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PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE APPLICATION OF KENTUCKY POWER COMPANY FOR:	)	
(1) A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY	)	
AUTHORIZING THE TRANSFER TO THE COMPANY OF AN	)	
UNDIVIDED FIFTY PERCENT INTEREST IN THE MITCHELL	)	
GENERATING STATION AND ASSOCIATED ASSETS; (2) APPROVAL	)	
OF THE ASSUMPTION BY KENTUCKY POWER COMPANY OF	)	
CERTAIN LIABILITIES IN CONNECTION WITH THE TRANSFER OF	)	
THE MITCHELL GENERATING STATION; (3) DECLARATORY	)	**CASE NO. 2012-00578**
RULINGS; (4) DEFERRAL OF COSTS INCURRED IN CONNECTION	)	
WITH THE COMPANY'S EFFORTS TO MEET FEDERAL CLEAN AIR	)	
ACT AND RELATED REQUIREMENTS; 5) FOR ALL OTHER	)	
REQUIRED APPROVALS AND RELIEF	)	

KENTUCKY POWER COMPANY RESPONSES TO

ALEXANDER DESHA, TOM VIERHELLER, BEVERLY MAY, AND SIERRA CLUB'S

INITIAL SET OF DATA REQUESTS

February 20. 2013

VERIFICATION

The undersigned, Mark A. Becker, being duly sworn, deposes and says he is the Manager, Resource Planning for American Electric Power Company that he has personal knowledge of the matters set forth in the foregoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge and belief

Mark A. Becker

Mark A. Becker

STATE OF OKLAHOMA)
) CASE NO. 2012-00578
COUNTY OF TULSA)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Mark A. Becker, this the 14 day of February, 2013.

Angela Brown

Notary Public

ANGELA BROWN
Notary Public in and for
STATE OF OKLAHOMA
Commission # 02003536
Expires: February 27, 2014

My Commission Expires: 2-27-14

VERIFICATION

The undersigned, Karl R. Bletzacker, being duly sworn, deposes and says he is Director, Fundamental Analysis for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge, and belief.

Karl R Bletzacker

Karl R. Bletzacker

STATE OF OHIO)
) CASE NO. 2012-00578
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Karl R. Bletzacker, this the 19 day of February 2013.

Holly M. Charles

Notary Public

NOTARY PUBLIC STATE OF OHIO

Holly M. Charles
Notary Public-State of Ohio
My Commission Expires
March 7, 2016

My Commission Expires: March 7, 2016

VERIFICATION

The undersigned, Jeffery D. LaFleur, being duly sworn, deposes and says he is Vice President Generating Assets APCO/KY, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge, and belief

Jeffery D. LaFleur

JEFFERY D. LAFLEUR

STATE OF WEST VIRGINIA)
) Case No. 2012-00578
COUNTY OF KANAWHA)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Jeffery D. LaFleur, this the 19 day of February 2013.

Dorothy E. Philyaw

Notary Public

OFFICIAL SEAL
STATE OF WEST VIRGINIA
NOTARY PUBLIC
DOROTHY E. PHILYAW
APPALACHIAN POWER
PO BOX 1986
CHARLESTON, WV 25327 1986
My commission expires October 2, 2019

My Commission Expires: October 2, 2019

VERIFICATION

The undersigned, John M. McManus, being duly sworn, deposes and says he is Vice President Environmental Services for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge and belief

John M. McManus

John M. McManus

STATE OF OHIO)
) CASE NO. 2012-00578
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by John M. McManus, this the 11 day of February 2013.

Janet White

Notary Public

JANET L. WHITE
[illegible] Public, State of Ohio
My Commission Expires: [illegible] Expires 09-09-2013

VERIFICATION

The undersigned, Gregory G. Pauley, being duly sworn, deposes and says he is the President and Chief Operating Officer for Kentucky Power Company, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his/her information, knowledge and belief

Greg G Pauley
Gregory G. Pauley

COMMONWEALTH OF KENTUCKY)
) CASE NO. 2012-00578
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Gregory G. Pauley, this the 11th day of February, 2013.

Judy K Rosquist 481393
Notary Public

My Commission Expires: January 23, 2017

VERIFICATION

The undersigned, Scott C. Weaver, being duly sworn, deposes and says he is Managing Director Resource Planning and Operation Analysis for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge and belief

Scott C. Weaver

STATE OF OHIO	)
	) CASE NO. 2012-00578
COUNTY OF FRANKLIN	)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Scott C. Weaver, this the 15th day of February 2013.

Cheryl L. Strawser
Notary Public, State of Ohio
My Commission Expires 10-01-2016

Notary Public

My Commission Expires: October 1, 2016

VERIFICATION

The undersigned, Ranie K. Wohnhas, being duly sworn, deposes and says he is the Managing Director Regulatory and Finance for Kentucky Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge, and belief

Ranie K. Wohnhas

Ranie K. Wohnhas

COMMONWEALTH OF KENTUCKY)
) CASE NO. 2012-00578
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Ranie K. Wohnhas, this the 11th day of February, 2013.

Judy K Rosquist 481393

Notary Public

My Commission Expires: January 23, 2017

Kentucky Power Company

REQUEST

Refer to page 6 of the Application.

a. Explain the basis for forecasting that the net book value of the 50% interest in the Mitchell Generating Station will be approximately $536 million at the time of closing.

b. Explain why the net book value of the 50% interest in the Mitchell Generating Station is expected to increase from $519 million as of December 31, 2011 to $536 million at the time of closing.

c. Identify the net book value of the 50% interest in the Mitchell Generating Station as of December 31, 2012.

d. Confirm whether the proposed transfer of the other 50% interest in the Mitchell Generating Station to Appalachian Power Company would also be made at a net book value of approximately $536 million at the time of closing.
    i. If not, explain why not.

e. Identify over what number of years the Company intends to recover the cost of obtaining the 50% interest in the Mitchell Generating Station.

RESPONSE

a-c. See the response to KPSC 1-2.

d. The Company confirms that a transfer to APCo of a 50% interest in the Mitchell Units will also be made at a net book value of approximately $536 million.

e. The Company intends to recover its 50% interest in the Mitchell Generating Station over the life of the units, which is expected to be through 2040.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

State whether Kentucky Power or AEP has estimated the fair market value of the 50% interest in the Mitchell Generating Station.

a. If so, identify that value and explain how you determined it.

b. If not, explain why not.

RESPONSE

No. Such an analysis was unnecessary because, as set out in the testimony of Company witness Weaver, the proposed asset transfer, when compared to a portfolio that initially relies on a market based solution, is the least-cost solution over the long-term economic study period.

a. Not applicable.

b. See above.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Identify each evaluation the Company took to assess the costs, benefits, and risks involved in obtaining a 50% interest in the Mitchell Generating Station. With regards to each such evaluation, explain the results and produce any reports or documents regarding such evaluation.

RESPONSE

See SC 1-3 Attachment 1.

WITNESS: Scott C Weaver

KPSC Case No. 2012-00578
Sierra Clubs First Set of Data Requests
February 6, 2013
Item No. 3
Attachment 1
Page 1 of 13

KENTUCKY POWER®
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KPCO Generation Selection Presentation and Support

Kentucky Power Company
November, 2012

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Topics

- ❑ KPCO Capacity and Energy Need
- ❑ Mitchell Transfer
- ❑ New Build and Market Alternative
- ❑ Mitchell Cost Data

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KPCo Generation Capacity Need

PJM Capacity Postion with NO Asset Transfers, Builds or Acquisitions
FRR Planning Perspective
("Length MW" refers to capacity above or below PJM Minimum Reserve Margin)

PJM PY	APCo Length MW	APCo Margin %	I&M Length MW	I&M Margin %	KPCo Length MW	KPCo Margin %	Total 3 Company Length MW	Total 3 Company Margin %	Min Reserve Margin (IRM) %
2013 /14	184	18.8%	671	32.0%	81	22.7%	936	24.2%	15.4%
2014 /15	(98)	13.8%	676	32.0%	60	20.7%	638	21.1%	15.4%
2015 /16	(1,244)	-4.7%	236	21.0%	(696)	-45.3%	(1,704)	0.6%	15.4%
2016 /17	(1,330)	-6.2%	389	24.9%	(656)	-42.9%	(1,597)	1.4%	15.4%
2017 /18	(1,295)	-5.6%	438	26.2%	(647)	-42.1%	(1,504)	2.2%	15.4%
2018 /19	(1,325)	-6.0%	456	26.6%	(644)	-41.5%	(1,513)	2.1%	15.4%
2019 /20	(1,319)	-5.8%	454	26.6%	(650)	-41.8%	(1,515)	2.1%	15.4%
2020 /21	(1,336)	-6.0%	498	27.7%	(647)	-41.5%	(1,485)	2.4%	15.4%
2021 /22	(1,391)	-6.7%	469	26.9%	(656)	-41.9%	(1,578)	1.7%	15.4%
2022 /23	(1,434)	-7.3%	451	26.5%	(664)	-42.3%	(1,647)	1.1%	15.4%
2023 /24	(1,442)	-7.4%	461	26.7%	(659)	-41.9%	(1,640)	1.2%	15.4%
2024 /25	(1,475)	-7.8%	97	17.8%	(666)	-42.2%	(2,044)	-2.2%	15.4%
2025 /26	(1,983)	-15.5%	59	16.8%	(918)	-63.3%	(2,842)	-8.9%	15.4%
2026 /27	(2,040)	-16.2%	31	16.1%	(927)	-63.6%	(2,936)	-9.5%	15.4%
2027 /28	(2,097)	-16.8%	14	15.7%	(938)	-63.9%	(3,021)	-10.0%	15.4%
2028 /29	(2,136)	-17.2%	(8)	15.2%	(946)	-64.1%	(3,090)	-10.5%	15.4%
2029 /30	(2,185)	-17.8%	(47)	14.3%	(951)	-64.2%	(3,183)	-11.1%	15.4%
2030 /31	(2,243)	-18.4%	(79)	13.5%	(962)	-64.5%	(3,284)	-11.7%	15.4%

- APCO includes (a) Clinch River 1&2 coal-to-gas fuel conversion 12/2014 and 6/2015 and (b) 5/31/15 retirements of Clinch River 3, Glen Lyn 5&6, Kanawha River 1&2 and Sporn 1&3 on 5/31/2015. WPCo to merge with APCo January 2014.
- KPCO includes Big Sandy 1 coal-to-gas fuel conversion and Big Sandy 2 retirement on 5/31/2015.

KPCo requires *at least* ~656 MW of additional capacity to satisfy its upcoming PJM reserve requirement.

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KPCO Energy Need

- KPCo needs baseload power to replace Big Sandy Unit 2 if it is retired

<u>Big Sandy Unit 2</u>	
Nominal Output	800 MW
2011 Net Generation	4,563,000 MWhs
Net Capacity Factor	65.1%

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Selection of Mitchell Plant

- The following criteria were used to select Mitchell Plant from Ohio Power assets historically relied upon by KPCo for pool energy and capacity

Criteria	Mitchell Plant
Baseload Unit?	✓
Environmentally-Controlled?	✓
Appropriate size for need?	✓
Reasonable Cost?	✓

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KPCO Alternatives

- Mitchell Plant compares favorably to other alternatives
  - Natural-Gas Combined Cycle (NGCC)
  - New build Coal

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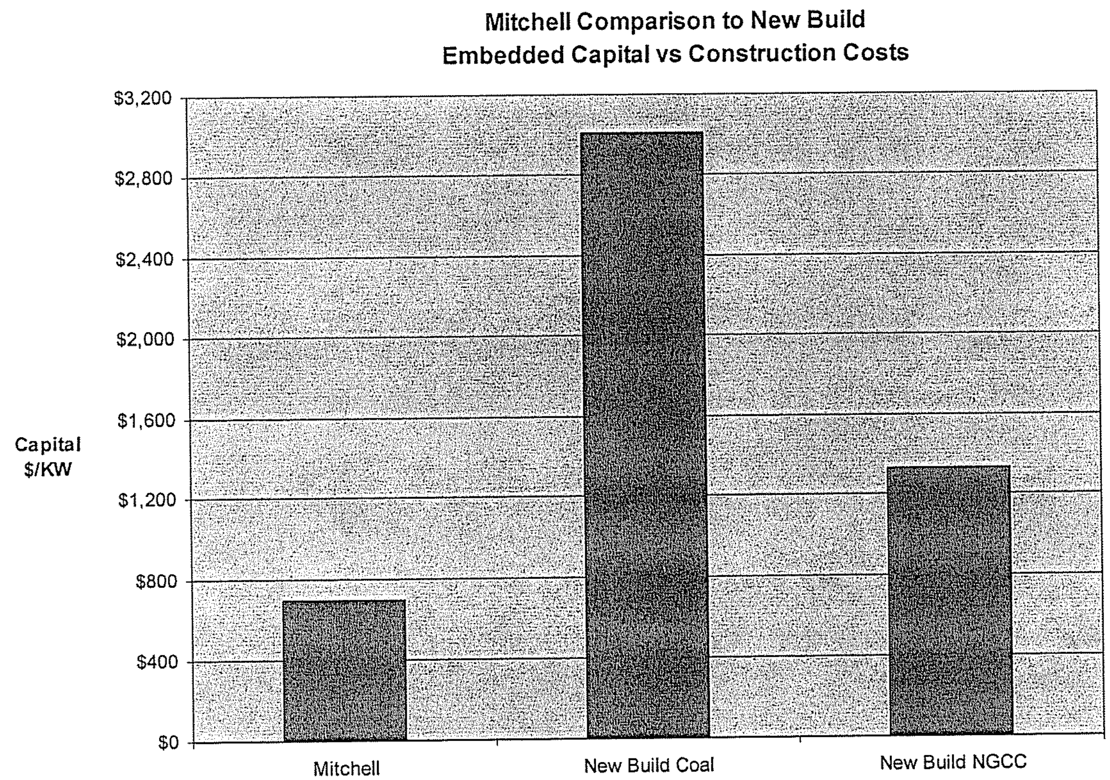
Capacity Cost vs. New Builds



- Compared to Mitchell Plant 12/31/2011 approximate rate base, the construction cost of new coal capacity is 4.3 times higher and new combined cycle is 1.9 times higher.

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Transfer of Mitchell Plant

- Mitchell Plant
  - KPCo receives 50% of Mitchell Units 1 and 2
  - Unit 1 Nominal 385 MW (770 MW x 50%)
  - Unit 2 Nominal 395 MW (790 MW x 50%)
- Total transfer to KPCo is nominal 780 MW

Transfers provide sufficient capacity and energy for KPCo intermediate-term needs

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PJM Capacity Position Post-Transfers

PJM Capacity Postion AFTER Asset Transfers of Amos 3 (APCo) and Mitchell Plant (50% each APCo and KPCo)
FRR Planning Perspective
("Length MW" refers to capacity above or below PJM Minimum Reserve Margin)

PJM PY	APCo Length MW	APCo Margin %	I&M Length MW	I&M Margin %	KPCo Length MW	KPCo Margin %	Total 3 Company Length MW	Total 3 Company Margin %	Min Reserve Margin (IRM) %
2013 /14	184	18.8%	671	32.0%	81	22.7%	936	24.2%	15.4%
2014 /15	1,428	39.1%	676	32.0%	766	83.5%	2,870	40.9%	15.4%
2015 /16	292	20.1%	236	21.0%	10	16.3%	538	20.1%	15.4%
2016 /17	205	18.7%	389	24.9%	50	19.8%	644	21.1%	15.4%
2017 /18	240	19.3%	438	26.2%	59	20.6%	737	21.9%	15.4%
2018 /19	210	18.8%	456	26.6%	62	20.9%	728	21.8%	15.4%
2019 /20	215	18.9%	454	26.6%	56	20.3%	725	21.7%	15.4%
2020 /21	199	18.6%	498	27.7%	59	20.6%	756	22.0%	15.4%
2021 /22	144	17.7%	469	26.9%	50	19.8%	663	21.2%	15.4%
2022 /23	101	17.0%	451	26.5%	42	19.0%	594	20.5%	15.4%
2023 /24	93	16.9%	461	26.7%	47	19.5%	601	20.6%	15.4%
2024 /25	60	16.3%	97	17.8%	40	18.9%	197	17.1%	15.4%
2025 /26	(448)	8.4%	59	16.8%	(212)	-2.8%	(601)	10.3%	15.4%
2026 /27	(505)	7.6%	31	16.1%	(221)	-3.4%	(695)	9.5%	15.4%
2027 /28	(561)	6.8%	14	15.7%	(232)	-4.2%	(779)	8.8%	15.4%
2028 /29	(602)	6.2%	(8)	15.2%	(240)	-4.8%	(850)	8.3%	15.4%
2029 /30	(650)	5.5%	(47)	14.3%	(245)	-5.1%	(942)	7.6%	15.4%
2030 /31	(708)	4.7%	(79)	13.5%	(256)	-5.9%	(1,043)	6.8%	15.4%

- APCO includes (a) Clinch River 1&2 coal-to-gas fuel conversion 12/2014 and 6/2015 and (b) 5/31/15 retirements of Clinch River 3, Glen Lyn 5&6, Kanawha River 1&2 and Sporn 1&3 on 5/31/2015. WPCo to merge with APCo January 2014.
- KPCO includes Big Sandy 1 coal-to-gas fuel conversion and Big Sandy 2 retirement on 5/31/2015.

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Summary

- Mitchell Plant's transfers were selected from Ohio Power generation based on multiple criteria
- Mitchell Plant's transfers compare favorably to new builds and market over the long-term
- KPCo's filing with supporting data is planned for mid-December.

Appendix

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Mitchell Forecasted
Rate Base and Environmental Projects

- The currently forecasted addition to KPCo total company rate base on 12/31/13 is approximately ~$537 million
- Shown below are the current and future expected major environmental capital projects

KPCO Transfer Environmental Capital Costs		Dollars in Thousands										
Plant	Project	2012	2013	Total 2012+2013	2014	2015	2016	2017	2018	2019	2020	Total 2014-2020
50% of Mitchell 1&2												
Mitchell 1-2	ESP Repairs	612	2,264	2,876	440	2,095	29	6,180	7,869	9,586	-	26,200
Mitchell 1-2	Dry Fly Ash Conversion	14,610	27,399	42,008	10,390	-	-	-	-	-	-	10,390
Mitchell 1-2	Waste Water Treatment System	566	1,529	2,095	4,346	4,967	4,128	6,753	7,613	-	-	27,807
Mitchell 1-2	Bottom Ash Pond Reline	-	-	-	-	-	721	3,209	3,392	-	-	7,322
Mitchell 1-2	New Landfill and Haul Road	4,604	16,279	20,883	13,205	7,269	403	1,942	2,877	2,097	2,223	30,017
Subtotal 50% of Mitchell 1&2		**20,392**	**47,470**	**67,862**	**28,381**	**14,331**	**5,280**	**18,085**	**21,752**	**11,683**	**2,223**	**101,735**

Note – These investments will be offset, whole or in part, by depreciation expense and the deferred tax offset to rate base.

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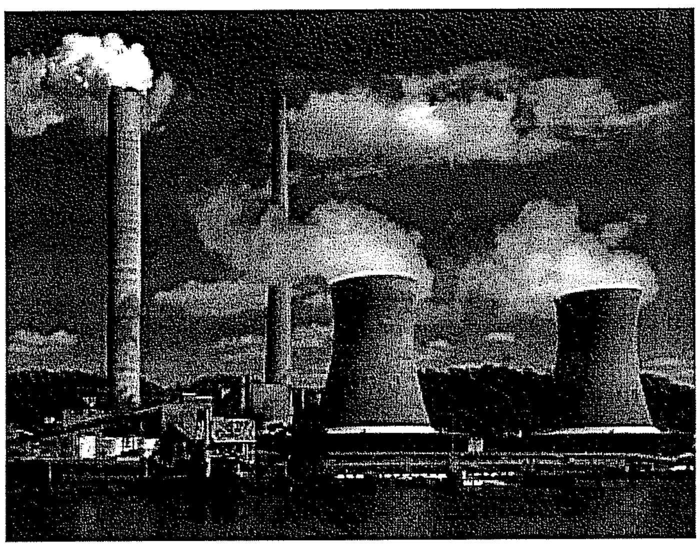
Mitchell Plant

- Located 12 miles south of Moundsville, WV
- 1,560 MW total output in service since 1971
- NO_x Control: Low-NO_x Burners and SCR
- SO_2 Control: Wet FGD System
- SO_3 Control: Trona Injection



Performance Statistics (2010-11)

Capacity Factor: 71%
Equivalent Availability: 77%
Heat Rate: 9.9 MMBtu/MWh

Kentucky Power Company

REQUEST

Refer to p. 5, lines 6-10 of the testimony of Gregory G. Pauley.

a. Identify, by name, title, and company, the people in "AEP Management" with whom the decision that the proposed Mitchell transfer was in "the best interest of the Company and its customers" was made "in collaboration with."

b. Produce all notes, minutes, reports, or other documents from or regarding any meeting between Mr. Pauley and any members of "AEP Management" regarding the proposed transfer of a 50% interest in the Mitchell Generating Station to Kentucky Power.

c. Describe the role, if any, that the interests of AEP's shareholders played in the decision to propose the transfer of a 50% interest in the Mitchell Generating Station to Kentucky Power.

RESPONSE

a. The people within AEP Management with whom Mr. Pauley collaborated with in the decision to acquire a 50% interest in the Mitchell units are as follows:

Charles Patton - President and COO - Appalachian Power Company
Robert Powers - EVP and COO - AEPSC
Mark McCullough - EVP Generation - AEPSC
Richard Munczinski - SVP Regulatory Services - AEPSC
Philip Nelson - Managing Director, Regulatory Pricing & Analysis - AEPSC

b. None of the requested documents exist.

c. The interests of AEP's shareholders were considered to the extent required by law, subject to Kentucky Power's obligation to provide adequate, efficient, and reasonable service at fair, just and reasonable rates.

WITNESS: Gregory G Pauley

Kentucky Power Company

REQUEST

Refer to p. 16, lines 20-22 of the testimony of Gregory G. Pauley.

a. Explain your contention that net book value is "an appropriate means of pricing the transfer."

b. State whether any other pricing of the Mitchell transfer was considered.
   i. If not, explain why not.
   ii. If so, identify such other pricing and explain why it was rejected.

c. State whether Kentucky Power attempted to negotiate a lower price for the Mitchell transfer than the net book value.
   i. If not, explain why not.
   ii. If so:
      1. Explain what negotiations occurred and when they occurred
      2. Provide any notes, minutes, reports, or other documentation of such negotiations
      3. Explain why any such lower price was rejected.

RESPONSE

a. Net book value is a standard transfer price used between wholly owned affiliates.

b. No other pricing was considered because, absent an arms length sale to a third party, other pricing would be speculative.

c. No, see responses to items a. and b. above.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

With regards to the Waterford Generating Station, located in Waterford, Ohio and owned by AEP affiliate Ohio Power Company:

a. Identify the net book value of Waterford as of December 31, 2011 or as of the most recent date for which such data is available

b. State whether Kentucky Power evaluated obtaining ownership of all or a portion of Waterford in order to replace all or some of the capacity and energy from the retiring Big Sandy 2 unit
   i. If so:
      1. Explain the results of such evaluation
      2. Produce any documents regarding such evaluation
      3. Explain why ownership of all or a portion of Waterford was not pursued further
   ii. If not, explain why not.

c. State whether Kentucky Power communicated with AEP or Ohio Power regarding the possibility of obtaining ownership of all or a portion of Waterford in order to replace all or some of the capacity and energy from the retiring Big Sandy 2 unit
   i. If so:
      1. Produce any such communications or notes, minutes, reports, or other documentation related to such communications
      2. Identify the dates of such communications
      3. Explain the results of such communications
   ii. If not, explain why not.

RESPONSE

a. The Company objects to this request as seeking information that is not relevant and is not likely to lead to the discovery of admissible evidence. Notwithstanding this objection, the net book value* of the Waterford plant as of December 31, 2011 was $188 million.

* NBV is equal to: Gross Plant (FERC account 101 + 106) less Accumulated Depreciation (FERC account 108) plus CWIP (FERC account 107)

b. & c. Ohio Power's generating assets were not reviewed on a unit by unit basis. Rather, all the assets of Ohio Power Company, which historically have been used to provide power to KPCo, were qualitatively screened to determine the generating units to be analyzed along with other viable resource options for KPCo. Refer to KPSC 1-27 as well as SC-1-3 Attachment 1.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

With regards to the Lawrenceburg Generating Station, located in Lawrenceburg, Indiana and purchased by AEP in May 2007:

a. Identify the net book value of Lawrenceburg as of December 31, 2011 or as of the most recent date for which such data is available

b. State whether Kentucky Power evaluated obtaining ownership of all or a portion of Lawrenceburg in order to replace all or some of the capacity and energy from the retiring Big Sandy 2 unit
   i. If so:
      1. Explain the results of such evaluation
      2. Produce any documents regarding such evaluation
      3. Explain why ownership of all or a portion of Lawrenceburg was not pursued further
   ii. If not, explain why not.

c. State whether Kentucky Power communicated with AEP regarding the possibility of obtaining ownership of all or a portion of Lawrenceburg in order to replace all or some of the capacity and energy from the retiring Big Sandy 2 unit
   i. If so:
      1. Produce any such communications or notes, minutes, reports, or other documentation related to such communications
      2. Identify the dates of such communications
      3. Explain the results of such communications
   ii. If not, explain why not.

RESPONSE

The Company objects to this request as seeking information that is not relevant and is not likely to lead to the discovery of admissible evidence. Notwithstanding this objection, the net book value* of the Lawrenceberg plant as of December 31, 2011 was $307 million.

* NBV is equal to: Gross Plant (FERC account 101 + 106) less Accumulated Depreciation (FERC account 108) plus CWIP (FERC account 107)

b & c. Ohio Power's generating assets were not reviewed on a unit by unit basis. Rather, all the assets of Ohio Power Company, which historically have been used to provide power to KPCo, were qualitatively screened to determine the generating units to be analyzed along with other viable resource options for KPCo. Refer to KPSC 1-27 as well as SC 1-3 Attachment 1.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

With regards to the Riverside Generating Station, located in Zelda, Kentucky:

a. State whether Kentucky Power evaluated obtaining ownership of all or a portion of Riverside in order to replace all or some of the capacity and energy from the retiring Big Sandy 2 unit
   i. If so:
      1. Explain the results of such evaluation
      2. Produce any documents regarding such evaluation
      3. Explain why ownership of all or a portion of Riverside was not pursued further
   ii. If not, explain why not.

b. State whether Kentucky Power communicated with the owners of Riverside regarding the possibility of obtaining ownership of all or a portion of Riverside in order to replace all or some of the capacity and energy from the retiring Big Sandy 2 unit
   i. If so:
      1. Produce any such communications or notes, minutes, reports, or other documentation related to such communications
      2. Identify the dates of such communications
      3. Explain the results of such communications
   ii. If not, explain why not.

RESPONSE

a/b. Yes, the Company reviewed information concerning the Riverside facility. This evaluation determined that the facility was not a economic option based on the cost of converting the facility to a combined cycle gas plant.

Please see SC 1-8 Attachments 1& 2 for additional detail. Confidential treatment is being sought for Attachment 1.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to Staff's First Request, Item 72.c. The response refers to Kentucky Power's response to the Attorney General's ("AG") Initial Data Request, Items 22 and 23. It is not clear in those responses that the Commission's question was addressed. Also, it is not clear the responses address why AEP and/or Kentucky Power chose not to go forward with negotiations. Explain where in the responses these questions are addressed

RESPONSE

[redacted]

[redacted]

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Please provide a comprehensive discussion regarding the due diligence and any and all other reviews that KPCo may have conducted regarding the options of either: (a) obtaining a long-term purchased power arrangement with Riverside Generating Co., LLC, ("Riverside"), the owner of a gas-fired 836 MW electric generating facility in Zelda, KY; or (b) purchasing Riverside's facilities.

RESPONSE

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

WITNESS: Ranie K Wohnhas

THESE DOCUMENTS HAVE BEEN REDACTED IN THEIR ENTIRETY.

Kentucky Power Company

REQUEST

Regarding the generating facilities owned by Riverside discussed in the preceding question, please provide a discussion of whether Riverside's facilities would be capable of meeting KPCo's base-load needs. If not, please discuss whether said facilities would require any retrofitting, and the nature and cost thereof.

RESPONSE

[redacted]

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to Kentucky Power's response to the AG's First Request, Item 22, Attachment 8.

a. If AEP or Kentucky Power had purchased the Riverside Generating ("RG") natural gas plant in Zelda, Kentucky at the initial non-binding offer made on March 09, 2010, provide and describe the financial impact on Off-System Sales ("OSS"), pool capacity costs, and PJM capacity costs to:

(1) Kentucky Power as a member of the East Pool Agreement;

(2) The other members of the East Pool Agreement;

(3) The members of the contemplated three member pool; and

(4) The members of any other agreement between the AEP subsidiaries of the East Pool Agreement.

b. Provide a further explanation of why AEP or Kentucky Power did not purchase the RG natural gas plant considering the capability of conversion to a 2x1 combined cycle ("CC") and 3x1 CC which would enhance the capacity of the facility.

c. Prepare an analysis of the purchase of the RG natural gas plant as an option scenario and compare to Options 1 through 4, using the same modeling as used for those four options. Include revenues from OSS, pool capacity costs, PJM capacity costs, and the financial impact to the current East Pool Agreement and the proposed three member pool.

d. Explain whether AEP or Kentucky Power considered including other utilities in a possible purchase/conversion of the RG natural gas plant as a way to offset the excess capacity and mitigate costs.

RESPONSE

a. The Company has not conducted such a study.

b. Please see the Company's Response to KPSC 2-17.

c. The Company understands this subpart to be seeking an analysis of the purchase of the Riverside Generating Co., LLC facility and converting it to a combined cycle natural gas-fired plant. Preparatory to undertaking such an analysis the Company must obtain a detailed engineering estimate of the conversion cost so that the requested analysis will be comparable to Options 1-3. The Company contacted Kiewett Corporation and Sargent & Lundy to determine the additional information required from Riverside Generating and the time to complete such an analysis. Based upon those discussions, Kentucky Power will require the following information from Riverside Generating:

(1) Site Plan

(2) Geo Tech Data & Study Reports

(3) General Arrangements including buildings

(4) One Line Diagrams of the facility

(5) Major Power Block Systems P&IDs

(6) Equipment Lists: Mechanical, Electrical, I&C

(7) Underground Utility Drawings including piping, duct banks, cathodic protection,

(8) Gas yard and fuel gas supply flow diagrams

(9) DCS Architecture

(10) Water Balance

(11) Heat Balances

(12) System Descriptions

(13) Air Permit

(14) NPDES Permit

(15) Gas Supply Agreements

(16) Transmission Interconnection Agreements

(17) Property Map

In addition, the engineering consultants will require one to two site visits, along with meetings with Riverside Generating personnel, to complete the conversion study and develop a cost estimate for use in the requested analysis.

It is anticipated the cost estimate will have a margin of error comparable to that of the estimates used in performing the analyses of Options 1-3.

The Company estimates that it will take eight to ten weeks to complete the analysis after the receipt of the requested information. The estimate cost of the engineering study is approximately $250,000.

d. No. If Kentucky Power had pursued this option it would have acquired the entirety of the unit.

WITNESS: Ranie K Wohnhas

KPSC Case No. 2011-00401
Commission Staff's Third Set of Data Requests
Order Dated March 14, 2012
Item No. 8
Page 1 of 1

Kentucky Power Company

REQUEST

Refer to Kentucky Power's response to Staff's Second Request, Item 29. Provide all analyses, explanations, and/or calculations that were used by Kentucky Power and/or American Electric Power ("AEP") to reach the decision to not purchase the Riverside Generating ("RG") natural gas plant in Zelda, Kentucky.

RESPONSE

The analyses, explanations, and/or calculations used by American Electric Power Service Corporation ("AEPSC") are summarized in the Company's responses and accompanying attachments to KPSC Staff 2-17, KPSC 2-29, AG 1-22 and AG 1-23. The analysis of whether to purchase the Riverside Generation ("RG") natural gas plant in Zelda, Kentucky in 2010 only reached review of the acquisition for the AEP-East system, and did not reach consideration of which particular operating company would own the RG unit.

At the time the RG unit was being reviewed, AEPSC also prepared the 2010 AEP East Integrated Resource Plan ("2010 IRP"), which was previously filed in response to Sierra Club 1-3. As set out at pages i-ii of the 2010 IRP plan, at the time AEP East system was not projected to require capacity additions until 2018-2019. Additionally, as set out in pages vi and 23 of the 2010 IRP, at the time AEP anticipated that implementation of any increased federal regulation of hazardous air pollutants would be "staggered" over the course of the decade, further making the acquisition of the RG unit at the beginning of the decade unnecessary.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to p. 4 lines 1-6 of the testimony of Karl Bletzacker. For each of the "long-term, energy-related commodity pricing forecasts for use in the Kentucky Power unit disposition analysis" referenced therein:

a. Identify the date of the forecast

b. Identify the annual forecasted price for each of the years 2012 through 2040

c. State whether the Fundamentals Analysis Group, or any other AEP group, has produced a more recent price forecast for each such commodity
    i. If so, identify the annual forecasted price for each of the years 2012 through 2040 set forth in that more recent price forecast.

RESPONSE

a. November 29, 2011

b. Please see Attachment 1 to this response.

c. Neither the Fundamentals Analysis Group nor any other AEP group has prepared a more recent price forecast.

WITNESS: Karl R Bletzacker

	Power Prices ($/MWh) -Nominal $'s									
	PJM - AEP GEN HUB		SPP		ERCOT North		ERCOT South		ERCOT West	
Year	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
2012	46.96	27.90	46.13	31.16	34.59	33.18	34.75	33.31	33.76	32.26
2013	47.45	28.52	50.19	34.31	37.87	36.08	38.15	36.30	37.03	35.16
2014	50.22	30.17	55.01	38.26	41.21	38.91	41.56	39.20	40.33	38.00
2015	56.61	33.64	58.96	41.26	42.59	40.30	43.32	41.03	41.82	39.57
2016	63.10	39.01	64.46	45.04	47.20	44.64	47.92	45.47	46.34	43.88
2017	63.56	41.42	65.91	46.93	48.63	46.08	49.03	46.52	47.59	45.04
2018	64.38	42.56	66.66	48.22	50.14	47.46	50.52	47.83	49.05	46.35
2019	65.15	43.52	67.43	49.34	51.36	48.54	51.50	48.67	50.14	47.28
2020	66.33	44.18	66.87	48.80	51.27	48.75	51.41	48.82	50.05	47.47
2021	67.64	45.76	68.52	50.78	53.02	50.55	53.03	50.44	51.71	49.15
2022	76.79	55.93	75.69	59.13	60.56	57.81	60.64	57.78	59.20	56.38
2023	78.33	56.84	76.53	60.17	62.14	59.28	62.34	59.35	60.80	57.86
2024	80.34	58.85	78.76	62.40	64.32	61.32	64.28	61.13	62.89	59.79
2025	82.18	60.37	80.50	63.83	65.64	62.82	65.64	62.62	64.20	61.28
2026	83.23	61.06	81.13	64.33	66.80	63.88	66.86	63.73	65.36	62.33
2027	84.57	62.64	83.15	66.12	68.28	65.35	68.17	65.02	66.75	63.73
2028	86.25	64.05	84.15	67.56	69.41	66.58	69.30	66.21	67.88	64.94
2029	87.64	65.66	85.57	69.56	70.91	68.06	70.65	67.50	69.31	66.34
2030	89.34	67.49	86.60	70.45	71.74	68.94	71.47	68.36	70.13	67.20

Coal ($/ton) FOB -Nominal $'s

Year	12395 Btu/lb 1.6# SO2 CAPP	12500 Btu/lb 1.6# SO2 CAPP CSX-Rail	12000 Btu/lb 1.2# SO2 CAPP Compliance	12000 Btu/lb 1.67# SO2 CAPP NYMEX	12500 Btu/lb 6# SO2 NAPP High Sulfur	13000 Btu/lb 4# SO2 NAPP Med Sulfur	11512 Btu/lb 4.3# SO2 I-Basin	8800 Btu/lb 0.8# SO2 PRB 8800	8400 Btu/lb 0.8# SO2 PRB 8400	11700 Btu/lb 0.9# SO2 Colorado
2012	79.97	80.00	82.00	79.50	56.75	70.00	52.47	15.75	12.85	41.50
2013	83.46	83.50	85.00	83.00	58.00	68.00	53.74	16.95	13.95	42.90
2014	84.83	85.00	86.33	83.83	60.00	68.00	54.33	17.50	14.49	43.91
2015	85.21	85.50	85.83	83.83	62.36	70.33	54.98	17.50	14.49	44.86
2016	85.52	85.91	85.33	83.83	64.72	72.00	56.34	17.40	14.84	45.82
2017	85.31	85.91	84.81	82.77	65.92	73.37	57.16	17.30	15.19	46.89
2018	86.94	87.55	86.43	84.35	67.18	74.77	58.07	17.72	15.56	47.58
2019	88.58	89.20	88.06	85.94	68.45	76.18	58.91	18.14	15.93	48.26
2020	90.22	90.85	89.69	87.53	69.71	77.59	59.74	18.57	16.31	48.93
2021	92.07	92.71	91.52	89.32	71.18	79.22	61.00	19.00	16.70	49.94
2022	91.66	92.30	91.12	88.93	70.90	78.90	60.76	19.07	16.75	49.72
2023	93.52	94.18	92.97	90.73	72.37	80.55	62.02	19.51	17.15	50.73
2024	95.41	96.08	94.85	92.56	73.87	82.21	63.30	19.96	17.55	51.75
2025	97.31	97.99	96.74	94.41	75.38	83.89	64.60	20.42	17.95	52.78
2026	99.24	99.94	98.66	96.28	76.91	85.60	65.91	20.89	18.36	53.83
2027	101.19	101.90	100.60	98.18	78.46	87.33	67.24	21.36	18.78	54.89
2028	103.18	103.90	102.57	100.10	80.04	89.08	68.59	21.84	19.21	55.96
2029	105.19	105.93	104.57	102.06	81.65	90.87	69.97	22.34	19.64	57.06
2030	107.24	107.99	106.61	104.04	83.27	92.68	71.36	22.84	20.09	58.17

Year	Natural Gas ($/mmbtu) -Nominal $'s Henry Hub	TCO Pool	Dominion South Point Pool	TCO Deliv	HSC	PEPL TX-OK	Swing Service Adder	Uranium Fuel UO2 ($/mmbtu) - Nominal $'s
2012	4.48	4.58	4.59	4.89	4.35	4.24	0.25	0.80
2013	4.94	5.01	5.01	5.32	4.81	4.69	0.25	0.82
2014	5.38	5.42	5.42	5.75	5.26	5.13	0.25	0.84
2015	5.52	5.53	5.57	5.86	5.42	5.27	0.25	0.85
2016	5.99	6.00	6.03	6.33	5.88	5.73	0.25	0.87
2017	6.13	6.14	6.18	6.48	6.02	5.88	0.25	0.89
2018	6.32	6.34	6.37	6.68	6.22	6.07	0.25	0.91
2019	6.46	6.47	6.51	6.82	6.35	6.21	0.25	0.92
2020	6.52	6.53	6.56	6.88	6.41	6.26	0.25	0.94
2021	6.75	6.77	6.80	7.12	6.65	6.50	0.25	0.96
2022	7.07	7.08	7.11	7.44	6.96	6.81	0.25	0.98
2023	7.26	7.28	7.31	7.64	7.16	7.01	0.25	1.00
2024	7.51	7.52	7.56	7.89	7.40	7.26	0.25	1.02
2025	7.75	7.76	7.79	8.13	7.64	7.49	0.25	1.04
2026	7.85	7.86	7.90	8.24	7.74	7.60	0.26	1.06
2027	8.04	8.06	8.09	8.43	7.94	7.79	0.26	1.08
2028	8.22	8.24	8.27	8.62	8.12	7.97	0.27	1.10
2029	8.41	8.42	8.45	8.80	8.30	8.15	0.27	1.13
2030	8.52	8.54	8.57	8.92	8.42	8.27	0.28	1.15

	Emissions ($/ton) - Nominal $'s			($/metric tonne) - Nominal $'s
Year	SO_2	NO_X Annual	NO_X Summer	CO_2
2012		650	1100	0.00
2013		550	950	0.00
2014		350	800	0.00
2015		250	350	0.00
2016		225	300	0.00
2017		35	125	0.00
2018		0	50	0.00
2019		0	0	0.00
2020		0	0	0.00
2021		0	0	0.00
2022		0	0	15.08
2023		0	0	15.28
2024		0	0	15.48
2025		0	0	15.67
2026		0	0	15.88
2027		0	0	16.08
2028		0	0	16.29
2029		0	0	16.50
2030		0	0	16.72

	Heat Rates (mmbtu/MWh)				
Year	AEP GEN HUB - HR	SPP - HR	ERCOT North - HR	ERCOT South - HR	ERCOT West - HR
2012	10.28	10.92	7.96	7.99	6.92
2013	9.51	10.74	7.89	7.95	6.97
2014	9.28	10.77	7.83	7.90	7.03
2015	10.25	11.22	7.87	8.01	7.15
2016	10.53	11.27	8.04	8.16	7.33
2017	10.36	11.23	8.08	8.15	7.36
2018	10.18	11.02	8.07	8.14	7.36
2019	10.09	10.90	8.09	8.11	7.36
2020	10.17	10.70	8.01	8.03	7.29
2021	10.00	10.56	7.98	7.99	7.27
2022	10.86	11.13	8.71	8.72	7.97
2023	10.78	10.94	8.69	8.72	7.97
2024	10.71	10.88	8.69	8.69	7.98
2025	10.61	10.77	8.60	8.60	7.90
2026	10.60	10.70	8.63	8.64	7.94
2027	10.51	10.69	8.61	8.60	7.92
2028	10.49	10.58	8.56	8.54	7.89
2029	10.42	10.51	8.55	8.52	7.88
2030	10.48	10.49	8.53	8.49	7.86

Year	Capacity Prices ($/MW-day) -Nominal $'s AEP GEN HUB Hub Cap.	SPP Cap.	Renewable Energy Subsidies ** ($/MWh) -Nominal $'s	Inflation Factor
2012	55.44	25.00	47.40	1.80%
2013	23.03	25.00	47.20	1.70%
2014	85.05	25.00	47.70	2.70%
2015	215.25	25.00	48.20	2.40%
2016	281.92	25.00	44.10	1.70%
2017	235.98	25.00	44.80	1.50%
2018	200.39	359.22	45.50	1.60%
2019	224.57	365.81	46.10	1.50%
2020	253.47	371.74	46.60	1.50%
2021	280.05	376.99	47.20	1.50%
2022	304.18	381.51	47.90	1.50%
2023	325.73	385.29	48.60	1.50%
2024	344.58	388.27	49.30	1.50%
2025	360.58	390.42	49.90	1.50%
2026	373.61	391.71	50.60	1.50%
2027	383.50	392.10	51.10	1.50%
2028	390.13	391.54	51.70	1.50%
2029	392.94	389.61	52.50	1.50%
2030	392.16	386.65	52.80	1.40%

Kentucky Power Company

REQUEST

Produce in machine readable format all input and output files, and all workpapers in electronic format with formulas intact, from all AuroraXMP modeling performed in preparing the analyses set forth in the Company's application.

RESPONSE

Please refer to the files SC 1-10 Nominal_Attachment 1.xls and SC 1-10 Real_Attachment 2.xls provided on the enclosed CD.

WITNESS: Karl R Bletzacker

	Power Prices ($/MWh) -Nominal $'s									
	PJM - AEP GEN HUB		SPP		ERCOT North		ERCOT South		ERCOT West	
Year	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
2012	46.96	27.90	46.13	31.16	34.59	33.18	34.75	33.31	33.76	32.26
2013	47.45	28.52	50.19	34.31	37.87	36.08	38.15	36.30	37.03	35.16
2014	50.22	30.17	55.01	38.26	41.21	38.91	41.56	39.20	40.33	38.00
2015	56.61	33.64	58.96	41.26	42.59	40.30	43.32	41.03	41.82	39.57
2016	63.10	39.01	64.46	45.04	47.20	44.64	47.92	45.47	46.34	43.88
2017	63.56	41.42	65.91	46.93	48.63	46.08	49.03	46.52	47.59	45.04
2018	64.38	42.56	66.66	48.22	50.14	47.46	50.52	47.83	49.05	46.35
2019	65.15	43.52	67.43	49.34	51.36	48.54	51.50	48.67	50.14	47.28
2020	66.33	44.18	66.87	48.80	51.27	48.75	51.41	48.82	50.05	47.47
2021	67.64	45.76	68.52	50.78	53.02	50.55	53.03	50.44	51.71	49.15
2022	76.79	55.93	75.69	59.13	60.56	57.81	60.64	57.78	59.20	56.38
2023	78.33	56.84	76.53	60.17	62.14	59.28	62.34	59.35	60.80	57.86
2024	80.34	58.85	78.76	62.40	64.32	61.32	64.28	61.13	62.89	59.79
2025	82.18	60.37	80.50	63.83	65.64	62.82	65.64	62.62	64.20	61.28
2026	83.23	61.06	81.13	64.33	66.80	63.88	66.86	63.73	65.36	62.33
2027	84.57	62.64	83.15	66.12	68.28	65.35	68.17	65.02	66.75	63.73
2028	86.25	64.05	84.15	67.56	69.41	66.58	69.30	66.21	67.88	64.94
2029	87.64	65.66	85.57	69.56	70.91	68.06	70.65	67.50	69.31	66.34
2030	89.34	67.49	86.60	70.45	71.74	68.94	71.47	68.36	70.13	67.20

Coal ($/ton) FOB -Nominal $'s									
12395 Btu/lb 1.6# SO2 CAPP	12500 Btu/lb 1.6# SO2 CAPP CSX-Rail	12000 Btu/lb 1.2# SO2 CAPP Compliance	12000 Btu/lb 1.67# SO2 CAPP NYMEX	12500 Btu/lb 6# SO2 NAPP High Sulfur	13000 Btu/lb 4# SO2 NAPP Med Sulfur	11512 Btu/lb 4.3# SO2 I-Basin	8800 Btu/lb 0.8# SO2 PRB 8800	8400 Btu/lb 0.8# SO2 PRB 8400	11700 Btu/lb 0.9# SO2 Colorado
79.97	80.00	82.00	79.50	56.75	70.00	52.47	15.75	12.85	41.50
83.46	83.50	85.00	83.00	58.00	68.00	53.74	16.95	13.95	42.90
84.83	85.00	86.33	83.83	60.00	68.00	54.33	17.50	14.49	43.91
85.21	85.50	85.83	83.83	62.36	70.33	54.98	17.50	14.49	44.86
85.52	85.91	85.33	83.83	64.72	72.00	56.34	17.40	14.84	45.82
85.31	85.91	84.81	82.77	65.92	73.37	57.16	17.30	15.19	46.89
86.94	87.55	86.43	84.35	67.18	74.77	58.07	17.72	15.56	47.58
88.58	89.20	88.06	85.94	68.45	76.18	58.91	18.14	15.93	48.26
90.22	90.85	89.69	87.53	69.71	77.59	59.74	18.57	16.31	48.93
92.07	92.71	91.52	89.32	71.18	79.22	61.00	19.00	16.70	49.94
91.66	92.30	91.12	88.93	70.90	78.90	60.76	19.07	16.75	49.72
93.52	94.18	92.97	90.73	72.37	80.55	62.02	19.51	17.15	50.73
95.41	96.08	94.85	92.56	73.87	82.21	63.30	19.96	17.55	51.75
97.31	97.99	96.74	94.41	75.38	83.89	64.60	20.42	17.95	52.78
99.24	99.94	98.66	96.28	76.91	85.60	65.91	20.89	18.36	53.83
101.19	101.90	100.60	98.18	78.46	87.33	67.24	21.36	18.78	54.89
103.18	103.90	102.57	100.10	80.04	89.08	68.59	21.84	19.21	55.96
105.19	105.93	104.57	102.06	81.65	90.87	69.97	22.34	19.64	57.06
107.24	107.99	106.61	104.04	83.27	92.68	71.36	22.84	20.09	58.17

Natural Gas ($/mmbtu) -Nominal $'s						
Henry Hub	TCO Pool	South Point Pool	TCO Deliv	HSC	PEPL TX-OK	Service Adder
4.48	4.58	4.59	4.89	4.35	4.24	0.25
4.94	5.01	5.01	5.32	4.81	4.69	0.25
5.38	5.42	5.42	5.75	5.26	5.13	0.25
5.52	5.53	5.57	5.86	5.42	5.27	0.25
5.99	6.00	6.03	6.33	5.88	5.73	0.25
6.13	6.14	6.18	6.48	6.02	5.88	0.25
6.32	6.34	6.37	6.68	6.22	6.07	0.25
6.46	6.47	6.51	6.82	6.35	6.21	0.25
6.52	6.53	6.56	6.88	6.41	6.26	0.25
6.75	6.77	6.80	7.12	6.65	6.50	0.25
7.07	7.08	7.11	7.44	6.96	6.81	0.25
7.26	7.28	7.31	7.64	7.16	7.01	0.25
7.51	7.52	7.56	7.89	7.40	7.26	0.25
7.75	7.76	7.79	8.13	7.64	7.49	0.25
7.85	7.86	7.90	8.24	7.74	7.60	0.26
8.04	8.06	8.09	8.43	7.94	7.79	0.26
8.22	8.24	8.27	8.62	8.12	7.97	0.27
8.41	8.42	8.45	8.80	8.30	8.15	0.27
8.52	8.54	8.57	8.92	8.42	8.27	0.28

Uranium Fuel UO2 ($/mmbtu) -Nominal $'s
0.80
0.82
0.84
0.85
0.87
0.89
0.91
0.92
0.94
0.96
0.98
1.00
1.02
1.04
1.06
1.08
1.10
1.13
1.15

Emissions ($/ton) -Nominal $'s			($/metric tonne) - Nominal $'s
SO_2	NO_X Annual	NO_X Summer	CO_2
	650	1100	0.00
	550	950	0.00
	350	800	0.00
	250	350	0.00
	225	300	0.00
	35	125	0.00
	0	50	0.00
	0	0	0.00
	0	0	0.00
	0	0	0.00
	0	0	15.08
	0	0	15.28
	0	0	15.48
	0	0	15.67
	0	0	15.88
	0	0	16.08
	0	0	16.29
	0	0	16.50
	0	0	16.72

Heat Rates (mmbtu/MWh)				
AEP GEN HUB - HR	SPP - HR	ERCOT North - HR	ERCOT South - HR	ERCOT West - HR
10.28	10.92	7.96	7.99	6.92
9.51	10.74	7.89	7.95	6.97
9.28	10.77	7.83	7.90	7.03
10.25	11.22	7.87	8.01	7.15
10.53	11.27	8.04	8.16	7.33
10.36	11.23	8.08	8.15	7.36
10.18	11.02	8.07	8.14	7.36
10.09	10.90	8.09	8.11	7.36
10.17	10.70	8.01	8.03	7.29
10.00	10.56	7.98	7.99	7.27
10.86	11.13	8.71	8.72	7.97
10.78	10.94	8.69	8.72	7.97
10.71	10.88	8.69	8.69	7.98
10.61	10.77	8.60	8.60	7.90
10.60	10.70	8.63	8.64	7.94
10.51	10.69	8.61	8.60	7.92
10.49	10.58	8.56	8.54	7.89
10.42	10.51	8.55	8.52	7.88
10.48	10.49	8.53	8.49	7.86

Capacity Prices ($/MW-day) -Nominal $'s AEP GEN HUB Hub Cap.	SPP Cap.	Renewable Energy Subsidies ** ($/MWh) - Nominal $'s	Inflation Factor
55.44	25.00	47.40	1.80%
23.03	25.00	47.20	1.70%
85.05	25.00	47.70	2.70%
215.25	25.00	48.20	2.40%
281.92	25.00	44.10	1.70%
235.98	25.00	44.80	1.50%
200.39	359.22	45.50	1.60%
224.57	365.81	46.10	1.50%
253.47	371.74	46.60	1.50%
280.05	376.99	47.20	1.50%
304.18	381.51	47.90	1.50%
325.73	385.29	48.60	1.50%
344.58	388.27	49.30	1.50%
360.58	390.42	49.90	1.50%
373.61	391.71	50.60	1.50%
383.50	392.10	51.10	1.50%
390.13	391.54	51.70	1.50%
392.94	389.61	52.50	1.50%
392.16	386.65	52.80	1.40%

	Power Prices ($/MWh) - Real (2008) $'s									
	PJM - AEP GEN HUB		SPP		ERCOT North		ERCOT South		ERCOT West	
Year	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
2012	44.20	26.26	43.42	29.33	32.56	31.23	32.71	31.35	31.78	30.36
2013	43.92	26.39	46.45	31.75	35.05	33.39	35.31	33.60	34.27	32.54
2014	45.26	27.19	49.57	34.48	37.14	35.07	37.46	35.33	36.35	34.25
2015	49.83	29.60	51.89	36.32	37.48	35.47	38.13	36.11	36.81	34.83
2016	54.61	33.76	55.79	38.98	40.84	38.63	41.47	39.35	40.11	37.98
2017	54.19	35.32	56.19	40.01	41.46	39.29	41.80	39.66	40.57	38.40
2018	54.02	35.72	55.94	40.47	42.07	39.83	42.39	40.14	41.16	38.90
2019	53.87	35.98	55.75	40.80	42.46	40.13	42.58	40.24	41.45	39.09
2020	54.03	35.98	54.47	39.75	41.76	39.71	41.87	39.76	40.77	38.66
2021	54.28	36.72	54.99	40.75	42.55	40.57	42.56	40.48	41.50	39.44
2022	60.71	44.22	59.84	46.75	47.88	45.71	47.95	45.68	46.81	44.58
2023	61.02	44.28	59.62	46.87	48.41	46.18	48.56	46.23	47.36	45.07
2024	61.66	45.16	60.44	47.89	49.36	47.06	49.34	46.91	48.27	45.89
2025	62.14	45.65	60.87	48.26	49.63	47.50	49.63	47.35	48.54	46.33
2026	62.00	45.49	60.44	47.92	49.76	47.59	49.81	47.47	48.69	46.43
2027	62.07	45.98	61.03	48.53	50.11	47.97	50.03	47.72	48.99	46.77
2028	62.37	46.31	60.85	48.85	50.19	48.14	50.11	47.87	49.08	46.96
2029	62.44	46.78	60.96	49.55	50.52	48.49	50.33	48.09	49.38	47.26
2030	62.77	47.42	60.85	49.50	50.40	48.43	50.22	48.03	49.27	47.21

Coal ($/ton) FOB - Real (2008) $'s									
12395 Btu/lb 1.6# SO2	12500 Btu/lb 1.6# SO2	12000 Btu/lb 1.2# SO2	12000 Btu/lb 1.67# SO2	12500 Btu/lb 6# SO2	13000 Btu/lb 4# SO2	11512 Btu/lb 4.3# SO2	8800 Btu/lb 0.8# SO2	8400 Btu/lb 0.8# SO2	11700 Btu/lb 0.9# SO2
CAPP	CAPP CSX-Rail	CAPP Compliance	CAPP NYMEX	NAPP High Sulfur	NAPP Med Sulfur	I-Basin	PRB 8800	PRB 8400	Colorado
75.28	75.30	77.19	74.83	53.42	65.89	49.39	14.83	12.10	39.06
77.24	77.28	78.67	76.82	53.68	62.94	49.74	15.69	12.91	39.71
76.45	76.60	77.80	75.55	54.07	61.28	48.97	15.77	13.06	39.58
74.99	75.25	75.54	73.78	54.88	61.90	48.39	15.40	12.75	39.48
74.01	74.35	73.84	72.55	56.01	62.31	48.75	15.06	12.84	39.65
72.74	73.25	72.31	70.57	56.21	62.55	48.73	14.75	12.95	39.98
72.96	73.47	72.53	70.78	56.38	62.74	48.73	14.87	13.06	39.92
73.24	73.75	72.81	71.06	56.59	62.98	48.71	15.00	13.17	39.90
73.49	74.00	73.06	71.30	56.79	63.20	48.66	15.12	13.29	39.86
73.89	74.40	73.45	71.68	57.12	63.57	48.95	15.25	13.40	40.08
72.47	72.98	72.05	70.31	56.06	62.39	48.04	15.08	13.25	39.31
72.85	73.36	72.42	70.68	56.38	62.74	48.31	15.20	13.36	39.51
73.22	73.74	72.79	71.04	56.69	63.09	48.58	15.32	13.47	39.72
73.58	74.09	73.15	71.39	57.00	63.43	48.84	15.44	13.57	39.91
73.93	74.45	73.49	71.73	57.30	63.77	49.10	15.56	13.68	40.10
74.27	74.79	73.83	72.06	57.59	64.09	49.35	15.68	13.79	40.28
74.61	75.13	74.17	72.38	57.88	64.41	49.60	15.79	13.89	40.47
74.94	75.47	74.50	72.71	58.16	64.73	49.85	15.91	13.99	40.65
75.34	75.87	74.90	73.10	58.51	65.11	50.14	16.04	14.11	40.87

Natural Gas ($/mmbtu) - Real (2008) $'s							
Henry Hub	TCO Pool	Dominion South Point Pool	TCO Deliv	HSC	PEPL TX-OK	Swing Service Adder	Uranium Fuel UO2 ($/mmbtu) - Real (2008) $'s
4.22	4.31	4.32	4.60	4.10	3.99	0.24	0.76
4.57	4.63	4.64	4.92	4.45	4.34	0.23	0.77
4.84	4.89	4.89	5.18	4.74	4.62	0.23	0.76
4.86	4.87	4.90	5.16	4.77	4.64	0.22	0.76
5.18	5.19	5.22	5.48	5.09	4.96	0.22	0.76
5.22	5.24	5.27	5.52	5.14	5.01	0.21	0.76
5.30	5.32	5.34	5.60	5.22	5.09	0.21	0.77
5.34	5.35	5.38	5.64	5.25	5.13	0.21	0.77
5.31	5.32	5.35	5.60	5.22	5.10	0.21	0.77
5.42	5.43	5.46	5.71	5.33	5.22	0.20	0.78
5.59	5.60	5.62	5.88	5.50	5.39	0.20	0.78
5.66	5.67	5.69	5.95	5.57	5.46	0.20	0.78
5.76	5.77	5.80	6.05	5.68	5.57	0.19	0.79
5.86	5.87	5.89	6.15	5.77	5.67	0.19	0.79
5.85	5.86	5.88	6.14	5.77	5.66	0.19	0.80
5.90	5.91	5.94	6.19	5.82	5.72	0.19	0.80
5.94	5.95	5.98	6.23	5.87	5.76	0.19	0.80
5.99	6.00	6.02	6.27	5.91	5.81	0.19	0.81
5.99	6.00	6.02	6.27	5.91	5.81	0.20	0.81

Emissions ($/ton) - Real (2008) $'s			($/metric tonne) - Real (2008) $'s	Heat Rates (mmbtu/MWh)				
SO_2	NO_X Annual	NO_X Summer	CO_2	AEP GEN HUB - HR	SPP - HR	ERCOT North - HR	ERCOT South - HR	ERCOT West - HR
617	1043	0.00		10.28	10.92	7.96	7.99	6.92
513	885	0.00		9.51	10.74	7.89	7.95	6.97
319	729	0.00		9.28	10.77	7.83	7.90	7.03
222	311	0.00		10.25	11.22	7.87	8.01	7.15
196	261	0.00		10.53	11.27	8.04	8.16	7.33
30	107	0.00		10.36	11.23	8.08	8.15	7.36
0	42	0.00		10.18	11.02	8.07	8.14	7.36
0	0	0.00		10.09	10.90	8.09	8.11	7.36
0	0	0.00		10.17	10.70	8.01	8.03	7.29
0	0	0.00		10.00	10.56	7.98	7.99	7.27
0	0	12.00		10.86	11.13	8.71	8.72	7.97
0	0	11.98		10.78	10.94	8.69	8.72	7.97
0	0	11.96		10.71	10.88	8.69	8.69	7.98
0	0	11.93		10.61	10.77	8.60	8.60	7.90
0	0	11.91		10.60	10.70	8.63	8.64	7.94
0	0	11.88		10.51	10.69	8.61	8.60	7.92
0	0	11.86		10.49	10.58	8.56	8.54	7.89
0	0	11.84		10.42	10.51	8.55	8.52	7.88
0	0	11.82		10.48	10.49	8.53	8.49	7.86

Capacity Prices ($/MW-day) - Real (2008) $'s AEP GEN HUB Hub Cap.	SPP Cap.	Renewable Energy Subsidies ** ($/MWh) - Real (2008) $'s	Inflation Factor
52.80	23.73	44.98	1.80%
21.46	23.32	44.03	1.70%
77.30	22.81	43.52	2.70%
191.12	22.24	42.89	2.40%
245.86	21.80	38.46	1.70%
202.70	21.46	38.46	1.50%
169.39	303.65	38.46	1.60%
186.94	304.52	38.38	1.50%
207.88	304.88	38.22	1.50%
226.29	304.62	38.14	1.50%
242.15	303.72	38.13	1.50%
255.48	302.19	38.12	1.50%
266.27	300.03	38.10	1.50%
274.52	297.23	37.99	1.50%
280.23	293.81	37.95	1.50%
283.40	289.75	37.76	1.50%
284.03	285.06	37.64	1.50%
281.85	279.46	37.66	1.50%
277.29	273.39	37.33	1.40%

Kentucky Power Company

REQUEST

Refer to p. 5 line 17 to p. 6 line 16 of the testimony of Karl Bletzacker.

a. Identify the name and date of each consultancies' natural gas forecast used in developing the natural gas price forecast used in this application. Produce each such forecast.

b. Identify the "price elasticity of supply over time" and the "corresponding change in natural gas prices" that resulted from applying it to the AuroraXMP natural gas burn.

c. With regards to the chart on p. 6 lines 5-16, identify each consultant natural gas price forecast included in the "Consultant's range," the date of each such forecast, and the annual natural gas price in $/mmBtu for each of 2012 through 2030 for each such forecast.

RESPONSE

a. Please refer to the Company's response to KPSC Staff 1-31.

b. Kentucky Power expects the price elasticity of supply ratio to be approximately 0.6 to 0.8. Therefore, a 10% increase in gas consumption could reasonably be expected to result in a 12% to 17% increase in price.

c. Please refer to the Company's response to KIUC 1-58.

WITNESS: Karl R Bletzacker

Kentucky Power Company

REQUEST

Refer to p. 6 lines 18-19 of the testimony of Karl Bletzacker.

a. Explain the basis for your contention that "despite current negative reaction, the environmental impacts of shale gas development will ultimately be manageable."

b. Identify and produce any documents or analyses supporting that contention.

c. State the estimated impact on the price of natural gas of the steps that may be taken to make the environmental impacts of shale gas development manageable.

RESPONSE

a/b. Please refer to the Company's response to KPSC 1-32.

c. No such study was performed.

WITNESS: Karl R Bletzacker

Kentucky Power Company

REQUEST

Refer to p. 7 lines 6-8 of the testimony of Karl Bletzacker.

a. Identify the "postponed Renewable Portfolio Standards" referenced therein.

b. Explain the impact that the postponement of Renewable Portfolio Standards would have on the price of natural gas.

RESPONSE

a. Mr. Bleztacker did not reference any actual Renewable Portfolio Standards (RPS) that would be postponed, but rather described the hypothetical situation if there would be such postponement.

b. To the extent natural gas would substitute for a postponed RPS, such substitution would result in increased natural gas consumption. Such increase in natural gas consumption would result in a corresponding increase in natural gas price.

WITNESS: Karl R Bletzacker

Kentucky Power Company

REQUEST

Refer to p. 8, lines 3-6 of the testimony of Karl Bletzacker.

a. Identify the impact, in dollars or percent, that the Mercury and Air Toxics Standard is projected to have on natural gas prices in the Fundamentals Analysis Group's natural gas price projection used in this proceeding.
    i. Describe how that impact was determined, and produce any documents or analyses that support such determination.

b. Identify each other "impending environmental regulation focused on coal-fired generation" that impacted the price of natural gas in the Fundamentals Analysis Group's natural gas price projection used in this proceeding.
    i. For each such regulation, identify the impact, in dollars per mmBtu or percent, on the natural gas price.

RESPONSE

a-b. The Company's price forecast assumed the anticipated impacts of various environmental regulations, including the costs associated with the Mercury and Air Toxics Standards (MATS). The impacts associated with MATS and others (Coal Combustion Residuals and Clean Water Act 316b) were not isolated and quantified.

WITNESS: Karl R Bletzacker

Kentucky Power Company

REQUEST

Refer to p. 11 line 10 to p. 12 line 2 of the testimony of Karl Bletzacker.

a. Identify and produce any documents or analyses supporting Kentucky Power's "current assessment" of the likelihood of successful federal climate legislation.

b. Explain the basis for selecting a $15/tonne price, as opposed to some other price, for the CO2 Price/Tax starting in 2022.

c. Identify the value assumed for the CO2 Price/Tax for each of the years 2023 through 2040, and explain the basis for such values.

d. Identify and produce any analyses, legislative proposals, or other documents on which your CO2 Price/Tax relies.

e. Identify the annual CO2 emissions per year from Mitchell Units 1 and 2 for the past five years.

f. Identify the projected annual CO2 emissions per year from Mitchell Units 1 and 2 for the years 2013 through 2040.

RESPONSE

a. No formal analysis has been completed. Prior efforts to established federal climate legislation have been unsuccessful. Senator Barbara Boxer, chair of the Senate Environment and Public Works Committee has indicated plans to move a climate bill through her committee and to the floor in 2013. It is unclear if or when future climate legislation could be passed by Congress.

b. Please refer to Bletzacker Direct Testimony page 12 at lines 5-10.

c. Please refer to the response provided to SC 1-10.

d. No analyses, current legislative proposals, or other documents, beyond that described in the Company's testimony, are available.

e. See the Company's response below for the annual CO2 emissions per year from Mitchell Units 1 and 2 for the past five years.

2008	10,576,902	short tons	http://ampd.epa.gov/ampd/
2009	9,446,783	short tons	http://ampd.epa.gov/ampd/
2010	10,006,803	short tons	ghgdata.epa.gov/ghgp/service/html/2010?id=1000976&ds=E
2011	9,148,197	short tons	http://ghgdata.epa.gov/ghgp/service/html/2011?id=1000976&ds=E
2012	7,695,799	short tons	http://ampd.epa.gov/ampd/

f. See SC 1-15f Attachment 1 for the Company's response to the projected annual CO2 emissions per year from Mitchell Units 1 and 2 for the years 2013 through 2040.

WITNESS: Karl R Bletzacker

Projected Annual CO2 Emissions 2013-2040

(TONS)	Option 6 Base		Option 6 High Band		Option 6 Low Band		Option 6 No Carbon		Option 6 Early Carbon	
	Mitchell 1	Mitchell 2	Mitchell 1	Mitchell 2	Mitchell 1	Mitchell 2	Mitchell 1	Mitchell 2	Mitchell 1	Mitchell 2
2014	1,913	2,067	2,216	2,384	1,831	1,976	1,910	2,060	1,903	2,050
2015	1,963	1,631	2,275	1,912	1,876	1,550	1,984	1,648	1,961	1,634
2016	1,803	2,199	2,038	2,408	1,662	2,041	1,823	2,222	1,776	2,177
2017	2,145	2,268	2,415	2,467	1,952	2,117	2,156	2,276	1,753	1,934
2018	2,153	2,034	2,422	2,207	1,961	1,897	2,158	2,035	1,752	1,717
2019	1,914	2,312	2,136	2,502	1,708	2,128	1,910	2,309	1,529	1,910
2020	2,075	2,282	2,374	2,499	1,844	2,099	2,083	2,285	1,650	1,895
2021	2,180	2,036	2,427	2,205	1,929	1,866	2,151	2,014	1,730	1,702
2022	1,577	2,002	1,940	2,333	1,395	1,776	1,936	2,328	1,561	1,988
2023	1,709	1,970	2,148	2,330	1,538	1,756	2,137	2,328	1,693	1,943
2024	1,824	1,688	2,225	1,957	1,587	1,470	2,213	1,957	1,750	1,625
2025	1,485	1,971	1,868	2,319	1,299	1,717	1,845	2,307	1,450	1,924
2026	1,933	2,068	2,359	2,434	1,424	1,651	2,346	2,430	1,842	1,990
2027	1,975	1,754	2,392	2,048	1,490	1,416	2,373	2,040	1,881	1,680
2028	1,713	2,067	2,117	2,455	1,239	1,627	2,096	2,436	1,627	1,988
2029	1,931	2,062	2,407	2,466	1,415	1,622	2,361	2,438	1,809	1,957
2030	1,882	1,707	2,414	2,068	1,360	1,354	2,316	2,010	1,734	1,611
2031	1,650	2,009	2,173	2,483	1,216	1,579	2,072	2,397	1,558	1,899
2032	1,860	2,013	2,470	2,512	1,372	1,581	2,324	2,414	1,749	1,912
2033	1,801	1,670	2,468	2,097	1,356	1,331	2,308	1,998	1,698	1,575
2034	1,597	1,954	2,216	2,527	1,194	1,546	2,046	2,384	1,499	1,845
2035	1,687	1,903	2,484	2,521	1,267	1,515	2,251	2,361	1,631	1,825
2036	1,740	1,627	2,525	2,124	1,336	1,300	2,288	1,977	1,689	1,553
2037	1,531	1,903	2,250	2,557	1,174	1,507	2,027	2,364	1,492	1,837
2038	1,683	1,911	2,551	2,562	1,291	1,508	2,276	2,357	1,666	1,841
2039	1,724	1,639	2,569	2,157	1,323	1,285	2,280	1,969	1,711	1,569
2040	1,445	1,874	2,267	2,579	1,112	1,468	2,012	2,353	1,476	1,841

Kentucky Power Company

REQUEST

Confirm whether each of the following commodity price forecasts used in the present application are the same as those used in your analysis in Case No. 2012-00401. If so, explain your basis for concluding that such forecast has not changed since the previous analysis. If not, explain how the forecast has changed.

a. Natural gas prices
b. CO2 prices
c. Coal prices
d. Peak energy prices
e. Off-peak energy prices
f. Capacity values

RESPONSE

The prices in "a." through "f." have not changed from those used in the Long-Term Forecast in Case No. 2012-00401. In the less-than-one-year period between Cases 2011-00401 and 2012-00578 there have been no substantive reasons to make changes to the long-term North American supply, demand and resulting price fundamentals of natural gas, CO2 and coal prices (energy and capacity values are discrete outputs of the AuroraXMP). In the nearby years, adjustments could be justified, given the vacatur of CSAPR and the effect of warmer-than-normal weather, but it would have no effect upon the analyses performed by witness Weaver, et al.

WITNESS: Karl R Bletzacker

Kentucky Power Company

REQUEST

Refer to p. 3 lines 14-16. Identify the amount of energy and capacity that the Mitchell Plant has provided to Kentucky Power in each of the past ten years.

RESPONSE

Kentucky Power receives capacity and energy from Ohio Power based on the average cost of all of Ohio Power's primary generation resources, including Mitchell. As such, the amounts Kentucky Power received specifically from Mitchell are not identifiable.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

For each of Mitchell Units 1 and 2, identify the following for each of 2003 through 2012:

a. Capacity factor
b. Availability
c. Forced outage rate
d. Heat rate
e. MWhs of energy generated
f. Fixed O&M expenses
g. Variable O&M expenses
h. Fuel costs
i. Non-environmental capital expenditures
j. Capital expenditures for environmental controls

RESPONSE

a-e. Refer to SC 1-18 Attachment 1 for the requested information.

f-j. Refer to SC 1-18 Attachment 2 for the requested information. A unit level breakout for cost data is not available for the years prior to 2006.

WITNESS: Jeffery D LaFleur

a.

Net Capacity Factor MWh(%)		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Mitchell 1		[redacted]									
Mitchell 2											

b.

Equivalent Availability (%)		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Mitchell 1		[redacted]									
Mitchell 2											

c.

Forced Outage Rate (%)		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Mitchell 1		6.14%	9.23%	13.93%	15.86%	12.17%	4.31%	3.84%	7.81%	9.62%	7.14%
Mitchell 2		5.60%	4.21%	13.80%	8.85%	14.41%	5.49%	1.48%	5.59%	7.78%	5.86%

d.

Heat Rate (BTU/KWh)		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Mitchell 1		[redacted]									
Mitchell 2											

e.

Net MWh		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Mitchell 1		[redacted]									
Mitchell 2											

		Years [1,3]									
Unit	Characteristic	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Mitchell 0	Environmental Capital[2]				$21,601,080	$15,402,663	$8,637,563	$988,387	$2,756,102	$8,731,507	$37,203,249
	Fixed O&M Expenses	$19,472,604	$21,454,751	$36,170,646	$8,143,287	$11,564,911	$10,510,231	$12,943,778	$12,087,179	$13,012,417	$17,082,932
	Fuel Costs[7]	$132,887,015	$137,087,335	$120,481,365	$5,458,774	$1,429,193	($70,943,393)	$648,612	$370,421	$725,706	$1,123,823
	Non-Environmental Capital[4]	$11,495,177	$12,922,082	$2,253,058	$2,013,746	$1,000,601	$2,864,460	$7,750,225	$2,427,960	$11,628,801	$21,588,306
	Variable O&M Costs[6]	$6,218,287	$7,754,980	$12,547,832	$3,696,503	$4,408,355	$9,095,641	$11,405,373	$12,663,108	$12,741,632	$13,841,044
Mitchell 0 Total		**$170,073,082**	**$179,219,148**	**$171,452,901**	**$40,913,391**	**$33,805,724**	**($39,835,497)**	**$33,736,375**	**$30,304,770**	**$46,840,064**	**$90,839,353**
Mitchell 1	Environmental Capital[2,5]				$208,317,148	$100,345,973	$26,913,595	$3,272,096	$721,195	$6,292,354	$3,777,602
	Fixed O&M Expenses				$13,418,834	$14,105,553	$4,137,453	$3,926,770	$4,524,707	$7,853,124	$5,015,721
	Fuel Costs[7]				$68,895,475	$59,614,978	$98,060,668	$112,132,481	$123,285,960	$103,840,184	$118,541,347
	Non-Environmental Capital[5]				$15,525,934	$17,034,841	$1,638,345	$2,848,838	$2,399,087	$8,437,828	$5,098,690
	Variable O&M Costs[6]				$5,214,360	$7,754,321	$6,194,659	$5,336,770	$6,326,712	$9,006,713	$7,079,326
Mitchell 1 Total					**$311,371,752**	**$198,855,665**	**$136,944,720**	**$127,516,955**	**$137,257,661**	**$135,430,202**	**$139,512,686**
Mitchell 2	Environmental Capital[2,5]				$202,910,390	$76,291,519	$7,513,494	$10,768,912	$1,046,974	$1,423,783	$3,977,754
	Fixed O&M Expenses				$8,935,097	$3,934,101	$2,180,624	$4,719,606	$3,764,560	$3,721,529	$8,562,848
	Fuel Costs[7]				$65,618,780	$81,459,851	$115,091,070	$109,161,168	$125,455,921	$131,261,801	$97,445,341
	Non-Environmental Capital[5]				$5,598,435	$797,856	$1,584,044	$4,433,443	$3,295,459	$3,859,510	$7,999,191
	Variable O&M Costs[6]				$6,199,327	$4,851,807	$4,669,388	$6,572,245	$6,091,507	$6,824,808	$8,421,945
Mitchell 2 Total					**$289,262,030**	**$167,335,134**	**$131,038,620**	**$135,655,375**	**$139,654,421**	**$147,091,431**	**$126,407,079**

Notes:

1 FERC Form 1 data for 2001-2005 by plant, not unit
2 Unable to differentiate Capital between Environmental and Non-Environmental for 2003-2005
3 2006-2012 costs from OPCo post-allocated actuals
4 Capital amounts are Capital Additions for 2003-2005
5 Capital amounts are actuals charged to 107xxxx accounts in OPCo for 2006-2012
6 Variable O&M defined as 1/2 O&M Maintenance plus Consumables
7 Fuel Costs exclude Comsumables

Kentucky Power Company

REQUEST

For each of Mitchell Units 1 and 2, identify the projected values for each of the following for each of 2013 through 2040:

a. Capacity factor
b. Availability
c. Forced outage rate
d. Heat rate
e. MWhs of energy generated
f. Fixed O&M expenses
g. Variable O&M expenses
h. Fuel costs
i. Non-environmental capital expenditures
j. Capital expenditures for environmental controls

RESPONSE

Refer to SC 1-19 Attachments 1 through 5 for the requested information.

