FILE

120

FirstEnergy

RECEIVED-DOCKETING DIV

2007 MAY -1 AM 10: 42

PUCO

76 South Main Street
Akron, Ohio 44308

Kathy J. Kolich
Senior Attorney

330-384-4580
Fax: 330-384-3875

Via Federal Express

April 30, 2007

Ms. Renee J. Jenkins
Director of Administration
Docketing Department
The Public Utilities of Ohio
180 East Broad Street, 13th Floor
Columbus, OH 43215

Re*: *Case No. 07-128-EL-ATA

Dear Ms. Jenkins:

Enclosed are the original and ten copies of revised Transmission and Ancillary Service Riders for Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company to be effective July 1, 2007. This filing includes a clean version of the tariff pages and a version marked to show the changes from the tariffs currently in effect.

The adjustments to the Riders are based on the July 22, 2005 Stipulation and Recommendation approved by the Commission in its August 31, 2005 Finding and Order in Case No. 04-1932-EL-ATA. The enclosed updated Exhibit B contains the schedules that support the requested rider adjustments and Exhibit D provides the information related to the biennial review of the Companies' controllable costs as requested by the Commission in its February 14, 2007 Finding and Order in Case No. 04-1833-EL-ATA.

Please do not hesitate to call me if you have any questions or need additional information.

Very truly y ours,

Kathy J. Kolich

Kathy J. Kolich

Enclosure
cc (via e-mail): representatives for
OCC, IEU-OH, Attorney General,
OPAE and Dominion Retail, Inc.

TABLE OF CONTENTS

TABLE OF CONTENTS

Filed pursuant to Order dated ~~December 20, 2006~~February 14, 2007, in Case No. ~~06-1335~~07-128-EL-ATA, before
The Public Utilities Commission of Ohio

Issued by Anthony J. Alexander, President

Effective: ~~January~~ July 1, 2007

Residential Transmission and Ancillary Service Rider

Residential Transmission and Ancillary Service Charges (RTASC) apply to Residential Customers (as defined below), served under the schedules to which this Rider applies.

RTASC = RBC x RTASPC

Where:

RBC = Base Charge(s) for the appropriate Residential Schedules as identified below, multiplied by the appropriate usage for the month.

RTASPC = Residential Transmission and Ancillary Service Percent Change, in accordance with the formula set forth below.

$$RTASPC = \left(\frac{RTAC - RE}{RBR}\right)\left(\frac{1}{1 - CAT}\right)$$

The RTASPC for the bills rendered July 1, ~~2006~~ 2007 through June 30, ~~2007~~ 2008 is ~~209.08~~233.25 percent.

Where:

RTAC = The amount of the Company's total projected transmission- and ancillary service-related costs for the Computation Period allocated to Residential Customers.

The Computation Period over which the RTASPC, as computed, and resulting RTASC will apply shall be January 1, 2006 through June 30, 2006 and July 1 through June 30 of each year thereafter.

RE = Net over- or undercollection of the RTAC, including applicable interest, as of the end of the initial 3-month period ending March 31, 2006 and the twelve-month period ending March 31of each year thereafter that immediately precedes the Computation Period.

RBR = The aggregate base revenue of the Residential Schedules collected through the RBC identified below for the 12-month period ending December 31, 2004, divided by the 2004 class energy sales. For the initial 6-month Computation Period the aggregate base revenue will be for the 6-month period ending June 30,2004.

CAT = The Ohio Commercial Activity Tax rate (expressed in decimal form) as established in Section 5751.02 of the Ohio Revised Code.

The RTASPCs shall be filed with the Public Utilities Commission of Ohio (Commission) by November 1, 2005 and by May 1 of each year thereafter. The RTASPC, and the resulting RTASC shall become effective for bills rendered on January 1, 2006 and every July 1 thereafter, unless otherwise ordered by the Commission.

Residential Customers are those customers taking all of their retail electric service under the following schedules with the following base charges:

	Transmission and Ancillary Service Residential Base Charges	
Residential Service – Standard Rate (Sheet No. 10)	Winter	Summer
For Customers without Water Heating		
First 500 kWh, per kWh	0.377 ¢	0.380 ¢
Over 500 kWh, per kWh	0.377 ¢	0.408 ¢
For Customers with Water Heating		
First 350 kWh, per kWh	0.377 ¢	0.380 ¢
Next 350 kWh, per kWh	0.154 ¢	0.154 ¢
Over 700 kWh, per kWh	0.377 ¢	0.408 ¢
Residential Service – Space Heating Rate (Sheet No. 11)		
For Customers without Water Heating		
First 900 kWh, per kWh	0.508 ¢	0.531 ¢
Over 900 kWh, per kWh	0.183 ¢	0.543 ¢
For Customers with Water Heating		
First 550 kWh, per kWh	0.508 ¢	0.531 ¢
Next 350 kWh, per kWh	0.183 ¢	0.183 ¢
Over 900 kWh, per kWh	0.183 ¢	0.543 ¢
***Heat Pump** - For Customers without Water Heating*		
General Purpose usage, per kWh	0.508 ¢	0.531 ¢
For Submetered usage, per kWh	0.183 ¢	0.543 ¢
***Heat Pump** - For Customers with Water Heating*		
First 550 kWh, per kWh	0.508 ¢	0.531 ¢
Next 350 kWh, per kWh	0.183 ¢	0.183 ¢
Over 900 kWh, per kWh	0.508 ¢	0.543 ¢
For Submetered usage, per kWh	0.183 ¢	0.543 ¢
Residential Service – Optional Time-of-Day (Sheet No. 12)		
All kW, per kW	$ 1.175	

	Transmission and Ancillary Service Residential Base Charges	
	Winter	Summer
Residential Service – Load Management Rate (Sheet No. 17)		
First 250 kWh, per kWh	0.409 ¢	0.413 ¢
Next 250 kWh, per kWh	0.382 ¢	0.386 ¢
Balance to 125 kWh per kW of billing load, per kWh	0.382 ¢	0.417 ¢
Over 125 kWh per kW of billing load, per kWh	0.101 ¢	0.101 ¢
Residential Service – Water Heating Service (Sheet No. 18)		
First 50 kWh, per kWh	1.289 ¢	
Over 50 kWh, per kWh	0.193 ¢	
Residential Service – Optional Electrically Heated Apt. Rate (Sheet No. 19)		
First 350 kWh, per kWh	0.469 ¢	0.474 ¢
Next 750 kWh, per kWh	0.157 ¢	0.487 ¢
Over 1,100 kWh, per kWh	0.446 ¢	0.487 ¢

Commercial Transmission and Ancillary Service Rider

Commercial Transmission and Ancillary Service Charges (CTASC) apply to Commercial Customers (as defined below), served under the schedules to which this Rider applies.

CTASC = CBC x CTASPC

Where:

CBC = Base Charge(s) for the appropriate Commercial Schedules as identified below, multiplied by the appropriate usage for the month.

CTASPC = Commercial Transmission and Ancillary Service Percent Change, in accordance with the formula set forth below.

$$\text{CTASPC} = \left[\frac{\text{CTAC - CE}}{\text{CBR}}\right]\left[\frac{1}{1 - \text{CAT}}\right]$$

The CTASPC for the bills rendered July 1, ~~2006~~ 2007 through June 30, ~~2007~~ 2008 is ~~188.48~~ 232.33 percent.

Where:

CTAC = The amount of the Company's total projected transmission- and ancillary service-related costs for the Computation Period allocated to Commercial Customers.

Non-Shopping Commercial Customers are Commercial Customers and commercial fixed-price contract customers.

The Computation Period over which the CTASPC, as computed, and resulting CTASC will apply shall be January 1, 2006 through June 30, 2006 and July 1 through June 30 of each year thereafter.

CE = Net over- or undercollection of the CTAC, including applicable interest, from Non-Shopping Commercial Customers as of the end of the initial 3-month period ending March 31, 2006 and the twelve-month period ending March 31 of each year thereafter that immediately precedes the Computation Period.

CBR = The aggregate base revenue of the Commercial Schedules collected through the CBC identified below for the 12-month period ending December 31, 2004, divided by the 2004 class energy sales. For the initial 6-month Computation Period the aggregate base revenue will be for the 6-month period ending June 30, 2004.

CAT = The Ohio Commercial Activity Tax rate (expressed in decimal form) as established in Section 5751.02 of the Ohio Revised Code.

The CTASPCs shall be filed with the Public Utilities Commission of Ohio (Commission) by November 1, 2005 and by May 1 of each year thereafter. The CTASPC, and the resulting CTASC shall become effective for bills rendered on January 1, 2006 and every July 1 thereafter, unless otherwise ordered by the Commission.

Commercial Customers are those customers taking all of their retail electric service under the following schedules with the following base charges:

	Transmission and Ancillary Service Commercial Base Charges
General Service – Secondary Voltages (Sheet No. 21)	
First 500 kWh, per kWh	0.578 ¢
Balance to 165 kWh per kW of billing load, per kWh	0.627 ¢
Next 85 kWh per kW of billing demand, per kWh	0.175 ¢
Over 250 kWh per kW of billing demand, per kWh	0.117 ¢
General Service – Secondary Voltages Optional Space and Water Heating (Sheet No. 22)	
Controlled Service, All kWh, per kWh	0.156 ¢
Seasonal Service, All kWh, per kWh	0.164 ¢
Traffic Lighting Service (Sheet No. 31)	
All kWh, per kWh	0.301 ¢
Private Outdoor Lighting Service (Sheet No. 32)	
All kWh, per kWh	0.227 ¢
Lighting Service – All Night Outdoor Lighting Rate (Sheet No. 33)	
First 500 kWh, per kWh	0.578 ¢
Over 500 kWh, per kWh	0.627 ¢
Street Lighting Service - Company Owned (Sheet No. 35)	
All kWh, per kWh	0.301 ¢
Street Lighting Service – Non-Company Owned (Sheet No. 36)	
All kWh, per kWh	0.301 ¢

Industrial Transmission and Ancillary Service Rider

Industrial Transmission and Ancillary Service Charges (ITASC) apply to Industrial Customers (as defined below), served under the schedules to which this Rider applies.

ITASC = IBC x ITASPC

Where:

IBC = Base Charge(s) for the appropriate Industrial Schedules as identified below, multiplied by the appropriate usage for the month.

ITASPC = Industrial Transmission and Ancillary Service Percent Change, in accordance with the formula set forth below.

$$\text{ITASPC} = \left(\frac{\text{ITAC - IE}}{\text{IBR}}\right)\left(\frac{1}{1 - \text{CAT}}\right)$$

The ITASPC for the bills rendered July 1, ~~2006~~ 2007 through June 30, ~~2007~~ 2008 is ~~177.48~~218.95 percent.

Where:

ITAC = The amount of the Company's total projected transmission- and ancillary service-related costs for the Computation Period allocated to Industrial Customers.

Non-Shopping Industrial Customers are Industrial Customers and industrial fixed-price contract customers.

The Computation Period over which the ITASPC, as computed, and resulting ITASC will apply shall be January 1, 2006 through June 30, 2006 and July 1 through June 30 of each year thereafter.

IE = Net over- or undercollection of the ITAC, including applicable interest, from Non-Shopping Industrial Customers as of the end of the initial 3-month period ending March 31, 2006 and the twelve-month period ending March 31 of each year thereafter that immediately precedes the Computation Period.

IBR = The aggregate base revenue of the Industrial Schedules collected through the IBC identified below for the 12-month period ending December 31, 2004, divided by the 2004 class energy sales. For the initial 6-month Computation Period the aggregate base revenue will be for the 6-month period ending June 30,2004.

CAT = The Ohio Commercial Activity Tax rate (expressed in decimal form) as established in Section 5751.02 of the Ohio Revised Code.

The ITASPCs shall be filed with the Public Utilities Commission of Ohio (Commission) by November 1, 2005 and by May 1 of each year thereafter. The ITASPC, and the resulting ITASC shall become effective for bills rendered on January 1, 2006 and every July 1 thereafter, unless otherwise ordered by the Commission.

Industrial Customers are those customers taking all of their retail electric service under the following schedules with the following base charges:

	Transmission and Ancillary Service Industrial Base Charges
General Service – Large (Sheet No. 23)	
First 2,000 kVa of billing demand, per kVa	$ 1.375
Next 2,000 kVa of billing demand, per kVa	$ 1.375
Over 4,000 kVa of billing demand, per kVa	$ 1.147
General Service – High Use Manufacturing (Sheet No. 28).	
First 8,000 kVa of billing demand, per kVa	$ 1.765
Next 16,000 kVa of billing demand, per kVa	$ 1.469
Over 24,000 kVa of billing demand, per kVa	$ 1.182
General Service – *Interruptible Electric* Arc Furnace Rate (Sheet No. *29*)	
All on-peak kWh, per kWh	0.280 ¢
All off-peak kWh, per kWh	0.280 ¢
Interruptible Rider - Metal Melting Load (Sheet No. 74)	
All on-peak kWh, per kWh	0.294 ¢
All off-peak kWh, per kWh	0.294 ¢
Interruptible Rider – Incremental Interruptible Service (Sheet No. 75)	
138 kV	
All on-peak kWh, per kWh	0.280 ¢
All off-peak kWh, per kWh	0.280 ¢
69 kV	
All on-peak kWh, per kWh	0.288 ¢
All off-peak kWh, per kWh	0.288 ¢
23-34.5 kV	
All on-peak kWh, per kWh	0.294 ¢
All off-peak kWh, per kWh	0.294 ¢
Primary	
All on-peak kWh, per kWh	0.303 ¢
All off-peak kWh, per kWh	0.303 ¢

TABLE OF CONTENTS

TABLE OF CONTENTS

Rider 19
Residential Transmission and Ancillary Service Rider

Residential Transmission and Ancillary Service Charges (RTASC) apply to Residential Customers (as defined below), served under the schedules to which this Rider applies.

RTASC = RBC x RTASPC

Where:

RBC = Base Charge(s) for the appropriate Residential Schedules as identified below, multiplied by the appropriate usage for the month.

RTASPC = Residential Transmission and Ancillary Service Percent Change, in accordance with the formula set forth below.

$$RTASPC = \left(\frac{RTAC - RE}{RBR}\right)\left(\frac{1}{1 - CAT}\right)$$

The RTASPC for the bills rendered July 1, ~~2006~~ 2007 through June 30, ~~2007~~ 2008 is ~~203.02~~240.22 percent.

Where:

RTAC = The amount of the Company's total projected transmission- and ancillary service-related costs for the Computation Period allocated to Residential Customers.

The Computation Period over which the RTASPC, as computed, and resulting RTASC will apply shall be January 1, 2006 through June 30, 2006 and July 1 through June 30 of each year thereafter.

RE = Net over- or undercollection of the RTAC, including applicable interest, as of the end of the initial 3-month period ending March 31, 2006 and the twelve-month period ending March 31 of each year thereafter that precedes the Computation Period.

RBR = The aggregate base revenue of the Residential Schedules collected through the RBC identified below for the 12-month period ending December 31, 2004, divided by the 2004 class energy sales. For the initial 6-month Computation Period the aggregate base revenue will be for the 6-month period ending June 30, 2004.

CAT = The Ohio Commercial Activity Tax rate (expressed in decimal form) as established in Section 5751.02 of the Ohio Revised Code.

The RTASPCs shall be filed with the Public Utilities Commission of Ohio (Commission) by November 1, 2005 and by May 1 of each year thereafter. The RTASPC, and the resulting RTASC shall become effective for bills rendered on January 1, 2006 and every July 1 thereafter, unless otherwise ordered by the Commission.

Residential Customers are those customers taking all of their retail electric service under the following schedules with the following base charges.

	Transmission and Ancillary Service Residential Base Charges	
Residential Schedule (Sheet No. 10)	Winter	Summer
First 500 kWh, per kWh	0.335 ¢	0.387 ¢
Next 500 kWh, per kWh	0.320 ¢	0.372 ¢
Over 1,000 kWh, per kWh	0.206 ¢	0.372 ¢
All use in excess of 125 kWh per kW (Load Mgmt)	0.141 ¢	0.141 ¢
Residential Add On Heat Pump Schedule (Sheet No. 11)		
All kWh, per kWh	0.181 ¢	0.339 ¢
Residential Water Heating Schedule (Sheet No. 12)		
First 500 kWh, per kWh	0.332 ¢	0.386 ¢
Next 500 kWh, per kWh	0.254 ¢	0.310 ¢
Over 1,000 kWh, per kWh	0.156 ¢	0.310 ¢
All use in excess of 125 kWh per kW (Load Mgmt)	0.129 ¢	0.129 ¢
Residential Space Heating Schedule (Sheet No. 13)		
First 500 kWh, per kWh	0.180 ¢	0.210 ¢
Next 500 kWh, per kWh	0.124 ¢	0.202 ¢
Over 1,000 kWh, per kWh	0.081 ¢	0.202 ¢
All use in excess of 125 kWh per kW (Load Mgmt)	0.065 ¢	0.065 ¢
Residential Water and Space Heating Schedule (Sheet No. 14)		
First 500 kWh, per kWh	0.217 ¢	0.256 ¢
Next 100 kWh, per kWh	0.161 ¢	0.202 ¢
Next 400 kWh, per kWh	0.147 ¢	0.202 ¢
Over 1,000 kWh, per kWh	0.091 ¢	0.202 ¢
All use in excess of 125 kWh per kW (Load Mgmt)	0.072 ¢	0.072 ¢

	Transmission and Ancillary Service Residential Base Charges	
Optional Electrically Heated Residential Apartment Schedule (Sheet No. 15)	Winter	Summer
For Customers with Water Heating		
First 300 kWh, per kWh	0.201 ¢	0.235 ¢
Next 300 kWh, per kWh	0.150 ¢	0.187 ¢
Next 1,400 kWh, per kWh	0.078 ¢	0.188 ¢
Next 300 kWh, per kWh	0.079 ¢	0.217 ¢
Over 2,300 kWh, per kWh	0.201 ¢	0.217 ¢
For Customers without Water Heating		
First 300 kWh, per kWh	0.203 ¢	0.237 ¢
Next 300 kWh, per kWh	0.079 ¢	0.233 ¢
Next 1,400 kWh, per kWh	0.078 ¢	0.223 ¢
Over 2,000 kWh, per kWh	0.078 ¢	0.223 ¢

Rider 20
Commercial Transmission and Ancillary Service Rider

Commercial Transmission and Ancillary Service Charges (CTASC) apply to Commercial Customers (as defined below), served under the schedules to which this Rider applies.

CTASC = CBC x CTASPC

Where:

CBC = Base Charge(s) for the appropriate Commercial Schedules as identified below, multiplied by the appropriate usage for the month.

CTASPC = Commercial Transmission and Ancillary Service Percent Change, in accordance with the formula set forth below.

$$CTASPC = \left(\frac{CTAC - CE}{CBR}\right)\left(\frac{1}{1 - CAT}\right)$$

The CTASPC for the bills rendered July 1, ~~2006~~ 2007 through June 30, ~~2007~~ 2008 is ~~183.22~~227.00 percent.

Where:

CTAC = The amount of the Company's total projected transmission- and ancillary service-related costs for the Computation Period allocated to Commercial Customers.

Non-Shopping Commercial Customers are Commercial Customers and commercial fixed-price contract customers.

The Computation Period over which the CTASPC, as computed, and resulting CTASC will apply shall be January 1, 2006 through June 30, 2006 and July 1 through June 30 of each year thereafter.

CE = Net over- or undercollection of the CTAC, including applicable interest from Non-Shopping Commercial Customers as of the end of the initial 3-month period ending March 31 of each year thereafter that immediately precedes the Computation Period.

CBR = The aggregate base revenue of the Commercial Schedules collected through the CBC identified below for the 12-month period ending December 31, 2004, divided by the 2004 class energy sales. For the initial 6-month Computation Period the aggregate base revenue will be for the 6-month period ending June 30, 2004.

CAT = The Ohio Commercial Activity Tax rate (expressed in decimal form) as established in Section 5751.02 of the Ohio Revised Code.

The CTASPCs shall be filed with the Public Utilities Commission of Ohio (Commission) by November 1, 2005 and by May 1 of each year thereafter. The CTASPC, and the resulting CTASC shall become effective for bills rendered on January 1, 2006 and every July 1 thereafter, unless otherwise ordered by the Commission.

Commercial Customers are those customers taking all of their retail electric service under the following schedules with the following base charges:

	Transmission and Ancillary Service Commercial Base Charges	
	Winter	Summer
General Service Schedule (Sheet No. 30)		
First 500 kWh, per kWh	0.305 ¢	0.328 ¢
Next 4,500 kWh, per kWh	0.292 ¢	0.315 ¢
Next 5,000 kWh, per kWh	0.256 ¢	0.274 ¢
Over 10,000 kWh, per kWh	0.204 ¢	0.221 ¢
Electric Space Conditioning Schedule (Sheet No. 31)		
All kWh, per kWh	0.129 ¢	0.409 ¢
Small General Service Schedule (Sheet No. 32)		
First 50 kW, per kW	$ 1.113	$ 1.183
Over 50 kW, per kW	$ 1.033	$ 1.096
All Electric Large General Service Schedule (Sheet No. 34)		
First 50 kW, per kW	$ 1.492	$ 1.492
Over 50 kW, per kW	$ 1.397	$ 1.397
Small School Schedule (Sheet No. 36)		
First 50 kW, per kW	$ 1.221	$ 1.287
Over 50 kW, per kW	$ 1.143	$ 1.211
Large School Schedule (Sheet No. 37)		
First 200 kW, per kW	$ 1.528	$ 1.627
Over 200 kW, per kW	$ 1.461	$ 1.566
Outdoor Night Lighting Schedule (Sheet No. 41)		
All kWh, per kWh	0.429 ¢	
Traffic Control Lighting Schedule (Sheet No. 44)		
All kWh, per kWh	0.172 ¢	
Emergency Schedule (Sheet No. 45)		
All kWh, per kWh	1.515 ¢	

	Transmission and Ancillary Service Commercial Base Charges	
General Commercial Schedule (Sheet No. 70)	Winter	Summer
First 500 kWh, per kWh	0.436 ¢	0.473 ¢
Next 7,000 kWh, per kWh	0.417 ¢	0.453 ¢
Over 7,500 kWh, per kWh	0.287 ¢	0.318 ¢
Large Commercial Schedule (Sheet No. 71)		
First 50 kW, per kW	$ 0.858	$ 0.925
Over 50 kW, per kW	$ 0.803	$ 0.865

Rider 21
Industrial Transmission and Ancillary Service Rider

Industrial Transmission and Ancillary Service Charges (ITASC) apply to Industrial Customers (as defined below), served under the schedules to which this Rider applies.

ITASC = IBC x ITASPC

Where:

IBC = Base Charge(s) for the appropriate Industrial Schedules as identified below, multiplied by the appropriate usage for the month.

ITASPC = Industrial Transmission and Ancillary Service Percent Change, in accordance with the formula set forth below.

$$\text{ITASPC} = \left(\frac{\text{ITAC - IE}}{\text{IBR}}\right)\left(\frac{1}{1 - \text{CAT}}\right)$$

The ITASPC for the bills rendered July 1, ~~2006~~ 2007 through June 30, ~~2007~~ 2008 is ~~207.02~~250.87 percent.

Where:

ITAC = The amount of the Company's total projected transmission- and ancillary service-related costs for the Computation Period allocated to Industrial Customers.

Non-Shopping Industrial Customers are Industrial Customers and industrial fixed-price contract customers.

The Computation Period over which the ITASPC, as computed, and resulting ITASC will apply shall be January 1, 2006 through June 30, 2006 and July 1 through June 30 of each year thereafter.

IE = Net over- or undercollection of the ITAC, including applicable interest, from Non-Shopping Industrial Customers as of the end of the initial 3-month period ending March 31, 2006 and the twelve-month period ending March 31 of each year thereafter that immediately precedes the Computation Period.

IBR = The aggregate base revenue of the Industrial Schedules collected through the IBC identified below for the 12-month period ending December 31, 2004, divided by the 2004 class energy sales. For the initial 6-month Computation Period the aggregate base revenue will be for the 6-month period ending June 30,2004.

CAT = The Ohio Commercial Activity Tax rate (expressed in decimal form) as established in Section 5751.02 of the Ohio Revised Code.

The ITASPCs shall be filed with the Public Utilities Commission of Ohio (Commission) by November 1, 2005 and by May 1 of each year thereafter. The ITASPC, and the resulting ITASC shall become effective for bills rendered on January 1, 2006 and every July 1 thereafter, unless otherwise ordered by the Commission.

Industrial Customers are those customers taking all of their retail electric service under the following schedules with the following base charges:

	Transmission and Ancillary Service Industrial Base Charges	
	Winter	Summer
Medium General Service Schedule (Sheet No. 33)		
First 200 kW, per kW	$ 1.249	$ 1.326
Over 200 kW, per kW	$ 1.138	$ 1.210
Large General Service Schedule (Sheet No. 35)		
First 500 kW, per kW	$ 1.310	
Next 500 kW, per kW	$ 1.238	
Over 1,000 kW, per kW	$ 1.092	
Low Load Factor Schedule (Sheet No. 38)		
First 50 kW, per kW	$ 0.337	$ 0.370
Over 50 kW, per kW	$ 0.310	$ 0.340
Minimum Charge	$ 0.095	$ 0.095
Optional Electric Process Heating and Electric Boiler Management Schedule (Sheet No. 39)		
First 140 kWh per kW of billing load, per kWh	0.160 ¢	0.176 ¢
Over 140 kWh per kW of billing load, per kWh	0.080 ¢	0.080 ¢
Industrial Schedule (Sheet No. 72)		
First 50 kW, per kW	$ 0.981	$ 1.058
Over 50 kW, per kW	$ 0.918	$ 0.989
Large Industrial Schedule (Sheet No. 73)		
First 5,000 kW, per kW	$ 0.834	$ 0.894
Over 5,000 kW, per kW	$ 0.789	$ 0.845

TABLE OF CONTENTS

The following rates, rules and regulations for electric service are applicable throughout Toledo Edison's service territory except as noted.

TABLE OF CONTENTS

Rider 16
Residential Transmission and Ancillary Service Rider

Residential Transmission and Ancillary Service Charges (RTASC) apply to Residential Customers (as defined below), served under the schedules to which this Rider applies.

RTASC = RBC x RTASPC

Where:

RBC = Base Charge(s) for the appropriate Residential Schedules as identified below, multiplied by the appropriate usage for the month.

RTASPC = Residential Transmission and Ancillary Service Percent Change, in accordance with the formula set forth below.

$$RTASPC = \left(\frac{RTAC - RE}{RBR}\right)\left(\frac{1}{1 - CAT}\right)$$

The RTASPC for the bills rendered July 1, ~~2006~~ 2007 through June 30, ~~2007~~ 2008 is ~~147.45~~214.98 percent.

Where:

RTAC = The amount of the Company's total projected transmission- and ancillary service-related costs for the Computation Period allocated to Residential Customers.

The Computation Period over which the RTASPC, as computed, and resulting RTASC will apply shall be January 1, 2006 through June 30, 2006 and July 1 through June 30 of each year thereafter.

RE = Net over- or undercollection of the RTAC, including applicable interest, as of the end of the initial 3-month period ending March 31, 2006 and the twelve month period ending March 31 of each year thereafter, that immediately precedes the Computation Period.

RBR = The aggregate base revenue of the Residential Schedules collected through the RBC identified below for the 12-month period ending December 31, 2004, divided by the 2004 class energy sales. For the initial 6-month Computation Period the aggregate base revenue will be for the 6-month period ending June 30, 2004.

CAT = The Ohio Commercial Activity Tax rate (expressed in decimal form) as established in Section 5751.02 of the Ohio Revised Code.

The RTASPCs shall be filed with the Public Utilities Commission of Ohio (Commission) by November 1, 2005 and by May 1 of each year thereafter. The RTASPC, and the resulting RTASC shall become effective for bills rendered on January 1, 2006 and every July 1 thereafter, unless otherwise ordered by the Commission.

Residential Customers are those customers taking all of their retail electric service under the following schedules with the following base charges:

	Transmission and Ancillary Service Residential Base Charges	
	Winter	Summer
Residential Rate "R-01" (Sheet No. 10)		
First 1,000 kWh, per kWh	0.503 ¢	0.546 ¢
Over 1,000 kWh, per kWh	0.417 ¢	0.497 ¢
Residential Add On Heat Pump Rate "R-02" (Sheet No. 11)		
All kWh, per kWh	0.341 ¢	0.690 ¢
Residential Rate "R-01a" (Sheet No. 12)		
First 1,000 kWh, per kWh	0.405 ¢	0.439 ¢
Over 1,000 kWh, per kWh	0.335 ¢	0.400 ¢
Residential Optional Heating Rate "R-06" (Sheet No. 13)		
First 1,000 kWh, per kWh	0.354 ¢	0.387 ¢
Over 1,000 kWh, per kWh (Under 125 Hrs Use)	0.294 ¢	0.355 ¢
Over 1,000 kWh, per kWh (Over 125 Hrs Use)	0.114 ¢	0.114 ¢
Residential Optional Heating Rate "R-06a" (Sheet No. 14)		
First 1,000 kWh, per kWh	0.297 ¢	0.325 ¢
Over 1,000 kWh, per kWh (Under 125 Hrs Use)	0.246 ¢	0.298 ¢
Over 1,000 kWh, per kWh (Over 125 Hrs Use)	0.097 ¢	0.096 ¢
Residential Hot Water Rate "R-04" (Sheet No. 15)		
First 500 kWh, per kWh	0.501 ¢	0.544 ¢
Next 400 kWh, per kWh	0.436 ¢	0.457 ¢
Over 900 kWh, per kWh	0.310 ¢	0.457 ¢
Residential Hot Water Rate "R-04a" (Sheet No. 16)		
First 500 kWh, per kWh	0.865 ¢	0.941 ¢
Next 400 kWh, per kWh	0.754 ¢	0.791 ¢
Over 900 kWh, per kWh	0.536 ¢	0.791 ¢

	Transmission and Ancillary Service Residential Base Charges	
Residential Heating Rate "R-07" (Sheet No. 17)	Winter	Summer
First 500 kWh, per kWh	0.332 ¢	0.362 ¢
Next 400 kWh, per kWh	0.288 ¢	0.302 ¢
Over 900 kWh, per kWh	0.165 ¢	0.328 ¢
Residential Heating Rate "R-07a" (Sheet No. 18)		
First 500 kWh, per kWh	0.274 ¢	0.299 ¢
Next 400 kWh, per kWh	0.238 ¢	0.250 ¢
Over 900 kWh, per kWh	0.140 ¢	0.271 ¢
Optional Electrically Heated Apartment Rate "R-09" (Sheet No. 19)		
First 300 kWh, per kWh	0.331 ¢	0.363 ¢
Next 300 kWh, per kWh	0.110 ¢	0.363 ¢
Next 400 kWh, per kWh	0.110 ¢	0.300 ¢
Next 1,000 kWh, per kWh	0.110 ¢	0.327 ¢
Over 2,000 kWh, per kWh	0.331 ¢	0.385 ¢
Optional Electrically Heated Apartment Rate "R-09a" (Sheet No. 20)		
First 300 kWh, per kWh	0.329 ¢	0.360 ¢
Next 300 kWh, per kWh	0.113 ¢	0.360 ¢
Next 400 kWh, per kWh	0.114 ¢	0.297 ¢
Next 1,000 kWh, per kWh	0.113 ¢	0.310 ¢
Over 2,000 kWh, per kWh	0.342 ¢	0.310 ¢

Rider 17
Commercial Transmission and Ancillary Service Rider

Commercial Transmission and Ancillary Service Charges (CTASC) apply to Commercial Customers (as defined below), served under the schedules to which this Rider applies.

CTASC = CBC x CTASPC

Where:

CBC = Base Charge(s) for the appropriate Commercial Schedules as identified below, multiplied by the appropriate usage for the month.

CTASPC = Commercial Transmission and Ancillary Service Percent Change, in accordance with the formula set forth below.

$$CTASPC = \left[\frac{CTAC - CE}{CBR}\right]\left[\frac{1}{1 - CAT}\right]$$

The CTASPC for the bills rendered July 1, ~~2006~~ 2007 through June 30, ~~2007~~ 2008 is ~~162.39~~215.37 percent.

Where:

CTAC = The amount of the Company's total projected transmission- and ancillary service-related costs for the Computation Period allocated to Commercial Customers.

Non-Shopping Commercial Customers are Commercial Customers and commercial fixed-price contract customers.

The Computation Period over which the CTASPC, as computed, and resulting CTASC will apply shall be January 1, 2006 through June 30, 2006 and July 1 through June 30 of each year thereafter.

CE = Net over- or undercollection of the CTAC, including applicable interest, from Non-Shopping Commercial Customers as of the end of the initial 3-month period ending March 31, 2006 and the twelve-month period ending March 31 of each year thereafter that immediately precedes the Computation Period.

CBR = The aggregate base revenue of the Commercial Schedules collected through the CBC identified below for the 12-month period ending December 31, 2004, divided by the 2004 class energy sales. For the initial 6-month Computation Period the aggregate base revenue will be for the 6-month period ending June 30, 2004.

CAT = The Ohio Commercial Activity Tax rate (expressed in decimal form) as established in Section 5751.02 of the Ohio Revised Code.

The CTASPCs shall be filed with the Public Utilities Commission of Ohio (Commission) by November 1, 2005 and by May 1 of each year thereafter. The CTASPC, and the resulting CTASC shall become effective for bills rendered on January 1, 2006 and every July 1 thereafter, unless otherwise ordered by the Commission.

Commercial Customers are those customers taking all of their retail electric service under the following schedules with the following base charges:

	Transmission and Ancillary Service Commercial Base Charges	
Small General Service Rate "GS-16" (Sheet No. 40)	Winter	Summer
(With Demand Meter)		
First 50 kWd, per kWd	$ 1.329	$ 1.437
Over 50 kWd, per kWd	$ 1.239	$ 1.348
(Without Demand Meter)		
First 1,000 kWh, per kWh	1.483 ¢	1.600 ¢
Over 1,000 kWh, per kWh	1.292 ¢	1.426 ¢
Small School Rate "SR-1a" (Sheet No. 41)		
First 50 kW, per kW	$ 0.780	$ 0.850
Over 50 kW, per kW	$ 0.721	$ 0.792
Large School Rate "SR-2a" (Sheet No. 42)		
First 200 kVa, per kVa	$ 1.025	$ 1.095
Over 200 kVa, per kVa	$ 0.976	$ 1.051
General Service Rate "GS-14" (Sheet No. 44)		
First 500 kWh, per kWh	0.488 ¢	0.536 ¢
Next 4,500 kWh, per kWh	0.468 ¢	0.513 ¢
Next 5,000 kWh, per kWh	0.387 ¢	0.422 ¢
Over 10,000 kWh, per kWh	0.298 ¢	0.322 ¢
Small General Service Schedule (Sheet No. 45)		
First 50 kW, per kW	$ 1.281	$ 1.378
Over 50 kW, per kW	$ 1.239	$ 1.334
Medium General Service Schedule (Sheet No. 46)		
First 200 kW, per kW	$ 1.541	$ 1.648
Over 200 kW, per kW	$ 1.468	$ 1.581
General Service Electric Space Conditioning Rate "GS-1" (Sheet No. 47)		
All kWh, per kWh	0.215 ¢	0.683 ¢

	Transmission and Ancillary Service Commercial Base Charges	
	Winter	Summer
Optional Electric Process Heating and Electric Boiler Load Management Rate "GS-3" (Sheet No. 48)		
First 140 kWh per kW of billing load, per kWh	0.681 ¢	0.752 ¢
Over 140 kWh per kW of billing load, per kWh	0.313 ¢	0.313 ¢
General Service Heating Rate "GS-17" (Sheet No. 49)		
(With Demand Meter)		
First 50 kWd, per kWd	$ 1.279	$ 1.372
Over 50 kWd, per kWd	$ 1.202	$ 1.296
(Without Demand Meter)		
First 1,000 kWh, per kWh	1.097 ¢	1.531 ¢
Over 1,000 kWh, per kWh	0.954 ¢	1.356 ¢
Controlled Water Heating Rate "GS-19" (Sheet No. 50)		
All kWh, per kWh	1.109 ¢	
Controlled Water Heating Rate "GS-19a" (Sheet No. 51)		
All kWh, per kWh	1.112 ¢	

Rider 18
Industrial Transmission and Ancillary Service Rider

Industrial Transmission and Ancillary Service Charges (ITASC) apply to Industrial Customers (as defined below), served under the schedules to which this Rider applies.

ITASC = IBC x ITASPC

Where:

IBC = Base Charge(s) for the appropriate Industrial Schedules as identified below, multiplied by the appropriate usage for the month.

ITASPC = *Industrial Transmission and Ancillary Service* Percent Change, in accordance with the formula set forth below.

$$\text{ITASPC} = \left(\frac{\text{ITAC - IE}}{\text{IBR}}\right)\left(\frac{1}{1 - \text{CAT}}\right)$$

The ITASPC for the bills rendered July 1, ~~2006~~ 2007 through June 30, ~~2007~~ 2008 is ~~143.18~~156.52 percent.

