FILE

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BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Duke Energy Ohio, Inc., for the Establishment of a Charge Pursuant to Revised Code Section 4909.18.	)	Case No. 12-2400-EL-UNC
In the Matter of the Application of Duke Energy Ohio, Inc., for Approval to Change Accounting Methods.	)	Case No. 12-2401-EL-AAM
In the Matter of the Application of Duke Energy Ohio, Inc., for the Approval of a Tariff for a New Service.	)	Case No. 12-2402-EL-ATA

APPLICATION OF DUKE ENERGY OHIO, INC.

Comes now Duke Energy Ohio, Inc., (Duke Energy Ohio or Company) and states as follows:

1. Duke Energy Ohio is an Ohio corporation engaged in the business of supplying electric generation, transmission, and distribution service to approximately 690,000 customers in southwestern Ohio, all of whom will be affected by this Application. Duke Energy Ohio is a public utility, as defined by Ohio Revised Code (R.C.) 4905.02, and an electric light company, as defined by R.C. 4905.03, and is subject to the jurisdiction of the Public Utilities Commission of Ohio (Commission).

2. This Application is made pursuant to R.C. 4905.04, R.C. 4905.05, R.C. 4905.06, R.C. 4905.13, and R.C. 4909.18 and related sections of the Ohio Revised Code. The Company seeks the following:

a. An order from the Commission, under the authority of R.C. 4905.04, R.C. 4905.05, and R.C. 4905.06, establishing the amount of the cost-based charge, pursuant to Ohio's newly adopted state compensation mechanism,[1] for the provision by Duke Energy Ohio of capacity services throughout its service territory;

b. An order from the Commission, under the authority of R.C. 4905.13, authorizing Duke Energy Ohio to modify its accounting practices to establish a deferral, as of the date of the filing of this Application, to account for the difference between the amounts being recovered by Duke Energy Ohio for the provision of capacity services and Duke Energy Ohio's cost of providing capacity services as such cost is established pursuant to Ohio's newly adopted state compensation mechanism; and

c. An order from the Commission, under the authority of R.C. 4909.18, approving a new tariff to allow for the future recovery of the deferred amounts as described herein.

3. Duke Energy Ohio is a fixed resource requirement (FRR) entity in PJM Interconnection, LLC, (PJM) and is a signatory to PJM's Reliability Assurance Agreement (RAA), which is a part of PJM's Tariff approved by the Federal Energy Regulatory Commission (FERC). The RAA requires Duke Energy Ohio to self-supply the capacity resources for its entire load zone or service territory in an amount that will satisfy the criteria under Schedule 8.1 of said agreement, including a reserve margin.[2] The RAA further provides that the state compensation mechanism, where it exists, *will* prevail to determine the pricing of capacity that is supplied by

[1] *In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company*, Case No. 10-2929-EL-UNC, Opinion and Order (July 2, 2012).

[2] At its outset, Duke Energy Ohio's FRR Plan, as approved by the FERC, provided an opportunity for wholesale suppliers to file an independent FRR plan and for competitive retail electric service providers to "opt out" of Duke Energy Ohio's FRR Plan by providing their own capacity, prior to the implementation of Duke Energy Ohio's FRR Plan capacity commitment.

FRR entities.[3] Both the Commission and the FERC agree with the controlling effect of the state compensation mechanism.[4] And the FERC has held that the RAA does not permit an FRR entity to change the state compensation mechanism once established.[5]

4. On July 2, 2012, the Commission completed its review of capacity pricing and determined that "the state mechanism shall be based on the costs incurred by the FRR entity for its FRR capacity obligations… ."[6] As the Commission reasoned, it has an obligation to ensure that an FRR entity receives just and reasonable compensation for the services it renders.[7] The Commission also adopted a methodology, in reliance upon traditional rate-making principles, to establish a just and reasonable cost for the provision of capacity by an FRR entity.[8]

5. The Company's status as an FRR entity obligates it to ensure the existence of adequate capacity resources in its footprint for the duration of its FRR plan, which terminates on May 31, 2015. Duke Energy Ohio is providing capacity services for the load-serving entities in its service territory, a service that the Commission has found should be "characterized as an intrastate wholesale matter," and, therefore, is providing a service that is not a retail electric service, as defined by Ohio law.[9] Duke Energy Ohio has committed owned legacy generation resources to fulfilling its obligations as an FRR entity. See Attachment A for an identification of the Company's Legacy Generating Assets.

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[3] PJM RAA, Schedule 8.1, Section D.8 (emphasis added).

[4] *American Electric Power Service Corporation v. PJM Interconnection, LLC*, FERC Docket No. EL11-2183-000, FERC Order, at page 8 (a state compensation mechanism prevails and it is the absence of such a mechanism that conditions subsequent rights)(January 20, 2011). See also, Response of the Public Utilities Commission of Ohio, at page 3 (July 30, 2012)(recognizing that Ohio has a state compensation mechanism that prevails, consistent with the RAA).

[5] *American Electric Power Service Corporation*, 134 FERC ¶ 61,039 (2011).

[6] *In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company*, Case No. 10-2929-EL-UNC, Opinion and Order (July 2, 2012), at page 23.

[7] Id, at page 22. See also, Id, Concurring Opinion, at page 3 ("a cost-based compensation method is necessary and appropriate")(July 2, 2012).

[8] Id. (Under Ohio law, "all charges for service *shall* be just and reasonable.")(Emphasis added.)

[9] Id, at page 13.

6. R.C. 4909.18 allows a public utility to file an application with the Commission to establish any charge and to amend its tariffs. Where such application relates to a new service or is otherwise not for an increase in an existing charge, then the Commission may approve such application without a hearing, unless the Commission determines that it may be unjust or unreasonable.

7. Duke Energy Ohio is currently receiving, for the capacity it self-supplies as an FRR entity, only the auction-based final zonal capacity price (FZCP) in effect for the rest of the PJM region for the current PJM delivery year. The FZCP structure, which will persist through May 31, 2015, applies with regard to all retail load in the Company's service territory.[10] As demonstrated in this Application and the attachments hereto, the FZCP is significantly less than Duke Energy Ohio's cost of providing capacity sufficient to meet its FRR obligations.

8. Duke Energy Ohio seeks the determination of a charge derived from the state compensation mechanism implemented by the Commission on July 2, 2012; said final mechanism supplanting the interim mechanisms previously in place. More specifically, through this Application, Duke Energy Ohio respectfully requests that the Commission determine that the rate for capacity services associated with its FRR obligations is $224.15/MW-Day, calculated using the formula that the Commission has previously determined to be reasonable in respect of another FRR entity under its jurisdiction.[11] The charge so determined will apply for the duration of the Company's commitment as an FRR entity.

9. In addition to such determination, Duke Energy Ohio seeks authority, pursuant to R.C. 4905.13, to defer, commencing with the date on which this Application is filed, the

[10] *In the Matter of Application of Duke Energy Ohio, Inc., for Authority to Establish a Standard Service Offer Pursuant to Section 4828.143, Revised Code, in the Form of an Electric Security Plan, Accounting Modifications and Tariffs for Generation Service*, Case No. 11-3549-EL-SSO, *et al.*, Stipulation and Recommendation, at paragraphs II.B. and IV.A. (October 24, 2011).

[11] *In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company*, Case No. 10-2929-EL-UNC, Opinion and Order (July 2, 2012).

difference between the amount it has a right to collect pursuant to such state mechanism and the FZCP.[12] Duke Energy Ohio submits that, for the remaining term of its FRR plan, the average FZCP will approximate $66.06/MW-Day. Therefore, reducing the Company's capacity cost by the estimated amount charged to suppliers yields an incremental difference of approximately $158.08/MW-Day. Additionally, the Company is seeking carrying charges on the unrecovered balance of the deferral, calculated at the long-term debt rate as shown in Attachment B. Subsequently, in an appropriate proceeding as referenced herein, Duke Energy Ohio will request approval to begin collection of the deferred amounts, including carrying costs.

10. Finally, Duke Energy Ohio seeks approval of a new tariff, designated as Rider Deferred Recovery – Capacity Obligation (Rider DR-CO), which would allow for the collection, over time, of the deferred difference between the amount collectible pursuant to Ohio's state compensation mechanism and the FZCP.

11. Because the Commission has not previously set any charge for Duke Energy Ohio pursuant to the new state compensation mechanism and Duke Energy Ohio has never before had a tariff for the collection of the costs incurred by it in fulfilling its obligations as an FRR entity to provide capacity pursuant to the state compensation mechanism, this is a new charge and therefore, under R.C. 4909.18, an application for a new service, namely, the provision of capacity as provided for under Ohio's state compensation mechanism finally adopted by the Commission on July 2, 2012.[13] Further, because Duke Energy Ohio is seeking only the establishment of the level of that charge, deferral authority for subsequent collection, and

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[12] See, *e.g., Elyria Foundry Co. v. Public Utilities Comm'n of Ohio* (2007), 113 Ohio St.3d 305, 308-309 (Commission's power to authorize deferrals upheld).

[13] See, *e.g., City of Cleveland v. Public Utilities Comm'n of Ohio* (1981), 67 Ohio St.2d 446, 448 (where tariff reflected first filing, the application was for a new service and not an increase in rates). See also, *Cookson Pottery v. Public Utilities Comm'n of Ohio* (1954), 161 Ohio St. 498, 504-505 ("an application not involving a rate increase...necessarily includes an application to either *establish for the first time a new rate* or to reduce the rate once established")(emphasis added).

approval of the mechanism by which the collection will be made, this Application seeks no increase in amounts to be paid by customers. Consequently, the provisions of R.C. 4909.18(A)-(E) and R.C. 4909.19 are not applicable to this filing.[14] Moreover, because the Company has relied upon the methodology recently adopted and approved by the Commission for purposes of establishing a just and reasonable charge, Duke Energy Ohio's Application herein is not unjust or unreasonable and should therefore be approved without a hearing.

12. The Commission has the authority to approve, in these proceedings, a tariff for the collection of the deferral discussed herein.[15] The Commission's jurisdiction over capacity service pricing for an FRR entity such as Duke Energy Ohio results from its general supervisory authority, set forth in R.C. 4905.04, 4905.05, and 4905.06, as explained by the Commission recently.[16] Ohio law undeniably provides that a public utility is required to render all services as required by law.[17] Further, Ohio law provides that, in exchange for furnishing adequate service, public utilities are entitled to impose just and reasonable charges.[18] The proposed new tariff provision, Rider DR-CO, will allow Duke Energy Ohio to provide the capacity service for which it is obligated as an FRR entity and as mandated under Ohio's state compensation mechanism.

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[14] See, *e.g.*, *Ohio Consumers' Counsel v. Public Utilities Comm'n of* Ohio, (2006), 111 Ohio St.3d 300, 305 (notice, investigation, and hearing requirements of R.C. 4909.19 not applicable where the request is not one for an increase in existing rates).

[15] See, *e.g., In the Matter of the Application of The Dayton Power and Light Company for Approval of Its Transmission Cost Recovery Rider*, Case No. 09-256-EL-UNC (institution of rider to recover deferred transmission costs); *In the Matter of the Application of Columbia Gas of Ohio, Inc., for Approval of Tariffs to Recover, Through an Automatic Adjustment Clause, Costs Associated with the Establishment of an Infrastructure Replacement Program and for Approval of Certain Accounting Treatment*, Case No. 07-478-GA-UNC (institution of rider to recover deferred riser replacement costs); *In the Matter of the Joint Application of The East Ohio Gas Company d.b.a. Dominion East Ohio, Columbia Gas of Ohio, Inc., Vectren Energy Delivery of Ohio, Northeast Ohio Natural Gas Corp., and Oxford Natural Gas Company for Approval of an Adjustment Mechanism to Recover Uncollectible Expenses*, Case No. 03-1127-GA-UNC (institution of uncollectible expense rider).

