STITES & HARBISON PLLC

ATTORNEYS

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February 26, 2010

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HAND DELIVERED

Jeff R. Derouen
Executive Director
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

RE: ***P.S.C. Case No. 2009-00459 - Kentucky Power Company's Responses to Data Requests***

Dear Mr. Derouen:

Enclosed please find and accept for filing the original and ten copies of Kentucky Power Company's Responses to the following Data Requests:

(a) Second Data Requests by Commission Staff;

(b) First Data Requests by Community Action Kentucky, Inc.;

(c) Attorney General's Initial Requests for Information;

(d) First Data Requests by Wal-Mart Stores East, LP. and Sam's East, Inc.; and

(e) First Data Requests by Kentucky Industrial Utility Customers, Inc.

Also enclosed is the original and ten copies of the Company's Petition for Confidential Treatment of certain portions of the Company's Responses to the Attorney General's First Set, Nos. 47 and 51, and Kentucky Industrial Utility Customers, Inc. First Set, Nos. 15 and 17, along with a sealed envelope containing the unredacted responses for which confidential treatment is being sought.

Copies of the public Responses are being served on the persons below. In addition, copies of the Responses for which confidential treatment is being sought are being served on the Attorney General, counsel for Kentucky Industrial Utility Customers, Inc. and Mr. Kollen, in accordance with the non-disclosure agreement signed by each.

Please do not hesitate to contact me if you have any questions.

STITES & HARBISON PLLC
ATTORNEYS

Very truly yours,

Mark R. Overstreet

cc: Holly Rachel Smith
Michael L. Kurtz
Dennis G. Howard II
Joe F. Childers
Richard Hopgood
Lane Kollen
Steve W. Chris

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF:

ADJUSTMENT OF RATES OF	)	
KENTUCKY POWER COMPANY	)	Case No. 2009-00459

KENTUCKY POWER RESPONSES TO COMMISSION STAFF'S SECOND SET OF DATA REQUESTS

February 26, 2010

AFFIDAVIT

William E. Avera, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

William E. Avera

State of Texas)
)ss
County of Travis)

Subscribed and sworn to before me, a Notary Public, by William E. Avera this 24th day of February 2010.

Notary Public

My Commission Expires 1/10/2011

ADRIEN MCKENZIE
Notary Public
STATE OF TEXAS
My Comm Exp Jan. 10, 2011

AFFIDAVIT

Dennis W. Bethel, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Dennis W. Bethel

Dennis W. Bethel

State of Ohio)
)ss
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by Dennis W. Bethel this 24th day of February 2010.

Ellen A. McQuinch

Notary Public

My Commission Expires May 11, 2011

AFFIDAVIT

Jay F. Godfrey, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Jay F. Godfrey

State of Ohio)
)ss
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by Jay F. Godfrey this 24th day of February 2010.

Barbara R. Pletcher
Notary Public

My Commission Expires October 1, 2013

BARBARA R. PLETCHER
NOTARY PUBLIC • STATE OF OHIO
Recorded in Franklin County
My commission expires Oct. 1, 2013

AFFIDAVIT

Diana L. Gregory, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to her at a hearing before the Public Service Commission of Kentucky, she would give the answers recorded following each of said questions and that said answers are true.

Diana L. Gregory

Diana L. Gregory

State of Ohio)
)ss
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by Diana L. Gregory this 24th day of February 2010.

Lowell P. McCoy

Notary Public

My Commission Expires 6/29/10

LOWELL P. McCOY
NOTARY PUBLIC - STATE OF OHIO
MY COMMISSION EXPIRES JUNE 29, 2010

AFFIDAVIT

James E. Henderson, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

James E. Henderson

James E. Henderson

State of Ohio)
)ss
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by James E. Henderson this 24th day of February 2010.

Catherine Hurston

Notary Public

NOTARIAL SEAL STATE OF OHIO

Catherine Hurston
Notary Public, State of Ohio
My Commission Expires 11-15-2014

My Commission Expires ______________

AFFIDAVIT

Daniel E. High, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Daniel E. High

Daniel E. High

State of Ohio)
)ss
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by Daniel E. High this 24th day of February 2010.

Ellen A. McGuinness

Notary Public

My Commission Expires May 11, 2011

AFFIDAVIT

David A. Jolley, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

David A. Jolley
David A. Jolley

State of Ohio)
)ss
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by David A. Jolley this 24th day of February 2010.

Notary Public

My Commission Expires ____________

NOTARIAL SEAL STATE OF OHIO

MARTIN ROSENTHAL
Attorney at Law
Notary Public, State of Ohio
My Commission Has No Expiration
Section 147.03 R.C.

AFFIDAVIT

Hugh E. McCoy, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Hugh E. McCoy

Hugh E. McCoy

State of Ohio)
)ss
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by Hugh E. McCoy this 23rd day of February 2010.

Pauline A Lutz

Notary Public

My Commission Expires

NOTARIAL SEAL STATE OF OHIO

PAULINE A LUTZ
NOTARY PUBLIC
STATE OF OHIO
MY COMM. EXP. 9-12-11

AFFIDAVIT

Timothy C. Mosher, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

T.C Mosher
Timothy C. Mosher

Commonwealth of Kentucky)
) Case No. 2009-00459
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by Timothy C. Mosher this 24th day of February 2010.

Judy K Rosquist
Notary Public

My Commission Expires January 23, 2013

AFFIDAVIT

Thomas M. Myers, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Thomas M. Myers

State of Ohio)
)ss
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by Thomas M. Myers this 24th day of February 2010.

Notary Public

My Commission Expires January 4, 2014

DONNA J. STEPHENS
Notary Public, State of Ohio
My Commission Expires 01-04-2014

AFFIDAVIT

Everett G. Phillips, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Everett G. Phillips
Everett G. Phillips

Commonwealth of Kentucky)
) Case No. 2009-00459
County of Pike)

Subscribed and sworn to before me, a Notary Public, by Everett G. Phillips this 25 day of FEBUARY 2010.

Nelson R. Scott
Notary Public

My Commission Expires 8-7-2011

AFFIDAVIT

David M. Roush, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

David M. Roush

David M. Roush

State of Ohio)
)ss
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by David M. Roush this 24th day of February 2010.

Ellen A. McAninch
Notary Public

My Commission Expires May 11, 2011

AFFIDAVIT

Errol K. Wagner, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Errol K. Wagner

Errol K. Wagner

Commonwealth of Kentucky)
) Case No. 2009-00459
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by Errol K. Wagner this 24th day of February 2010.

Judy K Rosquist

Notary Public

My Commission Expires January 23, 2013

AFFIDAVIT

Scott C. Weaver, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

____
Scott C. Weaver

State of Ohio)
)ss
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by Scott C. Weaver this 25th day of February 2010.

____
Notary Public

My Commission Expires ____________________

AFFIDAVIT

Ranie K Wohnhas, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Ranie K. Wohnhas

Ranie K Wohnhas

Commonwealth of Kentucky)
) Case No. 2009-00459
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by Ranie K Wohnhas this 25th day of February 2010.

Judy K Rosquist

Notary Public

My Commission Expires January 23, 2013

Kentucky Power Company

REQUEST

Refer to the revised proposed tariff filed on January 15, 2010.

a. Refer to Original Sheet No. 6-8, Tariff RS - TOD2.

(1) Provide a narrative explanation for how the service charge and energy charges were developed.
(2) Explain the reason for the 500-customer limit.
(3) State how Kentucky Power will market this tariff to its customers.
(4) The Roush Testimony indicates that a customer under this tariff would be required to pay $3.55 per month to pay for the cost of a more sophisticated meter. Explain why this requirement is not included in the tariff.

b. Refer to Original Sheet No. 7-1, Tariff SGS. This tariff page, as well as Tariffs MGS, MGS-TOD, LGS, QP, CS-IRP, and C1P-TOD, includes a change in the "Delayed Payment Charge" Section. The current language states, "[t]his tariff is net if account is paid in full within 15 days of date of bill." The proposed language states, "[t]his tariff is due and payable in full on or before the due date stated on the bill". A similar change is being made to Tariffs MW and OL. Explain the reason for the change and the effect it will have on customers.

c. Refer to Original Sheet Nos. 7-3 and 7-4, Tariff SGS-TOD.

(1) Provide a narrative explanation for how the service charge and energy charges were developed.
(2) Explain the reason for the 500 customer limit.
(3) State how Kentucky Power will market this tariff to its customers.
(4) In the "Special Terms and Conditions" section, it is stated that, existing customers may initially choose to take service under this tariff without satisfying any requirement to remain on their current tariff for at least 12 months." Explain the meaning and purpose of this statement.

d. Refer to Original Sheet 9-4, Tariff LGS-TOD.

(1) Provide a narrative explanation of how all tariff charges were developed.
(2) Explain the reason for the 500 customer limit.
(3) State how Kentucky Power will market this tariff to its customers.

e. Refer to Original Sheet No. 15-1, Tariff SL. Under the "Fuel Adjustment Clause" Section, a text change was made by adding "Capacity Charge" to the last sentence. Explain the reason for this change.

f. Refer to Original Sheet Nos. 24-1 through 24-6, Rider ECS-C&E.

(1) Explain why this tariff is proposed to be available only through May 31, 2012.
(2) Explain all differences between this tariff and the current Rider ECS.
(3) Provide the effect this proposed tariff would have on customers currently taking service under Rider ECS.

g. Refer to Original Sheet Nos. 25-1 though 25-3, Rider EPCS. Provide the effect the proposed changes would have on customers currently taking service under this tariff.

h. Refer to Original Sheet No. 27-4, Tariff NMS. The Commission established interconnection and net metering guidelines in Case No. 2008-001691. These guidelines state that no application fee may be charged for Level 1 applications and that a utility may require each customer to submit a fee of up to $100 for Level 2 applications. Kentucky Power filed, and the Commission subsequently approved, tariffs in accordance with these guidelines. Explain why the Commission should now approve a $50 application fee for both Level 1 and Level 2 applications.

i. Refer to Original Sheet No. 35-1, Tariff TA. State whether the Balancing Adjustment Factor would be a separate line item on the customer bill.

RESPONSE

a. (1) The Tariff RS-TOD2 service charge is the sum of the proposed Tariff RS service charge of $8.00 and the $3.55 incremental cost of the special metering required. The Tariff RS-TOD2 energy charges were designed in a manner that would produce the same revenues as Tariff RS based upon the average residential customer. The differentiation in the energy charges by pricing period was based upon the relationship between market prices in each pricing period.

(2) The proposed 500 customer limit was due to the experimental nature of the proposed tariff.

(3) Specific marketing plans have not been developed at this time.

(4) The requirement is not stated in the proposed tariff since the service charge in the proposed tariff reflects the inclusion of this incremental cost.

b. The reason for the change was to make the language consistent among the tariffs and consistent with the presentation on the bills. The due date as stated on the bill will continue to be 15 days from the date of the bill. It will have no impact on customers.

c. (1) The Tariff SGS-TOD service charge is the sum of the proposed Tariff SGS service charge of $11.50 and the $3.55 incremental cost of the special metering required. The Tariff SGS-TOD energy charges were designed in a manner that would produce the same revenues as Tariff SGS based upon the average SGS customer. The differentiation in the energy charges by pricing period was based upon the relationship between market prices in each pricing period.

(2) The proposed 500 customer limit was due to the experimental nature of the proposed tariff.

(3) Specific marketing plans have not been developed at this time.

(4) Item 13 of Kentucky Power's Terms and Conditions of Service provides that customers that change their initial rate schedule selection must remain on such subsequent selection for 12 months before any other selection may be made. The language in Tariff SGS-TOD is intended to waive this requirement should a customer wish to take service under Tariff SGS-TOD.

d. (1) The Tariff LGS-TOD rates were designed in a manner that would produce the same revenues as Tariff LGS based upon the average LGS customer. The Tariff LGS-TOD service charges are the same as the proposed Tariff LGS service charges. The Tariff LGS-TOD demand charges were designed to recover 100% of secondary and primary demand (fixed) costs and 10% of transmission demand costs. The off-peak energy charges were designed to collect variable costs plus $0.01 per kWh for fixed costs. The on-peak energy charges were designed to collect variable costs plus all fixed costs not otherwise collected through the demand and off-peak energy charges.

(2) The proposed 500 customer limit was due to the experimental nature of the proposed tariff.

(3) Specific marketing plans have not been developed at this time.

e. The text change was made to clarify that customer billings for the Capacity Charge, which is a per kWh charge, uses this same table of monthly kWh consumption.

f. (1) Proposed Rider ECS is a very new service offering for the Company. The curtailment demand credit is based upon the Reliability Pricing Model auction price. For the year beginning June 1, 2012, this price dropped dramatically. Given these circumstances, the Company believes that a revised or new emergency curtailable service offering may be needed beginning June 1, 2012 and thus has requested that proposed Rider ECS expire May 31, 2012.

(2) Current Rider ECS was a stand-alone offering developed by the Company. The proposed Rider ECS is entirely different and similar to a PJM Interconnection, LLC offered program. The difference is that current Rider ECS compensated customers for energy reduced when they were called upon during an emergency, whereas proposed Rider ECS compensates customers for committing to curtail during an emergency and reduces such compensation should there be non-performance.

(3) There are no customers currently taking serving under the current Rider ECS.

g. There are no customers currently taking serving under the current Rider PCS.

h. Upon further consideration of the Commission's order, the Company now believes that there should be not be a Level 1 application fee and there should be a $100 Level 2 application fee.

i. No. The balancing adjustment factor will be combined the Tariff TA factor and shown as a single line on the bill.

WITNESS: David M Roush

Kentucky Power Company

REQUEST

Refer to Volume 1 of the application, pages 339 and 340 of 367. For each of the last five (5) years ending September 30, provide the amount of total Sales for Resale, Other Electric Revenue, Rent from Electric Property, and Miscellaneous Revenues.

RESPONSE

For the requested information, please refer to attached pages 2 through 3 of this response.

WITNESS: Errol K Wagner

Kentucky Power Company
Other Revenue Analysis

Account	Description	Twelve Months Ended September 30: 2005	2006	2007	2008	2009
4470001	Sales for Resale - Assoc Cos	2,249,276.60	1,979,621.73	1,078,726.14	1,867,236.78	(120,938.21)
4470002	Sales for Resale - NonAssoc	29,646,525.06	38,372,466.48	37,311,417.79	25,641,776.17	11,573,535.45
4470004	Sales for Resale-Nonaff-Ancill	31,075.75	28,476.87	25,452.02	26,086.76	69,409.04
4470005	Sales for Resale-Nonaff-Transm	831,802.29	518,145.24	770,964.49	738,241.82	760,169.91
4470006	Sales for Resale-Bookout Sales	384,821,946.78	217,408,927.32	136,887,970.56	139,768,733.20	73,697,187.82
4470007	Sales for Resale-Option Sales	4,465,953.33	632,846.07	94,478.05	-	-
4470010	Sales for Resale-Bookout Purch	(381,761,801.21)	(206,583,031.91)	(133,090,089.62)	(133,608,171.50)	(66,738,445.19)
4470011	Sales for Resale-Option Purch	(3,322,628.76)	(502,713.47)	(46,396.81)	-	-
4470019	Tier I Steam Revenue	-	-	-	-	-
4470026	Sale for Resl - Real from East	(5,706,360.00)	(882,215.58)	(13,863.15)	(1,000.31)	-
4470027	Whsal/Muni/Pb Ath Fuel Rev	1,613,311.01	1,581,988.04	2,222,087.08	2,134,062.59	2,854,516.67
4470028	Sale/Resale - NA - Fuel Rev	28,790,289.36	31,540,769.74	34,108,063.28	30,620,204.15	31,911,329.75
4470033	Whsal/Muni/Pub Auth Base Rev	1,773,237.45	1,971,999.69	2,386,828.29	2,358,004.68	3,301,778.88
4470035	Sls for Rsl - Fuel Rev - Assoc	3,203,957.50	3,733,161.04	2,691,372.17	2,459,287.94	412,583.53
4470064	Purch Pwr PhysTrad - Non Assoc	(10,195,734.98)	(12,014,587.20)	(21,859,277.21)	(11,942,590.05)	(3,450,109.87)
4470066	PWR Trding Trans Exp-NonAssoc	(228,926.02)	(276,388.38)	(214,397.63)	(60,506.40)	(116,216.67)
4470072	Sales for Resale - Hedge Trans	(3,243,892.00)	(2,604,141.00)	(86,175.45)	-	-
4470074	Sale for Resale-Aff-Trnf Price	-	-	-	-	-
4470081	Financial Spark Gas - Realized	(1,911,729.39)	(2,773,019.69)	1,622,322.38	(1,204,349.85)	(362,053.13)
4470082	Financial Electric Realized	(629,193.09)	(2,571,904.80)	3,993,844.45	(979,419.69)	(10,093,809.29)
4470083	Dedicated Finan Spark-Realzd	-	-	-	-	-
4470086	Sales for Resale-Affil Pool	8,263,958.85	-	-	-	-
4470088	Pool Sales to Dow Plt- Affil	5,072.00	42,973.09	-	-	-
4470089	PJM Energy Sales Margin	10,131,343.52	3,424,474.15	6,607,913.31	31,004,719.59	(1,705,496.71)
4470090	PJM Spot Energy Purchases	(23,858,766.36)	(10,416,793.18)	(14,414,503.86)	12,112,614.10	-
4470091	PJM Explicit Congestion OSS	(379,759.12)	(486,715.53)	(352,475.29)	(510,837.71)	22,986.66
4470092	PJM Implicit Congestion-OSS	(1,528,826.81)	(2,376,035.05)	(611,690.78)	-	-
4470093	PJM Implicit Congestion-LSE	(9,280,539.34)	(15,500,248.14)	(6,255,616.51)	(8,749,287.04)	(7,166,538.48)
4470094	PJM Transm. Loss - OSS	(4,689.56)	91,632.80	39,994.22	-	-
4470095	PJM Ancillary Serv.-Reg	675,287.68	-	0.66	-	-
4470096	PJM Ancillary Serv.-Spin	45,310.53	131,734.26	-	-	-
4470097	PJM Ancillary Serv.-Sync	0.00	-	-	-	-
4470098	PJM Oper Reserve Rev-OSS	664,924.78	810,695.73	838,670.94	495,088.54	1,188,378.76
4470099	Capacity Cr. Net Sales	1,375.05	3,515.23	547,889.03	2,231,923.40	1,874,847.01
4470100	PJM FTR Revenue-OSS	1,603,809.21	3,029,265.69	3,724,934.36	6,119,416.34	2,577,156.93
4470101	PJM FTR Revenue-LSE	13,827,760.68	25,400,816.95	6,789,086.69	8,448,914.80	7,620,773.43
4470103	PJM Energy Sales Cost	50,994,937.08	42,852,198.93	50,999,638.24	67,269,400.72	23,737,605.72
4470104	PJM OATT Ancill.-Reactive	-	-	-	-	-
4470105	PJM OATT Ancill.-Black	0.00	-	-	-	-
4470106	PJM Pt2Pt Trans.Purch-NonAff.	(418,455.52)	(53,088.93)	(43,575.25)	(20,078.15)	(5,751.54)
4470107	PJM NITS Purch-NonAff	6,893.67	(11,877.11)	(106,218.43)	151,832.21	8,824.42
4470108	PJM Oper.Reserve Rev-LSE	(2,015,255.99)	(1,592,472.15)	-	-	-
4470109	PJM FTR Revenue-Spec	111,201.04	(64,569.79)	30,474.20	804,288.30	(366,048.52)
4470110	PJM TO Admin. Exp.-NonAff.	(57,621.29)	(23,472.29)	(15,477.50)	(31,925.15)	6,077.38
4470111	Buckeye Excess Energy-OSS	0.00	-	-	-	-
4470112	Non-Trading Bookout Sales-OSS	6,349,293.35	15,274,314.65	15,131,035.72	20,280,892.72	6,345,982.83
4470113	PJM Non-ECR Purchases-OSS	-	-	-	-	-
4470114	PJM Transm. Loss - LSE	(116,007.41)	232,716.80	113,456.72	-	-
4470115	PJM Meter Corrections-OSS	(17,819.37)	(31,863.37)	(57,011.67)	296,062.89	(183,877.10)
4470116	PJM Meter Corrections-LSE	(86,997.97)	252,437.04	59,698.80	12,009.93	(30,860.45)
4470117	Realiz. Sharing-447 Optim	2,311,487.00	(1,255,125.00)	6,964.33	-	-
4470118	Realiz. Sharing-PJM OSS	124,025.00	(454,221.25)	3,340.86	-	-
4470119	PJM SECA Transm. Expense	(1,283,000.40)	(719,942.94)	-	-	-
4470124	PJM Incremental Spot-OSS	(69,119.53)	(73,472.12)	(13,855.12)	(69,993.00)	(6,816.60)
4470125	PJM Incremental Exp Cong-OSS	(5,061.76)	(76,774.78)	49,436.86	(43,779.13)	(91,553.03)
4470126	PJM Incremental Imp Cong-OSS	(555,849.41)	(966,858.59)	(5,974,937.06)	(14,080,295.50)	(549,832.55)
4470128	Sales for Res-Aff. Pool Energy	36,799,611.00	55,114,724.00	54,843,604.71	66,756,438.01	60,627,897.00
4470131	Non-Trading Bookout Purch-OSS	(5,802,153.69)	(8,065,017.61)	(3,828,571.78)	(3,234,425.66)	(520,843.63)
4470132	Spark Gas - Realized	348,565.64	(654,657.17)	-	-	-
4470141	PJM Contract Net Charge Credit	-	-	-	(12.79)	12.83
4470143	Financial Hedge Realized	-	4,426,992.36	1,113,748.01	(1,968,168.32)	2,885,619.01
4470144	Realiz.Sharing - 06 SIA	-	(24,913.00)	(4,393.00)	12,968.00	(7,457.00)
4470145	PJM Hourly Net Purch.-FERC	-	(0.00)	-	-	-
4470146	Pur Power (Trading) ERCOT Area	-	-	-	-	-
4470150	Transm. Rev.-Dedic. Whlsl/Muni	-	235,540.25	502,087.77	527,193.55	621,801.97
4470155	OSS Physical Margin Reclass	-	-	1,844,666.18	(342,627.41)	(9,932,835.72)
4470156	OSS Optim. Margin Reclass	-	-	(1,844,666.18)	342,627.41	9,932,835.72
4470166	Marginal Explicit Losses	-	-	(65,320.97)	(298,981.10)	3,583.85
4470167	MISO FTR Revenues OSS	-	-	-	32,357.42	7,747.63
4470168	Interest Rate Swaps-Power	-	-	-	(593.95)	(11,292.38)
4470169	Capacity Sales Trading	-	-	-	64,086.20	(89,351.87)

Kentucky Power Company
Other Revenue Analysis

Account	Description	2005	2006	2007	2008	2009
		Twelve Months Ended September 30:				
4470170	Non-ECR Auction Sales-OSS	-	-	-	-	14,849,736.72
4470174	PJM Whlse FTR Rev - OSS	-	-	-	-	24,802.97
4470202	PJM OpRes-LSE-Credit	-	60,740.21	234,223.18	293,479.50	2,692,643.16
4470203	PJM OpRes-LSE-Charge	-	(376,545.80)	(2,122,751.66)	(2,398,129.65)	(3,138,016.35)
4470204	PJM Spinning-Credit	-	917.97	12,535.52	(819.46)	79,194.72
4470205	PJM Spinning-Charge	-	(2,967.10)	(5,914.42)	-	(13,392.11)
4470206	PJM Trans loss credits-OSS	-	-	1,745,213.05	4,530,806.68	1,415,681.34
4470207	PJM transm loss charges - LSE	-	-	(7,680,760.26)	(24,798,901.34)	(14,632,644.64)
4470208	PJM Transm loss credits-LSE	-	-	2,874,121.69	11,927,955.21	8,273,650.08
4470209	PJM transm loss charges-OSS	-	-	(3,252,304.38)	(10,831,477.84)	(2,446,622.98)
4470210	PJM ML OSS 3 Pct Rev	-	-	-	17,707,528.64	2,742,144.70
4470211	PJM ML OSS 3 Pct Fuel	-	-	-	(6,549,792.75)	(1,871,743.17)
4470212	PJM ML OSS 3 Pct NonFuel	-	-	-	(1,050,049.41)	(340,198.90)
4470214	PJM 30m Suppl Reserve CR OSS	-	-	-	34,214.36	77,467.12
4470215	PJM 30m Suppl Reserve CH OSS	-	-	-	-	(11,558.96)
4470216	PJM Explicit Loss not in ECR	-	-	-	(400,560.37)	(440,418.54)
	Total Sales for Resale	137,212,042.23	177,718,459.40	169,346,017.76	233,893,679.08	147,753,239.42
4500000	Forfeited Discounts	1,523,385.27	1,717,192.78	1,707,395.19	1,669,864.92	1,809,068.04
4510001	Misc Service Rev - Nonaffil	137,681.36	231,118.06	369,373.70	445,851.85	395,705.89
4510007	Service Rev-Indirect Cost-NAC	1,436.02	1,852.22			
	Total Misc Revenues	1,662,502.65	1,950,163.06	2,076,768.89	2,115,716.77	2,204,773.93
4540001	Rent From Elect Property - Af	328,507.14	273,359.79	292,140.15	266,616.51	248,838.69
4540002	Rent From Elect Property-NAC	2,600,641.75	2,850,390.54	3,108,276.78	10,347,367.59	4,776,989.86
4540004	Rent From Elect Prop-ABD-Nonaf	72,999.00	102,984.74	95,372.38	80,784.50	81,331.10
	Total Rent from Elec Prop	3,002,147.89	3,226,735.07	3,495,789.31	10,694,768.60	5,107,159.65
4560007	Oth Elect Rev - DSM Program	(2,283,347.66)	818,791.48	995,300.52	1,027,945.12	1,149,667.95
4560012	Oth Elect Rev - Nonaffiliated	17,310.26	13,103.06	(511.22)	73,981.89	(45,532.57)
4560013	Oth Elect Rev-Trans-Nonaffil	145,292.37	162,769.58	69,756.00	13,992.00	-
4560014	Oth Elect Revenues - Ancillary	5,753.63	-	-	-	-
4560015	Other Electric Revenues - ABD	1,647,885.78	863,540.05	697,180.77	433,609.04	3,006,371.40
4560016	Financial Trading Rev-Unreal	0.01	-	-	-	140,522.74
4560031	MTM Credit Risk Reserve	-	-	-	-	-
4560041	Miscellaneous Revenue-NonAffil	41,506.04	29,310.96	(10.34)	6.68	0.56
4560043	Oth Elec Rv-Trn-Aff-Trnf Price	-	-	-	-	-
4560049	Merch Generation Finan -Realzd	(346,981.24)	(1,130,193.35)	(129,929.41)	26,247.01	1,264.02
4560050	Oth Elec Rev-Coal Trd Rlzd G-L	1,256,709.27	(152,325.71)	(835,734.11)	(282,175.52)	685,787.01
4560052	Realized Spark/MGG Transfer	-	-	-	-	-
4560058	PJM NITS Revenue-NonAff.	3,175,403.71	3,682,041.57	1,071,512.10	675.98	-
4560059	PJM NITS - Affilate	-	-	-	-	-
4560060	PJM Pt2Pt Trans Rev.-NonAff.	1,764,297.28	1,060,344.54	104,371.92	-	-
4560061	PJM TO Adm. Serv.-Affiliate	-	-	-	-	-
4560062	PJM TO Admin. Rev..-NonAff.	247,408.30	215,783.92	35,361.74	(2.08)	-
4560063	PJM Pt2Pt Transm. Serv.-Affil.	-	-	-	-	-
4560064	Buckeye Admin. Fee Revenue	117,546.26	80,913.72	5,857.20	-	-
4560066	PJM Transm Dist /Meter-Affil.	-	-	-	-	-
4560067	OthElecRev Phys Coal Purch Exp	(1,183,206.24)	-	-	-	-
4560068	SECA Transmission Revenue	9,294,380.81	4,508,234.30	(1,161,707.40)	(409,216.25)	-
4560070	Wires Revenue - Affiliated	-	-	-	-	-
4560072	Hedge Ineffectiveness Revenue	-	-	-	-	-
4560084	MTM-Coal Procurement	-	-	-	-	-
4560085	PJM Expansion Cost Recov	5,157.66	111,472.33	19,791.48	-	-
4560086	LSE FTR MTM	-	-	-	-	-
4560087	OSS FTR MTM	-	-	-	-	-
4560095	RTO Form. Cost Recovery	-	19,489.22	3,971.98	-	-
4560097	Sales of Renew. Energy Credits	-	-	355.59	-	-
4560109	Interest Rate Swaps-Coal	-	-	-	(3.43)	(653.53)
4560111	MTM Aff GL Coal Trading	-	-	-	-	(140,522.74)
4560112	Realized GL Coal Trading-Affil	-	-	-	-	(208,389.40)
4561002	RTO Formation Cost Recovery	-	-	11,815.52	16,173.22	13,648.10
4561003	PJM Expansion Cost Recov	-	-	61,843.55	79,182.19	77,303.15
4561005	PJM Point to Point Trans Svc	-	-	702,469.82	1,208,822.32	995,822.07
4561006	PJM Trans Owner Admin Rev	-	-	146,754.27	211,498.46	160,808.27
4561007	PJM Network Integ Trans Svc	-	-	3,079,652.32	3,550,513.05	3,757,983.22
4561019	Oth Elec Rev Trans Non Affil	-	-	-	51,516.00	70,920.00
	Total Other Electric Revenues	13,905,116.24	10,283,275.67	4,878,102.30	6,002,765.68	9,665,000.25

Kentucky Power Company

REQUEST

Refer to Volume 1 of the Application, page 349 of 367. Explain the large increases in the amounts charged Kentucky Power by Appalachian Power Company, Indiana Michigan Power Co., and Public Service Co. of Oklahoma over the four (4) year period shown.

RESPONSE

The increase in charges from Appalachian Power is due primarily to Appalachian Power Company's payments on behalf of Kentucky Power of $0.9 million in the test year and $1.0 million in the 12 months ended December 2008 for a transformer and related materials for the Dwale, KY substation.

The increase in charges from Indiana Michigan Power is due primarily to employee labor and expenses for storm damage restoration expenses of $0.2 million related to the severe storms in Kentucky in January 2009 and February 2009.

The increase in charges from Public Service Company of Oklahoma is due primarily to employee labor and expenses of $0.3 million for storm damage restoration expenses related to the February 2009 severe storm.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

Refer to Volume 2 of the application, Section III. Provide a copy of pages 1-62 in electronic form on CD-Rom with the formulas intact and unprotected.

RESPONSE

Please see the attached electronic file.

WITNESS: David M. Roush

Kentucky Power Company

REQUEST

Refer to Volume 2 of the application, Section III, page 10 of 488.

a. Refer to column 1. Explain the "Book to Bill Adjustment."

b. Column 1 contains a row titled "Fuel" which shows a total of $9,513,955. Explain what this row represents.

c. When the "Fuel" row reaches column 9, titled "Revenue with Annualized Fuel," the amount is reduced to $5,704,918. Explain the difference in these two amounts.

d. Refer to column 9. Explain how the .0023217 fuel rate was calculated.

RESPONSE

a. The book to bill adjustment reflects the difference between the kWh recorded on the Company's books and the kWh that when multiplied by test year rates match the revenue as recorded on the Company's books.

b. Column (4) of the row labeled "Fuel" represents the test year billing under the Company's monthly fuel adjustment clause assuming the current fuel basing point was in effect for the entire period.

c. Column (9) of the row labeled "Fuel" represents the test year billing at the Company's annualized fuel factor of $0.0023217.

d. The Company's annualized fuel adjustment factor is calculated as the jurisdictional total fuel cost of $219,625,727 as shown on Exhibit EKW-4, Column (5), divided by Billed and Accrued kWh of 7,148,876,499 kWh as shown on Exhibit EKW-4, Column (11) less the current base fuel amount of $0.0284 per kWh as shown on Exhibit EKW-4, Column (12).

WITNESS: David M Roush

Kentucky Power Company

REQUEST

Refer to Volume 2 of the application, Section III, page 11.

a. Refer to column 1. Explain what is meant by "Customer Charge - NH" and "Customer Charge - HT."

b. Explain the employee discount policy.

RESPONSE

a. The service charge for employees is different depending upon whether their residence has electric heat "HT" or does not have electric heat "NH".

b. Company employees that are also customers of the Company receive a discount on the service charge portion of their electric bill. Employees with electric heat "HT" do not pay the service charge. Employees without electric heat "NH" pay one-half of the service charge.

WITNESS: David M Roush

Kentucky Power Company

REQUEST

Refer to Volume 2 of application, Section III, page 29 of 488. Column 3 shows a current "Alternate Feed" rate of $4.04. Provide the location of this rate in Kentucky Power's tariff.

RESPONSE

The rate cannot be found in KPCo's current tariff. Such service is currently being provided under a KPSC approved special contract.

WITNESS: David M Roush

Kentucky Power Company

REQUEST

Refer to Volume 2 of the application, Section III, page 38 of 488.

a. Explain how the Employee Discount of ($59,120) in the Proposed Revenue column was calculated.

b. Confirm that the reason Environmental Surcharge revenues go from $4,762,458 to $0 is due to Kentucky Power's proposal to roll environmental costs into base rates.

RESPONSE

a. The discount was calculated as 1,854 Employees Without Electric Heat Bills x $4 + 6,463 Employees With Electric Heat Bills x $8 = $59,120.

b. Yes, the environmental surcharge revenues fall to $0 because the Company is proposing to include the test year level in base rates.

WITNESS: David M Roush

Kentucky Power Company

REQUEST

Refer to Volume 2 of the Application, Section V, Workpaper S-6, page 1 of 4. Provide an explanation for the two adjustments in column 4 or provide the location of same in the Application.

RESPONSE

Section V, Workpaper S-6, Line No. 4, Distribution Plant, Column 4 amount of ($1,149,668) relates to the test year revenues associated with the DSM activities (Please See Section V, Workpaper S-6, Page 2 of 4, Line No. 7). This adjustment removes the revenues which include the cost recovery, lost revenues, and incentives associated with the DSM activity from the test year annual revenue requirement. These revenues should be excluded from base rates due to the fact that DSM revenues are recovered through the DSM surcharge. The DSM activity cost should have also been removed from the test year cost of service as stated in the Company response to Commission Staff 1 st Set Item No. 58.

Section V, Workpaper S-4, Page 1 of 4, Line 5, Various Trans. Agreement, Column 4 amount of ($5,005,564), relates to the items listed on Section V, Workpaper S-6, Page 2 of 4, lines 17 through 21. These various transmission agreement revenues were removed from the Operating Revenue because these same transmission revenues were included in Section V, Workpaper S-7, Line 10 in the amount of $5,005,565 as a negative expense. These transmission revenues are used to reduce the annual cost-of-service. This is a reclassification of the test year transmission revenues to a negative expense.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

Refer to pages 5 and 9-10 of the Direct Testimony of Timothy C. Mosher.

The sentence at line 7 of page 5 refers to "[i]ncreasing efficiencies . . . ," while the answer starting at line 21 of page 9 and continuing to page 10 refers to Kentucky Power meeting its goal of providing reliable cost-effective service "[t]hrough effort, efficiencies and commitment . ." Provide a list of all efficiencies, cost-saving measures, best practices programs, etc. that have been implemented by Kentucky Power since its last general rate case and, for each efficiency, measure or program, quantify the dollar impact of the benefit it has provided Kentucky Power's customers.

RESPONSE

Since our last general rate case in 2006, Kentucky Power has implemented the following programs, procedures or processes that are designed to produce more reliable service:

1. Improvement of performance within station breaker zones: We focused tree trimming efforts to establish a four year cycle within the station zones. We've also concentrated on identifying and replacing faulty cutouts within the station zones. These two activities were undertaken primarily to improve reliability by stabilizing SAIFI (System Average Interruption Frequency Index) and reducing the number of large outage cases.

2. Crew productivity and job site efficiency goals were established for the field personnel to better understand how their individual and team performance preparing for work and working a specific plan affected service to the customer. Jobsite efficiency increased from 68% in 2005 to 82% in 2009, while the utilization measurement stabilized during the same timeframe. The net effect is more maintenance work completed and services installed faster.

3. LEAD (Line Equipment Analysis Device) equipment, a tool that AEP developed and patented to identify distribution hardware in the beginning stages of deterioration and failure, was employed to detect (EMI), electro-magnetic interference. EMI detection allows failing cutouts and lightning arrestors to be located and replaced before an outage occurs.

4. Utility vehicle standardization was introduced and followed, reducing the overall costs of new vehicles.

5. A Kentucky (DDC), Distribution Dispatch Center, was established to centralize the daily dispatch operation as well a create a more efficient function during storm restoration. A total of thirteen employees cover Kentucky operations on a twenty-four hour basis. During major storms, dispatching is returned to the local areas and the DDC functions as the clearinghouse between distribution and transmission.

6. Kentucky Power was reorganized into an operating company with three Customer and Distribution Services Managers respectively in Ashland, Pikeville and Hazard. The managers report to a Customer Operations Director who reports to the company President and Chief Operating Officer. The new organization has allowed a closer relationship in the communities and a direct responsibility for service reliability.

7. The Company has spent more for reliability each year since the last rate than was included for the purpose of designing rates.

Savings have not been quantified.

WITNESS: Timothy C Mosher

Kentucky Power Company

REQUEST

Refer to the Direct Testimony of William E. Avera ("Avera Testimony") at page 9.

The information in footnotes 4 and 5 is a year old. If available, provide more recent utility sector analyses from Fitch Ratings, Ltd. and Moody's Investor Services.

RESPONSE

Copies of the most recent publications from Fitch Ratings Ltd. and Moody's Investors Service in Dr. Avera's possession are contained on the CD attached to this set of Data Requests.

WITNESS: William E. Avera

FitchRatings
KNOW YOUR RISK

Corporates

Global Power
North America
Special Report

U.S. Utilities, Power, and Gas 2010 Outlook

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Related Research

- *Pipeline/Midstream/MLP 2010 Outlook, Dec. 3, 2009*

Table of Contents

Overview

The U.S. Utilities, Power, and Gas (UPG) sector 2010 outlook is framed in the context of Fitch Ratings' outlook for a slow U.S. economic recovery in 2010, with stable outlooks for most of the business segments within the UPG universe except for negative 2010 credit outlook for competitive generators and retail propane distributors. Forces driving the credit outlook are summarized below:

- Growth in power sales adjusted for weather will resume after the declines of 2008–2009. Natural gas sales volume is expected to be relatively flat year on year.
- Market prices for natural gas and electric power and capacity are likely to remain in a low band. Relatively low prices are:
  - Beneficial or neutral for electric and gas utilities.
  - Unfavorable for competitive power generators and natural gas storage and midstream services.
- While non-energy commodity prices are up from their trough in 2009, we do not foresee an overheated economy with rapid expansion in the prices of construction materials; however, U.S. dollar weakness is likely to raise costs of imported machinery and equipment, and could eventually raise prices of U.S. construction materials, increasing capital investment cost pressures.
- Electric utilities reduced their 2010 capital expenditure budgets from earlier planned amounts, but the overall level of investment remains greater than internal funding and will require external financing, including raising equity capital.
- Continued good access to debt and equity capital markets is expected, along with gradual improvement in bank market conditions.
- Electric and gas utilities are in a long-term cycle of rising unit costs, requiring frequent base rate increases to maintain stable financial results.
- While Fitch expects that most utilities will achieve reasonable regulatory outcomes, the dependence on rate increases exposes utilities to potential resistance from regulators, state politicians, and consumers/voters.
- Fitch expects passage within two years of national laws limiting greenhouse gas (GHG) emissions and possibly a national renewable portfolio standard, as well as more stringent environmental regulations on other emissions. This will have little effect on cash flow in 2010, but longer-term consequences for many competitive power generators are unfavorable, especially for owners of coal-fired generation, and it will add to cost pressures for integrated electric utilities and their consumers.

The "Credit Outlook Summary by Segment" table on page 2 of this report delineates the outlook and median rating with supporting bullet points for each business segment in the UPG sector. Fitch's business segment outlooks are formulated based on an analysis of fundamental factors, not by tallying the current rating outlooks of individual issuers in the business segment. Rating Outlooks for individual companies often vary from segment outlooks due to the specific circumstances of each entity. As of Dec. 1, 2009, more than 86% of individual issuer Rating Outlooks in the UPG sector are Stable.

Resilient Performance in 2009

Companies in the UPG sector weathered the recession and financial crisis of 2008–2009 with considerably less pain than sectors such as financial institutions, cyclical industrials, and retailers. The absence of significant defaults in the sector is in stark contrast to the upswing in defaults and bankruptcy filings across the rest of the U.S.

Credit Outlook Summary by Segment

The segment credit outlooks in the left column reflect fundamental analysis of factors influencing developments in the segment, not the aggregate Rating Outlooks of the entities in the segment. Median ratings indicated are based on the issuer default ratings (IDR) of entities rated by Fitch Ratings, with the exception of the public power utility segment, which is based on senior instrument ratings. Public power utilities are not assigned IDRs.

Segment	Drivers in Credit Outlooks for 2010
Utility Parent Companies Median IDR: BBB **Credit Outlook** Stable (One Year) Negative (Longer Term)	• Continued cost cutting for earnings and cash flow growth. • Investment focus on organic growth, investments in transmission, and renewables. • M&A activity will be limited. • Focus on core businesses; selective divestitures. • Equity issuance needed to maintain balanced capital mix.
Electric Utilities, Investor-Owned Median IDR Integrated Electric: BBB Median IDR Electric Distribution: BBB **Credit Outlook** Stable (One Year) Stable to Negative (Longer Term)	• Sustained high capital spending for the majority of companies. • Relatively low gas and power prices will mitigate effect of rising infrastructure costs in 2010. • Rising unit costs longer term due to new infrastructure and carbon regulations. • Serial base rate cases to recover infrastructure investments in 2010 and longer term. • Significant new debt, hybrids, and equity issuance to fund capex.
Gas Distributors, Investor-Owned Median IDR: A– **Credit Outlook** Stable (One Year and Longer Term)	• Oversupply of gas into the 2010 winter season will relieve rate pressure. • Sales growth constrained by continued weakness in the housing sector. • Capital expenditures will remain fairly low and manageable. • Expect consistent regulatory treatment and manageable external funding.
Competitive Generation Companies **Generating Companies and Energy Trading** Median IDR: BB– **Credit Outlook** Negative (One Year) Negative to Stable (Longer Term)	• Excess power reserve margins will linger with modest demand growth. • Low gas and power price environment will hold down margins for most generators. • Need to replace expiring hedges and contracts in a weak pricing environment. • Uncertainty surrounding carbon legislation remains a key operating and credit issue for this group.
Natural Gas Midstream Companies **Midstream and Pipeline Companies** Median IDR: BBB– **Credit Outlook: Pipelines** Stable (One Year and Longer Term) **Credit Outlook: Midstream** Stable (One Year and Longer Term) **Credit Outlook: Propane** Negative (One Year and Longer Term)	• Development of low-risk, contractually supported pipelines to connect increased shale gas production to high-demand eastern markets. • Midstream processing volumes and margins likely to be supported by significant price advantage of NGLs over oil-based naptha as ethylene feedstock. • Modest increase in volumes on natural gas and refined products pipelines due to recovering economic activity. • Companies are likely to continue to pursue conservative financial practices.
Public Power Utilities **Municipal, State, and Federal Agencies and Cooperatives** Median Rating[a] (Retail Systems): A+ Median Rating[a] (Wholesale Systems): A **Credit Outlook** Stable (One Year) Stable to Negative (Longer Term)	• Benefit from less state regulatory oversight; local control over rate-setting. • Continued lower usage and decreased revenues from surplus power sales anticipated for 2010. • Growing pressure for local governments to slow rate increases and boost transfers from the utility system to replace lost city tax revenue and fund pension obligations. • Generation investment will continue, albeit at a slower pace. • Rising unit costs longer term due to new infrastructure and carbon regulations. • Improving access to third party liquidity; expect extension of federal stimulus program which provides for issuance of taxable Build America Bonds by municipal entities.

[a]Median ratings shown for Public Power Utilities are senior unsecured debt ratings.
Source: Fitch.

economy, consistent with the defensive reputation of the sector.

In general, companies in the UPG sector entered 2009 in reasonably sound financial condition; some drew down their bank credit facilities during the banking crisis in late 2008 and repaid the loans as the bank and financial markets stabilized during 2009.

Rate-regulated utilities benefited during the market disruption from bond investors' preference for low-risk infrastructure investments. Regulated utilities and holding companies with higher investment-grade ratings had adequate to robust bond and commercial paper market access throughout 2009, and the bond market became more open to funding companies with speculative-grade ratings at progressively lower spreads during the second half of 2009.

Electric and gas utilities' sales volumes were reduced as a result of cyclical sales declines, especially lower industrial consumption of gas and power, with greatest impact in the Midwest. Residential demand was also lower, particularly in markets with the greatest impact from the housing collapse. While reduced sales hurt cash flow, lower costs of natural gas and power purchases, combined with timing differences in cost recoveries and collections of prior fuel deferrals, helped support operating cash flow and reduced working capital needs. Some integrated electric utilities that rely on spot sales of excess power into the wholesale market and rely on profits from wholesale sales suffered from a material decline in spot market prices.

Competitive generators and midstream gas processors were exposed to oversupply of natural gas and declines in power and gas spot and forward prices to the extent production was unhedged. However, generators and midstream processors that entered 2009 with their sales significantly hedged avoided most of the impact of lower margins.

Key Drivers of the 2010 Outlook

Fitch's 2010 credit outlook for the Utilities, Power, and Gas sector incorporates the following framing economic and capital market assumptions:

- General economic recovery continues over the course of 2010.
- Capital market conditions are expected to be open and the bank market to have a gradual improvement in spreads.
- Interest rates are expected to rise over the course of the year from very low levels.
- Weather-adjusted power demand expected to return to growth in 2010–2011. Power is expected to form a longer-term growth trend averaging about 1.4% to 1.6% per annum. Recovering industrial and commercial demand for natural gas should offset increased efficiency, resulting in flat sales overall for gas.

Fitch's 2010 U.S. economic outlook is for a slow recovery, with a projected modest 1.8% rise in GDP. Industrial production and GDP appear to be gaining, albeit from a low base. Fitch expects the pace of expansion to remain weak by the standard of prior recoveries. While job losses are slowing, unemployment is not improving, and could weigh on consumer sentiment and spending for several quarters. While there is a risk of a double-dip recession, which would continue to suppress sales growth in the sector and would result in a more adverse near-term credit environment, this is not Fitch's base case.

Interest Rates

U.S. Treasury interest rates in 2009 were at historically low levels, with short-term rates near zero for the first half of the year. Later in 2009, the long end of the yield curve began to move up. In the low rate environment, utilities achieved low-cost long-term debt financing, with 20- to 30-year taxable utility operating company issues at 5.50%–6%. As long as U.S. Treasury policy keeps rates low, the dollar would remain under pressure. Assuming that the economic recovery takes hold, the Federal Reserve would have to devise an exit from its easy-money monetary policy, allowing short-term interest rates to revert to a more normal level, and long-term rates to move up as well.

Access to Capital and Credit Markets

Access to the debt capital market is expected to remain open to the UPG sector issuers in 2010–2011.

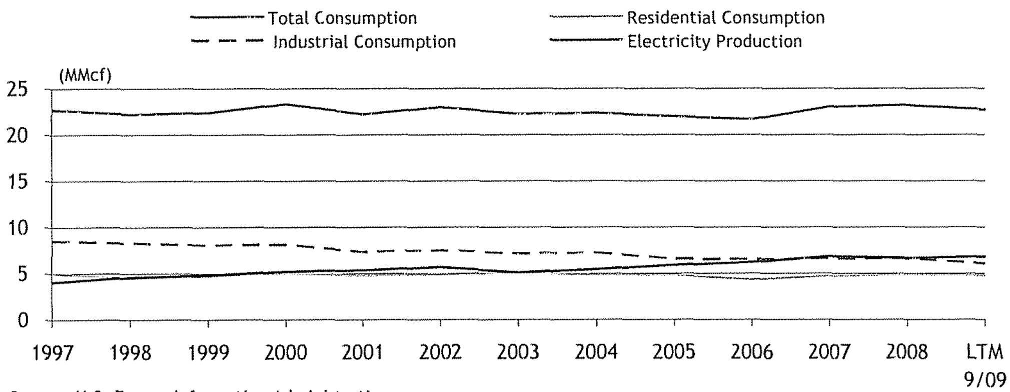
Access to equity capital in addition to debt will be critical for utilities and utility holding companies to maintain stable credit profiles, given the forecast for capital expenditures in the sector in excess of internal cash flow. The utility sector will have difficulty to satisfy equity investors' expectations for growth in a general economic recovery. Companies with strong market valuations or better growth fundamentals are better positioned to raise equity without excessive dilution. Many utilities are considering the use of hybrid securities to minimize dilution.

Fitch is monitoring expiring bank credit facilities and the pricing, covenants and terms of new and replacement facilities. A recent Fitch study tallied approximately $163 billion of credit facilities of companies in the UPG sector expiring in 2010–2014, with approximately 40% ($65 billion) of maturities concentrated in 2012. Fitch concluded that expiring credit facilities are not likely to create a liquidity issue for the sector, although credit costs are likely to be higher than prior to the credit crisis. Fitch expects that companies with expiring credit facilities will close the gap by means of alternatives such as diversifying credit providers and using new types of credit facilities, relying more on capital market debt and less on bank facilities for direct funding or back-up, and altering collateral-intensive business practices to reduce needs for back-up credit. (*For more on this topic, please refer to "Fitch Review of Bank Credit Facilities in the Utilities, Power, and Gas Sector," published on Oct. 28, 2009.*)

Gas and Power Demand

The trend over the past decade has been for declining natural gas consumption by industrial users to be offset by higher usage for power generation. In 2009, extremely low natural gas prices caused the dispatch of gas combined-cycle units to displace some production by less-efficient coal plants. Assuming somewhat higher gas prices in 2010, gas is likely to give back some share to coal at the margin. Beyond 2010, Fitch expects

U.S. Natural Gas Consumption by Customer Sector

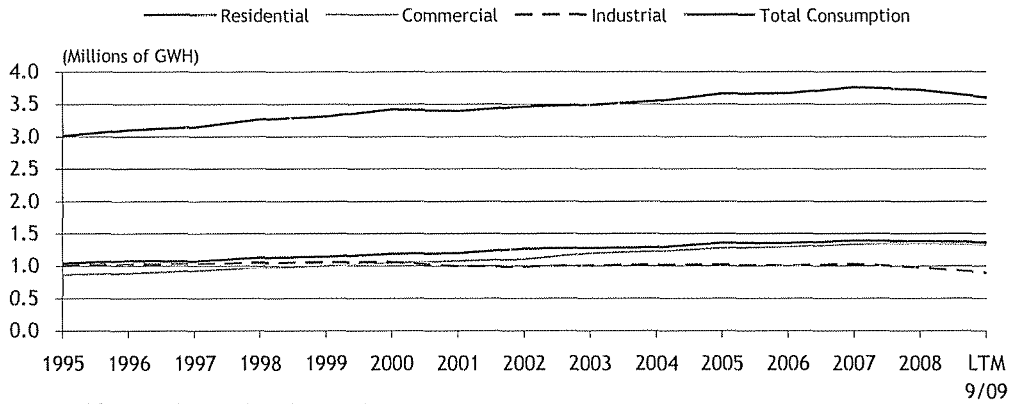


Source: *U.S. Energy Information Administration.*

that use of natural gas for power generation will be growing and taking share away from coal, offsetting shrinkage in primary demand for gas as a fuel for residential, commercial, and industrial applications. On balance, weather-adjusted sales of natural gas are forecasted to be approximately flat.

On a weather-adjusted basis, Fitch expects that U.S. electricity sales will rise in 2010 by 1% to 2%, largely due to a rebound in industrial usage straddling 2010–2011 that would recover some but by no means all of the industrial demand lost in 2008–2009. Longer run, Fitch foresees U.S. power consumption growing at 1.4%–1.6% annually. Growth in U.S. per capita electricity consumption has been in a long-term secular decline since 1960, and that trend is likely to continue as state and federal policies increasingly favor energy-efficiency and demand-reduction programs. In those states with aggressive policies promoting demand reduction, electric utilities are likely to press for tariff decoupling mechanisms to replicate those already in effect for many natural gas distributors and in a few jurisdictions for electricity.

U.S. Electricity Consumption by Customer Sector



Source: U.S. Energy Information Adminstration.

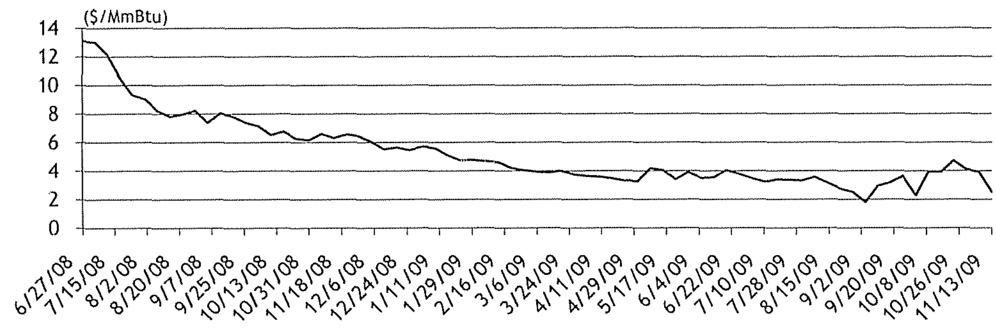
Commodity Prices

While market prices of gas and electric power are expected to rise from the 2009 trough, prices are likely to remain well below the levels that prevailed in early 2008. Relatively low gas and power prices are a favorable element in the credit outlook of most electric and gas distribution utilities and many integrated electric utilities, but form a more challenging market environment for competitive generators with conventional power generation assets and midstream gas processors to the extent that sales are dependent on market prices rather than contracts signed at more favorable prices.

Producers of steam coal remain in a pinch between their own rising production and pension costs and the gas-on-coal competition at the margin for power production. Coal stockpiles at power plants will enter 2010 materially above historical levels. While demand and prices for met coal can rise with global economic recovery, steam coal prices are likely to be constrained.

Prices of steel, cement, and other construction materials are up somewhat from their trough in early 2009, and prices are expected to increase over the course of 2010, especially due to the weak U.S. dollar. However, we see no basis for a return in 2010 to the runaway inflation of construction materials of early 2008.

Natural Gas Spot Prices — Henry Hub



MmBtu – Million British thermal units.
Source: Bloomberg.

Natural Gas Price Environment

Natural gas supply has exceeded demand for much of 2009, reflecting a combination of lower consumption, high production, and historically high gas inventory levels. Rapid expansion of shale gas production as well as greater accessibility to Rockies' gas production contributed to the 2008–2009 collapse of U.S. gas prices as the recession depressed industrial demand. Fitch believes that price weakness will continue throughout 2010 as the industry works through high inventory levels and demand remains weak; the dramatic reduction in rig count during 2009 may only gradually reduce the gas oversupply, especially since new shale production tends to have very high initial production levels.

Weather is a dominant factor in natural gas demand in the residential and commercial markets. Fitch does not forecast the weather; however, given the drops in natural gas demand in the industrial sector of the economy, it is not clear that even a colder-than-normal winter would be enough to support materially higher natural gas prices in 2010.

Wholesale Electricity Prices

As a result of the decline in U.S. power consumption in 2009 along with some new power capacity coming on line, capacity reserve margins have increased to the extent that all U.S. power regions are currently oversupplied, with capacity reserve margins in excess of 30% in most regions. Additions of renewable resources (largely wind) and a few large coal plants that came on line in 2009 or will enter service in 2010 also tend to prolong the industry overcapacity. Excess power capacity will only gradually be absorbed by the modest increase in power demand.

The relatively low band of natural gas prices foreseen for 2010–2011 is expected to combine with high capacity reserve margins to keep electric power and capacity prices in a moderately low range in 2010 compared with the prices that prevailed in 2007 through mid-2008. Increasing output of wind and solar generation over the next several years will also play a role in reducing round-the-clock energy prices and market clearing heat rates, especially in those markets with the most abundant resources of wind (Midwest and Plains, Texas) if transmission is adequate to move power to load centers. In 2010–2013, 30% or more of the new power generation coming on line in the U.S. will be wind, solar or other renewable generation, stimulated by tax subsidies, state renewable portfolio standards, and feed-in tariffs in some states. Finally, construction of new electric transmission facilities in New England and PJM and in ERCOT over the next five years is expected to begin to lower electricity prices in congested zones and to raise prices outside the congestion zones.

Capital Expenditures

Overall, companies in the UPG sector responded to the recessionary environment and reduced gas and power demand by deferring capital expenditures (capex) budgeted for 2009 and 2010 or cutting out discretionary projects, but the effects differ by segments within the sector. Overall, capex in the sector will remain well in excess of depreciation charges relating to the existing asset base.

- Capex for the competitive power generation sector remains in excess of depreciation charges, despite more limited access to capital by the independent generators as well as the court overturn of the Environmental Protection Agency's (EPA) Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR) regulations, which caused some companies to delay environmental compliance projects. In 2010, capex will include more environmental compliance work, investments in renewable power sources that carry abundant tax incentives and up-rates of existing nuclear plant capacity.
- Constrained by uncertain access to capital, gas midstream companies, and master limited partnerships (MLPs) reduced capex very sharply in 2009, cutting back to maintenance levels and completion of major projects already under construction. Some major pipeline infrastructure projects are under construction, and these have put some stress on credit ratios of their sponsors. In 2010, companies will spend to complete major pipeline projects and to extend gathering lines to new shale-producing areas, and could ramp up discretionary capex if funding is available and market conditions improve with enhanced economic activity.
- Gas distribution utilities generally have modest capex budgets, averaging around 1.5x annual depreciation charges. Spending is expected to decline year on year in 2010.
- Electric utilities have been in a pattern of increasing capex from 2005–2008 and had budgeted to continue to grow in 2009. In 2009, the investor-owned electric utilities reduced their aggregate capex by 10% from the originally budgeted 2009 levels, and cut their 2010 plans by 9% from the original plans for 2010. After those cuts, 2010 capital expenditures for the segment as a whole are now budgeted to be essentially flat with the record $84 billion level of 2008, and Fitch expects to see some growth in capex in 2011. The ratio of capex to annual depreciation and amortization charges will on average be higher for integrated utilities than for utilities that are pure transmission and distribution (T&D) providers. Fitch notes that there is considerable divergence in capital investment among the T&D utilities, including some that are investing heavily for advanced metering or transmission and grid reliability projects and several with very minimal capex. (*For more information on this topic, please refer to "Electric Utility Capital Expenditures: The Show Will Go On," published on Oct. 14, 2009*).

Ratio of Capital Expenditures to Depreciation and Amortization

(12 Months Ended Sept. 30, 2009)

	Average	Minimum	Maximum
Parent Companies (Consolidated)	2.3	0.7	4.9
Electric Integrated Utilities	2.7	0.8	6.7
Electric Distribution Utilities	1.5	0.3	4.6
Gas Distribution Utilities	1.5	0.9	3.0
Competitive Generators	2.8	0.9	7.0
Pipeline and Midstream Gas	2.5	1.0	7.6

Source: Fitch Ratings, company financial statements.

Public Policy Will Drive Fundamental Changes

While it is still uncertain whether a major energy bill will be enacted in 2010, the presidential administration and Congressional leadership are intent upon enacting a law to address climate change, including limits on GHG emissions using a cap-and-trade program, implementing standards for energy efficiency and conservation, and promoting investments in renewable resources. However, it has so far proven difficult to find bipartisan support or to muster sufficient support within the Democratic majority to pass a Senate bill that will raise costs for consumers and disadvantage some states more than others.

If the Congress is unsuccessful in passing new laws on these matters, the EPA has the authority to take a more vigorous approach to carry out the federal court mandate defining carbon dioxide and other GHGs as dangerous pollutants subject to regulation under the Clean Air Act. Compliance with an EPA rule is likely to be more difficult and costly for electric power generators and integrated utilities than a compromise bill crafted by Congress; thus, the electric industry has united to support Congressional action. Also, EPA is expected to act on new regulations to replace vacated Clean Air Interstate Rule and Clean Air Mercury Rule with important effects on coal-fired generating units, though not likely to have material effect in 2010.

Fitch assumes that there will either be a national law within the next two years that will regulate carbon emissions, or the EPA will step in with new regulations with more severe impact. If the EPA establishes rules, they are likely to take several additional years of litigation and implementation. Fitch conducts sensitivities of the effects of possible emissions prices or a tax on carbon emissions in its credit reviews of power generators, but has not developed stress cases around potential EPA regulations.

Renewable Energy and Technology Innovation

Roughly half the states have adopted renewable portfolio standards (RPS) requiring utilities to source a larger share of their electric power from defined renewable sources, and more continue to jump on the bandwagon. There is growing pressure in some states to establish feed-in tariffs and/or net metering of electricity. The longer-term effect of these requirements may be adverse for electric utility credit if utilities become loaded up with costly and inflexible power purchase obligations, akin to the problems that occurred in the 1980s–1990s following the implementation of the Public Utility Regulatory Policy Act of 1978. As higher costs of renewable resources and related transmissions are pushed into consumer tariffs, it could make it more difficult for utilities to achieve base rate increases to recover other rising cost elements and maintain satisfactory equity returns.

In 2009, significant tax incentives (*see the Federal Tax Matters section on page 9*) have begun to stimulate a sharp increase in investments in wind, solar, biomass, and other resources defined as renewable power. Federal loan guarantees for renewable resources, advanced clean energy technologies, and electric transmission, as well as grants from the Department of Energy for advanced metering and Smart Grid projects are additional sources of stimulus.

We have entered a period of high technology innovation in renewable energy resources, demand reduction, energy efficiency, and electric power transmission networks. A significant amount of work is underway to prepare for potential charging of plug-in electric vehicles, a development that would require substantial new investments in the utility distribution grid. The industry is testing technologies for carbon capture and storage, integrated gasification with combined cycle electric production (IGCC), battery storage, and pursuing licensing of new nuclear reactor designs. The U.S. has increased federal funding for energy-related research at the national laboratories. Burgeoning and often conflicting policies and technology changes will lead to fundamental and largely unpredictable changes in the energy and electricity sector over the next five to 10 years, but with relatively small impact in 2010.

Federal Tax Matters

Many companies in the UPG sector will lower their tax bills for 2009 and 2010 as a result of a host of economic stimulus tax provisions. Tax credits for investments in renewable energy and extended tax loss carry-backs will temporarily turn the tax return into a profit center for several companies in the sector.

The American Recovery and Reinvestment Act of 2009 (ARRA), an economic stimulus package, extended and expanded tax benefits available to specific project investments, particularly for various renewable energy technologies:

- **Renewable Energy Production Tax Credits (PTC):** ARRA extended eligibility dates of a tax credit for facilities producing electricity from wind, biomass, geothermal energy, municipal solid waste, and qualified hydropower and marine renewable energy. The "placed in service date" for wind facilities was extended to Dec. 31, 2012, and for the other types of facilities to Dec. 31, 2013.
- **Election of Investment Tax Credits in Lieu of PTC:** Businesses that place in service facilities that produce electricity from wind and some other renewable resources can choose either the energy investment tax credit (generally a 30% tax credit for investments in energy projects) or the PTC, which provides a credit per kWh for electricity produced from renewable sources. A business may not claim both credits for the same facility. A taxpayer electing the ITC in lieu of PTC receives a cash payment 60 days after achieving the commercial operation date.
- **Bonus Depreciation:** Businesses can deduct half the adjusted basis of qualifying property in the year it is placed in service. The extension applies to qualifying property placed in service in 2009 (2010 for long production period property and certain transportation property).

Net operating loss (NOL) carry-back was extended for a maximum carry-back of 5 years rather than the normal two-year period applicable to nearly all companies, except for recipients of TARP relief, as a provision of the Homeownership and Business Assistance Act of 2009 (November 2009). The carry-back can be applied to NOLs generated in either 2008 or 2009 but not for both years. The effect is an immediate increase in available cash for the taxpayer.

Meanwhile, the prior administration's dividend tax cut is scheduled to expire at the end of 2010, and there is wide speculation that additional taxes or higher tax rates will be applied to fund the federal deficit, including eliminating the current favorable treatment of capital gains and dividend income. Given the sector's heavy capex requirements, Fitch would consider any such changes in federal income and capital gains tax rates to be unfavorable developments that would likely lower equity valuations of regulated utilities and utility holding companies.

Pension Funding

Many companies that entered 2009 with severe erosion in the value of their pension funds relative to projected benefit obligations opted to make cash contributions to comply with the U.S. Pension Protection Act of 2006, as moderated by the Worker, Retiree, and Employer Recovery Act of 2008. Cash contributions in 2009, combined with the recovery in bond and stock market values, have reduced the gap, but a number of companies will need to continue cash contributions in 2010 (absent a significant run-up in market values of investments).

Bankruptcy and Restructuring

There were no notable defaults or bankruptcy filings in the UPG sector in 2009. That stands in sharp contrast to the upswing in defaults and bankruptcy filings in other corporate sectors as a result of the severe national and global recession. A peak default period in the UPG sector was from 2001–2003.

SemGroup restructured and emerged from bankruptcy as a new public company in early December 2009, approximately 16 months after the company and its major wholly owned subsidiaries filed a bankruptcy petition on July 22, 2008. Pre-petition lenders were estimated to recover 100% on some secured obligations and secured trading exposures, an estimated 55% on one secured working capital loan facility, and 75% on a secured revolving credit. Unsecured lenders and general creditors were estimated to recover 5% to 10% of their exposure via the allocation of 5% of the equity in the new public company to the unsecured class.

SemGroup's 2008 insolvency resulted from its inability to post required margin collateral to trading counterparties. The company adopted a trading strategy based on the sale of naked call and put options that did not adhere to the SemGroup risk management policy and violated the terms of its pre-petition credit agreement. When SemGroup experienced trading losses, it increased and rolled forward its options positions, causing increased losses and occasioning growing demands for margin collateral that the company could not satisfy.

Utility Parent Companies

2010 Outlook — Stable
Longer-Term Outlook — Negative

The utility parent companies (UPCs) are poised for an improved economic and financial environment as compared to that of a year ago. With economic activity picking up, industrial sales have shown signs of stabilization in the third quarter. As industrial sales recover, it is likely that the commercial sales, which have been weak in certain regions, could follow suit. However, with revenue growth rates well below historical levels, Fitch expects UPCs to continue their cost-cutting focus in both their regulated and unregulated businesses to drive earnings and cash flow growth or support stability.

UPCs have withstood the credit crisis well. Overall, the companies were in a financially sound situation before the credit crisis hit, and liquidity during 2009 was bolstered by reduced working capital needs due to falling commodity prices, reduction in discretionary capex, and capital market issuances. Access to capital markets remains open and relatively low cost for creditworthy borrowers. Fitch expects UPCs to extend their conservative balance sheet stance in 2010, given the current fragile nature of economy and recovering credit markets, combined with the stated intentions of most management teams to maintain a stable credit profile. For regulated businesses, Fitch expects the utility parent companies to use a judicious mix of debt and equity to finance high levels of planned investments, most of which is mandated and earmarked for reliability, environment compliance, and renewable energy projects. For unregulated businesses, UPCs will need to balance the capital structure against rising business risk due to lower cash flows brought on by a fall in commodity prices and increasing proportion of unhedged output in the outer years.

Fitch expects climate change to remain a predominant focus for most UPCs despite the uncertainty around the contents and timing of passage of a national law. While some UPCs have been more proactive than others, Fitch expects more and more companies to pursue low/zero carbon technologies more aggressively than before. This could be manifested in both regulated and unregulated businesses investing a greater proportion of total capex in clean technologies and renewable generation as well as associated transmission, energy efficiency, and smart grid investments, and in retirements of older coal-fired power plants that cannot be economically retrofitted.

Parents of utilities are generally taking advantage of opportunities to invest in regulated rate base, driven by legislative/regulatory mandates as well as a strategic pursuit of cleaner technologies as highlighted above. Fitch expects UPCs to seek out those investment opportunities where prospects of cost recovery are high and the prospect is for a reasonable return on equity (ROE).

As of late November 2009, utility stocks as measured by the Philadelphia Utility Index (UTY) have declined 3% in 2009 and underperformed the S&P 500 by 18%. The increase in risk appetite among investors clearly worked against the defensive utility sector as signs of economic recovery emerged. Utility stocks that have a greater proportion of unregulated businesses have lagged their regulated peers due to a sharp fall in commodity prices. The sunset of reduced dividend tax rates on Dec. 31, 2010 further reduces the investment appeal of utility equity and is expected to increase the cost of equity capital.

Notwithstanding the turmoil in the economy and the adverse capital market conditions, especially in the early part of 2009, ratings in the UPC sector have remained generally stable. The UPC's median 'BBB' issuer default rating (IDR) and senior unsecured ratings are the same as a year ago. Year to date, there have been three upgrades and seven downgrades in the sector. Approximately 82% (37 of 45 observed companies) of Fitch's UPC issuers have Stable Rating Outlooks and 16% (seven of 45) have Negative Outlooks, while only 2% (one of 45) has a Positive Outlook.

Sector downgrades in 2009 reflect a challenging operating and financial environment due to both weak industrial sales and rising operating costs (NISource Inc.; IDR 'BBB–'/Stable), financial pressure, and associated execution risk from plans to build new nuclear plants (SCANA Corp.; IDR 'BBB+'/Stable), weak commodity prices, and lower profitability of the unregulated generation portfolio (PEPCO Holdings Inc.; 'BBB'/Negative), and reassessment of financial and liquidity risk (Constellation Energy Group, Inc. (CEG); 'BBB–'/Stable) among others. Fitch upgraded only three IDRs of parent holding companies in 2009. Two reflected gradually improved financial ratios and favorable state regulatory developments (Avista Corp.; IDR 'BBB–'/Stable and DPL Inc.; IDR 'A–'/Stable), and one resulted from demonstration of support by a foreign parent (Energy East Corp.; IDR 'BBB+'/Stable).

Ratings are not anticipated to change meaningfully in 2010. Fitch expects the overall ratings for the UPCs to be stable primarily due to modestly rising economic activity, and managements' relatively conservative financial and business strategies. Concerns would be a fall in economic activity and power demand, an increase in populist regulatory decisions, volatile commodity prices, adverse climate change mandates, and shareholder-friendly decisions that result in increased leverage.

Mergers, Acquisitions, and Divestitures

Fitch expects limited merger & acquisition (M&A) activity in the near term given uncertainties that remain around economic recovery, commodity prices, state regulatory responses, and carbon legislation, combined with the high costs of bank financing and relatively low equity valuations. Exelon Corporation's (EXC) failed bid to acquire NRG Energy, Inc. (NRG) in 2009 highlights the difficulty in pulling off a hostile deal. The ongoing delay for Entergy Corp.'s spinoff of Enexus is reflective of the difficult state regulatory environment related to M&A activities. Electricité de France's investment in a 49.99% joint venture interest in Constellation Energy Group's nuclear fleet was consummated late in 2009, after a controversial state regulatory proceeding that highlighted the regulatory hazards of merger/divestiture activity. That said, the case for industry consolidation remains strong given the fragmented industry, the scale of capital investments needed relative to the size of the companies, and the potential for operational synergies to drive down rates for consumers.

Fitch expects a majority of the UPCs to focus on organic growth, especially as regulated businesses take advantage of the attractive incentives for renewables and transmission development to drive rate base growth. As demands on capital increase, some UPCs could shed non-core assets, including businesses that are collateral intensive.

On the unregulated generation side, while there are good arguments for consolidation of smaller gencos, we see greater potential for asset acquisitions given low valuations. This could be driven by unregulated generators seeking "tuck-in" acquisitions or utilities short of generation seeking to grow their rate base. An emerging trend seems to be for unregulated generators to acquire renewable assets, such as the recent announcements by NRG to acquire an offshore wind developer and a solar farm in California and CEG to purchase wind assets in Maryland. It is quite possible that different forms of partnerships develop between traditional utility companies and the new generation clean technology companies to exploit relative strengths. Finally, a weaker dollar could spur cross-border asset acquisitions by foreign buyers or joint venture investments with foreign participants. Notable recent announcements of cross-border partnerships are AES Corporation selling a 15% stake to China Investment Corporation and Duke Energy signing agreements with several Chinese companies to develop a variety of renewable and clean energy technologies.

Electric Utilities

2010 Outlook — Stable
Longer-Term Outlook — Stable to Negative

Fitch's near-term outlook for the utility sector is stable, despite some challenges. The combination of high capital expenditures and relatively weak electricity demand will continue to pressure credit quality and require base rate increases in 2010 and beyond. Favorably, most regulated utilities are entering 2010 on sound financial footing. Moreover, overall rate pressures are mitigated by low fuel prices, strong capital market access, and low interest rates. Fitch's stable outlook assumes most states will continue the constructive regulation of recent years. However, given the lingering rate of unemployment and voter concerns about the economy, there could well be pockets of adverse rate decisions, and those companies with little financial cushion could suffer adverse effects.

Regulation

Decisions by state regulators will continue to be a key driver of individual company credit ratings in 2010. In general, state regulation is likely to continue to be even-handed; however, there could be isolated cases of adverse regulatory or politically motivated decisions on utility rates in an election year, which is considered to be event risk rather than a sector trend. Positively, low fuel costs should largely offset the impact of rising base rates in 2010. However, even with modest electricity demand growth next year, total customer demand is expected to remain below 2007 levels, and under-earning seems likely, even in the case of some companies that have base rate cases decided in 2009 and 2010. Some of the rate requests filed in late 2008 or early 2009 and still pending were made prior to the recognition of the full impact of recessionary load loss on demand; consequently, utilities are already playing catch up by seeking ways to cut operating costs and/or defer capex.

Numerous electric utilities have filed for base rate increases to recover costs of investments in system growth and reliability, as well as to adjust the allocation of operating and maintenance costs and capital recovery to lower demand levels. In addition, a number of multi-year rate settlement periods will end, enabling these utilities to deal with the rising costs and loss of load. Numerous state commissions are expected to reach decisions on new base rates in 2010. (*See the "Electric Rate Case Pending 2010 Decision" table below.*)

Electric Rate Cases Pending 2010 Decision

Arizona Public Service Company	Indiana Michigan Power Company
Atlantic City Electric Company	Monongahela Power Company
Black Hills Power, Inc.	New York State Electric & Gas Corp.
Central Hudson Gas & Electric Corp.	Northwestern Corporation
Connecticut Light and Power Co.	PacifiCorp
Consolidated Edison Co. of New York[a]	Potomac Edison
Delmarva Power & Light Co.	Potomac Electric Power Company
Duke Energy North Carolina	Public Service Co. of New Hampshire
Empire District Electric Company (MO and AK)	Public Service Electric and Gas Co.
Florida Power and Light Co.	Rochester Gas and Electric Corp.
Florida Power Corp.	Southwestern Electric Power Company (AK and TX)
Georgia Power Company	Union Electric Co.
Illinois Power Company	Western Massachusetts Electric Co.

[a]A settlement proposal is pending.
Source: C Three Regulatory Database, Fitch Ratings.

An emerging regulatory trend for integrated electric utilities is the initiation of electricity revenue decoupling in response to the recent softness of demand and state policies that include ambitious energy-efficiency targets. Tariff mechanisms that mitigate the effect of variances in sales are common among gas utilities, which have experienced declining demand for many years and whose sales have an extreme weather sensitivity; in gas distributors, this may take the form of minimum bills that recover a large part of fixed costs, fixed/variable tariff components, or explicit weather normalization or volume decoupling mechanisms. While such tariffs have not been common for residential consumers of electric utilities, Fitch sees states beginning to implement some mechanisms of this sort on the electric side, although in a few cases at a pilot scale. States that allow or initiated electric decoupling programs include: California; Ohio (Ohio utilities can request decoupling under existing rules), Vermont, New York (Consolidated Edison of NY, Orange & Rockland Utilities, Central Hudson Gas and Electric), Maryland (Baltimore Gas & Electric); and pilot scale programs in Wisconsin and Idaho. In Fitch's view, volume decoupling reduces cash flow volatility and lowers business risk, and will be particularly meaningful in states that have set aggressive energy reduction goals.

For electric T&D utilities in states that restructured their electricity markets, staggered power auctions or other competitive power procurement processes are becoming more customary and standard. Staggered contracts for up to three years create realized prices that are a blend of past and future prices, which moderates single-year commodity price volatility for customers. Most states that deregulated generation supply have already completed or are nearing completion of full transition to market-based generation rates. Solicitations for energy, capacity, and/or other services in the next six months are expected to include Duquesne, Metropolitan Edison/Penelec, Penn Power, PPL Electric Delivery, Philadelphia Electric Co., Illinois Power Agency, West

Penn Power, and the New Jersey Basic Generation Service auctions for the state's electricity utilities. While in prior years' outlooks, Fitch noted significant uncertainty regarding the ability of electric T&D utilities to obtain full and timely pass-through of generation costs in tariffs, this risk has subsided as auctions that place the price risk with consumers have become routine; the significant decline in wholesale market power prices has also helped to make the transition less controversial than in prior years.

Capital Spending

While many utilities responded to the economic downturn and court decisions that set aside the CAIR and CAMR by reducing or deferring capital spending budgets for 2009 and 2010, capital spending remains high relative to historical trends. In many cases, utility managements responded to weak demand by adjusting budgeted expenditures to accommodate lower demand curves and deferring, but not cancelling, new generation projects; however, projects to enhance distribution reliability generally were not delayed. Despite these deferrals, Fitch forecasts spending will continue to run at more than double depreciation on average. To fund the system investments, internal cash flow will need to be supplemented with external capital, and management will face choices of increasing leverage or shoring up the capital structure with new equity issuance.

Drivers of 2010 capital spending levels for electric utilities include: increasing environmental compliance mandates; new transmission lines needed to serve intermittent renewable power sources located far from load, reduce basis differentials within regional transmission organizations (RTO), or improve system reliability; advanced metering; and self-building for renewables mandates. Fitch notes that for integrated utilities with responsibility for generation as well as power distribution, 2009 capital spending averaged approximately 2.7x depreciation of existing assets, while for restructured electric T&D utilities, capex averaged a more manageable 1.5x depreciation charges (see the "Capital Spending Relative to Depreciation Charges" table on page 6). Fitch notes that utilities have good track records for full and timely recovery of environmental spending and that recovery of the transmission investments is often supported by RTO orders to build and constructive Federal Energy Regulatory Commission (FERC) tariffs, which are both significant spending categories for 2010.

Fitch believes capital investments will remain elevated for several years. Global climate change and GHG legislation is going to present enormous challenges to the industry over the intermediate to longer term, as utilities consider their options to comply with anticipated reductions in emissions, such as carbon capture and sequestration, integrated gasification combined-cycle power generation (IGCC), up-rates of existing nuclear plants or new-build nuclear, or renewable energy resources (27 states, and counting, have enacted RPS standards). While the low gas price environment makes power generation with natural gas an easy choice for near-term capacity needs and to back up intermittent wind or solar power, utility managements and state regulators are leery of renewed gas price volatility if eventually the oversupply of natural gas should self-correct. Moreover, gas is not a carbon-free choice, and longer term carbon goals under a national energy bill would not be met if load growth is mainly met through gas-fired capacity additions. Uncertainty about what to build and when is exacerbated by unknown impacts of energy efficiency and electric car efforts, and when pressures on customer bills from carbon allowances will ramp up to a meaningful level. The rating impact of these longer-term developments will be case by case, based on legislative and regulatory integrated resource plans and cost recovery decisions. For example, Ohio passed a law requiring future costs of carbon laws to be passed through to customers in the fuel adjustment mechanism, an encouraging sign for the credit of integrated electric utilities in the state.

Natural Gas Distributors

2010 Outlook — Stable
Longer-Term Outlook — Stable

Fitch's 2010 outlook for local gas distribution companies (LDCs) remains stable with expectations for continued operating, regulatory, and financial stability within the space in the long term. Natural gas prices have moderated as the quantity of gas in storage has hit historic highs heading into the 2009–2010 winter heating season. This will mean lower rates for consumers, alleviating some concern regarding rising bad debt expense given high unemployment and weakness in the economy. Additionally, state regulatory relations continue to be constructive for gas LDCs; many LDCs continue to successfully pursue progressive rate design crafted to stabilize financial exposure to changes in volumes sold.

Overall, gas LDCs weathered last year's capital market turmoil maintaining liquidity and access to capital markets. Gas prices were well off their mid-2008 highs by the start of the 2008–2009 heating season, and LDCs had delayed building inventory. Also, Fitch's concerns about increased bad debt expense in 2009 did not meaningfully materialize. Sales growth for the sector slowed significantly as the recessionary economy and a weak housing market slowed customer growth across the board. Continued weakness in the housing sector will constrain demand throughout 2010. Sales volumes have also been affected by a significant decline in industrial demand, particularly in the U.S. Midwest.

Fitch expects that moderate economic growth should help return industrial demand to more normalized levels in the second half of 2010. As a result of slower growth and slackened demand, LDC capital expenditures are expected to be focused on system maintenance rather than expansion and should remain fairly low (averaging approximately 1.5x depreciation charges), so there is not a need for significant external funding. The relatively low capital spending, coupled with lower rates charged to consumers via purchased gas cost adjustment mechanisms, will reduce the chance for any potential rate shock to customers and limit LDC exposure to adverse regulatory developments. Additionally, competitive energy sources, including fuel oil and propane, are correlated to crude oil prices and thus remain priced well above natural gas, limiting the potential for fuel-switching during 2010.

Conservation and the impact of weather on usage remain industry-wide concerns for natural gas LDCs, many of which have pursued rate designs in their regulatory jurisdictions intended to help address usage volatility. Currently, 18 states have approved the implementation of revenue decoupling, which helps prevent margin erosion stemming from declines in customer usage due to conservation or energy-efficiency increases. Additionally, more than half of U.S. states have some form of either full decoupling or weather normalization, which helps stabilize revenues from the effects of weather. These rate designs help insulate the utility's cash flow from changes in volume of sales, providing earnings and cash flow consistency and stability. Fitch continues to view the implementation of rate mechanisms that reduce cash flow volatility favorably; more predictable cash flow translates to lower business risk for LDCs.

Competitive Generation Companies

2010 Outlook — Negative
Longer-Term Outlook — Stable

Fitch's 2010 outlook for competitive generation companies is negative, as continued demand and price weakness will weigh on cash flow and credit metrics. Fitch typically views the competitive generators in two distinct subgroups: affiliated generators, which are subsidiaries of large utility holding companies or financial institutions and typically have investment-grade IDRs; and independent generators, which are standalone companies that typically have speculative-grade IDRs. Fitch's 2010 outlook is negative for both subgroups. Fitch expects that continued power price weakness, slack demand, and uncertainty surrounding carbon legislation will all weigh on the credit outlook for the competitive generating space throughout 2010. Fitch believes that earnings and cash flow, while likely improved over 2009 results, will continue to be muted, barring any significant recovery in commodity prices or industrial demand.

Last year proved to be a challenging environment for competitive generators across the spectrum. Lower demand and wholesale power prices pressured earnings and cash flow, particularly for some of the more highly levered independent generators, who in some cases were forced to sell assets, pay down some debt, and amend credit facility covenants. Dynegy Inc., for example, amended the covenants under it secured credit agreement and announced an agreement with LS Power to sell assets in exchange for cash and LS Power's class B units in Dynegy. These moves precipitated a negative rating action by Fitch in August when the transaction was announced. Negative rating and Outlook actions, in fact, were prevalent for many of the independent generators and affiliated generators under Fitch coverage, with a downgrade to Dynegy Inc. (DYN; IDR: 'B–'/Negative Outlook) and Outlook changes to Ameren Energy Generating Co. (IDR: 'BBB+'/Negative Outlook), Brookfield Renewable Power (BRPI; IDR 'BBB–'/Negative Outlook), Edison Mission Energy (EME; IDR: 'BB–'/Rating Watch Negative), Midwest Generation (IDR: 'BB'/Rating Watch Negative), RRI Energy (RRI; IDR 'B'/Negative Outlook) and Texas Competitive Electric Holdings (TCEH; IDR: 'B'/Negative Outlook).

Despite the discouraging fundamentals for this business segment, Fitch believes that the competitive generators have taken steps that will tend to mitigate further downside should wholesale power prices continue to languish through the year. The independent generators, in particular, have focused on cutting operating costs and hedging or contracting significant amounts of their expected generation for 2010 and 2011, actions that some of the companies had not previously taken in a more robust wholesale power pricing environment. Liquidity across the space remains adequate with most companies possessing sizable cash balances and revolver availability. Fitch also notes that despite declines in value from the peak in early 2009, enterprise valuations for most power generators are strong relative to outstanding indebtedness, which would lead to strong recoveries for secured debt for all but the most highly leveraged competitive generator issuers in a case of default.

Capital spending will remain muted as generators continue to take a conservative approach to growth spending, and environmental spending is delayed given the uncertainty surrounding carbon legislation and absent new mercury and sulfur dioxide rules. Notable exceptions include NRG, which continues to pursue its Repowering NRG capex program and has recently been an active investor in renewable resources; TCEH, which is in the process of completing the third of three large baseload power plants; and Exelon Generation Co., which is pursuing a large-scale nuclear up-rate program. Additionally, Fitch sees the potential for opportunistic asset sales and acquisitions, as more highly leveraged generators look to shore up balance sheets or more stable names look to grow and diversify their portfolios. With equity prices not reflecting the value of underlying assets, Fitch continues to believe there is a compelling argument for consolidation and acquisition within the space.

Longer term, looming carbon legislation remains a key operating and credit issue for the competitive generating space. The financial impact could be significant depending on the individual company's generation portfolio, as well as the specific form and cost assigned to emissions under proposed legislation and the direction of commodity prices. While the impacts of carbon legislation will vary for individual companies and in different power regions, it is reasonable to assume that less-efficient coal-fired generation will begin to be displaced first by gas-fired generation and, in the longer term by renewable projects, new nuclear, and potentially by carbon capture and sequestration clean coal technology (should that technology prove to be economically viable). Emission-free competitive generators with low variable-costs will be the biggest beneficiaries of carbon legislation. More-efficient natural gas-fired competitive generators are likely to see their generation dispatched more frequently as well.

Longer-term concerns include debt, credit facility, and term loan B maturities in the 2013–2016 timeframe; the roll off of current hedges; and the ability of competitive generators to recontract expected generation at levels that would support ratings. Debt maturities in 2010 are manageable, as most issuers do not face any significant refinancing. Additionally, with capital markets returning to a more normal pattern, access to capital should be open. However, particularly for the speculative-grade independent generators, capital will likely be significantly more expensive than prior to the financial crisis, reflecting changes in the bank market conditions, higher financing costs and weak equity valuations.

Public Power Utilities

2010 Outlook — Stable
Longer-Term Outlook — Stable to Negative

Fitch's Public Power and Electric Cooperative 2010 Outlook — Stable

Fitch's 2010 outlook for the public power and electric cooperative sectors continues to be stable despite the pressures that correspond with the national economic recession. After a rocky first half of 2009, capital market access has stabilized. However, there appears to be a lagging ripple-effect from the economic downturn that is working its way through local governments and creating downward rate pressure on public power utility systems that will persist well into 2010. Other credit pressures on the sector include: declining energy consumption related to the economic downturn, the need for rate increases in a difficult economic climate, limited/costly access to external liquidity, and state specific mandates — with the potential for federal mandates in 2010–2011 — regarding renewable energy sources and GHG emissions.

These pressures coincide with declines in natural gas and purchased power prices that have reduced the expenditure levels and provided some relief to many retail utilities. However, a softening of power market prices has resulted in lower-than-budgeted revenues from surplus power sales for several utilities. Growth levels have favorably slowed to more manageable levels in certain regions, providing an opportunity to adjust and re-evaluate system capital needs. While these current trends have not resulted in significant changes to the credit quality of the overall public power and electric cooperative sectors, Fitch intends to monitor variations specific to regions. Fitch notes that events in the next five to 10 years primarily related to expected environmental legislation could increase the cost structures of many electric utilities and potentially place pressure on credit ratings. Decisions regarding timely rate recovery of increased costs and the subsequent change in a utility's competitive position within its regional market will be key credit drivers. Fitch believes that the public power business model will continue to allow these utilities to perform well in 2010 and provide investors with a generally stable credit sector. Fitch's outlook for the sectors over the long term remains stable yet recognizes that increasing negative pressures are affecting the industry, primarily due to environmental mandates related to increased renewable energy resource requirements and GHG emissions restrictions. The possibility of carbon legislation being enacted looms over the public power industry and the specter of the proposed legislation is already impacting decisions on whether to build additional fossil-fuel baseload generation.

Short-Term Public Power Outlook

While there have been noticeable downward trends in financial metrics such as debt service coverage, cash-on-hand, and operating margins for both wholesale and retail public power systems, overall the sectors continue to benefit from solid credit fundamentals, including: essentiality of electric service, local control over rate-setting without state commission oversight, a cost advantage compared to neighboring investor-owned utilities, and benefits associated with a predominantly residential and commercial customer bases. Fitch expects that the average ratings for wholesale and retail utility systems, including electric cooperatives, will continue to be 'A' and 'A+', respectively. Fitch has noted in certain regions an increase in efforts by local governments to slow electric rate increases and boost transfers from the utility system to replace lower tax revenues and to fund the growing local government pension obligations. If unchecked, this trend could result in public power utilities with reduced liquidity and credit protection.

While varying in degree from region to region, overall the economic downturn and financial market disruptions have not yet resulted in material credit pressure on public power utilities. Public power and electric cooperatives have continued to have access to the capital markets, although borrowing costs have been higher than budgeted. Construction costs have declined and, in some cases, capital spending has been delayed. Generation investment is continuing, albeit at a slower pace, both through direct ownership and long-term bilateral contracts. Supply-related investments have been designed not only to meet load growth but increasingly to comply with local and state renewable resource requirements. Many utilities continue to realign their debt structure by reducing outstanding variable-rate exposure, given the disruptions in that market and the contraction/costliness in available liquidity facilities.

The economic contraction in many markets resulted in slower growth levels and consumption declines. Collection delinquencies and turn-off actions have increased only slightly despite the negative economic conditions, rising unemployment levels, and home foreclosures. Public power and electric cooperative utilities that are commodity purchasers have benefited from the recent decline in natural gas and wholesale power prices. However, several utilities that typically sell excess power into these markets have experienced lower-than-budgeted revenues from surplus sales, but many have maintained their financial margins through the use of conservative forecasting and budgeting practices, given the volatility of these revenue sources.

Long-Term Public Power Outlook

Fitch's long-term outlook for the sectors is stable but recognizes increasing negative credit pressures. Approval of national environmental mandates is still pending; however many utilities already face pressure from state or locally established renewable portfolio standards and must assess how to meet long-term load growth within an evolving environmental and generally more restrictive and costly regulatory framework. The growing pressure to enact carbon emissions restrictions to combat global climate change is expected to result in the enactment of national carbon legislation in the near future, but the structure, timing, and implementation schedule is still uncertain. Utilities, however, are already making decisions based on the anticipated legislation. Several large, baseload coal-fired power plants have been cancelled, and some of this planned future capacity is being replaced by natural gas and renewable generation. To the extent public power utilities rely mainly on natural gas-fired resources going forward, Fitch believes there could be a renewed risk of over-reliance on natural gas and the associated volatile fuel price exposure.

While Fitch believes that the public power and electric cooperative business models will continue to allow these utilities to perform well and prove to be stable credit sectors, increasingly negative market and industry factors could adversely impact some regions more than others. The utilities with greater credit exposure are those that have large capital improvement needs, relatively high leverage, below-average financial and rate flexibility, and a heavy reliance on fossil fuel generation. Conversely, systems that show stable to improving financial metrics, have limited new capital needs, and have a greener generation portfolio are expected to maintain Stable Outlooks and in some cases realize improved credit profiles.

Pipeline and Midstream Sector

Companies in the Pipeline/Midstream segment in 2009 faced the following pressing concerns: adequacy of liquidity, access to capital markets, the oncoming recession and its effects on demand for energy products, ability to defer capital spending, and commodity price trends. In response to these difficult operating conditions, companies overwhelming "played defense" and adopted cautious financial practices. In the face of a weakening economy and constrained capital markets, companies issued high-cost debt and equity to shore up their liquidity positions. Discretionary spending was cut to sustainable levels. Many MLPs adopted more conservative distribution practices to increase cash retention.

Entering 2010, business fundamentals are better than they were six or 12 months ago, but many challenges remain. Growth has slowed. Several large pipeline projects, burdened by increased construction and capital costs, will generate lower-than-expected, single-digit returns. The economy remains fragile. Given this backdrop, Fitch expects companies to stay the course by avoiding excess leverage and maintaining disciplined operating and growth strategies.

Natural Gas Pipelines

2010 Outlook — Stable
Longer-Term Outlook— Stable

Fitch foresees stable short-term and longer-term outlooks for interstate and intrastate natural gas pipelines. However, credit measures for companies funding large expansion projects will likely remain under pressure through 2010.

During 2008, completions of new natural gas pipelines and expansions of existing pipelines in the U.S represented the greatest amount of pipeline construction in more than 10 years. The added capacity for each of the top 15 projects exceeded 1 billion cubic feet per day (Bcf/d). The U.S. Energy Information Administration (EIA) reports that the number of proposed projects suggests construction activity will remain strong through 2011, with 2009 potentially showing the second-highest level of capacity additions in the decade. More than 10,200 miles of potential new gas pipelines are scheduled to be added in 2009–2011, but a portion of these projects will likely be delayed or canceled.

Even with cuts in discretionary spending by sponsor companies, weak commodity prices, and a slowly recovering economy, there is still a demand for new pipeline infrastructure to access unconventional resources, particularly natural gas from shale formations. Additionally, the costs of steel pipe, equipment, labor, and financing have declined from 2008–2009 highs, which will help companies attain adequate returns on their investments.

New North American Pipeline Capacity

	Proposed for 2010			Proposed for 2011		
	Added Capacity (MMcf/d)	Estimated Cost ($ Mil.)	Miles	Added Capacity (MMcf/d)	Estimated Cost ($ Mil.)	Miles
Central	3,655	1,820	871	1,528	491	290
Midwest	0	0	0	2,067	1,416	254
Northeast	2,491	1,276	249	4,318	2,465	599
Southeast	9,911	2,006	601	9,364	3,748	1,000
Southwest	6,283	577	293	13,915	2,162	688
Western	345	107	27	5,276	5,377	1,686
Mexico/Canada	1,920	N.A.	29	980	49	41
Total	**24,605**	**5,786**	**2,070**	**37,448**	**15,707**	**4,528**

N.A. – Not available.
Source: Energy Information Administration.

Products Pipelines

2010 Outlook — Stable
Longer Term — Stable

The pace of the economic recovery will affect demand for oil products and transportation volume, affecting crude oil and refined products pipelines. However, following reduced throughput in 2009, Fitch expects product demand to stabilize.

Midstream Services

2010 Outlook — Stable
Longer Term — Stable

For natural gas gatherers, both the short-term and long-term outlooks are stable, while for gas processors the short-term outlook is negative. After several years of high processing margins, in late 2008 natural gas liquids (NGL) unit margins dropped. While margins have recovered back to more historical norms, future commodity margins are uncertain. Financial performance for some companies will also be affected by hedging practices and their economic sensitivity to natural gas prices. Fitch expects natural gas to trade in a relatively low price range, which is unfavorable to most processors. Moreover, in some production basins, price-induced drilling reductions are expected to lower gathering volumes until demand recovers, an adverse trend for both processors and gatherers.

Retail Propane

2010 Outlook — Negative
Longer-Term Outlook— Negative

Fitch maintains a modestly negative short- and long-term outlook for the retail propane sector. Given propane's strong correlation to crude oil prices, Fitch remains concerned that retail propane prices could spike, particularly with a weak dollar, and margins could contract from current levels. Additionally, continued weakness in housing starts and a warmer winter could weigh on volumes sold. If sales volumes show a greater post-recession recovery and product margins hold up, the credit outlook would move toward stable.

For more information on the credit outlook for these businesses, please refer to Fitch's report, "Pipeline/Midstream/MLP 2010 Outlook," published on Dec. 3, 2009.

Appendix: Ratings and Rating Outlooks by Segment

Utility Parent Companies

Company Name	IDR	Rating Outlook	Senior Unsecured Rating
Above Segment Median Rating			
WGL Holdings, Inc.	A+	Stable	A+
FPL Group, Inc.	A	Stable	A
NICOR Inc.	A	Stable	A
OGE Energy Corp.	A	Stable	A
Sempra Energy	A	Stable	A
Southern Company	A	Stable	A
AGL Resources, Inc.	A–	Stable	A–
DPL Inc.	A–	Stable	A–
KeySpan Corporation	A–	Stable	A–
Laclede Group, Inc.(The)	A–	Stable	**NR**
MDU Resources Group, Inc.	A–	Negative	A
National Fuel Gas Company	A–	Stable	A–
NSTAR	A–	Stable	A
Wisconsin Energy Corporation	A–	Negative	A–
Ameren Corporation	BBB+	Stable	BBB+
Consolidated Edison, Inc.	BBB+	Stable	BBB+
Dominion Resources, Inc.	BBB+	Stable	BBB+
Energy East Corporation	BBB+	Stable	**NR**
Exelon Corporation	BBB+	Stable	BBB+
MidAmerican Energy Holdings Co.	BBB+	Stable	BBB+
Public Service Enterprise Group Inc	BBB+	Stable	BBB+
SCANA Corporation	BBB+	Stable	BBB+
Xcel Energy Inc.	BBB+	Stable	BBB+
At Segment Median Rating			
American Electric Power Company	BBB	Stable	BBB
Black Hills Corp.	BBB	Stable	BBB
DTE Energy Company	BBB	Negative	BBB
FirstEnergy Corp.	BBB	Stable	BBB
IDACORP, Inc.	BBB	Negative	**NR**
Northeast Utilities	BBB	Stable	BBB
PEPCO Holdings	BBB	Negative	BBB
PPL Corporation	BBB	Stable	BBB
Progress Energy, Inc	BBB	Stable	BBB
Below Segment Median Rating			
Allegheny Energy, Inc.	BBB–	Stable	BBB–
Avista Corporation	BBB–	Stable	BBB
CenterPoint Energy Inc.	BBB–	Stable	BBB–
CILCORP, Inc.	BBB–	Stable	BBB–
Constellation Energy Group, Inc.	BBB–	Stable	BBB–
Edison International	BBB–	Stable	**NR**
IPALCO Enterprises, Inc.	BBB–	Stable	**BBB–**
NiSource Inc.	BBB–	Stable	BBB
Otter Tail Corporation	BBB–	Stable	BBB–
Pinnacle West Capital Corporation	BBB–	Negative	BBB–
TECO Energy, Inc.	BBB–	Stable	BBB–
CMS Energy Corporation	BB+	Stable	BB+
PSEG Energy Holdings, Inc.	BB+	Stable	BB
PNM Resources	BB	Stable	BB
NV Energy Inc.	BB–	Positive	BB–
Energy Future Holdings Corp.	B	Negative	B
Energy Future Intermediate Holding Company LLC	B	Negative	**B+**

NR – Not rated. Note: Bold indicates senior secured.
Source: Fitch.

Investor-Owned Electric Utilities

Integrated Electric Utilities

Company Name	IDR	Rating Outlook	Senior Unsecured Rating
Above Segment Median Rating			
Mississippi Power Company	A+	Stable	AA–
Oklahoma Gas and Electric Company	A+	Stable	AA–
Alabama Power Company	A	Stable	A+
Dayton Power & Light Company	A	Stable	**AA–**
Florida Power and Light	A	Stable	A+
Georgia Power Company	A	Negative	A+
Wisconsin Electric Power Company	A	Negative	A+
Carolina Power & Light Co.	A–	Stable	A
Florida Power Corp.	A–	Stable	A
Gulf Power Company	A–	Stable	A
MidAmerican Energy Company	A–	Stable	A
Northern States Power Company (MN)	A–	Stable	A
Northern States Power Company (WI)	A–	Stable	A
Pacific Gas and Electric Company	A–	Stable	A
Southern California Edison Company	A–	Stable	A
AEP Texas North Company	BBB+	Stable	A–
Columbus Southern Power Company	BBB+	Stable	A–
Public Service Company of Colorado	BBB+	Stable	A–
South Carolina Electric & Gas Co.	BBB+	Stable	A–
Union Electric Co.	BBB+	Stable	A–
Virginia Electric and Power	BBB+	Stable	A–
At Segment Median Rating			
AEP Texas Central Company	BBB	Negative	BBB+
Black Hills Power, Inc.	BBB	Stable	BBB+
Central Illinois Light Company	BBB	Stable	BBB+
Detroit Edison Company (DECo)	BBB	Stable	A–
Idaho Power Company	BBB	Negative	BBB+
Ohio Power Company	BBB	Stable	BBB+
Otter Tail Power	BBB	Stable	BBB+
PacifiCorp	BBB	Stable	BBB+
Public Service Company of New Hampshire	BBB	Stable	**BBB+**
Public Service Company of Oklahoma	BBB	Stable	BBB+
Southwestern Electric Power Company	BBB	Negative	BBB+
Southwestern Public Service Company	BBB	Stable	BBB+
Tampa Electric Company	BBB	Stable	BBB+
Below Segment Median Rating			
Appalachian Power Company	BBB–	Stable	BBB
Arizona Public Service Company	BBB–	Stable	BBB
Consumers Energy Company	BBB–	Stable	BBB
Empire District Electric Company	BBB–	Negative	BBB
Indiana Michigan Power Company	BBB–	Stable	BBB
Indianapolis Power & Light Company	BBB–	Stable	BBB
Kansas Gas and Electric Company	BBB–	Stable	**BBB+**
Kentucky Power Company	BBB–	Stable	BBB
Monongahela Power Company	BBB–	Stable	BBB–
Northern Indiana Public Service Co.	BBB–	Stable	BBB
Northwestern Corporation	BBB–	Stable	BBB
Westar Energy, Inc.	BBB–	Stable	BBB
Nevada Power Company d/b/a NV Energy	BB	Positive	BB
Public Service Company of New Mexico	BB	Stable	BB+
Sierra Pacific Power Company d/b/a NV Energy	BB	Positive	**BBB–**
Tucson Electric Power Company	BB	Positive	BB+

Note: Bold indicates senior secured. *Continued on next page.*
Source: Fitch.

Investor-Owned Electric Utilities (Continued)

Electric Distribution Companies

Company Name	IDR	Rating Outlook	Senior Unsecured Rating
Above Segment Median Rating			
NSTAR Electric Co.	A+	Stable	AA–
San Diego Gas & Electric Company	A+	Stable	AA–
American Transmission Company	A	Stable	A+
Central Hudson Gas & Electric Corp	A–	Stable	A
Orange and Rockland Utilities, Inc.	A–	Negative	A
Rockland Electric Co.	A–	Negative	**NR**
Consolidated Edison Co. of New York	BBB+	Stable	A–
Delmarva Power & Light	BBB+	Stable	A–
PECO Energy Company	BBB+	Stable	**A**
Potomac Electric Power Company	BBB+	Stable	A–
Public Service Electric and Gas Co.	BBB+	Stable	**A**
At Segment Median Rating			
Atlantic City Electric	BBB	Stable	BBB+
Baltimore Gas and Electric Company	BBB	Stable	BBB+
CenterPoint Energy Houston Electric, LLC	BBB	Stable	BBB+
Connecticut Light and Power Co.	BBB	Stable	BBB+
Jersey Central Power & Light Co.	BBB	Stable	BBB+
New York State Electric & Gas Corp	BBB	Negative	BBB+
PPL Electric Utilities Corporation	BBB	Stable	A–
Western Massachusetts Electric Co.	BBB	Stable	BBB+
Below Segment Median Rating			
Central Illinois Public Service Co.	BBB–	Stable	BBB
Illinois Power Company	BBB–	Stable	BBB
Metropolitan Edison Company	BBB–	Stable	BBB
Ohio Edison Company	BBB–	Stable	BBB
Oncor Electric Delivery Company	BBB–	Stable	BBB–
Pennsylvania Electric Company	BBB–	Stable	BBB
Pennsylvania Power Company	BBB–	Stable	BBB
Potomac Edison Company (The)	BBB–	Stable	**BBB+**
Rochester Gas and Electric Corp	BBB–	Stable	BBB
West Penn Power Company	BBB–	Stable	BBB–
Cleveland Electric Illuminating Co.	BB+	Stable	BBB–
Commonwealth Edison Company	BB+	Stable	BBB–
Texas New Mexico Power Company	BB+	Stable	BBB–
Toledo Edison Company	BB+	Stable	BBB–

NR – Not rated. Note: *Bold indicates senior secured.*
Source: Fitch.

Competitive Generation Companies

Company Name	IDR	Rating Outlook	Senior Unsecured Rating
Above Segment Median Rating			
AmerenEnergy Generating Company	BBB+	Negative	BBB+
Exelon Generation Company, LLC	BBB+	Stable	BBB+
PSEG Power, LLC	BBB+	Stable	BBB+
Southern Power Company	BBB+	Stable	BBB+
FirstEnergy Solutions Corp. (FES)	BBB	Stable	BBB
PPL Energy Supply	BBB	Stable	BBB+
Allegheny Energy Supply Company	BBB–	Stable	BBB–
Allegheny Generating Company	BBB–	Stable	BBB–
Brookfield Renewable Power, Inc.	BBB–	Negative	BBB
Midwest Generation, LLC	BB	RWN	**BBB–**
At Segment Median Rating			
Edison Mission Energy	BB–	RWN	BB–
Mission Energy Holding Co.	BB–	Stable	**BB–**
Below Segment Median Rating			
AES Corporation	B+	Stable	BB
Mirant Americas Generation, LLC	B+	Stable	B
Mirant Corporation	B+	Stable	**NR**
Mirant Mid-Atlantic, LLC	B+	Stable	BB+
Mirant North America, LLC	B+	Stable	BB–
NRG Energy, Inc.	B	RWE	B+
Reliant Energy Inc	B	Negative	B+
Texas Competitive Electric Holdings	B	Negative	B
Dynegy Holdings, Inc.	B–	Negative	B
Dynegy, Inc.	B–	Negative	**NR**

NR – Not rated. RWN – Rating Watch Negative. RWE – Rating Watch Evolving. Note: Bold indicates senior secured.
Source: Fitch.

Pipeline and Midstream Companies

Company Name	IDR	Rating Outlook	Senior Unsecured Rating
Above Segment Median Rating			
Northern Natural Gas Co.	A	Stable	A
Centennial Energy Holdings, Inc.	A–	Negative	A–
LOOP LLC	A–	Stable	A–
EQT Corporation	BBB+	Stable	BBB+
Texas Eastern Transmission, LP	BBB+	Stable	BBB+
Texas Gas Transmission, LLC	BBB+	Stable	BBB+
Boardwalk Pipelines, LLC	BBB	Stable	BBB
CenterPoint Energy Resources Corp.	BBB	Stable	BBB
DCP Midstream LLC	BBB	Stable	BBB
Enogex Inc.	BBB	Stable	BBB
Kinder Morgan Energy Partners, L.P.	BBB	Stable	BBB
Northwest Pipeline Corporation	BBB	Stable	BBB
Rockies Express Pipeline LLC	BBB	Stable	BBB
Transcontinental Gas Pipe Line Corp	BBB	Stable	BBB
At Segment Median Rating			
Colorado Interstate Gas Co.	BBB–	Stable	BBB–
El Paso Natural Gas Co.	BBB–	Stable	BBB–
Energy Transfer Partners, L.P.	BBB–	Stable	BBB–
Enterprise Products Operating, LLC.	BBB–	Stable	BBB–
NGPL PipeCo LLC	BBB–	Stable	BBB–
NPOP (Kaneb Pipe Line Operating Partnership, L.P.)	BBB–	Stable	BBB–
NuStar Logistics, L.P.	BBB–	Stable	BBB–
Panhandle Eastern Pipeline Co.	BBB–	Stable	BBB–
Southern Natural Gas Co.	BBB–	Stable	BBB–
Southern Union Company	BBB–	Stable	BBB–
Tennessee Gas Pipeline Co.	BBB–	Stable	BBB–
TEPPCO Partners L.P.	BBB–	Stable	BBB–
Williams Companies, Inc.	BBB–	Stable	BBB–
Below Segment Median Rating			
AmeriGas Partners, L.P.	BB+	Stable	BB+
El Paso Corp.	BB+	Stable	BB+
El Paso Exploration & Production Co.	BB+	Stable	BB
Kinder Morgan Inc.	BB+	Stable	**BB+**
Williams Partners, LP	BB	Stable	BB
Energy Transfer Equity, L.P.	BB–	Stable	**BB**
Enterprise GP Holdings L.P.	BB–	Stable	**BB**
Star Gas Partners L.P.	B	Stable	BB–

Note: Bold indicates senior secured.
Source: Fitch.

Natural Gas Distribution Companies

Company Name	IDR	Rating Outlook	Senior Unsecured Rating
Above Segment Median Rating			
Southern California Gas Company	A+	Stable	AA–
Washington Gas Light Company	A+	Stable	AA–
Brooklyn Union Gas Co.	A	Stable	A+
Nicor Gas Company	A	Stable	A+
Wisconsin Gas Company, LLC	A	Stable	A+
At Segment Median Rating			
Atlanta Gas Light Co.	A–	Stable	A
Cascade Natural Gas Corporation	A–	Negative	A
KeySpan Gas East Corporation	A–	Stable	A
Laclede Gas Company	A–	Stable	**A+**
NSTAR Gas	A–	Stable	A
UGI Utilities, Inc.	A–	Stable	A
Below Segment Median Rating			
Berkshire Gas Company	BBB+	Stable	A–
Central Maine Power Company	BBB+	Stable	A–
Connecticut Natural Gas	BBB+	Stable	A–
Public Service Company of North Carolina	BBB+	Stable	A–
Atmos Energy Corporation	BBB	Stable	BBB+
Southern Connecticut Gas	BBB	Negative	A–
Southwest Gas Corporation	BBB	Stable	BBB
Michigan Consolidated Gas Company	BBB–	Stable	**BBB+**
Mountaineer Gas Company	BB–	Stable	BB

Note: Bold indicates senior secured.
Source: Fitch.

Public Power Companies — Retail Segment

Company Name	Rating Outlook	Senior Unsecured Rating
Above Median (A+)		
Chelan County Public Utility District No. 1 (Wash.)	Stable	AA+
San Antonio (Texas) (CPS Energy)	Stable	AA+
Chattanooga — Electric Power Board (Tenn.)	Stable	AA
Colorado Springs Utilities	Stable	AA
Grant County Public Utility District No. 2 (Wash.) — Electric System	Stable	AA
Lincoln (Neb.) — Electric System	Stable	AA
Memphis (Tenn.) — Memphis Light, Gas & Water	Stable	AA
Nashville (Tenn.) — Electric System	Stable	AA
Omaha Public Power District (Neb.)	Stable	AA
Orlando Utilities Commission (Fla.)	Stable	AA
Springfield (Mo.) — City Utilities (Electric)	Stable	AA
St. Cloud (Fla.) — Utility System	Stable	AA
Anaheim Public Utilities Department (Calif.)	Negative	AA–
Austin Combined Utility System (Texas)	Stable	AA–
Austin Energy (Texas)	Stable	AA–
Concord (N.C.) Utilities System	Stable	AA–
Hydro-Quebec	Stable	AA–
JEA (Fla.) — Electric	Stable	AA–
Los Angeles Department of Water and Power (Calif.)	Stable	AA–
New Braunfels Utilities (Texas)	Stable	AA–
Pasadena (Calif.) — Water and Power Department	Stable	AA–
Richmond (Va.)	Stable	AA–
Riverside Public Utilities (Calif.)	Stable	AA–
Rochester Public Utilities (Minn.)	Stable	AA–
Snohomish County Public Utility District No. 1 (Wash.)	Stable	AA–
Tallahassee (Fla.) — Energy System	Stable	AA–
At Median (A+)		
Anchorage Municipal Light & Power (Alaska)	Stable	A+
Bryan, Texas Utilities	Stable	A+
California Department of Water Resources	Positive	A+
Dover (Del.)	Stable	A+
Eugene Water and Electric Board (Ore.)	Stable	A+
Farmington (N.M.) Utility System	Stable	A+
Garland Power & Light (Texas)	Stable	A+
Glendale (Calif.) — Water and Power	Stable	A+
Georgetown (Texas)	Stable	A+
Greer (S.C.) — Commission of Public Works	Stable	A+
Imperial Irrigation District (Calif.)	RWN	A+
Jacksonville Beach (Fla.) — Combined Utility System	Stable	A+
Kansas City (Kan.) — Board of Public Utilities	Stable	A+
Kerrville Public Utility Board (Texas)	Stable	A+
Lakeland Energy System (Fla.)	Stable	A+
Muscatine Power & Water (Iowa)	Stable	A+
Ocala (Fla.)	Stable	A+
Pedernales Electric Cooperative, Inc. (Texas)	Stable	A+
Redding (Calif.)	Stable	A+
Roseville Electric System (Calif.)	Stable	A+
Tacoma Power (Wash.)	Stable	A+
Turlock Irrigation District (Calif.)	Stable	A+
Below Median (A+)		
Benton County Public Utility District No. 1 (Wash.)	Stable	A
Brownsville Public Utility Board (Texas)	Stable	A
Bryan, Rural Electric	Stable	A
Floresville (Texas) — Electric Light and Power System	Stable	A
Gallup (N.M.) — Utility System	Stable	A
Granbury (TX)	Negative	A
Grays Harbor County Public Utility District No. 1 (Wash.)	Stable	A
Kissimmee Utility Authority (Fla.)	Stable	A
Modesto Irrigation District (Calif.)	Stable	A

RWN – Rating Watch Negative. *Continued on next page.*
Source: Fitch.

Public Power Companies — Retail Segment (Continued)

Company Name	Rating Outlook	Senior Unsecured Rating
Below Median (A+) (Continued)		
Overton Power District No. 5 (NV)	Stable	A
Paducah (Kent.)	Stable	A
Reedy Creek Improvement District (Fla.)	Stable	A
Sacramento Municipal Utility District (Calif.)	Stable	A
Silicon Valley Power (Calif.)	Stable	A
Vero Beach (Fla.)	Stable	A
Winter Park (Fla.)	Negative	A
Alameda Power & Telecom (Calif.)	Positive	A–
Batavia (Ill.) — Electric Utility	Stable	A–
Boerne Utility System (Texas)	Stable	A–
Chugach Electric Association, Inc. (Alaska)	Stable	A–
Cowlitz CO Public Utility District	Stable	A–
Fort Pierce Utilities (Fla.)	Stable	A–
Klickitat County Public Utility District No. 1 (WA)	Stable	A–
Long Island Power Authority (N.Y.)	Negative	A–
Los Alamos County (N.M.) — Utility System	Stable	A–
Lubbock Power & Light (Texas)	Stable	A–
Pend Oreille County Public Utility District No. 1 (Wash.)	Stable	A–
Seguin (Texas)	Stable	A–
Leesburg (Fla.) — Electric System	Stable	BBB+
Lodi (Calif.) — Electric Utility	Positive	BBB+
Puerto Rico Electric Power Authority	Stable	BBB+
Virgin Islands Water & Power Authority	Negative	BBB
Vermont Electric Cooperative Inc.	Stable	BBB–
Guam Power Authority	Positive	BB+

Source: Fitch.

Public Power Companies — Wholesale Segment

Company Name	Rating Outlook	Senior Unsecured Rating
Above Median (A)		
Tennessee Valley Authority	Stable	AAA
Associated Electric Cooperative Inc. (MO)	Stable	AA
Energy Northwest (Wash) — Bonneville Power Agency	Positive	AA
Grant County Public Utility District No. 2 (Wash.) — Hydro Projects	Stable	AA
New York Power Authority	Stable	AA
Platte River Power Authority (Colo.)	Stable	AA
South Carolina Public Service Authority (Santee Cooper)	Stable	AA
Basin Electric Power Cooperative	Stable	AA–
Intermountain Power Agency (Utah)	Stable	AA–
Western Minnesota Municipal Power Agency	Stable	AA–
Arkansas Electric Cooperative Corp.	Stable	A+
Connecticut Municipal Electric Energy Cooperative	Stable	A+
Florida Municipal Power Authority — All Requirements Project	Stable	A+
Florida Municipal Power Authority — Stanton I	Stable	A+
Florida Municipal Power Authority — Stanton II	Stable	A+
Florida Municipal Power Authority — Tri-City Project	Stable	A+
Illinois Municipal Electric Agency	Stable	A+
Indiana Municipal Power Agency	Stable	A+
Lower Colorado River Authority (Texas)	Stable	A+
Municipal Electric Authority of Georgia (CC/CT Proj)	Stable	A+
Municipal Electric Authority of Georgia (General Res)	Stable	A+
Municipal Electric Authority of Georgia (Project One)	Stable	A+
Municipal Electric Authority of Georgia (Telecom)	Stable	A+
Nebraska Public Power District	Stable	A+
Walnut Energy Center Authority (Calif.)	Stable	A+
Wisconsin Public Power Inc.	Stable	A+
Buckeye Power, Inc (Ohio)	Stable	A+
At Median (A)		
American Municipal Power — Issuer Rating	Stable	A
American Municipal Power-Inc. — Joint Venture No. 5	Stable	A
American Municipal Power-Inc. — Prairie State Project	Stable	A
Berkshire Wind Power Cooperative Corporation (MA)	Stable	A
Brazos Electric Power Cooperative, Inc. (Texas)	Stable	A
Florida Municipal Power Authority — St. Lucie Project	Stable	A
Grand River Dam Authority (Okla.)	Stable	A
Massachusetts Municipal Wholesale Elec Co. (Nuclear Mix No. 1)	Stable	A
Massachusetts Municipal Wholesale Elec Co. (Project 3)	Stable	A
Massachusetts Municipal Wholesale Elec Co. (Project 4)	Stable	A
Massachusetts Municipal Wholesale Elec Co. (Project 5)	Stable	A
Massachusetts Municipal Wholesale Elec Co. (Project 6)	Stable	A
Massachusetts Municipal Wholesale Elec Co. (Stoney Brook Intermediate)	Stable	A
Massachusetts Municipal Wholesale Elec Co. (Wyman)	Stable	A
Missouri Joint Municipal Electric Utility Commission (Iatan 2 Project)	Stable	A
M-S-R Public Power Agency (Calif.)	Stable	A
Municipal Energy Agency of Nebraska	Stable	A
North Carolina Municipal Power Agency No. 1	Stable	A
Northern California Power Authority — Geothermal Project	Stable	A
Northern California Power Authority — Hydroelectric Project	Stable	A
Oglethorpe Power Co. (Ga.)	Stable	A
Oglethorpe Power Co. (Ga.) — Scherer Facilities	Stable	A
Old Dominion Electric Cooperative (Va.)	Stable	A
Texas Municipal Power Agency	Stable	A
Tri-State Generation & Transmission Association, Inc. (Colo.)	Stable	A
Below Median (A)		
American Municipal Power-Inc. — Joint Venture No. 2	Stable	A–
Central Iowa Power Cooperative	Stable	A–
Delaware Municipal Electric Cooperative	Stable	A–
Energy Northwest (Wash.) — Wind Project	Stable	A–
Golden Spread Electric Cooperative, Inc. (Texas)	Stable	A–
Great River Energy (MN)	Stable	A–
Missouri Joint Municipal Electric Utility Commission (Plum Point Project)	Stable	A–
Missouri Joint Municipal Electric Utility Commission (Prairie State Project)	Stable	A–
Northern Illinois Municipal Power Agency	Stable	A–
PowerSouth Energy Cooperative, Inc.	Stable	A–
South Texas Electric Cooperative	Stable	A–

Continued on next page.
Source: Fitch.

Public Power Companies — Wholesale Segment (Continued)

Company Name	Rating Outlook	Senior Unsecured Rating
Wholesale Segment — Below Median (A) (Continued)		
Western Farmers Electric Cooperative (Okla.)	Negative	A–
Central Valley Financing Authority (Calif.)	Stable	BBB+
North Carolina Eastern Municipal Power Agency	Positive	BBB+
Piedmont Municipal Power Agency (S.C.)	Stable	BBB+
Sacramento Cogeneration Authority (Calif.) — P&G Project	Stable	BBB+
Sacramento Power Authority (Calif.) — Campbell Project	Stable	BBB+
Sacramento Municipal Utility District Financing Authority (Calif.) — Cosumnes Project	Stable	BBB
Big Rivers Electric Corporation (Kent.)	Stable	BBB–
Sam Rayburn Municipal Power Agency (Texas)	Stable	BBB–

Source: Fitch.

Annual Outlook

U.S. Electric Utilities Face Challenges Beyond Near-Term

Table of Contents:

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The outlook for the U.S. investor-owned electric utility sector is stable. This outlook expresses Moody's expectations for the fundamental credit conditions in the industry over the next 12 to 18 months.

- The U.S. investor-owned electric utility sector is well positioned within investment-grade range, and its business fundamentals should remain intact over the near term.
- The U.S. regulatory structure continues to benefit the sector with recovery assurances for operating costs and capital investments—translating into roughly a three-notch "lift" over non-utility, capital-intensive industrial issuers, solely from a financial metric perspective.
- While the financial profile remains relatively stable overall, expectations for modest deterioration in key credit metrics will erode positioning for issuers within a given rating category.
- Liquidity remains a high priority and will become even more critical as the year progresses, with sizeable credit-facility expirations scheduled for 2011-2012.

Key longer-term challenges include:

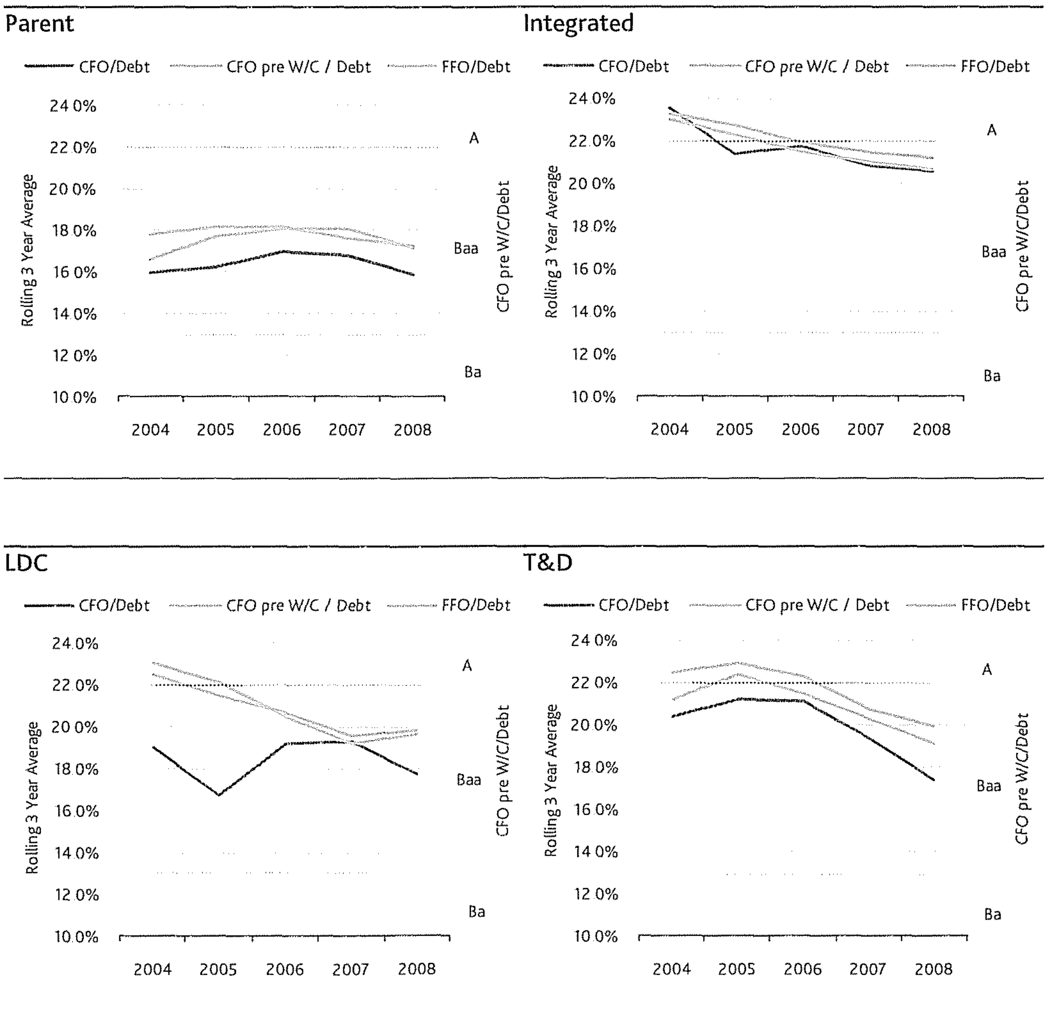
- **Political risks** from growing consumer intolerance for steadily increasing rates—a condition that could be intensified by prolonged high unemployment.
- **Regulatory risks** associated with the recovery of costs or investments, and from increasingly stringent environmental mandates, especially potential carbon dioxide emission restrictions.
- **Technological risks** from distributed generation, energy efficiency, renewable generation sources, sizeable new transmission capacity needs, or other technological developments that could weaken the traditional business model.

Overview

The fundamental credit outlook for the U.S. investor-owned electric utility sector remains stable, thanks to a supportive regulatory framework that provides good transparency into operating cost and capital investment recovery; adequate liquidity profiles; relatively unfettered access to the capital markets; and reasonably stable financial credit metrics. The investor-owned utility business model remains well positioned within its investment-grade rating category for 2010 and at least the first half of 2011.

The sector's key financial credit metrics are generally stable, but are not improving. In fact, for many sub-sectors the metrics have shown a modest but steady decline over the past few years. This erosion of financial strength may ultimately lead to lower ratings for individual companies, but does not warrant a change to our near-term stable sector outlook. As a whole, the sector can withstand some modest deterioration to its financial profile for some time, but declining metrics will eventually erode much of the "cushion" that utilities currently enjoy within their respective rating categories

Graph A: Rolling three-year average cash flow to debt (by sub-sector) scaled to the Regulated Electric and Gas Utility Rating Methodology



Summary of sectors

The U.S. electric utility sector is relatively large in terms of revenues, assets and debt, and is extremely capital intensive. In general, the sector is primarily considered regulated, reflecting its monopoly status as a provider of essential services. Although we generally refer to the sector as comprising regulated electric (and natural gas distribution) utilities, for comparison purposes, we also examine selected elements of numerous sub-sectors.[1]

In this report, we review selected three-year average financials for 2006-2008 and classify the sub-sectors as follows:

» 52 parent utility holding companies (Parent holdcos)

» 70 vertically integrated electric utilities (Integrateds)

» 40 transmission and distribution only utilities (T&Ds)

» 30 local natural gas distribution utilities (LDCs)

» 14 generation and transmission cooperatives (Cooperatives)

» 9 municipal electric utility systems (Municipals)

We also examine several related utility sub-sectors by including some of the larger, international utilities, many of whom enjoy various forms of state-sponsorship. These sub-sectors include seven European-based utility companies (Europe); 11 Asia-based utilities, excluding Japan (Asia ex-Japan); and eight Japanese utility companies (Japan).

While primarily non-regulated, we also examine eight merchant wholesale generators (Merchants) and eight merchant wholesale generators that remain affiliated with their legacy regulated utilities (Affiliates). Finally, strictly for comparison purposes, we examine seven large, capital intensive industrial companies (Industrials); seven large, high-tech companies (Technology); and eight refiners (Refining).

[1] See Appendix, page 15, for a list of the individual companies included in the sub-sector indices and their ratings.

Table 1: Comparison of selected financial metrics by sub-sectors (2006-2008 average)

	# ISSUERS	PP&E / ASSETS	EQUITY / ASSETS	DEBT / EBITDA	CFO / DEBT	TOTAL DEBT	CFO
Parent Holdcos	52	60%	25%	4.3x	16%	$7,810	$1,251
Integrated	70	71%	30%	3.6x	21%	$2,308	$477
T&D	40	57%	30%	3.8x	16%	$1,822	$292
LDC	30	64%	30%	3.1x	20%	$551	$112
Cooperative	14	71%	15%	9.3x	6%	$1,193	$75
Municipal	9	70%[2]	10%[3]	7.5x	13%	$2,625	$352
Europe	7	47%	22%	4.0x	20%	$43,193	$8,702
Asia (ex-Japan)	11	70%	42%	6.9x	17%	$7,526	$1,262
Japan	8	72%	24%	n/a	9%	$26,810	$2,355
Merchant	8	54%	17%	8.2x	12%	$8,051	$938
Affiliate	8	59%	30%	2.3x	35%	$2,585	$916
Industrials	7	16%	31%	2.2x	53%	$11,996	$6,407
Technology	7	15%	52%	0.6x	179%	$5,529	$9,888
Refining	8	58%	39%	1.6x	45%	$2,389	$1,070

Key Trends and Rating Implications

Regulation remains supportive to sector

Regulation is expected to remain a critical component for the investor-owned sector's credit profile.[4] The sector benefits from a regulatory framework that allows a utility to recover its operating costs (including fuel, operating and maintenance [O&M], selling, general and administrative expenses [SG&A], interest expenses, and taxes) through revenues, along with an agreed-upon profit margin. These revenue requirements are designed to provide "just and reasonable" rates for "used and useful" assets, which comprise a utility's rate base. As a result, *utilities can attain their given ratings with a significantly lower financial metric threshold than other non-utility industrial peers.* From a purely financial-metric perspective, the benefits of regulation translate roughly *into three notches of rating lift* and without the benefits of regulation, much of the sector would likely be considered non-investment-grade.[5]

We believe regulators will continue to provide utilities with reasonably timely recovery of prudently incurred costs and investments. We also believe regulators prefer to regulate a financially healthy sector. We do not consider regulators obstructionist, but see them as relatively transparent arbiters of a set of facts that are presented within the guidelines of a given state's legal/regulatory framework. Indeed, regulators have awarded more than $10 billion of revenue increases since 2004, as the next graph shows.

While we generally view any rate increases above the rate of inflation as a potential credit positive, a sustained trend of meaningful annual rate increases could eventually cause some credit concerns, due to the potential for increased political tensions over affordability.

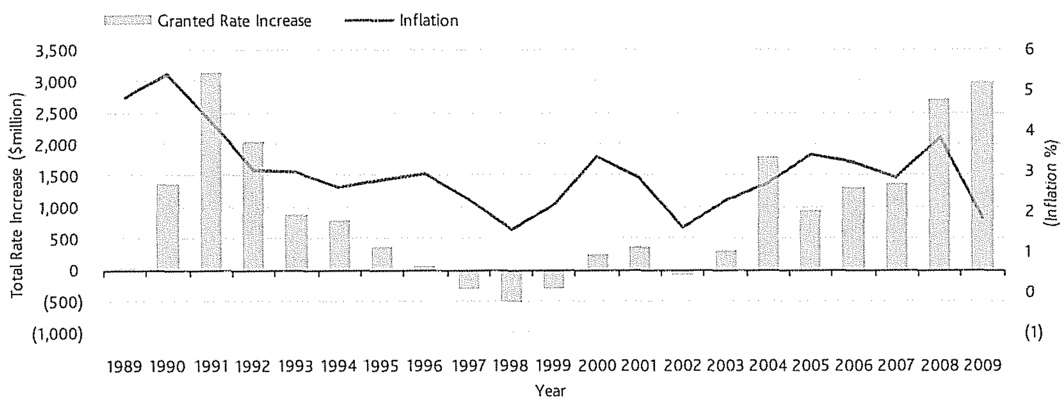
2 Moody's estimate.

3 Moody's estimate.

4 See our Rating Methodology for Regulated Electric and Gas Utilities, published in August 2009.

5 In general, industrial sectors require a 20%-30% RCF / debt and a 10%-15% FCF / debt threshold in order to be considered investment-grade. This compares to a roughly 10% RCF / debt threshold for regulated utilities.

Graph B: Regulatory rate relief and inflation



Source: Regulatory Research Associates, a subsidiary of SNL Financial LC

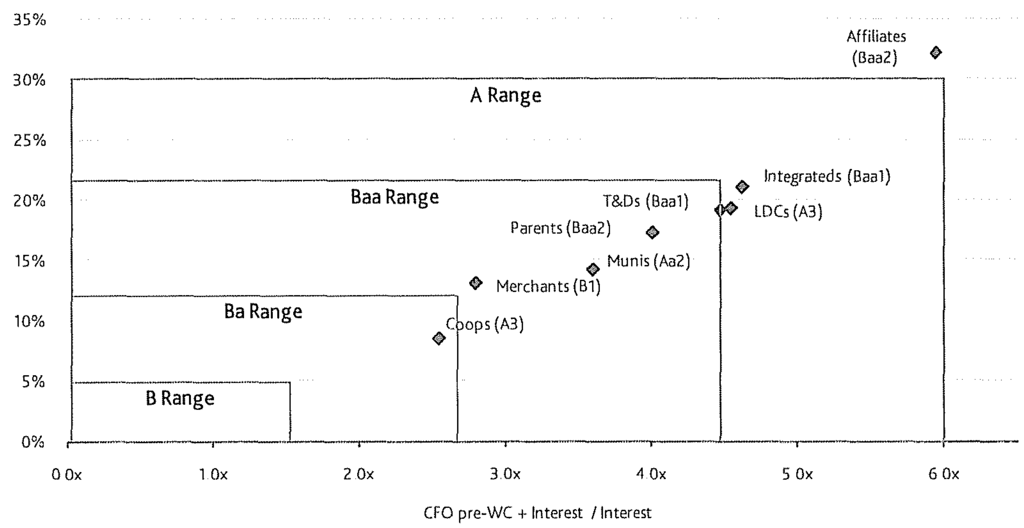
When evaluating regulation, we consider the general regulatory (and political) environment for a given utility and its relationship with its various constituents (including large industrial customers). In addition, we evaluate the framework and mechanisms that allow a utility to recover its costs and investments and earn allowed returns. We are less concerned with the official allowed return on equity, instead focusing on the earned returns and cash flows. We typically do not take rating actions based on a staff, administrative law judge or intervener recommendation, but prefer to see the actual commission-issued written orders.

The ability to realize recovery is critical to a utility's credit quality. Many jurisdictions have moved towards a more transparent ratemaking approach, using numerous cost trackers or other pass-through mechanisms. In general, we view these tracker mechanisms as a credit benefit, as they are designed to ensure recovery of a specific set of costs. Still, we remain cautious about longer-term risks associated with future requests for base rate relief, presumably due to the trackers crowding-out other financial recovery requests. We believe regulators and residential consumers remain focused on the ultimate all-in costs, and not so much on the rate structure components. We also believe that large industrial and commercial customers are less concerned with the fuel and purchased power trackers, as they are equally well versed with these commodity costs and their non-margin pass-through nature of recovery.

Key financial metrics remain comfortably within investment grade rating category

The sector remains comfortably within our investment grade financial metric ranges. Nevertheless, key financial credit metrics are not improving, and many sub-sectors have seen a modest but steady decline. This erosion of financial strength is generally a credit negative, but is not sufficient to warrant a change to our fundamental sector outlook at this time. In fact, we believe the sector can withstand some modest erosion to its financial profile without jeopardizing ratings. But as the financial metrics drift lower over time, much of the cushion that utilities currently enjoy within their respective rating category will begin to erode, and ultimately lead to negative rating action.

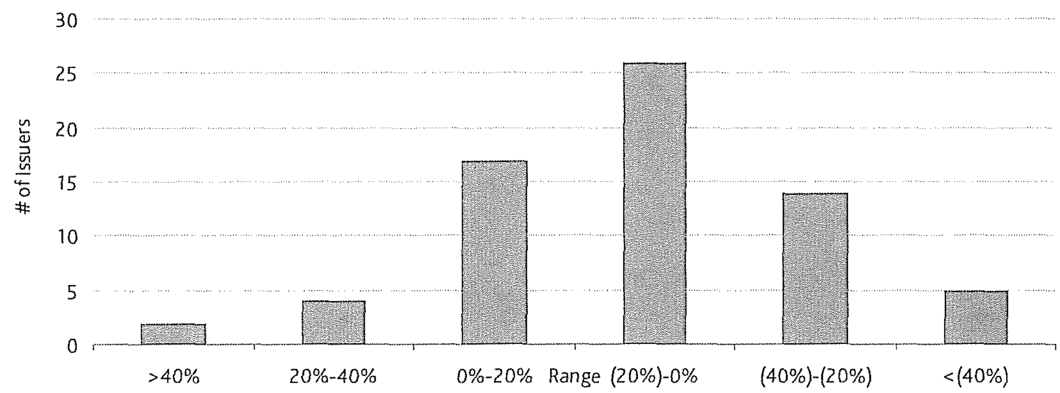
Graph C: Illustrative positioning for utility sub-sectors, scaled to our Regulated Electric and Gas Utilities Rating Methodology



Source: Moody's

Over the past several years, we have witnessed a steady erosion in the ratio of cash flow from operations adjusted for working capital changes (CFO pre-w/c) to debt for a significant number of vertically integrated electric utilities. In the following graph, we illustrate how the rolling three-year average CFO pre-w/c to debt ratios over the 2003-2005 period compares with the 2006-2008 period for roughly 70 vertically integrated electric utilities. The average decline is roughly 7%.

Graph D: Percentage change in CFO pre-w/c to debt for 70 vertically integrated electric utilities (rolling three-year average for 2003-2005 versus 2006-2008)[6]



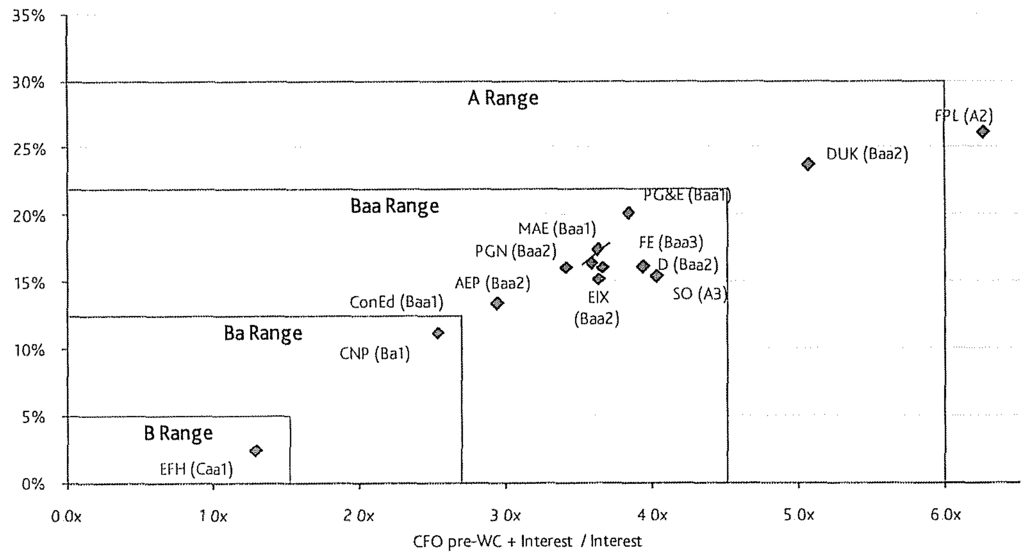
Source: Moody's

We consider most utilities to be reasonably well positioned within their respective rating categories, both from our subjective assessments of regulatory support and diversification, and the more quantitative assessments of financial performance. Over the next 12-18 months, some companies are expected to experience a decline in their financial metrics, such as Duke Energy and DPL and several

6 Excludes Entergy New Orleans and Northwestern, where the CFO pre w/c to debt improved by 100% and 165%, respectively.

companies actively pursuing new nuclear construction. Others are expected to improve, such as Dominion Resources, American Electric Power and Consolidated Edison. The next graph shows how several of the larger, well known utility parent holding companies' historical financial profiles (results as of LTM 3Q 2009) compare to our general rating guidelines.[7]

Graph E: Selected parent utility holding companies as of LTM 3Q 2009



Source: Moody's

Liquidity management increasing in priority

Managing liquidity continues to be a key factor when assessing the sector. Over the near-term, liquidity is expected to take an even higher priority, due to the sizeable credit facility expirations scheduled for 2011 and 2012 (roughly $65 billion each year, according to our estimates). We do not expect utilities to immediately resolve the significant credit-facility expirations scheduled in 2011 and 2012. We do expect to continue our ongoing discussions regarding liquidity and refinancing plans with management—especially when facing expiration within 12 months, effectively making the facilities current.

Today, we believe credit capacity at most major financial institutions remains open to the utility sector, but the costs associated with credit facilities have increased significantly. We view fully syndicated, multi-year facilities more favorably than 364-day facilities and much more favorably than bi-laterals. We also view management's active evaluation of numerous alternatives to traditional syndicated, multi-year facilities (which include direct lien and other programs) positively, especially when used as complementary sources to cash and traditional facilities, since it reduces reliance on any particular funding. When used as complementary supplements to traditional sources, such alternative sources of liquidity are not expected to cause any material changes to our ratings or rating outlooks. Even so, we might have concerns over a utility we consider overly reliant on a particular source of alternative liquidity.[8]

7 See our rating methodology, "Regulated Electric and Gas Utilities," August 2009.

8 See Special Comment, "Right-Way Hedging for Power Companies," June 2009.

Table 2: Selected liquidity data (2006-2008 average)

	# ISSUERS	CASH	FCF*	STD & CPLTD**	IMPLIED CAPACITY REQUIRED
		A	B	C	(A+B+C)
Technology	7	$7,489	$6,374	($867)	$12,996
Industrial	7	$2,966	$2,644	($1,405)	$4,205
Europe	7	$9,088	($1,220)	($7,045)	$823
Refining	8	$379	$253	($203)	$429
Cooperative	14	$71	($58)	($109)	($96)
LDC	30	$12	($35)	($131)	($154)
T&D	40	$39	($103)	($252)	($316)
Affiliate	8	$120	($94)	($429)	($403)
Integrated	70	$34	($217)	($266)	($449)
Merchant	8	$751	($644)	($661)	($554)
Asia (ex-Japan)	11	$709	($364)	($956)	($611)
Parent	52	$313	($478)	($1,031)	($1,196)
Japan	8	$704	$113	($3,841)	($3,024)
Municipal	9	$563	n/a	n/a	n/a

* FCF = CFO less dividends less capital investments.

** STD & CPLTD = short term debt and current portions of long term debt.

While our liquidity sensitivity increases once a credit facility is within 12 months of its scheduled expiration, effectively going "current" on the balance sheet, it does not mean negatively biased rating actions are imminent. Our strict analysis does not assume the capital markets will remain open, or that unfettered access will remain an option, even if historical evidence overwhelmingly demonstrates this is true. Credit markets have been known to freeze, if temporarily. Some utilities are considering pre-funding their maturities or holding higher cash balances on their balance sheets. Such strategies would generally be viewed as a credit positive, despite any temporary increase in leverage metrics.

The question over how much liquidity the sector needs continues to be debated internally, and by bankers and management teams. We believe there is no such thing as too much liquidity; in numerous cases, we have seen issuers (both utilities and non-utilities alike) experience serious stress because they misjudged their liquidity needs. The recent credit crunch featured a virtuous circle, whereby market access remained easiest for those who needed it least because their liquidity was already strong.

Utilities remain exposed to large, long-term capital investment challenges, volatile commodity prices and legal judgments which can wreak havoc on even the strongest liquidity profiles. However, we also see liquidity benefits related to a utility's ability to issue secured notes, to divest non-core assets or operations, and to obtain emergency rate relief. Prospectively, a utility's transmission system might represent a sizeable source of alternative liquidity. From a credit perspective, we believe a strong balance sheet coupled with abundant sources of liquidity represents one of the best defenses against business and operating risk and potential negative rating actions.

Pension underfunding remains a concern

We observe that pension costs are usually a recoverable expense under most rate-making structures, but the means of recovery varies by state. Some jurisdictions provide more timely recovery when actual pension costs exceed what is allowed in the existing rates (i.e., a pension cost tracker with periodic true-up mechanisms).

We treat underfunded pension obligations as debt. According to their 2008 annual reports, utilities underfunded their pension plans by roughly $33 billion, equivalent to a 73% funding status at the end of 2008. While 2009 proved a very good year for the stock market, we estimate that the funded status of these plans only improved modestly, with pension plans still underfunded by $29 billion, or 78% funded at the end of 2009. Given that the S&P 500 was up roughly 23% year-on-year, one would expect the funded status of pensions should have improved dramatically, but due to a sizeable contraction in discount rates, they do not appear to have done so.

For financial reporting purposes, the two major drivers behind the funded status of a pension plan are asset performance and discount rates. Asset performance should have been very strong in 2009: assuming a typical asset mix of 60% equities, 30% fixed income and 10% alternative investments, we estimate that total asset returns rose by about 15%. Yet we believe there will be only a slight improvement in funded status because we expect a meaningful contraction in discount rates. A general rule of thumb is that a 100 basis-point change in discount rate will change the obligation by 8%-12%.

We expect that there will be a 50 bp - 75 bp reduction in the average discount rate used by utilities for the full-year 2009. While credit spreads in corporate yields have not moved meaningfully—the Moody's Aa index has remained relatively unchanged—spreads on financial bonds have significantly contracted since December 2008. We believe many companies used financial bond yields when constructing discount rates for 2008, and due to subsequent contractions in these yields, the discount rates for 2009 will have to be lower, which in turn leads to a larger obligation.

The rules for calculating a plan's funded status are different for funding purposes than for financial reporting purposes.[9] At the heart of the rules is the concept that a company must have a fully-funded plan within seven years. If we take our estimate of $29 billion and divide by seven, we would get a required contribution of $4.1 billion for 2010. Of course, a few smoothing mechanisms allow companies to work around their required contribution calculations.

The U.S. Internal Revenue Service in March 2009 relaxed some of its rules for calculating discount rates for funding purposes, effectively allowing companies to cherry-pick the best rates from September, October, November or December, 2008. This one-time allowance should significantly reduce required contributions for 2010, but without a large rally in the markets or increasing interest rates, large contributions might arise in 2011 and 2012. This is exactly the same timeframe in which the vast majority of less expensive, multi-year credit facilities are scheduled to expire, potentially introducing some incremental stress on liquidity management.

9 An in-depth analysis of those rules is beyond the scope of this document, but suffice it to say they are extremely complex.

Longer-term challenges lie beyond scope of ratings horizon

There are numerous challenges that face the utility sector, none of which can be considered new as they have existed for decades. These challenges, which primarily relate to regulation (and recovery assurances), political support (or intervention, which can be either positive or negative for the credit) and resource availabilities (and long-term planning), raise the business and operating risk profile for the sector.

Nevertheless, these fundamental challenges are also considered to be longer-term in nature and beyond the horizon of our 12-18 month ratings outlook. More importantly, the emergence of these risks tend to develop slowly and are expected to have little impact on financial statements over the near to intermediate term horizon. As a result, the sector enjoys the benefit of time to consider changes in its corporate and / or financing strategies. But any issue that arises more quickly than we anticipate could have negative consequences for ratings.

Inadequate attention to these challenges could conceivably push much of this sector into the non-investment grade category. For now, we think this unlikely, since most utility companies, regulators and politicians would prefer to see the industry remain financially healthy and investment-grade—especially because increasingly expensive and uncertain financing would have adverse consequences for customers. The recent financial turmoil has underscored the benefits of strong credit ratings.

The desire to refurbish, enhance and rebuild a relatively antiquated electric infrastructure is driving the need for steadily increasing rates. We see significant pressure being applied from a global political push to "de-carbonize" the traditional electric supply infrastructure, primarily through increased renewable generation, which tend to be more costly than traditional sources (when excluding the potential costs associated with pollution). We continue to incorporate a view that new nuclear generation capacity also appears to represent a critical component to long-term energy policy. Another component to the refurbishment of the electric infrastructure is focused on additional transmission capacity (to alleviate congestion and provide a means to bring renewable resources to demand centers) as well as intelligent distribution networks. Regardless, these investments will result in higher costs, and therefore rates, for end-use consumers.

Impact of new nuclear generation capacity aspirations

Over the next few years, several companies in the utility sector are seriously considering the construction of new nuclear generating capacity—a long-term commitment that could be very costly. This could put significant pressure on the utility sector's overall capital investment plans, and utilities that pursue these projects will take on higher business and operating risk profiles, net of most risk mitigation efforts.

Several utilities experienced negative rating actions in 2009 that were directly or indirectly related to their nuclear ambitions. While they are pursuing numerous ways to mitigate their risk, we believe these efforts cannot fully resolve the higher business and operating risks associated with building a new nuclear facility.

We also believe that one of the most effective ways to ease risk would be to strengthen balance sheets and bolster liquidity reserves on the front end of the construction cycle, but so far we have not seen much evidence that any of the utilities actively pursuing new nuclear generation are doing either.

For additional insight into our views regarding the credit implications associated with new nuclear generation construction, please see our Special Comment "New Nuclear Generation: Ratings Pressure Increasing," June 2009 (117883).

The prospect for steadily increasing rates raise another regulatory recovery risks for the sector relating to costs or investments associated with refurbishing such a large component of the nation's critical infrastructure. Under almost every scenario we evaluate, revenue requirements are expected to steadily increase over the next few years, but we see little evidence regarding wage inflation and unemployment remains high. These elements could lead to political intervention of some form, a credit negative. Conceptually, investors might expect to see the sector strengthen its balance sheet and bolster its liquidity sources in the face of such challenges.

Alas, this does not seem to be the case. As long as the regulatory safety net remains in place, utilities appear comfortable managing their operations as they have for years, and ratings should likewise remain relatively stable. If, on the other hand, the regulatory environment changed, and the recoverability of costs and investments became more questionable, the sector could conceivably fall into the non-investment grade category. This is especially the case if many of the costs and investments have already been made. Ultimately, the question comes down to how much of an increase in utility costs a consumer can withstand, and how cautiously each company positions itself to withstand affordability pressures.

In our July 2009 Industry Outlook Update report[10], we estimated that consumers might stop tolerating rate increases at a 50%-or-so rise above the current average U.S. rate of $0.10 per kwh. At the time we wrote that, this "inflection point" would not be reached until about 2018 or 2019. Whether or not this inflection point remains the base case is unclear, but recessionary pressures on residential household budgets, and a lack of clear evidence of wage inflation, lead us to wonder whether the inflection point might arrive sooner. We are paying particularly close attention to the regulatory situation in Florida as a potential barometer and leading indicator associated with this risk.

Illustrative financial projections indicate pending ratings pressure

Our illustrative projection model examines the historical financial results for the 70 vertically integrated electric utilities comprised in our "Integrated" peer group over the past seven years (2002-2008) and incorporates numerous assumptions to provide an indication as to how the sector might fare over the next five years (2010-2014).

We assume revenues are fully regulated and are derived only from the sale of electricity. We assume volume increases of 1% per year over the next five years. Rates are assumed to increase by 5% per year over the next three years (2010-2012), with 3% rate increases thereafter. As a result, revenues increase from roughly $200 billion to almost $230 billion in 2014. Fuel and purchased power costs are projected to remain at roughly half of revenues (as it has over the past five-year, three-year and two-year averages), and that O&M and SG&A expenses grow at 3% and 2% per year, respectively.

Capital expenditures are forecasted by applying a multiplier to prior-year depreciation and amortization expense. Over the past seven-year, five-year, three-year and two-year averages, this ratio was 184%, 215%, 241% and 253%, respectively. We assume an average multiplier of 225% over the next two years (2010-2011), 217% over the next three years (2010-2012) and 205% over the next five years (2010-2014). As a result, capital expenditures are forecasted to remain relatively steady at approximately $40 billion per year, which is contrary to most conventional wisdom that capital expenditures are going to increase significantly. Our assumption for a slightly lower capital spending is in part premised by our views of prolonged high unemployment and increased regulatory scrutiny regarding investments and utility's reluctance to invest without a higher assurance for recovery. We

[10] See Moody's Related Research at the back of this report for links to our previous Industry Outlook and Industry Outlook update reports.

also assume dividends will increase by 2% annually over the five-year forecast, from about $8.8 billion today to almost $9.8 billion in 2014.

Table 3: Historical and projected financial results (in $ billions)

	HISTORICAL					PROJECTED		
	7-YEAR	5-YEAR	3-YEAR	2-YEAR	LTM 3Q 2009	2-YEAR	3-YEAR	5-YEAR
Revenue	$171.7	$179.5	$189.4	$194.2	$193.5	$211.4	$217.9	$228.7
EBITDA	$44.1	$45.6	$47.0	$47.9	$48.8	$55.9	$58.5	$62.5
Interest	$9.8	$9.6	$10.0	$10.4	$11.9	$14.3	$14.9	$15.8
Net income	$10.5	$11.3	$10.4	$9.0	$4.2	$14.4	$15.4	$16.9
CFO	$33.3	$33.8	$34.5	$34.3	$32.9	$33.0	$35.8	$38.1
CFO pre-w/c	$35.4	$36.0	$36.6	$37.6	$32.9	$33.1	$36.2	$38.7
FFO	$35.4	$36.2	$36.9	$38.7	$43.6	$37.7	$38.8	$41.3
Capital exp.	$33.0	$36.3	$42.1	$45.1	$49.9	$41.9	$41.4	$40.9
Dividends	$8.7	$8.3	$7.5	$7.6	$9.1	$9.1	$9.2	$9.4
FCF	$(8.5)	$(10.8)	$(15.1)	$(18.5)	$(26.1)	$(18.0)	$(14.8)	$(12.2)
PP&E, net	$325.9	$340.1	$355.9	$369.8	$400.7	$433.2	$443.5	$463.0
Debt	$157.6	$162.1	$167.5	$175.4	$199.4	$224.0	$230.0	$239.7
Equity	$129.7	$138.7	$148.3	$153.7	$167.1	$174.7	$178.3	$186.9
CFO pre-w/c interest	4.6x	4.7x	4.6x	4.6x	3.8x	3.3x	3.4x	3.4x
CFO – pre-w/c / debt	22.5%	22.2%	21.9%	21.4%	16.5%	14.8%	15.7%	16.1%
RCF / debt	16.9%	17.2%	17.6%	17.7%	11.9%	12.6%	12.8%	13.3%
Debt / Capitalization	54.8%	53.9%	53.0%	53.3%	54.4%	56.2%	56.3%	56.2%

Our simple projection model indicates a steady deterioration in several key financial credit metrics over the next few years before they begin to improve in the later years—primarily as a result of decreased capital spending. Conceptually, should a utility's financial profile exhibit a decline in its credit metrics from roughly 4.5x interest coverage, 20%+ CFO pre-w/c to debt, high-teens-range retained cash flow (RCF) to debt and approximately 53% debt to capitalization, to 3.5x interest coverage, mid-teen-range CFO pre-w/c to debt, low-teen-range RCF to debt and 56% debt to capitalization, negative ratings actions would be likely.

We acknowledge that our model does not incorporate any new material infusions of equity, but instead assumes negative FCF balances are financed with debt. Nevertheless, equity does build over the projection horizon with retained earnings. It is possible that negative rating pressure could build over the next few years for the sector unless companies balance their debt and equity mixes more effectively, or otherwise strengthen their balance sheets (as with the sector's "back-to-basics" program that was common from roughly 2002-2004).

U.S. Public Power Electric Utility Sector Outlook: Recession and Climate Policy Decisions Create Uncertainty

The credit position of the U. S. public power electric utility sector has been stable over the past year. But recessionary pressures and the prospect of more aggressive environmental regulation create uncertainty in the outlook. We rate over $100 billion of revenue bond debt from U.S. municipal and government-owned utilities. The sector's credit quality came under pressure in 2009 from the unsettled credit markets, fuel-price volatility, and the increasing cost of new generation capacity.

Power supply decisions have been complicated by the potentially more significant role of mandated renewable energy as part of a utility's resource portfolio. Public-power electric utility retail rates have risen over past two years, creating a situation of additional political risk for some utilities that seek to recover higher costs through rate increases, as recessionary pressures cut into demand.

The U.S. recession has reduced electric demand, which could lead to rating pressures for many public power electric utilities. Lower demand could weaken debt-service coverage margins or liquidity, unless rates are raised to compensate. Weakening financial metrics could factor into negative rating changes. The weakening fiscal health of local governments may also lead to increased utility general-fund transfers to support a municipality's general finances, thereby weakening a utility's balance sheet and causing negative rating pressure.

Despite these uncertainties and pressures, companies in the sector enjoy something like a monopoly position, as providers of an essential service, combined with their ability to recover costs through rate-setting processes not subject to regulation. Additionally, public-power electric utilities have shown good ability to manage through the recent turmoil in credit and fuel markets..

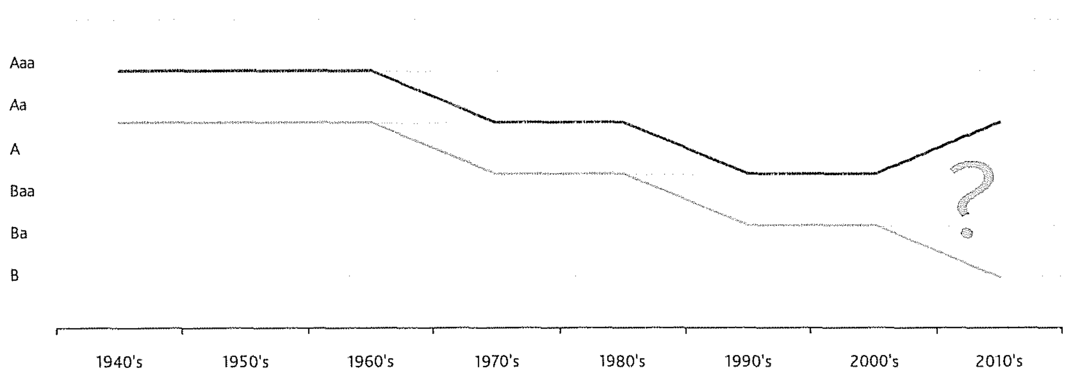
Conclusion

The utility sector's fundamentals remain intact, but face significant credit implications over the longer term. The sector's basic central-station dispatch structure is under increased scrutiny, as U.S. policy focuses increasingly on de-carbonization of electric supplies, enhanced energy efficiency programs and smart-grid initiatives. While expensive, proponents of these efforts note that their costs will prove more competitive than building new base-load generation over the long-term. Because the political debate regarding national energy policy is slow, utilities are being forced to make long-term investment decisions amid a cloudy regulatory framework, making it difficult to plan and manage infrastructure refurbishment.

It is notable that the utility sector's stable fundamental credit conditions withstood the severe market turmoil of 2007-2009, when many other industrial sectors experienced ratings deterioration and saw numerous negative outlooks and reviews for possible downgrade. Nevertheless, the sector's average rating has declined over time, from the Aaa-Aa range during the 1940s-1960s to the A-Baa range today. Although the basic operating structure remains the same—generating, transmitting and distributing electricity to end use consumers—the utility sector's regulatory, political, financial and capital market frameworks have all changed significantly over time.

It remains unclear how the utility sector will address its current hurdles, considering the shift in policy priorities they would seem to demand. Many industry participants are raising concerns about how the sector will manage the sizeable financing requirements needed to fund its substantial infrastructure investment plans, while also managing price increases for ratepayers at long-term affordable levels.

Graph F: Illustrative long-term sector rating migration



Appendix: Comparable Peer Indices by Sub-Sector

Parent Holding Companies

RATING	ISSUER NAME	RATING	ISSUER NAME
A2	FPL Group, Inc.	Baa2	Public Service Enterprise Group
A2	NSTAR	Baa2	SCANA Corporation
A3	E.ON US	Baa3	Ameren Corporation
A3	National Grid USA	Baa3	Black Hills Corporation
A3	Southern Company (The)	Baa3	Cleco Corporation
A3	Wisconsin Energy Corporation	Baa3	Constellation Energy Group, Inc.
Baa1	Alliant Energy Corporation	Baa3	Iberdrola USA
Baa1	Consolidated Edison, Inc.	Baa3	Entergy Corporation
Baa1	DPL Inc.	Baa3	FirstEnergy Corp.
Baa1	Exelon Corporation	Baa3	Great Plains Energy Incorporated
Baa1	Integrys Energy Group, Inc.	Baa3	Pepco Holdings, Inc.
Baa1	MidAmerican Energy Holdings Co.	Baa3	Pinnacle West Capital Corporation
Baa1	OGE Energy Corp.	Baa3	TECO Energy, Inc.
Baa1	PG&E Corporation	Baa3	UIL Holdings Corporation
Baa1	Sempra Energy	Baa3	Westar Energy, Inc.
Baa1	Vectren Utility Holdings, Inc.	Ba1	Allegheny Energy, Inc.
Baa1	Xcel Energy Inc.	Ba1	CenterPoint Energy, Inc.
Baa2	American Electric Power Company	Ba1	CMS Energy Corporation
Baa2	Dominion Resources Inc.	Ba1	Duquesne Light Holdings, Inc.
Baa2	DTE Energy Company	Ba1*	NV Energy Inc.
Baa2	Duke Energy Corporation	Ba1**	UniSource Energy Corporation
Baa2	Edison International	Baa3***	NiSource Inc.
Baa2	Hawaiian Electric Industries	Ba2	PNM Resources, Inc.
Baa2	IDACORP, Inc.	Ba2	Puget Energy
Baa2	Northeast Utilities	B1*	AEI
Baa2	PPL Corporation	B1*	AES Corporation, (The)
Baa2	Progress Energy, Inc.	Caa1*	Energy Future Holdings Corp.

*CFR
**Sr. Secured
***Guaranteed

Vertically Integrated Utilities

RATING	ISSUER NAME	RATING	ISSUER NAME
Aa3	Madison Gas and Electric	Baa1	Public Service Co. of Colorado
A1	Florida Power & Light Company	Baa1	Public Service Company of Oklahoma
A1	Mississippi Power Company	Baa1	South Carolina Electric & Gas Co
A1	Wisconsin Electric Power	Baa1	Southwestern Public Service Company
A2	Alabama Power Company	Baa1	Tampa Electric Company
A2	Dayton Power & Light Company	Baa1	Virginia Electric and Power Company
A2	Georgia Power Company	Baa2	Appalachian Power Company
A2	Gulf Power Company	Baa2	Arizona Public Service Company
A2	Kentucky Utilities Co.	Baa2	Black Hills Power, Inc.
A2	Louisville Gas & Electric Company	Baa2	Cleco Power LLC
A2	MidAmerican Energy Company	Baa2	Consumers Energy Company
A2	Oklahoma Gas & Electric	Baa2	El Paso Electric Company
A2	San Diego Gas & Electric	Baa2	Empire District Electric Company
A2	Wisconsin Power and Light	Baa2	Entergy Arkansas, Inc.
A2	Wisconsin Public Service Corp.	Baa2	Entergy Louisiana, LLC
A3	Columbus Southern Power	Baa2	Indiana Michigan Power Company
A3	Duke Energy Carolinas, LLC	Baa2	Indianapolis Power & Light Company
A3	Northern States Power Co. (MN)	Baa2	Kentucky Power Company
A3	Northern States Power Co. (WI)	Baa2	Portland General Electric Company
A3*	NorthWestern Corporation	Baa2	Public Service Co. of New Hampshire
A3	Pacific Gas & Electric Company	Baa2	Union Electric Company
A3	Progress Energy Carolinas, Inc.	Baa3	Avista Corp.
A3	Progress Energy Florida, Inc.	Baa3	Central Illinois Light Company
A3	Southern California Edison	Baa3	Central Vermont Public Service Co
Baa1	ALLETE, Inc.	Baa3	Entergy Gulf States Louisiana
Baa1	Detroit Edison Company	Baa3	Entergy Mississippi, Inc.
Baa1	Duke Energy Indiana, Inc.	Baa3	Monongahela Power Company
Baa1	Duke Energy Kentucky, Inc.	Baa3	Public Service Co. of New Mexico
Baa1	Duke Energy Ohio, Inc.	Baa3	Puget Sound Energy, Inc.
Baa1	Green Mountain Power Corp.	Baa3	Southwestern Electric Power Comp
Baa1	Hawaiian Electric Company, Inc.	Baa3	Tucson Electric Power Company
Baa1	Idaho Power Company	Ba1	Entergy Texas, Inc.
Baa1	Kansas City Power & Light Co.	Ba2	Entergy New Orleans, Inc.
Baa1	Ohio Power Company	Ba3	Nevada Power Company
Baa1	PacifiCorp	Ba3	Sierra Pacific Power Company

Transmission & Distribution Utilities

RATING	ISSUER NAME	RATING	ISSUER NAME
A1	NSTAR Electric Company	Rating	Issuer Name
A3	Central Hudson Gas & Electric Co	Baa2	Duquesne Light Company
A3	Consolidated Edison Co of NY	Baa2	Jersey Central Power & Light Company
A3	Massachusetts Electric Company	Baa2	Metropolitan Edison Company
A3	Narragansett Electric Company	Baa2	New York State Electric and Gas
A3	New England Power Company	Baa2	Ohio Edison Company
A3	Niagara Mohawk Power Corp.	Baa2	Pennsylvania Electric Company
A3	PECO Energy Company	Baa2	Pennsylvania Power Company
Baa1	Central Maine Power Company	Baa2	Potomac Electric Power Company
Baa1	Connecticut Light and Power Co.	Baa2	Rochester Gas & Electric Corporation
Baa1*	Oncor Electric Delivery Company	Baa2	United Illuminating Company
Baa1	Orange and Rockland Utilities, Inc	Baa2	Western Massachusetts Electric Co.
Baa1	PPL Electric Utilities Corporation	Baa3	CenterPoint Energy Houston
Baa1	Public Service Electric and Gas	Baa3	Central Illinois Public Service
Baa1	Superior Water, Light and Power	Baa3	Cleveland Electric Illuminating
Baa2	AEP Texas Central Company	Baa3	Commonwealth Edison Company
Baa2	AEP Texas North Company	Baa3	Illinois Power Company
Baa2	Atlantic City Electric Company	Baa3	Potomac Edison Company (The)
Baa2	Baltimore Gas and Electric Co.	Baa3	Texas-New Mexico Power Company
Baa2	Delmarva Power & Light Company	(P)Baa3	Toledo Edison Company
Baa3	West Penn Power Company		

Natural Gas Local Distribution Utility Companies

RATING	ISSUER NAME	RATING	ISSUER NAME
Aa3*	New Jersey Natural Gas Company	A3	UGI Utilities, Inc.
A1	Alabama Gas Corporation	Baa1	Boston Gas Company
A1	Wisconsin Gas LLC	Baa1	Cascade Natural Gas Corp.
A2	Northern Illinois Gas Company	Baa1	Connecticut Natural Gas Corporation
A2	Southern California Gas Company	Baa1	Indiana Gas Company, Inc.
A2	Washington Gas Light Company	Baa1	Laclede Gas Company
A3	Atlanta Gas Light Company	Baa1	Michigan Consolidated Gas Company
A3	Colonial Gas Company	Baa1	South Jersey Gas Company
A3	KeySpan Gas East Corporation	Baa2	Bay State Gas Company
A3	North Shore Gas Company	Baa2	Berkshire Gas Company
A3	Northwest Natural Gas Company	Baa2	Northern Indiana Public Service
A3	Peoples Gas Light and Coke Co.	Baa2	Southern Connecticut Gas Company
A3	Piedmont Natural Gas Company	Baa2	Yankee Gas Services Company
A3	Public Service Co. of NC	Baa3	Southwest Gas Corporation
A3	Questar Gas Company	Ba2**	SourceGas LLC

* Senior secured rating **CFR

Unaffiliated Merchants (CFRs)		Affiliated Merchants	
RATING	ISSUER NAME	RATING	ISSUER NAME
Ba2	Covanta Holding Corporation	A3	Exelon Generation Company, LLC
Ba3	NRG Energy, Inc.	Baa1	KeySpan Generation LLC
B1	Edison Mission Energy	Baa1	PSEG Power LLC
B1	Mirant Corporation	Baa1	Southern Power Company
B1	RRI Energy, Inc.	Baa2	FirstEnergy Solutions Corp.
B2	Calpine Corporation	Baa2	PPL Energy Supply, LLC
B2	Dynegy Holdings Inc.	Baa3	Allegheny Energy Supply Company,
Caa3	Texas Competitive Electric Hldgs.		
Baa3	AmerenEnergy Generating Co.		
Municipals		**G&T Cooperatives**	
RATING	ISSUER NAME	RATING	ISSUER NAME
Aa1	City of San Antonio, TX	A2	Arkansas Electric Cooperative Co
Aa1	Orlando, FL	A2	Associated Electric Cooperative
Aa2	Jacksonville Electric Authority, FL	A2	Basin Electric Power Cooperative
Aa2	New York Power Authority	A2	Buckeye Power, Inc.
Aa2	Santee Cooper	A3	Dairyland Power Cooperative
Aa2	Seattle City Light	A3	Golden Spread Electric Cooperative
Aa3	Los Angeles Dept of Water & Pwr	A3*	Great River Energy
A1	Municipal Electric Authority of Georgia	A3*	Old Dominion Electric Cooperative
A1	Sacramento Municipal Utility District	Baa1	Minnkota Power Cooperative, Inc
		Baa1	Oglethorpe Power Corporation
		Baa1	PowerSouth Energy Cooperative
		Baa1	South Mississippi Electric Power
		Baa2	Hoosier Energy Rural Electric Co
*FMB Rating		Baa2	Tri-State G&T Association Inc.

Europe		Industrials	
RATING	ISSUER NAME	RATING	ISSUER NAME
Aa3	Electricite de France	Aa2	General Electric Company
A2	E.ON AG	A1	Illinois Tool Works Inc.
A2	ENEL S.p.A.	A2	Boeing Company (The)
A2	RWE AG	A2	Caterpillar Inc.
A3	Essent N.V.	A2	Emerson Electric Company
A3	Iberdrola S.A.	A2	United Technologies Corp.
NR	Endesa S.A.	Baa1	Ingersoll-Rand Company Ltd

Japan		Technology	
RATING	ISSUER NAME	RATING	ISSUER NAME
Aa2	Chubu Electric Power Company	Aaa	Microsoft Corporation
Aa2	Chugoku Electric Power Company	A1	Cisco Systems, Inc.
Aa2	Hokkaido Electric Power Company	(P)A1	Intel Corporation
Aa2	Hokuriku Electric Power Company	A2	Dell Inc.
Aa2	Kansai Electric Power Company	A2	Hewlett-Packard Company
Aa2	Kyushu Electric Power Company	A2	Oracle Corporation
Aa2	Okinawa Electric Power Company	NR	Google Inc.
Aa2	Tokyo Electric Power Company		

Asia (ex-Japan)		Refiner	
RATING	ISSUER NAME	RATING	ISSUER NAME
Aa3	Transpower New Zealand Limited	Baa2	Sunoco, Inc.
A1	SP AusNet	Baa2	Valero Energy Corporation
A2	CLP Holdings Limited	Ba1	Tesoro Corporation
A2	Korea District Heating Corporation	Ba2	Frontier Oil Corporation
A2	Korea Electric Power Corporation	Ba3	Holly Corp.
Baa1	Spark Infrastructure	B2	Alon USA Energy, Inc.
Baa1	Tenaga Nasional Berhad	B2	CVR Energy Inc.
Baa1	VECTOR Limited	B3	United Refining Company
Baa3	NTPC Limited		
Ba3	National Power Corporation		
NR	Envestra Ltd.		

Moody's Related Research

Industry Outlooks:

» National Gas Transmission Solid but new Concerns Emerge, September 2009 (120250)

» U.S. Regulated Electric Utilities: Six Month Update, July 2009 (118776)

» U.S. Coal Industry Outlook: Six-Month Update, April 2009 (116778)

» U.S. Investor-Owned Electric Utilities, January 2009 (113690)

Special Comments:

» U.S. Electric Utility Sector Weathers the Recession, November 2009 (121216)

» Evaluating the Leverage of Unregulated Power Companies, October 2009 (120835)

» Gas Pipelines: Which Are Vulnerable to Emerging Risks?, October 2009 (120716)

» Investor Owned Utilities Face Significant Bank Facility Refinancing Risk as Substantial 2011-2012 Maturities Approach, October 2009 (120596)

» New Nuclear Generation: Ratings Pressure Increasing, June 2009 (117883)

» Right-Way Hedging for Power Companies, June 2009 (117978)

» Default, Recovery, and Credit Loss Rates for Regulated Utilities, 1983-2008, May 2009 (115424)

» Analyzing Partnerships in the Midstream Sector, March 2009 (115149)

» Carbon Risks Becoming More Imminent for U.S. Electric Utility Sector, March 2009 (115175)

» Credit Roadmap for Energy Utilities and Power Companies in the Americas, March 2009 (115514)

» Near Term Bank Credit Facility Renewals to be More Challenging for U.S. Electric and Gas Utilities, January 2009 (114031)

Rating Methodologies:

» Regulated Electric and Gas Utilities, August 2009 (118481)

» Global Unregulated Utilities and Power Companies, August 2009 (118508)

» Natural Gas Pipeline, December 2009 (121678)

» U.S. Electric Generation & Transmission Cooperatives, December 2009 (121189)

» Global Mining Industry, May 2009 (116843)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

» contacts continued from page 1

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Kentucky Power Company

REQUEST

Refer to the Avera Testimony at page 10, lines 4-6.

Provide a description of the new generation facilities that Kentucky Power plans to invest in during 2010.

RESPONSE

Kentucky Power has no plans for new generation facilities in 2010. Kentucky Power's planned capital investment during 2010 for generation assets relate to existing facilities.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

Refer to the Avera Testimony at page 10.

Footnote 8 appears to be out of date. Provide the most recent electric utility sector analyses from Moody's Investor Service and Fitch Ratings Ltd. discussing energy market volatility.

RESPONSE

Copies discussing energy market volatility from the most recent publications from Fitch Ratings Ltd. and Moody's Investors Service in Dr. Avera's possession were provided in the response to Staff's 2nd Set, Item No. 11.

WITNESS: William E Avera

Kentucky Power Company

REQUEST

Refer to the Avera Testimony at page 11.

Provide copies of the articles referenced in Footnotes 11-13.

RESPONSE

Copies of the above-referenced articles are included in Dr. Avera's workpapers, copies of which are provided on the CD labeled "Avera WP's and documentation" in response to KIUC 1st, Item No. 1.

WITNESS: William E. Avera

Kentucky Power Company

REQUEST

Refer to the Avera Testimony at page 12.

a. Explain whether Kentucky Power has requested that the Commission alter its Fuel Adjustment Clause mechanism to recover costs in a more timely fashion in order to alleviate investor concerns regarding the lag between expenses incurred and recovered through rates.

b. Provide an explanation of whether Kentucky Power is proposing to earn a return on its fuel costs.

c. Provide a list of utilities earning a return on fuel costs and an explanation of how that is related to exposure to fluctuations in power supply costs.

d. Provide a list of states whose utility regulatory commissions have explicitly authorized t he electric utility to earn a return on fuel costs and copies of the relevant orders.

e. The fuel procurement process is well established in Kentucky and should be well understood by Kentucky Power. Provide an explanation of what actions the Commission has taken to heighten either company or investor concerns regarding fuel procurement disallowances and how this relates to exposure to fluctuations in power supply costs.

f. Provide the most recent "U. S. Investor Owned Electric Utilities: Six Month Industry Update" from Moody's Investor Service.

RESPONSE

a) Kentucky Power is not requesting that the Commission alter its Fuel Adjustment Clause mechanism.

b) Kentucky Power is not proposing to earn a return on fuel costs. Kentucky Power has, however, historically earned a return on its coal inventory.

c) Dr. Avera has not conducted any detailed study to identify those utilities that may be permitted to earn a return on fuel costs; nor was such a study necessary to support his analyses and conclusions. Dr. Avera is aware that Baltimore Gas and Electric Company is permitted to recover an administrative charge that includes a shareholder return component.

d) Please refer to the response to subpart (c), above.

e) Dr. Avera's testimony at page 12 did not claim that the Commission had taken any steps to heighten the risks associated with KPCo's ability to recover its power supply costs. Rather, his testimony explained that, despite regulatory provisions that allow for periodic rate adjustments to reflect changes in power costs, investors nonetheless recognize that utilities such as KPCo remain exposed to the potential need to finance power cost deferrals, especially during times of volatile energy prices.

f) A copy of the requested document is attached.

WITNESS: William E Avera / E K WAGNER

Moody's Global Infrastructure

Industry Outlook

July 2009

U.S. Regulated Electric Utilities

Six-Month Update

Table of Contents:

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W. Larry Hess *Team Managing Director*	1.212.553.3837

(Analyst contacts continued on page 21)

The outlook for the U.S. investor-owned electric utility sector is stable. This *outlook* expresses Moody's expectations for the fundamental credit conditions in the industry over the next 12 to 18 months.

- Sector well-positioned within investment-grade range, with continued strong access to capital, protection from widespread economic turmoil and regulators still granting timely cost recovery
- Longer-term pressures on sector serve to raise over-all operating risks
- Modest declines in financial profile over past few years not alarming at this time but few issuers appear to be taking material steps to mitigate
- Utilities gradually expected to adjust "tone at the top" management strategies with balance-sheet strengthening and more conservative corporate finance philosophies

Key challenges include:

- Growing consumer intolerance for steadily increasing rates
- Exposure to increasingly stringent environmental regulations, including those related to carbon dioxide and mercury
- Wave of credit facility expirations in 2011-2012
- Protracted recessionary conditions adding to business and operating risks, raising some doubts over availability of credit and ongoing regulatory recovery

Moody's Investors Service

Overview

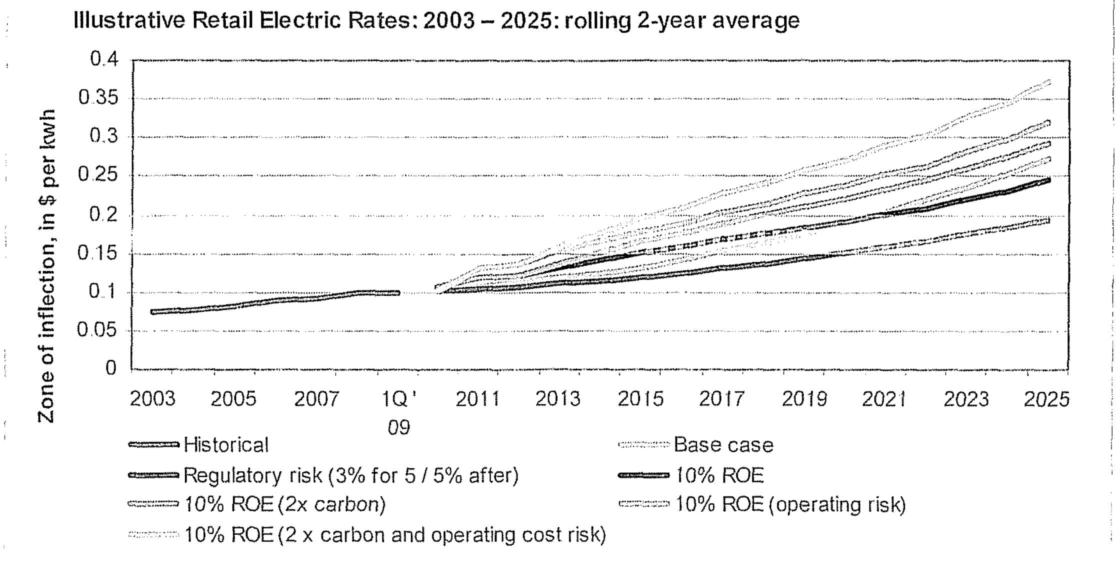
All the evidence we have seen suggests that the fundamental credit outlook for the electric utility sector will remain stable over the next 12-18 months. While most industrial sectors have negative sector outlooks today, we continue to view regulated utilities as relatively well insulated—although not immune—from economic and financial market turmoil. Regulation provides a key material benefit to the sector's overall credit profile, and we believe regulators will provide timely recovery of prudently incurred costs and investments over the near term. We have long held that regulators would rather regulate financially healthy companies than imperiled ones, and that utilities maintain effective constituency outreach efforts.

