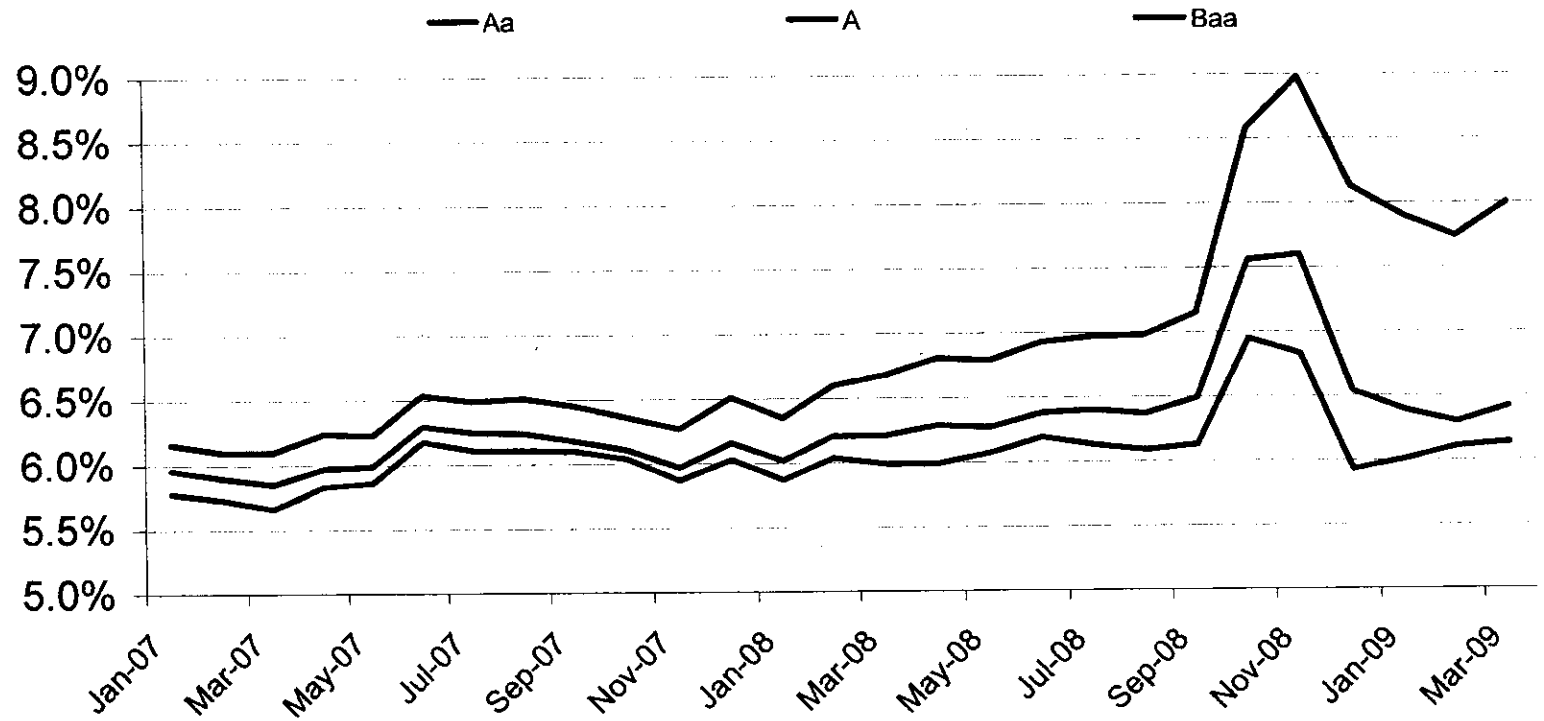
Public Utility Bond Yields
Jan '07 - Mar '09