WITNESS: Jeffery D LaFleur

%

Capacity Factor

	Mitchell 1 50%	Mitchell 2 50%
2014	[redacted]	
2015		
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		
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2038		
2039		
2040		

%	Mitchell 1 50%	Mitchell 2 50%
	Average Annual Availability	
2014	[redacted]	[redacted]
2015	[redacted]	[redacted]
2016	[redacted]	[redacted]
2017	[redacted]	[redacted]
2018	[redacted]	[redacted]
2019	[redacted]	[redacted]
2020	[redacted]	[redacted]
2021	[redacted]	[redacted]
2022	[redacted]	[redacted]
2023	[redacted]	[redacted]
2024	[redacted]	[redacted]
2025	[redacted]	[redacted]
2026	[redacted]	[redacted]
2027	[redacted]	[redacted]
2028	[redacted]	[redacted]
2029	[redacted]	[redacted]
2030	[redacted]	[redacted]
2031	[redacted]	[redacted]
2032	[redacted]	[redacted]
2033	[redacted]	[redacted]
2034	[redacted]	[redacted]
2035	[redacted]	[redacted]
2036	[redacted]	[redacted]
2037	[redacted]	[redacted]
2038	[redacted]	[redacted]
2039	[redacted]	[redacted]
2040	[redacted]	[redacted]

%	Mitchell 1 50%	Mitchell 2 50%
	Forced Outage Rate	
2014	[redacted]	[redacted]
2015	[redacted]	[redacted]
2016	[redacted]	[redacted]
2017	[redacted]	[redacted]
2018	[redacted]	[redacted]
2019	[redacted]	[redacted]
2020	[redacted]	[redacted]
2021	[redacted]	[redacted]
2022	[redacted]	[redacted]
2023	[redacted]	[redacted]
2024	[redacted]	[redacted]
2025	[redacted]	[redacted]
2026	[redacted]	[redacted]
2027	[redacted]	[redacted]
2028	[redacted]	[redacted]
2029	[redacted]	[redacted]
2030	[redacted]	[redacted]
2031	[redacted]	[redacted]
2032	[redacted]	[redacted]
2033	[redacted]	[redacted]
2034	[redacted]	[redacted]
2035	[redacted]	[redacted]
2036	[redacted]	[redacted]
2037	[redacted]	[redacted]
2038	[redacted]	[redacted]
2039	[redacted]	[redacted]
2040	[redacted]	[redacted]

MBTU/MWH

	Mitchell 1 50%	Mitchell 2 50%
	Avg. Heat Rate	
2014	[redacted]	
2015		
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		
2026		
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2036		
2037		
2038		
2039		
2040		

MWh's

	Mitchell 1 50%	Mitchell 2 50%
	Generation	
2014	[redacted]	
2015		
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		
2026		
2027		
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2037		
2038		
2039		
2040		

$000

	Mitchell 1 50%	Mitchell 2 50%
	Fixed O&M	
2014	12,296	12,199
2015	12,321	15,661
2016	17,654	15,040
2017	14,429	14,764
2018	15,102	16,953
2019	18,246	16,100
2020	17,499	17,589
2021	13,660	13,520
2022	16,345	16,341
2023	16,672	16,668
2024	17,005	17,002
2025	17,345	17,342
2026	17,692	17,689
2027	18,046	18,042
2028	18,407	18,403
2029	18,775	18,771
2030	19,151	19,147
2031	19,534	19,530
2032	19,924	19,920
2033	20,323	20,319
2034	20,729	20,725
2035	21,144	21,139
2036	21,567	21,562
2037	21,998	21,993
2038	22,438	22,433
2039	22,887	22,882
2040	23,345	23,340

$000

	Mitchell 1 50%	Mitchell 2 50%
	Variable O&M	
2014	9,332	10,081
2015	9,646	8,019
2016	9,147	11,161
2017	11,193	11,838
2018	11,547	10,918
2019	10,585	12,794
2020	11,812	12,997
2021	12,783	11,944
2022	9,514	12,085
2023	10,618	12,250
2024	11,675	10,812
2025	9,789	13,003
2026	13,130	14,051
2027	13,825	12,275
2028	12,352	14,909
2029	14,347	15,319
2030	14,409	13,073
2031	13,020	15,860
2032	15,126	16,376
2033	15,119	14,026
2034	13,829	16,919
2035	15,054	16,993
2036	16,041	15,003
2037	14,559	18,100
2038	16,505	18,749
2039	17,448	16,598
2040	15,109	19,603

$000

	Mitchell 1 50%	Mitchell 2 50%
	Fuel Costs	
2014	[redacted]	
2015		
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		

$000

	Mitchell 1 50%	Mitchell 2 50%
	Non-Environmental Capital	
2014	12,620	12,620
2015	11,128	11,128
2016	4,838	4,838
2017	3,554	3,554
2018	6,300	6,300
2019	14,273	14,273
2020	8,264	8,264
2021	24,262	24,262
2022	12,353	12,353
2023	12,662	12,662
2024	12,979	12,979
2025	13,303	13,303
2026	13,636	13,636
2027	13,977	13,977
2028	14,326	14,326
2029	14,684	14,684
2030	15,051	15,051
2031	15,428	15,428
2032	15,813	15,813
2033	16,209	16,209
2034	16,614	16,614
2035	17,029	17,029
2036	13,964	13,964
2037	8,588	8,588
2038	3,521	3,521
2039	722	722
2040	0	0

$000	Mitchell 1 50%	Mitchell 2 50%
	Environmental Capital Expenditures	
2014	7,608	7,608
2015	3,567	3,567
2016	2,483	2,483
2017	8,084	8,084
2018	9,458	9,458
2019	5,365	5,365
2020	0	0
2021	0	0
2022	0	0
2023	0	0
2024	0	0
2025	0	0
2026	0	0
2027	0	0
2028	0	0
2029	0	0
2030	0	0
2031	0	0
2032	0	0
2033	0	0
2034	0	0
2035	0	0
2036	0	0
2037	0	0
2038	0	0
2039	0	0
2040	0	0

%	Mitchell 1 50%	Mitchell 2 50%
	Capacity Factor	
2014	[redacted]	
2015		
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		
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2040		

%

Average Annual Availability

	Mitchell 1 50%	Mitchell 2 50%
2014	[redacted]	
2015		
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		
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2036		
2037		
2038		
2039		
2040		

%	Mitchell 1 50%	Mitchell 2 50%
	Forced Outage Rate	
2014	[redacted]	
2015		
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
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2038		
2039		
2040		

MBTU/MWH

	Mitchell 1 50%	Mitchell 2 50%
	Avg. Heat Rate	
2014	[redacted]	[redacted]
2015	[redacted]	[redacted]
2016	[redacted]	[redacted]
2017	[redacted]	[redacted]
2018	[redacted]	[redacted]
2019	[redacted]	[redacted]
2020	[redacted]	[redacted]
2021	[redacted]	[redacted]
2022	[redacted]	[redacted]
2023	[redacted]	[redacted]
2024	[redacted]	[redacted]
2025	[redacted]	[redacted]
2026	[redacted]	[redacted]
2027	[redacted]	[redacted]
2028	[redacted]	[redacted]
2029	[redacted]	[redacted]
2030	[redacted]	[redacted]
2031	[redacted]	[redacted]
2032	[redacted]	[redacted]
2033	[redacted]	[redacted]
2034	[redacted]	[redacted]
2035	[redacted]	[redacted]
2036	[redacted]	[redacted]
2037	[redacted]	[redacted]
2038	[redacted]	[redacted]
2039	[redacted]	[redacted]
2040	[redacted]	[redacted]

MWh's

	Mitchell 1 50%	Mitchell 2 50%
	Generation	
2014	[redacted]	[redacted]
2015	[redacted]	[redacted]
2016	[redacted]	[redacted]
2017	[redacted]	[redacted]
2018	[redacted]	[redacted]
2019	[redacted]	[redacted]
2020	[redacted]	[redacted]
2021	[redacted]	[redacted]
2022	[redacted]	[redacted]
2023	[redacted]	[redacted]
2024	[redacted]	[redacted]
2025	[redacted]	[redacted]
2026	[redacted]	[redacted]
2027	[redacted]	[redacted]
2028	[redacted]	[redacted]
2029	[redacted]	[redacted]
2030	[redacted]	[redacted]
2031	[redacted]	[redacted]
2032	[redacted]	[redacted]
2033	[redacted]	[redacted]
2034	[redacted]	[redacted]
2035	[redacted]	[redacted]
2036	[redacted]	[redacted]
2037	[redacted]	[redacted]
2038	[redacted]	[redacted]
2039	[redacted]	[redacted]
2040	[redacted]	[redacted]

$000

	Mitchell 1 50%	Mitchell 2 50%
	Fixed O&M	
2014	12,296	12,199
2015	12,321	15,661
2016	17,654	15,040
2017	14,429	14,764
2018	15,102	16,953
2019	18,246	16,100
2020	17,499	17,589
2021	13,660	13,520
2022	16,345	16,341
2023	16,672	16,668
2024	17,005	17,002
2025	17,345	17,342
2026	17,692	17,689
2027	18,046	18,042
2028	18,407	18,403
2029	18,775	18,771
2030	19,151	19,147
2031	19,534	19,530
2032	19,924	19,920
2033	20,323	20,319
2034	20,729	20,725
2035	21,144	21,139
2036	21,567	21,562
2037	21,998	21,993
2038	22,438	22,433
2039	22,887	22,882
2040	23,345	23,340

$000

	Mitchell 1 50%	Mitchell 2 50%
	Variable O&M	
2014	9,332	10,081
2015	9,787	8,097
2016	9,643	11,437
2017	11,856	12,146
2018	12,185	11,189
2019	11,153	13,124
2020	12,714	13,345
2021	13,427	12,249
2022	10,191	12,464
2023	11,263	12,549
2024	12,298	11,103
2025	10,747	13,495
2026	12,425	13,757
2027	13,207	12,060
2028	11,771	14,656
2029	13,569	15,050
2030	13,977	13,053
2031	13,020	15,860
2032	15,126	16,376
2033	15,119	14,026
2034	13,829	16,919
2035	15,054	16,993
2036	16,041	15,003
2037	14,559	18,100
2038	16,505	18,749
2039	17,448	16,598
2040	15,109	19,603

$000	Mitchell 1 50%	Mitchell 2 50%
	Fuel Costs	
2014	[redacted]	
2015		
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		
2026		
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2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		

$000

	Mitchell 1 50%	Mitchell 2 50%
	Non-Environmental Capital	
2014	12,620	12,620
2015	11,128	11,128
2016	4,838	4,838
2017	3,554	3,554
2018	6,300	6,300
2019	14,273	14,273
2020	8,264	8,264
2021	24,262	24,262
2022	12,353	12,353
2023	12,662	12,662
2024	12,979	12,979
2025	13,303	13,303
2026	13,636	13,636
2027	13,977	13,977
2028	14,326	14,326
2029	14,684	14,684
2030	15,051	15,051
2031	15,428	15,428
2032	15,813	15,813
2033	16,209	16,209
2034	16,614	16,614
2035	17,029	17,029
2036	13,964	13,964
2037	8,588	8,588
2038	3,521	3,521
2039	722	722
2040	0	0

$000

	Mitchell 1 50%	Mitchell 2 50%
	Environmental Capital Expenditures	
2014	7,608	7,608
2015	3,567	3,567
2016	2,483	2,483
2017	8,084	8,084
2018	9,458	9,458
2019	5,365	5,365
2020	0	0
2021	0	0
2022	0	0
2023	0	0
2024	0	0
2025	0	0
2026	0	0
2027	0	0
2028	0	0
2029	0	0
2030	0	0
2031	0	0
2032	0	0
2033	0	0
2034	0	0
2035	0	0
2036	0	0
2037	0	0
2038	0	0
2039	0	0
2040	0	0

%

	Mitchell 1 50%	Mitchell 2 50%
	Capacity Factor	
2014	[redacted]	
2015		
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		
2026		
2027		
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2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		

%	Mitchell 1 50%	Mitchell 2 50%
	Average Annual Availability	
2014	[redacted]	
2015		
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		
2026		
2027		
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2035		
2036		
2037		
2038		
2039		
2040		

%

Forced Outage Rate

	Mitchell 1 50%	Mitchell 2 50%
2014	[redacted]	
2015		
2016		
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MBTU/MWH

	Mitchell 1 50%	Mitchell 2 50%
	Avg. Heat Rate	
2014	[redacted]	
2015		
2016		
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2020		
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MWh's

	Mitchell 1 50%	Mitchell 2 50%
	Generation	
2014	[redacted]	[redacted]
2015	[redacted]	[redacted]
2016	[redacted]	[redacted]
2017	[redacted]	[redacted]
2018	[redacted]	[redacted]
2019	[redacted]	[redacted]
2020	[redacted]	[redacted]
2021	[redacted]	[redacted]
2022	[redacted]	[redacted]
2023	[redacted]	[redacted]
2024	[redacted]	[redacted]
2025	[redacted]	[redacted]
2026	[redacted]	[redacted]
2027	[redacted]	[redacted]
2028	[redacted]	[redacted]
2029	[redacted]	[redacted]
2030	[redacted]	[redacted]
2031	[redacted]	[redacted]
2032	[redacted]	[redacted]
2033	[redacted]	[redacted]
2034	[redacted]	[redacted]
2035	[redacted]	[redacted]
2036	[redacted]	[redacted]
2037	[redacted]	[redacted]
2038	[redacted]	[redacted]
2039	[redacted]	[redacted]
2040	[redacted]	[redacted]

$000

	Mitchell 1 50%	Mitchell 2 50%
	Fixed O&M	
2014	12,296	12,199
2015	12,321	15,661
2016	17,654	15,040
2017	14,429	14,764
2018	15,102	16,953
2019	18,246	16,100
2020	17,499	17,589
2021	13,660	13,520
2022	16,345	16,341
2023	16,672	16,668
2024	17,005	17,002
2025	17,345	17,342
2026	17,692	17,689
2027	18,046	18,042
2028	18,407	18,403
2029	18,775	18,771
2030	19,151	19,147
2031	19,534	19,530
2032	19,924	19,920
2033	20,323	20,319
2034	20,729	20,725
2035	21,144	21,139
2036	21,567	21,562
2037	21,998	21,993
2038	22,438	22,433
2039	22,887	22,882
2040	23,345	23,340

$000

	Mitchell 1 50%	Mitchell 2 50%
	Variable O&M	
2014	8,932	9,637
2015	9,219	7,616
2016	8,427	10,361
2017	10,179	11,050
2018	10,512	10,183
2019	9,439	11,775
2020	10,488	11,956
2021	11,301	10,949
2022	8,413	10,721
2023	9,556	10,917
2024	10,150	9,413
2025	8,559	11,323
2026	9,666	11,216
2027	10,417	9,909
2028	8,927	11,728
2029	10,505	12,049
2030	10,398	10,365
2031	9,583	12,459
2032	11,146	12,861
2033	11,369	11,178
2034	10,327	13,380
2035	11,302	13,524
2036	12,304	11,988
2037	11,160	14,329
2038	12,654	14,793
2039	13,382	13,003
2040	11,617	15,345

$000	Mitchell 1 50%	Mitchell 2 50%
	Fuel Costs	
2014	[redacted]	[redacted]
2015	[redacted]	[redacted]
2016	[redacted]	[redacted]
2017	[redacted]	[redacted]
2018	[redacted]	[redacted]
2019	[redacted]	[redacted]
2020	[redacted]	[redacted]
2021	[redacted]	[redacted]
2022	[redacted]	[redacted]
2023	[redacted]	[redacted]
2024	[redacted]	[redacted]
2025	[redacted]	[redacted]
2026	[redacted]	[redacted]
2027	[redacted]	[redacted]
2028	[redacted]	[redacted]
2029	[redacted]	[redacted]
2030	[redacted]	[redacted]
2031	[redacted]	[redacted]
2032	[redacted]	[redacted]
2033	[redacted]	[redacted]
2034	[redacted]	[redacted]
2035	[redacted]	[redacted]
2036	[redacted]	[redacted]
2037	[redacted]	[redacted]
2038	[redacted]	[redacted]
2039	[redacted]	[redacted]
2040	[redacted]	[redacted]

$000

	Mitchell 1 50%	Mitchell 2 50%
	Non-Environmental Capital	
2014	12,620	12,620
2015	11,128	11,128
2016	4,838	4,838
2017	3,554	3,554
2018	6,300	6,300
2019	14,273	14,273
2020	8,264	8,264
2021	24,262	24,262
2022	12,353	12,353
2023	12,662	12,662
2024	12,979	12,979
2025	13,303	13,303
2026	13,636	13,636
2027	13,977	13,977
2028	14,326	14,326
2029	14,684	14,684
2030	15,051	15,051
2031	15,428	15,428
2032	15,813	15,813
2033	16,209	16,209
2034	16,614	16,614
2035	17,029	17,029
2036	13,964	13,964
2037	8,588	8,588
2038	3,521	3,521
2039	722	722
2040	0	0

$000

	Mitchell 1 50%	Mitchell 2 50%
	Environmental Capital Expenditures	
2014	7,608	7,608
2015	3,567	3,567
2016	2,483	2,483
2017	8,084	8,084
2018	9,458	9,458
2019	5,365	5,365
2020	0	0
2021	0	0
2022	0	0
2023	0	0
2024	0	0
2025	0	0
2026	0	0
2027	0	0
2028	0	0
2029	0	0
2030	0	0
2031	0	0
2032	0	0
2033	0	0
2034	0	0
2035	0	0
2036	0	0
2037	0	0
2038	0	0
2039	0	0
2040	0	0

%	Mitchell 1 50%	Mitchell 2 50%
	Capacity Factor	
2014	[redacted]	
2015		
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%	Mitchell 1 50%	Mitchell 2 50%
	Average Annual Availability	
2014	[redacted]	
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%	Mitchell 1 50%	Mitchell 2 50%
	Forced Outage Rate	
2014	[redacted]	
2015		
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REDACTED

MBTU/MWH

	Mitchell 1 50%	Mitchell 2 50%
	Avg. Heat Rate	
2014	[redacted]	
2015		
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MWh's

	Mitchell 1 50%	Mitchell 2 50%
	Generation	
2014	[redacted]	[redacted]
2015	[redacted]	[redacted]
2016	[redacted]	[redacted]
2017	[redacted]	[redacted]
2018	[redacted]	[redacted]
2019	[redacted]	[redacted]
2020	[redacted]	[redacted]
2021	[redacted]	[redacted]
2022	[redacted]	[redacted]
2023	[redacted]	[redacted]
2024	[redacted]	[redacted]
2025	[redacted]	[redacted]
2026	[redacted]	[redacted]
2027	[redacted]	[redacted]
2028	[redacted]	[redacted]
2029	[redacted]	[redacted]
2030	[redacted]	[redacted]
2031	[redacted]	[redacted]
2032	[redacted]	[redacted]
2033	[redacted]	[redacted]
2034	[redacted]	[redacted]
2035	[redacted]	[redacted]
2036	[redacted]	[redacted]
2037	[redacted]	[redacted]
2038	[redacted]	[redacted]
2039	[redacted]	[redacted]
2040	[redacted]	[redacted]

$000

	Mitchell 1 50%	Mitchell 2 50%
	Fixed O&M	
2014	12,296	12,199
2015	12,321	15,661
2016	17,654	15,040
2017	14,429	14,764
2018	15,102	16,953
2019	18,246	16,100
2020	17,499	17,589
2021	13,660	13,520
2022	16,345	16,341
2023	16,672	16,668
2024	17,005	17,002
2025	17,345	17,342
2026	17,692	17,689
2027	18,046	18,042
2028	18,407	18,403
2029	18,775	18,771
2030	19,151	19,147
2031	19,534	19,530
2032	19,924	19,920
2033	20,323	20,319
2034	20,729	20,725
2035	21,144	21,139
2036	21,567	21,562
2037	21,998	21,993
2038	22,438	22,433
2039	22,887	22,882
2040	23,345	23,340

$000

	Mitchell 1 50%	Mitchell 2 50%
	Variable O&M	
2014	9,316	10,045
2015	9,748	8,102
2016	9,247	11,280
2017	11,245	11,883
2018	11,568	10,924
2019	10,561	12,778
2020	11,849	13,020
2021	12,603	11,817
2022	11,680	14,062
2023	13,280	14,481
2024	14,165	12,535
2025	12,154	15,224
2026	15,952	16,512
2027	16,618	14,281
2028	15,130	17,571
2029	17,558	18,115
2030	17,751	15,391
2031	16,367	18,923
2032	18,913	19,638
2033	19,396	16,776
2034	17,727	20,644
2035	20,114	21,084
2036	21,116	18,225
2037	19,299	22,485
2038	22,359	23,122
2039	23,114	19,932
2040	21,066	24,612

$000

	Mitchell 1 50%	Mitchell 2 50%
	Fuel Costs	
2014	[redacted]	
2015		
2016		
2017		
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$000

	Mitchell 1 50%	Mitchell 2 50%
	Non-Environmental Capital	
2014	12,620	12,620
2015	11,128	11,128
2016	4,838	4,838
2017	3,554	3,554
2018	6,300	6,300
2019	14,273	14,273
2020	8,264	8,264
2021	24,262	24,262
2022	12,353	12,353
2023	12,662	12,662
2024	12,979	12,979
2025	13,303	13,303
2026	13,636	13,636
2027	13,977	13,977
2028	14,326	14,326
2029	14,684	14,684
2030	15,051	15,051
2031	15,428	15,428
2032	15,813	15,813
2033	16,209	16,209
2034	16,614	16,614
2035	17,029	17,029
2036	13,964	13,964
2037	8,588	8,588
2038	3,521	3,521
2039	722	722
2040	0	0

$000

	Mitchell 1 50%	Mitchell 2 50%
	Environmental Capital Expenditures	
2014	7,608	7,608
2015	3,567	3,567
2016	2,483	2,483
2017	8,084	8,084
2018	9,458	9,458
2019	5,365	5,365
2020	0	0
2021	0	0
2022	0	0
2023	0	0
2024	0	0
2025	0	0
2026	0	0
2027	0	0
2028	0	0
2029	0	0
2030	0	0
2031	0	0
2032	0	0
2033	0	0
2034	0	0
2035	0	0
2036	0	0
2037	0	0
2038	0	0
2039	0	0
2040	0	0

%	Mitchell 1 50%	Mitchell 2 50%
	Capacity Factor	
2014	[redacted]	
2015		
2016		
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%	Mitchell 1 50%	Mitchell 2 50%
	Average Annual Availability	
2014	[redacted]	
2015		
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%	Mitchell 1 50%	Mitchell 2 50%
	Forced Outage Rate	
2014	[redacted]	
2015		
2016		
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MBTU/MWH

	Mitchell 1 50%	Mitchell 2 50%
	Avg. Heat Rate	
2014	[redacted]	
2015		
2016		
2017		
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MWh's

	Mitchell 1 50%	Mitchell 2 50%
	Generation	
2014	[redacted]	
2015		
2016		
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$000

	Mitchell 1 50%	Mitchell 2 50%
	Fixed O&M	
2014	12,296	12,199
2015	12,321	15,661
2016	17,654	15,040
2017	14,429	14,764
2018	15,102	16,953
2019	18,246	16,100
2020	17,499	17,589
2021	13,660	13,520
2022	16,345	16,341
2023	16,672	16,668
2024	17,005	17,002
2025	17,345	17,342
2026	17,692	17,689
2027	18,046	18,042
2028	18,407	18,403
2029	18,775	18,771
2030	19,151	19,147
2031	19,534	19,530
2032	19,924	19,920
2033	20,323	20,319
2034	20,729	20,725
2035	21,144	21,139
2036	21,567	21,562
2037	21,998	21,993
2038	22,438	22,433
2039	22,887	22,882
2040	23,345	23,340

$000

	Mitchell 1 50%	Mitchell 2 50%
	Variable O&M	
2014	9,283	9,995
2015	9,637	8,029
2016	9,007	11,050
2017	9,140	10,099
2018	9,391	9,215
2019	8,451	10,568
2020	9,386	10,791
2021	10,131	9,984
2022	9,415	12,002
2023	10,519	12,082
2024	11,196	10,404
2025	9,550	12,687
2026	12,517	13,524
2027	13,171	11,761
2028	11,733	14,338
2029	13,442	14,544
2030	13,277	12,335
2031	12,296	14,987
2032	14,228	15,556
2033	14,254	13,223
2034	12,972	15,978
2035	14,563	16,295
2036	15,578	14,319
2037	14,194	17,468
2038	16,347	18,061
2039	17,329	15,888
2040	15,445	19,259

$000

	Mitchell 1 50%	Mitchell 2 50%
	Fuel Costs	
2014	[redacted]	[redacted]
2015	[redacted]	[redacted]
2016	[redacted]	[redacted]
2017	[redacted]	[redacted]
2018	[redacted]	[redacted]
2019	[redacted]	[redacted]
2020	[redacted]	[redacted]
2021	[redacted]	[redacted]
2022	[redacted]	[redacted]
2023	[redacted]	[redacted]
2024	[redacted]	[redacted]
2025	[redacted]	[redacted]
2026	[redacted]	[redacted]
2027	[redacted]	[redacted]
2028	[redacted]	[redacted]
2029	[redacted]	[redacted]
2030	[redacted]	[redacted]
2031	[redacted]	[redacted]
2032	[redacted]	[redacted]
2033	[redacted]	[redacted]
2034	[redacted]	[redacted]
2035	[redacted]	[redacted]
2036	[redacted]	[redacted]
2037	[redacted]	[redacted]
2038	[redacted]	[redacted]
2039	[redacted]	[redacted]
2040	[redacted]	[redacted]

$000

	Mitchell 1 50%	Mitchell 2 50%
	Non-Environmental Capital	
2014	12,620	12,620
2015	11,128	11,128
2016	4,838	4,838
2017	3,554	3,554
2018	6,300	6,300
2019	14,273	14,273
2020	8,264	8,264
2021	24,262	24,262
2022	12,353	12,353
2023	12,662	12,662
2024	12,979	12,979
2025	13,303	13,303
2026	13,636	13,636
2027	13,977	13,977
2028	14,326	14,326
2029	14,684	14,684
2030	15,051	15,051
2031	15,428	15,428
2032	15,813	15,813
2033	16,209	16,209
2034	16,614	16,614
2035	17,029	17,029
2036	13,964	13,964
2037	8,588	8,588
2038	3,521	3,521
2039	722	722
2040	0	0

Kentucky Power Company

REQUEST

Refer to p. 6 line 16 through p. 7 line 3 of the testimony of Jeffery LaFleur.

a. Please provide all analyses prepared by or for the Company to support its position that the Mitchell units could continue to operate through 2040;

b. Please identify all coal units in the United States of which the Company is aware that are comparable to Mitchell Units 1 or 2 in terms of design, capacity, and capacity factor whose owner is projecting a useful life of 65 or more years;

c. Produce the most recent depreciation analysis, or condition or performance assessment for Mitchell Unit 1, Mitchell Unit 2, or both units combined.

RESPONSE

a. No specific analysis exists that supports the Company's position that the Mitchell units could continue to operate through 2040. However, AEP operating companies do monitor the major components of their generating units, and utilize preventative and predictive maintenance, consistent with good utility practice, to replace or repair equipment as necessary. The Company believes that the units can operate through 2040 with continued equipment maintenance, repairs or replacement as long as such activity is economically feasible.

b. The Company is aware of other super-critical coal fired plants with planned service lives approaching those planned for the generating assets. See SC 1-20 Attachment 1 for the requested information.

c. See enclosed CD for 'SC 1-20 Attachment 2_OPCO 2007 Depr Study' for the most recent depreciation analysis for the Mitchell Plant. The depreciation analysis was performed as of December 2007 using an estimated 60 year life for the Plant. The analysis was not filed with the Public Utility Commission of Ohio (PUCO) due to Ohio Generation deregulation.

WITNESS: Jeffery D LaFleur

STEAM PLANTS: SUPER-CRITICAL COAL-FIRED UNITS

Line	Owner	Power Plant/Unit	In-Service Year	Planned Retirement Year	Lifespan	Nameplate Capacity (MW)[4]
	Ameren Missouri[1]					
		Sioux 1	1967	2033	66	549.7
		Sioux 2	1968	2033	65	549.7
	Consumers Energy[2]					
		J.H. Campbell 2	1967	2030	63	403.9
	Detroit Edison[3]					
		Monroe 1	1971	2037	66	817.2
		Monroe 2	1973	2039	66	822.6
		Monroe 3	1973	2039	66	822.6
		Monroe 4	1974	2040	66	817.2

Sources:

1. Docket ER-2010-0036, Exhibit JTS-2
2. Case No. U-16054, Exhibit A-2 (DBK-1)
3. Case No. U-16117, Direct Testimony of Dr. Ronald White, Statement G, 64-73

4 http://www.eia.gov/pub/electricity/f860y1 O.zip

Kentucky Power Company

REQUEST

Refer to p. 4 lines 19-23 of the testimony of Scott Weaver.

a. Identify, by name, position, and company, each individual who performed the economic modeling for this proceeding.

b. Identify and explain what steps were taken to validate the results of the economic modeling.

RESPONSE

a. The economic modeling was performed by the following individuals:
Ismael Martinez, Resource Planning Analyst I, American Electric Power Service Corporation Mark Becker, Manager - Resource Planning, American Electric Power Service Corporation

b. In general, the economic modeling results were validated through a number of steps including:

1. The initial step of the economic modeling validation process, performed by Messrs. Becker and Martinez, was to review and verify the major input data entered in the Strategist model, such as; the operating characteristics and costs for KPCO's existing units and the various Big Sandy retrofits and replacement options outlined in Mr. Weaver's Direct Testimony.

2. The results for the Strategist optimizations were summarized using the files found in response to Commission Staff Set 1 Question 1. The data contained in the results summary files for each of the Big Sandy options was reviewed on an individual basis. The results for each option run were then compared against one another as an additional verification of the reasonableness of the results. All results were reviewed by Resource Planning management and KPCO management.

WITNESS: Scott C Weaver

Information Collection Request Boiler MACT Emissions Report

American Electric Power Company
Mitchell Power Plant
Unit 1 Stack
Moundsville, West Virginia
March 31, 2010

Platt Environmental Services, Inc.

Platt Environmental Services, Inc.

1520 Kensington Road, Suite 204
Oak Brook, IL 60523-2141
630-521-9400
630-521-9494 fax

Information Collection Request Boiler MACT Emissions Report

American Electric Power Company
Mitchell Power Plant
Unit 1 Stack
Moundsville, West Virginia
March 31, 2010

Report Submittal Date
May 11, 2010

Prepared By

Platt Environmental Services

Report No. M101301A

Table of Contents

1.0 Introduction

PLATT ENVIRONMENTAL SERVICES (PES) conducted an information collection request (ICR) boiler maximum achievable control technology (MACT) emissions test program for American Electric Power Company at the Mitchell Power Plant on the Unit 1 Stack on March 31, 2010. This report summarizes the results of the test program and test methods used.

The test location, test date, and test parameters are summarized below, in Table 1.

Table 1

Test Overview

Test Location	Test Date	Test Method	Test Parameter
Unit 1 Stack	March 31, 2010	USEPA Method 3A	Oxygen (O_2) and Carbon Dioxide (CO_2)
		USEPA Method 26A	Hydrogen Chloride (HCl), Hydrogen Fluoride (HF), Hydrogen Cyanide (HCN)

The identification of individuals associated with the test program is summarized below in Table 2.

Table 2

Test Personnel

Location	Address	Contact
Test Coordinator	American Electric Power Company 1 Riverside Plaza Columbus, Ohio 43215	Mr. Stephen M. Anasis 614-716-1263 (phone) 614-716-1252 (fax) smanasis@aep.com
Test Facility	American Electric Power Company Mitchell Power Plant Moundsville, West Virginia	Mr. Jeff Palmer jwpalmer@aep.com
Testing Company Representative	Platt Environmental Services, Inc. 1520 Kensington Road, Suite 204 Oak Brook, Illinois 60523	Mr. Jim Robertson 630-521-9400 (phone) jrobertson@plattenv.com

The test crew consisted of Messrs. S. Dyra, R. Sollars, W. Mullenix, and J. Robertson of PES. The purpose of the test program was to evaluate the emissions of the constituents listed in Table 1 to satisfy the USEPA information request.

2.0 Executive Summary

Selected results of the test program are summarized below, in Table 3. A complete summary of emission test results follows the narrative portion of this report.

Table 3

Test Results

Test Location	Test Parameter	Emission Rate
Unit 1 Stack	HCl, lb/mmBtu	< 0.013164
	HF, lb/mmBtu	< 0.020092
	HCN, lb/mmBtu	< 0.000219

Compounds expressed above as less than or equal to values had a fraction or fractions that were below detection limits. Detection limits for each fraction were used to determine the emission rate for these compounds.

3.0 Test Methodology

Emissions testing were conducted following the methods specified in 40 CFR, Part 60, Appendix A and 40CFR63, Appendix A. Schematics of the sampling trains used and copies of field data sheets for each test run are included in the Appendix.

The following methodologies were used during the test program:

Method 1 Sample and Velocity Traverse Determination

Test measurement points were selected in accordance with Method 1, 40 CFR, Part 60, Appendix A. The characteristics of the measurement location are summarized below, in Table 4.

Table 4

Sample Point Selection

Test Location	Upstream Distance	Downstream Distance	Test Parameter	Number of Sampling Points
Unit 1 Stack	>2.0	>8.0	HCl, HF, HCN	12

Method 2 Volumetric Flow Rate Determination

Gas velocity was measured following Method 2, 40 CFR, Part 60, Appendix A, for purposes of calculating stack gas volumetric flow rate. An S-type pitot tube, differential pressure gauge, thermocouple and temperature readout were used to determine gas velocity at each sample point. All of the equipment used was calibrated in accordance with the specifications of the Method. Calibration data is presented in the Appendix.

Method 3A Oxygen (O2)/Carbon Dioxide (CO2) Determination

A Servomex analyzer was used to determine stack gas oxygen (O_2) and carbon dioxide content and, by difference, nitrogen content in accordance with Method 3A, 40 CFR, Part 60, Appendix A for purposes of calculating stack gas molecular weight as well as for calculating emissions on a lb/mmBtu basis. The O_2 instrument has a nondispersive infrared-based detector and operates in a range of 0-25% and the CO_2 instrument also uses a nondispersive infrared-based detector and operates in the range of 0-20%. All of the equipment used was calibrated in accordance with the specifications of the Method.

Method 26A Halide Determination

Stack gas Hydrogen Chloride (HCl), Hydrogen Fluoride (HF), and Hydrogen Cyanide (HCN) concentrations and emission rates were determined in accordance with Method 26A. An Environmental Supply Company, Inc. sampling train was used to collect the sample. A multiple-point sample was extracted isokinetically from the gas stream and passed through dilute (0.1 N) sulfuric acid. In the dilute acid, the HCl dissolved and formed chloride (Cl) ions. The sample train consisted of a Teflon® filter placed on the outlet of a heated borosilicate glass probe liner and six impingers. The first three impingers contained the dilute sulfuric acid, the fourth and fifth impingers contained a 0.6 N sodium hydroxide (NaOH) scrubber solution to remove any HCN, and the sixth impinger contained silica gel to absorb any remaining moisture. A DI rinse was performed on each set of impingers, and samples were stored in nalgene sample containers for transport. The dilute sulfuric acid samples were then analyzed for the above halides by Maxxam Analytics, Inc. All of the equipment used was calibrated in accordance with the specifications of the Method. Calibration data is presented in the Appendix.

4.0 Test Results Summaries

Client: American Electric Power Company
Facility: Mitchell Power Plant
Test Location: Unit 1 Stack
Test Method: 26A

Source Condition	Normal	Normal	Normal	
Date	3/31/10	3/31/10	3/31/10	
Start Time	8:31	10:20	11:59	
End Time	9:49	11:37	13:16	
	Run 1	Run 2	Run 3	Average
Stack Conditions				
Average Gas Temperature, °F	123.8	124.8	125.1	124.6
Flue Gas Moisture, percent by volume	13.4%	13.7%	13.9%	13.7%
Average Flue Pressure, in. Hg	28.57	28.57	28.57	28.57
Gas Sample Volume, dscf	39.765	45.640	45.640	43.682
Average Gas Velocity, ft/sec	48.920	49.011	49.239	49.057
Gas Volumetric Flow Rate, acfm	2,625,874	2,630,762	2,642,997	2,633,211
Gas Volumetric Flow Rate, dscfm	1,964,044	1,957,809	1,961,238	1,961,030
Average %CO_2 by volume, dry basis	12.1	12.1	12.0	12.1
Average %O_2 by volume, dry basis	6.7	6.7	6.8	6.7
Isokinetic Variance	102.0	102.0	101.8	101.9
Hydrogen Chloride (HCl) Emissions				
ppm	< 10.54	< 9.18	< 9.18	< 9.63
ug/dscm	< 15985.57	< 13927.81	< 13927.89	< 14613.76
lb/hr	< 117.5990	< 102.1360	< 102.3160	< 107.3503
lb/mmBtu	< 0.014160	< 0.012731	< 0.012602	< 0.013164
Hydrogen Fluoride (HF) Emissions				
ppm	< 12.81	< 55.82	< 11.16	< 26.60
ug/dscm	< 10657.05	< 46426.02	< 9285.26	< 22122.78
lb/hr	< 78.4000	< 340.4530	< 68.2100	< 162.3543
lb/mmBtu	< 0.009440	< 0.042436	< 0.008401	< 0.020092
Hydrogen Cyanide (HCN) Emissions				
ppm	< 0.237	< 0.206	< 0.206	< 0.216
ug/dscm	< 266.43	< 232.13	< 232.13	< 243.56
lb/hr	< 1.9600	< 1.7020	< 1.7050	< 1.7890
lb/mmBtu	< 0.000236	< 0.000212	< 0.000210	< 0.000219

5.0 Conclusion and Certification

PLATT ENVIRONMENTAL SERVICES is pleased to have been of service to American Electric Power Company. If you have any questions regarding this test report, please do not hesitate to contact us at 630-521-9400.

CERTIFICATION

As project manager, I hereby certify that this test report represents a true and accurate summary of emissions test results and the methodologies employed to obtain those results, and the test program was performed in accordance with the methods specified in this test report.

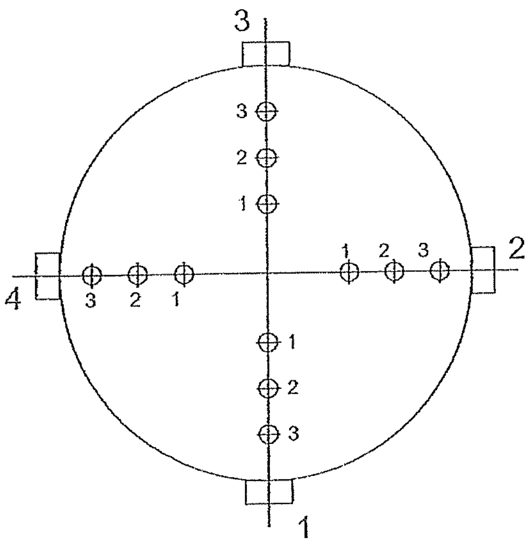
PLATT ENVIRONMENTAL SERVICES

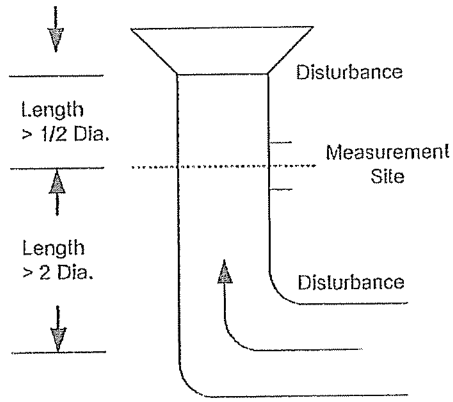
James F. Robertson — Program Manager

Jeffrey M. Crivlare — Quality Assurance

APPENDIX

EQUAL AREA TRAVERSE FOR ROUND DUCTS





Job: American Electric Power Company

Mitchell Power Plant

Moundsville, West Virginia

Date: March 31, 2010

Unit No: 1

Test Location: Stack

Stack Diameter: 33.75 Feet

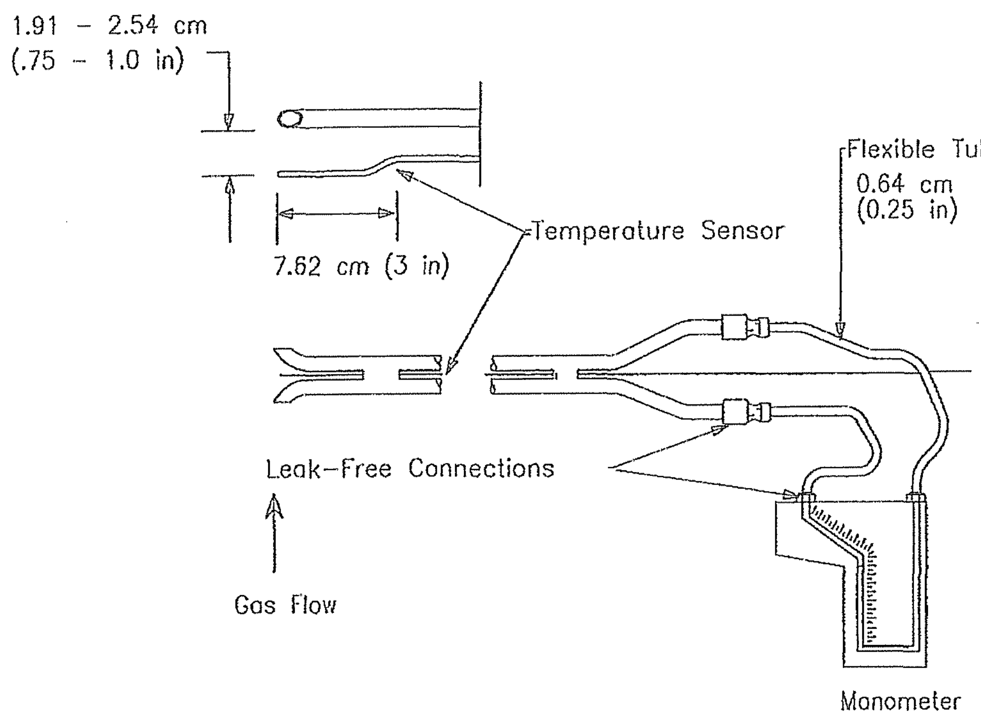
Stack Area: 894.618 Square Feet

No. Points Across Diameter: 6

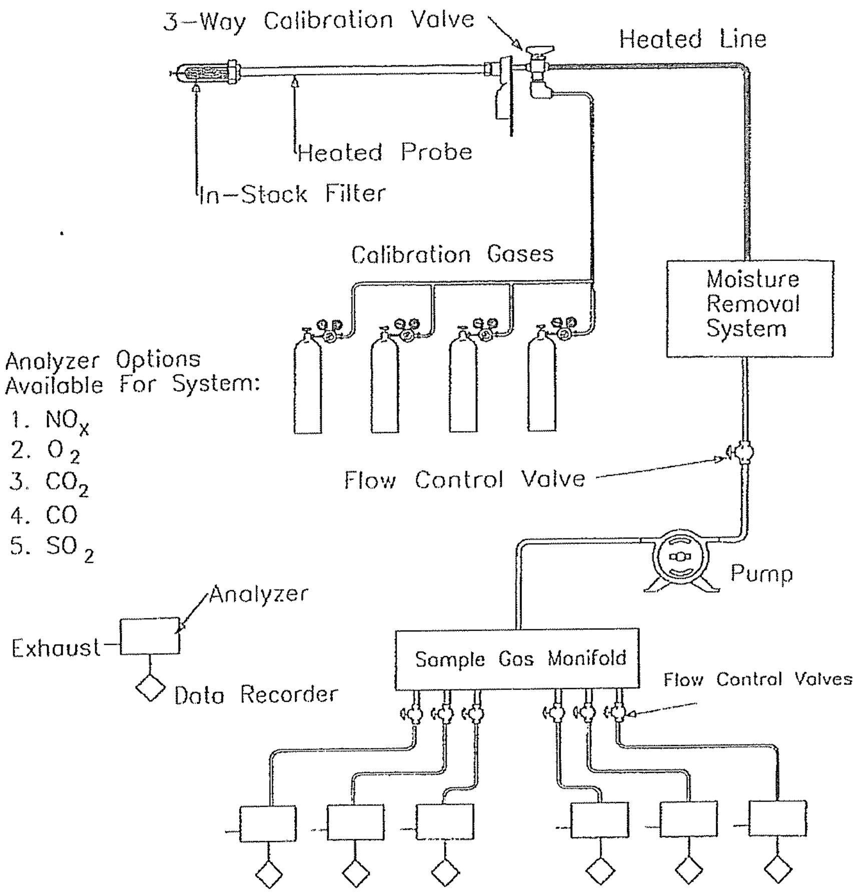
No. of Ports: 4

Port Length: 14 Inches

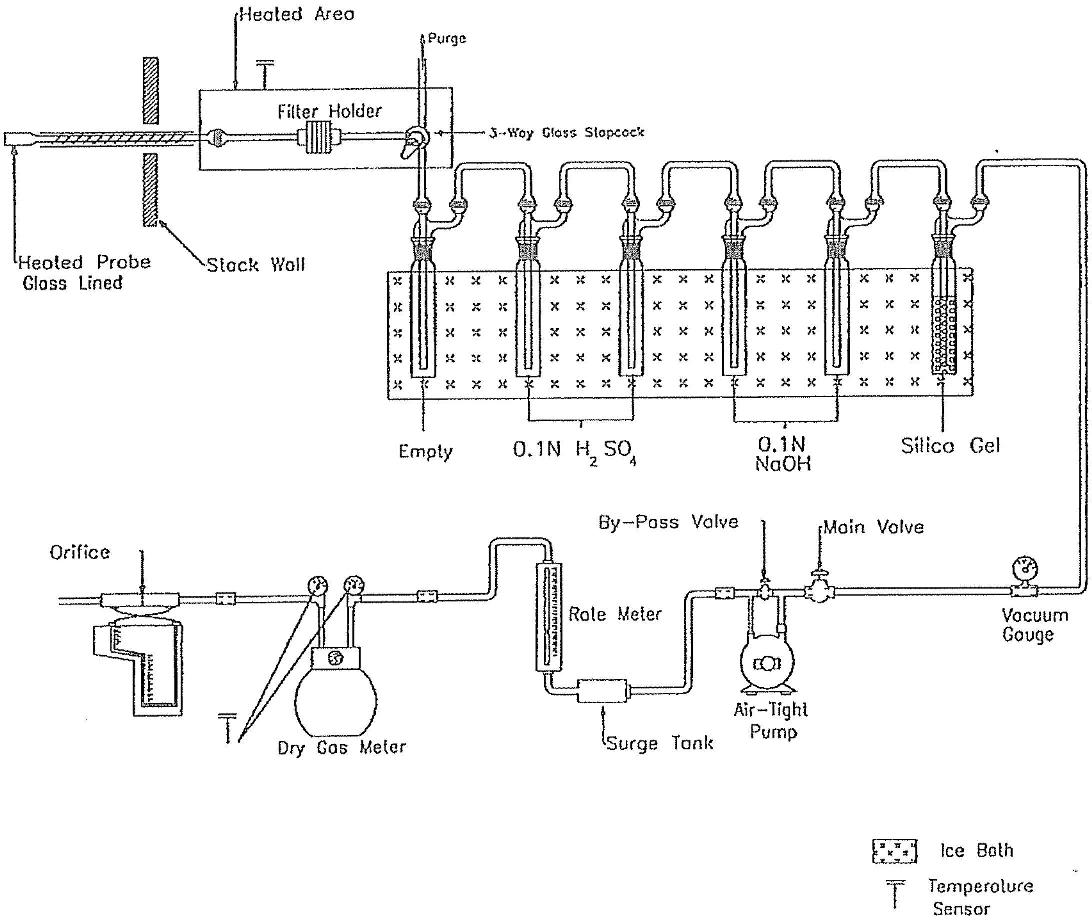
USEPA Method 2 - S-Type Pitot Tube Diagram



USEPA Method 3A Extractive Gaseous Sampling Diagram



USEPA Method 26A – Halogen Sample Train Diagram



Client: American Electric Power Company
Facility: Mitchell Power Plant
Test Location: Unit 1 Stack
Run: 1
Date: 3/31/2010

Method 26A (HCl) Calculations

Dry Molecular Weight

$$Md = 0.44 \times (\%CO_2) + 0.32 \times (\%O_2) + 0.28 \times \%N_2$$

$\%CO_2 =$ 12.1 $\%O_2 =$ 6.7 $\%N_2 =$ 81.2

Md = 30.20

Wet Molecular Weight

$$Ms = Md \times (1\text{-}Bws) + (18.0 \times Bws)$$

Md = 30.20 Bws = 0.147

Ms = 28.57

Meter Volume at Standard Conditions

$$Vm(std) = 17.647 \times Y \times Vm \times \frac{(Pbar + DH/13.6)}{Tm}$$

Y = 1.004 Vm = 42.564 Pbar = 28.67
DH = 1.22 Tm = 545.4

Vm(std) = 39.765

Volume of Water Vapor Condensed

$$Vw(std) = 0.0471 \times (\text{net } H_2O \text{ gain})$$

Net H_2O = 145.5

Vw(std) = 6.853

Moisture Content

$$Bws = \frac{Vwc(std)}{Vwc(std) + Vm(std)}$$

Vw(std) = 6.853 Vm(std) = 39.765

Bws = 0.147

Client: American Electric Power Company
Facility: Mitchell Power Plant
Test Location: Unit 1 Stack
Run: 1
Date: 3/31/2010

Method 26A (HCl) Calculations

Average Duct Velocity

$$Vs = 85.49 \times Cp \times \text{Sqrt DP (avg)} \times (\text{Ts (avg)} / (Ps \times Ms))^{1/2}$$

Cp = 0.840 Ts (avg) = 583.8 Sqrt DP (avg): 0.806
Ps = 28.57 Ms = 28.57

Vs = 48.92

Volumetric Flow Rate (Actual Basis)

$$Q = Vs \times A \times 60$$

Vs = 48.92 A = 894.618

Q = 2625874

Volumetric Flow Rate (Standard Basis)

$$Qstd = 17.647 \times Q \times \frac{Ps}{\text{Ts (avg)}}$$

Q = 2625874 Ps = 28.57 Ts (avg) = 583.8

Qstd = 2267949

Volumetric Flow Rate (Standard Dry Basis)

$$Qstd(dry) = Qstd \times (1\text{-}Bws)$$

Qstd = 2267949 Bws = 0.147

Qstd(dry) = 1964044

Isokinetic Variation:

$$\%ISO = \frac{0.0945 \times Ts \times Vm(std)}{Vs \times \theta \times An \times Ps \times (1\text{-}Bws)}$$

Ts = 583.8 Vm(std) = 39.765 Vs = 48.920
An = 0.0002961 θ = 60.0 Ps = 28.57
Bws = 0.147

%ISO = 102.0

Client: American Electric Power Company
Facility: Mitchell Power Plant
Test Location: Unit 1 Stack
Run: 1
Date: 3/31/2010

Method 26A (HCl) Calculations

HCl Concentration:

$$\text{ug/dscm of HCl} = \frac{\text{ug of sample}}{\text{Vm(std)*0.028317}}$$

mg of HCl = 18.0000   Vm(std) = 39.765

ug/dscm of HCl = 15985.5700

HCl Emission Rate:

$$\text{ER lb/mmBtu} = \frac{\text{g of sample/453.6}}{\text{Vm (std)}} \times \text{Fd (dscf/mmBtu)} \times \frac{20.9}{(20.9\text{-}\%O_2)}$$

ER lb/mmBtu = 0.0142 lb/mmBtu

Client: American Electric Power Company
Facility: Mitchell Power Plant
Project #: M101301

Location: Unit 1 Stack
Date: 3/31/10

Sample Calculations

O2 %

$$(6.72\ \% - 0.00\ \%) \times \frac{11.99\ \%}{12.01\ \% - 0.00\ \%} = 6.70\ \%$$

CO2 %

$$(12.10\ \% - 0.01\ \%) \times \frac{9.83\ \%}{9.85\ \% - 0.01\ \%} = 12.10\ \%$$

$$C_{gas} = (C - C_o) \times \frac{C_{ma}}{C_m - C_o}$$

where:

C_{gas} = Effluent gas concentration, dry basis, ppm
C = Average gas concentration indicated by gas analyzer, dry basis, ppm
C_o = Average of initial and final system calibration bias check responses for the zero gas, ppm
C_m = Average of initital and final system calibration bias check responses for the upscale calibration gas, ppm
C_{ma} = Actual concentration of the upscale calibration gas, ppm

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Volumetric Flow Nomenclature

A = Cross-sectional area of stack or duct, ft^2

B_{ws} = Water vapor in gas stream, proportion by volume

C_p = Pitot tube coefficient, dimensionless

M_d = Dry molecular weight of gas, lb/lb-mole

M_s = Molecular weight of gas, wet basis, lb/lb-mole

M_w = Molecular weight of water, 18.0 lb/lb-mole

P_{bar} = Barometric pressure at testing site, in. Hg

P_g = Static pressure of gas, in. Hg (in. H_2O/13.6)

P_s = Absolute pressure of gas, in. Hg = $P_{bar} + P_g$

P_{std} = Standard absolute pressure, 29.92 in. Hg

Q_{acfm} = Actual volumetric gas flow rate, acfm

Q_{sd} = Dry volumetric gas flow rate corrected to standard conditions, dscf/hr

R = Ideal gas constant, 21.85 in. Hg-ft^3/°R-lb-mole

T_s = Absolute gas temperature, °R

T_{std} = Standard absolute temperature, 528°R

v_s = Gas velocity, ft/sec

$V_{w(std)}$ = Volume of water vapor in gas sample, corrected to standard conditions, scf

Y = Dry gas meter calibration factor

Δp = Velocity head of gas, in. H_2O

K_1 = 17.647 °R/in. Hg

%EA = Percent excess air

%CO_2 = Percent carbon dioxide by volume, dry basis

%O_2 = Percent oxygen by volume, dry basis

%N_2 = Percent nitrogen by volume, dry basis

0.264 = Ratio of O_2 to N_2 in air, v/v

0.28 = Molecular weight of N_2 or CO, divided by 100

0.32 = Molecular weight of O_2 divided by 100

0.44 = Molecular weight of CO_2 divided by 100

13.6 = Specific gravity of mercury (Hg)

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Volumetric Air Flow Calculations

$$Vm\,(std) = 17.647 \times Vm \times \left[\frac{(P_{bar} + (\frac{DH}{13.6}))}{(460 + Tm)} \right] \times Y$$

$$Vw\,(std) = 0.0471 \times Vlc$$

$$Bws = \left[\frac{Vw\,(std)}{Vw\,(std) + Vm\,(std)} \right]$$

$$Md = (0.44 \times \%CO_2) + (0.32 \times \%O_2) + [0.28 \times (100 - \%CO_2 \ - \%O_2)]$$

$$Ms = Md \times (1 - Bws) + (18 \times Bws)$$

$$Vs = \sqrt{\frac{(Ts + 460)}{Ms \times Ps}} \times \sqrt{DP} \times Cp \times 85.49$$

$$Acfm = Vs \times Area\ (of\ stack\ or\ duct) \times 60$$

$$Scfm = Acfm \times 17.647 \times \left[\frac{Ps}{(460 + Ts)} \right]$$

$$Scfh = Scfm \times 60 \frac{min}{hr}$$

acfm = actual cubic feet per minute
scfm = standard cubic feet per minute
scfh = standard cubic feet per hour

Cp = pitot tube correction factor
Ps = absolute flue gas pressure
Ms = molecular weight of gas (lb/lb mole)
Md = dry molecular weight of gas (lb/lb mole)
Bws = water vapor in gas stream proportion by volume

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Particulate Nomenclature

A = Cross-sectional area of stack or duct, square feet
A_n = Cross-sectional area of nozzle, square feet
B_{ws} = Water vapor in gas stream, by volume
C_a = Acetone blank residue concentration, g/g
C_{acf} = Concentration of particulate matter in gas stream at actual conditions, gr/acf
C_p = Pitot tube coefficient
C_s = Concentration of particulate matter in gas stream, dry basis, corrected to standard conditions, gr/dscf
IKV = Isokinetic sampling variance, must be 90.0 % ≤ IKV ≤ 110.0%
M_d = Dry molecular weight of gas, lb/lb-mole
M_s = Molecular weight of gas, wet basis, lb/lb-mole
M_w = Molecular weight of water, 18.0 lb/lb-mole
m_a = Mass of residue of acetone after evaporation, grams
P_{bar} = Barometric pressure at testing site, inches mercury
P_g = Static pressure of gas, inches mercury (inches water/13.6)
P_s = Absolute pressure of gas, inches mercury = $P_{bar} + P_g$
P_{std} = Standard absolute pressure, 29.92 inches mercury
Q_{acfm} = Actual volumetric gas flow rate, acfm
Q_{sd} = Dry volumetric gas flow rate corrected to standard conditions, dscfh
R = Ideal gas constant, 21.85 inches mercury cubic foot/°R-lb-mole
T_m = Dry gas meter temperature, °R
T_s = Gas temperature, °R
T_{std} = Absolute temperature, 528°R
V_a = Volume of acetone blank, ml
V_{aw} = Volume of acetone used in wash, ml
W_a = Weight of residue in acetone wash, grams
m_n = Total amount of particulate matter collected, grams
V_{lc} = Total volume of liquid collected in impingers and silica gel, ml
V_m = Volume of gas sample as measured by dry gas meter, dcf
$V_{m(std)}$ = Volume of gas sample measured by dry gas meter, corrected to standard conditions, dscf
v_s = Gas velocity, ft/sec
$V_{w(std)}$ = Volume of water vapor in gas sample, corrected to standard conditions, scf
Y = Dry gas meter calibration factor
ΔH = Average pressure differential across the orifice meter, inches water
Δp = Velocity head of gas, inches water
ρ_a = Density of acetone, 0.7855 g/ml (average)
ρ_w = Density of water, 0.002201 lb/ml
θ = Total sampling time, minutes
K_1 = 17.647 °R/in. Hg
K_2 = 0.04707 ft³/ml
K_4 = 0.09450/100 = 0.000945
K_p = Pitot tube constant, $85.49\frac{\text{ft}}{\text{sec}}\left[\frac{(\text{lb/lb}-\text{mole})(\text{in. Hg})}{(^\circ\text{R})(\text{in. H}_2\text{O})}\right]^{1/2}$
%EA = Percent excess air
$\%CO_2$ = Percent carbon dioxide by volume, dry basis
$\%O_2$ = Percent oxygen by volume, dry basis
%CO = Percent carbon monoxide by volume, dry basis
$\%N_2$ = Percent nitrogen by volume, dry basis
0.264 = Ratio of O_2 to N_2 in air, v/v
28 = Molecular weight of N_2 or CO
32 = Molecular weight of O_2
44 = Molecular weight of CO_2
13.6 = Specific gravity of mercury (Hg)

PLATT ENVIRONMENTAL SERVICES, INC.

Particulates Calculation Formulas

1. $V_{w(std)} = V_{lc}\left(\frac{\rho_w}{M_w}\right)\left(\frac{RT_{std}}{P_{std}}\right) = K_2 V_{lc}$

2. $V_{m(std)} = V_m Y \left(\frac{T_{std}}{T_m}\right)\left(\frac{(P_{bar} + (\frac{\Delta H}{13.6}))}{P_{std}}\right) = K_1\, V_m\, Y \frac{(P_{bar} + (\frac{\Delta H}{13.6}))}{T_m}$

3. $B_{ws} = \frac{V_{w(std)}}{(V_{m(std)} + V_{w(std)})}$

4. $M_d = 0.44(\%CO_2) + 0.32(\%O_2) + 0.28(\%N_2)$

5. $M_s = M_d(1 - B_{ws}) + 18.0(B_{ws})$

6. $C_a = \frac{m_a}{V_a \rho_a}$

7. $W_a = C_a V_{aw} \rho_a$

8. $C_{acf} = 15.43 K_i\left(\frac{m_n P_s}{V_{w(std)} + V_{m(std)}\ T_s}\right)$

9. $C_S = (15.43 \text{ grains/gram})\ (m_n / V_{m(std)})$

10. $v_s = K_p C_p \sqrt{\frac{\Delta P\ T_s}{P_s M_s}}$

11. $Q_{acfm} = v_s A (60_{sec/min})$

12. $Q_{sd} = (3600_{sec/hr})(1 - B_{ws})\ v_s \left(\frac{T_{std} P_s}{T_s P_{std}}\right) A$

13. $E \text{ (emission rate, lbs/hr)} = Q_{std}(C_s / 7000 \text{ grains/lb})$

14. $IKV = \frac{T_s V_{m(std)} P_{std}}{T_{std} v_s \theta A_n P_s 60(1 - B_{ws})} = K_4 \frac{T_s V_{m(std)}}{P_s v_s A_n \theta (1 - B_{ws})}$

15. $\%EA = \left(\frac{\%O_2 - (0.5\,\%CO)}{0.264\,\%N_2 - (\%O_2 - 0.5\,\%CO)}\right) \times 100$

Maxxam Analytics *Driven by Service and Science*

Your Project #: M101301
Site: AEP, MITCHELL
Your C.O.C. #: N/A

Attention: Eric Ehlers
Platt Environmental Inc
1520 Kensington Rd.
Suite 204
Oak Brook, IL
USA 60523-2139

Report Date: 2010/04/22

CERTIFICATE OF ANALYSIS

MAXXAM JOB #: B042760
Received: 2010/04/08, 12:30

Sample Matrix: Stack Sampling Train
Samples Received: 7

Analyses	Quantity	Date Extracted	Date Analyzed	Laboratory Method	Method Reference
Hydrogen Cyanide in Impingers	7	2010/04/20	2010/04/20		EPA CTM-33
Volume of Sodium Hydroxide Impinger	7	N/A	2010/04/22		

* RPDs calculated using raw data. The rounding of final results may result in the apparent difference.

Encryption Key

Mike Challis
22 Apr 2010 16:03:03 -04:00

Please direct all questions regarding this Certificate of Analysis to your Project Manager.

MIKE CHALLIS, CET, B.Sc, C.Chem, Customer Service Manager, US Air Toxics
Email: Mike.Challis@MaxxamAnalytics.com
Phone# (905) 817-5790

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Maxxam has procedures in place to guard against improper use of the electronic signature and have the required "signatories", as per section 5.10.2 of ISO/IEC 17025:2005(E), signing the reports. For Service Group specific validation please refer to the Validation Signature Page.

Total cover pages: 1

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Maxxam Job #: B042760
Report Date: 2010/04/22

Platt Environmental Inc
Client Project #: M101301
Project name: AEP, MITCHELL

EPA CTM 033 HYDROGEN CYANIDE (STACK SAMPLING TRAIN)

Maxxam ID		FO0628		FO0629	FO0630	FO0630		
Sampling Date		2010/03/31		2010/03/30	2010/03/30	2010/03/30		
COC Number		N/A		N/A	N/A	N/A		
	Units	REAGENT BLANK-NAOH	RDL	T#1-U1-STACK-NAOH	T#2-U1-STACK-NAOH	T#2-U1-STACK-NAOH Lab-Dup	RDL	QC Batch
Volume	ml	100	1	630	650	N/A	1	2130406
Cyanide (CN)	ug	(15.6) ND	100	(0) ND	(50.1) ND	(50.4) ND	300	2128870

N/A = Not Applicable
RDL = Reportable Detection Limit
QC Batch = Quality Control Batch

Maxxam ID		FO0631	FO0632	FO0633	FO0634		
Sampling Date		2010/03/30	2010/03/31	2010/03/31	2010/03/31		
COC Number		N/A	N/A	N/A	N/A		
	Units	T#3-U1-STACK-NAOH	T#1-U2-STACK-NAOH	T#2-U2-STACK-NAOH	T#3-U2-STACK-NAOH	RDL	QC Batch
Volume	ml	660	640	640	660	1	2130406
Cyanide (CN)	ug	(0) ND	(46.7) ND	(54.2) ND	(58.2) ND	300	2128870

N/A = Not Applicable
RDL = Reportable Detection Limit
QC Batch = Quality Control Batch

Maxxam Analytics International Corporation o/a Maxxam Analytics 6740 Campobello Road, Mississauga, Ontario L5N 2L8 Tel: (905) 817-5700 Toll-Free: 800-563-6266 Fax: (905) 817-5777 www.maxxam.ca

Maxxam Analytics *Driven by Service and Science*

Maxxam Job #: B042760
Report Date: 2010/04/22

Platt Environmental Inc
Client Project #: M101301
Project name: AEP, MITCHELL

Test Summary

Maxxam ID FO0628 Collected 2010/03/31
Sample ID REAGENT BLANK-NAOH Shipped
Matrix Stack Sampling Train Received 2010/04/08

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Hydrogen Cyanide in Impingers	IC	2128870	2010/04/20	2010/04/20	LLE
Volume of Sodium Hydroxide Impinger		2130406	N/A	2010/04/22	LLE

Maxxam ID FO0629 Collected 2010/03/30
Sample ID T#1-U1-STACK-NAOH Shipped
Matrix Stack Sampling Train Received 2010/04/08

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Hydrogen Cyanide in Impingers	IC	2128870	2010/04/20	2010/04/20	LLE
Volume of Sodium Hydroxide Impinger		2130406	N/A	2010/04/22	LLE

Maxxam ID FO0630 Collected 2010/03/30
Sample ID T#2-U1-STACK-NAOH Shipped
Matrix Stack Sampling Train Received 2010/04/08

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Hydrogen Cyanide in Impingers	IC	2128870	2010/04/20	2010/04/20	LLE
Volume of Sodium Hydroxide Impinger		2130406	N/A	2010/04/22	LLE

Maxxam ID FO0630 Dup Collected 2010/03/30
Sample ID T#2-U1-STACK-NAOH Shipped
Matrix Stack Sampling Train Received 2010/04/08

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Hydrogen Cyanide in Impingers	IC	2128870	2010/04/20	2010/04/20	LLE

Maxxam ID FO0631 Collected 2010/03/30
Sample ID T#3-U1-STACK-NAOH Shipped
Matrix Stack Sampling Train Received 2010/04/08

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Hydrogen Cyanide in Impingers	IC	2128870	2010/04/20	2010/04/20	LLE
Volume of Sodium Hydroxide Impinger		2130406	N/A	2010/04/22	LLE

Maxxam ID FO0632 Collected 2010/03/31
Sample ID T#1-U2-STACK-NAOH Shipped
Matrix Stack Sampling Train Received 2010/04/08

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Hydrogen Cyanide in Impingers	IC	2128870	2010/04/20	2010/04/20	LLE
Volume of Sodium Hydroxide Impinger		2130406	N/A	2010/04/22	LLE

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Maxxam Job #: B042760
Report Date: 2010/04/22

Platt Environmental Inc
Client Project #: M101301
Project name: AEP, MITCHELL

Test Summary

Maxxam ID FO0633
Sample ID T#2-U2-STACK-NAOH
Matrix Stack Sampling Train

Collected 2010/03/31
Shipped
Received 2010/04/08

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Hydrogen Cyanide in Impingers	IC	2128870	2010/04/20	2010/04/20	LLE
Volume of Sodium Hydroxide Impinger		2130406	N/A	2010/04/22	LLE

Maxxam ID FO0634
Sample ID T#3-U2-STACK-NAOH
Matrix Stack Sampling Train

Collected 2010/03/31
Shipped
Received 2010/04/08

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Hydrogen Cyanide in Impingers	IC	2128870	2010/04/20	2010/04/20	LLE
Volume of Sodium Hydroxide Impinger		2130406	N/A	2010/04/22	LLE

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Maxxam Job #: B042760
Report Date: 2010/04/22

Platt Environmental Inc
Client Project #: M101301
Project name: AEP, MITCHELL

EPA CTM 033 HYDROGEN CYANIDE (STACK SAMPLING TRAIN)

Hydrogen Cyanide in Impingers: Negative peak noticed at Cyanide retention time, sample diluted and analyzed at higher dilution to confirm no matrix interference.

Results relate only to the items tested.

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Maxxam Analytics

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Platt Environmental Inc
Attention: Eric Ehlers
Client Project #: M101301
P.O. #:
Project name: AEP, MITCHELL

Quality Assurance Report

Maxxam Job Number: GB042760

QA/QC Batch Num Init	QC Type	Parameter	Date Analyzed yyyy/mm/dd	Value	%Recovery	Units	QC Limits
2128870 LLE	Matrix Spike (FO0630)	Cyanide (CN)	2010/04/20		99	%	80 - 120
	Spiked Blank	Cyanide (CN)	2010/04/20		102	%	90 - 110
	Method Blank	Cyanide (CN)	2010/04/20	(0) ND, RDL=100		ug	
	RPD - Sample/Sample Dup	Cyanide (CN)	2010/04/20	NC		%	20

Matrix Spike: A sample to which a known amount of the analyte of interest has been added. Used to evaluate sample matrix interference.
Spiked Blank: A blank matrix to which a known amount of the analyte has been added. Used to evaluate analyte recovery.
Method Blank: A blank matrix containing all reagents used in the analytical procedure. Used to identify laboratory contamination.
NC (RPD): The RPD was not calculated. The level of analyte detected in the parent sample and its duplicate was not sufficiently significant to permit a reliable calculation.

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Validation Signature Page

Maxxam Job #: B042760

The analytical data and all QC contained in this report were reviewed and validated by the following individual(s).

FRANK MO, B.Sc., Inorganic Lab. Manager

Maxxam has procedures in place to guard against improper use of the electronic signature and have the required "signatories", as per section 5.10.2 of ISO/IEC 17025:2005(E), signing the reports. For Service Group specific validation please refer to the Validation Signature Page.

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Maxxam Analytics — *Driven by Service and Science*

Your Project #: M101301
Site: AEP, MITCHELL
Your C.O.C. #: N/A

Attention: Eric Ehlers
Platt Environmental Inc
1520 Kensington Rd.
Suite 204
Oak Brook, IL
USA 60523-2139

Report Date: 2010/05/10

CERTIFICATE OF ANALYSIS

MAXXAM JOB #: B050110
Received: 2010/04/26, 13:46

Sample Matrix: Stack Sampling Train
Samples Received: 7

Analyses	Quantity	Date Extracted	Date Analyzed	Laboratory Method	Method Reference
Hydrogen Halides in NaOH Imp. (1)	7	2010/05/03	2010/05/03	BRL SOP-00108	EPA Modified M26A

* RPDs calculated using raw data. The rounding of final results may result in the apparent difference.

(1) This test was performed in Maxxam Mississauga under Maxxam Burlington SCC Accreditation

Encryption Key

Mike Challis
10 May 2010 08:10:47 -04:00

Please direct all questions regarding this Certificate of Analysis to your Project Manager.

MIKE CHALLIS, CET, B.Sc, C.Chem, Customer Service Manager, US Air Toxics
Email: Mike.Challis@MaxxamAnalytics.com
Phone# (905) 817-5790

==
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Total cover pages: 1

Maxxam Analytics *Driven by Service and Science*

Maxxam Job #: B050110
Report Date: 2010/05/10

Platt Environmental Inc
Client Project #: M101301
Project name: AEP, MITCHELL

RESULTS OF ANALYSES OF STACK SAMPLING TRAIN

Maxxam ID		FR5649	FR5650		FR5651	FR5651		
Sampling Date		2010/03/31	2010/03/30		2010/03/30	2010/03/30		
COC Number		N/A	N/A		N/A	N/A		
	Units	REAGENT BLANK-NAOH	T#1-U1-STACK-NAOH	RDL	T#2-U1-STACK-NAOH	T#2-U1-STACK-NAOH Lab-Dup	RDL	QC Batch
Hydrochloric Acid	ug	(0) ND	(0) ND	18000	(0) ND	(0) ND	18000	2140262
Hydrofluoric Acid	ug	(0) ND	(0) ND	12000	(0) ND	(0) ND	60000	2140262

N/A = Not Applicable
RDL = Reportable Detection Limit
QC Batch = Quality Control Batch

Maxxam ID		FR5652	FR5653	FR5654	FR5655		
Sampling Date		2010/03/30	2010/03/31	2010/03/31	2010/03/31		
COC Number		N/A	N/A	N/A	N/A		
	Units	T#3-U1-STACK-NAOH	T#1-U2-STACK-NAOH	T#2-U2-STACK-NAOH	T#3-U2-STACK-NAOH	RDL	QC Batch
Hydrochloric Acid	ug	(0) ND	(14858.7000) ND	(0) ND	(0) ND	18000	2140262
Hydrofluoric Acid	ug	(0) ND	(0) ND	(0) ND	(0) ND	12000	2140262

N/A = Not Applicable
RDL = Reportable Detection Limit
QC Batch = Quality Control Batch

Maxxam Analytics

Driven by Service and Science

Maxxam Job #: B050110
Report Date: 2010/05/10

Platt Environmental Inc
Client Project #: M101301
Project name: AEP, MITCHELL

Test Summary

Maxxam ID FR5649 — Collected 2010/03/31
Sample ID REAGENT BLANK-NAOH — Shipped
Matrix Stack Sampling Train — Received 2010/04/26

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Hydrogen Halides in NaOH Imp.	IC/SPEC	2140262	2010/05/03	2010/05/03	A S

Maxxam ID FR5650 — Collected 2010/03/30
Sample ID T#1-U1-STACK-NAOH — Shipped
Matrix Stack Sampling Train — Received 2010/04/26

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Hydrogen Halides in NaOH Imp.	IC/SPEC	2140262	2010/05/03	2010/05/03	A S

Maxxam ID FR5651 — Collected 2010/03/30
Sample ID T#2-U1-STACK-NAOH — Shipped
Matrix Stack Sampling Train — Received 2010/04/26

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Hydrogen Halides in NaOH Imp.	IC/SPEC	2140262	2010/05/03	2010/05/03	A S

Maxxam ID FR5651 Dup — Collected 2010/03/30
Sample ID T#2-U1-STACK-NAOH — Shipped
Matrix Stack Sampling Train — Received 2010/04/26

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Hydrogen Halides in NaOH Imp.	IC/SPEC	2140262	2010/05/03	2010/05/03	A S

Maxxam ID FR5652 — Collected 2010/03/30
Sample ID T#3-U1-STACK-NAOH — Shipped
Matrix Stack Sampling Train — Received 2010/04/26

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Hydrogen Halides in NaOH Imp.	IC/SPEC	2140262	2010/05/03	2010/05/03	A S

Maxxam ID FR5653 — Collected 2010/03/31
Sample ID T#1-U2-STACK-NAOH — Shipped
Matrix Stack Sampling Train — Received 2010/04/26

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Hydrogen Halides in NaOH Imp.	IC/SPEC	2140262	2010/05/03	2010/05/03	A S

Maxxam ID FR5654 — Collected 2010/03/31
Sample ID T#2-U2-STACK-NAOH — Shipped
Matrix Stack Sampling Train — Received 2010/04/26

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Hydrogen Halides in NaOH Imp.	IC/SPEC	2140262	2010/05/03	2010/05/03	A S

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Maxxam Job #: B050110
Report Date: 2010/05/10

Platt Environmental Inc
Client Project #: M101301
Project name: AEP, MITCHELL

Test Summary

Maxxam ID FR5655
Sample ID T#3-U2-STACK-NAOH
Matrix Stack Sampling Train

Collected 2010/03/31
Shipped
Received 2010/04/26

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Hydrogen Halides in NaOH Imp.	IC/SPEC	2140262	2010/05/03	2010/05/03	A_S

GENERAL COMMENTS
Results relate only to the items tested.

Maxxam Analytics *Driven by Service and Science*

Platt Environmental Inc
Attention: Eric Ehlers
Client Project #: M101301
P.O. #:
Project name: AEP, MITCHELL

Quality Assurance Report

Maxxam Job Number: GB050110

QA/QC Batch Num Init	QC Type	Parameter	Date Analyzed yyyy/mm/dd	Value	%Recovery	Units	QC Limits
2140262 A_S	Matrix Spike (FR5651)	Hydrochloric Acid	2010/05/03		109	%	80 - 120
		Hydrofluoric Acid	2010/05/03		83	%	80 - 120
	Spiked Blank	Hydrochloric Acid	2010/05/03		102	%	90 - 110
		Hydrofluoric Acid	2010/05/03		99	%	90 - 110
	Method Blank	Hydrochloric Acid	2010/05/03	(0) ND, RDL=18000		ug	
		Hydrofluoric Acid	2010/05/03	(0) ND, RDL=12000		ug	
	RPD - Sample/Sample Dup	Hydrochloric Acid	2010/05/03	NC		%	20
		Hydrofluoric Acid	2010/05/03	NC		%	20

Matrix Spike: A sample to which a known amount of the analyte of interest has been added. Used to evaluate sample matrix interference.
Spiked Blank: A blank matrix to which a known amount of the analyte has been added. Used to evaluate analyte recovery.
Method Blank: A blank matrix containing all reagents used in the analytical procedure. Used to identify laboratory contamination.
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Validation Signature Page

Maxxam Job #: B050110

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SGS

Analysis Report

April 16, 2010

PLATT ENVIRONMENTAL SERVICE
1905 S. MOUNT PROSPECT RD. - UNIT C
MOUNT PROSPECT IL 60018

ATTN: JENNA GHANMA

Client Sample ID:	ACG01	Sample ID By:	Platt Environmental Services
Date Sampled:	Mar 31, 2010	Sample Taken At:	Mitchell
Date Received:	Apr 5, 2010	Sample Taken By:	------
Product Description:	COAL	Sample ID:	Unit 1 Test 1 Coal Composite Sample
		Project Name/#:	M101301
		Customer:	American Electric Power

SGS Minerals Sample ID: 491-1044352-001

		Method	As Received	Dry	DAF
Moisture, Total %		ASTM D3302	5.35		
Ash %		ASTM D3174	10.13	10.70	
Volatile Matter %		ASTM D3175	32.90	34.76	
Fixed Carbon %		ASTM D3172 (by diff)	51.62	54.54	
Sulfur %		ASTM D4239 Method B	1.83	1.93	
Gross Calorific Value	BTU/LB	ASTM D5865	12685	13402	15008
Carbon %		ASTM D5373	70.55	74.54	
Hydrogen %		ASTM D5373	4.38	4.63	
Nitrogen %		ASTM D5373	1.56	1.65	
Oxygen %		ASTM D5373 (by diff)	6.20	6.55	
Chlorine, Cl %		ASTM D4208	0.11	0.11	
Fluorine, F UG/G		ASTM D3761	72	76.0	

Vanessa Chambliss

Vanessa Chambliss
Branch Manager

SGS North America Inc. | Minerals Services Division
16130 Van Drunen Road South Holland t (708) 331-2900 f (708) 333-3060 www.sgs.com/minerals

SGS

Analysis Report

April 16, 2010

PLATT ENVIRONMENTAL SERVICE
1905 S. MOUNT PROSPECT RD. - UNIT C
MOUNT PROSPECT IL 60018

ATTN: JENNA GHANMA

Client Sample ID:	ACG02	Sample ID By:	Platt Environmental Services
Date Sampled:	Mar 31, 2010	Sample Taken At:	Mitchell
Date Received:	Apr 5, 2010	Sample Taken By:	------
Product Description:	COAL	Sample ID:	Unit 1 Test 2 Coal Composite Sample
		Project Name/#:	M101301
		Customer:	American Electric Power

SGS Minerals Sample ID: 491-1044352-002

		Method	As Received	Dry	DAF
Moisture, Total %		ASTM D3302	1.73		
Ash %		ASTM D3174	11.36	11.56	
Volatile Matter %		ASTM D3175	34.28	34.88	
Fixed Carbon %		ASTM D3172 (by diff)	52.63	53.56	
Sulfur %		ASTM D4239 Method B	2.11	2.15	
Gross Calorific Value	BTU/LB	ASTM D5865	12955	13183	14906
Carbon %		ASTM D5373	73.43	74.72	
Hydrogen %		ASTM D5373	4.78	4.86	
Nitrogen %		ASTM D5373	1.60	1.62	
Oxygen %		ASTM D5373 (by diff)	4.99	5.09	
Chlorine, Cl %		ASTM D4208	0.10	0.10	
Fluorine, F UG/G		ASTM D3761	98	100.0	

Vanessa Chambliss

Vanessa Chambliss
Branch Manager

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SGS

Analysis Report

April 16, 2010

PLATT ENVIRONMENTAL SERVICE
1905 S. MOUNT PROSPECT RD. - UNIT C
MOUNT PROSPECT IL 60018

ATTN: JENNA GHANMA

Client Sample ID:	ACG03	Sample ID By:	Platt Environmental Services
Date Sampled:	Mar 31, 2010	Sample Taken At:	Mitchell
Date Received:	Apr 5, 2010	Sample Taken By:	------
Product Description:	COAL	Sample ID:	Unit 1Test 3 Coal Composite Sample
		Project Name/#:	M101301
		Customer:	American Electric Power

SGS Minerals Sample ID: 491-1044352-003

		Method	As Received	Dry	DAF
Moisture, Total %		ASTM D3302	1.76		
Ash %		ASTM D3174	11.27	11.48	
Volatile Matter %		ASTM D3175	34.17	34.78	
Fixed Carbon %		ASTM D3172 (by diff)	52.80	53.74	
Sulfur %		ASTM D4239 Method B	2.09	2.13	
Gross Calorific Value	BTU/LB	ASTM D5865	13055	13289	15012
Carbon %		ASTM D5373	73.19	74.50	
Hydrogen %		ASTM D5373	4.61	4.69	
Nitrogen %		ASTM D5373	1.59	1.61	
Oxygen %		ASTM D5373 (by diff)	5.49	5.59	
Chlorine, Cl %		ASTM D4208	0.10	0.10	
Fluorine, F UG/G		ASTM D3761	87	89.0	

Vanessa Chambliss

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Branch Manager

SGS North America Inc | Minerals Services Division
16130 Van Drunen Road South Holland t (708) 331-2900 f (708) 333-3060 www.sgs.com/minerals

Client: American Electric Power Company
Facility: Mitchell Power Plant
Test Location: Unit 1 Stack
Test Method: 26A

Test 1		Test 2		Test 3	
% Hydrogen	4.38	% Hydrogen	4.78	% Hydrogen	4.61
% Carbon	70.55	% Carbon	73.43	% Carbon	73.19
% Sulfur	1.83	% Sulfur	2.11	% Sulfur	2.09
% Nitrogen	1.56	% Nitrogen	1.60	% Nitrogen	1.59
% Oxygen	6.20	% Oxygen	4.99	% Oxygen	5.49
HHV (Btu/lb)	12685	HHV (Btu/lb)	12955	HHV (Btu/lb)	13055
Fd(dscf/MMBtu)=	9640.85	Fd(dscf/MMBtu)=	9948.16	Fd(dscf/MMBtu)=	9777.83
Fc(scf/MMBtu)=	1785.30	Fc(scf/MMBtu)=	1819.45	Fc(scf/MMBtu)=	1799.62

AVERAGE FUEL FACTORS	
Fd(dscf/MMBtu)=	9788.95
Fc(scf/MMBtu)=	1801.46

Client:	American Electric Power Company	
Facility:	Mitchell Power Plant	
Test Location:	Unit 1 Stack	
Project #:	M101301	
Test Method:	26A	
Test Engineer:	S. Dyra	
Test Technician:	R. Sollars/W. Mullenix	
lb/mmBtu Emissions by:	Calculated	
Type of Fuel Firing:	Coal, Sub-Bituminous	
Calculated Fuel Factor Fd, dscf/mmBtu:	9788.95	
Temp ID:	CM8	
Meter ID:	CM8	
Pitot ID:	075A	
Pitot Tube Coefficient:	0.840	
Probe Length:	12.0	ft
Probe Liner Material:	Glass	
Nozzle Diameter:	0.233/0.250	in.
Nozzle Kit ID Number and Material:	Teflon 2	
Meter Calibration Factor (Y):	1.004	
Meter Orifice Setting (Delta H):	1.476	
Sample Plane:	Horizontal	
Port Length:	14.00	in.
Port Size (diameter):	6.00	in.
Port Type:	Flange	
Duct Shape:	Circular	
Diameter	33.75	ft
Duct Area:	894.618	Sq. Ft.
Upstream Diameters:	>2.0	
Downstream Diameters:	>8.0	
Number of Ports Sampled:	4	
Number of Points per Port:	3	
Minutes per Point:	5.0	
Minutes per Reading:	5.0	
Total Number of Traverse Points:	12	
Test Length:	60	min.
Train Type:	Anderson Box	
Source Condition:	Normal	
# of Runs	3	

Client: American Electric Power Company
Facility: Mitchell Power Plant
Test Location: Unit 1 Stack
Test Method: 26A

		Run 1	Run 2	Run 3
Identify Analyte:	Hydrogen Chloride (HCl)			
Molecular Weight:	36.45			
mg (net) collected:		18	18	18
Identify Analyte:	Hydrogen Fluoride (HF)			
Molecular Weight:	19.99			
mg (net) collected:		12	60	12
Identify Analyte:	Hydrogen Cyanide (HCN)			
Molecular Weight:	27.03			
mg (net) collected:		0.3	0.3	0.3

Run 1-Method 26A

Client: American Electric Power Company
Facility: Mitchell Power Plant
Test Location: Unit 1 Stack
Source Condition: Normal

Date: 3/31/10
Start Time: 8:31
End Time: 9:49

DRY GAS METER CONDITIONS

ΔH:	1 22	in. H_2O
Meter Temperature, Tm:	85 4	°F
Sqrt ΔP:	0.806	in. H_2O
Stack Temperature, Ts:	123 8	°F
Meter Volume, Vm:	42 564	ft^3
Meter Volume, Vmstd:	39.765	dscf
Meter Volume, Vwstd:	6.853	wscf
Isokinetic Variance:	102.0	%I
Calculated Fuel Factor Fd:	9,640 85	dscf/mmBtu
Test Length	60.00	in mins
Nozzle Diameter	0.233	in inches
Barometric Pressure	28 67	in Hg
Calculated Fo:	1.17	

STACK CONDITIONS

Static Pressure	-1.30	in. H_2O
Flue Pressure (Ps):	28.57	in. Hg. abs.
Carbon Dioxide:	12 10	%
Oxygen:	6.70	%
Nitrogen:	81.20	%
Gas Weight dry, Md:	30 204	lb/lb mole
Gas Weight wet, Ms:	28.660	lb/lb mole
Excess Air:	45 464	%
Gas Velocity, Vs:	48.920	fps
Volumetric Flow:	2,625,874	acfm
Volumetric Flow:	1,964,044	dscfm
Volumetric Flow:	2,267,949	scfm
Fo Validity:	Pass	

MOISTURE DETERMINATION

Initial Impinger Content:	2665.1	ml	Silica Initial Wt.	692.8
Final Impinger Content:	2807 2	ml	Silica Final Wt.	696.2
Difference:	142.1		Difference:	3.4

Total Water Gain: 145 5   Moisture, Bws: 0 147   Supersaturation Value, Bws: 0.134

Port-Point No.	Clock Time	Velocity Head Δp In. H2O	Orifice ΔH In. H2O	Actual Meter Vol. ft^3	Sqrt. Δp	Stack Temp °F	Meter Temp Inlet °F	Meter Temp Outlet °F	Collected Vol. ft^3	Point Vel ft/sec
1-1	8:31:00	0.69	1.30	37.363	0.831	124	82	81	3.627	50.446
1-2	8:36:00	0.66	1.20	40.990	0.812	124	84	81	3.510	49.338
1-3	8:41:00	0.62	1.20	44.500	0.787	123	87	82	3.450	47.819
	8:46:00			47.950						
2-1	8.50.00	0.68	1.30	47.950	0.825	125	87	83	3.620	50.079
2-2	8:55:00	0.68	1.20	51.570	0.825	124	89	83	3.640	50.079
2-3	9:00:00	0.61	1.20	55.210	0.781	123	91	84	3.196	47.432
	9:05:00			58.406						
3-1	9.15.00	0.67	1.30	58.701	0.819	124	86	84	3.649	49.710
3-2	9:20:00	0.65	1.20	62.350	0.806	125	88	85	3.560	48.952
3-3	9:25:00	0.64	1.20	65.010	0.800	124	89	85	3.497	48.584
	9.30.00			69.407						
4-1	9:34:00	0.65	1.20	69.407	0.806	124	85	85	3.543	48.952
4-2	9:39:00	0.64	1.20	72.950	0.800	123	89	85	3.530	48.584
4-3	9:44:00	0.60	1.10	76.480	0.775	123	89	85	3.742	47.041
	9:49:00			80.222						
Total				42.564			87.3	83.6	42 564	
Average			1.22		0.806	123 8	85.4			

Run 2-Method 26A

Client:	American Electric Power Company	Date:	3/31/10
Facility:	Mitchell Power Plant	Start Time:	10:20
Location:	Unit 1 Stack	End Time:	11:37
Source Condition:	Normal		

DRY GAS METER CONDITIONS			STACK CONDITIONS		
ΔH:	1.63	In. H_2O	Static Pressure	-1.30	in. H_2O
Meter Temperature, Tm:	87.7	°F	Flue Pressure (Ps):	28.57	in. Hg. abs.
Sqrt ΔP:	0.806	In. H_2O	Carbon Dioxide:	12.10	%
Stack Temperature, Ts:	124.8	°F	Oxygen:	6.70	%
Meter Volume, Vm:	49.003	cf	Nitrogen:	81.2	%
Meter Volume, Vmstd:	45.640	dscf	Gas Weight dry, Md:	30.204	lb/lb mole
Meter Volume, Vwstd:	7.682	wscf	Gas Weight wet, Ms:	28.532	lb/lb mole
Isokinetic Variance:	102.0	%I	Excess Air:	45.464	%
Calculated Fuel Factor Fd:	9,948.16	dscf/mmBtu	Gas Velocity, Vs:	49.011	fps
Test Length	60.00	in mins.	Volumetric Flow:	2,630,762	acfm
Nozzle Diameter	0.250	in inches	Volumetric Flow:	1,957,809	dscfm
Barometric Pressure	28.67	in Hg	Volumetric Flow:	2,268,608	scfm
Calculated Fo:	1.17		Fo Validity:	Pass	

MOISTURE DETERMINATION

Initial Impinger Content:	2872.8	ml	Silica Initial Wt.	696.2
Final Impinger Content:	3032.9	ml	Silica Final Wt.	699.2
Difference:	160.1		Difference:	3.0

Total Water Gain: 163.1   Moisture, Bws: 0.144   Supersaturation Value, Bws: 0.137

Port-Point No.	Clock Time	Velocity Head Δp In. H2O	Orifice ΔH In. H2O	Actual Meter Vol. ft³	Sqrt. Δp	Stack Temp °F	Meter Temp Inlet °F	Meter Temp Outlet °F	Collected Vol. ft³	Point Vel ft/sec
1-1	10:20:00	0.64	1.60	93.419	0.800	124	86	66	4.041	48.654
1-2	10:25:00	0.63	1.60	97.460	0.794	125	88	85	4.000	48.272
1-3	10:30:00	0.59	1.50	101.460	0.768	124	89	65	3.877	46.714
	10:35:00			105.337						
2-1	10:39:00	0.65	1.60	105.337	0.806	124	89	86	4.053	49.032
2-2	10:44:00	0.64	1.60	109.390	0.800	125	90	86	4.060	48.654
2-3	10:49:00	0.61	1.50	113.450	0.781	125	91	86	4.057	47.500
	10:54:00			117.507						
3-1	11:03:00	0.69	1.70	117.507	0.831	126	87	86	4.173	50.518
3-2	11:08:00	0.70	1.80	121.680	0.837	125	89	86	4.240	50.883
3-3	11:13:00	0.65	1.60	125.920	0.806	125	91	87	4.134	49.032
	11:18:00			130.054						
4-1	11:22:00	0.71	1.80	130.054	0.843	125	87	87	4.266	51.245
4-2	11:27:00	0.69	1.70	134.320	0.831	125	91	87	4.170	50.518
4-3	11:32:00	0.60	1.50	138.490	0.775	124	92	87	3.932	47.109
	11:37:00			142.422						
Total				49.003			89.2	86.2	49.003	
Average			1.63		0.806	124.8	87.7			

Run 3-Method 26A

Client:	American Electric Power Company	Date:	3/31/10
Facility:	Mitchell Power Plant	Start Time:	11:59
Location:	Unit 1 Stack	End Time:	13:16
Source Condition:	Normal		

DRY GAS METER CONDITIONS			STACK CONDITIONS		
ΔH:	1 66	In. H_2O	Static Pressure	-1 30	in. H_2O
Meter Temperature, Tm:	88.7	°F	Flue Pressure (Ps):	28 57	in. Hg abs
Sqrt ΔP:	0 809	In. H_2O	Carbon Dioxide:	12.00	%
Stack Temperature, Ts:	125.1	°F	Oxygen:	6 80	%
Meter Volume, Vm:	49 088	cf	Nitrogen:	81 2	%
Meter Volume, Vmstd:	45 640	dscf	Gas Weight dry, Md	30 192	lb/lb mole
Meter Volume, Vwstd:	7.790	wscf	Gas Weight wet, Ms:	28 497	lb/lb mole
Isokinetic Variance:	101 8	%I	Excess Air:	46.458	%
Calculated Fuel Factor Fd:	9,777.83	dscf/mmBtu	Gas Velocity, Vs:	49 239	fps
Test Length	60.00	in mins	Volumetric Flow:	2,642,997	acfm
Nozzle Diameter	0.250	in inches	Volumetric Flow:	1,961,238	dscfm
Barometric Pressure	28 67	in Hg	Volumetric Flow:	2,277,860	scfm
Calculated Fo:	1.18		Fo Validity:	Pass	

MOISTURE DETERMINATION

Initial Impinger Content:	2943.7	ml	Silica Initial Wt.	699.2
Final Impinger Content:	3105.6	ml	Silica Final WL	702.7
Difference:	161 9		Difference:	3.5

Total Water Gain: 165.4 Moisture, Bws: 0.146 Supersaturation Value, Bws: 0 139

Port-Point No.	Clock Time	Velocity Head Δp In. H2O	Orifice ΔH In. H2O	Actual Meter Vol. ft^3	Sqrt. Δp	Stack Temp °F	Meter Temp Inlet °F	Meter Temp Outlet °F	Collected Vol. ft^3	Point Vel ft/sec
1-1	11:59:00	0.72	1.80	51.437	0.849	126	88	87	4.263	51.651
1-2	12:04:00	0.68	1.70	55.700	0.825	125	91	87	4.180	50.196
1-3	12:09.00	0.62	1.60	59.880	0.787	124	92	87	4.008	47.930
	12:14.00			63.888						
2-1	12:17:00	0.70	1.80	63.888	0.837	125	88	87	4.192	50.029
2-2	12:22:00	0.69	1.70	68.080	0.831	125	91	87	4.220	50.564
2-3	12:27:00	0.67	1.70	72.300	0.819	125	92	87	4.134	49.825
	12:32.00			76.434						
3-1	12:42.00	0.67	1.70	76.573	0.819	126	88	87	4.047	49.825
3-2	12:47:00	0.64	1.60	80.620	0.800	126	90	87	4.130	48.697
3-3	12.52.00	0.62	1.60	84.750	0.787	125	92	87	4.016	47.930
	12.57:00			88.766						
4-1	13:01:00	0.66	1.70	88.766	0.812	125	88	87	4.094	49.452
4-2	13:06:00	0.63	1.60	92.860	0.794	125	91	87	4.050	48.315
4-3	13:11.00	0.56	1.40	96.910	0.748	124	92	88	3.754	45 552
	13:16:00			100.664						
Total				49 038			90 3	87.1	49 038	
Average			1.66		0.809	125 1	88 7			

Client: American Electric Power Company
Facility: Mitchell Power Plant
Project #: M101301

Location: Unit 1 Stack
Date: 3/31/10

		Hour 1							Hour 2		
Time	O2 %	CO2 %	Time	O2 %	CO2 %	Time	O2 %	CO2 %	Time	O2 %	CO2 %
8:31	6.69	12.00	9:01	6.75	12.06	9:31	6.73	12.07			
8:32	6.73	12.00	9:02	6.74	12.07	9:32	6.76	12.05			
8:33	6.71	12.03	9:03	6.69	12.11	9:33	6.73	12.07			
8:34	6.70	12.05	9:04	6.70	12.10	9:34	6.77	12.04			
8:35	6.71	12.05	9:05	6.68	12.12	9:35	6.79	12.02			
8:36	6.73	12.04	9:06	6.69	12.11	9:36	6.79	12.02			
8:37	6.70	12.07	9:07	6.66	12.14	9:37	6.74	12.06			
8:38	6.71	12.06	9:08	6.69	12.12	9:38	6.75	12.06			
8:39	6.69	12.08	9:09	6.74	12.07	9:39	6.75	12.07			
8:40	6.75	12.03	9:10	6.75	12.06	9:40	6.71	12.10			
8:41	6.71	12.06	9:11	6.74	12.07	9:41	6.72	12.09			
8:42	6.75	12.03	9:12	6.74	12.07	9:42	6.76	12.05			
8:43	6.69	12.08	9:13	6.77	12.05	9:43	6.73	12.08			
8:44	6.69	12.09	9:14	6.79	12.03	9:44	6.74	12.08			
8:45	6.72	12.07	9:15	6.77	12.05	9:45	6.76	12.06			
8:46	6.70	12.08	9:16	6.76	12.05	9:46	6.75	12.06			
8:47	6.69	12.09	9:17	6.75	12.06	9:47	6.76	12.05			
8:48	6.74	12.05	9:18	6.72	12.09	9:48	6.79	12.03			
8:49	6.70	12.08	9:19	6.74	12.06	9:49	6.79	12.02			
8:50	6.69	12.09	9:20	6.71	12.09						
8:51	6.66	12.12	9:21	6.74	12.06						
8:52	6.73	12.07	9:22	6.79	12.02						
8:53	6.71	12.09	9:23	6.73	12.07						
8:54	6.72	12.08	9:24	6.73	12.08						
8:55	6.72	12.08	9:25	6.73	12.07						
8:56	6.74	12.06	9:26	6.73	12.08						
8:57	6.73	12.07	9:27	6.70	12.10						
8:58	6.72	12.08	9:28	6.68	12.10						
8:59	6.71	12.09	9:29	6.73	12.06						
9:00	6.74	12.07	9:30	6.74	12.06						
									Average	6.72	12.10
									Min	6.66	12.00
									Max	6.79	12.14

Client: American Electric Power Company
Facility: Mitchell Power Plant
Project #: M101301

Location: Unit 1 Stack
Date: 3/31/10

		Hour 3						Hour 4			
Time	O2 %	CO2 %	Time	O2 %	CO2 %	Time	O2 %	CO2 %	Time	O2 %	CO2 %
10:20	6.73	12.09	10:50	6.73	12.11	11:20	6.71	12.12			
10:21	6.74	12.09	10:51	6.72	12.12	11:21	6.73	12.10			
10:22	6.72	12.10	10:52	6.72	12.12	11:22	6.78	12.06			
10:23	6.73	12.09	10:53	6.67	12.15	11:23	6.75	12.09			
10:24	6.75	12.07	10:54	6.67	12.15	11:24	6.75	12.09			
10:25	6.75	12.07	10:55	6.71	12.13	11:25	6.78	12.06			
10:26	6.73	12.09	10:56	6.70	12.13	11:26	6.77	12.07			
10:27	6.76	12.07	10:57	6.70	12.13	11:27	6.75	12.10			
10:28	6.74	12.08	10:58	6.71	12.12	11:28	6.78	12.08			
10:29	6.73	12.09	10:59	6.72	12.12	11:29	6.76	12.09			
10:30	6.72	12.10	11:00	6.75	12.09	11:30	6.74	12.11			
10:31	6.73	12.09	11:01	6.72	12.12	11:31	6.77	12.08			
10:32	6.74	12.07	11:02	6.74	12.09	11:32	6.70	12.14			
10:33	6.75	12.07	11:03	6.75	12.09	11:33	6.74	12.11			
10:34	6.79	12.04	11:04	6.73	12.10	11:34	6.72	12.13			
10:35	6.78	12.05	11:05	6.72	12.11	11:35	6.65	12.18			
10:36	6.73	12.09	11:06	6.71	12.13	11:36	6.70	12.14			
10:37	6.74	12.09	11:07	6.71	12.13	11:37	6.73	12.11			
10:38	6.74	12.10	11:08	6.70	12.13						
10:39	6.75	12.09	11:09	6.69	12.14						
10:40	6.75	12.08	11:10	6.70	12.13						
10:41	6.70	12.13	11:11	6.72	12.11						
10:42	6.68	12.15	11:12	6.72	12.11						
10:43	6.73	12.10	11:13	6.73	12.10						
10:44	6.71	12.13	11:14	6.69	12.14						
10:45	6.76	12.08	11:15	6.69	12.14						
10:46	6.74	12.09	11:16	6.75	12.09						
10:47	6.77	12.07	11:17	6.75	12.09						
10:48	6.78	12.06	11:18	6.72	12.11						
10:49	6.75	12.09	11:19	6.70	12.13						

	O2 %	CO2 %
Average	6.73	**12.10**
Min	6.67	12.04
Max	6.79	12.15

Client: American Electric Power Company   Location: Unit 1 Stack
Facility: Mitchell Power Plant   Date: 3/31/10
Project #: M101301

Time	O2 %	CO2 %	Time	O2 %	CO2 %	Time	O2 %	CO2 %	Time	O2 %	CO2 %
		Hour 5						Hour 6			
11:59	6.72	12.13	12:29	6.80	12.08	12:59	6.73	12.14			
12:00	6.72	12.13	12:30	6.78	12.09	13:00	6.76	12.12			
12:01	6.76	12.11	12:31	6.76	12.12	13:01	6.76	12.12			
12:02	6.77	12.09	12:32	6.70	12.17	13:02	6.74	12.14			
12:03	6.78	12.09	12:33	6.73	12.14	13:03	6.73	12.14			
12:04	6.81	12.07	12:34	6.75	12.12	13:04	6.75	12.13			
12:05	6.74	12.13	12:35	6.75	12.12	13:05	6.68	12.18			
12:06	6.73	12.13	12:36	6.77	12.10	13:06	6.68	12.18			
12:07	6.73	12.14	12:37	6.81	12.07	13:07	6.79	12.09			
12:08	6.75	12.11	12:38	6.76	12.11	13:08	6.83	12.05			
12:09	6.78	12.09	12:39	6.76	12.12	13:09	6.76	12.11			
12:10	6.75	12.11	12:40	6.76	12.12	13:10	6.79	12.09			
12:11	6.72	12.15	12:41	6.74	12.13	13:11	6.77	12.10			
12:12	6.70	12.16	12:42	6.76	12.12	13:12	6.80	12.08			
12:13	6.72	12.15	12:43	6.74	12.13	13:13	6.80	12.08			
12:14	6.74	12.14	12:44	6.75	12.13	13:14	6.77	12.11			
12:15	6.74	12.14	12:45	6.79	12.09	13:15	6.74	12.13			
12:16	6.75	12.13	12:46	6.76	12.11	13:16	6.70	12.16			
12:17	6.74	12.13	12:47	6.73	12.14						
12:18	6.74	12.13	12:48	6.75	12.12						
12:19	6.75	12.12	12:49	6.75	12.13						
12:20	6.75	12.12	12:50	6.73	12.15						
12:21	6.77	12.11	12:51	6.76	12.11						
12:22	6.75	12.12	12:52	6.74	12.13						
12:23	6.76	12.12	12:53	6.78	12.10						
12:24	6.72	12.15	12:54	6.75	12.12						
12:25	6.75	12.12	12:55	6.73	12.14						
12:26	6.73	12.14	12:56	6.77	12.10						
12:27	6.74	12.13	12:57	6.76	12.12						
12:28	6.77	12.10	12:58	6.74	12.14						

	O2 %	CO2 %
Average	6.75	12.10
Min	6.70	12.07
Max	6.81	12.17

PLATT ENVIRONMENTAL SERVICES, INC.

