393

CONFIDENTIAL PROPRIETARY
TRADE SECRET

WITNESS RESPONSIBLE: John P. Steffen

Ohio Energy Group First Set Data Requests
CG&E Case No. 03-93-EL-ATA
Date Received: February 25, 2004
Response Due: March 8, 2004

OEG-DR-01-016

REQUEST:

16. For each year 2005 through 2010, please provide the Company's most recent budget/projection of RTC revenues, both under the Commission's authority granted in Case No. 99-1658-EL-ETP, et. al., and under the Company's proposed Electric Reliability and Rate Stabilization Plan, including the effects of the proposed two year extension for the residential customers.

RESPONSE:

The most recent budget/projection of implicit and explicit RTC revenues under the Commission's authority granted in Case No. 99-1658-EL-ETP is shown in the table below:

2005	$127 million
2006	$128 million
2007	$130 million
2008	$132 million
2009	$85 million
2010	$90 million

The Company has not yet calculated the magnitude of the RTC revenues under the proposed Electric Reliability and Rate Stabilization Plan.

CONFIDENTIAL PROPRIETARY
TRADE SECRET

WITNESS RESPONSIBLE: John P. Steffen

Ohio Energy Group First Set Data Requests
CG&E Case No. 03-93-EL-ATA
Date Received: February 25, 2004
Response Due: March 8, 2004

OEG-DR-01-017
CONFIDENTIAL PROPRIETARY TRADE SECRET

REQUEST:

17. Please provide a copy of all studies prepared by or on behalf of CG&E that describe and/or quantify how much RTC revenue CG&E will collect through 2010 under the Stipulation approved in Case No. 99-1658-EL-ETP.

RESPONSE:

CONFIDENTIAL PROPRIETARY TRADE SECRET

See the attachment, taken from Exhibit No. LJP-R-2, Page 3 of 5 from Case No. 99-1658-EL-ETP.

Also, see responses to questions OEG-DR-01-14 and OEG-DR-01-16.

WITNESS RESPONSIBLE: John P. Steffen

THE CINCINNATI GAS & ELECTRIC COMPANY
RTC REVENUE

	Residential	Secondary Distribution Small	Secondary Distribution Large	Primary Distribution	Transmission	Lighting	Total
Regulatory Transition Charge (¢ per kWh)							
During Market Development Period [2]	0.6114	0.8163	0.5685	0.3732	0.2378	0.1785	
After Market Development Period [3]	0.6114	0.9499	0.6719	0.4562	0.3043	0.2290	
Projected Sales (kWh) [1]							
2001	6,634,849,000	555,301,959	6,799,863,309	2,674,548,924	3,476,293,590	103,746,445	
2002	6,733,518,000	565,969,825	6,930,494,991	2,725,929,490	3,543,076,415	105,739,511	
2003	6,856,218,000	578,523,956	7,084,224,643	2,786,395,040	3,621,667,613	108,084,985	
2004	6,988,431,000	593,519,298	7,267,847,753	2,858,618,403	3,715,541,241	110,886,548	
2005	7,158,155,000	625,604,132	7,660,737,567	3,013,151,366	3,916,398,270	116,880,921	
2006	7,293,953,000	650,913,220	7,970,656,057	3,135,049,723	4,074,837,876	121,609,390	
2007	7,400,349,000	668,930,422	8,191,282,884	3,221,827,533	4,187,628,911	124,975,524	
2008	7,583,380,000	688,577,083	8,431,862,999	3,316,453,448	4,310,620,665	128,646,088	
2009	-	704,818,307	8,630,742,360	3,394,677,459	4,412,293,745	131,680,417	
2010	-	718,934,819	8,803,603,906	3,462,668,040	4,500,665,740	134,317,790	
Projected Revenues							
2001	$ 40,565,467	$ 4,532,930	$ 38,657,223	$ 9,981,417	$ 8,266,626	$ 185,187	$ 102,188,850
2002	$ 41,168,729	$ 4,620,012	$ 39,399,864	$ 10,173,169	$ 8,425,436	$ 188,745	$ 103,975,954
2003	$ 41,918,917	$ 4,722,491	$ 40,273,817	$ 10,398,826	$ 8,612,326	$ 192,932	$ 106,119,309
2004	$ 42,727,267	$ 4,844,898	$ 41,317,714	$ 10,668,364	$ 8,835,557	$ 197,932	$ 108,591,733
2005	$ 43,764,960	$ 5,106,807	$ 43,551,293	$ 11,245,081	$ 9,313,195	$ 208,632	$ 113,189,968
2006	$ 44,595,229	$ 6,183,025	$ 53,554,838	$ 14,302,097	$ 12,399,732	$ 278,486	$ 131,313,405
2007	$ 45,245,734	$ 6,354,170	$ 55,037,230	$ 14,697,977	$ 12,742,955	$ 286,194	$ 134,364,259
2008	$ 46,364,785	$ 6,540,794	$ 56,653,687	$ 15,129,661	$ 13,117,219	$ 294,600	$ 138,100,745
2009	$ -	$ 6,695,069	$ 57,989,958	$ 15,486,519	$ 13,426,810	$ 301,548	$ 93,899,704
2010	$ -	$ 6,829,162	$ 59,151,415	$ 15,796,692	$ 13,695,526	$ 307,588	$ 95,780,382
	$ 346,351,087	$56,429,357	$ 485,587,039	$ 127,879,801	$ 108,835,180	$ 2,441,844	$1,127,524,309

[1] Source: Exhibit No. LJP-R-1, page 1 of 2 (Workpaper of Stephen J. Baron entitled "Analysis of Proposed Settlement, RTC Revenue Recovery")
[2] Source: Stipulation and Recommendation filed May 8, 2000 and unbundled rate tariff, as summarized in AK Steel Exhibit No. 12
[3] Source: Stipulation and Recommendation filed May 8, 2000

CONFIDENTIAL PROPRIETARY
TRADE SECRET

02822

Exhibit No. LJP-R-2
Page 3 of 5

Ohio Energy Group First Set Data Requests
CG&E Case No. 03-93-EL-ATA
Date Received: February 25, 2004
Response Due: March 8, 2004

OEG-DR-01-045

REQUEST:

45. Please provide a functionalized income statement for calendar year 2004, separating electric from gas, and further separating electric into generation, transmission, and distribution.

RESPONSE:

Please see the attached for income statements for CG&E's electric and gas segments and for the combined company. Statements separating electric into generation, transmission, and distribution functions are not available.

Confidential Material attached

WITNESS RESPONSIBLE: John P. Steffen

OEG-DR-.-045

CONFIDENTIAL PROPRIETARY
TRADE SECRET

02824

Income Statement (standard)

2004	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Operating Revenues													
Base Retail Revenues - Electric	118,802	107,007	103,770	98,616	98,966	110,493	128,502	133,718	120,595	99,848	100,612	111,844	1,332,773
Transfer Revenues - Electric	0	0	0	0	0	0	0	0	0	0	0	0	0
Unbilled - Electric	338	-6,425	-1,184	-4,219	4,525	8,067	6,277	212	-12,136	-974	4,421	1,686	588
FCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
Rate Relief - Electric	0	0	0	0	0	0	0	0	0	0	0	0	0
Wholesale Transfer Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales for Resale	15,232	13,346	13,356	11,925	13,458	15,989	17,775	17,309	14,988	12,846	13,217	14,743	174,182
Off System Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue - Electric	4,893	4,830	4,771	4,675	4,823	5,664	5,924	6,338	5,592	4,924	4,973	4,864	62,270
Electric Transfer Cost	0	0	0	0	0	0	0	0	0	0	0	0	0
Retail Revenue Refund	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Electric Revenue	139,266	118,757	120,712	110,996	121,771	140,212	158,478	157,577	129,039	116,644	123,224	133,137	1,569,813
Base Revenues - Gas	30,128	29,028	23,897	17,362	11,850	9,339	8,752	8,537	8,817	10,688	16,050	24,361	198,809
Unbilled - Gas	-7,482	-21,914	-2,680	-14,783	-2,876	-2,233	250	1,080	2,603	9,607	22,954	8,829	-6,644
Fuel Clause Revenue	63,775	49,281	43,072	20,001	11,251	7,331	7,509	7,550	8,623	15,523	33,020	49,556	316,493
Rate Relief - Gas	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue - Gas	17	17	17	17	17	17	17	17	17	17	17	17	200
Total Gas Revenue	86,438	56,412	64,306	22,597	20,241	14,453	16,528	17,184	20,060	35,835	72,040	82,763	508,857
Other Revenue - Non-Reg	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Revenues	225,704	175,170	185,019	133,593	142,012	154,665	175,006	174,761	149,098	152,479	195,264	215,900	2,078,671
O&M Expenses													
Gas Cost	56,867	32,359	41,598	8,965	9,295	5,923	7,673	8,155	10,114	22,411	50,805	55,749	309,914
Fuel Expense	33,065	25,697	25,761	21,586	23,444	25,315	29,443	28,475	21,636	21,431	21,836	25,277	302,965
Deferred Fuel Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Power Expense	1,880	3,116	3,668	2,834	4,389	6,341	8,549	7,888	7,212	5,659	5,152	6,306	62,993
Total Fuel, Def. Fuel, PP Exp.	34,946	28,813	29,429	24,420	27,833	31,656	37,992	36,363	28,848	27,090	26,988	31,582	365,958
Other Variable Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
Other O&M Expense													
Operations Expense	32,121	29,295	29,661	30,322	31,108	30,849	32,768	31,967	30,493	30,858	30,204	27,830	367,474
Maintenance Expense	9,370	9,753	10,689	11,618	12,233	11,608	9,136	8,555	8,695	9,797	9,553	9,551	120,556
Other Expense	1,097	471	2,040	1,787	1,822	2,793	4,017	3,981	3,035	2,605	2,775	3,646	30,068
Total Other O&M Expense	42,587	39,520	42,390	43,726	45,163	45,249	45,921	44,502	42,223	43,260	42,532	41,027	518,099
Total Operating and Maintenance	134,400	100,692	113,417	77,111	82,291	82,828	91,586	89,020	81,185	92,760	120,325	128,358	1,193,971
Other Expenses													
Amort Cust Chc Reg Asset (RTC)	3,312	3,312	3,312	3,312	3,312	3,312	3,312	3,312	3,312	3,312	3,312	3,312	39,742

CONFIDENTIAL PROPRIETARY

Income Statement (standard)

2004	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Amort Other Reg Assets	107	107	107	107	107	107	107	107	107	107	107	107	1,280
Depreciation & Amortization	12,680	13,130	13,142	13,158	13,201	13,472	13,514	13,528	13,544	13,561	13,603	13,623	160,158
Property Tax Expense	7,357	7,357	7,357	7,357	7,357	7,357	7,357	7,357	7,357	7,357	7,357	7,357	88,279
Payroll Tax Expense	910	908	919	918	917	903	886	882	906	930	920	912	10,912
Revenue Tax Expense	12,528	10,562	10,201	7,224	6,644	7,055	8,350	8,462	7,974	7,479	9,495	11,467	107,441
Other Tax Expense	145	135	127	116	117	126	135	149	151	130	118	125	1,574
Total Operating Expenses	171,437	136,202	148,581	109,303	113,946	115,159	125,247	122,817	114,534	125,636	156,236	165,260	1,603,356
Pretax Operating Income	54,267	38,968	36,438	24,291	28,066	39,506	49,760	51,944	34,564	26,843	40,028	50,640	475,314
Income Taxes													
Current Income Tax	12,056	2,894	7,233	-641	4,205	8,907	13,155	14,348	7,894	6,799	15,690	15,588	108,127
Deferred Income Tax	5,749	9,131	3,770	6,784	3,274	2,912	2,627	2,272	1,851	143	-3,573	693	35,633
Total Income Taxes	17,805	12,024	11,003	6,143	7,479	11,819	15,782	16,620	9,746	6,943	12,116	16,281	143,760
Operating Income	36,462	26,944	25,434	18,148	20,588	27,687	33,978	35,324	24,818	19,900	27,912	34,359	331,554
Other Income and Deductions													
Interest Income	722	713	713	713	713	713	713	713	713	713	713	713	8,562
AFUDC Equity	49	62	79	100	119	123	133	163	197	231	262	200	1,718
Other Income	185	185	185	185	185	185	185	185	185	185	185	185	2,219
Less: Other Deductions	2,085	474	487	475	477	488	471	471	527	477	468	532	7,433
Less: Current Tax Below the Line	-493	151	145	150	149	145	153	152	130	151	154	129	1,117
Less: Deferred Tax Below the Line	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Other Income / (Deductions)	-636	335	344	373	391	387	407	437	438	501	536	437	3,949
Interest Expense													
Short Term Interest Expense	25	204	369	345	388	500	481	417	223	34	49	83	3,119
Long Term Interest Expense	7,688	7,096	7,096	7,096	7,096	7,096	7,096	7,096	7,846	7,846	7,846	7,846	88,748
Other Interest Expense	154	154	153	152	151	150	149	148	147	147	146	145	1,796
Amortization - Debt Items	467	463	459	459	459	459	459	459	472	472	472	472	5,572
Minority Interest	0	0	0	0	0	0	0	0	0	0	0	0	0
Less: AFUDC Debt	27	35	44	56	68	73	87	110	130	150	158	114	1,052
Less: Capitalized Interest	236	272	315	322	197	98	111	126	138	150	161	113	2,239
Total Interest Expense	8,071	7,611	7,717	7,674	7,830	8,035	7,988	7,886	8,421	8,198	8,195	8,319	95,943
Net income from utility operations	27,754	19,668	18,061	10,848	13,149	20,040	26,396	27,876	16,835	12,204	20,254	26,476	239,560
Nonregulated Activities													
Equity in Earn of Uncon Sub-Aftertax (calc)	0	0	0	0	0	0	0	0	0	0	0	0	0
Equity in Earn of Uncon Sub-Aftertax (inpu	0	0	0	0	0	0	0	0	0	0	0	0	0

02825

CONFIDENTIAL PROPRIETARY

OEG-DR-[illegible]-045

Income Statement (standard) [redacted]

2004	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Net Income	27,754	19,668	18,061	10,848	13,149	20,040	26,396	27,876	16,835	12,204	20,254	26,476	239,560
Preferred Dividends	70	70	70	70	70	70	70	70	70	70	70	70	846
Income Available for Common	27,684	19,597	17,991	10,777	13,078	19,969	26,326	27,805	16,764	12,133	20,183	26,406	238,714
Ending Common Shares	0	0	0	0	0	0	0	0	0	0	0	0	0
Average Common Shares	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings Per Share	0.16	0.11	0.10	0.06	0.07	0.11	0.15	0.15	0.09	0.07	0.11	0.15	1.33
Diluted Ending Common Shares	0	0	0	0	0	0	0	0	0	0	0	0	0
Diluted Average Common Shares	0	0	0	0	0	0	0	0	0	0	0	0	0
Diluted Earnings Per Share	0.15	0.11	0.10	0.06	0.07	0.11	0.14	0.15	0.09	0.07	0.11	0.14	1.31

02826

02827

Ohio Energy Group First Set Data Requests
CG&E Case No. 03-93-EL-ATA
Date Received: February 25, 2004
Response Due: March 8, 2004

OEG-DR-01-046

REQUEST:

46. Please provide a functionalized balance sheet for calendar year 2004, separating electric from gas, and further separating electric into generation, transmission, and distribution.

RESPONSE:

See the attached for balance sheets for CG&E's electric and gas segments and for the combined company. Statements separating electric into generation, transmission, and distribution functions are not available.

Confidential

WITNESS RESPONSIBLE: John P. Steffen

CONFIDENTIAL PROPRIETARY
TRADE SECRET

OEG-DR-[illegible]-046

Balance Sheet [redacted]

2004	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Assets													
Utility Plant													
Utility Plant in Service	6,385,192	6,391,595	6,397,702	6,421,057	6,567,708	6,585,044	6,591,271	6,598,979	6,607,662	6,616,475	6,627,059	6,713,309	6,713,309
Accumulated Depreciation	2,436,126	2,446,713	2,457,200	2,467,620	2,478,087	2,488,886	2,499,712	2,510,454	2,521,266	2,532,142	2,543,123	2,554,050	2,554,050
CWIP	173,807	186,932	200,894	195,995	65,580	64,571	77,953	88,516	98,117	107,360	112,428	53,344	53,344
Net Utility Plant	4,122,873	4,131,813	4,141,395	4,149,432	4,155,201	4,160,729	4,169,511	4,177,041	4,184,514	4,191,693	4,196,364	4,212,603	4,212,603
Current Assets													
Cash	0	0	0	0	0	0	0	0	0	0	0	0	0
Short Term Investments	0	0	0	0	0	0	0	0	0	0	0	0	0
Accounts Receivable	258,037	254,262	279,518	275,894	309,162	300,281	290,390	275,960	281,261	297,372	292,769	271,187	271,187
Accrued Unbilled Revenue	-7,144	-35,484	-39,347	-58,349	-56,699	-50,866	-44,339	-43,046	-52,579	-43,946	-16,571	-6,056	-6,056
Fuel Inventory	26,059	26,059	26,059	26,059	26,059	26,059	26,059	26,059	26,059	26,059	26,059	26,059	26,059
Materials and Supplies	50,352	50,352	50,352	50,352	50,352	50,352	50,352	50,352	50,352	50,352	50,352	50,352	50,352
Natural Gas in Storage	39,529	39,529	39,529	39,529	39,529	39,529	39,529	39,529	39,529	39,529	39,529	39,529	39,529
Deferred Fuel Balance	21,071	37,991	39,469	50,506	52,462	53,869	53,705	53,101	51,610	44,721	26,938	20,743	20,743
Other Current Assets	96,908	96,908	96,908	96,908	96,908	96,908	96,908	96,908	96,908	96,908	96,908	96,908	96,908
Total Current Assets	484,811	469,617	492,487	480,898	517,772	516,131	512,604	498,862	493,139	510,995	515,984	498,722	498,722
Other Assets													
Regulatory Assets													
Amounts Due From Customer - Inc Tax	44,327	44,327	44,327	44,327	44,327	44,327	44,327	44,327	44,327	44,327	44,327	44,327	44,327
Costs of Reacquired Debt	13,885	13,759	13,633	13,508	13,382	13,257	13,131	13,005	12,880	12,754	12,629	12,503	12,503
Post In Service Cost & Def Oper Cost	2,074	2,255	2,436	2,617	2,798	2,979	3,160	3,341	3,522	3,703	3,884	4,064	4,064
Deferred DSM Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
Deferred Merger Cost	605	590	576	562	548	534	520	505	491	477	463	449	449
Coal Contracts Buyout	0	0	0	0	0	0	0	0	0	0	0	0	0
Custumer Choice Reg Asset (RTC)	514,592	512,686	510,963	508,967	507,096	506,044	506,203	505,960	504,480	502,499	500,529	498,604	498,604
Other Regulatory Assets	4,041	3,926	3,810	3,695	3,580	3,464	3,349	3,234	3,118	3,003	2,887	2,772	2,772
Total Regulatory Assets	579,524	577,544	575,746	573,676	571,730	570,604	570,689	570,372	568,818	566,763	564,719	562,719	562,719
Other Deferred Debits	362,517	362,264	362,012	361,760	361,507	361,254	361,000	360,746	361,980	361,716	361,450	361,192	361,192
Investment in Unconsolidated Subs	0	0	0	0	0	0	0	0	0	0	0	0	0
LT Debt Receivable - Assigned Inter-Co	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Other Assets	942,041	939,808	937,758	935,436	933,238	931,858	931,689	931,118	930,799	928,479	926,169	923,911	923,911
Total Assets	5,549,724	5,541,237	5,571,641	5,565,766	5,606,210	5,608,719	5,613,804	5,607,021	5,608,451	5,631,167	5,638,517	5,635,236	5,635,236
Liabilities and Capitalization													
Minority Interest	0	0	0	0	0	0	0	0	0	0	0	0	0
Capitalization													
Common at Par	762,136	762,136	762,136	762,136	762,136	762,136	762,136	762,136	762,136	762,136	762,136	762,136	762,136

TRADE SECRET

OEG-DR-[illegible]-046

02829

Balance Sheet [redacted]

2004	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Paid in Capital	586,527	586,527	586,527	586,527	586,527	586,527	586,527	586,527	586,527	586,527	586,527	586,527	586,527
Contributed Capital	0	0	0	0	0	0	0	0	0	0	0	0	0
Retained Earnings	529,719	549,387	567,448	522,527	535,675	555,715	526,138	554,014	570,849	526,876	547,130	573,606	573,606
Retained Earnings Subsidiaries	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Common	1,878,382	1,898,050	1,916,111	1,871,190	1,884,339	1,904,378	1,874,802	1,902,676	1,919,513	1,875,539	1,895,793	1,922,269	1,922,269
Preferred Stock	20,485	20,485	20,485	20,485	20,485	20,485	20,485	20,485	20,485	20,485	20,485	20,485	20,485
Long Term Debt	1,626,329	1,516,433	1,516,532	1,516,632	1,516,731	1,516,831	1,516,931	1,517,030	1,667,130	1,667,230	1,667,329	1,667,429	1,667,429
LT Debt Payable - Assigned Inter-Co	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Capitalization	3,525,196	3,434,968	3,453,129	3,408,307	3,421,555	3,441,694	3,412,218	3,440,193	3,607,127	3,563,254	3,583,607	3,610,163	3,610,163
Current Liabilities													
Short Term Debt	20,022	143,507	151,349	124,439	186,068	214,193	170,635	163,315	15,477	11,401	28,198	38,084	38,084
Accounts Payable	348,330	348,330	348,330	348,330	348,330	348,330	348,330	348,330	348,330	348,330	348,330	348,330	348,330
Provision For Refund	0	0	0	0	0	0	0	0	0	0	0	0	0
Deferred Gas Revenue (PGA)	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Taxes Payable	110,067	106,468	113,137	120,494	127,850	94,905	97,784	103,350	110,706	118,063	125,074	132,430	132,430
Income Taxes Payable	12,092	15,665	20,264	17,447	22,330	17,361	31,197	46,226	27,244	34,724	51,097	6,461	6,461
Accrued Interest	24,984	28,541	20,957	20,987	27,653	17,954	22,027	28,541	21,707	22,487	29,903	20,954	20,954
Dividends Payable	55,353	0	0	55,557	0	0	55,761	0	0	55,965	0	0	0
Other Current Liabilities	102,259	101,393	100,527	99,661	98,795	97,930	97,064	96,198	95,332	94,466	93,600	92,734	92,734
Total Current Liabilities	673,107	745,905	754,565	786,916	811,026	790,673	822,799	785,961	618,797	685,436	676,201	638,994	638,994
Deferred Credits													
Unamortized ITC	75,697	75,228	74,759	74,290	73,821	73,351	72,882	72,413	71,944	71,475	71,005	70,536	70,536
Other Deferred Credits	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Regulatory Liabilities	126,932	126,932	126,932	126,932	126,932	126,932	126,932	126,932	126,932	126,932	126,932	126,932	126,932
Other Regulatory Liab, Ratemaking	0	0	0	0	0	0	0	0	0	0	0	0	0
Customer Advances	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Deferred Credits	202,629	202,160	201,691	201,221	200,752	200,283	199,814	199,345	198,876	198,406	197,937	197,468	197,468
Woodsdale Lease	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Liabilities	219,662	219,476	219,289	219,101	218,912	218,722	218,531	218,340	218,147	217,954	217,760	224,417	224,417
Accumulated DITs Plant	691,220	696,043	700,895	705,440	709,648	713,366	716,862	720,321	724,158	728,341	732,819	737,106	737,106
Accumulated DITs Non Plant	237,909	242,686	242,074	244,781	244,317	243,979	243,580	242,862	241,346	237,775	230,393	227,068	227,068
Total Liabilities and Capitalization	5,549,724	5,541,237	5,571,641	5,565,766	5,606,210	5,608,719	5,613,804	5,607,021	5,608,451	5,631,167	5,638,517	5,635,236	5,635,236

02830

Ohio Marketers Group's Second Set Interrogatories
CG&E Case No. 03-93-EL-ATA
Date Received: May 20, 2004
Response Due: May 24, 2004

OMG-INT-02-007

REQUEST:

7. Please provide the number of kWh sold to customers other than retail customers ("Off System") by CG&E in 2003.

RESPONSE:

CONFIDENTIAL AND PROPRIETARY TRADE SECRET INFORMATION

Objection. This interrogatory requests information that is not relevant or reasonably calculated to lead to admissible evidence because the off system sales includes the results of CG&E's non-regulated wholesale trading operations, not limited to sales from CG&E's generating facilities. Subject to this objection, the amount is 158,487,904 MWh.

WITNESS RESPONSIBLE: John P. Steffen

ư2831

Ohio Marketers Group's Second Set Interrogatories
CG&E Case No. 03-93-EL-ATA
Date Received: May 20, 2004
Response Due: May 24, 2004

OMG-INT-02-008

REQUEST:

8. Please provide the gross revenue collected by CG&E Off System power sales in 2003?

RESPONSE:

CONFIDENTIAL AND PROPRIETARY TRADE SECRET INFORMATION

Objection. This interrogatory requests information that is not relevant or reasonably calculated to lead to admissible evidence because the off system sales includes the results of CG&E's non-regulated wholesale trading operations, not limited to sales from CG&E's generating facilities. Subject to this objection, the amount is $5,302,641,167.

WITNESS RESPONSIBLE: John P. Steffen

02832

03-93-EL-ATA
03-2079-EL-AAM
03-2081-EL-AAM
03-2080-EL-ATA

Transcript Vol IV
pgs 11-16

2004 JUN 10 PM 2:50

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CONFIDENTIAL

(The following is confidential testimony.)

EXAMINER KINGERY: Anybody who is not a signatory of the confidentiality agreement then will need to leave the room for this part of the hearing.

MR. RANDAZZO: We have signed, Dan Neilsen has signed, but if I need to sign personally, I can.

MR. COLBERT: I'm just trying to remember who has signed. I know Dave has signed.

EXAMINER KINGERY: Are you with CG&E?

MR. COLBERT: Yeah, they're all with the Company.

EXAMINER KINGERY: Okay.

MS. HOTZ: OCC would like this document marked Exhibit 12, please.

EXAMINER KINGERY: It will be so marked.

(EXHIBIT MARKED FOR IDENTIFICATION.)

\- - -

CROSS-EXAMINATION

By Ms. Hotz:

Q. Good morning, Mr. Steffen.

A. Good morning.

Q. Do you recognize this document marked OCC Exhibit No. 12?

A. I do.

Q. And you're responsible for this response?

A. I am.

Q. How did you calculate this discovery response?

A. Basically, we looked at some estimated costs going forward, the costs being those costs that would be included in the POLR calculation, and calculated a revenue requirement thereon, looked at those relative to the cap that was then proposed, which was 10 percent, calculated the carryovers, and the final column of the chart shows the cap amounts, or the recovery amounts for each of the years in question and, again, all on a projected basis.

Q. So when you say you calculated the carryovers, what do you mean by that?

A. Our proposal that existed at the time of this data response included the provision that to the extent we exceeded the cap, the 10 percent cap, in any year, we would defer the excess for recovery in subsequent years. That provision does not exist in the stipulation that was filed in this case.

Q. With regard to the dollar amounts in the second column under "current year revenue requirement," are those numbers still the same even though the cap has changed in the stipulation?

A. As I indicated, all of these are estimates. When you look at the POLR and look at the kinds of things that are included in the POLR, particularly with regard to environmental expenditures, the assumptions that you make about what compliance plan will be in place, what the legal requirements will be, et cetera, will cause the numbers to change.

So I guess I would just kind of qualify my answer by saying if you made the same set of assumptions, you would get to the same set of numbers.

Q. But the stipulation does not change these numbers; is that right?

MR. FINNIGAN: I'm going to object. You mean the total cost or the total that could be recovered under the revised caps?

MS. HOTZ: I mean the numbers in the second column under Current Year Revenue Requirement.

Q. Do those change pursuant to the stip?

A. The stip changed the caps for each year, but if you made a similar set of assumptions about the items that go into the calculation of the revenue requirement, if you made those same assumptions, these numbers would not change pursuant to the stipulation.

Q. Is there any reason why you would make other assumptions since the stipulation?

A. To me, the most significant item of variance is the environmental expenditures. I'm certainly not an environmental expert. I rely on the people in our environmental area to make those kinds of estimates.

My understanding is that's very

(The following is confidential testimony.)

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EXAMINER KINGERY: Are you with CG&E?

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- - -

CONFIDENTIAL

CROSS-EXAMINATION

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A. To me, the most significant item of variance is the environmental expenditures. I'm certainly not an environmental expert. I rely on the people in our environmental area to make those kinds of estimates.

My understanding is that's very

fluid now, so I can't say that I would make a different set of assumptions today, but I wouldn't represent that there may not be an equally valid different set of assumptions today. This is very fluid.

Same with the Homeland Security, it's not a major component of that, but again, as the thinking evolves on what needs to be done to protect the electric system, costs could increase over what was anticipated at this point in time.

So I really don't know anything today that I would tell you would or would not change these numbers. I think it's just important to note that at any point in time the assumptions you make will drive the result.

Q. But that's completely independent of the stipulation.

A. Yes. The stipulation deals only with the caps, not the items included in the calculation of the POLR. It just deals with the amount of the cap that applies to the amount of the calculated POLR.

MS. HOLZ: I'm finished with this

section dealing with this confidential document.

EXAMINER KINGERY: Okay, let's go off the record for a minute.

(Discussion held off the record.)

EXAMINER KINGERY: Do you have any redirect?

MR. FINNIGAN: May we have just a moment?

EXAMINER KINGERY: Yes.

MR. FINNIGAN: No redirect on this point.

EXAMINER KINGERY: All right, thank you. Okay, this will be the end of the confidential portion of the transcript.

(This concludes the confidential transcript.)

02840

OCC EXHIBIT _______

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

Consolidated Duke Energy Ohio, Inc., Rate Stabilization Plan Remand and Rider Adjustment Cases.	)	Case Nos. 03-93-EL-ATA
	)	03-2079-EL-AAM
	)	03-2081-EL-AAM
	)	03-2080-EL-ATA
	)	05-724-EL-UNC
	)	05-725-EL-UNC
	)	06-1068-EL-UNC
	)	06-1069-EL-UNC
	)	06-1085-EL-UNC

CONFIDENTIAL

SUPPLEMENTAL TESTIMONY

OF

MICHAEL P. HAUGH

ON BEHALF OF
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL
10 West Broad Street, Suite 1800
Columbus, OH 43215

April 17, 2007

SQ1. ARE YOU THE SAME MICHAEL P. HAUGH WHOSE TESTIMONY WAS PREVIOUSLY FILED IN THIS CASE?

SA1. Yes.

SQ2. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY?

SA2. The purpose of my testimony is to address the Stipulation filed on April 9, 2007 in this case ("2007 Stipulation"). I recommend that the Public Utilities Commission of Ohio ("PUCO" or "Commission") not approve the 2007 Stipulation because it does not meet the criteria regarding the reasonableness of a stipulation.

SQ3. WHAT IS YOUR UNDERSTANDING OF THE CRITERIA THE COMMISSION USES TO EVALUATE A STIPULATION?

SA3. In the past, the Commission has applied a three-part test in determining if a stipulation should be adopted. The three-part test asks three questions. First, is the stipulation a product of serious bargaining among capable, knowledgeable parties? Second, taken as a package does the stipulation benefit ratepayers and the public interest? Third, does the stipulation violate any important regulatory principle or practice? My testimony will address the second and third parts of the test.

SQ4. DOES THE 2007 STIPULATION BENEFIT RATEPAYERS AND THE PUBLIC INTEREST?