Where:

ITAC = The amount of the Company's total projected transmission- and ancillary service-related costs for the Computation Period allocated to Industrial Customers.

Non-Shopping Industrial Customers are Industrial Customers and industrial fixed-price contract customers.

The Computation Period over which the ITASPC, as computed, and resulting ITASC will apply shall be January 1, 2006 through June 30, 2006 and July 1 through June 30 of each year thereafter.

IE = Net over- or undercollection of the ITAC, including applicable interest, from Non-Shopping Industrial Customers as of the end of the initial 3-month period ending March 31, 2006 and the twelve-month period ending March 31 of each year thereafter that immediately precedes the Computation Period.

IBR = The aggregate base revenue of the Industrial Schedules collected through the IBC identified below for the 12-month period ending December 31, 2004, divided by the 2004 class energy sales. For the initial 6-month Computation Period the aggregate base revenue will be for the 6-month period ending June 30,2004.

CAT = The Ohio Commercial Activity Tax rate (expressed in decimal form) as established in Section 5751.02 of the Ohio Revised Code.

The ITASPCs shall be filed with the Public Utilities Commission of Ohio (Commission) by November 1, 2005 and by May 1 of each year thereafter. The ITASPC, and the resulting ITASC shall become effective for bills rendered on January 1, 2006 and every July 1 thereafter, unless otherwise ordered by the Commission.

Industrial Customers are those customers taking all of their retail electric service under the following schedules with the following IBC's:

	Transmission and Ancillary Service Industrial Base Charges	
Large General Service Rate "GS-12" (Sheet No. 43)	Winter	Summer
First 200 kVa, per kVa	$ 1.516	$ 1.621
Over 200 kVa, per kVa	$ 1.444	$ 1.554
Large Power Rate "PV-44" (Sheet No. 60)		
(Bulk)		
First 1,000 kVa, per kVa	$ 2.110	
Next 29,000 kVa, per kVa	$ 2.091	
Over 30,000 kVa, per kVa	$ 1.986	
(Primary)		
First 1,000 kVa, per kVa	$ 2.040	
Next 29,000 kVa, per kVa	$ 2.023	
Over 30,000 kVa, per kVa	$ 2.023	
(Sub-Transmission)		
First 1,000 kVa, per kVa	$ 2.387	
Next 29,000 kVa, per kVa	$ 2.357	
Over 30,000 kVa, per kVa	$ 2.248	
Large General Service Rate "PV-45" (Sheet No. 61)		
First 500 kW, per kW	$ 1.942	
Next 500 kW, per kW	$ 1.891	
Over 1,000 kW, per kW	$ 1.839	
Small Water & Waste Water Rate "WR-1" (Ordinance Rate)		
First 130 kWh per kW of billing load, per kWh	0.797 ¢	
Next 170 kWh per kW of billing load, per kWh	0.211 ¢	
Next 150 kWh per kW of billing load, per kWh	0.157 ¢	
Over 450 kWh per kW of billing load, per kWh	0.145 ¢	
Medium Water & Waste Water Rate "WR-2" (Ordinance Rate)		
First 130 kWh per kW of billing load, per kWh	1.107 ¢	
Next 170 kWh per kW of billing load, per kWh	0.261 ¢	
Next 150 kWh per kW of billing load, per kWh	0.181 ¢	
Over 450 kWh per kW of billing load, per kWh	0.164 ¢	

Exhibit B Index

Exhibit Number	Description
B-1	Calculation of OE Transmission and Ancillary Service Rider charges
B-2	Calculation of CEI Transmission and Ancillary Service Rider charges
B-3	Calculation of TE Transmission and Ancillary Service Rider charges
B-4	Index of Transmission and Ancillary Service Costs to be Recovered Through Rider
B-5	Monthly Projected Transmission- and Ancillary Service-Related Costs to be Included in the Riders
B-6	Prior 12 Months of Transmission- and Ancillary Service-Related Costs
B-7	Monthly Projected kWh Sales Data
B-8	Coincident Peak Data
B-9	Calculation of OE Reconciliation Adjustment
B-10	Calculation of CEI Reconciliation Adjustment
B-11	Calculation of TE Reconciliation Adjustment
B-12	Monthly Transmission and Ancillary Service Revenues
B-13	Definitions for Use in Exhibit B

Exhibit B-1 provides the method used to determine the Ohio Edison Company Transmission and Ancillary Service Rider charges. The Ohio Edison Rider charges will be effective July 1, 2007.

Ohio Edison Residential Rider

Let RTASPC = Residential Transmission and Ancillary Service Percentage.

Then RTASPC = $\left(\frac{RTAC-RE}{RBR}\right)\left(\frac{1}{(1-CAT)}\right) = \left(\frac{(TDC*RDA)+(TEC*REA)-[(E*RDA*DA)+(E*REA*EA)]}{RBR}\right)\left(\frac{1}{(1-CAT)}\right)$

Where

RTAC = the amount of the projected total transmission- and ancillary service-related costs allocated to OE's Residential Customers.

RE = the residential net reconciliation adjustment, including applicable interest, as of the end of the twelve-month period ending March 31 of each year that immediately precedes the Computation Period.

TDC = OE's projected total transmission- and ancillary service-related demand costs in the upcoming 12 months during which the Rider charge will be in effect (see Exhibit B-5), divided by the projected kWh's for the 12-month period ending June 30, 2008 (see Exhibit B-7).
= $\frac{\$\ 112{,}013{,}721}{8{,}072{,}061{,}071}$ = \$0.013877 per kWh

TEC = OE's projected total transmission- and ancillary service-related energy costs in the upcoming 12 months during which the Rider charge will be in effect (see Exhibit B-5), divided by the projected kWh's for the 12-month period ending June 30, 2008 (see Exhibit B-7).
= $\frac{\$\ 61{,}916{,}017}{8{,}072{,}061{,}071}$ = \$0.007670 per kWh

E = OE's total net reconciliation adjustment for the 12-month period ending March 31, 2007, including projected interest to be earned over the upcoming months during which the Rider charge will be in effect (see Exhibit B-9), divided by the projected kWh's for the 12-month period ending June 30, 2008 (see Exhibit B-7).
= $\frac{\$\ (4{,}814{,}917)}{8{,}072{,}061{,}071}$ = -\$0.000596 per kWh

RDA = the percentage of OE's TDC that is attributed to OE's Residential Customers, adjusted for voltage level (see Exhibit B-8).
= 41.62%

REA = the percentage of OE's TEC that is attributed to OE's Residential Customers (see Exhibit B-7).
= 37.49%

DA = Percent of OE's historical costs allocated on Demand (see Exhibit B-6).
= 72.67%

EA = Percent of OE's historical costs allocated on Energy (see Exhibit B-6).
= 27.33%

RBR = the aggregate transmission and ancillary service base revenue of the OE Residential Schedules collected through the 12-month period ending December 31, 2004 (see Exhibit B-12), divided by the 2004 class energy sales (see Exhibit B-7).
= $\frac{\$\ 23{,}525{,}988}{6{,}160{,}316{,}297}$ = \$0.003819 per kWh

CAT = the Ohio Commercial Activity Tax rate in the upcoming 12 months during which the Rider charge will be in effect.
= 0.169%

So, RTASPC = $\left(\frac{(\$0.013877*0.4162)+(\$0.007670*0.3749)-[(-\$0.000596*0.4162*0.7267)+(-\$0.000596*0.3749*0.2733)]}{\$0.003819}\right)\left(\frac{1}{(1-0.00169)}\right)$
= 233.25% percent

The components used to calculate the OE Rider Charges, along with their locations in Exhibit B, are summarized in the following table:

Component	Exhibit
TDC	B-5, B-7
TEC	B-5, B-7
RDA	B-8
REA	B-7
DA	B-6
EA	B-6
RBR	B-12, B-7
E	B-9, B-7

Exhibit B-1 provides the method used to determine the Ohio Edison Company Transmission and Ancillary Service Rider charges. The Ohio Edison Rider charges will be effective July 1, 2007.

Ohio Edison Commercial Rider

Let CTASPC = Commercial Transmission and Ancillary Service Percentage.

Then CTASPC = $\left[\left(\frac{CTAC-CE}{CBR}\right)\left(\frac{1}{(1-CAT)}\right)\right] = \left[\left(\frac{(TDC*CDA)+(TEC*CEA)-[(E*CDA*DA)+(E*CEA*EA)]}{CBR}\right)\left(\frac{1}{(1-CAT)}\right)\right]$

Where

CTAC = the amount of the projected total transmission- and ancillary service-related costs allocated to OE's Commercial Customers.

CE = the commercial net reconciliation adjustment, including applicable interest, as of the end of the twelve-month period ending March 31 of each year that immediately precedes the Computation Period.

TDC = OE's projected total transmission- and ancillary service-related demand costs in the upcoming 12 months during which the Rider charge will be in effect (see Exhibit B-5), divided by the projected kWh's for the 12-month period ending June 30, 2008 (see Exhibit B-7).

= $\frac{\$\ 112,013,721}{6,044,170,453}$ = $0.018533 per kWh

TEC = OE's projected total transmission- and ancillary service-related energy costs in the upcoming 12 months during which the Rider charge will be in effect (see Exhibit B-5), divided by the projected kWh's for the 12-month period ending June 30, 2008 (see Exhibit B-7).

$\frac{\$\ 61,916,017}{6,044,170,453}$ = $0.010244 per kWh

E = OE's total net reconciliation adjustment for the 12-month period ending March 31, 2007, including projected interest to be earned over the upcoming months during which the Rider charge will be in effect (see Exhibit B-9), divided by the projected kWh's for the 12-month period ending June 30, 2008 (see Exhibit B-7).

= $\frac{\$\ (4,814,917)}{6,044,170,453}$ = -$0.000797 per kWh

CDA = the percentage of OE's TDC that is attributed to OE's Commercial Customers, adjusted for voltage level (see Exhibit B-8).

= 33.46%

CEA = the percentage of OE's TEC that is attributed to OE's Commercial Customers (see Exhibit B-7).

= 28.06%

DA = Percent of OE's historical costs allocated on Demand (See Exhibit B-6).

= 72.67%

EA = Percent of OE's historical costs allocated on Energy (See Exhibit B-6).

= 27.33%

CBR = the aggregate transmission and ancillary service base revenue of the OE Commercial Schedules collected through the 12-month period ending December 31, 2004 (see Exhibit B-12), divided by the 2004 class energy sales (see Exhibit B-7).

= $\frac{\$\ 17,029,317}{4,233,325,783}$ = $0.004023 per kWh

CAT = the Ohio Commercial Activity Tax rate in the upcoming 12 months during which the Rider charge will be in effect.

= 0.169%

So, CTASPC = $\left[\left(\frac{(\$0.018533*0.3346)+(\$0.010244*0.2806)-[(-\$0.000797*0.3346*0.7267)+(-\$0.000797*0.2806*0.2733)]}{\$0.004023}\right)\left(\frac{1}{(1-0.00169)}\right)\right]$

= 232.33% percent

The components used to calculate the OE Rider Charges, along with their locations in Exhibit B, are summarized in the following table:

Component	Exhibit
TDC	B-5, B-7
TEC	B-5, B-7
CDA	B-8
CEA	B-7
DA	B-6
EA	B-6
CBR	B-12, B-7
E	B-9, B-7

Exhibit B-1 provides the method used to determine the Ohio Edison Company Transmission and Ancillary Service Rider charges. The Ohio Edison Rider charges will be effective July 1, 2007.

Ohio Edison Industrial Rider

Let ITASPC = Industrial Transmission and Ancillary Service Percentage.

Then ITASPC = $\left(\frac{ITAC-IE}{IBR}\right)\left(\frac{1}{(1-CAT)}\right) = \left(\frac{(TDC*IDA)+(TEC*IEA)-[(E*IDA*DA)+(E*IEA*EA)]}{IBR}\right)\left(\frac{1}{(1-CAT)}\right)$

Where

ITAC = the amount of the projected total transmission- and ancillary service-related costs allocated to OE's Industrial Customers.

IE = the industrial net reconciliation adjustment, including applicable interest, as of the end of the twelve-month period ending March 31 of each year that immediately precedes the Computation Period.

TDC = OE's projected total transmission- and ancillary service-related demand costs in the upcoming 12 months during which the Rider charge will be in effect (see Exhibit B-5), divided by the projected kWh's for the 12-month period ending June 30, 2008 (see Exhibit B-7).

= $\frac{\$\ 112{,}013{,}721}{7{,}850{,}765{,}988}$ = \$0.014268 per kWh

TEC = OE's projected total transmission- and ancillary service-related energy costs in the upcoming 12 months during which the Rider charge will be in effect (see Exhibit B-5), divided by the projected kWh's for the 12-month period ending June 30, 2008 (see Exhibit B-7).

$\frac{\$\ 61{,}916{,}017}{7{,}850{,}765{,}988}$ = \$0.007887 per kWh

E = OE's total net reconciliation adjustment for the 12-month period ending March 31, 2007, including projected interest to be earned over the upcoming months during which the Rider charge will be in effect (see Exhibit B-9), divided by the projected kWh's for the 12-month period ending June 30, 2008 (see Exhibit B-7).

= $\frac{\$\ (4{,}814{,}917)}{7{,}850{,}765{,}988}$ = -\$0.000613 per kWh

IDA = the percentage of OE's TDC that is attributed to OE's Industrial Customers, adjusted for voltage level (see Exhibit B-8).

= 24.92%

IEA = the percentage of OE's TEC that is attributed to OE's Industrial Customers (see Exhibit B-7).

= 34.45%

DA = Percent of OE's historical costs allocated on Demand (See Exhibit B-6).

= 72.67%

EA = Percent of OE's historical costs allocated on Energy (See Exhibit B-6).

= 27.33%

IBR = the aggregate transmission and ancillary service base revenue of the OE Industrial Schedules collected through the 12-month period ending December 31, 2004 (see Exhibit B-12), divided by the 2004 class energy sales (see Exhibit B-7).

= $\frac{\$\ 19{,}444{,}876}{6{,}598{,}471{,}737}$ = \$0.002947 per kWh

CAT = the Ohio Commercial Activity Tax rate in the upcoming 12 months during which the Rider charge will be in effect.

= 0.169%

So, ITASPC = $\left(\frac{(\$0.014268*0.2492)+(\$0.007887*0.3445)-[(-\$0.000613*0.2492*0.7267)+(-\$0.000613*0.3445*0.2733)]}{\$0.002947}\right)\left(\frac{1}{(1-0.00169)}\right)$

= 218.95% percent

The components used to calculate the OE Rider Charges, along with their locations in Exhibit B, are summarized in the following table:

Component	Exhibit
TDC	B-5, B-7
TEC	B-5, B-7
IDA	B-8
IEA	B-7
DA	B-6
EA	B-6
IBR	B-12, B-7
E	B-9, B-7

Exhibit B-2 provides the method used to determine the Cleveland Electric Illuminating Company Transmission and Ancillary Service Rider charges. The CEI Rider charges will be effective July 1, 2007.

CEI Residential Rider

Let RTASPC = Residential Transmission and Ancillary Service Percentage.

Then RTASPC = $\left(\frac{RTAC-RE}{RBR}\right)\left(\frac{1}{(1-CAT)}\right) = \left(\frac{(TDC*RDA)+(TEC*REA)-[(E*RDA*DA)+(E*REA*EA)]}{RBR}\right)\left(\frac{1}{(1-CAT)}\right)$

Where

RTAC = the amount of the projected total transmission- and ancillary service-related costs allocated to CEI's Residential Customers.

RE = the residential net reconciliation adjustment, including applicable interest, as of the end of the twelve-month period ending March 31 of each year that immediately precedes the Computation Period.

TDC = CEI's projected total transmission- and ancillary service-related demand costs in the upcoming 12 months during which the Rider charge will be in effect (see Exhibit B-5), divided by the projected kWh's for the 12-month period ending June 30, 2008 (see Exhibit B-7).

= $\frac{\$\ 70,287,522}{5,248,180,862}$ = $0.013393 per kWh

TEC = CEI's projected total transmission- and ancillary service-related energy costs in the upcoming 12 months during which the Rider charge will be in effect (see Exhibit B-5), divided by the projected kWh's for the 12-month period ending June 30, 2008 (see Exhibit B-7).

$\frac{\$\ 51,738,885}{5,248,180,862}$ = $0.009858 per kWh

E = CEI's total net reconciliation adjustment for the 12-month period ending March 31, 2007, including projected interest to be earned over the upcoming months during which the Rider charge will be in effect (see Exhibit B-10), divided by the projected kWh's for the 12-month period ending June 30, 2008 (see Exhibit B-7).

= $\frac{\$\ (3,352,056)}{5,248,180,862}$ = -$0.000639 per kWh

RDA = the percentage of CEI's TDC that is attributed to CEI's Residential Customers, adjusted for voltage level (see Exhibit B-8).

= 34.31%

REA = the percentage of CEI's TEC that is attributed to CEI's Residential Customers (see Exhibit B-7).

= 30.18%

DA = Percent of CEI's historical costs allocated on Demand (See Exhibit B-6).

= 67.26%

EA = Percent of CEI's historical costs allocated on Energy (See Exhibit B-6).

= 32.74%

RBR = the aggregate transmission and ancillary service base revenue of the CEI Residential Schedules collected through the 12-month period ending December 31, 2004 (see Exhibit B-12), divided by the 2004 class energy sales (see Exhibit B-7).

= $\frac{\$\ 5,240,185}{1,615,104,573}$ = $0.003244 per kWh

CAT = the Ohio Commercial Activity Tax rate in the upcoming 12 months during which the Rider charge will be in effect.

= 0.169%

So, RTASPC = $\left(\frac{(\$0.013393*0.3431)+(\$0.009858*0.3018)-[(-\$0.000639*0.3431*0.6726)+(-\$0.000639*0.3018*0.3274)]}{\$0.003244}\right)\left(\frac{1}{(1-0.00169)}\right)$

= 240.22% percent

The components used to calculate the CEI Rider Charges, along with their locations in Exhibit B, are summarized in the following table:

Component	Exhibit
TDC	B-5, B-7
TEC	B-5, B-7
RDA	B-8
REA	B-7
DA	B-6
EA	B-6
RBR	B-12, B-7
E	B-10, B-7

Exhibit B-2 provides the method used to determine the Cleveland Electric Illuminating Company Transmission and Ancillary Service Rider charges. The CEI Rider charges will be effective July 1, 2007.

CEI Commercial Rider

Let CTASPC = Commercial Transmission and Ancillary Service Percentage.

Then CTASPC = $\left(\frac{CTAC-CE}{CBR}\right)\left(\frac{1}{(1-CAT)}\right) = \left(\frac{(TDC*CDA)+(TEC*CEA)-[(E*CDA*DA)+(E*CEA*EA)]}{CBR}\right)\left(\frac{1}{(1-CAT)}\right)$

Where

CTAC = the amount of the projected total transmission- and ancillary service-related costs allocated to CEI's Commercial Customers.

CE = the commercial net reconciliation adjustment, including applicable interest, as of the end of the twelve-month period ending March 31 of each year that immediately precedes the Computation Period.

TDC = CEI's projected total transmission- and ancillary service-related demand costs in the upcoming 12 months during which the Rider charge will be in effect (see Exhibit B-5), divided by the projected kWh's for the 12-month period ending June 30, 2008 (see Exhibit B-7).
= $\frac{\$\ 70,287,522}{4,307,048,348}$ = $0.016319 per kWh

TEC = CEI's projected total transmission- and ancillary service-related energy costs in the upcoming 12 months during which the Rider charge will be in effect (see Exhibit B-5), divided by the projected kWh's for the 12-month period ending June 30, 2008 (see Exhibit B-7).
$\frac{\$\ 51,738,885}{4,307,048,348}$ = $0.012013 per kWh

E = CEI's total net reconciliation adjustment for the 12-month period ending March 31, 2007, including projected interest to be earned over the upcoming months during which the Rider charge will be in effect (see Exhibit B-10), divided by the projected kWh's for the 12-month period ending June 30, 2008 (see Exhibit B-7).
= $\frac{\$\ (3,352,056)}{4,307,048,348}$ = -$0.000778 per kWh

CDA = the percentage of CEI's TDC that is attributed to CEI's Commercial Customers, adjusted for voltage level (see Exhibit B-8).
= 28.11%

CEA = the percentage of CEI's TEC that is attributed to CEI's Commercial Customers (see Exhibit B-7).
= 24.69%

DA = Percent of CEI's historical costs allocated on Demand (See Exhibit B-6).
= 67.26%

EA = Percent of CEI's historical costs allocated on Energy (See Exhibit B-6).
= 32.74%

CBR = the aggregate transmission and ancillary service base revenue of the CEI Commercial Schedules collected through the 12-month period ending December 31, 2004 (see Exhibit B-12), divided by the 2004 class energy sales (see Exhibit B-7).
= $\frac{\$\ 6,694,921}{1,954,356,359}$ = $0.003426 per kWh

CAT = the Ohio Commercial Activity Tax rate in the upcoming 12 months during which the Rider charge will be in effect.
= 0.169%

So, CTASPC = $\left(\frac{(\$0.016319*0.2811)+(\$0.012013*0.2469)-[(-\$0.000778*0.2811*0.6726)+(-\$0.000778*0.2469*0.3274)]}{\$0.003426}\right)\left(\frac{1}{(1-0.00169)}\right)$

= 227.00% percent

The components used to calculate the CEI Rider Charges, along with their locations in Exhibit B, are summarized in the following table:

Component	Exhibit
TDC	B-5, B-7
TEC	B-5, B-7
CDA	B-8
CEA	B-7
DA	B-6
EA	B-6
CBR	B-12, B-7
E	B-10, B-7

Exhibit B-2 provides the method used to determine the Cleveland Electric Illuminating Company Transmission and Ancillary Service Rider charges. The CEI Rider charges will be effective July 1, 2007.

CEI Industrial Rider

Let ITASPC = Industrial Transmission and Ancillary Service Percentage.

Then ITASPC = $\left(\frac{ITAC-IE}{IBR}\right)\left(\frac{1}{(1-CAT)}\right) = \left(\frac{(TDC*IDA)+(TEC*IEA)-[(E*IDA*DA)+(E*IEA*EA)]}{IBR}\right)\left(\frac{1}{(1-CAT)}\right)$

Where

ITAC = the amount of the projected total transmission- and ancillary service-related costs allocated to CEI's Industrial Customers.

IE = the industrial net reconciliation adjustment, including applicable interest, as of the end of the twelve-month period ending March 31 of each year that immediately precedes the Computation Period.

TDC = CEI's projected total transmission- and ancillary service-related demand costs in the upcoming 12 months during which the Rider charge will be in effect (see Exhibit B-5), divided by the projected kWh's for the 12-month period ending June 30, 2008 (see Exhibit B-7).

= $\frac{\$\ 70{,}287{,}522}{8{,}135{,}497{,}113}$ = \$0.008640 per kWh

TEC = CEI's projected total transmission- and ancillary service-related energy costs in the upcoming 12 months during which the Rider charge will be in effect (see Exhibit B-5), divided by the projected kWh's for the 12-month period ending June 30, 2008 (see Exhibit B-7).

$\frac{\$\ 51{,}738{,}885}{8{,}135{,}497{,}113}$ = \$0.006360 per kWh

E = CEI's total net reconciliation adjustment for the 12-month period ending March 31, 2007, including projected interest to be earned over the upcoming months during which the Rider charge will be in effect (see Exhibit B-10), divided by the projected kWh's for the 12-month period ending June 30, 2008 (see Exhibit B-7).

= $\frac{\$\ (3{,}352{,}056)}{8{,}135{,}497{,}113}$ = -\$0.000412 per kWh

IDA = the percentage of CEI's TDC that is attributed to CEI's Industrial Customers, adjusted for voltage level (see Exhibit B-8).

= 37.58%

IEA = the percentage of CEI's TEC that is attributed to CEI's Industrial Customers (see Exhibit B-7).

= 45.13%

DA = Percent of CEI's historical costs allocated on Demand (See Exhibit B-6).

= 67.26%

EA = Percent of CEI's historical costs allocated on Energy (See Exhibit B-6).

= 32.74%

IBR = the aggregate transmission and ancillary service base revenue of the CEI Industrial Schedules collected through the 12-month period ending December 31, 2004 (see Exhibit B-12), divided by the 2004 class energy sales (see Exhibit B-7).

= $\frac{\$\ 18{,}586{,}185}{7{,}409{,}504{,}496}$ = \$0.002508 per kWh

CAT = the Ohio Commercial Activity Tax rate in the upcoming 12 months during which the Rider charge will be in effect.

= 0.169%

So, ITASPC = $\left(\frac{(\$0.008640*0.3758)+(\$0.006360*0.4513)-[(-\$0.000412*0.3758*0.6726)+(-\$0.000412*0.4513*0.3274)]}{\$0.002508}\right)\left(\frac{1}{(1-0.00169)}\right)$

= 250.87% percent

The components used to calculate the CEI Rider Charges, along with their locations in Exhibit B, are summarized in the following table:

Component	Exhibit
TDC	B-5, B-7
TEC	B-5, B-7
IDA	B-8
IEA	B-7
DA	B-6
EA	B-6
IBR	B-12, B-7
E	B-10, B-7

Exhibit B-3 provides the method used to determine the Toledo Edison Company Transmission and Ancillary Service Rider charges. The Toledo Edison Rider charges will be effective July 1, 2007.

Toledo Edison Residential Rider

Let RTASPC = Residential Transmission and Ancillary Service Percentage.

Then $RTASPC = \left(\frac{RTAC-RE}{RBR}\right)\left(\frac{1}{(1-CAT)}\right) = \left(\frac{(TDC*RDA)+(TEC*REA)-[(E*RDA*DA)+(E*REA*EA)]}{RBR}\right)\left(\frac{1}{(1-CAT)}\right)$

Where

RTAC = the amount of the projected total transmission- and ancillary service-related costs allocated to TE's Residential Customers.

RE = the residential net reconciliation adjustment, including applicable interest, as of the end of the twelve-month period ending March 31 of each year that immediately precedes the Computation Period.

TDC = TE's projected total transmission- and ancillary service-related demand costs in the upcoming 12 months during which the Rider charge will be in effect (see Exhibit B-5), divided by the projected kWh's for the 12-month period ending June 30, 2008 (see Exhibit B-7).

$= \frac{\$\ 40{,}073{,}057}{2{,}260{,}660{,}692} = \$0.017726$ per kWh

TEC = TE's projected total transmission- and ancillary service-related energy costs in the upcoming 12 months during which the Rider charge will be in effect (see Exhibit B-5), divided by the projected kWh's for the 12-month period ending June 30, 2008 (see Exhibit B-7).

$\frac{\$\ 24{,}664{,}801}{2{,}260{,}660{,}692} = \$0.010910$ per kWh

E = TE's total net reconciliation adjustment for the 12-month period ending March 31, 2007, including projected interest to be earned over the upcoming months during which the Rider charge will be in effect (see Exhibit B-11), divided by the projected kWh's for the 12-month period ending June 30, 2008 (see Exhibit B-7).

$= \frac{\$\ (7{,}330{,}719)}{2{,}260{,}660{,}692} = -\$0.003243$ per kWh

RDA = the percentage of TE's TDC that is attributed to TE's Residential Customers, adjusted for voltage level (see Exhibit B-8).
= 34.05%

REA = the percentage of TE's TEC that is attributed to TE's Residential Customers (see Exhibit B-7).
= 24.96%

DA = Percent of TE's historical costs allocated on Demand (See Exhibit B-6).
= 70.07%

EA = Percent of TE's historical costs allocated on Energy (See Exhibit B-6).
= 29.93%

RBR = the aggregate transmission and ancillary service base revenue of the TE Residential Schedules collected through the 12-month period ending December 31, 2004 (see Exhibit B-12), divided by the 2004 class energy sales (see Exhibit B-7).

$= \frac{\$\ 6{,}212{,}488}{1{,}363{,}947{,}461} = \$0.00455$ per kWh

CAT = the Ohio Commercial Activity Tax rate in the upcoming 12 months during which the Rider charge will be in effect.
= 0.169%

So, $RTASPC = \left(\frac{(\$0.017726 * 0.3405)+(\$0.010910 * 0.2496)-[(-\$0.003243 * 0.3405 * 0.7007)+(-\$0.003243 * 0.2496 * 0.2993)]}{\$0.004550}\right)\left(\frac{1}{(1-0.00169)}\right)$

= 214.98% percent

The components used to calculate the TE Rider Charges, along with their locations in Exhibit B, are summarized in the following table:

Component	Exhibit
TDC	B-5, B-7
TEC	B-5, B-7
RDA	B-8
REA	B-7
DA	B-6
EA	B-6
RBR	B-12, B-7
E	B-11, B-7

Exhibit B-3 provides the method used to determine the Toledo Edison Company Transmission and Ancillary Service Rider charges. The Toledo Edison Rider charges will be effective July 1, 2007.

Toledo Edison Commercial Rider

Let CTASPC = Commercial Transmission and Ancillary Service Percentage.

Then $CTASPC = \left[\left(\frac{CTAC-CE}{CBR}\right)\left(\frac{1}{(1-CAT)}\right)\right] = \left[\left(\frac{(TDC*CDA)+(TEC*CEA)-[(E*CDA*DA)+(E*CEA*EA)]}{CBR}\right)\left(\frac{1}{(1-CAT)}\right)\right]$

Where

CTAC = the amount of the projected total transmission- and ancillary service-related costs allocated to TE's Commercial Customers.

CE = the commercial net reconciliation adjustment, including applicable interest, as of the end of the twelve-month period ending March 31 of each year that immediately precedes the Computation Period.

TDC = TE's projected total transmission- and ancillary service-related demand costs in the upcoming 12 months during which the Rider charge will be in effect (see Exhibit B-5), divided by the projected kWh's for the 12-month period ending June 30, 2008 (see Exhibit B-7).

= $\frac{\$ \ 40{,}073{,}057}{2{,}007{,}395{,}213}$ = $0.019963 per kWh

TEC = TE's projected total transmission- and ancillary service-related energy costs in the upcoming 12 months during which the Rider charge will be in effect (see Exhibit B-5), divided by the projected kWh's for the 12-month period ending June 30, 2008 (see Exhibit B-7).

$\frac{\$ \ 24{,}664{,}801}{2{,}007{,}395{,}213}$ = $0.012287 per kWh

E = TE's total net reconciliation adjustment for the 12-month period ending March 31, 2007, including projected interest to be earned over the upcoming months during which the Rider charge will be in effect (see Exhibit B-11), divided by the projected kWh's for the 12-month period ending June 30, 2008 (see Exhibit B-7).

= $\frac{\$ \ (7{,}330{,}719)}{2{,}007{,}395{,}213}$ = -$0.003652 per kWh

CDA = the percentage of TE's TDC that is attributed to TE's Commercial Customers, adjusted for voltage level (see Exhibit B-8).
= 28.70%

CEA = the percentage of TE's TEC that is attributed to TE's Commercial Customers (see Exhibit B-7).
= 21.87%

DA = Percent of TE's historical costs allocated on Demand (See Exhibit B-6).
= 70.07%

EA = Percent of TE's historical costs allocated on Energy (See Exhibit B-6).
= 29.93%

CBR = the aggregate *transmission and ancillary service base revenue of the* TE Commercial Schedules collected through the 12-month period ending December 31, 2004 (see Exhibit B-12), divided by the 2004 class energy sales (see Exhibit B-7).

= $\frac{\$ \ 5{,}773{,}047}{1{,}321{,}741{,}986}$ = $0.004368 per kWh

CAT = the Ohio Commercial Activity Tax rate in the upcoming 12 months during which the Rider charge will be in effect.
= 0.169%

So, $CTASPC = \left[\left(\frac{(\$0.019963 * 0.2870)+(\$0.012287 * 0.2187)-[(-\$0.003652 * 0.2870 * 0.7007)+(-\$0.003652 * 0.2187 * 0.2993)]}{\$0.004368}\right)\left(\frac{1}{(1-0.00169)}\right)\right]$

= 215.37% percent

The components used to calculate the TE Rider Charges, along with their locations in Exhibit B, are summarized in the following table:

Component	Exhibit
TDC	B-5, B-7
TEC	B-5, B-7
CDA	B-8
CEA	B-7
DA	B-6
EA	B-6
CBR	B-12, B-7
E	B-11, B-7

Exhibit B-3 provides the method used to determine the Toledo Edison Company Transmission and Ancillary Service Rider charges. The Toledo Edison Rider charges will be effective July 1, 2007.

Toledo Edison Industrial Rider

Let ITASPC = Industrial Transmission and Ancillary Service Percentage.

Then ITASPC = $\left(\frac{ITAC - IE}{IBR}\right)\left(\frac{1}{(1-CAT)}\right) = \left(\frac{(TDC * IDA) + (TEC * IEA) - [(E * IDA * DA) + (E * IEA * EA)]}{IBR}\right)\left(\frac{1}{(1-CAT)}\right)$

Where

ITAC = the amount of the projected total transmission- and ancillary service-related costs allocated to TE's Industrial Customers.

IE = the industrial net reconciliation adjustment, including applicable interest, as of the end of the twelve-month period ending March 31 of each year that immediately precedes the Computation Period.

TDC = TE's projected total transmission- and ancillary service-related demand costs in the upcoming 12 months during which the Rider charge will be in effect (see Exhibit B-5), divided by the projected kWh's for the 12-month period ending June 30, 2008 (see Exhibit B-7).
= $\frac{\$\ 40{,}073{,}057}{5{,}127{,}757{,}043}$ = \$0.007815 per kWh

TEC = TE's projected total transmission- and ancillary service-related energy costs in the upcoming 12 months during which the Rider charge will be in effect (see Exhibit B-5), divided by the projected kWh's for the 12-month period ending June 30, 2008 (see Exhibit B-7).
$\frac{\$\ 24{,}664{,}801}{5{,}127{,}757{,}043}$ = \$0.004810 per kWh

E = TE's total net reconciliation adjustment for the 12-month period ending March 31, 2007, including projected interest to be earned over the upcoming months during which the Rider charge will be in effect (see Exhibit B-11), divided by the projected kWh's for the 12-month period ending June 30, 2008 (see Exhibit B-7).
= $\frac{\$\ (7{,}330{,}719)}{5{,}127{,}757{,}043}$ = -\$0.001430 per kWh

IDA = the percentage of TE's TDC that is attributed to TE's Industrial Customers, adjusted for voltage level (see Exhibit B-8).
= 37.24%

IEA = the percentage of TE's TEC that is attributed to TE's Industrial Customers (see Exhibit B-7).
= 53.17%

DA = Percent of TE's historical costs allocated on Demand (See Exhibit B-6).
= 70.07%

EA = Percent of TE's historical costs allocated on Energy (See Exhibit B-6).
= 29.93%

IBR = the aggregate transmission and ancillary service base revenue of the TE Industrial Schedules collected through the 12-month period ending December 31, 2004 (see Exhibit B-12), divided by the 2004 class energy sales (see Exhibit B-7).
= $\frac{\$\ 19{,}585{,}606}{5{,}042{,}837{,}574}$ = \$0.003884 per kWh

CAT = the Ohio Commercial Activity Tax rate in the upcoming 12 months during which the Rider charge will be in effect.
= 0.169%

So, ITASPC = $\left(\frac{(\$0.007815 * 0.3724) + (\$0.004810 * 0.5317) - [(-\$0.001430 * 0.3724 * 0.7007) + (-\$0.001430 * 0.5317 * 0.2993)]}{\$0.003884}\right)\left(\frac{1}{(1-0.00169)}\right)$

= 156.52% percent

The components used to calculate the TE Rider Charges, along with their locations in Exhibit B, are summarized in the following table:

Component	Exhibit
TDC	B-5, B-7
TEC	B-5, B-7
IDA	B-8
IEA	B-7
DA	B-6
EA	B-6
IBR	B-12, B-7
E	B-11, B-7

Exhibit B-4 sets forth the costs to be recovered through the Transmission and Ancillary Service Riders, along with a brief description of the nature of such costs. It further describes the frequency with which each of these costs is incurred, as well as whether *each cost is classified as demand or energy-based.*

Cost	Description	Frequency	Type
Schedule 1	Scheduling, System Control and Dispatch Service	Monthly	Demand
Schedule 2	Reactive Supply and Voltage Control from Generation Sources Service	Monthly	Demand
Schedule 3	Regulation and Frequency Response Service	Monthly	Demand
Schedule 4	Energy Imbalance Service (Suspended)	Monthly	-
Schedule 5	Operating Reserve – Spinning Reserve Service	Monthly	Demand
Schedule 6	Operating Reserve – Supplemental Reserve Service	Monthly	Demand
Schedule 7	Firm Point-to-Point Transmission Service	Monthly	Demand
Schedule 8	Non – Firm Point-to-Point Transmission Service	Monthly	Demand
Schedule 9	Network Integration Transmission Service	Monthly	Demand
Schedule 10	ISO Cost Recovery Adder	Monthly	Demand
Schedule 11	Wholesale Distribution Service	Monthly	[1] Demand
Schedule 12	Gross Receipts Tax Adder	Monthly	Demand
Schedule 13	Reserved Capacity Multipliers (within Michigan)	Monthly	[2] N/A
Schedule 14	Regional Through and Out Rate	Monthly	Demand
Schedule 15	Power factor Correction Service	Monthly	Demand
Schedule 16	Financial Transmission Rights Admin. Service Cost Recovery Adder	Monthly	Energy
Schedule 17	Energy Market Support Admin. Service Cost Recovery Adder	Monthly	Energy
Schedule 18	Sub-Regional rate Adjustment	Monthly	Demand
Schedule 19	Zonal Transition Adjustment	Monthly	Demand
Schedule 20	Treatment of Station Power	Monthly	Demand
Schedule 22	SECA Charges to Midwest ISO Zones, Sub-Zones, and Customers	Monthly	Demand
Schedule 24	Balancing Authority Costs incurred as a result of implementing the Markets and Services	Monthly	Demand
Schedule 26	Network Upgrade Charges for Reserved Capacity	Monthly	Demand
FERC Schedule 10	FERC Annual Charges Recovery	Annual	Energy
Congestion Expense	Bilateral Transactions Congestion Charge / Credit	Weekly	Energy
FTR Credit	Charge / Credit from Financial Transmission Rights	Weekly	Energy
Gross Losses	Bilateral Transactions Marginal Losses Charge	Weekly	Energy
Loss Credit	Credit of Difference between Marginal and Physical Losses	Weekly	Energy
Revenue Neutrality Uplift	Charge / Credit to Maintain Midwest ISO Market Revenue Neutrality	Weekly	Energy
Revenue Sufficiency Guarantee	Charge Associated with the Reliability Assessments Commitment process to ensure adequate resources	Weekly	Energy
Deferred Costs	Amortization of Deferred Costs	Monthly	Mixed
Other	FERC-approved Schedules that MISO may develop in the future	Unknown	-

Each of these costs will be determined by company books, supported by MISO invoices.