[16] *In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company*, Case No. 10-2929-EL-UNC, Opinion and Order, at p. 22 (July 2, 2012).

[17] R.C. 4905.04.

[18] R.C. 4905.22.

13. As incorporated herein, the formulaic methodology recently approved by the Commission for establishing a cost-based state compensation mechanism relies extensively on publicly available data and includes only the following elements of the annual capacity revenue requirement that have been approved previously by the Commission.

a. Rate base is limited to Net Plant, Accumulated Deferred Income Taxes, and an allowance for Materials and Supplies. No request is being made to include construction work in progress, plant held for future use, prepayments, or cash working capital in rate base.

b. Return on rate base using the Company's cost of capital and a return on equity (ROE) at 11.15 percent as recently approved by the Commission for a comparable utility operating as an FRR entity. The capital structure excludes all purchase accounting adjustments associated with the merger between Duke Energy Corp. and Cinergy Corp.

c. Operating and Maintenance Expenses include only those accounts attributable to capacity costs as approved by the Commission and exclude all costs associated with the operation of the Company's gas assets that were transferred to an affiliate in 2011.

d. Depreciation expense on capacity-related rate base.

e. Allocable capacity-related taxes other than income.

f. Income and commercial activities taxes at statutory rates reflecting the Staff's adjustments as approved by the Commission. Consistent with the methodology approved by the Commission in its July 2, 2012, Opinion and Order, income taxes reflect the benefit of the production tax credit.

g. Net costs of capacity being purchased to fulfill the FRR obligation.

h. All projected margins from the sale of energy and ancillary services derived from the Company's generating assets are included as an offset to the overall revenue requirement.

14. The average annual revenue requirement required for the Company to achieve an 11.15 percent ROE on its investment in resources used to provide the services to which Duke Energy Ohio is obligated as an FRR entity from August 1, 2012, through May 31, 2015, is $364,876,433 or approximately $224.15/MW-Day. This figure represents the cost of providing capacity service consistent with the Company's FRR obligation. However, a portion of this revenue requirement is being recovered via the FZCP. Netting this additional revenue against the Company's overall costs results in a net annual revenue requirement for Duke Energy Ohio's capacity service as an FRR entity from August 1, 2012, through May 31, 2015, of $257,337,205 or a cost-based charge of approximately $158.08/MW-Day above the market-based FZCP revenues. This is the incremental amount of revenue, and the average incremental capacity rate, needed to ensure that the Company has the opportunity to earn 11.15 percent on its shareholders' investment in capacity-related service through the term of its FRR obligation. See Attachment B.

15. As reasoned by the Commission in recently adopting Ohio's state compensation mechanism, a utility with FRR capacity obligations should earn reasonable and fair compensation on the services it provides.[19] The Commission recently found that Reliability Pricing Model-based capacity pricing would be insufficient to yield reasonable compensation for an Ohio FRR entity's provision of capacity in fulfillment of its FRR capacity obligations.[20] Similarly, absent sufficient capacity compensation for rendering service as an FRR entity, Duke

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[19] *In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company*, Case No. 10-2929-EL-UNC, Opinion and Order, at page 23 (July 2, 2012)("[i]f [Reliability Pricing Model]-based capacity is adopted, AEP-Ohio may earn an usually low return on equity of 7.6 percent in 2012 and 2.4 percent in 2013 with a loss of $240 million between 2012 and 2013").
[20] Id.

Energy Ohio will be operating at a significant loss, with an estimated average annualized ROE of negative 8.90 percent, for the period August 1, 2012, through May 31, 2015. Indeed, Duke Energy Ohio currently requires at least $122 million on an annualized basis through May 31, 2015, to earn even 0 percent on its equity investment. See Attachment C. It is undeniable that Duke Energy Ohio is not earning fair and reasonable compensation for its services.

16. The Application herein will not affect Duke Energy Ohio's advancement of the policies of the state of Ohio, which guide the Commission's review of rate proposals under R.C. 4928.141, *et seq.*[21] Indeed, Duke Energy Ohio will continue to charge suppliers the FZCP in PJM for the duration of its FRR plan, thereby ensuring that there will be no disruption in the vibrant competitive market in its service territory.

17. The proposed tariff amendment, instituting Rider DR-CO, will allow for the collection of the amounts deferred, as set forth herein. See Attachment D. Rider DR-CO would initially be set at zero and would be adjusted, initially, through an application filed no later than March 1, 2013. Through such proceeding, the Commission would approve the establishment of a rate that would allow for the collection of $258,747,429 per year for three years. As the FZCP and the PJM load for subsequent PJM planning years become known, Duke Energy Ohio proposes to adjust that rate through the filing, in that same docket, of updated information. Such updates would be filed annually, by each March 1. As these filings would make no more than arithmetic modifications, no Commission process should be necessary in order to effectuate the updates. At the end of the deferral collection period, Duke Energy Ohio will file an application to true up the total collected amount, whether such true-up would result in a positive or a negative amount.

[21] See *In re Application of Columbus Southern Power, et al.*, 128 Ohio St.3d 512, 2011-Ohio-1788 at ¶ 62.

18. For the reasons stated above, Duke Energy Ohio respectfully requests that the Commission determine its cost-based pricing consistent with the traditional rate-making principles that form the basis of the state compensation mechanism and as supported by Attachment B, approve the Company's request to create a deferral to record the difference between the cost-based price for capacity and the price being recovered via the FZCP for future recovery with a carrying cost at the long-term debt rate on the unrecovered balance, and approve the creation of Rider DR-CO. Duke Energy Ohio will subsequently seek to recover the deferred balance through Rider DR-CO. To the extent that Duke Energy Ohio has, at the time of recovery of the deferred balance, transferred its legacy generating assets to an affiliate, as has been approved by the Commission, that portion of the recovery attributable to the time period during which the assets were owned by the affiliate should then be passed through to such affiliate.[22]

19. Duke Energy Ohio submits that this proposal appropriately balances the objectives of enabling the Company to recover its costs as an FRR entity under the state compensation mechanism and promoting retail competition in its service territory.

WHEREFORE, Duke Energy Ohio seeks an order from this honorable Commission, establishing \$224.15/MW-Day as the appropriate charge for its provision of capacity pursuant to the terms of the RAA and the prevailing state compensation mechanism; allowing the deferral of any and all amounts by which such charge exceeds Duke Energy Ohio's current recovery of capacity, at the FZCP, supplied consistent with its FRR obligations, from the date of filing this Application through May 31, 2015, and including carrying charges at the long-term debt rate on the unrecovered balance; and implementing a tariff, Rider Deferred Recovery – Capacity Obligation, to allow for the subsequent recovery of deferred amounts as described herein.

[22] See *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan*, Case No. 11-346-EL-SSO, *et al.*, Opinion and Order at page 60 (August 8, 2012).

Respectfully submitted,

DUKE ENERGY OHIO, INC.

Julia S. Janson, President

Stephen G. De May, Vice President
and Treasurer

VERIFICATION

STATE OF OHIO)
)
COUNTY OF HAMILTON)

I, Julia S. Janson, President of Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc., being first duly sworn, hereby verify that the information contained in this Application is true and correct to the best of my knowledge, information and belief.

Julia S. Janson

Julia S. Janson

Sworn to and subscribed in my presence this 27th day of Aug 2012.

Amy B Spiller

Notary Public

AMY BETH SPILLER, Attorney at Law
Notary Public, State of Ohio
My Commission Has No Expiration Date
Section 147.03

My commission expires: ________

444705

VERIFICATION

STATE OF NORTH CAROLINA)
)
COUNTY OF MECKLENBURG)

I, Stephen G. De May, Vice President and Treasurer of Duke Energy Corporation and Treasurer of Duke Energy Ohio, Inc., being first duly sworn, hereby verify that the information contained in this Application is true and correct to the best of my knowledge, information and belief.

Stephen G. De May

Stephen G. De May

Sworn to and subscribed in my presence this 27 day of August 2012.

Katie Jamison

Notary Public

My commission expires: June 14, 2016

444705

Attorneys for Applicant

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ATTACHMENT A

LEGACY GENERATING ASSETS

Summary of Duke Energy Ohio Legacy Generation	
Station	**Ownership**
Beckjord 1	100.00%
Beckjord 2	100.00%
Beckjord 3	100.00%
Beckjord 4	100.00%
Beckjord 5	100.00%
Beckjord 6	37.50%
Beckjord CT 1	100.00%
Beckjord CT 2	100.00%
Beckjord CT 3	100.00%
Beckjord CT 4	100.00%
Conesville 4	40.00%
Dick's Creek CT 1	100.00%
Dick's Creek CT 3	100.00%
Dick's Creek CT 4	100.00%
Dick's Creek CT 5	100.00%
Killen 2	33.00%
Killen CT	33.00%
Miami Fort 7	64.00%
Miami Fort 8	64.00%
Miami Fort CT 3	100.00%
Miami Fort CT 4	100.00%
Miami Fort CT 5	100.00%
Miami Fort CT 6	100.00%
Stuart 1	39.00%
Stuart 2	39.00%
Stuart 3	39.00%
Stuart 4	39.00%
Stuart Diesel	39.00%
Zimmer 1	46.50%

ATTACHMENT B

DUKE ENERGY OHIO DAILY CAPACITY RATES
Twelve Months Ending December 31, 2011

Line			
1	**Capacity Daily Rates (before credits for margins from sales of capacity, energy, and ancillary services)**		
2–3	$/MW	=	Annual Production Fixed Cost [A] / (5 CP Demand/365)[B]
4–5	**$323.26**	=	$526,225,032 / 4459.85 / 365
6	**Capacity Daily Rates (After credits for margins from sales of energy and ancillary services)**		
7–8	$/MW	=	Annual Production Fixed Cost Net of Margins from Energy and Ancillary Services [c] / (5 CP Demand/365)[B]
9–10	**$224.15**	=	$364,876,433 / 4459.85 / 365
11	**Capacity Daily Rates (Net of Existing Sales at FZCP)**		
12–13	$/MW	=	Annual Production Fixed Cost Net of Existing Sales at FZCP and Margins from Energy and Ancillary Services [c] / (5 CP Demand/365)[B]
14–15	**$158.08**	=	$257,337,205 / 4459.85 / 365
16	Average of demand at time of five highest daily peaks (MW)		4,460

Note: [A] From page 3, line 6 + line 7.
[B] Average of 5 highest monthly peaks (MW)
Form 1, page 400, column (b) less DEK and wholesale demand. (See workpaper)

Generator Step Up Transformer Workpaper
Twelve Months Ending December 31, 2011

Line	Description	Reference	Amount
1	GSU & Associated Investment	(A)	$23,208,297
2	Total Transmission Investment	FF1, P.207, L.58, Col.g	$608,828,977
3	Percent (GSU to Total Trans. Investment)	L.1 / L.2	3.81%
4	Transmission Depreciation Expense	FF1, P.336, L.7, Col.b	$11,199,710
5	GSU Related Depreciation Expense	L.3 x L.4	$426,928
6	Station Equipment Acct. 353 Investment	FF1, P.207, L.50, Col.g	$338,926,542
7	Percent (GSU to Acct. 353)	L.1 / L.6	6.85%
8	Transmission O&M (Accts 562 & 570)	FF1,P.321, L. 93, Col.b, and L.107, Col.b	$2,931,899
9	GSU & Associated Investment O&M	L.7 x L.8	$200,764

Note: (A) Same as amount shown in Attachment H-22 Formula rate filed with PJM.