SA4. No. There are a number of areas where the 2007 Stipulation does not benefit ratepayers and is not in the public interest. The 2007 Stipulation is ambiguous and meaningless in parts, and harmful to ratepayers in other parts.

SQ5. WHERE DO YOU FIND THE 2007 STIPULATION TO BE AMBIGUOUS OR MEANINGLESS?

SA5. First, paragraph three of the 2007 Stipulation states that interested parties shall meet to determine how to handle DE-Ohio's management of its portfolio of coal assets, emission allowances, and purchased power arrangements post-2008. This paragraph does not accomplish anything except an agreement to meet and "use their best efforts to agree and make a recommendation."[1] The procurement of coal, emission allowances, and power raises important issues that has already been raised and reviewed by the Auditor. Regarding the determination of how these issues should be handled post-2008, a docket already exists for the determination of such issues (i.e. Case 06-986-EL-UNC dealing with extension of the rate stabilization plan post-2008). That docket already exists to address the issues that are the subject of paragraph three, and that docket (or related dockets) better serves the purpose of exploring the post-2008 issues than the provision in the 2007 Stipulation.

[1] 2007 Stipulation at page 5.

Second, there seems to be a fundamental disagreement over the meaning of paragraph eight between DE-Ohio's witness and the PUCO Staff ("Staff"). During the hearing in this case held on April 10, 2007, DE-Ohio Witness Charles R. Whitlock seemed to think that the only limitation on the use of former Duke Energy North American Assets ("DENA Assets") was the time frame for purchasing the capacity. Specifically, he stated that DE-Ohio would be able to purchase capacity off the DENA Assets by using a series of short term (seven days or less) purchases.[2] Counsel for the Staff then questioned Mr. Whitlock as to whether his interpretation of that provision was necessarily the interpretation of all parties or just his own.[3] Judging from the nature of the cross examination, the intent of this paragraph from Staff's perspective appears to be that the use of DENA Assets would be further limited (I will discuss my perspective on this topic later in this testimony). However, DE-Ohio seems to believe that paragraph eight allows DE-Ohio to purchase capacity from these units whenever it wants, assuming it is only for a seven day period, this point was confirmed by DE-Ohio in response to OCC Interrogatory R-RR-DE-5a (MPH Attachment - S1). . The signing of the 2007 Stipulation by both the Staff and DE-Ohio appears to mask a disagreement over the use of the DENA Assets that should not exist at such an early point following the execution of a stipulation.

[2] Transcript Vol I at page 143 (Whitlock).

[3] Transcript Vol I at page 156-157.

SQ6. WHERE DO YOU FIND THE 2007 STIPULATION TO BE HARMFUL TO RATEPAYERS?

SA6. Paragraph five does not take into account the recommendation, contained in my testimony filed on March 9, 2007,[4] to remove the return on the Construction Work in Progress ("CWIP") from the AAC. In addition, paragraph eight does not provide adequate protection for ratepayers against DE-Ohio overcharging for the DENA Assets. Paragraph eight allows DE-Ohio to determine the "market price" by either using the midpoint of broker quotes, the average price of third party transactions, or another method determined by DE-Ohio and Staff.[5] DE-Ohio Witness Whitlock admitted during the hearing in this case that during situations when DE-Ohio would purchase capacity from the DENA Assets, there are usually very few broker quotes.[6] This is one reason that I opposed the use of the DENA Assets, in my testimony filed on March 9, 2007.[7] When questioned how he would determine third party transaction prices, DE-Ohio Witness Whitlock used an example of calling possible counterparties and whatever price was offered, that would be the price of the transaction.[8] The proposed methodology to formulate a "market price" for the DENA Assets does not provide proper protections (i.e. the determination of costs from an objective standpoint) for customers paying the SRT.

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[4] Prepared Testimony of Michael P. Haugh at pages 19-20.

[5] 2007 Stipulation at page 7.

[6] Transcript Vol I at page 145 (Whitlock).

[7] Prepared Testimony of Michael P. Haugh at pages 13-14.

[8] Transcript Vol I at page 150 (Whitlock).

SQ7. WHAT COULD BE DONE TO LIMIT YOUR CONCERNS REGARDING THE VALUATION OF THE DENA ASSETS?

SA7. First and foremost, there needs to be strict rules as to when the DENA Assets can be used. As I stated in my testimony in this case filed on March 9, 2007, the use of these assets should be limited to emergency situations where there are no other options.[9]

Secondly, the guidelines for formulating a price for the DENA Assets need to be more stringent. If there are limited broker quotes and transactions in the capacity market, there will be too much uncertainty regarding the true market price. If the Company is to use the formula set forth in Paragraph eight of the 2007 Stipulation, for emergency situations, there needs to be a minimum number of broker quotes and transactions to determine the price of the DENA capacity. I suggest the Company provide a minimum of three bids and offers from three separate brokers. I would also suggest a minimum of three third-party transactions be required. Finally, when formulating a price there needs to be a cap on the amount DE-Ohio is charging to the customers who are paying the SRT. I suggest that the price be capped at the median price DE-Ohio has paid for capacity during the time frame in which the emergency occurs. I believe this cap should be implemented if any capacity from the DENA Assets is used because the 2007 Stipulation allows for the price to be determined by an "alternative method"

[9] Prepared Testimony of Michael P. Haugh at pages 15.

determined by Staff and DE-Ohio.[10] As we enter the summer months and the chances of a capacity emergency increase, a concrete method of valuation of the DENA assets needs to be in place.

SQ8. DOES THE STIPULATION VIOLATE ANY IMPORTANT REGULATORY PRINCIPLE OR PRACTICE?

SA8. Yes. Paragraph five addresses calculations for a return on CWIP that is included in proposed AAC charges, and violates traditional regulatory practices that can and should be used to guide the development of realistic costs in order to ensure reasonable standard service offer rates. The Commission has stated in this regard that it "will continue to consider the reasonableness of expenditures" in the AAC category and that "[i]t is not in the public interest to cede this review."[11] A reasonable methodology should be used to reflect actual costs for charges such as the AAC. However, paragraph five of the 2007 Stipulation would permit a return on CWIP that would not traditionally have been allowed in ratemaking proceedings. I recommended removing a return on CWIP in my earlier testimony, and I supported that recommendation with calculations that would reduce the AAC to 5.6 percent of "little g." My proposed adjustment provides a reasonable means to develop costs for the standard service offer prices.

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[10] 2007 Stipulation at page 7.

[11] Entry on Rehearing at page 10.(November 23, 2004).

SQ9. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THE 2007 STIPULATION?

SA9. I recommend that the Commission not approve the 2007 Stipulation and that the Commission decide this matter based on the record in this case. Specifically the Commission should restrict the ability of DE-Ohio to recover capacity costs associated with the DENA Assets through the SRT, except under emergency situations, and disallow DE-Ohio's return on CWIP in the AAC.

SQ10. DOES THIS CONCLUDE YOUR SUPPLEMENTAL TESTIMONY AT THIS TIME?

SA10. Yes, it does. However, I reserve the right to incorporate new information that may subsequently become available.

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CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing (confidential) Supplemental Testimony of Michael P. Haugh on behalf of the Office of the Ohio Consumers' Counsel has been served electronically upon the persons listed below, this 17th day of April, 2007.

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Ohio Consumers' Counsel
Rider Remand
First Set of Interrogatories
Duke Energy Ohio, Inc.
Case No. 03-93-EL-ATA, *et al.*
Date Received: April 11, 2007
Response Due: April 13, 2007

R-RI-DE-5

REQUEST:

Regarding paragraph 8 of the April Stipulation:

a. What, if anything, would prevent DE-Ohio from overlapping periods of "7 days or less," or prevent DE-Ohio from tacking one or more periods of "7 days or less" onto a period of "7 days or less," in order to use former Duke Energy North America assets for purposes of the SRT?

b. What, if anything, would prevent DE-Ohio from using the former Duke Energy North America plants in a manner other than described by DE-Ohio Witness Whitlock in his testimony on April 10, 2007 (i.e. when he described an unusual event two or three months ago when Vermillion capacity was used to meet capacity requirements)?

c. How many times and for what periods of time, since January 1, 2006, has DE-Ohio used DENA assets to meet its capacity reserve margin, either for the 15 percent reserve margin or the 4.1 percent required for MISO Module E?

d. Have any former Duke Energy North America plants other than the Vermillion plant been used in the past to provide capacity in connection with service to DE-Ohio's standard service offer customers (whether compensated for or not)?

e. If the response to the previous sub-part of this interrogatory is negative, why has no other plant been used for the stated purpose?

f. How would plants other than the Vermillion plant provide the firm capacity needed so that they could be used for DE-Ohio's capacity requirements, and what are the costs other than for the capacity itself that would be needed for these plants (i.e. other than Vermillion) to be useful to meet DE-Ohio's capacity requirements?

g. If the "midpoint of broker quotes received" is used for pricing under sub-part "a." of paragraph 8, how would standard service offer customers "benefit" (i.e. as stated in Company Remand Rider Exhibit 2, page 9, line 16) as compared with DE-Ohio making a purchase according to the lowest broker quote? .

h. How would the "broker quotes" be documented under sub-part "a." of paragraph 8 and how would they be audited (if at all)?

i. What source(s) would DE-Ohio use to determine the "[a]verage price of 3rd party purchases transacted" if the "midpoint of broker quotes received" is used for pricing under sub-part "b." of paragraph 8?

j. What was the average price, by month, that DE-Ohio paid for capacity purchased in 2006 and 2007?

k. What was the highest price, by month, that DE-Ohio paid for capacity purchased in 2006 and during what time frame was that capacity purchased?

l. In the response to the previous sub-part of this interrogatory, why did DE-Ohio purchase the capacity?

m. On how many occasions and for what periods of time since January 1, 2006 did DE-Ohio purchase capacity on a short term basis (seven days or less)?

n. In response to the previous sub-part of this interrogatory, when where those purchases made (i.e. provide dates) and why did DE-Ohio purchase capacity on a short term basis (seven days or less)?

RESPONSE:

a. Assuming the referenced assets are available, nothing prevents this scenario, however unlikely.

b. Qualified as a Designated Network Resource, whether the capacity is already sold, and a lack of assurance of cost recovery from the Commission.

c. For the delivery period October 25, 2006 at no charge to consumers.

d. No.

e. No economic circumstances have arisen.

f. One way would be to buy firm transmission from a plant that is located outside of the MISO footprint to the MISO border, from PJM for example. This would be an incremental cost to the cost of capacity. Another way might be to settle the capacity transactions financially, meaning that if a PJM asset were to be utilized, DE-Ohio could merely buy capacity from another supplier in MISO to satisfy the Module E Requirement, while simultaneously selling capacity to PJM for the asset outside of the MISO footprint. The capacity revenues from PJM and the capacity expenses from MISO would then be net against each other in the SRT. This option does not have a transmission cost component but will be either a credit or charge for the difference to the SRT.

g. If the "midpoint of the broker quotes received" methodology were to be employed, it would require broker quotes that contain both buy bids and sell offers. Consequently, the lowest midpoint between buy bids and sell offers, which is below the broker quote for a sell offer could be utilized.

h. DE-Ohio will maintain the broker quotes as part of its business records and such records shall be subject to the SRT audit.

i. DE-Ohio would use the weighted average of all reported capacity purchases and sales transacted contemporaneously within the same period.

j. DE-Ohio has not performed such calculations.

k. During 2006, August was the highest priced month for which capacity was purchased at $168 per MwDay or $7.00 per MwHour. Capacity purchases were made for the August 1-2 and August 3 time frame.

l. The purchases were made a day or a few days in advance of the delivery period to comply with MISO Module E requirements due to the unexpected loss of generation or an increase in expected load obligations.

m. Since January 1, 2006 DE-Ohio made 11 short-term purchases (seven days or less) for the following periods:
For 2006: March 4-6; March 9-10; March 28; April 29-30 (for two separate blocks); July 30-31; July 17-21; August 1-2; August 3; August 25-26; October 16-20. No short-term purchases in 2007.

n. Generally, the short-term purchases noted in "m" above, were made a day or a few days in advance of the delivery period to comply with MISO Module E requirements due to the unexpected loss of generation or an increase in expected load obligations.

WITNESS RESPONSIBLE: N/A

- - -

CONFIDENTIAL EXCERPT
FROM THE DUKE ENERGY RIDER REMAND HEARING ON
TUESDAY, APRIL 10, 2007

- - -

(Confidential Portion.)
MR. REILLY: Thank you, your Honor.
Q. (By Mr. Reilly) Mr. Schwartz, as I mentioned before, I put two documents in front of you, one is identified as Commission-Ordered Exhibit No. 1 and Commission --
EXAMINER KINGERY: Commission-Ordered Remand Exhibit 1.
Q. Commission-Ordered Remand Exhibit No. 1 and the other is Commission-Ordered Remand Exhibit 1A; do you see those documents?
A. Yes.
Q. Okay. I will represent to you that the 1A is the public version of 1, all right?
A. Yes.
Q. I would like to talk from now on about, unless I tell you differently, Commission-Ordered Remand Exhibit No. 1 which is the full confidential

version of the document titled Report of the Financial and Management/Performance Audit of the Fuel and Purchased Power Rider of Duke Energy. Do you see that document?
A. Yes.
Q. Okay. Have you seen that document before?
A. Yes.
Q. Could you tell me how?
A. This is a report prepared by my company, Energy Ventures Analysis, and Larkin & Associates and submitted in response to our assignment with the Public Utilities Commission.
Q. Your assignment with the Public Utilities Commission, could you expand on that a little bit? Tell me how that came about.
A. Yes. We are retained under contract with the Public Utilities Commission to perform an audit, both a management/performance audit and a financial audit of the fuel and purchased power rider for Duke Energy - Ohio for the year ended June 30th, 2006.
Q. Now, we're going to talk a little bit about Energy Ventures Analysis, Inc., but I wanted to differentiate, I see two associations mentioned on

the cover page of this document, Energy Ventures Analysis, Inc., and Larkin & Associates. Do you see those two?
A. Yes.
Q. Could you tell me who those -- you said Energy Ventures was your company?
A. Yes. I'm with Energy Ventures Analysis.
Q. And who is Larkin & Associates?
A. Larkin & Associates is the financial auditor who was retained under a subcontract with Energy Ventures Analysis under the contract with the Public Utilities Commission.
Q. Retained by whom?
A. Retained by Energy Ventures Analysis. We subcontracted with Larkin & Associates to perform the financial audit.
Q. And tell me what Energy Ventures Analysis is.
A. We are a consulting firm. We do work for the energy industry including especially the electric power industry as well as coal, natural gas, and transportation industries. We do work on fuel procurement advice and planning. We do auditing work both for regulated companies as well as for public

31

utility commissions.
Q. **How long have you been doing this work?**
A. Since 1981.
Q. **Energy Ventures Analysis has been doing this work since 1981, correct?**
A. Yes, sir.
Q. **I'd like to talk about you for a little bit. How long have you been doing this work?**
A. I was one of the founders of Energy Ventures Analysis in 1981.
Q. **Were you doing this work before founding --**
A. Yes.
Q. **-- Ventures?**
A. Yes. I was with another consulting firm beginning in 1977.
EXAMINER KINGERY: Excuse me one minute. I think you have to actually turn the thing upside down and right back here there's a little on/off switch. Thank you.
Q. **So you've been doing the work that you've just described since 1977.**
A. Yes, sir.
Q. **All right, Mr. Schwartz, would you**

32

describe for us your career history in the energy area?
A. Yes. I began work at a firm called Energy and Environmental Analysis in 1977. The principal nature of the work were managing projects for the Department of Energy and the Environmental Protection Agency with regards to analyses of the energy business, U.S. energy policy, and the impact of environmental regulations on energy production and especially electricity production.
I left that firm in 1981 and was one of the founders of Energy Ventures Analysis, and since that time most of our work has been for the private sector energy industry especially with regards to energy markets analysis, fuel procurement consulting, both directly for both regulated and unregulated companies, as well as management auditing for the companies and for independent regulatory agencies such as public utility commissions.
Q. **You've done auditing for public utility commissions before.**
A. Yes, sir.
Q. **For how long have you been doing that?**
A. I think our first assignment for a public

33

utility commission was in 1983 for the Public Utility Commission of Ohio, it was a management/performance audit of Cincinnati Gas & Electric Company.
Q. **Would you describe for us your educational background?**
A. Yes. I have a Bachelor of Science in geological engineering.
Q. **And have you done any teaching?**
A. No. I don't do teaching at a school or university. I frequently do lectures in front of trade associations.
Q. **And you said -- drawing your attention to Commission-Ordered Remand Exhibit No. 1, this was prepared under your direction and by you?**
A. Yes, sir.
Q. **In response to your contract that was ordered by the Commission.**
A. Yes.
MR. REILLY: Your Honor, with that we would offer Mr. Schwartz for cross-examination.
EXAMINER KINGERY: Thank you.
MR. COLBERT: No questions, your Honor.
EXAMINER KINGERY: Thank you.
Ms. Hotz.

34

CROSS-EXAMINATION

By Ms. Hotz:
Q. **Good morning, Mr. Schwartz.**
A. Good morning.
Q. **If I ask you a question that's supposed to go to the financial auditor, would you please let me know, because it's hard for me to distinguish in this exactly which questions go to who?**
A. Yes, ma'am.
Q. **Okay. Thank you.**
EXAMINER KINGERY: Before you get started, I'm not sure whether that one is on or not.
EXAMINER FARKAS: It's on the back.
(Discussion held off the record.)
Q. **How did you come to be employed by the Public Utilities Commission of Ohio to be an auditor in this case?**
A. We submitted a proposal in response to a request for proposals, it was I believe a two-year contract, we did the audit last year and then this is the second year of the contract.
Q. **Do you have a copy of the RFP with you?**
A. No, I don't.
MS. HOTZ: May I approach the witness,

please?
EXAMINER KINGERY: You may.
MS. HOTZ: This is a copy of the RFP that was issued by the Commission. I don't want to mark this as an exhibit or anything.
MR. COLBERT: Your Honor, just for the record I believe this is already an exhibit in the record from prior questioning of this witness several years ago in this case.
EXAMINER KINGERY: Thank you.
Q. (By Ms. Hotz) The RFP starts behind the entry, it's about five pages back. EVA was employed by this Commission previously as an auditor in electric fuel component cases before such cases ceased; isn't that correct?
A. Yes.
Q. And you just said that you participated in one of those?
A. More than one.
Q. About how many do you think you participated in?
A. Approximately ten.
Q. How do you see your responsibility in this case compared to your responsibility in an EFC

case?
MR. REILLY: Objection; relevance.
MS. HOTZ: Well, he addresses differences in his audit report between the EFC --
EXAMINER KINGERY: I'll allow the question.
A. I can't speak from a legal standpoint, but from a professional standpoint we viewed our responsibility as being similar to those that were at issue in the electric fuel component cases.
Q. And how did you -- what led you to believe that they were similar?
A. The terms of the request for proposal and their contract that resulted from it.
Q. In fact, under the RFP issued by the Commission to solicit an auditor for this case the RFP made reference to Appendix D and Appendix E to chapters 4901:1-11 OAC; is that not correct?
A. That's correct.
Q. So did you take a different approach in auditing this case than you would have in auditing an EFC case?
A. Not that I can think of, no.
Q. Did you see your goals differently in

this case from auditing an EFC case?
A. No.
Q. Did you conduct the audit differently than you would have in an EFC case?
A. Yes in one regard, in that some of the issues in the audit related to separation of time periods with regards to whether or not some of the activities took place during a period covered by the rider FPP; that would not have been an issue in one of the prior EFC cases. There would not have been a time separation of what was within a regulated period and what was not.
Q. Do you feel that it hampered your audit due to this time separation?
A. I'm not sure what you mean by "hampered." It certainly proposed issues that we had to analyze and address, but I think we have covered them.
Q. On page 1-3 of your report you stated that one difference between the EFC and the FPP audit was that the EFC included all costs and the FPP was intended to simply capture the difference between current and baseline costs, correct?
A. Yes.
Q. Did you find that relying on the EFC

procedures and yet focusing on the difference between the current and the baseline costs rather than all costs created difficulty?
A. There were certainly issues that had to be resolved with regards to understanding what was the baseline cost and what subjects were to be addressed in both time periods in order to establish the difference. When there was a continuing EFC each year, those type of issues didn't arise.
Q. What kind of issues are you talking about? How did you resolve those issues?
A. A couple that come to mind are with regard to, one was with regards to environmental costs and what were the costs of reagent utilization, or what was the cost in the baseline period, when there were new reagents and new issues that were created now that there was no baseline comparison to.
Another was with regards to the allocation of coal contracting resale activities and whether they occurred during the period covered by the FPP or not and how those costs needed to be allocated among those periods.
Those are at least two issues I can think of, there may have been others.

Q. **What are reagents?**
A. Reagents are chemicals used in the process of removing pollutants from emissions from the power plants.
Q. **A second difference that you identified between the EFC and the FPP was that in the FPP you considered only the native load, correct?**
A. I wouldn't say that we considered only the native load. I would say that the FPP only applies to native load customers.
Q. **Okay. But so why did you identify that as a difference between an EFC and an FPP?**
A. Because that affects some of the company's management and accounting practices with regards to what fuel and purchased power costs are incurred for native load customers as opposed to nonnative load customers.
MS. HOTZ: Will you please read that answer again?
(Answer read.)
Q. **How does it affect the company's management and contracts?**
A. One obvious area that comes to mind is the management of emission allowances where the

company has two separate accounting groups and management decisions for the purchase and sale of emission allowances needed to cover emissions from the coal fired power plants, one for the native load customers and one for the nonnative load customers, and therefore the cost basis and the costs of emissions are different and are managed separately.
Q. **Why are the costs of emission allowances different for the native load than for the nonnative load?**
A. Because there may be differences in the allocation of the baseline allowances allocated between customer groups and then the actual emissions associated with generation in order to serve those groups, as well as the timing of purchases of allowances in order to cover any differences.
Q. **So in the FPP how was your focus different regarding the nonnative load compared to your focus in the EFC?**
A. I don't understand the question.
Q. **Well, you said that -- previously you said that you did consider the nonnative load in the FPP but you did it differently than you did in the EFC, and I just wonder how is that different? How is**

it different?
A. My recollections of the EFC process, and those are somewhat older so I'm not sure I can recall precisely, but my recollections of the EFC process are that there was one unified cost of fuel and purchased power including emission allowances that was allocated among all groups rather than separated into the native load portion and the nonnative load portion, of which the FPP only applied to the native load customers, and as a result it has created from both a management audit and maybe even more importantly a financial audit the necessity to account for the costs incurred for those customers separately.
MR. SMALL: We have lost some of the audio portion of this.
EXAMINER KINGERY: Let's go off the record for just a minute.
(Discussion held off the record.)
EXAMINER KINGERY: Let's go back on the record.
MS. HOTZ: Will you please read the answer again?
(Answer read.)

Q. **During the FPP audit, once costs were allocated between native load and nonnative load customers did you follow any of the nonnative load costs after that allocation occurred?**
A. I think my answer is no, but you probably need to follow up on that question with regards to the financial auditor, and also that because the focus of the management/performance audit was with regards to first the management decisions and the incurring of the overall costs, that portion was being audited. After an allocation, no, we would not have continued to track the costs after allocation to nonnative load customers.
Q. **In the same area of your audit report you identify the fact that during the transition period CG&E operated as a deregulated entity and that CG&E's reentry into regulatory oversight with respect to the FPP created a host of issues. What were those issues as they relate to the allocation of utility assets?**
A. I'll answer to the best of my recollection. I'd like to just point out, though, that you are reading from the area of our audit report that is a review of the audit from the prior year, and I think these issues were thoroughly

examined in last year's audit report and to the best of my knowledge many, if not all of them, were resolved between the Commission and the company with procedures that were then applied in this year's audit report.

But to answer your question, with regards to those issues that -- I'm merely bringing that out in order to point out it's more than a year old so I'll try to remember what those issues were.

One area of issues, for instance, was on the question of the allocation of the zero cost emission allowances granted by EPA to the ownership base of the power plants owned and/or operated by the company and how the calculation of the allocation of the ownership of those assets was to be done among the different customer classes.

A second issue that was created was a methodology to allocate the value of existing contract commitments principally for coal, but potentially for any fuel supply, between native load and nonnative load customers.

Those are two that I can recall at the present time.

Q. Do you believe that your audit was

compromised by these Commissions -- by these issues?

MR. COLBERT: Objection, your Honor. Now she's asking whether this year's audit was compromised by issues that were resolved last year in a stipulation that I believe OCC signed.

EXAMINER KINGERY: If the stipulation resolved those issues, then he can say that the answer would be no. So I'll allow the question.

A. I'm really not sure I understand what you mean by "compromised."

Q. Were you unable to look at things that you wanted to look at this year or last year because of these issues?

A. Yes, we were able to look at what we wanted to look at.

Q. Okay.

EXAMINER KINGERY: You say you were able to.

THE WITNESS: Yes, ma'am.

EXAMINER KINGERY: Okay.

Q. You also note in the audit report there was a host of FPP audit issues that related to CG&E's approach to fuel procurement, correct?

A. Yes.

Q. Do you think that the issues relating to CG&E's approach to fuel procurement were adequately dealt with or do you believe that they compromised your ability to do a fair audit?

A. I do not believe they compromised our ability to do a fair audit. I believe that many of the issues were dealt with a year ago in the audit in the stipulation. There's some issues that we have still addressed this year with regards to the management approach to fuel procurement. As I'm sure you can tell from the audit report, it doesn't mean that we agree with everything the company has done in their approach, but we have been able to audit it, understand it, and comment on it to the best of our ability.

Q. If you believe that CG&E's approach to fuel procurement were adequately dealt with so as to not compromise your ability to conduct a fair audit, why did you identify the issue of CG&E's approach to fuel procurement in your introduction?

A. Again, first of all, you are reading from the portion of the report that refers to last year's audit, not this year's audit. But the fact that CG&E's approach to fuel procurement or what this year

is called Duke Energy - Ohio's approach to fuel procurement is something that would be a subject of continuing interest to ourselves or any management auditor that would be addressed in every year's management audit.

So I don't think we viewed it as all issues having been settled a year ago and that there were any areas that we were not able to continue to go into, and we did review them this year.

Q. On page 1-3 of your report you state that CG&E believed that it had the license to evaluate and select which approach to use in computing the FPP, correct?

A. Yes. Again, this was a year ago, not this year.

Q. Did CG&E offer you any logic or rationale behind its selection and evaluation for the approaches it used in computing the FPP?

A. Yes.

Q. Did you find that you had trouble understanding the logic or rationale behind CG&E's selection and evaluation of the approaches it used for the FPP?

A. I don't understand what you mean by

47

"trouble."

Q. Did you have difficulty understanding why they used the approach that they used after they explained to you why they did?

MR. COLBERT: Objection, your Honor. We're questioning about last year's audit and it might be helpful if we could move on to this year's.

MS. HOTZ: There's no separation in this audit report between this year's audit and last year's audit. There's absolutely no separation.

MR. COLBERT: There's an entire section that's titled Initial Audit of the Fuel and Purchased Power Factor which is last year's audit, contains last year's stipulation, et cetera, that's what she's asking about. The next section is titled Follow-Up Audit of Fuel and it starts with what happened this year.

MS. HOTZ: This is dated October 17th, 2006, this was given to us.

EXAMINER KINGERY: We're going to allow the questions. He did put the information in this year's audit.

THE WITNESS: I'm sorry, is there a question pending?

48

MS. HOTZ: Yes.

Would you please read it again?

(Question read.)

A. Perhaps it was not clear from the titles here in this report with regard to the sections, but Mr. Colbert is correct that the section we are reading from titled Initial Audit of the Fuel and Purchased Power Factor is, in fact, a reference to a summary of last year's audit which is what we called the initial audit which was the period ending June 30th, 2005.

And we felt it necessary, in order to introduce this year's audit, to summarize the issues that had been dealt with in last year's audit and the stipulation that then established the procedures that we were then auditing against for the current audit and, in fact, so far everything we are discussing was the summary of what we addressed in the 2005 audit, not in the 2006 audit.

So I may not recall all of the events of what we dealt with a year ago as I really had not prepared to address that today, but I will answer your questions to the best of my ability.

Q. Okay.

49

A. To the best of my recollection, no, we understood the logic and the basis for the decisions that the company made with regards to calculation of the FPP and the various alternatives which they considered; some of which we agreed with, some of which we disagreed with. We made recommendations a year ago; I don't have all of those recommendations in front of me today. The result of those recommendations was the stipulation that is summarized in this section of this year's audit report.

Q. On page 1-3 you note that CG&E's elections had very significant ratepayer impacts. How did you know that CG&E's elections had very significant ratepayer impacts?

A. Because at the time in last year's audit we had either prepared ourselves or asked the company to prepare calculations of the impact on the FPP with regards to different alternative definitions of what issues should be included and what should not be included in the FPP and how the costs should be allocated. So at the time we did an analysis of and had an understanding of what the ratepayer impacts were.

50

Q. Do you recall the dollar amount?

A. No.

Q. Did those elections negatively affect the ratepayers or did they positively affect the ratepayers?

A. There were a range of potential selections and outcomes, and I would say that the ultimate decisions that were agreed to in the stipulations were somewhere in the middle of the range of potential outcomes of what would be favorable or unfavorable to the ratepayer.

Q. Additionally you stated that CG&E continuously modified its approach to many of these items. Did CG&E provide rationale or justification for modifying its approaches?

A. Yes.

Q. Were you able to determine that CG&E's modifications were justified?

A. There was a logic and a rationale; that doesn't mean we agreed with all of those. We disagreed with some of those and they were resolved in the process of the stipulation.

Q. Do you recall what approaches you did not agree with?

51

A. Some of them, yes, I do.
Q. What were they?
A. One was with regards to the treatment of nitrogen oxide emission allowances and ammonia reagent costs for removal of nitrogen oxides. Another was with regards to the allocation of margins on resale of fuel contracts. A third was the baseline allocation of the zero cost sulfur dioxide emission allowances at the power plants among customer classes. At a minimum those were three of the issues that I recall dealing with that had fairly significant impacts.
Q. Were you able to calculate the effect of these modifications on FPP customers?
A. Yes, we were.
Q. Do you recall the general dollar amount?
A. No.
Q. On footnote 3 you stated that during the fourth quarter a credit was not provided the FPP for the monetization of a 2005 coal hedge that had been previously flowed through the FPP, correct?
A. Yes.
Q. Did CG&E provide a reasonable justification for that change?

52

A. I don't recall. I think you need to address that question to the financial auditor.
Q. Okay. Thanks.
On page 1-6 you state that DE-Ohio has new senior management of the fuel procurement function and state that this person has limited experience in the fuel area. From your experience is it unusual for a new senior manager of the fuel procurement function to have limited experience in the fuel area?
A. It's difficult to generalize from my experience. I would say it's not unusual, no, but it's certainly, you know, less than 50 percent of the time if that's what you mean by "unusual." But it's not rare.
Q. Do you think that this could be a problem?
A. I think based on our review addressing the issues in this case, no, we did not consider it to be a problem.
Q. You stated on page 1-6 that the recorded delivered coal prices are higher than they would have been if large quantities of older below market contract purchases had not been resold. Can you

53

please explain how the sale of the older below-market contract purchases resulted in higher coal prices?
A. Yes. There were some existing coal contracts that were long-term contracts where the pricing -- where they had been signed at a time when coal prices were lower, and because the coal market price has increased, those contract prices were currently below market. That was the definition of what we meant by "below market contracts."
Had those coals under those contracts been delivered to the power plants and burned in those power plants, the cost of coal would have been less at those power plants than the cost of replacing those coals with market price purchases. So the delivered cost as reported by Duke Energy - Ohio in this case measured on the Federal Energy Regulatory Commission form 423 was higher because those lower priced contracts had been resolved in the marketplace and replaced by higher cost purchases at market prices.
To the extent that the value -- the proceeds of the resale of that coal were credited to the FPP in this process, that would mitigate either wholly or in part that increased cost.