[1] Wholesale distribution services are mostly based on demand, but also include adjustments that may be energy-based. This schedule includes charges associated with adjustments to other schedules.

[2] These costs are no longer assessed.

Exhibit B-5 provides the projected transmission- and ancillary service-related costs to be charged to the Ohio Operating Companies during the 12 months in which the Rider charges will be in effect. Pages 1 and 2 lay out costs based upon current MISO billing practices under which MISO bills the Ohio Operating Companies on a combined basis, while pages 3 through 8 show costs from each company's books. Page 9 summarizes the monthly demand and energy-related cost information by company, and page 10 shows how the amortization of the deferral is split between demand and energy for each company based on demand and energy charges during the deferral period.

OHIO COMPANIES' TRANSMISSION- AND ANCILLARY SERVICE-RELATED COSTS

Schedule	[1] Month in which Bill will be Received (Demand-Based)						[2] Total
	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	
1	$ 556,736	$ 564,144	$ 471,149	$ 387,448	$ 399,990	$ 454,787	$ 2,834,254
2	$ 1,218,233	$ 1,234,444	$ 1,030,953	$ 847,803	$ 875,245	$ 995,152	$ 6,201,830
3	$ 666,030	$ 674,893	$ 563,672	$ 463,509	$ 478,539	$ 544,068	$ 3,390,710
4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	$ 999,145	$ 1,012,441	$ 845,552	$ 695,334	$ 717,846	$ 816,184	$ 5,086,501
6	$ 536,345	$ 551,945	$ 453,587	$ 365,545	$ 381,515	$ 435,644	$ 2,724,581
7 (69 kv)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7 (138 kv)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8 (69 kv)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8 (138 kv)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9 (69 kv)	$ 3,463,115	$ 3,533,573	$ 2,945,783	$ 2,448,570	$ 2,538,005	$ 2,897,683	$ 17,826,728
9 (138 kv)	$ 12,705,336	$ 12,874,404	$ 10,752,140	$ 8,842,006	$ 9,128,208	$ 10,378,758	$ 64,680,853
10	$ 997,945	$ 1,011,225	$ 844,531	$ 694,498	$ 716,978	$ 815,203	$ 5,080,380
11	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	$ 125,666	$ 124,458	$ 107,062	$ 110,432	$ 108,956	$ 118,091	$ 694,665
26	$ 14,735	$ 14,931	$ 12,865	$ 10,254	$ 10,939	$ 12,037	$ 75,761
[4] Amortization	$ 1,026,172	$ 1,031,674	$ 1,037,207	$ 1,042,772	$ 1,048,368	$ 1,053,997	$ 6,240,190
Total	$ 22,309,458	$ 22,628,131	$ 19,064,522	$ 15,908,171	$ 16,404,588	$ 18,521,604	$ 114,836,474

Schedule	[1] Month in which Bill will be Received (Energy-Based)						[2] Total
	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	
16	$ 96,575	$ 97,607	$ 104,529	$ 108,277	$ 104,526	$ 80,629	$ 592,143
17	$ 1,731,400	$ 1,714,759	$ 1,475,083	$ 1,521,504	$ 1,501,167	$ 1,627,033	$ 9,570,945
[3] FERC 10	$ 320,661	$ 324,928	$ 271,366	$ 223,157	$ 230,380	$ 261,942	$ 1,632,434
Congestion Expense	$ 808,205	$ 775,843	$ 580,326	$ 88,328	$ 1,434,396	$ 2,673,003	$ 6,360,101
FTR Credit	$ (93,027)	$ 88,108	$ (9,946)	$ (289)	$ (137,075)	$ (288,860)	$ (441,089)
Gross Losses	$ 8,486,554	$ 8,672,147	$ 3,945,734	$ 4,313,814	$ 4,601,280	$ 5,345,957	$ 35,365,486
Loss Credit	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenue Neutrality	$ 2,000,000	$ 2,000,000	$ 2,000,000	$ 2,000,000	$ 2,000,000	$ 2,000,000	$ 12,000,000
Rev. Sufficiency Guarantee	$ 1,200,000	$ 1,200,000	$ 1,200,000	$ 1,200,000	$ 1,200,000	$ 1,200,000	$ 7,200,000
[4] Amortization	$ 637,057	$ 640,500	$ 643,963	$ 647,446	$ 650,948	$ 654,471	$ 3,874,385
Total	$ 15,187,425	$ 15,513,893	$ 10,211,054	$ 10,102,237	$ 11,585,622	$ 13,554,174	$ 76,154,405

[1] Projected monthly transmission- and ancillary service-related costs for the Ohio Operating Companies for the last 6 months of 2007.

[2] Calculation: Sum of 6 monthly values

[3] Currently billed every August.

[5] "Amortization" represents the monthly portion of the deferred transmission- and ancillary service-related costs (and interest) based upon the actual split by company in the 2005 schedules to be amortized and expensed over a five year period, commencing January 1, 2006. Amortization expense will be further split between energy and demand, based upon the costs that were deferred. See page 10 for the allocation between demand and energy. These values represent totals for the three Ohio Operating Companies.

Note: This schedule is based upon current MISO billing practices under which MISO bills the Ohio Operating Companies on a combined basis.

OHIO COMPANIES' TRANSMISSION- AND ANCILLARY SERVICE-RELATED COSTS

Schedule	[1] Month in which Bill will be Received (Demand-Based)						[2] Total	[3] 12 Month Total
	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08		
1	$ 459,126	$ 400,813	$ 420,815	$ 375,087	$ 446,466	$ 570,481	$ 2,672,787	$ 5,507,042
2	$ 1,004,709	$ 877,103	$ 920,873	$ 820,806	$ 977,006	$ 1,181,319	$ 5,781,815	$ 11,983,645
3	$ 549,293	$ 479,533	$ 503,458	$ 448,774	$ 534,147	$ 662,632	$ 3,177,836	$ 6,568,546
4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	$ 824,022	$ 719,380	$ 755,263	$ 673,196	$ 801,301	$ 993,999	$ 4,767,160	$ 9,853,662
6	$ 412,592	$ 360,252	$ 378,164	$ 337,089	$ 401,216	$ 497,724	$ 2,387,037	$ 5,111,618
7 (69 kv)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7 (138 kv)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8 (69 kv)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8 (138 kv)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9 (69 kv)	$ 2,939,543	$ 2,559,082	$ 2,682,982	$ 2,380,869	$ 2,791,492	$ 3,353,230	$ 16,707,199	$ 34,533,927
9 (138 kv)	$ 10,478,433	$ 9,147,582	$ 9,604,073	$ 8,560,443	$ 10,189,503	$ 12,276,122	$ 60,256,155	$ 124,937,008
10	$ 823,032	$ 744,161	$ 754,355	$ 672,383	$ 800,338	$ 992,798	$ 4,787,067	$ 9,867,447
11	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	$ 87,839	$ 81,010	$ 80,200	$ 75,256	$ 77,519	$ 82,540	$ 484,364	$ 1,179,030
26	$ 12,557	$ 10,962	$ 11,509	$ 10,259	$ 12,211	$ 15,147	$ 72,646	$ 148,427
[5] Amortization	$ 1,059,658	$ 1,065,324	$ 1,071,023	$ 1,076,755	$ 1,082,521	$ 1,088,479	$ 6,443,759	$ 12,683,949
Total	$ 18,650,805	$ 16,445,201	$ 17,182,715	$ 15,430,916	$ 18,113,719	$ 21,714,471	$ 107,537,827	$ 222,374,301

Schedule	[1] Month in which Bill will be Received (Energy-Based)						[2] Total	[3] 12 Month Total
	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08		
16	$ 89,558	$ 80,949	$ 125,940	$ 121,915	$ 125,957	$ 101,632	$ 645,950	$ 1,238,093
17	$ 1,983,466	$ 1,829,247	$ 1,810,968	$ 1,699,332	$ 1,750,428	$ 1,863,817	$ 10,937,259	$ 20,508,204
[4] FERC 10	$ 264,458	$ 230,869	$ 242,390	$ 216,051	$ 257,166	$ 319,007	$ 1,529,941	$ 3,162,376
Congestion Expense	$ 538,407	$ (952,161)	$ 4,044,378	$ 3,304,360	$ 1,496,556	$ 161,328	$ 8,592,868	$ 14,952,968
FTR Credit	$ (652,571)	$ 73,593	$ (2,852,901)	$ (3,038,267)	$ (1,267,679)	$ (150,717)	$ (7,888,542)	$ (8,329,631)
Gross Losses	$ 1,732,158	$ 4,871,825	$ 5,205,389	$ 4,889,858	$ 3,794,475	$ 5,252,324	$ 25,746,028	$ 61,111,514
Loss Credit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenue Neutrality	$ 2,000,000	$ 2,000,000	$ 2,000,000	$ 2,000,000	$ 2,000,000	$ 2,000,000	$ 12,000,000	$ 24,000,000
Rev. Sufficiency Guarantee	$ 1,100,000	$ 1,100,000	$ 1,100,000	$ 1,100,000	$ 1,100,000	$ 1,100,000	$ 6,600,000	$ 13,800,000
[5] Amortization	$ 658,014	$ 661,561	$ 665,129	$ 668,718	$ 672,327	$ 676,045	$ 4,001,795	$ 7,876,180
Total	$ 7,713,490	$ 9,895,883	$ 12,341,294	$ 10,961,966	$ 9,929,229	$ 11,323,436	$ 62,165,299	$ 138,319,704

[1] Projected monthly transmission- and ancillary service-related costs for the Ohio Operating Companies for the first 6 months of 2008.

[2] Calculation: Sum of 6 monthly values

[3] Calculation: Sum of 12 monthly values

[4] Currently billed every August.

[5] "Amortization" represents the monthly portion of the deferred transmission- and ancillary service-related costs (and interest) based upon the actual split by company in the 2005 schedules to be amortized and expensed over a five year period, commencing January 1, 2006. Amortization expense will be further split between energy and demand, based upon the costs that were deferred. See page 10 for the allocation between demand and energy. These values represent totals for the three Ohio Operating Companies.

Note: This schedule is based upon current MISO billing practices under which MISO bills the Ohio Operating Companies on a combined basis.

OHIO EDISON'S TRANSMISSION- AND ANCILLARY SERVICE-RELATED COSTS

Schedule	[1] Month in which Bill will be Received (Demand-Based)						[2] Total
	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	
1	$ 251,167	$ 261,229	$ 211,819	$ 169,785	$ 176,667	$ 201,630	$ 1,272,298
2	$ 549,596	$ 571,614	$ 463,496	$ 371,519	$ 386,578	$ 441,201	$ 2,784,003
3	$ 300,474	$ 312,512	$ 253,416	$ 203,116	$ 211,361	$ 241,213	$ 1,522,091
4							$ -
5	$ 450,756	$ 468,815	$ 380,143	$ 304,705	$ 317,058	$ 361,855	$ 2,283,332
6	$ 225,696	$ 234,738	$ 190,349	$ 152,567	$ 158,760	$ 181,183	$ 1,143,293
7 (69 kv)							$ -
7 (138 kv)							$ -
8 (69 kv)							$ -
8 (138 kv)							$ -
9 (69 kv)	$ 2,681,672	$ 2,755,903	$ 2,290,582	$ 1,902,772	$ 1,962,017	$ 2,240,272	$ 13,833,217
9 (138 kv)	$ 5,731,911	$ 5,961,541	$ 4,833,946	$ 3,874,686	$ 4,031,747	$ 4,601,426	$ 29,035,256
10	$ 450,215	$ 468,251	$ 379,684	$ 304,339	$ 316,675	$ 361,421	$ 2,280,584
11							$ -
12							$ -
13							$ -
14							$ -
15							$ -
18							$ -
19							$ -
20							$ -
22							$ -
24	$ 55,921	$ 55,384	$ 47,643	$ 49,142	$ 48,485	$ 52,551	$ 309,126
26	$ 6,647	$ 6,914	$ 5,793	$ 4,494	$ 4,832	$ 5,336	$ 34,016
[4] Amortization	$ 575,152	$ 578,106	$ 581,077	$ 584,064	$ 587,067	$ 590,086	$ 3,495,552
Total	$ 11,279,208	$ 11,675,005	$ 9,637,946	$ 7,921,187	$ 8,201,248	$ 9,278,174	$ 57,992,768

Schedule	[1] Month in which Bill will be Received (Energy-Based)						[2] Total
	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	
16	$ 42,976	$ 43,435	$ 46,515	$ 48,183	$ 46,514	$ 35,880	$ 263,504
17	$ 770,473	$ 763,068	$ 656,412	$ 677,069	$ 668,019	$ 724,029	$ 4,259,070
[3] FERC 10	$ 144,664	$ 150,459	$ 122,001	$ 97,790	$ 101,754	$ 116,132	$ 732,800
Congestion Expense	$ 359,651	$ 345,250	$ 258,245	$ 39,306	$ 638,308	$ 1,189,486	$ 2,830,245
FTR Credit	$ (41,397)	$ 39,208	$ (4,426)	$ (129)	$ (60,998)	$ (128,543)	$ (196,285)
Gross Losses	$ 3,776,517	$ 3,859,105	$ 1,755,851	$ 1,919,647	$ 2,047,570	$ 2,378,951	$ 15,737,641
Loss Credit							$ -
Revenue Neutrality	$ 890,000	$ 890,000	$ 890,000	$ 890,000	$ 890,000	$ 890,000	$ 5,340,000
Rev. Sufficiency Guarantee	$ 534,000	$ 534,000	$ 534,000	$ 534,000	$ 534,000	$ 534,000	$ 3,204,000
[4] Amortization	$ 312,895	$ 314,502	$ 316,118	$ 317,743	$ 319,377	$ 321,019	$ 1,901,654
Total	$ 6,789,778	$ 6,939,028	$ 4,574,716	$ 4,523,611	$ 5,184,542	$ 6,060,955	$ 34,072,630

[1] Projected monthly transmission- and ancillary service-related costs for Ohio Edison for the last 6 months of 2007 reflect projected costs from MISO bills. Demand-based costs reflect a coincident peak allocation basis, whereas energy-based costs are based on each Ohio Operating Company's contribution to the projected total Ohio kWh consumption.

[2] Calculation: Sum of 6 monthly values

[3] Currently billed every August.

[4] "Amortization" represents the monthly portion of the deferred transmission- and ancillary service-related costs (and interest) based upon the actual split by company in the 2005 schedules to be amortized and expensed over a five year period, commencing January 1, 2006. Amortization expense will be further split between energy and demand, based upon the costs that were deferred. See page 10 for the allocation between demand and energy.

OHIO EDISON'S TRANSMISSION- AND ANCILLARY SERVICE-RELATED COSTS

Schedule	[1] Month in which Bill will be Received (Demand-Based)						[2] Total	[3] 12 Month Total
	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08		
1	$ 205,211	$ 176,414	$ 185,862	$ 161,730	$ 197,195	$ 262,205	$ 1,188,616	$ 2,460,913
2	$ 449,065	$ 386,048	$ 406,723	$ 353,915	$ 431,523	$ 542,959	$ 2,570,232	$ 5,354,235
3	$ 245,512	$ 211,061	$ 222,363	$ 193,502	$ 235,921	$ 304,560	$ 1,412,919	$ 2,935,010
4							$ -	$ -
5	$ 368,305	$ 316,627	$ 333,578	$ 290,268	$ 353,918	$ 456,863	$ 2,119,559	$ 4,402,891
6	$ 184,412	$ 158,561	$ 167,024	$ 145,346	$ 177,209	$ 228,765	$ 1,061,316	$ 2,204,610
7 (69 kv)							$ -	$ -
7 (138 kv)							$ -	$ -
8 (69 kv)							$ -	$ -
8 (138 kv)							$ -	$ -
9 (69 kv)	$ 2,267,394	$ 1,973,571	$ 2,071,132	$ 1,833,020	$ 2,155,723	$ 2,600,863	$ 12,901,704	$ 26,734,921
9 (138 kv)	$ 4,683,437	$ 4,026,212	$ 4,241,841	$ 3,691,088	$ 4,500,490	$ 5,642,368	$ 26,785,435	$ 55,820,692
10	$ 367,862	$ 327,535	$ 333,177	$ 289,918	$ 353,493	$ 456,311	$ 2,128,295	$ 4,408,880
11							$ -	$ -
12							$ -	$ -
13							$ -	$ -
14							$ -	$ -
15							$ -	$ -
18							$ -	$ -
19							$ -	$ -
20							$ -	$ -
22							$ -	$ -
24	$ 39,088	$ 36,049	$ 35,689	$ 33,489	$ 34,496	$ 36,731	$ 215,542	$ 524,668
26	$ 5,613	$ 4,825	$ 5,083	$ 4,423	$ 5,393	$ 6,962	$ 32,300	$ 66,316
[5] Amortization	$ 593,123	$ 596,176	$ 599,246	$ 602,333	$ 605,438	$ 608,719	$ 3,605,034	$ 7,100,586
Total	$ 9,409,021	$ 8,213,079	$ 8,601,718	$ 7,599,032	$ 9,050,798	$ 11,147,305	$ 54,020,953	$ 112,013,721

Schedule	[1] Month in which Bill will be Received (Energy-Based)						[2] Total	[3] 12 Month Total
	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08		
16	$ 39,853	$ 36,022	$ 56,043	$ 54,252	$ 56,051	$ 45,226	$ 287,448	$ 550,952
17	$ 882,642	$ 814,015	$ 805,881	$ 756,203	$ 778,940	$ 829,399	$ 4,867,080	$ 9,126,151
[4] FERC 10	$ 118,202	$ 101,615	$ 107,057	$ 93,157	$ 113,585	$ 146,623	$ 680,238	$ 1,413,038
Congestion Expense	$ 239,591	$ (423,712)	$ 1,799,748	$ 1,470,440	$ 665,967	$ 71,791	$ 3,823,826	$ 6,654,071
FTR Credit	$ (290,394)	$ 32,749	$ (1,269,541)	$ (1,352,029)	$ (564,117)	$ (67,069)	$ (3,510,401)	$ (3,706,686)
Gross Losses	$ 770,810	$ 2,167,962	$ 2,316,398	$ 2,175,987	$ 1,688,541	$ 2,337,284	$ 11,456,983	$ 27,194,624
Loss Credit							$ -	$ -
Revenue Neutrality	$ 890,000	$ 890,000	$ 890,000	$ 890,000	$ 890,000	$ 890,000	$ 5,340,000	$ 10,680,000
Rev. Sufficiency Guarantee	$ 489,500	$ 489,500	$ 489,500	$ 489,500	$ 489,500	$ 489,500	$ 2,937,000	$ 6,141,000
[5] Amortization	$ 322,671	$ 324,332	$ 326,002	$ 327,682	$ 329,371	$ 331,156	$ 1,961,215	$ 3,862,869
Total	$ 3,462,876	$ 4,432,483	$ 5,521,089	$ 4,905,192	$ 4,447,838	$ 5,073,909	$ 27,843,388	$ 61,916,017

[1] Projected monthly transmission- and ancillary service-related costs for OE for the first 6 months of 2008 reflect projected costs from MISO bills.
Demand-based costs reflect a coincident peak allocation basis, whereas energy-based costs are based on each Ohio Operating Company's contribution to the projected total Ohio kWh consumption.

[2] Calculation: Sum of 6 monthly values

[3] Calculation: Sum of 12 monthly values

[4] Currently billed every August.

[5] "Amortization" represents the monthly portion of the deferred transmission- and ancillary service-related costs (and interest) based upon the actual split by company in the 2005 schedules to be amortized and expensed over a five year period, commencing January 1, 2006. Amortization expense will be further split between energy and demand, based upon the costs that were deferred. See page 10 for the allocation between demand and energy.

CLEVELAND ELECTRIC ILLUMINATING'S TRANSMISSION- AND ANCILLARY SERVICE-RELATED COSTS

Schedule	[1] Month in which Bill will be Received (Demand-Based)						[2] Total
	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	
1	$ 211,029	$ 211,139	$ 178,219	$ 150,435	$ 152,109	$ 171,610	$ 1,074,541
2	$ 461,767	$ 462,009	$ 389,973	$ 329,177	$ 332,841	$ 375,511	$ 2,351,279
3	$ 252,456	$ 252,589	$ 213,217	$ 179,967	$ 181,980	$ 205,299	$ 1,285,508
4							$ -
5	$ 378,723	$ 378,921	$ 319,843	$ 269,978	$ 272,985	$ 307,979	$ 1,928,428
6	$ 225,696	$ 234,738	$ 190,349	$ 152,567	$ 158,760	$ 181,183	$ 1,143,293
7 (69 kv)							$ -
7 (138 kv)							$ -
8 (69 kv)							$ -
8 (138 kv)							$ -
9 (69 kv)							$ -
9 (138 kv)	$ 4,815,915	$ 4,818,439	$ 4,067,156	$ 3,433,090	$ 3,471,308	$ 3,916,322	$ 24,522,231
10	$ 378,268	$ 378,466	$ 319,456	$ 269,653	$ 272,655	$ 307,609	$ 1,926,107
11							$ -
12							$ -
13							$ -
14							$ -
15							$ -
18							$ -
19							$ -
20							$ -
22							$ -
24	$ 46,999	$ 46,547	$ 40,041	$ 41,301	$ 40,749	$ 44,166	$ 259,805
26	$ 5,585	$ 5,588	$ 4,874	$ 3,981	$ 4,160	$ 4,542	$ 28,731
[4] Amortization	$ 308,349	$ 310,121	$ 311,902	$ 313,695	$ 315,499	$ 317,314	$ 1,876,880
Total	$ 7,084,788	$ 7,098,557	$ 6,035,032	$ 5,143,845	$ 5,203,047	$ 5,831,533	$ 36,396,803

Schedule	[1] Month in which Bill will be Received (Energy-Based)						[2] Total
	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	
16	$ 36,119	$ 36,505	$ 39,094	$ 40,496	$ 39,093	$ 30,155	$ 221,462
17	$ 647,543	$ 641,320	$ 551,681	$ 569,042	$ 561,436	$ 608,510	$ 3,579,533
[3] FERC 10	$ 121,545	$ 121,609	$ 102,648	$ 86,645	$ 87,610	$ 98,841	$ 618,899
Congestion Expense	$ 302,269	$ 290,165	$ 217,042	$ 33,035	$ 536,464	$ 999,703	$ 2,378,678
FTR Credit	$ (34,792)	$ 32,952	$ (3,720)	$ (108)	$ (51,266)	$ (108,034)	$ (164,967)
Gross Losses	$ 3,173,971	$ 3,243,383	$ 1,475,704	$ 1,613,366	$ 1,720,879	$ 1,999,388	$ 13,226,692
Loss Credit							$ -
Revenue Neutrality	$ 748,000	$ 748,000	$ 748,000	$ 748,000	$ 748,000	$ 748,000	$ 4,488,000
Rev. Sufficiency Guarantee	$ 448,800	$ 448,800	$ 448,800	$ 448,800	$ 448,800	$ 448,800	$ 2,692,800
[4] Amortization	$ 237,153	$ 238,515	$ 239,886	$ 241,265	$ 242,652	$ 244,047	$ 1,443,518
Total	$ 5,680,609	$ 5,801,250	$ 3,819,135	$ 3,780,541	$ 4,333,667	$ 5,069,411	$ 28,484,614

[1] Projected monthly transmission- and ancillary service-related costs for CEI for the last 6 months of 2007 reflect projected costs from MISO bills.
Demand-based costs reflect a coincident peak allocation basis, whereas energy-based costs are based on each Ohio Operating Company's contribution to the projected total Ohio kWh consumption.

[2] Calculation: Sum of 6 monthly values

[3] Currently billed every August.

[4] "Amortization" represents the monthly portion of the deferred transmission- and ancillary service-related costs (and interest) based upon the *actual split by company* in the 2005 schedules to be amortized and expensed over a five year period, commencing January 1, 2006. Amortization expense will be further split between energy and demand, based upon the costs that were deferred. See page 10 for the allocation between demand and energy.

CLEVELAND ELECTRIC ILLUMINATING'S TRANSMISSION- AND ANCILLARY SERVICE-RELATED COSTS

Schedule	[1] Month in which Bill will be Received (Demand-Based)						[2] Total	[3] 12 Month Total
	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08		
1	$ 171,709	$ 151,897	$ 159,271	$ 144,075	$ 170,769	$ 214,151	$ 1,011,871	$ 2,086,412
2	$ 375,753	$ 332,396	$ 348,533	$ 315,280	$ 373,696	$ 443,451	$ 2,189,110	$ 4,540,388
3	$ 205,431	$ 181,729	$ 190,549	$ 172,379	$ 204,306	$ 248,743	$ 1,203,138	$ 2,488,646
4							$ -	$ -
5	$ 308,177	$ 272,624	$ 285,853	$ 258,582	$ 306,491	$ 373,134	$ 1,804,860	$ 3,733,288
6	$ 154,306	$ 136,525	$ 143,128	$ 129,479	$ 153,462	$ 186,839	$ 903,739	$ 2,047,032
7 (69 kv)							$ -	$ -
7 (138 kv)							$ -	$ -
8 (69 kv)							$ -	$ -
8 (138 kv)							$ -	$ -
9 (69 kv)							$ -	$ -
9 (138 kv)	$ 3,918,845	$ 3,466,668	$ 3,634,963	$ 3,288,157	$ 3,897,397	$ 4,608,289	$ 22,814,319	$ 47,336,550
10	$ 307,807	$ 282,015	$ 285,509	$ 258,269	$ 306,122	$ 372,683	$ 1,812,407	$ 3,738,514
11							$ -	$ -
12							$ -	$ -
13							$ -	$ -
14							$ -	$ -
15							$ -	$ -
18							$ -	$ -
19							$ -	$ -
20							$ -	$ -
22							$ -	$ -
24	$ 32,852	$ 30,298	$ 29,995	$ 28,146	$ 28,992	$ 30,870	$ 181,152	$ 440,957
26	$ 4,696	$ 4,154	$ 4,356	$ 3,940	$ 4,671	$ 5,686	$ 27,504	$ 56,235
[5] Amortization	$ 319,139	$ 320,976	$ 322,825	$ 324,684	$ 326,556	$ 328,439	$ 1,942,619	$ 3,819,499
Total	$ 5,798,716	$ 5,179,282	$ 5,404,981	$ 4,922,993	$ 5,772,462	$ 6,812,285	$ 33,890,719	$ 70,287,522

Schedule	[1] Month in which Bill will be Received (Energy-Based)						[2] Total	[3] 12 Month Total
	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08		
16	$ 33,495	$ 30,275	$ 47,102	$ 45,596	$ 47,108	$ 38,010	$ 241,585	$ 463,047
17	$ 741,816	$ 684,138	$ 677,302	$ 635,550	$ 654,660	$ 697,068	$ 4,090,535	$ 7,670,068
[4] FERC 10	$ 98,905	$ 87,493	$ 91,740	$ 82,987	$ 98,364	$ 119,751	$ 579,240	$ 1,198,139
Congestion Expense	$ 201,364	$ (356,108)	$ 1,512,598	$ 1,235,831	$ 559,712	$ 60,337	$ 3,213,733	$ 5,592,410
FTR Credit	$ (244,061)	$ 27,524	$ (1,066,985)	$ (1,136,312)	$ (474,112)	$ (56,368)	$ (2,950,315)	$ (3,115,282)
Gross Losses	$ 647,827	$ 1,822,063	$ 1,946,815	$ 1,828,807	$ 1,419,134	$ 1,964,369	$ 9,629,015	$ 22,855,706
Loss Credit							$ -	$ -
Revenue Neutrality	$ 748,000	$ 748,000	$ 748,000	$ 748,000	$ 748,000	$ 748,000	$ 4,488,000	$ 8,976,000
Rev. Sufficiency Guarantee	$ 411,400	$ 411,400	$ 411,400	$ 411,400	$ 411,400	$ 411,400	$ 2,468,400	$ 5,161,200
[5] Amortization	$ 245,452	$ 246,865	$ 248,286	$ 249,716	$ 251,156	$ 252,604	$ 1,494,079	$ 2,937,597
Total	$ 2,884,198	$ 3,701,649	$ 4,616,258	$ 4,101,576	$ 3,715,421	$ 4,235,170	$ 23,254,271	$ 51,738,885

[1] Projected monthly transmission- and ancillary service-related costs for CEI for the first 6 months of 2008 reflect projected costs from MISO bills. Demand-based costs reflect a coincident peak allocation basis, whereas energy-based costs are based on each Ohio Operating Company's contribution to the projected total Ohio kWh consumption.

[2] Calculation: Sum of 6 monthly values

[3] Calculation: Sum of 12 monthly values

[4] Currently billed every August.

[5] "Amortization" represents the monthly portion of the deferred transmission- and ancillary service-related costs (and interest) based upon the actual split by company in the 2005 schedules to be amortized and expensed over a five year period, commencing January 1, 2006. Amortization expense will be further split between energy and demand, based upon the costs that were deferred. See page 10 for the allocation between demand and energy.

TOLEDO EDISON'S TRANSMISSION- AND ANCILLARY SERVICE-RELATED COSTS

Schedule	[1] Month in which Bill will be Received (Demand-Based) Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	[2] Total
1	$ 94,540	$ 91,776	$ 81,111	$ 67,228	$ 71,213	$ 81,548	$ 487,415
2	$ 206,870	$ 200,821	$ 177,484	$ 147,107	$ 155,825	$ 178,440	$ 1,066,548
3	$ 113,099	$ 109,792	$ 97,039	$ 80,426	$ 85,197	$ 97,557	$ 583,111
4							$ -
5	$ 169,666	$ 164,705	$ 145,566	$ 120,652	$ 127,803	$ 146,350	$ 874,741
6	$ 84,953	$ 82,469	$ 72,889	$ 60,411	$ 63,994	$ 73,278	$ 437,994
7 (69 kv)							$ -
7 (138 kv)							$ -
8 (69 kv)							$ -
8 (138 kv)							$ -
9 (69 kv)	$ 781,443	$ 777,670	$ 655,201	$ 545,798	$ 575,988	$ 657,411	$ 3,993,512
9 (138 kv)	$ 2,157,510	$ 2,094,425	$ 1,851,038	$ 1,534,229	$ 1,625,153	$ 1,861,010	$ 11,123,366
10	$ 169,462	$ 164,507	$ 145,390	$ 120,507	$ 127,648	$ 146,174	$ 873,689
11							$ -
12							$ -
13							$ -
14							$ -
15							$ -
18							$ -
19							$ -
20							$ -
22							$ -
24	$ 22,746	$ 22,527	$ 19,378	$ 19,988	$ 19,721	$ 21,374	$ 125,734
26	$ 2,502	$ 2,429	$ 2,218	$ 1,779	$ 1,948	$ 2,158	$ 13,035
[4] Amortization	$ 142,671	$ 143,447	$ 144,228	$ 145,013	$ 145,803	$ 146,597	$ 867,758
Total	$ 3,945,462	$ 3,854,568	$ 3,391,544	$ 2,843,139	$ 3,000,293	$ 3,411,896	$ 20,446,903

Schedule	[1] Month in which Bill will be Received (Energy-Based) Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	[2] Total
16	$ 17,480	$ 17,667	$ 18,920	$ 19,598	$ 18,919	$ 14,594	$ 107,178
17	$ 313,383	$ 310,371	$ 266,990	$ 275,392	$ 271,711	$ 294,493	$ 1,732,341
[3] FERC 10	$ 54,452	$ 52,860	$ 46,717	$ 38,721	$ 41,016	$ 46,969	$ 280,735
Congestion Expense	$ 146,285	$ 140,428	$ 105,039	$ 15,987	$ 259,626	$ 483,814	$ 1,151,178
FTR Credit	$ (16,838)	$ 15,948	$ (1,800)	$ (52)	$ (24,811)	$ (52,284)	$ (79,837)
Gross Losses	$ 1,536,066	$ 1,569,859	$ 714,178	$ 780,800	$ 832,832	$ 967,618	$ 6,401,153
Loss Credit							$ -
Revenue Neutrality	$ 362,000	$ 362,000	$ 362,000	$ 362,000	$ 362,000	$ 362,000	$ 2,172,000
Rev. Sufficiency Guarantee	$ 217,200	$ 217,200	$ 217,200	$ 217,200	$ 217,200	$ 217,200	$ 1,303,200
[4] Amortization	$ 87,010	$ 87,483	$ 87,959	$ 88,438	$ 88,920	$ 89,404	$ 529,213
Total	$ 2,717,038	$ 2,773,615	$ 1,817,202	$ 1,798,085	$ 2,067,413	$ 2,423,807	$ 13,597,161

[1] Projected monthly transmission- and ancillary service-related costs for Toledo Edison for the last 6 months of 2007 reflect projected costs from MISO bills. Demand-based costs reflect a coincident peak allocation basis, whereas energy-based costs are based on each Ohio Operating Company's contribution to the projected total Ohio kWh consumption.

[2] Calculation: Sum of 6 monthly values

[3] Currently billed every August.

[4] "Amortization" represents the monthly portion of the deferred transmission- and ancillary service-related costs (and interest) based upon the actual split by company in the 2005 schedules to be amortized and expensed over a five year period, commencing January 1, 2006. Amortization expense will be further split between energy and demand, based upon the costs that were deferred. See page 10 for the allocation between demand and energy.