Procedures for Calibration

Dry Gas Meters

The test meters are calibrated according to Method 5, Section 5.3 and "Procedures for Calibrating and Using Dry Gas Volume Meters as Calibration Standards" by P.R. Westlin and R.T. Shigehara, March 10, 1978.

Analytical Balance

The accuracy of the analytical balance is checked with Class S, Stainless Steel Type 303 weights manufactured by F. Hopken and Son, Jersey City, New Jersey.

Temperature Sensing Devices

The potentiometer and thermocouples are calibrated utilizing a NBS traceable millivolt source.

Nozzles

The nozzles are measured according to Method 5, Section 5.1.

Pitot Tubes

The pitot tubes used during this test program are fabricated according to the specification described and illustrated in the Code of Federal Regulations, Title 40, Part 60, Appendix A, Methods 1 through 5 as published in the Federal Register, Volume 42, No. 160; hereafter referred to by the appropriate method number. The pitot tubes comply with the alignment specifications in Method 2, Section 4; and the pitot tube assemblies are in compliance with specifications in the same section.

Stack Temperature Sensor Calibration

Meter Box # : CM8 *Name :* P. Platt

Ambient Temperature : 65 °F *Date :* March 22, 2010

Calibrator Model # : CL23A

Serial # : T-249465

Date Of Certification : September 22, 2006

Primary Standards Directly Traceable National Institute of Standards and Technology (NIST)

Reference Source Temperature (°F)	Test Thermometer Temperature (°F)	Temperature Difference %
0	-2	0.4
250	249	0.1
600	601	0.1
1200	1209	0.5

$$\frac{(\text{Ref. Temp., °F} + 460) - (\text{Test Therm. Temp., °F} + 460)}{\text{Ref. Temp., °F} + 460} * 100 <= 1.5\ \%$$

Meter Box Calibration

Dry Gas Meter No.	CM8	Date:	March 22, 2010
Standard Meter No.	4819699	Calibrated By:	P. Platt
Standard Meter (Y)	1.0008	Barometric Pressure:	29.29

Run Number		Orifice Setting in H_2O Chg (H)	Standard Meter Gas Volume vr	Dry Gas Meter Gas Volume vd	Standard Meter Temp. F° tr	Dry Gas Meter Inlet Temp. F° tdi	Dry Gas Meter Outlet Temp. F° tdo	Dry Gas Meter Avg. Temp. F° td	Time Min	Time Sec	Y	Chg (H)
Final			579.453	13.074	61	64	62					
Initial			574.309	7.932	59	64	61					
Difference	1	0.20	5.144	5.142	60	64	62	63	18	30	1.005	1.447
Final			585.311	18.944	61	65	62					
Initial			579.777	13.415	61	63	62					
Difference	2	0.50	5.534	5.529	61	64	62	63	12	30	1.003	1.432
Final			590.976	24.613	62	65	63					
Initial			585.520	19.172	61	65	63					
Difference	3	0.70	5.456	5.441	62	65	63	64	10	30	1.006	1.455
Final			597.025	30.677	61	65	63					
Initial			591.565	25.200	62	64	63					
Difference	4	0.90	5.460	5.477	62	65	63	64	9	15	0.999	1.451
Final			603.253	36.889	62	68	64					
Initial			597.710	31.335	62	65	63					
Difference	5	1.20	5.543	5.554	62	67	64	65	8	15	1.001	1.492
Final			574.095	7.700	59	67	61					
Initial			568.848	2.489	59	67	60					
Difference	6	2.00	5.247	5.211	59	67	61	64	6	15	1.011	1.578
									Average		1.004	1.476

Stack Temperature Sensor Calibration

Meter Box # : CM 8 *Name :* JEA

Ambient Temperature : 64 °F *Date :* April 16, 2010

Calibrator Model # : CL23A

Serial # : T-249465

Date Of Certification : September 22, 2006

Primary Standards Directly Traceable National Institute of Standards and Technology (NIST)

Reference Source Temperature (°F)	Test Thermometer Temperature (°F)	Temperature Difference %
0	-2	0.4
250	251	0.1
600	602	0.2
1200	1208	0.5

$$\frac{(\text{Ref. Temp., °F} + 460) - (\text{Test Therm. Temp., °F} + 460)}{\text{Ref. Temp., °F} + 460} * 100 <= 1.5\ \%$$

Meter Box Calibration

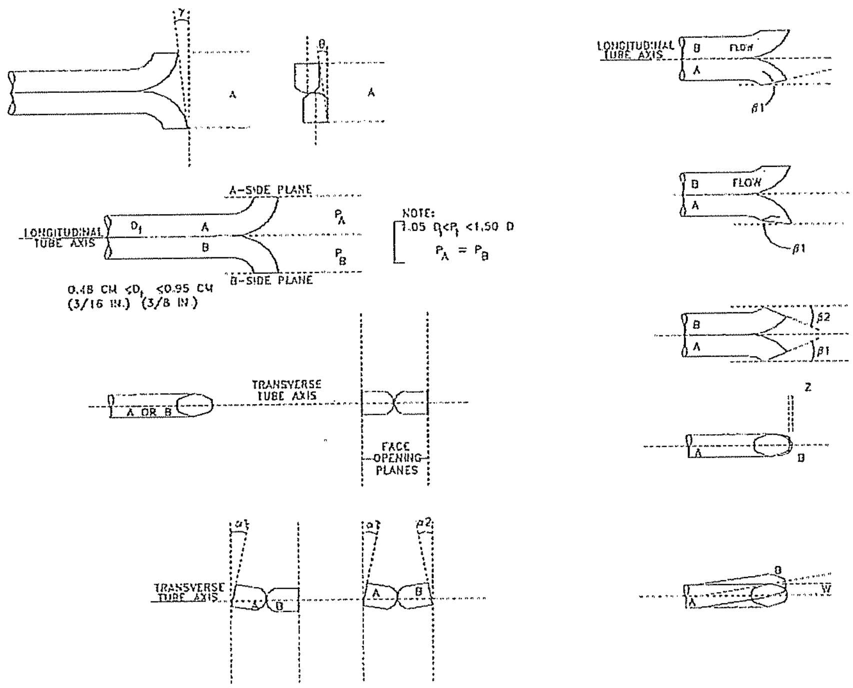
Dry Gas Meter No.	CM 8	Date:	April 16, 2010
Standard Meter No.	4319699	Calibrated By:	JEA
Standard Meter (Y)	1.0008	Barometric Pressure:	29.41

Run Number	Orifice Setting in H_2O Chg (H)	Standard Meter Gas Volume vr	Dry Gas Meter Gas Volume vd	Standard Meter Temp. F° tr	Dry Gas Meter Inlet Temp. F° tdi	Dry Gas Meter Outlet Temp. F° tdo	Dry Gas Meter Avg. Temp. F° td	Time Min	Time Sec	Y	Chg (H)
Final		89.613	56.100	63	66	66					
Initial		84.003	50.471	63	65	65					
Difference 1	0.20	5.610	5.629	63	66	66	66	19	18	1.001	1.327
Final		95.731	62.227	63	67	67					
Initial		89.807	56.292	63	66	66					
Difference 2	0.50	5.924	5.935	63	67	67	67	13	40	1.004	1.489
Final		101.467	67.968	64	69	67					
Initial		95.847	62.336	64	68	67					
Difference 3	0.70	5.620	5.632	64	69	67	68	11	1	1.003	1.507
Final		107.942	74.457	64	70	67					
Initial		101.628	68.152	64	69	67					
Difference 4	0.90	6.314	6.305	64	70	67	68	11	0	1.007	1.529
Final		115.530	82.077	64	69	68					
Initial		108.097	74.620	63	69	67					
Difference 5	1.20	7.433	7.457	64	69	68	68	11	15	1.003	1.536
Final		83.903	50.373	63	65	64					
Initial		77.138	43.649	63	66	64					
Difference 6	2.00	6.765	6.724	63	66	64	65	8	0	1.004	1.570

Average 1.004 1.493

S TYPE PITOT TUBE INSPECTION FORM

Pitot Tube No 75 Date: 3/15/2010 Inspectors Name: SD



Pitot tube assembly level? x yes ___ no

Pitot tube openings damaged? ___ yes (explain below) x no

a_1 = 0 ° (<10°), a_2 = 0 ° (<10°) z = A sin g = 0.016 (in.); (<0.125 in.)

b_1 = 1 ° (<5°), b_2 = 0.5 ° (<5°) w = A sin q = 0.024 (in.); (<0.03125 in.)

γ = 1 °, θ = 1.5 °, A = 0.929 (in.) P_A = 0.464 (in.), P_B = 0.465 (in.), D_t = 0.375 (in.)

Calibration required? ___ yes x no

Platt Environmental Services, Inc.

1520 Kensington Road, Suite 204
Oak Brook, IL 60523-2141
630-521-9400
630-521-9494 fax

Nozzle Calibration Sheet
Set No. 2 Glass

Nominal Diameter	0.120	0.150	0.200	0.230	0.250	0.275	0.310	0.375	0.425	0.500	Other
Nozzle Diameter	0.120	0.153	.199	.233	0.250	.274	.316	.368	0.431	0.499	
Nozzle Identification Number											

Client: American Electric Power Company
Facility: Mitchell Power Plant
Fuel Type: Coal, Sub-Bituminous
Fuel Factor: 9788.95
Diluent: O2 %

Location: Unit 1 Stack
Date: 3/31/10
Operator: J. Robertson
Project #: M101301
Fuel Factor: by *Calculated*

O2 % Correction Data

Run #	Cma	Precal	Postcal	Pre zero	Post zero	Co	Cm	C	Cgas	Span Bias	Span Drift	Zero Bias	Zero Drift
1	11.99	12.01	12.00	0.00	0.00	0.00	12.01	6.72	6.7	0.05	-0.05	0.00	0.00
2	11.99	12.00	11.97	0.00	0.00	0.00	11.99	6.73	6.7	0.18	-0.14	0.00	0.00
3	11.99	11.97	11.99	0.00	-0.01	-0.01	11.98	6.75	6.8	0.09	0.09	0.05	-0.05

CO2 % Correction Data

Run #	Cma	Precal	Postcal	Pre zero	Post zero	Co	Cm	C	Cgas	Span Bias	Span Drift	Zero Bias	Zero Drift
1	9.83	9.85	9.84	0.00	0.02	0.01	9.85	12.10	12.1	0.05	-0.05	-0.11	0.11
2	9.83	9.84	9.87	0.02	0.06	0.04	9.86	12.10	12.1	-0.11	0.16	-0.32	0.21
3	9.83	9.87	9.89	0.06	0.07	0.07	9.88	12.10	12.0	-0.21	0.11	-0.37	0.05

Cma = Concentration of Cal Gas
Cm=Average Pre and Post Span
C = Average value of test
Cgas = Corrected gas value of test
Co=Average Pre and Post Zero

Calibration Corrected Data

Hour #	Run Date	Start Time	End Time	CO2 %	O2 %
1 & 2	3/31/10	8:31	9:49	12.1	6.7
3 & 4	3/31/10	10:20	11:37	12.1	6.7
5 & 6	3/31/10	11:59	13:16	12.0	6.8

Client: American Electric Power Company
Facility: Mitchell Power Plant
Location: Unit 1 Stack
Date: 3/31/10
Project #: M101301

Linearity Cal/Pre 1 Cal

Time	O2 %		CO2 %	
8:07	21.90	ih	18.69	ih
8:08	21.90		18.69	
8:09	11.23		2.42	
8:10	-0.34		0.00	
8:11	0.02		0.00	iz
8:12	0.01		0.00	
8:13	0.00	iz	0.00	
8:14	0.00		0.00	
8:15	9.78		7.12	
8:16	12.94		9.39	
8:17	12.26		9.91	
8:18	12.01	im	9.85	im

8:07	21.90		18.69	
8:08	21.90		18.69	
8:09	11.23		2.42	
8:10	-0.34		0.00	
8:11	0.02		0.00	
8:12	0.01		0.00	
8:13	0.00		0.00	z
8:14	0.00	z	0.00	
8:15	9.78		7.12	
8:16	12.94		9.39	
8:17	12.26		9.91	
8:18	12.01	m	9.85	m

Client: American Electric Power Company
Facility: Mitchell Power Plant
Project #: M101301
Location: Unit 1 Stack
Date: 3/31/10

Post 1/Pre 2

Time	O2 %		CO2 %	
9:57	0.00	z	0.02	z
9:58	6.21		4.68	
9:59	12.00	m	9.84	m

Post 2/Pre 3

Time	O2 %		CO2 %	
11:39	11.97	m	9.87	m
11:40	11.95		9.05	
11:41	0.31		0.14	
11:42	0.00	z	0.06	z

Post 3

Time	O2 %		CO2 %	
13:25	-0.01	z	0.07	z
13:26	5.44		2.76	
13:27	11.99		9.87	
13:28	11.99	m	9.89	m

Client: American Electric Power Company
Facility: Mitchell Power Plant
Project #: M101301

Location: Unit 1 Stack
Date: 3/31/10
Operator: J. Robertson

Calibration Gases

Type	Setting	Cylinder ID	Cylinder Value	Analyzer Response	Difference, % of Span	Expiration Date	Final Bottle Pressure, PSI
O2 %	Zero		0.000	0.00	0.00%		
	Mid	CC114878	11.990	12.01	-0.09%	3/1/2013	
	High	CC97654	21.900	21.90	0.00%	3/1/2013	
CO2 %	Zero		0.000	0.00	0.00%		
	Mid	CC114878	9.827	9.85	-0.12%	3/1/2013	
	High	CC97654	18.720	18.69	0.16%	3/1/2013	

Response Time Data

Type	RM Analyzer s/n	Analyzer Span	RM Gas Span
O2 %	01440D1/3790	25	21.9
CO2 %	01440D1/3790	20	18.72
	Start	95% Response	Time (min)
Upscale			2
Downscale			2

Airgas

Airgas Specialty Gases
12722 S. Wentworth Avenue
Chicago IL 60628
1-773-785-3000
FAX 1-773-785-1928
http://www.airgas.com

CERTIFICATE OF ANALYSIS
Grade of Product: EPA Protocol

Part Number:	E03NI78E15A1066	Reference Number:	54-124210051-3
Cylinder Number:	CC114878	Cylinder Volume:	151 Cu.Ft.
Laboratory:	ASG - Chicago - IL	Cylinder Pressure:	2015 PSIG
Analysis Date:	Mar 01, 2010	Valve Outlet:	590

Expiration Date: Mar 01, 2013

Certification performed in accordance with "EPA Traceability Protocol (Sept. 1997)" using the assay procedures listed. Analytical Methodology does not require correction for analytical interferences. This cylinder has a total analytical uncertainty as stated below with a confidence level of 95%. There are no significant impurities which affect the use of this calibration mixture. All concentrations are on a volume/volume basis unless otherwise noted.
Do Not Use This Cylinder below 150 psig,i.e. 1 Mega Pascal

ANALYTICAL RESULTS

Component	Requested Concentration	Actual Concentration	Protocol Method	Total Relative Uncertainty
CARBON DIOXIDE	10.00 %	9.827 %	G1	+/- 1% NIST Traceable
OXYGEN	12.00 %	11.99 %	G1	+/- 1% NIST Traceable
NITROGEN	Balance			

CALIBRATION STANDARDS

Type	Lot ID	Cylinder No	Concentration	Expiration Date
NTRM/CO2	1	CC59142	13.78% CARBON DIOXIDE/	Oct 02, 2012
NTRM/O2	981202	CC73607	14.84% OXYGEN/	Oct 02, 2012

ANALYTICAL EQUIPMENT

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
HORIBA 510	NDIR	Feb 17, 2010
HORIBA MPA-510	Paramagnetic	Feb 17, 2010

Triad Data Available Upon Request

Notes:

Curt Stewart

Approved for Release

Airgas

Airgas Specialty Gases
12722 S. Wentworth Avenue
Chicago IL 60628
1-773-785-3000
FAX 1-773-785-1928
http://www.airgas.com

CERTIFICATE OF ANALYSIS
Grade of Product: EPA Protocol

Part Number:	E03NI59E15A3452	Reference Number:	54-124210051-2
Cylinder Number:	CC97654	Cylinder Volume:	159 Cu.Ft.
Laboratory:	ASG - Chicago - IL	Cylinder Pressure:	2015 PSIG
Analysis Date:	Mar 01, 2010	Valve Outlet:	590

Expiration Date: Mar 01, 2013

Certification performed in accordance with "EPA Traceability Protocol (Sept. 1997)" using the assay procedures listed. Analytical Methodology does not require correction for analytical interferences. This cylinder has a total analytical uncertainty as stated below with a confidence level of 95%. There are no significant impurities which affect the use of this calibration mixture. All concentrations are on a volume/volume basis unless otherwise noted.
Do Not Use This Cylinder below 150 psig, i.e. 1 Mega Pascal

ANALYTICAL RESULTS

Component	Requested Concentration	Actual Concentration	Protocol Method	Total Relative Uncertainty
CARBON DIOXIDE	19.00 %	18.72 %	G1	+/- 1% NIST Traceable
OXYGEN	22.00 %	21.90 %	G1	+/- 1% NIST Traceable
NITROGEN	Balance			

CALIBRATION STANDARDS

Type	Lot ID	Cylinder No	Concentration	Expiration Date
NTRM/O2	60608	CC207980	22.61% OXYGEN/NITROGEN	May 01, 2010
NTRM/CO2	80613	CC255428	20.09% CARBON DIOXIDE/NITROGEN	Jul 15, 2012

ANALYTICAL EQUIPMENT

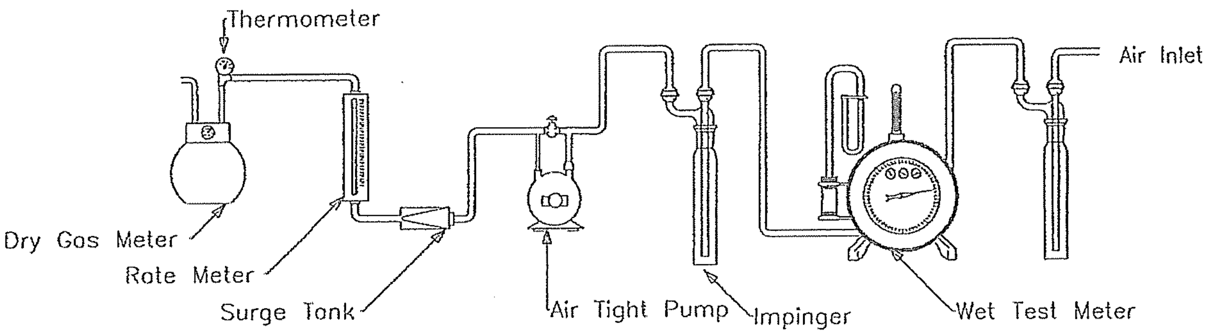
Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
HORIBA 510	NDIR	Feb 17, 2010
Thermo 6700	FTIR	Feb 17, 2010

Triad Data Available Upon Request

Notes:

Approved for Release

Dry Gas Meter Calibration Sample Train Diagram



Isokinetic Sampling Cover Sheet

Test Engineer: S. DYRA
Test Technician: B. SOLLARS / [illegible]

Plant Information

Run Number: #1
Test Location: UNIT 1 STACK
Duct Shape: Circular or Rectangular
Flue Area: 894.618
Port Type: FLANGE
Test Method: M26A

Date: 3/21/10
Client Name: AEP
Length: N/A Width: N/A or Diameter: 33.75
Upstream Diameters: 72.0
Port Length: 14"
Source Condition:

Project Number: M101030I
Plant Name: MITCHELL
Downstream Diameters: 78.0
Port Diameter: 6"

Meter and Probe Data

Meter ID: CM 8
Pitot ID: 075A
Nozzle Kit ID TEFLON 2
Probe Length: 12'
Pre-Test Nozzle Leak Check: .001 @ 12 "Hg
Pre-Test Pitot Leak Check: ✓ @ 4.2 "H_2O

Meter Y Value: 1.001
Pitot Coefficient: .840
Nozzle Diameter: .233
Probe Liner: GLASS

ΔH Value: 1.476
Train Type: ANDERSON
Filter Number/Weight: —
Thimble Number/Weight: —
Post-Test Nozzle Leak Check: .000 @ 10 "Hg
Post-Test Pitot Leak Check: ✓ @ 3.5 "H_2O

Traverse Data

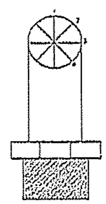
Ports Sampled: 4
Total Points: 12
Points/Port: 3
Total Test Time: 60
Min/Point: 5
Sample Plane: Horizontal or Vertical

Stack Parameters

Barometric Pressure: 28.67
Static Pressure: -1.3
CO_2 %: / / / Avg. 12.1
O_2 %: / / /Avg. 6.7
Determined by: Method 3 or Method 3A
Imp and/or silica balance Model and S/N: SS10-19
Servomex Serial #: S/N 01440D1 / 2790
Initial Imp. Volume or Weight: 2635.1
Final Imp. Volume or Weight: 2807.2
Imp. Volume or Weight Gain: 172.1
Initial Silica Weight: 692.8
Final Silica Weight: 696.2
Silica Weight Gain: 3.4

Comments:

Post-Test Nozzle Verification:



1)_____ 2)_____ 3)_____ 4)_____

DS-004 Rcv042809

Isokinetic Sampling Field Data Sheet

Project Number: M1010301
Client: AEP
Plant: MITCHELL
Date: 3/31/10
Test Location: UNIT 1 STACK
Test Method: M26A
Test Number: #1
Operator: SD
Test Tech: RDDS/WJK
Page Number: 1 of 1

Port-Point #.	Time	(ΔP)	Orifice Setting (ΔH)	Meter Volume (V_m) ft^3, Actual	Square Root, ΔP	Meter Rate, Cubic Feet/ Min.	Theoretical Meter Volume, (V_m) ft^3, per point	Theoretical Meter Volume, (V_m) ft^3, total	Stack Temp, °F	Meter Temp Inlet, °F	Meter Temp Outlet, °F	Pump Vacuum, " Hg	Probe Temp. °F	Filter Temp. °F	Impinger Outlet Well Temp °F
1-1	8:31	.69	1.3	37.363	.831		3.613		124	82	81	3	250	250	62
1-2	8:36	.66	1.2	40.99	.812		3.540	40.976	124	84	81	3	251	252	55
1-3	8:41	.62	1.2	44.58	.787		3.447	44.516	123	87	82	3	250	250	50
	8:46			47.950				47.963							
2-1	8:50	.68	1.3	47.950	.825		3.607		125	87	83	3	250	251	56
2-2	8:55	.68	1.3	51.57	.825		3.617	51.557	124	89	83	3	250	256	52
2-3	9:00	.61	1.2	55.21	.781		3.438	55.173	123	91	84	3	254	250	55
	9:05			58.406				58.611							
3-1	9:15	.67	1.3	58.701	.819		3.583		124	86	84	3	250	250	49
3-2	9:20	.65	1.2	62.35	.806		3.536	62.284	125	88	85	3	255	252	51
3-3	9:26	.64	1.2	65.91	.800		3.515	65.820	124	89	85	3	254	252	52
	9:30			69.407				69.335							
4-1	9:34	.65	1.2	69.407	.806		3.533		124	86	85	3	252	252	52
4-2	9:39	.64	1.2	72.95	.800		3.518	72.940	122	89	85	3	256	252	49
4-3	9:44	.60	1.1	76.48	.775		3.406	76.458	123	89	85	3	258	252	49
	9:49			80.222				79.864							

PLATT ENVIRONMENTAL SERVICES INC.

IMPINGER WEIGHT SHEET

PLANT: AEP Mitchell

UNIT NO: 1

LOCATION: stack

DATE: 3/31/10

TEST NO: 1

METHOD: 26a

WEIGHED/MEASURED BY: SFR

BALANCE ID: 510.19

	FINAL WEIGHT	INITIAL WEIGHT	IMPINGER	IMPINGER
Circle One:	MLS / GRAMS	MLS / GRAMS	GAIN	CONTENTS
IMPINGER 1	694.3	593.5	100.8	Sulfuric Acid
IMPINGER 2	758.0	733.7	24.3	Sulfuric Acid
IMPINGER 3	763.6	720.6	43.0	Sulfuric Acid
IMPINGER 4	591.3	587.3	4.0	NaOH
IMPINGER 5	696.2	692.8	3.4	Silica
IMPINGER 6				
IMPINGER 7				
IMPINGER 8				

- add 30mL 3.0N NaOH

3503.4	3327.9 +30 = 3357.9	175.5
FINAL TOTAL	INITIAL TOTAL	TOTAL GAIN

100 mL 1.0N NaOH Rinse
Add 50mL 3.0N NaOH ///

2807.2

2635.1+30 = 2665.1

2635.1 + 30
692.8
3327.9

3357.9 use as initial

Isokinetic Sampling Cover Sheet

Test Engineer: S. DYRA
Test Technician: R. SOLLARS / W. MULLINEX

Plant Information

Run Number: #2	Date: 3/31/10	Project Number: M1010301
Test Location: UNIT 1 STACK	Client Name: AEP	Plant Name: MITCHELL
Duct Shape: Circular or Rectangular	Length: N/A Width: N/A or	Diameter: 33.75
Flue Area: 894.618	Upstream Diameters: 72.0	Downstream Diameters: 78.0
Port Type: FLANGE	Port Length: 14"	Port Diameter: 6"
Test Method: M26A	Source Condition:	

Meter and Probe Data

Meter ID: CMX	Meter Y Value: 1.004	ΔH Value: 1.476
Pitot ID: 075A	Pitot Coefficient: .840	Train Type: ANDERSON
Nozzle Kit ID GLASS 2	Nozzle Diameter: .250	Filter Number/Weight: —
Probe Length: 12'	Probe Liner: GLASS	Thimble Number/Weight: —

Pre-Test Nozzle Leak Check: .000 @ 12 "Hg Post-Test Nozzle Leak Check: .000 @ 10 "Hg
Pre-Test Pitot Leak Check: ✓ @ 3.5 "H_2O Post-Test Pitot Leak Check: ✓ @ 3.6 "H_2O

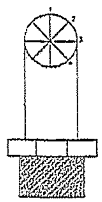
Traverse Data

Ports Sampled: 4	Points/Port: 3	Min/Point: 5
Total Points: 12	Total Test Time: 60	Sample Plane: Horizontal or Vertical

Stack Parameters

Barometric Pressure: 28.67 Static Pressure: -1.3
CO_2 %: / / / Avg. 12.1 O_2 %: / / /Avg. 6.70 Determined by: Method 3 or Method 3A
Imp and/or silica balance Model and S/N: CS10-19 Servomex Serial #: S/N 01440D1/3790
Initial Imp. Volume or Weight: 2872.8 Final Imp. Volume or Weight: 3032.9 Imp. Volume or Weight Gain: 160.1
Initial Silica Weight: 696.2 Final Silica Weight: 699.2 Silica Weight Gain: 3.0

Comments:

Post-Test Nozzle Verification:  1)____ 2)____ 3)____ 4)____

Isokinetic Sampling Field Data Sheet

Project Number: M1010301 Date: 3/31/10 Test Number: #2

Client: AEP Test Location: UNIT 1 STACK Operator: SD Test Tech: RODS/WITH

Plant: MITCHELL Test Method: M26A Page Number: 1 of 1

Port-Point #.	Time	(ΔP)	Orifice Setting (ΔH)	Meter Volume (V_m) ft^3, Actual	Square Root, ΔP	Meter Rate, Cubic Feet/ Min.	Theoretical Meter Volume, (V_m) ft^3, per point	Theoretical Meter Volume, (V_m) ft^3, total	Stack Temp, °F	Meter Temp Inlet, °F	Meter Temp Outlet, °F	Pump Vacuum, " Hg	Probe Temp. °F	Filter Temp. °F	Impinger Outlet Well Temp °F
1-1	10:20	.64	1.6	93.419	.808		4.039		124	86	86	3	255	251	60
1-2	10:25	.63	1.6	97.46	.794		4.098	97.458	125	88	85	3	257	254	56
1-3	10:30	.59	1.5	101.46	.768		3.885	101.406	124	89	85	3	258	252	52
	10:35			105.337				105.351							
2-1	10:39	.65	1.6	105.337	.806		4.082		124	89	86	3	256	249	54
2-2	10:44	.64	1.6	109.39	.800		4.051	109.419	125	90	86	3	257	253	51
2-3	10:49	.61	1.5	113.45	.781		3958	113.469	125	91	86	3	254	252	50
	10:54			117.366				117.427							
3-1	11:03	.69	1.7	117.507	.831		4.191		126	87	86	3	255	250	51
3-2	11:08	.70	1.8	121.68	.837		4.232	121.698	125	89	86	3	257	254	50
3-3	11:13	.65	1.6	125.92	.806		4.090	125.930	125	91	87	2	256	251	50
	11:18			130.054				130.019							
4-1	11:22	.71	1.8	130.054	.843		4.359		125	87	87	3	251	254	52
4-2	11:27	.69	1.7	134.32	.831		4.213	134.313	125	91	87	3	258	256	51
4-3	11:32	.60	1.5	138.49	.775		3.936	138.526	124	92	87	3	257	253	51
	11:37			142.422				142.462							

PLATT ENVIRONMENTAL SERVICES INC.

IMPINGER WEIGHT SHEET

PLANT: AEP - Mitchell

UNIT NO: 1

LOCATION: Stack

DATE: 3/31/10

TEST NO: 2

METHOD: 26a

WEIGHED/MEASURED BY: JFK

BALANCE ID: 510-19

Circle One:	FINAL WEIGHT MLS / GRAMS	INITIAL WEIGHT MLS / GRAMS	IMPINGER GAIN	IMPINGER CONTENTS
IMPINGER 1	814.0	724.6	89.4	Sulfuric Acid
IMPINGER 2	793.3	748.2	45.1	Sulfuric Acid
IMPINGER 3	775.8	725.2	50.6	Sulfuric Acid
IMPINGER 4	649.8	644.8	5.0	NaOH
IMPINGER 5	699.2	696.2	3.0	Silica
IMPINGER 6				
IMPINGER 7				
IMPINGER 8				

- add 30mL 30N NaOH

FINAL TOTAL	INITIAL TOTAL	TOTAL GAIN
3732.1	3539.0	193.1

2842.8 mls + 30 mls

696.2 grams

3569.0 use as initial

Isokinetic Sampling Cover Sheet

Test Engineer: S. DYZA

Test Technician: R. SOLLARS/W. MULLINEX

Plant Information

Run Number: #3
Date: 3/31/10
Project Number: M1010301
Test Location: UNIT 1 STACK
Client Name: AEP
Plant Name: MITCHELL
Duct Shape: Circular or Rectangular
Length: N/A Width: N/A or Diameter: 22.75
Flue Area: 894.618
Upstream Diameters: 72.0
Downstream Diameters: 5.80
Port Type: FLANGE
Port Length: 14"
Port Diameter: 6"
Test Method: M26A
Source Condition:

Meter and Probe Data

Meter ID: CM8
Meter Y Value: 1.004
ΔH Value: 1.476
Pitot ID: 075 A
Pitot Coefficient: .840
Train Type: ANDERSON
Nozzle Kit ID GLASS 2
Nozzle Diameter: .250
Filter Number/Weight: —
Probe Length: 12'
Probe Liner: GLASS
Thimble Number/Weight: —
Pre-Test Nozzle Leak Check: .002 @ 12 "Hg
Post-Test Nozzle Leak Check: .000 @ 10 "Hg
Pre-Test Pitot Leak Check: ✓@ 3.6 "H_2O
Post-Test Pitot Leak Check: ✓@ 4.0 "H_2O

Traverse Data

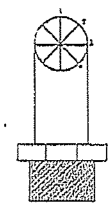
Ports Sampled: 4
Points/Port: 3
Min/Point: 5
Total Points: 12
Total Test Time: 60
Sample Plane: Horizontal or Vertical

Stack Parameters

Barometric Pressure: 28.67
Static Pressure: -1.3
CO_2 %: / / / Avg. 12.0
O_2 %: / / /Avg. 6.8
Determined by: Method 3 or Method 3A
Imp and/or silica balance Model and S/N: S10-19
Servomex Serial #: S/N 01440D1/3790
Initial Imp. Volume or Weight: 2943.7
Final Imp. Volume or Weight: 3105.6
Imp. Volume or Weight Gain: 161.9
Initial Silica Weight: 699.2
Final Silica Weight: 702.7
Silica Weight Gain: 3.5

Comments:

Post-Test Nozzle Verification:



1)______ 2)______ 3)______ 4)______

Isokinetic Sampling Field Data Sheet

Project Number: M1010301 Date: 3/31/10 Test Number: #3
Client: AEP Test Location: UNIT 1 STACK Operator: SD Test Tech: ROBS/WOM
Plant: MITCHELL Test Method: M26A Page Number: 1 of 1

Port-Point #.	Time	(ΔP)	Orifice Setting (ΔH)	Meter Volume (V_m) ft^3, Actual	Square Root, ΔP	Meter Rate, Cubic Feet/ Min.	Theoretical Meter Volume, (V_m) ft^3, per point	Theoretical Meter Volume, (V_m) ft^3, total	Stack Temp, °F	Meter Temp Inlet, °F	Meter Temp Outlet, °F	Pump Vacuum, " Hg	Probe Temp. °F	Filter Temp. °F	Impinger Outlet Well Temp °F
1-1	11:59	.72	1.8	51.437	.849		4.289		126	88	87	3	258	255	67
1-2	12:04	.68	1.7	55.70	.825		4.183	55.726	125	91	87	2	259	252	60
1-3	12:09	.62	1.6	59.88	.787		4.001	59.908	124	92	87	3	258	253	58
	12:14			63.888				63.910							
2-1	12:17	.70	1.8	63.888	.837		4.232		125	88	87	3	251	250	63
2-2	12:22	.69	1.7	68.08	.831		4.215	68.120	125	91	87	3	258	253	58
2-3	12:27	.67	1.7	72.30	.819		4.156	72.334	125	92	87	3	258	251	56
	12:32			76.534				76.489							
3-1	12:42	.67	1.7	76.573	.819		4.137		126	88	87	3	254	257	61
3-2	12:47	.64	1.6	80.62	.800		4.051	80.710	126	90	87	3	258	250	56
3-3	12:52	.62	1.6	84.75	.787		3.998	84.761	125	92	87	3	250	251	54
	12:57			88.766				88.758							
4-1	13:01	.66	1.7	88.766	.812		4.110		125	88	87	3	252	251	57
4-2	13:06	.63	1.6	92.86	.794		4.026	92.876	125	91	87	3	255	256	54
4-3	13:11	.56	1.4	96.91	.748		3.806	96.902	124	92	88	3	257	255	52
	13:16			100.604				100.708							

PLATT ENVIRONMENTAL SERVICES INC.

IMPINGER WEIGHT SHEET

PLANT: AEP- Mitchell

UNIT NO: 1

LOCATION: Stack

DATE: 3/31/10

TEST NO: 3

METHOD: 26A

WEIGHED/MEASURED BY: JFK

BALANCE ID: S10-19

Circle One:	FINAL WEIGHT MLS / GRAMS	INITIAL WEIGHT MLS / GRAMS	IMPINGER GAIN	IMPINGER CONTENTS
IMPINGER 1	830.0	739.8	90.2	Sulfuric Acid
IMPINGER 2	869.2	826.5	42.7	Sulfuric Acid
IMPINGER 3	767.8	716.0	51.8	Sulfuric Acid
IMPINGER 4	638.6	631.4	7.2	NaOH
IMPINGER 5	702.7	699.2	3.5	Silica
IMPINGER 6				
IMPINGER 7				
IMPINGER 8				

3808.3	3612.9	195.4
FINAL TOTAL	INITIAL TOTAL	TOTAL GAIN

2913.7 + 30
699.2
3612.9

3642.9 use as initial

Information Collection Request
Boiler MACT Emissions Report

American Electric Power Company
Mitchell Power Plant
Unit 2 Stack
Moundsville, West Virginia
April 1, 2010

Platt Environmental Services, Inc.

Platt Environmental Services, Inc.

1520 Kensington Road, Suite 204
Oak Brook, IL 60523-2141
630-521-9400
630-521-9494 fax

Information Collection Request
Boiler MACT Emissions Report

American Electric Power Company
Mitchell Power Plant
Unit 2 Stack
Moundsville, West Virginia
April 1, 2010

Report Submittal Date
May 11, 2010

Prepared By

Platt Environmental Services

Report No. M101301B

Table of Contents

1.0 Introduction

PLATT ENVIRONMENTAL SERVICES (PES) conducted an information collection request (ICR) boiler maximum achievable control technology (MACT) emissions test program for American Electric Power Company at the Mitchell Power Plant on the Unit 2 Stack on April 1, 2010. This report summarizes the results of the test program and test methods used.

The test location, test date, and test parameters are summarized below, in Table 1.

Table 1

Test Overview

Test Location	Test Date	Test Method	Test Parameter
Unit 2 Stack	April 1, 2010	USEPA Method 3A	Oxygen (O_2) and Carbon Dioxide (CO_2)
		USEPA Method 26A	Hydrogen Chloride (HCl), Hydrogen Fluoride (HF), Hydrogen Cyanide (HCN)

The identification of individuals associated with the test program is summarized below in Table 2.

Table 2

Test Personnel

Location	Address	Contact
Test Coordinator	American Electric Power Company 1 Riverside Plaza Columbus, Ohio 43215	Mr. Stephen M. Anasis 614-716-1263 (phone) 614-716-1252 (fax) smanasis@aep.com
Test Facility	American Electric Power Company Mitchell Power Plant Moundsville, West Virginia	Mr. Jeff Palmer jwpalmer@aep.com
Testing Company Representative	Platt Environmental Services, Inc. 1520 Kensington Road, Suite 204 Oak Brook, Illinois 60523	Mr. Jim Robertson 630-521-9400 (phone) jrobertson@plattenv.com

The test crew consisted of Messrs. S. Dyra, R. Sollars, W. Mullenix, and J. Robertson of PES. The purpose of the test program was to evaluate the emissions of the constituents listed in Table 1 to satisfy the USEPA information request.

2.0 Executive Summary

Selected results of the test program are summarized below, in Table 3. A complete summary of emission test results follows the narrative portion of this report.

Table 3

Test Results

Test Location	Test Parameter	Emission Rate
Unit 2 Stack	HCl, lb/mmBtu	< 0.012238
	HF, lb/mmBtu	< 0.008158
	HCN, lb/mmBtu	< 0.000204

Compounds expressed above as less than or equal to values had a fraction or fractions that were below detection limits. Detection limits for each fraction were used to determine the emission rate for these compounds.

3.0 Test Methodology

Emissions testing were conducted following the methods specified in 40 CFR, Part 60, Appendix A and 40CFR63, Appendix A. Schematics of the sampling trains used and copies of field data sheets for each test run are included in the Appendix.

The following methodologies were used during the test program:

Method 1 Sample and Velocity Traverse Determination

Test measurement points were selected in accordance with Method 1, 40 CFR, Part 60, Appendix A. The characteristics of the measurement location are summarized below, in Table 4.

Table 4

Sample Point Selection

Test Location	Upstream Distance	Downstream Distance	Test Parameter	Number of Sampling Points
Unit 2 Stack	>2.0	>8.0	HCl, HF, HCN	12

Method 2 Volumetric Flow Rate Determination

Gas velocity was measured following Method 2, 40 CFR, Part 60, Appendix A, for purposes of calculating stack gas volumetric flow rate. An S-type pitot tube, differential pressure gauge, thermocouple and temperature readout were used to determine gas velocity at each sample point. All of the equipment used was calibrated in accordance with the specifications of the Method. Calibration data is presented in the Appendix.

Method 3A Oxygen (O2)/Carbon Dioxide (CO2) Determination

A Servomex analyzer was used to determine stack gas oxygen (O_2) and carbon dioxide content and, by difference, nitrogen content in accordance with Method 3A, 40 CFR, Part 60, Appendix A for purposes of calculating stack gas molecular weight as well as for calculating emissions on a lb/mmBtu basis. The O_2 instrument has a nondispersive infrared-based detector and operates in a range of 0-25% and the CO_2 instrument also uses a nodispersive infrared-based detector and operates in the range of 0-20%. All of the equipment used was calibrated in accordance with the specifications of the Method.

Method 26A Halide Determination

Stack gas Hydrogen Chloride (HCl), Hydrogen Fluoride (HF), and Hydrogen Cyanide (HCN) concentrations and emission rates were determined in accordance with Method 26A. An Environmental Supply Company, Inc. sampling train was used to collect the samples. A multiple-point sample was extracted isokinetically from the gas stream and passed through dilute (0.1 N) sulfuric acid. In the dilute acid, the HCl dissolved and formed chloride (Cl) ions. The sample train consisted of a Teflon® filter placed on the outlet of a heated borosilicate glass probe liner and six impingers. The first three impingers contained the dilute sulfuric acid, the fourth and fifth impingers contained a 0.6 N sodium hydroxide (NaOH) scrubber solution to remove any HCN, and the sixth impinger contained silica gel to absorb any remaining moisture. A DI rinse was performed on each set of impingers, and samples were stored in nalgene sample containers for transport. The dilute sulfuric acid samples were then analyzed for the above halides by Maxxam Analytics, Inc. All of the equipment used was calibrated in accordance with the specifications of the Method. Calibration data is presented in the Appendix.

4.0 Test Results Summaries

Client: American Electric Power Company
Facility: Mitchell Power Plant
Test Location: Unit 2 Stack
Test Method: 26A

Source Condition	Normal	Normal	Normal	
Date	4/1/10	4/1/10	4/1/10	
Start Time	8:05	9:50	11:29	
End Time	9:21	11:04	12:44	
	Run 1	Run 2	Run 3	Average
Stack Conditions				
Average Gas Temperature, °F	122.6	123.4	122.8	122.9
Flue Gas Moisture, percent by volume	13.0%	13.3%	13.0%	13.1%
Average Flue Pressure, in. Hg	28.57	28.58	28.58	28.58
Gas Sample Volume, dscf	45.271	43.916	44.349	44.512
Average Gas Velocity, ft/sec	48.040	47.096	47.425	47.520
Gas Volumetric Flow Rate, acfm	2,578,621	2,527,999	2,545,660	2,550,760
Gas Volumetric Flow Rate, dscfm	1,941,766	1,894,860	1,916,616	1,917,747
Average %CO_2 by volume, dry basis	12.3	12.8	12.8	12.6
Average %O_2 by volume, dry basis	6.2	6.0	5.9	6.0
Isokinetic Variance	102.0	101.4	101.3	101.6
Hydrogen Chloride (HCl) Emissions				
ppm	< 9.26	< 9.54	< 9.45	< 9.42
ug/dscm	< 14041.35	< 14474.44	< 14333.12	< 14282.97
lb/hr	< 102.1250	< 102.7320	< 102.8970	< 102.5847
lb/mmBtu	< 0.012215	< 0.012314	< 0.012184	< 0.012238
Hydrogen Fluoride (HF) Emissions				
ppm	< 11.25	< 11.60	< 11.49	< 11.45
ug/dscm	< 9360.90	< 9649.63	< 9555.41	< 9521.98
lb/hr	< 68.0830	< 68.4880	< 68.5980	< 68.3897
lb/mmBtu	< 0.008143	< 0.008209	< 0.008123	< 0.008158
Hydrogen Cyanide (HCN) Emissions				
ppm	< 0.208	< 0.215	< 0.212	< 0.212
ug/dscm	< 234.02	< 241.24	< 238.89	< 238.05
lb/hr	< 1.7020	< 1.7120	< 1.7150	< 1.7097
lb/mmBtu	< 0.000204	< 0.000205	< 0.000203	< 0.000204

5.0 Conclusion and Certification

PLATT ENVIRONMENTAL SERVICES is pleased to have been of service to American Electric Power Company. If you have any questions regarding this test report, please do not hesitate to contact us at 630-521-9400.

CERTIFICATION

As project manager, I hereby certify that this test report represents a true and accurate summary of emissions test results and the methodologies employed to obtain those results, and the test program was performed in accordance with the methods specified in this test report.

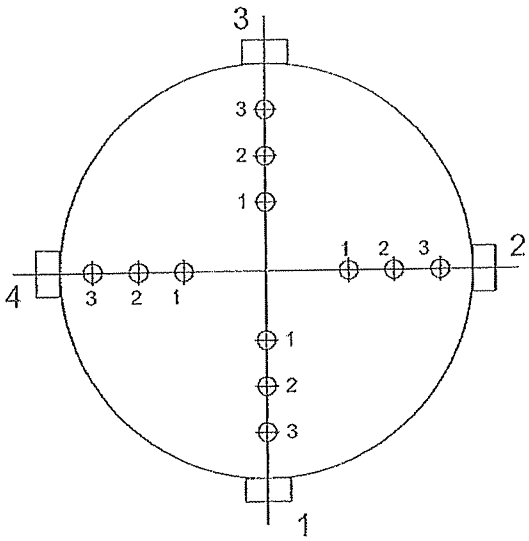
PLATT ENVIRONMENTAL SERVICES

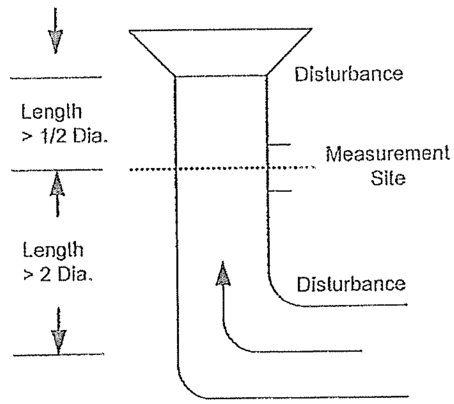
James F. Robertson — Program Manager

Jeffrey M. Crivlare — Quality Assurance

APPENDIX

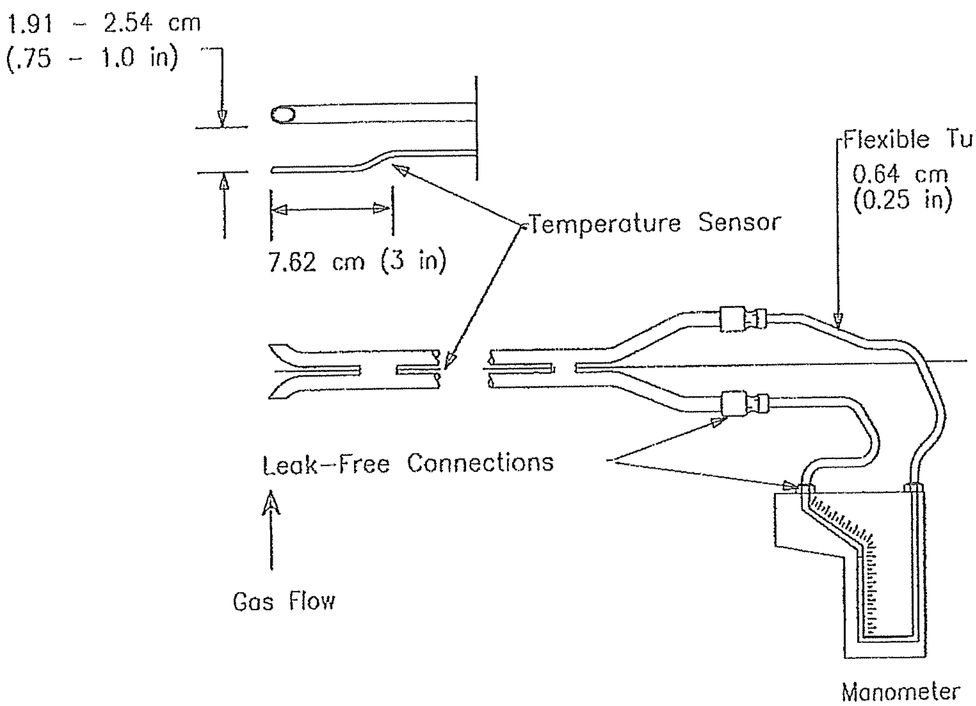
EQUAL AREA TRAVERSE FOR ROUND DUCTS



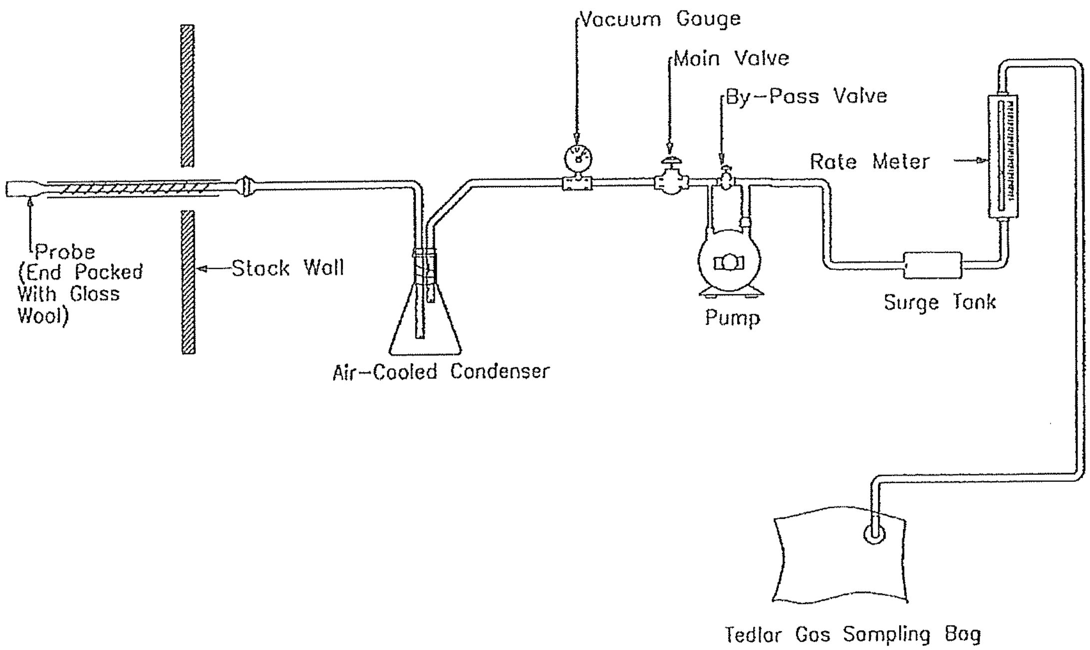


Job:	American Electric Power Company
	Mitchell Power Plant
	Moundsville, West Virginia
Date:	April 1, 2010
Unit No:	2
Test Location:	Stack
Stack Diameter:	33.75 Feet
Stack Area:	894.618 Square Feet
No. Points Across Diameter:	6
No. of Ports:	4
Port Length:	14 Inches

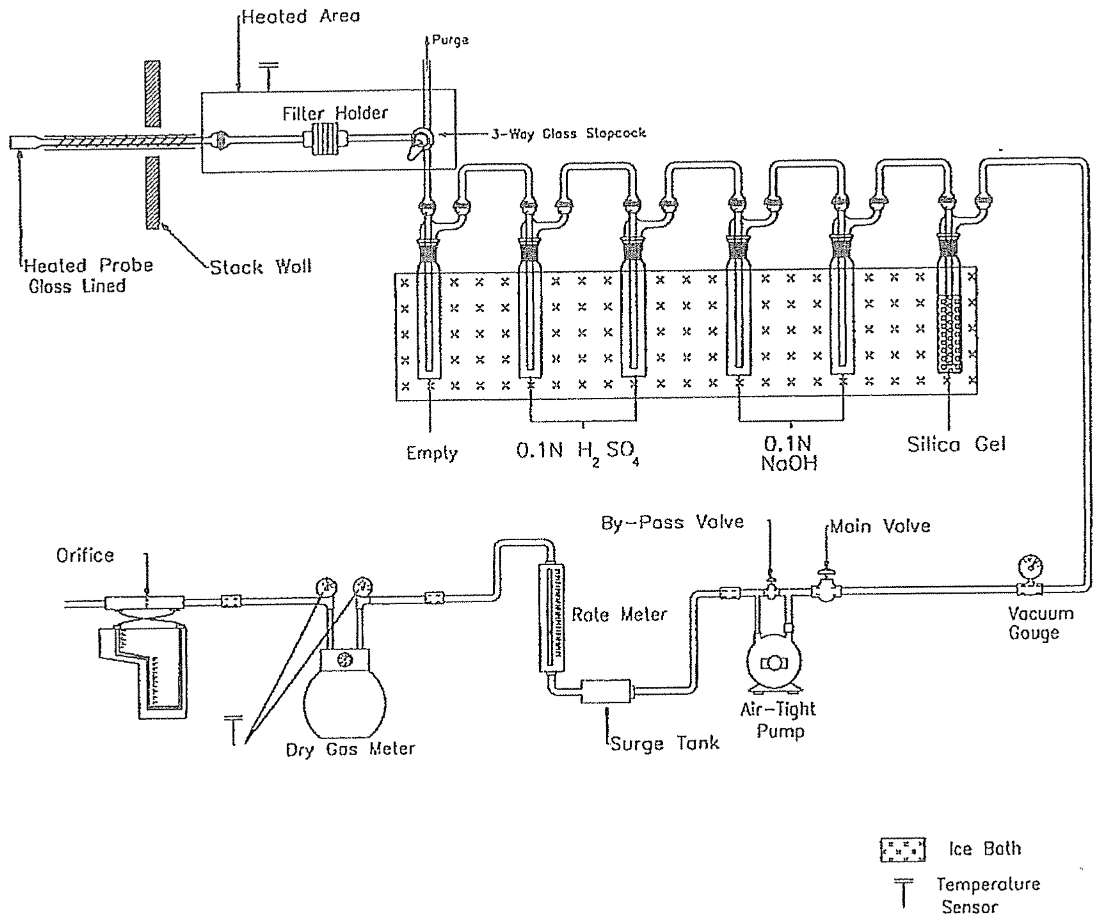
USEPA Method 2 - S-Type Pitot Tube Diagram



USEPA Method 3A - Integrated Oxygen/Carbon Dioxide Sample Train Diagram



USEPA Method 26A – Halogen Sample Train Diagram



Client: American Electric Power Company
Facility: Mitchell Power Plant
Test Location: Unit 2 Stack
Run: 1
Date: 4/1/2010

Method 26A (HCl) Calculations

Dry Molecular Weight

$$Md = 0.44 \times (\%CO_2) + 0.32 \times (\%O_2) + 0.28 \times \%N_2$$

$\%CO_2 =$ 12.3 $\%O_2 =$ 6.2 $\%N_2 =$ 81.5

Md = 30.22

Wet Molecular Weight

$$Ms = Md \times (1\text{-}Bws) + (18.0 \times Bws)$$

Md = 30.22 Bws = 0.137

Ms = 28.63

Meter Volume at Standard Conditions

$$Vm(std) = 17.647 \times Y \times Vm \times \frac{(Pbar + DH/13.6)}{Tm}$$

Y = 1.004 Vm = 48.548 Pbar = 28.67
DH = 1.59 Tm = 547.0

Vm(std) = 45.271

Volume of Water Vapor Condensed

$$Vw(std) = 0.0471 \times (\text{net } H_2O \text{ gain})$$

Net H_2O = 152.1

Vw(std) = 7.164

Moisture Content

$$Bws = \frac{Vwc(std)}{Vwc(std) + Vm(std)}$$

Vw(std) = 7.164 Vm(std) = 45.271

Bws = 0.137

Client: American Electric Power Company
Facility: Mitchell Power Plant
Test Location: Unit 2 Stack
Run: 1
Date: 4/1/2010

Method 26A (HCl) Calculations

Average Duct Velocity

$$Vs = 85.49 \times Cp \times \text{Sqrt DP (avg)} \times (\text{Ts (avg)} / (Ps \times Ms))^{1/2}$$

Cp = 0.840 Ts (avg) = 582.6 Sqrt DP (avg): 0.793
Ps = 28.57 Ms = 28.63

Vs = 48.04

Volumetric Flow Rate (Actual Basis)

$$Q = Vs \times A \times 60$$

Vs = 48.04 A = 894.618

Q = 2578621

Volumetric Flow Rate (Standard Basis)

$$Qstd = 17.647 \times Q \times \frac{Ps}{\text{Ts (avg)}}$$

Q = 2578621 Ps = 28.57 Ts (avg) = 582.6

Qstd = 2231915

Volumetric Flow Rate (Standard Dry Basis)

$$Qstd(dry) = Qstd \times (1\text{-}Bws)$$

Qstd = 2231915 Bws = 0.137

Qstd(dry) = 1941766

Isokinetic Variation:

$$\%ISO = \frac{0.0945 \times Ts \times Vm(std)}{Vs \times \theta \times An \times Ps \times (1\text{-}Bws)}$$

Ts = 582.6 Vm(std) = 45.271 Vs = 48.040
An = 0.0003409 θ = 60.0 Ps = 28.57
Bws = 0.137

%ISO = 102.0

Client: American Electric Power Company
Facility: Mitchell Power Plant
Test Location: Unit 2 Stack
Run: 1
Date: 4/1/2010

Method 26A (HCl) Calculations

HCl Concentration:

$$\text{ug/dscm of HCl} = \frac{\text{ug of sample}}{\text{Vm(std)*0.028317}}$$

mg of HCl = 14.8590 Vm(std) = 45.271

ug/dscm of HCl = 11591.1400

HCl Emission Rate:

$$\text{ER lb/mmBtu} = \frac{\text{g of sample/453.6}}{\text{Vm (std)}} \times \text{Fd (dscf/mmBtu)} \times \frac{20.9}{(20.9\text{-}\%O_2)}$$

ER lb/mmBtu = 0.0101 lb/mmBtu

Client: American Electric Power Company
Facility: Mitchell Power Plant
Project #: M101301

Location: Unit 2 Stack
Date: 4/1/10

Sample Calculations

O2 %

$$(6.18\ \% - 0.01\ \%) \times \frac{11.99\ \%}{11.95\ \% - 0.01\ \%} = 6.20\ \%$$

CO2 %

$$(12.30\ \% - 0.06\ \%) \times \frac{9.83\ \%}{9.86\ \% - 0.06\ \%} = 12.30\ \%$$

$$C_{gas} = (C - C_o) \times \frac{C_{ma}}{C_m - C_o}$$

where:

C_{gas} = Effluent gas concentration, dry basis, ppm
C = Average gas concentration indicated by gas analyzer, dry basis, ppm
C_o = Average of initial and final system calibration bias check responses for the zero gas, ppm
C_m = Average of initital and final system calibration bias check responses for the upscale calibration gas, ppm
C_{ma} = Actual concentration of the upscale calibration gas, ppm

PLATT ENVIRONMENTAL SERVICES, INC.

Volumetric Flow Nomenclature

A = Cross-sectional area of stack or duct, ft^2

B_{ws} = Water vapor in gas stream, proportion by volume

C_p = Pitot tube coefficient, dimensionless

M_d = Dry molecular weight of gas, lb/lb-mole

M_s = Molecular weight of gas, wet basis, lb/lb-mole

M_w = Molecular weight of water, 18.0 lb/lb-mole

P_{bar} = Barometric pressure at testing site, in. Hg

P_g = Static pressure of gas, in. Hg (in. H_2O/13.6)

P_s = Absolute pressure of gas, in. Hg = $P_{bar} + P_g$

P_{std} = Standard absolute pressure, 29.92 in. Hg

Q_{acfm} = Actual volumetric gas flow rate, acfm

Q_{sd} = Dry volumetric gas flow rate corrected to standard conditions, dscf/hr

R = Ideal gas constant, 21.85 in. Hg-ft^3/°R-lb-mole

T_s = Absolute gas temperature, °R

T_{std} = Standard absolute temperature, 528°R

v_s = Gas velocity, ft/sec

$V_{w(std)}$ = Volume of water vapor in gas sample, corrected to standard conditions, scf

Y = Dry gas meter calibration factor

Δp = Velocity head of gas, in. H_2O

K_1 = 17.647 °R/in. Hg

%EA = Percent excess air

$\%CO_2$ = Percent carbon dioxide by volume, dry basis

$\%O_2$ = Percent oxygen by volume, dry basis

$\%N_2$ = Percent nitrogen by volume, dry basis

0.264 = Ratio of O_2 to N_2 in air, v/v

0.28 = Molecular weight of N_2 or CO, divided by 100

0.32 = Molecular weight of O_2 divided by 100

0.44 = Molecular weight of CO_2 divided by 100

13.6 = Specific gravity of mercury (Hg)

PLATT ENVIRONMENTAL SERVICES, INC.

Volumetric Air Flow Calculations

$$Vm\,(std) = 17.647 \times Vm \times \left[\frac{(P_{bar} + (\frac{DH}{13.6}))}{(460 + Tm)} \right] \times Y$$

$$Vw\,(std) = 0.0471 \times Vlc$$

$$Bws = \left[\frac{Vw\,(std)}{Vw\,(std) + Vm\,(std)} \right]$$

$$Md = (0.44 \times \%CO_2) + (0.32 \times \%O_2) + \left[0.28 \times (100 - \%CO_2 - \%O_2)\right]$$

$$Ms = Md \times (1 - Bws) + (18 \times Bws)$$

$$Vs = \sqrt{\frac{(Ts + 460)}{Ms \times Ps}} \times \sqrt{DP} \times Cp \times 85.49$$

$$Acfm = Vs \times Area\ (of\ stack\ or\ duct) \times 60$$

$$Scfm = Acfm \times 17.647 \times \left[\frac{Ps}{(460 + Ts)} \right]$$

$$Scfh = Scfm \times 60 \frac{min}{hr}$$

acfm = actual cubic feet per minute
scfm = standard cubic feet per minute
scfh = standard cubic feet per hour

Cp = pitot tube correction factor
Ps = absolute flue gas pressure
Ms = molecular weight of gas (lb/lb mole)
Md = dry molecular weight of gas (lb/lb mole)
Bws = water vapor in gas stream proportion by volume

PLATT ENVIRONMENTAL SERVICES, INC.

Particulate Nomenclature

A = Cross-sectional area of stack or duct, square feet
A_n = Cross-sectional area of nozzle, square feet
B_{ws} = Water vapor in gas stream, by volume
C_a = Acetone blank residue concentration, g/g
C_{acf} = Concentration of particulate matter in gas stream at actual conditions, gr/acf
C_p = Pitot tube coefficient
C_s = Concentration of particulate matter in gas stream, dry basis, corrected to standard conditions, gr/dscf
IKV = Isokinetic sampling variance, must be 90.0 % ≤ IKV ≤ 110.0%
M_d = Dry molecular weight of gas, lb/lb-mole
M_s = Molecular weight of gas, wet basis, lb/lb-mole
M_w = Molecular weight of water, 18.0 lb/lb-mole
m_a = Mass of residue of acetone after evaporation, grams
P_{bar} = Barometric pressure at testing site, inches mercury
P_g = Static pressure of gas, inches mercury (inches water/13.6)
P_s = Absolute pressure of gas, inches mercury = $P_{bar} + P_g$
P_{std} = Standard absolute pressure, 29.92 inches mercury
Q_{acfm} = Actual volumetric gas flow rate, acfm
Q_{sd} = Dry volumetric gas flow rate corrected to standard conditions, dscfh
R = Ideal gas constant, 21.85 inches mercury cubic foot/°R-lb-mole
T_m = Dry gas meter temperature, °R
T_s = Gas temperature, °R
T_{std} = Absolute temperature, 528°R
V_a = Volume of acetone blank, ml
V_{aw} = Volume of acetone used in wash, ml
W_a = Weight of residue in acetone wash, grams
m_n = Total amount of particulate matter collected, grams
V_{1c} = Total volume of liquid collected in impingers and silica gel, ml
V_m = Volume of gas sample as measured by dry gas meter, dcf
$V_{m(std)}$ = Volume of gas sample measured by dry gas meter, corrected to standard conditions, dscf
v_s = Gas velocity, ft/sec
$V_{w(std)}$ = Volume of water vapor in gas sample, corrected to standard conditions, scf
Y = Dry gas meter calibration factor
ΔH = Average pressure differential across the orifice meter, inches water
Δp = Velocity head of gas, inches water
ρ_a = Density of acetone, 0.7855 g/ml (average)
ρ_w = Density of water, 0.002201 lb/ml
θ = Total sampling time, minutes
K_1 = 17.647 °R/in. Hg
K_2 = 0.04707 ft^3/ml
K_4 = 0.09450/100 = 0.000945
K_p = Pitot tube constant, $85.49 \frac{\text{ft}}{\text{sec}}\left[\frac{(\text{lb/lb}-\text{mole})(\text{in. Hg})}{(^\circ\text{R})(\text{in. H}_2\text{O})}\right]^{1/2}$
%EA = Percent excess air
$\%CO_2$ = Percent carbon dioxide by volume, dry basis

$\%O_2$ = Percent oxygen by volume, dry basis
%CO = Percent carbon monoxide by volume, dry basis
$\%N_2$ = Percent nitrogen by volume, dry basis
0.264 = Ratio of O_2 to N_2 in air, v/v
28 = Molecular weight of N_2 or CO
32 = Molecular weight of O_2
44 = Molecular weight of CO_2
13.6 = Specific gravity of mercury (Hg)

PLATT ENVIRONMENTAL SERVICES, INC.

Particulates Calculation Formulas

1. $$V_{w(std)} = V_{lc}\left(\frac{\rho_w}{M_w}\right)\left(\frac{RT_{std}}{P_{std}}\right) = K_2 V_{lc}$$

2. $$V_{m(std)} = V_m Y \left(\frac{T_{std}}{T_m}\right)\left(\frac{(P_{bar} + (\frac{\Delta H}{13.6}))}{P_{std}}\right) = K_1 V_m Y \frac{(P_{bar} + (\frac{\Delta H}{13.6}))}{T_m}$$

3. $$B_{ws} = \frac{V_{w(std)}}{(V_{m(std)} + V_{w(std)})}$$

4. $$M_d = 0.44(\%CO_2) + 0.32(\%O_2) + 0.28(\%N_2)$$

5. $$M_s = M_d(1 - B_{ws}) + 18.0(B_{ws})$$

6. $$C_a = \frac{m_a}{V_a \rho_a}$$

7. $$W_a = C_a V_{aw} \rho_a$$

8. $$C_{acf} = 15.43 K_i \left(\frac{m_n P_s}{V_{w(std)} + V_{m(std)}\ T_s}\right)$$

9. $$C_S = (15.43\ \text{grains/gram})\ (m_n / V_{m(std)})$$

10. $$v_s = K_p C_p \sqrt{\frac{\Delta P\ T_s}{P_s M_s}}$$

11. $$Q_{acfm} = v_s A(60_{sec/min})$$

12. $$Q_{sd} = (3600_{sec/hr})(1 - B_{ws})\ v_s \left(\frac{T_{std} P_s}{T_s P_{std}}\right) A$$

13. $$E\ (\text{emission rate, lbs/hr}) = Q_{std}(C_s / 7000\ \text{grains/lb})$$

14. $$IKV = \frac{T_s V_{m(std)} P_{std}}{T_{std} v_s \theta A_n P_s 60(1 - B_{ws})} = K_4 \frac{T_s V_{m(std)}}{P_s v_s A_n \theta(1 - B_{ws})}$$

15. $$\%EA = \left(\frac{\%O_2 - (0.5\,\%CO)}{0.264\,\%N_2 - (\%O_2 - 0.5\,\%CO)}\right) \times 100$$

Maxxam Analytics — Driven by Service and Science

Your Project #: M101301
Site: AEP, MITCHELL
Your C.O.C. #: N/A

Attention: Eric Ehlers
Platt Environmental Inc
1520 Kensington Rd.
Suite 204
Oak Brook, IL
USA 60523-2139

Report Date: 2010/04/22

CERTIFICATE OF ANALYSIS

MAXXAM JOB #: B042760
Received: 2010/04/08, 12:30

Sample Matrix: Stack Sampling Train
Samples Received: 7

Analyses	Quantity	Date Extracted	Date Analyzed	Laboratory Method	Method Reference
Hydrogen Cyanide in Impingers	7	2010/04/20	2010/04/20		EPA CTM-33
Volume of Sodium Hydroxide Impinger	7	N/A	2010/04/22		

* RPDs calculated using raw data. The rounding of final results may result in the apparent difference.

Encryption Key

Mike Challis
22 Apr 2010 16:03:03 -04:00

Please direct all questions regarding this Certificate of Analysis to your Project Manager.

MIKE CHALLIS, CET, B.Sc, C.Chem, Customer Service Manager, US Air Toxics
Email: Mike.Challis@MaxxamAnalytics.com
Phone# (905) 817-5790

==

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Total cover pages: 1

Maxxam Analytics

Maxxam Job #: B042760
Report Date: 2010/04/22

Platt Environmental Inc
Client Project #: M101301
Project name: AEP, MITCHELL

EPA CTM 033 HYDROGEN CYANIDE (STACK SAMPLING TRAIN)

Maxxam ID		FO0628		FO0629	FO0630	FO0630		
Sampling Date		2010/03/31		2010/03/30	2010/03/30	2010/03/30		
COC Number		N/A		N/A	N/A	N/A		
	Units	REAGENT BLANK-NAOH	RDL	T#1-U1-STACK-NAOH	T#2-U1-STACK-NAOH	T#2-U1-STACK-NAOH Lab-Dup	RDL	QC Batch
Volume	ml	100	1	630	650	N/A	1	2130406
Cyanide (CN)	ug	(15.6) ND	100	(0) ND	(50.1) ND	(50.4) ND	300	2128870

N/A = Not Applicable
RDL = Reportable Detection Limit
QC Batch = Quality Control Batch

Maxxam ID		FO0631	FO0632	FO0633	FO0634		
Sampling Date		2010/03/30	2010/03/31	2010/03/31	2010/03/31		
COC Number		N/A	N/A	N/A	N/A		
	Units	T#3-U1-STACK-NAOH	T#1-U2-STACK-NAOH	T#2-U2-STACK-NAOH	T#3-U2-STACK-NAOH	RDL	QC Batch
Volume	ml	660	640	640	660	1	2130406
Cyanide (CN)	ug	(0) ND	(46.7) ND	(54.2) ND	(58.2) ND	300	2128870

N/A = Not Applicable
RDL = Reportable Detection Limit
QC Batch = Quality Control Batch

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Maxxam Job #: B042760
Report Date: 2010/04/22

Platt Environmental Inc
Client Project #: M101301
Project name: AEP, MITCHELL

Test Summary

Maxxam ID FO0628
Sample ID REAGENT BLANK-NAOH
Matrix Stack Sampling Train

Collected 2010/03/31
Shipped
Received 2010/04/08

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Hydrogen Cyanide in Impingers	IC	2128870	2010/04/20	2010/04/20	LLE
Volume of Sodium Hydroxide Impinger		2130406	N/A	2010/04/22	LLE

Maxxam ID FO0629
Sample ID T#1-U1-STACK-NAOH
Matrix Stack Sampling Train

Collected 2010/03/30
Shipped
Received 2010/04/08

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Hydrogen Cyanide in Impingers	IC	2128870	2010/04/20	2010/04/20	LLE
Volume of Sodium Hydroxide Impinger		2130406	N/A	2010/04/22	LLE

Maxxam ID FO0630
Sample ID T#2-U1-STACK-NAOH
Matrix Stack Sampling Train

Collected 2010/03/30
Shipped
Received 2010/04/08

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Hydrogen Cyanide in Impingers	IC	2128870	2010/04/20	2010/04/20	LLE
Volume of Sodium Hydroxide Impinger		2130406	N/A	2010/04/22	LLE

Maxxam ID FO0630 Dup
Sample ID T#2-U1-STACK-NAOH
Matrix Stack Sampling Train

Collected 2010/03/30
Shipped
Received 2010/04/08

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Hydrogen Cyanide in Impingers	IC	2128870	2010/04/20	2010/04/20	LLE

Maxxam ID FO0631
Sample ID T#3-U1-STACK-NAOH
Matrix Stack Sampling Train

Collected 2010/03/30
Shipped
Received 2010/04/08

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Hydrogen Cyanide in Impingers	IC	2128870	2010/04/20	2010/04/20	LLE
Volume of Sodium Hydroxide Impinger		2130406	N/A	2010/04/22	LLE

Maxxam ID FO0632
Sample ID T#1-U2-STACK-NAOH
Matrix Stack Sampling Train

Collected 2010/03/31
Shipped
Received 2010/04/08

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Hydrogen Cyanide in Impingers	IC	2128870	2010/04/20	2010/04/20	LLE
Volume of Sodium Hydroxide Impinger		2130406	N/A	2010/04/22	LLE

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Maxxam Analytics

Driven by Service and Science

Maxxam Job #: B042760
Report Date: 2010/04/22

Platt Environmental Inc
Client Project #: M101301
Project name: AEP, MITCHELL

Test Summary

Maxxam ID FO0633
Sample ID T#2-U2-STACK-NAOH
Matrix Stack Sampling Train

Collected 2010/03/31
Shipped
Received 2010/04/08

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Hydrogen Cyanide in Impingers	IC	2128870	2010/04/20	2010/04/20	LLE
Volume of Sodium Hydroxide Impinger		2130406	N/A	2010/04/22	LLE

Maxxam ID FO0634
Sample ID T#3-U2-STACK-NAOH
Matrix Stack Sampling Train

Collected 2010/03/31
Shipped
Received 2010/04/08

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Hydrogen Cyanide in Impingers	IC	2128870	2010/04/20	2010/04/20	LLE
Volume of Sodium Hydroxide Impinger		2130406	N/A	2010/04/22	LLE

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Maxxam Analytics

Driven by Service and Science

Maxxam Job #: B042760
Report Date: 2010/04/22

Platt Environmental Inc
Client Project #: M101301
Project name: AEP, MITCHELL

EPA CTM 033 HYDROGEN CYANIDE (STACK SAMPLING TRAIN)

Hydrogen Cyanide in Impingers: Negative peak noticed at Cyanide retention time, sample diluted and analyzed at higher dilution to confirm no matrix interference.

Results relate only to the items tested.

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Maxxam Analytics

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Platt Environmental Inc
Attention: Eric Ehlers
Client Project #: M101301
P.O. #:
Project name: AEP, MITCHELL

Quality Assurance Report

Maxxam Job Number: GB042760

QA/QC Batch Num Init	QC Type	Parameter	Date Analyzed yyyy/mm/dd	Value	%Recovery	Units	QC Limits
2128870 LLE	Matrix Spike (FO0630)	Cyanide (CN)	2010/04/20		99	%	80 - 120
	Spiked Blank	Cyanide (CN)	2010/04/20		102	%	90 - 110
	Method Blank	Cyanide (CN)	2010/04/20	(0) ND, RDL=100		ug	
	RPD - Sample/Sample Dup	Cyanide (CN)	2010/04/20	NC		%	20

Matrix Spike: A sample to which a known amount of the analyte of interest has been added. Used to evaluate sample matrix interference.
Spiked Blank: A blank matrix to which a known amount of the analyte has been added. Used to evaluate analyte recovery.
Method Blank: A blank matrix containing all reagents used in the analytical procedure. Used to identify laboratory contamination.
NC (RPD): The RPD was not calculated. The level of analyte detected in the parent sample and its duplicate was not sufficiently significant to permit a reliable calculation.

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Validation Signature Page

Maxxam Job #: B042760

The analytical data and all QC contained in this report were reviewed and validated by the following individual(s).

FRANK MO, B.Sc., Inorganic Lab. Manager

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Maxxam Analytics

Driven by Service and Science

Your Project #: M101301
Site: AEP, MITCHELL
Your C.O.C. #: N/A

Attention: Eric Ehlers
Platt Environmental Inc
1520 Kensington Rd.
Suite 204
Oak Brook, IL
USA 60523-2139

Report Date: 2010/05/10

CERTIFICATE OF ANALYSIS

MAXXAM JOB #: B050110
Received: 2010/04/26, 13:46

Sample Matrix: Stack Sampling Train
Samples Received: 7

Analyses	Quantity	Date Extracted	Date Analyzed	Laboratory Method	Method Reference
Hydrogen Halides in NaOH Imp. (1)	7	2010/05/03	2010/05/03	BRL SOP-00108	EPA Modified M26A

* RPDs calculated using raw data. The rounding of final results may result in the apparent difference.

(1) This test was performed in Maxxam Mississauga under Maxxam Burlington SCC Accreditation

Encryption Key

Mike Challis
10 May 2010 08:10:47 -04:00

Please direct all questions regarding this Certificate of Analysis to your Project Manager.

MIKE CHALLIS, CET, B.Sc, C.Chem, Customer Service Manager, US Air Toxics
Email: Mike.Challis@MaxxamAnalytics.com
Phone# (905) 817-5790

==
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Total cover pages: 1

Maxxam Analytics *Driven by Service and Science*

Maxxam Job #: B050110
Report Date: 2010/05/10

Platt Environmental Inc
Client Project #: M101301
Project name: AEP, MITCHELL

RESULTS OF ANALYSES OF STACK SAMPLING TRAIN

Maxxam ID		FR5649	FR5650		FR5651	FR5651		
Sampling Date		2010/03/31	2010/03/30		2010/03/30	2010/03/30		
COC Number		N/A	N/A		N/A	N/A		
	Units	REAGENT BLANK-NAOH	T#1-U1-STACK-NAOH	RDL	T#2-U1-STACK-NAOH	T#2-U1-STACK-NAOH Lab-Dup	RDL	QC Batch
Hydrochloric Acid	ug	(0) ND	(0) ND	18000	(0) ND	(0) ND	18000	2140262
Hydrofluoric Acid	ug	(0) ND	(0) ND	12000	(0) ND	(0) ND	60000	2140262

N/A = Not Applicable
RDL = Reportable Detection Limit
QC Batch = Quality Control Batch

Maxxam ID		FR5652	FR5653	FR5654	FR5655		
Sampling Date		2010/03/30	2010/03/31	2010/03/31	2010/03/31		
COC Number		N/A	N/A	N/A	N/A		
	Units	T#3-U1-STACK-NAOH	T#1-U2-STACK-NAOH	T#2-U2-STACK-NAOH	T#3-U2-STACK-NAOH	RDL	QC Batch
Hydrochloric Acid	ug	(0) ND	(14858.7000) ND	(0) ND	(0) ND	18000	2140262
Hydrofluoric Acid	ug	(0) ND	(0) ND	(0) ND	(0) ND	12000	2140262

N/A = Not Applicable
RDL = Reportable Detection Limit
QC Batch = Quality Control Batch

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Maxxam Analytics

Driven by Service and Science

Maxxam Job #: B050110
Report Date: 2010/05/10

Platt Environmental Inc
Client Project #: M101301
Project name: AEP, MITCHELL

Test Summary

Maxxam ID	FR5649	Collected	2010/03/31
Sample ID	REAGENT BLANK-NAOH	Shipped	
Matrix	Stack Sampling Train	Received	2010/04/26

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Hydrogen Halides in NaOH Imp.	IC/SPEC	2140262	2010/05/03	2010/05/03	A S

Maxxam ID	FR5650	Collected	2010/03/30
Sample ID	T#1-U1-STACK-NAOH	Shipped	
Matrix	Stack Sampling Train	Received	2010/04/26

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Hydrogen Halides in NaOH Imp.	IC/SPEC	2140262	2010/05/03	2010/05/03	A S

Maxxam ID	FR5651	Collected	2010/03/30
Sample ID	T#2-U1-STACK-NAOH	Shipped	
Matrix	Stack Sampling Train	Received	2010/04/26

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Hydrogen Halides in NaOH Imp.	IC/SPEC	2140262	2010/05/03	2010/05/03	A S

Maxxam ID	FR5651 Dup	Collected	2010/03/30
Sample ID	T#2-U1-STACK-NAOH	Shipped	
Matrix	Stack Sampling Train	Received	2010/04/26

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Hydrogen Halides in NaOH Imp.	IC/SPEC	2140262	2010/05/03	2010/05/03	A S

Maxxam ID	FR5652	Collected	2010/03/30
Sample ID	T#3-U1-STACK-NAOH	Shipped	
Matrix	Stack Sampling Train	Received	2010/04/26

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Hydrogen Halides in NaOH Imp.	IC/SPEC	2140262	2010/05/03	2010/05/03	A S

Maxxam ID	FR5653	Collected	2010/03/31
Sample ID	T#1-U2-STACK-NAOH	Shipped	
Matrix	Stack Sampling Train	Received	2010/04/26

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Hydrogen Halides in NaOH Imp.	IC/SPEC	2140262	2010/05/03	2010/05/03	A S

Maxxam ID	FR5654	Collected	2010/03/31
Sample ID	T#2-U2-STACK-NAOH	Shipped	
Matrix	Stack Sampling Train	Received	2010/04/26

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Hydrogen Halides in NaOH Imp.	IC/SPEC	2140262	2010/05/03	2010/05/03	A S

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Maxxam Analytics

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Maxxam Job #: B050110
Report Date: 2010/05/10

Platt Environmental Inc
Client Project #: M101301
Project name: AEP, MITCHELL

Test Summary

Maxxam ID	FR5655	Collected	2010/03/31
Sample ID	T#3-U2-STACK-NAOH	Shipped	
Matrix	Stack Sampling Train	Received	2010/04/26

Test Description	Instrumentation	Batch	Extracted	Analyzed	Analyst
Hydrogen Halides in NaOH Imp.	IC/SPEC	2140262	2010/05/03	2010/05/03	A S

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Maxxam Job #: B050110
Report Date: 2010/05/10

Platt Environmental Inc
Client Project #: M101301
Project name: AEP, MITCHELL

GENERAL COMMENTS

Results relate only to the items tested.