54

Q. Who benefited from the sale of the older, below-market contract purchases?
A. It depended on the contract and the timing of the contract with regards to the stipulation, and the timing of the resale of the coal; that was an issue that was addressed in the stipulation last year.
To the extent the resale took place prior to the beginning of the FPP period, that is prior to January 1st, 2005, the company would have benefited from the resale of that coal based on the terms of the stipulation. If the resale took place after January 1st, 2005, the proceeds from the resale would be credited to the FPP and the FPP ratepayers would benefit.
Q. You state on page 1-6 under item 4 that DE-Ohio considers itself to be unregulated because native load customers are not obligated to purchase power from DE-Ohio; is that correct?
A. Yes.
Q. How did DE-Ohio's perception of itself as unregulated affect your ability to conduct this audit?
A. I wouldn't say it affected our ability to

conduct the audit in any meaningful way.
Q. Why did you bring it up in the audit report?
A. Because if affects DE-Ohio's management decisions with regards to fuel procurement.
Q. How does it affect their management decisions?
A. Because to the -- DE-Ohio did not consider any sales to native load customers to be firm for a duration beyond December 31st, 2008, and, therefore, was reluctant to or avoided entering into any fuel contracts that would extend past that date with fixed prices. As opposed to its behavior with regards to nonnative load customers where they had contracts extending beyond that date, they would -- DE-Ohio's practice was to attempt to match the term of the fuel contract, and when I use "fuel" I'm including things such as emission allowances, with the terms of the power sale commitment.
Q. On page 1-6 you stated that the regulated part of Duke --
EXAMINER KINGERY: Go off the record.
(Off the record.)
EXAMINER KINGERY: We are back on the

record.
Q. On page 1-6 you stated that the regulated part of Duke does not employ active management of its coal emission allowances and energy supply. Why do you think the regulated parts of Duke do not employ active management of its coal emission allowances and energy supply?
A. To the best of my understanding, and obviously I did not perform an audit of the regulated part of Duke so my comments are limited by my knowledge, the regulated entities of Duke have customers who will continue to purchase electricity for some indefinite period in the future and are not constrained by a particular time frame in which to match their sales and their generation and, therefore, their fuel supply for generation and as a result, to the best of my knowledge, employ a portfolio method of fuel procurement which means that some of their fuel purchases are hedged or purchased at firm prices for varying periods into the future, not necessarily matched against their best estimate load forecast at any given point in time.
MS. HOTZ: Could you read that answer back, please?

(Answer read.)
Q. You said something about these purchases for the regulated parts are hedged for firm prices over a period of time; is that correct? Did I understand that?
A. Yes.
Q. Okay. How is that different than active management?
A. The difference is that the active management is really doing two things. The objective of active management is to match to the best extent possible the commitment to sell power with the commitment to supply power either by generation or purchased power, and supply the inputs necessary to generate power, meaning especially the fuel supply and emission allowances associated with that generation, as precisely as possible, and continue to reevaluate that position on a daily basis and, based upon the reevaluation, either buying or selling additional commitments for fuel or purchased power or emission allowances so that there is a daily balancing of commitments to sell power with commitments to supply power. And the cost difference between the two is hedged.

In a portfolio management system there is not really a matching precisely of the costs to supply generation with the future demand for electricity from all ratepayer classes because that demand continues for an indefinite period and is not precisely known.
Rather, the fuel supply and emission allowance supply or purchased power supply is purchased on a series of contracts with varying lengths of commitments and varying terms and conditions and some portion is left unhedged at any given point in time.
And a second difference is that under that system the portfolio is not continually readjusted on a daily basis, which may be the active part of the active management system, to consistently true up the supply and demand for electricity.
Q. Because of the differences that you identified in the FPP and the EFC audits do you believe that EVA was able to conduct an audit that was adequate to determine whether DEO Ohio purchased fuel and purchased power for Ohio customers that did not hurt the Ohio customers?
A. I'm not sure what you mean by "hurt," but

with that qualification I believe we were able to conduct an audit adequately and fully with regards to the extent of our normal practices and procedures.

Q. On page 1-6 you state that DE-Ohio employs active management of its coal emission allowance and energy supply, correct?

A. Yes.

Q. Do you believe that EVA can adequately audit DE-Ohio's purchased fuel and purchased power practices as long as it actively manages its coal emission allowance and energy supply?

A. There are some difficulties created by the frequency and number of transactions entered into in an active management system and as a result our approach, which I believe follows standard audit procedures, was really to select examples of transactions in order to audit specific samples rather than every transaction because the number and nature of the transactions would have been too extensive.

With that qualification I believe we are able to adequately audit the transactions in accordance with standard auditing procedures.

Q. How were the samples selected that you relied upon?

A. They were done in a random basis and -- again, some of this will need to be directed to the financial auditor as well -- looking at both individual transactions and then monthly average calculations of costs associated both for the purchase and sale of fuel as well as the purchase and sale of emission allowances on a regular basis.

Q. When you are auditing a company that does not use active management, do you test samples also?

MR. COLBERT: Objection, your Honor. We haven't established that he has audited companies without active management.

Q. Have you ever audited a company without active -- that does not use active management?

A. Yes, ma'am.

Q. When you do so, do you have to sample transactions in order to audit?

A. Typically with regards to the coal transactions, they are large enough and less frequent enough that we are able to review all of the transactions and supporting documentation.

With regards to some of the other fuel procurement decisions, especially natural gas purchases or oil purchases, no, in those cases frequently we just look at individual samples.

Q. So what percentage of the actual transactions in those cases do you think you sample?

A. I'm not sure I can quote a percentage for you. I think it varies. But depending upon the circumstances it could be anywhere from 10 percent to half of the transactions, as well as a complete summary on a monthly basis of the financial impacts of the transactions.

Q. In the case of active management, when you would do an audit of that kind, what percentage of the transactions do you think you would sample in such an audit?

A. I am not sure I can give you a precise answer, but it would probably be in the range of 10 to 20 percent of the transactions, probably no more than that.

Q. You define "management" on page -- "active management" on page 1-6 as using transactable forward markets. What do you mean by "transactable forward markets"?

A. I mean a market in which a company can purchase or sell a product at current prices for future delivery in a transactable, meaning that it is a market where there's sufficient buyers and sellers where the availability of that product, in this case coal or power or allowances, is such that a party can participate either by buying or selling in that market and be able to purchase or sell the quantity that they need on a regular basis at a price that is defined in a market and not unduly influenced by the size of their transactions.

MS. HOTZ: Could you read that answer again, please?

(Answer read.)

Q. On page 1-7 you list the four conditions under which margins for fuel transactions are flowed through the FPP. Do you think those four conditions are reasonable?

A. These four conditions were established in conformance with the stipulated agreement that was entered into in last year's audit, and except for the language in the parenthesis in item B, which the company has later taken out of its procedures, we found those provisions to be in accordance with the previous stipulation.

Q. Do you have an opinion as to whether or

63

not those conditions are reasonable?
MR. COLBERT: Objection; asked and answered.
MS. HOTZ: He didn't answer the question.
EXAMINER KINGERY: I will allow the question.
A. Yes.
Q. Do you think that DE-Ohio might be unfairly able to retain margins for fuel transactions for its shareholders at the expense of customers who pay for the original fuel purchases?
MR. COLBERT: Objection; assumes facts not in evidence about who paid for what.
MS. HOTZ: Well, the resold coal directly addresses that very circumstance.
EXAMINER KINGERY: You can clarify the question.
Q. On page 1-7 you discuss how the calculation of the margin on the resale of contract coal -- what is the reason you included this discussion?
A. I included this discussion because the resale of coal was a significant issue both in last year's audit and in this year's audit in dollar

64

amounts and the treatment and allocation of those margins between the FPP and non-FPP accounts, we thought that that was a significant issue and something that was worthy of identifying and bringing to the attention of the Commission and intervenors.
Q. You give an example of the calculation of the margin, and you talk about -- in that example you identify the original cost of coal as $40 per ton, and then you talk about -- in that example you talk about how the FPP customers have to purchase it for $46 per ton. Does that mean that under that example the FPP customers would pay $6 more per ton than they would have if the coal had not been resold?
A. Yes, but it depends on the allocation of the $10 margin. If the $10 margin was allocated to the FPP customer as a cost of coal, then the FPP customer on a net basis would wind up paying $4 less. If the profit or the margin on the sale was not allocated to the FPP customer, then the FPP customer pays $6 more. Again, this is a hypothetical example used to illustrate how this works.
Q. So what was the reason that you had that example in there?
A. In order to clarify for the Commission

65

and readers of this report the impact of the margin on the resale of preexisting commitments and whether or not -- on the costs incurred in the FPP and the impact of whether or not that margin was credited to the FPP account or not.
Q. On page 1-7 you state that DE-Ohio did not pass through over 35 million in margins generated from the resale of coal covered by paragraph D of the stipulation. Do you mean that DE-Ohio did not pass through over 35 million in margins because of paragraph D of the stipulation?
A. I'm not sure I would quite agree with the word "because." Maybe I could substitute "in accordance with paragraph D of the stipulation"; that is correct.
Q. Okay. Do you believe that the resale of contract coal combined with DE-Ohio's method of calculating the margin on the resale of contract coal that goes to the FPP is a means whereby DE-Ohio may -- whereby DE-Ohio shareholders can benefit from the long-term contracts at the cost of the FPP customers?
A. To a certain extent, yes, with maybe some additional modifiers in your sentence. That is, to

66

the extent these contracts were preexisting contracts which were resold prior to January 1st, 2005, that would generally be correct. I think the company might take issue of the terminology "at the expense of the FPP customers," but it is true that the net effect of those decisions would be to shift money that otherwise would have been credited as a lower cost of coal purchased to the FPP customers had the coal been delivered and not resold.
Q. On page 1-8 you state that DE-Ohio flattens its coal position on a daily basis, correct?
A. Yes, ma'am.
Q. What does that mean?
A. That means, as I previously described, the goal of active management, meaning that on a daily basis DE-Ohio evaluates its need for coal over the remaining term of the RSP period based on its demand for electricity, its existing commitments to purchase coal, allowances, and purchased power, and the most economical way to supply its projected demand for electricity over that period to firm customers, and then either purchases or sells coal, allowances, and power in order to make the supply of electricity equal to the projected demand. That's

what is termed as flattening the position.

Q. If DE-Ohio decides that its coal position is long on a day and it must sell coal, how does it decide the price for the coal it is selling?

A. The price for the coal that it is selling on a daily basis is the market price for that coal at that point in time. The cost of the coal that it is selling is the cost of the existing commitments to purchase the coal.

MS. HOTZ: Would you read that again, please?

(Answer read.)

Q. Is that existing commitments to purchase the coal?

A. (Witness nods head.)

Q. When DE-Ohio sells coal in its active management, does it account for the original cost of the coal it sells that day?

A. Yes.

Q. How does DE-Ohio decide which coal or at which original cost it will sell that day?

A. The original cost is based upon the coal that is committed by generating station by coal type. The daily transactions are typically short-term in

nature, what has been, you know, sometimes used as an acronym the NYMEX coal contracts, and to the best of my understanding the NYMEX transactions are based upon the average cost of the existing transactions.

The long-term contracts, when resold, those are not usually done on a daily active management basis for purposes of flattening a position, but rather are resold based upon an analysis of the value of those contracts in the marketplace compared to the cost of replacing that coal. And they tend to be longer term transactions done on a less frequent basis where the coal to be resold is identified with a particular coal contract.

Q. So do they ever use -- are you saying that they never use long-term contracts to flatten their position?

A. Not on a daily basis, no. But the long-term contracts are part of their fuel supply in the evaluation of whether or not they have a flat position. And in looking at future demand for power, yes, long-term contracts are part of what they use to flatten their long-term position, but that would not be considered to be a daily active management.

Q. Were you able to audit the active

management by DE-Ohio to determine if DE-Ohio consistently followed the same methodology or used different methodologies from day to day in flattening its coal position?

A. Yes.

Q. So did you find that they consistently followed the same methodology?

A. Yes, we did.

Q. On page 1-8 you state that EVA told DE-Ohio that it should be prepared to provide an audit trail and demonstrate that its approach yields a lower FPP cost. When did EVA tell DE-Ohio that?

A. In the prior year audit report recommendations.

Q. And what was DE-Ohio's response?

A. The best of my recollection in the prior year was that DE-Ohio had agreed with that and would be prepared to provide that type of documentation in this year's audit.

Q. Did DE-Ohio provide that type of documentation in this audit?

A. No, we did not feel that the documentation provided was adequate to address that issue in our initial audit, and we tried to work with

DE-Ohio over the course of the audit to obtain additional documentation in order to analyze that.

Q. So you were never able to really make a decision.

A. We don't believe that the documentation provided was such to demonstrate that the approach was a lower cost approach, no. That doesn't mean we have reached a conclusion that it is not a lower cost approach.

Q. How could Duke demonstrate that its approach yields a lower FPP cost?

A. By a look-back analysis comparison of the impact of a daily active management approach relative to not entering into a daily transaction and reevaluating its portfolio on a longer term periodic basis accounting for all of the costs of active management as well as the differences in cost of fuel, allowances, and purchased power.

Q. Besides the lack of an audit trail and the lack of documentation that active management is an economical way to manage its fuel emission allowances and purchased power supply, what other reasons is the approach problematical? And I developed that question from page 1-8, paragraph 8.

71

A. I don't have a specific list of reasons to give you. I think some of the issues we were thinking of in writing that statement were the extent of the costs necessary to manage the procurement in this fashion and whether they were really being included and taken into account in the total evaluation of the economics.

Q. Do you believe that the forecast of future coal prices should be a determinative factor in coal purchasing and sale decisions?

A. I believe it is a significant factor that should be evaluated and considered in the decision-making process.

Q. Why?

A. Because the fuel markets, like all markets, fluctuate in terms of pricing and availability of supply and demand, and I believe that the company by being a regular participant in the markets and analyzing the changes in supply and demand for the product can do a better job of entering into its contracting decisions at times more favorable to the company than times less favorable to the company.

Q. Did Duke indicate that they were

72

unwilling to take into consideration the forecasted future coal prices?

A. I'm not sure about the word "unwilling." But certainly Duke Energy's policy with regards to purchasing coal as well as allowances and purchased power was to make decisions to, as they call flatten the position, that is balance their supply and demand, at a regular -- on a regular basis, that is daily, independent of any consideration of expectations of changes in the market prices for any of those products.

Q. On page 1-8 you state that Duke's delay in resolving the allocation of zero cost emission allowances between native and nonnative loads led to Duke not managing the emission allowance position for 2006 per its own protocol. Do you believe that Duke's failure to manage emission allowances per its own protocol was unreasonable?

A. No, and I'd like to state that your predicate to your question is not accurate and it's not what was said in this report. We did not make the statement that Duke delayed in the allocation, but rather based on my knowledge of the events that happened the delay in the allocation was something

73

that was a process of negotiation between Duke and the Commission as well as any intervenors which were part of the stipulation. The way you phrased the question would have made it sound as though that delay was all of Duke's own volition, and I never said that, nor do I believe that.

Q. Okay. Under the stipulation Duke is permitted to buy DENA assets and recover the cost from native load customers under certain circumstances. Do you believe that the market is liquid enough at this time to assure that the cost it pays for DENA generation is at market or not?

A. I'm not certain. It's not an issue that I've evaluated. I also have not seen the stipulation with regards to that provision for a very long period of time. There are provisions in there with regards to a determination of the market price, and I haven't tried to conduct an analysis of the market to determine an answer to your question of whether or not it would provide sufficient liquidity that the method outlined in the stipulation will be adequate to measure the market price properly.

Q. Do you believe that Duke provides sufficient audit trails for a future auditor to be

74

assured that DENA generation was purchased at market or not?

A. I do not believe that the existing procedures and documentation would have been adequate to do that had DENA assets been purchased during the prior audit period. I'm not sure what the future documentation will be under the terms of the stipulation, how it will be prepared, so I really can't address what will be done in the future.

Q. What kinds of documentation do you think that Duke should be required to provide to ensure that any DENA generation purchase was at market?

MR. COLBERT: Objection, your Honor. This is now the third question where she's characterized it as the purchase of the DENA asset generation and, of course, DE-Ohio owns that generation and did not purchase from itself, and she's inaccurately describing the contents of the stipulation.

EXAMINER KINGERY: Could you rephrase the question, please?

Q. What kinds of documentation do you think that Duke should be required to provide to ensure that any DENA generation purchase pursuant to the

75

stipulation was at a market price?
MR. COLBERT: Objection; same objection, your Honor.
MS. HOTZ: I can't hear you. I can't hear what your objection is.
MR. COLBERT: Same objection.
MS. HOTZ: What was your objection?
MR. COLBERT: You're mischaracterizing it as a purchase. DE-Ohio owns all of the generation to which you are referring, and it can't purchase from itself. That also mischaracterizes the stipulation as it's been written and filed.
Q. (By Ms. Hotz) Under the stipulation there is a provision that states: The parties agree that DE-Ohio may recover short-term capacity purchases from its generating assets formerly owned by Duke Energy North America through the SRT. DE-Ohio and Staff shall agree on a pricing methodology prior to DE-Ohio's purchase of such capacity. Such purchases shall be acquired at a market price. And then it goes on to discuss particular ways that the market price would be determined.
What I'm asking you is what kinds of documentation do you think that Duke should be

76

required to provide to ensure that the DENA purchase or the DENA purchase recovery amount is at market price?
A. I haven't previously considered this so I'm not prepared to give you a comprehensive answer to your question, but typically the type of documentation we would expect to see would be a solicitation of offerings from other parties with a written summary of those -- that solicitation and including the terms of the solicitation -- the offers that were made, the availability of offers from other parties, the pricing, as well as a summary of available evidence of public market prices such as what might be represented in trade publications or broker quotations.
And then a written summary and economic analysis of what the appropriate market price was based upon that information with some type of decision memoranda that was approved, then, by management as to how the transaction was priced and consummated and the logic why this was the most economic source of generation for the customer.
Q. Do you think that the generation market is liquid enough for Duke to obtain six bids for

77

emergency generation from at least three suppliers?
A. Six bids from three suppliers?
Q. Yes.
A. I don't know.
Q. Duke has stipulated to passing back to FPP customers [redacted] as the total amount of benefit that FPP customers may receive for the margin Duke gets from the coal received from [redacted] discount and then resold. Do you think there is a way to determine if this is fair?
A. "Fair" is a very difficult word. I try not to let my children use it because it's something that always causes arguments. I'm not sure I'm equipped to propound with regards to what is fair.
There is an economic analysis supporting the calculation of that amount that I believe is attached to the stipulation that shows the methodology. There is a logic there that's not necessarily the logic which I would have recommended or did recommend in this audit report. Fairness is something maybe that the hearing examiner will have to opine on.
Q. Okay. What is the effect of the recurring overstatement of coal inventory at the

78

Zimmer station?
A. The effect is that there is a net increase in the cost of fuel for the Zimmer plant, that would be the net financial effect. Our concern was that normally variations in actual inventory from calculated inventory should be random in nature, that is sometimes being increases and sometimes decreases, and a persistent reduction in the inventory levels might be a sign of problems with regards to weighing or sampling accuracy rather than a random variation.
Q. How would DE-Ohio's presentation of several alternate sensitivity analyses of key variables, i.e., emission allowance prices, market coal prices, in its transaction review and approval process benefit the FPP customers, and I took that from page 1-10, No. 5?
A. It would provide both the company and then an auditor greater understanding of the potential for alternate outcomes of a long-term commitment decision. Right now the principal way of measuring the decision to enter into a long-term contract commitment is to measure it against current forward market prices for both coal and emission allowances and power at the time the transaction's

79

entered into, and what we were recommending was a presentation of the alternate impacts of different price forecasts and whether or not the transaction, you know, what the risk was of the transaction continuing to be economic under different alternate projected markets.

Q. On page 2-11 you note that Duke views each coal procurement as a hedge and transacts substantially more coal than it actually requires for its own generation. This means at different times a great deal of time buying and selling coal. In what way would these transactions increase costs?

A. I'm not quite sure I understand your question. What did you mean, in what way would it increase costs?

Q. With all these transactions what item, what activities would they be -- would Duke be involved in that would increase costs?

A. Do you mean costs other than the cost of fuel itself?

Q. Yes. Yes.

A. Oh. One component would be margins paid to brokerage firms is part of the purchase and sale for helping to arrange the transaction. A second

80

component would be the staffing cost required. And a third component would be what is generally known as the backroom support, that is accounting and computer support and monitoring and accounting for the transactions. Because the volume of transactions is larger, the cost to do that would be higher.

Q. Were you able to calculate the increased costs associated with all these transactions?

A. No, we did not make an effort to calculate those costs.

Q. Do you know if any of these transactions are between DE-Ohio and its affiliates?

A. I believe the answer is yes, we know, and that there were no transactions with their affiliates, that is in these affiliates I'm referring to coal, emission allowances, and purchased power.

Q. So there were no purchased power transactions between DE-Ohio and its affiliates.

A. That's correct.

Q. Okay. On page 2-14 you state that in evaluating just the NYMEX coal leg of the active management process EVA believes that the cost of coal for native customers was increased through daily flattening of its coal position. What did EVA have

81

to do to evaluate the NYMEX coal leg?

A. We had to obtain from the company a summary of the gains and losses on its NYMEX transactions on a monthly basis, which is presented there in Exhibit 2-16, presumably that's of the confidential version of the report, and it included both the financial transactions as well as the physical transactions through what is known as portfolio optimization.

Q. What other parts of the process would EVA need to evaluate to determine the full effect of active management on native load customers?

A. We would need to consider on a similar basis the market prices for electricity at that point in time and any transactions to sell or purchase power as well as the market prices for emission allowances and transactions to sell or purchase allowances that were matched to the decisions to buy or sell coal at that point in time.

Q. Why did EVA not evaluate those parts of the process?

A. It's a complex process with a number of components to it and we -- just in the process of asking for information and receiving information the

82

company did not get to a point where we had asked for and gotten all of that information to try to pull that analysis together.

The company does this on a daily basis based upon a large computerized model that yields an optimization decision of buying or selling individual products, and that each individual decision is economic at the time it's executed based upon the market prices input into that decision model.

The net effect of that over time may not turn out to be economic if supply or demand for power changes or market prices for power, or market prices for coal, or market prices for allowances change, and we were attempting to analyze on a look-back basis whether the net effect was a gain or loss for the FPP.

Q. Were you able to analyze the model that was used?

A. Not in any great level of detail. We received significant verbal explanations of the process involved and the inputs and the result, but no, we didn't perform an analysis of the model itself, nor would I consider ourselves to be capable of doing that analysis.

Q. Who would be?

A. There are companies that specialize in preparing -- in developing linear optimization models that I think would be certainly more capable of looking at something like that than we would be.

Q. On page 2-15 you stated that the originators at Duke were rewarded through bonuses for their coal trading activities. Who are originators?

A. Originators are company employees who have the responsibility for purchasing coal for fuel supply as well as reselling it.

Q. So they arrange for the buying and the selling --

A. That's correct.

Q. -- is that what they do?

A. They're company employees that if you used more traditional terms might be called fuel procurement agents --

Q. Okay.

A. -- for the company.

EXAMINER KINGERY: Excuse me, Ms. Hotz, how much longer do you have, do you estimate?

MS. HOTZ: I've got a ways to go.

EXAMINER KINGERY: Then why don't we take

a lunch break. It's 12:20 now; 1:30.

(Thereupon, at 12:20 p.m. a lunch recess was taken until 1:30 p.m.)

Tuesday Afternoon Session,
April 10, 2007.

EXAMINER KINGERY: Let's go back on the record.

SETH SCHWARTZ

previously duly sworn, as prescribed by law, was examined and testified further as follows:

CROSS-EXAMINATION (Continued)

By Ms. Hotz:

Q. On page 2-15 you state that EVA was not provided the TARs to renew the initial audit. What are TARs?

A. That's a transaction report. It's a summary of the proposed transaction and the economic analysis and the decision making which was prepared by the company for any long-term contract transaction.

Q. Why was EVA not provided the TARs to review?

A. It was in the prior audit period. They had taken bids for new contracts but had not yet consummated them, and my recollection today is that

the company had taken the position in last year's audit that since the transactions were not completed during last year's audit it wasn't appropriate for us to review them at that point in time and that they -- the review was deferred to this year's audit for the review.

Q. So you received the TARs in this year's review?

A. Yes.

Q. On page 2-18 you appear to be somewhat critical of the [redacted] agreement, correct?

A. I have to state that the copy of the report I am looking at here on the stand does not have page 2-18 in it. It's out of order.

EXAMINER KINGERY: Neither do ours as a matter of fact.

A. The -- our criticisms are related to the company not wanting to enter into fixed pricing provisions that extended beyond the end of 2008 which had been originally offered by the supplier which we thought would have been in the company's benefit. I think, again, the company's position was that they were constrained by the expiration of the RSP period

87

and not wanting to make any firm commitments beyond that because of the uncertainty of future power sales past that period.

Q. Did Duke explain to you the purpose of entering into th[redacted]eement?

A. Yes. The purpose of entering into the [redacted]greement was to obtain an additional committed supply of high sulfur coal for the new scrubbers that were being built and completed during 2007 and to have a fixed committed supply of volume with fixed pricing through the end of 2008 but a longer-term volume commitment from a larger supply area.

Q. Did the contract provide a fixed price for -- did the contract provide a fixed price?

A. The contract only provides a fixed price now through the end of 2008 with a market price mechanism for price redetermination after that date.

Q. Has Duke recently procured coal with BTU dead-bands?

A. I am not sure as I sit here now.

Q. Well, on page 2-20 you have a discussion of BTU dead-bands, and I wondered why you had put that in the audit report.

88

A. Because it was our concern that the -- and I believe the answer to your question is no. I am just -- your first question was no, that I don't think any of the newer contracts have dead-bands for price adjustment for variation in BTU content. The reason why we thought having a dead-band was not in the utility's interest was that we -- in our opinion it provided the supplier the ability and the incentive to supply coal at the lower end of the dead-band without experiencing a financial penalty. And I don't think that provision exists in Duke Energy's newer contracts, but it did exist in some of the older contracts.

Q. Did you believe that there was some way that you could -- that Duke could get out of those contracts?

A. No.

Q. On page 2-25 through 2-26 you discuss the [redacted] Agreement. What would you suggest that Duke do about the [redacted] Agreement?

A. The discussion of [redacted] was something that we had discussed with company personnel at greater length than we thought was

89

sensible to put in writing in the audit report. We think the company has considerable motivation to ensure that it receives deliveries on all of the coal that it is due under the [redacted] Agreement. And their representations to us were that they were going to use every contractual and legal avenue necessary to -- to obtain all of the coal that they were owed.

Q. Did they give you any specifics as to how they were going to do that?

A. I think the specifics were to attempt to achieve the deliveries on a more timely basis and negotiation with the possible resort to litigation, if necessary.

Q. Were you satisfied with the -- with their plan?

A. Yes.

Q. On page 2-27 EVA recommends that the economic benefit of a swap of 2007 shipments under the [redacted] agreement for noncompliance coal be passed through the FPP. Did Duke agree with that recommendation?

A. Yes. I believe under the terms of the procedures that were agreed to under the stipulation

90

that, in fact, all of the benefit of that swap would be passed through the cost of coal including the FPP to the extent it was part of the applicable share to the FPP customers.

Q. On page 2-29 you noted that a violation of [redacted] sulted in a monetary penalty assessed against [redacted] Did that monetary penalty benefit FPP customers?

A. Yes.

Q. On page 2-29 you recommended that the FPP should be credited with the difference in cost between the undelivered tonnage by [redacted] DE-Ohio in spot market coal. Do you know how much that difference was?

A. No, I don't.

Q. When should that amount or should that amount be credited to FPP -- to the FPP?

A. That amount should have been credited to the FPP during the first half of 2006.

Q. Do you know if it was credited?

A. No, I don't.

Q. Did DE-Ohio indicate their intentions to you about this?

A. I don't recall.

91

Q. On page 3-5 EVA states that it's inappropriate for the director of portfolio optimization to retain responsibility for allowance trading. Why does EVA believe that?

A. Because the -- in our opinion it was too much of a demand on his time that needed to be spent on managing the overall functions of the department rather than performing one of the functions solely on his own.

Q. Is the director of portfolio optimization still responsible for allowance trading at Duke?

A. My understanding is that, no, that he now supervises somebody with that responsibility.

Q. Throughout your discussion of the various coal purchases that DE-Ohio engaged in you discussed long-term coal contracts, short-term contracts, and spot market purchases. Obviously you are aware that Duke has purchased various types of -- has purchased various types of coal purchases yet you make the recommendation on page 1-9 under 2 at the bottom that DE-Ohio should develop and implement a portfolio strategy such that it purchases coal through a variety of short-, medium-, and long-term agreements with appropriate supply and supplier diversification.

92

Why did EVA make that recommendation knowing that they -- that Duke was already purchasing in spot and short-term and long-term contracts?

A. Because Duke Energy - Ohio is not entering into any long-term contracts which would extend past the end of the rate stabilization period, the end of December, 2008. So at the point in time where we were conducting the audit, in fact, Duke Energy - Ohio did not have long-term contracts as part of its portfolio. They may have had the remaining term of older long-term contracts but no newer long-term contracts, so as a result, the company was really largely purchased almost entirely on a short-term and spot basis with almost nothing purchased after December of 2008, at least with regards to firm pricing.

So largely that recommendation is going to renewing a portfolio with a term that extended past 2008 and that's the nature of the recommendation.

Q. Now, would you be the right person to ask questions about on-site investigations?

A. On-site investigations of what?

Q. Of the power plant performance.

93

A. No.

Q. Okay. I would like to go back to the RFP right now. On page 3 the RFP requires the auditor to include in their investigation a market price comparison on all coal which is purchased to ensure that the price paid by the company during the audit period is reasonable, correct?

A. Yes.

Q. Did you have difficulty finding a market price comparison on all coal to compare to the prices paid by Duke during the audit period?

A. Not all coals have an easily discernible liquid market price but in general the answer to your question is no. We were able to determine what the market prices were at any point in time.

Q. Is finding a market price on all coal and comparing it to the prices paid by Duke a fairly simple process?

A. I'm not sure I would describe it as simple. But it's certainly achievable and something that can be done.

Q. What kind of complications does an auditor encounter when trying to compare other coal prices to prices paid by the company?

94

A. The important adjustments that need to be made between published market prices and actual prices paid by the company include adjustments for variations in coal quality, variations in transaction point meaning what the origination point is compared to where the market pricing information is, and also to the extent one is trying to compare things in the context of when the decisions were entered into, adjustment needs to be made for the timing of the transaction. To a lesser extent one could consider differences for the type of transaction with regards to the length and size of the contract.

Q. Do you recall if there were any particular coal contracts that Duke had during your audit that were particularly difficult to find a comparison?

A. Some of the higher sulfur coals are difficult to establish valid current market price evidence outside of the results of direct solicitations and comparisons with other offers received by the company.

Q. On page 4 of the RFP the auditor is directed to investigate the company's environmental compliance activities, correct?

A. Yes.

Q. Are you the right person to ask about this?

A. Yes.

Q. Okay. Exactly what kinds of environmental compliance activities did you investigate?

A. The key activities were emissions and planned emission control strategies from the coal-fired power plants for compliance with the Clean Air Act amendments both of 1990 and then the newly promulgated clean air interstate rule.