TOLEDO EDISON'S TRANSMISSION- AND ANCILLARY SERVICE-RELATED COSTS

Schedule	[1] Month in which Bill will be Received (Demand-Based)						[2] Total	[3] 12 Month Total
	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08		
1	$ 82,206	$ 72,503	$ 75,683	$ 69,282	$ 78,502	$ 94,125	$ 472,300	$ 959,716
2	$ 179,892	$ 158,659	$ 165,617	$ 151,611	$ 171,787	$ 194,909	$ 1,022,473	$ 2,089,021
3	$ 98,350	$ 86,742	$ 90,546	$ 82,893	$ 93,919	$ 109,329	$ 561,779	$ 1,144,890
4							$ -	$ -
5	$ 147,540	$ 130,128	$ 135,832	$ 124,346	$ 140,892	$ 164,002	$ 842,741	$ 1,717,482
6	$ 73,874	$ 65,166	$ 68,012	$ 62,264	$ 70,546	$ 82,121	$ 421,982	$ 859,976
7 (69 kv)							$ -	$ -
7 (138 kv)							$ -	$ -
8 (69 kv)							$ -	$ -
8 (138 kv)							$ -	$ -
9 (69 kv)	$ 672,149	$ 585,511	$ 611,850	$ 547,849	$ 635,769	$ 752,367	$ 3,805,495	$ 7,799,007
9 (138 kv)	$ 1,876,150	$ 1,654,701	$ 1,727,270	$ 1,581,197	$ 1,791,616	$ 2,025,465	$ 10,656,400	$ 21,779,766
10	$ 147,363	$ 134,611	$ 135,669	$ 124,196	$ 140,723	$ 163,804	$ 846,366	$ 1,720,054
11							$ -	$ -
12							$ -	$ -
13							$ -	$ -
14							$ -	$ -
15							$ -	$ -
18							$ -	$ -
19							$ -	$ -
20							$ -	$ -
22							$ -	$ -
24	$ 15,899	$ 14,663	$ 14,516	$ 13,621	$ 14,031	$ 14,940	$ 87,670	$ 213,404
26	$ 2,248	$ 1,983	$ 2,070	$ 1,895	$ 2,147	$ 2,499	$ 12,842	$ 25,877
[5] Amortization	$ 147,396	$ 148,172	$ 148,953	$ 149,738	$ 150,527	$ 151,321	$ 896,106	$ 1,783,864
Total	$ 3,443,068	$ 3,052,839	$ 3,176,016	$ 2,908,891	$ 3,290,459	$ 3,754,882	$ 19,626,155	$ 40,073,057

Schedule	[1] Month in which Bill will be Received (Energy-Based)						[2] Total	[3] 12 Month Total
	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08		
16	$ 16,210	$ 14,652	$ 22,795	$ 22,067	$ 22,798	$ 18,395	$ 116,917	$ 224,095
17	$ 359,007	$ 331,094	$ 327,785	$ 307,579	$ 316,827	$ 337,351	$ 1,979,644	$ 3,711,985
[4] FERC 10	$ 47,351	$ 41,762	$ 43,593	$ 39,907	$ 45,217	$ 52,634	$ 270,464	$ 551,199
Congestion Expense	$ 97,452	$ (172,341)	$ 732,033	$ 598,089	$ 270,877	$ 29,200	$ 1,555,309	$ 2,706,487
FTR Credit	$ (118,115)	$ 13,320	$ (516,375)	$ (549,926)	$ (229,450)	$ (27,280)	$ (1,427,826)	$ (1,507,663)
Gross Losses	$ 313,521	$ 881,800	$ 942,175	$ 885,064	$ 686,800	$ 950,671	$ 4,660,031	$ 11,061,184
Loss Credit							$ -	$ -
Revenue Neutrality	$ 362,000	$ 362,000	$ 362,000	$ 362,000	$ 362,000	$ 362,000	$ 2,172,000	$ 4,344,000
Rev. Sufficiency Guarantee	$ 199,100	$ 199,100	$ 199,100	$ 199,100	$ 199,100	$ 199,100	$ 1,194,600	$ 2,497,800
[5] Amortization	$ 89,891	$ 90,365	$ 90,841	$ 91,319	$ 91,801	$ 92,285	$ 546,502	$ 1,075,715
Total	$ 1,366,416	$ 1,761,751	$ 2,203,947	$ 1,955,199	$ 1,785,970	$ 2,014,358	$ 11,067,840	$ 24,664,801

[1] Projected monthly transmission- and ancillary service-related costs for Toledo Edison for the first 6 months of 2008 reflect projected costs from MISO bills. Demand-based costs reflect a coincident peak allocation basis, whereas energy-based costs are based on each Ohio Operating Company's contribution to the projected total Ohio kWh consumption.

[2] Calculation: Sum of 6 monthly values

[3] Calculation: Sum of 12 monthly values

[4] Currently billed every August.

[5] "Amortization" represents the monthly portion of the deferred transmission- and ancillary service-related costs (and interest) based upon the actual split by company in the 2005 schedules to be amortized and expensed over a five year period, commencing January 1, 2006. Amortization expense will be further split between energy and demand, based upon the costs that were deferred. See page 10 for the allocation between demand and energy.

SUMMARY OF DEMAND AND ENERGY TRANSMISSION- AND ANCILLARY SERVICE-RELATED COSTS BY COMPANY

Company	[1] Company Total Demand-Based Costs						[2] Total
	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	
OE	$ 11,279,208	$ 11,675,005	$ 9,637,946	$ 7,921,187	$ 8,201,248	$ 9,278,174	$ 57,992,768
CEI	$ 7,084,788	$ 7,098,557	$ 6,035,032	$ 5,143,845	$ 5,203,047	$ 5,831,533	$ 36,396,803
TE	$ 3,945,462	$ 3,854,568	$ 3,391,544	$ 2,843,139	$ 3,000,293	$ 3,411,896	$ 20,446,903
Total	$ 22,309,458	$ 22,628,131	$ 19,064,522	$ 15,908,171	$ 16,404,588	$ 18,521,604	$ 114,836,474

Company	[1] Company Total Demand-Based Costs						[2] Total	[3] Total
	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08		
OE	$ 9,409,021	$ 8,213,079	$ 8,601,718	$ 7,599,032	$ 9,050,798	$ 11,147,305	$ 54,020,953	$ 112,013,721
CEI	$ 5,798,716	$ 5,179,262	$ 5,404,981	$ 4,922,993	$ 5,772,462	$ 6,812,285	$ 33,890,719	$ 70,287,522
TE	$ 3,443,068	$ 3,052,839	$ 3,176,016	$ 2,908,891	$ 3,290,459	$ 3,754,882	$ 19,626,155	$ 40,073,057
Total	$ 18,650,805	$ 16,445,201	$ 17,182,715	$ 15,430,916	$ 18,113,719	$ 21,714,471	$ 107,537,827	$ 222,374,301

Company	[4] Company Total Energy-Based Costs						[2] Total
	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	
OE	$ 6,789,778	$ 6,939,028	$ 4,574,716	$ 4,523,611	$ 5,184,542	$ 6,060,955	$ 34,072,630
CEI	$ 5,680,609	$ 5,801,250	$ 3,819,135	$ 3,780,541	$ 4,333,667	$ 5,069,411	$ 28,484,614
TE	$ 2,717,038	$ 2,773,615	$ 1,817,202	$ 1,798,085	$ 2,067,413	$ 2,423,807	$ 13,597,161
Total	$ 15,187,425	$ 15,513,893	$ 10,211,054	$ 10,102,237	$ 11,585,622	$ 13,554,174	$ 76,154,405

Company	[4] Company Total Energy-Based Costs						[2] Total	[5] Total
	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08		
OE	$ 3,462,876	$ 4,432,483	$ 5,521,089	$ 4,905,192	$ 4,447,838	$ 5,073,909	$ 27,843,388	$ 61,916,017
CEI	$ 2,884,198	$ 3,701,649	$ 4,616,258	$ 4,101,576	$ 3,715,421	$ 4,235,170	$ 23,254,271	$ 51,738,885
TE	$ 1,366,416	$ 1,761,751	$ 2,203,947	$ 1,955,199	$ 1,765,970	$ 2,014,356	$ 11,067,640	$ 24,664,801
Total	$ 7,713,490	$ 9,895,883	$ 12,341,294	$ 10,961,966	$ 9,929,229	$ 11,323,436	$ 62,165,299	$ 138,319,704

Company	[6] Company Total Costs						[2] Total
	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	
OE	$ 18,068,986	$ 18,614,033	$ 14,212,663	$ 12,444,798	$ 13,385,789	$ 15,339,129	$ 92,065,398
CEI	$ 12,765,397	$ 12,899,807	$ 9,854,167	$ 8,924,386	$ 9,536,715	$ 10,900,945	$ 64,881,417
TE	$ 6,662,501	$ 6,628,183	$ 5,208,746	$ 4,641,224	$ 5,067,706	$ 5,835,704	$ 34,044,064
Total	$ 37,496,884	$ 38,142,023	$ 29,275,576	$ 26,010,408	$ 27,990,210	$ 32,075,778	$ 190,990,878

Company	[6] Company Total Costs						[2] Total	[7] Total
	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08		
OE	$ 12,871,897	$ 12,645,563	$ 14,122,807	$ 12,504,224	$ 13,498,636	$ 16,221,214	$ 81,864,340	$ 173,929,738
CEI	$ 8,682,914	$ 8,880,931	$ 10,021,239	$ 9,024,569	$ 9,487,882	$ 11,047,455	$ 57,144,990	$ 122,026,407
TE	$ 4,809,484	$ 4,814,590	$ 5,379,963	$ 4,864,090	$ 5,056,429	$ 5,769,238	$ 30,693,795	$ 64,737,859
Total	$ 26,364,295	$ 26,341,084	$ 29,524,009	$ 26,392,882	$ 28,042,948	$ 33,037,907	$ 169,703,126	$ 360,694,004

[1] These values reflect the total costs from the MISO invoices that are allocated to each Ohio Operating Company based on each Operating Company's books. The amount on each Company's books reflects a coincident peak allocation basis.

[2] Calculation: Sum of 6 monthly totals.

[3] Calculation: Sum of 12 monthly totals. These values reflect the total projected transmission and ancillary service-related costs (demand-based) to be incurred by each of the Ohio Operating Companies during the last 6 months of 2007 and first 6 months of 2008. They are used in Exhibits B-1, 2, and 3 to calculate "TDC."

[4] These values reflect the total costs from the MISO Invoices that are allocated to each Ohio Operating Company based on each Operating Company's books. The amount on each Company's books will reflect an energy allocation basis.

[5] Calculation: Sum of 12 monthly totals. These values reflect the total projected transmission and ancillary service-related costs (energy-based) to be incurred by each of the Ohio Operating Companies during the last 6 months of 2007 and first 6 months of 2008. They are used in Exhibits B-1, 2, and 3 to calculate "TEC."

[6] Calculation: Company Total Demand-Based Costs + Company Total Energy-Based Costs

[7] Calculation: Sum of 12 monthly totals.

CALCULATION OF DEMAND AND ENERGY AMORTIZATION ALLOCATION PERCENTAGES (2005 DEFERRAL)

Company	[1] Company Demand-Based Costs						[2] Total
	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	
OE	$ 5,067,466	$ 4,494,253	$ 4,451,527	$ 5,794,352	$ 4,765,330	$ 8,188,185	$ 32,761,113
CEI	$ 2,603,941	$ 2,986,721	$ 2,665,176	$ 3,625,095	$ 3,020,683	$ 670,472	$ 15,572,088
TE	$ 1,922,112	$ 1,954,160	$ 1,910,872	$ 2,509,794	$ 1,808,385	$ 2,556,388	$ 12,661,711
Total	$ 9,593,519	$ 9,435,134	$ 9,027,575	$ 11,929,241	$ 9,594,399	$ 11,415,045	$ 60,994,913

Company	[1] Company Demand-Based Costs						[2] Total
	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	
OE	$ 4,341,752	$ 8,912,779	$ 5,116,813	$ 4,653,349	$ 7,523,115	$ 6,535,201	$ 37,083,007
CEI	$ 5,134,776	$ 4,269,437	$ 2,260,141	$ 2,435,808	$ (35,113)	$ 3,691,577	$ 17,756,627
TE	$ 2,255,935	$ 3,127,517	$ 1,926,110	$ 2,031,187	$ 2,256,573	$ 2,370,703	$ 13,968,024
Total	$ 11,732,463	$ 16,309,732	$ 9,303,064	$ 9,120,343	$ 9,744,575	$ 12,597,481	$ 68,807,658

Company	[1] Company Energy-Based Costs						[2] Total
	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	
OE	$ -	$ -	$ -	$ 1,585,720	$ 2,276,918	$ 3,815,285	$ 7,677,922
CEI	$ -	$ -	$ -	$ 874,687	$ 1,481,397	$ 2,538,802	$ 4,894,885
TE	$ -	$ -	$ -	$ 608,908	$ 1,013,339	$ 1,668,018	$ 3,290,266
Total	$ -	$ -	$ -	$ 3,069,315	$ 4,771,654	$ 8,022,105	$ 15,863,073

Company	[1] Company Energy-Based Costs						[2] Total
	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	
OE	$ 4,764,537	$ 3,224,474	$ 4,999,190	$ 6,032,551	$ 2,651,184	$ 8,646,816	$ 30,318,752
CEI	$ 3,114,237	$ 2,132,074	$ 3,395,477	$ 4,133,116	$ 1,874,236	$ 6,089,263	$ 20,738,402
TE	$ 1,998,404	$ 1,419,364	$ 2,199,700	$ 2,624,030	$ 1,128,942	$ 3,579,777	$ 12,950,217
Total	$ 9,877,178	$ 6,775,911	$ 10,594,366	$ 12,789,697	$ 5,654,362	$ 18,315,857	$ 64,007,371

Company	[3] TOTAL DEMAND-BASED COSTS	[3] TOTAL ENERGY-BASED COSTS	[4] TOTAL COSTS	[5] DEMAND-BASED % OF TOTAL	[6] ENERGY-BASED % OF TOTAL
	2005	2005	2005	2005	2005
OE	$ 69,844,120	$ 37,996,674	$ 107,840,795	64.77%	35.23%
CEI	$ 33,328,715	$ 25,633,287	$ 58,962,003	56.53%	43.47%
TE	$ 26,629,736	$ 16,240,483	$ 42,870,219	62.12%	37.88%

Company	[7] Amortization of Deferral					
	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07
OE	$ 888,047	$ 892,608	$ 897,195	$ 901,807	$ 906,444	$ 911,106
CEI	$ 545,502	$ 548,636	$ 551,788	$ 554,960	$ 558,151	$ 561,361
TE	$ 229,680	$ 230,930	$ 232,187	$ 233,451	$ 234,722	$ 236,001

Company	[7] Amortization of Deferral					
	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08
OE	$ 915,794	$ 920,508	$ 925,248	$ 930,015	$ 934,809	$ 939,875
CEI	$ 564,591	$ 567,841	$ 571,111	$ 574,401	$ 577,712	$ 581,043
TE	$ 237,287	$ 238,536	$ 239,793	$ 241,057	$ 242,328	$ 243,606

[1] Company demand and energy-based costs are based on actual MISO schedules' bills and related costs for each Ohio Operating Company for 2005.

[2] Calculation: Sum of 6 monthly totals.

[3] Calculation: Sum of 12 monthly totals.

[4] Calculation: Sum of 12 monthly totals (demand-based and energy-based).

[5] Calculation: (Total demand-based costs) / (Total Costs). These values are the allocation percentages used in B-5 pages 3 through 8 to allocate amortization between demand and energy.

[6] Calculation: (Total energy-based costs) / (Total Costs). These values are the allocation percentages used in B-5 pages 3 through 8 to allocate amortization between demand and energy.

[7] Deferral amount to be amortized by company. These values (taken from company books) are multiplied by the demand and energy allocation percentages above.

Exhibit B-6 will provide 12 months of historical transmission- and ancillary service-related costs charged to the Ohio Operating Companies. The May 1, 2007 filing for the rider effective July 1, 2007 includes actual transmission- and ancillary service-related costs for each of the Ohio Operating Companies for the 12 months ended March 2007.

OHIO COMPANIES' TRANSMISSION- AND ANCILLARY SERVICE-RELATED COSTS

Schedule	[1] Month in which Bill was Received (Demand-Based)						[2] Total
	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	
1	$ 335,200	$ 971,472	$ (13,171)	$ 439,258	$ 539,941	$ 345,491	$ 2,618,192
2	$ 783,037	$ 919,217	$ 1,280,792	$ 998,039	$ 1,226,729	$ 784,798	$ 5,992,612
3	$ 409,568	$ 480,738	$ 692,136	$ 541,252	$ 665,367	$ 425,825	$ 3,214,887
4	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	$ 614,314	$ 721,148	$ 1,038,178	$ 811,925	$ 998,052	$ 638,673	$ 4,822,291
6	$ 307,650	$ 361,109	$ 519,899	$ 406,564	$ 499,792	$ 319,867	$ 2,414,881
7 (69 kv)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7 (138 kv)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8 (69 kv)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8 (138 kv)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9 (69 kv)	$ 1,976,178	$ 2,001,901	$ 3,820,694	$ 2,595,472	$ 3,355,050	$ 1,935,054	$ 15,684,350
9 (138 kv)	$ 6,209,690	$ 6,628,309	$ 11,828,687	$ 9,762,233	$ 12,020,846	$ 7,580,551	$ 54,030,315
10	$ 508,356	$ 161,834	$ 1,611,731	$ 438,806	$ 669,602	$ 465,968	$ 3,856,297
11	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	$ -	$ -	$ (7,849)	$ -	$ -	$ -	$ (7,849)
18	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	$ (184,804)	$ -	$ -	$ -	$ -	$ -	$ (184,804)
24	$ -	$ -	$ 50,086	$ 50,392	$ 47,527	$ 40,242	$ 188,248
26	$ -	$ -	$ -	$ -	$ -	$ -	$ -
[4] Amortization	$ 1,082,437	$ 1,087,766	$ 1,093,123	$ 1,233,603	$ 1,240,489	$ 1,247,413	$ 6,984,832
Total	$ 12,041,625	$ 13,333,496	$ 21,914,306	$ 17,277,546	$ 21,263,396	$ 13,783,882	$ 99,614,250

Schedule	[1] Month in which Bill was Received (Energy-Based)						[2] Total
	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	
16	$ 89,004	$ 92,573	$ 29,118	$ 90,144	$ 58,188	$ 85,193	$ 444,220
17	$ 663,118	$ 569,743	$ 397,094	$ 698,674	$ 646,215	$ 489,955	$ 3,464,799
[3] FERC 10	$ -	$ -	$ -	$ -	$ 1,813,111	$ 149,845	$ 1,962,956
Congestion Expense	$ 4,274,391	$ 1,120,675	$ 309,340	$ 671,148	$ 932,949	$ 743,183	$ 8,051,687
FTR Credit	$ (4,114,463)	$ (1,732,383)	$ (9,352)	$ (3,136,063)	$ (2,132,252)	$ (1,549,441)	$ (12,673,954)
Gross Losses	$ 3,658,000	$ 3,738,805	$ 4,433,379	$ 7,450,322	$ 6,997,891	$ 2,267,746	$ 28,546,142
Loss Credit	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenue Neutrality	$ 489,307	$ 73,030	$ 773,543	$ 1,656,197	$ 1,197,059	$ 894,049	$ 5,083,184
Rev. Sufficiency Guarantee	$ 720,111	$ 827,465	$ 304,333	$ 922,422	$ 1,567,932	$ 383,448	$ 4,725,711
[4] Amortization	$ 451,716	$ 453,990	$ 456,277	$ 517,982	$ 520,899	$ 523,833	$ 2,924,698
Total	$ 6,231,184	$ 5,143,899	$ 6,693,732	$ 8,870,826	$ 11,601,992	$ 3,987,810	$ 42,529,443

[1] Actual monthly transmission- and ancillary service-related costs for the Ohio Companies for April to September 2006.

[2] Calculation: Sum of 6 monthly values.

[3] Currently billed every August.

[4] "Amortization" represents the monthly portion of the deferred transmission- and ancillary service-related costs (and interest) based upon the actual split by company in the 2005 schedules to be amortized and expensed over a five year period, commencing January 1, 2006. Amortization expense will be further split between energy and demand, based upon the costs that were deferred. See page 9 for the allocation between demand and energy. These values represent totals for the three Ohio Operating Companies.

OHIO COMPANIES' TRANSMISSION- AND ANCILLARY SERVICE-RELATED COSTS

Schedule	[1] Month in which Bill was Received (Demand-Based)						[2] Total	[3] 12 Month Total
	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07		
1	$ 380,582	$ 381,505	$ 431,512	$ 490,386	$ 459,816	$ 434,051	$ 2,577,852	$ 5,196,044
2	$ 820,592	$ 821,882	$ 935,475	$ 904,934	$ 894,495	$ 888,134	$ 5,265,511	$ 11,258,123
3	$ 445,045	$ 445,795	$ 507,350	$ 490,852	$ 485,153	$ 481,702	$ 2,855,898	$ 6,070,785
4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	$ 667,603	$ 668,659	$ 761,070	$ 736,198	$ 727,730	$ 722,555	$ 4,283,815	$ 9,106,106
6	$ 334,299	$ 334,860	$ 381,097	$ 368,719	$ 364,426	$ 361,835	$ 2,145,236	$ 4,560,116
7 (69 kv)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7 (138 kv)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8 (69 kv)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8 (138 kv)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9 (69 kv)	$ 2,190,949	$ 2,191,586	$ 2,486,507	$ 2,437,196	$ 2,322,498	$ 2,367,634	$ 13,996,369	$ 29,680,718
9 (138 kv)	$ 8,225,761	$ 8,066,802	$ 9,262,272	$ 8,769,040	$ 8,405,631	$ 9,030,720	$ 51,760,226	$ 105,790,542
10	$ 833,771	$ 884,649	$ 894,714	$ 1,116,104	$ 998,925	$ 945,480	$ 5,673,642	$ 9,529,939
11	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (7,849)
18	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (184,804)
24	$ 46,614	$ 45,765	$ 50,573	$ 54,567	$ 55,966	$ 50,946	$ 304,431	$ 492,678
26	$ -	$ -	$ -	$ -	$ -	$ 10,758	$ 10,758	$ 10,758
[5] Amortization	$ 1,254,379	$ 1,261,318	$ 1,268,173	$ 1,274,995	$ 1,281,856	$ 1,288,749	$ 7,629,470	$ 14,614,302
Total	$ 15,199,594	$ 15,102,822	$ 16,978,743	$ 16,642,991	$ 15,996,495	$ 16,582,564	$ 96,503,209	$ 196,117,459

Schedule	[1] Month in which Bill was Received (Energy-Based)						[2] Total	[3] 12 Month Total
	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07		
16	$ 100,504	$ 94,163	$ 68,520	$ 73,165	$ 29,167	$ 76,561	$ 442,080	$ 886,300
17	$ 655,750	$ 815,634	$ 896,692	$ 665,152	$ 752,127	$ 422,368	$ 4,207,723	$ 7,672,522
[4] FERC 10	$ 1,022	$ 10,110	$ 94,598	$ 2,291	$ (32,720)	$ 10,335	$ 85,636	$ 2,048,592
Congestion Expense	$ 151,036	$ 1,464,907	$ 289,959	$ (20,654)	$ 391,756	$ 2,404,417	$ 4,681,421	$ 12,733,108
FTR Credit	$ (2,087,460)	$ (2,265,274)	$ (1,002,590)	$ (2,277,652)	$ (875,420)	$ (2,389,016)	$ (10,897,413)	$ (23,571,367)
Gross Losses	$ 2,903,808	$ 3,249,562	$ 3,365,528	$ 3,963,208	$ 6,059,439	$ 4,479,619	$ 24,021,164	$ 52,567,306
Loss Credit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenue Neutrality	$ 389,381	$ 1,029,156	$ 702,955	$ 308,415	$ 2,842,915	$ 640,035	$ 5,892,857	$ 10,976,041
Rev. Sufficiency Guarantee	$ 978,054	$ 932,757	$ 2,481,902	$ 801,939	$ 2,211,639	$ 894,488	$ 8,300,780	$ 13,026,491
[5] Amortization	$ 526,783	$ 529,722	$ 532,624	$ 535,508	$ 538,408	$ 541,322	$ 3,204,368	$ 6,129,065
Total	$ 3,598,878	$ 5,860,736	$ 7,430,188	$ 4,051,373	$ 11,917,310	$ 7,080,129	$ 39,938,615	$ 82,468,058

[1] Actual monthly transmission- and ancillary service-related costs for the Ohio Companies for October 2006 to March 2007.

[2] Calculation: Sum of 6 monthly values

[3] Calculation: Sum of 12 monthly values

[4] Currently billed every August.

[5] "Amortization" represents the monthly portion of the deferred transmission- and ancillary service-related costs (and interest) based upon the actual split by company in the 2005 schedules to be amortized and expensed over a five year period, commencing January 1, 2006. Amortization expense will be further split between energy and demand, based upon the costs that were deferred. See page 9 for the allocation between demand and energy.

OHIO EDISON'S TRANSMISSION- AND ANCILLARY SERVICE-RELATED COSTS

Schedule	[1] Month in which Bill was Received (Demand-Based)						[2] Total
	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	
1	$ 143,600	$ 456,078	$ (21,558)	$ 186,825	$ 245,223	$ 140,396	$ 1,150,564
2	$ 335,452	$ 427,445	$ 570,212	$ 424,485	$ 557,140	$ 318,911	$ 2,633,645
3	$ 175,458	$ 223,549	$ 308,295	$ 230,204	$ 302,186	$ 173,045	$ 1,412,737
4							$ -
5	$ 263,171	$ 335,341	$ 462,432	$ 345,327	$ 453,282	$ 259,537	$ 2,119,090
6	$ 131,797	$ 167,920	$ 231,575	$ 172,920	$ 226,988	$ 129,986	$ 1,061,186
7 (69 kv)							$ -
7 (138 kv)							$ -
8 (69 kv)							$ -
8 (138 kv)							$ -
9 (69 kv)	$ 1,522,574	$ 1,596,303	$ 2,655,200	$ 2,005,751	$ 2,655,878	$ 1,522,888	$ 11,958,593
9 (138 kv)	$ 2,710,143	$ 3,065,512	$ 5,483,318	$ 4,174,947	$ 5,466,776	$ 3,050,839	$ 23,951,535
10	$ 217,612	$ 77,181	$ 733,187	$ 33,724	$ 304,720	$ 190,184	$ 1,556,609
11							$ -
12							$ -
13							$ -
14							$ -
15	$ -	$ -	$ (3,800)	$ -	$ -	$ -	$ (3,800)
18							$ -
19							$ -
20							$ -
22	$ (184,804)	$ -	$ -	$ -	$ -	$ -	$ (184,804)
24	$ -	$ -	$ 21,906	$ 22,186	$ 20,671	$ 17,493	$ 82,256
26							$ -
[4] Amortization	$ 599,087	$ 601,485	$ 603,893	$ 616,190	$ 619,336	$ 622,499	$ 3,662,489
Total	$ 5,914,090	$ 6,950,813	$ 11,044,660	$ 8,212,559	$ 10,852,200	$ 6,425,779	$ 49,400,101

Schedule	[1] Month in which Bill was Received (Energy-Based)						[2] Total
	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	
16	$ 39,221	$ 40,447	$ 12,735	$ 39,691	$ 25,301	$ 37,032	$ 194,428
17	$ 292,194	$ 248,928	$ 173,668	$ 307,622	$ 281,070	$ 212,980	$ 1,516,460
[3] FERC 10	$ -	$ -	$ -	$ -	$ 878,737	$ 66,856	$ 945,593
Congestion Expense	$ 1,883,427	$ 489,290	$ 135,296	$ 295,504	$ 405,728	$ 323,058	$ 3,532,302
FTR Credit	$ (1,811,666)	$ (814,302)	$ (4,146)	$ (1,379,018)	$ (937,361)	$ (673,953)	$ (5,620,446)
Gross Losses	$ 1,611,797	$ 1,633,854	$ 1,938,951	$ 3,280,952	$ 3,042,155	$ 985,744	$ 12,493,453
Loss Credit	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenue Neutrality	$ 215,174	$ 31,005	$ 338,366	$ 728,334	$ 521,490	$ 388,663	$ 2,223,033
Rev. Sufficiency Guarantee	$ 317,369	$ 362,695	$ 133,096	$ 406,034	$ 683,351	$ 166,680	$ 2,069,226
[4] Amortization	$ 225,258	$ 226,159	$ 227,065	$ 231,689	$ 232,871	$ 234,061	$ 1,377,103
Total	$ 2,772,774	$ 2,218,075	$ 2,955,032	$ 3,910,807	$ 5,133,343	$ 1,741,120	$ 18,731,152

[1] Actual monthly transmission- and ancillary service-related costs for OE for April 2006 to September 2006.

[2] Calculation: Sum of 6 monthly values

[3] Currently billed every August.

[4] "Amortization" represents the monthly portion of the deferred transmission- and ancillary service-related costs (and interest) based upon the actual split by company in the 2005 schedules to be amortized and expensed over a five year period, commencing January 1, 2006. Amortization expense will be further split between energy and demand, based upon the costs that were deferred. See page 9 for the allocation between demand and energy.

OHIO EDISON'S TRANSMISSION- AND ANCILLARY SERVICE-RELATED COSTS

Schedule	[1] Month in which Bill was Received (Demand-Based) Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	[2] Total	[3] 12 Month Total
1	$ 162,605	$ 166,938	$ 189,852	$ 220,846	$ 210,608	$ 190,721	$ 1,141,570	$ 2,292,134
2	$ 350,269	$ 359,731	$ 411,698	$ 408,513	$ 410,143	$ 390,244	$ 2,330,597	$ 4,964,242
3	$ 189,967	$ 195,121	$ 223,282	$ 221,584	$ 222,452	$ 211,659	$ 1,264,065	$ 2,676,803
4							$ -	$ -
5	$ 284,965	$ 292,667	$ 334,943	$ 332,341	$ 333,678	$ 317,489	$ 1,896,083	$ 4,015,173
6	$ 142,695	$ 146,565	$ 167,719	$ 166,450	$ 167,096	$ 158,990	$ 949,514	$ 2,010,701
7 (69 kv)							$ -	$ -
7 (138 kv)							$ -	$ -
8 (69 kv)							$ -	$ -
8 (138 kv)							$ -	$ -
9 (69 kv)	$ 1,730,650	$ 1,714,249	$ 1,941,286	$ 1,913,774	$ 1,826,055	$ 1,968,203	$ 11,094,217	$ 23,052,811
9 (138 kv)	$ 3,575,033	$ 3,522,708	$ 4,120,632	$ 3,954,306	$ 3,891,160	$ 3,744,324	$ 22,808,164	$ 46,759,699
10	$ 357,998	$ 534,721	$ 392,923	$ 501,012	$ 455,599	$ 419,835	$ 2,662,088	$ 4,218,696
11							$ -	$ -
12							$ -	$ -
13							$ -	$ -
14							$ -	$ -
15	$ -	$ -	$ -				$ -	$ (3,800)
18							$ -	$ -
19							$ -	$ -
20							$ -	$ -
22							$ -	$ (184,804)
24	$ 20,307	$ 20,266	$ 22,421	$ 26,163	$ 24,872	$ 22,620	$ 136,649	$ 218,905
26						$ 4,727	$ 4,727	$ 4,727
[5] Amortization	$ 625,688	$ 628,895	$ 632,119	$ 635,360	$ 638,618	$ 641,893	$ 3,802,572	$ 7,465,062
Total	$ 7,440,178	$ 7,581,862	$ 8,436,875	$ 8,380,347	$ 8,180,280	$ 8,070,707	$ 48,090,248	$ 97,490,349

Schedule	[1] Month in which Bill was Received (Energy-Based) Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	[2] Total	[3] 12 Month Total
16	$ 43,784	$ 41,699	$ 30,378	$ 35,047	$ 12,952	$ 33,993	$ 197,853	$ 392,281
17	$ 285,668	$ 361,150	$ 397,535	$ 319,280	$ 336,910	$ 187,531	$ 1,888,074	$ 3,404,534
[4] FERC 10	$ (799)	$ 4,755	$ 42,200	$ 2,069	$ (16,141)	$ 4,837	$ 36,921	$ 982,514
Congestion Expense	$ 65,793	$ 648,711	$ 128,550	$ (9,841)	$ 173,953	$ 1,067,561	$ 2,074,728	$ 5,607,031
FTR Credit	$ (916,091)	$ (1,002,577)	$ (443,432)	$ (1,003,037)	$ (387,316)	$ (1,060,723)	$ (4,813,176)	$ (10,433,622)
Gross Losses	$ 1,264,911	$ 1,439,778	$ 1,492,076	$ 1,891,523	$ 2,686,190	$ 1,988,951	$ 10,763,429	$ 23,256,883
Loss Credit	$ -	$ -	$ -				$ -	$ -
Revenue Neutrality	$ 161,083	$ 455,966	$ 311,663	$ 148,668	$ 1,269,724	$ 284,176	$ 2,631,280	$ 4,854,312
Rev. Sufficiency Guarantee	$ 425,982	$ 412,042	$ 1,100,282	$ 392,673	$ 988,339	$ 397,193	$ 3,716,510	$ 5,785,735
[5] Amortization	$ 235,260	$ 236,466	$ 237,678	$ 238,896	$ 240,121	$ 241,353	$ 1,429,774	$ 2,806,877
Total	$ 1,565,590	$ 2,597,990	$ 3,296,931	$ 2,015,278	$ 5,304,731	$ 3,144,872	$ 17,925,393	$ 36,656,544

[1] Actual monthly transmission- and ancillary service-related costs for OE for October 2006 to March 2007.

[2] Calculation: Sum of 6 monthly values

[3] Calculation: Sum of 12 monthly values

[4] Currently billed every August.

[5] "Amortization" represents the monthly portion of the deferred transmission- and ancillary service-related costs (and interest) based upon the actual split by company in the 2005 schedules to be amortized and expensed over a five year period, commencing January 1, 2006. Amortization expense will be further split between energy and demand, based upon the costs that were deferred. See page 9 for the allocation between demand and energy.

CLEVELAND ELECTRIC ILLUMINATING'S TRANSMISSION- AND ANCILLARY SERVICE-RELATED COSTS

Schedule	[1] Month in which Bill was Received (Demand-Based)						[2] Total
	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	
1	$ 124,647	$ 348,545	$ 10,917	$ 170,478	$ 203,325	$ 140,337	$ 998,247
2	$ 291,181	$ 339,400	$ 485,504	$ 387,343	$ 461,948	$ 318,781	$ 2,284,157
3	$ 152,303	$ 177,501	$ 262,500	$ 210,062	$ 250,558	$ 172,965	$ 1,225,889
4							$ -
5	$ 228,439	$ 266,268	$ 393,741	$ 315,111	$ 375,835	$ 259,424	$ 1,838,818
6	$ 114,403	$ 133,331	$ 197,178	$ 157,789	$ 188,207	$ 129,925	$ 920,834
7 (69 kv)							$ -
7 (138 kv)							$ -
8 (69 kv)							$ -
8 (138 kv)							$ -
9 (69 kv)							$ -
9 (138 kv)	$ 2,314,339	$ 2,432,527	$ 4,669,002	$ 3,790,969	$ 4,533,074	$ 3,111,574	$ 20,851,485
10	$ 187,605	$ 63,638	$ 595,343	$ 367,659	$ 251,672	$ 188,568	$ 1,654,485
11							$ -
12							$ -
13							$ -
14							$ -
15	$ -	$ -	$ (2,449)	$ -	$ -	$ -	$ (2,449)
18							$ -
19							$ -
20							$ -
22							$ -
24	$ -	$ -	$ 18,218	$ 18,488	$ 17,388	$ 14,665	$ 68,759
26							$ -
[4] Amortization	$ 335,722	$ 337,758	$ 339,805	$ 378,824	$ 381,119	$ 383,428	$ 2,156,656
Total	$ 3,748,639	$ 4,098,967	$ 6,969,759	$ 5,796,722	$ 6,663,126	$ 4,719,667	$ 31,996,882

Schedule	[1] Month in which Bill was Received (Energy-Based)						[2] Total
	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	
16	$ 32,569	$ 33,638	$ 10,591	$ 33,076	$ 21,287	$ 31,047	$ 162,208
17	$ 242,666	$ 207,020	$ 144,432	$ 256,350	$ 236,418	$ 178,583	$ 1,265,469
[3] FERC 10	$ -	$ -	$ -	$ -	$ 571,068	$ 57,244	$ 628,312
Congestion Expense	$ 1,564,216	$ 406,967	$ 112,520	$ 246,251	$ 341,309	$ 270,899	$ 2,942,162
FTR Credit	$ (1,503,646)	$ (612,535)	$ (3,448)	$ (1,140,856)	$ (773,093)	$ (564,812)	$ (4,598,390)
Gross Losses	$ 1,338,664	$ 1,358,745	$ 1,612,545	$ 2,734,257	$ 2,559,869	$ 826,294	$ 10,430,374
Loss Credit	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenue Neutrality	$ 179,308	$ 25,915	$ 281,405	$ 606,721	$ 438,111	$ 326,127	$ 1,857,588
Rev. Sufficiency Guarantee	$ 263,487	$ 301,467	$ 110,690	$ 338,333	$ 573,905	$ 139,740	$ 1,727,623
[4] Amortization	$ 163,390	$ 164,381	$ 165,378	$ 184,367	$ 185,484	$ 186,608	$ 1,049,608
Total	$ 2,280,656	$ 1,885,598	$ 2,434,114	$ 3,258,499	$ 4,154,358	$ 1,451,731	$ 15,464,956

[1] Actual monthly transmission- and ancillary service-related costs for CEI for April 2006 to September 2006.

[2] Calculation: Sum of 6 monthly values

[3] Currently billed every August.

[4] "Amortization" represents the monthly portion of the deferred transmission- and ancillary service-related costs (and interest) based upon the actual split by company in the 2005 schedules to be amortized and expensed over a five year period, commencing January 1, 2006. Amortization expense will be further split between energy and demand, based upon the costs that were deferred. See page 9 for the allocation between demand and energy.