Maxxam Analytics

Driven by 2nd Science

Platt Environmental Inc
Attention: Eric Ehlers
Client Project #: M101301
P.O. #:
Project name: AEP, MITCHELL

Quality Assurance Report

Maxxam Job Number: GB050110

QA/QC Batch Num Init	QC Type	Parameter	Date Analyzed yyyy/mm/dd	Value	%Recovery	Units	QC Limits
2140262 A_S	Matrix Spike (FR5651)	Hydrochloric Acid	2010/05/03		109	%	80 - 120
		Hydrofluoric Acid	2010/05/03		83	%	80 - 120
	Spiked Blank	Hydrochloric Acid	2010/05/03		102	%	90 - 110
		Hydrofluoric Acid	2010/05/03		99	%	90 - 110
	Method Blank	Hydrochloric Acid	2010/05/03	(0) ND, RDL=18000		ug	
		Hydrofluoric Acid	2010/05/03	(0) ND, RDL=12000		ug	
	RPD - Sample/Sample Dup	Hydrochloric Acid	2010/05/03	NC		%	20
		Hydrofluoric Acid	2010/05/03	NC		%	20

Matrix Spike: A sample to which a known amount of the analyte of interest has been added. Used to evaluate sample matrix interference.
Spiked Blank: A blank matrix to which a known amount of the analyte has been added. Used to evaluate analyte recovery.
Method Blank: A blank matrix containing all reagents used in the analytical procedure. Used to identify laboratory contamination.
NC (RPD): The RPD was not calculated. The level of analyte detected in the parent sample and its duplicate was not sufficiently significant to permit a reliable calculation.

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Validation Signature Page

Maxxam Job #: B050110

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SGS

Analysis Report

April 16, 2010

PLATT ENVIRONMENTAL SERVICE
1905 S. MOUNT PROSPECT RD. - UNIT C
MOUNT PROSPECT IL 60018

ATTN: JENNA GHANMA

Client Sample ID:	ACG04	Sample ID By:	Platt Environmental Services
Date Sampled:	Apr 1, 2010	Sample Taken At:	Mitchell
Date Received:	Apr 5, 2010	Sample Taken By:	------
Product Description:	COAL	Sample ID:	Unit 2 Test 1 Coal Composite Sample
		Project Name/#:	M101301
		Customer:	American Electric Power

SGS Minerals Sample ID: 491-1044352-004

		Method	As Received	Dry	DAF
Moisture, Total %		ASTM D3302	5.16		
Ash %		ASTM D3174	10.70	11.28	
Volatile Matter %		ASTM D3175	32.59	34.36	
Fixed Carbon %		ASTM D3172 (by diff)	51.55	54.36	
Sulfur %		ASTM D4239 Method B	1.90	2.00	
Gross Calorific Value	BTU/LB	ASTM D5865	12647	13336	15032
Carbon %		ASTM D5373	71.16	75.03	
Hydrogen %		ASTM D5373	4.43	4.67	
Nitrogen %		ASTM D5373	1.55	1.64	
Oxygen %		ASTM D5373 (by diff)	5.10	5.38	
Chlorine, Cl %		ASTM D4208	0.11	0.11	
Fluorine, F UG/G		ASTM D3761	85	90.0	

Vanessa Chambliss

Vanessa Chambliss
Branch Manager

SGS

Analysis Report

April 16, 2010

PLATT ENVIRONMENTAL SERVICE
1905 S. MOUNT PROSPECT RD. - UNIT C
MOUNT PROSPECT IL 60018

ATTN: JENNA GHANMA

Client Sample ID:	ACG05	Sample ID By:	Platt Environmental Services
Date Sampled:	Apr 1, 2010	Sample Taken At:	Mitchell
Date Received:	Apr 5, 2010	Sample Taken By:	-------
Product Description:	COAL	Sample ID:	Unit 2 Test 2 Coal Composite Sample
		Project Name/#:	M101301
		Customer:	American Electric Power

SGS Minerals Sample ID: 491-1044352-005

		Method	As Received	Dry	DAF
Moisture, Total %		ASTM D3302	5.36		
Ash %		ASTM D3174	10.60	11.20	
Volatile Matter %		ASTM D3175	31.90	33.71	
Fixed Carbon %		ASTM D3172 (by diff)	52.14	55.09	
Sulfur %		ASTM D4239 Method B	1.93	2.04	
Gross Calorific Value	BTU/LB	ASTM D5865	12619	13334	15017
Carbon %		ASTM D5373	70.72	74.72	
Hydrogen %		ASTM D5373	4.30	4.55	
Nitrogen %		ASTM D5373	1.51	1.60	
Oxygen %		ASTM D5373 (by diff)	5.58	5.89	
Chlorine, Cl %		ASTM D4208	0.10	0.10	
Fluorine, F UG/G		ASTM D3761	83	88.0	

Vanessa Chambliss

Vanessa Chambliss
Branch Manager

SGS North America Inc. | Minerals Services Division
16130 Van Drunen Road South Holland t (708) 331-2900 f (708) 333-3060 www.sgs.com/minerals
Member of the SGS Group (Société Générale de Surveillance)

SGS

Analysis Report

April 16, 2010

PLATT ENVIRONMENTAL SERVICE
1905 S. MOUNT PROSPECT RD. - UNIT C
MOUNT PROSPECT IL 60018

ATTN: JENNA GHANMA

Client Sample ID:	ACG06	Sample ID By:	Platt Environmental Services
Date Sampled:	Apr 1, 2010	Sample Taken At:	Mitchell
Date Received:	Apr 5, 2010	Sample Taken By:	------
Product Description:	COAL	Sample ID:	Unit 2 Test 3 Coal Composite Sample
		Project Name/#:	M101301
		Customer:	American Electric Power

SGS Minerals Sample ID: 491-1044352-006

		Method	As Received	Dry	DAF
Moisture, Total %		ASTM D3302	4.97		
Ash %		ASTM D3174	11.44	12.04	
Volatile Matter %		ASTM D3175	32.35	34.04	
Fixed Carbon %		ASTM D3172 (by diff)	51.24	53.92	
Sulfur %		ASTM D4239 Method B	1.81	1.90	
Gross Calorific Value	BTU/LB	ASTM D5865	12525	13179	14984
Carbon %		ASTM D5373	70.41	74.09	
Hydrogen %		ASTM D5373	4.38	4.61	
Nitrogen %		ASTM D5373	1.53	1.61	
Oxygen %		ASTM D5373 (by diff)	5.46	5.75	
Chlorine, Cl %		ASTM D4208	0.09	0.09	
Fluorine, F UG/G		ASTM D3761	78	82.0	

Vanessa Chambliss

Vanessa Chambliss
Branch Manager

SGS North America Inc. | Minerals Services Division
16130 Van Drunen Road South Holland t (708) 331-2900 f (708) 333-3060 www.sgs.com/minerals

Client: American Electric Power Company
Facility: Mitchell Power Plant
Test Location: Unit 2 Stack
Test Method: 26A

Test 1		Test 2		Test 3	
% Hydrogen	4.43	% Hydrogen	4.30	% Hydrogen	4.38
% Carbon	71.16	% Carbon	70.72	% Carbon	70.41
% Sulfur	1.90	% Sulfur	1.93	% Sulfur	1.81
% Nitrogen	1.55	% Nitrogen	1.51	% Nitrogen	1.53
% Oxygen	5.10	% Oxygen	5.58	% Oxygen	5.46
HHV (Btu/lb)	12647	HHV (Btu/lb)	12619	HHV (Btu/lb)	12525
Fd(dscf/MMBtu)=	9801.06	Fd(dscf/MMBtu)=	9715.37	Fd(dscf/MMBtu)=	9772.84
Fc(scf/MMBtu)=	1806.15	Fc(scf/MMBtu)=	1798.96	Fc(scf/MMBtu)=	1804.52

AVERAGE FUEL FACTORS	
Fd(dscf/MMBtu)=	9763.09
Fc(scf/MMBtu)=	1803.21

Client:	American Electric Power Company	
Facility:	Mitchell Power Plant	
Test Location:	Unit 2 Stack	
Project #:	M1010301	
Test Method:	26A	
Test Engineer:	S. Dyra	
Test Technician:	R. Sollars/W. Mullenix	
lb/mmBtu Emissions by:	Calculated	
Type of Fuel Firing:	Coal, Sub-Bituminous	
Calculated Fuel Factor Fd, dscf/mmBtu:	9763.09	
Temp ID:	CM8	
Meter ID:	CM8	
Pitot ID:	075A	
Pitot Tube Coefficient:	0.840	
Probe Length:	12.0	ft
Probe Liner Material:	Glass	
Nozzle Diameter:	0.250	in.
Nozzle Kit ID Number and Material:	Glass	
Meter Calibration Factor (Y):	1.004	
Meter Orifice Setting (Delta H):	1.476	
Sample Plane:	Horizontal	
Port Length:	14.00	in.
Port Size (diameter):	6.00	in.
Port Type:	Flange	
Duct Shape:	Circular	
Diameter	33.75	ft
Duct Area:	894.618	Sq. Ft.
Upstream Diameters:	>2.0	
Downstream Diameters:	>8.0	
Number of Ports Sampled:	4	
Number of Points per Port:	3	
Minutes per Point:	5.0	
Minutes per Reading:	5.0	
Total Number of Traverse Points:	12	
Test Length:	60	min.
Train Type:	Anderson Box	
Source Condition:	Normal	
# of Runs	3	

Client: American Electric Power Company
Facility: Mitchell Power Plant
Test Location: Unit 2 Stack
Test Method: 26A

		Run 1	Run 2	Run 3
Identify Analyte:	Hydrogen Chloride (HCl)			
Molecular Weight:	36.45			
mg (net) collected:		18	18	18
Identify Analyte:	Hydrogen Fluoride (HF)			
Molecular Weight:	19.99			
mg (net) collected:		12	12	12
Identify Analyte:	Hydrogen Cyanide (HCN)			
Molecular Weight:	27.03			
mg (net) collected:		0.3	0.3	0.3

Run 1-Method 26A

Client:	American Electric Power Company	Date:	4/1/10
Facility:	Mitchell Power Plant	Start Time:	8:05
Test Location:	Unit 2 Stack	End Time:	9:21
Source Condition:	Normal		

DRY GAS METER CONDITIONS			STACK CONDITIONS		
ΔH:	1 59	in H_2O	Static Pressure	-1 30	in H_2O
Meter Temperature, Tm:	87 0	°F	Flue Pressure (Ps):	28 57	in. Hg abs.
Sqrt ΔP:	0.793	in. H_2O	Carbon Dioxide:	12 30	%
Stack Temperature, Ts:	122 6	°F	Oxygen:	6.20	%
Meter Volume, Vm:	48.548	ft^3	Nitrogen:	81 50	%
Meter Volume, Vmstd:	45 271	dscf	Gas Weight dry, Md:	30 216	lb/lb mole
Meter Volume, Vwstd:	7.164	wscf	Gas Weight wet, Ms:	28 628	lb/lb mole
Isokinetic Variance:	102.0	%I	Excess Air:	40.481	%
Calculated Fuel Factor Fd:	9,801 06	dscf/mmBtu	Gas Velocity, Vs:	48.040	fps
Test Length	60 00	in mins	Volumetric Flow:	2,578,621	acfm
Nozzle Diameter	0 250	in inches	Volumetric Flow:	1,941,766	dscfm
Barometric Pressure	28 67	in Hg	Volumetric Flow:	2,231,915	scfm
Calculated Fo:	1.20		Fo Validity:	Pass	

MOISTURE DETERMINATION

Initial Impinger Content:	2679.7	ml	Silica Initial Wt.	716 3
Final Impinger Content:	2827.6	ml	Silica Final Wt.	720.5
Difference:	147.9		Difference:	4.2

Total Water Gain: 152.1 Moisture, Bws: 0.137 Supersaturation Value, Bws: 0.130

Port-Point No.	>0.5 >2.0 Time	Velocity Head Δp In. H2O	Orifice ΔH In. H2O	Actual Meter Vol. ft^3	Sqrt. Δp	Stack Temp °F	Meter Temp Inlet °F	Meter Temp Outlet °F	Collected Vol. ft^3	Point Vel ft/sec
1-1	8:05:00	0.64	1.60	14.165	0.800	124	84	65	4.005	48.482
1-2	8:10:00	0.62	1.60	18.170	0.787	123	85	65	3.980	47.718
1-3	8:15:00	0.54	1.40	22.150	0.735	122	86	65	3.652	44.534
	8:20:00			25.802						
2-1	8:24:00	0.71	1.60	25.802	0.843	123	86	65	4.208	51.065
2-2	8:29.00	0.70	1.60	30.010	0.837	122	89	65	4.270	50.704
2-3	8:34:00	0.63	1.60	34.280	0.784	122	90	66	4.525	48.102
	8:39:00			38.805						
3-1	8:47:00	0.64	1.60	38.805	0.800	123	87	86	4.035	48.482
3-2	8:52.00	0.65	1.60	42.840	0.806	123	89	66	4.100	48.859
3-3	8:57:00	0.61	1.50	46.940	0.781	122	90	87	3.932	47.332
	9:02:00			50.872						
4-1	9.06:00	0.63	1.60	50.872	0.794	123	87	87	4.008	48.102
4-2	9:11:00	0.60	1.50	54.880	0.775	122	91	87	3.930	46.942
4-3	9:16:00	0.58	1 50	58.810	0.762	122	92	87	3.903	46.153
	9.21.00			62.713						
Total				48 548			88.0	85 9	48 548	
Average			1 59		0 793	122.6	87 0			

Run 2-Method 26A

Client:	American Electric Power Company	Date:	4/1/10
Facility:	Mitchell Power Plant	Start Time:	9:50
Location:	Unit 2 Stack	End Time:	11:04
Source Condition:	Normal		

DRY GAS METER CONDITIONS			STACK CONDITIONS		
ΔH:	1.55	in H_2O	Static Pressure	-1.20	in H_2O
Meter Temperature, Tm:	90.3	°F	Flue Pressure (Ps):	28.58	in. Hg abs
Sqrt ΔP:	0.777	in. H_2O	Carbon Dioxide:	12.80	%
Stack Temperature, Ts:	123.4	°F	Oxygen:	6.00	%
Meter Volume, Vm:	47.388	cf	Nitrogen:	81.2	%
Meter Volume, Vmstd:	43.916	dscf	Gas Weight dry, Md:	30.288	lb/lb mole
Meter Volume, Vwstd:	7.301	wscf	Gas Weight wet, Ms:	28.654	lb/lb mole
Isokinetic Variance:	101.4	%I	Excess Air:	38.868	%
Calculated Fuel Factor Fd:	9,715.37	dscf/mmBtu	Gas Velocity, Vs:	47.096	fps
Test Length	60.00	in mins.	Volumetric Flow:	2,527,999	acfm
Nozzle Diameter	0.250	in inches	Volumetric Flow:	1,894,660	dscfm
Barometric Pressure	28.67	in Hg	Volumetric Flow:	2,185,536	scfm
Calculated Fo:	1.16		Fo Validity:	Pass	

MOISTURE DETERMINATION

Initial Impinger Content:	2876.2	ml	Silica Initial Wt.	720.5
Final Impinger Content:	3028.1	ml	Silica Final Wt.	723.6
Difference:	151.9		Difference:	3.1

Total Water Gain: 155.0 Moisture, Bws: 0.143 Supersaturation Value, Bws: 0.133

Port-Point No.	>0.5 >2.0 Time	Velocity Head Δp In. H2O	Orifice ΔH In. H2O	Actual Meter Vol. ft^3	Sqrt. Δp	Stack Temp °F	Meter Temp Inlet °F	Meter Temp Outlet °F	Collected Vol. ft^3	Point Vel ft/sec
1-1	9:50:00	0.62	1.60	75.688	0.787	124	88	88	3.972	47.725
1-2	9:55:00	0.59	1.50	79.660	0.768	124	91	88	3.930	46.556
1-3	10:00:00	0.57	1.40	83.590	0.755	123	92	88	3.821	45.760
	10:05:00			87.411						
2-1	10:10:00	0.63	1.60	87.411	0.794	124	89	88	4.009	48.103
2-2	10:15:00	0.62	1.60	91.420	0.787	123	92	88	4.010	47.725
2-3	10:20:00	0.60	1.50	95.430	0.775	123	93	89	3.934	46.940
	10:25:00			99.364						
3-1	10:32:00	0.64	1.60	99.364	0.800	125	90	89	4.046	48.469
3-2	10:37:00	0.65	1.70	103.410	0.806	123	93	89	4.110	48.856
3-3	10:42:00	0.58		107.520	0.762	122	94	89	3.881	46.160
	10:47:00			111.401						
4-1	10:49:00	0.62	1.60	111.401	0.787	124	92	89	4.019	47.725
4-2	10:54:00	0.59	1.50	115.420	0.768	123	94	90	3.930	46.556
4-3	10:59:00	0.54	1.40	119.350	0.735	123	94	90	3.726	44.540
	11:04:00			123.076						
Total				47.388			91.8	88.8	47.388	
Average			1.55		0.777	123.4	90.3			

Run 3-Method 26A

Client:	American Electric Power Company	Date:	4/1/10
Facility:	Mitchell Power Plant	Start Time:	11:29
Location:	Unit 2 Stack	End Time:	12:44
Source Condition:	Normal		

DRY GAS METER CONDITIONS			STACK CONDITIONS		
ΔH:	1.60	in H_2O	Static Pressure	-1.20	in. H_2O
Meter Temperature, Tm:	91.8	°F	Flue Pressure (Ps):	28.58	in. Hg abs.
Sqrt ΔP:	0.763	in. H_2O	Carbon Dioxide:	12.80	%
Stack Temperature, Ts:	122.8	°F	Oxygen:	5.90	%
Meter Volume, Vm:	47.979	cf	Nitrogen:	81.3	%
Meter Volume, Vmstd:	44.349	dscf	Gas Weight dry, Md:	30.284	lb/lb mole
Meter Volume, Vwstd:	8.106	wscf	Gas Weight wet, Ms:	28.687	lb/lb mole
Isokinetic Variance:	101.3	%I	Excess Air:	37.910	%
Calculated Fuel Factor Fd:	9,772.84	dscf/mmBtu	Gas Velocity, Vs:	47.425	fps
Test Length	60.00	in mins.	Volumetric Flow:	2,545,660	acfm
Nozzle Diameter	0.250	in inches	Volumetric Flow:	1,916,816	dscfm
Barometric Pressure	28.67	in Hg	Volumetric Flow:	2,203,007	scfm
Calculated Fo:	1.17		Fo Validity:	Pass	

MOISTURE DETERMINATION

Initial Impinger Content:	2943.9	ml	Silica Initial Wt.	723.6
Final Impinger Content:	3113.1	ml	Silica Final Wt.	726.5
Difference:	169.2		Difference:	2.9

Total Water Gain: 172.1 Moisture, Bws: 0.155 Supersaturation Value, Bws: 0.130

Port-Point No.	>0.5 >2.0 Time	Velocity Head Δp in. H2O	Orifice ΔH in. H2O	Actual Meter Vol. ft^3	Sqrt. Δp	Stack Temp °F	Meter Temp Inlet °F	Meter Temp Outlet °F	Collected Vol. ft^3	Point Vel ft/sec
1-1	11:20:00	0.62	1.60	36.155	0.787	124	91	90	4.015	47.673
1-2	11:34:00	0.59	1.50	40.170	0.768	124	94	90	3.890	46.505
1-3	11:39:00	0.55	1.40	44.060	0.742	122	94	90	3.792	44.901
	11:44:00			47.852						
2-1	11:47:00	0.67	1.70	47.852	0.819	123	92	91	4.158	49.558
2-2	11:52:00	0.65	1.70	52.010	0.806	123	95	91	4.150	48.813
2-3	11:57.00	0.58	1.70	56.160	0.762	121	95	91	3.883	46.110
	12:02.00			60.043						
3-1	12:11:00	0.65	1.70	60.043	0.806	123	91	91	4.097	48.813
3-2	12:16.00	0.63	1.60	64.140	0.794	123	93	91	4.070	48.056
3-3	12:21:00	0.61	1.60	68.210	0.781	123	93	91	3.993	47.267
	12:26:00			72.203						
4-1	12:29:00	0.65	1.70	72.203	0.806	123	91	91	4.117	48.813
4-2	12:34:00	0.62	1.60	76.320	0.787	123	93	91	3.990	47.673
4-3	12:39.00	0.55	1.40	80.310	0.742	122	92	91	3.824	44.901
	12:44:00			84.134						
Total				47.979			92.8	90.8	47.979	
Average			1.60		0.763	122.8	91.8			

Client: American Electric Power Company Location: Unit 2 Stack
Facility: Mitchell Power Plant Date: 4/1/10
Project #: M101301

Hour 1						Hour 2					
Time	O2 %	CO2 %	Time	O2 %	CO2 %	Time	O2 %	CO2 %	Time	O2 %	CO2 %
8:05	6.40	12.11	8:35	6.10	12.37	9:05	6.00	12.45			
8:06	6.41	12.09	8:36	6.10	12.36	9:06	5.98	12.47			
8:07	6.44	12.07	8:37	6.17	12.30	9:07	5.95	12.48			
8:08	6.35	12.15	8:38	6.19	12.29	9:08	5.97	12.46			
8:09	6.27	12.22	8:39	6.19	12.29	9:09	5.97	12.48			
8:10	6.27	12.22	8:40	6.16	12.32	9:10	6.00	12.45			
8:11	6.28	12.21	8:41	6.13	12.34	9:11	5.99	12.43			
8:12	6.35	12.15	8:42	6.12	12.35	9:12	5.93	12.49			
8:13	6.38	12.13	8:43	6.09	12.38	9:13	5.93	12.48			
8:14	6.35	12.15	8:44	6.09	12.37	9:14	5.95	12.48			
8:15	6.36	12.14	8:45	6.07	12.39	9:15	5.97	12.46			
8:16	6.31	12.19	8:46	6.08	12.39	9:16	5.96	12.48			
8:17	6.28	12.21	8:47	6.09	12.38	9:17	5.95	12.48			
8:18	6.27	12.22	8:48	6.06	12.40	9:18	5.97	12.46			
8:19	6.29	12.21	8:49	6.11	12.36	9:19	5.94	12.50			
8:20	6.27	12.23	8:50	6.10	12.37	9:20	5.93	12.50			
8:21	6.24	12.25	8:51	6.10	12.37	9:21	5.90	12.53			
8:22	6.26	12.23	8:52	6.06	12.40						
8:23	6.24	12.25	8:53	6.06	12.40						
8:24	6.27	12.22	8:54	6.04	12.42						
8:25	6.23	12.25	8:55	6.02	12.43						
8:26	6.26	12.23	8:56	6.03	12.43						
8:27	6.25	12.24	8:57	5.99	12.46						
8:28	6.24	12.25	8:58	6.01	12.45						
8:29	6.20	12.28	8:59	6.03	12.43						
8:30	6.16	12.31	9:00	6.02	12.43						
8:31	6.13	12.33	9:01	6.01	12.44						
8:32	6.17	12.31	9:02	6.01	12.44						
8:33	6.16	12.31	9:03	6.03	12.42						
8:34	6.15	12.32	9:04	6.02	12.43						

Average	6.18	12.30
Min	5.99	12.07
Max	6.44	12.46

Client: American Electric Power Company
Facility: Mitchell Power Plant
Project #: M101301

Location: Unit 2 Stack
Date: 4/1/10

Time	O2 %	CO2 %	Time	O2 %	CO2 %	Time	O2 %	CO2 %	Time	O2 %	CO2 %
	Hour 3						Hour 4				
9:50	5.89	12.71	10:20	5.98	12.75	10:50	5.93	12.80			
9:51	5.89	12.73	10:21	5.95	12.79	10:51	5.89	12.83			
9:52	5.91	12.74	10:22	5.97	12.77	10:52	5.86	12.85			
9:53	5.93	12.73	10:23	5.99	12.75	10:53	5.93	12.80			
9:54	5.94	12.74	10:24	5.96	12.78	10:54	5.89	12.84			
9:55	5.93	12.76	10:25	5.91	12.82	10:55	5.87	12.86			
9:56	5.89	12.80	10:26	5.92	12.81	10:56	5.91	12.82			
9:57	5.92	12.79	10:27	5.93	12.81	10:57	5.94	12.80			
9:58	5.85	12.84	10:28	5.88	12.84	10:58	5.91	12.82			
9:59	5.89	12.82	10:29	5.89	12.82	10:59	5.86	12.86			
10:00	5.92	12.80	10:30	5.93	12.79	11:00	5.85	12.87			
10:01	5.91	12.80	10:31	5.92	12.79	11:01	5.88	12.85			
10:02	5.92	12.80	10:32	5.92	12.77	11:02	5.88	12.85			
10:03	5.94	12.78	10:33	5.92	12.78	11:03	5.91	12.82			
10:04	5.94	12.78	10:34	5.97	12.75	11:04	5.89	12.83			
10:05	5.96	12.77	10:35	5.97	12.76						
10:06	5.97	12.77	10:36	5.99	12.74						
10:07	5.96	12.77	10:37	5.99	12.74						
10:08	5.97	12.77	10:38	5.97	12.77						
10:09	5.95	12.78	10:39	5.95	12.77						
10:10	6.00	12.74	10:40	6.01	12.72						
10:11	6.00	12.74	10:41	6.03	12.72						
10:12	5.99	12.75	10:42	6.07	12.67						
10:13	5.95	12.78	10:43	5.99	12.74						
10:14	5.94	12.79	10:44	5.98	12.75						
10:15	5.96	12.77	10:45	6.01	12.73						
10:16	5.98	12.75	10:46	5.98	12.76						
10:17	5.98	12.76	10:47	5.96	12.78						
10:18	6.00	12.74	10:48	5.95	12.78						
10:19	5.98	12.75	10:49	5.97	12.77						
									Average	5.95	12.80
									Min	5.85	12.67
									Max	6.07	12.84

Client: American Electric Power Company
Facility: Mitchell Power Plant
Project #: M101301

Location: Unit 2 Stack
Date: 4/1/10

		Hour 5						Hour 6			
Time	O2 %	CO2 %	Time	O2 %	CO2 %	Time	O2 %	CO2 %	Time	O2 %	CO2 %
11:29	5.86	12.86	11:59	5.89	12.84	12:29	5.93	12.79			
11:30	5.90	12.84	12:00	5.90	12.83	12:30	5.93	12.79			
11:31	5.86	12.88	12:01	5.89	12.84	12:31	5.91	12.81			
11:32	5.87	12.86	12:02	5.89	12.84	12:32	5.86	12.85			
11:33	5.88	12.85	12:03	5.85	12.87	12:33	5.82	12.89			
11:34	5.90	12.85	12:04	5.88	12.84	12:34	5.82	12.88			
11:35	5.88	12.86	12:05	5.86	12.85	12:35	5.86	12.85			
11:36	5.87	12.86	12:06	5.84	12.87	12:36	5.87	12.84			
11:37	5.87	12.86	12:07	5.87	12.84	12:37	5.88	12.83			
11:38	5.86	12.87	12:08	5.87	12.84	12:38	5.89	12.82			
11:39	5.87	12.86	12:09	5.88	12.84	12:39	5.89	12.82			
11:40	5.88	12.85	12:10	5.89	12.83	12:40	5.88	12.83			
11:41	5.89	12.84	12:11	5.88	12.84	12:41	5.92	12.80			
11:42	5.87	12.85	12:12	5.95	12.79	12:42	5.96	12.77			
11:43	5.87	12.85	12:13	5.96	12.78	12:43	5.94	12.77			
11:44	5.87	12.85	12:14	5.97	12.77	12:44	5.95	12.77			
11:45	5.90	12.83	12:15	5.91	12.82						
11:46	5.94	12.80	12:16	5.88	12.85						
11:47	5.93	12.81	12:17	5.92	12.81						
11:48	5.91	12.82	12:18	5.92	12.81						
11:49	5.92	12.81	12:19	5.92	12.81						
11:50	5.95	12.79	12:20	5.92	12.81						
11:51	5.93	12.80	12:21	5.91	12.82						
11:52	5.86	12.86	12:22	5.92	12.81						
11:53	5.90	12.82	12:23	5.91	12.82						
11:54	5.88	12.84	12:24	5.90	12.83						
11:55	5.86	12.86	12:25	5.89	12.83						
11:56	5.86	12.87	12:26	5.90	12.82						
11:57	5.85	12.87	12:27	5.94	12.79						
11:58	5.87	12.85	12:28	5.89	12.84						
									Average	5.89	12.80
									Min	5.84	12.77
									Max	5.97	12.88

PLATT ENVIRONMENTAL SERVICES, INC.

Procedures for Calibration

Dry Gas Meters

The test meters are calibrated according to Method 5, Section 5.3 and "Procedures for Calibrating and Using Dry Gas Volume Meters as Calibration Standards" by P.R. Westlin and R.T. Shigehara, March 10, 1978.

Analytical Balance

The accuracy of the analytical balance is checked with Class S, Stainless Steel Type 303 weights manufactured by F. Hopken and Son, Jersey City, New Jersey.

Temperature Sensing Devices

The potentiometer and thermocouples are calibrated utilizing a NBS traceable millivolt source.

Nozzles

The nozzles are measured according to Method 5, Section 5.1.

Pitot Tubes

The pitot tubes used during this test program are fabricated according to the specification described and illustrated in the Code of Federal Regulations, Title 40, Part 60, Appendix A, Methods 1 through 5 as published in the Federal Register, Volume 42, No. 160; hereafter referred to by the appropriate method number. The pitot tubes comply with the alignment specifications in Method 2, Section 4; and the pitot tube assemblies are in compliance with specifications in the same section.

Stack Temperature Sensor Calibration

Meter Box # : CM8 *Name :* P. Platt

Ambient Temperature : 65 °F *Date :* March 22, 2010

Calibrator Model # : CL23A

Serial # : T-249465

Date Of Certification : September 22, 2006

Primary Standards Directly Traceable National Institute of Standards and Technology (NIST)

Reference Source Temperature (° F)	Test Thermometer Temperature (° F)	Temperature Difference %
0	-2	0.4
250	249	0.1
600	601	0.1
1200	1209	0.5

$$\frac{(\text{Ref. Temp., °F} + 460) - (\text{Test Therm. Temp., °F} + 460)}{\text{Ref. Temp., °F} + 460} * 100 <= 1.5\ \%$$

Meter Box Calibration

Dry Gas Meter No.	CM8	Date:	March 22, 2010
Standard Meter No.	4819699	Calibrated By:	P. Platt
Standard Meter (Y)	1.0008	Barometric Pressure:	29.29

Run Number		Orifice Setting in H_2O Chg (H)	Standard Meter Gas Volume vr	Dry Gas Meter Gas Volume vd	Standard Meter Temp. F° tr	Dry Gas Meter Inlet Temp. F° tdi	Dry Gas Meter Outlet Temp. F° tdo	Dry Gas Meter Avg. Temp. F° td	Time Min	Time Sec	Y	Chg (H)
Final			579.453	13.074	61	64	62					
Initial			574.309	7.932	59	64	61					
Difference	1	0.20	5.144	5.142	60	64	62	63	18	30	1.005	1.447
Final			585.311	18.944	61	65	62					
Initial			579.777	13.415	61	63	62					
Difference	2	0.50	5.534	5.529	61	64	62	63	12	30	1.003	1.432
Final			590.976	24.613	62	65	63					
Initial			585.520	19.172	61	65	63					
Difference	3	0.70	5.456	5.441	62	65	63	64	10	30	1.006	1.455
Final			597.025	30.677	61	65	63					
Initial			591.565	25.200	62	64	63					
Difference	4	0.90	5.460	5.477	62	65	63	64	9	15	0.999	1.451
Final			603.253	36.889	62	68	64					
Initial			597.710	31.335	62	65	63					
Difference	5	1.20	5.543	5.554	62	67	64	65	8	15	1.001	1.492
Final			574.095	7.700	59	67	61					
Initial			568.848	2.489	59	67	60					
Difference	6	2.00	5.247	5.211	59	67	61	64	6	15	1.011	1.578

Average 1.004 1.476

Stack Temperature Sensor Calibration

Meter Box # : CM 8 *Name :* JEA

Ambient Temperature : 64 °F *Date :* April 16, 2010

Calibrator Model # : CL23A

Serial # : T-249465

Date Of Certification : September 22, 2006

Primary Standards Directly Traceable National Institute of Standards and Technology (NIST)

Reference Source Temperature (° F)	Test Thermometer Temperature (° F)	Temperature Difference %
0	-2	0.4
250	251	0.1
600	602	0.2
1200	1208	0.5

$$\frac{(\text{Ref. Temp., °F} + 460) - (\text{Test Therm. Temp., °F} + 460)}{\text{Ref. Temp., °F} + 460} * 100 <= 1.5\ \%$$

Meter Box Calibration

Dry Gas Meter No.	CM 8	Date:	April 16, 2010
Standard Meter No.	4319699	Calibrated By:	JEA
Standard Meter (Y)	1.0008	Barometric Pressure:	29.41

Run Number		Orifice Setting in H_2O Chg (H)	Standard Meter Gas Volume vr	Dry Gas Meter Gas Volume vd	Standard Meter Temp. F° tr	Dry Gas Meter Inlet Temp. F° tdi	Dry Gas Meter Outlet Temp. F° tdo	Dry Gas Meter Avg. Temp. F° td	Time Min	Time Sec	Y	Chg (H)
Final			89.613	56.100	63	66	66					
Initial			84.003	50.471	63	65	65					
Difference	1	0.20	5.610	5.629	63	66	66	66	19	18	1.001	1.327
Final			95.731	62.227	63	67	67					
Initial			89.807	56.292	63	66	66					
Difference	2	0.50	5.924	5.935	63	67	67	67	13	40	1.004	1.489
Final			101.467	67.968	64	69	67					
Initial			95.847	62.336	64	68	67					
Difference	3	0.70	5.620	5.632	64	69	67	68	11	1	1.003	1.507
Final			107.942	74.457	64	70	67					
Initial			101.628	68.152	64	69	67					
Difference	4	0.90	6.314	6.305	64	70	67	68	11	0	1.007	1.529
Final			115.530	82.077	64	69	68					
Initial			108.097	74.620	63	69	67					
Difference	5	1.20	7.433	7.457	64	69	68	68	11	15	1.003	1.536
Final			83.903	50.373	63	65	64					
Initial			77.138	43.649	63	66	64					
Difference	6	2.00	6.765	6.724	63	66	64	65	8	0	1.004	1.570
									Average		1.004	1.493

Platt Environmental Services, Inc.

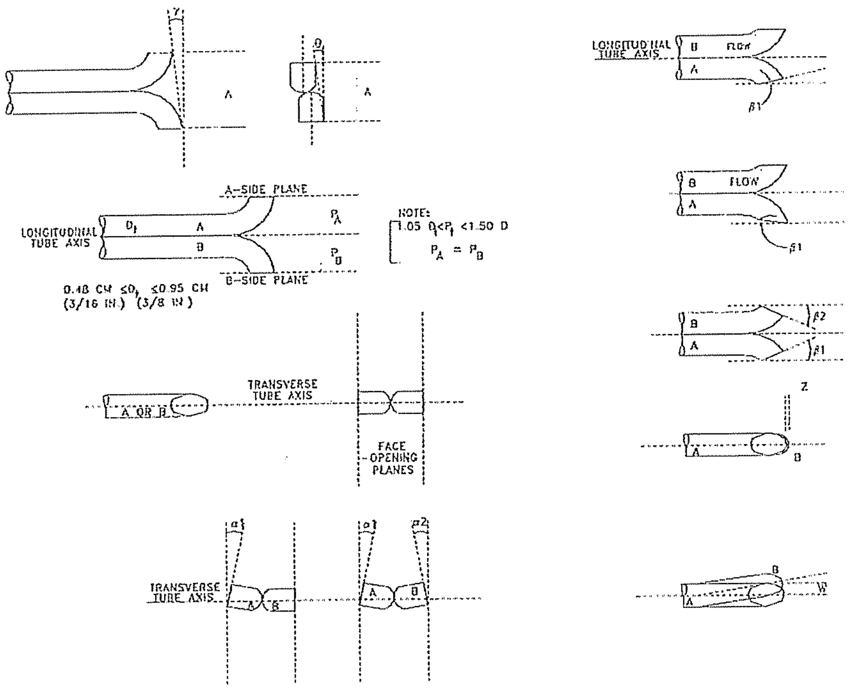
1520 Kensington Road, Suite 204
Oak Brook, IL 60523-2141
630-521-9400
630-521-9494 fax

Nozzle Calibration Sheet
Set No. 2 Glass

Nominal Diameter	0.120	0.150	0.200	0.230	0.250	0.275	0.310	0.375	0.425	0.500	Other
Nozzle Diameter	0.120	0.153	.199	.233	0.250	.274	.316	.368	0.431	0.499	
Nozzle Identification Number											

S TYPE PITOT TUBE INSPECTION FORM

Pitot Tube No 75 Date: 3/15/2010 Inspectors Name: SD



Pitot tube assembly level? x yes ___ no

Pitot tube openings damaged? ___ yes (explain below) x no

a_1 = 0 ° (<10°), a_2 = 0 ° (<10°) z = A sin g = 0.016 (in.); (<0.125 in.)

b_1 = 1 ° (<5°), b_2 = 0.5 ° (<5°) w = A sin q = 0.024 (in.); (<0.03125 in.)

γ = 1 °, θ = 1.5 °, A = 0.929 (in.) P_A = 0.464 (in.), P_B = 0.465 (in.), D_t = 0.375 (in.)

Calibration required? ___ yes x no

Client: American Electric Power Company
Facility: Mitchell Power Plant
Fuel Type: Coal, Sub-Bituminous
Fuel Factor: 9763 09
Diluent: O2 %

Location: Unit 2 Stack
Date: 4/1/10
Operator: J. Robertson
Project #: M101301
Fuel Factor: by Calculated

O2 % Correction Data

Run #	Cma	Precal	Postcal	Pre zero	Post zero	Co	Cm	C	Cgas	Span Bias	Span Drift	Zero Bias	Zero Drift
1	11.99	11.96	11.94	0.02	0.00	0.01	11.95	6.18	6.2	0.09	-0.09	0.09	-0.09
2	11.99	11.94	11.92	0.00	0.00	0.00	11.93	5.95	6.0	0.18	-0.09	0.09	0.00
3	11.99	11.92	11.91	0.00	-0.01	-0.01	11.92	5.89	5.9	0.23	-0.05	0.14	-0.05

CO2 % Correction Data

Run #	Cma	Precal	Postcal	Pre zero	Post zero	Co	Cm	C	Cgas	Span Bias	Span Drift	Zero Bias	Zero Drift
1	9.83	9.85	9.86	0.05	0.06	0.06	9.86	12.30	12.3	-0.05	0.05	-0.05	0.05
2	9.83	9.86	9.88	0.06	0.10	0.08	9.87	12.80	12.8	-0.16	0.11	-0.27	0.21
3	9.83	9.88	9.90	0.10	0.12	0.11	9.89	12.80	12.8	-0.27	0.11	-0.37	0.11

Cma = Concentration of Cal Gas
Cm=Average Pre and Post Span
C = Average value of test
Cgas = Corrected gas value of test
Co=Average Pre and Post Zero

Calibration Corrected Data

Hour #	Run Date	Start Time	End Time	CO2 %	O2 %
1 & 2	4/1/10	8:05	9:21	12.3	6.2
3 & 4	4/1/10	9:50	11:04	12.8	6.0
5 & 6	4/1/10	11:29	12:44	12.8	5.9

Client: American Electric Power Company
Facility: Mitchell Power Plant
Location: Unit 2 Stack
Date: 4/1/10
Project #: M101301

Linearity Cal/Pre 1 Cal

Time	O2 %		CO2 %	
7:40	21.90	ih	18.67	ih
7:41	14.19		10.68	
7:42	0.07		0.09	
7:43	0.02	iz	0.05	iz
7:44	8.27		6.12	
7:45	11.96		10.01	
7:46	11.96		10.02	
7:47	11.96		10.02	
7:48	11.96		10.00	
7:49	11.96	im	9.85	im

7:40	21.90		18.67	
7:41	14.19		10.68	
7:42	0.07		0.09	
7:43	0.02	z	0.05	z
7:44	8.27		6.12	
7:45	11.96		10.01	
7:46	11.96		10.02	
7:47	11.96		10.02	
7:48	11.96		10.00	
7:49	11.96	m	9.85	m

Client: American Electric Power Company
Facility: Mitchell Power Plant
Project #: M101301
Location: Unit 2 Stack
Date: 4/1/10

Post 1/Pre 2

Time	O2 %		CO2 %	
9:42	11.94	m	9.86	m
9:43	7.79		4.99	
9:44	0.02		0.08	
9:45	0.00	z	0.06	z

Post 2/Pre 3

Time	O2 %		CO2 %	
11:12	0.00	z	0.10	z
11:13	6.22		4.74	
11:14	11.92		9.87	
11:15	11.92	m	9.88	m

Post 3

Time	O2 %		CO2 %	
12:52	11.90		9.89	
12:53	11.91	m	9.90	m
12:54	9.20		4.16	
12:55	0.02		0.14	
12:56	0.00		0.13	
12:57	-0.01	z	0.12	z

Client: American Electric Power Company
Facility: Mitchell Power Plant
Project #: M101301

Location: Unit 2 Stack
Date: 4/1/10
Operator: J. Robertson

Calibration Gases

Type	Setting	Cylinder ID	Cylinder Value	Analyzer Response	Difference, % of Span	Expiration Date	Final Bottle Pressure, PSI
O2 %	Zero		0.000	0.02	-0.09%		
	Mid	CC114878	11.990	11.96	0.14%	3/1/2013	
	High	CC97654	21.900	21.90	0.00%	3/1/2013	
CO2 %	Zero		0.000	0.05	-0.27%		
	Mid	CC114878	9.827	9.85	-0.12%	3/1/2013	
	High	CC97654	18.720	18.67	0.27%	3/1/2013	

Response Time Data

Type	RM Analyzer s/n	Analyzer Span	RM Gas Span
O2 %	01440D1/3790	25	21.9
CO2 %	01440D1/3790	20	18.72
	Start	95% Response	Time (min)
Upscale			2
Downscale			2

Airgas

Airgas Specialty Gases
12722 S. Wentworth Avenue
Chicago IL 60628
1-773-785-3000
FAX 1-773-785-1928
http://www.airgas.com

CERTIFICATE OF ANALYSIS
Grade of Product: EPA Protocol

Part Number:	E03NI78E15A1066	Reference Number:	54-124210051-3
Cylinder Number:	CC114878	Cylinder Volume:	151 Cu.Ft.
Laboratory:	ASG - Chicago - IL	Cylinder Pressure:	2015 PSIG
Analysis Date:	Mar 01, 2010	Valve Outlet:	590

Expiration Date: Mar 01, 2013

Certification performed in accordance with "EPA Traceability Protocol (Sept. 1997)" using the assay procedures listed. Analytical Methodology does not require correction for analytical interferences. This cylinder has a total analytical uncertainty as stated below with a confidence level of 95%. There are no significant impurities which effect the use of this calibration mixture. All concentrations are on a volume/volume basis unless otherwise noted.
Do Not Use This Cylinder below 150 psig.i.e. 1 Mega Pascal

ANALYTICAL RESULTS

Component	Requested Concentration	Actual Concentration	Protocol Method	Total Relative Uncertainty
CARBON DIOXIDE	10.00 %	9.827 %	G1	+/- 1% NIST Traceable
OXYGEN	12.00 %	11.99 %	G1	+/- 1% NIST Traceable
NITROGEN	Balance			

CALIBRATION STANDARDS

Type	Lot ID	Cylinder No	Concentration	Expiration Date
NTRM/CO2	1	CC59142	13.78% CARBON DIOXIDE/	Oct 02, 2012
NTRM/O2	981202	CC73607	14.84% OXYGEN/	Oct 02, 2012

ANALYTICAL EQUIPMENT

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
HORIBA 510	NDIR	Feb 17, 2010
HORIBA MPA-510	Paramagnetic	Feb 17, 2010

Triad Data Available Upon Request

Notes:

Curt Stewart

Approved for Release

Airgas

Airgas Specialty Gases
12722 S. Wentworth Avenue
Chicago IL 60628
1-773-785-3000
FAX 1-773-785-1928
http://www.airgas.com

CERTIFICATE OF ANALYSIS
Grade of Product: EPA Protocol

Part Number:	E03NI59E15A3452	Reference Number:	54-124210051-2
Cylinder Number:	CC97654	Cylinder Volume:	159 Cu.Ft.
Laboratory:	ASG - Chicago - IL	Cylinder Pressure:	2015 PSIG
Analysis Date:	Mar 01, 2010	Valve Outlet:	590

Expiration Date: Mar 01, 2013

Certification performed in accordance with "EPA Traceability Protocol (Sept. 1997)" using the assay procedures listed. Analytical Methodology does not require correction for analytical interferences. This cylinder has a total analytical uncertainty as stated below with a confidence level of 95%. There are no significant impurities which affect the use of this calibration mixture. All concentrations are on a volume/volume basis unless otherwise noted.
Do Not Use This Cylinder below 150 psig.i.e. 1 Mega Pascal

ANALYTICAL RESULTS

Component	Requested Concentration	Actual Concentration	Protocol Method	Total Relative Uncertainty
CARBON DIOXIDE	19.00 %	18.72 %	G1	+/- 1% NIST Traceable
OXYGEN	22.00 %	21.90 %	G1	+/- 1% NIST Traceable
NITROGEN	Balance			

CALIBRATION STANDARDS

Type	Lot ID	Cylinder No	Concentration	Expiration Date
NTRM/O2	60608	CC207980	22.51% OXYGEN/NITROGEN	May 01, 2010
NTRM/CO2	80613	CC256428	20.09% CARBON DIOXIDE/NITROGEN	Jul 15, 2012

ANALYTICAL EQUIPMENT

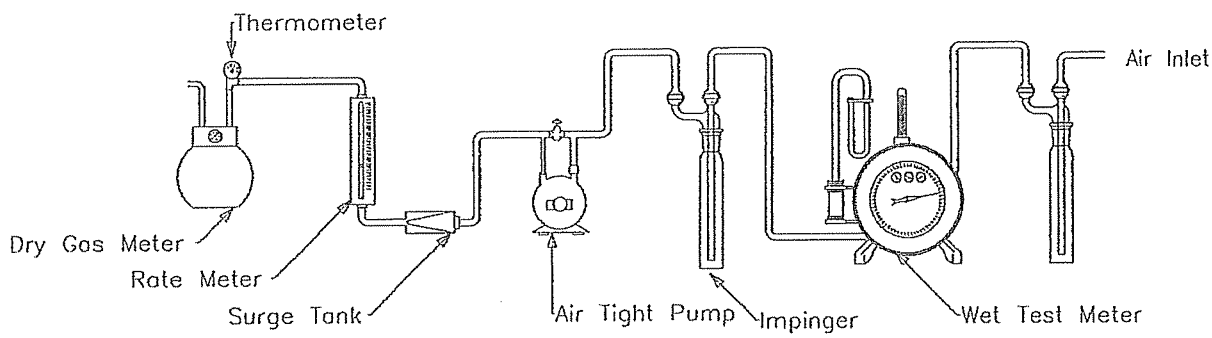
Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
HORIBA 510	NDIR	Feb 17, 2010
Thermo 6700	FTIR	Feb 17, 2010

Triad Data Available Upon Request

Notes:

Approved for Release

Dry Gas Meter Calibration Sample Train Diagram



Isokinetic Sampling Cover Sheet

Test Engineer: S. DYRA
Test Technician: R. SOLLARS / W. MULLINEY

Plant Information

Run Number: #1
Test Location: UNIT 2 STACK
Duct Shape: Circular or Rectangular
Flue Area: 894.618
Port Type: FLANGE
Test Method: M26A

Date: 4/1/10
Client Name: AEP
Length: N/A Width: N/A or Diameter: 33.75
Upstream Diameters: 7.20
Port Length: 12"
Source Condition: Normal

Project Number: M1010301
Plant Name: MITCHELL
Downstream Diameters: 7.80
Port Diameter: 6"

Meter and Probe Data

Meter ID: CM 8
Pitot ID: 075A
Nozzle Kit ID: GLASS 2
Probe Length: 12'
Pre-Test Nozzle Leak Check: .002 @ 10 "Hg
Pre-Test Pitot Leak Check: ✓ @ 3.7 "H_2O

Meter Y Value: 1.004
Pitot Coefficient: .840
Nozzle Diameter: .250
Probe Liner: GLASS

ΔH Value: 1.476
Train Type: ANDERSON
Filter Number/Weight: —
Thimble Number/Weight: —
Post-Test Nozzle Leak Check: .002 @ 12 "Hg
Post-Test Pitot Leak Check: ✓ @ 3.6 "H_2O

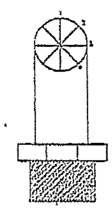
Traverse Data

Ports Sampled: 4
Total Points: 12
Points/Port: 3
Total Test Time: 60
Min/Point: 5
Sample Plane: Horizontal or Vertical

Stack Parameters

Barometric Pressure: 28.79
Static Pressure: -1.3
CO_2 %: / / / Avg. 12.3
O_2 %: / / /Avg. 6.2
Determined by: Method 3 or Method 3A
Imp and/or silica balance Model and S/N: SS10-19
Servomex Serial #: S/N 01440D11 3790
Initial Imp. Volume or Weight: 2679.7
Final Imp. Volume or Weight: 2827.6
Imp. Volume or Weight Gain: 147.9
Initial Silica Weight: 716.3
Final Silica Weight: 720.5
Silica Weight Gain: 4.2

Comments:

Post-Test Nozzle Verification:  1)____ 2)____ 3)____ 4)____

Isokinetic Sampling Field Data Sheet

Project Number: M1010301 Date: 4/1/10 Test Number: #1

Client: AEP Test Location: UNIT 2 STACK Operator: SD Test Tech: BOBS/WJM

Plant: MITCHELL Test Method: M26A Page Number: 1 of 1

Port-Point #.	Time	(ΔP)	Orifice Setting (ΔH)	Meter Volume (V_m) ft^3, Actual	Square Root, ΔP	Meter Rate, Cubic Feet/ Min.	Theoretical Meter Volume, (V_m) ft^3, per point	Theoretical Meter Volume, (V_m) ft^3, total	Stack Temp, °F	Meter Temp Inlet, °F	Meter Temp Outlet, °F	Pump Vacuum, " Hg	Probe Temp. °F	Filter Temp. °F	Impinger Outlet Well Temp °F
1-1	8:05	.64	1.6	14.165	.800		4.028		124	84	85	3	250	250	66
1-2	8:10	.62	1.6	18.17	.787		3.972	18.193	123	85	85	3	250	250	61
1-3	8:15	.54	1.4	22.15	.735		3.713	22.165	122	86	85	3	250	250	51
	8:20			25.802				25.878							
2-1	8:24	.71	1.8	25.802	.843		4.254		123	86	85	3	252	251	59
2-2	8:29	.70	1.8	30.01	.837		4.239	30.056	122	89	85	3	254	250	50
2-3	8:34	.63	1.6	34.28	.794		4.029	34.295	122	90	86	3	250	250	50
	8:39			38.323				38.325							
3-1	8:47	.64	1.6	38.805	.809		4.046		123	87	86	3	256	252	55
3-2	8:52	.65	1.6	42.84	.806		4.085	42.851	123	89	86	3	254	251	50
3-3	8:57	.61	1.5	46.94	.781		3.968	46.937	122	90	87	4	253	250	49
	9:02			50.872				50.905							
4-1	9:06	.63	1.6	50.872	.794		4.018		123	87	87	4	251	251	58
4-2	9:11	.60	1.5	54.88	.775		3.939	54.890	122	91	87	4	257	251	50
4-3	9:16	.58	1.5	58.81	.762		3.877	58.829	122	92	87	4	256	251	50
	9:21			62.713				62.766							

PLATT ENVIRONMENTAL SERVICES INC.

IMPINGER WEIGHT SHEET

PLANT: AEP- Mitchell

UNIT NO: 2

LOCATION: Stack

DATE: 4/1/10

TEST NO: 1

METHOD: 26a

WEIGHED/MEASURED BY: JFK

BALANCE ID: 510-19

Circle One:	FINAL WEIGHT MLS / GRAMS	INITIAL WEIGHT MLS / GRAMS	IMPINGER GAIN	IMPINGER CONTENTS
IMPINGER 1	720.0	610.9	109.1	Sulfuric Acid
IMPINGER 2	750.1	725.3	24.8	Sulfuric Acid
IMPINGER 3	765.9	723.2	42.7	Sulfuric Acid -30.0
IMPINGER 4	591.6	590.3	1.3	NaOH
IMPINGER 5	720.5	716.3	4.2	Silica
IMPINGER 6		+30.0		
IMPINGER 7				
IMPINGER 8				

FINAL TOTAL	INITIAL TOTAL	TOTAL GAIN
3548.1	3396.0	152.1
2827.6	2679.7	147.9

2649.7 + 30
716.3
3366.0

3396.0 use as initial

Isokinetic Sampling Cover Sheet

Test Engineer: S. DYRA
Test Technician: R. BOLLARS / W. MULLIVEX

Plant Information

Run Number: #2
Test Location: UNIT 2 STACK
Duct Shape: Circular or Rectangular
Flue Area: 894.618
Port Type: FLANGE
Test Method: M26A

Date: 4/1/10
Client Name: AEP
Length: N/A Width: N/A or Diameter: 33.75
Upstream Diameters: 72.0
Port Length: 14"
Source Condition: Normal

Project Number: MI010201
Plant Name: MITCHELL
Downstream Diameters: 78.0
Port Diameter: 6"

Meter and Probe Data

Meter ID: CM 8
Pitot ID: 075 A
Nozzle Kit ID: GLASS 2
Probe Length: 12'
Pre-Test Nozzle Leak Check: .000 @ 12 "Hg
Pre-Test Pitot Leak Check: √ @ 3.6 "H_2O

Meter Y Value: 1.004
Pitot Coefficient: .840
Nozzle Diameter: .250
Probe Liner: GLASS

ΔH Value: 1.476
Train Type: ANDERSON
Filter Number/Weight: —
Thimble Number/Weight: —
Post-Test Nozzle Leak Check: .000 @ 14 "Hg
Post-Test Pitot Leak Check: √ @ 4.0 "H_2O

Traverse Data

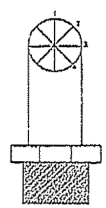
Ports Sampled: 4
Total Points: 12
Points/Port: 3
Total Test Time: 60
Min/Point: 5
Sample Plane: Horizontal or Vertical

Stack Parameters

Barometric Pressure: 28.79
Static Pressure: -1.2
CO_2 %: ___/___/___/ Avg. 12.8
O_2 %: ___/___/___/Avg. 6.0
Determined by: Method 3 or Method 3A
Imp and/or silica balance Model and S/N: ___
Servomex Serial #: S/N 01440D1 / 3790
Initial Imp. Volume or Weight: 2876.2
Final Imp. Volume or Weight: 3028.1
Imp. Volume or Weight Gain: 151.9
Initial Silica Weight: 1205
Final Silica Weight: 723.6
Silica Weight Gain: 3.1

Comments:

Post-Test Nozzle Verification:



1)___ 2)___ 3)___ 4)___

Isokinetic Sampling Field Data Sheet

Project Number: M010301
Client: AEP
Plant: MITCHELL
Date: 4/1/10
Test Location: UNIT 2 STACK
Test Method: M26A
Test Number: #2
Operator: SD
Test Tech: BDDS/WJM
Page Number: 1 of 1

Port-Point #.	Time	(ΔP)	Orifice Setting (ΔH)	Meter Volume (V_m) ft^3, Actual	Square Root, ΔP	Meter Rate, Cubic Feet/Min.	Theoretical Meter Volume, (V_m) ft^3, per point	Theoretical Meter Volume, (V_m) ft^3, total	Stack Temp, °F	Meter Temp Inlet, °F	Meter Temp Outlet, °F	Pump Vacuum, " Hg	Probe Temp. °F	Filter Temp. °F	Impinger Outlet Well Temp °F
1-1	9:50	.62	1.6	75.688	.787		3.991		124	88	88	4	251	254	64
1-2	9:55	.59	1.5	79.666	.768		3.904	79.679	124	91	88	4	258	252	59
1-3	10:00	.57	1.4	83.59	.755		3.844	83.582	123	92	88	4	258	250	60
	10:05			87.41				87.426							
2-1	10:10	.63	1.6	87.411	.794		4.026		124	89	88	4	252	249	62
2-2	10:15	.62	1.6	91.142	.787		4.009	91.437	123	97	88	4	256	254	50
2-3	10:20	.60	1.5	95.43	.775		3.951	95.446	123	93	89	4	259	254	52
	10:25			99.364				99.397							
3-1	10:32	.64	1.60	99.364	.800		4.062		125	90	89	4	250	254	56
3-2	10:37	.65	1.7	103.41	.806		4.117	103.426	123	93	89	4	256	254	57
3-3	10:42	.58	1.5	107.52	.762		3.891	107.538	122	94	89	4	254	253	57
	10:47			111.401				111.429							
4-1	10:49	.62	1.6	111.401	.787		4.009		124	97	89	4	252	252	56
4-2	10:54	.59	1.5	115.47	.768		3.925	115.416	123	94	90	5	257	252	50
4-3	10:59	.54	1.4	119.35	.735		3.755	119.335	123	94	90	5	255	253	50
	11:04			123.076				123.089							

PLATT ENVIRONMENTAL SERVICES INC.

IMPINGER WEIGHT SHEET

PLANT: AEP- Mitchell

UNIT NO: 2

LOCATION: Stack

DATE: 4/1/10

TEST NO: 2

METHOD: 26a

WEIGHED/MEASURED BY: JFR

BALANCE ID: S10-19

	FINAL WEIGHT	INITIAL WEIGHT	IMPINGER	IMPINGER
Circle One:	MLS / GRAMS	MLS / GRAMS	GAIN	CONTENTS
IMPINGER 1	832.0	727.4	104.6	Sulfuric Acid
IMPINGER 2	776.5	747.1	29.4	Sulfuric Acid
IMPINGER 3	769.9	725.5	-30.0 44.4	Sulfuric Acid
IMPINGER 4	649.7	646.2	3.5	NaOH
IMPINGER 5	723.6	720.5	3.1	Silica
IMPINGER 6		+30.0		
IMPINGER 7				
IMPINGER 8				

FINAL TOTAL   INITIAL TOTAL   TOTAL GAIN

2846.2 +30
720.5

3596.7 use as initial

Isokinetic Sampling Cover Sheet

Test Engineer: S. DYRA
Test Technician: R. SOLLARS / W. MULLINS

Plant Information

Run Number: #3
Test Location: UNIT 2 STACK
Duct Shape: Circular or Rectangular
Flue Area: 894.618
Port Type: FLANGE
Test Method: M26A

Date: 3/1/10
Client Name: AEP
Length: N/A Width: N/A or Diameter: 33.75
Upstream Diameters: 72.0
Port Length: 12"
Source Condition: Normal

Project Number: M010301
Plant Name: MITCHELL
Downstream Diameters: 78.0
Port Diameter: 6"

Meter and Probe Data

Meter ID: CMB
Pitot ID: 075A
Nozzle Kit ID: GLASS 2
Probe Length: 12'
Pre-Test Nozzle Leak Check: .000 @ 12 "Hg
Pre-Test Pitot Leak Check: ✓ @ 4.0 "H_2O

Meter Y Value: 1.004
Pitot Coefficient: .840
Nozzle Diameter: .250
Probe Liner: GLASS

ΔH Value: 1.476
Train Type: ANDERSON
Filter Number/Weight: —
Thimble Number/Weight: —
Post-Test Nozzle Leak Check: .020 @ 15 "Hg
Post-Test Pitot Leak Check: ✓ @ 3.7 "H_2O

Traverse Data

Ports Sampled: 4
Total Points: 12

Points/Port: 3
Total Test Time: 60

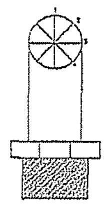
Min/Point: 5
Sample Plane: Horizontal or Vertical

Stack Parameters

Barometric Pressure: 28.79
Static Pressure: -1.2
CO_2 %: / / / Avg. 12.8
O_2 %: / / / Avg. 5.9
Determined by: Method 3 or Method 3A
Imp and/or silica balance Model and S/N: SFO-19
Servomex Serial #: S/N 01440D113790
Initial Imp. Volume or Weight: 2943.9
Final Imp. Volume or Weight: 3113.1
Imp. Volume or Weight Gain: 169.2
Initial Silica Weight: 123.6
Final Silica Weight: 126.5
Silica Weight Gain: 2.9

Comments:

Post-Test Nozzle Verification:



1)____ 2)____ 3)____ 4)____

Isokinetic Sampling Field Data Sheet

Project Number: M1010301
Client: AEP
Plant: MITCHELL
Date: 4/1/10
Test Location: UNIT 2 STACK
Test Method: M26A
Test Number: 13
Operator: SD
Test Tech: RDS/WJM
Page Number: 1 of 1

Port-Point #.	Time	(ΔP)	Orifice Setting (ΔH)	Meter Volume (V_m) ft^3, Actual	Square Root, ΔP	Meter Rate, Cubic Feet/ Min.	Theoretical Meter Volume, (V_m) ft^3, per point	Theoretical Meter Volume, (V_m) ft^3, total	Stack Temp, °F	Meter Temp Inlet, °F	Meter Temp Outlet, °F	Pump Vacuum, " Hg	Probe Temp. °F	Filter Temp. °F	Impinger Outlet Well Temp °F
1-1	11:29	.62	1.8	36.155	.787		4.009		124	91	90	4	253	256	60
1-2	11:34	.59	1.5	40.17	.768		3.921	40.164	124	94	90	4	257	255	58
1-3	11:39	.55	1.2	44.06	.742		3.793	44.085	122	94	90	4	254	255	54
	11:44			47.852				47.878							
2-1	11:47	.67	1.7	47.852	.89		4.179		123	92	91	5	256	251	57
2-2	11:52	.65	1.7	52.61	.806		4.127	52.021	123	95	91	5	254	252	57
2-3	11:57	.58	1.7	56.16	.762		3.905	56.157	121	95	91	5	252	250	50
	12:02			60.043				60.062							
3-1	12:11	.65	1.7	60.043	.806		4.112		123	91	91	6	256	251	55
3-2	12:16	.63	1.6	64.14	.794		4.056	64.155	123	93	91	6	256	252	58
3-3	12:21	.61	1.6	68.21	.781		3.991	68.211	123	92	91	6	260	250	50
	12:26			72.203				72.201							
4-1	12:29	.65	1.7	72.203	.806		4.112		123	91	91	6	254	250	56
4-2	12:34	.62	1.6	76.32	.787		4.023	76.315	123	93	91	6	255	251	57
4-3	12:39	.55	1.2	80.31	.742		3.789	80.338	122	92	91	6	255	255	52
	12:44			84.134				84.127							

PLATT ENVIRONMENTAL SERVICES INC.

IMPINGER WEIGHT SHEET

PLANT: AEP - Mitchell

UNIT NO: 2

LOCATION: Stack

DATE: 4/1/10

TEST NO: 3

METHOD: 26A

WEIGHED/MEASURED BY: JFK

BALANCE ID: 310-19

Circle One:	FINAL WEIGHT MLS / GRAMS	INITIAL WEIGHT MLS / GRAMS	IMPINGER GAIN	IMPINGER CONTENTS
IMPINGER 1	852.8	742.6	110.2	Sulfuric Acid
IMPINGER 2	856.3	827.2	29.1	Sulfuric Acid
IMPINGER 3	767.5	711.3	56.2 - 40	Sulfuric Acid
IMPINGER 4	636.5	632.8	3.7	NaOH
IMPINGER 5	726.5	723.6	2.9	Silica
IMPINGER 6		+ 40.0		
IMPINGER 7				
IMPINGER 8				

Add 40mL 3.0N NaOH

FINAL TOTAL   INITIAL TOTAL   TOTAL GAIN

2913.9
723.6
3637.5

+ 30

3667.5 use as initial

Kentucky Power Company

REQUEST

State whether AEP or Kentucky Power has performed any air quality modeling to evaluate the Mitchell Generating Station's compliance with the 1-hour SO2 NAAQS.

a. If so, identify and produce the results of such modeling.

b. If not, explain why not.

RESPONSE

Neither AEP or Kentucky Power has performed air modeling of the Mitchell Plant to evaluate compliance with the 1-hour SO2 NAAQS.

a. Not applicable.

b. The 1-hour SO2 NAAQS will take several years to implement. It is unknown if, when, or how the Mitchell Plant may be impacted, or whether modeling will be necessary.

WITNESS: John M McManus

Kentucky Power Company

REQUEST

Identify the year in which each FGD system was installed on each of Mitchell Units 1 and 2, and the SO2 removal efficiency achieved by each FGD for each of the past five years.

RESPONSE

The FGD systems for Mitchell Units 1 and 2 were both installed in 2007. SO2 removal efficiency within each FGD system is not a monitored operating parameter.

WITNESS: John M McManus

Kentucky Power Company

REQUEST

Refer to p. 4 lines 19-23 of the testimony of Scott Weaver.

a. Identify, by name, position, and company, each individual who performed the economic modeling for this proceeding.

b. Identify and explain what steps were taken to validate the results of the economic modeling.

RESPONSE

a. The economic modeling was performed by the following individuals:
Ismael Martinez, Resource Planning Analyst I, American Electric Power Service Corporation Mark Becker, Manager - Resource Planning, American Electric Power Service Corporation

b. In general, the economic modeling results were validated through a number of steps including:

1. The initial step of the economic modeling validation process, performed by Messrs. Becker and Martinez, was to review and verify the major input data entered in the Strategist model, such as the operating characteristics and costs for KPCO's existing units and the various Big Sandy retrofits and replacement options outlined in Mr. Weaver's Direct Testimony.

2. The results for the Strategist optimizations were summarized using the files found in response to KPSC 1-1. The data contained in the results summary files for each of the Big Sandy options were reviewed on an individual basis. The results for each option run were then compared against one another as an additional verification of the reasonableness of the results. All results were reviewed by Resource Planning management and KPCO management.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to p. 5, line 8 to p. 7 line 17 of the testimony of Scott Weaver.

a. Identify, by name, position, and company, each individual who was involved in identifying the six alternative options that "were assumed to be available to KPCo."

b. Provide all analyses underlying the Company's decision to assume the six options summarized in Table 1, as opposed to other possible resource options

c. State whether the Company considered any options other than those listed in Options 1 through 6 in Table 1
   i. If so, provide detailed descriptions of all other options considered, the level to which they were considered (i.e. discussion only, analysis, modeling, etc…), and any analyses, modeling files, or workpapers that examined such options
   ii. If not, explain why not

d. Explain why the Company chose not to include in its application an option in which it would retire Big Sandy Unit 2 and replace it with a mix of NGCC units and purchases, but starting with a lower initial quantity of NGCC capacity, for example 350MW, coming into service in January 2017, followed by a second addition of new gas CC capacity coming into service five years later.

e. Explain why the Company chose not to include in its application an option in which it would retire Big Sandy Unit 2 and replace it with a combination of fossil resources, renewable energy purchases, and demand side management beyond the levels set forth on page 7 of Exhibit SCW-1.

RESPONSE

a. Greg Pauley - President and COO - Kentucky Power Company
Charles Patton - President and COO - Appalachian Power Company
Robert Powers - EVP and COO - AEPSC
Mark McCullough - EVP Generation - AEPSC
Richard Munczinski - SVP Regulatory Services - AEPSC
Philip Nelson - Managing Director, Regulatory Pricing & Analysis - AEPSC
Scott Weaver - Managing Director, Resource Planning & Operation Analysis - AEPSC
Ranie Wohnhas - Managing Director, Regulatory and Finance - Kentucky Power Company

b. The requested analyses does not exist.

c. No other options were considered. The Company believes that the options contained in Table 1 covered in a broad sense all operational and economical options.

d. The Company chose to install a larger combined-cycle (NGCC) unit in 2017 to capture the economies of scale (i.e. lower $/kW capital cost) that the addition of single larger NGCC unit would provide over the addition of 2 smaller NGCC units at different points in time.

e. If Big Sandy Unit 2 is retired, KPCO would require the addition of base load resources to meet its energy and capacity needs. Considering the availability and capacity factors associated with renewables, Commission precedent regarding approval of renewable resources, and the Company's projections for DSM, a portfolio with a different mix of fossil, renewable and DSM resources was neither a reasonable, nor likely to be the least cost, alternative.

WITNESS: Scott C Weaver

KENTUCKY POWER COMPANY

REQUEST

State whether you have evaluated whether the 1-hour SO2 NAAQS will necessitate upgrades to the FGDs on Mitchell Unit 1 or Unit 2.

a. If so:
   i. Explain the results of such evaluation
   ii. Produce any documents regarding that evaluation.
   iii. Identify the estimated cost of such upgrades.

b. If not, explain why not.

RESPONSE

a. No evaluation has been completed.
   i. Not applicable.
   ii. Not applicable.
   iii. Not applicable.

b. The 1-hour SO2 NAAQS will take several years to implement. It is unknown if, when, or how the Mitchell Plant may be impacted, or whether modeling will be necessary.

WITNESS: John M McManus

KENTUCKY POWER COMPANY

REQUEST

State whether you have evaluated whether the 1-hour SO2 NAAQS will necessitate the use of a lower-sulfur coal blend for Mitchell Unit 1 or Unit 2.

a. If so, explain the results of such evaluation and produce any documents regarding the evaluation.

b. If not, explain why not.

RESPONSE

No evaluation has been completed.

a. Not applicable.

b. The 1-hour SO2 NAAQS will take several years to implement. It is unknown if, when, or how the Mitchell Plant may be impacted, or whether modeling will be necessary.

WITNESS: John M McManus

KENTUCKY POWER COMPANY

REQUEST

State whether you have evaluated the impacts of a potential GHG NSPS standard for existing fossil fuel units on the cost or operations of Mitchell Unit 1, Mitchell Unit 2, or both units.

a. If so, explain the results of such evaluation and produce any documents regarding the evaluation.

b. If not, explain why not.

RESPONSE

No evaluation has been completed.

a. Not applicable.

b. EPA has not yet issued a draft guidance document regarding existing source GHG NSPS. Accordingly, any evaluation of potential impacts of an existing source GHG NSPS has not been performed.

WITNESS: John M McManus

Kentucky Power Company

REQUEST

With regards to the Strategist modeling the Company performed for this proceeding:

a. Identify the level of off-system sales projected for each year of 2013 through 2040

b. Identify the level of off-system sales revenues projected for each year of 2013 through 2040

c. State when the Company carried out the analysis used to determine the projected levels of off- system sales and off-system sales revenues the Company used in its application.

d. State whether the Company's Strategist modeling allocates 100% of off-system sales revenues to ratepayers

e. State whether the Company presently allocates a portion of its off-system sales revenues to shareholders.
   i. If so, identify what portion of off-system sales revenues are allocated to shareholders

f. If off-system sales revenues were allocated in the Strategist modeling differently than the Company presently allocates such revenues
   i. Explain why
   ii. Explain how treating the allocation of off-system sales revenues in the Strategist modeling the same as the Company's present allocation would impact the results of such modeling.

RESPONSE

a. Please see Attachment 1 for a summary of the off-system sales energy for the Company's recommended plan (Option #6) under FT-CSAPR (Base) commodity pricing.

b. Please see Attachment 1 for a summary of the off-system sales revenues for the Company's recommended plan (Option #6) under FT-CSAPR (Base) commodity pricing.

c. In late 2012, when the analysis for this filing was being conducted

d. The Strategist modeling allocates 100% of off-system sales revenues to reducing KPCo's overall revenue requirement

e. Yes. See also the response to part f.

f. The resulting Strategist®-modeled output was not intended to be a formal ratemaking/cost-of-service exercise. Rather its intent was to holistically assess the relative economics of the modeled options. To the extent that specific, unquestioned "benefits" due to incurrence of OSS margins would then advantage both the KPCo customer and, potentially, flow to the Company under any of the particular modeled options, no specific adjustments were then made to the modeling.

The need for any Strategist® analysis adjustment pertaining to OSS margins is unnecessary based on the facts. Those facts include recognition in the Company 'System Sales Clause', of a threshold or "base" level of OSS margin—clearly identified in that tariff—that would need to be achieved before such incremental OSS margin sharing would occur. Further, Tariff S.C.C. also prescribes that customers would incur an incremental charge equal to 60% of the difference between actual monthly/annual OSS margins and these monthly/actual "base" levels, if such actual amounts fall below the base. Further, to establish the value to be compared to that 'base' OSS Margin, an additional adjustment calls for the netting out from KPCo's OSS Margin, monthly environmental costs allocated to non-associated utilities as part of the Company's Environmental Surcharge Report. In recognition of this, and that "base" OSS margin threshold in the tariff (currently, $15.290 million annually), the going-in notion was that subsequent years achievement of such adjusted KPCo OSS margin levels would either approach, or not materially exceed this base level; hence, no OSS "adjustment" was deemed necessary.

WITNESS: Mark A Becker

Option #6
FT-CSAPR (Base) Commodity Pricing

	KPCO Off-System Energy Sales (GWh)	KPCO Off-System Energy Sales Revenue ($000)
2014	2,162	133,752
2015	899	51,874
2016	599	37,870
2017	680	41,655
2018	558	35,999
2019	646	41,722
2020	597	39,264
2021	615	40,978
2022	382	31,844
2023	452	38,136
2024	441	38,055
2025	259	23,730
2026	1,878	164,035
2027	1,605	144,304
2028	1,580	146,065
2029	1,769	164,514
2030	1,435	138,793
2031	1,404	140,092
2032	1,773	174,966
2033	1,402	145,443
2034	1,351	143,100
2035	1,321	145,219
2036	1,182	135,437
2037	1,179	136,356
2038	1,111	135,287
2039	1,052	130,610
2040	811	107,805

Kentucky Power Company

REQUEST

Refer to pp. 27-29 of the rebuttal testimony of Scott Weaver in Case No. 2012-00401. State whether the 20% demand vector used in the initial modeling in Case No. 2012-00401 was also used in the modeling performed for the present proceeding. If so, explain why.

RESPONSE

No demand vector was employed in the risk modeling in the present proceeding.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

State whether you assumed a correlation between any of the following factors in any of the economic modeling carried out for this proceeding.

a. Natural gas prices and coal prices
b. Natural gas prices and CO_2 prices
c. Natural gas prices and market energy prices
d. Natural gas prices and energy demand
e. Coal prices and CO_2 prices
f. Coal prices and market energy prices
g. Coal prices and energy demand
h. CO_2 prices and market energy prices
i CO_2 prices and energy demand
j. Market energy prices and energy demand

RESPONSE

a. Yes.
b. No.
c. Yes.
d. Yes.
e. No.
f. Yes.
g. Yes.
h. No.
i. No.
j. Yes.

WITNESS: Karl R Bletzacker

Kentucky Power Company

REQUEST

For each correlation identified in your responses to request #31 above:

a. Identify the assumed correlation

b. State whether the same assumed correlation was used in both the Strategist and Aurora modeling.
   i. If not, explain how and why the assumed correlations differ.

c. Explain the basis for each assumed correlation

d. Identify and produce any documents or analyses supporting each correlation.

RESPONSE

a. See Table:

	Coal	Natural Gas	Retail Cost of Electricity	Electric Demand
Coal	1.00	0.18	0.53	(0.29)
Natural Gas		1.00	0.47	0.08
Retail Cost of Electricity			1.00	(0.19)
Demand				1.00

b. The correlations used in the Aurora modeling were built from the ground up using publicly available information. Strategist employs a suite of fundamental forecasts for which the implicit correlations between components have not been estimated.

c. Correlations were developed by reviewing the historical commodity price data from the following sources:

Coal : EIA prices 1949-2010
Natural Gas: EIA prices 1984-2010
Retail Cost of Electricity: EIA State Historical Tables
Demand: Worldbank.org per capita consumption data

d. See SC 1-32 Attachment 1

WITNESS: Karl R Bletzacker

Table 7.9 Coal Prices, 1949-2011
(Dollars per Short Ton)

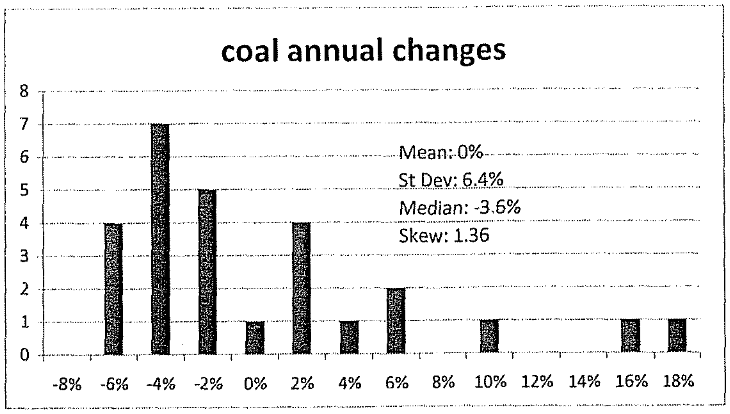
Year	Bituminous Coal		Subbituminous Coal		Lignite [1]		Anthracite		Total				
	Nominal [2]	Real [3]	Nominal [2]	Real [3]	Nominal [2]	Real [3]	Nominal [2]	Real [3]	Nominal [2]	Real [3]	Nominal	Real	
Graph Clear													
1949	[4] 4.90	[4,R] 33.80	[4]	[4]	2.37	[R] 16.35	8.9	[R] 61.38	5.24	[R] 36.14	5.24	36.14	
1950	[4] 4.86	[4,R] 33.16	[4]	[4]	2.41	[R] 16.44	9.34	[R] 63.73	5.19	[R] 35.41	5.19	35.41	-0.0202
1951	[4] 4.94	[4,R] 31.44	[4]	[4]	2.44	[R] 15.53	9.94	[R] 63.26	5.29	[R] 33.67	5.29	33.67	-0.04914
1952	[4] 4.92	[4,R] 30.78	[4]	[4]	2.39	[R] 14.95	9.58	[R] 59.94	5.27	[R] 32.97	5.27	32.97	-0.02079
1953	[4] 4.94	[4,R] 30.54	[4]	[4]	2.38	[R] 14.71	9.87	[R] 61.02	5.23	[R] 32.34	5.23	32.34	-0.01911
1954	[4] 4.54	[4,R] 27.82	[4]	[4]	2.43	[R] 14.89	8.76	[R] 53.67	4.81	[R] 29.47	4.81	29.47	-0.08874
1955	[4] 4.51	[4,R] 27.17	[4]	[4]	2.38	[R] 14.34	8	[R] 48.19	4.69	[R] 28.25	4.69	28.25	-0.0414
1956	[4] 4.83	[4,R] 28.13	[4]	[4]	2.39	[R] 13.92	8.33	[R] 48.51	5.01	[R] 29.18	5.01	29.18	0.03292
1957	[4] 5.09	[4,R] 28.69	[4]	[4]	2.35	[R] 13.25	9.11	[R] 51.35	5.28	[R] 29.76	5.28	29.76	0.019877
1958	[4] 4.87	[4,R] 26.85	[4]	[4]	2.35	[R] 12.96	9.14	[R] 50.39	5.07	[R] 27.95	5.07	27.95	-0.06082
1959	[4] 4.79	[4,R] 26.10	[4]	[4]	2.25	[R] 12.26	8.55	[R] 46.58	4.95	[R] 26.97	4.95	26.97	-0.03506
1960	[4] 4.71	[4,R] 25.31	[4]	[4]	2.29	[R] 12.30	8.01	[R] 43.04	4.83	[R] 25.95	4.83	25.95	-0.03782
1961	[4] 4.60	[4,R] 24.44	[4]	[4]	2.24	[R] 11.90	8.26	[R] 43.89	4.73	[R] 25.13	4.73	25.13	-0.0316
1962	[4] 4.50	[4,R] 23.59	[4]	[4]	2.23	[R] 11.69	7.99	[R] 41.88	4.62	[R] 24.22	4.62	24.22	-0.03621
1963	[4] 4.40	[4,R] 22.82	[4]	[4]	2.17	[R] 11.25	8.64	[R] 44.81	4.55	[R] 23.60	4.55	23.6	-0.0256
1964	[4] 4.46	[4,R] 22.78	[4]	[4]	2.14	[R] 10.93	8.93	[R] 45.61	4.6	[R] 23.49	4.6	23.49	-0.00466
1965	[4] 4.45	[4,R] 22.32	[4]	[4]	2.13	[R] 10.68	8.51	[R] 42.69	4.55	[R] 22.82	4.55	22.82	-0.02852
1966	[4] 4.56	[4,R] 22.24	[4]	[4]	1.98	[R] 9.66	8.08	[R] 39.41	4.62	[R] 22.53	4.62	22.53	-0.01271
1967	[4] 4.64	[4,R] 21.96	[4]	[4]	1.92	9.09	8.15	[R] 38.57	4.69	[R] 22.19	4.69	22.19	-0.01509
1968	[4] 4.70	[4,R] 21.33	[4]	[4]	1.79	[R] 8.12	8.78	[R] 39.85	4.75	[R] 21.56	4.75	21.56	-0.02839
1969	[4] 5.02	[4,R] 21.71	[4]	[4]	1.86	8.05	9.91	[R] 42.87	5.08	[R] 21.97	5.08	21.97	0.019017
1970	[4] 6.30	[4,R] 25.89	[4]	[4]	1.86	[R] 7.64	11.03	[R] 45.32	6.34	[R] 26.05	6.34	26.05	0.185708
1971	[4] 7.13	[4,R] 27.90	[4]	[4]	1.93	[R] 7.55	12.08	[R] 47.27	7.15	[R] 27.98	7.15	27.98	0.074088
1972	[4] 7.78	[4,R] 29.19	[4]	[4]	2.04	[R] 7.65	12.4	[R] 46.52	7.72	[R] 28.96	7.72	28.96	0.035025
1973	[4] 8.71	[4,R] 30.96	[4]	[4]	2.09	7.43	13.65	[R] 48.51	8.59	[R] 30.53	8.59	30.53	0.054213
1974	[4] 16.01	[4,R] 52.17	[4]	[4]	2.19	7.14	22.19	[R] 72.30	15.82	[R] 51.55	15.82	51.55	0.688503
1975	[4] 19.79	[4,R] 58.91	[4]	[4]	3.17	9.44	32.26	[R] 96.04	19.35	[R] 57.60	19.35	57.6	0.117362
1976	[4] 20.11	[4,R] 56.62	[4]	[4]	3.74	[R] 10.53	33.92	[R] 95.50	19.56	[R] 55.07	19.56	55.07	-0.04392
1977	[4] 20.59	[4,R] 54.50	[4]	[4]	4.03	[R] 10.67	34.86	[R] 92.26	19.95	[R] 52.80	19.95	52.8	-0.04122
1978	[4] 22.64	[4,R] 55.99	[4]	[4]	5.68	[R] 14.05	35.25	[R] 87.18	21.86	[R] 54.06	21.86	54.06	0.023864
1979	27.31	[R] 62.35	9.55	[R] 21.80	6.48	[R] 14.80	41.06	[R] 93.75	23.75	[R] 54.23	23.75	54.23	0.003145
1980	29.17	[R] 61.04	11.08	[R] 23.18	7.6	[R] 15.90	42.51	[R] 88.95	24.65	[R] 51.58	24.65	51.58	-0.04887
1981	31.51	[R] 60.28	12.18	[R] 23.30	8.85	[R] 16.93	44.28	[R] 84.71	26.4	[R] 50.51	26.4	50.51	-0.02074
1982	32.15	[R] 57.97	13.37	[R] 24.11	9.79	[R] 17.65	49.85	[R] 89.89	27.25	[R] 49.14	27.25	49.14	-0.02712
1983	31.11	[R] 53.96	13.03	[R] 22.60	9.91	[R] 17.19	52.29	[R] 90.70	25.98	[R] 45.06	25.98	45.06	-0.08303
1984	30.63	[R] 51.21	12.41	[R] 20.75	10.45	[R] 17.47	48.22	[R] 80.61	25.61	[R] 42.81	25.61	42.81	-0.04993
1985	30.78	[R] 49.94	12.57	[R] 20.40	10.68	[R] 17.33	45.8	[R] 74.32	25.2	[R] 40.89	25.2	40.89	-0.04485
1986	28.84	[R] 45.78	12.26	[R] 19.46	10.64	[R] 16.89	44.12	[R] 70.04	23.79	[R] 37.77	23.79	37.77	-0.0763
1987	28.19	[R] 43.49	11.32	[R] 17.46	10.85	[R] 16.74	43.65	[R] 67.34	23.07	[R] 35.59	23.07	35.59	-0.05772
1988	27.66	[R] 41.26	10.45	[R] 15.59	10.06	[R] 15.00	44.16	[R] 65.87	22.07	[R] 32.92	22.07	32.92	-0.07502
1989	27.4	[R] 39.38	10.16	[R] 14.60	9.91	[R] 14.24	42.93	[R] 61.70	21.82	[R] 31.36	21.82	31.36	-0.04739
1990	27.43	[R] 37.96	9.7	[R] 13.42	10.13	[R] 14.02	39.4	[R] 54.52	21.76	[R] 30.11	21.76	30.11	-0.03986
1991	27.49	[R] 36.74	9.68	[R] 12.94	10.89	[R] 14.55	36.34	[R] 48.57	21.49	[R] 28.72	21.49	28.72	-0.04616
1992	26.78	[R] 34.96	9.68	[R] 12.64	10.81	[R] 14.11	34.24	[R] 44.70	21.03	[R] 27.46	21.03	27.46	-0.04387
1993	26.15	[R] 33.40	9.33	[R] 11.92	11.11	[R] 14.19	32.94	[R] 42.07	19.85	[R] 25.35	19.85	25.35	-0.07684
1994	25.68	[R] 32.12	8.37	[R] 10.47	10.77	[R] 13.47	36.07	[R] 45.12	19.41	[R] 24.28	19.41	24.28	-0.04221
1995	25.56	[R] 31.32	8.1	9.93	10.83	[R] 13.27	39.78	[R] 48.75	18.83	[R] 23.07	18.83	23.07	-0.04984
1996	25.17	[R] 30.27	7.87	[R] 9.46	10.92	[R] 13.13	36.78	[R] 44.23	18.5	[R] 22.25	18.5	22.25	-0.03554
1997	24.64	[R] 29.12	7.42	[R] 8.77	10.91	[R] 12.89	35.12	[R] 41.50	18.14	[R] 21.43	18.14	21.43	-0.03685
1998	24.87	[R] 29.06	6.96	[R] 8.13	11.08	[R] 12.95	42.91	[R] 50.14	17.67	[R] 20.65	17.67	20.65	-0.0364
1999	23.92	[R] 27.54	6.87	[R] 7.91	11.04	[R] 12.71	35.13	[R] 40.45	16.63	[R] 19.15	16.63	19.15	-0.07264
2000	24.15	[R] 27.22	7.12	[R] 8.02	11.41	[R] 12.86	40.9	[R] 46.10	16.78	[R] 18.91	16.78	18.91	-0.01253
2001	25.36	[R] 27.95	6.67	[R] 7.35	11.52	[R] 12.70	47.67	[R] 52.54	17.38	[R] 19.16	17.38	19.16	0.013221
2002	26.57	[R] 28.82	7.34	[R] 7.96	11.07	[R] 12.01	47.78	[R] 51.82	17.98	[R] 19.50	17.98	19.5	0.017745
2003	26.73	[R] 28.40	7.73	8.21	11.2	11.9	49.87	[R] 52.98	17.85	[R] 18.96	17.85	18.96	-0.02769
2004	30.56	[R] 31.57	8.12	8.39	12.27	12.68	39.77	[R] 41.09	19.93	[R] 20.59	19.93	20.59	0.08597
2005	36.8	36.8	8.68	8.68	13.49	13.49	41	41	23.59	23.59	23.59	23.59	0.145702
2006	39.32	[R] 38.09	9.95	9.64	14	13.56	43.61	[R] 42.25	25.16	24.37	25.16	24.37	0.033065
2007	40.8	[R] 38.41	10.69	10.06	14.89	[R] 14.02	52.24	[R] 49.18	26.2	[R] 24.66	26.2	24.66	0.0119
2008	51.39	[R] 47.33	12.31	[R] 11.34	16.5	[R] 15.20	60.76	[R] 55.96	31.25	[R] 28.78	31.25	28.78	0.167072
2009	55.44	[R] 50.52	13.35	[R] 12.17	17.26	[R] 15.73	57.1	[R] 52.04	33.24	[R] 30.29	33.24	30.29	0.052467
2010	[R] 60.88	[R] 54.85	[R] 14.11	[R] 12.71	[R] 18.76	[R] 16.90	[R] 59.51	[R] 53.62	[R] 35.61	[R] 32.08	35.61	32.08	0.059095
2011[E]	57.64	50.85	15.8	13.94	19.38	17.1	70.99	62.62	36.91	32.56	36.91	32.56	0.014963

[1]Because of withholding to protect company confidentiality, lignite prices exclude Texas for 1955-1977 and Montana for 1974-1978. As a result, lignite prices for 1974-1977 are for North Dakota only.	R=Revised E=Estimate.	-0.00817 0.064428
[2]See "Nominal Dollars" in Glossary.	Note: Prices are free-on-board (F.O.B.) rail/barge prices, which are the F.O.B. prices of coal at the point of first sale, excluding freight or shipping and insurance costs. For 1949-2000, prices are for open market and captive coal sales; for 2001-2007, prices are for open market coal sales; for 2008 forward, prices are for open market and captive coal sales. See "Captive Coal," "Free on Board (F.O.B.)," and "Open Market Coal" in Glossary.	-0.0364 -0.07684 0.167072 1.358608
[3]In chained (2005) dollars, calculated by using gross domestic product implicit price deflators in Table D1. See "Chained Dollars" in Glossary.	Web Page: For related information, see http://www.eia.gov/coal/.	
[4]Through 1978, subbituminous coal is included in "Bituminous Coal."	Sources: - 1949-1975-Bureau of Mines (BOM), Minerals Yearbook. - 1976-U.S. Energy Information Administration (EIA), Energy Data Report, Coal-Bituminous and Lignite in 1976, and BOM, Minerals Yearbook. - 1977 and 1978-EIA, Energy Data Reports, Bituminous Coal and Lignite Production and Mine Operations, and Coal-Pennsylvania Anthracite. - 1979-EIA, Coal Production, and Energy Data Report, Coal-Pennsylvania Anthracite. - 1980-1992-EIA, Coal Production, annual reports. - 1993-2000-EIA, Coal Industry Annual, annual reports and unpublished revisions. - 2001-2010-EIA, Annual Coal Report, annual reports. - 2011-EIA, Form EIA-7A, "Coal Production Report," and U.S. Department of Labor, Mine Safety and Health Administration, Form 7000-2, "Quarterly Mine Employment and Coal Production Report."	