ANNUAL PRODUCTION FIXED COST
Twelve Months Ending December 31, 2011

Rate Schedule 101
Page 3

Line	Description	Reference	Req thru 5/15 [C]	Annualized
1	Return on Rate Base	P.4, L.18	$372,542,287	$131,485,513
2	Operation & Maintenance Expense	P.11, L.12	479,587,228	169,266,081
3	Depreciation Expense	P.13, L.10	223,343,099	78,826,976
4	Taxes Other Than Income Taxes	P.14, L.6	177,971,898	62,813,611
5	Income Tax	P.15, L.7	97,352,081	$34,359,558
6	Total Revenue Requirement	Sum (L.1 thru L.5)	**$1,350,796,592**	**$476,751,738**
7	[redacted]	[redacted]	[redacted]	[redacted]
8	[redacted]	[redacted]	[redacted]	[redacted]
9	Total Fixed Costs to Collect Over Remainder of FRR	Sum (L. 6 thru L.8)	**$1,186,276,446**	**$418,685,804**
10	[redacted]	[redacted]	[redacted]	[redacted]
11	[redacted]	[redacted]	[redacted]	[redacted]
12	Total Revenue to Recover Through End of FRR	Sum (L.9 thru L.11)	725,235,452	255,965,454
13	Plus: Commercial Activities Tax	(B)	3,886,630	1,371,752
14	Net Revenue to Collect		**$729,122,082**	**$257,337,205**

Note: (A) Internally calculated based on projected market prices, FRR obligations, and projections of market prices.
(B) Commercial Activities Tax at 0.26% of total revenue.
(C) Reflects the total for the period August 1, 2012, through May 31, 2015, which is the duration of the Company's FRR obligation.

RETURN ON PRODUCTION -RELATED INVESTMENT
Twelve Months Ending December 31, 2011

Line	Description	Reference	Amount	Demand	Energy
			(1)	(2)	(3)
1	**ELECTRIC PLANT**				
2	Gross Plant in Service	P.5, L.5	$3,608,188,601	$3,574,328,638	$33,859,963
3	Less: Accumulated Depreciation	P.5, L.10	1,306,015,709	1,301,540,820	4,474,889
4	Net Plant in Service	L.2 - L.3	$2,302,172,892	$2,272,787,818	$29,385,074
5	Less: Accumulated Deferred Taxes	P.5, L.11	(636,466,948)	(638,956,932)	2,489,984
6	Plant Held for Future Use	Note (A)	-	-	-
7	Construction Work in Progress	Note (A)	-	-	-
8	Subtotal - Electric Plant	L.4 + L.5 + L.6 + L.7	$1,665,705,944	$1,633,830,886	$31,875,058
9	**WORKING CAPITAL**				
10	Materials & Supplies				
11	Fuel	P.8, L.2	$83,305,297	$0	$83,305,297
12	Nonfuel	P.8, L.7	40,681,661	40,681,661	-
13	Total M & S	L.11 + L.12	$123,986,958	$40,681,661	$83,305,297
14	Prepayments	Note (B)	-	-	-
15	Cash Working Capital	Note (A)	-	-	-
16	Total Rate Base	L.8 + L.13 + L.14 + L.15	$1,789,692,902	$1,674,512,547	$115,180,355
17	Weighted Cost of Capital	P.10, L.4	7.852%	7.852%	7.852%
18	Return on Rate Base	L.16 x L.17	$140,529,667	$131,485,513	$9,044,153

Note (A) None requested.
(B) None requested. Commission approved formula excluded prepayments except for pre-paid pension asset.

PRODUCTION-RELATED
ELECTRIC PLANT IN SERVICE, ACCUMULATED DEPRECIATION AND ADIT
Twelve Months Ending December 31, 2011

		System		Production			
Line	Description	Reference	Amount	Reference	Amount	Demand	Energy
			(1)		(2)	(3)	(4)
1	**Gross Plant in Service (Note A)**						
2	Plant in Service (Excl. Gen & Intangible) (Note C)	FF1, P.204-207, L.100	$5,913,165,008	FF1, P.205, L.46(g)	$3,379,461,653	$3,379,461,653	$0
3	Allocated General & Intangible Plant	P.6, L.16	168,803,540		86,793,890	54,265,855	32,528,035
4	Common Plant	P.7, L.17	$298,250,155		141,933,058	140,601,130	1,331,928
5	Total	L.2 + L.3 + L.4	$6,380,218,703		$3,608,188,601	$3,574,328,638	$33,859,963
						99%	1%
6	Percent of Total Gross Plant in Service	L.5 ÷ Line 2, Col.(1)			56.55%	56.02%	0.53%
7	Accum Provision for Depreciation (Notes A & D)	FF1, P.219	$2,091,025,475	FF1, P.219, L.20+L.24	$1,226,882,363	$1,226,882,363	$0
8	General Plant	FF1, p. 219, L.28	21,340,622	Note (B)	10,972,730	6,860,443	4,112,286
9	Allocated Common Plant	P.7, L.18	143,816,541		68,160,616	67,798,014	362,602
10	Total	L.7 + L.8 + L.9	$2,256,182,638		$1,306,015,709	$1,301,540,820	$4,474,889
11	Accum Deferred Income Taxes (Note A)	FF1, P.234 (Acct. 190, L.8) P. 272-273 (Acct 281, L.8) P.274-275 (Acct 282, L.5) P.276-277 (Acct. 283, L.9)	($1,435,857,338)	P.5a, P.5b	($636,466,948)	($638,956,932)	$2,489,984

Note: (A) Excludes ARO amounts.
(B) Allocated using factors on P.6, line 15, for General Plant. See P.7 for Common.
(C) Includes Generator Step-Up Transformers and Other Generation related investments previously included in the transmission accounts.
(D) Includes Accumulated Depreciation associated with the Generator Step-Up Transformers and Other Generation investments.

Workpaper

ELECTRIC PLANT IN SERVICE, ACCUMULATED DEPRECIATION AND ADIT
Twelve Months Ending December 31, 2011

Rate Schedule 101
Page 5a WP

Line No.	Account Title	Total Company	Legacy Generation	Other Electric	Gas
	Account 190 (Detailed Accounts)				
1	Accrual NQ Pension ST	211,667	68,326	90,255	53,086
2	Accrual OPEB ST	754,644	243,599	321,780	189,265
3	Accrual Post Retirement ST	263,011	84,900	112,148	65,963
4	Accrued Pension Admin Fees	1,297,854	1,298,479	(625)	-
5	Accrued Vacation	4,101,676	1,468,226	1,492,710	1,140,740
6	Annual Incentive Plan Comp	1,221,256	696,439	133,437	391,380
7	Asset Retirement Obligation	7,429,180	1,821,556	241,057	5,366,567
8	Bad Debts - Tax over Book	538,955	-	481,408	57,547
9	Cash Flow Hedge - Reg Asset/Liab	(660,340)	-	(660,340)	-
10	Demand Side Management (DSM) Defer	-	-	-	-
11	Emission Allowance Expense	36,398,482	36,398,482	-	-
12	Employee Benefits	-	-	-	-
13	Environmental Reserve	(16)	-	-	(16)
14	FAS 106 OPEB OCI	3,612,740	3,612,730	6	4
15	FAS 112 Medical Expenses Accrual	2,389,124	906,861	919,277	562,986
16	FAS 112 Medical Funding Payment	(372,956)	(122,886)	(157,457)	(92,613)
17	FAS 87 Non Qual Plan OCI	42,247	42,247	-	-
18	FAS 87 Qual Plan OCI	(18,880,817)	(18,880,817)	-	-
19	Federal Benefit of State for 190 CY	54,489	-	54,489	-
20	Federal Benefit of State for 190 PY	839,222	-	839,222	-
21	Federal Benefit of State on 190 Gain Contingency PY	390,179	-	390,179	-
22	FERC - FIT Adj Offset to Regulatory Asset (254100)	($2,634,885)	$0	($2,197,337)	($437,548)
23	Gas Supplier Refunds	147,962	-	-	147,962
24	Joint Owner Pension Receivable	(5,034,832)	(5,031,751)	(3,081)	-
25	Joint Owner Pension Receivable-NC	6,482,672	6,482,672	-	-
26	KY 190002 Adjustment to Deferreds	(34,714)	-	(34,714)	-
27	Lease Meters-Current	(4,351,201)	-	1,695,129	(6,046,330)
28	Leased Meters - Elec & Gas	15,607,854	-	12,834,583	2,773,271
29	Mark to Market - LT	(1,365,344)	(1,365,344)	-	-
30	Mark to Market - ST	(783,126)	(783,126)	-	-
31	Meters & Transformers	-	-	-	-
32	MGP Sites	9,776,179	-	(218,438)	9,994,617
33	Miscellaneous	(1,283,890)		(1,283,890)	-
34	Natural Gas in Transit	96,538	-	-	96,538
35	Non-qualifed Pension - Payment	(303,570)	(124,585)	(178,985)	-
36	Non-qualified Pension - Accrual	1,419,357	478,194	647,039	294,124
37	OCI - Actuarial GL NQ	(42,247)	(42,247)	-	-
38	OCI - Actuarial GL Qual	18,880,817	18,880,817	-	-
39	OCI - FAS 106 Actuarial Gain/Loss	(3,612,588)	(3,612,588)	-	-
40	Offsite Gas Storage Costs	3,437,449	-	-	3,437,449
41	OPEB Admin Fees	(3,310,616)	(3,309,476)	(1,140)	-
42	OPEB Expense Accrual	16,139,592	5,103,746	7,069,135	3,966,711
43	OPEB Funding Payment	(1,889,025)	(680,698)	(698,433)	(509,894)
44	Other Noncurrent After-tax DTA for EPRI Credit	220,341	172,607	23,867	23,867
45	Payable 401 (K) Match	61,544	20,173	26,049	15,322
46	Property Tax - Propane Inventory	536,061	-	-	536,061
47	Property Tax Reserves	17,258,304	14,450,964	(5,447,194)	8,254,534
48	Retirement Plan Expense - Underfunded	(6,012,992)	(7,977,650)	5,481,004	(3,516,346)
49	Retirement Plan Funding - Underfunded	-	-	-	-

Workpaper

ELECTRIC PLANT IN SERVICE, ACCUMULATED DEPRECIATION AND ADIT
Twelve Months Ending December 31, 2011