Q. What kind of planned emission control strategies did you investigate?

A. The company has instigated a series of control strategies at each of its coal-fired power plants, in some cases including retrofit of emission control technologies; in other cases using alternate fuels in order to reduce emissions to meet the targets in the -- in the regulations. And I should also mention part of their control strategies are the purchasing of emission allowances to cover any emissions that exceed the amount of free allowances that they were already granted.

Q. On page 4 of the RFP on the second bullet the auditor is directed to take into consideration allowance management strategy. What did you take into consideration with regard to allowance management strategy?

A. We reviewed the planned operation levels of the power plant, that is, generation levels of the plants owned by Duke Energy - Ohio in their ownership shares, the targeted emissions associated with that generation, the effect of changes in emission control technology used on those plants and, therefore, their projected emissions in the future compared to their current inventory of emission allowances and their planned purchases of emission allowances to comply with the law.

Q. Did you think that decision makers should compare various compliance strategies with others based on the cost items included in each of the strategies?

A. Yes.

Q. How do you -- how do you measure all of those different costs?

A. Some of the costs are measured in the form of capital cost for investment. Some are

measured in the form of operation and maintenance costs. Others are purchases of reagents to operate emission control technology as well as the cost of fuel that would be used under varying alternate control technology options.

Q. So did you consider the different strategies on a plant-by-plant basis?

A. We reviewed the work the company had done on a plant-by-plant basis, yes.

Q. And that's how the company did it, on a plant-by-plant basis?

A. Both plant by plant and overall for the company as well. The emission allowance strategy is done on a company-wide basis. Individual economic decisions in each plant is on a plant-by-plant basis.

Q. And what about retrofits?

A. The retrofits are specific to each plant, yes.

Q. What kind of cost items did you consider as relevant for plant environmental upgrades and making comparisons with a fuel purchasing strategy or an emission allowance purchasing strategy?

A. The capital cost of construction, the operation maintenance costs of operation, the cost of

emission allowances, and the varying cost of fuel associated with different strategies.

Q. Did you find that the company relied upon methodologies used internally to analyze compliance options?

A. I'm not sure I understand your question.

Q. I am not sure I understand it either, but I got it out of the RFP. What methodology -- what methodologies did the company rely upon to analyze compliance options?

A. The methodology generally known as a net present value of different alternatives, capital and operating and fuel costs, to evaluate the lowest cost compliance option.

Q. How -- do you know how the company did their discounting on the net present value?

A. I'm not positive I recall. I believe that -- if you are asking what the discount rate was, I believe it was at a weighted average cost of capital, but I am not positive.

Q. What was your opinion of the methodologies used by the company to weigh the options for compliance?

A. My opinion was the methodologies were

99

reasonable and appeared to consider all of the relevant factors.

Q. Under E on page 4 of the RFP the auditor is directed to investigate and report on instances during the audit period in which customers requested that their power supplies be interrupted, correct?

A. Yes.

Q. Why would a customer request that their power supply be interrupted?

A. I think the language in the RFP refers to the company requesting that a customer interrupt power supplies, not the customer requesting.

Q. No, there really is, there really is on page 4. There is a reference. But in any case you probably didn't have an experience with that in this audit review?

A. No, we did not.

Q. Okay. And you don't know why a customer would request their power supply be interrupted?

MR. COLBERT: I am going to object. That's not what it says in the RFP on page 4.

EXAMINER KINGERY: Let's go to the actual RFP and read it.

Q. Okay, okay. They are distinguishing between when a customer's power supply was interrupted or the company requested them to be interrupted. I interpreted it otherwise.

100

A. That was my interpretation, yes.

Q. Okay, okay. Under F of the RFP, the utility industry perspective section, the auditor is directed to discuss items impacting the utility on a macro level. Which items do you consider to be the most significant items impacting Duke?

A. With regards to the fuel and purchase power costs, we would view the most significant items to be changes in the fuel emission allowance and purchase power markets both structurally and in pricing, you know, affected by supply and demand.

Q. Do you recall that Duke Energy - Ohio is appropriately responding to these items impacting Duke on a macro level?

A. In general, yes. I can't say that we necessarily have anticipated or investigated all of the important items affecting Duke Energy on a macro level. But to the extent we did and inquired about them in the audit, we felt that they were being addressed.

Q. Did the staff direct -- direct you to -- to discuss particular items impacting Duke on a macro level?

101

A. No.

Q. On page 7 of the RFP there is an item C or interim reporting that required the auditor to provide the staff with a progress report, correct?

A. Yes.

Q. Did you submit the progress report to the staff?

A. Not as a written report, no. We had continuing verbal progress reports with the staff during the process of the audit.

Q. Did you discuss any initial or tentative findings and conclusions in that -- in your discussions?

A. Yes.

Q. Did you include any findings and conclusions in those discussions that you did not include in the final report?

A. Perhaps, yes.

Q. What findings and conclusions did you have in the initial discussions that were not in the final report?

MR. COLBERT: Objection, your Honor.

102

Besides this is beyond the scope of the report itself 4901.16 maintains as confidential matters in the scope of the -- of the investigation to the extent that they are not submitted in an audit -- in a report through a witness on the stand. This witness is testifying as to his report. The items that would not have been part of the report that are part of the investigation would remain confidential under statute.

MR. REILLY: Your Honor, in addition, I agree with what Mr. Colbert said, but I note to the extent the recommendation didn't make it into the report that signifies nothing more than the auditor rethought it, and I would argue it's not relevant.

MS. HOTZ: Well, if that's true, the auditor should be able to say that.

MR. REILLY: It's not relevant to the proceedings.

EXAMINER KINGERY: We are going to sustain the objection.

MS. HOTZ: That's all we have. Thank you.

EXAMINER KINGERY: Thank you.

MS. MOONEY: I have no questions.

EXAMINER KINGERY: You said you don't have anything?

MS. MOONEY: No.

EXAMINER KINGERY: Mr. Boehm?

MR. BOEHM: Just a few questions.

- - -

CROSS-EXAMINATION

By Mr. Boehm:

Q. Mr. Schwartz, are you familiar with the agreements or the order of the Commission that established the RSP for CG&E, now Duke Energy?

A. Generally, yes.

Q. All right. Do you know whether or not that -- that commitment on all sides expires on any particular date?

MR. COLBERT: Objection, your Honor, calling for a legal conclusion.

EXAMINER KINGERY: I don't think that's a legal conclusion. We will allow the question.

MR. BOEHM: It's a factual conclusion.

Q. Are you aware of that, Mr. Schwartz?

A. I am not specifically aware of all the provisions. It was my general understanding that there was a process in place through the end of 2008,

but I can't say exactly what was in the agreement.

Q. Let me tell you what I am getting at, Mr. Schwartz. My understanding is the aud -- the auditor took exception to CG&E's practice, if you will, of not buying long-term coal -- in the long-term coal contracts to the extent that they went past the end of 2008. That's -- that's the case, is it not?

A. Yes.

Q. Okay. Do you know whether or not there will be an FPP after 2008?

A. I haven't stayed familiar with the current status. Late in the audit process I was made aware the company was about to make a proposal to extend the FPP beyond that period. And I was informed about that, but I don't know where it currently stands.

Q. Do you know whether or not -- assume for the moment that that's not been done or at least not been done yet. Do you know of any other mechanism that the company would have to recover their -- their coal costs from their historic customers after the end of 2008?

A. To the extent that that pricing then goes

to the market pricing for electricity, there is an implied recovery of fuel costs in the market price but not a specific recovery of actual costs.

Q. And it is possible, is it not, that the market price would be at such a level that they wouldn't recover those costs?

A. Using the word recover makes it difficult. It's not likely the market price for electricity would be so low as to be less than the variable cost of running the coal-fired power plants. There may, however, be no margin above that. I am not sure.

Q. Okay. Do you know whether after 2008 Duke Energy would have a customer base such as it has right now where it's selling essentially all of its native generation to its historic customers?

MR. COLBERT: I am going to object, your Honor. Now, we are asking questions about what may happen after 2008, well beyond the scope of this audit.

MR. BOEHM: Not really, your Honor. I am asking whether he knows.

EXAMINER KINGERY: I will allow the question.

MR. BOEHM: Which is a different thing.

EXAMINER KINGERY: I will allow the question.

Q. Do you know?

A. No, I don't know what Duke Energy - Ohio's retail customers would be or whom they would be.

Q. Okay.

A. I do think, however, as part of our analysis and recommendation, it was our position that it is reasonable for the company to project that there will, in fact, be a demand for electricity to be supplied from these generating stations whether or not they had regulated retail sales or firm sales at the present time.

MR. BOEHM: I have no further questions of this witness. Thank you.

EXAMINER KINGERY: Thank you very much.

MR. REILLY: Your Honor, point of clarification.

EXAMINER KINGERY: Yes.

MR. REILLY: Staff has what it would view as cross-examination of the witness. Staff does not view that it presented the witness. It asked the

107

initial questions certainly as an accommodation for the Commission-ordered witness who was presenting the Commission-ordered exhibit. We have -- we do have questions. We would view them as on cross.

EXAMINER KINGERY: That's interesting.

MS. HOTZ: We object. We think it should be --

EXAMINER KINGERY: Go ahead.

MS. HOTZ: We think it should be only on the subject matter of my cross.

MR. REILLY: And that's the big difference between the two. Staff is essentially cut out of cross under the OCC interpretation.

EXAMINER KINGERY: Just a moment, please. We are going to go off the record for just a minute.

(Discussion off the record.)

EXAMINER KINGERY: Let's go back on the record. This is a little bit of a sticky situation. With regard to this witness it appears to us you represent the Commission because you introduced the witness, and so you appear to be counsel for the Commission because he's a Commission -- he is a witness for the Commission-ordered exhibit. However, we also recognize that staff may well have

108

cross-examination-type questions for this witness. Is there perhaps another Attorney General who you could bring in to represent the other party, unless nobody objects to your representing both, in which case that's fine with us.

MR. COLBERT: The company has no objection.

EXAMINER KINGERY: Thank you.

MR. REILLY: Just so I can understand an Assistant Attorney General can't present the witness as a matter of accommodation to the Commission -- as a matter of accommodation to the proceedings on behalf of the Commission? Because all I asked him was his qualifications, that was the extent of the questioning, and to identify the Commission-ordered exhibit.

EXAMINER KINGERY: Are you planning to have any redirect so to speak for this witness understanding that without redirect there will be no recross by any other parties?

MR. REILLY: I -- you mean would -- would I have questions in the areas that Ms. -- that were covered by OCC?

EXAMINER KINGERY: Or anybody else.

109

MR. REILLY: Probably, yes.

EXAMINER KINGERY: So as redirect as you are saying representing the Commission, you would have redirect questions on the areas that have been discussed by --

MR. REILLY: I would have some questions on some areas that have been raised already.

EXAMINER KINGERY: Okay. Then it sounds like you are representing both Commission and staff if you want to ask questions on cross on behalf of staff and you want to ask redirect on behalf of the Commission, so it's all right with us if you represent both parties, but it would need to be all right with all the other parties.

MS. HOTZ: OCC objects.

EXAMINER KINGERY: What a surprise.

MR. REILLY: Just so I'm clear if there were another Attorney General here, this wouldn't be a problem.

EXAMINER KINGERY: Right.

MR. REILLY: Okay.

EXAMINER KINGERY: We can pause if you would like while you go look and see if there is another Attorney General.

110

MR. REILLY: That's okay.

MR. BOEHM: Your Honor, I am reminded of one of my favorite poems from Bill Murray, "Roses are red, violets are blue, I'm schizophrenic, and so am I."

EXAMINER KINGERY: Thank you.

MR. REILLY: Okay.

MR. BOEHM: Having said that I have no objections.

EXAMINER FARKAS: You don't have to worry because this is all confidential too.

MR. REILLY: How am I examining the witness?

EXAMINER KINGERY: I don't know. You tell me.

MR. REILLY: Oh, on cross.

MR. SMALL: I don't believe that was the Bench's ruling.

EXAMINER KINGERY: I was looking for whether you objected, and OCC objects.

MS. HOTZ: Yes, yes.

EXAMINER KINGERY: Is there another Attorney General -- there are two other Attorney Generals that are listed as having made appearances.

111

MR. REILLY: Well, let's see if I can get through this without objection. If we get to objections, then we will have to do that.
EXAMINER KINGERY: Are you now attempting to examine on cross?
MR. REILLY: I am attempting to examine. If parties have objections, let them be raised on any question I ask.
EXAMINER KINGERY: Are you representing staff?
MR. REILLY: I am representing staff. That's the only way I can interview this witness.
MS. HOTZ: Then I believe he can only do it on redirect unless he finds someone else to do it on cross.
MR. REILLY: Is that the Bench's ruling?
EXAMINER KINGERY: Yes.
MR. REILLY: Okay.
EXAMINER KINGERY: Because there was an objection.
MR. REILLY: Okay.
EXAMINER KINGERY: You should have brought two hats.
MR. REILLY: Yes. I am ready to proceed.

112

EXAMINER KINGERY: Would you like to redirect?
MR. REILLY: I will -- I will -- I will do what your Honor is directing.

- - -

REDIRECT EXAMINATION

By Mr. Reilly:
Q. Mr. Schwartz, I would like to talk to you about the company's management of its coal -- it's management of its coal purchases for a bit, all right? Do you remember you talked to OCC's counsel about that?
A. Yes.
Q. Okay. And in the -- during that discussion with her you were talking about the size of the -- of the number of transactions that you -- that you -- that there were to look at. Do you remember that?
A. Yes.
Q. Okay. And as part of that discussion, you said that you didn't look at all the transactions, but you looked at a part of them in a number of areas. Do you recall that also?
A. Yes, I recall testifying that we looked at a sample of the transactions.

113

Q. Right. Now, those samples you looked at, did you consider them representative of the group you were examining?
A. Yes.
Q. All right. Now, I would like to -- now, as part of your discussion on active management also, I believe you were talking about the costs associated with active management. Do you remember that?
A. I remember that question and answer, yes.
Q. Okay. Do you know -- strike that.
When the company buys and sells coal or buys and sells emission allowances or buys and sells power, do they do that through brokers at all?
A. Sometimes through brokers, yes.
Q. Do you know, are those broker fees passed through the FPP, or does the company absorb them?
A. I am not certain.
Q. I would like to direct your attention -- if you could take a look at Commission-Ordered Remand Exhibit 1, that's your report, at page 5-29. Are you there?
A. Yes.
Q. Okay. There's a section there that's

114

titled "review related to service interruptions and unscheduled outages"; is that not correct?
MS. HOTZ: Objection. This is not an area we covered in our cross.
MR. REILLY: She asked directly out of the RFP on it. That's why I am asking it.
EXAMINER KINGERY: Where is it in the RFP it was asked?
MR. REILLY: Page 4, I believe is what you were talking about she asked directly about service interruptions.
EXAMINER KINGERY: Yes, she did. Overruled.
Q. Page 5-29 section "review related to service interruptions and unscheduled outages," do you see that?
A. Yes.
Q. Okay.
MS. HOTZ: I still object because I withdrew the question because I misunderstood the statement.
EXAMINER KINGERY: So far he has just asked if he sees it. Let's see what he asks.
MS. HOTZ: Okay. All right.

115

Q. Would you take a look at that section, please.
A. Yes.
Q. Okay. Does that address the service interruptions and unscheduled outages?
A. Yes.
Q. Now, I would like to talk to you about coal inventories and potential effect on pricing. OCC's counsel discussed this with regard to the Zimmer plant. Could you tell me, does a higher coal inventory generally lead to a higher or lower price?
A. To the extent that there is more coal accounted for in inventory than actually is in inventory, it has the effect of undercharging the current FPP customers and that that undercharge will be made up in future periods when the cost is actually charged to -- to coal burned.
Q. I got you. Would the reverse of that also be true, that the lower -- that if it was lower inventory, it would be a higher price, or have I got that right?
A. Yes. If the accounting for fuel inventory was -- was less than actual inventory and, therefore, the calculations were more coal was burned

116

than actually was burned, that would have been expense -- an expense that would have been charged to the FPP earlier than actually would occur once the adjustments are made.
MR. REILLY: May I have a moment, your Honor?
EXAMINER KINGERY: Yes, you may.
MR. REILLY: Thank you, Mr. Schwartz.
EXAMINER KINGERY: Thank you.
Recross?
MR. COLBERT: Nothing, your Honor.
EXAMINER KINGERY: Thank you.
Ms. Hotz?
MS. HOTZ: No, thanks.
EXAMINER KINGERY: You may step down. Thank you very much.
Let's take about a 5-minute break before we get started on the next witness.
(Recess taken.)
MR. REILLY: Your Honor, we would call Mr. Ralph Smith.
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117

RALPH SMITH
being first duly sworn, as prescribed by law, was examined and testified as follows:
DIRECT EXAMINATION
By Mr. Reilly:
Q. Mr. Smith, would you tell us your business address.
A. My business address is Larkin & Associates, PLLC, 15728 Farmington Road, Lavonia, Michigan.
Q. And what's your position with Larkin & Associates?
A. I am a senior regulatory consultant.
Q. Okay. Now, in front of you is a document that's been labeled for identification purposes as Commission-Ordered Remand Exhibit 1. Can you find that document up there for me.
A. Yes.
Q. Could you tell me have you seen this document before?
A. Yes.
Q. Did you have any relationship to the document?
A. Yes.

118

Q. And what was that?
A. I and my firm are responsible for chapter 5 in the document.
Q. And what does chapter 5 deal with?
A. Chapter 5 deals with the fuel economy and purchase power and initial allowance components, the FPP component audit.
Q. Now, Mr. Smith, would you go over your educational background for us. Just tell us a little bit about yourself.
A. Yes. I have a Bachelor's of science in accounting from the University of Michigan, Dearborn, 1979. I have a Master's in taxation from Walsh College in 1981. And I have a jurist doctorate degree from Wayne State University, 1986.
Q. Thank you. Now, would you also describe for us your -- your career today. What have you done and where have you done it since graduating from school?
A. Since graduating U of M with my accounting degree in 1979, I took a job with the predecessor firm to Larkin & Associates. That firm's name was Larkin, Chapski & Company. And during the first two years did a variety of auditing, tax work,

reviews, and then got involved with utility regulation. And since then the vast majority of my professional time and efforts have been devoted to addressing a wide range of issues having to do with utility regulation.

Q. Have you ever -- have you ever dealt with energy companies before?

A. Yes, on many occasions.

Q. Have you ever dealt with Duke - Ohio before -- Duke Energy - Ohio before?

A. Well, round 1 of the FPP review we dealt with Duke's predecessor Cincinnati Gas & Electric.

Q. Okay. So you were involved in round 1 of the FPP review.

A. Yes.

Q. So you have experience with the exact process and issues and questions that are going on in this proceeding on top --

A. Yes.

Q. -- of your other experiences?

A. Yes, that's true.

Q. Have you had any occasion to lecture at any places regarding accounting issues or legal issues involved with energy world?

A. I presented various speeches and lectures on behalf of NARUC, on behalf of NASUCA, and on behalf of some of the regulatory commission staffs. We have done training seminars for them.

Q. Now, Mr. Smith, I have also put in front of you a document that's identified as Commission-Ordered Remand Exhibit 1C. Do you see that document?

EXAMINER KINGERY: Is there also a 1B? We have 1A and 1C.

MR. REILLY: It should be 1B. If you could make the correction of 1B, if I could have that marked for identification as 1B.

EXAMINER KINGERY: It will be so marked.

(EXHIBIT MARKED FOR IDENTIFICATION.)

A. Yes, I have it.

Q. All right. Could you tell me what that is.

A. Yes. It's basically a letter that we sent to the Commission after getting the final copy of the report. I had noticed that there were certain things in chapter 5 that required correction and the letter describes the corrections that needed to be made and I believe the specific pages that had the

corrections on them are attached to the letter.

Q. Would it be safe -- would it be fair to call that an errata sheet?

A. Errata sheet is a good name for it, yes.

Q. If I could just direct everybody's attention to the docketing mark that is on the front page of the exhibit is showing that it has been docketed.

Now, Mr. Smith, were any of the corrections you made that are reflected in Exhibit 1B substantive in nature?

A. I view them more in the nature of correcting typos. They didn't affect our recommendations.

MR. REILLY: All right. Thank you, Mr. Smith. I guess we would offer the witness on behalf of the Commission.

EXAMINER KINGERY: Thank you.

Mr. Colbert?

MR. COLBERT: No questions.

EXAMINER KINGERY: Thank you.

Ms. Hotz?

MS. HOTZ: Yes, I have questions.

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CROSS-EXAMINATION

By Ms. Hotz:

Q. Did you say you have a jurist doctorate? Is that what you said, or you have a doctorate?

A. Jurist doctorate.

Q. Oh, I just wanted to make sure. I am going to direct your attention to page 1-3 of the audit report.

EXAMINER KINGERY: Could you turn the mike on? Could you turn your mike on, please?

MS. HOTZ: Oh, my mike.

Q. Okay. Did you hear me?

A. Page 1-3.

Q. Yes. Footnote 3. Are you familiar with that footnote or that circumstance addressed in that footnote?

A. Yes, I am.

Q. Did CG&E provide a reasonable justification for the change addressed in that footnote?

A. I believe they did.

Q. What was that?

A. I think this was addressed in the -- the audit report for the previous round. And if you refer to page 5-25 of report dated October 7, 2005, for the audit period January through June, 2005, CG&E had credited certain gains on the sale of coal against fuel costs, but it has advised us at that point that it would reverse that treatment in its fourth quarter 2005 FPP filing. That was based on their clarification of which types of coal sales transactions would flow through the FPP.

Q. Was that related to the stipulation, the provisions in the stipulation?

A. This item, I believe, was addressed in the stipulation that resulted as a result of the prior audit.

Q. Okay. On page 1-6 of the audit report, I believe that would have been EVA's -- EVA states that DE-Ohio employs active management of its coal emission allowance and energy supply. Do you see it there?

A. Page 1-6?

Q. Yes.

A. Yeah. You know, this is really EVA's part of the report, but I see that they made a statement there.

Q. Are you familiar with DEO employing an

active management of its coal emission allowance and energy supply?

MR. COLBERT: Objection, your Honor. She is outside of the -- the audit findings of this witness.

MS. HOTZ: Well, the previous auditor told me to direct this question to the financial auditor.

EXAMINER KINGERY: She can ask the question. If he doesn't know, he doesn't know.

Q. Are you familiar that -- are you familiar with DEO -- DE-Ohio's active management of its coal emission allowance and energy supply?

A. I am familiar with their what's been called active management.

Q. Okay. Do you believe that you can adequately audit DE-Ohio's purchased fuel and purchased power practices as long as DE-Ohio actively manages its coal emission allowance and energy supply?

A. Yes. And I've stated as much on page 5-39 and 5-40 of the report.

Q. 5 what was that again?

A. 5-39 and 5-40. They did provide a good

audit trail to us, and we reviewed it. We believe that the costs related to DE-Ohio's active management can ultimately be tracked to supporting documentation. We do have some other recommendations to improve their documentation, but we do believe that their present and active management is auditable.

Q. What suggestions did you have?

A. If you look at starting at page 5-39 and 5-40, 5-41, on those pages that contains our recommendations. Specifically for the active management starting at the top of page 5-40, their active management reflects a reaction to daily market changes and because of that it can be very challenging to understand the reasoning for each active management transaction and how it relates to the responsibility to serve their native load customers, and for that reason we believe that it's imperative that the company maintain documentation not only of the costs being concluded in the FPP but also of the reasons in support for the company's active management decisions.

Q. So about how many of these active management decisions would be made each month?

A. It's hard to put a quantitative number on that. They basically look at their positions each business day and look at their market information each business day, look at their load forecasts, and decide if they need to make some adjustments in their portfolio, and so they are making -- and they call that active management. If they determine, for example, that it's economically advantageous to purchase power rather than generating at one of their plants, then that's the decision they will make on that day. If they determine that the cost of emission allowances is such that it may be beneficial to sell some emission allowances and to perhaps purchase power and not generate using one of their own units, that's the decision they will make, and they are constantly looking at not only market data but at their own existing positions and making these types of decisions almost continuously.

Q. So you would say several -- more than several times a day, would they be making these kinds of decisions?

A. If you -- you know, I mean, if you get it down to a very granular basis, they are probably doing some kind of active management decision

virtually every business day.
Q. Okay. What kind of reasons would you like them to document? What would be a reason that would be documented?
A. I think the -- what I foresee is a way of improving their documentation would be just for them to memorialize somehow the data that they were looking at that particular point in time and how they evaluated that data to make that particular decision.
Q. What kind of data would they -- would they be referring to in these reasons?
A. Data would include the current positions, their current load forecasts, their evaluation of market conditions, and their evaluation of all that data to determine why they made particular transactions at a particular point in time.
Q. Did you present this recommendation to Duke?
A. Yes. It's in our report on 5-40.
Q. And what was their response?
A. I believe they agree with it.
Q. Okay. Now, I am going to ask you about on-site investigation. On page 3 of the RFP under the power plant performance, the RFP requires the

auditor to conduct an on-site investigation of at least one of the company's generating stations and report findings, conclusions, and recommendations, correct?
A. Yes.
Q. Do you believe that this on-site investigation is an important aspect to the FPP and the SRT audit that was performed?
A. Yes.
Q. Why was it important?
A. I think it's important to actually go on-site and see the operation of one of their major generating units. And there's a number of audit steps that tie into that process and we followed the procedures from former Chapter 4901:1-11 of the Ohio Administrative Code in order to conduct the on-site review and review the related documentation.
Q. So you followed the Ohio Administrative Code step by step in doing your investigation?
A. Pretty much, yes.
Q. Okay. Is there something in the Ohio Administrative Code that outlines how to investigate fuel handling?
A. Yes, I believe there is and if you look

at one of the attachments to section 5 of the report, Attachment 5-2 presents our initial data request to the company. And if you will start looking at page -- well, the first page has some data requests related to minimum review requirements and then the second page starting at LA-2-17 has a bunch of information related to the station visitation and review of the company's coal processing procedure from receipt of coal to the disposition of fly ash. And those particular questions run through LA-2-33.
And these were pretty much taken directly out of Chapter 4901:1-11 of the Ohio Administrative Code and are basically applying in the current context the procedures that had previously been applied when the company had an EFC.
Q. So is that also true with investigation of quality, control, and maintenance at plants?
A. Yes. We basically used that same guidance from Chapter 4901:1-11 as guidance for everything we needed to do. We adapted it to the current context, of course, but that was the fundamental source of guidance for our review.
Q. Did you investigate and report on any other items besides fuel handling, quality control,

or maintenance during your on-site investigation?
A. I believe we did. Yeah, the description of what we did specific to station visitation starts at page 5-25 of our report and runs through 5-28.
Q. What does an auditor find out on an on-site investigation that it would not find out without an on-site investigation?
A. You get to see how the plant is set up, how they actually take the coal from the barges and delivered into the plant. We climbed up the conveyor belt and saw their scale. We walked around in the coal pile. We went inside the plant. We got descriptions of the various types of equipment. It's just -- it's very helpful to see the actual plant in operation and to see it physically as opposed to just looking at paper invoices. The auditing profession tends to really encourage on-site review as opposed to just paper document review, especially for major items, and I think it's beneficial.
Q. Okay. So when you are talking about major items, are you talking about items that cost a lot, or are you talking about -- when you say major items, what do you mean?
A. An item that would be material to the

scope of the review that's being conducted.
Q. Okay.
A. And the EFC procedures provide for basically visiting one plant during each review period so during this particular review period we visited the company's Beckjord generating station. During the earlier phase we visited Zimmer.
Q. Have you been — have you done many on-site investigations in your auditing of electric companies?
A. The Zimmer visit was my first visit to a coal plant, but in a lot of our regulatory consulting engagements we do go on-site to the company's offices usually for interviewing people.
MS. HOTZ: That's all I have. Thank you.
EXAMINER KINGERY: Thank you.
Mr. Boehm was here. We'll go off the record for a minute.
(Off the record.)
EXAMINER KINGERY: Do you have any redirect?
MR. REILLY: No redirect.
EXAMINER KINGERY: Okay. Thank you very much. You may step down.

(Witness excused.)
EXAMINER KINGERY: At this time would the company like to present its first witness?
MR. COLBERT: Yes, your Honor. Thank you. The company would call Mr. Chuck Whitlock.
Your Honor, we would mark Mr. Whitlock's direct and supplemental testimony as Duke Energy - Ohio Remand 27 and 28.
EXAMINER KINGERY: I think it makes more sense if we start over with 1. We've been talking about it, so we're thinking Remand Rider Exhibit 1. I know that's long. We can just abbreviate it as "RR" or something in our briefs.
MR. COLBERT: That's fine.
EXAMINER KINGERY: But then we start at 1 again, so I think that would be nice.
MR. COLBERT: Okay. Duke Energy - Ohio Remand Rider 1.
EXAMINER KINGERY: Yes.
MR. COLBERT: And 2.
(EXHIBITS MARKED FOR IDENTIFICATION.)
MR. REILLY: Excuse me, your Honor, before we get started, just so we keep things clear, if we're going to call the exhibits in this case

"Rider," should the exhibits presented -- should the Commission-ordered exhibits be redesignated?
EXAMINER KINGERY: They can be, although we didn't have any Commission-ordered exhibits in the nonrider phase of it, I don't believe.
MR. REILLY: Oh, no --
EXAMINER KINGERY: It's fewer words. Thank you.
MR. COLBERT: Your Honor, it's already also been docketed, but it might be appropriate to mark the stipulation as Joint Exhibit Remand Rider 1.
EXAMINER KINGERY: It will be so marked.
MR. COLBERT: Thank you.
(EXHIBIT MARKED FOR IDENTIFICATION.)
MR. COLBERT: We would not move it in until later in the proceeding.
EXAMINER KINGERY: That's fine.
Would you raise your right hand, please?
(Witness sworn.)
EXAMINER KINGERY: You may be seated.
THE WITNESS: Thank you.
MR. REILLY: Excuse me. Before we get started, on behalf of the Commission I would move Commission-Ordered Exhibits 1 and 1A and 1B into

evidence.
EXAMINER KINGERY: Any objections?
(No response.)
EXAMINER KINGERY: They will be admitted.
(EXHIBITS ADMITTED INTO EVIDENCE.)
MR. COLBERT: Your Honor, just very quickly, Mr. Whitlock has recently had surgery and it may be necessary for him on occasion to stand up or put his leg up on the chair that I've got there for him; it's meant as no disrespect to the court.
THE WITNESS: I actually won't stand on the chair. I might put my leg on it.
MR. COLBERT: That would be appreciated.
EXAMINER KINGERY: Whatever you need to do is fine.
THE WITNESS: Thank you.
EXAMINER KINGERY: Yes.

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CHARLES WHITLOCK
being first duly sworn, as prescribed by law, was examined and testified as follows:

DIRECT EXAMINATION

By Mr. Colbert:
Q. Mr. Whitlock, do you have the two

exhibits that we just marked as Remand Rider Exhibits 1 and 2 in front of you, and are they your direct and supplemental testimony that you have filed in this case?
A. I do, and they are.
Q. And would you state your name and business address for the record, please?
A. It's Charles R. Whitlock, 139 East Fourth Street, Cincinnati, Ohio 45202.
Q. And, Mr. Whitlock, do you have any changes or amendments to the documents that are marked as your supplemental and direct testimony?
A. We should probably change the -- on both my title is changed, and it says that I work for Duke Energy Americas. I actually work for Duke Energy Shared Services, and my title has changed from President to Senior Vice-President, Commercial Asset Management.
Q. Do you have any other changes?
A. I don't believe so.
MR. COLBERT: Your Honor, Mr. Whitlock is available for cross-examination.
EXAMINER KINGERY: Thank you very much.
OCC?