CLEVELAND ELECTRIC ILLUMINATING'S TRANSMISSION- AND ANCILLARY SERVICE-RELATED COSTS

Schedule	[1] Month in which Bill was Received (Demand-Based)						[2] Total	[3] 12 Month Total
	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07		
1	$ 147,827	$ 139,655	$ 158,756	$ 174,886	$ 165,077	$ 164,199	$ 950,400	$ 1,948,648
2	$ 319,020	$ 300,609	$ 344,187	$ 320,218	$ 320,775	$ 335,975	$ 1,940,784	$ 4,224,941
3	$ 173,018	$ 163,054	$ 186,668	$ 173,693	$ 173,981	$ 182,225	$ 1,052,638	$ 2,278,528
4							$ -	$ -
5	$ 259,542	$ 244,566	$ 280,020	$ 260,509	$ 260,972	$ 273,338	$ 1,578,946	$ 3,417,764
6	$ 129,964	$ 122,479	$ 140,216	$ 130,475	$ 130,687	$ 136,880	$ 790,700	$ 1,711,534
7 (69 kv)							$ -	$ -
7 (138 kv)							$ -	$ -
8 (69 kv)							$ -	$ -
8 (138 kv)							$ -	$ -
9 (69 kv)							$ -	$ -
9 (138 kv)	$ 3,128,444	$ 2,947,907	$ 3,375,261	$ 3,140,219	$ 2,973,418	$ 3,594,720	$ 19,159,970	$ 40,011,455
10	$ 322,287	$ 128,378	$ 328,309	$ 402,293	$ 360,176	$ 353,146	$ 1,894,588	$ 3,549,074
11							$ -	$ -
12							$ -	$ -
13							$ -	$ -
14							$ -	$ -
15	$ -	$ -	$ -				$ -	$ (2,449)
18							$ -	$ -
19							$ -	$ -
20							$ -	$ -
22							$ -	$ -
24	$ 17,025	$ 16,747	$ 18,195	$ 20,750	$ 20,437	$ 18,595	$ 111,749	$ 180,508
26						$ 4,070	$ 4,070	$ 4,070
[5] Amortization	$ 385,743	$ 388,071	$ 390,407	$ 392,686	$ 394,979	$ 397,280	$ 2,349,167	$ 4,505,824
Total	$ 4,882,870	$ 4,451,466	$ 5,222,019	$ 5,015,730	$ 4,800,502	$ 5,460,427	$ 29,833,014	$ 61,829,895

Schedule	[1] Month in which Bill was Received (Energy-Based)						[2] Total	[3] 12 Month Total
	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07		
16	$ 36,708	$ 34,457	$ 24,647	$ 27,803	$ 10,647	$ 27,945	$ 162,207	$ 324,414
17	$ 239,499	$ 298,462	$ 322,567	$ 253,158	$ 275,797	$ 154,164	$ 1,543,647	$ 2,809,116
[4] FERC 10	$ 1,392	$ 2,933	$ 35,808	$ (223)	$ (11,271)	$ 4,107	$ 32,745	$ 661,057
Congestion Expense	$ 55,160	$ 536,056	$ 104,333	$ (7,819)	$ 142,997	$ 877,612	$ 1,708,339	$ 4,650,502
FTR Credit	$ (757,965)	$ (828,453)	$ (362,991)	$ (825,956)	$ (317,790)	$ (871,991)	$ (3,965,146)	$ (8,563,536)
Gross Losses	$ 1,060,481	$ 1,189,192	$ 1,210,845	$ 1,502,124	$ 2,209,895	$ 1,635,061	$ 8,807,598	$ 19,237,972
Loss Credit	$ -	$ -	$ -				$ -	$ -
Revenue Neutrality	$ 135,049	$ 376,622	$ 252,721	$ 117,730	$ 1,040,865	$ 233,613	$ 2,156,601	$ 4,014,188
Rev. Sufficiency Guarantee	$ 357,136	$ 341,227	$ 892,428	$ 309,670	$ 809,979	$ 326,881	$ 3,037,322	$ 4,764,945
[5] Amortization	$ 187,734	$ 188,868	$ 190,005	$ 191,114	$ 192,230	$ 193,350	$ 1,143,300	$ 2,192,908
Total	$ 1,315,195	$ 2,139,365	$ 2,670,363	$ 1,567,601	$ 4,353,347	$ 2,580,742	$ 14,626,612	$ 30,091,568

[1] Actual monthly transmission- and ancillary service-related costs for CEI for October 2006 to March 2007.

[2] Calculation: Sum of 6 monthly values

[3] Calculation: Sum of 12 monthly values

[4] Currently billed every August.

[5] "Amortization" represents the monthly portion of the deferred transmission- and ancillary service-related costs (and interest) based upon the actual split by company in the 2005 schedules to be amortized and expensed over a five year period, commencing January 1, 2006. Amortization expense will be further split between energy and demand, based upon the costs that were deferred. See page 9 for the allocation between demand and energy.

TOLEDO EDISON'S TRANSMISSION- AND ANCILLARY SERVICE-RELATED COSTS

Schedule	[1] Month in which Bill was Received (Demand-Based)						[2] Total
	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	
1	$ 66,953	$ 166,850	$ (2,529)	$ 81,956	$ 91,393	$ 64,758	$ 469,380
2	$ 156,404	$ 152,372	$ 225,076	$ 186,212	$ 207,641	$ 147,106	$ 1,074,811
3	$ 81,807	$ 79,689	$ 121,340	$ 100,986	$ 112,624	$ 79,815	$ 576,260
4							$ -
5	$ 122,704	$ 119,539	$ 182,005	$ 151,487	$ 168,935	$ 119,713	$ 864,383
6	$ 61,450	$ 59,859	$ 91,145	$ 75,856	$ 84,598	$ 59,955	$ 432,861
7 (69 kv)							$ -
7 (138 kv)							$ -
8 (69 kv)							$ -
8 (138 kv)							$ -
9 (69 kv)	$ 453,604	$ 405,598	$ 1,165,494	$ 589,721	$ 699,172	$ 412,166	$ 3,725,756
9 (138 kv)	$ 1,185,208	$ 1,130,271	$ 1,676,367	$ 1,796,317	$ 2,020,996	$ 1,418,137	$ 9,227,295
10	$ 103,138	$ 21,015	$ 283,202	$ 37,422	$ 113,210	$ 87,216	$ 645,203
11							$ -
12							$ -
13							$ -
14							$ -
15	$ -	$ -	$ (1,600)	$ -	$ -	$ -	$ (1,600)
18							$ -
19							$ -
20							$ -
22							$ -
24	$ -	$ -	$ 9,962	$ 9,718	$ 9,468	$ 8,084	$ 37,233
26							$ -
[4] Amortization	$ 147,628	$ 148,524	$ 149,426	$ 238,589	$ 240,033	$ 241,486	$ 1,165,686
Total	$ 2,378,896	$ 2,283,715	$ 3,899,887	$ 3,268,264	$ 3,748,070	$ 2,638,436	$ 18,217,268

Schedule	[1] Month in which Bill was Received (Energy-Based)						[2] Total
	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	
16	$ 17,214	$ 18,488	$ 5,792	$ 17,377	$ 11,600	$ 17,113	$ 87,585
17	$ 128,256	$ 113,797	$ 78,993	$ 134,702	$ 128,727	$ 98,392	$ 682,869
[3] FERC 10	$ -	$ -	$ -	$ -	$ 363,306	$ 25,745	$ 389,051
Congestion Expense	$ 826,748	$ 224,417	$ 61,525	$ 129,393	$ 185,912	$ 149,226	$ 1,577,222
FTR Credit	$ (799,152)	$ (305,546)	$ (1,759)	$ (616,189)	$ (421,797)	$ (310,676)	$ (2,455,118)
Gross Losses	$ 707,539	$ 746,206	$ 881,882	$ 1,435,113	$ 1,395,867	$ 455,707	$ 5,622,315
Loss Credit	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenue Neutrality	$ 94,825	$ 16,110	$ 153,771	$ 321,142	$ 237,458	$ 179,258	$ 1,002,564
Rev. Sufficiency Guarantee	$ 139,255	$ 163,303	$ 60,546	$ 178,055	$ 310,676	$ 77,028	$ 928,862
[4] Amortization	$ 63,067	$ 63,450	$ 63,835	$ 101,927	$ 102,543	$ 103,164	$ 497,987
Total	$ 1,177,754	$ 1,040,226	$ 1,304,586	$ 1,701,520	$ 2,314,292	$ 794,958	$ 8,333,336

[1] Actual monthly transmission- and ancillary service-related costs for TE for April 2006 to September 2006.

[2] Calculation: Sum of 6 monthly values

[3] Currently billed every August.

[4] "Amortization" represents the monthly portion of the deferred transmission- and ancillary service-related costs (and Interest) based upon the actual split by company in the 2005 schedules to be amortized and expensed over a five year period, commencing January 1, 2006. Amortization expense will be further split between energy and demand, based upon the costs that were deferred. See page 9 for the allocation between demand and energy.

TOLEDO EDISON'S TRANSMISSION- AND ANCILLARY SERVICE-RELATED COSTS

Schedule	[1] Month in which Bill was Received (Demand-Based)						[2] Total	[3] 12 Month Total
	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07		
1	$ 70,150	$ 74,912	$ 82,904	$ 94,654	$ 84,131	$ 79,131	$ 485,882	$ 955,262
2	$ 151,304	$ 161,542	$ 179,590	$ 176,203	$ 163,577	$ 161,915	$ 994,130	$ 2,068,941
3	$ 82,060	$ 87,621	$ 97,400	$ 95,575	$ 88,720	$ 87,818	$ 539,194	$ 1,115,454
4							$ -	$ -
5	$ 123,095	$ 131,426	$ 146,107	$ 143,349	$ 133,080	$ 131,728	$ 808,786	$ 1,673,169
6	$ 61,640	$ 65,817	$ 73,162	$ 71,794	$ 66,643	$ 65,966	$ 405,021	$ 837,882
7 (69 kv)							$ -	$ -
7 (138 kv)							$ -	$ -
8 (69 kv)							$ -	$ -
8 (138 kv)							$ -	$ -
9 (69 kv)	$ 460,298	$ 477,336	$ 545,221	$ 523,422	$ 496,442	$ 399,431	$ 2,902,151	$ 6,627,908
9 (138 kv)	$ 1,522,283	$ 1,596,187	$ 1,766,378	$ 1,674,515	$ 1,541,053	$ 1,691,676	$ 9,792,092	$ 19,019,387
10	$ 153,486	$ 221,551	$ 173,482	$ 212,799	$ 183,150	$ 172,498	$ 1,116,966	$ 1,762,169
11							$ -	$ -
12							$ -	$ -
13							$ -	$ -
14							$ -	$ -
15	$ -	$ -	$ -				$ -	$ (1,600)
18							$ -	$ -
19							$ -	$ -
20							$ -	$ -
22							$ -	$ -
24	$ 9,282	$ 8,751	$ 9,957	$ 7,654	$ 10,657	$ 9,731	$ 56,032	$ 93,265
26						$ 1,961	$ 1,961	$ 1,961
[5] Amortization	$ 242,948	$ 244,352	$ 245,647	$ 246,949	$ 248,259	$ 249,575	$ 1,477,730	$ 2,643,417
Total	$ 2,876,547	$ 3,069,495	$ 3,319,849	$ 3,246,914	$ 3,015,713	$ 3,051,430	$ 18,579,947	$ 36,797,216

Schedule	[1] Month in which Bill was Received (Energy-Based)						[2] Total	[3] 12 Month Total
	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07		
16	$ 20,012	$ 18,007	$ 13,495	$ 10,315	$ 5,569	$ 14,623	$ 82,020	$ 169,605
17	$ 130,583	$ 156,021	$ 176,591	$ 92,714	$ 139,420	$ 80,672	$ 776,002	$ 1,458,871
[4] FERC 10	$ 429	$ 2,422	$ 16,590	$ 445	$ (5,308)	$ 1,391	$ 15,970	$ 405,021
Congestion Expense	$ 30,082	$ 280,139	$ 57,077	$ (2,994)	$ 74,806	$ 459,244	$ 898,354	$ 2,475,576
FTR Credit	$ (413,404)	$ (434,244)	$ (196,168)	$ (448,659)	$ (170,314)	$ (456,302)	$ (2,119,091)	$ (4,574,210)
Gross Losses	$ 578,416	$ 620,592	$ 662,606	$ 569,562	$ 1,163,354	$ 855,607	$ 4,450,136	$ 10,072,451
Loss Credit	$ -	$ -	$ -				$ -	$ -
Revenue Neutrality	$ 73,249	$ 196,568	$ 138,571	$ 42,017	$ 532,326	$ 122,247	$ 1,104,977	$ 2,107,540
Rev. Sufficiency Guarantee	$ 194,936	$ 179,488	$ 489,192	$ 99,596	$ 413,322	$ 170,414	$ 1,546,948	$ 2,475,811
[5] Amortization	$ 103,789	$ 104,388	$ 104,942	$ 105,498	$ 106,057	$ 106,620	$ 631,293	$ 1,129,280
Total	$ 718,093	$ 1,123,381	$ 1,462,894	$ 468,493	$ 2,259,232	$ 1,354,516	$ 7,386,609	$ 15,719,945

[1] Actual monthly transmission- and ancillary service-related costs for TE for October 2006 to March 2007.

[2] Calculation: Sum of 6 monthly values

[3] Calculation: Sum of 12 monthly values

[4] Currently billed every August.

[5] "Amortization" represents the monthly portion of the deferred transmission- and ancillary service-related costs (and interest) based upon the actual split by company in the 2005 schedules to be amortized and expensed over a five year period, commencing January 1, 2006. Amortization expense will be further split between energy and demand, based upon the costs that were deferred. See page 9 for the allocation between demand and energy.

CALCULATION OF HISTORICAL ALLOCATION BETWEEN DEMAND AND ENERGY COSTS

Company	[1] Company Demand-Based Costs						[2] Total
	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	
OE	$ 5,914,090	$ 6,950,813	$ 11,044,660	$ 8,212,559	$ 10,852,200	$ 6,425,779	$ 49,400,101
CEI	$ 3,748,639	$ 4,098,967	$ 6,969,759	$ 5,796,722	$ 6,663,126	$ 4,719,667	$ 31,996,882
TE	$ 2,378,896	$ 2,283,715	$ 3,899,887	$ 3,268,264	$ 3,748,070	$ 2,638,436	$ 18,217,268
Total	$ 12,041,625	$ 13,333,496	$ 21,914,306	$ 17,277,546	$ 21,263,396	$ 13,783,882	$ 99,614,250

Company	[1] Company Demand-Based Costs						[2] Total
	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	
OE	$ 7,440,178	$ 7,581,862	$ 8,436,875	$ 8,380,347	$ 8,180,280	$ 8,070,707	$ 48,090,248
CEI	$ 4,882,870	$ 4,451,466	$ 5,222,019	$ 5,015,730	$ 4,800,502	$ 5,460,427	$ 29,833,014
TE	$ 2,876,547	$ 3,069,495	$ 3,319,849	$ 3,246,914	$ 3,015,713	$ 3,051,430	$ 18,579,947
Total	$ 15,199,594	$ 15,102,822	$ 16,978,743	$ 16,642,991	$ 15,996,495	$ 16,582,564	$ 96,503,209

Company	[1] Company Energy-Based Costs						[2] Total
	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	
OE	$ 2,772,774	$ 2,218,075	$ 2,955,032	$ 3,910,807	$ 5,133,343	$ 1,741,120	$ 18,731,152
CEI	$ 2,280,656	$ 1,885,598	$ 2,434,114	$ 3,258,499	$ 4,154,358	$ 1,451,731	$ 15,464,956
TE	$ 1,177,754	$ 1,040,226	$ 1,304,586	$ 1,701,520	$ 2,314,292	$ 794,958	$ 8,333,336
Total	$ 6,231,184	$ 5,143,899	$ 6,693,732	$ 8,870,826	$ 11,601,992	$ 3,987,810	$ 42,529,443

Company	[1] Company Energy-Based Costs						[2] Total
	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	
OE	$ 1,565,590	$ 2,597,990	$ 3,296,931	$ 2,015,278	$ 5,304,731	$ 3,144,872	$ 17,925,393
CEI	$ 1,315,195	$ 2,139,365	$ 2,670,363	$ 1,567,601	$ 4,353,347	$ 2,580,742	$ 14,626,612
TE	$ 718,093	$ 1,123,381	$ 1,462,894	$ 468,493	$ 2,259,232	$ 1,354,516	$ 7,386,609
Total	$ 3,598,878	$ 5,860,736	$ 7,430,188	$ 4,051,373	$ 11,917,310	$ 7,080,129	$ 39,938,615

Company	[3] TOTAL DEMAND-BASED COSTS	[3] TOTAL ENERGY-BASED COSTS	[4] TOTAL COSTS	[5] DEMAND-BASED % OF TOTAL	[6] ENERGY-BASED % OF TOTAL
	2006-07	2006-07	2006-07	2006-07	2006-07
OE	$ 97,490,349	$ 36,656,544	$ 134,146,893	72.67%	27.33%
CEI	$ 61,829,895	$ 30,091,568	$ 91,921,463	67.26%	32.74%
TE	$ 36,797,216	$ 15,719,945	$ 52,517,161	70.07%	29.93%

Company	[7] Amortization of Reconciliation Deferral					
	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06
OE	$ 824,345	$ 827,644	$ 830,957	$ 847,879	$ 852,207	$ 856,559
CEI	$ 499,113	$ 502,138	$ 505,183	$ 563,191	$ 566,604	$ 570,036
TE	$ 210,695	$ 211,974	$ 213,261	$ 340,516	$ 342,577	$ 344,651

Company	[7] Amortization of Reconciliation Deferral					
	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07
OE	$ 860,948	$ 865,360	$ 869,796	$ 874,256	$ 878,739	$ 883,247
CEI	$ 573,477	$ 576,939	$ 580,412	$ 583,800	$ 587,209	$ 590,630
TE	$ 346,737	$ 348,740	$ 350,589	$ 352,447	$ 354,316	$ 356,195

[1] Company demand and energy-based costs are based on actual MISO schedules' bills for each Ohio Operating Company from April 2006 through March 2007.

[2] Calculation: Sum of 6 monthly totals.

[3] Calculation: Sum of 12 monthly totals for the time period April 2006 - March 2007.

[4] Calculation: Sum of 12 monthly totals (demand-based and energy-based).

[5] *Calculation: (Total demand-based costs) / (Total Costs). These allocation percentages are referenced in Exhibits B-1, 2, and 3 as "DA" to allocate the reconciliation adjustment between demand and energy.*

[6] Calculation: (Total energy-based costs) / (Total Costs). These allocation percentages are referenced in Exhibits B-1, 2, and 3 as "EA" to allocate the reconciliation adjustment between demand and energy.

[7] Reconciliation Deferral amount to be amortized by company. These values (taken from company books) are multiplied by the demand and energy allocation percentages above.

Exhibit B-7 provides the projected kWh Sales (adjusted for transmission and distribution losses) by Ohio Operating Company and customer class. These projections are based on estimated Non-shopping Customer kWh consumption that will occur in the 12 months during which the Rider charges will be in effect. These totals are exclusive of the following schedules: CEI Outdoor Lighting, CEI Street Lighting, TE Outdoor Security Lighting (GS-18), TE Street Lighting (SL-1), and TE Outdoor Night Lighting (GS-13). Page 2 provides actual kWh Sales data for 2004, while page 3 provides projected kWh sales data for the last 6 months of 2007 and the first 6 months of 2008.

Ohio Operating Company	Customer Class	[1] Projected 2007 kWh Consumption (Adjusted for Losses)						[2] Total
		Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	
OE	Residential	830,948,875	758,945,980	607,714,133	631,169,555	688,494,621	858,438,396	4,375,711,561
	Commercial	607,773,210	601,083,263	517,320,335	529,495,675	506,894,146	534,070,331	3,296,636,960
	Industrial	680,276,114	712,899,119	657,032,056	702,228,253	649,791,331	613,319,100	4,015,545,972
	Total	2,118,998,199	2,072,928,362	1,782,066,524	1,862,893,483	1,845,180,098	2,005,827,828	11,687,894,493
CEI	Residential	559,757,849	513,540,077	401,894,091	411,618,704	442,793,299	545,525,266	2,875,129,287
	Commercial	426,340,414	423,087,008	367,570,275	374,224,963	363,858,997	391,589,175	2,346,670,831
	Industrial	751,065,951	782,147,447	708,551,362	729,185,624	676,514,618	658,296,516	4,305,761,517
	Total	1,737,164,214	1,718,774,532	1,478,015,728	1,515,029,291	1,483,166,914	1,595,410,957	9,527,561,636
TE	Residential	232,699,539	226,151,790	176,347,139	178,018,585	193,347,612	240,544,567	1,247,109,231
	Commercial	187,947,270	188,123,518	164,119,691	164,359,457	159,320,999	173,686,515	1,037,557,450
	Industrial	436,306,913	460,963,713	432,251,747	452,756,204	431,981,049	428,142,521	2,642,402,147
	Total	856,953,722	875,239,021	772,718,577	795,134,246	784,649,660	842,373,603	4,927,068,828
Total	Residential	1,623,406,263	1,498,637,848	1,185,955,364	1,220,806,844	1,324,635,532	1,644,508,229	8,497,950,079
	Commercial	1,222,060,894	1,212,293,789	1,049,010,301	1,068,080,095	1,030,074,141	1,099,346,021	6,680,865,242
	Industrial	1,867,648,978	1,956,010,278	1,797,835,164	1,884,170,080	1,758,286,998	1,699,758,137	10,963,709,636
	Total	4,713,116,135	4,666,941,914	4,032,800,829	4,173,057,020	4,112,996,671	4,443,612,387	26,142,524,957

Ohio Operating Company	Customer Class	[1] Projected 2008 kWh Consumption (Adjusted for Losses)						[2] Total	[3] Total	[4] Total
		Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08			
OE	Residential	904,827,736	813,521,401	741,597,974	633,001,946	619,647,482	746,168,282	4,458,764,822	8,834,476,383	37.49%
	Commercial	563,445,018	523,801,042	539,818,745	530,818,414	568,524,985	589,181,280	3,315,589,484	6,612,226,444	28.06%
	Industrial	703,987,343	662,220,889	674,075,166	684,383,501	694,724,221	682,905,933	4,102,297,052	8,117,843,024	34.45%
	Total	2,172,260,098	1,999,543,332	1,955,491,885	1,848,203,861	1,882,896,687	2,018,255,495	11,876,651,358	23,564,545,851	100.00%
CEI	Residential	569,560,274	513,436,452	477,111,028	407,272,458	413,797,115	487,570,875	2,868,748,203	5,743,877,490	30.18%
	Commercial	412,409,046	380,029,839	391,615,418	369,420,138	394,816,169	403,978,496	2,352,269,107	4,698,939,939	24.69%
	Industrial	720,549,628	677,269,155	701,573,055	701,323,486	741,413,479	742,919,725	4,285,048,528	8,590,810,045	45.13%
	Total	1,702,518,949	1,570,735,446	1,570,299,501	1,478,016,082	1,550,026,763	1,634,469,096	9,506,065,838	19,033,627,474	100.00%
TE	Residential	247,508,286	223,504,622	213,597,976	168,628,164	166,636,429	207,197,947	1,227,073,424	2,474,182,655	24.96%
	Commercial	192,506,344	178,460,168	186,548,843	177,629,109	194,597,436	200,748,185	1,130,490,085	2,168,047,536	21.87%
	Industrial	454,239,889	425,827,740	442,339,610	431,076,285	439,522,376	435,723,782	2,628,729,682	5,271,131,829	53.17%
	Total	894,254,520	827,792,530	842,486,430	777,333,558	800,756,241	843,669,913	4,986,293,191	9,913,362,019	100.00%
Total	Residential	1,721,896,297	1,550,462,475	1,432,306,979	1,208,902,568	1,200,081,026	1,440,937,103	8,554,586,448	17,052,536,528	32.47%
	Commercial	1,168,360,408	1,082,291,049	1,117,983,007	1,077,867,661	1,157,938,590	1,193,907,961	6,798,348,677	13,479,213,918	25.67%
	Industrial	1,878,776,861	1,765,317,783	1,817,987,831	1,816,783,272	1,875,660,076	1,861,549,440	11,016,075,262	21,979,784,898	41.86%
	Total	4,769,033,566	4,398,071,308	4,368,277,816	4,103,553,501	4,233,679,692	4,496,394,504	26,369,010,387	52,511,535,344	100.00%

[1] POLR load forecasts (adjusted for transmission and distribution losses) for July 2007 through June 2008 as of March 9, 2007.

[2] Calculation: Sum of 6 monthly values.

[3] Calculation: Sum of 12 monthly values.

[4] Calculation: Percent of 12 month total (July 2007 to June 2008) for each company; referenced in Exhibits B-1, 2, and 3 as "REA," "CEA," and "IEA."

Ohio Operating Company	Customer Class	Actual 2004 kWh Consumption[1]						Total[2]
		Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	
OE	Residential	676,755,256	659,556,318	545,530,964	489,273,126	425,296,645	458,501,807	**3,254,914,116**
	Commercial	359,138,375	373,005,986	335,958,542	334,728,624	330,036,456	358,881,918	**2,091,749,901**
	Industrial	508,019,431	556,912,055	534,609,508	556,317,842	541,221,699	536,845,025	**3,233,925,560**
	Total	1,543,913,062	1,589,474,359	1,416,099,014	1,380,319,592	1,296,554,800	1,354,228,750	8,580,589,577
CEI	Residential	186,338,035	169,315,661	136,932,335	127,798,878	109,713,744	116,084,668	**846,183,321**
	Commercial	174,661,085	195,815,699	180,574,260	155,686,659	158,507,283	172,458,680	**1,037,703,666**
	Industrial	561,833,848	579,494,552	654,784,322	630,910,194	599,891,295	678,928,252	**3,705,842,463**
	Total	922,832,968	944,625,912	972,290,917	914,395,731	868,112,322	967,471,600	5,589,729,450
TE	Residential	162,405,943	146,576,785	123,094,814	108,251,103	92,666,843	94,947,196	**727,942,684**
	Commercial	114,297,897	111,269,956	110,573,745	101,218,326	102,410,509	107,354,333	**647,124,766**
	Industrial	426,436,862	457,127,185	405,304,255	429,898,810	406,005,860	425,288,354	**2,550,061,326**
	Total	703,140,702	714,973,926	638,972,814	639,368,239	601,083,212	627,589,883	3,925,128,776

Ohio Operating Company	Customer Class	Actual 2004 kWh Consumption[1]						Total[2]	Total[3]
		Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04		
OE	Residential	511,566,828	519,375,613	481,683,703	436,546,904	406,551,932	549,677,201	**2,905,402,181**	**6,160,316,297**
	Commercial	375,191,215	373,999,140	372,398,592	359,855,863	313,511,124	346,619,948	**2,141,575,882**	**4,233,325,783**
	Industrial	569,709,158	553,437,854	607,813,049	549,998,728	550,610,202	532,977,186	**3,364,546,177**	**6,598,471,737**
	Total	1,456,467,201	1,446,812,607	1,461,895,344	1,346,401,495	1,270,673,258	1,429,274,335	8,411,524,240	**16,992,113,817**
CEI	Residential	133,473,776	135,401,549	129,302,799	113,536,631	110,861,789	146,344,708	**768,921,252**	**1,615,104,573**
	Commercial	155,117,484	160,916,739	183,767,341	122,155,189	142,261,146	152,434,794	**916,652,693**	**1,954,356,359**
	Industrial	620,777,572	666,064,180	678,840,166	599,293,602	581,852,228	556,834,285	**3,703,662,033**	**7,409,504,496**
	Total	909,368,832	962,382,468	991,910,306	834,985,422	834,975,163	855,613,787	5,389,235,978	**10,978,965,428**
TE	Residential	113,154,730	114,585,772	103,260,903	91,063,250	92,556,910	121,383,212	**636,004,777**	**1,363,947,461**
	Commercial	111,127,176	117,114,594	114,775,424	113,598,940	106,719,297	111,281,789	**674,617,220**	**1,321,741,986**
	Industrial	434,063,443	414,100,449	425,591,030	402,689,349	412,614,746	403,717,231	**2,492,776,248**	**5,042,837,574**
	Total	658,345,349	645,800,815	643,627,357	607,351,539	611,890,953	636,382,232	3,803,398,245	**7,728,527,021**

[1] Actual kWh Consumption for 2004.

[2] Calculation: Sum of 6 monthly values.

[3] Calculation: Sum of 12 monthly values. These values are used as divisors on Exhibit B-1, 2, and 3 to calculate the RBR, CBR, and IBR.

FE West Operating Company	Customer Class	[1] Projected 2007 kWh Consumption						[2] Total
		Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	
OE	Residential	759,237,987	693,448,942	555,268,403	576,699,622	629,077,535	784,355,163	**3,998,087,653**
	Commercial	555,560,228	549,444,732	472,877,036	484,006,288	463,346,349	488,187,929	**3,013,422,562**
	Industrial	657,895,029	689,444,738	635,415,701	679,124,943	628,413,196	593,140,901	**3,883,434,509**
	Total	1,972,693,245	1,932,338,412	1,663,561,140	1,739,830,854	1,720,837,080	1,865,683,993	10,894,944,724
CEI	Residential	511,450,747	469,221,569	367,210,631	376,096,010	404,580,237	498,446,436	**2,627,005,629**
	Commercial	390,783,624	387,801,551	336,914,914	343,014,601	333,513,157	358,930,637	**2,150,958,484**
	Industrial	711,259,456	740,693,632	670,998,139	690,538,786	640,659,343	623,406,801	**4,077,556,157**
	Total	1,613,493,826	1,597,716,752	1,375,123,685	1,409,649,397	1,378,752,737	1,480,783,874	8,855,520,271
TE	Residential	212,617,568	206,634,891	161,128,381	162,655,581	176,661,713	219,785,571	**1,139,483,705**
	Commercial	174,020,378	174,183,565	151,958,422	152,180,422	147,515,313	160,816,344	**960,674,443**
	Industrial	424,439,365	448,425,500	420,494,499	440,441,235	420,231,165	416,497,044	**2,570,528,808**
	Total	811,077,311	829,243,955	733,581,302	755,277,238	744,408,191	797,098,960	4,670,686,956

FE West Operating Company	Customer Class	[1] Projected 2008 kWh Consumption						[2] Total	[3] Total
		Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08		
OE	Residential	826,741,103	743,314,504	677,598,069	578,373,878	566,171,904	681,773,959	**4,073,973,418**	**8,072,061,071**
	Commercial	515,039,523	478,801,348	493,442,547	485,215,700	519,683,147	538,565,626	**3,030,747,891**	**6,044,170,453**
	Industrial	680,826,160	640,433,822	651,898,093	661,867,284	671,867,794	660,438,328	**3,967,331,479**	**7,850,765,988**
	Total	2,022,606,786	1,862,549,674	1,822,938,709	1,725,456,862	1,757,722,845	1,880,777,913	11,072,052,788	**21,966,997,512**
CEI	Residential	520,407,223	469,126,886	435,936,347	372,124,845	378,066,424	445,493,508	**2,621,175,233**	**5,248,180,862**
	Commercial	378,014,132	348,335,350	358,954,692	338,610,499	361,888,501	370,286,690	**2,156,089,864**	**4,307,048,348**
	Industrial	682,360,498	641,373,889	664,389,683	664,153,341	702,118,564	703,544,980	**4,057,940,956**	**8,135,497,113**
	Total	1,580,781,852	1,458,836,126	1,459,280,722	1,374,888,685	1,442,093,489	1,519,325,178	8,835,206,052	**17,690,726,323**
TE	Residential	226,148,321	204,216,173	195,164,471	154,075,553	152,255,705	189,316,764	**1,121,176,987**	**2,260,660,692**
	Commercial	178,241,624	165,236,270	172,725,574	164,466,792	180,177,766	185,872,744	**1,046,720,770**	**2,007,395,213**
	Industrial	441,884,564	414,245,225	430,307,972	419,351,010	427,567,368	423,872,095	**2,557,228,235**	**5,127,757,043**
	Total	846,274,509	783,697,668	798,198,018	737,893,355	760,000,839	799,061,603	4,725,125,992	**9,395,812,948**

[1] Projected July 2007 through June 2008 data as of March 9, 2007.

[2] Calculation: Sum of 6 monthly values.

[3] Calculation: Sum of 12 monthly values (July 2007 through June 2008). These values are used as divisors on Exhibit B-1, 2, and 3 to calculate both the TDC and TEC as well as E.

Exhibit B-8 provides the 4 summer system coincident peaks for the Ohio Companies' Non-shopping Customers. The non-shopping customers' peak has been adjusted to model 2006 coincident peaks consistent with 2007-08 energy sales. It also provides similar data by rate schedule for each Ohio Operating Company. In addition, it shows the proportion of load among each of the company's schedules by voltage (either 69 kV and below or 138 kV and above).

Ohio Edison's Summer Coincident Peaks					
Date/Time	Month/Year	Company Peak (KW)	Residential	[1] Commercial	Industrial
6/22/06 15:00	Jun-06	4,451,554	1,618,866	1,667,663	1,165,025
7/31/06 15:00	Jul-06	4,438,456	2,167,524	1,141,134	1,129,798
8/1/06 17:00	Aug-06	4,477,521	1,979,384	1,394,835	1,103,301
9/8/06 15:00	Sep-06	3,859,492	1,266,143	1,448,711	1,144,637
	Total	17,227,023	7,031,918	5,652,343	4,542,761
	[2] % Total	100.00%	40.82%	32.81%	26.37%
	[3] Demand Allocation %	100.00%	**41.62%**	**33.46%**	**24.92%**

CEI's Summer Coincident Peaks					
Date/Time	Month/Year	Company Peak (KW)	Residential	[1] Commercial	Industrial
6/22/06 15:00	Jun-06	3,908,086	1,241,449	1,207,229	1,459,408
7/31/06 15:00	Jul-06	3,920,051	1,637,108	861,786	1,421,157
8/1/06 17:00	Aug-06	3,880,604	1,437,609	1,089,136	1,353,858
9/8/06 15:00	Sep-06	3,158,257	784,287	1,021,586	1,352,383
	Total	14,866,997	5,100,453	4,179,738	5,586,806
	[2] % Total	100.00%	34.31%	28.11%	37.58%
	[3] Demand Allocation %	100.00%	**34.31%**	**28.11%**	**37.58%**

Toledo Edison's Summer Coincident Peaks					
Date/Time	Month/Year	Company Peak (KW)	Residential	[1] Commercial	Industrial
6/22/06 15:00	Jun-06	1,890,285	585,476	601,606	703,203
7/31/06 15:00	Jul-06	1,759,646	682,321	379,908	697,417
8/1/06 17:00	Aug-06	1,674,616	560,571	437,577	676,467
9/8/06 15:00	Sep-06	1,660,849	441,438	512,817	706,593
	Total	6,985,395	2,269,806	1,931,909	2,783,680
	[2] % Total	100.00%	32.49%	27.66%	39.85%
	[3] Demand Allocation %	100.00%	**34.05%**	**28.70%**	**37.24%**

[1] Commercial includes both commercial and street lighting.

[2] Class' contribution to the Company peak for allocating all non-voltage differentiated demand schedules.

[3] Represents a weighted average of voltage and non-voltage differentiated demand schedules.
Calculation: [(Class' share of total company 7, 8, and 9 schedule costs) x (% of company MISO total from 7, 8, and 9 costs) + (Class' share of company peak) x (% of company MISO Total from all other demand-based schedules' costs)]
Source: Exhibit B-8 page 5; Exhibit B-8 page 5; Exhibit B-8 page 1; Exhibit B-8 page 5

Note: The allocation percentages that appear in **BOLD** are referenced in Exhibits B-1, 2, and 3 as "RDA", "CDA", and "IDA."