For the longer term, however, we are becoming increasingly concerned about possible changes to our fundamental assumptions about regulatory risk, particularly the prospect of a more adversarial political (and therefore regulatory) environment. A prolonged recessionary climate with high unemployment, or an intense period of inflation, could make cost recovery more uncertain. This could easily spark a negative vicious cycle.

We first highlighted these regulatory concerns in the 2004-2005 timeframe, as the sector's "back to basics" period came to an end and we questioned whether the (then-recent) improvement in financial metrics had reached its peak. Today, we have an eye on the theoretical "inflection point" beyond which consumers will no longer tolerate annual rate increases without protest. We do not know where this inflection point lies, but we believe it exists somewhere near the point at which consumers begin to change their behavior—as when gasoline reached $4 per gallon last year—and begin to contact their elected officials with vocal protests. But because consumers cannot easily alter their electricity consumption, the inflection point could actually spark a major political reaction. We believe this reaction could develop suddenly, and probably not at a welcome time. Should this happen, it is unclear how regulators would react and how the sector would fare.

The average annual electric bill costs the typical U.S. household about 3.4% of its disposable income. We estimate that the inflection point might be crossed once an annual electric bill reaches roughly 5%-10% of a given household's disposable income—and that this could happen within the next decade, judging from our base-case projections. In various downside scenarios, the inflection point could accelerate by several years, to 2013-2015—well within our typical ratings horizon.

It appears that many of the chief executives and regulators with whom we speak regularly have either not yet arrived at a consensus view of exactly where this inflection point lies, or are uncertain how close we are to approaching this point. This uncertainty is truly surprising, in our opinion, given the magnitude of the potential risk to both a utility's credit profile and its shareholder's equity.



Utilities remain well positioned within rating category

Of all the factors affecting U.S. electric utility ratings, we have long considered regulatory support perhaps the most critical driver. We continue to believe regulators prefer to oversee financially healthy utilities, and certainly for the near term, we believe the sector will continue to enjoy reasonably good regulatory support. Our focus remains fixed on cash flow, not on authorized returns on equity (ROEs). We also remain more interested in written regulatory orders—not initial indications from utilities, regulatory staff, intevenors, or administrative law judges (although they may offer some hint about the likely rulings).

We believe today's utilities generally act as solid corporate citizens within their respective service territories. Most utilities practice reasonably effective constituency outreach programs: they are large employers; provide socialized relief for special customer classes; serve as effective tax-collecting (and taxpaying) agencies for state and local governments; and usually support parochial philanthropic endeavors. For these reasons, utilities tend to get the political support they need, when they need it—ultimately a credit positive.

Regulatory oversight is crucial for sector

We consider most utility issuers reasonably well-positioned within their respective ratings categories. Four principal sub-sectors comprise our utility universe: parent utility holding companies; vertically integrated utilities; transmission and distribution-only utilities (T&Ds); and natural gas local distribution companies (LDCs). For a list of the issuers that comprise these sub-sectors, see Appendix B, page 15.

We place the operating utility sectors, which include the vertically integrated electric, T&D and LDC utilities in the A3 / Baa1 ratings category range. The utility parent holding companies tend to be rated about one notch lower, in the Baa1 / Baa2 range.

In general, we incorporate a view the regulatory framework across the U.S. represents a material credit positive, but is less favorable than the regulatory frameworks in Europe or Asia. This is primarily due to the highly fragmented and parochial effects of state-by-state regulatory policies. We note that the business activities that are primarily regulated by the Federal Energy Regulatory Commission (FERC) typically receive a more favorable view. Our regulatory views are usually slightly less favorable when evaluating the utility parent holding companies, largely reflecting non-regulated business activities, which typically comprise roughly 15%-25% of consolidated operations.

The operating utility sub-sectors are also well positioned in terms of rates and cost recovery, where the vast majority of costs and investments are recovered in a reasonably timely basis. Of course, regulatory lag on various issues will remain a factor. As a result, we generally incorporate a view that utilities derive a benefit from diversification across state lines, broadening the risk of regulatory jurisdictions and implied recovery lag.

We tend to view the rates and recovery mechanisms for the vertically integrated utilities as slightly less favorable than the T&D and LDC peers, primarily because of the greater uncertainties related to fuel commodities and increasingly stringent environmental mandates such as carbon regulations.

Finally, we consider the sector's overall liquidity adequate, although this assumes that utilities will continue to enjoy unfettered access to the capital markets. Little evidence to date suggests we should change our views regarding access to the capital markets. Nevertheless, our assumption represents a major component to our liquidity assessments, and ultimately ratings, so unexpected challenges to access could result in a materially adverse ratings consequence across the entire sector.

Utilities, in general, have proven capable of issuing senior secured debt in times of crisis—debt that has performed extremely well historically in terms of expected loss and recovery values.[1] During the most recent financial turmoil, most utilities had little trouble accessing capital across the entire capital structure. Yet we are often reminded that the past is not a reliable indicator of future performance. While challenged market access

[1] See Special Comment, "Proposed Wider Notching Between Certain Senior Secured Debt Ratings and Senior Unsecured Debt Ratings for Investment Grade Regulated Utilities," May 2009.

strikes us as unlikely, its effects could be substantial, not unlike the "tail risk" often discussed in hedging strategies, and possibly resulting in multiple notch rating changes over a very short period of time.

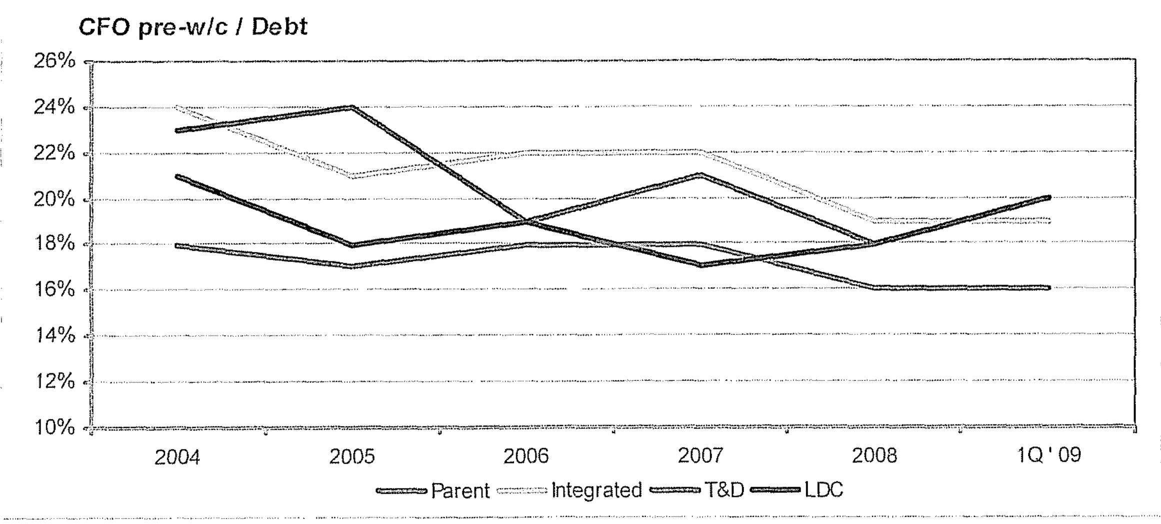
Over the past three years, the principal sub-sectors have produced relatively stable, if modestly deteriorating, key financial credit ratios.

Selected historical credit metrics

	CFO / Debt 5-yr	CFO / Interest 5-yr	CFO / Debt 3-yr	CFO / Interest 3-yr	CFO / Debt 2008	CFO / Interest 2008	CFO / Debt LTM 1Q 2009	CFO / Interest LTM 1Q 2009
Parent	17%	3.9	17%	3.9	16%	3.7	16%	3.7
Integrated	21%	4.7	21%	4.6	19%	4.4	19%	4.2
T&D	21%	4.6	19%	4.2	18%	4.0	20%	4.7
LDC	19%	4.5	18%	4.3	18%	4.5	20%	4.3

CFO / Debt = cash flow from operations before changes in working capital / total adjusted debt outstanding

While a modest decline in the financial ratios is not alarming today, the breadth of the decline across sub-factors is noticeable (with the exception of LDCs) when comparing the more recent results with the historical averages. We noted the possibility of this deterioration several years ago, when we questioned whether the industry's "back-to-basics" strategy was being retired prematurely, or at least before the originally articulated balance sheet goals were reached.



Regulation provides multiple notches of ratings benefit

About 50% of the utility sector's rating stems directly from its status as a regulated monopoly that provides an essential service to the general population. To gauge regulation's influence on the utility sector's ratings, we evaluated selected financial credit metrics, using the 3-year average financials (2006-2008) for the utility sector, and ran them through the rating methodologies for a selected group of large, capital-intensive, commodity-exposed industrial peers. Although many of these industrial sectors are also affected by various forms of regulation, regulation over profitability is less evident than the utility sector.[2]

[2] These industries may be affected by regulation, but our key interest for the electric utilities is the cost-recovery mechanism, which these other sectors lack.

Clearly, based only on the financial metrics, the utility sector would be, at best, a borderline investment-grade sector, if not for the regulatory support. The utility parent holding companies would more clearly appear in the non-investment-grade range. This is primarily a result of the industrial peers being required to maintain RCF/debt ratios of roughly 30% to be considered investment-grade, while utility-sector issuers need only maintain ratios above roughly 10%.

We conducted a second exercise, evaluating the selected industrial peer financials within our general utility rating methodology framework. Again, we only examined the three-year historical average financial ratios and excluded all other industry-specific rating factors. As the next table shows, the industrial peers appear to be strongly investment-grade when compared to the lower financial metric thresholds held out for utilities on a cash flow measure, but less so when evaluated on a capitalization perspective.

	Implied utility ratings based on selected industrial rating methodologies								Selected industrial ratings based on Utility rating methodology	
	Parent utility companies				Integrated utilities					
Sectors *	RCF/ Debt	Debt / Capz.	Debt / EBITDA	FCF / Debt	RCF/ Debt	Debt / Capz.	Debt / EBITDA	FCF / Debt	RCF/ Debt	Debt / Capz.
Airlines	--	Ba	Ba	Caa	--	Baa	Ba	Caa	Baa	Caa
Capital Goods	Ba	A	Ba	Caa	Ba	A	Baa	Caa	Aaa	Baa
Chemicals	--	Ba	Ba	Caa	--	Baa	Ba	Caa	Aa	Ba
Coal	Ba	Ba	Ba	Caa	Ba	Baa	Baa	Caa	Aaa	Baa
Oil & Gas integrated	Ba	Ba	--	--	Ba	Baa	--	--	Aaa	Aa
Packaging	--	--	Ba	Ca	--	--	Ba	Ca	A	B
Paper & Forest Prod.	Ba	--	Ba	Caa	Ba	--	Ba	Caa	Baa	Ba
Pharmaceutical	Ba	Ba	--	Caa	Ba	Ba	--	Caa	Aa	Baa
Shipping	B	--	Ba	B	Ba	--	Baa	B	Baa	Ba
Steel	--	Ba	Ba	Caa	--	Baa	Baa	Caa	Aaa	A

** Most of these selected groups of comparable industrial peers include 8-12 companies.*

Because the regulatory benefit is so critical to our ratings, it tends to represent the most important risk factor. While we continue to consider regulatory risk a lower risk today, we believe there are potential longer-term regulatory risks that could emerge on two fronts:

- Regulatory support for timely recovery could erode; and
- Regulators could reduce the authorized returns on investments, based on the perception that utilities have lower business risks than other industrial sectors and will find it easier to compete for capital.

Theoretically, regulators could attack the standard cost of capital arguments that assert competitive ROEs and other returns are necessary to attract capital. Our concern is that regulators could attempt to modify their views on the appropriate returns, since the sector's leverage is already benefited by regulation.

What could change the sector outlook to negative?

The electric utility industry appears reasonably well-positioned today within its investment-grade rating category, despite increasing business challenges. Modestly declining financial metrics—a fundamental credit negative—could eventually force us into a more negative position for the sector. For now, though, we continue to incorporate a view that regulators will ultimately provide timely financial relief.

A shift to a negative outlook could emerge based on our view that few utility management teams are taking meaningful steps to strengthen their balance sheets and therefore may not be sufficiently positioned to withstand unexpected shocks or challenges to the longer-term fundamental business plan, for its given rating category.

Nevertheless, most utility executives agree with our general view of the pending risks and challenges. They also believe they have enough time to assess the situation and gain better clarity about the facts. Our concern is if one or more challenges appear unannounced, at exactly the worst possible time. Since there is general agreement that these risks are legitimate, we conclude that conservative utility management teams would otherwise take precautionary measures to protect their franchise.

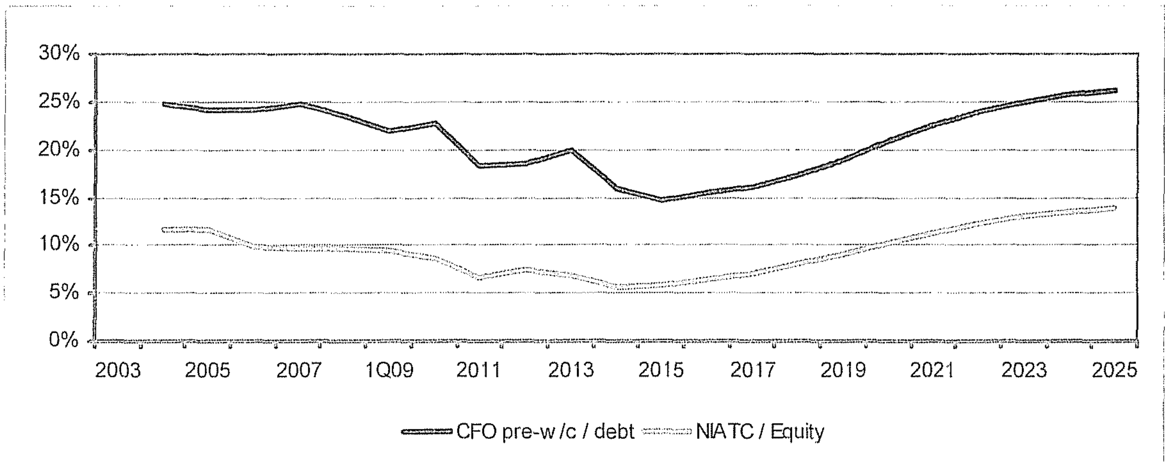
Beyond a widespread management failure to actively strengthen their balance sheets, the outlook for this sector could turn negative with a material change in the regulatory environment, which today tends to support the utilities' recovery of reasonable costs from ratepayers. We foresee no significant changes in this regulatory support at this time but will be carefully evaluating many of the rate case proceedings currently underway, including those in Texas, Florida, Virginia, New York and South Carolina.

Base-case financial projections for vertically integrated utilities

We evaluated historical financial statements for about 75 vertically integrated electric utilities, creating a hypothetical utility to illustrate financial projections over the next 20 years. Some of our assumptions:

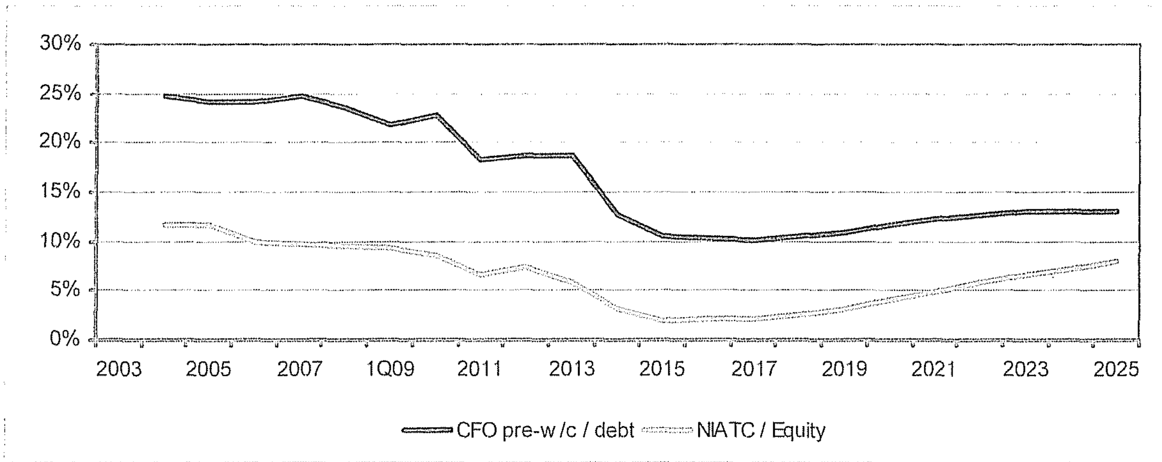
- All revenues come from sales of electricity.
- Volumes rise modestly over the next few years before reversing and remaining flat (0% growth) by the late 2010s. We believe these volume assumptions reflect a modest economic recovery over the next few years followed by flat volume growth associated with energy efficiency programs.
- Total authorized rate increases of 5% per year between 2010-2014, followed by 7.5% rate increases every year thereafter.
- Fuel and purchase power expenses alternating between 50% and 55% of total revenue every year, reflecting the volatility of fuel commodities. This creates some "choppiness" in our financial returns, so we illustrate the results of our models with rolling two-year averages.
- Carbon costs begin in 2014 at $5 per ton, increasing to $10 per ton in 2015 and by an additional $2.50 per ton annually thereafter.
- Energy efficiency costs, renewable energy costs, and other incremental costs total roughly 3% of revenues for the next three years, and 5% of revenues thereafter. We assume all "tracker" mechanisms are incorporated into this assumption. Any automatic recovery is assumed to be captured in the annual rate increase assumption noted previously.
- Operating and maintenance costs grow by 2% every year.
- Annual projected capital expenditures are based on the previous year's depreciation and amortization. Capital expenditures will amount to 250% of the previous year's D&A in 2010-2011, gradually scaling down to 125% by 2019 before rising again, to 275% by 2025. These capital expenditure trends reflect the sector's need for infrastructure investment—and herd cyclicality.
- We adjust the dividend-payout ratio and the amount of new debt financing (assuming a 6% coupon on all incremental new debt) to maintain a general debt-to-capitalization ratio of about 50%.

As a result of these base case assumptions, our hypothetical utility would generate CFO pre-w/c to debt and ROE over the next two decades as illustrated in the next graph:



Even allowing for some volatility in the financial ratios, this hypothetical utility would most likely be positioned for ratings upgrades. This could be based on the continued regulatory support and steadily improving CFO/debt ratios, possibly in the 2014-2015 timeframe, when the visibility over carbon-cost implications is clearer, and the majority of the bank credit facilities have already rolled.

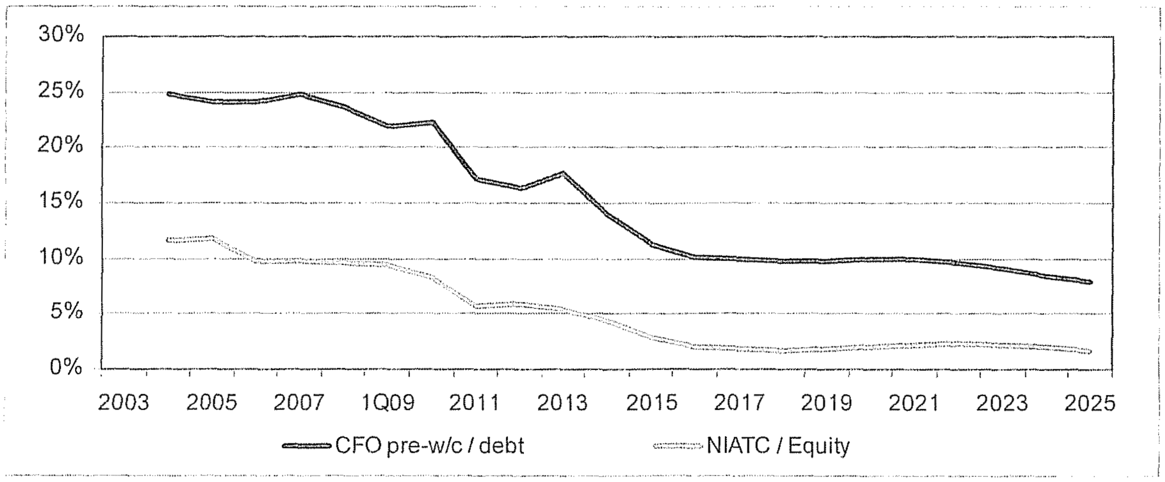
If, however, our base-case assumptions included a more costly carbon impact—for example, doubling our per-ton cost estimates to $10/ton in 2014 and $20/ton in 2015, and increasing by $5/ton every year thereafter—our hypothetical company's results would look less robust. This utility is likely to suffer modest rating downgrades, possibly around 2011-2013, as CFO / debt ratios approach the 10% threshold before showing signs of improvement in 2014-2015.



Carbon obviously represents a significant potential risk to this sector's long-term credit profile. Although we do not consider ROE a primary credit driver, we would be concerned if it fell significantly below the 9%-10% range over a sustained period: the lower the ROE, the greater uncertainty over the sector's capital allocation and stewardship by management teams and boards of directors. Presumably, management could look for better uses for their capital.

The current economic climate could make it impossible for our hypothetical utility regulators to authorize annual rate increases of 5%-7.5%, which is incorporated into our illustration. If today's severe economic conditions persist—as we believe they may into 2010, if not beyond—rate increases could eventually spark a backlash by both ratepayers and regulators.

If rate increases were limited to only 3% a year over the next five years, followed by 5% annual increases thereafter (versus 5% annual increases over the next five years and 7.5% annually thereafter), there could be a material amount of pressure on both the credit, as well as the equity, all other assumptions held constant.



Three primary challenges

The utility sector faces three major threats that would increase its overall business and operating risk profile. For the most part, these risks are not new to the sector, but are arguably downplayed or dismissed. Utilities have not yet reached a crisis point, but we think these challenges may combine and emerge together in the 2011-2013 timeframe, as the majority of the credit facilities expire and the incremental operating costs associated with carbon begin to appear. As a result, we believe the most effective course of action to protect existing ratings (and equity values) is to take active evasive measures and strengthen the balance sheet and bolster liquidity reserves. This will not be easy.

As noted previously, the biggest challenge is maintaining a supportive regulatory relationship. One component of this regulatory risk includes increasingly stringent environmental mandates for carbon and mercury. The likely passage of some federal law regulating carbon dioxide emissions—possibly as soon as this year or next[3]—could be a fundamental sector-changing event, with unknown effects on balance sheets and liquidity. Such uncertainties increasingly represent a primary consideration for credit ratings. We are struck by the industry's apparent lack of urgency regarding new, complex and potentially costly carbon rules. Moreover, we expect incrementally strict environmental mandates over the near to intermediate term concerning mercury, NOX, and SOX, among other pollutants. Again, though, few utilities appear visibly concerned.

A second big risk stems from the sector's heavy reliance on unfettered access to the capital markets as a component of its liquidity. The capital markets have accepted this reliance over many decades, and many utility issuers have been all but untouched by the recent and ongoing turmoil in the financial markets. Even so, the reliance on third-party financing remains a critical risk factor—especially as numerous bank credit facilities expire over 2011-2012. The increasing burden on our overall liquidity analysis may eventually stop us from assuming the sector has unfettered access to the capital markets. The dramatic changes in credit availability and the financial institutions require some caution. We believe utilities will see their available borrowing capacity decrease, possibly by as much as 25%-30%; that tenors will shorten, with two-year facilities more widespread than five-year; and that pricing will be substantially higher than today.

Finally, we are not sure today's level of authorized cost relief will continue. Utilities are among the most capital-intensive of all industrial sectors, with aging infrastructures that require constant maintenance and long-term capital investment. In addition, public policy agendas are influencing utilities' operating cost structure, which will contribute to increasing rate pressure. Utilities will find it increasingly difficult to balance a need for higher

[3] Most industry participants predict that new environmental mandates will take effect around 2012-2013.

rates with the ability to post returns that attract new capital investment. At some point, ratepayers and regulators may begin to resist these higher rates.

Consumers have limited ability to absorb new rate increases

All of these pressures indicate that there is pressure for higher electric rates, and we believe consumers and ratepayers may eventually complain to their elected officials. Once this inflection point is breached, the political and regulatory reaction will represent a major, fundamental and highly uncertain risk for the sector.

Regulators might find it increasingly difficult to authorize steadily increasing rates, especially in today's uncertain economic climate. No one knows how big an increase consumers can absorb; in any case the size would vary by location.

Even so, gasoline prices offer a look at how consumers react once this inflection point is reached, when $4-a-gallon gasoline in 2008 led to a distinct shift in behavior among U.S. motorists. That shift still persists a year later, even with gasoline prices much lower nationwide.

Although we acknowledge that electricity volumes are more inelastic than gasoline, we attempt to illustrate the possible U.S. consumer inflection point regarding electric rates. Our illustration begins with average household income in 2007. We subtract about 30% to reflect state and federal taxes and other primary deductions. The result is average disposable household income. We then compare the average annual utility bill to the average disposable household income, and arrive at the average electric bill as a percentage of disposable household income. As of 2007, this ratio was about 3.4%.

While no one claims to know exactly at what point consumers will begin to object to higher electric rates, we believe this inflection point is crossed roughly when the electric bill reaches 5%-10% of disposable income. This would imply annual electric bills of about $3,500-$1,800 from the current $1,200, and total aggregate rate increases of roughly 100%-50% over the existing national average of 10.65 cents per kwh.

Sharply higher utility bills and lackluster income growth: A politically volatile mix

If U.S. household outlays for electric and gas bills advance by 20% annually between 2010-2012, they would represent a record 4% of disposable personal income (DPI) by the end of that period. Aggregate outlays on electric and gas rose by 21.3% annualized on average during the three years that ended in the first quarter of 1977, while spending on electric and gas rose no higher than 2.8% of DPI—mostly because DPI grew by a comparatively rapid annual 9.9% on average.

By contrast, U.S. consumers would be enraged if their overall electric and gas bills soared more than 20% annualized during the 2010-2012 period if DPI rose by a much slower 1.8% annually, on average. DPI growth could indeed be this low, based on expectations of a soft U.S. labor market subject to competitive pressures from workforces in China and India—a marked contrast from 1977, when American workers were not yet subject to wage pressures from competitively priced labor in the emerging markets.

Consumer spending on gasoline and fuel oil soared by 26% during the 12 months that ended September 2008. These prices became a political issue, even though DPI rose at a relatively normal 5.3% during this period. Any sharp acceleration of energy costs amid decidedly weak income growth is likely to spark political discord.

Sources: John Lonski, Managing Director, Moody's Capital Markets Research Group; National Income Product Accounts (NIPA)

Carbon dioxide regulations represent huge risk

Six months into the Obama administration, legislation concerning federally mandated carbon dioxide regulations—the American Clean Energy and Security Act of 2009 (ACES), also known as the Waxman-Markey bill—has passed the House, and now resides with the Senate. The vast majority of our industry contacts—utility executives, regulators, legislators, bankers, consultants, and investors alike—feel that carbon-emission restrictions are now inevitable. Most expect the passage of some form of carbon-emission limits in 2009 or 2010, with actual implementation likely around 2012-2013.

But few market participants claim to understand the intricacies of the current version of the bill, and in any case, details will continue to change as the bill goes through the Senate (and eventually the House-Senate reconciliation process, if it passes). But we note that any version of ACES that becomes law could place a steep cost-burden on the electric utility industry, which relies heavily on emission-producing coal and natural gas.

The current legislation aims to achieve a 17% reduction in carbon emissions by 2020 from 2005 levels, and an 83% reduction by 2050. Assuming the electric utility sector was responsible for about two-thirds of the 6 trillion metric tons of carbon produced in 2005, the sector would have to reduce its own carbon emissions by about 1 trillion metric tons by 2020.[4] Estimates for the industry's carbon emission costs vary widely—from roughly the mid-single digits initially ($5/ton) growing to anywhere from $25/ton to $100/ton by 2025. We anticipate that the costs will begin at about $5/ton, increase rapidly to about $10/ton, and then rise at a modest but steady annual $2.50/ton.

We believe carbon-emission taxes could threaten some utilities' liquidity. For a simple utility that sells 20 Twh's of electricity, with 50% generated from coal and 25% from natural gas, the costs of carbon might range from $60 million-$300 million annually (assuming carbon taxes of $5/ton-$25/ton). Although we accept that most issuers would be able to recover their carbon costs from ratepayers, the timing related to any potential recovery remains unclear. This could put significant pressure on an issuer's liquidity position; in the current environment, this presents a material concern.

[4] This assumes that the electric utility sector must reduce its own carbon emissions by the same amount as the overall mandate—i.e., by 17% by 2020).

	Millions of Metric Tons	
	Total Sources	Energy Related
2005 CO2 emissions	6,032	5,975
Percentage derived by utilities	67%	67%
Implied utility CO2 emissions	4,011	3,974
Estimated total MW capacity (US)		950,000
Assumed % coal		50%
Assumed % natural gas		20%
Implied MW's by fuel source		
Coal		475,000
Natural gas		190,000
		665,000
Assumed capacity factors		
Coal		70%
Natural gas		25%
Implied generation (MWh's)		
Coal		2,912.7
Natural gas		416.1
		3,328.8
Implied CO2 emissions		
Coal (1 MWH = 1 ton)		2,912.7
Natural gas (1 MWH = 0.5 tons)		208.1
		3,120.8

From a credit perspective, we believe the carbon-emission legislation poses a major risk for the sector, primarily because of its complexity and apparent implications to liquidity. The legislation may become less imposing for the utility sector as it makes its way through the U.S. Senate, in part based on the sector's effective lobbying efforts. But the bill's complexity creates an expectation that a utility's financial statements could become less transparent with respect to these costs and their overall financial implications—a credit negative.

Liquidity harder to manage amid tighter credit markets

About 10% of the sector's $110 billion of credit facilities are expected to expire around October 2009, with another 10% expiring in April 2010. The remainder is due to expire in 2011 and 2012.

We believe the turmoil impacting the financial institutions will remove about 30% of the utility industry's current available credit which will drop overall liquidity capacity to roughly $77 billion from about $110 billion—a drop of about $30 billion. That is a lot of credit capacity coming out of the system.

The maturities of these credit facilities are most likely be in the 1-2 year tenor. More restrictive covenant packages, and possibly even material adverse-change clauses, may become more standard.

The capacity reduction results in a roughly $33 billion of liquidity sources removed from the system. Several utilities—including DTE Energy, FPL Group, NICOR, Southern and TECO Energy—have been reasonably successful in rolling over near-term credit facilities. Liquidity appears more challenged for others, such as AEP and Duke Energy. Ultimately, we believe the issue is one of pricing, not capacity availability.

No one knows how much carbon costs will impact working capital, and therefore liquidity. We would be concerned if more stringent borrowing restrictions and financial covenant requirements conspire to challenge the sector's ability to borrow on its facilities.

Two key issues sum up the unknowable effect of these potential emissions costs: How utilities will plan their long-term investments in this environment, and what their projected financial statements show.

Pension obligations weigh further on debts

In our last industry outlook we reviewed the 2007 funded status of pensions for several utilities. Based on these numbers we estimated that the utility sector might have exposure of upwards of $40 billion in under-funded pensions at the end of 2008. The actual pension disclosures indicated a modestly lower exposure, at $33 billion or a 73% funded status. While this funded status is better than we estimated it is by no means reason to celebrate.

From a credit perspective, Moody's treats under-funded pension obligations as a debt equivalent. As such $33 billion of additional debt equivalents clearly adds downward pressure to the credit ratings of some utilities. However, large pension under-funding in isolation did not lead to a broad wave of rating downgrades but were a factor in some downgrades, and will likely be a factor in future rating actions.

An important determinant in the rating impact on affected issuers is the magnitude of cash required to meet increased funding obligations relative to the company's liquid resources.[5] Pension funding requirements are governed by the Pension Protection Act of 2006 (PPA), which became effective in 2008. A required contribution must be paid within 8.5 months of the close of the plan year. As plan years begin one day after the fiscal year closes this would mean that a company with a December 31, 2008 year end may have until September 15, 2010 to make its contribution. However, companies' plans which were under-funded in the prior year compared to the PPA transition thresholds must make quarterly contributions in the current year.

While the PPA is very strict in many regards, there is some flexibility regarding required quarterly contributions. If a plan sponsor previously made voluntary contributions, which are referred to as prior year credits, it may be able to defer some or all of the required quarterly payments until the next year. Specifically if the plan is at least 80% funded in the current plan year it may be able utilize its prior year credits to defer payments. What these provisions effectively mean is that many plans which were in decent shape at the end of 2007 could push 2009 contributions off until 2010. If funding levels do not increase by the end of 2008, a utility might be required to make two years of contributions in 2010. Several may be positioned to push contributions off until 2011, but eventually the contributions will be made. We observe that many utilities are using prior year credits to delay funding requirements until 2010.

As the year draws to a close and we get some insight into probable 2009 funding levels we will take a very close look at potential liquidity issues due to large pension contributions in 2010 and 2011. This potential use of liquidity could become more of a concern depending on the state of the credit markets at this time, and the success utilities have in managing their liquidity sources.

Capital planning for future uncertainties

The electric utility sector depends on long-lived physical assets and long-term planning—both of which pose challenges for companies' business and operating risk profiles. Changes to federal and state policies over base-load requirements and emission regulations can wreak havoc on utility managers' ability to plan and invest.

[5] See Special Comment, "Managing Ratings With Increased Pension Liability," March 2009.

Moreover, the apparent solutions to several of the sector's challenges—renewables, smart grids, efficiency measures—may raise near-term costs for consumers. In essence, it is easier to maintain the status quo (and continue polluting with carbon-based fuels) than to change consumer behaviors. The up-front costs have to be authorized for recovery and amortized over a longer-term period of time, thus creating challenges for consumer acceptance. Of course, it is difficult to estimate the unintended consequences associated with burning those carbon-based fuels.

Nevertheless, we know consumer behaviors can change quickly, as the makers of horse-drawn carriages, typewriters, videocassettes, or even SUVs can attest. Although consumers may be slow to risk their own personal comfort by changing their use of an essential service like electric power, few analysts think the electric utility sector is immune to the risks of changing technology.

Federal initiatives associated with renewable energy standards also cause us some concern. We believe a material increase in renewable energy sources can create challenges with transmission grid operators, primarily because they cannot be scheduled. The greater the percentage of renewable resources used to generate power, the likelier we are to see "problems" for grid operators—and thus higher costs for ratepayers.

Conclusion

Historically, we have held that utilities manage their financial positions in a relatively conservative manner—that safe and reliable service is fundamental to their business plans and that they need healthy, regular infusions of debt and equity to fund their sizeable negative free cash flows.

Most of our issuers expect Washington to impose some form of carbon tax over the near- to intermediate term. Whether enacted this year or next, few believe it will disappear. But we believe utilities tend to downplay the magnitude of the potential risks from such legislation, with managements continuing to assume they will see the appropriate regulatory relief to cover their costs. Today, we continue to believe that prudently incurred costs and investments will be recovered, but we do not consider future cost-recovery a given. The uncertain economic climate clouds our visibility regarding these assumptions.

The sector needs significant capital to refurbish its infrastructure, implying sizeable negative free cash flows that must be financed in the capital markets. But credit availability is now tighter and costlier than even a year ago, and may remain this way indefinitely. Today we believe the sector will maintain unfettered access to the capital markets, and that expiring credit facilities will be rolled over into new facilities without a material reduction in capacity.

Regulators continue to scrutinize authorized ROEs, and intervenors increasingly feel that trackers and other recovery mechanisms can lower a utility's business risk profile. We expect to see growing tension between utilities—which need financial relief for increasing costs and investment—and consumers, whose tolerance for higher rates may be tested further in a poor economic environment.

Since few, if any, industry participants disagree with the risks identified in this report, we are somewhat baffled that utility management teams seem reluctant to proactively strengthen their balance sheets in the face of such challenges. In essence, we are talking about protecting the ultimate franchise of the utility's service territory and their ability to assure a safe and reliable essential service.

Appendix A: Macroeconomic Risk Scenarios

Our central outlook for the global economy has worsened since late last year, now taking the shape of a hook when plotted on a graph, as opposed to a "U."

This means we expect that the global recession this year will be deeper than we thought six months ago and that it will be followed by a slow and painful recovery for most economies in 2010, not a steep rebound, as previously thought.

We also can't rule out the risk that the global economy will follow a darker path, the downside scenario described below. The central and downside scenarios both begin with a severe downturn. It is the shape of the recovery that distinguishes them.

Central scenario (hook-shaped recovery): The prospect for a robust recovery is bleak, taking the shape of a hook. The U.S. economy could shrink between 2% and 3% in 2009, before expanding 1% to 2% in 2010—meaning that once the recovery takes shape, growth will be tepid at best.

Implications for the industry: Our stable outlook on the U.S. regulated utilities industry incorporates this view.

Downside scenario (L-shaped recovery): A recovery in 2010, if one emerges, takes the shape of an "L"—signifying years of little or no economic growth for most major economies.

There is a real risk of this happening. But it is too early to adopt this scenario as our base case because it is too early to tell whether fiscal and monetary stimulus policies are working. Some signs should emerge this summer. Odds are the fiscal packages will limit the damage.

Implications for the industry: Worsening U.S. unemployment adds to pressures on consumers, and commodity prices begin to rise, increasing bills for ratepayers. The hardship that some consumers face in paying their monthly bills creates political pressure against utilities. Regulators begin to question more closely, and in some cases deny, the utilities' requests for cost recovery, putting pressure on the companies' revenues and cash flow. Access to capital deteriorates and liquidity becomes a concern.

For the full report, published by the economists at Moody's Global Financial Risk Unit on May 6, 2009, please click here.

Appendix B: Peer index composition

PORTFOLIO: Parents		Vertically Integrated Utilities		T & D utilities		LDC utilities	
Entity Name	Current LT Rating	Entity Name	Current LT Rating	Entity Name	Current LT Rating	Entity Name	Current LT Rating
AES Corporation, (The)	B1	Alabama Power Company	A2	AEP Texas Central Company	Baa2	Alabama Gas Corporation	A1
Allegheny Energy, Inc.	Ba1	ALLETE, Inc.	Baa1	AEP Texas North Company	Baa2	Atlanta Gas Light Company	A3
Alliant Energy Corporation		Appalachian Power Company	Baa2	AES El Salvador Trust	Ba2	Bay State Gas Company	Baa2
Ameren Corporation	Baa3	Arizona Public Service Company	Baa2	American Transmission Company LLC *	A1	Berkshire Gas Company	Baa2
American Electric Power Company	Baa2	Avista Corp.	Baa3	Atlantic City Electric Company	Baa1	Boston Gas Company	Baa1
Black Hills Corporation	Baa3	Black Hills Power, Inc.	Baa2	Baltimore Gas and Electric Company	Baa2	Cascade Natural Gas Corp.	Baa1
CenterPoint Energy, Inc.	Ba1	Central Illinois Light Company	Ba1	CenterPoint Energy Houston Electric	Baa3	Colonial Gas Company	A2
Cleco Corporation	Baa3	Central Vermont Public Service	Ba2	Central Hudson Gas & Electric	A2	Connecticut Natural Gas	Baa1
CMS Energy Corporation	Ba1	Cleco Power LLC	Baa1	Central Illinois Public Service	Ba1	Indiana Gas Company, Inc.	Baa1
Consolidated Edison, Inc.	Baa1	Columbus Southern Power Company	A3	Central Maine Power Company	Baa1	KeySpan Gas East Corporation	A3
Constellation Energy Group, Inc.	Baa3	Consumers Energy Company	Baa2	Cleveland Electric Illuminating	Baa3	Laclede Gas Company	Baa1
Dominion Resources Inc.	Baa2	Dayton Power & Light Company	A2	Commonwealth Edison Company	Baa3	Michigan Consolidated Gas Company	Baa1
DPL Inc.	Baa1	Detroit Edison Company (The)	Baa1	Connecticut Light and Power	Baa1	New Jersey Natural Gas Company	Aa3
DTE Energy Company	Baa2	Duke Energy Carolinas, LLC	A3	Consolidated Edison Company of NY	A3	North Shore Gas Company	A3
Duke Energy Corporation	Baa2	Duke Energy Indiana, Inc.	Baa1	Delmarva Power & Light Company	Baa2	Northern Illinois Gas Company	A2
Duquesne Light Holdings, Inc.	Ba1	Duke Energy Kentucky, Inc.	Baa1	Duquesne Light Company	Baa2	Northwest Natural Gas Company	A3
Edison International	Baa2	Duke Energy Ohio, Inc.	Baa1	Empresa Electrica de Guatemala, S.A.	Ba3	Peoples Gas Light and Coke	A3
Emera Inc.	Baa2	El Paso Electric Company	Baa2	FortisAlberta Inc.	Baa1	Piedmont Natural Gas Company	A3
Enersis S.A.	Baa3	Empire District Electric Company	Baa2	Georgia Transmission Corporation *	Baa1	Public Service Co. of NC	A3
Entergy Corporation	Baa3	Entergy Arkansas, Inc.	Baa2	Illinois Power Company	Ba1	Questar Gas Company	A3
Exelon Corporation	Baa1	Entergy Gulf States Louisiana, LLC	Baa3	International Transmission Company *	A3	SourceGas LLC	Ba2
FirstEnergy Corp.	Baa3	Entergy Louisiana, LLC	Baa2	ITC Midwest LLC *	A3	South Jersey Gas Company	A3
FPL Group, Inc.	A2	Entergy Mississippi, Inc.	Baa3	Jersey Central Power & Light Company	Baa2	Southern California Gas Company	A2
Great Plains Energy Incorporated	Baa3	Entergy New Orleans, Inc.	Ba2	Massachusetts Electric Company	A3	Southern Connecticut Gas Company	Baa1
IDACORP, Inc.	Baa2	Entergy Texas, Inc.	Ba1	Metropolitan Edison Company	Baa2	Southwest Gas Corporation	Baa3
Integrys Energy Group, Inc.	Baa1	Florida Power & Light Company	A1	Michigan Electric Transmission Company, LLC *	A3	Terasen Gas (Vancouver Island) Inc.	A3
MidAmerican Energy Holdings Co.	Baa1	FortisBC Inc	Baa2	Narragansett Electric Company	A3	Terasen Gas Inc.	A3
NiSource Inc.	Baa3	Georgia Power Company	A2	New England Power Company	A3	Terasen Inc.	Baa2

U.S. Regulated Electric Utilities

PORTFOLIO: Parents

Entity Name	Current LT Rating
Northeast Utilities	Baa2
NSTAR	A2
NV Energy Inc.	Ba1
OGE Energy Corp.	Baa1
Pepco Holdings, Inc.	Baa3
PG&E Corporation	Baa1
Pinnacle West Capital Corporation	Baa3
PNM Resources, Inc.	Ba2
PPL Corporation	Baa2
Progress Energy, Inc.	Baa2
Public Service Enterprise Group	Baa2
Puget Energy, Inc.	Ba2
SCANA Corporation	Baa1
Sempra Energy	Baa1
Southern Company (The)	A3
TECO Energy, Inc.	Baa3
UIL Holdings Corporation	Baa3
UniSource Energy Corporation	Ba1
Vectren Utility Holdings, Inc.	Baa1
Westar Energy, Inc.	Baa3
Wisconsin Energy Corporation	A3
Xcel Energy Inc.	Baa1

Vertically Integrated Utilities

Entity Name	Current LT Rating
Green Mountain Power Corporation	A3
Gulf Power Company	A2
Hawaiian Electric Company, Inc.	Baa1
Idaho Power Company	Baa1
Indiana Michigan Power Company	Baa2
Indianapolis Power & Light Company	Baa2
Kansas City Power & Light Company	Baa1
Kansas City Power & Light (MO)	Baa3
Kentucky Power Company	Baa2
Kentucky Utilities Co.	A2
Louisville Gas & Electric Company	A2
Madison Gas and Electric Company	Aa3
MDU Electric & Gas Utilities	Not Rated
MidAmerican Energy Company	A2
Mississippi Power Company	A1
Monongahela Power Company	Baa3
Nevada Power Company	Ba3
Northern Indiana Public Service	Baa2
Northern States Power (Minnesota)	A3
Northern States Power (Wisconsin)	A3
NorthWestern Corporation	Baa2
Nova Scotia Power Inc.	Baa1
Ohio Power Company	A3
Oklahoma Gas & Electric Company	A2
Pacific Gas & Electric Company	A3
PacifiCorp	Baa1
Portland General Electric Company	Baa2
Progress Energy Carolinas, Inc.	A3
Progress Energy Florida, Inc.	A3
Public Service Company of Colorado	Baa1
Public Service Company of NH	Baa2

T & D utilities

Entity Name	Current LT Rating
New York State Electric and Gas	Baa2
Newfoundland Power Inc.	Baa1
Niagara Mohawk Power Corporation	A3
NSTAR Electric Company	A1
Ohio Edison Company	Baa2
Oncor Electric Delivery Company	Baa1
Orange and Rockland Utilities, Inc.	Baa1
PECO Energy Company	A3
Pennsylvania Electric Company	Baa2
Pennsylvania Power Co.	Baa2
Potomac Edison Company (The)	Baa3
Potomac Electric Power Company	Baa2
PPL Electric Utilities Corporation	Baa1
Public Service Electric and Gas Company	Baa1
Rochester Gas & Electric Corporation	Baa2
Superior Water, Light and Power	Baa1
Texas-New Mexico Power Company	Baa3
Toledo Edison Company	Baa3
Transelec S.A. *	Baa3
United Illuminating Company	Baa2
West Penn Power Company	Baa3
Western Massachusetts Electric	Baa2

* Transmission only

LDC utilities

Entity Name	Current LT Rating
UGI Utilities, Inc.	A3
Washington Gas Light Company	A2
Wisconsin Gas LLC	A1
Yankee Gas Services Company	Baa2

U.S. Regulated Electric Utilities

PORTFOLIO: Parents		Vertically Integrated Utilities		T & D utilities		LDC utilities	
Entity Name	Current LT Rating	Entity Name	Current LT Rating	Entity Name	Current LT Rating	Entity Name	Current LT Rating
		Public Service Company of NM	Baa3				
		Public Service Company of Oklahoma	Baa1				
		Puget Sound Energy, Inc.	Baa3				
		San Diego Gas & Electric Company	A2				
		Sierra Pacific Power Company	Ba3				
		South Carolina Electric & Gas	A3				
		Southern California Edison Company	A3				
		Southern Indiana Gas & Electric	Baa1				
		Southwestern Electric Power	Baa3				
		Southwestern Public Service	Baa1				
		Tampa Electric Company	Baa1				
		Tucson Electric Power Company	Baa3				
		Union Electric Company	Baa2				
		Virginia Electric and Power Company	Baa1				
		Wisconsin Electric Power Company	A1				
		Wisconsin Power and Light Company	A2				
		Wisconsin Public Service Corporation	A2				

** Transmission only*

PORTFOLIO: Unregulated Power - affiliated		Unregulated Power - independent		Cooperatives	
Entity Name	Current LT Rating	Entity Name	Current LT Rating	Entity Name	Current LT Rating
Allegheny Energy Supply Company	Baa3	AEI	B1	Arkansas Electric Cooperative Corporation	A2
AmerenEnergy Generating Company	Baa3	AES Chivor & Cia. S.C.A. E.S.P.	Ba2	Associated Electric Cooperative, Inc.	A2
Exelon Generation Company, LLC	A3	AES Gener S.A.	Baa3	Basin Electric Power Cooperative	A2
FirstEnergy Solutions Corp.	Baa2	Calpine Corporation	B2	Big Rivers Electric Corporation	(P)Baa1
KeySpan Generation LLC	Baa1	Covanta Holding Corporation	Ba2	Buckeye Power, Inc.	A2
PPL Energy Supply, LLC	Baa2	Dynegy Holdings Inc.	B2	Chugach Electric Association, Inc.	A3
PSEG Power L.L.C.	Baa1	Edison Mission Energy	B1	Dairyland Power Cooperative	A2
Southern Power Company	Baa1	Empresa Electrica del Norte Grande S.A.	Ba3	Golden Spread Electric Cooperative, Inc.	A3
System Energy Resources, Inc.	(P)Ba1	Mirant Corporation	B1	Great River Energy	A3
		NRG Energy, Inc.	Ba3	Hoosier Energy Rural Electric Cooperative Inc	Baa2
		RRI Energy, Inc.	B1	Minnkota Power Cooperative, Inc	Baa1
		Texas Competitive Electric Holdings Co LLC	Caa2	Oglethorpe Power Corporation	Baa1
		TransAlta Corporation	Baa2	Old Dominion Electric Cooperative	A3
				PowerSouth Energy Cooperative	Baa1
				South Mississippi Electric Power Assoc	Baa1
				Tri-State G&T Association Inc.	Baa2

Appendix C: Estimated Inflection Points by State

State-by-State Electricity Bill/Household Disposable Income Study*

Source:	BEA		EIA	Moody's	Estimates		
State	2007 Annual Household Income	2007 Annual Household Disposable Income	2007 Average Retail Electricity Price (Cents/KWh)	2007 Average Yearly Bill / Disposable Income	Implied Max Rate	Implied Max rate increase	Un-employ-ment Rate
Colorado	$61,141	$42,799	9.25	1.8%	$0.251	172%	7.9%
Utah	$53,529	$37,470	8.15	2.1%	$0.195	139%	6.0%
Minnesota	$58,058	$40,641	9.18	2.3%	$0.204	122%	8.1%
New Mexico	$44,356	$31,049	9.12	2.3%	$0.202	122%	7.5%
Washington	$58,080	$40,656	7.26	2.3%	$0.158	117%	9.2%
Wyoming	$48,744	$34,121	7.75	2.4%	$0.163	111%	5.3%
New Hampshire	$67,576	$47,303	14.88	2.4%	$0.312	110%	6.5%
Idaho	$49,184	$34,429	6.36	2.4%	$0.133	109%	8.0%
Michigan	$49,370	$34,559	10.21	2.4%	$0.210	106%	14.2%
California	$55,734	$39,014	14.42	2.6%	$0.280	94%	11.3%
Illinois	$52,506	$36,754	10.12	2.6%	$0.194	92%	10.3%
Wisconsin	$51,277	$35,894	10.87	2.6%	$0.206	90%	9.0%
Kansas	$48,497	$33,948	8.19	2.7%	$0.154	88%	7.8%
Rhode Island	$54,210	$37,947	14.05	2.7%	$0.260	85%	11.3%
Nebraska	$49,174	$34,422	7.59	2.7%	$0.140	84%	5.4%
Alaska	$62,993	$44,095	15.18	2.7%	$0.277	82%	10.3%
Oregon	$50,235	$35,165	8.19	2.8%	$0.145	77%	10.6%
Montana	$43,655	$30,559	8.77	2.8%	$0.155	76%	7.1%
North Dakota	$47,205	$33,044	7.30	2.9%	$0.128	75%	5.1%
District of Columbia	$50,783	$35,548	11.18	2.9%	$0.192	71%	10.0%
New Jersey	$60,508	$42,356	14.14	2.9%	$0.242	71%	9.1%
Iowa	$48,908	$34,236	9.45	2.9%	$0.161	70%	5.8%
South Dakota	$46,418	$32,493	8.07	3.0%	$0.137	69%	5.4%
Massachusetts	$58,463	$40,924	16.23	3.0%	$0.269	65%	8.7%
Vermont	$47,390	$33,173	14.15	3.0%	$0.233	65%	7.9%
Virginia	$59,161	$41,413	8.74	3.1%	$0.143	64%	7.1%
Ohio	$49,099	$34,369	9.57	3.1%	$0.155	62%	10.8%
West Virginia	$42,091	$29,464	6.73	3.1%	$0.108	60%	7.3%
Maine	$47,894	$33,526	16.52	3.1%	$0.264	60%	8.9%
Indiana	$47,453	$33,217	8.26	3.2%	$0.131	58%	10.7%
Missouri	$46,005	$32,204	7.69	3.2%	$0.120	56%	9.8%
Maryland	$65,630	$45,941	11.89	3.4%	$0.176	48%	7.0%
Pennsylvania	$48,437	$33,906	10.95	3.4%	$0.162	48%	8.5%
New York	$48,944	$34,261	17.10	3.6%	$0.236	38%	8.9%
Nevada	$54,058	$37,841	11.82	3.7%	$0.160	35%	10.9%
Oklahoma	$43,216	$30,251	8.58	3.7%	$0.115	34%	6.5%
Georgia	$48,641	$34,049	9.10	3.8%	$0.121	33%	9.7%

State-by-State Electricity Bill/Household Disposable Income Study*

Source:	BEA		EIA	Moody's	Estimates		
State	2007 Annual Household Income	2007 Annual Household Disposable Income	2007 Average Retail Electricity Price (Cents/KWh)	2007 Average Yearly Bill / Disposable Income	Implied Max Rate	Implied Max rate increase	Un-employ-ment Rate
Kentucky	$39,452	$27,616	7.34	3.9%	$0.095	29%	10.2%
Connecticut	$64,141	$44,899	19.11	3.9%	$0.245	28%	8.1%
Delaware	$54,589	$38,212	13.16	4.0%	$0.166	26%	8.0%
Arizona	$47,215	$33,051	9.66	4.0%	$0.121	25%	8.7%
Arkansas	$40,795	$28,557	8.73	4.1%	$0.106	22%	8.2%
Hawaii	$64,022	$44,815	24.12	4.2%	$0.285	18%	6.8%
North Carolina	$43,513	$30,459	9.40	4.2%	$0.111	18%	10.3%
South Carolina	$44,213	$30,949	9.19	4.3%	$0.107	16%	10.7%
Tennessee	$41,195	$28,837	7.84	4.4%	$0.089	14%	9.8%
Florida	$45,794	$32,056	11.22	4.9%	$0.115	2%	10.0%
Alabama	$42,212	$29,548	9.32	4.9%	$0.094	1%	8.8%
Louisiana	$41,313	$28,919	9.37	5.0%	$0.094	1%	7.3%
Texas	$46,053	$32,237	12.34	5.2%	$0.118	-4%	7.8%
Mississippi	$37,279	$26,095	9.36	5.4%	$0.086	-8%	11.4%
National	**$50,233**	**$35,163**	**10.65**	**3.4%**	**$0.157**	**47%**	**8.6%**

** Assumes implied maximum electric bills of 5% of calculated household disposable income.*

Moody's Related Research

Industry Outlooks

- U.S. Investor-Owned Electric Utility Sector, January 2009 (113690)
- North American Natural Gas Transmission & Distribution, March 2009 (115150)
- U.S. Coal Industry Outlook: Six-Month Update, April 2009 (116778)
- EMEA Electric and Gas Utilities, November 2008 (112344)

Special Comments

- Right-Way Hedging for Power Companies, June 2009 (117978)
- New Nuclear Generation: Ratings Pressure Increasing, June 2009 (117883)
- Texas T&D Utilities: Low Business Risk, but Credit Challenges Remain, June 2009 (117479)
- Proposed Wider Notching Between Certain Senior Secured Debt Ratings and Senior Unsecured Debt Ratings for Investment Grade Regulated Utilities, May 2009 (116748)
- Carbon Risks Becoming More Imminent for U.S. Electric Utility Sector, March 2009 (115175)
- Managing Ratings With Increased Pension Liability, March 2009 (115011)
- Near Term Bank Credit Facility Renewals To Be More Challenging For U.S. Electric And Gas Utilities, January 2009 (114031)
- Investor-Owned Electric Utilities in Ohio, January 2009 (114137)
- Carbon Dioxide: Regulating Emissions Following a Long and Winding Road, November 2008 (112822)
- U.S. Investor Owned Electric Utilities Somewhat Insulated (but not immune) from market stress, September 2008 (111891)
- New Nuclear Generating Capacity: Potential Credit Implications for U.S. Investor Owned Utilities, May 2008 (109152)
- EU Climate Change Strategy, May 2008 (108846)
- Decommissioning and Waste Costs for New Generation of Nuclear Power Structures, May 2008 (109086)
- New Generating Capacity in a Carbon Constrained World, March 2008 (107453)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

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REQUEST

Refer to the Avera Testimony at page 13.

a. Provide copies of the documents referenced in Footnotes 15-16.

b. Footnote 17 does not appear to be timely. Provide the most recent Standard & Poor's Corporation reports regarding credit issues affecting the electric utility industry.

RESPONSE

a. Copies of the above-referenced articles are included in Dr. Avera's workpapers, copies of which are provided on a CD in response to KIUC 1st Set, No. 1.

b. A copy of the most recent S&P publication addressing the top ten credit issues confronting electric utilities is attached.

WITNESS: William E. Avera

STANDARD
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January 22, 2010

Top 10 Investor Questions: U.S. Regulated Electric Utilities

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Top 10 Investor Questions: U.S. Regulated Electric Utilities

Regulated U.S. electric utility companies face many issues in 2010, including uncertainty about carbon regulation, reduced demand for two consecutive years, shifting capital expenditure plans, and numerous regulatory proceedings. Below we present our views regarding issues raised in many of the questions we receive about issuer credit quality and the industry.

Credit Concerns

What impact does the December 2009 Environmental Protection Agency's (EPA) endangerment finding that greenhouse gas emissions need to be regulated through the Clean Air Act have on electric utility credit quality?

In the near term, we believe the EPA ruling will have minimal effect on electric utility credit. Longer term, the ruling increases the likelihood that a plan to restrict or tax carbon-based emissions will gain traction in the U.S. Congress and legislators will forge a consensus. Whether that happens in 2010 is uncertain, given the difficulty in reaching agreement on healthcare and the looming midterm national elections in November.

We believe costs will likely rise to meet whatever mandate Washington establishes. For regulated electric utilities, Standard & Poor's Ratings Services continues to believe that ratepayers will bear the costs associated with reducing carbon emissions utilities will recover their costs through state regulatory proceedings. Ultimately, the dollar amount of the costs and the timeliness in recovering the money spent will be important factors affecting our view of a utility's credit quality.

Interestingly, in the past few months several electric providers, including American Electric Power Co. Inc., Duke Energy Corp, Exelon Corp., and Progress Energy Inc., have announced plans to close coal facilities in part as a symbolic response to the EPA's action and in consideration that future coal restrictions would make these plants uneconomic.

Has the recession caused electricity demand to decline permanently?

We believe it's likely that there has been some permanent loss of industrial load due to the shutdown of plants, especially those associated with the auto industry. The average loss is around 10% industrywide, with several pockets of acute weakness, especially in hard-hit Michigan, where Detroit Edison had a 25% drop.

With unemployment nationally above 10%, it's too early to tell if demand reduction for residential and commercial customers will continue. Sales have fallen for two consecutive years. A lethargic economy in 2010 may dampen electricity sales growth, which has closely followed GDP growth during previous recoveries.

Greater energy awareness by consumers may ultimately reduce demand meaningfully in the future. Smart-metering experiments by many electric utilities, including PPL Corp. and Pacific Gas and Electric Co., are a first step in sending price signals that could change customer behavior. In addition, government incentives for smart energy went to several electric utilities, including Duke Energy, Florida Power & Light Co., Progress Energy, Centerpoint Energy Inc., and PECO Energy Co.

How are regulators responding to cost pressures exacerbated by the economic malaise?

Early rulings by regulatory commissions are showing mixed results thus far in 2010. We continue to analyze each decision on a company-by-company basis, concentrating on the long-term credit implications and cash flow impact.

Recent examples include Michigan where regulators granted DTE Energy Co. a constructive rate order. Importantly, approved implementation of revenue "decoupling" (the insulation of a utility's financial health from declining sales due to conservation and other factors) and an uncollectible rider should help stem cash flow attrition in Michigan. Conversely, Florida regulators sharply reduced the dollar amounts requested for base rate increases for Florida Power Corp. and Florida Power & Light, leading to negative CreditWatch listings for both companies. An overbuilt real estate market, rising unemployment, projections of slow economic growth, and a populist message by the Florida governor were all factors in the rate-case outcomes.

Economic weakness is another challenge to managing regulatory risk. Many companies have authorized recovery mechanisms for fuel, trackers for pension and uncollectible expenses, and passing costs for renewable energy wind and solar projects through to customers. We view all of these adjustors as conducive for credit quality because they can generally help to smooth cash flows and keep balance-sheet deferrals to manageable levels.

What type of Federal government support can the industry expect?

With President Obama's commitment to newer and greener energy, we would expect that renewable energy will continue to receive favorable treatment from Washington. In January 2010, the Feds announced a $2.3 billion clean energy manufacturing tax credit. Renewable technologies, such as wind, solar, carbon dioxide capture and sequestration, and intelligent transmission grids are some of the areas that may benefit.

Greater disbursements from the Dept. of Energy (DOE) could also be a source of support. The DOE established its loan program in 2005, but rulemaking delays and funding appropriations prevented disbursements until 2009, when a solar panel manufacturer received $535 million. Additional projects are in the queue, including several new nuclear plants.

We believe incentive ratemaking from the Federal Energy Regulatory Commission for interstate transmission projects is another plus from a credit perspective for electric utilities. The FERC's authorized returns on equity have trended in excess of 100 basis points above rate-base investments in most cases. Our expectations are that electric utilities will continue benefitting given the FERC's commitment to national transmission expansion and the growing need to deliver renewable energy to load centers.

Will regulated electric utilities continue to be able to access capital markets in 2010?

We expect that regulated electric utilities will be able to access debt and equity markets throughout 2010 due to the industry's current solid investment-grade profile and fixed assets with substantial collateral value.

Debt issuance for the sector was robust for 2008 and 2009, with utilities issuing $80 billion in aggregate. Volume for 2010 likely will be lower given the amount of early refinancings completed in 2009 and upcoming maturities totaling less than $20 billion for the year. Curtailment of growth projects also reduces the need for capital.

Tackling the renewal of expiring credit facilities will be a priority item in 2010 for many electric utilities. Maintaining adequate liquidity is an important credit factor.

What do you expect from commodity prices?

Natural gas has bounced back from its September 2009 trough of $2.50 per thousand cubic feet, steadily rising to more than double that amount as the winter heating season started. Increased supplies from shale production, considerable gas reserves in storage, and lower demand from electric utilities will likely keep prices in check in 2010. However, short-term price volatility from numerous possibilities, including a sharp cold snap, a summer heat wave, or supply disruption, is always possible.

Coal production is pegged to be higher in 2010 despite higher stockpiles. With much of the supply locked in under high-price contracts, prices remain elevated at more than $50 per ton for Central Appalachian Basin coal. Several utilities had more than a 50-day supply on hand entering the winter, including large coal burner American Electric Power. With many of the contracts expiring this year, longer-term the fundamentals point to lower coal costs for electric utilities in the future.

How much renewable capacity will utilities install in 2010?

Projections from Global Energy Solutions and Edison Electric Institute are for about 3 gigawatts (GW) of wind and solar to become operational in 2010. This amount would be on par with 2009 and less than 2008 (6 GW) and 2007 (5 GW) totals. Difficulty in obtaining financing, reduced customer demand, and reluctance by electric utilities to enter into long-term purchase power agreements held back installations.

For newbuilds, wind has been the leader in renewable capacity, but advances in solar panel and related technology will likely boost solar capacity additions in coming years. Currently, renewable sources represent more than 8% of installed capacity; hydroelectric, wood, and biofuels are the predominant sources. If utilities adopted a national renewable portfolio standard of 15% by 2020 as some in Washington have proposed, a large amount of capital spending for wind and solar projects, some by the utilities themselves, would be needed to meet this mandate.

What level of capital expenditures do you expect?

We currently expect that capital budgets will focus on maintenance and reliability projects for the most part as electric utilities pare back their growth capital. Estimates are that the industry spent about $80 billion in 2009 and will spend a similar figure in 2010.

Utilities have scaled back or cancelled several larger projects, including the $1.6 billion Big Stone coal plant in South Dakota, American Electric Power's and Allegheny Energy's $3 billion PATH transmission project, and PEPCO Holdings Inc.'s $1 billion MAPP transmission project.

Longer-term, the industry has a lot of capital projects looming, especially for potential carbon compliance, renewable capacity, and transmission extensions and buildouts.

What are the current prospects for nuclear power?

We believe the prospects for nuclear power are flat. Many existing operators continue to seek license extensions (32 approvals and 12 applications under review) and increased output through turbine advances. The saga of waste storage and Yucca Mountain continue to be an unresolved problem for the industry, but, in our view, the real issues holding back development are slackening demand for electricity and reluctance to rely on unpredictable capital markets to support large projects with long lead times.

Support in Washington for a build-out of new nuclear units has been primarily in the form of a promise of DOE loans. At present, the dedicated amount of $18.5 billion may be enough to fund two new nuclear plants based on some costs estimates. The dollar cost compared with the existing assets base and market value for the largest electric utilities is clearly a constraint.

At present, several electric utilities including SCANA Corp and Southern Co. are still going forward with plans to build new nuclear units; in-service dates are still eight to 10 years away. In our view, any regulated electric utility that proceeds on the path to construction must have state political support, a legislatively approved cost recovery framework, and financially viable partners in place before spend a sizable amount of dollars to limit credit quality erosion. In addition, we will consider whether utilities are likely to recover financing costs as they occur, which would minimize deferrals and balance-sheet weakness, and ultimately preserve credit quality.

Will new accounting rules in the U.S. affect any electric utility ratings?

We expect that accounting rule changes related to affiliates being consolidated onto the balance sheet in 2010 will not have any impact on electric credit ratings. Standard & Poor's continues to adjust financial statements to better reflect the issuer's financial position as it relates to credit risk. Some of the adjustments include operating leases, postretirement benefits, and hybrid instruments similar to other corporate entities, as well as power purchase agreements and securitized costs unique to electric utilities.

Longer-term, a change from U.S. GAAP to the International Financial Reporting Standards that the Securities and Exchange Commission is considering could impact the income statement and equity section on the balance sheet for U.S. regulated electric utilities. If a change in standards occurs, we will continue to stress fundamental analysis based on the issuer's economic picture. The focus will remain on cash flow generation and sustainability and less emphasis on income, as restrictions on the ability of U.S. electric utilities to record regulatory assets or liabilities could increase earnings volatility.

Kentucky Power Company

REQUEST

Refer to the Avera Testimony at page 14.

Provide the Standard & Poor's Corporation document referenced in Footnote 20.

RESPONSE

A copy of the above-referenced document is included in Dr. Avera's workpapers, please refer to tab WP-14 on the CD provided in response to KIUC 1st, Item No. 1.

WITNESS: William E Avera

Kentucky Power Company

REQUEST

Refer to the Avera Testimony at page 16.

Provide a copy of the document referenced in Footnote 27.

RESPONSE

A copy of the above-referenced document is included in Dr. Avera's workpapers, copies of which are provided on a CD in response to KIUC 1st, Item No. 1.

WITNESS: William E Avera

Kentucky Power Company

REQUEST

Refer to the Avera Testimony at page 17.

Provide a copy of the documents referenced in Footnotes 28-29.

RESPONSE

Copies of the above-referenced documents are included in Dr. Avera's workpapers, copies of which are provided on the CD in response to KIUC 1st Set, Item No. 1, please refer to tab WP-19 and WP-20, respectively.

WITNESS: William E. Avera

Kentucky Power Company

REQUEST

Refer to the Avera Testimony at pages 23-27 and Exhibits WEA-2 and WEA-4.

a. Provide the most recent Value Line company profile sheets for each of the companies in the Utility Proxy Group.

b. For each electric utility listed in Value Line, but not selected for the Utility Proxy Group, provide the reason that it was not selected.

c. For each utility in the Utility Proxy Group, provide:

(1) Whether the utility operates in a traditional or restructured regualtion state.

(2) The percentage of revenues derived from non-regulated operations, and from international operations for 2009.

(3) Whether the utility operates in traditional or restructured states.

(4) The percentage of generation that is nuclear generation.

d. Explain why it is not circular to have American Electric Power in the Utility Proxy Group.

e. Provide a list of the state utility regulatory commissions and the attendant orders that explicitly based return on equity awards on the estimated returns of non-utility sector companies.

f. Part A of this testimony discusses the various risks faced both by Kentucky Power specifically and the electric utility industry generally. There is neither a comparable discussion of the risks faced by the Non-Utility Proxy Group nor any discussion of how these risks are comparable to the electric industry. Provide such discussions of the risks faced by each company and non-utility industry.

RESPONSE

a) Copies of the requested documents are attached.

b) Please refer to tab WP-49 of Dr. Avera's workpapers provided on the CD in response to KIUC 1st Set, Item No. 1.

c) Dr. Avera did not compile the requested information in the course of preparing his direct testimony because it was not necessary to support his analyses and conclusions. To the extent it is available, information responsive to this request can be obtained from the individual Form 10-K Reports filed by the respective utilities in Dr. Avera's proxy group, which are publicly available at: http://www.sec.gov/edgar/searchedgar/companysearch.html.

d. KPCo's equity capital is provided solely by its parent, American Electric Power Company, Inc. ("AEP"), and AEP meets the comparable risk criteria used to define the proxy group. Under these circumstances, it is appropriate to include AEP in the proxy group used to estimate the ROE for KPCo. Moreover, in Dr. Avera's experience, including the parent company in the proxy group used to estimate a fair ROE for an operating utility subsidiary is widely accepted by state and federal regulators. Because observable stock prices depend partially on investors' growth perceptions, and indirectly on their perceptions of the regulatory process, it can be implied that DCF cost of equity estimates for all regulated utilities involve some degree of circularity. This reinforces the need to consider other benchmarks. As noted in *Regulatory Finance, Utilities' Cost of Capital,* Public Utility Reports, Inc. (1994):
The circularity problem, to the extent it exists, can be mitigated by referencing data on non-regulated companies as well as on other utilities. (p. 202)

This is directly analogous to the approach recommended by Dr. Avera.

e. Dr. Avera has not conducted any detailed review of past regulatory orders to identify those cases in which regulators have "explicitly based return on equity awards on the estimated returns of non-utility sector companies." Dr. Avera would note, however, that in the early days of utility regulation it was common practice to base authorized returns solely on data for firms in the competitive sector of the economy. As explained in Dr. Avera's testimony, regulatory standards reflect the need to establish a rate of return that is commensurate with those available on other investments of comparable risk. As noted in *Regulatory Finance, Utilities' Cost of Capital,* Public Utility Reports, Inc. (1994):
It should be emphasized that the definition of a comparable risk class of companies does not entail similarity of operation, product lines, or environmental conditions, but rather

similarity of experienced business and financial risk. ... Investors do make such risk comparisons between industrial and utility stocks. (p. 58)

f. Dr. Avera did not include a discussion of the individual risks faced by the various industries or companies represented in his Non-Utility Proxy Group because this was not necessary to support his analyses and conclusions. As discussed in Dr. Avera's testimony, his analyses focused on an analysis of four objective risk indicators that are widely referenced by investors. These indicators provide broad, objective measures of overall investment risk that consider company and industry-specific factors. As a result, they provide a sound basis on which to compare the investment risks of the Non-Utility Proxy Group to those of KPCo and the Utility Proxy Group.

WITNESS: William E Avera

ALLEGHENY ENERGY NYSE-AYE

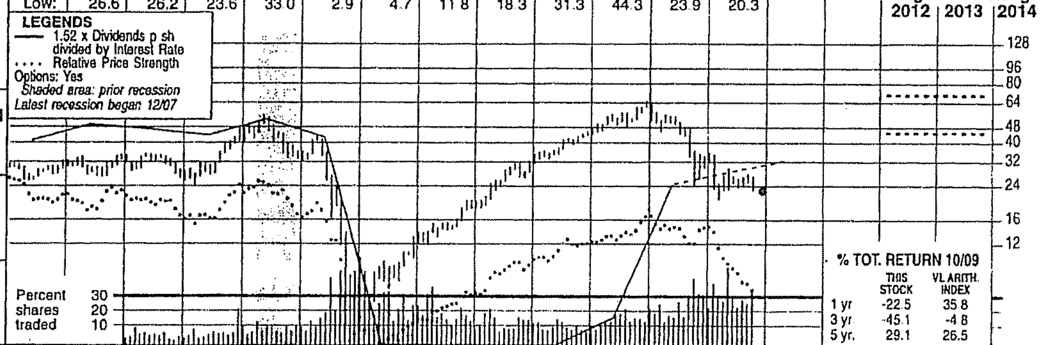
RECENT PRICE 22.60 | P/E RATIO 9.7 (Trailing: 10.9; Median: 22.0) | RELATIVE P/E RATIO 0.58 | DIV'D YLD 2.7% | VALUE LINE 148

TIMELINESS 4 Lowered 8/28/09
SAFETY 3 Raised 11/30/07
TECHNICAL 3 Raised 10/2/09
BETA .95 (1.00 = Market)

High:	34.9	35.2	48.8	55.1	43.9	13.1	20.2	32.3	46.3	65.5	64.8	36.0
Low:	26.6	26.2	23.6	33.0	2.9	4.7	11.8	18.3	31.3	44.3	23.9	20.3

LEGENDS
— 1.52 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area: prior recession
Latest recession began 12/07

Target Price Range 2012 | 2013 | 2014



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+210%)	34%
Low	45	(+100%)	21%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	1	0	0	0	0	0	0
Options	0	0	0	0	1	0	0	1	0
to Sell	1	0	0	0	1	0	0	0	0

Institutional Decisions

	4Q2008	1Q2009	2Q2009
to Buy	156	185	160
to Sell	157	129	145
Hld's(000)	139791	140739	140600

% TOT. RETURN 10/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-22.5	35.8
3 yr.	-45.1	-4.8
5 yr.	29.1	26.5

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
19.82	20.55	21.94	19.10	19.35	21.04	25.43	36.33	27.34	23.54	19.47	20.05	18.53	18.88	19.78	19.99	19.71	21.05	Revenues per sh	25.85
3.62	3.76	4.15	3.88	4.47	4.36	5.11	4.36	5.99	d1.52	d.06	2.67	2.79	3.58	4.12	3.95	3.85	4.10	"Cash Flow" per sh	5.20
1.88	1.91	2.04	1.73	2.30	2.15	2.70	2.11	3.73	d4.00	d2.64	.60	.94	1.89	2.42	2.33	2.25	2.35	Earnings per sh A	3.35
1.63	1.64	1.65	1.69	1.72	1.72	1.72	1.72	1.72	1.29	--	--	--	--	.15	.60	.60	.80	Div'd Decl'd per sh B	1.20
4.88	4.26	2.64	2.38	2.29	1.86	2.39	3.52	3.70	3.18	2.00	1.93	1.87	2.71	5.07	5.87	6.45	6.45	Cap'l Spending per sh	6.35
16.62	17.26	17.65	17.80	18.43	16.61	15.35	15.76	21.63	15.21	11.94	9.85	10.34	12.58	15.16	16.83	18.70	20.45	Book Value per sh C	25.90
117.66	119.29	120.70	121.84	122.44	122.44	110.44	110.44	125.28	126.98	127.01	137.43	163.95	165.36	167.22	169.36	170.00	171.00	Common Shs Outst'g E	174.00
14.0	11.6	12.0	17.2	12.6	14.3	11.8	15.6	11.7	--	--	25.4	26.9	20.4	22.0	19.4	Bold figures are		Avg Ann'l P/E Ratio	17.0
.83	.76	.80	1.08	.73	.74	.67	1.01	.60	--	--	1.34	1.43	1.10	1.17	1.16	Value Line		Relative P/E Ratio	1.15
6.2%	7.4%	6.7%	5.7%	5.9%	5.6%	5.4%	5.2%	3.9%	5.3%	--	--	--	--	.3%	1.3%	estimates		Avg Ann'l Div'd Yield	2.1%

CAPITAL STRUCTURE as of 9/30/09
Total Debt $4488.1 mill. Due in 5 Years $1971.4 mill.
LT Debt $4327.4 mill. LT Interest $240 mill.
(LT interest earned: 3.5x)

Pension Assets-12/08 $750 mill. Oblig. $1.1 bill.
Pfd Stock None
Common Stock 169,562,824 shs
as of 10/31/09

MARKET CAP: $3.8 billion (Mid Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
2808.4	4011.9	3425.1	2988.5	2472.4	2756.1	3037.9	3121.5	3307.0	3385.9	3350	3600	Revenues ($mill)	4500
314.5	238.4	454.0	d497.1	d329.2	72.6	153.4	318.7	412.9	395.4	385	400	Net Profit ($mill)	580
37.8%	61.5%	35.2%	--	--	36.5%	45.8%	35.1%	37.6%	34.2%	40.0%	40.0%	Income Tax Rate	36.0%
2.2%	3.1%	2.3%	--	--	--	--	--	1.6%	8.7%	8.0%	8.0%	AFUDC % to Net Profit	8.0%
56.0%	58.5%	53.8%	65.6%	76.4%	76.2%	67.9%	61.8%	60.9%	59.1%	58.0%	56.0%	Long-Term Debt Ratio	51.0%
42.1%	39.8%	45.0%	33.2%	22.5%	22.6%	31.6%	37.7%	39.1%	40.9%	42.0%	44.0%	Common Equity Ratio	49.0%
4023.8	4374.2	6019.7	5822.7	6749.8	5992.4	5360.2	5514.4	6479.3	6966.7	7530	7900	Total Capital ($mill)	9210
5207.2	5539.3	6853.0	6882.6	7453.5	6303.0	6277.4	6512.9	7196.6	8002.2	8730	9300	Net Plant ($mill)	9950
9.7%	7.4%	9.3%	NMF	NMF	4.3%	5.3%	7.4%	7.8%	7.3%	6.5%	6.5%	Return on Total Cap'l	7.5%
17.8%	13.1%	16.3%	NMF	NMF	5.1%	8.9%	15.1%	16.3%	13.9%	12.0%	11.5%	Return on Shr. Equity	13.0%
18.1%	13.4%	16.6%	NMF	NMF	5.0%	8.8%	15.3%	16.3%	13.9%	12.0%	11.5%	Return on Com Equity D	13.0%
6.1%	2.6%	9.4%	NMF	NMF	5.0%	8.8%	15.3%	15.3%	10.3%	9.0%	7.5%	Retained to Com Eq	8.5%
67%	81%	44%	NMF	NMF	7%	3%	0%	6%	26%	27%	34%	All Div'ds to Net Prof	36%

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	-10.5	+4.0	-1.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	10149	9705	9730
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	270	428	349

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	--	-3.5%	5.0%
"Cash Flow"	-1.0%	--	4.5%
Earnings	.5%	--	7.0%
Dividends	-17.5%	-24.5%	30.0%
Book Value	-1.5%	-2.0%	9.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	845.6	722.2	816.6	737.1	3121.5
2007	847.6	826.5	846.6	786.3	3307.0
2008	875.0	953.5	849.6	707.8	3385.9
2009	975.2	814.7	793.7	766.4	3350
2010	950	950	900	800	3600

Cal-endar	EARNINGS PER SHARE AF Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.66	.19	.65	.37	1.89
2007	.65	.49	.67	.65	2.42
2008	.80	.91	.52	.10	2.33
2009	.67	.41	.59	.58	2.25
2010	.70	.45	.60	.60	2.35

Cal-endar	QUARTERLY DIVIDENDS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	--	--	--	--	--
2006	--	--	--	--	--
2007	--	--	--	.15	.15
2008	.15	.15	.15	.15	.60
2009	15	.15	.15		

BUSINESS: Allegheny Energy (formerly Allegheny Power System), a holding company, distributes electricity through three subsidiaries in Pennsylvania, West Virginia, Maryland, and Virginia. Regulated electricity operations serve 1.6 million customers. 2008 Electricity revenues: residential, 47%; commercial, 26%; industrial, 26%; other, 1%. 2008 retail electric breakdown: generation, 68%; transmission, 6%; distribution, 26%. Mining and metals companies are typically the largest industrial customers. 2008 depreciation rate: 2.4%. Has 4,455 employees. Chairman, President & Chief Executive Officer: Paul J. Evanson. Incorporated: MD. Address: 800 Cabin Hill Drive, Greensburg, Pennsylvania 15601. Telephone: 724-837-3000. Internet: www.alleghenyenergy.com.

Allegheny Energy's third-quarter earnings advanced 13% year over year. The company posted share earnings of $0.59 for the period, excluding nonrecurring charges of nearly $38 million ($19.3 million of pretax interest expense related to a debt tender offer and $18.3 million in hedging charges). Bottom-line growth was driven by improved performance in AYE's delivery business, which earned $56 million, compared to the small loss posted during last year's third quarter. The gain can be attributed to considerable recovery of purchased power cost in Virginia and increased revenues from the company's transmission expansion projects. That said, AYE continues to feel the adverse effects of poor macroeconomic conditions. On a year-over-year basis, total megawatt-hour sales retreated 4%, with industrial revenues down nearly 9%.

We have lowered our 2010 share-earnings estimate, reflecting AYE's struggling generation business. Recessionary pressures continue to weigh on this segment, resulting in a sharp decline in plant output. Although some economic improvement has been evident of late, an overall recovery will likely be a slow process. As a result, demand will probably remain suppressed in the year ahead.

Infrastructure investments should benefit the company down the road. Management announced that it has invested about $156 million over the past two years in its West Virginia service area. The funds have been geared toward upgrading the regions aging infrastructure (i.e., expanding existing service and replacing old distribution equipment.) The $156 million does not include AYE's ongoing *TrAIL* and *PATH* projects, which are both moving along as scheduled.

The shares are ranked 4 (Below Average) for Timeliness. Sluggish economic activity has really hampered performance over the past 12 months, most notably in the industrial segment. We believe these headwinds will likely persist in the year ahead, as well. However, our outlook out to 2012-2014 is more favorable. We look for the aforementioned infrastructure investments to help bolster growth over the next 3 to 5 years. Appreciation potential over this time is above average.

Michael Ratty *November 27, 2009*

(A) Diluted earnings. Excl. nonrecur. items: '98, d$2.44; '99, d48¢; '00, 3¢; '01, d26¢; '02, d$1.04; '03, d16¢; '04, d$2.46; '05, d54¢; '06, 6¢. Incl. 52¢ restruct. chg in '96, 70¢ in '00, 52¢ in '02;. Next egs. rpt. early Mar. (B) Div'd susp'd Dec. '02. Reinstated Oct. '07. Div'ds historically pd early Mar., June, Sept., Dec. (C) Incl. def'd chgs in '08, $4.54/sh. (D) Rate base varies. Rtn allowed on eq.: 10.5%-11.90%; earned on avg. com. eq. in '08: 14.0%. Reg. Clim.: Avg. (E) In mill. (F) Quarterlies may not add due to change in share count.

Company's Financial Strength	B++
Stock's Price Stability	80
Price Growth Persistence	50
Earnings Predictability	20

ALLETE NYSE-ALE

RECENT PRICE **34.01** | P/E RATIO **16.1** (Trailing: 16.1; Median: NMF) | RELATIVE P/E RATIO **0.95** | DIV'D YLD **5.2%** | VALUE LINE **688**

TIMELINESS **4** Lowered 5/29/09
SAFETY **2** New 10/1/04
TECHNICAL **3** Lowered 11/27/09
BETA .70 (1.00 = Market)

2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+30%)	11%
Low	35	(+5%)	6%

Insider Decisions

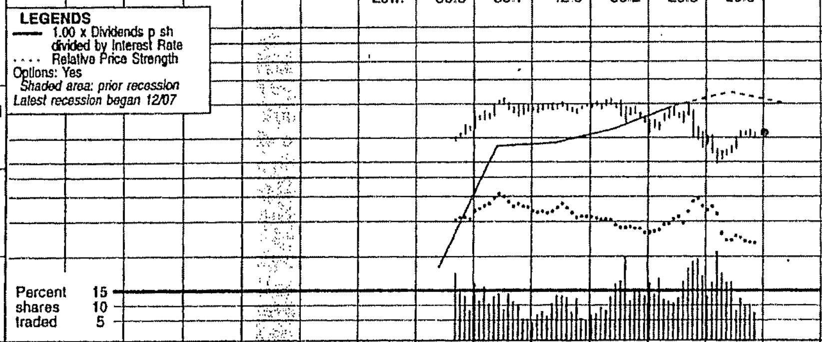
	F	M	A	M	J	J	A	S	O
to Buy	1	0	0	0	1	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2009	2Q2009	3Q2009
to Buy	82	80	73
to Sell	61	60	50
Hld's(000)	17770	19395	19827

	2004	2005	2006	2007	2008	2009
High:	37.5	51.7	49.3	51.3	49.0	35.3
Low:	30.8	35.7	42.6	38.2	28.3	23.3

Target Price Range 2012 | 2013 | 2014



% TOT. RETURN 11/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	3.5	60.4
3 yr.	-17.7	-4.1
5 yr.	12.0	22.3

ALLETE, in its current configuration, began trading on September 21, 2004, the day after it spun off its automotive services business, ADESA (NYSE: KAR), to shareholders and effected a 1-for-3 reverse stock split. ALLETE shareholders received one share of ADESA for each ALLETE share held. Data for the "old" ALLETE are not shown because they are not comparable.

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
--	--	--	--	--	25.30	24.50	25.23	27.33	24.57	*20.70*	*20.80*	Revenues per sh	*20.25*
--	--	--	--	--	2.97	3.85	4.14	4.42	4.23	*3.45*	*3.85*	"Cash Flow" per sh	*4.50*
--	--	--	--	--	1.35	2.48	2.77	3.08	2.82	*1.90*	*2.20*	Earnings per sh A	*2.75*
--	--	--	--	--	.30	1.25	1.45	1.64	1.72	*1.76*	*1.78*	Div'd Decl'd per sh B ■ †	*1.90*
--	--	--	--	--	2.12	1.95	3.37	6.82	9.24	*8.55*	*8.60*	Cap'l Spending per sh	*6.75*
--	--	--	--	--	21.23	20.03	21.90	24.11	25.37	*25.35*	*26.00*	Book Value per sh C	*28.25*
--	--	--	--	--	29.70	30.10	30.40	30.80	32.60	*35.00*	*36.50*	Common Shs Outst'g D	*42.00*
--	--	--	--	--	25.2	17.9	16.5	14.8	13.9	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
--	--	--	--	--	1.33	.95	.89	.79	.86	*Value Line*		Relative P/E Ratio	*.95*
--	--	--	--	--	.9%	2.8%	3.2%	3.6%	4.4%	*estimates*		Avg Ann'l Div'd Yield	*4.9%*
--	--	--	--	--	751.4	737.4	767.1	841.7	801.0	*725*	*760*	Revenues ($mill)	*855*
--	--	--	--	--	38.5	68.0	77.3	87.6	82.5	*60.0*	*75.0*	Net Profit ($mill)	*105*
--	--	--	--	--	38.8%	28.4%	37.5%	34.8%	34.3%	*34.0%*	*35.0%*	Income Tax Rate	*35.0%*
--	--	--	--	--	1.8%	.4%	1.4%	6.6%	5.8%	*8.0%*	*7.0%*	AFUDC % to Net Profit	*4.0%*
--	--	--	--	--	38.2%	39.1%	35.1%	35.6%	41.6%	*44.5%*	*46.5%*	Long-Term Debt Ratio	*49.0%*
--	--	--	--	--	61.8%	60.9%	64.9%	64.4%	58.4%	*55.5%*	*53.5%*	Common Equity Ratio	*51.0%*
--	--	--	--	--	1020.7	990.6	1025.6	1153.5	1415.4	*1595*	*1765*	Total Capital ($mill)	*2325*
--	--	--	--	--	883.1	860.4	921.6	1104.5	1387.3	*1625*	*1875*	Net Plant ($mill)	*2325*
--	--	--	--	--	5.1%	8.0%	8.6%	8.6%	6.7%	*5.0%*	*5.5%*	Return on Total Cap'l	*5.5%*
--	--	--	--	--	6.1%	11.3%	11.6%	11.8%	10.0%	*7.0%*	*8.0%*	Return on Shr. Equity	*9.0%*
--	--	--	--	--	6.1%	11.3%	11.6%	11.8%	10.0%	*7.0%*	*8.0%*	Return on Com Equity E	*9.0%*
--	--	--	--	--	4.7%	5.2%	5.0%	5.8%	3.9%	*Nil*	*1.0%*	Retained to Com Eq	*2.0%*
--	--	--	--	--	23%	54%	57%	51%	61%	*99%*	*86%*	All Div'ds to Net Prof	*75%*

CAPITAL STRUCTURE as of 9/30/09
Total Debt $645.7 mill. **Due in 5 Yrs** $107.4 mill.
LT Debt $628.4 mill. **LT Interest** $30.8 mill.
(LT interest earned: 4.8x)
Leases, Uncapitalized Annual rentals $8.3 mill.

Pension Assets-12/08 $273.7 mill. **Oblig.** $440.4 mill.

Pfd Stock None

Common Stock 34,891,615 shs.

MARKET CAP: $1.2 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	+1.1	+.3	+1.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	4.15	4.82	4.73
Capacity at Peak (Mw)	1761	1701	1757
Peak Load, Winter (Mw)	1586	1614	1582
Annual Load Factor (%)	*80.0*	*80.0*	*80.0*
% Change Customers (avg.)	+1.3	+1.3	.7
Fixed Charge Cov. (%)	503	503	438

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	--	--	*-4.0%*
"Cash Flow"	--	--	*1.0%*
Earnings	--	--	*-1.0%*
Dividends	--	--	*3.0%*
Book Value	--	--	*3.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2006	192.5	178.3	199.1	197.2	767.1
2007	205.3	223.3	200.8	212.3	841.7
2008	213.4	189.8	201.7	196.1	801.0
2009	199.6	164.7	178.8	*181.9*	*725*
2010	*205*	*175*	*190*	*190*	*760*

Calendar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2006	.68	.49	.78	.82	2.77
2007	.93	.80	.58	.77	3.08
2008	.82	.37	.85	.78	2.82
2009	.55	.29	.49	*.57*	*1.90*
2010	*.70*	*.35*	*.55*	*.60*	*2.20*

Calendar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.30	.315	.315	.315	1.25
2006	.3625	.3625	.3625	.3625	1.45
2007	.41	.41	.41	.41	1.64
2008	.43	.43	.43	.43	1.72
2009	.44	.44	.44	.44	

BUSINESS: ALLETE, Inc. is the parent company of Minnesota Power, which supplies electricity to 144,000 customers in northeastern Minn., and Superior Water, Light & Power in northwestern Wisc. Electric revenue mix, '08: taconite mining/processing, 31%; paper/wood products, 11%; other industrial, 2%; residential, 12%; commercial, 12%; wholesale, 23% other, 9%. Has real estate operation in Florida. Discontinued water-utility ops. in '01. Spun off automotive remarketing ops. in '04. Generating sources, '08: coal & lignite, 65%; hydro, 4%; purchased, 31%. '08 depr. rate: 2.5%. Has 1,500 employees. Chairman & CEO: Donald J. Shippar. President: Alan R. Hodnik. Inc.: MN. Address: 30 West Superior St., Duluth, MN 55802-2093. Tel.: 218-279-5000. Internet: www.allete.com.

ALLETE's utility subsidiary has filed a general rate case. Minnesota Power requested a tariff hike of $81 million (19%), based on a return of 11.5% on a common-equity ratio of 54.3%. An interim rate increase (subject to refund) of $48.5 million will take effect at the start of 2010. A final decision may well occur by the end of 2010.

Minnesota Power received a final order on the rate case it filed in 2008. The decision provided for an increase of $20.4 million, effective on November 1st, based on a 10.74% return on a 54.79% common-equity ratio. The order was disappointing, given that it was below the $35 million interim rate boost. In fact, refunds of previously collected revenues hurt share net by $0.40 in the first nine months of 2009 and will probably amount to another two or three cents in the fourth quarter.

Earnings are headed way down in 2009. Besides the effects of the aforementioned revenue refunds, ALLETE booked some unusual (but not nonrecurring) gains in 2008, which made the year-to-year comparison tougher. Also, the company's real estate operation in Florida is likely to swing from a small profit last year to a $5 million loss (primarily from property taxes) in 2009. Finally, average shares outstanding are up because ALLETE is gradually issuing common equity to finance its capital budget.

We estimate that the bottom line will make a partial recovery in 2010. We assume that Minnesota Power receives interim rate relief, and that the usage of power by the utility's industrial customers rebounds somewhat after a decline in 2009. Our share-net estimate is within ALLETE's targeted range of $2.05-$2.35.

The board of directors usually considers a dividend increase in January. We continue to estimate a boost in the quarterly disbursement, but have cut our forecast to an increase of just a half cent a share. But we wouldn't rule out the possibility of no increase at all, given the high payout ratio and the uncertainty about the pending rate case.

We don't recommend this stock. The yield is somewhat above the utility average, but 3- to 5-year total return potential is below the industry mean.

Paul E. Debbas, CFA *December 25, 2009*

(A) Diluted EPS. Excl. nonrec. gain (loss): '04, 2¢ net; '05, ($1.84); gain (losses) on discontinued operations: '04, $2.57, '05, (16¢); '06, (2¢); loss from accounting change: '04, 27¢. Next earnings report due mid-Feb. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '08: $7.65/sh. (D) In mill. (E) Rate base: Original cost deprec. Rate allowed on com. eq. in '09: 10.74%; earned on avg. com. eq., '08: 10.7%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	55
Earnings Predictability	65

ALLIANT ENERGY NYSE-LNT

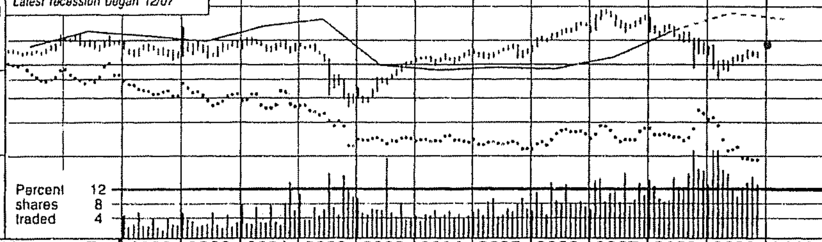
RECENT PRICE 30.49 | P/E RATIO 15.2 (Trailing: 16.3, Median: 13.0) | RELATIVE P/E RATIO 0.90 | DIV'D YLD 5.2% | VALUE LINE 689

TIMELINESS 5 Lowered 11/13/09
SAFETY 2 Raised 9/28/07
TECHNICAL 2 Raised 12/11/09
BETA .70 (1.00 = Market)

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
High:	34.9	32.4	37.8	33.2	31.0	25.1	28.8	30.6	40.0	46.5	42.4	31.0
Low:	28.0	25.2	25.8	27.5	14.3	15.0	23.5	25.6	27.5	34.9	22.8	20.3

Target Price Range 2012 | 2013 | 2014

LEGENDS
— 0.95 x Dividends p sh divided by Interest Rate
... Relative Price Strength
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+50%)	15%
Low	35	(+15%)	9%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2009	2Q2009	3Q2009
to Buy	108	130	112
to Sell	148	97	125
Hld's(000)	62748	62088	60163

Percent shares traded 12 8 4

% TOT. RETURN 11/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-8.7	60.4
3 yr.	-19.5	-4.1
5 yr.	23.5	22.3

Alliant Energy, formerly called Interstate Energy Corporation, was formed on April 21, 1998 through the merger of WPL Holdings, IES Industries, and Interstate Power. WPL stockholders received one share of Interstate Energy stock for each WPL share, IES stockholders received 1.14 Interstate Energy shares for each IES share, and Interstate Power stockholders received 1.11 Interstate Energy shares for each Interstate Power share.

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
27.83	30.44	30.97	28.26	28.19	25.56	28.02	28.93	31.15	33.33	*30.65*	*32.15*	Revenues per sh	*39.65*
5.71	6.57	5.82	4.52	4.19	4.69	5.46	4.33	5.12	4.56	*4.30*	*4.80*	"Cash Flow" per sh	*6.55*
2.19	2.47	2.42	1.18	1.57	1.85	2.21	2.06	2.69	2.54	*1.85*	*2.25*	Earnings per sh A	*3.10*
2.00	2.00	2.00	2.00	1.00	1.02	1.05	1.15	1.27	1.40	*1.50*	*1.60*	Div'd Decl'd per sh B ■ †	*1.92*
6.06	13.50	9.13	7.12	7.69	5.55	4.51	3.42	4.91	7.96	*10.80*	*9.40*	Cap'l Spending per sh	*11.65*
27.29	25.79	21.39	19.89	21.37	22.13	20.85	22.83	24.30	25.56	*27.05*	*28.55*	Book Value per sh C	*31.05*
78.98	79.01	89.68	92.30	110.96	115.74	117.04	116.13	110.36	110.45	*111.00*	*112.00*	Common Shs Outst'g D	*116.00*
13.0	11.8	12.6	19.9	12.7	14.0	12.6	16.8	15.1	13.4	*Bold figures are*		Avg Ann'l P/E Ratio	*13.0*
.74	.77	.65	1.09	72	.74	.67	.91	.80	.80	*Value Line*		Relative P/E Ratio	*.85*
7.0%	6.9%	6.6%	8.5%	5.0%	3.9%	3.8%	3.3%	3.1%	4.1%	*estimates*		Avg Ann'l Div'd Yield	*4.8%*
2198.0	2405.0	2777.3	2608.8	3128.2	2958.7	3279.6	3359.4	3437.6	3681.7	*3400*	*3600*	Revenues ($mill)	*4600*
178.2	203.1	194.9	113.1	176.6	229.5	337.8	260.1	320.8	280.0	*205*	*250*	Net Profit ($mill)	*360*
40.3%	54.0%	23.5%	24.2%	28.9%	26.7%	19.0%	43.8%	44.4%	33.4%	*15.0%*	*30.0%*	Income Tax Rate	*35.0%*
4.1%	4.3%	5.7%	6.8%	11.7%	8.1%	3.0%	3.1%	2.4%	8.8%	*6.0%*	*6.0%*	AFUDC % to Net Profit	*6.0%*
39.6%	47.0%	54.7%	56.4%	44.8%	45.0%	41.6%	31.4%	32.4%	36.3%	*40.0%*	*39.0%*	Long-Term Debt Ratio	*37.5%*
57.4%	50.2%	42.7%	39.2%	50.0%	50.2%	53.1%	62.9%	61.9%	58.6%	*55.5%*	*56.5%*	Common Equity Ratio	*58.5%*
3756.0	4061.4	4490.2	4679.1	4738.4	5104.7	4599.1	4218.4	4329.5	4815.6	*5395*	*5645*	Total Capital ($mill)	*6145*
3486.0	3719.3	3862.8	3729.2	4432.6	5284.6	4866.2	4944.9	4679.9	5353.5	*6100*	*6300*	Net Plant ($mill)	*7000*
6.1%	6.6%	6.2%	4.1%	5.7%	6.1%	8.9%	7.5%	8.6%	7.0%	*5.5%*	*6.0%*	Return on Total Cap'l	*7.5%*
7.9%	9.4%	9.6%	5.5%	6.8%	8.2%	12.6%	9.0%	11.0%	9.1%	*6.5%*	*7.5%*	Return on Shr. Equity	*9.5%*
8.0%	9.6%	9.8%	5.8%	6.7%	8.2%	13.1%	9.1%	11.3%	9.3%	*7.0%*	*8.0%*	Return on Com Equity E	*10.0%*
.7%	1.9%	1.6%	NMF	2.5%	3.8%	8.1%	4.0%	5.9%	3.8%	*.5%*	*1.5%*	Retained to Com Eq	*3.5%*
92%	81%	85%	NMF	67%	58%	42%	59%	50%	62%	*90%*	*79%*	All Div'ds to Net Prof	*67%*

CAPITAL STRUCTURE as of 9/30/09
Total Debt $2427.4 mill. **Due in 5 Yrs** $890.0 mill.
LT Debt $2155.9 mill. **LT Interest** $135.0 mill.
(LT interest earned: 3.3x)

Pension Assets-12/08 $565.9 mill **Oblig.** $896.4 mill.
Pfd Stock $243.8 mill. **Pfd Div'd** $18.7 mill.
449,765 shs. $100 par; 8,199,460 shs. $25 par

Common Stock 110,634,276 shs.

MARKET CAP: $3.4 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	-1.7	+1.8	-1.2
Avg. Indust. Use (MWH)	4180	4282	4386
Avg. Indust. Revs. per KWH (¢)	5.96	5.77	5.86
Capacity at Peak (Mw)	4985	4902	4945
Peak Load, Summer (Mw)	5987	5751	5491
Annual Load Factor (%)	52.0	53.0	53.5
% Change Customers (yr-end)	+1.8	-1.8	+.1
Fixed Charge Cov. (%)	350	416	300

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	0.5%	1.5%	*4.0%*
"Cash Flow"	-1.0%	-0.5%	*6.0%*
Earnings	3.0%	7.0%	*4.0%*
Dividends	-4.5%	-5.0%	*7.0%*
Book Value	2.0%	3.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	930.9	696.8	890.4	841.3	3359.4
2007	912.7	746.2	907.3	871.4	3437.6
2008	992.0	827.4	980.3	882.0	3681.7
2009	949.9	742.3	885.7	*822.1*	*3400*
2010	*960*	*800*	*925*	*915*	*3600*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.56	.39	.75	.36	2.06
2007	.56	.43	1.05	.65	2.69
2008	.62	.47	.99	.46	2.54
2009	.30	.34	.77	*.44*	*1.85*
2010	*.40*	*.40*	*.85*	*.60*	*2.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.263	.263	.263	.263	1.05
2006	.288	.288	.288	.288	1.15
2007	.318	.318	.318	.318	1.27
2008	.35	.35	.35	.35	1.40
2009	.375	.375	.375	.375	

BUSINESS: Alliant Energy Corp., formerly named Interstate Energy, is a holding company formed through the merger of WPL Holdings, IES Industries, and Interstate Power. Supplies elect. (65% of revs.), gas (19%), and other services (16%) in Wisconsin, Iowa, Minnesota, & Illinois. Elect. revs. by state: WI, 48%; IA, 49%; MN, 3%. Elect. rev.: resid., 35%; comm'l, 27%; ind'l, 30%; wholesale, 8%; other, 5%. Fuel sources, '08: coal, 54%; nuclear, 17%; gas, 3%; wind, 3%; other, 23%. Fuel costs: 50% of revs. '08 deprec. rate: 3.3%. Est'd plant age: 11 yrs. Has 5,318 employees. Chairman, president & chief executive officer: William D. Harvey. Inc.: Wisconsin. Address: 4902 N. Biltmore Lane, Madison, WI 53718. Telephone: 608-458-3311. Internet: www.alliantenergy.com.

Alliant Energy reported lower revenues for the third quarter. The company has been operating in an unfavorable environment in recent times. Performance in the third quarter was hurt by cool summer weather, along with lower industrial and wholesale revenue due to economic softness. Wisconsin Power and Light (WPL) continues to experience weakness, and the wind development business has yet to benefit from existing or pending legislation intended to spur growth in renewable energy markets. On the bright side, healthy results at Interstate Power and Light (IPL) supported performance. Overall, share net came in at $0.77 for the interim, well below the prior-year tally. In keeping with *Value Line* convention, our earnings presentation excludes an aftertax nonrecurring charge of $128.2 million ($1.16 per share) related to the early retirement of debt.

The business environment may well remain challenging in the near term. We anticipate an unfavorable comparison for the fourth quarter. The company has reduced its 2009 share-net guidance from $1.80-$2.00 to $1.75-$1.90. Consequently, we have lowered our bottom-line call by a nickel, to $1.85. Results may improve in 2010, assuming a favorable rate case outcome (discussed below) and a resurgence in the wind development market.

The company is seeking higher rates. IPL originally filed a request for an annual increase of $171 million (17%), but has since revised this request, and is now seeking an increase of $146 million (14%). An interim hike of $84 million (8%) has been effective since March. The company's focus on procuring rate relief is important, as it depends on such approved revenue increases to help its utilities cope with rising costs and allow them to recover sizable capital investments.

These shares carry our Lowest (5) rank for Timeliness. But the stock earns high marks for Safety, Price Stability, and Earnings Predictability. Moreover, we project higher revenues and share earnings by 2012-2014. As a result, this issue has worthwhile risk-adjusted total return potential, given its healthy dividend yield. Conservative, income-oriented investors may find this issue attractive.

Michael Napoli, CPA *December 25, 2009*

(A) Diluted EPS. Excl. nonrecur. gains (losses): '99, 32¢; '00, $2.56; '01, (28¢); '03, net 24¢; '04, (58¢); '05, ($1.05); '06, 83¢; '07, $1.09; '08, 7¢. Next egs. rpt. due in February.
(B) Div'ds historically paid in mid-Feb., May, Aug., and Nov. ■ Div'd reinvest. plan avail. † shareholder invest. plan avail. (C) Incl. deferred chgs. in '08: $213.3 mill., $1.93/sh. (D) In mill.
(E) Rate base: Orig. cost. Regul. Clim.: WI, Above Avg.; IA, Below Avg.

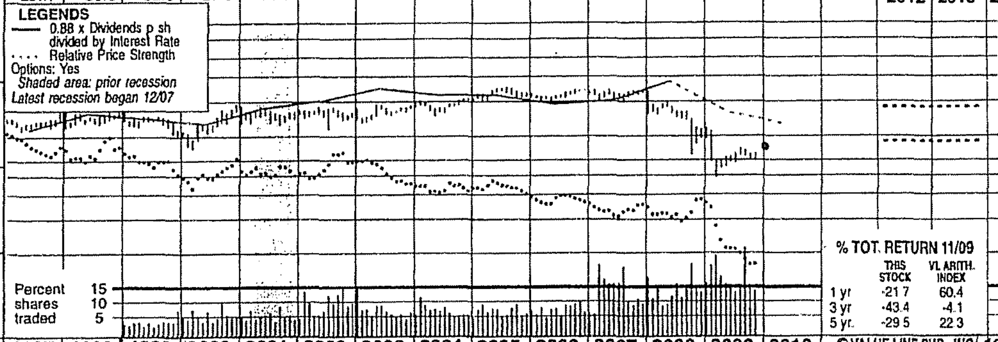
Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	75

AMEREN NYSE-AEE

RECENT PRICE 28.10 | P/E RATIO 11.4 (Trailing: 10.3 Median: 15.0) | RELATIVE P/E RATIO 0.67 | DIV'D YLD 5.5% | VALUE LINE 690

TIMELINESS 4 Lowered 9/25/09
SAFETY 3 Lowered 6/26/09
TECHNICAL 2 Raised 12/11/09
BETA .80 (1.00 = Market)

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
High:	44.3	42.9	46.9	46.0	45.3	46.5	50.4	56.8	55.2	55.0	54.3	35.3
Low:	35.6	32.0	27.6	36.5	34.7	37.4	40.6	47.5	48.0	47.1	25.5	19.5



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+60%)	16%
Low	30	(+5%)	7%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2009	2Q2009	3Q2009
to Buy	149	148	163
to Sell	181	137	122
Hld's(000)	117277	121636	135268

% TOT. RETURN 11/09

	THIS STOCK	VL ARITH. INDEX
1 yr	-21.7	60.4
3 yr	-43.4	-4.1
5 yr.	-29.5	22.3

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
20.23	20.13	20.59	22.13	24.24	24.18	25.68	28.10	32.64	24.93	28.20	26.43	33.12	33.30	36.23	36.92	29.85	32.25	Revenues per sh	37.00
4.83	5.13	5.14	5.12	4.96	5.36	5.36	6.11	6.33	5.28	6.29	5.57	6.10	6.02	6.76	6.44	5.95	5.80	"Cash Flow" per sh	6.50
2.77	3.01	2.95	2.86	2.44	2.82	2.81	3.33	3.41	2.66	3.14	2.82	3.13	2.66	2.98	2.88	2.75	2.55	Earnings per sh A	3.00
2.34	2.40	2.46	2.51	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	1.54	1.54	Div'd Decl'd per sh B ■ †	1.70
2.61	3.08	3.05	3.18	2.77	2.37	4.16	6.77	7.99	5.11	4.19	4.13	4.63	4.99	6.96	9.75	7.10	4.55	Cap'l Spending per sh	6.25
21.60	22.22	22.71	23.06	22.00	22.27	22.52	23.30	24.26	24.93	26.73	29.71	31.09	31.86	32.41	32.80	33.10	34.00	Book Value per sh C	37.25
102.12	102.12	102.12	102.12	137.22	137.22	137.22	137.22	138.05	154.10	162.90	195.20	204.70	206.60	208.30	212.30	238.00	242.00	Common Shs Outst'g D	252.00
14.6	11.6	12.6	13.8	15.5	14.2	13.5	11.0	12.1	15.8	13.5	16.3	16.7	19.4	17.4	14.2	Bold figures are		Avg Ann'l P/E Ratio	12.0
.86	.76	.84	.86	.89	.74	.77	.72	.62	.86	.77	.86	.89	1.05	.92	.86	Value Line		Relative P/E Ratio	.80
5.8%	6.9%	6.6%	6.3%	6.7%	6.3%	6.7%	6.9%	6.2%	6.1%	6.0%	5.5%	4.9%	4.9%	4.9%	6.2%	estimates		Avg Ann'l Div'd Yield	4.8%

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
3523.6	3855.8	4505.9	3841.0	4593.0	5160.0	6780.0	6880.0	7546.0	7839.0	7100	7800	Revenues ($mill)	9300
397.8	469.8	481.0	393.0	517.0	541.0	628.0	547.0	629.0	615.0	645	645	Net Profit ($mill)	790
39.4%	39.1%	38.4%	38.9%	36.8%	34.3%	35.6%	32.7%	33.5%	33.7%	32.5%	33.0%	Income Tax Rate	34.5%
3.6%	2.9%	4.3%	2.8%	1.9%	1.8%	2.9%	.7%	.8%	4.6%	1.0%	1.0%	AFUDC % to Net Profit	1.0%
42.4%	44.4%	44.2%	46.0%	47.3%	45.5%	44.9%	43.8%	45.0%	47.8%	47.5%	47.0%	Long-Term Debt Ratio	45.0%
53.5%	51.8%	52.2%	51.4%	50.6%	52.6%	53.3%	54.6%	53.4%	50.8%	51.0%	51.5%	Common Equity Ratio	54.0%
5773.4	6176.9	6419.3	7468.0	8606.0	11036	11932	12063	12654	13712	15450	15875	Total Capital ($mill)	17400
7165.2	7705.7	8426.6	8914.0	10917	13297	13572	14286	15069	16567	17425	17700	Net Plant ($mill)	19400
8.2%	8.9%	8.7%	6.5%	7.4%	6.0%	6.5%	5.7%	6.2%	5.7%	5.5%	5.5%	Return on Total Cap'l	6.0%
12.0%	13.7%	13.4%	9.7%	11.4%	9.0%	9.5%	8.1%	9.0%	8.6%	7.5%	7.5%	Return on Shr. Equity	8.0%
12.5%	14.3%	14.0%	9.9%	11.6%	9.1%	9.7%	8.1%	9.2%	8.7%	7.5%	7.5%	Return on Com Equity E	8.0%
1.2%	3.4%	3.6%	.2%	2.2%	.9%	1.7%	.2%	1.3%	1.0%	3.5%	3.0%	Retained to Com Eq	3.5%
91%	77%	75%	98%	81%	91%	83%	97%	86%	88%	55%	59%	All Div'ds to Net Prof	55%

CAPITAL STRUCTURE as of 9/30/09
Total Debt $7884.0 mill. **Due in 5 Yrs** $1739.0 mill.
LT Debt $7321.0 mill. **LT Interest** $472.0 mill.
(LT interest earned: 3.5x)
Leases, Uncapitalized Annual rentals $392.0 mill.
Pension Assets-12/08 $2.39 bill. **Oblig.** $3.30 bill.
Pfd Stock $195.0 mill. **Pfd Div'd** $10.0 mill.
1,137,595 shs. $3.50 to $7.64 cum. (no par), $100 stated value, redeemable at $102.176-$110/sh.; 191,204 shs., $100 par, 4.50% to 4.64%, redeem. at $102-$110/sh.; 800,000 shs. 4.00% to 6.625%, $100 par, redeem. at $100-$103.50/sh.
Common Stock 236,921,011 shs. as of 10/30/09
MARKET CAP: $6.7 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	+4.5	+6.4	-1.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	4.29	4.39	4.43
Capacity at Peak (Mw)	21177	21150	NA
Peak Load, Summer (Mw)	16416	16580	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	315	302	296

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	4.0%	4.5%	.5%
"Cash Flow"	2.0%	1.5%	Nil
Earnings	.5%	-1.5%	1.0%
Dividends	--	--	-6.5%
Book Value	3.5%	5.0%	2.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	1800	1550	1910	1620	6880.0
2007	2019	1723	1997	1807	7546.0
2008	2081	1790	2060	1908	7839.0
2009	1916	1684	1815	1685	7100
2010	2000	1800	2100	1900	7800

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.34	.60	1.42	.30	2.66
2007	.59	.69	1.18	.52	2.98
2008	.66	.98	.97	.27	2.88
2009	.66	.77	1.04	.28	2.75
2010	.50	.65	1.05	.35	2.55

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.635	.635	.635	.635	2.54
2006	.635	.635	.635	.635	2.54
2007	.635	.635	.635	.635	2.54
2008	.635	.635	.635	.635	2.54
2009	.385	.385	.385	.385	

BUSINESS: Ameren Corp. is a holding company formed through the merger of Union Electric and CIPSCO. Acquired CILCORP 1/03; Illinois Power 10/04. Has 1.2 million electric and 127,000 gas customers in Missouri; 1.2 million electric and 830,000 gas customers in Illinois. Electric revenue breakdown, '08: residential, 32%; commercial, 24%; industrial, 8%; other, 36%. Generating sources, '08: coal, 70%; nuclear, 9%; hydro, 2%; gas, 1%, purchased, 18%. Fuel costs: 45% of revenues. '08 reported depreciation rates: 3%-4%. Has 9,500 employees. Chairman: Gary L. Rainwater. President & CEO: Thomas R. Voss. Inc.: Missouri. Address: One Ameren Plaza, 1901 Chouteau Avenue, P.O. Box 66149, St. Louis, Missouri 63166-6149. Tel.: 314-621-3222. Internet: www.ameren.com.

Ameren has revised its rate applications in Illinois. The company's three electric and gas utilities in the state originally requested tariff increases totaling $176 million for electricity and $43 million for gas. The filings were based on returns of 11.75%-12.25% on the electric side and 11.25%-11.6% on the gas side, on common equity ratios ranging from 43.6%-48.7%. But Ameren reduced the requested increases to $126 million (electric), based on ROEs of 11.3%-11.7%, and $19 million (gas), based on ROEs of 10.8%-11.2%. The utility is also seeking an electric rate rider of $19 million for reliability spending. New tariffs should take effect in May of 2010.

A rate case is pending in Missouri, as well. Ameren is seeking a rate boost of $402 million (18%), based on a return of 11.5% on a common-equity ratio of 47.4%. The utility is also requesting an interim rate increase of $37 million. New rates are expected to go into effect in June of 2010.

The company's utility operations are underearning their allowed ROEs by a wide margin. Combined, Ameren's allowed ROE is around 10.7%, but its utility business is likely to earn an ROE of just 6%-7% in the year that is just ending. Financing and operating costs are rising, and the weak economy and a mild summer have hurt kilowatt-hour sales.

We estimate that share earnings will decline in 2010. Even though rate relief should help raise profits from the regulated utilities, unfavorable conditions in the power markets suggest that income from the nonregulated activities will decline. We estimate that the decrease from the nonregulated side will offset the increase from the regulated side. Average shares outstanding will be higher, too.

Ameren has taken steps to deal with the tough operating environment. In early 2009, the board of directors slashed the annual dividend from $2.54 a share to $1.54 a share. The company also cut its 2010-2013 capital budget. Finally, Ameren took a pretax charge of $17.5 million in the third quarter because it reduced the employee headcount by nearly 300.

This untimely stock's yield is somewhat above average for a utility. Total return potential *to* 2012-2014 is about average, by industry standards.

Paul E. Debbas, CFA *December 25, 2009*

(A) Diluted EPS. Excl. nonrecurring gain (loss): '03, 11¢; '05, (11¢). Next earnings report due mid-Feb. (B) Dividends historically paid in late March, June, Sept., and Dec. ■ Dividend reinvestment plan available. † Shareholder investment plan available. (C) Incl. intangibles. In '08: $12.86/sh. (D) In millions. (E) Rate base: Original cost depreciated. Rate allowed on common equity in MO in '09: 10.76%; in IL in '08: 10.65% electric, 10.68% gas; earned on average com. eq., '08: 8.8%. Regulatory Climate: MO, Average; IL, Below Average.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	25
Earnings Predictability	90

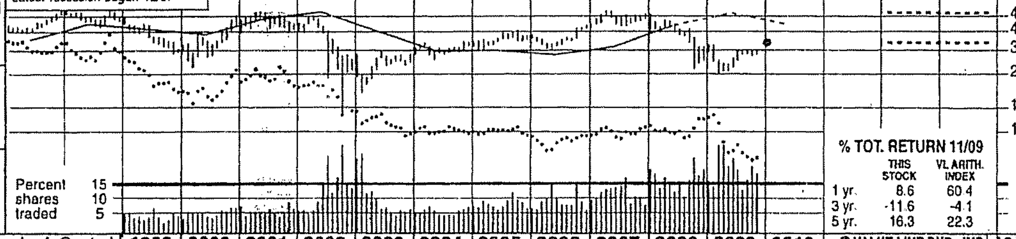
AMERICAN ELEC. PWR. NYSE-AEP

RECENT PRICE 35.06 | P/E RATIO 11.8 (Trailing: 12.4 Median: 13.0) | RELATIVE P/E RATIO 0.70 | DIV'D YLD 4.7% | VALUE LINE 691

TIMELINESS 3 Raised 12/18/09
SAFETY 3 Lowered 10/4/02
TECHNICAL 2 Raised 12/11/09
BETA .70 (1.00 = Market)

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
High:	53.3	48.2	48.9	51.2	48.8	31.5	35.5	40.8	43.1	51.2	49.1	36.5
Low:	42.1	30.6	25.9	39.3	15.1	19.0	28.5	32.3	32.3	41.7	25.5	24.0

LEGENDS
—— 0.97 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



Target Price Range 2012 | 2013 | 2014

2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+45%)	13%
Low	35	(Nil)	5%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	1	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2009	2Q2009	3Q2009
to Buy	247	278	242
to Sell	202	205	210
Hld's(000)	280280	340533	338920

Percent shares traded 15 10 5

% TOT. RETURN 11/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	8.6	60.4
3 yr.	-11.6	-4.1
5 yr.	16.3	22.3

American Electric Power acquired Central and South West Corporation (CSW) in 2000. CSW common stockholders received 0.6 of an AEP common share for each of their shares, for a total of $4.5 billion. The transaction was effected under pooling-of-interests accounting rules. The data on this page prior to 2000 do not reflect the addition of CSW.

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
35.63	42.53	190.10	42.96	36.82	35.51	30.76	31.82	33.41	35.56	28.25	30.00	Revenues per sh	36.25
6.36	5.11	7.65	6.99	5.76	5.89	5.96	6.54	6.64	6.62	6.15	6.35	"Cash Flow" per sh	7.25
2.69	1.04	3.27	2.86	2.53	2.61	2.64	2.86	2.86	2.99	2.95	3.00	Earnings per sh A	3.50
2.40	2.40	2.40	2.40	1.65	1.40	1.42	1.50	1.58	1.64	1.64	1.66	Div'd Decl'd per sh B ■ †	1.90
4.47	5.51	5.69	5.08	3.44	4.28	6.11	8.89	8.88	9.83	6.40	4.75	Cap'l Spending per sh	6.00
25.79	25.01	25.54	20.85	19.93	21.32	23.08	23.73	25.17	26.33	27.40	28.75	Book Value per sh C	33.25
194.10	322.02	322.24	338.84	395.02	395.86	393.72	396.67	400.43	406.07	478.00	483.00	Common Shs Outst'g D	495.00
14.3	34.3	13.9	12.7	10.7	12.4	13.7	12.9	16.3	13.1	Bold figures are		Avg Ann'l P/E Ratio	12.0
.82	2.23	.71	.69	.61	.66	.73	.70	.87	.80	Value Line		Relative P/E Ratio	.80
6.2%	6.7%	5.3%	6.6%	6.1%	4.3%	3.9%	4.1%	3.4%	4.2%	estimates		Avg Ann'l Div'd Yield	4.5%
6916.0	13694	61257	14555	14545	14057	12111	12622	13380	14440	13500	14500	Revenues ($mill)	18000
532.0	332.0	1063.0	976.0	984.0	1038.0	1036.0	1131.0	1147.0	1208.0	1370	1445	Net Profit ($mill)	1745
32.8%	66.1%	36.0%	25.2%	38.8%	33.1%	29.3%	33.0%	31.1%	31.3%	32.5%	33.0%	Income Tax Rate	33.0%
1.9%	--	--	--	3.8%	3.6%	5.4%	9.9%	9.8%	9.9%	12.0%	12.0%	AFUDC % to Net Profit	11.0%
55.1%	52.9%	54.6%	56.0%	60.6%	56.2%	54.8%	56.7%	58.3%	59.1%	53.5%	54.0%	Long-Term Debt Ratio	52.0%
43.5%	44.4%	44.6%	43.1%	38.7%	43.1%	44.9%	43.0%	41.4%	40.7%	46.5%	46.0%	Common Equity Ratio	48.0%
11506	18151	18459	16393	20333	19584	20222	21902	24342	26290	28275	30225	Total Capital ($mill)	34300
13055	22393	24543	21684	22029	22801	24284	26781	29870	32987	34450	35125	Net Plant ($mill)	37300
6.6%	3.8%	7.5%	7.5%	6.6%	7.0%	6.6%	6.7%	6.3%	6.2%	6.5%	6.5%	Return on Total Cap'l	7.0%
10.3%	3.9%	12.7%	13.5%	12.3%	12.1%	11.3%	11.9%	11.3%	11.2%	10.5%	10.5%	Return on Shr. Equity	10.5%
10.4%	3.7%	12.8%	13.7%	12.4%	12.2%	11.3%	12.0%	11.4%	11.3%	10.5%	10.5%	Return on Com Equity E	10.5%
1.1%	NMF	3.4%	2.4%	4.5%	5.7%	5.2%	5.7%	5.1%	5.1%	5.0%	4.5%	Retained to Com Eq	5.0%
89%	NMF	74%	82%	64%	54%	54%	53%	55%	55%	53%	55%	All Div'ds to Net Prof	54%

CAPITAL STRUCTURE as of 9/30/09
Total Debt $17605 mill. **Due in 5 Yrs** $5357 mill.
LT Debt $15713 mill. **LT Interest** $864 mill.
Incl. $2132 mill. securitized bonds; $325 million capitalized leases.
(LT interest earned: 2.9x)

Leases, Uncapitalized Annual rentals $336 mill.
Pension Assets-12/08 $3.16 bill. **Oblig.** $4.30 bill.

Pfd Stock $61 mill. **Pfd Div'd** $3 mill.
607,044 shs. 4%-5%, cumulative, callable at $102-$110.
Common Stock 477,658,465 shs.
as of 10/28/09
MARKET CAP: $17 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	-.6	+5.3	-.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	4.50	4.65	5.08
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.2	+.6	NA
Fixed Charge Cov. (%)	265	250	244

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	.5%	-18.0%	1.5%
"Cash Flow"	.5%	-.5%	1.5%
Earnings	-.5%	--	3.0%
Dividends	-4.0%	-6.0%	3.0%
Book Value	--	2.5%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	3108	2936	3594	2984	12622
2007	3169	3146	3789	3276	13380
2008	3467	3546	4191	3236	14440
2009	3458	3202	3547	3293	13500
2010	3500	3500	4000	3500	14500

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.96	.44	1.01	.45	2.86
2007	.68	.64	1.02	.52	2.86
2008	1.02	.70	.93	.34	2.99
2009	.89	.68	.93	.45	2.95
2010	.90	.70	.95	.45	3.00

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.35	.35	.35	.37	1.42
2006	.37	.37	.37	.39	1.50
2007	.39	.39	.39	.41	1.58
2008	.41	.41	.41	.41	1.64
2009	.41	.41	.41	.41	

BUSINESS: American Electric Power Company, Inc. (AEP), through 10 operating utilities, serves about 5.2 million customers in Arkansas, Kentucky, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, and West Virginia. Electric revenue breakdown, '08: residential, 31%; commercial, 23%; industrial, 22%; wholesale, 20%; other, 4%. Sold 50% stake in Yorkshire Holdings (British utility) '01; sold SEEBOARD (British utility) '02; sold Houston Pipeline '05. Generating sources not available. Fuel costs: 40% of revenues. '08 depreciation rate: 3.0%. Has 21,700 employees. Chairman, President & CEO: Michael G. Morris. Incorporated: New York. Address: 1 Riverside Plaza, Columbus, Ohio 43215-2373. Telephone: 614-716-1000. Internet: www.aep.com.

We estimate that American Electric Power's earnings will decline slightly in the year that is just ending. Although some of AEP's utility subsidiaries benefited from rate increases, some negative factors outweighed this positive one. The state of the economy and unusually mild summer weather conditions hurt the company's retail electric sales. AEP's wholesale power business was much less profitable than a year earlier, as both prices and volume declined. Too, interest expense and average shares outstanding were higher. Our 2009 share-earnings estimate, which we raised by a nickel due to a better-than-expected third-quarter tally, is within the company's targeted range of $2.90-$3.05. Meanwhile, the stock is ranked 3 (Average) for Timeliness.

We expect share profits in 2010 to return to the 2008 level. It seems that the economy will be in better shape, and we assume a return to normal weather patterns. AEP's utilities should also benefit from an anticipated $317 million of rate relief. The company has reached a settlement of its rate case in Arkansas (where it received a $17.8 million tariff hike, based on a 10.25% return on equity), and much bigger rate cases are pending in Virginia and Texas. On the other hand, higher operating and maintenance costs and another increase in average shares outstanding should hold back the bottom-line increase. We are sticking with our 2010 estimate, which is at the midpoint of AEP's guidance of $2.80-$3.20. The board of directors hasn't raised the dividend since 2007, but we tentatively estimate an increase in late 2010. AEP's targeted payout ratio is 50%-60%, which seems achievable.

Transmission projects in the Midwest should enhance the company's earning power in the next decade. AEP has partners in each of five projects, which are expected to be completed in the 2013-2015 time frame. The company's share of the projects is estimated to total $1.75 billion. AEP will be allowed to earn very attractive ROEs (over 12%) on most of this investment. Several other transmission projects are under consideration, as well.

Compared with other utilities, this stock's yield and 3- to 5-year total return potential are about average.

Paul E. Debbas, CFA *December 25, 2009*

(A) Excl. nonrec. gains (losses): '01, (26¢); '02, ($3.86); '03, ($1.92); '04, 24¢; '05, (62¢); '06, (20¢); '07, (20¢); '08, 40¢; gains (losses) on disc. ops.: '02, (57¢); '03, (32¢); '04, 15¢; '05, 7¢; '06, 2¢; '08, 3¢; '09, (1¢). Next earnings report due late Jan. (B) Div'ds historically paid early Mar., June, Sept. & Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. intang. In '08: $16.68/sh. (D) In mill. (E) Rate base: various. Rates allowed on com. eq.: 9.96%-15.7%; earned on avg. com. eq., '08: 11.7%. Regul. Climate: Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	35
Earnings Predictability	90

EDISON INTERNAT'L NYSE-EIX

RECENT PRICE 34.20 | P/E RATIO 11.1 (Trailing: 10.4 Median: 12.0) | RELATIVE P/E RATIO 0.67 | DIV'D YLD 3.7% | VALUE LINE 2234

TIMELINESS 3 Raised 5/18/07
SAFETY 3 Raised 11/11/05
TECHNICAL 3 Lowered 1/1/10
BETA .80 (1.00 = Market)

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
High:	31.0	29.6	30.0	16.1	19.6	22.1	32.5	49.2	47.2	60.3	55.7
Low:	25.1	21.6	14.1	6.3	7.8	10.6	21.2	30.4	37.9	42.8	26.7

(The High/Low row prints 36.7 / 23.1 in an additional column after 55.7 / 26.7.)

2012-14 PROJECTIONS

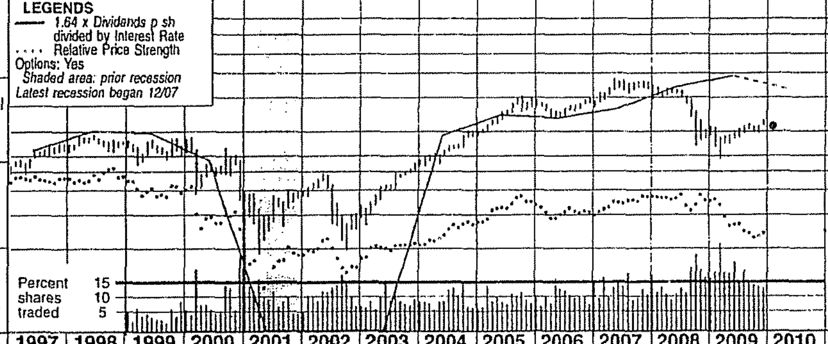
	Price	Gain	Ann'l Total Return
High	60	(+75%)	18%
Low	40	(+15%)	8%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	1	0	0	0
Options	0	0	0	0	0	1	0	0	1
to Sell	0	0	0	0	0	1	0	0	1

Institutional Decisions

	1Q2009	2Q2009	3Q2009
to Buy	185	203	182
to Sell	200	174	172
Hld's(000)	243729	246061	242860



Target Price Range 2012 | 2013 | 2014

% TOT. RETURN 12/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	12.5	60.8
3 yr.	-16.3	1.9
5 yr.	25.0	25.9

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
17.47	18.64	18.95	20.13	24.58	29.12	27.85	35.96	35.10	35.26	37.25	31.30	36.38	38.74	40.25	43.31	37.30	41.45	Revenues per sh	52.25
3.63	3.67	3.95	4.45	5.49	6.65	7.20	d.52	4.35	4.79	5.88	3.79	6.99	7.25	7.60	8.08	7.90	8.20	"Cash Flow" per sh	9.75
1.57	1.56	1.66	1.64	1.75	1.86	2.03	d5.84	1.30	1.82	2.38	.69	3.34	3.28	3.32	3.68	3.10	3.25	Earnings per sh A	4.25
1.42	1.11	1.00	1.00	1.00	1.04	1.08	.83	--	--	--	.80	1.02	1.10	1.18	1.23	1.25	1.28	Div'd Decl'd per sh B ■ †	1.50
2.81	2.54	2.18	1.75	2.08	2.75	3.55	4.57	2.86	4.88	3.95	5.32	5.73	7.78	8.67	8.67	13.40	15.05	Cap'l Spending per sh	14.25
13.31	13.72	14.34	15.07	14.71	14.55	15.01	7.43	10.04	13.62	16.52	18.57	20.30	23.66	25.92	29.21	30.20	32.05	Book Value per sh C	39.50
447.80	447.80	443.61	424.52	375.76	350.55	347.21	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	Common Shs Outst'g D	325.81
14.8	9.7	10.0	10.8	13.7	15.1	12.9	--	10.0	7.8	7.0	NMF	11.7	13.0	16.0	12.4	10.2		Avg Ann'l P/E Ratio	12.0
.87	.64	.67	.68	.79	.79	.74	--	.51	.43	.40	NMF	.62	.70	.85	.76	.65		Relative P/E Ratio	.80
6.1%	7.4%	6.0%	5.7%	4.2%	3.7%	4.1%	3.9%	--	--	--	3.1%	2.6%	2.6%	2.2%	2.7%	4.0%		Avg Ann'l Div'd Yield	3.0%

CAPITAL STRUCTURE as of 9/30/09
Total Debt $11375 mill. Due in 5 Yrs $1949.0 mill.
LT Debt $10448 mill. LT Interest $653.0 mill.
(LT interest earned: 3.5x)
Leases, Uncapitalized Annual rentals $1.69 bill.
Pension Assets-12/08 $2.34 bill.
Oblig. $3.44 bill.
Pfd Stock $907.0 mill. Pfd Div'd $51.0 mill.
4,800,198 shs. 4.08% to 4.78%, $25 par, call. $25.50 to $28.75/sh. 8,000,000 shs. 5.349% to 6.125%, $100 par.
Common Stock 325,811,206 shs as of 11/3/09
MARKET CAP: $11 billion (Large Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
9670.0	11717	11436	11488	12135	10199	11852	12622	13113	14112	12150	13500	Revenues ($mill)	17000
776.8	d1982	536.1	644.0	738.0	220.0	1132.0	1134.0	1151.0	1266.0	1150	1200	Net Profit ($mill)	1570
27.5%	--	NMF	37.8%	22.4%	--	26.0%	31.4%	27.3%	30.7%	30.0%	29.5%	Income Tax Rate	28.0%
--	--	--	3.3%	3.7%	11.4%	4.9%	5.1%	8.2%	8.9%	10.0%	10.0%	AFUDC % to Net Profit	7.0%
66.1%	75.6%	73.3%	66.6%	68.1%	60.5%	54.6%	51.3%	49.1%	51.2%	51.5%	52.0%	Long-Term Debt Ratio	51.0%
25.7%	15.0%	18.9%	25.6%	31.1%	37.8%	40.9%	43.5%	46.0%	44.5%	44.5%	44.0%	Common Equity Ratio	46.0%
20261	16080	17279	17352	17299	15995	16167	17725	18375	21374	22150	23725	Total Capital ($mill)	28000
7331.0	7819.0	8013.0	8247.0	12587	13475	14469	15913	17403	18969	21775	25075	Net Plant ($mill)	33700
5.6%	NMF	6.6%	6.7%	7.2%	4.2%	9.4%	8.6%	8.3%	7.4%	7.0%	6.5%	Return on Total Cap'l	7.5%
11.3%	NMF	11.6%	11.1%	13.4%	3.5%	15.4%	13.1%	12.3%	12.1%	10.0%	10.0%	Return on Shr. Equity	11.0%
13.6%	NMF	13.6%	11.9%	13.6%	3.5%	16.7%	14.0%	13.0%	12.8%	10.5%	10.0%	Return on Com Equity E	11.0%
6.4%	NMF	13.6%	11.9%	13.6%	NMF	12.2%	10.1%	9.2%	8.6%	6.0%	6.5%	Retained to Com Eq	7.5%
57%	NMF	17%	18%	1%	121%	29%	31%	33%	35%	40%	39%	All Div'ds to Net Prof	34%

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	+2.9	+.1	+1.1
Avg. Indust. Use (MWH)	710	704	711
Avg. Indust. Revs. per KWH (¢)	7.19	6.86	6.88
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	22889	23303	22020
Annual Load Factor (%)	52.7	52.2	55.6
% Change Customers (yr-end)	+1.5	+.8	+.3
Fixed Charge Cov. (%)	266	278	298

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	5.0%	2.5%	4.0%
"Cash Flow"	3.5%	9.0%	4.0%
Earnings	7.0%	13.5%	3.5%
Dividends	1.5%	--	4.0%
Book Value	6.0%	14.5%	7.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	2751	3001	3802	3068	12622
2007	2912	3047	3942	3212	13113
2008	3113	3477	4295	3227	14112
2009	2812	2834	3664	2840	12150
2010	3100	3200	3900	3300	13500

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.56	.53	1.39	.80	3.28
2007	1.00	.28	1.40	.65	3.32
2008	.92	.79	1.31	.66	3.68
2009	.78	.78	1.08	.46	3.10
2010	.80	.75	1.20	.50	3.25

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.27	.27	.27	.27	1.08
2007	.29	.29	.29	.29	1.16
2008	.305	.305	.305	.305	1.22
2009	.31	.31	.31	.31	1.24
2010	.315				

BUSINESS: Edison International (formerly SCECorp) is a holding company for Southern California Edison (SCE), which supplies electricity to 4.9 million customers in a 50,000 sq. mi. area in central, coastal, and southern California (excl. Los Angeles and San Diego). Edison Mission Group (EMG) is an independent power producer. Electric revenue breakdown, '08: residential, 38%; commercial, 42%; industrial, 7%; other, 13%. Generating sources, '08: nuclear, 19%; gas, 8%; coal, 6%; hydro, 3%; purchased, 64%. Fuel costs: 42% of revs. '08 reported deprec. rate (utility): 4.3%. Has 18,300 employees. Chairman, President & CEO: Theodore F. Craver, Jr. Inc.: CA. Address: 2244 Walnut Grove Ave., Rosemead, CA 91770. Tel.: 626-302-2222. Internet: www.edison.com.

Edison International's earnings should advance moderately in 2010. We expect the regulated utility operations to provide the profit growth. Southern California Edison's earning power increases each year as the utility's rate base expands. In 2009, SCE's rate base rose by more than $2 billion from $12.6 billion at the end of 2008, and, based on the utility's capital spending plans, its rate base is likely to rise by more than $1 billion this year, *to as much as* $16.1 billion. Our 2010 share-earnings estimate of $3.25 would produce a 5% bottom-line increase over the estimated 2009 tally. Edison has not yet provided earnings guidance for 2010, but expects to do so when it reports fourth-quarter results in early March.

SCE has some large transmission projects in various stages of development. The California commission approved the last eight of 11 segments of a $2 billion transmission line that should begin operating in 2014. Some permits are still needed before SCE can break ground on these eight segments, however. The utility has roughly $3 billion of additional transmission projects planned in its five-year (2009-2013) capital forecast.

The future of Edison Mission Energy (EME) is in question. This subsidiary is profitable, but its income declined sharply in 2009 because conditions in the power markets were much less favorable than in 2008. More significantly, EME is still trying to determine the most cost-effective way to make needed environmental upgrades at its coal-fired plants. Shutting down these facilities is possible if the company cannot find a cost-effective way to attain environmental compliance.

The board of directors raised the dividend in late 2009. The increase was modest, *just half of a cent* a share (1.6%). Edison's payout ratio is low, by utility standards, because a portion of its profits comes from its generally less stable non-regulated operations.

This stock's yield is low, by utility standards. It is roughly one percentage point below the industry average. Although total return potential to 2012-2014 is above the utility norm, the uncertainty surrounding EME makes our projections fairly tentative.

Paul E. Debbas, CFA *February 5, 2010*

(A) Diluted EPS. Excl. nonrecur. gains (losses): '01, $1.88; '02, $1.48; '03, (12¢); '04, $2.12; '09, (70¢) net; losses from disc. ops.: '07, 1¢; '09, 1¢. Incl. nonrecur. losses: '00, $7.58; '01, $1.88. '07 EPS don't add due to rounding. Next egs. report due early Mar. (B) Div'ds historically paid late Jan., Apr., July & Oct. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. def'd chgs. In '08: $16.62/sh. (D) In mill. (E) Rate base: net orig. cost. Rate all'd on com. eq. in '08: 11.5%; earned on avg. com. eq., '08: 13.3%. Regul. Clim.: Above Avg.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	75
Earnings Predictability	45

FIRSTENERGY NYSE-FE

RECENT PRICE 42.65 | P/E RATIO 14.6 (Trailing: 11.7 Median: 14.0) | RELATIVE P/E RATIO 0.87 | DIV'D YLD 5.2% | VALUE LINE 157

TIMELINESS 5 Lowered 11/20/09

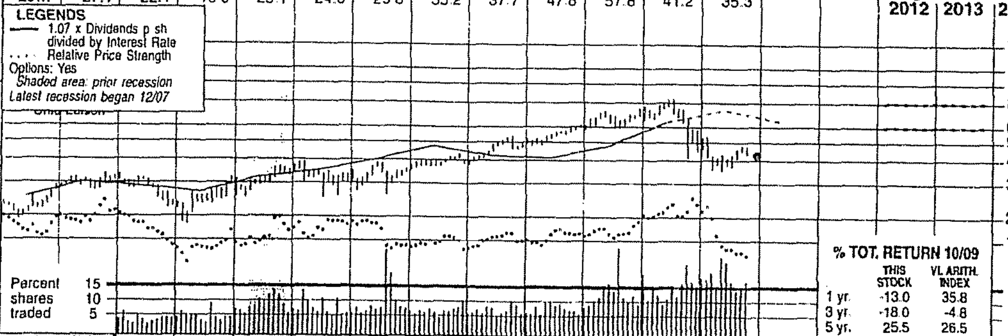
SAFETY 2 Raised 6/2/06

TECHNICAL 3 Lowered 11/27/09

BETA .80 (1.00 = Market)

High:	34.1	33.2	32.1	37.0	39.1	38.9	43.4	53.4	61.7	75.0	84.0	53.6
Low:	27.1	22.1	18.0	25.1	24.8	25.8	35.2	37.7	47.8	57.8	41.2	35.3

Target Price Range 2012 | 2013 | 2014



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+90%)	20%
Low	60	(+40%)	13%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	16	0	0	0	1	1	0
to Sell	0	0	13	1	0	0	0	3	1

Institutional Decisions

	4Q2008	1Q2009	2Q2009
to Buy	229	209	184
to Sell	216	233	238
Hld's(000)	215365	213912	217534

% TOT. RETURN 10/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-13.0	35.8
3 yr.	-18.0	-4.8
5 yr.	25.5	26.5

FirstEnergy was formed through the affiliation of Ohio Edison Company and Centerior Energy in November of 1997. Ohio Edison stockholders received one share of FirstEnergy for every Ohio Edison share, and Centerior stockholders received .52 of a FirstEnergy share for each Centerior share. In November of 2001, FirstEnergy acquired GPU. GPU holders received $40 in cash or stock for each GPU share.

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
27.19	31.31	26.88	40.83	37.31	37.76	36.35	36.03	42.00	44.70	*42.00*	*41.00*	Revenues per sh	*52.50*
6.89	7.28	5.48	6.45	4.79	7.60	7.55	7.22	8.34	9.04	*9.10*	*8.00*	"Cash Flow" per sh	*10.50*
2.50	2.69	2.84	2.54	1.47	2.77	2.84	3.82	4.22	4.38	*3.30*	*3.25*	Earnings per sh A	*5.00*
1.50	1.50	1.50	1.50	1.50	1.91	1.71	1.85	2.05	2.20	*2.20*	*2.20*	Div'd Decl'd per sh B ■	*2.60*
2.69	2.74	2.86	3.35	2.60	2.57	3.66	4.12	5.36	9.47	*5.80*	*5.40*	Cap'l Spending per sh	*5.50*
19.63	20.72	24.86	23.92	25.13	26.04	27.86	28.30	29.45	27.17	*28.25*	*29.30*	Book Value per sh C	*35.75*
232.45	224.53	297.64	297.64	329.84	329.84	329.84	319.21	304.84	304.84	*304.84*	*304.84*	Common Shs Outst'g D	*304.84*
11.3	9.2	10.9	13.0	22.5	14.1	16.1	14.2	15.6	15.6	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*13.5*
.64	.60	.56	.71	1.28	.74	.86	.77	.83	.93	*estimates*		Relative P/E Ratio	*.90*
5.3%	6.1%	4.8%	4.6%	4.5%	4.9%	3.7%	3.4%	3.1%	3.2%			Avg Ann'l Div'd Yield	*3.8%*
6319.6	7029.0	7999.4	12152	12307	12453	11989	11501	12802	13627	*12800*	*12500*	Revenues ($mill)	*16000*
644.8	661.7	727.0	827.6	490.8	932.6	951.0	1265.0	1309.0	1342.0	*1010*	*990*	Net Profit ($mill)	*1565*
38.0%	36.3%	39.5%	41.5%	43.9%	42.2%	42.1%	38.6%	40.3%	36.7%	*38.0%*	*40.0%*	Income Tax Rate	*40.0%*
2.1%	4.1%	4.9%	3.0%	6.5%	2.7%	2.0%	2.1%	2.4%	3.9%	*13.0%*	*9.0%*	AFUDC % to Net Profit	*3.0%*
52.3%	52.3%	60.1%	60.2%	53.1%	52.8%	46.5%	48.6%	49.7%	52.4%	*53.5%*	*53.5%*	Long-Term Debt Ratio	*52.5%*
39.8%	41.5%	37.2%	38.0%	45.0%	45.4%	52.4%	51.4%	50.3%	47.7%	*46.5%*	*46.5%*	Common Equity Ratio	*47.5%*
11470	11205	19907	18756	18414	18938	17527	17570	17846	17383	*18500*	*19275*	Total Capital ($mill)	*22900*
9093.3	7575.1	12428	12680	13269	13478	13998	14667	15383	17723	*17775*	*18025*	Net Plant ($mill)	*18300*
7.8%	7.9%	4.9%	6.3%	4.6%	6.5%	7.1%	9.0%	9.0%	9.4%	*7.0%*	*6.5%*	Return on Total Cap'l	*8.5%*
11.8%	12.4%	9.2%	11.1%	5.7%	10.4%	10.1%	14.0%	14.6%	16.2%	*11.5%*	*11.0%*	Return on Shr. Equity	*14.5%*
12.5%	12.9%	8.9%	10.5%	5.4%	10.6%	10.2%	13.9%	14.6%	16.2%	*11.5%*	*11.0%*	Return on Com Equity E	*14.5%*
5.0%	5.7%	4.3%	4.3%	NMF	4.9%	4.2%	7.4%	7.7%	8.1%	*4.0%*	*3.5%*	Retained to Com Eq	*7.0%*
65%	60%	56%	63%	101%	55%	59%	47%	47%	50%	*67%*	*68%*	All Div'ds to Net Prof	*51%*

CAPITAL STRUCTURE as of 6/30/09
Total Debt $14780 mill **Due in 5 Yrs** $7375.0 mill.
LT Debt $10399 mill **LT Interest** $598.0 mill.
Incl. $284.8 mill 9% ($25 par) cumulative mandatorily redeemable preferred securities.
(LT interest earned: 4.0x)

Leases, Uncapitalized Annual rentals $203.0 mill.
Pension Assets-12/08 $3.75 bill. **Oblig.** $4.70 bill.

Pfd Stock None

Common Stock 304,835,407 shs.
as of 8/3/09
MARKET CAP: $13 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	+6.7	+2.0	-3.6
Avg. Indust. Use (MWH)	NMF	NMF	NMF
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.5	+1.0	+.2
Fixed Charge Cov. (%)	355	363	366

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	8.5%	3.0%	*4.0%*
"Cash Flow"	6.0%	8.0%	*4.0%*
Earnings	7.5%	12.5%	*3.0%*
Dividends	3.0%	6.5%	*4.0%*
Book Value	5.0%	3.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	2705	2751	3365	2680	11501
2007	2973	3109	3641	3079	12802
2008	3277	3245	3904	3201	13627
2009	3334	3017	3408	*3041*	*12800*
2010	*3000*	*3000*	*3500*	*3000*	*12500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.67	.93	1.40	.84	3.82
2007	.92	1.10	1.34	.87	4.22
2008	.90	.85	1.54	1.09	4.38
2009	.94	.84	.77	*.75*	*3.30*
2010	*.70*	*.70*	*1.15*	*.70*	*3.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.4125	.4125	.4125	.43	1.67
2006	.45	.45	.45	.45	1.80
2007	.50	.50	.50	.50	2.00
2008	.55	.55	.55	.55	2.20
2009	.55	.55	.55		

BUSINESS: FirstEnergy Corp. is a holding company for Ohio Edison, Pennsylvania Power, Cleveland Electric, Toledo Edison, Metropolitan Edison, Penelec, and Jersey Central Power & Light. Provides electric service to 4.5 million customers in Ohio (58% of revenues), New Jersey (22%) and Pennsylvania (20%). Electric revenue breakdown by customer class not provided by company. Generating sources: coal, 44%; nuclear, 26%; purchased, 30%. Fuel costs: 41% of revenues. '08 reported deprec. rates: 2.3%-4.7%. Has 14,700 employees. Chairman: George M. Smart. President & CEO: Anthony J. Alexander. COO: Richard R. Grigg. Inc.: Ohio. Address: 76 South Main Street, Akron, Ohio 44308-1890. Tel.: 800-736-3402. Internet: www.firstenergycorp.com.

We have reduced our 2009 share-earnings estimate for FirstEnergy. Third-quarter profits were well below our estimate due to an unusually mild summer (which hurt the company's nonregulated generating business as well as its regulated distribution operations) and a $0.30-a-share charge for the early retirement of debt. Even before we cut our estimate, earnings were headed down. This year, the company's customers in Ohio made the transition to market-based prices for the generation portion of their power. The timing of the transition was fortuitous for customers (and came at the expense of the company) because it occurred when market prices were low. Thus, even though the prices that were determined in an auction were higher than what customers were paying before the change, they weren't high enough to offset the revenues that were lost when a transition charge on customers' bills ended.

We have lowered our 2010 profit estimate by $0.25 a share, to $3.25. Some of the output expected from the company's plants is still not hedged for 2010, and conditions in the power markets are worse than we had expected three months ago. We believe that volume as well as margins will be affected. The state of the economy in the company's service area is worrisome, as well. FirstEnergy plans to provide 2010 guidance at an analyst meeting in early December.

FirstEnergy plans to complete an unfinished gas-fired plant. Last year, it bought the plant for $253.6 million from a company that had spent $300 million on construction. As of September, FirstEnergy had spent an additional $64 million on the facility, and expects to spend an additional $180 million to complete it by the end of 2010. The unit will provide 707 megawatts of capacity.

Untimely FirstEnergy stock offers a dividend yield that is fractionally above the industry average. That's a reflection of the company's bottom-line weakness and lack of near-term dividend growth. Assuming that conditions in the power markets improve in the next 3 to 5 years, this should result in a total return for FirstEnergy that is superior to those of most utilities.

Paul E. Debbas, CFA *November 27, 2009*

(A) Dil. EPS. Excl. nonrec. losses: '04, 11¢; '05, 28¢; '09, 3¢ net; gain (loss) from disc. ops.: '03, (33¢); '05, 5¢. '06 & '07 EPS don't add due to change in shs. or rounding. Next egs. report due late Feb. (B) Div'ds paid early Mar., June, Sept. & Dec. Five div'ds decl. in '04. ■ Div'd reinv. plan avail. (C) Incl. intang.: In '08: $28.59/sh. (D) In mill. (E) Rate base: Depr. orig. cost. Rate all'd on com. eq. in NJ in '05: 9.75%; in PA in '07: 10.1%; in OH in '09: 10%-11%; earn. on avg. com. eq., '08: 14.7%. Regul. Climate: OH, Above Avg.; PA, NJ, Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	85
Earnings Predictability	70

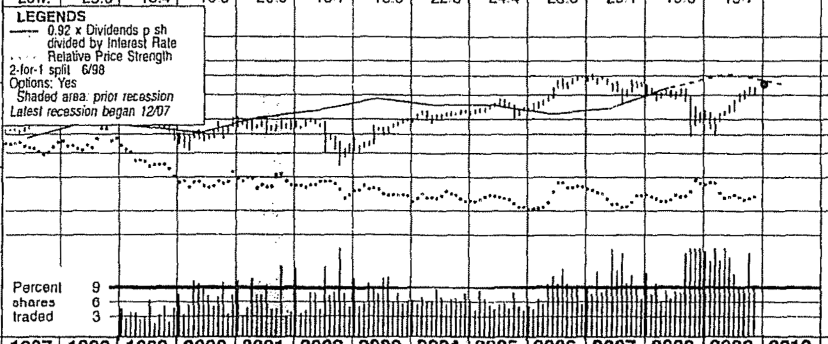
OGE ENERGY CORP. NYSE-OGE

RECENT PRICE 36.37 | P/E RATIO 14.3 (Trailing: 14.4; Median: 13.0) | RELATIVE P/E RATIO 0.85 | DIV'D YLD 4.0% | VALUE LINE 703

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
High:	30.0	29.1	24.8	24.7	24.2	24.3	27.0	30.6	40.6	41.3	36.2	37.1
Low:	25.6	18.4	16.5	20.0	13.7	16.0	22.8	24.4	26.3	29.1	19.6	19.7

TIMELINESS 3 Raised 6/27/08
SAFETY 2 Raised 7/1/05
TECHNICAL 3 Raised 10/9/09
BETA .75 (1.00 = Market)

LEGENDS
— 0.92 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 6/98
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



Target Price Range 2012 | 2013 | 2014

2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+25%)	9%
Low	30	(-20%)	Nil

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	2	0	2	0	0	0	0	0
Options	0	0	0	0	0	0	2	0	0
to Sell	1	1	0	0	0	0	2	0	0

Institutional Decisions

	1Q2009	2Q2009	3Q2009
to Buy	101	100	97
to Sell	123	120	109
Hld's(000)	47108	47786	46842

Percent shares traded 9 6 3

% TOT. RETURN 11/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	37.7	60.4
3 yr.	1.0	-4.1
5 yr.	67.9	22.3

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
17.94	16.79	16.13	17.18	18.23	20.02	27.90	42.33	40.80	38.52	43.24	54.74	65.65	43.92	41.37	43.54	*27.85*	*30.75*	Revenues per sh	*37.75*
2.87	3.07	3.16	3.31	3.38	3.90	4.06	4.15	3.61	3.75	3.65	3.74	3.89	4.47	4.79	4.80	*5.15*	*5.70*	"Cash Flow" per sh	*6.50*
1.39	1.51	1.52	1.62	1.61	2.04	1.94	1.89	1.29	1.43	1.73	1.78	1.83	2.45	2.64	2.49	*2.50*	*2.80*	Earnings per sh A	*3.25*
1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.34	1.37	1.40	*1.43*	*1.46*	Div'd Decl'd per sh B ■ †	*1.60*
1.58	1.87	1.75	2.00	2.03	1.86	2.33	2.30	2.89	2.99	2.07	3.02	3.30	5.34	6.08	8.02	*9.10*	*6.50*	Cap'l Spending per sh	*4.75*
11.24	11.41	11.61	11.91	12.19	12.91	13.09	13.66	13.34	12.53	13.75	14.28	15.19	17.59	18.31	20.29	*21.40*	*22.75*	Book Value per sh C	*28.00*
80.69	80.71	80.75	80.76	80.77	80.80	77.86	77.92	77.99	78.50	87.40	90.00	90.60	91.20	91.80	93.50	*97.00*	*97.50*	Common Shs Outst'g D	*103.00*
12.8	11.1	11.9	12.3	14.0	13.3	12.1	10.6	17.4	14.1	11.8	14.1	14.9	13.7	13.8	12.4	*Bold figures are*		Avg Ann'l P/E Ratio	*11.5*
.76	.73	.80	.77	.81	.69	.69	.69	.89	.77	.67	.74	.79	.74	.73	.77	*Value Line*		Relative P/E Ratio	*.75*
7.5%	8.0%	7.4%	6.7%	5.9%	4.9%	5.7%	6.6%	5.9%	6.6%	6.5%	5.3%	4.9%	4.0%	3.8%	4.5%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*

CAPITAL STRUCTURE as of 9/30/09
Total Debt $2528.2 mill. Due in 5 Yrs $708.0 mill.
LT Debt $1930.8 mill. LT Interest $125.5 mill.
(LT interest earned: 3.6x)

Leases, Uncapitalized Annual rentals $8.1 mill.

Pension Assets-12/08 $389.9 mill. Oblig. $547.0 mill.

Pfd Stock None

Common Stock 96,791,187 shs.

MARKET CAP: $3.5 billion (Mid Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
2172.4	3298.7	3182.4	3023.9	3779.0	4926.6	5948.2	4005.6	3797.6	4070.7	*2700*	*3000*	Revenues ($mill)	*3900*
151.3	147.0	100.6	111.7	141.8	157.8	166.1	226.1	244.2	231.4	*240*	*275*	Net Profit ($mill)	*335*
37.3%	34.2%	34.3%	36.4%	35.4%	34.5%	30.2%	34.8%	32.3%	30.4%	*31.5%*	*31.0%*	Income Tax Rate	*30.0%*
.5%	1.5%	.7%	.8%	.4%	1.1%	1.3%	3.8%	1.6%	1.7%	*10.0%*	*7.0%*	AFUDC % to Net Profit	*3.0%*
52.8%	60.8%	59.5%	60.4%	54.4%	52.6%	49.5%	45.6%	44.4%	53.3%	*51.5%*	*55.0%*	Long-Term Debt Ratio	*53.5%*
47.2%	39.2%	40.5%	39.6%	45.6%	47.4%	50.5%	54.4%	55.6%	46.7%	*48.5%*	*45.0%*	Common Equity Ratio	*46.5%*
2159.9	2712.8	2566.9	2485.8	2637.7	2709.7	2726.6	2950.1	3025.5	4058.6	*4285*	*4930*	Total Capital ($mill)	*6200*
3242.0	3219.5	3263.7	3204.3	3309.5	3581.0	3567.4	3867.5	4246.3	5249.8	*5870*	*6225*	Net Plant ($mill)	*6850*
8.8%	7.6%	6.2%	6.6%	7.1%	7.4%	7.6%	9.1%	9.5%	7.0%	*7.5%*	*7.0%*	Return on Total Cap'l	*7.0%*
14.8%	13.8%	9.7%	11.4%	11.8%	12.3%	12.1%	14.1%	14.5%	12.2%	*11.5%*	*12.5%*	Return on Shr. Equity	*11.5%*
14.8%	13.8%	9.7%	11.4%	11.8%	12.3%	12.1%	14.1%	14.5%	12.2%	*11.5%*	*12.5%*	Return on Com Equity E	*11.5%*
4.7%	4.1%	NMF	1.2%	3.6%	3.4%	3.4%	6.6%	7.1%	5.4%	*5.0%*	*6.0%*	Retained to Com Eq	*6.0%*
68%	70%	103%	89%	70%	73%	72%	53%	51%	55%	*58%*	*51%*	All Div'ds to Net Prof	*48%*

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	+1.5	- -	+1.5
Avg. Indust. Use (MWH)	748	738	864
Avg. Indust. Revs. per KWH (¢)	4.86	5.22	4.53
Capacity at Peak (Mw)	6688	6800	6781
Peak Load, Summer (Mw)	6473	6317	6472
Annual Load Factor (%)	53.9	53.7	53.8
% Change Customers (yr-end)	+1.3	+1.0	+1.0
Fixed Charge Cov. (%)	431	483	373

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	9.0%	1.0%	-2.0%
"Cash Flow"	3.0%	5.0%	5.5%
Earnings	3.5%	11.0%	4.5%
Dividends	.5%	.5%	2.5%
Book Value	4.5%	7.0%	7.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	1109.8	934.3	1130.6	830.9	4005.6
2007	881.5	913.4	1044.5	958.2	3797.6
2008	994.7	1135.7	1254.3	686.0	4070.7
2009	606.6	644.1	845.3	*604*	*2700*
2010	*650*	*700*	*1000*	*650*	*3000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.27	.63	1.32	.24	2.45
2007	.19	.68	1.37	.40	2.64
2008	.14	.62	1.50	-.23	2.49
2009	.18	.72	1.40	*.20*	*2.50*
2010	*.20*	*.75*	*1.60*	*.25*	*2.80*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.333	.333	.333	.333	1.33
2007	.34	.34	.34	.34	1.36
2008	.3475	.3475	.3475	.3475	1.39
2009	.355	.355	.355	.355	
2010	.3625				

BUSINESS: OGE Energy Corp. is a holding company for Oklahoma Gas and Electric Company (OG&E), which supplies electricity to 773,000 customers in Oklahoma (88% of electric revenues) and western Arkansas (9%); wholesale is (3%). Owns Enogex pipeline subsidiary. Acquired Transok 6/99. Electric revenue breakdown, '08: residential, 38%; commercial, 25%; industrial, 19%; other, 18%. Generating sources, '08: coal, 58%; gas, 26%; wind, 2%; purchased, 14%. Fuel costs: 69% of revenues. '08 reported depreciation rate (utility): 2.7%. Has 3,400 employees. Chairman, President & CEO: Peter B. Delaney. COO: Danny P. Harris. Inc.: Oklahoma. Address: 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321. Tel.: 405-553-3000. Internet: www.oge.com.

The Oklahoma commission has approved a regulatory settlement concerning a wind project that OGE Energy's utility subsidiary is building. The $270 million, 101-megawatt project is nearing completion. Oklahoma Gas and Electric will recover the costs through a rate rider on customers' bills until the project is added to the utility's rate base in 2011, following the resolution of a rate case that OG&E plans to file by mid-2010.

OG&E has a lot of opportunities to expand its transmission rate base. A $218 million transmission line is scheduled to enter service in early 2010. The utility will recover its costs via a rate rider, as well. Its capital budget calls for $813 million to be spent on transmission from 2009 through 2013. This will help OGE attain its goal of average annual earnings growth of 5%-7% over that time, using 2009 as the base year.

After a flat tally in 2009, earnings should improve considerably in 2010. For the year now ending, profit growth at the utility has been offset by a decline at OGE's Enogex pipeline subsidiary. This was expected, since Enogex benefited from unsustainably high commodity spreads in 2008. In 2010, OG&E will have a full year of revenues from the rate hikes that were enacted in Oklahoma and Arkansas in 2009. We believe that Enogex will also fare better as its proportion of fixed-fee business continues to expand, thereby lessening the company's exposure to commodity prices. Our 2010 share-net forecast is within OGE's guidance of $2.70-$2.95.

The board of directors raised the dividend. The annual disbursement was boosted by $0.03 a share (2.1%). OGE states that it expects identical yearly dividend growth through 2012. The company should have no trouble attaining this goal, given that the increases are small, finances are sound, and the payout ratio is moderate.

This stock has jumped more than 40% this year. That tops not only most utility equities but the rise in the Value Line Composite Average, as well. At the current quotation, the stock's valuation is higher than usual. The yield is below average for a utility, and this issue's 3- to 5-year total return potential is unimpressive.

Paul E. Debbas, CFA *December 25, 2009*

(A) Diluted EPS. Excl. nonrec. losses: '02, 39¢; '03, 14¢; '04, 6¢; gains on discont. ops.: '02, 12¢; '04, 1¢; '05, 49¢; '06, 39¢. '06 EPS don't add to total due to rounding. Next earnings report due mid-Feb. (B) Div'ds historically paid in late Jan., Apr., July, and Oct. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. def'd charges. In '08: $4.24/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in OK in '09: 10.75%; in AR in '09: 10.25%; earned on avg. com. eq., '08: 13.1%. Regul. Climate: Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	90
Earnings Predictability	95

OTTER TAIL CORP. NDQ-OTTR

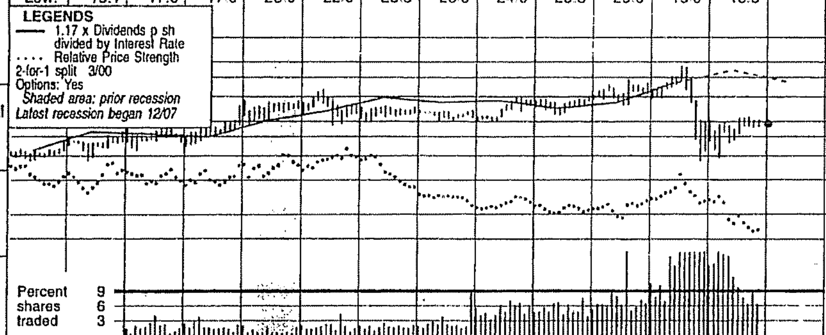
RECENT PRICE 23.43 | P/E RATIO 23.2 (Trailing: 26.9; Median: 17.0) | RELATIVE P/E RATIO 1.37 | DIV'D YLD 5.1% | VALUE LINE 704

TIMELINESS 4 Lowered 11/14/08
SAFETY 2 New 7/27/90
TECHNICAL 2 Raised 12/4/09
BETA .95 (1.00 = Market)

High:	21.4	22.8	29.0	31.0	34.9	28.9	27.5	32.0	31.9	39.4	46.2	25.4
Low:	15.1	17.0	17.8	23.0	22.8	23.8	23.8	24.0	25.8	29.0	15.0	15.5

Target Price Range 2012 | 2013 | 2014

LEGENDS
—— 1.17 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 3/00
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+50%)	15%
Low	25	(+5%)	7%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	2	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	1	0	0	0	0	0	0	0

Institutional Decisions

	1Q2009	2Q2009	3Q2009
to Buy	61	54	43
to Sell	43	41	41
Hld's(000)	16765	16375	16660

Percent shares traded 9 6 3

% TOT. RETURN 11/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	29.3	60.4
3 yr.	-14.9	-4.1
5 yr.	5.3	22.3

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
11.86	12.86	14.70	16.13	16.80	18.14	19.48	23.45	26.53	27.75	29.28	30.45	35.59	37.43	41.50	37.06	*30.75*	*33.80*	Revenues per sh	*39.40*
2.25	2.33	2.47	2.78	2.95	2.75	2.91	3.21	3.40	3.44	3.30	2.88	3.35	3.39	3.55	2.81	*2.85*	*3.40*	"Cash Flow" per sh	*4.40*
1.12	1.17	1.19	1.24	1.29	1.29	1.45	1.60	1.68	1.79	1.51	1.50	1.78	1.69	1.78	1.09	*.80*	*1.20*	Earnings per sh A	*1.90*
.84	.86	.88	.90	.93	.96	.99	1.02	1.04	1.06	1.08	1.10	1.12	1.15	1.17	1.19	*1.19*	*1.19*	Div'd Decl'd per sh B ■	*1.30*
1.38	1.36	1.66	2.85	1.79	1.23	1.37	1.85	2.17	2.95	1.97	1.72	2.04	2.35	5.43	7.51	*5.60*	*5.70*	Cap'l Spending per sh	*6.00*
7.62	7.90	8.24	8.61	8.96	9.47	10.30	10.87	11.33	12.25	12.98	14.81	15.80	16.67	17.55	19.14	*18.85*	*19.60*	Book Value per sh C	*21.25*
22.36	22.36	22.36	22.43	23.46	23.76	23.85	23.85	24.65	25.59	25.72	28.98	29.40	29.52	29.85	35.38	*35.80*	*37.00*	Common Shs Outst'g D	*40.00*
15.6	13.8	14.2	14.0	12.8	14.4	13.9	13.5	16.4	16.0	17.8	17.3	15.4	17.3	19.0	30.1	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.92	.91	.95	.88	.74	.75	.79	.88	84	.87	1.01	.91	.82	93	1.01	1.84	*Value Line*		Relative P/E Ratio	*1.00*
4.8%	5.3%	5.2%	5.2%	5.6%	5.2%	4.9%	4.7%	3.8%	3.7%	4.0%	4.2%	4.1%	3.9%	3.5%	3.6%	*estimates*		Avg Ann'l Div'd Yield	*4.6%*
						464.6	559.4	654.1	710.1	753.2	882.3	1046.4	1105.0	1238.9	1311.2	*1100*	*1250*	Revenues ($mill)	*1575*
						36.9	40.2	43.6	46.1	39.7	40.0	52.9	50.8	54.0	35.1	*30.0*	*45.0*	Net Profit ($mill)	*75.0*
						32.2%	30.3%	31.5%	30.3%	27.4%	29.8%	34.6%	34.8%	34.1%	30.0%	*20.0%*	*30.0%*	Income Tax Rate	*30.0%*
						.7%	.8%	3.1%	5.7%	5.0%	2.4%	1.7%	1.9%	4.2%	6.1%	*6.0%*	*8.0%*	AFUDC % to Net Profit	*8.0%*
						38.7%	39.5%	43.5%	44.0%	43.2%	37.1%	35.0%	33.5%	38.9%	32.9%	*37.0%*	*34.0%*	Long-Term Debt Ratio	*32.0%*
						53.9%	53.5%	53.5%	53.4%	54.3%	60.7%	62.9%	64.5%	59.4%	65.6%	*62.0%*	*65.0%*	Common Equity Ratio	*67.0%*
						455.6	484.4	522.2	587.2	614.6	706.5	738.2	763.0	882.1	1032.5	*1085*	*1100*	Total Capital ($mill)	*1260*
						503.0	515.9	543.0	587.9	633.3	682.1	697.1	718.6	854.0	1037.6	*1150*	*1200*	Net Plant ($mill)	*1450*
						9.7%	9.6%	9.3%	9.0%	7.8%	6.8%	8.3%	7.7%	7.2%	4.3%	*3.5%*	*5.0%*	Return on Total Cap'l	*6.5%*
						13.2%	13.7%	14.8%	14.0%	11.4%	9.0%	11.0%	10.0%	10.0%	5.1%	*4.5%*	*6.0%*	Return on Shr. Equity	*9.0%*
						14.1%	14.8%	14.9%	14.5%	11.7%	9.1%	11.2%	10.2%	10.2%	5.1%	*4.5%*	*6.0%*	Return on Com Equity E	*9.0%*
						4.5%	5.4%	5.8%	6.0%	3.2%	2.5%	4.2%	3.3%	3.5%	NMF	*NMF*	*NMF*	Retained to Com Eq	*2.5%*
						70%	65%	63%	60%	73%	73%	63%	68%	66%	108%	*144%*	*99%*	All Div'ds to Net Prof	*70%*

CAPITAL STRUCTURE as of 9/30/09
Total Debt $535.1 mill. **Due in 5 Yrs** $248.0 mill.
LT Debt $411.3 mill. **LT Interest** $20.0 mill.
(LT interest earned: 2.7x)

Leases, Uncapitalized Annual rentals $46 mill.
Pension Assets-12/08 $127.5 mill. **Oblig.** $182.6 mill.
Pfd Stock $15.5 mill. **Pfd Div'd** $.7 mill.
155,000 shs. $3.60-$6.75, cum., no par ($100 liquidating value).
Common Stock 35,689,751 shs.
as of 10/31/09
MARKET CAP: $825 million (Small Cap)

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	+2.5	+3.3	+3.0
Avg. Indust. Use (MWH)	30169	31458	32402
Avg. Indust. Revs. per KWH (¢)	5.04	5.20	5.15
Capacity at Peak (Mw)	711	NA	NA
Peak Load, Winter (Mw)	690	705	773
Annual Load Factor (%)	66.2	NA	NA
% Change Customers (yr-end)	+.5	+.2	NA
Fixed Charge Cov. (%)	446	410	257

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	8.5%	7.0%	*.5%*
"Cash Flow"	1.5%	-1.0%	*5.0%*
Earnings	2.0%	-1.5%	*4.0%*
Dividends	2.5%	2.0%	*2.0%*
Book Value	7.0%	8.0%	*3.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	257.8	279.9	280.6	286.7	1105.0
2007	301.1	305.9	302.2	329.7	1238.9
2008	300.2	323.6	352.9	334.5	1311.2
2009	277.2	246.9	257.4	*318.5*	*1100*
2010	*300*	*290*	*310*	*350*	*1250*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.50	.37	.45	.37	1.69
2007	.34	.53	.44	.47	1.78
2008	.27	.12	.31	.39	1.09
2009	.12	.07	.29	*.32*	*.80*
2010	*.20*	*.20*	*.35*	*.45*	*1.20*

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.28	.28	.28	.28	1.12
2006	.288	.288	.288	.288	1.15
2007	.293	.293	.293	.293	1.17
2008	.298	.298	.298	.298	1.19
2009	.298	.298	.298	.298	

BUSINESS: Otter Tail Corporation is the parent of Otter Tail Power Company, which supplies electricity to over 129,000 customers in a mainly rural area in Minnesota (50% of retail elec. revs.), North Dakota (41%), and South Dakota (9%). Electric revenue breakdown, '08: residential, 31%; commercial & farms, 36%; industrial, 23%; other, 10%. Fuel costs: 10% of revenues. Has operations in manufacturing, plastics, health services, food ingredients, & others. 2008 reported depreciation rate: 4.3%. Has 4,166 employees. Chairman: John MacFarlane. President & Chief Executive Officer: John D. Erickson. Incorporated: Minnesota. Address: 215 South Cascade St., P.O. Box 496, Fergus Falls, Minnesota 56538-0496. Telephone: 800-664-1259. Internet: www.ottertail.com.

Otter Tail Corporation reported unimpressive results for the third quarter. Revenues declined roughly 27%, year over year. Otter Tail Power Company's operating environment has remained challenging, characterized by unseasonably cool summer weather in the Midwest, lower industrial demand, and a deflated wholesale market. On the bright side, the utility benefited from rate increases in the Dakotas, and greater renewable energy and transmission rider revenues. The company's nonelectric operations have also experienced headwinds, though its food ingredient processing business posted solid results. Operating expenses declined considerably, largely due to a lower nonelectric cost of goods sold and efforts to improve efficiencies. Income tax expense also decreased significantly, and net income increased about 12%. However, share earnings declined 6% for the quarter, owing partly to a modest increase in the share count. Looking forward,

Weakness may well persist in the near term. We anticipate unfavorable comparisons for the fourth quarter, and lower revenues and share earnings for the full year. The company now expects 2009 earnings to be closer to the low end of its previously announced range of $0.70 to $1.10 per share. We concur, and have adjusted our share-net estimate accordingly. Performance may well improve in 2010, assuming a better operating climate in that year.

Otter Tail Power Company has withdrawn from development project Big Stone II. The proposed 500-to-600-megawatt coal-fired power plant in South Dakota will not be built. The company cited economic softness, existing environmental regulation, and uncertainty surrounding proposed federal climate legislation as reasons for withdrawing from the project. OTTR will now evaluate other options to meet future demand for electricity.

This stock is ranked to trail the broader market for the year ahead. But from the present quotation, this good-quality issue offers decent risk-adjusted total return potential. That's supported by our solid 2012-2014 earnings projections. Income-oriented investors may find the dividend yield attractive, as well.

Michael Napoli, CPA *December 25, 2009*

(A) Diluted earnings. Excl. nonrecurring gains: '98, 7¢; '99, 34¢; gains from discont. operations: '04, 8¢; '05, 33¢; '06, 1¢. Next earnings report due early February. (B) Div'ds historically paid in early March, June, Sept., and Dec. ■ Div'd reinvestment plan avail. (C) Incl. intangibles. In '08: $4.02/sh. (D) In mill., adj. for split. (E) Regulatory Climate: MN, ND, Average; SD, Above Average.

Company's Financial Strength	A
Stock's Price Stability	75
Price Growth Persistence	40
Earnings Predictability	75

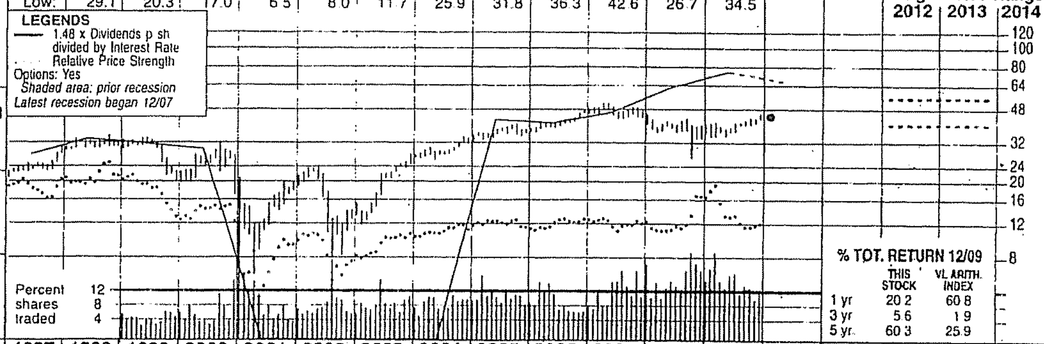
PG&E CORP. NYSE-PCG

RECENT PRICE 44.07 | P/E RATIO 13.6 (Trailing: 13.3 / Median: 14.0) | RELATIVE P/E RATIO 0.82 | DIV'D YLD 4.1% | VALUE LINE 2239

TIMELINESS 3 Lowered 6/26/09
SAFETY 2 Raised 5/12/06
TECHNICAL 2 Raised 2/5/10
BETA .55 (1.00 = Market)

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
High:	35.1	34.0	31.8	20.9	23.8	28.0	34.5	40.1	48.2	52.2	45.7	45.8
Low:	29.1	20.3	17.0	6.5	8.0	11.7	25.9	31.8	36.3	42.6	26.7	34.5

Target Price Range 2012 | 2013 | 2014



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+25%)	10%
Low	40	(-10%)	2%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	4	0	0	1	0	1	0	0	0
to Sell	11	0	0	1	0	1	0	0	0

Institutional Decisions

	1Q2009	2Q2009	3Q2009
to Buy	215	217	179
to Sell	168	184	194
Hld's(000)	249542	249954	253016

% TOT. RETURN 12/09

	THIS STOCK	VL ARITH. INDEX
1 yr	20.2	60.8
3 yr	5.6	1.9
5 yr	60.3	25.9

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
24.77	24.28	23.24	23.82	36.87	52.12	57.74	67.75	63.18	32.74	25.05	26.47	31.78	36.02	37.42	40.51	35.75	37.25	Revenues per sh	42.50
5.42	5.99	6.31	5.24	5.98	6.08	7.15	.80	5.66	1.14	4.80	5.71	7.12	7.76	8.02	8.44	8.40	8.75	"Cash Flow" per sh	10.00
2.33	2.76	2.95	2.16	1.57	1.88	2.24	d9.21	3.02	d2.36	2.05	2.12	2.35	2.76	2.78	3.22	3.15	3.40	Earnings per sh A	4.25
1.88	1.96	1.96	1.77	1.20	1.20	1.20	1.20	--	--	--	--	1.23	1.32	1.44	1.56	1.68	1.80	Div'd Decl'd per sh B ■ †	2.20
4.13	2.54	2.25	3.05	4.36	4.23	4.39	4.54	7.33	7.94	4.08	3.72	4.90	6.90	7.83	10.05	10.15	10.10	Cap'l Spending per sh	11.25
19.77	20.07	20.77	20.73	21.30	21.08	19.10	8.19	11.89	9.47	10.12	20.62	19.60	22.44	24.18	25.97	27.60	29.25	Book Value per sh C	35.75
427.22	430.24	414.03	403.50	417.67	382.60	360.59	387.19	363.38	381.67	416.52	418.62	368.27	348.14	353.72	361.06	369.00	376.00	Common Shs Outst'g D	400.00
14.8	9.5	9.4	10.9	15.5	16.8	13.1	--	4.8	--	9.5	13.8	15.4	14.8	16.8	12.1	12.5		Avg Ann'l P/E Ratio	11.5
.87	.62	.63	.68	.89	.87	.75	--	.25	--	.54	.73	.82	.80	.89	.73	.80		Relative P/E Ratio	.75
5.5%	7.5%	7.1%	7.5%	4.9%	3.8%	4.1%	4.8%	--	--	--	--	3.4%	3.2%	3.1%	4.0%	4.3%		Avg Ann'l Div'd Yield	4.5%

CAPITAL STRUCTURE as of 9/30/09
Total Debt $11991 mill. Due in 5 yrs $3975 mill.
LT Debt $10767 mill. LT Interest $581.0 mill.
Incl. $928 mill. Energy Recovery Bonds
(LT interest earned: 3.1x)
Pension Assets-12/08 $8.07 bill. Oblig. $9.77 bill.
Pfd Stock $258.0 mill. Pfd Div'd $14.0 mill.
5,973,456 shs. 4.36% to 7.04%, cum. and $25 par. redeemable from $25.75 to $27.25; 5,784,825 shs. 5.00% to 6.00%, cum. nonredeemable and $25 par; 5,500,000 shs. 6.30% and 6.57%, cum. $25 par, subject to mandatory redemption
Common Stock 370,960,212 shs. as of 10/27/09
MARKET CAP: $16 billion (Large Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
20820	26232	22959	12495	10435	11080	11703	12539	13237	14628	13200	14000	Revenues ($mill)	17000
825.0	d3324	1099.0	d874.0	791.0	901.0	904.0	1005.0	1020.0	1198.0	1170	1290	Net Profit ($mill)	1735
1.6%	--	35.6%	--	36.7%	35.0%	37.6%	35.5%	34.6%	26.2%	33.5%	33.5%	Income Tax Rate	33.5%
--	--	1.6%	--	3.7%	3.6%	5.6%	6.7%	9.4%	9.5%	10.0%	9.0%	AFUDC % to Net Profit	7.0%
46.5%	62.1%	58.9%	51.5%	42.4%	45.1%	48.3%	51.7%	52.6%	52.2%	51.0%	49.5%	Long-Term Debt Ratio	45.0%
48.0%	30.4%	34.9%	42.8%	53.9%	53.2%	50.0%	46.8%	46.1%	46.5%	48.0%	49.5%	Common Equity Ratio	54.0%
14339	10428	12399	8438.0	7815.0	16242	14446	16696	18558	20163	21200	22275	Total Capital ($mill)	26500
16776	16591	19167	16928	18107	18989	19955	21785	23656	26261	28050	29850	Net Plant ($mill)	36900
7.4%	NMF	13.3%	NMF	16.3%	7.6%	8.1%	7.6%	7.4%	7.8%	7.0%	7.0%	Return on Total Cap'l	8.0%
10.8%	NMF	21.5%	NMF	17.6%	10.1%	12.1%	12.5%	11.6%	12.4%	11.0%	11.5%	Return on Shr. Equity	12.0%
11.6%	NMF	22.9%	NMF	18.5%	10.3%	12.3%	12.7%	11.8%	12.6%	11.5%	11.5%	Return on Com Equity E	12.0%
5.2%	NMF	22.9%	NMF	18.5%	10.3%	7.7%	6.8%	6.0%	6.8%	5.5%	5.5%	Retained to Com Eq	6.0%
56%	NMF	10%	--	2%	1%	39%	47%	50%	47%	54%	53%	All Div'ds to Net Prof	51%

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	+5.8	+2.2	+2.3
Avg. Indust. Use (MWH)	12513	12021	12765
Avg. Indust. Revs. per KWH (¢)	8.53	8.26	8.67
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	NMF	NMF	NMF
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	+2.7	+2.0	+.3
Fixed Charge Cov. (%)	268	257	288

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	--	-1.0%	2.0%
"Cash Flow"	3.5%	16.0%	3.5%
Earnings	4.5%	NMF	6.5%
Dividends	.5%	--	7.5%
Book Value	1.5%	18.0%	6.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	3148	3017	3168	3206	12539
2007	3356	3187	3279	3415	13237
2008	3733	3578	3674	3643	14628
2009	3431	3194	3235	3340	13200
2010	3500	3500	3500	3500	14000

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.60	.65	1.09	.43	2.76
2007	.71	.74	.77	.56	2.78
2008	.62	.80	.83	.97	3.22
2009	.65	.87	.80	.83	3.15
2010	.70	.90	.95	.85	3.40

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.33	.33	.33	.33	1.32
2007	.33	.36	.36	.36	1.41
2008	.36	.39	.39	.39	1.53
2009	.39	.42	.42	.42	1.65
2010	.42				

BUSINESS: PG&E Corporation is a holding company for Pacific Gas and Electric Company and nonutility subsidiaries. Supplies electricity and gas to most of northern and central California. Has 5.1 million electric. 4.3 million gas customers. Electric revenue breakdown. '08: residential. 41%; commercial, 39%; industrial, 12%; other, 8%. Generating sources. '08: nuclear. 27%; hydro, 9%; purchased and other, 64%. Fuel costs: 45% of revenues. '08 reported depreciation rate (utility): 3.3%. Has 21,700 employees. Chairman, President & Chief Executive Officer: Peter A. Darbee. Incorporated: California. Address: One Market, Spear Tower, Suite 2400, San Francisco, California 94105. Telephone: 415-267-7000. Internet: www.pgecorp.com.