Rate Schedule 101
Page 5a WP

Line No.	Account Title	Total Company	Legacy Generation	Other Electric	Gas
50	Save-A-Watt Regulated Deferred Liability	3,824,541	-	3,824,541	-
51	Severance Accrual ST	(19,494)	(487)	(11,847)	(7,160)
52	SIT - Known Reserves - Cur Asset	61,541	76,502	(14,961)	-
53	Surplus Materials Write-Off Asset	862,907	862,907	-	-
54	Surplus Materials Write-off Liab	4,084	4,084	-	-
55	Tax Int Accrual - Non-cur Liab	1,356,403	(376,601)	1,733,004	-
56	Tax Interest Accrual - Cur Liab	-	-	-	-
57	Unamortized Debt Discount	(2,159,580)	(2,330,151)	1,539,206	(1,368,635)
58	Unamortized Debt Premium	579,251	1,276,384	(418,204)	(278,929)
59	Unbilled Revenue - Ruel	4,144,444	-	-	4,144,444
60	Uncollectible Provision PIP ADJ	(1,535,805)	-	-	(1,535,805)
61	**Total Account 190**	$106,154,529	$49,812,488	$28,622,879	$27,719,162
	Account 281 (Detailed Accounts)				
62	Pollution Control	($41,315,543)	($41,315,543)	$0	$0
	Account 282 (Detailed Accounts)				
63	263A ADJUSTMENT	(6,613,243)	(1,555,714)	(5,057,529)	-
64	481(a) Fixed Asset Retirement	353,687	353,687	-	-
65	AFUDC Interest	(854,247)	182	(652,935)	(201,494)
66	Asset Retirement Costs - ARO	(198,911)	192,413	2,698	(394,022)
67	Book Capital Lease Meters	(19,755,547)	-	(15,225,028)	(4,530,519)
68	Book Depr On Trans Equip to ADR	310,651	(305)	265,454	45,502
69	Book Depreciation/Amortization	291,610,629	149,441,734	92,829,604	49,339,291
70	Book Gain/Loss on Property	(88,395)	1,434	(89,829)	-
71	Casualty Loss	($3,525,213)	(3,525,213)	-	-
72	Contributions in Aid (CIACs)	4,298,337	486,708	812,158	2,999,471
73	Cost of Removal	(2,685,591)	87,979	(1,644,622)	(1,128,948)
74	Equipment Repairs - Annual Adj	(73,214,162)	(73,214,162)	-	-
75	Excess Salvage	864,620	-	125,782	738,838
76	FAS 34	(5,484,853)	(5,472,458)	(15,757)	3,362
77	FERC - FIT Adj Offset to Regulatory Liability (182320)	22,467,884	-	16,976,628	5,491,256
78	FERC - FIT Plant Adj (Util - 410)	(1,018,036,656)	(389,773,184)	(494,485,251)	(133,778,221)
79	FERC - FIT Plant Adj (Util - 411)	9,420,173	-	9,420,173	-
80	FERC - FIT Plant Adj (Util - 411)	(2,737,895)	(3,424,067)	490,898	195,274
81	FERC - SIT Adj Offset to Regulatory Liability (182320)	(8,792,929)	-	(7,733,802)	(1,059,127)
82	FERC - SIT Plant Adj (Util - 410)	(9,176,360)	(17,062,585)	13,276,898	(5,390,673)
83	FERC - SIT Plant Adj (Util 411)	4,433,793	(1,181,782)	4,951,445	664,130
84	FERC - SIT Plant Adj (Util 411)	287,127	-	287,127	-
85	FIN 48 After Tax NC 282 CY Dec Payable	(1,131,353)	-	(1,131,353)	-
86	FIN 48 After Tax NC 282 CY Dec Payable	(126,065)	-	(126,065)	-
87	FIN 48 After Tax NC 282 CY Inc Payable	4,239,389	-	4,239,389	-
88	FIN 48 After Tax NC 282 CY Inc Payable	472,389	-	472,389	-
89	FIN 48 After Tax NC 282 Gain Contingency PY Dec Payable	(21,204,671)	-	(21,204,671)	-
90	FIN 48 After Tax NC 282 Gain Contingency PY Dec Payable	(437,159)	-	(437,159)	-
91	FIN 48 After Tax NC 282 Gain Contingency PY Inc Payable	21,204,668	-	21,204,668	-
92	FIN 48 After Tax NC 282 Gain Contingency PY Inc Payable	437,160	-	437,160	-
93	FIN 48 After Tax NC 282 PY Dec Payable	(15,878,859)	-	(15,878,859)	-

Workpaper

ELECTRIC PLANT IN SERVICE, ACCUMULATED DEPRECIATION AND ADIT
Twelve Months Ending December 31, 2011

Rate Schedule 101
Page 5a WP

Line No.	Account Title	Total Company	Legacy Generation	Other Electric	Gas
94	FIN 48 After Tax NC 282 PY Dec Payable	(1,785,521)	-	(1,785,521)	-
95	FIN 48 After Tax NC 282 PY Inc Payable	33,767,646	-	33,767,646	-
96	FIN 48 After Tax NC 282 PY Inc Payable	3,778,844	-	3,778,844	-
97	Impairment of Plant Assets	57,601,570	57,601,570	-	-
98	KY - Bonus Depreciation Adj	475,392	172,964	140,399	162,029
99	KY 282101 Adjustment to Deferreds	(1,683,642)	-	(1,683,642)	-
100	Loss on ACRS	(13,121,594)	(216,010)	(8,305,308)	(4,600,276)
101	Miscellaneous	(23,336,468)	-	(23,336,468)	-
102	Non-Cash Overhead Basis Adj	38,713,770	3,989,717	34,832,192	(108,139)
103	OH - Bonus Depreciation Adj	158,159	19,737	123,438	14,984
104	OH - Franchise Tax Adj	(64,166)	(14,864)	(33,013)	(16,289)
105	Other Non-Current After-Tax DTL for PP&E	$7,880,939	($63,481,303)	$107,988,105	($36,625,863)
106	Other Non-Current AT ST DTL for PP&E	(3,812,312)	(9,649,738)	7,663,300	(1,825,874)
107	Purchase Accounting Adjustment	-	-	-	-
108	Repairs 481(a) (Pursuant to 3115)	(27,352,656)	(27,352,656)	-	-
109	Repairs Allowed on Post ADR Prop	(746,844)	(270,620)	(252,561)	(223,663)
110	Section 174 R&E Deduction	(956,942)	(590,008)	(366,934)	-
111	Self Developed Software	(7,667,618)	(2,609,750)	(3,405,012)	(1,652,856)
112	T & D Repairs - Annual Adj.	-	-	-	-
113	T & D Repairs 481(a) (pursuant to 3115)	-	-	-	-
114	Tax Depreciation/Amortization	(526,275,801)	(173,344,265)	(221,558,996)	(131,372,540)
115	Tax Gains/Losses	(11,078,329)	89,378	(11,174,271)	6,564
116	Tax Interest Capitalized	9,224,545	6,400,248	1,933,285	891,012
117	**Total Account 282**	($1,295,822,630)	($553,900,933)	($479,564,906)	($262,356,791)
	Account 283 (Detailed Accounts)				
118	ARO Regulatory Asset	(5,141,980)	(4,828)	(162,998)	(4,974,154)
119	Deferred Fuel Cost Purch Gas Adjustment.	2,098,533	-	-	2,098,533
120	Deferred Ohio Smart Grid Costs	1,857,810	-	1,273,283	584,527
121	Deferred Pipeline Installation Costs	-	-	-	-
122	Emission Allowance Trading	(43,641,559)	(43,641,559)	-	-
123	Inventory & Contract Write-up	(1,623,109)	(1,623,109)	-	-
124	KY 283101 Adjustment to Deferreds	(17,357)	-	(17,357)	-
125	Loss on Reacquired Debt-Amort	(1,988,719)	-	(1,276,482)	(712,237)
126	Merger Costs	634,496	334,802	196,942	102,752
127	Miscellaneous Current Taxable Inc. Adj - DTL	-	-	-	-
128	Miscellaneous NC Taxable Income Adj - DTL	(26,118,288)	(26,118,288)	-	-
129	Noncurrent Bad Debt Provision	2,190,454	-	308,348	1,882,106
130	Other Deferred State Taxes - After-Tax	(2,338,440)	-	(2,338,440)	-
131	Other Non-Current After-Tax DTL	(13,210,667)	$0	($13,210,667)	$0
132	Partnership Income K-1	73,930	-	73,930	-
133	POST IN SERVICE - CARRYING COSTS	(5,723,324)	-	-	(5,723,324)
134	Rate Case - Deferred Costs	-	-	-	-
135	Reg Asset - Accr Pension FAS158 - FAS87Qual	5,545,067	-	3,896,713	1,648,354
136	Reg Asset - Accr Pension FAS158 - FAS87NQ	(89,861)	-	(119,045)	29,184
137	Reg Asset - Accr Pension FAS158 - FAS87Qual	(35,692,092)	-	(24,763,664)	(10,928,428)
138	Reg Asset - DEO Econ Dev				
139	Reg Asset - Elec Rate Case Expense	(422,108)	-	(373,403)	(48,705)
140	Reg Asset - MGP Costs	(24,490,345)	-	(834,746)	(23,655,599)
141	Reg Asset Hurricane Ike Storm Damage	(4,495,822)	-	(4,495,822)	-
142	Reg Asset Smart Grid Deferred Depr.	(2,818,417)	-	(2,226,548)	(591,869)
143	Reg Asset Smart Grid Dfd Other O&M	(5,578,268)	-	(3,571,389)	(2,006,879)
144	Reg Asset Smart Grid Gas Furnace	(2,448,113)	-	(2,448,113)	-
145	Reg Asset Smart Grid PISCC	(3,543,660)	-	(2,838,737)	(704,923)
146	Reg Asset/Liab Def Revenue	(3,007,946)	(3,007,946)	-	-
147	Reg Asset/Liab Def Revenue NC	78,634	78,634	-	-
148	Reg Asset-Pension Post Retirement PAA-FAS 106 and Oth	(8,981,533)	-	(5,669,590)	(3,311,943)
149	Reg Asset-Pension Post Retirement PAA-FAS87NQ and Oth	(135,944)	-	(84,876)	(51,068)
150	Reg Asset-Pension Post Retirement PAA-FAS87Qual and Oth	(18,118,251)	-	(11,424,050)	(6,694,201)
151	Reg Liab RSLI & Other Misc Dfd Costs	57,906	-	57,906	-
152	Retirement Plan Expense - Overfunded	62,281,262	22,063,458	31,682,075	8,535,729
153	Retirement Plan Funding - Overfunded	(28,566,515)	-	(28,566,515)	-
154	Reverse Book Partnership Earnings	-	-	-	-
155	RSP Costs Capitalization	(39,143,238)	(39,143,238)	-	-
156	RTC Amortization	-	-	-	-
157	Sec 481 Adj - State Inc Tax	(886)	(886)	-	-
158	Tax Int Accrual - Non-cur Asset	(502,819)	-	(502,819)	-

Workpaper

ELECTRIC PLANT IN SERVICE, ACCUMULATED DEPRECIATION AND ADIT
Twelve Months Ending December 31, 2011

Rate Schedule 101
Page 5a WP

Line No.	Account Title	Total Company	Legacy Generation	Other Electric	Gas
159	Tax Interest Accrual - Cur Asset	-	-	-	-
160	Vacation Carryover - Reg Asset	(1,852,525)	-	(1,166,445)	(686,080)
161	Total Account 283	($204,873,694)	($91,062,960)	($68,602,509)	($45,208,225)
	Total Account 190	$106,154,529	$49,812,488	$28,622,879	$27,719,162
	Total Account 281	($41,315,543)	($41,315,543)	$0	$0
	Total Account 282	($1,295,822,630)	($553,900,933)	($479,564,906)	($262,356,791)
	Total Account 283	(204,873,694)	(91,062,960)	(68,602,509)	(45,208,225)
		(1,435,857,338)	(636,466,948)	(519,544,536)	(279,845,854)