OE	Jun-06	Jul-06	Aug-06	Sep-06	[2] % at 69 kV	[3] % at 138 kV	[4] 69 kV	[5] 138 kV
Residential Schedules								
Rate 10 (Standard Res)	976,815	1,343,727	1,227,093	772,691	100.00%	100.00%	4,320,326	4,320,326
Rate 11 (Opt Space Heat)	183,453	224,581	205,088	140,026	100.00%	100.00%	753,147	753,147
Rate 12 (Opt Time-of-Day)	1,365	1,698	1,550	1,081	100.00%	100.00%	5,695	5,695
Rate 14 (Opt Ctrl Serv Rider)	87,196	109,427	99,928	73,018	100.00%	100.00%	369,569	369,569
Rate 17 (Load Management)	367,082	484,521	442,465	276,964	100.00%	100.00%	1,571,033	1,571,033
Rate 18 (Water Heating)	526	515	470	498	100.00%	100.00%	2,009	2,009
Rate 19 (Opt Elec Heat Apt)	2,428	3,056	2,790	1,865	100.00%	100.00%	10,140	10,140
TOTAL OE RESIDENTIAL	**1,618,866**	**2,167,524**	**1,979,384**	**1,266,143**	100.00%	100.00%	**7,031,918**	**7,031,918**
Commercial Schedules								
[1] Rate 21 (General Serv)	1,664,043	1,137,626	1,391,244	1,444,072	100.00%	100.00%	5,636,985	5,636,985
All Night Outdoor Lighting	0	0	0	0	100.00%	100.00%	0	0
Traffic Lighting	3,620	3,508	3,591	4,640	100.00%	100.00%	15,358	15,358
Private Outdoor Lighting	0	0	0	0	100.00%	100.00%	0	0
Street Lighting	0	0	0	0	100.00%	100.00%	0	0
TOTAL OE COMMERCIAL	**1,667,663**	**1,141,134**	**1,394,835**	**1,448,711**	100.00%	100.00%	**5,652,343**	**5,652,343**
Industrial Schedules								
Rate 23 (Gen Serv - Large)	745,983	719,832	702,950	734,310	86.86%	100.00%	2,521,611	2,903,076
Rate 28 (GS - High Use Man)	419,042	409,966	400,351	410,327	43.29%	100.00%	709,820	1,639,686
TOTAL OE INDUSTRIAL	**1,165,025**	**1,129,798**	**1,103,301**	**1,144,637**	71.13%	100.00%	**3,231,431**	**4,542,761**

[1] Includes OE Rate 22

[2] % of schedule at 69 kV and below

[3] % of schedule at 138 kV and above

[4] Calculation: (Sum of schedule's 4 CP load) x (% at 69 kV)

[5] Calculation: (Sum of schedule's 4 CP load) x (% at 138 kV)

CEI	Jun-06	Jul-06	Aug-06	Sep-06	[1] % at 138 kV	[2] 138 kV
Residential Schedules						
Res Apt. With WH (30)	2,485	2,989	2,625	1,602	100.00%	9,702
Res Apt. No WH (40)	830	1,139	1,000	519	100.00%	3,488
Residential (50)	1,090,312	1,455,321	1,277,974	688,861	100.00%	4,512,468
Res WH (60)	72,738	87,362	76,716	50,043	100.00%	286,860
Res W & S Heat (70)	67,458	79,066	69,431	39,441	100.00%	255,397
Res Space Heat (80)	4,941	6,553	5,754	2,861	100.00%	20,108
Res AOHP	2,686	4,677	4,107	960	100.00%	12,430
TOTAL CEI RESIDENTIAL	**1,241,449**	**1,637,108**	**1,437,609**	**784,287**	100.00%	**5,100,453**
Commercial Schedules						
General Commercial (100)	563	397	502	442	100.00%	1,903
General Service (105)	323,410	231,628	292,734	254,055	100.00%	1,101,826
Small School (116)	20,347	13,724	17,345	22,733	100.00%	74,149
Large Commercial (120)	5,646	3,973	5,021	4,862	100.00%	19,503
Small Gen Serv (125)	678,191	484,310	612,077	576,821	100.00%	2,351,399
All Elec Lrg Gen Serv (130)	58,093	40,569	51,272	50,483	100.00%	200,417
Large School (135)	57,902	40,020	50,577	63,850	100.00%	212,349
Elec Space Cond (102)	62,390	46,771	59,110	47,676	100.00%	215,947
Traffic Lighting (31c)	685	395	499	665	100.00%	2,244
Outdoor Night Light (926)	0	0	0	0	100.00%	0
TOTAL CEI COMMERCIAL	**1,207,229**	**861,786**	**1,089,136**	**1,021,586**	100.00%	**4,179,738**
Industrial Schedules						
Industrial (140)	71,289	66,281	63,142	66,209	100.00%	266,922
Med Gen Serv (145)	418,237	432,129	411,666	389,765	100.00%	1,651,796
Low Load Factor (150)	1,596	1,595	1,519	1,672	100.00%	6,382
Large Industrial (170)	136,425	125,958	119,994	125,322	100.00%	507,700
Large Gen Serv (175)	783,232	748,159	712,730	717,924	100.00%	2,962,044
Process Heating (101)	48,628	47,036	44,808	51,491	100.00%	191,963
TOTAL CEI INDUSTRIAL	**1,459,408**	**1,421,157**	**1,353,858**	**1,352,383**	100.00%	**5,586,806**

[1] All CEI schedules are served at 138 kV and above.

[2] Calculation: (Sum of schedule's 4 CP load) x (% at 138 kV)

TE	Jun-06	Jul-06	Aug-06	Sep-06	[1] % at 69 kV	[2] % at 138 kV	[3] 69 kV	[4] 138 kV
Residential Schedules								
Standard Res (R-01)	408,948	486,448	399,649	312,156	100.00%	100.00%	1,607,202	1,607,202
Standard Res (R-01a)	26,641	31,270	25,690	21,465	100.00%	100.00%	105,067	105,067
Res AOHP (R-02)	119	187	154	69	100.00%	100.00%	528	528
Res WH (R-04)	71,804	81,324	66,813	56,916	100.00%	100.00%	276,856	276,856
Res WH (R-04a)	3,105	3,453	2,836	2,474	100.00%	100.00%	11,868	11,868
Res Opt Heat (R-06)	844	916	753	525	100.00%	100.00%	3,038	3,038
Res Opt Heat (R-06a)	73	72	59	43	100.00%	100.00%	247	247
Res Heat (R-07)	68,432	72,774	59,788	44,088	100.00%	100.00%	245,081	245,081
Res Heat (R-07a)	3,251	3,462	2,844	2,209	100.00%	100.00%	11,767	11,767
Res Apt (R-09)	2,072	2,208	1,814	1,375	100.00%	100.00%	7,468	7,468
Res Apt (R-09a)	188	207	170	117	100.00%	100.00%	683	683
TOTAL TE RESIDENTIAL	**585,476**	**682,321**	**560,571**	**441,438**	100.00%	100.00%	**2,269,806**	**2,269,806**
Commercial Schedules								
Space Cond (GS-1)	14,371	11,131	12,820	9,210	100.00%	100.00%	47,532	47,532
Process Heat (GS-3)	16,174	8,432	9,712	14,920	100.00%	100.00%	49,237	49,237
Gen Serv (GS-14)	64,292	43,520	50,127	51,656	99.81%	100.00%	209,197	209,596
Small GS (GS-16)	579	374	431	443	100.00%	100.00%	1,827	1,827
Gen Serv Heat (GS-17)	16,221	10,436	12,020	13,608	96.33%	100.00%	50,367	52,286
Control WH (GS-19)	125	73	84	106	100.00%	100.00%	389	389
Control WH (GS-19a)	1	1	1	1	100.00%	100.00%	4	4
Med GS	261,412	162,514	187,183	220,556	95.19%	100.00%	791,661	831,664
Sm GS	186,600	118,305	136,264	155,677	94.89%	100.00%	566,347	596,846
Small Sch (SR-1a)	18,649	11,448	13,186	22,970	92.16%	100.00%	61,060	66,255
Large Sch (SR-2a)	23,181	13,674	15,749	23,669	95.11%	100.00%	72,543	76,273
Street Lighting (SL-1)	0	0	0	0	100.00%	100.00%	0	0
Outdoor Night Lighting (GS-13)	0	0	0	0	100.00%	100.00%	0	0
TOTAL TE COMMERCIAL	**601,606**	**379,908**	**437,577**	**512,817**	95.77%	100.00%	**1,850,165**	**1,931,909**
Industrial Schedules								
Large GS (GS-12)	2,160	2,135	2,071	2,775	100.00%	100.00%	9,141	9,141
Large GS (PV-45 & PV-44)	684,583	678,730	658,342	688,303	51.98%	100.00%	1,408,636	2,709,957
Sm Wst&Swr (WR1)	1,169	1,222	1,186	1,192	100.00%	100.00%	4,769	4,769
Md Wst&Swr (WR2)	15,291	15,330	14,869	14,323	100.00%	100.00%	59,813	59,813
TOTAL TE INDUSTRIAL	**703,203**	**697,417**	**676,467**	**706,593**	53.25%	100.00%	**1,482,359**	**2,783,680**

[1] % of schedule at 69 kV and below

[2] % of schedule at 138 kV and above

[3] Calculation: (Sum of schedule's 4 CP load) x (% at 69 kV)

[4] Calculation: (Sum of schedule's 4 CP load) x (% at 138 kV)

Operating Company	MISO Schedule	[11] MISO Demand-based Costs	[12] % of Total
OE	7, 8, and 9	$ 82,555,612	73.70%
	All Other Demand-based Schedules	$ 29,458,109	26.30%
	TOTAL	$ 112,013,721	100.00%
CEI	7, 8, and 9	$ 47,336,550	67.35%
	All Other Demand-based Schedules	$ 22,950,972	32.65%
	TOTAL	$ 70,287,522	100.00%
TE	7, 8, and 9	$ 29,578,773	73.81%
	All Other Demand-based Schedules	$ 10,494,285	26.19%
	TOTAL	$ 40,073,057	100.00%

Operating Company	Customer Class	[1] 69 kV	[2] 138 kV	[3] % of Total (69 kV)	[4] % of Total (138 kV)	[5] Company Total 7, 8 & 9 Area Costs	[6] Company Total 7, 8 & 9 Bulk Costs	[7] Schedule 7, 8 & 9 - Area $	[8] Schedule 7, 8 & 9 - Bulk $	[9] Schedule 7, 8 & 9 - TOTAL $	[10] % of Total $ (7, 8 & 9)
OE	Residential	7,031,918	7,031,918	44.18%	40.82%	$ 26,734,921	$ 55,820,692	$ 11,812,023	$ 22,785,448	$ 34,597,471	41.91%
	Commercial	5,652,343	5,652,343	35.51%	32.81%	$ 26,734,921	$ 55,820,692	$ 9,494,640	$ 18,315,327	$ 27,809,967	33.69%
	Industrial	3,231,431	4,542,761	20.30%	26.37%	$ 26,734,921	$ 55,820,692	$ 5,427,991	$ 14,719,916	$ 20,147,907	24.41%
	Company Total	15,915,693	17,227,023	100.00%	100.00%	$ -	$ -	$ 26,734,653	$ 55,820,692	$ 82,555,345	100.00%
CEI	Residential	0	5,100,453	0.00%	34.31%	$ -	$ 47,336,550	$ -	$ 16,241,170	$ 16,241,170	34.31%
	Commercial	0	4,179,738	0.00%	28.11%	$ -	$ 47,336,550	$ -	$ 13,306,304	$ 13,306,304	28.11%
	Industrial	0	5,586,806	0.00%	37.58%	$ -	$ 47,336,550	$ -	$ 17,789,075	$ 17,789,075	37.58%
	Company Total	0	14,866,997	0.00%	100.00%	$ -	$ -	$ -	$ 47,336,550	$ 47,336,550	100.00%
TE	Residential	2,269,806	2,269,806	40.52%	32.49%	$ 7,799,007	$ 21,779,766	$ 3,159,768	$ 7,076,246	$ 10,236,013	34.61%
	Commercial	1,850,165	1,931,909	33.03%	27.66%	$ 7,799,007	$ 21,779,766	$ 2,575,622	$ 6,024,283	$ 8,599,905	29.08%
	Industrial	1,482,359	2,783,680	26.46%	39.85%	$ 7,799,007	$ 21,779,766	$ 2,063,617	$ 8,679,237	$ 10,742,854	36.32%
	Company Total	5,602,330	6,985,395	100.00%	100.00%	$ -	$ -	$ 7,799,007	$ 21,779,766	$ 29,578,773	100.00%

[1] Calculation: Sum of each Ohio Company's class total at 69 kV
[2] *Calculation: Sum of each Ohio Company's class total at 138 kV*
[3] Calculation: (Class total at 69 kV) / (Company total at 69 kV)
[4] Calculation: (Class total at 138 kV) / (Company total at 138 kV)
[5] Calculation: Sum of Company's MISO schedules 7, 8, and 9 69 kV costs (Source: Exhibit B-5)
[6] Calculation: Sum of Company's MISO schedules 7, 8, and 9 138 kV costs (Source: Exhibit B-5)
[7] Calculation: (% of Total at 69 kV) x (*Sum of Company's MISO schedules 7, 8, and 9 69 kV costs)*
[8] Calculation: (% of Total at 138 kV) x (Sum of Company's MISO schedules 7, 8, and 9 138 kV costs)
[9] Calculation: Sum of Company's MISO schedules 7, 8, and 9 area and bulk costs, allocated by voltage
[10] Calculation: (Class total 7, 8, and 9 costs) / (Company total 7, 8, and 9 costs)
[11] Ohio Company MISO demand-based costs (Source: Exhibit B-5)
[12] Calculation: (Demand-based schedules' costs) / (Total demand-based costs)

Exhibit B-9 provides the calculation of the Reconciliation Adjustment for the Ohio Edison Riders. This calculation will be performed annually and is based on *12 months of data.*

Ohio Edison Totals							
	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Total
[1] Total Transmission and Ancillary Service Revenue	$ 9,040,595	$ 9,861,531	$ 11,354,912	$ 13,614,606	$ 11,980,454	$ 9,979,961	$ 65,832,059
[2] Booked Costs	$ 8,696,267	$ 9,179,144	$ 14,011,501	$ 12,137,526	$ 15,998,002	$ 8,177,279	$ 68,199,717
[3] Difference	$ 344,329	$ 682,387	$ (2,656,589)	$ 1,477,080	$ (4,017,548)	$ 1,802,682	$ (2,367,658)
[4] Interest Base	$ 172,164	686,205.38	$ (298,173)	$ (889,436)	$ (2,164,169)	$ (3,282,549)	$ (5,775,958)
[5] Carrying Charges	$ 683	$ 2,722	$ (1,508)	$ (4,499)	$ (10,947)	$ (16,659)	$ (30,208)
[6] Total Reconciliation with Carrying Charges	$ 345,012	$ 685,109	$ (2,658,097)	$ 1,472,581	$ (4,028,495)	$ 1,786,023	$ (2,397,867)

Ohio Edison Totals								
	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Total	Year Total
[1] Total Transmission and Ancillary Service Revenue	$ 10,478,852	$ 10,165,568	$ 9,961,131	$ 11,314,498	$ 10,861,764	$ 11,175,040	$ 63,956,852	$ 129,788,911
[2] Booked Costs	$ 9,016,666	$ 10,190,424	$ 11,744,166	$ 10,407,392	$ 13,496,307	$ 11,227,201	$ 66,082,156	$ 134,281,873
[3] Difference	$ 1,462,186	$ (24,856)	$ (1,783,035)	$ 907,106	$ (2,634,544)	$ (52,161)	$ (2,125,304)	$ (4,492,962)
[4] Interest Base	$ (1,666,774)	$ (956,568)	$ (1,865,368)	$ (2,312,799)	$ (3,188,256)	$ (4,547,788)	$ (14,537,553)	$ (20,313,511)
[5] Carrying Charges	$ (8,459)	$ (4,855)	$ (9,467)	$ (11,737)	$ (16,180)	$ (23,080)	$ (73,778)	$ (103,987)
[6] Total Reconciliation with Carrying Charges	$ 1,453,727	$ (29,711)	$ (1,792,502)	$ 895,368	$ (2,650,724)	$ (75,241)	$ (2,199,082)	$ (4,596,949)

[1] Transmission and Ancillary Service revenues, as well as Amortization amounts, are based on Ohio Edison accounting records.

[2] Source: Company books and MISO invoices, amortization of deferrals from the corresponding AAM case, and amortization of deferrals associated with the prior Reconciliation Adjustment, including applicable interest. Values also include expenses associated with the Commercial Activity Tax (CAT).

[3] Calculation: Total Transmission and Ancillary Service Revenue - Booked Costs

[4] Calculation: (Monthly Difference x 0.5) + Cumulative Balance of the Reconciliation with Carrying Charges

[5] Carrying Charges *are applied to the overage/underage* each month and interest is compounded monthly. This calculation uses the interest rate authorized by the Commission in the Rate Stabilization Plan Case (Case No. 03-2144-EL-ATA).

[6] Calculation: Difference + Carrying Charges

[7] Total to be Reconciled through March 2007	$	(4,596,949)
[8] April 2007 Interest	$	(23,330)
[9] May 2007 Interest	$	(23,448)
[10] June 2007 Interest	$	(23,567)
[11] Total to be Reconciled through June 2007	$	(4,667,293)
[12] Incremental Monthly Recovery	$	(388,941)
Monthly Nominal Interest Rate		0.50750%
[15] Total Interest Earned July 2007 - June 2008	$	(147,623)
[16] Total to be Reconciled July 2007 - June 2008	**$**	**(4,814,917)**

	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07
[13] Balance at end of Month	$ (4,472,823)	$ (4,083,882)	$ (3,694,941)	$ (3,305,999)	$ (2,917,058)	$ (2,528,117)
[14] Interest Earned During Month	$ (22,700)	$ (20,841)	$ (18,973)	$ (17,095)	$ (15,208)	$ (13,311)

	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Total
[13] Balance at end of Month	$ (2,139,176)	$ (1,750,235)	$ (1,361,294)	$ (972,353)	$ (583,412)	$ (194,471)	$ (28,003,760)
[14] Interest Earned During Month	$ (11,405)	$ (9,489)	$ (7,563)	$ (5,628)	$ (3,683)	$ (1,727)	$ (147,623)

[7] The total amount to be reconciled, including all carrying charges, through March 2007. Source: Exhibit B-9 page 1. Since the Rider charges are in effect until June 30, 2007, this total earns compounded interest during April, May and June 2007.

[8] Calculation: .005075 x Total to be Reconciled through March 2007

[9] Calculation: .005075 x (Total to be Reconciled through March 2007 x (1.005075))

[10] Calculation: .005075 x [(Total to be Reconciled through March 2007 x (1.005075)) x (1.005075)]

[11] Calculation: Total to be Reconciled for the 12 months ending June 30, 2007

[12] The entire amount to be recovered in the 12 months ending June 30, 2008 is going to be collected on amonthly basis. It is assumed that the total will be recouped in equal monthly increments and that all customers will pay their bills by their respective deadlines (usually 2 weeks). This implies that OE will receive approximately half of the total monthly amount in the month that it is to be billed. Calculation: Total to be Recovered through June 2007 / 12

[13] Calculation: Total to be Recovered through June 2007 - Total Amount recovered through the indicated month.

[14] Calculation: .005075 x (interest earned in previous month(s) + Balance at end of current Month)

[15] Calculation: sum of interest earned during the 12 months ended June 30, 2008

[16] Calculation: Total to be Reconciled through June 2007 + (Total interest earned July 2007 - June 2008). This value represents the Ohio Edison Total to be Reconciled through the 3 Transmission and Ancillary Service Riders during the time period that the Rider charges will be in effect, the 12 months ending June 2008. This total appears in **BOLD** and is referenced in Exhibit B-1 as "E."

Exhibit B-10 provides the calculation of the Reconciliation Adjustment for the *CEI Riders*. This calculation will be performed annually and is based on 12 months of data.

	CEI Totals						
	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Total
[1] Total Transmission and Ancillary Service Revenue	$ 6,181,967	$ 6,929,212	$ 8,285,946	$ 9,945,562	$ 9,156,431	$ 6,869,401	$ 47,368,520
[2] Booked Costs	$ 6,035,724	$ 5,991,772	$ 9,412,490	$ 9,065,564	$ 10,827,007	$ 6,178,543	$ 47,511,101
[3] Difference	$ 146,243	$ 937,440	$ (1,126,544)	$ 879,998	$ (1,670,576)	$ 690,858	$ (142,581)
[4] Interest Base	$ 73,122	615,402.91	$ 524,549	$ 404,427	$ 11,568	$ (478,222)	$ 1,150,846
[5] Carrying Charges	$ 439	$ 3,698	$ 3,152	$ 2,430	$ 70	$ (2,861)	$ 6,927
[6] Total Reconciliation with Carrying Charges	$ 146,683	$ 941,138	$ (1,123,393)	$ 882,428	$ (1,670,506)	$ 687,997	$ (135,654)

	CEI Totals							
	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Total	Year Total
[1] Total Transmission and Ancillary Service Revenue	$ 7,231,815	$ 6,638,190	$ 6,399,239	$ 6,949,756	$ 7,055,362	$ 7,196,623	$ 41,470,985	$ 88,839,505
[2] Booked Costs	$ 6,205,586	$ 6,597,735	$ 7,899,036	$ 6,590,559	$ 9,161,187	$ 8,048,653	$ 44,502,756	$ 92,013,856
[3] Difference	$ 1,026,228	$ 40,455	$ (1,499,797)	$ 359,197	$ (2,105,825)	$ (852,030)	$ (3,031,771)	$ (3,174,351)
[4] Interest Base	$ 377,460	$ 913,060	$ 188,853	$ (380,355)	$ (1,255,868)	$ (2,742,059)	$ (2,898,909)	$ (1,748,063)
[5] Carrying Charges	$ 2,258	$ 5,463	$ 1,092	$ (2,200)	$ (7,263)	$ (15,470)	$ (16,119)	$ (9,192)
[6] Total Reconciliation with Carrying Charges	$ 1,028,487	$ 45,918	$ (1,498,705)	$ 356,997	$ (2,113,088)	$ (867,500)	$ (3,047,890)	$ (3,183,544)

[1] Transmission and Ancillary Service revenues, as well as Amortization amounts, are based on CEI accounting records.

[2] Source: Company books and MISO invoices, amortization of deferrals from the corresponding AAM case, and amortization of deferrals associated with the prior Reconciliation Adjustment, including applicable interest. Values also include expenses associated with the Commercial Activity Tax (CAT).

[3] Calculation: Total Transmission and Ancillary Service Revenue - Booked Costs

[4] Calculation: (Monthly Difference x 0.5) + Cumulative Balance of the Reconciliation with Carrying Charges

[5] Carrying Charges are applied to the *overage/underage* each month and interest is compounded monthly. This calculation uses the interest rate authorized by the Commission in the Rate Stabilization Plan Case (Case No. 03-2144-EL-ATA).

[6] Calculation: Difference + Carrying Charges

[7] Total to be Reconciled through March 2007	$	(3,183,544)
[8] April 2007 Interest	$	(17,960)
[9] May 2007 Interest	$	(18,062)
[10] June 2007 Interest	$	(18,164)
[11] Total to be Reconciled through June 2007	$	(3,237,730)
[12] Incremental Monthly Recovery	$	(269,811)
Monthly Nominal Interest Rate		0.56417%
[15] Total Interest Earned July 2007 - June 2008	$	(114,326)
[16] Total to be Reconciled July 2007 - June 2008	$	(3,352,056)

	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07
[12] Balance at end of Month	$ (3,102,824)	$ (2,833,013)	$ (2,563,203)	$ (2,293,392)	$ (2,023,581)	$ (1,753,770)
[13] Interest Earned During Month	$ (17,505)	$ (16,082)	$ (14,650)	$ (13,211)	$ (11,763)	$ (10,307)

	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Total
[13] Balance at end of Month	$ (1,483,959)	$ (1,214,149)	$ (944,338)	$ (674,527)	$ (404,716)	$ (134,905)	$ (19,426,378)
[14] Interest Earned During Month	$ (8,843)	$ (7,371)	$ (5,890)	$ (4,401)	$ (2,904)	$ (1,398)	$ (114,326)

[7] The total amount to be reconciled, including all carrying charges, through March 2007. Source: Exhibit B-10 page 1. Since the Rider charges are in effect until June 30, 2007, this total earns compounded interest during April, May and June 2007.

[8] Calculation: .0056417 x Total to be Reconciled through March 2007

[9] Calculation: .0056417 x (Total to be Reconciled through March 2007 x (1.0056417))

[10] Calculation: .0056417 x [(Total to be Reconciled through March 2007 x (1.0056417)) x (1.0056417)]

[11] Calculation: Total to be Reconciled for the 12 months ending June 30, 2007

[12] The entire amount to be recovered in the 12 months ending June 30, 2008 is going to be collected on amonthly basis. It is assumed that the total will be recouped in equal monthly increments and that all customers will pay their bills by their respective deadlines (usually 2 weeks). This implies that CEI will receive approximately half of the total monthly amount in the month that it is to be billed. Calculation: Total to be Recovered through June 2007 / 12

[13] Calculation: Total to be Recovered through June 2007 - Total Amount recovered through the indicated month

[14] Calculation: .0056417 x (interest earned in previous month(s) + Balance at end of current Month)

[15] Calculation: sum of interest earned during the 12 months ended June 30, 2008

[16] Calculation: Total to be Reconciled through June 2007 + (Total Interest earned July 2007 - June 2008). This value represents the CEI Total to be Reconciled through the 3 Transmission and Ancillary Service Riders during the time period that the Rider charges will be in effect, the 12 months ending June 2008. This total appears in **BOLD** and is referenced in Exhibit B-2 as "E."

Exhibit B-11 provides the calculation of the Reconciliation Adjustment for the Toledo Edison Riders. This calculation will be performed annually and is based on 12 months of data.

Toledo Edison Totals	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Total
[1] Total Transmission and Ancillary Service Revenue	$ 3,166,182	$ 3,721,851	$ 4,160,718	$ 5,111,180	$ 4,324,190	$ 3,636,574	$ 24,120,695
[2] Booked Costs	$ 3,559,942	$ 3,327,812	$ 5,208,801	$ 4,975,100	$ 6,066,859	$ 3,437,176	$ 26,575,690
[3] Difference	$ (393,760)	$ 394,039	$ (1,048,083)	$ 136,080	$ (1,742,669)	$ 199,399	$ (2,454,994)
[4] Interest Base	$ (196,880)	(197,925.47)	$ (526,138)	$ (985,305)	$ (1,794,528)	$ (2,576,960)	$ (6,277,736)
[5] Carrying Charges	$ (1,185)	$ (1,191)	$ (3,166)	$ (5,928)	$ (10,797)	$ (15,505)	$ (37,771)
[6] Total Reconciliation with Carrying Charges	$ (394,945)	$ 392,848	$ (1,051,248)	$ 130,152	$ (1,753,466)	$ 183,894	$ (2,492,765)

Toledo Edison Totals	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Total	Year Total
[1] Total Transmission and Ancillary Service Revenue	$ 3,082,890	$ 3,581,393	$ 3,740,402	$ 3,733,466	$ 3,777,581	$ 3,724,307	$ 21,640,039	$ 45,760,734
[2] Booked Costs	$ 3,597,845	$ 4,196,601	$ 4,786,634	$ 3,719,290	$ 5,278,874	$ 4,409,819	$ 25,989,063	$ 52,564,752
[3] Difference	$ (514,955)	$ (615,208)	$ (1,046,232)	$ 14,176	$ (1,501,293)	$ (685,512)	$ (4,349,024)	$ (6,804,018)
[4] Interest Base	$ (2,750,243)	$ (3,331,872)	$ (4,180,140)	$ (4,718,183)	$ (5,486,590)	$ (6,608,889)	$ (27,075,916)	$ (33,353,652)
[5] Carrying Charges	$ (16,547)	$ (17,548)	$ (22,015)	$ (24,849)	$ (28,896)	$ (34,807)	$ (144,663)	$ (182,434)
[6] Total Reconciliation with Carrying Charges	$ (531,503)	$ (632,756)	$ (1,068,247)	$ (10,673)	$ (1,530,189)	$ (720,319)	$ (4,493,686)	$ (6,986,451)

[1] Transmission and Ancillary Service revenues, as well as Amortization amounts, are based on Toledo Edison accounting records.

[2] Source: Company books and MISO invoices, amortization of deferrals from the corresponding AAM case, and amortization of deferrals associated with the prior Reconciliation Adjustment, including applicable interest. Values also include expenses associated with the Commercial Activity Tax (CAT).

[3] Calculation: Total Transmission and Ancillary Service Revenue - Booked Costs

[4] Calculation: (Monthly Difference x 0.5) + Cumulative Balance of the Reconciliation with Carrying Charges

[5] Carrying Charges are applied to the overage/underage each month and interest is compounded monthly. This calculation uses the interest rate authorized by the Commission in the Rate Stabilization Plan Case (Case No. 03-2144-EL-ATA).

[6] Calculation: Difference + Carrying Charges

[7] Total to be Reconciled through March 2007	$	(6,986,451)
[8] April 2007 Interest	$	(36,795)
[9] May 2007 Interest	$	(36,989)
[10] June 2007 Interest	$	(37,184)
[11] Total to be Reconciled through June 2007	$	(7,097,420)
[12] Incremental Monthly Recovery	$	(591,452)
Monthly Nominal Interest Rate		0.52667%
[15] Total Interest Earned July 2007 - June 2008	$	(233,299)
[16] Total to be Reconciled July 2007 - June 2008	**$**	**(7,330,719)**

	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07
[12] Balance at end of Month	$ (6,801,694)	$ (6,210,242)	$ (5,618,791)	$ (5,027,339)	$ (4,435,887)	$ (3,844,436)
[13] Interest Earned During Month	$ (35,822)	$ (32,896)	$ (29,954)	$ (26,997)	$ (24,024)	$ (21,036)

	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Total
[13] Balance at end of Month	$ (3,252,984)	$ (2,661,532)	$ (2,070,081)	$ (1,478,629)	$ (887,177)	$ (295,726)	$ (42,584,518)
[14] Interest Earned During Month	$ (18,032)	$ (15,012)	$ (11,976)	$ (8,924)	$ (5,856)	$ (2,772)	$ (233,299)

[7] The total amount to be reconciled, including all carrying charges, through March 2007. Source: Exhibit B-11 page 1. Since the Rider charges are in effect until June 30, 2007, this total earns compounded interest during April, May and June 2007.

[8] Calculation: .0052667 x Total to be Reconciled through March 2007

[9] Calculation: .0052667 x (Total to be Reconciled through March 2007 x (1.0060167))

[10] Calculation: .0052667 x [(Total to be Reconciled through March 2007 x (1.0052667)) x (1.0052667)]

[11] Calculation: Total to be Reconciled for the 12 months ending June 30, 2007

[12] The entire amount to be recovered in the 12 months ending June 30, 2008 is going to be collected on amonthly basis. It is assumed that the total will be recouped in equal monthly increments and that all customers will pay their bills by their respective deadlines (usually 2 weeks). This implies that TE will receive approximately half of the total monthly amount in the month that it is to be billed. Calculation: Total to be Recovered through June 2007 / 12

[13] Calculation: Total to be Recovered through June 2007 - Total Amount recovered through the indicated month

[14] Calculation: .0052667 x (interest earned in previous month(s) + Balance at end of current Month)

[15] Calculation: Sum of interest earned during the 12 months ended June 30, 2008

[16] Calculation: Total to be Reconciled through June 2007 + (Total Interest earned July 2007 - June 2008). This value represents the Toledo Edison Total to be Reconciled through the 3 Transmission and Ancillary Service Riders during the time period that the Rider charges will be in effect, the 12 months ending June 2008. This total appears in **BOLD** and is referenced in Exhibit B-3 as "E."

Exhibit B-12 provides historic revenue, by Ohio Operating Company and customer class. These totals are exclusive of the following schedules: *CEI* Outdoor Lighting, *CEI Street Lighting*, *TE Outdoor Security* Lighting (GS-18), TE Street Lighting (SL-1), and **TE** Outdoor Night Lighting (GS-13).

Ohio Operating Company	Customer Class	[1] Transmission & Ancillary Services Revenue						[2] Total
		Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	
OE	Residential	$ 2,390,244	$ 2,288,867	$ 1,961,829	$ 1,807,727	$ 1,640,010	$ 1,861,061	$ 11,949,738
	Commercial	$ 1,380,205	$ 1,412,224	$ 1,325,747	$ 1,329,833	$ 1,364,390	$ 1,489,511	$ 8,301,911
	Industrial	$ 1,548,591	$ 1,562,988	$ 1,576,087	$ 1,637,284	$ 1,632,138	$ 1,597,625	$ 9,554,713
	Total	$ 5,319,039	$ 5,264,079	$ 4,863,664	$ 4,774,845	$ 4,636,538	$ 4,948,197	$ 29,806,362
CEI	Residential	$ 532,953	$ 470,383	$ 399,146	$ 384,790	$ 345,467	$ 413,724	$ 2,546,463
	Commercial	$ 534,492	$ 588,700	$ 536,410	$ 535,596	$ 546,868	$ 613,986	$ 3,356,053
	Industrial	$ 1,420,808	$ 1,405,219	$ 1,565,352	$ 1,509,267	$ 1,565,008	$ 1,698,182	$ 9,163,836
	Total	$ 2,488,252	$ 2,464,302	$ 2,500,908	$ 2,429,653	$ 2,457,343	$ 2,725,892	$ 15,066,352
TE	Residential	$ 685,262	$ 579,068	$ 508,415	$ 465,722	$ 420,281	$ 470,361	$ 3,129,109
	Commercial	$ 479,088	$ 429,686	$ 449,844	$ 429,797	$ 445,633	$ 506,129	$ 2,740,177
	Industrial	$ 1,586,677	$ 1,631,626	$ 1,485,664	$ 1,675,560	$ 1,627,538	$ 1,664,204	$ 9,671,269
	Total	$ 2,751,027	$ 2,640,381	$ 2,443,922	$ 2,571,079	$ 2,493,452	$ 2,640,694	$ 15,540,555
Total	Residential	$ 3,608,459	$ 3,338,319	$ 2,869,390	$ 2,658,240	$ 2,405,757	$ 2,745,146	$ 17,625,310
	Commercial	$ 2,393,784	$ 2,430,610	$ 2,312,001	$ 2,295,227	$ 2,356,891	$ 2,609,627	$ 14,398,140
	Industrial	$ 4,556,075	$ 4,599,833	$ 4,627,103	$ 4,822,111	$ 4,824,685	$ 4,960,011	$ 28,389,818
	Total	$ 10,558,318	$ 10,368,762	$ 9,808,494	$ 9,775,577	$ 9,587,333	$ 10,314,783	$ 60,413,269

Ohio Operating Company	Customer Class	[1] Transmission & Ancillary Services Revenue						[2] Total	[3] 12 Month Total
		Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04		
OE	Residential	$ 2,117,415	$ 2,152,338	$ 1,997,652	$ 1,752,452	$ 1,551,493	$ 2,004,899	$ 11,576,249	$ **23,525,988**
	Commercial	$ 1,537,975	$ 1,526,569	$ 1,537,886	$ 1,495,083	$ 1,267,863	$ 1,362,029	$ 8,727,406	$ **17,029,317**
	Industrial	$ 1,678,315	$ 1,661,772	$ 1,777,872	$ 1,624,818	$ 1,587,951	$ 1,559,434	$ 9,890,163	$ **19,444,876**
	Total	$ 5,333,706	$ 5,340,679	$ 5,313,410	$ 4,872,354	$ 4,407,307	$ 4,926,363	$ 30,193,818	$ **60,000,181**
CEI	Residential	$ 507,702	$ 517,385	$ 493,200	$ 391,749	$ 347,477	$ 436,208	$ 2,693,721	$ **5,240,185**
	Commercial	$ 634,618	$ 600,784	$ 667,168	$ 483,706	$ 464,514	$ 488,078	$ 3,338,868	$ **6,694,921**
	Industrial	$ 1,650,320	$ 1,695,117	$ 1,718,040	$ 1,525,794	$ 1,452,269	$ 1,380,811	$ 9,422,350	$ **18,586,185**
	Total	$ 2,792,639	$ 2,813,286	$ 2,878,408	$ 2,401,250	$ 2,264,260	$ 2,305,097	$ 15,454,939	$ **30,521,291**
TE	Residential	$ 581,145	$ 590,660	$ 532,743	$ 439,122	$ 417,411	$ 522,298	$ 3,083,380	$ **6,212,488**
	Commercial	$ 528,734	$ 544,732	$ 541,108	$ 507,501	$ 445,950	$ 464,845	$ 3,032,870	$ **5,773,047**
	Industrial	$ 1,684,463	$ 1,663,177	$ 1,662,417	$ 1,620,192	$ 1,628,603	$ 1,655,485	$ 9,914,337	$ **19,585,606**
	Total	$ 2,794,342	$ 2,798,569	$ 2,736,269	$ 2,566,815	$ 2,491,964	$ 2,642,628	$ 16,030,587	$ **31,571,142**
Total	Residential	$ 3,206,262	$ 3,260,382	$ 3,023,596	$ 2,583,324	$ 2,316,382	$ 2,963,405	$ 17,353,350	$ 34,978,661
	Commercial	$ 2,701,327	$ 2,672,085	$ 2,746,162	$ 2,486,291	$ 2,178,327	$ 2,314,952	$ 15,099,145	$ 29,497,285
	Industrial	$ 5,013,098	$ 5,020,066	$ 5,158,329	$ 4,770,804	$ 4,668,823	$ 4,595,730	$ 29,226,850	$ 57,616,668
	Total	$ 10,920,687	$ 10,952,534	$ 10,928,086	$ 9,840,419	$ 9,163,532	$ 9,874,088	$ 61,679,345	$ 122,092,614

[1] *For purposes* of calculating these base charges, actual 2004 data was used.

[2] Calculation: Sum of 6 monthly values

[3] Calculation: Sum of 12 monthly values.

Note: The total monthly transmission and ancillary services revenues that appear in BOLD are used in Exhibits B-1, 2, and 3 to calculate "RBR," "CBR," and "IBR."

Terms, when capitalized in Exhibits B-1 through B-13, shall have the following meanings:

Non-Shopping Customers - all customers who receive all of their retail electric service from an Ohio Operating Company.