MR. SAUER: Thank you, your Honor.
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CROSS-EXAMINATION
By Mr. Sauer:
Q. Good afternoon, Mr. Whitlock. My name is Larry Sauer and I represent the Office of the Ohio Consumers' Counsel.
THE WITNESS: Your Honor, could we get a microphone?
EXAMINER KINGERY: Yes.
Could you use the one over there? Thank you.
THE WITNESS: Sorry.
MR. SAUER: That's all right. Thank you.
Q. Is this better?
A. Yes. Thank you.
Q. I have a few questions for you this afternoon, Mr. Whitlock. Initially if you could turn to page 10 of your testimony.
MR. COLBERT: Mr. Sauer, which testimony?
MR. SAUER: His supplemental.
MR. COLBERT: Thank you.
Q. At line 19 you talk about 15 percent capacity reserve margin that DE-Ohio relies upon in

their SRT charge calculations; do you see that?
A. Yes, sir.
Q. And what is the basis for that 15 percent?
A. That 15 percent itself is a calculation that's really kind of industry practice that looks at loss of load expectation over a planning horizon, it takes into account the E4 rate, the required operating reserves, and then deviations for temperature above normal, weather-normal temperatures.
Q. And when you say an industry practice, is that something that MISO or PJM have built into their standards, or where exactly does that come from?
A. I mean, various structured markets have different requirements, PJM does have a capacity reserve margin, and I believe it is 15 percent. MISO has a day-ahead operating reserve requirement. Some of the New England markets have -- they are various and sundry, but they're in or around 15 percent. They're basically made up of the same components that I talked about, right, the planned E4 rate, changes in weather, and what you have to have from a capacity standpoint to meet operating reserve requirements.

Q. And staying on page 10 in your supplemental testimony you refer to something as a designated network resource --
A. Uh-huh.
Q. -- that MISO has. Can you explain what a, you refer to as a DNR, what is that?
A. A designated network resource is a resource that's available to meet an energy requirement on a firm basis so that it works on network transmission on a firm basis. It's the firmest supply that you can have.
Q. And is this in a longer term planning mode or more of a day-ahead?
A. If it's a DNR on a longer term basis, it would be a DNR on a shorter term basis. Again, a designated network resource doesn't have time, it works or it doesn't work as a designated network resource. Does that help?
Q. This, again, is in the long-term planning mode then?
A. I don't -- what is "it"?
Q. The DNR. The reference to a DNR, is that only if you're discussing long-term planning?
A. Again, a DNR -- if a DNR meets it on a

long-term basis, it will meet it on a short-term basis so I'm struggling a little bit with the question.

Q. Okay. I'm wasn't sure if it only applied in your SRT calculations as part of the longer term capacity requirement.

A. Let me try it this way, I mean, the SRT is a long-term resource planning, it's where we recover our costs for our long-term resource plan, right? So it's a long-term capacity obligation. It's the company's approach to procure those assets on a long-term basis, right?

Now, a long-term basis, again, we're restricted by approval, we get preapproval for those SRT costs, so we basically go out a year in advance. It's my opinion that we should procure longer term resource capacity, you know, through like last year we should have bought some in '7 and some in '8, but we get annual approval to do those types of things.

If in the short-term we do not have enough designated network resource capacity to meet MISO's operating requirements, that 4 percent, it's 4.1 percent of our forecasted load, we will buy a designated network resource to make sure that we meet

MISO's module E. Does that help?

Q. I think so, yes.

So when you say it's a firm contract or -- did you say it was a firm contract? Was that your reference to a DNR, as a firm contract?

A. You asked me what a DNR was and I said a DNR is a resource that will allow you to use network transmission to meet a load obligation. It's the firmest of resources.

Q. And when you say "network transmission," is that --

A. As opposed to like point-to-point transmission.

Q. Okay. And if that's the firmest of firm, what other resource options are there below a DNR?

A. For capacity?

Q. Yes.

A. There really aren't any. I mean, the idea of -- I don't think there are. I mean, I guess you could buy nonfirm capacity; I don't know why you would buy it, I don't think it gives you anything, right? If the capacity can be recalled from you, it doesn't do anything to help you meet your load obligation.

Q. So then an option, for example, wouldn't be a DNR.

A. An option for capacity or an option for energy?

Q. An option for capacity.

A. Once I exercise the option is it a firm option --

Q. Well, I don't know --

A. -- that would qualify as a DNR, then yeah, it would be a DNR once I exercised it.

Q. Okay. Of the DENA assets, Mr. Whitlock, how many of those assets are within the Midwest ISO?

A. Vermilion.

Q. So just one?

A. Yes.

Q. And you consider DENA assets outside of the MISO footprint to be DNR.

A. You would have to request transmission from PJM and then have transmission, firm transmission, granted out of PJM, and then MISO would do a transmission study to see if those were -- or could qualify as a designated network resource inside of MISO.

Q. Has such a study been done?

A. I don't recall.

Q. And have you reviewed the stipulation that was filed in these proceedings yesterday?

A. I'd like to have one in front of me if you're going to ask me some questions on it.

Q. I believe if you look at, under the stip, paragraph No. 8 -- do you have the stip?

A. I do.

Q. Okay. And did you see paragraph 8?

A. Yeah, I'm looking at it.

Q. Okay. And if I understand your supplemental testimony, you're advocating for the DENA assets to be included within DE-Ohio's capacity purchases as part of the SRT rider, correct?

A. I do.

Q. And the stipulation that was filed in this case yesterday essentially changes your recommendations regarding the DENA assets; does it not?

A. Could you repeat the question?

MR. SAUER: Could I have the question reread, please?

(Question read.)

A. Not insofar as it relates to recovery of

143

those costs through the SRT, right? I mean, in my testimony I say we should recover the costs if we use those assets to meet our capacity requirements and recover those dollars through the SRT.
Q. But does this -- I'm sorry.
A. The stipulation says basically the same thing, that they will be recovered, in the first sentence, through the SRT.
Q. Is it your perspective that through the stipulation there's a limitation as to the usage of these DENA assets?
A. Yes.
Q. And what would that limitation be?
A. It says seven days or less.
Q. And what does that mean to you?
A. Seven days or less.
Q. Would that limit it to use in, say, in an emergency situation only?
A. No. It means seven days or less.
Q. Could you have a series of seven-day events?
A. I believe if they -- I believe so. If they were seven days or less, you could have multiple of those occurrences. Just my reading of it.

144

Q. Is this the first time you're really seeing this stipulation, or were you involved in the discussions that led up to this?
A. No; I was on vacation two weeks and I came back, the first day I saw it was yesterday and it was fluid yesterday, right, so it was changing. So I saw it yesterday.
Q. Okay. Under 8 there are several subpoints, A, B, and C. Do you see those in the stipulation that was filed yesterday?
A. I do.
Q. In a situation where from your perspective we're in a seven-day period where the DENA assets are appropriate for cost recovery, how many broker quotes would you anticipate might be available to help establish a market price under the stipulation?
A. It's going to depend but, again, the majority of the capacity, the majority of the capacity market is going to be procured over a long -- over a longer period of time. Let's make it a year, right, that I'll procure a year in advance a 15 percent reserve margin. Now, if weather is a lot hotter or I lose more than my historic E4 rate, that

145

will put me in a situation where I would be in this circumstance. And so it's rare when capacity is transacted in a very short-term market.
You know, how many broker quotes would I receive? I'll tell you what, if I had to -- again, we're going to be a buyer to maintain our module E requirements in this example, so I'm going to call all of the brokers that I deal with to have them help me get quotes for this period of time, and there might be -- I might get one. I might get five different quotes.
Q. How many brokers do you typically deal with?
A. Around that number, right? I mean, fivish, we'll call it, for power and capacity. Now all of those won't have quotes at the same time, right? They all might. They all might have the same quote, I don't know.
Q. Well, of these brokers that are providing the quotes, would you say that the capacity market is a large or small portion of their business?
A. The term "capacity market's" a significant part of their business, right? The short-term capacity market, again, is not.

146

Q. Okay. And in the long-term capacity market how many capacity transactions occur per day?
A. I don't know. On average? Probably less than one a day, or one a day, two a day, I don't know.
Q. Now, if I understood what you had said earlier, because the capacity market is typically traded in a long-term basis, that it takes some unusual event like an extreme weather situation or a unit goes down or something like that. When was the last time that Duke experienced a situation like that?
A. You know, we had one this -- we had one, I want to say it was like two months ago, maybe three months ago, where we did not have -- we were not going to comply with module E and we actually used the Vermilion capacity that was not committed in the marketplace to satisfy our module E requirement, and we charged zero through -- we don't recover any of those costs, right?
I mean, we basically used that Vermilion asset or the DENA -- the legacy DENA asset to satisfy our module E requirement. And I believe it was two or three months ago. And it was because of outages.

147

Q. And did the cost of that capacity get included in the SRT calculation?
A. No, it didn't.
Q. During that event that you're talking about what was the market price that was being experienced at that time?
A. For capacity or for --
Q. For capacity, yes.
A. Again, we basically polled the market for offers and the offers that we got, I don't remember the exact numbers, we probably have them recorded, but the offers were -- they were high-priced offers, right? And we were like -- we felt like it was not prudent for us to buy that when we had excess capacity of our own, again, it wasn't dedicated to the FPP, to the MBSSO customer, so we used that instead.
So we were basically the buyer, right, because we were the one that had the shortfall. There weren't other buyers. There were sellers, but their price was high, and we didn't buy it and instead used Vermilion resources at no charge.
Q. When you say the price was high, can you kind of give me a range?

148

A. Yeah, you know, I want to say it was -- I'd hate to do it and then be wrong, so is there some way that we could --
Q. Subject to check?
A. Is there a mechanism that we can provide you that data with --
MR. COLBERT: Sure.
A. -- other than me speculating about it?
MR. COLBERT: Your Honor, DE-Ohio will be happy to provide the parties with the data that Mr. Whitlock is referring to. We will get it. I mean, if Mr. Whitlock can do an estimate subject to check, we have no objection to that as well.
MR. SAUER: Mr. Colbert, you're offering to put that into the record, then?
MR. COLBERT: Yes.
MR. SAUER: Not just get it to the parties, but put it into the record?
MR. COLBERT: We can do that, too.
EXAMINER KINGERY: We'll have another day of hearings; you can bring it at that time.
MR. COLBERT: I need to confer with them to see whether it should be confidential, but if it is, we'll file it under seal.

149

EXAMINER KINGERY: That's fine.
MR. SAUER: Thank you.
Q. (By Mr. Sauer) And so given the situation that you've just kind of been talking about here, you would anticipate, if this event now occurs under this stipulation, that the capacity costs for DENA would be a midpoint of the broker quotes that are received and, admittedly, there aren't going to be very many of those, correct?
A. Yeah. Again, there would be the, I mean, there are going to be broker quotes to the degree I can get broker quotes, right? I mean, in that event I would do the exact same thing I did before, I would call counterparties and I would call brokers and ask them what's the market for capacity for whatever the time period -- for the next day. And I would get the number of quotes that I got, and I would get the number of offers that I got, and they would be at the level at which they gave them to me.
Q. And then under B it says the average price of third-party purchases transacted, and how do you envision that would be -- those transactions would be identified?
A. How would the transactions be identified

150

or consummated?
Q. How would they be I guess initially identified and then if they become consummated, how would they be --
A. I would poll the market. I mean, I would call counterparties that I know that have capacity that qualifies, again, that will fulfill my module E requirement, and I would call those counterparties and see if they had capacity available tomorrow, and if they did, I would ask them what their offer was for that capacity.
And if it was -- say I called three different counterparties and the first two didn't have any and the last one had it, then I would buy it, and they would tell me the price and I would buy it.
Q. And, again, is it your anticipation that only the Vermilion plant would be available in these situations?
A. Yeah. I mean --
Q. Realistically.
A. The PJM capacity, right, at the end of this year, right, I will have sold in the new PJM capacity market -- by Friday I'll find out -- we

offered it all into PJM and we'll get a clearing price from PJM on this Friday, so that capacity will be sold.
Now, I'll have the ability to go out and buy capacity from PJM, again, subsequent -- if we said that we wanted to use those assets, we would do the transmission studies, et cetera, and we could buy back the capacity that we sold from PJM and use the PJM capacity to meet this requirement. But likely, you're right, that it's Vermilion.
Candidly, there probably will not be excess legacy DENA capacity available for the MBSSO customer because we'll sell it because, again, that market is a long-term market.
Q. And did I understand you earlier to say that you've not been actively managing your generation portfolio beyond 2008?
A. Are you referring to something in my testimony?
Q. No, something you said earlier on the stand where if you had your way, you would have been doing something in 2007-2008 already.
A. I think what I was talking about was, again, this 15 percent, or X percent, reserve margin

is designed for a longer period of time than the next-day planning. It's a long-term resource planning, right? It's saying do I have enough resource.
Because, again, this is steel in the ground that we're talking about. I mean, that's probably in laymen's term. A designated network resource is that steel in the ground kind of idea and that's a much longer lead time than seven days or a day or even a year, right? It says we need to have so many resources available to produce the energy to light the light bulbs.
So what I said was is that instead of us planning for kind of a one-year or one year at a time approach, we should plan for a longer period of time; that's what I said.
Q. Okay.
A. But I don't think I said actively manage. I don't know.
Q. I'm sorry.
A. We can talk about active management.
Q. Mr. Whitlock, I believe in your direct testimony you had estimated SRT purchases for 2007 to be $8 million or approximately $8 million. Do you

recall that?
A. What page is that?
Q. I think it was on one of your schedules.
A. Yeah, I see it.
Q. And that is --
A. It's almost 9 million.
Q. Is that a projection for 2007?
A. Yes.
Q. And do you know what your final SRT costs for 2006 were?
A. I don't, but I'm sure we can provide it. I don't.
MR. COLBERT: Your Honor, just to clarify, we are still under seal, right?
EXAMINER KINGERY: Yes, we are.
MR. COLBERT: Thank you.
EXAMINER KINGERY: We've been under seal all day.
MR. COLBERT: Just wanted to make sure.
Q. (By Mr. Sauer) I apologize, I didn't mark it in your testimony but I think you had an estimate in here, maybe an actual number through September of '06 of approximately -- yes, on page 8, line 4, I think you're estimating your SRT expenses to be

$4 million. Does that look right?
A. Yeah, I see -- yeah.
Q. So do you know what the difference was or what you're anticipating the difference to be between an SRT charge in 2006 of $4 million to an SRT charge in 2007 of almost $9 million?
A. When we do the estimate, I mean, the actuals are what we actually paid, right, and for the products that we buy. And then the estimate is a calculation based on the products that we think we're going to buy at the prices that we think we'll be able to execute those, right?
I haven't done a line-by-line comparison, although it would be easy to do to say here are the products in 2006, here are the similar products in 2007, and here are the prices and the various prices. So it would be easy to do that, I just -- I don't have that in front of me.
Q. And to the extent that you do overestimate the SRT charges and there's a true-up, the actual costs that you incur are actually charged back to the customers, then?
A. If we overestimate it, it wouldn't be charged back, right? We would give them a credit.

155

Q. A credit coming back to the customers.
A. Yes.
Q. And that's with interest?
A. I don't know.
MR. SAUER: Thank you. That's all we have, your Honor.
EXAMINER KINGERY: Thank you.
Mr. Boehm, do you have any?
MR. BOEHM: No cross.
EXAMINER KINGERY: Staff?
MR. REILLY: Thank you, your Honor.
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CROSS-EXAMINATION
By Mr. Reilly:
Q. Good afternoon, Mr. Whitlock. My name is Steve Reilly. I'm here on behalf of the staff of the Commission. I just have a few questions for you.
I'd like to direct your attention to what Mr. Sauer called the stipulation that was filed yesterday. Do you have a copy of that up there?
A. Yes, sir.
Q. Thank you.
If you could turn to page 7, I'd like to talk to you about paragraph 8 on that page for a

156

second. And I would like you to take a look at the first sentence in paragraph 8. And you were talking with Mr. Sauer about the term as used in that paragraph, "short-term." Do you recall that discussion with Mr. Sauer?
A. I believe so.
Q. All right. Now, you weren't involved, I think you said, in the discussions that led up to this stipulation; is that correct?
A. Yeah; I was on vacation. I mean, I was involved in some discussions starting yesterday, right.
Q. Were you involved in discussion with any party aside from your own company, Duke - Ohio?
A. No, sir.
Q. Okay. So you weren't involved with discussions with any other party to this stipulation besides Duke, correct?
A. No, sir. Or, I mean, ask that question again. I think I -- I was not involved with any other parties other than, I mean, I talked to Paul Colbert about it.
Q. All right. Mr. Colbert works for Duke - Ohio, correct?

157

A. Duke Energy Shared Services.
Q. Very good.
A. I got in that conundrum before.
Q. So you don't know how any other party may view the term "short-term," correct?
A. It defines short-term as seven days or less.
Q. All right. Now, when you were talking with Mr. Sauer, the question of multiple occurrences came up; do you recall that?
A. I do.
Q. You would not be in a position to say how any other party would view multiple occurrences being tacked together, are you?
A. I'm not.
Q. All right. That would be a subject that would be ultimately decided, if there was great disagreement, in an enforcement proceeding; is it not -- is that not correct?
A. I don't know where it would be decided, but --
Q. All right.
MR. REILLY: Nothing further.
EXAMINER KINGERY: Redirect?

158

MR. COLBERT: No redirect, your Honor.
EXAMINER KINGERY: Thank you very much. You may step down.
(Witness excused.)
EXAMINER KINGERY: Would you like to call one more witness?
MR. COLBERT: Yes. Your Honor, the company's going to call Mr. Don Wathen.
EXAMINER KINGERY: Would you raise your right hand?
(Witness sworn.)
EXAMINER KINGERY: You may be seated.
MR. COLBERT: Your Honor, we would mark the FPP testimony as DE-Ohio Remand Rider 3.
EXAMINER KINGERY: Yes.
MR. COLBERT: And the direct and supplemental of the AAC as Remand Riders 4 and 5. DE-Ohio Remand Riders 4 and 5.
EXAMINER KINGERY: That's direct and supplemental in that order.
MR. COLBERT: That's correct. Trying to keep them in the order they were filed.
EXAMINER KINGERY: They will be so marked.

159

MR. COLBERT: Thank you, your Honor.
(EXHIBITS MARKED FOR IDENTIFICATION.)
- - -
WILLIAM DON WATHEN, JR.
being first duly sworn, as prescribed by law, was examined and testified as follows:
DIRECT EXAMINATION
By Mr. Colbert:
Q. Mr. Wathen, do you have in front of you what has now been marked DE-Ohio Remand Rider 3, 4, and 5?
A. I do.
Q. And are those your direct testimony in the FPP proceeding and direct and supplemental in the AAC proceeding?
A. It is.
Q. And were those prepared by you or under your direct supervision?
A. Yes.
Q. And do you have -- well, do you have any amendments or changes to those?
A. I do have one typo on page 4, it's Exhibit 4, on line 21. Change the word "energy" to --

160

EXAMINER KINGERY: Just a minute. I was trying to collect my exhibits.
MR. COLBERT: Exhibit 4, that would be the direct of the AAC.
EXAMINER KINGERY: The thickest of the three is No. 3; is that correct? Okay, and you are now making a correction on No. 4.
THE WITNESS: Four.
EXAMINER KINGERY: Which is the one filed on September 5th.
THE WITNESS: It's got the one captioned 1085.
EXAMINER KINGERY: Yes. Okay. What page?
THE WITNESS: On page 4, line 21.
EXAMINER KINGERY: Okay. Thank you.
THE WITNESS: "Energy" should be "entry."
Q. (By Mr. Colbert) Do you have any other changes or corrections, Mr. Wathen?
A. No, I don't.
MR. COLBERT: Your Honor, Mr. Wathen is available for cross-examination.
EXAMINER KINGERY: Thank you very much. Mr. Sauer?

161

MR. SAUER: Thank you, your Honor.
- - -
CROSS-EXAMINATION
By Mr. Sauer:
Q. Make sure I've got your exhibits correct, Mr. Wathen. Remand Exhibit No. 3 is your September 1st direct testimony?
A. I'm sorry, I can't hear you very well.
Q. Exhibit 3 is your direct testimony filed September 1st?
A. In the rider FPP case.
Q. In the rider FPP case. And Exhibit 4 is the direct testimony in the AAC?
A. That's right.
Q. And then Exhibit 5 would be the supplemental, okay. Thank you.
If you could turn to page 5 of your Exhibit 5, at line 14 you talk about a new formula to determine market price; do you see that?
A. I do.
Q. Can you describe what you mean by "a new formula"?
A. Well, I think the, what we'd call a market based standard service offer is a, it's really

162

a combination of a lot of different components that in the course of several stipulations, orders, and rehearing orders we've come up with a method to simulate market prices through this MBSSO, that's what I mean by "new formula."
Q. So what you're saying, it's a simulation of a market price?
A. Yes.
Q. So if there's not a functional market, you really can't be certain that what you have is a market price; is that what you're saying?
A. I think by definition in this case this is the market price.
Q. As part of the AAC charge you're proposing recovery of the interest on construction work in progress; is that correct?
A. I'm proposing recovery of a return on construction work in progress, that's right.
Q. And how many environmental compliance projects are included in CWIP recovery that you're proposing in the AAC charge?
A. I don't have a comprehensive list off the top of my head, but it's going to be dozens.
Q. Each plant has a construction project

163

ongoing?
A. Again, subject to check, I would say most coal plants do. I doubt if the gas-fired plants do.
Q. Okay. And are the environmental compliance projects designed to make the plants compliant with current clean air regulations or future regulatory clean air targets?
A. I'm not the person who came up with those plans, so I probably can't speak too specifically to them, so I'm not sure exactly which set of environmental compliance plans they're for.
Q. Well, if the construction project is designed to meet current clean air requirements and those facilities aren't completed yet, how would the plants be operating under compliance?
A. Well, when we operate a plant, let's just take the current environmental regulations, if we're not complying with environmental regulations, we have two choices: Shut the plant down and buy purchased power, or buy emission allowances and generate power.
Q. Can you also buy sulfur coal to operate those plants?
A. I'm not sure what each plant's specifications are, but it's not a simple thing to

164

change over coal specs.
Q. But when you're making those decisions and operating under those conditions, your emission allowance costs are being run through the FPP; are they not?
A. If we choose to run -- if we operate a plant that isn't complying and we operate it for the sake of FPP consumers, and it emits beyond its allowance, we would have to buy an EA, assuming that purchased power was too expensive otherwise we would have bought the power. And yes, they would flow through -- at least the FPP share of it would flow through the rider FPP.
Q. So essentially aren't you asking the customers to pay twice, then, if they're paying for any emission allowances that you may be charging them through the FPP and then in addition to that you're charging a return on the construction projects that would be run through the AAC?
A. I don't see how.
Q. If you -- at the time the construction projects are completed and the retrofit is in place, would your emission allowance costs then go down?
A. To the extent that we were able to reduce

165

our emissions, we would have a lesser need to buy emission allowances, so our emission costs in that respect would go down.
MR. SAUER: We have nothing else, your Honor.
EXAMINER KINGERY: Thank you.
Mr. Boehm?
MR. BOEHM: No questions, your Honor.
EXAMINER KINGERY: Staff.
MR. REILLY: No questions.
EXAMINER KINGERY: No questions?
MR. REILLY: No.
EXAMINER KINGERY: Redirect?
MR. COLBERT: No redirect, your Honor.
EXAMINER KINGERY: You may step down. Thank you very much.
(Witness excused.)
EXAMINER KINGERY: Let's go off the record for a minute.
(Discussion held off the record.)
EXAMINER KINGERY: Let's go back on the record.
I believe, Mr. Colbert, you wanted to move some exhibits?

166

MR. COLBERT: Yes, I would move Remand Rider -- Duke Energy - Ohio Remand Riders 1, 2, 3, 4, and 5 into evidence.
EXAMINER KINGERY: Any objections?
(No response.)
EXAMINER KINGERY: They will be admitted.
(EXHIBITS ADMITTED INTO EVIDENCE.)
MR. COLBERT: And then just as we marked the joint exhibit, but we will wait until testimony has been presented on that to move it.
EXAMINER KINGERY: Thank you. And that is Joint Exhibit --
MR. COLBERT: Joint Exhibit Remand Rider 1.
EXAMINER KINGERY: Yes, Remand Rider 1, and that was the stipulation --
MR. COLBERT: That's correct.
EXAMINER KINGERY: -- as docketed yesterday.
Okay. With that we will adjourn for today and reconvene at 9 o'clock on Thursday, April 19th. I believe we have this room. Thank you.
MR. BOEHM: Thank you, your Honor.
(Thereupon, at 3:58 p.m. the hearing

adjourned.)

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CERTIFICATE

We do hereby certify that the foregoing is a true and correct transcript of the proceedings taken by us in this matter on Tuesday, April 10, 2007, and carefully compared with our original stenographic notes.

____
Maria DiPaolo Jones, Registered Diplomate Reporter and CRR.

____
Karen Sue Gibson, Registered Merit Reporter.

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BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

- - -

In the Matter of the : Consolidated Duke Energy : Case Nos. 03-93-EL-ATA
Ohio, Inc., Rate : 03-2079-EL-AAM
Stabilization Plan : 03-2081-EL-AAM
Remand and Rider : 03-2080-EL-ATA
Adjustment Cases. : 05-724-EL-UNC
: 05-725-EL-UNC
: 06-1068-EL-UNC
: 06-1069-EL-UNC
: 06-1085-EL-UNC

- - -

PROCEEDINGS

before Ms. Jeanne Kingery and Mr. Scott Farkas, Hearing Examiners, at the Public Utilities Commission of Ohio, 180 East Broad Street, Room 11-C, Columbus, Ohio, called at 9:00 a.m. on Thursday, April 19, 2007.

- - -

REMAND RIDER - VOLUME II

- - -

ARMSTRONG & OKEY, INC.
185 South Fifth Street, Suite 101
Columbus, Ohio 43215-5201
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- - -

2

(Begin Confidential Portion.)

A. Well, I think the stipulation ensures that it is -- that we don't -- or the stipulation is nondiscriminatory, so I think that was intended to be phrased so, therefore, for instance, we had a finding on a fuel settlement component with [redacted]ompany and we are passing through the benefits of that to both residential and nonresidential, so I think all customer classes are benefiting from that particular piece so that would be nondiscriminatory.

MR. COLBERT: Your Honor, just -- no objection to the answer or the question, but to the extent that the witness is going to discuss the [redacted]portion of the case, that is confidential. That portion has been redacted from the stipulation and that part of the record should be under seal.

(End Confidential Portion.)

C2911

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

Consolidated Duke Energy Ohio, Inc. Rate Stabilization Plan Remand and Rider Adjustment Cases.	))))))))))	Case Nos. 03-93-EL-ATA 03-2079-EL-AAM 03-2080-EL-ATA 03-2081-EL-AAM 05-724-EL-UNC 05-725-EL-UNC 06-1068-EL-UNC 06-1069-EL-UNC 06-1085-EL-UNC

CONFIDENTIAL

INITIAL POST-REMAND BRIEF, HEARING PHASE II,
BY
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL

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Dated: May 17, 2007

02912

TABLE OF CONTENTS

Page

02913

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

Consolidated Duke Energy Ohio, Inc. Rate Stabilization Plan Remand and Rider Adjustment Cases.	))))))))))	Case Nos. 03-93-EL-ATA 03-2079-EL-AAM 03-2080-EL-ATA 03-2081-EL-AAM 05-724-EL-UNC 05-725-EL-UNC 06-1068-EL-UNC 06-1069-EL-UNC 06-1085-EL-UNC

INITIAL POST-REMAND BRIEF, HEARING PHASE II, BY THE OFFICE OF THE OHIO CONSUMERS' COUNSEL

I. INTRODUCTON

A. Prefatory Comments

The briefs submitted to the Public Utilities Commission of Ohio ("PUCO" or "Commission") in Phase I of in these cases identified the parties who supported the proposals offered by Duke Energy Ohio, Inc. ("Duke Energy Ohio" or the "Company," including its predecessor company, "CG&E") in Phase I. Those parties supporting Duke's proposals remain essentially the same in Phase II of these proceedings. This situation further demonstrates the importance of evidence regarding the side deals between the Duke-affiliated companies and parties or members of parties to these proceedings.

Serious negotiation of a stipulation regarding the Company's Fuel and Purchased Power ("FPP") tracker, System Reliability Tracker ("SRT"), and Annually Adjusted

Component ("AAC") charges could only take place with parties that represent customers who bear the full brunt of the rate increases and that have not otherwise been "captured" by the Company by means of other financial arrangements. Such serious negotiation did not take place regarding the stipulation entered into by parties and filed on April 9, 2007 ("2007 Stipulation," Joint Remand Rider Ex. 1[1]).

The OCC files this brief with redactions to protect information regarding side deals that is alleged by Duke Energy Ohio and others to be confidential, as directed by the PUCO. The OCC maintains its previous arguments that such information should be released to the public domain. The true nature of the rate plan in Duke Energy Ohio's service area should be available for public scrutiny.

B. Burden of Proof

The burden of proof in these cases rests upon Duke Energy Ohio, and the OCC does not bear any burden of proof in these cases. In a hearing regarding a proposal that does not involve an increase in rates, R.C. 4909.18 provides that "the burden of proof to show that the proposals in the application are just and reasonable shall be upon the public utility." In a hearing regarding a proposal that does involve an increase in rates, R.C. 4909.19 provides that, "[a]t any hearing involving rates or charges sought to be increased, the burden of proof to show that the increased rates or charges are just and reasonable shall be on the public utility." In the following sections, the OCC will explain how Duke

[1] For notational convenience, the portions of the case before and after the Court's deliberations are cited separately. The proceedings prior to the appeal are referred to, collectively, as the "*Post-MDP Service Case*," and the proceedings after the appeal are referred to, collectively, as the "*Post-MDP Remand Case*," the latter of which was separated in some respects into Phase I and Phase II. However, a single record exists that is applicable to the ultimate decisions. Exhibit references to the portion of the proceedings in Phase I after remand from the Court contain the word "Remand" to distinguish them from other exhibits. Exhibit references to the potion of the proceedings in Phase II after remand from the Court contain the words "Remand Rider."

Energy Ohio has failed to prove that its post-MDP pricing proposals should be adopted without alteration by the Commission.

C. The OCC Position

The Commission should only approve standard service offer rates with bases that can be checked and monitored for appropriateness by the PUCO rather than being based on Duke Energy Ohio's desired rates.[2] The Commission's objective should be to approve a good proxy for market-based rates based upon measurable and verifiable costs.[3] As stated by OCC Witness Talbot, "[t]here should be no overlap or duplication of items and the components should work together to achieve standard service offer rates that provide for reasonably priced service and meet the three standards of rate stability for customers, financial stability for the company, and encouragement of competition."[4]

In support for this objective, the OCC supports the positions presented by Energy Ventures Analysis ("EVA" or "Auditor") in its report to the Commission ("Auditor's Report," PUCO Ordered Remand-Rider Exhibit 1(A)). The Auditor's Report makes many recommendations regarding the manner in which the FPP and SRT should be dealt. These recommendations should be followed to prevent the Company from making procurement decisions that are detrimental to customers. As an example, the Auditor's Report states that under the Order in the *Post-MDP Service Case*, "CG&E believed that it had the license to evaluate and select which approach [to computing the FPP] to use," "CG&E continuously modified its approach to many . . . items," and "CG&E's elections

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[2] See, e.g. OCC Initial Post-Remand Brief, Phase I, at 13-14 (April 13, 2007).

[3] OCC Remand Ex. 1 at 6 (Talbot). OCC Witness Talbot testified that rate components should "meet[ ] the double standard of reflecting measurable accounting costs and verifiable costs." Id. at 47.