Workpaper

ELECTRIC PLANT IN SERVICE, ACCUMULATED DEPRECIATION AND ADIT (PRODUCTION)
Twelve Months Ending December 31, 2011

Rate Schedule 101
Page 5b WP

Line No.	Account Title	Legacy Generation	Percent Allocated To Demand	Amount Demand	Amount Energy	Allocation Basis
	Account 190 (Detailed Accounts)					
1	Accrual NQ Pension ST	68,326	63%	$42,719	$25,607	S&W
2	Accrual OPEB ST	243,599	63%	152,305	91,294	S&W
3	Accrual Post Retirement ST	84,900	63%	53,082	31,818	S&W
4	Accrued Pension Admin Fees	1,298,479	63%	811,844	486,635	S&W
5	Accrued Vacation	1,468,226	63%	917,974	550,252	S&W
6	Annual Incentive Plan Comp	696,439	63%	435,432	261,007	S&W
7	Asset Retirement Obligation	1,821,556	0%	-	1,821,556	Excluded AROs from Rate Base
8	Bad Debts - Tax over Book	-	100%	-	-	
9	Cash Flow Hedge - Reg Asset/Liab	-	100%	-	-	
10	Demand Side Management (DSM) Defer	-	100%	-	-	
11	Emission Allowance Expense	36,398,482	0%	-	36,398,482	100% energy
12	Employee Benefits	-	100%	-	-	
13	Environmental Reserve	-	100%	-	-	
14	FAS 106 OPEB OCI	3,612,730	63%	2,258,775	1,353,955	S&W
15	FAS 112 Medical Expenses Accrual	906,861	63%	566,994	339,867	S&W
16	FAS 112 Medical Funding Payment	(122,886)	63%	(76,832)	(46,054)	S&W
17	FAS 87 Non Qual Plan OCI	42,247	63%	26,414	15,833	S&W
18	FAS 87 Qual Plan OCI	(18,880,817)	63%	(11,804,790)	(7,076,027)	S&W
19	Federal Benefit of State for 190 CY	-	100%	-	-	
20	Federal Benefit of State for 190 PY	-	100%	-	-	
21	Federal Benefit of State on 190 Gain Contingency PY	-	100%	-	-	
22	FERC - FIT Adj Offset to Regulatory Asset (254100)	-	100%	-	-	
23	Gas Supplier Refunds	-	100%	-	-	
24	Joint Owner Pension Receivable	(5,031,751)	100%	(5,031,751)	-	100% demand
25	Joint Owner Pension Receivable-NC	6,482,672	100%	6,482,672	-	100% demand
26	KY 190002 Adjustment to Deferreds	-	100%	-	-	
27	Lease Meters-Current	-	100%	-	-	
28	Leased Meters - Elec & Gas	-	100%	-	-	
29	Mark to Market - LT	(1,365,344)	100%	(1,365,344)	-	100% energy
30	Mark to Market - ST	(783,126)	100%	(783,126)	-	100% energy
31	Meters & Transformers	-	100%	-	-	
32	MGP Sites	-	100%	-	-	
33	Miscellaneous	-	100%	-	-	
34	Natural Gas in Transit	-	100%	-	-	
35	Non-qualifed Pension - Payment	(124,585)	63%	(77,894)	(46,691)	S&W
36	Non-qualified Pension - Accrual	478,194	63%	298,980	179,214	S&W
37	OCI - Actuarial GL NQ	(42,247)	63%	(26,414)	(15,833)	S&W
38	OCI - Actuarial GL Qual	18,880,817	63%	11,804,790	7,076,027	S&W
39	OCI - FAS 106 Actuarial Gain/Loss	(3,612,588)	63%	(2,258,686)	(1,353,902)	S&W
40	Offsite Gas Storage Costs	-	100%	-	-	
41	OPEB Admin Fees	(3,309,476)	63%	(2,069,173)	(1,240,303)	S&W
42	OPEB Expense Accrual	5,103,746	63%	3,190,998	1,912,748	S&W
43	OPEB Funding Payment	(680,698)	63%	(425,591)	(255,107)	S&W
44	Other Noncurrent After-tax DTA for EPRI Credit	172,607	100%	172,607	-	100% Demand
45	Payable 401 (K) Match	20,173	63%	12,613	7,560	S&W
46	Property Tax - Propane Inventory	-	100%	-	-	
47	Property Tax Reserves	14,450,964	100%	14,450,964	-	100% Demand
48	Retirement Plan Expense - Underfunded	(7,977,650)	63%	(4,987,840)	(2,989,810)	S&W
49	Retirement Plan Funding - Underfunded	-	100%	-	-	
50	Save-A-Watt Regulated Deferred Liability	-	100%	-	-	
51	Severance Accrual ST	(487)	63%	(304)	(183)	S&W
52	SIT - Known Reserves - Cur Asset	76,502	100%	76,502	-	
53	Surplus Materials Write-Off Asset	862,907	100%	862,907	-	100% demand
54	Surplus Materials Write-off Liab	4,084	100%	4,084	-	100% demand
55	Tax Int Accrual - Non-cur Liab	(376,601)	100%	(376,601)	-	100% demand
56	Tax Interest Accrual - Cur Liab	-	100%	-	-	
57	Unamortized Debt Discount	(2,330,151)	100%	(2,330,151)	-	100% demand
58	Unamortized Debt Premium	1,276,384	100%	1,276,384	-	100% demand
59	Unbilled Revenue - Ruel	-	100%	-	-	
60	Uncollectible Provision PIP ADJ	-	100%	-	-	

ELECTRIC PLANT IN SERVICE, ACCUMULATED DEPRECIATION AND ADIT (PRODUCTION)
Twelve Months Ending December 31, 2011

Line No.	Account Title	Legacy Generation	Percent Allocated To Demand	Amount Demand	Amount Energy	Allocation Basis
61	Total Account 190	$49,812,488		$12,284,543	$37,527,945	
	Account 281 (Detailed Accounts)					
62	Pollution Control	($41,315,543)	100%	($41,315,543)	$0	100% demand
	Account 282 (Detailed Accounts)					
63	263A ADJUSTMENT	($1,555,714)	100%	($1,555,714)	$0	100% demand
64	481(a) Fixed Asset Retirement	353,687	100%	353,687	-	100% demand
65	AFUDC Interest	182	100%	182	-	100% demand
66	Asset Retirement Costs - ARO	192,413	100%	192,413	-	100% demand
67	Book Capital Lease Meters	-	0%	-	-	
68	Book Depr On Trans Equip to ADR	(305)	100%	(305)	-	100% demand
69	Book Depreciation/Amortization	149,441,734	100%	149,441,734	-	100% demand
70	Book Gain/Loss on Property	1,434	100%	1,434	-	100% demand
71	Casualty Loss	(3,525,213)	100%	(3,525,213)	-	100% demand
72	Contributions in Aid (CIACs)	486,708	100%	486,708	-	100% demand
73	Cost of Removal	87,979	100%	87,979	-	100% demand
74	Equipment Repairs - Annual Adj	(73,214,162)	100%	(73,214,162)	-	100% demand
75	Excess Salvage	-	0%	-	-	
76	FAS 34	(5,472,458)	100%	(5,472,458)	-	100% demand
77	FERC - FIT Adj Offset to Regulatory Liability (182320)	-	0%	-	-	
78	FERC - FIT Plant Adj (Util - 410)	(389,773,184)	100%	(389,773,184)	-	100% demand
79	FERC - FIT Plant Adj (Util - 411)	-	0%	-	-	
80	FERC - FIT Plant Adj (Util - 411)	(3,424,067)	100%	(3,424,067)	-	100% demand
81	FERC - SIT Adj Offset to Regulatory Liability (182320)	-	0%	-	-	
82	FERC - SIT Plant Adj (Util - 410)	(17,062,585)	100%	(17,062,585)	-	100% demand
83	FERC - SIT Plant Adj (Util 411)	(1,181,782)	100%	(1,181,782)	-	100% demand
84	FERC - SIT Plant Adj (Util 411)	-	0%	-	-	
85	FIN 48 After Tax NC 282 CY Dec Payable	-	0%	-	-	
86	FIN 48 After Tax NC 282 CY Dec Payable	-	0%	-	-	
87	FIN 48 After Tax NC 282 CY Inc Payable	-	0%	-	-	
88	FIN 48 After Tax NC 282 CY Inc Payable	-	0%	-	-	
89	FIN 48 After Tax NC 282 Gain Contingency PY Dec Payable	-	0%	-	-	
90	FIN 48 After Tax NC 282 Gain Contingency PY Dec Payable	-	0%	-	-	
91	FIN 48 After Tax NC 282 Gain Contingency PY Inc Payable	-	0%	-	-	
92	FIN 48 After Tax NC 282 Gain Contingency PY Inc Payable	-	0%	-	-	
93	FIN 48 After Tax NC 282 PY Dec Payable	-	0%	-	-	
94	FIN 48 After Tax NC 282 PY Dec Payable	-	0%	-	-	
95	FIN 48 After Tax NC 282 PY Inc Payable	-	0%	-	-	
96	FIN 48 After Tax NC 282 PY Inc Payable	-	0%	-	-	
97	Impairment of Plant Assets	57,601,570	100%	57,601,570	-	100% demand
98	KY - Bonus Depreciation Adj	172,964	100%	172,964	-	100% demand
99	KY 282101 Adjustment to Deferreds	-	0%	-	-	
100	Loss on ACRS	(216,010)	100%	(216,010)	-	100% demand
101	Miscellaneous	-	0%	-	-	
102	Non-Cash Overhead Basis Adj	3,989,717	100%	3,989,717	-	100% demand
103	OH - Bonus Depreciation Adj	19,737	100%	19,737	-	100% demand
104	OH - Franchise Tax Adj	(14,864)	100%	(14,864)	-	100% demand
105	Other Non-Current After-Tax DTL for PP&E	(63,481,303)	100%	(63,481,303)	-	100% demand
106	Other Non-Current AT ST DTL for PP&E	(9,649,738)	100%	(9,649,738)	-	100% demand
107	Purchase Accounting Adjustment	-	0%	-	-	
108	Repairs 481(a) (Pursuant to 3115)	(27,352,656)	100%	(27,352,656)	-	100% demand
109	Repairs Allowed on Post ADR Prop	(270,620)	100%	(270,620)	-	100% demand
110	Section 174 R&E Deduction	(590,008)	100%	(590,008)	-	100% demand
111	Self Developed Software	(2,609,750)	100%	(2,609,750)	-	100% demand
112	T & D Repairs - Annual Adj.	-	0%	-	-	
113	T & D Repairs 481(a) (pursuant to 3115)	-	0%	-	-	
114	Tax Depreciation/Amortization	(173,344,265)	100%	(173,344,265)	-	100% demand
115	Tax Gains/Losses	89,378	100%	89,378	-	100% demand
116	Tax Interest Capitalized	6,400,248	100%	6,400,248	-	100% demand

Workpaper

ELECTRIC PLANT IN SERVICE, ACCUMULATED DEPRECIATION AND ADIT (PRODUCTION)
Twelve Months Ending December 31, 2011