2005 Defla	2011 Deflator
0.144992	0.127904
0.146569	0.129295
0.157113	0.138597
0.159842	0.141004
0.161719	0.14266
0.163217	0.143981
0.166018	0.146452
0.171693	0.151458
0.177419	0.15651
0.181395	0.160017
0.183537	0.161907
0.186127	0.164191
0.188221	0.166039
0.190751	0.168271
0.192797	0.170075
0.195828	0.172749
0.199387	0.175888
0.20506	0.180893
0.211356	0.186447
0.220315	0.19435
0.231224	0.203974
0.243378	0.214695
0.25554	0.225423
0.266575	0.235158
0.281363	0.248203
0.306887	0.270719
0.335938	0.296346
0.355184	0.313324
0.377841	0.333311
0.404366	0.356709
0.437949	0.386335
0.477898	0.421576
0.522669	0.46107
0.554538	0.489183
0.576565	0.508614
0.598225	0.527721
0.616288	0.543655
0.629865	0.555633
0.648216	0.571821
0.670413	0.591402
0.695791	0.613789
0.722683	0.637512
0.748259	0.660074
0.765841	0.675584
0.783037	0.690753
0.799423	0.705208
0.816212	0.720018
0.831461	0.73347
0.846477	0.746716
0.85569	0.754843
0.868407	0.766062
0.887361	0.782782
0.907098	0.800193
0.922051	0.813384
0.941456	0.830501
0.967946	0.853869
1	0.882146
1.032417	0.910742
1.062449	0.937235
1.085823	0.957855
1.097392	0.96806
1.110037	0.979215
1.1336	1

-0.08
-0.06
-0.04
-0.02
0
0.02
0.04
0.06
0.08
0.1
0.12
0.14
0.16
0.18

Bin	*Frequency*
-0.08	0
-0.06	4
-0.04	7
-0.02	5
0	1
0.02	4
0.04	1
0.06	2
0.08	0
0.1	1
0.12	0
0.14	0
0.16	1
0.18	1
More	0

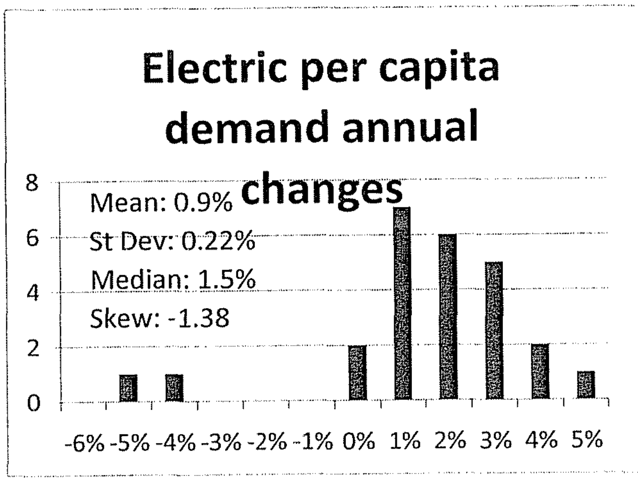


see http://www.eia.gov/coal/.

	kWh/capita	
1980	9,862	
1981	9,977	0.011661
1982	9,544	-0.0434
1983	9,742	0.020746
1984	10,282	0.05543
1985	10,414	0.012838
1986	10,424	0.00096
1987	10,887	0.044417
1988	11,298	0.037751
1989	11,532	0.020712
1990	11,713	0.015695
1991	12,134	0.035943
1992	12,015	-0.009807
1993	12,262	0.020558
1994	12,455	0.01574
1995	12,660	0.016459
1996	12,854	0.015324
1997	12,890	0.002801
1998	13,155	0.020559
1999	13,282	0.009654
2000	13,671	0.029288
2001	13,047	-0.045644
2002	13,296	0.019085
2003	13,307	0.000827
2004	13,389	0.006162
2005	13,705	0.023601
2006	13,583	-0.008902
2007	13,657	0.005448
2008	13,663	0.000439
2009	12,914	-0.05482
		0.009404
		0.022483
		0.015324
		-0.05482
		0.044417
		-1.378485

-0.06
-0.05
-0.04
-0.03
-0.02
-0.01
0
0.01
0.02
0.03
0.04
0.05

Bin	*Frequency*
-0.06	0
-0.05	1
-0.04	1
-0.03	0
-0.02	0
-0.01	0
0	2
0.01	7
0.02	6
0.03	5
0.04	2
0.05	1
More	0

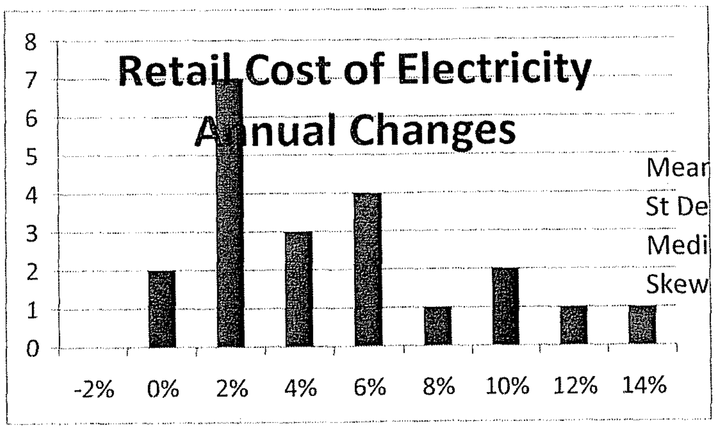


http://data.worldbank.org/indicator/EG.USE.ELEC.KH.PC?page=2

	Nominal	Real	
1990	6.57	4.188455	
1991	6.75	4.455496	0.063757
1992	6.82	4.60748	0.034111
1993	6.93	4.78692	0.038945
1994	6.91	4.872987	0.01798
1995	6.89	4.960921	0.018045
1996	6.86	5.031601	0.014247
1997	6.85	5.115005	0.016576
1998	6.74	5.087644	-0.005349
1999	6.64	5.086651	-0.000195
2000	6.81	5.330745	0.047987
2001	7.29	5.833405	0.094295
2002	7.2	5.856362	0.003935
2003	7.44	6.178929	0.05508
2004	7.61	6.497944	0.05163
2005	8.14	7.180666	0.105067
2006	8.9	8.105606	0.12881
2007	9.13	8.556957	0.055684
2008	9.74	9.329504	0.090283
2009	9.82	9.506345	0.018955
2010	9.83	9.625681	0.012553
2011	9.9	9.9	0.028499
			0.042424
			0.036896
			0.034111
			-0.005349
			0.12881
			0.879784

-0.02
0
0.02
0.04
0.06
0.08
0.1
0.12
0.14

Bin	*Frequency*
-0.02	0
0	2
0.02	7
0.04	3
0.06	4
0.08	1
0.1	2
0.12	1
0.14	1
More	0



State	US-TOTAL
Industry Sector Category	Total Electric Industry

Sum of Total Price (Cents per kilowatthour)	
Year	Total
1990	6.57
1991	6.75
1992	6.82
1993	6.93
1994	6.91
1995	6.89
1996	6.86
1997	6.85
1998	6.74
1999	6.64
2000	6.81
2001	7.29
2002	7.2
2003	7.44
2004	7.61
2005	8.14
2006	8.9
2007	9.13
2008	9.74
2009	9.82
2010	9.83
2011	9.9
Grand Total	169.77

State Historical Tables for 2011
Released: October 1, 2012
Next Update: September 2013

Average Price by State by Provider, 1990-2011

Year	State	Industry Sector Category	Residential Price (Cents per kilowatthour)	Commercial Price (Cents per kilowatthour)	Industrial Price (Cents per kilowatthour)	Other Price (Cents per kilowatthour)	Transportation Price (Cents per kilowatthour)	Total Price (Cents per kilowatthour)
1990	AK	Total Electric Industry	10.11	9.01	7.91	13.22	NA	9.48
1990	AL	Total Electric Industry	6.59	6.72	4.34	5.61	NA	5.57
1990	AR	Total Electric Industry	8.07	6.95	5.10	7.08	NA	6.70
1990	AZ	Total Electric Industry	9.04	8.29	5.58	5.41	NA	7.75
1990	CA	Total Electric Industry	9.98	9.46	7.28	4.53	NA	8.84
1990	CO	Total Electric Industry	7.02	5.67	4.49	7.28	NA	5.89
1990	CT	Total Electric Industry	10.01	9.11	7.55	12.83	NA	9.16
1990	DC	Total Electric Industry	6.10	6.35	5.16	5.78	NA	5.94
1990	DE	Total Electric Industry	8.39	6.91	4.51	10.33	NA	6.46
1990	FL	Total Electric Industry	7.77	6.66	5.08	6.83	NA	7.04
1990	GA	Total Electric Industry	7.46	7.33	4.83	8.11	NA	6.56
1990	HI	Total Electric Industry	10.26	10.18	7.57	9.40	NA	9.02
1990	IA	Total Electric Industry	7.81	6.27	3.98	6.04	NA	5.93
1990	ID	Total Electric Industry	4.87	4.25	2.62	4.65	NA	3.80
1990	IL	Total Electric Industry	9.92	7.77	5.40	6.70	NA	7.49
1990	IN	Total Electric Industry	6.87	6.05	4.07	8.08	NA	5.36
1990	KS	Total Electric Industry	7.83	6.64	4.94	8.17	NA	6.57
1990	KY	Total Electric Industry	5.69	5.37	3.58	4.69	NA	4.48
1990	LA	Total Electric Industry	7.41	7.05	4.19	6.88	NA	6.00
1990	MA	Total Electric Industry	9.66	8.56	7.89	10.90	NA	8.85
1990	MD	Total Electric Industry	7.22	6.71	5.10	8.31	NA	6.30
1990	ME	Total Electric Industry	9.30	8.03	5.96	10.85	NA	7.65
1990	MI	Total Electric Industry	7.83	8.14	5.85	9.98	NA	7.10
1990	MN	Total Electric Industry	6.80	5.98	4.14	6.72	NA	5.33
1990	MO	Total Electric Industry	7.36	6.46	4.95	6.81	NA	6.46
1990	MS	Total Electric Industry	6.89	7.21	4.65	8.03	NA	6.11
1990	MT	Total Electric Industry	5.45	4.68	2.87	4.26	NA	3.96
1990	NC	Total Electric Industry	7.84	6.42	4.77	7.00	NA	6.38
1990	ND	Total Electric Industry	6.26	6.45	4.79	3.66	NA	5.75
1990	NE	Total Electric Industry	6.23	5.73	4.19	6.39	NA	5.57
1990	NH	Total Electric Industry	10.34	9.50	7.47	12.74	NA	9.09
1990	NJ	Total Electric Industry	10.36	8.94	7.36	15.96	NA	9.08
1990	NM	Total Electric Industry	8.94	8.14	4.98	5.78	NA	7.10
1990	NV	Total Electric Industry	5.70	6.19	4.70	4.49	NA	5.38
1990	NY	Total Electric Industry	11.44	10.47	5.78	7.96	NA	9.37
1990	OH	Total Electric Industry	8.05	7.43	4.03	6.14	NA	5.89
1990	OK	Total Electric Industry	6.58	5.74	3.63	5.33	NA	5.48
1990	OR	Total Electric Industry	4.73	4.79	3.16	4.77	NA	4.18
1990	PA	Total Electric Industry	9.22	8.09	5.97	10.80	NA	7.65
1990	RI	Total Electric Industry	9.84	8.93	8.35	9.06	NA	9.15
1990	SC	Total Electric Industry	7.15	6.15	4.18	5.53	NA	5.59
1990	SD	Total Electric Industry	6.95	6.68	4.66	4.11	NA	6.13
1990	TN	Total Electric Industry	5.69	6.09	4.69	6.86	NA	5.31
1990	TX	Total Electric Industry	7.20	6.17	4.03	6.25	NA	5.78
1990	UT	Total Electric Industry	7.13	6.26	3.80	4.16	NA	5.46
1990	VA	Total Electric Industry	7.25	6.06	4.27	5.31	NA	6.03
1990	VT	Total Electric Industry	9.27	8.50	6.62	12.13	NA	8.28
1990	WA	Total Electric Industry	4.39	4.15	2.39	3.13	NA	3.40
1990	WI	Total Electric Industry	6.63	5.78	3.99	6.47	NA	5.37
1990	WV	Total Electric Industry	5.90	5.36	3.56	8.19	NA	4.73
1990	WY	Total Electric Industry	5.97	5.17	3.47	7.90	NA	4.21
1990	US-TOTAL	Total Electric Industry	7.83	7.34	4.74	6.40	NA	6.57
1990	AK	Full-Service Providers	10.11	9.01	7.91	13.22	NA	9.48
1990	AL	Full-Service Providers	6.59	6.72	4.34	5.61	NA	5.57
1990	AR	Full-Service Providers	8.07	6.95	5.10	7.08	NA	6.70
1990	AZ	Full-Service Providers	9.04	8.29	5.58	5.41	NA	7.75
1990	CA	Full-Service Providers	9.98	9.46	7.28	4.53	NA	8.84
1990	CO	Full-Service Providers	7.02	5.67	4.49	7.28	NA	5.89
1990	CT	Full-Service Providers	10.01	9.11	7.55	12.83	NA	9.16
1990	DC	Full-Service Providers	6.10	6.35	5.16	5.78	NA	5.94
1990	DE	Full-Service Providers	8.39	6.91	4.51	10.33	NA	6.46
1990	FL	Full-Service Providers	7.77	6.66	5.08	6.83	NA	7.04
1990	GA	Full-Service Providers	7.46	7.33	4.83	8.11	NA	6.56
1990	HI	Full-Service Providers	10.26	10.18	7.57	9.40	NA	9.02
1990	IA	Full-Service Providers	7.81	6.27	3.98	6.04	NA	5.93
1990	ID	Full-Service Providers	4.87	4.25	2.62	4.65	NA	3.80
1990	IL	Full-Service Providers	9.92	7.77	5.40	6.70	NA	7.49
1990	IN	Full-Service Providers	6.87	6.05	4.07	8.08	NA	5.36
1990	KS	Full-Service Providers	7.83	6.64	4.94	8.17	NA	6.57
1990	KY	Full-Service Providers	5.69	5.37	3.58	4.69	NA	4.48
1990	LA	Full-Service Providers	7.41	7.05	4.19	6.88	NA	6.00
1990	MA	Full-Service Providers	9.66	8.56	7.89	10.90	NA	8.85
1990	MD	Full-Service Providers	7.22	6.71	5.10	8.31	NA	6.30
1990	ME	Full-Service Providers	9.30	8.03	5.96	10.85	NA	7.65
1990	MI	Full-Service Providers	7.83	8.14	5.85	9.98	NA	7.10
1990	MN	Full-Service Providers	6.80	5.98	4.14	6.72	NA	5.33
1990	MO	Full-Service Providers	7.36	6.46	4.95	6.81	NA	6.46
1990	MS	Full-Service Providers	6.89	7.21	4.65	8.03	NA	6.11
1990	MT	Full-Service Providers	5.45	4.68	2.87	4.26	NA	3.96
1990	NC	Full-Service Providers	7.84	6.42	4.77	7.00	NA	6.38
1990	ND	Full-Service Providers	6.26	6.45	4.79	3.66	NA	5.75
1990	NE	Full-Service Providers	6.23	5.73	4.19	6.39	NA	5.57
1990	NH	Full-Service Providers	10.34	9.50	7.47	12.74	NA	9.09
1990	NJ	Full-Service Providers	10.36	8.94	7.36	15.96	NA	9.08
1990	NM	Full-Service Providers	8.94	8.14	4.98	5.78	NA	7.10
1990	NV	Full-Service Providers	5.70	6.19	4.70	4.49	NA	5.38
1990	NY	Full-Service Providers	11.44	10.47	5.78	7.96	NA	9.37
1990	OH	Full-Service Providers	8.05	7.43	4.03	6.14	NA	5.89
1990	OK	Full-Service Providers	6.58	5.74	3.63	5.33	NA	5.48
1990	OR	Full-Service Providers	4.73	4.79	3.16	4.77	NA	4.18
1990	PA	Full-Service Providers	9.22	8.09	5.97	10.80	NA	7.65

1990	RI	Full-Service Providers	9.84	8.93	8.35	9.06	NA	9.15
1990	SC	Full-Service Providers	7.15	6.15	4.18	5.53	NA	5.59
1990	SD	Full-Service Providers	6.95	6.68	4.66	4.11	NA	6.13
1990	TN	Full-Service Providers	5.69	6.09	4.69	6.86	NA	5.31
1990	TX	Full-Service Providers	7.20	6.17	4.03	6.25	NA	5.78
1990	UT	Full-Service Providers	7.13	6.26	3.80	4.16	NA	5.46
1990	VA	Full-Service Providers	7.25	6.06	4.27	5.31	NA	6.03
1990	VT	Full-Service Providers	9.27	8.50	6.62	12.13	NA	8.28
1990	WA	Full-Service Providers	4.39	4.15	2.39	3.13	NA	3.40
1990	WI	Full-Service Providers	6.63	5.78	3.99	6.47	NA	5.37
1990	WV	Full-Service Providers	5.90	5.36	3.56	8.19	NA	4.73
1990	WY	Full-Service Providers	5.97	5.17	3.47	7.90	NA	4.21
1990	US-TOTAL	Full-Service Providers	7.83	7.34	4.74	6.40	NA	6.57
1991	AK	Total Electric Industry	10.67	9.27	8.22	12.12	NA	9.80
1991	AL	Total Electric Industry	6.69	6.81	4.37	5.77	NA	5.64
1991	AR	Total Electric Industry	8.10	6.95	5.05	6.83	NA	6.69
1991	AZ	Total Electric Industry	9.14	8.30	5.58	6.14	NA	7.85
1991	CA	Total Electric Industry	10.79	10.04	7.58	5.05	NA	9.42
1991	CO	Total Electric Industry	7.07	5.73	4.56	7.34	NA	5.95
1991	CT	Total Electric Industry	10.51	9.49	7.93	13.42	NA	9.60
1991	DC	Total Electric Industry	6.58	6.64	5.43	6.07	NA	6.25
1991	DE	Total Electric Industry	8.62	7.03	4.73	10.99	NA	6.70
1991	FL	Total Electric Industry	7.91	6.77	5.19	6.85	NA	7.16
1991	GA	Total Electric Industry	7.50	7.36	4.78	8.54	NA	6.56
1991	HI	Total Electric Industry	10.52	10.33	7.71	9.56	NA	9.22
1991	IA	Total Electric Industry	7.76	6.23	4.01	6.14	NA	5.94
1991	ID	Total Electric Industry	4.88	4.24	2.62	4.83	NA	3.84
1991	IL	Total Electric Industry	9.87	7.95	5.49	6.84	NA	7.63
1991	IN	Total Electric Industry	6.73	5.94	4.04	7.91	NA	5.32
1991	KS	Total Electric Industry	7.83	6.62	4.95	8.15	NA	6.57
1991	KY	Total Electric Industry	5.68	5.34	3.39	4.65	NA	4.41
1991	LA	Total Electric Industry	7.40	7.03	4.15	6.36	NA	5.94
1991	MA	Total Electric Industry	10.40	9.22	8.52	11.65	NA	9.53
1991	MD	Total Electric Industry	7.90	7.03	5.50	8.75	NA	6.81
1991	ME	Total Electric Industry	10.45	9.06	6.70	12.24	NA	8.60
1991	MI	Total Electric Industry	8.06	8.19	5.89	9.16	NA	7.21
1991	MN	Total Electric Industry	6.92	6.07	4.26	6.93	NA	5.46
1991	MO	Total Electric Industry	7.39	6.39	4.90	6.90	NA	6.46
1991	MS	Total Electric Industry	6.88	7.18	4.49	7.87	NA	6.02
1991	MT	Total Electric Industry	5.76	5.00	2.92	4.34	NA	4.14
1991	NC	Total Electric Industry	7.95	6.48	4.82	7.05	NA	6.47
1991	ND	Total Electric Industry	6.21	6.39	4.87	3.75	NA	5.76
1991	NE	Total Electric Industry	6.09	5.61	4.15	6.22	NA	5.48
1991	NH	Total Electric Industry	10.38	9.60	7.44	12.79	NA	9.13
1991	NJ	Total Electric Industry	10.81	9.26	7.67	16.32	NA	9.46
1991	NM	Total Electric Industry	9.08	8.23	4.83	5.89	NA	7.14
1991	NV	Total Electric Industry	5.89	6.32	4.95	4.88	NA	5.60
1991	NY	Total Electric Industry	11.97	10.85	6.16	7.89	NA	9.79
1991	OH	Total Electric Industry	8.16	7.53	4.20	6.08	NA	6.11
1991	OK	Total Electric Industry	7.03	6.08	3.85	5.63	NA	5.78
1991	OR	Total Electric Industry	4.81	4.85	3.15	5.30	NA	4.25
1991	PA	Total Electric Industry	9.58	8.31	6.29	11.20	NA	8.00
1991	RI	Total Electric Industry	10.99	9.88	9.27	10.13	NA	10.17
1991	SC	Total Electric Industry	7.22	6.22	4.16	5.71	NA	5.63
1991	SD	Total Electric Industry	6.91	6.73	4.64	4.35	NA	6.13
1991	TN	Total Electric Industry	5.65	6.07	4.51	6.87	NA	5.21
1991	TX	Total Electric Industry	7.57	6.58	4.15	6.20	NA	6.06
1991	UT	Total Electric Industry	7.12	6.09	3.85	4.37	NA	5.46
1991	VA	Total Electric Industry	7.34	6.05	4.23	5.35	NA	6.09
1991	VT	Total Electric Industry	9.53	8.92	7.02	13.42	NA	8.63
1991	WA	Total Electric Industry	4.36	4.19	2.29	3.21	NA	3.37
1991	WI	Total Electric Industry	6.73	5.82	4.03	6.68	NA	5.45
1991	WV	Total Electric Industry	5.91	5.41	3.67	8.60	NA	4.84
1991	WY	Total Electric Industry	6.00	5.20	3.49	6.62	NA	4.25
1991	US-TOTAL	Total Electric Industry	8.04	7.53	4.83	6.51	NA	6.75
1991	AK	Full-Service Providers	10.67	9.27	8.22	12.12	NA	9.80
1991	AL	Full-Service Providers	6.69	6.81	4.37	5.77	NA	5.64
1991	AR	Full-Service Providers	8.10	6.95	5.05	6.83	NA	6.69
1991	AZ	Full-Service Providers	9.14	8.30	5.58	6.14	NA	7.85
1991	CA	Full-Service Providers	10.79	10.04	7.58	5.05	NA	9.42
1991	CO	Full-Service Providers	7.07	5.73	4.56	7.34	NA	5.95
1991	CT	Full-Service Providers	10.51	9.49	7.93	13.42	NA	9.60
1991	DC	Full-Service Providers	6.58	6.64	5.43	6.07	NA	6.25
1991	DE	Full-Service Providers	8.62	7.03	4.73	10.99	NA	6.70
1991	FL	Full-Service Providers	7.91	6.77	5.19	6.85	NA	7.16
1991	GA	Full-Service Providers	7.50	7.36	4.78	8.54	NA	6.56
1991	HI	Full-Service Providers	10.52	10.33	7.71	9.56	NA	9.22
1991	IA	Full-Service Providers	7.76	6.23	4.01	6.14	NA	5.94
1991	ID	Full-Service Providers	4.88	4.24	2.62	4.83	NA	3.84
1991	IL	Full-Service Providers	9.87	7.95	5.49	6.84	NA	7.63
1991	IN	Full-Service Providers	6.73	5.94	4.04	7.91	NA	5.32
1991	KS	Full-Service Providers	7.83	6.62	4.95	8.15	NA	6.57
1991	KY	Full-Service Providers	5.68	5.34	3.39	4.65	NA	4.41
1991	LA	Full-Service Providers	7.40	7.03	4.15	6.36	NA	5.94
1991	MA	Full-Service Providers	10.40	9.22	8.52	11.65	NA	9.53
1991	MD	Full-Service Providers	7.90	7.03	5.50	8.75	NA	6.81
1991	ME	Full-Service Providers	10.45	9.06	6.70	12.24	NA	8.60
1991	MI	Full-Service Providers	8.06	8.19	5.89	9.16	NA	7.21
1991	MN	Full-Service Providers	6.92	6.07	4.26	6.93	NA	5.46
1991	MO	Full-Service Providers	7.39	6.39	4.90	6.90	NA	6.46
1991	MS	Full-Service Providers	6.88	7.18	4.49	7.87	NA	6.02
1991	MT	Full-Service Providers	5.76	5.00	2.92	4.34	NA	4.14
1991	NC	Full-Service Providers	7.95	6.48	4.82	7.05	NA	6.47
1991	ND	Full-Service Providers	6.21	6.39	4.87	3.75	NA	5.76
1991	NE	Full-Service Providers	6.09	5.61	4.15	6.22	NA	5.48
1991	NH	Full-Service Providers	10.38	9.60	7.44	12.79	NA	9.13
1991	NJ	Full-Service Providers	10.81	9.26	7.67	16.32	NA	9.46
1991	NM	Full-Service Providers	9.08	8.23	4.83	5.89	NA	7.14
1991	NV	Full-Service Providers	5.89	6.32	4.95	4.88	NA	5.60
1991	NY	Full-Service Providers	11.97	10.85	6.16	7.89	NA	9.79
1991	OH	Full-Service Providers	8.16	7.53	4.20	6.08	NA	6.11

1991	OK	Full-Service Providers	7.03	6.08	3.85	5.63	NA	5.78
1991	OR	Full-Service Providers	4.81	4.85	3.15	5.30	NA	4.25
1991	PA	Full-Service Providers	9.58	8.31	6.29	11.20	NA	8.00
1991	RI	Full-Service Providers	10.99	9.88	9.27	10.13	NA	10.17
1991	SC	Full-Service Providers	7.22	6.22	4.16	5.71	NA	5.63
1991	SD	Full-Service Providers	6.91	6.73	4.64	4.35	NA	6.13
1991	TN	Full-Service Providers	5.65	6.07	4.51	6.87	NA	5.21
1991	TX	Full-Service Providers	7.57	6.58	4.15	6.20	NA	6.06
1991	UT	Full-Service Providers	7.12	6.09	3.85	4.37	NA	5.46
1991	VA	Full-Service Providers	7.34	6.05	4.23	5.35	NA	6.09
1991	VT	Full-Service Providers	9.53	8.92	7.02	13.42	NA	8.63
1991	WA	Full-Service Providers	4.36	4.19	2.29	3.21	NA	3.37
1991	WI	Full-Service Providers	6.73	5.82	4.03	6.68	NA	5.45
1991	WV	Full-Service Providers	5.91	5.41	3.67	8.60	NA	4.84
1991	WY	Full-Service Providers	6.00	5.20	3.49	6.62	NA	4.25
1991	US-TOTAL	Full-Service Providers	8.04	7.53	4.83	6.51	NA	6.75
1992	AK	Total Electric Industry	10.82	9.45	7.74	14.21	NA	9.95
1992	AL	Total Electric Industry	6.69	6.85	4.29	5.84	NA	5.57
1992	AR	Total Electric Industry	8.28	7.11	5.02	6.77	NA	6.71
1992	AZ	Total Electric Industry	9.58	8.64	5.76	5.74	NA	8.13
1992	CA	Total Electric Industry	11.07	10.33	7.59	5.54	NA	9.66
1992	CO	Total Electric Industry	7.20	5.77	4.59	7.61	NA	6.02
1992	CT	Total Electric Industry	11.07	9.86	8.22	13.92	NA	10.04
1992	DC	Total Electric Industry	6.61	6.91	5.68	6.23	NA	6.47
1992	DE	Total Electric Industry	8.66	7.01	4.71	10.82	NA	6.70
1992	FL	Total Electric Industry	7.75	6.58	5.02	6.81	NA	6.99
1992	GA	Total Electric Industry	7.73	7.50	4.76	8.70	NA	6.67
1992	HI	Total Electric Industry	10.90	10.53	7.83	9.71	NA	9.44
1992	IA	Total Electric Industry	8.02	6.35	4.02	6.38	NA	5.98
1992	ID	Total Electric Industry	4.93	4.30	2.72	4.43	NA	3.87
1992	IL	Total Electric Industry	10.29	8.09	5.47	6.93	NA	7.69
1992	IN	Total Electric Industry	6.86	6.00	4.00	8.19	NA	5.30
1992	KS	Total Electric Industry	7.90	6.67	4.93	8.88	NA	6.56
1992	KY	Total Electric Industry	5.70	5.29	3.16	4.66	NA	4.19
1992	LA	Total Electric Industry	7.52	7.19	4.22	6.44	NA	6.01
1992	MA	Total Electric Industry	10.62	9.31	8.60	11.27	NA	9.66
1992	MD	Total Electric Industry	7.97	7.09	5.40	8.92	NA	6.80
1992	ME	Total Electric Industry	11.37	9.27	6.90	12.91	NA	9.05
1992	MI	Total Electric Industry	8.11	8.28	5.90	9.30	NA	7.23
1992	MN	Total Electric Industry	7.01	6.13	4.33	6.94	NA	5.52
1992	MO	Total Electric Industry	7.44	6.39	4.78	7.06	NA	6.41
1992	MS	Total Electric Industry	7.01	7.27	4.41	8.45	NA	6.03
1992	MT	Total Electric Industry	5.84	5.17	2.89	4.49	NA	4.19
1992	NC	Total Electric Industry	8.11	6.63	4.93	7.07	NA	6.60
1992	ND	Total Electric Industry	6.33	6.48	4.87	3.85	NA	5.81
1992	NE	Total Electric Industry	6.27	5.64	4.06	6.77	NA	5.53
1992	NH	Total Electric Industry	11.36	10.38	8.17	13.43	NA	9.97
1992	NJ	Total Electric Industry	10.87	9.33	7.71	16.74	NA	9.51
1992	NM	Total Electric Industry	9.06	8.27	4.80	5.66	NA	7.12
1992	NV	Total Electric Industry	6.19	6.33	4.92	4.82	NA	5.69
1992	NY	Total Electric Industry	12.43	11.17	6.50	8.71	NA	10.19
1992	OH	Total Electric Industry	8.24	7.57	4.14	6.22	NA	6.06
1992	OK	Total Electric Industry	7.17	6.10	3.86	5.68	NA	5.80
1992	OR	Total Electric Industry	4.93	4.88	3.22	4.98	NA	4.31
1992	PA	Total Electric Industry	9.67	8.47	6.21	11.43	NA	8.04
1992	RI	Total Electric Industry	11.17	10.05	9.22	10.27	NA	10.30
1992	SC	Total Electric Industry	7.19	6.17	4.03	5.72	NA	5.53
1992	SD	Total Electric Industry	7.10	6.78	4.66	4.55	NA	6.22
1992	TN	Total Electric Industry	5.70	6.50	4.60	7.42	NA	5.21
1992	TX	Total Electric Industry	7.74	6.73	4.20	6.34	NA	6.16
1992	UT	Total Electric Industry	6.97	5.97	3.68	4.36	NA	5.30
1992	VA	Total Electric Industry	7.63	6.23	4.28	5.57	NA	6.28
1992	VT	Total Electric Industry	9.56	9.24	7.30	12.88	NA	8.83
1992	WA	Total Electric Industry	4.46	4.31	2.24	3.34	NA	3.43
1992	WI	Total Electric Industry	6.91	5.91	4.00	7.04	NA	5.48
1992	WV	Total Electric Industry	6.17	5.63	3.84	8.59	NA	5.05
1992	WY	Total Electric Industry	6.08	5.17	3.52	6.40	NA	4.27
1992	US-TOTAL	Total Electric Industry	8.21	7.66	4.83	6.74	NA	6.82
1992	AK	Full-Service Providers	10.82	9.45	7.74	14.21	NA	9.95
1992	AL	Full-Service Providers	6.69	6.85	4.29	5.84	NA	5.57
1992	AR	Full-Service Providers	8.28	7.11	5.02	6.77	NA	6.71
1992	AZ	Full-Service Providers	9.58	8.64	5.76	5.74	NA	8.13
1992	CA	Full-Service Providers	11.07	10.33	7.59	5.54	NA	9.66
1992	CO	Full-Service Providers	7.20	5.77	4.59	7.61	NA	6.02
1992	CT	Full-Service Providers	11.07	9.86	8.22	13.92	NA	10.04
1992	DC	Full-Service Providers	6.61	6.91	5.68	6.23	NA	6.47
1992	DE	Full-Service Providers	8.66	7.01	4.71	10.82	NA	6.70
1992	FL	Full-Service Providers	7.75	6.58	5.02	6.81	NA	6.99
1992	GA	Full-Service Providers	7.73	7.50	4.76	8.70	NA	6.67
1992	HI	Full-Service Providers	10.90	10.53	7.83	9.71	NA	9.44
1992	IA	Full-Service Providers	8.02	6.35	4.02	6.38	NA	5.98
1992	ID	Full-Service Providers	4.93	4.30	2.72	4.43	NA	3.87
1992	IL	Full-Service Providers	10.29	8.09	5.47	6.93	NA	7.69
1992	IN	Full-Service Providers	6.86	6.00	4.00	8.19	NA	5.30
1992	KS	Full-Service Providers	7.90	6.67	4.93	8.88	NA	6.56
1992	KY	Full-Service Providers	5.70	5.29	3.16	4.66	NA	4.19
1992	LA	Full-Service Providers	7.52	7.19	4.22	6.44	NA	6.01
1992	MA	Full-Service Providers	10.62	9.31	8.60	11.27	NA	9.66
1992	MD	Full-Service Providers	7.97	7.09	5.40	8.92	NA	6.80
1992	ME	Full-Service Providers	11.37	9.27	6.90	12.91	NA	9.05
1992	MI	Full-Service Providers	8.11	8.28	5.90	9.30	NA	7.23
1992	MN	Full-Service Providers	7.01	6.13	4.33	6.94	NA	5.52
1992	MO	Full-Service Providers	7.44	6.39	4.78	7.06	NA	6.41
1992	MS	Full-Service Providers	7.01	7.27	4.41	8.45	NA	6.03
1992	MT	Full-Service Providers	5.84	5.17	2.89	4.49	NA	4.19
1992	NC	Full-Service Providers	8.11	6.63	4.93	7.07	NA	6.60
1992	ND	Full-Service Providers	6.33	6.48	4.87	3.85	NA	5.81
1992	NE	Full-Service Providers	6.27	5.64	4.06	6.77	NA	5.53
1992	NH	Full-Service Providers	11.36	10.38	8.17	13.43	NA	9.97
1992	NJ	Full-Service Providers	10.87	9.33	7.71	16.74	NA	9.51
1992	NM	Full-Service Providers	9.06	8.27	4.80	5.66	NA	7.12

1992	NV	Full-Service Providers	6.19	6.33	4.92	4.82	NA	5.69
1992	NY	Full-Service Providers	12.43	11.17	6.50	8.71	NA	10.19
1992	OH	Full-Service Providers	8.24	7.57	4.14	6.22	NA	6.06
1992	OK	Full-Service Providers	7.17	6.10	3.86	5.68	NA	5.80
1992	OR	Full-Service Providers	4.93	4.88	3.22	4.98	NA	4.31
1992	PA	Full-Service Providers	9.67	8.47	6.21	11.43	NA	8.04
1992	RI	Full-Service Providers	11.17	10.05	9.22	10.27	NA	10.30
1992	SC	Full-Service Providers	7.19	6.17	4.03	5.72	NA	5.53
1992	SD	Full-Service Providers	7.10	6.78	4.66	4.55	NA	6.22
1992	TN	Full-Service Providers	5.70	6.50	4.60	7.42	NA	5.21
1992	TX	Full-Service Providers	7.74	6.73	4.20	6.34	NA	6.16
1992	UT	Full-Service Providers	6.97	5.97	3.68	4.36	NA	5.30
1992	VA	Full-Service Providers	7.63	6.23	4.28	5.57	NA	6.28
1992	VT	Full-Service Providers	9.56	9.24	7.30	12.88	NA	8.83
1992	WA	Full-Service Providers	4.46	4.31	2.24	3.34	NA	3.43
1992	WI	Full-Service Providers	6.91	5.91	4.00	7.04	NA	5.48
1992	WV	Full-Service Providers	6.17	5.63	3.84	8.59	NA	5.05
1992	WY	Full-Service Providers	6.08	5.17	3.52	6.40	NA	4.27
1992	US-TOTAL	Full-Service Providers	8.21	7.66	4.83	6.74	NA	6.82
1993	AK	Total Electric Industry	11.15	9.55	8.19	12.77	NA	10.12
1993	AL	Total Electric Industry	6.82	6.93	4.34	5.89	NA	5.67
1993	AR	Total Electric Industry	8.27	7.04	4.85	6.93	NA	6.62
1993	AZ	Total Electric Industry	9.65	8.70	5.80	5.64	NA	8.21
1993	CA	Total Electric Industry	11.30	10.46	7.33	5.05	NA	9.69
1993	CO	Total Electric Industry	7.24	5.82	4.52	7.72	NA	6.05
1993	CT	Total Electric Industry	11.39	10.04	8.29	14.08	NA	10.26
1993	DC	Total Electric Industry	7.18	7.15	5.91	6.47	NA	6.78
1993	DE	Total Electric Industry	9.01	7.25	4.88	11.78	NA	6.98
1993	FL	Total Electric Industry	7.99	6.69	5.26	6.96	NA	7.20
1993	GA	Total Electric Industry	7.79	7.44	4.74	8.50	NA	6.71
1993	HI	Total Electric Industry	12.28	11.68	8.95	11.26	NA	10.66
1993	IA	Total Electric Industry	8.02	6.36	3.92	5.85	NA	5.97
1993	ID	Total Electric Industry	4.99	4.42	2.81	4.99	NA	4.00
1993	IL	Total Electric Industry	10.28	8.00	5.45	7.03	NA	7.75
1993	IN	Total Electric Industry	6.67	5.83	3.88	9.00	NA	5.17
1993	KS	Total Electric Industry	7.86	6.70	4.94	8.91	NA	6.60
1993	KY	Total Electric Industry	5.70	5.29	3.30	4.68	NA	4.32
1993	LA	Total Electric Industry	7.76	7.38	4.44	7.11	NA	6.26
1993	MA	Total Electric Industry	11.00	9.67	8.66	12.21	NA	9.98
1993	MD	Total Electric Industry	8.21	7.17	5.45	8.28	NA	6.96
1993	ME	Total Electric Industry	11.43	9.45	6.96	13.22	NA	9.10
1993	MI	Total Electric Industry	8.16	8.02	5.34	9.15	NA	7.14
1993	MN	Total Electric Industry	7.09	6.19	4.40	7.17	NA	5.60
1993	MO	Total Electric Industry	7.26	6.26	4.71	7.10	NA	6.33
1993	MS	Total Electric Industry	7.12	7.45	4.59	8.70	NA	6.18
1993	MT	Total Electric Industry	5.77	5.10	3.10	4.51	NA	4.36
1993	NC	Total Electric Industry	8.18	6.59	4.90	7.07	NA	6.63
1993	ND	Total Electric Industry	6.31	6.48	4.85	3.99	NA	5.83
1993	NE	Total Electric Industry	6.25	5.68	4.04	6.99	NA	5.54
1993	NH	Total Electric Industry	12.31	11.01	9.04	13.30	NA	10.85
1993	NJ	Total Electric Industry	11.41	9.73	8.09	17.54	NA	9.99
1993	NM	Total Electric Industry	9.18	8.37	4.86	6.13	NA	7.23
1993	NV	Total Electric Industry	6.51	6.51	5.04	4.87	NA	5.87
1993	NY	Total Electric Industry	13.17	11.66	6.66	9.14	NA	10.72
1993	OH	Total Electric Industry	8.36	7.59	4.25	6.23	NA	6.22
1993	OK	Total Electric Industry	7.14	6.21	4.14	5.87	NA	5.96
1993	OR	Total Electric Industry	5.02	4.93	3.33	5.33	NA	4.43
1993	PA	Total Electric Industry	9.55	8.29	6.04	11.56	NA	7.92
1993	RI	Total Electric Industry	11.38	10.17	9.03	11.14	NA	10.40
1993	SC	Total Electric Industry	7.33	6.22	4.06	5.67	NA	5.64
1993	SD	Total Electric Industry	7.04	6.75	4.60	4.55	NA	6.20
1993	TN	Total Electric Industry	5.76	6.68	4.62	7.91	NA	5.22
1993	TX	Total Electric Industry	8.00	6.94	4.32	6.68	NA	6.39
1993	UT	Total Electric Industry	6.85	5.96	3.78	4.49	NA	5.33
1993	VA	Total Electric Industry	7.57	6.14	4.19	5.56	NA	6.23
1993	VT	Total Electric Industry	9.84	9.31	7.50	13.50	NA	9.04
1993	WA	Total Electric Industry	4.60	4.50	2.40	3.53	NA	3.65
1993	WI	Total Electric Industry	7.03	5.95	3.98	6.98	NA	5.52
1993	WV	Total Electric Industry	6.30	5.78	3.96	9.22	NA	5.22
1993	WY	Total Electric Industry	5.96	5.04	3.50	6.62	NA	4.25
1993	US-TOTAL	Total Electric Industry	8.32	7.74	4.85	6.88	NA	6.93
1993	AK	Full-Service Providers	11.15	9.55	8.19	12.77	NA	10.12
1993	AL	Full-Service Providers	6.82	6.93	4.34	5.89	NA	5.67
1993	AR	Full-Service Providers	8.27	7.04	4.85	6.93	NA	6.62
1993	AZ	Full-Service Providers	9.65	8.70	5.80	5.64	NA	8.21
1993	CA	Full-Service Providers	11.30	10.46	7.33	5.05	NA	9.69
1993	CO	Full-Service Providers	7.24	5.82	4.52	7.72	NA	6.05
1993	CT	Full-Service Providers	11.39	10.04	8.29	14.08	NA	10.26
1993	DC	Full-Service Providers	7.18	7.15	5.91	6.47	NA	6.78
1993	DE	Full-Service Providers	9.01	7.25	4.88	11.78	NA	6.98
1993	FL	Full-Service Providers	7.99	6.69	5.26	6.96	NA	7.20
1993	GA	Full-Service Providers	7.79	7.44	4.74	8.50	NA	6.71
1993	HI	Full-Service Providers	12.28	11.68	8.95	11.26	NA	10.66
1993	IA	Full-Service Providers	8.02	6.36	3.92	5.85	NA	5.97
1993	ID	Full-Service Providers	4.99	4.42	2.81	4.99	NA	4.00
1993	IL	Full-Service Providers	10.28	8.00	5.45	7.03	NA	7.75
1993	IN	Full-Service Providers	6.67	5.83	3.88	9.00	NA	5.17
1993	KS	Full-Service Providers	7.86	6.70	4.94	8.91	NA	6.60
1993	KY	Full-Service Providers	5.70	5.29	3.30	4.68	NA	4.32
1993	LA	Full-Service Providers	7.76	7.38	4.44	7.11	NA	6.26
1993	MA	Full-Service Providers	11.00	9.67	8.66	12.21	NA	9.98
1993	MD	Full-Service Providers	8.21	7.17	5.45	8.28	NA	6.96
1993	ME	Full-Service Providers	11.43	9.45	6.96	13.22	NA	9.10
1993	MI	Full-Service Providers	8.16	8.02	5.34	9.15	NA	7.14
1993	MN	Full-Service Providers	7.09	6.19	4.40	7.17	NA	5.60
1993	MO	Full-Service Providers	7.26	6.26	4.71	7.10	NA	6.33
1993	MS	Full-Service Providers	7.12	7.45	4.59	8.70	NA	6.18
1993	MT	Full-Service Providers	5.77	5.10	3.10	4.51	NA	4.36
1993	NC	Full-Service Providers	8.18	6.59	4.90	7.07	NA	6.63
1993	ND	Full-Service Providers	6.31	6.48	4.85	3.99	NA	5.83
1993	NE	Full-Service Providers	6.25	5.68	4.04	6.99	NA	5.54

1993	NH	Full-Service Providers	12.31	11.01	9.04	13.30	NA	10.85
1993	NJ	Full-Service Providers	11.41	9.73	8.09	17.54	NA	9.99
1993	NM	Full-Service Providers	9.18	8.37	4.86	6.13	NA	7.23
1993	NV	Full-Service Providers	6.51	6.51	5.04	4.87	NA	5.87
1993	NY	Full-Service Providers	13.17	11.66	6.66	9.14	NA	10.72
1993	OH	Full-Service Providers	8.36	7.59	4.25	6.23	NA	6.22
1993	OK	Full-Service Providers	7.14	6.21	4.14	5.87	NA	5.96
1993	OR	Full-Service Providers	5.02	4.93	3.33	5.33	NA	4.43
1993	PA	Full-Service Providers	9.55	8.29	6.04	11.56	NA	7.92
1993	RI	Full-Service Providers	11.38	10.17	9.03	11.14	NA	10.40
1993	SC	Full-Service Providers	7.33	6.22	4.06	5.67	NA	5.64
1993	SD	Full-Service Providers	7.04	6.75	4.60	4.55	NA	6.20
1993	TN	Full-Service Providers	5.76	6.68	4.62	7.91	NA	5.22
1993	TX	Full-Service Providers	8.00	6.94	4.32	6.68	NA	6.39
1993	UT	Full-Service Providers	6.85	5.96	3.78	4.49	NA	5.33
1993	VA	Full-Service Providers	7.57	6.14	4.19	5.56	NA	6.23
1993	VT	Full-Service Providers	9.84	9.31	7.50	13.50	NA	9.04
1993	WA	Full-Service Providers	4.60	4.50	2.40	3.53	NA	3.65
1993	WI	Full-Service Providers	7.03	5.95	3.98	6.98	NA	5.52
1993	WV	Full-Service Providers	6.30	5.78	3.96	9.22	NA	5.22
1993	WY	Full-Service Providers	5.96	5.04	3.50	6.62	NA	4.25
1993	US-TOTAL	Full-Service Providers	8.32	7.74	4.85	6.88	NA	6.93
1994	AK	Total Electric Industry	11.32	9.66	8.37	12.57	NA	10.25
1994	AL	Total Electric Industry	6.69	6.76	4.12	6.28	NA	5.48
1994	AR	Total Electric Industry	8.07	6.88	4.60	6.46	NA	6.35
1994	AZ	Total Electric Industry	9.30	8.32	5.63	5.47	NA	7.93
1994	CA	Total Electric Industry	11.43	10.90	7.09	5.00	NA	9.78
1994	CO	Total Electric Industry	7.36	6.00	4.58	7.43	NA	6.07
1994	CT	Total Electric Industry	11.47	9.99	7.90	14.00	NA	10.18
1994	DC	Total Electric Industry	7.47	7.15	4.63	6.72	NA	7.12
1994	DE	Total Electric Industry	8.91	7.00	4.62	11.17	NA	6.78
1994	FL	Total Electric Industry	7.78	6.35	5.13	6.72	NA	6.96
1994	GA	Total Electric Industry	7.72	7.33	4.57	8.71	NA	6.57
1994	HI	Total Electric Industry	12.45	11.67	8.82	11.21	NA	10.68
1994	IA	Total Electric Industry	8.09	6.32	3.88	5.96	NA	5.92
1994	ID	Total Electric Industry	5.09	4.37	2.82	4.64	NA	4.00
1994	IL	Total Electric Industry	9.98	7.68	5.18	6.47	NA	7.41
1994	IN	Total Electric Industry	6.78	5.91	3.97	9.02	NA	5.25
1994	KS	Total Electric Industry	7.89	6.66	4.93	10.94	NA	6.61
1994	KY	Total Electric Industry	5.77	5.29	3.24	4.67	NA	4.26
1994	LA	Total Electric Industry	7.61	7.20	4.22	6.81	NA	6.05
1994	MA	Total Electric Industry	11.09	9.75	8.46	12.60	NA	10.00
1994	MD	Total Electric Industry	8.39	7.19	5.30	8.58	NA	7.03
1994	ME	Total Electric Industry	12.32	10.16	7.18	14.63	NA	9.63
1994	MI	Total Electric Industry	8.28	7.93	5.25	10.54	NA	7.09
1994	MN	Total Electric Industry	7.16	6.25	4.41	7.21	NA	5.63
1994	MO	Total Electric Industry	7.29	6.20	4.62	7.07	NA	6.28
1994	MS	Total Electric Industry	7.06	7.22	4.48	8.60	NA	6.05
1994	MT	Total Electric Industry	5.96	5.17	3.30	4.49	NA	4.51
1994	NC	Total Electric Industry	8.17	6.56	4.93	6.91	NA	6.62
1994	ND	Total Electric Industry	6.37	6.45	4.71	3.82	NA	5.77
1994	NE	Total Electric Industry	6.31	5.58	3.99	6.53	NA	5.49
1994	NH	Total Electric Industry	12.91	10.91	9.32	13.36	NA	11.32
1994	NJ	Total Electric Industry	11.54	9.84	7.94	17.70	NA	10.06
1994	NM	Total Electric Industry	9.14	8.30	4.70	6.05	NA	7.11
1994	NV	Total Electric Industry	7.16	6.97	5.45	5.19	NA	6.37
1994	NY	Total Electric Industry	13.55	11.67	6.77	9.31	NA	10.92
1994	OH	Total Electric Industry	8.56	7.72	4.14	6.36	NA	6.19
1994	OK	Total Electric Industry	7.03	6.09	4.07	5.29	NA	5.84
1994	OR	Total Electric Industry	5.33	4.97	3.47	5.27	NA	4.60
1994	PA	Total Electric Industry	9.55	8.28	5.93	11.43	NA	7.87
1994	RI	Total Electric Industry	11.26	9.95	8.86	11.23	NA	10.24
1994	SC	Total Electric Industry	7.49	6.37	4.03	5.84	NA	5.67
1994	SD	Total Electric Industry	7.06	6.60	4.51	4.62	NA	6.19
1994	TN	Total Electric Industry	5.88	6.63	4.52	7.74	NA	5.23
1994	TX	Total Electric Industry	8.08	7.04	4.27	6.79	NA	6.42
1994	UT	Total Electric Industry	6.91	5.87	3.83	4.50	NA	5.36
1994	VA	Total Electric Industry	7.75	5.84	4.16	5.63	NA	6.20
1994	VT	Total Electric Industry	9.96	9.42	7.50	14.88	NA	9.13
1994	WA	Total Electric Industry	4.97	4.72	2.79	3.83	NA	4.02
1994	WI	Total Electric Industry	7.08	5.87	3.89	7.00	NA	5.46
1994	WV	Total Electric Industry	6.36	5.83	3.98	9.44	NA	5.25
1994	WY	Total Electric Industry	6.04	5.02	3.51	6.45	NA	4.26
1994	US-TOTAL	Total Electric Industry	8.38	7.73	4.77	6.84	NA	6.91
1994	AK	Full-Service Providers	11.32	9.66	8.37	12.57	NA	10.25
1994	AL	Full-Service Providers	6.69	6.76	4.12	6.28	NA	5.48
1994	AR	Full-Service Providers	8.07	6.88	4.60	6.46	NA	6.35
1994	AZ	Full-Service Providers	9.30	8.32	5.63	5.47	NA	7.93
1994	CA	Full-Service Providers	11.43	10.90	7.09	5.00	NA	9.78
1994	CO	Full-Service Providers	7.36	6.00	4.58	7.43	NA	6.07
1994	CT	Full-Service Providers	11.47	9.99	7.90	14.00	NA	10.18
1994	DC	Full-Service Providers	7.47	7.15	4.63	6.72	NA	7.12
1994	DE	Full-Service Providers	8.91	7.00	4.62	11.17	NA	6.78
1994	FL	Full-Service Providers	7.78	6.35	5.13	6.72	NA	6.96
1994	GA	Full-Service Providers	7.72	7.33	4.57	8.71	NA	6.57
1994	HI	Full-Service Providers	12.45	11.67	8.82	11.21	NA	10.68
1994	IA	Full-Service Providers	8.09	6.32	3.88	5.96	NA	5.92
1994	ID	Full-Service Providers	5.09	4.37	2.82	4.64	NA	4.00
1994	IL	Full-Service Providers	9.98	7.68	5.18	6.47	NA	7.41
1994	IN	Full-Service Providers	6.78	5.91	3.97	9.02	NA	5.25
1994	KS	Full-Service Providers	7.89	6.66	4.93	10.94	NA	6.61
1994	KY	Full-Service Providers	5.77	5.29	3.24	4.67	NA	4.26
1994	LA	Full-Service Providers	7.61	7.20	4.22	6.81	NA	6.05
1994	MA	Full-Service Providers	11.09	9.75	8.46	12.60	NA	10.00
1994	MD	Full-Service Providers	8.39	7.19	5.30	8.58	NA	7.03
1994	ME	Full-Service Providers	12.32	10.16	7.18	14.63	NA	9.63
1994	MI	Full-Service Providers	8.28	7.93	5.25	10.54	NA	7.09
1994	MN	Full-Service Providers	7.16	6.25	4.41	7.21	NA	5.63
1994	MO	Full-Service Providers	7.29	6.20	4.62	7.07	NA	6.28
1994	MS	Full-Service Providers	7.06	7.22	4.48	8.60	NA	6.05
1994	MT	Full-Service Providers	5.96	5.17	3.30	4.49	NA	4.51

1994	NC	Full-Service Providers	8.17	6.56	4.93	6.91	NA	6.62
1994	ND	Full-Service Providers	6.37	6.45	4.71	3.82	NA	5.77
1994	NE	Full-Service Providers	6.31	5.58	3.99	6.53	NA	5.49
1994	NH	Full-Service Providers	12.91	10.91	9.32	13.36	NA	11.32
1994	NJ	Full-Service Providers	11.54	9.84	7.94	17.70	NA	10.06
1994	NM	Full-Service Providers	9.14	8.30	4.70	6.05	NA	7.11
1994	NV	Full-Service Providers	7.16	6.97	5.45	5.19	NA	6.37
1994	NY	Full-Service Providers	13.55	11.67	6.77	9.31	NA	10.92
1994	OH	Full-Service Providers	8.56	7.72	4.14	6.36	NA	6.19
1994	OK	Full-Service Providers	7.03	6.09	4.07	5.29	NA	5.84
1994	OR	Full-Service Providers	5.33	4.97	3.47	5.27	NA	4.60
1994	PA	Full-Service Providers	9.55	8.28	5.93	11.43	NA	7.87
1994	RI	Full-Service Providers	11.26	9.95	8.86	11.23	NA	10.24
1994	SC	Full-Service Providers	7.49	6.37	4.03	5.84	NA	5.67
1994	SD	Full-Service Providers	7.06	6.60	4.51	4.62	NA	6.19
1994	TN	Full-Service Providers	5.88	6.63	4.52	7.74	NA	5.23
1994	TX	Full-Service Providers	8.08	7.04	4.27	6.79	NA	6.42
1994	UT	Full-Service Providers	6.91	5.87	3.83	4.50	NA	5.36
1994	VA	Full-Service Providers	7.75	5.84	4.16	5.63	NA	6.20
1994	VT	Full-Service Providers	9.96	9.42	7.50	14.88	NA	9.13
1994	WA	Full-Service Providers	4.97	4.72	2.79	3.83	NA	4.02
1994	WI	Full-Service Providers	7.08	5.87	3.89	7.00	NA	5.46
1994	WV	Full-Service Providers	6.36	5.83	3.98	9.44	NA	5.25
1994	WY	Full-Service Providers	6.04	5.02	3.51	6.45	NA	4.26
1994	US-TOTAL	Full-Service Providers	8.38	7.73	4.77	6.84	NA	6.91
1995	AK	Total Electric Industry	11.24	9.54	8.38	13.26	NA	10.17
1995	AL	Total Electric Industry	6.71	6.73	4.05	7.35	NA	5.47
1995	AR	Total Electric Industry	7.98	6.83	4.51	6.65	NA	6.27
1995	AZ	Total Electric Industry	9.09	8.06	5.26	5.15	NA	7.62
1995	CA	Total Electric Industry	11.61	10.49	7.37	6.73	NA	9.91
1995	CO	Total Electric Industry	7.42	6.07	4.52	7.87	NA	6.12
1995	CT	Total Electric Industry	11.95	10.33	7.94	14.38	NA	10.50
1995	DC	Total Electric Industry	7.62	7.15	4.36	6.33	NA	7.12
1995	DE	Total Electric Industry	9.09	7.08	4.72	11.95	NA	6.91
1995	FL	Total Electric Industry	7.82	6.39	5.16	6.69	NA	7.01
1995	GA	Total Electric Industry	7.85	7.32	4.52	8.60	NA	6.62
1995	HI	Total Electric Industry	13.32	12.16	9.27	12.11	NA	11.29
1995	IA	Total Electric Industry	8.24	6.44	3.94	6.13	NA	6.03
1995	ID	Total Electric Industry	5.33	4.48	2.81	5.13	NA	4.09
1995	IL	Total Electric Industry	10.37	7.88	5.27	6.80	NA	7.69
1995	IN	Total Electric Industry	6.74	5.92	3.94	9.12	NA	5.24
1995	KS	Total Electric Industry	7.92	6.68	4.82	9.21	NA	6.56
1995	KY	Total Electric Industry	5.62	5.25	2.93	4.68	NA	4.07
1995	LA	Total Electric Industry	7.23	6.77	3.97	6.97	NA	5.75
1995	MA	Total Electric Industry	11.26	9.93	8.41	14.31	NA	10.12
1995	MD	Total Electric Industry	8.43	6.91	4.23	8.79	NA	7.06
1995	ME	Total Electric Industry	12.51	10.28	6.65	15.67	NA	9.49
1995	MI	Total Electric Industry	8.34	7.86	5.13	10.71	NA	7.05
1995	MN	Total Electric Industry	7.17	6.19	4.30	7.21	NA	5.58
1995	MO	Total Electric Industry	7.25	6.18	4.53	7.05	NA	6.25
1995	MS	Total Electric Industry	6.99	7.01	4.44	8.56	NA	5.98
1995	MT	Total Electric Industry	6.09	5.31	3.44	6.21	NA	4.65
1995	NC	Total Electric Industry	8.12	6.47	4.85	7.21	NA	6.58
1995	ND	Total Electric Industry	6.23	6.20	4.50	4.21	NA	5.71
1995	NE	Total Electric Industry	6.37	5.56	3.84	5.86	NA	5.40
1995	NH	Total Electric Industry	13.50	11.38	9.56	12.32	NA	11.72
1995	NJ	Total Electric Industry	11.98	10.23	8.15	18.07	NA	10.44
1995	NM	Total Electric Industry	8.93	7.91	4.40	5.95	NA	6.77
1995	NV	Total Electric Industry	7.11	6.75	5.05	5.00	NA	6.10
1995	NY	Total Electric Industry	13.90	11.92	5.79	9.07	NA	11.06
1995	OH	Total Electric Industry	8.60	7.68	4.17	6.26	NA	6.24
1995	OK	Total Electric Industry	6.82	5.78	3.75	4.93	NA	5.57
1995	OR	Total Electric Industry	5.49	5.06	3.47	5.49	NA	4.67
1995	PA	Total Electric Industry	9.72	8.33	5.92	11.29	NA	7.93
1995	RI	Total Electric Industry	11.47	10.08	8.87	11.44	NA	10.38
1995	SC	Total Electric Industry	7.53	6.35	4.00	5.87	NA	5.69
1995	SD	Total Electric Industry	7.08	6.55	4.43	4.58	NA	6.20
1995	TN	Total Electric Industry	5.91	6.65	4.50	7.56	NA	5.21
1995	TX	Total Electric Industry	7.71	6.64	3.98	6.44	NA	6.10
1995	UT	Total Electric Industry	6.94	5.92	3.72	4.46	NA	5.30
1995	VA	Total Electric Industry	7.84	6.07	4.16	5.21	NA	6.26
1995	VT	Total Electric Industry	10.52	9.80	7.56	14.03	NA	9.46
1995	WA	Total Electric Industry	4.97	4.82	2.96	3.75	NA	4.10
1995	WI	Total Electric Industry	6.97	5.78	3.78	6.85	NA	5.36
1995	WV	Total Electric Industry	6.50	5.86	4.03	9.36	NA	5.34
1995	WY	Total Electric Industry	6.09	5.11	3.50	7.16	NA	4.32
1995	US-TOTAL	Total Electric Industry	8.40	7.69	4.66	6.88	NA	6.89
1995	AK	Full-Service Providers	11.24	9.54	8.38	13.26	NA	10.17
1995	AL	Full-Service Providers	6.71	6.73	4.05	7.35	NA	5.47
1995	AR	Full-Service Providers	7.98	6.83	4.51	6.65	NA	6.27
1995	AZ	Full-Service Providers	9.09	8.06	5.26	5.15	NA	7.62
1995	CA	Full-Service Providers	11.61	10.49	7.37	6.73	NA	9.91
1995	CO	Full-Service Providers	7.42	6.07	4.52	7.87	NA	6.12
1995	CT	Full-Service Providers	11.95	10.33	7.94	14.38	NA	10.50
1995	DC	Full-Service Providers	7.62	7.15	4.36	6.33	NA	7.12
1995	DE	Full-Service Providers	9.09	7.08	4.72	11.95	NA	6.91
1995	FL	Full-Service Providers	7.82	6.39	5.16	6.69	NA	7.01
1995	GA	Full-Service Providers	7.85	7.32	4.52	8.60	NA	6.62
1995	HI	Full-Service Providers	13.32	12.16	9.27	12.11	NA	11.29
1995	IA	Full-Service Providers	8.24	6.44	3.94	6.13	NA	6.03
1995	ID	Full-Service Providers	5.33	4.48	2.81	5.13	NA	4.09
1995	IL	Full-Service Providers	10.37	7.88	5.27	6.80	NA	7.69
1995	IN	Full-Service Providers	6.74	5.92	3.94	9.12	NA	5.24
1995	KS	Full-Service Providers	7.92	6.68	4.82	9.21	NA	6.56
1995	KY	Full-Service Providers	5.62	5.25	2.93	4.68	NA	4.07
1995	LA	Full-Service Providers	7.23	6.77	3.97	6.97	NA	5.75
1995	MA	Full-Service Providers	11.26	9.93	8.41	14.31	NA	10.12
1995	MD	Full-Service Providers	8.43	6.91	4.23	8.79	NA	7.06
1995	ME	Full-Service Providers	12.51	10.28	6.65	15.67	NA	9.49
1995	MI	Full-Service Providers	8.34	7.86	5.13	10.71	NA	7.05
1995	MN	Full-Service Providers	7.17	6.19	4.30	7.21	NA	5.58

1995	MO	Full-Service Providers	7.25	6.18	4.53	7.05	NA	6.25
1995	MS	Full-Service Providers	6.99	7.01	4.44	8.56	NA	5.98
1995	MT	Full-Service Providers	6.09	5.31	3.44	6.21	NA	4.65
1995	NC	Full-Service Providers	8.12	6.47	4.85	7.21	NA	6.58
1995	ND	Full-Service Providers	6.23	6.20	4.50	4.21	NA	5.71
1995	NE	Full-Service Providers	6.37	5.56	3.84	5.86	NA	5.40
1995	NH	Full-Service Providers	13.50	11.38	9.56	12.32	NA	11.72
1995	NJ	Full-Service Providers	11.98	10.23	8.15	18.07	NA	10.44
1995	NM	Full-Service Providers	8.93	7.91	4.40	5.95	NA	6.77
1995	NV	Full-Service Providers	7.11	6.75	5.05	5.00	NA	6.10
1995	NY	Full-Service Providers	13.90	11.92	5.79	9.07	NA	11.06
1995	OH	Full-Service Providers	8.60	7.68	4.17	6.26	NA	6.24
1995	OK	Full-Service Providers	6.82	5.78	3.75	4.93	NA	5.57
1995	OR	Full-Service Providers	5.49	5.06	3.47	5.49	NA	4.67
1995	PA	Full-Service Providers	9.72	8.33	5.92	11.29	NA	7.93
1995	RI	Full-Service Providers	11.47	10.08	8.87	11.44	NA	10.38
1995	SC	Full-Service Providers	7.53	6.35	4.00	5.87	NA	5.69
1995	SD	Full-Service Providers	7.08	6.55	4.43	4.58	NA	6.20
1995	TN	Full-Service Providers	5.91	6.65	4.50	7.56	NA	5.21
1995	TX	Full-Service Providers	7.71	6.64	3.98	6.44	NA	6.10
1995	UT	Full-Service Providers	6.94	5.92	3.72	4.46	NA	5.30
1995	VA	Full-Service Providers	7.84	6.07	4.16	5.21	NA	6.26
1995	VT	Full-Service Providers	10.52	9.80	7.56	14.03	NA	9.46
1995	WA	Full-Service Providers	4.97	4.82	2.96	3.75	NA	4.10
1995	WI	Full-Service Providers	6.97	5.78	3.78	6.85	NA	5.36
1995	WV	Full-Service Providers	6.50	5.86	4.03	9.36	NA	5.34
1995	WY	Full-Service Providers	6.09	5.11	3.50	7.16	NA	4.32
1995	US-TOTAL	Full-Service Providers	8.40	7.69	4.66	6.88	NA	6.89
1996	AK	Total Electric Industry	11.36	9.58	8.47	13.34	NA	10.24
1996	AL	Total Electric Industry	6.63	6.49	3.90	6.82	NA	5.35
1996	AR	Total Electric Industry	7.77	6.74	4.47	6.58	NA	6.15
1996	AZ	Total Electric Industry	8.95	7.97	5.19	5.39	NA	7.54
1996	CA	Total Electric Industry	11.33	9.83	6.97	6.45	NA	9.48
1996	CO	Total Electric Industry	7.49	5.93	4.35	7.69	NA	6.05
1996	CT	Total Electric Industry	12.05	10.29	7.86	14.35	NA	10.51
1996	DC	Total Electric Industry	7.77	7.40	4.36	6.41	NA	7.35
1996	DE	Total Electric Industry	8.97	7.00	4.68	12.04	NA	6.88
1996	FL	Total Electric Industry	7.99	6.63	5.11	6.80	NA	7.18
1996	GA	Total Electric Industry	7.66	7.17	4.29	8.96	NA	6.43
1996	HI	Total Electric Industry	14.26	12.99	10.03	12.91	NA	12.12
1996	IA	Total Electric Industry	8.16	6.53	3.91	5.98	NA	5.94
1996	ID	Total Electric Industry	5.28	4.26	2.68	4.79	NA	3.96
1996	IL	Total Electric Industry	10.34	7.97	5.24	6.84	NA	7.69
1996	IN	Total Electric Industry	6.77	5.94	3.93	9.19	NA	5.23
1996	KS	Total Electric Industry	7.86	6.67	4.70	9.10	NA	6.52
1996	KY	Total Electric Industry	5.55	5.19	2.92	4.66	NA	4.03
1996	LA	Total Electric Industry	7.55	7.12	4.32	7.78	NA	6.07
1996	MA	Total Electric Industry	11.25	9.94	8.43	14.53	NA	10.13
1996	MD	Total Electric Industry	8.26	6.83	4.15	8.64	NA	6.96
1996	ME	Total Electric Industry	12.58	10.35	6.26	23.03	NA	9.46
1996	MI	Total Electric Industry	8.47	7.94	5.08	10.84	NA	7.10
1996	MN	Total Electric Industry	7.13	6.14	4.26	7.26	NA	5.54
1996	MO	Total Electric Industry	7.08	6.04	4.44	7.03	NA	6.11
1996	MS	Total Electric Industry	7.04	7.09	4.41	8.68	NA	6.01
1996	MT	Total Electric Industry	6.22	5.51	3.30	6.42	NA	4.72
1996	NC	Total Electric Industry	8.05	6.39	4.79	7.02	NA	6.53
1996	ND	Total Electric Industry	6.19	6.07	4.44	4.14	NA	5.65
1996	NE	Total Electric Industry	6.29	5.49	3.68	6.49	NA	5.32
1996	NH	Total Electric Industry	13.44	11.32	9.16	13.34	NA	11.59
1996	NJ	Total Electric Industry	11.99	10.32	8.15	18.29	NA	10.50
1996	NM	Total Electric Industry	8.93	7.93	4.35	5.93	NA	6.76
1996	NV	Total Electric Industry	6.90	6.61	4.90	4.56	NA	5.95
1996	NY	Total Electric Industry	14.04	12.08	5.62	9.13	NA	11.13
1996	OH	Total Electric Industry	8.60	7.71	4.21	6.28	NA	6.30
1996	OK	Total Electric Industry	6.71	5.80	3.78	5.08	NA	5.56
1996	OR	Total Electric Industry	5.69	5.15	3.41	5.74	NA	4.77
1996	PA	Total Electric Industry	9.73	8.34	5.93	11.29	NA	7.96
1996	RI	Total Electric Industry	11.81	10.14	8.51	11.82	NA	10.48
1996	SC	Total Electric Industry	7.50	6.38	3.89	6.03	NA	5.67
1996	SD	Total Electric Industry	7.00	6.57	4.45	4.59	NA	6.18
1996	TN	Total Electric Industry	5.88	6.64	4.52	7.96	NA	5.24
1996	TX	Total Electric Industry	7.77	6.71	4.03	6.44	NA	6.16
1996	UT	Total Electric Industry	6.96	5.90	3.70	4.45	NA	5.28
1996	VA	Total Electric Industry	7.60	5.91	3.99	5.26	NA	6.09
1996	VT	Total Electric Industry	10.99	10.14	7.58	12.96	NA	9.74
1996	WA	Total Electric Industry	5.03	4.88	2.85	3.84	NA	4.19
1996	WI	Total Electric Industry	6.88	5.68	3.66	6.79	NA	5.25
1996	WV	Total Electric Industry	6.38	5.71	3.91	9.27	NA	5.21
1996	WY	Total Electric Industry	6.13	5.08	3.45	7.22	NA	4.31
1996	US-TOTAL	Total Electric Industry	8.36	7.64	4.60	6.91	NA	6.86
1996	AK	Full-Service Providers	11.36	9.58	8.47	13.34	NA	10.24
1996	AL	Full-Service Providers	6.63	6.49	3.90	6.82	NA	5.35
1996	AR	Full-Service Providers	7.77	6.74	4.47	6.58	NA	6.15
1996	AZ	Full-Service Providers	8.95	7.97	5.19	5.39	NA	7.54
1996	CA	Full-Service Providers	11.33	9.83	6.97	6.45	NA	9.48
1996	CO	Full-Service Providers	7.49	5.93	4.35	7.69	NA	6.05
1996	CT	Full-Service Providers	12.05	10.29	7.86	14.35	NA	10.51
1996	DC	Full-Service Providers	7.77	7.40	4.36	6.41	NA	7.35
1996	DE	Full-Service Providers	8.97	7.00	4.68	12.04	NA	6.88
1996	FL	Full-Service Providers	7.99	6.63	5.11	6.80	NA	7.18
1996	GA	Full-Service Providers	7.66	7.17	4.29	8.96	NA	6.43
1996	HI	Full-Service Providers	14.26	12.99	10.03	12.91	NA	12.12
1996	IA	Full-Service Providers	8.16	6.53	3.91	5.98	NA	5.94
1996	ID	Full-Service Providers	5.28	4.26	2.68	4.79	NA	3.96
1996	IL	Full-Service Providers	10.34	7.97	5.24	6.84	NA	7.69
1996	IN	Full-Service Providers	6.77	5.94	3.93	9.19	NA	5.23
1996	KS	Full-Service Providers	7.86	6.67	4.70	9.10	NA	6.52
1996	KY	Full-Service Providers	5.55	5.19	2.92	4.66	NA	4.03
1996	LA	Full-Service Providers	7.55	7.12	4.32	7.78	NA	6.07
1996	MA	Full-Service Providers	11.25	9.94	8.43	14.53	NA	10.13
1996	MD	Full-Service Providers	8.26	6.83	4.15	8.64	NA	6.96

1996	ME	Full-Service Providers	12.58	10.35	6.26	23.03	NA	9.46
1996	MI	Full-Service Providers	8.47	7.94	5.08	10.84	NA	7.10
1996	MN	Full-Service Providers	7.13	6.14	4.26	7.26	NA	5.54
1996	MO	Full-Service Providers	7.08	6.04	4.44	7.03	NA	6.11
1996	MS	Full-Service Providers	7.04	7.09	4.41	8.68	NA	6.01
1996	MT	Full-Service Providers	6.22	5.51	3.30	6.42	NA	4.72
1996	NC	Full-Service Providers	8.05	6.39	4.79	7.02	NA	6.53
1996	ND	Full-Service Providers	6.19	6.07	4.44	4.14	NA	5.65
1996	NE	Full-Service Providers	6.29	5.49	3.68	6.49	NA	5.32
1996	NH	Full-Service Providers	13.44	11.32	9.16	13.34	NA	11.59
1996	NJ	Full-Service Providers	11.99	10.32	8.15	18.29	NA	10.50
1996	NM	Full-Service Providers	8.93	7.93	4.35	5.93	NA	6.76
1996	NV	Full-Service Providers	6.90	6.61	4.90	4.56	NA	5.95
1996	NY	Full-Service Providers	14.04	12.08	5.62	9.13	NA	11.13
1996	OH	Full-Service Providers	8.60	7.71	4.21	6.28	NA	6.30
1996	OK	Full-Service Providers	6.71	5.80	3.78	5.08	NA	5.56
1996	OR	Full-Service Providers	5.69	5.15	3.41	5.74	NA	4.77
1996	PA	Full-Service Providers	9.73	8.34	5.93	11.29	NA	7.96
1996	RI	Full-Service Providers	11.81	10.14	8.51	11.82	NA	10.48
1996	SC	Full-Service Providers	7.50	6.38	3.89	6.03	NA	5.67
1996	SD	Full-Service Providers	7.00	6.57	4.45	4.59	NA	6.18
1996	TN	Full-Service Providers	5.88	6.64	4.52	7.96	NA	5.24
1996	TX	Full-Service Providers	7.77	6.71	4.03	6.44	NA	6.16
1996	UT	Full-Service Providers	6.96	5.90	3.70	4.45	NA	5.28
1996	VA	Full-Service Providers	7.60	5.91	3.99	5.26	NA	6.09
1996	VT	Full-Service Providers	10.99	10.14	7.58	12.96	NA	9.74
1996	WA	Full-Service Providers	5.03	4.88	2.85	3.84	NA	4.19
1996	WI	Full-Service Providers	6.88	5.68	3.66	6.79	NA	5.25
1996	WV	Full-Service Providers	6.38	5.71	3.91	9.27	NA	5.21
1996	WY	Full-Service Providers	6.13	5.08	3.45	7.22	NA	4.31
1996	US-TOTAL	Full-Service Providers	8.36	7.64	4.60	6.91	NA	6.86
1996	US-TOTAL	Restructured Retail Service Providers	9.43	9.75	4.61	0.00	NA	4.64
1996	US-TOTAL	Energy-Only Providers	9.43	9.75	4.61	0.00	NA	4.64
1997	AK	Total Electric Industry	11.44	9.51	7.48	14.75	NA	10.07
1997	AL	Total Electric Industry	6.74	6.34	3.71	6.47	NA	5.33
1997	AR	Total Electric Industry	7.80	6.78	4.45	6.61	NA	6.15
1997	AZ	Total Electric Industry	8.82	7.83	5.05	4.84	NA	7.38
1997	CA	Total Electric Industry	11.50	9.98	6.95	7.50	NA	9.54
1997	CO	Total Electric Industry	7.42	5.77	4.28	8.00	NA	5.95
1997	CT	Total Electric Industry	12.13	10.28	7.76	14.52	NA	10.52
1997	DC	Total Electric Industry	7.87	7.43	4.42	6.54	NA	7.39
1997	DE	Total Electric Industry	9.22	7.19	4.82	12.45	NA	7.00
1997	FL	Total Electric Industry	8.08	6.62	5.04	6.80	NA	7.19
1997	GA	Total Electric Industry	7.74	7.11	4.13	9.05	NA	6.37
1997	HI	Total Electric Industry	14.80	13.26	10.32	13.20	NA	12.49
1997	IA	Total Electric Industry	8.21	6.61	3.95	6.09	NA	5.97
1997	ID	Total Electric Industry	5.15	4.17	2.60	4.68	NA	3.87
1997	IL	Total Electric Industry	10.43	7.93	5.29	6.84	NA	7.71
1997	IN	Total Electric Industry	6.94	6.04	3.91	9.44	NA	5.29
1997	KS	Total Electric Industry	7.71	6.47	4.51	5.97	NA	6.31
1997	KY	Total Electric Industry	5.58	5.29	2.80	4.64	NA	4.03
1997	LA	Total Electric Industry	7.39	6.99	4.39	6.48	NA	5.99
1997	MA	Total Electric Industry	11.59	10.29	8.78	14.49	NA	10.48
1997	MD	Total Electric Industry	8.33	6.86	4.21	8.80	NA	6.98
1997	ME	Total Electric Industry	12.75	10.39	6.36	23.23	NA	9.51
1997	MI	Total Electric Industry	8.57	7.84	4.97	10.88	NA	7.04
1997	MN	Total Electric Industry	7.23	6.23	4.33	7.12	NA	5.61
1997	MO	Total Electric Industry	7.09	6.00	4.46	6.77	NA	6.09
1997	MS	Total Electric Industry	7.02	6.69	4.12	8.61	NA	5.91
1997	MT	Total Electric Industry	6.40	5.80	3.66	6.68	NA	5.20
1997	NC	Total Electric Industry	8.03	6.43	4.71	6.78	NA	6.48
1997	ND	Total Electric Industry	6.27	6.15	4.38	4.27	NA	5.65
1997	NE	Total Electric Industry	6.38	5.46	3.61	6.19	NA	5.30
1997	NH	Total Electric Industry	13.67	11.35	9.06	14.06	NA	11.66
1997	NJ	Total Electric Industry	12.08	10.35	8.11	18.35	NA	10.54
1997	NM	Total Electric Industry	8.92	7.92	4.42	6.17	NA	6.80
1997	NV	Total Electric Industry	6.77	6.31	4.48	3.83	NA	5.60
1997	NY	Total Electric Industry	14.12	12.13	5.20	9.17	NA	11.13
1997	OH	Total Electric Industry	8.63	7.67	4.16	6.12	NA	6.25
1997	OK	Total Electric Industry	6.63	5.73	3.63	4.76	NA	5.42
1997	OR	Total Electric Industry	5.56	4.97	3.23	6.44	NA	4.61
1997	PA	Total Electric Industry	9.90	8.41	5.89	11.71	NA	7.99
1997	RI	Total Electric Industry	12.12	10.40	8.52	12.35	NA	10.70
1997	SC	Total Electric Industry	7.51	6.33	3.71	6.04	NA	5.50
1997	SD	Total Electric Industry	7.08	6.63	4.42	4.72	NA	6.22
1997	TN	Total Electric Industry	6.03	5.91	3.81	7.88	NA	5.31
1997	TX	Total Electric Industry	7.82	6.74	4.05	6.45	NA	6.17
1997	UT	Total Electric Industry	6.89	5.72	3.49	4.34	NA	5.17
1997	VA	Total Electric Industry	7.75	5.97	4.00	5.14	NA	6.14
1997	VT	Total Electric Industry	11.45	10.33	7.44	9.56	NA	9.89
1997	WA	Total Electric Industry	4.95	4.79	2.59	4.06	NA	4.04
1997	WI	Total Electric Industry	6.88	5.60	3.72	6.77	NA	5.22
1997	WV	Total Electric Industry	6.26	5.54	3.71	8.71	NA	5.02
1997	WY	Total Electric Industry	6.22	5.27	3.46	5.84	NA	4.33
1997	US-TOTAL	Total Electric Industry	8.43	7.59	4.53	6.91	NA	6.85
1997	AK	Full-Service Providers	11.44	9.51	7.48	14.75	NA	10.07
1997	AL	Full-Service Providers	6.74	6.34	3.71	6.47	NA	5.33
1997	AR	Full-Service Providers	7.80	6.78	4.45	6.61	NA	6.15
1997	AZ	Full-Service Providers	8.82	7.83	5.05	4.84	NA	7.38
1997	CA	Full-Service Providers	11.50	9.98	6.95	7.50	NA	9.54
1997	CO	Full-Service Providers	7.42	5.77	4.28	8.00	NA	5.95
1997	CT	Full-Service Providers	12.13	10.28	7.76	14.52	NA	10.52
1997	DC	Full-Service Providers	7.87	7.43	4.42	6.54	NA	7.39
1997	DE	Full-Service Providers	9.22	7.19	4.82	12.45	NA	7.00
1997	FL	Full-Service Providers	8.08	6.62	5.04	6.80	NA	7.19
1997	GA	Full-Service Providers	7.74	7.11	4.13	9.05	NA	6.37
1997	HI	Full-Service Providers	14.80	13.26	10.32	13.20	NA	12.49
1997	IA	Full-Service Providers	8.21	6.61	3.95	6.09	NA	5.97
1997	ID	Full-Service Providers	5.15	4.17	2.60	4.68	NA	3.87
1997	IL	Full-Service Providers	10.43	7.93	5.29	6.84	NA	7.71
1997	IN	Full-Service Providers	6.94	6.04	3.91	9.44	NA	5.29