[4] Id. at 17 (Talbot), noting the Commission's test for a "rate stabilization plan."

had very significant ratepayer impacts."[5] OCC-sponsored testimony also supports a prohibition against SRT charges in connection with assets formerly owned by Duke Energy North America ("DENA Assets") and currently owned by Duke Energy Ohio.

OCC-sponsored testimony supports Commission review of the charges that Duke Energy Ohio proposes for the AAC charge. The Commission should eliminate that portion of the proposed charge that can be attributed to a return on all construction work in progress ("CWIP").

II. PROCEDURAL HISTORY

The procedural and substantive history of these consolidated cases, as supplemented herein, is contained in the OCC Initial Brief, Hearing Phase I, that was submitted on April 13, 2007 and the OCC Reply Brief, Hearing Phase I, that was submitted on April 27, 2007.

Phase II of the hearing convened on April 19, 2007, and featured the submission the Auditor's Report prepared by EVA, as assisted by Larkin & Associates. Mr. Seth Schwartz of EVA and Mr. Ralph Smith of Larkin & Associates ("Larkin") supported the results of the Auditor's Report in their live testimony. The Audit's Report was prepared by EVA and Larkin for the audit period July 1, 2005 through June 30, 2006.[6] The Auditor's Report states that the Commission requested that EVA "follow the general guidance that had been provided for the Electric Fuel Component audits" from the formerly applicable Ohio Administrative Rules and that the Auditor's Report was also

[5] PUCO Ordered Remand Rider Exhibit 1 at 1-3 (Auditor's Report).

[6] Id. at 1-1.

guided by the contents of a stipulation ("FPP Stipulation") that followed EVA's submission of an earlier report on October 7, 2005.[7]

The second day of the hearing for Phase II convened on April 19, 2007 and largely dealt with the subject of the 2007 Stipulation.

III. ARGUMENT

A. The Auditor's Report Should be Followed Regarding FPP Charges.

The audit of Duke Energy Ohio's practices revealed that the Company's treatment of matters that affect the FPP calculation has needlessly raised costs. The Audit's Report contained the following major recommendations regarding Duke Energy Ohio's transactions that affect FPP charges:

> 1. EVA recommends for the audit period that the Company pass through the native load portion of the net margins associated with the trading of DE-Ohio coal assets purchased for delivery during the audit period except for these specifically excluded by paragraph D of the [FPP S]tipulation. * * *
> 2. EVA recommends that DE-Ohio adopt traditional utility procurement strategies related to the procurement of coal and emission allowances and cease its "active management" of such procurements throughout the balance of the RSP period. Accordingly, DE-Ohio should develop and implement a portfolio strategy such that it purchases coal through a variety of short, medium and long-term agreements with appropriate supply and supplier diversification with credit-worthy counterparties. EVA further recommends that DE-Ohio no longer seek to flatten its position on a daily basis.
> 3. EVA recommends that as long as the FPP is in effect coal suppliers should not be required to allow the resale of their coal for the offers to be considered.
> 4. EVA recommends that DE-Ohio initiate a study to report on the recurring overstatement of coal inventory at the Zimmer station.

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[7] Id. at 1-2 through 1-3.

5. EVA recommends that DE-Ohio present several alternative sensitivity analyses of key variables, i.e., emission allowance prices and market coal prices, in its transaction review and approval process.[8]

The Auditor's recommendations should be followed by the Commission.

Regarding the first major recommendation, EVA noted that Duke Energy Ohio should pass through the margins, consistent with the FPP Stipulation.[9] The FPP Stipulation should be followed, and all margins not excluded by the FPP Stipulation should be passed through the FPP.

EVA's second major recommendation that the Company should develop a portfolio approach to the purchase of coal essentially argues that the Company's self-imposed constraint against the purchase of coal on a longer-term basis does not offer lower costs than a purchasing regimen that is not artificially constrained. EVA observed that "DE-Ohio has no volumes [of coal] committed for the period beginning in 2009 leaving DE-Ohio's customers totally exposed to the market at that time."[10] Company Witness Whitlock makes this same argument regarding capacity purchases that are charged as part of the SRT:

> 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.[11]

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[8] Id. at 1-9 through 1-10.

[9] Id. at 1-7 and 2-13.

[10] Id. at 2-19.

[11] Company Remand Rider Ex. 1 at 7 (Whitlock).

The Auditor's Report states that Duke Energy Ohio has passed up attractive coal contracts that have increased FPP charges and left an exposure to coal markets after 2008.[12]

On cross examination, the Auditor stated his "position that it is reasonable for the [C]ompany to project that there will, in fact, be a demand for electricity to be supplied from these [Company] generating stations whether or not they had regulated retail sales or firm sales at the present time."[13] The Company does not properly match the duration of its coal contracts with the duration of its sales of electricity -- the basis for its different treatment of coal purchases by jurisdiction[14] -- because the Company has the statutory obligation to provide a standard service offer after 2008.[15] The Company's self-imposed restriction on the periods covered by its coal contracts raises fuel costs, a policy that does not serve either Duke Energy Ohio or its customers.

EVA's third major recommendation would permit the consideration of bids from bidders who seek to limit the resale of their coal. The Company should follow this recommendation because it opens up additional opportunities to obtain low-cost bids. The Auditor's Report states that "Not every coal producer allows their coal to be resold. CG&E buys from those who do."[16] Duke Energy Ohio's defense of its practice is disingenuous. Company Witness Whitlock stated that "DE-Ohio does *include the resale*

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[12] PUCO Ordered Remand Rider Exhibit 1 at 2-19 (Auditor's Report).

[13] Tr. Vol. Remand Rider Vol. I at 106 (April 10, 2007) (Auditor).

[14] Id. at 56.

[15] R.C. 4928.14(A).

[16] PUCO Ordered Remand Rider Exhibit 1 at 2-11 (Auditor's Report).

of coal as a condition on its RFPs but does not exclude an offer from consideration if the supplier will not permit the resale of coal."[17] The Company's claim that it is willing to purchase coal from suppliers who place restrictions on the resale of coal, but such coal suppliers are *told not to bid*, bodes poorly for Duke Energy Ohio's agreement in the 2007 Stipulation to accept the Auditor's third major recommendation (i.e. which the Company claims to be following at present).[18] Duke Energy Ohio should be ordered to remove the restriction on the resale of coal from its requests for proposals and to select bids on a least cost basis.

An important step needed to carry out EVA's third major recommendation is for Duke Energy Ohio to draft a policies and procedures manual for fuel procurement. An earlier audit found the Company's manual lacked detail such that "EVA did not find the [existing] document to be particularly useful or relevant."[19] The situation was not corrected by Duke Energy Ohio for the most recent audit, such that the policies and procedure manual "contains no specific information regarding such items as contract mix, inventory targets, or the procurement process."[20] The manual should describe "how the company solicits bids, qualified new suppliers, purchases coal on an emergency basis, etc.," and the solicitation process should remove the restriction on the resale of coal.[21]

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[17] Company Remand Rider Ex. 2 at 9 (Whitlock Supplemental) (emphasis added).

[18] Joint Remand Rider Ex. 1 at 7-8 ("accepts all audit recommendations . . . except as set forth in paragraphs one through eight above").

[19] PUCO Ordered Remand Rider Exhibit 1 at 2-8 (Auditor's Report).

[20] Id. (citations omitted). The recommendation is not stated under "Management Audit Recommendations" (id. at 1-9 through 1-10), but is ancillary to the major recommendations regarding coal purchasing.

[21] Id., footnote 11.

EVA's fourth major recommendation would initiate a study into the overstatement of coal inventory at the Zimmer station. The Auditor's Report states that "DE-Ohio continues to follow the PUCO guidelines for adjustment to the DE-Ohio plants."[22] The overstatement existed for all five years listed in the Auditor's Report. The Auditor's Report states that "the Zimmer situation is a problem that DE-Ohio needs to address . . . forthwith."[23] The Commission should order Duke Energy Ohio to address the persistent problem.

EVA's fifth major recommendation regarding alternate sensitivity analyses in its transaction review and approval process resulted from EVA's observation that "DE-Ohio did not appear to have conducted any sensitivity analysis of the critical assumptions related to SO_2, i.e., the variable operating cost of the scrubber and emission allowance costs, or the market price."[24] The Company should conduct such a sensitivity analysis, which would be available for the next performance audit. A sensitivity analysis will provide the Commission and the intervenors with additional information with which to evaluate the reasonableness of the price assumptions utilized by Duke Energy Ohio. The Company's assumptions could significantly affect the costs that are passed on to consumers. The analysis would also be useful for a performance audit that includes a discussion of expenses that are used in the calculation of the AAC -- further discussed in a later section -- that was recommended by OCC Witness Haugh.[25]

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[22] Id. at 2-10.

[23] Id. at 2-11.

[24] Id. at 2-18.

[25] OCC Remand Rider Ex. 1 at 5-6 (Haugh).

Duke Energy Ohio should be ordered to follow all of EVA's recommendations, those stated in the "Management Audit Recommendations" section of the Auditor's Report as well as the ancillary recommendations that follow from the findings contained within the Auditor's Report.

B. Capacity Costs Should be Based on Actual Costs, Which Excludes Charges Related to the DENA Assets at this Time.

The Commission should only approve rates based upon measurable and verifiable costs for capacity. The Reserve Margin charge in the stipulation submitted on May 29, 2004 ("2004 Stipulation," Joint Ex. 1) was inappropriately based on the hypothetical cost of building new peaking units when capacity was available at much lower prices.[26] As stated in the OCC's briefs for Phase I, the SRT is the sole successor to the Reserve Margin component in the 2004 Stipulation, the charge for lining up reserve capacity.[27] The Infrastructure Maintenance Fund ("IMF") charge should be eliminated since it was added by the Company -- without any supporting costs -- in its Application for Rehearing in the *Post-MDP Service Case*. The SRT should be reasonable, and not set to reflect any hypothetical and/or poorly documented costs proposed by Duke Energy Ohio.

The Auditor's Report contained the following major recommendation regarding Duke Energy Ohio's SRT charges:

> 6. EVA recommends that purchase of reserve capacity from DENA Assets should not be eligible for inclusion in the SRT, as is currently the case.[28]

[26] See, e.g., OCC Initial Post-Remand Brief, Phase I, at 20 (April 13, 2007), citing OCC Remand Ex. 1 at 46 (Talbot).

[27] Id.

[28] PUCO Ordered Remand Rider Exhibit 1 at 1-10 (Auditor's Report).

In PUCO Case No. 05-732-EL-MER ("*Duke/Cinergy Merger Case*"), the Commission found that "costs that may be related to the transfer of the DENA assets will not be . . . passed on to Ohio customers without approval of the Commission."[29] Further, in Case No. 05-724-EL-UNC, the Commission adopted a stipulation filed on October 27, 2005 ("SRT Stipulation"[30]) in which it was stated that Duke Energy Ohio could not use the DENA Assets in its SRT calculations without an application to the Commission requesting approval.[31] The record does not support any change in the prohibition against charging for the DENA Assets, and the Auditor's recommendation should be followed by the Commission.

The Auditor's Report states that Duke Energy Ohio "has not demonstrated that its native customers are paying more for capacity in the market than they would if DE-Ohio purchased capacity for the legacy DENA [plants].[32] The Auditor's Report discusses the alternatives available to the Duke Energy Ohio:

> EVA agrees with DE-Ohio as to the types of capacity products it is considering and notes that this list may change over time. As a result, monitoring of the market for alternatives is appropriate. EVA supports the use of a greater mix of products similar to what DE-Ohio employed in 2005 rather than the heavy reliance on one type of product in 2006. Further, and as noted below, DE-Ohio should be considering the use of multi-year arrangements rather than only single-year and spot products in its mix. * * * In fact, it is not clear to EVA that DE-Ohio had previously been precluded

[29] *Duke/Cinergy Merger Case*, Case No. 05-732-EL-MER, Order at 15 (December 21, 2005).

[30] The SRT Stipulation is reviewed in the Auditor's Report. PUCO Ordered Remand Rider Exhibit 1at 6-1 through 6-2 (Auditor's Report). The SRT Stipulation itself is an exhibit in the record. OCC Remand Rider Exhibit 4.

[31] *In re Setting of SRT*, Case No. 05-724-EL-UNC, Order at 6 (November 22, 2005).

[32] PUCO Ordered Remand Rider Exhibit 1at 6-5 (Auditor's Report).

> from doing so. EVA believes that DE-Ohio should employ a portfolio strategy similar to what EVA is recommending for fuel.[33]

Contrary to the assertion of Company Witness Whitlock, therefore, EVA recommends the expansion of options applied by Duke Energy Ohio beyond the limited options selected by the Company's management in order to hold down costs for consumers.[34] OCC Witness Haugh pointed out that the "Company [did] not provide[ ] any market pricing mechanism in its Application."[35] Mr. Haugh stated that "DE-Ohio has not demonstrated that use of the DENA assets will provide benefits to customers."[36] The pricing mechanism was only addressed in the 2007 Stipulation. That approach is inadequate, and will be discussed below regarding the weaknesses in the 2007 Stipulation.[37]

The Auditor's Report states that affiliate transactions "are always problematic," "mak[ing] the market suspicious regarding pricing and potentially reduce[ing]

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[33] Id. at 6-4 through 6-5.

[34] Company Remand Rider Exhibit 2 at 11 (Whitlock Supplemental) ("[l]imiting the options . . . [which] can only increase the cost to consumers"). The opportunity presented by the DENA Assets appears to be limited. Although Company Witness Whitlock stated that the location of DENA Assets "should not exclude them from consideration for Rider STR capacity purchases" (Company Remand Rider Exhibit 2 at 14), Mr. Whitlock stated under cross examination that he did not know whether a MISO transmission study had been conducted to determine whether the DENA Assets located in the PJM footprint could qualify as a Designated Network Resource ("DNR") to meet MISO requirements. Tr. Vol. Remand Rider Vol. I at 141-142 (April 10, 2007) (Whitlock).

[35] OCC Remand Rider Exhibit 1 at 12 (Haugh).

[36] Id. at 11 (Haugh).

[37] In short, basing the price for using the DENA Assets on a "market" price documented by Duke Energy Ohio's market trading personnel assures that they will not be "the most reasonably priced capacity available." Company Remand Rider Exhibit 2 at 11 (Whitlock Supplemental).

competitive offers."[38] Thus, Duke Energy Ohio helped to create a problem by reducing the number of market participants in the Duke/Cinergy merger,[39] and its proposal to use the DENA Assets may compound that problem by discouraging the remaining market. Company Witness Whitlock stated that "there is no reason to believe that DE-Ohio's motives are nefarious and that the Company will not continue to act in the best interests of its consumers."[40] Mr. Whitlock misses the Auditor's fundamental point: the Company is expected to act in its *own best interests*, which creates the need for regulatory oversight and the audit process whereby EVA recommended adjustments to the Company's purchasing activities that would better align the Company's operations to the *public interest*.

The Auditor's Report states that such affiliate transactions "put[ ] a greater burden on the audit process which is then required to determine whether the transaction price was for no more than the market."[41] Part of that burden also falls to parties such as the OCC in future proceedings, and ultimately upon the Commission that must evaluate evidence presented by a future auditor and parties to future proceedings.

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[38] PUCO Ordered Remand Rider Exhibit 1at 6-5 (Auditor's Report). The Auditor's conclusions are correct, although pricing for the use of the DENA Assets is "problematic" because the generators are owned by Duke Energy Ohio as the result of the Duke-Cinergy merger. OCC Remand Rider Ex. 1 at 12 (Haugh).

[39] OCC Remand Rider Exhibit 1 at 12 (Haugh) (Q&A 23).

[40] Company Remand Rider Ex. 2 at 12-13 (Whitlock Supplemental).

[41] PUCO Ordered Remand Rider Exhibit 1at 6-5 (Auditor's Report).

Finally the Auditor's Report states that "DE-Ohio should not be disadvantaged by this [Auditor's Report] position as the legacy DENA assets should be able to be sold at market prices, which is what DE-Ohio is proposing to pay."[42]

The Commission should retain its current position that reserve capacity from DENA Assets is not eligible for inclusion in the calculation of the SRT.

C. A Return on CWIP Should Not be Included in the AAC Charges.

The calculation of the AAC and the underlying transactions were not within the scope of the Auditor's Report, a matter that should be adjusted so that future reviews consider a wider range of Company activities. The AAC, according to Attachment 1 to the Company's Application for Rehearing in Case No. 03-93-EL-UNC, is defined as a component "to recover costs associated with homeland security, taxes, and environmental compliance."[43] The review should include the managerial decisions that involved expenditures that potentially qualify for inclusion in the AAC.

The cross examination of OCC Witness Haugh missed the distinction between the additional review of the AAC that he recommended and the PUCO Staff's inquiries in this area.[44] The PUCO Staff investigated the Company's accounts regarding capital environmental plant additions, and to some extent verified the existence of certain plant additions.[45] Mr. Haugh recommended, however, that a "Management Performance

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[42] Id.

[43] Duke Energy Application for Rehearing, Attachment 1 (October 29, 2004).

[44] See, e.g., Tr. Remand Rider Vol. II at 61-62 (April 19, 2007) (Haugh) ("track costs").

[45] See, e.g., Tr. Remand Rider Vol. II at 29 (April 19, 2007) (Tufts) ("financial audit activities as well as a physical audit").

audit[ ]" should be conducted regarding the decisions related to expenditures that potentially qualify for inclusion in the AAC, similar to those conducted for the SRT and FPP cases as well as those in the natural gas industry.[46] Such a review would extend well beyond the verification of the Company's accounting records. An objective review should be undertaken regarding the sensitivity analyses recommended by EVA with respect to coal bid evaluations that should consider "critical assumptions related to SO_2" such as the operating cost of scrubbers.[47] Duke Energy Ohio's cross-examination of Mr. Haugh demonstrated that the Company believes there are important trade-offs between its environmental-related expenditures and its fuel/purchased power activities.[48] The absence of a managerial audit of the AAC in conjunction with that of the FPP limits the Commission's insights into such possible trade-offs.

The reasonableness of a return on CWIP for environmental plant in the AAC calculations is another matter not covered by Staff's inquiries. Asked whether he formulated an opinion regarding whether a return on such CWIP is an appropriate component of the AAC, Staff Witness Tufts stated that he "did not form an opinion and that's not part of [his] testimony."[49] Neither the Company nor the Staff provided any detail -- for example, of the percentage completion of environmental upgrades at Duke Energy Ohio's plants -- that might further inform the Commission regarding the Company's cost of providing service. Like the instruction to EVA that its audit should

[46] OCC Remand Rider Ex. 1 at 5 (Haugh).

[47] PUCO Ordered Remand Rider Exhibit 1at 2-18 (Auditor's Report).

[48] Tr. Remand Rider Vol. II at 52-53 (April 19, 2007) (Haugh).

[49] Tr. Remand Rider Vol. II at 35 (April 19, 2007) (Tufts).

"follow the general guidance that had been provided for the Electric Fuel Component audits,"[50] the Commission should be interested in evaluating the Company's AAC cost submissions in light of past regulatory practice. Such practice considered only CWIP upgrades that were 75 percent or more complete before determining whether any return on CWIP should be included in rates.[51]

Without more detailed knowledge of the CWIP accounts, the calculations available to the Commission are provided in the testimony of Company Witness Wathen and OCC Witness Haugh. Mr. Wathen provides a calculation of 9.1 percent of "little g" based upon the inclusion of all CWIP, regardless of its state of completion.[52] As OCC Witness Haugh pointed out, this calculation takes advantage of the CWIP regulatory concept while completely ignoring regulatory practice for the evaluation of generation costs while plant additions are in progress.[53]

Mr. Haugh's calculation of 5.6 percent of "little g" excludes the return on CWIP from the calculation of the AAC.[54] Mr. Haugh explained that the elimination of a return on CWIP is consistent with Commission discretion regarding the treatment of CWIP for rate setting purposes. In the present situation, elimination of the return on CWIP is appropriate since customers may receive little or no benefit from the plant additions.[55]

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[50] PUCO Ordered Remand Rider Exhibit 1at 1-2 (Auditor's Report).

[51] OCC Remand Rider Ex. 1 at 6 (Haugh).

[52] Company Remand Rider Ex. 4 at 11 (Wathen).

[53] OCC Remand Rider Exhibit 1 at 7 (Haugh).

[54] Id. at 11 (Haugh).

[55] Id. at 7.

Mr. Haugh's result is also consistent with the previous statements within the context of the *Post-MDP Service Case*, including the Commission's statement that the AAC should include "expenses."[56] The Company's proposed AAC in the 2004 Stipulation for purposes of charging market-based rates requested $60,172,508 out of a total calculation of $107,514,533.[57] The Commission's related finding resulted in only approval of $53,725,267,[58] a result that is inconsistent with Company Witness Wathen's calculations.

A managerial performance audit of the AAC should be included along with the next review of the Company's FPP and SRT trackers. The AAC should be set for 5.6 percent of "little g" as calculated by OCC Witness Haugh in the pending proceedings.

D. Charges for Generation Service Should be Located in the Generation Portion of the Customers' Bills

The RSC, SRT, IMF, and AAC charges that resulted from the *Post-MDP Service Case* were incorrectly stated and billed to customers as distribution charges when all these charges are part of the Company's standard service offer for generation service.[59] The RSC was created in the *Post-MDP Service Case* as a portion of "little g," and is clearly generation-related.[60] OCC Witness Haugh's testimony cites the testimony of Company Witness Wathen regarding the generation-related nature of the SRT and AAC charges.[61] The Commission stated that the AAC charge is "not . . . placed upon

[56] Id. at 9, quoting *Post-MDP Service Case*, Order at 32 (September 29, 2004).

[57] Id. at 8-9.

[58] Id.

[59] OCC Remand Rider Ex. 1, MPH Attachment 2 (Haugh).

[60] See, e.g., OCC Remand Ex. 1 at 22 (Talbot).

[61] OCC Remand Rider Ex. 1 at 17 (Haugh).

distribution or transmission, and is not an ancillary service."[62] The charges that were set in these cases were all clearly generation-related. They have appeared, however, in the distribution portion of customers' bills.[63] This misplacement should be corrected.

As OCC Witness Haugh points out, Duke Energy Ohio includes the SRT and the IMF in a line item entitled "Delivery Riders."[64] The IMF was not addressed, other than regarding its incorrect categorization by Duke Energy Ohio, in Phase II of these proceedings because it is not a "tracker" whose level was to be set based upon the Company's incurred costs. This, of course, is the problem with the IMF: the SRT is the true successor to the Reserve Margin charge that was stated in the 2004 Stipulation and the IMF has not been justified in the record of these cases.[65] Therefore, the charge that should be shown under the portion of the customers' bill for "Generation Charges" should include only the SRT portion of the charges formerly listed at "Delivery Riders."[66]

The generation-related charges that result from the Commission's final determinations in these cases should be charged to customers as generation charges. The change in the Company's bills should take place at the same time that new standard service offer charges are billed to customers.

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[62] *Post-MDP Service Case*, Entry on Rehearing at 17 (November 23, 2004).

[63] OCC Remand Rider Ex. 1 at 16 (Haugh).

[64] Id. at 18.

[65] See, e.g., OCC Remand Ex. 1 at 48 (Talbot).

[66] OCC Remand Rider Ex. 1, MPH Attachment 2 (Haugh).

IV. THE TEST FOR APPROVAL OF A PARTIAL STIPULATION

A. The Test for a Partial Stipulation Emphasizes the Public Interest.

The 2007 Stipulation was filed just prior to the hearing on Phase II of these cases and its recommendations are part of the record that the Commission will consider in these cases.[67] The standard of review for consideration of a partial stipulation has been discussed in a number of Commission cases and by the Ohio Supreme Court. See, e.g., *CG&E ETP Case*, PUCO Case No. 99-1212-EL-ETP, et al., at 65 (July 19, 2000).

Among other places, the Ohio Supreme Court has addressed its review of stipulations in *Consumers Counsel v. Pub. Util. Comm.*, (1992), 64 Ohio St. 3d 123, 125 ("*Consumers' Counsel 1992*"). Citing *Akron v. Pub. Util. Comm.* (1978), 55 Ohio St.2d 155, 157, the Ohio Supreme Court stated in *Consumers' Counsel 1992* that:

> The Commission, of course, is not bound to the terms of any stipulation; however, such terms are properly accorded substantial weight. Likewise, the commission is not bound by the findings of its staff. Nevertheless, those findings are the result of detailed investigations and are entitled to careful consideration.
>
> In *Duff v. Pub. Util. Comm.* (1978), . . . in which several of the appellants challenged the correctness of a stipulation, we stated:
>
> A stipulation entered into by the parties present at a commission hearing is merely a recommendation made to the commission and is in no sense legally binding upon the commission. The commission may take the stipulation into consideration, but must determine what is just and reasonable from the evidence presented at the hearing.[68]

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[67] Joint Remand Rider Ex. 1 (2007 Stipulation).

[68] *Consumers' Counsel 1992* at 125.

The present cases involved negotiations between CG&E and a few parties that seem to have been directed at serving parties with narrow interests while broader interests were ignored. While the PUCO Staff executed the 2007 Stipulation, testimony by the Auditor is critical of many of the positions taken in the 2007 Stipulation. The PUCO Staff presented merely a cursory explanation for the abandonment of the Auditor's recommendations. The result advanced by the 2007 Stipulation is not "just and reasonable."

The Court in *Consumers' Counsel 1992* considered whether a just and reasonable result was achieved with reference to criteria adopted by the Commission in evaluating settlements:

> 1. Is the settlement a product of serious bargaining among capable, knowledgeable parties?
>
> 2. Does the settlement, as a package, benefit ratepayers and the public interest?
>
> 3. Does the settlement package violate any important regulatory principle or practice?[69]

The OCC submits that the 2007 Stipulation, which "recommend[s] that the Public Utilities Commission of Ohio . . . approve the [2007 Stipulation]," violates the criteria set out by the Commission and the Ohio Supreme Court.[70]

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[69] Id. at 126.

[70] Joint Ex. 1 at 2.

B. The Partial Stipulation Fails the Test for Approval of a Settlement.

1. The *Settlement* Was *Not* the Product of Serious Bargaining.

The Commission's deliberations should include consideration of the narrow interests pursued by supporters of the 2007 Stipulation so that they can be accurately contrasted with the interests of those parties having broader interests who oppose the 2007 Stipulation. The OCC Initial Brief, Phase I, stated that there is narrow support for the 2004 Stipulation once the support of those connected with side deals is disregarded.[71] The 2007 Stipulation was again executed or has gone unopposed by Staff; OHA, OEG, and IEU[72] whose members have "option agreements"; the City of Cincinnati ("City"); and People Working Cooperatively ("PWC").[73] The OCC's participation in drafting an agreement would have provided credibility to the argument that serious bargaining took place over the 2007 Stipulation, but the OCC's efforts to correct even the obvious flaws in the document were entirely rebuffed.

The option agreements that were discussed in detail in Phase I of these proceedings provide OHA, OEG, and IEU members with protections against the increases that are the subject of Phase II of these proceedings. The option agreements are numerous, but can be summarized by discussion of the three representative agreements that are featured in the testimony of OCC Witness Hixon.[74] The option agreement for

[71] OCC Initial Post-Remand Brief, Phase I, at 37-38.

[72] IEU, while not a signatory to the 2007 Stipulation, made it publicly known that it did not oppose the agreement. Tr. Remand Rider Vol. II at 153 (April 19, 2007) (position statement by IEU Counsel Neilsen).

[73] Joint Remand Rider Ex. 1 at 9 (2007 Stipulation).

[74] OCC Remand Ex. 2(A).

[redacted](an OHA member) provides reimbursement o[redacted]charges and the [redacted] The option agreement fo[redacted](an OEG member) provides reimbursement of[redacted]and [redacted]charges as well as[redacted][78] The option agreement for Marathon[79] (an IEU member) provides for reimbursement of the AAC, half the SRT charges, and the remainder of FPP charges after removal of its emission allowance component.[80] The legacy of the side agreements in the *Post-MDP Service Case* continues: serious bargaining did not take place between Duke Energy Ohio and parties whose members are shielded from the brunt of rate increases that are the subject of negotiations.

The City withdrew from the *Post-MDP Service Case* on July 13, 2004 without any apparent participation other than the execution of a side deal with the Company that provided the City with $1 million.[81] The City did not file an initial brief by the June 22, 2004 deadline, and did not file a reply brief by the July 6, 2004 deadline before it withdrew. The City reentered these cases in a Motion to Intervene dated February 21, 2007. The City's only apparent participation in the *Post-Remand Case* was to execute the 2007 Stipulation. The City has not demonstrated any knowledge of the issues in these

[75] Id., BEH Attachment 17 (Bate stamp 89).

[76] Id.; see also id. at 51 (Hixon).

[77] Id., BEH Attachment 17 (Bate stamp 11).

[78] Id.; see also id. at 52 (Hixon).

[79] Id., BEH Attachment 17 (Bate stamp 44).

[80] Id., see also id. at 52 (Hixon).

[81] OCC Remand Ex. 6 at ¶4.

cases. Its execution of the 2007 Stipulation is designed to protect its side deal that depends upon an outcome to these cases that is satisfactory to the Company.[82] Serious bargaining did not take place between Duke Energy Ohio and the City.

The support of PWC is best explained by its Motion to Strike a Portion of the BRIED {*sic*, "BRIEF"} *of Ohio Partners for Affordable Energy*.[83] That Motion explains PWC's dependency on funds provided by Duke Energy Ohio.[84] Like the City, PWC has not demonstrated any knowledge of the issues in these cases. Its participation in the prehearing conference held on December 14, 2006 focused on protesting the possible consolidation of cases involving the Company's trackers with issues identified by the Supreme Court of Ohio. According to PWC's counsel: "My client is sort of an unusual party in this case, and my client . . . would not have intervened in all of these other [rider] cases at this point."[85] Its "issues," as reflected by its Motion to Strike, seem driven by protecting its status as a recipient of the Company's funding. Despite its protestations, PWC has focused on maintaining the financial support for its narrow interests. The Commission, on the other hand, should disregard such narrow interests and base its decision upon the public interest.

The circumstances of these cases, and of the parties to the 2007 Stipulation, demonstrate that the partial settlement was reached without serious bargaining that involved capable, knowledgeable parties. A full evidentiary record has been presented to

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[82] OCC Remand Ex. 6 at ¶6 ("order unacceptable to CG&E" "in Case No. 03-93-EL-ATA or a related case *necessary to carry out the terms and conditions of the Stipulation*").

[83] PWC Reply Brief and Motion to Strike (April 27, 2007).

[84] Id. at 3-5.

[85] Tr. at 26-27 (December 12, 2006) (transcribed prehearing conference).

the Commission, including an extensive management performance audit by a consultant selected by the Commission. The Commission should reach its decision in these cases without relying upon the 2007 Stipulation.

2. The Settlement Package Does Not Benefit the Public Interest.

The settlement package stated in the 2007 Stipulation does not provide a benefit to ratepayers or serve the public interest. Instead of adopting the 2007 Stipulation without alteration, the Commission should adopt all the EVA recommendations regarding the FPP and the SRT (the latter as supported by OCC testimony) and reject the inclusion of a return on CWIP as part of the AAC. Support for these positions is stated above, and the present discussion will focus on the numerous weaknesses contained within the 2007 Stipulation that result in a settlement package that does not benefit the public interest.

Paragraph 1 of the 2007 Stipulation addresses credits to customers that were the subject of EVA's first major management audit recommendation. Paragraph 1 addresses one source of credits recommended by EVA, but not all the recommended credits. In particular, the 2007 Stipulation states that "Recommendation 1 on page 1-9 of the Auditor's Report dated October 12, 2006, shall be withdrawn."[86] As stated above, all credits recommended by EVA should be flowed back to customers who incur FPP charges.