Rate Schedule 101
Page 5h WP

Line No.	Account Title	Legacy Generation	Percent Allocated To Demand	Amount Demand	Amount Energy	Allocation Basis
117	Total Account 282	($553,900,933)		($553,900,933)	$0	
	Account 283 (Detailed Accounts)					
118	ARO Regulatory Asset	(4,828)	100%	($4,828)	$0	100% demand
119	Deferred Fuel Cost Purch Gas Adjustment.	-	100%	-	-	
120	Deferred Ohio Smart Grid Costs	-	100%	-	-	
121	Deferred Pipeline Installation Costs	-	100%	-	-	
122	Emission Allowance Trading	(43,641,559)	0%	-	(43,641,559)	100% energy
123	Inventory & Contract Write-up	(1,623,109)	100%	(1,623,109)	-	100% demand
124	KY 283101 Adjustment to Deferreds	-	100%	-	-	
125	Loss on Reacquired Debt-Amort	-	100%	-	-	
126	Merger Costs	334,802	0%	-	334,802	Omit
127	Miscellaneous Current Taxable Inc. Adj - DTL	-	100%	-	-	
128	Miscellaneous NC Taxable Income Adj - DTL	(26,118,288)	100%	(26,118,288)	-	To be conservative, allocate all to Demand
129	Noncurrent Bad Debt Provision	-	100%	-	-	
130	Other Deferred State Taxes - After-Tax	-	100%	-	-	
131	Other Non-Current After-Tax DTL	-	100%	-	-	
132	Partnership Income K-1	-	100%	-	-	
133	POST IN SERVICE - CARRYING COSTS	-	100%	-	-	
134	Rate Case - Deferred Costs	-	100%	-	-	
135	Reg Asset - Accr Pension FAS158 - FAS87Qual	-	100%	-	-	
136	Reg Asset - Accr Pension FAS158 - FAS87NQ	-	100%	-	-	
137	Reg Asset - Accr Pension FAS158 - FAS87Qual	-	100%	-	-	
138	Reg Asset - OEO Econ Dev	-	100%	-	-	
139	Reg Asset - Elec Rate Case Expense	-	100%	-	-	
140	Reg Asset - MGP Costs	-	100%	-	-	
141	Reg Asset Hurricane Ike Storm Damage	-	100%	-	-	
142	Reg Asset Smart Grid Deferred Depr.	-	100%	-	-	
143	Reg Asset Smart Grid Dfd Other O&M	-	100%	-	-	
144	Reg Asset Smart Grid Gas Furnace	-	100%	-	-	
145	Reg Asset Smart Grid PISCC	-	100%	-	-	
146	Reg Asset/Liab Def Revenue	(3,007,946)	100%	(3,007,946)	-	To be conservative, allocate all to Demand
147	Reg Asset/Liab Def Revenue NC	78,634	100%	78,634	-	
148	Reg Asset-Pension Post Retirement PAA-FAS 106 and Oth	-	100%	-	-	
149	Reg Asset-Pension Post Retirement PAA-FAS87NQ and Oth	-	100%	-	-	
150	Reg Asset-Pension Post Retirement PAA-FAS87Qual and Oth	-	100%	-	-	
151	Reg Liab RSLI & Other Misc Dfd Costs	-	100%	-	-	
152	Retirement Plan Expense - Overfunded	22,063,458	63%	13,794,662	8,268,796	S&W
153	Retirement Plan Funding - Overfunded	-	100%	-	-	
154	Reverse Book Partnership Earnings	-	100%	-	-	
155	RSP Costs Capitalization	(39,143,238)	100%	(39,143,238)	-	To be conservative, allocate all to Demand
156	RTC Amortization	-	100%	-	-	
157	Sec 481 Adj - State Inc Tax	(886)	100%	(886)	-	100% demand
158	Tax Int Accrual - Non-cur Asset	-	100%	-	-	
159	Tax Interest Accrual - Cur Asset	-	100%	-	-	
160	Vacation Carryover - Reg Asset	-	100%	-	-	
161	Total Account 283	($91,062,960)		($56,024,999)	($35,037,961)	
	Total Account 190	$49,812,488		$12,284,543	$37,527,945	
	Total Account 281	(41,315,543)		(41,315,543)	-	
	Total Account 282	(553,900,933)		(553,900,933)	-	
	Total Account 283	(91,062,960)		(56,024,999)	(35,037,961)	
		($636,466,948)		($638,956,932)	$2,489,984	

PRODUCTION-RELATED GENERAL PLANT ALLOCATION (Gross Plant)
Twelve Months Ending December 31, 2011

Line	Acct	Description	Total System (A)	Allocation Factor	Related to Production	Demand	Energy
			(1)	(2)	(3)=(1)*(2)	(4)	(5)
1		GENERAL PLANT (A)					
2	389	Land	$951,856	(B)	$489,417	$305,997	$183,420
3	390	Structures	24,870,920	(B)	12,787,907	7,995,340	4,792,567
4	391	Office Furniture & Equipment	3,012,092	(B)	1,548,730	968,307	580,423
5	392	Transportation Equipment	4,249,299	(B)	2,184,866	1,366,036	818,830
6	393	Stores Equipment	-	(B)	0	0	0
7	394	Tools, Shop & Garage Equipment	13,977,270	(B)	7,186,707	4,493,321	2,693,386
8	395	Lab Equipment	125,110	(B)	64,328	40,220	24,108
9	396	Power Operated Equipment	1,088,311	(B)	559,578	349,863	209,715
10	397	Communications Equipment	41,923,534	(B)	21,555,867	13,477,303	8,078,564
11	398	Miscellaneous Equipment	71,746	(B)	36,890	23,065	13,825
12	Sum	Subtotal	$90,270,138		$46,414,290	$29,019,452	$17,394,838
13	Calc	Percent			51.417%	32.147%	19.270%
14	303	INTANGIBLE PLANT	$78,533,402	(B)	$40,379,600	$25,246,403	$15,133,197
15	Calc	Percent			51.417%	32.147%	19.270%
16	Sum	TOTAL GENERAL AND INTANGIBLE	$168,803,540		$86,793,890	$54,265,855	$32,528,035

Note: (A) Data from Form 1, pages 204-207.
(B) Allocation factors based on wages and salaries in electric operation and maintenance expenses excluding A&G.

a. Total wages and salaries in electric operation and maintenance expenses excluding administrative and general expense, FF1, P.354, Col.(b), Ln.28 - L.27.	$104,144,423
b. Production wages and salaries in electric operation and maintenance expense, FF1, P.354, Col.(b), L.20.	$53,548,045
c. Production Labor as Percent of All Labor (excl. A&G)	51.42%
d. Percent production labor allocated to demand (Page 12 wp)	62.52%

PRODUCTION-RELATED COMMON PLANT ALLOCATION (Gross Plant)
Twelve Months Ending December 31, 2011

Line	Acct	COMMON PLANT	Total System (A)	Electric (B)	Production Demand	Production Energy
			(1)	(2)	(3)	(4)
		Organization	$60,936	$50,882		
1	1030	Miscellaneous Intangible Plant	121,525,222	101,473,560		
2	1890	Land and Land Rights	2,159,616	1,803,279		
3	1900	Structures & Improvements	114,812,886	95,868,760		
4	1910	Office Furniture & Equipment	3,937,989	3,288,221		
5	1911	Electronic Data Processing - Non SmartGrid	777,724	649,400		
6	1920	Transportation Equipment	85,311	71,235		
7	1921	Trailers	474,273	396,018		
8	1930	Stores Equipment	170,074	142,012		
9	1940	Tools, Shop & Garage Equipment	1,583,528	1,322,246		
10	1950	Laboratory Equipment	23,250	19,414		
11	1960	Power Operated Equipment	153,899	128,506		
12	1970	Communication Equipment - Non SmartGrid	51,956,109	43,383,351		
13	1980	Miscellaneous Equipment	429,603	358,719		
14	1990, 1991	Retirement Work in Process - ARO	99,735	83,279		
15		Total Common Plant (FF1, Pg. 201, L.8, Col.(h))	$298,250,155			
16		Common Plant Allocated to Electric		$249,038,879		
17		Allocated to Production (C)			$140,601,130	$1,331,928
18		Accumulated Depreciation (FF1, Pg. 201, L.14,Col.(h))	$143,816,541	$120,086,812	$67,798,014	$362,602

Note: (A) Form 1, page 356.
(B) 83.5% Common Plant Allocation factor (Form 1, Page 356.2).
(C) Electric share of common plant times allocation plant allocation factors on P.5.

PRODUCTION-RELATED MATERIALS & SUPPLIES
Twelve Months Ending December 31, 2011

		SYSTEM		PRODUCTION			
		Reference	Amount	Reference	Amount	Demand	Energy
			(1)		(2)	(3)	(4)
1	**Materials & Supplies (A)**						
2	Fuel	FF1, P.227, L.1, Col.(c)	$83,305,297		$83,305,297	$0	$83,305,297
3	Non-Fuel						
4	Production	FF1, P.227, L.7	$40,712,928	(B)	$40,681,661	$40,681,661	$0
5	Transmission	FF1, P.227, L.8	15,567,661		0	0	0
6	Distribution	FF1, P.227, L.9	53,246,189		0	0	0
7	Total Non-Fuel	L.4 + L.5 + L.6	$109,526,778		$40,681,661	$40,681,661	$0

Note: (A) Form 1 includes Gas & Electric.
(B) Allocation to Electric from Internal Accounting Records.

PRODUCTION-RELATED GENERAL PLANT ALLOCATION
ADMINISTRATIVE & GENERAL EXPENSE ALLOCATION
Twelve Months Ending December 31, 2011

			SYSTEM		PRODUCTION			
		Account	Reference	Amount	Reference	Amount	Demand	Energy
				(1)	(2)	(3)	(4)	(5)
1	Administrative & General Expense							
2	Related to Salaries & Wages							
3	A&G Salaries	920	FF1, P.323	$39,458,630				
4	Outside Services	923	FF1, P.323	23,949,569				
5	Employee Pension & Benefits	926	FF1, P.323	39,270,593				
6	Office Supplies	921	FF1, P.323	26,537,635				
7	Injuries & Damages	925	FF1, P.323	5,550,657				
8	Franchise Requirements	927	FF1, P.323	0				
9	Duplicate Charges - Vr.	929	FF1, P.323	(2,177,122)				
10	Total		L. 3 thru L.9	$132,589,962	(A)	$68,173,918	$42,624,151	$25,549,766
11	Miscellaneous General Expenses	930.2	FF1, P.323	421,972	(A)	216,966	135,653	81,313
12	Admin Expense Transfer - Credit	922	FF1, P.323	2,489	(A)	1,280	800	480
13	Property Insurance	924	FF1, P.323	5,635,613	(C)	3,187,094	3,157,185	29,908
14	Regulatory Commission Expenses	928	FF1, P.323	0	(B)	0	0	0
15	Rents	931	FF1, P.323	12,240,223	(A)	6,293,568	3,934,907	2,358,661
16	Maintenance of General Plant	935	FF1, P.323	3,338,824	(A)	1,716,727	1,073,343	643,383
17	Total A&G Expense		L.10 thru 16	$154,229,083		$79,589,553	$50,926,039	$28,663,511

Note: All costs associated with plants transferred to DECAM have been removed from Column (1).
(A) Allocation % based on Salaries and Wages from Note B, P.6.
(B) Excludes all regulatory assessments.
(C) Allocation % based on Plant from P.5, L.5.