PG&E's utility subsidiary has filed a general rate case. Pacific Gas and Electric is seeking a total rate increase of $1.048 billion (6.4%). New tariffs would take effect at the start of 2011. The utility is asking for a mechanism that would reflect increases in the rate base and its operating and maintenance expenses. If granted, this would provide rate hikes of $275 million in 2012 and $343 million in 2013. The utility's cost of capital will be reconsidered in a separate filing, which will occur in 2012, with a ruling taking effect at the start of 2013. Accordingly, the allowed return on equity will remain at 11.35% for now.

The utility is building generating facilities. Two gas-fired plants should enter commercial operation later this year. The expected cost for both facilities is $912 million. Pacific G&E is also asking the California regulators for permission to construct a 246-megawatt windfarm at a cost of $911 million. If the commission gives the utility the go-ahead, this project would go into service in 2011.

Pacific G&E is awaiting a ruling on a proposed electric reliability program. The utility wants to spend $800 million over a six-year period to enhance system reliability. The California commission's decision is expected soon.

We estimate that earnings fell slightly in 2009 but will advance this year. The fourth-quarter comparison was tough because a tax settlement added $0.29 a share to profits in the year-earlier period. In 2010, ongoing growth in the utility's rate base should lead to increased earnings.

We expect a dividend increase at the board meeting later this month. We figure that the directors will raise the quarterly disbursement by $0.03 a share (7.1%), as it has in each of the past three years.

This stock's valuation is high. The yield is fractionally below the industry average. Although we project good profit and dividend growth over the 3- to 5-year period, with the quotation already within our 2012-2014 Target Price Range, total return potential over that time is subpar. All told, we believe better selections are available elsewhere.

Paul E. Debbas, CFA *February 5, 2010*

(A) Diluted EPS. Excl. nonrec. gains (losses): '94, (55¢); '95, 4¢; '96, (41¢); '97, 18¢; '99, ($2.44); '04, $6.95; '09, 18¢; gain from disc. ops.: '08, 41¢. Incl. nonrec. loss: '00, $11.83. '06 EPS don't add due to rounding. Next earnings report due late Feb. (B) Div'ds historically paid in mid-Jan., Apr., July, Oct. ■ Div'd reinvest plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '08: $16.61/sh. (D) In mill. (E) Rate base: net orig. cost. Rate allowed on com. eq. in '07: 11.35%; earned on avg. com. eq. '08: 12.9%. Regul. Clim.: Above Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	85
Earnings Predictability	10

PORTLAND GENERAL NYSE-POR

RECENT PRICE 19.90 | P/E RATIO 12.7 (Trailing: 13.0 Median: NMF) | RELATIVE P/E RATIO 0.77 | DIV'D YLD 5.3% | VALUE LINE 2242

TIMELINESS 3 Raised 1/1/10

SAFETY 2 New 11/10/06

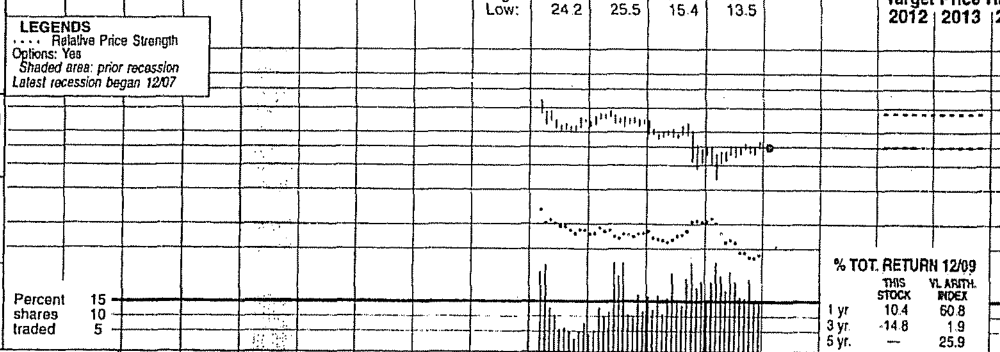
TECHNICAL 3 Raised 1/29/10

BETA .75 (1.00 = Market)

	2006	2007	2008	2009
High:	35.0	31.3	27.7	21.4
Low:	24.2	25.5	15.4	13.5

Target Price Range 2012 | 2013 | 2014

LEGENDS
.... Relative Price Strength
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+50%)	15%
Low	20	(Nil)	5%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	1

Institutional Decisions

	1Q2009	2Q2009	3Q2009
to Buy	124	95	91
to Sell	76	107	100
Hld's(000)	71477	72019	71579

% TOT. RETURN 12/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	10.4	60.8
3 yr.	-14.8	1.9
5 yr.	—	25.9

On April 3, 2006, Portland General Electric's existing stock (which was owned by Enron) was canceled, and 62.5 million shares were issued to Enron's creditors or the Disputed Claims Reserve (DCR). The stock began trading on a when-issued basis that day, and regular trading began on April 10, 2006. Shares issued to the DCR were released over time to Enron's creditors until all of the remaining shares were released in June, 2007.

1999	2000	2001	2002	2003	2004	2005[G]	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
--	--	--	--	--	--	23.14	24.32	27.87	27.89	23.60	24.60	Revenues per sh	27.75
--	--	--	--	--	--	4.75	4.64	5.21	4.71	4.20	4.65	"Cash Flow" per sh	5.25
--	--	--	--	--	--	1.02	1.14	2.33	1.39	1.40	1.65	Earnings per sh [A]	2.00
--	--	--	--	--	--	--	.68	.93	.97	1.01	1.05	Div'd Decl'd per sh [B]	1.20
--	--	--	--	--	--	4.08	5.94	7.28	6.12	10.00	7.45	Cap'l Spending per sh	4.75
--	--	--	--	--	--	19.15	19.58	21.05	21.64	20.70	21.30	Book Value per sh [C]	23.75
--	--	--	--	--	--	62.50	62.50	62.53	62.58	75.25	75.25	Common Shs Outst'g [D]	80.00
--	--	--	--	--	--	--	23.4	11.9	16.3	13.5		Avg Ann'l P/E Ratio	12.5
--	--	--	--	--	--	--	1.26	.63	.99	.90		Relative P/E Ratio	.85
--	--	--	--	--	--	--	2.5%	3.3%	4.3%	5.4%		Avg Ann'l Div'd Yield	4.8%
--	--	--	--	--	1454.0	1446.0	1520.0	1743.0	1745.0	1775	1850	Revenues ($mill)	2225
--	--	--	--	--	92.0	64.0	71.0	145.0	87.0	100	125	Net Profit ($mill)	160
--	--	--	--	--	37.0%	40.2%	33.6%	33.8%	28.7%	29.0%	27.0%	Income Tax Rate	25.0%
--	--	--	--	--	9.8%	18.8%	33.8%	17.9%	17.2%	20.0%	14.0%	AFUDC % to Net Profit	6.0%
--	--	--	--	--	41.1%	42.3%	43.4%	49.9%	46.2%	50.0%	53.0%	Long-Term Debt Ratio	50.0%
--	--	--	--	--	58.9%	57.7%	56.6%	50.1%	53.8%	50.0%	47.0%	Common Equity Ratio	50.0%
--	--	--	--	--	2171.0	2076.0	2161.0	2629.0	2518.0	3125	3420	Total Capital ($mill)	3800
--	--	--	--	--	2275.0	2436.0	2718.0	3066.0	3301.0	3840	4175	Net Plant ($mill)	4600
--	--	--	--	--	5.6%	4.6%	4.7%	6.9%	5.0%	4.5%	5.0%	Return on Total Cap'l	5.5%
--	--	--	--	--	7.2%	5.3%	5.8%	11.0%	6.4%	6.5%	8.0%	Return on Shr. Equity	8.5%
--	--	--	--	--	7.2%	5.3%	5.8%	11.0%	6.4%	6.5%	8.0%	Return on Com Equity [E]	8.5%
--	--	--	--	--	7.2%	5.3%	3.5%	6.6%	2.0%	2.0%	3.0%	Retained to Com Eq	3.5%
--	--	--	--	--	--	--	39%	40%	69%	68%	63%	All Div'ds to Net Prof	60%

CAPITAL STRUCTURE as of 9/30/09
Total Debt $1592.0 mill. **Due in 5 Yrs** $528.0 mill.
LT Debt $1408.0 mill. **LT Interest** $87.0 mill.
(LT interest earned: 2.3x)
Leases, Uncapitalized Annual rentals $7.0 mill.

Pension Assets-12/08 $347.0 mill.
Oblig. $467.0 mill.

Pfd Stock None

Common Stock 75,191,682 shs.
as of 10/26/09

MARKET CAP: $1.5 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	+3.6	+1.0	+.7
Avg. Indust. Use (MWH)	15736	11450	11392
Avg. Indust. Revs. per KWH (¢)	5.83	6.38	6.42
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw) [F]	3706	3664	4031
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.7	+1.4	+.8
Fixed Charge Cov. (%)	206	320	226

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	--	--	.5%
"Cash Flow"	--	--	1.5%
Earnings	--	--	3.5%
Dividends	--	--	5.5%
Book Value	--	--	2.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	381.0	351.0	372.0	416.0	1520.0
2007	436.0	402.0	435.0	470.0	1743.0
2008	471.0	425.0	400.0	449.0	1745.0
2009	485.0	389.0	445.0	456	1775
2010	510	420	450	470	1850

Cal-endar	EARNINGS PER SHARE [A] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	d.10	.43	.16	.64	1.14
2007	.88	.73	.32	.40	2.33
2008	.44	.63	--	.32	1.39
2009	.47	.31	.43	.19	1.40
2010	.50	.45	.35	.35	1.65

Cal-endar	QUARTERLY DIVIDENDS PAID [B] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	--	--	.225	.225	.45
2007	.225	.225	.235	.235	.92
2008	.235	.245	.245	.245	.97
2009	.245	.245	.255	.255	1.00
2010	.255				

BUSINESS: Portland General Electric Company (PGE) provides electricity to 818,000 customers in 52 cities in a 4,000-square-mile area of Oregon, including Portland and Salem. The company is in the process of decommissioning the Trojan nuclear plant, which it closed in 1993. Electric revenue breakdown, '08: residential, 43%; commercial, 34%; industrial, 9%; other, 14%. Generating sources include coal, gas, hydro, wind, and purchased; breakdown is not available. Fuel costs: 50% of revenues. '08 reported depreciation rate: 3.7%. Has 2,800 employees. Chairman: Corbin A. McNeill, Jr. Chief Executive Officer and President: Jim Piro. Inc.: Oregon. Address: 121 SW Salmon Street, Portland, Oregon 97204. Tel.: 503-464-8000. Internet: www.portlandgeneral.com.

Portland General Electric plans to file a rate case later this month. In 2010, the utility is likely to earn a return on equity of just 7%-8%. That's well below PGE's allowed ROE of 10%. Electric sales have fallen short of the forecasted level due to the weak economy. Meanwhile, operating and maintenance costs are up, and the effects of a state tax law are hurting the company. A ruling from the Oregon commission should come in time for new tariffs to take effect at the start of 2010.

We have trimmed our 2009 share-earnings estimate by a nickel. This reflects a $5 million aftertax charge that PGE will take to write off a portion of the cost of a hydro project (associated with a construction delay) that it won't be allowed to recover in rates. The company might still recoup some or all of these costs from insurance or from companies involved in the project.

We estimate higher profits in 2010. In 2009, extended outages at two coal-fired facilities hurt the bottom line. The plants are back on line, so we assume normal operations this year. Our estimate remains at the upper end of PGE's targeted range of $1.50-$1.65 a share.

PGE is deciding what to do with its 65%-owned Boardman coal-fired plant. Retrofitting the facility to meet stricter environmental guidelines would cost an estimated $520 million-$560 million. So, PGE proposes spending $40 million for environmental compliance in the short term, with the plant being shut or switched to a different fuel source in 2020.

Two sizable projects are under construction, and others are being proposed. PGE is adding a third phase to its Biglow Canyon windfarm. The 175-megawatt addition will cost an estimated $426 million and should begin operating in the third quarter. The utility is also installing an advanced metering system at a cost of $130 million-$135 million. This project should be completed by yearend. Potential projects for the next decade include gas base-load and peaking plants, additional wind capacity, and a transmission line in Oregon.

This stock's yield is fractionally above the utility mean. Total return potential to 2012-2014 is only average for the group.

Paul E. Debbas, CFA *February 5, 2010*

(A) Diluted earnings. '06 EPS don't add to full-year total due to rounding. Next earnings report due late February. (B) Dividends paid mid-Jan., Apr., July, and Oct. (C) Incl. deferred charges. In '08: $304.0 mill., $4.86/sh. (D) In millions. (E) Rate base: Net original cost. Rate allowed on common equity in '09: 10.0%; earned on average common equity, '08: 6.5%. Regulatory Climate: Below Average. (F) Summer peak in '06 (G) '05 per-share data are pro forma, based on shares outstanding when the stock began trading in '06

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	NMF
Earnings Predictability	NMF

PPL CORPORATION NYSE-PPL

RECENT PRICE 30.55 | P/E RATIO 15.0 (Trailing: 19.5 Median: 13.0) | RELATIVE P/E RATIO 0.89 | DIV'D YLD 5.1% | VALUE LINE 160

TIMELINESS 5 Lowered 9/25/09
SAFETY 3 Lowered 11/28/08
TECHNICAL 3 Raised 10/9/09
BETA .70 (1.00 = Market)

High:	14.5	16.0	23.1	31.2	20.0	22.2	27.1	33.7	37.3	54.6	55.2	34.4
Low:	10.4	10.2	9.2	15.5	13.0	15.8	19.9	25.5	27.8	34.4	26.8	24.3

Target Price Range 2012 | 2013 | 2014

2012-14 PROJECTIONS

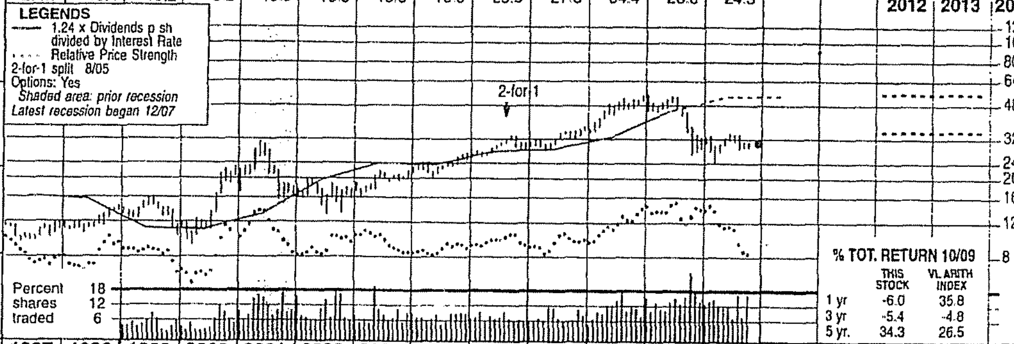
	Price	Gain	Ann'l Total Return
High	55	(+80%)	19%
Low	35	(+15%)	8%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	6	0	1	0	0	2	0	0	0
to Sell	2	1	0	0	0	1	0	0	0

Institutional Decisions

	4Q2008	1Q2009	2Q2009
to Buy	167	170	176
to Sell	219	198	184
Hld's(000)	233086	233367	231668



% TOT. RETURN 10/09

	THIS STOCK	VL ARITH INDEX
1 yr	-6.0	35.8
3 yr	-5.4	-4.8
5 yr.	34.3	26.5

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC	12-14
8.96	8.76	8.63	8.94	9.17	12.03	15.97	19.59	19.53	16.38	15.75	15.37	16.36	17.92	17.41	21.47	19.75	20.10	Revenues per sh	23.50
1.98	1.84	2.05	2.14	2.11	2.43	2.56	3.32	3.51	3.20	3.60	3.59	3.84	4.26	5.10	4.71	3.70	6.05	"Cash Flow" per sh	7.50
1.04	.84	.97	1.03	.99	1.12	1.01	1.64	1.79	1.54	1.84	1.87	1.92	2.29	2.63	2.45	1.15	3.20	Earnings per sh A	3.75
.83	.84	.84	.84	.84	.67	.50	.53	.53	.72	.77	.82	.96	1.10	1.22	1.34	1.38	1.60	Div'd Decl'd per sh B ■	1.90
1.60	1.62	1.26	1.11	.93	.97	1.11	1.59	2.99	2.74	2.17	1.94	2.13	3.62	4.51	3.79	3.45	5.00	Cap'l Spending per sh	5.00
7.97	7.89	8.15	8.44	8.45	5.69	5.61	6.94	6.33	6.71	9.19	11.21	11.62	13.30	14.88	13.55	13.30	14.95	Book Value per sh C	19.50
304.26	310.96	318.81	325.33	332.50	314.82	287.39	290.08	293.16	331.47	354.72	378.14	380.15	385.04	373.27	374.58	377.00	378.00	Common Shs Outst'g D	370.00
14.1	13.0	10.8	11.4	10.8	10.9	13.4	8.9	12.4	11.1	10.6	12.5	15.1	14.1	17.3	17.6	Bold figures are		Avg Ann'l P/E Ratio	12.0
.83	.85	.72	.71	.62	.57	.76	.58	.64	.61	.60	.66	.80	.76	.92	1.05	Value Line		Relative P/E Ratio	.80
5.7%	7.7%	8.0%	7.1%	7.8%	5.5%	3.7%	3.6%	2.4%	4.2%	4.0%	3.5%	3.3%	3.4%	2.7%	3.1%	estimates		Avg Ann'l Div'd Yield	4.3%
						4590.0	5683.0	5725.0	5429.0	5587.0	5812.0	6219.0	6899.0	6498.0	8044.0	7450	7600	Revenues ($mill)	8700
						332.0	500.0	576.0	536.0	667.0	692.0	739.0	899.0	1031.0	940.0	455	1245	Net Profit ($mill)	1430
						33.5%	36.3%	29.7%	25.7%	27.1%	22.8%	14.0%	23.2%	20.7%	31.8%	36.0%	36.0%	Income Tax Rate	36.0%
						2.1%	4.0%	4.3%	3.4%	1.2%	.7%	--	--	2.6%	--	Nil	Nil	AFUDC % to Net Profit	Nil
						65.7%	65.4%	64.8%	66.5%	71.1%	61.6%	57.5%	55.4%	54.1%	57.1%	59.5%	57.0%	Long-Term Debt Ratio	52.5%
						28.2%	29.5%	23.7%	25.1%	28.5%	37.9%	42.0%	42.2%	43.6%	40.5%	38.0%	41.0%	Common Equity Ratio	45.5%
						5716.0	6826.0	7845.0	8868.0	11455	11171	10513	12151	12747	12529	13150	13800	Total Capital ($mill)	15800
						5644.0	5948.0	6135.0	9566.0	10446	11209	10916	12069	12605	12416	12750	13600	Net Plant ($mill)	15700
						7.9%	9.7%	9.6%	8.8%	7.6%	8.4%	9.3%	9.3%	9.8%	9.2%	5.5%	11.0%	Return on Total Cap'l	11.0%
						16.9%	21.2%	20.8%	18.1%	20.2%	16.1%	16.5%	16.6%	17.6%	17.5%	8.5%	21.0%	Return on Shr. Equity	19.0%
						19.0%	23.6%	28.2%	21.1%	19.6%	16.3%	16.7%	17.3%	18.2%	18.2%	8.5%	21.5%	Return on Com Equity E	19.5%
						9.4%	16.1%	20.2%	12.4%	11.7%	9.3%	8.8%	9.3%	10.0%	8.5%	NMF	11.0%	Retained to Com Eq	10.0%
						54%	35%	35%	49%	43%	43%	47%	47%	46%	54%	NMF	50%	All Div'ds to Net Prof	50%

CAPITAL STRUCTURE as of 9/30/09
Total Debt $7870.0 mill. **Due in 5 Yrs** $2348.0 mill.
LT Debt $7250.0 mill. **LT Interest** $453.0 mill.
Incl. 23 mill. units 7.75%, $25 liq. value; 82,000 units 8.23%, $1000 face value.
(LT interest earned: 4.0x)
Leases, Uncapitalized Annual rentals $117.0 mill.
Pension Assets-12/08 $3.48 bill. **Oblig.** $4.38 bill.
Pfd Stock $319.0 mill. **Pfd Div'd** $18.0 mill.
505,189 shs. 3.35%-6.75%, $100 par, cumulative, callable $102.00-$110.00; 10 mill. shs. 6.25%, $100 liq. preference, redeemable after 4/6/11.
Common Stock 377,068,461 shs. as of 10/23/09
MARKET CAP: $11.5 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	-1.8	+3.5	+.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw) F	7554	7577	7316
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.9	+.7	+.5
Fixed Charge Cov. (%)	314	330	367

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	6.5%	2.0%	3.5%
"Cash Flow"	8.0%	6.5%	8.0%
Earnings	9.0%	7.5%	7.5%
Dividends	4.5%	12.5%	7.5%
Book Value	6.5%	13.5%	6.0%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	1781	1642	1752	1724	6899.0
2007	1546	1573	1774	1605	6498.0
2008	1526	1024	2981	2513	8044.0
2009	2351	1673	1805	1621	7450
2010	1900	1800	2100	1800	7600

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.73	.52	.58	.46	2.29
2007	.57	.62	.87	.57	2.63
2008	.65	.50	.55	.74	2.45
2009	.64	.07	.12	.32	1.15
2010	.85	.75	.80	.80	3.20

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.205	.23	.23	.25	.92
2006	.25	.275	.275	.275	1.08
2007	.275	.305	.305	.305	1.19
2008	.305	.335	.335	.335	1.31
2009	.335	.345	.345	.345	

BUSINESS: PPL Corporation (formerly PP&L Resources, Inc.) is a holding company for PPL Utilities (formerly Pennsylvania Power & Light Company), which distributes electricity to about 1.4 million customers in a 10,000-square-mile area in eastern & central Pennsylvania. Plans to sell gas distribution subsidiary. Also has subsidiaries in power generation & marketing, foreign electricity distribution in U.K. (2.6 million customers). Electric revenue breakdown & generating sources not provided by company. Fuel costs: 41% of revenues. '08 reported depreciation rate: 2.4%-2.6%. Has 11,100 employees. Chairman, President & CEO: James H. Miller. Inc.: Pennsylvania. Address: Two North Ninth St., Allentown, Pennsylvania 18101-1179. Tel.: 800-345-3085. Internet: www.pplweb.com.

PPL Corporation's earnings are likely to rise significantly in 2010. At the start of the year, the prices that the company's customers pay for the generation portion of their electricity will no longer be subject to below-market price caps. Instead, customers will pay market-based prices. Because PPL's generating plants are nonregulated, the company benefits from supplying this power at market-based rates. Thus, even though market prices have been trending downward for the past several months, they are still well above the prices that PPL's plants have been fetching. Our 2010 earnings estimate of $3.20 a share is within the company's targeted range of $3.10-$3.50 a share. Considering the large bottom-line increase that is probable next year, we figure that a hefty boost in the dividend is also likely.

Mark-to-market gains or losses can affect the company's earnings. These losses reduced share net by $0.45 in the first nine months of 2009, and the stock is untimely. Since these items are unpredictable, we do not assume any such gains or losses in our estimates and projections.

PPL's utility subsidiary in Pennsylvania needs rate relief. PPL Utilities' profits fell 24% in the first nine months of 2009 due to weak sales and higher operating and maintenance expenses. Because PPL is earning a return on equity of just 7.5%—well below a healthy level for a utility—it plans to file a rate case in the first quarter of 2010. New tariffs wouldn't take effect until the start of 2011, however.

It is questionable whether earnings will advance in 2011. Although the company isn't fully hedged for 2011, it appears as if the price PPL will receive for the power it generates will be slightly below the expected price in 2010. If PPL Utilities receives reasonable rate treatment, then the company might be able to maintain its earning power. Our preliminary forecast of earnings in 2011 is $3.20-$3.25 a share.

This stock offers a decent yield and 3- to 5-year total return potential that is above the utility average. Even if 2011 proves to be a tough year, we think there will be enough earnings and dividend growth subsequently to produce a respectable total return through the 2012-2014 period.

Paul E. Debbas, CFA November 27, 2009

(A) Diluted EPS. Excl. nonrec. gains (losses): '01, ($1.18); '02, (89¢); '03, 24¢; '04, 3¢; '05, (2¢); '07, (12¢); gains (losses) on disc. ops.: '03, (6¢); '04, (1¢); '05, (12¢); '07, 19¢; '08, 3¢; '09, (14¢). '08 EPS don't add due to rounding. Next egs. report due early Feb. (B) Div'ds historically paid in early Jan., Apr., July, and Oct. ■ Div'd reinv. plan avail. (C) Incl. intang. In '08: $4.38/sh. (D) In mill., adj. for split. (E) Rate base: Fair value. Rate all'd on com. eq. in '08: none spec.; earn. on avg. com. eq., '08: 16.7%. Reg. Clim.: Avg. (F) Summer peak in '06 & '08.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	90
Earnings Predictability	85

PROGRESS ENERGY NYSE-PGN

RECENT PRICE 38.34 | P/E RATIO 12.3 (Trailing: 13.1; Median: 15.0) | RELATIVE P/E RATIO 0.73 | DIV'D YLD 6.5% | VALUE LINE 162

TIMELINESS 3 Lowered 5/22/09
SAFETY 2 Lowered 6/7/02
TECHNICAL 3 Raised 10/23/09
BETA .65 (1.00 = Market)

High:	49.6	47.9	49.4	49.3	52.7	48.0	47.9	46.0	49.6	52.8	49.2	40.8
Low:	39.2	29.3	28.3	38.8	32.8	37.4	40.1	40.2	40.3	43.1	32.6	31.3

2012-14 PROJECTIONS

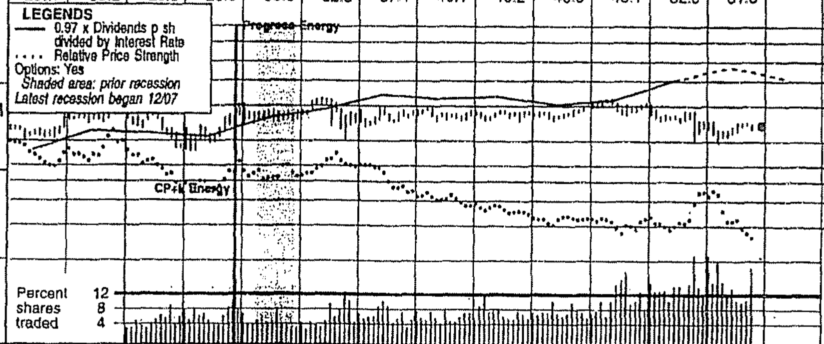
	Price	Gain	Ann'l Total Return
High	50	(+30%)	12%
Low	35	(-10%)	5%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	1	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	5	2	3	0	0	4	0

Institutional Decisions

	4Q2008	1Q2009	2Q2009
to Buy	211	220	219
to Sell	218	208	185
Hld's(000)	146742	162070	164814



Target Price Range 2012 | 2013 | 2014

% TOT. RETURN 10/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	1.9	35.8
3 yr.	-2.9	-4.8
5 yr.	20.6	26.5

Progress Energy was formed on November 30, 2000 through the merger of CP&L Energy and Florida Progress. Florida Progress common shareholders exchanged each share held for $54 in cash and/or CP&L common stock. They also received one Contingent Value Obligation for each share of Florida Progress stock, entitling them to payments when four synthetic fuel plants achieved certain economic levels from 2001 to 2007. Data prior to merger are for CP&L only and are not comparable with Progress Energy data.

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
21.04	19.99	38.69	34.18	35.54	39.56	40.11	37.38	35.19	34.72	*35.35*	*37.25*	Revenues per sh	*39.90*
6.06	5.37	8.14	7.02	7.54	7.40	6.53	5.93	6.13	6.09	*6.10*	*6.15*	"Cash Flow" per sh	*6.50*
2.55	2.34	3.43	3.84	3.41	3.10	2.94	2.05	2.69	2.96	*3.05*	*3.15*	Earnings per sh A	*3.60*
2.02	2.08	2.14	2.18	2.26	2.32	2.38	2.42	2.44	2.46	*2.48*	*2.50*	Div'd Decl'd per sh B†■	*2.56*
4.32	4.61	5.56	5.05	4.14	4.04	4.29	5.56	7.59	8.84	*7.15*	*7.10*	Cap'l Spending per sh	*6.95*
21.38	26.32	27.45	28.73	30.26	30.90	31.90	32.37	32.38	32.55	*31.90*	*32.90*	Book Value per sh C	*36.80*
159.60	206.09	218.73	232.43	246.00	247.00	252.00	256.00	260.10	264.00	*280.00*	*282.00*	Common Shs Outst'g E	*288.00*
15.2	15.3	12.4	11.9	12.4	14.1	14.8	21.6	17.9	14.3	*Bold figures are*	*Value Line estimates*	Avg Ann'l P/E Ratio	*12.0*
.87	.99	.64	.65	.71	.74	.79	1.17	.95	.86			Relative P/E Ratio	*.85*
5.2%	5.8%	5.0%	4.8%	5.3%	5.3%	5.5%	5.5%	5.1%	5.8%			Avg Ann'l Div'd Yield	*5.9%*
3357.6	4118.9	8461.5	7945.0	8743.0	9772.0	10108	9570.0	9153.0	9167.0	*9900*	*10500*	Revenues ($mill)	*11500*
382.3	369.9	695.1	815.2	818.1	763.5	727.0	514.0	693.0	773.0	*855*	*890*	Net Profit ($mill)	*1030*
40.3%	35.4%	--	--	--	13.1%	--	28.4%	32.5%	33.8%	*33.0%*	*33.0%*	Income Tax Rate	*33.0%*
3.0%	5.6%	2.6%	1.0%	3.4%	.8%	1.8%	1.4%	2.5%	3.9%	*3.0%*	*3.0%*	AFUDC % to Net Profit	*3.0%*
46.6%	51.6%	60.9%	59.0%	56.1%	55.2%	56.2%	51.3%	50.6%	55.1%	*55.0%*	*54.5%*	Long-Term Debt Ratio	*52.5%*
52.5%	47.6%	38.5%	40.4%	43.4%	44.3%	43.3%	48.1%	48.8%	44.4%	*45.0%*	*45.5%*	Common Equity Ratio	*47.5%*
6500.6	11407	15580	16517	17162	17247	18577	17214	17252	19346	*19825*	*20380*	Total Capital ($mill)	*22290*
6764.8	10437	10915	10656	14434	14363	14442	15245	16605	18293	*19450*	*19780*	Net Plant ($mill)	*21700*
7.3%	4.3%	6.4%	6.8%	6.5%	6.2%	5.6%	4.8%	5.6%	5.6%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
11.0%	6.7%	11.4%	12.0%	10.9%	9.9%	8.9%	6.1%	8.1%	8.9%	*9.5%*	*9.5%*	Return on Shr. Equity	*9.5%*
11.1%	6.7%	11.5%	12.1%	10.9%	9.9%	9.0%	6.1%	8.2%	8.9%	*9.5%*	*9.5%*	Return on Com Equity D	*9.5%*
2.5%	NMF	4.3%	5.0%	3.7%	2.6%	1.7%	NMF	.7%	1.5%	*2.0%*	*2.0%*	Retained to Com Eq	*3.0%*
78%	101%	63%	59%	67%	74%	81%	119%	91%	84%	*81%*	*79%*	All Div'ds to Net Prof	*72%*

CAPITAL STRUCTURE as of 9/30/09
Total Debt $11484 mill. **Due in 5 Yrs** $3630 mill.
LT Debt $10834 mill. **LT Interest** $540 mill.
(LT interest earned: 3.1x)
Pension Assets-12/08 $1.29 bill. **Oblig.** $2.33 bill.
Pfd Stock $92.8 mill. **Pfd Div'd** $4.5 mill.
921,814 shs. $4.00 to $5.44 cum. no par. callable from $101 to $110 per sh. Sinking funds began in 1984 and 1986, respectively.
Common Stock 279,626,073 shs. **as of 11/2/09**
MARKET CAP: $10.7 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	-2.3	+3.5	-1.7
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	6.38	6.58	6.78
Capacity at Peak (Mw)	21322	21776	21775
Peak Load, Summer (Mw)	21717	22327	21373
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+2.0	+3.5	+1.0
Fixed Charge Cov. (%)	204	249	NA

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	6.0%	--	*2.0%*
"Cash Flow"	--	-4.5%	*1.5%*
Earnings	-.5%	-6.5%	*6.0%*
Dividends	2.5%	2.0%	*1.0%*
Book Value	5.5%	2.5%	*2.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	2250	2316	2731	2273	9570
2007	2072	2129	2750	2202	9153
2008	2066	2244	2696	2161	9167
2009	2442	2312	2824	*2322*	*9900*
2010	*2500*	*2450*	*3150*	*2400*	*10500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.34	.08	1.12	.51	2.05
2007	.62	.41	1.27	.39	2.69
2008	.58	.77	1.18	.43	2.96
2009	.66	.62	1.22	*.55*	*3.05*
2010	*.68*	*.67*	*1.25*	*.55*	*3.15*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.59	.59	.59	.59	2.36
2006	.605	.605	.605	.605	2.42
2007	.61	.61	.61	.61	2.44
2008	.615	.615	.615	.615	2.46
2009	.62	.62	.62	.62	

BUSINESS: Progress Energy, parent of CP&L Energy and Florida Progress, supplies electricity to portions of North Carolina, South Carolina, and Florida. Other operations include coal mining, wholesale generation, and financial services. Electric revenues: residential, 42%; commercial, 25%; industrial, 11%; other, 22%. Power costs: 48% of revs; labor costs: 13%. Fuel sources: gas/oil/coal, 58%; nuclear, 27%; hydro, less than 1%; purch. power, 14%. Has 11,000 employees. '08 depreciation rate: 2.7%. Est'd plant age: 8 years. Chairman, Chief Executive Officer, and President: William D. Johnson. Incorporated: North Carolina. Address: 411 Fayetteville Street, Raleigh, North Carolina 27602. Telephone: 1-800-662-7232. Internet: www.progress-energy.com.

Progress Energy posted decent third-quarter results. The company reported earnings of $1.22 a share, a modest increase from the $1.18 reported during the same period last year. Performance was driven by increased revenues (up 5% year over year), modest base-rate relief, favorable returns on nuclear and environmental investments, and lower operation and maintenance costs. Gains were partially offset by declining retail growth and share dilution, stemming from PGN's issuance of 14.4 million common shares last January. From a geographic standpoint, Progress Energy Florida (PEF) posted a bottom-line gain of 13%, while Progress Energy Carolina's (PEC) earnings retreated roughly 3%. Both regions continue to be impacted by lower consumer demand, reflective of the weak economy.

PEF's rate case ruling has been delayed. The Florida Public Service Commission announced it will delay its decision until January, 2010, previously scheduled for mid-November. PEF was seeking a base-rate increase of $499 million, or approximately 11%. The request is based on an ROE of 12.54% on a common equity ratio of 50.52%. Drivers for the case include a generator replacement at Crystal River 3, a repowering project at its Bartow plant, and additional investments geared toward upgrading its transmission facilities. We have revised our 2010 earnings estimate to reflect reasonable regulatory relief.

The company's Smart Grid program received a boost. PGN was recently awarded $200 million in federal stimulus money to aid the development of new Smart Grid infrastructure. The U.S. Department of Energy distributed the funds as part of the $3.4 billion nationwide project to upgrade the country's power grid. The grants will be split evenly among PGN's Florida and Carolina utilities.

The stock's main appeal is its adequately covered dividend. The stock lacks attractive total return potential over our 3- 5-year outlook. However, at its current quotation, it is yielding 6.5%, well above the 4.8% utility average. Furthermore, management appears committed to slowly increasing its payout, as it has done so for 21 consecutive years.

Michael Ratty *November 27, 2009*

(A) EPS diluted. Excl. nonrecur.: '00, 69¢; '01, (75¢); '02, ($1.32); '03, (3¢); '05, (39¢); '07, (73¢). Next egs. report due early Mar.
(B) Div'ds historically paid in early Feb., May, Aug., and Nov. ■ Div'd reinvestment plan available. † Shareholder investment plan avail.
(C) Incl. def. charges in '08: $32.75/sh.
(D) Rate Base: orig. cost. Rate allowed on common equity. In '88 in N.C.: 12.75%; in '88 in S.C.: 12.75%; in '02 in Fla.: rev. sharing incentive plan; earn. on '08 avg. com. eq.: 9.6%. Regul. Clim.: Avg. (E) In millions.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	25
Earnings Predictability	80

P.S. ENTERPRISE GP. NYSE-PEG

RECENT PRICE 31.62 | P/E RATIO 10.2 (Trailing: 10.8; Median: 13.0) | RELATIVE P/E RATIO 0.64 | DIV'D YLD 4.4% | VALUE LINE 163

TIMELINESS 3 Lowered 8/28/09
SAFETY 3 Lowered 3/7/03
TECHNICAL 4 Lowered 8/28/09
BETA .80 (1.00 = Market)

High:	21.4	21.3	25.0	25.8	23.6	22.3	26.3	34.2	36.3	49.9	52.3	34.0
Low:	15.2	16.0	12.8	18.4	10.0	16.0	19.0	24.7	29.5	32.2	22.1	23.7

Target Price Range 2012 | 2013 | 2014

2012-14 PROJECTIONS

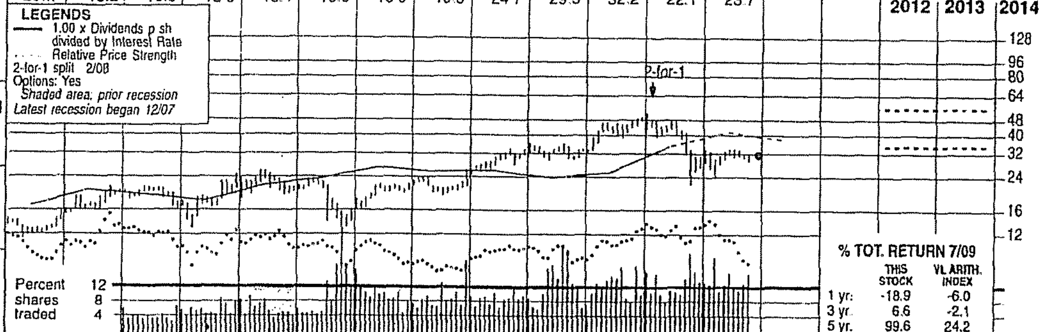
	Price	Gain	Ann'l Total Return
High	55	(+75%)	19%
Low	35	(+10%)	8%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	1	0	0	1	0	0	0	0	0
to Sell	1	0	0	1	0	0	0	1	0

Institutional Decisions

	4Q2008	1Q2009	2Q2009
to Buy	208	235	232
to Sell	189	199	198
Hld's(000)	303240	307286	306963



% TOT. RETURN 7/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-18.9	-6.0
3 yr.	6.6	-2.1
5 yr.	99.6	24.2

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
11.71	12.09	12.60	12.94	13.73	12.78	15.01	22.83	23.84	18.62	23.54	23.09	24.74	24.07	25.28	27.94	*24.30*	*25.10*	Revenues per sh	*30.00*
2.57	2.67	2.73	2.58	2.57	2.83	2.82	2.71	3.14	3.01	2.92	3.02	3.42	3.91	4.36	4.68	*4.80*	*5.20*	"Cash Flow" per sh	*6.25*
1.36	1.39	1.36	1.23	1.21	1.40	1.56	1.78	1.85	1.88	1.88	1.52	1.79	1.85	2.59	2.90	*2.95*	*3.25*	Earnings per sh A	*3.75*
1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.10	1.12	1.14	1.17	1.29	*1.33*	*1.40*	Div'd Decl'd per sh B ■†	*1.70*
1.77	1.74	1.59	1.25	1.17	1.15	1.34	2.31	4.99	4.03	2.86	2.64	2.04	2.01	2.65	3.50	*3.95*	*6.40*	Cap'l Spending per sh	*4.00*
10.53	10.85	11.13	11.16	11.23	10.99	9.23	9.61	10.05	8.85	11.71	12.05	11.99	13.35	14.35	15.36	*17.00*	*18.90*	Book Value per sh C	*24.00*
487.38	489.40	489.40	466.94	463.92	463.92	432.83	415.94	411.68	450.53	472.27	476.20	502.33	505.29	508.52	506.02	*506.00*	*506.00*	Common Shs Outst'g D	*490.00*
12.3	9.9	10.4	11.2	10.9	12.7	12.5	10.3	12.0	10.0	10.6	14.3	16.5	17.8	16.5	13.6	*Bold figures are*		Avg Ann'l P/E Ratio	*12.5*
.73	.65	.70	.70	.63	.66	.71	.67	.61	.55	.60	.76	.88	.96	.88	.81	*Value Line*		Relative P/E Ratio	*.85*
6.5%	7.9%	7.6%	7.8%	8.2%	6.1%	5.5%	5.9%	4.9%	5.7%	5.4%	5.1%	3.8%	3.5%	2.7%	3.3%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*
						6497.0	9498.0	9815.0	8390.0	11116	10996	12430	12164	12853	14139	*12300*	*12700*	Revenues ($mill)	*14700*
						780.0	858.0	842.0	842.8	856.0	725.0	862.0	934.0	1323.0	1477.0	*1505*	*1665*	Net Profit ($mill)	*1845*
						41.9%	36.4%	30.7%	22.7%	35.2%	38.1%	38.6%	36.6%	44.5%	45.9%	*38.0%*	*38.0%*	Income Tax Rate	*38.0%*
						--	--	--	--	13.9%	15.9%	11.5%	4.7%	2.7%	3.2%	*3.0%*	*3.0%*	AFUDC % to Net Profit	*2.0%*
						46.8%	50.4%	67.8%	67.1%	69.8%	69.0%	64.9%	60.3%	54.0%	50.5%	*50.5%*	*43.5%*	Long-Term Debt Ratio	*43.0%*
						40.9%	38.1%	27.2%	24.3%	29.8%	30.6%	34.6%	39.2%	45.5%	49.0%	*49.0%*	*56.0%*	Common Equity Ratio	*57.0%*
						9779.0	10501	15198	16378	18554	18744	17381	17197	16041	15856	*17475*	*17075*	Total Capital ($mill)	*20700*
						7078.0	7702.0	10064	11449	12422	13750	13336	13002	13275	14433	*15550*	*17900*	Net Plant ($mill)	*20700*
						9.5%	9.8%	7.4%	7.2%	7.0%	6.3%	7.3%	7.7%	10.4%	11.2%	*10.5%*	*11.5%*	Return on Total Cap'l	*10.5%*
						15.0%	16.5%	17.2%	15.6%	15.3%	12.5%	14.1%	13.7%	17.9%	18.8%	*17.5%*	*17.5%*	Return on Shr. Equity	*15.5%*
						17.2%	19.1%	18.6%	19.7%	15.4%	12.6%	14.2%	13.8%	18.1%	19.0%	*17.5%*	*17.5%*	Return on Com Equity E	*15.5%*
						5.3%	7.5%	7.8%	8.3%	6.5%	3.5%	5.3%	5.3%	9.9%	10.5%	*9.5%*	*10.0%*	Retained to Com Eq	*8.5%*
						73%	65%	62%	61%	58%	73%	63%	62%	45%	45%	*45%*	*43%*	All Div'ds to Net Prof	*46%*

CAPITAL STRUCTURE as of 9/30/09
Total Debt $8457.0 mill. **Due in 5 Yrs** $5352.0 mill.
LT Debt $7566.0 mill. **LT Interest** $473.0 mill.
Incl. $1.2 bill. securitized bonds.
(LT interest earned: 5.7x)
Leases, Uncapitalized Annual rentals $39.0 mill.
Pension Assets-12/08 $2.36 bill. **Oblig.** $3.57 bill.
Pfd Stock $80.0 mill **Pfd Div'd** $4.0 mill.
795,234 shs. 4.08% to 6.92%, cum. $100 par, call from $102.75 to $103.00 a sh.

Common Stock 505,980,424 shs.
as of 10/15/09
MARKET CAP: $16 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	-2.6	+2.4	NA
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH(¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	+1.0	NA
Fixed Charge Cov. (%)	242	386	528

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	7.0%	3.0%	2.5%
"Cash Flow"	5.0%	7.5%	6.5%
Earnings	6.5%	5.5%	7.5%
Dividends	1.0%	2.0%	6.0%
Book Value	2.5%	7.0%	9.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	3461	2556	3212	2935	12164
2007	3508	2718	3356	3271	12853
2008	3792	3367	3718	3262	14139
2009	3921	2561	3039	*2779*	*12300*
2010	*3500*	*2800*	*3400*	*3000*	*12700*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.41	.35	.75	.34	1.85
2007	.64	.56	.96	.43	2.59
2008	.85	.64	.94	.47	2.90
2009	.88	.61	.96	*.50*	*2.95*
2010	*.95*	*.68*	*1.10*	*.52*	*3.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.28	.28	.28	.28	1.12
2006	.285	.285	.285	.285	1.14
2007	.2925	.2925	.2925	.2925	1.17
2008	.3225	.3225	.3225	.3225	1.29
2009	.3325	.3325	.3325		

BUSINESS: Public Service Enterprise Group Incorporated is a holding company for Public Service Electric and Gas Company, which serves 2.1 million electric and 1.7 million gas customers in New Jersey. PSEG Power is a nonregulated power generator with nuclear, gas, and coal-fired plants. PSEG Energy Holdings is a power producer domestically and abroad. Company stopped breaking down data on electric and gas operating statistics in 2002. Fuel costs: 55% of revenues. '08 reported deprec. rate (utility): 2.5%. Has 9,800 employees. Chairman, President & Chief Executive Officer: Dr. Ralph Izzo. Incorporated: New Jersey. Address: 80 Park Plaza, P.O. Box 1171, Newark, New Jersey 07101-1171. Telephone: 973-430-7000. Internet: www.pseg.com.

Public Service Enterprise Group's utility subsidiary has revised its rate application. Public Service Electric & Gas raised its electric and gas requests by $13 million and $9 million, respectively. PSE&G is now seeking an electric rate increase of $147.0 million and a gas tariff hike of $105.9 million, based on a return of 11.5% on a common-equity ratio of 51.2%. The utility clearly needs rate relief; it earned an ROE of just 8.6% for the 12 months that ended on September 30th. Further revisions are possible in early 2010. An order from the New Jersey regulators is expected in the first half of 2010.

We estimate that earnings will wind up slightly higher in 2009. At PSEG Power, the company's nonregulated power-generating subsidiary, contracts that were signed a few years ago have expired and were replaced by contracts with higher margins. Lower fuel costs are a plus, too. On the other hand, the weak economy and an unusually mild summer reduced the demand for power. (This hurt PSE&G's profits, as well.) Our estimate of $2.95 a share is below the company's targeted range of $3.00-$3.25 a share because our figure includes $0.05 a share of charges in the first nine months of 2009 that the company is excluding from its guidance.

We expect higher profits in 2010. That's based on our expectation of higher margins at PSEG Power, rate relief at PSE&G, and a return to normal weather conditions. We're sticking with our forecast of $3.25 a share. Wall Street is looking ahead to 2011, however, and there is a chance of little or no earnings improvement based on forward prices for power and the fact that a portion of PSEG Power's expected generation is unhedged.

We look for a dividend increase in the first quarter of 2010. We estimate that the board of directors will raise the annual disbursement by $0.07 a share (5.3%). This increase would be larger than the one the board declared earlier this year but smaller than that in 2008. PSEG is targeting a 40%-50% payout ratio.

We have a neutral stance towards this stock. Compared with other utilities, its below-average yield is offset by 3- to 5-year total return potential that's a cut above average.

Paul E. Debbas, CFA *November 27, 2009*

(A) Diluted EPS. Excl. nonrec. losses: '99, $1.75 net; '02, $1.30; '05, 3¢; '06, 35¢; '08, 96¢; gains (loss) from disc. ops.: '05, (33¢); '06, 12¢; '07, 3¢; '08, 40¢. Next earnings report due late Jan. (B) Div'ds historically paid in late Mar., June, Sept., and Dec. ■ Div'd reinvestment plan available. † Shareholder investment plan available. (C) Incl. intang. In '08: $12.69/sh. (D) In mill., adj. for split. (E) Rate base: Net original cost. Rate allowed on com. eq. in '03: 9.75%; earned on avg. com. eq., '08: 19.2%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	80
Earnings Predictability	80

SCANA CORP. NYSE-SCG

RECENT PRICE 35.13 | P/E RATIO 11.9 (Trailing: 11.9; Median: 13.0) | RELATIVE P/E RATIO 0.71 | DIV'D YLD 5.5% | VALUE LINE 164

TIMELINESS 3 Lowered 3/27/09
SAFETY 2 Lowered 9/10/99
TECHNICAL 3 Raised 10/16/09
BETA .65 (1.00 = Market)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
High:	37.3	32.6	31.1	30.0	32.1	35.7	39.7	43.7	42.4	45.5	44.1	36.9
Low:	27.9	21.1	22.0	24.3	23.5	28.1	32.8	36.6	36.9	32.9	27.8	26.0

2012-14 PROJECTIONS

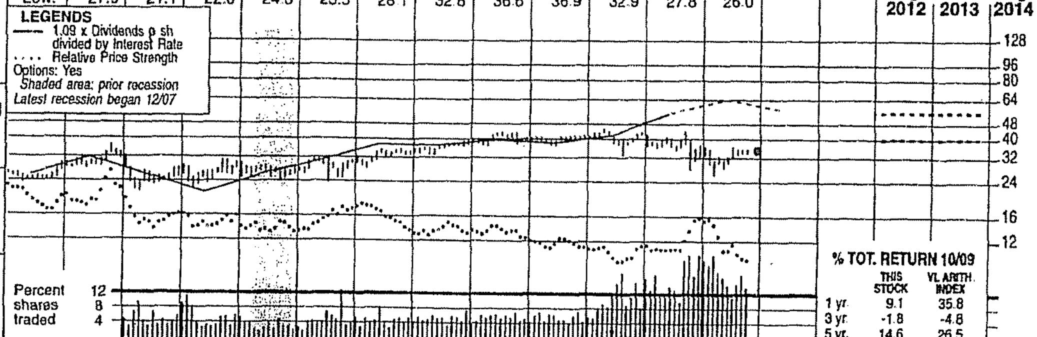
	Price	Gain	Ann'l Total Return
High	55	(+55%)	16%
Low	40	(+15%)	8%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	1	0	0	0	0	0

Institutional Decisions

	4Q2008	1Q2009	2Q2009
to Buy	146	153	143
to Sell	145	149	131
Hld's(000)	55540	55775	54074



% TOT. RETURN 10/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	9.1	35.8
3 yr.	-1.8	-4.8
5 yr.	14.6	26.5

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
13.56	13.77	13.06	14.25	14.19	15.76	15.93	32.78	32.95	26.65	30.85	34.38	41.54	39.00	39.50	45.08	33.85	32.80	Revenues per sh	35.75
3.50	3.77	3.68	3.75	3.53	3.62	3.15	4.43	4.55	4.56	4.95	5.26	7.41	5.67	5.72	5.85	5.85	5.65	"Cash Flow" per sh	6.75
1.86	1.60	1.86	2.05	1.90	2.12	1.44	2.12	2.15	2.38	2.50	2.67	2.78	2.59	2.74	2.95	2.95	3.00	Earnings per sh A	3.50
1.37	1.41	1.44	1.47	1.51	1.54	1.32	1.15	1.20	1.30	1.38	1.46	1.56	1.68	1.76	1.84	1.88	1.92	Div'd Decl'd per sh B ■ †	2.10
3.46	4.21	3.09	2.34	2.45	2.87	2.37	3.28	4.99	6.41	6.94	4.84	3.37	4.50	6.20	7.66	10.60	8.50	Cap'l Spending per sh	12.50
14.30	14.69	15.00	15.86	16.66	16.86	20.27	19.40	20.95	19.64	20.82	21.69	23.28	24.32	25.30	25.81	27.15	28.55	Book Value per sh C	33.25
93.24	96.04	103.62	106.18	107.32	103.57	103.57	104.73	104.73	110.83	110.74	113.00	115.00	117.00	117.00	118.00	124.00	131.00	Common Shs Outst'g D	141.00
12.8	14.0	12.3	13.1	13.4	14.5	17.5	12.5	12.6	12.2	13.0	13.6	14.4	15.4	15.0	12.7	Bold figures are		Avg Ann'l P/E Ratio	13.5
.76	.92	.82	.82	.77	.75	1.00	.81	.65	.67	.74	.72	.77	.83	.80	.76	Value Line		Relative P/E Ratio	.90
5.8%	6.3%	6.3%	5.5%	5.9%	5.0%	5.2%	4.3%	4.4%	4.5%	4.2%	4.0%	3.9%	4.2%	4.3%	4.9%	estimates		Avg Ann'l Div'd Yield	4.5%

CAPITAL STRUCTURE as of 9/30/09
Total Debt $4507.0 mill. **Due in 5 Yrs** $1883.0 mill.
LT Debt $4166.0 mill. **LT Interest** $231.0 mill.
(LT interest earned: 3.3x)
Leases, Uncapitalized Annual rentals $18.0 mill.
Pension Assets-12/08 $629.4 mill. **Oblig.** $709.5 mill.
Pfd Stock $113.0 mill. **Pfd Div'd** $7.0 mill.
125,209 shs. 5% cum., $50 par., callable $52.50; 220,287 shs. 4.50% to 6.00% cum., $50 par, callable $50.50 to $51.00; 1,000,000 shs. 6.52% cum., $100 par, callable $100.00.
Common Stock 123,132,614 shs. **as of 10/31/09**
MARKET CAP: $4.3 billion (Mid Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
1650.0	3433.0	3451.0	2954.0	3416.0	3885.0	4777.0	4563.0	4621.0	5319.0	4200	4300	Revenues ($mill)	5050
160.0	228.0	231.0	259.0	285.0	305.0	323.0	306.0	327.0	353.0	370	390	Net Profit ($mill)	505
41.0%	38.2%	34.9%	32.2%	31.5%	32.5%	--	26.5%	29.2%	35.4%	31.0%	35.5%	Income Tax Rate	35.5%
4.4%	3.9%	11.3%	13.5%	10.5%	8.5%	.9%	2.6%	4.6%	8.5%	20.0%	10.0%	AFUDC % to Net Profit	15.0%
40.8%	57.4%	53.9%	55.7%	57.1%	55.4%	51.4%	50.9%	48.4%	58.0%	58.0%	56.5%	Long-Term Debt Ratio	55.5%
54.8%	40.3%	43.8%	42.1%	40.8%	42.6%	46.6%	47.2%	49.7%	40.5%	40.5%	42.5%	Common Equity Ratio	43.5%
3829.0	5048.0	5006.0	5176.0	5646.0	5752.0	5739.0	6027.0	5952.0	7519.0	8320	8840	Total Capital ($mill)	10850
3829.0	4475.0	4803.0	5474.0	6417.0	6762.0	6734.0	7007.0	7538.0	8305.0	9255	9980	Net Plant ($mill)	13450
5.9%	6.8%	6.9%	7.0%	6.9%	7.1%	7.4%	6.8%	7.3%	6.2%	6.0%	6.0%	Return on Total Cap'l	6.0%
7.1%	10.6%	10.0%	11.3%	11.8%	11.9%	11.6%	10.3%	10.6%	11.2%	10.5%	10.0%	Return on Shr. Equity	10.5%
7.1%	10.9%	10.2%	11.6%	12.1%	12.2%	11.8%	10.5%	10.8%	11.4%	11.0%	10.0%	Return on Com Equity E	10.5%
--	4.8%	4.6%	5.5%	5.5%	5.6%	5.3%	3.8%	4.0%	4.4%	4.0%	3.5%	Retained to Com Eq	4.5%
99%	57%	56%	54%	55%	55%	56%	65%	64%	62%	63%	65%	All Div'ds to Net Prof	60%

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	-1.4	+2.6	-.5
Avg. Indust. Use (MWH)	12005	9815	8143
Avg. Indust. Revs. per KWH (¢)	5.16	5.30	5.69
Capacity at Yearend (Mw)	5749	5688	5661
Peak Load, Summer (Mw)	4747	4926	4789
Annual Load Factor (%)	57.5	56.7	57.9
% Change Customers (yr-end)	+2.2	+2.5	+1.6
Fixed Charge Cov. (%)	261	272	276

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	11.0%	6.5%	-2.5%
"Cash Flow"	4.5%	4.0%	2.5%
Earnings	3.0%	3.5%	4.0%
Dividends	1.5%	6.5%	3.0%
Book Value	4.5%	4.0%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	1389	944.0	1062	1168	4563.0
2007	1363	1007	1079	1172	4621.0
2008	1533	1218	1266	1302	5319.0
2009	1343	878.0	921.0	1058	4200
2010	1250	900	1050	1100	4300

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.80	.46	.76	.57	2.59
2007	.73	.47	.79	.75	2.74
2008	.94	.48	.80	.73	2.95
2009	.94	.45	.84	.72	2.95
2010	.95	.45	.85	.75	3.00

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.365	.39	.39	.39	1.54
2006	.39	.42	.42	.42	1.65
2007	.42	.44	.44	.44	1.74
2008	.44	.46	.46	.46	1.82
2009	.46	.47	.47	.47	

BUSINESS: SCANA Corporation is a holding company for South Carolina Electric & Gas Company, which supplies electricity to 654,000 customers in South Carolina. Supplies gas and transmission service to 1.2 million customers in North and South Carolina and Georgia. Owns gas pipelines. Acquired PSNC Energy 2/00. Electric revenue breakdown, '08: residential, 41%; commercial, 31%; industrial, 17%; other, 11%. Generating sources, '08: coal, 64%; nuclear, 18%; oil & gas, 12%; hydro, 4%; purchased, 2%. Fuel costs: 65% of revenues. '08 reported deprec. rate: 3.1%. Has 5,800 employees. Chairman, President & CEO: William B. Timmerman. Inc.: South Carolina. Address: 100 SCANA Parkway, Cayce, SC 29033. Tel.: 803-217-9000. Internet: www.scana.com.

We now estimate that SCANA's earnings will be flat in 2009. We raised our share-net estimate by a dime because third-quarter profits were better than we expected, thanks to a tax refund. Our revised estimate is at the upper end of the company's targeted range of $2.80-$2.95. Rate relief (discussed below) and the benefits of an improving economy should enable earnings to advance slightly in 2010. We're sticking with our estimate of $3.00 a share.

South Carolina Electric & Gas received a $22.5 million (1.1%) electric rate hike under the Base Load Review Act (BLRA). The BLRA enables the utility to receive rate relief annually (outside the parameters of a general rate case) to recover the construction work in progress for base-load generating facilities such as the nuclear plant that SCE&G is proposing to build. This facility would provide 1,229 megawatts of capacity at a cost (including transmission) of $6.9 billion. The company won't be able to begin construction until it obtains a license from the Nuclear Regulatory Commission (probably in the second half of 2011), but it is incurring preconstruction costs for things such as site preparation. The BLRA lessens, but does not eliminate, the risks associated with building such a large project.

SCE&G received a gas rate increase, as well. Gas tariffs were raised by $13.0 million (2.4%) at the start of November. Under state law, the utility was entitled to an increase because its earned return on equity was more than half a percentage point below the allowed ROE of 10.25% for the 12-month period that ended on March 31st.

A general rate application is possible in 2010. The state of the economy will play a part in determining whether SCE&G files a rate case.

We expect a dividend increase in the first quarter of 2010. That has been the pattern in recent years. We estimate that the board of directors will raise the quarterly disbursement by one cent a share (2.1%).

For utility investors, SCANA stock offers a yield and 3- to 5-year total return potential that are somewhat above the industry averages.

Paul E. Debbas, CFA *November 27, 2009*

(A) Excl. nonrec. gains (losses): '95, (16¢); '97, 16¢; '99, 29¢; '00, 28¢; '01, $3.00; '02, ($3.72); '03, 31¢; '04, (23¢); '05, 3¢; '06, 9¢. Next earnings report due mid-Feb. (B) Div'ds historically paid in early Jan., Apr., July, and Oct. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. intangibles. In '08: $7.67/sh. (D) In millions. (E) Rate base: Net original cost. Rate allowed on com. eq. in SC: 11% electric in '08, 10.25% gas in '05; in NC: 10.6% in '08; earned on avg. com. eq., '08: 11.5% Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	95

KPSC Case No. 2009-00459
Staff 2nd Set of Data Requests
Order dated February 12, 2010
Item No. 20

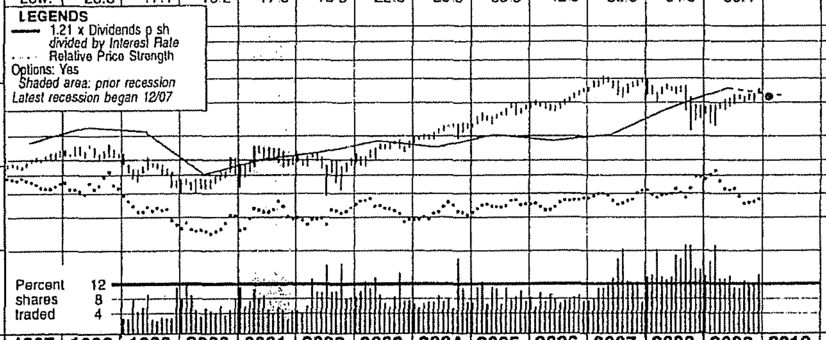
SEMPRA ENERGY NYSE-SRE

RECENT PRICE 51.45 | P/E RATIO 10.4 (Trailing: 10.5 / Median: 11.0) | RELATIVE P/E RATIO 0.63 | DIV'D YLD 3.3% | VALUE LINE 2243

TIMELINESS 3 Lowered 9/25/09
SAFETY 2 Lowered 2/4/00
TECHNICAL 3 Raised 10/16/09
BETA .85 (1.00 = Market)

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
High:	29.3	26.0	24.9	28.6	26.3	30.9	37.9	47.9	57.3	66.4	63.0	57.2
Low:	23.8	17.1	16.2	17.3	15.5	22.3	29.5	35.5	42.9	50.9	34.3	36.4

LEGENDS
—— 1.21 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



Target Price Range
2012 | 2013 | 2014

2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	95	(+85%)	19%
Low	70	(+35%)	11%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	1	2	4	3	3	0	0	1	1
to Sell	2	2	4	4	3	2	0	1	2

Institutional Decisions

	1Q2009	2Q2009	3Q2009
to Buy	195	219	183
to Sell	189	176	198
Hld's(000)	159086	160709	160869

% TOT. RETURN 12/09

	THIS STOCK	VL ARITH INDEX
1 yr.	35.6	60.8
3 yr.	8.2	1.9
5 yr.	74.1	25.9

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
16.99	17.01	16.05	17.09	19.51	23.31	22.89	35.38	39.27	29.38	34.81	40.18	45.64	44.89	43.79	44.21	31.05	36.15	Revenues per sh	46.00
3.95	4.01	4.33	4.83	5.27	5.16	5.36	4.91	5.39	5.71	5.56	6.58	5.96	6.74	6.93	7.40	8.00	8.70	"Cash Flow" per sh	10.75
1.81	1.75	1.94	1.98	2.20	1.24	1.66	2.06	2.55	2.79	3.01	3.93	3.52	4.23	4.26	4.43	4.80	5.10	Earnings per sh A	6.00
1.48	1.52	1.56	1.56	1.56	1.56	1.56	1.00	1.00	1.00	1.00	1.00	1.16	1.20	1.24	1.37	1.56	1.72	Div'd Decl'd per sh B ■ †	2.10
3.20	2.26	1.89	1.79	1.74	1.85	2.48	3.76	5.22	5.92	4.63	4.62	5.46	7.28	7.70	8.47	10.35	10.25	Cap'l Spending per sh	9.50
13.01	12.65	13.04	13.46	13.82	12.29	12.58	12.35	13.17	13.79	17.17	20.78	23.95	28.66	31.87	32.75	35.65	39.10	Book Value per sh C	50.75
116.52	116.54	116.54	116.63	113.63	237.00	237.40	201.90	204.48	204.91	226.60	234.18	257.19	262.01	261.21	243.32	246.50	249.00	Common Shs Outst'g D	250.00
14.3	11.8	11.2	11.3	10.8	21.1	12.8	9.4	9.7	8.2	9.0	8.6	11.8	11.5	14.0	11.8	10.0		Avg Ann'l P/E Ratio	14.0
.84	.77	.75	.71	.62	1.10	.73	.61	.50	.45	.51	.45	.63	.62	.74	.72	.65		Relative P/E Ratio	.95
5.7%	7.4%	7.2%	7.0%	6.6%	6.0%	7.4%	5.2%	4.1%	4.4%	3.7%	2.9%	2.8%	2.5%	2.1%	2.6%	3.2%		Avg Ann'l Div'd Yield	2.5%
						5435.0	7143.0	8029.0	6020.0	7887.0	9410.0	11737	11761	11438	10758	7650	9000	Revenues ($mill)	11500
						405.0	440.0	534.0	586.0	655.0	930.0	898.0	1118.0	1135.0	1123.0	1205	1305	Net Profit ($mill)	1530
						30.7%	38.0%	28.8%	19.9%	23.2%	17.2%	--	31.3%	33.6%	29.2%	30.0%	30.0%	Income Tax Rate	30.0%
						2.2%	3.6%	5.2%	10.8%	8.4%	2.9%	5.3%	7.2%	11.5%	13.2%	12.0%	12.0%	AFUDC % to Net Profit	10.0%
						47.6%	56.2%	55.7%	58.6%	48.4%	45.3%	43.1%	37.0%	34.8%	44.5%	47.0%	46.0%	Long-Term Debt Ratio	44.5%
						49.0%	40.4%	41.2%	38.6%	49.0%	52.6%	55.1%	61.4%	63.7%	54.2%	52.0%	53.0%	Common Equity Ratio	55.0%
						6092.0	6166.0	6532.0	7312.0	7931.0	9255.0	11178	12229	13071	14692	16925	18400	Total Capital ($mill)	23100
						5394.0	5726.0	6217.0	6832.0	10474	11086	12101	13175	14884	16865	18650	20325	Net Plant ($mill)	24000
						8.3%	9.0%	10.2%	9.8%	9.8%	11.3%	9.2%	10.3%	9.6%	8.5%	8.5%	8.5%	Return on Total Cap'l	8.0%
						12.7%	16.3%	18.4%	19.3%	16.0%	18.4%	14.1%	14.5%	13.3%	13.8%	13.5%	13.0%	Return on Shr. Equity	12.0%
						13.2%	17.2%	19.4%	20.4%	16.6%	18.9%	14.4%	14.8%	13.5%	14.0%	13.5%	13.5%	Return on Com Equity E	12.0%
						.9%	7.4%	11.9%	13.1%	11.3%	14.9%	10.1%	11.0%	9.7%	9.7%	9.0%	9.0%	Retained to Com Eq	8.0%
						94%	58%	40%	37%	33%	22%	31%	26%	29%	31%	33%	33%	All Div'ds to Net Prof	35%

CAPITAL STRUCTURE as of 9/30/09
Total Debt $8318.0 mill. **Due in 5 Yrs** $3022.0 mill.
LT Debt $6845.0 mill. **LT Interest** $380.0 mill.
(LT interest earned: 5.9x)
Leases, Uncapitalized Annual rentals $99.0 mill.
Pension Assets-12/08 $1.74 bill. **Oblig.** $2.87 bill.
Pfd Stock $179.0 mill. **Pfd Div'd** $9.0 mill.
1,373,770 shs. 4.40%-5% cumulative, $20 par, callable $20.25-$24; 2,040,000 shs. $1.70-$1.82 cum., no par, callable $25.595-$26; 800,000 shs. $4.36-$4.75 cum., no par, callable $100-$101.50; 811,073 shs. 6% cum., $25 par.
Common Stock 246,442,856 shs. **as of 11/5/09**
MARKET CAP: $13 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	+5.3	+.2	+1.8
Avg. Indust. Use (MWH)	4596	4474	4569
Avg. Indust. Revs. per KWH (¢)	8.00	10.06	9.15
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	NMF	NMF	NMF
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	+1.3	+.7	+.5
Fixed Charge Cov. (%)	409	419	347

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	8.5%	5.0%	.5%
"Cash Flow"	3.5%	5.0%	7.5%
Earnings	9.0%	9.0%	5.5%
Dividends	-2.0%	5.0%	8.5%
Book Value	9.0%	16.0%	8.5%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	3336	2486	2694	3245	11761
2007	3004	2661	2663	3110	11438
2008	3270	2503	2692	2293	10758
2009	2108	1689	1853	2000	7650
2010	2400	2000	2100	2500	9000

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.90	.71	1.29	1.33	4.23
2007	.86	1.06	1.24	1.10	4.26
2008	.92	.98	1.24	1.30	4.43
2009	1.29	1.06	1.27	1.18	4.80
2010	1.30	1.20	1.30	1.30	5.10

Calendar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.29	.30	.30	.30	1.19
2007	.30	.31	.31	.31	1.23
2008	.31	.32	.35	.35	1.33
2009	.35	.39	.39	.39	1.52
2010	.39				

BUSINESS: Sempra Energy is a holding company for San Diego Gas & Electric Co., which sells electricity and gas mainly in San Diego County, & Southern California Gas Co., which distributes gas to most of Southern California. Customers: 1.4 million electric, 6.6 million gas. Electric revenue breakdown, '08: residential, 42%; commercial, 37%; industrial, 9%; other, 12%. Purchases most of its power; the rest is nuclear and gas. Has various nonutility subsidiaries (47% of '08 earnings). Acq'd EnergySouth 10/08. Power costs: 54% of revenues. '08 deprec. rate: 3.0%. Has 13,600 employees. Chairman & CEO: Donald E. Felsinger. President & COO: Neal E. Schmale. Inc.: California. Address: 101 Ash St., San Diego, CA 92101-3017. Tel.: 619-696-2034. Internet: www.sempra.com.

Wall Street is awaiting an announcement regarding Sempra Energy's joint venture with RBS. The joint venture for this commodities (mainly energy related) trading operation has been in effect since the start of the second quarter of 2009. The structure of the agreement is very attractive for Sempra. Maintaining the status quo is not an option because European regulators are forcing RBS to sell its stake. It is possible that another bank will purchase RBS's 51% stake in the operation, or will make an offer for the whole business. On the other hand, it is not out of the question that Sempra will buy RBS's share. If a bank buys the entire business, Sempra would probably use at least some of the cash to repurchase stock and retire debt. It might also use the money to fund acquisitions. However, the sale of the whole operation would be dilutive to Sempra's earnings. Note that our estimates and projections are for Sempra in its current configuration.

Meanwhile, the company continues to proceed with some large projects. It owns a 25% stake in the Rockies Express gas pipeline project that was completed last fall. Sempra's share of the cost was $1.7 billion. The company's two utility subsidiaries are building an advanced metering system for a total of $1.4 billion, and San Diego Gas & Electric is seeking some remaining approvals that it needs before it can construct a transmission line for $1.9 billion.

We have lowered our 2010 earnings estimate by $0.15 a share, to $5.10. That's because interest expense will probably be higher than we had expected, following the issuance of $750 million of long-term debt last fall. Our revised profit estimate for 2010 is still within Sempra's targeted range of $5.00-$5.25 a share.

We estimate that the board of directors will raise the dividend later this month. This is when the directors normally consider a dividend hike. We estimate a boost of $0.04 a share (10.3%) in the quarterly payout, but we don't know how the situation with the RBS joint venture will affect the board's decision.

Investors should stay on the sidelines for now. An unfavorable outcome to the joint venture might hurt the share price.

Paul E. Debbas, CFA *February 5, 2010*

(A) Diluted egs. Excl. nonrec. gain (losses): '05, 17¢; '06, (6¢); '09, (26¢); gain (losses) from disc. ops.: '04, (10¢); '05, (4¢); '06, $1.21; '07, (10¢). '08 EPS don't add due to rounding. Next egs. report due late Feb. (B) Div'ds histor. paid mid-Jan., Apr., July & Oct. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '08: $10.38/sh. (D) In mill. Excl. ESOP shs. (E) Rate base: Net orig. cost. Rate all'd on com. eq.: SDG&E in '08, 11.1%; SoCalGas in '03, 10.82%; earn. on avg. com. eq., '08: 13.6%. Reg. Clim.: Above Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	100
Earnings Predictability	95

UIL HOLDINGS NYSE-UIL

RECENT PRICE 27.30 | P/E RATIO 14.9 (Trailing: 13.4 Median: 17.0) | RELATIVE P/E RATIO 0.89 | DIV'D YLD 6.3% | VALUE LINE 167

TIMELINESS 4 Lowered 11/13/09
SAFETY 2 Raised 2/29/08
TECHNICAL 3 Raised 9/11/09
BETA .70 (1.00 = Market)

High:	32.5	32.2	33.6	31.8	35.3	27.6	32.8	33.7	43.8	43.0	37.8	31.2
Low:	25.0	23.3	22.7	26.3	16.9	18.5	25.1	27.4	27.4	27.0	25.1	17.0

2012-14 PROJECTIONS

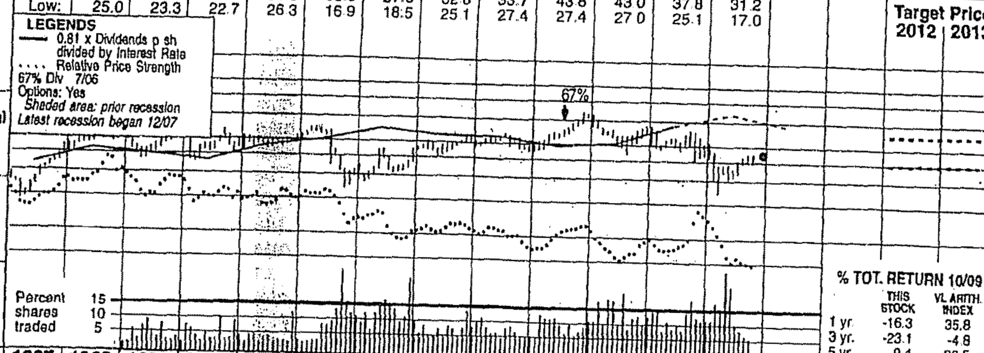
	Price	Gain	Ann'l Total Return
High	35	(+30%)	12%
Low	25	(-10%)	5%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	2	1	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	1	0	0	0	0	0	1	0

Institutional Decisions

	4Q2008	1Q2009	2Q2009
to Buy	68	55	80
to Sell	43	53	34
Hld's(000)	11775	11952	15882



% TOT. RETURN 10/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-16.3	35.8
3 yr.	-23.1	-4.8
5 yr.	9.4	26.5

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
27.82	27.97	29.38	30.89	30.64	29.34	29.01	37.54	46.15	47.55	40.39	45.87	49.88	34.03	39.23	37.69	30.65	32.45	Revenues per sh	40.60
4.90	4.77	4.91	4.81	5.40	5.34	4.67	5.53	6.61	5.89	4.69	4.37	4.13	4.65	5.48	5.93	5.40	5.80	"Cash Flow" per sh	6.80
1.88	1.91	2.18	1.90	1.96	1.80	2.23	2.56	2.53	1.85	1.24	1.54	1.30	1.86	1.87	1.89	1.90	2.00	Earnings per sh A	2.30
1.60	1.66	1.69	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	Div'd Decl'd per sh B ■	1.73
4.04	2.69	2.53	2.01	1.44	1.63	1.48	2.31	2.01	2.41	2.19	2.04	2.25	3.09	9.92	8.57	7.50	7.80	Cap'l Spending per sh	8.10
18.03	18.23	18.72	18.72	18.94	19.05	19.55	20.42	21.25	20.28	20.65	22.84	22.39	18.53	18.55	18.85	19.35	19.85	Book Value per sh C	21.75
23.47	23.48	23.50	23.50	23.18	23.39	23.44	23.46	23.53	23.79	23.86	24.01	24.32	24.86	25.03	25.17	30.00	30.20	Common Shs Outst'g E	30.80
13.6	10.5	9.3	11.4	10.1	16.3	12.6	10.8	11.5	15.0	18.0	18.7	23.5	18.7	18.4	16.7	Bold figures are		Avg Ann'l P/E Ratio	14.0
.80	.69	.62	.71	.58	.85	.72	.70	.59	.82	1.03	.99	1.25	1.01	.98	1.00	Value Line		Relative P/E Ratio	.95
6.2%	8.2%	8.3%	8.0%	8.8%	5.9%	6.2%	6.2%	5.9%	6.2%	7.7%	6.0%	5.7%	5.0%	5.0%	5.5%	estimates		Avg Ann'l Div'd Yield	5.4%

CAPITAL STRUCTURE as of 9/30/09
Total Debt $713.3 mill. **Due in 5 Yrs.** $255.0 mill
LT Debt $604.2 mill. **LT Interest** $30.0 mill.
(LT interest earned: 3.9x)
Leases, Uncapitalized: Ann. rentals $13.1 mill.

Pension Assets-12/08 $212 mill. **Oblig.** $348 mill.

Pfd Stock None

Common Stock 29,929,591 shs.
as of 10/29/09
MARKET CAP: $825 million (Small Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
680.0	880.9	1085.8	1131.0	963.7	1101.3	1213.1	846.0	982.0	948.7	920	980	Revenues ($mill)	1250
52.2	59.9	59.4	44.0	29.5	36.9	31.4	45.4	46.7	48.1	57.0	60.5	Net Profit ($mill)	70.0
56.0%	44.5%	44.8%	45.2%	53.1%	45.4%	44.1%	31.2%	39.5%	42.2%	40.0%	40.0%	Income Tax Rate	40.0%
4.3%	4.4%	3.2%	5.1%	8.5%	1.1%	9.0%	8.0%	8.3%	8.2%	8.0%	8.0%	AFUDC % to Net Profit	8.0%
50.5%	52.2%	49.9%	45.0%	50.1%	47.2%	47.2%	47.0%	50.8%	53.6%	52.0%	52.0%	Long-Term Debt Ratio	52.0%
44.6%	47.8%	50.1%	55.0%	49.9%	52.8%	52.8%	53.0%	49.2%	46.4%	48.0%	48.0%	Common Equity Ratio	48.0%
1026.5	1001.3	998.6	877.8	988.2	1039.6	1031.5	869.2	943.6	1023.6	1205	1250	Total Capital ($mill)	1400
521.5	550.7	546.4	517.1	548.8	563.9	592.1	647.0	878.4	1073.6	1150	1180	Net Plant ($mill)	1250
7.1%	7.9%	8.1%	7.3%	4.3%	4.5%	4.1%	6.5%	6.2%	6.1%	6.0%	6.0%	Return on Total Cap'l	6.5%
10.3%	12.5%	11.9%	9.1%	6.0%	6.7%	5.8%	9.9%	10.1%	10.1%	10.0%	10.0%	Return on Shr. Equity	10.5%
11.4%	12.5%	11.9%	9.1%	6.0%	6.7%	5.8%	9.9%	10.1%	10.1%	10.0%	10.0%	Return on Com Equity D	10.5%
2.5%	4.0%	3.8%	.6%	NMF	NMF	NMF	NMF	3.1%	1.0%	1.0%	1.5%	Retained to Com Eq	2.5%
78%	68%	68%	93%	NMF	NMF	NMF	NMF	70%	90%	91%	87%	All Div'ds to Net Prof	76%

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	-3.1	Nil	-3.2
Avg. Indust. Use (MWH)	657	665	650
Avg. Indust. Revs. per KWH (¢)	10.2	9.9	8.4
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	Nil	+.5	Nil
Fixed Charge Cov. (%)	323	343	322

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	2.0%	-3.5%	1.5%
"Cash Flow"	.5%	-1.5%	4.0%
Earnings	--	--	3.5%
Dividends	--	--	Nil
Book Value	--	-2.0%	2.5%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	200.3	199.8	261.1	184.8	846.0
2007	274.6	216.7	267.9	222.8	982.0
2008	234.6	216.1	278.7	219.3	948.7
2009	235.5	200.4	255.2	228.9	920
2010	240	220	280	240	980

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.15	.42	1.21	.08	1.86
2007	.22	.38	.92	.35	1.87
2008	.23	.45	.86	.35	1.89
2009	.48	.51	.73	.18	1.90
2010	.45	.47	.75	.33	2.00

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.432	.432	.432	.432	1.73
2006	.432	.432	.432	.432	1.73
2007	.432	.432	.432	.432	1.73
2008	.432	.432	.432	.432	1.73
2009	.432	.432	.432	.432	

BUSINESS: UIL Holdings, parent of The United Illuminating Company, provides electricity to 324,000 customers in largely urban and suburban southern Connecticut. Revenue distribution: resid, 40%; commer, 47%; indust, 12%; other, 1%. Largest industrial customers: primary metals, fabricated metal products, transportation equipment. Sold American Payment Systems in 2004. Sold Xcelecom in 2006. Fuel costs: 54% of revenues; labor costs, 14%. 2008 depreciation rate: 4.0%. Has 981 employees. Non-Executive Chairman: F. Patrick McFadden. Chief Executive Officer & President: James P. Torgerson. Incorporated: Connecticut. Address: 157 Church Street, P.O. Box 1564, New Haven, Connecticut 06506-0901. Telephone: 203-499-2394. Internet: www.uil.com.

UIL Holdings posted mixed results in the third quarter. The Connecticut-based energy provider reported earnings of $0.73 a share for the period, down 15% from last year's figure. The loss reflects decreased profits from UIL's distribution business (down 20%), which were hurt by lower demand tied to the weak economic environment. Share dilution related to the equity offering in May further reduced the company's bottom line. Positive drivers included favorable regulatory relief, decoupling, lower operating costs, and higher transmission profits. Management noted that its transmission business continues to outperform and is expected to earn its allowed ROE of 12.5% this year.

Expansion projects and infrastructure upgrades could offer a boost down the road. We continue to view UIL's joint venture with NRG Energy favorably. The two joined forces last year to form GennConn, and are currently in the process of constructing two, 200-megawatt peaking generation units (Devon and Middletown), also known as the GenConn project. Management recently indicated that the building of both units was moving along as scheduled, with Devon set to come on line in June, 2010, and Middletown in June, 2011. Pending completion, we look for these units to bolster UIL's generation capabilities and act as key earnings drivers over the long term.

The company's capital spending plan is geared toward infrastructure upgrades. Management announced its intention to spend $1.0 billion over the next five years in an effort to improve its aging infrastructure. The funds will be allocated on a 70/30 basis, with roughly $700 million going toward distribution needs, and the remaining $300 million toward transmission. Management also noted it will likely target higher-return upgrades (i.e., new substations and advanced information technology). The plan is expected to result in a 5% annual growth in the rate base.

Though untimely, these shares offer a healthy dividend, well above the industry average. Income-oriented investors may find appeal in the stock's current 6.3% yield. However, due to the high payout ratio, we do not foresee any increases over the next 3 to 5 years.

Michael Ratty *November 27, 2009*

(A) EPS basic. Excl. nonrecur. gains (losses): '92, 35¢; '93, (34¢); '94, (6¢); '96, 17¢; '00, 4¢; '03, (26¢); '04, $2.14; '06, ($5.07). Next egs. report due late Feb. (B) Div'ds historically paid in early Jan., early April, early July, and early Oct. ■ Div'd reinvest. plan avail. (C) Incl. deferred chgs. & regul. assets. In '08: $30.77/sh. (D) Rate base: orig. cost. Rate allowed on common equity in '08: 8.75%. Earned on average common equity in '08: 10.0%. Regul. Clim.: Below Average. (E) In millions. Adjust for stock dividends.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	45
Earnings Predictability	75

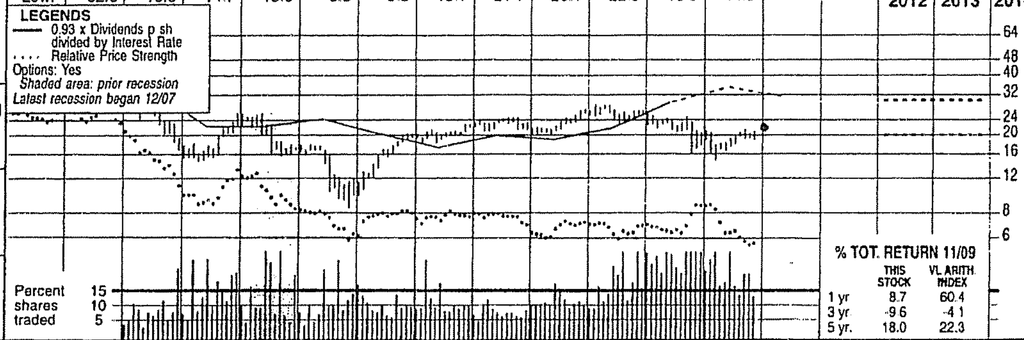
WESTAR ENERGY NYSE-WR

RECENT PRICE 21.85 | P/E RATIO 14.6 (Trailing: 15.7 Median: 16.0) | RELATIVE P/E RATIO 0.86 | DIV'D YLD 5.6% | VALUE LINE 706

TIMELINESS 4 Lowered 10/2/09
SAFETY 2 Raised 4/1/05
TECHNICAL 2 Raised 12/18/09
BETA .75 (1.00 = Market)

High:	44.2	33.9	25.9	25.9	18.0	20.5	22.9	25.0	27.2	28.6	25.9	22.1
Low:	32.6	16.8	14.7	15.6	8.5	9.8	18.1	21.1	20.1	22.8	16.0	14.9

Target Price Range 2012 | 2013 | 2014



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+35%)	13%
Low	20	(-10%)	4%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	2	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	1	0	0	0	0	0

Institutional Decisions

	1Q2009	2Q2009	3Q2009
to Buy	103	104	103
to Sell	107	107	106
Hld's(000)	81480	72451	75911

% TOT. RETURN 11/09

	THIS STOCK	VL ARITH. INDEX
1 yr	8.7	60.4
3 yr	-9.6	-4.1
5 yr.	18.0	22.3

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
30.99	26.26	25.01	31.67	32.90	30.86	30.21	33.80	31.20	24.77	20.06	17.02	18.23	18.37	18.09	16.98	*17.05*	*17.95*	Revenues per sh	*21.50*
5.33	4.98	5.17	5.52	3.47	6.35	7.51	6.96	5.32	4.77	3.77	3.12	3.28	3.94	3.77	3.14	*3.70*	*4.10*	"Cash Flow" per sh	*4.55*
2.76	2.51	2.71	2.60	d.46	2.13	1.48	.89	d.58	1.00	1.48	1.17	1.55	1.88	1.84	1.31	*1.40*	*1.70*	Earnings per sh A	*2.10*
1.94	1.98	2.03	2.07	2.10	2.14	2.14	1.44	1.20	1.20	.87	.80	.92	.98	1.08	1.16	*1.20*	*1.24*	Div'd Decl'd per sh B■†	*1.40*
3.86	3.86	3.77	3.09	3.22	2.77	4.09	4.40	3.37	1.89	2.06	2.19	2.45	3.95	7.84	8.65	*5.65*	*5.90*	Cap'l Spending per sh	*7.45*
23.08	23.93	24.71	25.14	30.79	29.40	27.83	27.20	25.97	13.68	14.23	16.13	16.31	17.62	19.14	20.18	*21.10*	*22.25*	Book Value per sh C	*27.20*
61.62	61.62	62.86	64.63	65.41	65.91	67.40	70.08	70.08	71.51	72.84	86.03	86.84	87.39	95.46	108.31	*109.00*	*110.00*	Common Shs Outst'g E	*114.00*
12.6	11.6	11.7	11.7	--	18.4	17.2	20.6	--	14.0	10.8	17.4	14.8	12.2	14.1	17.0	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*12.5*
.74	.76	.78	.73	--	.96	.98	1.34	--	.76	.62	.92	.79	.66	.75	1.02	*estimates*		Relative P/E Ratio	*.85*
5.6%	6.8%	6.4%	6.8%	6.3%	5.5%	8.4%	7.9%	5.8%	8.6%	5.5%	3.9%	4.0%	4.3%	4.2%	5.2%			Avg Ann'l Div'd Yield	*5.3%*

CAPITAL STRUCTURE as of 9/30/09
Total Debt $2659.5 mill. **Due in 5 Yrs** $170.0 mill.
LT Debt $2490.9 mill. **LT Interest** $140.0 mill.
(LT interest earned: 2.4x)

Pension Assets-12/08 $311 mill. **Oblig.** $629 mill.

Pfd Stock $21.4 mill. **Pfd Div'd** $1.0 mill.
121,613 shs. 4 1/2%, callable 108; 54,970 shs. 4 1/4%, callable 101.50; 37,780 shs. 5%, callable 102. All cum. $100 par.

Common Stock 109,029,629 shs. as of 10/22/09
MARKET CAP: $2.4 billion (Mid Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
2036.2	2368.5	2186.3	1771.1	1461.1	1464.5	1583.3	1605.7	1726.8	1839.0	*1860*	*1975*	Revenues ($mill)	*2450*
100.4	62.7	d40.0	72.0	108.1	100.1	134.9	165.3	168.4	136.8	*155*	*190*	Net Profit ($mill)	*240*
--	42.4%	NMF	53.4%	43.1%	25.0%	31.0%	25.4%	27.5%	24.8%	*28.0%*	*30.0%*	Income Tax Rate	*30.0%*
--	--	--	--	5.0%	--	--	--	10.4%	28.5%	*10.0%*	*10.0%*	AFUDC % to Net Profit	*10.0%*
60.3%	62.6%	61.8%	71.6%	66.2%	53.8%	52.1%	50.0%	50.6%	49.8%	*52.0%*	*51.5%*	Long-Term Debt Ratio	*47.5%*
39.2%	36.9%	37.7%	22.9%	33.2%	45.5%	47.2%	49.3%	48.9%	49.7%	*47.5%*	*48.5%*	Common Equity Ratio	*52.5%*
4783.4	5169.3	4822.4	4272.4	3127.3	3049.2	3000.4	3124.2	3738.3	4400.1	*4820*	*5070*	Total Capital ($mill)	*5920*
3889.4	3993.4	4042.9	3995.4	3909.5	3911.0	3947.7	4071.6	4803.7	5533.5	*5850*	*6100*	Net Plant ($mill)	*6800*
4.5%	3.4%	1.5%	4.4%	7.0%	5.5%	6.2%	6.7%	5.8%	4.2%	*4.5%*	*5.0%*	Return on Total Cap'l	*5.5%*
5.3%	3.2%	NMF	5.9%	10.2%	7.1%	9.4%	10.6%	9.1%	6.2%	*6.5%*	*7.5%*	Return on Shr. Equity	*7.5%*
5.3%	3.2%	NMF	7.3%	10.3%	7.1%	9.5%	10.7%	9.2%	6.2%	*6.5%*	*7.5%*	Return on Com Equity D	*7.5%*
NMF	NMF	NMF	NMF	4.9%	3.2%	4.3%	5.5%	4.3%	1.2%	*1.0%*	*2.0%*	Retained to Com Eq	*2.5%*
NMF	NMF	NMF	120%	53%	56%	55%	49%	53%	80%	*85%*	*72%*	All Div'ds to Net Prof	*66%*

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	+4.8	+2.3	-2.0
Avg. Indust. Use (MWH)	5824	5819	5769
Avg. Indust. Revs. per KWH (¢)	4.58	4.55	5.06
Capacity at Peak (Mw)	6033	6178	6508
Peak Load, Summer (Mw)	4914	4836	4754
Annual Load Factor (%)	54.0	54.5	55.0
% Change Customers (yr-end)	+1.2	+1.0	+.7
Fixed Charge Cov. (%)	291	302	263

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	-5.5%	-7.0%	3.0%
"Cash Flow"	-3.5%	-5.0%	4.0%
Earnings	1.5%	21.5%	4.0%
Dividends	-6.5%	-0.5%	4.5%
Book Value	-4.0%	1.0%	6.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	340.0	406.6	515.9	343.2	1605.7
2007	370.3	415.2	548.5	392.8	1726.8
2008	406.8	451.2	574.9	406.1	1839.0
2009	421.8	467.8	528.5	*441.9*	*1860*
2010	*440*	*480*	*595*	*460*	*1975*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.30	.40	1.03	.15	1.88
2007	.34	.36	.99	.15	1.84
2008	.23	.06	.81	.21	1.31
2009	.10	.35	.73	*.22*	*1.40*
2010	*.15*	*.40*	*.90*	*.25*	*1.70*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.23	.23	.23	.23	.92
2006	.23	.25	.25	.25	.98
2007	.25	.27	.27	.27	1.06
2008	.27	.29	.29	.29	1.14
2009	.29	.30	.30	.30	

BUSINESS: Westar Energy, Inc., formerly Western Resources, is the parent of Kansas Gas & Electric Company. Westar supplies electricity to 679,000 customers in east Kansas. Electric revenue sources: residential and rural, 40%; commercial, 38%; industrial, 22%. Sold investment in ONEOK in 2003 and 85% ownership in Protection One in 2004. 2008 depreciation rate: 3.7%. Estimated plant age: 16 years. Fuels: coal, 53%; nuclear, 8%; gas, 38%; other, 1%. Has 2,415 employees. Barclays Global Investors owns 6.1% of common; off. & dir.; less than 1% (4/09 proxy). Chairman: Charles Q. Chandler IV. Pres. & CEO: William B. Moore. Inc.: Kansas. Address: 818 South Kansas Avenue, Topeka, Kansas 66612. Telephone: 785-575-6300. Internet: www.westarenergy.com.

Westar Energy reported a moderate decline in revenues and share earnings for the third quarter. This was partly a result of lower retail sales, owing to cool summer weather and softness in the broader economy. Wholesale revenue also declined, primarily due to lower average market prices. In light of third-quarter weakness, the company has lowered its share-net guidance for full-year 2009, and we concur. Overall, we anticipate just modest bottom-line improvement for the current year. Results may prove more favorable in 2010, assuming a better operating environment.

The company is seeking higher rates in Kansas. In June, it filed an abbreviated rate case, requesting an increase in retail prices of $19.7 million. Westar cited costs associated with investments in natural gas and wind generation facilities. Testimony from the Kansas Corporation Commission recommends a base rate case adjustment of $17.1 million. Management anticipates a final decision on this matter by late January. This follows other rate hikes granted in Kansas earlier in the year. The company's focus on obtaining rate relief is encouraging, as it depends upon such approved increases to compensate for rising costs and capital outlays.

Westar continues to progress with an expansion of its transmission system. This 345-kilovolt, 100-mile line from Wichita to Salina ought to be placed into service in late summer 2010. The project should improve the flow of power to the area. Meanwhile, the Prairie Wind joint-venture project appears closer to approval. The construction of extra-high capacity transmission lines should enhance access to lower-cost electric power markets, and improve the efficiency of the electric grid.

This stock has fallen a notch in Timeliness since our September review, and is now ranked to trail the broader market for the year ahead. Looking further out, we anticipate higher share earnings at the company by 2012-2014. But, from the present quotation, this issue has unimpressive total return potential for the coming 3 to 5 years. Still, income-oriented investors may find this issue's healthy dividend yield attractive.

Michael Napoli, CPA — *December 25, 2009*

(A) EPS basic. Excl. nonrecur gains (losses): '94, $0.31; '96, ($0.19); '97, $7.97; '98, ($1.45); '99, ($1.31); '00, $1.07; '01, 27¢, '02, ($12.06); '03, 77¢; '08, 39¢. Next egs. rep't due in February. (B) Div'ds historically paid in early Jan., April, July, and Oct. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. regulatory assets. In 2008: $9.55/sh. (D) Rate base deter.: fair value; Rate allowed on common equity in '09: 10.4%. Regul. Clim.: Avg. (E) In mill.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	65

WISCONSIN ENERGY NYSE-WEC

RECENT PRICE 47.87 | P/E RATIO 14.9 (Trailing: 15.5; Median: 15.0) | RELATIVE P/E RATIO 0.88 | DIV'D YLD 3.2% | VALUE LINE 707

TIMELINESS 3 Lowered 6/26/09
SAFETY 2 Lowered 7/11/97
TECHNICAL 3 Raised 10/23/09
BETA .65 (1.00 = Market)

High:	34.0	31.6	23.6	24.6	26.5	33.7	34.6	40.8	48.7	50.5	49.6	48.7
Low:	27.0	19.1	16.8	19.1	20.2	22.6	29.5	33.3	38.2	41.1	34.9	36.3

LEGENDS
— 1.36 x Dividends p sh divided by Interest Rate
···· Relative Price Strength
Options: Yes
Shaded area: prior recession
Latest recession began 12/07

Target Price Range 2012 | 2013 | 2014

2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+55%)	14%
Low	55	(+15%)	7%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	0	0	1	0	2	0	0
to Sell	0	1	0	0	1	0	2	0	0

Institutional Decisions

	1Q2009	2Q2009	3Q2009
to Buy	152	139	110
to Sell	137	159	159
Hld's(000)	80778	76941	80851

Percent shares traded 12 8 4

% TOT. RETURN 11/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	7.1	60.4
3 yr.	4.1	-4.1
5 yr.	53.3	22.3

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
15.61	15.99	15.98	15.88	15.86	17.13	19.11	28.28	34.04	32.20	34.24	29.33	32.62	34.17	36.24	37.90	35.90	39.75	Revenues per sh	46.25
3.84	3.81	4.28	4.25	2.96	4.13	4.53	4.48	5.44	5.68	5.71	5.16	5.78	5.80	5.97	5.91	6.15	7.05	"Cash Flow" per sh	8.75
1.81	1.67	2.13	1.97	.54	1.65	1.88	1.08	1.84	2.32	2.26	1.85	2.56	2.64	2.84	3.03	3.10	3.70	Earnings per sh A	4.50
1.34	1.40	1.46	1.51	1.54	1.56	1.56	1.37	.80	.80	.80	.83	.88	.92	1.00	1.08	1.35	1.55	Div'd Decl'd per sh B ■ †	2.15
3.43	2.76	2.50	3.53	3.13	3.52	4.44	5.29	6.03	5.07	5.89	5.70	6.79	8.35	10.56	9.73	7.50	7.00	Cap'l Spending per sh	6.75
15.67	16.01	16.89	17.42	16.51	16.46	16.89	17.00	17.81	18.44	19.92	21.31	22.91	24.70	26.50	28.54	30.20	32.25	Book Value per sh C	38.00
105.32	108.94	110.82	111.68	112.87	115.61	118.90	118.65	115.42	116.03	118.43	116.99	116.98	116.97	116.94	116.92	117.00	117.00	Common Shs Outst'g D	117.00
15.2	15.2	13.1	14.3	NMF	18.0	13.3	18.7	12.1	10.5	12.4	17.5	14.5	16.0	16.5	14.8	Bold figures are		Avg Ann'l P/E Ratio	14.0
.90	1.00	.88	.90	NMF	.94	.76	1.22	.62	.57	.71	.92	.77	.86	.88	.91	Value Line		Relative P/E Ratio	.95
4.9%	5.5%	5.2%	5.4%	6.0%	5.2%	6.3%	6.8%	3.6%	3.3%	2.8%	2.6%	2.4%	2.2%	2.1%	2.4%	estimates		Avg Ann'l Div'd Yield	3.4%

CAPITAL STRUCTURE as of 9/30/09
Total Debt $4881.7 mill. **Due in 5 Yrs** $2121.0 mill.
LT Debt $3631.2 mill. **LT Interest** $203.3 mill.
Incl. $149.0 mill. capitalized leases
(LT interest earned: 3.2x)
Leases, Uncapitalized Annual rentals $23.6 mill.
Pension Assets-12/08 $719.2 mill. **Oblig.** $1.14 bill.
Pfd Stock $30.4 mill. **Pfd Div'd** $1.2 mill.
260,000 shs. 3.60%, $100 par, callable at $101; 44,498 shs. 6%, $100 par.
Common Stock 116,911,016 shs.

MARKET CAP: $5.6 billion (Large Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
2272.6	3354.7	3928.5	3736.2	4054.3	3431.1	3815.5	3996.4	4237.8	4431.0	4200	4650	Revenues ($mill)	5400
231.5	132.0	218.8	270.8	269.2	221.2	304.8	313.7	337.7	359.8	365	440	Net Profit ($mill)	520
33.8%	43.7%	40.9%	37.4%	35.5%	37.5%	32.9%	35.8%	39.1%	37.6%	37.0%	37.0%	Income Tax Rate	37.0%
5.8%	12.3%	6.9%	4.1%	6.9%	10.0%	12.5%	19.0%	23.8%	27.2%	19.0%	14.0%	AFUDC % to Net Profit	10.0%
48.8%	58.9%	62.2%	59.8%	59.9%	56.2%	52.8%	51.3%	50.3%	54.8%	53.5%	57.0%	Long-Term Debt Ratio	54.5%
45.9%	40.5%	37.2%	39.6%	39.6%	43.3%	46.7%	48.2%	49.2%	44.8%	46.0%	42.5%	Common Equity Ratio	45.5%
4372.8	4979.9	5523.8	5400.3	5963.3	5762.3	5741.5	5992.8	6302.1	7442.0	7700	8840	Total Capital ($mill)	9825
3846.6	4152.4	4188.0	4398.8	5926.1	5903.1	6362.9	7052.5	7681.2	8517.0	9035	9470	Net Plant ($mill)	10750
6.7%	4.7%	5.8%	7.1%	6.3%	5.6%	7.0%	6.6%	7.0%	6.3%	6.5%	6.5%	Return on Total Cap'l	7.0%
10.3%	6.4%	10.5%	12.5%	11.3%	8.8%	11.2%	10.7%	10.8%	10.7%	10.5%	11.5%	Return on Shr. Equity	11.5%
10.9%	6.5%	10.6%	12.6%	11.4%	8.8%	11.3%	10.8%	10.9%	10.7%	10.5%	11.5%	Return on Com Equity E	11.5%
1.9%	NMF	6.0%	8.3%	7.4%	4.9%	7.5%	7.1%	7.1%	7.0%	6.0%	7.0%	Retained to Com Eq	6.0%
84%	NMF	43%	35%	35%	45%	34%	35%	35%	35%	43%	41%	All Div'ds to Net Prof	48%

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	-4.0	+2.2	-2.2
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.80	6.02	6.05
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	6376	6166	5740
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.9	+.2	+.5
Fixed Charge Cov. (%)	260	258	270

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	8.5%	1.5%	4.0%
"Cash Flow"	4.5%	1.0%	7.0%
Earnings	7.5%	6.0%	8.0%
Dividends	-4.0%	4.5%	13.5%
Book Value	4.5%	7.5%	6.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	1247.0	814.4	839.8	1095.2	3996.4
2007	1301.1	906.5	881.5	1148.7	4237.8
2008	1431.8	946.1	852.5	1200.6	4431.0
2009	1396.2	842.5	821.9	1139.4	4200
2010	1500	950	900	1300	4650

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.88	.50	.60	.65	2.64
2007	.85	.49	.70	.80	2.84
2008	1.04	.49	.65	.85	3.03
2009	1.20	.54	.50	.86	3.10
2010	1.25	.60	.90	.95	3.70

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.22	.22	.22	.22	.88
2006	.23	.23	.23	.23	.92
2007	.25	.25	.25	.25	1.00
2008	.27	.27	.27	.27	1.08
2009	.3375	.3375	.3375	.3375	

BUSINESS: Wisconsin Energy Corporation (WEC) is a holding company for We Energies, which provides electric, gas & steam service in WI & upper MI. Customers: 1.1 mill. elec., 1 mill. gas. Acq'd Edison Sault Electric 5/98; WICOR 4/00. Discontinued pump-manufacturing ops. in '04. Sold Point Beach nuclear plant in '07. Electric rev. breakdown, '08: residential, 36%; small comm'l & ind'l, 33%; large comm'l & ind'l, 25%; other, 6%. Generating sources, '08: coal, 57%; gas, 6%; hydro, 1%; wind, less than 1%; purchased, 36%. Fuel costs: 56% of revs. '08 reported depr. rate (utility): 3.7%. Has 4,900 empls. Chairman, Pres. & CEO: Gale E. Klappa. Inc.: WI. Address: 231 W. Michigan St., P.O. Box 2949, Milwaukee, WI 53201. Tel.: 414-221-2345. Internet: www.wisconsinenergy.com.

Wisconsin Energy's utility subsidiary expects an order on its rate case soon. We Energies is seeking an electric tariff hike of $96 million (3.7%) based on a 10.75% return on a 53% common-equity ratio. It is requesting a gas rate increase of $61 million (4.2%) based on a 10.75% return on a 48% common-equity ratio. It also wants a $2.7 million boost in steam rates. New rates should take effect at the start of 2010. The company is also requesting a $42 million (33%) rate increase in Michigan. It will self-implement a rate increase at the start of 2010, with the final order due in mid-2010.

The income from a new coal-fired unit should enable Wisconsin Energy's profits to rise substantially in 2010 after a modest advance in 2009. This year, a decline in kilowatt-hour sales has restrained the company's earnings growth. We look for improvement in 2010. But, by far the biggest impetus for bottom-line growth will be the profits from a coal-fired unit, built under the company's "Power the Future" program, which should begin commercial operation in late 2009. This facility is owned by a Wisconsin Energy nonregulated subsidiary that is leasing it to We Energies under an agreement that is designed to produce a 12.7% ROE. But . . . **Binding arbitration has begun in order to resolve a dispute with Bechtel,** which is building the Power the Future plants for Wisconsin Energy. Bechtel has filed two claims for a total of $485 million. If the decision, which is expected in late 2010 or early 2011, is unfavorable, Wisconsin Energy might still be able to recover at least some of these costs under the Power the Future regulatory program.

We expect a significant dividend hike in the first quarter of 2010. Wisconsin Energy is trying to raise its payout ratio, which is very low, by utility standards.

The company has agreed to sell Edison Sault Electric. The purchase price is $61.5 million, some $2 million above book value. The deal requires various regulatory approvals and might close as early as mid-2010.

Even reflecting the anticipated dividend hike, this stock's yield is low for a utility. Total return potential to 2012-2014 is a cut above average for the group.

Paul E. Debbas, CFA *December 25, 2009*

(A) Diluted EPS. Excl. nonrec. gains (losses): '99, (9¢); '00, 19¢ net; '01, 1¢ net; '02, (88¢); '03, (20¢) net; '04, (81¢); gains on disc. ops.: '04, $1.54; '05, 4¢; '06, 4¢. '06 earnings don't add due to rounding. Next earnings report due early Feb. (B) Div'ds historically paid in early Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '08: $14.57/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '08: 10.75%; earned on avg. com. eq., '08: 11.0%. Regulatory Climate: Above Average.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	90
Earnings Predictability	90

XCEL ENERGY NYSE-XEL

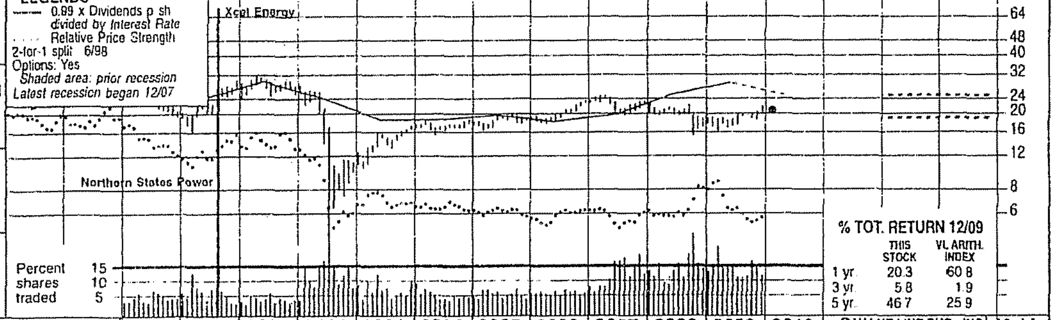
RECENT PRICE 20.80 | P/E RATIO 14.1 (Trailing: 14.1, Median: 15.0) | RELATIVE P/E RATIO 0.85 | DIV'D YLD 4.8% | VALUE LINE 2245

TIMELINESS 3 Lowered 7/17/09
SAFETY 2 Raised 5/14/04
TECHNICAL 3 Raised 10/30/09
BETA .65 (1.00 = Market)

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
High:	30.8	27.9	30.0	31.8	28.5	17.4	18.8	20.2	23.6	25.0	22.9	21.9
Low:	25.7	19.3	16.1	24.2	5.1	10.4	15.5	16.5	17.8	19.6	15.3	16.0

Target Price Range 2012 | 2013 | 2014

LEGENDS
—— 0.89 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 6/98
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	25	(+20%)	9%
Low	19	(-10%)	3%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	2	0	1	2	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2009	2Q2009	3Q2009
to Buy	168	180	158
to Sell	174	171	175
Hld's(000)	266312	260458	267095

% TOT. RETURN 12/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	20.3	60.8
3 yr.	5.8	1.9
5 yr.	46.7	25.9

Xcel Energy was formed through the merger of Northern States Power and New Century Energies on August 21, 2000. NSP stockholders received one share of Xcel for every NSP share, and NCE stockholders received 1.55 shares of Xcel for each NCE share. *Data prior to 2000 reflect NSP on a stand-alone basis and are not comparable with Xcel data.*

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
18.42	34.11	43.56	23.89	19.90	20.84	23.86	24.16	23.40	24.69	21.10	22.80	Revenues per sh	26.75
4.13	4.12	5.09	3.14	3.35	3.27	3.28	3.61	3.45	3.50	3.50	3.70	"Cash Flow" per sh	4.50
1.43	1.60	2.27	.42	1.23	1.27	1.20	1.35	1.35	1.46	1.49	1.60	Earnings per sh A	2.00
1.45	1.48	1.50	1.13	.75	.81	.85	.88	.91	.94	.97	1.00	Div'd Decl'd per sh B ■	1.10
13.87	3.63	7.40	6.04	2.49	3.19	3.25	4.00	4.89	4.66	3.95	4.85	Cap'l Spending per sh	5.75
16.42	16.37	17.95	11.70	12.95	12.99	13.37	14.28	14.70	15.35	15.90	16.55	Book Value per sh C	19.25
155.73	339.79	345.02	398.71	398.96	400.46	403.39	407.30	428.78	453.79	457.00	460.50	Common Shs Outst'g D	470.00
16.6	14.3	12.4	NMF	11.6	13.6	15.4	14.8	16.7	13.7	12.7		Avg Ann'l P/E Ratio	11.5
.95	.93	.64	NMF	.66	.72	.82	.80	.89	.83	.83		Relative P/E Ratio	.75
6.1%	6.4%	5.3%	6.6%	5.2%	4.7%	4.6%	4.4%	4.0%	4.7%	5.1%		Avg Ann'l Div'd Yield	4.8%
2869.0	11592	15028	9524.4	7937.5	8345.3	9625.5	9840.3	10034	11203	9642.6	10500	Revenues ($mill)	12600
240.1	545.8	784.7	177.6	510.0	526.9	499.0	568.7	575.9	645.7	685.5	745	Net Profit ($mill)	970
21.6%	35.8%	28.2%	32.7%	23.7%	23.2%	25.8%	24.2%	33.8%	34.4%	35.1%	35.0%	Income Tax Rate	35.0%
2.5%	4.4%	7.1%	46.7%	8.9%	10.9%	8.5%	9.8%	12.5%	15.9%	16.8%	12.0%	AFUDC % to Net Profit	12.0%
54.7%	58.8%	66.7%	59.6%	55.3%	55.0%	51.7%	52.1%	49.7%	52.2%	52.0%	53.0%	Long-Term Debt Ratio	51.0%
40.5%	40.5%	32.8%	39.5%	43.8%	44.1%	47.3%	47.0%	49.4%	47.1%	47.5%	46.0%	Common Equity Ratio	48.5%
6316.2	13745	18911	11815	11790	11801	11398	12371	12748	14800	15300	16500	Total Capital ($mill)	18600
4451.5	15273	21165	18816	13667	14096	14696	15549	16676	17689	18575	19825	Net Plant ($mill)	23700
5.4%	6.0%	6.0%	5.4%	6.1%	6.2%	6.2%	6.2%	6.3%	6.0%	6.0%	6.0%	Return on Total Cap'l	7.0%
8.4%	9.6%	12.5%	3.7%	9.7%	9.9%	9.1%	9.6%	9.0%	9.1%	9.5%	9.5%	Return on Shr. Equity	10.5%
8.6%	9.7%	12.6%	3.7%	9.8%	10.0%	9.2%	9.7%	9.1%	9.2%	9.5%	9.5%	Return on Com Equity E	10.5%
NMF	.9%	4.3%	NMF	3.9%	3.9%	2.9%	3.6%	3.1%	3.8%	3.5%	3.5%	Retained to Com Eq	5.0%
100%	91%	66%	NMF	60%	62%	69%	63%	66%	59%	65%	62%	All Div'ds to Net Prof	54%

CAPITAL STRUCTURE as of 9/30/09
Total Debt $8623.9 mill. **Due in 5 Yrs** $2868.8 mill.
LT Debt $7945.4 mill. **LT Interest** $516.5 mill.
Incl. 8,000,000 shares 7.875% tax-deductible Trust Originated Preferred Securities, liquidation value $25/share; 7,760,000 shares 7.60%, cumulative, $25 par; $100 mill. 7.85% tax-deductible Trust Preferred Securities.
(LT interest earned: 2.9x)
Leases, Uncapitalized Annual rentals $186.4 mill.
Pension Assets-12/08 $2.19 bill. **Oblig.** $2.60 bill.
Pfd Stock $105.0 mill. **Pfd Div'd** $4.2 mill.
1,049,800 shares $3.60 to $4.56, cumulative, $100 par, callable $102.00 to $103.75.
Common Stock 456,645,598 shs. as of 10/26/09
MARKET CAP: $9.5 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	+1.8	+2.0	+.8
Avg. C & I Use (MWH)	153	153	155
Avg. C & I Revs. per KWH (¢)	6.55	6.57	7.28
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	21255	21108	20596
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.2	+.9	+1.1
Fixed Charge Cov. (%)	238	256	248

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	2.5%	-3.5%	2.0%
"Cash Flow"	-1.5%	-2.0%	4.0%
Earnings	-2.5%	1.0%	6.5%
Dividends	-4.0%	-4.0%	3.0%
Book Value	-.5%	1.0%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	2888	2074	2411	2467	9840.3
2007	2764	2267	2400	2603	10034
2008	3028	2615	2852	2708	11203
2009	2696	2016	2314	2617	9642.6
2010	2700	2450	2700	2650	10500

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.36	.24	.53	.23	1.35
2007	.28	.16	.59	.31	1.35
2008	.35	.24	.51	.36	1.46
2009	.38	.25	.48	.37	1.49
2010	.35	.28	.57	.40	1.60

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.215	.215	.2225	.2225	.88
2007	.2225	.2225	.23	.23	.91
2008	.23	.23	.2375	.2375	.94
2009	.2375	.2375	.245	.245	.97
2010	.245				

BUSINESS: Xcel Energy Inc. is the parent of Northern States Power, which supplies power to Minnesota, Wisconsin, North Dakota, South Dakota, Michigan, & gas to Minnesota, Wisconsin, North Dakota, & Michigan; Public Service of Colorado, which supplies power & gas to Colorado; & Southwestern Public Service, which supplies power to Texas & New Mexico. Customers: 3.4 mill. electric, 1.9 mill. gas. Electric revenue breakdown, '08: residential, 28%; commercial & industrial, 53%; other, 19%. Generating sources not available. Fuel costs: 61% of revs. '08 reported deprec. rate: 3.2%. Has 11,200 employees. Chairman, President & CEO: Richard C. Kelly. Inc.: MN. Address: 414 Nicollet Mall, Minneapolis, MN 55401. Tel.: 612-330-5500. Internet: www.xcelenergy.com.

Xcel Energy's utility subsidiary in Colorado has received part of the rate increase that it was granted. Public Service of Colorado had filed for an electric rate increase of $177.4 million (6.7%), partly to place the Comanche 3 coal-fired unit in the rate base. The Colorado commission granted the utility a rate hike of $128.3 million, based on a return on equity of 10.5%. But, because Comanche 3 didn't enter commercial operation at the end of 2009, as scheduled, P.S. of Colorado was permitted to put just $67.0 million of the rate increase in effect at the start of 2010. Once Comanche 3 begins service (something that was expected in February of 2010), electric rates will be raised by an additional $54.0 million. The utility will receive the remaining $7.3 million at the start of 2011, to reflect higher property taxes.

Northern States Power has received small electric rate increases in Wisconsin and South Dakota. In Wisconsin, NSP was granted a tariff hike of $6.4 million (1.2%) based on a return of 10.4% on a common-equity ratio of 52.3%. In South Dakota, the utility received a rate increase of $10.9 million in a regulatory settlement that did not specify an allowed ROE.

We estimate that earnings will rise in 2010. The rate relief that Xcel's utilities received in early 2010, along with a full year of increases granted in 2009, are the primary reasons for bottom-line growth. Our share-profit estimate of $1.60 is at the midpoint of Xcel's targeted range of $1.55-$1.65. (The delay for Comanche 3 is not expected to affect earnings; Xcel did not revise its 2010 guidance.)

Xcel is proposing a nuclear uprate program at its two nuclear stations. This would add 235 megawatts of capacity and extend the plants' life by 20 years. The cost would be $1.1 billion. The company still needs some federal and state regulatory approvals before it can proceed with the program.

More-attractive selections are available elsewhere. The share price didn't fall as much as most other utilities in the sharp market downturn that began in September of 2008. The yield is about equal to the industry average, but 3- to 5-year total return potential is below average.

Paul E. Debbas, CFA *February 5, 2010*

(A) Diluted EPS. Excl. nonrec. loss: '02, $6.27; gains (losses) on discont. ops.: '03, 27¢; '04, (30¢); '05, 3¢; '06, 1¢; '09, (1¢). '06, '07 & '09 EPS don't add due to rounding. Next egs. report due late Apr. (B) Div'ds historically paid in mid-Jan., April, July, and Oct. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '08: $5.23/sh. (D) In mill., adj. for split. (E) Rate base: Varies. Rate allowed on com. eq.: MN '09, 10.88%; WI '08, 10.75%; CO '10 (elec.), 10.5%; CO '07 (gas) 10.25%; TX '86, 15.05%; earned on avg. com. eq., '08: 9.7%. Regulatory Climate: Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	25
Earnings Predictability	60

Kentucky Power Company

REQUEST

Refer to the Avera Testimony at page 29 and Exhibit WEA-2.

Provide a detailed explanation of how the stock prices were estimated to determine the expected dividend yield.

RESPONSE

As indicated in footnote (a) to Exhibit WEA-2, the stock prices used to compute the dividend yield for each of the utilities in the proxy group were those reported by the Value Line Investment Survey in its *Summary and Index* (Nov. 6, 2009).

WITNESS: William E Avera

Kentucky Power Company

REQUEST

Refer to the Avera Testimony at page 35 and Exhibit WEA-2.

For regulated utilities, the return on equity and overall returns are determined in part through rate proceedings by state regulatory commissions. Provide an explanation of why the sustainable growth approach does not produce a circular argument for determining regulated utility returns.

RESPONSE

While Dr. Avera's testimony indicates that the earnings growth projections of securities analysts provide a superior guide to investors' expectations, the sustainable growth approach is frequently referenced in regulatory proceedings and is consistent with the theory underlying the constant growth DCF model. In implementing the constant growth DCF model, a key requirement is that the growth rates reflect the forward-looking expectations of investors, which includes their assumptions regarding the actual rates of return expected in future periods. These expected earned rates of return are dependent on the authorized rates of return that are expected in future periods. This is also the case for future growth in earnings, dividends, and book value, which are all ultimately tied to a utility's ability to recover its reasonable and necessary costs of service, including a fair ROE. In other words, it is investors' expectations – including those for future allowed ROEs – that determine observable stock prices, and these are the only proper basis for the growth rate used in applying the DCF model.

WITNESS: William E Avera

Kentucky Power Company

REQUEST

Refer to the Avera Testimony at page 36 and Exhibit WEA-2.

Other than Mr. Avera's professional judgment, there does not appear to be any basis for using the expected growth rate in stock prices as the appropriate variable in the DCF analysis. Provide appropriate academic studies or texts that recommend using the expected growth rate in stock price as an appropriate variable in the analysis.

RESPONSE

Reference to investors' expectations for growth in share prices in applying the DCF model is based directly on the theory and assumptions underlying this approach, and not on Dr. Avera's professional judgment. The DCF model is based on the premise that observable stock prices are equal to the present value of the cash flows that investors expect to receive, both in the form of dividends and stock price appreciation over their holding period. Thus, growth in stock price is directly related to investors' expected returns, and projected stock prices from investment advisory services such as the Value Line Investment Survey ("Value Line") are widely reported and available to investors. For example, Value Line reports the annualized total expected return based on expected share price appreciation for each of the stocks it covers (*see*, *e.g.*, WP-40 provided on the CD in response to KIUC 1st Set, Item No. 1). In other words, projected growth in stock price is directly relevant to an analysis of the future cash flows that investors expect to receive when they purchase common stocks and is entirely consistent with the underlying basis of the DCF model. Similarly, under the assumptions required to derive the constant growth form of the DCF model, stock price, earnings, dividends, and book value are all expected to grow at the same rate. Dr. Myron Gordon noted in his seminal article, *The Cost of Capital to a Public Utility* (1974), that growth in stock price could serve as another guide to investors' growth expectations in the constant growth DCF model, observing that, "[T]he rate of growth in the price of a stock … will respond to all of the factors mentioned above and, in addition, to the yield investors require on the share." Similarly, *The Cost of Capital – A Practitioner's Guide,*(1997) published by the Society of Utility and Regulatory Financial Analysts, observed that under the assumptions of the DCF model, "The stock price grows proportionally to the growth rate." Copies of the above-referenced sources are contained on the CD provided in response to KIUC 1st-Set, Item No. 1.

WITNESS: William E Avera

THE COST OF CAPITAL TO A PUBLIC UTILITY

Myron J. Gordon

1974
MSU Public Utilities Studies

Division of Research
Graduate School of Business Administration
Michigan State University
East Lansing, Michigan

The Institute of Public Utilities, Graduate School of Business Administration, Michigan State University, publishes books, monographs, and occasional papers as part of its program of promoting academic interest in the study of public utilities and regulation. The views and opinions expressed in these works are solely those of the authors, and acceptance for publication does not constitute endorsement by the Institute, its member companies, or Michigan State University.

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To Joe and David

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Preface

In 1966 I was asked by Harry Trebing and Boyd Nelson to testify before the Federal Communications Commission on the cost of capital to the American Telephone and Telegraph Company. I agreed to do so because tackling that problem appeared to be an exciting and important challenge for a number of reasons. Although a considerable period of time had passed since the publication of the 1958 article by Modigliani and Miller and my 1962 book on the cost of capital and corporation finance, I knew of no serious effort to apply the theory. Furthermore, it seemed to me that of all the areas in which the theory might be applied, public utility rate of return regulation was the most promising. In addition to the practical value of this application, I also believed that the further development of the theory would profit from being confronted with reality in a more serious way than through the conventional methods of regression analysis and tests of significance.

My expectations with regard to the practical and intellectual rewards from carrying out the study were more than realized. On the practical value of my testimony (FCC Docket No. 16258, Staff Exhibit No. 17) the commission made the following comment in its Interim Decision and Order in the case.

> 234. We have found his approach and methods useful in analysis and evaluation of the effect of capital structure, i.e., the ratios of debt and equity upon overall cost of capital. It lends support to our conclusion that a regulatory determination of revenue requirements can rely, in part, on announced and anticipated changes in capital structure.

> 235. We have not had the opportunity to analyze, evaluate and test fully his model to determine all of its implications insofar as fixing an overall rate of return is concerned. However, we believe that it merits further attention as a means of making available more objective data and substantive support for the exercise of the subjective judgements in fixing a rate of return. We would, therefore, encourage further study and refinement of the model to make it more useful in resolving the special problems which arise in the field of regulated entities.

Notwithstanding its refusal to accept my model as a decision rule, the commission's conclusion that a "fair rate of return to the Respondent on their interstate operations is in the range of 7% to 7½%" was in agreement with my findings.

The commission followed up on its conclusion that my work merited further attention by supporting a research study on the cost of capital for a public utility during 1970–1971, and the Institute of Public Utilities supported the continuation of that research in 1971–1972.

Although the research culminating in this book is addressed to the specific problem of determining the cost of capital to a public utility, it has a much broader interest. The alternative theories of security valuation and the cost of capital are established and analyzed on a level of abstraction that is valid for all industries. The models are then modified to take account of the institutional arrangements that prevail in the utility industry. This is of interest both to establish the cost of capital to a public utility and to demonstrate how one goes about adapting general financial models to deal with the special circumstances of a particular industry.

With each security valuation model adapted to reflect the circumstances of the utility industry, sample data from the industry may be and is used to test the basic security valuation assumptions under which the underlying theory is true. The pages that follow contain what may well be the most effective tests of the alternative security valuation theories carried out to date. Finally, the sample data are used to establish and compare the cost of capital under each of the theories. The adaptation and testing of the alternative theories and the resolution of numerous measurement problems well may contribute to solving the problems of cost of capital measurement in other industries.

The author's foremost debt in carrying out this work is to Boyd Nelson and Harry Trebing. Over the years they provided encouragement, a great deal of knowledge about the public utility industry,

and useful comments on the work at various stages in its progress. Extensive discussions with Paul Halpern and other members of the University of Toronto faculty helped clarify my thinking on numerous issues on cost of capital theory and econometric techniques. Shyam Bagrodia, Lawrence Gould, Can Le, Paul Roth, and Kamal Pradhan collected data, programmed the computations, checked equations, and helped in a variety of other ways. Edith Kosow and Linda Palanica typed numerous drafts of the manuscript as it developed. The latter's ability to hold the manuscript together in the face of all these revisions has been a remarkable accomplishment. The editorial advice of Elizabeth Johnston contributed materially to the style and clarity of exposition. Finally, the Federal Communications Commission and the Institute of Public Utilities provided the necessary financial support. None of the above necessarily subscribes to the conclusion reached in this book.

1

The Problem and the Findings

It may be inefficient to allow two or more firms to compete in the production or distribution of goods and services such as electricity, water, and telecommunications. Consequently, either the government provides the product or a private firm is given an exclusive franchise subject to regulation by a government agency. Regulation, which protects the consumer against monopoly pricing by the firm, includes control over the prices the utility charges for its products. The purpose of this study is to establish operational rules for the overall level of prices a utility should be allowed to charge.

Ordinarily a utility will sell two or more products, or its product may sell at two or more prices depending on the class of customer, the quantity he buys, or some other basis of discrimination among customers. In that event, determining the prices a utility should be allowed to charge may be decomposed into two problems: the relative structure of prices and the overall level of prices. Given the relative structure of prices, fixing the overall level of prices is equivalent to fixing the price for a single product utility. Under plausible conditions the price determines the utility's profit. These conditions are that the utility's cost is a unique function of its output and that it produces the output which maximizes its profit. Given the capital employed by the utility, the price also determines its return on capital; as will be seen, a useful statement of the decision problem facing a regulatory agency is to ask what rate of return a utility should be allowed to earn.

1.1 The Problem

The regulatory process is constrained by law and judicial decisions. In the *Bluefield Water Works* case the Supreme Court stated: "The return should be reasonably sufficient to . . . support its credit and enable it to raise the money necessary for the proper discharge of its public duties." To realize this objective recognition should be given to the "returns being currently earned on investments in other business undertakings of corresponding risks and uncertainties. . . ."[1] In the *Hope* case, after stating that return should be commensurate with the return enjoyed by "other enterprises having corresponding risks," the court stated return "should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."[2]

These guidelines are purposely general, but they are sufficiently precise to allow the following operational elaboration and rationalization from an economic viewpoint. The theoretical and practical justification of our market economy is that it serves the consumer—the public—better than any other arrangement of our economic affairs. In the case of companies designated as public utilities, regulatory agencies are employed to replace the marketplace to the minimum extent necessary to realize the same objective.

Other things the same, the lower a utility's rate of return (and the price charged to the consumer), the higher the level of consumer welfare.[3] However, the consumer interest requires that the demand for service at the price charged be satisfied. Otherwise, nonprice rationing of the product is required, and demand at a price above the cost of production remains unsatisfied. Both conditions generally are regarded as unsatisfactory. Hence, a regulatory agency's concern

[1] *Bluefield Water Works and Improvement Company* v. *Public Service Commission of West Virginia*, 262 U.S. 679, 692 (1923).

[2] *FPC* v. *Hope Natural Gas Company*, 320 U.S. 591, 603 (1944).

[3] The power of a regulatory agency does not extend beyond the utility companies under its control. Hence, the possibilities of compensating changes in other prices, taxes, and subsidies are excluded as means of maximizing consumer welfare.

includes the adequacy of the utility's facilities to meet the demand for its product. In principle, a regulatory agency can order a utility to make capital expenditures, but in practice the only instrument it can use to secure a desired level of capital facilities is the rate of return the utility is allowed to earn. The agency cannot use the public purse to provide a utility with the funds necessary to meet its capital requirements.

The immediate decision maker with respect to a utility's expenditure on capital facilities is the utility management.[4] As a first approximation we may assume that the objective of a utility management in its investment and other decisions is to serve the company's owners—its present stockholders. It is consistent with this objective for the management to be concerned with the welfare of consumers, employees, and other groups which may influence the fortunes of the company. However, the stockholders own a utility; they have the ultimate power to hire and fire the management, and the management is charged with acting in the interest of the stockholders. Furthermore, the rationale for private ownership of property is that its use in the interest of its owners, subject to whatever constraints society imposes by law, serves society better than charging the managers with serving the public interest. A reasonable measure of how well the welfare of a company's owners is served by the management is the market value of the firm's outstanding common stock. Hence. we may take as the management's objective the maximization of the market value of the stock.

To summarize, the regulatory agency's objective is to determine a price above the cost of producing the utility's product that provides the utility with the lowest rate of return on its capital consistent with the investment decision the public interest requires. Since the objective of the utility management is to maximize the price of its stock, the allowed rate of return on capital must satisfy the condition that no other investment rate would result in a higher share price. For example, assume that an 8 percent return makes the price per share independent of the utility's investment decision, while a higher (lower) rate of return makes the share price an increasing (decreasing) function of the investment rate. In that event

[4] If the regulatory agency were to make the specified capital expenditure decisions for a utility and assume direct responsibility for providing the required funds, the utility, for all practical purposes, would be publicly owned.

8 percent is the rate of return the utility should be allowed to earn, and we call this figure the utility's cost of capital for any investment rate. To illustrate, for the rate of return and investment rate figures shown below, let the share price figures indicated result. Furthermore, at each rate of return no other investment rate would result in a higher share price.

Rate of Return	*Investment Rate*	*Share Price*
.07	.03	$25.00
.08	.05	$29.00
.09	.07	$35.00

The cost of capital for each investment rate is the rate of return on the same line.

It is clear that measuring a utility's cost of capital involves how investors value its stock, how share value varies with the utility's allowed rate of return and its investment decision, and perhaps how the investment is financed. In very general terms the problem may be stated as follows. The value of a share of stock is equal to its dividend expectation discounted at the yield investors require on the stock. The dividend expectation is a function of the allowed rate of return, the level of investment, and its financing. The required rate of return also may be a function of these variables. Given the allowed rate of return, the rational utility management represents the interest group it is supposed to serve by selecting the investment rate and financing mix which maximize the stock price. The rational regulatory agency represents the interest group it is supposed to serve by selecting the lowest rate of return which realizes the desired investment rate. Both take as given how investors value the utility's stock.

1.2 *Limitations of the Problem Statement*

If three assumptions made in developing the above model of the regulatory process actually are true, implementing it will, in fact, determine the prices a utility should be allowed to charge for its products. The first assumption is that the management will produce the output of each period at the lowest possible cost. The second is that the management's investment and financing decisions are made with the objective of maximizing the market value of

the outstanding common equity. The third is that the utility sells one undifferentiated product or that the relative structure of prices for its different products is somehow fixed. All of these assumptions are open to question.[5]

When prices are controlled to realize a specified return over cost, the incentive to minimize cost is impaired. The stockholder suffers little, if at all, from inefficient operations or expenditures which increase management's income without any compensating reduction in other costs. Control over costs by the regulatory agency or another form of profit control which would provide some inducement for management to minimize costs might result in a lower overall level of prices to the consumer.

When the shares of a company are widely held, as is usually the case for public utilities, management gains some freedom from stockholders' control. Management then may subordinate the maximization of the price of the firm's stock in its investment and financing decisions to other goals. Management's welfare is an increasing function of the size or rate of growth of the firm and is a decreasing function of the firm's risk of insolvency. Consequently, at any allowed rate of return management may undertake a higher level of investment than is called for by the interests of the stockholders. Management's desire for security may persuade it to adopt financing policies, for example, a lower debt-equity ratio than is called for by the stockholders' and/or the consumers' interests.

The third possible limitation of our problem statement is the assumption that the utility sells one product or that the relative structure of prices can be ignored. Assume a utility that is selling a single product at a price yielding the allowed rate of return, and that price is well below the price that maximizes the return on the capital stock. Also assume that the product can be sold in some quantity in another market at a lower price. If the lower price exceeds the long-run marginal cost of the output, including the allowed rate of return, capturing the market will benefit the utility's present consumers. With the allowed rate of return given, the return in excess of the long-run marginal cost of the output

[5] A recent discussion of these and related issues from a cost of capital perspective is to be found in S. C. Myers [36].

accrues to the utility's present consumers in the form of a lower price.[6]

Entering the second market will not be in the interest of the present consumers if the price in that market is below the long-run marginal cost. The difference is covered by the present consumers through a rise in the price they must pay. However, entering the market may be beneficial to stockholders and/or management. Stockholders benefit if the allowed rate of return exceeds the firm's cost of capital and if an expansion of capacity is required to meet the demand under the prices in the old and new markets. As Harvey Averch and L. L. Johnson [1] have shown, when the allowed rate of return is above the cost of capital, the market value of the stock of the existing shareholders increases with the quantity of capital the firm employs. When the allowed rate of return is equal to the cost of capital, the stockholders neither gain nor lose when the firm enters a new market. However, management gains if its welfare is an increasing function of the utility's size and if entering the market requires an expansion of the firm.

Consequently, control over the allowed rate of return may not be sufficient to protect the consumer against monopoly pricing by a utility. Losses on sales in other markets fall on the consumer, and the price he pays is raised toward the monopoly price. This form of price discrimination is in the interest of the stockholder when the allowed rate of return is in excess of the cost of capital and when capital requirements are increased. Only the latter condition is necessary for this form of price discrimination to benefit management.[7]

Recognizing these limitations does not invalidate our formulation of the problem a regulatory agency faces in controlling utility prices. The prices must provide the firm with a rate of return adequate

[6] This is the rationale for price discrimination by a public utility. See S. C. Littlechild [28] for an application of the theory to telephone service pricing and references to the literature.

[7] Price discrimination that benefits the consumer may not require an increase in capacity because such discrimination frequently finds a market for off-peak or unused capacity. However, price discrimination that raises the price to the consumer typically requires an increase in capacity. In any event, a utility with two markets and the demand more price elastic in one is motivated to push the price in that market below cost in order to increase demand to the point where an increase in capacity is required.

to generate the capital to meet the demand for service. Furthermore, once we have established how a utility's cost of capital depends on its investment rate and financing policies, it may be possible to evaluate what if any departures in the allowed rate of return from the cost of capital are desirable to deal with the considerations raised above.

1.3 *Summary of the Findings*

Chapter 2 establishes the perfectly competitive capital markets theory of the cost of capital. According to this theory the yield investors require on a corporation's stock is independent of the firm's dividend and stock financing rates, and the yield increases with the leverage or debt-equity ratio because investors are indifferent between leverage on personal and corporate account. The consequence of these assumptions, it will be seen, is that the price of a utility's stock is independent of the level and financing of its investment when its allowed rate of return on assets is equal to what the yield on its stock would be in the absence of leverage. Therefore, the leverage-free yield on the utility's stock is its cost of capital under the perfect capital markets theory of security valuation. That is, a rate of return on assets equal to the leverage-free yield on a utility's stock is the lowest rate of return that secures the investment the public interest requires, and it secures any level of investment the public interest requires.

Chapter 3 deals with a number of questions that differentiate regulated from unregulated firms. The general proof of the perfectly competitive capital markets cost of capital theorem shows that share price is independent of the level of investment and of its financing when the return on investment and not the return on assets is equal to the leverage-free yield on the firm's stock. The chapter demonstrates that regulatory practice makes the return on investment and the return on assets and accounting income for a period divided by the book value of the assets all equal. The regulatory practice that produces this result is the use of historical cost as the rate base in determining a utility's income. This practice has been questioned, but it is shown that historical cost is superior to opportunity cost and other valuation bases not only under the criterion of administrative feasibility but also under purely economic criteria. The chapter also examines the consequences of the corporate income tax, the personal income tax, and inflation for a utility's cost of capital and allowed rate of return.

Chapter 4 establishes the traditional cost of capital theory and demonstrates that it differs from the perfect capital markets theory only in that the yield investors require on a share does not increase as rapidly with the firm's leverage rate. Consequently, the cost of debt capital is below the cost of equity capital, and if the utility is assumed to have some leverage rate the average cost of capital is a decreasing function of the assigned leverage rate. Chapter 4 also discusses a number of other questions. Under both theories, it is shown, the market-book value ratio for a utility's stock is equal to one when the allowed return on assets is equal to the theory's cost of capital and when the coupon or imbedded interest rate on the firm's outstanding debt is equal to the current interest rate. Hence, the regulatory agency has a cut-and-dried alternative to measuring the cost of capital and setting the allowed rate of return equal to it. The regulatory agency may raise the allowed rate of return as along as the market-book value ratio is below one and vice versa.

All prior investigations of the subject have ignored the possible consequence of a difference between the current interest rate and the imbedded rate on the firm's outstanding debt. Chapter 4 establishes that, when the two interest rates differ, the traditional cost of capital is unchanged. The perfect capital markets cost of capital, on the other hand, is a decreasing function of the ratio of the current interest rate to the coupon interest rate, and an exact expression for the cost of capital is obtained when the two interest rates differ. The conclusion that the allowed rate of return is above (below) the cost of capital under both theories when the market-book value ratio is above (below) one remains true.

The conclusion of the previous analysis is that the perfectly competitive capital markets cost of capital is

$$z = [Pk + Li]/[P + L]$$

when the current and coupon rates of interest are the same. The traditional cost of capital is

$$z = [Ek + Bc]/[E + B].$$

In these expressions P and L are the market values of the utility's common equity and debt, E and B are the book values or historical costs of these quantities, i and c are the current yield and imbedded interest rates on the firm's debt, and k is the yield at which the utility's stock is selling.

Of the variables required to measure the perfect capital markets and traditional cost of capital the only one that poses any problems is the yield at which the utility's stock is currently selling. Regardless of how share yield may vary with leverage or other variables, its value, given these variables, is the sum of the dividend yield and the *expected* rate of growth in the dividend. The latter quantity is difficult to measure accurately, and chapter 5 investigates alternative approaches to the problem. Sample data for 54 utility companies over the eleven-year period 1958–1968 are used along with theoretical analysis to test and choose among alternative rules for measuring expected growth and share yield.

Chapter 6 has two purposes. One is to use the chapter 5 measure of share yield and sample data to illustrate the implementation of both cost of capital measures and to examine the data that result. The other purpose is to test the security valuation assumptions under which each theory is true. On the implementation, we find that every firm in every year had a market-book value ratio greater than one. Hence, if either of these theories is true, every firm in every year had an allowed rate of return in excess of its cost of capital. The ratio of the allowed rate of return to the traditional cost of capital was on average much smaller than the market-book value ratio, and the relation between these ratios varied over a wide range among firms. Hence, the market-book value ratio only can be used to determine the direction in which the allowed rate of return should be changed. To estimate what the allowed rate of return should be under the traditional cost of capital theory, the formula presented above should be used.

Turning to the perfect capital markets data, we frequently encounter firms with a cost of capital above the allowed rate of return notwithstanding a market-book value ratio above one and a return on common above the firm's share yield. Further analysis reveals that this surprising state of affairs is due to the fact that the perfect capital markets cost of capital can be measured without bias only in the special and uninteresting case where the allowed rate of return already is equal to the cost of capital. When the allowed rate of return is above (below) the "true" cost of capital, the measured cost of capital is biased up (down). The existence of another measurement formula which avoids this bias is uncertain.

In testing the two theories, the evidence with regard to leverage clearly supports the traditional theory and provides absolutely no basis for accepting the perfect capital markets leverage theorem. The security valuation assumptions common to both theories, that share yield is independent of the firm's retention and stock financing rates, imply that share yield is independent of the expected growth in the dividend. The data provide strong evidence that, on the contrary, share yield is an increasing function of the growth rate. It is further shown that share risk is an increasing function of the share's rate of return, retention rate, and stock financing rate. Since the yield investors require on a share increases with its risk, this test provides further support for the conclusion that share yield increases with the firm's retention and stock financing rates.

Chapter 7 presents the theoretical bases for the findings just described. The institutional arrangements under which capital markets operate, the properties of shares, and the preferences of investors make personal leverage a poor substitute for corporate leverage and make the traditional theory on the relation between share yield and leverage more accurate than the perfect capital markets theory. The reasons why we might expect share yield to increase with both forms of equity financing also are examined.

Chapter 8 builds a stock value model which incorporates our knowledge of how investors value shares and which recognizes the influence on share price of a firm's allowed rate of return, its investment policy, and its financing through debt, retention, and the sale of stock. Expressions for the cost of capital from each source are obtained, and as one would expect each cost of capital is a function of the level of financing. However, there are two solutions to the cost of capital from each source depending on which of two policies the regulatory agency follows. Under what will be called the *constrained policy*, the utility is permitted to take its rate of return on assets as given in making its investment and financing decision. As a consequence, the agency must set the rate of return so that the price of the stock is maximized at the investment rate the public interest requires. Under this policy not only the cost of capital but also its ratio to the return on common equity and the market-book value ratio for the common stock are

increasing functions of the investment rate. Furthermore, under this policy the regulatory agency must determine the investment rate the public interest requires and estimate the parameters of the stock value model in order to arrive at the cost of capital or allowed return on assets for the desired investment rate.

The other policy available to the regulatory agency stems from the bilateral monopoly relation between the utility and the agency. The latter may adjust the allowed rate of return on assets to keep the market-book value ratio of the common stock a constant. If this ratio is set so that the market value exceeds the book value by the difference between share price and the proceeds to the firm on a stock issue, the stockholders are indifferent to the firm's investment rate and its financing. The return on assets that realizes this market-book value ratio, therefore, is the utility's cost of capital. Under this policy the cost of debt capital is a saucer-shaped function of the leverage rate. The costs of retention and stock capital depend on the values of the parameters, but they typically are increasing functions of the utility's investment rate, and they are lower at every investment rate over the relevant values of the investment rate than under a constrained policy. Furthermore, the bilateral monopoly policy requires of the agency far less information. It is not required to estimate the parameters of the stock value model or the investment rate the public interest requires. The latter may be left to the utility. However, the cost of capital does depend upon the utility's financial policy, and if the management has an interest in the financial policy apart from the stockholders, simply maintaining the required market-book value ratio may not result in the lowest possible rate of return on assets. The agency, therefore, serves the consumer interest by establishing the cost of capital under an optimal financial policy and allowing a utility that rate of return.

Chapter 9 uses the sample data for the 54 firms and eleven years in a combined time series cross-section regression analysis to test the model and to estimate its parameters. The equation explains the variation in share price across firms and over time very well. Furthermore, all the parameters involved in cost of capital measurement have the correct sign and are statistically significant. One interesting finding is the very high correlation between share yield and the interest rate on long-term bonds as the latter varies over time. Chapter 9 also uses the model and its parameter estimates to obtain illustrative data on the cost of capital from each source under the constrained and the bilateral monopoly policies for the sample mean firm in selected years.

Chapter 10 describes the use of the model to obtain a utility's overall cost of capital and presents illustrative data for the sample mean firm in 1963 and 1968 under the constrained and the bilateral monopoly policies. Maintaining a debt-equity ratio is not a source of funds, and reasons are given for not using changes in that ratio as a long-run source of funds under both policies. Hence, given a debt-equity ratio arrived at to either minimize the overall cost of capital in the long run or provide a satisfactory risk situation, the combination of retention and stock financing which minimizes the cost of capital at each investment rate is established.

The chapter then presents a comparative analysis of the rate of return actually allowed and the alternative cost of capital figures for the sample mean firm in 1963 and 1968. In both years the allowed rate of return was above the constrained policy cost of capital and above the bilateral monopoly cost of capital. This relation held for all the firms in each of the years 1958 through 1968. The traditional theory cost of capital appears to be above the bilateral monopoly values, but, when allowance is made for its incorrect assumptions on how investors value shares, the cost of capital is the same under both theories. In fact, the traditional theory overstates a utility's true (bilateral monopoly) cost of capital only when the utility is allowed a rate of return in excess of the traditional formula cost of capital. The spread between the actual return on assets and the bilateral monopoly cost of capital has narrowed considerably since 1968, and it is possible that some firms now earn little if anything more than their cost of capital.

The remainder of chapter 10 is devoted to drawing some conclusions on regulatory policy, the reactions of utility companies, and the implications of both for the allowed rate of return, financing and investment behavior, and consumer welfare.

2

Perfectly Competitive Capital Markets

Our problem is to establish the rate of return a utility should be allowed to earn. As outlined in chapter 1, our formulation of the problem assumes that the objective of the regulatory agency is to allow the utility the lowest rate of return consistent with the investment in plant equipment by the utility that satisfies the demand for its output, and the objective of the utility is to maximize the market value of its outstanding common equity. As formulated, the problem's solution requires that we establish how investors value a utility's common stock since this will determine how a utility's price per share responds to the regulatory agency's rate of return decisions and the utility's investment and financing decisions.

This chapter will state the general principles of share valuation and then establish how a utility's share price and cost of capital respond to alternative investment and financing plans under the assumption that the stock market is perfectly competitive. The first three sections deal with single period stock issue, debt and retention financed investment decisions. The next three sections assume that the utility is expected to invest and finance by each of these methods continuously at some rate over time. It will be seen that the conclusions reached hold under quite general assumptions with regard to a utility's investment and financing plans. The models developed provide the basis for subsequent implementation and testing.

2.1 General Model of Share Valuation

The value of a share of stock, like the value of any other asset, may be represented as the present value of the future cash flows it is expected to provide. Let V_0 = the present value of a share of stock, D_t = the dividend the share is expected to pay in period t, P_n = the price at which the share is expected to sell at the end of $t = n$, and k = the discount rate that converts a cash flow during or at the end of period t to its present value. For an investor with a one period horizon,

$$V_0 = \frac{D_1 + P_1}{1 + k}. \tag{2.1.1}$$

For an investor with an n period horizon,

$$V_0 = \sum_{t=1}^{n} \frac{D_t}{(1 + k)^t} + \frac{P_n}{(1 + k)^n}, \tag{2.1.2}$$

and for an investor with an infinite horizon,

$$V_0 = \sum_{t=1}^{\infty} \frac{D_t}{(1 + k)^t}. \tag{2.1.3}$$

Alternatively, we could say Eq. (2.1.3) is equivalent to Eq. (2.1.2) by assuming that the price at which a share is expected to sell at the end of $t = n$ is

$$P_n = \frac{D_{n+1} + P_{n+1}}{1 + k}. \tag{2.1.4}$$

The dividend that a share will pay during $t = n$ and its price

at the end of $t = n$ are uncertain at $t = 0$. Therefore, D_t for $t = 1, 2, \ldots, n$ and P_n as of $t = 0$ are the expected values of these variables.

An investor may be represented as estimating the expected values of D_t and P_n, deciding on a value of k for the share, and computing V_0. By comparing V_0 with the actual current price of the share, P_0, the investor decides whether to buy, sell, or hold the share. Our objective is not to arrive at investment recommendations; therefore, we are not interested in determining V_0 for a share. Our objective is to explain the current price for a share. Accordingly, we postulate some consensus or average among investors for D_t, P_n, and k for a share. These market averages for the variables yield $V_0 = P_0$, the current price of a share.[1]

The particular equation that will be the basis for the models that follow is:

$$P_0 = \sum_{t=1}^{\infty} \frac{D_t}{(1 + k)^t}. \tag{2.1.5}$$

It is not convenient to use models with P_n on the right-hand side for two reasons. First, it is difficult to represent P_n as a function of a firm's rate of return and its investment and financing decisions. Second, in empirical work it is difficult to arrive at a defensible estimate of P_n on any basis other than a "hot tip." By contrast, one can represent D_t, $t = 1, 2, \ldots, \infty$ as a function of the variables mentioned above, and defensible objective estimates of D_t can be obtained. With P_0 known and with defensible estimates of D_t, the value of k for a share can be derived.

We have referred to k as the discount rate that converts a future payment to its present value. k also may be referred to as the rate of return that the market requires on a share, or as the yield at which the share is selling, or the rate of return the market expects to earn on the share. Given P_0 and D_t, $t = 1, 2, \ldots, \infty$, the value of k that satisfies Eq. (2.1.5) is each of these quantities. If the yield the market (all investors on average) requires on a share is above

[1] There are, of course, other plausible representations of how a share or any other asset is valued; for example, see A. A. Robichek and S. C. Myers [38, pp. 67–93]. The one adopted appears most useful both for theoretical reasons and for empirical implementation.

the value of k that satisfies Eq. (2.1.5), the price per share will fall until k is equal to the yield investors require on the share. The market, of course, then expects to earn a rate of return of k on the share.

The yield at which a share is selling is quite different from the yield an investor (or the market) realizes on a share over a period of time. At the end of $t = 1$ the return realized on holding a share from $t = 0$ to $t = 1$ is known precisely. Solving Eq. (2.1.1) for k, with P_0 substituted for V_0, results in

$$k = \frac{D_1}{P_0} + \frac{P_1 - P_0}{P_0}. \tag{2.1.6}$$

The realized yield on a share is the dividend yield plus the rate of growth in price. It may be positive or negative, and it varies over a wide range from period to period. By contrast, the required yield at each point in time cannot be negative (since no one will hold a share with the expectation he will lose money doing so), and it fluctuates in a reasonably narrow range.

2.2 A Stationary Firm

A useful point of departure in the development of our theory of stock valuation is to apply the previous model to a stationary, debt-free firm. This purely hypothetical firm has no debt in its capital structure and is not expected to undertake any investment and financing. That is, the firm is not expected to sell shares, issue debt, or retain earnings, all of which involve obtaining funds for investment.

The symbols that frequently will be used in this and the following chapters are defined below:

P = price per share of stock;
E = book value per share of stock;
N = number of shares outstanding;
D = dividend per share of stock;
Y = earnings per share of stock;
L = market value of debt on a per share basis;
B = book value of debt on a per share basis;

i = current rate of interest;
c = coupon or imbedded interest rate on outstanding debt;
r = rate of return on common equity investment;
π = Y/E = rate of return on common equity (at book value);
x = $(E\pi + Bc)/(E + B)$ = rate of return on total assets (at book values);
k = yield at which share is selling;
ρ = value k would have if the firm had no debt in its capital structure; and
z = cost of capital.

Where the meaning is clear, a symbol without a subscript refers to its current value and/or its value in every future period. That is, P is P_0, and x means $x_t = x$ for $t = 1, 2, \ldots, \infty$.

Returning to our stationary firm, with no investment and financing, it is reasonable to expect earnings in every future period to be the same as current earnings. Furthermore, the dividend in each period will be equal to the earnings, and with no debt in the capital structure, Eq. (2.1.5) becomes

$$P = \sum_{t=1}^{\infty} \frac{Y}{(1 + k)^t} = \frac{Y}{\rho} = \frac{Ex}{\rho}. \tag{2.2.1}$$

The price per share is the multiple $1/\rho$ of the current earnings per share.

A word on the measurement of k at this point may be useful. The yield investors require on a share cannot be observed directly. It only can be inferred from the price and the dividend expectation. For a firm that satisfies the conditions leading to Eq. (2.2.1) we can establish $k = \rho = Y/P$. In general, if the dividend is not expected to grow, $k = D/P$, which is equal to Y/P since $D = Y$. Given a number of firms which satisfy the above conditions, we can establish k by observing Y and P for each. k will vary among the shares, and a theory of security valuation explains the variation in k among the shares.

Eq. (2.2.1) may be used to illustrate how a share's price adjusts so that k is the yield investors require and expect on a share. Let Y = \$1.00 and P = \$12.50, so that k = .08 or 8 percent. If the share loses favor with investors so that the required yield rises to 10 percent, they will sell the stock and/or refrain from buying it. The consequence will be a fall in the price until P reaches \$10.00 and $k = .10$. During this period, the return realized by an individual who held the share would not be 8 or 10 percent, but −12 percent since

$$k \text{ realized} = \frac{\$1.00 + \$10.00 - \$12.50}{\$12.50} = \frac{-\$1.50}{\$12.50}$$
$$= -.12. \qquad (2.2.2)$$

Alternatively, assume k remained unchanged between $t = 0$ and $t = 1$, but with $Y_0 = \$1.00$, Y_1 falls to \$.50, and the expected future earnings and dividends per period fall from \$1.00 to \$.80. We then would have $P_1 = \$.80/.08 = \$10.00$, and

$$k \text{ realized} = \frac{\$.50 + \$10.00 - \$12.50}{\$12.50} = \frac{-\$2.00}{\$12.50}$$
$$= -.16. \qquad (2.2.3)$$

2.3 Cost of Capital: Stock Financing

Assume that the company discussed in the previous section is a utility, that it decides to consider an investment which costs I, and that it is expected to earn a rate of return equal to x, the rate of return on its existing capital.[2] Assume also that if the investment is undertaken it will be financed with the sale of stock and that no further investment is contemplated thereafter.

If the return investors require on a share of stock is independent of the number of shares placed on the market, the number of shares that must be issued to finance the investment is $n = I/P$. Before the issue is marketed, investors will be advised of the company's plans and expectations so that P will change to reflect the expected consequences of the investment and financing. Furthermore, the P that enters into the determination of n, the number of shares

[2] It will be shown in chapter 3 that it is correct to take a utility's rate of return on its existing capital as its rate of return on investment.

issued, is this new P. Hence, the utility may reckon that the investment and financing will change P from its Eq. (2.2.1) value to

$$P = \frac{(NEx + Ix)/(N + n)}{\rho}$$
$$= \frac{NEx + Ix}{\rho(N + I/P)}. \qquad (2.3.1)$$

Simplifying Eq. (2.3.1) results in

$$P = \frac{NEx + I(x - \rho)}{N\rho}. \qquad (2.3.2)$$

If $x = \rho$ it is clear that Eq. (2.3.2) reduces to Eq. (2.2.1), and the investment will not change the price per share. On the other hand, if $x > \rho$, P rises and vice versa.

A numerical illustration may be helpful. Assume that initially $E = \$10.00$, $x = .10$, $N = 10{,}000$, and $\rho = .08$. Then $P = Ex/\rho = \$12.50$. If the company announces the intention to issue shares to finance an investment that costs $I = \$20{,}000$ with a rate of return of $x = .10$, the market will react in the following way. It will calculate the price, number of shares, and earnings per share that will result in the sale of additional shares at a price that provides the current yield of .08. That price is

$$P = \frac{(\$10.00)(10{,}000)(.10) + (\$20{,}000)(.10 - .08)}{(10{,}000)(.08)}$$
$$= \frac{\$1.04}{.08} = \$13.00. \qquad (2.3.3)$$

If P rises above \$13.00, new investors would be buying the stock to yield less than 8 percent and vice versa. Either of these outcomes contradicts our assumption that new shares are sold to realize the same rate of return that the existing shares are yielding. The rise in the price per share by \$.50 enables the existing shareholders to capture the difference between $x = .10$ and $\rho = .08$ in the form of a capital gain.[3]

With $x > \rho$ the issue raises the price per share; given the objective of maximizing the price per share, the utility management may be expected to undertake the investment. It clearly should not do so if $x < \rho$. With $x = \rho$ price per share is unchanged, stockholders are indifferent to the decision, and management may be expected to undertake the investment if the public requires the capacity.

It is customary to call the rate of return on an investment that leaves the price per share or value of the existing common equity unchanged a company's cost of capital. Therefore, under the assumptions made we have established that a utility's cost of new equity capital, z, is equal to ρ. In chapter 1 it was established that the regulatory agency should set the utility's rate of return on assets at $x = z$. Hence, it should set $x = \rho$. The simplifying assumptions with respect to the firm's financial structure and investment and financing plan may be withdrawn without changing the conclusion (as will be seen in chapter 3). The assumption that the yield investors require on a share is independent of the number of shares placed on the market, however, is critical to the conclusion that the cost of new equity capital is equal to ρ. For this assumption to be true it is necessary that the market for utility shares be perfectly competitive. Arguments for and against believing this is true will be examined in chapter 5.

One relatively unimportant qualification to the perfectly competitive capital markets assumption may be dealt with now. Normally, a new issue is sold through an investment banker who buys the issue for resale at a discount off the market price. If the investment banker buys the issue at the fraction $1 - \psi$ of the market price, the number of shares issued is $n = I/P(1 - \psi)$, and it can be shown that the cost of new equity capital becomes $\rho/(1 - \psi)$. If $\psi = .05$, this raises the cost of capital by only about 5 percent, in our previous illustration from .08 to .0842. Usually existing shareholders are given rights to purchase the new issue at a discount

[3]Notice that the entire difference between the return on the investment and the yield at which the stock is selling accrues to the shareholders at the time the investment opportunity is discovered. The investors who buy the new shares obtain nothing they could not have obtained if the investment opportunity had not been discovered.

off the market price at the announcement date, and the investment banker purchases all unsold shares. This does not change the conclusion that the cost of the capital is $\rho/(1 - \psi)$, regardless of subscription discount.[4] In return for this commitment the investment banker is given a fee equal to a fraction ψ of the value of the stock. ψ is smaller on a rights offering than on an issue placed directly on the market.

2.4 Cost of Capital: Debt Financing

Instead of selling stock to finance the investment, let our utility issue debt. Let the amount borrowed per share outstanding be $L = I/N$. The expression for the price per share changes from the Eq. (2.2.1) value to

$$P = \frac{Ex + L(x - i)}{k}. \tag{2.4.1}$$

We now use k instead of ρ for the discount rate since the firm has debt in its capital structure. Also, the number of shares outstanding does not change, and the earnings per share increased from $Y = Ex$ to $Y = Ex + L(x - i)$ on the assumption that $x > i$.

If k is independent of the amount of leverage in the utility's capital structure, it is clear that $k = \rho$ and that the investment raises P if $x > i$. The cost of debt capital, therefore, is the interest rate, i.

It is reasonable to believe, however, that as the leverage in a firm's capital structure increases, the risk on its shares increases, and the yield investors require on the stock rises. However, until a 1958 article by Franco Modigliani and M. H. Miller [34], there was no theoretical basis for deciding how k increases with the amount of debt in a firm's capital structure. They argued that a rational investor should be indifferent between leverage on personal account and leverage on corporate account. They went on to

[4]It is easily shown that a rights issue is merely a stock dividend and an ordinary issue combined in a way that puts the burden of disposing of the new issue on the stockholders. If the rights sell at their so-called theoretical value, the stockholders neither gain nor lose as a consequence of being involved in the issue.

demonstrate that if this proposition is true the stock of a levered corporation should sell at a yield of

$$k = \rho + (\rho - i)(L/P), \tag{2.4.2}$$

where L and P are the market values of the debt and equity on a per share basis.

The authors' proof was somewhat difficult, and we simply will provide an intuitive basis for understanding their theorem. Assume an unlevered corporation with P, Ex, and ρ, the price, earnings, and yield on a per share basis. An investor with wealth equal to QP can borrow QL and invest the sum $Q(P + L)$ in the corporation's stock. For simplicity, let $Q = 1$. The individual can expect to earn on his equity in the stock he owns a periodic income of Y_p, where

$$Y_p = P\rho + L(\rho - i). \tag{2.4.3}$$

Since the share's expected yield is ρ, he can expect to earn ρ on P and on L, and he pays interest at the rate i on L. Notice that the individual has constructed a levered earnings stream from an unlevered one.

Dividing Eq. (2.4.3) through by P we find that the return the investor expects to earn on his equity in the stock he owns is[5]

$$k_p = \rho + (\rho - i)(L/P). \tag{2.4.4}$$

If the investor considers the risk and the other relevant characteristics of corporate leverage at the rate L/P as identical to personal leverage at that rate, Eq. (2.4.4), the yield he can earn on personal leverage at the rate L/P, is the yield the investor requires on a share of stock with corporate leverage at the rate L/P. Hence, Eq. (2.4.2), which is equal to Eq. (2.4.4), is the yield investors require on a share in a corporation with leverage at the rate L/P.

[5] He owns $(P + L)/P$ shares with a market value of $P + L$, and his equity in the shares is P.

Substituting Eq. (2.4.2) for k in Eq. (2.4.1), the latter becomes

$$P = \frac{Ex + L(x - i)}{\rho + (\rho - i)(L/P)}$$

$$= \frac{Ex + L(x - \rho)}{\rho}. \tag{2.4.5}$$

It is evident that a debt financed investment can be expected to raise the price per share if $x > \rho$ and leave P unchanged if $x = \rho$. Hence, the utility's cost of debt capital, like its cost of new equity capital, is $z = \rho$, the yield at which its stock would sell in the absence of leverage.

Before proceeding it may be useful to restate the argument. An investor whose wealth is invested in an unlevered corporation's stock will have his expected earnings increase if the corporation engages in debt financing. However, if the rate of return the corporation expects to earn on the investment is equal to the yield at which its unlevered stock sells, an investor can obtain the same earnings expectation through personal leverage. Therefore, if he is indifferent about the source of leverage, the yield at which the share would sell with corporate leverage at the rate L/P must be equal to the yield the investor can expect with personal leverage at the rate L/P. Consequently, corporate leverage with the return on investment $x = \rho$ will not raise or lower the price per share—the required yield on the share rising proportionately with the expected earnings. However, if the rate of return on investment that the corporation expects to earn is $x > \rho$, the investor cannot obtain with personal leverage what the corporation can do for him, and the corporate leverage will raise the share's price as well as its expected earnings.

The Modigliani-Miller theorem requires that investors consider personal leverage a perfect substitute for corporate leverage. This will be true if the capital markets are perfectly competitive. Specifically, the theorem is true if the terms, including the interest rate and maturity at which individual investors and corporations can borrow, are identical.

2.5 Cost of Capital: Retention Financing

The third major source of funds for investment is the retention of earnings. Assume that the utility considers financing the investment of I by retaining that amount of earnings during the current year. The dividend per share in period one would be reduced from $D_1 = Y = Ex$ to $D_1 = Ex - bEx$, where $bEx = I/N$. The fraction of the earnings per share retained is $b = I/NEx$, where NEx is earnings on the total common equity. Assuming that no further investment is contemplated, the dividend in every subsequent year is raised from Ex to $Ex + xbEx$. The retention raises the common equity per share by bEx, and a return of x is expected on the investment.

The retention financing changes the expression for the price per share from the Eq. (2.2.1) value to

$$P = \frac{Ex - bEx}{1 + \rho} + \sum_{t=2}^{\infty} \frac{Ex + xbEx}{(1 + \rho)^t}$$

$$= \frac{\rho(Ex - bEx)}{\rho(1 + \rho)} + \frac{Ex + xbEx}{\rho(1 + \rho)}$$

$$= \frac{Ex}{\rho} + \frac{bEx(x - \rho)}{\rho(1 + \rho)}. \tag{2.5.1}$$

Once again the investment of I raises the price per share if $x > \rho$, the leverage-free yield at which the share is selling. Hence, the cost of retention capital as well as the cost of new equity and debt capital is $z = \rho$; regardless of the method of finance the regulatory agency should set $x = \rho$.

2.6 Continuous Retention Financing

If a utility currently is retaining the fraction b of its income, a plausible hypothesis is that it is expected to retain that fraction for the indefinite future. If the utility has no debt and if it is expected to earn a return of x on its investment, its income in the coming period is expected to be

$$Y_1 = Y_0 + xbY_0 = Y_0(1 + bx). \tag{2.6.1}$$

Y_1 will be larger than Y_0 by the return of x on the increase in the common equity of bY_0. By the law of compound interest, income in period t is expected to be

$$Y_t = Y_0(1 + bx)^t. \tag{2.6.2}$$

With b the fraction of income retained, the dividend in t is expected to be $D_t = (1 - b)Y_t$. Hence, bx is the expected rate of growth in the dividend and income.

Substituting Eq. (2.6.1) for Y_t and $(1 - b)Y_t$ for D_t in Eq. (2.1.5), the latter now becomes[6]

$$P = \sum_{t=1}^{\infty} \frac{(1 - b)Y_0(1 + bx)^t}{(1 + \rho)^t}. \tag{2.6.3}$$

The above summation is finite and may be carried out if $\rho > bx$. In that event,

$$P = \frac{(1 - b)Y}{\rho - bx}, \tag{2.6.4}$$

where P is the price at the start of period one, and Y is the expected income in $t = 1$. The price per share is equal to the current dividend divided by the amount by which the required yield exceeds the expected rate of growth in the dividend.

To establish the influence of retention financed investment on P, we take the derivative dP/db. Making the perfectly competitive capital markets assumption that ρ is independent of b,

$$\frac{dP}{db} = (x - \rho)\frac{Y}{(\rho - bx)^2}. \tag{2.6.5}$$

$dP/db = 0$ if $x = \rho$. Hence, the cost of retention capital remains ρ under the expectation of continuous retention and investment.

[6] The discount rate is ρ, the value of k when the firm has no debt in its capital structure.

This model has been objected to on the following grounds. If $x > \rho$ with both independent of b, price rises continuously with retention so that $b = 1$ is optimal if that is the upper limit on b. However, with $b = 1$, $\rho < bx$, and we cannot go from Eq. (2.6.3) to Eq. (2.6.4). Furthermore, with $b = 1$, $D = 0$, and we obtain nonsense results on that count. There are various ways out of the dilemma. One possibility is to make x a decreasing function of b. Another is to make ρ an increasing function of b. However, the first solution contradicts the proposition to be proved in chapter 3, namely, that a utility's return on investment in any time period is independent of the level of investment. The second solution contradicts the perfectly competitive capital markets assumption. Furthermore, while either or both solutions reduce the likelihood of finding $b = 1$ optimal and/or $\rho < bx$, they do not guarantee an answer to the problem.

The dilemma of an infinite price as a consequence of $\rho = bx$ and a zero price as a consequence of $b = 1$ may be avoided by giving up the assumptions that a firm is expected to earn at the rate x and retain at the rate b indefinitely. If the current values of b and x are not very large, it is reasonable to believe investors expect these values to continue indefinitely. However, if x is very large, investors are likely to believe it will be reduced at some time in the future, and at that time the retention and investment rates also will be reduced. A model that reflects this change in the dividend expectation's rate of growth is presented on pages 33–34.

Recall that if a utility's dividend is equal to its earnings and that if the earnings are not expected to grow, we can take the yield at which the share is selling as being $\rho = Y/P$, with $\rho = k$ on the assumption of no leverage. If the dividend in $t = 1$ is $(1 - b)Y_1$, and if it is expected to grow at the rate bx indefinitely, the yield at which the share is selling is

$$\rho = \frac{(1 - b)Y}{P} + bx. \tag{2.6.6}$$

Eq. (2.6.6) is Eq. (2.6.4) solved for ρ.

It is instructive to compare Eq. (2.6.6) with Eq. (2.1.6), the latter being the one period realized value for k. In both, k is the current

dividend yield plus a rate of growth. In Eq. (2.1.6) the growth rate is the realized growth in the price of the stock, while in Eq. (2.6.6) the growth rate is the *expected* rate of growth in the dividend. Earnings and price are expected to grow at the same rate.

It also is instructive to see what happens when we set $x = \rho$. In that event Eq. (2.6.4) becomes

$$P = \frac{(1 - b)Y}{\rho(1 - b)}. \tag{2.6.7}$$

Hence, if $x = \rho$, we may take Y/P as the measure of ρ regardless of b. However, it cannot be assumed that $x = \rho$, and the earnings yield cannot in general be used as a measure of ρ.

2.7 Continuous Debt Financing

Assume now that the utility has some debt in its capital structure. The utility still is expected to retain and invest the fraction b of its income, but it also is expected to borrow and invest an amount periodically that maintains its existing debt-equity ratio. The ratio that the utility is expected to maintain under the perfectly competitive capital markets (PCCM) theory is L/P, which is based on the market values of the debt and common equity rather than B and E, their book values.

With some debt in the capital structure, the amount the utility will earn on its common equity during $t = 1$ no longer is $E_0 x$ but is

$$Y_1 = xE_0 + (x - c)B_0. \tag{2.7.1}$$

In addition to a return of x on E_0, the utility will earn x on the book value of its debt and pay interest at the coupon or imbedded rate on the book value of its outstanding debt. During period one the utility is expected to retain bY_1 and increase its debt by an amount ΔB_0. The utility is expected to earn a return of x on both bY_1 and ΔB_0 and pay interest at the current rate i on the debt. Hence,

$$Y_2 = Y_1 + xbY_1 + (x - i)\Delta B_0. \tag{2.7.2}$$

The value of ΔB_0 may be determined as follows. With bY_1 the increase in the common equity at book value, and with P_0/E_0 the market-book value ratio, the increase in the common equity at market value is $bY_1(P_0/E_0)$. If the utility is to maintain its debt-equity ratio at market value unchanged, as assumed above, ΔB_0 must be the fraction L_0/P_0 of $bY_1(P_0/E_0)$. Hence,

$$\Delta B_0 = (L_0/P_0)bY_1(P_0/E_0) = bY_1(L_0/E_0), \tag{2.7.3}$$

and from Eq. (2.7.2),

$$\begin{aligned} Y_2 &= Y_1 + xbY_1 + (x-i)bY_1(L_0/E_0) \\ &= Y_1[1 + br_1], \end{aligned} \tag{2.7.4}$$

where

$$r_1 = x + (x-i)(L_0/E_0). \tag{2.7.5}$$

The debt-equity ratio at $t = 0$ in this expression is the debt at market value and the equity at book value.

The Eq. (2.7.5) value of r is the added income to the common divided by the increase in common equity in period one. Therefore, it may be called the return on common equity investment during period one. Further assumptions are necessary to establish the return on common equity investment in subsequent periods. If the current interest rate i is different than the coupon rate c, and if future borrowing is expected to take place at the interest rate i, L/E will change over time. Chapter 4 will consider the problems posed by $i \neq c$. This chapter assumes that $i = c$, in which case $L = B$. In that event, the return on common equity investment in every future period is expected to be

$$r = x + (x-c)(B/E). \tag{2.7.6}$$

Furthermore, $r = \pi$, where π is the return on the existing common equity.

On the basis of the preceding argument, income in period t is expected to be

$$Y_t = Y_0[1 + br]^t, \tag{2.7.7}$$

with $r = \pi$ given by Eq. (2.7.6). Substituting $(1 - b)Y_t$ for D_t and Eq. (2.7.7) for Y_t in Eq. (2.1.5), we now have

$$\begin{aligned} P_0 &= \sum_{t=1}^{\infty} \frac{(1-b)Y_0(1+br)^t}{(1+k)^t} \\ &= \frac{(1-b)Y}{k - br}, \end{aligned} \tag{2.7.8}$$

where k is the yield on a share with a leverage rate of L/P. Eq. (2.7.8) is the same as Eq. (2.6.4) with r replacing x and k replacing ρ. The measure of share yield remains the dividend yield plus its expected rate of growth.

The cost of retention capital under the perfect capital markets assumptions remains equal to ρ. To see this note that Eq. (2.7.8) may be written as follows:

$$\begin{aligned} P &= \frac{(1-b)[Ex + L(x-i)]}{\rho + (L/P)(\rho - i) - bx - b(L/E)(x-i)} \\ &= \frac{(1-b)[Ex + L(x-i)] - L(\rho - i)}{\rho - bx - b(L/E)(x-i)}. \end{aligned} \tag{2.7.9}$$

It can be shown that the derivative with respect to b is

$$\frac{dP}{db} = (x - \rho)\frac{[x + (L/E)(x-i)](L+E)}{[\rho - bx - b(L/E)(x-i)]^2}. \tag{2.7.10}$$

The right-hand side of Eq. (2.7.10) is $x - \rho$ multiplied by a quantity that is positive if $x > i$. Hence, $dP/db = 0$ if $x = \rho$, and the cost of retention capital when the firm maintains a leverage rate of L/P is equal to ρ.

With the debt-equity ratio given so that the retention rate is the only financing and investment decision, we have seen that the cost of capital remains equal to ρ. In addition to the debt financing involved in maintaining a debt-equity ratio, a utility may change its leverage rate. It can be shown that when $x = \rho$ the share price is independent of the firm's leverage rate. Hence, the cost of debt capital remains equal to ρ when retention is present.

2.8 Continuous New Equity Financing

In addition to or as an alternative to expanding through the periodic retention of earnings, a utility can expand through the sale of stock.[7] Consideration of the sale of stock as a source of funds requires the introduction of the following variables not listed previously.

- W_t = total common equity at end of period t;
- W_t^* = total common equity at end of t that accrues to shareholders at $t = 0$;
- s = funds raised from the sale of stock as a fraction of existing common equity;
- Q_t = funds raised from sale of stock during t; and
- v = fraction of Q_t that accrues to shareholders at the start of t.

Let a utility's total common equity at $t = 0$ be $W_0 = NE_0$, and let the expected rate of growth in the common equity due to the sale of stock be s. The common equity one period later will be

$$W_1 = W_0 + bNY_1 + sW_0. \tag{2.8.1}$$

Since $NY_1 = rW_0$,

$$W_1 = W_0 + brW_0 + sW_0 = W_0[1 + br + s], \tag{2.8.2}$$

and

$$W_n = W_0[1 + br + s]^n. \tag{2.8.3}$$

In each period the total equity is raised by the fraction br due to retention and by s due to the sale of additional shares.

At the end of $t = n$ the total common equity will include the equity of the shareholders at $t = 0$ and the equity arising from

[7] This section is based on chapter 9 of M. J. Gordon [15].

the sale of shares from $t = 0$ through $t = n$. What we are interested in, however, is the expected equity and the dividend at $t = n$ on a share outstanding at $t = 0$. Let $Q_n = sW_{n-1}$ be the funds raised from the sale of stock during n, and let v be the fraction of the funds provided during n that accrues to the shareholders at the start of n. The meaning and derivation of v will be developed in the course of what follows.

Let W_n^* be the portion of the total common equity at the end of $t = n$ that belongs to the share outstanding at $t = 0$. Then

$$W_1^* = W_0 + brW_0 + vsW_0, \tag{2.8.4}$$

and

$$W_n^* = W_0[1 + br + vs]^n. \tag{2.8.5}$$

Dividing both sides of Eq. (2.8.5) by N and multiplying by r, we obtain

$$Y_{n+1}^* = Y_1[1 + br + vs]^n. \tag{2.8.6}$$

The earnings on a share at $t = 0$ are expected to grow at the rate br due to retention and at vs due to the sale of additional stock. Making the indicated substitutions, our stock value model becomes

$$P = \sum_{t=1}^{\infty} \frac{(1 - b)Y[1 + br + vs]^{t-1}}{(1 + k)^t}. \tag{2.8.7}$$

If $k > br + vs$, Eq. (2.8.7) becomes

$$P = \frac{(1 - b)Y}{k - br - vs}. \tag{2.8.8}$$

The only change in Eq. (2.7.8) necessary to recognize the expectation of continuous stock financing at the rate s is the change in the expected rate of growth to $br + vs$.