[86] Joint Remand Rider Ex. 1 at 4, ¶1 (2007 Stipulation). The 2007 Stipulation does not explain how such a recommendation can be "withdrawn." The Commission ordered the preparation of the Auditor's Report (i.e. "PUCO Ordered Remand Rider Exhibit 1"). EVA's Seth Schwartz and Larkin and Associate's Ralph Smith defended the findings and conclusions contained in the Auditor's Report without any withdrawal or retraction.

Paragraph 2 also states that an EVA recommendation "shall be withdrawn," this time the second major management audit recommendation.[87] EVA recommended that Duke Energy Ohio adopt a portfolio approach to the procurement of coal and emission allowances. Paragraph 3 of the 2007 Stipulation offers "meet[ings] to discuss the terms and conditions under which DE-Ohio may purchase and manage coal assets, emission allowances, and purchased power for the period after December 31, 2008" in order to "make a recommendation . . . *for consideration no later than the next FPP audit*."[88] *This* provision for meetings in the 2007 Stipulation concedes that the EVA recommendation regarding coal procurement has substance. The provision for meetings also recognizes that the 2007 Stipulation was rushed into place before the Phase II hearings were held and without carefully dealing with all the substantive matters at issue. The Commission should act on EVA's recommendations rather than adopt an unaltered 2007 Stipulation that would essentially hand Duke Energy Ohio "veto" authority over progress on fuel purchasing procedures.

Paragraph 4 of the 2007 Stipulation would reinstate the Company's proposed treatment of transmission congestion costs and reject the Commission's removal of those costs from the FPP to "Rider TCR, as approved in paragraph 26 of the PUCO's December 20, 2006 Order in Case No. 03-93-EL-ATA *et al.*"[89] The record does not contain an explanation for the change, offering the Commission no hope of explaining the change from its previous order.

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[87] *Joint Remand Rider Ex. 1* at 5, ¶2.

[88] Id. at 5, ¶3.

[89] Id. at 6, ¶4.

Paragraph 5 of the 2007 Stipulation states that "DE-Ohio's proposed Rider AAC Calculation shall be adjusted in accordance with the Staff corrected supplemental testimony of L'Nard E. Tufts."[90] That testimony contained small additions to the Company's CWIP accounts. The controversy in these cases regarding AAC charges does not, however, involve Mr. Tufts' work or dispute regarding the manner in which any AAC calculations were carried out. The controversy in these cases is whether a return on CWIP should be included in the AAC, a matter on which Staff Witness Tufts stated no opinion.[91] The Commission should reject Paragraph 5 of the 2007 Stipulation and set the AAC charge at 5.6 percent of "little g" as supported in OCC Witness Haugh's testimony as part of the PUCO's efforts "to consider the reasonableness of expenditures" in the AAC category.[92]

Paragraph 6 states that "DE-Ohio shall work with the Staff to amend its bill format" "to reflect generation-related charges such as the FPP, SRT, and AAC, in the generation portion of the customer bill."[93] The proper placement of generation-related charges was raised in the testimony of OCC Witness Haugh.[94] The agreement that "such amendments will not result in additional programming or billing costs" is the correct

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[90] Id. at 6, ¶5. Construed literally, the 2007 Stipulation does not make a recommendation regarding AAC charges. Paragraph 5 states agreement regarding the Company's calculations, not the AAC charge. The Company's calculations having been adjusted by agreement between certain parties, the issue of whether to accept the inclusion of a return on CWIP remains unaddressed by the 2007 Stipulation.

[91] Tr. Remand Rider Vol. II at 35 (April 19, 2007) (Tufts) ("I did not form an opinion and that's not part of my testimony.").

[92] *Post-MDP Service Case*, Entry on Rehearing at 10 (November 23, 2004).

[93] Joint Remand Rider Ex. 1 at 6, ¶6.

[94] OCC Remand Rider Ex. 1 at 16-18 (Haugh).

result.[95] However, that result is not particularly gratifying as part of the settlement quid pro quo since the Company caused the problem when it prepared customer bills that did not recognize the Commission's determinations that these charges are generation in nature.[96] Paragraph 6 is also vague, referring to charges "*such as* the FPP, SRT, and AAC."[97] The RSC, SRT, IMF, and AAC -- all charges that resulted from the *Post-MDP Service Case* that dealt with standard service offer generation rates pursuant to R.C. 4928.14(A) -- were incorrectly stated and billed to customers as distribution charges when all these charges are part of the Company's charges for generation service.[98]

Paragraph 7 states a minor concession on the part of Duke Energy Ohio by providing for the collection of "DE-Ohio's projected 2007 planning reserve capacity purchases by year-end," which would not require the payment of interest.[99] The Commission's Entry dated December 20, 2006 set the SRT at zero and provided for interest as part of the true-up following its decision in these cases.[100] Paragraph 5 of the 2007 Stipulation also refers to collections -- this time for the AAC -- trued-up "such that the amount calculated to be recovered in 2007, will be recovered by December 31, 2007" and does not include interest charges.[101] However, the AAC should be set at a level

[95] Joint Remand Rider Ex. 1 at 6, ¶6.

[96] OCC Remand Rider Ex. 1 at 16-17 (Haugh), citing Commission orders including the Entry on Rehearing dated November 23, 2004 in the Post-MDP Service Case.

[97] Joint Remand Rider Ex. 1 at 6, ¶6 (emphasis added).

[98] OCC Remand Rider Ex. 1, MPH Attachment 2 (Haugh).

[99] Joint Remand Rider Ex. 1 at 7, ¶7.

[100] Entry at 6 (December 20, 2006).

[101] Joint Remand Rider Ex. 1 at 5, ¶5.

below that currently being charged, as recommended by OCC Witness Haugh.[102] Therefore, the absence of interest charges on the true-up of AAC charges is only a concession on the part of Duke Energy Ohio if the higher AAC charges requested by the Company are approved.

Paragraph 8 of the 2007 Stipulation presented the most obvious controversy at hearing, and remains an unsettled element regarding Duke Energy Ohio's intentions under the agreement. Paragraph 8 would render EVA's "recommendation 6 on page 1-10 of the . . . Audit[or's] Report . . . inapplicable."[103] EVA's recommendation would exclude the use of the DENA Assets for purposes of calculating the SRT. In its place, the Company proposes to charge for capacity from the DENA Assets based upon broker quotes, prices for third party transactions, or by a method acceptable to only the Company and the PUCO Staff.[104] The use of broker quotes or third party transaction prices would not deliver savings from "the most reasonably priced capacity available" that was promised by Company Witness Whitlock.[105] To the contrary, use of the DENA Assets presents the danger of unreasonably high charges that could result from the Company's determination of costs associated with *Company-owned generation.*[106]

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[102] OCC Remand Rider Ex. 1 at 11 (Haugh).

[103] Joint Remand Rider Ex. 1 at 7, ¶8.

[104] Id.

[105] Company Remand Rider Ex. 2 at 11 (Whitlock Supplemental).

[106] Company Witness Smith agreed that the word "purchases" in paragraph 8 of the 2007 Stipulation is inappropriate under circumstances where the generating facilities are owned by the Company. Tr. Remand Rider Vol. II at 95 (April 19, 2007) (Smith).

Paragraph 8 is weakly worded and unable to protect customers from the Company's overcharges if Duke Energy Ohio is permitted to use the DENA Assets.[107] For instance, the 2007 Stipulation does not provide for Commission approval of an agreement reached between the Company and the PUCO Staff regarding charges for using the DENA Assets. Also, OCC Witness Haugh noted the apparent disagreement regarding the interpretation of paragraph 8 that broke out as early as the cross-examination of Company Witness Whitlock on April 10, 2007. In Mr. Haugh's supplemental testimony filed on April 17, 2007, he observed that the Assistant Attorney General's cross-examination of Mr. Whitlock revealed Staff's more narrow interpretation of paragraph 8 that would not permit the Company to repeatedly use the DENA Assets.[108] The 2007 Stipulation was apparently executed hastily and without complete agreement between the stipulating parties.

Apparently in response to the cross-examination of Mr. Whitlock and Mr. Haugh's pre-filed supplemental testimony, Staff and the Company produced a "Clarification" on April 19, 2007 that permitted use of the DENA Assets "during two consecutive seven day periods" only with "Commission approval."[109] According to Company Witness Smith, the Clarification permits Duke Energy Ohio to use the DENA Assets in a series of transactions, without Commission approval, as long as at least one

[107] See OCC Remand Rider Ex. 2 at 3-5 (Haugh Supplemental).

[108] Id. at 3, citing Tr. Remand Rider I at 143 (Whitlock).

[109] OCC Ex. Remand Rider 3 at 1-2 ("Clarification of April 9, 2007, Stipulation and Recommendation"). Company Witness Smith could not satisfactorily explain his vision of the Commission approval process. Tr. Remand Rider Vol. II at 93 (Smith).

day separates the seven day periods.[110] The Clarification therefore appears to protect consumers to the extent that Duke Energy Ohio may only use its DENA Assets for seven-eighths of the year. The confusion over fashioning consumer protections involving the use of the DENA Assets reveals a weakness in the 2007 Stipulation as well as the underlying wisdom behind EVA's recommendation against their use in computing the SRT.

Paragraph 9 is deceptive in its provision regarding Duke Energy Ohio's acceptance of "all audit recommendations made in the Report of the Financial and Management/Performance Audit . . . except as set forth in paragraphs one through eight above."[111] As noted above, Company Witness Whitlock testified that Duke Energy Ohio "does not exclude an offer from consideration if the [coal] supplier will not permit the resale of coal."[112] From that statement, the Company apparently believes it already complies with EVA's major recommendation 3 which states that "coal suppliers should not be required to allow the resale of their coal for the offers to be considered."[113] Company Witness Whitlock admits, however, that Duke Energy Ohio "include[s] the resale of coal as a condition on its RFPs."[114] That condition on the RFPs renders meaningless the Company's "agreement" in Paragraph 9 to consider bids that Duke Energy Ohio actively discourages and that the Company would consider non-complying

[110] Tr. Remand Rider Vol. II at 92-93 (Smith).

[111] Joint Remand Rider Ex. 1 at 7-8, ¶9.

[112] Company Remand Rider Ex. 2 at 9 (Whitlock Supplemental).

[113] PUCO Ordered Remand Rider Exhibit 1at 1-10 (Auditor's Report).

[114] Company Remand Rider Ex. 2 at 9 (Whitlock Supplemental).

with its RFPs. The Commission should reject the Company's subterfuge whereby it states agreement to an EVA recommendation but intends (in practice) the opposite result.

The 2007 Stipulation contains numerous faults that result from the narrow interests of those who fashioned the agreement and the haste with which the agreement was patched together. The broad public interest is not served by approval of the 2007 Stipulation. The Commission should order the Company to comply with all the recommendations contained in the Auditor's Report and the OCC-sponsored testimony.

3. The Settlement Package Violates Important Regulatory Policies and Practices.

Paragraph 5 of the 2007 Stipulation addresses the calculation of the AAC, and adoption of that provision would violate a traditional regulatory policy and practice. That paragraph fails to recognize the Commission's earlier statements that AAC calculations would consider "expenses."[115] Even if CWIP calculations regarding capital expenditures are considered for purposes of setting the AAC, Commission policies and practices should be used to guide the development of reasonable standard service offer rates. As stated above, the Commission informed EVA that it should use the previously effective provisions regarding electric fuel component cases in the evaluation of Company practices as they related to the FPP.[116] Similar evaluation of CWIP amounts, i.e. pursuant to regulatory practices that pre-dated electric restructuring in Ohio, should be applied for the purpose of deciding which costs are appropriately associated with capital expenditures.

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[115] OCC Remand Rider Ex. 1 at 9, quoting *Post-MDP Service Case*, Order at 32 (September 29, 2004).

[116] PUCO Ordered Remand Rider Exhibit 1 at 1-2 through 1-3 (Auditor's Report).

The Commission should undertake the evaluation of AAC costs, in the PUCO's words, "to consider the reasonableness of expenditures" in the AAC category because "[i]t is not in the public interest to cede this review."[117] Reasonable methods should be used to reflect actual costs for charges such as the AAC. As stated in OCC Witness Haugh's evaluation of regulatory principles and practices, "[p]aragraph five of the 2007 Stipulation would permit a return on CWIP that would not traditionally have been allowed in ratemaking proceedings."[118]

Staff Witness Tufts evaluated the accounts and physical assets associated with the Company's AAC calculation. He did not, as stated above, formulate an opinion as to whether a return on CWIP was appropriate for standard service offer rates.[119] Staff Witness Cahaan supported the reasonableness of paragraph 5 based entirely upon its adoption of "calculations put forth by Staff witness Tufts."[120] Such an endorsement by Mr. Cahaan is meaningless regarding the policy of including or excluding a return on CWIP, a matter upon which Mr. Tufts offered no opinion. The Commission should reject Paragraph 5 of the 2007 Stipulation and set the AAC charge at 5.6 percent of "little g" as supported in OCC Witness Haugh's calculations and testimony.

Paragraph 8 of the 2007 Stipulation addresses the pricing of capacity from the DENA Assets, and adoption of that provision would violate a traditional regulatory policy and practice. That paragraph improperly supports Duke Energy Ohio's breach of

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[117] *Post-MDP Service Case*, Entry on Rehearing at 10 (November 23, 2004).

[118] OCC Remand Rider Ex. 1 at 7 (Haugh).

[119] Tr. Remand Rider Vol. II at 35 (April 19, 2007) (Tufts) ("I did not form an opinion and that's not part of my testimony.").

[120] Staff Remand Rider Ex. 3, Answer 3.

the SRT Stipulation as well as the Company's violation of the Commission's Order that adopted the SRT Stipulation in its entirety.[121] The SRT Stipulation was entered into by Duke Energy Ohio, the OCC, and other parties who agreed in October 2005 to a number of provisions in Case No. 05-724-EL-UNC.[122] Among other matters, "CG&E agreed to "provide OCC with workpapers and other data supporting the use of DENA Assets as part of the SRT and if any interested party is concerned about the use of DENA Assets in the SRT the Commission will hold a hearing."[123] The Company failed to provide the OCC with any such information.[124]

The subject of the proceeding to which the SRT Stipulation applied was the "price for competitive retail electric service for the period of January 1, 2006, through December 31, 2006."[125] The workpapers and other supporting data should have been provided to the OCC *before* the hearing in which the Company proposed to include the use of DENA Assets. Company Witness Smith agreed that the SRT Stipulation contemplated the provision of information to the OCC before the hearing that is mentioned in the SRT Stipulation.[126] Duke Energy Ohio's Senior Counsel, who executed the SRT Stipulation,[127] stated at the hearing on April 29, 2007 that "frankly, we are having a hearing. That's what we are doing." The workpapers and supporting data,

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[121] *In re Setting of SRT*, Case No. 05-724-EL-UNC, Order at 6 (November 22, 2005).

[122] OCC Remand Rider Ex. 4.

[123] Id. at 5, ¶8.

[124] Tr. Remand Rider Vol. II at 97-98 (April 19, 2007) (Smith) ("I don't know how you would").

[125] OCC Remand Rider Ex. 4 at 3 (last "WHEREAS").

[126] Tr. Remand Rider Vol. II at 101 (April 19, 2007) (Smith).

[127] OCC Remand Rider Ex. 4 at 5.

therefore (and by admission), should have been presented to the OCC *before* the hearings in these cases.

Company Witness Whitlock submitted testimony regarding the Company's request to use the DENA Assets on November 16, 2006.[128] The required workpapers and other supporting data, however, were never provided to the OCC. The SRT Stipulation anticipated that the Company would work towards documentation that would support use of the DENA Assets if it sought to include their use in a SRT calculation. Company Witness Smith, however, stated that such documentation would not be provided before the Company's request to use the DENA Assets.[129] The effect of the Company's actions -- in this case its lack of actions -- is to raise suspicions that Duke Energy Ohio's motives are "nefarious."[130] The SRT Stipulation was designed to counter natural suspicions with the sharing of information, a design that has been thwarted by Duke Energy Ohio's non-compliance. The Commission should not approve the use of the DENA Assts for the calculation of the SRT under these circumstances.

V. CONCLUSION

The OCC supports the positions presented in the Auditor's Report. The Auditor's Report makes many recommendations regarding the manner in which the FPP and SRT should be dealt. OCC-sponsored testimony also supports the Auditor's recommendation

[128] Company Remand Rider Ex. 2 at 10-14 (Whitlock Supplemental).

[129] Tr. Remand Rider Vol. II at 97-98 (April 19, 2007) (Smith).

[130] The word choice is that of Company Witness Whitlock, so disingenuously stated that "there is no reason to believe that DE-Ohio's motives are nefarious. . . ." Company Remand Rider Ex. 2 at 13 (Whitlock Supplemental).

that would continue the prohibition against including the cost of using DENA Assets in the calculation of SRT charges.

OCC-sponsored testimony also supports Commission review of the charges that Duke Energy Ohio proposes for the AAC charge. The Commission should eliminate that portion of the proposed charge that can be attributed to a return on all CWIP and set the AAC at 5.6 percent of "little g." Future management performance audits should include a review of Duke Energy's operations that contribute to the AAC charges.

Respectfully submitted,

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CERTIFICATE OF SERVICE

The undersigned hereby certifies that a true and correct copy of the foregoing (Confidential) *Initial Post-Remand Brief, Hearing Phase II, by the Office of the Ohio Consumers' Counsel,* has been served upon the below-named persons in unredacted form (pursuant to the Attorney Examiners' instructions) via electronic transmittal this 17th day of May 2007.

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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

Consolidated Duke Energy Ohio, Inc. Rate Stabilization Plan Remand, and Rider Adjustment Cases.	) Case Nos.	03-93-EL-ATA
	)	03-2079-EL-AAM
	)	03-2081-EL-AAM
	)	03-2080-EL-ATA
	)	05-725-EL-UNC
	)	06-1069-EL-UNC
	)	05-724-EL-UNC
	)	06-1085-EL-UNC
	)	06-1068-EL-UNC

OHIO PARTNERS FOR AFFORDABLE ENERGY'S
INITIAL BRIEF
PHASE 2

CONFIDENTIAL VERSION

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May 17, 2007

TABLE OF CONTENTS

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

Consolidated Duke Energy Ohio, Inc. Rate Stabilization Plan Remand, and Rider Adjustment Cases.	) Case Nos.	03-93-EL-ATA
	)	03-2079-EL-AAM
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	)	06-1068-EL-UNC

OHIO PARTNERS FOR AFFORDABLE ENERGY'S
INITIAL BRIEF
PHASE 2
CONFIDENTIAL VERSION

I. INTRODUCTION

Ohio Partners for Affordable Energy ("OPAE"), an intervenor in the above-captioned cases, hereby submits its initial brief in Phase 2 of these consolidated proceedings before the Public Utilities Commission of Ohio ("Commission"). This second part of the proceedings concerns applications made by The Cincinnati Gas & Electric Company ("CG&E"), now Duke Energy Ohio, Inc. ("Duke") to adjust riders previously allowed by the Commission. CG&E-Duke calls these riders the fuel and purchased power ("FPP") tracker, the system reliability tracker ("SRT") and the annually adjusted component ("AAC") of the market-based standard service offer.

On April 9, 2007, CG&E-Duke filed a stipulation and recommendation purporting to represent a fair and reasonable solution of the issues raised in these cases. Joint Exhibit Remand Rider ("Jt. Ex. R.R.") 1 at 3. In addition to CG&E-Duke, the April 9, 2007 stipulation was signed by the Staff of the Commission ("Staff"), Ohio Energy

Group ("OEG"), the Ohio Hospital Association ("Hospitals"), the City of Cincinnati and People Working Cooperatively ("PWC"). The Industrial Energy Users-Ohio ("IEU-O") did not sign the stipulation but stated on the record that it did not oppose it. Tr. Remand Rider (R.R.) II at 153.

II. THE APRIL 9, 2007 STIPULATION IS NOT THE PRODUCT OF SERIOUS BARGAINING AMONG THE PARTIES.

A. THE APRIL 9, 2007 STIPULATION IS NOT SUPPORTED BY A WIDE RANGE OF PARTIES TO THESE CASES.

In considering the reasonableness of a stipulation, the Commission uses a three-prong test approved by the Ohio Supreme Court:

1. Is the settlement a product of serious bargaining among capable, knowledgeable parties?
2. Does the settlement, as a package, benefit ratepayers and the public interest?
3. Does the settlement package violate any important regulatory principle or practice?

Ohio Consumers' Counsel v. Pub. Util. Comm. (1992), 64 Ohio St.3d 123, 126.

Contrary to the first prong of the Commission's test, serious bargaining among the parties did not take place at the settlement negotiations. The stipulation is not balanced and does not represent the views of all customer classes who are parties to these cases.

The Ohio Supreme Court has affirmed the Commission's rate stabilization plan concept solely on the basis of stipulations supported by a wide range of parties to the cases. In *Constellation NewEnergy, Inc. v. Pub. Util. Comm.*, 104 Ohio St.3d 530, 2004-Ohio-6767, the Court affirmed the Commission's finding in approving a rate plan on the basis of the reasonableness of a stipulation supported by all customer classes. As the Court stated in a subsequent case involving the rate plan of FirstEnergy Corp.:

> The absence of a stipulation signed by customer groups factually distinguishes this case from *Constellation.* In *Constellation* we also noted that "no entire customer class was excluded from settlement negotiations and that the following classes were represented and signed the stipulation: residential customers, low-income customers, commercial customers, industrial customers, and competitive retail electric service providers." When it enacted R.C. 4928.14, the General Assembly anticipated that at the end of the market-development period, customers would be offered both a market-based standard service as required by R.C. 4928.14(A) and service at a price determined through a competitive-bidding process as required by R.C. 4928.14(B); one very narrow exception contained in R.C. 4928.14(B) permits the commission to determine that a competitive-bidding process is not required. In *Constellation,* the customer groups, by stipulation, agreed to accept a market-based standard service offer and waive any right to a price determined by competitive bid. Those facts are not present in this case.

Ohio Consumers' Counsel v. Pub. Util. Comm., 2006-Ohio-2110 ¶18. The Court made it clear that the stipulation signed by a wide range of parties was the determining factor that allowed the Court to affirm the Commission's orders. The Court made a strong distinction between Commission orders that could be made pursuant to a stipulation supported by a wide range of parties and orders that could not be made absent such a stipulation. In the same opinion, the Court also stated:

> In contrast to the customer groups in *Constellation*, the customer groups here did not agree to the FirstEnergy rates, and most customer groups, including the OCC, which represents all residential customers, opposed them. Under these circumstances, the PUCO had no authority to adopt the rate-stabilization plan without also ensuring that a reasonable means for customer participation had been developed.

Id. ¶19.

In short, the Court has affirmed the Commission's rate stabilization orders on the basis of customer agreement in a stipulation. The Court has explicitly stated that such customer agreement is the determining factor in the Court's affirmation of the Commission's rate stabilization orders.

The Commission's own orders also emphasize the need for a broad range of parties supporting the stipulation. The Commission's paragraph finding a market-based standard service offer in its Opinion and Order in Case No. 03-93-EL-ATA, et al., reads as follows:

> The Commission finds that the rate under the stipulation is a market-based rate. The Commission notes that Section 4928.14, Revised Code, allows it flexibility in approving processes for determining market-based rates for the standard service offer. The Commission finds that the stipulation was negotiated among five suppliers and organizations representing various categories of consumers, from low income residential consumers to large industrial users. The stipulation also includes provisions that provide for changes to reflect changes in certain costs. In addition, the stipulation, as revised by this opinion and order, allows the Commission to monitor the prices and confirm that, over time, those prices remain market-based and that consumers have adequate options for choosing among generation suppliers.

Opinion and Order (September 29, 2004) at 26. Thus, the Commission made the finding of a market-based rate only in the context of a stipulation that "was negotiated among five suppliers and organizations representing various categories of consumers, from low income residential consumers to large industrial users." Id. The Court cited the Commission's finding as follows:

> After considering data and arguments from OCC and others attempting to refute CG&E's evidence, the commission found that CG&E's standard service offer was a market-based rate. The Commission stated that (1) R.C. 4928.14 allowed it flexibility in approving methods for determining market-based rates for standard service offers, (2) the stipulation was negotiated among five suppliers and other organizations representing various categories of consumers, from low-income residential consumers to large industrial users, (3) the stipulation allowed for modifications to reflect changes in certain costs, and (4) revisions to the stipulation would allow the Commission to monitor prices and confirm that prices will remain market based over time. ¶42.

The Court found that the stipulation among several competitors in retail electric service and various categories of consumers was one of the criterion relied on by the Commission in finding that the standard service offer was market based. The Court then found as follows:

> We conclude that the Commission's approval of CG&E's alternative to the competitive bidding process was reasonable and lawful. The commission found that CG&E's price to compare, as part of the standard service offer, was market based, and OCC has offered no evidence to contradict that finding. Various customer groups were parties to the stipulation and approved the price to compare and the method by which the price to compare would be tested to ensure that it remains market based. CG&E's rate stabilization plan provides for a reasonable means of customer participation. ¶56.

It is obvious that there was no finding of the reasonableness of the market-based standard service offer except in the context of a stipulation to which various customer groups agreed.

The April 9, 2007 stipulation has no support from marketers, residential customers or any other customer group that will be subject to its terms. OCC, which by statute, represents all residential customers, opposes the stipulation, as does OPAE, which has served as an advocate for residential and low-income customers since its founding in 1996. OPAE also represents the interests of its member agencies located in the CG&E service territories that are commercial customers of CG&E.

The Commission should be suspect of any claim that the stipulation is balanced and represents the views of all customer classes. The stipulation clearly does not represent the views or satisfy the interests of the residential class or any other class. The Commission cannot find that serious bargaining took place among the parties when the stipulation is not a balanced agreement representative of the customer classes.

B. THE PARTIES SUPPORTING THE APRIL 9, 2007 STIPULATION RECEIVE DIRECT BENEFITS OR ARE IMMUNE FROM THE TERMS OF THE *STIPULATION*.

The April 9, 2007 stipulation was submitted by CG&E and five other parties, all of whom supported the Case No. 03-93-EL-ATA, et al., stipulation whose approval by the Commission is the subject of the remand by the Ohio Supreme Court. The persistence of the stipulation approach to Commission-case solving is remarkable, given that these proceedings call the entire stipulation process into question. The Court questioned the validity of a stipulation on the basis that there may be no serious bargaining among the parties if side arrangements are made. Thus, the motive of the parties who signed the April 9, 2007 stipulation is an issue in these cases.

One party supporting the stipulation is People Working Cooperatively ("PWC"). PWC operates demand-side management programs funded by CG&E-Duke. PWC has conceded "that its primary purpose for participating in these proceedings was to assure that funding promised by the stipulation in Cincinnati Gas & Electric Company's ETP case, be continued and that it be extended through the end of the market development period". PWC Motion to Strike (April 27, 2007) at 3. While PWC claims that its concern for the interests of consumers is demonstrated by its desire to extend the funding it receives from CG&E-Duke for its projects, PWC's position demonstrates no regard for the overall impact of the stipulation on residential customer bills.

PWC's position is distinct from the position of OPAE, which is concerned with the impact of the stipulation on customer bills. In its reply to OPAE's memorandum contra the motion to strike, PWC complains that OPAE asserts evidence not on the record, while PWC itself uses evidence not admitted into the record in these cases regarding a settlement offer made by OPAE to CG&E-Duke. While OPAE's settlement offer has not been admitted into the record of these cases, it is worth noting, again, that PWC's own words prove OPAE's points. OPAE's settlement offer shows that OPAE not only requests funding for energy efficiency programs but also requests that the rate caps stay in place, that the enhanced shopping credit for residential customers be made available to Percentage of Income Payment Plan ("PIPP") customers, and that PIPP arrearages cease to be collected. OPAE had four points to its settlement proposal, not simply one for money, as PWC falsely implies.

OPAE's opposition to the stipulation is based on the stipulations' impact on customers; there is no basis for PWC to claim that OPAE, like PWC, is only interested in funding for its own projects. Thus, PWC's support for the stipulation should not be construed as support from the residential class.

The City of Cincinnati also signed the April 9, 2007 stipulation. The City of Cincinnati signed a settlement agreement with CG&E under which the City agreed to withdraw from Case No. 03-93-EL-ATA. Under the agreement, CG&E provided the City with one million dollars ($1,000,000) in total consideration for certain amendments to three electricity agreements between CG&E and the City. OCC Remand Ex. 6. The settlement agreement was conditioned upon the City not opposing the stipulation filed in Case No. 03-93-EL-ATA. The settlement agreement also would terminate on the day that the Commission issues an order unacceptable to CG&E in carrying out the terms of the stipulation in Case No. 03-93-EL-ATA. Id. at 2. Therefore, the City of Cincinnati's support for the stipulation in these rider cases is a product of its separate side agreement with CG&E.

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The customer groups supporting the April 9, 2007 stipulation are OEG, the Hospitals and IEU-O. In the remand case, OCC witness Beth Hixon testified about option agreements made by Cinergy Retail Sales, LLC ("CRS") with individual customers who are members of OEG, the Hospitals and IEU-O. OCC Remand Ex. 1 at 48. Under the option agreements with CRS, the customer takes generation service from CG&E and grants CRS the exclusive option to provide generation to the customer during 2005 through 2008. CRS has the right to exercise the option at any time. In exchange for this right, CRS pays the customers the option payment set forth in the agreement. The option payments generally follow the pattern of CRS reimbursing components of CG&E's charges set forth in the stipulation in Case No. 03-93-EL-ATA, et al. OCC Remand Ex. 2A at 51.

Pursuant to the option agreements of the Hospitals, OEG and IEU-O, the [redacted] is rebated back to the customers. It should be noted that the [redacted] The various option agreements have different arrangements for reductions to the [redacted] although all the option agreements have discounts of the [redacted] and some have a discount [redacted] OCC Remand Ex. 2A, Attachment 17. Thus, the signatory parties to the April 9, 2007 stipulation do not pay the [redacted] and generally do not pay the [redacted] These parties with option agreements obviously have fewer problems with these riders than customers who must pay the full amount, including the full amount of any increases. A stipulation supported exclusively by customer parties who do not pay the full amount of the increases is obviously not supported by customers. There is no serious bargaining when the signatory parties agree to charges that do not apply to themselves.

Ms. Hixon testified that the effect of the side agreements was to insulate certain large customers from the rate increases proposed by CG&E. Pursuant to the side agreements, those customer parties supported CG&E's proposals for post-market development period generation pricing to the detriment of other customers who did not benefit from the inducements offered only to a limited number of parties by CG&E. As a result of the side agreements, CG&E's proposals do not have support from customers who actually pay all the rate increases. While the Commission's rules allow for a standard service offer that varies from its rules where there is substantial support from a number of interested stakeholders [Ohio Adm. Code 4901:1-35-02(C)], here there is no support from parties representing customers who will actually pay all the rate increases in CG&E's generation pricing stipulation. Id. at 59.

The side agreements show that a great deal of negotiation and agreement was undertaken outside the view of OCC and OPAE in these cases. The large electricity users that support the stipulation are favored with side agreements. The side agreements distort any negotiating process that was conducted in the open. The open negotiating sessions could not involve serious bargaining because the large electricity users have reached side agreements under which they are not subject to many of the generation rate increases that are publicly proposed by CG&E and set forth in the stipulation. The reason for the support of the stipulation by large electricity users is that they are actually exempt from portions of the generation price increases publicly proposed by CG&E and as set forth in the April 9, 2007 stipulation.