Duke Energy Ohio (Consolidated) Cost of Capital
Twelve Months Ending December 31, 2011

Line	Description	Reference	Total Company Capitalization	Weighted Cost Ratios	Cost of Capital	Weighted Cost of Capital %
			(1)	(2)	(3)	(4) = (2 x 3)
1	Long Term Debt	(A)	$2,542,087,279	46.84%	4.11%	1.925%
2	Preferred Stock	(B)	0	0.00%	0.00%	0.000%
3	Common Stock	(C)	2,885,228,457	53.16%	11.15%	5.927%
4	Total		$5,427,315,736	100.00%		7.85%

Note: (A) Page 10 WP.
(B) Duke Energy Ohio has no preferred equity.
(C) Page 10 WP.
ROE based on approved rate in Case 10-2929-EL-UNC.

Duke Energy Ohio Consolidated
Capital Structure
December 31, 2011
(In Dollars)

	Actual 12/31/11		Purchase Accounting		Goodwill Impairments Sep09 and Jun10	Other Asset Impairment Charges		Adjusted 12/31/11	Midwest DENA Equity BU 75032	Midwest DENA Equity BU 75012 (3)	Capital Structure excluding Purchase accounting and Midwest DENA	
Current Maturities of Long-Term Debt	$ 507,186,062		$ -					$ 507,186,062			$ 507,186,062	
Non-Current Liabilities												
Long-Term Debt	$ 2,047,916,406		$ 5,979,144					$ 2,053,895,550			$ 2,053,895,550	
Deferred Debt Expense	$ (15,878,296)		$ (3,603,474)					$ (19,481,770)			$ (19,481,770)	
0257010 Unamortized Gain-Debt	$ 487,437							$ 487,437			$ 487,437	
Total Long-Term Debt Excl. Current Maturities	**$ 2,032,525,547**	28%	**$ 2,375,670**		**$ -**	**$ -**		**$ 2,034,901,217**	**$ -**	**$ -**	**$ 2,034,901,217**	41%
Total Long Term Debt	**$ 2,539,711,609**	33%	**$ 2,375,670**		**$ -**	**$ -**		**$ 2,542,087,279**	**$ -**	**$ -**	**$ 2,542,087,279**	47%
Common Stock Equity												
0201000 Common Stock Issued	$ 762,136,231		$ -					$ 762,136,231	$ -	$ -	$ 762,136,231	
0207001 Premium on capital stock	$ -		$ 362,457,437					$ 362,457,437			$ 362,457,437	
0208000 Donations From Stockholder	$ 28,950,000		$ 197,206,819					$ 226,156,819			$ 226,156,819	
0208001 Donations From Stockholder-DENA	$ 1,462,336,840		$ -					$ 1,462,336,840	$ (1,462,336,840)		$ -	
0208010 Donat Recvd From Stkhld Tax	$ 15,641,578		$ 68,538,328					$ 84,179,906			$ 84,179,906	
0210020 Gain on Redemption of Capital	$ -		$ 147,685					$ 147,685			$ 147,685	
0211003 Misc Paid In Capital	$ -		$ -					$ -		$ (1,171,126,922)	$ (1,171,126,922)	
0211004 Misc Paid In Capital Purch Acctg	$ 1,123,780,148		$ (2,879,949,148)					$ (1,756,169,000)			$ (1,756,169,000)	
0211008 Misc PIC Pushdown Adj RE	$ 1,756,169,000		$ -					$ 1,756,169,000			$ 1,756,169,000	
0211005 Misc Paid in Capital Premerger Equity	$ 557,581,098		$ (603,514,486)					$ (45,933,388)			$ (45,933,388)	
0211007 Misc PIC Premerg RE for Div	$ 140,474,493		$ (625,474,493)					$ (485,000,000)			$ (485,000,000)	
0211110 PIC - Sharesaver (BDMS account)	$ -		$ (3,350,836)					$ (3,350,836)			$ (3,350,836)	
0214010 Common stock equity inter-company	$ -		$ (21,750,868)					$ (21,750,868)			$ (21,750,868)	
0216000/0216100 Unappropriated RE/Undistr Subsid Earnings	$ (846,467,235)		$ 897,879,035	(1)	1,403,452,846	66,703,441	(1)	$ 1,521,568,087	$ (118,321,307)		$ 1,403,246,780	
0216100 Unappropriated RE/Undistr Subsid Earnings-Equitization	$ -		$ -					$ -	$ 1,698,890,655	$ -	$ 1,698,890,655	
0438000 Dividends Declared on Common Stock	$ -							$ -			$ -	
Current Year Net Income	$ 194,332,094		$ 23,012,765	(2)	-	51,585,816	(2)	$ 268,930,675	$ (27,930,761)	$ (92,609,786)	$ 148,390,128	
Accum other comprehensive income (loss)	$ (27,759,807)		$ (45,455,363)					$ (73,215,170)	$ -		$ (73,215,170)	
Total Common Stock Equity	**$ 5,167,174,440**	72%	**$ (2,630,253,125)**		**$ 1,403,452,846**	**$ 118,289,257**		**$ 4,058,663,418**	**$ 90,301,747**	**$ (1,263,736,708)**	**$ 2,885,228,457**	59%
% Including Total LTD		67%										53%
TOTAL CAPITALIZATION (excluding current maturities)	**$ 7,199,699,987**		**$ (2,627,877,455)**		**$ 1,403,452,846**	**$ 118,289,257**		**$ 6,093,564,635**	**$ 90,301,747**	**$ (1,263,736,708)**	**$ 4,920,129,674**	
TOTAL CAPITALIZATION	**$ 7,706,886,049**		**$ (2,627,877,455)**		**$ 1,403,452,846**	**$ 118,289,257**		**$ 6,600,750,697**	**$ 90,301,747**	**$ (1,263,736,708)**	**$ 5,427,315,736**	

Notes:
(1) Purchase Accounting & Other Asset Impairment Charges income statement impacts are adjusted in prior year retained earnings balances net of tax at an assumed tax rate of 38% - 2006, 33.5% - 2007, 37.4% - 2008, 35.4% - 2009 and 35.4% - 2010.
(2) Purchase Accounting & Other Asset Impairment Charges income statement impacts are adjusted in current year retained earnings balances net of tax at an assumed tax rate of 35.4%.
(3) Midwest DENA Assets were reclassed from B.U. 75032 to B.U. 75012 in June 2011.

ANNUAL FIXED COSTS
PRODUCTION O & M EXPENSE
EXCLUDING FUEL USED IN ELECTRIC GENERATION
Twelve Months Ending December 31, 2011

Line No.	Description	Account Number	Total Company	(Demand) Fixed	(Energy) Variable
			(1)	(2)	(3)
1	Fuel and Fuel Related Expenses	501	$493,120,673		$493,120,673
2	Rents	507	509,240	509,240	0
3	Other Production Expenses (C)	557	25,319,519	25,319,519	0
4	System Control of Load Dispatching	556	0	0	0
5	Other Steam Expenses (C)	(A)	199,881,780	92,310,519	105,580,002
6	Combustion Turbine	(A)	0		
7	Purchased Power (D)	555	173,973,216	0	0
8	Total Production Expense Excluding				
9	Fuel Used In Electric Generation above		$892,804,428	$118,139,278	$598,700,675
10	A & G Expense P.10, L.17		79,589,553	50,926,039	28,663,511
11	Generator Step Up related O&M	(B)	2,931,899	200,764	2,731,135
12	Total O & M		$975,325,880	$169,266,081	$630,095,321

NOTE: (A) Amounts recorded in Accounts 500, 502-509, 510-514, 546, 548-550 and 551-554 classified into Fixed and Variable Components in accordance with P.13 and P.13 WP.

(B) FF1, P.321, L.93 & L.107 (ACCTS. 562 & 570) times GSU Investment to Account 353 ratio (See P.2)

(C) Excludes costs attributable to the Midwest Gas Assets transferred to DECAM in April 2011.

(D) For purposes of calculating the revenue requirement on page 3, all purchased power expense is forecasted through remainder of FRR. 2011 actual expense is ignored.

CLASSIFICATION OF FIXED AND VARIABLE
PRODUCTION EXPENSES
Twelve Months Ending December 31, 2011

Line No.	Description	FERC Account Number	Demand Related	Energy Related
1	**POWER PRODUCTION EXPENSES**			
2	**Steam Power Generation**			
3	Operation supervision and engineering	500	xx	-
4	Fuel	501	-	xx
5	Steam expenses	502	xx	-
6	Steam from other sources	503	-	xx
7	Steam transferred-Cr.	504	-	xx
8	Electric expenses	505	xx	-
9	Miscellaneous steam power expenses	506	xx	-
10	Rents	507	xx	-
11	Allowances	509	-	xx
12	Maintenance supervision and engineering	510	-	xx
13	Maintenance of structures	511	xx	-
14	Maintenance of boiler plant	512	-	xx
15	Maintenance of electric plant	513	-	xx
16	Maintenance of miscellaneous steam plant	514	xx	-
17	Total steam power generation expenses			
18	**Hydraulic Power Generation**			
19	Operation supervision and engineering	535	xx	-
20	Water for power	536	xx	-
21	Hydraulic expenses	537	xx	-
22	Electric expenses	538	xx	-
23	Misc. hydraulic power generation expenses	539	xx	-
24	Rents	540	xx	-
25	Maintenance supervision and engineering	541	xx	-
26	Maintenance of structures	542	xx	-
27	Maintenance of reservoirs, dams and waterways	543	xx	-
28	Maintenance of electric plant	544	-	xx
29	Maintenance of miscellaneous hydraulic plant	545	xx	-
30	Total hydraulic power generation expenses			
31	**Other Power Generation**			
32	Operation supervision and engineering	546	xx	-
33	Fuel	547	-	xx
34	Generation expenses	548	xx	-
35	Miscellaneous other power generation expenses	549	xx	-
36	Rents	550	xx	-
37	Maintenance supervision and engineering	551	xx	-
38	Maintenance of structures	552	xx	-
39	Maintenance of generation and electric plant	553	xx	-
40	Maintenance of misc. other power generation plant	554	xx	-
41	Total other power generation expenses			
42	**Other Power Supply Expenses**			
43	Purchased power	555	-	xx
44	System control and load dispatching	556	xx	-
45	Scheduling, System Control & Dispatch Services	561.4	xx	-
46	Reliability, Planning and Standards Development	561.8	xx	-
47	Other expenses	557	xx	-
48	Station equipment operation expense (A)	562	xx	-
49	Station equipment maintenance expense (A)	570	xx	-
50	Market Facilitation, Monitoring and Compliance Services	575.7	xx	-

Note: (A) Allocable share of Generator Step-Up Charges from page 2.

PRODUCTION-RELATED DEPRECIATION EXPENSE
Twelve Months Ending December 31, 2011

Line	Production Plant	Depreciation Expense	(Demand) Fixed	(Energy) Variable
		(1)	(2)	(3)
1	Steam (A)	$70,962,135	$70,962,135	$0
2	Nuclear	0	0	0
3	Hydro	0	0	0
4	Conventional	0	0	0
5	Pump Storage	0	0	0
6	Other Production (B)	191,607	191,607	0
7	Int. Comb	0	0	0
8	Production Related General, Common & Intangible Plant (C)	14,993,358	4,819,966	2,889,184
9	Common Plant (D)	5,146,873	2,426,340	12,977
10	Generator Step Up Related Depreciation (E)	426,928	426,928	0
11	Total Production	$91,720,901	$78,826,976	$2,902,161

Note: (A) P.336 of the Form 1, L.2(b). Excludes expenses for AROs.
(B) Excludes depreciation associated with assets transferred to DECAM during 2011.
(C) Total General & Intangible Plant (from P.336 of the FF1 adjusted for amortization adjustments) times ratio of Production Related General Plant to Total General Plant, computed on P. 6.
(D) P.336 of Form 1, L.11(b). Allocations based on ratio of plant from P.7.