1997	KS	Full-Service Providers	7.71	6.47	4.51	5.97	NA	6.31
1997	KY	Full-Service Providers	5.58	5.29	2.80	4.64	NA	4.03
1997	LA	Full-Service Providers	7.39	6.99	4.39	6.48	NA	5.99
1997	MA	Full-Service Providers	11.59	10.29	8.78	14.49	NA	10.48
1997	MD	Full-Service Providers	8.33	6.86	4.21	8.80	NA	6.98
1997	ME	Full-Service Providers	12.75	10.39	6.36	23.23	NA	9.51
1997	MI	Full-Service Providers	8.57	7.84	4.97	10.88	NA	7.04
1997	MN	Full-Service Providers	7.23	6.23	4.33	7.12	NA	5.61
1997	MO	Full-Service Providers	7.09	6.00	4.46	6.77	NA	6.09
1997	MS	Full-Service Providers	7.02	6.69	4.12	8.61	NA	5.91
1997	MT	Full-Service Providers	6.40	5.80	3.66	6.68	NA	5.20
1997	NC	Full-Service Providers	8.03	6.43	4.71	6.78	NA	6.48
1997	ND	Full-Service Providers	6.27	6.15	4.38	4.27	NA	5.65
1997	NE	Full-Service Providers	6.38	5.46	3.61	6.19	NA	5.30
1997	NH	Full-Service Providers	13.67	11.35	9.06	14.06	NA	11.66
1997	NJ	Full-Service Providers	12.08	10.35	8.11	18.35	NA	10.54
1997	NM	Full-Service Providers	8.92	7.92	4.42	6.17	NA	6.80
1997	NV	Full-Service Providers	6.77	6.31	4.48	3.83	NA	5.60
1997	NY	Full-Service Providers	14.12	12.13	5.20	9.17	NA	11.13
1997	OH	Full-Service Providers	8.63	7.67	4.16	6.12	NA	6.25
1997	OK	Full-Service Providers	6.63	5.73	3.63	4.76	NA	5.42
1997	OR	Full-Service Providers	5.56	4.97	3.23	6.44	NA	4.61
1997	PA	Full-Service Providers	9.90	8.41	5.89	11.71	NA	7.99
1997	RI	Full-Service Providers	12.12	10.40	8.52	12.35	NA	10.70
1997	SC	Full-Service Providers	7.51	6.33	3.71	6.04	NA	5.50
1997	SD	Full-Service Providers	7.08	6.63	4.42	4.72	NA	6.22
1997	TN	Full-Service Providers	6.03	5.91	3.81	7.88	NA	5.31
1997	TX	Full-Service Providers	7.82	6.74	4.05	6.45	NA	6.17
1997	UT	Full-Service Providers	6.89	5.72	3.49	4.34	NA	5.17
1997	VA	Full-Service Providers	7.75	5.97	4.00	5.14	NA	6.14
1997	VT	Full-Service Providers	11.45	10.33	7.44	9.56	NA	9.89
1997	WA	Full-Service Providers	4.95	4.79	2.59	4.06	NA	4.04
1997	WI	Full-Service Providers	6.88	5.60	3.72	6.77	NA	5.22
1997	WV	Full-Service Providers	6.26	5.54	3.71	8.71	NA	5.02
1997	WY	Full-Service Providers	6.22	5.27	3.46	5.84	NA	4.33
1997	US-TOTAL	Full-Service Providers	8.43	7.59	4.53	6.91	NA	6.85
1997	CA	Restructured Retail Service Providers	0.00	7.59	0.00	0.00	NA	7.59
1997	ID	Restructured Retail Service Providers	0.00	0.00	4.53	0.00	NA	4.53
1997	IL	Restructured Retail Service Providers	8.43	7.59	4.53	0.00	NA	4.82
1997	MA	Restructured Retail Service Providers	8.43	0.00	4.53	0.00	NA	4.60
1997	MO	Restructured Retail Service Providers	0.00	7.59	0.00	0.00	NA	7.59
1997	NH	Restructured Retail Service Providers	8.43	7.59	4.53	0.00	NA	6.61
1997	NY	Restructured Retail Service Providers	8.43	7.59	4.53	0.00	NA	6.59
1997	OR	Restructured Retail Service Providers	0.00	7.59	4.53	0.00	NA	4.53
1997	PA	Restructured Retail Service Providers	8.43	7.59	4.53	0.00	NA	6.27
1997	RI	Restructured Retail Service Providers	0.00	7.59	4.53	0.00	NA	7.24
1997	WA	Restructured Retail Service Providers	0.00	7.59	4.53	0.00	NA	4.55
1997	US-TOTAL	Restructured Retail Service Providers	8.43	7.59	4.53	0.00	NA	4.71
1997	CA	Energy-Only Providers	0.00	7.59	0.00	0.00	NA	7.59
1997	ID	Energy-Only Providers	0.00	0.00	4.53	0.00	NA	4.53
1997	IL	Energy-Only Providers	8.43	7.59	4.53	0.00	NA	4.82
1997	MA	Energy-Only Providers	8.43	0.00	4.53	0.00	NA	4.60
1997	MO	Energy-Only Providers	0.00	7.59	0.00	0.00	NA	7.59
1997	NH	Energy-Only Providers	8.43	7.59	4.53	0.00	NA	6.61
1997	NY	Energy-Only Providers	8.43	7.59	4.53	0.00	NA	6.59
1997	OR	Energy-Only Providers	0.00	7.59	4.53	0.00	NA	4.53
1997	PA	Energy-Only Providers	8.43	7.59	4.53	0.00	NA	6.27
1997	RI	Energy-Only Providers	0.00	7.59	4.53	0.00	NA	7.24
1997	WA	Energy-Only Providers	0.00	7.59	4.53	0.00	NA	4.55
1997	US-TOTAL	Energy-Only Providers	8.43	7.59	4.53	0.00	NA	4.71
1998	AK	Total Electric Industry	11.50	9.48	7.17	13.68	NA	9.97
1998	AL	Total Electric Industry	6.94	6.54	3.89	7.26	NA	5.56
1998	AR	Total Electric Industry	7.51	5.90	4.16	5.98	NA	5.78
1998	AZ	Total Electric Industry	8.68	7.76	5.12	4.43	NA	7.33
1998	CA	Total Electric Industry	10.60	9.66	6.59	5.06	NA	9.03
1998	CO	Total Electric Industry	7.45	5.67	4.34	7.92	NA	5.95
1998	CT	Total Electric Industry	11.95	10.01	7.70	11.65	NA	10.30
1998	DC	Total Electric Industry	8.00	7.43	4.38	6.56	NA	7.41
1998	DE	Total Electric Industry	9.13	7.07	4.65	13.17	NA	6.88
1998	FL	Total Electric Industry	7.89	6.38	4.81	6.64	NA	7.01
1998	GA	Total Electric Industry	7.67	7.01	4.23	8.99	NA	6.40
1998	HI	Total Electric Industry	13.82	12.31	9.41	12.28	NA	11.56
1998	IA	Total Electric Industry	8.38	6.67	3.99	6.21	NA	6.04
1998	ID	Total Electric Industry	5.28	4.34	2.77	4.59	NA	4.02
1998	IL	Total Electric Industry	9.85	7.77	5.11	6.80	NA	7.46
1998	IN	Total Electric Industry	7.01	6.08	3.95	9.83	NA	5.34
1998	KS	Total Electric Industry	7.65	6.34	4.46	7.96	NA	6.28
1998	KY	Total Electric Industry	5.61	5.30	2.91	4.67	NA	4.16
1998	LA	Total Electric Industry	7.07	6.56	4.15	6.62	NA	5.78
1998	MA	Total Electric Industry	10.60	9.35	8.18	14.35	NA	9.59
1998	MD	Total Electric Industry	8.44	6.82	4.14	8.82	NA	6.99
1998	ME	Total Electric Industry	13.02	10.33	6.61	23.64	NA	9.75
1998	MI	Total Electric Industry	8.67	7.81	5.03	10.74	NA	7.09
1998	MN	Total Electric Industry	7.33	6.28	4.45	7.48	NA	5.71
1998	MO	Total Electric Industry	7.08	5.99	4.43	6.25	NA	6.08
1998	MS	Total Electric Industry	7.03	6.62	4.22	8.45	NA	5.98
1998	MT	Total Electric Industry	6.50	5.87	3.19	6.07	NA	4.80
1998	NC	Total Electric Industry	8.01	6.35	4.63	6.79	NA	6.45
1998	ND	Total Electric Industry	6.49	6.20	4.30	4.27	NA	5.70
1998	NE	Total Electric Industry	6.46	5.45	3.60	6.27	NA	5.30
1998	NH	Total Electric Industry	13.92	11.64	9.42	13.76	NA	11.93
1998	NJ	Total Electric Industry	11.39	10.09	7.94	17.92	NA	10.17
1998	NM	Total Electric Industry	8.85	7.80	4.47	6.11	NA	6.78
1998	NV	Total Electric Industry	7.00	6.50	4.57	4.02	NA	5.76
1998	NY	Total Electric Industry	13.66	11.63	4.95	8.85	NA	10.71
1998	OH	Total Electric Industry	8.70	7.67	4.30	6.07	NA	6.38
1998	OK	Total Electric Industry	6.57	5.66	3.65	4.88	NA	5.43
1998	OR	Total Electric Industry	5.82	5.00	3.50	6.67	NA	4.90
1998	PA	Total Electric Industry	9.93	8.26	5.63	12.45	NA	7.86
1998	RI	Total Electric Industry	10.91	9.26	7.61	11.51	NA	9.58
1998	SC	Total Electric Industry	7.50	6.24	3.69	5.99	NA	5.53

1998	SD	Total Electric Industry	7.27	6.62	4.44	4.28	NA	6.26
1998	TN	Total Electric Industry	6.32	6.28	4.17	8.71	NA	5.62
1998	TX	Total Electric Industry	7.65	6.57	3.94	6.40	NA	6.07
1998	UT	Total Electric Industry	6.84	5.71	3.45	4.50	NA	5.16
1998	VA	Total Electric Industry	7.51	5.61	3.82	4.98	NA	5.88
1998	VT	Total Electric Industry	11.61	10.12	7.27	8.91	NA	9.83
1998	WA	Total Electric Industry	5.03	4.81	2.64	3.61	NA	4.03
1998	WI	Total Electric Industry	7.17	5.87	3.86	7.01	NA	5.44
1998	WV	Total Electric Industry	6.29	5.56	3.78	9.39	NA	5.07
1998	WY	Total Electric Industry	6.28	5.25	3.38	5.15	NA	4.31
1998	US-TOTAL	Total Electric Industry	8.26	7.41	4.48	6.63	NA	6.74
1998	AK	Full-Service Providers	11.50	9.48	7.17	13.68	NA	9.97
1998	AL	Full-Service Providers	6.94	6.54	3.89	7.26	NA	5.56
1998	AR	Full-Service Providers	7.51	5.90	4.16	5.98	NA	5.78
1998	AZ	Full-Service Providers	8.68	7.76	5.12	4.43	NA	7.33
1998	CA	Full-Service Providers	10.60	9.66	6.59	5.06	NA	9.03
1998	CO	Full-Service Providers	7.45	5.67	4.34	7.92	NA	5.95
1998	CT	Full-Service Providers	11.95	10.01	7.70	11.65	NA	10.30
1998	DC	Full-Service Providers	8.00	7.43	4.38	6.56	NA	7.41
1998	DE	Full-Service Providers	9.13	7.07	4.65	13.17	NA	6.88
1998	FL	Full-Service Providers	7.89	6.38	4.81	6.64	NA	7.01
1998	GA	Full-Service Providers	7.67	7.01	4.23	8.99	NA	6.40
1998	HI	Full-Service Providers	13.82	12.31	9.41	12.28	NA	11.56
1998	IA	Full-Service Providers	8.38	6.67	3.99	6.21	NA	6.04
1998	ID	Full-Service Providers	5.28	4.34	2.77	4.59	NA	4.02
1998	IL	Full-Service Providers	9.85	7.77	5.11	6.80	NA	7.46
1998	IN	Full-Service Providers	7.01	6.08	3.95	9.83	NA	5.34
1998	KS	Full-Service Providers	7.65	6.34	4.46	7.96	NA	6.28
1998	KY	Full-Service Providers	5.61	5.30	2.91	4.67	NA	4.16
1998	LA	Full-Service Providers	7.07	6.56	4.15	6.62	NA	5.78
1998	MA	Full-Service Providers	10.60	9.35	8.18	14.35	NA	9.59
1998	MD	Full-Service Providers	8.44	6.82	4.14	8.82	NA	6.99
1998	ME	Full-Service Providers	13.02	10.33	6.61	23.64	NA	9.75
1998	MI	Full-Service Providers	8.67	7.81	5.03	10.74	NA	7.09
1998	MN	Full-Service Providers	7.33	6.28	4.45	7.48	NA	5.71
1998	MO	Full-Service Providers	7.08	5.99	4.43	6.25	NA	6.08
1998	MS	Full-Service Providers	7.03	6.62	4.22	8.45	NA	5.98
1998	MT	Full-Service Providers	6.50	5.87	3.19	6.07	NA	4.80
1998	NC	Full-Service Providers	8.01	6.35	4.63	6.79	NA	6.45
1998	ND	Full-Service Providers	6.49	6.20	4.30	4.27	NA	5.70
1998	NE	Full-Service Providers	6.46	5.45	3.60	6.27	NA	5.30
1998	NH	Full-Service Providers	13.92	11.64	9.42	13.76	NA	11.93
1998	NJ	Full-Service Providers	11.39	10.09	7.94	17.92	NA	10.17
1998	NM	Full-Service Providers	8.85	7.80	4.47	6.11	NA	6.78
1998	NV	Full-Service Providers	7.00	6.50	4.57	4.02	NA	5.76
1998	NY	Full-Service Providers	13.66	11.63	4.95	8.85	NA	10.71
1998	OH	Full-Service Providers	8.70	7.67	4.30	6.07	NA	6.38
1998	OK	Full-Service Providers	6.57	5.66	3.65	4.88	NA	5.43
1998	OR	Full-Service Providers	5.82	5.00	3.50	6.67	NA	4.90
1998	PA	Full-Service Providers	9.93	8.26	5.63	12.45	NA	7.86
1998	RI	Full-Service Providers	10.91	9.26	7.61	11.51	NA	9.58
1998	SC	Full-Service Providers	7.50	6.24	3.69	5.99	NA	5.53
1998	SD	Full-Service Providers	7.27	6.62	4.44	4.28	NA	6.26
1998	TN	Full-Service Providers	6.32	6.28	4.17	8.71	NA	5.62
1998	TX	Full-Service Providers	7.65	6.57	3.94	6.40	NA	6.07
1998	UT	Full-Service Providers	6.84	5.71	3.45	4.50	NA	5.16
1998	VA	Full-Service Providers	7.51	5.61	3.82	4.98	NA	5.88
1998	VT	Full-Service Providers	11.61	10.12	7.27	8.91	NA	9.83
1998	WA	Full-Service Providers	5.03	4.81	2.64	3.61	NA	4.03
1998	WI	Full-Service Providers	7.17	5.87	3.86	7.01	NA	5.44
1998	WV	Full-Service Providers	6.29	5.56	3.78	9.39	NA	5.07
1998	WY	Full-Service Providers	6.28	5.25	3.38	5.15	NA	4.31
1998	US-TOTAL	Full-Service Providers	8.26	7.41	4.48	6.63	NA	6.74
1998	CA	Restructured Retail Service Providers	8.26	7.41	4.48	0.00	NA	6.63
1998	ID	Restructured Retail Service Providers	0.00	0.00	4.48	0.00	NA	4.48
1998	IL	Restructured Retail Service Providers	8.26	7.41	4.48	0.00	NA	5.34
1998	MO	Restructured Retail Service Providers	0.00	7.41	0.00	0.00	NA	7.41
1998	MT	Restructured Retail Service Providers	0.00	0.00	4.48	0.00	NA	4.48
1998	NH	Restructured Retail Service Providers	8.26	7.41	4.48	0.00	NA	7.10
1998	NY	Restructured Retail Service Providers	8.26	7.41	4.48	0.00	NA	7.38
1998	OR	Restructured Retail Service Providers	8.26	7.41	4.48	0.00	NA	4.90
1998	PA	Restructured Retail Service Providers	8.26	7.41	4.48	0.00	NA	6.76
1998	RI	Restructured Retail Service Providers	8.26	0.00	4.48	0.00	NA	4.56
1998	WA	Restructured Retail Service Providers	0.00	7.41	4.48	0.00	NA	4.49
1998	US-TOTAL	Restructured Retail Service Providers	8.26	7.41	4.48	0.00	NA	6.15
1998	CA	Energy-Only Providers	8.26	7.41	4.48	0.00	NA	6.63
1998	ID	Energy-Only Providers	0.00	0.00	4.48	0.00	NA	4.48
1998	IL	Energy-Only Providers	8.26	7.41	4.48	0.00	NA	5.34
1998	MO	Energy-Only Providers	0.00	7.41	0.00	0.00	NA	7.41
1998	MT	Energy-Only Providers	0.00	0.00	4.48	0.00	NA	4.48
1998	NH	Energy-Only Providers	8.26	7.41	4.48	0.00	NA	7.10
1998	NY	Energy-Only Providers	8.26	7.41	4.48	0.00	NA	7.38
1998	OR	Energy-Only Providers	8.26	7.41	4.48	0.00	NA	4.90
1998	PA	Energy-Only Providers	8.26	7.41	4.48	0.00	NA	6.76
1998	RI	Energy-Only Providers	8.26	0.00	4.48	0.00	NA	4.56
1998	WA	Energy-Only Providers	0.00	7.41	4.48	0.00	NA	4.49
1998	US-TOTAL	Energy-Only Providers	8.26	7.41	4.48	0.00	NA	6.15
1999	AK	Total Electric Industry	11.16	9.20	7.32	14.16	NA	9.78
1999	AL	Total Electric Industry	7.03	6.54	3.82	7.02	NA	5.54
1999	AR	Total Electric Industry	7.43	5.82	4.12	6.26	NA	5.68
1999	AZ	Total Electric Industry	8.53	7.51	5.04	4.66	NA	7.23
1999	CA	Total Electric Industry	10.64	9.44	6.27	4.15	NA	8.75
1999	CO	Total Electric Industry	7.38	5.61	4.38	8.23	NA	5.95
1999	CT	Total Electric Industry	11.46	9.69	7.42	10.93	NA	9.96
1999	DC	Total Electric Industry	8.00	7.47	4.59	6.55	NA	7.45
1999	DE	Total Electric Industry	9.17	7.39	4.71	13.24	NA	7.10
1999	FL	Total Electric Industry	7.73	6.22	4.77	6.61	NA	6.85
1999	GA	Total Electric Industry	7.56	6.67	4.15	8.47	NA	6.24
1999	HI	Total Electric Industry	14.30	12.74	9.70	12.66	NA	11.97
1999	IA	Total Electric Industry	8.35	6.45	3.89	6.30	NA	5.93
1999	ID	Total Electric Industry	5.26	4.20	2.63	4.47	NA	3.89

1999	IL	Total Electric Industry	8.83	7.38	4.99	5.95	NA	6.96
1999	IN	Total Electric Industry	6.96	6.05	3.89	9.70	NA	5.29
1999	KS	Total Electric Industry	7.64	6.25	4.47	8.91	NA	6.22
1999	KY	Total Electric Industry	5.58	5.27	2.99	4.55	NA	4.17
1999	LA	Total Electric Industry	7.12	6.59	4.25	6.20	NA	5.81
1999	MA	Total Electric Industry	10.09	8.64	7.53	13.73	NA	8.99
1999	MD	Total Electric Industry	8.39	6.82	4.26	8.77	NA	7.04
1999	ME	Total Electric Industry	13.07	10.51	6.42	24.29	NA	9.77
1999	MI	Total Electric Industry	8.73	7.85	5.03	10.17	NA	7.12
1999	MN	Total Electric Industry	7.41	6.31	4.56	7.49	NA	5.83
1999	MO	Total Electric Industry	7.12	5.96	4.38	6.26	NA	6.06
1999	MS	Total Electric Industry	6.75	6.19	4.02	7.93	NA	5.65
1999	MT	Total Electric Industry	6.78	6.35	2.74	6.34	NA	4.77
1999	NC	Total Electric Industry	7.99	6.33	4.57	6.74	NA	6.44
1999	ND	Total Electric Industry	6.50	6.19	4.04	4.23	NA	5.49
1999	NE	Total Electric Industry	6.52	5.44	3.57	6.47	NA	5.31
1999	NH	Total Electric Industry	13.64	11.18	9.19	12.78	NA	11.60
1999	NJ	Total Electric Industry	11.40	9.73	7.67	17.43	NA	9.98
1999	NM	Total Electric Industry	8.62	7.52	4.24	5.76	NA	6.57
1999	NV	Total Electric Industry	7.13	6.66	4.77	3.94	NA	5.93
1999	NY	Total Electric Industry	13.23	10.11	4.74	8.74	NA	9.95
1999	OH	Total Electric Industry	8.68	7.67	4.33	5.97	NA	6.40
1999	OK	Total Electric Industry	6.60	5.58	3.60	4.80	NA	5.37
1999	OR	Total Electric Industry	5.75	4.94	3.48	6.68	NA	4.83
1999	PA	Total Electric Industry	8.86	6.53	4.71	9.63	NA	6.71
1999	RI	Total Electric Industry	10.12	7.73	7.31	11.20	NA	8.62
1999	SC	Total Electric Industry	7.55	6.30	3.72	5.98	NA	5.57
1999	SD	Total Electric Industry	7.42	6.70	4.55	4.17	NA	6.35
1999	TN	Total Electric Industry	6.34	6.29	4.19	8.71	NA	5.63
1999	TX	Total Electric Industry	7.55	6.52	3.97	6.36	NA	6.04
1999	UT	Total Electric Industry	6.27	5.29	3.36	4.21	NA	4.86
1999	VA	Total Electric Industry	7.48	5.55	3.84	5.00	NA	5.86
1999	VT	Total Electric Industry	12.17	10.67	7.35	13.32	NA	10.28
1999	WA	Total Electric Industry	5.10	4.86	2.65	3.66	NA	4.01
1999	WI	Total Electric Industry	7.31	5.88	3.89	7.11	NA	5.53
1999	WV	Total Electric Industry	6.27	5.53	3.80	9.10	NA	5.09
1999	WY	Total Electric Industry	6.34	5.28	3.34	5.27	NA	4.30
1999	US-TOTAL	Total Electric Industry	8.16	7.26	4.43	6.35	NA	6.64
1999	AK	Full-Service Providers	11.16	9.20	7.32	14.16	NA	9.78
1999	AL	Full-Service Providers	7.03	6.54	3.82	7.02	NA	5.54
1999	AR	Full-Service Providers	7.43	5.82	4.12	6.26	NA	5.68
1999	AZ	Full-Service Providers	8.53	7.51	5.04	4.66	NA	7.23
1999	CA	Full-Service Providers	10.71	10.05	7.16	4.16	NA	9.34
1999	CO	Full-Service Providers	7.38	5.61	4.38	8.23	NA	5.95
1999	CT	Full-Service Providers	11.46	9.69	7.42	10.93	NA	9.96
1999	DC	Full-Service Providers	8.00	7.47	4.59	6.55	NA	7.45
1999	DE	Full-Service Providers	9.17	7.39	4.73	13.24	NA	7.12
1999	FL	Full-Service Providers	7.73	6.22	4.77	6.61	NA	6.85
1999	GA	Full-Service Providers	7.56	6.67	4.15	8.47	NA	6.24
1999	HI	Full-Service Providers	14.30	12.74	9.70	12.66	NA	11.97
1999	IA	Full-Service Providers	8.35	6.45	3.89	6.30	NA	5.93
1999	ID	Full-Service Providers	5.26	4.20	2.74	4.47	NA	3.98
1999	IL	Full-Service Providers	8.83	7.39	5.02	5.95	NA	6.98
1999	IN	Full-Service Providers	6.96	6.05	3.89	9.70	NA	5.29
1999	KS	Full-Service Providers	7.64	6.25	4.47	8.91	NA	6.22
1999	KY	Full-Service Providers	5.58	5.27	2.99	4.55	NA	4.17
1999	LA	Full-Service Providers	7.12	6.59	4.25	6.20	NA	5.81
1999	MA	Full-Service Providers	10.09	8.90	7.75	13.73	NA	9.16
1999	MD	Full-Service Providers	8.39	6.82	4.26	8.77	NA	7.04
1999	ME	Full-Service Providers	13.07	10.51	6.42	24.29	NA	9.77
1999	MI	Full-Service Providers	8.73	7.86	5.05	10.17	NA	7.14
1999	MN	Full-Service Providers	7.41	6.31	4.56	7.49	NA	5.83
1999	MO	Full-Service Providers	7.12	5.97	4.38	6.26	NA	6.07
1999	MS	Full-Service Providers	6.75	6.19	4.02	7.93	NA	5.65
1999	MT	Full-Service Providers	6.78	6.35	2.84	6.34	NA	5.01
1999	NC	Full-Service Providers	7.99	6.33	4.57	6.74	NA	6.44
1999	ND	Full-Service Providers	6.50	6.19	4.04	4.23	NA	5.49
1999	NE	Full-Service Providers	6.52	5.44	3.57	6.47	NA	5.31
1999	NH	Full-Service Providers	13.84	11.39	9.21	12.78	NA	11.75
1999	NJ	Full-Service Providers	11.40	9.74	7.69	17.43	NA	9.99
1999	NM	Full-Service Providers	8.62	7.53	4.25	5.76	NA	6.58
1999	NV	Full-Service Providers	7.13	6.66	4.77	3.94	NA	5.93
1999	NY	Full-Service Providers	13.32	11.19	4.77	8.74	NA	10.40
1999	OH	Full-Service Providers	8.68	7.67	4.33	5.96	NA	6.40
1999	OK	Full-Service Providers	6.60	5.58	3.60	4.80	NA	5.37
1999	OR	Full-Service Providers	5.75	4.94	3.55	6.68	NA	4.87
1999	PA	Full-Service Providers	9.19	7.90	5.22	9.63	NA	7.67
1999	RI	Full-Service Providers	10.13	8.49	7.39	11.20	NA	9.02
1999	SC	Full-Service Providers	7.55	6.30	3.72	5.98	NA	5.57
1999	SD	Full-Service Providers	7.42	6.70	4.55	4.17	NA	6.35
1999	TN	Full-Service Providers	6.34	6.29	4.19	8.71	NA	5.63
1999	TX	Full-Service Providers	7.55	6.52	3.97	6.36	NA	6.04
1999	UT	Full-Service Providers	6.27	5.29	3.36	4.21	NA	4.86
1999	VA	Full-Service Providers	7.48	5.55	3.84	5.00	NA	5.86
1999	VT	Full-Service Providers	12.17	10.67	7.35	13.32	NA	10.28
1999	WA	Full-Service Providers	5.10	4.86	2.70	3.66	NA	4.10
1999	WI	Full-Service Providers	7.31	5.88	3.89	7.11	NA	5.53
1999	WV	Full-Service Providers	6.27	5.53	3.80	9.10	NA	5.09
1999	WY	Full-Service Providers	6.34	5.28	3.34	5.27	NA	4.30
1999	US-TOTAL	Full-Service Providers	8.16	7.26	4.43	6.35	NA	6.66
1999	CA	Restructured Retail Service Providers	4.10	3.65	3.00	3.28	NA	3.28
1999	DE	Restructured Retail Service Providers	0.00	4.81	3.17	0.00	NA	3.30
1999	ID	Restructured Retail Service Providers	0.00	0.00	1.55	0.00	NA	1.55
1999	IL	Restructured Retail Service Providers	5.00	2.42	2.14	0.00	NA	2.23
1999	MA	Restructured Retail Service Providers	5.50	3.46	3.85	0.00	NA	3.60
1999	MI	Restructured Retail Service Providers	0.00	0.93	2.94	0.00	NA	2.80
1999	MO	Restructured Retail Service Providers	0.00	2.41	0.00	0.00	NA	2.41
1999	MT	Restructured Retail Service Providers	0.00	0.00	2.25	0.00	NA	2.25
1999	NH	Restructured Retail Service Providers	2.94	2.91	3.29	0.00	NA	2.93
1999	NJ	Restructured Retail Service Providers	4.74	3.66	3.91	0.00	NA	3.77
1999	NM	Restructured Retail Service Providers	2.69	2.69	2.71	0.00	NA	2.71

1999	NY	Restructured Retail Service Providers	3.82	3.85	3.46	0.00	NA	3.83
1999	OH	Restructured Retail Service Providers	0.00	0.00	0.00	151.19	NA	151.19
1999	OR	Restructured Retail Service Providers	0.00	0.00	1.76	0.00	NA	1.76
1999	PA	Restructured Retail Service Providers	4.15	3.89	3.86	13.33	NA	3.90
1999	RI	Restructured Retail Service Providers	3.26	3.37	3.18	0.00	NA	3.36
1999	WA	Restructured Retail Service Providers	0.00	0.00	2.23	0.00	NA	2.23
1999	US-TOTAL	Restructured Retail Service Providers	8.17	7.26	4.43	6.45	NA	5.81
1999	CA	Energy-Only Providers	4.10	3.65	3.00	3.28	NA	3.28
1999	DE	Energy-Only Providers	0.00	4.81	3.17	0.00	NA	3.30
1999	ID	Energy-Only Providers	0.00	0.00	1.55	0.00	NA	1.55
1999	IL	Energy-Only Providers	5.00	2.42	2.14	0.00	NA	2.23
1999	MA	Energy-Only Providers	5.50	3.46	3.85	0.00	NA	3.60
1999	MI	Energy-Only Providers	0.00	0.93	2.94	0.00	NA	2.80
1999	MO	Energy-Only Providers	0.00	2.41	0.00	0.00	NA	2.41
1999	MT	Energy-Only Providers	0.00	0.00	2.25	0.00	NA	2.25
1999	NH	Energy-Only Providers	2.94	2.91	3.29	0.00	NA	2.93
1999	NJ	Energy-Only Providers	4.74	3.66	3.91	0.00	NA	3.77
1999	NM	Energy-Only Providers	2.69	2.69	2.71	0.00	NA	2.71
1999	NY	Energy-Only Providers	3.82	3.85	3.46	0.00	NA	3.83
1999	OH	Energy-Only Providers	0.00	0.00	0.00	151.19	NA	151.19
1999	OR	Energy-Only Providers	0.00	0.00	1.76	0.00	NA	1.76
1999	PA	Energy-Only Providers	4.15	3.89	3.86	13.33	NA	3.90
1999	RI	Energy-Only Providers	3.26	3.37	3.18	0.00	NA	3.36
1999	WA	Energy-Only Providers	0.00	0.00	2.23	0.00	NA	2.23
1999	US-TOTAL	Energy-Only Providers	8.17	7.26	4.43	6.45	NA	5.81
2000	AK	Total Electric Industry	11.45	9.77	7.56	14.17	NA	10.08
2000	AL	Total Electric Industry	7.05	6.58	3.87	7.12	NA	5.61
2000	AR	Total Electric Industry	7.45	5.93	4.20	6.39	NA	5.77
2000	AZ	Total Electric Industry	8.44	7.34	5.27	4.53	NA	7.25
2000	CA	Total Electric Industry	10.89	10.25	7.14	4.87	NA	9.47
2000	CO	Total Electric Industry	7.31	5.55	4.25	7.77	NA	5.88
2000	CT	Total Electric Industry	10.86	9.27	7.32	10.06	NA	9.52
2000	DC	Total Electric Industry	8.03	7.55	4.74	6.67	NA	7.52
2000	DE	Total Electric Industry	8.54	5.89	3.73	14.19	NA	6.08
2000	FL	Total Electric Industry	7.77	6.25	4.84	6.96	NA	6.91
2000	GA	Total Electric Industry	7.60	6.50	4.10	8.51	NA	6.21
2000	HI	Total Electric Industry	16.41	14.81	11.69	14.76	NA	14.03
2000	IA	Total Electric Industry	8.37	6.57	3.89	6.13	NA	5.93
2000	ID	Total Electric Industry	5.39	4.24	3.11	4.13	NA	4.17
2000	IL	Total Electric Industry	8.83	7.31	4.99	5.63	NA	6.94
2000	IN	Total Electric Industry	6.87	5.93	3.81	9.37	NA	5.18
2000	KS	Total Electric Industry	7.65	6.25	4.55	7.29	NA	6.27
2000	KY	Total Electric Industry	5.47	5.14	3.01	4.40	NA	4.18
2000	LA	Total Electric Industry	7.67	7.18	5.00	6.98	NA	6.48
2000	MA	Total Electric Industry	10.53	9.13	8.20	15.32	NA	9.49
2000	MD	Total Electric Industry	7.95	6.55	4.14	8.89	NA	6.74
2000	ME	Total Electric Industry	12.49	10.23	6.89	11.45	NA	9.69
2000	MI	Total Electric Industry	8.52	7.90	5.09	10.77	NA	7.11
2000	MN	Total Electric Industry	7.52	6.36	4.57	7.60	NA	5.87
2000	MO	Total Electric Industry	7.04	5.83	4.43	6.02	NA	6.02
2000	MS	Total Electric Industry	6.93	6.41	4.14	8.33	NA	5.85
2000	MT	Total Electric Industry	6.49	5.60	3.97	0.68	NA	5.00
2000	NC	Total Electric Industry	7.97	6.36	4.58	6.53	NA	6.48
2000	ND	Total Electric Industry	6.44	6.08	3.98	4.19	NA	5.44
2000	NE	Total Electric Industry	6.53	5.42	3.61	6.10	NA	5.31
2000	NH	Total Electric Industry	13.15	10.81	9.17	12.41	NA	11.25
2000	NJ	Total Electric Industry	10.27	9.14	8.58	12.11	NA	9.47
2000	NM	Total Electric Industry	8.36	7.06	4.69	5.64	NA	6.58
2000	NV	Total Electric Industry	7.28	6.74	4.98	4.77	NA	6.17
2000	NY	Total Electric Industry	13.97	12.65	5.37	8.99	NA	11.38
2000	OH	Total Electric Industry	8.61	7.61	4.37	6.10	NA	6.41
2000	OK	Total Electric Industry	7.03	6.14	4.09	5.46	NA	5.88
2000	OR	Total Electric Industry	5.88	5.06	3.56	7.10	NA	4.89
2000	PA	Total Electric Industry	9.53	7.71	5.63	10.71	NA	7.65
2000	RI	Total Electric Industry	11.28	9.50	8.76	25.19	NA	10.18
2000	SC	Total Electric Industry	7.58	6.35	3.74	6.29	NA	5.62
2000	SD	Total Electric Industry	7.42	6.64	4.49	4.30	NA	6.32
2000	TN	Total Electric Industry	6.33	6.28	4.09	8.79	NA	5.58
2000	TX	Total Electric Industry	7.96	6.88	4.42	6.77	NA	6.49
2000	UT	Total Electric Industry	6.29	5.23	3.35	4.14	NA	4.84
2000	VA	Total Electric Industry	7.52	5.65	3.90	5.05	NA	5.94
2000	VT	Total Electric Industry	12.30	10.61	7.31	12.20	NA	10.27
2000	WA	Total Electric Industry	5.13	4.86	3.30	3.65	NA	4.33
2000	WI	Total Electric Industry	7.53	6.03	4.04	7.40	NA	5.71
2000	WV	Total Electric Industry	6.27	5.46	3.76	9.88	NA	5.07
2000	WY	Total Electric Industry	6.50	5.29	3.36	4.87	NA	4.34
2000	US-TOTAL	Total Electric Industry	8.24	7.43	4.64	6.56	NA	6.81
2000	AK	Full-Service Providers	11.45	9.77	7.56	14.17	NA	10.08
2000	AL	Full-Service Providers	7.05	6.58	3.87	7.12	NA	5.61
2000	AR	Full-Service Providers	7.45	5.93	4.20	6.39	NA	5.77
2000	AZ	Full-Service Providers	8.44	7.37	5.27	4.53	NA	7.26
2000	CA	Full-Service Providers	10.85	10.55	7.22	4.79	NA	9.66
2000	CO	Full-Service Providers	7.31	5.55	4.25	7.77	NA	5.88
2000	CT	Full-Service Providers	10.86	9.27	7.32	10.06	NA	9.52
2000	DC	Full-Service Providers	8.03	7.55	4.74	6.67	NA	7.52
2000	DE	Full-Service Providers	8.54	6.12	3.68	14.19	NA	6.17
2000	FL	Full-Service Providers	7.77	6.25	4.84	6.96	NA	6.91
2000	GA	Full-Service Providers	7.60	6.50	4.10	8.51	NA	6.21
2000	HI	Full-Service Providers	16.41	14.81	11.69	14.76	NA	14.03
2000	IA	Full-Service Providers	8.37	6.57	3.89	6.13	NA	5.93
2000	ID	Full-Service Providers	5.39	4.24	3.11	4.13	NA	4.17
2000	IL	Full-Service Providers	8.83	7.53	4.76	5.55	NA	6.99
2000	IN	Full-Service Providers	6.87	5.93	3.81	9.37	NA	5.18
2000	KS	Full-Service Providers	7.65	6.25	4.55	7.29	NA	6.27
2000	KY	Full-Service Providers	5.47	5.14	3.01	4.40	NA	4.18
2000	LA	Full-Service Providers	7.67	7.18	5.00	6.98	NA	6.48
2000	MA	Full-Service Providers	10.53	9.20	8.27	15.34	NA	9.57
2000	MD	Full-Service Providers	7.96	6.55	4.13	8.89	NA	6.74
2000	ME	Full-Service Providers	12.92	10.77	7.18	21.70	NA	9.96
2000	MI	Full-Service Providers	8.53	7.90	5.10	10.77	NA	7.12
2000	MN	Full-Service Providers	7.52	6.36	4.57	7.60	NA	5.87

2000	MO	Full-Service Providers	7.04	5.83	4.43	6.02	NA	6.02
2000	MS	Full-Service Providers	6.93	6.41	4.14	8.33	NA	5.85
2000	MT	Full-Service Providers	6.48	5.70	2.48	7.18	NA	4.74
2000	NC	Full-Service Providers	7.97	6.36	4.58	6.53	NA	6.48
2000	ND	Full-Service Providers	6.44	6.08	3.98	4.19	NA	5.44
2000	NE	Full-Service Providers	6.53	5.42	3.61	6.10	NA	5.31
2000	NH	Full-Service Providers	13.14	10.87	9.10	12.41	NA	11.26
2000	NJ	Full-Service Providers	10.29	9.23	8.16	11.94	NA	9.47
2000	NM	Full-Service Providers	8.36	7.06	4.69	5.64	NA	6.58
2000	NV	Full-Service Providers	7.28	6.74	4.98	4.77	NA	6.17
2000	NY	Full-Service Providers	14.03	12.54	4.97	8.71	NA	11.23
2000	OH	Full-Service Providers	8.61	7.61	4.47	6.10	NA	6.50
2000	OK	Full-Service Providers	7.03	6.14	4.09	5.46	NA	5.88
2000	OR	Full-Service Providers	5.88	5.06	3.56	7.10	NA	4.89
2000	PA	Full-Service Providers	9.35	8.21	5.31	10.60	NA	7.82
2000	RI	Full-Service Providers	11.28	9.71	8.70	20.44	NA	10.20
2000	SC	Full-Service Providers	7.58	6.35	3.74	6.29	NA	5.62
2000	SD	Full-Service Providers	7.42	6.64	4.49	4.30	NA	6.32
2000	TN	Full-Service Providers	6.33	6.28	4.09	8.79	NA	5.58
2000	TX	Full-Service Providers	7.96	6.88	4.42	6.77	NA	6.49
2000	UT	Full-Service Providers	6.29	5.23	3.35	4.14	NA	4.84
2000	VA	Full-Service Providers	7.52	5.65	3.90	5.05	NA	5.94
2000	VT	Full-Service Providers	12.30	10.61	7.31	12.20	NA	10.27
2000	WA	Full-Service Providers	5.13	4.86	3.42	3.65	NA	4.41
2000	WI	Full-Service Providers	7.53	6.03	4.04	7.40	NA	5.71
2000	WV	Full-Service Providers	6.27	5.46	3.76	9.88	NA	5.07
2000	WY	Full-Service Providers	6.50	5.29	3.36	4.87	NA	4.34
2000	US-TOTAL	Full-Service Providers	8.21	7.36	4.57	6.48	NA	6.78
2000	AZ	Restructured Retail Service Providers	0.00	3.68	0.00	0.00	NA	3.68
2000	CA	Restructured Retail Service Providers	13.64	7.82	6.78	9.36	NA	7.63
2000	DE	Restructured Retail Service Providers	5.29	3.71	5.42	0.00	NA	4.08
2000	IL	Restructured Retail Service Providers	0.00	5.49	6.92	0.00	NA	6.28
2000	MA	Restructured Retail Service Providers	11.39	8.39	7.11	14.83	NA	8.15
2000	MD	Restructured Retail Service Providers	4.86	8.81	0.00	0.00	NA	8.52
2000	ME	Restructured Retail Service Providers	12.27	8.47	6.59	9.56	NA	9.39
2000	MI	Restructured Retail Service Providers	6.22	5.62	4.91	0.00	NA	5.03
2000	MT	Restructured Retail Service Providers	11.05	4.58	8.02	0.00	NA	7.49
2000	NH	Restructured Retail Service Providers	14.59	9.26	22.46	0.00	NA	10.72
2000	NJ	Restructured Retail Service Providers	9.53	8.71	13.82	0.00	NA	9.41
2000	NM	Restructured Retail Service Providers	2.82	2.82	2.81	0.00	NA	2.81
2000	NY	Restructured Retail Service Providers	12.30	13.06	9.41	10.63	NA	12.38
2000	OH	Restructured Retail Service Providers	0.00	0.00	2.71	0.00	NA	2.71
2000	PA	Restructured Retail Service Providers	11.69	6.95	6.27	10.96	NA	7.18
2000	RI	Restructured Retail Service Providers	0.00	5.11	12.98	48.98	NA	9.19
2000	WA	Restructured Retail Service Providers	0.00	0.00	2.19	0.00	NA	2.19
2000	US-TOTAL	Restructured Retail Service Providers	12.07	8.65	6.24	11.42	NA	7.97
2000	AZ	Energy-Only Providers	0.00	3.68	0.00	0.00	NA	3.68
2000	CA	Energy-Only Providers	12.27	9.10	8.87	8.44	NA	9.15
2000	DE	Energy-Only Providers	5.20	3.42	3.52	0.00	NA	3.44
2000	IL	Energy-Only Providers	0.00	4.11	4.27	0.00	NA	4.19
2000	MA	Energy-Only Providers	4.44	3.56	3.76	1.69	NA	3.60
2000	MD	Energy-Only Providers	4.21	6.39	0.00	0.00	NA	5.06
2000	ME	Energy-Only Providers	4.07	4.51	4.26	4.33	NA	4.22
2000	MI	Energy-Only Providers	6.22	4.09	4.06	0.00	NA	4.10
2000	MT	Energy-Only Providers	2.42	2.38	7.50	0.00	NA	6.68
2000	NH	Energy-Only Providers	3.08	2.68	2.36	0.00	NA	2.70
2000	NJ	Energy-Only Providers	4.81	4.33	4.11	0.00	NA	4.34
2000	NM	Energy-Only Providers	2.82	2.82	2.81	0.00	NA	2.81
2000	NY	Energy-Only Providers	6.13	7.29	4.86	3.65	NA	6.67
2000	OH	Energy-Only Providers	0.00	0.00	2.51	0.00	NA	2.51
2000	PA	Energy-Only Providers	4.54	4.31	3.95	5.33	NA	4.19
2000	RI	Energy-Only Providers	0.00	3.07	3.20	3.44	NA	3.11
2000	WA	Energy-Only Providers	0.00	0.00	2.14	0.00	NA	2.14
2000	US-TOTAL	Energy-Only Providers	5.69	5.84	5.10	4.47	NA	5.50
2000	CA	Delivery-Only Service	1.36	-1.28	-2.09	0.92	NA	-1.52
2000	DE	Delivery-Only Service	0.09	0.30	1.90	0.00	NA	0.64
2000	IL	Delivery-Only Service	0.00	1.38	2.65	0.00	NA	2.09
2000	MA	Delivery-Only Service	6.94	4.83	3.34	13.14	NA	4.55
2000	MD	Delivery-Only Service	0.66	2.42	0.00	0.00	NA	3.46
2000	ME	Delivery-Only Service	8.20	3.96	2.34	5.22	NA	5.18
2000	MI	Delivery-Only Service	0.00	1.53	0.85	0.00	NA	0.93
2000	MT	Delivery-Only Service	8.63	2.20	0.52	0.00	NA	0.81
2000	NH	Delivery-Only Service	11.51	6.58	20.10	0.00	NA	8.03
2000	NJ	Delivery-Only Service	4.72	4.38	9.71	0.00	NA	5.07
2000	NY	Delivery-Only Service	6.18	5.77	4.55	6.98	NA	5.71
2000	OH	Delivery-Only Service	0.00	0.00	0.19	0.00	NA	0.19
2000	PA	Delivery-Only Service	7.15	2.64	2.32	5.62	NA	2.99
2000	RI	Delivery-Only Service	0.00	2.04	9.77	45.54	NA	6.08
2000	WA	Delivery-Only Service	0.00	0.00	0.05	0.00	NA	0.05
2000	US-TOTAL	Delivery-Only Service	6.37	2.81	1.14	6.95	NA	2.47
2001	AK	Total Electric Industry	12.12	10.29	7.61	14.37	NA	10.54
2001	AL	Total Electric Industry	7.01	6.53	3.79	7.11	NA	5.60
2001	AR	Total Electric Industry	7.72	6.19	4.43	6.91	NA	6.05
2001	AZ	Total Electric Industry	8.30	7.37	5.24	4.93	NA	7.27
2001	CA	Total Electric Industry	12.09	12.15	9.23	8.48	NA	11.22
2001	CO	Total Electric Industry	7.47	5.67	4.48	8.36	NA	6.02
2001	CT	Total Electric Industry	10.90	9.26	7.62	10.00	NA	9.62
2001	DC	Total Electric Industry	7.79	7.45	4.81	6.39	NA	7.40
2001	DE	Total Electric Industry	8.61	7.00	4.81	14.17	NA	6.80
2001	FL	Total Electric Industry	8.59	7.08	5.18	7.60	NA	7.67
2001	GA	Total Electric Industry	7.72	6.61	4.28	8.56	NA	6.39
2001	HI	Total Electric Industry	16.34	14.81	11.68	16.81	NA	14.05
2001	IA	Total Electric Industry	8.41	6.69	4.18	5.67	NA	6.14
2001	ID	Total Electric Industry	6.01	5.13	3.71	4.66	NA	4.92
2001	IL	Total Electric Industry	8.71	7.40	4.65	6.37	NA	6.90
2001	IN	Total Electric Industry	6.92	5.29	4.11	9.06	NA	5.30
2001	KS	Total Electric Industry	7.66	6.20	4.55	8.91	NA	6.24
2001	KY	Total Electric Industry	5.58	5.20	3.04	4.53	NA	4.24
2001	LA	Total Electric Industry	7.92	7.58	5.58	8.43	NA	6.96
2001	MA	Total Electric Industry	12.47	11.64	9.37	15.52	NA	11.55
2001	MD	Total Electric Industry	7.67	6.36	4.37	9.42	NA	6.60

2001	ME	Total Electric Industry	13.13	11.64	7.15	25.40	NA	10.55
2001	MI	Total Electric Industry	8.26	7.54	5.08	10.38	NA	6.97
2001	MN	Total Electric Industry	7.61	6.03	4.34	7.43	NA	5.97
2001	MO	Total Electric Industry	7.00	5.89	4.39	6.08	NA	6.03
2001	MS	Total Electric Industry	7.37	6.94	4.40	8.95	NA	6.26
2001	MT	Total Electric Industry	6.88	5.91	6.59	7.47	NA	6.48
2001	NC	Total Electric Industry	8.12	6.42	4.61	6.68	NA	6.58
2001	ND	Total Electric Industry	6.47	5.99	3.98	3.79	NA	5.48
2001	NE	Total Electric Industry	6.50	5.48	3.76	6.51	NA	5.39
2001	NH	Total Electric Industry	12.49	10.53	9.11	13.28	NA	10.95
2001	NJ	Total Electric Industry	10.21	9.09	8.33	11.21	NA	9.36
2001	NM	Total Electric Industry	8.74	7.50	5.45	6.37	NA	7.16
2001	NV	Total Electric Industry	9.08	8.45	6.56	6.15	NA	7.86
2001	NY	Total Electric Industry	14.04	12.87	5.56	8.77	NA	11.55
2001	OH	Total Electric Industry	8.37	8.46	4.27	5.86	NA	6.62
2001	OK	Total Electric Industry	7.27	6.35	4.29	5.39	NA	6.10
2001	OR	Total Electric Industry	6.29	5.45	4.21	7.33	NA	5.44
2001	PA	Total Electric Industry	9.68	8.62	5.76	11.46	NA	8.01
2001	RI	Total Electric Industry	12.13	11.54	9.36	22.86	NA	11.45
2001	SC	Total Electric Industry	7.69	6.45	3.86	6.39	NA	5.77
2001	SD	Total Electric Industry	7.42	6.55	4.46	3.71	NA	6.35
2001	TN	Total Electric Industry	6.32	6.31	4.05	8.83	NA	5.59
2001	TX	Total Electric Industry	8.86	7.74	5.27	7.56	NA	7.38
2001	UT	Total Electric Industry	6.72	5.58	3.53	4.53	NA	5.21
2001	VA	Total Electric Industry	7.79	5.85	4.16	5.16	NA	6.18
2001	VT	Total Electric Industry	12.67	11.28	7.89	18.85	NA	10.86
2001	WA	Total Electric Industry	5.70	5.45	4.75	4.69	NA	5.34
2001	WI	Total Electric Industry	7.90	6.34	4.36	7.70	NA	6.08
2001	WV	Total Electric Industry	6.26	5.44	3.74	10.36	NA	5.07
2001	WY	Total Electric Industry	6.77	5.41	3.43	5.07	NA	4.46
2001	US-TOTAL	Total Electric Industry	8.58	7.92	5.05	7.20	NA	7.29
2001	AK	Full-Service Providers	12.12	10.29	7.61	14.37	NA	10.54
2001	AL	Full-Service Providers	7.01	6.53	3.79	7.11	NA	5.60
2001	AR	Full-Service Providers	7.72	6.19	4.43	6.91	NA	6.05
2001	AZ	Full-Service Providers	8.30	7.36	5.24	4.93	NA	7.27
2001	CA	Full-Service Providers	12.08	12.41	9.54	8.47	NA	11.41
2001	CO	Full-Service Providers	7.47	5.67	4.48	8.36	NA	6.02
2001	CT	Full-Service Providers	10.91	9.26	7.62	10.00	NA	9.62
2001	DC	Full-Service Providers	7.80	7.47	4.80	5.96	NA	7.42
2001	DE	Full-Service Providers	8.61	7.09	4.90	14.17	NA	7.00
2001	FL	Full-Service Providers	8.59	7.08	5.18	7.60	NA	7.67
2001	GA	Full-Service Providers	7.72	6.61	4.28	8.56	NA	6.39
2001	HI	Full-Service Providers	16.34	14.81	11.68	16.81	NA	14.05
2001	IA	Full-Service Providers	8.41	6.69	4.18	5.67	NA	6.14
2001	ID	Full-Service Providers	6.01	5.13	3.71	4.66	NA	4.92
2001	IL	Full-Service Providers	8.71	7.51	4.57	6.48	NA	7.02
2001	IN	Full-Service Providers	6.92	5.29	4.11	9.06	NA	5.30
2001	KS	Full-Service Providers	7.66	6.20	4.55	8.91	NA	6.24
2001	KY	Full-Service Providers	5.58	5.20	3.04	4.53	NA	4.24
2001	LA	Full-Service Providers	7.92	7.58	5.58	8.43	NA	6.96
2001	MA	Full-Service Providers	12.47	11.77	9.37	15.22	NA	11.60
2001	MD	Full-Service Providers	7.66	6.35	4.31	9.58	NA	6.59
2001	ME	Full-Service Providers	15.24	12.57	7.32	20.21	NA	11.33
2001	MI	Full-Service Providers	8.26	7.54	5.08	10.38	NA	6.98
2001	MN	Full-Service Providers	7.61	6.03	4.34	7.43	NA	5.97
2001	MO	Full-Service Providers	7.00	5.89	4.39	6.08	NA	6.03
2001	MS	Full-Service Providers	7.37	6.94	4.40	8.95	NA	6.26
2001	MT	Full-Service Providers	6.88	6.09	4.57	7.47	NA	6.12
2001	NC	Full-Service Providers	8.12	6.42	4.61	6.68	NA	6.58
2001	ND	Full-Service Providers	6.47	5.99	3.98	3.79	NA	5.48
2001	NE	Full-Service Providers	6.50	5.48	3.76	6.51	NA	5.39
2001	NH	Full-Service Providers	12.49	10.53	9.11	13.28	NA	10.95
2001	NJ	Full-Service Providers	10.22	9.11	8.46	11.17	NA	9.42
2001	NM	Full-Service Providers	8.74	7.50	5.45	6.37	NA	7.16
2001	NV	Full-Service Providers	9.08	8.45	6.56	6.15	NA	7.86
2001	NY	Full-Service Providers	13.99	12.68	5.03	8.56	NA	11.29
2001	OH	Full-Service Providers	8.32	8.44	4.24	5.92	NA	6.65
2001	OK	Full-Service Providers	7.27	6.35	4.29	5.39	NA	6.10
2001	OR	Full-Service Providers	6.29	5.45	4.21	7.33	NA	5.44
2001	PA	Full-Service Providers	9.39	8.80	5.78	11.35	NA	7.95
2001	RI	Full-Service Providers	12.13	11.81	9.37	-13.91	NA	11.52
2001	SC	Full-Service Providers	7.69	6.45	3.86	6.39	NA	5.77
2001	SD	Full-Service Providers	7.42	6.55	4.46	3.71	NA	6.35
2001	TN	Full-Service Providers	6.32	6.31	4.05	8.83	NA	5.59
2001	TX	Full-Service Providers	8.86	7.74	5.29	7.52	NA	7.39
2001	UT	Full-Service Providers	6.72	5.58	3.53	4.53	NA	5.21
2001	VA	Full-Service Providers	7.79	5.85	4.16	5.16	NA	6.18
2001	VT	Full-Service Providers	12.67	11.17	7.89	18.85	NA	10.82
2001	WA	Full-Service Providers	5.70	5.45	4.43	4.69	NA	5.27
2001	WI	Full-Service Providers	7.90	6.34	4.36	7.70	NA	6.08
2001	WV	Full-Service Providers	6.26	5.44	3.74	10.36	NA	5.07
2001	WY	Full-Service Providers	6.77	5.41	3.43	5.07	NA	4.46
2001	US-TOTAL	Full-Service Providers	8.55	7.84	5.01	7.15	NA	7.25
2001	CA	Restructured Retail Service Providers	12.72	6.66	5.41	8.70	NA	6.54
2001	CT	Restructured Retail Service Providers	9.45	9.43	0.00	0.00	NA	9.45
2001	DC	Restructured Retail Service Providers	6.82	7.39	5.41	6.69	NA	7.32
2001	DE	Restructured Retail Service Providers	5.66	5.12	4.40	0.00	NA	4.53
2001	IL	Restructured Retail Service Providers	0.00	6.31	5.14	5.97	NA	5.67
2001	MA	Restructured Retail Service Providers	13.54	10.76	9.37	17.80	NA	10.82
2001	MD	Restructured Retail Service Providers	8.47	6.52	5.29	8.76	NA	6.70
2001	ME	Restructured Retail Service Providers	12.73	10.52	7.08	27.69	NA	10.17
2001	MI	Restructured Retail Service Providers	0.00	7.01	5.39	0.00	NA	6.04
2001	MT	Restructured Retail Service Providers	4.70	4.86	9.85	0.00	NA	8.34
2001	NH	Restructured Retail Service Providers	0.00	9.80	0.00	0.00	NA	9.80
2001	NJ	Restructured Retail Service Providers	8.58	8.71	7.09	12.68	NA	8.07
2001	NY	Restructured Retail Service Providers	15.00	13.55	11.42	11.00	NA	13.30
2001	OH	Restructured Retail Service Providers	9.83	8.90	4.49	4.39	NA	6.14
2001	PA	Restructured Retail Service Providers	11.98	7.98	5.66	18.27	NA	8.38
2001	RI	Restructured Retail Service Providers	0.00	10.49	9.30	20.83	NA	11.00
2001	TX	Restructured Retail Service Providers	9.55	8.93	0.93	407.76	NA	6.30
2001	VA	Restructured Retail Service Providers	7.47	6.14	4.98	5.64	NA	6.75

2001	WA	Restructured Retail Service Providers	0.00	0.00	9.83	0.00	NA	9.83
2001	US-TOTAL	Restructured Retail Service Providers	12.08	9.67	6.07	8.47	NA	8.66
2001	CA	Energy-Only Providers	13.21	8.02	7.49	10.78	NA	8.21
2001	CT	Energy-Only Providers	4.97	5.03	0.00	0.00	NA	4.97
2001	DC	Energy-Only Providers	4.42	4.42	4.39	4.42	NA	4.42
2001	DE	Energy-Only Providers	3.03	4.06	3.62	0.00	NA	3.70
2001	IL	Energy-Only Providers	0.00	4.60	4.18	4.49	NA	4.37
2001	MA	Energy-Only Providers	6.70	6.46	5.89	5.04	NA	6.39
2001	MD	Energy-Only Providers	5.24	4.66	3.70	4.61	NA	4.51
2001	ME	Energy-Only Providers	4.76	5.92	5.02	5.21	NA	5.11
2001	MI	Energy-Only Providers	0.00	6.23	4.80	0.00	NA	5.37
2001	MT	Energy-Only Providers	2.30	2.64	9.20	0.00	NA	7.21
2001	NH	Energy-Only Providers	0.00	6.76	0.00	0.00	NA	6.76
2001	NJ	Energy-Only Providers	4.33	4.60	3.62	8.18	NA	4.21
2001	NY	Energy-Only Providers	7.03	8.28	7.18	4.52	NA	7.79
2001	OH	Energy-Only Providers	3.72	3.81	2.63	3.08	NA	3.03
2001	PA	Energy-Only Providers	4.70	4.68	3.78	5.30	NA	4.43
2001	RI	Energy-Only Providers	0.00	6.62	6.62	5.42	NA	6.53
2001	TX	Energy-Only Providers	5.86	7.35	0.00	401.22	NA	4.74
2001	VA	Energy-Only Providers	4.59	4.42	4.52	4.52	NA	4.53
2001	WA	Energy-Only Providers	0.00	0.00	6.17	0.00	NA	6.17
2001	US-TOTAL	Energy-Only Providers	5.34	6.22	4.69	5.23	NA	5.51
2001	CA	Delivery-Only Service	-0.48	-1.35	-2.08	-2.09	NA	-1.67
2001	CT	Delivery-Only Service	4.48	4.40	0.00	0.00	NA	4.48
2001	DC	Delivery-Only Service	2.40	2.97	1.01	2.27	NA	2.90
2001	DE	Delivery-Only Service	2.63	1.06	0.78	0.00	NA	0.83
2001	IL	Delivery-Only Service	0.00	1.71	0.95	1.48	NA	1.29
2001	MA	Delivery-Only Service	6.84	4.31	3.49	12.77	NA	4.43
2001	MD	Delivery-Only Service	3.23	1.87	1.60	4.15	NA	2.19
2001	ME	Delivery-Only Service	7.97	4.59	2.05	22.48	NA	5.06
2001	MI	Delivery-Only Service	0.00	0.78	0.59	0.00	NA	0.67
2001	MT	Delivery-Only Service	2.39	2.22	0.66	0.00	NA	1.13
2001	NH	Delivery-Only Service	0.00	3.04	0.00	0.00	NA	3.04
2001	NJ	Delivery-Only Service	4.25	4.11	3.47	4.50	NA	3.86
2001	NY	Delivery-Only Service	7.97	5.28	4.24	6.48	NA	5.51
2001	OH	Delivery-Only Service	6.11	5.10	1.86	1.31	NA	3.11
2001	PA	Delivery-Only Service	7.28	3.30	1.88	12.96	NA	3.95
2001	RI	Delivery-Only Service	0.00	3.87	2.67	15.41	NA	4.47
2001	TX	Delivery-Only Service	3.68	1.59	0.93	6.53	NA	1.56
2001	VA	Delivery-Only Service	2.88	1.72	0.45	1.12	NA	2.22
2001	WA	Delivery-Only Service	0.00	0.00	3.66	0.00	NA	3.66
2001	US-TOTAL	Delivery-Only Service	6.74	3.44	1.38	3.24	NA	3.15
2002	AK	Total Electric Industry	12.05	10.13	7.65	14.04	NA	10.46
2002	AL	Total Electric Industry	7.12	6.63	3.82	7.46	NA	5.71
2002	AR	Total Electric Industry	7.25	5.68	4.01	6.52	NA	5.61
2002	AZ	Total Electric Industry	8.27	7.28	5.20	4.56	NA	7.21
2002	CA	Total Electric Industry	12.64	13.36	9.81	6.60	NA	12.19
2002	CO	Total Electric Industry	7.37	5.67	4.52	6.64	NA	6.00
2002	CT	Total Electric Industry	10.96	9.32	7.68	10.35	NA	9.71
2002	DC	Total Electric Industry	7.98	7.32	4.95	6.59	NA	7.34
2002	DE	Total Electric Industry	8.70	7.15	4.85	14.13	NA	6.91
2002	FL	Total Electric Industry	8.16	6.64	5.23	7.43	NA	7.31
2002	GA	Total Electric Industry	7.63	6.46	3.95	8.31	NA	6.24
2002	HI	Total Electric Industry	15.63	14.11	11.02	16.85	NA	13.39
2002	IA	Total Electric Industry	8.35	6.56	4.06	4.92	NA	6.01
2002	ID	Total Electric Industry	6.59	5.71	4.34	5.18	NA	5.58
2002	IL	Total Electric Industry	8.39	7.52	4.89	5.88	NA	6.94
2002	IN	Total Electric Industry	6.91	5.98	3.95	9.75	NA	5.34
2002	KS	Total Electric Industry	7.67	6.28	4.53	9.30	NA	6.31
2002	KY	Total Electric Industry	5.65	5.30	3.09	4.61	NA	4.26
2002	LA	Total Electric Industry	7.10	6.64	4.42	7.05	NA	5.99
2002	MA	Total Electric Industry	10.93	10.02	8.34	13.11	NA	10.06
2002	MD	Total Electric Industry	7.74	6.31	4.01	9.42	NA	6.18
2002	ME	Total Electric Industry	12.74	10.68	7.05	23.39	NA	10.35
2002	MI	Total Electric Industry	8.28	7.79	5.02	10.43	NA	7.09
2002	MN	Total Electric Industry	7.49	5.88	4.07	7.36	NA	5.80
2002	MO	Total Electric Industry	7.06	5.88	4.42	6.20	NA	6.09
2002	MS	Total Electric Industry	7.28	6.83	4.40	8.76	NA	6.24
2002	MT	Total Electric Industry	7.23	6.28	3.71	7.04	NA	5.70
2002	NC	Total Electric Industry	8.19	6.51	4.70	6.70	NA	6.74
2002	ND	Total Electric Industry	6.39	5.85	3.98	3.68	NA	5.45
2002	NE	Total Electric Industry	6.73	5.62	3.89	6.37	NA	5.55
2002	NH	Total Electric Industry	11.89	10.06	9.09	12.84	NA	10.60
2002	NJ	Total Electric Industry	10.38	8.90	7.72	14.81	NA	9.30
2002	NM	Total Electric Industry	8.50	7.22	4.48	6.23	NA	6.73
2002	NV	Total Electric Industry	9.43	9.06	7.25	6.54	NA	8.42
2002	NY	Total Electric Industry	13.55	12.33	5.18	8.68	NA	11.16
2002	OH	Total Electric Industry	8.24	7.81	4.87	5.42	NA	6.77
2002	OK	Total Electric Industry	6.73	5.75	3.81	5.06	NA	5.59
2002	OR	Total Electric Industry	7.12	6.59	4.72	9.44	NA	6.32
2002	PA	Total Electric Industry	9.74	8.50	5.83	11.59	NA	8.06
2002	RI	Total Electric Industry	10.20	8.65	7.96	16.46	NA	9.20
2002	SC	Total Electric Industry	7.72	6.48	3.85	6.44	NA	5.83
2002	SD	Total Electric Industry	7.40	6.24	4.54	3.63	NA	6.26
2002	TN	Total Electric Industry	6.41	6.45	4.15	8.92	NA	5.72
2002	TX	Total Electric Industry	8.05	6.95	4.66	6.55	NA	6.62
2002	UT	Total Electric Industry	6.79	5.60	3.84	4.69	NA	5.39
2002	VA	Total Electric Industry	7.79	5.87	4.13	5.14	NA	6.23
2002	VT	Total Electric Industry	12.78	11.10	7.90	19.26	NA	10.87
2002	WA	Total Electric Industry	6.29	6.11	4.88	4.94	NA	5.88
2002	WI	Total Electric Industry	8.18	6.54	4.43	8.08	NA	6.28
2002	WV	Total Electric Industry	6.23	5.41	3.81	10.01	NA	5.11
2002	WY	Total Electric Industry	6.97	5.71	3.55	5.93	NA	4.68
2002	US-TOTAL	Total Electric Industry	8.44	7.89	4.88	6.75	NA	7.20
2002	AK	Full-Service Providers	12.05	10.13	7.65	14.04	NA	10.46
2002	AL	Full-Service Providers	7.12	6.63	3.82	7.46	NA	5.71
2002	AR	Full-Service Providers	7.25	5.68	4.01	6.52	NA	5.61
2002	AZ	Full-Service Providers	8.27	7.28	5.20	4.56	NA	7.21
2002	CA	Full-Service Providers	12.63	13.84	10.23	6.53	NA	12.52
2002	CO	Full-Service Providers	7.37	5.67	4.52	6.64	NA	6.00
2002	CT	Full-Service Providers	10.96	9.32	7.69	10.34	NA	9.72

2002	DC	Full-Service Providers	7.98	7.51	4.95	4.88	NA	7.47
2002	DE	Full-Service Providers	8.70	7.17	5.20	14.13	NA	7.23
2002	FL	Full-Service Providers	8.16	6.64	5.23	7.43	NA	7.31
2002	GA	Full-Service Providers	7.63	6.46	3.95	8.31	NA	6.24
2002	HI	Full-Service Providers	15.63	14.11	11.02	16.85	NA	13.39
2002	IA	Full-Service Providers	8.35	6.56	4.06	4.92	NA	6.01
2002	ID	Full-Service Providers	6.59	5.71	4.34	5.18	NA	5.58
2002	IL	Full-Service Providers	8.39	7.41	4.75	5.76	NA	7.01
2002	IN	Full-Service Providers	6.91	5.98	3.95	9.75	NA	5.34
2002	KS	Full-Service Providers	7.67	6.28	4.53	9.30	NA	6.31
2002	KY	Full-Service Providers	5.65	5.30	3.09	4.61	NA	4.26
2002	LA	Full-Service Providers	7.10	6.64	4.42	7.05	NA	5.99
2002	MA	Full-Service Providers	10.89	10.21	8.58	12.46	NA	10.26
2002	MD	Full-Service Providers	7.73	6.36	3.49	10.34	NA	6.18
2002	ME	Full-Service Providers	12.95	12.58	6.68	12.19	NA	10.06
2002	MI	Full-Service Providers	8.28	7.91	5.04	10.43	NA	7.15
2002	MN	Full-Service Providers	7.49	5.88	4.07	7.36	NA	5.80
2002	MO	Full-Service Providers	7.06	5.88	4.42	6.20	NA	6.09
2002	MS	Full-Service Providers	7.28	6.83	4.40	8.76	NA	6.24
2002	MT	Full-Service Providers	7.23	6.47	3.87	7.06	NA	6.16
2002	NC	Full-Service Providers	8.19	6.51	4.70	6.70	NA	6.74
2002	ND	Full-Service Providers	6.39	5.85	3.98	3.68	NA	5.45
2002	NE	Full-Service Providers	6.73	5.62	3.89	6.37	NA	5.55
2002	NH	Full-Service Providers	11.88	10.05	9.11	12.85	NA	10.60
2002	NJ	Full-Service Providers	10.38	8.92	7.68	14.81	NA	9.32
2002	NM	Full-Service Providers	8.50	7.22	4.48	6.23	NA	6.73
2002	NV	Full-Service Providers	9.43	9.06	7.25	6.54	NA	8.42
2002	NY	Full-Service Providers	13.46	12.05	4.63	8.46	NA	10.89
2002	OH	Full-Service Providers	7.98	7.72	4.73	5.42	NA	6.62
2002	OK	Full-Service Providers	6.73	5.75	3.81	5.06	NA	5.59
2002	OR	Full-Service Providers	7.12	6.59	4.72	9.44	NA	6.32
2002	PA	Full-Service Providers	9.57	8.51	5.84	11.33	NA	7.98
2002	RI	Full-Service Providers	10.21	8.69	7.83	14.94	NA	9.22
2002	SC	Full-Service Providers	7.72	6.48	3.85	6.44	NA	5.83
2002	SD	Full-Service Providers	7.40	6.24	4.54	3.63	NA	6.26
2002	TN	Full-Service Providers	6.41	6.45	4.15	8.92	NA	5.72
2002	TX	Full-Service Providers	8.05	6.95	4.66	6.55	NA	6.62
2002	UT	Full-Service Providers	6.79	5.60	3.84	4.69	NA	5.39
2002	VA	Full-Service Providers	7.79	5.87	4.13	5.14	NA	6.22
2002	VT	Full-Service Providers	12.78	11.10	7.90	19.26	NA	10.87
2002	WA	Full-Service Providers	6.29	6.11	4.23	4.94	NA	5.77
2002	WI	Full-Service Providers	8.18	6.54	4.43	8.08	NA	6.28
2002	WV	Full-Service Providers	6.23	5.41	3.81	10.01	NA	5.11
2002	WY	Full-Service Providers	6.97	5.71	3.55	5.93	NA	4.68
2002	US-TOTAL	Full-Service Providers	8.40	7.77	4.78	6.65	NA	7.13
2002	CA	Restructured Retail Service Providers	13.92	9.58	8.35	22.89	NA	9.09
2002	CT	Restructured Retail Service Providers	10.45	9.26	7.14	17.73	NA	9.08
2002	DC	Restructured Retail Service Providers	7.90	7.19	0.00	7.16	NA	7.20
2002	DE	Restructured Retail Service Providers	0.00	4.85	3.90	0.00	NA	3.93
2002	IL	Restructured Retail Service Providers	0.00	8.26	5.29	7.05	NA	6.38
2002	MA	Restructured Retail Service Providers	13.86	9.51	7.74	17.20	NA	9.18
2002	MD	Restructured Retail Service Providers	7.94	6.07	5.87	7.77	NA	6.19
2002	ME	Restructured Retail Service Providers	12.73	10.49	7.10	25.77	NA	10.38
2002	MI	Restructured Retail Service Providers	0.00	6.30	4.70	0.00	NA	5.64
2002	MT	Restructured Retail Service Providers	6.04	4.99	3.51	6.01	NA	3.83
2002	NH	Restructured Retail Service Providers	13.00	11.72	8.52	12.61	NA	10.48
2002	NJ	Restructured Retail Service Providers	10.39	7.81	8.29	0.00	NA	8.16
2002	NY	Restructured Retail Service Providers	15.11	13.13	8.70	10.69	NA	12.56
2002	OH	Restructured Retail Service Providers	10.56	8.33	5.64	4.75	NA	7.73
2002	PA	Restructured Retail Service Providers	12.06	8.41	5.72	16.54	NA	9.03
2002	RI	Restructured Retail Service Providers	9.46	8.45	8.30	16.71	NA	9.04
2002	VA	Restructured Retail Service Providers	8.72	6.75	5.55	5.68	NA	7.31
2002	WA	Restructured Retail Service Providers	0.00	0.00	13.60	0.00	NA	13.60
2002	US-TOTAL	Restructured Retail Service Providers	12.00	9.61	6.61	9.69	NA	8.77
2002	CA	Energy-Only Providers	8.12	6.00	6.18	17.16	NA	6.14
2002	CT	Energy-Only Providers	5.23	4.72	4.10	4.76	NA	4.73
2002	DC	Energy-Only Providers	5.27	4.25	0.00	4.71	NA	4.30
2002	DE	Energy-Only Providers	0.00	3.97	3.57	0.00	NA	3.58
2002	IL	Energy-Only Providers	0.00	5.69	3.67	3.97	NA	4.37
2002	MA	Energy-Only Providers	6.34	5.35	4.51	4.55	NA	5.12
2002	MD	Energy-Only Providers	4.77	4.27	4.51	4.59	NA	4.44
2002	ME	Energy-Only Providers	5.02	5.61	5.01	3.90	NA	5.21
2002	MI	Energy-Only Providers	0.00	5.56	4.41	0.00	NA	5.09
2002	MT	Energy-Only Providers	3.07	3.15	3.28	3.27	NA	3.26
2002	NH	Energy-Only Providers	10.23	8.95	5.72	9.84	NA	7.70
2002	NJ	Energy-Only Providers	6.13	4.35	5.08	0.00	NA	4.79
2002	NY	Energy-Only Providers	7.25	7.93	5.62	4.06	NA	7.31
2002	OH	Energy-Only Providers	4.45	4.05	2.69	3.00	NA	3.56
2002	PA	Energy-Only Providers	5.83	5.50	4.33	4.53	NA	5.36
2002	RI	Energy-Only Providers	4.94	4.83	5.60	4.25	NA	5.09
2002	VA	Energy-Only Providers	4.50	4.33	4.46	4.46	NA	4.45
2002	WA	Energy-Only Providers	0.00	0.00	10.07	0.00	NA	10.07
2002	US-TOTAL	Energy-Only Providers	5.43	5.86	4.53	4.30	NA	5.27
2002	CA	Delivery-Only Service	5.80	3.57	2.17	5.73	NA	2.95
2002	CT	Delivery-Only Service	5.22	4.54	3.05	12.97	NA	4.34
2002	DC	Delivery-Only Service	2.63	2.94	0.00	2.46	NA	2.90
2002	DE	Delivery-Only Service	0.00	0.88	0.33	0.00	NA	0.35
2002	IL	Delivery-Only Service	0.00	2.57	1.62	3.08	NA	2.02
2002	MA	Delivery-Only Service	7.52	4.16	3.23	12.65	NA	4.06
2002	MD	Delivery-Only Service	3.17	1.80	1.35	3.18	NA	1.74
2002	ME	Delivery-Only Service	7.71	4.88	2.09	21.86	NA	5.17
2002	MI	Delivery-Only Service	0.00	0.73	0.29	0.00	NA	0.55
2002	MT	Delivery-Only Service	2.97	1.83	0.22	2.74	NA	0.57
2002	NH	Delivery-Only Service	2.77	2.76	2.79	2.77	NA	2.78
2002	NJ	Delivery-Only Service	4.26	3.47	3.22	0.00	NA	3.37
2002	NY	Delivery-Only Service	7.87	5.20	3.09	6.63	NA	5.26
2002	OH	Delivery-Only Service	6.11	4.28	2.95	1.75	NA	4.17
2002	PA	Delivery-Only Service	6.23	2.91	1.39	12.01	NA	3.67
2002	RI	Delivery-Only Service	4.52	3.62	2.70	12.46	NA	3.95
2002	VA	Delivery-Only Service	4.22	2.42	1.09	1.22	NA	2.86
2002	WA	Delivery-Only Service	0.00	0.00	3.54	0.00	NA	3.54

2002	US-TOTAL	Delivery-Only Service	6.57	3.75	2.08	5.39	NA	3.50
2003	AK	Total Electric Industry	11.98	10.49	7.86	NA	0.00	10.50
2003	AL	Total Electric Industry	7.39	6.85	3.98	NA	0.00	5.88
2003	AR	Total Electric Industry	7.24	5.54	4.04	NA	0.00	5.57
2003	AZ	Total Electric Industry	8.35	7.09	5.37	NA	0.00	7.34
2003	CA	Total Electric Industry	12.23	12.48	9.59	NA	5.80	11.78
2003	CO	Total Electric Industry	8.14	6.60	5.10	NA	7.32	6.77
2003	CT	Total Electric Industry	11.31	9.93	7.99	NA	7.72	10.16
2003	DC	Total Electric Industry	7.84	7.35	5.57	NA	7.64	7.40
2003	DE	Total Electric Industry	8.59	7.31	5.15	NA	0.00	6.96
2003	FL	Total Electric Industry	8.55	7.13	5.41	NA	7.21	7.72
2003	GA	Total Electric Industry	7.70	6.66	4.02	NA	4.81	6.32
2003	HI	Total Electric Industry	16.73	15.02	12.20	NA	0.00	14.47
2003	IA	Total Electric Industry	8.57	6.24	4.16	NA	0.00	6.11
2003	ID	Total Electric Industry	6.24	5.56	4.16	NA	0.00	5.22
2003	IL	Total Electric Industry	8.38	7.30	4.86	NA	5.87	6.86
2003	IN	Total Electric Industry	7.04	6.12	3.92	NA	8.36	5.37
2003	KS	Total Electric Industry	7.71	6.42	4.61	NA	0.00	6.35
2003	KY	Total Electric Industry	5.81	5.37	3.21	NA	0.00	4.42
2003	LA	Total Electric Industry	7.84	7.42	5.57	NA	7.32	6.93
2003	MA	Total Electric Industry	11.60	10.48	8.93	NA	4.09	10.56
2003	MD	Total Electric Industry	7.73	6.95	4.89	NA	5.78	6.45
2003	ME	Total Electric Industry	12.37	10.34	6.35	NA	0.00	9.79
2003	MI	Total Electric Industry	8.35	7.55	4.96	NA	8.21	6.85
2003	MN	Total Electric Industry	7.65	6.12	4.36	NA	0.00	6.01
2003	MO	Total Electric Industry	6.96	5.78	4.49	NA	0.00	6.02
2003	MS	Total Electric Industry	7.60	7.25	4.48	NA	0.00	6.46
2003	MT	Total Electric Industry	7.56	6.85	4.03	NA	0.00	6.14
2003	NC	Total Electric Industry	8.32	6.65	4.79	NA	0.00	6.86
2003	ND	Total Electric Industry	6.49	5.64	3.96	NA	0.00	5.47
2003	NE	Total Electric Industry	6.87	5.81	4.18	NA	0.00	5.64
2003	NH	Total Electric Industry	11.98	10.30	9.75	NA	0.00	10.83
2003	NJ	Total Electric Industry	10.67	9.11	7.99	NA	7.15	9.48
2003	NM	Total Electric Industry	8.69	7.36	4.95	NA	0.00	7.00
2003	NV	Total Electric Industry	9.02	8.79	7.30	NA	0.00	8.29
2003	NY	Total Electric Industry	14.31	12.93	7.14	NA	9.38	12.44
2003	OH	Total Electric Industry	8.26	7.55	4.79	NA	6.17	6.73
2003	OK	Total Electric Industry	7.47	6.38	4.59	NA	0.00	6.35
2003	OR	Total Electric Industry	7.06	6.38	4.63	NA	6.68	6.18
2003	PA	Total Electric Industry	9.59	8.62	5.80	NA	7.78	8.02
2003	RI	Total Electric Industry	11.61	10.09	8.88	NA	0.00	10.47
2003	SC	Total Electric Industry	8.01	6.81	4.00	NA	0.00	6.08
2003	SD	Total Electric Industry	7.47	6.04	4.51	NA	0.00	6.35
2003	TN	Total Electric Industry	6.55	6.68	4.29	NA	0.00	5.84
2003	TX	Total Electric Industry	9.16	7.84	5.27	NA	6.62	7.50
2003	UT	Total Electric Industry	6.90	5.59	3.79	NA	6.01	5.41
2003	VA	Total Electric Industry	7.76	5.74	4.23	NA	5.46	6.27
2003	VT	Total Electric Industry	12.82	11.29	8.05	NA	0.00	10.98
2003	WA	Total Electric Industry	6.31	6.07	4.76	NA	6.45	5.86
2003	WI	Total Electric Industry	8.67	6.97	4.71	NA	0.00	6.64
2003	WV	Total Electric Industry	6.24	5.45	3.81	NA	0.00	5.13
2003	WY	Total Electric Industry	7.04	5.74	3.65	NA	0.00	4.76
2003	US-TOTAL	Total Electric Industry	8.72	8.03	5.11	NA	7.54	7.44
2003	AK	Full-Service Providers	11.98	10.49	7.86	NA	0.00	10.50
2003	AL	Full-Service Providers	7.39	6.85	3.98	NA	0.00	5.88
2003	AR	Full-Service Providers	7.24	5.54	4.04	NA	0.00	5.57
2003	AZ	Full-Service Providers	8.35	7.09	5.37	NA	0.00	7.34
2003	CA	Full-Service Providers	12.23	12.83	9.79	NA	7.38	12.05
2003	CO	Full-Service Providers	8.14	6.60	5.10	NA	7.32	6.77
2003	CT	Full-Service Providers	11.34	9.93	8.01	NA	7.72	10.18
2003	DC	Full-Service Providers	7.85	7.52	5.86	NA	0.00	7.58
2003	DE	Full-Service Providers	8.59	7.32	5.61	NA	0.00	7.43
2003	FL	Full-Service Providers	8.55	7.13	5.41	NA	7.21	7.72
2003	GA	Full-Service Providers	7.70	6.66	4.02	NA	4.81	6.32
2003	HI	Full-Service Providers	16.73	15.02	12.20	NA	0.00	14.47
2003	IA	Full-Service Providers	8.57	6.24	4.16	NA	0.00	6.11
2003	ID	Full-Service Providers	6.24	5.56	4.16	NA	0.00	5.22
2003	IL	Full-Service Providers	8.38	7.35	4.74	NA	5.87	7.07
2003	IN	Full-Service Providers	7.04	6.12	3.92	NA	8.36	5.37
2003	KS	Full-Service Providers	7.71	6.42	4.61	NA	0.00	6.35
2003	KY	Full-Service Providers	5.81	5.37	3.21	NA	0.00	4.42
2003	LA	Full-Service Providers	7.84	7.42	5.57	NA	7.32	6.93
2003	MA	Full-Service Providers	11.55	10.78	9.26	NA	4.09	10.82
2003	MD	Full-Service Providers	7.72	7.10	4.40	NA	5.31	6.46
2003	ME	Full-Service Providers	8.66	7.45	4.03	NA	0.00	4.70
2003	MI	Full-Service Providers	8.35	7.59	4.98	NA	8.21	7.04
2003	MN	Full-Service Providers	7.65	6.12	4.36	NA	0.00	6.01
2003	MO	Full-Service Providers	6.96	5.78	4.49	NA	0.00	6.02
2003	MS	Full-Service Providers	7.60	7.25	4.48	NA	0.00	6.46
2003	MT	Full-Service Providers	7.56	6.99	4.29	NA	0.00	6.65
2003	NC	Full-Service Providers	8.32	6.65	4.79	NA	0.00	6.86
2003	ND	Full-Service Providers	6.49	5.64	3.96	NA	0.00	5.47
2003	NE	Full-Service Providers	6.87	5.81	4.18	NA	0.00	5.64
2003	NH	Full-Service Providers	11.98	10.31	9.91	NA	0.00	10.88
2003	NJ	Full-Service Providers	10.68	9.13	7.77	NA	7.15	9.56
2003	NM	Full-Service Providers	8.69	7.36	4.95	NA	0.00	7.00
2003	NV	Full-Service Providers	9.02	8.79	7.30	NA	0.00	8.29
2003	NY	Full-Service Providers	14.28	13.17	8.79	NA	9.96	13.21
2003	OH	Full-Service Providers	7.95	7.16	4.63	NA	6.17	6.45
2003	OK	Full-Service Providers	7.47	6.38	4.59	NA	0.00	6.35
2003	OR	Full-Service Providers	7.06	6.38	4.63	NA	6.68	6.18
2003	PA	Full-Service Providers	9.50	8.70	5.81	NA	7.64	7.99
2003	RI	Full-Service Providers	11.61	10.19	9.14	NA	0.00	10.64
2003	SC	Full-Service Providers	8.01	6.81	4.00	NA	0.00	6.08
2003	SD	Full-Service Providers	7.47	6.04	4.51	NA	0.00	6.35
2003	TN	Full-Service Providers	6.55	6.68	4.29	NA	0.00	5.84
2003	TX	Full-Service Providers	9.16	7.84	5.27	NA	6.62	7.50
2003	UT	Full-Service Providers	6.90	5.59	3.79	NA	6.01	5.41
2003	VA	Full-Service Providers	7.76	5.74	4.23	NA	5.46	6.27
2003	VT	Full-Service Providers	12.82	11.29	8.05	NA	0.00	10.98
2003	WA	Full-Service Providers	6.31	6.06	4.25	NA	6.45	5.78

2003	WI	Full-Service Providers	8.67	6.97	4.71	NA	0.00	6.64
2003	WV	Full-Service Providers	6.24	5.45	3.81	NA	0.00	5.13
2003	WY	Full-Service Providers	7.04	5.74	3.65	NA	0.00	4.76
2003	US-TOTAL	Full-Service Providers	8.68	7.89	5.01	NA	6.82	7.38
2003	CA	Restructured Retail Service Providers	12.84	9.66	8.90	NA	3.94	9.27
2003	CT	Restructured Retail Service Providers	10.38	9.71	7.33	NA	0.00	9.44
2003	DC	Restructured Retail Service Providers	7.79	7.20	5.43	NA	7.64	7.19
2003	DE	Restructured Retail Service Providers	0.00	4.66	4.62	NA	0.00	4.62
2003	IL	Restructured Retail Service Providers	0.00	7.00	5.11	NA	0.00	5.75
2003	MA	Restructured Retail Service Providers	13.91	9.56	8.14	NA	0.00	9.31
2003	MD	Restructured Retail Service Providers	7.87	6.33	6.28	NA	5.88	6.40
2003	ME	Restructured Retail Service Providers	12.44	10.37	6.83	NA	0.00	10.14
2003	MI	Restructured Retail Service Providers	0.00	5.96	4.91	NA	0.00	5.00
2003	MT	Restructured Retail Service Providers	4.95	5.47	3.77	NA	0.00	4.06
2003	NH	Restructured Retail Service Providers	0.00	7.35	6.97	NA	0.00	6.99
2003	NJ	Restructured Retail Service Providers	10.48	8.82	8.50	NA	0.00	8.75
2003	NY	Restructured Retail Service Providers	14.81	12.52	5.68	NA	9.31	10.67
2003	OH	Restructured Retail Service Providers	10.31	8.97	5.65	NA	0.00	8.17
2003	PA	Restructured Retail Service Providers	11.47	8.23	5.70	NA	9.42	8.32
2003	RI	Restructured Retail Service Providers	0.00	9.36	8.02	NA	0.00	8.78
2003	VA	Restructured Retail Service Providers	9.85	0.00	0.00	NA	0.00	9.85
2003	WA	Restructured Retail Service Providers	0.00	9.48	9.03	NA	0.00	9.04
2003	US-TOTAL	Restructured Retail Service Providers	11.54	9.82	6.26	NA	8.23	8.44
2003	CA	Energy-Only Providers	7.41	5.76	6.18	NA	3.47	5.94
2003	CT	Energy-Only Providers	5.20	5.05	4.23	NA	0.00	4.91
2003	DC	Energy-Only Providers	5.19	4.21	4.33	NA	5.08	4.31
2003	DE	Energy-Only Providers	0.00	4.02	4.41	NA	0.00	4.41
2003	IL	Energy-Only Providers	0.00	4.70	3.67	NA	0.00	4.02
2003	MA	Energy-Only Providers	6.19	5.16	4.80	NA	0.00	5.09
2003	MD	Energy-Only Providers	4.74	4.21	4.67	NA	4.62	4.55
2003	ME	Energy-Only Providers	5.01	5.33	4.49	NA	0.00	4.98
2003	MI	Energy-Only Providers	0.00	5.18	4.43	NA	0.00	4.50
2003	MT	Energy-Only Providers	2.30	3.66	3.48	NA	0.00	3.51
2003	NH	Energy-Only Providers	0.00	4.95	4.52	NA	0.00	4.55
2003	NJ	Energy-Only Providers	5.90	5.35	5.14	NA	0.00	5.27
2003	NY	Energy-Only Providers	7.98	8.22	3.99	NA	6.93	7.02
2003	OH	Energy-Only Providers	4.48	4.28	3.01	NA	0.00	3.89
2003	PA	Energy-Only Providers	5.97	5.45	4.51	NA	6.84	5.37
2003	RI	Energy-Only Providers	0.00	4.89	4.81	NA	0.00	4.86
2003	VA	Energy-Only Providers	5.50	0.00	0.00	NA	0.00	5.50
2003	WA	Energy-Only Providers	0.00	8.47	8.47	NA	0.00	8.47
2003	US-TOTAL	Energy-Only Providers	5.43	6.02	4.47	NA	6.16	5.30
2003	CA	Delivery-Only Service	5.43	3.90	2.72	NA	0.47	3.33
2003	CT	Delivery-Only Service	5.19	4.66	3.11	NA	0.00	4.53
2003	DC	Delivery-Only Service	2.60	2.99	1.10	NA	2.56	2.88
2003	DE	Delivery-Only Service	0.00	0.64	0.21	NA	0.00	0.21
2003	IL	Delivery-Only Service	0.00	2.30	1.44	NA	0.00	1.73
2003	MA	Delivery-Only Service	7.72	4.40	3.35	NA	0.00	4.22
2003	MD	Delivery-Only Service	3.13	2.11	1.61	NA	1.26	1.85
2003	ME	Delivery-Only Service	7.43	5.04	2.34	NA	0.00	5.16
2003	MI	Delivery-Only Service	0.00	0.78	0.48	NA	0.00	0.51
2003	MT	Delivery-Only Service	2.65	1.81	0.30	NA	0.00	0.55
2003	NH	Delivery-Only Service	0.00	2.40	2.44	NA	0.00	2.44
2003	NJ	Delivery-Only Service	4.58	3.47	3.36	NA	0.00	3.48
2003	NY	Delivery-Only Service	6.82	4.30	1.69	NA	2.37	3.65
2003	OH	Delivery-Only Service	5.83	4.69	2.64	NA	0.00	4.28
2003	PA	Delivery-Only Service	5.50	2.78	1.18	NA	2.58	2.95
2003	RI	Delivery-Only Service	0.00	4.47	3.21	NA	0.00	3.92
2003	VA	Delivery-Only Service	4.35	0.00	0.00	NA	0.00	4.35
2003	WA	Delivery-Only Service	0.00	1.01	0.56	NA	0.00	0.57
2003	US-TOTAL	Delivery-Only Service	6.11	3.80	1.80	NA	2.07	3.13
2004	AK	Total Electric Industry	12.44	10.99	8.33	NA	0.00	10.99
2004	AL	Total Electric Industry	7.62	7.12	4.15	NA	0.00	6.08
2004	AR	Total Electric Industry	7.36	5.64	4.16	NA	0.00	5.67
2004	AZ	Total Electric Industry	8.46	7.28	5.35	NA	0.00	7.45
2004	CA	Total Electric Industry	12.20	11.64	9.27	NA	6.42	11.35
2004	CO	Total Electric Industry	8.42	6.89	5.11	NA	5.81	6.95
2004	CT	Total Electric Industry	11.63	9.90	7.89	NA	7.25	10.26
2004	DC	Total Electric Industry	8.00	7.45	4.74	NA	7.37	7.47
2004	DE	Total Electric Industry	8.78	7.44	6.06	NA	0.00	7.53
2004	FL	Total Electric Industry	8.99	7.61	5.84	NA	7.45	8.16
2004	GA	Total Electric Industry	7.86	6.88	4.43	NA	5.12	6.58
2004	HI	Total Electric Industry	18.06	16.19	13.35	NA	0.00	15.70
2004	IA	Total Electric Industry	8.96	6.75	4.33	NA	0.00	6.40
2004	ID	Total Electric Industry	6.10	5.37	3.82	NA	0.00	4.97
2004	IL	Total Electric Industry	8.37	7.54	4.65	NA	5.70	6.80
2004	IN	Total Electric Industry	7.30	6.31	4.13	NA	8.76	5.58
2004	KS	Total Electric Industry	7.74	6.45	4.69	NA	0.00	6.37
2004	KY	Total Electric Industry	6.11	5.60	3.34	NA	0.00	4.63
2004	LA	Total Electric Industry	8.05	7.58	5.82	NA	7.09	7.13
2004	MA	Total Electric Industry	11.75	10.99	8.48	NA	4.65	10.77
2004	MD	Total Electric Industry	7.80	7.56	5.99	NA	6.46	7.15
2004	ME	Total Electric Industry	12.16	9.89	6.56	NA	0.00	9.69
2004	MI	Total Electric Industry	8.33	7.57	4.92	NA	7.89	6.94
2004	MN	Total Electric Industry	7.92	6.31	4.63	NA	6.75	6.24
2004	MO	Total Electric Industry	6.97	5.80	4.62	NA	4.91	6.07
2004	MS	Total Electric Industry	8.21	7.99	4.83	NA	0.00	7.00
2004	MT	Total Electric Industry	7.86	7.42	4.15	NA	0.00	6.40
2004	NC	Total Electric Industry	8.45	6.70	4.88	NA	0.00	6.97
2004	ND	Total Electric Industry	6.79	5.86	4.13	NA	0.00	5.69
2004	NE	Total Electric Industry	6.96	5.84	4.28	NA	0.00	5.70
2004	NH	Total Electric Industry	12.49	10.99	10.01	NA	0.00	11.37
2004	NJ	Total Electric Industry	11.23	9.96	9.03	NA	10.94	10.29
2004	NM	Total Electric Industry	8.67	7.39	5.22	NA	0.00	7.10
2004	NV	Total Electric Industry	9.69	9.08	7.24	NA	0.00	8.56
2004	NY	Total Electric Industry	14.54	12.98	7.04	NA	7.92	12.55
2004	OH	Total Electric Industry	8.45	7.75	4.89	NA	9.21	6.89
2004	OK	Total Electric Industry	7.72	6.55	4.76	NA	0.00	6.50
2004	OR	Total Electric Industry	7.18	6.45	4.43	NA	6.50	6.21
2004	PA	Total Electric Industry	9.58	8.51	5.87	NA	7.32	8.00
2004	RI	Total Electric Industry	12.19	10.53	9.37	NA	0.00	10.96