The meaning of v may be explained simply as follows. When a new issue is sold at a price per share $P = E$, the equity of the new shareholders in the firm is equal to the funds they contribute, and the equity of the existing shareholders is not changed. However, if $P > E$, part of the funds raised accrues to the existing shareholders. Specifically, it can be shown that

$$v = 1 - \frac{E}{P} \tag{2.8.9}$$

is the fraction of the funds raised by the sale of stock that increases the book value of the existing shareholders' common equity. Also, v is the fraction of earnings and dividends generated by the new funds that accrues to the existing shareholders.

A more rigorous derivation of v follows. If the market for a firm's new shares is perfectly competitive, the number of shares given to new shareholders during $t = n$ in return for Q_n dollars must satisfy two conditions. The first is that the new issue must be sold at the prevailing price per share at the time of the issue. The other condition is that the dividend expectation a new shareholder obtains should have a present value equal to Q_n, the money he invests, when discounted at the rate k. With r the return the utility earns on common equity investment, b the retention rate, and $(1 - v) Q_n$ the book value of the common equity obtained by the new shareholders, their dividend in $n + 1$ will be

$$D^*_{n+1} = (1 - b)r(1 - v)Q_n. \tag{2.8.10}$$

Once in the corporation the new shares are identical with the old shares. Their dividends also are expected to grow at the rate $br + vs$. Hence, the above two conditions are satisfied if

$$Q_n = \sum_{t=n+1}^{\infty} \frac{(1 - b)r(1 - v)Q_n(1 + br + vs)^{t-n-1}}{(1 + k)^{t-n}}$$

$$= \frac{(1 - b)r(1 - v)Q_n}{k - br - vs}. \tag{2.8.11}$$

Dividing both sides of Eq. (2.8.11) by Q_n and solving for v, we obtain

$$v = \frac{r - k}{r - rb - s}. \tag{2.8.12}$$

It can be shown that Eqs. (2.8.12) and (2.8.9) produce identical values of v. The interesting property of Eq. (2.8.12) is that it makes clear that the cost of new equity capital is ρ for continuous new equity financing as well as one-shot new equity financing. When $r = k$, $v = 0$, and new stock financing at the rate s has no impact on P. Of course, if $r = k$ then $x = \rho$. When $r > k$, v is positive, and share price increases with s.

The assumption that a utility is expected to stock finance at the rate s has implications for the measurement of k. The yield at which a share with continuous growth at the rate g sells is

$$k = \frac{D}{P} + g, \tag{2.8.13}$$

the current dividend yield plus the expected rate of growth in the dividend. However, now $g = br + vs$ and not simply br. It also should be noted that continuous stock financing at the rate s poses problems similar to continuous retention at the rate b. When $k < br + vs$, the model breaks down in explosive growth. The above discussion of the resolution of the dilemma posed by $\rho < bx$ applies here. It also may have been noted from Eq. (2.8.12) that v is negative with $r > k$ when $r < rb + s$ or $r(1 - b) < s$. This is reasonable, although it may appear strange. Notice that $r(1 - b)$ and s are the outflow and inflow of funds due to dividends and stock financing expressed as fractions of the common equity. When $r(1 - b) < s$ the company is expected, in effect, to draw funds from stockholders for all future time. Clearly it is nonoptimal for a company to set $s > r(1 - b)$, and the case may be ignored.

2.9 *Finite Horizon Model*

We have seen that if $x > \rho$ and b and/or s are large we can have $k \leq g$, and our continuous growth models break down. A resolution of this dilemma consistent with the perfectly competitive capital markets assumptions is provided by withdrawing the assumption that the dividend is expected to grow at the current rate g for all future time. Specifically, a utility with a very large x reasonably will invest at a very high rate. The resultant high values of b and/or s when combined with the high values of r and v result in $k \leq g$. However, investors reasonably may expect that the high x will not last forever. After n periods x is expected to fall to a lower level, and r, v, b, and s also fall. If we assume that the current value of g is expected to prevail for n periods and that thereafter the dividend is expected to grow at a normal rate of $\breve{g}$, our stock value model becomes

$$\begin{aligned} P &= \sum_{t=1}^{n} \frac{(1-b)Y(1+g)^t}{(1+k)^t} \\ &+ \sum_{t=n+1}^{\infty} \frac{(1-b)Y(1+g)^n(1+\breve{g})^{t-n}}{(1+k)^t} \\ &= \sum_{t=1}^{n} \frac{(1-b)Y(1+g)^t}{(1+k)^t} \\ &+ \frac{(1-b)Y(1+g)^n(1+\breve{g})}{(1+k)^n(k-\breve{g})}. \end{aligned} \tag{2.9.1}$$

Eq. (2.9.1) produces a finite P with $k \leq g$ as long as $k > \breve{g}$.

With P known, Eq. (2.9.1) may be used to measure k since k is an implicit function of the other variables. Under this assumption with respect to a share's dividend expectation, k is an average of g and $\breve{g}$ plus the dividend yield. The relative importance of g and $\breve{g}$ in determining the measure of k depends on the value of n. As $n \to \infty$, the relative importance of $\breve{g}$ in the measurement of k declines. Using Eq. (2.9.1) to measure k requires the determination of n and $\breve{g}$ as well as g.

2.10 Conclusion

It has been established that, regardless of how investment is financed, a utility's cost of capital, z, is equal to ρ, the yield at which its stock would sell in the absence of leverage. When $x = \rho$, the price of a utility's stock is independent of its investment and financing decisions, and the stockholder is indifferent as to the level of investment and its financing. Hence $x = \rho$ is the lowest

rate of return the utility can be allowed to earn that is consistent with the investment decision that the public interest requires. This does not mean the stockholder is indifferent as to the level of x. Clearly P increases with x, and the happiness of stockholders increases with the level x. If $x > \rho$ initially the stockholder is made very unhappy by reducing x to ρ, but after that happens his well-being is not changed by the utility's investment decision. However, if $x < \rho$ the price of his stock is further reduced as the firm's investment is increased. Accordingly, one cannot expect a management acting in the stockholders' interest to undertake the investment required by the public interest when $x < \rho$. Conversely, $x > \rho$ will result in a higher investment decision as well as a higher consumer price than the public interest requires.

Our conclusion that ρ is a utility's cost of capital and therefore the rate of return a utility should be allowed to earn was based on certain assumptions as to how the yield investors require on a share responds to each financing and investment alternative. It was assumed that the yield investors require on a share is independent of the funds raised by the sale of additional shares, is independent of the funds raised by the retention of earnings, and increases with the funds raised by issue of debt in accordance with the Modigliani-Miller theorem on indifference between leverage on personal and corporate account. Without these assumptions, which sometimes are referred to as the perfectly competitive capital markets assumptions, ρ ceases to be the cost of capital and ceases to be the rate of return a utility should be allowed to earn on its capital.

3

The Special Consequences of Regulation

The previous chapter demonstrated that under a set of assumptions with regard to how investors value shares (called the perfectly competitive capital markets assumptions) a firm's cost of capital is ρ regardless of the firm's method of financing and level of investment. It will be recalled that ρ is the yield at which the firm's stock would sell in the absence of debt in the firm's capital structure, and it is determined by investors in the marketplace. We showed that ρ is the firm's cost of capital by demonstrating that if the firm is allowed a return of ρ on its assets the value or price per share at any point in time will be independent of the investment and financing decisions of the firm.

The stock value models employed to reach this conclusion were not perfectly general in that the firm's return on investment, the return on the book value of its existing assets, and the earnings in the current period divided by the book value of the existing assets were all equal. The same conclusion regarding a firm's cost of capital could have been reached without assuming this equality, which will not hold for an unregulated company. This chapter will demonstrate that regulatory practice makes these three rates of return all equal and that the models, therefore, have a concrete reality that is useful for implementing and testing alternative security valuation and cost of capital theories.

The equality of these three rates of return is due to the regulatory practice of setting the price of a firm's product to provide it with an income in each period equal to the allowed rate of return multiplied by the historical cost or book value of its assets. The use of historical cost as the rate base has been questioned, and its economic efficiency in terms of consumer welfare will be compared with the major alternative, the opportunity cost of the assets and production required to provide the same output.

Chapter 2 ignored the presence of the corporate and personal income taxes. The consequence of these taxes for the PCCM cost of capital and the allowed rate of return for a public utility will be established. Finally, this chapter will examine the consequences of inflation for the cost of capital and allowed rate of return with historical cost used for determination of the rate base.

3.1 Rate of Return on Investment Under Regulation

The rate of return an investment is expected to earn, sometimes referred to as its internal rate of return, is the discount rate that equates its expected future cash flows with its cost. Similarly, the rate of return on a firm's assets is the discount rate that equates their expected future cash flows with their cost. For a nonregulated firm the rate of return on assets, the marginal rate of return on investment for some investment level, the average rate on that level of investment, and the current earnings divided by the book or historical cost value of the assets customarily will be different. The regulatory process, it will be seen, makes these figures equal for a public utility.

For a nonregulated corporation an investment's internal rate of return will vary over a wide range among its investment opportunities. In arriving at its capital budget, a nonregulated corporation that wishes to maximize the value of its common equity will rank the investment opportunities according to their internal rates of return and undertake every investment with a rate of return in excess of its cost of capital. In terms of our previous model, the average rate of return on investment when the amount invested

is I would be $x = f(I)$ with $dx/dI < 0$ since x falls as I increases. Substituting $f(I)$ for x as the rate of return on investment in the previous equations, their solution for the cost of capital would produce the following result: Share price is maximized when the rate of return on the last dollar invested, the marginal rate of return on investment, is equal to ρ.

A utility may and should calculate the internal rate of return on each investment opportunity using expected demand and current sales price for its product. The internal rates of return so calculated will vary over a wide range among the investment opportunities. The utility should reject all investments with internal rates of return below ρ and undertake all with internal rates of return above ρ. The average rate of return on the accepted projects will be above ρ. Assuming that the current rate of return on assets is $x = \rho$, it does not follow that x will rise when the investments are undertaken. If x is the rate of return the utility is allowed to earn, undertaking the projects with internal rates of return above x initially will lead the regulatory agency to reduce the prices charged by the utility for its product so that the utility's income increases by only xI as a consequence of the investment. Therefore, a utility's marginal rate of return on investment is equal to the average which is equal to the rate of return on its existing assets.

A utility may undertake an investment project with an internal rate of return below x because the public interest requires it to do so. For example, the firm may be required to extend service to customers in isolated areas. The regulatory agency will raise the rate of return on that project to x by allowing the utility to raise the price of its product. This situation will prevail so long as the regulated price is below the profit-maximizing price and so long as a rise in the price will raise the utility's profit. When the product price allowed by the agency is above the profit-maximizing price, regulation ceases to be effective.

The regulatory process which makes the average and marginal return on investment and the return on assets and current earnings divided by the book value of assets all the same may be restated as follows. A regulatory agency that decided a utility should be allowed a return of ρ would measure ρ and apply it to the book value of its assets, the rate base, to arrive at the allowed level of earnings for the period. The price of the product then would be set so that the utility's revenue is expected to exceed all costs, including incomes taxes,[1] by the allowed earnings. Let x_t, $t = 1, 2, \ldots, \infty$, be the rate of return on assets at the start of $t = 1$ that the utility will be allowed to earn during t. It is immediately clear that the return in period t on the investment made during $t = 1$ and the return in period t on the assets on hand at the start of $t = 1$ will be x_t, and they both have the same value. Furthermore, on the reasonable assumption that the return on assets realized during the period that just ended, x_o, is the expected value of x_t for all t, the rates of return on assets and investment are equal to earnings over book.

The regulatory practice described above greatly simplifies theoretical and empirical work on security valuation and cost of capital to a public utility. This simplification is in large measure due to the use of historical cost or book value for the rate base.[2] We all know that for an unregulated firm it is the return on investment, not the return on existing assets, that determines whether or not an investment will be made. In fact, the superiority of economics and economists over accounting and its practitioners is demonstrated by proving that the historical cost of existing assets is not relevant for a firm's investment decision. Does it follow that a regulatory agency is irrational in using a historical cost rate base to determine the earnings a utility is allowed to earn?

Alternatives to historical cost that have been suggested are market value and opportunity cost. The former cannot be used because the regulatory process determines market value. We may write $V = X/\rho$, where V = market value of the firm, and X = earnings of the firm. Multiplying V by ρ to determine X gets us nowhere. Another market value figure is what the firm's assets can be sold for in their best alternative use to their employment by the firm. For the assets of a public utility this is a meaningless figure.

Opportunity cost of a utility's assets may be defined as the purchase cost, under current prices and technology, of the assets needed to provide the same capacity as the existing assets. The argument

[1] A later section will examine what this practice implies for the interpretation and treatment of the corporate income tax. It will be seen that the conclusions reached here ignoring the tax will hold with the tax present.

[2] The stock value models in the previous chapter took advantage of this simplification in that the same expressions for a firm's dividend expectation cannot be used for an unregulated firm.

advanced in favor of historical over opportunity cost is administrative feasibility. Historical cost is an accounting determination that the regulatory agency can control with the resources at its command. That is, the agency can specify rules for measuring the depreciated historical cost of a utility's assets and not be confronted with a wide range of values that can be defended as being consistent with the rules specified. By contrast, opportunity cost involves a considerable engineering and business competence, and experts in the field could arrive at widely divergent figures depending on their judgments as to the feasibility and operating characteristics of the latest technology for producing some level of output. However, it can be shown that administrative feasibility is not the sole justification for historical cost. The following sections will show that, on economic grounds alone, historical cost is both a rational basis for controlling a utility and superior to opportunity cost as a basis for arriving at a utility's revenue and income.

3.2 Cost of Capital: Historical Cost Regulation

In principle, both historical cost and opportunity cost can be used as the value of the rate base in determining a utility's income. The choice between them, however, influences a good deal more than the rate base. The cost of capital and the cost of production that the utility is allowed to recover in the price also depend on whether historical or opportunity cost is used in the revenue determination process. It will be useful to begin with a comparison of two alternative approaches to the implementation of historical cost.

Assume that when a utility is established the regulatory agency announces it will be allowed to earn the current cost of capital on the historical cost of its assets for all future time. If the probability that consumer demand will not be able to provide the required revenue in the foreseeable future is practically zero, the shares in the utility are like a consol, a government bond with no maturity date. For example, assume that the utility's shares are issued at a price of $100 and have the same book value at the start of $t = 1$ and that the yield on long-term government bonds is 7 percent at that time. The shares would pay $7.00 a year in every future period and would sell at $100 as long as the yield on long-term governments remained 7 percent.

An investor with an infinite horizon is only concerned with the risk of his periodic income. He would find these shares risk free. The shares would be risky, however, for an investor with a one period horizon, that is, an investor who is concerned with the change in the value of his wealth from one period to the next. As the long-term government bond yield changed, the value of a share in this utility would rise or fall. Perhaps more important is the fact that a change in the interest rate makes further investment by the utility and the policy of the regulatory agency incompatible. Furthermore, with a rise in the interest rate, additional investment by the utility will be detrimental to the interest of the stockholders.

Assume that during $t = j - 1$ the long-term interest rate rises to 9 percent. The price of the share falls to $77.77, and the one period return on a share is −15.23 percent. With old shares selling to earn 9 percent, no one will buy new shares at a price of $100, the book value of the old shares. Selling the new shares at a price below $100 will reduce the income per share below $7.00 and further harm the old shareholders. In particular, their dividend per share will fall below $7.00. If 50 shares with a book value of $100 per share are outstanding at the start of $t = j$, and if an additional investment of $5,000 is desired, Eq. (2.3.2) can be used to establish that a new issue must be at a price of $55.56 to provide the purchasers with a 9 percent return on their investment. The dividend per share and the periodic income to the old shareholders fall to $5.00. The retention of earnings during j to finance investment would have a similar consequence for the income of the old shareholders.[3]

In short, a constant allowed rate of return over time with share yield changing over time will provide shareholders with a periodic income equal to the allowed rate of return only if no new investment is undertaken by the utility. Furthermore, new investment will benefit or harm existing shareholders if the yield on shares is below or above the allowed rate of return. The reason for this state of affairs is that, unlike bonds, a new issue of shares cannot be given

[3]The income during j would be the dividend plus the change in the value of the share during j. If the entire income per share of $7.00 was retained, the price per share would rise from $77.77 to $83.22 at the end of j, and the income in j would be the difference, or $5.45.

a return different from outstanding shares.

Assume now that the regulatory agency announces that its policy will be to allow a return on book in each future period equal to the yield investors require on their stock at the start of each period. If that required yield at the start of $t = 1$ is 6 percent, the utility will be allowed to earn 6 percent of book during $t = 1$. Earnings per share with a book value per share of $100 will be $6.00. If the yield investors require at the start of $t = 2$ rises to 9 percent, income during $t = 2$ will rise to 9 percent of book value. What is implied is that income during $t = 2, 3, \ldots, \infty$ on a share outstanding at the start of $t = 1$ is uncertain. However, the expected value of the allowed rate of return in every future period may be taken as being equal to the yield investors require at the start of $t = 1$. Consequently, the price and book value per share will be equal both at the start of each period and at the end of each period regardless of what happens to the yield investors require on the share from one period to the next. Hence, the one period income in every period will be exactly equal to the yield investors require on the stock at the start of the period. The infinite horizon income is uncertain, but the one period horizon income is certain. The share under this regulatory policy becomes similar to a one period government bond. It is intuitively evident and will be rigorously shown in chapter 4 that under this regulatory policy shareholders are indifferent to the issue of stock or the retention of earnings to finance investment. Either form of financing investment does not change the return the shareholders earn, and the new money earns a return investors require.

We have reached a very striking conclusion. The perfect implementation of the regulatory policy described would make share yield and the cost of capital for a public utility equal to the interest rate on a one period government bond. That is, if a utility's income in each period were set exactly equal to the book value of the stock multiplied by the yield investors require on the stock at the start of the period, that yield figure would be equal to the short-term government bond rate. Furthermore, the short-term government bond rate would be the utility's cost of capital because the shareholders would be indifferent to the utility's investment and financing policy.

This conclusion assumes that the PCCM assumptions on security valuation are true. It also assumes perfect implementation of the policy by the regulatory agency. If the agency could not forecast utility revenue perfectly, the actual one period return would depart more or less from the allowed rate of return.[4] What is perhaps more important is the possibility that political pressure on behalf of stockholders or consumers will persuade the agency to keep the allowed rate of return above or below the yield investors require for one or more periods. In particular, the allowed rate of return may lag changes in the required yield. Price then will depart from book value, and investors will realize one period windfall gains or losses. Furthermore, investors become uncertain as to the one period return on a utility's share, and the yield they require will rise in relation to the yield on a one period government bond.

3.3 *Cost of Capital: Opportunity Cost Regulation*

Opportunity cost implies that a regulatory agency will establish the revenue and income a utility is allowed to earn as follows. At the start of each period the agency determines the most efficient method of producing an output equal to the capacity of the utility's actual facilities. The agency next determines the current outlay on facilities necessary to acquire the same capacity and the operating costs of producing the output with these currently available facilities. The agency then sets a price which covers the revenue requirements of these facilities—their production costs plus the required income to the stockholders.[5] The latter is equal to the opportunity cost of the utility's facilities multiplied by the cost of capital if the opportunity cost of the assets and production are not expected to change over time. If they are expected to rise or fall, the allowed rate of return must depart correspondingly from the cost of capital.

Assume that scientific progress will cause the opportunity cost of producing a given output to decline over time. Specifically, with the revenue in each period fixed on the basis of the opportunity

[4]However, these deviations would balance out over time, and they should have little or no influence on the dividend and value of the stock.

[5]It is possible to set the price to the consumer so that it covers production cost with the actual facilities plus the cost of capital times the opportunity cost of the facilities. Doing so would not seem to realize the goal of using opportunity cost in controlling a utility. In any event, the conclusions reached in the analysis that follows would not be changed under this more restricted application of opportunity cost.

cost of the facilities and output, the historical cost income on a facility acquired by the utility at the start of $t = 1$ will fall at an annual rate of 3 percent over time. The historical cost income is what the investor will receive in return for the funds he provided at $t = 1$ to acquire the facility. That is, his rate of return is the discount rate that equates his investment with the historical cost income over time. Consequently, if the yield investors require on utility shares is 9 percent, the regulatory agency must allow a 12 percent return on opportunity cost in each period to provide an investor with the 9 percent return he requires.

All we are saying is that if investors require a 9 percent return on investment in utility shares they will not buy these shares unless they can expect to earn 9 percent. Under historical cost the expected income in each future period is 9 percent of the investment. With opportunity cost, revenue and income determination, and historical cost income expected to fall by 3 percent per year, a first period income equal to 12 percent of the investment and subsequent income declining at the rate of 3 percent per year provide the same 9 percent return. The investor certainly will not accept a dividend with an initial value equal to 9 percent of his investment and a growth rate of -3 percent. With the allowed rate of return in each period determined in this way, a utility's share will sell at a price equal to the opportunity cost of the assets on a per share basis. Furthermore, the return on investment will be equal to the cost of capital, and shareholders will be indifferent to the level of investment and its financing.

Urbanization and resource depletion can make the opportunity cost of assets and production rise over time. If the opportunity cost determination of revenue makes the historical cost income rise at an annual rate of 3 percent, a 9 percent yield on shares is provided by a periodic income equal to 6 percent of the opportunity cost of assets. The conclusion, therefore, is that investors obtain from consumers a return equal to the yield they require on the historical cost of their investment regardless of whether historical or opportunity cost is used to determine the utility's revenue in each period. The only difference between the two approaches is the distribution over time of the payments that provide the required return. Under historical cost the payments are independent of time, and under opportunity cost they fall if technological progress is positive and vice versa.

The previous analysis assumed that scientific progress, resource depletion, urbanization, and so forth, cause the opportunity cost of production to change at a known constant rate over time. This is most unrealistic. The revenue requirements to cover the opportunity cost of production will change unexpectedly from one period to the next. The result will be windfall gains and losses to shareholders and uncertainty as to what the one period income will be from one period to the next. The yield investors require and the cost of capital to a public utility will be raised correspondingly.

The issue between historical cost and opportunity cost therefore may be stated as follows. Under historical cost an unexpected change, for example, a fall in the opportunity cost of production, has no impact on the price the consumer pays until the existing facilities are replaced. Under opportunity cost the price falls immediately. The risk to the shareholder is higher under opportunity cost and the return he requires is correspondingly higher. However, the risk to the consumer is also higher under opportunity cost. Unexpected changes in the opportunity cost of production are reflected in the price immediately and are not deferred until the existing facilities are replaced.[6] Consequently, the higher yield investors require and the higher cost of capital to a utility under opportunity cost revenue determination provide consumers with no compensating benefits.

It has just been shown that on purely theoretical grounds the consumer is better off under historical cost control of a utility's revenue and income than under opportunity cost control. It is also clear that opportunity cost control is far more difficult to implement in that the information requirements are quite formidable in comparison with those of historical cost. Under some circumstances error in information used for decisions will not bias the decisions one way or the other. However, regulatory control of an industry has been questioned on the grounds that the agency is used by the firms in an industry to serve their own ends. The use of opportunity cost in determining a utility's revenue and income clearly would make it easier for an agency that was so inclined to serve the firms it is supposed to control.

[6] With part of the facilities replaced in each period, historical cost smooths the impact of unexpected changes in the opportunity cost of production on the price he pays. His risk is thereby reduced.

3.4 The Corporate Income Tax

How if at all do the corporate and personal income taxes modify our conclusion that under perfectly competitive capital markets a utility's cost of capital is ρ regardless of the method and level of financing? We first will consider the corporate income tax.

With interest a tax deductible expense, debt financing increases a firm's return on its assets. That is, if earnings before interest and taxes are independent of the tax rate and the capital structure, the larger the fraction of the capital financed by debt, the larger the sum of the interest on debt plus the after-tax earnings on common. Specifically, with corporate income taxes at the rate τ, and with X the pretax earnings on assets per share, the after-tax earnings are

$$\begin{aligned} X^\tau &= (1-\tau)(X - iL) + iL \\ &= (1-\tau)X + \tau iL. \end{aligned} \tag{3.4.1}$$

X^τ is τiL larger with a debt of L than with no debt in the capital structure.

This tax benefit from corporate leverage is not available to individuals through personal leverage. In addition, as Modigliani and Miller [33] have shown, with losses carried backward and forward, this gain to stockholders from corporate leverage is risk free. They demonstrated that as a consequence the yield at which a share will sell is no longer the value given by Eq. (2.4.2). Instead, it is

$$k = \rho + (1-\tau)(\rho - i)(L/P). \tag{3.4.2}$$

Since k equates a share's dividend expectation with its price, and since the dividend is net of the corporate income tax, k is the after-tax value of the yield on a share. Correspondingly, ρ is the after-tax yield on an unlevered share. Finally, Modigliani and Miller showed that with a corporate income tax the after-tax cost of equity capital is ρ, and the after-tax cost of debt capital is $(1-\tau)\rho$. With $\tau = .5$, the cost of debt capital is one-half the cost of equity capital.

This conclusion holds under the traditional assumption that the corporate income tax falls entirely on the corporation's profits. The firm maximizes earnings before taxes, and a rise or fall in the corporate income tax rate will change only the after-tax profits correspondingly. Regardless of whether or not this is true for unregulated manufacturing corporations, it does not appear to be true for regulated utilities. Rather, the regulatory agency controls x^τ, the interest on debt, dividends on preferred, plus after-tax earnings on common divided by the total capital. When the tax rate changes the regulatory agency changes the price of the product and thus pretax earnings, X, which keeps x^τ equal to a predetermined value.[7] Also, with the tax rate and everything else unchanged, a rise in the leverage rate initially will raise X^τ by τiL. However, with x^τ the allowed rate of return, the regulatory agency can be expected to reduce x to restore x^τ to its previous value. Gordon [17] has argued that the consequence is to make Eq. (3.4.2) invalid for a utility. The no-tax Eq. (2.4.2) holds, and the after-tax cost of debt capital is ρ, the same as the after-tax cost of equity capital.[8]

Robert Hamada [20] and E. J. Elton and M. J. Gruber [10] have argued that Eq. (3.4.2) is true and that a utility's cost of debt capital is $(1 - \tau)\rho$ even if regulatory agencies behave as described above. Their proof proceeded from the assumption that a utility's risk arises from uncertainty as to its future volume of sales. That is, the regulatory agency sets the price of the utility's product so that the expected value of its sales quantity will generate an after-tax rate of return on assets with an expected value of x^τ. With the sales volume the source of uncertainty, the random variable that is independent of the firm's financial structure is $\tilde{X}$ and not $\tilde{X}^\tau$. However, if we assume instead that the source of uncertainty with regard to a utility's future earnings is the rate of return the utility is allowed to earn, $\tilde{x}^\tau$ or $\tilde{X}^\tau$ is the random variable that is independent

[7] Indirect but relevant evidence on this point is provided by the comparative attitude toward preferred stock financing by manufacturing and utility corporations. The former avoid financing with preferred stock since the dividend is not deductible as an expense in computing the corporate income tax. By contrast, utilities continue to raise funds through the sale of preferred issues. The obvious explanation is that the utilities do not see a tax disadvantage in preferred stock by comparison with debt.

[8] Here, as in the no tax world, raising the leverage rate raises the earnings on the common. However, this does not raise the value of the common stock under the Modigliani-Miller leverage theorem as explained earlier.

of a utility's financial structure and the no-tax expression for k, Eq. (2.4.2), holds.[9]

It seems quite reasonable to believe that the year-to-year differences between the actual and expected sales volume are negligible, particularly when it is kept in mind that the expected value changes from one year to the next on the basis of new information. Fluctuations in wage rates and material prices are also a minor source of uncertainty as to future earnings. A regulatory agency that sets x^τ equal to ρ will change product prices from one year to the next in response to changes in the expected value of sales, material prices, and so forth. The risk of a utility share arises due to uncertainty with regard to the future values of x^τ in relation to the cost of capital. Regulatory lag, lack of information, and changing political forces all operate to make the relation between x^τ and ρ uncertain.[10]

3.5 *The Personal Income Tax*

The personal income tax can influence a corporation's cost of capital due to the different tax treatment of dividends and capital gains. Let τ_p be the tax rate on dividends, τ_g be the tax rate on capital gains, and ρ^τ be the after personal income tax yield an investor requires on a share of stock. For a corporation that finances exclusively with the sale of stock, the after-tax analogue to Eq. (2.3.1) is

$$P = \frac{(1 - \tau_p)[NEx + Ix]/[N + n]}{\rho^\tau}$$

$$= \frac{(1 - \tau_p)[NEx + Ix] - I\rho^\tau}{N\rho^\tau}. \tag{3.5.1}$$

If we set $x = \rho^\tau/(1 - \tau_p)$, P is independent of I. Hence the cost of capital acquired from the sale of stock is $z = \rho^\tau/(1 - \tau_p)$. With

[9] This conclusion is demonstrated in M. J. Gordon and J. S. McCallum [19].

[10] If the investor has a finite horizon, he expects to sell the share n periods hence, and he is concerned with P_n as well as D_t up to $t = n$. P_n will depend on x^τ at $t = n$ and ρ at $t = n$. Hence, the current price and yield will depend on this uncertainty with respect to future values of x^τ and ρ and their relation.

ρ^τ the yield on a share on an after personal income tax basis, $\rho = \rho^\tau/(1 - \tau_p)$ is the pretax yield.[11] Dividing the numerator and denominator of Eq. (3.5.1) by $1 - \tau_p$ makes it clear that ρ remains the cost of capital raised from the sale of stock when dividend income is taxed at the rate τ_p.

For a corporation that finances exclusively with the retention of earnings, a stock value model that may be used to recognize the consequences of the personal income tax is

$$P_0 = \frac{(1 - \tau_p)(1 - b)Ex + P_0 + (1 - \tau_g)P_0 xb}{1 + \rho^\tau}$$

$$= \frac{(1 - \tau_p)(1 - b)Ex}{\rho^\tau - (1 - \tau_g)xb}. \qquad (3.5.2)$$

This is a one period horizon model with the first term in the numerator the after-tax dividend, the second term the tax-free recovery of the price at $t = 0$, and the last term the after-tax capital gain due to retention and growth in price at the rate xb.[12] Taking the derivative with respect to the retention rate,

$$\frac{dP}{db} = \frac{(1 - \tau_p)Ex}{[\rho^\tau - (1 - \tau_g)xb]^2}[x(1 - \tau_g) - \rho^\tau]. \qquad (3.5.3)$$

Therefore, the current price is independent of the retention rate when $x = \rho^\tau/(1 - \tau_g)$. As stated earlier, $\rho = \rho^\tau/(1 - \tau_p)$, and $\rho^\tau = \rho(1 - \tau_p)$, so that the cost of capital is $z = \rho(1 - \tau_p)/(1 - \tau_g)$. Since $\tau_g < \tau_p$, the cost of capital on retention financed investment is reduced below ρ with the personal income tax.

The stock financing model, Eq. (3.5.1), assumed no debt in the capital structure and a single period investment. Introducing debt into the capital structure and introducing the expectation of stock financing at the rate s for the indefinite future does not change

[11] Both ρ and ρ^τ are on an after corporate income tax basis. They differ in that ρ^τ is net of the personal income tax.

[12] An infinite horizon model with the dividend growing at the rate xb produces the same equation if it is assumed that the capital gain is taxed at the rate τ_g whether or not it is realized.

the conclusion that the cost of stock financing capital remains ρ with the personal income tax.

The retention model represented by Eq. (3.5.2) assumes the investor wants to consume his entire income on the share, the dividend plus the capital gain. At the other extreme, it may be assumed that he does not intend to consume any part of the income. Unrealized capital gains are free of taxation, and capital gains are realized free of income taxation on death. Under these circumstances $\tau_g = 0$, and the utility's cost of capital is only $\rho(1 - \tau_p)$.

Introducing leverage into the capital structure produces a slight complication. To do so we first replace x and ρ^τ in Eq. (3.5.2) with r and k^τ. Eq. (3.5.3) becomes

$$\frac{dP}{db} = \frac{(1 - \tau_p)Er}{[k^\tau - (1 - \tau_g)rb]^2}[r(1 - \tau_g) - k^\tau]. \qquad (3.5.4)$$

The derivative is equal to zero when $r(1 - \tau_g) - k^\tau$ is equal to zero. To evaluate it, replace k^τ with $k(1 - \tau_p)$ and replace r and k with their functions of leverage rate, assuming it is L/P in both cases. The result is

$$r(1 - \tau_g) - k^\tau = [(x - i)L/P](1 - \tau_g)$$
$$- [\rho + (\rho - i)L/P](1 - \tau_p). \qquad (3.5.5)$$

Setting the latter expression equal to zero and solving for x results in

$$x = \rho\frac{(1 - \tau_p)}{(1 - \tau_g)} + \frac{L}{P + L}i\left[1 - \frac{(1 - \tau_p)}{(1 - \tau_g)}\right]. \qquad (3.5.6)$$

With leverage the cost of capital is greater than $\rho(1 - \tau_p)/(1 - \tau_g)$ by the second term on the right-hand side of the equation. The additional term may be explained by the fact that raising the retention rate raises the debt financing, and the cost of capital on debt financing is ρ, not $\rho(1 - \tau_p)/(1 - \tau_g)$.

We now have a state of affairs where the cost of capital depends on its source. The cost of debt and stock financing capital is ρ, while the cost of retention capital falls between $\rho(1 - \tau_p)$ and a figure slightly above $\rho(1 - \tau_p)/(1 - \tau_g)$, depending on the considerations discussed earlier. The customary way in which the overall cost of capital is determined is to take a weighted average of the cost from each source, using as weights the relative amounts of each type of capital in the capital structure. (See, for example, W. G. Lewellyn [26].) If the market values of the debt and equity are the weights, the cost of capital is

$$z = \frac{L\rho + sP\rho + brP\rho(1 - \tau_p)/(1 - \tau_g)}{P + L}, \tag{3.5.7}$$

where L, sP, and brP each divided by $P + L$ are the fractions of capital raised by debt, stock financing, and retention, respectively. The alternative solution is to take z equal to the cost of retention capital if earnings are adequate to support the investment rate, and to take z equal to ρ if stock financing and/or leverage on the retained earnings is required.

The most perplexing problem posed by the differential tax treatment of dividends and capital gains is the measurement of share yield and the cost of capital. Solving Eq. (3.5.2) for ρ, recalling that $\rho = \rho^{\tau}/(1 - \tau_p)$, we obtain

$$\rho = \frac{(1 - b)Ex}{P_0} + xb(1 - \tau_g)/(1 - \tau_p) \tag{3.5.8}$$

for share yield in the absence of leverage and stock financing. No additional problems are raised by modifying the equation to allow leverage and stock financing. The values of τ_g and τ_p vary among investors, with $\tau_g = \tau_p = 0$ for tax-free, nonprofit institutions, and τ_p varying among individuals depending on their income. The appropriate values of these parameters for our equation are some weighted average of their values, but, with no basis for calculating the weights, all we can say is that $(1 - \tau_g)/(1 - \tau_p) > 1$, and the cost of capital is equal to or greater than its value in the absence of the personal income tax. Consequently, in what follows the personal income tax will be incorporated in the analysis only where recognizing it appears critical for the validity of the conclusions reached.

3.6 Inflation and the Cost of Capital

The analysis so far, like other theoretical work in security valuation and the cost of capital, has ignored the question of inflation. Doing so, it may be argued, is particularly dangerous in the case of regulated companies because the rate of return they are allowed to earn is related to the book values of their assets, while book values are not relevant for unregulated companies. Dealing with the subject of inflation can be a formidable task, and to limit its scope we will assume a world in which retention is the only source of funds for corporate investment.

Consider an unregulated company that in the absence of inflation is expected to retain the fraction b of its income and earn a return of x on the funds invested. As shown earlier, its income in $t + 1$ is expected to be

$$Y_{t+1} = Y_t[1 + bx], \tag{3.6.1}$$

and the yield at which its stock sells is measured by the expression $k = (D/P) + bx$, with x the rate of return on investment. If inflation is expected to take place at the rate ϵ, earnings and dividends are expected to grow at the rate ϵ in the absence of retention. Furthermore, the rate of return on any investment will be greater than x due to the fact that the cash flows on an investment follow the outlay in time. The consequence is that with inflation at the rate ϵ

$$\begin{aligned} Y_{t+1} &= Y_t[1 + bx][1 + \epsilon] \\ &= Y_t[1 + bx + \epsilon + bx\epsilon]. \end{aligned} \tag{3.6.2}$$

The term $bx\epsilon$ is small and will be ignored.

The immediate impact of inflation is a rise in the expected growth in the dividend from bx to $bx + \epsilon$ and a rise in the yield at which shares are selling to the current dividend yield plus the higher growth rate. Inflation has no immediate impact on the cash flows on bonds. Hence, investors may be expected to move from bonds to shares, raising the prices of shares and lowering the prices of bonds. The end result will be a rise in the interest rate and a rise in the yield on shares. But the rise in k will not be equal to the rise in the growth rate, and share prices will rise somewhat.[13]

Consider now a regulated company. It is allowed a return of x on the book value of its asset base. The expectation of inflation will not change the expected rate of growth in its asset base and will not directly change the allowed rate of return. In other words, the direct impact of inflation on a regulated share is the same as the direct impact on a bond. However, the introduction of inflation at the rate ϵ will make the yield on a regulated share compare unfavorably with the yield on an unregulated share. Investors will move out of regulated shares into unregulated shares, depressing the price and raising the yield on the former. In other words, share price and yield change from $P = (1 - b)Ex/(k - bx)$ to

$$P' = \frac{(1-b)Ex}{k' - bx}, \tag{3.6.3}$$

where $k' > k$ and $P' < P$. However, with $x < k'$ the utility's rate of return is below its cost of capital. The regulatory agency must raise x to $x' = k'$, which restores P' to its former value $P = E$.

A numerical illustration may help. Assume a regulated and an unregulated company both with $E = \$10.00$, $b = .4$, $x = .10$, and $k = .10$ so that $P = \$10.00$ for both shares. Let investor expectations change from no inflation to inflation at the rate $\epsilon = .03$. The current earnings and dividend for the unregulated company do not change, but the growth in the dividend and earnings is expected to increase additionally at the inflation rate. Finally, let the yield investors require on the share rise to $k' = .12$. The consequence is a rise in share price from $P = \$10.00$ to

$$P' = \frac{(1-b)Ex}{k' - bx - b}$$

$$= \frac{(.6)(\$10.00)(.10)}{.12 - (.4)(.10) - .03} = \$12.00. \tag{3.6.4}$$

[13]There are conditions under which the rise in k will be equal to the rise in the growth rate and keep the real return on the share unchanged. Whether or not this takes place is not critical for the analysis.

If investors continue to require the same yield on a share in the regulated as in the unregulated company, the cost of capital rises from $\rho = k = .10$ to $.12$. If the allowed rate of return on assets and investment remains $x = .10$, the price of the regulated share falls to \$7.50. To provide a rate of return on investment equal to the cost of capital, however, the regulatory agency must raise the allowed rate of return on assets and investment to $x' = .12$. The consequence is a rise in income per share from \$1.00 to \$1.20. The price per share remains at or returns to \$10.00, but it is now given by the expression

$$P = \frac{(1-b)Ex'}{k' - bx} = \frac{(.6)(\$10.00)(.12)}{.12 - (.4)(.12)}$$

$$= \frac{\$.72}{.12 - .048} = \$10.00. \tag{3.6.5}$$

As long as inflation is expected to take place at $\epsilon = .03$ and nothing else changes, the regulated share with $x = .12$ is competitive with the unregulated share.

This last statement may be questioned. The price of the unregulated share rises with inflation, but the regulated share's price does not. This does not make the unregulated share more attractive because the price also falls with a fall in the inflation rate. Given $\epsilon = .03$, the price and dividend are expected to grow at the rate .07, with .04 due to retention and .03 due to inflation. The price of the regulated share does not remain at \$10.00 forever. It is expected to grow at a rate of .048 due to retention. Furthermore, the current dividend is higher on the regulated share. The important point is that with $\epsilon = 0$ an investor is indifferent between the two shares when they both sell at \$10.00, and with $\epsilon = .03$ the investor is indifferent between the two shares when the price of the unregulated share rises to \$12.00.

Assume now that the expected rate of inflation is equal to the past rate. For the unregulated share, no explicit recognition of inflation is necessary. The growth due to retention and stock financing incorporates the consequences of inflation as well, and the yield investors require reflects the expected rate of inflation. For the regulated firm, the yield investors require also reflects the expected rate of inflation, and the allowed rate of return should be equal to share yield if it is to be equal to the cost of capital. The important conclusion to be drawn from this analysis is that share yield, allowed rate of return, and dividend growth for a regulated firm will vary with the rate of inflation, but no explicit recognition of the inflation rate is needed to measure the variables. Adjustment for the inflation rate is needed only if one wants to know the real and not the monetary return and yield on a share.

It is of some interest to compare the consequences of a change in the inflation rate for a bond, an unregulated share, and a regulated share. For a bond the required yield varies with inflation. Since the future payments are independent of the inflation rate, the value of the bond varies inversely with the inflation rate. For an unregulated share, the required yield also varies with the inflation rate. However, the rate of growth in the dividend and the inflation rate change by the same amount. Hence, if share yield changes by the same amount as the inflation rate, share price remains unchanged. If k does not rise by an amount equal to the inflation rate, share price as well as the future dividends on the share rise. For a regulated share, the regulatory agency adjusts the allowed rate of return to keep it equal to the required yield, and a change in the inflation rate leaves the price per share unchanged regardless of the relation between the changes in k and the inflation rate.

Where is the risk on a regulated share if the regulatory agency continuously adjusts the return on the share to keep it equal to the yield investors require? There is no risk with regard to the price of the stock. Price uncertainty exists only if investors believe that the regulatory agency will respond to changes in the yield investors require with a lag. The periodic income on a share is uncertain if the regulatory agency changes the allowed rate of return with no lag. However, if investor welfare associated with a dividend expectation is determined by discounting the expectation at the required yield on the expectation, investor welfare does not change with simultaneous changes in the required yield and the allowed return on the share.

4

The Traditional Theory and Changes in the Interest Rate

This chapter begins by presenting the formulas used to measure the cost of capital under the PCCM and the traditional theories of the cost of capital. We then review the rationalization that has been presented for the traditional theory and establish the assumptions analogous to those developed for the PCCM theory under which the traditional formula provides a utility's cost of capital.

The chapter next takes up an interesting but neglected question in implementing both the PCCM and the traditional theories: What is the relation between the ratio of the market to book value of a utility's common stock and the ratio of the allowed rate of return to the cost of capital? It will be shown that the market-book ratio is one when the allowed rate of return-cost of capital ratio is one if the coupon or imbedded interest rate is equal to the current interest rate on the utility's debt. We then examine whether the same conclusion holds when the coupon and current interest rates are different. This is an important question, since the implementation of both theories is quite simple if the allowed rate of return is equal to the cost of capital when the market-book ratio is equal to one.

4.1 Measurement Models for the PCCM Cost of Capital

The previous chapter established that under the PCCM assumptions with regard to how investors value shares a utility's cost of capital is equal to ρ regardless of the level and financing of investment. Recall that ρ is the yield at which the stock would sell in the absence of leverage. Hence, it is a "what-would-have-been" statistic and is not observable for a utility with leverage in its capital structure. However, under the PCCM theory it is also true that the yield at which the stock of a levered firm is selling is given by

$$k = \rho + (\rho - i)L/P. \tag{2.4.2}$$

Solving this expression for ρ results in

$$\rho = [Pk + Li]/[P + L]. \tag{4.1.1}$$

Therefore, to establish ρ we need only observe P, L, i, and k. P, L, and i are clearly observable, and it was established previously that under all security valuation assumptions k is equal to the dividend yield on the share plus the expected rate of growth in the price. Furthermore, chapter 2 established that if the firm's retention rate, stock financing rate, leverage rate, and rate of return on common equity investment are not expected to change, the rate of growth in the dividend is equal to the rate of growth in the price. Hence, k is in principle observable, and chapter 5 will establish rules for going from Eq. (2.8.13) to a numerical value for k.

It should not be inferred from Eq. (4.1.1) that ρ depends on the relative amounts of debt and equity in the capital structure. As the L/P ratio changes, k changes on the basis of Eq. (2.4.2) to keep ρ independent of the leverage rate.

The naïve reader of Modigliani and Miller might infer that there is a simpler way to establish ρ. In their 1958 paper [34] they stated that

$$V \equiv N[P + L] = \bar{X}/\rho, \tag{4.1.2}$$

where V = value of a firm, N = number of shares outstanding, and $\bar{X}$ = earnings before interest. The naïve reader might believe

$\bar{X} = \bar{X}_1$, the expected value of earnings before interest in the next period. In that event $\rho = \bar{X}_1/N[P + L]$ with all the variables on the right-hand side readily observed or estimated. However, $\bar{X} = \bar{X}_1$ is correct for establishing V, given ρ, or for measuring ρ, given V, only for a firm that is not expected to undertake any investment with a rate of return in excess of ρ.[1] Therefore, one may say that the cost of capital has been proved to be ρ for a firm that has no reason to determine its cost of capital since the firm is not expected to have investment opportunities with a return in excess of ρ.

Assume that the PCCM theory of security valuation and cost of capital also holds for a firm that is expected to earn $x_t > \rho$ on the investment of I_t in $t = 0, 1, \ldots, \infty$. The value of the firm is

$$V = \frac{\bar{X}_1}{\rho} + \sum_{t=0}^{\infty} \frac{I_t(x_t - \rho)}{\rho(1 + \rho)^{t+1}}. \tag{4.1.3}$$

If we are willing to assume that $x_t = x$ for all t and that $I_t = \lambda\bar{X}_1(1 + \Delta)^t$, Eq. (4.1.3) becomes

$$V = N[P + L] = \frac{\bar{X}_1}{\rho} + \frac{\lambda X_1(x - \rho)}{\rho(\rho - \Delta)}\frac{(1 + \Delta)}{(1 + \rho)}. \tag{4.1.4}$$

Regardless of whether or not this simplification is valid, it is clear that $V > \bar{X}_1/\rho$, provided $\rho > \Delta$ and $\bar{X}_1/V$ more or less understates the true value of ρ. Hence, $\bar{X}_1/V$ cannot be used as an estimate of ρ.

Given that the assumptions which take us from Eq. (4.1.3) to Eq. (4.1.4) are true, λ, x, and Δ may be estimated, and Eq. (4.1.4) may be solved for ρ. More than one value of ρ will satisfy the equation, but it is possible that only one value is true on economic grounds. However, this line of attack will not be followed in estimating ρ. Instead, Eq. (2.8.13) will be used to estimate k, and

[1] In their 1958 article Modigliani and Miller defined $\bar{X}$ as the expected value of the random variable X, and X is mistakenly defined as a simple average of X_t for $t = 1, 2, \ldots, \infty$. See [34] n. 6, p. 265. In their dividend policy article Miller and Modigliani [31] recognize that the future income accruing to the owners of the existing debt and equity is $\bar{X} = \bar{X}_1$ in every future period plus the present value of the excess of the rate of return over ρ on all future investments.

Eq. (2.4.2) will be used to derive ρ. The validity of this course of action, which depends on the validity of the PCCM theory for a firm with extraordinary investment opportunities, is beyond the scope of this work.

4.2 The Traditional Cost of Capital

Insofar as any theory has guided practice in arriving at the rate of return a utility is allowed to earn, it has been the traditional theory of the cost of capital. That theory continues to dominate rate of return testimony and, presumably, regulatory decisions. The formula that implements the traditional theory cost of capital is

$$z = [Ek + Bc]/[E + B]. \tag{4.2.1}$$

In this equation E and B are the book values of the utility's common stock and debt, k is the yield at which its stock is selling, and c is the coupon or imbedded interest rate on the utility's outstanding debt. It can be seen that the PCCM formula differs from the traditional formula in that market values of the common equity and debt replace the book values, and the current interest rate on the debt replaces the coupon rate.

According to some writers, such as Ezra Solomon [43] and A. A. Robichek and S. C. Myers [38], the traditional theory uses market values for the debt and equity and the current interest rate, that is, Eq. (4.1.1) represents the traditional as well as the PCCM cost of capital. According to them, the traditional and PCCM theories differ only in how k varies with the leverage rate. The relation between k and the leverage rate is given by the expression

$$k = \rho + \alpha L/P, \tag{4.2.2}$$

with $\alpha < \rho - i$ at least up to some value for L/P. However, in regulatory testimony it is Eq. (4.2.1) that is used, and it will be taken as the version of the traditional theory appropriate for public utilities.[2]

[2] As the term *traditional* implies, the theory has grown up out of practice, and variations in practice give rise to different versions. Furthermore, I know of no representation of the traditional theory before the use of market values was popularized in the work of Modigliani and Miller, in which market values appear anywhere but in the measurement of k.

The rationale for the traditional theory as represented by Eq. (4.2.1) may be summarized as follows. A utility's income should be large enough to cover the actual interest on its outstanding debt and provide the common stockholders with a return on the amount they have invested in the corporation equal to the yield the market requires on its stock. It is evident that allowing the utility to earn a return equal to the Eq. (4.2.1) value of z accomplishes just that. The presumption is that if the utility's income after interest and taxes provides the stockholders with the current yield on the book value of their investment they are treated fairly, and if they are so treated the utility will be able and willing to undertake whatever investment the public interest requires.

What happens to the traditional cost of capital as the leverage rate B/E varies depends on how k varies with B/E. If

$$k = \rho + (\rho - c)B/E, \tag{4.2.3}$$

z is independent of B/E as may be seen by substituting Eq. (4.2.3) for k in Eq. (4.2.1). However, it is universally agreed that, regardless of how leverage is measured, the traditional theory holds that its coefficient is less than $\rho - c$ or $\rho - i$ depending on whether c or i is taken as the interest rate.[3] Hence,

$$k = \rho + \alpha B/E, \tag{4.2.4}$$

with $\alpha > 0$ but materially less than $\rho - c$. Substituting Eq. (4.2.4) for k in Eq. (4.2.1) we find that

$$z = \frac{E[\rho + \alpha B/E] + Bc}{E + B}$$

$$= \frac{\rho + (\alpha + c)B/E}{1 + B/E} = \frac{\rho E + (\alpha + c)B}{E + B}. \tag{4.2.5}$$

With $\alpha = \rho - c$, $z = \rho$, but with $\alpha < \rho - c$, the cost of capital is less than ρ, and z falls in relation to ρ as B/E rises.[4] The implication is that the cost of debt capital is below the cost of equity

[3] For example, see David Durand [9] and Ezra Solomon [43].

[4] This may be seen by taking the derivative $\partial z/\partial(B/E)$.

capital, falling between the interest rate and the leverage-free yield on the common stock. Alternatively, one may say that the weighted average cost of capital is a decreasing function of the leverage rate.

Eq. (4.2.5) provides a utility's overall cost of capital on the assumption that the firm's leverage rate, B/E, is given. To establish the cost of debt capital, we can substitute Eq. (4.2.4) for k in Eq. (2.4.1). The result with B and c replacing L and i, respectively, is

$$P = \frac{Ex + B(x - c)}{\rho + \alpha B/E}. \tag{4.2.6}$$

Taking the derivative of P with respect to B results in

$$\frac{\partial P}{\partial B} = \frac{x(\rho - \alpha) - \rho c}{[\rho + \alpha B/E]^2}. \tag{4.2.7}$$

Setting this expression equal to zero and solving for x establishes that the cost of debt capital is $\rho c/(\rho - \alpha)$, which is less than ρ since $\alpha < \rho - c$. Setting $B = 0$ in Eq. (4.2.5) makes it clear that the cost of equity capital is ρ.

It should be noted that Eq. (4.2.5) must be used to establish the traditional cost of capital only if a different leverage rate than the firm's actual leverage rate is considered correct. In that event, estimates of ρ and α are required, and something like Eq. (4.2.4) must be used to estimate ρ and α. If the actual debt-equity ratio is considered correct, Eq. (4.2.1) can be used to measure z, and one need only observe k in addition to the current values of B, E, and c.

So far we have only stated the rule for measuring the traditional cost of capital, presented the intuitive rationalization for it, and examined some of its consequences. We have not established the conditions under which the traditional theory formula actually provides a utility with its cost of capital as the term is used in the modern theory of finance. What are these conditions? Eq. (4.2.4) must correctly describe how the yield on a utility's stock varies with B/E, and, as implied by the equation, k must be independent of the firm's retention rate, stock financing rate, and overall investment rate. If these conditions are satisfied, setting the return on

assets, x, equal to Eq. (4.2.5) makes the price per share independent of the firm's investment and financing decisions, subject only to the constraint that B/E remains unchanged. Therefore, the traditional and PCCM theories share the assumptions that k is independent of the firm's retention and stock financing rates. Under both theories the cost of equity capital is ρ. The two theories differ only on the variation in k with leverage and the cost of debt capital.

4.3 *Use of the Book and Market Value Relation*

One of the most interesting and at the same time neglected questions with regard to both the traditional and the PCCM cost of capital theories is the relation between book and market values of a utility's stock under each theory. A widely believed theorem is that the market-book value ratio $P/E \gtreqless 1$ when the ratio of the allowed rate of return to the cost of capital $x/\rho \gtreqless 1$. In that event, two very important conclusions follow. One is that estimating a utility's cost of capital is no longer necessary since the relation between the book and market values of its stock may be used to set the allowed rate of return equal to the cost of capital. The other important conclusion is that if the above theorem holds under both the PCCM and traditional theories the regulatory agency does not even have to differentiate between them. Adjusting the allowed rate of return to keep book and market values equal implements whichever of the two is correct.

Let us consider first the PCCM theory and begin with our stock value model:

$$P = \frac{(1 - b)Y}{k - br - vs} = \frac{(1 - b)E\pi}{k - br - vs}, \tag{2.8.8}$$

where π is the return on the existing common equity, and r is the return on new equity investment.

When $x = \rho$, $v = 0$, and the vs term disappears regardless of s. Furthermore, when the current and imbedded interest rates are the same, $B = L$, $\pi = r$, and $Y = Er$. Hence, we can make these substitutions: $\pi = r = x + (x - i)L/E$, and $k = \rho + (\rho - i)L/P$. Doing so and substituting ρ for x, since we have set $x = \rho$, results in

$$P = \frac{(1-b)[E\rho + L(\rho - i)]}{\rho + (\rho - i)L/P - b[\rho + (\rho - i)L/E]}$$

$$= \frac{(1-b)[E\rho + L(\rho - i)] - L(\rho - i)}{\rho - b\rho - b(\rho - i)L/E}$$

$$= E\frac{(1-b)\rho - b(\rho - i)L/E}{(1-b)\rho - b(\rho - i)L/E} = E. \qquad (4.3.1)$$

It also can be shown that $P \gtrless E$ when $x \gtrless \rho$.

Under the traditional theory we proceed as follows. The allowed rate of return, x, is set equal to the Eq. (4.2.5) value of z instead of ρ, and the expression for k is Eq. (4.2.4). With $v = 0$, $c = i$, and $B = L$, Eq. (2.8.8) becomes

$$P = \frac{(1-b)[Ez + B(z-c)]}{\rho + \alpha B/E - b[z + (z-c)B/E]}$$

$$= E\frac{(1-b)[\rho + \alpha B/E]}{(1-b)[\rho + \alpha B/E]} = E. \qquad (4.3.2)$$

Hence, $P = E$ when the allowed rate of return is set equal to the cost of capital.

However, it should be noted that when $P/E \neq 1$ the change in the allowed rate of return necessary to equate it with the cost of capital depends on the firm's leverage rate and equity financing rate. A given difference between P and E implies a decreasing difference between x and z as the firm's leverage rate, equity financing rate, or the two combined increase. The impact of leverage is illustrated by considering our PCCM stock value model with $b = s = 0$. The appropriate expression is Eq. (2.4.1), which may be written as follows:

$$\frac{P}{E} = \frac{x + (x-i)L/E}{\rho + (\rho - i)L/P}$$

$$= \frac{x}{\rho} + \frac{(x-\rho)L/E}{\rho}. \qquad (4.3.3)$$

It is clear that with $L = 0$ the equation reduces to $P/E = x/\rho$. Hence, if $P = 2E$, the regulatory agency can conclude $x = 2\rho$, and x should be reduced by one-half. However, if the leverage rate is positive the P/E ratio is greater than the x/ρ ratio. For example, with $L/E = 2$, a P/E ratio of 2.0 implies an x/ρ ratio of only 1.33,[5] and reducing x by one-half would be to overreact.

When $L = 0$ and $b > 0$, Eq. (2.6.4) may be written as

$$\frac{P}{E} = \frac{(1-b)x}{\rho - bx}. \qquad (4.3.4)$$

With $b = .3$, a P/E ratio of 2.0 implies $x/\rho = 1.54$. With both $b > 0$ and $L > 0$, the PCCM stock value model is

$$\frac{P}{E} = \frac{(1-b)r}{k - br}$$

$$= \frac{(1-b)[x + (x-i)L/E] - (\rho - i)L/E}{\rho - bx - b(x-i)L/E}. \qquad (4.3.5)$$

With $b = .3$, $L/E = 2$, $i = .05$, and $\rho = .07$, a P/E ratio of 2.0 implies an x/ρ ratio of only 1.14. The P/E ratio is very much larger than the x/ρ ratio, and a slight reduction in x will bring it down to the cost of capital.

In general, for a given excess of x over z, the P/E ratio rises with the leverage rate, with the retention (and stock financing) rate, and with the two combined. This is true under the traditional as well as the PCCM theories of security valuation and cost of capital. Hence, if either theory is considered correct and the current and coupon interest rates are the same, the adjustment in x for a given difference between price and book is smaller, the higher the leverage rate, the equity financing rate, and the two together.

[5]Eq. (4.3.3) can be written

$$\frac{x}{\rho} = \frac{P/E + L/E}{1 + L/E}$$

to calculate the x/ρ ratio implicit in a given P/E ratio.

4.4 Traditional Theory: Coupon and Current Interest Rates

We now consider what if anything happens to the cost of capital and the market-book value ratio under the traditional theory when the current and coupon rates of interest are different. In the absence of stock financing (which will be considered in a later section to simplify the analysis), we may take as our stock value expression Eq. (2.8.8) modified as follows:

$$\frac{P}{E} = \frac{(1-b)\pi}{k-br} = \frac{(1-b)[x+(x-c)B/E]}{\rho+\alpha B/E - b[x+(x-i)B/E]}. \tag{4.4.1}$$

In this expression it is assumed that the firm will be allowed to earn x for the indefinite future and that debt will be incurred at the current interest rate i sufficient to maintain the existing leverage rate as the equity increases due to retention.

If we set $b = 0$ in Eq. (4.4.1), the current interest rate does not enter into the determination of P/E, and it therefore has no influence on the cost of debt capital or P/E when $b = 0$. The interesting question is what happens to the cost of capital when the debt-equity ratio is fixed at some value and when the level of financing depends on the equity financing decision. To answer this question, we take the derivative of the Eq. (4.4.1) value of P/E with respect to the retention rate:

$$\frac{\partial P/E}{\partial b} = [\pi/(k-br)^2](r-k)$$

$$= \frac{\pi}{(k-br)^2}[x(1+B/E) - iB/E - \rho - \alpha B/E]. \tag{4.4.2}$$

Setting this expression equal to zero and solving for x results in

$$x = \frac{\rho E + (\alpha + i)B}{E+B}. \tag{4.4.3}$$

Comparison with Eq. (4.2.5) reveals that the cost of capital rises above that value when i rises above c. It also can be shown that $P/E < 1$ when x is set equal to the Eq. (4.2.5) value of z, and

$P/E > 1$ when x is set equal to the Eq. (4.4.3) value as long as $i > c$.

However, it is not the practice of regulatory agencies to use the current rate of interest in implementing the traditional theory, as Eq. (4.4.3) implies. Rather, their behavior may be summarized as follows: A rise in the current rate of interest will raise the allowed rate of return immediately insofar as the rise in i raises ρ. However, the current rate of interest does not appear in Eq. (4.2.5), and the regulatory agency does not consider it in arriving at x. Over time, the imbedded rate of interest moves toward the current rate due to refinancing and additional debt; as this takes place the allowed rate of return rises to cover the higher coupon interest on the debt. In other words, the regulatory agency changes x over time to maintain $\pi = k$. This implies that the return on common equity investment, r, is kept equal to π, and π replaces r in the denominator of Eq. (4.4.1). Since i does not appear in the equation, the cost of capital under the traditional theory remains Eq. (4.2.5), and $P/E = 1$ when x is equal to that value regardless of the current interest rate.

Given the widespread presumption that market and not book values of variables are the correct quantities to use in economic decisions, it may be thought that the traditional theory cannot be valid, relying as it does on book values of the equity, debt, and interest rate. The presumption is not valid in this instance. A rational policy for the regulatory agency is to set x so that the return on the assets exceeds the interest on the debt by the amount necessary to provide the required yield on the common. There is no need to give to or take from the stockholders the difference between the current and imbedded rate on the outstanding debt. They must be given at least, and need be given no more than, the yield they require on the stock. This is realized by setting x so that $\pi = k$ immediately and raising x over time as c moves toward i so as to maintain the required return on the common. If investors expect the regulatory agency to behave in this way, they expect the return on common equity investment $r = \pi$, the return on the existing equity. The consequence is that $P/E = 1$, and Eq. (4.2.5) is the cost of capital regardless of the current interest rate.

A numerical illustration may help. Assume that initially $c = i = .05$, $k = .10$, and $B = E = 50$. The cost of capital is $z = .075$. Let the interest rate rise to .07, and with it let k rise to .12. The traditional cost of capital rises to $z = .085$ on the basis of

$k = .12$ and $c = .05$. As the coupon rate of interest rises from .05 to .07 the cost of capital rises to .095. However, there is absolutely no need to raise x to .095 immediately. Doing so only results in windfall gains or losses when i changes. A policy of keeping $\pi = k$ through time keeps Eq. (4.2.5) as the cost of capital.

4.5 PCCM Theory: Coupon and Current Interest Rates

Turning to the PCCM theory, its cost of capital was found to be equal to ρ regardless of the level of investment and of how it is financed under the assumption that current and coupon rates of interest are the same. To establish the impact of $i \neq c$ on the cost of debt capital we may write Eq. (2.4.1) as follows:

$$\frac{P}{E} = \frac{x + (x - c)B/E + (x - i)B'/E}{\rho + (\rho - i)(L + B')/P}, \tag{4.5.1}$$

where B' is an increment in the firm's debt. Simplifying and taking the derivative $\partial P/E/\partial B'$, we find that it is equal to zero when $x = \rho$.[6]

The cost of retention capital, however, does not remain equal to ρ as i departs from c. The appropriate stock value model is

$$\frac{P}{E} = \frac{(1 - b)\pi}{k - br}$$

$$= \frac{(1 - b)[x + (x - c)B/E]}{\rho + (\rho - i)L/P - b[x + (x - i)L/E]}. \tag{4.5.2}$$

The derivative with respect to b given $i > c$ is a very involved expression. However, if we set $x = \rho$ and simplify, Eq. (4.5.2) becomes

[6]This expression is correct only if the debt has an infinite maturity. Otherwise c will rise toward i as the debt is refunded, and the dividend has a negative instead of a zero growth rate. The only consequence is that P/E falls between the above value and one. The conclusion with regard to $\partial(P/E)/\partial B'$ is not changed.

$$\frac{P}{E} = \frac{(1 - b)\rho + (\rho - c)B/E - (\rho - i)L/E - b(\rho - c)B/E}{(1 - b)\rho - b(\rho - i)L/E}. \tag{4.5.3}$$

Taking the derivative with respect to b results in

$$\frac{\partial P/E}{\partial b} = Q[(\rho - c)B/E - (\rho - i)L/E][(\rho - i)L/E]$$

$$= Q[\rho(B - L) + iL - cB][(\rho - i)L/E^2], \tag{4.5.4}$$

where Q is a positive quantity. If the debt has an infinite maturity, $iL = cB$ since $i/c = B/L$. If the debt has a finite maturity, $iL > cB$. In either case $\partial P/E/\partial b > 0$ when $x = \rho$. Consequently, some value of $x < \rho$ is necessary for $\partial P/E/\partial b = 0$, and the cost of retention capital is below ρ when $i > c$.

The above analysis was based on the assumption that the regulatory agency is expected to adjust x on the basis of changes in ρ without regard for the value of c. That is, if i rises above c, x is raised on the basis of Eq. (4.1.1) to keep it equal to ρ. With no further change in i, ρ and x remain unchanged regardless of the fact that c did not change initially, and c rises over time toward i.

To summarize, a difference between the current and coupon rates of interest creates a difference under the PCCM theory of security valuation between the cost of debt capital and the cost of retention capital. The cost of the former remains equal to ρ, but the cost of the latter and, it can be shown, the cost of stock financed capital fall below ρ. If $x = \rho$ is maintained the firm will earn more than its cost of capital on equity financing, and if x is reduced to the cost of equity capital the firm will earn less than the cost of capital on its debt financing.

As might be inferred from the previous analysis, the PCCM value of P/E rises with the ratio of the current to the coupon interest rate when $x = \rho$ is maintained. This could be demonstrated by taking the derivative of P/E with respect to i in Eq. (4.5.3). However, the resultant expression is quite complicated since ρ and L/E are functions of i. When $b = 0$, Eq. (4.5.3) reduces to

$$\frac{P}{E} = \frac{\rho + (\rho - c)B/E - (\rho - i)L/E}{\rho}. \tag{4.5.5}$$

It is clear that with $i > c$ and $B > L$, $P/E > 1$, and it increases as i/c or B/L rise.[7]

We can see that P/E rises with i/c when $b > 0$ by inspecting Eq. (4.5.3). Recall that when $i = c$ we have $L = B$. Hence, as i rises above c, L falls below B. Also, as i rises ρ rises. It is clear, then, that as i rises $(\rho - c)B/E$ rises in relation to the value of $(\rho - i)L/E$. Hence, P/E is an increasing function of i/c under the PCCM theory.

The conclusion that a rise in the interest rate raises P/E may seem strange. We typically find that P/E varies inversely with the interest rate, but this may be due to the failure of the allowed rate of return to move with ρ, which varies with the interest rate. We assume that the rise in ρ with i is matched by a rise in x equal to the rise in ρ. If c were to be raised by an amount equal to the rise in i, $P/E = 1$ would remain true. Hence, the failure of c to rise with i raises P/E. Regardless of whether or not it is reasonable to believe that P/E rises with i, there is no doubt that the PCCM theory leads to that conclusion.

To obtain some sense of the variation in P/E with i for various values of b, Table 1 presents the Eq. (4.5.3) values of P/E for certain combinations of the variables. In all cases $B/E = 1.5$, and $c = .04$. When $i = .05$, $\rho = .07$, and $L/E = 1.3$. When $i = .06$, $\rho = .08$, and $L/E = 1.1$.[8] It seemed plausible to raise ρ with i. The values of P/E in Table 1 reveal that it rises both with i and b. However, it is clear that the variation in P/E with i/c is large, while for any i/c the variation in P/E with b is negligible. Table 1 does not consider the variation in P/E with the debt-equity ratio,

[7] Eq. (4.5.5) is not strictly correct when the outstanding debt has finite maturities. The equation assumes that the firm will earn and pay the current dividend forever. However, if the debt has finite maturities the imbedded interest rate will move toward the current rate, and over time the dividend will fall from $\rho + (\rho - c)B/E$ to $\rho + (\rho - i)B/E$. In other words, the dividend has a negative growth rate, and P/E is somewhere between the Eq. (4.5.5) value and one. The longer the maturities of the debt, the closer P/E is to the Eq. (4.5.5) value.

[8] These values for L/E are roughly correct for the indicated relations between the current and coupon interest rates when the outstanding debt has maturities that range up to thirty years and the shorter maturities have the lowest coupons.

but it is evident that with $i > c$ the P/E ratio is higher the higher the leverage ratio.

To summarize, assume the following: The PCCM Eq. (2.4.2) describes how share yield varies with leverage; the regulatory agency sets $x = \rho$ measured by Eq. (4.1.1); and the interest rate rises so that $i > c$. We have seen that P/E rises above one and the cost of retention capital falls below ρ. P/E is an increasing function of i/c, and with $i > c$ and $x = \rho$, P/E is an increasing function of b. Therefore, setting $x = \rho$ does not provide a utility with its cost of capital and does not secure $P/E = 1$ if $i \neq c$ under the PCCM theory. Paradoxically, the regulatory practice of setting x so that π is equal to a predetermined value and changing x over time so that π is unchanged and $r = \pi$ realizes this goal.

The above practice means that we can replace r with π in Eq. (4.5.2); it becomes

$$\frac{P}{E} = \frac{(1 - b)[x + (x - c)B/E]}{\rho + (\rho - i)L/P - b[x + (x - c)L/E]}. \tag{4.5.6}$$

Taking the derivative with respect to b results in

$$\frac{\partial P/E}{\partial b} = Q[x + (x - c)B/E - \rho - (\rho - i)L/E]. \tag{4.5.7}$$

Setting this expression equal to zero and solving for x establishes that the cost of retention capital is

$$z = x = \rho\,\frac{E + L}{E + B} + \frac{cB - iL}{E + B}. \tag{4.5.8}$$

Table 1. ***Market-Book Value Ratios Under Different Interest and Retention Rates***

Interest rate	*Retention rate b* 0.0	0.2	0.3	0.4
$i = .04$	1.00	1.00	1.00	1.00
$i = .05$	1.27	1.30	1.32	1.36
$i = .06$	1.48	1.51	1.54	1.58

NOTE: Based on Eq. (4.5.6) with $B/E = 1.5$, and $c = .04$. When $i = .05$, $\rho = .07$, and $L/E = 1.3$. When $i = .06$, $\rho = .08$, and $L/E = 1.1$.

If the debt has an infinite maturity, $Bc = iL$, and the cost of retention capital is below ρ because $L < B$ with $i > c$. If the debt has a finite maturity, the cost of retention capital is below ρ because $Bc < iL$ and $L < B$.

The cost of retention capital is below ρ when $i > c$ under the PCCM theory regardless of which of the above assumptions are made concerning how the regulatory agency behaves. If the regulatory agency sets x to provide the coupon interest on the debt and the required yield on the common without regard for the current interest rate, and if it then raises x over time as c moves toward i so as to maintain the required return on the common, there are two advantages. First, it is more realistic. Second, an exact and simple expression for the cost of retention capital results.

Finally, if the regulatory agency sets x equal to the cost of capital as determined in Eq. (4.5.8), the market-book value ratio for the common stock is $P/E = 1$ regardless of the current interest rate. To see this, substitute π for r and Eq. (4.5.8) for x in Eq. (4.5.2) and simplify. The result is $P/E = 1$ regardless of i/c.

4.6 Stock Financing: Cost of Capital and Market-Book Ratio

It is time to examine the consequences of stock financing for the P/E ratio and the cost of capital under each theory when the coupon and current interest rates are different. The stock value model that may be used to deal with these problems is

$$\frac{P}{E} = \frac{(1-b)\pi}{k - br - vs}, \tag{4.6.1}$$

where v = the equity accretion rate and s = the stock financing rate.

Chapter 2 presented two expressions for v. One was

$$v = 1 - E/P, \tag{2.8.9}$$

and the other was

$$v = (r-k)/(r - rb - s). \tag{2.8.12}$$

The latter is the more fundamental expression for v, and Eq. (2.8.9)

is true only when $r = \pi$. To see this, substitute $k = D/P + br + vs$ with $D = (1-b)E\pi$ in Eq. (2.8.12). The result is

$$v = \frac{r - br - vs - (1-b)E\pi/P}{r - br - s} = 1 - \frac{\pi E}{rP}, \tag{4.6.2}$$

which is equal to the Eq. (2.8.9) value when $r = \pi$. When $i = c$, $\pi = x + (x - c)B/E$, $r = x + (x - c)L/E$, and $\pi = r$. However, when $i > c$, $\pi > r$, and Eq. (2.8.9) overstates the value of v.

To establish the influence of stock financing on the cost of capital when $i \neq c$, it is necessary to establish the influence of $i \neq c$ on v. Under the PCCM theory of stock valuation $k = \rho + (\rho - i)L/P$, and, if x does not change over time in response to changes in c, $r = x + (x - i)L/E$. If $x = \rho$ and $P = E$, then $k = r$ and $v = 0$. However, if $i > c$, then $P > E$, $r > k$, and v is positive even though $x = \rho$. Consequently, with $x = \rho$, P/E rises as i/c rises. Furthermore, with i/c fixed at some value greater than one and with $x = \rho$, P/E rises with s since v is positive at $s = 0$. This implies that the cost of stock financed capital is below ρ when $i > c$, but an exact expression for the cost of stock financed capital cannot be obtained. Substituting Eq. (2.8.12) for v in Eq. (4.6.1) with the appropriate expressions for r and k results in an unmanageable equation. Eq. (2.8.9) cannot be used since $\pi > r$ and $i > c$, and Eq. (2.8.9) overstates the value of v as shown previously.

The above analysis has assumed that the regulatory agency arrives at a value for x, ρ, or some other value and maintains that value over time regardless of the change in c due to $i \neq c$. The last section argued that it is more realistic to assume that the regulatory agency changes x over time as c moves toward i so as to maintain unchanged some return on the common equity. If the regulatory agency is expected to behave this way, $r = \pi$, and $v = 1 - E/P$ even though $i \neq c$. Our stock value model, Eq. (4.6.1), with the PCCM theory for determining k becomes

$$\frac{P}{E} = \frac{(1-b)\pi}{\rho + (\rho - i)L/P - b\pi - s(1 - E/P)}$$

$$= \frac{(1-b)\pi - (\rho - i)L/E - s}{\rho - b\pi - s}. \tag{4.6.3}$$

Taking the derivative with respect to s results in

$$\frac{\partial P/E}{\partial s} = Q[-\rho + b\pi + s + (1-b)\pi - (\rho - i)L/E - s]. \tag{4.6.4}$$

Making the substitution $\pi = x + (x - c)B/E$, setting the expression equal to zero, and solving for x provides the cost of stock financed capital. It is

$$z = x = \rho\frac{E+L}{E+B} + \frac{cB - iL}{E+B}. \tag{4.6.5}$$

Eq. (4.6.5) is identical to Eq. (4.5.8). Hence, under the PCCM theory of security valuation and the above assumption about regulatory behavior, the cost of retention and stock financed capital is the same and is below ρ when $i > c$.

The cost of debt capital remains equal to ρ, but ρ is the cost of debt involved in a change in the debt-equity ratio. If the firm maintains its existing debt-equity ratio, Eq. (4.6.5) is its cost of capital. With regard to the P/E ratio, when x is set equal to its Eq. (4.6.5) value, P/E remains equal to one regardless of the i/c ratio.

Stock financing poses no problem for the P/E ratio and the cost of capital under the traditional theory when $i \neq c$ for the simple reason that i does not enter into the traditional theory's model of stock valuation. The cost of stock financed capital, like the cost of retention capital, remains equal to the Eq. (4.2.5) value of z regardless of the current interest rate. It should be repeated, however, that z is an increasing function of ρ and c. Hence, a rise in i raises the cost of capital immediately insofar as ρ is correlated with i, and over time z rises due to the rise in i because c moves toward i over time.

4.7 Conclusions

Chapters 3 and 4 have raised some complex and interrelated questions with regard to the PCCM and traditional theories of the cost of capital. It may be helpful, therefore, at this point to review

the chain of reasoning and summarize the conclusions reached.

The critical assumptions of both theories concern the relation between the yield on a share and the firm's financing from each source. Central to the PCCM theory are the assumptions that k is independent of the rates of retention and stock financing and that the variation in k with the firm's leverage rate is given by the expression

$$k = \rho + (\rho - i)L/P. \tag{2.4.2}$$

With three secondary assumptions that the return on existing assets and investment are equal, that there are no corporate and personal income taxes, and that the current and coupon interest rates are the same, we reached the conclusion that a utility's cost of capital is $z = \rho$, the leverage-free yield on its stock regardless of the level and method of its financing. Furthermore, in Eq. (4.1.1) we presented a simple formula for measuring the PCCM value of z.

With regard to the secondary assumptions, chapter 3 established that equality between the return on assets and investment is correct for a utility when $i = c$. It also was established that a utility differs from an unregulated company in a way that allows ignoring (treating like any other expense) the corporate income tax, but the favorable treatment of capital gains under the personal income tax reduces the cost of retention capital below ρ by some amount. Finally, chapter 4 has established that when the coupon and current interest rates differ the cost of capital involved in a change in the debt-equity ratio remains equal to ρ. However, given the debt-equity ratio, the cost of capital varies inversely with the i/c ratio. Under reasonable assumptions with regard to the regulatory process, it was found that the PCCM cost of capital is

$$z = \rho\frac{E+L}{E+B} + \frac{cB - iL}{E+B}, \tag{4.5.8}$$

which is equal to ρ when $c = i$, but as i/c rises z falls below ρ. However, when x is equal to the above value of z, $P/E = 1$ regardless of i/c. Therefore, Eq. (4.5.8) is the cost of capital under the assumptions that the personal income tax may be ignored and that the firm's debt-equity ratio is given.

Turning to the traditional theory, the central assumptions are that k is independent of the retention and stock financing rates and that the variation in k with the firm's leverage rate is given by the expression

$$k = \rho + \alpha B/E. \tag{4.2.4}$$

With these assumptions and the secondary assumptions referred to above we reached the conclusion that a utility's cost of retention and stock financing capital is ρ and that its cost of debt capital is below ρ, falling somewhere between i and ρ. If the utility's debt-equity ratio is fixed at some level, the average cost of capital is a decreasing function of the debt-equity ratio selected. Therefore, under the same assumptions which make Eq. (4.5.8) the PCCM cost of capital, the traditional cost of capital is

$$z = \frac{\rho E + (\alpha + c)B}{E + B}. \tag{4.2.5}$$

Withdrawing the assumption that the coupon and current interest rates are the same does not change these conclusions. The cost of capital is independent of the i/c ratio. Furthermore, under the traditional theory the P/E ratio is independent of the i/c ratio, and it is equal to one when the allowed rate of return is equal to the cost of capital. These conclusions hold under the assumption that investors expect the allowed rate of return to change over time to cover changes in the imbedded interest rate due to $i \neq c$.

Finally, it was shown that the cost of capital will vary with the rate of inflation investors expect. However, the rate of inflation does not have to be recognized explicitly in measuring share yield and the cost of capital for a regulated company.

A major accomplishment in these chapters has been to establish the consequences for the PCCM and the traditional cost of capital theories of withdrawing all but one of the secondary assumptions made in chapters 2 and 3. The one exception is due to the different tax treatment of dividend and capital gains under the personal income tax. With this qualification, which is probably not important, and with the plausible assumption that the leverage rate is given, we have in Eqs. (4.5.8) and (4.2.5) the cost of capital under each theory. However, both of these expressions assume we know ρ among

other variables. Since ρ cannot be observed directly, a procedure must be found to measure ρ and implement the models. Furthermore, each cost of capital measure is correct only if its central assumptions with regard to the influence of the alternative financing methods on share yield are correct. The implementation and the testing of the valuation assumptions of both theories are taken up in chapter 6. The next chapter deals with the measurement of share yield, the critical variable in the measurement of ρ.

5

Measurement of the Variables to Implement the Theories

The previous chapter established that under the PCCM theory a utility's cost of capital is

$$z = \rho \frac{E + L}{E + B} + \frac{cB - iL}{E + B}, \tag{4.5.8}$$

subject only to the qualification that the personal income tax can be ignored. Under the same assumption,

$$z = \frac{\rho E + (\alpha + c)B}{E + B} \tag{4.2.5}$$

is the traditional cost of capital.

We cannot observe ρ directly, but under the PCCM theory with regard to the relation between k and ρ the latter is given by

$$\rho = [kP + iL]/[P + L]. \tag{4.1.1}$$

Under the traditional theory the assumption that the existing debt-equity ratio will continue makes the cost of capital

$$z = [kE + cB]/[E + B]. \tag{4.2.1}$$

Therefore, to implement the two theories requires the measurement of the following: E and P, the book and market value of the common equity; B and L, the book and market value of the debt; c and i, the coupon and current interest rates; and k, the yield at which the stock is selling.

It will be seen that the only variable in the above equations which presents any serious measurement problems is share yield, and most of the chapter is devoted to developing and testing alternative measures of share yield. To do this and to present illustrative data on the cost of capital under both theories, data for 54 electric utility companies over the period 1958–1968 will be used.

5.1 Dividend Yield and Growth

We have seen that utility companies satisfy assumptions under which investors reasonably may expect a firm's dividend to grow at a constant rate, g. Consequently, to measure the yield at which a firm's stock is selling we may use the expression

$$k = (D/P) + g. \tag{2.8.13}$$

To implement this and other measures of k will require the precise definition of a large number of variables. This process will be facilitated by switching to a mnemonic code in referring to the variables.

For the dividend yield at the end of T we use

$$\text{DIYD}(T) = \text{DIV}(T)/\text{PPS}(T), \tag{5.1.1}$$

where

$\text{DIV}(T)$ = dividend per share paid during T, and
$\text{PPS}(T)$ = price per share at end of T.

Eq. (5.1.1) is valid if the dividend is paid continuously in time.

If it is paid periodically, DIV(T) should be replaced by DIV(T + 1), forecast at the end of T. However, the latter poses problems of implementation that are not worth the effort in view of the fact that DIV(T) and DIV(T + 1) as of the end of T typically differ by a very small amount.[1]

The difficult quantity to measure is g. In chapter 2 it was established that under plausible assumptions $g = br + sv$, the sum of the retention and stock financing growth rates. This quantity will be called the intrinsic infinite horizon growth rate, and in our mnemonic code it is

$$\text{GRTH}(T) = \text{RTGR}(T) + \text{SFGR}(T), \tag{5.1.2}$$

with RTGR(T) the expected growth rate due to retention at the end of T and SFGR(T) the expected growth rate due to stock financing at the end of T. The next two sections are devoted to the measurement of GRTH(T), and subsequent sections will take up alternative measures of growth.

5.2 The Retention Growth Rate

The expected rate of growth in the dividend due to retention is the product of the expected retention rate and the expected rate of return on common investment. In addition to those defined above, the variables that will be employed to measure RTGR(T) are listed below.

RRC(T) = rate of return on common equity during T;
AFC(T) = income available for the common equity during T;
CSS(T) = common equity at end of T;
ASO(T) = actual shares outstanding at end of T;
BVS(T) = CSS(T)/ASO(T) = book value per share at end of T;
EPS(T) = earnings per share during T; and
RETR(T) = retention rate during T.

[1] Since dividends are paid quarterly, the relevant difference is in the quarterly dividend.

For the expected rate of return on common equity investment we use the rate of return on the existing common equity during T. It is

$$\mathrm{RRC}(T) = \mathrm{AFC}(T)/.5\ [\mathrm{CCS}(T) + \mathrm{CSS}\ (T-1)]. \tag{5.2.1}$$

For the expected retention rate, we first define the earnings per share during T as

$$\mathrm{EPS}(T) = \mathrm{RRC}(T)^*\ [\mathrm{BVS}(T) + \mathrm{BVS}(T-1)]\ .5. \tag{5.2.2}$$

The retention rate is

$$\mathrm{RETR}(T) = 1.0 - \mathrm{DIV}(T)/\mathrm{EPS}(T). \tag{5.2.3}$$

Hence,

$$\mathrm{RTGR}(T) = \mathrm{RRC}(T)^*\ \mathrm{RETR}(T) \tag{5.2.4}$$

is the expected rate of growth due to retention of earnings.

The measurement rules used to arrive at RTGR(T) may be questioned on three counts. The first is the assumption that the return on the existing common equity may be taken as the return on future additions to the common equity. The return on additions to the common equity may be written as

$$\mathrm{RCI}(T) = \mathrm{RRA}(T) + [\mathrm{RRA}(T) - \mathrm{AAR}(T)]\,\mathrm{DEQ}(T), \tag{5.2.5}$$

where RRA(T) is the rate of return on assets, AAR(T) is the current interest rate, and DEQ(T) is the debt-equity ratio. Letting IMBR(T) equal the coupon interest rate on the outstanding debt, the return on the existing common equity may be written as

$$\mathrm{RRC}(T) = \mathrm{RRA}(T) + [\mathrm{RRA}(T) - \mathrm{IMBR}(T)]\,\mathrm{DEQ}(T). \tag{5.2.6}$$

Eqs. (5.2.5) and (5.2.6) differ due to the difference between the coupon and the current interest rates. Why should RRC(T) instead of RCI(T) continue to be used as the expected rate of return on common equity investment?

It is clear that leverage on common equity investment that keeps

the leverage rate unchanged will take place at the current and not the imbedded interest rate. However, as argued in chapter 4, the behavior of regulatory agencies makes it reasonable for investors to expect that the allowed rate of return on assets will rise over time to cover the rise of the imbedded rate. That is, as leverage takes place at an interest rate above the imbedded rate, the latter rises, and the allowed rate of return rises to cover the higher imbedded rate. The conclusion is that, when the current and imbedded rates differ, investors expect the current rate of return on equity rather than the current rate of return on assets to prevail for the indefinite future.

The second measurement rule that may be questioned concerns the treatment of deferred income taxes in the measurement of a utility's return on common equity. Utility companies ordinarily use accelerated depreciation for tax purposes and straight-line depreciation in their financial statements. The reduction in taxes paid may be flowed through to earnings. In that event the tax charged against income before taxes is the tax paid, and the reported income to common and the common equity are correct as reported. The accelerated depreciation for tax purposes is simply an indirect means of reducing the effective tax rate.

However, many companies exclude the tax reduction from reported income. It is reported as a deferred charge in the income statement and is carried to a reserve for deferred taxes instead of the common equity. A liability that is to be paid in the distant future, or never, and that bears a zero interest rate is no liability. For an unregulated company it is therefore correct to add the deferred tax charge to income and to add the reserve to the common equity. The same reasoning, however, does not hold for a regulated utility. In principle, a regulatory agency sets the price of a utility's product so that its income, excluding the deferred tax charge, is equal to the allowed rate of return times the rate base excluding the deferred tax reserve. Consequently, if the deferred tax charge is included in income it is an addition to common equity on which the firm earns a zero rate of return. Retained earnings which earn a zero return are worthless and properly are excluded from income and common equity.

However, investors may not be certain that the regulatory agency will follow this policy forever. They may assign a nonzero probability to the chance event that the regulatory agency will transfer the reserve for deferred taxes to the common equity and allow the utility to earn the current return on equity (the return with the deferred tax charge and reserve excluded from common earnings and equity) on the larger equity base. If investors are certain this will happen in the near future, the correct figure for the current retention rate is one minus the dividend divided by the earnings per share with the latter including the deferred tax charge.[2]

It is also possible but less likely that investors believe that the allowed rate of return will be changed when the reserve is transferred to the common equity. That is, the firm will be allowed a return on common equal to the current common earnings including the deferred tax charge divided by the common equity including the reserve. In this event the return on common equity should be calculated with the charge and the reserve included in common earnings and equity, respectively.

If either or both of these hypotheses are accepted as true, implementing them poses formidable empirical problems. Assume a firm that invests a constant amount per period. In the year that accelerated depreciation is first adopted, income on common, including the charge, and return on common, with the charge and reserve included in common earnings and equity, will be at a maximum in relation to prior years' values. Over time, income and return on common gradually will fall to their original values. If investment is increasing over time, the same jump in both statistics takes place, and they gradually fall back toward but not to the values that prevailed before accelerated depreciation was allowed. Given this downward trend in the charge as a percentage of income, excluding the charge, and in the return on common equity, the averages of the relevant statistics over the recent past do not provide a correct prediction of their future values. The error will depend on how recently accelerated depreciation was adopted for tax purposes.

The decision to exclude the charge and the reserve for deferred taxes in calculating RETR and RRC was made on the following grounds. It is well known that the charge as a percentage of the reserve declines with the length of time the firm has been on accelerated depreciation. The relation between the charge and the reserve also will fluctuate from one period to the next with the level of investment and other variables. However, initially the charge

[2] This subject is examined extensively in E. F. Brigham and J. L. Pappas [6].

is very large in relation to the reserve, and including both amounts in earnings and equity, respectively, at this point in time materially raises RRC. With the passage of time the charge asymptotically approaches zero, and the reserve asymptotically approaches a large quantity so that including them lowers RRC. Therefore, including the charge and the reserve in calculating RRC implies the regulatory agency will make a change in RRC that is an arbitrary function of how long the firm has been on accelerated depreciation at the time RRC(T) is calculated. This is not reasonable. In fact, when regulatory agencies do shift from deferring to flowing through the tax savings they frequently do not transfer the reserve to the common equity, and they do not change the allowed rate of return.[3]

5.3 The Stock Financing Growth Rate

Establishing the expected rate of growth due to stock financing involves the following additional variables:

EACR(T) = equity accretion rate during T;
RGA(T) = rate of growth in assets during T;
RGAS(T) = smoothed rate of growth in assets during T;
STD(T) = book value of short-term debt at end of T;
LTD(T) = book value of long-term debt at end of T;
PFDS(T) = book value of preferred stock at end of T;
DEBB(T) = STD(T) + LTD(T) + PFDS(T) = total debt at end of T;
CEQ(T) = common equity plus reserve for deferred taxes; and
TTA(T) = total assets at the end of T.

From Eq. (2.8.9) the equity accretion rate during T is one minus the book value per share divided by the market value. The measurement definition employed is

$$\text{EACR}(T) = 1.0 - [\text{BVS}(T) + \text{BVS}(T-1)]/.9[\text{PPS}(T) + \text{PPS}(T-1)]. \qquad (5.3.1)$$

[3] See Brigham and Pappas [6, pp. 104–105].

Ideally, EACR(T) should be based on the book value at the time of issue and the proceeds per share to the company on the issue. The former cannot be established and the latter is difficult to determine. The substitutes employed are averages of the book and market values at the start and end of the year. The market value figure was further reduced by 10 percent to recognize that the proceeds typically will be less than the market value for a number of reasons.[4]

The expected annual rate of stock financing is difficult to measure since stock financing takes place very irregularly over time. Changes in the debt-equity ratio are used in the interval between stock issues. We could have used an exponentially smoothed average of the funds raised from the sale of stock divided by the book value of the outstanding common equity, but the following alternative approach was considered more accurate. If a utility maintains a constant debt-equity ratio, the rate of growth in its assets is equal to the rate of growth in its common equity. That is,

$$\mathrm{RGA}(T) = \mathrm{SFR}(T) + \mathrm{RTGR}(T). \qquad (5.3.2)$$

Hence, given the rate of growth in assets,

$$\mathrm{SFR}(T) = \mathrm{RGA}(T) - \mathrm{RTGR}(T). \qquad (5.3.3)$$

The rate of growth in assets also fluctuates considerably from one period to the next. Consequently, the expected rate of growth in assets is taken as an exponential geometric average of the current and prior smoothed values. It is obtained from

$$Ln[1 + \mathrm{RGAS}(T)] = \lambda Ln[1 + \mathrm{RGA}(T)] + (1 - \lambda) Ln[1 + \mathrm{RGAS}(T - 1)], \qquad (5.3.4)$$

with $\lambda = .20$ and the initial smoothed value of RGAS(T) arbitrarily set at RGAS(1952) = .05.

The rate of growth in assets during T is measured as

[4] If the new issue arises from the conversion of a convertible bond or preferred, the issue price will be below the market price. A new issue sold to the public or through rights also will net less than the current market price.

$$\mathrm{RGA}(T) = [\mathrm{TTA}(T)/\mathrm{TTA}(T - 1)] - 1.0, \qquad (5.3.5)$$

with

$$\mathrm{TTA}(T) = \mathrm{DEBB}(T) + \mathrm{CEQ}(T). \qquad (5.3.6)$$

For the stock financing rate, therefore, we used

$$\mathrm{SFRS}(T) = \mathrm{RGAS}(T) - \mathrm{RTGR}(T). \qquad (5.3.7)$$

The stock financing growth rate then is

$$\mathrm{SFGR}(T) = \mathrm{EACR}(T)^* \mathrm{SFRS}(T). \qquad (5.3.8)$$

Eqs. (5.2.4) and (5.3.8) complete our measurement of GRTH(T), the intrinsic rate of growth in dividend and price.

Before proceeding, two points should be noted. First, in computing the rate of growth in assets, the reserve for deferred taxes was included in total assets. Since the government is providing these funds at a zero interest rate, the investment they finance need not be financed by the sale of stock. However, with the passage of time the rate of growth in this reserve will fall to a negligible value, and the fraction of the total asset growth financed by the deferred tax reserve will have to be financed by other means. It is reasonable, therefore, to take the rate of growth in total assets less the portion financed by retention as a forecast of the stock financing requirements.

The second point to note is our use of a smoothed value for rate of growth in assets and not for any of the other variables such as the return on common. Smoothing dampens both the random fluctuations and the permanent changes in a variable. If random fluctuations are the major factor in year-to-year changes, smoothing produces a more accurate measure of the expected value of a variable. On the other hand, if random fluctuations are small relative to permanent changes, smoothing causes the value of the variable used to lag the true value. Inspection of the raw data revealed that year-to-year changes in these variables are small relative to changes over time so that smoothing does little to eliminate random fluctuations. On the other hand, year-to-year fluctuations in the rate of growth in assets are large relative to the changes over time so that the current value can be widely off the mark as a measure of the expected future value.

5.4 Other Measures of Growth

The measure of expected growth in the dividend established in the previous two sections, the intrinsic growth rate, is not the only possible measure of the variable. Another plausible measure is some average of the past rates of growth in the dividend. Under our model of security valuation, dividend, earnings, and price per share all are expected to grow at the same rate. Hence, the rates of growth in the dividend, earnings, and price also are candidates for estimates of the expected rate of growth in the dividend.

Let us consider first the rate of growth in earnings per share. The earnings per share during T adjusted for stock splits and stock dividends to make interperiod comparisons valid is

$$\mathrm{AYPS}(T) = \mathrm{AFC}(T)/.5\,[\mathrm{ANS}(T) + \mathrm{ANS}(T-1)], \qquad (5.4.1)$$

where ANS(T) is the number of shares outstanding at the end of T adjusted for stock splits and dividends. The rate of growth in earnings per share during T is

$$\mathrm{YGR}(T) = [\mathrm{AYPS}(T) - \mathrm{AYPS}(T-1)]/\mathrm{AYPS}(T-1). \qquad (5.4.2)$$

For reasons to be given shortly, the smoothed rate of growth in earnings is superior to the current rate as a forecast of the expected rate. The smoothed rate of earnings growth is obtained from

$$Ln[1 + \mathrm{YGRS}(T)] = \lambda Ln[1 + \mathrm{YGR}(T)] + (1-\lambda)Ln[1 + \mathrm{YGRS}(T-1)], \qquad (5.4.3)$$

with $\lambda = .15$ and YGRS(1953) = .04.

The primary reason for a difference between YGR and GRTH is a change in the rate of return on the common equity. To illustrate, assume a firm that has been earning a return on common of .10 and retaining one-half of its income to finance its investment. The rate of growth under both measures will be .05. If the firm's rate

of return on common rises from .10 to .11, the retention growth rate will rise from .05 to (.5)(.11) = .055. However, the earnings growth rate will rise from .05 to .155.[5] Furthermore, the earnings growth rate in subsequent periods will be .055 if the return on common remains .11. This example suggests that the intrinsic growth rate is superior to the earnings growth rate as a measure of expected growth. Investors nonetheless may look to past data on earnings growth for information on expected future growth, and it is the growth investors expect that should be used to measure share yield.

A number of considerations suggest that investors may, in fact, use earnings growth as a measure of expected future growth. First, the intrinsic growth rate includes stock financing growth as well as retention growth. The former is difficult for us to measure and may be even more difficult for investors. Consequently, investors may use past earnings growth to forecast the future since it incorporates in one statistic growth from all sources. Second, we saw that inflation will result in a rise in the allowed rate of return on equity for a regulated company. If this response to inflation takes place with a lag, that is, the regulatory agency raises RRC over time, earnings growth will reflect the forecast rate of growth better than intrinsic growth. Finally, it appears that security analysts use past growth in earnings more than any other variable to forecast future growth.

Given that earnings growth is used by investors to forecast future growth, the smoothed value of the variable YGRS is superior to the current value. The previous illustration revealed that YGR overreacts to changes in the allowed rate of return and therefore is subject to large random fluctuations. The data on YGR confirm this conclusion.

The use of dividend growth as a forecast of future growth is subject to the same limitations as earnings if the firm pays a constant fraction of its earnings in dividends. That is, under this assumption the dividend growth rate in any period is the same as the earnings growth rate. Firms tend to change their dividend rate from one

[5] Let the book value per share at the start of T be BVS($T-1$) = \$50.00. With RRC(T) = .10, AYP(T) = \$5.00, and with RETR(T) = .5, BVS(T) = \$52.50. If RRC($T+1$) = .10, AYP($T+1$) = \$5.25, and YGR($T+1$) = RTGR($T+1$) = .05. However, if RRC($T+1$) = .11, RTGR($T+1$) = (.11)(.5) = .055, while AYP($T+1$) = \$5.775, and YGR($T+1$) = (\$5.775 − \$5.00)/\$5.00 = .155.

period to the next to make the dividend fluctuate less than earnings. This would suggest that dividend growth may be superior to earnings growth. However, firms also change their dividend rate in order to make the short-run changes in dividend growth inversely correlated with expected growth. For example, consider a firm that experiences a rise in its rate of return on assets and investment. For a variety of reasons, some related to this event, the firm may raise its investment rate and secure additional funds from retention. Specifically, the firm decides not to raise its dividend for a number of periods. The firm's rate of return and retention rate have gone up, and its expected future growth is higher, but the rate of growth in the dividend is zero over this period. Conversely, a fall in the rate of return on investment and in the retention rate would result in an abnormally large rise in the dividend.

The foregoing discussion suggests that, insofar as dividend growth is used to forecast future growth, it is the smoothed value $DGRS(T)$ and not the current value that should be used. For the current value of dividend growth we use

$$DGR(T) = [DIV(T) - DIV(T-1)]/DIV(T-1), \qquad (5.4.4)$$

with $DIV(T)$ and $DIV(T-1)$ adjusted for stock splits and dividends over the years. $DGRS(T)$ is measured in the same way as YGRS, with $\lambda = .30$ and not .15 on the grounds that random fluctuations are less pronounced in the dividend than in earnings.

Intrinsic growth and earnings growth also will differ due to outside financing. If there is no retention and no financing and if the return on common is unchanged, both growth rates are zero. However, if assets grow due to increased debt or the sale of stock there will be a positive earnings growth rate, its value depending on the relation between the return on assets and the interest rate or the relation between the return on common and the yield at which the stock is sold. The intrinsic growth rate will depend on the relation between the book and market values of the stock given the rate of growth in assets. Which measure of growth reflects investor expectations best is difficult to judge.

The third alternative to the intrinsic growth rate is the rate of growth in the price of the stock. It will respond to all the factors mentioned above and, in addition, to the yield investors require on the share. A change in the yield investors require due to a

change in the interest rate or some other cause will change a share's price and its rate of growth. Changes in share price on this account have no informational content with regard to expected future growth in the dividend. For a variety of reasons, the annual growth rate in share price fluctuates over so wide a range of positive and negative values as to suggest it would be a poor estimator of dividend growth. That is, either the smoothed value would be unreasonably large or negative, or the smoothing constant λ would have to be so small as to deny much relevance for the recent past.[6]

5.5 *Choice Among Growth Measures*

The previous sections have described a number of different quantities that investors may use in arriving at the expected rate of growth in a share's dividend. Insofar as these measures differ, they result in different measures of share yield. How are we to select among these measures of growth the best estimate of investor expectation and hence the best measure of share yield?

It is clear that, other things the same, the dividend yield on a share will vary inversely with the expected rate of growth. The current dividend is given. Hence, the higher the expected growth rate, the higher the price per share and the lower the dividend yield. Accordingly, the measure of growth that explains the variation in dividend yield among shares best would seem to be the best measure of growth.

The dividend yield may be expected to vary among shares with other variables than the growth rate. The greater the risk of a dividend expectation's growth, the lower the price and the higher the dividend yield on the share. Risk variables that may influence the dividend yield are:

[6] This conclusion is confirmed by the work on the Sharpe [40] capital asset pricing model. In this empirical work the average realized dividend yield and rate of growth in price is used as an estimate of the yield at which a share is selling. However, the resultant estimates are so poor that practically all the empirical work is on portfolios rather than shares. Portfolio yields allow smoothing over shares as well as time, and even here the range of average realized yields is beyond the bounds of reason as measures of expected yield. See M. C. Jensen [22], Irwin Friend and Marshall Blume [13], and W. F. Sharpe [41].

$\mathrm{LEVM}(T)$ = debt-equity ratio with both variables measured at their market values at the end of T;
$\mathrm{PEE}(T)$ = sales of electricity as a percentage of total sales during T;
$\mathrm{QLE}(T)$ = an index of the quality of earnings during T; and
$\mathrm{COEV}(T)$ = an index of the instability of return on assets as of the end of T.

The derivation and rationale for the inclusion of each of the above variables is presented below.

Previous chapters have shown that the yield investors require on a share should increase with the firm's leverage rate. It follows that the dividend yield on a share should vary with that rate. Under the PCCM theory of security valuation the relevant figures for a firm's leverage rate are the market values of its debt and common equity. Establishing the market value of a firm's debt is a formidable problem because many of its outstanding debts may be privately placed or traded very infrequently. In either case no published market price is available. To deal with this problem it was found convenient to arrive at a computed market value for all outstanding preferred stock and long-term bond issues as follows. The market value of a preferred stock was taken as its periodic dividend divided by the current yield on utility grade preferred stocks. For a bond, the market value at any point in time T was taken as the present value of the remaining coupon payments and the principal at maturity discounted at the yield for a bond of that or a comparable quality rating. The call price sets an upper limit on the market value of a bond, but this posed no problem since the coupon rate was below the current rate over the entire period 1958–1968. For short-term debt, market value was set equal to book value.

Hence, the market value of a utility's total debt was determined as follows. The computed price per each bond or preferred stock, obtained as above, was multiplied by the quantity of each security outstanding to obtain the market value of the outstanding preferred stock and long-term debt issue. The book value of the short-term debt was added to obtain the total debt of a utility at market value. Dividing by the number of outstanding shares of common results in the debt on a per share basis, and dividing that figure by the

price per share results in $\mathrm{LEVM}(T)$. We would expect $\mathrm{DIYD}(T)$ to vary with $\mathrm{LEVM}(T)$.

Utilities sell both gas and electricity, and it generally is accepted that gas companies are riskier than electric utility companies. Hence, we would expect the dividend yield on a share to vary inversely with $\mathrm{PEE}(T)$, the percentage of electricity sales to total sales.

The quality of earnings index is

$$\mathrm{QLE}(T) = [\mathrm{DNT}(T) - \mathrm{FTS}(T) - \mathrm{ITC}(T)]/\mathrm{AFC}(T), \qquad (5.5.1)$$

where

$\mathrm{DNT}(T)$ = deferred income tax charge for period T;
$\mathrm{FTS}(T)$ = flow-through tax savings for period T; and
$\mathrm{ITC}(T)$ = interest charged to construction for period T.

Deferred income taxes arise, it will be recalled, when the tax saving due to accelerated depreciation is excluded from income. The arguments presented earlier for including the charge in income when calculating the retention and/or the retention rate suggest that the price of a utility's stock will vary more or less with the charge. It can be argued similarly that the quality of earnings is lower as the flow-through tax savings component of income is increased. Finally, interest charged to construction arises as follows. Construction in progress and income to common are increased by the interest on the construction. It may be expected that this component of income will be replaced by the earnings on the asset when it goes into production. Nonetheless, some utility analysts question the quality of earnings insofar as interest on construction is included.

The dividend yield on a share varies with the risk or uncertainty of the dividend expectation. This will increase with the instability of the return on its assets and the portion of the return financed by debt. The latter has been accounted for by the inclusion of a leverage variable; the former may be accounted for by the coefficient of variation in the return on assets. The return on assets in period T is defined as

$$\mathrm{RRA}(T) = [\mathrm{INT}(T) + \mathrm{PFDD}(T) + \mathrm{AFC}(T)]/.5\,[\mathrm{TTA}(T) + \mathrm{TTA}(T-1)], \qquad (5.5.2)$$

where

$$\begin{aligned} INT(T) &= \text{interest on all debt during } T; \\ PFDD(T) &= \text{preferred dividends paid during } T; \text{ and} \\ TTA(T) &= DEBB(T) + CSS(T). \end{aligned}$$

The coefficient of variation in the return on assets is

$$COEV(T) = RASD(T)/RAMV(T), \tag{5.5.3}$$

where

$$\begin{aligned} RASD(T) &= \text{the standard deviation of } RRA(J) \text{ with } J = T - 9 \text{ to } T, \text{ and} \\ RAMV(T) &= \text{the mean of } RRA(J) \text{ with } J = T - 9 \text{ to } T. \end{aligned}$$

The model used to explain variation in dividend yield among shares is, therefore,

$$DIYD(T) = \alpha_0 + \alpha_1 GR\text{—} + \alpha_2 LEVM + \alpha_3 PEE + \alpha_4 QLE + \alpha_5 COEV. \tag{5.5.4}$$

GR— is measured in turn by GRTH, YGRS, and DGRS.

Our hypotheses are that α_1, α_3, and α_4 are negative and that α_2 and α_5 are positive. However, our objective in running this regression is not to explain variation in dividend yield among utility shares. Our objective is to estimate the growth investors expect on a utility share. The performance of a growth measure in explaining variation in DIYD(T) among shares is taken as a measure of its accuracy as an estimate of the growth investors expect.

5.6 *Estimation of the Growth Rate*

To test each of the growth measures suggested above, GRTH, YGRS, and DGRS, Eq. (5.5.4) was run three times on the electric utility sample for the years 1958–1968, each run using a different measure of growth. The dividend yield was inversely correlated with the growth measure at the 5 percent significance level in every year for all three growth variables.

This suggested that investors might use more than one source of information in estimating growth. Accordingly, we ran DIYD on the above risk variables and all three measures of growth. GRTH and YGRS were each significant in practically every year, but DGRS was not significant in all but a few years, and in those years it was barely significant. The conclusion that follows is that dividend growth provides little information about the growth investors expect that is not contained in GRTH and YGRS.

Table 2. ***Regression of Dividend Yield on Intrinsic Growth, Earnings Growth, and Risk Variables, 1958–1968***

$DIYD = \alpha_0 + \alpha_1 GRTH + \alpha_2 YGRS + \alpha_3 LEVM + \alpha_4 PEE + \alpha_5 QLE + \alpha_6 COEV$

Year	α_0	α_1	α_2	α_3	α_4	α_5	α_6	Cor. Coef.
1958	.0491	−.1861	−.0980	.0051	−.0001	−.0011	−.0589	.883
		−4.30	−3.45	2.39	−0.01	−0.37	−0.16	
1959	.0602	−.2101	−.1292	.0057	−.0066	−.0066	.0332	.906
		−4.65	−4.04	2.57	−1.96	−2.36	0.08	
1960	.0565	−.2276	−.1443	.0041	−.0038	−.0079	.0718	.912
		−5.09	−4.33	1.71	−1.19	−2.53	0.18	
1961	.0489	−.2852	−.0444	.0049	−.0049	−.0013	−.4862	.867
		−5.85	−1.40	1.62	−1.65	−0.36	−1.36	
1962	.0480	−.1815	−.0898	.0060	−.0043	−.0022	−.3413	.884
		−3.71	−1.99	2.50	−1.65	−0.76	−0.90	
1963	.0447	−.1053	−.1841	.0066	−.0005	−.0009	.0045	.895
		−1.97	−3.36	2.82	−0.20	−0.35	0.01	
1964	.0470	−.1055	−.1655	.0041	−.0040	−.0031	.0234	.880
		−1.87	−2.94	1.45	−1.71	−1.04	0.07	
1965	.0516	−.1557	−.1916	.0058	−.0029	−.0001	.2914	.878
		−2.48	−2.94	1.92	−1.11	−0.03	0.77	
1966	.0714	−.2224	−.2606	.0050	−.0080	.0030	.1969	.921
		−3.64	−4.12	1.62	−2.82	0.85	0.57	
1967	.0714	−.3275	−.2300	.0081	−.0043	−.0009	.8133	.868
		−4.75	−3.04	1.94	−1.10	−0.17	1.98	
1968	.0605	−.2409	−.1002	.0050	−.0026	−.0010	.0533	.814
		−3.90	−1.83	1.29	−0.72	−0.25	0.13	

NOTE: Numbers below regression coefficients are their t values.

Table 2 contains the regression results for

$$\mathrm{DIYD} = \alpha_0 + \alpha_1 \mathrm{GRTH} + \alpha_2 \mathrm{YGRS} + \alpha_3 \mathrm{LEVM} + \alpha_4 \mathrm{PEE} + \alpha_5 \mathrm{QLE} + \alpha_6 \mathrm{COEV} + \mathrm{ERR}, \qquad (5.6.1)$$

where ERR is the residual or error term. The correlation between DIYD and GRTH or YGRS is highly significant in every year, and there is only one year in which the significance of either coefficient is materially below the 5 percent level. The leverage coefficient α_3 has the correct sign in every year and is significant at the 5 percent level in six of the eleven years. It may be noted that the simple correlation between DIYD and LEVM is very high, but LEVM also has a strong inverse correlation with the growth variables. High growth firms have low leverage rates and vice versa so that the partial correlation between DIYD and LEVM is not very strong.

The PEE coefficient has the correct sign in every year, but it has a t value above two in only two years, and it differs negligibly from zero in two years. The QLE coefficient has $t > 2$ only in 1959 and 1960, and in several of the years it differs negligibly from zero. Among the risk variables, COEV contributes least to explaining the variation in DIYD among shares. The COEV coefficient is significant at the 5 percent level in only one year, and in three years α_6 has the incorrect sign.

Since DIYD's partial correlation with both GRTH and YGRS was significant in every year but one, it would seem that both measures of growth are used by investors in arriving at the growth they expect. Therefore, a better measure of growth than either variable is a weighted average of the two, and the best set of weights is the relative values of their coefficients. Specifically, the weighted average growth rate for company J in the year T is

$$\mathrm{GRAV}(J,T) = \frac{\alpha_1(T)^* \mathrm{GRTH}(J,T) + \alpha_2(T)^* \mathrm{YGRS}(J,T)}{\alpha_1(T) + \alpha_2(T)}. \qquad (5.6.2)$$

GRAV has the same impact on DIYD as the two original variables combined. That is, the regression of DIYD on GRAV and on the risk variables produces a coefficient equal to the sum of the coefficients of GRTH and YGRS. In view of the poor performance

of COEV, the values of α_1 and α_2 used to obtain GRAV were obtained from Eq. (5.6.1), with COEV omitted from the independent variables.

Our use of the Eq. (5.6.1) regression statistics to obtain the best possible estimate of the growth investors expect is somewhat unconventional. Ordinarily the equation is used to establish how DIYD varies with the independent variables and/or to obtain an error-free measure of DIYD for a firm. The error-free measure of DIYD for firm J in the year T is

$$\overline{\mathrm{DIYD}}(J,T) = \mathrm{DIYD}(J,T) - \mathrm{ERR}(J,T). \qquad (5.6.3)$$

The rationale is that investors observe the variables on the right-hand side of Eq. (5.6.1) without error and arrive at the value of $\overline{\mathrm{DIYD}}$ for a firm. The value of the variable that we observe, however, is subject to random error for various possible reasons, and the Eq. (5.6.1) regression provides $\overline{\mathrm{DIYD}}$ for the firm, which is free of error.

However, our situation is just the reverse. We can measure the dividend yield free of error, and our measure of the growth rate is subject to error as an estimate of the growth rate investors expect. Furthermore, the error-free value of DIYD which we observe reflects the growth rate investors expect. It therefore would seem reasonable to infer this correct growth rate from the regression.

$$\mathrm{GRAV} = \alpha_0 + \alpha_1 \mathrm{DIYD} + \alpha_2 \mathrm{LEVM} + \alpha_3 \mathrm{PEE} + \alpha_4 \mathrm{QLE} + \alpha_5 \mathrm{ERR}. \qquad (5.6.4)$$

The independent variables other than DIYD may be interpreted as follows. The growth rate consistent with a given value of DIYD increases with the leverage rate and decreases with PEE and QLE. Table 3 presents the Eq. (5.6.4) regression statistics. The correlation between GRAV and DIYD is very strong, and the correlation with the other variables is more or less as expected.

The growth rate investors expect for firm J in year T that we infer from the Eq. (5.6.4) regression statistics is

$$\mathrm{GRAVC}(J,T) = \mathrm{GRAV}(J,T) - \mathrm{ERR}(J,T). \qquad (5.6.5)$$

Table 3. ***Regression of Average Growth Rate on Dividend Yield and Risk Variables, 1958–1968***

$GRAV = \alpha_0 + \alpha_1\ DIYD + \alpha_2\ LEVM + \alpha_3\ PEE + \alpha_4\ QLE$

Year	α_0	α_1	α_2	α_3	α_4	*Cor. Coef.*
1958	.1376	−2.364	.0015	.0057	−.0085	.868
		−10.07	.24	.64	−1.01	
1959	.1536	−2.093	.0021	−.0167	−.0170	.881
		−10.89	.36	−2.19	−2.56	
1960	.1337	−1.844	−.0053	−.0088	−.0188	.898
		−10.22	−.10	−1.36	−2.87	
1961	.1210	−1.755	−.0105	−.0095	−.0113	.848
		−7.84	−1.48	−1.49	−1.52	
1962	.1372	−2.234	−.0007	−.0102	−.0161	.854
		−9.06	−.10	−1.58	−2.18	
1963	.1281	−2.269	.0016	.0002	−.0076	.871
		−9.67	.23	.04	−1.10	
1964	.1427	−2.258	−.0099	−.0125	−.0173	.862
		−8.76	−1.28	−2.04	−2.17	
1965	.1289	−1.818	−.0041	−.0098	−.0065	.857
		−8.10	−.66	−1.74	−.80	
1966	.1309	−1.415	−.0044	−.0142	.0028	.911
		−10.34	−1.01	−3.06	.46	
1967	.1164	−1.020	−.0088	−.0079	−.0093	.857
		−8.12	−1.97	−1.51	−1.34	
1968	.1324	−1.552	−.0061	−.0068	−.0015	.801
		−7.44	−.98	−.92	−.18	

NOTE: Numbers below regression coefficients are their t values.

While GRAVC is superior to GRAV, we cannot be certain that GRAVC is, in fact, completely free of error. Assume that the true value of expected growth is GTRU and that the relation between GRAV(*J,T*) and GTRU(*J,T*) is

$$\mathrm{GRAV}(J,T) = \lambda_0 + \lambda_1\ \mathrm{GTRU}(J,T) + \mathrm{ERR}(J,T), \qquad (5.6.6)$$

with $\lambda_0 \neq 0$ or $\lambda_1 \neq 1$. GRAVC eliminates the error in GRAV due to ERR, but it does not correct for systematic bias in GRAV. GRAVC will have systematic error if investors believe that, across all firms, GRAV is on average above or below the growth they expect to prevail in the future. While this is possible, there appears little ground for believing it to be true for utility companies.

If GRAVC is the rate of growth investors expect, the yield they require on a share is

$$\mathrm{KGAVC} = \mathrm{DIYD} + \mathrm{GRAVC}. \qquad (5.6.7)$$

Table 4 presents the sample means and standard deviations of GRAVC for 1958–1968 and, for comparison, the interest rate on Aa rated bonds.[7] KGAVC follows the broad movement in AAR over the eleven-year period, but from one year to the next they do not always move together. The spread between KGAVC and AAR appears large, but it is not beyond the bounds of reason.

Table 4. ***Sample Means and Standard Deviations of Share Yield Based on Predicted Growth Rate, GRAVC, 1958–1968***

	Share yield		*Yield on*
Year	*Mean*	*Std. dev.*	*Aa bonds*
1958	.0910	.0097	.0422
1959	.0966	.0081	.0471
1960	.0909	.0070	.0449
1961	.0835	.0056	.0450
1962	.0885	.0068	.0431
1963	.0885	.0068	.0439
1964	.0889	.0067	.0446
1965	.0912	.0049	.0475
1966	.0993	.0041	.0546
1967	.1028	.0023	.0640
1968	.0976	.0045	.0675

5.7 *Finite Horizon Growth Models*

A number of writers have questioned the validity of share value models based on the assumption that the current rate of growth

[7] Share yield based on GRAV instead of GRAVC has the same sample mean in each year, but the standard deviation averages about one-third larger.

in the dividend is expected to prevail forever.[8] If the dividend is expected to grow for N periods at the rate GRAV and thereafter at a long-run normal rate of GRLR, and if investors require a yield of KGON on the share, its price is given by the expression

$$\mathrm{PPS}(T) = \sum_{t=1}^{N} \frac{\mathrm{DIV}(T)\,[1+\mathrm{GRAV}]^t}{[1+\mathrm{KGON}]^t} + \frac{\mathrm{DIV}(T)\,[1+\mathrm{GRAV}]^N[1+\mathrm{GRLR}]}{[\mathrm{KGON}-\mathrm{GRLR}]\,[1+\mathrm{KGON}]^N}. \qquad (5.7.1)$$

Given KGON, N, and GRLR in addition to DIV and GRAV, Eq. (5.7.1) can be used to arrive at the price at which a share should sell. However, we know PPS and want to establish KGON. This may be done if GRLR and N are known. The solution of Eq. (5.7.1) for KGON also will produce a measure of growth that is a weighted average of GRAV and GRLR, its value depending on their relative magnitudes and the value of N. The growth rate equivalent to GRAV for N periods and GRLR thereafter is

$$\mathrm{GRON} = \mathrm{KGON} - \mathrm{DIV}\,[1+\mathrm{GRAV}]/\mathrm{PPS} \qquad (5.7.2)$$

An investigator who has reason to believe that a firm's dividend is expected to grow at the rate GRAV for N periods and at the rate GRLR thereafter reasonably might use this information to arrive at KGON and consider this measure of share yield superior to KGAV or even KGAVC. One advantage of KGON over KGAV is that the former does not require the regression analysis of sample data to arrive at the share yield for a firm. A more important advantage is that it is free of the systematic as well as the random errors of measurement in GRAV discussed in the previous section.

The problem involved in using Eq. (5.7.1) to arrive at an error-free measure of share yield is in arriving at the values of N and GRLR. Without special information N and GRLR must be assigned the same values for all corporations. However, doing so would not eliminate the random error, and it would not eliminate the systematic error unless the values assigned to N and GRLR were the correct ones for all firms in the sample. These are very brave assumptions.

[8]For example, see B. G. Malkiel [29] and R. M. Soldofsky and J. T. Murphy [42].

Conceivably, we could test a set of values for N and GRLR as follows. Compute KGON and GRON for each firm. Regress DIYD on GRON and the risk variables. If the multiple correlation is higher with GRON than with GRAV as the growth variable, it is a better measure of growth. All possible combinations of N and GRLR could not be tested. Instead, GRLR = .045 was used on the assumption that this value could not be far off the mark, and GRON was tested for various values of N in the interval five to thirty years. The hypothesis was that if the multiple correlation reached a maximum for a value in the interval $5 \le N \le 30$, that value of N is the horizon and that value of GRON is the best estimate of the growth investors expect. What we found was that as N goes from five to infinity (GRON = GRAV when $N = \infty$) the multiple correlation fell, reaching a minimum at about $N = 15$, and then rose continuously. There is undoubtedly some technical explanation for these results, but regardless of the explanation the assumption of a common finite horizon for all shares cannot be used to obtain a better measure of growth than GRAV. Compared with KGAV, KGON eliminates neither the random nor the systematic error under the estimating methods available to us.

5.8 The Earnings Yield

The earnings yield on a share has been widely used as a measure of share yield both in regulatory proceedings and in empirical research on security valuation.[9] Therefore, an examination of alternative measures of share yield is not complete without considering this alternative.

There are two conditions under which the earnings yield on a share is an accurate measure of the yield at which the share is selling. The derivation of Eq. (2.2.1) established that the earnings yield is correct when a firm pays all of its earnings in dividends, engages in no outside financing, and when, as a consequence, its dividends are not expected to grow. Without even looking at the

[9]On the latter see, for example, J. F. Weston [48] and Miller and Modigliani [32]. H. Benishay [3], D. H. Bower and R. S. Bower [4], and B. G. Malkiel and J. G. Cragg [30] used the price/earnings ratio in their empirical work.

data to be presented it is clear that these conditions are not satisfied, and this rationalization of the earnings yield can be dismissed at once.

The derivation of Eq. (2.6.7) established the other condition under which the earnings yield on a share is equal to its yield. With stock financing the relevant stock valuation model is

$$P = \frac{(1 - b)Y}{k - br - vs}. \tag{2.8.8}$$

When $r = k$, $s = 0$. The denominator becomes $(1 - b)k$, Eq. (2.8.8) reduces to

$$P = Y/k, \tag{5.8.1}$$

and $k = Y/P$, the earnings yield. If there is any group of firms for which the return on investment is in general equal to the yield investors require on a share, it is the public utility group. Hence it is possible that the earnings yield provides an accurate measure of share yield.

A firm's earnings yield is

$$\mathrm{KEYD}(T) = \mathrm{EPS}(T)/\mathrm{PPS}(T), \tag{5.8.2}$$

with the measurement of EPS(T) given by Eq. (5.2.2). As with RRC(T) and other variables discussed earlier, KEYD is subject to random year-to-year fluctuations and permanent changes from one period to the next. However, the former are comparatively small, and an average of past values of the variable would not be as accurate as the current value. The elimination of the random fluctuations also would cause the measure used to lag changes in the true value.

Table 5 presents the mean and standard deviation of KEYD for the 54 companies in our sample for the years 1958–1968. For comparison, Table 5 also presents the yield on Aa rated bonds in each year. The sample average values of KEYD are about equal to the yield on Aa rated bonds from 1961 on, and the standard deviation of KEYD indicates that the values of KEYD for many of the firms in the sample were below the interest rate. Therefore, if risk makes share yields higher than the risk-free interest rate,

Table 5. *Sample Means and Standard Deviations of Earnings Yield, 1958–1968*

Year	Earnings yield: Mean	Earnings yield: Std. dev.	Yield on Aa bonds
1958	.0059	.0072	.0422
1959	.0601	.0096	.0471
1960	.0537	.0091	.0449
1961	.0442	.0069	.0450
1962	.0497	.0066	.0431
1963	.0491	.0065	.0439
1964	.0472	.0064	.0446
1965	.0519	.0070	.0475
1966	.0613	.0101	.0546
1967	.0700	.0116	.0640
1968	.0651	.0076	.0675

these data suggest that earnings yield is a very poor approximation of the yield at which a share is selling.

Further evidence on the question is provided by running the regression

$$\mathrm{KEYD}(T) = \alpha_0 + \alpha_1 \mathrm{GRAV}(T) + \alpha_2 \mathrm{LEVM}(T) + \alpha_3 \mathrm{PEE}(T) + \alpha_4 \mathrm{QLE}(T). \tag{5.8.3}$$

A necessary condition for KEYD to be the correct measure of share yield is that $\alpha_1 = 0$. To see this recall that share yield is equal to KEYD when $r = k$. Also, when $r = k$ price is independent of the retention and stock financing rates and of the expected rate of growth in the dividend. Since the current earnings per share are independent of the growth rate, we would expect to find the earnings yield independent of the growth rate. Hence, in the above regression KEYD should be independent of GRAV, either because $r = k$ or because investors do not use GRAV in estimating the rate of growth in the dividend.

Table 6 presents the regression results for Eq. (5.8.3) for each of the years 1958–1968. Notice that α_1, the coefficient of GRAV, is negative and statistically significant at the 5 percent level or better in every year except 1968. The inverse correlation between the variables would arise when $r \neq k$ since firms with high growth rates can be expected to have $r > k$, and their shares would sell

Table 6. *Regression of Earnings Yield on Average Growth and Risk Variables, 1958–1968*

$KEYD = \alpha_0 + \alpha_1\ GRAV + \alpha_2\ LEVM + \alpha_3\ PEE + \alpha_4\ QLE$

Year	α_0	α_1	α_2	α_3	α_4	*Cor. Coef.*
1958	.0547	−.1309	.0111	−.0016	−.0044	.677
		−2.90	3.40	−.32	−.93	
1959	.0779	−.1804	.0122	−.0199	−.0091	.738
		−2.96	2.86	−3.32	−1.72	
1960	.0680	−.2736	.0105	−.0085	−.0048	.763
		−4.02	2.37	−1.57	−.86	
1961	.0619	−.2881	.0070	−.0078	−.0019	.756
		−4.74	1.55	−1.91	−.40	
1962	.0625	−.1844	.0074	−.0090	−.0107	.704
		−3.28	1.74	−2.15	−2.18	
1963	.0575	−.2096	.0098	−.0035	−.0019	.713
		−3.84	2.42	−.85	−.42	
1964	.0666	−.2145	.0034	−.0111	−.0115	.715
		−3.64	.67	−2.73	−2.10	
1965	.0788	−.3082	.0043	−.0140	−.0055	.747
		−4.69	.95	−3.30	−.91	
1966	.1017	−.4240	.0081	−.0241	−.0014	.840
		−4.88	1.74	−4.84	−.22	
1967	.1023	−.4624	.0113	−.0181	−.0126	.761
		−3.91	1.94	−2.71	−1.40	
1968	.0641	−.0651	.0170	−.0105	−.0017	.690
		−1.00	4.17	−2.14	−.31	

NOTE: Numbers below regression coefficients are their *t* values.

at lower earnings yields than shares with low growth rates. The conclusion is that KEYD is a poor measure of share yield.

5.9 Summary and Conclusion

As stated initially in this chapter, the implementation of the PCCM or the traditional theories of a firm's cost of capital to establish the return a utility should be allowed to earn requires the measurement of the yield investors require on the firm's stock. The measurement of this variable, therefore, is a condition for implementing either cost of capital model.

Under the very restrictive assumption that the return on common equity investment is equal to the yield investors require on a share, earnings yield may be used as a measure of share yield. However, analysis of sample data for 54 electric utility companies over the period 1958–1968 revealed that this assumption is very wide of the mark. Return on investment and share yield differs by amounts that vary among firms, and, on average, earnings yield understates the yield investors require on a share.

On the assumption that the dividend is expected to grow indefinitely at the rate *g*, the sum of the dividend yield and the expected growth rate provides a correct measure of share yield. It then was shown that two plausible measures of this growth rate are YGRS, the smoothed rate of growth in earnings per share, and GRTH, the sum of the retention and stock financing growth rates. A superior measure of growth is GRAV, a weighted average of GRTH and YGRS with the weights determined by their contribution to the explanation of the variation in dividend yield among shares. GRAV is nonetheless subject to error insofar as there are random fluctuations in GRTH and YGRS from one year to the next and insofar as investors expect that, in the long run, growth will on average be above or below GRAV. The random error in GRAV is eliminated by using GRAVC, the value predicted by regressing GRAV on DIYD and other variables that investors use in estimating growth for a firm.

A finite horizon stock value model was investigated for the purpose of establishing whether it could be used to eliminate the systematic error in GRAVC that might exist if long-run growth was above or below GRAV on average. The effort proved fruitless, and our measures of growth and share yield may be in error on this account.

6

Implementing and Testing the Theories

This chapter begins by describing the procedures employed and presenting the results obtained in implementing the traditional cost of capital theory. Recall that the market-book value ratio for a utility's stock is above (below) one when the allowed rate of return-cost of capital ratio is above (below) one. Hence, the two ratios are alternative means of implementing the theory, and the comparative analysis of the data for the two ratios is a means of establishing the usefulness and limitations of each ratio for that purpose. It will be seen that our measurement of the cost of capital is not free of error, but it nonetheless is more accurate than the market-book ratio as a means of arriving at the rate of return a utility should be allowed to earn.

The same type of analysis may be applied to the PCCM cost of capital theory since the market-book ratio is above (below) one when the allowed rate of return-cost of capital ratio is above (below) one under the PCCM theory as well. However, we find that the PCCM cost of capital estimates are not consistent with this theorem. Furthermore, we find that the inconsistency between the two ratios is due to a problem in implementing the PCCM leverage theorem. The theory produces the correct figure for a firm's cost of capital only in the special and uninteresting case where the actual rate of return already is equal to the cost of capital. Under the assumptions common to both theories, only the traditional theory is free of logical problems and amenable to implementation for a utility with a rate of return different from the cost of capital.

The following analysis establishes that under the assumptions common to both cost of capital theories only the traditional does not become entangled in a web of difficulties and unreasonable empirical statements. For the traditional theory to be correct it still must be established that the assumptions with regard to security valuation on which it is based are correct. In particular, share yield should be an increasing function of the leverage rate, and it should be independent of the utility's retention and stock financing rates. The remainder of the chapter is devoted to testing these theorems. Since the PCCM theory has no empirical relevance in a world where a firm's rate of return differs from its cost of capital, it would seem that no purpose is served in testing the PCCM leverage theorem. However, the theorem has generated so much attention in the literature that it may be of interest to see what the data say with regard to its validity.

6.1 *Implementing the Traditional Theory*

It was shown in chapter 4 that under the traditional cost of capital (and the PCCM) theory the rate of return a utility earns on its assets is above its cost of capital if the market-book value ratio of its stock is above one and vice versa. The market-book value ratio (MBR) is simply

$$\text{MBR} = \text{PPS}/\text{BVS}, \tag{6.1.1}$$

and Table 7 presents the 54 firm sample averages of the variable for the years 1958–1968. It can be seen that the MBR averages vary from 1.93 to 2.69 over the eleven years. Furthermore, for every firm in every year MBR > 1. Hence, if the traditional (or the PCCM) theory assumptions with regard to security valuation are true, every firm in every year enjoyed a rate of return in excess of its cost of capital.

However, it is very dangerous to infer from the magnitude of MBR the extent to which a utility's allowed rate of return should

Table 7. ***Sample Average Values of the Traditional Cost of Capital and Related Variables***

Year	*MBR*	*RRA*	*TRCC*	*RRA/TRCC*	*RRC*	*KGAVC*	*RRC/KGAVC*
1958	2.01	.0630	.0557	1.14	.1122	.0910	1.24
1959	1.94	.0648	.0580	1.12	.1160	.0966	1.21
1960	2.19	.0654	.0567	1.16	.1156	.0909	1.27
1961	2.62	.0658	.0545	1.21	.1150	.0835	1.38
1962	2.43	.0686	.0567	1.21	.1209	.0885	1.37
1963	2.48	.0698	.0573	1.22	.1219	.0885	1.38
1964	2.69	.0722	.0579	1.25	.1265	.0889	1.43
1965	2.53	.0746	.0591	1.26	.1313	..0912	1.44
1966	2.22	.0761	.0627	1.21	.1337	.0993	1.34
1967	1.93	.0757	.0643	1.18	.1329	.1028	1.29
1968	1.96	.0740	.0630	1.18	.1279	.0976	1.31

be reduced to bring that figure into equality with its cost of capital. Columns 2, 3, and 4 present the sample average values of RRA, TRCC, and the ratio RRA/TRCC. With the utility's existing debt-equity ratio considered correct, the traditional cost of capital is provided by Eq. (4.2.1). In our mnemonic code the expression is

$$\text{TRCC} = [\text{BVS}^*\,\text{KGAVC} + \text{BDS}^*\,\text{IMBR}]/[\text{BVS} + \text{BDS}], \tag{6.1.2}$$

with

$$\text{BDS}(T) = \text{DEQ}(T)^*\,\text{BVS}(T), \tag{6.1.3}$$

$$\text{IMBR}(T) = [\text{PFDD}(T) + \text{INT}(T)]/.5\,[\text{DEBB}(T) + \text{DEBB}(T-1)], \tag{6.1.4}$$

and all the other variables previously defined.

Inspection of the values of RRA/TRCC in Table 7 reveals that they are very much smaller than MBR. For example, in 1958 we have MBR = 2.01 and RRA/TRCC = 1.14, and in 1964 the ratios are 2.69 and 1.25. It was noted on pages 63–65 that leverage and retention will make MBR > RRA/TRCC when the latter is above one. Stock financing, of course, will add to the difference.

A numerical illustration can demonstrate more vividly the wide variation in MBR consistent with any given difference between RRA and TRCC. Assume a firm with RRA = .08, KGAVC = .099, DEQ = 2.0, and IMBR = .06. Eq. (6.1.2) may be used to find that TRCC = .073. The firm's return on common is

$$\text{RRC} = \text{RRA} + (\text{RRA} - \text{IMBR})\text{DEQ} = .12. \tag{6.1.5}$$

With RRA/TRCC = 1.1, the ratio RRC/KGAVC = 1.21. It is clear that varying IMBR and/or DEQ will change the RRC/KGAVC ratio consistent with RRA/TRCC = 1.1. To calculate MBR we must further specify RETR and SFRS. If RETR = .40 and SFRS = .03, then, from Eq. (2.8.12),

$$\text{EACR} = \frac{\text{RRC} - \text{KGAVC}}{\text{RRC} - \text{RRC}^*\text{RETR} - \text{SFRS}}$$

$$= \frac{.12 - .099}{.042} = .5, \tag{6.1.6}$$

and, from Eq. (2.8.8), the market-book value ratio is

$$\text{MBR} = \frac{[1.0 - \text{RETR}]\text{RRC}}{\text{KGAVC} - \text{RETR}^*\text{RRC} - \text{EACR}^*\text{SFRS}} = 2.0. \tag{6.1.7}$$

Furthermore, it is evident that varying RETR and SFRS as well as DEQ and IMBR would change the MBR consistent with the given ratio of RRA/TRCC = 1.1. Reducing RETR to .2 and SFRS to zero reduces MBR from 2.0 to 1.28.

The conclusion is that MBR $\lesseqgtr$ 1 is unquestionable evidence that the allowed rate of return is above or below the cost of capital, provided that the traditional theory is true. However, MBR is a poor indication of the change in RRA needed to make it equal to KGAVC. The alternative is to determine RRC and KGAVC. Notice, these variables are selected rather than RRA and TRCC because we have seen that the regulatory process actually involves adjusting RRA so that RRC = KGAVC. TRCC is merely KGAVC adjusted to allow for the coupon interest on the outstanding debt at the given debt-equity ratio.

However, using KGAVC to determine RRC and RRA also is not free of difficulties. The specific problem that arises is the accuracy of KGAVC as a measure of share yield. Assume that in the example given above all the data are observed free of error except for KGAVC and SFRS. Specifically, suppose we observe SFRS = .09 instead of the true value, .03. To calculate KGAVC we cannot use the Eq. (6.1.6) value of EACR since it requires knowledge of KGAVC. Instead, knowing that MBR = 2, we use EACR = 1 − (1/MBR) to arrive at the value of KGAVC. Using GRTH instead of GRAVC as the measure of growth, share yield is

$$\text{KGTH} = \text{DIYD} + \text{RETR}^*\text{RRC} + \text{EACR}^*\text{SFRS}$$

$$= .036 + .048 + .045 = .129. \tag{6.1.8}$$

The use of GRAVC instead of GRTH to measure growth may reduce but is unlikely to completely eliminate the error in taking SFRS = .09 when it is, in fact, .03. In any event, using KGTH as the measure of share yield with the above measurement error in SFRS results in the conclusion that RRC should be .129 instead of its appropriate value of .099.

In the above example it is easy to discover that there is something wrong with our measure of share yield. With MBR = 2 we know that RRC > KGAVC. We therefore know that KGAVC = .129 cannot be true with RRC = .12. Unfortunately, we cannot go beyond the statement that KGAVC < .12 to the exact figure for KGAVC. A modest check on the accuracy of KGAVC as a measure of share yield is available, however. For the 54 sample firms over the eleven years, a total of 594 observations, there were 26 cases in which MBR > 1 and RRC/KGAVC < 1. There were 6 other cases in which MBR > 1.6 and 1.0 < RRC/KGAVC < 1.05. In most of these cases SFRS was well above average. SFRS fluctuates over a wide range over time for individual firms and among firms, and there are *a priori* grounds for believing that it is difficult to measure. Therefore, it is likely that in some cases the observed values of KGAVC overstate the true values due to error in the measurement of SFRS.[1] In other cases, the observed KGAVC may be below its

[1] Although KGAV is different from KGTH it is not far different. The rationale for using KGAVC instead of KGTH is that the other information that enters into the former's value reduces if not eliminates the error in KGTH due to error in SFRS and the other variables which determine KGTH.

true value because SFRS is below the value investors actually expect.

We have been very careful to indicate that KGAVC is subject to error as a measure of share yield for two reasons. First, there is no magic formula for arriving at the yield investors require on a share. Second, there are ways in which available data can be used in individual cases when the investigator is not constrained to employ objective general purpose rules in arriving at share yield. However, it should not be inferred from the discussion that we consider KGAVC to be seriously in error as a measure of share yield. Rather, we find the development of KGAVC in chapter 5 convincing evidence that the measurement error in KGAVC is negligible in all but a few cases.

6.2 Implementing the PCCM Theory

When the current and coupon interest rates are the same, the PCCM cost of capital is the leverage-free yield on the firm's stock. Eq. (4.1.1) provides a means for measuring ρ, and in our mnemonic code ρ is

$$\text{PCRO} = [\text{PPS*KGAVC} + \text{LPS*AAR}]/[\text{PPS} + \text{LPS}]. \quad (6.2.1)$$

When the two interest rates AAR and IMBR differ, and when the leverage rate is given, the cost of capital is given by Eq. (4.6.5). In our mnemonic code, the expression is

$$\text{PCCC} = \text{PCRO}\,\frac{\text{BVS} + \text{LPS}}{\text{BVS} + \text{BDS}} + \frac{\text{BDS*IMBR} - \text{LPS*AAR}}{\text{BVS} + \text{BDS}}. \quad (6.2.2)$$

When AAR = IMBR, LPS = BDS, and PCCC = PCRO. PCCC falls below PCRO as AAR rises in relation to IMBR.

Table 8 reproduces the 54 company sample average values of MBR, RRC, KGAVC, RRC/KGAVC, and RRA for the years 1958–1968. The table also presents PCRO, RRA/PCRO, PCCC, and RRA/PCCC. It can be seen that with MBR and RRC/KGAVC above one in every year, RRA/PCRO is below one in every year. If PCRO were the

Table 8. Sample Average Values of the PCCM Cost of Capital and Related Variables

Year	*MBR*	*RRC*	*KGAVC*	*RRC/KGAVC*	*RRA*	*PCRO*	*RRA/PCRO*	*PCCC*	*RRA/PCCC*
1958	2.01	.1122	.0910	1.24	.0630	.0691	.92	.0634	1.00
1959	1.94	.1160	.0966	1.21	.0648	.0748	.87	.0650	1.00
1960	2.19	.1156	.0909	1.27	.0654	.0716	.92	.0647	1.02
1961	2.62	.1150	.0835	1.38	.0658	.0691	.95	.0627	1.05
1962	2.43	.1209	.0885	1.37	.0686	.0706	.97	.0658	1.05
1963	2.48	.1219	.0885	1.38	.0698	.0717	.98	.0665	1.05
1964	2.69	.1265	.0889	1.43	.0722	.0731	.99	.0678	1.07
1965	2.53	.1313	.0912	1.44	.0746	.0755	.99	.0681	1.10
1966	2.22	.1337	.0993	1.34	.0761	.0822	.92	.0703	1.08
1967	1.93	.1329	.1028	1.29	.0757	.0867	.87	.0695	1.09
1968	1.96	.1279	.0976	1.31	.0740	.0849	.87	.0673	1.10

PCCM cost of capital, these data would pose a problem: Why is the allowed return less than the cost of capital when the market-book ratio is above one? However, PCRO is not the cost of capital when AAR $\neq$ IMBR. Furthermore, when AAR > IMBR, as was the case in all of the eleven years, MBR > 1 when RRA = PCRO. Hence, MBR > 1 with RRA < PCRO is consistent with the theory developed in chapter 4.

However, chapter 4 also established that regardless of the relation between AAR and IMBR, MBR $\lesseqgtr$ 1 when RRA $\lesseqgtr$ PCCC. Table 8 reveals that RRA/PCCC equals one in two years, and it is very close to one in most of the remaining years. These values are sample averages, and as one would imagine a large fraction of the firms in each year had MBR > 1 and RRA/PCCC < 1. This fact cannot be attributed to error in the measurement of KGAVC. In practically all of the cases in which RRA/PCCC < 1, we had RRC > KGAVC as well as MBR > 1. Furthermore, PCCC > TRCC. Why should the PCCM cost of capital be consistently above the traditional cost of capital, and why should the PCCM cost of capital exceed the rate of return on assets when share yield is below the rate of return on common?

The reason why PCCC > TRCC is easy to establish. When the current and imbedded interest rates are the same, the expressions for PCRO and TRCC differ only in that the former is based on PPS and the latter is based on BVS. PCCC is PCRO adjusted for the difference in interest rates, and with PPS > BVS for every firm in every year, PCCC > TRCC for every firm in every year.

Which, if either, cost of capital figure is correct will depend on which, if either, theory of security valuation is correct. Under the traditional theory KGAVC is independent of the return the firm is allowed to earn (see Eq. [4.2.4]). Hence, lowering RRA to TRCC will lower RRC and leave KGAVC unchanged. With RRC reduced to the given KGAVC we will have PPS = BVS, or MBR = 1, and RRA = TRCC.

Under the PCCM theory KGAVC is a decreasing function of RRC. To see this recall that under the PCCM theory

$$\text{KGAVC} = \text{PCCC} + [\text{PCCC} - \text{AAR}]\,\text{LPS}/\text{PPS}. \qquad (6.2.3)$$

Reducing RRA to TRCC reduces RRC, which in turn reduces PPS and thereby raises KGAVC. Consequently, reducing RRA to TRCC would reduce RRC to the initial value of KGAVC, but KGAVC would

rise and result in RRC < KGAVC and PPS < BVS. We therefore would find RRA < PCCC.

A more difficult question to answer is why RRA < PCCC with PPS > BVS and RRC > KGAVC. To see how this can take place, assume a firm that initially has RRA = PCCC = TRCC, RRC = KGAVC, and PPS = BVS. If we now raise RRA, it is clear that RRC and PPS are raised. TRCC is not changed because none of the terms on the right-hand side of Eq. (6.1.2), the expression for TRCC, change as a consequence of the rise in RRA. The same may not be true of Eq. (6.2.1), the expression for PCCC when IMBR = AAR. PPS rises with RRA, and that will tend to raise PCCC, but we saw that under the PCCM theory of security valuation the rise in RRA and RRC will reduce KGAVC. It can be shown that the percentage fall in KGAVC is less than the percentage rise in PPS so that PPS* KGAVC rises with RRC. However, PPS also appears in the denominator of Eq. (6.2.1), and it also can be shown that the fall in KGAVC with the rise in PPS makes PCCC independent of RRA if the rate of growth in the dividend is zero.

With PCCC independent of RRA, a rise in RRA will result in RRA > PCCC along with RRC > KGAVC and PPS > BVS. However, if the firm's retention rate is positive and/or the dividend is expected to grow due to stock financing, PCCC rises with RRA, and we may have RRA $\lesseqgtr$ PCCC with PPS > BVS and RRC > KGAVC. Earlier we saw that with growth we could not use the Modigliani-Miller measure of PCCC. We now see that KGAVC and the PCCM theorem on the relation between PCCC and KGAVC also cannot be used. Accepting that the PCCM theory of security valuation is correct, our measure of the cost of capital under the theory, Eq. (6.2.2), more or less overstates the true value when RRC > KGAVC and understates the true value when RRC < KGAVC. Although our measure of PCCC is far superior to the measure implicitly suggested in the writings of Modigliani and Miller,[2] it is nonetheless

[2]The measure of PCCC implicit in the 1958 paper by Modigliani and Miller [34] was earnings including interest divided by the market value of the stock and the debt. Pages 58–60 presented the theoretical basis for rejecting this measure. The measure of share yield analogous to their measure of PCCC is the share's earnings yield, and pages 101–104 demonstrated that earnings yield is grossly in error as a measure of share yield. In their empirical work Modigliani and Miller [32] attempted to adjust for the presence of growth, but the estimates they obtained for the cost of capital demonstrate that the crude adjustment they employed is also grossly in error.

biased as discussed above. There may be a measurement procedure that avoids this bias, but its discovery will be left to others.

6.3 Tests of the PCCM Leverage Theorem

At first glance it would appear to be relatively simple to use statistical regression analysis to test the PCCM leverage theorem. The theory states that

$$k = \rho + (\rho - i)L/P. \qquad (2.4.2)$$

Accordingly, we could run the regression

$$\text{KGAV} = \alpha_0 + \alpha_1 \text{LEVM} \qquad (6.3.1)$$

on the sample data.[3] An estimate of ρ is provided by α_0, and α_1 is an estimate of $\rho - i$. Hence, the theory states that $\alpha_0 - \alpha_1 = i$. The above regression was run on the sample data, and $\alpha_0 - \alpha_1$ exceeded i by margins well beyond what could be attributed to chance. In other words, the yield investors require on a share does not increase with leverage as rapidly as the PCCM theory predicts.

Eq. (6.3.1) can be criticized as a means of testing the theorem on the grounds that it assumes ρ is the same for all firms in the sample, or that α_0 and α_1 are independent of the variables other than LEVM which cause KGAV to vary among firms. To recognize the influence of other risk variables on KGAV, we may use the regression equation

$$\text{KGAV} = \alpha_0 + \alpha_1 \text{LEVM} + \alpha_2 \text{GRAV} + \alpha_3 \text{PEE} + \alpha_4 \text{QLE}. \qquad (6.3.2)$$

KGAV and LEVM are correlated with the other risk variables. In particular, KGAV and GRAV are correlated, and LEVM has a large

[3]KGAV and GRAV are used in the tests which follow. KGAVC is equal to the dividend yield plus a function of the dividend yield. Regressing it on GRAVC, which is a function of the dividend yield, would not produce meaningful results.

inverse correlation with GRAV so that Eq. (6.3.1) actually overestimates the partial correlation between KGAV and LEVM. In using Eq. (6.3.2) to test the leverage theorem, however, we cannot compare $\alpha_0 - \alpha_1$ and i since α_0 is no longer an estimate of ρ. Instead, α_0 is the value KGAV would have when all the risk variables, not just LEVM, are equal to zero. The sample average estimate of ρ on the basis of Eq. (6.3.2) is

$$\alpha_0^* = \alpha_0 + \alpha_2 \overline{\text{GRAV}} + \alpha_3 \overline{\text{PEE}} + \alpha_4 \overline{\text{QLE}}, \qquad (6.3.3)$$

where the bars over the variables indicate sample means.

Table 9 presents the regression statistics for Eq. (6.3.2), and Table 10 presents α_0^*, $\alpha_0^* - \alpha_1$, i, and the t values for the difference between $\alpha_0^* - \alpha_1$ and i, recognizing that the estimates of all the coefficients α_0 through α_4 are subject to sampling error. A t value greater than 1.7 signifies that there is a less than 5 percent chance that the excess of $\alpha_0^* = \alpha_1$ over i is due to chance.

It may be thought that the above results are suspect because KGAV = DIYD + GRAV, and GRAV is one of the independent variables. This is not true since the same results would have been obtained with DIYD the dependent variable in Eq. (6.3.2). In that event, all the regression coefficients would have been the same as those appearing in Table 9 except the coefficient of GRAV. Its value would have been $\alpha_2' = \alpha_2 - 1$. However, the correct value of α_0^* would be obtained by substituting α_2' for α_2 in Eq. (6.3.3) and then adding the average value of GRAV to the result.[4] The outcome would be the same values of $\alpha_0^* - i$ and α_1 as appear in Table 10.

The previous test of the leverage theorem may be questioned on the following grounds. The introduction of additional risk variables recognizes that ρ may vary among the firms in the sample. Substituting in Eq. (6.3.3) the values of the independent variables

[4]In Brigham and Gordon [5] this procedure was not followed and the results seemed to be less at variance with the leverage theorem than they actually were. There, the leverage free value of k, α_0^*, was calculated at a zero growth rate by setting GRAV = 0. It is open to question whether setting GRAV = 0 in Eq. (6.3.2) results in the value of KGAV when GRAV = 0. In any event, if the PCCM theory is correct and Eq. (6.3.2) is a valid model for the determination of share yield, the PCCM theorem on the relation between α_0^* and α_1 should hold at the sample average value of GRAV.

Table 9. Regression of Share Yield on the PCCM Leverage Variable and Risk Variables

$$KGAV = \alpha_0 + \alpha_1 LEVM + \alpha_2 GRAV + \alpha_3 PEE + \alpha_4 QLE$$

Year	*KGAV*	α_0	α_1	*LEVM*	α_2	*GRAV*	α_3	*PEE*	α_4	*QLE*	R^2 *S.E.*
1958	.091	.049	.005	.882	.715	.053	.000	.868	−.001	.069	.941
	(.014)	(.004)	(.002)	(.270)	(.028)	(.019)	(.003)	(.157)	(.003)	(.168)	(.0035)
1959	.097	.060	.006	.840	.662	.057	−.007	.864	−.007	.053	.919
	(.012)	(.004)	(.002)	(.263)	(.031)	(.017)	(.003)	(.158)	(.003)	(.187)	(.0034)
1960	.091	.057	.004	.768	.631	.055	−.004	.860	−.008	.035	.902
	(.010)	(.005)	(.002)	(.260)	(.036)	(.016)	(.003)	(.163)	(.003)	(.163)	(.0033)
1961	.084	.046	.005	.643	.683	.054	−.003	.857	−.003	.012	.890
	(.009)	(.005)	(.003)	(.202)	(.040)	(.013)	(.003)	(.166)	(.003)	(.148)	(.0031)
1962	.089	.047	.006	.687	.719	.056	−.003	.854	−.003	−.009	.933
	(.010)	(.004)	(.002)	(.212)	(.031)	(.014)	(.002)	(.168)	(.003)	(.159)	(.0027)
1963	.089	.045	.007	.648	.711	.056	−.001	.854	−.001	−.023	.935
	(.010)	(.003)	(.002)	(.209)	(.030)	(.014)	(.002)	(.165)	(.003)	(.157)	(.0026)
1964	.089	.047	.004	.592	.729	.058	−.004	.852	−.003	−.058	.940
	(.010)	(.004)	(.003)	(.196)	(.031)	(.013)	(.002)	(.167)	(.003)	(.150)	(.0024)
1965	.091	.053	.005	.599	.658	.058	−.003	.852	−.000	−.050	.884
	(.008)	(.004)	(.003)	(.214)	(.038)	(.012)	(.002)	(.167)	(.004)	(.134)	(.0028)
1966	.099	.073	.004	.671	.515	.060	−.008	.852	.003	−.069	.797
	(.007)	(.005)	(.003)	(.264)	(.047)	(.012)	(.003)	(.166)	(.003)	(.143)	(.0031)
1967	.103	.079	.004	.753	.438	.057	−.005	.851	−.002	−.076	.522
	(.006)	(.007)	(.003)	(.261)	(.069)	(.012)	(.004)	(.167)	(.005)	(.135)	(.0046)
1968	.098	.061	.005	.783	.658	.053	−.003	.854	−.001	−.087	.831
	(.010)	(.005)	(.003)	(.241)	(.046)	(.014)	(.003)	(.166)	(.004)	(.155)	(.0041)

NOTE: Figures in parentheses are standard deviations of the variables and standard errors of the regression coefficients. R^2 is the coefficient of determination, and S.E. is the standard error of estimate.

Table 10. *Test of the PCCM Leverage Theorem Based on Table 9 Model*

Year	α_0^*	$\alpha_0^* - \alpha_1$	i	*t value* $(\alpha_0^* - \alpha_1) - i$
1958	.0866	.0815	.0422	10.03
1959	.0918	.0861	.0471	9.84
1960	.0877	.0836	.0449	9.03
1961	.0801	.0749	.0450	6.10
1962	.0842	.0779	.0431	8.80
1963	.0842	.0776	.0439	9.16
1964	.0865	.0824	.0446	9.05
1965	.0880	.0828	.0475	8.40
1966	.0965	.0923	.0546	8.88
1967	.0999	.0960	.0640	5.28
1968	.0939	.0892	.0675	4.16

other than LEVM for a particular firm would produce that firm's value of $\alpha_0^* = \rho$. If $\alpha_0^* = \rho$ varies among firms, the coefficient of LEVM, which is an estimate of $\rho - i$, also should vary among them. However, $\alpha_1 = \rho - i$ is constrained by the regression to be the same for all firms. To overcome this problem, rewrite Eq. (2.4.2) as[5]

$$k = \rho(1 + L/P) - iL/P. \qquad (6.3.4)$$

A reasonable representation of the influence of the other risk variables on ρ is

$$\rho = \rho^* + \sum_{j=1}^{n} \beta_j u_j, \qquad (6.3.5)$$

where u_j is the j^{th} risk variable, β_j is the variation in ρ with u_j, and ρ^* is the value of ρ when all the included risk variables have their risk-free values. If all the risk variables are included, $\rho^* = i$. Substituting Eq. (6.3.4) and simplifying we obtain

$$k = \rho^* + (\rho^* - i)L/P + \sum_{j=i}^{n} \beta_j u_j[1 + L/P]. \qquad (6.3.6)$$

[5]This test was suggested to the writer by Paul Halpern.

Table 11. Regression of Share Yield on the PCCM Leverage Variable and the Transformed Risk Variables

	KGAV = $\alpha_0 + \alpha_1$ LEVM + α_2 GRAV*Z + α_3 PEE*Z + α_4 QLE*Z								R^2
Year	α_0	α_1	α_2	GRAV*Z	α_3	PEE*Z	α_4	QLE*Z	S.E.
1958	.064	−.017	.405	.097	.002	1.63	.000	.122	.9293
	(.003)	(.002)	(.018)	(.030)	(.002)	(.35)	(.002)	(.336)	(.0038)
1959	.072	−.014	.379	.103	−.001	1.58	−.003	.084	.9123
	(.003)	(.002)	(.019)	(.027)	(.002)	(.34)	(.001)	(.379)	(.0036)
1960	.067	−.015	.381	.096	−.000	1.53	−.004	.049	.8790
	(.004)	(.002)	(.025)	(.021)	(.002)	(.33)	(.002)	(.313)	(.0036)
1961	.057	−.016	.438	.087	−.001	1.40	−.003	.008	.8846
	(.004)	(.003)	(.027)	(.017)	(.002)	(.28)	(.002)	(.260)	(.0032)
1962	.059	−.017	.444	.094	−.000	1.43	−.001	−.030	.9370
	(.003)	(.002)	(.019)	(.021)	(.001)	(.30)	(.001)	(.294)	(.0026)
1963	.058	−.017	.445	.092	.000	1.40	−.001	−.050	.9371
	(.003)	(.002)	(.018)	(.019)	(.001)	(.29)	(.001)	(.279)	(.0026)
1964	.060	−.019	.466	.092	−.002	1.35	−.002	−.108	.9417
	(.003)	(.002)	(.019)	(.018)	(.001)	(.27)	(.002)	(.265)	(.0024)
1965	.063	−.015	.421	.091	−.001	1.35	−.001	−.095	.8801
	(.003)	(.002)	(.025)	(.016)	(.002)	(.28)	(.002)	(.242)	(.0029)
1966	.080	−.008	.308	.098	−.004	1.41	.001	−.135	.7913
	(.004)	(.002)	(.028)	(.015)	(.002)	(.31)	(.002)	(.277)	(.0031)
1967	.082	−.007	.283	.098	−.001	1.48	.001	−.148	.5911
	(.005)	(.003)	(.037)	(.016)	(.002)	(.34)	(.003)	(.254)	(.0042)
1968	.073	−.012	.373	.093	−.001	1.52	.000	−.169	.8510
	(.004)	(.003)	(.024)	(.022)	(.002)	(.33)	(.002)	(.297)	(.0038)

NOTE: Figures in parentheses are standard deviations of the variables and standard errors of the regression coefficients. R^2 is the coefficient of determination, and S.E. is the standard error of estimate.

Table 12. Test of the PCCM Leverage Theorem Based on Table 11 Model

Year	α_0	$\alpha_0 - \alpha_1$	i	t value $(\alpha_0 - \alpha_1) - i$
1958	.0641	.0816	.0422	9.32
1959	.0716	.0856	.0471	9.08
1960	.0673	.0823	.0449	7.82
1961	.0572	.0732	.0450	5.43
1962	.0593	.0760	.0431	8.37
1963	.0579	.0749	.0439	8.55
1964	.0597	.0789	.0446	7.94
1965	.0631	.0782	.0475	6.64
1966	.0797	.0874	.0546	7.07
1967	.0822	.0889	.0640	4.28
1968	.0729	.0848	.0675	3.51

The appropriate regression equation is

$$\text{KGAV} = \alpha_0 + \alpha_1 \text{ LEVM} + \alpha_2 \text{ GRAV} * Z + \alpha_3 \text{ PEE} * Z + \alpha_4 \text{ QLE} * Z, \tag{6.3.7}$$

where $Z = 1 + L/P = 1 + \text{LEVM}$.

Table 11 presents the regression results obtained with Eq. (6.3.7). It can be seen that α_0, which is an estimate of ρ^* in Eq. (6.3.6), is above the interest rate by a wide margin in every year. Hence, all the variables responsible for the risk of utility shares were not included in the regression. With $\alpha_0 > i$ it should not be surprising to find α_1, which is an estimate of $\rho^* - i$, negative in every year. Table 12 presents the t values for the difference between $\alpha_0 - \alpha_1$ and i. They are very large, and the probability that $\alpha_0 - \alpha_1 > i$ due to sampling fluctuations in the parameter estimates is extremely small. These data and the previous tests of the PCCM leverage theorem provide no basis for accepting the theory. The yield investors require on a share does not rise as rapidly with leverage as the PCCM theory predicts.

6.4 Test of the Traditional Leverage Theorem

Under the traditional theory the relation between share yield and leverage is

$$k = \rho + \alpha B/E. \quad (4.2.4)$$

Regarding the leverage coefficient, the traditional theory says only that $0 < \alpha < \rho - i$. Furthermore, it says nothing about the influence of other risk variables on the leverage coefficient. Hence, the theory may be represented by

$$\text{KGAV} = \alpha_0 + \alpha_1\text{LEV} + \alpha_2\text{GRAV} + \alpha_3\text{PEE} + \alpha_4\text{QLE}. \quad (6.4.1)$$

In this equation

$$\text{LEV} = \text{DEBB}/[\text{CSS} + \text{RDT}], \quad (6.4.2)$$

where CSS is the common equity and RDT is the reserve for deferred taxes. It seemed reasonable to use LEV instead of DEQ as the leverage variable since RDT is no less subordinate to the firm's debt than is the common equity.

Table 13 presents the regression statistics obtained with Eq. (6.4.1). In every year the LEV coefficient has the correct sign, but it is not significant at the 5 percent level in six of the eleven years. The traditional theory maintains that, up to a leverage rate that does not seriously impair the firm's ability to meet its contractual obligations, share yield may increase with leverage, but not as rapidly as the PCCM theory predicts. That is, $0 \leq \alpha_1 < \alpha_0 - i$ when LEV is the only independent variable. Assuming that α_1 is independent of the nonleverage risk of a firm, the theory implies that $0 \leq \alpha_1 < \alpha_0^* - i$ when α_0^* is defined as in Eq. (6.3.3). Comparison of α_1 and $\alpha^*_0 - i$ reveals that α_1 is smaller by amounts that are significant at the 1 percent level or better. Hence, our results are in agreement with the traditional theory on the relation between share yield and leverage. No effort was made to test the hypothesis by the methods analogous to Eq. (6.3.7). In view of the results obtained with that equation's test of PCCM theorem, the analogous test of the traditional theory is unlikely to change our conclusion.

6.5 *The Dividend and Stock Financing Theorems*

The assumptions common to the PCCM and traditional theories are that the yield investors require on a share is independent of

Table 13. *Regression of Share Yield on Traditional Leverage Variable and Risk Variables*

	$KGAV = \alpha_0 + \alpha_1 LEV + \alpha_2 GRAV + \alpha_3 PEE + \alpha_4 QLE$						R^2
Year	α_0	α_1	*LEV*	α_2	α_3	α_4	*S.E.E.*
1958	.049	.004	1.79	.684	−.000	−.002	.943
	(.004)	(.001)	(.38)	(.025)	(.003)	(.003)	(.003)
1959	.063	.003	1.70	.628	−.008	−.008	.915
	(.004)	(.002)	(.34)	(.028)	(.003)	(.003)	(.004)
1960	.060	.001	1.67	.597	−.005	−.009	.897
	(.004)	(.002)	(.31)	(.030)	(.003)	(.003)	(.004)
1961	.048	.002	1.61	.651	−.004	−.003	.887
	(.005)	(.002)	(.28)	(.034)	(.003)	(.003)	(.003)
1962	.047	.004	1.55	.696	−.004	−.003	.934
	(.004)	(.002)	(.29)	(.027)	(.002)	(.003)	(.003)
1963	.045	.004	1.49	.681	−.001	.001	.936
	(.003)	(.001)	(.31)	(.026)	(.002)	(.003)	(.003)
1964	.047	.003	1.46	.716	−.005	−.003	.943
	(.003)	(.001)	(.32)	(.026)	(.002)	(.003)	(.002)
1965	.055	.003	1.43	.631	−.005	−.001	.883
	(.004)	(.002)	(.32)	(.033)	(.002)	(.004)	(.003)
1966	.075	.003	1.47	.486	−.010	.003	.797
	(.004)	(.002)	(.32)	(.038)	(.003)	(.004)	(.003)
1967	.082	.002	1.56	.400	−.006	−.003	.517
	(.006)	(.002)	(.34)	(.056)	(.004)	(.005)	(.005)
1968	.059	.005	1.65	.632	−.003	.002	.840
	(.005)	(.002)	(.34)	(.040)	(.003)	(.004)	(.004)

NOTE: Figures in parentheses are standard deviations of the variables and standard errors of the regression coefficients. R^2 is the coefficient of determination, and S.E.E. is the standard error of estimate.

the firm's dividend and stock financing rates. To test these hypotheses, recall that our basic stock value model with $r = \pi$ is

$$P = \frac{(1 - b)Er}{k - br - vs}. \quad (2.8.8)$$

The hypotheses are that k is independent of b and s. If we assume that k is independent of r and v, the hypotheses imply that k is independent of the rate of growth in the dividend, $br + vs$. Since k is equal to the dividend yield plus the growth rate, a change in the growth rate changes the dividend yield by the same amount in the opposite direction so that k does not change as the growth rate changes.

Eq. (6.4.1) and the estimates in Table 13 provide a test of the hypotheses. If they are true we should find the coefficient of GRAV, $\alpha_2 = 0$. In fact, the estimate of α_2 is greater than zero, and the difference is highly significant in every year. The conclusion is that the yield investors require on a share is an increasing function of the expected growth in its dividend rate. Since growth varies with retention and stock financing when r and v are positive, share yield is an increasing function of retention and stock financing.

The validity of drawing the above conclusions from the data may be questioned on the grounds that with KGAV = DIYD + GRAV the presence of GRAV on both sides of the equation creates correlation between share yield and growth. This objection is readily dealt with by replacing KGAV with DIYD as the dependent variable. In that event the value of the GRAV coefficient predicted by the theory becomes minus one since variation in growth should be offset by equal changes in dividend yield in the opposite direction to keep share yield independent of GRAV. However, the GRAV coefficients we would obtain with DIYD the dependent variable are simply the values of α_2 in Table 13 minus one. The values of $\alpha_2 - 1$ fall between $-.38$ and $-.60$ over the eleven sample years, and they all differ from minus one by amounts that are statistically significant at the 1 percent level or higher.

A more serious basis for questioning the conclusion that share yield increases with growth is the possibility of measurement error in the growth variable. In that event, correlation between KGAV and GRAV will arise when there is no correlation between the error-free measures of the variables. Similarly, in the regression with DIYD as the dependent variable, measurement error in GRAV can cause bias in the absolute value of the regression coefficient toward zero. It can be shown [23, pp. 179–81] that in a simple regression of DIYD on GRAV, with error in the measurement of GRAV and with DIYD measured free of error, the expected value of the regression coefficient is given by the expression

$$\alpha_2 = \frac{\alpha_2^*}{1 + \theta}. \tag{6.5.1}$$

In this expression α_2^* is the true value of the regression coefficient, and θ is the ratio of the variance of the measurement error in GRAV to the mean sum of squares of the error-free measure of GRAV. In a multiple regression the relation between the observed and true value of the coefficient will depart more or less from Eq. (6.5.1). Assuming that Eq. (6.5.1) is true, the variance of the measurement error in GRAV must be larger than the variance in GRAV for the true value of the regression coefficient of DIYD on GRAV to be minus one since most of the sample values of the coefficient fall between zero and $-.5$. We, of course, do not know the measurement error in the observed values of GRAV, but it seems unlikely that its variance is greater than the mean sum of squares in the error-free values of the variable.

There is, fortunately, an alternative approach to testing the hypothesis that share yield is an increasing function of the expected rate of growth in the dividend. The hypothesis is true if share risk is an increasing function of growth, and the recent developments in portfolio and capital asset pricing theory provide the measure of share risk with which share yield should vary. W. F. Sharpe [40, 41], John Lintner [27], and Jan Mossin [35] have demonstrated that under plausible assumptions the yield at which a share sells is given by the expression

$$E(R_j) = R_F + \beta_j[E(R_m) - R_F], \tag{6.5.2}$$

where

$E(R_j)$ = expected value of the yield on the j^{th} share;
R_F = return on a risk-free asset;
$E(R_m)$ = expected value of the yield on a portfolio of all shares on the market; and
β_j = the covariance between R_j and R_m divided by the variance of R_m.

The equation states that the amount by which the yield on a share exceeds the risk-free rate depends on β_j, its BETA factor.

The rationale for this expression, developed further in the above references and in E. F. Fama [11], is that the covariance between a share's return and the return on a market portfolio is the risk that cannot be diversified away by portfolio policy and therefore is the risk that determines the yield investors require on a share. It follows that any variable with which share yield is correlated should be correlated with the share's BETA. Specifically, if share yield is an increasing function of GRAV, risk increases with GRAV, and BETA should be positively correlated with GRAV.

Common practice in estimating BETA for a share is to run the regression

$$\mathrm{HPR}(J, T) - \mathrm{RFR}(T) = \alpha_j + \beta_j[\mathrm{HPR}(M, T) - \mathrm{RFR}(T)], \tag{6.5.3}$$

where

$$\mathrm{HPR}(J, T) = \frac{[\mathrm{DIV}(J, T) + \mathrm{PPS}(J, T) - \mathrm{PPS}(J, T-1)]}{\mathrm{PPS}(J, T-1)};$$

$\mathrm{RFR}(T)$ = interest rate on a one period risk-free bond; and

$\mathrm{HPR}(M, T)$ = one period return, dividend plus change in price divided by start of period price for the market portfolio.

Eq. (6.5.3) was run for each utility in our sample for the years 1958–1968 using monthly values of $\mathrm{HPR}(J, T)$, $\mathrm{HPR}(M, T)$, and $\mathrm{RFR}(T)$ for the ten years preceding the year in question. The sample values of BETA then were regressed against GRAV and the other risk variables for each of the years 1958–1968:

$$\mathrm{BETA} = \lambda_0 + \lambda_1 \mathrm{GRAV} + \lambda_2 \mathrm{LEV} + \lambda_3 \mathrm{PEE} + \lambda_4 \mathrm{QLE}. \tag{6.5.4}$$

In every year the correlation between BETA and GRAV was positive and significant at the 5 percent level or higher. Insofar as error in the measurement of GRAV biases its coefficient toward zero, the estimates of its value understate the covariation in share risk and growth. The covariation between BETA and the other variables

typically was not significant, reflecting the modest influence of these variables on share yield.

It may be argued that the hypothesis that share yield is independent of the dividend rate and the stock financing rate still has not been adequately tested on the following grounds. GRAV varies with the profitability of investment as well as the rates of retention and stock financing. It is possible that the covariation between KGAV and GRAV (or BETA and GRAV) is due to the covariation of KGAV and BETA with the return on investment and not the rate of equity capital financing. To deal with this objection we ran the regression

Table 14. *Regression of BETA on Return, Financing, and Risk Variables, 1958–1968*

$BETA = \lambda_0 + \lambda_1 RRC + \lambda_2 RETR + \lambda_3 SFRS + \lambda_4 LEV + \lambda_5 PEE + \lambda_6 QLE$

Year	λ_0	λ_1	λ_2	λ_3	λ_4	λ_5	λ_6	*Cor. Coef.*
1958	−.160	1.70	.65	1.93	−.019	.230	−.080	.56
		1.40	2.67	1.92	−.37	1.86	−.68	
1959	−.460	2.21	.75	2.54	.057	.236	.244	.56
		1.54	2.79	2.28	.87	1.71	2.07	
1960	−.362	3.39	.59	2.97	−.008	.178	.125	.50
		2.34	1.93	2.42	−.10	1.31	.86	
1961	−.119	2.66	.21	1.30	.064	.067	−.010	.34
		2.17	.80	1.28	.83	.63	−.07	
1962	−.267	3.82	.74	3.18	−.012	.130	−.050	.60
		3.47	2.88	3.09	−.16	1.31	−.38	
1963	.150	3.55	.58	3.56	−.184	.089	−.290	.60
		3.28	2.18	3.41	−2.31	.85	−2.11	
1964	.002	3.40	.77	3.67	−.145	.124	−.209	.59
		3.05	2.35	3.08	−1.64	1.11	−1.25	
1965	−.022	2.87	.81	2.68	−.100	.082	−.305	.54
		2.70	2.62	2.33	−1.21	.74	−1.74	
1966	−.115	2.59	1.07	2.39	−.121	.109	−.191	.63
		2.51	3.67	2.03	−1.63	1.06	−1.26	
1967	.491	−.63	.37	−.26	−.011	−.118	−.085	.34
		−.64	1.25	−.22	−.15	−1.11	−.50	
1968	.386	−.26	.43	−.26	−.002	−.150	.011	.42
		−.32	2.16	−.29	−.04	−1.68	.10	

NOTE: The numbers below the regression coefficients are their t values.

$$\text{BETA} = \lambda_0 + \lambda_1\text{RRC} + \lambda_2\text{RETR} + \lambda_3\text{SFRS} + \lambda_4\text{LEV} + \lambda_5\text{PEE} + \lambda_6\text{QLE}. \tag{6.5.5}$$

EACR was not included among the independent variables because it is a profitability variable like RRC. The two are highly correlated, and since EACR is based on the market-book value ratio of the firm's stock, RRC is a better measure of profitability. The inclusion of EACR increases the standard errors of the RRC, RETR, and SFRS coefficients.

Table 14 presents the regression coefficients of Eq. (6.5.5). BETA is positively correlated with return in all but the last two years, and the *t* values are above two in seven of the remaining nine years. BETA also is positively correlated with both the retention and stock financing rate variables. λ_2 is positive in every year and significant at the 5 percent level in all but two years. λ_3 is negative in two years and not significantly positive in one additional year. The coefficients of LEV, PEE, and QLE do not differ significantly from zero for the most part, and the LEV and PEE coefficients commonly have the incorrect sign. This is not surprising in view of their modest influence on risk and their correlation with the return and financing variables.

The positive correlation between growth and BETA, the measure of risk that explains variation in share yield among firms, and the positive correlation between BETA and the equity financing variables would appear to provide convincing empirical evidence for rejecting the PCCM and traditional theorems on the subject. Share yield is not independent of a firm's dividend and stock financing rates.

7

PCCM and Traditional Theories: Theoretical Limitations

The sample data for utility firms analyzed in the previous chapter provide no empirical support for the PCCM leverage theorem or the retention and stock financing theorems common to both the PCCM and traditional theories of stock valuation and cost of capital. This chapter nonetheless goes on to examine the assumptions on which the theorems are based. This is done for two reasons. First, economic data rarely satisfy the conditions under which the techniques of statistical inference may be used without qualification, and the sample data employed in the last chapter are no exception. Consequently, confidence in our conclusions is materially increased if the assumptions which lead to those conclusions have intuitive merit, that is, seem true on the basis of our common sense knowledge of human behavior and/or our knowledge of the laws or conventions under which individuals and firms make financial decisions. Second, consideration of the theoretical grounds for rejecting the theorems helps lay the foundation for the alternative theory of stock valuation and cost of capital to be developed in the next chapter.

7.1 The Leverage Theorem

Modigliani and Miller [34] and others have demonstrated quite carefully how indifference between leverage on personal and corporate accounts makes the yield at which a share sells

$$k = \rho + (\rho - i)L/P, \tag{2.4.2}$$

with ρ the yield at which the corporation's stock would sell in the absence of leverage. The value of ρ may vary among corporations with their business risk, but it has been shown by R. S. Hamada [21] and others that the substitution of the appropriate function of a corporation's business risk allows the generalization of Eq. (2.4.2) to include all corporations regardless of their business risk class.

To summarize the basis for the theorem, assume that highly levered shares sell at lower yields and that modestly levered shares sell at higher yields than their Eq. (2.4.2) values. Any investor will sell the former and buy the latter, using personal leverage to achieve the same risk position and a higher return than he formerly had. The consequence is to move share yields into agreement with their Eq. (2.4.2) values. The critical assumptions for the conclusion that personal and corporate leverage are perfect substitutes are that individuals and corporations borrow at the same interest rate and that individuals are indifferent between a given degree of leverage on corporate account and the same degree of leverage on personal account. That is, an unlevered position in the stock of a corporation with a 2:1 leverage rate is looked on as being identical to a 2:1 personal leverage rate in an otherwise identical corporation with no debt in its capital structure.

In their 1966 paper Modigliani and Miller [32] found that the evidence supports their theory. However, their empirical methods and findings were questioned by Jean Crockett and Irwin Friend [8], A. A. Robichek, J. G. McDonald, and R. C. Higgins [37], and M. J. Gordon [17]. In addition, empirical work by Alexander Barges [2], Eugene Brigham and M. J. Gordon [5], J. F. Weston [48], R. F. Wippern [49], and others as well as the findings presented in the last chapter failed to confirm the theorem. The PCCM leverage theorem has continued to enjoy wide acceptance in the literature

because the theoretical arguments advanced against it have not been as convincing as the evidence.[1]

The theorem has been questioned on the grounds that individuals cannot borrow at the same interest rates as corporations. It is true that the interest rates on personal loans may run considerably higher than corporate bond rates. However, personal loans are limited by the individual's employment income and are not a suitable instrument for personal leverage on a meaningful scale. Personal leverage to buy stock with the stock as security for the loan can be undertaken at interest rates that are trivially, if at all, higher than corporate bond rates. Hence, interest rate differences are not an important basis for differentiating between personal and corporate leverage.

It also has been argued that corporate leverage is subject to limited liability, while personal leverage is not. If a corporation has a 1:1 debt-equity ratio at the time an investor buys, say, $10,000 of stock and its assets subsequently become worthless, an investor is not liable for his pro rata share of its debts (that is, $10,000). By contrast, it is argued that an individual who borrows $10,000 to buy $20,000 of stock in an unlevered corporation is liable for the $10,000 debt if the stock becomes worthless. In fact, an investor can lever on personal account on a meaningful scale only by means of a call loan. Furthermore, the loan will be called when the stock falls to the investor's equity, and if he does not put up additional cash the stock, which has been in the lender's hands, will be sold to pay off the debt.[2] Hence, the investor need never fear that he will be held liable for the debt.

If the investor has a bank balance or other assets apart from his levered position in the stock, he can and may put up the additonal cash required when the value of the stock falls to the amount of the loan. However, one may question whether he actually is engaging in personal leverage. Let an individual with a net worth of $100,000 put it all in the stock of a corporation with a 1:1 leverage rate. The analogous personal leverage involves borrowing $100,000 and

[1] There has been an extensive discussion of the subject on a theoretical level. See J. E. Stiglitz [44] and the references cited there.

[2] Government regulations set minimum margin requirements, and a lender is required to call for more margin before the value of the stock falls to the amount of the loan. However, this analysis assumes the absence of legal restrictions on personal leverage. Their presence further impairs the validity of the theory.

buying $200,000 worth of stock in an unlevered corporation. In this case the investor is wiped out when the stock falls by one-half in value. He could meet a call for more margin if he had borrowed $50,000, bought $100,000 of the unlevered stock, and kept $50,000 in the bank or a bond. However, consolidating the investor's monetary assets against his debt reveals that he has no leverage on personal account. He has taken an unlevered position in an unlevered corporation.

7.2 *The Inferiority of Personal Leverage*

The significant difference between personal and corporate leverage is in the terms under which each can borrow. A corporation can borrow on a long-term basis on the security of its fixed assets or its general credit standing. Individuals can do likewise to buy homes and certain other assets. However, our questioning of the officers of financial institutions revealed that they will lend individuals large sums to buy stock only on the basis of a call loan. Anyone who questions this statement should approach the loan officer of a financial institution and ask to borrow $5,000,000 to buy $10,000,000 of a stock or a portfolio of shares on a ten- or twenty-year note. Make clear that the financial institution may hold the stock as security, but the stock may not be sold until the loan falls due. At that time the bank may sell the stock and take the amount loaned or the proceeds from the sale of the stock, whichever is less. One may wonder why a corporation can use long-term debt to finance part of its investment in real assets but stockholders cannot use long-term debt to finance investment in an otherwise identical unlevered corporation's stock, but this appears to be the case in the world in which we live.

It is intuitively evident that personal leverage through call loans is considerably more risky than holding stock in a corporation that is levered by means of long-term debt. To illustrate, let V_0 be the value of a corporation's assets at $t = 0$, and assume first that the corporation has no debt in its capital structure. An investor who puts his wealth in the company's stock with personal leverage on a 1:1 basis is wiped out when the stock falls below one-half of V_0. Alternatively, let the corporation finance V_0 through corporate leverage on a 1:1 basis, and let the investor take an unlevered

position in its stock. A fall in the value of the company below $.5\,V_0$, the amount of its debt, does not bankrupt the company and wipe out the stockholders. The corporation's financial planning of its debt structure, the reluctance of its creditors to put the company in receivership, and the reluctance of the courts to force a reorganization that wipes out the common equity, all allow a company to survive for a considerable time after the value of its assets has fallen below the amount of its debt. If the value of the corporation's assets subsequently rises above $.5\,V_0$, the interval during which the value was below $.5\,V_0$ is merely regarded as an unpleasant interlude. Furthermore, even during this period when the value of the assets is less than the amount of the debt, the common stock has a positive value.[3]

A more rigorous analysis could demonstrate the following. An investor's wealth n periods hence has a higher expected value and a lower variance if a given degree of leverage is provided by the corporation through long-term debt than if the same degree of leverage is provided on personal account through a call loan. While such an analysis might further illuminate the differences between personal and corporate leverage, the considerable superiority of the latter should be clear.

If the two forms of leverage were perfect substitutes, would we see individuals engage in margin trading on an extensive scale? With interest a tax allowed expense under the corporate income tax and with share yield given by Eq. (3.4.2), there is an advantage to corporate leverage by nonregulated companies. However, even among nonregulated companies, if levered companies were selling below their indicated yields and unlevered companies were selling above their indicated yields, investors would take advantage of this state of affairs by engaging in personal leverage on unlevered companies.