PRODUCTION-RELATED
TAXES OTHER THAN INCOME TAXES
Twelve Months Ended December 31, 2011

		System		Production Amount	
	Description	Reference	Amount (1)	Allocator	Demand (2)
1	Labor Related	(A)	9,506,466	(B)	$4,887,949
2	Property Related	(A)	100,481,972	(C)	56,292,050
3	Other	(A)	2,916,016	(C)	1,633,612
4	Ohio Excise (kWh) Tax	(A)	71,919,288	(D)	0
5	Commercial Activities Tax	(A)	3,220,328	(E)	0
6	Total Taxes Other Than Income Taxes	Sum	$188,044,070		$62,813,611

Note: (A) Taxes other than Income Taxes will be those reported in FF1, P. 262 & 263. Excludes taxes associated with assets transferred to DECAM.

(B) Total (Col. (1), L.1) allocated on the basis of wages & salaries in Electric O & M Expenses (excl. A & G), P.354, Col.(b) and Services

	Amount	%	
(1) Total W & S (excl. A & G)	104,144,423	100.00%	
(2) Production W & S	53,548,045	51.42%	
(3) Production W&S (Percent Demand)		62.52%	------> (See P.12 workpaper)

(C) Allocated based on gross plant (Page 6). (Excludes taxes on assets transferred to DECAM).

(D) Recovered via separate rider in distribution charges.

(E) Actual amount for 2011 is ignored. Instead, the CAT is Incorporated in revenue requirement calculation on P.3.

PRODUCTION-RELATED INCOME TAX
Twelve Months Ended December 31, 2011

Rate Schedule 101
Page 15

Line	Description	Reference	Amount	(Demand) Fixed	(Energy) Variable
			(1)	(2)	(3)
1	Return on Rate Base	P.4, L.18	$140,529,667	$131,485,513	$9,044,153
2	Interest Expense	P.10,L.1*P.4,L.16	34,446,005	32,229,142	2,216,862
3	Taxable Income	L.1 - L.2	106,083,662	99,256,371	6,827,291
4	Effective Income Tax Rate	P.16, L.2	35.2796%	35.2796%	35.2796%
5	Income Tax Calculated	L.1 x L.2	37,425,927	35,017,284	2,408,643
6	ITC Adjustment	P.16, L.13	(663,957)	(657,726)	(6,231)
7	Income Tax	L.3 + L.4	$36,761,970	$34,359,558	$2,402,412
8	Commercial Activities Tax	ORC 5751	0.26%	0.26%	0.26%

COMPUTATION OF EFFECTIVE INCOME TAX RATE
Twelve Months Ended December 31, 2011

Line	Description	Reference	Amount
1	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} * {1 - DPAD} =	(A)	31.8500%
2	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		35.2796%
3	where WCLTD and WACC from Exhibit B-11 and FIT, SIT & p as shown below.		
4	GRCF=1 / (1 - T)		1.467351431
5	Federal Income Tax Rate	FIT	35.0000%
6	State Income Tax Rate	SIT	0.0000%
7	Percent of FIT deductible for state purposes	p	0.0000%
8	Weighted Cost of Long Term Debt	WCLTD	1.9247%
9	Weighted Average Cost of Capital	WACC	7.8522%
10	Amortized Investment Tax Credit (enter negative)	FF1, P.114, L.19, Col.g	($800,115)
11	Gross Plant Allocation Factor	L.19	56.55%
12	Production Plant Related ITC Amortization	L.10 x L.11	(452,487)
13	ITC Adjustment	L.12 x L.4	(663,957)
	Gross Plant Allocator Total		
14	Gross Plant	P.6, L.6, Col.2	$6,380,218,703
15	Production Plant Gross	P.6, L.5, Col.2	3,608,188,601
16	Demand Related Production Plant	P.6, L.5, Col.3	3,574,328,638
17	Energy Related Production Plant	P.6, L.5, Col.4	$33,859,963
18	Production Plant Gross Plant Allocator	L.16 / L.15	56.55%
19	Production Plant - Demand Related	L.17 / L. 16	99.06%
20	Production Plant - Energy Related	L.18 / L.16	0.94%

Note: (A) Gross Domestic Production Tax Credit, Section 199, Internal Revenue Code.
Assume 9% of Taxable Income for credit.

ATTACHMENT C

CONFIDENTIAL PROPRIETARY TRADE SECRET

Duke Energy Ohio
Revenue Requirement for Capacity Cost Calculation

	Description	Total For Period (a)	Avg Annual	Comment
1	[redacted]	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]	[redacted]
3	[redacted]	[redacted]	[redacted]	
4	[redacted]	[redacted]	[redacted]	[redacted]
5	Total Revenue (Current Projection)	$625,561	$220,786	Sum Lines 1 thru 4
6	Fixed Costs (excluding return)	880,902	310,907	O&M, Depreciation, Other Taxes Based on 2011 Form 1
7	Earnings Before Interest & Taxes	(255,341)	(90,120)	Line 5 - Line 6
8	Interest Expense	91,316	32,229	Wtd avg cost of debt at 12/31/11 from SEET times Rate Base
9	Taxable Income	(346,656)	(122,349)	Revenue required for 0% ROE (*i.e.*, Break even)
10	Return on Equity at 11.15% ROE	281,225	99,256	Incremental Revenue to go from of 0% ROE to 11.15% ROE
11	Income Taxes on Incremental Return + CAT	97,353	34,360	Reflects adjustment for Gross Domestic Production Tax Credit
12	Commercial Activities Tax	3,887	1,372	0.26% of Total Revenue
13	Total Incremental Revenue Required	**$729,122**	**$257,337**	
14	[redacted]	[redacted]	[redacted]	[redacted]
15	Average Annualized Net Amount	$729,122	$257,337	L.14-L.1
16	Average Capacity Rate ($/MW-Day)			
17	Total Cost of Capacity (Before FZCP Sales)		$224.15	L.14 ÷ 5 CP (4459.85 MW) ÷ 365 days
18	Net Cost of Capacity (After FZCP Sales)		**$158.08**	L.15 ÷ 5 CP (4459.85 MW) ÷ 365 days
19	Rate Base		$1,674,513	P.4 (Attachment B)
20	Equity Ratio		53.2%	P.10 (Attachment B)
21	Earnings Before Interest & Taxes		($90,120)	Line 7
22	Tax Expense		(43,164)	Line 21 * Tax Rate
23	Earnings After Taxes		($46,956)	Line 21 - Line 22
24	Return on Rate Base		-5.27%	Line 23 ÷ (Line 19 * Line 20)
25	Interest Expense		$32,229	Line 8
26	Net Income		($79,185)	Line 23 - Line 25
27	Return on Equity		**-8.90%**	Line 26 ÷ (Line 19 * Line 20)

ATTACHMENT D

Duke Energy Ohio
139 East Fourth Street
Cincinnati, Ohio 45202

RIDER DR-CO

DEFERRED RECOVERY – CAPACITY OBLIGATION RIDER

APPLICABILITY

Applicable to all jurisdictional retail customers in the Company's electric service area including those customers taking service from a competitive retail electric service provider..

DESCRIPTION

The Deferred Recovery – Capacity Obligation Rider recovers deferred costs related to Duke Energy Ohio's fixed resource requirement (FRR) obligation to provide capacity in its service territory. Rider DR-CO rates are applicable for the entire recovery period. Duke Energy Ohio will make a filing subsequent to the recovery period to true-up amounts collected under Rider DR-CO that are over or under the amount of the deferred capacity costs associated with the Company's FRR obligation.

CHARGE

For the period ____ through _____, the following Rider DR-CO rates apply:

Duke Energy Ohio
139 East Fourth Street
Cincinnati, Ohio 45202

Tariff Sheet	Charge (per kWh/kW)
Rate RS, Residential Service	
Summer, First 1000 kWh	$0.000000
Summer, Additional kWh	$0.000000
Winter, First 1000 kWh	$0.000000
Winter, Additional kWh	$0.000000
Rate ORH, Optional Residential Service With Electric Space Heating	
Summer, First 1000 kWh	$0.000000
Summer, Additional kWh	$0.000000
Winter, First 1000 kWh	$0.000000
Winter, Additional kWh	$0.000000
Winter, kWh greater than 150 times demand	$0.000000
Rate TD, Optional Time-of-Day Rate	
Summer, On-Peak kWh	$0.000000
Summer, Off-Peak kWh	$0.000000
Winter, On-Peak kWh	$0.000000
Winter, Off-Peak kWh	$0.000000
Rate CUR, Common Use Residential Service	
Summer, First 1000 kWh	$0.000000
Summer, Additional kWh	$0.000000
Winter, First 1000 kWh	$0.000000
Winter, Additional kWh	$0.000000
Rate DS, Service at Secondary Distribution Voltage	
First 1000 kW	$0.000000
Additional kW	$0.000000
Billing Demand Times 300	$0.000000
Additional kWh	$0.000000
Rate GS-FL, Optional Unmetered For Small Fixed Loads	
kWh Greater Than or Equal to 540 Hours	$0.000000
kWh Less Than 540 Hours	$0.000000
Rate EH, Optional Rate For Electric Space Heating	
All kWh	$0.000000

Filed pursuant to an Order dated ________________ in Case No. 12-___-EL-___ before the Public Utilities Commission of Ohio.

Issued: Effective:

Issued by Julie Janson, President

Duke Energy Ohio
139 East Fourth Street
Cincinnati, Ohio 45202

CHARGES (Contd.)

Tariff Sheet	RC Charge (per kWh/kW)
Rate DM, Secondary Distribution Service, Small	
Summer, First 2800 kWh	$0.000000
Summer, Next 3200 kWh	$0.000000
Summer, Additional kWh	$0.000000
Winter, First 2800 kWh	$0.000000
Winter, Next 3200 kWh	$0.000000
Winter, Additional kWh	$0.000000
Rate DP, Service at Primary Distribution Voltage	
First 1000 kW	$0.000000
Additional kW	$0.000000
Billing Demand Times 300	$0.000000
Additional kWh	$0.000000
Rate TS, Service at Transmission Voltage	
First 50,000 kVA	$0.000000
Additional kVA	$0.000000
Billing Demand Times 300	$0.000000
Additional kWh	$0.000000
Rate SL, Street Lighting Service	
All kWh	$0.000000
Rate TL, Traffic Lighting Service	
All kWh	$0.000000
Rate OL, Outdoor Lighting Service	
All kWh	$0.000000
Rate NSU, Street Lighting Service for Non-Standard Units	
All kWh	$0.000000
Rate NSP, Private Outdoor Lighting for Non-Standard Units	
All kWh	$0.000000
Rate SC, Street Lighting Service - Customer Owned	
All kWh	$0.000000
Energy Only – All kWh	$0.000000
Rate SE, Street Lighting Service - Overhead Equivalent	
All kWh	$0.000000
Rate UOLS, Unmetered Outdoor Lighting Electric Service	
All kWh	$0.000000

Filed pursuant to an Order dated ______________ in Case No. 12-___-EL-___ before the Public Utilities Commission of Ohio.

Issued: Effective:

Issued by Julie Janson, President