Certainly CG&E made no effort to meet the concerns of OPAE in the settlement process. OPAE was never invited to negotiate a side agreement, nor were any offers made to OPAE that might have induced OPAE to sign or support a stipulation. OPAE did not get a special deal. Small business customers did not get special deals. Residential customers did not get special deals. Only the large users got special deals and were induced to sign the stipulation and recommend it to the Commission even though the special deal was the large users were not actually subject to the terms of the stipulation that they were recommending. The clear benefit to the large users in signing or supporting the April 9, 2007 stipulation is that they are not subject to the terms of the stipulation.

The customer parties supporting the April 9, 2007 stipulation are the ones with side deals that exempt them from the stipulation's terms. This is prima facie evidence that there is no customer support for the April 9, 2007 stipulation's terms. No customer actually subject to the terms of the stipulation supports it. The stipulation is an illusion that falsely seeks to convince the Commission that customer support exists for a CG&E proposal. Support from customers relatively unaffected by the rate increases proposed in the stipulation cannot outweigh the unanimous opposition of representatives of customer groups subject to the terms of the stipulation. Under the circumstances, the Commission must find that there is no customer support for the April 9, 2007 stipulation.

END CONFIDENTIAL

III. THE APRIL 9, 2007 STIPULATION VIOLATES IMPORTANT REGULATORY PRACTICES AND PRINCIPLES AND FAILS TO BENEFIT RATEPAYERS AND THE PUBLIC INTEREST BY ALLOWING FOR THE RECOVERY OF A RETURN ON CONSTRUCTION WORK IN PROGRESS THROUGH CG&E-DUKE'S AAC.

Contrary to the second and third prongs of the Commission's three-prong test, the April 9, 2007 stipulation and recommendation fails to benefit ratepayers and the public interest and violates important regulatory practices and principles by allowing for the recovery of a return on construction work in progress ("CWIP") through CG&E-Duke's AAC. Paragraph 5 of the April 9, 2007 stipulation permits CG&E-Duke recovery of a return on CWIP to be included in the AAC charges. The stipulation is contrary to the recommendation of the management/performance auditor that a return on CWIP be excluded from the AAC. Commission-Ordered Ex. 1 at I-9.

The Commission has not already determined that a return on CWIP may be included in the AAC. OCC R.R. Ex. 1 at 8-9. The Commission's orders regarding the components of the AAC mention "expenses," which do not describe the return on CWIP. The Commission did not approve a set formula for the calculation of the AAC, but adopted a flexible approach citing factors such as proven expenses and other factors as may be appropriate from time to time. OCC Ex. R.R. 1 at 9. The Commission has also stated that it will continue to consider the reasonableness of "expenditures" and that it will seek to ensure that CG&E-Duke's generation rates are market based. Thus, this proceeding is the first opportunity that the parties have had to present their views regarding a reasonable level of AAC charges.

The Staff of the Commission has offered no justification for the inclusion of a return on CWIP in the AAC. Staff witness L'Nard E. Tufts merely verified CG&E-Duke's

revenue requirement by tracing numbers from CG&E-Duke's filing to its records. Staff R.R. Ex. 2 at 2. Adjustments were made to update and correct numbers based on the information supplied by CG&E-Duke. Although the Staff signed the stipulation, the Staff made no recommendations and provided inadequate justification for the appropriateness of the inclusion of a return on CWIP in the AAC.

The return on CWIP should be excluded from the revenue that CG&E-Duke seeks to obtain through the AAC. The inclusion of a return on CWIP results in unreasonable AAC charges.

First, a return on CWIP would not traditionally have been allowed in ratemaking proceedings. A revenue requirement determined in Ohio through a traditional regulatory cost calculation would require that any CWIP be at least 75% complete before the Commission would consider allowing a return on CWIP. CG&E-Duke has not demonstrated that the CWIP portion of the environmental compliance net plant is or will be at least 75% complete (or any other percentage) during the time that the AAC is being collected.

Second, under a traditional regulatory paradigm, CG&E-Duke might propose allowing a return on CWIP that customers would pay up front during plant construction. After construction is complete, the customers have a claim that the return on CWIP will provide lower capital costs at a future date when the plant is in service. The current regulatory paradigm does not provide any assurance of lower capital costs for customers at a future date. The future is too uncertain to guarantee the claimed benefit would ever be realized by the consumers who would pay the 2007 AAC because it is not known which customers will receive service from CG&E-Duke's generating units in the future.

CG&E-Duke will argue that the traditional regulatory treatment does not apply and that the current generation market is deregulated. In reality, the AAC has no place in the deregulated environment. As OCC witness Michael P. Haugh points out, the "new" formula used by CG&E-Duke to determine a market price for standard service generation simply seeks cost-based recovery that is similar to the traditional methodology for the treatment of CWIP, but without any limitation regarding the percentage of completion for additions to environmental plant and without any assurance of lower capital costs in the future. OCC Ex. R.R. 1 at 7. Clearly, CG&E-Duke is seeking for itself the best of both worlds: cost recovery using traditional revenue requirement methodology (such as CWIP) instead of a market approach, but disregard for traditional rules governing cost recovery such as those that governed CWIP. Id.

In a truly competitive market, CWIP would not be earned at all. A return on the plant would not occur until the plant is fully operational. In a proper market approach, the entire AAC would be a generation charge that is avoidable for customers who switched to another supplier. Thus, in a deregulated generation environment, CWIP is inappropriate.

Under the circumstances of an application requesting recovery of a typically regulated concept such as CWIP, it is obvious that traditional regulatory practices can and should be used to guide development of realistic costs to ensure reasonable standard service offer rates. A reasonable method should be used to reflect actual costs for charges such as the AAC.

The CWIP portion should be removed from the "Return on Environmental Plant" calculation in CG&E-Duke's filing for purposes of setting a more reasonable AAC charge. Mr. Haugh removed the $244,413,759 CWIP amount from the "Return on Environmental Plant" filing by CG&E-Duke witness Wathen's Attachment WDW-2, Schedule 2. This reduces the "Pre-Tax Return" to $53,938,303 and reduces the "Total Environmental Compliance Increase" to $50,429,411. OCC Ex. R.R. 1 at 11. The removal of the CWIP portion of the Environmental Plant reduces the revenue requirement for the 2007 AAC to $45,246,994. Id.; MPH Attachment 1.

IV. THE APRIL 9, 2007 STIPULATION VIOLATES IMPORTANT REGULATORY PRACTICES AND PRINCIPLES AND DOES NOT BENEFIT RATEPAYERS OR THE PUBLIC INTEREST BY ALLOWING, WITHOUT APPROPRIATE RESTRICTIONS, THE RECOVERY OF CAPACITY COSTS ASSOCIATED WITH THE DENA ASSETS THROUGH THE SRT.

The April 9, 2007 stipulation and recommendation also rejects the management/performance auditor's recommendation regarding the use of Duke Energy North America ("DENA") assets. The auditor recommends that CG&E-Duke's purchases of reserve capacity from DENA assets not be eligible for inclusion in the SRT. The auditor does not believe that customers would pay more for capacity from the market than they would for capacity from the DENA assets. Commission-Ordered Ex. 1 at 6-5. The auditor also believes that CG&E-Duke could sell the DENA capacity on the open market. Id. Moreover, the auditor stated that affiliate transactions are problematic and burdensome to audit. Id.

The auditor's recommendations reflect the Commission's current orders regarding the DENA assets. The Commission has previously found that costs related to the transfer of the DENA assets may not be passed on to Ohio customers without prior approval of the Commission. Finding and Order, Case No. 05-732-EL-MER (December 21, 2005) at 15. Further, in Case No. 05-724-EL-UNC, the Commission adopted a stipulation, which states that CG&E-Duke may not use the DENA assets to satisfy the SRT margin requirements without an application to the Commission requesting approval of a market price associated with the DENA assets. Case No. 05-724-EL-UNC, Opinion and Order (November 22, 2005) at 5; OCC R.R. Ex. 4. CG&E-Duke has not provided any market pricing mechanism in its application. OCC Ex. R.R. 1 at 12.

OCC witness Haugh concurred with the auditor's recommendation that charges related to DENA assets should not be collected from customers in CG&E-Duke's SRT. CG&E has not shown that customers are better off by using DENA assets than paying for capacity in the market. Thus, CG&E-Duke has not demonstrated that use of the DENA assets benefits customers. The use of the DENA assets may result in SRT costs that do not provide reasonably-priced retail electric service for Ohio customers. OCC Ex. R.R. 1 at 15. CG&E-Duke should be allowed to purchase capacity from the DENA assets in the future only in an emergency situation and only if CG&E-Duke demonstrates that the DENA assets clearly offered a better price or a better product for customers than that offered in the open market.

With regard to the use of DENA capacity, CG&E-Duke and the Staff presented a clarification of the April 9, 2007 stipulation and recommendation. OCC R.R. Ex. 3. This clarification states that Paragraph 8 of the stipulation is intended to permit CG&E-Duke to use its DENA capacity on an emergency basis where capacity to meet operational requirements is necessary with less than seven days advance notice during two consecutive seven-day periods. In that event, CG&E-Duke must obtain Commission approval before using such capacity during the second seven-day period. The Staff and CG&E agreed that CG&E-Duke may recover short term (seven days or less) capacity purchases from its DENA assets through the SRT. CG&E-Duke and the Staff would agree on a pricing methodology before CG&E-Duke purchases the DENA capacity. CG&E-Duke and the Staff also agreed that the recommendation of the auditor was inapplicable to the extent it is in conflict with their agreement. OCC R.R. Ex. 3.

In spite of this effort by CG&E-Duke to clarify the stipulation with regard to the use of DENA assets, it was obvious at the hearing that CG&E-Duke and the Staff are not in agreement over the meaning of Paragraph 8 of the April 9, 2007 stipulation. CG&E-Duke apparently believes that the April 9, 2007 stipulation allows it to purchase capacity from the DENA assets whenever it wants assuming that it is only for a seven-day period. The Staff would limit DENA purchases to an emergency situation. The April 9, 2007 stipulation, therefore, appears to mask a disagreement over the use of the DENA assets between CG&E-Duke and the Staff. Such disagreement should not exist at such an early point following the execution of a stipulation. OCC R.R. Ex. 2 at 3.

OCC witness Haugh testified that if a circumstance arose where CG&E-Duke was in an emergency situation and unable to meet its capacity needs, then use of the DENA assets could be appropriate. The DENA capacity should be used only as a last resort and if there is a pre-determined reasonable method to set the price for the capacity from the DENA assets. OCC Ex. R.R. 1 at 15-16.

The stipulation does not provide a reasonable method to set the price for the capacity from the DENA assets. Therefore, the stipulation does not provide adequate protection for ratepayers against CG&E-Duke's overcharging for the DENA assets. Paragraph 8 of the stipulation allows CG&E-Duke to determine the "market price" by either using the midpoint of broker quotes, the average price of third-party transactions, or another method determined by CG&E-Duke and the Staff. In reality, there are usually very few broker quotes. OCC R.R. Ex. 2 at 4. The problem with the stipulated method is that there is a limited market. If there are very few or no transactions, then there is only speculation about the market price. Given the lack of transactions in the capacity market, the market price for capacity would be determined with limited or no market data. This is not an acceptable solution for determining the market price of the DENA assets, nor does it provide a reasonable cost for capacity for CG&E-Duke customers. OCC Ex. R.R. 1 at 14.

Contrary to the stipulation, the guidelines for formulating a price for the DENA assets need to be more stringent. If there are limited broker quotes and transactions in the capacity market, there will be too much uncertainty regarding the true market price. The formula set forth in Paragraph 8 of the April 9, 2007 stipulation should not be used unless there is a minimum number of broker quotes and transactions to determine the price of the DENA capacity.

OCC witness Haugh suggested that a minimum of three bids and offers from three separate brokers would be needed. He also suggested a minimum of three third-party transactions be required. Finally, when formulating a price, there needs to be a cap on the amount CG&E-Duke is charging to the customers who are paying the SRT. OCC witness Haugh suggested that the price be capped at the median price CG&E-Duke has paid for capacity during the time frame in which the emergency occurs. He believes this cap should be implemented if any capacity from the DENA assets is used. OCC R.R. Ex. 2 at 6.

The April 9, 2007 stipulation's treatment of the DENA assets (and the awkward attempt to clarify its meaning) renders the stipulation harmful to ratepayers and against the public interest. The use of DENA assets should be limited to emergency situations where there are no other options. Moreover, the Commission should adopt the limitations and safeguards recommended by OCC witness Haugh for pricing the DENA capacity in the event of its use in an emergency situation. The stipulated methodology to formulate a "market price" for the DENA assets does not provide proper protections for customers paying the SRT. The stipulation, therefore, violates important regulatory principles and practices by allowing for the use of DENA assets and recovery of costs through the SRT without adequate limitations and safeguards.

V. THE STIPULATION AND RECOMMENDATION VIOLATES IMPORTANT REGULATORY PRACTICES AND POLICIES AND FAILS TO BENEFIT RATEPAYERS AND THE PUBLIC INTEREST BY FAILING WITHOUT JUSTIFICATION TO ADOPT RECOMMENDATIONS MADE BY THE MANAGEMENT/PERFORMANCE AUDITOR.

The April 9, 2007 stipulation proposes to accept some, but not all, of the management/performance auditor's recommendations. By presenting this suspect stipulation and recommendation to the Commission, CG&E has been able to choose the audit recommendations that it is willing to implement, and ignore those that it chooses to ignore. This is inappropriate and should not be allowed.

The disregard for the auditor's recommendations regarding the recovery of a return on CWIP through the AAC and the use of DENA assets has already been discussed in this brief. As has been discussed, the disregard for the CWIP and DENA audit recommendations has caused the stipulation to violate the second and third prongs of the Commission's three-prong test. The stipulation does not benefit ratepayers and the public interest, and it violates important regulatory practices and policies by allowing the return on CWIP and the use of the DENA assets under inappropriate circumstances.

In addition, the stipulation disregards other audit recommendations without any justification other than CG&E-Duke's desire to disregard them. For example, the auditor recommended that CG&E-Duke discontinue its active management practices and adopt a traditional utility procurement strategy related to the procurement of coal, emission allowances and forward power purchases. Commission-Ordered Exhibit 1 at I-9. The April 9, 2006 stipulation and recommendation states that the auditor's recommendation at I-9 that active management practices be discontinued will be withdrawn. Jt. Ex. R.R. 1 at 5. In addition, the April 9, 2007 stipulation states that interested parties shall meet to determine how to handle CG&E-Duke's management of its portfolio of coal assets, emission allowances, and purchased power arrangements post-2008. Id.

OCC witness Haugh found this provision of the stipulation to be ambiguous or meaningless. The stipulation does not accomplish anything except an agreement to meet and use best efforts to make a recommendation. In addition, a docket already exists for the determination of issues such as the procurement of coal, emission allowances and power in the post-2008 period. Case No. 06-986-EL-UNC. This docket serves the purpose of exploring post-2008 issues more appropriately than the provision in the April 9, 2007 stipulation. OCC R.R. Ex. 2 at 2.

The stipulation does not adequately address the auditor's concern that active management be discontinued. There is no basis on the record to disregard the auditor's recommendation; therefore, the Commission should adopt the recommendation of the auditor that active management be discontinued.

The auditor also recommended that CG&E-Duke present several alternative sensitivity analyses of key variables (i.e., emission allowance prices and market coal prices) in its transaction review and approval process. CG&E-Duke should maintain detailed documentation of all emission allowance prices, market coal prices, and power purchase transactions to enable the next FPP auditor to review adequately the management of the procurement process for coal, emission allowances and power. If the auditor discovers that CG&E-Duke's management of the procurement process for coal, emission allowances, and power has resulted in imprudently incurred costs in the FPP price, then those imprudent costs should be refunded to FPP customers.

OCC witness Haugh recommended that audits of current and future AAC filings be conducted annually if these charges continue in the future. OCC Ex. R.R. 1 at 6. An audit of the charges associated with the AAC is the only way the Commission will be able to conclude whether the proposed AAC charge is reasonable and properly calculated. The audit of the AAC should be included with the audit of the 2007 and 2008 SRT and FPP riders, if those charges continue in the future. An audit of the first six months of 2007 AAC costs should be included within the scope of the next FPP and SRT audit period, July 1, 2006 through June 31, 2007. AAC costs incurred from July 1, 2007 and beyond should be included within the scope of subsequent annual FPP and SRT audits.

The Commission should adopt the auditor's recommendation that adequate documentation of the procurement practices be available so that the next auditor will have the documentation needed to evaluate their effectiveness. The Commission should also adopt the recommendation of OCC witness Haugh for an audit of the AAC. The recommendations of OCC witness Haugh fit together with the auditor's recommendation so that the auditor's recommendation for sensitivity analyses for allowance, fuel and power procurement processes can be accomplished in one audit for the FPP and the AAC together. Contrary to what CG&E-Duke may argue, this one audit of the FPP and AAC together will not be overly burdensome but will merely extend the scope of the current audit to include costs for coal, allowances and purchased power with costs for environmental compliance.

VI. CONCLUSION

The April 9, 2007 stipulation and recommendation fails all three prongs of the Commission's three-prong test for the reasonableness of stipulations. It is not the product of serious bargaining among the parties. It violates important regulatory practices and principles. It does not benefit ratepayers and the public interest. Based on the evidence of record, the April 9, 2007 stipulation must be rejected.

In rejecting the stipulation, the Commission should adopt the recommendations made by the management/performance auditor and OCC witness Haugh in these cases. The Commission should disallow recovery of a return on CWIP in the AAC. Only if the return on CWIP is eliminated will the Commission use a reasonable means to develop costs for the standard service offer prices. The Commission should also not allow any recovery through the SRT of capacity costs of the DENA assets. The DENA assets should be used only on an emergency basis and then subject to the pricing methodology set forth in the testimony of OCC witness Haugh. Finally, the AAC should be audited and the scope of the combined FPP-AAC audit should be expanded as set forth above.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that a copy of Ohio Partners for Affordable Energy's Initial Brief Phase 2 Confidential Version has been electronically delivered to the following parties in the above-captioned proceedings on this 17th day of May 2007.

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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

Consolidated Duke Energy Ohio, Inc. Rate Stabilization Plan Remand and Rider Adjustment Cases.	)	Case Nos. 03-93-EL-ATA 03-2079-EL-AAM 03-2080-EL-ATA 03-2081-EL-AAM 05-724-EL-UNC 05-725-EL-UNC 06-1068-EL-UNC 06-1069-EL-UNC 06-1085-EL-UNC

CONFIDENTIAL

REPLY POST-REMAND BRIEF, HEARING PHASE II,
BY
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Dated: May 30, 2007

02975

TABLE OF CONTENTS

02976

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

Consolidated Duke Energy Ohio, Inc. Rate Stabilization Plan Remand and Rider Adjustment Cases.	))))))))))	Case Nos. 03-93-EL-ATA 03-2079-EL-AAM 03-2080-EL-ATA 03-2081-EL-AAM 05-724-EL-UNC 05-725-EL-UNC 06-1068-EL-UNC 06-1069-EL-UNC 06-1085-EL-UNC

REPLY POST-REMAND BRIEF, HEARING PHASE II,
BY
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I. INTRODUCTION

A. Prefatory Comments

The briefs submitted to the Public Utilities Commission of Ohio ("PUCO" or "Commission") by the Office of the Ohio Consumers' Counsel ("OCC") in Phase I and Phase II described the sides taken by parties to these cases and closely examined the reasons for the positions taken by those parties. In part, the OCC's examination addressed the deal struck between Duke Energy Ohio, Inc. ("Duke Energy Ohio" or the "Company," including its predecessor company, "CG&E") and parties that represent customers who do not bear the full brunt of the rate increases proposed by the Company. The paucity of support in Phase II briefs from signatories to the stipulation ("2007

Stipulation," Joint Remand Rider Ex. 1[1]) regarding the Company's Fuel and Purchased Power ("FPP") tracker, System Reliability Tracker ("SRT"), and Annually Adjusted Component ("AAC") charges also speaks to the lack of actual involvement in the Phase II proceedings by most of the signatories to the 2007 Stipulation, and also their lack of knowledge concerning the Company's proposals.

B. Burden of Proof

The OCC's Initial Post-Remand Brief, Phase II ("OCC Initial Phase II Brief") set out the burden of proof, as stated in R.C. 4909.18 and/or R.C. 4909.19, which rests upon Duke Energy Ohio in these cases. The burden of proof upon the applicant, in this case Duke Energy Ohio, is statutory and is not shifted or otherwise changed by the activities of the signatories to the 2007 Stipulation. The present cases vividly illustrate why the burden of proof is not shifted by a stipulation. If such a shift could take place, the burden could have been shifted by the Company's hurried and haphazard efforts to present a stipulation in Phase II of these proceedings. The Company has the statutory burden to demonstrate that the rate increases that they have requested are reasonable.

The OCC does not bear any burden of proof in these cases. As explained in the OCC Initial Phase II Brief, and will further explain in the following sections, how Duke

[1] The notational conventions used by the OCC in earlier briefs and during the hearings will again be observed. The proceedings prior to the appeal are referred to, collectively, as the "*Post-MDP Service Case*," and the proceedings after the appeal are referred to, collectively, as the "*Post-MDP Remand Case*," the latter of which was separated in some respects into Phase I and Phase II. Exhibit references to the portion of the proceedings in Phase I after remand from the Court contain the word "Remand" to distinguish them from other exhibits. Exhibit references to the potion of the proceedings in Phase II after remand from the Court contain the words "Remand Rider."

Energy Ohio has failed to prove that its post-MDP pricing proposals should be adopted without alteration by the Commission.

II. PROCEDURAL HISTORY

The procedural and substantive history of these consolidated cases is contained in the OCC's briefs in these proceedings, the last of which (i.e. the OCC Initial Phase II Brief) was submitted on May 17, 2007. Initial briefs for Phase II of these proceedings were submitted on that date in opposition to the Company's proposals by the OCC and the OPAE.

Initial briefs were submitted in support of the 2007 Stipulation by Duke Energy Ohio ("Company Initial Phase II Brief") and the PUCO's Staff ("Staff Initial Phase II Brief"). Duke Energy Ohio incorrectly states: "The cases that OCC sought to suspend and stay included cases seeking to set the 2007 market price for the Annually Adjusted Component (AAC), System Reliability Tracker (SRT), and Fuel and Purchased Power (FPP) component of DE-Ohio's MBSSO."[2] The OCC never sought to "suspend and stay . . . cases," but instead sought to stay the *rate increases* sought by the Company until the Commission decided cases on remand from the Supreme Court of Ohio.[3]

Staff incorrectly asserts that "Mr. Michael Haugh, testifying on behalf of OCC, was the only witness to suggest the [2007] Stipulation did not meet all three criteria."[4] The featured witnesses during the hearing on April 10, 2007 were two *Staff* witnesses

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[2] Company Initial Phase II Brief at 3-4, citing "OCC's Motion to Stay the AAC, FPP, and SRT" dated December 12, 2006.

[3] OCC Motion to Stay All Rate Increases (December 12, 2006).

[4] Staff Initial Phase II Brief at 4.

who supported the Auditor's Report prepared by Energy Ventures Analysis ("EVA" or "Auditor"), as assisted by Larkin & Associates ("Larkin"). Those witnesses support the OCC's positions regarding prudent fuel and capacity procurement practices that the Company should follow to reduce the FPP and SRT charges.[5] These include recommendations that the 2007 Stipulation rejects.[6]

EVA's assigned tasks did not deal with the Company's proposed AAC charges, but the Auditor's Report recommends that the Company examine its assumptions relating to fuel purchases in connection with costs that are used in calculation of the AAC.[7] That recommendation supports the OCC's recommendation that the next audit address the AAC charges.

III. ARGUMENT

A. The Test for a Partial Stipulation Emphasizes the Public Interest.

The 2007 Stipulation was filed just prior to the hearing on Phase II of these cases, and its recommendations are part of the record that the Commission will consider in these cases.[8] The standard of review for consideration of a partial stipulation has been discussed in a number of Commission cases and by the Ohio Supreme Court. See, e.g., *CG&E ETP Case*, PUCO Case No. 99-1212-EL-ETP, et al., at 65 (July 19, 2000).

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[5] The conflict between the testimony in support of the Auditor's Report and the 2007 Stipulation explains attempts by Staff's counsel to conduct cross-examination of Mr. Schwartz rather than re-direct. Tr. Vol. Remand Rider Vol. I at 110, lines 12-16 (April 10, 2007).

[6] See, e.g., Joint Remand Rider Ex. 1 at ¶¶1, 2, and 8 (2007 Stipulation).

[7] OCC Initial Phase II Brief at 9, citing PUCO Ordered Remand Rider Exhibit 1 at 2-18 (Auditor's Report).

[8] Joint Remand Rider Ex. 1 (2007 Stipulation).

The Court in *Consumers' Counsel 1992* considered whether a just and reasonable result was achieved with reference to criteria adopted by the Commission in evaluating settlements:

> 1. Is the settlement a product of serious bargaining among capable, knowledgeable parties?
>
> 2. Does the settlement, as a package, benefit ratepayers and the public interest?
>
> 3. Does the settlement package violate any important regulatory principle or practice?[9]

The OCC submits that the 2007 Stipulation violates the criteria set out by the Commission and the Ohio Supreme Court.[10]

B. The Partial Stipulation Fails the Test for Approval of a Settlement.

1. The Settlement Was Not the Product of Serious Bargaining by Capable, Knowledgeable Parties.

The PUCO Staff states, without the benefit of reading the initial Phase II briefs, that "[n]o one questions" that the 2007 Stipulation is the product of serious bargaining among capable and knowledgeable parties.[11] The initial briefs by both the OCC and OPAE argued that the 2007 Stipulation does not satisfy the first criterion for the evaluation of partial stipulations.[12] Key testimony was presented by OCC Witness Hixon regarding side agreements in the *Post-MDP Service Case* that resulted in option agreements that provide OHA, OEG, and IEU members with protections against the

[9] Id. at 126.

[10] Joint Ex. 1 at 2.

[11] Staff Initial Phase II Brief at 1 and 4.

[12] OCC Initial Phase II Brief at 21-24; OPAE Initial Phase II Brief at 2-10.

increases that are the subject of the 2007 Stipulation.[13] Serious bargaining did not take place between Duke Energy Ohio and parties whose members are shielded from the brunt of rate increases that are the subject of the 2007 Stipulation.

The first criterion for the evaluation of partial stipulations asks whether the parties were capable and knowledgeable. The absence of briefs by many of the stipulating parties echoes their general lack of involvement in the *Post-MDP Remand Case*. This lack of involvement is also evidenced by the parties' lack of discovery activity, lack of contributions to pleadings, absence at depositions, and lack of participation in hearings (including the lack of sponsored witnesses).[14] The record does not contain opinions by signatories to the 2007 Stipulation regarding a "Clarification" to that stipulation other than the support by the Company and the Staff who executed the document.[15] Even the PUCO Staff, the sponsor of the Auditor's Report and witnesses who supported that document stated disinterest in the OCC's discovery activities. Staff's counsel attended the deposition of the DERS president Whitlock on January 9, 2007.[16] Staff, like other parties, was offered copies of hundreds of documents that were used (in part) in the attachments to OCC Witness Hixon's testimony. After the deposition, Staff stated in response to the motions in limine by Duke Energy Ohio and its affiliates that it "has no

[13] OCC Remand Ex. 2(A) (Hixon).

[14] The transcripts that are part of the record show the list of parties represented at depositions. OMG Remand Ex. 4 (Whitlock) (OCC, DERS, Company, IEU, OEG, Kroger, OHA, Staff); OCC Remand Ex. 7 (George) (OCC, Kroger, Company); OCC Remand Ex. 8 (Ziolkowski) (OCC, Company); OCC Remand Ex. 9 (Ficke) (OCC, Company, Cinergy). Witness were sponsored by the OCC, Company, Staff (including EVA and Larkin representatives), and OMG (by means of OCC deposition of Charles Whitlock, OMG Ex. 4).

[15] The document was entered into the record as OCC Remand Rider Ex. 3.

[16] OMG Remand Ex. 4 (Whitlock).

such agreement [involving DERS]."[17] A party that declines to accept and review copies of documents that were important to these cases -- especially in a remand that was ordered by the highest court in Ohio in part due to the non-disclosure of such documents -- is not "knowledgeable," regardless of the identity of that party.

"Capable, knowledgeable parties" should not be confused, as the Company does, with past regulatory experience.[18] The OCC became capable and knowledgeable in these proceedings by means of its efforts to develop a perspective independent of that exhibited by Duke Energy Ohio. Non-Company signatories to the 2007 Stipulation have not exerted such efforts. The circumstances of these cases, and of the parties to the 2007 Stipulation, demonstrate that the partial settlement was reached without *serious bargaining* that involved *capable, knowledgeable parties.*

2. The Settlement Package Does Not Benefit the Public Interest.

The settlement package stated in the 2007 Stipulation does not provide a benefit to ratepayers or serve the public interest. Instead of adopting the 2007 Stipulation without alteration, the Commission should adopt all of the Auditor's recommendations regarding the FPP and the SRT (the latter as supported by OCC testimony) and reject the inclusion of a return on CWIP as part of the AAC in order to protect customers from paying unreasonable charges.

Staff minimizes the important impact on customers of paragraphs 2-4 and 6-9 in the 2007 Stipulation, characterizing them as merely "process matters" not involving

[17] Staff Memorandum in Response to Motions *in Limine* at 2 (February 7, 2007).

[18] Company Initial Phase II Brief at 6.

revenues.[19] The OCC's Initial Phase II Brief demonstrates the importance of many of those paragraphs to the level of standard service offer charges, drawing support from EVA's recommendations that are rejected in paragraphs 1, 2, and 8 of the 2007 Stipulation.[20] The present discussion focuses on statements contained the initial briefs submitted by Duke Energy Ohio and the PUCO Staff that discuss specific provisions within the 2007 Stipulation.

Paragraphs 1 through 3 of the 2007 Stipulation relate to the purchase of coal, emission allowances, and purchased power. The Company seeks to eliminate major recommendations 1 and 2 in the Auditor's Report (i.e. the recommendations "shall be withdrawn"[21]) in order to replace the discontinuation of the Company's active coal management with meetings to "discuss" Duke Energy's coal procurement practices.[22] The Company states that "there is no reason to delay discussions,"[23] but further

[19] Staff Initial Phase II Brief at 7, citing Staff Remand Ex. 1 (but correctly identified as Staff Remand Rider Ex. 3 at Q&A 3 (Cahaan)).

[20] OCC Initial Phase II Brief at 24-31. The OCC also points out that the Company 's agreement in paragraph 9 to the audit recommendations "except as set forth in paragraphs one through eight" apparently does not mean that Duke Energy will remove the restrictions that it places in its RFPs for coal purchases. Id. at 30-31. The removal of such restrictions could provide savings for standard service offer customers.

[21] Joint Remand Rider Ex. 1 at 4-5. ¶¶1-2 (2007 Stipulation). As stated in the OCC's Initial Phase II Brief, the stipulating parties have not explained how an *independent*, Commission ordered audit -- designated "PUCO Ordered Remand Rider Exhibit 1" and entered into the record for these cases -- can be "withdrawn." OCC Initial Phase II Brief at 24, footnote 86. EVA's Seth Schwartz and Larkin's Ralph Smith, both Staff witnesses, defended the findings and conclusions contained in the Auditor's Report without any withdrawal or retraction.

[22] The interrelatedness of the provisions is evidenced by the Company's statement that the 2007 Stipulation provides a "bill credit . . . in an amount greater than that recommended by the FPP auditor during 2007." Company Initial Phase II Brief at 7. The Company seeks to retain its current coal procurement practices that may increase FPP charges. Also, the credit for 2007 "resolves all issues associated with the settlement of the [redacted] contracts for past, current, and future FPP periods." Joint Remand Rider Ex. 1 at 4, ¶1. The credits would take place in 2007, but would cover 30 months following the 12-month audit period.

[23] Company Initial Phase II Brief at 8.