In fact, margin trading is very limited, and the amount in force overstates the true amount of personal leverage. Margin trading

[3] To illustrate, on 30 September 1970 the Chicago, Milwaukee, St. Paul and Pacific Railroad had outstanding $210,000,000 of debt. The market value of the whole railroad on that date was $78,000,000 on the basis of the market value of its debt and common equity. However, the market value of the common stock was positive, $29,000,000, and the market value of the debt was down to $49,000,000. For more on the advantage of corporate over personal leverage see Gordon [18].

typically arises in the following circumstances. An investor with $740,000 in stocks, $200,000 in bonds, and $60,000 in cash decides to make a short-term speculative investment in $100,000 of a stock. Instead of selling some of his bonds the investor might buy the stock with $50,000 from his bank account and a margin loan for the balance. With the investor's debt consolidated with his debt assets, the investor is not positively levered on personal account.

Our conclusion is that with an unlevered stock selling to yield ρ an investor who wants a higher return would not consider personal leverage a reasonable means to that end. Instead, he would buy a levered share to earn a yield greater than ρ but less than the PCCM theory value of k. It has been argued, however, that leverage on personal account is not necessary for Eq. (2.4.2) or its after-tax analogue to hold. With few exceptions investors hold some fraction of their wealth in risk-free assets such as bonds. That is, they are negatively levered. Consider an investor with half of his wealth in bonds and half in the shares of a corporation that has a 1:1 leverage ratio, and assume that the stock is selling at a yield below its PCCM theory value, while an unlevered share in the same risk class is selling at a yield of ρ. The investor can raise the yield on his portfolio without engaging in personal leverage by selling his bonds and levered shares and investing the entire proceeds in the unlevered shares.[4]

The theory now has to be reformulated as follows. Investors who want some degree of risk are indifferent as to the combination of corporate and personal leverage that produces it as long as the personal leverage falls between -1 and 0, where -1 means all of the investor's wealth is in bonds and 0 means all of his wealth is in shares. If this is true, the upper limit of zero on personal leverage impairs the validity of the theorem. Highly levered shares which provide a high risk and high return are suitable for any portfolio, while the bar to positive leverage on personal account prevents an investor who wants a high return and high risk portfolio

[4]To illustrate, let $i = .04$, $\rho = .08$, and the yield on a share with $L/P = 1$ be equal to .10 and not $.12 = \rho + (\rho - i)L/P$. An investor with $50,000 in bonds and $50,000 in the levered stock has a yield on his portfolio of .07. By selling out and investing the proceeds in the unlevered share, which provides a yield of $\rho = .08$, his yield is raised, and his risk is unchanged if personal and corporate leverage are perfect substitutes under these circumstances.

from investing in unlevered shares with a low return and low risk. Consequently, share yield should increase at a less rapid rate with leverage than $\rho - i$. Furthermore, the widespread tendency of investors to hold part of their wealth in bonds or similar risk-free assets may not be accidental. They may view a division of their wealth between a bond and a risky (measured by variance) portfolio of shares as less risky in a fundamental sense than investing their entire wealth in a portfolio of shares that has the same risk (measured by variance) as the bond-stock portfolio. The consequence is that share yield will rise less rapidly with risk than the PCCM theory suggests.

7.3 The Dividend Rate Theorem

One of the two security valuation assumptions common to both the PCCM and traditional theories of the cost of capital is that the yield at which a share sells is independent of its dividend rate. In chapter 2 we showed that a share's price is independent of the dividend rate when $x = \rho$ or $r = k$ on the assumption that ρ (or k) is independent of the firm's retention rate. Under this assumption P rises or falls with b, the retention rate, if the return on investment is above or below the share's yield. However, the change in P is due to the profitability of investment and not the method of financing since the same change in P would take place with any other method of financing under the PCCM theory of share valuation. An analogous argument holds for the traditional theory. Hence, the critical question is whether or not the yield on a share is independent of its dividend rate.

Until the problem was formulated in this way by Gordon [15], the only grounds for questioning the PCCM dividend rate theorem was the evidence.[5] Casual empiricism by the investment community and the work of David Durand [9], Wippern [49], J. E. Walter [47], and Friend and Marshall Puckett [14], among others, found that a rise in the dividend (with other things, including earnings, the same) raised the price of a share. Modigliani and Miller [31,

[5]The theory was developed further by E. M. Lerner and W. T. Carlton [25] and Douglas Vickers [46].

34], the most categorical defenders of the PCCM theory on dividend policy, dismissed this evidence on the grounds that the studies did not distinguish between the dividend and its informational content with regard to the firm's earnings. Their position may be summarized as follows. A corporation pays a stable fraction of its normal long-run earnings in dividends, and the corporation's management is recognized by investors as the best estimator of those earnings. Hence, what appears to be a variation in price with the dividend among shares or over time for a given share actually reflects the variation in price with normal long-run earnings.

While there is some merit in this position, it must be handled with care. If it is assumed that all corporations pay the same fraction of normal long-run earnings in dividends, the two variables cannot be distinguished, and the dividend policy theorem cannot be tested.[6] If dividend rates may differ among corporations, testing the theorem requires that the dividend and earnings must be arrived at independently. In that event, of course, correlation between price and the dividend always can be questioned on the grounds that the earnings figures contain errors of measurement regardless of how carefully they are obtained, and correlation with the dividend is due to its use by investors as a proxy for normal long-run earnings.

Gordon [15] has argued that the yield at which a share sells is an increasing function of the firm's retention rate on the following grounds. The single discount rate, k, used to represent the valuation of a dividend expectation is actually an average of k_t, $t = 1 \rightarrow \infty$, with k_t the discount rate used to convert the dividend in period t to its present value. The uncertainty of a dividend payment increases with its time in the future, and since k_t is an increasing function of a dividend's risk, k_t may be an increasing function of t. When a firm raises its retention rate, the near dividends are reduced, and distant dividends are raised. Since the weights on the k_t that result in the average k are the D_t, raising a firm's retention rate will raise the single valued k that we use as the yield investors require on a share.[7]

[6] Nonetheless, this is what Miller and Modigliani [34] did in their test of the dividend policy theorem. See Gordon [17] for a fuller discussion of the error in this test of the theorem.

[7] For a rigorous proof of this proposition see the appendix in Gordon [18].

Robichek and Meyers [38] and Houng-Yhi Chen [7] have examined more thoroughly the necessary conditions for the k_t in the above formulation of the problem to be an increasing function of t. Let $D_t^* = \alpha_t D_t$ be the certain equivalent of D_t, the latter being the expected value of the dividend in t. The present value of the dividend during t, the random variable $\tilde{D}_t$, therefore can be written

$$V_t = \frac{D_t}{(1 + k_t)^t} = \frac{D_t^*}{(1 + i)^t}, \qquad (7.3.1)$$

where i is the risk-free interest rate. Similarly,

$$V_{t+1} = \frac{D_{t+1}}{(1 + k_{t+1})^{t+1}} = \frac{D_{t+1}^*}{(1 + i)^{t+1}}. \qquad (7.3.2)$$

If $\tilde{D}_t$ and $\tilde{D}_{t+1}$ are equally risky, $\alpha_t = \alpha_{t+1}$. Since $\alpha_t = D_t^*/D_t$ and $\alpha_{t+1} = D_{t+1}^*/D_{t+1}$,

$$(1 + k_{t+1})^{t+1} = (1 + k_t)^t(1 + i). \qquad (7.3.3)$$

As Robichek and Myers [38, pp. 79–86] have shown, this equation is only satisfied if k_t is a decreasing function of t or if $k_t = k = i$ for all t. The latter condition is not consistent with uncertainty and aversion to risk. The former conclusion makes k, the average of the k_t we use, a decreasing function of the retention rate instead of an increasing function.

It is, of course, unreasonable to believe that the uncertainty of a dividend is independent of its time in the future. If the uncertainty increases with t, we have $\alpha_{t+1} < \alpha_t$. However, Chen [7] has shown that if uncertainty increases at a constant rate so that α_t/α_{t+1} is a constant regardless of t, the k_t are independent of t. The necessary condition for the k_t to rise with t is that the α_t decline at an increasing rate over time. This is a strong condition. While the α_t may in fact decline at an increasing rate, it is not intuitively evident that this is true.

Chen examined the following specific case. Let the risk of the dividend in $t + 1$, given the dividend in t, be

$$w_{t+1} = \sigma/D_t, \qquad (7.3.4)$$

where σ is the standard deviation of $\tilde{D}_{t+1}$ given the dividend in t is known to be D_t. It can be shown that

$$w_{t+1} = \sigma\sqrt{t+1}/D_0, \tag{7.3.5}$$

where D_0 is the current dividend. Hence, under the above assumptions w_t increases at a decreasing rate, α_t falls at a decreasing rate, and the k_t fall as t increases.

Other assumptions on how the expectations with regard to future dividends are formed would result in k_t independent or an increasing function of time. However, the empirical basis for specific assumptions as to how the uncertainty of a dividend increases with time would be hard to establish. A more promising line of inquiry is to consider the risk-free interest rate. The Robichek-Myers model assumes that i is independent of t if the payment in t is certain. However, the term structure of interest rates on government bonds reveals that the risk-free rate is an increasing function of time. James Tobin [45] has used portfolio theory to show that an investor with a one period horizon will find that the risk of a government bond increases with its maturity. The consequence is the rising term structure that typically prevails. With i_t an increasing function of t, the likelihood that k_t is an increasing function of time is materially increased.

7.4 Dividend Policy with a One Period Horizon

Up to this point the influence of dividend policy on the risk and yield of a share has been investigated in the context of an infinite horizon model, one in which the objective was to evaluate the risk of D_t for $t = 1 \to \infty$. An alternative approach that is more amenable to theoretical analysis involves the use of a one period model where we only need consider the risk of the dividend for one period and of the price at the end of the period.

For an investor with a one period horizon, the price of a share is

$$P_0 = \frac{D_1 + P_1}{1 + k_0}, \tag{7.4.1}$$

where, for the purpose of what follows, D_1 and P_1 are the expected values of the dividend and price at the end of $t = 1$, k_0 is the factor that converts $D_1 + P_1$ to their present value, and it is fixed on the basis of the risk of $\tilde{D}_1 + \tilde{P}_1$, which are random variables. Finally, P_0 has a single value set in the market. We can write

$$Q = \tilde{D}_1 + \tilde{P}_1 = (1-b)E_0\tilde{r}_1 + (1-b)\,E_0\tilde{r}_1/[\tilde{k}_1 - \tilde{r}_1 b] \tag{7.4.2}$$

on the assumptions that the firm will not engage in stock financing and that the return on the common equity during $t = 1$, $\tilde{\pi}_1$, is equal to $\tilde{r}_1$, the return the company is expected to earn on common equity investment as of the end of $t = 1$. The random variables on the right-hand side of Eq. (7.4.2) are $\tilde{r}_1$ and $\tilde{k}_1$ on the assumption that b is fixed and E_0 is known.

If it can be shown that the variance of Q is an increasing function of b, it is not consistent with aversion to risk to have k_0 independent of b. Rather, with the variance of Q increasing with b, k_0 should rise, and P_0 should fall as b increases.

An exact solution for the variance of Q could not be obtained, but an approximation that should be adequate for our purpose can be obtained on the assumption that the expected value of $1/x = E(1/x) \cong 1/E(x)$. In that event a Taylor series expansion of Q about its mean may be used, and dropping subscripts the variance of Q to a first approximation is

$$\begin{aligned} \text{Var } Q &= E[f(\tilde{r},\tilde{k}) - f(r,k)]^2 \\ &\cong E[\tilde{r} - r]^2[\partial f/\partial\tilde{r}]^2 \\ &+ E[\tilde{k} - k]^2[\partial f/\partial\tilde{k}]^2 \\ &+ 2E[\tilde{r} - r][\tilde{k} - k][\partial f/\partial\tilde{r}][\partial f/\partial\tilde{k}], \end{aligned} \tag{7.4.3}$$

where $Q = f[\tilde{r}, \tilde{k}]$, and $\partial f/\partial\tilde{r}$ and $\partial f/\partial\tilde{k}$ are evaluated at $\tilde{r} = r$ and $\tilde{k} = k$. Making the indicated substitutions results in

$$\text{Var}(Q) = \text{var}(\tilde{k})\left[\frac{-(1-b)r}{(k-br)^2}\right]^2$$

$$+ \operatorname{var}(\tilde{r})\left[(1-b)\left[1+\frac{k}{(k-br)^2}\right]^2\right]$$

$$-2\operatorname{cov}(\tilde{k},\tilde{r})\frac{(1-b)^2 r}{(k-br)^2}\left[1+\frac{k}{(k-br)^2}\right]. \tag{7.4.4}$$

The change in the variance of Q with b is

$$\frac{\partial[\operatorname{var} Q]}{\partial b}=\frac{2(1-b)}{(k-br)^5}\times$$

$$\Big\{(\operatorname{var}(\tilde{k}))(r^2)(2r-k-br)$$

$$+(\operatorname{var}(\tilde{r}))(k(2r-k-br)-(k-br)^3)((k-br)^2+k)$$

$$-(\operatorname{cov}(\tilde{k},\tilde{r}))(2r)((r-k)(k-br)^2+(k)(2r-k-br))\Big\}. \tag{7.4.5}$$

The above expression is formidable, but some conclusions are possible.

First, if we assume that $r = k$, Eq. (7.4.5) reduces to

$$\frac{\partial[\operatorname{Var} Q]}{\partial b}=\frac{2}{r^2(1-b)^3}\{\operatorname{var}(\tilde{k})$$

$$+[1-r^2(1-b)^4]\operatorname{var}(\tilde{r})-2\rho\sigma_k\sigma_r\}, \tag{7.4.6}$$

where ρ = correlation between $\tilde{k}$ and $\tilde{r}$, and σ_k and σ_r are the standard deviations of the variables. We have, for all Q_1 and Q_2, the identity

$$[Q_1\sigma_k - Q_2\sigma_r]^2 = Q_1^2 \operatorname{var}\tilde{k}$$

$$+Q_2^2\operatorname{var}\tilde{r}-2Q_1Q_2\sigma_k\sigma_r. \tag{7.4.7}$$

Eq. (7.4.7) is positive regardless of the values of Q_1 and Q_2. Hence, in Eq. (7.4.6), letting Q_1^2 and Q_2^2 be the coefficients of var $\tilde{k}$ and

var $\tilde{r}$ respectively, ∂ [Var Q]/∂b is positive if

$$Q_1Q_2=\sqrt{1-r^2(1-b)^4}>\rho. \tag{7.4.8}$$

Q_1Q_2 is very close to one. For example, with $r = .20$ and $b = 0$, $Q_1Q_2 = .96$, and as r falls and/or b rises Q_1Q_2 approaches one. Since $\tilde{r}$ and $\tilde{k}$ are not perfectly correlated, the inequality in Eq. (7.4.8) is satisfied, and ∂[Var Q]/∂b is positive. Note that since Eq. (7.4.7) is positive, satisfying the inequality (7.4.8) is a strong condition for Eq. (7.4.6) to be positive.

It can be shown that with $r < k$ it remains true that the variance of Q increases with b regardless of the correlation between $\tilde{r}$ and $\tilde{k}$. With $r > k$, stronger conditions are necessary. Examination of these conditions is too involved to reproduce here, but it supports the conclusion that Var Q increases with b, the risk of a share increases with its retention rate, and the yield at which a share sells should increase with the retention rate.

7.5 The Stock Financing Theorem

The other security valuation assumption common to the PCCM and the traditional cost of capital theories is that the yield at which a share sells is independent of the amount or rate at which funds are raised through the sale of stock. We saw on pages 18–21 and 44–46 that, when this assumption holds, the price of a stock is independent of stock financing when $r = k$ or $x = \rho$ under the PCCM theory and when x is equal to the Eq. (4.2.1) value of z under the traditional theory. Hence, the cost of stock financing capital is $z = \rho$ or z equal to its Eq. (4.2.1) value under the respective theories.

It is easily shown that the yield at which a stock is selling is independent of the firm's stock financing rate when investors consider the stock a perfect substitute for all or practically all other stocks on the market. What this statement means is illustrated by considering the market for government and corporate bonds, which carry a negligible risk of default. Let w_{ij} be the fraction of wealth the i^{th} investor has in the bonds of the j^{th} organization. Given the yield and other attributes of a bond and the attributes of an investor, there is an equilibrium value of $w_{ij} \geq 0$. If the j^{th} government or corporation decides to put a new bond issue on the market, it must persuade one or more investors to increase the fraction of wealth invested in the bond. It is generally accepted that, other things the same, a negligible difference in yield will persuade investors to absorb the issue. They will reduce their relative positions in other bonds to the extent necessary to absorb the issue because quality bonds are near perfect substitutes for each other.

The reasons for this substitutability are obvious. The coupon and principal payments on the bond are stated in the contract, and the probability of default is zero or negligible. This and other information on the bond that is of interest to the investor can be established and evaluated at a modest cost. Consequently, a very small increase in yield over that available on other bonds will move the issue. However, it should be noted that the bond market is not perfectly competitive. There is some spread between the price to the public and the price to the corporation on a bond issue, and new issues usually sell at yields slightly higher than seasoned issues of comparable quality even though they can be purchased without paying a commission.[8]

Corporate stocks differ from quality bonds in ways which would make the market for the former considerably more imperfect. We say that the yield at which a company's stock sells at any point in time reflects the stock's dividend expectation and its risk. However, by comparison with a quality bond there is considerable disagreement among investors as to the expected value and risk of the dividend expectation. Furthermore, obtaining and evaluating the information necessary to reach a conclusion about whether or not the expected yield on a stock is attractive is comparatively quite expensive and time consuming. Finally, an investor who is favorably disposed toward a stock can derive the advantages of diversification only by limiting the fraction of his portfolio in the stock.

Evidence that the market for stock issues is more imperfect than the market for bonds is provided by the fact that investment bankers

[8]However, if the demand for bonds is strong in relation to the supply, a new issue may sell at a slightly lower yield than outstanding bonds of the same quality since the quantity desired can be obtained without bidding up the price.

charge higher commissions on a stock issue than on a bond issue.[9] Furthermore, when the bond market is declining, the volume of new issues may decline due to reluctance by corporations to pay increasing interest rates. When the stock market is declining, it is common to find that new issues practically disappear on the advice of investment bankers. A market that ceases to function for extended periods with minor exceptions hardly can be called perfectly competitive.

It should be noted that a large fraction of new stock issues are privileged subscriptions. That is, each shareholder is given rights to buy his pro rata share of the new issue at a discount off the market price. The traditional defense of this practice, that each shareholder should have the right to maintain his relative ownership of the corporation, does not appear to have much merit. A real advantage is that the investment bankers are called upon to take only the shares that are not purchased at the subscription price, and their fee is correspondingly smaller.[10] In effect, the corporation's stockholders take on the job of marketing the issue. Another advantage of a rights issue is that it is difficult to determine whether or not the issue has failed. If a stock is selling at $50 per share and a new issue is placed with an investment banker, it is comparatively easy to determine whether the stock has gone up or down. By contrast, on a rights issue the naïve stockholder is persuaded that the value of the rights is a profit, and the decline in the price of the stock when it goes ex rights makes it difficult to evaluate whether or not the new issue has depressed the price of the stock.

Employing the marketing services of an investment banker and increasing the yield on the stock (reducing its price) may be regarded as alternative means of selling a new issue of shares, but they are more likely to be complementary. The investment banker is a charlatan if he honestly cannot say the new issue offers the expectation of a higher yield than other shares with comparable

[9]It can be argued that the investment banker's margin on a stock issue reflects the greater probability that the issue will not be fully subscribed at the issue price. This reflects the greater difficulty of correctly pricing a stock issue.

[10]If the stock is selling at $50 per share and the subscription price is $40 per share, the investment banker need only guarantee that the stock does not fall below the $40 price.

risk, and a new stock issue cannot be offered at a higher yield than that at which the firm's outstanding shares are selling. Consequently, a new issue should raise the yield for some period after it is announced.

Unfortunately, it has been quite difficult to test this theorem empirically. Common practice has been to examine the behavior of a stock's price from the date on which the new issue is first announced until some date after it is placed on the market. The research of Friend [12] and others has not established any clear evidence that new issues raise or lower the price of a share when the share's price movement is deflated by the movement of the market over the time period. However, the theory makes statements about the yield and not the price. Typically, a new issue is sold to take advantage of extraordinarily profitable investment opportunities, and information to that effect associated with a new issue will tend to raise the price of a stock. The above evidence therefore may be interpreted to provide some support for the conclusion that share yield increases with stock financing.[11]

A secondary issue is the sale of a large bloc of stock by an individual or organization other than the corporation through an investment banker. Since the proceeds of the issue do not go to the corporation, the sale carries no information with regard to the investment plans and profitability expectations of the corporation. M. S. Scholes [39] recognized that investigating the price behavior of such issues avoided the profitable investment opportunity problem posed by primary issues, and he examined the influence of such issues on price. Although secondary issues usually are smaller than primary issues, Scholes found they tended to depress the price of the stock. However, he classified his sample according to whether the seller was an institution, such as a mutual fund, or an individual connected with the corporation who might be expected to have inside information. He found that the fall in price was significant only for the

[11] Analyses of the price behavior of shares over the time period a new issue is announced and absorbed by the market deflate the price by a market index. Since companies that engage in stock financing are more profitable and have higher growth rates than stocks in general, deflating the price by a market index instead of an index of comparable stocks biases the price performance upward.

latter group and attributed his findings to the informational content of the sales decision by the insider.

Alan Kraus and Hans Stoll [24] examined the impact on price of bloc trade sales. A bloc trade generally is smaller than a secondary issue, and the sellers are predominantly financial institutions. Nonetheless, bloc sales were found to have a depressing impact on price. Furthermore, the time pattern of the price movement supported the market absorption and not the informational content explanation.

The previous analysis has been concerned only with a single new issue that is not expected to be repeated in the foreseeable future. Assume for such an issue that placing it on the market temporarily reduces the price by about 5 percent and that the investment banker takes the issue at a price 5 percent off the price at which it is sold to the public. The 10 percent difference between the proceeds to the company and the price at which the stock otherwise would sell raises the cost of capital by 10 percent, from, say, 9 to 9.9 percent.

With new stock financing expected to take place more or less continuously over time at some rate, the situation is somewhat different. If stock financing is expected to take place on average at the periodic rate s and if the equity accretion due to the stock financing is expected to be at the rate v, the dividend is expected to grow at the rate vs due to stock financing. We saw earlier that the yield investors require on a share increases with the retention rate because the rate of growth in the dividend varies with retention. Hence, with k an increasing function of dividend growth, k will vary with vs just as it varies with br.

Conceivably a company may engage in stock financing with $v = 0$, in which case there is zero growth due to stock financing. The yield at which that company's stock sells will not be independent of its stock financing rate. For a company that is expected to stock finance more or less regularly, the yield at which the stock sells not only will rise for a short period around the date at which the issue is placed on the market but also will be an increasing function of s on a permanent basis. Therefore, share yield varies with s on two counts. First, a higher yield is necessary to persuade the market to hold periodically increasing amounts of the firm's stock, and, second, a higher yield is required to cover the risk associated with the growth due to stock financing.

7.6 Conclusion

This chapter has provided the basis for questioning the validity of the PCCM leverage theorem and the PCCM and traditional dividend rate and stock financing theorems. In the process, alternative hypotheses about the relation between share yield (and price) and these financing policy variables have been indicated. The following chapter undertakes the development of a stock valuation and cost of capital model which incorporates these alternative hypotheses.

8

The Cost of Capital in Imperfect Capital Markets

Recognition of the fact that capital markets are not perfectly competitive requires significant departure from the line of attack followed in the previous chapters in arriving at a utility's cost of capital. In perfectly competitive capital markets the cost of capital is independent of the level and financing of the firm's investment and is equal to the leverage-free yield on the firm's stock. Cost of capital determination under the theory involved little more than measuring share yield.

The traditional theory departs from the PCCM theory only in the leverage assumption; the cost of capital is a function of the utility's leverage rate. However, in implementing the theory the practice is to fix the leverage rate on the basis of exogenous considerations. Consequently, given the leverage rate, the cost of capital here also is independent of the level and financing of investment, and the only problem is measuring share yield.

We have seen that the yield at which a utility's stock sells is an increasing function of its retention and stock financing rates as well as of its leverage rate. Knowing a share's yield under the firm's existing investment and financing policies does not tell us what the yield would be under alternative policies. What is more important, knowing share yield, even under the desired investment and financing policies, does not tell us the cost of capital. All we know is that, with share yield a function of investment rate, the marginal yield investors require at any investment rate is above the average yield at that investment rate. Our task then is to construct a share value model which correctly represents the influence on share price of a utility's investment and financing policies. Manipulation of the model will provide the yield at which the share sells for any combination of investment and financing policies.

Given this model of share valuation, how should it be used to determine a utility's cost of capital? There are two answers to this question depending on the policy adopted by the regulatory agency. Under one policy the agency sets the allowed rate of return under the constraint that the utility may take it as given in making its investment and financing decisions. The utility makes these decisions with the objective of maximizing share price. Under the other policy the agency recognizes the bilateral monopoly relation with the utility and adjusts the allowed rate of return in response to changes in the utility's investment and financing decisions to make the price of the stock independent of these decisions. It will be seen that the bilateral monopoly policy results in a lower cost of capital and also requires less information to implement than the alternative policy, which we call the constrained policy.

The pages that follow will develop the imperfect capital markets stock value model and arrive at the cost of capital from each source—retention, debt, and sale of stock—under the constrained and the bilateral monopoly regulatory policies. The following chapters will test the model, estimate its parameters, and provide illustrative estimates of the cost of capital from each source under both policies.

8.1 Retention Share Value and the Cost of Capital

Our fundamental and perfectly general stock value model is that the price of a share is the present value of the expected future dividends. With the current dividend $(1 - b)Y$ and with the assumption that the dividend is expected to grow forever at the rate $g = br$, our stock value model becomes

$$P = \frac{(1-b)Y}{k - br}. \tag{8.1.1}$$

The evidence in chapter 6 established that rather than k being independent of g, it increases with g. If we assume that k is a linear function of g,

$$k = \alpha_0 + \alpha_1 br. \tag{8.1.2}$$

α_0 is the yield at which the share would sell in the absence of growth and the growth coefficient $\alpha_1 > 0$. Substituting Eq. (8.1.2) for k, Eq. (8.1.1) becomes

$$P = \frac{(1-b)Y}{\alpha_0 + (\alpha_1 - 1)br}. \tag{8.1.3}$$

Taking the derivative $\partial P/\partial b$ we find

$$\frac{\partial P}{\partial b} = \frac{Y}{[\alpha_0 + (\alpha_1 - 1)br]^2}[(1-\alpha_1)r - \alpha_0]. \tag{8.1.4}$$

This equation states that price increases with retention if $(1 - \alpha_1)r > \alpha_0$. This implies that a firm should retain all of its earnings if $r > \alpha_0/(1 - \alpha_1)$ and retain nothing if $r < \alpha_0/(1 - \alpha_1)$.

The alternative hypothesis to a linear relation between k and g is that k increases with g by increasing amounts. This assumption is plausibly and conveniently represented by the expression

$$k = br + 1/[\alpha_0 e^{\alpha_1 br}]. \tag{8.1.5}$$

$1/\alpha_0$ is the yield at which the share would sell when $br = 0$ and $\alpha_1 > 0$. As br increases k may fall at first, but beyond some value of br, k will increase with g in decreasing amounts.[1] An interesting property of this function is that $k - br$ falls as br increases, asymptotically approaching zero as $br \to \infty$. Figure 1 illustrates how k and $k - g$ vary with g. $k - g$ is the vertical distance between the curves marked k and g.

Eq. (8.1.5) is a plausible expression for k since $k - g$, the dividend yield, approaches but never reaches zero as g rises. By contrast, for small values of α_1, the Eq. (8.1.2) value of k may result in

[1] k is minimized at $br = (1/\alpha_1)\ln(\alpha_1/\alpha_0)$.

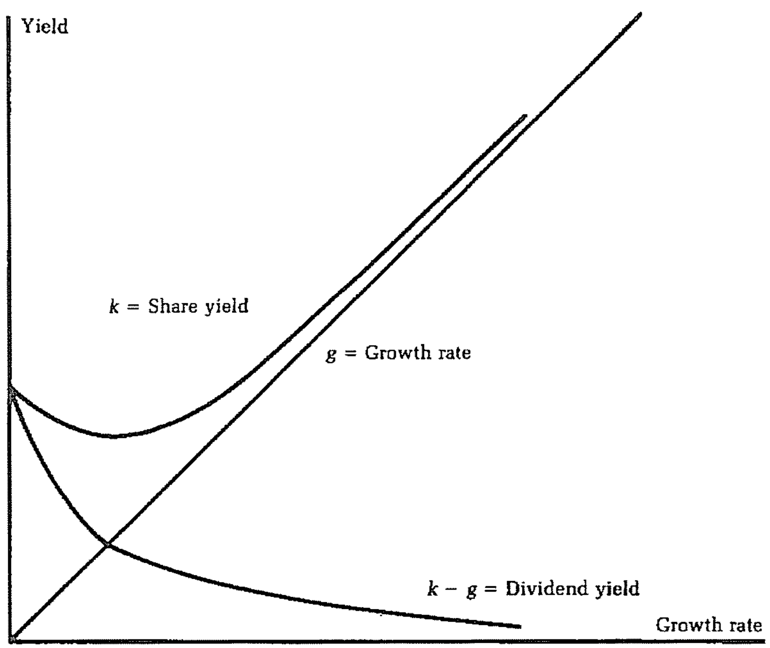

FIGURE 1. ***Variation in Share Yield and in Dividend Yield with the Growth Rate***

$k - g = 0$ for some value of g. Eq (8.1.5) is convenient for a number of reasons, as will be seen in the course of what follows. Substituting the equation for k in Eq. (8.1.1) results in

$$P = \alpha_0(1 - b)Ye^{\alpha_1 br}. \tag{8.1.6}$$

This equation states that P is the multiple α_0 of the dividend when $br = 0$, and the multiple increases with $g = br$. The coefficient α_1 may be looked on as the price the market is willing to pay for growth.

Eq. (8.1.6) is linear in the logarithims; hence, linear regression analysis of sample data may be used to estimate the values of the coefficients α_0 and α_1. This equation and the related Eq. (8.1.5) for k have two clear advantages over the Eq. (8.1.2) expression for k. With k a linear function of g we are led to an estimating equation of the form

$$\frac{D}{P} = \alpha_0 + \alpha_1 g + \dots. \tag{8.1.7}$$

In Eq. (8.1.7) the change in price with growth is an increasing percentage of the price, but if P/D is made the dependent variable, the change in price is a decreasing percentage of the price as g increases. By contrast, in Eq. (8.1.6) the change in price with growth is a constant percentage of the price, and it is the same with P, P/D, or D/P the dependent variable. This is the first advantage. The second is that in Eq. (8.1.6) the least squares estimates of the coefficients minimize the squared ratios of the actual to the estimated price or dividend yield. Eq. (8.1.7) minimizes the squared differences between the actual and estimated dividend yield, which will not necessarily make the error expressed as a percentage of the price independent of the price.[2]

Taking the derivate $\partial P/\partial b$ in Eq. (8.1.6) and setting it equal to zero, we find that share price is maximized when

$$b = 1 - 1/\alpha_1 r. \tag{8.1.8}$$

Hence, when k is given by Eq. (8.1.5) there is an optimal retention rate which increases both with the rate of return on investment, r, and with α_1, the index of the market's willingness to pay for growth in the dividend.

Let us assume that the regulatory agency allows the utility the freedom to make whatever retention decision it wishes given the rate of return decision of the regulatory agency. Since the objective of the utility is to maximize the share price, Eq. (8.1.8) provides the utility's retention rate as a function of the agency's return decision. Solving the equation for r, we find that

$$r = 1/\alpha_1(1 - b) \tag{8.1.9}$$

[2]It is also true that the least squares estimates of the coefficients of Eq. (8.1.7) with D/P the dependent variable differ from the coefficients with P/D the dependent variable so that given values of D and g produce different values of P depending on which set of coefficients are used. By contrast, when Eq. (8.1.6) is used it does not matter whether D/P or P/D is made the dependent variable.

is the return on common equity the utility must be allowed to earn to persuade it to retain the fraction b of its income. It is clear that r increases with b.

A retention rate of b and a return on common equity equal to r produce a rate of growth of br in the common equity and assets. Hence, the investment rate is br. To illustrate the model, assume that $\alpha_1 = 15$ and that the desired investment rate is .05. Multiply both sides of Eq. (8.1.9) by b, set $br = .05$, set $\alpha_1 = 15$, and solve for b; the result is $b = .43$. With $br = .05$, the solution for $r = .117$. If the demand for service requires a rate of growth in assets of $br = .04$, the combination of $b = .375$ and $r = .106$ maximizes share price at the required investment rate.

Recall that the above solution for the rate of return allows the utility to take the rate of return on common as given in making its retention decision. Under this assumption, with the debt-equity ratio fixed and with retention the only source of equity funds, the utility's cost of capital may be determined as follows. With no debt in the capital structure, $r = x$, and Eq. (8.1.9) provides a firm's cost of capital. With a leverage rate of B/E and the coupon rate of interest equal to c, we have $r = x + (x - c)\,B/E$. Substituting this expression for r, the cost of capital is

$$z = x = \frac{1}{\alpha_1(1-b)(1+B/E)} + \frac{cB/E}{1+B/E}. \qquad (8.1.10)$$

Since the investment rate is an increasing function of the retention rate when there is no stock financing and the leverage rate is fixed, it is clear from Eq. (8.1.10) that the cost of capital is an increasing function of the investment rate. It also can be shown that the cost of retention capital for any value of b falls as the given leverage rate is raised as long as $1/\alpha_1(1 - b)$ is greater than the coupon rate of interest.

8.2 *The Bilateral Monopoly Cost of Retention Capital*

The previous section established a utility's cost of retention capital if the utility may take the allowed rate of return as given in deciding its retention rate. However, there is a bilateral monopoly relation

between the utility and the regulatory agency. The latter may adjust the allowed rate of return in response to the retention rate selected by the utility. The consequences of each of these regulatory policies for the cost of capital, its relation to share yield, and the market-book value relation now are examined.

Figure 2 presents share price as a function of the retention rate for alternative values of the allowed rate of return. The retention rate b is on the horizontal axis, and share price P is on the vertical axis. The horizontal line E is the book value per share. If the allowed rate of return is set at r_2, share price is maximized at a retention rate of b_2, and the investment rate is b_2r_2. Similarly, b_1 and b_3 are the optimal retention rates when r_2 and r_3 are the allowed rates of return. It is clear that the price of the stock and the welfare of the stockholders are increasing functions of the investment rate needed to satisfy the demand for service. Stimulating the demand

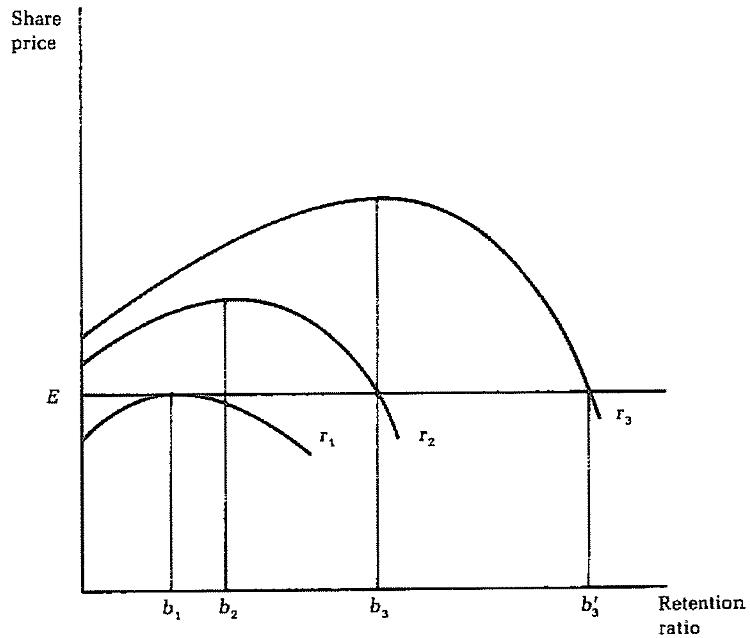

FIGURE 2. ***Comparison of Constrained and Bilateral Monopoly Cost of Retention Capital***

for service and/or increasing the capital requirements to meet the demand for service benefit the stockholders.

Assume now that the regulatory agency decides to adjust the allowed rate of return on assets (and common, given the debt-equity ratio) to keep the price per share of the common stock equal to its book value. Furthermore, let the investment rate that satisfies the public's demand for service be $g = b_3' r_3$. If the regulatory agency knows this and if it knows the coefficients of Eq. (8.1.6), it will set the return on assets so that the return on common $r = r_3$. If the utility sets $b = b_3'$, the result will be an investment rate that satisfies the demand for service and $P = E$.

The utility well may recognize that with $r = r_3$ setting $b = b_3 < b_3'$ will result in a higher price per share. However, the management knows that if it sets $b = b_3$ the regulatory agency will reduce r from r_3 to r_2, and the combination $b_3 r_2$ results in $P = E$ once again. The management might just as well set $b = b_3'$ and provide the investment rate that satisfies the demand for service. The stockholder, of course, is indifferent to the retention rate since the price of the stock is independent of the retention rate. Furthermore, the dividend plus the growth in price during the coming period divided by the current price will be exactly equal to the yield he requires on the stock regardless of the retention rate.

What if the utility management refuses to accept the regulatory agency's policy of maintaining $P = E$? With $r = r_3$, the management sets $b = b_3$, and when the agency reduces r to r_2, the utility counters with $b = b_2 < b_3$. The downward spiral continues until $b = 0$ or a positive b maximizes share price at $P = E$. The stockholders have gained nothing, but the investment rate is inadequate to meet the demand for service. If the public's dissatisfaction with inadequate service can be turned against the agency, it may be forced to give up the policy that maintains $P = E$. Although this possibility cannot be denied, it would seem that the relative power position of a regulatory agency committed to the public interest would enable it to enforce its policy. However, it must be acknowledged that where a bilateral monopoly exists considerations outside the scope of economic theory, narrowly defined, enter into the solution that will obtain.

Under a bilateral monopoly policy the agency need not burden itself with the difficult tasks of estimating the demand for service and the coefficients of Eq. (8.1.6). The agency need only concern

itself with keeping the market value of the stock equal to its book value. With stockholders indifferent to the investment rate, the management may just as well keep consumers happy by selecting the investment rate that satisfies the demand for service. Since the utility management is likely to be better informed on the demand for service than the agency, it would seem advisable for the agency to follow this simple policy. The only argument against leaving the responsibility to the management is that the management may inject its own preference into the decision. The bias then would be in the direction of a higher investment rate since growth provides various benefits to a management. However, carrying this policy too far may destroy the utility's monopoly position. Raising the investment rate increases the price of the product due to the higher capital base and the rise in the required rate of return. At some point the demand for service may not be equal to the supply at a price which covers the cost of the required capital, and the utility is in the position of a competitive firm that has overinvested.

To see the implications of this policy for the cost of capital and allowed rate of return, set $P = E$, substitute $Y = Er$ in Eq. (8.1.6), and rewrite it as follows:

$$r = 1/\alpha_0(1 - b)e^{\alpha_1 br}. \tag{8.2.1}$$

Comparison with Eq. (8.1.9) reveals that when $b = 0$ the two values of r are the same if $\alpha_0 = \alpha_1$. If $\alpha_0 > \alpha_1$ the bilateral monopoly solution results in a lower r at $b = 0$. As b rises both the Eq. (8.2.1) and the Eq. (8.1.9) values of r rise, but the bilateral monopoly value rises less rapidly due to the presence of the exponential term.

All the relevant considerations support the bilateral monopoly approach to regulatory policy. The cost of capital is lower, and the utility has no inducement to overinvest or underinvest. Furthermore, the regulatory agency has two alternative and complementary courses of action in implementing the policy. The agency can estimate the investment rate that satisfies the demand for service, set br equal to that value in Eq. (8.2.1), and solve for r. Alternatively, the agency can rely on the possibly superior information available to the utility on the investment rate that satisfies the demand for service and simply adjust the allowed rate of return to keep the market-book value ratio equal to one.

8.3 Leverage Share Value and the Cost of Capital

The presence of leverage in the capital structure is recognized by adding a leverage rate variable to Eq. (8.1.6) as follows:

$$P = \alpha_0 (1 - b) Y e^{\alpha_1 br} e^{\alpha_2 B/E}. \tag{8.3.1}$$

The leverage rate, B/E, is based on the book values of the debt and equity since the empirical work of the previous chapter provided no basis for believing that market values should be used. Given the dividend and its growth rate, an increase in leverage and the risk associated with it should cause the share price to fall. Hence, we would expect that $\alpha_2 < 0$. With this form of the function the share price goes down by α_2 percent for every 1 percent increase in the leverage. In consequence, share yield increases by increasing amounts as leverage rises. Ezra Solomon [43] and most other advocates of the traditional theory postulate a relationship of this kind between leverage and share yield. By contrast, the linear regression of share yield on leverage and other variables implies that the rise in share yield with leverage is independent of the leverage rate.

Leverage has a favorable impact on share price through its impact on earnings and return on investment since $Y = Er$ and $r = x + (x - c)B/E$. Assuming for the moment that $b = 0$, Eq. (8.3.1) can be written

$$P/E = \alpha_0 [x + (x - c)B/E] e^{\alpha_2 B/E}. \tag{8.3.2}$$

Dividing both sides of Eq. (8.3.1) by book value so that the market-book value ratio is the dependent variable facilitates the analysis that follows. Taking the derivative of P/E with respect to leverage results in

$$\frac{\partial (P/E)}{\partial (B/E)} = \left[\alpha_0 e^{\alpha_2 B/E}\right] \times \left[(x - c)(1 + \alpha_2 B/E) - \frac{\partial c}{\partial (B/E)} \frac{B}{E} + \alpha_2 x\right]. \tag{8.3.3}$$

5

We are interested in whether P/E is maximized at some value of B/E and, if so, what that value is. The second order conditions necessary to answer the first question are extremely difficult to evaluate. However, we can proceed as follows. Eq. (8.3.3) is positive at $(B/E) = 0$ if $-\alpha_2 < (x - c)/x$. Since $\alpha_2 < 0$ and is very small in absolute amount relative to $(x - c)/c$, this condition is easily satisfied. At $(B/E) = 0$ it is possible that $\partial c/\partial (B/E)$ is zero or negative, but when B/E passes some value, $\partial c/\partial (B/E)$ becomes positive, and it rises by increasing amounts. Hence, P/E does reach a maximum at a finite value of B/E. Over this, the relevant range of B/E, we find its optimal value by setting Eq. (8.3.3) equal to zero and solving for B/E. The result is

$$\frac{B}{E} = \frac{x - c + \alpha_2 x}{-\alpha_2 (x - c) + \partial c/\partial (B/E)}. \tag{8.3.4}$$

The optimal leverage rate increases with $x - c$, and it decreases as $-\alpha_2$ and $\partial c/\partial (B/E)$ are raised.

The cost of debt capital is obtained by setting Eq. (8.3.3) equal to zero and solving for x instead of B/E. The result is

$$z = x = \frac{c[1 + \alpha_2 (B/E) + \partial c/\partial (B/E)]}{1 + \alpha_2 + \alpha_2 (B/E)}. \tag{8.3.5}$$

With $\alpha_2 < 0$ it can be shown that the cost of debt capital increases with the interest rate and with the leverage rate. The cost of capital also increases with $-\alpha_2$, the leverage risk coefficient, and with the response of the interest rate to changes in leverage.

It should be noted that the interest rate in the above model is the coupon or imbedded rate of interest. If the current interest rate is above the coupon rate, the latter will move over time to equality with the current rate. Hence, for a given leverage rate, the appropriate value of the coupon rate is a weighted average of the coupon and current interest rates. The weights depend on the refunding and the new debt financing required to maintain the existing leverage rate during the year.

As the firm's leverage rate is raised, the interest rate at which it borrows is raised more or less regardless of the relation between the coupon and the current interest rates. It could be argued that only the new debt during the year will be at the higher interest rate. In that event the definition of the coupon rate in the previous paragraph accounts for this change in the interest rate since $\partial c/\partial(B/E) > 0$ in Eq. (8.3.5). However, bond contracts subordinate or otherwise restrict additional debt, and the change in the coupon rate with the leverage rate should reflect some refinancing of the existing debt or a risk premium on the new debt commensurate with its subordination.

With a positive retention rate the optimum leverage rate is finite if $-\alpha_2 > (x - c)\alpha_1 b$. In that event the counterpart to Eq. (8.3.4) with $\partial c/\partial(B/E) = 0$ is

$$\frac{B}{E} = \frac{x - c + \alpha_2 x + (x - c)x\alpha_1 b}{-\alpha_2(x - c) - (x - c)^2\alpha_1 b}. \tag{8.3.6}$$

Since $\alpha_1 > 0$, the optimum leverage rate is an increasing function of the retention rate. The value of x that satisfies $\partial(P/E)/\partial(B/E) = 0$ when $b > 0$ is a quadratic function of x. The economically valid solution and hence the cost of debt capital is a decreasing function of the retention rate. The cost of capital remains an increasing function of the interest rate, the leverage rate, and $-\alpha_2$.

Under the analysis just presented the regulatory agency was presumed to follow a constrained policy. That is, it allows the rate of return that maximizes share price at the debt-equity ratio it desires the utility to adopt. Under the policy the cost of debt capital and share price are increasing functions of the desired debt-equity ratio. By contrast, under a policy that recognizes the bilateral monopoly relation between the agency and the utility, the allowed rate of return is adjusted to maintain the market-book ratio for the common stock equal to one. How does the allowed rate of return vary with the debt-equity ratio when the condition that the price of the stock remains unchanged is satisfied?

It is not easy to answer this question by analytic methods since Eq. (8.3.2) cannot be arranged to make x an explicit function of B/E with P/E set equal to one. It will be shown in the next chapter, however, that the values of the parameters cause x to fall initially and then rise as B/E rises. The leverage rate at which x is minimized, of course, minimizes the cost of debt capital.

The yield at which the common stock sells rises continuously

with the debt-equity ratio, but this only compensates shareholders for their risk. When the share price is independent of the debt-equity ratio, stockholders are indifferent to that ratio. Consumers are concerned with the return on assets, and their interest is served by the debt-equity ratio that minimizes the return on assets. It should be noted, however, that the utility's risk increases with the leverage rate, and management may consider its welfare to vary inversely with the risk to the firm. Management therefore may prefer a debt-equity ratio lower than the one that minimizes the cost of capital, particularly since the stockholders are indifferent to the ratio's value.

8.4 External Finance, Share Value, and the Cost of Capital

The third source of funds to finance investment, the sale of additional shares, is the most difficult to incorporate into our model. The consequences of stock financing may be classified as short term and long term. This section will develop an imperfect capital markets model that captures the long-term consequences of stock financing. The next section modifies the model to incorporate the short-term consequences.

Our perfectly general model with stock financing present is

$$\frac{P}{E} = \frac{(1 - b)r}{k - br - vs}, \tag{2.8.8}$$

where s is the stock financing rate and v is the equity accretion rate on stock financing. As shown in chapter 2, the equity accretion rate is

$$v = (r - k)/(r - rb - s). \tag{2.8.12}$$

Under the PCCM theory of stock valuation, k is independent of s. Hence, if $r = k$, $v = 0$ regardless of s, and share price is independent of the stock financing rate. The cost of external equity capital is ρ, the leverage-free value of k.

However, if $r > k$ the consequence of stock financing for the value of P poses some problems. First, with v given, the denominator of Eq. (2.8.8) approaches zero as s rises and $P \to \infty$. But we cannot take v as given since Eq. (2.8.12) shows that with $r > k$ v rises with s. The unreasonable conclusion is that stock financing easily can generate an infinite share price for a profitable firm for which $r > k$.

Recognition that capital markets are not perfectly competitive is a means of avoiding the above ridiculous conclusion.[3] Our hypotheses are that the yield investors require on a share is an increasing function of both the dividend growth rate and the stock financing rate. The expression for share yield that incorporates these hypotheses and the leverage theorem is

$$k = br + vs + 1/[\alpha_0 e^{\alpha_1 br} e^{\alpha_2 B/E} e^{\alpha_3 vs} e^{\alpha_4 s^2}]. \tag{8.4.1}$$

With $\alpha_3 > 0$ and $\alpha_4 < 0$, k increases with vs, the dividend growth due to stock financing, and also with s, the stock financing rate. Substituting this expression for k in Eq. (2.8.8) and representing all the terms of no immediate interest by A_0, we have

$$P/E = A_0(1 - b) r e^{\alpha_3 vs} e^{\alpha_4 s^2}. \tag{8.4.2}$$

This expression simply states that, given the current dividend $(1 - b)rE$, share price increases with the expected rate of dividend growth due to stock financing, vs, and it decreases with the stock financing rate s.

Eq. (8.4.2) poses two questions. Why are there two stock financing terms, and why does the second term have the squared value of s? On the first question, it is clear that yield should rise with vs, the stock financing growth rate. However, with vs the only stock financing variable, share yield is independent of the stock financing rate when $v = 0$. This is clearly not reasonable. Rather, as reflected in Eq. (8.4.1), share yield should increase with the stock financing rate and with the growth due to stock financing. Substituting this expression for k in Eq. (2.8.8) results in a stock price equation with two stock financing terms.

[3] Another way out of the dilemma is to assume r is a decreasing function of the investment rate. This is not a correct assumption for regulated companies. For unregulated companies the assumption is unlikely to deal with the finite price problem.

To answer why the squared value of s is used in Eq. (8.4.2), let us replace it with s and take the derivative of P/E with respect to s:

$$\frac{\partial(P/E)}{\partial s} = (P/E)\left[\alpha_3 v + \alpha_3 s \frac{\partial v}{\partial s} + \alpha_4\right]. \tag{8.4.3}$$

With $\partial(P/E)/\partial s > 0$ at $s = 0$ it will remain so as s increases. The reason is that with $v = 1 - E/P$, when $\partial(P/E)/\partial s > 0$, $\partial v/\partial s > 0$. Hence, the second term in Eq. (8.4.3) is positive and increases with s if $\partial(P/E)/\partial s > 0$ at $s = 0$, and P/E rises with s without end.

By contrast, with Eq. (8.4.2) as it stands, we obtain, using $v = 1 - E/P$,

$$\frac{\partial(P/E)}{\partial s} = \frac{(P/E)[\alpha_3 v + 2\alpha_4 s]}{\left[1 - \dfrac{\alpha_3 s}{P/E}\right]}. \tag{8.4.4}$$

As s is increased, P/E increases in decreasing amounts and is maximized at the optimal stock financing rate

$$s = -\alpha_3 v/2\alpha_4. \tag{8.4.5}$$

The optimal stock financing rate varies directly with α_3 and v and inversely with $-\alpha_4$. However, since $v = 1 - E/P$, it is an implicit function of all the other variables and parameters which determine P, and Eq. (8.4.5) cannot be used directly to find the optimal stock financing rate.

To establish the optimal stock financing rate we must determine v for any value of s and the other variables. To do so we may proceed as follows. Substitute the Eq. (8.4.1) value of k in Eq. (2.8.12). The result is

$$\begin{aligned} v &= \frac{r - br - vs - 1/[A_0 e^{\alpha_3 vs} e^{\alpha_4 s^2}]}{r - br - s} \\ &= 1 - \frac{1}{r(1 - b) A_0 e^{\alpha_3 vs} e^{\alpha_4 s^2}}. \end{aligned} \tag{8.4.6}$$

When $s = 0$, v is an explicit function of the variables on the right-hand side of Eq. (8.4.6), and we may obtain $v \gtreqless 0$, depending on the values of the variables and the coefficients.

When $v < 0$ at $s = 0$ we also have $P/E < 1$ since $v = 1 - E/P$. As s rises above zero, both v and P/E fall, and the rise in s makes a bad situation worse. Hence, when $v < 0$ at $s = 0$ the optimal course of action is $s = 0$.[4] When $v = 0$ and $P/E = 1$, a rise in s reduces v and P/E. Hence, in this case also the optimal course of action is $s = 0$.

When $v > 0$ and $P/E > 1$ at $s = 0$, a rise in s raises v and P/E. There is some positive value of v greater than the value of v at $s = 0$ which satisfies Eq. (8.4.6) at each value of s. Trial and error calculations may be used to find this value of v and the associated value of P/E at each value of s. For each value of s and the values of the variables other than v on the right-hand side of Eq. (8.4.6) there is also a negative value of v that satisfies the equation. However, this solution to the equation can be ruled out on economic grounds. As s rises the one admissible solution for v and P/E for each s either will reach a maximum at a finite s or rise continuously with s. In the former case we have an optimal s for the given values of the variables and coefficients. In either case we can find the value of r necessary to make a stock financing rate at least equal to some value optimal policy.

8.5 Further Consequences of Stock Financing

The previous section established how we measure v given s, r, the other variables, and the parameters of Eq. (8.4.2). It also established that the optimal stock financing rate is

$$s = \alpha_3 v / -2\alpha_4. \tag{8.4.5}$$

The interpretation of this expression is somewhat tricky because v depends on s, among other variables. Instead of attempting this, let us consider the equity accretion rate necessary to make some value of s optimal policy. Solving Eq. (8.4.5) for v we obtain

[4] There are some combinations of the coefficients and variables in Eq. (8.4.6) which result in two positive solutions for v with $v < 0$ at $s = 0$. However, these combinations of the variables and coefficients can be ruled out on economic grounds.

$$v = -2\alpha_4 s/\alpha_3. \tag{8.5.1}$$

If a stock financing rate of $s = s^*$ is desired, the value of $v = v^*$ needed to make it optimal policy is provided by Eq. (8.5.1). The problem that remains is to determine the return on common equity that will realize $v = v^*$ when $s = s^*$, and we proceed as follows. Assign a value to r in Eq. (8.4.6) and find the value of v that satisfies the equation with $s = s^*$ and the given values of all the other variables. If there is no solution for v or if $v < v^*$, raise r. There is some value of $r = r^*$ at which $v = v^*$ with $s = s^*$. It is the return on common equity needed to make s^* optimal policy. Given the firm's debt-equity ratio, the return on assets $x = x^*$ needed to realize $r = r^*$ can be determined.

The bilateral monopoly solution to the cost of new equity capital is considerably simpler than the above competitive solution. Under a policy of maintaining $P/E = 1$, $v = 0$ regardless of s. Market price is independent of the stock financing rate, the existing shareholders are indifferent to the stock financing rate, and the regulatory agency need only maintain $P/E = 1$ to generate whatever stock financing rate the demand for service requires.

To determine the consequences of such a policy for the rate of return on common equity, we set $P/E = 1$ and $v = 0$ in Eq. (8.4.2) and solve for r. The result is

$$r = 1/A_0(1-b)e^{\alpha_4 s^2}. \tag{8.5.2}$$

Taking the derivative with respect to s we find that

$$\frac{\partial r}{\partial s} = \frac{-2\alpha_4 s}{A_0(1-b)e^{\alpha_4 s^2}}. \tag{8.5.3}$$

Since $\alpha_4 < 0$, Eq. (8.5.3) is positive, and r rises with the stock financing rate. That is, maintaining $P/E = 1$ involves raising r with s. However, this is of no benefit to the shareholder since the yield he requires has gone up correspondingly. Also, it can be shown that the value of r that satisfies Eq. (8.5.2) is less than the value of r that satisfies Eq. (8.5.1) for any value of s.

The previous analysis recognized that if a corporation is expected to stock finance periodically at some average annual rate then the yield investors require on the stock is raised directly by the stock financing rate and indirectly by the growth due to the stock financing. In addition to these long-run influences on share price, stock financing will have two short-run consequences. First, Eq. (2.8.12) should be modified to recognize that the firm does not receive the entire amount paid by the public for the issue. Second, the expression for v should recognize that the issue causes a slight temporary depression in the price. This is accomplished as follows. With Q_n the amount invested in the corporation by new shareholders during n, the equity in the corporation they receive is $(1 - v - \psi)Q_n$, where ψ is the fraction of Q_n that accrues to the investment banker. The dividend they can expect in $n + 1$ is Eq. (2.8.10) changed accordingly:

$$D^*_{n+1} = (1 - b)r(1 - v - \psi)Q_n. \tag{8.5.4}$$

Once in the corporation the new shares are identical with the old. Their dividends also are expected to grow at the rate $br + vs$. However, to bring the shares in required a higher yield or some depression of the price at the time of the issue. This is recognized by changing Eq. (2.8.11) to

$$\begin{aligned} Q_n &= \sum_{t=n+1}^{\infty} \frac{(1 - b)r(1 - v - \psi)Q_n(1 + br + vs)^{t-n-1}}{(1 + \eta k)^{t-n}} \\ &= [(1 - b)r(1 - v - \psi)Q_n]/[\eta k - br - vs], \end{aligned} \tag{8.5.5}$$

where $\eta > 1$ is the ratio of the yield on a share at the time of a new issue to the yield at other times. Dividing both sides by Q_n and solving for v results in

$$v = \frac{r[1 - \psi(1 - b)] - \eta k}{r - br - s}. \tag{8.5.6}$$

Plausible values of ψ and η are $\psi = .05$ and $\eta = 1.05$. The consequence is that the numerator of this expression is less than the numerator of Eq. (2.8.12) for given values of r, b, s, and k, while the denominator is unchanged. In other words, introducing ψ and η reduces v.

Substituting the Eq. (8.4.1) value for k in this expression for v results in

$$v = \frac{r[1 - b(\eta - \psi) - \psi]}{r[1 - b] + s[\eta - 1]} - \frac{\eta}{[r(1 - b) + s(\eta - 1)]\, A_0 e^{\alpha_3 vs} e^{\alpha_4 s^2}}. \tag{8.5.7}$$

While this expression may appear considerably more involved than Eq. (8.4.6), the differences are not important. The first term is reduced from one to a number that is slightly less than one, and it falls somewhat as s rises. The numerator of the second term is raised slightly, and the denominator is reduced slightly and rises less rapidly with s. The characteristics of the solution to Eq. (8.5.7) are the same as the characteristics of the solution to Eq. (8.4.6). The only difference is that for any s the solution value of v is reduced somewhat. Eqs. (8.4.5) and (8.5.1) remain unchanged. However, the value of r needed to generate any value of v is raised so that the cost of stock financed capital under our constrained model of regulatory policy is an increasing function of ψ and η.

However, with $\eta > 1.0$ and/or $\psi > 0$, the bilateral monopoly solution to regulatory policy is somewhat more complicated than it is with $\eta = 1.0$ and $\psi = 0$. The proceeds to the corporation from a stock issue are less than the market price of the stock, and with price equal to book the issue reduces both the book and market value of the stock.[5] The equity of the existing shareholders is diluted by the stock issue. In other words, with $P = E$ and $r = k$, a stock issue or stock financing at some rate make the return the shareholders can expect to earn a decreasing function of the stock financing. Therefore, it is against the interest of the existing shareholders for the firm to engage in stock financing when the proceeds per share on the issue are less than the book value per share.

To make shareholders indifferent to the rate at which a utility stock finances, the regulatory agency must set $r > k$ so that $P > E$ by a margin that makes the proceeds per share on the new issue equal to the book value of the outstanding stock. With $r > k$, $P > E$, and the stock sells to earn k prior to a new issue. With

[5] The price (and book value) per share after the issue is a weighted average of the preissue price and the proceeds to the corporation per share issued. The weights are the relative amounts of old and new shares.

the new shares sold at a price of E per share, the buyers receive a return above k for coming into the company, but they do not receive r since part of the proceeds on the issue goes to the investment banker. Both the new and the old shares earn Er per share, and they sell at a yield of k and a price of P, the old price per share.

All this may seem very complicated, but it need not trouble the regulatory agency. The agency need only estimate the proportion that the proceeds per share on an issue bear to the price of the stock and adjust the allowed rate of return so that the price per share is the indicated ratio of the book value per share. If the proceeds on an issue are 91 percent of market price, the agency should maintain market price at about 110 percent of book value. The welfare of the stockholders is independent of the firm's stock financing rate, and the utility may be expected to set s to satisfy the demand for service.

9

Estimation of the Parameters and Implementation of the Model

This chapter begins with tests of the stock value model developed in the previous chapters and experiments with alternative forms of the model, using the sample of utility firms for the years 1958–1968 described in chapter 5. The objective is to find the form that is best suited for estimating the cost of capital from each source and in the aggregate. The parameter estimates and the sample data then are used to arrive at illustrative estimates of the cost of capital from each source: retention, debt, and the sale of stock. These results are obtained under the constrained and the bilateral monopoly policies.

The next chapter takes up the problem of the overall cost of capital. That is, it develops an algorithm for determining the allowed rate of return necessary to obtain a given investment rate with the choice between retention and stock financing being made so as to minimize the allowed rate of return. The debt-equity ratio is taken as fixed for reasons that will become clear in the course of the discussion. Chapter 10 continues with a comparative analysis of the cost of capital under the different theories and the allowed rate of return for certain of the sample years, and it concludes with some observations on the implications of the models and the data for regulatory policy and related issues.

9.1 Alternative Forms of the Model

The use of our stock value model to arrive at a utility's cost of capital requires the estimation of its parameters. For that purpose the model must be put in logarithmic form. The mnenomic code introduced in chapter 5 is employed to allow the precise definition of the variables. With some rearrangement of terms and certain variables added, the stock value expression developed in the previous chapter, Eq. (8.4.2), becomes

$$ln[\text{PPS/DIV}] = ln\alpha_0 + \alpha_1\text{RTGR} + \alpha_2\text{SFGR} + \alpha_3\text{XYGR}$$
$$+ \alpha_4\text{SFRS2} + \alpha_5\text{LEV} + \alpha_6\text{PEE}. \quad (9.1.1)$$

In the above, SFRS2 is the squared value of SFRS, and XYGR = YGRS − RTGR − SFGR. XYGR was added to the independent variables to recognize the influence of the smoothed rate of growth in earnings on the rate of growth investors expect. PEE was included to recognize the influence of this business risk variable on the valuation of utility stocks. The quality of earnings, QLE, was not included because it was not significant in most years in earlier regressions, and the number of independent variables is already large.

With *ln*[PPS/DIV] as the dependent variable, the coefficient of the dividend is constrained to be equal to unity. If *ln*DIV had been left on the right-hand side of the equation, the data would generate the value of its coefficient and test the hypothesis that it is equal to one. A DIV coefficient different from unity implies that the price-dividend multiplier is not independent of the level of the dividend. The hypothesis that the price-dividend multiplier depends on the scale of the dividend variable does not have much intuitive merit, but other variations on Eq. (8.4.2) do have some intuitive merit, and it would be advisable to test the hypotheses they represent.

Table 15 presents regression statistics for six variations of the model. The data for the 54-firm sample over the eleven years

Table 15. Parameter Estimates for Six Variations of the Imperfect Capital Markets Model

Equation number	Dependent variable	*ln*[1/AAR]			*RTGR*	*SFGR*	*XYGR*	*LEV*	*SFRS2*	*PEE*	R^2 *S.E.E.*
9.1.2	*ln*[PPS/DIV]										
	.485	.772			11.561	10.949	2.579	−.152	−12.167	.184	.733
		(.035)			(.487)	(.678)	(.443)	(.017)	(4.860)	(.033)	(.1290)
9.1.3	*ln*PPS			*ln*DIV							
	.580	.768		.912	10.711	10.512	2.450	−.163	−10.121	.185	.844
		(.034)		(.020)	(.514)	(.674)	(.437)	(.017)	(4.802)	(.032)	(.1269)
9.1.4	*ln*PPS		*ln*EPS	*ln*DIVR							
	.651	.728	.902	.404	6.285	10.561	2.478	−.152	−14.089	.206	.852
		(.034)	(.019)	(.090)	(.918)	(.656)	(.425)	(.017)	(4.727)	(.032)	(.1235)
9.1.5	*ln*[PPS/EPS]			*ln*DIVR							
	.541	.735		.541	7.573	11.038	2.618	−.141	−16.030	.203	.630
		(.035)		(.088)	(.902)	(.663)	(.434)	(.017)	(4.812)	(.032)	(.1262)
9.1.6	*ln*[PPS/BVS]			*ln*[DIV/BVS]							
	.105	.726		.808	11.422	11.493	2.626	−.137	−20.572	.207	.795
		(.034)		(.030)	(.472)	(.662)	(.429)	(.017)	(4.886)	(.032)	(.1248)
9.1.7	*ln*[PPS/BVS]		*ln*RRC	*ln*DIVR							
	−1.060	.724	.311	1.787	23.894	12.617	2.621	−.131	−29.916	.204	.798
		(.034)	(.128)	(.246)	(3.150)	(.711)	(.424)	(.017)	(5.359)	(.032)	(.1233)

NOTE: The numbers in the dependent variable column are $\ln\alpha_0$. The other columns contain the parameter estimates of the independent variables with their standard errors in parentheses.

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1958–1968 were pooled to obtain the regression statistics. $Ln[1/AAR]$, where AAR is the interest rate on Aa rated bonds, was included among the independent variables to permit pooling by accounting for changes in the valuation of shares from one year to the next. In each of the six equations the coefficient of $ln[1/AAR]$ is highly significant, and it therefore accounts for much if not all of the change in share valuation over the eleven-year period.

Eq. (9.1.2) in Table 15 is Eq. (9.1.1) with the interest rate variable added. Eq. (9.1.3) has lnDIV on the right-hand side to test the hypothesis that PPS/DIV is independent of the level of the dividend. The coefficient of lnDIV is .912. It is less than one by a statistically significant amount, but the difference is not material. Furthermore, the coefficient of RTGR is also smaller than in Eq. (9.1.2). That plus the differences in the other coefficients make the consequences of Eqs. (9.1.2) and (9.1.3) practically identical in estimating a firm's cost of capital.

The dividend can be written DIV = EPS*DIVR, where DIVR is the dividend rate. Eq. (9.1.4) decomposes DIV into EPS and DIVR and estimates the parameters of each. Eq. (9.1.5) assumes that EPS is simply a scale variable and makes the ratio PPS/EPS independent of EPS. The parameter estimates obtained with Eqs. (9.1.4) and (9.1.5) are very close, but the latter has somewhat more theoretical merit in constraining the coefficient of lnEPS at unity. The striking feature of the result obtained is that the coefficient of DIVR is very much less than one. There is a theoretical basis for this result. With the future uncertain, the value of a dividend may increase with its earnings coverage. In other words, retained earnings are valuable on two counts—dividend growth and dividend coverage. The higher the earnings in relation to the dividend, the smaller the likelihood that a fall in earnings will force a cut in the dividend. However, the value of the DIVR coefficient seems extremely low. Also, the RTGR coefficient is very much below its Eq. (9.1.2) value and the SFGR coefficient. We would expect investors to be at least as confident in retention growth as in stock financing growth and to place at least as high a value on retention growth. It would appear that correlation among the variables has resulted in the understatement of both the DIVR and the RTGR coefficients.

Eq. (9.1.7) is Eq. (9.1.4) with both PPS and EPS deflated by BVS. BVS is a very plausible scale variable and a particularly attractive deflator for a public utility. Also, EPS/BVS is equal to RRC, the

utility's return on common. However, the coefficients make no economic sense and only provide a vivid demonstration of what correlation among the independent variables can do.

Eq. (9.1.6) is Eq. (9.1.3) with both PPS and DIV deflated by BVS. The coefficient of DIV/BVS is .81, below one by an amount that is plausibly rationalized by the earnings coverage hypothesis. The values of the RTGR and SFGR coefficients are also reasonable in that they are about equal in size. These properties of the coefficients plus the virtue of using BVS as a scale deflator persuade us to use Eq. (9.1.6) to estimate the model's coefficients.

The following additional observations may be made with regard to the six equations. The R^2 values in Table 15 are not comparable since the dependent variables are different. However, the standard error of the estimate, S.E.E., is comparable over the six equations. Eq. (9.1.7) has the lowest S.E.E., but the S.E.E. for Eq. (9.1.6) is not much higher and is below the value for three of the four other equations.

A major use of the parameter estimates is to arrive at the cost of retention capital and the cost of new equity capital. When the dividend coefficient is constrained at one, the cost of retention capital is given by the Eq. (8.1.9) value with the dividend coefficient substituted for one in the first term of the expression. Hence, the cost of retention capital increases with the ratio of the DIV, DIVR, or DIV/BVS coefficient to the RTGR coefficient. Since this ratio is about the same for the Eqs. (9.1.4) to (9.1.7) estimates of the parameters, the cost of retention capital is independent of which equation form is used. From Eq. (8.5.1) we see that the cost of new equity capital varies with the ratio of the absolute value of the SFRS2 coefficient to the SFGR coefficient. This ratio varies over a wide range in the Eqs. (9.1.4) to (9.1.7) parameter estimates. Eq. (9.1.7) produces the second highest value for the ratio, and Eq. (9.1.6) has the next highest value. We cannot estimate the cost of stock financed capital as reliably as we can estimate the cost of retention capital.

9.2 Estimates of the Parameters

Given that Eq. (9.1.6) is the form of the model to be employed to explain the valuation of utility stocks, we can use the parameter estimates appearing in Table 15. All the coefficients have the correct sign and are significantly different from zero at the 5 percent confidence level or better. In fact, the parameter estimates are very high multiples of their standard errors, and their true values fall in a fairly narrow interval around the estimates. However, use of Eq. (9.1.6) implies that the interest rate is the only factor responsible for change in the valuation of a share over time. The variation in price with each growth variable, leverage, and so forth, is the same in each of the eleven years. Furthermore, given the values of RRC and other such corporate variables, the optimal retention and stock financing rates are the same in every year.

The alternative hypothesis is that one or more parameters besides α_0 change from one year to the next.[1] If the other parameters also change, we may take the coefficients based on the most recent cross-section data as the best estimates of the parameters. That is, to establish the cost of capital during 1965 we use the coefficients obtained from the 1964 data. Table 16 presents the parameter estimates for each of the eleven years 1958–1968 of the cross-section version of Eq. (9.1.6), which is

$$\begin{aligned} ln[\text{PPS/BVS}] &= ln\alpha_0 + \alpha_1 ln[\text{DIV/BVS}] + \alpha_2 \text{RTGR} \\ &+ \alpha_3 \text{SFGR} + \alpha_4 \text{XYGR} + \alpha_5 \text{LEV} \\ &+ \alpha_6 \text{SFRS2} + \alpha_7 \text{PEE}. \qquad (9.2.1) \end{aligned}$$

The coefficients of DIV/PPS, RTGR, and SFGR each have the correct sign in every year. Furthermore, their values are very high multiples of their standard errors, and the probability that each differs from zero due to chance is extremely small. The earnings growth, the leverage, and the percentage electric variable coefficients all have the correct sign in every year. However, each is not significantly different from zero at the 5 percent level in three or more years. Finally, SFRS2, the stock financing variable, has the incorrect sign in three years. In these years and in three of the eight years when it had the correct sign, the coefficients differed from zero by amounts that were not significant at the 5 percent level.

[1] In each year the constant term is $ln\alpha_0 + \alpha_6 ln[1/\text{AAR}]$ with AAR the interest rate for that year.

Table 16. ***Cross-Section Estimates of the Parameters of an Imperfect Capital Markets Model***

$ln[PPS/BVS] = ln\alpha_0 + \alpha_1 ln[DIV/BVS] + \alpha_2 RTGR + \alpha_3 SFGR + \alpha_4 XYGR + \alpha_5 LEV + \alpha_6 SFRS2 + \alpha_7 PEE$

Year	$ln\alpha_0$	α_1	α_2	α_3	α_4	α_5	α_6	α_7	R^2 *S.E.E.*
1958	1.508	.463	7.47	16.31	1.14	−.064	−28.36	.042	.918
		(.090)	(1.09)	(2.10)	(.64)	(.030)	(8.60)	(.066)	(.0734)
1959	1.456	.556	8.97	17.69	1.86	−.048	−42.12	.191	.893
		(.098)	(1.05)	(2.07)	(.87)	(.041)	(12.06)	(.081)	(.0857)
1960	1.521	.589	10.02	20.60	3.02	−.006	−53.80	.190	.905
		(.096)	(1.29)	(2.23)	(.86)	(.048)	(15.07)	(.077)	(.0889)
1961	1.804	.670	14.94	13.47	.78	−.032	−22.43	.218	.846
		(.103)	(1.76)	(2.89)	(1.01)	(.063)	(25.21)	(.088)	(.1015)
1962	2.501	.859	11.98	8.54	2.45	−.134	3.50	.203	.850
		(.084)	(1.21)	(2.18)	(1.25)	(.055)	(25.16)	(.082)	(.0948)
1963	2.302	.800	12.65	12.04	4.77	−.085	−35.73	.136	.882
		(.075)	(1.20)	(2.14)	(1.37)	(.047)	(26.66)	(.080)	(.0863)
1964	2.451	.849	11.28	9.16	5.19	−.090	4.23	.210	.878
		(.075)	(1.22)	(1.72)	(1.51)	(.047)	(27.30)	(.079)	(.0884)
1965	2.033	.799	13.35	12.62	4.71	−.039	−2.10	.237	.877
		(.077)	(1.33)	(4.06)	(1.63)	(.051)	(3.81)	(.077)	(.0905)
1966	1.689	.835	15.52	12.65	6.72	−.027	.590	.344	.915
		(.074)	(1.58)	(3.83)	(1.51)	(.050)	(3.57)	(.075)	(.0869)
1967	1.760	.658	7.67	33.65	4.77	−.046	−14.53	.106	.883
		(.079)	(2.13)	(4.73)	(1.61)	(.047)	(4.04)	(.089)	(.0976)
1968	2.010	.652	6.13	14.71	.84	−.096	−5.10	.121	.886
		(.068)	(1.63)	(2.78)	(1.31)	(.034)	(2.07)	(.070)	(.0796)

NOTE: The numbers in parentheses are the standard errors of the parameter estimates.

Overall, the equation does an excellent job of explaining the variation in the market-book value ratio among utility stocks. The model explains from 85 to 92 percent of the variation in PPS/BVS in each of the eleven years. The equation was run with SFRS instead of SFRS2, and the results were practically identical. Therefore, the only bases for the squared value of the stock financing rate are the reasons advanced on pages 159–62.

The major disquieting question raised by the parameter estimates is the wide range of values for each coefficient over the eleven years. It does not seem reasonable that the true values of the parameters exhibit this range of variation. The more likely explanation is sampling fluctuations due to the relatively small sample size and high correlation among the independent variables. Pooling the eleven years is a means of increasing the sample size, and the standard errors of the pooled estimates of the parameters are considerably smaller. However, as stated above, the implicit assumption that all the parameters except the constant term do not change over time is also disquieting.

As indicated earlier, the cost of retention capital depends on α_1/α_2, and the cost of new equity capital depends on α_3/α_6. To test whether the RTGR and SFGR coefficients are constant over the eleven years and, indirectly, whether the cost of capital from retention and stock financing is constant, Eq. (9.1.6) was run with dummy variables for each of these coefficients. The equation is

$$\begin{aligned} ln(\mathrm{PPS/BVS}) = {} & ln\alpha_0 + \alpha_1\, ln(\mathrm{DIV/BVS}) + \alpha_2 \mathrm{RTGR} \\ & + \alpha_3 \mathrm{SFGR} + \alpha_4 \mathrm{XYGR} + \alpha_5 \mathrm{LEV} + \alpha_6 \mathrm{SFRS2} \\ & + \alpha_7 \mathrm{PEE} + \sum_{i=59}^{68} \alpha_i X_i \\ & + \sum_{j=59}^{68} \alpha_j Z_j + \alpha_8\, ln[1/\mathrm{AAR}], \end{aligned} \tag{9.2.2}$$

where X_i is the firm's value of RTGR in the year i and zero in every other year and Z_j is the firm's value of SFGR in the year j and zero in every other year. The results appear in Table 17.

The retention growth dummy coefficients clearly perform very well. Only three of the ten are not significantly different from zero at the 5 percent level of significance, and these three differ little from zero in absolute value. Also, their values are the largest in the years 1961–1965, when interest rates were low and confidence in the growth prospects of utility stocks was high. It would seem reasonable to believe that the coefficient of RTGR should be high when interest rates are low and when confidence in future growth is high, and the introduction of dummy variables for the RTGR coefficient produces this result.

Table 17. *Pooled Parameter Estimates of Eq. (9.2.2) with Dummy Year Variables for the Retention and Stock Financing Growth Rate Coefficients*

$ln\alpha_0$	α_1 $ln(DIV/BVS)$	α_2 $RTGR$	α_3 $SFGR$	α_4 $XYGR$	α_5 LEV	α_6 $SFRS2$	α_7 PEE	α_8 $ln(1/AAR)$	
.2835	.768	8.60	13.72	2.69	−.091	−17.13	.210	.595	
	(.025)	(.81)	(1.67)	(.34)	(.014)	(4.82)	(.024)	(.106)	
RTGR Dummy Coefficients									
α_{10} X(59)	α_{11} X(60)	α_{12} X(61)	α_{13} X(62)	α_{14} X(63)	α_{15} X(64)	α_{16} X(65)	α_{17} X(66)	α_{18} X(67)	α_{19} X(68)
−.06	1.51	6.54	4.12	4.95	5.76	4.67	2.83	1.04	3.48
(.83)	(.84)	(.82)	(.76)	(.76)	(.75)	(.78)	(.91)	(1.15)	(1.27)
SFGR Dummy Coefficients									
α_{20} Z(59)	α_{21} Z(60)	α_{22} Z(61)	α_{23} Z(62)	α_{24} Z(63)	α_{25} Z(64)	α_{26} Z(65)	α_{27} Z(66)	α_{28} Z(67)	α_{29} Z(68)
−.45	1.13	.44	−3.19	−3.10	−2.75	−3.44	−3.00	2.59	−0.73
(1.67)	(1.75)	(1.69)	(1.81)	(1.85)	(1.98)	(1.98)	(2.13)	(2.12)	(2.09)

Unfortunately, the SFGR dummy coefficients do not perform as well. None of them is significant at the 5 percent level, although those that are above 2.0 in absolute value are larger than their standard errors. Somewhat more disturbing is the rough inverse correlation between the RTGR and SFGR dummy variables. It would seem that if low interest rates and confidence in the future lead investors to place a high value on retention growth they should also value stock financing growth highly. However, this is an area in which our independent knowledge is very limited, and the analysis of the influence of stock financing on price through the model is quite difficult. No hypothesis on how the SFGR coefficient varies over time commands much confidence.

There is another reason for accepting the Eq. (9.2.2) coefficient estimates. A plausible alternative is to drop the SFGR dummy variables. However, doing so makes the $(\alpha_3 + \alpha_j)/-2\alpha_6$ ratio even smaller than the Table 17 values and reduces the cost of new equity capital. Later in the chapter we show that the Table 17 values of $(\alpha_3 + \alpha_j)/-2\alpha_6$ yield a comparatively low cost of new equity capital. Dropping the dummy variables will produce cost of capital estimates which are lower still and therefore unacceptable.

For any particular year, Eq. (9.2.2) may be written

$$\begin{aligned} ln(\text{PPS}/\text{BVS}) = {} & ln\, \alpha_0 + \alpha_1\, ln(\text{DIV}/\text{BVS}) + \alpha_2'\, \text{RTGR} \\ & + \alpha_3'\text{SFGR} + \alpha_5\text{LEV} + \alpha_6\text{SFRS2} + \alpha_7\text{PEE} \\ & + \alpha_8\, ln[1/\text{AAR}]. \end{aligned} \tag{9.2.3}$$

In this expression α_2' and α_3' are the coefficients of RTGR and SFGR with the values of the appropriate dummy variable coefficients for the year added.

9.3 *Cost of Retention Capital in Selected Years*

This section uses the data for 1963 and 1968 to establish the cost of retention capital as of the end of those years. Using Eq. (8.1.6) as the stock value model, Eq. (8.1.9) provides the rate of return on common that maximizes share price as a function of the retention rate. When the stock value model is given by Eq.

(9.2.3), the RRC that maximizes share price at a retention rate of RETR is

$$\text{RRC} = \alpha_1/\alpha_2' [1 - \text{RETR}]. \tag{9.3.1}$$

The rate of return on assets necessary to provide a firm with a given value of RRC is a function of its leverage rate and the interet rate on its debt. Substituting Eq. (5.2.6) for RRC in Eq. (9.3.1) and solving for RRA we obtain the RRA that maximizes share price for a given value of the retention rate. This is the firm's cost of retention capital, and the expression for it is

$$\text{COCR} = \frac{\alpha_1}{\alpha_2'[1 - \text{RETR}]\,[1 + \text{DEQ}]} + \frac{\text{IMBR*DEQ}}{1 + \text{DEQ}}. \tag{9.3.2}$$

COCR varies directly with IMBR and inversely with DEQ if α_1/α_2' (1 − RETR) > IMBR. Furthermore, it is evident that COCR is an increasing function of RETR.

With SFR = 0, the rate of growth in the common equity and in assets is RGA = RTGR = RRC*RETR. Hence, for any RGA the pair of values for RRC and RETR which have a product equal to RGA and which satisfy Eq. (9.3.1) are the solution to our problem under a constrained policy. The agency takes the solution value of RETR and uses Eq. (9.3.2) to arrive at the return on assets it should allow the utility.

Table 18 presents the constrained COCR for RETR over the range 0.0 to 0.75 for a company with the following characteristics. The parameters and AAR have their 1963 values, SFR and XYGR are set equal to zero, and LEV and PEE have their sample mean values. In calculating COCR, DEQ has its 1963, and IMBR its 1964, sample mean value. The rationale for using the 1964 value for IMBR is that the relevant figure is a weighted average of the 1963 values for IMBR and AAR, and the 1964 IMBR is a satisfactory approximation of that average.

As we would expect, the optimizing RRC is an increasing function of RETR. COCR also rises with RETR. Since RGA is the product of RETR and RRC, it rises more rapidly than RETR. For each value of RGA, COCR is the rate of return needed to evoke that investment rate with no stock financing and the leverage rate maintained at the sample mean value.

Table 18 also presents DIYD, KGYD, and MBR. The dividend yield falls continuously as RETR rises since RTGR = RETR*RRC is rising, and DIYD varies inversely with the rate of growth in the dividend. Share yield rises as RETR rises since it is an increasing function of the rate of growth in the dividend. Finally, the market-book value ratio rises as both RETR and the RRC that makes RETR optimal rise. Since BVS is given, PPS is MBR times a constant, and all the data in Table 18 are independent of the value assigned

Table 18. ***Constrained Cost of Retention Capital and Related Variables, Sample Mean Firm, 1963***

RETR	*RGA*	*COCR*	*RRC*	*KGYD*	*DIYD*	*MBR*
0.0000	0.0000	0.0451	0.0566	0.0577	0.0577	0.9823
0.0250	0.0015	0.0456	0.0581	0.0580	0.0565	1.0018
0.0500	0.0030	0.0462	0.0596	0.0584	0.0554	1.0228
0.0750	0.0046	0.0468	0.0612	0.0588	0.0542	1.0454
0.1000	0.0063	0.0474	0.0629	0.0592	0.0530	1.0698
0.1250	0.0081	0.0481	0.0647	0.0598	0.0517	1.0962
0.1500	0.0100	0.0489	0.0666	0.0604	0.0504	1.1249
0.1750	0.0120	0.0496	0.0687	0.0610	0.0490	1.1561
0.2000	0.0142	0.0504	0.0708	0.0618	0.0476	1.1902
0.2250	0.0164	0.0513	0.0731	0.0626	0.0461	1.2276
0.2500	0.0189	0.0522	0.0755	0.0635	0.0446	1.2689
0.2750	0.0215	0.0532	0.0781	0.0646	0.0431	1.3145
0.3000	0.0243	0.0543	0.0809	0.0658	0.0415	1.3651
0.3250	0.0273	0.0554	0.0839	0.0671	0.0398	1.4218
0.3500	0.0305	0.0566	0.0871	0.0686	0.0381	1.4854
0.3750	0.0340	0.0579	0.0906	0.0704	0.0364	1.5572
0.4000	0.0378	0.0594	0.0944	0.0723	0.0346	1.6391
0.4250	0.0419	0.0609	0.0985	0.0746	0.0327	1.7329
0.4500	0.0463	0.0626	0.1030	0.0771	0.0308	1.8413
0.4750	0.0513	0.0645	0.1079	0.0800	0.0288	1.9679
0.5000	0.0566	0.0665	0.1133	0.0834	0.0268	2.1173
0.5250	0.0626	0.0688	0.1193	0.0873	0.0247	2.2955
0.5500	0.0692	0.0713	0.1259	0.0918	0.0226	2.5113
0.5750	0.0766	0.0741	0.1333	0.0970	0.0204	2.7765
0.6000	0.0850	0.0773	0.1416	0.1032	0.0182	3.1084
0.6250	0.0944	0.0808	0.1511	0.1104	0.0160	3.5329
0.6500	0.1052	0.0849	0.1618	0.1191	0.0139	4.0894
0.6750	0.1177	0.0896	0.1743	0.1294	0.0117	4.8413
0.7000	0.1322	0.0951	0.1888	0.1418	0.0096	5.8951
0.7250	0.1493	0.1016	0.2060	0.1570	0.0076	7.4398
0.7500	0.1699	0.1094	0.2266	0.1757	0.0058	9.8366

Table 19. ***Constrained Cost of Retention Capital and Related Variables, Sample Mean Firm, 1968***

RETR	*RGA*	*COCR*	*RRC*	*KGYD*	*DIYD*	*MBR*
0.0000	0.0000	0.0529	0.0636	0.0776	0.0776	0.8191
0.0250	0.0016	0.0535	0.0652	0.0777	0.0761	0.8354
0.0500	0.0033	0.0541	0.0669	0.0779	0.0745	0.8529
0.0750	0.0052	0.0547	0.0687	0.0781	0.0729	0.8718
0.1000	0.0071	0.0554	0.0706	0.0783	0.0713	0.8921
0.1250	0.0091	0.0561	0.0727	0.0786	0.0695	0.9141
0.1500	0.0112	0.0569	0.0748	0.0790	0.0678	0.9380
0.1750	0.0135	0.0577	0.0771	0.0794	0.0659	0.9641
0.2000	0.0159	0.0585	0.0795	0.0799	0.0641	0.9925
0.2250	0.0185	0.0594	0.0820	0.0806	0.0621	1.0237
0.2500	0.0212	0.0604	0.0848	0.0813	0.0601	1.0581
0.2750	0.0241	0.0614	0.0877	0.0821	0.0580	1.0961
0.3000	0.0272	0.0625	0.0908	0.0831	0.0558	1.1384
0.3250	0.0306	0.0637	0.0942	0.0842	0.0536	1.1856
0.3500	0.0342	0.0650	0.0978	0.0856	0.0513	1.2387
0.3750	0.0381	0.0664	0.1017	0.0871	0.0490	1.2986
0.4000	0.0424	0.0678	0.1060	0.0889	0.0465	1.3668
0.4250	0.0470	0.0695	0.1106	0.0910	0.0440	1.4450
0.4500	0.0520	0.0712	0.1156	0.0934	0.0414	1.5355
0.4750	0.0575	0.0732	0.1211	0.0963	0.0387	1.6411
0.5000	0.0636	0.0753	0.1272	0.0996	0.0360	1.7656
0.5250	0.0703	0.0777	0.1338	0.1035	0.0332	1.9143
0.5500	0.0777	0.0803	0.1413	0.1081	0.0304	2.0942
0.5750	0.0860	0.0832	0.1496	0.1135	0.0275	2.3153
0.6000	0.0954	0.0865	0.1589	0.1199	0.0245	2.5921
0.6250	0.1060	0.0903	0.1695	0.1275	0.0216	2.9461
0.6500	0.1181	0.0945	0.1816	0.1367	0.0186	3.4102
0.6750	0.1320	0.0995	0.1956	0.1478	0.0157	4.0372
0.7000	0.1483	0.1052	0.2119	0.1613	0.0129	4.9159
0.7250	0.1676	0.1120	0.2312	0.1779	0.0102	6.2041
0.7500	0.1907	0.1201	0.2543	0.1985	0.0078	8.2028

to BVS. It should be noted that if RETR were increased with RRC held constant, MBR would be maximized at a finite RETR. For example, with RRC = .087, MBR rises with RETR until it is equal to .35 and falls thereafter.

Table 19 presents similar results obtained on the basis of the 1968 values of the parameters and variables. Between 1963 and 1968 a number of important changes took place. First, α_2' fell somewhat—from 13.56 to 12.08. The consequence is that the optimizing RRC for each RETR is slightly higher in 1968. The imbedded interest rate rose significantly, from .038 to .047, between the two years so that, notwithstanding the slight rise in DEQ, the cost of retention capital rose for each RRC. That is, the RRA needed to provide a given RRC rose between 1963 and 1968 due to the rise in IMBR.

The most striking change between 1963 and 1968 was the rise in AAR from .0422 to .0675. This reduces the constant term, $\alpha_0\,(1/AAR)^{\alpha_n}$. That plus the reduction in α_2' raises KGYD and reduces MBR at each RETR and the RRC that optimizes it. The interesting consequence for the results in Table 19 is that up to RETR = .20 the optimal RRC < KGYD and MBR < 1. As RRC/KGYD rises above one, MBR rises above one.

The 1968 figures pose a challenging problem. Why is the RRC a firm should be allowed to earn lower than KGYD, and why is MBR < 1 in the interval 0 < RETR < .20? With MBR < 1 the firm can raise its value by retiring outstanding stock, but we assume SFR = 0. With that constraint the firm need only be allowed RRC = .0636 with KGYD = .0776 to secure RETR = 0. This may be explained as follows. KGYD is an average of the discount rates which converts the infinite stream of dividends to their present value. In 1968 the level of these discount rates was high in relation to the rate at which they rise with time; at a zero growth rate, growth in the dividend was discounted at a lower rate than the level of the dividend. The term structure of interest rates may help explain this. When interest rates are expected to fall, the yield to maturity on bonds is a decreasing function of the bond's maturity. Investors are then willing to reinvest the interest on a bond at a lower return than the yield at which the bond is selling.[2]

Before proceeding it should be noted that COCR is the cost of retention capital. That is, DEQ is held constant, and SFR = 0 is

[2] To elaborate, let an annuity type bond, one for which the interest and principal are paid in n equal annual payments, sell at a higher yield than a balloon type bond, one for which interest and principal are paid in one payment at the end of n periods. If the owner of an annuity type bond could deduct one dollar per period from the payments he would receive and exchange each dollar for a balloon type bond to earn a rate of return between the yields at which the two bonds are selling, his wealth would be increased. It is also true that his investment is increased and the return he requires on the increased investment is below the yield on his existing investment.

maintained. The consequence is that the cost of capital may rise more rapidly with the desired investment rate than would be the case if SFR also were allowed to vary. One cannot, therefore, conclude that these tables represent the rate at which the cost of capital rises with the desired investment rate without restriction on the firm's financing policy. It also should be noted that RRC rises by increasing amounts with RETR, but the rise in COCR with RGA is practically independent of the level of RGA. That is, the rise in COCR to secure a given increase in RGA is less than the rise in RRC needed to secure a given increase in RETR.

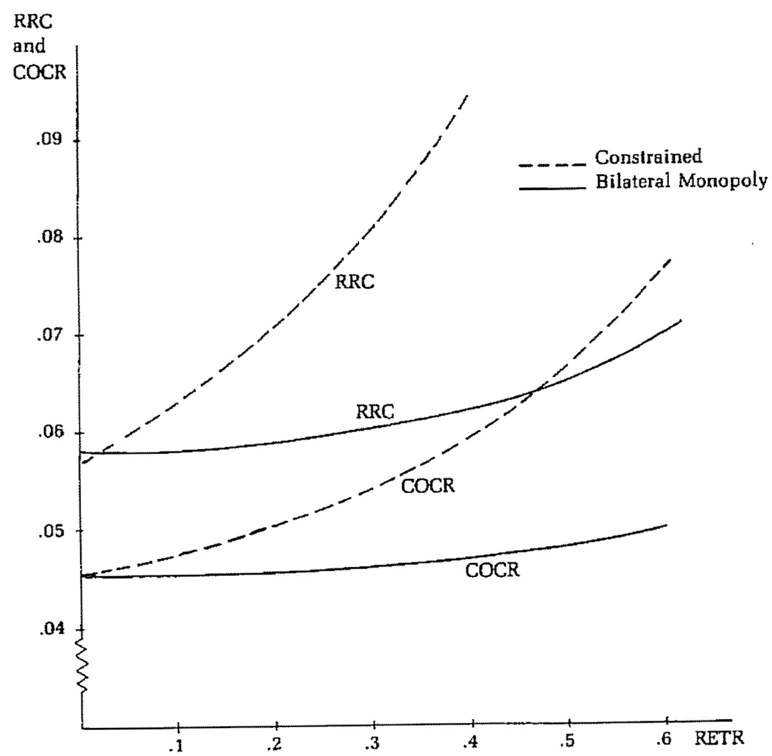

FIGURE 3. ***Constrained and Bilateral Monopoly Cost of Retention Capital and Return on Common, 1963***

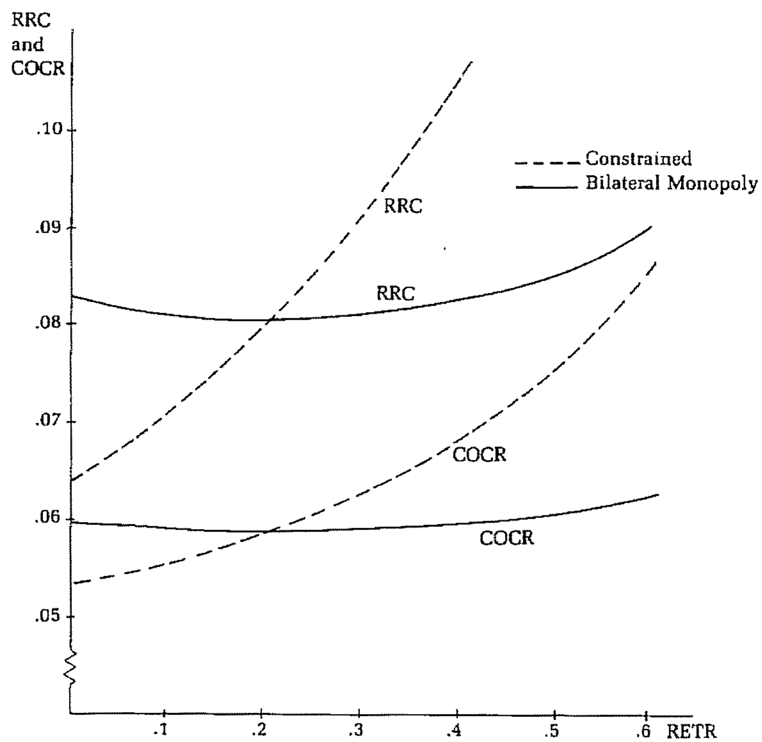

FIGURE 4. ***Constrained and Bilateral Monopoly Cost of Retention Capital and Return on Common, 1968***

The previous pages presented the cost of retention capital for 1963 and 1968 under the assumption that the regulatory agency follows a constrained policy. By contrast, under a bilateral monopoly policy the regulatory agency adjusts the allowed rate of return to keep the utility's market-book value ratio equal to one.

Figure 3 presents RRC and COCR as functions of RETR under both the constrained and bilateral monopoly policies for 1963. Since MBR $\cong$ 1 at RETR = 0 under the constrained policy, COCR is about the same under both policies at RETR = 0. However, as RETR and RGA = RETR*RRC rise, both RRC and COCR rise less rapidly under the bilateral monopoly policy. Notice that RRC and COCR rise with RETR under the bilateral monopoly as well as the constrained policy. The reason is that under the bilateral monopoly policy RRC = KGYD is always true, and the yield investors require on the stock rises with RGA = RETR*RRC. Hence, the RRC necessary to maintain PPS unchanged rises with RGA.

Figure 4 presents the same data for 1968. For that year the constrained COCR results in MBR < 1 at RETR = 0, and MBR only reaches one at RETR $\cong$ .20. In consequence, at RETR = 0 the bilateral monopoly COCR is higher, and it falls to equality with the constrained policy COCR at RETR $\cong$ .20. As RETR rises above this value, COCR rises under both policies, but the rise is less rapid under the bilateral monopoly policy.

9.4 *Cost of Debt Capital in Selected Years*

When we adopt the stock value model of Eq. (8.3.2), the cost of debt capital is given by Eq. (8.3.5). The expression, however, reflected the assumptions that the coefficient of the dividend variable DIV/BVS is equal to one, LEV = DEQ, and the retention and stock financing rates are both equal to zero. Also, the Eq. (8.3.5) cost of debt capital does not specify how the interest rate varies with the leverage rate.

Continuing to assume that SFR = 0 and LEV = DEQ, the other assumptions are withdrawn by substituting Eq. (5.2.6) for RRC in Eq. (9.2.3), taking the derivative of PPS/BVS with respect to DEQ, and setting it equal to zero. The result is

$$\begin{aligned} 0 = {} & \left[\alpha_2'(1 + \mathrm{DEQ})\mathrm{RETR}\right]\mathrm{RRA}^2 \\ & + \left[\alpha_1 - \alpha_2'(1 + 2\mathrm{DEQ})\mathrm{RETR{*}IMBR} + \alpha_5(1 + \mathrm{DEQ})\right. \\ & \left. - \alpha_2'(1 + \mathrm{DEQ})\mathrm{RETR{*}DEQ{*}}\partial\,\mathrm{IMBR}/\partial\,\mathrm{DEQ}\right]\mathrm{RRA} \\ & + \left[(-\alpha_1 + \alpha_2\,\mathrm{RETR{*}DEQ{*}IMBR} - \alpha_5\,\mathrm{DEQ})\mathrm{IMBR}\right. \\ & \left. + (\alpha_2'\,\mathrm{RETR{*}DEQ^2{*}IMBR} - \alpha_1\,\mathrm{DEQ})\partial\,\mathrm{IMBR}/\partial\,\mathrm{DEQ}\right]. \end{aligned} \quad (9.4.1)$$

Notwithstanding the number of terms, Eq. (9.4.1) is simply a quadratic function of RRA. Of the two solutions, only one is positive if $\partial \text{IMBR}/\partial \text{DEQ} \geq 0$ and if all the other variables and parameters fall within the ranges of their plausible values. The positive solution, therefore, is COCD, the cost of debt capital, and the negative solution may be ignored.

Estimating the variation in IMBR with DEQ by statistical methods is quite difficult and, for reasons to be given later, is not worth the effort. Instead, it is assumed that

$$\text{IMBR} = [\beta_0 + \beta_1 \text{DEQ} + \beta_2 \text{DEQ}^2]\text{FAC}, \tag{9.4.2}$$

with $\beta_0 = 1.0$, $\beta_1 = -.06$, $\beta_2 = .035$, and FAC determined so that IMBR is equal to its actual value when DEQ is equal to its actual value for the firm and year in question. That is, Eq. (9.4.2) is solved for FAC with the BETAs assigned the above values and IMBR and DEQ assigned their actual values for the firm. This makes the function IMBR of DEQ defined by Eq. (9.4.2) pass through the one observation we have. With the above values for the coefficients the relation between IMBR/FAC and DEQ is as follows:

DEQ	0	1.0	1.5	2.0	3.0	4.0
IMBR/FAC	1.0	.975	.999	1.02	1.135	1.34

Hence, IMBR is relatively stable over the range of DEQ from 0.0 to 2.0, rises about 10 percent as DEQ goes to 3.0, and rises quite sharply with DEQ as it rises above 3.0.

The top half of Table 20 presents the cost of debt capital and certain other statistics as a function of the leverage rate on the basis of the 1963 values of the parameters in Eq. (9.4.1). DEQ varies in intervals of .25 over the range 0.0 to 4.0. IMBR is the coupon rate of interest at each value of DEQ on the basis of Eq. (9.4.2). COCD is the positive solution to Eq. (9.4.1) for RRA with RETR equal to its sample mean value and with IMBR and $\partial \text{IMBR}/\partial \text{DEQ}$ given by Eq. (9.4.2). RRC is the return on common when COCD is the return on assets. Table 20 also presents RTGR based on RRC times the sample average value of RETR. Finally, KGYD and MBR are computed with XYGR = 0, AAR equal to its value at the end of the year, and PEE equal to its sample mean value.

COCD rises with DEQ both because IMBR rises with DEQ and because the risk to the common equity, recognized through α_5, rises with DEQ. However, COCD is initially quite low, and it does

Table 20. ***Constrained Cost of Debt Capital and Related Variables, Sample Mean Firm, 1963 and 1968***

DEQ	*IMBR*	*COCD*	*RRC*	*RTGR*	*KGYD*	*MBR*
			1963 Sample Mean Firm			
0.0000	0.0384	0.0424	0.0424	0.0146	0.0488	0.8150
0.2500	0.0380	0.0415	0.0424	0.0146	0.0495	0.7966
0.5000	0.0376	0.0412	0.0430	0.0148	0.0505	0.7880
0.7500	0.0375	0.0414	0.0443	0.0153	0.0519	0.7941
1.0000	0.0375	0.0422	0.0469	0.0162	0.0536	0.8203
1.2500	0.0377	0.0436	0.0510	0.0176	0.0559	0.8721
1.5000	0.0380	0.0456	0.0570	0.0197	0.0588	0.9553
1.7500	0.0385	0.0483	0.0653	0.0225	0.0623	1.0772
2.0000	0.0392	0.0515	0.0762	0.0263	0.0663	1.2464
2.2500	0.0401	0.0554	0.0898	0.0310	0.0709	1.4744
2.5000	0.0411	0.0598	0.1066	0.0368	0.0760	1.7771
2.7500	0.0423	0.0648	0.1266	0.0436	0.0817	2.1766
3.0000	0.0436	0.0702	0.1500	0.0517	0.0881	2.7045
3.2500	0.0452	0.0762	0.1770	0.0610	0.0951	3.4064
3.5000	0.0469	0.0826	0.2078	0.0716	0.1030	4.3490
3.7500	0.0487	0.0895	0.2425	0.0836	0.1118	5.6303
4.0000	0.0507	0.0969	0.2814	0.0970	0.1219	7.3974
			1968 Sample Mean Firm			
0.0000	0.0473	0.0522	0.0522	0.0166	0.0640	0.7513
0.2500	0.0467	0.0511	0.0522	0.0166	0.0651	0.7342
0.5000	0.0463	0.0506	0.0528	0.0168	0.0664	0.7263
0.7500	0.0461	0.0509	0.0545	0.0173	0.0681	0.7319
1.0000	0.0461	0.0519	0.0576	0.0183	0.0703	0.7561
1.2500	0.0463	0.0536	0.0627	0.0199	0.0731	0.8039
1.5000	0.0467	0.0561	0.0701	0.0223	0.0766	0.8807
1.7500	0.0474	0.0593	0.0803	0.0255	0.0806	0.9933
2.0000	0.0482	0.0633	0.0936	0.0298	0.0853	1.1497
2.2500	0.0493	0.0681	0.1104	0.0351	0.0904	1.3607
2.5000	0.0505	0.0735	0.1309	0.0416	0.0960	1.6410
2.7500	0.0520	0.0796	0.1554	0.0494	0.1021	2.0113
3.0000	0.0537	0.0863	0.1842	0.0586	0.1088	2.5013
3.2500	0.0555	0.0936	0.2174	0.0691	0.1161	3.1537
3.5000	0.0576	0.1015	0.2551	0.0811	0.1243	4.0311
3.7500	0.0599	0.1100	0.2978	0.0947	0.1335	5.2261
4.0000	0.0624	0.1190	0.3455	0.1099	0.1441	6.8771

not rise above 5 percent until DEQ = 2.0. COCD rises by large and increasing amounts as DEQ goes from 2.0 to 4.0. A good part of this is due to the rise in IMBR with DEQ, and the validity of the simulation depends on the values assigned to the coefficients of Eq. (9.4.2).

As COCD rises, the value of RRC rises, and with RETR given, RTGR also rises. Since KGYD is an increasing function of RTGR and DEQ, it rises with DEQ and with the RRC that makes each DEQ optimal. Of course, MBR rises as the RRC that makes each DEQ optimal rises.

The bottom half of Table 20 presents IMBR, COCD, and the other variables based on the 1968 coefficients and exogenous variables. Between 1963 and 1968 interest rates rose sharply, and IMBR is about 1 percent higher at each DEQ for 1968. The consequence is a higher COCD at each DEQ and corresponding changes in the other variables.

It already has been noted that the accuracy of the simulations in Table 20 depends on the values assigned to the parameters of Eq. (9.4.2), and the only empirical basis for these values is their intuitive merit. There is perhaps a more serious limitation to the simulations due to the failure of Eq. (9.4.2) to take account of possible differences between the current and the imbedded interest rates. Assume that Eq. (9.4.2) and its parameter estimates are correct if AAR = IMBR. In that event the equation is not correct if AAR ≠ IMBR at the current value of DEQ. If AAR > IMBR, IMBR rises more sharply with DEQ than Eq. (9.4.2) predicts.[3] On the other hand, if AAR < IMBR at the current DEQ, IMBR is a flatter function of DEQ than Eq. (9.4.2). The consequence is that for 1963, when AAR was slightly higher than IMBR, COCD rises somewhat more sharply with DEQ as the latter rises above its sample mean value. In 1968 AAR was significantly above IMBR, and, correspondingly, COCD becomes significantly larger than the Table 20 values as DEQ rises above its sample mean value.

Table 21 presents COCD as a function of DEQ for 1963 and 1968 under the bilateral monopoly regulatory policy. In both years COCD

[3]This is evident as DEQ rises above its current value and new debt is incurred at the current interest rate. As DEQ is reduced below its current value, outstanding debt is retired through purchase at prices below par, and IMBR falls more sharply as DEQ falls below its current value.

Table 21. *Bilateral Monopoly Cost of Debt Capital and Related Variables, Sample Mean Firm, 1963 and 1968*

DEQ	*IMBR*	*COCD*	*RRC*	*RTGR*	*KGYD*	*MBR*
			1963 Sample Mean Firm			
0.0000	0.0384	0.0540	0.0540	0.0186	0.0540	1.0000
0.2500	0.0380	0.0520	0.0555	0.0191	0.0555	1.0000
0.5000	0.0376	0.0500	0.0562	0.0194	0.0562	1.0000
0.7500	0.0375	0.0480	0.0576	0.0199	0.0576	1.0000
1.0000	0.0375	0.0480	0.0585	0.0202	0.0585	1.0000
1.2500	0.0377	0.0480	0.0609	0.0210	0.0609	1.0000
1.5000	0.0380	0.0480	0.0630	0.0217	0.0630	1.0000
1.7500	0.0385	0.0480	0.0646	0.0223	0.0646	1.0000
2.0000	0.0392	0.0480	0.0656	0.0226	0.0656	1.0000
2.2500	0.0401	0.0480	0.0658	0.0227	0.0658	1.0000
2.5000	0.0411	0.0490	0.0688	0.0237	0.0688	1.0000
2.7500	0.0423	0.0500	0.0712	0.0246	0.0712	1.0000
3.0000	0.0436	0.0510	0.0731	0.0252	0.0731	1.0000
3.2500	0.0452	0.0520	0.0742	0.0256	0.0742	1.0000
3.5000	0.0469	0.0530	0.0745	0.0257	0.0745	1.0000
3.7500	0.0487	0.0540	0.0738	0.0254	0.0738	1.0000
4.0000	0.0507	0.0560	0.0770	0.0266	0.0770	1.0000
			1968 Sample Mean Firm			
0.0000	0.0473	0.0710	0.0710	0.0226	0.0710	1.0000
0.2500	0.0467	0.0670	0.0721	0.0229	0.0721	1.0000
0.5000	0.0463	0.0650	0.0744	0.0236	0.0744	1.0000
0.7500	0.0461	0.0630	0.0757	0.0241	0.0757	1.0000
1.0000	0.0461	0.0620	0.0779	0.0248	0.0779	1.0000
1.2500	0.0463	0.0610	0.0794	0.0252	0.0794	1.0000
1.5000	0.0467	0.0600	0.0799	0.0254	0.0799	1.0000
1.7500	0.0474	0.0600	0.0821	0.0261	0.0821	1.0000
2.0000	0.0482	0.0600	0.0836	0.0266	0.0836	1.0000
2.2500	0.0483	0.0610	0.0874	0.0278	0.0874	1.0000
2.5000	0.0505	0.0610	0.0872	0.0277	0.0872	1.0000
2.7500	0.0520	0.0620	0.0895	0.0285	0.0895	1.0000
3.0000	0.0537	0.0630	0.0910	0.0289	0.0910	1.0000
3.2500	0.0555	0.0650	0.0958	0.0305	0.0958	1.0000
3.5000	0.0576	0.0660	0.0953	0.0303	0.0953	1.0000
3.7500	0.0599	0.0680	0.0983	0.0313	0.1983	1.0000
4.0000	0.0624	0.0700	0.1004	0.0319	0.1004	1.0000

falls as DEQ rises up to about DEQ = 2.0 and rises with DEQ thereafter. In chapter 4 we found the cost of debt capital to be below the cost of equity capital and independent of the debt-equity ratio. There are two reasons for the different relation portrayed in Table 21. One is the assumption reflected in Eq. (9.4.2) that IMBR is a function of DEQ that initially falls and then rises as DEQ rises. The other reason is the assumption reflected in Eq. (9.2.3) that the risk of leverage makes share price an exponential function of the leverage rate and not the linear function assumed in chapter 4. It is evident that the values of COCD at each DEQ and the DEQ that minimizes COCD depend on the value of α_5, the leverage coefficient, the values assigned to the parameters of Eq. (9.4.2), and the other parameters of the stock value equation. They also depend on the values of the retention and stock financing rates.

For both years COCD is higher at DEQ = 0 under the bilateral monopoly policy than under the constrained policy. The reason is that under the former MBR = 1 for all values of DEQ, while under the latter the RRC that makes DEQ = 0 optimal policy results in MBR < 1. As DEQ rises, the RRC that makes it optimal policy results in a rise in MBR, and the constrained COCD rises above the bilateral monopoly values.

It should be recalled that maintaining a particular value of DEQ, unlike maintaining a particular value of RETR, provides no funds for investment. Only an increase in DEQ provides such funds, and the next chapter will give reasons why changes in DEQ should not be looked on as a source of funds in computing the cost of capital. Consequently, if retention and debt are the only sources of funds, DEQ and RETR should be viewed as follows under the bilateral monopoly policy. A value is assigned to DEQ; given that value we find the combination of RETR and RRC which realizes a desired value of RGA = RETR*RRC and satisfies MBR = 1. The value of RRC so obtained combined with the given value of DEQ and the interest rate produce the cost of capital, that is, the return the utility should be allowed on its assets. The value assigned to DEQ can be the one that minimizes COCR, or DEQ can be assigned a value that provides a satisfactory level of financial risk.

9.5 *Cost of Stock Financed Capital in Selected Years*

The determination of the cost of stock financed capital was described on pages 162–66. Recall that the equity accretion rate that makes a stock financing rate of SFR optimal is

$$\mathrm{EACR} = -2.0\alpha_6 \mathrm{SFR}/\alpha_3'. \qquad (9.5.1)$$

The difficult task is to find the RRC which realizes this EACR. The expression for EACR given by Eq. (8.5.6), modified to suit the stock valuation model of Eq. (9.2.3), may be written as

$$\mathrm{EACR} = \frac{\mathrm{RRC}[1 - \mathrm{RETR}(\mathrm{ETA} - \mathrm{PSI}) - \mathrm{PSI}]}{\mathrm{RRC}[1 - \mathrm{RETR}] + \mathrm{SFR}[\mathrm{ETA} - 1]} - \frac{\mathrm{ETA}^*\mathrm{DIV}}{[\mathrm{RRC}(1-\mathrm{RETR})+\mathrm{SFR}(\mathrm{ETA}-1)]A_0\exp[\alpha_3'\mathrm{EACR}^*\mathrm{SFR}+\alpha_6\mathrm{SFR2}]} \qquad (9.5.2)$$

A_0 represents all the terms in Eq. (9.2.3) which do not contain SFR.

All the coefficients in Eq. (9.5.2) are known, and all the variables except RRC are known. EACR on the R.H.S. (right-hand side) of Eq. (9.5.2) is assigned the Eq. (9.5.1) value. We therefore assign a value to RRC and compute the L.H.S. (left-hand side) value of EACR. Assume it is below the R.H.S. value. We raise RRC and recompute. At some point the L.H.S. value is equal to the R.H.S. value of EACR since the L.H.S. value is an increasing function of RRC. Hence, the solution value of RRC realizes the EACR which makes the SFR in Eq. (9.5.1) optimal. Given IMBR and DEQ, we go from RRC to the value of RRA that generates it, and that is COCS, the cost of stock capital for the Eq. (9.5.1) value of SFR.

Table 22 presents the optimizing RRC and COCS as functions of SFR on the basis of the 1963 data and the following assumptions: RETR = 0; XYGR = 0; AAR is equal to its 1963 value; and LEV, PEE, and DEQ have their sample mean values for 1963. RGA at any SFR is equal to the SFR, and SFR varies from 0.0 to 0.10 in intervals of .005. Of course, both RRC and COCS rise as the desired SFR = RGA rises. Table 22 also presents EACR, SFGR, KGYD, and MBR. SFGR is equal to SFR*EACR, and it is the rate of growth in the dividend due to stock financing.

The bottom half of Table 22 presents RRC, COCS, and the other variables based on the 1968 data for comparison with the 1963 data. Between 1963 and 1968 α_3' fell, thereby raising the EACR

Table 22. *Constrained Cost of Stock Financed Capital and Related Variables, Sample Mean Firm, 1963 and 1968*

SFR	*RRC*	*COCS*	*EACR*	*SFGR*	*KGYD*	*MBR*
			1963 Sample Mean Firm			
0.0000	0.0662	0.0487	0.0016	0.0000	0.0598	1.1072
0.0050	0.0676	0.0492	0.0171	0.0001	0.0601	1.1256
0.0100	0.0690	0.0497	0.0327	0.0003	0.0606	1.1449
0.0150	0.0706	0.0503	0.0503	0.0008	0.0612	1.1677
0.0200	0.0720	0.0509	0.0660	0.0013	0.0619	1.1890
0.0250	0.0734	0.0514	0.0819	0.0020	0.0626	1.2114
0.0300	0.0748	0.0519	0.0978	0.0029	0.0635	1.2349
0.0350	0.0762	0.0525	0.1138	0.0040	0.0645	1.2596
0.0400	0.0776	0.0530	0.1299	0.0052	0.0656	1.2856
0.0450	0.0790	0.0535	0.1461	0.0066	0.0667	1.3129
0.0500	0.0804	0.0541	0.1623	0.0081	0.0680	1.3416
0.0550	0.0818	0.0546	0.1786	0.0098	0.0695	1.3718
0.0600	0.0832	0.0551	0.1949	0.0117	0.0710	1.4035
0.0650	0.0844	0.0556	0.2099	0.0136	0.0725	1.4343
0.0700	0.0858	0.0561	0.2262	0.0158	0.0742	1.4694
0.0750	0.0872	0.0566	0.2426	0.0182	0.0761	1.5064
0.0800	0.0886	0.0572	0.2589	0.0207	0.0780	1.5453
0.0850	0.0900	0.0577	0.2751	0.0234	0.0801	1.5863
0.0900	0.0914	0.0582	0.2913	0.0262	0.0823	1.6295
0.0950	0.0928	0.0588	0.3074	0.0292	0.0846	1.6749
0.1000	0.0942	0.0593	0.3234	0.0323	0.0870	1.7228
			1968 Sample Mean Firm			
0.0000	0.0940	0.0636	0.0007	0.0000	0.0850	1.1060
0.0050	0.0956	0.0642	0.0133	0.0001	0.0853	1.1209
0.0100	0.0974	0.0648	0.0277	0.0003	0.0858	1.1386
0.0150	0.0990	0.0654	0.0409	0.0006	0.0863	1.1554
0.0200	0.1004	0.0659	0.0531	0.0011	0.0868	1.1714
0.0250	0.1020	0.0665	0.0671	0.0017	0.0874	1.1903
0.0300	0.1034	0.0669	0.0800	0.0024	0.0880	1.2085
0.0350	0.1048	0.0674	0.0933	0.0033	0.0886	1.2279
0.0400	0.1060	0.0679	0.1057	0.0042	0.0893	1.2466
0.0450	0.1074	0.0684	0.1197	0.0054	0.0901	1.2685
0.0500	0.1086	0.0688	0.1329	0.0066	0.0908	1.2898
0.0550	0.1096	0.0691	0.1452	0.0080	0.0916	1.3106
0.0600	0.1108	0.0696	0.1590	0.0095	0.0925	1.3347
0.0650	0.1118	0.0699	0.1721	0.0112	0.0935	1.3584
0.0700	0.1128	0.0703	0.1854	0.0130	0.0945	1.3837
0.0750	0.1136	0.0705	0.1980	0.0149	0.0955	1.4086
0.0800	0.1146	0.0709	0.2119	0.0170	0.0967	1.4370
0.0850	0.1152	0.0711	0.2242	0.0191	0.0978	1.4633
0.0900	0.1160	0.0714	0.2377	0.0214	0.0991	1.4934
0.0950	0.1168	0.0717	0.2514	0.0239	0.1005	1.5252
0.1000	0.1174	0.0719	0.2644	0.0264	0.1018	1.5570

needed to generate each SFR. Between the two years there also was a sharp rise in AAR, which, together with the fall in α_3', raised the RRC necessary to generate each SFR. Finally, the rise in IMBR offset slightly by the rise in DEQ raised the RRA needed to generate each RRC. The end result is that COCS is substantially higher at each SFR in 1968 than in 1963.

In both years MBR > 1 at SFR = 0. This in general will be true. We would have MBR = 1 at SFR = 0 if ETA = 1.0 and PSI = 0.0. With ETA > 1.0 and PSI > 0.0, stock financing at SFR = 0 leaves price per share unchanged only if MBR > 1. The return on common must be above the yield at which the stock is selling by a margin that covers the investment banker's charge for putting an issue on the market and the discount off market price at which the issue must be sold.

It was pointed out earlier that the margin of error in each of the stock financing cost of capital coefficients, α_3' and α_6, is large by comparison with the other cost of capital coefficients. What can we say about the accuracy of the estimates in Table 22? COCS at SFR = 0 exceeds KGYD insofar as ETA > 1.0 and PSI > 0. The margin of error in KGYD is small, and the possible range of error in ETA and PSI will not materially influence COCS. Hence, COCS at SFR = 0 is quite accurate. The rise in the optimizing RRC, and hence in COCS with SFR, is subject to some margin of error since it depends on the values of α_3' and α_6, which are of questionable reliability. It is therefore interesting to note that the Table 22 rise in COCS with SFR is quite small by comparison with the rise in COCR and COCD with the investment rate. A smaller α_3 and/or a larger $-\alpha_6$ would result in a sharper rise in COCS with SFR and higher values of COCS at high values of SFR. The problem is discussed further in the following chapter.

Comparison of COCS in Table 22 with COCR in Tables 18 and 19 reveals that at low values of RGA the cost of retention capital is below the cost of stock capital. As RGA rises, COCR rises more rapidly and becomes larger than COCS. Hence, at high values of RGA the cost of stock capital is lower. In the estimation of each function it is assumed that the other source of funds is not used. COCS at any SFR would be different with RETR $\neq$ 0, and COCR at any retention rate would be different with SFR $\neq$ 0. Nonetheless, it would seem reasonable to infer that for low investment rates retention would be the primary source of funds and, as the investment

Table 23. ***Bilateral Monopoly Cost of Stock Financed Capital and Related Variables, Sample Mean Firm, 1963 and 1968***

SFR	*RRC*	*COCS*	*EACR*	*KGYD*	*MBR*
		1963 Sample Mean Firm			
0.0	.0657	.0485	−.0045	.0597	1.1007
.01	.0659	.0486	−.0045	.0599	1.1009
.02	.0664	.0488	−.0045	.0604	1.1011
.03	.0671	.0490	−.0044	.0610	1.1000
.04	.0682	.0494	−.0044	.0620	1.1000
.05	.0697	.0500	−.0044	.0634	1.1010
.06	.0714	.0507	−.0044	.0649	1.1001
.07	.0736	.0515	−.0043	.0669	1.1007
.08	.0761	.0524	−.0043	.0692	1.1002
.09	.0791	.0536	−.0043	.0719	1.1003
.10	.0826	.0549	−.0043	.0751	1.1006
		1968 Sample Mean Firm			
0.0	.0934	.0634	−.0045	.0849	1.1005
.01	.0937	.0635	−.0045	.0852	1.1007
.02	.0944	.0638	−.0045	.0858	1.1007
.03	.0955	.0642	−.0045	.0868	1.1004
.04	.0971	.0647	−.0045	.0883	1.1006
.05	.0991	.0654	−.0044	.0901	1.1003
.06	.1017	.0663	−.0044	.0924	1.1008
.07	.1047	.0674	−.0044	.0952	1.1003
.08	.1084	.0687	−.0044	.0985	1.1007
.09	.1123	.0701	−.0043	.1021	1.1006

rate rose, the sale of stock would increase in relative importance. The next chapter takes up the cost of capital at each investment rate with both RETR and SFR optimally determined.

Under a bilateral monopoly policy the price per share of stock is kept independent of the firm's stock financing rate if the proceeds to the corporation per share sold are equal to the book value per share of the outstanding shares. With ETA = 1.05 and PSI = .05 this requires that the price per share be about 10 percent above the book value per share, or MBR = 1.10. This differential makes EACR ≅ 0 regardless of SFR. Table 23 presents the values of RRC, COCS, and related statistics at each value of SFR which realize MBR ≅ 1.10.

Comparison of Tables 22 and 23 reveals the following on the relation between the constrained and bilateral monopoly cost of

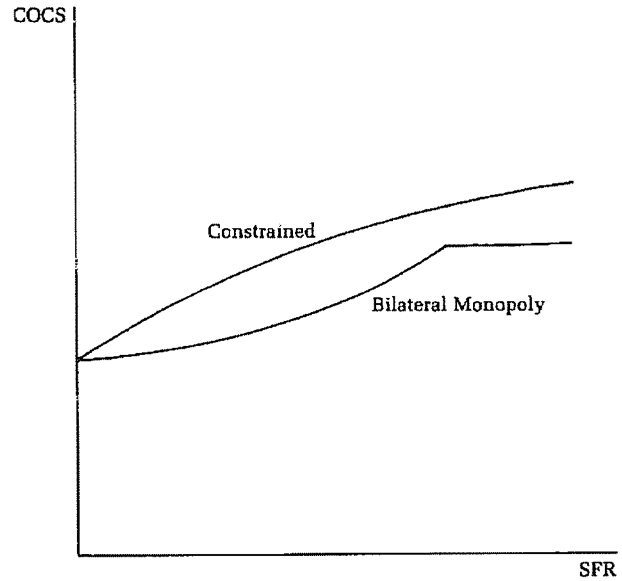

FIGURE 5. ***Relation Between Constrained and Bilateral Monopoly Cost of Stock Capital***

capital. At SFR = 0 the two values of RRC and of COCS are about the same. As SFR rises the constrained values of RRC and COCS rise above the bilateral monopoly values. However, the constrained values rise by amounts that are initially large and decrease as SFR rises, while the opposite is true for the bilateral monopoly values. It would appear then that at some SFR the bilateral monopoly values of RRC and COCS should rise above their constrained values. However, what happens is that when RRC reaches some value, .1123 in 1968, no further increase is necessary to secure MBR ≥ 1.10. With RRC = .1123, as SFR rises above .09 the MBR rises above 1.10. The consequence is that RRC = .1123 is large enough to achieve any desired stock financing rate. Furthermore, the bilateral monopoly values of RRC and COCS are below the constrained values for all values of SFR. Figure 5 describes the relation between COCS under the two regulatory policies.

10

The Overall Cost of Capital

This concluding chapter deals with three questions. The first is the overall cost of capital, that is, the combination of retention, stock, and debt financing that minimizes the rate of return on assets for any investment rate. The first section carries the work of the last chapter forward to answer this question under a constrained policy and presents illustrative data for the sample mean firms in 1963 and 1968. The second section does the same thing under the bilateral monopoly regulatory policy.

The second question to be considered is the relations among the allowed rate of return on assets, the traditional cost of capital, and the cost of capital under the two regulatory policies which may be followed in imperfect capital markets. The third section below develops estimates of each of these figures for the 1963 and 1968 sample mean firms. The plausibility of the estimates and the reasons for the differences among the figures also are examined.

The third and final question taken up in this chapter is whether considerations outside our frame of analysis make it inadequate or undesirable to allow a utility a rate of return on assets equal to its cost of capital. These considerations were raised and set aside in chapter 1. Do they lead to the conclusion that a rate of return equal to the cost of capital does not minimize the price consumers pay for a utility's service?

10.1 Overall Constrained Cost of Capital

The previous chapter established the cost of retention, new equity, and debt, holding the other two sources of funds fixed in each case. What we want to know is a utility's overall cost of capital. What combination of retention, debt, and stock financing results in the lowest return on assets that will generate a desired investment rate?

It was pointed out in chapter 9 that maintaining a debt-equity ratio is not a source of funds in that the firm's assets will grow at its equity financing rate. Changing the debt-equity ratio, however, is a source of funds. In the short run a small increase in the leverage rate is a very large source of funds, but in the long run even a very small periodic increase in the leverage rate ultimately results in an unreasonably large leverage rate. Furthermore, the risk taken by the firm rather than the stockholders well may influence the leverage rate a utility should have. For these and other reasons it is reasonable to look on changes in the leverage rate as a source of funds in the short but not the long run. That is, a utility may raise or lower its leverage rate to meet abnormal short-term fluctuations in investment, but in arriving at the firm's cost of capital the regulatory agency should not consider changes in the leverage rate as a source of funds. The cost of capital should be determined on the assumption that a desirable leverage rate, and one not necessarily equal to the existing rate, will be maintained for the indefinite future.

To find the optimal combination of retention and stock financing, we proceed as follows. Set RRA equal to its lowest plausible value, for example, .04. Next, set RGA = RETR = SFR = 0 and use Eq. (9.2.3) to calculate PPS. For this and all subsequent calculations not only the leverage rate but also other state variables such as PEE and the interest rate are known. Next, raise RGA to .005 and find the combination of RETR and SFR which satisfies RGA = .005 and maximizes PPS. Raise RGA to .01 and again find the combination of RETR and SFR which satisfies the value assigned to RGA and maximizes PPS. Repeat this process until RGA reaches what may be considered the upper limit on the desired investment rate. We next raise RRA by some increment, say, to .0425, and repeat the above process.

For any value of RRA, as RGA rises, with each RGA optimally

financed, we will find that PPS either will fall continuously, will rise and then fall, or will rise continuously. If PPS falls continuously, as is likely to be the case with RRA = .04, the RRA value is too low to justify a positive investment rate. With RRA = .04 it would be in the utility's interest to at best set RGA = SFR = RETR = 0. Assume that with RRA = .06 we find PPS is maximized at a finite RGA in the interval 0 < RGA < .10, say, at RGA = .045. Then RGA = .045 is optimal when RRA = .06. Alternatively, if the regulatory agency sets RRA = .06 it will be optimal for the company to set RGA = .045 and finance it in the way that maximizes PPS with RRA = .06 and RGA = .045.

Assume next that at RRA = .07 we find PPS is maximized at RGA = .075, and at RRA = .0725 we find PPS rises continuously with RGA. Then RRA = .07 makes .075 the optimal investment rate, while RRA = .0725 makes it optimal (maximizes share price) to maximize the investment rate.

The above computations were carried out for the 1963 and 1968 sample mean firms, that is, DEQ, LEV, PEE, and BVS were set equal to the sample mean values for the respective years. IMBR was set equal to the following year's sample mean value, AAR was set equal to its value for each year, and XYGR was set equal to zero. Table 24 illustrates the computations. With the 1963 values of the parameters and state variables and with RRA = .0525, the

Table 24. ***Variation in Price per Share and Other Variables with the Investment Rate when the Return on Assets Is .0525 and Each Investment Rate Is Optimally Financed, Sample Mean Firm, 1963***

RGA	*PPS*	*RETR*	*SFR*	*KGYD*
.000	$21.83	.000	.000	.0618
.010	22.44	.131	.000	.0622
.020	22.75	.200	.005	.0633
.030	22.99	.200	.015	.0641
.040	23.18	.200	.025	.0651
.050	23.31	.229	.0325	.0665
.060	23.34	.229	.0425	.0678
.070	23.23	.262	.0500	.0692
.080	22.96	.262	.0600	.0704
.090	22.41	.295	.0675	.0713
.100	21.43	.295	.0775	.0714

NOTE: For 1963, IMBR = .038 and DEQ = 1.64. Hence, with RRA = .0525, RRC = .0763. Also, BVS = $17.69.

table presents PPS and certain other statistics as RGA varies from 0.0 to .10 with each RGA optimally financed. That is, among the combinations of non-negative values of RETR and SFR which provide a given value of RGA, the combination shown maximizes PPS at that RGA. The table reveals that with RRA = .0525 the sample mean firm would maximize PPS with RGA = .06, the optimal financing of the RGA being obtained through RETR = .229 and SFR = .0425. RRA = .0525, with the 1963 values of DEQ and IMBR, yields RRC = .0763, and RTGR = RETR*RRC = .0175. That, combined with SFR = .0425, results in RGA = .06. PPS equals $23.34, and with BVS = $17.69, MBR = 1.32.

All that Table 24 tells us is that if a 6 percent rate of growth in assets were desired for our sample mean firm in 1963 it should have been allowed RRA = .0525. Obtaining the data in Table 24 for various values of RRA allows the determination of the cost of capital as a function of the investment rate. Table 25 presents the estimates for 1963 and 1968. The table also presents for each RGA the values of RRC, RETR, SFR, KGYD, and PPS.

For 1963 the cost of capital is only .0475 for an investment rate of .055 with financing, ideally, entirely by retention. The return on common necessary to secure this investment rate is only RRC

Table 25. ***Variation in Constrained Cost of Capital and Other Financial Variables with Rate of Growth in Assets, Sample Mean Firm, 1963 and 1968***

RGA	*COC*	*RRC*	*RETR*	*SFR*	*KGYD*	*PPS*[1]
			1963 Sample Mean Firm			
.005	.0475	.0631	.079	.0000	.0592	$18.95
.030	.0500	.0697	.179	.0175	.0619	20.79
.060	.0525	.0763	.229	.0425	.0678	23.34
.090	.0550	.0829	.272	.0675	.0776	27.01
.100	.0575	.0895	.279	.0750	.0854	31.69
			1968 Sample Mean Firm			
.005	.0550	.0695	.072	.0000	.0783	$15.42
.015	.0575	.0766	.196	.0000	.0793	16.79
.020	.0600	.0837	.239	.0000	.0810	18.30
.030	.0625	.0908	.303	.0025	.0831	19.94
.065	.0650	.0979	.332	.0325	.0872	22.18
.100	.0675	.1050	.310	.0675	.0955	26.32

[1]In 1963 BVS = $17.69, and in 1968 BVS = $17.52.

= .063, and investors would require only KGYD = .059 on the stock. An investment rate of RGA = .10 raises the cost of capital to only .0575 and RRC to .0895. RETR rises only to .279, and three-quarters of the funds are provided by the sale of stock. For 1968 the cost of capital is higher than for 1963, but otherwise the general picture is similar. At RGA = .005 we have COC = .055, and at RGA = .10 the cost of capital rises only to COC = .0675. As RGA rises above .03 all additional funds are optimally obtained through stock financing, and the required RRC rises in relation to KGYD.

In 1963 PPS was rising with RGA at RGA = .10 when RRA = .0575, and in 1968 PPS was rising with RGA at RGA = .10 when RRA = .0675. Hence, COC = .0575 at RGA > .10 in 1963, and COC = .0675 at RGA > .10 in 1968. These data reinforce the conclusion that the return elasticity of stock financed capital, that is, the percentage change in SFR resulting from a percentage change in RRC, is much higher than the return elasticity of retention capital. At low investment rates retention is the cheaper and the sole or predominant source of funds, but the cost of capital rises fairly sharply with the investment rate. When RGA reaches some level it is cheaper in each year to secure additional funds predominantly if not solely through the sale of stock. However, the rise in RRC needed to raise SFR is very small. For example, in 1968, raising RGA from .005 to .03 requires an increase in RRC from .0695 to .0908, but the further increase in RGA to .065, which is financed predominantly by the sale of stock, requires a further rise in RRC to only .0979.

The very high rate of return elasticity of stock capital is responsible for the very low range of the cost of capital as RGA goes from 0.0 to .10.[1] This is due to the values of the stock financing coefficients α_3' and α_6 in Eq. (9.2.3). Raising $-\alpha_6$ and/or reducing α_3' would reduce the return elasticity of stock financing. Reasons were given in chapter 8 for believing that these coefficient estimates are subject to a wider margin of error than the other cost of capital coefficients in Eq. (9.2.3). It is possible, of course, that the true value of α_3' is larger and that of α_6 smaller than the values used in Table 25. In that event the cost of capital is practically independent of the

[1]Although the data are not presented, the range in COC is even smaller as RGA rises to .20 since SFR is the only source of funds employed.

investment rate. It is more likely that the true values differ in the opposite direction. In that event the increase in the cost of capital with the investment rate as it rises above 3 percent is greater than the values of COC in Table 25.

There is another reason for believing that Table 25 understates the increase in the cost of capital with the stock financing rate. Our model assumes that ETA, the ratio of share price prior to a stock issue to the issue price, and PSI, the fraction of the proceeds from an issue that is taken by the investment banker, are both independent of the utility's stock financing rate. It may be more reasonable to believe that both ETA and PSI are increasing functions of the stock financing rate, in which case the cost of stock financed capital increases more rapidly with the investment rate.

In an attempt to obtain a rough idea of the impact on the cost of capital of raising the stock financing cost of capital, the data of Table 25 were recalculated with α_3 reduced by one standard error from 13.72 to 12.05 and α_6 raised by two standard errors from 17.13 to 26.77. The results appear in Table 26. At RGA = .005 the cost of capital is the same in the two tables for both years because retention is the sole source of funds at low values of RGA. Once stock financing becomes a source of funds the cost of capital rises more rapidly with RGA under the revised coefficients. However, notwithstanding the substantial changes in α_3 and α_6, the change in COC between the two tables is quite modest. At RGA = .10 in 1963 COC is raised from .0575 to .0625, and in 1968 it is raised from .0675 to .0725. The cost of capital is therefore not very sensitive to fairly wide changes in these coefficients.

The previous observations have been directed toward the change in COC with RGA. One also may question the general level of the cost of capital. At first glance a cost of capital of .0475, the figure for 1963 with RGA = .005, may seem ridiculously low. It should be recalled, however, that in 1963 the interest rate on Aa rated bonds was .0439. Furthermore, the figure to compare with AAR = .0439 is RRC = .0631. With AAR = .0439, is .0631 a high enough return on the common to justify a practically zero investment rate? Furthermore, no electric utility companies had as low an investment rate. The sample mean value of RGA is .058 in 1963. In Table 25 the COC for RGA = .060 was .0525. The return on common needed to generate RRA = .0525 was RRC = .0763. With the revised coefficients in Table 26, for RGA = .060 we have COC

= .0558 and RRC = .0851. These values for RRA and RRC and the corresponding values of KGYD are certainly within the bounds of reason for 1963, when the interest rate was comparatively low, shares in general sold at low yields, and the growth prospects of utility stocks were looked on with considerable favor.

The general level of the cost of capital figures for 1968 may be considered low on the grounds that over a considerable range of RGA the cost of capital is below the interest rate on Aa rated bonds. For example, in Table 25 we have COC = .065 at RGA = .065 with AAR = .067. However, common stockholders are concerned with the return on common and not return on assets. With RRA = .065 we have RRC = .0979 because IMBR = .0471. Furthermore, KGYD = .0871. It is certainly within the bounds of reason for investors to be satisfied with a yield of .0871 on a utility stock when AAR = .0675. Also, with KGYD = .0871 it is reasonable to have RRC = .0979 and to have RETR = .332 and SFR = .0325 an optimal financing policy. With the revised coefficients in Table 26, COC equals .0675 for RGA = .070, but this return on assets

Table 26. ***Variation in Constrained Cost of Capital and Other Financial Variables with Rate of Growth in Assets Using Revised Stock Financing Coefficients, Sample Mean Firm, 1963 and 1968***

RGA	*COC*	*RRC*	*RETR*	*SFR*	*KGYD*	*PPS*
			1963 Sample Mean Firm			
.005	.0475	.0631	.079	.0000	.0592	$18.95
.020	.0500	.0697	.179	.0025	.0616	20.76
.040	.0525	.0763	.262	.0200	.0658	22.91
.055	.0550	.0829	.302	.0300	.0710	25.50
.070	.0575	.0895	.335	.0400	.0775	28.53
.090	.0600	.0961	.364	.0500	.0851	32.05
.100	.0625	.1027	.414	.0575	.0939	36.07
			1968 Sample Mean Firm			
.005	.0550	.0695	.072	.0000	.0783	$15.42
.015	.0575	.0766	.196	.0000	.0793	16.79
.020	.0600	.0837	.239	.0000	.0810	18.30
.030	.0625	.0908	.303	.0025	.0831	19.94
.050	.0650	.0979	.332	.0175	.0863	21.90
.070	.0675	.1050	.357	.0325	.0913	24.40
.095	.0700	.1121	.402	.0550	.1008	27.60
.100	.0725	.1190	.400	.0525	.1043	31.34

provides RRC = .1050, and the yield investors require on the stock, .0913, makes RRC = .1050 adequate to generate the financing required for RGA = .07.

It should be emphasized that the COC figures will rise over time as IMBR moves toward AAR, assuming that AAR remains unchanged. Raising IMBR by about .02 to equality with AAR would raise COC at each investment rate by about the same amount.

10.2 *Overall Bilateral Monopoly Cost of Capital*

The procedure for finding the overall cost of capital at each investment rate under a bilateral monopoly policy is somewhat simpler than the procedure under a constrained policy. First, we set RGA = RETR = SFR = 0 and calculate the value of RRC that results in PPS = 1.1 BVS. Given DEQ and IMBR we calculate RRA and obtain the COC for RGA = 0. Second, increment RGA by some amount, say, to RGA = .005, and calculate the value of RRC for every combination of RETR and SFR that satisfies RGA = .005 and PPS = 1.1 BVS. RRC is minimized for some combination of RETR and SFR, and that combination is the optimal financing policy for RGA = .005. The value of RRA that provides this value of RRC is the overall COC at an investment rate of RGA = .005. For RGA = .01 we repeat the same calculations, and continuing up to any value of RGA we obtain COC as a function of the investment rate RGA. For a single investment rate only one calculation is necessary to obtain the required COC.

Table 27 presents COC as a function of RGA for the sample mean firm for 1963 and 1968. For 1963 the bilateral monopoly policy results in about the same values for RRC and COC at RGA = .005 as the constrained policy. As RGA rises the 1963 RRC and COC that maintain MBR = 1.1 rise very slowly and remain below the constrained values. For example, at RGA = .06 the bilateral monopoly cost of capital is COC = .0495, while the constrained value is .0525. The firm uses both retention and stock financing, but the latter is the primary source of funds as under the constrained policy. At RGA = .06, we have SFR = .045 and RETR = .220, which yields RTGR = .015.

For 1968 the overall bilateral monopoly cost of capital and RRC

Table 27. ***Variation in Bilateral Monopoly Cost of Capital and Other Financial Variables with Rate of Growth in Assets, Sample Mean Firm, 1963 and 1968***

RGA	*COC*	*RRC*	*RETR*	*SFR*	*KGYD*	*MBR*[1]
			1963 Sample Mean Firm			
.005	.0483	.0651	.077	.0000	.0596	1.10
.020	.0483	.0653	.153	.0100	.061	1.10
.040	.0488	.0664	.189	.0275	.062	1.10
.060	.0495	.0683	.220	.0450	.064	1.10
.070	.0500	.0696	.287	.0500	.065	1.10
.090	.0511	.0726	.301	.0675	.068	1.10
.100	.0517	.0743	.337	.0750	.070	1.10
			1968 Sample Mean Firm			
.005	.0627	.0913	.055	.0000	.083	1.10
.015	.0618	.0888	.169	.0000	.082	1.10
.020	.0616	.0880	.256	.0000	.082	1.10
.030	.0616	.0882	.283	.0050	.082	1.10
.050	.0620	.0894	.308	.0225	.084	1.10
.070	.0627	.0915	.355	.0375	.086	1.10
.095	.0641	.0952	.394	.0575	.090	1.10
.100	.0644	.0961	.416	.0600	.091	1.10

[1] With MBR = 1.1, PPS equals $19.46 for 1963 and $19.27 for 1968 for all values of RGA.

fall as RGA rises from zero at about .025. In the interval in which COC and RRC are falling, their values are above the respective constrained policy values given in Table 25. As RGA rises above .025 both the constrained and bilateral monopoly policy values of COC and RRC rise, but the latter values rise less rapidly. At RGA = .10 the constrained policy value of RRC equals .105, while the bilateral monopoly value of RRC is .096.

The constrained policy values of RRC and COC are below their bilateral monopoly policy values at RGA = 0 because share price is maximized under the former policy at an RRC which results in a price per share below book value. The bilateral monopoly policy of allowing an RRC that keeps PPS = 1.1 BVS regardless of RGA therefore results in higher RRC and PPS values.

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10.3 *Comparison of the Estimates Under the Different Theories*

There is theoretical as well as practical value in comparing the cost of capital and related statistics under the different theories, including in the comparison the actual values of the variables. Table 28 presents these figures for the 1963 and 1968 sample mean companies. The derivation of these estimates is not as straightforward as might first appear, and the comparative analysis is preceded by an explanation of how they were obtained.

The "Actual values" row presents the sample mean values of RGA, RRC, RETR, and SFR. RRA was derived from the sample mean values of RRC, DEQ, and IMBR.[2] PPS and KGYD are the values obtained from Eq. (9.2.3) on the basis of the coefficients in Table 17, the sample mean values of RRC, RETR, SFR, and the sample mean values of the state variables appearing in the table with XYGR = 0. Eq. (9.2.3) was used to obtain PPS, and the share yield was calculated from

$$KGYD = (DIV/PPS) + RTGR + SFGR, \qquad (10.3.1)$$

with DIV = BVS*RRC(1.0 − RETR). The sample mean values of PPS and KGYD were not used for the following reasons. KGYD presented the problems of choosing among GRTH, GRAV, and GRAVC and alternative averaging methods for measuring the sample mean value of DIYD. The same averaging problems arose in connection with PPS. The measures of KGYD and PPS adopted are logically superior to the alternative values, and the differences among them are negligible.[3]

Turning now to the constrained policy data, RGA is the actual sample mean value for the year. For 1968 the sample mean value was RGA = .0582, but RGA = .06 was used to obtain the solution since the solution for .0582 would not differ sufficiently to justify the additional computations. The variables RRC, RETR, and SFR have the values that make the RGA figure optimal policy for the

[2]The figure therefore differs from RRA in Tables 7 and 8 due to the fact that IMBR here is an average of IMBR values for the current year and the following year.

[3]The model predicts PPS and KGYD with a very high degree of accuracy, and all the sample mean measures of growth have about the same values.

Table 28. *Comparative Values of the Cost of Capital and Other Variables Under Alternative Models of the Cost of Capital, Sample Mean Firm, 1963 and 1968*

	RGA	*RRA*	*RRC*	*RETR*	*SFR*	*KGYD*	*PPS*
1963 Sample Mean Firm							
Actual values	.0582	.0698	.1219	.345	.0160	.0829	$42.55
Constrained policy values	.060	.0525	.0763	.229	.0425	.0678	$23.34
Bilateral monopoly policy values	.060	.0495	.0683	.220	.0450	.0635	$19.46
Traditional theory	.060	.0550	.0829	.302	.0350	.0720	$25.50
PCCM theory	.060	.0631	.1043	.336	.0250	.0797	$34.93
State variables	BVS = $17.69, AAR = .0439, LEV = 1.492, DEQ = 1.640, IMBR = .038, PEE = .854						
1968 Sample Mean Firm							
Actual values	.0702	.0756	.1279	.317	.0295	.0977	$32.96
Constrained policy values	.070	.0655	.0993	.327	.0375	.0882	$22.79
Bilateral monopoly policy values	.070	.0627	.0915	.355	.0375	.0861	$19.27
Traditional theory	.070	.0649	.0977	.384	.0325	.0885	$21.54
PCCM theory	.070	.0690	.1092	.366	.0300	.0929	$26.04
State variables	BVS = $17.52, AAR = .0675, LEV = 1.649, DEQ = 1.837, IMBR = .0471, PEE = .854						

utility. PPS and KGYD are the values of those variables for the given value of RGA employing the optimum values of RRC, RETR, and SFR under the constrained policy. Finally, RRA is the cost of capital based on the above solution value of RRC and the sample mean values of DEQ and IMBR.

The bilateral monopoly policy estimates in Table 28 are analogous to the constrained policy values. Given the actual RGA, the values of the other variables shown in the table minimize the cost of capital if the regulatory agency follows a bilateral monopoly policy.

Under the traditional theory the cost of capital is obtained by taking the actual current value of KGYD and incorporating it into the traditional theory formula, Eq. (6.1.2), along with the observed values of BVS, BDS, and IMBR. The sample mean values of KGYD and IMBR were .0829 and .038 in 1963, and the cost of capital under the traditional theory was

$$TRCC = \frac{(\$17.69)(.0829) + (\$29.01)(.038)}{\$17.69 + \$29.01} = .055. \qquad (10.3.2)$$

Hence, the 1963 traditional theory solutions for the values of RRA and RRC are RRA = .055 and RRC = .0829. Under the traditional theory the cost of capital is independent of RGA, RETR, SFR, and RRC. Thus TRCC = .055 regardless of the actual values of these variables since they do not appear in Eq. (10.3.2). RRA in the table has its actual value, and RRC is the traditional theory solution for its value. The traditional theory does not produce optimal values for RETR and SFR. Their values and the values for KGYD and PPS on the "Traditional theory" line of Table 28 will be explained shortly.

The PCCM values for the variables are obtained in the same way as the traditional theory values. First, the PCCM cost of capital formula, Eq. (6.2.2), is used to obtain PCCC. For 1963 the actual values of KGYD, PPS, and the other variables which enter the formula result in

$$\text{PCCC} = \frac{(\$42.55)(.0829) + (\$27.31)(.0439)}{\$42.55 + \$27.31} \times \left[\frac{\$17.69 + \$27.31}{\$17.69 + \$29.01}\right] + \frac{(\$29.01)(.038) - (\$27.31)(.0439)}{\$17.69 + \$29.01} = .0631 \qquad (9.5.2)$$

With RRA set equal to PCCC we next compute the required RRC on the basis of the actual sample values of IMBR and DEQ. PCCC, like TRCC, is independent of RETR and SFR, and the values of these variables and of KGYD and PPS shown under the PCCM cost of capital will be explained shortly.

We are now in a position to compare the actual values of RRA and the other variables with their values under the various cost of capital models. For both 1963 and 1968 the constrained policy cost of capital was well below the actual RRA. For 1963 the difference was over 1.7 percent, and for 1968 it was 1 percent. This difference between RRA and COC resulted in larger differences in RRC and PPS. In 1963 PPS was almost twice its constrained policy value.

In both years the actual values of SFR were below the constrained policy values, while the reverse was true for RETR. There are three

plausible reasons for this difference between actual and optimal financing policy. First, utility managements may not have maximized share price and used the generous RRC the utilities enjoyed in part to satisfy a preference for retention over stock financing. Second, our estimates of the coefficients may understate the cost of stock financed capital, and under the true values the optimal reliance on stock and retention financing would be closer to the actual values. Third, on average utility managements may not realize that a greater relative reliance on stock financing would result in a higher share price.

The bilateral monopoly policy values of RRA, RRC, KGYD, and PPS are lower than the constrained values in both years. The reasons for the differences have been discussed and need not be restated.

Perhaps the most interesting questions are raised when we turn to the traditional theory data. Under this theory, setting RRA so that RRC is equal to the observed value of KGYD should result in PPS = BVS. This conclusion holds under the assumption that KGYD is independent of RRC, RETR, and SFR. However, the evidence presented in chapters 6–8 leads to the conclusion that KGYD is an increasing function of these variables. Hence, with RRC = .1219 and KGYD = .0829 in 1963, reducing RRC to .0829 would reduce KGYD below .0829 and fail to reduce PPS to equality with BVS.

The traditional theory values of RETR, SFR, KGYD, and PPS in Table 28 therefore were arrived at as follows. With KGYD = .0829 we set RRC = .0829 and used Eq. (6.1.2) to calculate RRA. With RRC = .0829 and RGA = .06 we then calculated the combination of RETR and SFR that maximized PPS on the assumption that Eq. (9.2.3) describes how investors value shares. These are the traditional theory values of RETR and SFR in Table 28. Similarly, KGYD and PPS are the values of these variables for the given values of RRC, RETR, and SFR. Notice that if Eq. (9.2.3) correctly describes how investors value shares then reducing RRC from .1219 to .0829 in 1963 reduces KGYD to .0720 and results in PPS = \$25.20, which is well above BVS = \$19.46. The regulatory agency then would have to reduce RRA to bring RRC down from .0829 to .0720. Continuing this process until RRC = .0683, the bilateral monopoly value would finally result in PPS = 1.1 BVS, and RRC would be slightly above KGYD. At a slightly lower value RRC would equal KGYD, and PPS would equal BVS, but the firm then would be ill-advised to engage in stock financing.

Table 28 contains the values of the PCCM cost of capital and the values of the other variables analogous to the traditional theory values purely for reference. It will be recalled that the PCCM theory of stock valuation differs from the traditional theory only with regard to the influence of leverage on share value. We found no empirical basis for accepting the PCCM leverage theorem, and we experienced serious logical problems in implementing the theory. For these and other reasons it does not seem worthwhile to undertake a comparative analysis of these estimates.

10.4 Conclusion and Broader Policy Issues

The previous pages have established the return on assets that provides a utility with its cost of capital. When the allowed rate of return is equal to this figure, the shareholders earn a return on their investment in the company that is at least equal to the yield they require. What is perhaps more important, the utility can raise the funds it requires for further investment without damaging the existing shareholders. The latter is true because this rate of return makes the price of the stock independent of the utility's investment decision.

In arriving at a utility's cost of capital under a bilateral monopoly regulatory policy, the regulatory agency can follow three alternative, and in some respects complementary, courses of action. The simplest course takes advantage of the relation between the market and book values of the common stock that pertains when the allowed rate of return on assets is equal to the cost of capital. That is, the agency may simply raise (lower) the allowed rate of return when the market-book value ratio is below (above) 1.1. The second alternative is to use a slight modification of the traditional theory formula,

$$z = [1.1Ek + Bc]/[E + B], \qquad (10.4.1)$$

where E and B are the book values of the common equity and debt, c is the coupon rate of interest, and k is the yield at which the stock is selling. The third alternative course of action available to a regulatory agency is to use the models developed in the preceding pages to arrive at a utility's cost of capital directly. This is a considerably more expensive and formidable course of action than

the two previous alternatives, but it has advantages that will be discussed shortly.

The analyses in the preceding pages allow certain conclusions with regard to the cost of capital regardless of how it is measured. If a utility's investment rate is small, and if the regulatory agency keeps the allowed rate of return at or close to the cost of capital, the risk of the utility's stock should be very small and the yield at which the stock sells should only be slightly higher than the current interest rate. Hence, if the coupon rate of interest is equal to the current interest rate, the cost of capital is slightly above the interest rate. If the coupon rate of interest is below the current interest rate, the cost of capital actually can be below the current interest rate.

Given a difference between the yield investors require on a utility's stock and the current interest rate, a rate of return on assets equal to the cost of capital has the following properties. It will be a decreasing function of the utility's debt-equity ratio up to about a 3:1 or 4:1 debt-equity ratio. It will be an increasing function of the utility's investment rate, and it will depend on the combination of retention and sale of stock used to finance the investment rate. Departure in the combination of retention and stock financing from the optimal combination will increase the rate of return required to maintain a market-book value ratio of 1.10 and thereby raise the cost of capital.

The allowed rate of return that maintains a 1.10 market-book value ratio is also an increasing function of the current interest rate in two ways. A rise in the current interest rate raises the imbedded interest rate over time, and it immediately raises the yield investors require on the utility's stock, both of which raise the cost of capital. Finally, the cost of capital depends on the risk premium over the interest rate investors require on the utility's shares, which premium will vary with investor uncertainty. Uncertainty as to the magnitude and duration of differences between the return the agency allows the utility to earn on its common and the return investors require on the common stock increases the risk premium over the interest rate that investors require on the common.

The preceding observations may have indicated the advantages in having a regulatory agency arrive at a utility's cost of capital directly in preference to maintaining a market-book value ratio of 1.10 or to using Eq. (10.4.1). Recall that with the allowed rate of return adjusted to maintain a market-book value ratio of 1.10 the stockholders are indifferent to the investment and financing policy adopted by the utility. Hence, there is no conflict between the welfare of the stockholders and the consumers, both on an investment rate that satisfies the demand for service and on a financing policy that minimizes the cost of capital. However, a management well might find that its own welfare is maximized by an investment and financing policy that results in a higher cost of capital than the consumer interest requires.

The management of a company cannot diversify its portfolio of jobs in the same way an investor can diversify his portfolio of shares and other capital assets. The welfare of a utility's management therefore may be significantly increased by a debt-equity ratio below the ratio that minimizes the utility's cost of capital. The management also may prefer a higher retention rate and a lower stock financing rate than the combination that minimizes the cost of capital. Finally, the management's employment income and job satisfaction may be maximized at a higher investment rate than the public interest requires. Under these circumstances maintaining a market-book value ratio of 1.10 will not minimize the cost of capital to the consumer. It will only deny stockholders a rate of return in excess of the cost of capital. Using the traditional formula for arriving at the allowed rate of return will be no more effective than adjusting the market-book value ratio in avoiding a rate of return above the cost of capital due to overinvestment and nonoptimal financing policies.

To allow the utility a return on assets that minimizes the cost of capital to the consumer, a regulatory agency must estimate it directly. That is, the regulatory agency must estimate the investment rate the public interest requires and the leverage rate that minimizes the cost of capital or satisfies some other goal. Given this investment rate and leverage rate, the agency then must estimate the return on common and on assets that realizes a 1:1 market-book value ratio with an optimal (return minimizing) combination of retention and stock financing. Overinvestment by the utility and/or failure to adopt optimal financing policies will result in a share price below book value. The cost of these policies falls on the stockholders instead of the consumers, and the stockholders can be expected to pressure the management to change its policies.

It was pointed out in chapter 1 that the objective of regulatory

policy is not only to minimize the utility's return on assets but also to minimize the price paid by the consumer. A rate of return on assets above the cost of capital is justified if it reduces other costs by a larger amount. However, one problem raised in chapter 1 was that of utilities charging higher prices to consumers whose demand is relatively price inelastic in order to compensate for prices below production cost in markets where substitutes are available and the elasticity of demand is larger. One motivation for this type of price discrimination is the desire to expand the capital base to take advantage of a rate of return above the cost of capital. Consequently, a rate of return above the cost of capital places an additional burden on the consumer insofar as it encourages overinvestment, which also is motivated by management's own desire for growth. Hence, the effective prevention of overinvestment probably requires the control of relative prices in order to prevent price discrimination not justified by cost differences.

The other problem raised in chapter 1 was the motivation of management to perform efficiently—minimize production costs and invest profitably. With all the benefits from efficient performance passed on to the consumer, management's incentive is limited to pride in doing a job well, the fear of public ownership, and the fear of competition. The belief that these considerations do not provide adequate motivation has been used to justify regulatory lag. That is, eliminating an excess of the allowed rate of return over the cost of capital due to management's performance with a lag may spur management to perform more efficiently and may result in a lower long-run price to the consumer.

It is beyond the scope of this study to establish how a policy of regulatory lag should be carried out and to evaluate the possible benefits from such a policy, but three points should be noted. First, there is no benefit to be gained from a rate of return that differs from the cost of capital by a random amount or from a lag in adjusting the rate of return in response to a change in the cost of capital. Hence, the accurate measurement of the cost of capital is no less desirable under a policy of regulatory lag than under a policy which passes the benefits of improved efficiency on to the consumer with no lag. Second, regulatory lag increases the uncertainty as to the realized rate of return and thereby raises the cost of capital. The long-run gains in efficiency to the consumer from regulatory lag must offset this long-run cost as well as the short-run cost of allowing the utility to keep the gains due to improved performance for a limited period of time. Finally, a policy of regulatory lag poses truly formidable problems of cost measurement. One may presume that the policy should work both ways: Cost increases due to poor performance on the part of management also should be passed on to the consumer with a lag. On the other hand, cost increases or reductions which are beyond the control of management, such as raw material price changes and perhaps wage rate increases, should be passed on without a lag. One reasonably may doubt the ability of a regulatory agency to differentiate between changes in costs that are beyond the control of a utility and those that are within its control. The agency would find it extremely difficult to both obtain the required information from a utility and to adequately analyze and interpret the information it does obtain. The end result would be regulatory decisions based on criteria far different from those envisioned by the advocates of regulatory lag.

Appendix A

Glossary of Frequently Used Letter Code Symbols

Symbol	Definition[a]
b	Fraction of the earnings per share retained.
B_t	Book value of debt on a per share basis at end of t.
c	Coupon or imbedded interest rate on outstanding debt.
D_t	Dividend per share in period t.
D_n^*	Dividend in period n obtained by new stockholders.
E	Book value per share of stock.
g	Rate of growth in the dividend.
i	Current rate of interest.
I	Cost of an investment.
k	Yield at which a share is selling, that is, the discount rate that equates the dividend expectation of a share with its price.
k^τ	After personal income tax yield an investor requires on a share of stock.
L	Market value of debt on a per share basis.

[a]The following general rules hold with regard to the time of a variable. For a flow variable such as the dividend, a subscript denotes its value for that period. For example, D_t is the dividend during t. A flow variable without subscript is its value during $t = 1$. For a stock variable such as debt per share, a subscript denotes its value at the end of the period. For example, B_t is the debt per share at the end of t. A stock variable without subscript is its value at $t = 0$. For a rate variable such as return on common equity, the absence of a subscript indicates the current value and expected value for every future period unless the text indicates otherwise.

Symbol	Definition*
n	Number of new shares issued to finance an investment.
N	Number of shares outstanding.
P_t	Price at which the share is expected to sell at the end of t.
Q_n	Funds raised from the sale of stock during n.
r	Rate of return on common equity investment. For a public utility $r = \pi$.
s	Rate of growth in the common equity due to the sale of stock.
t	Subscript denoting time period.
v	The fraction of the funds provided during n that accrues to the shareholders at the start of n.
W_t	Total common equity at end of t.
W_t^*	Portion of the total common equity at the end of t that belongs to the shares outstanding at $t = 0$.
x	Rate of return on total assets before interest and taxes.
x^τ	After tax rate of return on total assets.
X	Pre-tax earnings on assets per share.
X^τ	After tax earnings on assets per share.
Y	Earnings per share of stock.
z	Cost of capital.
β_j	Measure of systematic risk on the j^{th} share.
η	Ratio of the yield on a share at the time of a new issue to the yield at other times.
π	Rate of return on common equity. $\pi = Y/E$.
ρ	Yield an investor requires on a share of stock when there is no debt in the capital structure.
ρ^τ	After personal income tax yield an investor requires on a share of stock when there is no debt in the capital structure.
τ	Corporate income tax rate.
τ_g	Tax rate on capital gains.
τ_p	Tax rate on dividends.
ψ	Fraction of the amount invested in the corporation by new shareholders which accrues to the investment banker.

*The following general rules hold with regard to the time of a variable. For a flow variable such as the dividend, a subscript denotes its value for that period. For example, D_t is the dividend during t. A flow variable without subscript is its value during $t = 1$. For a stock variable such as debt per share, a subscript denotes its value at the end of the period. For example, B_t is the debt per share at the end of t. A stock variable without subscript is its value at $t = 0$. For a rate variable such as return on common equity, the absence of a subscript indicates the current value and expected value for every future period unless the text indicates otherwise.

Appendix B

Glossary of Frequently Used Mnemonic Code Symbols

Symbol	Definition*
AAR(T)	Yield on Aa rated bonds at the end of T.
AFC(T)	Income available for the common equity during T.
ANS(T)	Number of shares outstanding at the end of T adjusted for stock splits and dividends.
ASO(T)	Actual shares outstanding at the end of T.
AYPS(T)	Earnings per share during T adjusted for stock splits and dividends to make earnings comparable over time.
BDS(T)	Book value of debt on a per share basis at the end of T.
BETA(T)	A measure of systematic risk as of the end of T.
BVS(T)	Book value per share at the end of T.
CEQ(T)	Common equity plus reserve for deferred taxes at the end of T.
COEV(T)	Coefficient of variation of the rate of return on assets as of the end of T.
CSS(T)	Common equity at the end of T.
DEBB(T)	Total debt at the end of T. DEBB = STD + LTD + PFDS.
DEQ(T)	Debt-equity ratio based on book values of the debt and common equity at the end of T. DEQ = DEBB/CSS.
COC(T)	Cost of capital at the end of T.

*For a rate variable such as RETR(T) or DEQ(T) the value is the actual value during or at the end of T and, unless the text indicates otherwise, the expected value in every subsequent period.

Symbol	Definition*
COCD(*T*)	Cost of debt capital at the end of *T*.
COCR(*T*)	Cost of retention capital at the end of *T*.
COCS(*T*)	Cost of stock capital at the end of *T*.
DGR(*T*)	Rate of growth in the dividend as of the end of *T*.
DIV(*T*)	Dividend per share during *T*.
DIVR(*T*)	Dividend rate during *T*. DIVR = DIV/EPS.
DIYD(*T*)	Dividend yield at the end of *T*.
DNT(*T*)	Deferred income taxes during *T*.
EACR(*T*)	Equity accretion rate during *T*.
EPS(*T*)	Earnings per share of stock during *T*.
ETA	Ratio of share yield on a new issue to share yield at other times.
FTS(*T*)	Flow-through tax savings during *T*.
GRAV(*T*)	Weighted average rate of growth at the end of *T*.
GRAVC(*T*)	GRAV(*T*) corrected for measurement errors.
GRTH(*T*)	Intrinsic infinite horizon growth rate at the end of *T*. GRTH = RTGR + SFGR.
IMBR(*T*)	Imbedded or coupon interest rate on debt during *T*.
INT(*T*)	Interest charges on outstanding debt during *T*.
ITC(*T*)	Interest charged to construction during *T*.
KEYD(*T*)	Earnings yield at the end of *T*.
KGAV(*T*)	Yield at which the share is selling at the end of *T* if the dividend is expected to grow forever at the rate GRAV.
KGAVC(*T*)	Share yield based on GRAVC as the growth measure.
KGTH(*T*)	Share yield based on GRTH as the growth measure.
KGYD	Yield at which a share sells at the end of *T* computed on basis of stock value model.
LEV(*T*)	Leverage rate based on book values of debt and common equity at the end of *T* with reserve for deferred taxes added to the common equity. LEV = DEBB/CEQ.
LEVM(*T*)	Debt-equity ratio with both measured at market value at the end of *T*. LEVM = LPS/PPS.
LPS(*T*)	Market value of debt on a per share basis at the end of *T*.
LTD(*T*)	Book value of long-term debt at the end of *T*.
MBR(*T*)	Ratio of market value to book value of the common stock at the end of *T*.
PCCC(*T*)	PCCM theory cost of capital at the end of *T*.
PCCM	Perfectly competitive capital markets.
PCRO(*T*)	Yield at which share would sell in absence of leverage at the end of *T*.

*For a rate variable such as RETR(*T*) or DEQ(*T*) the value is the actual value during or at the end of *T* and, unless the text indicates otherwise, the expected value in every subsequent period.

Symbol	Definition*
PEE(*T*)	Percentage of sales which are electricity sales.
PFDD(*T*)	Dividends on preferred stock during *T*.
PFDS(*T*)	Book value of preferred stock at the end of *T*.
PPS(*T*)	Price per share at the end of *T*.
PSI	Investment bankers' commission rate on a stock issue.
QLE(*T*)	An index of the quality of the utility's earnings during *T*.
RETR(*T*)	Retention rate during *T*.
RGA(*T*)	Investment rate or rate of growth in assets during *T*.
RGAS(*T*)	Smoothed value of RGA(*T*) as of the end of *T*.
RRA(*T*)	Rate of return on total assets during *T*.
RRC(*T*)	Rate of return on common equity during *T*. RRC = EPS/CSS.
RTGR(*T*)	Retention growth rate at the end of *T*.
SFGR(*T*)	Stock financing growth rate at the end of *T*.
SFR(*T*)	Stock financing rate during *T*.
SFRS(*T*)	Smoothed stock financing rate during *T*.
STD(*T*)	Book value of short-term debt at the end of *T*.
TRCC(*T*)	Traditional theory cost of capital.
TTA(*T*)	Total assets at the end of *T*.
YGR(*T*)	Rate of growth in earnings per share during *T*.
YGRS(*T*)	Smoothed rate of growth in earnings per share during *T*.
XYGR(*T*)	Excess of YGRS(*T*) over GRTH(*T*).

*For a rate variable such as RETR(*T*) or DEQ(*T*) the value is the actual value during or at the end of *T* and, unless the text indicates otherwise, the expected value in every subsequent period.

Appendix C

Firms in the Utility Company Sample

Allegheny Power Company
Atlantic City Electric Company
Baltimore Gas and Electric Company
Boston Edison Company
Carolina Power and Light Company
Central Hudson Gas and Electric Company
Central Illinois Light Company
Central Illinois Public Service Company
Central and South West Corporation
Cincinnati Gas and Electric Company
Cleveland Electric Illuminating Company
Columbus and Southern Ohio Electric Company
Commonwealth Edison Company
Consolidated Edison Company of New York
Consumers Power Company
Dayton Power and Light Company
Delmarva Power and Light Company
Detroit Edison Company
Duquesne Light Company
Florida Power Corporation
Florida Power and Light Company
Gulf States Utilities Company
Houston Lighting and Power Company
Idaho Power Company
Illinois Power Company
Indianapolis Power and Light Company
Iowa-Illinois Gas and Electric Company
Iowa Power and Light Company
Kansas City Power and Light Company
Kansas Gas and Electric Company
Long Island Lighting Company
Louisville Gas and Electric Company
Minnesota Power and Light Company

Montana Dakota Utilities Company
New York State Electric and Gas Corporation
Niagara Mohawk Power Corporation
Northern States Power Company (Minnesota)
Ohio Edison Company
Oklahoma Gas and Electric Company
Pacific Gas and Electric Company
Pennsylvania Power and Light Company
Philadelphia Electric Company
Public Service Company of Indiana, Inc.
Rochester Gas and Electric Corporation
San Diego Gas and Electric Company
South Carolina Electric and Gas Company
Southern California Edison Company
Toledo Edison Company
Union Electric Company
Utah Power and Light Company
Virginia Electric and Power Company
Washington Water Power Company
Wisconsin Electric Power Company
Wisconsin Public Service Corporation

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THE COST OF CAPITAL –

A PRACTITIONER'S GUIDE

BY

DAVID C. PARCELL

PREPARED FOR THE SOCIETY OF UTILITY
AND REGULATORY FINANCIAL ANALYSTS

1997 EDITION

Author's Note: This manual has been prepared as an educational reference on cost of capital concepts. Its purpose is to describe a broad array of cost of capital models and techniques. No cost of equity model or other concept is recommended or emphasized, nor is any procedure for employing any model recommended. Furthermore, no opinions or preferences are expressed by either the author or the Society of Utility And Regulatory Financial Analysts.

which states that the cost of equity is the sum of the dividend yield (current income) and the growth rate (future income).

Assumptions of DCF

The DCF method assumes that investors evaluate stocks in a classical economic framework and buy and sell securities rationally at prices which reflect that value assessment. Classical economic, or valuation, theory maintains that the value of a financial asset is determined by its earning power, or its ability to generate future cash flows. As a result, DCF theory assumes that the stock price of a firm fully considers and reflects the return expected by stockholders.

The DCF model most commonly used is known as the constant growth DCF, or Gordon model. The constant growth DCF model is based on the following assumptions.

The first four underly the general DCF model, while the last four are necessary for the constant growth model (Morin, 1994, 106-113). These assumptions are:

1. Investors evaluate common stocks in the classical economic framework.
2. Investors discount the expected cash flows at the same rate (K) in every future period.
3. K corresponds only to the specific steam of future cash flows.

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4. Dividends, rather than earnings, constitute the source of value.

5. The discount rate (K) must exceed the growth rate (g). As g approaches K, the stock price becomes infinite ($p_o = D_1/K-g$).

6. The constant growth rate will continue for an indefinite future.

7. Investors require the same K each year.

8. There is no external financing - growth is provided only by the retention of earnings.

Three other assumptions can be implied from the above assumptions:

9. The dividend payout ratio remains constant.

10. The price/earnings ratio remains constant.

11. The stock price grows proportionately to the growth rate.

Several studies have shown that these assumptions do not hold true in a technical sense (Whittaker, 1991, 286; Brennan and Moul, 1988, 28; Whittaker and Sefton, 1987, 19; Brealey and Myers, 1984, 51; Haugen, 1984, 403; Rao, 1984, 98). As stated earlier, however, the crucial factor to consider in evaluating the reliability of a model is not the strict real-world existence of its "intended use and ability to predict explain, and help the decision-maker attain his or her goal" (Morin, 1994, 110).

Kentucky Power Company

REQUEST

Refer to the Avera Testimony at page 39 and Exhibit WEA-2.

a. Provide a copy of the relevant pages in the Federal Energy Regulatory Commission ("FERC") document cited in footnote 45 that discuss the FERC's rationale and decision with regard to rate of return and "extreme outliers."

b. Explain whether the FERC decision establishing a threshold for "extreme outliers" for DCF estimates is specific to that particular 2004 case or is meant to be a hard and fast rule to be applied as a ceiling in all cases thereafter.

RESPONSE

a. Copies of FERC orders, including those cited in Dr. Avera's testimony, are publicly available at http://www.ferc.gov/. Please also see attached 2 pages for the relevant pages cited in footnote 45 as requested.

b. The FERC decision referenced in Dr. Avera's testimony at f. 45 has served as precedent in evaluating extreme outliers in subsequent cases. *See, e.g.*, *Potomac-Appalachian Transmission Highline, L.L.C.*, 122 FERC ¶61, 188 (2008) and *Tallgrass Transmission, LLC*, 125 FERC ¶ 61,248 (2008).

WITNESS: William E. Avera

109 FERC ¶ 61,147

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
Nora Mead Brownell, and Joseph T. Kelliher.

ISO New England, Inc., et al.	Docket Nos. RT04-2-001, RT04-2-002, RT04-2-003, RT04-2-004, ER04-116-001, ER04-116-002, ER04-116-003, and ER04-116-004
Bangor Hydro-Electric Company, et al.	Docket Nos. ER04-157-002, ER04-157-003, ER04-157-005, and ER04-157-007
The Consumers of New England v. New England Power Pool	Docket Nos. EL01-39-001, EL01-39-002, EL01-39-003, and EL01-39-004
New York Independent System Operator, Inc. and the New York Transmission Owners	Docket No. ER04-943-000
New England Power Pool	Docket No. ER05-3-000

ORDER ACCEPTING PARTIAL SETTLEMENT,
SUBJECT TO CONDITIONS; ACCEPTING, IN PART,
COMPLIANCE FILINGS; AND Granting, IN PART, AND
DENYING, IN PART, REQUESTS FOR REHEARING

(Issued November 3, 2004)

205. ROE Filers' witness, Dr. Avera, proposes that this group exclude firms that do not pay common dividends, or for which no growth rate data is currently available, as reported by I/B/E/S International, Inc. (I/B/E/S), or Value Line. We find this approach is generally acceptable. However, we will not preclude the presiding judge from finding candidates for inclusion in the proxy group for which comparable data can reasonably be substituted for the growth rate data reported by I/B/E/S or Value Line. We also find it appropriate, as Dr. Avera proposes, to exclude from consideration in the proxy group, companies whose low-end ROE was lower than these companies' reported debt cost. In addition, we agree that the inclusion of PPL Corporation (PPL) in this Proxy Group is inappropriate. Specifically, we find PPL should be excluded from the Proxy Group because its 17.7 percent cost of equity is an extreme outlier and the inclusion of this number in the calculation in an unreliable ROE that will skew the results. As Dr. Avera states in his testimony, it is often necessary to eliminate illogical results from cost of equity estimates that fail to meet threshold tests of economic logic. We believe a 13.3 percent growth rate is not a sustainable growth rate over time and therefore does not meet threshold tests of economic logic.

206. In the March 24 Order we accepted, subject to suspension, hearing and the application of our Pricing Policy Statement (when issued), the ROE Filers' proposed 100 basis point adder[106] attributable to new transmission investment. This incentive is, we stated, is an appropriate first step to encouraging vital capital investment in the enlargement, improvement, maintenance and operation of facilities for the transmission of electric energy in interstate commerce. In order to avoid any potential delay in the hearing as a result of this directive, we find it necessary to provide guidance regarding the types of investments that would qualify for this adder. We direct the parties and the presiding judge to develop a record, in this case, addressing the pros and cons of applying a 100 basis point adder for investments that, among other things: (i) are approved through the RTEP process; (ii) are capable of being installed relatively quickly; (iii) include the use of improved materials that allow significant increases in transfer capacity using existing rights-of-way and structures; (iv) utilize equipment that allows greater control of energy flows, enabling greater use of existing facilities; (v) has sophisticated monitoring and communication equipment that allows real-time rating of

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[106] This ROE adder will be applied to net book value over time of such transmission facilities (i.e., the dollar amount of the incentive that is reflected in the cost of service will decrease over time as the book value of the transmission assets are depreciated). In addition, the overall allowed equity return, adjusted for any ROE adder, will be limited to the zone of reasonableness for the public utility authorized to receive an incentive adder.

Kentucky Power Company

REQUEST

Refer to the Avera Testimony at page 42 and Exhibit WEA-6.

a. Explain why it was necessary to weight the firms in the calculations as opposed to performing the calculations on an unweighted basis.

b. Provide the CAPM analysis on an unweighted basis.

c. Explain how stock prices were selected and used in calculating the dividend yield referenced in Exhibit WEA-6 footnote (a). Were the March 27, 2008 closing prices or average stock prices used?

d. Explain why the 30-year Treasury Bond yield was not used in the calculation.

e. Provide the IBES and the Value Line average growth rates and explain how the 10.9 percent average growth rate was calculated.

RESPONSE

a. Dr. Avera's use of market value weights in the application of his forward-looking CAPM approach patterns the methodology used by S&P to construct the S&P 500, which weights the stock prices of the constituent firms based on market capitalization.

b. As noted in response to (a), above, Dr. Avera performed his calculations using market value weights in order to be consistent with the methodology used by S&P in constructing the S&P 500 Index. The Excel spreadsheet used to calculate Dr. Avera's forward-looking market rate of return on equity was provided on the CD provided in response to KIUC 1st Set, Item No. 1 and contains all information necessary to perform the requested calculations.

c. The stock prices used to calculate the dividend yields for each of the dividend paying firms in the S&P 500 were those reported by Value Line's proprietary stock screening program on October 1, 2009.

d. While 30-year government bond yields represent an alternative basis on which to apply the CAPM, the U.S. Treasury has not consistently offered debt instruments with a 30-year maturity. As a result, 20-year government bonds, which have been continuously sold and traded, provide a consistent and frequently referenced benchmark for the risk-free rate in applying the CAPM.

e. Please refer to WP-52 from Dr. Avera's workpapers, which were provided on the CD in response to KIUC 1st Set, Item No. 1, for all underlying data and calculations supporting the 9.2 percent weighted average growth rate.

WITNESS: William E. Avera

Kentucky Power Company

REQUEST

Refer to pages 7-8 of the Direct Testimony of Dennis W. Bethel ("Bethel Testimony"), specifically, the discussion of FERC Docket No. ER09-1279 and how Kentucky Power "[w]ill experience a cost decrease if the changes proposed by the AEP East Companies are approved . . . ." Describe the cost decrease Kentucky Power will experience and provide a calculation of the amount of the decrease on an annual basis.

RESPONSE

The changes proposed to the Transmission Agreement are fully described in the testimony of Dennis W. Bethel in FERC Docket No. ER09-1279 available at www.aep.com/go/oat under FERC Rate Schedule Filings and the section titled "AEP East Companies Transmission Agreement modification filing." As described by Mr. Bethel in that testimony, the most significant change is the replacement of the present bulk transmission investment cost sharing method (contained in Articles 5 and 6 of the present agreement) with a comprehensive transmission cost and revenue allocation methodology contained in the new Article 5 of the Transmission Agreement.. As filed, it is estimated that this new comprehensive allocation method would have reduced Kentucky Power's transmission cost by approximately $4,457,000 for calendar year 2009. The calculation is summarized in Exhibit AEP-205 and the details are contained in Exhibit AEP-210 available in Mr. Bethel's testimony in the above referenced Docket and website.

WITNESS: Dennis W Bethel

Kentucky Power Company

REQUEST

Refer to the Bethel Testimony, pages 10 and 11 of 23. Mr. Bethel refers to calculations performed by Kentucky Power witness David M. Roush. Provide the calculations referred to or the location of these calculations in the application.

RESPONSE

The references by Mr. Bethel are to the items contained in Exhibit DMR-4 of the testimony of David M.Roush.

WITNESS: Dennis W Bethel

Kentucky Power Company

REQUEST

Refer to page 8 of the Direct Testimony of Jay F. Godfrey ("Godfrey Testimony"). Several AEP operating companies that have contracts for long-term wind energy contracts are shown in Table 1.

a. Identify all states in which AEP operating companies are located that have adopted a renewable portfolio standard.

b. Have AEP operating companies entered into power purchase agreements for renewable energy for power generated by sources other than wind? If yes, provide the information shown in Table for those purchase agreements.

c. Compare the costs for energy purchases identified in the response to part b of this request to costs for energy purchases shown in Table 1. The response can be in the form of a general narrative discussion rather than specific costs for contracts entered into by various operating companies.

RESPONSE

a. As of January, 2010, 29 states and the District of Columbia, have adopted a Renewable Portfolio Standard (RPS), as cited by the Database of State Incentives for Renewables & Efficiency (http://www.dsireusa.org). Within the Summary Map of states with RPSs, at http://www.dsireusa.org/documents/summarymaps/RPS_map.ppt, are found: Michigan (Indiana Michigan Power Company), Ohio (Ohio Power Company, Columbus Southern Power Company), and Texas (Southwestern Electric Power Company). Additionally, two states have renewable goals, Virginia and West Virginia (Appalachian Power Company).

b. Please refer to the table below:

AEP Operating Companies' Long-Term Wind Energy Power Purchase Agreements

AEP Operating Company	Execution Date	Developer	Project	Contracted Quantity (MW)
Appalachian Power Company (APCo)	2/96 & amended 8/97	Gauley River Power Partnership, LP	Summersville Hydroelectric Project	80 MW
AEP Ohio (Ohio Power Company and Columbus Southern Power Company)	6/09	Wyandot Solar, LLC	Wyandot Solar facility	10 MW

c. The Summersville Hydro PPA was executed in 1996 and the price of this PPA is lower compared to current renewable contracts. Additionally, APCo is entitled to only a portion of the RECs associated with this 80 MW contract. AEP Ohio executed the Wyandott agreement for the output of the approximately 10MW solar facility expected on-line mid 2010. Currently, solar is approximately four times the cost of wind and the Wyandott Solar PPA falls within this range.