2004	SC	Total Electric Industry	8.12	6.91	4.13	NA	0.00	6.22
2004	SD	Total Electric Industry	7.65	6.18	4.59	NA	0.00	6.44
2004	TN	Total Electric Industry	6.90	7.05	4.46	NA	11.75	6.14
2004	TX	Total Electric Industry	9.73	7.90	5.87	NA	7.02	7.95
2004	UT	Total Electric Industry	7.21	5.90	4.01	NA	6.57	5.69
2004	VA	Total Electric Industry	7.99	5.88	4.27	NA	6.25	6.43
2004	VT	Total Electric Industry	12.94	11.42	7.96	NA	0.00	11.02
2004	WA	Total Electric Industry	6.37	6.17	4.28	NA	6.44	5.80
2004	WI	Total Electric Industry	9.07	7.24	4.93	NA	0.00	6.88
2004	WV	Total Electric Industry	6.23	5.46	3.83	NA	5.70	5.13
2004	WY	Total Electric Industry	7.21	5.98	3.91	NA	0.00	4.98
2004	US-TOTAL	Total Electric Industry	8.95	8.17	5.25	NA	7.18	7.61
2004	AK	Full-Service Providers	12.44	10.99	8.33	NA	0.00	10.99
2004	AL	Full-Service Providers	7.62	7.12	4.15	NA	0.00	6.08
2004	AR	Full-Service Providers	7.36	5.64	4.16	NA	0.00	5.67
2004	AZ	Full-Service Providers	8.46	7.28	5.35	NA	0.00	7.45
2004	CA	Full-Service Providers	12.20	11.81	9.33	NA	8.03	11.53
2004	CO	Full-Service Providers	8.42	6.89	5.11	NA	5.81	6.95
2004	CT	Full-Service Providers	11.63	9.90	7.90	NA	7.25	10.27
2004	DC	Full-Service Providers	7.97	7.40	4.63	NA	0.00	7.46
2004	DE	Full-Service Providers	8.78	7.44	5.82	NA	0.00	7.61
2004	FL	Full-Service Providers	8.99	7.61	5.84	NA	7.45	8.16
2004	GA	Full-Service Providers	7.86	6.88	4.43	NA	5.12	6.58
2004	HI	Full-Service Providers	18.06	16.19	13.35	NA	0.00	15.70
2004	IA	Full-Service Providers	8.96	6.75	4.33	NA	0.00	6.40
2004	ID	Full-Service Providers	6.10	5.37	3.84	NA	0.00	4.98
2004	IL	Full-Service Providers	8.37	8.03	4.57	NA	5.70	7.16
2004	IN	Full-Service Providers	7.30	6.31	4.13	NA	8.76	5.58
2004	KS	Full-Service Providers	7.74	6.45	4.69	NA	0.00	6.37
2004	KY	Full-Service Providers	6.11	5.60	3.34	NA	0.00	4.63
2004	LA	Full-Service Providers	8.05	7.58	5.82	NA	7.09	7.13
2004	MA	Full-Service Providers	11.72	11.57	8.47	NA	3.86	11.10
2004	MD	Full-Service Providers	7.78	7.62	5.60	NA	7.42	7.23
2004	ME	Full-Service Providers	8.41	5.79	4.85	NA	0.00	5.84
2004	MI	Full-Service Providers	8.33	7.66	4.86	NA	7.89	7.03
2004	MN	Full-Service Providers	7.92	6.31	4.63	NA	6.75	6.24
2004	MO	Full-Service Providers	6.97	5.80	4.62	NA	4.91	6.07
2004	MS	Full-Service Providers	8.21	7.99	4.83	NA	0.00	7.00
2004	MT	Full-Service Providers	7.86	7.57	4.54	NA	0.00	7.04
2004	NC	Full-Service Providers	8.45	6.70	4.88	NA	0.00	6.97
2004	ND	Full-Service Providers	6.79	5.86	4.13	NA	0.00	5.69
2004	NE	Full-Service Providers	6.96	5.84	4.28	NA	0.00	5.70
2004	NH	Full-Service Providers	12.49	11.02	10.10	NA	0.00	11.41
2004	NJ	Full-Service Providers	11.25	10.20	9.00	NA	25.28	10.62
2004	NM	Full-Service Providers	8.67	7.39	5.22	NA	0.00	7.10
2004	NV	Full-Service Providers	9.69	9.08	7.24	NA	0.00	8.56
2004	NY	Full-Service Providers	14.60	13.49	8.28	NA	11.75	13.54
2004	OH	Full-Service Providers	8.14	7.34	4.72	NA	9.21	6.60
2004	OK	Full-Service Providers	7.72	6.55	4.76	NA	0.00	6.50
2004	OR	Full-Service Providers	7.18	6.49	4.41	NA	6.50	6.22
2004	PA	Full-Service Providers	9.38	8.56	5.88	NA	7.26	7.91
2004	RI	Full-Service Providers	12.19	10.69	9.80	NA	0.00	11.21
2004	SC	Full-Service Providers	8.12	6.91	4.13	NA	0.00	6.22
2004	SD	Full-Service Providers	7.65	6.18	4.59	NA	0.00	6.44
2004	TN	Full-Service Providers	6.90	7.05	4.46	NA	11.75	6.14
2004	TX	Full-Service Providers	9.73	7.90	5.87	NA	7.02	7.95
2004	UT	Full-Service Providers	7.21	5.90	4.01	NA	6.57	5.69
2004	VA	Full-Service Providers	7.99	5.88	4.27	NA	6.25	6.43
2004	VT	Full-Service Providers	12.94	11.42	7.96	NA	0.00	11.02
2004	WA	Full-Service Providers	6.37	6.17	4.28	NA	6.44	5.80
2004	WI	Full-Service Providers	9.07	7.24	4.93	NA	0.00	6.88
2004	WV	Full-Service Providers	6.23	5.46	3.83	NA	5.70	5.13
2004	WY	Full-Service Providers	7.21	5.98	3.91	NA	0.00	4.98
2004	US-TOTAL	Full-Service Providers	8.91	8.02	5.14	NA	7.47	7.55
2004	CA	Restructured Retail Service Providers	12.55	10.21	9.08	NA	4.09	9.62
2004	CT	Restructured Retail Service Providers	11.56	9.69	7.45	NA	0.00	9.89
2004	DC	Restructured Retail Service Providers	8.28	7.55	4.87	NA	7.37	7.48
2004	DE	Restructured Retail Service Providers	0.00	7.14	6.62	NA	0.00	6.62
2004	ID	Restructured Retail Service Providers	0.00	0.00	0.01	NA	0.00	0.01
2004	IL	Restructured Retail Service Providers	0.00	5.96	4.81	NA	0.00	5.29
2004	MA	Restructured Retail Service Providers	13.12	9.91	8.52	NA	5.03	9.61
2004	MD	Restructured Retail Service Providers	8.75	7.32	6.55	NA	6.41	6.87
2004	ME	Restructured Retail Service Providers	12.23	10.21	6.66	NA	0.00	9.88
2004	MI	Restructured Retail Service Providers	9.62	7.22	5.22	NA	0.00	6.35
2004	MT	Restructured Retail Service Providers	0.00	6.05	3.81	NA	0.00	4.15
2004	NH	Restructured Retail Service Providers	0.00	8.41	7.33	NA	0.00	7.70
2004	NJ	Restructured Retail Service Providers	10.31	9.33	9.05	NA	9.11	9.24
2004	NV	Restructured Retail Service Providers	0.00	0.00	2.34	NA	0.00	2.34
2004	NY	Restructured Retail Service Providers	13.44	12.30	6.15	NA	7.42	10.60
2004	OH	Restructured Retail Service Providers	10.29	9.06	5.72	NA	0.00	8.20
2004	OR	Restructured Retail Service Providers	0.00	5.53	5.28	NA	0.00	5.48
2004	PA	Restructured Retail Service Providers	12.61	8.27	5.81	NA	9.05	8.97
2004	RI	Restructured Retail Service Providers	10.15	9.46	8.20	NA	0.00	8.93
2004	VA	Restructured Retail Service Providers	10.76	15.11	0.00	NA	0.00	10.78
2004	WA	Restructured Retail Service Providers	0.00	1,600.00	4.64	NA	0.00	4.64
2004	US-TOTAL	Restructured Retail Service Providers	11.51	9.61	6.50	NA	6.95	8.55
2004	CA	Energy-Only Providers	6.88	5.90	5.95	NA	3.59	5.90
2004	CT	Energy-Only Providers	6.22	5.24	4.63	NA	0.00	5.46
2004	DC	Energy-Only Providers	5.67	4.54	3.64	NA	4.80	4.59
2004	DE	Energy-Only Providers	0.00	5.10	6.43	NA	0.00	6.43
2004	IL	Energy-Only Providers	0.00	4.15	3.70	NA	0.00	3.89
2004	MA	Energy-Only Providers	5.88	5.63	5.27	NA	4.35	5.53
2004	MD	Energy-Only Providers	5.59	4.93	5.45	NA	5.26	5.31
2004	ME	Energy-Only Providers	5.01	5.43	4.83	NA	0.00	5.10
2004	MI	Energy-Only Providers	6.49	5.42	4.24	NA	0.00	4.91
2004	MT	Energy-Only Providers	0.00	4.16	3.35	NA	0.00	3.47
2004	NH	Energy-Only Providers	0.00	6.17	5.00	NA	0.00	5.40
2004	NJ	Energy-Only Providers	5.79	5.58	5.54	NA	6.84	5.59
2004	NY	Energy-Only Providers	7.32	8.20	4.51	NA	5.04	7.09
2004	OH	Energy-Only Providers	4.74	4.41	3.24	NA	0.00	4.08
2004	OR	Energy-Only Providers	0.00	4.43	4.42	NA	0.00	4.43

2004	PA	Energy-Only Providers	6.18	5.58	4.65	NA	5.88	5.58
2004	RI	Energy-Only Providers	5.38	5.38	5.31	NA	0.00	5.35
2004	VA	Energy-Only Providers	6.44	6.47	0.00	NA	0.00	6.44
2004	WA	Energy-Only Providers	0.00	1,600.00	4.27	NA	0.00	4.28
2004	US-TOTAL	Energy-Only Providers	5.50	6.02	4.60	NA	4.99	5.42
2004	CA	Delivery-Only Service	5.66	4.31	3.14	NA	0.50	3.72
2004	CT	Delivery-Only Service	5.34	4.45	2.82	NA	0.00	4.42
2004	DC	Delivery-Only Service	2.61	3.01	1.23	NA	2.57	2.89
2004	DE	Delivery-Only Service	0.00	2.04	0.19	NA	0.00	0.19
2004	ID	Delivery-Only Service	0.00	0.00	0.01	NA	0.00	0.01
2004	IL	Delivery-Only Service	0.00	1.81	1.11	NA	0.00	1.40
2004	MA	Delivery-Only Service	7.24	4.28	3.25	NA	0.67	4.08
2004	MD	Delivery-Only Service	3.16	2.40	1.10	NA	1.15	1.57
2004	ME	Delivery-Only Service	7.22	4.78	1.83	NA	0.00	4.78
2004	MI	Delivery-Only Service	3.13	1.80	0.98	NA	0.00	1.44
2004	MT	Delivery-Only Service	0.00	1.89	0.46	NA	0.00	0.68
2004	NH	Delivery-Only Service	0.00	2.24	2.33	NA	0.00	2.30
2004	NJ	Delivery-Only Service	4.52	3.75	3.51	NA	2.26	3.65
2004	NV	Delivery-Only Service	0.00	0.00	2.34	NA	0.00	2.34
2004	NY	Delivery-Only Service	6.12	4.10	1.64	NA	2.38	3.51
2004	OH	Delivery-Only Service	5.55	4.65	2.47	NA	0.00	4.12
2004	OR	Delivery-Only Service	0.00	1.10	0.86	NA	0.00	1.05
2004	PA	Delivery-Only Service	6.44	2.69	1.17	NA	3.18	3.38
2004	RI	Delivery-Only Service	4.77	4.08	2.89	NA	0.00	3.57
2004	VA	Delivery-Only Service	4.32	8.63	0.00	NA	0.00	4.35
2004	WA	Delivery-Only Service	0.00	0.00	0.37	NA	0.00	0.37
2004	US-TOTAL	Delivery-Only Service	6.00	3.59	1.90	NA	1.96	3.13
2005	AK	Total Electric Industry	13.30	11.56	9.29	NA	0.00	11.72
2005	AL	Total Electric Industry	8.00	7.50	4.52	NA	0.00	6.46
2005	AR	Total Electric Industry	8.00	6.18	4.74	NA	0.00	6.30
2005	AZ	Total Electric Industry	8.86	7.40	5.85	NA	0.00	7.79
2005	CA	Total Electric Industry	12.51	11.92	9.55	NA	6.55	11.63
2005	CO	Total Electric Industry	9.06	7.62	5.74	NA	5.01	7.64
2005	CT	Total Electric Industry	13.64	11.53	9.40	NA	8.78	12.06
2005	DC	Total Electric Industry	9.10	9.13	14.13	NA	7.37	9.18
2005	DE	Total Electric Industry	9.01	7.60	6.21	NA	0.00	7.76
2005	FL	Total Electric Industry	9.62	8.16	6.46	NA	8.03	8.76
2005	GA	Total Electric Industry	8.64	7.67	5.28	NA	5.90	7.43
2005	HI	Total Electric Industry	20.70	19.04	15.79	NA	0.00	18.33
2005	IA	Total Electric Industry	9.27	6.95	4.56	NA	0.00	6.69
2005	ID	Total Electric Industry	6.29	5.42	3.91	NA	0.00	5.12
2005	IL	Total Electric Industry	8.34	7.75	4.61	NA	5.61	6.95
2005	IN	Total Electric Industry	7.50	6.57	4.42	NA	9.14	5.88
2005	KS	Total Electric Industry	7.90	6.60	4.85	NA	0.00	6.55
2005	KY	Total Electric Industry	6.57	6.01	3.60	NA	0.00	5.01
2005	LA	Total Electric Industry	8.87	8.56	6.71	NA	7.63	8.03
2005	MA	Total Electric Industry	13.44	12.42	9.22	NA	4.80	12.18
2005	MD	Total Electric Industry	8.46	8.97	7.01	NA	7.73	8.13
2005	ME	Total Electric Industry	13.23	10.63	7.28	NA	0.00	10.57
2005	MI	Total Electric Industry	8.40	7.84	5.32	NA	13.07	7.23
2005	MN	Total Electric Industry	8.28	6.59	5.02	NA	6.21	6.61
2005	MO	Total Electric Industry	7.08	5.92	4.54	NA	4.77	6.13
2005	MS	Total Electric Industry	8.71	8.48	5.37	NA	0.00	7.54
2005	MT	Total Electric Industry	8.10	7.43	4.83	NA	0.00	6.72
2005	NC	Total Electric Industry	8.65	6.86	5.04	NA	8.33	7.19
2005	ND	Total Electric Industry	6.99	6.11	4.32	NA	0.00	5.92
2005	NE	Total Electric Industry	7.14	5.98	4.43	NA	0.00	5.87
2005	NH	Total Electric Industry	13.51	12.06	11.48	NA	0.00	12.53
2005	NJ	Total Electric Industry	11.74	10.61	9.76	NA	7.65	10.89
2005	NM	Total Electric Industry	9.13	7.81	5.61	NA	0.00	7.51
2005	NV	Total Electric Industry	10.20	9.48	7.71	NA	9.34	9.02
2005	NY	Total Electric Industry	15.72	14.36	8.23	NA	11.39	13.95
2005	OH	Total Electric Industry	8.51	7.93	5.10	NA	9.03	7.08
2005	OK	Total Electric Industry	7.95	7.00	5.11	NA	0.00	6.85
2005	OR	Total Electric Industry	7.25	6.51	4.83	NA	6.36	6.34
2005	PA	Total Electric Industry	9.86	8.50	6.29	NA	7.22	8.27
2005	RI	Total Electric Industry	13.04	11.71	10.01	NA	0.00	11.97
2005	SC	Total Electric Industry	8.67	7.39	4.55	NA	0.00	6.72
2005	SD	Total Electric Industry	7.77	6.20	4.95	NA	0.00	6.60
2005	TN	Total Electric Industry	6.98	7.17	4.73	NA	11.46	6.31
2005	TX	Total Electric Industry	10.93	8.85	7.14	NA	8.45	9.14
2005	UT	Total Electric Industry	7.52	6.07	4.24	NA	7.20	5.92
2005	VA	Total Electric Industry	8.16	6.05	4.46	NA	6.81	6.64
2005	VT	Total Electric Industry	12.96	11.33	7.77	NA	0.00	10.95
2005	WA	Total Electric Industry	6.54	6.33	4.27	NA	6.44	5.87
2005	WI	Total Electric Industry	9.66	7.67	5.39	NA	0.00	7.48
2005	WV	Total Electric Industry	6.21	5.53	3.85	NA	6.08	5.15
2005	WY	Total Electric Industry	7.48	6.17	3.99	NA	0.00	5.16
2005	US-TOTAL	Total Electric Industry	9.45	8.67	5.73	NA	8.57	8.14
2005	AK	Full-Service Providers	13.30	11.56	9.29	NA	0.00	11.72
2005	AL	Full-Service Providers	8.00	7.50	4.52	NA	0.00	6.46
2005	AR	Full-Service Providers	8.00	6.18	4.74	NA	0.00	6.30
2005	AZ	Full-Service Providers	8.86	7.40	5.85	NA	0.00	7.79
2005	CA	Full-Service Providers	12.49	11.97	9.39	NA	8.11	11.71
2005	CO	Full-Service Providers	9.06	7.62	5.74	NA	5.01	7.64
2005	CT	Full-Service Providers	13.64	11.52	9.42	NA	8.78	12.06
2005	DC	Full-Service Providers	9.09	9.21	1.15	NA	2.54	9.51
2005	DE	Full-Service Providers	9.01	7.60	6.46	NA	0.00	7.94
2005	FL	Full-Service Providers	9.62	8.16	6.46	NA	8.03	8.76
2005	GA	Full-Service Providers	8.64	7.67	5.28	NA	5.90	7.43
2005	HI	Full-Service Providers	20.70	19.04	15.79	NA	0.00	18.33
2005	IA	Full-Service Providers	9.27	6.95	4.56	NA	0.00	6.69
2005	ID	Full-Service Providers	6.29	5.42	3.91	NA	0.00	5.12
2005	IL	Full-Service Providers	8.34	8.41	4.60	NA	5.61	7.37
2005	IN	Full-Service Providers	7.50	6.57	4.42	NA	9.14	5.88
2005	KS	Full-Service Providers	7.90	6.60	4.85	NA	0.00	6.55
2005	KY	Full-Service Providers	6.57	6.01	3.60	NA	0.00	5.01
2005	LA	Full-Service Providers	8.87	8.56	6.71	NA	7.63	8.03
2005	MA	Full-Service Providers	13.25	13.10	9.00	NA	4.05	12.44
2005	MD	Full-Service Providers	8.44	9.19	6.72	NA	0.00	8.31
2005	ME	Full-Service Providers	9.20	8.33	4.80	NA	0.00	6.19

2005	MI	Full-Service Providers	8.40	7.87	5.33	NA	13.07	7.30
2005	MN	Full-Service Providers	8.28	6.59	5.02	NA	6.21	6.61
2005	MO	Full-Service Providers	7.08	5.92	4.54	NA	4.77	6.13
2005	MS	Full-Service Providers	8.71	8.48	5.37	NA	0.00	7.54
2005	MT	Full-Service Providers	8.10	7.43	5.44	NA	0.00	7.33
2005	NC	Full-Service Providers	8.65	6.86	5.04	NA	8.33	7.19
2005	ND	Full-Service Providers	6.99	6.11	4.32	NA	0.00	5.92
2005	NE	Full-Service Providers	7.14	5.98	4.43	NA	0.00	5.87
2005	NH	Full-Service Providers	13.51	12.06	11.61	NA	0.00	12.56
2005	NJ	Full-Service Providers	11.74	10.54	8.81	NA	3.31	10.95
2005	NM	Full-Service Providers	9.13	7.81	5.61	NA	0.00	7.51
2005	NV	Full-Service Providers	10.20	9.48	7.72	NA	9.34	9.03
2005	NY	Full-Service Providers	15.86	15.38	9.80	NA	13.47	15.18
2005	OH	Full-Service Providers	8.19	7.54	4.94	NA	9.03	6.78
2005	OK	Full-Service Providers	7.95	7.00	5.11	NA	0.00	6.85
2005	OR	Full-Service Providers	7.25	6.49	4.63	NA	6.36	6.32
2005	PA	Full-Service Providers	9.81	8.50	6.31	NA	7.22	8.29
2005	RI	Full-Service Providers	13.04	11.88	10.00	NA	0.00	12.12
2005	SC	Full-Service Providers	8.67	7.39	4.55	NA	0.00	6.72
2005	SD	Full-Service Providers	7.77	6.20	4.95	NA	0.00	6.60
2005	TN	Full-Service Providers	6.98	7.17	4.73	NA	11.46	6.31
2005	TX	Full-Service Providers	10.93	8.85	7.14	NA	8.45	9.14
2005	UT	Full-Service Providers	7.52	6.07	4.24	NA	7.20	5.92
2005	VA	Full-Service Providers	8.16	6.05	4.46	NA	6.81	6.64
2005	VT	Full-Service Providers	12.96	11.33	7.77	NA	0.00	10.95
2005	WA	Full-Service Providers	6.54	6.33	4.13	NA	6.44	5.87
2005	WI	Full-Service Providers	9.66	7.67	5.39	NA	0.00	7.48
2005	WV	Full-Service Providers	6.21	5.53	3.85	NA	6.08	5.15
2005	WY	Full-Service Providers	7.48	6.17	3.99	NA	0.00	5.16
2005	US-TOTAL	Full-Service Providers	9.40	8.46	5.61	NA	7.45	8.05
2005	CA	Restructured Retail Service Providers	16.93	11.45	10.15	NA	4.45	10.82
2005	CT	Restructured Retail Service Providers	13.65	11.59	8.17	NA	0.00	12.24
2005	DC	Restructured Retail Service Providers	9.50	9.08	8.00	NA	7.82	8.96
2005	DE	Restructured Retail Service Providers	0.00	7.51	5.59	NA	0.00	5.59
2005	IL	Restructured Retail Service Providers	0.00	5.87	4.63	NA	0.00	5.20
2005	MA	Restructured Retail Service Providers	15.49	11.48	9.77	NA	5.15	11.52
2005	MD	Restructured Retail Service Providers	9.43	8.50	7.23	NA	7.73	7.68
2005	ME	Restructured Retail Service Providers	13.31	10.65	7.45	NA	0.00	10.71
2005	MI	Restructured Retail Service Providers	9.66	7.71	5.26	NA	0.00	6.69
2005	MT	Restructured Retail Service Providers	0.00	5.33	4.42	NA	0.00	4.42
2005	NH	Restructured Retail Service Providers	0.00	11.85	8.79	NA	0.00	9.30
2005	NJ	Restructured Retail Service Providers	12.19	10.84	10.43	NA	10.04	10.66
2005	NV	Restructured Retail Service Providers	0.00	0.00	7.19	NA	0.00	7.19
2005	NY	Restructured Retail Service Providers	13.63	13.34	7.33	NA	11.15	11.91
2005	OH	Restructured Retail Service Providers	10.43	9.32	6.02	NA	0.00	8.55
2005	OR	Restructured Retail Service Providers	0.00	6.95	6.92	NA	0.00	6.93
2005	PA	Restructured Retail Service Providers	11.85	8.50	6.08	NA	7.26	8.03
2005	RI	Restructured Retail Service Providers	0.00	10.99	10.04	NA	0.00	10.78
2005	VA	Restructured Retail Service Providers	10.03	11.56	0.00	NA	0.00	10.04
2005	WA	Restructured Retail Service Providers	0.00	4.92	5.64	NA	0.00	5.62
2005	US-TOTAL	Restructured Retail Service Providers	12.26	10.60	7.08	NA	9.47	9.39
2005	CA	Energy-Only Providers	9.52	6.83	6.68	NA	3.95	6.75
2005	CT	Energy-Only Providers	7.44	6.57	5.46	NA	0.00	6.87
2005	DC	Energy-Only Providers	7.02	6.13	6.87	NA	5.28	6.16
2005	DE	Energy-Only Providers	0.00	5.53	5.40	NA	0.00	5.40
2005	IL	Energy-Only Providers	0.00	4.21	3.74	NA	0.00	3.95
2005	MA	Energy-Only Providers	7.54	6.90	6.36	NA	4.41	6.84
2005	MD	Energy-Only Providers	6.26	6.39	6.07	NA	6.54	6.18
2005	ME	Energy-Only Providers	6.46	6.07	5.55	NA	0.00	6.06
2005	MI	Energy-Only Providers	6.44	5.78	4.37	NA	0.00	5.19
2005	MT	Energy-Only Providers	0.00	3.31	3.94	NA	0.00	3.94
2005	NH	Energy-Only Providers	0.00	9.56	6.08	NA	0.00	6.66
2005	NJ	Energy-Only Providers	7.93	7.14	6.98	NA	7.06	7.07
2005	NV	Energy-Only Providers	0.00	0.00	6.68	NA	0.00	6.68
2005	NY	Energy-Only Providers	9.12	9.73	5.83	NA	8.66	8.78
2005	OH	Energy-Only Providers	5.07	4.69	3.53	NA	0.00	4.42
2005	OR	Energy-Only Providers	0.00	5.64	6.16	NA	0.00	6.02
2005	PA	Energy-Only Providers	7.02	6.41	5.20	NA	6.05	6.04
2005	RI	Energy-Only Providers	0.00	6.44	6.28	NA	0.00	6.41
2005	VA	Energy-Only Providers	7.55	7.48	0.00	NA	0.00	7.55
2005	WA	Energy-Only Providers	0.00	4.03	5.21	NA	0.00	5.17
2005	US-TOTAL	Energy-Only Providers	6.54	7.15	5.31	NA	7.40	6.41
2005	CA	Delivery-Only Service	7.42	4.62	3.48	NA	0.50	4.07
2005	CT	Delivery-Only Service	6.22	5.02	2.71	NA	0.00	5.37
2005	DC	Delivery-Only Service	2.48	2.95	1.12	NA	2.54	2.80
2005	DE	Delivery-Only Service	0.00	1.98	0.19	NA	0.00	0.19
2005	IL	Delivery-Only Service	0.00	1.66	0.89	NA	0.00	1.25
2005	MA	Delivery-Only Service	7.94	4.58	3.41	NA	0.74	4.68
2005	MD	Delivery-Only Service	3.17	2.12	1.16	NA	1.19	1.50
2005	ME	Delivery-Only Service	6.85	4.58	1.90	NA	0.00	4.64
2005	MI	Delivery-Only Service	3.22	1.93	0.89	NA	0.00	1.49
2005	MT	Delivery-Only Service	0.00	2.02	0.48	NA	0.00	0.48
2005	NH	Delivery-Only Service	0.00	2.29	2.71	NA	0.00	2.64
2005	NJ	Delivery-Only Service	4.26	3.71	3.45	NA	2.98	3.59
2005	NV	Delivery-Only Service	0.00	0.00	0.51	NA	0.00	0.51
2005	NY	Delivery-Only Service	4.51	3.60	1.49	NA	2.49	3.13
2005	OH	Delivery-Only Service	5.36	4.63	2.49	NA	0.00	4.13
2005	OR	Delivery-Only Service	0.00	1.31	0.76	NA	0.00	0.90
2005	PA	Delivery-Only Service	4.82	2.10	0.88	NA	1.21	1.99
2005	RI	Delivery-Only Service	0.00	4.55	3.75	NA	0.00	4.37
2005	VA	Delivery-Only Service	2.48	4.08	0.00	NA	0.00	2.49
2005	WA	Delivery-Only Service	0.00	0.89	0.43	NA	0.00	0.44
2005	US-TOTAL	Delivery-Only Service	5.72	3.45	1.77	NA	2.07	2.98
2006	AK	Total Electric Industry	14.83	11.93	11.54	NA	0.00	12.84
2006	AL	Total Electric Industry	8.75	8.18	4.90	NA	0.00	7.07
2006	AR	Total Electric Industry	8.85	6.96	5.24	NA	0.00	6.99
2006	AZ	Total Electric Industry	9.40	8.02	5.69	NA	0.00	8.24
2006	CA	Total Electric Industry	14.33	12.90	10.09	NA	6.29	12.82
2006	CO	Total Electric Industry	9.02	7.50	5.88	NA	7.78	7.61
2006	CT	Total Electric Industry	16.86	14.03	11.71	NA	14.55	14.83
2006	DC	Total Electric Industry	9.88	11.17	17.43	NA	10.68	11.08

2006	DE	Total Electric Industry	11.85	10.21	7.67	NA	0.00	10.13
2006	FL	Total Electric Industry	11.33	9.91	7.71	NA	10.32	10.45
2006	GA	Total Electric Industry	8.91	7.81	5.38	NA	6.12	7.63
2006	HI	Total Electric Industry	23.35	21.42	17.96	NA	0.00	20.72
2006	IA	Total Electric Industry	9.63	7.29	4.92	NA	7.05	7.01
2006	ID	Total Electric Industry	6.21	5.16	3.61	NA	0.00	4.92
2006	IL	Total Electric Industry	8.42	7.95	4.69	NA	5.59	7.07
2006	IN	Total Electric Industry	8.22	7.21	4.95	NA	9.66	6.46
2006	KS	Total Electric Industry	8.25	6.96	5.20	NA	0.00	6.89
2006	KY	Total Electric Industry	7.02	6.44	4.05	NA	0.00	5.43
2006	LA	Total Electric Industry	9.14	9.03	6.87	NA	14.10	8.30
2006	MA	Total Electric Industry	16.60	15.54	13.04	NA	10.68	15.45
2006	MD	Total Electric Industry	9.71	10.56	8.14	NA	8.43	9.95
2006	ME	Total Electric Industry	13.80	12.42	8.83	NA	0.00	11.80
2006	MI	Total Electric Industry	9.77	8.51	6.05	NA	10.06	8.14
2006	MN	Total Electric Industry	8.70	7.02	5.29	NA	7.95	6.98
2006	MO	Total Electric Industry	7.44	6.08	4.58	NA	5.75	6.30
2006	MS	Total Electric Industry	9.66	9.37	5.94	NA	0.00	8.33
2006	MT	Total Electric Industry	8.28	7.44	5.12	NA	0.00	6.91
2006	NC	Total Electric Industry	9.12	7.17	5.23	NA	3.23	7.53
2006	ND	Total Electric Industry	7.14	6.30	5.00	NA	0.00	6.21
2006	NE	Total Electric Industry	7.41	6.19	4.56	NA	0.00	6.07
2006	NH	Total Electric Industry	14.68	14.07	11.62	NA	0.00	13.84
2006	NJ	Total Electric Industry	12.84	11.62	10.42	NA	9.70	11.88
2006	NM	Total Electric Industry	9.06	7.61	5.57	NA	0.00	7.37
2006	NV	Total Electric Industry	11.08	10.12	8.03	NA	9.89	9.63
2006	NY	Total Electric Industry	16.89	15.51	9.39	NA	11.94	15.27
2006	OH	Total Electric Industry	9.34	8.44	5.61	NA	10.13	7.71
2006	OK	Total Electric Industry	8.55	7.34	5.46	NA	0.00	7.30
2006	OR	Total Electric Industry	7.48	6.77	4.85	NA	6.40	6.53
2006	PA	Total Electric Industry	10.35	8.94	6.63	NA	7.45	8.68
2006	RI	Total Electric Industry	15.12	13.51	12.51	NA	0.00	13.98
2006	SC	Total Electric Industry	9.03	7.60	4.71	NA	0.00	6.98
2006	SD	Total Electric Industry	7.83	6.47	4.84	NA	0.00	6.70
2006	TN	Total Electric Industry	7.75	8.00	5.17	NA	11.18	6.97
2006	TX	Total Electric Industry	12.86	9.85	7.82	NA	8.42	10.34
2006	UT	Total Electric Industry	7.59	6.15	4.21	NA	7.19	5.99
2006	VA	Total Electric Industry	8.49	6.21	4.69	NA	6.81	6.86
2006	VT	Total Electric Industry	13.39	11.67	8.33	NA	0.00	11.37
2006	WA	Total Electric Industry	6.82	6.63	4.44	NA	5.93	6.14
2006	WI	Total Electric Industry	10.51	8.37	5.85	NA	0.00	8.13
2006	WV	Total Electric Industry	6.35	5.59	3.71	NA	5.86	5.04
2006	WY	Total Electric Industry	7.75	6.28	4.04	NA	0.00	5.27
2006	US-TOTAL	Total Electric Industry	10.40	9.46	6.16	NA	9.54	8.90
2006	AK	Full-Service Providers	14.83	11.93	11.54	NA	0.00	12.84
2006	AL	Full-Service Providers	8.75	8.18	4.90	NA	0.00	7.07
2006	AR	Full-Service Providers	8.85	6.96	5.24	NA	0.00	6.99
2006	AZ	Full-Service Providers	9.40	8.02	5.69	NA	0.00	8.24
2006	CA	Full-Service Providers	14.32	12.93	9.95	NA	7.66	12.92
2006	CO	Full-Service Providers	9.02	7.50	5.88	NA	7.78	7.61
2006	CT	Full-Service Providers	16.85	14.02	11.70	NA	14.55	14.85
2006	DC	Full-Service Providers	9.86	12.23	0.95	NA	2.45	12.13
2006	DE	Full-Service Providers	11.85	10.35	7.47	NA	0.00	10.52
2006	FL	Full-Service Providers	11.33	9.91	7.71	NA	10.32	10.45
2006	GA	Full-Service Providers	8.91	7.81	5.38	NA	6.12	7.63
2006	HI	Full-Service Providers	23.35	21.42	17.96	NA	0.00	20.72
2006	IA	Full-Service Providers	9.63	7.29	4.92	NA	7.05	7.01
2006	ID	Full-Service Providers	6.21	5.16	3.61	NA	0.00	4.92
2006	IL	Full-Service Providers	8.42	8.59	4.46	NA	5.59	7.38
2006	IN	Full-Service Providers	8.22	7.21	4.95	NA	9.66	6.46
2006	KS	Full-Service Providers	8.25	6.96	5.20	NA	0.00	6.89
2006	KY	Full-Service Providers	7.02	6.44	4.05	NA	0.00	5.43
2006	LA	Full-Service Providers	9.14	9.03	6.87	NA	14.10	8.30
2006	MA	Full-Service Providers	16.40	16.78	12.55	NA	11.21	16.06
2006	MD	Full-Service Providers	9.69	11.25	8.85	NA	0.00	10.18
2006	ME	Full-Service Providers	13.36	13.27	5.94	NA	0.00	7.03
2006	MI	Full-Service Providers	9.77	8.42	6.13	NA	10.06	8.17
2006	MN	Full-Service Providers	8.70	7.02	5.29	NA	7.95	6.98
2006	MO	Full-Service Providers	7.44	6.08	4.58	NA	5.75	6.30
2006	MS	Full-Service Providers	9.66	9.37	5.94	NA	0.00	8.33
2006	MT	Full-Service Providers	8.28	7.45	6.08	NA	0.00	7.57
2006	NC	Full-Service Providers	9.12	7.17	5.23	NA	3.23	7.53
2006	ND	Full-Service Providers	7.14	6.30	5.00	NA	0.00	6.21
2006	NE	Full-Service Providers	7.41	6.19	4.56	NA	0.00	6.07
2006	NH	Full-Service Providers	14.68	14.37	11.28	NA	0.00	13.96
2006	NJ	Full-Service Providers	12.84	11.65	9.54	NA	10.18	12.03
2006	NM	Full-Service Providers	9.06	7.61	5.57	NA	0.00	7.37
2006	NV	Full-Service Providers	11.08	10.12	8.19	NA	9.89	9.75
2006	NY	Full-Service Providers	16.91	16.30	9.62	NA	14.48	16.08
2006	OH	Full-Service Providers	9.31	8.32	5.56	NA	10.13	7.68
2006	OK	Full-Service Providers	8.55	7.34	5.46	NA	0.00	7.30
2006	OR	Full-Service Providers	7.48	6.73	4.70	NA	6.40	6.50
2006	PA	Full-Service Providers	10.31	8.94	6.67	NA	7.47	8.70
2006	RI	Full-Service Providers	15.12	13.76	12.75	NA	0.00	14.24
2006	SC	Full-Service Providers	9.03	7.60	4.71	NA	0.00	6.98
2006	SD	Full-Service Providers	7.83	6.47	4.84	NA	0.00	6.70
2006	TN	Full-Service Providers	7.75	8.00	5.17	NA	11.18	6.97
2006	TX	Full-Service Providers	12.86	9.85	7.82	NA	8.42	10.34
2006	UT	Full-Service Providers	7.59	6.15	4.21	NA	7.19	5.99
2006	VA	Full-Service Providers	8.49	6.21	4.69	NA	6.81	6.86
2006	VT	Full-Service Providers	13.39	11.67	8.33	NA	0.00	11.37
2006	WA	Full-Service Providers	6.82	6.64	4.26	NA	5.93	6.14
2006	WI	Full-Service Providers	10.51	8.37	5.85	NA	0.00	8.13
2006	WV	Full-Service Providers	6.35	5.59	3.71	NA	5.86	5.04
2006	WY	Full-Service Providers	7.75	6.28	4.04	NA	0.00	5.27
2006	US-TOTAL	Full-Service Providers	10.36	9.18	6.00	NA	8.44	8.77
2006	CA	Restructured Retail Service Providers	18.35	12.58	10.70	NA	4.37	11.68
2006	CT	Restructured Retail Service Providers	16.99	14.08	11.83	NA	0.00	14.43
2006	DC	Restructured Retail Service Providers	10.57	10.11	8.29	NA	10.03	9.93
2006	DE	Restructured Retail Service Providers	13.22	9.80	7.90	NA	0.00	8.73
2006	IL	Restructured Retail Service Providers	0.00	6.15	5.23	NA	0.00	5.69

2006	MA	Restructured Retail Service Providers	19.25	14.45	13.42	NA	10.59	14.43
2006	MD	Restructured Retail Service Providers	11.00	9.96	7.94	NA	8.43	9.50
2006	ME	Restructured Retail Service Providers	13.81	12.42	9.49	NA	0.00	12.15
2006	MI	Restructured Retail Service Providers	10.11	9.64	5.12	NA	0.00	7.46
2006	MT	Restructured Retail Service Providers	0.00	5.38	4.55	NA	0.00	4.55
2006	NH	Restructured Retail Service Providers	0.00	12.39	13.30	NA	0.00	12.69
2006	NJ	Restructured Retail Service Providers	15.66	11.51	11.03	NA	9.68	11.27
2006	NV	Restructured Retail Service Providers	0.00	0.00	6.38	NA	0.00	6.38
2006	NY	Restructured Retail Service Providers	16.65	14.83	9.20	NA	11.64	13.99
2006	OH	Restructured Retail Service Providers	10.11	9.40	6.02	NA	0.00	8.09
2006	OR	Restructured Retail Service Providers	0.00	7.71	8.17	NA	0.00	7.95
2006	PA	Restructured Retail Service Providers	12.59	8.98	6.23	NA	6.61	8.23
2006	RI	Restructured Retail Service Providers	13.88	12.43	11.92	NA	0.00	12.26
2006	VA	Restructured Retail Service Providers	12.12	10.44	0.00	NA	0.00	11.10
2006	WA	Restructured Retail Service Providers	0.00	5.07	6.20	NA	0.00	6.16
2006	US-TOTAL	Restructured Retail Service Providers	14.43	11.99	8.21	NA	10.32	10.87
2006	CA	Energy-Only Providers	10.57	7.66	7.17	NA	3.82	7.41
2006	CT	Energy-Only Providers	10.71	8.95	8.70	NA	0.00	9.39
2006	DC	Energy-Only Providers	8.23	7.22	7.34	NA	7.58	7.26
2006	DE	Energy-Only Providers	10.64	8.45	7.59	NA	0.00	7.97
2006	IL	Energy-Only Providers	0.00	4.60	4.35	NA	0.00	4.47
2006	MA	Energy-Only Providers	11.67	9.76	9.85	NA	9.81	9.91
2006	MD	Energy-Only Providers	8.55	8.12	6.99	NA	7.18	7.86
2006	ME	Energy-Only Providers	6.82	7.71	7.50	NA	0.00	7.32
2006	MI	Energy-Only Providers	5.42	7.00	4.07	NA	0.00	5.58
2006	MT	Energy-Only Providers	0.00	3.31	4.02	NA	0.00	4.02
2006	NH	Energy-Only Providers	0.00	8.66	9.73	NA	0.00	9.02
2006	NJ	Energy-Only Providers	8.20	7.77	7.55	NA	7.24	7.67
2006	NV	Energy-Only Providers	0.00	0.00	6.15	NA	0.00	6.15
2006	NY	Energy-Only Providers	10.29	10.37	6.81	NA	9.09	9.79
2006	OH	Energy-Only Providers	5.04	4.87	3.91	NA	0.00	4.49
2006	OR	Energy-Only Providers	0.00	6.88	7.61	NA	0.00	7.26
2006	PA	Energy-Only Providers	8.27	7.20	5.68	NA	5.40	6.70
2006	RI	Energy-Only Providers	8.21	8.15	8.36	NA	0.00	8.22
2006	VA	Energy-Only Providers	9.60	9.81	0.00	NA	0.00	9.73
2006	WA	Energy-Only Providers	0.00	4.14	5.66	NA	0.00	5.62
2006	US-TOTAL	Energy-Only Providers	8.23	8.36	6.25	NA	8.24	7.66
2006	CA	Delivery-Only Service	7.79	4.92	3.54	NA	0.55	4.27
2006	CT	Delivery-Only Service	6.28	5.14	3.14	NA	0.00	5.04
2006	DC	Delivery-Only Service	2.35	2.89	0.95	NA	2.45	2.67
2006	DE	Delivery-Only Service	2.58	1.35	0.31	NA	0.00	0.77
2006	IL	Delivery-Only Service	0.00	1.54	0.88	NA	0.00	1.21
2006	MA	Delivery-Only Service	7.58	4.69	3.57	NA	0.78	4.52
2006	MD	Delivery-Only Service	2.45	1.84	0.95	NA	1.25	1.64
2006	ME	Delivery-Only Service	6.99	4.71	1.99	NA	0.00	4.82
2006	MI	Delivery-Only Service	4.69	2.65	1.05	NA	0.00	1.87
2006	MT	Delivery-Only Service	0.00	2.07	0.53	NA	0.00	0.53
2006	NH	Delivery-Only Service	0.00	3.73	3.56	NA	0.00	3.67
2006	NJ	Delivery-Only Service	7.47	3.74	3.49	NA	2.44	3.61
2006	NV	Delivery-Only Service	0.00	0.00	0.22	NA	0.00	0.22
2006	NY	Delivery-Only Service	6.37	4.47	2.38	NA	2.55	4.20
2006	OH	Delivery-Only Service	5.07	4.53	2.11	NA	0.00	3.60
2006	OR	Delivery-Only Service	0.00	0.82	0.56	NA	0.00	0.69
2006	PA	Delivery-Only Service	4.32	1.78	0.55	NA	1.21	1.54
2006	RI	Delivery-Only Service	5.67	4.28	3.57	NA	0.00	4.04
2006	VA	Delivery-Only Service	2.52	0.64	0.00	NA	0.00	1.37
2006	WA	Delivery-Only Service	0.00	0.93	0.54	NA	0.00	0.55
2006	US-TOTAL	Delivery-Only Service	6.19	3.63	1.96	NA	2.08	3.21
2007	AK	Total Electric Industry	15.18	12.19	12.63	NA	0.00	13.28
2007	AL	Total Electric Industry	9.32	8.70	5.27	NA	0.00	7.57
2007	AR	Total Electric Industry	8.73	6.91	5.25	NA	0.00	6.96
2007	AZ	Total Electric Industry	9.66	8.27	6.05	NA	0.00	8.54
2007	CA	Total Electric Industry	14.42	12.82	9.98	NA	8.37	12.80
2007	CO	Total Electric Industry	9.25	7.62	5.97	NA	7.18	7.76
2007	CT	Total Electric Industry	19.11	15.39	12.92	NA	14.18	16.45
2007	DC	Total Electric Industry	11.18	12.01	9.32	NA	11.32	11.79
2007	DE	Total Electric Industry	13.16	11.21	8.93	NA	0.00	11.35
2007	FL	Total Electric Industry	11.22	9.75	7.76	NA	9.73	10.33
2007	GA	Total Electric Industry	9.10	8.07	5.53	NA	6.42	7.86
2007	HI	Total Electric Industry	24.12	21.91	18.38	NA	0.00	21.29
2007	IA	Total Electric Industry	9.45	7.11	4.74	NA	0.00	6.83
2007	ID	Total Electric Industry	6.36	5.14	3.87	NA	0.00	5.07
2007	IL	Total Electric Industry	10.12	8.57	6.61	NA	6.43	8.46
2007	IN	Total Electric Industry	8.26	7.29	4.89	NA	10.09	6.50
2007	KS	Total Electric Industry	8.19	6.83	5.13	NA	0.00	6.84
2007	KY	Total Electric Industry	7.34	6.76	4.47	NA	0.00	5.84
2007	LA	Total Electric Industry	9.37	9.13	6.77	NA	13.91	8.39
2007	MA	Total Electric Industry	16.23	15.20	13.03	NA	9.24	15.16
2007	MD	Total Electric Industry	11.89	11.58	9.41	NA	10.15	11.50
2007	ME	Total Electric Industry	16.52	12.94	14.11	NA	0.00	14.59
2007	MI	Total Electric Industry	10.21	8.77	6.47	NA	9.76	8.53
2007	MN	Total Electric Industry	9.18	7.48	5.69	NA	8.27	7.44
2007	MO	Total Electric Industry	7.69	6.34	4.76	NA	6.16	6.56
2007	MS	Total Electric Industry	9.36	8.92	5.75	NA	0.00	8.03
2007	MT	Total Electric Industry	8.77	8.10	5.16	NA	0.00	7.13
2007	NC	Total Electric Industry	9.40	7.43	5.47	NA	9.09	7.83
2007	ND	Total Electric Industry	7.30	6.58	5.24	NA	0.00	6.42
2007	NE	Total Electric Industry	7.59	6.39	4.78	NA	0.00	6.28
2007	NH	Total Electric Industry	14.88	13.91	12.27	NA	0.00	13.98
2007	NJ	Total Electric Industry	14.14	12.99	10.08	NA	11.14	13.01
2007	NM	Total Electric Industry	9.12	7.66	5.60	NA	0.00	7.44
2007	NV	Total Electric Industry	11.82	10.09	8.28	NA	9.98	9.99
2007	NY	Total Electric Industry	17.10	15.92	8.71	NA	10.96	15.22
2007	OH	Total Electric Industry	9.57	8.67	5.76	NA	9.98	7.91
2007	OK	Total Electric Industry	8.58	7.33	5.41	NA	0.00	7.29
2007	OR	Total Electric Industry	8.19	7.20	5.06	NA	6.71	7.02
2007	PA	Total Electric Industry	10.95	9.20	6.87	NA	7.72	9.08
2007	RI	Total Electric Industry	14.05	12.67	12.04	NA	0.00	13.12
2007	SC	Total Electric Industry	9.19	7.74	4.83	NA	0.00	7.18
2007	SD	Total Electric Industry	8.07	6.61	5.09	NA	0.00	6.89
2007	TN	Total Electric Industry	7.84	8.09	5.19	NA	10.31	7.07

2007	TX	Total Electric Industry	12.34	9.87	7.79	NA	8.40	10.11
2007	UT	Total Electric Industry	8.15	6.54	4.52	NA	7.44	6.41
2007	VA	Total Electric Industry	8.74	6.38	5.07	NA	6.73	7.12
2007	VT	Total Electric Industry	14.15	12.29	8.92	NA	0.00	12.04
2007	WA	Total Electric Industry	7.26	6.55	4.57	NA	5.74	6.37
2007	WI	Total Electric Industry	10.87	8.71	6.16	NA	0.00	8.48
2007	WV	Total Electric Industry	6.73	5.85	3.95	NA	6.42	5.34
2007	WY	Total Electric Industry	7.75	6.25	4.10	NA	0.00	5.29
2007	US-TOTAL	Total Electric Industry	10.65	9.65	6.39	NA	9.70	9.13
2007	AK	Full-Service Providers	15.18	12.19	12.63	NA	0.00	13.28
2007	AL	Full-Service Providers	9.32	8.70	5.27	NA	0.00	7.57
2007	AR	Full-Service Providers	8.73	6.91	5.25	NA	0.00	6.96
2007	AZ	Full-Service Providers	9.66	8.27	6.05	NA	0.00	8.54
2007	CA	Full-Service Providers	14.41	12.82	9.88	NA	8.28	12.89
2007	CO	Full-Service Providers	9.25	7.62	5.97	NA	7.18	7.76
2007	CT	Full-Service Providers	19.45	15.47	11.12	NA	14.79	17.06
2007	DC	Full-Service Providers	11.16	13.72	0.00	NA	0.00	12.53
2007	DE	Full-Service Providers	13.18	12.61	9.91	NA	0.00	12.51
2007	FL	Full-Service Providers	11.22	9.75	7.76	NA	9.73	10.33
2007	GA	Full-Service Providers	9.10	8.07	5.53	NA	6.42	7.86
2007	HI	Full-Service Providers	24.12	21.91	18.38	NA	0.00	21.29
2007	IA	Full-Service Providers	9.45	7.11	4.74	NA	0.00	6.83
2007	ID	Full-Service Providers	6.36	5.14	3.87	NA	0.00	5.07
2007	IL	Full-Service Providers	10.12	9.41	6.46	NA	5.04	9.57
2007	IN	Full-Service Providers	8.26	7.29	4.89	NA	10.09	6.50
2007	KS	Full-Service Providers	8.19	6.83	5.13	NA	0.00	6.84
2007	KY	Full-Service Providers	7.34	6.76	4.47	NA	0.00	5.84
2007	LA	Full-Service Providers	9.37	9.13	6.77	NA	13.91	8.39
2007	MA	Full-Service Providers	16.11	15.71	11.61	NA	9.90	15.43
2007	MD	Full-Service Providers	11.87	12.78	9.82	NA	0.00	12.06
2007	ME	Full-Service Providers	13.07	11.86	10.63	NA	0.00	12.21
2007	MI	Full-Service Providers	10.21	8.73	6.57	NA	9.76	8.58
2007	MN	Full-Service Providers	9.18	7.48	5.69	NA	8.27	7.44
2007	MO	Full-Service Providers	7.69	6.34	4.76	NA	6.16	6.56
2007	MS	Full-Service Providers	9.36	8.92	5.75	NA	0.00	8.03
2007	MT	Full-Service Providers	8.77	8.18	5.24	NA	0.00	7.56
2007	NC	Full-Service Providers	9.40	7.43	5.47	NA	9.09	7.83
2007	ND	Full-Service Providers	7.30	6.58	5.24	NA	0.00	6.42
2007	NE	Full-Service Providers	7.59	6.39	4.78	NA	0.00	6.28
2007	NH	Full-Service Providers	14.88	14.03	11.92	NA	0.00	14.09
2007	NJ	Full-Service Providers	14.14	13.22	8.46	NA	6.51	13.19
2007	NM	Full-Service Providers	9.12	7.66	5.60	NA	0.00	7.44
2007	NV	Full-Service Providers	11.82	10.09	8.42	NA	9.98	10.10
2007	NY	Full-Service Providers	17.01	16.54	9.33	NA	13.59	16.16
2007	OH	Full-Service Providers	9.54	8.59	5.73	NA	9.98	7.89
2007	OK	Full-Service Providers	8.58	7.33	5.41	NA	0.00	7.29
2007	OR	Full-Service Providers	8.19	7.18	4.83	NA	6.71	7.02
2007	PA	Full-Service Providers	10.90	9.18	6.90	NA	7.68	9.12
2007	RI	Full-Service Providers	14.04	12.73	11.73	NA	0.00	13.21
2007	SC	Full-Service Providers	9.19	7.74	4.83	NA	0.00	7.18
2007	SD	Full-Service Providers	8.07	6.61	5.09	NA	0.00	6.89
2007	TN	Full-Service Providers	7.84	8.09	5.19	NA	10.31	7.07
2007	TX	Full-Service Providers	12.34	9.87	7.79	NA	8.40	10.11
2007	UT	Full-Service Providers	8.15	6.54	4.52	NA	7.44	6.41
2007	VA	Full-Service Providers	8.74	6.38	5.07	NA	6.73	7.12
2007	VT	Full-Service Providers	14.15	12.29	8.92	NA	0.00	12.04
2007	WA	Full-Service Providers	7.26	6.55	4.38	NA	5.74	6.37
2007	WI	Full-Service Providers	10.87	8.71	6.16	NA	0.00	8.48
2007	WV	Full-Service Providers	6.73	5.85	3.95	NA	6.42	5.34
2007	WY	Full-Service Providers	7.75	6.25	4.10	NA	0.00	5.29
2007	US-TOTAL	Full-Service Providers	10.59	9.29	6.17	NA	8.82	8.98
2007	CA	Restructured Retail Service Providers	19.92	12.78	10.50	NA	8.49	11.79
2007	CT	Restructured Retail Service Providers	15.40	15.25	14.35	NA	13.25	14.98
2007	DC	Restructured Retail Service Providers	13.41	11.49	9.32	NA	11.32	11.41
2007	DE	Restructured Retail Service Providers	12.25	9.74	8.30	NA	0.00	9.10
2007	IL	Restructured Retail Service Providers	0.00	7.48	6.63	NA	6.50	6.94
2007	MA	Restructured Retail Service Providers	17.44	14.86	14.07	NA	9.14	14.79
2007	MD	Restructured Retail Service Providers	12.75	10.99	9.34	NA	10.15	10.72
2007	ME	Restructured Retail Service Providers	16.59	12.95	14.14	NA	0.00	14.63
2007	MI	Restructured Retail Service Providers	0.00	9.56	5.17	NA	0.00	7.14
2007	MT	Restructured Retail Service Providers	7.14	5.82	5.04	NA	0.00	5.08
2007	NH	Restructured Retail Service Providers	16.07	13.34	13.12	NA	0.00	13.24
2007	NJ	Restructured Retail Service Providers	0.00	12.36	12.10	NA	11.51	12.27
2007	NV	Restructured Retail Service Providers	0.00	0.00	6.93	NA	0.00	6.93
2007	NY	Restructured Retail Service Providers	17.87	15.40	8.36	NA	10.70	13.91
2007	OH	Restructured Retail Service Providers	10.33	9.39	6.08	NA	0.00	8.17
2007	OR	Restructured Retail Service Providers	0.00	7.66	6.66	NA	0.00	6.92
2007	PA	Restructured Retail Service Providers	13.55	9.37	6.57	NA	9.95	8.52
2007	RI	Restructured Retail Service Providers	20.88	12.43	12.67	NA	0.00	12.54
2007	VA	Restructured Retail Service Providers	12.46	9.60	0.00	NA	0.00	10.70
2007	WA	Restructured Retail Service Providers	0.00	5.17	6.10	NA	0.00	6.10
2007	US-TOTAL	Restructured Retail Service Providers	15.80	12.35	8.37	NA	10.11	11.03
2007	CA	Energy-Only Providers	12.59	8.05	7.41	NA	7.95	7.82
2007	CT	Energy-Only Providers	11.42	10.36	10.93	NA	10.75	10.65
2007	DC	Energy-Only Providers	10.15	8.50	8.32	NA	8.70	8.51
2007	DE	Energy-Only Providers	10.92	8.79	7.94	NA	0.00	8.42
2007	IL	Energy-Only Providers	0.00	6.07	5.85	NA	5.58	5.93
2007	MA	Energy-Only Providers	10.67	10.32	10.65	NA	8.48	10.40
2007	MD	Energy-Only Providers	10.52	8.96	8.36	NA	8.97	8.89
2007	ME	Energy-Only Providers	9.55	8.24	12.13	NA	0.00	9.79
2007	MI	Energy-Only Providers	0.00	7.23	4.43	NA	0.00	5.68
2007	MT	Energy-Only Providers	3.57	3.69	4.50	NA	0.00	4.45
2007	NH	Energy-Only Providers	9.82	9.52	9.73	NA	0.00	9.62
2007	NJ	Energy-Only Providers	0.00	8.93	8.91	NA	9.35	8.93
2007	NV	Energy-Only Providers	0.00	0.00	6.73	NA	0.00	6.73
2007	NY	Energy-Only Providers	11.43	10.15	6.77	NA	8.44	9.47
2007	OH	Energy-Only Providers	5.31	5.11	4.08	NA	0.00	4.71
2007	OR	Energy-Only Providers	0.00	6.53	5.97	NA	0.00	6.12
2007	PA	Energy-Only Providers	8.39	7.17	5.87	NA	7.22	6.71
2007	RI	Energy-Only Providers	8.74	8.41	9.32	NA	0.00	8.72
2007	VA	Energy-Only Providers	9.92	8.97	0.00	NA	0.00	9.34

2007	WA	Energy-Only Providers	0.00	4.27	5.67	NA	0.00	5.67
2007	US-TOTAL	Energy-Only Providers	9.80	8.71	6.87	NA	8.28	8.09
2007	CA	Delivery-Only Service	7.33	4.73	3.09	NA	0.54	3.97
2007	CT	Delivery-Only Service	3.99	4.90	3.41	NA	2.49	4.33
2007	DC	Delivery-Only Service	3.26	2.99	1.00	NA	2.62	2.90
2007	DE	Delivery-Only Service	1.33	0.95	0.36	NA	0.00	0.68
2007	IL	Delivery-Only Service	0.00	1.41	0.79	NA	0.92	1.02
2007	MA	Delivery-Only Service	6.77	4.54	3.43	NA	0.66	4.40
2007	MD	Delivery-Only Service	2.24	2.03	0.98	NA	1.18	1.82
2007	ME	Delivery-Only Service	7.04	4.71	2.02	NA	0.00	4.83
2007	MI	Delivery-Only Service	0.00	2.34	0.75	NA	0.00	1.46
2007	MT	Delivery-Only Service	3.57	2.13	0.53	NA	0.00	0.63
2007	NH	Delivery-Only Service	6.25	3.82	3.39	NA	0.00	3.62
2007	NJ	Delivery-Only Service	0.00	3.43	3.19	NA	2.16	3.34
2007	NV	Delivery-Only Service	0.00	0.00	0.20	NA	0.00	0.20
2007	NY	Delivery-Only Service	6.45	5.25	1.58	NA	2.26	4.44
2007	OH	Delivery-Only Service	5.02	4.29	2.00	NA	0.00	3.46
2007	OR	Delivery-Only Service	0.00	1.13	0.68	NA	0.00	0.80
2007	PA	Delivery-Only Service	5.15	2.20	0.71	NA	2.72	1.81
2007	RI	Delivery-Only Service	12.14	4.02	3.36	NA	0.00	3.82
2007	VA	Delivery-Only Service	2.53	0.63	0.00	NA	0.00	1.36
2007	WA	Delivery-Only Service	0.00	0.90	0.42	NA	0.00	0.42
2007	US-TOTAL	Delivery-Only Service	6.00	3.63	1.50	NA	1.84	2.95
2008	AK	Total Electric Industry	16.55	13.64	14.17	NA	0.00	14.73
2008	AL	Total Electric Industry	10.40	9.87	6.11	NA	0.00	8.59
2008	AR	Total Electric Industry	9.27	7.61	5.89	NA	11.79	7.60
2008	AZ	Total Electric Industry	10.27	8.93	6.57	NA	0.00	9.11
2008	CA	Total Electric Industry	13.81	12.54	10.04	NA	8.16	12.48
2008	CO	Total Electric Industry	10.13	8.57	6.65	NA	8.32	8.59
2008	CT	Total Electric Industry	19.55	17.12	14.93	NA	14.69	17.79
2008	DC	Total Electric Industry	12.79	13.23	10.49	NA	13.77	13.10
2008	DE	Total Electric Industry	13.93	12.07	10.45	NA	0.00	12.36
2008	FL	Total Electric Industry	11.65	10.14	8.25	NA	10.18	10.74
2008	GA	Total Electric Industry	9.93	9.07	6.67	NA	7.15	8.84
2008	HI	Total Electric Industry	32.50	29.72	26.05	NA	0.00	29.20
2008	IA	Total Electric Industry	9.49	7.18	4.81	NA	0.00	6.89
2008	ID	Total Electric Industry	6.99	5.72	4.48	NA	0.00	5.69
2008	IL	Total Electric Industry	11.07	11.79	4.54	NA	7.23	9.26
2008	IN	Total Electric Industry	8.87	7.82	5.46	NA	9.60	7.09
2008	KS	Total Electric Industry	8.88	7.42	5.69	NA	0.00	7.45
2008	KY	Total Electric Industry	7.94	7.29	4.82	NA	0.00	6.26
2008	LA	Total Electric Industry	10.28	10.12	7.94	NA	11.88	9.44
2008	MA	Total Electric Industry	17.68	15.80	14.85	NA	9.39	16.27
2008	MD	Total Electric Industry	13.84	12.76	10.37	NA	11.52	13.00
2008	ME	Total Electric Industry	16.20	12.98	11.70	NA	0.00	13.83
2008	MI	Total Electric Industry	10.75	9.20	6.74	NA	11.83	8.94
2008	MN	Total Electric Industry	9.74	7.88	5.87	NA	8.04	7.79
2008	MO	Total Electric Industry	8.00	6.61	4.92	NA	5.40	6.84
2008	MS	Total Electric Industry	10.39	10.02	6.56	NA	0.00	8.99
2008	MT	Total Electric Industry	9.13	8.54	5.90	NA	0.00	7.72
2008	NC	Total Electric Industry	9.52	7.55	5.54	NA	6.57	7.96
2008	ND	Total Electric Industry	7.51	6.81	5.59	NA	0.00	6.69
2008	NE	Total Electric Industry	7.87	6.68	5.16	NA	0.00	6.58
2008	NH	Total Electric Industry	15.68	14.32	13.17	NA	0.00	14.65
2008	NJ	Total Electric Industry	15.66	14.48	10.86	NA	15.98	14.44
2008	NM	Total Electric Industry	10.01	8.67	6.38	NA	0.00	8.35
2008	NV	Total Electric Industry	11.93	10.07	7.98	NA	9.47	9.89
2008	NY	Total Electric Industry	18.30	16.84	10.14	NA	12.64	16.57
2008	OH	Total Electric Industry	10.06	9.22	6.19	NA	10.68	8.39
2008	OK	Total Electric Industry	9.09	7.88	5.90	NA	0.00	7.81
2008	OR	Total Electric Industry	8.49	7.29	5.21	NA	6.75	7.23
2008	PA	Total Electric Industry	11.35	9.38	7.02	NA	7.57	9.32
2008	RI	Total Electric Industry	17.45	15.36	14.20	NA	0.00	16.01
2008	SC	Total Electric Industry	9.89	8.42	5.37	NA	0.00	7.85
2008	SD	Total Electric Industry	8.27	6.97	5.31	NA	0.00	7.14
2008	TN	Total Electric Industry	8.91	9.24	6.29	NA	10.17	8.18
2008	TX	Total Electric Industry	13.04	10.75	8.79	NA	8.64	10.99
2008	UT	Total Electric Industry	8.26	6.66	4.59	NA	7.85	6.49
2008	VA	Total Electric Industry	9.62	7.32	5.82	NA	7.80	8.00
2008	VT	Total Electric Industry	14.48	12.49	9.19	NA	0.00	12.33
2008	WA	Total Electric Industry	7.54	6.76	4.55	NA	5.82	6.55
2008	WI	Total Electric Industry	11.51	9.28	6.51	NA	0.00	9.00
2008	WV	Total Electric Industry	7.06	6.08	4.20	NA	6.32	5.61
2008	WY	Total Electric Industry	8.21	6.71	4.47	NA	0.00	5.67
2008	US-TOTAL	Total Electric Industry	11.26	10.36	6.83	NA	10.74	9.74
2008	AK	Full-Service Providers	16.55	13.64	14.17	NA	0.00	14.73
2008	AL	Full-Service Providers	10.40	9.87	6.11	NA	0.00	8.59
2008	AR	Full-Service Providers	9.27	7.61	5.89	NA	11.79	7.60
2008	AZ	Full-Service Providers	10.27	8.93	6.57	NA	0.00	9.11
2008	CA	Full-Service Providers	13.79	12.41	9.77	NA	8.58	12.45
2008	CO	Full-Service Providers	10.13	8.57	6.65	NA	8.32	8.59
2008	CT	Full-Service Providers	19.49	17.48	13.95	NA	20.01	18.46
2008	DC	Full-Service Providers	12.74	15.02	0.00	NA	0.00	13.90
2008	DE	Full-Service Providers	13.89	13.19	11.66	NA	0.00	13.37
2008	FL	Full-Service Providers	11.65	10.14	8.25	NA	10.18	10.74
2008	GA	Full-Service Providers	9.93	9.07	6.67	NA	7.15	8.84
2008	HI	Full-Service Providers	32.50	29.72	26.05	NA	0.00	29.20
2008	IA	Full-Service Providers	9.49	7.18	4.81	NA	0.00	6.89
2008	ID	Full-Service Providers	6.99	5.72	4.48	NA	0.00	5.69
2008	IL	Full-Service Providers	11.07	32.29	2.31	NA	4.62	10.26
2008	IN	Full-Service Providers	8.87	7.82	5.46	NA	9.60	7.09
2008	KS	Full-Service Providers	8.88	7.42	5.69	NA	0.00	7.45
2008	KY	Full-Service Providers	7.94	7.29	4.82	NA	0.00	6.26
2008	LA	Full-Service Providers	10.28	10.12	7.94	NA	11.88	9.44
2008	MA	Full-Service Providers	17.51	16.13	15.44	NA	0.69	16.80
2008	MD	Full-Service Providers	13.78	14.22	10.33	NA	0.00	13.82
2008	ME	Full-Service Providers	15.20	12.53	10.87	NA	0.00	13.56
2008	MI	Full-Service Providers	10.75	9.12	6.74	NA	11.83	8.94
2008	MN	Full-Service Providers	9.74	7.88	5.87	NA	8.04	7.79
2008	MO	Full-Service Providers	8.00	6.61	4.92	NA	5.40	6.84
2008	MS	Full-Service Providers	10.39	10.02	6.56	NA	0.00	8.99

2008	MT	Full-Service Providers	9.13	8.57	5.72	NA	0.00	8.06
2008	NC	Full-Service Providers	9.52	7.55	5.54	NA	6.57	7.96
2008	ND	Full-Service Providers	7.51	6.81	5.59	NA	0.00	6.69
2008	NE	Full-Service Providers	7.87	6.68	5.16	NA	0.00	6.58
2008	NH	Full-Service Providers	15.68	14.09	12.91	NA	0.00	14.59
2008	NJ	Full-Service Providers	15.66	14.79	8.87	NA	-38.54	14.64
2008	NM	Full-Service Providers	10.01	8.67	6.38	NA	0.00	8.35
2008	NV	Full-Service Providers	11.93	10.07	8.04	NA	9.47	9.98
2008	NY	Full-Service Providers	17.98	17.95	10.55	NA	20.51	17.46
2008	OH	Full-Service Providers	10.03	9.15	6.16	NA	10.68	8.37
2008	OK	Full-Service Providers	9.09	7.88	5.90	NA	0.00	7.81
2008	OR	Full-Service Providers	8.49	7.26	4.90	NA	6.75	7.22
2008	PA	Full-Service Providers	11.29	9.28	7.00	NA	7.53	9.32
2008	RI	Full-Service Providers	17.46	16.04	14.86	NA	0.00	16.55
2008	SC	Full-Service Providers	9.89	8.42	5.37	NA	0.00	7.85
2008	SD	Full-Service Providers	8.27	6.97	5.31	NA	0.00	7.14
2008	TN	Full-Service Providers	8.91	9.24	6.29	NA	10.17	8.18
2008	TX	Full-Service Providers	13.04	10.75	8.79	NA	8.64	10.99
2008	UT	Full-Service Providers	8.26	6.66	4.59	NA	7.85	6.49
2008	VA	Full-Service Providers	9.61	7.32	5.82	NA	7.80	8.00
2008	VT	Full-Service Providers	14.48	12.49	9.19	NA	0.00	12.33
2008	WA	Full-Service Providers	7.54	6.76	4.34	NA	5.82	6.55
2008	WI	Full-Service Providers	11.51	9.28	6.51	NA	0.00	9.00
2008	WV	Full-Service Providers	7.06	6.08	4.20	NA	6.32	5.61
2008	WY	Full-Service Providers	8.21	6.71	4.47	NA	0.00	5.67
2008	US-TOTAL	Full-Service Providers	11.18	9.98	6.60	NA	9.96	9.54
2008	CA	Restructured Retail Service Providers	20.50	13.92	11.57	NA	7.62	12.87
2008	CT	Restructured Retail Service Providers	20.25	16.85	15.41	NA	13.42	16.69
2008	DC	Restructured Retail Service Providers	18.74	12.75	10.49	NA	13.77	12.72
2008	DE	Restructured Retail Service Providers	15.91	10.73	9.76	NA	0.00	10.38
2008	IL	Restructured Retail Service Providers	0.00	8.36	7.33	NA	7.46	8.03
2008	MA	Restructured Retail Service Providers	19.12	15.58	14.48	NA	10.13	15.56
2008	MD	Restructured Retail Service Providers	15.80	12.08	10.38	NA	11.52	11.87
2008	ME	Restructured Retail Service Providers	16.22	12.98	11.71	NA	0.00	13.83
2008	MI	Restructured Retail Service Providers	0.00	10.76	6.58	NA	0.00	9.09
2008	MT	Restructured Retail Service Providers	9.63	7.84	6.12	NA	0.00	6.23
2008	NH	Restructured Retail Service Providers	14.71	16.54	14.14	NA	0.00	15.31
2008	NJ	Restructured Retail Service Providers	0.00	13.79	13.52	NA	13.19	13.70
2008	NV	Restructured Retail Service Providers	0.00	0.00	7.42	NA	0.00	7.42
2008	NY	Restructured Retail Service Providers	20.78	16.03	9.87	NA	11.67	15.39
2008	OH	Restructured Retail Service Providers	10.73	9.87	6.49	NA	0.00	8.60
2008	OR	Restructured Retail Service Providers	0.00	7.97	7.16	NA	0.00	7.39
2008	PA	Restructured Retail Service Providers	14.42	10.14	7.24	NA	9.12	9.32
2008	RI	Restructured Retail Service Providers	14.35	12.57	12.90	NA	0.00	12.69
2008	VA	Restructured Retail Service Providers	13.03	14.75	0.00	NA	0.00	13.04
2008	WA	Restructured Retail Service Providers	0.00	0.00	6.43	NA	0.00	6.43
2008	US-TOTAL	Restructured Retail Service Providers	17.49	12.77	9.54	NA	11.12	12.12
2008	CA	Energy-Only Providers	13.69	9.09	8.38	NA	7.00	8.79
2008	CT	Energy-Only Providers	11.94	11.20	11.32	NA	10.97	11.28
2008	DC	Energy-Only Providers	5.42	9.70	11.30	NA	13.05	9.87
2008	DE	Energy-Only Providers	11.97	9.74	9.35	NA	0.00	9.60
2008	IL	Energy-Only Providers	0.00	6.87	6.50	NA	6.49	6.75
2008	MA	Energy-Only Providers	12.10	10.77	10.74	NA	9.44	10.86
2008	MD	Energy-Only Providers	12.30	9.96	9.39	NA	10.32	9.93
2008	ME	Energy-Only Providers	9.66	8.91	9.87	NA	0.00	9.45
2008	MI	Energy-Only Providers	0.00	8.65	5.61	NA	0.00	7.43
2008	MT	Energy-Only Providers	5.93	5.59	5.59	NA	0.00	5.59
2008	NH	Energy-Only Providers	8.74	13.03	10.74	NA	0.00	11.86
2008	NJ	Energy-Only Providers	0.00	10.38	10.35	NA	11.00	10.38
2008	NV	Energy-Only Providers	0.00	0.00	7.20	NA	0.00	7.20
2008	NY	Energy-Only Providers	13.33	11.05	7.72	NA	8.38	10.67
2008	OH	Energy-Only Providers	5.52	5.58	4.31	NA	0.00	5.03
2008	OR	Energy-Only Providers	0.00	6.81	6.42	NA	0.00	6.53
2008	PA	Energy-Only Providers	9.25	8.07	6.55	NA	6.53	7.53
2008	RI	Energy-Only Providers	10.01	8.37	9.31	NA	0.00	8.69
2008	VA	Energy-Only Providers	10.50	10.66	0.00	NA	0.00	10.50
2008	WA	Energy-Only Providers	0.00	0.00	6.07	NA	0.00	6.07
2008	US-TOTAL	Energy-Only Providers	10.91	9.34	7.76	NA	8.79	8.98
2008	CA	Delivery-Only Service	6.82	4.83	3.18	NA	0.62	4.07
2008	CT	Delivery-Only Service	8.31	5.65	4.09	NA	2.44	5.41
2008	DC	Delivery-Only Service	6.45	3.26	0.97	NA	2.40	3.14
2008	DE	Delivery-Only Service	3.94	0.98	0.41	NA	0.00	0.77
2008	IL	Delivery-Only Service	0.00	1.49	0.83	NA	0.97	1.28
2008	MA	Delivery-Only Service	7.02	4.81	3.74	NA	0.69	4.69
2008	MD	Delivery-Only Service	3.50	2.12	0.99	NA	1.20	1.93
2008	ME	Delivery-Only Service	6.55	4.07	1.84	NA	0.00	4.38
2008	MI	Delivery-Only Service	0.00	2.10	0.98	NA	0.00	1.65
2008	MT	Delivery-Only Service	3.70	2.25	0.53	NA	0.00	0.63
2008	NH	Delivery-Only Service	5.97	3.51	3.40	NA	0.00	3.46
2008	NJ	Delivery-Only Service	0.00	3.40	3.17	NA	2.18	3.32
2008	NV	Delivery-Only Service	0.00	0.00	0.22	NA	0.00	0.22
2008	NY	Delivery-Only Service	7.46	4.98	2.15	NA	3.29	4.73
2008	OH	Delivery-Only Service	5.22	4.29	2.18	NA	0.00	3.57
2008	OR	Delivery-Only Service	0.00	1.16	0.74	NA	0.00	0.86
2008	PA	Delivery-Only Service	5.16	2.07	0.69	NA	2.59	1.79
2008	RI	Delivery-Only Service	4.34	4.19	3.59	NA	0.00	4.00
2008	VA	Delivery-Only Service	2.53	4.10	0.00	NA	0.00	2.54
2008	WA	Delivery-Only Service	0.00	0.00	0.37	NA	0.00	0.37
2008	US-TOTAL	Delivery-Only Service	6.59	3.43	1.78	NA	2.34	3.13
2009	AK	Total Electric Industry	17.14	14.46	13.15	NA	0.00	15.09
2009	AL	Total Electric Industry	10.66	10.05	5.96	NA	0.00	8.83
2009	AR	Total Electric Industry	9.14	7.56	5.76	NA	12.32	7.57
2009	AZ	Total Electric Industry	10.73	9.35	6.65	NA	0.00	9.56
2009	CA	Total Electric Industry	14.74	13.42	10.07	NA	8.43	13.24
2009	CO	Total Electric Industry	10.00	8.15	6.39	NA	8.14	8.31
2009	CT	Total Electric Industry	20.33	16.86	14.92	NA	11.96	18.06
2009	DC	Total Electric Industry	13.76	12.96	8.41	NA	12.77	12.97
2009	DE	Total Electric Industry	14.07	11.98	9.34	NA	0.00	12.14
2009	FL	Total Electric Industry	12.39	10.77	9.32	NA	10.48	11.49
2009	GA	Total Electric Industry	10.13	8.94	6.12	NA	7.03	8.81
2009	HI	Total Electric Industry	24.20	21.86	18.14	NA	0.00	21.21

2009	IA	Total Electric Industry	9.99	7.55	5.27	NA	0.00	7.37
2009	ID	Total Electric Industry	7.80	6.49	5.17	NA	0.00	6.51
2009	IL	Total Electric Industry	11.27	8.99	6.84	NA	8.32	9.08
2009	IN	Total Electric Industry	9.50	8.32	5.81	NA	9.65	7.62
2009	KS	Total Electric Industry	9.53	7.87	6.10	NA	0.00	7.98
2009	KY	Total Electric Industry	8.37	7.63	4.91	NA	0.00	6.52
2009	LA	Total Electric Industry	8.10	7.69	5.25	NA	10.09	7.06
2009	MA	Total Electric Industry	16.87	15.37	14.08	NA	6.23	15.45
2009	MD	Total Electric Industry	14.98	11.97	9.92	NA	10.43	13.08
2009	ME	Total Electric Industry	15.65	12.55	9.95	NA	0.00	13.09
2009	MI	Total Electric Industry	11.60	9.24	6.99	NA	10.79	9.40
2009	MN	Total Electric Industry	10.04	7.92	6.26	NA	7.73	8.14
2009	MO	Total Electric Industry	8.54	6.96	5.42	NA	5.83	7.35
2009	MS	Total Electric Industry	10.22	9.50	6.61	NA	0.00	8.85
2009	MT	Total Electric Industry	8.93	8.32	5.45	NA	0.00	7.57
2009	NC	Total Electric Industry	9.99	7.98	5.99	NA	6.83	8.48
2009	ND	Total Electric Industry	7.58	6.81	5.25	NA	0.00	6.63
2009	NE	Total Electric Industry	8.52	7.33	5.75	NA	0.00	7.21
2009	NH	Total Electric Industry	16.26	14.55	13.83	NA	0.00	15.13
2009	NJ	Total Electric Industry	16.31	13.83	11.81	NA	12.37	14.52
2009	NM	Total Electric Industry	10.02	8.40	5.72	NA	0.00	8.09
2009	NV	Total Electric Industry	12.86	10.64	7.97	NA	9.95	10.36
2009	NY	Total Electric Industry	17.50	15.51	8.98	NA	13.13	15.52
2009	OH	Total Electric Industry	10.67	9.65	6.71	NA	10.73	9.01
2009	OK	Total Electric Industry	8.49	6.76	4.82	NA	0.00	6.94
2009	OR	Total Electric Industry	8.68	7.49	5.45	NA	6.83	7.48
2009	PA	Total Electric Industry	11.65	9.54	7.21	NA	7.77	9.60
2009	RI	Total Electric Industry	15.60	13.67	12.25	NA	0.00	14.23
2009	SC	Total Electric Industry	10.44	8.74	5.79	NA	0.00	8.42
2009	SD	Total Electric Industry	8.49	7.14	5.65	NA	0.00	7.39
2009	TN	Total Electric Industry	9.32	9.61	6.76	NA	10.69	8.69
2009	TX	Total Electric Industry	12.38	9.66	6.74	NA	9.83	9.86
2009	UT	Total Electric Industry	8.48	6.96	4.81	NA	8.31	6.77
2009	VA	Total Electric Industry	10.61	8.06	6.91	NA	8.42	8.93
2009	VT	Total Electric Industry	14.90	12.93	9.21	NA	0.00	12.75
2009	WA	Total Electric Industry	7.68	6.96	4.43	NA	5.91	6.60
2009	WI	Total Electric Industry	11.94	9.57	6.73	NA	0.00	9.38
2009	WV	Total Electric Industry	7.90	6.77	5.24	NA	7.56	6.65
2009	WY	Total Electric Industry	8.58	7.28	4.83	NA	0.00	6.08
2009	US-TOTAL	Total Electric Industry	11.51	10.17	6.81	NA	10.65	9.82
2009	AK	Full-Service Providers	17.14	14.46	13.15	NA	0.00	15.09
2009	AL	Full-Service Providers	10.66	10.05	5.96	NA	0.00	8.83
2009	AR	Full-Service Providers	9.14	7.56	5.76	NA	12.32	7.57
2009	AZ	Full-Service Providers	10.73	9.35	6.65	NA	0.00	9.56
2009	CA	Full-Service Providers	14.74	13.54	10.02	NA	9.23	13.35
2009	CO	Full-Service Providers	10.00	8.15	6.39	NA	8.14	8.31
2009	CT	Full-Service Providers	20.36	17.55	13.01	NA	0.00	19.12
2009	DC	Full-Service Providers	13.68	15.12	0.00	NA	0.00	14.38
2009	DE	Full-Service Providers	14.04	13.89	10.93	NA	0.00	13.56
2009	FL	Full-Service Providers	12.39	10.77	9.32	NA	10.48	11.49
2009	GA	Full-Service Providers	10.13	8.94	6.12	NA	7.03	8.81
2009	HI	Full-Service Providers	24.20	21.86	18.14	NA	0.00	21.21
2009	IA	Full-Service Providers	9.99	7.55	5.27	NA	0.00	7.37
2009	ID	Full-Service Providers	7.80	6.49	5.17	NA	0.00	6.51
2009	IL	Full-Service Providers	11.27	9.76	5.93	NA	7.80	10.39
2009	IN	Full-Service Providers	9.50	8.32	5.81	NA	9.65	7.62
2009	KS	Full-Service Providers	9.53	7.87	6.10	NA	0.00	7.98
2009	KY	Full-Service Providers	8.37	7.63	4.91	NA	0.00	6.52
2009	LA	Full-Service Providers	8.10	7.69	5.25	NA	10.09	7.06
2009	MA	Full-Service Providers	16.66	16.21	13.53	NA	0.00	16.07
2009	MD	Full-Service Providers	14.95	12.59	9.33	NA	0.00	14.22
2009	ME	Full-Service Providers	16.16	12.93	12.22	NA	0.00	14.46
2009	MI	Full-Service Providers	11.60	9.24	6.98	NA	10.79	9.45
2009	MN	Full-Service Providers	10.04	7.92	6.26	NA	7.73	8.14
2009	MO	Full-Service Providers	8.54	6.96	5.42	NA	5.83	7.35
2009	MS	Full-Service Providers	10.22	9.50	6.61	NA	0.00	8.85
2009	MT	Full-Service Providers	8.93	8.38	6.01	NA	0.00	8.21
2009	NC	Full-Service Providers	9.99	7.98	5.99	NA	6.83	8.48
2009	ND	Full-Service Providers	7.58	6.81	5.25	NA	0.00	6.63
2009	NE	Full-Service Providers	8.52	7.33	5.75	NA	0.00	7.21
2009	NH	Full-Service Providers	16.26	14.16	14.28	NA	0.00	15.23
2009	NJ	Full-Service Providers	16.31	14.59	11.70	NA	10.76	15.34
2009	NM	Full-Service Providers	10.02	8.40	5.72	NA	0.00	8.09
2009	NV	Full-Service Providers	12.86	10.64	8.21	NA	9.95	10.56
2009	NY	Full-Service Providers	17.16	16.21	8.62	NA	14.97	16.25
2009	OH	Full-Service Providers	10.63	9.64	6.76	NA	10.73	9.07
2009	OK	Full-Service Providers	8.49	6.76	4.82	NA	0.00	6.94
2009	OR	Full-Service Providers	8.68	7.53	5.26	NA	6.83	7.53
2009	PA	Full-Service Providers	11.60	9.52	7.16	NA	7.73	9.62
2009	RI	Full-Service Providers	15.60	14.10	12.83	NA	0.00	14.77
2009	SC	Full-Service Providers	10.44	8.74	5.79	NA	0.00	8.42
2009	SD	Full-Service Providers	8.49	7.14	5.65	NA	0.00	7.39
2009	TN	Full-Service Providers	9.32	9.61	6.76	NA	10.69	8.69
2009	TX	Full-Service Providers	12.38	9.66	6.74	NA	9.83	9.86
2009	UT	Full-Service Providers	8.48	6.96	4.81	NA	8.31	6.77
2009	VA	Full-Service Providers	10.61	8.06	6.91	NA	8.42	8.93
2009	VT	Full-Service Providers	14.90	12.93	9.21	NA	0.00	12.75
2009	WA	Full-Service Providers	7.68	6.96	4.44	NA	5.91	6.73
2009	WI	Full-Service Providers	11.94	9.57	6.73	NA	0.00	9.38
2009	WV	Full-Service Providers	7.90	6.77	5.24	NA	7.56	6.65
2009	WY	Full-Service Providers	8.58	7.28	4.83	NA	0.00	6.08
2009	US-TOTAL	Full-Service Providers	11.43	9.83	6.56	NA	9.20	9.67
2009	CA	Restructured Retail Service Providers	15.32	12.33	10.55	NA	7.41	11.75
2009	CT	Restructured Retail Service Providers	20.12	16.51	15.72	NA	11.96	16.69
2009	DC	Restructured Retail Service Providers	22.39	12.50	8.41	NA	12.77	12.38
2009	DE	Restructured Retail Service Providers	15.79	10.35	8.39	NA	0.00	9.62
2009	IL	Restructured Retail Service Providers	3.61	8.27	6.98	NA	8.34	7.52
2009	MA	Restructured Retail Service Providers	18.53	14.70	14.29	NA	6.23	14.71
2009	MD	Restructured Retail Service Providers	15.75	11.70	10.03	NA	10.43	11.54
2009	ME	Restructured Retail Service Providers	15.64	12.54	9.93	NA	0.00	13.07
2009	MI	Restructured Retail Service Providers	12.00	9.26	7.12	NA	0.00	8.38