Residential Customers - those customers taking all of their retail electric service from an Ohio Operating Company under the schedules listed on the applicable Residential Riders.

Commercial Customers - those customers taking all of their retail electric service from an Ohio Operating Company under the schedules listed on the applicable Commercial Riders.

Industrial Customers - those customers taking all of their retail electric service from an Ohio Operating Company under the schedules listed on the applicable Industrial Riders.

Ohio Operating Company - OE, CEI, or TE, as applicable (collectively, "Ohio Operating Companies").

TABLE OF CONTENTS

TABLE OF CONTENTS

Residential Transmission and Ancillary Service Rider

Residential Transmission and Ancillary Service Charges (RTASC) apply to Residential Customers (as defined below), served under the schedules to which this Rider applies.

RTASC = RBC x RTASPC

Where:

RBC = Base Charge(s) for the appropriate Residential Schedules as identified below, multiplied by the appropriate usage for the month.

RTASPC = Residential Transmission and Ancillary Service Percent Change, in accordance with the formula set forth below.

$$RTASPC = \left[\frac{RTAC - RE}{RBR}\right]\left[\frac{1}{1 - CAT}\right]$$

The RTASPC for the bills rendered July 1, 2007 through June 30, 2008 is 233.25 percent.

Where:

RTAC = The amount of the Company's total projected transmission- and ancillary service-related costs for the Computation Period allocated to Residential Customers.

The Computation Period over which the RTASPC, as computed, and resulting RTASC will apply shall be January 1, 2006 through June 30, 2006 and July 1 through June 30 of each year thereafter.

RE = Net over- or undercollection of the RTAC, including applicable interest, as of the end of the initial 3-month period ending March 31, 2006 and the twelve-month period ending March 31of each year thereafter that immediately precedes the Computation Period.

RBR = The aggregate base revenue of the Residential Schedules collected through the RBC identified below for the 12-month period ending December 31, 2004, divided by the 2004 class energy sales. For the initial 6-month Computation Period the aggregate base revenue will be for the 6-month period ending June 30,2004.

CAT = The Ohio Commercial Activity Tax rate (expressed in decimal form) as established in Section 5751.02 of the Ohio Revised Code.

The RTASPCs shall be filed with the Public Utilities Commission of Ohio (Commission) by November 1, 2005 and by May 1 of each year thereafter. The RTASPC, and the resulting RTASC shall become effective for bills rendered on January 1, 2006 and every July 1 thereafter, unless otherwise ordered by the Commission.

Residential Customers are those customers taking all of their retail electric service under the following schedules with the following base charges:

	Transmission and Ancillary Service Residential Base Charges	
Residential Service – Standard Rate (Sheet No. 10)	Winter	Summer
For Customers without Water Heating		
First 500 kWh, per kWh	0.377 ¢	0.380 ¢
Over 500 kWh, per kWh	0.377 ¢	0.408 ¢
For Customers with Water Heating		
First 350 kWh, per kWh	0.377 ¢	0.380 ¢
Next 350 kWh, per kWh	0.154 ¢	0.154 ¢
Over 700 kWh, per kWh	0.377 ¢	0.408 ¢
Residential Service – Space Heating Rate (Sheet No. 11)		
For Customers without Water Heating		
First 900 kWh, per kWh	0.508 ¢	0.531 ¢
Over 900 kWh, per kWh	0.183 ¢	0.543 ¢
For Customers with Water Heating		
First 550 kWh, per kWh	0.508 ¢	0.531 ¢
Next 350 kWh, per kWh	0.183 ¢	0.183 ¢
Over 900 kWh, per kWh	0.183 ¢	0.543 ¢
***Heat Pump** - For Customers without Water Heating*		
General Purpose usage, per kWh	0.508 ¢	0.531 ¢
For Submetered usage, per kWh	0.183 ¢	0.543 ¢
***Heat Pump** - For Customers with Water Heating*		
First 550 kWh, per kWh	0.508 ¢	0.531 ¢
Next 350 kWh, per kWh	0.183 ¢	0.183 ¢
Over 900 kWh, per kWh	0.508 ¢	0.543 ¢
For Submetered usage, per kWh	0.183 ¢	0.543 ¢
Residential Service – Optional Time-of-Day (Sheet No. 12)		
All kW, per kW	$ 1.175	

	Transmission and Ancillary Service Residential Base Charges	
	Winter	Summer
Residential Service – Load Management Rate (Sheet No. 17)		
First 250 kWh, per kWh	0.409 ¢	0.413 ¢
Next 250 kWh, per kWh	0.382 ¢	0.386 ¢
Balance to 125 kWh per kW of billing load, per kWh	0.382 ¢	0.417 ¢
Over 125 kWh per kW of billing load, per kWh	0.101 ¢	0.101 ¢
Residential Service – Water Heating Service (Sheet No. 18)		
First 50 kWh, per kWh	1.289 ¢	
Over 50 kWh, per kWh	0.193 ¢	
Residential Service – Optional Electrically Heated Apt. Rate (Sheet No. 19)		
First 350 kWh, per kWh	0.469 ¢	0.474 ¢
Next 750 kWh, per kWh	0.157 ¢	0.487 ¢
Over 1,100 kWh, per kWh	0.446 ¢	0.487 ¢

Commercial Transmission and Ancillary Service Rider

Commercial Transmission and Ancillary Service Charges (CTASC) apply to Commercial Customers (as defined below), served under the schedules to which this Rider applies.

CTASC = CBC x CTASPC

Where:

CBC = Base Charge(s) for the appropriate Commercial Schedules as identified below, multiplied by the appropriate usage for the month.

CTASPC = Commercial Transmission and Ancillary Service Percent Change, in accordance with the formula set forth below.

$$CTASPC = \left[\frac{CTAC - CE}{CBR}\right]\left[\frac{1}{1 - CAT}\right]$$

The CTASPC for the bills rendered July 1, 2007 through June 30, 2008 is 232.33 percent.

Where:

CTAC = The amount of the Company's total projected transmission- and ancillary service-related costs for the Computation Period allocated to Commercial Customers.

Non-Shopping Commercial Customers are Commercial Customers and commercial fixed-price contract customers.

The Computation Period over which the CTASPC, as computed, and resulting CTASC will apply shall be January 1, 2006 through June 30, 2006 and July 1 through June 30 of each year thereafter.

CE = Net over- or undercollection of the CTAC, including applicable interest, from Non-Shopping Commercial Customers as of the end of the initial 3-month period ending March 31, 2006 and the twelve-month period ending March 31 of each year thereafter that immediately precedes the Computation Period.

CBR = The aggregate base revenue of the Commercial Schedules collected through the CBC identified below for the 12-month period ending December 31, 2004, divided by the 2004 class energy sales. For the initial 6-month Computation Period the aggregate base revenue will be for the 6-month period ending June 30, 2004.

CAT = The Ohio Commercial Activity Tax rate (expressed in decimal form) as established in Section 5751.02 of the Ohio Revised Code.

The CTASPCs shall be filed with the Public Utilities Commission of Ohio (Commission) by November 1, 2005 and by May 1 of each year thereafter. The CTASPC, and the resulting CTASC shall become effective for bills rendered on January 1, 2006 and every July 1 thereafter, unless otherwise ordered by the Commission.

Commercial Customers are those customers taking all of their retail electric service under the following schedules with the following base charges:

	Transmission and Ancillary Service Commercial Base Charges
General Service – Secondary Voltages (Sheet No. 21)	
First 500 kWh, per kWh	0.578 ¢
Balance to 165 kWh per kW of billing load, per kWh	0.627 ¢
Next 85 kWh per kW of billing demand, per kWh	0.175 ¢
Over 250 kWh per kW of billing demand, per kWh	0.117 ¢
General Service – Secondary Voltages Optional Space and Water Heating (Sheet No. 22)	
Controlled Service, All kWh, per kWh	0.156 ¢
Seasonal Service, All kWh, per kWh	0.164 ¢
Traffic Lighting Service (Sheet No. 31)	
All kWh, per kWh	0.301 ¢
Private Outdoor Lighting Service (Sheet No. 32)	
All kWh, per kWh	0.227 ¢
Lighting Service – All Night Outdoor Lighting Rate (Sheet No. 33)	
First 500 kWh, per kWh	0.578 ¢
Over 500 kWh, per kWh	0.627 ¢
Street Lighting Service - Company Owned (Sheet No. 35)	
All kWh, per kWh	0.301 ¢
Street Lighting Service – Non-Company Owned (Sheet No. 36)	
All kWh, per kWh	0.301 ¢

Industrial Transmission and Ancillary Service Rider

Industrial Transmission and Ancillary Service Charges (ITASC) apply to Industrial Customers (as defined below), served under the schedules to which this Rider applies.

ITASC = IBC x ITASPC

Where:

IBC = Base Charge(s) for the appropriate Industrial Schedules as identified below, multiplied by the appropriate usage for the month.

ITASPC = Industrial Transmission and Ancillary Service Percent Change, in accordance with the formula set forth below.

$$\text{ITASPC} = \left[\frac{\text{ITAC - IE}}{\text{IBR}}\right]\left[\frac{1}{1 - \text{CAT}}\right]$$

The ITASPC for the bills rendered July 1, 2007 through June 30, 2008 is 218.95 percent.

Where:

ITAC = The amount of the Company's total projected transmission- and ancillary service-related costs for the Computation Period allocated to Industrial Customers.

Non-Shopping Industrial Customers are Industrial Customers and industrial fixed-price contract customers.

The Computation Period over which the ITASPC, as computed, and resulting ITASC will apply shall be January 1, 2006 through June 30, 2006 and July 1 through June 30 of each year thereafter.

IE = Net over- or undercollection of the ITAC, including applicable interest, from Non-Shopping Industrial Customers as of the end of the initial 3-month period ending March 31, 2006 and the twelve-month period ending March 31 of each year thereafter that immediately precedes the Computation Period.

IBR = The aggregate base revenue of the Industrial Schedules collected through the IBC identified below for the 12-month period ending December 31, 2004, divided by the 2004 class energy sales. For the initial 6-month Computation Period the aggregate base revenue will be for the 6-month period ending June 30,2004.

CAT = The Ohio Commercial Activity Tax rate (expressed in decimal form) as established in Section 5751.02 of the Ohio Revised Code.

The ITASPCs shall be filed with the Public Utilities Commission of Ohio (Commission) by November 1, 2005 and by May 1 of each year thereafter. The ITASPC, and the resulting ITASC shall become effective for bills rendered on January 1, 2006 and every July 1 thereafter, unless otherwise ordered by the Commission.

Industrial Customers are those customers taking all of their retail electric service under the following schedules with the following base charges:

	Transmission and Ancillary Service Industrial Base Charges
General Service – Large (Sheet No. 23)	
First 2,000 kVa of billing demand, per kVa	$ 1.375
Next 2,000 kVa of billing demand, per kVa	$ 1.375
Over 4,000 kVa of billing demand, per kVa	$ 1.147
General Service – High Use Manufacturing (Sheet No. 28).	
First 8,000 kVa of billing demand, per kVa	$ 1.765
Next 16,000 kVa of billing demand, per kVa	$ 1.469
Over 24,000 kVa of billing demand, per kVa	$ 1.182
General Service – Interruptible Electric Arc Furnace Rate (Sheet No. 29)	
All on-peak kWh, per kWh	0.280 ¢
All off-peak kWh, per kWh	0.280 ¢
Interruptible Rider - Metal Melting Load (Sheet No. 74)	
All on-peak kWh, per kWh	0.294 ¢
All off-peak kWh, per kWh	0.294 ¢
Interruptible Rider – Incremental Interruptible Service (Sheet No. 75)	
138 kV	
All on-peak kWh, per kWh	0.280 ¢
All off-peak kWh, per kWh	0.280 ¢
69 kV	
All on-peak kWh, per kWh	0.288 ¢
All off-peak kWh, per kWh	0.288 ¢
23-34.5 kV	
All on-peak kWh, per kWh	0.294 ¢
All off-peak kWh, per kWh	0.294 ¢
Primary	
All on-peak kWh, per kWh	0.303 ¢
All off-peak kWh, per kWh	0.303 ¢

TABLE OF CONTENTS

TABLE OF CONTENTS

Rider 19
Residential Transmission and Ancillary Service Rider

Residential Transmission and Ancillary Service Charges (RTASC) apply to Residential Customers (as defined below), served under the schedules to which this Rider applies.

RTASC = RBC x RTASPC

Where:

RBC = Base Charge(s) for the appropriate Residential Schedules as identified below, multiplied by the appropriate usage for the month.

RTASPC = Residential Transmission and Ancillary Service Percent Change, in accordance with the formula set forth below.

$$RTASPC = \left[\frac{RTAC - RE}{RBR}\right]\left[\frac{1}{1 - CAT}\right]$$

The RTASPC for the bills rendered July 1, 2007 through June 30, 2008 is 240.22 percent.

Where:

RTAC = The amount of the Company's total projected transmission- and ancillary service-related costs for the Computation Period allocated to Residential Customers.

The Computation Period over which the RTASPC, as computed, and resulting RTASC will apply shall be January 1, 2006 through June 30, 2006 and July 1 through June 30 of each year thereafter.

RE = Net over- or undercollection of the RTAC, including applicable interest, as of the end of the initial 3-month period ending March 31, 2006 and the twelve-month period ending March 31 of each year thereafter that precedes the Computation Period.

RBR = The aggregate base revenue of the Residential Schedules collected through the RBC identified below for the 12-month period ending December 31, 2004, divided by the 2004 class energy sales. For the initial 6-month Computation Period the aggregate base revenue will be for the 6-month period ending June 30, 2004.

CAT = The Ohio Commercial Activity Tax rate (expressed in decimal form) as established in Section 5751.02 of the Ohio Revised Code.

The RTASPCs shall be filed with the Public Utilities Commission of Ohio (Commission) by November 1, 2005 and by May 1 of each year thereafter. The RTASPC, and the resulting RTASC shall become effective for bills rendered on January 1, 2006 and every July 1 thereafter, unless otherwise ordered by the Commission.

Residential Customers are those customers taking all of their retail electric service under the following schedules with the following base charges.

	Transmission and Ancillary Service Residential Base Charges	
	Winter	Summer
Residential Schedule (Sheet No. 10)		
First 500 kWh, per kWh	0.335 ¢	0.387 ¢
Next 500 kWh, per kWh	0.320 ¢	0.372 ¢
Over 1,000 kWh, per kWh	0.206 ¢	0.372 ¢
All use in excess of 125 kWh per kW (Load Mgmt)	0.141 ¢	0.141 ¢
Residential Add On Heat Pump Schedule (Sheet No. 11)		
All kWh, per kWh	0.181 ¢	0.339 ¢
Residential Water Heating Schedule (Sheet No. 12)		
First 500 kWh, per kWh	0.332 ¢	0.386 ¢
Next 500 kWh, per kWh	0.254 ¢	0.310 ¢
Over 1,000 kWh, per kWh	0.156 ¢	0.310 ¢
All use in excess of 125 kWh per kW (Load Mgmt)	0.129 ¢	0.129 ¢
Residential Space Heating Schedule (Sheet No. 13)		
First 500 kWh, per kWh	0.180 ¢	0.210 ¢
Next 500 kWh, per kWh	0.124 ¢	0.202 ¢
Over 1,000 kWh, per kWh	0.081 ¢	0.202 ¢
All use in excess of 125 kWh per kW (Load Mgmt)	0.065 ¢	0.065 ¢
Residential Water and Space Heating Schedule (Sheet No. 14)		
First 500 kWh, per kWh	0.217 ¢	0.256 ¢
Next 100 kWh, per kWh	0.161 ¢	0.202 ¢
Next 400 kWh, per kWh	0.147 ¢	0.202 ¢
Over 1,000 kWh, per kWh	0.091 ¢	0.202 ¢
All use in excess of 125 kWh per kW (Load Mgmt)	0.072 ¢	0.072 ¢

	Transmission and Ancillary Service Residential Base Charges	
Optional Electrically Heated Residential Apartment Schedule (Sheet No. 15)	Winter	Summer
For Customers with Water Heating		
First 300 kWh, per kWh	0.201 ¢	0.235 ¢
Next 300 kWh, per kWh	0.150 ¢	0.187 ¢
Next 1,400 kWh, per kWh	0.078 ¢	0.188 ¢
Next 300 kWh, per kWh	0.079 ¢	0.217 ¢
Over 2,300 kWh, per kWh	0.201 ¢	0.217 ¢
For Customers without Water Heating		
First 300 kWh, per kWh	0.203 ¢	0.237 ¢
Next 300 kWh, per kWh	0.079 ¢	0.233 ¢
Next 1,400 kWh, per kWh	0.078 ¢	0.223 ¢
Over 2,000 kWh, per kWh	0.078 ¢	0.223 ¢

Rider 20
Commercial Transmission and Ancillary Service Rider

Commercial Transmission and Ancillary Service Charges (CTASC) apply to Commercial Customers (as defined below), served under the schedules to which this Rider applies.

CTASC = CBC x CTASPC

Where:

CBC = Base Charge(s) for the appropriate Commercial Schedules as identified below, multiplied by the appropriate usage for the month.

CTASPC = Commercial Transmission and Ancillary Service Percent Change, in accordance with the formula set forth below.

$$\text{CTASPC} = \left[\frac{\text{CTAC - CE}}{\text{CBR}}\right]\left[\frac{1}{1 - \text{CAT}}\right]$$

The CTASPC for the bills rendered July 1, 2007 through June 30, 2008 is 227.00 percent.

Where:

CTAC = The amount of the Company's total projected transmission- and ancillary service-related costs for the Computation Period allocated to Commercial Customers.

Non-Shopping Commercial Customers are Commercial Customers and commercial fixed-price contract customers.

The Computation Period over which the CTASPC, as computed, and resulting CTASC will apply shall be January 1, 2006 through June 30, 2006 and July 1 through June 30 of each year thereafter.

CE = Net over- or undercollection of the CTAC, including applicable interest from Non-Shopping Commercial Customers as of the end of the initial 3-month period ending March 31 of each year thereafter that immediately precedes the Computation Period.

CBR = The aggregate base revenue of the Commercial Schedules collected through the CBC identified below for the 12-month period ending December 31, 2004, divided by the 2004 class energy sales. For the initial 6-month Computation Period the aggregate base revenue will be for the 6-month period ending June 30, 2004.

CAT = The Ohio Commercial Activity Tax rate (expressed in decimal form) as established in Section 5751.02 of the Ohio Revised Code.

The CTASPCs shall be filed with the Public Utilities Commission of Ohio (Commission) by November 1, 2005 and by May 1 of each year thereafter. The CTASPC, and the resulting CTASC shall become effective for bills rendered on January 1, 2006 and every July 1 thereafter, unless otherwise ordered by the Commission.

Commercial Customers are those customers taking all of their retail electric service under the following schedules with the following base charges:

	Transmission and Ancillary Service Commercial Base Charges	
	Winter	Summer
General Service Schedule (Sheet No. 30)		
First 500 kWh, per kWh	0.305 ¢	0.328 ¢
Next 4,500 kWh, per kWh	0.292 ¢	0.315 ¢
Next 5,000 kWh, per kWh	0.256 ¢	0.274 ¢
Over 10,000 kWh, per kWh	0.204 ¢	0.221 ¢
Electric Space Conditioning Schedule (Sheet No. 31)		
All kWh, per kWh	0.129 ¢	0.409 ¢
Small General Service Schedule (Sheet No. 32)		
First 50 kW, per kW	$ 1.113	$ 1.183
Over 50 kW, per kW	$ 1.033	$ 1.096
All Electric Large General Service Schedule (Sheet No. 34)		
First 50 kW, per kW	$ 1.492	$ 1.492
Over 50 kW, per kW	$ 1.397	$ 1.397
Small School Schedule (Sheet No. 36)		
First 50 kW, per kW	$ 1.221	$ 1.287
Over 50 kW, per kW	$ 1.143	$ 1.211
Large School Schedule (Sheet No. 37)		
First 200 kW, per kW	$ 1.528	$ 1.627
Over 200 kW, per kW	$ 1.461	$ 1.566
Outdoor Night Lighting Schedule (Sheet No. 41)		
All kWh, per kWh	0.429 ¢	
Traffic Control Lighting Schedule (Sheet No. 44)		
All kWh, per kWh	0.172 ¢	
Emergency Schedule (Sheet No. 45)		
All kWh, per kWh	1.515 ¢	

	Transmission and Ancillary Service Commercial Base Charges	
General Commercial Schedule (Sheet No. 70)	Winter	Summer
First 500 kWh, per kWh	0.436 ¢	0.473 ¢
Next 7,000 kWh, per kWh	0.417 ¢	0.453 ¢
Over 7,500 kWh, per kWh	0.287 ¢	0.318 ¢
Large Commercial Schedule (Sheet No. 71)		
First 50 kW, per kW	$ 0.858	$ 0.925
Over 50 kW, per kW	$ 0.803	$ 0.865

Rider 21
Industrial Transmission and Ancillary Service Rider

Industrial Transmission and Ancillary Service Charges (ITASC) apply to Industrial Customers (as defined below), served under the schedules to which this Rider applies.

ITASC = IBC x ITASPC

Where:

IBC = Base Charge(s) for the appropriate Industrial Schedules as identified below, multiplied by the appropriate usage for the month.

ITASPC = Industrial Transmission and Ancillary Service Percent Change, in accordance with the formula set forth below.

$$\text{ITASPC} = \left[\frac{\text{ITAC - IE}}{\text{IBR}}\right]\left[\frac{1}{1 - \text{CAT}}\right]$$

The ITASPC for the bills rendered July 1, 2007 through June 30, 2008 is 250.87 percent.

Where:

ITAC = The amount of the Company's total projected transmission- and ancillary service-related costs for the Computation Period allocated to Industrial Customers.

Non-Shopping Industrial Customers are Industrial Customers and industrial fixed-price contract customers.

The Computation Period over which the ITASPC, as computed, and resulting ITASC will apply shall be January 1, 2006 through June 30, 2006 and July 1 through June 30 of each year thereafter.

IE = Net over- or undercollection of the ITAC, including applicable interest, from Non-Shopping Industrial Customers as of the end of the initial 3-month period ending March 31, 2006 and the twelve-month period ending March 31 of each year thereafter that immediately precedes the Computation Period.

IBR = The aggregate base revenue of the Industrial Schedules collected through the IBC identified below for the 12-month period ending December 31, 2004, divided by the 2004 class energy sales. For the initial 6-month Computation Period the aggregate base revenue will be for the 6-month period ending June 30,2004.

CAT = The Ohio Commercial Activity Tax rate (expressed in decimal form) as established in Section 5751.02 of the Ohio Revised Code.

The ITASPCs shall be filed with the Public Utilities Commission of Ohio (Commission) by November 1, 2005 and by May 1 of each year thereafter. The ITASPC, and the resulting ITASC shall become effective for bills rendered on January 1, 2006 and every July 1 thereafter, unless otherwise ordered by the Commission.

Industrial Customers are those customers taking all of their retail electric service under the following schedules with the following base charges:

	Transmission and Ancillary Service Industrial Base Charges	
	Winter	Summer
Medium General Service Schedule (Sheet No. 33)		
First 200 kW, per kW	$ 1.249	$ 1.326
Over 200 kW, per kW	$ 1.138	$ 1.210
Large General Service Schedule (Sheet No. 35)		
First 500 kW, per kW	$ 1.310	
Next 500 kW, per kW	$ 1.238	
Over 1,000 kW, per kW	$ 1.092	
Low Load Factor Schedule (Sheet No. 38)		
First 50 kW, per kW	$ 0.337	$ 0.370
Over 50 kW, per kW	$ 0.310	$ 0.340
Minimum Charge	$ 0.095	$ 0.095
Optional Electric Process Heating and Electric Boiler Management Schedule (Sheet No. 39)		
First 140 kWh per kW of billing load, per kWh	0.160 ¢	0.176 ¢
Over 140 kWh per kW of billing load, per kWh	0.080 ¢	0.080 ¢
Industrial Schedule (Sheet No. 72)		
First 50 kW, per kW	$ 0.981	$ 1.058
Over 50 kW, per kW	$ 0.918	$ 0.989
Large Industrial Schedule (Sheet No. 73)		
First 5,000 kW, per kW	$ 0.834	$ 0.894
Over 5,000 kW, per kW	$ 0.789	$ 0.845

TABLE OF CONTENTS

The following rates, rules and regulations for electric service are applicable throughout Toledo Edison's service territory except as noted.

TABLE OF CONTENTS

Rider 16
Residential Transmission and Ancillary Service Rider

Residential Transmission and Ancillary Service Charges (RTASC) apply to Residential Customers (as defined below), served under the schedules to which this Rider applies.

RTASC = RBC x RTASPC

Where:

RBC = Base Charge(s) for the appropriate Residential Schedules as identified below, multiplied by the appropriate usage for the month.

RTASPC = Residential Transmission and Ancillary Service Percent Change, in accordance with the formula set forth below.

$$RTASPC = \left[\frac{RTAC - RE}{RBR}\right]\left[\frac{1}{1 - CAT}\right]$$

The RTASPC for the bills rendered July 1, 2007 through June 30, 2008 is 214.98 percent.

Where:

RTAC = The amount of the Company's total projected transmission- and ancillary service-related costs for the Computation Period allocated to Residential Customers.

The Computation Period over which the RTASPC, as computed, and resulting RTASC will apply shall be January 1, 2006 through June 30, 2006 and July 1 through June 30 of each year thereafter.

RE = Net over- or undercollection of the RTAC, including applicable interest, as of the end of the initial 3-month period ending March 31, 2006 and the twelve month period ending March 31 of each year thereafter, that immediately precedes the Computation Period.

RBR = The aggregate base revenue of the Residential Schedules collected through the RBC identified below for the 12-month period ending December 31, 2004, divided by the 2004 class energy sales. For the initial 6-month Computation Period the aggregate base revenue will be for the 6-month period ending June 30, 2004.

CAT = The Ohio Commercial Activity Tax rate (expressed in decimal form) as established in Section 5751.02 of the Ohio Revised Code.

The RTASPCs shall be filed with the Public Utilities Commission of Ohio (Commission) by November 1, 2005 and by May 1 of each year thereafter. The RTASPC, and the resulting RTASC shall become effective for bills rendered on January 1, 2006 and every July 1 thereafter, unless otherwise ordered by the Commission.

Residential Customers are those customers taking all of their retail electric service under the following schedules with the following base charges:

	Transmission and Ancillary Service Residential Base Charges	
Residential Rate "R-01" (Sheet No. 10)	Winter	Summer
First 1,000 kWh, per kWh	0.503 ¢	0.546 ¢
Over 1,000 kWh, per kWh	0.417 ¢	0.497 ¢
Residential Add On Heat Pump Rate "R-02" (Sheet No. 11)		
All kWh, per kWh	0.341 ¢	0.690 ¢
Residential Rate "R-01a" (Sheet No. 12)		
First 1,000 kWh, per kWh	0.405 ¢	0.439 ¢
Over 1,000 kWh, per kWh	0.335 ¢	0.400 ¢
Residential Optional Heating Rate "R-06" (Sheet No. 13)		
First 1,000 kWh, per kWh	0.354 ¢	0.387 ¢
Over 1,000 kWh, per kWh (Under 125 Hrs Use)	0.294 ¢	0.355 ¢
Over 1,000 kWh, per kWh (Over 125 Hrs Use)	0.114 ¢	0.114 ¢
Residential Optional Heating Rate "R-06a" (Sheet No. 14)		
First 1,000 kWh, per kWh	0.297 ¢	0.325 ¢
Over 1,000 kWh, per kWh (Under 125 Hrs Use)	0.246 ¢	0.298 ¢
Over 1,000 kWh, per kWh (Over 125 Hrs Use)	0.097 ¢	0.096 ¢
Residential Hot Water Rate "R-04" (Sheet No. 15)		
First 500 kWh, per kWh	0.501 ¢	0.544 ¢
Next 400 kWh, per kWh	0.436 ¢	0.457 ¢
Over 900 kWh, per kWh	0.310 ¢	0.457 ¢
Residential Hot Water Rate "R-04a" (Sheet No. 16)		
First 500 kWh, per kWh	0.865 ¢	0.941 ¢
Next 400 kWh, per kWh	0.754 ¢	0.791 ¢
Over 900 kWh, per kWh	0.536 ¢	0.791 ¢

	Transmission and Ancillary Service Residential Base Charges	
	Winter	Summer
Residential Heating Rate "R-07" (Sheet No. 17)		
First 500 kWh, per kWh	0.332 ¢	0.362 ¢
Next 400 kWh, per kWh	0.288 ¢	0.302 ¢
Over 900 kWh, per kWh	0.165 ¢	0.328 ¢
Residential Heating Rate "R-07a" (Sheet No. 18)		
First 500 kWh, per kWh	0.274 ¢	0.299 ¢
Next 400 kWh, per kWh	0.238 ¢	0.250 ¢
Over 900 kWh, per kWh	0.140 ¢	0.271 ¢
Optional Electrically Heated Apartment Rate "R-09" (Sheet No. 19)		
First 300 kWh, per kWh	0.331 ¢	0.363 ¢
Next 300 kWh, per kWh	0.110 ¢	0.363 ¢
Next 400 kWh, per kWh	0.110 ¢	0.300 ¢
Next 1,000 kWh, per kWh	0.110 ¢	0.327 ¢
Over 2,000 kWh, per kWh	0.331 ¢	0.385 ¢
Optional Electrically Heated Apartment Rate "R-09a" (Sheet No. 20)		
First 300 kWh, per kWh	0.329 ¢	0.360 ¢
Next 300 kWh, per kWh	0.113 ¢	0.360 ¢
Next 400 kWh, per kWh	0.114 ¢	0.297 ¢
Next 1,000 kWh, per kWh	0.113 ¢	0.310 ¢
Over 2,000 kWh, per kWh	0.342 ¢	0.310 ¢

Rider 17
Commercial Transmission and Ancillary Service Rider

Commercial Transmission and Ancillary Service Charges (CTASC) apply to Commercial Customers (as defined below), served under the schedules to which this Rider applies.

CTASC = CBC x CTASPC

Where:

CBC = Base Charge(s) for the appropriate Commercial Schedules as identified below, multiplied by the appropriate usage for the month.

CTASPC = Commercial Transmission and Ancillary Service Percent Change, in accordance with the formula set forth below.

$$\text{CTASPC} = \left[\frac{\text{CTAC - CE}}{\text{CBR}}\right]\left[\frac{1}{1 - \text{CAT}}\right]$$

The CTASPC for the bills rendered July 1, 2007 through June 30, 2008 is 215.37 percent.

Where:

CTAC = The amount of the Company's total projected transmission- and ancillary service-related costs for the Computation Period allocated to Commercial Customers.

Non-Shopping Commercial Customers are Commercial Customers and commercial fixed-price contract customers.

The Computation Period over which the CTASPC, as computed, and resulting CTASC will apply shall be January 1, 2006 through June 30, 2006 and July 1 through June 30 of each year thereafter.

CE = Net over- or undercollection of the CTAC, including applicable interest, from Non-Shopping Commercial Customers as of the end of the initial 3-month period ending March 31, 2006 and the twelve-month period ending March 31 of each year thereafter that immediately precedes the Computation Period.

CBR = The aggregate base revenue of the Commercial Schedules collected through the CBC identified below for the 12-month period ending December 31, 2004, divided by the 2004 class energy sales. For the initial 6-month Computation Period the aggregate base revenue will be for the 6-month period ending June 30, 2004.

CAT = The Ohio Commercial Activity Tax rate (expressed in decimal form) as established in Section 5751.02 of the Ohio Revised Code.

The CTASPCs shall be filed with the Public Utilities Commission of Ohio (Commission) by November 1, 2005 and by May 1 of each year thereafter. The CTASPC, and the resulting CTASC shall become effective for bills rendered on January 1, 2006 and every July 1 thereafter, unless otherwise ordered by the Commission.

Commercial Customers are those customers taking all of their retail electric service under the following schedules with the following base charges:

	Transmission and Ancillary Service Commercial Base Charges	
	Winter	Summer
Small General Service Rate "GS-16" (Sheet No. 40)		
(With Demand Meter)		
First 50 kWd, per kWd	\$ 1.329	\$ 1.437
Over 50 kWd, per kWd	\$ 1.239	\$ 1.348
(Without Demand Meter)		
First 1,000 kWh, per kWh	1.483 ¢	1.600 ¢
Over 1,000 kWh, per kWh	1.292 ¢	1.426 ¢
Small School Rate "SR-1a" (Sheet No. 41)		
First 50 kW, per kW	\$ 0.780	\$ 0.850
Over 50 kW, per kW	\$ 0.721	\$ 0.792
Large School Rate "SR-2a" (Sheet No. 42)		
First 200 kVa, per kVa	\$ 1.025	\$ 1.095
Over 200 kVa, per kVa	\$ 0.976	\$ 1.051
General Service Rate "GS-14" (Sheet No. 44)		
First 500 kWh, per kWh	0.488 ¢	0.536 ¢
Next 4,500 kWh, per kWh	0.468 ¢	0.513 ¢
Next 5,000 kWh, per kWh	0.387 ¢	0.422 ¢
Over 10,000 kWh, per kWh	0.298 ¢	0.322 ¢
Small General Service Schedule (Sheet No. 45)		
First 50 kW, per kW	\$ 1.281	\$ 1.378
Over 50 kW, per kW	\$ 1.239	\$ 1.334
Medium General Service Schedule (Sheet No. 46)		
First 200 kW, per kW	\$ 1.541	\$ 1.648
Over 200 kW, per kW	\$ 1.468	\$ 1.581
General Service Electric Space Conditioning Rate "GS-1" (Sheet No. 47)		
All kWh, per kWh	0.215 ¢	0.683 ¢

	Transmission and Ancillary Service Commercial Base Charges	
	Winter	Summer
Optional Electric Process Heating and Electric Boiler Load Management Rate "GS-3" (Sheet No. 48)		
First 140 kWh per kW of billing load, per kWh	0.681 ¢	0.752 ¢
Over 140 kWh per kW of billing load, per kWh	0.313 ¢	0.313 ¢
General Service Heating Rate "GS-17" (Sheet No. 49)		
(With Demand Meter)		
First 50 kWd, per kWd	$ 1.279	$ 1.372
Over 50 kWd, per kWd	$ 1.202	$ 1.296
(Without Demand Meter)		
First 1,000 kWh, per kWh	1.097 ¢	1.531 ¢
Over 1,000 kWh, per kWh	0.954 ¢	1.356 ¢
Controlled Water Heating Rate "GS-19" (Sheet No. 50)		
All kWh, per kWh	1.109 ¢	
Controlled Water Heating Rate "GS-19a" (Sheet No. 51)		
All kWh, per kWh	1.112 ¢	

Rider 18
Industrial Transmission and Ancillary Service Rider

Industrial Transmission and Ancillary Service Charges (ITASC) apply to Industrial Customers (as defined below), served under the schedules to which this Rider applies.

ITASC = IBC x ITASPC

Where:

IBC = Base Charge(s) for the appropriate Industrial Schedules as identified below, multiplied by the appropriate usage for the month.

ITASPC = Industrial Transmission and Ancillary Service Percent Change, in accordance with the formula set forth below.

$$\text{ITASPC} = \left[\frac{\text{ITAC - IE}}{\text{IBR}}\right]\left[\frac{1}{1 - \text{CAT}}\right]$$

The ITASPC for the bills rendered July 1, 2007 through June 30, 2008 is 156.52 percent.

Where:

ITAC = The amount of the Company's total projected transmission- and ancillary service-related costs for the Computation Period allocated to Industrial Customers.

Non-Shopping Industrial Customers are Industrial Customers and industrial fixed-price contract customers.

The Computation Period over which the ITASPC, as computed, and resulting ITASC will apply shall be January 1, 2006 through June 30, 2006 and July 1 through June 30 of each year thereafter.

IE = Net over- or undercollection of the ITAC, including applicable interest, from Non-Shopping Industrial Customers as of the end of the initial 3-month period ending March 31, 2006 and the twelve-month period ending March 31 of each year thereafter that immediately precedes the Computation Period.

IBR = The aggregate base revenue of the Industrial Schedules collected through the IBC identified below for the 12-month period ending December 31, 2004, divided by the 2004 class energy sales. For the initial 6-month Computation Period the aggregate base revenue will be for the 6-month period ending June 30,2004.

CAT = The Ohio Commercial Activity Tax rate (expressed in decimal form) as established in Section 5751.02 of the Ohio Revised Code.

The ITASPCs shall be filed with the Public Utilities Commission of Ohio (Commission) by November 1, 2005 and by May 1 of each year thereafter. The ITASPC, and the resulting ITASC shall become effective for bills rendered on January 1, 2006 and every July 1 thereafter, unless otherwise ordered by the Commission.