WITNESS: Jay F. Godfrey

Kentucky Power Company

REQUEST

Refer to page 14 of the Godfrey Testimony. Starting at line 6, Mr. Godfrey states that if Congress does not extend the investment tax credit or the renewable energy production tax credit, it will end up costing Kentucky Power customers more to acquire additional megawatt-hours of renewable energy as part of a federal or state mandate.

a. Explain how much more it would cost Kentucky Power customers if these credits are not renewed.

b. Explain the relationship, if any, between the additional cost to Kentucky Power customers and the lost value of the tax credits to the seller of renewable energy.

RESPONSE

a. There will be no impact to the cost for the Kentucky Power customers for the existing life of the 20-year contract for the Lee-DeKalb Wind Energy Center that is the subject of this request. As stated by Mr. Godfrey, and also as stated in the testimony of Witness Weaver on Page 18, Lines 19-22: "with the current federal [Production Tax Credits] PTCs for wind development now set to expire at the end of 2012, it would be anticipated that the costs of wind projects placed into service <u>after</u> that expiration date will significantly increase." Currently equal to 2.1 cents per kWh, this "would equate to a pre-tax (revenue requirement) benefit of approximately 3 cents/kWh, or $30/MWh" (Weaver, Page 13, Lines 15-22). The PTC, as well as the Investment Tax Credit (ITC) alternative to the PTC (30% of a facility's cost) are benefits that serve to "buy-down" the cost of renewable energy, allowing the wind developer to offer the wind energy to wholesale customers at a lower price and still recover their required return on the capital investment made. Without the federal subsidy, the costs would be higher and would be passed along to the Kentucky Power customer during any future contract purchases.

b. See the response to (a) above.

WITNESS: Jay F. Godfrey

Kentucky Power Company

REQUEST

Refer to page 19 of the Godfrey Testimony.

Starting at line 10, Mr. Godfrey states that the wind power price will begin to escalate on January 1, 2012. This escalation in price appears to coincide with the possible expiration of the tax credits mentioned in the previous question. Describe the impact of the costs for customers from the combination of these two events.

RESPONSE

There will be no impact from the possible expiration of the tax credit, since the Lee-DeKalb wind power purchase is fixed for the life of the 20-year contract. There will be an impact only from the 2.25% escalation. Please refer to the response provided in Commission Staff 2nd Set, Item No. 29 for further explanation of the Production Tax Credit (PTC).

WITNESS: Jay F Godfrey

Kentucky Power Company

REQUEST

Provide the estimated annual cost of the wind power contract for the 20-year term of the contract.

RESPONSE

Refer to Witness Weaver's Confidential Exhibit SCW-3, Column D, for the cost of the wind power contract for each year for the first 10 years of the contract. In years 2021 through 2030 (Years 11 through 20 of the contract) the annual cost shown in Column D would continue to escalate at a 2.25% annual rate. [Year 2021 Cost = Column D Year 2020 Cost + (Column D Year 2020 Cost x 0.025)]

WITNESS: Jay F Godfrey

Kentucky Power Company

REQUEST

Refer to the Godfrey Testimony, Exhibit JFG-1, page 1.

Under the "Price" section, it is stated that, [p]urchaser will also reimburse Seller for any operating reserve or other PJM charges associated with scheduling the Renewable Energy to Purchaser via PJM's schedule process." State whether these costs are included in the $20 million estimated cost of the wind power contract. If no, estimate these costs for the 20-year term of the contract.

RESPONSE

The $20 million estimated cost will be paid to the developer. The PJM charges will be netted against and are not expected to exceed the PJM revenue.

WITNESS: Jay F Godfrey

Kentucky Power Company

REQUEST

State whether Kentucky Power intends for renewable power purchases, such as wind power, to be recovered through its fuel adjustment clause.

RESPONSE

KPCo's filing in this proceeding does not propose the recovery of the renewable purchase power cost, such as wind power, through the monthly fuel adjustment clause.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

Refer to the Direct Testimony of Diana L. Gregory ("Gregory Testimony"), pages 8 and 9. On page 8, starting at line 7, Ms. Gregory states the difference between transmission revenues and PJM OATT net costs would be deferred as either a net regulatory asset or liability for future refund or recovery through the balancing adjustment factor ("BAF"). On page 9, starting at line 17, Ms. Gregory states that, "[t]he final order in this proceeding should clearly provide for the future recovery of PJM OATT net costs in excess of applicable Kentucky Transmission related revenues in the next proceeding." Explain what is meant by the phrase "in the next proceeding."

RESPONSE

The phrase "in the next proceedings" means that the annual updates that Kentucky Power proposes to file under the Tariff TA as explained in witness Roush's testimony on page 21.

WITNESS: Diana L Gregory

Kentucky Power Company

REQUEST

Refer to Footnote 1 in the Gregory Testimony, which lists the utilities that make up the AEP East Companies.

a. Identify the other AEP East Companies that have submitted a transmission adjustment tariff similar to Kentucky Power's proposed Tariff TA to their state regulatory commissions for approval.

b. For all AEP East Companies identified in response to part a. of this request, provide the current status of their tariff requests.

RESPONSE

a. The other AEP East Companies that have submitted a transmission adjustment tariff similar to Kentucky Power's proposed Tariff TA to their state regulatory commissions for approval are Indiana Michigan Power Company, Columbus Southern Power Company and Ohio Power Company and Appalachian Power Company.

b. Indiana Michigan Power Company filed a tariff request with the Michigan Public Service Commission in January 2010. The case is scheduled for pre-hearing late February. Columbus Southern Power Company and Ohio Power Company received approval from the Public Utilities Commission of Ohio in 2006 for their tariff request. Appalachian Power Company received approval for their tariff rate adjustment clause in October 2009 from the Virginia State Corporation Commission.

WITNESS: Diana L Gregory

Kentucky Power Company

REQUEST

Refer to the Direct Testimony of Daniel E. High ("High Testimony") at Exhibit DEH-1.

a. Provide an electronic copy of the cost-of-service study in Excel format with all formuales intact and unprotected.

b. Provide the underlying work papers, if any, and a description of how they are applied to the cost-of-service study.

c. Provide a detailed narrative description of the exhibit that describes the various portions of the study and how they relate to each other.

d. Provide a detailed narrative description of how each classification and allocation factor is derived and where in the study it is found.

RESPONSE

a. AEP used an externally developed cost of service program called TACOS Gold v.5.3.0 to perform the class cost of service study. TACOS Gold was developed by Threshold Associates, Inc. The program is a cost allocation program that operates on a Windows operating system and the MS Office Suite. Licensing requirements do not permit the Company to provide copies of the program to third parties. The Company will provide access to the information on a Company-provided PC, once permission is received from the vendor, at a mutually agreeable time. The input and output files were saved in Excel 97 format and are provided on the attached CD "Staff Second Set - Item No. 36a".

b. The attachments ("Staff Second Set - Item No. 36b, pages 2 - 11 of 16" and "Staff Second Set - Item No. 36b, pages 12 - 16 of 16") which include the allocation workpapers used in the Class Cost of Service Study (TACOS Gold software). The allocations calculated in the workpapers are applied in the "Allocators" tab of the Class Cost of Service Study. Since the last five pages are from a load research report and not in Excel, these are shown in the second attachment ("Staff Second Set - Item No. 36b, pages 12 - 16 of 16").

c. The Direct Testimony of Daniel E. High provides the explanation of the development of the Class Cost of Service Study, specifically, the functionalization, classification and allocation of costs to the customer classes (as described in pages 4 through 16). Exhibit DEH-1 provides the report of the completed Study detailing rate base, revenue, expense and rate of return for each class for test year ended September 30, 2009. The "Method" column of Exhibit DEH-1 provides the allocation basis used throughout the Study. More specifically, Exhibit DEH-1, page 1 provides a summary of the rate base, operating revenue, operating expenses, income and rate of return for each customer class. Exhibit DEH-1, pages 2 through 9, provides the specific account data, allocation basis and the related allocated amounts to the customer classes. Exhibit DEH-1, pages 10 through 19, provides the allocation method and calculated functional factors for each customer class produced from the completed Study. These pages are used to allocate and functionalize the information shown in pages 2 through 9 and further summarized on page 1.

d. Please see the Direct Testimony of Daniel E. High beginning on page 4, line 8 through page 16, line 18 for the explanation of the functionalization, classification and allocation of costs in the Class Cost of Service Study. Further, the "Method" column shown on pages 1 through 9 of Exhibit DEH-1 identifies the allocation basis for each item in Study. Pages 10 through 19 of Exhibit DEH-1 are the allocation factors. Please also see Response to 36b above, which includes the allocation workpapers used in the Study.

WITNESS: Daniel E. High

Kentucky Power Company

REQUEST

Refer to the High Testimony at pages 5-11 and Exhibit DEH-1.

a. It does not appear that a zero intercept method or a minimum system approach was performed for classifying certain distribution plant into customer and demand categories. Provide the workpapers and the results of using these methods and show how they compare to the cost-of-service study presented in DEH-1.

b. The 12 CP method appears to skew the classification/allocation of costs into the demand category more heavily than other methods. The Peak and Average method works off the premise that average and peak demand are driving factors. Provide an explanation of why the latter method would not satisfy the criteria set out on pages 8-9.

RESPONSE

a. The Company has not prepared a minimum distribution system study using either the minimum size or minimum "zero" intercept methodologies in this proceeding or in its previous two proceedings which date back to the early 1990's. Instead, as discussed on page 11 of the Direct Testimony of Daniel E. High, the Company classifies accounts 369, 370, 371 and 373 as entirely customer-related. Distribution plant accounts 360 through 368 are classified as entirely demand related. This approach recognizes the standard engineering practice that the facilities included in accounts 360 through 368 are planned to meet the maximum expected demand on those facilities, not necessarily the number of customers being served by those facilities.

   As discussed by the NARUC Electric Utility Cost Allocation Manual, the minimum intercept method can sometimes produce statistically unreliable results and the minimum size method may not recognize the load-carrying capability of the minimum size distribution equipment.

   The preparation of such analyses require the collection of considerable information and a number of judgements and assumptions to be made and can not be completed in the time allotted for discovery. The Company's expectation and experience would indicate that any such analysis would result in slightly lower current rates of return for customer classes with large numbers of small customers such as Tariff RS and Tariff SGS.

b. KPCo does not believe that the 12 CP method skews the classification and allocation of production costs. Although not defined in the NARUC Electric Utility Cost Allocation Manual, the Company's understanding of the Peak and Average method is that it classifies a portion of production plant as energy-related and allocates the cost accordingly. This approach would generally shift cost responsibility from low to high load factor customers. A flaw in this approach is that while it assigns more base load production plant cost to high load factor customers, it does not symmetrically allocate a greater proportion of the lower cost fuel expense associated with such plants to high load factor customers and conversely higher cost fuel expense to low load factor customers. Further, the Peak and Average method fails to recongize the fundamental fact that power plants, transformers and utility equipment are rated based upon their peak capacity requirements, such as 400 MW for a power plant or 4 MVA for a transformer. The capacity ratings of such equipment must be matched to peak load requirements of customers, not average requirements. The 12 CP method is an accurate, cost-causation based methodology that is widely accepted as appropriate for the allocation of fixed costs.

WITNESS: Daniel E High

Kentucky Power Company

REQUEST

Refer to the High Testimony at Exhibit DEH-1, pages 10-19 of 19.

Provide a detailed description of:

a. Each listed allocation factor.

b. How each of the percentages is derived for each of the subcategory rows titled: Production, Bulktran, Subtran, Distpri, Distsec, Energy, Customer, and Total.

c. There appear to be allocation factors used in previous pages of the cost-of-service study that are not listed on pages 10-19 of 19. For each factor, provide a description of how it was derived and where in the cost-of-service study its derivation is found.

RESPONSE

a. Please see the Direct Testimony of Daniel E. High, pages 9 through 16, which discusses the allocation basis for each item in the Class Cost of Service Study. The specific calculations for each allocation method found on pages 10 through 19 of Exhibit DEH-1 were provided in "Staff Second Set - Item No. 36a". In that attachment, the page entitled "Methods" further describes how each factor was derived. The third column of the page shows the percentage of the method that is based upon the allocation factor shown in the fourth column of the page. Each allocator is defined on the page entitled "Allocators". The underlying support for page entitled "Allocators" was provided in the response to Staff Second Set - Item No. 36b.

In certain circumstances, factors are based upon the total of previously allocated costs. Such items are identified on the page entitled "Totals". Each individual item that is included in such totals is identified by the total name being shown in the third column of the page entitled "Accounts" and would be allocated based on the method shown in the foruth column.

b. See response to 38a.

c. All allocation factors used in pages 2 through 9 of Exhibit DEH-1 are shown on pages 10 through 19 of Exhibit DEH-1. Please see attachment "Staff Second Set - Item No. 38c", which displays an extra column in the Class Cost of Service Study, named "Allocation Factor Reference Page", that cross references the allocation factor descriptions shown on pages 2 through 9 to the allocation factor list reflected on pages 10 through 19.

WITNESS: Daniel E High

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2009

	METHOD	ALLOCATION FACTOR REFERENCE PAGE	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP-TOD	MW	OL	SL
ELECTRIC PLANT IN SERVICE												
PRODUCTION PLANT DEMAND	PROD_DEMAND	P. 15 Exhibit DEH-1	531,432,767	251,234,666	10,210,525	47,025,005	53,875,916	54,665,604	113,973,492	447,560	0	0
TRANSMISSION PLANT OTHER DEMAND TOTAL	TRANS_TOTAL	P. 19 Exhibit DEH-1	428,413,799	199,840,965	8,217,286	37,785,042	43,339,280	45,120,009	93,754,865	356,353	0	0
TRANSMISSION PLANT GSU TOTAL	PROD_DEMAND	P. 15 Exhibit DEH-1	1,582,896	748,314	30,412	140,066	160,472	162,824	339,475	1,333	0	0
TRANSMISSION PLANT			429,996,695	200,589,279	8,247,698	37,925,108	43,499,752	45,282,833	94,094,340	357,686	0	0
DISTRIBUTION PLANT												
360 LAND AND LAND RIGHTS	DIST_CPD	P. 11 Exhibit DEH-1	6,508,018	4,291,532	177,560	798,666	837,646	383,084	0	7,530	0	0
361 STRUCTURES AND IMPROVEMENTS	DIST_CPD	P. 11 Exhibit DEH-1	4,229,545	2,789,914	115,431	519,210	544,551	255,543	0	4,895	0	0
362 STATION EQUIPMENT	DIST_CPD	P. 11 Exhibit DEH-1	56,358,693	37,175,602	1,538,125	6,918,479	7,256,146	3,405,111	0	65,231	0	0
364 POLES	DIST_POLES	P. 12 Exhibit DEH-1	154,130,634	108,354,818	4,889,711	17,449,188	19,312,426	5,289,543	0	170,858	578,831	107,261
365 OVERHEAD LINES	DIST_OHLINES	P. 11 Exhibit DEH-1	138,152,587	94,380,033	4,244,398	15,938,442	17,418,131	5,542,329	0	154,673	400,170	74,411
366 UNDERGROUND CONDUIT	DIST_UGLINES	P. 12 & 13 Exhibit DEH-1	4,821,900	3,374,735	153,006	563,969	619,152	186,843	0	5,491	15,771	2,933
367 UNDERGROUND LINES	DIST_UGLINES	P. 12 & 13 Exhibit DEH-1	7,982,163	5,459,313	247,519	912,334	1,001,603	302,256	0	8,882	25,512	4,744
368 TRANSFORMERS	DIST_TRANSF	P. 12 Exhibit DEH-1	101,021,740	71,790,869	3,508,509	10,782,689	12,421,582	1,657,048	0	108,636	634,438	117,873
369 SERVICES	DIST_SERV	P. 12 Exhibit DEH-1	40,657,588	26,148,943	4,103,399	1,389,984	132,379	182	0	3,637	8,888,878	10,183
370 METERS	DIST_METERS	P. 11 Exhibit DEH-1	23,285,857	11,627,349	5,340,111	2,802,165	1,687,845	1,135,701	707,920	4,868	0	0
371 INSTALLATIONS ON CUST PREMISES	DIST_OL	P. 11 Exhibit DEH-1	18,199,577	0	0	0	0	0	0	0	18,199,577	0
372 LEASED PROP ON CUST PREMISES	DIST_OL	P. 11 Exhibit DEH-1	0	0	0	0	0	0	0	0	0	0
373 STREET LIGHTING	DIST_SL	P. 12 Exhibit DEH-1	2,974,559	0	0	0	0	0	0	0	0	2,974,559
DISTRIBUTION PLANT TOTAL			558,400,959	363,393,107	24,317,770	58,075,123	61,211,461	18,147,640	707,920	534,700	28,721,174	3,292,064
PTD PLANT	FORMULA		1,519,830,421	815,217,051	42,775,993	143,025,236	158,587,129	118,098,077	208,775,753	1,339,945	28,721,174	3,292,064
GENERAL PLANT TOTAL	LABOR_M	P. 15 Exhibit DEH-1	54,714,817	31,266,271	1,616,710	4,998,416	5,505,700	3,905,099	6,808,294	48,089	472,824	93,415
HR-J 765 LINE - AFUDC	BULK_TRANS	P. 10 Exhibit DEH-1	1,700,358	803,844	32,669	150,460	172,380	174,907	364,667	1,432	0	0
ASSET RETIREMENT OBLIGATION (ARO)	PROD_DEMAND	P. 15 Exhibit DEH-1	-3,290,698	-1,555,676	-63,225	-291,185	-333,606	-338,496	-705,738	-2,771	0	0
ELECTRIC PLANT IN SERVICE			1,572,954,698	845,731,489	44,362,148	147,882,927	163,931,602	121,837,587	215,242,975	1,386,695	29,193,797	3,385,478
ELECTRIC PLANT IN SERVICE - ADJUSTMENT			9,422,784	6,471,398	294,470	1,076,368	1,184,130	348,559	0	10,495	31,497	5,857
GROSS UTILITY PLANT	FORMULA		1,582,377,482	852,202,887	44,656,618	148,959,296	165,115,742	122,186,146	215,242,975	1,397,189	29,225,294	3,391,335
DEPRECIATION RESERVE												
PRODUCTION	RB_GUP_EPIS_P	P. 16 Exhibit DEH-1	223,176,861	105,508,693	4,287,938	19,748,281	22,625,340	22,956,972	47,863,484	187,954	0	0
TRANSMISSION	RB_GUP_EPIS_T	P. 17 Exhibit DEH-1	138,142,478	64,442,123	2,649,889	12,183,974	13,974,906	14,547,746	30,229,128	114,912	0	0
DISTRIBUTION	RB_GUP_EPIS_D	P. 16 Exhibit DEH-1	137,889,440	89,604,777	5,996,229	14,320,053	15,093,405	4,474,810	174,558	131,845	7,082,012	811,751
GENERAL	RB_GUP_EPIS_G	P. 16 Exhibit DEH-1	24,326,628	13,901,275	718,805	2,222,342	2,447,885	1,736,243	3,027,031	21,381	210,133	41,533
HR-J POST IN-SERVICE	BULK_TRANS	P. 10 Exhibit DEH-1	694,489	328,319	13,343	61,453	70,406	71,438	148,943	585	0	0
TOTAL DEPRECIATION RESERVE			524,029,696	273,783,188	13,666,004	48,536,103	54,211,843	43,787,210	81,443,144	456,676	7,292,145	853,284
ACCUMULATED DEPRECIATION - ADJUSTMENT	FORMULA		12,484,677	6,578,905	328,029	1,162,181	1,297,428	1,030,852	1,890,653	10,936	164,963	19,733
NET UTILITY PLANT	FORMULA		1,045,863,109	571,839,795	30,662,585	99,261,012	109,606,373	77,368,084	131,909,178	929,577	21,768,186	2,518,318

KENTUCKY POWER COMPANY
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	METHOD	ALLOCATION FACTOR REFERENCE PAGE	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP-TOD	MW	OL	SL
PLANT HELD FOR FUTURE USE TRANS	RB_GUP_EPIS_T	P. 17 Exhibit DEH-1	30,164	14,071	579	2,660	3,051	3,177	6,601	25	0	0
WORKING CAPITAL												
WORKING CAPITAL CASH												
WORKING CAPITAL CASH EXCL SYS SALES	EXP_OM	P. 14 Exhibit DEH-1	48,802,040	21,351,135	1,098,600	4,262,889	5,097,072	5,108,535	11,445,008	49,211	330,559	58,032
SYSTEM SALES ADD BACK DEMAND	PROD_DEMAND	P. 15 Exhibit DEH-1	1,088,084	514,391	20,906	96,282	110,308	111,825	233,355	916	0	0
SYSTEM SALES ADD BACK ENERGY	PROD_ENERGY	P. 15 Exhibit DEH-1	17,940,858	6,339,452	353,874	1,494,850	1,900,546	2,225,660	5,471,924	20,162	112,393	21,985
TOTAL WORKING CAPITAL CASH			67,830,982	28,204,978	1,474,379	5,854,020	7,107,927	7,446,120	17,150,288	70,290	442,952	80,027
WORKING CAPITAL CASH - ADJUSTMENT			8,197,233	4,161,510	239,529	705,339	936,116	516,651	1,477,802	7,192	148,372	4,622
WORKING CAPITAL MATERIALS & SUPPLIES												
FUEL	PROD_ENERGY	P. 15 Exhibit DEH-1	42,771,452	15,113,412	843,645	3,563,760	4,530,849	5,306,029	13,045,204	48,067	267,947	52,438
PRODUCTION	PROD_DEMAND	P. 15 Exhibit DEH-1	7,560,912	3,574,419	145,269	669,044	766,515	777,750	1,621,548	6,368	0	0
EMISSIONS	PROD_ENERGY	P. 15 Exhibit DEH-1	8,159,539	2,883,198	160,943	679,861	864,372	1,012,235	2,488,642	9,170	51,117	10,004
TRANSMISSION AND DISTRIBUTION	TDPLANT	P. 18 Exhibit DEH-1	2,302,422	1,313,381	75,805	223,593	243,901	147,911	221,306	2,079	66,700	7,656
TOTAL MATERIALS & SUPPLIES			60,794,325	22,884,408	1,225,662	5,136,259	6,405,737	7,243,925	17,376,700	65,683	385,864	70,097
WORKING CAPITAL MATERIALS & SUPPLIES - ADJUSTMENT			(21,230,418)	(7,501,828)	(418,759)	(1,768,940)	(2,249,022)	(2,633,748)	(6,475,233)	(23,859)	(133,001)	(26,028)
WORKING CAPITAL PREPAYMENTS	RB_GUP_EPIS	P. 17 Exhibit DEH-1	1,988,585	1,058,450	55,520	185,079	205,184	152,482	269,381	1,735	36,537	4,237
WORKING CAPITAL PREPAYMENTS - ADJUSTMENT			15,390,035	8,794,524	454,746	1,405,946	1,548,634	1,098,420	1,015,025	13,526	132,939	26,275
TOTAL WORKING CAPITAL	FORMULA		132,950,742	57,602,043	3,031,077	11,517,703	13,954,556	13,823,850	31,714,063	134,567	1,013,652	159,231
CONSTRUCTION WORK IN PROGRESS												
PRODUCTION	RB_GUP_EPIS_P	P. 16 Exhibit DEH-1	5,665,163	2,678,204	108,846	501,294	574,326	582,745	1,214,977	4,771	0	0
TRANSMISSION	RB_GUP_EPIS_T	P. 17 Exhibit DEH-1	14,048,792	6,553,625	269,468	1,239,084	1,421,218	1,479,474	3,074,237	11,686	0	0
DISTRIBUTION	RB_GUP_EPIS_D	P. 16 Exhibit DEH-1	6,370,789	4,145,947	277,441	662,578	698,361	207,046	8,077	6,100	327,679	37,559
GENERAL	RB_GUP_EPIS_G	P. 16 Exhibit DEH-1	600,836	343,343	17,754	54,889	60,460	42,883	74,764	528	5,180	1,026
TOTAL CWIP			26,685,580	13,721,119	673,508	2,457,846	2,754,364	2,312,148	4,372,054	23,086	332,869	38,585
RATE BASE OFFSETS												
ACCUMULATED DEFERRED FIT	RB_GUP	P. 17 Exhibit DEH-1	(170,075,156)	(91,444,410)	(4,796,841)	(15,989,788)	(17,725,045)	(13,173,845)	(23,273,069)	(149,936)	(3,156,569)	(366,054)
CUSTOMER ADVANCES	TDPLANT	P. 18 Exhibit DEH-1	(59,442)	(33,908)	(1,957)	(5,773)	(6,297)	(3,819)	(5,713)	(54)	(1,724)	(198)
CUSTOMER DEPOSITS	CUST_DEP	P. 10 Exhibit DEH-1	(17,319,382)	(13,487,338)	(714,404)	(1,664,889)	(730,704)	(467,888)	(152,780)	0	(101,398)	0
RATE BASE OFFSETS - ADJUSTMENT	LABOR_M	P. 15 Exhibit DEH-1	(5,386,512)	(3,078,083)	(159,161)	(492,081)	(542,022)	(384,447)	(670,259)	(4,734)	(46,529)	(9,196)
TOTAL RATE BASE OFFSETS			(192,840,492)	(108,043,740)	(5,672,163)	(18,152,530)	(19,004,068)	(14,029,779)	(24,101,821)	(154,724)	(3,306,220)	(375,448)
TOTAL RATE BASE	FORMULA		1,012,689,103	535,133,289	28,695,588	95,086,690	107,314,277	79,477,481	143,900,076	932,532	19,808,487	2,340,686

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	METHOD	ALLOCATION FACTOR REFERENCE PAGE	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP-TOD	MW	OL	SL
OPERATING REVENUES												
TOTAL REVENUE	REVSALES	P. 18 Exhibit DEH-1	507,240,229	197,715,587	14,507,207	51,889,457	57,778,205	55,902,899	121,184,366	582,698	6,546,076	1,133,734
TOTAL REVENUE YEAR END CUSTOMERS	REVYEC	P. 18 Exhibit DEH-1	2,525,034	(751,070)	44,711	(248,879)	1,217,237	(926,792)	3,151,840	0	42,273	(4,286)
SALES OF ELECTRICITY			509,765,263	196,964,517	14,551,918	51,640,578	58,995,442	54,976,107	124,336,206	582,698	6,588,349	1,129,448
OTHER OPERATING REVENUES												
FORFEITED DISCOUNTS	FORT	P. 14 Exhibit DEH-1	1,809,068	1,103,155	140,519	304,613	149,217	21,134	73,152	0	17,278	0
MISCELLANEOUS SERVICE REVENUE	RB_GUP_EPIS_D	P. 16 Exhibit DEH-1	395,706	257,515	17,233	41,154	43,377	12,860	502	379	20,353	2,333
RENT FROM ELECTRIC PROP POLES	DIST_POLES	P. 12 Exhibit DEH-1	4,776,990	3,298,288	151,547	540,805	598,552	163,320	0	5,295	17,878	3,324
RENT FROM ELECTRIC PROP OTHER DIST	RB_GUP_EPIS_D	P. 16 Exhibit DEH-1	330,170	214,886	14,379	34,339	36,193	10,730	419	316	16,982	1,947
OTHER ELECTRIC REVENUE DIST	RB_GUP_EPIS_D	P. 16 Exhibit DEH-1	3,006,371	1,956,470	130,924	312,670	328,556	97,705	3,811	2,879	154,632	17,724
OTHER ELECTRIC REVENUE WHEELING	TRANS_TOTAL	P. 19 Exhibit DEH-1	60,928	32,819	1,341	6,167	7,074	7,365	15,303	58	0	0
OTHER ELECTRIC REVENUE PRODUCTION	PROD_ENERGY	P. 15 Exhibit DEH-1	862,171	304,651	17,006	71,837	91,333	106,957	262,860	969	5,401	1,057
TOTAL OTHER OPERATING REVENUES			11,250,404	7,165,544	472,949	1,311,585	1,255,303	420,071	356,147	9,896	232,524	26,385
OTHER OPERATING REVENUE - ADJUSTMENT			781,638	508,670	34,040	81,292	85,683	25,403	991	748	40,203	4,608
TOTAL OPERATING REVENUE			521,797,305	204,638,731	15,058,908	53,033,456	60,336,427	55,421,580	124,693,344	593,343	6,861,076	1,160,441

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
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	METHOD	ALLOCATION FACTOR REFERENCE PAGE	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP-TOD	MW	OL	SL
OPERATION AND MAINTENANCE EXPENSE												
O&M EXPENSE PRODUCTION												
GENERATION EXPENSE DEMAND	PROD_DEMAND	P. 15 Exhibit DEH-1	20,811,678	9,838,714	399,859	1,841,567	2,109,859	2,140,784	4,463,367	17,527	0	0
GENERATION EXPENSE ENERGY	PROD_ENERGY	P. 15 Exhibit DEH-1	9,981,548	3,527,008	196,881	831,673	1,057,365	1,238,265	3,044,351	11,217	62,531	12,237
GENERATION EXPENSE FUEL	PROD_ENERGY	P. 15 Exhibit DEH-1	191,973,390	67,634,335	3,788,577	15,995,415	20,338,500	23,815,334	58,551,486	215,742	1,202,643	235,350
SYSTEM SALES	PROD_DEMAND	P. 15 Exhibit DEH-1	(8,704,672)	(4,115,131)	(167,245)	(770,252)	(882,468)	(895,402)	(1,866,844)	(7,331)	0	0
SYSTEM SALES	PROD_ENERGY	P. 15 Exhibit DEH-1	(143,526,865)	(50,715,620)	(2,830,994)	(11,958,802)	(15,204,368)	(17,805,281)	(43,775,396)	(161,297)	(899,143)	(175,963)
PURCHASED POWER DEMAND	PROD_DEMAND	P. 15 Exhibit DEH-1	98,530,187	46,580,113	1,893,080	8,718,662	9,988,854	10,135,266	21,131,233	82,080	0	0
PURCHASED POWER ENERGY	PROD_ENERGY	P. 15 Exhibit DEH-1	152,824,335	54,000,907	3,014,382	12,733,477	16,189,286	18,958,882	46,611,105	171,746	957,388	187,362
SYSTEM CONTROL	PROD_DEMAND	P. 15 Exhibit DEH-1	394,700	186,594	7,583	34,926	40,014	40,601	84,649	332	0	0
TOTAL PRODUCTION EXPENSES			474,515,838	181,067,672	9,298,363	40,155,720	49,721,897	56,328,931	133,886,192	499,544	2,222,562	434,958
O&M EXPENSE TOTAL TRANSMISSION	RB_GUP_EPIS_T	P. 17 Exhibit DEH-1	309,714	144,479	5,941	27,316	31,332	32,816	67,773	258	0	0
O&M EXPENSE REGIONAL MARKET	TRANS_TOTAL	P 19 Exhibit DEH-1	1,174,225	547,737	22,522	103,664	118,787	123,668	256,970	977	0	0
DISTRIBUTION OPERATION EXPENSE												
580 SUPERVISION & ENGINEERING	TOTOXEXP	P. 19 Exhibit DEH-1	913,465	578,576	58,322	97,229	96,536	32,760	4,081	803	34,416	10,740
581 LOAD DISPATCHING	DIST_CPD	P. 11 Exhibit DEH-1	2,432	1,804	66	299	313	147	0	3	0	0
582 STATION EXPENSES	DIST_CPD	P. 11 Exhibit DEH-1	233,407	153,961	6,370	28,653	30,051	14,102	0	270	0	0
583 OVERHEAD LINES	DIST_OHLINES	P. 11 Exhibit DEH-1	1,137,658	777,200	34,952	131,250	143,435	45,640	0	1,274	3,295	613
584 UNDERGROUND LINES	DIST_UGLINES	P. 12 & 13 Exhibit DEH-1	83,980	57,581	2,611	9,823	10,564	3,188	0	94	269	50
585 STREET LIGHTING	DIST_SL	P. 12 Exhibit DEH-2	53,816	0	0	0	0	0	0	0	0	53,816
586 METERS	DIST_METERS	P 11 Exhibit DEH-1	820,535	409,717	188,171	98,741	58,770	40,019	24,945	171	0	0
587 CUSTOMER INSTALLS	DIST_PCUST	P. 12 Exhibit DEH-1	135,655	87,162	13,678	4,680	498	28	0	12	29,562	34
588 MISCELLANEOUS DISTRIBUTION	RB_GUP_EPIS_D	P. 16 Exhibit DEH-1	2,775,090	1,605,958	120,852	286,616	304,203	90,188	3,518	2,657	142,736	16,361
589 RENTS	RB_GUP_EPIS_D	P 16 Exhibit DEH-1	1,575,316	1,025,175	66,603	163,837	172,685	51,197	1,997	1,508	81,026	9,287
TOTAL DISTRIBUTION OPER EXP	FORMULA		7,731,354	4,696,935	493,626	822,928	817,055	277,269	34,542	6,792	291,307	90,901
DISTRIBUTION MAINTENANCE EXPENSE												
590 SUPERVISION & ENGINEERING	TOTMXEXP	P. 19 Exhibit DEH-1	8,891	5,985	275	997	1,096	325	0	10	181	21
591 STRUCTURES	DIST_CPD	P. 11 Exhibit DEH-1	5,205	3,433	142	639	670	314	0	6	0	0
592 STATION EQUIPMENT	DIST_CPD	P. 11 Exhibit DEH-1	512,025	337,744	13,974	62,855	65,923	30,936	0	593	0	0
593 OVERHEAD LINES	TOTOHLINES	P. 19 Exhibit DEH-1	29,521,237	20,274,654	922,565	3,372,223	3,709,868	1,092,022	0	32,879	98,679	18,349
594 UNDERGROUND LINES	TOTUGLINES	P. 19 Exhibit DEH-1	186,163	127,644	5,787	21,331	23,418	7,067	0	208	596	111
595 LINE TRANSFORMER	DIST_TRANSF	P. 12 Exhibit DEH-1	175,156	124,474	6,083	18,696	21,537	2,873	0	188	1,100	205
596 STREET LIGHTING	DIST_SL	P. 12 Exhibit DEH-1	54,605	0	0	0	0	0	0	0	0	54,605
597 METERS	DIST_METERS	P. 11 Exhibit DEH-1	53,708	26,818	12,317	6,463	3,847	2,619	1,633	11	0	0
598 MISC DISTRIBUTION PLANT	DIST_OL	P. 11 Exhibit DEH-1	532,162	0	0	0	0	0	0	0	532,162	0
TOTAL DISTRIBUTION MAINT EXP	FORMULA		31,049,152	20,900,753	961,143	3,483,204	3,826,357	1,136,158	1,633	33,895	632,719	73,291
DISTRIBUTION EXPENSES			38,780,506	25,797,688	1,454,769	4,306,132	4,643,412	1,413,427	36,175	40,687	924,025	164,191
CUSTOMER ACCOUNTS												
901 SUPERVISION	TOTOX234	P. 18 Exhibit DEH-1	413,373	409,076	20,793	9,792	1,550	199	41	18	(26,111)	13
902 METER READ	CUST_902	P. 10 Exhibit DEH-1	754,340	601,634	94,411	48,659	8,234	1,092	226	84	0	0
903 CUSTOMER RECORDS	CUST_903	P. 10 Exhibit DEH-1	6,009,640	4,620,683	459,606	157,602	17,517	1,771	366	407	750,547	1,141
904 UNCOLLECTIBLES	CUST_TOTAL	P. 11 Exhibit DEH-1	(4,235,288)	(2,719,913)	(426,820)	(146,359)	(16,266)	(1,646)	(340)	(378)	(922,507)	(1,059)
905 MISCELLANEOUS	TOTOX234	P. 19 Exhibit DEH-1	7,516	7,438	378	178	28	4	i	0	(511)	0
TOTAL CUSTOMER ACCOUNTS			2,949,581	2,918,918	148,368	69,873	11,063	1,420	293	131	(200,581)	95
TOTAL CUSTOMER SERVICES	CUST_TOTAL	P. 11 Exhibit DEH-1	1,802,110	1,157,320	181,611	62,275	6,921	700	145	181	392,526	451

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	METHOD	ALLOCATION FACTOR REFERENCE PAGE	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP-TOD	MW	OL	SL
ADMINISTRATIVE & GENERAL EXPENSE												
A&G PRODUCTION DEMAND	PROD_DEMAND	P. 15 Exhibit DEH-1	8,343,100	3,944,198	160,298	738,258	845,812	858,209	1,789,289	7,026	0	0
A&G PRODUCTION ENERGY	PROD_ENERGY	P. 15 Exhibit DEH-1	2,865,019	1,012,362	56,511	238,716	303,503	355,421	873,825	3,220	17,948	3,513
A&G TRANSMISSION	EXP_OM_TRAN	P. 14 Exhibit DEH-1	1,283,502	603,382	24,810	114,084	130,854	136,228	283,066	1,076	0	0
A&G DISTRIBUTION	EXP_OM_DIST	P. 13 Exhibit DEH-1	8,706,885	5,792,021	326,620	966,800	1,042,525	317,338	8,122	9,135	207,459	36,864
A&G CUSTOMER ACCOUNTS	EXP_OM_CUSTACCT	P. 13 Exhibit DEH-1	1,523,898	1,508,056	76,654	36,100	5,716	734	152	68	-103,630	49
A&G CUSTOMER SERVICE	EXP_OM_CUSTSERV	P. 13 Exhibit DEH-1	382,387	245,570	38,536	13,214	1,469	149	31	34	83,289	96
TOTAL A&G EXPENSE EXCLUDING REGULATORY			23,114,791	13,105,590	683,430	2,107,172	2,329,878	1,668,079	2,954,496	20,559	205,067	40,521
A&G REGULATORY RECLASSIFIED	FORMULA		1,088	424	31	111	124	120	260	1	14	2
TOTAL A & G EXPENSES			23,115,879	13,106,014	683,461	2,107,283	2,330,002	1,668,199	2,954,756	20,560	205,081	40,524
TOTAL O&M EXPENSES			390,416,316	170,809,076	8,796,796	34,103,109	40,776,578	40,868,277	91,560,064	393,690	2,644,470	464,256
OPERATION & MAINTENANCE EXPENSE - ADJUSTMENT			65,577,861	33,292,076	1,916,231	5,642,709	7,488,927	4,133,207	11,823,219	57,535	1,186,977	36,979
ADJUSTED OPERATING AND MAINTENANCE EXP	FORMULA		455,994,177	204,101,152	10,713,027	39,745,818	48,265,505	45,001,485	103,383,284	451,225	3,831,447	501,234
DEPRECIATION EXPENSE												
PRODUCTION	RB_GUP_EPIS_P	P. 16 Exhibit DEH-1	19,561,410	9,247,650	375,837	1,730,935	1,983,109	2,012,176	4,195,229	16,474	0	0
TRANSMISSION	RB_GUP_EPIS_T	P 17 Exhibit DEH-1	7,597,948	3,544,369	145,735	670,128	768,631	800,138	1,662,627	6,320	0	0
DISTRIBUTION	RB_GUP_EPIS_D	P 16 Exhibit DEH-1	18,979,469	12,351,355	828,536	1,973,913	2,080,514	616,819	24,061	18,174	976,203	111,894
GENERAL PLANT	RB_GUP_EPIS_G	P. 16 Exhibit DEH-1	4,447,255	2,541,352	131,408	408,276	447,508	317,410	553,384	3,909	38,415	7,593
TOTAL DEPRECIATION EXPENSE			50,586,082	27,684,725	1,479,516	4,781,252	5,279,762	3,746,543	6,435,302	44,877	1,014,618	119,487
DEPRECIATION EXPENSE - ADJUSTMENT			12,957,354	6,803,362	337,111	1,204,007	1,345,345	1,079,473	1,992,025	11,334	164,963	19,733
ADJUSTED DEPRECIATION EXPENSE	FORMULA		63,543,436	34,488,088	1,816,626	5,985,259	6,625,108	4,826,017	8,427,327	56,211	1,179,582	139,220
TAXES OTHER THAN INCOME												
FEDERAL INSURANCE TAX	LABOR_M	P. 15 Exhibit DEH-1	2,856,586	1,632,375	84,407	260,981	287,446	203,881	355,453	2,511	24,675	4,877
FEDERAL UNEMPLOYMENT EXCISE TAX	LABOR_M	P. 15 Exhibit DEH-1	27,478	15,702	812	2,510	2,765	1,961	3,419	24	237	47
FEDERAL EXCISE TAX	LABOR_M	P. 15 Exhibit DEH-1	9,727	5,558	287	889	979	694	1,210	9	84	17
KENTUCKY SALES & USE TAX	TDPLANT	P. 18 Exhibit DEH-1	(566,333)	(323,056)	(18,646)	(54,998)	(59,993)	(36,382)	(54,435)	(511)	(16,428)	(1,883)
KENTUCKY R/E PRS & PROPERTY TAX	RB_GUP	P. 17 Exhibit DEH-1	9,181,190	4,936,456	258,938	863,179	956,853	711,155	1,256,353	8,094	170,401	19,761
LOUISIANA REAL & PERSONAL PROPERTY TAX	RB_GUP	P. 17 Exhibit DEH-1	199	107	6	19	21	15	27	0	4	0
KENTUCKY UNEMPLOYMENT TAX	LABOR_M	P. 15 Exhibit DEH-1	38,434	21,963	1,136	3,511	3,867	2,743	4,782	34	332	66
KENTUCKY PSC MAINTENANCE TAX	REVSALES	P. 18 Exhibit DEH-1	690,213	269,036	19,740	70,607	78,620	76,066	164,898	793	8,907	1,543
KENTUCKY MUNICIPAL LICENSE TAX	RB_GUP	P 17 Exhibit DEH-1	99	53	3	9	10	8	14	0	2	0
KENTUCKY LICENSE TAX	RB_GUP	P. 17 Exhibit DEH-1	114	61	3	11	12	9	16	0	2	0
OHIO GROSS RECEIPTS TAX	REVSALES	P. 18 Exhibit DEH-1	222,171	86,599	6,354	22,728	25,307	24,485	53,079	255	2,867	497
OHIO FRANCHISE TAX	PROD_DEMAND	P. 15 Exhibit DEH-1	18,414	8,705	354	1,629	1,867	1,894	3,949	16	0	0
WEST VIRGINIA REAL & PERSONAL PROPERTY TAX	RB_GUP	P. 17 Exhibit DEH-1	954	513	27	90	99	74	131	1	18	2
WEST VIRGINIA UNEMPLOYMENT TAX	LABOR_M	P. 15 Exhibit DEH-1	1,620	926	48	148	163	116	202	1	14	3
WEST VIRGINIA FRANCHISE TAX	LABOR_M	P. 15 Exhibit DEH-1	(39,839)	(22,766)	(1,177)	(3,639)	(4,009)	(2,843)	(4,957)	(35)	(344)	(68)
WEST VIRGINIA LICENSE TAX	LABOR_M	P. 15 Exhibit DEH-1	55	31	2	5	6	4	7	0	0	0
PENNSYLVANIA LICENSE TAX	PROD_DEMAND	P. 15 Exhibit DEH-1	39	18	1	3	4	4	8	0	0	0
FRINGE BENEFIT LOADING FICA	LABOR_M	P. 15 Exhibit DEH-1	(1,111,545)	(635,184)	(32,844)	(101,544)	(111,850)	(79,333)	(138,313)	(977)	(9,601)	(1,898)
FRINGE BENEFIT LOADING FUT	LABOR_M	P. 15 Exhibit DEH-1	(11,724)	(6,700)	(346)	(1,071)	(1,180)	(837)	(1,459)	(10)	(101)	(20)
FRINGE BENEFIT LOADING SUT	LABOR_M	P. 15 Exhibit DEH-1	(12,498)	-7,142	(369)	(1,142)	(1,258)	(892)	(1,555)	(11)	(108)	(21)
R/E PRS FRANCHISE - CARRS TAX	RB_GUP	P. 17 Exhibit DEH-1	(51,723)	(27,810)	(1,459)	(4,863)	(5,391)	(4,006)	(7,078)	(46)	(960)	(111)
TOTAL TAXES OTHER THAN INCOME			11,253,631	5,955,448	317,275	1,059,042	1,174,340	898,817	1,635,751	10,147	180,001	22,811
TAXES OTHER THAN INCOME TAXES - ADJUSTMENT			220,301	111,485	6,310	21,060	23,340	18,682	35,547	210	3,211	455
ADJUSTED TAXES OTHER THAN INCOME TAX	FORMULA		11,473,932	6,066,933	323,585	1,080,102	1,197,660	917,500	1,671,298	10,357	183,212	23,265
TOTAL OPERATING REVENUE			521,797,305	204,638,731	15,058,906	53,033,456	60,336,427	55,421,580	124,693,344	593,343	6,861,076	1,160,441
TOTAL OPERATING EXPENSE BEFORE TAXES			531,011,545	244,656,173	12,853,238	46,811,179	56,088,293	50,745,001	113,481,908	517,793	5,194,241	663,719
GROSS OPERATING INCOME	FORMULA		(9,214,240)	(40,017,442)	2,205,668	6,222,277	4,248,134	4,676,580	11,211,436	75,550	1,666,836	496,722
INTEREST CHARGE TAX	RATEBASE	P. 16 Exhibit DEH-1	(37,443,850)	(19,786,379)	(1,061,010)	(3,515,789)	(3,957,910)	(2,938,654)	(5,320,658)	(34,480)	(732,412)	(86,546)
INTEREST SYNCHRONIZATION TAX	RATEBASE	P. 16 Exhibit DEH-1	2,732,876	1,444,128	77,439	256,604	289,602	214,481	388,333	2,517	53,456	6,317
NET OPER INCOME BEFORE INCOME TAX	FORMULA		(43,925,214)	(58,359,693)	1,222,097	2,963,082	569,826	1,952,408	6,279,111	43,588	987,879	416,492

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KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2009

INCOME TAXES	METHOD	ALLOCATION FACTOR REFERENCE PAGE	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP-TOD	MW	OL	SL
SCHEDULE M INCOME ADJUSTMENTS												
BOOK VS TAX DEPRECIATION NORMALIZED	RB_GUP	P. 17 Exhibit DEH-1	(33,837,720)	(18,193,547)	(854,328)	(3,181,287)	(3,526,530)	(2,620,995)	(4,630,350)	(29,831)	(628,023)	(72,829)
BOOK VS TAX DEPRECIATION FLOWTHRU	RB_GUP	P. 17 Exhibit DEH-1	8,247,102	4,434,224	232,594	775,360	859,504	638,802	1,128,533	7,271	153,065	17,750
AOFUDC - HR/J	BULK_TRANS	P. 10 Exhibit DEH-1	11,364	5,372	218	1,005	1,152	1,169	2,437	10	0	0
ABFUDC	RB_CWIP	P. 16 Exhibit DEH-1	(807,411)	(415,152)	(20,378)	(74,366)	(83,337)	(89,957)	(132,283)	(698)	(10,071)	(1,167)
ABFUDC - HR/J	BULK_TRANS	P. 10 Exhibit DEH-1	22,044	10,421	424	1,951	2,235	2,268	4,728	19	0	0
SEC 481 PENSIONS/OPEB ADJUSTMENT	LABOR_M	P. 15 Exhibit DEH-1	(117)	(67)	(3)	(11)	(12)	(8)	(15)	(0)	(1)	(0)
INTEREST CAPITALIZATION	RB_GUP	P. 17 Exhibit DEH-1	1,565,806	841,866	44,161	147,211	163,187	121,284	214,265	1,380	29,061	3,370
DEFERRED FUEL	FUELREV	P. 15 Exhibit DEH-1	21,616,789	7,446,174	415,351	1,758,876	2,252,349	2,745,072	6,817,960	23,650	131,599	25,756
PROVISION FOR POSSIBLE REVENUE REFUNDS	REV	P. 18 Exhibit DEH-1	(704,806)	(276,177)	(20,326)	(71,641)	(81,516)	(74,948)	(168,702)	(602)	(9,228)	(1,564)
PERCENT REPAIR ALLOWANCE	RB_GUP	P. 17 Exhibit DEH-1	(1,783,802)	(959,098)	(50,309)	(167,706)	(185,908)	(138,169)	(244,095)	(1,573)	(33,107)	(3,839)
BOOK/TAX UNIT OF PROPERTY	RB_GUP	P. 17 Exhibit DEH-1	(3,603,276)	(1,937,376)	(101,623)	(338,766)	(375,529)	(279,102)	(493,072)	(3,177)	(66,876)	(7,755)
BOOK/TAX UNIT OF PROPERTY - SEC 481	RB_GUP	P. 17 Exhibit DEH-1	(27,693,495)	(14,889,978)	(781,042)	(2,603,632)	(2,886,185)	(2,145,077)	(3,789,575)	(24,414)	(513,987)	(59,605)
TAX AMORTIZATION OF POLLUTION CONTROL	PROD_DEMAND	P. 15 Exhibit DEH-1	2,724,318	1,287,920	52,343	241,087	276,188	280,236	584,270	2,294	0	0
CAPITALIZED RELOCATION COSTS	RB_GUP	P 17 Exhibit DEH-1	(175,409)	(94,312)	(4,947)	(16,491)	(18,281)	(13,587)	(24,003)	(155)	(3,256)	(378)
MTM BOOK GAIN ABOVE THE LINE TAX DEFERRAL	PROD_ENERGY	P. 15 Exhibit DEH-1	(15,542,308)	(5,491,917)	(306,564)	(1,295,001)	(1,646,458)	(1,928,107)	(4,740,371)	(17,467)	(97,367)	(19,055)
MARK & SPREAD DEFL -283 A/L	PROD_ENERGY	P. 15 Exhibit DEH-1	10,225,186	3,613,098	201,687	851,973	1,083,184	1,268,489	3,118,661	11,491	64,057	12,536
MARK & SPREAD DEFL -190 A/L	PROD_ENERGY	P. 15 Exhibit DEH-1	(9,599,748)	(3,392,098)	(189,350)	(799,861)	(1,016,939)	(1,190,800)	(2,927,903)	(10,788)	(60,139)	(11,769)
PROVISION FOR WORKERS COMP	LABOR_M	P. 15 Exhibit DEH-1	(62,124)	(35,500)	(1,836)	(5,675)	(6,251)	(4,434)	(7,730)	(55)	(537)	(106)
ACCRUED BOOK PENSION EXPENSE	LABOR_M	P. 15 Exhibit DEH-1	3,441,009	1,966,340	101,675	314,351	346,254	245,592	428,174	3,024	29,723	5,875
ACCURED BOOK PENSION COSTS - SFAS 158	LABOR_M	P. 15 Exhibit DEH-1	(1,093,177)	(624,688)	(32,301)	(99,868)	(110,002)	(78,022)	(136,027)	(961)	(9,443)	(1,866)
SUPPLEMENTAL EXECUTIVE RETIREMENT	LABOR_M	P. 15 Exhibit DEH-1	3,391	1,938	100	310	341	242	422	3	29	6
ACCRUED SUPPLEMENTAL EXEC RETIREMENT COSTS SFAS 158	LABOR_M	P. 15 Exhibit DEH-1	(1,798)	(1,027)	(53)	(164)	(181)	(128)	(224)	(2)	(16)	(3)
ACCRUED BOOK SUPPLEMENTAL SAVINGS PLAN EXP	LABOR_M	P. 15 Exhibit DEH-1	98,892	56,511	2,922	9,034	9,951	7,058	12,305	87	854	169
ACCRUED PSI PLAN EXPENSES	LABOR_M	P. 15 Exhibit DEH-1	(386,625)	(220,934)	(11,424)	(35,320)	(38,904)	(27,594)	(48,109)	(340)	(3,340)	(660)
BOOK PROVISION UNCOLLECTIBLE ACCOUNTS	CUST_TOTAL	P. 11 Exhibit DEH-1	(4,520,982)	(2,903,386)	(455,611)	(156,232)	(17,364)	(1,757)	(363)	(404)	(984,735)	(1,131)
PROVISION FOR TRADING CREDIT RISK ABOVE THE LINE	PROD_ENERGY	P. 15 Exhibit DEH-1	104,118	36,790	2,054	8,675	11,030	12,916	31,756	117	652	128
PROVISION FOR FAS 157 A/L	PROD_ENERGY	P. 15 Exhibit DEH-1	38,284	13,528	755	3,190	4,056	4,749	11,677	43	240	47
VACATION PAY SEC 481	LABOR_M	P. 15 Exhibit DEH-1	131,477	75,132	3,885	12,011	13,230	9,384	16,360	116	1,136	224
ACCRUED STATE INTEREST EXPENSE	REV	P. 18 Exhibit DEH-1	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
ACCRUED LONG TERM INTEREST EXPENSE - FIN 48	REV	P. 18 Exhibit DEH-1	260,839	102,195	7,522	26,510	30,164	27,733	62,425	297	3,415	579
REG ASSET ON DEFERRED RTO COSTS	TRANS_TOTAL	P. 19 Exhibit DEH-1	147,454	88,782	2,828	13,005	14,917	15,530	32,269	123	0	0
FEDERAL MITIGATION PROGRAMS	PROD_ENERGY	P. 15 Exhibit DEH-1	(426,072)	(150,554)	(8,404)	(35,501)	(45,135)	(52,857)	(129,951)	(479)	(2,669)	(522)
STATE MITIGATION PROGRAMS	PROD_ENERGY	P. 15 Exhibit DEH-1	(630,761)	(222,881)	(12,441)	(52,556)	(66,819)	(78,249)	(192,381)	(709)	(3,951)	(773)
DEFERRED BOOK CONTRACT REVENUE	REV	P. 18 Exhibit DEH-1	(13,380)	(5,242)	(386)	(1,360)	(1,547)	(1,423)	(3,202)	(15)	(175)	(30)
DEFERRED DEMAND SIDE MANAGEMENT EXPENSE	LABOR_M	P. 15 Exhibit DEH-1	24,873	14,213	735	2,272	2,503	1,775	3,095	22	215	42
BOOK > TAX BASIS - EMA A/C 283	PROD_ENERGY	P. 15 Exhibit DEH-1	214,244	75,704	4,226	17,851	22,698	26,578	65,344	241	.1,342	263
DEFERRED TAX GAIN EPA AUCTION	PROD_ENERGY	P. 15 Exhibit DEH-1	(38,059)	(13,446)	(751)	(3,171)	(4,032)	(4,721)	(11,608)	(43)	(238)	(47)
ADVANCE RENTAL INCOME	REV_OTHER	P. 17 Exhibit DEH-1	(6,933)	(5,690)	(376)	(1,041)	(997)	(334)	(283)	(8)	(185)	(21)
REG LIABILITY UNREALIZED MTM GAIN DEFERRAL	PROD_ENERGY	P. 15 Exhibit DEH-1	3,168,780	1,119,697	62,503	264,026	335,681	393,104	966,471	3,561	19,851	3,885
REG ASSET SFAS 158 PENSIONS	LABOR_M	P. 15 Exhibit DEH-1	1,093,177	624,688	32,301	99,866	110,002	78,022	136,027	961	9,443	1,866
REG ASSET SFAS 158 SERP	LABOR_M	P. 15 Exhibit DEH-1	1,798	1,027	53	164	181	128	224	2	16	3
REG ASSET SFAS 158 OPEB	LABOR_M	P. 15 Exhibit DEH-1	1,179,816	674,197	34,861	107,781	118,720	84,206	146,808	1,037	10,191	2,014
CAPITALIZED SOFTWARE COSTS TAX	RB_GUP	P. 17 Exhibit DEH-1	(764)	(411)	(22)	(72)	(80)	(59)	(105)	(1)	(14)	(2)
BOOK LEASES CAPITALIZED FOR TAX	RB_GUP	P. 17 Exhibit DEH-1	(71,801)	(38,605)	(2,025)	(6,750)	(7,483)	(5,562)	(9,825)	(63)	(1,333)	(155)
CAPITALIZED SOFTWARE COSTS BOOK	RB_GUP	P. 17 Exhibit DEH-1	1,331,392	715,850	37,549	125,172	138,756	103,127	182,188	1,174	24,710	2,866
BOOK AMORTIZATION LOSS REAQUIRED DEBT	RB_GUP	P. 17 Exhibit DEH-1	33,346	17,929	940	3,135	3,475	2,583	4,563	29	619	72
ACCRUED SFAS 106 POST RETIREMENT EXPENSE	LABOR_M	P. 15 Exhibit DEH-1	618,802	353,610	18,284	56,530	62,267	44,165	76,999	544	5,345	1,056
SFAS 106 POST RETIREMENT MEDICARE BENEFITS	LABOR_M	P. 15 Exhibit DEH-1	(851,119)	(486,366)	(25,149)	(77,753)	(85,644)	(60,746)	(105,907)	(746)	(7,352)	(1,453)
ACCRUED OPEB COSTS SFAS 158	LABOR_M	P. 15 Exhibit DEH-1	(1,179,816)	(674,197)	(34,861)	(107,781)	(118,720)	(84,206)	(146,808)	(1,037)	(10,191)	(2,014)
ACCRUED SFAS 112 POST EMPLOYMENT BENEFITS	LABOR_M	P. 15 Exhibit DEH-1	(359,347)	(205,346)	(10,618)	(32,828)	(36,160)	(25,647)	(44,715)	(316)	(3,104)	(614)
ACCRUED BOOK ARO EXPENSE SFAS 143	RB_GUP	P. 17 Exhibit DEH-1	2,852,343	1,533,621	80,445	268,166	297,268	220,936	390,314	2,515	52,939	6,139
ACCRUED SALES & USE TAX RESERVE	REV	P. 18 Exhibit DEH-1	(1,511,166)	(592,084)	(43,578)	(153,584)	(174,753)	(160,672)	(361,661)	(1,719)	(19,783)	(3,352)
ACCRUED SIT TAX RESERVE - LONG TERM FIN 48	REV	P. 18 Exhibit DEH-1	51,396	20,137	1,482	5,224	5,943	5,465	12,300	58	673	114
NON TAXABLE DEFERRED COMPENSATION CSV EARN	LABOR_M	P. 15 Exhibit DEH-1	34,434	19,677	1,017	3,146	3,465	2,458	4,285	30	297	59
NONDEDUCTIBLE MEALS & TRAVEL EXPENSE	LABOR_M	P. 15 Exhibit DEH-1	82,713	47,266	2,444	7,556	8,323	5,903	10,292	73	714	141
FIN 48 DSIT	REV	P. 18 Exhibit DEH-1	(43,069)	(16,874)	(1,242)	(4,377)	(4,981)	(4,579)	(10,308)	(49)	(564)	(96)
REMOVAL COSTS	RB_GUP	P. 17 Exhibit DEH-1	(8,077,641)	(4,343,110)	(227,814)	(759,428)	(841,843)	(625,676)	(1,105,344)	(7,121)	(149,920)	(17,386)
BOOK DEFFERAL MERGER COSTS	REV	P. 18 Exhibit DEH-1	(32,666)	(12,798)	(942)	(3,320)	(3,778)	(3,473)	(7,818)	(37)	(428)	(72)
REG ASSET ACCRUED SFAS 112	LABOR_M	P. 15 Exhibit DEH-1	359,347	205,346	10,618	32,828	36,160	25,647	44,715	316	3,104	614
1991 - 1996 IRS AUDIT SETTLEMENT	REV	P. 18 Exhibit DEH-1	(26,075)	(10,216)	(752)	(2,650)	(3,015)	(2,772)	(6,240)	(30)	(341)	(58)
TOTAL SCHEDULE M ADJUSTMENTS - PERBOOKS			(53,398,032)	(30,829,784)	(1,943,460)	(4,929,944)	(5,175,190)	(3,309,140)	(4,969,111)	(42,553)	(2,077,082)	(122,748)
ADJUSTMENTS TO PERBOOKS SCHEDULE M			27,446,160	13,060,289	703,659	2,495,171	2,909,506	2,538,821	5,284,220	27,083	375,111	54,289

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2009

	METHOD	ALLOCATION FACTOR REFERENCE PAGE	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP-TOD	MW	OL	SL
WEST VIRGINIA STATE TAXABLE INCOME	FORMULA		(69,876,086)	(76,129,188)	(17,724)	528,309	(1,695,858)	1,162,067	6,594,220	28,116	(714,091)	348,044
BONUS DEPRECIATION ADJUSTMENT FOR STATE	RB_GUP	P. 17 Exhibit DEH-1	22,637,800	12,171,679	638,455	2,128,316	2,359,287	1,753,474	3,097,754	19,957	420,154	48,723
KENTUCKY STATE TAXABLE INCOME	FORMULA		(47,238,286)	(63,957,509)	620,731	2,656,625	663,428	2,935,561	9,691,974	48,074	(293,937)	396,767
STATE INCOME TAX KENTUCKY	FORMULA		(2,834,297)	(3,837,451)	37,244	159,397	39,806	176,134	581,518	2,884	(17,636)	23,806
STATE INCOME TAX WEST VIRGINIA	FORMULA		(159,457)	(173,727)	(40)	1,206	(3,870)	2,698	15,048	64	(1,630)	794
TOTAL STATE INCOME TAXES			(2,993,754)	(4,011,177)	37,203	160,603	35,936	178,831	596,566	2,949	(19,266)	24,600
TAXABLE OPERATING INCOME	FORMULA		(66,882,332)	(72,118,011)	(54,928)	367,706	(1,731,794)	1,003,256	5,997,653	25,168	(694,825)	323,444
GROSS CURRENT FIT	FORMULA		(23,408,816)	(25,241,304)	(19,225)	128,697	(606,128)	351,139	2,099,179	8,809	(243,189)	113,205
FEEDBACK PRIOR ITC NORMALIZATION TAX	RB_GUP	P. 17 Exhibit DEH-1	(818,986)	(440,345)	(23,098)	(76,998)	(85,354)	(63,437)	(112,070)	(722)	(15,200)	(1,763)
FEDERAL INCOME TAX - ITC - ADJUSTMENT			292,039	157,021	8,236	27,458	30,436	22,621	39,963	257	5,420	629
CURRENT FIT AND ITC	FORMULA		(23,935,763)	(25,524,628)	(34,086)	79,158	(661,046)	310,323	2,027,071	8,344	(252,969)	112,071
DEFERRED FIT - CURRENT YEAR												
DIFIT FOR BOOK VS TAX DEPRECIATION NORMALIZED	RB_GUP	P. 17 Exhibit DEH-1	11,706,400	6,294,187	330,158	1,100,589	1,220,028	905,752	1,601,903	10,320	217,269	25,196
DFIT ABFUDC	RB_CWIP	P. 16 Exhibit DEH-1	282,595	145,304	7,132	26,028	29,168	24,485	48,289	244	3,525	409
WSEC 482 PENSION/OPEB ADJUSTMENT	LABOR_M	P. 15 Exhibit DEH-1	41	23	1	4	4	3	5	0	0	0
INTEREST CAPITALIZATION	RB_GUP	P. 17 Exhibit DEH-1	(548,032)	(294,661)	(15,456)	(51,524)	(57,115)	(42,449)	(74,993)	(483)	(10,171)	(1,180)
DEFERRED FUEL EXPENSE	FUELREV	P. 15 Exhibit DEH-1	(7,565,876)	(2,606,161)	(145,373)	(616,607)	(788,322)	(960,775)	(2,386,286)	(8,278)	(46,060)	(9,015)
PROVISION FOR POSSIBLE REVENUE REFUNDS	REV	P. 18 Exhibit DEH-1	246,717	96,662	7,115	25,074	28,531	26,232	59,046	281	3,230	547
PERCENT REPAIR ALLOWANCE	RB_GUP	P. 17 Exhibit DEH-1	624,331	335,684	17,608	58,697	65,067	48,359	85,433	550	11,587	1,344
BOOK/TAX UNIT OF PROPERTY	RB_GUP	P. 17 Exhibit DEH-1	1,261,147	678,082	35,568	118,568	131,435	97,686	172,575	1,112	23,407	2,714
BOOK/TAX UNIT OF PROPERTY - SEC 481	RB_GUP	P. 17 Exhibit DEH-1	9,692,723	5,211,492	273,365	911,271	1,010,165	750,777	1,326,351	8,545	179,895	20,862
TAX AMORTIZATION POLLUTION CONTROL	PROD_DEMAND	P. 15 Exhibit DEH-1	(953,511)	(450,772)	(18,320)	(84,374)	(96,666)	(98,083)	(204,494)	(803)	0	0
CAPITALIZED RELOCATION COSTS	RB_GUP	P. 17 Exhibit DEH-1	61,393	33,009	1,731	5,772	6,398	4,755	8,401	54	1,139	132
MTM BOOK GAIN ABOVE THE LINE TAX DEFERRAL	PROD_ENERGY	P. 15 Exhibit DEH-1	5,439,807	1,922,171	107,297	453,250	576,260	674,837	1,659,130	6,113	34,078	6,669
MARK & SPREAD DEFL -283 A/L	PROD_ENERGY	P. 15 Exhibit DEH-1	(3,578,816)	(1,264,685)	(70,590)	(298,191)	(379,118)	(443,971)	(1,091,531)	(4,022)	(22,420)	(4,388)
MARK & SPREAD DEFL -190 A/L	PROD_ENERGY	P. 15 Exhibit DEH-1	3,359,913	1,187,235	66,273	279,951	355,929	416,815	1,024,766	3,776	21,049	4,119
PROVISION FOR WORKERS COMP	LABOR_M	P. 15 Exhibit DEH-1	21,743	12,425	642	1,986	2,188	1,552	2,706	19	188	37
ACCRUED BOOK PENSION EXPENSE	LABOR_M	P. 15 Exhibit DEH-1	(1,204,352)	(688,218)	(35,586)	(110,023)	(121,189)	(85,957)	(149,861)	(1,059)	(10,403)	(2,056)
ACCURED BOOK PENSION COSTS - SFAS 158	LABOR_M	P. 15 Exhibit DEH-1	382,612	218,641	11,305	34,953	38,501	27,308	47,609	336	3,305	653
SUPPLEMENTAL EXECUTIVE RETIREMENT	LABOR_M	P. 15 Exhibit DEH-1	(1,187)	(678)	(35)	(108)	(119)	(85)	(148)	(1)	(10)	(2)
ACCRUED SUPPLEMENTAL EXEC RETIREMENT COSTS SFAS 158	LABOR_M	P. 15 Exhibit DEH-1	629	359	19	57	63	45	78	1	5	1
ACCRUED BOOK SUPPLEMENTAL SAVINGS PLAN EXP	LABOR_M	P. 15 Exhibit DEH-1	(34,612)	(19,779)	(1,023)	(3,162)	(3,483)	(2,470)	(4,307)	(30)	(299)	(59)
ACCRUED PSI PLAN EXPENSES	LABOR_M	P. 15 Exhibit DEH-1	135,318	77,326	3,998	12,362	13,616	9,658	16,838	119	1,169	231
BOOK PROVISION UNCOLLECTIBLE ACCOUNTS	CUST_TOTAL	P. 11 Exhibit DEH-1	1,582,343	1,016,185	159,464	54,681	6,077	615	127	141	344,657	396
ACCRUED COMPANYWIDE INCENTIVE PLAN	LABOR_M	P. 15 Exhibit DEH-1	1	1	0	0	0	0	0	0	0	0
PROVISION FOR TRADING CREDIT RISK ABOVE THE LINE	PROD_ENERGY	P. 15 Exhibit DEH-1	(36,442)	(12,877)	(719)	(3,036)	(3,860)	(4,521)	(11,115)	(41)	(228)	(45)
PROVISION FOR FAS 157 A/L	PROD_ENERGY	P. 15 Exhibit DEH-1	(13,400)	(4,735)	(264)	(1,117)	(1,420)	(1,662)	(4,087)	(15)	(84)	(16)
ACCRUED BOOK VACATION PAY	LABOR_M	P. 15 Exhibit DEH-1	(46,017)	(26,296)	(1,360)	(4,204)	(4,630)	(3,284)	(5,726)	(40)	(397)	(79)
ACCRUED LONG TERM INTEREST EXPENSE - FIN 48	REV	P. 18 Exhibit DEH-1	(91,294)	(35,768)	(2,633)	(9,278)	(10,557)	(9,707)	(21,849)	(104)	(1,195)	(203)
REG ASSET ON DEFERRED RTO COSTS	TRANS_TOTAL	P. 19 Exhibit DEH-1	(51,608)	(24,074)	(990)	(4,552)	(5,221)	(5,435)	(11,294)	(43)	0	0
FEDERAL MITIGATION PROGRAMS	PROD_ENERGY	P. 15 Exhibit DEH-1	149,126	52,694	2,941	12,425	15,798	18,500	45,483	168	934	183
STATE MITIGATION PROGRAMS	PROD_ENERGY	P. 15 Exhibit DEH-1	220,767	78,009	4,355	18,395	23,387	27,387	67,333	248	1,383	271
DEFERRED BOOK CONTRACT REVENUE	REV	P. 18 Exhibit DEH-1	4,683	1,835	135	476	542	498	1,121	5	61	10
DEFERRED DEMAND SIDE MANAGEMENT EXPENSE	LABOR_M	P. 15 Exhibit DEH-1	(8,705)	(4,974)	(257)	(795)	(876)	(621)	(1,083)	(8)	(75)	(15)
BOOK > TAX BASIS - EMA A/C 283	PROD_ENERGY	P. 15 Exhibit DEH-1	(74,985)	(26,496)	(1,479)	(6,248)	(7,943)	(9,302)	(22,870)	(84)	(470)	(92)
DEFERRED TAX GAIN EPA AUCTION	PROD_ENERGY	P. 15 Exhibit DEH-1	13,321	4,707	263	1,110	1,411	1,653	4,063	15	83	16
ADVANCE RENTAL INCOME	REV_OTHER	P. 17 Exhibit DEH-1	3,127	1,992	131	365	349	117	99	3	65	7
REG ASSET UNREAL MTM GAIN DEFERRAL	PROD_ENERGY	P. 15 Exhibit DEH-1	(1,109,073)	(391,894)	(21,876)	(92,409)	(117,488)	(137,586)	(338,265)	(1,246)	(6,948)	(1,360)
REG ASSET SFAS 158 PENSIONS	LABOR_M	P. 15 Exhibit DEH-1	(382,612)	(218,641)	(11,305)	(34,953)	(38,501)	(27,308)	(47,609)	(336)	(3,305)	(653)
REG ASSET SFAS 158 SERP	LABOR_M	P. 15 Exhibit DEH-1	(629)	(359)	(19)	(57)	(63)	(45)	(78)	(1)	(5)	(1)
REG ASSET SFAS 158 OPEB	LABOR_M	P. 15 Exhibit DEH-1	(412,935)	(235,969)	(12,201)	(37,723)	(41,552)	(29,472)	(51,383)	(363)	(3,567)	(705)
CAPITALIZED SOFTWARE COST TAX	RB_GUP	P. 17 Exhibit DEH-1	266	144	8	25	28	21	37	0	5	1
BOOK LEASES CAPITALIZED FOR TAX	RB_GUP	P. 17 Exhibit DEH-1	25,131	13,512	709	2,363	2,619	1,947	3,439	22	466	54
CAPITALIZED SOFTWARE COST BOOK	RB_GUP	P. 17 Exhibit DEH-1	(465,987)	(250,548)	(13,142)	(43,810)	(48,565)	(36,094)	(63,766)	(411)	(8,649)	(1,003)
BOOK AMORTIZATION LOSS REAQUIRED DEBT	RB_GUP	P. 17 Exhibit DEH-1	(11,671)	(6,275)	(329)	(1,097)	(1,216)	(904)	(1,597)	(10)	(217)	(25)
ACCRUED SFAS 106 POST RETIREMENT EXPENSE	LABOR_M	P. 15 Exhibit DEH-1	(216,561)	(123,764)	(6,400)	(19,786)	(21,794)	(15,458)	(26,950)	(190)	(1,871)	(370)
ACCRUED OPEB COSTS SFAS 158	LABOR_M	P. 15 Exhibit DEH-1	412,936	235,969	12,201	37,723	41,552	29,472	51,383	363	3,567	705
ACCRUED SFAS 112 POST EMPLOYMENT BENEFITS	LABOR_M	P. 15 Exhibit DEH-1	125,773	71,872	3,716	11,490	12,656	8,977	15,650	111	1,086	215
ACCRUED BOOK ARO EXPENSE SFAS 143	RB_GUP	P. 17 Exhibit DEH-1	(998,320)	(536,767)	(28,156)	(93,858)	(104,044)	(77,328)	(136,610)	(880)	(18,529)	(2,149)
ACCRUED SALES & USE TAX RESERVE	REV	P. 18 Exhibit DEH-1	628,009	207,223	15,252	53,754	61,164	56,235	126,581	602	6,924	1,173
ACCRUED SIT TAX RESERVE - LONG TERM FIN 48	REV	P. 18 Exhibit DEH-1	(17,989)	(7,048)	(519)	(1,828)	(2,080)	(1,913)	(4,305)	(20)	(236)	(40)
FIN 48 DSIT	REV	P. 18 Exhibit DEH-1	15,074	5,906	435	1,532	1,743	1,603	3,608	17	197	33
BOOK DEFFERAL MERGER COSTS	REV	P. 18 Exhibit DEH-1	11,433	4,479	330	1,162	1,322	1,216	2,736	13	150	25
REG ASSET ACCRUED SFAS 112	LABOR_M	P. 15 Exhibit DEH-1	(125,772)	(71,871)	(3,716)	(11,490)	(12,656)	(8,977)	(15,650)	(111)	(1,086)	(215)
1991 - 1996 IRS AUDIT SETTLEMENT	REV	P. 18 Exhibit DEH-1	9,127	3,576	263	928	1,065	970	2,184	10	119	20
FEDERAL INCOME TAX - DEFERRED - ADJUSTMENT			(8,016,836)	(3,717,661)	(201,640)	(723,950)	(852,684)	(764,843)	(1,630,127)	(8,078)	(102,201)	(15,631)
TOTAL CURRENT YEAR DFIT			10,350,145	6,869,812	469,027	971,812	925,893	370,223	69,001	6,531	621,120	26,725

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KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2009

	METHOD	ALLOCATION FACTOR REFERENCE PAGE	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP-TOD	MW	OL	SL
DEFERRED FIT - PRIOR YEAR												
GAIN/LOSS ON ACRS/MACRS PROPERTY	RB_GUP	P. 17 Exhibit DEH-1	(918,515)	(493,859)	(25,805)	(66,355)	(95,727)	(71,146)	(125,690)	(810)	(17,047)	(1,877)
ABFUDC	RB_CWIP	P. 16 Exhibit DEH-1	(181,758)	(93,458)	(4,587)	(16,741)	(18,760)	(15,748)	(29,778)	(157)	(2,267)	(263)
ABFUDC HRJ POST-IN SERVE	BULK_TRANS	P. 10 Exhibit DEH-1	(7,449)	(3,522)	(143)	(659)	(755)	(766)	(1,598)	(6)	0	0
ABFUDC - HRJ (TC)	BULK_TRANS	P. 10 Exhibit DEH-1	(319,206)	(150,905)	(6,133)	(28,248)	(32,361)	(32,835)	(68,458)	(269)	0	0
TAXES CAPITALIZED	LABOR_M	P. 15 Exhibit DEH-1	(46,737)	(26,708)	(1,381)	(4,270)	(4,703)	(3,336)	(5,816)	(41)	(404)	(80)
PENSIONS CAPITALIZED	LABOR_M	P. 15 Exhibit DEH-1	(5,793)	(3,310)	(171)	(529)	(583)	(413)	(721)	(5)	(50)	(10)
SAVING PLAN CAPITALIZED	LABOR_M	P. 15 Exhibit DEH-1	(3,358)	(1,919)	(99)	(307)	(338)	(240)	(418)	(3)	(29)	(6)
INTEREST CAPITALIZED	RB_GUP	P. 17 Exhibit DEH-1	257,373	138,382	7,259	24,197	26,823	19,936	35,219	227	4,777	554
ADR REPAIR ALLOWANCE	RB_GUP	P. 17 Exhibit DEH-1	(692,281)	(372,219)	(19,524)	(65,085)	(72,149)	(53,623)	(94,732)	(610)	(12,849)	(1,490)
CAPITALIZED RELOCATION COSTS	RB_GUP	P. 17 Exhibit DEH-1	293,928	158,036	8,290	27,634	30,633	22,767	40,221	259	5,455	633
TOTAL PRIOR YEAR DFIT			(1,623,796)	(849,478)	(42,396)	(150,361)	(167,919)	(135,404)	(251,770)	(1,415)	(22,414)	(2,639)
FEDERAL INCOME TAXES	FORMULA		(15,209,414)	(18,484,203)	392,545	900,607	98,928	545,142	1,844,303	13,460	345,737	138,158
TOTAL INCOME TAXES			(18,203,168)	(23,495,471)	429,749	1,061,210	132,864	723,973	2,440,869	16,408	326,471	160,758
TOTAL EXPENSES	FORMULA		512,808,377	221,160,702	13,262,987	47,872,389	56,221,157	51,468,974	115,922,777	534,201	5,520,712	824,477
NET OPERATING INCOME	FORMULA		8,988,928	(16,521,971)	1,775,919	5,161,067	4,115,270	3,952,607	8,770,567	59,141	1,340,364	335,964
AFUDC OFFSET												
PRODUCTION	PROD_DEMAND	P. 15 Exhibit DEH-1	554,942	282,349	10,662	49,105	56,259	57,084	119,015	467	0	0
TRANSMISSION	RB_GUP_EPIS_T	P. 17 Exhibit DEH-1	277,698	129,543	5,326	24,493	28,093	29,244	60,787	231	0	0
DISTRIBUTION	RB_GUP_EPIS_D	P. 16 Exhibit DEH-1	164,723	107,198	7,174	17,132	18,057	5,353	209	158	8,472	971
GENERAL	LABOR_M	P. 15 Exhibit DEH-1	26,898	15,371	795	2,457	2,707	1,920	3,347	24	232	46
AFUDC OFFSET			1,024,261	514,460	23,957	93,187	105,115	93,601	183,339	880	8,705	1,017
AFUDC OFFSET - ADJUSTMENT			1,190,864	598,141	27,854	108,344	122,213	108,826	213,160	1,023	10,121	1,182
ADJUSTED NET OPERATING INCOME	FORMULA		11,204,053	(15,409,370)	1,827,730	5,362,597	4,342,599	4,155,034	9,167,065	61,044	1,359,190	338,163

Kentucky Power Company

REQUEST

Refer to page 12 of the Direct Testimony of David E. Jolley ("Jolley Testimony") concerning the measures contained within the various compensation plans discussed in his testimony and a plan participant's maximum individual award percentage.

a. For each group of employees - non-exempt, exempt, exempt management employees, and senior management employees - identify the specific measures contained in the incentive compensation plan(s) available to them and the weight assigned each measure in each of the incentive compensation plans.

b. A participant's maximum individual award percentage is described as "[t]he greater of two times his or her target award percent or the Overall Score plus 50%." Explain what the "Overall Score" represents and provide the maximum Overall Score an employee can achieve.

RESPONSE

a. Copies of all incentive plans applicable to all groups of employees were provided in the response to KIUC's 1st set, Item No. 27. The plan documents include the specific measures and weight assigned.

b. The overall incentive plan score is the business unit score times the EPS modifier, less any applicable fatality adjustment and/or operating unit performance adjustment. The overall score can range from 0 to a maximum of 2.0.

The maximum award an employee can receive is 2.5 times their incentive target percent, if the overall score is 2.0.

WITNESS: David A Jolley

Kentucky Power Company

REQUEST

Refer to pages 14 and 18 of the Jolley Testimony.

On page 14, the amount of $5,650,647 requested to be included in the cost of service is identified as the target amount of incentive compensation for the test year.

a. Confirm whether the amount of $990,858 in long-term incentive compensation shown on page 18 is the test year target amount.

b. The proposed adjustments are based on the target and actual amounts of incentive and long-term incentive compensation for the test year. Clarify the specific 12-month period for which the company's results were measured that resulted in the actual levels of incentive and long-term incentive compensation.

RESPONSE

a. Yes, the $990,858 is the target amount for long term incentive compensation to be included in the cost of service for the test year.

b. The 12 month period of October 2008 through September 2009 was used to accumulate the actual levels of incentive and long term incentive compensation.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to page 5 of the Direct Testimony of Thomas M. Myers ("Myers Testimony").

The current system sales clause was approved in 2006 in the settlement in Kentucky Power's most recent rate case, meaning it was in effect for the full year in each of the calendar years, 2007, 2008 and 2009. For each of these years, provide a side-by-side comparison of the actual results for the company and its customers under the existing system sales clause and the "calculated" results that would have been realized under the proposed modification to the existing system sales clause.

RESPONSE

Please see the table below for a side-by-side comparison of the actual results for the company and its customers under the existing system sales clause and the "calculated" results that would have been realized under the proposed modification to the existing system sales clause for 2007, 2008, and 2009.

	2007		2008		2009	
	Customer	Company	Customer	Company	Customer	Company
Existing SSC	42,098,261	9,186,853	38,608,488	6,744,668	19,354,960	(2,518,900)
Proposed SSC	25,642,557	25,642,557	22,676,578	22,676,578	8,418,030	8,418,030

WITNESS: Thomas M. Myers

Kentucky Power Company

REQUEST

Refer to page 11 of the Myers Testimony.

The question and answer at the top of the page indicate that "[t]he unprecedented economic downturn . ." of the past year is one of the primary reasons for the proposed modification to the system sales clause. Explain why an event characterized as unprecedented should form the basis for a change of the sort being proposed to Kentucky Power's system sales clause.

RESPONSE

The question and answer at the top of page 11 of Mr. Myers Direct Testimony (page 11, lines 1-10), do not state that the unprecedented economic downturn of the past year is one of the primary reasons for the proposed modification to the system sales clause. The "unprecedented economic downturn" is identified as a contributor to "an OSS margin shortfall", (page 11, lines 4-5). Please refer to Mr. Myers Direct Testimony page 11, lines 1-10 for a summary of the company's rationale for proposing a modification to the current system sales clause.

WITNESS: Thomas M. Myers

Kentucky Power Company

REQUEST

Refer to the Direct Testimony of Everett G. Phillips ("Phillips Testimony") at page 4.

a. Provide an update to Figure 1 showing outages for the years 2004, 2005, and the full year for 2009, a breakout for trees inside and outside the right of way ("ROW").

b. Provide a similar update for Figure 1 including major storm events.

RESPONSE

(a) Please refer to the table below.

Outages Records by Cause - Excluding JMEDS						
	2009	2008	2007	2006	2005	2004
Trees - Outside ROW	16.1%	18.0%	13.8%	15.2%	11.3%	11.1%
Trees - Inside ROW	22.1%	21.0%	18.0%	22.1%	26.8%	30.7%
Equipment	20.8%	23.3%	25.5%	24.4%	26.3%	21.7%
Animal	9.3%	6.8%	8.3%	9.3%	5.3%	6.9%
Scheduled	6.9%	7.2%	8.9%	5.4%	6.2%	3.7%
Lightning	3.0%	2.3%	4.1%	5.6%	5.7%	5.9%
All Other	21.8%	21.5%	21.3%	18.1%	18.5%	20.1%

(b) Please refer to the table below.

Outages Records by Cause - Including JMEDs						
	2009	2008	2007	2006	2005	2004
Trees - Outside ROW	19.7%	18.2%	14.3%	15.7%	11.3%	12.7%
Trees - Inside ROW	22.0%	21.4%	18.3%	22.1%	26.8%	33.3%
Equipment	15.8%	23.0%	24.8%	24.1%	26.3%	19.4%
Animal	6.6%	6.6%	8.0%	9.2%	5.3%	6.0%
Scheduled	4.9%	7.0%	8.7%	5.3%	6.2%	3.2%
Lightning	2.2%	2.4%	4.8%	5.7%	5.7%	5.8%
All Other	28.7%	21.4%	21.1%	18.0%	18.5%	19.7%

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

Refer to the Phillips Testimony at page 7, lines 7-12.

Mr. Phillips states that Kentucky Power installed three distribution automation systems in the Inez, Cannonsburg, and Buckhorn areas to enable sectionalizing detection of a fault. State whether the distribution automation systems were able to minimize the number of sustained outages experienced in these areas as a result of the snow storm occurring in late December 2009. Include any supporting data in the response.

RESPONSE

On December 19, 2009, the Cannonsburg Distribution Automation (DA) system operated and prevented 1,326 customers from being outaged. 683 customers did experience an outage for 303 minutes before the problem was corrected.

Also on December 9, 2009, the Inez DA system operated to prevent 353 customers from experiencing a 113 minute outage.

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

Refer to the Phillips Testimony at page 12.

Provide a copy of the 2008 MSI customer survey report.

RESPONSE

Refer to the following pages for the 2008 Market Strategies International customer survey report.

WITNESS: Everett G Phillips

SUMMARY TABLE OF KENTUCKY POWER YTD'S RESIDENTIAL BENCHMARKING PERFORMANCE ON POSITIVE RATINGS

2008 YTD

		Kentucky Power YTD Versus the MSI Database				
	Kentucky Power YTD's Percent Positive Rating	MSI Average Positive Rating	Kentucky Power YTD Minus MSI Average (+/-)	Kentucky Power YTD's Rank	Number of Utilities Rated	Kentucky Power YTD's Quartile
Following Through On Promises	81	61	20	2	99	1
Showing Concern And Caring (Toward Customers)	81	65	16	5	100	1
Meeting Expectations	77	61	16	4	100	1
Being Well-Managed	77	61	16	8	104	1
Value of Things Done in the Community	68	52	16	10	94	1
Accessible By Phone During Outage	75	60	15	5	82	1
Being a Good Corporate Citizen in the Communities Served	77	62	15	8	101	1
Letting You Know What Caused Outage	62	47	15	2	80	1
Reliable Estimates of Power Restored	77	63	14	5	86	1
Protecting the Environment	68	54	14	11	104	1
Keeping Electric Rates as Low as Possible	63	49	14	10	89	1
Reasonableness of Electric Rates	71	57	14	16	92	1
Likelihood to Recommend	81	67	14	5	84	1
Being Responsive To Customer Needs	83	70	13	6	96	1
Doing Things Right the First Time	87	74	13	5	96	1
Helping Customers Use Energy Safely	80	67	13	11	92	1
Being An Energy Expert	78	66	12	6	83	1
Value of Customer Service	85	73	12	3	96	1
Being Easy To Reach	81	70	11	6	94	1
Restoring Electric Service When Outages Occur	88	77	11	4	92	1
Being A Company You Can Trust	81	70	11	14	104	1
Being Believable	76	66	10	16	102	1
Overall Satisfaction	86	76	10	13	106	1
Having Bills That Are Easy To Understand	90	81	9	7	101	1
Having Knowledgeable And Well-Trained Employees	82	73	9	10	95	1
Value of Electric Product Delivered	82	74	8	14	90	1
Being Easy To Do Business With	82	75	7	19	104	1
Comparison with Ideal	68	61	7	29	100	2
Providing Good Electric Power Quality	87	80	7	9	82	1
Providing Accurate Bills	86	80	6	20	101	1
Overall Favorability	75	69	6	38	106	2
Providing Reliable Service	87	86	1	45	105	2

SUMMARY TABLE OF KENTUCKY POWER YTD'S COMMERCIAL BENCHMARKING PERFORMANCE ON POSITIVE RATINGS

2008 YTD

	Kentucky Power YTD's Percent Positive Rating	Kentucky Power YTD Versus the MSI Database				Kentucky Power YTD's Quartile
		MSI Average Positive Rating	Kentucky Power YTD Minus MSI Average (+/-)	Kentucky Power YTD's Rank	Number of Utilities Rated	
Following Through On Promises	89	69	20	1	86	1
Value of Things Done in the Community	76	57	19	3	81	1
Being Believable	87	69	18	3	87	1
Letting You Know What Caused Outage	69	51	18	4	74	1
Keeping Electric Rates as Low as Possible	69	51	18	4	79	1
Reasonableness of Electric Rates	74	56	18	3	80	1
Showing Concern And Caring (Toward Customers)	86	69	17	2	83	1
Being Well-Managed	82	65	17	4	89	1
Accessible By Phone During Outage	78	63	15	7	74	1
Reliable Estimates of Power Restored	82	67	15	7	76	1
Protecting the Environment	72	57	15	4	88	1
Being An Energy Expert	86	72	14	1	74	1
Comparison with Ideal	85	71	14	7	88	1
Being Responsive To Customer Needs	89	75	14	6	84	1
Being A Company You Can Trust	88	74	14	7	89	1
Being a Good Corporate Citizen in the Communities Served	78	65	13	12	83	1
Meeting Expectations	81	68	13	11	88	1
Having Knowledgeable And Well-Trained Employees	91	78	13	3	82	1
Likelihood to Recommend	85	72	13	6	78	1
Restoring Electric Service When Outages Occur	92	79	13	3	80	1
Doing Things Right the First Time	92	80	12	2	85	1
Value of Electric Product Delivered	90	78	12	2	80	1
Having Bills That Are Easy To Understand	92	81	11	2	87	1
Overall Favorability	88	77	11	7	91	1
Value of Customer Service	88	77	11	4	83	1
Overall Satisfaction	93	83	10	6	91	1
Providing Good Electric Power Quality	91	81	10	4	77	1
Providing Accurate Bills	90	82	8	11	85	1
Being Easy To Do Business With	87	79	8	14	88	1
Being Easy To Reach	77	72	5	23	84	2
Providing Reliable Service	93	88	5	12	89	1

Kentucky Power MSI Residential and Small Commercial 2008 YE Survey Results

Notes:

1. Results based on responses from a sample of Kentucky Power residential and small commercial customers
2. Results indicate respondees responding favorably (4 or 5) on 1 to 5 scale
3. Benchmarking based on questions asked to differing sets of utilities (based on their level of survey participation, some utilities may not ask customers all questions) varying in size/service territory
4. Results from all benchmarkable questions in MSI surveys (numerous questions/responses not provided are specific to AEP)

Breakdown of Data Provided by Column

Questions - Specific topic area in which respondee is asked about favorability on 1 to 5 scale
Kentucky Power's % Positive Rating - % of respondees delivering favorable response to question (4-5)
MSI Average Positive Rating - % favorable response from all respondees in MSI national peer group
Kentucky Power YTD Minus MSI Average - Kentucky Power rating minus MSI Average Positive Rating
Kentucky Power YTD's Rank - Based on score, Kentucky Power's placement among peer group
Number of Utilities Rated - Indication of peer group size for each question
Kentucky Power YTD's Quartile Ranking - Quartile ranking based on placement amongst peer group for each question

Kentucky Power Company

REQUEST

Refer to the Phillips Testimony at pages 13-15.

a. Explain whether moving the vegetation management plan from a performance-based approach to a cycle-based approach, including a tree inventory, was discussed in Kentucky Power's focused management audit of its Hazard District.

b. Explain whether the proposed cycle-based vegetation management plan calls for clearing ROW in the same manner as currently used in the circuit station zone. If not, explain how circuits will be trimmed past the first station zone.

RESPONSE

a) Moving the vegetation management plan from a performance-based approach to a cycle-based approach was discussed in KPCo's focused management audit of its Hazard District. Specifically, Recommendations V-1 and V-2 as proposed to KPCo, recommended determining the annual vegetation management workload increment and moving the vegetation management program to a pruning cycle of 3-8 years for rural areas and 2-3 years for urban areas.

b) The proposed cycle-based vegetation management plan calls for clearing all ROW on circuit in the same manner as currently used in the circuit's station zone, on a four-year cycle.

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

Refer to the Phillips Testimony at page 14, which states: "[D]epending on the field data obtained and the rainfall in a particular area, some lines may be maintained on a three-year interval, while maintenance on others may stretch to every four to six years."

a. Following this reasoning, explain why a few drought years followed by a number of wetter-than-normal years,would not again place the company behind in its tree trimming program because the tree growth would accelerate.

b. Explain why it would not be better to simply remain with the four-year cycle regardless of rainfall.

RESPONSE

a. In the section of his direct testimony beginning at page 14 on line 12, Company witness Phillips identifies inputs to the Company's cycle-based approach to vegetation management. These inputs, including the vegetation profile the Company intends to develop, will determine the appropriate vegetation management cycle to be used. Therefore, the Company believes that by using these inputs to develop its vegetation management plan, it will be able to adjust to drought and wetter-than-normal years.

b. As the Company further assesses its circuits during the transition to its cycle based approach, it may determine that due to yard trees or cycle-busters, that some urban circuits should be maintained on a three-year cycle while some rural circuits, where herbicides have been used or due to the type of vegetation, may only need to be maintained on a five- or six-year cycle. Therefore, the overall average vegetation management cycle for all of the Company's circuits should be approximately every four years. The Company will be able to tailor its vegetation management activities according to the vegetation inventoried throughout the system rather than selecting a frequency, such as every four years, which may be too frequent or too seldom.

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

Refer to the Phillips Testimony at page 15.

a. Provide a discussion of how the tree inventory will be conducted.

b. Explain whether the inventory will follow the general guidelines discussed in the company's previous focused-management audit.

c. During the first year that the tree inventory is being conducted and additional crews are being acquired, explain whether the new vegetation management plan calls for existing crews to immediately begin the more aggressive cycle trimming.

d. Provide the number of IO-13 customer reports for the years 2004, 2005, and 2006.

e. Provide a copy of a typical IO-13 customer report.

RESPONSE

a. The inventory will be conducted using physical inspection of the areas to be maintained while the required vegetation management work is being planned on each circuit.

b. The Company's inventory will include the suggested data as mentioned on page 101 of the "Final Report - Focused Management Audit of the Hazard Service Area". This finding specifies a count of trees categorized by the work needed, a measure of brush and total tree exposure and annual growth and mortality rates.

c. The new vegetation management calls for all crews to begin implementing the cycle-based program once they have received all required training.

d.

Year	IO-13 Count
2004	2,843
2005	2,289
2006	2,196

e. Refer to the following page for a copy of a typical IO-13 customer report.

WITNESS: Everett G Phillips

```
FORM NO.     OSPRFD16      AMERICAN ELECTRIC POWER SYSTEM     ORDER NO:036058394
PROGRAM NO.  OSPOFD04            KENTUCKY POWER COMPANY       DATE:     02/23/10
REPRINT      N                 ORDER PROCESSING SYSTEM        TIME:     10.50.52
                         INVESTIGATION ORDER FIELD DOCUMENT   PAGE       1 OF  1
CO 03  DIVISION 04  AREA 011 SUB 018      TYPE TREE TRIMMING
STATUS ACTIVE                             DATE/TIME INITIATED 02/23/10 10:50
CUST READY DT:   /  /
CONTACT: [redacted]                       PHONE [redacted]   H PH OWNR CD _
CUST NM1 [redacted]                          PH              H CUST CONTACTS _
CUST NM2 ____________________________        PH              W ACCT TYPE E
SERV  [redacted]                          ACCT NO [redacted]  STATUS A
ADDR:                                     PRIMARY TARIFF:      15      CC __
                                          SECONDARY TARIFF:
                                          LIFE SUPPORT ____________________
DIRECTIONS: US 119 IN JOHNS CREEK TO WINNS BRANCH TO ANGELA ST TO END OF ST

DESC: TREES IN LINES POLE TO POLE...TREE TO SOUTH OF THIS ADDR ([redacted]
      [redacted])...DOG IN HOUSE...
REPS:      SOCKET AMP 200  DERATING FCTR ____  APPT: DATE ________  TIME ________
 MKTG _______________     CUST SERV ________________  INTRVL USE CD _
 DSGN _______________     METER __________________  LINE ________________
MTR RDG:INST __________    HAZ DOG               CYCLE NO 19  ROUTE NO 02
        RMK ______________________________       KEY NO ____  SEQ NO  01430
            ______________________________       PREM NB 030673881 GEN 00
  REMOTE LOC _____________________________       PROGRAM ID  _________
SERVICE POINT 1             TOS: 240S3  SINGLE PHASE 120/240 3 WIRE
RQ ACT ID  KIND MFR DEVC SERIAL NO STAT LOC TI    FS      PREV RDG RC    BILL K
    DIAL K     DIALS TOD SEAL SBTR USE LR ACT READING   RC BILL INT  KE CNST
M  __  01 KWH    04 EH006 538255378   C  FL  9 ________  15722     R        1.
E        1.         5   __  _      N
T
E
R

I
N
F
O
MV90 ID ________                  INTERNAL ID NBR 030673881005382553 78
POLE DATA SERV 38821082B10257 ____________  STATION 4118    JOHNSCREE
          XFMR 38821082B10257 ____________  CIRCUIT 01      META
ACTION REQUESTED ____________________             ISOLATING DEVICE ________
R POLE #1082-204                                                MTR COMM CD
E
M                                                               ITRON PGM #
A
R
K
      MORE REMARKS?  N
*****************************************************************************
                                                               TRIP NBR:    1
ACTION   : ______________________________________________________________
TAKEN      ______________________________________________________________

COMPLETED: BY _______________            DATE __/__/__   TIME __:__
SIGNED BY CUSTOMER ______________________________      ORDER COMPLETE? _
```

Kentucky Power Company

REQUEST

Refer to the Phillips Testimony at page 17.

a. Update Figure 6 to include a breakout of estimated contractor and company costs.

b. Explain whether the estimated increased costs from the updated Figure 6 are included in the company's rate request.

RESPONSE

a) All costs associated with the incremental work to be performed as presented in Figure 6 at page 17 of Company witness Phillips' Direct Testimony are contractor costs.

b) Yes. All estimated costs have been included in the Company's proposal.

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

Refer to the Phillips Testimony at page 19.

a. Explain whether or not the existing ROW widths are as wide as recommended and allowed according to IEEE standards.

b. In instances where ROW is not as wide as recommended widths, explain when it would not be possible to widen a narrow ROW.

RESPONSE

a) IEEE standards do not specifically address recommended or allowed ROW widths for distribution facilities. For minimum approach distances for distribution facilities, KPCo's standards are in accordance with the requirements of the National Electrical Safety Code (NESC), the American National Standards Institute (ANSI), and the Occupational Safety and Health Administration (OSHA).

The Company's distribution easements are typically defined by a centerline description with no prescribed width. These easements grant the Company the right to cut, trim, or otherwise maintain vegetation that may endanger the safe operation of the electric facilities. The easement applies to the property physically crossed by the electric facilities. Typically, distribution easements are maintained at a width of 20 feet from the centerline or 40 feet in total.

b) Widths of maintained ROWs will depend on site-related factors that could include specific ROW agreements with property owners, voltage class, Department of Transportation restrictions, USDA Forest Service Special Use Permit requirements, multiple lines in a corridor, and type of construction (single pole or steel tower). On some occasions, existing narrow ROWs are not widened due to the property owner's objections. In most cases, the Company is able to work with property owners to arrive at an equitable solution that may involve the removal of hazard trees outside the maintained ROW or the widening the ROW in selected areas.

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

Refer to the Phillips Testimony at pages 21-26.

Describe how Kentucky Power proposes to fund the five years of incremental annual increases covering the transition to the four-year trimming cycle.

RESPONSE

The Company proposes to fund the Reliability and Service Enhancement Plan through the adjustment shown in Section V, Workpaper S-4, Page 41 of the application. Further information regarding the requested capital and O&M Reliability Adjustment was provided in the direct testimony of Company witness Wagner.

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

Refer to pages 7-8 of the Direct Testimony of David M. Roush ("Roush Testimony") and Section V, Workpaper S-4, page 23 in Volume 2 of the Application.

a. When were the PJM Schedule 12 charges for AEP last updated?

b. Provide the calculation of the January 2010 PJM Enhancement expense of $1,845,721 shown on Line 1 on the workpaper.

RESPONSE

a. PJM Schedule 12 charges for AEP-owned facilities are updated annually in late May of each year to be effective for the ensuing July 1 to June 30 period. PJM Schedule 12 charges for facilities owned by others are updated on various time schedules pursuant to a FERC-approved formula or through Section 205 filings.

b. For the requested information, please refer to attached pages 2 through 3 of this response.

WITNESS: David M Roush

Trans. Enhancement Charges (PJM OATT Schedule 12)

Required Transmission Enhancements owned by: Trans-Allegheny Interstate Line Company (TrAILCo)

PJM Upgrade ID	Annual Revenue Requirement	Monthly Revenue Requirement (Jun2009-May2010)	AEP Share AEP
b0216	$ 9,089,137.18	$ 757,428.10	17.97% $ 136,109.83
b0321.1	$ 575,637.10	$ 47,969.76	17.97% $ 8,620.17
b0328.2 b0347.1 b0347.2 b0347.3 b0347.4	$ 31,308,738.36	$ 2,609,061.53	17.97% $ 468,848.36
b0559	$ 77,998.22	$ 6,499.85	17.97% $ 1,168.02
b0495	$ 1,107,040.49	$ 92,253.37	17.97% $ 16,577.93
TOTAL	$ 47,262,046.16	$ 3,938,503.85	$ 631,324.31

Required Transmission Enhancements owned by: Potomac-Appalachian Transmission Highline, L.L.C. (PATH)

PJM Upgrade ID	Annual Revenue Requirement	Monthly Revenue Requirement (Jan2010-Dec2010)	AEP Share AEP
b0490 b0491	$ 12,480,138.00	$ 1,040,011.50	17.97% $ 186,890.07
b0492 b0560	$ 10,572,847.00	$ 881,070.58	17.97% $ 158,328.38
TOTAL	$ 23,052,985.00	$ 1,921,082.08	$ 345,218.45

Required Transmission Enhancements owned by: Dominion Virginia Power's Network Customers

PJM Upgrade ID	Annual Revenue Requirement	Monthly Revenue Requirement (Jan2010-Dec2010)	AEP Share AEP
b0217	$ 334,766.00	$ 27,897.17	17.97% $ 5,013.12
b0222	$ 278,313.00	$ 23,192.75	17.97% $ 4,167.74
b0231	$ 686,436.00	$ 57,203.00	17.97% $ 10,279.38
TOTAL	$ 14,616,778.00	$ 1,218,064.86	$ 19,460.24
	$ 14,558,980.00	$ 1,213,248.36	
	$ 57,798.00	$ 4,816.50	

Required Transmission Enhancements owned by: PSE&G's Network Customers

PJM Upgrade ID	Annual Revenue Requirement	Monthly Revenue Requirement (Jan2010-Dec2010)	AEP Share AEP
b0498	$ 6,767,186.00	$ 563,932.17	17.97% $ 101,338.61
b0489	$ 16,186,105.00	$ 1,348,842.08	17.97% $ 242,386.92
TOTAL	$ 65,550,144.00	$ 5,462,512.01	$ 343,725.53

Required Transmission Enhancements owned by: PPL Electric Utilities Corp. dba PPL Utilities

PJM Upgrade ID	Annual Revenue Requirement	Monthly Revenue Requirement (Jun2009-May2010)	AEP Share AEP
b0487	$ 3,446,167.00	$ 287,180.58	17.97% $ 51,606.35
b0171.2	$ 17,289.00	$ 1,440.75	17.97% $ 258.90
b0172.1	$ 12,397.00	$ 1,033.08	17.97% $ 185.64
b0284.2	$ 15,719.00	$ 1,309.92	17.97% $ 235.39
TOTAL	$ 3,582,910.00	$ 298,575.83	$ 52,286.29

Required Transmission Enhancements owned by: AEP East Operating Companies

PJM Upgrade ID	Annual Revenue Requirement	Monthly Revenue Requirement (Jul2009-Jun2010)	AEP Share AEP
b0504	$ 894,796.00	$ 74,566.33	17.97% $ 13,399.57
b0318	$ 2,251,918.00	$ 187,659.83	99.00% $ 185,783.23
	$ 3,146,714.00	$ 262,226.16	$ 199,182.80

Required Transmission Enhancements owned by: Atlantic Electric's Network Customers

PJM Upgrade ID	Annual Revenue Requirement	Monthly Revenue Requirement (Jun2009-May2010)	AEP Share AEP
b0210.A	$ 5,680,025.00	$ 473,335.42	17.97% $ 85,058.37
TOTAL	$ 13,842,367.00	$ 1,153,530.58	$ 85,058.37

Required Transmission Enhancements owned by: Delmarva's Network Customers

PJM Upgrade ID	Annual Revenue Requirement	Monthly Revenue Requirement (Jun2009-May2010)	AEP Share AEP
b0512	$ 1,418,277.00	$ 118,189.75	17.97% $ 21,238.70
TOTAL	$ 3,589,146.00	$ 299,095.50	$ 21,238.70

Required Transmission Enhancements owned by: PEPCO's Network Customers

PJM Upgrade ID	Annual Revenue Requirement	Monthly Revenue Requirement (Jun2009-May2010)	AEP Share AEP
b0512	$ 9,898,240.00	$ 824,853.33	17.97% $ 148,226.14
TOTAL	$ 17,192,094.00	$ 1,432,674.50	$ 148,226.14

AEP Zone Monthly	**$ 1,845,720.83**
AEP Zone Annual	**$ 22,148,650.01**

Kentucky Power Company

REQUEST

Refer to page 12 of the Roush Testimony, line 8.

Mr. Roush states that, for the Street Lighting class, Kentucky Power is proposing to limit service on new metal or concrete poles to existing installations. Explain the reason for this proposal.

RESPONSE

The Company receives very few requests for new metal or concrete poles. Less than 1.5% of the current installations under Tariff S.L. are served under this provision.

WITNESS: David M Roush

Kentucky Power Company

REQUEST

Refer to pages 13 and 14 of the Roush Testimony.

In discussing the proposed experimental time-of-day service tariffs for residential, small general service, and large general service customers, Mr. Roush states that the tariffs were designed to be revenue neutral and that on average, customers would not pay more or less by selecting the experimental tariff.

a. Given that statement, provide the incentive customers would have to choose the time-of-day rate.

b. Given that Kentucky Power does not know where current customer usage falls within the three time periods included in the proposed tariffs, explain how Kentucky Power was able to design the tariffs to be revenue neutral.

RESPONSE

a. The objective of the time-of-day tariff offerings is that they provide an incentive to customers to manage their usage by consuming less during high price periods and/or shifting usage to lower cost periods. Thus customers do not simply save money by selecting the tariff, they save money by responding to the price signals provided by the tariff.

b. The Company utilized its load research information to develop class kWh usage by pricing period. This allowed the Company to design the rates on a revenue neutral basis for each class.

WITNESS: David M Roush

Kentucky Power Company

REQUEST

Refer to page 13 of the Roush Testimony.

Mr. Roush states that a $3.55 per-month charge would apply to customers of time-of-day tariffs to cover the additional cost of a more sophisticated meter.

a. Provide the cost to Kentucky Power of the more sophisticated meter.

b. At the rate of $3.55 per month, a customer would contribute $42.60 annually toward the cost of the meter. State whether Kentucky Power intends for this monthly charge to cease once the cost of the meter has been paid by the customer through the monthly charge. If no, explain why this proposed charge is reasonable.

RESPONSE

a. The incremental meter cost is $319.

b. The monthly charge of $3.55 includes a return on the investment, a return of the investment (depreciation), taxes and administrative and general expense based upon a 30-year useful life. Further, the Company is obligated to maintain, repair, replace and test the meter. The development of the charge in this manner is consistent with sound cost of service and ratemaking principles and is reasonable. The customer is neither purchasing the meter nor assuming the ongoing maintenance, repair and replacement obligations so the charge should not end once the customer has made payments equal to the initial capital outlay.

WITNESS: David M Roush

Kentucky Power Company

REQUEST

Refer to page 15 of the Roush Testimony.

Starting at line 4, Mr. Roush states that changes are being proposed to Tariff OP in order to make transitions between Tariff LGS and Tariff QP easier for customers.

a. Explain why these transitions occur. Include the frequency of these transitions in your response.

b. Provide the effects the proposed changes would have on current customers of Tariff QP.

RESPONSE

a. Tariff LGS is available to customers with normal maximum demand greater than 100 kW but not more than 1,000 kW. To receive service under Tariff QP, customers must contract for no less than 1,000 kW. Customers would transition from Tariff LGS to Tariff QP as their usage increased and their demand exceeded 1,000 kW. Similarly, customers would trasition from Tariff QP to Tariff LGS as their usage decreases and their demand falls below 1,000 kW. During a typical month, one or two customers move between Tariffs LGS and QP.

b. The proposed changes did not change the total requested revenue for Tariff QP. Under the proposed design, lower load factor customer served under Tariff QP would receive slightly lower increases than they would have received under the existing design.

WITNESS: David M Roush

Kentucky Power Company

REQUEST

Refer to pages 19-21 of the Roush Testimony and Exhibit DMR-4.

a. Identify where in the company's cost-of-service study the embedded cost of transmission of $49,514,393 included in its proposed base rates can be found.

b. Starting at line 16 of page 19, Mr. Roush states that, "[t]he proposed Transmission Adjustment Tariff (Tariff T.A.) compares the charges under PJM's Tariff to the embedded cost of transmission as determined from KPCo's cost-of-service study and included in KPCo's proposed base rates." State whether the difference in these two amounts is due to the PJM Tariff charges being calculated at the January 2010 rate. If not, explain why the PJM Tariff charges and the embedded cost of transmission would be different.

c. Absent the proposed transmission adjustment tariff, state whether the proposed rates would include the embedded cost of transmission per the cost-of- service study or the amount of $42,475,930 calculated and shown in the exhibit.

RESPONSE

a. For the requested information, please refer to attached pages 2 through 8 of this response.

b. The difference in the two amounts is primarily due to the difference between KPCo costs and AEP East average costs for transmission. For example, KPCo's embedded cost of transmission is based upon KPCo's own investment in transmission, own expenditures on transmission O&M, taxes, and other costs, net of any transmission-related receipts. Whereas, PJM Tariff charges for Network Integration Transmission Service and Schedule 1A charges in the AEP East Zone are based upon those costs for all AEP-East operating companies.

c. Absent the proposed transmission adjustment tariff, the proposed rates would include the embedded cost of transmission per the cost-of-service study.

WITNESS: David M Roush

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2009

	METHOD	TOTAL RETAIL	Bulk Tranmission	Subtransmission	Total Transmission
ELECTRIC PLANT IN SERVICE					
PRODUCTION PLANT DEMAND	PROD_DEMAND	531,432,767	0	0	0
TRANSMISSION PLANT OTHER DEMAND TOTAL	TRANS_TOTAL	428,413,799	296,890,763	131,523,036	428,413,799
TRANSMISSION PLANT GSU TOTAL	PROD_DEMAND	1,582,896	0	0	0
TRANSMISSION PLANT		429,996,695	296,890,763	131,523,036	428,413,799
DISTRIBUTION PLANT					
360 LAND AND LAND RIGHTS	DIST_CPD	6,506,018	0	0	0
361 STRUCTURES AND IMPROVEMENTS	DIST_CPD	4,229,545	0	0	0
362 STATION EQUIPMENT	DIST_CPD	56,358,693	0	0	0
364 POLES	DIST_POLES	154,130,634	0	0	0
365 OVERHEAD LINES	DIST_OHLINES	138,152,587	0	0	0
366 UNDERGROUND CONDUIT	DIST_UGLINES	4,921,900	0	0	0
367 UNDERGROUND LINES	DIST_UGLINES	7,962,163	0	0	0
368 TRANSFORMERS	DIST_TRANSF	101,021,740	0	0	0
369 SERVICES	DIST_SERV	40,657,586	0	0	0
370 METERS	DIST_METERS	23,285,957	0	0	0
371 INSTALLATIONS ON CUST PREMISES	DIST_OL	18,199,577	0	0	0
372 LEASED PROP ON CUST PREMISES	DIST_OL	0	0	0	0
373 STREET LIGHTING	DIST_SL	2,974,559	0	0	0
DISTRIBUTION PLANT TOTAL		558,400,959	0	0	0
PTD PLANT	FORMULA	1,519,830,421	296,890,763	131,523,036	428,413,799
GENERAL PLANT TOTAL	LABOR_M	54,714,617	2,120,295	939,294	3,059,589
HR-J 765 LINE - AFUDC	BULK_TRANS	1,700,358	1,700,358	0	1,700,358
ASSET RETIREMENT OBLIGATION (ARO)	PROD_DEMAND	-3,290,698	0	0	0
ELECTRIC PLANT IN SERVICE		1,572,954,698	300,711,416	132,462,330	433,173,746
ELECTRIC PLANT IN SERVICE - ADJUSTMENT		9,422,784	0	0	0
GROSS UTILITY PLANT	FORMULA	1,582,377,482	300,711,416	132,462,330	433,173,746
DEPRECIATION RESERVE					
PRODUCTION	RB_GUP_EPIS_P	223,176,661	0	0	0
TRANSMISSION	RB_GUP_EPIS_T	138,142,478	95,380,328	42,253,623	137,633,950
DISTRIBUTION	RB_GUP_EPIS_D	137,689,440	0	0	0
GENERAL	RB_GUP_EPIS_G	24,326,628	942,703	417,619	1,360,322
HR-J POST IN-SERVICE	BULK_TRANS	694,489	694,489	0	694,489
TOTAL DEPRECIATION RESERVE		524,029,696	97,017,520	42,671,242	139,688,761
ACCUMULATED DEPRECIATION - ADJUSTMENT	FORMULA	12,484,677	4,376,022	1,938,584	6,314,606
NET UTILITY PLANT	FORMULA	1,045,863,109	199,317,874	87,852,504	287,170,378
PLANT HELD FOR FUTURE USE TRANS	RB_GUP_EPIS_T	30,164	20,827	9,226	30,053

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2009

	METHOD	TOTAL RETAIL	Bulk Tranmission	Subtransmission	Total Transmission
WORKING CAPITAL					
WORKING CAPITAL CASH					
WORKING CAPITAL CASH EXCL SYS SALES	EXP_OM	48,802,040	240,440	106,515	346,954
SYSTEM SALES ADD BACK DEMAND	PROD_DEMAND	1,088,084	0	0	0
SYSTEM SALES ADD BACK ENERGY	PROD_ENERGY	17,940,858	0	0	0
TOTAL WORKING CAPITAL CASH		67,830,982	240,440	106,515	346,954
WORKING CAPITAL CASH - ADJUSTMENT		8,197,233	(92,538)	23,690	(68,848)
WORKING CAPITAL MATERIALS & SUPPLIES					
FUEL	PROD_ENERGY	42,771,452	0	0	0
PRODUCTION	PROD_DEMAND	7,560,912	0	0	0
EMISSIONS	PROD_ENERGY	8,159,539	0	0	0
TRANSMISSION AND DISTRIBUTION	TDPLANT	2,302,422	694,358	305,850	1,000,208
TOTAL MATERIALS & SUPPLIES		60,794,325	694,358	305,850	1,000,208
WORKING CAPITAL MATERIALS & SUPPLIES - ADJUSTMENT		(21,230,418)	0	0	0
WORKING CAPITAL PREPAYMENTS	RB_GUP_EPIS	1,968,585	376,346	165,779	542,126
WORKING CAPITAL PREPAYMENTS - ADJUSTMENT		15,390,035	596,393	264,203	860,596
TOTAL WORKING CAPITAL	FORMULA	132,950,742	1,814,999	866,037	2,681,037
CONSTRUCTION WORK IN PROGRESS					
PRODUCTION	RB_GUP_EPIS_P	5,665,163	0	0	0
TRANSMISSION	RB_GUP_EPIS_T	14,048,792	9,699,974	4,297,102	13,997,076
DISTRIBUTION	RB_GUP_EPIS_D	6,370,789	0	0	0
GENERAL	RB_GUP_EPIS_G	600,836	23,284	10,315	33,598
TOTAL CWIP		26,685,580	9,723,257	4,307,417	14,030,674
RATE BASE OFFSETS					
ACCUMULATED DEFERRED FIT	RB_GUP	(170,075,156)	(32,514,313)	(14,322,441)	(46,836,754)
CUSTOMER ADVANCES	TDPLANT	(59,442)	(17,926)	(7,896)	(25,823)
CUSTOMER DEPOSITS	CUST_DEP	(17,319,382)	0	0	0
RATE BASE OFFSETS - ADJUSTMENT	LABOR_M	(5,386,512)	(208,738)	(92,471)	(301,209)
TOTAL RATE BASE OFFSETS		(192,840,492)	(35,713,268)	(15,654,800)	(51,368,069)
TOTAL RATE BASE	FORMULA	1,012,689,103	175,163,689	77,380,384	252,544,073
OPERATING REVENUES					
TOTAL REVENUE	REVSALES	507,240,229	0	0	0
TOTAL REVENUE YEAR END CUSTOMERS	REVYEC	2,525,034	0	0	0
SALES OF ELECTRICITY		509,765,263	0	0	0
OTHER OPERATING REVENUES					
FORFEITED DISCOUNTS	FORT	1,809,068	0	0	0
MISCELLANEOUS SERVICE REVENUE	RB_GUP_EPIS_D	395,706	0	0	0
RENT FROM ELECTRIC PROP POLES	DIST_POLES	4,776,990	0	0	0
RENT FROM ELECTRIC PROP OTHER DIST	RB_GUP_EPIS_D	330,170	0	0	0
OTHER ELECTRIC REVENUE DIST	RB_GUP_EPIS_D	3,006,371	0	0	0
OTHER ELECTRIC REVENUE WHEELING	TRANS_TOTAL	69,928	48,460	21,468	69,928
OTHER ELECTRIC REVENUE PRODUCTION	PROD_ENERGY	862,171	0	0	0
TOTAL OTHER OPERATING REVENUES		11,250,404	48,460	21,468	69,928
OTHER OPERATING REVENUE - ADJUSTMENT		781,638	0	0	0
TOTAL OPERATING REVENUE		521,797,305	12,847,212	6,167,030	19,014,241

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2009

	METHOD	TOTAL RETAIL	Bulk Tranmission	Subtransmission	Total Transmission
OPERATION AND MAINTENANCE EXPENSE					
O&M EXPENSE PRODUCTION					
GENERATION EXPENSE DEMAND	PROD_DEMAND	20,811,678	0	0	0
GENERATION EXPENSE ENERGY	PROD_ENERGY	9,981,548	0	0	0
GENERATION EXPENSE FUEL	PROD_ENERGY	191,973,390	0	0	0
SYSTEM SALES	PROD_DEMAND	(8,704,672)	0	0	0
SYSTEM SALES	PROD_ENERGY	(143,526,865)	0	0	0
PURCHASED POWER DEMAND	PROD_DEMAND	98,530,187	0	0	0
PURCHASED POWER ENERGY	PROD_ENERGY	152,824,335	0	0	0
SYSTEM CONTROL	PROD_DEMAND	394,700	0	0	0
TOTAL PRODUCTION EXPENSES		474,515,838	0	0	0
O&M EXPENSE TOTAL TRANSMISSION	RB_GUP_EPIS_T	309,714	213,842	94,732	308,574
O&M EXPENSE REGIONAL MARKET	TRANS_TOTAL	1,174,225	813,738	360,487	1,174,225
DISTRIBUTION OPERATION EXPENSE					
580 SUPERVISION & ENGINEERING	TOTOXEXP	913,465	0	0	0
581 LOAD DISPATCHING	DIST_CPD	2,432	0	0	0
582 STATION EXPENSES	DIST_CPD	233,407	0	0	0
583 OVERHEAD LINES	DIST_OHLINES	1,137,658	0	0	0
584 UNDERGROUND LINES	DIST_UGLINES	83,980	0	0	0
585 STREET LIGHTING	DIST_SL	53,816	0	0	0
586 METERS	DIST_METERS	820,535	0	0	0
587 CUSTOMER INSTALLS	DIST_PCUST	135,655	0	0	0
588 MISCELLANEOUS DISTRIBUTION	RB_GUP_EPIS_D	2,775,090	0	0	0
589 RENTS	RB_GUP_EPIS_D	1,575,316	0	0	0
TOTAL DISTRIBUTION OPER EXP	FORMULA	7,731,354	0	0	0
DISTRIBUTION MAINTENANCE EXPENSE					
590 SUPERVISION & ENGINEERING	TOTMXEXP	8,891	0	0	0
591 STRUCTURES	DIST_CPD	5,205	0	0	0
592 STATION EQUIPMENT	DIST_CPD	512,025	0	0	0
593 OVERHEAD LINES	TOTOHLINES	29,521,237	0	0	0
594 UNDERGROUND LINES	TOTUGLINES	186,163	0	0	0
595 LINE TRANSFORMER	DIST_TRANSF	175,156	0	0	0
596 STREET LIGHTING	DIST_SL	54,605	0	0	0
597 METERS	DIST_METERS	53,708	0	0	0
598 MISC DISTRIBUTION PLANT	DIST_OL	532,162	0	0	0
TOTAL DISTRIBUTION MAINT EXP	FORMULA	31,049,152	0	0	0
DISTRIBUTION EXPENSES		38,780,506	0	0	0
CUSTOMER ACCOUNTS					
901 SUPERVISION	TOTOX234	413,373	0	0	0
902 METER READ	CUST_902	754,340	0	0	0
903 CUSTOMER RECORDS	CUST_903	6,009,640	0	0	0
904 UNCOLLECTIBLES	CUST_TOTAL	(4,235,288)	0	0	0
905 MISCELLANEOUS	TOTOX234	7,516	0	0	0
TOTAL CUSTOMER ACCOUNTS		2,949,581	0	0	0
TOTAL CUSTOMER SERVICES	CUST_TOTAL	1,802,110	0	0	0

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2009

	METHOD	TOTAL RETAIL	Bulk Tranmission	Subtransmission	Total Transmission
ADMINISTRATIVE & GENERAL EXPENSE					
A&G PRODUCTION DEMAND	PROD_DEMAND	8,343,100	0	0	0
A&G PRODUCTION ENERGY	PROD_ENERGY	2,865,019	0	0	0
A&G TRANSMISSION	EXP_OM_TRAN	1,293,502	895,708	396,800	1,292,508
A&G DISTRIBUTION	EXP_OM_DIST	8,706,885	0	0	0
A&G CUSTOMER ACCOUNTS	EXP_OM_CUSTACCT	1,523,898	0	0	0
A&G CUSTOMER SERVICE	EXP_OM_CUSTSERV	382,387	0	0	0
TOTAL A&G EXPENSE EXCLUDING REGULATORY		23,114,791	895,708	396,800	1,292,508
A&G REGULATORY RECLASSIFIED	FORMULA	1,088	228	100	329
TOTAL A & G EXPENSES		23,115,879	895,937	396,900	1,292,837
TOTAL O&M EXPENSES		390,416,316	1,923,516	852,120	2,775,636
OPERATION & MAINTENANCE EXPENSE - ADJUSTMENT		65,577,861	(740,304)	189,521	(550,783)
ADJUSTED OPERATING AND MAINTENANCE EXP	FORMULA	455,994,177	1,183,212	1,041,640	2,224,852
DEPRECIATION EXPENSE					
PRODUCTION	RB_GUP_EPIS_P	19,561,410	0	0	0
TRANSMISSION	RB_GUP_EPIS_T	7,597,948	5,245,995	2,323,983	7,569,979
DISTRIBUTION	RB_GUP_EPIS_D	18,979,469	0	0	0
GENERAL PLANT	RB_GUP_EPIS_G	4,447,255	172,340	76,347	248,686
TOTAL DEPRECIATION EXPENSE		50,586,082	5,418,335	2,400,330	7,818,665
DEPRECIATION EXPENSE - ADJUSTMENT		12,957,354	4,376,022	1,938,584	6,314,606
ADJUSTED DEPRECIATION EXPENSE	FORMULA	63,543,436	9,794,357	4,338,914	14,133,271
TAXES OTHER THAN INCOME					
FEDERAL INSURANCE TAX	LABOR_M	2,856,586	110,698	49,039	159,738
FEDERAL UNEMPLOYMENT EXCISE TAX	LABOR_M	27,478	1,065	472	1,537
FEDERAL EXCISE TAX	LABOR_M	9,727	377	167	544
KENTUCKY SALES & USE TAX	TDPLANT	(566,333)	(170,793)	(75,231)	(246,024)
KENTUCKY R/E PRS & PROPERTY TAX	RB_GUP	9,181,190	1,755,225	773,170	2,528,395
LOUISIANA REAL & PERSONAL PROPERTY TAX	RB_GUP	199	38	17	55
KENTUCKY UNEMPLOYMENT TAX	LABOR_M	38,434	1,489	660	2,149
KENTUCKY PSC MAINTENANCE TAX	REVSALES	690,213	0	0	0
KENTUCKY MUNICIPAL LICENSE TAX	RB_GUP	99	19	8	27
KENTUCKY LICENSE TAX	RB_GUP	114	22	10	31
OHIO GROSS RECEIPTS TAX	REVSALES	222,171	0	0	0
OHIO FRANCHISE TAX	PROD_DEMAND	18,414	0	0	0
WEST VIRGINIA REAL & PERSONAL PROPERTY TAX	RB_GUP	954	182	80	263
WEST VIRGINIA UNEMPLOYMENT TAX	LABOR_M	1,620	63	28	91
WEST VIRGINIA FRANCHISE TAX	LABOR_M	(39,839)	(1,544)	(684)	(2,228)
WEST VIRGINIA LICENSE TAX	LABOR_M	55	2	1	3
PENNSYLVANIA LICENSE TAX	PROD_DEMAND	39	0	0	0
FRINGE BENEFIT LOADING FICA	LABOR_M	(1,111,545)	(43,074)	(19,082)	(62,157)
FRINGE BENEFIT LOADING FUT	LABOR_M	(11,724)	(454)	(201)	(656)
FRINGE BENEFIT LOADING SUT	LABOR_M	(12,498)	-484	(215)	-699
R/E PRS FRANCHISE - CARRS TAX	RB_GUP	(51,723)	(9,888)	(4,356)	(14,244)
TOTAL TAXES OTHER THAN INCOME		11,253,631	1,773,025	781,361	2,554,385
TAXES OTHER THAN INCOME TAXES - ADJUSTMENT		220,301	33,644	14,840	48,484
ADJUSTED TAXES OTHER THAN INCOME TAX	FORMULA	11,473,932	1,806,669	796,201	2,602,870
TOTAL OPERATING REVENUE		521,797,305	12,847,212	6,167,030	19,014,241
TOTAL OPERATING EXPENSE BEFORE TAXES		531,011,545	12,784,238	6,176,755	18,960,993
GROSS OPERATING INCOME	FORMULA	(9,214,240)	(12,735,778)	(6,155,288)	(18,891,065)
INTEREST CHARGE TAX	RATEBASE	(37,443,850)	(6,476,620)	(2,861,115)	(9,337,735)
INTEREST SYNCRONIZATION TAX	RATEBASE	2,732,876	472,702	208,821	681,524
NET OPER INCOME BEFORE INCOME TAX	FORMULA	(43,925,214)	(18,739,695)	(8,807,581)	(27,547,276)

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2009

	METHOD	TOTAL RETAIL	Bulk Tranmission	Subtransmission	Total Transmission
INCOME TAXES					
SCHEDULE M INCOME ADJUSTMENTS					
BOOK VS TAX DEPRECIATION NORMALIZED	RB_GUP	(33,837,720)	(6,468,965)	(2,849,556)	(9,318,521)
BOOK VS TAX DEPRECIATION FLOWTHRU	RB_GUP	8,247,102	1,576,649	694,508	2,271,158
AOFUDC - HR/J	BULK_TRANS	11,364	11,364	0	11,364
ABFUDC	RB_CWIP	(807,411)	(294,191)	(130,327)	(424,518)
ABFUDC - HR/J	BULK_TRANS	22,044	22,044	0	22,044
SEC 481 PENSIONS/OPEB ADJUSTMENT	LABOR_M	(117)	(5)	(2)	(7)
INTEREST CAPITALIZATION	RB_GUP	1,565,806	299,345	131,860	431,205
DEFERRED FUEL	FUELREV	21,616,789	0	0	0
PROVISION FOR POSSIBLE REVENUE REFUNDS	REV	(704,906)	(66)	(29)	(95)
PERCENT REPAIR ALLOWANCE	RB_GUP	(1,783,802)	(341,020)	(150,218)	(491,239)
BOOK/TAX UNIT OF PROPERTY	RB_GUP	(3,603,276)	(688,860)	(303,441)	(992,301)
BOOK/TAX UNIT OF PROPERTY - SEC 481	RB_GUP	(27,693,495)	(5,294,336)	(2,332,136)	(7,626,472)
TAX AMORTIZATION OF POLLUTION CONTROL	PROD_DEMAND	2,724,318	0	0	0
CAPITALIZED RELOCATION COSTS	RB_GUP	(175,409)	(33,534)	(14,772)	(48,306)
MTM BOOK GAIN ABOVE THE LINE TAX DEFERRAL	PROD_ENERGY	(15,542,306)	0	0	0
MARK & SPREAD DEFL -283 A/L	PROD_ENERGY	10,225,186	0	0	0
MARK & SPREAD DEFL -190 A/L	PROD_ENERGY	(9,599,748)	0	0	0
PROVISION FOR WORKERS COMP	LABOR_M	(62,124)	(2,407)	(1,066)	(3,474)
ACCRUED BOOK PENSION EXPENSE	LABOR_M	3,441,009	133,346	59,072	192,418
ACCURED BOOK PENSION COSTS - SFAS 158	LABOR_M	(1,093,177)	(42,363)	(18,767)	(61,129)
SUPPLEMENTAL EXECUTIVE RETIREMENT	LABOR_M	3,391	131	58	190
ACCRUED SUPPLEMENTAL EXEC RETIREMENT COSTS SFAS	LABOR_M	(1,798)	(70)	(31)	(101)
ACCRUED BOOK SUPPLEMENTAL SAVINGS PLAN EXP	LABOR_M	98,892	3,832	1,698	5,530
ACCRUED PSI PLAN EXPENSES	LABOR_M	(386,625)	(14,982)	(6,637)	(21,620)
BOOK PROVISION UNCOLLECTIBLE ACCOUNTS	CUST_TOTAL	(4,520,982)	0	0	0
PROVISION FOR TRADING CREDIT RISK ABOVE THE LINE	PROD_ENERGY	104,118	0	0	0
PROVISION FOR FAS 157 A/L	PROD_ENERGY	38,284	0	0	0
VACATION PAY SEC 481	LABOR_M	131,477	5,095	2,257	7,352
ACCRUED STATE INTEREST EXPENSE	REV	(1)	(0)	(0)	(0)
ACCRUED LONG TERM INTEREST EXPENSE - FIN 48	REV	260,839	24	11	35
REG ASSET ON DEFERRED RTO COSTS	TRANS_TOTAL	147,454	102,186	45,268	147,454
FEDERAL MITIGATION PROGRAMS	PROD_ENERGY	(426,072)	0	0	0
STATE MITIGATION PROGRAMS	PROD_ENERGY	(630,761)	0	0	0
DEFERRED BOOK CONTRACT REVENUE	REV	(13,380)	(1)	(1)	(2)
DEFERRED DEMAND SIDE MANAGEMENT EXPENSE	LABOR_M	24,873	964	427	1,391
BOOK > TAX BASIS - EMA A/C 283	PROD_ENERGY	214,244	0	0	0
DEFERRED TAX GAIN EPA AUCTION	PROD_ENERGY	(38,059)	0	0	0
ADVANCE RENTAL INCOME	REV_OTHER	(8,933)	(38)	(17)	(56)
REG LIABILITY UNREALIZED MTM GAIN DEFERRAL	PROD_ENERGY	3,168,780	0	0	0
REG ASSET SFAS 158 PENSIONS	LABOR_M	1,093,177	42,363	18,767	61,129
REG ASSET SFAS 158 SERP	LABOR_M	1,798	70	31	101
REG ASSET SFAS 158 OPEB	LABOR_M	1,179,816	45,720	20,254	65,974
CAPITALIZED SOFTWARE COSTS TAX	RB_GUP	(764)	(146)	(64)	(210)
BOOK LEASES CAPITALIZED FOR TAX	RB_GUP	(71,801)	(13,727)	(6,047)	(19,773)
CAPITALIZED SOFTWARE COSTS BOOK	RB_GUP	1,331,392	254,530	112,120	366,650
BOOK AMORTIZATION LOSS REAQUIRED DEBT	RB_GUP	33,346	6,375	2,808	9,183
ACCRUED SFAS 106 POST RETIREMENT EXPENSE	LABOR_M	618,802	23,980	10,623	34,603
SFAS 106 POST RETIREMENT MEDICARE BENEFITS	LABOR_M	(851,119)	(32,982)	(14,611)	(47,594)
ACCRUED OPEB COSTS SFAS 158	LABOR_M	(1,179,816)	(45,720)	(20,254)	(65,974)
ACCRUED SFAS 112 POST EMPLOYMENT BENEFITS	LABOR_M	(359,347)	(13,925)	(6,169)	(20,094)
ACCRUED BOOK ARO EXPENSE SFAS 143	RB_GUP	2,852,343	545,300	240,203	785,503
ACCRUED SALES & USE TAX RESERVE	REV	(1,511,166)	(141)	(62)	(203)
ACCRUED SIT TAX RESERVE - LONG TERM FIN 48	REV	51,396	5	2	7
NON TAXABLE DEFERRED COMPENSATION CSV EARN	LABOR_M	34,434	1,334	591	1,926
NONDEDUCTIBLE MEALS & TRAVEL EXPENSE	LABOR_M	82,713	3,205	1,420	4,625
FIN 48 DSIT	REV	(43,069)	(4)	(2)	(6)
REMOVAL COSTS	RB_GUP	(8,077,641)	(1,544,252)	(680,238)	(2,224,490)
BOOK DEFFERAL MERGER COSTS	REV	(32,666)	(3)	(1)	(4)
REG ASSET ACCRUED SFAS 112	LABOR_M	359,347	13,925	6,169	20,094
1991 - 1996 IRS AUDIT SETTLEMENT	REV	(26,075)	(2)	(1)	(3)
TOTAL SCHEDULE M ADJUSTMENTS - PERBOOKS		(53,399,032)	(11,739,954)	(5,186,302)	(16,926,257)
ADJUSTMENTS TO PERBOOKS SCHEDULE M		27,448,160	2,306,647	1,016,133	3,322,780

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2009

	METHOD	TOTAL RETAIL	Bulk Tranmission	Subtransmission	Total Transmission
WEST VIRGINIA STATE TAXABLE INCOME	FORMULA	(69,876,086)	(28,173,003)	(12,977,750)	(41,150,753)
BONUS DEPRECIATION ADJUSTMENT FOR STATE	RB_GUP	22,637,800	4,327,807	1,906,384	6,234,191
KENTUCKY STATE TAXABLE INCOME	FORMULA	(47,238,286)	(23,845,196)	(11,071,366)	(34,916,562)
STATE INCOME TAX KENTUCKY	FORMULA	(2,834,297)	(343,783)	(153,620)	(497,404)
STATE INCOME TAX WEST VIRGINIA	FORMULA	(159,457)	(21,987)	(9,782)	(31,769)
TOTAL STATE INCOME TAXES		(2,993,754)	(365,770)	(163,403)	(529,173)
TAXABLE OPERATING INCOME	FORMULA	(66,882,332)	(27,807,233)	(12,814,347)	(40,621,580)
GROSS CURRENT FIT	FORMULA	(23,408,816)	(3,244,162)	(1,443,178)	(4,687,340)
FEEDBACK PRIOR ITC NORMALIZATION TAX	RB_GUP	(818,986)	(156,571)	(68,969)	(225,539)
FEDERAL INCOME TAX - ITC - ADJUSTMENT		292,039	55,831	24,593	80,424
CURRENT FIT AND ITC	FORMULA	(23,935,763)	(3,335,062)	(1,483,364)	(4,818,426)
DEFERRED FIT - CURRENT YEAR					
DIFIT FOR BOOK VS TAX DEPRECIATION NORMALIZED	RB_GUP	11,706,400	2,237,984	985,824	3,223,809
DFIT ABFUDC	RB_CWIP	282,595	102,967	45,615	148,582
WSEC 482 PENSION/OPEB ADJUSTMENT	LABOR_M	41	2	1	2
INTEREST CAPITALIZATION	RB_GUP	(548,032)	(104,771)	(46,151)	(150,922)
DEFERRED FUEL EXPENSE	FUELREV	(7,565,876)	0	0	0
PROVISION FOR POSSIBLE REVENUE REFUNDS	REV	246,717	23	10	33
PERCENT REPAIR ALLOWANCE	RB_GUP	624,331	119,357	52,576	171,934
BOOK/TAX UNIT OF PROPERTY	RB_GUP	1,261,147	241,101	106,204	347,305
BOOK/TAX UNIT OF PROPERTY - SEC 481	RB_GUP	9,692,723	1,853,017	816,248	2,669,265
TAX AMORTIZATION POLLUTION CONTROL	PROD_DEMAND	(953,511)	0	0	0
CAPITALIZED RELOCATION COSTS	RB_GUP	61,393	11,737	5,170	16,907
MTM BOOK GAIN ABOVE THE LINE TAX DEFERRAL	PROD_ENERGY	5,439,807	0	0	0
MARK & SPREAD DEFL -283 A/L	PROD_ENERGY	(3,578,816)	0	0	0
MARK & SPREAD DEFL -190 A/L	PROD_ENERGY	3,359,913	0	0	0
PROVISION FOR WORKERS COMP	LABOR_M	21,743	843	373	1,216
ACCRUED BOOK PENSION EXPENSE	LABOR_M	(1,204,352)	(46,671)	(20,675)	(67,346)
ACCURED BOOK PENSION COSTS - SFAS 158	LABOR_M	382,612	14,827	6,568	21,395
SUPPLEMENTAL EXECUTIVE RETIREMENT	LABOR_M	(1,187)	(46)	(20)	(66)
ACCRUED SUPPLEMENTAL EXEC RETIREMENT COSTS SFAS	LABOR_M	629	24	11	35
ACCRUED BOOK SUPPLEMENTAL SAVINGS PLAN EXP	LABOR_M	(34,612)	(1,341)	(594)	(1,935)
ACCRUED PSI PLAN EXPENSES	LABOR_M	135,318	5,244	2,323	7,567
BOOK PROVISION UNCOLLECTIBLE ACCOUNTS	CUST_TOTAL	1,582,343	0	0	0
ACCRUED COMPANYWIDE INCENTIVE PLAN	LABOR_M	1	0	0	0
PROVISION FOR TRADING CREDIT RISK ABOVE THE LINE	PROD_ENERGY	(36,442)	0	0	0
PROVISION FOR FAS 157 A/L	PROD_ENERGY	(13,400)	0	0	0
ACCRUED BOOK VACATION PAY	LABOR_M	(46,017)	(1,783)	(790)	(2,573)
ACCRUED LONG TERM INTEREST EXPENSE - FIN 48	REV	(91,294)	(8)	(4)	(12)
REG ASSET ON DEFERRED RTO COSTS	TRANS_TOTAL	(51,609)	(35,765)	(15,844)	(51,609)
FEDERAL MITIGATION PROGRAMS	PROD_ENERGY	149,126	0	0	0
STATE MITIGATION PROGRAMS	PROD_ENERGY	220,767	0	0	0
DEFERRED BOOK CONTRACT REVENUE	REV	4,683	0	0	1
DEFERRED DEMAND SIDE MANAGEMENT EXPENSE	LABOR_M	(8,705)	(337)	(149)	(487)
BOOK > TAX BASIS - EMA A/C 283	PROD_ENERGY	(74,985)	0	0	0
DEFERRED TAX GAIN EPA AUCTION	PROD_ENERGY	13,321	0	0	0
ADVANCE RENTAL INCOME	REV_OTHER	3,127	13	6	19
REG ASSET UNREAL MTM GAIN DEFERRAL	PROD_ENERGY	(1,109,073)	0	0	0
REG ASSET SFAS 158 PENSIONS	LABOR_M	(382,612)	(14,827)	(6,568)	(21,395)
REG ASSET SFAS 158 SERP	LABOR_M	(629)	(24)	(11)	(35)
REG ASSET SFAS 158 OPEB	LABOR_M	(412,935)	(16,002)	(7,089)	(23,091)
CAPITALIZED SOFTWARE COST TAX	RB_GUP	268	51	23	74
BOOK LEASES CAPITALIZED FOR TAX	RB_GUP	25,131	4,804	2,116	6,921
CAPITALIZED SOFTWARE COST BOOK	RB_GUP	(465,987)	(89,086)	(39,242)	(128,327)
BOOK AMORTIZATION LOSS REAQUIRED DEBT	RB_GUP	(11,671)	(2,231)	(983)	(3,214)
ACCRUED SFAS 106 POST RETIREMENT EXPENSE	LABOR_M	(216,581)	(8,393)	(3,718)	(12,111)
ACCRUED OPEB COSTS SFAS 158	LABOR_M	412,936	16,002	7,089	23,091
ACCRUED SFAS 112 POST EMPLOYMENT BENEFITS	LABOR_M	125,773	4,874	2,159	7,033
ACCRUED BOOK ARO EXPENSE SFAS 143	RB_GUP	(998,320)	(190,855)	(84,071)	(274,926)
ACCRUED SALES & USE TAX RESERVE	REV	528,909	49	22	71
ACCRUED SIT TAX RESERVE - LONG TERM FIN 48	REV	(17,989)	(2)	(1)	(2)
FIN 48 DSIT	REV	15,074	1	1	2
BOOK DEFFERAL MERGER COSTS	REV	11,433	1	0	2
REG ASSET ACCRUED SFAS 112	LABOR_M	(125,772)	(4,874)	(2,159)	(7,033)
1991 - 1996 IRS AUDIT SETTLEMENT	REV	9,127	1	0	1
FEDERAL INCOME TAX - DEFERRED - ADJUSTMENT		(8,016,836)	(503,477)	(221,782)	(725,259)
TOTAL CURRENT YEAR DFIT		10,350,145	3,592,432	1,582,488	5,174,920

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2009

	METHOD	TOTAL RETAIL	Bulk Tranmission	Subtransmission	Total Transmission
DEFERRED FIT - PRIOR YEAR					
GAIN/LOSS ON ACRS/MACRS PROPERTY	RB_GUP	(918,515)	(175,598)	(77,350)	(252,949)
ABFUDC	RB_CWIP	(181,758)	(66,226)	(29,338)	(95,564)
ABFUDC HRJ POST-IN SERVE	BULK_TRANS	(7,449)	(7,449)	0	(7,449)
ABFUDC - HRJ (TC)	BULK_TRANS	(319,206)	(319,206)	0	(319,206)
TAXES CAPITALIZED	LABOR_M	(46,737)	(1,811)	(802)	(2,613)
PENSIONS CAPITALIZED	LABOR_M	(5,793)	(224)	(99)	(324)
SAVING PLAN CAPITALIZED	LABOR_M	(3,358)	(130)	(58)	(188)
INTEREST CAPITALIZED	RB_GUP	257,373	49,204	21,674	70,878
ADR REPAIR ALLOWANCE	RB_GUP	(692,281)	(132,348)	(58,299)	(190,646)
CAPITALIZED RELOCATION COSTS	RB_GUP	293,928	56,192	24,752	80,944
TOTAL PRIOR YEAR DFIT		(1,623,796)	(597,597)	(119,520)	(717,117)
FEDERAL INCOME TAXES	FORMULA	(15,209,414)	(2,103,006)	(941,982)	(3,044,988)
TOTAL INCOME TAXES		(18,203,168)	(2,468,776)	(1,105,384)	(3,574,160)
TOTAL EXPENSES	FORMULA	512,808,377	10,315,462	5,071,371	15,386,833
NET OPERATING INCOME	FORMULA	8,988,928	2,548,488	1,102,140	3,650,628
AFUDC OFFSET					
PRODUCTION	PROD_DEMAND	554,942	0	0	0
TRANSMISSION	RB_GUP_EPIS_T	277,698	191,736	84,939	276,676
DISTRIBUTION	RB_GUP_EPIS_D	164,723	0	0	0
GENERAL	LABOR_M	26,898	1,042	462	1,504
AFUDC OFFSET		1,024,261	192,779	85,401	278,180
AFUDC OFFSET - ADJUSTMENT		1,190,864	224,135	99,292	323,428
ADJUSTED NET OPERATING INCOME	FORMULA	11,204,053	2,948,664	1,280,352	4,229,016
REVENUE REQUIREMENT ANALYSIS					
TOTAL RATE BASE		1,012,689,103	175,163,689	77,380,384	252,544,073
ADJUSTED NET OPERATING INCOME	FORMULA	11,204,053	2,948,664	1,280,352	4,229,016
TOTAL EXPENSES	FORMULA	512,808,377	10,315,462	5,071,371	15,386,833
TOTAL OPERATING REVENUE	FORMULA	521,797,305	12,847,212	6,167,030	19,014,241
LESS:					
OTHER OPERATING REVENUE	FORMULA	12,032,042	74,557	34,888	109,445
SALES OF ELECTRICITY	FORMULA	509,765,263	12,772,655	6,132,142	18,904,797
REQUIRED INCOME	FORMULA	86,239,690	15,730,116	7,077,599	22,807,715
INCOME INCREASE	FORMULA	75,035,636	12,781,452	5,797,247	18,578,700
GROSS REVENUE CONVERSION FACTOR		1.647564			
PROPOSED REVENUE INCREASE		123,626,013	21,058,261	9,551,336	30,609,596
TOTAL REVENUE REQUIRED	FORMULA	645,423,318	33,905,472	15,718,365	49,623,838
LESS:					
OTHER OPERATING REVENUE	FORMULA	12,032,042	74,557	34,888	109,445
REQUIRED RATE REVENUE	FORMULA	633,391,276	33,830,915	15,683,478	49,514,393

Kentucky Power Company

REQUEST

Refer to the Roush Testimony at page 20.

Starting at line 20, Mr. Roush states that the Tariff TA would not apply to Tariffs OL and SL since they do not have an embedded cost of transmission. Given that $49,514,393 of transmission costs are included in Kentucky Power's proposed rates, and therefore are proposed to be recovered through the lighting schedules, explain why it would not be appropriate to apply the Tariff TA to the lighting schedules.

RESPONSE

KPCo's proposed rates include $49,514,393 of transmission costs, however none of that cost is included in the Tariff OL and SL class revenue requirements. Transmission costs are allocated to the customer classes based upon the class usage at the time of the Company's monthly peak demands. The lighting classes were not consuming electricity at the time of the Company's monthly peaks and therefore are not allocated transmission costs. Given this, it would not be appropriate to apply Tariff TA to the lighting schedules.

WITNESS: David M Roush

Kentucky Power Company

REQUEST

Refer to page 21 of the Roush Testimony.

Mr. Roush discusses the annual filings for Tariff TA and the BAF. Explain whether Kentucky Power anticipates that these annual filings would be tariff filings or case filings requiring an order from the Commission.

RESPONSE

Kentucky Power anticipates that these annual filings would be tariff filings similar to the way the Net Merger Savings Credit BAF filings were handled in the past.

WITNESS: David M Roush

Kentucky Power Company

REQUEST

Refer to the Roush Testimony, Exhibit DMR-3, page 1 of 4.

This schedule shows that the Street Lighting class has a current return on rate base of 14.45 percent, more than twice the return of any other class. Given its high rate of return, explain why it is appropriate to allocate any revenue increase to this class.

RESPONSE

Since the Company has proposed to eliminate only 10% of the difference from cost-of-service in this proceeding to mitigate the impact on classes with low rates of return, the concept applies correspondingly to classes with high rates of return. Under the Company's proposal, the street lighting class does receive a below average increase and is moving closer to cost of service in the same proportion as all other classes.

WITNESS: David M Roush

Kentucky Power Company

REQUEST

Refer to the Direct Testimony of Errol K. Wagner ("Wagner Testimony") at page 8.

Starting at line 13, Mr. Wagner states that Kentucky Power paid an annual capacity charge of $57,077,395 for the September 30, 2009 test year. Provide the capacity charge for each of the last five-year periods ending September 30.

RESPONSE

Attached on page 2 of 2 is the monthly AEP Pool capacity charge KPCo paid for the sixty months ending September 30, 2009.

WITNESS: Errol K Wagner

Kentucky Power Compant
AEP Pool Capacity Charge
for the Following Twelve Months Periods

(1)	Month (2)	Twelve Months Ending 2009 (3)	Twelve Months Ending 2008 (4)	Twelve Months Ending 2007 (5)	Twelve Months Ending 2006 (6)	Twelve Months Ending 2005 (7)
1	Oct	$4,793,805	$3,139,594	$2,726,094	$3,068,852	$1,857,139
2	Nov	$4,751,761	$3,095,797	$2,785,770	$3,009,664	$1,793,310
3	Dec	$5,276,715	$3,100,767	$2,830,229	$3,285,102	$1,864,356
4	Jan	$5,164,497	$3,714,122	$2,651,161	$3,173,069	$2,484,659
5	Feb	$4,496,431	$3,827,012	$3,110,369	$3,274,426	$3,034,222
6	Mar	$4,476,614	$3,915,346	$3,958,243	$3,492,649	$3,178,613
7	Apr	$4,478,997	$4,138,446	$3,655,866	$3,432,888	$3,240,968
8	May	$4,702,227	$4,194,177	$4,350,459	$3,536,993	$3,249,662
9	Jun	$4,480,173	$3,959,874	$3,220,907	$3,816,015	$3,218,782
10	Jul	$4,740,041	$4,157,357	$3,208,316	$3,610,397	$2,806,143
11	Aug	$4,917,888	$4,075,591	$3,225,025	$2,872,903	$2,564,201
12	Sep	$4,798,246	$4,856,078	$3,088,727	$2,790,646	$2,585,550
13	Total	$57,077,395	$46,174,161	$38,811,166	$39,363,604	$31,877,605

Kentucky Power Company

REQUEST

Refer to the Wagner Testimony, pages 8-10, concerning the AEP transmission agreement and Section V, Workpaper S-4, page 7 in Volume 2 of the application.

Page 10 of the Wagner Testimony refers to the workpaper and the Bethel Testimony. The workpaper reflects an increase in Kentucky Power's transmission agreement revenues while the Bethel Testimony refers to Kentucky Power receiving a cost decrease due to changes in how transmission issues are dealt with by the AEP East Companies. Explain whether the revenue increase referenced by Mr. Wagner and the cost decrease discussed in the Bethel Testimony are, or are not, one and the same.

RESPONSE

They are not the same. Section V, Workpaper S-4, Page 7 adjusts the test year transmission revenues for two known and measurable adjustments. Column 5 annualizes the test year transmission revenues to the September 2009 actual level. Column 6 adjusts the transmission revenues to reflect the increase in KPCo's MLR from 7.069% to 7.084%. Increasing the Company's MLR increases KPCo's investment obligation and reduces KPCo's surplus. This, in turn, reduces the monthly transmission revenue KPCo receives from the Transmission Pool. Please note the monthly $7,750 amount in column 6 should be a negative $7,750 as shown on Exhibit EKW-12. Therefore, the amount shown on line 13 column 7 should be ($1,000,837) not the ($1,186,837) as currently shown. Taking the KPSC Jurisdiction allocation factor of 0.986 times the ($1,000,837) results in a negative adjustment of ($986,825) versus the negative adjustment of ($1,170,221) as shown on Section V, Workpaper S-4, Page 7, Line Number 16.

The cost decrease referenced by Mr. Bethel is not directly related to the adjustments discussed above, but is related to the proposed modifications to the Transmission Agreement in FERC Docket No.ER09-1279. The cost decreases that result for Kentucky Power Company in the as filed proposal in Docket ER09-1279 are not contained in the adjustment referenced above. The cost decrease referenced by Mr. Bethel will automatically flow through the Transmission Tracker (Tariff T.A.) proposed by KPCO in this case if Tariff T. A. is approved by the PSC and the as filed modifications to the Transmission Agreement are approved by FERC in Docket ER09-1279.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

Refer to page 10 of the Wagner Testimony and Workpaper S-2, page 3.

a. Explain why the gross revenue conversion factor is based on a three-year average of uncollectible accounts rather than on the test-year level of uncollectible accounts.

b. Describe the company's standard policy on when it charges, or writes off, uncollectible accounts as bad debts.

c. For the three 12-months periods included in the workpaper, provide an end-of-period comparison of the level of uncollectible accounts that were 30, 60 and 90 days old.

RESPONSE

a. The primary purpose of the three year average is so any one year event does not have a disproportionate and improper impact on the conversion factor. For example, if a large industrial customer went out of business in the test year owing KPCo a sixty day balance on their account, it would have an unreasonable impact on the conversion factor if only a one year uncollectible percentage were used. In addition, a three year average allows any trends in the uncollectible percentage (upward or downward) to be seen readily.

b. KPCo's charge-off policy is that any final bill that remains unpaid at the end of the fourth month after the final bill was generated will be transferred to an uncollectible account receivable status. For example, any unpaid portion of a final bill produced in August will be charged-off as uncollectible at the end of December.

c. Attached is the requested information.

WITNESS: Errol K Wagner

Kentucky Power Company
Uncollectible Accounts
12 Months Ended September 30, Years 2007 thru 2009

	Net Charge Offs	Accounts Receivable Aging 30 Day	60 Day	90 Day	Total
October 2006	$249,377.15	$3,995,846	$1,126,159	$455,465	$5,577,470
November 2006	$88,385.86	$3,582,577	$1,080,740	$475,078	$5,138,395
December 2006	$76,757.04	$3,964,157	$850,271	$431,456	$5,245,884
January 2007	$79,482.80	$5,004,059	$869,738	$362,808	$6,236,605
February 2007	$57,516.54	$5,651,986	$1,270,960	$345,349	$7,268,295
March 2007	$33,607.23	$6,058,380	$648,439	$283,796	$6,990,615
April 2007	$5,700.17	$5,744,958	$835,989	$298,491	$6,879,438
May 2007	$74,543.38	$4,327,266	$879,847	$328,752	$5,535,865
June 2007	$102,668.60	$3,594,738	$825,331	$387,210	$4,807,279
July 2007	$253,610.06	$3,916,373	$678,902	$380,612	$4,975,887
August 2007	$194,333.12	$4,568,682	$670,701	$338,045	$5,577,428
September 2007	$180,097.25	$4,087,643	$634,364	$308,845	$5,030,852
Total Year 2007	**$1,396,079.20**				
October 2007	$86,816.54	$4,342,996	$534,879	$236,532	$5,114,407
November 2007	$71,390.28	$3,707,123	$642,653	$212,590	$4,562,366
December 2007	$38,381.00	$3,663,995	$518,650	$210,982	$4,393,627
January 2008	$53,381.39	$4,876,202	$452,115	$171,252	$5,499,569
February 2008	$55,525.51	$6,067,328	$517,357	$151,508	$6,736,193
March 2008	($27,658.59)	$6,048,583	$667,928	$183,178	$6,899,689
April 2008	$18,426.76	$5,621,512	$675,848	$208,007	$6,505,367
May 2008	$31,350.67	$4,730,584	$728,922	$240,252	$5,699,758
June 2008	$123,036.80	$3,470,927	$676,200	$270,427	$4,417,554
July 2008	$330,918.17	$4,213,409	$558,412	$274,976	$5,046,797
August 2008	$183,584.32	$5,454,055	$545,986	$239,278	$6,239,319
September 2008	$103,196.50	$4,911,449	$586,735	$213,104	$5,711,288
Total Year 2008	**$1,068,349.35**				
October 2008	$83,877.88	$4,157,409	$557,607	$114,628	$4,829,644
November 2008	$50,621.28	$4,526,324	$503,053	$136,231	$5,165,608
December 2008	$57,016.74	$4,601,513	$387,733	$97,186	$5,086,432
January 2009	$53,637.10	$7,207,256	$358,908	$109,612	$7,675,776
February 2009	$20,812.35	$8,181,358	$688,442	$154,218	$9,024,018
March 2009	$20,470.27	$7,250,651	$875,778	$217,715	$8,344,144
April 2009	$82,240.31	$6,031,177	$999,584	$323,315	$7,354,076
May 2009	$88,765.73	$5,235,368	$850,830	$371,840	$6,458,038
June 2009	$151,572.72	$4,989,054	$790,748	$382,276	$6,162,078
July 2009	$239,083.42	$4,582,631	$664,012	$368,373	$5,615,016
August 2009	$255,240.51	$5,698,515	$713,673	$332,391	$6,744,579
September 2009	$163,808.59	$5,482,491	$711,034	$283,594	$6,477,119
Total Year 2009	**$1,267,146.90**				

Kentucky Power Company

REQUEST

Refer to page 15 of the Wagner Testimony.

Explain whether the change to Kentucky Power's environmental surcharge calculation referenced therein requires a change to its environmental surcharge tariff.

RESPONSE

Nothing in the Environmental Surcharge Tariff needs to be changed as a result of the discussion at page 15 of my testimony.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

Refer to page 26 of the Wagner Testimony.

The last sentence concerning the coal stock adjustment indicates that the adjustment was made by reducing short- term debt because "[t]he coal inventory is 'usually' financed with short-term debt."

a. In the context of this sentence, explain what 'usually' means.

b. If coal inventory is not "always" fianced by short-term debt, explain why it is appropriate to apply the adjustment entirely to short-term debt.

c. Explain how the financing for the coal inventory can be traced to short-term debt.

RESPONSE

a. In the context of this sentence the term "usually" means "the general practice" is to use short term debt.

In Case Numbers 8429, 8734, 91-066 and 2005-00341 KPCo has consistently reflected adjustments (increase or decrease) in the value of fuel inventory by making an adjustment to the short term debt value at the end of the test year. In Case No. 8429 KPCo proposed an increase in its short term debt of $10,939,466 to reflect an equal increase in the value of fuel inventory.

The Commission at page eight of its June 18,1982 Order in that case states "the Commission has reduced Kentucky Power's adjustment [to its short term debt] by $4,108,704 to reflect the lower level of inventory and the weighted average price".

The September 2009 coal inventory of 62 days basically turned over approximately 6 times per year. In addition the 32 day adjustment in coal inventory we are discussing in this proceeding was a temporary run up in coal inventory due to the temporary reduced demand for coal fired generation at the Big Sandy Plant.

b. See the Company's response to "a" above. The temporary run up in the coal inventory level of 62 days at September 30, 2009 is down to 45 days as of January 27, 2010, approximately 4 months after the end of the test year.

c. The funds spent on coal inventory can not be specifically tracked. The reason for the requested rate treatment is stated in "a" above.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

Refer to page 34 of the Wagner Testimony and Section V, Workpaper S-4, page 8.

Explain why an adjustment to include this below-the-line item in the company's cost of service is appropriate.

RESPONSE

The interest income recorded in Account 4190005 is a direct result of the interest earned as a result of the Company being in a "cash long position" from the Kentucky operations. Therefore, the ratepayers should receive the benefit of this interest income.

The interest expense recorded in Account 4300003 should not have been included in this adjustment due to the fact that the interest expense amount of $1,923,535 was also included in the $2,056,695 reflected on Section V, Workpaper S-3, Page 2 of 3, Line Number 16.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

Refer to pages 35-36 of the Wagner Testimony and Exhibits EKW-14, 15, and 16.

Explain why the capacity rates of three of the five AEP East Companies, including Kentucky Power, change in lock-step with each other while the capacity rates for the other two companies change independently of the rates of the former.

RESPONSE

The capacity rates of the three deficit companies, including Kentucky Power, change in lock-step because the deficit members pay a weighted average cost of the supplying company's capacity equalization rates. The two surplus members receive payments based on their individual capacity equalization rate.

Here is an example of the calculations using the information on Exhibit EKW-14. The deficit Companies (APCo, KPCo, CSP) pay the rate based upon the weighted average cost of the surplus companies (I&M and OPCo). The surplus companies, I&M and OPCo, surplus capacity total 3,345,400 MW (Column 7, Exhibit EKW-14). OPCo is 86.695% (2,900,300/3,345,400) of the surplus and I&M is 13.305% (445,100/3,345,400) of the surplus. Now take the OPCo rate in Column 9 (or $11.65) times the 86.695% and add that result to the I&M rate in column 9 (or $14.06) times 13.305%, the result is $11.9706. This amount is the weighted average rate the deficit companies pay and is reflected in column 9. That is why the deficit companies monthly rate is the same and the surplus companies' actual rate are different.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

Refer to page 36 of the Wagner Testimony and Section V, Workpaper 5-4, page 10.

Confirm that the Miscellaneous Service Charge revenue adjustment is not a normalization adjustment but is based solely on increases proposed for Miscellaneous Service Charges.

RESPONSE

That is correct. The adjustment on Section V, Workpaper S-4, Page 10 reflects only the increased revenues the Company would have received if the proposed miscellaneous service charges rates would have been in effect for the entire twelve months ending September 2009.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

Refer to pages 37-38 of the Wagner Testimony and Section V, Workpaper 5-4, page 14.

a. For the test year and the two prior 12-month periods shown in the workpaper, provide a schedule which identifies the level of expense incurred for routine planned maintenance, by activity, and the level incurred for unplanned maintenance/repairs. Identify by name each planned maintenance activity performed in each of the three periods.

b. For each planned maintenance activity routinely performed for the Big Sandy Station, provide the timeframe, or cycle, on which it is performed.

c. Explain why it is appropriate to calculate the proposed adjustment for Big Sandy plant maintenance based on a three-year average.

RESPONSE

a. Please see page 3 of 34 attached for the requested information.

b. Please see pages 4 through 34 attached for the requested information.

c. The test year level of plant maintenance expense was not a normal level due to the fact that there were no scheduled outages on either unit. The question that needs to be addressed is: What adjustment is required to the test year level of maintenance expense to reflect a normal level in the Company's cost-of-service? Reviewing the Company's response to KIUC 1st Set Item No. 42 b, which looks at both a ten year average constant dollar adjustment and a five year constant dollar amount, the difference between the two amounts are not material. Considering the fact that todays Big Sandy Plant has substantial changes in the facilities in-service today (e.g., an SCR, versus ten years ago) supports selection of a shorter time period. The size and the influence that Big Sandy Unit No. 2 has on the expenditure levels of maintenance at the Plant, and considering Big Sandy Unit No. 2 is on a three year cycle for its scheduled outages (as described below) supports the Company's proposed three-year period. Each Big Sandy Plant unit has a different outage schedule. Unit 1 is a 260 MW typical drum unit which can run on a 4 year outage cycle without sacrificing reliability. Unit 2 is an 800 series unit , comparable to Mitchell and Amos units (sisters units). It has been determined that Unit 2 should be on a 3 year maintenance cycle.

Cycles are for General Boiler Inspection & Repair (GBIR) outages. This means once every three years Unit 2 will be out of service for at least 4 weeks to do inspection and repairs. The outages in-between the 3 year GBIR outages are called "Touch up outages", and last 2 weeks. The touch up outages are to correct known problems, and for inspection to determine the scope of the next GBIR outages. GBIR outages look at everything, intending to prevent failures by finding small problems before they develop into big problems. Small projects are done during the touch up outages, but the work must fit within the 2 week outage schedule. Most major capital expenditures are done during the GBIR outages and the major capital work tends to set the outage length and the scope of the work performed. These major capital projects often involve a maintenance portion. For example, when a turbine rotor is replaced on Unit 2 (capital work, we have spares because of the series units), the repair of the turbine rotor must then be repaired under maintenance work. The longer the outage, the more inspection and repair can be performed on the unit, and more funds are required. GBIR outages roughly requires twice the budget just for the prevent maintenance performed or planned work on our table in the Generation Operations and Maintenance Routine Outage (GOMRO). The Generation Non Routine Outages (GNRRO) projects have some latitude as to when performed, so to the level of these costs can vary somewhat from year to year.

Looking at the 2007 - 2009 time frame, 2007 was a touch up outage (2 weeks or less) for both units. 2008 was a GBIR outage (4 weeks or more) for both units, and 2009 had no scheduled outages on either unit. These were all considerations that were included in selecting the three year time period.