2009	MT	Restructured Retail Service Providers	8.33	6.80	5.08	NA	0.00	5.18
2009	NH	Restructured Retail Service Providers	19.70	16.07	13.46	NA	0.00	14.70
2009	NJ	Restructured Retail Service Providers	14.26	12.65	11.86	NA	12.46	12.43
2009	NV	Restructured Retail Service Providers	0.00	7.88	6.05	NA	0.00	6.05
2009	NY	Restructured Retail Service Providers	19.63	15.02	9.19	NA	12.91	14.60
2009	OH	Restructured Retail Service Providers	11.41	9.75	6.37	NA	0.00	8.47
2009	OR	Restructured Retail Service Providers	0.00	6.03	6.48	NA	0.00	6.38
2009	PA	Restructured Retail Service Providers	13.98	9.69	7.66	NA	9.76	9.36
2009	RI	Restructured Retail Service Providers	15.48	12.94	11.79	NA	0.00	12.63
2009	VA	Restructured Retail Service Providers	14.20	13.00	0.00	NA	0.00	14.19
2009	WA	Restructured Retail Service Providers	0.00	0.00	4.41	NA	0.00	4.41
2009	US-TOTAL	Restructured Retail Service Providers	16.98	12.52	8.79	NA	11.31	11.47
2009	CA	Energy-Only Providers	8.30	7.73	7.58	NA	6.64	7.67
2009	CT	Energy-Only Providers	11.17	10.26	10.86	NA	8.66	10.46
2009	DC	Energy-Only Providers	3.56	10.26	9.73	NA	10.43	10.20
2009	DE	Energy-Only Providers	11.63	9.35	7.96	NA	0.00	8.81
2009	IL	Energy-Only Providers	0.00	6.56	6.01	NA	7.15	6.25
2009	MA	Energy-Only Providers	11.75	9.80	9.87	NA	5.28	9.94
2009	MD	Energy-Only Providers	12.14	9.49	8.87	NA	9.21	9.47
2009	ME	Energy-Only Providers	9.05	8.36	7.90	NA	0.00	8.51
2009	MI	Energy-Only Providers	6.80	7.18	6.01	NA	0.00	6.70
2009	MT	Energy-Only Providers	4.76	4.60	4.60	NA	0.00	4.60
2009	NH	Energy-Only Providers	10.61	10.28	9.26	NA	0.00	9.75
2009	NJ	Energy-Only Providers	8.82	8.92	8.38	NA	9.59	8.79
2009	NV	Energy-Only Providers	0.00	6.67	5.78	NA	0.00	5.78
2009	NY	Energy-Only Providers	10.34	9.09	6.50	NA	9.24	8.87
2009	OH	Energy-Only Providers	6.25	6.19	5.06	NA	0.00	5.66
2009	OR	Energy-Only Providers	0.00	4.25	5.74	NA	0.00	5.43
2009	PA	Energy-Only Providers	8.79	7.77	6.87	NA	7.07	7.53
2009	RI	Energy-Only Providers	9.66	8.73	8.56	NA	0.00	8.69
2009	VA	Energy-Only Providers	11.78	10.00	0.00	NA	0.00	11.76
2009	WA	Energy-Only Providers	0.00	0.00	4.03	NA	0.00	4.03
2009	US-TOTAL	Energy-Only Providers	9.70	8.58	6.92	NA	8.63	8.07
2009	CA	Delivery-Only Service	7.01	4.60	2.97	NA	0.77	4.08
2009	CT	Delivery-Only Service	8.95	6.25	4.86	NA	3.30	6.23
2009	DC	Delivery-Only Service	10.15	3.17	0.95	NA	2.75	3.09
2009	DE	Delivery-Only Service	4.17	1.00	0.42	NA	0.00	0.82
2009	IL	Delivery-Only Service	3.61	1.70	0.97	NA	1.19	1.27
2009	MA	Delivery-Only Service	6.78	4.89	4.42	NA	0.95	4.76
2009	MD	Delivery-Only Service	3.61	2.21	1.16	NA	1.22	2.06
2009	ME	Delivery-Only Service	6.59	4.18	2.02	NA	0.00	4.56
2009	MI	Delivery-Only Service	5.20	2.09	1.10	NA	0.00	1.68
2009	MT	Delivery-Only Service	3.57	2.21	0.48	NA	0.00	0.58
2009	NH	Delivery-Only Service	9.09	5.79	4.19	NA	0.00	4.95
2009	NJ	Delivery-Only Service	5.44	3.73	3.48	NA	2.87	3.65
2009	NV	Delivery-Only Service	0.00	1.21	0.27	NA	0.00	0.27
2009	NY	Delivery-Only Service	9.29	5.93	2.68	NA	3.67	5.73
2009	OH	Delivery-Only Service	5.16	3.56	1.32	NA	0.00	2.81
2009	OR	Delivery-Only Service	0.00	1.78	0.73	NA	0.00	0.95
2009	PA	Delivery-Only Service	5.19	1.92	0.79	NA	2.69	1.82
2009	RI	Delivery-Only Service	5.82	4.21	3.23	NA	0.00	3.94
2009	VA	Delivery-Only Service	2.42	3.00	0.00	NA	0.00	2.43
2009	WA	Delivery-Only Service	0.00	0.00	0.38	NA	0.00	0.38
2009	US-TOTAL	Delivery-Only Service	7.28	3.94	1.88	NA	2.68	3.41
2010	AK	Total Electric Industry	16.26	13.95	14.14	NA	0.00	14.76
2010	AL	Total Electric Industry	10.67	10.18	6.01	NA	0.00	8.89
2010	AR	Total Electric Industry	8.86	7.31	5.44	NA	11.33	7.28
2010	AZ	Total Electric Industry	10.97	9.47	6.63	NA	0.00	9.69
2010	CA	Total Electric Industry	14.75	13.10	9.80	NA	8.27	13.01
2010	CO	Total Electric Industry	11.04	9.13	6.90	NA	9.34	9.15
2010	CT	Total Electric Industry	19.25	16.45	14.50	NA	11.46	17.39
2010	DC	Total Electric Industry	14.01	13.42	7.78	NA	11.04	13.35
2010	DE	Total Electric Industry	13.80	11.36	9.57	NA	0.00	11.97
2010	FL	Total Electric Industry	11.44	9.76	8.85	NA	8.58	10.58
2010	GA	Total Electric Industry	10.07	9.06	6.22	NA	7.46	8.87
2010	HI	Total Electric Industry	28.10	25.93	21.94	NA	0.00	25.12
2010	IA	Total Electric Industry	10.42	7.91	5.36	NA	0.00	7.66
2010	ID	Total Electric Industry	7.99	6.64	5.15	NA	0.00	6.54
2010	IL	Total Electric Industry	11.52	8.88	6.82	NA	6.71	9.13
2010	IN	Total Electric Industry	9.56	8.38	5.87	NA	9.21	7.67
2010	KS	Total Electric Industry	10.03	8.25	6.23	NA	0.00	8.35
2010	KY	Total Electric Industry	8.57	7.88	5.05	NA	0.00	6.73
2010	LA	Total Electric Industry	8.98	8.50	5.84	NA	9.46	7.80
2010	MA	Total Electric Industry	14.59	14.53	13.71	NA	6.46	14.26
2010	MD	Total Electric Industry	14.32	11.75	9.57	NA	9.78	12.70
2010	ME	Total Electric Industry	15.71	12.51	9.17	NA	0.00	12.84
2010	MI	Total Electric Industry	12.46	9.81	7.08	NA	10.65	9.88
2010	MN	Total Electric Industry	10.59	8.38	6.29	NA	7.77	8.41
2010	MO	Total Electric Industry	9.08	7.50	5.50	NA	6.14	7.78
2010	MS	Total Electric Industry	9.87	9.32	6.32	NA	0.00	8.59
2010	MT	Total Electric Industry	9.16	8.55	5.49	NA	0.00	7.88
2010	NC	Total Electric Industry	10.12	8.16	6.17	NA	7.09	8.67
2010	ND	Total Electric Industry	8.13	7.21	5.81	NA	0.00	7.11
2010	NE	Total Electric Industry	8.94	7.63	6.00	NA	0.00	7.52
2010	NH	Total Electric Industry	16.32	14.26	12.75	NA	0.00	14.84
2010	NJ	Total Electric Industry	16.57	13.89	11.81	NA	11.91	14.68
2010	NM	Total Electric Industry	10.52	8.57	6.01	NA	0.00	8.40
2010	NV	Total Electric Industry	12.36	9.78	7.37	NA	9.40	9.73
2010	NY	Total Electric Industry	18.74	16.31	8.78	NA	13.74	16.41
2010	OH	Total Electric Industry	11.32	9.73	6.40	NA	8.62	9.14
2010	OK	Total Electric Industry	9.14	7.45	5.35	NA	0.00	7.59
2010	OR	Total Electric Industry	8.87	7.59	5.41	NA	6.99	7.56
2010	PA	Total Electric Industry	12.70	10.10	7.66	NA	7.92	10.31
2010	RI	Total Electric Industry	15.92	13.11	11.82	NA	13.86	14.08
2010	SC	Total Electric Industry	10.50	8.90	5.74	NA	0.00	8.49
2010	SD	Total Electric Industry	8.97	7.55	6.07	NA	0.00	7.82
2010	TN	Total Electric Industry	9.23	9.66	6.58	NA	11.09	8.61
2010	TX	Total Electric Industry	11.60	9.19	6.44	NA	9.82	9.34
2010	UT	Total Electric Industry	8.71	7.15	4.93	NA	8.69	6.94
2010	VA	Total Electric Industry	10.45	7.65	6.66	NA	7.70	8.69
2010	VT	Total Electric Industry	15.57	13.44	9.53	NA	0.00	13.24

2010	WA	Total Electric Industry	8.04	7.37	4.07	NA	7.42	6.66
2010	WI	Total Electric Industry	12.65	9.98	6.85	NA	0.00	9.78
2010	WV	Total Electric Industry	8.79	7.66	5.86	NA	8.33	7.45
2010	WY	Total Electric Industry	8.77	7.42	4.98	NA	0.00	6.20
2010	US-TOTAL	Total Electric Industry	11.54	10.19	6.77	NA	10.57	9.83
2010	AK	Full-Service Providers	16.26	13.95	14.14	NA	0.00	14.76
2010	AL	Full-Service Providers	10.67	10.18	6.01	NA	0.00	8.89
2010	AR	Full-Service Providers	8.86	7.31	5.44	NA	11.33	7.28
2010	AZ	Full-Service Providers	10.97	9.47	6.63	NA	0.00	9.69
2010	CA	Full-Service Providers	14.74	13.22	9.79	NA	8.87	13.16
2010	CO	Full-Service Providers	11.04	9.13	6.90	NA	9.34	9.15
2010	CT	Full-Service Providers	19.47	16.48	12.05	NA	11.16	18.15
2010	DC	Full-Service Providers	14.02	14.92	0.00	NA	0.00	14.38
2010	DE	Full-Service Providers	13.78	13.42	10.80	NA	0.00	13.25
2010	FL	Full-Service Providers	11.44	9.76	8.85	NA	8.58	10.58
2010	GA	Full-Service Providers	10.07	9.06	6.22	NA	7.46	8.87
2010	HI	Full-Service Providers	28.10	25.93	21.94	NA	0.00	25.12
2010	IA	Full-Service Providers	10.42	7.91	5.36	NA	0.00	7.66
2010	ID	Full-Service Providers	7.99	6.64	5.15	NA	0.00	6.54
2010	IL	Full-Service Providers	11.52	9.83	6.04	NA	7.33	10.57
2010	IN	Full-Service Providers	9.56	8.38	5.87	NA	9.21	7.67
2010	KS	Full-Service Providers	10.03	8.25	6.23	NA	0.00	8.35
2010	KY	Full-Service Providers	8.57	7.88	5.05	NA	0.00	6.73
2010	LA	Full-Service Providers	8.98	8.50	5.84	NA	9.46	7.80
2010	MA	Full-Service Providers	14.31	14.30	12.22	NA	0.00	14.01
2010	MD	Full-Service Providers	14.35	12.26	9.45	NA	0.00	13.74
2010	ME	Full-Service Providers	15.47	13.06	12.27	NA	0.00	14.12
2010	MI	Full-Service Providers	12.46	9.95	7.07	NA	10.65	10.07
2010	MN	Full-Service Providers	10.59	8.38	6.29	NA	7.77	8.41
2010	MO	Full-Service Providers	9.08	7.50	5.50	NA	6.14	7.78
2010	MS	Full-Service Providers	9.87	9.32	6.32	NA	0.00	8.59
2010	MT	Full-Service Providers	9.16	8.61	6.17	NA	0.00	8.53
2010	NC	Full-Service Providers	10.12	8.16	6.17	NA	7.09	8.67
2010	ND	Full-Service Providers	8.13	7.21	5.81	NA	0.00	7.11
2010	NE	Full-Service Providers	8.94	7.63	6.00	NA	0.00	7.52
2010	NH	Full-Service Providers	16.32	14.54	13.14	NA	0.00	15.48
2010	NJ	Full-Service Providers	16.58	14.63	10.47	NA	0.00	15.61
2010	NM	Full-Service Providers	10.52	8.57	6.01	NA	0.00	8.40
2010	NV	Full-Service Providers	12.36	9.85	7.58	NA	9.40	9.91
2010	NY	Full-Service Providers	18.51	17.48	9.28	NA	17.89	17.56
2010	OH	Full-Service Providers	11.31	9.89	6.10	NA	10.88	9.32
2010	OK	Full-Service Providers	9.14	7.45	5.35	NA	0.00	7.59
2010	OR	Full-Service Providers	8.87	7.62	5.44	NA	6.99	7.63
2010	PA	Full-Service Providers	12.68	10.43	7.67	NA	7.74	10.60
2010	RI	Full-Service Providers	15.93	13.38	12.32	NA	0.00	14.80
2010	SC	Full-Service Providers	10.50	8.90	5.74	NA	0.00	8.49
2010	SD	Full-Service Providers	8.97	7.55	6.07	NA	0.00	7.82
2010	TN	Full-Service Providers	9.23	9.66	6.58	NA	11.09	8.61
2010	TX	Full-Service Providers	11.60	9.19	6.44	NA	9.82	9.34
2010	UT	Full-Service Providers	8.71	7.15	4.93	NA	8.69	6.94
2010	VA	Full-Service Providers	10.45	7.65	6.66	NA	7.70	8.69
2010	VT	Full-Service Providers	15.57	13.44	9.53	NA	0.00	13.24
2010	WA	Full-Service Providers	8.04	7.38	3.98	NA	7.42	6.70
2010	WI	Full-Service Providers	12.65	9.98	6.85	NA	0.00	9.78
2010	WV	Full-Service Providers	8.79	7.66	5.86	NA	8.33	7.45
2010	WY	Full-Service Providers	8.77	7.42	4.98	NA	0.00	6.20
2010	US-TOTAL	Full-Service Providers	11.44	9.82	6.49	NA	9.55	9.67
2010	CA	Restructured Retail Service Providers	20.36	11.72	9.86	NA	7.47	10.95
2010	CT	Restructured Retail Service Providers	18.74	16.44	15.32	NA	12.01	16.76
2010	DC	Restructured Retail Service Providers	13.83	13.16	7.78	NA	11.04	12.94
2010	DE	Restructured Retail Service Providers	14.99	9.93	8.56	NA	0.00	9.57
2010	IL	Restructured Retail Service Providers	15.80	8.12	6.95	NA	6.69	7.45
2010	MA	Restructured Retail Service Providers	16.96	14.72	14.25	NA	6.46	14.57
2010	MD	Restructured Retail Service Providers	14.00	11.55	9.59	NA	9.78	11.42
2010	ME	Restructured Retail Service Providers	15.72	12.51	9.14	NA	0.00	12.82
2010	MI	Restructured Retail Service Providers	12.46	8.79	7.14	NA	0.00	7.94
2010	MT	Restructured Retail Service Providers	9.17	6.83	5.09	NA	0.00	5.20
2010	NH	Restructured Retail Service Providers	16.44	13.82	12.61	NA	0.00	13.28
2010	NJ	Restructured Retail Service Providers	15.48	13.25	12.26	NA	11.91	13.05
2010	NV	Restructured Retail Service Providers	0.00	7.72	5.18	NA	0.00	5.67
2010	NY	Restructured Retail Service Providers	20.02	15.53	8.51	NA	13.25	15.03
2010	OH	Restructured Retail Service Providers	11.35	9.48	6.87	NA	8.00	8.77
2010	OR	Restructured Retail Service Providers	0.00	6.55	5.04	NA	0.00	5.49
2010	PA	Restructured Retail Service Providers	12.88	9.48	7.64	NA	9.12	9.31
2010	RI	Restructured Retail Service Providers	14.34	12.80	11.59	NA	13.86	12.49
2010	WA	Restructured Retail Service Providers	0.00	5.41	5.09	NA	0.00	5.10
2010	US-TOTAL	Restructured Retail Service Providers	15.30	12.21	8.56	NA	11.04	11.23
2010	CA	Energy-Only Providers	9.99	7.12	6.69	NA	6.65	6.96
2010	CT	Energy-Only Providers	10.33	10.03	10.33	NA	7.94	10.14
2010	DC	Energy-Only Providers	10.65	9.56	6.48	NA	8.08	9.44
2010	DE	Energy-Only Providers	10.79	8.78	8.04	NA	0.00	8.57
2010	IL	Energy-Only Providers	11.83	6.32	5.99	NA	5.50	6.13
2010	MA	Energy-Only Providers	9.31	9.29	9.27	NA	5.71	9.23
2010	MD	Energy-Only Providers	10.50	9.20	8.46	NA	8.43	9.18
2010	ME	Energy-Only Providers	8.86	8.11	7.04	NA	0.00	8.11
2010	MI	Energy-Only Providers	6.38	6.51	5.85	NA	0.00	6.17
2010	MT	Energy-Only Providers	5.50	4.56	4.56	NA	0.00	4.56
2010	NH	Energy-Only Providers	9.08	8.31	8.17	NA	0.00	8.25
2010	NJ	Energy-Only Providers	10.68	9.18	8.58	NA	8.89	9.06
2010	NV	Energy-Only Providers	0.00	6.70	5.01	NA	0.00	5.34
2010	NY	Energy-Only Providers	10.31	9.02	5.56	NA	8.94	8.70
2010	OH	Energy-Only Providers	6.56	6.08	5.42	NA	4.87	5.90
2010	OR	Energy-Only Providers	0.00	4.12	4.56	NA	0.00	4.43
2010	PA	Energy-Only Providers	9.20	7.80	6.99	NA	7.94	7.72
2010	RI	Energy-Only Providers	8.18	8.52	8.27	NA	9.09	8.46
2010	WA	Energy-Only Providers	0.00	4.55	4.55	NA	0.00	4.55
2010	US-TOTAL	Energy-Only Providers	8.88	8.22	6.62	NA	8.06	7.73
2010	CA	Delivery-Only Service	10.37	4.60	3.17	NA	0.82	3.99
2010	CT	Delivery-Only Service	8.41	6.40	4.99	NA	4.07	6.62
2010	DC	Delivery-Only Service	3.18	3.59	1.31	NA	2.95	3.50
2010	DE	Delivery-Only Service	4.20	1.15	0.52	NA	0.00	1.00

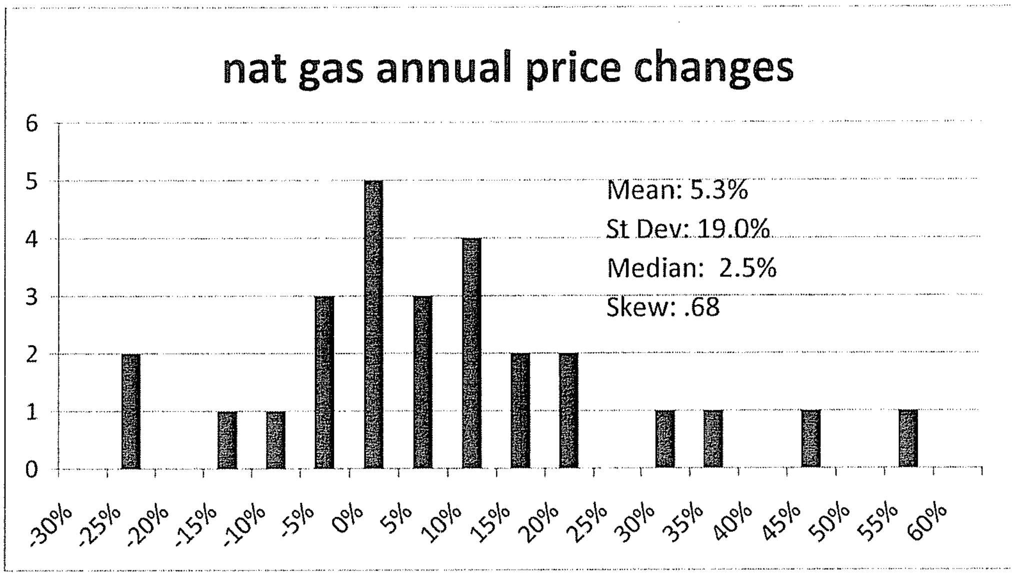
2010	IL	Delivery-Only Service	3.97	1.80	0.96	NA	1.19	1.32
2010	MA	Delivery-Only Service	7.65	5.43	4.99	NA	0.75	5.34
2010	MD	Delivery-Only Service	3.50	2.35	1.14	NA	1.35	2.25
2010	ME	Delivery-Only Service	6.86	4.39	2.10	NA	0.00	4.71
2010	MI	Delivery-Only Service	6.08	2.29	1.29	NA	0.00	1.77
2010	MT	Delivery-Only Service	3.67	2.27	0.53	NA	0.00	0.64
2010	NH	Delivery-Only Service	7.36	5.51	4.44	NA	0.00	5.04
2010	NJ	Delivery-Only Service	4.81	4.08	3.68	NA	3.02	3.99
2010	NV	Delivery-Only Service	0.00	1.02	0.17	NA	0.00	0.34
2010	NY	Delivery-Only Service	9.71	6.51	2.95	NA	4.31	6.32
2010	OH	Delivery-Only Service	4.79	3.41	1.46	NA	3.13	2.88
2010	OR	Delivery-Only Service	0.00	2.42	0.48	NA	0.00	1.06
2010	PA	Delivery-Only Service	3.68	1.68	0.64	NA	1.18	1.60
2010	RI	Delivery-Only Service	6.16	4.28	3.32	NA	4.77	4.04
2010	WA	Delivery-Only Service	0.00	0.85	0.54	NA	0.00	0.55
2010	US-TOTAL	Delivery-Only Service	6.41	3.99	1.93	NA	2.98	3.50
2011	AK	Total Electric Industry	17.62	15.10	15.71	NA	0.00	16.08
2011	AL	Total Electric Industry	11.09	10.47	6.25	NA	0.00	9.10
2011	AR	Total Electric Industry	9.02	7.50	5.63	NA	11.10	7.43
2011	AZ	Total Electric Industry	11.08	9.50	6.55	NA	0.00	9.71
2011	CA	Total Electric Industry	14.78	13.05	10.11	NA	8.14	13.05
2011	CO	Total Electric Industry	11.27	9.44	7.06	NA	9.79	9.39
2011	CT	Total Electric Industry	18.11	15.57	13.24	NA	10.25	16.35
2011	DC	Total Electric Industry	13.40	12.90	6.89	NA	10.19	12.81
2011	DE	Total Electric Industry	13.70	10.64	8.91	NA	0.00	11.48
2011	FL	Total Electric Industry	11.51	9.85	8.55	NA	8.81	10.61
2011	GA	Total Electric Industry	11.05	9.87	6.60	NA	7.94	9.61
2011	HI	Total Electric Industry	34.68	32.37	28.40	NA	0.00	31.59
2011	IA	Total Electric Industry	10.46	7.85	5.21	NA	0.00	7.56
2011	ID	Total Electric Industry	7.87	6.41	5.10	NA	0.00	6.44
2011	IL	Total Electric Industry	11.78	8.64	6.42	NA	6.81	8.97
2011	IN	Total Electric Industry	10.06	8.77	6.17	NA	9.74	8.01
2011	KS	Total Electric Industry	10.65	8.78	6.71	NA	0.00	8.89
2011	KY	Total Electric Industry	9.20	8.49	5.33	NA	0.00	7.17
2011	LA	Total Electric Industry	8.96	8.44	5.69	NA	8.33	7.68
2011	MA	Total Electric Industry	14.67	14.33	13.38	NA	6.14	14.11
2011	MD	Total Electric Industry	13.31	11.28	8.76	NA	9.03	11.93
2011	ME	Total Electric Industry	15.38	12.29	8.88	NA	0.00	12.58
2011	MI	Total Electric Industry	13.27	10.33	7.32	NA	8.53	10.40
2011	MN	Total Electric Industry	10.96	8.63	6.47	NA	8.23	8.65
2011	MO	Total Electric Industry	9.75	8.04	5.85	NA	6.90	8.32
2011	MS	Total Electric Industry	10.17	9.48	6.53	NA	0.00	8.78
2011	MT	Total Electric Industry	9.75	9.12	5.27	NA	0.00	8.23
2011	NC	Total Electric Industry	10.26	8.13	6.01	NA	7.04	8.64
2011	ND	Total Electric Industry	8.58	7.61	6.24	NA	0.00	7.50
2011	NE	Total Electric Industry	9.32	7.99	6.43	NA	0.00	7.88
2011	NH	Total Electric Industry	16.52	14.04	12.27	NA	0.00	14.74
2011	NJ	Total Electric Industry	16.23	13.47	11.43	NA	10.69	14.30
2011	NM	Total Electric Industry	11.00	9.07	6.06	NA	0.00	8.74
2011	NV	Total Electric Industry	11.61	9.05	6.65	NA	8.58	8.97
2011	NY	Total Electric Industry	18.26	15.81	7.83	NA	13.45	15.89
2011	OH	Total Electric Industry	11.42	9.63	6.12	NA	6.64	9.03
2011	OK	Total Electric Industry	9.47	7.60	5.46	NA	0.00	7.80
2011	OR	Total Electric Industry	9.54	8.15	5.47	NA	7.89	8.04
2011	PA	Total Electric Industry	13.26	10.03	7.73	NA	8.93	10.45
2011	RI	Total Electric Industry	14.33	12.37	11.27	NA	14.11	13.04
2011	SC	Total Electric Industry	11.05	9.30	5.94	NA	0.00	8.80
2011	SD	Total Electric Industry	9.35	7.76	6.20	NA	0.00	8.05
2011	TN	Total Electric Industry	9.98	10.27	7.23	NA	12.07	9.28
2011	TX	Total Electric Industry	11.08	8.83	6.24	NA	10.08	9.00
2011	UT	Total Electric Industry	8.96	7.35	5.10	NA	9.24	7.13
2011	VA	Total Electric Industry	10.64	7.95	6.49	NA	8.24	8.84
2011	VT	Total Electric Industry	16.26	14.00	9.83	NA	0.00	13.80
2011	WA	Total Electric Industry	8.28	7.49	4.09	NA	8.54	6.78
2011	WI	Total Electric Industry	13.02	10.42	7.33	NA	0.00	10.21
2011	WV	Total Electric Industry	9.39	8.14	6.18	NA	8.60	7.88
2011	WY	Total Electric Industry	9.11	7.72	5.41	NA	0.00	6.58
2011	US-TOTAL	Total Electric Industry	11.72	10.23	6.82	NA	10.46	9.90
2011	AK	Full-Service Providers	17.62	15.10	15.71	NA	0.00	16.08
2011	AL	Full-Service Providers	11.09	10.47	6.25	NA	0.00	9.10
2011	AR	Full-Service Providers	9.02	7.50	5.63	NA	11.10	7.43
2011	AZ	Full-Service Providers	11.08	9.50	6.55	NA	0.00	9.71
2011	CA	Full-Service Providers	14.75	13.16	10.14	NA	8.82	13.22
2011	CO	Full-Service Providers	11.27	9.44	7.06	NA	9.79	9.39
2011	CT	Full-Service Providers	17.92	15.37	10.78	NA	10.15	16.67
2011	DC	Full-Service Providers	13.44	14.36	0.00	NA	0.00	13.79
2011	DE	Full-Service Providers	13.72	12.56	10.44	NA	0.00	12.96
2011	FL	Full-Service Providers	11.51	9.85	8.55	NA	8.81	10.61
2011	GA	Full-Service Providers	11.05	9.87	6.60	NA	7.94	9.61
2011	HI	Full-Service Providers	34.68	32.37	28.40	NA	0.00	31.59
2011	IA	Full-Service Providers	10.46	7.85	5.21	NA	0.00	7.56
2011	ID	Full-Service Providers	7.87	6.41	5.10	NA	0.00	6.44
2011	IL	Full-Service Providers	11.79	9.90	6.02	NA	6.65	10.75
2011	IN	Full-Service Providers	10.06	8.77	6.17	NA	9.74	8.01
2011	KS	Full-Service Providers	10.65	8.78	6.71	NA	0.00	8.89
2011	KY	Full-Service Providers	9.20	8.49	5.33	NA	0.00	7.17
2011	LA	Full-Service Providers	8.96	8.44	5.69	NA	8.33	7.68
2011	MA	Full-Service Providers	14.49	14.56	12.55	NA	0.00	14.22
2011	MD	Full-Service Providers	13.29	11.54	9.12	NA	0.00	12.75
2011	ME	Full-Service Providers	14.47	13.08	11.83	NA	0.00	13.53
2011	MI	Full-Service Providers	13.27	10.60	7.43	NA	8.53	10.69
2011	MN	Full-Service Providers	10.96	8.63	6.47	NA	8.23	8.65
2011	MO	Full-Service Providers	9.75	8.04	5.85	NA	6.90	8.32
2011	MS	Full-Service Providers	10.17	9.48	6.53	NA	0.00	8.78
2011	MT	Full-Service Providers	9.75	9.21	6.68	NA	0.00	9.11
2011	NC	Full-Service Providers	10.26	8.13	6.01	NA	7.04	8.64
2011	ND	Full-Service Providers	8.58	7.61	6.24	NA	0.00	7.50
2011	NE	Full-Service Providers	9.32	7.99	6.43	NA	0.00	7.88
2011	NH	Full-Service Providers	16.52	15.34	16.24	NA	0.00	16.11
2011	NJ	Full-Service Providers	16.23	14.22	9.49	NA	12.15	15.29
2011	NM	Full-Service Providers	11.00	9.07	6.06	NA	0.00	8.74

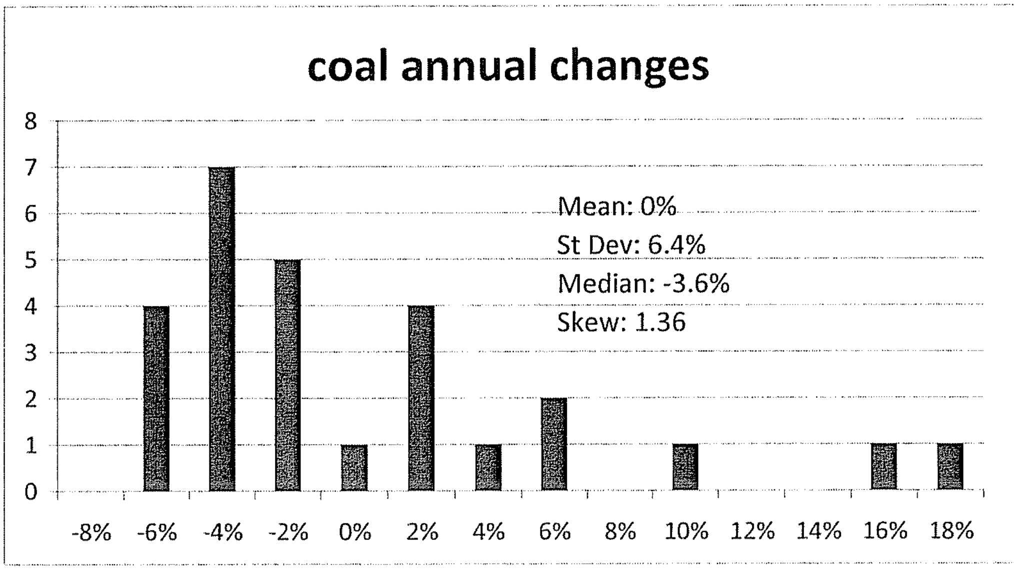
2011	NV	Full-Service Providers	11.61	9.11	6.84	NA	8.58	9.14
2011	NY	Full-Service Providers	18.06	17.11	9.18	NA	11.04	17.17
2011	OH	Full-Service Providers	11.57	10.31	6.05	NA	12.11	9.48
2011	OK	Full-Service Providers	9.47	7.60	5.46	NA	0.00	7.80
2011	OR	Full-Service Providers	9.54	8.16	5.51	NA	7.89	8.11
2011	PA	Full-Service Providers	13.24	11.67	9.06	NA	7.65	12.47
2011	RI	Full-Service Providers	14.34	12.64	11.82	NA	0.00	13.59
2011	SC	Full-Service Providers	11.05	9.30	5.94	NA	0.00	8.80
2011	SD	Full-Service Providers	9.35	7.76	6.20	NA	0.00	8.05
2011	TN	Full-Service Providers	9.98	10.27	7.23	NA	12.07	9.28
2011	TX	Full-Service Providers	11.08	8.83	6.24	NA	10.08	9.00
2011	UT	Full-Service Providers	8.96	7.35	5.10	NA	9.24	7.13
2011	VA	Full-Service Providers	10.64	7.95	6.49	NA	8.24	8.84
2011	VT	Full-Service Providers	16.26	14.00	9.83	NA	0.00	13.80
2011	WA	Full-Service Providers	8.28	7.50	4.02	NA	8.54	6.83
2011	WI	Full-Service Providers	13.02	10.42	7.33	NA	0.00	10.21
2011	WV	Full-Service Providers	9.39	8.14	6.18	NA	8.60	7.88
2011	WY	Full-Service Providers	9.11	7.72	5.41	NA	0.00	6.58
2011	US-TOTAL	Full-Service Providers	11.60	9.93	6.60	NA	9.35	9.79
2011	CA	Restructured Retail Service Providers	22.90	12.10	9.96	NA	7.26	11.29
2011	CT	Restructured Retail Service Providers	18.37	15.63	14.07	NA	10.28	16.15
2011	DC	Restructured Retail Service Providers	12.91	12.69	6.89	NA	10.19	12.45
2011	DE	Restructured Retail Service Providers	12.78	9.34	7.76	NA	0.00	8.87
2011	IL	Restructured Retail Service Providers	11.58	7.81	6.49	NA	6.82	7.13
2011	MA	Restructured Retail Service Providers	16.14	14.16	13.68	NA	6.14	13.98
2011	MD	Restructured Retail Service Providers	13.44	11.19	8.70	NA	9.03	11.13
2011	ME	Restructured Retail Service Providers	15.40	12.28	8.85	NA	0.00	12.57
2011	MI	Restructured Retail Service Providers	13.25	8.30	6.72	NA	0.00	7.48
2011	MT	Restructured Retail Service Providers	9.84	6.24	4.43	NA	0.00	4.54
2011	NH	Restructured Retail Service Providers	14.94	12.45	11.04	NA	0.00	11.86
2011	NJ	Restructured Retail Service Providers	16.30	13.03	11.94	NA	10.58	13.07
2011	NV	Restructured Retail Service Providers	0.00	7.48	4.63	NA	0.00	5.18
2011	NY	Restructured Retail Service Providers	19.27	15.04	7.22	NA	13.87	14.47
2011	OH	Restructured Retail Service Providers	11.04	9.09	6.20	NA	6.45	8.42
2011	OR	Restructured Retail Service Providers	0.00	7.78	4.99	NA	0.00	5.85
2011	PA	Restructured Retail Service Providers	13.33	9.20	7.53	NA	8.93	8.87
2011	RI	Restructured Retail Service Providers	13.96	12.08	11.03	NA	14.11	11.86
2011	WA	Restructured Retail Service Providers	0.00	5.19	4.83	NA	0.00	4.84
2011	US-TOTAL	Restructured Retail Service Providers	14.58	11.61	7.89	NA	10.79	10.60
2011	CA	Energy-Only Providers	10.10	6.54	5.96	NA	6.44	6.34
2011	CT	Energy-Only Providers	9.72	9.29	9.29	NA	6.77	9.39
2011	DC	Energy-Only Providers	9.69	9.07	5.55	NA	7.17	8.92
2011	DE	Energy-Only Providers	9.74	8.14	7.28	NA	0.00	7.87
2011	IL	Energy-Only Providers	6.99	5.93	5.50	NA	5.59	5.71
2011	MA	Energy-Only Providers	8.38	8.52	8.38	NA	5.42	8.40
2011	MD	Energy-Only Providers	9.45	8.70	7.38	NA	7.76	8.61
2011	ME	Energy-Only Providers	8.41	7.76	6.82	NA	0.00	7.76
2011	MI	Energy-Only Providers	7.35	6.25	5.71	NA	0.00	5.97
2011	MT	Energy-Only Providers	6.10	3.93	3.92	NA	0.00	3.92
2011	NH	Energy-Only Providers	8.11	7.83	7.54	NA	0.00	7.71
2011	NJ	Energy-Only Providers	11.26	8.76	8.11	NA	7.60	8.83
2011	NV	Energy-Only Providers	0.00	6.45	4.47	NA	0.00	4.85
2011	NY	Energy-Only Providers	9.34	8.19	4.33	NA	9.02	7.84
2011	OH	Energy-Only Providers	6.55	6.00	5.23	NA	4.89	5.83
2011	OR	Energy-Only Providers	0.00	4.31	3.85	NA	0.00	3.99
2011	PA	Energy-Only Providers	8.55	7.37	6.66	NA	7.58	7.16
2011	RI	Energy-Only Providers	7.80	7.87	7.63	NA	8.48	7.81
2011	WA	Energy-Only Providers	0.00	4.33	4.34	NA	0.00	4.34
2011	US-TOTAL	Energy-Only Providers	8.42	7.61	6.15	NA	7.80	7.18
2011	CA	Delivery-Only Service	12.80	5.57	4.01	NA	0.82	4.94
2011	CT	Delivery-Only Service	8.65	6.34	4.78	NA	3.51	6.76
2011	DC	Delivery-Only Service	3.22	3.62	1.34	NA	3.02	3.53
2011	DE	Delivery-Only Service	3.03	1.21	0.48	NA	0.00	0.99
2011	IL	Delivery-Only Service	4.60	1.88	0.99	NA	1.23	1.42
2011	MA	Delivery-Only Service	7.76	5.64	5.30	NA	0.72	5.59
2011	MD	Delivery-Only Service	3.99	2.49	1.32	NA	1.26	2.52
2011	ME	Delivery-Only Service	6.99	4.53	2.03	NA	0.00	4.81
2011	MI	Delivery-Only Service	5.90	2.05	1.01	NA	0.00	1.51
2011	MT	Delivery-Only Service	3.74	2.31	0.51	NA	0.00	0.62
2011	NH	Delivery-Only Service	6.83	4.62	3.50	NA	0.00	4.16
2011	NJ	Delivery-Only Service	5.04	4.27	3.82	NA	2.98	4.24
2011	NV	Delivery-Only Service	0.00	1.03	0.16	NA	0.00	0.33
2011	NY	Delivery-Only Service	9.93	6.85	2.89	NA	4.85	6.62
2011	OH	Delivery-Only Service	4.49	3.08	0.96	NA	1.57	2.59
2011	OR	Delivery-Only Service	0.00	3.47	1.14	NA	0.00	1.86
2011	PA	Delivery-Only Service	4.79	1.83	0.87	NA	1.35	1.71
2011	RI	Delivery-Only Service	6.16	4.21	3.40	NA	5.63	4.04
2011	WA	Delivery-Only Service	0.00	0.85	0.49	NA	0.00	0.50
2011	US-TOTAL	Delivery-Only Service	6.16	4.01	1.73	NA	2.99	3.42

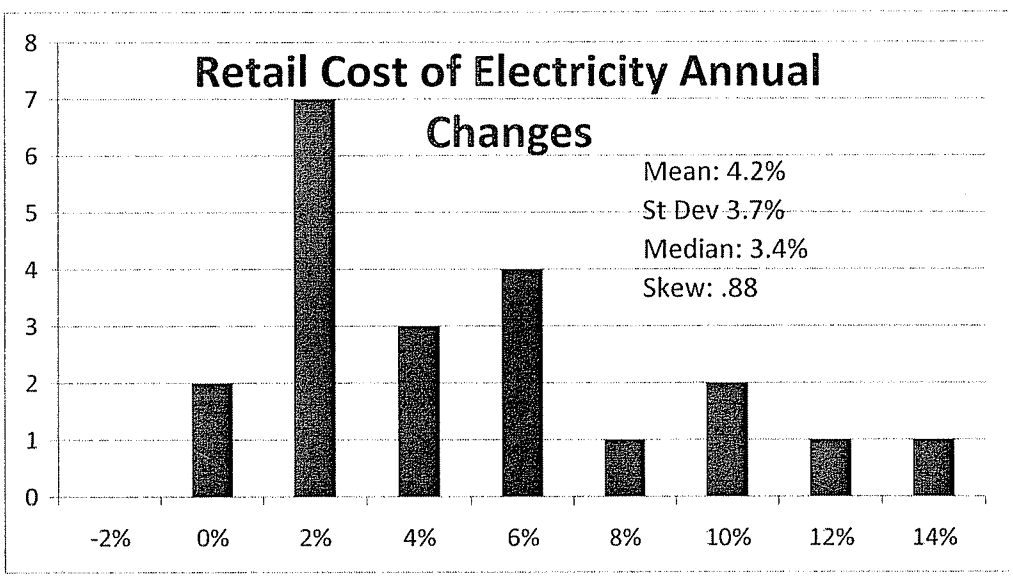
Natural Gas

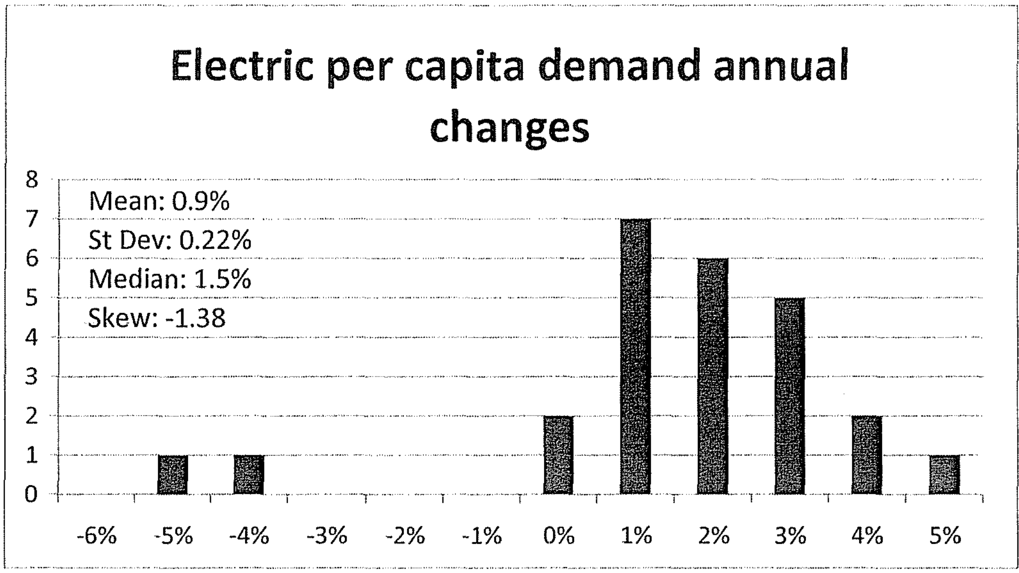
	1	2	3	4	5	6	7	8	9	10	11	12
1984	3.94	4.02	3.91	3.96	3.98	4.02	4.06	3.69	4.02	3.99	3.92	3.97
1985	3.89	3.94	3.97	3.91	3.89	3.86	3.69	3.70	3.68	3.59	3.46	3.45
1986	3.52	3.52	3.50	3.33	3.15	3.11	3.08	3.04	3.02	2.94	2.90	2.99
1987	2.98	3.03	2.91	2.86	2.81	2.84	2.92	2.89	2.83	2.69	2.76	2.84
1988	2.91	2.95	2.87	2.79	2.75	2.87	2.87	2.92	3.05	2.92	2.98	3.08
1989	3.17	3.10	2.89	2.83	2.94	2.98	3.08	3.04	2.99	2.84	2.98	3.10
1990	3.24	3.10	2.94	2.83	2.81	3.00	3.03	2.91	2.92	2.81	3.14	3.19
1991	3.08	2.94	2.78	2.74	2.76	2.86	2.74	2.78	2.91	2.92	2.92	3.05
1992	2.90	2.70	2.61	2.74	2.90	3.00	3.01	3.18	3.23	3.50	3.33	3.17
1993	3.11	2.94	3.06	3.24	3.58	3.44	3.34	3.35	3.54	3.15	3.15	3.27
1994	3.04	3.26	3.33	3.15	3.17	3.17	3.12	3.15	2.92	2.80	2.84	2.86
1995	2.79	2.71	2.74	2.72	2.80	2.89	2.89	2.87	2.89	2.83	2.67	2.83
1996	3.14	3.16	3.17	3.22	3.18	3.41	3.49	3.46	3.05	2.94	3.46	4.18
1997	4.28	3.76	3.07	2.92	3.11	3.41	3.44	3.34	3.50	3.86	4.76	3.42
1998	3.08	3.08	3.06	3.23	3.12	2.98	3.31	3.01	2.78	2.99	2.99	3.10
1999	2.85	2.92	2.77	2.88	3.25	3.12	3.11	3.39	3.59	3.21	3.71	3.19
2000	3.27	3.48	3.54	3.72	4.15	5.19	5.20	4.63	5.21	5.66	5.20	6.64
2001	8.91	7.08	6.10	6.30	5.77	5.38	4.03	4.32	3.66	3.37	4.02	3.90
2002	3.79	3.76	3.84	4.21	4.07	4.15	3.95	3.67	3.99	4.32	4.65	4.74
2003	5.28	5.83	7.63	5.60	5.69	6.40	5.83	5.48	5.58	5.33	5.54	5.89
2004	6.41	6.35	6.23	6.31	6.48	6.94	6.68	6.51	6.06	6.30	7.50	7.49
2005	7.05	7.09	7.24	7.79	7.51	7.30	7.68	8.20	10.26	12.16	11.57	10.77
2006	10.80	9.34	8.81	8.29	7.99	7.39	7.40	8.10	7.68	6.42	8.47	8.66
2007	7.88	8.57	8.79	8.20	8.41	8.45	8.02	7.60	7.00	7.43	8.14	8.27
2008	8.37	8.91	9.49	9.84	11.05	11.85	12.48	10.20	8.99	7.80	7.93	8.16
2009	7.97	7.26	6.85	5.71	5.49	5.55	5.70	5.61	5.37	5.65	6.34	6.22
2010	6.84	6.64	6.50	5.88	5.81	6.02	6.31	6.22	5.72	5.70	5.48	5.74
2011	5.68	5.75	5.68	5.62	5.79	6.09	6.15	6.19	5.93	5.43	5.28	5.03
2012	4.86	4.74	4.84	4.20	4.31	4.65	4.86	5.17				

All Distributions based on real changes








Electric per capita demand annual changes
Mean: 0.9%
St Dev: 0.22%
Median: 1.5%
Skew: -1.38
8
7
6
5
4
3
2
1
0
-6%
-5%
-4%
-3%
-2%
-1%
0%
1%
2%
3%
4%
5%

Kentucky Power Company

REQUEST

Refer to pp. 5-7, Table 1 of the testimony of Scott Weaver.

a. Explain why the Company decided to include in Option 2 and Option 3 a natural gas combined cycle (CC) plant with duct-firing for peaking purposes, rather than a CC to serve base and intermediate load and a combustion turbine unit to serve peak load.

b. Identify the heat rate(s) the Company assumed for the natural gas CC plants with duct-firing in Option 2 and Option 3, respectively, for each year through 2040, and explain the basis for such assumed heat rates.

c. Identify the annual capacity factor(s) the Company assumed for the natural gas CC plants with duct-firing in Option 2 and Option 3 for each year through 2040 and explain the basis for such assumed capacity factors.

d. Identify the annual capacity factors the Company assumed for the new-build CC units assumed in Options 3B, 4A, 4B, 5B, and 6 for each year through 2040, and explain the basis for such assumed capacity factors.

e. Identify the annual capacity factors the Company assumed for the 50% Mitchell interest in Options 5A and 6 for each year through 2040, and explain the basis for such assumed capacity factors.

f. Identify the annual fixed O&M costs assumed for the 50% Mitchell ownership interest in Options 5A and 6 for each year through 2040.

g. Identify the annual variable O&M costs assumed for the 50% Mitchell ownership interest in Options 5A and 6 for each year through 2040.

h. Identify the annual capital costs assumed for the 50% Mitchell ownership interest in Options 5A and 6 for each year through 2040.

i. Identify the annual fuel costs assumed for the 50% Mitchell ownership interest in Options 5A and 6 for each year through 2040.

RESPONSE

a. (Incremental) peaking capacity could be achieved at a lower capital cost by installing duct-firing on the CC plant compared to installing a separate combustion turbine unit to serve peak load. The duct firing capacity on the CC unit could be installed for approximately $4/kW where a separate CT facility could be installed for $800/kW.

b. The average heat rate at maximum capacity assumed for Option #2 through 2040 was 6,710 Btu/kWh and 6,860 Btu/kWh for Option 3. These average heat rates at maximum are based on the non-duct-fired (un-fired) heat rates for these options, rather than the higher duct-fired heat rates. The un-fired heat rates were assumed because the Company anticipates that the unit will be run the majority of the time without duct-firing and at that duct-firing will only be utilized on a limited basis during peak periods.

c. Please see SC 1-33 c._Attachment 1 for a summary of Option #2A, #2B, #3A and #3B CC annual capacity factors under FT-CSAPR (Base) commodity pricing. These capacity factors were not assumed in the analysis, but a result of a generation dispatch performed by Strategist.

d. Please see SC 1-33 d._Attachment 2 for a summary of Option #3B, #4A, #4B, #5B and #6 CC annual capacity factors under FT-CSAPR (Base) commodity pricing. These capacity factors were not assumed in the analysis, but a result of a generation dispatch performed by Strategist.

e. Please see response to SC 1-19 for a summary of the annual capacity factors for the 50% Mitchell ownership under all commodity price forecasts used by the Company in their analyses.

f. Please see response to SC 1-19 for a summary of the fixed O&M costs for the % Mitchell ownership interest in Options 5A and 6.

g. Please see response to SC 1-19 for a summary of the annual variable O&M costs assumed for the 50% Mitchell ownership interest in Options #5A and 6.

h. Please see response to SC 1-19 for a summary of the annual capital costs for the % Mitchell ownership interest in Options 5A and 6.

i. Please see response SC 1-19. for the annual fuel costs assumed for the 50% Mitchell ownership interests in Options #5A and #6.

WITNESS: Scott C Weaver

FT-CSAPR (Base) Commodity Pricing
Annual Capacity Factors (%)

	Option #2A	Option #2B	Option #3A	Option #3B
2017	26	27	25	26
2018	44	46	43	44
2019	44	45	43	44
2020	45	46	44	45
2021	44	45	43	44
2022	49	51	46	48
2023	47	50	44	47
2024	48	50	45	47
2025	46	48	45	47
2026	47	48	44	45
2027	48	49	44	45
2028	47	48	44	44
2029	47	48	44	45
2030	49	48	45	45
2031	50	49	45	46
2032	51	50	46	47
2033	52	51	46	47
2034	52	51	47	48
2035	51	49	47	47
2036	54	53	48	49
2037	53	53	48	49
2038	53	52	47	48
2039	53	53	48	50
2040	51	51	46	48

FT-CSAPR (Base) Commodity Pricing
Annual Capacity Factors (%)

	Option 4A		Option 4B	Option 5B		Option 6
	352 MW Generic CC	381 MW Big Sandy Brownfield CC	762 MW Big Sandy Brownfield CC	381 MW Big Sandy Brownfield CC	352 MW Generic CC	381 MW Big Sandy Brownfield CC
2017	0	0	0	0	0	0
2018	0	0	0	0	0	0
2019	0	0	0	0	0	0
2020	0	0	0	0	0	0
2021	37	0	0	52	0	0
2022	35	0	0	56	0	0
2023	35	0	0	54	0	0
2024	35	0	0	55	0	0
2025	35	0	0	54	0	0
2026	31	56	48	53	0	42
2027	30	56	49	54	0	43
2028	30	56	48	54	0	42
2029	30	56	48	53	0	42
2030	31	57	48	54	0	45
2031	31	57	49	57	30	47
2032	30	58	50	58	29	47
2033	31	59	51	58	30	50
2034	31	59	51	59	29	49
2035	31	58	49	58	30	49
2036	31	61	53	60	30	53
2037	30	61	53	60	29	52
2038	31	61	52	60	30	51
2039	30	61	53	61	29	52
2040	31	61	51	60	30	49

KENTUCKY POWER COMPANY

REQUEST

Refer to p. 20 of the testimony of Scott Weaver and Table 1-1 of Exhibit SCW-1, page 3.

a. Identify the Company's projection of peak demand and internal load for each of 2031 through 2040, and the basis for that projection.

b. Describe the factors driving the Company's projection that the compound rate of growth from 2021 to 2030 will be higher than from 2011 to 2020.

c. Provide Kentucky Power's weather-normalized peak demand and internal load by year for 2001 through 2010, and the corresponding compound annual rate of growth for each.

d. Provide Kentucky Power's actual, weather-normalized internal load by major retail rate class for 2001 through 2010

e. Provide Kentucky Power's projection of internal load by major retail rate class by year through 2040.

f. State whether the peak demand and internal load projections for Kentucky Power found on Exhibit SCW-1, page 3 include the impacts of demand response and energy efficiency projected at page 7 of Exhibit SCW-1.

g. State whether the peak demand and internal load projections for Kentucky Power found on Exhibit SCW-1, page 3 incorporates the impacts of federal energy efficiency provisions, such as those found in the Energy Independence and Security Act of 2007 and the American Recovery and Reinvestment Act of 2009.

h. If so, identify each such provision that is incorporated, and the level of peak demand reduction and/or energy savings that is assumed from each such provision.

RESPONSE

a. Please see SC 1-34 Attachment 1.

b. Table 1-1 of Exhibit SCW-1, page 3, identifies the compound growth rate from 2012 to 2021, not 2011 to 2020. Comparing the peak demand compound growth rates from 2012 to 2021 (as shown of 0.45%) to the rate from 2021 to 2030 (calculated as 0.61%) shows the growth slightly higher in the later period. The first year of the calculation of the 2012-2021 compound growth rates is 2012. The 2012 peak demand as shown is the actual summer peak for KPCo. It has not been adjusted for the impact of weather. Nor does it recognize the diversity with PJM as is done in the forecast period. The Company has observed over history an approximately 3.5% diversity with PJM. This means that at the time of the PJM-RTO summer peak, the KPCo summer peak is generally 3.5% lower than the Company's non-coincident summer peak. In planning for capacity in the PJM-RTO, the Company recognizes its load at the same time as the RTO peak. This allows for a lower (diversified) peak demand for the Company. Using entirely forecast (normalized and diversified) period peak demands from 2013 to 2021, the compound growth rate is 0.53%.

c. Please see SC 1-34 Attachment 2.

d & e. Please see SC 1-34 Attachment 3.

f. No, the peak demand and internal load projections for Kentucky Power found on Exhibit SCW-1, page 3 do not include the impacts of demand response and energy efficiency projected at page 7 of Exhibit SCW-1

g. Yes, the peak demand and internal load projections for Kentucky Power found on Exhibit SCW-1, page 3 incorporate the impacts of federal energy efficiency provisions, such as those found in the Energy Independence and Security Act of 2007 and the American Recovery and Reinvestment Act of 2009.

h. The Company sales forecast for the residential and commercial classes uses Itron Inc. Statistically Adjusted End-Use models. These proprietary models incorporate the efficiency impacts of all legislated appliance standards and building code impacts as measured by the Energy Information Administration of the Department of Energy. The Company has not calculated the impact of these on this forecast.

WITNESS: Scott C Weaver

KPCo Projected (Summer) Peak Demand and Internal Load
(Sept 2012 Load Forecast)

Year	MW		GWh
2012	1,183	(A)	7,444
2013	1,180		7,427
2014	1,188		7,464
2015	1,195		7,495
2016	1,199		7,528
2017	1,201		7,558
2018	1,208		7,592
2019	1,215		7,628
2020	1,221		7,661
2021	1,231		7,696
2022	1,240		7,736
2023	1,242		7,777
2024	1,248		7,820
2025	1,259		7,859
2026	1,269		7,905
2027	1,279		7,953
2028	1,286		8,002
2029	1,291		8,045
2030	1,301		8,091
2031	1,311		8,137
2032	1,317		8,185
2033	1,329		8,225
2034	1,331		8,267
2035	1,340		8,311
2036	1,346		8,356
2037	1,360		8,401
2038	1,370		8,445
2039	1,379		8,489
2040	1,378		8,533

(A) Actual KPCo summer peak demand on June 29, 2012 @ 4PM).

10-Year (2012-2021)		
Gowth in Consumption:	48	253
Compound Annual Growth Rate:	0.45%	0.37%

20-Year (2012-2031)		
Gowth in MW:	128	694
Compound Annual Growth Rate:	0.54%	0.47%

10-Year (2021-2030)		
Gowth in MW:	69	395
Compound Annual Growth Rate:	0.61%	0.56%

KPCo Weather Normalized (Summer) Peak Demand and Internal Load
(Sept 2012 Load Forecast)

Year	MW	GWh
2001	1,239	7,468
2002	1,281	7,741
2003	1,233	7,552
2004	1,275	7,847
2005	1,261	7,971
2006	1,238	7,864
2007	1,247	7,704
2008	1,239	7,874
2009	1,214	7,610
2010	1,260	7,728
2011	1,227	7,595
10-Year (2001-2010)		
Gowth in Consumption:	21	261
Compound Annual Growth Rate:	0.19%	0.38%

Kentucky Power - GWh Sales: Forecast & Actual, Weather Normalized

		Residential		Commercial		Industrial		Other Ultimate		Total Ultimate		Munis, Co-ops		Total	
Notes	Year	GWh	Growth	GWh	Growth	GWh	Growth	GWh	Growth	GWh	Year	GWh	Growth	GWh	Growth
Actual	2001	2,346	0.3%	1,282	2.6%	3,126	-1.0%	11	-1.0%	6,766	0.1%	79	-1.6%	6,845	0.1%
Actual	2002	2,454	4.6%	1,316	2.7%	3,154	0.9%	11	0.3%	6,936	2.5%	93	16.6%	7,029	2.7%
Actual	2003	2,391	-2.6%	1,324	0.6%	2,930	-7.1%	11	-7.0%	6,655	-4.0%	90	-2.8%	6,746	-4.0%
Actual	2004	2,447	2.3%	1,381	4.3%	3,181	8.6%	11	5.5%	7,020	5.5%	96	6.2%	7,116	5.5%
Actual	2005	2,494	1.9%	1,404	1.7%	3,343	5.1%	10	-10.0%	7,251	3.3%	96	0.7%	7,348	3.3%
Actual	2006	2,509	0.6%	1,418	1.0%	3,311	-0.9%	10	-2.2%	7,248	0.0%	98	1.7%	7,346	0.0%
Actual	2007	2,434	-3.0%	1,424	0.4%	3,174	-4.1%	10	2.8%	7,042	-2.8%	99	1.0%	7,141	-2.8%
Actual	2008	2,460	1.1%	1,429	0.4%	3,322	4.7%	10	1.4%	7,221	2.5%	100	1.2%	7,322	2.5%
Actual	2009	2,453	-0.3%	1,438	0.6%	3,206	-3.5%	10	0.4%	7,108	-1.6%	94	-5.8%	7,203	-1.6%
Actual	2010	2,501	1.9%	1,439	0.1%	3,256	1.5%	10	0.6%	7,206	1.4%	100	5.6%	7,306	1.4%
Actual	2011	2,369	-5.3%	1,387	-3.6%	3,250	-0.2%	11	2.1%	7,016	-2.6%	94	-5.4%	7,110	-2.7%
Actual	2012	2,315	-2.3%	1,364	-1.6%	3,060	-5.9%	11	-0.2%	6,749	-3.8%	95	0.7%	6,844	-3.7%
Forecast	2013	2,265	-2.2%	1,390	1.9%	3,089	0.9%	11	2.0%	6,754	0.1%	98	3.4%	6,852	0.1%
Forecast	2014	2,239	-1.1%	1,401	0.8%	3,122	1.1%	11	1.0%	6,772	0.3%	99	0.9%	6,872	0.3%
Forecast	2015	2,220	-0.8%	1,408	0.5%	3,149	0.9%	11	1.1%	6,788	0.2%	100	0.6%	6,888	0.2%
Forecast	2016	2,205	-0.7%	1,405	-0.2%	3,175	0.8%	11	0.7%	6,796	0.1%	100	0.5%	6,896	0.1%
Forecast	2017	2,194	-0.5%	1,406	0.0%	3,203	0.9%	11	0.3%	6,813	0.3%	101	0.4%	6,914	0.3%
Forecast	2018	2,187	-0.3%	1,409	0.3%	3,228	0.8%	11	0.1%	6,835	0.3%	101	0.4%	6,937	0.3%
Forecast	2019	2,186	-0.1%	1,415	0.4%	3,253	0.8%	11	0.2%	6,865	0.4%	102	0.4%	6,966	0.4%
Forecast	2020	2,180	-0.3%	1,418	0.3%	3,276	0.7%	11	0.2%	6,886	0.3%	102	0.4%	6,988	0.3%
Forecast	2021	2,181	0.1%	1,428	0.6%	3,302	0.8%	11	0.2%	6,922	0.5%	102	0.4%	7,025	0.5%
Forecast	2022	2,184	0.1%	1,435	0.5%	3,327	0.8%	11	0.2%	6,957	0.5%	103	0.4%	7,059	0.5%
Forecast	2023	2,187	0.1%	1,444	0.6%	3,352	0.7%	11	0.2%	6,993	0.5%	103	0.4%	7,097	0.5%
Forecast	2024	2,193	0.3%	1,453	0.6%	3,375	0.7%	11	0.2%	7,033	0.6%	104	0.4%	7,136	0.6%
Forecast	2025	2,200	0.3%	1,465	0.8%	3,400	0.7%	11	0.2%	7,076	0.6%	104	0.4%	7,180	0.6%
Forecast	2026	2,205	0.2%	1,473	0.6%	3,428	0.8%	11	0.2%	7,117	0.6%	104	0.3%	7,222	0.6%
Forecast	2027	2,211	0.3%	1,481	0.5%	3,456	0.8%	11	0.2%	7,159	0.6%	105	0.3%	7,264	0.6%
Forecast	2028	2,219	0.4%	1,488	0.5%	3,484	0.8%	11	0.1%	7,202	0.6%	105	0.3%	7,307	0.6%
Forecast	2029	2,228	0.4%	1,497	0.6%	3,513	0.8%	11	0.2%	7,249	0.7%	105	0.3%	7,354	0.6%
Forecast	2030	2,236	0.4%	1,504	0.5%	3,540	0.8%	11	0.1%	7,291	0.6%	106	0.3%	7,397	0.6%
Forecast	2031	2,245	0.4%	1,510	0.4%	3,569	0.8%	11	0.1%	7,335	0.6%	106	0.3%	7,441	0.6%
Forecast	2032	2,255	0.5%	1,515	0.3%	3,595	0.8%	11	0.1%	7,377	0.6%	106	0.2%	7,483	0.6%
Forecast	2033	2,264	0.4%	1,519	0.3%	3,623	0.8%	11	0.1%	7,417	0.5%	107	0.2%	7,524	0.5%
Forecast	2034	2,272	0.4%	1,522	0.2%	3,648	0.7%	11	0.2%	7,454	0.5%	107	0.2%	7,560	0.5%
Forecast	2035	2,284	0.5%	1,527	0.3%	3,675	0.7%	11	0.3%	7,497	0.6%	107	0.2%	7,604	0.6%
Forecast	2036	2,294	0.4%	1,533	0.4%	3,700	0.7%	11	0.4%	7,538	0.5%	107	0.2%	7,645	0.5%
Forecast	2037	2,308	0.6%	1,539	0.4%	3,727	0.7%	12	0.4%	7,585	0.6%	107	0.2%	7,692	0.6%
Forecast	2038	2,318	0.4%	1,543	0.2%	3,752	0.7%	12	0.3%	7,624	0.5%	108	0.1%	7,731	0.5%
Forecast	2039	2,329	0.5%	1,546	0.2%	3,777	0.7%	12	0.3%	7,663	0.5%	108	0.1%	7,771	0.5%
Forecast	2040	2,340	0.5%	1,548	0.2%	3,801	0.7%	12	0.2%	7,701	0.5%	108	0.1%	7,809	0.5%
Forecast	2041	2,356	0.7%	1,553	0.3%	3,827	0.7%	12	0.2%	7,747	0.6%	108	0.1%	7,855	0.6%

Kentucky Power Company

REQUEST

Describe all current DSM programs offered by Kentucky Power, including demand-response, interruptible load, and efficiency programs. For each such program, identify the:

a. Annual cost of implementation for the life of the program
b. MW and MWh reductions achieved per year
c. Life expectancy of individual program measures
d. Total Resource Cost test score for each program
e. Monetary savings from each program

RESPONSE

Please see response to KPSC 1-8.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Describe each new DSM program, including demand-response, interruptible load, and efficiency programs, that Kentucky Power plans to offer in the future. For each such program, identify the estimated:

a. Annual cost of implementation for the life of the program
b. MW and MWh reductions achieved per year
c. Life expectancy of individual program measures
d. Total Resource Cost test score for each program
e. Monetary savings from each program

RESPONSE

While the Company continually is looking for possible new DSM programs, we currently have no specific DSM programs to be offered in the near future.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Provide any DSM potential studies performed by or for AEP and/or Kentucky Power in the last five years, including attendant workbooks or calculations. State whether such studies are incorporated into the current case. If so, explain how. If not, explain why not.

RESPONSE

While the Company continually evaluates the potential for and cost of energy efficiency programs, no formal study of energy efficiency within the Company's service territory in the state of Kentucky has been prepared by or for the Company in the last five years.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

With regards to each of AEP's operating companies, identify:

a. How many MWs of capacity from energy efficiency and demand response programs each company bid into the 2015/16 PJM Base Residual Auction

b. How many of these MWs successfully cleared the auction

c. What percentage of the efficiency MWs available to be bid does this represent

RESPONSE

a. Only AEP Ohio participated in the 2015/2016 PJM BRA. It bid 203.6 MW of Energy Efficiency.

b. 203.6 MW cleared the auction.

c. This represents approximately 72% of Ohio Power's available energy efficiency MWs.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to p. 7 of Exhibit SCW-1.

a. Explain how the total demand response peak reduction and the cumulative energy efficiency projections for Kentucky Power and AEP-East identified therein were determined.

b. Identify the annual budget for energy efficiency programs, demand response programs, and interruptible load programs projected for Kentucky Power for each of 2013 through 2040.

c. Explain what is meant by "PJM Approved" interruptible demand response
   i. Explain why Kentucky Power is projected to get zero peak demand reduction through PJM Approved interruptible demand response programs for each year of 2012 through 2031.

d. State whether the projected levels of cumulative energy efficiency identified therein for Kentucky Power represent the implementation of all cost-effective energy efficiency programs and measures.
   i. If so, produce any analysis supporting that claim
   ii. If not, explain why not, and identify what the level of all cost-effective energy savings is for Kentucky Power for each year of 2013 through 2040.

e. State whether the projected levels of peak demand reduction identified therein for Kentucky Power represent the implementation of all cost effective demand response programming.
   i. If so, produce any analysis supporting that claim.
   ii. If not, explain why not, and identify what the level of cost effective demand response is for Kentucky Power for each year of 2013 through 2040.

f. State whether Kentucky Power or AEP performed or reviewed any DSM modeling in determining the total demand response peak reduction and cumulative energy efficiency projections identified therein.
   i. If so, identify the model used, and produce, in machine readable format with formulas intact, the input and output files and workpapers for such modeling.
   ii. If not, explain why not.

g. Explain why you project no additional cumulative energy savings from energy efficiency after 2022 through 2031 for Kentucky Power. Produce any documents supporting that explanation.

h. Explain why you project virtually no additional peak demand reduction from demand response programs after 2022 through 2031 for Kentucky Power. Produce any documents supporting that explanation.

i. Explain why the level of cumulative energy savings from energy efficiency for Kentucky Power is projected to be lower, as a percent of total internal load, in 2022 than is the level, as a percent of internal load, that is projected for the AEP-East system in 2013.

j. Explain why the AEP-East system is projected to achieve three to four times as much energy savings, as a percent of internal load, from energy efficiency than Kentucky Power is projected to achieve in each of 2013 through 2031.

k. Explain why the AEP-East system is projected to achieve more than twice as much peak demand reduction, as a percent of total demand, from demand response than Kentucky Power is projected to achieve in each of 2013 through 2031.

l. Identify the level of peak demand reduction and cumulative energy savings that are projected for Kentucky Power and the AEP-East system for each year of 2032 through 2040.

RESPONSE

a. In the absence of a state mandate, projected installed energy efficiency reductions are approximately equivalent to the "realistically achievable" levels prescribed in the 2009 EPRI study, "Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S."

b. Please see the 2013 data in the table below. The Company has not prepared a budget beyond 2013.

2013 DSM Forecast	
Program	TOTAL COST
TEE - All Electric	$266,700
TEE - Base Load	$3,050
Mobile Home Heat Pump	$101,100
New Construction - Mobile Home	$86,550
Modified Energy Fitness Program	$462,750
Energy Education for Students	$27,170
Community Outreach CFL	$56,850
HEHP - Resistance Heat & Non Resistance Heat	$271,550
Residential Efficient Products	$482,250
Small Commercial AC HP	$13,700
HVAC Diagnostic and Tune-up	$47,925
Commercial Incentive	$1,135,635
Residential Commercial Load Management	$21,425
TOTAL	$2,976,655

c. "PJM Approved" demand response means demand response programs that are already approved as capacity resources by PJM. The anticipated incremental demand response programs would be expected to be similarly approved.

d. The levels equate, approximately, to the "realistically achievable" levels in the EPRI study, which is a subset of the "economic potential". The EPRI study does not enumerate annual levels of economic potential by year. The Economic Potential (national results) in the study are 2010: 5%; 2020: 12.5%, and 2030: 13.6% relative to the 2008 AEO Reference Case. It is not practical or even possible to "implement all cost-effective energy efficiency programs and measures".

e. The EPRI study does not enumerate the economic potential for demand response in any year.

f. The Company has not performed any unique DSM modeling; it has relied on the EPRI study.

g. A continuous level of energy efficiency relative to a forecast implies a continued, or maintenance level of energy efficiency programs.

h. The Company does not make projections of demand response capabilities or consumer acceptance that far in the future. These levels will continue to be evaluated periodically and modified as warranted.

i. The reasons are many and varied that Kentucky Power's cumulative energy efficiency impact relative to a forecast in 2022 is less as a percentage of total load than the total cumulative impact of all AEP in 2013 and the comparison is not particularly meaningful. The primary reasons that Kentucky Power lags other AEP East jurisdictions in terms of percentage energy efficiency is the exclusion of KPCo's industrial load from utility energy efficiency programs and a heavier emphasis on low-income programs which may not have the impact on energy savings that programs focused on lighting measures do.

j. There are two primary reasons why the cumulative impact of AEP East energy efficiency exceeds that of KPCo. The first is the presence of aggressive energy efficiency mandates in Ohio, Indiana, and Michigan, for which there is no guarantee those levels will be achieved. The second is the exclusion of KPCo industrial load from consideration.

k. KPCo demand response potential is limited due to the high prevalence of mining operations, which does not lend itself to demand reduction.

l. See SC 1-39 Attachment 1.

WITNESS: Ranie K Wohnhas

Energy Impact - Energy Efficiency and Grid Programs (GWh)

Year	KPCo	AEP East
2032	119	7,635
2033	119	7,635
2034	119	7,635
2035	119	7,635
2036	119	7,635
2037	119	7,635
2038	119	7,635
2039	119	7,635
2040	119	7,635

Peak Demand Impact - Energy Efficiency and Grid Programs (MW)

Year	KPCo	AEP East
2032	63	2603
2033	63	2603
2034	63	2603
2035	63	2603
2036	63	2603
2037	63	2603
2038	63	2603
2039	63	2603
2040	63	2603

Kentucky Power Company

REQUEST

Refer to p. 27 lines 6-11 of the testimony of Scott Weaver.

a. Explain how demand side management has been "incorporated into the Company's resource planning process."

b. State whether you modeled demand side management in the Strategist modeling.
   i. If so, explain how.
   ii. If not, explain why not.

RESPONSE

a. Demand-side resources are considered on an equal basis with supply resources with consideration given for their likely customer acceptance.

b. Demand-side management resources including energy efficiency, "smart grid" technologies, and demand response capabilities were included either as available resources (demand response) or reductions to the load forecast (energy efficiency and smart grid).

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to Exhibit SCW-3, page 2. With regards to each of the long-term commodity price forecasts for each of the scenarios listed therein:

a. Identify the date the forecast was created

b. Identify and produce all analyses or documents that the Company reviewed and/or prepared in developing the forecast

c. Explain how the 2012 price forecast listed therein for each commodity compares to the actual price of that commodity in 2012.

RESPONSE

a. November 29, 2011

b. Please refer to the Company's response to KPSC Staff 1-31.

c. The Long-Term Forecast is created with the assumption of normal weather (heating and cooling degree-days). Actual 2012 values are not weather-normalized.

WITNESS: Karl R Bletzacker

Kentucky Power Company

REQUEST

Refer to p. 29 line 21 through p. 31 line 13 of the testimony of Scott Weaver.

a. Please list each combination of commodity pricing scenarios the Company used to test the sensitivity of its “base” evaluation, e.g. “lower band” natural gas plus "early carbon”, or “higher band” natural gas plus “no carbon”

b. Please provide the results of each combination of commodity pricing scenarios the Company used to test the sensitivity of its base evaluation

RESPONSE

a. The Company did not combine any of the commodity pricing scenarios to test sensitivity of its "base" evaluation.

b. n/a

WITNESS: Mark A Becker

Kentucky Power Company

REQUEST

Refer to p. 34 lines 12-15 of the testimony of Scott Weaver. With regards to the decision of Kentucky Power to opt-out of the latest annual PJM-RPM (3-year forward) capacity market/auction and remain under the Fixed Resource Requirement framework:

a. Identify and explain all bases for Kentucky Power's decision to opt-out

b. Identify and produce all analyses, reports, and other documents regarding Kentucky Power's decision to opt-out

c. State whether Kentucky Power's decision to opt-out forecloses the Company from bidding its efficiency and peak demand savings into the PJM Base Residual Auctions
   i. If so, explain whether and how that inability to bid efficiency and peak demand savings factored into Kentucky Power's opt-out decision.

RESPONSE

a. The election to use the FRR option for the 2015/2016 planning year was made in early 2012, and was not related to the Bridge Agreement. APCo, Indiana Michigan Power Company and Kentucky Power Company (the companies) elected FRR status for the 2015/2016 delivery year based upon a qualitative analysis that considered multiple factors, as follows: a) PJM's rules would have prohibited the companies from electing FRR status again for 5 years had they switched to RPM; b) the FRR option has historically carried with it a lower installed reserve margin requirement, which allows the companies to procure less capacity than had they elected RPM; c) the collective benefits of the diversity achieved across the three companies, by relying on a larger fleet of assets to minimize the risk of any one company failing to meet its PJM capacity requirement due to unplanned resource outages; and d) the fact that the composition of APCo's and Kentucky Power's future generating assets had not yet been resolved.

b. Please see the Company's response to KIUC 1-18.

c. No.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to p. 35 line 8 to p. 36 line 7 of the testimony of Scott Weaver.

a. Explain your basis for contending that "the price of capacity under the PJM/RPM construct could begin to ultimately mirror, or exceed, Net CONE on a consistent basis"

b. Explain how likely it is that the price of capacity under the PJM/RPM construct would equal or exceed Net CONE on a consistent basis.

c. Identify and produce any analyses or reports projecting that the price of capacity under the PJM/RPM construct would equal or exceed Net CONE on a consistent basis.

d. Provide an example of the price of capacity exceeding CONE "on a consistent basis" within PJM or any other electricity capacity market within the United States.

e. Explain your basis for contending that "the price of the attendant PJM market energy could likewise exceed projected pricing levels"

f. Explain how like it is that the price of the attendant PJM market energy would exceed projected pricing levels

g. Identify and produce any analyses or projections that the price of the attendant PJM market energy may exceed projected pricing levels

h. With respect to Options #4A and #4B, state whether Kentucky Power has pursued short or long term bilateral agreements to procure capacity or energy in an effort to mitigate the "pricing uncertainty and economic risks" associated with an increase (or decrease) in the price of energy or capacity in the PJM market in future years.
    i. If so, explain the results of such effort.
    ii. If not, explain why not.

RESPONSE

a. This statement was intended as a qualitative statement in the context that KPCo and its customers could be exposed to up-side cost risk by effectively being "price-takers" under a PJM-RPM construct. Note the previous statement on lines 14-17 of Mr. Weaver's direct testimony that indicates that the prices that clear as part of the PJM-RPM are on a single-year basis. Hence, current experienced capacity pricing may not be sustainable.

b. The Company has not performed any assessment as to the likelihood that the price or capacity under the PJM/RPM construct would equal or exceed Net CONE on a consistent basis. See also the response to part a. of this request.

c. The Company is not aware of any examples of the price of capacity exceeding CONE on a consistent basis within PJM or other capacity markets; however as noted in Mr. Weaver's testimony it should be re-iterated that, particularly, the PJM-RPM capacity construct is a relative new, emerging market and, arguably, has not been tested by way of the reasonable prospect that significant coal-fired capacity in its footprint could be retired as a result of the known and emerging federal EPA rulemaking.

d & e. See response to c.

f. The statement is intended to suggest that (PJM) market energy pricing exposure could exceed forecasted values, similar to a possible exposure to greater-than-forecasted PJM-RPM capacity pricing. That is, the need for (baseload) energy--which is what is at issue for KPCo--and the need for capacity would go hand-in-hand if KPCo were to rely on a "market" solution.

g. Unique pricing scenarios were provided by the AEP Fundamental Pricing group. Specifically, evaluations were performed that examined a "FT-CSAPR Higher Band" scenario which did offer higher (PJM) on and off-peak energy pricing (see Exhibit SCW-3). Such long-term pricing scenario was introduced into the Strategist model and resulted in a unique set of modeled results that were offered in Exhibit SCW-5.

h. No. KPCo is a Member Company of the AEP-East system (Pool) which has, and continues to be, capacity and energy "long" within PJM. As indicated on Mr. Weaver's testimony, a 'stand-alone' KPCo could enter into a competitive solicitation for capacity and energy depending upon the ultimate disposition outcome for Big Sandy Unit 2 (as well as Big Sandy Unit 1, as discussed in Mr. Weaver's testimony).

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to p. 37 lines 4-14 of the testimony of Scott Weaver.

a. Explain the basis for your contention that "it is very reasonable to assume that a long term (minimum, 10-20 year term) competitive purchase power agreement ("PPA") solicitation-for not only up to as much as 1,100 MW of replacement capacity, but for the largely baseload energy also being replaced would likely be offered/priced at the cost of a new-build combined cycle in response to such an RFP."

b. Identify and produce any analyses or documents supporting that contention.

c. Explain how that contention squares with the fact that the AEP Fundamentals Group is projecting that the PJM/RTO capacity price will, in most years, be well below the cost of a new-build combined cycle.

RESPONSE

a. The contention is based on the assumption that, given the anticipated longer term of such a PPA, a newer (or newly-built) combined cycle facility that could perform economically at higher capacity factors would be more cost-competitive than an existing, smaller and older facility because it would likely have a better heat rate and be less likely to require extensive capital upgrades and re-investment. Further, given the environmental restrictions on building new coal-fired generating facilities and the cost of nuclear generating facilities, the most reasonable option to serve as such a baseload capacity/energy proxy for such longer-term market offers would be the costs and attendant performance parameters associated with a new combined cycle gas facility.

b. No such documents or analyses exist. This determination of a reasonable market proxy for such a baseload duty cycle cost-basis was established based on consultation with PJM market experts within the AEPSC Commercial Operations group.

c. The PJM/RTO capacity price represents a "net" cost of new entry (CONE) price, meaning that the capacity cost would be discounted to reflect the energy value a new facility would likewise receive in the PJM energy market. Therefore it is expected that the capacity price to clear would be below the full (fixed and variable) costs of a new-build gas facility.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to p. 37 line 19 to p. 38 line 4 of the testimony of Scott Weaver. Identify all steps that AEP or Kentucky Power took to determine whether there are existing CC generating assets available as an option for replacing all or part of capacity and/or energy from the Big Sandy 2 unit.

RESPONSE

An AEP Service Corporation group, Strategic Initiatives, monitors market activity and notifies operating company management when it becomes aware of generating assets that may be available for sale.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to p. 38 lines 4-9 of the testimony of Scott Weaver.

a. State whether Kentucky Power or AEP has carried out any analysis supporting the contention that "there is an emerging concern that these [CC] facilities will soon be facing significant, time-based turbine inspections and expensive re-builds as well as other steam-cycle and balance-of-plant maintenance issues, thereby lessening their relative economic values"
   i. If so, produce such analysis
   ii. If not, explain the basis for that contention.

RESPONSE

a. There was no analysis performed. Heavy duty industrial gas turbines require major maintenance at OEM specified intervals. These intervals are typically based on the number of unit start/stop cycles or the number of operating hours, whichever comes first. For example, if an industrial gas turbine starts up and shuts down frequently, it will perform the required maintenance based on the number of startups since it would reach required starts-based maintenance milestone before it would reach any hours-based maintenance milestone. A baseload gas turbine (one that runs many hours per year) would in contrast reach the hours-based maintenance milestone first.

   Large industrial gas turbine OEMs like GE and Siemens typically require major maintenance to be performed every 400 to 500 start/stop cycles or every 8,000 to 12,000 hours, whichever comes first as noted above. These maintenance cycles on an F-class gas turbines (GE 7FA or SW501F) typically cost approximately $700,000 per gas turbine to repair fuel combustion hardware (every 400 to 500 start/stop cycles or 8,000 to 12,000 hours) and $4,000,000 to $7,000,000 to inspect and repair turbine section (every 800 to 900 start/stop cycles or every 24,000 hours). In addition, the combustion and turbine hardware have a limited life in that they can only be repaired a finite number of times. Hence, after the maximum number of repairs for a given part is reached, it generally must be replaced at a fairly high cost.

As indicated in the cited testimony, as the already available/operating gas turbine based facilities age via the number of start/stop cycles or operating hours, the cost to maintain the units for safe and reliable operation can increase dramatically on an ongoing basis since many of those parts will have to replaced at a fairly high cost and the ongoing repair costs can increase due to the degraded condition of the gas turbine components prior to eventual replacement.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to p. 39 lines 7-8 of the testimony of Scott Weaver. Produce the competitive solicitation referenced therein, and any responses received to such solicitation.

RESPONSE

Please refer to the response to KPSC 1-24.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to p. 45 line 16 to p. 47 line 4 of the testimony of Scott Weaver. State whether any of the following uncertainties were considered in your evaluation. If so, explain how the uncertainty was considered and provide any documentation of that consideration. If not, explain why not.

a. Uncertainty regarding future peak demand
b. Uncertainty regarding future internal retail load
c. Uncertainty regarding future environmental regulations
d. Uncertainty regarding future emission price
e. The possibility of a reduction in the cost of electricity from sources other than coal or natural gas

RESPONSE

a., b., d., and e. Uncertainty around future peak demand, load, emission price (including CO2), and electricity cost, were considered as part of the Company's AuroraXMP stochastic analysis as described in Mr. Weaver's testimony. Further, unique long-term commodity pricing scenarios around, specifically, potential CO2 pricing and timing were established by the AEP Fundamental Analysis group that were discretely modeled in Strategist.

c. Uncertainty around costs associated with future environmental regulations, through 2020, were considered in the capital cost assumptions for the Mitchell Units as described in Mr. Weaver's testimony. Such costs were then reflected explicitly in the Strategist modeling. Moreover, such environmental regulation costs were considered 'globally' --as one of the major underlying drivers-- of the AEP Fundamental Analysis group's respective long-term commodity pricing scenarios summarized on TABLE 2 (pages 17 and 18) of Mr. Weaver's direct testimony.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Produce all STRATEGIST input and output files (in machine readable format), and all work papers (in electronic format with formulas intact), for each option and under each commodity pricing scenario that the Company evaluated in preparing the analyses set forth in the Company's application.

RESPONSE

See the Company's response to AG 1-12.

The Company is unable to provide the requested Strategist input and output files. Strategist is a proprietary utility planning application that is licensed solely by Ventyx Inc., which owns Strategist in its entirety. Kentucky Power contacted Ventyx Inc. and it confirmed that the application software, source code, database, and associated documentation, including input files, are its confidential and proprietary intellectual property. Access to the documentation may be granted solely by Ventyx Inc., at its own discretion, under a mutually binding Nondisclosure Agreement. Access to the database and/or the application itself is granted only under exclusive license with Ventyx Inc. Ventyx does not allow access to the Strategist source code under any circumstances. Kentucky Power will assist the Sierra Club in contacting Ventyx, Inc. to obtain the required Nondisclosure Agreement. Once the Sierra Club provides Kentucky Power with the name of the licensed Strategist user, Kentucky Power will verify the license with Ventyx and provide the requested files to the licensee.

WITNESS: Mark A Becker

Kentucky Power Company

REQUEST

Produce any modeling input and output files, workpapers, and results for the modeling of any options or scenarios that the Company did not include in the application but which were evaluated in preparing the analyses set forth in the application.

RESPONSE

The Company has provided the information for all of the options and scenarios evaluated in preparing the analyses for this application. See response to Attorney General 1-12 and KPSC 1-1 for inputs and output files for the scenarios evaluated in preparing the analyses for this application.

WITNESS: Mark A Becker