Industrial Customers are those customers taking all of their retail electric service under the following schedules with the following IBC's:

	Transmission and Ancillary Service Industrial Base Charges	
Large General Service Rate "GS-12" (Sheet No. 43)	Winter	Summer
First 200 kVa, per kVa	$ 1.516	$ 1.621
Over 200 kVa, per kVa	$ 1.444	$ 1.554
Large Power Rate "PV-44" (Sheet No. 60)		
(Bulk)		
First 1,000 kVa, per kVa	$ 2.110	
Next 29,000 kVa, per kVa	$ 2.091	
Over 30,000 kVa, per kVa	$ 1.986	
(Primary)		
First 1,000 kVa, per kVa	$ 2.040	
Next 29,000 kVa, per kVa	$ 2.023	
Over 30,000 kVa, per kVa	$ 2.023	
(Sub-Transmission)		
First 1,000 kVa, per kVa	$ 2.387	
Next 29,000 kVa, per kVa	$ 2.357	
Over 30,000 kVa, per kVa	$ 2.248	
Large General Service Rate "PV-45" (Sheet No. 61)		
First 500 kW, per kW	$ 1.942	
Next 500 kW, per kW	$ 1.891	
Over 1,000 kW, per kW	$ 1.839	
Small Water & Waste Water Rate "WR-1" (Ordinance Rate)		
First 130 kWh per kW of billing load, per kWh	0.797 ¢	
Next 170 kWh per kW of billing load, per kWh	0.211 ¢	
Next 150 kWh per kW of billing load, per kWh	0.157 ¢	
Over 450 kWh per kW of billing load, per kWh	0.145 ¢	
Medium Water & Waste Water Rate "WR-2" (Ordinance Rate)		
First 130 kWh per kW of billing load, per kWh	1.107 ¢	
Next 170 kWh per kW of billing load, per kWh	0.261 ¢	
Next 150 kWh per kW of billing load, per kWh	0.181 ¢	
Over 450 kWh per kW of billing load, per kWh	0.164 ¢	

		FTR Revenues/Credits	Congestion Revenues/Credits	Net Losses	Revenue Sufficiency Guarantee Costs
a	What drives this cost?	MISO currently allocates FTRs at no cost. Instead the owner of an FTR generally receives revenue to offset or hedge the expense of congestion. The driver of FTR revenue is the magnitude of congestion.	The major drivers of congestion are: 1) transmission and generation asset availability; 2) load levels; 3) the location of the load and the generation; and 4) fuel cost of marginal generating units at various locations.	The major drivers of net losses are 1) transmission and generation asset availability; 2) load levels; 3) the location of the load and generation; and 4) fuel cost of marginal generating units at various locations.	The driver of Revenue Sufficiency Guarantee is reliability.

		FTR Revenues/Credits	***Congestion Revenues/Credits***	***Net Losses***	***Revenue Sufficiency Guarantee Costs***
b.	Describe in detail the MISO process or markets with which this cost is associated.	A congestion management process benefits the MISO market. MISO's congestion management process enables it to maximize the use of the transmission system for the benefit of all participants (i.e. utilize the lowest cost energy sources to serve load.) Loads are assessed their respective share of the congestion cost through the difference between the congestion portions of the LMP of their source (generator or location of purchased power) and sink (load). MISO provides FTRs to entities serving retail load as a financial hedge to offset congestion costs. The MISO Business Practices Manual for FTRs more fully describes the FTR allocation process and can be found on the MISO website at www.midwestiso.org.	A congestion management process benefits the MISO market. MISO's congestion management process enables it to maximize the use of the transmission system for the benefit of all participants (i.e. utilize the lowest cost energy sources to serve load.) Loads are assessed their respective share of the congestion cost through the difference between the congestion portions of the LMP of their source (generator or location of purchased power) and sink (load). The MISO Business Practices Manual for Energy Markets describes this process in more detail.	MISO incorporates the cost to provide marginal losses in the economic dispatch equation in order to dispatch the most economical generation on a real time basis. Each load is assessed its respective share of marginal loss cost as a portion of the *LMP at the load's* withdrawal point on the transmission system utilizing the same source- sink methodology as congestion. Calculating LMP's based on marginal, rather than average, losses results in MISO over collecting revenues. As a result, load serving entities are entitled to an over-collection rebate. Hence, the cost of net losses represents the cost of marginal losses net of the rebate for over collection.	Revenue Sufficiency Guarantee ("RSG") is a mechanism that ensures Generation Resources that are started up and dispatched by MISO for reliability recovery of their start-up costs, no load costs, and energy offer. The *point at which* MISO orders the generators on for reliability determines whether RSG is Day-ahead or Real-time. Real-time RSG cost is assessed to both generators and loads which do not match exactly their committed day-ahead schedules. Day-ahead RSG is accessed to Load Serving Entities by load ratio share.

		FTR Revenues/Credits	Congestion Revenues/Credits	Net Losses	Revenue Sufficiency Guarantee Costs
c	Describe the control the Companies have over this cost	As a load serving entity, the Companies are entitled to a load ratio share of economically feasible FTRs from MISO. In requesting this entitlement, the Companies choose the most valuable FTRs based on MISO market history. Consequently the Companies only have control over entitlement nominations to receive an FTR allocation. Actual FTR revenue/credit depends upon actual differences in Day-Ahead LMP's in the energy market, issues over which the Companies have no control.	See response to (a) above. As load serving entities, the Companies have no control over the drivers of congestion cost.	See response to (a) above. As load serving entities, the Companies have no control over the drivers of net losses.	As a MISO charge, the Companies must incur RSG cost. Load can be assessed RSG charges if it does not meet the day-ahead market cleared MW quantity. Therefore, the Companies have partial control over RSG by minimizing their load forecasting variances. However, due to events beyond the Companies' control, it is not feasible for the Companies to perfectly forecast their load each and every day.

		FTR Revenues/Credits	Congestion Revenues/Credits	Net Losses	Revenue Sufficiency Guarantee Costs
d	What options do the Companies have in incurring this cost?	N/A. FTRs are an entitlement for the load serving entity and as such are allocated by MISO free of charge. There are no costs associated with the allocation of FTRs.	The Companies have no option. They must incur this cost. However, FTR revenue offsets this cost as evidenced by the Congestion Graph, attached as Exhibit D-1.	The Companies have no option. They must incur this cost. The cost of losses is an integral part of the overall LMP and, therefore, is an *unavoidable cost.*	As a MISO charge, the Companies must incur this cost. Load forecast variance affects the amount of RSG that will be charged to the Companies. The Companies continue to review and refine their load forecast in order to minimize RSG costs.
e	What options have the Companies pursued and why?	As shown in the Congestion Graph which is attached as Exhibit D-1 and 1a, the Companies have been quite successful in controlling net congestion cost with the use of the "free" FTR's. As such, no other options have been pursued.	Congestion is an inherent reality of the energy market. Other than hedging through FTRs, the Companies are unaware of any other current cost effective options that can be implemented.	Net losses are an inherent reality of the energy market. No options exist to negate being assessed marginal losses.	With respect to load forecast variance, the Companies continue to review and refine their forecast model so as to minimize RSG costs. The Companies currently have no other available option to further manage the RSG costs.

Case No. 07-0128-EL-ATA
Exhibit D

		FTR Revenues/Credits	Congestion Revenues/Credits	Net Losses	Revenue Sufficiency Guarantee Costs
f	Have the Companies evaluated the potential impacts of pursuing the other options? If so, provide the *expected* impacts of pursuing each of those options.	Although the Companies continue to monitor market developments and cost management tools and techniques, the Companies are unaware of any cost effective options beyond those currently being implemented by the Companies.	Although the Companies continue to monitor market developments and cost management tools and techniques, the Companies are unaware of any cost effective options beyond those currently being implemented by the Companies.	Although the Companies continue to monitor market developments and cost management tools and techniques, the Companies *are unaware of any cost* options available to manage this cost. See response to (e) above).	As explained in the response to (e) above, the Companies continue to review and refine load forecasting methods in an effort to minimize RSG costs. Although the Companies continue to monitor market developments and cost management tools and techniques, the Companies are unaware of any additional cost effective options currently available to further manage this cost.
g	If the Companies have not evaluated the other options, please do so and provide the expected impacts of these options.	See response to (f) above.	See response to (f) above.	See response to (f) above.	See response to (f) above.
h	Please provide graphically, the monthly cost since the Companies began operating in MISO	See the Congestion Graph which is attached as Exhibit D-1 and 1a. The sign convention is a credit (revenue) when negative and a debit (expense) when positive.	See the Congestion Graph attached as Exhibit D-1. The sign convention is negative for a credit (revenue) and positive for a debit (cost).	See the Net Losses Graph attached as Exhibit D-2.	See the RSG Graphs of DA (Day ahead). RT (real time) RSG and total RSG attached as Exhibit D-3a,b and c.

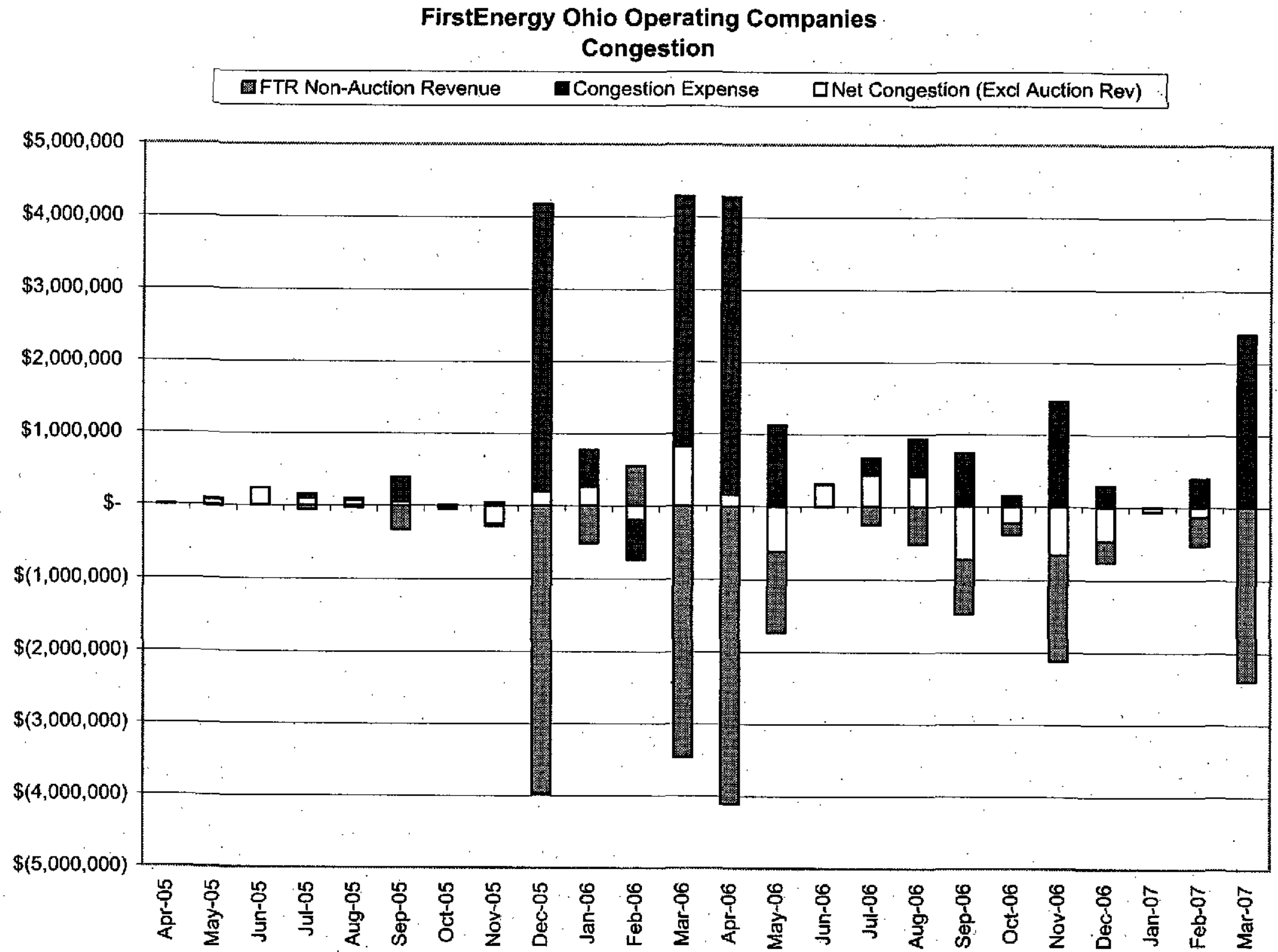
		FTR Revenues/Credits	Congestion Revenues/Credits	Net Losses	Revenue Sufficiency Guarantee Costs
i	If these costs/revenues discussed in (h) show a decreasing or increasing trend please explain such trend.	FTR Revenues act as an offset to congestion. No trends are observed in attached Exhibit D-1.	Congestion is offset by FTR Revenue. No trends are observed in the attached Exhibit D-1.	Net losses reflect seasonal levels of load, scheduled generation outages, and wholesale transmission flow through the MISO Market. Net losses tend to be higher in the higher load periods due to increased transmission line flow and higher market cost to supply losses.	RSG costs depend upon load deviation between real-time actual and scheduled day-ahead values. As explained in (e) above, the Companies minimize RSG by continuously reviewing and refining their load forecast model. Therefore, the fluctuation observed in the Total RSG Cost Chart (Exhibit D-3c) is a direct result of the variability of generation commitment costs required in real-time to balance load and generation. Since the start of the MISO market, RSG costs have trended downward

		FTR Revenues/Credits	Congestion Revenues/Credits	Net Losses	Revenue Sufficiency *Guarantee Costs*
j	*If there* are spikes in the trend, please explain in detail the cause of such spikes	Spikes in FTR Revenue reflect times of extreme congestion, caused by a larger spread between *source LMP's and sink* LMP's. Spikes in December 2005, March and April 2006, and March 2007 were observed in the Congestion Graph (Exhibit D-1). The spikes in FTR Revenues (Exhibit D-1a) correlate to the spikes in congestion for these same months.	Spikes in congestion reflect times of *extreme* transmission system constraint resulting in higher *basis values (i.e., a larger* spread between source LMP's and sink LMP's.) Spikes in December 2005, March and April 2006, and March 2007 were observed in the Congestion Cost chart. The Companies do not have the necessary information from MISO to explain the exact causes for the spikes in congestion during these months. However one or all of the drivers discussed in (a.) above more than likely contributed to these spikes.	Spikes in net losses were observed for September, October and December 2005, July-August 2006, and February 2007. These spikes are due to increased loads or high energy prices during the respective months. Hurricane Katrina affected energy prices in September, October and December 2005, thus causing increased costs for generation used to replace losses.	Since December 2005, Total RSG Costs have declined in the MISO Market as a result of *market maturity.* Discounting the market maturity phase of April 2005 through December 2005, the Total RSG Costs spiked in August and December 2006 and February 2007 (Exhibit D-3c). The spike of August 2006 represents a normal seasonal condition caused by high prices due to all time summer peak loads being set and higher cost peaking generation being online. February 2007's spike appears to have been caused by an extremely cold month with high loads and expensive fuel costs. This resulted in significant increase in RSG due to peaking costs not recovered through LMP.

		FTR Revenues/Credits	Congestion Revenues/Credits	Net Losses	Revenue Sufficiency Guarantee Costs
k	Provide any internal documents or written policies used to ensure the cost is being minimized.	The Companies have implemented a plan to minimize congestion cost through the use of FTRs. As evidenced in Exhibit D-1 and 1a, this approach appears to be successful. Although employees have been directed to follow this practice and a portion of their compensation is tied to the results, there is no formal written policy related to these costs and revenues.	As indicated in (a) above, the *Companies*, as load serving entities, have no control over the drivers of congestion cost. Therefore, there are no formal written policies related to this cost.	As indicated in (a) above, the Companies, as load serving entities, have no control over the drivers of this cost. Therefore, there are no formal written policies related to this cost.	There are no written documents or written policy which ensure cost minimization specific for RSG. The Companies continue to review and refine their load forecasting methods to minimize RSG costs
l	Provide any departments, divisions, units, etc. that are involved with managing the cost and what their responsibilities are with regard to ensuring that the costs are minimized.	In late 2006, FirstEnergy created the Regulated Commodity Sourcing organization which, among other things, is responsible for all commodity procurement decision making for FirstEnergy's regulated utilities. This responsibility includes managing regulated generation resources as well as overseeing competitive procurements on behalf of the utilities. See previous responses for methods employed to minimize these costs.	In late 2006, FirstEnergy created the Regulated Commodity Sourcing organization which, among other things, is responsible for all commodity procurement decision making for FirstEnergy's regulated utilities. This responsibility includes managing regulated generation resources as well as overseeing competitive procurements on behalf of the utilities. See previous responses for methods employed to minimize these costs.	In late 2006, FirstEnergy created the Regulated Commodity Sourcing organization which, among other things, is responsible for all commodity procurement decision making for FirstEnergy's regulated utilities. This responsibility includes managing regulated generation resources as well as overseeing competitive procurements on behalf of the utilities. See previous responses for methods employed to minimize these costs.	In late 2006, FirstEnergy created the Regulated Commodity Sourcing organization which, among other things, is responsible for all commodity procurement decision making for FirstEnergy's regulated utilities. This responsibility includes managing regulated generation resources as well as overseeing competitive procurements on behalf of the utilities. See previous responses for methods employed to minimize these costs.

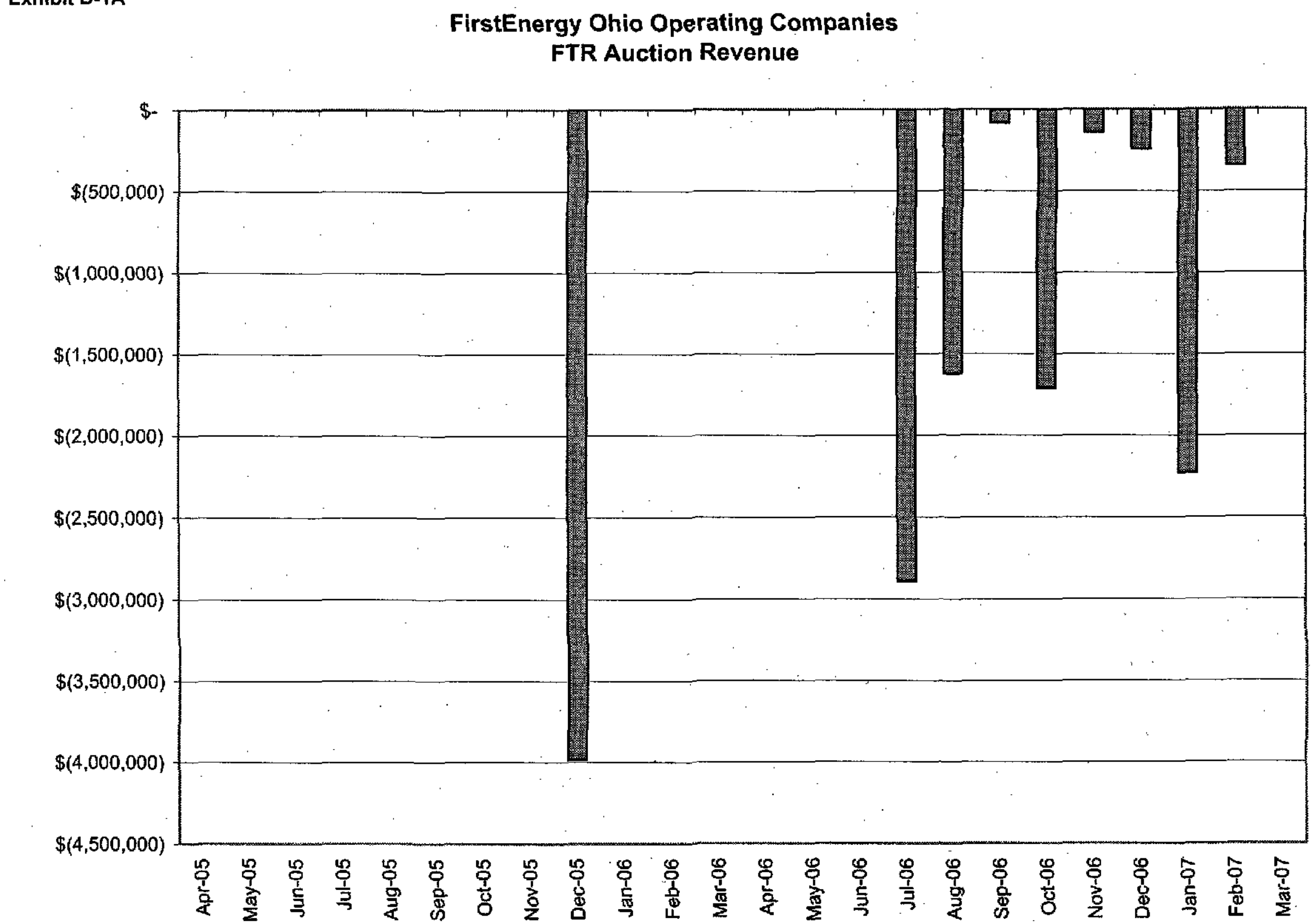
		FTR Revenues/Credits	Congestion Revenues/Credits	Net Losses	Revenue Sufficiency Guarantee Costs
m	Provide any additional information that could enhance Staff's review of these costs.	BPM 5 - Section 2.6 and 2.9 Midwest ISO - Section 7 and 8	BPM 5 - Section 2.1.2	BPM 5 - Section 2.16	BPM 5 - Section 2.71 Revenue Sufficiency Guarantee FAQs

Exhibit D-1



Negative $ represent revenue (or a credit to expenses)

Exhibit D-1A



Negative $ represent revenue (or a credit to expenses)

Exhibit D-2

FirstEnergy Ohio Operating Companies
Net Transmission Losses

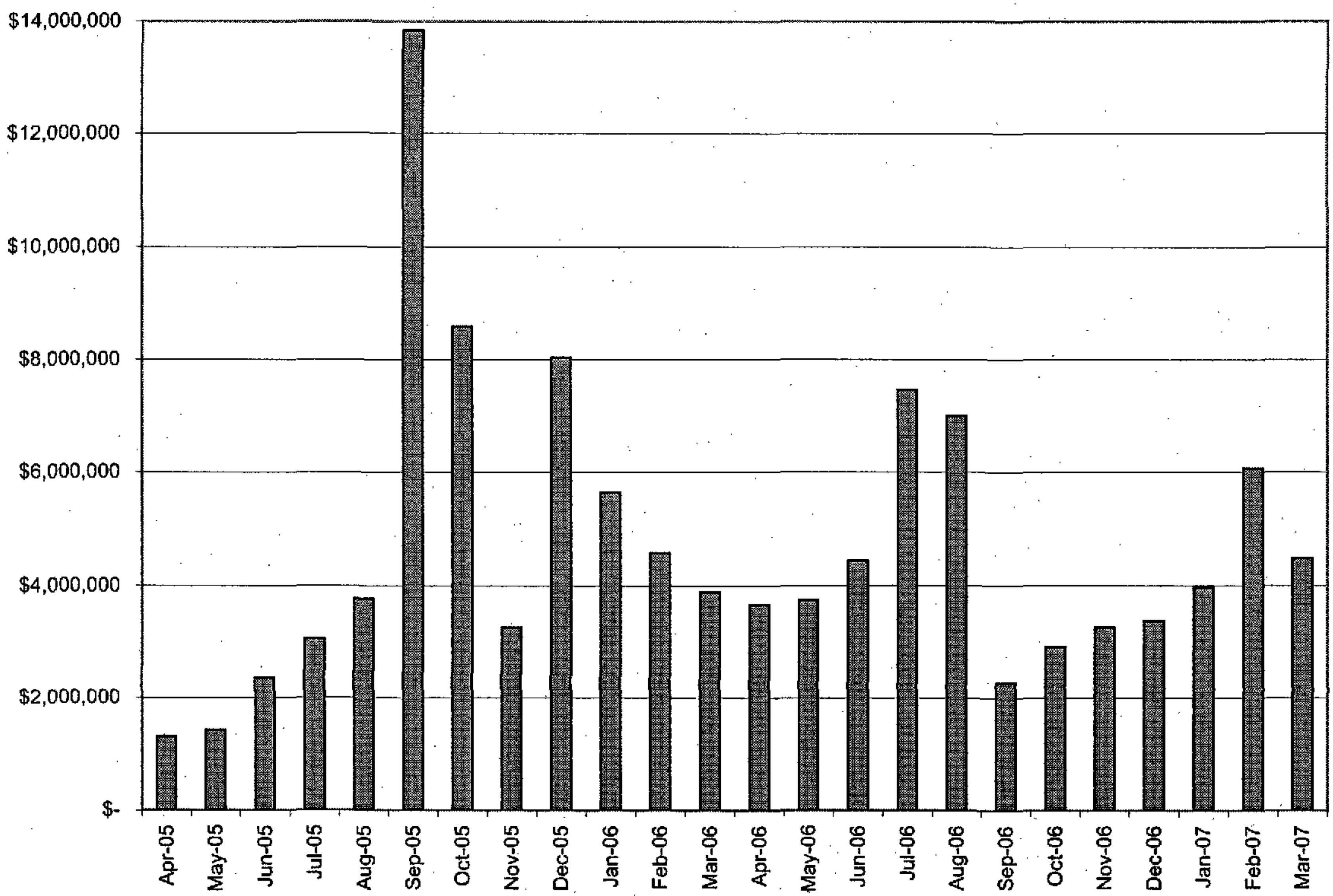
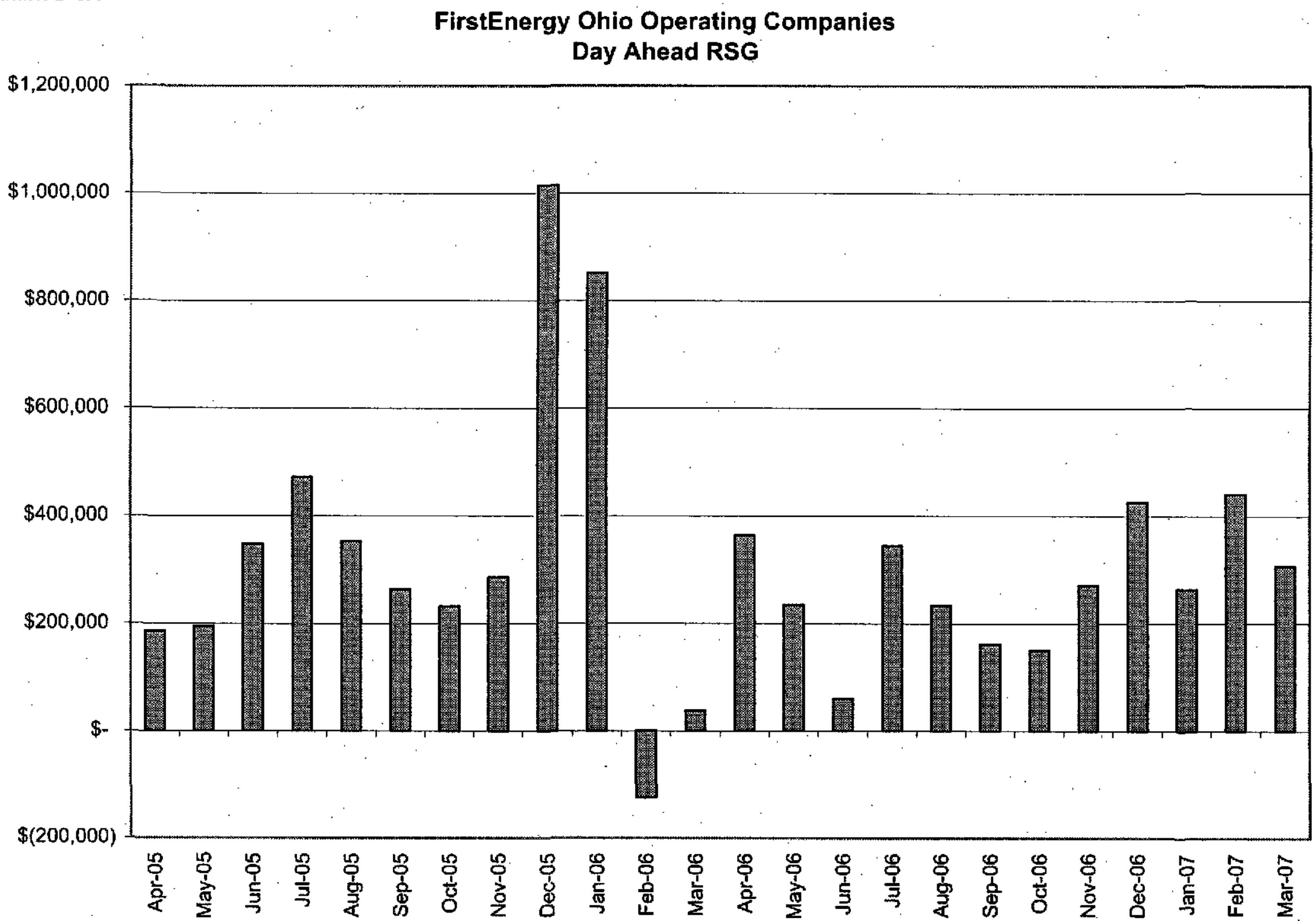


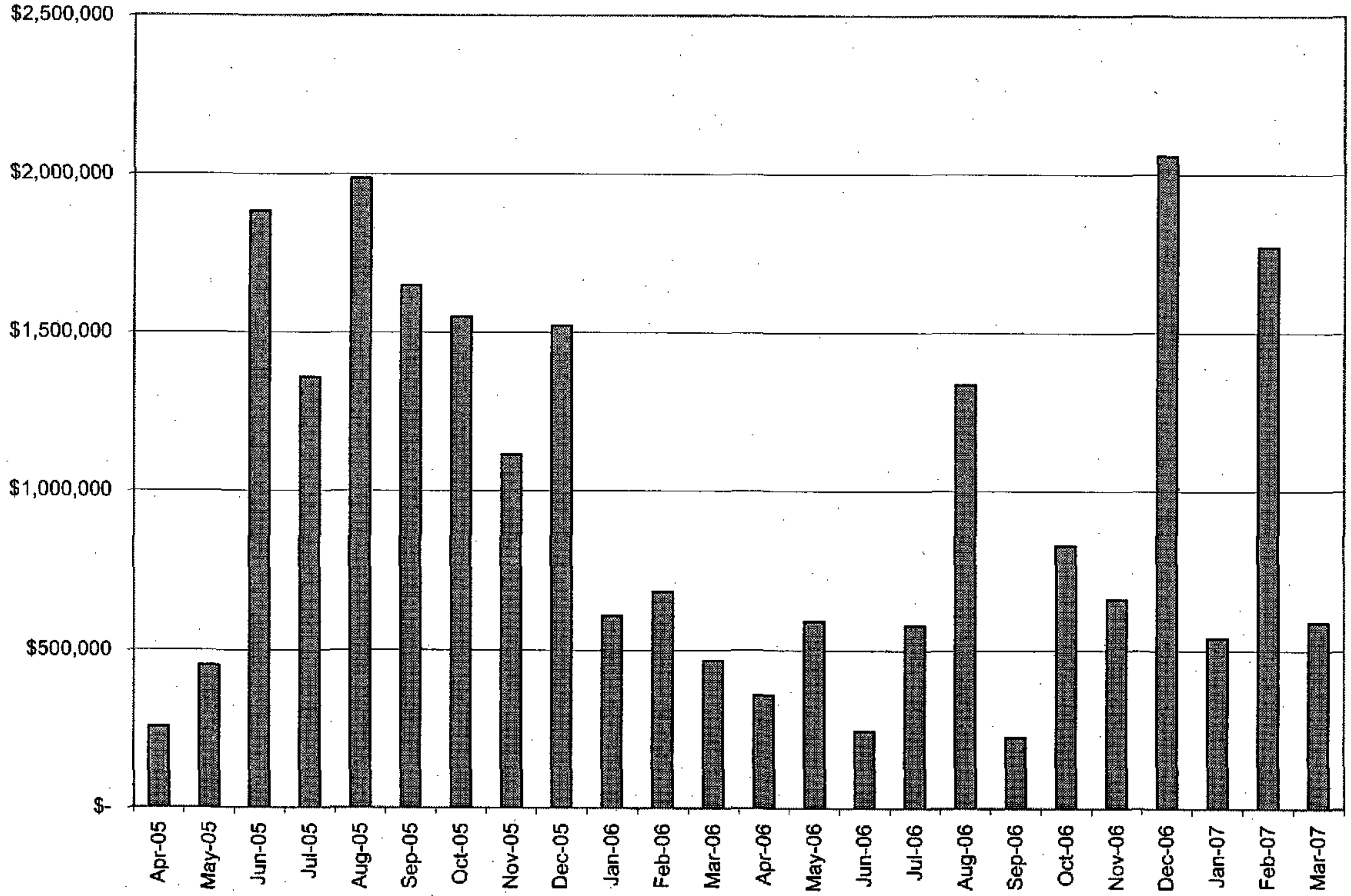
Exhibit D-3A



Negative $ represent revenue (or a credit to expenses)
April 2005 - December 2005 based on operational data.

Exhibit D-3B

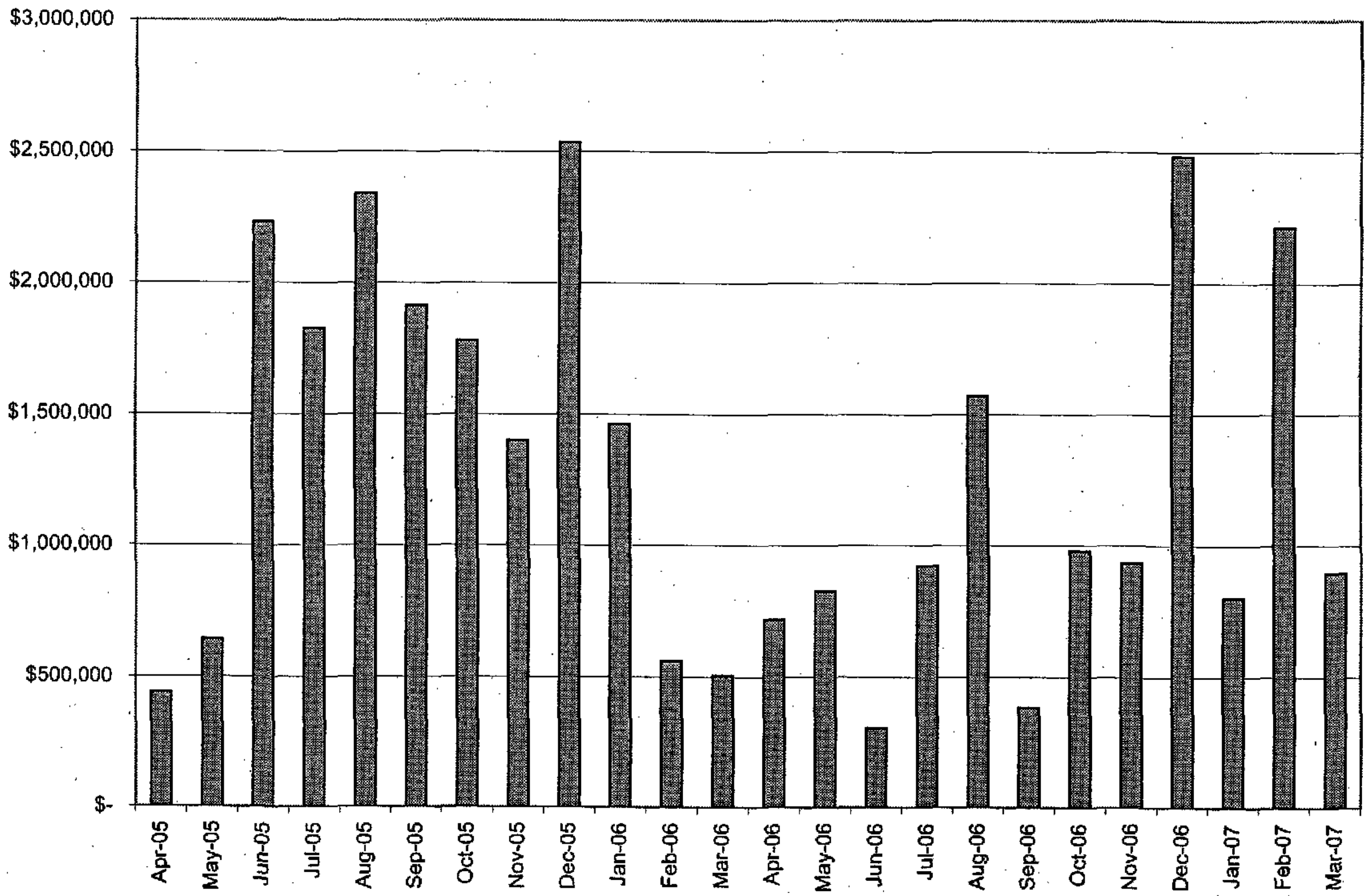
FirstEnergy Ohio Operating Companies
Real Time RSG



April 2005 - December 2005 based on operational data.

Exhibit D-3C

FirstEnergy Ohio Operating Companies
Total RSG



April 2005 - December 2005 based on operational data.