WITNESS: Errol K Wagner

BSP PLANNED and UNPLANNED ROUTINE MAINTENANCE EXPENSES

TEST YEARS PLUS TWO YEARS PRIOR

		Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Fiscal 2007
BCO - Base Operations & Main	GBCOO	538,595	357,458	899,975	618,236	723,233	770,436	496,846	486,449	425,325	429,245	530,157	265,550	6,541,505
O&M Outage - Routine	GOMRO	468,798	67,788	3,091	5,347	15,953	49,649	516,030	1,164,291	251,924	38,489	2,086	1,039	2,584,485
PLANNED TOTAL		1,007,393	425,246	903,066	623,583	739,186	820,085	1,012,876	1,650,740	677,249	467,734	532,243	266,589	9,125,990
General Expense	AGENX	72,771	5,392	134,022	79,549	78,231	99,037	179,292	127,340	76,266	98,386	93,763	71,784	1,115,833
Cap Blkt - Environmental New	EVNCB	808	2,318	940	0	0	0	0	0	0	0	0	0	4,066
Forced Outage	GFRCO	127	180	0	0	0	54,780	27	12,954	10,224	1,315	27	0	79,634
NOMI	GNOMI	9,265	(300)	(60,436)	50,056	1,284	67,413	13,715	12,887	78,663	214,679	246,691	314,423	948,340
O&M Outage - Non Routine	GNRRO	182,572	33,406	7,600	2,002	7,175	189,945	583,945	1,288,145	(159,280)	107,409	1,138	10,622	2,254,679
Opportunity Outage	GOPPO	90,076	9,849	22,081	20,907	72,750	34,141	32,077	8,525	25,554	96,339	45,299	14,363	471,961
Cap Blkt - Prod Plant Blnkt	GWSCB	368	1,352	0	1,009	356	0	0	3,805	37,307	25,271	19,419	0	88,887
Landfill & dam Raising Env Std	LFECS	0	0	0	0	0	0	0	0	0	2,050	0	0	2,050
Non Capital	OTHNC	6,552	8,907	7,111	3,065	5,534	7,962	7,903	40,132	7,647	9,424	8,368	4,771	117,376
System Accrual Exp or Capital	EROCB	0	0	0	0	0	0	0	297	0	0	0	0	297
Cap Blk - Outage	OUTCB									186				186
Projects Other Capital Standard	MPOCS	0	0	0	0	0	942	0	(942)	0	0	0	0	0
UNPLANNED TOTAL		362,539	61,104	111,318	156,588	165,330	454,220	816,959	1,493,143	76,567	554,873	414,705	415,963	5,083,309

		Oct-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Fiscal 2008
BCO - Base Operations & Main	GBCOO	303,258	332,475	330,781	319,952	421,507	276,271	276,285	338,668	314,202	387,165	411,843	188,462	3,900,869
O&M Outage - Routine	GOMRO	5,957	(2,560)	2,913	92,607	13,980	96,765	341,231	3,146,189	1,254,187	453,446	24,549	104,137	5,533,401
PLANNED TOTAL		309,215	329,915	333,694	412,559	435,487	373,036	617,516	3,484,857	1,568,389	840,611	436,392	292,599	9,434,270
General Expense	AGENX	98,104	86,181	75,025	79,613	122,071	100,946	107,150	164,387	232,187	88,906	128,559	103,843	1,386,972
Forced Outage	GFRCO	148,746	(36,745)	41,547	12,110	197,186	19,284	(6,418)	107,831	(106,046)	(55,743)	113,086	74,217	509,055
NOMI	GNOMI	327,176	242,678	428,868	245,865	419,296	378,847	307,618	301,698	536,611	540,260	568,055	345,251	4,642,223
O&M Outage - Non Routine	GNRRO	17,151	(1,101)	3,000	32,014	78,271	488,363	382,307	1,870,201	703,222	63,995	36,803	366,074	4,040,300
Opportunity Outage	GOPPO	91,932	83,558	36,430	24,307	116,617	20,114	3,921	83,941	118,133	190,344	239,013	(51,180)	957,130
ap Blkt - Prod Plant Blnkt	GWSCB	(48,744)	0	0	0	(7,341)	0	0	4,550	(5,117)	0	0	0	(56,652)
.dfill & Dam Raising Env Std	LFECS	0	2,224	13,900	0	0	0	0	0	0	0	0	0	16,124
Non Capital	OTHNC	4,372	5,051	5,141	3,186	6,739	14,286	3,472	10,004	11,397	3,041	7,752	8,440	82,881
New Generation	MPNCS	0	0	0	0	0	0	51	0	0	0	0	0	51
Cap Stnd - Software	OSWCS	96	0	0	0	0	0	0	0	0	0	0	0	96
UNPLANNED TOTAL		638,833	381,846	603,911	397,095	932,839	1,021,840	798,101	2,542,612	1,490,387	830,803	1,093,268	846,645	11,578,180

		Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Fiscal 2009
BCO - Base Operations & Main	GBCOO	252,661	224,729	182,177	423,778	270,106	268,045	199,377	312,344	272,911	333,718	172,704	171,353	3,083,903
O&M Outage - Routine	GOMRO	648,683	717,789	186,905	97,686	146,856	(30,190)	7,486	4,647	22,502	(6,005)	(341)	5,645	1,801,663
PLANNED TOTAL		901,344	942,518	369,082	521,464	416,962	237,855	206,863	316,991	295,413	327,713	172,363	176,998	4,885,566
General Expense	AGENX	103,390	126,672	147,207	118,985	95,142	66,145	79,083	77,824	68,956	107,329	87,299	79,538	1,157,570
Forced Outage	GFRCO	23	366	102	0	18,609	0	(1,069)	253	20,529	5,563	241	(136)	44,481
NOMI	GNOMI	269,932	164,882	211,166	426,143	510,393	338,263	182,649	297,835	276,377	339,009	367,980	287,866	3,672,495
O&M Outage - Non Routine	GNRRO	949,112	744,792	957,701	(74,637)	1,999	113,038	226,786	(948)	9,406	(1,710)	5,554	936	2,932,029
Opportunity Outage	GOPPO	5,191	32,608	219,213	23,010	163,696	(60,798)	5,683	287,007	48,180	91,944	37,640	198,976	1,052,350
Landfill & Dam Raising Env Std	LFECS	0	0	0	6,105	0	0	0	0	0	0	0	0	6,105
Non-Capital	OTHNC	4,962	8,448	3,991	9,260	3,886	158	3,317	2,240	6,926	6,600	5,354	8,371	63,513
System Accrual Exp or Capital	SYSCB	0	0	57,004	(4,042)	11,176	21,186	28,604	(862)	33,236	(88,142)	8,673	31,458	98,291
UNPLANNED TOTAL		1,332,610	1,077,768	1,596,384	504,824	804,901	477,992	525,053	663,349	463,610	460,593	512,741	607,009	9,026,834

Models in Authorized Status With Auto Trigger Ind 2/18/2010

WOT System Cd	WOT System Code Description	Account Nbr	WOT Unit Cond Reqd	WOT WO Nbr Task	WOT WR Task Title	WOT Unit	WO Type	WOT Job Type	Pm Frequency Code
000	ALL SYSTEMS	5100000		0095112301	OUTAGE MEETINGS - UNIT 2.	0	MO	PM	1YR
	general system	5100000		0095112301	OUTAGE MEETINGS - UNIT 2.	0	MO	PM	1YR
	General System	5100000		0095112301	OUTAGE MEETINGS - UNIT 2.	0	MO	PM	1YR
	general systems	5100000		0095112301	OUTAGE MEETINGS - UNIT 2.	0	MO	PM	1YR
	General systems	5100000		0095112301	OUTAGE MEETINGS - UNIT 2.	0	MO	PM	1YR
	General Systems	5100000		0095112301	OUTAGE MEETINGS - UNIT 2.	0	MO	PM	1YR
	** GENERAL SYSTEMS **	5100000		0095112301	OUTAGE MEETINGS - UNIT 2.	0	MO	PM	1YR
	GENERAL SYSTEMS	5100000		0095112301	OUTAGE MEETINGS - UNIT 2.	0	MO	PM	1YR
000									
110	PRIMARY AIR	5120000		4135369901	U2 #1 PA FAN - CLEAN OIL TANK SUCTION SCREEN	2	MO	PM	ANN
	PRIMARY AIR	5120000		4135411901	U2 #2 PA FAN - CLEAN OIL TANK SUCTION SCREEN	2	MO	PM	ANN
110									
115	FORCED DRAFT	5120000		4135365301	U2 #1 FD FAN - CLEAN OIL TANK SUCTION SCREEN	2	MO	PM	ANN
	FORCED DRAFT	5120000		4135368101	U2 #2 FD FAN - CLEAN OIL TANK SUCTION SCREEN	2	MO	PM	ANN
115									
165	SCR SELECTIVE CAT. REDUCTION	5120000		4095479501	MONTHLY AMMONIA MONITORING	2	MO	PM	MON
165									
235	FUEL OIL SUPPLY/STORAGE	5120000		4073293101	U2 ICE - INSPECT HEAT TRACE FUEL OIL PIPING	2	MO	PM	1YR
235									
250	PULVERIZER (COAL)	5120000		0094700801	#11 RAW COAL PIPE (FEEDER TO PULVERIZER) - INSPECT & REPAIR.	1	MO	PM	1YR
	PULVERIZER (COAL)	5120000		0094701201	#15 RAW COAL PIPE (FEEDER TO PULVERIZER) - INSPECT & REPAIR.	1	MO	PM	1YR
250									
260	BURNER/IGNITORS	5120000		4053588401	PM INSP BURNER #25	1	MO	PM	1YR
	MAIN BURNER/IGNITORS	5120000		4053588401	PM INSP BURNER #25	1	MO	PM	1YR
260									
310	BOILER, GENERAL	5120000		4072711201	INSPECT BW FLASH TANK STEAM HTR 8A VA UMO 803 U2	2	MO	PM	TEN
	BOILER, GENERAL	5120000		4098249305	NAIS / PENTHOUSE SEALS & CASING - I/R	2	MO	GM	50Y
	BOILER, GENERAL	5120000		4098249306	PLANT SUPPORT / PENTHOUSE SEALS & CASING - I/R	2	MO	GM	50Y
	BOILER, GENERAL	5120000		4100272008	UDC INSPECT 3YR. WATERWALLS - DESLAG, INSPECT .	1	MO	IS	50Y
	BOILER, GENERAL	5120000		4100272009	WATERWALLS - DESLAG, INSPECT, REPAIR & PADWELD.	1	MO	IS	50Y
	BOILER, GENERAL..	5120000		4072711201	INSPECT BW FLASH TANK STEAM HTR 8A VA UMO 803 U2	2	MO	PM	TEN
	BOILER, GENERAL..	5120000		4098249305	NAIS / PENTHOUSE SEALS & CASING - I/R	2	MO	GM	50Y
	BOILER, GENERAL..	5120000		4098249306	PLANT SUPPORT / PENTHOUSE SEALS & CASING - I/R	2	MO	GM	50Y
	BOILER, GENERAL..	5120000		4100272008	UDC INSPECT 3YR. WATERWALLS - DESLAG, INSPECT .	1	MO	IS	50Y
	BOILER, GENERAL..	5120000		4100272009	WATERWALLS - DESLAG, INSPECT, REPAIR & PADWELD.	1	MO	IS	50Y
310									
370	REHEAT SPRHTR & LINES	5120000		4098288808	UDC INSPECT 3 YR. -2ND RH BOILER TUBES; INSPECT AND REPAIR.	2	MO	IS	50Y
370									
440	CIRCULATING WATER	5130000		4090635201	U-2 SULFURIC ACID TANK - THICKNESS CHECK	2	MO	PM	2YR
	CIRCULATING WATER	5130000		4090637901	U1-SULFURIC ACID TANK - THICKNESS CHECKS	1	MO	PM	2YR
440									
740	COMBUSTION CONTROLS	5120000		0094233001	PERFORM MECHANICAL ADJUSTMENTS AND CALIBRATE BURNER TIP	1	MO	PM	1YR
740									
							ount All:	32	
130	AIRHEATERS, MAIN	5120000	E	4057659901	PRIMARY AIR BYPASS DAMPER DRIVE - SOUTH	2	MO	PM	5YR
	AIRHEATERS, MAIN	5120000		4057663501	PRIMARY AIR BYPASS DAMPER DRIVE - NORTH	2	MO	PM	5YR
130									
150	PRECIPITATOR	5120000		4057318001	U2 ICE 1YR SIR INSPECTION/CLEAN	2	MO	PM	1YR
150									
175	EMISSIONS MONITORING	5120000		4061784801	U2 ICE 1YR ELEC BOILER SO3 INSPECTION	2	MO	PM	1YR
	EMISSIONS MONITORING	5120000		4062602101	U2 ICE 1YR SULPHUR SYSTEM AIR HEATER CURRENT READINGS	2	MO	PM	1YR
175									
180	INSTRUMENT/CONTROL AIR	5140000		4057663401	U2 ICE-4YR NO 1 AIR COMPR VALVES CRV811,812,813 & PRV012	2	MO	PM	4YR
	INSTRUMENT/CONTROL AIR	5140000		4057699701	ICE - CONTROL AIR DRYER VALVE PRV-1004 UNIT 1 BYPASS VALVE	1	MO	PM	ANN
	INSTRUMENT/CONTROL AIR	5140000		4057703601	ICE-PLANT AIR COMPRESSOR #1 WEST-PERFORM LOOP CALIBRATION	1	MO	PM	3YR
	INSTRUMENT/CONTROL AIR	5140000		4057830701	ICE - PLANT AIR COMPRESSOR NO 3 - CALIBRATE SWITCHES	2	MO	PM	2YR
	INSTRUMENT/CONTROL AIR	5140000		4057832801	ICE - PLANT AIR COMPRESSOR NO 2 - CALIBRATE SWITCHES	2	MO	PM	2YR
	INSTRUMENT/CONTROL AIR	5140000		4057833301	ICE-PLANT AIR COMPRESSOR #1 EAST -PERFORM LOOP CALIBRATION	1	MO	PM	3YR
	INSTRUMENT/CONTROL AIR	5140000		4057835301	ICE - UNIT 2 PLANT AIR COMPRESSOR NO. 2 - STROKE CRV-821, 82	2	MO	PM	4YR
	INSTRUMENT/CONTROL AIR	5140000		4057836901	ICE - PLANT AIR COMPRESSOR #1 WEST-PERFORM CALIBRATION	1	MO	PM	4YR
	INSTRUMENT/CONTROL AIR	5140000		4057838201	ICE -PLANT AIR COMPRESSOR #1 EAST-PERFORM CALIBRATION	1	MO	PM	4YR
180									
210	COAL UNLOADING	5120000		4073637501	ICE 3MO STA 11 CABLE REEL RAIL CAR UNLOADER INSP	0	MO	PM	3MO
	COAL UNLOADING & RAILS	5120000		4073637501	ICE 3MO STA 11 CABLE REEL RAIL CAR UNLOADER INSP	0	MO	PM	3MO
210									
220	COAL CONVEYING & STORAGE	5120000		0093359301	MOTOR, COAL CONVEYOR #15 - PERFORM INSPECTION CHECK SHEET.	0	MO	PM	1YR
	COAL CONVEYING & STORAGE	5120000		0093359501	U2 ICE CONVEYOR #15 UPPER MOTOR INSPECTION	0	MO	PM	1YR
	COAL CONVEYING & STORAGE	5120000		0093363501	UY ICE 1YR MOTOR 13A CONVEYOR FEEDER INSPECTION	0	MO	PM	1YR
	COAL CONVEYING & STORAGE	5120000		0093363701	UY ICE MOTOR #13B CONVEYOR FEEDER INSPECTION	0	MO	PM	1YR
	COAL CONVEYING & STORAGE	5120000		0093363901	U1 ICE MOTOR INSPECTION - COAL FEEDER STA #1	0	MO	PM	1YR
	COAL CONVEYING & STORAGE	5120000		0093366301	UY ICE MOTOR 13A CRUSHER INSPECTION	0	MO	PM	1YR

Models in Authorized Status With Auto Trigger Ind 2/18/2010

WOT System Cd	WOT System Code Description	Account Nbr	WOT Unit Cond Reqd	WOT WO Nbr Task	WOT WR Task Title	WOT Unit	WO Type	WOT Job Type	Pm Frequency Code
	COAL CONVEYING & STORAGE	5120000		0093366501	UY ICE MOTOR 13B CRUSHER INSPECTION	0	MO	PM	1YR
220									
240	COAL FEEDER (PULVERIZER)	5120000		0093583901	PLT MECH INSPECTION COAL FEEDER # 21	2	MO	PM	DAY
	COAL FEEDER (PULVERIZER)	5120000		0093583901	PLT MECH INSPECTION COAL FEEDER # 21	2	MO	PM	OUT
	COAL FEEDER (PULVERIZER)	5120000		0093583902	ICE CALIBRATE FEEDER # 21	2	MO	PM	DAY
	COAL FEEDER (PULVERIZER)	5120000		0093583902	ICE CALIBRATE FEEDER # 21	2	MO	PM	OUT
	COAL FEEDER (PULVERIZER)	5120000		0093584001	PLT MECH INSP COAL FEEDER # 22	2	MO	PM	DAY
	COAL FEEDER (PULVERIZER)	5120000		0093584001	PLT MECH INSP COAL FEEDER # 22	2	MO	PM	OUT
	COAL FEEDER (PULVERIZER)	5120000		0093584002	ICE CALIBRATION FEEDER # 22	2	MO	PM	DAY
	COAL FEEDER (PULVERIZER)	5120000		0093584002	ICE CALIBRATION FEEDER # 22	2	MO	PM	OUT
	COAL FEEDER (PULVERIZER)	5120000		0093584201	PLT MECH INSP COAL FEEDER, #24	2	MO	PM	DAY
	COAL FEEDER (PULVERIZER)	5120000		0093584201	PLT MECH INSP COAL FEEDER, #24	2	MO	PM	OUT
	COAL FEEDER (PULVERIZER)	5120000		0093584202	ICE CALIBRATE FEEDER # 24	2	MO	PM	DAY
	COAL FEEDER (PULVERIZER)	5120000		0093584202	ICE CALIBRATE FEEDER # 24	2	MO	PM	OUT
	COAL FEEDER (PULVERIZER)	5120000		0093584301	PLT MECH INSP COAL FEEDER # 25	2	MO	PM	DAY
	COAL FEEDER (PULVERIZER)	5120000		0093584301	PLT MECH INSP COAL FEEDER # 25	2	MO	PM	OUT
	COAL FEEDER (PULVERIZER)	5120000		0093584302	ICE CALIBRATE COAL FEEDER # 25	2	MO	PM	DAY
	COAL FEEDER (PULVERIZER)	5120000		0093584302	ICE CALIBRATE COAL FEEDER # 25	2	MO	PM	OUT
	COAL FEEDER (PULVERIZER)	5120000		0093584401	PLT MECH INSP COAL FEEDER # 26	2	MO	PM	DAY
	COAL FEEDER (PULVERIZER)	5120000		0093584401	PLT MECH INSP COAL FEEDER # 26	2	MO	PM	OUT
	COAL FEEDER (PULVERIZER)	5120000		0093584402	ICE CALIBRATE FEEDER # 26	2	MO	PM	DAY
	COAL FEEDER (PULVERIZER)	5120000		0093584402	ICE CALIBRATE FEEDER # 26	2	MO	PM	OUT
	COAL FEEDER (PULVERIZER)	5120000		4056603101	INSPECTION #23 COAL FEEDER	2	MO	PM	DAY
	COAL FEEDER (PULVERIZER)	5120000		4056603101	INSPECTION #23 COAL FEEDER	2	MO	PM	OUT
	COAL FEEDER (PULVERIZER)	5120000		4056603102	ICE CALIBRATE FEEDER # 23	2	MO	PM	DAY
	COAL FEEDER (PULVERIZER)	5120000		4056603102	ICE CALIBRATE FEEDER # 23	2	MO	PM	OUT
	COAL FEEDER (TO PULVERIZER)	5120000		0093583901	PLT MECH INSPECTION COAL FEEDER # 21	2	MO	PM	DAY
	COAL FEEDER (TO PULVERIZER)	5120000		0093583901	PLT MECH INSPECTION COAL FEEDER # 21	2	MO	PM	OUT
	COAL FEEDER (TO PULVERIZER)	5120000		0093583902	ICE CALIBRATE FEEDER # 21	2	MO	PM	DAY
	COAL FEEDER (TO PULVERIZER)	5120000		0093583902	ICE CALIBRATE FEEDER # 21	2	MO	PM	OUT
	COAL FEEDER (TO PULVERIZER)	5120000		0093584001	PLT MECH INSP COAL FEEDER # 22	2	MO	PM	DAY
	COAL FEEDER (TO PULVERIZER)	5120000		0093584001	PLT MECH INSP COAL FEEDER # 22	2	MO	PM	OUT
	COAL FEEDER (TO PULVERIZER)	5120000		0093584002	ICE CALIBRATION FEEDER # 22	2	MO	PM	DAY
	COAL FEEDER (TO PULVERIZER)	5120000		0093584002	ICE CALIBRATION FEEDER # 22	2	MO	PM	OUT
	COAL FEEDER (TO PULVERIZER)	5120000		0093584201	PLT MECH INSP COAL FEEDER, #24	2	MO	PM	DAY
	COAL FEEDER (TO PULVERIZER)	5120000		0093584201	PLT MECH INSP COAL FEEDER, #24	2	MO	PM	OUT
	COAL FEEDER (TO PULVERIZER)	5120000		0093584202	ICE CALIBRATE FEEDER # 24	2	MO	PM	DAY
	COAL FEEDER (TO PULVERIZER)	5120000		0093584202	ICE CALIBRATE FEEDER # 24	2	MO	PM	OUT
	COAL FEEDER (TO PULVERIZER)	5120000		0093584301	PLT MECH INSP COAL FEEDER # 25	2	MO	PM	DAY
	COAL FEEDER (TO PULVERIZER)	5120000		0093584301	PLT MECH INSP COAL FEEDER # 25	2	MO	PM	OUT
	COAL FEEDER (TO PULVERIZER)	5120000		0093584302	ICE CALIBRATE COAL FEEDER # 25	2	MO	PM	DAY
	COAL FEEDER (TO PULVERIZER)	5120000		0093584302	ICE CALIBRATE COAL FEEDER # 25	2	MO	PM	OUT
	COAL FEEDER (TO PULVERIZER)	5120000		0093584401	PLT MECH INSP COAL FEEDER # 26	2	MO	PM	DAY
	COAL FEEDER (TO PULVERIZER)	5120000		0093584401	PLT MECH INSP COAL FEEDER # 26	2	MO	PM	OUT
	COAL FEEDER (TO PULVERIZER)	5120000		0093584402	ICE CALIBRATE FEEDER # 26	2	MO	PM	DAY
	COAL FEEDER (TO PULVERIZER)	5120000		0093584402	ICE CALIBRATE FEEDER # 26	2	MO	PM	OUT
	COAL FEEDER (TO PULVERIZER)	5120000		4056603101	INSPECTION #23 COAL FEEDER	2	MO	PM	DAY
	COAL FEEDER (TO PULVERIZER)	5120000		4056603101	INSPECTION #23 COAL FEEDER	2	MO	PM	OUT
	COAL FEEDER (TO PULVERIZER)	5120000		4056603102	ICE CALIBRATE FEEDER # 23	2	MO	PM	DAY
	COAL FEEDER (TO PULVERIZER)	5120000		4056603102	ICE CALIBRATE FEEDER # 23	2	MO	PM	OUT
240									
250	PULVERIZER (COAL)	5120000		0093580502	ICE PULV #11 CLEAN AIR CURVE (1000 HRS)	1	MO	PM	DAY
	PULVERIZER (COAL)	5120000		0093582902	ICE #21 CLEAN AIR CURVE	2	MO	PM	DAY
	PULVERIZER (COAL)	5120000		0093583002	ICE #22 CLEAN AIR CURVE	2	MO	PM	DAY
	PULVERIZER (COAL)	5120000		0093583102	U2 ICE #23 CLEAN AIR CURVE	2	MO	PM	DAY
	PULVERIZER (COAL)	5120000		0093583202	ICE U-2 CLEAN AIR CURVE 24 PULV	2	MO	PM	DAY
	PULVERIZER (COAL)	5120000		0093583302	ICE U2 #25 CLEAN AIR CURVE	2	MO	PM	DAY
	PULVERIZER (COAL)	5120000		0093583801	INSPECTION PULVERIZER #26 (2000 HRS)	2	MO	PM	DAY
	PULVERIZER (COAL)	5120000		0093583802	ICE CLEAN AIR CURVE PULV #26 (2000 HRS)	2	MO	PM	DAY
	PULVERIZER (COAL)	5120000		4073043301	COUPLING INSPECTION ON #16 PULVERIZER U1	1	MO	PM	1YR
	PULVERIZER (COAL)	5120000		4073044001	COUPLING INSPECTION ON #15 PULVERIZER U1	1	MO	PM	1YR
250									
345	CHEMICAL CLEANING	5120000		0093429001	ICE U2 MOTOR, LARGE CHEMICAL CLEANING PP-INSPECTION	0	MO	PM	1YR
	CHEMICAL CLEANING	5120000		0093429101	ICE U2 MOTOR, SMALL CHEMICAL CLEANING PP -INSPECTION	0	MO	PM	1YR
345									
380	SOOTBLOWERS	5120000		4057592001	EAST LUBE AIR PREHEATER CLEANING DEVICE - EAST CARRIAGE	1	MO	PM	ANH
	SOOTBLOWERS	5120000		4057592201	WEST LUBE AIR PREHEATER CLEANING DEVICE WEST CARRIAGE	1	MO	PM	ANH
	SOOTBLOWERS	5120000		4057660301	NORTH AIR PREHEATER CLEANING DEVICE CARRIAGE ASSEMBLY	2	MO	PM	5YR
	SOOTBLOWERS	5120000		4057843401	AIR PREHEATER CLEANING DEVICE-SOUTH-CARRIAGE ASEMBLY	2	MO	PM	5YR
	SOOTBLOWERS	5120000		4062594201	U1 SOOTBLOWER EAST SEAL AIR BLOWER MTR COUPLING	1	MO	PM	1YR
	SOOTBLOWERS	5120000		4062594201	U1 SOOTBLOWER EAST SEAL AIR BLOWER MTR COUPLING	1	MO	PM	ANN

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WOT System Cd	WOT System Code Description	Account Nbr	WOT Unit Cond Reqd	WOT WO Nbr Task	WOT WR Task Title	WOT Unit	WO Type	WOT Job Type	Pm Frequency Code
	SOOTBLOWERS	5120000		4062595301	U1 SOOTBLOWER WEST SEAL AIR BLOWER MTR COUPLING	1	MO	PM	1YR
	SOOTBLOWERS	5120000		4062595301	U1 SOOTBLOWER WEST SEAL AIR BLOWER MTR COUPLING	1	MO	PM	ANN
	SOOTBLOWERS	5120000		4062605301	SEAL AIR BLOWER SOOTBLOWER SYSTEM WEST UNIT 2	2	MO	PM	1YR
	SOOTBLOWERS	5120000		4062607001	SEAL AIR BLOWER SOOTBLOWER SYSTEM EAST UNIT2	2	MO	PM	1YR
380									
415	CONDENSATE	5120000		4065936701	U2 ICE CONDENSATE FILTER INLET / DRAIN VALVES - STROKE	2	MO	PM	3YR
415									
440	CIRCULATING WATER	5130000		4057574601	NO. 2 RIVER WATER MAKE UP PUMP (REBUILD)	0	MO	PM	5YR
	CIRCULATING WATER	5130000		4057578201	NO 3 RIVER WATER MAKE UP PUMP REBUILD	0	MO	PM	5YR
440									
450	SERVICE AND FIRE WATER	5120000		0093432601	U2 ICE MOTOR INSPECTION #1 COOLING WATER PUMP	2	MO	PM	1YR
450									
630	SWITCHGEAR	5130000		4120257401	U1 ICE 4YR CH2-1 600V SWGR BREAKER INSP	1	MO	PM	4YR
630									
815	ASH HANDLING, FLY ASH	5120000		4057313201	ICE - CALIBRATE RECIRC POND PRESSURE TRANSMITTER & SWITCHES	2	MO	PM	4YR
	ASH HANDLING, FLY ASH	5120000		4057698801	INSPECT FLYASH LINES TO HORSEFORD HOLLOW	2	MO	PM	5YR
	ASH HANDLING, FLY ASH	5120000		4079075401	U2 FLUIDIZING AIR BLOWER	2	MO	PM	3MO
815									
835	SUMP PUMPS	5110000		4074489801	ICE PERFORM DEAD HEAD TEST ON WASTE WATER SUMP PUMPS	2	MO	PM	2YR
	SUMPS PUMPS	5110000		4074489801	ICE PERFORM DEAD HEAD TEST ON WASTE WATER SUMP PUMPS	2	MO	PM	2YR
835									
			E				ount All:	103	
000	ALL SYSTEMS	5120000	N	0093609201	CY - LUB CRUSHER - COAL #11-A, BRGS.& CPLS.	0	MO	PM	1YR
	ALL SYSTEMS	5120000		0093609301	CY - LUB CRUSHER - COAL 11-B, BRGS.& CPLS.	0	MO	PM	1YR
	general system	5120000		0093609201	CY - LUB CRUSHER - COAL #11-A, BRGS.& CPLS.	0	MO	PM	1YR
	general system	5120000		0093609301	CY - LUB CRUSHER - COAL 11-B, BRGS.& CPLS.	0	MO	PM	1YR
	General System	5120000		0093609201	CY - LUB CRUSHER - COAL #11-A, BRGS.& CPLS.	0	MO	PM	1YR
	General System	5120000		0093609301	CY - LUB CRUSHER - COAL 11-B, BRGS.& CPLS.	0	MO	PM	1YR
	general systems	5120000		0093609201	CY - LUB CRUSHER - COAL #11-A, BRGS.& CPLS.	0	MO	PM	1YR
	general systems	5120000		0093609301	CY - LUB CRUSHER - COAL 11-B, BRGS.& CPLS.	0	MO	PM	1YR
	General systems	5120000		0093609201	CY - LUB CRUSHER - COAL #11-A, BRGS.& CPLS.	0	MO	PM	1YR
	General systems	5120000		0093609301	CY - LUB CRUSHER - COAL 11-B, BRGS.& CPLS.	0	MO	PM	1YR
	General Systems	5120000		0093609201	CY - LUB CRUSHER - COAL #11-A, BRGS.& CPLS.	0	MO	PM	1YR
	General Systems	5120000		0093609301	CY - LUB CRUSHER - COAL 11-B, BRGS.& CPLS.	0	MO	PM	1YR
	** GENERAL SYSTEMS **	5120000		0093609201	CY - LUB CRUSHER - COAL #11-A, BRGS.& CPLS.	0	MO	PM	1YR
	** GENERAL SYSTEMS **	5120000		0093609301	CY - LUB CRUSHER - COAL 11-B, BRGS.& CPLS.	0	MO	PM	1YR
	GENERAL SYSTEMS	5120000		0093609201	CY - LUB CRUSHER - COAL #11-A, BRGS.& CPLS.	0	MO	PM	1YR
	GENERAL SYSTEMS	5120000		0093609301	CY - LUB CRUSHER - COAL 11-B, BRGS.& CPLS.	0	MO	PM	1YR
000									
020	EQUIPMENT - SHOP/GENERAL	5140000		0093561801	INSPECT ABRASIVE CUTOFF SAW.	0	MO	PM	4WK
	EQUIPMENT - SHOP/GENERAL	5140000		0093580001	INSPECTION CRANES - SOUTH MACHINE SHOP BRIDGE (P&H)	0	MO	PM	3MO
	EQUIPMENT - SHOP/GENERAL	5140000		0093580101	INSPECTION CRANES - NORTH MACHINE SHOP BRIDGE (P&H)	0	MO	PM	3MO
	EQUIPMENT - SHOP/GENERAL	5140000		0093615401	INSPECTION CRANE - CONDENSER PIT HOIST U1 - 3 TON	0	MO	PM	1YR
	EQUIPMENT - SHOP/GENERAL	5140000		0093616001	INSPECTION CRANE - MACHINE SHOP, 10 TON	0	MO	PM	1YR
	EQUIPMENT - SHOP/GENERAL	5140000		0093617701	INSPECTION CRANE - WELDING BOOTH BRIDGE, 1-1/2 TON	0	MO	PM	1YR
	EQUIPMENT-SHOP/GENERAL	5140000		0093561801	INSPECT ABRASIVE CUTOFF SAW.	0	MO	PM	4WK
	EQUIPMENT-SHOP/GENERAL	5140000		0093580001	INSPECTION CRANES - SOUTH MACHINE SHOP BRIDGE (P&H)	0	MO	PM	3MO
	EQUIPMENT-SHOP/GENERAL	5140000		0093580101	INSPECTION CRANES - NORTH MACHINE SHOP BRIDGE (P&H)	0	MO	PM	3MO
	EQUIPMENT-SHOP/GENERAL	5140000		0093615401	INSPECTION CRANE - CONDENSER PIT HOIST U1 - 3 TON	0	MO	PM	1YR
	EQUIPMENT-SHOP/GENERAL	5140000		0093616001	INSPECTION CRANE - MACHINE SHOP, 10 TON	0	MO	PM	1YR
	EQUIPMENT-SHOP/GENERAL	5140000		0093617701	INSPECTION CRANE - WELDING BOOTH BRIDGE, 1-1/2 TON	0	MO	PM	1YR
020									
030	TOOLS, GENERAL	5140000		0093352601	SHOP GRINDERS - INSP U1,U2,WELD SHOP & COAL YARD	0	MO	PM	4WK
	TOOLS, GENERAL	5140000		0093353001	PORTABLE LIGHT PLANT - PERFORM INSPECTION.	0	MO	PM	3MO
	TOOLS, GENERAL	5140000		0093400801	INSPECTION - STEAM JENNY	0	MO	PM	MON
	TOOLS, GENERAL	5140000		0093403901	RESCUE CART - CHECK SUPPLIES ON CART.	0	MO	PM	MON
	TOOLS, GENERAL	5140000		0093460301	REPLACEMENT OF PARTS - TOOL ROOM (DAY CREW)	0	MO	PM	1YR
	TOOLS, GENERAL	5140000		0093553201	UNO - CONTACT BODE FINN FOR ROUTINE INSPECTION.	0	MO	PM	4MO
	TOOLS, GENERAL	5140000		0093571801	LUBRICATION PUMP - PORTABLE GORMAN-RUPP - FOUR CYL. GAS.	0	MO	PM	3MO
	TOOLS, GENERAL	5140000		0093585601	SEMI-ANNUAL LABORATORY FUME HOOD TESTS	0	MO	PM	6MO
	TOOLS, GENERAL	5140000		0093592501	INSPECTION WELDERS - SHIFT "A"	0	MO	PM	50Y
	TOOLS, GENERAL	5140000		0093592601	INSPECTION WELDERS - SHIFT "B"	0	MO	PM	50Y
	TOOLS, GENERAL	5140000		0093592701	INSPECTION WELDERS - SHIFT "C"	0	MO	PM	50Y
	TOOLS, GENERAL	5140000		0093592801	INSPECTION WELDERS - SHIFT "D"	0	MO	PM	50Y
	TOOLS, GENERAL	5140000		0093611201	TOOL ROOM	0	MO	PM	1YR
	TOOLS, GENERAL	5140000		0093618101	INSPECTION WELDERS - ELECTRIC 6 & 8 PACK WELDERS	0	MO	PM	50Y
030									
035	TEST EQUIPMENT	5140000		4084152501	U0 ICE 1YR - CALIBRATE RIVER WATER TEMP RECORDER	0	MO	PM	ANN
	TEST EQUIPMENT	5140000		4084247201	ICE 1YR HOT STICK SAFETY INSPECTION	0	MO	PM	ANN
	TEST EQUIPMENT	5140000		4084248801	U0 ICE 1YR - CALIBRATE SEWAGE PLANT FLOW MONITORS	0	MO	PM	ANN
035									

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WOT System Cd	WOT System Code Description	Account Nbr	WOT Unit Cond Reqd	WOT WO Nbr Task	WOT WR Task Title	WOT Unit	WO Type	WOT Job Type	Pm Frequency Code
040	MOBILE EQUIPMENT	5120000		0093376901	VEHICLE INSPECTION - 1995 GMC SWEEPER TRUCK,	0	MO	PM	3MO
	MOBILE EQUIPMENT	5120000		0093377001	VEHICLE INSPECTION - 1992 CHEVROLET 1/2T 4X4,	0	MO	PM	6MO
	MOBILE EQUIPMENT	5120000		0093580301	INSPECTION LOCOMOTIVE #102	0	MO	PM	3MO
	MOBILE EQUIPMENT	5120000		0093580401	UY ICE 3MO LOCOMOTIVE #103 INSPECTION	0	MO	PM	3MO
	MOBILE EQUIPMENT	5120000		0093610801	CATERPILLAR LOADER #1 988F (SERIAL #2ZR00751) - CONTACT	0	MO	PM	1YR
	MOBILE EQUIPMENT	5120000		0093610901	#1 D8N DOZER (SERIAL #5TJ00769) - CONTACT WHAYNE	0	MO	PM	1YR
	MOBILE EQUIPMENT	5120000		0093611001	#2 D8N DOZER (SERIAL #5TJ2366) - CONTACT WHAYNE	0	MO	PM	1YR
	MOBILE EQUIPMENT	5120000		4073565710	FLAT BED DIESEL CHANGE OIL AND FILTER	0	MO	PM	M3
	MOBILE EQUIPMENT	5140000		0093378901	VEHICLE INSPECTION - 1997 INTERNATIONAL L P 5000,	0	MO	PM	6MO
	MOBILE EQUIPMENT	5140000		0093558701	SUPER SUCKER TRUCK - INSPECTION AND LUBRICATION.	0	MO	PM	6MO
040									
050	CRANES	5120000		0093613701	INSPECTION - SILO ROOM HOIST	2	MO	PM	1YR
	CRANES	5120000		0093615101	INSPECTION CRANE - TRIPPER ROOM	1	MO	PM	1YR
	CRANES	5120000		0093615301	INSPECTION CRANE - BOILER ROOM ROOF JIB, 3 TON	1	MO	PM	1YR
	CRANES	5120000		0093616101	INSPECTION CRANE - S. PULVERIZER HOIST, 15 TON	2	MO	PM	1YR
	CRANES	5120000		0093616201	INSPECTION CRANE - N. PULVERIZER HOIST, 15 TON	2	MO	PM	1YR
	CRANES	5120000		0093616401	INSPECTION CRANE - BURNER DECK HOIST (EAST), 3 TON	2	MO	PM	1YR
	CRANES	5120000		0093616501	INSPECTION CRANE - S. SLAG BLOWER HOIST, 2 TON	2	MO	PM	1YR
	CRANES	5120000		0093616701	INSPECTION CRANE - N. SLAG BLOWER HOIST, 2 TON	2	MO	PM	1YR
	CRANES	5120000		0093616801	INSPECTION CRANE - W. ASH HOPPER JIB, 3 TON	2	MO	PM	1YR
	CRANES	5120000		0093616901	INSPECTION CRANE - E. ASH HOPPER JIB, 3 TON	2	MO	PM	1YR
	CRANES	5120000		0093617401	INSPECTION CRANE - U2 PENTHOUSE COOLING FAN	2	MO	PM	1YR
	CRANES	5120000		0094377001	U2 ICE 1YR N&S PULV HOIST INSPECTION	2	MO	PM	6MO
	CRANES	5120000		0094377101	U2 ICE 1YR N & S PULV HOIST INSP	2	MO	PM	1YR
	CRANES	5130000		0093615201	INSPECTION CRANE - TURBINE ROOM JIB, 3 TON	0	MO	PM	1YR
	CRANES	5130000		0093617201	INSPECTION CRANE - TURBINE ROOM BRIDGE, 10 TON	2	MO	PM	1YR
	CRANES	5130000		0093617301	INSPECTION CRANE - TURBINE ROOM BRIDGE, 4 TON	2	MO	PM	1YR
	CRANES	5130000		0093617501	INSPECTION CRANE - TURBINE ROOM BRIDGE, 95 TON	2	MO	PM	1YR
	CRANES	5130000		0093617601	INSPECTION CRANE - TURBINE ROOM BRIDGE, 40 TON	2	MO	PM	1YR
	CRANES	5130000		0093617801	INSPECTION CRANE - TURBINE ROOM BRIDGE, 20 TON	0	MO	PM	1YR
	CRANES	5130000		0093617901	INSPECTION CRANE - TURBINE ROOM BRIDGE, 40 TON	0	MO	PM	1YR
	CRANES	5140000		4077575501	TEREX 55-TON MOBILE CRANE INSPECTION	0	MO	PM	6MO
	CRANES / HOISTS	5120000		0093613701	INSPECTION - SILO ROOM HOIST	2	MO	PM	1YR
	CRANES / HOISTS	5120000		0093615101	INSPECTION CRANE - TRIPPER ROOM	1	MO	PM	1YR
	CRANES / HOISTS	5120000		0093615301	INSPECTION CRANE - BOILER ROOM ROOF JIB, 3 TON	1	MO	PM	1YR
	CRANES / HOISTS	5120000		0093616101	INSPECTION CRANE - S. PULVERIZER HOIST, 15 TON	2	MO	PM	1YR
	CRANES / HOISTS	5120000		0093616201	INSPECTION CRANE - N. PULVERIZER HOIST, 15 TON	2	MO	PM	1YR
	CRANES / HOISTS	5120000		0093616401	INSPECTION CRANE - BURNER DECK HOIST (EAST), 3 TON	2	MO	PM	1YR
	CRANES / HOISTS	5120000		0093616501	INSPECTION CRANE - S. SLAG BLOWER HOIST, 2 TON	2	MO	PM	1YR
	CRANES / HOISTS	5120000		0093616701	INSPECTION CRANE - N. SLAG BLOWER HOIST, 2 TON	2	MO	PM	1YR
	CRANES / HOISTS	5120000		0093616801	INSPECTION CRANE - W. ASH HOPPER JIB, 3 TON	2	MO	PM	1YR
	CRANES / HOISTS	5120000		0093616901	INSPECTION CRANE - E. ASH HOPPER JIB, 3 TON	2	MO	PM	1YR
	CRANES / HOISTS	5120000		0093617401	INSPECTION CRANE - U2 PENTHOUSE COOLING FAN	2	MO	PM	1YR
	CRANES / HOISTS	5120000		0094377001	U2 ICE 1YR N&S PULV HOIST INSPECTION	2	MO	PM	6MO
	CRANES / HOISTS	5120000		0094377101	U2 ICE 1YR N & S PULV HOIST INSP	2	MO	PM	1YR
	CRANES / HOISTS	5130000		0093615201	INSPECTION CRANE - TURBINE ROOM JIB, 3 TON	0	MO	PM	1YR
	CRANES / HOISTS	5130000		0093617201	INSPECTION CRANE - TURBINE ROOM BRIDGE, 10 TON	2	MO	PM	1YR
	CRANES / HOISTS	5130000		0093617301	INSPECTION CRANE - TURBINE ROOM BRIDGE, 4 TON	2	MO	PM	1YR
	CRANES / HOISTS	5130000		0093617501	INSPECTION CRANE - TURBINE ROOM BRIDGE, 95 TON	2	MO	PM	1YR
	CRANES / HOISTS	5130000		0093617601	INSPECTION CRANE - TURBINE ROOM BRIDGE, 40 TON	2	MO	PM	1YR
	CRANES / HOISTS	5130000		0093617801	INSPECTION CRANE - TURBINE ROOM BRIDGE, 20 TON	0	MO	PM	1YR
	CRANES / HOISTS	5130000		0093617901	INSPECTION CRANE - TURBINE ROOM BRIDGE, 40 TON	0	MO	PM	1YR
	CRANES / HOISTS	5140000		4077575501	TEREX 55-TON MOBILE CRANE INSPECTION	0	MO	PM	6MO
	CRANES/HOISTS	5120000		0093613701	INSPECTION - SILO ROOM HOIST	2	MO	PM	1YR
	CRANES/HOISTS	5120000		0093615101	INSPECTION CRANE - TRIPPER ROOM	1	MO	PM	1YR
	CRANES/HOISTS	5120000		0093615301	INSPECTION CRANE - BOILER ROOM ROOF JIB, 3 TON	1	MO	PM	1YR
	CRANES/HOISTS	5120000		0093616101	INSPECTION CRANE - S. PULVERIZER HOIST, 15 TON	2	MO	PM	1YR
	CRANES/HOISTS	5120000		0093616201	INSPECTION CRANE - N. PULVERIZER HOIST, 15 TON	2	MO	PM	1YR
	CRANES/HOISTS	5120000		0093616401	INSPECTION CRANE - BURNER DECK HOIST (EAST), 3 TON	2	MO	PM	1YR
	CRANES/HOISTS	5120000		0093616501	INSPECTION CRANE - S. SLAG BLOWER HOIST, 2 TON	2	MO	PM	1YR
	CRANES/HOISTS	5120000		0093616701	INSPECTION CRANE - N. SLAG BLOWER HOIST, 2 TON	2	MO	PM	1YR
	CRANES/HOISTS	5120000		0093616801	INSPECTION CRANE - W. ASH HOPPER JIB, 3 TON	2	MO	PM	1YR
	CRANES/HOISTS	5120000		0093616901	INSPECTION CRANE - E. ASH HOPPER JIB, 3 TON	2	MO	PM	1YR
	CRANES/HOISTS	5120000		0093617401	INSPECTION CRANE - U2 PENTHOUSE COOLING FAN	2	MO	PM	1YR
	CRANES/HOISTS	5120000		0094377001	U2 ICE 1YR N&S PULV HOIST INSPECTION	2	MO	PM	6MO
	CRANES/HOISTS	5120000		0094377101	U2 ICE 1YR N & S PULV HOIST INSP	2	MO	PM	1YR
	CRANES/HOISTS	5130000		0093615201	INSPECTION CRANE - TURBINE ROOM JIB, 3 TON	0	MO	PM	1YR
	CRANES/HOISTS	5130000		0093617201	INSPECTION CRANE - TURBINE ROOM BRIDGE, 10 TON	2	MO	PM	1YR
	CRANES/HOISTS	5130000		0093617301	INSPECTION CRANE - TURBINE ROOM BRIDGE, 4 TON	2	MO	PM	1YR
	CRANES/HOISTS	5130000		0093617501	INSPECTION CRANE - TURBINE ROOM BRIDGE, 95 TON	2	MO	PM	1YR
	CRANES/HOISTS	5130000		0093617601	INSPECTION CRANE - TURBINE ROOM BRIDGE, 40 TON	2	MO	PM	1YR

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WOT System Cd	WOT System Code Description	Account Nbr	WOT Unit Cond Reqd	WOT WO Nbr Task	WOT WR Task Title	WOT Unit	WO Type	WOT Job Type	Pm Frequency Code
	CRANES/HOISTS	5130000		0093617801	INSPECTION CRANE - TURBINE ROOM BRIDGE, 20 TON	0	MO	PM	1YR
	CRANES/HOISTS	5130000		0093617901	INSPECTION CRANE - TURBINE ROOM BRIDGE, 40 TON	0	MO	PM	1YR
	CRANES/HOISTS	5140000		4077575501	TEREX 55-TON MOBILE CRANE INSPECTION	0	MO	PM	6MO
050									
090	FIRE PROTECTION	5110000		0093575501	PERFORM HYDROSTATIC TESTING ON FIRE HOSE	0	MO	PM	MON
	FIRE PROTECTION	5140000		0093367601	MOTOR, FIRE PUMP #1 U1 - PERFORM INSPECTION CHECK SHEET.	0	MO	PM	1YR
	FIRE PROTECTION	5140000		0093367701	U0 ICE 1YR MOTOR, FIRE PUMP #2 U1 INSPECTION	0	MO	PM	1YR
	FIRE PROTECTION	5140000		0093378801	VEHICLE INSPECTION - 1996 INTERNATIONAL FIRE TRUCK,	1	MO	PM	6MO
	FIRE PROTECTION	5140000		0093407401	QUARTERLY FIRE SYSTEM FLUSH	1	MO	PM	3MO
	FIRE PROTECTION	5140000		0093407501	POST INDICATOR VALVE QUARTERLY SPRING TEST.	1	MO	PM	3MO
	FIRE PROTECTION	5140000		0093407601	MONTHLY FIRE SYSTEM LOCK CHECK U1.	1	MO	PM	MON
	FIRE PROTECTION	5140000		0093407701	MONTHLY FIRE SYSTEM LOCK CHECK ON U2.	1	MO	PM	MON
	FIRE PROTECTION	5140000		0093407901	MONTHLY FIRE EXTINGUISHER AND HOSE INSPECTION U#1	0	MO	PM	MON
	FIRE PROTECTION	5140000		0093408001	MONTHLY FIRE EXTINGUISHER AND HOSE INSPECTION U#2	0	MO	PM	MON
	FIRE PROTECTION	5140000		0093409301	FIRE EXTINGUISHERS AND HOSES -	0	MO	PM	MON
	FIRE PROTECTION	5140000		0093409401	FIRE EXTINGUISHERS AND HOSES -	0	MO	PM	MON
	FIRE PROTECTION	5140000		0093409501	FIRE EXTINGUISHERS AND HOSES -	0	MO	PM	MON
	FIRE PROTECTION	5140000		0093409601	FIRE EXTINGUISHERS AND HOSES -	0	MO	PM	MON
	FIRE PROTECTION	5140000		0093409701	FIRE EXTINGUISHERS AND HOSES -	0	MO	PM	MON
	FIRE PROTECTION	5140000		0093433701	MOTOR, DIESEL DRIVEN FIRE PUMP U2 - PERFORM INSPECTION CHECK	2	MO	PM	1YR
	FIRE PROTECTION	5140000		0093435001	U2 ICE 1YR MOTOR, HIGH DEMAND FIRE PUMP INSPECTION	2	MO	PM	1YR
	FIRE PROTECTION	5140000		0093435701	U2 ICE 1YR MOTOR, LOW DEMAND FIRE PUMP	0	MO	PM	1YR
	FIRE PROTECTION	5140000		0093450901	MOTOR, DIESEL DRIVEN FIRE PUMP U1 - PERFORM INSPECTION CHECK	0	MO	PM	1YR
	FIRE PROTECTION	5140000		0093575201	INSPECTION - FIRE TRUCK	1	MO	PM	2WK
	FIRE PROTECTION	5140000		4128445001	HIGH DEMAND FIRE PUMP U2 - CLEAN STRAINERS	2	MO	PM	QTR
	FIRE PROTECTION	5140000		4128445301	LOW DEMAND FIRE PUMP U2 - CLEAN STRAINERS	2	MO	PM	QTR
	FIRE PROTECTION	5140000		4128445501	DIESEL DRIVEN FIRE PUMP U2 - CLEAN STRAINERS	0	MO	PM	QTR
	FIRE PROTECTION	5140000		4128445701	EAST FIRE PUMP U1 - CLEAN STRAINERS	1	MO	PM	QTR
	FIRE PROTECTION	5140000		4128446001	MIDDLE FIRE PUMP #2 U1 - CLEAN STRAINERS	1	MO	PM	QTR
	FIRE PROTECTION	5140000		4128446401	DIESEL DRIVEN FIRE PUMP U1 - CLEAN STRAINERS	1	MO	PM	QTR
090									
110	PRIMARY AIR	5120000		0093595301	OIL SAMPLE, U1 PA FAN MOTOR BEARINGS, C-TEAM	1	MO	PM	3MO
	PRIMARY AIR	5120000		0093595401	FILTER U1 PA FAN BEARINGS AND THEN SAMPLE BEARINGS	1	MO	PM	MON
	PRIMARY AIR	5120000		0093596401	FILTER U2 PA FAN BEARINGS, OIL SAMPLE BOTH FAN AND MOTOR	2	MO	PM	3MO
110									
115	FORCED DRAFT	5120000		0093596701	OIL SAMPLE, U2 FD FAN MOTOR BEARINGS AND FAN BEARINGS	2	MO	PM	3MO
	FORCED DRAFT	5120000		0093596801	OIL SAMPLE, U1 FD FAN BEARINGS, U1 AIR COMPRESSOR	1	MO	PM	3MO
	FORCED DRAFT	5120000		0093615601	INSPECTION CRANE - FAN ROOM HOIST, 10 TON	1	MO	PM	1YR
115									
130	AIRHEATERS, MAIN	5120000		0093595501	OIL SAMPLE, U1 AIR HEATER GEARBOXES, U1 AIR HEATER TOP	1	MO	PM	DAY
	AIRHEATERS, MAIN	5120000		0093596001	OIL SAMPLE, U2 AIR HEATER GEARBOXES AND EAST AND WEST	2	MO	PM	3MO
	AIRHEATERS, MAIN	5120000		4057645501	WEST AIR PREHEATER LUBE OIL SYSTEM WEST FILTER	1	MO	PM	ANN
	AIRHEATERS, MAIN	5120000		4057646601	EAST AIR PREHEATER LUBE OIL SYSTEM EAST FILTER	1	MO	PM	ANN
	AIRHEATERS, MAIN	5120000		4057663801	AIR PREHEATER BYPASS DAMPER DRIVE - NORTH LUBRICATION	2	MO	PM	5YR
	AIRHEATERS, MAIN	5120000		4057664001	AIR PREHEATER BYPASS DAMPER DRIVE - SOUTH LUBRICATION	2	MO	PM	5YR
	AIRHEATERS, MAIN	5120000		4057665701	ICE- AIR HEATER PRIMARY AIR BYPASS DAMPERS UNIT 2	2	MO	PM	4YR
	AIRHEATERS, MAIN	5120000		4057878201	ICE U1 2YR AIR HEATER LEAKAGE TEST	1	MO	PM	2YR
	AIRHEATERS, MAIN	5120000		4057879101	ICE -PERFORM AIR HEATER LEAKAGE TEST U2	2	MO	PM	2YR
130									
150	PRECIPITATOR	5120000		0093801801	U1 ICE 2WK PRECIP RAPPER INSPECTION	1	MO	PM	2WK
	PRECIPITATOR	5120000		0094379301	U2 ICE 2WK PRECIP RAPPER INSPECTION	2	MO	PM	2WK
150									
165	SCR SELECTIVE CAT. REDUCTION	5120000		4071811501	U2 ICE 1YR AMMONIA SENSOR CALIBRATION	2	MO	PM	ANN
	SCR SELECTIVE CAT. REDUCTION	5120000		4092432801	SCR ECONOMIZER #1 - PERFORM ANNUAL INSPECTION	0	MO	PM	ANN
	SCR SELECTIVE CAT. REDUCTION	5120000		4092520701	SCR ECONOMIZER #2 - PERFORM ANNUAL INSPECTION	0	MO	PM	ANN
	SCR SELECTIVE CAT. REDUCTION	5120000		4092523101	#1 LIQUID UREA TRANSFER PP - ANNUAL INSPECTION	0	MO	PM	ANN
	SCR SELECTIVE CAT. REDUCTION	5120000		4092523401	#2 LIQUID UREA TRANSFER PP - PERFORM ANNUAL INSPECTION	0	MO	PM	ANN
	SCR SELECTIVE CAT. REDUCTION	5120000		4092525601	RECYCLE TRANSFER PP #1 - PERFORM ANNUAL INSPECTION	0	MO	PM	ANN
	SCR SELECTIVE CAT. REDUCTION	5120000		4092526001	#2 RECYCLE TRANSFER PP - PERFORM ANNUAL INSPECTION	0	MO	PM	ANN
	SCR SELECTIVE CAT. REDUCTION	5120000		4092529001	#1 UREA SOLUTION FEED PP - PERFORM ANNUAL INSPECTION	0	MO	PM	ANN
	SCR SELECTIVE CAT. REDUCTION	5120000		4092677501	#2 UREA SOLUTION FEED PUMP - PERFORM ANNUAL INSPECTION	0	MO	PM	ANN
	SCR SELECTIVE CAT. REDUCTION	5120000		4092880801	UREA CONVEYOR - PERFORM ANNUAL INSPECTION	0	MO	PM	ANN
	SCR SELECTIVE CAT. REDUCTION	5120000		4092881401	#1 UREA MIX TANK - ANNUAL INSPECTION	0	MO	PM	ANN
	SCR SELECTIVE CAT. REDUCTION	5120000		4092994301	#2 UREA MIX TANK - ANNUAL INSPECTION	0	MO	PM	ANN
	SCR SELECTIVE CAT. REDUCTION	5120000		4092999801	#1 AOD HYDROLYZER - ANNUAL INSPECTION	0	MO	PM	ANN
	SCR SELECTIVE CAT. REDUCTION	5120000		4093003601	#2 AOD HYDROLYZER - ANNUAL INSPECTION	0	MO	PM	ANN
	SCR SELECTIVE CAT. REDUCTION	5120000		4093004401	#1 SCR LAY-UP FAN - ANNUAL INSPECTION	2	MO	PM	ANN
	SCR SELECTIVE CAT. REDUCTION	5120000		4093005201	#2 SCR LAY-UP FAN - ANNUAL INSPECTION	2	MO	PM	ANN
	SCR SELECTIVE CAT. REDUCTION	5140000		4092189901	SCR AIR COMPRESSOR - PERFORM CHANGEOUT OF COOLANT	0	MO	PM	2YR
	SCR SELECTIVE CAT. REDUCTION	5140000		4092201701	SCR AIR COMPRESSOR - 6 MONTH INSPECTION	0	MO	PM	6MO
165									

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WOT System Cd	WOT System Code Description	Account Nbr	WOT Unit Cond Reqd	WOT WO Nbr Task	WOT WR Task Title	WOT Unit	WO Type	WOT Job Type	Pm Frequency Code
175	EMISSIONS MONITORING	5120000		0093592201	CHANGE AMMONIA SYSTEM AIR BLOWER OIL WITH AEON PD GARDNER-DE	2	MO	PM	1YR
	EMISSIONS MONITORING	5120000		0093592301	U2 ICE 1YR CALIBRATE AMMONIA LEAK DETECTOR	2	MO	PM	1YR
	EMISSIONS MONITORING	5120000		0093634101	ANNUAL CEMS RATA. ASSIST WITH TEST. RECORD TIME SPENT IN	0	MO	PM	1YR
	EMISSIONS MONITORING	5120000		0094693301	INSPECT UNIT 2 SO3 SYSTEM PIPING	2	MO	PM	1YR
	EMISSIONS MONITORING	5120000		0094695001	INSPECT UNIT 2 SO3 SYSTEM TANK PAD VALVES	2	MO	PM	1YR
	EMISSIONS MONITORING	5120000		0094696401	STROKE SO2 ARV1002A & ARV1002B TEMP CONTROL	2	MO	PM	2YR
	EMISSIONS MONITORING	5120000		0094699001	CLEAN AND INSPECT UNIT 2 SO3 LANCES AND PIPING	2	MO	PM	OUT
	EMISSIONS MONITORING	5120000		4146330301	CHANGE SO2 BLOWER INLET FILTER	1	MO	PM	2MO
175									
180	INSTRUMENT/CONTROL AIR	5140000		0093450701	U-2 AIR DRYER, (UNIVERSAL BLOWER RAI) LUBRICATION.	2	MO	PM	SEM
	INSTRUMENT/CONTROL AIR	5140000		0093610201	LUBRICATION - #3 PLANT AIR COMPRESSOR	2	MO	PM	1YR
	INSTRUMENT/CONTROL AIR	5140000		0093610401	LUBRICATION - #1 PLANT AIR COMPRESSOR.	2	MO	PM	1YR
	INSTRUMENT/CONTROL AIR	5140000		0094226701	U1 ICE 6MO CONTROL AIR DRYER INSPECTION	1	MO	PM	6MO
	INSTRUMENT/CONTROL AIR	5140000		0094375301	U2 ICE 6MO CONTROL AIR DRYER INSPECTION/FILTERS	2	MO	PM	6MO
	INSTRUMENT/CONTROL AIR	5140000		4057654601	ICE - CONDUCT NO 1 COMPRESSOR PERFORMANCE TEST	2	MO	PM	1YR
	INSTRUMENT/CONTROL AIR	5140000		4057703301	U1 AIR DRYER BLOWER LUBRICATION	1	MO	PM	1YR
	INSTRUMENT/CONTROL AIR	5140000		4057837101	CONDUCT NO. 2 AIR COMPRESSOR PERFORMANCE TEST	2	MO	PM	1YR
	INSTRUMENT/CONTROL AIR	5140000		4074745101	WEST AIR COMPRESSOR MOTOR	1	MO	PM	9MO
	INSTRUMENT/CONTROL AIR	5140000		4074750701	U1 EAST AIR COMPRESSOR MOTOR	1	MO	PM	9MO
180									
210	COAL UNLOADING	5120000		0093588701	COAL YARD TRUCK SCALE COMPUTER - CHANGE PASSWORD.	0	MO	PM	2MO
	COAL UNLOADING	5120000		4072859901	LUBRICATE TRACK SWITCHES 1-2, 2, 3 WEST AND 2-3 EAST	0	MO	PM	MON
	COAL UNLOADING	5120000		4073605101	STA 11 RAIL CAR UNLOADER - MECHANICAL INSPECTION	0	MO	PM	MON
	COAL UNLOADING	5120000		4073605902	STA 11 RAIL CAR UNLOADER (SHAKEOUT)- MECH - CHANGE OIL	0	MO	PM	2YR
	COAL UNLOADING & RAILS	5120000		0093588701	COAL YARD TRUCK SCALE COMPUTER - CHANGE PASSWORD.	0	MO	PM	2MO
	COAL UNLOADING & RAILS	5120000		4072859901	LUBRICATE TRACK SWITCHES 1-2, 2, 3 WEST AND 2-3 EAST	0	MO	PM	MON
	COAL UNLOADING & RAILS	5120000		4073605101	STA 11 RAIL CAR UNLOADER - MECHANICAL INSPECTION	0	MO	PM	MON
	COAL UNLOADING & RAILS	5120000		4073605902	STA 11 RAIL CAR UNLOADER (SHAKEOUT)- MECH - CHANGE OIL	0	MO	PM	2YR
210									
215	COAL SAMPLING	5120000		0093610501	#13 NORTH CONVEYOR SAMPLE CUTTER - INSPECT.	0	MO	PM	3MO
	COAL SAMPLING	5120000		0093610601	#13 SOUTH CONVEYOR SAMPLE CUTTER - INSPECT.	0	MO	PM	3MO
	COAL SAMPLING	5120000		0093625601	REPLACE OF PARTS COAL SAMPLER - STA. 12	0	MO	PM	1YR
	COAL SAMPLING	5120000		4073588201	STA 12 SAMPLING SYSTEM - MECHANICAL CHECKOUT	0	MO	PM	MON
	COAL SAMPLING	5120000		4073589001	STA 12 SAMPLING SYSTEM - MECH, CHANGE BRG. LUBRICATION	0	MO	PM	2YR
	COAL SAMPLING	5120000		4073589801	STA 12 SAMPLING SYSTEM - ICE: CALIBRATE INSTRUMENTATION	0	MO	PM	1YR
	COAL SAMPLING	5120000		4110637701	AF SAMPLER TWO WEEK LUBE AND INSPECTION	0	MO	PM	2WK
	COAL SAMPLING	5120000		4110641801	AF SAMPLER QUARTERLY ICE INSPECTION	0	MO	PM	3MO
	COAL SAMPLING	5120000		4110678101	AF SAMPLER QUARTERLY MECHANICAL INSPECTION	0	MO	PM	3MO
	COAL SAMPLING	5120000		4112676901	AF SAMPLER 2-YR MOTOR BEARINGS	0	MO	PM	2YR
	COAL SAMPLING	5120000		4112677201	AF SAMPLER 4-YR CHANGE OIL	0	MO	PM	4YR
	COAL SAMPLING	5120000		4112678701	AF SAMPLER 4-YR BIAS TEST	0	MO	PM	4YR
	COAL SAMPLING	5120000		4114176201	AR SAMPLER QUARTERLY MECHANICAL CHECK	0	MO	PM	3MO
	COAL SAMPLING	5120000		4114177501	AR SAMPLER ANNUAL MECHANICAL INSPECTION	0	MO	PM	ANN
	COAL SAMPLING	5120000		4114178101	AR SAMPLER QUARTERLY ICE INSPECTION	0	MO	PM	3MO
	COAL SAMPLING	5120000		4114178701	AR SAMPLER BIAS TESTING (4 YR)	0	MO	PM	4YR
	COAL SAMPLING	5120000		4114179601	CY - CLEAN DITCH, AR SAMPLER HYD UNIT	0	MO	PM	3MO
215									
220	COAL CONVEYING & STORAGE	5120000		0093358101	MOTOR - COAL CONVEYOR #1 - PERFORM INSPECTION CHECK SHEET.	0	MO	PM	1YR
	COAL CONVEYING & STORAGE	5120000		0093358301	MOTOR C11 INSPECTION	0	MO	PM	1YR
	COAL CONVEYING & STORAGE	5120000		0093358501	MOTOR, COAL CONVEYOR #12 - PERFORM INSPECTION CHECK SHEET.	0	MO	PM	1YR
	COAL CONVEYING & STORAGE	5120000		0093358701	MOT C13 N INSP	0	MO	PM	1YR
	COAL CONVEYING & STORAGE	5120000		0093358901	MOTOR, COAL CONVEYOR #13 SOUTH - PERFORM INSPECTION CHECK	0	MO	PM	1YR
	COAL CONVEYING & STORAGE	5120000		0093359101	MOTOR, COAL CONVEYOR #14 - PERFORM INSPECTION CHECK SHEET.	0	MO	PM	1YR
	COAL CONVEYING & STORAGE	5120000		0093359601	MOTOR, COAL CONVEYOR #16 - PERFORM INSPECTION CHECK SHEET.	0	MO	PM	1YR
	COAL CONVEYING & STORAGE	5120000		0093359801	MOTOR, COAL CONVEYOR #17 - PERFORM INSPECTION CHECK SHEET.	0	MO	PM	1YR
	COAL CONVEYING & STORAGE	5120000		0093362401	MOTOR, COAL CONVEYOR #3 - PERFORM INSPECTION CHECK SHEET.	0	MO	PM	1YR
	COAL CONVEYING & STORAGE	5120000		0093362601	MOTOR, COAL CONVEYOR #4 - PERFORM INSPECTION CHECK SHEET.	0	MO	PM	1YR
	COAL CONVEYING & STORAGE	5120000		0093362801	MOTOR, COAL CONVEYOR FEEDER #10E AND #10W - PERFORM	0	MO	PM	1YR
	COAL CONVEYING & STORAGE	5120000		0093363001	MOTOR, COAL CONVEYOR FEEDER #11A - PERFORM INSPECTION CHECK	0	MO	PM	1YR
	COAL CONVEYING & STORAGE	5120000		0093363301	MOTOR, COAL CONVEYOR FEEDER #11B - PERFORM INSPECTION CHECK	0	MO	PM	1YR
	COAL CONVEYING & STORAGE	5120000		0093364101	MOTOR, CR 11A - COAL CRUSHER - INSPECTION	0	MO	PM	1YR
	COAL CONVEYING & STORAGE	5120000		0093366101	MOTOR, CR 11B - COAL CRUSHER - INSPECTION	0	MO	PM	1YR
	COAL CONVEYING & STORAGE	5120000		0093381301	INSPECTION - #11A CRUSHER HAMMERS.	0	MO	PM	3MO
	COAL CONVEYING & STORAGE	5120000		0093381401	INSPECTION - #11B CRUSHER HAMMERS.	0	MO	PM	3MO
	COAL CONVEYING & STORAGE	5120000		0093596501	OIL SAMPLE, COAL CONVEYOR GEARBOXES: 13N,13S,15U,15L,16,17	0	MO	PM	3MO
	COAL CONVEYING & STORAGE	5120000		0093598601	INSPECTION CRANE - TRACTOR SHED BRIDGE (P&H)	0	MO	PM	6MO
	COAL CONVEYING & STORAGE	5120000		0093609601	LUBRICATION CRUSHER - FROZEN COAL #13-A, DRIVE CHAIN	0	MO	PM	1YR
	COAL CONVEYING & STORAGE	5120000		0093609701	LUBRICATION CRUSHER - FROZEN COAL #13B, DRIVE CHAIN	0	MO	PM	1YR
	COAL CONVEYING & STORAGE	5120000		0093611101	TELESCOPIC CHUTE - CHANGE SHEAR PINS.	0	MO	PM	6MO
	COAL CONVEYING & STORAGE	5120000		0093614801	INSPECTION CRANE - STA. 12 ELECTRIC HOIST. 7 TON	0	MO	PM	1YR
	COAL CONVEYING & STORAGE	5120000		0093614901	INSPECTION CRANE - STA. 14 ELECTRIC HOIST, 7 TON	0	MO	PM	1YR

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WOT System Cd	WOT System Code Description	Account Nbr	WOT Unit Cond Reqd	WOT WO Nbr Task	WOT WR Task Title	WOT Unit	WO Type	WOT Job Type	Pm Frequency Code
	COAL CONVEYING & STORAGE	5120000		0093615001	INSPECTION CRANE - TRACTOR SHED CRANE, 3 TON	0	MO	PM	1YR
	COAL CONVEYING & STORAGE	5120000		0093625401	REPLACEMENT OF PARTS CRUSHER - COAL #CR-13A	0	MO	PM	1YR
	COAL CONVEYING & STORAGE	5120000		0095099201	#CR-13A COAL CRUSHER - PACK BEARINGS & FALK CLP WITH GREASE.	0	MO	PM	1YR
	COAL CONVEYING & STORAGE	5120000		0095099301	#CR-13B COAL CRUSHER - PACK BEARINGS & FALK CLP WITH GREASE.	0	MO	PM	1YR
	COAL CONVEYING & STORAGE	5120000		0095105501	#13N COAL CONVEYOR - PACK FALK COUPLING WITH GREASE.	0	MO	PM	ANH
	COAL CONVEYING & STORAGE	5120000		0095105701	#11 COAL CONVEYOR - PACK FALK COUPLING WITH GREASE.	0	MO	PM	ANH
	COAL CONVEYING & STORAGE	5120000		0095105901	#13S COAL CONVEYOR - PACK FALK COUPLING WITH GREASE.	0	MO	PM	ANH
	COAL CONVEYING & STORAGE	5120000		0095106601	#16 & 17 COAL CONVEYOR - INSPECT (V) BELT ON DRIVE GEAR.	0	MO	PM	6MO
	COAL CONVEYING & STORAGE	5120000		4072860301	INSPECT COAL CONVEYOR 10E AND 10W BELTS AND SHEAVES	0	MO	PM	1YR
	COAL CONVEYING & STORAGE	5120000		4072860501	11A FEEDER DRIVE INSP	0	MO	PM	2YR
	COAL CONVEYING & STORAGE	5120000		4072861201	11B FEEDER DRIVE INSPECTION	0	MO	PM	2YR
	COAL CONVEYING & STORAGE	5120000		4072861601	INSPECT COUPLINGS ON #12 COAL CONVEYOR DRIVE GEARBOX	0	MO	PM	ANH
	COAL CONVEYING & STORAGE	5120000		4073130801	INSPECT EMERGENCY CONVEYOR COAL HANDLING EQUIP. MISC. U2	0	MO	PM	1YR
	COAL CONVEYING & STORAGE	5120000		4073132001	INSPECT COUPLING ON COAL CONVEYOR #15 LOWER	0	MO	PM	ANH
	COAL CONVEYING & STORAGE	5120000		4073133401	INSPECT COUPLING ON COAL CONVEYOR #15 UPPER	0	MO	PM	ANH
	COAL CONVEYING & STORAGE	5120000		4073161801	LUBE COAL CHUTE ACTUATOR AND GATE ON CONVEYOR #15, #16, #17	0	MO	PM	6MO
	COAL CONVEYING & STORAGE	5120000		4073171701	LUBE COAL CHUTE ACTUATOR & GATE STATION 14	0	MO	PM	6MO
	COAL CONVEYING & STORAGE	5120000		4073172101	INSPECT LUBRICATION IN COAL CHUTE ACTUATOR & GATE STATION 14	0	MO	PM	2YR
	COAL CONVEYING & STORAGE	5120000		4073197301	INSP LIMITORQUE ON COALCHUTE ACTUATOR & GATE 15,16 & 17 CONV	0	MO	PM	2YR
	COAL CONVEYING & STORAGE	5120000		4073197701	EXHAUSTER SILO ROOM U2 WEST	2	MO	PM	3MO
	COAL CONVEYING & STORAGE	5120000		4073199401	EXHAUSTER SILO ROOM U2 EAST	2	MO	PM	3MO
	COAL CONVEYING & STORAGE	5120000		4073415501	INSPECT #1 COAL CONVEYOR	0	MO	PM	ANH
	COAL CONVEYING & STORAGE	5120000		4073441001	INSPECT COAL CONVEYOR #3	0	MO	PM	ANH
	COAL CONVEYING & STORAGE	5120000		4073490801	INSPECT COAL CONVEYOR #4	0	MO	PM	ANH
	COAL CONVEYING & STORAGE	5120000		4073496201	INSPECT COAL CONVEYOR #14	0	MO	PM	ANH
	COAL CONVEYING & STORAGE	5120000		4073518601	COAL CONVEYOR FEEDER STATION 1	0	MO	PM	1YR
	COAL CONVEYING & STORAGE	5120000		4081606201	#11 BELT SCALE STATE CERTIFICATION	0	MO	PM	6MO
	COAL CONVEYING & STORAGE	5120000		4103597801	PLT SUPV - #13 CONVEYORS BRIDGE EXPANSION JOINT INSPECTIONS	0	MO	PM	ANN
	COAL CONVEYING & STORAGE	5120000		4103597802	AEPSC - #13 CONVEYORS BRIDGE EXPANSION JOINT INSPECTIONS	0	MO	PM	ANN
	COAL CONVEYING & STORAGE	5120000		4103784501	PLT SUPV - #14 CONVEYORS BRIDGE EXPANSION JOINT INSPECTIONS	0	MO	PM	ANN
	COAL CONVEYING & STORAGE	5120000		4103784502	AEPSC - #14 CONVEYORS BRIDGE EXPANSION JOINT INSPECTIONS	0	MO	PM	ANN
	COAL CONVEYING & STORAGE	5120000		4103798401	PLT SUPV - #12 CONVEYORS BRIDGE EXPANSION JOINT INSPECTIONS	0	MO	PM	ANN
	COAL CONVEYING & STORAGE	5120000		4103798402	AEPSC - #12 CONVEYORS BRIDGE EXPANSION JOINT INSPECTIONS	0	MO	PM	ANN
	COAL CONVEYING & STORAGE	5120000		4103801001	PLT SUPV - #3 CONVEYORS BRIDGE EXPANSION JOINT INSPECTIONS	0	MO	PM	ANN
	COAL CONVEYING & STORAGE	5120000		4103801002	AEPSC - #3 CONVEYORS BRIDGE EXPANSION JOINT INSPECTIONS	0	MO	PM	ANN
	COAL CONVEYING & STORAGE	5120000		4103802001	PLT SUPV - #1 CONVEYORS BRIDGE EXPANSION JOINT INSPECTIONS	0	MO	PM	ANN
	COAL CONVEYING & STORAGE	5120000		4103802002	AEPSC - #1 CONVEYORS BRIDGE EXPANSION JOINT INSPECTIONS	0	MO	PM	ANN
	COAL CONVEYING & STORAGE	5120000		4128444601	COAL WETTING PUMP - CLEAN STRAINERS	0	MO	PM	QTR
	COAL CONVEYING & STORAGE	5120000		4128760501	INSPECTION CRANE - STATION 2 HOIST	0	MO	PM	ANN
	COAL CONVEYING & STORAGE	5120000		4129844901	1 MO INSP U1 BUNKER ROOM COAL TRIPPER CHUTE	0	MO	PM	MON
220									
235	FUEL OIL SUPPLY/STORAGE	5120000		0093561601	INSPECTION - FUEL OIL STORAGE TANK #6	0	MO	PM	1YR
	FUEL OIL SUPPLY/STORAGE	5120000		0093561701	INSPECTION - FUEL OIL STORAGE TANK #7	0	MO	PM	1YR
	FUEL OIL SUPPLY/STORAGE	5120000		0093599501	CLEAN SUCTION TWIN STRAINER BASKETS GOING TO THE FOUR IMO	0	MO	PM	6MO
	FUEL OIL SUPPLY/STORAGE	5120000		4073251501	FUEL OIL PUMP #1 - MECHANICAL INSPECTION	0	MO	PM	1YR
	FUEL OIL SUPPLY/STORAGE	5120000		4073252401	FUEL OIL PUMP #2 - MECHANICAL INSPECTION	0	MO	PM	1YR
	FUEL OIL SUPPLY/STORAGE	5120000		4073257401	FUEL OIL PUMP #3 - MECHANICAL INSPECTION	0	MO	PM	1YR
	FUEL OIL SUPPLY/STORAGE	5120000		4073292701	FUEL OIL PUMP #4 - MECHANICAL INSPECTION	0	MO	PM	1YR
	FUEL OIL SUPPLY/STORAGE	5120000		4073336701	FUEL OIL UNLOADING PUMP - MECH. CHANGE OIL	0	MO	PM	2MO
235									
250	PULVERIZER (COAL)	5120000		0093371101	MOTOR, SEAL AIR BLOWER MIDDLE U1 - PERFORM INSPECTION	1	MO	PM	1YR
	PULVERIZER (COAL)	5120000		0093373201	MOTOR, SEAL AIR BLOWER NORTH U1 - PERFORM INSPECTION	1	MO	PM	1YR
	PULVERIZER (COAL)	5120000		0093373301	MOTOR, SEAL AIR BLOWER SOUTH U1 - PERFORM INSPECTION	1	MO	PM	1YR
	PULVERIZER (COAL)	5120000		0093436401	MOTOR, PULVERIZER SEAL AIR BLOWER EAST U2 - PERFORM	2	MO	PM	1YR
	PULVERIZER (COAL)	5120000		0093438301	MOTOR, PULV. SEAL AIR BLOWER WEST U2 - PERFORM INSPECTION	2	MO	PM	1YR
	PULVERIZER (COAL)	5120000		0093591301	PULVERIZER BURNER PIPING UNIT 1 - THICKNESS CHECKS	1	MO	PM	3YR
	PULVERIZER (COAL)	5120000		0093594101	PULVERIZER #13 - CHANGE OIL IN GEARBOX.	1	MO	PM	1YR
	PULVERIZER (COAL)	5120000		0093594201	PULVERIZER #14 - CHANGE OIL IN GEARBOX.	1	MO	PM	1YR
	PULVERIZER (COAL)	5120000		0093594401	PULVERIZER #16 - CHANGE OIL IN GEARBOX.	1	MO	PM	1YR
	PULVERIZER (COAL)	5120000		0093594501	PULVERIZER #21 - CHANGE OIL IN GEARBOX.	2	MO	PM	1YR
	PULVERIZER (COAL)	5120000		0093594601	PULVERIZER #22 - CHANGE OIL IN GEARBOX.	2	MO	PM	1YR
	PULVERIZER (COAL)	5120000		0093594701	PULVERIZER #23 - CHANGE OIL IN GEARBOX.	2	MO	PM	1YR
	PULVERIZER (COAL)	5120000		0093594801	PULVERIZER #24 - CHANGE OIL IN GEARBOX.	2	MO	PM	1YR
	PULVERIZER (COAL)	5120000		0093594901	PULVERIZER #25 - CHANGE OIL IN GEARBOX.	2	MO	PM	1YR
	PULVERIZER (COAL)	5120000		0093595101	OIL SAMPLE, U1 PULVERIZER MOTOR BEARINGS, B-TEAM	1	MO	PM	3MO
	PULVERIZER (COAL)	5120000		0093595201	OIL SAMPLE, U1 PULVERIZER GEARBOXES AND CIRC WATER PUMP,	1	MO	PM	3MO
	PULVERIZER (COAL)	5120000		0093595801	OIL SAMPLE, U2 PULVERIZER MOTOR BEARINGS, D-TEAM	2	MO	PM	3MO
	PULVERIZER (COAL)	5120000		0093595901	OIL SAMPLE, U2 PULVERIZER GEARBOXES AND U2 AIR COMPRESSOR	2	MO	PM	3MO
	PULVERIZER (COAL)	5120000		4062612601	INSPECT U1 MIDDLE SEAL AIR BLOWER COUPLING	1	MO	PM	ANH
	PULVERIZER (COAL)	5120000		4062662901	INSPECT U1 SOUTH SEAL AIR BLOWER COUPLING	1	MO	PM	ANH
	PULVERIZER (COAL)	5120000		4062663501	INSPECT U1 NORTH SEAL AIR BLOWER COUPLING	1	MO	PM	ANH

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WOT System Cd	WOT System Code Description	Account Nbr	WOT Unit Cond Reqd	WOT WO Nbr Task	WOT WR Task Title	WOT Unit	WO Type	WOT Job Type	Pm Frequency Code
	PULVERIZER (COAL)	5120000		4062866001	ICE - #21 PULV - CALIBRATE SEAL ALARMS-3YR	2	MO	PM	3YR
	PULVERIZER (COAL)	5120000		4062866002	ICE - #22 PULV - CALIBRATE SEAL ALARMS-3YR	2	MO	PM	3YR
	PULVERIZER (COAL)	5120000		4062866003	ICE - #23 PULV - CALIBRATE SEAL ALARMS-3YR	2	MO	PM	3YR
	PULVERIZER (COAL)	5120000		4062866004	ICE - #24 PULV - CALIBRATE SEAL ALARMS-3YR	2	MO	PM	3YR
	PULVERIZER (COAL)	5120000		4062866005	ICE - #25 PULV - CALIBRATE SEAL ALARMS-3YR	2	MO	PM	3YR
	PULVERIZER (COAL)	5120000		4062866006	ICE - #26 PULV - CALIBRATE SEAL ALARMS-3YR	2	MO	PM	3YR
	PULVERIZER (COAL)	5120000		4063915901	U2 PULV - INSPECT EAST SEAL AIR BLOWER COUPLING	2	MO	PM	1YR
	PULVERIZER (COAL)	5120000		4063916901	U2 PULV - INSPECT WEST SEAL AIR BLOWER COUPLING	2	MO	PM	1YR
	PULVERIZER (COAL)	5120000		4073044601	COUPLING INSPECTION ON #14 PULVERIZER U1	1	MO	PM	1YR
	PULVERIZER (COAL)	5120000		4073045101	COUPLING INSPECTION ON #13 PULVERIZER U1	1	MO	PM	1YR
	PULVERIZER (COAL)	5120000		4073045701	INSPECT COUPLING ON #12 PULVERIZER U1	1	MO	PM	1YR
	PULVERIZER (COAL)	5120000		4073046501	COUPLING INSPECTIN ON #11 PULVERIZER U1	1	MO	PM	1YR
250									
260	BURNER/IGNITORS	5120000		0093614601	INSPECTION CRANE - CAR SHAKER HOIST (EAST) 2-1/2 TON	1	MO	PM	1YR
	BURNER/IGNITORS	5120000		0093614701	INSPECTION CRANE - CAR SHAKER HOIST (WEST), 2-3/4 TON	1	MO	PM	1YR
	BURNER/IGNITORS	5120000		4064113701	U1 ICE 1YR OIL LIGHTER GAUGES CHECK CALB/REPLACE	1	MO	PM	1YR
	BURNER/IGNITORS	5120000		4064115201	U1 ICE 2YR OIL LIGHTER SLC 502 REPLACE BATTERIES	1	MO	PM	2YR
	BURNER/IGNITORS	5120000		4064228001	ICE - CALIBRATE OIL LIGHTER INSTRUMENTS-3YR	2	MO	PM	3YR
	BURNER/IGNITORS	5120000		4073086601	U1 ICE 1YR OIL LIGHTER AIR SUPP MANIFOLD CHANGE FILTERS	1	MO	PM	1YR
	BURNER/IGNITORS	5140000		4064183601	ICE - #21 PULV - CHECK ATOMIZING AIR VALVE STROKE	2	MO	PM	2YR
	BURNER/IGNITORS	5140000		4064183602	ICE - #22 PULV - CHECK ATOMIZING AIR VALVE STROKE	2	MO	PM	2YR
	BURNER/IGNITORS	5140000		4064183603	ICE - #23 PULV - CHECK ATOMIZING AIR VALVE STROKE	2	MO	PM	2YR
	BURNER/IGNITORS	5140000		4064183604	ICE - #24 PULV - CHECK ATOMIZING AIR VALVE STROKE	2	MO	PM	2YR
	BURNER/IGNITORS	5140000		4064183605	ICE - #25 PULV - CHECK ATOMIZING AIR VALVE STROKE	2	MO	PM	2YR
	BURNER/IGNITORS	5140000		4064183606	ICE - #26 PULV - CHECK ATOMIZING AIR VALVE STROKE	2	MO	PM	2YR
	MAIN BURNER/IGNITORS	5120000		0093614601	INSPECTION CRANE - CAR SHAKER HOIST (EAST) 2-1/2 TON	1	MO	PM	1YR
	MAIN BURNER/IGNITORS	5120000		0093614701	INSPECTION CRANE - CAR SHAKER HOIST (WEST), 2-3/4 TON	1	MO	PM	1YR
	MAIN BURNER/IGNITORS	5120000		4064113701	U1 ICE 1YR OIL LIGHTER GAUGES CHECK CALB/REPLACE	1	MO	PM	1YR
	MAIN BURNER/IGNITORS	5120000		4064115201	U1 ICE 2YR OIL LIGHTER SLC 502 REPLACE BATTERIES	1	MO	PM	2YR
	MAIN BURNER/IGNITORS	5120000		4064228001	ICE - CALIBRATE OIL LIGHTER INSTRUMENTS-3YR	2	MO	PM	3YR
	MAIN BURNER/IGNITORS	5120000		4073086601	U1 ICE 1YR OIL LIGHTER AIR SUPP MANIFOLD CHANGE FILTERS	1	MO	PM	1YR
	MAIN BURNER/IGNITORS	5140000		4064183601	ICE - #21 PULV - CHECK ATOMIZING AIR VALVE STROKE	2	MO	PM	2YR
	MAIN BURNER/IGNITORS	5140000		4064183602	ICE - #22 PULV - CHECK ATOMIZING AIR VALVE STROKE	2	MO	PM	2YR
	MAIN BURNER/IGNITORS	5140000		4064183603	ICE - #23 PULV - CHECK ATOMIZING AIR VALVE STROKE	2	MO	PM	2YR
	MAIN BURNER/IGNITORS	5140000		4064183604	ICE - #24 PULV - CHECK ATOMIZING AIR VALVE STROKE	2	MO	PM	2YR
	MAIN BURNER/IGNITORS	5140000		4064183605	ICE - #25 PULV - CHECK ATOMIZING AIR VALVE STROKE	2	MO	PM	2YR
	MAIN BURNER/IGNITORS	5140000		4064183606	ICE - #26 PULV - CHECK ATOMIZING AIR VALVE STROKE	2	MO	PM	2YR
260									
310	BOILER, GENERAL	5120000		0093435601	U2 MOTOR, HYDROSTATIC TEST PP INSPECTION	2	MO	PM	1YR
	BOILER, GENERAL	5120000		4061287201	U2 ICE 6MO PENTHOUSE SEAL AIR DIFFERENTIAL-CALIBRATE	2	MO	PM	6MO
	BOILER, GENERAL	5120000		4072630501	INSPECT MAIN STEAM ATTEMPERATOR BYPASS VA. FMO-101 U2	2	MO	PM	10Y
	BOILER, GENERAL	5120000		4072713101	INSPECT BS FLASH TANK STEAM HEATER 8B VA UMO 804 U2	2	MO	PM	TEN
	BOILER, GENERAL	5120000		4072783601	INSPECT BW FLASH TANK DRAIN TO HEATER 8A VALVE UMO805 U2	2	MO	PM	TEN
	BOILER, GENERAL	5120000		4072785201	INSPECT BW FLASH TANK DRAIN TO HEATER 8B VALVE UMO 806 U2	2	MO	PM	TEN
	BOILER, GENERAL	5120000		4072786701	INSPECT HYDROSTATIC TEST PUMP U2	2	MO	PM	3YR
	BOILER, GENERAL	5120000		4072788501	INSPECT HPTE DRAIN VALVE DMO-151 U2	2	MO	PM	TEN
	BOILER, GENERAL	5120000		4072830401	INSPECT PENTHOUSE SEAL AIR FAN MOTOR COUPLING - WEST	2	MO	PM	1YR
	BOILER, GENERAL	5120000		4072830701	INSPECT PENTHOUSE SEAL AIR BLOWER COUPLING - EAST U2	2	MO	PM	1YR
	BOILER, GENERAL	5120000		4074163101	ICE - U1 ATTEMPERATOR CONTROL VALVES - RV51 AND RV52	1	MO	PM	1YR
	BOILER, GENERAL..	5120000		0093435601	U2 MOTOR, HYDROSTATIC TEST PP INSPECTION	2	MO	PM	1YR
	BOILER, GENERAL..	5120000		4061287201	U2 ICE 6MO PENTHOUSE SEAL AIR DIFFERENTIAL-CALIBRATE	2	MO	PM	6MO
	BOILER, GENERAL..	5120000		4072630501	INSPECT MAIN STEAM ATTEMPERATOR BYPASS VA. FMO-101 U2	2	MO	PM	10Y
	BOILER, GENERAL..	5120000		4072713101	INSPECT BS FLASH TANK STEAM HEATER 8B VA UMO 804 U2	2	MO	PM	TEN
	BOILER, GENERAL..	5120000		4072783601	INSPECT BW FLASH TANK DRAIN TO HEATER 8A VALVE UMO805 U2	2	MO	PM	TEN
	BOILER, GENERAL..	5120000		4072785201	INSPECT BW FLASH TANK DRAIN TO HEATER 8B VALVE UMO 806 U2	2	MO	PM	TEN
	BOILER, GENERAL..	5120000		4072786701	INSPECT HYDROSTATIC TEST PUMP U2	2	MO	PM	3YR
	BOILER, GENERAL..	5120000		4072788501	INSPECT HPTE DRAIN VALVE DMO-151 U2	2	MO	PM	TEN
	BOILER, GENERAL..	5120000		4072830401	INSPECT PENTHOUSE SEAL AIR FAN MOTOR COUPLING - WEST	2	MO	PM	1YR
	BOILER, GENERAL..	5120000		4072830701	INSPECT PENTHOUSE SEAL AIR BLOWER COUPLING - EAST U2	2	MO	PM	1YR
	BOILER, GENERAL..	5120000		4074163101	ICE - U1 ATTEMPERATOR CONTROL VALVES - RV51 AND RV52	1	MO	PM	1YR
310									
360	MAIN STEAM SPRHTR & LINE	5120000		0093602801	INSPECTION PIPE HANGERS, INSULATION & LAGGING AUDIT	2	MO	PM	6MO
	MAIN STEAM SPRHTR & LINE	5120000		4072738501	INSPECT SH BYPASS LIMITORQUE OPERATOR - MO7	1	MO	PM	TEN
	MAIN STEAM SPRHTR & LINE	5120000		4072739001	INSPECT SH "A" BYPASS VALVE AND OPERATOR U1 - MO6	1	MO	PM	TEN
	MAIN STEAM SPRHTR & LINE	5120000		4073679601	INSPECT UMO-1 SH BYPASS BLOCK VALVE (10 YR. INSP)	2	MO	PM	TEN
	MAIN STEAM SPRHTR & LINES	5120000		0093602801	INSPECTION PIPE HANGERS, INSULATION & LAGGING AUDIT	2	MO	PM	6MO
	MAIN STEAM SPRHTR & LINES	5120000		4072738501	INSPECT SH BYPASS LIMITORQUE OPERATOR - MO7	1	MO	PM	TEN
	MAIN STEAM SPRHTR & LINES	5120000		4072739001	INSPECT SH "A" BYPASS VALVE AND OPERATOR U1 - MO6	1	MO	PM	TEN
	MAIN STEAM SPRHTR & LINES	5120000		4073679601	INSPECT UMO-1 SH BYPASS BLOCK VALVE (10 YR. INSP)	2	MO	PM	TEN
360									
380	SOOTBLOWERS	5120000		0093438101	MOTOR, SEAL AIR BLOWER SOOT BLOWER SYSTEM EAST - PERFORM	2	MO	PM	1YR

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WOT System Cd	WOT System Code Description	Account Nbr	WOT Unit Cond Reqd	WOT WO Nbr Task	WOT WR Task Title	WOT Unit	WO Type	WOT Job Type	Pm Frequency Code
	SOOTBLOWERS	5120000		0093438201	MOTOR, SEAL AIR BLOWER SOOT BLOWER SYSTEM WEST - PERFORM	2	MO	PM	1YR
	SOOTBLOWERS	5120000		0093620301	ICE U2 3MO IK SOOTBLOWERS INSPECTION	2	MO	PM	3MO
	SOOTBLOWERS	5120000		4062127301	U1 MECH MONTHLY IK SOOTBLOWER INSPECTION	1	MO	PM	MON
	SOOTBLOWERS	5120000		4062127901	U1 MECH MONTHLY IR & AIR HEATER SOOTBLOWER INSPECTION	1	MO	PM	MON
	SOOTBLOWERS	5120000		4062132401	U2 MECH MONTHLY IK SOOTBLOWERS INSPECTION	2	MO	PM	MON
	SOOTBLOWERS	5120000		4062134901	U2 MECH MONTHLY IR & AIR HEATER SOOTBLOWER INSPECTION	2	MO	PM	MON
	SOOTBLOWERS	5120000		4062599101	CHECK U1 IK SOOTBLOWER PRESSURE	1	MO	PM	1YR
	SOOTBLOWERS	5120000		4062602301	U1 IR SOOTBLOWER PRESSURE CHECK	1	MO	PM	1YR
	SOOTBLOWERS	5120000		4062602701	ICE-U1 6MO ACOUSTIC HORN INLINE FILTER INSP	1	MO	PM	6MO
	SOOTBLOWERS	5120000		4062609801	U2 CHECK IR SOOTBLOWER STEAM PRESSURE	2	MO	PM	1YR
	SOOTBLOWERS	5120000		4062876601	U2 ICE 6MO AIR HEATER SOOTBLOWER CHECK INSTRUMENTATION/CYLIN	2	MO	PM	6MO
380									
390	AUXILIARY BOILER	5120000		0093599601	AUXILIARY BOILER INSPECTION	2	MO	PM	6MO
	AUXILIARY BOILER	5120000		4093047601	ICE 3YR - AUX BOILER FD FAN DRIVE - INSPECTION	2	MO	PM	3YR
	AUXILIARY BOILER	5120000		4093048601	ICE 3YR - AUX BOILER FUEL OIL VALVES BRV-452 & BRV-401	2	MO	PM	3YR
390									
410	CONDENSERS	5120000		0093428401	MOTOR, AUXILIARY HOTWELL PUMP #2 U2 - PERFORM INSPECTION	2	MO	PM	1YR
	CONDENSERS	5120000		4065948701	U2 AUX HOTWELL PUMP MOTOR #2 - CHANGE LUBRICANT	2	MO	PM	1YR
	CONDENSERS	5130000		0093571701	LUBRICATION PUMP - #1 RDV	2	MO	PM	3MO
	CONDENSERS	5130000		0093604901	MOTOR NASH PUMP - EAST	1	MO	PM	1YR
	CONDENSERS	5130000		0093618001	INSPECTION PUMP - R.D.V. #1	2	MO	PM	1YR
	CONDENSERS	5130000		4065372601	U1 ICE 3YR CALIBRATE EAST NASH PUMP INSTRUMENTS	1	MO	PM	3YR
	CONDENSERS	5130000		4065373001	U1 ICE 3 YR CALIBRATE / STROKE WEST NASH PUMP INSTRUMENTS	1	MO	PM	3YR
	CONDENSERS	5130000		4065500401	U1 WEST NASH PUMP INSP / CHANGE OIL IN MOTOR	1	MO	PM	ANN
	CONDENSERS	5130000		4065502901	U1 EAST NASH PUMP INSP / CHANGE OIL IN MOTOR	1	MO	PM	ANH
	CONDENSERS	5130000		4065583201	U2 NASH PUMP #2 COUPLING INSP / CHANGE OIL IN MOTOR	2	MO	PM	ANH
	CONDENSERS	5130000		4065588101	U2 NASH PUMP #3 COUPLING	2	MO	PM	2YR
	CONDENSERS	5130000		4065734401	U1 HOTWELL PUMP SOUTH INSPECTION	1	MO	PM	ANH
	CONDENSERS	5130000		4065740701	U1 HOTWELL PUMP NORTH INSPECTION	1	MO	PM	ANH
	CONDENSERS	5130000		4065889801	U2 CONDENSATE BOOSTER PUMP #2 - COUPLING INSP/CHANGE MOTOR O	2	MO	PM	ANH
	CONDENSERS	5130000		4065890601	U2 HOTWELL PUMP #1 - INSPECT COUPLING/CHANGE MOTOR OIL	2	MO	PM	ANH
	CONDENSERS	5130000		4065894401	U2 HOTWELL PUMP #2 - INSPECT COUPLING/CHANGE MOTOR OIL	2	MO	PM	ANH
	CONDENSERS	5130000		4065895301	U2 HOTWELL PUMP #3 - INSPECT COUPLING/CHANGE MOTOR OIL	2	MO	PM	ANH
	CONDENSERS	5130000		4066149202	ICE U2 - DEAD HEAD TEST CONDENSATE BOOSTER PUMPS	2	MO	PM	2YR
410									
415	CONDENSATE	5120000		0093370801	MOTOR, MISCELLANEOUS DRAIN TANK PUMP #1S U1 - PERFORM	1	MO	PM	1YR
	CONDENSATE	5120000		0093370901	MOTOR, MISCELLANEOUS DRAIN TANK PUMP #2N U1 - PERFORM	1	MO	PM	1YR
	CONDENSATE	5120000		0093432501	MOTOR, CONDENSATE RECLAIM PUMP #1 U2 - PERFORM INSPECTION	2	MO	PM	1YR
	CONDENSATE	5120000		0093446201	MOTOR, EVAPORATOR FEED PUMP U1 - PERFORM INSPECTION CHECK	1	MO	PM	1YR
	CONDENSATE	5120000		4065548601	COND CU PP #3 - CHECK COUPLING / CHANGE OIL IN MOTOR	2	MO	PM	ANH
	CONDENSATE	5120000		4065551701	U2 CONDENSATE CLEANUP PP #1 - CHECK COUPLING / CHANGE OIL	2	MO	PM	ANH
	CONDENSATE	5120000		4065553401	U2 COND CLEANUP PP #2 - CHECK COUPLING / CHANGE OIL IN MOTOR	2	MO	PM	ANH
	CONDENSATE	5120000		4065629201	U1 LP HTR #2 N. DRAIN PP - INSP COUPLING / CHANGE OIL IN MTR	1	MO	PM	ANH
	CONDENSATE	5120000		4065630401	U1 LP HTR #1 S. DRAIN PP - INSP COUPLING / CHANGE OIL IN MTR	1	MO	PM	ANH
	CONDENSATE	5130000		4065590801	U1 INSP COUPLING / LUBE MTR COND BOOSTER PP WEST	1	MO	PM	ANH
	CONDENSATE	5130000		4065628401	U1 COND BOOSTER PP EAST - INSP COUPLING / LUBE MOTOR	1	MO	PM	ANH
	CONDENSATE	5130000		4065852701	U2 CONDENSATE BOOSTER PUMP #1 - COUPLING INSP/CHG MOTOR OIL	2	MO	PM	ANH
	CONDENSATE	5130000		4065859601	U2 CONDENSATE BOOSTER PUMP #3 - INSP COUPLING/CHANGE MTR OIL	2	MO	PM	ANH
	CONDENSATE	5130000		4066149201	ICE U2 - DEAD HEAD TEST CONDENSATE BOOSTER PUMPS	2	MO	PM	2YR
	CONDENSATE	5130000		4066149203	ICE U2 - DEAD HEAD TEST CONDENSATE BOOSTER PUMPS	2	MO	PM	2YR
415									
420	FEEDWATER	5120000		0093428301	MOTOR, AUXILIARY HOTWELL PUMP #1 U2 - PERFORM INSPECTION CHE	2	MO	PM	1YR
	FEEDWATER	5120000		0093448901	AUXILIARY FEED PUMP - INSPECTION.	1	MO	PM	1YR
	FEEDWATER	5120000		0093449001	ICE U1 1YR AUXILIARY FEED PUMP MOTOR INSPECTION	1	MO	PM	1YR
	FEEDWATER	5120000		4065947101	U2 AUX HOTWELL PUMP MOTOR #1 - CHANGE LUBRICANT	2	MO	PM	1YR
	FEEDWATER	5120000		4072557401	CHANGE LUBE FW CHEM PP #2	2	MO	PM	1YR
	FEEDWATER	5120000		4072558601	CHANGE LUBE FW CHEM PP #1	2	MO	PM	1YR
	FEEDWATER	5120000		4072629401	FMO 74/75 LIMITORQUE INSPECTION	2	MO	PM	2YR
	FEEDWATER	5120000		4072630201	AUX BOILER FP COUPLING INSPECTION - U2	2	MO	PM	2YR
	FEEDWATER	5120000		4072691401	U1 FEEDWATER CHEMICAL FEED PP (EAST & WEST)	1	MO	PM	6MO
420									
440	CIRCULATING WATER	5120000		4057032101	PERFORM LIMITORQUE INSPECTION MO41	2	MO	PM	10Y
	CIRCULATING WATER	5130000		0093437701	MOTOR, RIVER MAKEUP PUMP MIDDLE (OLD BLDG.) - PERFORM	2	MO	PM	1YR
	CIRCULATING WATER	5130000		0093437801	MOTOR, RIVER MAKEUP PUMP WEST (OLD BUILDING) - PERFORM	2	MO	PM	1YR
	CIRCULATING WATER	5130000		0093591501	CIRCULATING WATER SYSTEM UNIT 1 - THICKNESS CHECKS	1	MO	PM	3YR
	CIRCULATING WATER	5130000		0093591601	CIRCULATING WATER SYSTEM UNIT 1 - THICKNESS CHECKS	1	MO	PM	3YR
	CIRCULATING WATER	5130000		0093596101	OIL SAMPLE, U2 CIRCULATING WATER PUMP BEARINGS, CIRCULATING	2	MO	PM	3MO
	CIRCULATING WATER	5130000		0093614301	INSPECTION CRANE - RIVER WATER MAKE-UP BLDG.(OLD) 5 TON.	1	MO	PM	1YR
	CIRCULATING WATER	5130000		0093614401	INSPECTION CRANE - CIRCULATING WATER GANTRY, 2 TON	2	MO	PM	1YR
	CIRCULATING WATER	5130000		4056751901	CALIBRATE D/P SWITCHES SELF CLEANING STRAINERS OLD RIVER MU	0	MO	PM	4YR
	CIRCULATING WATER	5130000		4056795501	ICE 1YR STROKE RIVER WATER MO VALVES	0	MO	PM	ANN

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WOT System Cd	WOT System Code Description	Account Nbr	WOT Unit Cond Reqd	WOT WO Nbr Task	WOT WR Task Title	WOT Unit	WO Type	WOT Job Type	Pm Frequency Code
	CIRCULATING WATER	5130000		4056806601	CHANGE OIL SPEED REDUCER WEST AND MIDDLE STRAINERS	2	MO	PM	6MO
	CIRCULATING WATER	5130000		4057036201	ICE- 6MO-CLEAN RIVER WATER FLOW PROBES	0	MO	PM	6MO
	CIRCULATING WATER	5130000		4057038001	NO. 1 RIVER WATER MAKE UP PUMP - REBUILD	0	MO	PM	5YR
	CIRCULATING WATER	5130000		4057278001	CALIBRATE D/P SWITCHES RIVER WATER STRAINERS	2	MO	PM	4YR
	CIRCULATING WATER	5130000		4057279301	INSPECT MO 48, 51 AND 52 CAISSON VALVES	0	MO	PM	4YR
	CIRCULATING WATER	5130000		4057568301	INSPECT UNDERWATER PIPING AND STRAINERS	0	MO	PM	3YR
	CIRCULATING WATER	5130000		4057572001	CHANGE OIL IN THE STRAINER 1-4 SPEED REDUCTION UNITS	2	MO	PM	6MO
	CIRCULATING WATER	5130000		4057583701	ICE 1YR DEAD HEAD PUMP TEST ON RIVER MU PUMP # 1	0	MO	PM	1YR
	CIRCULATING WATER	5130000		4057585501	ICE - PERFORM DEAD HEAD TEST N NO. 3 MAKE UP PUMP (RIVER)	0	MO	PM	1YR
	CIRCULATING WATER	5130000		4057586801	ICE - PERFORM DEAD HEAD TEST ON NO. 2 RIVER MAKE UP PUMP	0	MO	PM	1YR
	CIRCULATING WATER	5130000		4057650501	ICE - PERFORM DEAD HEAD TEST ON MIDDLE RIVER MAKE UP PUMP	1	MO	PM	1YR
	CIRCULATING WATER	5130000		4057651101	ICE 3YR STROKE RIVER WTR STRAINER BACKWASH VALVES RV413, 414	0	MO	PM	3YR
	CIRCULATING WATER	5130000		4057652301	ICE 4YR FUNCTIONAL TEST OF RIVER MU PUMP SEAL WATER REG	0	MO	PM	4YR
	CIRCULATING WATER	5130000		4073638101	U2 FLUME MAKE-UP VALVE RRV-1	2	MO	PM	2YR
	CIRCULATING WATER	5130000		4108712801	RIVER MAKEUP PUMP #1 NEW BUILDING - THICKNESS CHECKS	0	MO	PM	3YR
	CIRCULATING WATER	5130000		4108756701	RIVER MAKEUP PUMP #2 NEW BUILDING - THICKNESS CHECKS	0	MO	PM	3YR
	CIRCULATING WATER	5130000		4108757701	RIVER MAKEUP PUMP #3 NEW BUILDING - THICKNESS CHECKS	0	MO	PM	3YR
	CIRCULATING WATER	5130000		4108758801	MOTOR, RIVER MAKEUP PUMP #1 (NEW BUILDING) - PERFORM	0	MO	PM	1YR
	CIRCULATING WATER	5130000		4108761501	MOTOR, RIVER MAKEUP PUMP #2 (NEW BUILDING) - PERFORM	0	MO	PM	1YR
	CIRCULATING WATER	5130000		4108762201	MOTOR, RIVER MAKEUP PUMP #3 (NEW BUILDING) - PERFORM	0	MO	PM	1YR
440									
450	SERVICE AND FIRE WATER	5120000		0093366701	MOTOR, COOLING WATER BOOSTER PUMP #1 EAST U1 - PERFORM	1	MO	PM	1YR
	SERVICE AND FIRE WATER	5120000		0093366901	MOTOR, COOLING WATER BOOSTER PUMP #2 WEST U1 - PERFORM	1	MO	PM	1YR
	SERVICE AND FIRE WATER	5120000		0093367101	MOTOR, COOLING WATER PUMP #1 EAST U1 - PERFORM INSPECTION	1	MO	PM	1YR
	SERVICE AND FIRE WATER	5120000		0093367301	MOTOR, COOLING WATER PUMP #2 WEST U1 - PERFORM INSPECTION CH	1	MO	PM	1YR
	SERVICE AND FIRE WATER	5120000		0093370501	MOTOR, LOW PRESSURE SERVICE WATER PUMP #11 - PERFORM	1	MO	PM	1YR
	SERVICE AND FIRE WATER	5120000		0093370601	MOTOR, LOW PRESSURE SERVICE WATER PUMP #12 - PERFORM	1	MO	PM	1YR
	SERVICE AND FIRE WATER	5120000		0093370701	MOTOR, LOW PRESSURE SERVICE WATER PUMP #13 - PERFORM	1	MO	PM	1YR
	SERVICE AND FIRE WATER	5120000		0093432701	MOTOR, COOLING WATER PUMP #2 U2 - PERFORM INSPECTION	2	MO	PM	1YR
	SERVICE AND FIRE WATER	5120000		0093433601	MOTOR, COOLING WATER PUMP #3 U2 - PERFORM INSPECTION CHECK	2	MO	PM	1YR
	SERVICE AND FIRE WATER	5120000		0093433601	MOTOR, COOLING WATER PUMP #3 U2 - PERFORM INSPECTION CHECK	2	MO	PM	DAY
	SERVICE AND FIRE WATER	5120000		0093438401	MOTOR, SERVICE WATER PUMP #1 U2 - PERFORM INSPECTION	2	MO	PM	1YR
	SERVICE AND FIRE WATER	5120000		0093438501	MOTOR, SERVICE WATER PUMP #2 U2 - PERFORM INSPECTION	2	MO	PM	1YR
	SERVICE AND FIRE WATER	5120000		0093591201	UNIT 1 COOLING WATER SYSTEM - INSPECTION	1	MO	PM	4YR
	SERVICE AND FIRE WATER	5120000		0093597401	UNIT-1 LP SERVICE WATER - THICKNESS CHECKS	2	MO	PM	4YR
	SERVICE AND FIRE WATER	5120000		4073556501	U2 INSPECT COUPLING ON #3 COOLING WATER PUMP	2	MO	PM	ANH
	SERVICE AND FIRE WATER	5120000		4073558201	U2 CHANGE OIL IN #3 COOLING WATER PUMP MOTOR BEARINGS	2	MO	PM	1YR
	SERVICE AND FIRE WATER	5120000		4073558901	U2 CHANGE OIL IN #2 COOLING WATER PUMP MOTOR BEARINGS	2	MO	PM	1YR
	SERVICE AND FIRE WATER	5120000		4073562301	U2 COUPLING INSPECTION ON #1 COOLING WATER PUMP	2	MO	PM	ANH
	SERVICE AND FIRE WATER	5120000		4073563301	U2 INSPECT COUPLING ON #2 COOLING WATER PUMP	2	MO	PM	ANH
	SERVICE AND FIRE WATER	5120000		4073563901	U2 INSPECT COUPLING ON #1 SERVICE WATER PUMP	2	MO	PM	ANH
	SERVICE AND FIRE WATER	5120000		4073564401	U2 INSPECT COUPLING ON #2 SERVICE WATER PUMP	2	MO	PM	ANH
	SERVICE AND FIRE WATER	5120000		4073566901	U1 COUPLING CHECK ON #12 LOW PRESSURE SERVICE WATER PUMP	1	MO	PM	1YR
	SERVICE AND FIRE WATER	5120000		4073567701	U1 COUPLING CHECK ON #11 LOW PRESSURE SERV WATER PUMP	1	MO	PM	1YR
450									
480	DEMINERALIZER	5120000		0093438601	MOTOR, SOFTENED WATER BOOSTER PUMP #1 U2 - PERFORM	0	MO	PM	1YR
	DEMINERALIZER	5120000		0093439401	MOTOR, SOFTENED WATER BOOSTER PUMP #2 U2 - PERFORM	0	MO	PM	1YR
	DEMINERALIZER	5120000		0093439501	MOTOR, SOFTENED WATER BOOSTER PUMP #3 U2 - PERFORM	0	MO	PM	1YR
	DEMINERALIZER	5120000		4065580401	U2 DEMIN ACID PPS - CHANGE OIL	2	MO	PM	6MO
480									
485	EVAPORATORS	5120000		0093613101	OPEN THE COIL EVAPORATOR AND CLEAN REFUSE FROM	2	MO	PM	6MO
485									
490	POTABLE/CITY WATER	5110000		0093409901	INSPECTION - EMERGENCY EYE-WASH STATIONS - LAB, EAST SIDE	2	MO	PM	WKL
	POTABLE/CITY WATER	5110000		0093410001	INSPECTION - EMERGENCY EYE-WASH STATIONS - BENEATH	2	MO	PM	WKL
	POTABLE/CITY WATER	5110000		0093410101	INSPECTION - EMERGENCY EYE-WASH STATIONS - BASEMENT (EAST	1	MO	PM	WKL
	POTABLE/CITY WATER	5110000		0093410201	INSPECTION - EMERGENCY CHEMICAL WASH STATIONS - ELEV. 690,	1	MO	PM	WKL
	POTABLE/CITY WATER	5110000		0093411601	INSPECTION - EMERGENCY EYE-WASH STATIONS - SULFURIC ACID	2	MO	PM	WKL
	POTABLE/CITY WATER	5110000		0093411701	INSPECTION - CHECK EMERGENCY EYE-WASH STATIONS	2	MO	PM	WKL
490									
515	EXTRACTION STEAM	5120000		4073072001	U2 ICE - CHECK CALIB DEA DESUPH INSTRUMENTS	2	MO	PM	6YR
	EXTRACTION STEAM	5120000		4073072601	U2 ICE STROKE CRV-1001 DEA DESUPH VALVE	2	MO	PM	2YR
515									
520	TURBINE, STEAM	5130000		0093439601	MOTOR, STEAM PACKING EXHAUSTER U2 - PERFORM INSPECTION	2	MO	PM	1YR
	TURBINE, STEAM	5130000		4073086901	U2 ICE 3 YEAR TURBINE PERFORMANCE TESTING	2	MO	PM	3YR
	TURBINE, STEAM	5130000		4073236001	U2 VALVES & PIPING MISC. TURBINE DMO-301	2	MO	PM	4YR
	TURBINE, STEAM	5130000		4073236401	U2 VALVES & PIPING MISC. TURBINE DMO-101	2	MO	PM	4YR
520									
540	TURBINE LUBE OIL	5130000		0093371001	MOTOR, OIL TRANSFER CLEANUP PUMP #1 U1 - PERFORM INSPECTION	0	MO	PM	1YR
	TURBINE LUBE OIL	5130000		0093401001	UNIT-1 LUBRICATING OIL SYSTEM - INSPECTION.	1	MO	PM	3YR
	TURBINE LUBE OIL	5130000		0093428601	MOTOR, AUXILIARY PUMP -60 HP SUCTION U2 - PERFORM INSPECTION	2	MO	PM	1YR
	TURBINE LUBE OIL	5130000		0093586001	QUARTERLY EHC SAMPLES TO STAUFFER	2	MO	PM	3MO
	TURBINE LUBE OIL	5130000							

Models in Authorized Status With Auto Trigger Ind 2/18/2010

WOT System Cd	WOT System Code Description	Account Nbr	WOT Unit Cond Reqd	WOT WO Nbr Task	WOT WR Task Title	WOT Unit	WO Type	WOT Job Type	Pm Frequency Code
	TURBINE LUBE OIL	5130000		0093587101	SEMI-ANNUAL TURBINE OIL/EHC SAMPLES TO DOLAN LAB	1	MO	PM	6MO
	TURBINE LUBE OIL	5130000		4073249401	U2 CHANGE OIL - TURNING GEAR OIL PUMP - 75 HP MOTOR	2	MO	PM	2YR
540									
570	GENERATOR	5130000		0093370301	MOTOR, HYDROGEN COOLING PUMP #1 NORTH U1 - PERFORM INSPECTIO	1	MO	PM	1YR
	GENERATOR	5130000		0093370401	MOTOR, HYDROGEN COOLING PUMP #2 SOUTH U1 - PERFORM	1	MO	PM	1YR
	GENERATOR	5130000		0093435401	U2 ICE , H2 COOLING PUMP MOTOR #1 U2 - PERF INSPECTION	2	MO	PM	1YR
	GENERATOR	5130000		0093435501	U2 ICE H2 COOLING PUMP MOTOR,#2 U2 - PERF INSPECTION	2	MO	PM	1YR
	GENERATOR	5130000		4073409601	U2 #2 HYDROGEN COOLING WATER PUMP COUPLING INSPECTION	2	MO	PM	ANH
	GENERATOR	5130000		4073411101	U2 #1 HYDROGEN COOLING WATER PUMP COUPLING INSPECTION	2	MO	PM	ANH
570									
590	GENERATOR, STATOR WATER	5130000		0093434801	MOTOR, GENERATOR STATOR COOLING PUMP #1 U2 - PERFORM	2	MO	PM	1YR
	GENERATOR, STATOR WATER	5130000		0093434901	MOTOR, GENERATOR STATOR COOLING PUMP #2 U2 - PERFORM	2	MO	PM	1YR
	GENERATOR, STATOR WATER	5130000		4073408401	U2 #2 STATOR COOLING PUMP - CHANGE OIL	2	MO	PM	1YR
	GENERATOR, STATOR WATER	5130000		4073409001	U2 #1 STATOR COOLING PUMP - CHANGE OIL	2	MO	PM	1YR
590									
630	SWITCHGEAR	5130000		4093052201	ICE UY 4YR 4KV BREAKERS COAL YARD	2	MO	PM	4YR
	SWITCHGEAR	5130000		4093053601	ICE 6 YR - 4KV BREAKER REBUILD COAL YARD	2	MO	PM	6YR
	SWITCHGEAR	5130000		4093055501	ICE 3 YR - STA 12 600V FEED BREAKERS	2	MO	PM	3YR
630									
665	D.C. ELECTRIC SYSTEM	5130000		0093564701	U1 ICE 3MO PLANT BATTERY INSPECTION	1	MO	PM	3MO
	D.C. ELECTRIC SYSTEM	5130000		0093564801	U2 ICE 3MO PLANT BATTERY INSPECTION	2	MO	PM	3MO
	D.C. ELECTRIC SYSTEM	5130000		4058674601	ICE U1 6MO BATTERY CHARGER INSPECTION	1	MO	PM	6MO
	D.C. ELECTRIC SYSTEM	5130000		4058674901	ICE U2 6MO BATTERY CHARGER INSPECTION	2	MO	PM	6MO
	D.C.ELECTRIC SYSTEM	5130000		0093564701	U1 ICE 3MO PLANT BATTERY INSPECTION	1	MO	PM	3MO
	D.C.ELECTRIC SYSTEM	5130000		0093564801	U2 ICE 3MO PLANT BATTERY INSPECTION	2	MO	PM	3MO
	D.C.ELECTRIC SYSTEM	5130000		4058674601	ICE U1 6MO BATTERY CHARGER INSPECTION	1	MO	PM	6MO
	D.C.ELECTRIC SYSTEM	5130000		4058674901	ICE U2 6MO BATTERY CHARGER INSPECTION	2	MO	PM	6MO
665									
680	VOICE COMMUNICATIONS	5140000		0093908501	U1 ICE 3MO PUBLIC ADDRESS (PA) INSPECTION	1	MO	PM	3MO
	VOICE COMMUNICATIONS	5140000		0093908501	U1 ICE 3MO PUBLIC ADDRESS (PA) INSPECTION	1	MO	PM	MON
	VOICE COMMUNICATIONS	5140000		0093997101	U2 ICE 3MO PUBLIC ADDRESS (PA) INSPECTION	2	MO	PM	3MO
680									
700	** CONTROLS AND COMPUTERS **	5120000		0094232501	U1 ICE 1YR MAIN STEAM TEMP RECORDER/CALIBRATE	1	MO	PM	1YR
	** CONTROLS AND COMPUTERS **	5120000		0094232501	U1 ICE 1YR MAIN STEAM TEMP RECORDER/CALIBRATE	1	MO	PM	WKL
	** CONTROLS AND COMPUTERS **	5130000		0093448401	U1 ICE 1WK ELECT INSP	1	MO	PM	WKL
	** CONTROLS AND COMPUTERS **	5130000		0093448501	U2 ICE 1WK ELECT INSP	2	MO	PM	WKL
	** CONTROLS AND COMPUTERS **	5130000		0093775201	U1 ICE 3MO C1 SAFETY CONTROLS INSPECTION	0	MO	PM	3MO
	** CONTROLS AND COMPUTERS **	5130000		0094378001	ICE 6WK C13N&S SAFETY CONTROLS INSPECTION	0	MO	PM	6WK
	** CONTROLS AND COMPUTERS **	5130000		0094378501	ICE C11 3MO SAFETY CONTROLS INSPECTION	0	MO	PM	3MO
	** CONTROLS AND COMPUTERS **	5130000		0094378601	ICE C12 3MO SAFETY CONTROLS INSPECTION	0	MO	PM	3MO
	** CONTROLS AND COMPUTERS **	5130000		0094378701	ICE C15U&L SAFETY CONTROLS INSPECTION	0	MO	PM	3MO
	** CONTROLS AND COMPUTERS **	5130000		0094378801	ICE C16 3MO SAFETY CONTROLS INSPECTION	0	MO	PM	3MO
	** CONTROLS AND COMPUTERS **	5130000		0094378901	ICE C17 3MO SAFETY CONTROLS INSPECTION	0	MO	PM	3MO
	** CONTROLS AND COMPUTERS **	5130000		0094379001	ICE C14 3MO SAFETY CONTROLS INSPECTION	0	MO	PM	3MO
	** CONTROLS AND COMPUTERS **	5130000		0094379101	U1 ICE 3MO C3 SAFETY CONTROLS INSPECTION	0	MO	PM	3MO
	** CONTROLS AND COMPUTERS **	5130000		0094379201	ICE C10 3MO SAFETY CONTROLS INSPECTION	0	MO	PM	3MO
	** CONTROLS AND COMPUTERS **	5130000		4071374501	ICE U1 WEEKLY ROUTINE	1	MO	PM	ANN
	** CONTROLS AND COMPUTERS **	5130000		4072862301	ICE 1YR COALYARD SLC -CLEAN CABINET/BATTERY	0	MO	PM	1YR
	** CONTROLS AND COMPUTERS **	5130000		4073130101	U2 ICE BCO EXHAUST HOOD THERMOCOUPLES	2	MO	PM	1YR
	** CONTROLS AND COMPUTERS **	5130000		4073639401	U1 ICE CALIBRATE SERVICE WATER INSTRUMENTS	1	MO	PM	3YR
	** CONTROLS AND COMPUTERS **	5130000		4073646701	U2 ICE CALIBRATE SERVICE WATER INSTRUMENTS	2	MO	PM	4YR
	** CONTROLS AND COMPUTERS **	5130000		4139821601	ICE U2 WEEKLY ROUTINE	2	MO	PM	ANN
	CONTROLS AND COMPUTERS	5120000		0094232501	U1 ICE 1YR MAIN STEAM TEMP RECORDER/CALIBRATE	1	MO	PM	1YR
	CONTROLS AND COMPUTERS	5120000		0094232501	U1 ICE 1YR MAIN STEAM TEMP RECORDER/CALIBRATE	1	MO	PM	WKL
	CONTROLS AND COMPUTERS	5130000		0093448401	U1 ICE 1WK ELECT INSP	1	MO	PM	WKL
	CONTROLS AND COMPUTERS	5130000		0093448501	U2 ICE 1WK ELECT INSP	2	MO	PM	WKL
	CONTROLS AND COMPUTERS	5130000		0093775201	U1 ICE 3MO C1 SAFETY CONTROLS INSPECTION	0	MO	PM	3MO
	CONTROLS AND COMPUTERS	5130000		0094378001	ICE 6WK C13N&S SAFETY CONTROLS INSPECTION	0	MO	PM	6WK
	CONTROLS AND COMPUTERS	5130000		0094378501	ICE C11 3MO SAFETY CONTROLS INSPECTION	0	MO	PM	3MO
	CONTROLS AND COMPUTERS	5130000		0094378601	ICE C12 3MO SAFETY CONTROLS INSPECTION	0	MO	PM	3MO
	CONTROLS AND COMPUTERS	5130000		0094378701	ICE C15U&L SAFETY CONTROLS INSPECTION	0	MO	PM	3MO
	CONTROLS AND COMPUTERS	5130000		0094378801	ICE C16 3MO SAFETY CONTROLS INSPECTION	0	MO	PM	3MO
	CONTROLS AND COMPUTERS	5130000		0094378901	ICE C17 3MO SAFETY CONTROLS INSPECTION	0	MO	PM	3MO
	CONTROLS AND COMPUTERS	5130000		0094379001	ICE C14 3MO SAFETY CONTROLS INSPECTION	0	MO	PM	3MO
	CONTROLS AND COMPUTERS	5130000		0094379101	U1 ICE 3MO C3 SAFETY CONTROLS INSPECTION	0	MO	PM	3MO
	CONTROLS AND COMPUTERS	5130000		0094379201	ICE C10 3MO SAFETY CONTROLS INSPECTION	0	MO	PM	3MO
	CONTROLS AND COMPUTERS	5130000		4071374501	ICE U1 WEEKLY ROUTINE	1	MO	PM	ANN
	CONTROLS AND COMPUTERS	5130000		4072862301	ICE 1YR COALYARD SLC -CLEAN CABINET/BATTERY	0	MO	PM	1YR
	CONTROLS AND COMPUTERS	5130000		4073130101	U2 ICE BCO EXHAUST HOOD THERMOCOUPLES	2	MO	PM	1YR
	CONTROLS AND COMPUTERS	5130000		4073639401	U1 ICE CALIBRATE SERVICE WATER INSTRUMENTS	1	MO	PM	3YR
	CONTROLS AND COMPUTERS	5130000		4073646701	U2 ICE CALIBRATE SERVICE WATER INSTRUMENTS	2	MO	PM	4YR

Models in Authorized Status With Auto Trigger Ind 2/18/2010

WOT System Cd	WOT System Code Description	Account Nbr	WOT Unit Cond Reqd	WOT WO Nbr Task	WOT WR Task Title	WOT Unit	WO Type	WOT Job Type	Pm Frequency Code
	CONTROLS AND COMPUTERS	5130000		4139821601	ICE U2 WEEKLY ROUTINE	2	MO	PM	ANN
700									
740	COMBUSTION CONTROLS	5120000		0093392701	ICE 3MO RIVER WATER INTAKE FLOW PROBE INSPECTION	1	MO	PM	3MO
	COMBUSTION CONTROLS	5120000		0093402301	U1 ICE 1MO BOILER CAMERAS INSP	1	MO	PM	MON
	COMBUSTION CONTROLS	5120000		0093419901	U1 ICE 1MO O2 ANALYZER CALIBRATION	1	MO	PM	MON
	COMBUSTION CONTROLS	5120000		0093420901	U2 ICE 1MO O2 ANALYZER INSPECTION	2	MO	PM	MON
	COMBUSTION CONTROLS	5120000		0093789301	U1 ICE 1MON O2 ANALYZER PROBE CALIBRATION	1	MO	PM	MON
	COMBUSTION CONTROLS	5120000		0094378101	ICE 3MO STA 14 ROTOBINDICATOR INSPECTION	2	MO	PM	3MO
	COMBUSTION CONTROLS	5120000		4057039301	U2 ICE 3YR PERFORM CALIB CHECK RIVER WATER TEMP RECORDER	1	MO	PM	3YR
	COMBUSTION CONTROLS	5120000		4058151101	U1 ICE 3MO BOILER CAMERA FILTERS	1	MO	PM	3MO
	COMBUSTION CONTROLS	5120000		4065935601	U2 ICE CONDENSATE FILTER INSTRUMENTATION - CALIBRATE	2	MO	PM	4YR
	COMBUSTION CONTROLS	5120000		4133614901	ICE 6 MON U1 BOILER TEMP START-UP PROBES	1	MO	PM	6MO
740									
800	** PLANT WASTE SYSTEMS **	5120000		4064228301	DMAI U2 (1MO) PLANT LUBRICATION	0	MO	PM	MON
	** PLANT WASTE SYSTEMS **	5120000		4064231901	U2 (12MO) PLANT LUBRICATION	0	MO	PM	ANN
	** PLANT WASTE SYSTEMS **	5140000		4064223501	U1-(12 MO) PLANT LUBRICATION	0	MO	PM	ANN
	PLANT WASTE SYSTEMS	5120000		4064228301	DMAI U2 (1MO) PLANT LUBRICATION	0	MO	PM	MON
	PLANT WASTE SYSTEMS	5120000		4064231901	U2 (12MO) PLANT LUBRICATION	0	MO	PM	ANN
	PLANT WASTE SYSTEMS	5140000		4064223501	U1-(12 MO) PLANT LUBRICATION	0	MO	PM	ANN
800									
805	ASH HANDLING, BOTTOM	5120000		0093353601	MOTOR, ASH HANDLING WATER PUMP U1 MIDDLE - PERFORM INSPECTIO	1	MO	PM	1YR
	ASH HANDLING, BOTTOM	5120000		0093353801	MOTOR, ASH HANDLING WATER PUMP U1 WEST - PERFORM INSPECTION	1	MO	PM	1YR
	ASH HANDLING, BOTTOM	5120000		0093591401	BOTTOM ASH HOPPER UNIT 1 - THICKNESS CHECKS	1	MO	PM	4YR
	ASH HANDLING, BOTTOM	5120000		4063105201	U2 EAST CLINKER GRINDER, MOTOR & SLUICE GATE INSPECTION	2	MO	PM	3MO
	ASH HANDLING, BOTTOM	5120000		4063107901	U2 WEST CLINKER GRINDER, MOTOR & SLUICE GATE INSPECTION	2	MO	PM	3MO
	ASH HANDLING, BOTTOM	5120000		4063110201	U2 ICE 3 YR BOTTOM ASH INSTRUMENTS - CALIBRATE	2	MO	PM	3YR
	ASH HANDLING, BOTTOM	5120000		4063113201	U2 ICE 2YR BOTTOM ASH PUMPS DEAD HEAD TEST	2	MO	PM	2YR
	ASH HANDLING, BOTTOM	5120000		4063114801	U2 ICE 3 YR STROKE BOTTOM ASH PYRITE VALVES	2	MO	PM	3YR
	ASH HANDLING, BOTTOM	5120000		4063115601	U2 SOUTH ASH PIPING (801)	2	MO	PM	2YR
	ASH HANDLING, BOTTOM	5120000		4063116501	U2 NORTH ASH PIPING (802)	2	MO	PM	2YR
	ASH HANDLING, BOTTOM	5120000		4063116801	U2 BOTTOM ASH WATER PUMP #1 COUPLING	2	MO	PM	ANH
	ASH HANDLING, BOTTOM	5120000		4063120701	U2 BOTTOM ASH WATER PUMP #2 COUPLING	2	MO	PM	ANH
	ASH HANDLING, BOTTOM	5120000		4063122601	U2 BOTTOM ASH WATER PUMP SPARE COUPLING	2	MO	PM	ANH
	ASH HANDLING, BOTTOM	5120000		4063128801	U1 WEST ASH HANDLING WATER PP - INSPECT COUPLING	1	MO	PM	ANH
	ASH HANDLING, BOTTOM	5120000		4063165201	U1 MIDDLE ASH HANDLING WATER PP COUPLING - INSPECT	1	MO	PM	ANH
	ASH HANDLING, BOTTOM	5120000		4063169001	U1 WEST ASH HANDLING WATER PP MOTOR - CHANGE OIL	1	MO	PM	6MO
	ASH HANDLING, BOTTOM	5120000		4063169002	U1 MIDDLE ASH HANDLING WATER PP MOTOR - CHANGE OIL	1	MO	PM	6MO
	ASH HANDLING, BOTTOM	5120000		4063178901	U1 BOTTOM ASH PIPING NORTH	1	MO	PM	2YR
	ASH HANDLING, BOTTOM	5120000		4063179701	U1 BOTTOM ASH PIPING SOUTH	1	MO	PM	2YR
	ASH HANDLING, BOTTOM	5120000		4063216601	U1 ICE 3 YR BOTTOM ASH / PYRITE INSTRUMENTS - CALIBRATE	1	MO	PM	3YR
	ASH HANDLING, BOTTOM	5120000		4063218201	U1 ICE 3 YR RV-401 ASH JET SUPPLY PP NORTH	1	MO	PM	3YR
	ASH HANDLING, BOTTOM	5120000		4063218202	U1 ICE 3 YR RV-407 ASH JET SUPPLY PP SOUTH	1	MO	PM	3YR
	ASH HANDLING, BOTTOM	5120000		4063218203	U1 ICE 3 YR RV-403 & 404 PYRITES PRESS CONT VV & 3-WAY VV	1	MO	PM	3YR
	ASH HANDLING, BOTTOM	5120000		4063229101	U1 CLINKER GRINDER INSPECTION	1	MO	PM	3MO
	ASH HANDLING, BOTTOM	5120000		4063231601	U1 ICE 2 YR MIDDLE ASH HANDLING WTR PP DEAD HEAD TEST	1	MO	PM	2YR
	ASH HANDLING, BOTTOM	5120000		4063231602	U1 ICE 2 YR WEST ASH HANDLING WTR PP #2 - DEAD HEAD TEST	1	MO	PM	2YR
	ASH HANDLING, BOTTOM	5120000		4063236201	U1 CLINKER GRINDER GEARBOX - CHANGE OIL	1	MO	PM	1YR
805									
815	ASH HANDLING, FLY ASH	5120000		0093436501	MOTOR, RECIRCULATING ASH POND PUMP #1 - PERFORM INSPECTION	2	MO	PM	1YR
	ASH HANDLING, FLY ASH	5120000		0093436601	MOTOR, RECIRCULATING ASH POND PUMP #2 - PERFORM INSPECTION	2	MO	PM	1YR
	ASH HANDLING, FLY ASH	5120000		0093436701	MOTOR, RECIRCULATING ASH POND PUMP #3 - PERFORM INSPECTION	2	MO	PM	1YR
	ASH HANDLING, FLY ASH	5120000		0093436801	MOTOR, RECIRCULATING ASH POND PUMP #4 - PERFORM INSPECTION	2	MO	PM	1YR
	ASH HANDLING, FLY ASH	5120000		0093449101	#1 FLYASH SLURRY PP IMPELLER INSP/CLEARANCE	2	MO	PM	4MO
	ASH HANDLING, FLY ASH	5120000		0093449201	INSPECTION PUMP-IMPELLER CLEARANCE-# 2 FLYASH SLURRY PP.	2	MO	PM	4MO
	ASH HANDLING, FLY ASH	5120000		0093574401	INSPECTION - HYDROVEYOR NOZZLES (RRV-804)	2	MO	PM	MON
	ASH HANDLING, FLY ASH	5120000		0093574501	INSPECTION - HYDROVEYOR NOZZLES (RRV-805).	2	MO	PM	MON
	ASH HANDLING, FLY ASH	5120000		0093574601	INSPECTION - HYDROVEYOR NOZZLES (RRV-806).	2	MO	PM	MON
	ASH HANDLING, FLY ASH	5120000		0093574701	INSPECTION - HYDROVEYOR NOZZLES (RRV-807).	2	MO	PM	MON
	ASH HANDLING, FLY ASH	5120000		0093574801	INSPECTION - HYDROVEYOR U1.	1	MO	PM	4MO
	ASH HANDLING, FLY ASH	5120000		0093574901	INSPECTION - HYDROVEYOR NOZZLES UNIT 2 -	2	MO	PM	4MO
	ASH HANDLING, FLY ASH	5120000		0093620101	INSPECTION GATES - FLYASH	1	MO	PM	1YR
	ASH HANDLING, FLY ASH	5120000		4057274701	ICE 1YR #1 FLYASH SLURRY PP DEAD HEAD TEST	2	MO	PM	1YR
	ASH HANDLING, FLY ASH	5120000		4057311201	ICE - ASH HANDLING INSTRUMENT CALIBRATION UNIT 1	1	MO	PM	3YR
	ASH HANDLING, FLY ASH	5120000		4057317501	U2 ICE 1MO FLYASH VACUUM IMPULSE LINES	2	MO	PM	MON
	ASH HANDLING, FLY ASH	5120000		4057321901	ICE U2 3 YR SLURRY TANK LEVEL CONTROLS	2	MO	PM	3YR
	ASH HANDLING, FLY ASH	5120000		4057537701	ECONOMIZER HYDROVEYOR PIPING INSPECTION	2	MO	PM	ANN
	ASH HANDLING, FLY ASH	5120000		4057538401	U2-ECONOMIZER HYDROVEYOR & PIPING VACUUM TEST	2	MO	PM	ANN
	ASH HANDLING, FLY ASH	5120000		4057539101	PERFORM VACUUM TEST OF UNIT 1 FLYASH SYSTEM	1	MO	PM	ANN
	ASH HANDLING, FLY ASH	5120000		4057539601	PERFORM VACUUM TEST OF FLYASH SYSTEM	2	MO	PM	ANN
	ASH HANDLING, FLY ASH	5120000		4069524101	HYDROVEYOR VVS RRV-804, 805, 806, 807 - INSPECTION	2	MO	PM	2WK
	ASH HANDLING, FLY ASH	5120000		4073504401	SLURRY TANK; INSPECT & REPAIR SPLASH POTS	2	MO	PM	ANN

Models in Authorized Status With Auto Trigger Ind 2/18/2010

WOT System Cd	WOT System Code Description	Account Nbr	WOT Unit Cond Reqd	WOT WO Nbr Task	WOT WR Task Title	WOT Unit	WO Type	WOT Job Type	Pm Frequency Code
815									
830	WASTE POND	5120000		4084450001	RED WATER PUMP - CLEAN-OUT SUMP	0	MO	PM	SMN
	WASTE POND/DRY STORAGE	5120000		4084450001	RED WATER PUMP - CLEAN-OUT SUMP	0	MO	PM	SMN
830									
835	SUMP PUMPS	5110000		0093439701	MOTOR, WASTE WATER SUMP PUMP #1 U2 - PERFORM INSPECTION CHEC	2	MO	PM	1YR
	SUMP PUMPS	5110000		0093439801	MOTOR, WASTE WATER SUMP PUMP #2 U2 - PERFORM INSPECTION	2	MO	PM	1YR
	SUMP PUMPS	5110000		0093439901	MOTOR, WASTE WATER SUMP PUMP #3 U2 - PERFORM INSPECTION	2	MO	PM	1YR
	SUMP PUMPS	5120000		4073924301	#1 EAST CY RUNOFF PUMP - PERFORM DEAD HEAD TEST	0	MO	PM	1YR
	SUMP PUMPS	5120000		4073956001	ICE 1YR #2 WEST CY RUNOFF PUMP DEAD HEAD TEST	0	MO	PM	1YR
	SUMP PUMPS	5120000		4073956501	ICE 1YR #1 WEST CY RUNOFF PUMP DEAD HEAD TEST	0	MO	PM	1YR
	SUMP PUMPS	5120000		4073956901	ICE 1YR #2 EAST CY RUNOFF PUMP DEAD HEAD TEST	0	MO	PM	1YR
	SUMP PUMPS	5120000		4073957201	ICE 1YR #1 EAST CY RUNOFF PUMP DEAD HEAD TEST	0	MO	PM	1YR
	SUMP PUMPS	5120000		4073958101	ICE 1MO WEST COAL PILE RUNOFF INST CHECKS	0	MO	PM	MON
	SUMP PUMPS	5120000		4073987801	ICE 1MO EAST COAL PILE RUNOFF SUMP - INST CHECKS	0	MO	PM	MON
	SUMPS PUMPS	5110000		0093439701	MOTOR, WASTE WATER SUMP PUMP #1 U2 - PERFORM INSPECTION CHEC	2	MO	PM	1YR
	SUMPS PUMPS	5110000		0093439801	MOTOR, WASTE WATER SUMP PUMP #2 U2 - PERFORM INSPECTION	2	MO	PM	1YR
	SUMPS PUMPS	5110000		0093439901	MOTOR, WASTE WATER SUMP PUMP #3 U2 - PERFORM INSPECTION	2	MO	PM	1YR
	SUMPS PUMPS	5120000		4073924301	#1 EAST CY RUNOFF PUMP - PERFORM DEAD HEAD TEST	0	MO	PM	1YR
	SUMPS PUMPS	5120000		4073956001	ICE 1YR #2 WEST CY RUNOFF PUMP DEAD HEAD TEST	0	MO	PM	1YR
	SUMPS PUMPS	5120000		4073956501	ICE 1YR #1 WEST CY RUNOFF PUMP DEAD HEAD TEST	0	MO	PM	1YR
	SUMPS PUMPS	5120000		4073956901	ICE 1YR #2 EAST CY RUNOFF PUMP DEAD HEAD TEST	0	MO	PM	1YR
	SUMPS PUMPS	5120000		4073957201	ICE 1YR #1 EAST CY RUNOFF PUMP DEAD HEAD TEST	0	MO	PM	1YR
	SUMPS PUMPS	5120000		4073958101	ICE 1MO WEST COAL PILE RUNOFF INST CHECKS	0	MO	PM	MON
	SUMPS PUMPS	5120000		4073987801	ICE 1MO EAST COAL PILE RUNOFF SUMP - INST CHECKS	0	MO	PM	MON
835									
920	ELEVATOR	5120000		0093579901	LUBRICATION MANLIFT - STACK, SKY CLIMBER (ALIMAK)	2	MO	PM	3MO
	ELEVATOR / MANLIFT	5120000		0093579901	LUBRICATION MANLIFT - STACK, SKY CLIMBER (ALIMAK)	2	MO	PM	3MO
	ELEVATOR/MAN LIFT	5120000		0093579901	LUBRICATION MANLIFT - STACK, SKY CLIMBER (ALIMAK)	2	MO	PM	3MO
920									
930	HVAC	5110000		0093586301	U1 ICE 3MO HVAC INSP	1	MO	PM	3MO
	HVAC	5110000		0093598301	U1 ICE 1 YR 17 TON UNIT INSPECTION HVAC	0	MO	PM	ANN
	HVAC	5110000		0093598401	U1 ICE 1 YR 45 TON UNIT INSPECTION HVAC	0	MO	PM	1YR
	HVAC	5110000		4102335001	ICE 1YR HEAT TRACE INSPECTION	1	MO	PM	1YR
	HVAC	5120000		0093637901	HAVE COAL YARD SEPTIC TANKS (3) PUMPED.	0	MO	PM	2YR
	HVAC	5120000		4086203101	1 MO - VISUAL CHECK OF STA. 11 ENGART DUST COLLECTOR	0	MO	PM	MON
	HVAC	5120000		4086245001	2 MO - GREASE STA 11 ENGART DUST COLLECTOR	0	MO	PM	2MO
	HVAC	5120000		4086246001	DAILY - ENGART DUCT EXTRACTOR INSPECTION	0	MO	PM	DAY
930									
980	LIGHTING	5110000		0093565201	ICE 3MO DC BATTERY INSP - EMERGENCY STACK	0	MO	PM	3MO
	LIGHTING	5110000		4081923401	U0 ICE 1WK STACK LIGHTING INSPECTION	0	MO	PM	WKL
980									
990	MISCELLANEOUS	5120000		0093383601	STORES SAFETY MEETING.	0	MO	PM	MON
	MISCELLANEOUS	5120000		0093545201	TO COVER EMPLOYEES SAFETY MEETING FOR THE MONTH.	0	MO	PM	MON
	MISCELLANEOUS	5120000		0093545401	TO COVER EMPLOYEES SAFETY MEETING FOR THE MONTH.	0	MO	PM	MON
	MISCELLANEOUS	5120000		0093545501	TO COVER EMPLOYEES SAFETY MEETING FOR THE MONTH.	0	MO	PM	MON
	MISCELLANEOUS	5120000		0093545601	TO COVER EMPLOYEES SAFETY MEETING FOR THE MONTH.	0	MO	PM	MON
	MISCELLANEOUS	5120000		0093545701	TO COVER EMPLOYEES SAFETY MEETING FOR THE MONTH.	0	MO	PM	MON
	MISCELLANEOUS	5120000		0093545801	TO COVER EMPLOYEES SAFETY MEETING FOR THE MONTH.	0	MO	PM	MON
	MISCELLANEOUS	5120000		0093586601	REQUALIFYING WELDERS WELDING CERTIFICATION LOG.	0	MO	PM	WKL
	MISCELLANEOUS	5120000		0094376601	PERFORM CALIBRATION FOR SO2 VAPORIZER HEATERS, UNIT 2	0	MO	PM	1YR
	MISCELLANEOUS	5120000		4097811201	UNIT 2 STEAM LEADS INFRARED ROUTE	0	MO	PM	6MO
	MISCELLANEOUS	5140000		0093401501	LOW VOLTAGE AND HIGH VOLTAGE ELECTRICAL GLOVE REPLACEMENT.	0	MO	PM	2MO
	MISCELLANEOUS	5140000		0093401601	HIGH VOLTAGE ELECTRICAL GLOVE REPLACEMENT.	0	MO	PM	6MO
	MISCELLANEOUS	5140000		0093403101	LOW & HIGH VOLTAGE ELECTRICAL GLOVE REPLACEMENT.	0	MO	PM	6MO
	MISCELLANEOUS	5140000		0093403201	LOW VOLTAGE AND HIGH VOLTAGE ELECTRICAL GLOVE REPLACEMENT.	0	MO	PM	2MO
	MISCELLANEOUS	5140000		0093403301	LOW VOLTAGE AND HIGH VOLTAGE ELECTRICAL GLOVE REPLACEMENT.	0	MO	PM	2MO
	MISCELLANEOUS	5140000		0093403501	LOW VOLTAGE ELECTRICAL GLOVES - REPLACEMENT.	0	MO	PM	2MO
	MISCELLANEOUS	5140000		0093403601	LOW VOLTAGE ELECTRICAL GLOVES - REPLACEMENT.	0	MO	PM	2MO
	MISCELLANEOUS	5140000		0093403701	INSULATING ELECTRICAL SLEEVES - TESTING.	0	MO	PM	1YR
	MISCELLANEOUS	5140000		0093403801	INSULATING ELECTRICAL BLANKETS - TESTING.	0	MO	PM	1YR
	MISCELLANEOUS	5140000		0093404001	LOW VOLTAGE ELECTRICAL GLOVES - REPLACEMENT.	0	MO	PM	2MO
	MISCELLANEOUS	5140000		0093405401	LOW VOLTAGE ELECTRICAL GLOVES - REPLACEMENT.	0	MO	PM	2MO
	MISCELLANEOUS	5140000		0093405501	LOW VOLTAGE ELECTRICAL GLOVES - REPLACEMENT.	0	MO	PM	2MO
	MISCELLANEOUS	5140000		0093405601	LOW VOLTAGE ELECTRICAL GLOVES - REPLACEMENT.	0	MO	PM	2MO
	MISCELLANEOUS	5140000		0093405701	LOW VOLTAGE ELECTRICAL GLOVES - REPLACEMENT.	0	MO	PM	2MO
	MISCELLANEOUS	5140000		0093405801	LOW VOLTAGE ELECTRICAL GLOVES - REPLACEMENT.	0	MO	PM	2MO
	MISCELLANEOUS	5140000		0093405901	LOW VOLTAGE ELECTRICAL GLOVES - REPLACEMENT.	0	MO	PM	2MO
	MISCELLANEOUS	5140000		0093406001	LOW VOLTAGE ELECTRICAL GLOVES - REPLACEMENT.	0	MO	PM	2MO
	MISCELLANEOUS	5140000		0093578301	TRAINING - FIRE BRIGADE	0	MO	PM	MON
	MISCELLANEOUS	5140000		0093578401	TRAINING - FIRE BRIGADE	0	MO	PM	MON
	MISCELLANEOUS	5140000		0093578501	TRAINING - FIRE BRIGADE	0	MO	PM	MON

Models in Authorized Status With Auto Trigger Ind 2/18/2010

WOT System Cd	WOT System Code Description	Account Nbr	WOT Unit Cond Reqd	WOT WO Nbr Task	WOT WR Task Title	WOT Unit	WO Type	WOT Job Type	Pm Frequency Code
	MISCELLANEOUS	5140000		0093578601	TRAINING - FIRE BRIGADE	0	MO	PM	MON
	MISCELLANEOUS	5140000		0093578701	TRAINING - FIRE BRIGADE	0	MO	PM	MON
	MISCELLANEOUS	5140000		0093578801	TRAINING - FIRST RESPONDER	0	MO	PM	3MO
	MISCELLANEOUS	5140000		0093578901	TRAINING - FIRST RESPONDER	0	MO	PM	3MO
	MISCELLANEOUS	5140000		0093579001	TRAINING - FIRST RESPONDER	0	MO	PM	3MO
	MISCELLANEOUS	5140000		0093579101	TRAINING - FIRST RESPONDER	0	MO	PM	3MO
	MISCELLANEOUS	5140000		0093579301	TRAINING - FIRST RESPONDER	0	MO	PM	MON
	MISCELLANEOUS	5140000		4086138001	G BROOKS - BALANCING CERTIFICATION	0	MO	PM	6MO
	MISCELLANEOUS	5140000		4086138501	J PERKINS - BALANCING CERTIFICATION	0	MO	PM	6MO
	MISCELLANEOUS	5140000		4086139101	NELSON KELLY - BALANCING CERTIFICATION	0	MO	PM	6MO
	MISCELLANEOUS	5140000		4086140601	STEVE JACKSON - BALANCING CERTIFICATION	0	MO	PM	6MO
	MISCELLANEOUS	5140000		4086142001	ED BOLT - BALANCING CERTIFICATION	0	MO	PM	6MO
	MISCELLANEOUS	5140000		4086143001	BILL BRADLEY - BALANCING CERTIFICATION	0	MO	PM	6MO
	MISCELLANEOUS	5140000		4086143201	RUSTY WHITLEY - BALANCING CERTIFICATION	0	MO	PM	6MO
	MISCELLANEOUS	5140000		4086143801	STEVE SARGENT - BALANCING CERTIFICATION	0	MO	PM	6MO
	MISCELLANEOUS	5140000		4086144201	WILLIAM PRINCE - BALANCING CERTIFICATION	0	MO	PM	6MO
	MISCELLANEOUS	5140000		4097810501	UNIT 1 STEAM LEADS INFRARED ROUTE	0	MO	PM	6MO
	MISCELLANEOUS	5140000		4104162701	LARRY SWORD - BALANCING CERTIFICATION	0	MO	PM	6MO
	MISC NON-EQUIPMENT	5120000		0093383601	STORES SAFETY MEETING.	0	MO	PM	MON
	MISC NON-EQUIPMENT	5120000		0093545201	TO COVER EMPLOYEES SAFETY MEETING FOR THE MONTH.	0	MO	PM	MON
	MISC NON-EQUIPMENT	5120000		0093545401	TO COVER EMPLOYEES SAFETY MEETING FOR THE MONTH.	0	MO	PM	MON
	MISC NON-EQUIPMENT	5120000		0093545501	TO COVER EMPLOYEES SAFETY MEETING FOR THE MONTH.	0	MO	PM	MON
	MISC NON-EQUIPMENT	5120000		0093545601	TO COVER EMPLOYEES SAFETY MEETING FOR THE MONTH.	0	MO	PM	MON
	MISC NON-EQUIPMENT	5120000		0093545701	TO COVER EMPLOYEES SAFETY MEETING FOR THE MONTH.	0	MO	PM	MON
	MISC NON-EQUIPMENT	5120000		0093545801	TO COVER EMPLOYEES SAFETY MEETING FOR THE MONTH.	0	MO	PM	MON
	MISC NON-EQUIPMENT	5120000		0093586601	REQUALIFYING WELDERS WELDING CERTIFICATION LOG.	0	MO	PM	WKL
	MISC NON-EQUIPMENT	5120000		0094376601	PERFORM CALIBRATION FOR SO2 VAPORIZER HEATERS, UNIT 2	0	MO	PM	1YR
	MISC NON-EQUIPMENT	5120000		4097811201	UNIT 2 STEAM LEADS INFRARED ROUTE	0	MO	PM	6MO
	MISC NON-EQUIPMENT	5140000		0093401501	LOW VOLTAGE AND HIGH VOLTAGE ELECTRICAL GLOVE REPLACEMENT.	0	MO	PM	2MO
	MISC NON-EQUIPMENT	5140000		0093401601	HIGH VOLTAGE ELECTRICAL GLOVE REPLACEMENT.	0	MO	PM	6MO
	MISC NON-EQUIPMENT	5140000		0093403101	LOW & HIGH VOLTAGE ELECTRICAL GLOVE REPLACEMENT.	0	MO	PM	6MO
	MISC NON-EQUIPMENT	5140000		0093403201	LOW VOLTAGE AND HIGH VOLTAGE ELECTRICAL GLOVE REPLACEMENT.	0	MO	PM	2MO
	MISC NON-EQUIPMENT	5140000		0093403301	LOW VOLTAGE AND HIGH VOLTAGE ELECTRICAL GLOVE REPLACEMENT.	0	MO	PM	2MO
	MISC NON-EQUIPMENT	5140000		0093403501	LOW VOLTAGE ELECTRICAL GLOVES - REPLACEMENT.	0	MO	PM	2MO
	MISC NON-EQUIPMENT	5140000		0093403601	LOW VOLTAGE ELECTRICAL GLOVES - REPLACEMENT.	0	MO	PM	2MO
	MISC NON-EQUIPMENT	5140000		0093403701	INSULATING ELECTRICAL SLEEVES - TESTING.	0	MO	PM	1YR
	MISC NON-EQUIPMENT	5140000		0093403801	INSULATING ELECTRICAL BLANKETS - TESTING.	0	MO	PM	1YR
	MISC NON-EQUIPMENT	5140000		0093404001	LOW VOLTAGE ELECTRICAL GLOVES - REPLACEMENT.	0	MO	PM	2MO
	MISC NON-EQUIPMENT	5140000		0093405401	LOW VOLTAGE ELECTRICAL GLOVES - REPLACEMENT.	0	MO	PM	2MO
	MISC NON-EQUIPMENT	5140000		0093405501	LOW VOLTAGE ELECTRICAL GLOVES - REPLACEMENT.	0	MO	PM	2MO
	MISC NON-EQUIPMENT	5140000		0093405601	LOW VOLTAGE ELECTRICAL GLOVES - REPLACEMENT.	0	MO	PM	2MO
	MISC NON-EQUIPMENT	5140000		0093405701	LOW VOLTAGE ELECTRICAL GLOVES - REPLACEMENT.	0	MO	PM	2MO
	MISC NON-EQUIPMENT	5140000		0093405801	LOW VOLTAGE ELECTRICAL GLOVES - REPLACEMENT.	0	MO	PM	2MO
	MISC NON-EQUIPMENT	5140000		0093405901	LOW VOLTAGE ELECTRICAL GLOVES - REPLACEMENT.	0	MO	PM	2MO
	MISC NON-EQUIPMENT	5140000		0093406001	LOW VOLTAGE ELECTRICAL GLOVES - REPLACEMENT.	0	MO	PM	2MO
	MISC NON-EQUIPMENT	5140000		0093578301	TRAINING - FIRE BRIGADE	0	MO	PM	MON
	MISC NON-EQUIPMENT	5140000		0093578401	TRAINING - FIRE BRIGADE	0	MO	PM	MON
	MISC NON-EQUIPMENT	5140000		0093578501	TRAINING - FIRE BRIGADE	0	MO	PM	MON
	MISC NON-EQUIPMENT	5140000		0093578601	TRAINING - FIRE BRIGADE	0	MO	PM	MON
	MISC NON-EQUIPMENT	5140000		0093578701	TRAINING - FIRE BRIGADE	0	MO	PM	MON
	MISC NON-EQUIPMENT	5140000		0093578801	TRAINING - FIRST RESPONDER	0	MO	PM	3MO
	MISC NON-EQUIPMENT	5140000		0093578901	TRAINING - FIRST RESPONDER	0	MO	PM	3MO
	MISC NON-EQUIPMENT	5140000		0093579001	TRAINING - FIRST RESPONDER	0	MO	PM	3MO
	MISC NON-EQUIPMENT	5140000		0093579101	TRAINING - FIRST RESPONDER	0	MO	PM	3MO
	MISC NON-EQUIPMENT	5140000		0093579301	TRAINING - FIRST RESPONDER	0	MO	PM	MON
	MISC NON-EQUIPMENT	5140000		4086138001	G BROOKS - BALANCING CERTIFICATION	0	MO	PM	6MO
	MISC NON-EQUIPMENT	5140000		4086138501	J PERKINS - BALANCING CERTIFICATION	0	MO	PM	6MO
	MISC NON-EQUIPMENT	5140000		4086139101	NELSON KELLY - BALANCING CERTIFICATION	0	MO	PM	6MO
	MISC NON-EQUIPMENT	5140000		4086140601	STEVE JACKSON - BALANCING CERTIFICATION	0	MO	PM	6MO
	MISC NON-EQUIPMENT	5140000		4086142001	ED BOLT - BALANCING CERTIFICATION	0	MO	PM	6MO
	MISC NON-EQUIPMENT	5140000		4086143001	BILL BRADLEY - BALANCING CERTIFICATION	0	MO	PM	6MO
	MISC NON-EQUIPMENT	5140000		4086143201	RUSTY WHITLEY - BALANCING CERTIFICATION	0	MO	PM	6MO
	MISC NON-EQUIPMENT	5140000		4086143801	STEVE SARGENT - BALANCING CERTIFICATION	0	MO	PM	6MO
	MISC NON-EQUIPMENT	5140000		4086144201	WILLIAM PRINCE - BALANCING CERTIFICATION	0	MO	PM	6MO
	MISC NON-EQUIPMENT	5140000		4097810501	UNIT 1 STEAM LEADS INFRARED ROUTE	0	MO	PM	6MO
	MISC NON-EQUIPMENT	5140000		4104162701	LARRY SWORD - BALANCING CERTIFICATION	0	MO	PM	6MO
990									
			N				ount All:	775	
105	BOILER DUCTS	5120000	OO	0094373301	ICE FO2 FD FAN INLET VANE DAMPER DRIVE INSP	2	MO	PM	WKL
	BOILER DUCTS	5120000		0094374401	ICE FO2 PA FAN INLET/OUTLET DAMPER DRIVE INSPECTION	2	MO	PM	WKL
105									

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WOT System Cd	WOT System Code Description	Account Nbr	WOT Unit Cond Reqd	WOT WO Nbr Task	WOT WR Task Title	WOT Unit	WO Type	WOT Job Type	Pm Frequency Code
110	PRIMARY AIR	5120000		0095309701	#1 PRIMARY AIR FAN - LUBRICATION	2	MO	PM	DAY
	PRIMARY AIR	5120000		0095309801	#2 PRIMARY AIR FAN - LUBRICATION	2	MO	PM	DAY
110									
115	FORCED DRAFT	5120000		0094901201	LUBRICATION - FORCED DRAFT FAN, EAST	1	MO	PM	DAY
	FORCED DRAFT	5120000		0094901301	LUBRICATION - FORCED DRAFT FAN, WEST	1	MO	PM	DAY
115									
150	PRECIPITATOR	5120000		0094900501	ICE FO1 MAIN PRECIP/HOPPER INSPECTION	1	MO	PM	DAY
	PRECIPITATOR	5120000		0095309101	ICE FO2 PRECIP/HOPPER INSPECTION	2	MO	PM	3MO
150									
165	SCR SELECTIVE CAT. REDUCTION	5120000		4096747301	ICE FO2 NORTH BOOSTER FAN IMPULSE LINES	2	MO	PM	MON
	SCR SELECTIVE CAT. REDUCTION	5120000		4096748101	ICE FO2 SOUTH BOOSTER FAN IMPULSE LINES	2	MO	PM	MON
	SCR SELECTIVE CAT. REDUCTION	5120000		4102496301	ICE FO2 ECONOMIZER OUTLET IMPULSE LINES	2	MO	PM	WKL
165									
180	INSTRUMENT/CONTROL AIR	5140000		4057702401	ICE FO1 CONTROL AIR PRESS REGULATING VALVES FUNCTION TESTS	1	MO	PM	2YR
180									
240	COAL FEEDER (PULVERIZER)	5130000		4045651801	ICE FO1 COAL FEEDER ELECTRONIC CABINETS - CLEAN	1	MO	PM	ANN
	COAL FEEDER (TO PULVERIZER)	5130000		4045651801	ICE FO1 COAL FEEDER ELECTRONIC CABINETS - CLEAN	1	MO	PM	ANN
240									
250	PULVERIZER (COAL)	5120000		0094232201	U1 ICE FO1 E&W FD FAN INLET VANE INSPECTION	1	MO	PM	DAY
250									
260	BURNER/IGNITORS	5120000		0094690801	ICE FO1 OIL LIGHTER INSPECTION	1	MO	PM	MON
	BURNER/IGNITORS	5120000		4102564401	ICE FO2 OIL LIGHTER INSPECTION	2	MO	PM	MON
	MAIN BURNER/IGNITORS	5120000		0094690801	ICE FO1 OIL LIGHTER INSPECTION	1	MO	PM	MON
	MAIN BURNER/IGNITORS	5120000		4102564401	ICE FO2 OIL LIGHTER INSPECTION	2	MO	PM	MON
260									
310	BOILER, GENERAL	5120000		0094375201	ICE FO2 ATTEMP VALVES FRV-101,201,401 INSP	2	MO	PM	6MO
	BOILER, GENERAL	5120000		0094900401	BOILER - OPEN & CLOSE DOORS, DESLAG, HYDRO, AND AIR TEST.	1	MO	PM	DAY
	BOILER, GENERAL	5120000		0095308401	BOILER; OPEN & CLOSE DOORS; DESLAG, HYDRO AND AIR TEST.	2	MO	PM	DAY
	BOILER, GENERAL	5120000		0095310401	PLT COAL AIR EXPANSION JOINTS (ALL) - INSPECT & LUBRICATE	2	MO	PM	DAY
	BOILER, GENERAL	5120000		4072789701	INSPECT MAIN STEAM ATTEMPERATOR BYPASS VALVE FMO-101	2	MO	PM	2YR
	BOILER, GENERAL	5120000		4073688601	INSPECT MAIN STEAM LEAD DRAIN VA MO-29, U1	1	MO	PM	2YR
	BOILER, GENERAL	5120000		4073723201	U1 - INSPECT MAIN STEAM LEAD DRAIN MO-30	1	MO	PM	2YR
	BOILER, GENERAL..	5120000		0094375201	ICE FO2 ATTEMP VALVES FRV-101,201,401 INSP	2	MO	PM	6MO
	BOILER, GENERAL..	5120000		0094900401	BOILER - OPEN & CLOSE DOORS, DESLAG, HYDRO, AND AIR TEST.	1	MO	PM	DAY
	BOILER, GENERAL..	5120000		0095308401	BOILER; OPEN & CLOSE DOORS; DESLAG, HYDRO AND AIR TEST.	2	MO	PM	DAY
	BOILER, GENERAL..	5120000		0095310401	PLT COAL AIR EXPANSION JOINTS (ALL) - INSPECT & LUBRICATE	2	MO	PM	DAY
	BOILER, GENERAL..	5120000		4072789701	INSPECT MAIN STEAM ATTEMPERATOR BYPASS VALVE FMO-101	2	MO	PM	2YR
	BOILER, GENERAL..	5120000		4073688601	INSPECT MAIN STEAM LEAD DRAIN VA MO-29, U1	1	MO	PM	2YR
	BOILER, GENERAL..	5120000		4073723201	U1 - INSPECT MAIN STEAM LEAD DRAIN MO-30	1	MO	PM	2YR
310									
360	MAIN STEAM SPRHTR & LINE	5120000		0093806801	ICE FO2 ARV-542 INSPECTION	2	MO	PM	DAY
	MAIN STEAM SPRHTR & LINE	5120000		0093807901	ICE FO1 RV-1 INSPECTION	1	MO	PM	DAY
	MAIN STEAM SPRHTR & LINE	5120000		0094370501	U2 ICE FO2 URV 1&2 INSPECTION	2	MO	PM	DAY
	MAIN STEAM SPRHTR & LINE	5120000		4072738201	INSPECT SH BYPASS VALVE AND LIMITORQUE U1 - MO7	1	MO	PM	2YR
	MAIN STEAM SPRHTR & LINE	5120000		4072738601	INSPECT SH "A" BYPASS VALVE AND LIMITORQUE U1-MO6	1	MO	PM	2YR
	MAIN STEAM SPRHTR & LINE	5120000		4073678901	STROKE FRV-101 & FMO-101 SH ATTEMPERATORS	2	MO	PM	2YR
	MAIN STEAM SPRHTR & LINE	5120000		4073679901	INSPECT SH BYPASS BLOCK VALVE, UMO-1 (2 YEAR INSP)	2	MO	PM	2YR
	MAIN STEAM SPRHTR & LINE	5120000		4081653101	U2 ICE 1YR BRV-5 TEST/CALIBRATE	2	MO	PM	1YR
	MAIN STEAM SPRHTR & LINES	5120000		0093806801	ICE FO2 ARV-542 INSPECTION	2	MO	PM	DAY
	MAIN STEAM SPRHTR & LINES	5120000		0093807901	ICE FO1 RV-1 INSPECTION	1	MO	PM	DAY
	MAIN STEAM SPRHTR & LINES	5120000		0094370501	U2 ICE FO2 URV 1&2 INSPECTION	2	MO	PM	DAY
	MAIN STEAM SPRHTR & LINES	5120000		4072738201	INSPECT SH BYPASS VALVE AND LIMITORQUE U1 - MO7	1	MO	PM	2YR
	MAIN STEAM SPRHTR & LINES	5120000		4072738601	INSPECT SH "A" BYPASS VALVE AND LIMITORQUE U1-MO6	1	MO	PM	2YR
	MAIN STEAM SPRHTR & LINES	5120000		4073678901	STROKE FRV-101 & FMO-101 SH ATTEMPERATORS	2	MO	PM	2YR
	MAIN STEAM SPRHTR & LINES	5120000		4073679901	INSPECT SH BYPASS BLOCK VALVE, UMO-1 (2 YEAR INSP)	2	MO	PM	2YR
	MAIN STEAM SPRHTR & LINES	5120000		4081653101	U2 ICE 1YR BRV-5 TEST/CALIBRATE	2	MO	PM	1YR
360									
380	SOOTBLOWERS	5120000		4057661301	SOUTH AIR PREHEATER CLEANING DEVICE	2	MO	PM	DAY
	SOOTBLOWERS	5120000		4057663201	NORTH AIR PREHEATER CLEANING DEVICE	2	MO	PM	DAY
380									
415	CONDENSATE	5120000		0094372201	ICE FO2 CRV-101 STROKE	2	MO	PM	3MO
	CONDENSATE	5120000		4065455701	ICE FO1 STROKE CODENSATE VALVES	1	MO	PM	OUT
	CONDENSATE	5120000		4065787901	ICE FO2 STROKE CONDENSATE VALVES CRV-301, 101, & 102	2	MO	PM	3MO
415									
440	CIRCULATING WATER	5130000		0093565101	CLEANING - CIRCULATING WATER PUMP INLET SCREENS	2	MO	PM	DAY
440									
510	TURBINE INLET VALVES	5130000		0094377201	ICE FO2 REPLACE SERVO FILTERS - MAIN TURBINE	2	MO	PM	1YR
	TURBINE INLET VALVES	5130000		0094377201	ICE FO2 REPLACE SERVO FILTERS - MAIN TURBINE	2	MO	PM	OUT
	TURBINE INLET VALVES	5130000		0094377301	ICE FO2 REPLACE SERVO FILTER - BFP	2	MO	PM	1YR
	TURBINE INLET VALVES	5130000		0094377301	ICE FO2 REPLACE SERVO FILTER - BFP	2	MO	PM	OUT
510									

Models in Authorized Status With Auto Trigger Ind 2/18/2010

WOT System Cd	WOT System Code Description	Account Nbr	WOT Unit Cond Reqd	WOT WO Nbr Task	WOT WR Task Title	WOT Unit	WO Type	WOT Job Type	Pm Frequency Code
540	TURBINE LUBE OIL	5130000		4073249701	U2 CHANGE OIL 75 HP BACK-UP OIL TURBINE MOTOR	2	MO	PM	2YR
	TURBINE LUBE OIL	5130000		4073250301	U2 CHANGE OIL - 60 HP TURBINE SUCTION OIL PUMP MOTOR	2	MO	PM	1YR
	TURBINE LUBE OIL	5130000		4073250301	U2 CHANGE OIL - 60 HP TURBINE SUCTION OIL PUMP MOTOR	2	MO	PM	2YR
540									
665	D.C. ELECTRIC SYSTEM	5130000		4103779201	FO1 ICE 1YR INVERTER INSPECTION	1	MO	PM	ANN
	D.C. ELECTRIC SYSTEM	5130000		4103781401	FO2 ICE 1YR INVERTER INSPECTION	2	MO	PM	ANN
	D.C.ELECTRIC SYSTEM	5130000		4103779201	FO1 ICE 1YR INVERTER INSPECTION	1	MO	PM	ANN
	D.C.ELECTRIC SYSTEM	5130000		4103781401	FO2 ICE 1YR INVERTER INSPECTION	2	MO	PM	ANN
665									
700	** CONTROLS AND COMPUTERS **	5130000		0093809001	ICE FO2 TURBINE LVDT/ROD END BEARING INSPECTION	2	MO	PM	DAY
	** CONTROLS AND COMPUTERS **	5130000		4045652501	U2 COAL FEEDER ELECTRONIC CABINETS - CLEAN	2	MO	PM	ANN
	CONTROLS AND COMPUTERS	5130000		0093809001	ICE FO2 TURBINE LVDT/ROD END BEARING INSPECTION	2	MO	PM	DAY
	CONTROLS AND COMPUTERS	5130000		4045652501	U2 COAL FEEDER ELECTRONIC CABINETS - CLEAN	2	MO	PM	ANN
700									
740	COMBUSTION CONTROLS	5120000		0094121601	ICE FO2 O2 ANALYZER INSPECTION	2	MO	PM	DAY
	COMBUSTION CONTROLS	5120000		0094122201	ICE FO1 O2 ANALYZER INSPECTION	1	MO	PM	MON
	COMBUSTION CONTROLS	5120000		4100461201	ICE FO2 SECONDARY AIR FLOW PORTS-ROD OUT	2	MO	PM	3MO
	COMBUSTION CONTROLS	5120000		4137140301	ICE FO1 FUEL OIL EXCESS CHAMBER-CHECK LEVEL ALARM	1	MO	PM	OUT
740									
990	MISCELLANEOUS	5120000		4073671501	U2 ICE FO STROKE COOLING WATER VALVE CRV-501	0	MO	PM	2YR
	MISC NON-EQUIPMENT	5120000		4073671501	U2 ICE FO STROKE COOLING WATER VALVE CRV-501	0	MO	PM	2YR
990									
			OO				ount All:	76	
240	COAL FEEDER (PULVERIZER)	5120000	R	0093581401	INSPECTION FEEDER - COAL #11 NEW STOCK	1	MO	PM	DAY
	COAL FEEDER (PULVERIZER)	5120000		0093581501	INSPECTION FEEDER - COAL #12 NEW STOCK	1	MO	PM	DAY
	COAL FEEDER (PULVERIZER)	5120000		0093581601	INSPECTION FEEDER - COAL #13 NEW STOCK	1	MO	PM	DAY
	COAL FEEDER (PULVERIZER)	5120000		0093581701	INSPECTION FEEDER - COAL #14 NEW STOCK	1	MO	PM	DAY
	COAL FEEDER (PULVERIZER)	5120000		0093581801	INSPECTION FEEDER - COAL #15 NEW STOCK	1	MO	PM	DAY
	COAL FEEDER (PULVERIZER)	5120000		0093581901	INSPECTION FEEDER - COAL #16 NEW STOCK	1	MO	PM	DAY
	COAL FEEDER (TO PULVERIZER)	5120000		0093581401	INSPECTION FEEDER - COAL #11 NEW STOCK	1	MO	PM	DAY
	COAL FEEDER (TO PULVERIZER)	5120000		0093581501	INSPECTION FEEDER - COAL #12 NEW STOCK	1	MO	PM	DAY
	COAL FEEDER (TO PULVERIZER)	5120000		0093581601	INSPECTION FEEDER - COAL #13 NEW STOCK	1	MO	PM	DAY
	COAL FEEDER (TO PULVERIZER)	5120000		0093581701	INSPECTION FEEDER - COAL #14 NEW STOCK	1	MO	PM	DAY
	COAL FEEDER (TO PULVERIZER)	5120000		0093581801	INSPECTION FEEDER - COAL #15 NEW STOCK	1	MO	PM	DAY
	COAL FEEDER (TO PULVERIZER)	5120000		0093581901	INSPECTION FEEDER - COAL #16 NEW STOCK	1	MO	PM	DAY
240									
250	PULVERIZER (COAL)	5120000		0093580501	INSPECTION PULVERIZER #11 (1000 HRS)	1	MO	PM	DAY
	PULVERIZER (COAL)	5120000		0093580601	INSPECTION PULVERIZER #12 (1000 HRS)	1	MO	PM	DAY
	PULVERIZER (COAL)	5120000		0093580602	ICE #12 CLEAN AIR CURVE PULVERIZER (1000 HRS)	1	MO	PM	DAY
	PULVERIZER (COAL)	5120000		0093580701	INSPECTION PULVERIZER #13 (1000 HRS)	1	MO	PM	DAY
	PULVERIZER (COAL)	5120000		0093580702	ICE #13 CLEAN AIR CURVE PULVERIZER (1000 HRS)	1	MO	PM	DAY
	PULVERIZER (COAL)	5120000		0093581101	INSPECTION PULVERIZER #14 (1000 HRS)	1	MO	PM	DAY
	PULVERIZER (COAL)	5120000		0093581102	U1 ICE #14 CLEAN AIR CURVE (1000 HRS)	1	MO	PM	DAY
	PULVERIZER (COAL)	5120000		0093581201	INSPECTION PULVERIZER #15 (1000 HRS)	1	MO	PM	DAY
	PULVERIZER (COAL)	5120000		0093581202	ICE # 15 PULV CLEAN AIR CURVE 1000 HOURS	1	MO	PM	DAY
	PULVERIZER (COAL)	5120000		0093581301	INSPECTION PULVERIZER #16 (1000 HRS)	1	MO	PM	DAY
	PULVERIZER (COAL)	5120000		0093581302	U1 ICE PULV #16 CLEAN AIR CURVE	1	MO	PM	DAY
	PULVERIZER (COAL)	5120000		0093582901	INSPECTION PULVERIZER #21 (2000 HRS)	2	MO	PM	DAY
	PULVERIZER (COAL)	5120000		0093583001	INSPECTION PULVERIZER #22 (2000 HRS)	2	MO	PM	DAY
	PULVERIZER (COAL)	5120000		0093583101	INSPECTION PULVERIZER #23 (2000 HRS)	2	MO	PM	DAY
	PULVERIZER (COAL)	5120000		0093583201	INSPECTION PULVERIZER #24 (2000 HRS)	2	MO	PM	DAY
	PULVERIZER (COAL)	5120000		0093583301	INSPECTION PULVERIZER #25 (2000 HRS)	2	MO	PM	DAY
250									
			R				ount All:	28	
105	BOILER DUCTS	5120000	U	0094372801	U2 ICE OUTR BURNER REGISTER DRIVE INSP	2	MO	PM	OUT
	BOILER DUCTS	5120000		4070784901	U2 ICE OUTR FD FAN INLET VANE DAMPER DRIVE INSP	2	MO	PM	OUT
	BOILER DUCTS	5120000		4070785101	U2 ICE OUTR PA FAN INLET/OUTLET DAMPER DRIVE INSP	2	MO	PM	OUT
	BOILER DUCTS	5120000		4072833701	ICE U2 OUTR #1 & 2 FD FAN OUTLET DAMPER DRIVES	2	MO	PM	OUT
	BOILER DUCTS	5120000		4098236701	PLANT SUPV - INSPECT SECONDARY AIR DUCTWORK AND DAMPERS.	2	MO	PM	50Y
	BOILER DUCTS	5120000		4098236702	NAIS - SECONDARY AIR DUCTWORK AND DAMPERS-VACUUM SERVICES	2	MO	PM	50Y
	BOILER DUCTS	5120000		4098236703	YOUNGS - SECONDARY AIR DUCTWORK AND DAMPERS-SCAFFOLDING	2	MO	PM	50Y
	BOILER DUCTS	5120000		4098236704	MMI - SECONDARY AIR DUCTWORK AND DAMPERS-INSULATION	2	MO	PM	50Y
	BOILER DUCTS	5120000		4098236705	MCON- INSPECT SECONDARY AIR DUCTWORK AND DAMPERS.	2	MO	PM	50Y
	BOILER DUCTS	5120000		4098249201	PLANT SUPV - INSPECT PRIMARY AIR DUCTWORK AND DAMPERS.	2	MO	PM	50Y
	BOILER DUCTS	5120000		4098249202	NAIS - PRIMARY AIR DUCTWORK AND DAMPERS-VACUUM SERVICES	2	MO	PM	50Y
	BOILER DUCTS	5120000		4098249203	YOUNGS - PRIMARY AIR DUCTWORK AND DAMPERS-SCAFFOLDING	2	MO	PM	50Y
	BOILER DUCTS	5120000		4098249204	MMI - PRIMARY AIR DUCTWORK AND DAMPERS-INSULATION	2	MO	PM	50Y
	BOILER DUCTS	5120000		4098249205	MCON- INSPECT PRIMARY AIR DUCTWORK AND DAMPERS.	2	MO	PM	50Y
	BOILER DUCTS	5120000		4098254801	PLT SUPV GAS OUTLET DUCTS I/R	2	MO	PM	50Y
	BOILER DUCTS	5120000		4098254802	NAIS VACUUM GAP GAS OUTLET DUCTS I/R	2	MO	PM	50Y
	BOILER DUCTS	5120000		4098254803	MMI INSUL GAS OUTLET DUCTS I/R	2	MO	PM	50Y

Models in Authorized Status With Auto Trigger Ind 2/18/2010

WOT System Cd	WOT System Code Description	Account Nbr	WOT Unit Cond Reqd	WOT WO Nbr Task	WOT WR Task Title	WOT Unit	WO Type	WOT Job Type	Pm Frequency Code
	BOILER DUCTS	5120000		4098254804	YGS SCAFFOLD GAS OUTLET DUCTS I/R	2	MO	PM	50Y
	BOILER DUCTS	5120000		4098254805	MCON/GAS OUTLET DUCTS I/R	2	MO	GM	50Y
	BOILER DUCTS	5120000		4099494401	PLT SUPV - I/R PRIMARY AIR SHUTOFF DAMPERS 21 THRU 26	2	MO	PM	50Y
	BOILER DUCTS	5120000		4099494402	PLT MECH - I/R PRIMARY AIR SHUTOFF DAMPERS 21 THRU 26	2	MO	PM	50Y
	BOILER DUCTS	5120000		4099494403	PLT ICE - I/R PRIMARY AIR SHUTOFF DAMPERS 21 THRU 26	2	MO	PM	50Y
	BOILER DUCTS	5120000		4099494404	SCAF - I/R PRIMARY AIR SHUTOFF DAMPERS 21 THRU 26	2	MO	PM	50Y
	BOILER DUCTS	5120000		4099494405	INSL - I/R PRIMARY AIR SHUTOFF DAMPERS 21 THRU 26	2	MO	PM	50Y
	BOILER DUCTS	5120000		4099494406	VAC - I/R PRIMARY AIR SHUTOFF DAMPERS 21 THRU 26	2	MO	PM	50Y
	BOILER DUCTS	5120000		4099494801	PLT SUPV - I/R HOT AIR DAMPERS 21 THRU 26	2	MO	PM	50Y
	BOILER DUCTS	5120000		4099494802	PLT MECH - I/R HOT AIR DAMPERS 21 THRU 26	2	MO	PM	50Y
	BOILER DUCTS	5120000		4099494803	PLT ICE - I/R HOT AIR DAMPERS 21 THRU 26	2	MO	PM	50Y
	BOILER DUCTS	5120000		4099494804	SCAF - I/R HOT AIR DAMPERS 21 THRU 26	2	MO	PM	50Y
	BOILER DUCTS	5120000		4099494805	INSL - I/R HOT AIR DAMPERS 21 THRU 26	2	MO	PM	50Y
	BOILER DUCTS	5120000		4099494806	VAC - I/R HOT AIR DAMPERS 21 THRU 26	2	MO	PM	50Y
	BOILER DUCTS	5120000		4099498101	PLT SUPV - I/R CAPACITY DAMPERS 21 THRU 26	2	MO	PM	50Y
	BOILER DUCTS	5120000		4099498102	PLT MECH - I/R CAPACITY DAMPERS 21 THRU 26	2	MO	PM	50Y
	BOILER DUCTS	5120000		4099498103	PLT ICE - I/R CAPACITY DAMPERS 21 THRU 26	2	MO	PM	50Y
	BOILER DUCTS	5120000		4099498104	SCAF - I/R CAPACITY DAMPERS 21 THRU 26	2	MO	PM	50Y
	BOILER DUCTS	5120000		4099498105	INSL - I/R CAPACITY DAMPERS 21 THRU 26	2	MO	PM	50Y
	BOILER DUCTS	5120000		4099498106	VAC - I/R CAPACITY DAMPERS 21 THRU 26	2	MO	PM	50Y
	BOILER DUCTS	5120000		4099498401	PLT SUPV - I/R TEMPERING AIR DAMPERS 21 THRU 26	2	MO	PM	50Y
	BOILER DUCTS	5120000		4099498402	PLT MECH - I/R TEMPERING AIR DAMPERS 21 THRU 26	2	MO	PM	50Y
	BOILER DUCTS	5120000		4099498403	PLT ICE - I/R TEMPERING AIR DAMPERS 21 THRU 26	2	MO	PM	50Y
	BOILER DUCTS	5120000		4099498404	SCAF - I/R TEMPERING AIR DAMPERS 21 THRU 26	2	MO	PM	50Y
	BOILER DUCTS	5120000		4099498405	INSL - I/R TEMPERING AIR DAMPERS 21 THRU 26	2	MO	PM	50Y
	BOILER DUCTS	5120000		4099498406	VAC - I/R TEMPERING AIR DAMPERS 21 THRU 26	2	MO	PM	50Y
105									
110	PRIMARY AIR	5120000		4099614401	BS/MECH #1 P.A. FAN; INSPECT,CLEAN ROTOR	2	MO	PM	50Y
	PRIMARY AIR	5120000		4099614402	CEAP SAND - #1 P.A. FAN; SANDBLASTING	2	MO	PM	50Y
	PRIMARY AIR	5120000		4099614403	CMS - #1 P.A. FAN; NDE	2	MO	PM	50Y
	PRIMARY AIR	5120000		4099614404	BS/SUPV #1 P.A. FAN; BEARING REPAIRS	2	MO	PM	50Y
	PRIMARY AIR	5120000		4099614405	BS/ICE - #1 P.A. FAN; INSPECT, CLEAN ROTOR	2	MO	PM	50Y
	PRIMARY AIR	5120000		4099614406	YGS SCAFFOLD #1 P.A. FAN; INSPECT, CLEAN ROTOR	2	MO	PM	50Y
	PRIMARY AIR	5120000		4099614407	NAIS VACUUM #1 P.A. FAN; INSPECT, CLEAN ROTOR	2	MO	PM	50Y
110									
115	FORCED DRAFT	5120000		0095083401	U2 ICE OUTR #1 FD FAN MOTOR INSPECTION	2	MO	PM	OUT
	FORCED DRAFT	5120000		0095083501	U2 ICE OUTR #2 FD FAN MOTOR INSPECTION	2	MO	PM	OUT
	FORCED DRAFT	5120000		0095309501	#1 FORCED DRAFT FAN - LUBRICATION	2	MO	PM	WKL
	FORCED DRAFT	5120000		0095309601	#2 FORCED DRAFT FAN - LUBRICATION	2	MO	PM	WKL
	FORCED DRAFT	5120000		4099613101	BS/MECH #2 F.D. FAN; CLEAN, INSPECT, LUBRICATE & REPAIR.	2	MO	PM	50Y
	FORCED DRAFT	5120000		4099613102	YGS SCAFFOLD #2 F.D. FAN; SCAFFOLDING	2	MO	PM	50Y
	FORCED DRAFT	5120000		4099613103	CEAP SAND - #2 F.D. FAN; SANDBLASTING	2	MO	PM	50Y
	FORCED DRAFT	5120000		4099613104	CMS NDE #2 F.D. FAN; CLEAN, INSPECT, LUBRICATE & REPAIR.	2	MO	PM	50Y
	FORCED DRAFT	5120000		4099613105	BS/SUPV #2 F.D. FAN; BEARING REPAIRS	2	MO	PM	50Y
	FORCED DRAFT	5120000		4099613106	NAIS VACUUM #2 F.D. FAN; CLEAN, INSPECT, & REPAIR.	2	MO	PM	50Y
	FORCED DRAFT	5120000		4099613107	BS/ICE #2 F.D. FAN; CLEAN, INSPECT, LUBRICATE & REPAIR.	2	MO	PM	50Y
	FORCED DRAFT	5120000		4099613901	BS/MECH #1 F.D. FAN; CLEAN, INSPECT, LUBRICATE & REPAIR.	2	MO	PM	50Y
	FORCED DRAFT	5120000		4099613902	YGS SCAFFOLD #1 F.D. FAN; SCAFFOLDING	2	MO	PM	50Y
	FORCED DRAFT	5120000		4099613903	CEAP SAND - #1 F.D. FAN; SANDBLASTING	2	MO	PM	50Y
	FORCED DRAFT	5120000		4099613904	CMS - #1 F.D. FAN; NDE	2	MO	PM	50Y
	FORCED DRAFT	5120000		4099613905	BS/SUPV #1 F.D. FAN; BEARING REPAIRS	2	MO	PM	50Y
	FORCED DRAFT	5120000		4099613906	BS/ICE #1 F.D. FAN; CLEAN, INSPECT, LUBRICATE & REPAIR.	2	MO	PM	50Y
	FORCED DRAFT	5120000		4099613907	NAIS VACUUM #1 F.D. FAN; CLEAN, INSPECT, LUBRICATE & REPAIR.	2	MO	PM	50Y
115									
130	AIRHEATERS, MAIN	5120000		4057540201	ICE - STROKE EAST & WAST AIR HEATER BYPASS DAMPERS UNIT 1	1	MO	PM	4YR
	AIRHEATERS, MAIN	5120000		4057585301	ICE - CHECK THERMOCOUPLES FOR AIR AND GAS REC. UNIT 1	1	MO	PM	4YR
	AIRHEATERS, MAIN	5120000		4057698001	U2 ICE OUTR CALIBRATE AIR HEATER BYPASS CONTROLS	2	MO	PM	4YR
	AIRHEATERS, MAIN	5120000		4057880301	U2 ICE OUTR INSPECT T/C, RTD AIR & GAS RECORDER	2	MO	PM	OUT
	AIRHEATERS, MAIN	5120000		4099595701	BS/SUPV INSPECT & REPAIR #2 AIR HEATER	2	MO	PM	50Y
	AIRHEATERS, MAIN	5120000		4099595702	MCCON - INSPECT & REPAIR #2 AIR HEATER	2	MO	PM	50Y
	AIRHEATERS, MAIN	5120000		4099595703	ALSTOM ABB SERVICE TECH - INSPECT & REPAIR #2 AIR HEATER	2	MO	PM	50Y
	AIRHEATERS, MAIN	5120000		4099595704	NAIS VAC - INSPECT & REPAIR #2 AIR HEATER	2	MO	PM	50Y
	AIRHEATERS, MAIN	5120000		4099595705	MMI INSUL INSPECT & REPAIR #2AIR HEATER	2	MO	PM	50Y
	AIRHEATERS, MAIN	5120000		4099595706	YGS SCAFFOLD INSPECT & REPAIR #2 AIR HEATER	2	MO	PM	50Y
	AIRHEATERS, MAIN	5120000		4099595707	BS/MECH INSPECT & REPAIR #2 AIR HEATER	2	MO	PM	50Y
	AIRHEATERS, MAIN	5120000		4099595708	NAIS HIGH PRESSURE WASH #2 AIR HEATER	2	MO	PM	50Y
	AIRHEATERS, MAIN	5120000		4099596801	BS/SUPV INSPECT & REPAIR #1 AIR HEATER	2	MO	PM	50Y
	AIRHEATERS, MAIN	5120000		4099596802	MCON - INSPECT & REPAIR #1 AIR HEATER	2	MO	PM	50Y
	AIRHEATERS, MAIN	5120000		4099596803	ALSTOM ABB SERVICE TECH - INSPECT & REPAIR #1 AIR HEATER	2	MO	PM	50Y
	AIRHEATERS, MAIN	5120000		4099596804	NAIS VAC - INSPECT & REPAIR #1 AIR HEATER	2	MO	PM	50Y
	AIRHEATERS, MAIN	5120000		4099596805	MMI INSUL INSPECT & REPAIR #1 AIR HEATER	2	MO	PM	50Y

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WOT System Cd	WOT System Code Description	Account Nbr	WOT Unit Cond Reqd	WOT WO Nbr Task	WOT WR Task Title	WOT Unit	WO Type	WOT Job Type	Pm Frequency Code
	AIRHEATERS, MAIN	5120000		4099596806	YGS SCAFFOLD INSPECT & REPAIR #1 AIR HEATER	2	MO	PM	50Y
	AIRHEATERS, MAIN	5120000		4099596807	BS/MECH INSPECT & REPAIR #1 AIR HEATER	2	MO	PM	50Y
	AIRHEATERS, MAIN	5120000		4099596808	NAIS IS TO HIGH PRESSURE WASH/#1 AIR HEATER	2	MO	PM	50Y
130									
150	PRECIPITATOR	5120000		4057279201	U1 ICE OUTR MAIN PRECIPITATOR/HOPPER INSPECTION	1	MO	PM	OUT
	PRECIPITATOR	5120000		4060154401	U2 ICE OUTR PRECIP/HOPPER INSPECTION	2	MO	PM	OUT
	PRECIPITATOR	5120000		4061780001	U1 ICE OUTR PRECIP TRANSFORMER CLEAN/CHANGE FILTERS 1YR	1	MO	PM	OUT
	PRECIPITATOR	5120000		4061783501	U1 ICE OUTR 2YR INTERNAL INPSECTION OF PRECIPITATOR TRANSFOR	1	MO	PM	2YR
	PRECIPITATOR	5120000		4061789301	U2 ICE OUTR 1 YR PRECIP TRANSFORMERS-INSPECT FILTERS	2	MO	PM	OUT
150									
165	SCR SELECTIVE CAT. REDUCTION	5120000		4090356501	ICE U2 OUTR NORTH BOOSTER FAN IMPULSE LINES	2	MO	PM	ANN
	SCR SELECTIVE CAT. REDUCTION	5120000		4090357601	ICE U2 OUTR SOUTH BOOSTER FAN IMPULSE LINES	2	MO	PM	ANN
	SCR SELECTIVE CAT. REDUCTION	5120000		4090360001	ICE U2 OUTR ECONOMIZER OUTLET IMPULSE LINES	2	MO	PM	ANN
	SCR SELECTIVE CAT. REDUCTION	5120000		4090365701	ICE U2 OUTR NORTH BOOSTER FAN CALIBRATION	2	MO	PM	ANN
	SCR SELECTIVE CAT. REDUCTION	5120000		4090367601	ICE U2 OUTR SOUTH BOOSTER FAN CALIBRATION	2	MO	PM	ANN
	SCR SELECTIVE CAT. REDUCTION	5120000		4099524401	PLT SUPV - I/R SCR BYPASS DAMPERS	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099524402	PLT MECH - I/R SCR BYPASS DAMPERS	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099524403	INSL - I/R SCR BYPASS DAMPERS	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099524404	VAC - I/R SCR BYPASS DAMPERS	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099524405	SCAF - I/R SCR BYPASS DAMPERS	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099524801	PLT SUPV - I/R SCR OUTLET DAMPERS	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099524802	PLT MECH - I/R SCR OUTLET DAMPERS	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099524803	INSL - I/R SCR OUTLET DAMPERS	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099524804	VAC - I/R SCR OUTLET DAMPERS	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099524805	SCAF - I/R SCR OUTLET DAMPERS	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099525201	PLT SUPV - I/R SCR INLET DAMPERS	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099525202	PLT MECH - I/R SCR INLET DAMPERS	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099525203	INSL - I/R SCR INLET DAMPERS	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099525204	VAC - I/R SCR INLET DAMPERS	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099525205	SCAF - I/R SCR INLET DAMPERS	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099602601	BS/SUPV I/R SCR DUCT, SCR OUTLET TO AIR HEATER	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099602602	MCON- I/R SCR DUCT, SCR OUTLET TO AIR HEATER	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099602603	MMI INSUL I/R SCR DUCT, SCR OUTLET TO AIR HEATER	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099602604	YGS SCAFFOLD I/R SCR DUCT, SCR OUTLET TO AIR HEATER	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099602605	NAIS VACUUM INSPECT & REPAIR SCR DUCT OUTLET BACK TO AIR HTR	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099605401	BS/SUPV I/R SCR DUCT, SCR INLET TO REACTOR	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099605402	MCON- I/R SCR DUCT, SCR INLET TO REACTOR	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099605403	MMI INSUL I/R SCR DUCT, SCR INLET DUCT TO REACTOR	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099605404	YGS SCAFFOLD I/R SCR DUCT, SCR INLET DUCT TO REACTOR	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099605405	NAIS VACUUM INSPECT & REPAIR SCR DUCT, INLET DUCT TO REACTOR	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099606101	BS/SUPV I/R SCR DUCT, ECON OUTLET TO SCR INLET	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099606102	MCON- I/R SCR DUCT, ECON OUTLET TO SCR INLET	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099606103	MMI INSUL I/R SCR DUCT, ECON OUTLET TO SCR INLET	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099606104	YGS SCAFFOLD I/R SCR DUCT, ECON OUTLET TO SCR INLET	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099606105	NAIS VACUUM INSPECT & REPAIR SCR DUCT, ECON OUTLET	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099606701	BS/SUPV ROUTINE INSPECTION OF THE SOUTH BOOSTER FAN	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099606702	BS/MECH ROUTINE INSPECTION OF THE SOUTH BOOSTER FAN	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099606703	HOWDEN FAN SERVICE MAN ROUTINE INSPECTION OF S BOOSTER FAN	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099606704	BS/ICE ROUTINE INSPECTION OF THE SOUTH BOOSTER FAN	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4099606705	NORTH AMERICAN/ROUTINE INSPECT/ SOUTH BOOSTER FAN	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4101838901	BS/SUPV ROUTINE INSPECTION OF THE NORTH BOOSTER FAN	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4101838902	RSO/MECH ROUTINE INSPECTION OF THE NORTH BOOSTER FAN	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4101838903	HOWDEN FAN SERVICE MAN ROUTINE INSPECTION NORTH BOOSTER FAN	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4101838904	BS/ICE INSPECTION OF THE NORTH BOOSTER FAN	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4101838905	NORTH AMERICAN/ROUTINE INSPECT/NORTH BOOSTER FAN	2	MO	PM	50Y
	SCR SELECTIVE CAT. REDUCTION	5120000		4106354701	LAB - SAMPLE SCR CATYLIST PER AEP RECOMMENDATIONS.	2	MO	PM	50Y
165									
175	EMISSIONS MONITORING	5120000		0094676301	INSPECT UNIT 1 SO3 SYSTEM PIPING.	1	MO	PM	1YR
	EMISSIONS MONITORING	5120000		0094678301	U1 ICE OUTR MCC SO3 INSPECTION	1	MO	PM	1YR
	EMISSIONS MONITORING	5120000		0094681701	OBTAIN SAMPLE OF CONVERTER CATALYST; INSPECT CONVERTER	1	MO	PM	1YR
	EMISSIONS MONITORING	5120000		0094697501	OBTAIN SAMPLE OF CONVERTER CATALYST; INSPECT CONVERTER	2	MO	PM	2YR
	EMISSIONS MONITORING	5120000		0094700401	U1 ICE OUTR S03 CONTROLS INSPECTION	1	MO	PM	1YR
	EMISSIONS MONITORING	5120000		0095067301	SO2 & SO3 SYSTEM; INSPECT & REPAIR PIPING, VALVES, ETC.	2	MO	PM	50Y
175									
180	INSTRUMENT/CONTROL AIR	5140000		0094227401	U1 ICE OUTR INSPECT CONTROL AIR TRAPS	1	MO	PM	1YR
	INSTRUMENT/CONTROL AIR	5140000		4057653601	U2 ICE OUTR- INSPECT, LUBRICATE, TEST OPERATE PRV-1004 CONT	2	MO	PM	1YR
	INSTRUMENT/CONTROL AIR	5140000		4057653801	U2 ICE OUTR 18MO INSPECT DESICANT IN CONTROL AIR DRYERS	2	MO	PM	ANH
	INSTRUMENT/CONTROL AIR	5140000		4057661901	U2 ICE OUTR CONTROL AIR REG VALVES FUNCTIONAL TEST	2	MO	PM	2YR
	INSTRUMENT/CONTROL AIR	5140000		4057834501	U1 ICE 5YR CONTROL AIR DRYER DESICCANT-REPLACE	1	MO	PM	5YR
180									
215	COAL SAMPLING	5120000		4110748901	AF SAMPLER 6 MOS MECHANICAL INSPECTION	0	MO	PM	6MO

Models in Authorized Status With Auto Trigger Ind 2/18/2010

WOT System Cd	WOT System Code Description	Account Nbr	WOT Unit Cond Reqd	WOT WO Nbr Task	WOT WR Task Title	WOT Unit	WO Type	WOT Job Type	Pm Frequency Code
215									
250	PULVERIZER (COAL)	5120000		0094212601	U1 ICE OUTR EAST FD FAN INLET/OUTLET DAMPER DRIVES	1	MO	PM	OUT
	PULVERIZER (COAL)	5120000		0094700901	#12 RAW COAL PIPE (FEEDER TO PULVERIZER) - INSPECT & REPAIR.	1	MO	PM	1YR
	PULVERIZER (COAL)	5120000		0094701001	#13 RAW COAL PIPE (FEEDER TO PULVERIZER) - INSPECT & REPAIR.	1	MO	PM	1YR
	PULVERIZER (COAL)	5120000		0094701101	#14 RAW COAL PIPE (FEEDER TO PULVERIZER) - INSPECT & REPAIR.	1	MO	PM	1YR
	PULVERIZER (COAL)	5120000		0094701301	#16 RAW COAL PIPE (FEEDER TO PULVERIZER) - INSPECT & REPAIR.	1	MO	PM	1YR
	PULVERIZER (COAL)	5120000		0094704701	PULVERIZER BURNERS U-1 - INSPECTION	1	MO	PM	ANH
	PULVERIZER (COAL)	5120000		4045095201	U1 ICE OUTR F/D FAN INLET/OUTLET DAMPER DRIVES WEST	1	MO	PM	DAY
	PULVERIZER (COAL)	5120000		4062647301	ICE U1 OUTR #11 PULV CALIBRATE INSTRUMENTS	1	MO	PM	OUT
	PULVERIZER (COAL)	5120000		4062647302	ICE U1 OUTR #12 PULV CALIBRATE INSTRUMENTS	1	MO	PM	OUT
	PULVERIZER (COAL)	5120000		4062647303	ICE U1 OUTR #13-PULV CALIBRATE INSTRUMENTS	1	MO	PM	OUT
	PULVERIZER (COAL)	5120000		4062647304	ICE U1 OUTR #14 PULV CALIBRATE INSTRUMENTS	1	MO	PM	OUT
	PULVERIZER (COAL)	5120000		4062647305	ICE U1 OUTR #15 PULV CALIBRATE INSTRUMENTS	1	MO	PM	OUT
	PULVERIZER (COAL)	5120000		4062647306	ICE U1 OUTR #16 PULV CALIBRATE INSTRUMENTS	1	MO	PM	OUT
	PULVERIZER (COAL)	5120000		4062870801	U2 ICE OUTR #21 PULV - CALIBRATE INSTRUMENTS	2	MO	PM	OUT
	PULVERIZER (COAL)	5120000		4062870802	U2 ICE OUTR #22 PULV - CALIBRATE INSTRUMENTS	2	MO	PM	OUT
	PULVERIZER (COAL)	5120000		4062870803	U2 ICE OUTR #23 PULV - CALIBRATE INSTRUMENTS	2	MO	PM	OUT
	PULVERIZER (COAL)	5120000		4062870804	U2 ICE OUTR #24 PULV - CALIBRATE INSTRUMENTS	2	MO	PM	OUT
	PULVERIZER (COAL)	5120000		4062870805	U2 ICE OUTR #25 PULV - CALIBRATE INSTRUMENTS	2	MO	PM	OUT
	PULVERIZER (COAL)	5120000		4062870806	U2 ICE OUTR #26 PULV - CALIBRATE INSTRUMENTS	2	MO	PM	OUT
	PULVERIZER (COAL)	5120000		4062933201	U2 ICE OUTR #21 PULV DAMPERS- STROKE	2	MO	PM	OUT
	PULVERIZER (COAL)	5120000		4062933202	U2 ICE OUTR #22 PULV DAMPERS-STROKE	2	MO	PM	OUT
	PULVERIZER (COAL)	5120000		4062933203	U2 ICE OUTR #23 PULV DAMPERS-STROKE	2	MO	PM	OUT
	PULVERIZER (COAL)	5120000		4062933204	U2 ICE OUTR #24 PULV DAMPERS-STROKE	2	MO	PM	OUT
	PULVERIZER (COAL)	5120000		4062933205	U2 ICE OUTR #25 PULV DAMPERS-STROKE	2	MO	PM	OUT
	PULVERIZER (COAL)	5120000		4062933206	U2 ICE OUTR #26 PULV DAMPERS-STROKE	2	MO	PM	OUT
	PULVERIZER (COAL)	5120000		4062977401	U2 ICE OUTR #21 PULV - CALIBRATE LUBE OIL INSTRUMENTS	2	MO	PM	OUT
	PULVERIZER (COAL)	5120000		4062977402	U2 ICE OUTR #22 PULV - CALIBRATE LUBE OIL INSTRUMENTS	2	MO	PM	OUT
	PULVERIZER (COAL)	5120000		4062977403	U2 ICE OUTR #23 PULV - CALIBRATE LUBE OIL INSTRUMENTS	2	MO	PM	OUT
	PULVERIZER (COAL)	5120000		4062977404	U2 ICE OUTR #24 PULV - CALIBRATE LUBE OIL INSTRUMENTS	2	MO	PM	OUT
	PULVERIZER (COAL)	5120000		4062977405	U2 ICE OUTR #25 PULV - CALIBRATE LUBE OIL INSTRUMENTS	2	MO	PM	OUT
	PULVERIZER (COAL)	5120000		4062977406	U2 ICE OUTR #26 PULV - CALIBRATE LUBE OIL INSTRUMENTS	2	MO	PM	OUT
	PULVERIZER (COAL)	5120000		4084108201	ICE U1 OUTR #11 PULV - STROKE DAMPERS	1	MO	PM	OUT
	PULVERIZER (COAL)	5120000		4084108202	ICE U1 OUTR #12 PULV - STROKE DAMPERS	1	MO	PM	OUT
	PULVERIZER (COAL)	5120000		4084108203	ICE U1 OUTR #13 PULV - STROKE DAMPERS	1	MO	PM	OUT
	PULVERIZER (COAL)	5120000		4084108204	ICE U1 OUTR #14 PULV - STROKE DAMPERS	1	MO	PM	OUT
	PULVERIZER (COAL)	5120000		4084108205	ICE U1 OUTR #15 PULV - STROKE DAMPERS	1	MO	PM	OUT
	PULVERIZER (COAL)	5120000		4084108206	ICE U1 OUTR #16 PULV - STROKE DAMPERS	1	MO	PM	OUT
	PULVERIZER (COAL)	5120000		4084339201	ICE U1 OUTR #13 PULV - STROKE DAMPERS	1	MO	PM	OUT
	PULVERIZER (COAL)	5120000		4084341601	ICE U1 OUTR #14 PULV - STROKE DAMPERS	1	MO	PM	OUT
	PULVERIZER (COAL)	5120000		4084342801	ICE U1 OUTR #15 PULV - STROKE DAMPERS	1	MO	PM	OUT
	PULVERIZER (COAL)	5120000		4084343601	ICE U1 OUTR #16 PULV - STROKE DAMPERS	1	MO	PM	OUT
250									
260	BURNER/IGNITORS	5120000		0093620201	OUTR MECH INSPECTION OIL LIGHTERS/GUNS	1	MO	PM	1YR
	BURNER/IGNITORS	5120000		0094370301	U2 ICE OUTR-OIL LIGHTER INSPECTION	2	MO	PM	OUT
	BURNER/IGNITORS	5120000		0095112501	PLT MECH OIL LIGHTERS (ALL) U2 - INSPECTION.	2	MO	PM	WKL
	BURNER/IGNITORS	5120000		4064116701	ICE U1 OUTR BURNER OIL LIGHTER VALVES	1	MO	PM	OUT
	BURNER/IGNITORS	5120000		4064127301	U1 ICE OUTR OIL LIGHTER INSPECTION	1	MO	PM	OUT
	BURNER/IGNITORS	5120000		4064128401	ICE U1 OUTR OIL LIGHTER OIL PRESSURE TRANSMITTERS	1	MO	PM	OUT
	BURNER/IGNITORS	5120000		4064130601	ICE U1 OUTR BURNER SHROUD DRIVE INSPECTION	1	MO	PM	OUT
	BURNER/IGNITORS	5120000		4064184701	ICE OUTR 21 PULV - STROKE BURNER SHUTOFF VALVES	2	MO	PM	OUT
	BURNER/IGNITORS	5120000		4064184702	ICE OUTR 22 PULV - STROKE BURNER SHUTOFF VALVES	2	MO	PM	OUT
	BURNER/IGNITORS	5120000		4064184703	ICE OUTR 23 PULV - STROKE BURNER SHUTOFF VALVES	2	MO	PM	OUT
	BURNER/IGNITORS	5120000		4064184704	ICE OUTR 24 PULV - STROKE BURNER SHUTOFF VALVES	2	MO	PM	OUT
	BURNER/IGNITORS	5120000		4064184705	ICE OUTR 25 PULV - STROKE BURNER SHUTOFF VALVES	2	MO	PM	OUT
	BURNER/IGNITORS	5120000		4064184706	ICE OUTR 26 PULV - STROKE BURNER SHUTOFF VALVES	2	MO	PM	OUT
	BURNER/IGNITORS	5120000		4064222901	ICE - #21 OIL LIGHTER FUEL/AIR REGULATING VALVE - OUTAGER	2	MO	PM	OUT
	BURNER/IGNITORS	5120000		4064222902	ICE - #22 OIL LIGHTER FUEL/AIR REGULATING VALVE - OUTAGER	2	MO	PM	OUT
	BURNER/IGNITORS	5120000		4064222903	ICE - #23 OIL LIGHTER FUEL/AIR REGULATING VALVE - OUTAGER	2	MO	PM	OUT
	BURNER/IGNITORS	5120000		4064222904	ICE - #24 OIL LIGHTER FUEL/AIR REGULATING VALVE - OUTAGER	2	MO	PM	OUT
	BURNER/IGNITORS	5120000		4064222905	ICE - #25 OIL LIGHTER FUEL/AIR REGULATING VALVE - OUTAGER	2	MO	PM	OUT
	BURNER/IGNITORS	5120000		4064222906	ICE - #26 OIL LIGHTER FUEL/AIR REGULATING VALVE - OUTAGER	2	MO	PM	OUT
	BURNER/IGNITORS	5120000		4099615101	BS/SUPV #21 A,B,C,D,E,F BURNERS; INSP& REPAIR	2	MO	PM	50Y
	BURNER/IGNITORS	5120000		4099615102	MCON PIPE - #21A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	BURNER/IGNITORS	5120000		4099615103	BS/ICE #21 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	BURNER/IGNITORS	5120000		4099615104	RJEINTES REFRACT-#21 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	BURNER/IGNITORS	5120000		4099615105	NAIS VACUUM #21 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	BURNER/IGNITORS	5120000		4099615601	BS/SUPV #22 A,B,C,D,E,F BURNERS; INSP& REPAIR	2	MO	PM	50Y
	BURNER/IGNITORS	5120000		4099615602	MCON PIPE - #22A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	BURNER/IGNITORS	5120000		4099615603	BS/ICE #22 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	BURNER/IGNITORS	5120000		4099615604	RJEINTES REFRACT-#22 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y

Models in Authorized Status With Auto Trigger Ind

2/18/2010

WOT System Cd	WOT System Code Description	Account Nbr	WOT Unit Cond Reqd	WOT WO Nbr Task	WOT WR Task Title	WOT Unit	WO Type	WOT Job Type	Pm Frequency Code
	BURNER/IGNITORS	5120000		4099615605	NAIS VACUUM #22 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	BURNER/IGNITORS	5120000		4099617001	BS/SUPV #23 A,B,C,D,E,F BURNERS; INSP& REPAIR	2	MO	PM	50Y
	BURNER/IGNITORS	5120000		4099617002	MCON PIPE - #23A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	BURNER/IGNITORS	5120000		4099617003	BS/ICE #23 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	BURNER/IGNITORS	5120000		4099617004	RJEINTES REFRACT-#23 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	BURNER/IGNITORS	5120000		4099617005	NAIS VACUUM #23 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	BURNER/IGNITORS	5120000		4099618201	BS/SUPV #26 A,B,C,D,E,F BURNERS; INSP& REPAIR	2	MO	PM	50Y
	BURNER/IGNITORS	5120000		4099618202	MCON PIPE - #26A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	BURNER/IGNITORS	5120000		4099618203	BS/ICE #26 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	BURNER/IGNITORS	5120000		4099618204	RJEINTES REFRACT-#26 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	BURNER/IGNITORS	5120000		4099618205	NAIS VACUUM #26 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	BURNER/IGNITORS	5120000		4099619001	BS/SUPV #25 A,B,C,D,E,F BURNERS; INSP& REPAIR	2	MO	PM	50Y
	BURNER/IGNITORS	5120000		4099619002	MCON PIPE - #25A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	BURNER/IGNITORS	5120000		4099619003	BS/ICE #25 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	BURNER/IGNITORS	5120000		4099619004	RJEINTES REFRACT-#25 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	BURNER/IGNITORS	5120000		4099619005	NAIS VACUUM #25 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	BURNER/IGNITORS	5120000		4099619401	BS/SUPV #24 A,B,C,D,E,F BURNERS; INSP& REPAIR	2	MO	PM	50Y
	BURNER/IGNITORS	5120000		4099619402	MCON PIPE - #24A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	BURNER/IGNITORS	5120000		4099619403	BS/ICE #24 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	BURNER/IGNITORS	5120000		4099619404	RJEINTES REFRACT-#24 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	BURNER/IGNITORS	5120000		4099619405	NAIS VACUUM #24 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	MAIN BURNER/IGNITORS	5120000		0093620201	OUTR MECH INSPECTION OIL LIGHTERS/GUNS	1	MO	PM	1YR
	MAIN BURNER/IGNITORS	5120000		0094370301	U2 ICE OUTR-OIL LIGHTER INSPECTION	2	MO	PM	OUT
	MAIN BURNER/IGNITORS	5120000		0095112501	PLT MECH OIL LIGHTERS (ALL) U2 - INSPECTION.	2	MO	PM	WKL
	MAIN BURNER/IGNITORS	5120000		4064116701	ICE U1 OUTR BURNER OIL LIGHTER VALVES	1	MO	PM	OUT
	MAIN BURNER/IGNITORS	5120000		4064127301	U1 ICE OUTR OIL LIGHTER INSPECTION	1	MO	PM	OUT
	MAIN BURNER/IGNITORS	5120000		4064128401	ICE U1 OUTR OIL LIGHTER OIL PRESSURE TRANSMITTERS	1	MO	PM	OUT
	MAIN BURNER/IGNITORS	5120000		4064130601	ICE U1 OUTR BURNER SHROUD DRIVE INSPECTION	1	MO	PM	OUT
	MAIN BURNER/IGNITORS	5120000		4064184701	ICE OUTR 21 PULV - STROKE BURNER SHUTOFF VALVES	2	MO	PM	OUT
	MAIN BURNER/IGNITORS	5120000		4064184702	ICE OUTR 22 PULV - STROKE BURNER SHUTOFF VALVES	2	MO	PM	OUT
	MAIN BURNER/IGNITORS	5120000		4064184703	ICE OUTR 23 PULV - STROKE BURNER SHUTOFF VALVES	2	MO	PM	OUT
	MAIN BURNER/IGNITORS	5120000		4064184704	ICE OUTR 24 PULV - STROKE BURNER SHUTOFF VALVES	2	MO	PM	OUT
	MAIN BURNER/IGNITORS	5120000		4064184705	ICE OUTR 25 PULV - STROKE BURNER SHUTOFF VALVES	2	MO	PM	OUT
	MAIN BURNER/IGNITORS	5120000		4064184706	ICE OUTR 26 PULV - STROKE BURNER SHUTOFF VALVES	2	MO	PM	OUT
	MAIN BURNER/IGNITORS	5120000		4064222901	ICE - #21 OIL LIGHTER FUEL/AIR REGULATING VALVE - OUTAGER	2	MO	PM	OUT
	MAIN BURNER/IGNITORS	5120000		4064222902	ICE - #22 OIL LIGHTER FUEL/AIR REGULATING VALVE - OUTAGER	2	MO	PM	OUT
	MAIN BURNER/IGNITORS	5120000		4064222903	ICE - #23 OIL LIGHTER FUEL/AIR REGULATING VALVE - OUTAGER	2	MO	PM	OUT
	MAIN BURNER/IGNITORS	5120000		4064222904	ICE - #24 OIL LIGHTER FUEL/AIR REGULATING VALVE - OUTAGER	2	MO	PM	OUT
	MAIN BURNER/IGNITORS	5120000		4064222905	ICE - #25 OIL LIGHTER FUEL/AIR REGULATING VALVE - OUTAGER	2	MO	PM	OUT
	MAIN BURNER/IGNITORS	5120000		4064222906	ICE - #26 OIL LIGHTER FUEL/AIR REGULATING VALVE - OUTAGER	2	MO	PM	OUT
	MAIN BURNER/IGNITORS	5120000		4099615101	BS/SUPV #21 A,B,C,D,E,F BURNERS; INSP& REPAIR	2	MO	PM	50Y
	MAIN BURNER/IGNITORS	5120000		4099615102	MCON PIPE - #21A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	MAIN BURNER/IGNITORS	5120000		4099615103	BS/ICE #21 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	MAIN BURNER/IGNITORS	5120000		4099615104	RJEINTES REFRACT-#21 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	MAIN BURNER/IGNITORS	5120000		4099615105	NAIS VACUUM #21 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	MAIN BURNER/IGNITORS	5120000		4099615601	BS/SUPV #22 A,B,C,D,E,F BURNERS; INSP& REPAIR	2	MO	PM	50Y
	MAIN BURNER/IGNITORS	5120000		4099615602	MCON PIPE - #22A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	MAIN BURNER/IGNITORS	5120000		4099615603	BS/ICE #22 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	MAIN BURNER/IGNITORS	5120000		4099615604	RJEINTES REFRACT-#22 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	MAIN BURNER/IGNITORS	5120000		4099615605	NAIS VACUUM #22 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	MAIN BURNER/IGNITORS	5120000		4099617001	BS/SUPV #23 A,B,C,D,E,F BURNERS; INSP& REPAIR	2	MO	PM	50Y
	MAIN BURNER/IGNITORS	5120000		4099617002	MCON PIPE - #23A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	MAIN BURNER/IGNITORS	5120000		4099617003	BS/ICE #23 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	MAIN BURNER/IGNITORS	5120000		4099617004	RJEINTES REFRACT-#23 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	MAIN BURNER/IGNITORS	5120000		4099617005	NAIS VACUUM #23 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	MAIN BURNER/IGNITORS	5120000		4099618201	BS/SUPV #26 A,B,C,D,E,F BURNERS; INSP& REPAIR	2	MO	PM	50Y
	MAIN BURNER/IGNITORS	5120000		4099618202	MCON PIPE - #26A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	MAIN BURNER/IGNITORS	5120000		4099618203	BS/ICE #26 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	MAIN BURNER/IGNITORS	5120000		4099618204	RJEINTES REFRACT-#26 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	MAIN BURNER/IGNITORS	5120000		4099618205	NAIS VACUUM #26 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	MAIN BURNER/IGNITORS	5120000		4099619001	BS/SUPV #25 A,B,C,D,E,F BURNERS; INSP& REPAIR	2	MO	PM	50Y
	MAIN BURNER/IGNITORS	5120000		4099619002	MCON PIPE - #25A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	MAIN BURNER/IGNITORS	5120000		4099619003	BS/ICE #25 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	MAIN BURNER/IGNITORS	5120000		4099619004	RJEINTES REFRACT-#25 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	MAIN BURNER/IGNITORS	5120000		4099619005	NAIS VACUUM #25 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	MAIN BURNER/IGNITORS	5120000		4099619401	BS/SUPV #24 A,B,C,D,E,F BURNERS; INSP& REPAIR	2	MO	PM	50Y
	MAIN BURNER/IGNITORS	5120000		4099619402	MCON PIPE - #24A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	MAIN BURNER/IGNITORS	5120000		4099619403	BS/ICE #24 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	MAIN BURNER/IGNITORS	5120000		4099619404	RJEINTES REFRACT-#24 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
	MAIN BURNER/IGNITORS	5120000		4099619405	NAIS VACUUM #24 A,B,C,D,E,F BURNERS; INSP & REPAIR	2	MO	PM	50Y
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WOT System Cd	WOT System Code Description	Account Nbr	WOT Unit Cond Reqd	WOT WO Nbr Task	WOT WR Task Title	WOT Unit	WO Type	WOT Job Type	Pm Frequency Code
310	BOILER, GENERAL	5110000		4007480901	PLT SUPV - BOILER ROOM HOUSEKEEPING	2	MO	PM	50Y
	BOILER, GENERAL	5120000		0094211601	U1 ICE OUTR MO-29 & MO-30 STROKE/SET LIMITS	1	MO	PM	OUT
	BOILER, GENERAL	5120000		0094694201	U1 ICE OUTR VCC 250V DC INSP	1	MO	PM	OUT
	BOILER, GENERAL	5120000		0095085201	U2 ICE OUTR VCC 2-TB-V, 2-HU-V, 2-BU-V, 2-BM-V INSP	2	MO	PM	OUT
	BOILER, GENERAL	5120000		4007480902	VAC - BOILER ROOM HOUSEKEEPING	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4071796401	ICE U2 OUTR PROPORTION DAMPERS STROKE	2	MO	PM	OUT
	BOILER, GENERAL	5120000		4072545501	ICE U2 OUTR STROKE FLASH TANK VALVES	2	MO	PM	OUT
	BOILER, GENERAL	5120000		4097440901	PLANT PERSONNEL/1ST REHEAT PROPORTIONING DAMPERS -	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4097440902	NAIS 1ST REHEAT PROPORTIONING DAMPERS - INSPECT AND REPACK	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4097440903	YOUNGS/ 1ST REHEAT PROPORTIONING DAMPERS-INSPECT AND REPACK	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4097440904	MMI/ 1ST REHEAT PROPORTIONING DAMPERS-INSPECT AND REPACK	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4097440905	MCON/ 1ST REHEAT PROPORTIONING DAMPERS-INSPECT AND REPACK	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4097440906	SUPV/ 1ST REHEAT PROPORTIONING DAMPERS-INSPECT AND REPACK	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4097442301	PLANT PERAONAL /2ND REHEAT PROPORTIONING DAMPERS	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4097442302	NAIS/2ND REHEAT PROPORTIONING DAMPERS - INSPECT AND REPACK	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4097442303	YOUNGS/2ND REHEAT PROPORTIONING DAMPERS - INSPECT AND REPACK	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4097442304	MMI/2ND REHEAT PROPORTIONING DAMPERS - INSPECT AND REPACK	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4097442305	MCON/2ND REHEAT PROPORTIONING DAMPERS - INSPECT AND REPACK	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4097442306	SUPV/2ND REHEAT PROPORTIONING DAMPERS - INSPECT AND REPACK	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4098249301	PLTSUPV / PENTHOUSE SEALS & CASING - I/R	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4098249302	INSL - PENTHOUSE SEALS & CASING - I/R	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4098249303	MCON SCAF - PENTHOUSE SEALS & CASING - I/R	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4098249304	MCON BOIL - PENTHOUSE SEALS & CASING - I/R	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4098249501	PLT SUPV - BOILER CASING; REPAIR AS NEEDED.	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4098249502	INSL - PLANNED OUTAGE BOILER CASING REPAIRS	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4098249503	MCON BOIL - PLANNED OUTAGE BOILER CASING REPAIRS	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4098249504	MCON SCAF - PLANNED OUTAGE BOILER CASING REPAIRS	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4098249505	NAIS / PLANNED OUTAGE BOILER CASING REPAIRS	2	MO	GM	50Y
	BOILER, GENERAL	5120000		4098249506	PLANT PERSONAL / PLANNED OUTAGE BOILER CASING REPAIRS	2	MO	GM	50Y
	BOILER, GENERAL	5120000		4098249601	BS/SUPV REPLACE 10 PROPORTIONING DAMPER SHAFTS	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4098249602	YGS SCAFFOLD REPLACE 10 PROPORTIONING DAMPER SHAFTS	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4098249603	MMI INSUL REMOVAL/REPLACE 10 PROPORTIONING DAMPER SHAFTS	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4098249604	MCON/REPLACE 10 PROPORTIONING DAMPER SHAFTS	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4098249605	NAIS VACUUM REPLACE 10 PROPORTIONING DAMPER SHAFTS	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4098249701	BS/SUPV REPLACE 10 PROPORTIONING DAMPER SHAFTS	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4098249702	YGS SCAFFOLD REPLACE 10 PROPORTIONING DAMPER SHAFTS	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4098249703	MMI INSUL REMOVAL/REPLACE 10 PROPORTIONING DAMPER SHAFTS	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4098249704	MCON/REPLACE 10 PROPORTIONING DAMPER SHAFTS	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4098249705	NAIS VACUUM REPLACE 10 PROPORTIONING DAMPER SHAFTST	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4098290401	BS/SUPV SUPPORT ECON.; INSPECT AND REPAIR.	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4098290402	NAIS DESLAG ECON.; PRESSURE WASH	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4098290403	MCON BOIL - ECON.; INSPECT AND REPAIR.	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4098290404	MCON CARP - ECON.; INSPECT AND REPAIR.	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4098290405	REO/ENG ECON; INSPECT AND REPAIR.	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4098290406	YGS SCAFFOLD ECON; INSPECT AND REPAIR.	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4098290407	UDC INSPECT 3YR. ECON.; INSPECT AND REPAIR.	2	MO	IS	50Y
	BOILER, GENERAL	5120000		4098527701	PLANT SUV.WATERWALL TUBES; INSPECT AND TAKE SAMPLES.	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4098527702	WATER BLASTER DESLAG/ BOILER WATERWALL TUBES	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4098527703	SCAFFOLDERS/ WATERWALL TUBES;	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4098527704	SAND BLASTERS /WATERWALL TUBES; FOR INSPECTION AND REPAIR	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4098527705	REO/ WATERWALL TUBES; DESLAG, SCAFFOLD, INSPECT	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4098527706	NDE/ WATERWALL TUBES; INSPECT	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4098527707	BOILERMAKERS/ WATERWALL TUBES, PAD WELD. &TAKE SAMPLES.	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4098527708	UDC 3 YR. INSPECT-WATERWALL TUBES INSPECT AND TAKE SAMPLES.	2	MO	IS	50Y
	BOILER, GENERAL	5120000		4099525901	BS/SUPV BMO-1 BOILER DIVISION VV; OPEN, INSPECT .	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099525902	SOUTHEAST BMO-1 BOILER DIVISION VV; OPEN, INSPECT	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099525903	CMS BMO-1 BOILER DIVISION VALVE; NDE	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099525904	BS/ICE BMO-1 BOILER DIVISION VALVE; OPEN, INSPECT	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099525905	BS/MECH BMO-1 BOILER DIVISION VALVE; OPEN, INSPECT	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099526201	BS/SUPV BMO-2 BOILER DIVISION VALVE; OPEN, INSP/REP	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099526202	SOUTHEAST BMO-2 BOILER DIVISION VALVE; OPEN, INSPECT .	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099526203	CMS BMO-2 BOILER DIVISION VALVE; NDE	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099526204	BS/ICE BMO-2 BOILER DIVISION VALVE; OPEN, INSPECT	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099526205	BS/MECH BMO-2 BOILER DIVISION VALVE; OPEN, INSPECT	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099527101	BS/SUPV BMO-3 BOILER DIVISION VV; OPEN, INSPECT	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099527102	SOUTHEAST BMO3 BOILER DIVISION VV; OPEN, INSPECT AND REBUILD	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099527103	CMS BMO-3 BOILER DIVISION VV; NDE	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099527104	BS/ICE BMO-3 BOILER DIVISION VALVE; OPEN, INSPECT	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099527105	BS/MECH BMO-3 BOILER DIVISION VALVE; OPEN, INSPECT	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099527601	BS/SUPV BMO-4 BOILER DIVISION VV; OPEN, INSPECT	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099527602	SOUTHEAST BMO4 BOILER DIVISION VV; OPEN, INSPECT AND REBUILD	2	MO	PM	50Y

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WOT System Cd	WOT System Code Description	Account Nbr	WOT Unit Cond Reqd	WOT WO Nbr Task	WOT WR Task Title	WOT Unit	WO Type	WOT Job Type	Pm Frequency Code
	BOILER, GENERAL	5120000		4099527603	CMS NDE BMO-4 BOILER DIVISION VALVE; NDE	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099527604	BS/ICE BMO-4 BOILER DIVISION VALVE; OPEN, INSPECT	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099527605	BS/MECH BMO-4 BOILER DIVISION VALVE; OPEN, INSPECT	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099593201	BS/SUPV INSPECT FLASH TANK INTERNALS	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099593202	BS/WELD MAINT INSPECT FLASH TANK INTERNALS	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099593203	ENERFAB INSPECT FLASH TANK INTERNALS	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099598101	BS/SUPV SCISSORS; I&R CASING, MEMBRANE, SEALS & HANGERS	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099598102	MCON BOIL - SCISSORS; I & R, CASING, MEMBRANE , & HANGERS	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099598103	MMI INSUL SCISSORS; I & R, CASING, MEMBRANE CRACKS & HANGERS	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099598104	YGS SCAFFOLD SCISSORS; I & R, CASING, CRACKS, & HANGERS	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099598105	NAIS VACUUM SCISSORS; I & R, CASING, MEMBRANE	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099598106	UDC INSPECT - SCISSORS CASING, MEMBRANE CRACKS, & HANGERS	2	MO	IS	50Y
	BOILER, GENERAL	5120000		4099601401	BS/SUPV APER. FL. & SCREEN ROWS; INSPECT AND REPAIR	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099601402	HTT NDE/APER. FL. & SCREEN ROWS; INSPECT AND REPAI	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099601403	MCON/APER. FL. & SCREEN ROWS; , INSPECT AND REPAIR	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099601404	UDC 3YR INSPECTION APER. FL. & SCREEN ROWS INSPECT	2	MO	IS	50Y
	BOILER, GENERAL	5120000		4099601901	BS/SUPV INSPECT AND REPAIR THE HRA SIDE WALL AND REAR	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099601902	MCON BOILER/ INSPECT AND REPAIR THE HRA SIDE WALL AND REAR	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099601903	YGS SCAFFOLD INSPECT AND REPAIR THE HRA SIDE WALL AND REAR	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099601904	REO/ INSPECT AND REPAIR THE HRA SIDE WALL AND REAR	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4099601905	UDC INSPECT THE HRA SIDE WALL AND REAR	2	MO	IS	50Y
	BOILER, GENERAL	5120000		4100272001	PLANT SUPERVISOR/WATERWALLS - DESLAG, INSPECT,	1	MO	PM	50Y
	BOILER, GENERAL	5120000		4100272002	NAIS WATER BLASTER/WATERWALLS - DESLAG, INSPECT,	1	MO	PM	50Y
	BOILER, GENERAL	5120000		4100272003	YOUNG SCAFFOLDING/WATERWALLS - DESLAG, INSPECT	1	MO	PM	50Y
	BOILER, GENERAL	5120000		4100272004	ADKINS SANDBLASTER/WATERWALLS - DESLAG, INSPECT	1	MO	PM	50Y
	BOILER, GENERAL	5120000		4100272005	REO/WATERWALLS - DESLAG, INSPECT .	1	MO	PM	50Y
	BOILER, GENERAL	5120000		4100272006	NDE/WATERWALLS - DESLAG, INSPECT, REPAIR & PADWELD.	1	MO	PM	50Y
	BOILER, GENERAL	5120000		4100272007	BOILERMAKERS/WATERWALLS - DESLAG, INSPECT, .	1	MO	PM	50Y
	BOILER, GENERAL	5120000		4100367601	PANT SUPERV/ECONOMIZER - DESLAG, INSPECT, REPAIR & PADWELD.	1	MO	PM	50Y
	BOILER, GENERAL	5120000		4100367602	NAIS/ECONOMIZER - DESLAG, INSPECT, REPAIR & PADWELD.	1	MO	PM	50Y
	BOILER, GENERAL	5120000		4100367603	YOUNG SCAFFOLDING/ECONOMIZER - DESLAG, INSPECT,	1	MO	PM	50Y
	BOILER, GENERAL	5120000		4100367604	REO/ECONOMIZER - DESLAG, INSPECT,	1	MO	PM	50Y
	BOILER, GENERAL	5120000		4100367605	HT NDE/ECONOMIZER - DESLAG, INSPECT,	1	MO	PM	50Y
	BOILER, GENERAL	5120000		4100367606	BOILER MAKERS/ECONOMIZER - REPAIR & PADWELD.	1	MO	PM	50Y
	BOILER, GENERAL	5120000		4100367607	UDC INSPECTION 3 YR. ECONOMIZER - DESLAG, INSPECT	1	MO	IS	50Y
	BOILER, GENERAL	5120000		4101021101	BS/SUPV DRV-450; OPEN, INSPECT AND REPAIR.	2	MO	PM	50Y
	BOILER, GENERAL	5120000		4101040301	PLT SUPV/INSPECT- REPAIR PENTHOUSE CASING-PENETRATION SEALS	1	MO	PM	50Y
	BOILER, GENERAL	5120000		4101040302	REO/INSPECT - REPAIR PENTHOUSE CASING- PENETRATION SEALS	1	MO	PM	50Y
	BOILER, GENERAL	5120000		4101040303	NAIS/INSPECT/REPAIR PENTHOUSE CASING / PENETRATION SEALS	1	MO	PM	50Y
	BOILER, GENERAL	5120000		4101040304	SCAFFOLD/INSPECT/REPAIR PENTHOUSE CASING / PENETRATION SEALS	1	MO	PM	50Y
	BOILER, GENERAL	5120000		4101040305	MMI/INSPECT / REPAIR PENTHOUSE CASING/ PENETRATION SEALS	1	MO	PM	50Y
	BOILER, GENERAL	5120000		4101040306	BOILER MAKERS/ REPAIR PENTHOUSE CASING / PENETRATION SEALS	1	MO	PM	50Y
	BOILER, GENERAL	5120000		4103042201	BS/SUPV FINISH, SUPERHEATER; DESLAG, SCAFFOLD, INS/REP	2	MO	PM	50Y
	BOILER, GENERAL..	5110000		4007480901	PLT SUPV - BOILER ROOM HOUSEKEEPING	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		0094211601	U1 ICE OUTR MO-29 & MO-30 STROKE/SET LIMITS	1	MO	PM	OUT
	BOILER, GENERAL..	5120000		0094694201	U1 ICE OUTR VCC 250V DC INSP	1	MO	PM	OUT
	BOILER, GENERAL..	5120000		0095085201	U2 ICE OUTR VCC 2-TB-V, 2-HU-V, 2-BU-V, 2-BM-V INSP	2	MO	PM	OUT
	BOILER, GENERAL..	5120000		4007480902	VAC - BOILER ROOM HOUSEKEEPING	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4071796401	ICE U2 OUTR PROPORTION DAMPERS STROKE	2	MO	PM	OUT
	BOILER, GENERAL..	5120000		4072545501	ICE U2 OUTR STROKE FLASH TANK VALVES	2	MO	PM	OUT
	BOILER, GENERAL..	5120000		4097440901	PLANT PERSONNEL/1ST REHEAT PROPORTIONING DAMPERS -	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4097440902	NAIS 1ST REHEAT PROPORTIONING DAMPERS - INSPECT AND REPACK	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4097440903	YOUNGS/ 1ST REHEAT PROPORTIONING DAMPERS-INSPECT AND REPACK	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4097440904	MMI/ 1ST REHEAT PROPORTIONING DAMPERS-INSPECT AND REPACK	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4097440905	MCON/ 1ST REHEAT PROPORTIONING DAMPERS-INSPECT AND REPACK	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4097440906	SUPV/ 1ST REHEAT PROPORTIONING DAMPERS-INSPECT AND REPACK	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4097442301	PLANT PERAONAL /2ND REHEAT PROPORTIONING DAMPERS	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4097442302	NAIS/2ND REHEAT PROPORTIONING DAMPERS - INSPECT AND REPACK	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4097442303	YOUNGS/2ND REHEAT PROPORTIONING DAMPERS - INSPECT AND REPACK	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4097442304	MMI/2ND REHEAT PROPORTIONING DAMPERS - INSPECT AND REPACK	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4097442305	MCON/2ND REHEAT PROPORTIONING DAMPERS - INSPECT AND REPACK	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4097442306	SUPV/2ND REHEAT PROPORTIONING DAMPERS - INSPECT AND REPACK	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4098249301	PLTSUPV / PENTHOUSE SEALS & CASING - I/R	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4098249302	INSL - PENTHOUSE SEALS & CASING - I/R	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4098249303	MCON SCAF - PENTHOUSE SEALS & CASING - I/R	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4098249304	MCON BOIL - PENTHOUSE SEALS & CASING - I/R	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4098249501	PLT SUPV - BOILER CASING; REPAIR AS NEEDED.	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4098249502	INSL - PLANNED OUTAGE BOILER CASING REPAIRS	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4098249503	MCON BOIL - PLANNED OUTAGE BOILER CASING REPAIRS	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4098249504	MCON SCAF - PLANNED OUTAGE BOILER CASING REPAIRS	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4098249505	NAIS / PLANNED OUTAGE BOILER CASING REPAIRS	2	MO	GM	50Y

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WOT System Cd	WOT System Code Description	Account Nbr	WOT Unit Cond Reqd	WOT WO Nbr Task	WOT WR Task Title	WOT Unit	WO Type	WOT Job Type	Pm Frequency Code
	BOILER, GENERAL..	5120000		4098249506	PLANT PERSONAL / PLANNED OUTAGE BOILER CASING REPAIRS	2	MO	GM	50Y
	BOILER, GENERAL..	5120000		4098249601	BS/SUPV REPLACE 10 PROPORTIONING DAMPER SHAFTS	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4098249602	YGS SCAFFOLD REPLACE 10 PROPORTIONING DAMPER SHAFTS	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4098249603	MMI INSUL REMOVAL/REPLACE 10 PROPORTIONING DAMPER SHAFTS	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4098249604	MCON/REPLACE 10 PROPORTIONING DAMPER SHAFTS	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4098249605	NAIS VACUUM REPLACE 10 PROPORTIONING DAMPER SHAFTS	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4098249701	BS/SUPV REPLACE 10 PROPORTIONING DAMPER SHAFTS	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4098249702	YGS SCAFFOLD REPLACE 10 PROPORTIONING DAMPER SHAFTS	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4098249703	MMI INSUL REMOVAL/REPLACE 10 PROPORTIONING DAMPER SHAFTS	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4098249704	MCON/REPLACE 10 PROPORTIONING DAMPER SHAFTS	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4098249705	NAIS VACUUM REPLACE 10 PROPORTIONING DAMPER SHAFTST	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4098290401	BS/SUPV SUPPORT ECON.; INSPECT AND REPAIR.	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4098290402	NAIS DESLAG ECON.; PRESSURE WASH	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4098290403	MCON BOIL - ECON.; INSPECT AND REPAIR.	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4098290404	MCON CARP - ECON.; INSPECT AND REPAIR.	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4098290405	REO/ENG ECON; INSPECT AND REPAIR.	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4098290406	YGS SCAFFOLD ECON; INSPECT AND REPAIR.	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4098290407	UDC INSPECT 3YR. ECON.; INSPECT AND REPAIR.	2	MO	IS	50Y
	BOILER, GENERAL..	5120000		4098527701	PLANT SUV.WATERWALL TUBES; INSPECT AND TAKE SAMPLES.	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4098527702	WATER BLASTER DESLAG/ BOILER WATERWALL TUBES	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4098527703	SCAFFOLDERS/ WATERWALL TUBES;	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4098527704	SAND BLASTERS /WATERWALL TUBES; FOR INSPECTION AND REPAIR	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4098527705	REO/ WATERWALL TUBES; DESLAG, SCAFFOLD, INSPECT	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4098527706	NDE/ WATERWALL TUBES; INSPECT	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4098527707	BOILERMAKERS/ WATERWALL TUBES, PAD WELD. &TAKE SAMPLES.	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4098527708	UDC 3 YR. INSPECT-WATERWALL TUBES INSPECT AND TAKE SAMPLES.	2	MO	IS	50Y
	BOILER, GENERAL..	5120000		4099525901	BS/SUPV BMO-1 BOILER DIVISION VV; OPEN, INSPECT .	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099525902	SOUTHEAST BMO-1 BOILER DIVISION VV; OPEN, INSPECT	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099525903	CMS BMO-1 BOILER DIVISION VALVE; NDE	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099525904	BS/ICE BMO-1 BOILER DIVISION VALVE; OPEN, INSPECT	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099525905	BS/MECH BMO-1 BOILER DIVISION VALVE; OPEN, INSPECT	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099526201	BS/SUPV BMO-2 BOILER DIVISION VALVE; OPEN, INSP/REP	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099526202	SOUTHEAST BMO-2 BOILER DIVISION VALVE; OPEN, INSPECT .	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099526203	CMS BMO-2 BOILER DIVISION VALVE; NDE	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099526204	BS/ICE BMO-2 BOILER DIVISION VALVE; OPEN, INSPECT	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099526205	BS/MECH BMO-2 BOILER DIVISION VALVE; OPEN, INSPECT	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099527101	BS/SUPV BMO-3 BOILER DIVISION VV; OPEN, INSPECT	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099527102	SOUTHEAST BMO3 BOILER DIVISION VV; OPEN, INSPECT AND REBUILD	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099527103	CMS BMO-3 BOILER DIVISION VV; NDE	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099527104	BS/ICE BMO-3 BOILER DIVISION VALVE; OPEN, INSPECT	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099527105	BS/MECH BMO-3 BOILER DIVISION VALVE; OPEN, INSPECT	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099527601	BS/SUPV BMO-4 BOILER DIVISION VV; OPEN, INSPECT	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099527602	SOUTHEAST BMO4 BOILER DIVISION VV; OPEN, INSPECT AND REBUILD	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099527603	CMS NDE BMO-4 BOILER DIVISION VALVE; NDE	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099527604	BS/ICE BMO-4 BOILER DIVISION VALVE; OPEN, INSPECT	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099527605	BS/MECH BMO-4 BOILER DIVISION VALVE; OPEN, INSPECT	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099593201	BS/SUPV INSPECT FLASH TANK INTERNALS	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099593202	BS/WELD MAINT INSPECT FLASH TANK INTERNALS	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099593203	ENERFAB INSPECT FLASH TANK INTERNALS	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099598101	BS/SUPV SCISSORS; I&R CASING, MEMBRANE, SEALS & HANGERS	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099598102	MCON BOIL - SCISSORS; I & R, CASING, MEMBRANE , & HANGERS	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099598103	MMI INSUL SCISSORS; I & R, CASING, MEMBRANE CRACKS & HANGERS	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099598104	YGS SCAFFOLD SCISSORS; I & R, CASING, CRACKS, & HANGERS	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099598105	NAIS VACUUM SCISSORS; I & R, CASING, MEMBRANE	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099598106	UDC INSPECT - SCISSORS CASING, MEMBRANE CRACKS, & HANGERS	2	MO	IS	50Y
	BOILER, GENERAL..	5120000		4099601401	BS/SUPV APER. FL. & SCREEN ROWS; INSPECT AND REPAIR	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099601402	HTT NDE/APER. FL. & SCREEN ROWS; INSPECT AND REPAI	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099601403	MCON/APER. FL. & SCREEN ROWS; , INSPECT AND REPAIR	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099601404	UDC 3YR INSPECTION APER. FL. & SCREEN ROWS INSPECT	2	MO	IS	50Y
	BOILER, GENERAL..	5120000		4099601901	BS/SUPV INSPECT AND REPAIR THE HRA SIDE WALL AND REAR	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099601902	MCON BOILER/ INSPECT AND REPAIR THE HRA SIDE WALL AND REAR	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099601903	YGS SCAFFOLD INSPECT AND REPAIR THE HRA SIDE WALL AND REAR	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099601904	REO/ INSPECT AND REPAIR THE HRA SIDE WALL AND REAR	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4099601905	UDC INSPECT THE HRA SIDE WALL AND REAR	2	MO	IS	50Y
	BOILER, GENERAL..	5120000		4100272001	PLANT SUPERVISOR/WATERWALLS - DESLAG, INSPECT,	1	MO	PM	50Y
	BOILER, GENERAL..	5120000		4100272002	NAIS WATER BLASTER/WATERWALLS - DESLAG, INSPECT,	1	MO	PM	50Y
	BOILER, GENERAL..	5120000		4100272003	YOUNG SCAFFOLDING/WATERWALLS - DESLAG, INSPECT	1	MO	PM	50Y
	BOILER, GENERAL..	5120000		4100272004	ADKINS SANDBLASTER/WATERWALLS - DESLAG, INSPECT	1	MO	PM	50Y
	BOILER, GENERAL..	5120000		4100272005	REO/WATERWALLS - DESLAG, INSPECT .	1	MO	PM	50Y
	BOILER, GENERAL..	5120000		4100272006	NDE/WATERWALLS - DESLAG, INSPECT, REPAIR & PADWELD.	1	MO	PM	50Y
	BOILER, GENERAL..	5120000		4100272007	BOILERMAKERS/WATERWALLS - DESLAG, INSPECT, .	1	MO	PM	50Y

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WOT System Cd	WOT System Code Description	Account Nbr	WOT Unit Cond Reqd	WOT WO Nbr Task	WOT WR Task Title	WOT Unit	WO Type	WOT Job Type	Pm Frequency Code
	BOILER, GENERAL..	5120000		4100367601	PANT SUPERV/ECONOMIZER - DESLAG, INSPECT, REPAIR & PADWELD.	1	MO	PM	50Y
	BOILER, GENERAL..	5120000		4100367602	NAIS/ECONOMIZER - DESLAG, INSPECT, REPAIR & PADWELD.	1	MO	PM	50Y
	BOILER, GENERAL..	5120000		4100367603	YOUNG SCAFFOLDING/ECONOMIZER - DESLAG, INSPECT,	1	MO	PM	50Y
	BOILER, GENERAL..	5120000		4100367604	REO/ECONOMIZER - DESLAG, INSPECT,	1	MO	PM	50Y
	BOILER, GENERAL..	5120000		4100367605	HT NDE/ECONOMIZER - DESLAG, INSPECT,	1	MO	PM	50Y
	BOILER, GENERAL..	5120000		4100367606	BOILER MAKERS/ECONOMIZER - REPAIR & PADWELD.	1	MO	PM	50Y
	BOILER, GENERAL..	5120000		4100367607	UDC INSPECTION 3 YR. ECONOMIZER - DESLAG, INSPECT	1	MO	IS	50Y
	BOILER, GENERAL..	5120000		4101021101	BS/SUPV DRV-450; OPEN, INSPECT AND REPAIR.	2	MO	PM	50Y
	BOILER, GENERAL..	5120000		4101040301	PLT SUPV/INSPECT- REPAIR PENTHOUSE CASING-PENETRATION SEALS	1	MO	PM	50Y
	BOILER, GENERAL..	5120000		4101040302	REO/INSPECT - REPAIR PENTHOUSE CASING- PENETRATION SEALS	1	MO	PM	50Y
	BOILER, GENERAL..	5120000		4101040303	NAIS/INSPECT/REPAIR PENTHOUSE CASING / PENETRATION SEALS	1	MO	PM	50Y
	BOILER, GENERAL..	5120000		4101040304	SCAFFOLD/INSPECT/REPAIR PENTHOUSE CASING / PENETRATION SEALS	1	MO	PM	50Y
	BOILER, GENERAL..	5120000		4101040305	MMI/INSPECT / REPAIR PENTHOUSE CASING/ PENETRATION SEALS	1	MO	PM	50Y
	BOILER, GENERAL..	5120000		4101040306	BOILER MAKERS/ REPAIR PENTHOUSE CASING / PENETRATION SEALS	1	MO	PM	50Y
	BOILER, GENERAL..	5120000		4103042201	BS/SUPV FINISH, SUPERHEATER; DESLAG, SCAFFOLD, INS/REP	2	MO	PM	50Y
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360	MAIN STEAM SPRHTR & LINE	5120000		0094210501	U1 ICE OUTR RV-1 STROKE/ CALIBRATE	1	MO	PM	OUT
	MAIN STEAM SPRHTR & LINE	5120000		0094374701	U2 ICE OUTR ARV-542 CALIBRATION	2	MO	PM	OUT
	MAIN STEAM SPRHTR & LINE	5120000		4070413001	U2 ICE OUTR URV 1&2 INSPECTION	2	MO	PM	OUT
	MAIN STEAM SPRHTR & LINE	5120000		4071747501	ICE U1 OUTR -CALIBRATE SUPERHEAT ATTEMP CONTROLS	1	MO	PM	OUT
	MAIN STEAM SPRHTR & LINE	5120000		4098250601	PLANT SUPV/PLATEN SUPERHEATER; INSPECT AND REPAIR.	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4098250602	SCAFFOLDING CONTRACTOR/ PLATEN SUPERHEATER; INSPECT	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4098250603	SANDBLAST/PLATEN SUPERHEATER; INSPECT AND REPAIR.	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4098250604	MCON/ PLATEN SUPERHEATER; , INSPECT AND REPAIR.	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4098250605	NDE/PLATEN SUPERHEATER; INSPECT AND REPAIR.	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4098250606	REO/PLATEN SUPERHEATER; INSPECTION	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4098250607	UDC INSPECT 3 YR - PLATEN SUPERHEATER INSPECT AND REPAIR.	2	MO	IS	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4100251801	PLANT SUPV./SECONDARY SUPERHEATER - DESLAG, INSPECT	1	MO	PM	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4100251802	NAIS/ SECONDARY SUPERHEATER - INSPECT, REPAIR & PADWELD.	1	MO	PM	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4100251803	YOUNG SCAFFOLDING/SECONDARY SUPERHEATER - DESLAG, INSPECT,	1	MO	PM	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4100251804	SANDBLASTERS/SECONDARY SUPERHEATER - DESLAG, INSPECT,	1	MO	PM	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4100251805	REO /SECONDARY SUPERHEATER - DESLAG, INSPECT	1	MO	PM	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4100251806	APTECH/SECONDARY SUPERHEATER - DESLAG, INSPECT	1	MO	PM	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4100251807	BOILERMAKERS/SECONDARY SUPERHEATER - REPAIR & PADWELD.	1	MO	PM	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4100251808	CDC INSPECTION 3 YR. SECONDARY SUPERHEATER - INSPECT	1	MO	IS	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4101292501	PLANT SUPV/PRIMARY SUPERHEATER - DESLAG, INSPECT	1	MO	PM	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4101292502	NAIS DESLAG/PRIMARY SUPERHEATER - DESLAG, INSPECT	1	MO	PM	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4101292503	REO/PRIMARY SUPERHEATER - DESLAG, INSPECT,	1	MO	PM	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4101292504	BOILER MAKERS/PRIMARY SUPERHEATER REPAIR & PADWELD.	1	MO	PM	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4101292505	YOUNGS/PRIMARY SUPERHEATER - DESLAG, INSPECT,	1	MO	PM	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4101292506	PDM/PRIMARY SUPERHEATER - DESLAG, INSPECT,	1	MO	PM	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4101292507	NDE/PRIMARY SUPERHEATER - DESLAG, INSPECT.	1	MO	PM	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4101292508	UDC INSPECTION 3 YR - PRIMARY SUPERHEATER - INSPECT .	1	MO	IS	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4102998601	BS/SUPV SAFETY VALVES DISASSEMBLE/CHECK SEAT/LAPP AND REPAI.	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4102998602	YGS SCAFFOLD SAFETY VALVES; CHECK SEAT, LAPP AND REPAIR.	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4102998603	MMI INSUL SAFETY VALVE INSPECTIONS	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4102998604	PCVL SAFETY VALVE INSPECTION	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4103042202	NAIS EXPLOSIVE BLASTING - FINISH SH; EXPLOSIVE CLEANING	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4103042203	NAIS DESLAG FINISHING SUPERHEATER; WATER WASH	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4103042204	SANDBLAST -FINISH, SUPERHEATER; SANDBLASTING	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4103042205	YGS SCAFFOLD FINISH, SUPERHEATER;	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4103042206	HTT NDE FINISH, SUPERHEATER; NDE	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4103042207	MCON- FINISH, SUPERHEATER; DESLAG, SCAFFOLD,	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4103042208	MMI INSUL FINISH, SUPERHEATER; INSPECT AND REPAIR.	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4103042209	REO/FINISH, SUPERHEATER; DESLAG, SCAFFOLD, INSPECT	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINE	5120000		4103042210	UDC 3YR. INS.FINISH, SUPERHEATER; DESLAG, SCAFFOLD, INSPECT	2	MO	IS	50Y
	MAIN STEAM SPRHTR & LINES	5120000		0094210501	U1 ICE OUTR RV-1 STROKE/ CALIBRATE	1	MO	PM	OUT
	MAIN STEAM SPRHTR & LINES	5120000		0094374701	U2 ICE OUTR ARV-542 CALIBRATION	2	MO	PM	OUT
	MAIN STEAM SPRHTR & LINES	5120000		4070413001	U2 ICE OUTR URV 1&2 INSPECTION	2	MO	PM	OUT
	MAIN STEAM SPRHTR & LINES	5120000		4071747501	ICE U1 OUTR -CALIBRATE SUPERHEAT ATTEMP CONTROLS	1	MO	PM	OUT
	MAIN STEAM SPRHTR & LINES	5120000		4098250601	PLANT SUPV/PLATEN SUPERHEATER; INSPECT AND REPAIR.	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4098250602	SCAFFOLDING CONTRACTOR/ PLATEN SUPERHEATER; INSPECT	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4098250603	SANDBLAST/PLATEN SUPERHEATER; INSPECT AND REPAIR.	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4098250604	MCON/ PLATEN SUPERHEATER; , INSPECT AND REPAIR.	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4098250605	NDE/PLATEN SUPERHEATER; INSPECT AND REPAIR.	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4098250606	REO/PLATEN SUPERHEATER; INSPECTION	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4098250607	UDC INSPECT 3 YR - PLATEN SUPERHEATER INSPECT AND REPAIR.	2	MO	IS	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4100251801	PLANT SUPV./SECONDARY SUPERHEATER - DESLAG, INSPECT	1	MO	PM	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4100251802	NAIS/ SECONDARY SUPERHEATER - INSPECT, REPAIR & PADWELD.	1	MO	PM	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4100251803	YOUNG SCAFFOLDING/SECONDARY SUPERHEATER - DESLAG, INSPECT,	1	MO	PM	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4100251804	SANDBLASTERS/SECONDARY SUPERHEATER - DESLAG, INSPECT,	1	MO	PM	50Y

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WOT System Cd	WOT System Code Description	Account Nbr	WOT Unit Cond Reqd	WOT WO Nbr Task	WOT WR Task Title	WOT Unit	WO Type	WOT Job Type	Pm Frequency Code
	MAIN STEAM SPRHTR & LINES	5120000		4100251805	REO /SECONDARY SUPERHEATER - DESLAG, INSPECT	1	MO	PM	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4100251806	APTECH/SECONDARY SUPERHEATER - DESLAG, INSPECT	1	MO	PM	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4100251807	BOILERMAKERS/SECONDARY SUPERHEATER - REPAIR & PADWELD.	1	MO	PM	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4100251808	CDC INSPECTION 3 YR. SECONDARY SUPERHEATER - INSPECT	1	MO	IS	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4101292501	PLANT SUPV/PRIMARY SUPERHEATER - DESLAG, INSPECT	1	MO	PM	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4101292502	NAIS DESLAG/PRIMARY SUPERHEATER - DESLAG, INSPECT	1	MO	PM	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4101292503	REO/PRIMARY SUPERHEATER - DESLAG, INSPECT,	1	MO	PM	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4101292504	BOILER MAKERS/PRIMARY SUPERHEATER REPAIR & PADWELD.	1	MO	PM	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4101292505	YOUNGS/PRIMARY SUPERHEATER - DESLAG, INSPECT,	1	MO	PM	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4101292506	PDM/PRIMARY SUPERHEATER - DESLAG, INSPECT,	1	MO	PM	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4101292507	NDE/PRIMARY SUPERHEATER - DESLAG, INSPECT.	1	MO	PM	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4101292508	UDC INSPECTION 3 YR - PRIMARY SUPERHEATER - INSPECT .	1	MO	IS	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4102998601	BS/SUPV SAFETY VALVES DISASSEMBLE/CHECK SEAT/LAPP AND REPAI.	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4102998602	YGS SCAFFOLD SAFETY VALVES; CHECK SEAT, LAPP AND REPAIR.	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4102998603	MMI INSUL SAFETY VALVE INSPECTIONS	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4102998604	PCVL SAFETY VALVE INSPECTION	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4103042202	NAIS EXPLOSIVE BLASTING - FINISH SH; EXPLOSIVE CLEANING	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4103042203	NAIS DESLAG FINISHING SUPERHEATER; WATER WASH	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4103042204	SANDBLAST -FINISH, SUPERHEATER; SANDBLASTING	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4103042205	YGS SCAFFOLD FINISH, SUPERHEATER;	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4103042206	HTT NDE FINISH, SUPERHEATER; NDE	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4103042207	MCON- FINISH, SUPERHEATER; DESLAG, SCAFFOLD,	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4103042208	MMI INSUL FINISH, SUPERHEATER; INSPECT AND REPAIR.	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4103042209	REO/FINISH, SUPERHEATER; DESLAG, SCAFFOLD, INSPECT	2	MO	PM	50Y
	MAIN STEAM SPRHTR & LINES	5120000		4103042210	UDC 3YR. INS.FINISH, SUPERHEATER; DESLAG, SCAFFOLD, INSPECT	2	MO	IS	50Y
360									
370	REHEAT SPRHTR & LINES	5120000		4098288801	BS/SUPV 2ND RH BOILER TUBES; DESLAG, SCAFFOLD, INS/REP	2	MO	PM	50Y
	REHEAT SPRHTR & LINES	5120000		4098288802	NAIS DESLAG 2ND RH BOILER TUBES; WATER WASH	2	MO	PM	50Y
	REHEAT SPRHTR & LINES	5120000		4098288803	HTT NDE 2ND RH BOILER TUBES; NDE	2	MO	PM	50Y
	REHEAT SPRHTR & LINES	5120000		4098288804	MCON BOILER - 2ND RH BOILER TUBES; DESLAG, SCAFFOLD, INS/REP	2	MO	PM	50Y
	REHEAT SPRHTR & LINES	5120000		4098288805	REO/ENG 2ND RH BOILER TUBES; INSPECT AND REPAIR.	2	MO	PM	50Y
	REHEAT SPRHTR & LINES	5120000		4098288806	MMI INSUL 2ND RH BOILER TUBES; INSPECT AND REPAIR.	2	MO	PM	50Y
	REHEAT SPRHTR & LINES	5120000		4098288807	YOUNG SCAFFOLDING/ 2ND RH BOILER TUBES;	2	MO	PM	50Y
	REHEAT SPRHTR & LINES	5120000		4098519401	BS/SUPV 1ST RH BOILER TUBES; DELAG, SCAFFOLD, INS/REP	2	MO	PM	50Y
	REHEAT SPRHTR & LINES	5120000		4098519402	NAIS 1ST RH BOILER TUBES; DELAG, SCAFFOLD, INSPECT/ REPAIR.	2	MO	PM	50Y
	REHEAT SPRHTR & LINES	5120000		4098519403	MCON - 1ST RH BOILER TUBES; DELAG, SCAFFOLD, INS/REP	2	MO	PM	50Y
	REHEAT SPRHTR & LINES	5120000		4098519404	YGS SCAFFOLD 1ST RH BOILER TUBES; SCAFFOLD, INSPECT & REPAIR	2	MO	CD	50Y
	REHEAT SPRHTR & LINES	5120000		4098519405	REO/ENG 1ST RH BOILER TUBES; INSPECT AND REPAIR.	2	MO	PM	50Y
	REHEAT SPRHTR & LINES	5120000		4098519406	UDC INSPECTION 3 YR -1ST RH BOILER TUBES INSPECT AND REPAIR.	2	MO	IS	50Y
	REHEAT SPRHTR & LINES	5120000		4100168401	PLANT SUPVISOR/REHEAT SUPERHEATER - INSPECT AND REPAIR	1	MO	PM	50Y
	REHEAT SPRHTR & LINES	5120000		4100168402	NAIS/REHEAT SUPERHEATER - INSPECT AND REPAIR	1	MO	PM	50Y
	REHEAT SPRHTR & LINES	5120000		4100168403	SCAFFOLDING/REHEAT SUPERHEATER - INSPECT AND REPAIR	1	MO	PM	50Y
	REHEAT SPRHTR & LINES	5120000		4100168404	SAND BLASTERS/REHEAT SUPERHEATER - INSPECT AND REPAIR	1	MO	PM	50Y
	REHEAT SPRHTR & LINES	5120000		4100168405	REO /REHEAT SUPERHEATER - INSPECTION	1	MO	PM	50Y
	REHEAT SPRHTR & LINES	5120000		4100168406	APTECH/REHEAT SUPERHEATER - INSPECT AND REPAIR	1	MO	PM	50Y
	REHEAT SPRHTR & LINES	5120000		4100168407	BOILERMAKERS/REHEAT SUPERHEATER - INSPECT AND REPAIR	1	MO	PM	50Y
	REHEAT SPRHTR & LINES	5120000		4100168408	UDC INSPECT 3 YR. REHEAT SUPERHEATER - INSPECT	1	MO	IS	50Y
370									
380	SOOTBLOWERS	5120000		4062649801	U2 ICE OUTR 4 YR SOOT BLOWER INSTRUMENT CALIBRATION	2	MO	PM	4YR
	SOOTBLOWERS	5120000		4062655201	U2 ICE OUTR 2 YR SOOT BLOWER STROKE VALVES	2	MO	PM	2YR
380									
410	CONDENSERS	5130000		4065889001	U2 ICE OUTR NASH PP #3 - CALIBRATE INSTRUMENTS	2	MO	PM	OUT
	CONDENSERS	5130000		4065890401	U2 ICE OUTR NASH PP #2 CALIBRATE INSTRUMENTS	2	MO	PM	OUT
	CONDENSERS	5130000		4101033001	BS/SUPV MAIN CONDENSER; INSPECT FOR LEAKS AND PLUG.	2	MO	PM	50Y
	CONDENSERS	5130000		4101033002	BS/MECH MAINT MAIN CONDENSER; INSP FOR LEAKS & PLUG	2	MO	PM	50Y
	CONDENSERS	5130000		4101033003	BS/LAB MAIN CONDENSER; INSPECT FOR LEAKS AND PLUG.	2	MO	PM	50Y
	CONDENSERS	5130000		4101033004	NAIS WTR BLAST/MAIN CONDENSER; INSPECT FOR LEAKS AND PLUG.	2	MO	PM	50Y
	CONDENSERS	5130000		4101033005	EDDY/CSI/MAIN CONDENSER; INSPECT FOR LEAKS AND PLUG.	2	MO	GM	50Y
	CONDENSERS	5130000		4101078501	BS/SUPV AUX CONDENSER; INSPECT FOR LEAKS	2	MO	PM	50Y
	CONDENSERS	5130000		4101078502	BS/MECH MAINT AUX COND INSPECT FOR LEAKS & PLUG IF IN SERVIC	2	MO	PM	50Y
	CONDENSERS	5130000		4101078503	BS/LAB AUXILIARY CONDENSER; INSPECT FOR LEAKS	2	MO	PM	50Y
	CONDENSERS	5130000		4101078504	NAIS WTR BLAST/AUXILIARY CONDENSER; INSPECT FOR LEAKS	2	MO	PM	50Y
	CONDENSERS	5130000		4101078505	EDDY/CSI/AUXILIARY CONDENSER; INSPECT FOR LEAKS AND PLUG	2	MO	GM	50Y
410									
415	CONDENSATE	5120000		4065494001	U1 ICE OUTR CALIBRATE CONDENSATE LEVEL CONTROLS	1	MO	PM	3YR
	CONDENSATE	5120000		4065890901	U2 ICE OUTR CONDENSATE VALVES - STROKE	2	MO	PM	OUT
	CONDENSATE	5130000		0095111801	U2 ICE OUTR MOTOR-#3 COND BOOSTER PP INSP	2	MO	PM	DAY
	CONDENSATE	5130000		4066052801	U2 ICE OUTR CALIBRATE CONDENSATE PRESSURE SWITCHES	2	MO	PM	4YR
415									
420	FEEDWATER	5120000		0094225401	U1 ICE OUTR BOILER FEED PUMP EMERGENCY LEAK OFF VALVES	1	MO	PM	OUT
	FEEDWATER	5120000		0094374901	U2 ICE OUTR STROKE BFP ELO FRV 1 & 2	2	MO	PM	OUT

Models in Authorized Status With Auto Trigger Ind

2/18/2010

WOT System Cd	WOT System Code Description	Account Nbr	WOT Unit Cond Reqd	WOT WO Nbr Task	WOT WR Task Title	WOT Unit	WO Type	WOT Job Type	Pm Frequency Code
420									
425	FEEDWATER HEATERS	5120000		0094224801	U1 ICE OUTR HIGH PRESSURE HEATER DRAIN VALVES (6)	1	MO	PM	OUT
	FEEDWATER HEATERS	5120000		4072736901	U2 ICE OUTR STROKE HP HTR DR VALVES	2	MO	PM	OUT
	FEEDWATER HEATERS	5120000		4072737601	U2 ICE OUTR STROKE LP HTR DR VALVES	2	MO	PM	2YR
	FEEDWATER HEATERS	5120000		4100440301	BS/SUPV DEAERATOR STORAGE TANK; OPEN, INSPECT AND REPAIR.	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4100440302	CMS NDE DEAERATOR STORAGE TANK; OPEN, INSPECT AND REPAIR.	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4100440303	ENERFAB MCON DEAERATOR STORAGE TANK; OPEN/INSPECT AND REPAIR	2	MO	GM	50Y
	FEEDWATER HEATERS	5120000		4100583801	BS/SUPV DEAERATOR; OPEN/INSPECT TRAYS, SPRAY VALVES & SHELL	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4100583802	CMS NDE DEAERATOR; OPEN, INSPECT TRAYS,SPRAY VALVES & SHELL.	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4100583803	ENFB MCON-DEAERATOR; OPEN/INSPECT TRAYS SPRAY VALVES & SHELL	2	MO	GM	50Y
	FEEDWATER HEATERS	5120000		4100676301	BS/SUPV #7B HP HEATER; INSPECT & REPAIR	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4100676302	APS EXP PLUGS - CONT. #7B HP. HEATER; HEATER PLUGGING	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4100676303	CSI EDDY CURRENT TESTING - #7B H.P. HEATER; INSPECT & REPAIR	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4100676304	NAIS HYD WTR BLASTING - #7B H.P. HEATER; INSPECT & REPAIR	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4100676305	MMI INS #7B HP HEATER; INSPECT & REPAIR	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4100676306	CMS NDE #7B HP HEATER; INSPECT & REPAIR	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4100676307	ENERFAB MCON #7B HP HEATER; INSPECT & REPAIR	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4100679001	BS/SUPV #7A HP HEATER; INSPECT & REPAIR	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4100679002	APS EXP PLUGS - CONT. #7A HP. HEATER; HEATER PLUGGING	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4100679003	CSI EDDY CURRENT TESTING - #7A H.P. HEATER; INSPECT & REPAIR	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4100679004	NAIS HYD WTR BLASTING - #7A H.P. HEATER; INSPECT & REPAIR	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4100679005	MMI INS #7A HP HEATER; INSPECT & REPAIR	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4100679006	CMS NDE #7A HP HEATER; INSPECT & REPAIR	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4100679007	ENERFAB MCON #7A HP HEATER; INSPECT & REPAIR	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4100980501	BS/SUPV #4 L.P. HEATER; INSPECT & REPAIR.	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4100980502	NAIS HYD WTR BLAST #4 L.P. HEATER; INSPECT & REPAIR.	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4100980503	CSI EDDY CURRENT #4 L.P. HEATER; INSPECT & REPAIR.	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4100980504	ENERFAB MCON #4 L.P. HEATER; INSPECT & REPAIR.	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4100980801	BS/SUPV #3 L.P. HEATER; INSPECT & REPAIR.	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4100980802	NAIS HYD WTR BLAST #3 L.P. HEATER; INSPECT & REPAIR.	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4100980803	CSI EDDY CURRENT #3 L.P. HEATER; INSPECT & REPAIR.	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4100980804	ENERFAB MCON #3 L.P. HEATER; INSPECT & REPAIR.	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4100981201	BS/SUPV #2 L.P. HEATER; INSPECT & REPAIR.	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4100981202	NAIS HYD WTR BLAST #2 L.P. HEATER; INSPECT & REPAIR.	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4100981203	CSI EDDY CURRENT #2 L.P. HEATER; INSPECT & REPAIR.	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4100981204	ENERFAB MCON #2 L.P. HEATER; INSPECT & REPAIR.	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4100981801	BS/SUPV #1 L.P. HEATER; INSPECT & REPAIR.	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4100981802	NAIS HYD WTR BLAST #1 L.P. HEATER; INSPECT & REPAIR.	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4100981803	CSI EDDY CURRENT #1 L.P. HEATER; INSPECT & REPAIR.	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4100981804	ENERFAB MCON #1 L.P. HEATER; INSPECT & REPAIR.	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4101495601	BS/SUPV #8B HIGH PRESSURE HEATER; INSPECT AND REPAIR.	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4101495602	EST EXP PLUGS #8B HIGH PRESSURE HEATER;HEATER PLUGGING	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4101495603	NAIS/HP #8B HIGH PRESSURE HEATER; WATER BLASTING	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4101495604	MMI INSUL #8B HIGH PRESSURE HEATER; INSULATION	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4101495605	CMS NDE #8B HIGH PRESSURE HEATER; INSPECT AND REPAIR.	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4101495606	BS/MECH #8B HIGH PRESSURE HEATER; INSPECT AND REPAIR.	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4101495607	REO/ENG TEST #8B HIGH PRESSURE HEATER; INSPECT AND REPAIR.	2	MO	GM	50Y
	FEEDWATER HEATERS	5120000		4101495608	EDDY/CSI/#8B HIGH PRESSURE HEATER; INSPECT AND REPAIR.	2	MO	GM	50Y
	FEEDWATER HEATERS	5120000		4101496001	BS/SUPV #8A HIGH PRESSURE HEATER; INSPECT & REPAIR.	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4101496002	EST EXP PLUGS #8A HIGH PRESSURE HEATER; HEATER PLUGGING	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4101496003	MMI INSUL (I) #8A HIGH PRESSURE HEATER; INSULATION	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4101496004	BS/MECH #8A HIGH PRESSURE HEATER; INSPECT & REPAIR.	2	MO	PM	50Y
	FEEDWATER HEATERS	5120000		4101496005	REO/ENG TEST - #8A HIGH PRESSURE HEATER; INSPECT & REPAIR.	2	MO	GM	50Y
	FEEDWATER HEATERS	5120000		4101496006	EDDY/CSI/#8A HIGH PRESSURE HEATER; INSPECT & REPAIR.	2	MO	GM	50Y
	FEEDWATER HEATERS	5120000		4101496007	CLEAN/NAIS/#8A HIGH PRESSURE HEATER; INSPECT & REPAIR.	2	MO	GM	50Y
425									
440	CIRCULATING WATER	5130000		0093429201	MOTOR, CIRCULATING WATER BOOSTER PUMP #1 EAST - PERFORM	2	MO	PM	1YR
	CIRCULATING WATER	5130000		0093430201	MOTOR, CIRCULATING WATER BOOSTER PUMP #2 WEST - PERFORM	2	MO	PM	1YR
	CIRCULATING WATER	5130000		4073071401	COOLING TOWER U2 CLEANING DIST DECK	2	MO	PM	OUT
	CIRCULATING WATER	5130000		4100437901	BS/SUPV I&R, & CLEAN BASIN U-2 COOLING TOWER	2	MO	PM	50Y
	CIRCULATING WATER	5130000		4100437902	BS/YARD U-2 COOLING TOWER INSPECT, REPAIR, & CLEAN BASIN	2	MO	PM	50Y
	CIRCULATING WATER	5130000		4100437903	BS/MECH COOLING TOWER INSPECT, REPAIR, & CLEAN BASIN	2	MO	PM	50Y
	CIRCULATING WATER	5130000		4100437904	REO ENG COOLING TOWER INSPECT, REPAIR, & CLEAN BASIN	2	MO	PM	50Y
	CIRCULATING WATER	5130000		4100437905	YGS SCAFFOLD CARP COOLING TOWER INSPECT, REPAIR/CLEAN BASIN	2	MO	PM	50Y
	CIRCULATING WATER	5130000		4100437906	ENERFAB MCON PIPE COOLING TOWER INSPECT, REPAIR/CLEAN BASIN	2	MO	PM	50Y
	CIRCULATING WATER	5130000		4100437907	MARLEY CONSLT - U-2 COOLING TOWER I&R, & CLEAN BASIN	2	MO	PM	50Y
	CIRCULATING WATER	5130000		4100439401	BS/SUPV CIRCULATING WATER PIPING AND VALVES; INSP/REP	2	MO	PM	50Y
	CIRCULATING WATER	5130000		4100439402	PCVL VALVE CONT - CIRCULATING WATER PIPING AND VALVES;	2	MO	PM	50Y
	CIRCULATING WATER	5130000		4100439403	COATINGS - CIRCULATING WATER PIPING AND VALVES;	2	MO	PM	50Y
	CIRCULATING WATER	5130000		4100439404	ENERFAB MCON CIRCULATING WATER PIPING AND VALVES;	2	MO	PM	50Y
	CIRCULATING WATER	5130000		4100439405	BS/LAB CIRCULATING WATER PIPING AND VALVES; I & R	2	MO	GM	50Y

Models in Authorized Status With Auto Trigger Ind

2/18/2010

WOT System Cd	WOT System Code Description	Account Nbr	WOT Unit Cond Reqd	WOT WO Nbr Task	WOT WR Task Title	WOT Unit	WO Type	WOT Job Type	Pm Frequency Code
440									
450	SERVICE AND FIRE WATER	5120000		4101544701	BS/SUPV #2 COOLING WATER COOLERS; OPEN, INSPECT AND REPAIR.	2	MO	PM	50Y
	SERVICE AND FIRE WATER	5120000		4101544702	BS/MECH #2 COOLING WATER COOLERS; OPEN, INSPECT AND REPAIR.	2	MO	GM	50Y
	SERVICE AND FIRE WATER	5120000		4101544703	NAIS CLEAN #2 COOLING WATER COOLERS; OPEN, I&R.	2	MO	GM	50Y
	SERVICE AND FIRE WATER	5120000		4101544704	CSI EDDY #2 COOLING WATER COOLERS; OPEN, INSPECT AND REPAIR.	2	MO	GM	50Y
	SERVICE AND FIRE WATER	5120000		4101544705	COAT/CEAP#2 COOLING WATER COOLERS; OPEN, INSPECT AND REPAIR.	2	MO	GM	50Y
	SERVICE AND FIRE WATER	5120000		4101546101	BS/SUPV #1 COOLING WATER COOLERS; OPEN, INSPECT AND REPAIR.	2	MO	PM	50Y
	SERVICE AND FIRE WATER	5120000		4101546102	BS/MECH #1 COOLING WATER COOLERS; OPEN, INSPECT AND REPAIR.	2	MO	GM	50Y
	SERVICE AND FIRE WATER	5120000		4101546103	NAIS CLEAN #1 COOLING WATER COOLERS; OPEN, I&R.	2	MO	GM	50Y
	SERVICE AND FIRE WATER	5120000		4101546104	CSI EDDY/#1 COOLING WATER COOLERS; OPEN, INSPECT AND REPAIR.	2	MO	GM	50Y
	SERVICE AND FIRE WATER	5120000		4101546105	COAT/CEAP#1 COOLING WATER COOLERS; OPEN, INSPECT AND REPAIR.	2	MO	GM	50Y
450									
470	WATER PRETREAT & FILTER	5120000		4101496101	BS/LAB CONDENSATE STORAGE TANK; OPEN, INSPECT AND REPAIR.	2	MO	PM	50Y
	WATER PRETREAT & FILTER	5120000		4101533401	BS/LAB CONTAMINATED STORAGE TANK; INSPECT AND REPAIR	2	MO	PM	50Y
470									
510	TURBINE INLET VALVES	5130000		0094377401	U2 ICE OUTR REPLACE SERVO VALVES ON THE MT VALVES	2	MO	PM	5YR
	TURBINE INLET VALVES	5130000		0094377401	U2 ICE OUTR REPLACE SERVO VALVES ON THE MT VALVES	2	MO	PM	OUT
	TURBINE INLET VALVES	5130000		4073339801	U2 ICE OUTR TURBINE VALVE LIMIT SWITCHES/LVDT INSP	2	MO	PM	OUT
	TURBINE INLET VALVES	5130000		4101434801	BS/SUPV 2ND RH INTER.& STOP VALVES	2	MO	PM	50Y
	TURBINE INLET VALVES	5130000		4101434802	MMI INSUL 2ND RH COMBINED (INT. & STOP) VALVES	2	MO	PM	50Y
	TURBINE INLET VALVES	5130000		4101434803	YGS SCAFFOLD 2ND RH COMBINED (INT. & STOP) VALVES	2	MO	PM	50Y
	TURBINE INLET VALVES	5130000		4101434804	FED SANDBLAST 2ND RH COMBINED (INT. & STOP) VALVES	2	MO	PM	50Y
	TURBINE INLET VALVES	5130000		4101434805	CMS @ CMS NDE & REPAIR 12ND RH COMBINED (INT. & STOP) VALVES	2	MO	PM	50Y
	TURBINE INLET VALVES	5130000		4101434806	CMS @ BSP NDE & REPAIR 2ND RH COMBINED (INT. & STOP) VALVE	2	MO	PM	50Y
	TURBINE INLET VALVES	5130000		4101434807	RSO/TBMEC 2ND RH COMBINED (INT. & STOP) VALVES	2	MO	PM	50Y
	TURBINE INLET VALVES	5130000		4101435101	BS/SUPV 1ST RH COMBINED(INT.&STOP) VALVES	2	MO	PM	50Y
	TURBINE INLET VALVES	5130000		4101435102	MMI INSUL 1ST RH COMBINED (INT. & STOP) VALVES	2	MO	PM	50Y
	TURBINE INLET VALVES	5130000		4101435103	YGS SCAFFOLD ST RH COMBINED (INT. & STOP) VALVES	2	MO	PM	50Y
	TURBINE INLET VALVES	5130000		4101435104	FED SANDBLASTING 1ST RH COMBINED (INT. & STOP) VALVES	2	MO	PM	50Y
	TURBINE INLET VALVES	5130000		4101435105	CMS @ CMS NDE & REPAIR 1ST RH COMBINED (INT. & STOP) VALVES	2	MO	PM	50Y
	TURBINE INLET VALVES	5130000		4101435106	CMS @ BSP NDE & REPAIR 1ST RH COMBINED (INT. & STOP) VALVE	2	MO	PM	50Y
	TURBINE INLET VALVES	5130000		4101435107	RSO/TBMEC 1ST RH COMBINED (INT. & STOP) VALVES	2	MO	PM	50Y
	TURBINE INLET VALVES	5130000		4101438201	BS/SUPV- CONTROL VALVES; REMOVE, SEND TO CMS & RE-INSTALL.	2	MO	PM	50Y
	TURBINE INLET VALVES	5130000		4101438202	MMI INSUL CONTROL VALVES; REMOVE, SEND TO CMS & RE-INSTALL.	2	MO	PM	50Y
	TURBINE INLET VALVES	5130000		4101438203	YGS SCAFFOLD CONTROL VALVES REMOVE SEND TO CMS & RE-INSTALL	2	MO	PM	50Y
	TURBINE INLET VALVES	5130000		4101438204	FED SANDBLAST CONTROL VALVES;	2	MO	PM	50Y
	TURBINE INLET VALVES	5130000		4101438205	CMS @ BIG SANDY / NDE & REPAIR	2	MO	PM	50Y
	TURBINE INLET VALVES	5130000		4101438206	CMS & CMS NDE & REPAIR	2	MO	PM	50Y
	TURBINE INLET VALVES	5130000		4101438207	RSO/TBMEC CONTROL VALVES; REMOVE, SEND TO CMS & RE-INSTALL.	2	MO	PM	50Y
	TURBINE INLET VALVES	5130000		4101438301	BS/SUPV MAIN STOP VALVES; REMOVE, SEND TO CMS & RE-INSTALL.	2	MO	PM	50Y
	TURBINE INLET VALVES	5130000		4101438302	MMI INSUL MAIN STOP VALVES REMOVE REPAIR/INSTALL	2	MO	PM	50Y
	TURBINE INLET VALVES	5130000		4101438303	YGS SCAFFOLD MAIN STOP VALVE INSP	2	MO	PM	50Y
	TURBINE INLET VALVES	5130000		4101438304	FED SANDBLAST MAIN STOP VALVES	2	MO	PM	50Y
	TURBINE INLET VALVES	5130000		4101438305	CMS NDE MAIN STOP VALVES	2	MO	PM	50Y
	TURBINE INLET VALVES	5130000		4101438306	CMS MAIN STOP VALVES: REPAIRS	2	MO	PM	50Y
	TURBINE INLET VALVES	5130000		4101438307	RSO/TBMEC MAIN STOP VALVES REMOVE SEND TO CMS & RE-INSTALL.	2	MO	PM	50Y
510									
515	EXTRACTION STEAM	5120000		4101536101	BS/SUPV SUPPORT I & R TURBINE BLEED STEAM CHECK VALVES	2	MO	PM	50Y
	EXTRACTION STEAM	5120000		4101536102	CUSTOM VALVE CONTR I & R TURBINE BLEED STEAM CHECK VALVES	2	MO	PM	50Y
	EXTRACTION STEAM	5120000		4101536103	YGS SCAFFOLD I/R TURBINE BLEED STEAM CHECK VALVES	2	MO	PM	50Y
	EXTRACTION STEAM	5120000		4101536104	MMI INSUL I/R TURBINE BLEED STEAM CHECK VALVES	2	MO	PM	50Y
	EXTRACTION STEAM	5120000		4101536105	BS/ICE INSPECT & REPAIR TURBINE BLEED STEAM CHECK VALVES	2	MO	GM	50Y
	EXTRACTION STEAM	5120000		4101536106	BS/MECH INSPECT & REPAIR TURBINE BLEED STEAM CHECK VALVES	2	MO	GM	50Y
	EXTRACTION STEAM	5120000		4101538501	BS/SUPV INSPECT AND REPAIR HP HEATER ISOLATION VALVES	2	MO	PM	50Y
	EXTRACTION STEAM	5120000		4101538502	BS/ICE HP HTR ISOLATION VALVES INSP	2	MO	PM	50Y
	EXTRACTION STEAM	5120000		4101538503	BS/MECH INSPECT AND REPAIR HP HEATER ISOLATION VALVES	2	MO	PM	50Y
	EXTRACTION STEAM	5120000		4101538504	CUSTOM VALVE INSPECT AND REPAIR HP HEATER ISOLATION VALVES	2	MO	PM	50Y
	EXTRACTION STEAM	5120000		4101538505	MMI INSUL INSPECT AND REPAIR HP HEATER ISOLATION VALVES	2	MO	GM	50Y
	EXTRACTION STEAM	5120000		4101538506	YGS SCAFFOLD INSPECT AND REPAIR HP HEATER ISOLATION VALVES	2	MO	GM	50Y
515									
520	TURBINE, STEAM	5120000		4072858701	U1 ICE OUTR - STROKE MAIN/FPT VALVES	1	MO	PM	OUT
	TURBINE, STEAM	5120000		4073017601	ICE U1 OUTR STROKE MO 31, 32, 34, 35, 38 AND 39	1	MO	PM	OUT
	TURBINE, STEAM	5130000		0094377501	ICE U2 OUTR INSP/CHARGE EHC ACCUMULATORS	2	MO	PM	OUT
	TURBINE, STEAM	5130000		4073015601	U1 ICE OUTR - CHECK STROKE SEAL REGULATOR VALVE	1	MO	PM	OUT
	TURBINE, STEAM	5130000		4073084101	U2 ICE OUTR MAIN TURBINE TRANSMITTER	2	MO	PM	6YR
	TURBINE, STEAM	5130000		4073084102	U2 ICE OUTR BFPT TRANSMITTER	2	MO	PM	6YR
	TURBINE, STEAM	5130000		4073084401	U2 ICE OUTR STEAM SEAL CONTROL SRV-075	2	MO	PM	OUT
	TURBINE, STEAM	5130000		4073084402	U2 ICE OUTR STEAM SEAL CONTROL SRV-076	2	MO	PM	OUT
	TURBINE, STEAM	5130000		4073084601	U2 ICE OUTR EHC SYSTEM FLUSH	2	MO	PM	OUT
	TURBINE, STEAM	5130000		4073085501	U2 ICE OUTR - STROKE COOLING STEAM VALVES	2	MO	PM	OUT
	TURBINE, STEAM	5130000		4100387501	BS/SUPV BFPT CONTROL VALVE RACK	2	MO	PM	50Y

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WOT System Cd	WOT System Code Description	Account Nbr	WOT Unit Cond Reqd	WOT WO Nbr Task	WOT WR Task Title	WOT Unit	WO Type	WOT Job Type	Pm Frequency Code
	TURBINE, STEAM	5130000		4100387502	RSO/TBMEC BFPT CONTROL VALVE RACK	2	MO	PM	50Y
	TURBINE, STEAM	5130000		4100387503	YGS SCAFFOLD BFPT CONTROL VALVE RACK	2	MO	PM	50Y
	TURBINE, STEAM	5130000		4101021102	RSO/MECH DRV-450; OPEN, INSPECT AND REPAIR.	2	MO	PM	50Y
	TURBINE, STEAM	5130000		4101021103	BS/ICE DRV-450; OPEN, INSPECT AND REPAIR.	2	MO	PM	50Y
	TURBINE, STEAM	5130000		4101021104	YGS SCAFFOLD DRV-450; OPEN, INSPECT AND REPAIR.	2	MO	PM	50Y
	TURBINE, STEAM	5130000		4101089901	BS/SUPV LAST STAGE BLADE INSP LP ROTORS	2	MO	PM	50Y
	TURBINE, STEAM	5130000		4101089902	HTT NDE LAST STAGE BLADE INSP ON LP ROTORS	2	MO	PM	50Y
	TURBINE, STEAM	5130000		4101089903	BS/MECH LAST STAGE BLADE INSPECTION; NDE OF LP ROTORS	2	MO	CD	50Y
	TURBINE, STEAM	5130000		4101089904	BS/ICE LAST STAGE BLADE INSPECTION; NDE OF LP ROTORS	2	MO	CD	50Y
	TURBINE, STEAM	5130000		4101091101	BS/SUPV FRONT STAND & OIL DEFLECTORS	2	MO	PM	50Y
	TURBINE, STEAM	5130000		4101091102	BS/ICE REMOVE & INSTALL THERMOCOUPLES	2	MO	PM	50Y
	TURBINE, STEAM	5130000		4101091103	RSO/TBMEC REMOVE & INSTALL STANDARDS & OIL DEFL.	2	MO	PM	50Y
	TURBINE, STEAM	5130000		4101091104	CMS @ CMS / OIL DEFLECTOR REPAIR % MISC.	2	MO	PM	50Y
	TURBINE, STEAM	5130000		4101091105	CMS @ BIG SANDY OIL DEFLECTOR REPAIR & MISC.	2	MO	PM	50Y
	TURBINE, STEAM	5130000		4101387601	BS/SUPV VENTILATOR VALVE (HP & 1STRH)	2	MO	PM	50Y
	TURBINE, STEAM	5130000		4101387602	MMI INSUL TO REMOVE AND INSTALL	2	MO	PM	50Y
	TURBINE, STEAM	5130000		4101387603	YGS SCAFFOLD VENTILATOR VALVES; INSPECT AND REPAIR.	2	MO	PM	50Y
	TURBINE, STEAM	5130000		4101387604	FED SANDBLAST PARTS AND FLANGE SURFACES	2	MO	PM	50Y
	TURBINE, STEAM	5130000		4101387605	RSO/TBMEC TO DISASSEMBLE REPAIR AND REASSEMBLE	2	MO	PM	50Y
	TURBINE, STEAM	5130000		4101387606	CMS @ CMS NDE ADN REPAIR WORK	2	MO	PM	50Y
	TURBINE, STEAM	5130000		4101387607	CMS VENTILATOR VALVES; INSPECT AND REPAIR.	2	MO	PM	50Y
520									
540	TURBINE LUBE OIL	5120000		4056999201	U1 ICE OUTR EBOP BFPT	1	MO	PM	OUT
	TURBINE LUBE OIL	5130000		0093428501	U2 ICE OUTR AUXILIARY-75 HP BACKUP OIL PP MOTOR INSP	2	MO	PM	2YR
	TURBINE LUBE OIL	5130000		4057316701	U1 ICE OUTR EBOP MAIN TURBINE	1	MO	PM	OUT
	TURBINE LUBE OIL	5130000		4070274901	U2 ICE OUTR EBOP TEST MAIN TURBINE	2	MO	PM	OUT
	TURBINE LUBE OIL	5130000		4073016701	U1 ICE OUTR - STROKE RV-910 TURBINE OIL COOLER VALVE	1	MO	PM	OUT
	TURBINE LUBE OIL	5130000		4073341601	U2 ICE OUTR TURBINE OIL TEMPERATURE CONTROL-CALIBRATE	2	MO	PM	OUT
	TURBINE LUBE OIL	5130000		4090957901	PM U-2 VAPOR EXTRACTOR-CHANGE OIL IN SUTORBILT BLOWER	2	MO	PM	9MO
	TURBINE LUBE OIL	5130000		4100985801	BS/SUPV MAIN TURBINE OIL COOLERS; DRAIN AND CLEAN.	2	MO	PM	50Y
	TURBINE LUBE OIL	5130000		4100985802	RSO TO INSPECT/REPAIR/INSTALL.	2	MO	PM	50Y
	TURBINE LUBE OIL	5130000		4100985803	SAFEWAY SCAFFOLD/MAIN TURBINE OIL TANK COOLERS.	2	MO	PM	50Y
	TURBINE LUBE OIL	5130000		4101023801	BS/SUPV LUBE OIL SYSTEM CHECK VALVES; INSPECT WELDS.	2	MO	PM	50Y
	TURBINE LUBE OIL	5130000		4101023802	RSO/MECH INSP LUBE OIL SYSTEM CHECK VALVES; INSPECT WELDS.	2	MO	PM	50Y
	TURBINE LUBE OIL	5130000		4139839601	U1 ICE OUTR EHC SYSTEM FLUSH	1	MO	PM	OUT
540									
570	GENERATOR	5130000		0094692301	U1 ICE OUTR GENERATOR BRUSH RIGGING INSPECTION	1	MO	PM	1YR
	GENERATOR	5130000		0095083801	U2 ICE OUTR MAIN FIELD BREAKER INSPECTION	2	MO	PM	2YR
	GENERATOR	5130000		0095083901	U2 ICE OUTR MAIN EXCITER RECTIFIER INSP	2	MO	PM	OUT
570									
580	GENERATOR, SEAL OIL	5130000		4100433501	BS/SUPV HYD SEALING SYSTEM CHANGE FILTERS/INSPECT FLOAT TRAP	2	MO	PM	50Y
	GENERATOR, SEAL OIL	5130000		4100433502	RSO/TBMEC SEAL OIL SYS CHANGE FLTRS/CUNO/ INSPECT FLOAT TRAP	2	MO	PM	50Y
	SEAL OIL, GENERATOR	5130000		4100433501	BS/SUPV HYD SEALING SYSTEM CHANGE FILTERS/INSPECT FLOAT TRAP	2	MO	PM	50Y
	SEAL OIL, GENERATOR	5130000		4100433502	RSO/TBMEC SEAL OIL SYS CHANGE FLTRS/CUNO/ INSPECT FLOAT TRAP	2	MO	PM	50Y
580									
590	GENERATOR, STATOR WATER	5120000		4066047001	U2 ICE OUTR STATOR COOLING WATER TANK LEVEL	2	MO	PM	OUT
590									
600	** ELECTRICAL SYSTEMS **	5130000		0095086301	U2 ICE OUTR ELECTRICAL MISC	2	MO	PM	OUT
	ELECTRICAL SYSTEMS	5130000		0095086301	U2 ICE OUTR ELECTRICAL MISC	2	MO	PM	OUT
600									
610	TRANSFORMER-MAIN, AUX, RAT	5130000		0094376001	U2 ICE OUTR TRANSFORMERS POTENTIAL-GENERATOR INSPECTION	2	MO	PM	OUT
	TRANSFORMER-MAIN, AUX, RAT	5130000		0094692501	U1 ICE OUTR GENERATOR GROUNDING TRANSFORMER INSP	1	MO	PM	OUT
	TRANSFORMER-MAIN, AUX, RAT	5130000		0094694301	U1 ICE OUTR EAST GSU TRANSFORMER INSPECTION	1	MO	PM	OUT
	TRANSFORMER-MAIN, AUX, RAT	5130000		0094694302	SAFE - EAST GSU TRANSFORMER INSPECTION	1	MO	PM	OUT
	TRANSFORMER-MAIN, AUX, RAT	5130000		0094694401	U1 ICE OUTR WEST GSU TRANSFORMER INSPECTION	1	MO	PM	OUT
	TRANSFORMER-MAIN, AUX, RAT	5130000		0094694402	U1 SCAFF OUTR WEST GSU TRANSFORMER INSPECTION	1	MO	PM	OUT
	TRANSFORMER-MAIN, AUX, RAT	5130000		0095084301	U2 ICE OUTR GENERATOR GROUNDING TRANSFORMER INSP	2	MO	PM	OUT
	TRANSFORMER-MAIN, AUX, RAT	5130000		4119198701	U1 ICE OUTR TRANSFORMERS POTENTIAL-GENERATOR INSPECTION	1	MO	PM	OUT
	TRANSFORMER-MAIN,AUX,RAT	5130000		0094376001	U2 ICE OUTR TRANSFORMERS POTENTIAL-GENERATOR INSPECTION	2	MO	PM	OUT
	TRANSFORMER-MAIN,AUX,RAT	5130000		0094692501	U1 ICE OUTR GENERATOR GROUNDING TRANSFORMER INSP	1	MO	PM	OUT
	TRANSFORMER-MAIN,AUX,RAT	5130000		0094694301	U1 ICE OUTR EAST GSU TRANSFORMER INSPECTION	1	MO	PM	OUT
	TRANSFORMER-MAIN,AUX,RAT	5130000		0094694302	SAFE - EAST GSU TRANSFORMER INSPECTION	1	MO	PM	OUT
	TRANSFORMER-MAIN,AUX,RAT	5130000		0094694401	U1 ICE OUTR WEST GSU TRANSFORMER INSPECTION	1	MO	PM	OUT
	TRANSFORMER-MAIN,AUX,RAT	5130000		0094694402	U1 SCAFF OUTR WEST GSU TRANSFORMER INSPECTION	1	MO	PM	OUT
	TRANSFORMER-MAIN,AUX,RAT	5130000		0095084301	U2 ICE OUTR GENERATOR GROUNDING TRANSFORMER INSP	2	MO	PM	OUT
	TRANSFORMER-MAIN,AUX,RAT	5130000		4119198701	U1 ICE OUTR TRANSFORMERS POTENTIAL-GENERATOR INSPECTION	1	MO	PM	OUT
610									
615	BUS, FROM TRANSFORMERS	5130000		0094704601	U1 ICE OUTR ISOPHASE BUS INSPECTION	1	MO	PM	2YR
	BUS, FROM TRANSFORMERS	5130000		0095111401	U2 ICE OUTR ISOPHASE BUS INSP	2	MO	PM	2YR
	BUS,FROM TRANSFORMERS	5130000		0094704601	U1 ICE OUTR ISOPHASE BUS INSPECTION	1	MO	PM	2YR
	BUS,FROM TRANSFORMERS	5130000		0095111401	U2 ICE OUTR ISOPHASE BUS INSP	2	MO	PM	2YR

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WOT System Cd	WOT System Code Description	Account Nbr	WOT Unit Cond Reqd	WOT WO Nbr Task	WOT WR Task Title	WOT Unit	WO Type	WOT Job Type	Pm Frequency Code
615									
630	SWITCHGEAR	5120000		0094701801	U2 ICE OUTR MCC SO3 INSPECTION	2	MO	PM	1YR
	SWITCHGEAR	5120000		0094701801	U2 ICE OUTR MCC SO3 INSPECTION	2	MO	PM	2YR
	SWITCHGEAR	5130000		0093353101	U1 ICE OUTR BUS 1B & BREAKERS 1B1/1B15 INSP	1	MO	PM	OUT
	SWITCHGEAR	5130000		0093353401	U2 ICE OUTR 4YR 4KV BREAKER INSP 2A, 2B, 2C	2	MO	PM	4YR
	SWITCHGEAR	5130000		0094372901	U2 ICE OUTR 600V TRIP UNITS - 21A,21B,21C - CALIBRATE	2	MO	PM	OUT
	SWITCHGEAR	5130000		0094693601	U1 ICE OUTR 1A 4KV BREAKERS INSP	1	MO	PM	OUT
	SWITCHGEAR	5130000		0094693701	U1 ICE OUTR 1B 4KV BREAKERS INSP	1	MO	PM	OUT
	SWITCHGEAR	5130000		0094693801	U1 ICE OUTR 11A 600V SWGR BREAKER INSP	1	MO	PM	OUT
	SWITCHGEAR	5130000		0094693901	U1 ICE OUTR 11B 600V SWGR BREAKER INSP	1	MO	PM	OUT
	SWITCHGEAR	5130000		0094694001	U1 ICE OUTR 600V MCC INSPECTION 11A BUS	1	MO	PM	2YR
	SWITCHGEAR	5130000		0094694101	U1 ICE OUTR 600V MCC INSPECTION 11B BUS	1	MO	PM	2YR
	SWITCHGEAR	5130000		0094901601	U1 ICE OUTR BUS 1A & BREAKERS 1A1/1A15 INSP	1	MO	PM	OUT
	SWITCHGEAR	5130000		0095084901	U2 ICE OUTR 8YR 4KV BKR REBUILD	2	MO	PM	6YR
	SWITCHGEAR	5130000		0095085001	U2 ICE OUTR 600 V FEED BREAKERS 21A, 21B, 21C INSPECTION	2	MO	PM	OUT
	SWITCHGEAR	5130000		0095085101	U2 ICE OUTR 600V BUS 21A, 21B, 21C INSP	2	MO	PM	OUT
	SWITCHGEAR	5130000		0095310501	U2 ICE OUTR BKR 2A5, 2B10, 2C9 INSP	2	MO	PM	1YR
	SWITCHGEAR	5130000		4093056501	U2 ICE OUTR STA 14 600V FEED BREAKERS	2	MO	PM	2YR
	SWITCHGEAR	5130000		4097314801	U2 ICE OUTR MCC 2TBW-A INSP	2	MO	PM	2YR
	SWITCHGEAR	5130000		4097449501	U2 ICE OUTR 600V BKR/TRIP UNIT- 2SCRL, 2SCRM INSP	2	MO	PM	4YR
	SWITCHGEAR	5130000		4097450101	U2 ICE 8YR 600V BUS 2SCRL, 2SCRM- BREAKER REBUILD	2	MO	PM	TEN
	SWITCHGEAR	5130000		4097588301	U2 ICE OUTR MCC 2SB-L INSPECTION	2	MO	PM	2YR
	SWITCHGEAR	5130000		4097600801	U2 ICE OUTR MCC 2UCPB1-L INSPECTION	2	MO	PM	2YR
	SWITCHGEAR	5130000		4097600901	U2 ICE OUTR MCC 2UUS1-L INSPECTION	2	MO	PM	2YR
	SWITCHGEAR	5130000		4097601001	U2 ICE OUTR MCC 2REAC21-L INSPECTION	2	MO	PM	2YR
	SWITCHGEAR	5130000		4097601101	U2 ICE OUTR MCC 2BF-L INSPECTION	2	MO	PM	2YR
	SWITCHGEAR	5130000		4097922501	U2 ICE OUTR MCC 2UUS2-M INSPECTION	2	MO	PM	2YR
	SWITCHGEAR	5130000		4097922801	U2 ICE OUTR MCC 2UCPB2-M INSPECTION	2	MO	PM	2YR
	SWITCHGEAR	5130000		4097924101	U2 ICE OUTR MCC 2SB-M INSPECTION	2	MO	PM	2YR
	SWITCHGEAR	5130000		4097924201	U2 ICE OUTR MCC 2REAC22-M INSPECTION	2	MO	PM	2YR
	SWITCHGEAR	5130000		4097924501	U2 ICE OUTR MCC 2BF-M INSPECTION	2	MO	PM	2YR
	SWITCHGEAR	5130000		4099022601	U2 ICE OUTR MCC CH-14-1 INSPECTION	2	MO	PM	2YR
	SWITCHGEAR	5130000		4099022901	U2 ICE OUTR MCC CH-14-2 INSPECTION	2	MO	PM	2YR
	SWITCHGEAR	5130000		4099023701	U2 ICE OUTR MCC CH14-3 & 2CVR-2 INSPECTION	2	MO	PM	2YR
	SWITCHGEAR	5130000		4099024101	U2 ICE OUTR MCC 2CVR & 2CVRF INSPECTION	2	MO	PM	2YR
	SWITCHGEAR	5130000		4101584701	U2 ICE OUTR MCC 2TBC-C INSPECTION	2	MO	PM	2YR
	SWITCHGEAR	5130000		4101584801	U2 ICE OUTR MCC 2EB-C, 2BBF-C INSPECTION	2	MO	PM	2YR
	SWITCHGEAR	5130000		4101584901	U2 ICE OUTR MCC 2SM-C INSPECTION	2	MO	PM	2YR
	SWITCHGEAR	5130000		4101585001	U2 ICE OUTR MCC 2TBG-C, 2TCL-C INSPECTION	2	MO	PM	2YR
	SWITCHGEAR	5130000		4101585101	U2 ICE OUTR MCC 2TBD-C INSPECTION	2	MO	PM	2YR
	SWITCHGEAR	5130000		4101585201	U2 ICE OUTR MCC 2TBC-B INSPECTION	2	MO	PM	2YR
	SWITCHGEAR	5130000		4101585301	U2 ICE OUTR MCC 2EB-B, 2BBF-B INSPECTION	2	MO	PM	2YR
	SWITCHGEAR	5130000		4101585401	U2 ICE OUTR MCC 2SM-B INSPECTION	2	MO	PM	2YR
	SWITCHGEAR	5130000		4101585501	U2 ICE OUTR MCC 2TBG-B INSPECTION	2	MO	PM	2YR
	SWITCHGEAR	5130000		4101585601	U2 ICE OUTR MCC 2TBW-B INSPECTION	2	MO	PM	2YR
	SWITCHGEAR	5130000		4101585701	U2 ICE OUTR MCC 2TI-B INSPECTION	2	MO	PM	2YR
	SWITCHGEAR	5130000		4101585801	U2 ICE OUTR MCC 2EB-A, 2BBF-A INSPECTION	2	MO	PM	2YR
	SWITCHGEAR	5130000		4101585901	U2 ICE OUTR MCC 2SM-A INSPECTION	2	MO	PM	2YR
	SWITCHGEAR	5130000		4101586001	U2 ICE OUTR MCC 2PCR-A INSPECTION	2	MO	PM	2YR
	SWITCHGEAR	5130000		4101586101	U2 ICE OUTR MCC 2TBD-A, 2TOH-A INSPECTION	2	MO	PM	2YR
	SWITCHGEAR	5130000		4101586201	U2 ICE OUTR MCC 2TI-A INSPECTION	2	MO	PM	2YR
630									
700	** CONTROLS AND COMPUTERS **	5120000		4073084901	U2 ICE OUTR MAIN TURBINE PRESSURE TRANSMITTERS	2	MO	PM	OUT
	** CONTROLS AND COMPUTERS **	5130000		0094231601	U1 ICE OUTR CALIBRATE 4KV PROTECTIVE RELAYS	1	MO	PM	OUT
	** CONTROLS AND COMPUTERS **	5130000		0094240901	U1 ICE OUTR H2 SEAL OIL SYSTEM - CALIBRATE	1	MO	PM	OUT
	** CONTROLS AND COMPUTERS **	5130000		0094241201	U1 ICE OUTR MT FRONT STANDARD GAUGES - CALIBRATE	1	MO	PM	OUT
	** CONTROLS AND COMPUTERS **	5130000		0094241901	U1 ICE OUTR MAIN TURBINE THRUST BEARING THERMOCOUPLES INSP	1	MO	PM	OUT
	** CONTROLS AND COMPUTERS **	5130000		0094242401	ICE U1 OUTR CALIBRATE HYDROGEN PURITY ANALYZER	1	MO	PM	OUT
	** CONTROLS AND COMPUTERS **	5130000		0094371101	U2 ICE OUTR GEN HYD SEAL OIL SYSTEM GAUGES-CALIBRATE	2	MO	PM	OUT
	** CONTROLS AND COMPUTERS **	5130000		0094371301	U2 ICE OUTR CALIBRATE GEN SEAL OIL SYSTEM PRESSURE SWITCHES	2	MO	PM	OUT
	** CONTROLS AND COMPUTERS **	5130000		0094371401	U2 ICE OUTR HYD SEAL OIL TANK FLOAT SWITCH-CALIBRATE	2	MO	PM	OUT
	** CONTROLS AND COMPUTERS **	5130000		0094373701	U2 ICE OUTR TEST MT VENTILATOR VALVES	2	MO	PM	OUT
	** CONTROLS AND COMPUTERS **	5130000		0094374601	U2 ICE OUTR EMERGENCY THROW OVER SWITCH-CHECK OPERATION	2	MO	PM	OUT
	** CONTROLS AND COMPUTERS **	5130000		0094375001	U2 ICE OUTR 4KV PROTECTIVE RELAYS-CALIBRATE	2	MO	PM	OUT
	** CONTROLS AND COMPUTERS **	5130000		0094375501	U2 ICE OUTR INTERLOCK CHECKS	2	MO	PM	OUT
	** CONTROLS AND COMPUTERS **	5130000		0094376301	U2 ICE OUTR CALIBRATE MAIN TURBINE LUBE OIL PRESSURE GAUGES	2	MO	PM	OUT
	** CONTROLS AND COMPUTERS **	5130000		0094714501	U1 ICE OUTR TURBINE INSTRUMENTS - CALIBRATE	1	MO	PM	OUT
	** CONTROLS AND COMPUTERS **	5130000		4057193901	U1 ICE OUTR INTERLOCK CHECKS	1	MO	PM	OUT
	** CONTROLS AND COMPUTERS **	5130000		4066143801	U2 ICE OUTR CONDENSATE PRESS/LEVEL TRANSMITTERS-CALIBRATE	2	MO	PM	3YR
	** CONTROLS AND COMPUTERS **	5130000		4072859001	U1 ICE OUTR MAIN TURBINE PRESSURE SWITCHES CALIBRATE	1	MO	PM	OUT
	** CONTROLS AND COMPUTERS **	5130000		4073085901	U2 ICE OUTR TURBINE RECORDERS CALIBRATION	2	MO	PM	OUT

Models in Authorized Status With Auto Trigger Ind 2/18/2010

WOT System Cd	WOT System Code Description	Account Nbr	WOT Unit Cond Reqd	WOT WO Nbr Task	WOT WR Task Title	WOT Unit	WO Type	WOT Job Type	Pm Frequency Code
	** CONTROLS AND COMPUTERS **	5130000		4073087401	U2 ICE OUTR - TURB PRESSURE GAUGES-CHECK CALB	2	MO	PM	OUT
	** CONTROLS AND COMPUTERS **	5130000		4073088001	U2 ICE OUTR EHC COOLER CALIBRATION	2	MO	PM	OUT
	** CONTROLS AND COMPUTERS **	5130000		4073381901	U2 ICE OUTR CALIBRATE STATOR COOLING WATER TRANSMITTERS	2	MO	PM	OUT
	** CONTROLS AND COMPUTERS **	5130000		4101387608	BSP/ICE	2	MO	PM	50Y
	** CONTROLS AND COMPUTERS **	5130000		4102051901	BSP/ SUPV	2	MO	PM	50Y
	** CONTROLS AND COMPUTERS **	5130000		4102051902	MMI/INSULATION REMOVE AND INSTALL	2	MO	PM	50Y
	** CONTROLS AND COMPUTERS **	5130000		4102051903	YOUNGS SCAFFOLD/ BUILD SCAFFOLD AROUND VALVE	2	MO	PM	50Y
	** CONTROLS AND COMPUTERS **	5130000		4102051904	FEDERAL SANDBLAST/ VALVE PARTS	2	MO	PM	50Y
	** CONTROLS AND COMPUTERS **	5130000		4102051905	RSO TBMEC TO INSPECT AND REPAIR.	2	MO	PM	50Y
	** CONTROLS AND COMPUTERS **	5130000		4102051906	CMS@ CMS NDE AND REPAIR WORK	2	MO	PM	50Y
	** CONTROLS AND COMPUTERS **	5130000		4102051907	CMS @ BSP/ NDE AND REPAIR	2	MO	PM	50Y
	** CONTROLS AND COMPUTERS **	5130000		4102051908	BSP/ICE	2	MO	PM	50Y
	CONTROLS AND COMPUTERS	5120000		4073084901	U2 ICE OUTR MAIN TURBINE PRESSURE TRANSMITTERS	2	MO	PM	OUT
	CONTROLS AND COMPUTERS	5130000		0094231601	U1 ICE OUTR CALIBRATE 4KV PROTECTIVE RELAYS	1	MO	PM	OUT
	CONTROLS AND COMPUTERS	5130000		0094240901	U1 ICE OUTR H2 SEAL OIL SYSTEM - CALIBRATE	1	MO	PM	OUT
	CONTROLS AND COMPUTERS	5130000		0094241201	U1 ICE OUTR MT FRONT STANDARD GAUGES - CALIBRATE	1	MO	PM	OUT
	CONTROLS AND COMPUTERS	5130000		0094241901	U1 ICE OUTR MAIN TURBINE THRUST BEARING THERMOCOUPLES INSP	1	MO	PM	OUT
	CONTROLS AND COMPUTERS	5130000		0094242401	ICE U1 OUTR CALIBRATE HYDROGEN PURITY ANALYZER	1	MO	PM	OUT
	CONTROLS AND COMPUTERS	5130000		0094371101	U2 ICE OUTR GEN HYD SEAL OIL SYSTEM GAUGES-CALIBRATE	2	MO	PM	OUT
	CONTROLS AND COMPUTERS	5130000		0094371301	U2 ICE OUTR CALIBRATE GEN SEAL OIL SYSTEM PRESSURE SWITCHES	2	MO	PM	OUT
	CONTROLS AND COMPUTERS	5130000		0094371401	U2 ICE OUTR HYD SEAL OIL TANK FLOAT SWITCH-CALIBRATE	2	MO	PM	OUT
	CONTROLS AND COMPUTERS	5130000		0094373701	U2 ICE OUTR TEST MT VENTILATOR VALVES	2	MO	PM	OUT
	CONTROLS AND COMPUTERS	5130000		0094374601	U2 ICE OUTR EMERGENCY THROW OVER SWITCH-CHECK OPERATION	2	MO	PM	OUT
	CONTROLS AND COMPUTERS	5130000		0094375001	U2 ICE OUTR 4KV PROTECTIVE RELAYS-CALIBRATE	2	MO	PM	OUT
	CONTROLS AND COMPUTERS	5130000		0094375501	U2 ICE OUTR INTERLOCK CHECKS	2	MO	PM	OUT
	CONTROLS AND COMPUTERS	5130000		0094376301	U2 ICE OUTR CALIBRATE MAIN TURBINE LUBE OIL PRESSURE GAUGES	2	MO	PM	OUT
	CONTROLS AND COMPUTERS	5130000		0094714501	U1 ICE OUTR TURBINE INSTRUMENTS - CALIBRATE	1	MO	PM	OUT
	CONTROLS AND COMPUTERS	5130000		4057193901	U1 ICE OUTR INTERLOCK CHECKS	1	MO	PM	OUT
	CONTROLS AND COMPUTERS	5130000		4066143801	U2 ICE OUTR CONDENSATE PRESS/LEVEL TRANSMITTERS-CALIBRATE	2	MO	PM	3YR
	CONTROLS AND COMPUTERS	5130000		4072859001	U1 ICE OUTR MAIN TURBINE PRESSURE SWITCHES CALIBRATE	1	MO	PM	OUT
	CONTROLS AND COMPUTERS	5130000		4073085901	U2 ICE OUTR TURBINE RECORDERS CALIBRATION	2	MO	PM	OUT
	CONTROLS AND COMPUTERS	5130000		4073087401	U2 ICE OUTR - TURB PRESSURE GAUGES-CHECK CALB	2	MO	PM	OUT
	CONTROLS AND COMPUTERS	5130000		4073088001	U2 ICE OUTR EHC COOLER CALIBRATION	2	MO	PM	OUT
	CONTROLS AND COMPUTERS	5130000		4073381901	U2 ICE OUTR CALIBRATE STATOR COOLING WATER TRANSMITTERS	2	MO	PM	OUT
	CONTROLS AND COMPUTERS	5130000		4101387608	BSP/ICE	2	MO	PM	50Y
	CONTROLS AND COMPUTERS	5130000		4102051901	BSP/ SUPV	2	MO	PM	50Y
	CONTROLS AND COMPUTERS	5130000		4102051902	MMI/INSULATION REMOVE AND INSTALL	2	MO	PM	50Y
	CONTROLS AND COMPUTERS	5130000		4102051903	YOUNGS SCAFFOLD/ BUILD SCAFFOLD AROUND VALVE	2	MO	PM	50Y
	CONTROLS AND COMPUTERS	5130000		4102051904	FEDERAL SANDBLAST/ VALVE PARTS	2	MO	PM	50Y
	CONTROLS AND COMPUTERS	5130000		4102051905	RSO TBMEC TO INSPECT AND REPAIR.	2	MO	PM	50Y
	CONTROLS AND COMPUTERS	5130000		4102051906	CMS@ CMS NDE AND REPAIR WORK	2	MO	PM	50Y
	CONTROLS AND COMPUTERS	5130000		4102051907	CMS @ BSP/ NDE AND REPAIR	2	MO	PM	50Y
	CONTROLS AND COMPUTERS	5130000		4102051908	BSP/ICE	2	MO	PM	50Y
700									
740	COMBUSTION CONTROLS	5120000		0094216601	U1 ICE OUTR O2 PROBE INSP	1	MO	PM	OUT
	COMBUSTION CONTROLS	5120000		0094217401	ICE OUTR DRUM LEVEL NARROW RANGE TRANSMITTER	1	MO	PM	OUT
	COMBUSTION CONTROLS	5120000		0094225101	U1 ICE OUTR L/P HEATER DRAIN VALVES & POSITIONERS	1	MO	PM	OUT
	COMBUSTION CONTROLS	5120000		0094232401	PERFORM MECHANICAL ADJUSTMENTS AND CALIBRATE THE MAIN	1	MO	PM	1YR
	COMBUSTION CONTROLS	5120000		0094232601	PERFORM MECHANICAL ADJUSTMENTS AND CALIBRATE THE FEEDWATER	1	MO	PM	1YR
	COMBUSTION CONTROLS	5120000		0094232701	PERFORM MECHANICAL ADJUSTMENTS AND CALIBRATE THE BFPT	1	MO	PM	1YR
	COMBUSTION CONTROLS	5120000		0094232901	PERFORM MECHANICAL ADJUSTMENTS AND CALIBRATE THE PULVERIZER	1	MO	PM	1YR
	COMBUSTION CONTROLS	5120000		0094233601	PERFORM MECHANICAL ADJUSTMENTS AND CALIBRATE THE BOILER	1	MO	PM	1YR
	COMBUSTION CONTROLS	5120000		0094237501	U1 ICE OUTR PLT ICE REPLACE THE S/H & R/H OUTLET HEADER THER	1	MO	PM	OUT
	COMBUSTION CONTROLS	5120000		0094237502	U1 MECH OUTR WELD S/H & R/H OUTLET HEADER THERMOCOUPLES	1	MO	PM	OUT
	COMBUSTION CONTROLS	5120000		0094243501	U1 ICE OUTR BFPT THRUST TRIP CHECK/CALIBRATE	1	MO	PM	OUT
	COMBUSTION CONTROLS	5120000		0094370401	U2 ICE OUTR TEMPERING AIR FLOW TRANSMITTER-CALIBRATE	2	MO	PM	OUT
	COMBUSTION CONTROLS	5120000		0094374101	U2 ICE OUTR FURNACE PRESS CONTACTOR/RECORDER-CALIBRATE	2	MO	PM	OUT
	COMBUSTION CONTROLS	5120000		0094374301	U2 ICE OUTR SECONDARY AIR FLOW METERS/PORTS	2	MO	PM	OUT
	COMBUSTION CONTROLS	5120000		0094374801	U2 ICE OUTR CALIBRATE F/W FLOW TRANSDUCERS AND RECEIVERS	2	MO	PM	OUT
	COMBUSTION CONTROLS	5120000		0094375101	U2 ICE OUTR CALIBRATE FFC-1A/FFC-1B FEEDWATER FLOW SUCTION	2	MO	PM	OUT
	COMBUSTION CONTROLS	5120000		0094375401	ICE U2 OUTR REMOVE O2 PROBES	2	MO	PM	OUT
	COMBUSTION CONTROLS	5120000		0094375402	ICE U2 OUTR REPAIR O2 PROBES	2	MO	PM	OUT
	COMBUSTION CONTROLS	5120000		0094375403	ICE U2 OUTR INSTALL O2 PROBES	2	MO	PM	OUT
	COMBUSTION CONTROLS	5120000		0094713401	U1 ICE OUTR BOILER INSTRUMENTATION - CALIBRATE	1	MO	PM	OUT
	COMBUSTION CONTROLS	5120000		4062610701	U1 ICE OUTR SOOTBLOWER INSTRUMENT CALIBRATION	1	MO	PM	6YR
	COMBUSTION CONTROLS	5120000		4062612301	U1 ICE OUTR 2YR SOOTBLOWER STROKE VALVES	1	MO	PM	2YR
	COMBUSTION CONTROLS	5120000		4065454601	U1 ICE OUTR CALIBRATE CONDENSATE INSTRUMENTS	1	MO	PM	3YR
	COMBUSTION CONTROLS	5120000		4071843201	U2 ICE OUTR FLASH TANK CONTROLS-CALIBRATE	2	MO	PM	OUT
	COMBUSTION CONTROLS	5120000		4072553301	U2 ICE OUTR 100# HEADER CONTROLS-CALIBRATE	2	MO	PM	OUT
	COMBUSTION CONTROLS	5120000		4072717001	U2 ICE OUTR HP HTR LEVEL CONTROLS-CALIBRATE	2	MO	PM	3YR
	COMBUSTION CONTROLS	5120000		4072719601	U2 ICE OUTR LP HEATER LEVEL CONTROLS-CALIBRATE	2	MO	PM	3YR

Models in Authorized Status With Auto Trigger Ind

2/18/2010

WOT System Cd	WOT System Code Description	Account Nbr	WOT Unit Cond Reqd	WOT WO Nbr Task	WOT WR Task Title	WOT Unit	WO Type	WOT Job Type	Pm Frequency Code
	COMBUSTION CONTROLS	5120000		4072735701	U2 ICE OUTR BFP INSTRUMENTS-CALIBRATE	2	MO	PM	4YR
	COMBUSTION CONTROLS	5120000		4072736101	U2 ICE OUTR SHELL PRESS TRANSMITTERS-CALIBRATE	2	MO	PM	4YR
	COMBUSTION CONTROLS	5120000		4072736601	U2 ICE OUTR FEEDWATER PRESS TRANSMITTERS-CALIBRATE	2	MO	PM	6YR
	COMBUSTION CONTROLS	5120000		4081957001	U1 ICE OUTR BOILER CAMERA INSPECTION	1	MO	PM	OUT
	COMBUSTION CONTROLS	5120000		4111206301	U2 ICE OUTR BOILER CAMERA INSPECTION	2	MO	PM	OUT
	COMBUSTION CONTROLS	5120000		4119200601	ICE U1 OUTR DRUM LEVEL WIDE RANGE TRANSMITTER CALIB	1	MO	PM	OUT
740									
805	ASH HANDLING, BOTTOM	5120000		4111233901	REBUILD 801 ASH GATE	2	MO	PM	50Y
	ASH HANDLING, BOTTOM	5120000		4111233902	REBUILD 802 ASH GATE	2	MO	PM	50Y
	ASH HANDLING, BOTTOM	5120000		4111727701	REBUILD ASH GATE U1	1	MO	PM	50Y
805									
815	ASH HANDLING, FLY ASH	5120000		0095067401	PLT MECH SLURRY TANK; INSPECT & REPAIR SPLASH POTS.	2	MO	PM	50Y
	ASH HANDLING, FLY ASH	5120000		4057318201	ICE - ASH HANDLING PRESSURE SWITCH CALIBRATION UNIT 2	2	MO	PM	3YR
	ASH HANDLING, FLY ASH	5120000		4057367701	ASH HANDLING VACUUM/PRESSURE TRANSMITTERS UNIT 2	2	MO	PM	6YR
	ASH HANDLING, FLY ASH	5120000		4099599001	BS/SUPV PLANT SUPVISION	2	MO	PM	50Y
	ASH HANDLING, FLY ASH	5120000		4099599002	YGS SCAFFOLD FOR REPAIRS OF SCREENS, WEIRES, ECT.	2	MO	PM	50Y
	ASH HANDLING, FLY ASH	5120000		4099599003	MMI INSUL REMOVE AND INSTALL AS NEEDED	2	MO	PM	50Y
	ASH HANDLING, FLY ASH	5120000		4099599004	RJEINTES REFRACTORY , REPLACEMENT OR REPAIR AS NEEDED	2	MO	PM	50Y
	ASH HANDLING, FLY ASH	5120000		4099599005	MCON / ASH HOPPER REPAIRS	2	MO	PM	50Y
	ASH HANDLING, FLY ASH	5120000		4099599006	VAC. CONTRACTOR/ASH HOPPER; INSPECT, CLEAN	2	MO	PM	50Y
815									
			U				ount All:	995	
							ount All:	2009	

Kentucky Power Company

REQUEST

Refer to page 40 of the Wagner Testimony and Workpaper S-4, page 26.

The discussion in the testimony refers to three parts in the proposed adjustment to the system sales margin that could be characterized as "normalizing" the test-year system sales margins. Confirm that the calculation in the workpaper includes an additional, fourth, component which reflects the proposed changes in the system sales tracker.

RESPONSE

That is correct. Section V, Workpaper S-4, Page 26, Lines 14 and 15 does reflect the effect of the proposed change in the system sales tracker.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

Refer to page 41 of the Wagner Testimony and Workpaper S-4, page 27.

Provide a detailed description of what makes up the company's intangible expense.

RESPONSE

The intangible balance of $21,071,907 is comprised of Account 302, Franchise and Consents in the amount of $52,919 and Account 303, Capitalized Software in the amount of $21,018,988.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

Refer to pages 42-43 of the Wagner Testimony and Workpaper S-4, page 41.

Confirm that the proposed adjustment to remove revenues associated with the system sales tracker is based on the proposed changes in the system sales tracker.

RESPONSE

This is not correct. Section V, Workpaper S-4, Page 31 removes from test year revenues the net incremental revenues the Company received from the ratepayers due to the fact the actual system sales margins did not meet the level of system sales margins built into base rates. These revenues should be removed due to the fact that these incremental revenues are one time nonrecurring revenues once the new base rates are established. The proposed base rates do not include these net incremental revenues becuase such net incremental revenues are not known and measurable.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

Refer to pages 44-46 of the Wagner Testimony and Workpaper S-4, page 29, specifically the discussion and calculation of the asset retirement obligation ("ARO") and accretion adjustment.

a. Identify where in the depreciation study or in the Direct Testimony of James H. Henderson ("Henderson Testimony") it can be verified that the ARO costs associated with asbestos removal at the Big Sandy plant are not included in the proposed depreciation expense.

b. Provide the calculations showing the derivations of the ARO depreciation expense and the accretion amortization expense shown in the workpaper.

RESPONSE

a) Page 10, Lines 7 through 10, of the Henderson Testimony states that Kentucky Power has recognized an ARO for asbestos at Big Sandy Plant. Further, on Lines 15 through 18, the Henderson Testimony states that "Rate-regulated companies such as Kentucky Power can continue to collect asset retirement costs (removal costs) that are NOT [emphasis added] within the scope of SFAS 143 through depreciation rates when authorized by a ratemaking [body] such as the Public Service Commission of Kentucky." Because the Big Sandy ARO is within the scope of SFAS 143 as explained in Wagner Testimony, Page 44 Line 12 through Page 45 Line 14, the Big Sandy ARO costs are not included in the proposed depreciation expense.

b) The calculations showing the derivation of the annual ARO depreciation expense ($179,508) and the accretion amortization expense ($299,880) are shown on Page 46, Lines 7 through 10, of the Wagner Testimony. The monthly ARO depreciation expense of $14,959 times 12 results in an annual ARO depreciation expense of $179,508. The monthly ARO accretion expense of $24,990 times 12 resulted in an annual ARO accretion expense of $299,880, for a total adjustment of $479,388 ($179,508 + $299,880).

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

Refer to page 55 of the Wagner Testimony.

Mr. Wagner states that Kentucky Power is proposing a reconnection charge for customers who have requested disconnection and then reconnection within a 12-month period. Explain the necessity of this proposed charge.

RESPONSE

The Company is proposing to have the costs assigned to the cost causer. Currently the Company disconnects the Customer's service upon request without charge; and the customer avoids paying any monthly charge even though the Company has investments deployed (transformer and service drop) which are dedicated to provide service to this location. When the customer calls in to re-establish their account (and the Company is required to incur the cost to perform a second trip to the customer's service location with in a twelve month period). The Company and its ratepayers incur the cost of two trips to the customer's service location without any revenue to offset the additional or incremental cost incurred. The proposed reconnection charge will require the reconnecting customer to bear their appropriate portion of this expense, rather than require the entire customer base to bear these costs.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

Refer to the Wagner Testimony, Exhibit EKW-6.

a. Refer to line 2. Explain the differences in the transportation hours among the special charges.

b. Refer to line 7. Provide the calculation for the transportation hourly rate of $8.74.

c. Refer to line 9. Provide the calculations for the fringe benefits rate.

RESPONSE

a. As stated in Wagner Testimony at page 52, lines 10 through 12, the information regarding the transportation hours was obtained from the employees who perform the work and their supervisors. The work performed for columns 1 and 2 (Reconnect Regular Hours and Reconnect into O. T. Hours), are generally performed in batches; that is, an employee will be given a group of work orders to work for, say, 4 or 8 hours. In the case of the work performed in columns 3 and 4, the employees are called out to perform one specific customer's reconnect. Column 5 work is again performed in batches-with an employee being assigned a group of work orders in a specific area. The work to be performed in the Collection Trip Charge (EKW-6, col. 5) is a different type of work than the work performed when a reconnect is required.

b. The Company has several different classification of vehicles. For each classification of vehicle the Company uses the lease cost and the fuel cost for the prior year for each classification of vehicles along with a three year average for maintenance cost also for each classification of vehicle. The total annual cost for each vehicle classification is divided by the total number of vehicles in that classification to arrive at an average annual cost per vehicle per classification. The total annual cost per vehicle is then divided by 1,165 productive hours (2080 hours less an average vacation time, sick time, training time, safety meeting time, plus other nonproductive time) to arrive at an hourly rate. This hourly rate is applied to the labor time to perform a specific job to arrive at the transportation cost associated with that specific job. (See the attached sheet for the different vehicle classifications and their associated rates) Employees who perform these Reconnect and Collection Trip Charge duties drive vehicle classification 24. (See Page 3 of this response)
c. Please see Page 4 of this response.

WITNESS: Errol K Wagner

Kentucky Power Company

Vehicle Rates - AEP Fleet Services Corporate Averages

Class	Description	Total AVG Cost	Hourly Rate Based on 1,160 Hrs
10		$ 2,136.85	$ 1.84
12	PASSENGER - COMPACT	$ 6,187.96	$ 5.33
13	PASSENGER - STANDARD	$ 6,271.81	$ 5.41
20	1/4T VAN 4X2 MINIVAN	$ 7,636.26	$ 6.58
21	1/4T SPORT UTILITY 4X2	$ 6,341.34	$ 5.47
22	1/4T SPORT UTILITY 4X4	$ 9,048.96	$ 7.80
23	1/4T PICKUP 4X2 REG CAB	$ 8,878.52	$ 7.65
24	**1/4T PICKUP 4X4 REG CAB**	**$ 10,143.07**	**$ 8.74**
30	3/4T VAN FULL SIZE AWD CARGO	$ 9,522.30	$ 8.21
32	3/4T SPORT UTILITY 4X4	$ 9,721.57	$ 8.38
33	1/2T PICKUP 4X2 REG CAB	$ 8,645.74	$ 7.45
34	1/2T PICKUP 4X4 REG CAB	$ 9,694.68	$ 8.36
40	3/4T VAN FULL SIZE 4X2 CARGO	$ 11,492.40	$ 9.91
41	3/4T SPORT UTILITY 4X2	$ 13,833.26	$ 11.93
42	3/4T SPORT UTILITY 4X4	$ 6,810.01	$ 5.87
43	3/4T PICKUP 4X2 REG CAB	$ 8,404.14	$ 7.24
44	3/4T PICKUP 4X4 REG CAB	$ 11,862.31	$ 10.23
45	3/4T SERVICE TRUCK 4X2	$ 12,532.83	$ 10.80
46	3/4T SERVICE TRUCK 4X4	$ 14,907.66	$ 12.85
49	3/4T FLATBED/DUMP/STAKE/STEP VAN 4X2	$ 11,804.84	$ 10.18
50	1T VAN 4X2	$ 9,598.96	$ 8.27
53	1T PICKUP 4X2	$ 10,041.53	$ 8.66
54	1T PICKUP 4X4	$ 12,605.74	$ 10.87
55	1T SERVICE TRUCK 4X2	$ 12,674.52	$ 10.93
56	1T SERVICE TRUCK 4X4	$ 16,779.66	$ 14.47
59	1T FLATBED/DUMP/STAKE/STEP VAN 4X2	$ 17,043.00	$ 14.69
60	SD MATERIAL HANDLER 4X2	$ 31,605.97	$ 27.25
61	SD MATERIAL HANDLER 4X4	$ 36,847.24	$ 31.76
65	SD SERVICE TRUCK 4X2	$ 16,121.64	$ 13.90
66	SD SERVICE TRUCK 4X4	$ 20,613.01	$ 17.77
67	SD AERIAL MANLIFT 4X2	$ 27,351.76	$ 23.58
68	SD AERIAL MANLIFT 4X4	$ 36,684.24	$ 31.62
69	SD FLATBED/DUMP/STAKE/STEP VAN 4X2	$ 15,133.68	$ 13.05
70	MD MATERIAL HANDLER 4X2	$ 35,993.77	$ 31.03
71	MD DIGGER DERRICK/CRANE 4X2	$ 30,299.56	$ 26.12
72	MD DIGGER DERRICK/CRANE 4X4	$ 35,775.49	$ 30.84
73	MD DIGGER DERRICK/PIN ON 4X2	$ 25,390.46	$ 21.89
74	MD DIGGER DERRICK/PIN ON 4X4	$ 39,231.79	$ 33.82
75	MD SERVICE TRUCK 4X2	$ 23,002.46	$ 19.83

Kentucky Power Company

Vehicle Rates - AEP Fleet Services Corporate Averages

Class	Description	Total AVG Cost	Hourly Rate Based on 1,160 Hrs
76	MD SERVICE TRUCK 4X4	$ 28,805.85	$ 24.83
77	MD AERIAL MANLIFT 4X2	$ 31,703.19	$ 27.33
78	MD AERIAL MANLIFT 4X4	$ 39,737.35	$ 34.26
79	MD FLATBED/DUMP/STAKE/STEP VAN 4X2	$ 14,553.77	$ 12.55
80	HD ROAD TRACTOR 6X4	$ 32,810.21	$ 28.28
81	HD DIGGER DERRICK/CRANE 6X4	$ 37,549.65	$ 32.37
82	HD DIGGER DERRICK/CRANE 6X4	$ 39,846.33	$ 34.35
83	HD DIGGER DERRICK/PIN ON 4X2	$ 34,996.26	$ 30.17
84	HD DIGGER DERRICK/PIN ON 6X4	$ 48,755.70	$ 42.03
85	HD SERVICE TRUCK 4X2	$ 19,252.28	$ 16.60
86	HD MATERIAL HANDLER 6X6	$ 36,866.27	$ 31.78
87	HD AERIAL MANLIFT 4X2	$ 37,136.46	$ 32.01
88	HD PRESSURE DIGGER 6X4	$ 31,639.36	$ 27.28
89	HD FLATBED/DUMP/STAKE/STEP VAN 6X4	$ 24,945.12	$ 21.50
91	LIGHT DUTY TRAILER	$ 1,918.14	$ 1.65
92	LIGHT DUTY TRAILER T&D MATERIAL	$ 2,403.60	$ 2.07
93	HEAVY DUTY TRAILER	$ 4,029.08	$ 3.47
94	HEAVY DUTY SPECIALTY TRAILER	$ 3,430.46	$ 2.96
95	FORKLIFT	$ 5,188.49	$ 4.47
96	TRENCHING EQUIPMENT TRENCHER	$ 4,838.93	$ 4.17
97	DOZER TRACK & RUBBER TIRE	$ 15,046.05	$ 12.97
98	ALL TERRAIN VEHICLE	$ 3,140.63	$ 2.71
99	MISCELLANEOUS EQUIPMENT	$ 1,892.44	$ 1.63

Kentucky Power Company
Fringe Benefits Rate

Account	Account Description	Fringe Benefit Rate
4081033	Fringe Benefit Loading - FICA	7.65
4081034	Fringe Benefit Loading - FUT	0.10
4081035	Fringe Benefit Loading - SUT	0.10
9250010	Frg Ben Loading - Workers Comp	0.80
9260050	Frg Ben Loading - Pension	4.90
9260051	Frg Ben Loading - Grp Ins	15.30
9260052	Frg Ben Loading - Savings	3.70
9260053	Frg Ben Loading - OPEB	8.50
		41.05

4081033	Fringe Benefit Loading - FICA	7.65
9260052	Frg Ben Loading - Savings	3.70
		11.35

Kentucky Power Company

REQUEST

Refer to page 6 of the Direct Testimony of Ranie K. Wohnhas ("Wohnhas Testimony") which refers to Kentucky Power's Case No. 9061 as support for the proposed adjustment for interest on customer deposits.

Explain whether Kentucky Power is aware of the more recent case, Case No. 1999-00176, in which the Commission established its current treatment of customer deposits as a rate-base item and treatment of interest on customer deposits.

RESPONSE

Kentucky Power was not aware of the Commission's Order in this proceeding. After reviewing the case filings and final order, Kentucky Power respectfully disagrees with the Commission's conclusion and believes its treatment of customer deposits in the application is appropriate.

In particular, the Company notes that customer deposits are not cost-free capital. By law, the Company is required to pay 6% interest on the deposits. .

The Company's position is that the customer deposit balance should be used to reduce rate base, and that the annual level of interest expense paid on the customers deposit should be included as a cost-of-service item in the determination of the Company's revenue requirement just as interest earned on any temporary investment is used to reduce the cost-of-service in determining the Company's revenue requirement. The interest paid on customer deposits is a cost of doing business and should be reflected in the rate making process.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to pages 8-9 of the Wohnhas Testimony, specifically the discussion of the adjustment for Major Event storms.

a. Explain why the company believes that three years is the appropriate period of time over which to amortize its deferred storm costs.

b. Provide a schedule of the $10,306,227 in major storm-related costs incurred by Kentucky Power in 2009 which shows the cost for each of the three storm events separately and broken down into materials costs, in-house labor, contract labor, transportation costs, housing for contract crews, and any other category the company considers material.

c. For each of the three storms, provide the total number of customers that lost power during the event, the number of customers without power reported on a daily basis during the duration of the storm event, the number of calls the company received from consumers during the event, and the average response time for answering those calls during that specific storm event.

RESPONSE

a. Due to the increased frequency of recent major storms and base rate case activity the Company believes the three year period is an appropriate period of time over which to amortize its deferred storm costs.

b. Please see pages 2 through 14 of this response. This is the exhibit that was provided in Case No. 2009-00352, Commission First Set of Data Request Dated September 30, 2009, Item No. 5.

c.

Ice Storm (January 27, 2009):

Outage Date	No. of Customers Out of Power	No. of Calls Received	Avg. Speed of Answer (seconds)
1/27/09	22,458	17,450	59
1/28/09	33,206	24,050	116
1/29/09	25,233	11,020	48
1/30/09	17,619	7,403	62
1/31/09	9,838	4,377	55
2/01/09	4,925	2,648	92
2/02/09	2,708	4,748	71
2/03/09	595	3,752	80
2/04/09	245	2,545	49

Wind Storm (February 11, 2009):

Outage Date	No. of Customers Out of Power	No. of Calls Received	Avg. Speed of Answer (seconds)
2/11/09	38,073	27,876	82
2/12/09	38,788	24,352	113
2/13/09	12,156	7,532	76
2/14/09	4,757	2,106	42
2/15/09	1,332	787	23

Thunder/Wind Storm (May 8, 2009):

Outage Date	No. of Customers Out of Power	No. of Calls Received	Avg. Speed of Answer (seconds)
5/08/09	16,059	15,120	47
5/09/09	17,972	10,034	59
5/10/09	6,932	2,925	31
5/11/09	2,089	2,950	27

WITNESS: Ranie K Wohnhas

KENTUCKY POWER COMPANY
2009 MAJOR STORMS
EXPENSE DEFERRAL REQUEST
YTD SEPTEMBER

Major Storms	Source	Incremental O&M
ICE STORM	Exhibit 1; Page 5 of 13	$ 7,678,410
WIND STORM	Exhibit 1; Page 9 of 13	$ 3,405,215
THUNDER STORM	Exhibit 1; Page 13 of 13	$ 1,339,469
TOTAL MAJOR STORMS 2009		$ 12,423,094
BASE CASE STORM EXPENSE		$ 2,116,867
MAJOR STORM DEFERRAL REQUEST		$ 10,306,227

Kentucky Power Company
2009 Ice Storm
Detailed Restoration Costs - Total
YTD September

			A Capitalized (Capital)	B Accumulated Depreciation (Removal)	C Expensed (O&M)	D Deferred Asset	A+B+C+D Total Cost to Restore
In House Costs	Regular Time	Dollars	$ 56,380	$ 13,495	$ 226,983	$ -	$ 296,858
Salary & Wages		Hours	1,749.6	482.2	7,047.0	0.0	9,278.8
	Overtime	Dollars	$ 157,131	$ 36,910	$ 557,959	$ -	$ 752,000
		Hours	4,874.0	1,130.4	17,088.8	0.0	23,093.2
	Salary & Wage	ST Fringes	$ 22,592	$ 5,437	$ 11,588	$ -	$ 39,617
	Overheads	OT Fringes	$ 18,691	$ 4,391	$ 9,826	$ -	$ 32,908
		Other Labor Fringes	$ 1,089	$ 252	$ 311	$ -	$ 1,652
		Incentives	$ 7,574	$ 1,733	$ 27,065	$ -	$ 36,372
		Construction/Retirement	$ 206,857	$ 43,992	$ -	$ -	$ 250,849
		All Other Overheads	$ 12,975	$ 2,778	$ 267,232	$ -	$ 282,985
	Total Salary & Wages		**$ 483,289**	**$ 108,988**	**$ 1,100,964**	**$ -**	**$ 1,693,241**
Transportation		Fleet	$ 41,193	$ 9,134	$ 149,160	$ -	$ 199,487
	Total Transportation		**$ 41,193**	**$ 9,134**	**$ 149,160**	**$ -**	**$ 199,487**
Other Cost Category		Cell Phone	$ 1,694	$ 375	$ 10,461	$ -	$ 12,530
		External Communications	$ -	$ -	$ 8,036	$ -	$ 8,036
		Employee/Contractor Exps	$ 56,179	$ 13,858	$ 233,505	$ -	$ 303,542
	Total Other Cost Category		**$ 57,873**	**$ 14,233**	**$ 252,002**	**$ -**	**$ 324,108**
Materials &	**Towers, Poles,**	Poles	$ 72,070	$ -	$ -	$ -	$ 72,070
Supplies	**& Fixtures**	Cross arms	$ 6,903	$ -	$ -	$ -	$ 6,903
	Overhead Conductors	Wire	$ 93,640	$ -	$ -	$ -	$ 93,640
	& Devices	Cutouts	$ 15,220	$ -	$ -	$ -	$ 15,220
		Splices	$ 23,073	$ -	$ -	$ -	$ 23,073
		Other	$ 56,804	$ (5,761)	$ 12,548	$ -	$ 63,591
	Line Transformers		$ 105,460	$ (4,704)	$ -	$ -	$ 100,756
	Services		$ -	$ -	$ -	$ -	$ -
	Meters		$ -	$ -	$ -	$ -	$ -
	Lighting & Signal Systems		$ -	$ -	$ -	$ -	$ -
	Other		$ 54,999	$ (2,083)	$ 20,214	$ -	$ 73,130
	Total Materials		**$ 428,169**	**$ (12,548)**	**$ 32,762**	**$ -**	**$ 448,383**
Cost of Providing Temporary Electric Svc			$ -	$ -	$ -	$ -	$ -
TOTAL IN HOUSE COSTS			**$ 1,010,524**	**$ 119,807**	**$ 1,534,888**	**$ -**	**$ 2,665,219**

Kentucky Power Company
2009 Ice Storm
Detailed Restoration Costs - Total
YTD September

		A Capitalized (Capital)	B Accumulated Depreciation (Removal)	C Expensed (O&M)	D Deferred Asset	A+B+C+D Total Cost to Restore
Outside Contracted Services						
Asplundh Tree Expert	Dollars	$ -	$ -	$ 1,413,897	$ -	$ 1,413,897
	Hours	0.0	0.0	39,936.0	0.0	39,936.0
ACRT Inc.	Dollars	$ 694	$ 131	$ 4,211	$ -	$ 5,036
	Hours	0.0	0.0	0.0	0.0	0.0
Area Wide Protective	Dollars	$ 14,329	$ 2,709	$ 87,016	$ -	$ 104,054
	Hours	0.0	0.0	0.0	0.0	0.0
BFD Power Services Inc.	Dollars	$ 159,732	$ 30,195	$ 969,971	$ -	$ 1,159,898
	Hours	987.1	186.6	5,994.3	0.0	7,168.0
Consumer's Energy (EST)	Dollars	$ 197,909	$ 37,412	$ 1,201,800	$ -	$ 1,437,121
	Hours	925.4	174.9	5,619.6	0.0	6,720.0
Davis H. Elliot	Dollars	$ 110,571	$ 20,902	$ 671,441	$ -	$ 802,914
	Hours	1,374.9	259.9	8,349.2	0.0	9,984.0
Hydaker Wheatlake Co.	Dollars	$ 262,734	$ 49,666	$ 1,595,452	$ -	$ 1,907,852
	Hours	1,894.9	358.2	11,506.9	0.0	13,760.0
Lee Electrical Construction	Dollars	$ 5,449	$ 1,030	$ 33,087	$ -	$ 39,566
	Hours	66.1	12.5	401.4	0.0	480.0
Mastec North America Inc	Dollars	$ 6,780	$ 1,282	$ 41,170	$ -	$ 49,231
	Hours	105.8	20.0	642.2	0.0	768.0
Midwest Electric	Dollars	$ 71,916	$ 13,595	$ 436,709	$ -	$ 522,220
	Hours	581.7	110.0	3,532.3	0.0	4,224.0
New River Electrical Corp	Dollars	$ 10,331	$ 1,953	$ 62,735	$ -	$ 75,019
	Hours	37.5	7.1	227.5	0.0	272.0
Pike Electric Inc	Dollars	$ 81,797	$ 15,462	$ 496,710	$ -	$ 593,969
	Hours	1,059.8	200.3	6,435.8	0.0	7,696.0
C.W. Wright Construction	Dollars	$ 19,477	$ 3,682	$ 118,276	$ -	$ 141,435
	Hours	138.8	26.2	842.9	0.0	1,008.0
Other Contractors (i.e. excavating, environmental)	Dollars	$ 33,654	$ 6,362	$ 204,366	$ -	$ 244,382
TOTAL OUTSIDE CONTRACTED SERVICES	Dollars	$ 975,373	$ 184,380	$ 7,336,841	$ -	$ 8,496,594
	Hours	**7,172.0**	**1,355.8**	**83,488.1**	**0.0**	**92,015.9**
Recorded Restoration Costs		**$ 1,985,897**	**$ 304,187**	**$ 8,871,729**	**$ -**	**$ 11,161,813**
Estimated Cost Yet To Be Recorded		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Restoration Costs		**$ 1,985,897**	**$ 304,187**	**$ 8,871,729**	**$ -**	**$ 11,161,813**

Kentucky Power Company
2009 Ice Storm
Detailed Restoration Costs - O&M
YTD September

			A Expensed Total (O&M)	B Expensed Incremental (O&M)	C Expensed Non-Incremental (O&M)
In House Costs	Regular Time	Dollars	$ 226,983	$ -	$ 226,983
Salary & Wages		Hours	7,047.0	0.0	7,047.0
	Overtime	Dollars	$ 557,959	$ 557,959	$ -
		Hours	17,088.8	17,088.8	0.0
	Salary & Wage	ST Fringes	$ 11,588	$ -	$ 11,588
	Overheads	OT Fringes	$ 9,826	$ 9,826	$ -
		Other Labor Fringes	$ 311	$ -	$ 311
		Incentives	$ 27,065	$ -	$ 27,065
		Construction/Retirement	$ -	$ -	$ -
		All Other Overheads	$ 267,232	$ -	$ 267,232
	Total Salary & Wages		**$ 1,100,964**	**$ 567,785**	**$ 533,179**
Transportation		Fleet	$ 149,160	$ 4,047	$ 145,113
	Total Transportation		**$ 149,160**	**$ 4,047**	**$ 145,113**
Other Cost Category		Cell Phone	$ 10,461	$ -	$ 10,461
		External Communications	$ 8,036	$ 8,036	$ -
		Employee/Contractor Exps	$ 233,505	$ 233,505	$ -
	Total Other Cost Category		**$ 252,002**	**$ 241,541**	**$ 10,461**
Materials &	**Towers, Poles,**	Poles	$ -	$ -	$ -
Supplies	**& Fixtures**	Cross arms	$ -	$ -	$ -
					$ -
	Overhead Conductors	Wire	$ -	$ -	$ -
	& Devices	Cutouts	$ -	$ -	$ -
		Splices	$ -	$ -	$ -
		Other	$ 12,548	$ 12,548	$ -
					$ -
	Line Transformers		$ -	$ -	$ -
					$ -
	Services		$ -	$ -	$ -
					$ -
	Meters		$ -	$ -	$ -
					$ -
	Lighting & Signal Systems		$ -	$ -	$ -
					$ -
					$ -
	Other		$ 20,214	$ 20,214	$ -
	Total Materials		**$ 32,762**	**$ 32,762**	**$ -**
Cost of Providing Temporary Electric Svc			$ -	$ -	$ -
TOTAL IN HOUSE COSTS			**$ 1,534,888**	**$ 846,135**	**$ 688,753**

Kentucky Power Company
2009 Ice Storm
Detailed Restoration Costs - O&M
YTD September

		A Expensed Total (O&M)	B Expensed Incremental (O&M)	C Expensed Non-Incremental (O&M)
Outside Contracted Services				
Asplundh Tree Expert	Dollars	$ 1,413,897	$ 1,120,043	$ 293,854
	Hours	39,936.0	31,636.0	8,300.0
ACRT Inc.	Dollars	$ 4,211	$ 4,211	$ -
	Hours	0.0	0.0	0.0
Area Wide Protective	Dollars	$ 87,016	$ 87,016	$ -
	Hours	0.0	0.0	0.0
BFD Power Services Inc.	Dollars	$ 969,971	$ 969,971	$ -
	Hours	5,994.3	5,994.3	0.0
Consumer's Energy	Dollars	$ 1,201,800	$ 1,201,800	$ -
	Hours	5,619.6	5,619.6	0.0
Davis H. Elliot	Dollars	$ 671,441	$ 460,729	$ 210,712
	Hours	8,349.2	5,729.0	2,620.2
Hydaker Wheatlake Co.	Dollars	$ 1,595,452	$ 1,595,452	$ -
	Hours	11,506.9	11,506.9	0.0
Lee Electrical Construction	Dollars	$ 33,087	$ 33,087	$ -
	Hours	401.4	401.4	0.0
Mastec North America Inc	Dollars	$ 41,170	$ 41,170	$ -
	Hours	642.2	642.2	0.0
Midwest Electric	Dollars	$ 436,709	$ 436,709	$ -
	Hours	3,532.3	3,532.3	0.0
New River Electrical Corp	Dollars	$ 62,735	$ 62,735	$ -
	Hours	227.5	227.5	0.0
Pike Electric Inc	Dollars	$ 496,710	$ 496,710	$ -
	Hours	6,435.8	6,435.8	0.0
C.W. Wright Construction	Dollars	$ 118,276	$ 118,276	$ -
	Hours	842.9	842.9	0.0
Other Contractors (i.e. excavating, environmental)	Dollars	$ 204,366	$ 204,366	$ -
TOTAL OUTSIDE CONTRACTED SERVICES	Dollars	**$ 7,336,841**	**$ 6,832,275**	**$ 504,566**
	Hours	**83,488.1**	**72,567.9**	**10,920.2**
Recorded Restoration Costs		**$ 8,871,729**	**$ 7,678,410**	**$ 1,193,319**
Estimated Cost Yet To Be Recorded		**$ -**	**$ -**	**$ -**
Total Restoration Costs		**$ 8,871,729**	**$ 7,678,410**	**$ 1,193,319**

Kentucky Power Company
2009 Wind Storm
Detailed Restoration Costs - Total
YTD September

			A Capitalized (Capital)	B Accumulated Depreciation (Removal)	C Expensed (O&M)	D Deferred Asset	A+B+C+D Total Cost to Restore
In House Costs Salary & Wages	Regular Time	Dollars	$ 16,457	$ 7,527	$ 132,864	$ -	$ 156,848
		Hours	549.1	267.3	4,769.5	0.0	5,585.9
	Overtime	Dollars	$ 51,350	$ 9,629	$ 580,267	$ -	$ 641,246
		Hours	1,890.2	903.8	21,199.2	0.0	23,993.2
	Salary & Wage Overheads	ST Fringes	$ 6,626	$ 3,032	$ 9,841	$ -	$ 19,499
		OT Fringes	$ 6,123	$ 2,917	$ 31,542	$ -	$ 40,582
		Other Labor Fringes	$ 378	$ 194	$ 2,121	$ -	$ 2,693
		Incentives	$ 2,778	$ 1,451	$ 34,618	$ -	$ 38,847
		Construction/Retirement	$ 125,806	$ 8,747	$ -	$ -	$ 134,553
		All Other Overheads	$ 3,202	$ 1,566	$ 84,671	$ -	$ 89,439
	Total Salary & Wages		**$ 212,720**	**$ 35,063**	**$ 875,924**	**$ -**	**$ 1,123,707**
Transportation		Fleet	$ 14,557	$ 5,998	$ 147,692	$ -	$ 168,247
	Total Transportation		**$ 14,557**	**$ 5,998**	**$ 147,692**	**$ -**	**$ 168,247**
Other Cost Category		Cell Phone	$ 4,045	$ 1,485	$ 9,912	$ -	$ 15,442
		External Communications	$ -	$ -	$ -	$ -	$ -
		Employee/Contractor Exps	$ 13,838	$ 6,011	$ 128,911	$ -	$ 148,760
	Total Other Cost Category		**$ 17,883**	**$ 7,496**	**$ 138,823**	**$ -**	**$ 164,202**
Materials & Supplies	**Towers, Poles, & Fixtures**	Poles	$ 27,359	$ -	$ -	$ -	$ 27,359
		Cross arms	$ 3,201	$ -	$ -	$ -	$ 3,201
	Overhead Conductors & Devices	Wire	$ 20,992	$ -	$ -	$ -	$ 20,992
		Cutouts	$ 7,833	$ -	$ 227	$ -	$ 8,060
		Splices	$ 16,121	$ -	$ 4,235	$ -	$ 20,356
		Other	$ 21,421	$ -	$ 11,709	$ -	$ 33,130
	Line Transformers		$ 61,759	$ -	$ -	$ -	$ 61,759
	Services		$ -	$ -	$ -	$ -	$ -
	Meters		$ -	$ -	$ -	$ -	$ -
	Lighting & Signal Systems		$ -	$ -	$ -	$ -	$ -
	Other		$ 18,455	$ (1,920)	$ 28,452	$ -	$ 44,987
	Total Materials		**$ 177,141**	**$ (1,920)**	**$ 44,623**	**$ -**	**$ 219,844**
Cost of Providing Temporary Electric Svc			$ -	$ -	$ -	$ -	$ -
TOTAL IN HOUSE COSTS			**$ 422,301**	**$ 46,637**	**$ 1,207,062**	**$ -**	**$ 1,676,000**

Kentucky Power Company
2009 Wind Storm
Detailed Restoration Costs - Total
YTD September

		A Capitalized (Capital)	B Accumulated Depreciation (Removal)	C Expensed (O&M)	D Deferred Asset	A+B+C+D Total Cost to Restore
Outside Contracted Services						
Asplundh Tree Expert	Dollars	$ -	$ -	$ 539,579	$ -	$ 539,579
	Hours	0.0	0.0	22,784.0	0.0	22,784.0
ACRT Inc.	Dollars	$ 482	$ 57	$ 1,532	$ -	$ 2,072
	Hours	0.0	0.0	0.0	0.0	0.0
Area Wide Protective	Dollars	$ 15,329	$ 1,817	$ 48,683	$ -	$ 65,830
	Hours	0.0	0.0	0.0	0.0	0.0
Entergy Arkansas	Dollars	$ 95,125	$ 11,278	$ 302,104	$ -	$ 408,507
	Hours	1,199.7	142.2	3,810.1	0.0	5,152.0
Entergy Mississippi	Dollars	$ 97,013	$ 11,502	$ 308,097	$ -	$ 416,611
	Hours	1,207.2	143.1	3,833.7	0.0	5,184.0
Davis H. Elliot	Dollars	$ 137,119	$ 16,256	$ 435,470	$ -	$ 588,846
	Hours	1,512.7	179.3	4,804.0	0.0	6,496.0
Entergy Texas	Dollars	$ 2,355	$ 279	$ 7,480	$ -	$ 10,115
	Hours	27.7	3.3	88.0	0.0	119.0
Gulf States Power	Dollars	$ 40,592	$ 4,813	$ 128,915	$ -	$ 174,320
	Hours	551.4	65.4	1,751.2	0.0	2,368.0
Mastec North America Inc	Dollars	$ 31,165	$ 3,695	$ 98,974	$ -	$ 133,833
	Hours	279.4	33.1	887.4	0.0	1,200.0
Henkels & McCoy Inc.	Dollars	$ 105,105	$ 12,461	$ 333,796	$ -	$ 451,362
	Hours	633.4	75.1	2,011.5	0.0	2,720.0
New River Electrical Corp	Dollars	$ 4,392	$ 521	$ 13,950	$ -	$ 18,863
	Hours	0.0	0.0	0.0	0.0	0.0
Pike Electric Inc	Dollars	$ 61,894	$ 7,338	$ 196,567	$ -	$ 265,800
	Hours	819.7	97.2	2,603.2	0.0	3,520.0
Riggs Distler & Company	Dollars	$ 64,365	$ 7,631	$ 204,415	$ -	$ 276,411
	Hours	376.3	44.6	1,195.1	0.0	1,616.0
Killen Contractors Inc.	Dollars	$ 38,244	$ 4,534	$ 121,458	$ -	$ 164,237
	Hours	361.4	42.8	1,147.8	0.0	1,552.0
Other Contractors (i.e. excavating, environmental)	Dollars	$ 17,800	$ 2,110	$ 56,531	$ -	$ 76,442
TOTAL OUTSIDE CONTRACTED SERVICES	Dollars	**$ 710,983**	**$ 84,292**	**$ 2,797,553**	**$ -**	**$ 3,592,828**
	Hours	**6,968.8**	**826.2**	**44,916.0**	**0.0**	**52,711.0**
Recorded Restoration Costs		**$ 1,133,284**	**$ 130,929**	**$ 4,004,615**	**$ -**	**$ 5,268,828**
Estimated Cost Yet To Be Recorded		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Restoration Costs		**$ 1,133,284**	**$ 130,929**	**$ 4,004,615**	**$ -**	**$ 5,268,828**

Kentucky Power Company
2009 Wind Storm
Detailed Restoration Costs - O&M
YTD September

			A Expensed Total (O&M)	B Expensed Incremental (O&M)	C Expensed Non-Incremental (O&M)
In House Costs	Regular Time	Dollars	$ 132,864	$ -	$ 132,864
Salary & Wages		Hours	4,769.5	0.0	4,769.5
	Overtime	Dollars	$ 580,267	$ 580,267	$ -
		Hours	21,199.2	21,199.2	0.0
	Salary & Wage	ST Fringes	$ 9,841	$ -	$ 9,841
	Overheads	OT Fringes	$ 31,542	$ 31,542	$ -
		Other Labor Fringes	$ 2,121	$ -	$ 2,121
		Incentives	$ 34,618	$ -	$ 34,618
		Construction/Retirement	$ -	$ -	$ -
		All Other Overheads	$ 84,671	$ -	$ 84,671
	Total Salary & Wages		**$ 875,924**	**$ 611,809**	**$ 264,115**
Transportation		Fleet	$ 147,692	$ 12,284	$ 135,408
	Total Transportation		**$ 147,692**	**$ 12,284**	**$ 135,408**
Other Cost Category		Cell Phone	$ 9,912	$ -	$ 9,912
		External Communications	$ -	$ -	$ -
		Employee/Contractor Exps	$ 128,911	$ 128,911	$ -
	Total Other Cost Category		**$ 138,823**	**$ 128,911**	**$ 9,912**
Materials &	**Towers, Poles,**	Poles	$ -	$ -	$ -
Supplies	**& Fixtures**	Cross arms	$ -	$ -	$ -
					$ -
	Overhead Conductors	Wire	$ -	$ -	$ -
	& Devices	Cutouts	$ 227	$ 227	$ -
		Splices	$ 4,235	$ 4,235	$ -
		Other	$ 11,709	$ 11,709	$ -
					$ -
	Line Transformers		$ -	$ -	$ -
					$ -
	Services		$ -	$ -	$ -
					$ -
	Meters		$ -	$ -	$ -
					$ -
	Lighting & Signal		$ -	$ -	$ -
	Systems				$ -
					$ -
	Other		$ 28,452	$ 28,452	$ -
	Total Materials		**$ 44,623**	**$ 44,623**	**$ -**
Cost of Providing Temporary Electric Svc			$ -	$ -	$ -
TOTAL IN HOUSE COSTS			**$ 1,207,062**	**$ 797,627**	**$ 409,435**

Kentucky Power Company
2009 Wind Storm
Detailed Restoration Costs - O&M
YTD September

		A Expensed Total (O&M)	B Expensed Incremental (O&M)	C Expensed Non-Incremental (O&M)
Outside Contracted Services				
Asplundh Tree Expert	Dollars	$ 539,579	$ 437,212	$ 102,367
	Hours	22,784.0	18,461.5	4,322.5
ACRT Inc.	Dollars	$ 1,532	$ 1,532	$ -
	Hours	0.0	0.0	0.0
Area Wide Protective	Dollars	$ 48,683	$ 48,683	$ -
	Hours	0.0	0.0	0.0
Entergy Arkansas	Dollars	$ 302,104	$ 302,104	$ -
	Hours	3,810.1	3,810.1	0.0
Entergy Mississippi	Dollars	$ 308,097	$ 308,097	$ -
	Hours	3,833.7	3,833.7	0.0
Davis H. Elliot	Dollars	$ 435,470	$ 347,874	$ 87,596
	Hours	4,804.0	3,837.7	966.3
Entergy Texas	Dollars	$ 7,480	$ 7,480	$ -
	Hours	88.0	88.0	0.0
Gulf States Power	Dollars	$ 128,915	$ 128,915	$ -
	Hours	1,751.2	1,751.2	0.0
Mastec North America Inc	Dollars	$ 98,974	$ 98,974	$ -
	Hours	887.4	887.4	0.0
Henkels & McCoy Inc.	Dollars	$ 333,796	$ 333,796	$ -
	Hours	2,011.5	2,011.5	0.0
New River Electrical Corp	Dollars	$ 13,950	$ 13,950	$ -
	Hours	0.0	0.0	0.0
Pike Electric Inc	Dollars	$ 196,567	$ 196,567	$ -
	Hours	2,603.2	2,603.2	0.0
Riggs Distler & Company	Dollars	$ 204,415	$ 204,415	$ -
	Hours	1,195.1	1,195.1	0.0
Killen Contractors Inc.	Dollars	$ 121,458	$ 121,458	$ -
	Hours	1,147.8	$ 1,147.8	$ -
Other Contractors (i.e. excavating, environmental)	Dollars	$ 56,531	56,531	$ -
TOTAL OUTSIDE CONTRACTED SERVICES		**$ 2,797,553**	**$ 2,607,588**	**$ 189,965**
		44,916.0	**39,627.2**	**5,288.8**
ecorded Restoration Costs		**$ 4,004,615**	**$ 3,405,215**	**$ 599,400**
Estimated Cost Yet To Be Recorded		**$ -**	**$ -**	**$ -**
Total Restoration Costs		**$ 4,004,615**	**$ 3,405,215**	**$ 599,400**

Kentucky Power Company
2009 Thunder Storm
Detailed Restoration Costs - Total
YTD September

			A Capitalized (Capital)	B Accumulated Depreciation (Removal)	C Expensed (O&M)	D Deferred Asset	A+B+C+D Total Cost to Restore
In House Costs	Regular Time	Dollars	$ 10,960	$ 3,098	$ 38,627	$ -	$ 52,685
Salary & Wages		Hours	372.0	105.0	1,341.9	0.0	1,818.9
	Overtime	Dollars	$ 58,284	$ 16,506	$ 183,788	$ -	$ 258,578
		Hours	1,401.2	396.5	4,640.3	0.0	6,438.0
	Salary & Wage	ST Fringes	$ 4,248	$ 1,201	$ 946	$ -	$ 6,395
	Overheads	OT Fringes	$ 6,480	$ 1,835	$ 2,081	$ -	$ 10,396
		Other Labor Fringes	$ 9	$ 3	$ 1	$ -	$ 13
		Incentives	$ 943	$ 259	$ 3,178	$ -	$ 4,380
		Construction/Retirement	$ 107,274	$ 17,340	$ -	$ -	$ 124,614
		All Other Overheads	$ (439)	$ (124)	$ 7,182	$ -	$ 6,619
	Total Salary & Wages		**$ 187,759**	**$ 40,118**	**$ 235,803**	**$ -**	**$ 463,680**
Transportation		Fleet	$ 16,528	$ 4,413	$ 54,391	$ -	$ 75,332
	Total Transportation		**$ 16,528**	**$ 4,413**	**$ 54,391**	**$ -**	**$ 75,332**
Other Cost Category		Cell Phone	$ 332	$ 85	$ 1,228	$ -	$ 1,645
		External Communications	$ -	$ -	$ -	$ -	$ -
		Employee/Contractor Exps	$ 16,761	$ 4,770	$ 30,954	$ -	$ 52,485
	Total Other Cost Category		**$ 17,093**	**$ 4,855**	**$ 32,182**	**$ -**	**$ 54,130**
aterials &	**Towers, Poles,**	Poles	$ 26,496	$ -	$ -	$ -	$ 26,496
Supplies	**& Fixtures**	Cross arms	$ 5,712	$ -	$ -	$ -	$ 5,712
	Overhead Conductors	Wire	$ 19,160	$ -	$ -	$ -	$ 19,160
	& Devices	Cutouts	$ 6,544	$ -	$ -	$ -	$ 6,544
		Splices	$ 8,332	$ -	$ -	$ -	$ 8,332
		Other	$ 44,897	$ -	$ 10,074	$ -	$ 54,971
	Line Transformers		$ 36,699	$ -	$ -	$ -	$ 36,699
	Services		$ -	$ -	$ -	$ -	$ -
	Meters		$ -	$ -	$ -	$ -	$ -
	Lighting & Signal Systems		$ -	$ -	$ -	$ -	$ -
	Other		$ 60,233	$ (5,057)	$ 1,686	$ -	$ 56,862
	Total Materials		**$ 208,073**	**$ (5,057)**	**$ 11,760**	**$ -**	**$ 214,776**
Cost of Providing Temporary Electric Svc			$ -	$ -	$ -	$ -	$ -
TOTAL IN HOUSE COSTS			**$ 429,453**	**$ 44,329**	**$ 334,136**	**$ -**	**$ 807,918**

Kentucky Power Company
2009 Thunder Storm
Detailed Restoration Costs - Total
YTD September

		A Capitalized (Capital)	B Accumulated Depreciation (Removal)	C Expensed (O&M)	D Deferred Asset	A+B+C+D Total Cost to Restore
Outside Contracted Services						
Asplundh Tree Expert	Dollars	$ -	$ -	$ 274,309	$ -	$ 274,309
	Hours	0.0	0.0	8,064.0	0.0	8,064.0
Area Wide Protective	Dollars	$ 10,346	$ 2,921	$ 24,149	$ -	$ 37,416
	Hours	0.0	0.0	0.0	0.0	0.0
Bowlin Energy LLC	Dollars	$ 77,208	$ 21,800	$ 180,215	$ -	$ 279,223
	Hours	504.4	142.4	1,177.2	0.0	1,824.0
Davis H. Elliot	Dollars	$ 168,306	$ 47,521	$ 392,852	$ -	$ 608,680
	Hours	1,672.3	472.2	3,903.5	0.0	6,048.0
Fischel	Dollars	$ 25,028	$ 7,067	$ 58,419	$ -	$ 90,513
	Hours	190.2	53.7	444.0	0.0	688.0
N.G. Gilbert	Dollars	$ 29,222	$ 8,251	$ 68,209	$ -	$ 105,682
	Hours	207.9	58.7	485.4	0.0	752.0
Mastec North America Inc	Dollars	$ 15,465	$ 4,366	$ 36,097	$ -	$ 55,928
	Hours	154.8	43.7	361.4	0.0	560.0
New River Electrical Corp	Dollars	$ 692	$ 195	$ 1,616	$ -	$ 2,504
	Hours	4.7	1.3	11.0	0.0	17.0
Pike Electric Inc	Dollars	$ 60,336	$ 17,036	$ 140,833	$ -	$ 218,205
	Hours	791.9	223.6	1,848.5	0.0	2,864.0
Other Contractors (i.e. excavating, environmental)	Dollars	$ 3,238	$ 914	$ 7,557	$ -	$ 11,709
TOTAL OUTSIDE CONTRACTED SERVICES	Dollars	**$ 389,841**	**$ 110,072**	**$ 1,184,256**	**$ -**	**$ 1,684,169**
	Hours	**$ 3,526**	**$ 996**	**$ 16,295**	**$ -**	**20,817.0**
Recorded Restoration Costs		**$ 819,294**	**$ 154,401**	**$ 1,518,392**	**$ -**	**$ 2,492,087**
Estimated Cost Yet To Be Recorded		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Restoration Costs		**$ 819,294**	**$ 154,401**	**$ 1,518,392**	**$ -**	**$ 2,492,087**

Kentucky Power Company
2009 Thunder Storm
Detailed Restoration Costs - O&M
YTD September

			A Expensed Total (O&M)	B Expensed Incremental (O&M)	C Expensed Non-Incremental (O&M)
In House Costs Salary & Wages	Regular Time	Dollars	$ 38,627	$ -	$ 38,627
		Hours	1,341.9	0.0	1,341.9
	Overtime	Dollars	$ 183,788	$ 183,788	$ -
		Hours	4,640.3	4,640.3	0.0
	Salary & Wage Overheads	ST Fringes	$ 946	$ -	$ 946
		OT Fringes	$ 2,081	$ 2,081	$ -
		Other Labor Fringes	$ 1	$ -	$ 1
		Incentives	$ 3,178	$ -	$ 3,178
		Construction/Retirement	$ -	$ -	$ -
		All Other Overheads	$ 7,182	$ -	$ 7,182
	Total Salary & Wages		**$ 235,803**	**$ 185,869**	**$ 49,934**
Transportation		Fleet	$ 54,391	$ 2,967	$ 51,424
	Total Transportation		**$ 54,391**	**$ 2,967**	**$ 51,424**
Other Cost Category		Cell Phone	$ 1,228	$ -	$ 1,228
		External Communications	$ -	$ -	$ -
		Employee/Contractor Exps	$ 30,954	$ 30,954	$ -
	Total Other Cost Category		**$ 32,182**	**$ 30,954**	**$ 1,228**
Materials & Supplies	**Towers, Poles, & Fixtures**	Poles	$ -	$ -	$ -
		Cross arms	$ -	$ -	$ -
					$ -
	Overhead Conductors & Devices	Wire	$ -	$ -	$ -
		Cutouts	$ -	$ -	$ -
		Splices	$ -	$ -	$ -
		Other	$ 10,074	$ 10,074	$ -
					$ -
	Line Transformers		$ -	$ -	$ -
					$ -
	Services		$ -	$ -	$ -
					$ -
	Meters		$ -	$ -	$ -
					$ -
	Lighting & Signal Systems		$ -	$ -	$ -
					$ -
					$ -
	Other		$ 1,686	$ 1,686	$ -
	Total Materials		**$ 11,760**	**$ 11,760**	**$ -**
Cost of Providing Temporary Electric Svc			$ -	$ -	$ -
TOTAL IN HOUSE COSTS			**$ 334,136**	**$ 231,550**	**$ 102,586**

Kentucky Power Company
2009 Thunder Storm
Detailed Restoration Costs - O&M
YTD September

		A Expensed Total (O&M)	B Expensed Incremental (O&M)	C Expensed Non-Incremental (O&M)
Outside Contracted Services				
Asplundh Tree Expert	Dollars	$ 274,309	$ 233,764	$ 40,545
	Hours	8,064.0	6,872.1	1,191.9
Area Wide Protective	Dollars	$ 24,149	$ 24,149	$ -
	Hours	0.0	0.0	0.0
Bowlin Energy LLC	Dollars	$ 180,215	$ 180,215	$ -
	Hours	1,177.2	1,177.2	0.0
Davis H. Elliot	Dollars	$ 392,852	$ 357,060	$ 35,792
	Hours	3,903.5	3,547.4	356.1
Fischel	Dollars	$ 58,419	$ 58,419	$ -
	Hours	444.0	444.0	0.0
N.G. Gilbert	Dollars	$ 68,209	$ 68,209	$ -
	Hours	485.4	485.4	0.0
Mastec North America Inc	Dollars	$ 36,097	$ 36,097	$ -
	Hours	361.4	361.4	0.0
New River Electrical Corp	Dollars	$ 1,616	$ 1,616	$ -
	Hours	11.0	11.0	0.0
Pike Electric Inc	Dollars	$ 140,833	$ 140,833	$ -
	Hours	1,848.5	1,848.5	0.0
Other Contractors *(i.e. excavating, environmental)*	Dollars	$ 7,557	$ 7,557	$ -
TOTAL OUTSIDE CONTRACTED SERVICES	Dollars	**$ 1,184,256**	**$ 1,107,919**	**$ 76,337**
	Hours	**16,295.0**	**$ 14,747.0**	**1,548.0**
Recorded Restoration Costs		**$ 1,518,392**	**$ 1,339,469**	**$ 178,923**
Estimated Cost Yet To Be Recorded		$ -	$ -	$ -
Total Restoration Costs		**$ 1,518,392**	**$ 1,339,469**	**$ 178,923**

Kentucky Power Company

REQUEST

Refer to page 10 of the Wohnhas Testimony and Section V, Workpaper S-4, page 34.

Explain why it is appropriate to include an adjustment for wage and salary increases that occur seven and eight months after the end of the test year.

RESPONSE

The merit increases constitute a known and measurable adjustment that reflects costs that the utility will incur, and will be a part of the Company's expenses, in the first year that new rates will be in effect.

WITNESS: Ranie K. Wohnhas

Kentucky Power Company

REQUEST

Refer to the Direct Testimony of Hugh E. McCoy, pages 18-22; page 5 of the Wohnhas Testimony; and Section V, Schedule 4, page 1 of the Application.

a. Beginning on line 21 of page 20, Mr. McCoy states that Kentucky Power's [p]ension funding shortfall under FAS 87 grew substantially over the period 2000-2003 . . ." Beginning on line 22 of page 18, Mr. McCoy states that the additional cash contributions of $15,390,035, which Kentucky Power proposes to include in its rate base, were made in 2005. Under the conditions described by Mr. McCoy, explain in detail why the company did not make the additional cash contributions prior to 2005.

b. Provide the specific dates in 2005 on which Kentucky Power made these additional cash contributions to its pension fund.

c. If these cash contributions were made in 2005 to address funding shortfalls that occurred during 2000-2003, explain how this reflects the pension plan's "pre-funding status" as referenced at lines 1-3 of the Wohnhas Testimony.

d. These contributions, in the amount of $15,390,035, have been on Kentucky Power's books since 2005. Explain what changes, if any, might occur in the future that will affect this account balance.

RESPONSE

a. The Company's pension plan was adequately funded prior to the December 2002 pension funding shortfall. The funding level improved during 2003; and the improvement was expected to continue over the next few years through normal market fluctuations. Accordingly, no additional contributions were made. However, in 2004, the funding shortfall increased, so that at the end of the year the shortfall was worse than it had been at the end of 2002. This 2004 funding shortfall increase occurred largely as a result of an unanticipated decline in interest rates. At that time, it became clear that the situation required a significant additional contribution.

b. The company's pension contributions in 2005 were made quarterly, as follows:

March 30	$ 3,045,764
June 30	3,045,764
September 30	3,045,764
December 29	6,638,236
Total	$15,775,528

The total prepaid pension asset declined to $15,390,035 by September 30, 2009 as described in the Company's answer below to Part d. of this question.

c. The "pre-funding status" that Witness Wohnhas refers to in his testimony is the $15,390,035 prepaid pension asset to be included in prepayments. The prepaid pension asset, which is equal to the cumulative amount of pension contributions beyond the cumulative amount of FAS 87 pension cost, is largely the result of the 2005 contributions.

d. In accordance with FAS 87, the prepaid pension asset is equal to the cumulative amount of pension contributions beyond the cumulative amount of FAS 87 pension cost. As such, the prepaid pension asset balance increases by the amount of cash pension contributions and decreases by the amount of accrued FAS 87 cost.

Accordingly, the amount of the prepaid pension asset increases in the future to the extent that cash pension contributions exceed the amount of accrued FAS 87 pension cost. Changes that could occur that would result in cash contributions beyond the amount of pension cost include minimum pension contributions required by ERISA and discretionary contributions. Minimum pension contributions occur in certain underfunding situations in accordance with the Pension Protection Act. Required minimum contributions in excess of pension cost are projected for the Company for 2011 and 2012 but may vary significantly based on future market returns.

Discretionary contributions occur when an employer makes additional contributions beyond the minimum required in order to improve the pension's funded status. This could occur when Congress temporarily reduces the normal amount of minimum required contributions. This was the case in 2005, when the Company made discretionary contributions sufficient to eliminate the pension funding shortfall.

On the other hand, the amount of the prepaid pension asset decreases in the future to the extent that the amount of FAS 87 pension cost exceeds cash contributions. This could occur when pension cost includes amortization of investment market return losses such as those experienced during the difficult market of 2008. FAS 87 defers the effects of unanticipated investment losses (or gains) and amortizes them to pension cost over a period of years. This FAS 87 deferral and amortization results in a smoothing of pension cost as markets fluctuate over time.

As a result of FAS 87's pension cost smoothing, the effects of investment gains or losses generally are reflected in pension contributions more quickly than they are reflected in pension cost. As such, pension cost is rarely equal to the amount of pension contributions for a particular year. The result is a FAS 87 prepaid pension asset when cumulative contributions exceed cumulative pension cost, or a FAS 87 accrued pension liability when cumulative pension cost exceeds cumulative pension contributions. Over time, equilibrium should be reached, as pension cost and pension contributions should be about the same over an employee's career.

WITNESS: Hugh E McCoy

Kentucky Power Company

REQUEST

Refer to page 13 of the Henderson Testimony, specifically, his discussion of the reasons for the proposed increase in the composite depreciation rate for Transmission Plant.

a. Identify and describe the factors that contributed to the reductions in the average service lives for Accounts 353, 354, and 355.

b. Explain why the period 1994-2008 was used in developing the increased removal costs reflected in the proposed depreciation rates.

RESPONSE

a. The Company's current average service lives are based on a 1989 depreciation study. Mr. Henderson did not specifically identify factors that caused the results of the current life analyses to change over the past 19 years.

b. The 15 year period of 1994-2008 provides representative data to estimate future gross salvage and cost of removal (both increases and decreases) for the Company's property.

WITNESS: James E Henderson

Kentucky Power Company

REQUEST

Refer to page 78 of 350 of the depreciation schedule attached to the Henderson Testimony.

Given that retirements for Account 354, Towers and Fixtures, are described as "minimal" and "limited," explain how Mr. Henderson was able to derive the 75 percent gross removal percentage.

RESPONSE

Please refer to page 7, Item 5 in Section II of Exhibit JEH-1 in the direct testimony of Witness Henderson for an explanation of how net salvage was estimated for all accounts.

Please also refer to page 104 of 350 of the Depreciation Study for the calculations for Transmission Plant net salvage for the derivation of the 75% gross removal percentage.

WITNESS: James E Henderson