Source: Mergent Bond Record, April 2009

EXHIBIT __ (SAR - 3)
SCHEDULE B

RECENT HIGH GRADE UTILITY BOND ISSUANCE ACTIVITY
SIX MONTHS ENDING JUNE 30, 2009

Date	Issuer	Sector	Ratings	Term	Size	Pricing Spread
5/11	San Diego Gas & Electric Co. (FMB)	Electric Utility	A1/A+	30	$300	185
3/17	Southern California Edison (FMB)	Electric Utility	A2/A	30	$500	235
2/26	Alabama Power Co.	Electric Utility	A2/A	30	$500	235
2/4	Georgia Power Co.	Electric Utility	A2/A	30	$500	225
3/10	South Carolina Elec. & Gas (FMB)	Electric Utility	A2/A-	30	$175	240
3/18	Duke Energy Indiana (FMB)	Electric Utility	A3/A	30	$450	270
5/19	PPL Electric Utilities (FMB)	Electric Utility	A3/A-	30	$300	210
1/5	PacifiCorp *(FMB)*	Electric Utility	A3/A-	30	$650	310
7/7	Interstate Power & Light Co.	Electric Utility	A3/BBB+	30	$300	185
3/3	Pacific Gas & Electric Co.	Electric Utility	A3/BBB+	30	$550	270
3/11	Florida Power & Light Co. (FMB)	Electric Utility	Aa3/A	30	$500	220
1/21	Electricite de France S.A. (EDF)	Electric Utility	Aa3/A+	30	$1,750	388
3/23	Consolidated Edison Co.	Electric Utility	A1/A-	10	$475	400
3/3	Mississippi Power Co.	Electric Utility	A2/A	10	$125	275
1/8	Progress Energy Carolinas	Electric Utility	A2/A-	10	$600	285
5/28	Public Service Company of Colorado (FMB)	Electric Utility	A3/A	10	$400	150
5/18	Central Maine Power Co.	Electric Utility	A3/A	10	$150	250
3/18	Duke Energy Ohio (FMB)	Electric Utility	A3/A	10	$450	250
3/25	Idaho Power Co. (FMB)	Electric Utility	A3/A-	10	$100	340
1/5	PacifiCorp *(FMB)*	Electric Utility	A3/A-	10	$350	310
3/19	Kansas City Power & Light Co.	Electric Utility	A3/BBB+	10	$400	460
2/9	Connecticut Light & Power *(FMB)*	Electric Utility	A3/BBB+	10	$250	250
1/21	Electricite de France S.A. (EDF)	Electric Utility	Aa3/A+	10	$2,000	400
6/24	Rochester Gas & Electric (FMB)	Electric Utility	Baa1/A-	10	$150	225
6/23	Virginia Electric & Power Co.	Electric Utility	Baa1/A-	10	$350	138
3/23	Northwestern Energy (FMB)	Electric Utility	Baa1/A-	10	$250	370
	Average Pricing Spread					273

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
AVERAGE COST OF CAPITAL
FOR THE TWELVE MONTHS ENDING JUNE 30, 2011, 2012 AND 2013

Schedule A -	Average Cost of Capital
Schedule B -	Long Term Debt - Average Capitalization and Cost
Schedule C -	Preferred Stock - Average Capitalization and Cost
Schedule D -	Calculation of Average Common Equity

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
AVERAGE COST OF CAPITAL
FOR THE TWELVE MONTHS ENDING JUNE 30, 2011
($000)

	Amount (1)	Percent of Capitalization (2)	Cost Rate (3)	Weighted Cost of Capital (4)	Pre-tax Weighted Cost of Capital (5)
Long Term Debt	$ 483,150	49.1%	5.37%	2.63%	2.63%
Customer Deposits	8,269	0.8%	4.85%	0.04%	0.04%
Preferred Stock	21,027	2.1%	5.05%	0.11%	0.18%
Common Equity	472,600	48.0%	10.00%	4.80%	7.95%
Total	$ 985,046	100.0%		7.58%	10.80%

EXHIBIT __ (SAR - 4)
SCHEDULE A - 1

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
AVERAGE COST OF CAPITAL
FOR THE TWELVE MONTHS ENDING JUNE 30, 2012
($000)

	Amount (1)	Percent of Capitalization (2)	Cost Rate (3)	Weighted Cost of Capital (4)	Pre-tax Weighted Cost of Capital (5)
Long Term Debt	$ 507,406	49.2%	5.82%	2.86%	2.86%
Customer Deposits	8,269	0.8%	4.85%	0.04%	0.04%
Preferred Stock	21,027	2.0%	5.05%	0.10%	0.17%
Common Equity	495,300	48.0%	10.00%	4.80%	7.95%
Total	$ 1,032,002	100.0%		7.80%	11.02%

EXHIBIT __ (SAR - 4)
SCHEDULE A - 2

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
AVERAGE COST OF CAPITAL
FOR THE TWELVE MONTHS ENDING JUNE 30, 2013
($000)

	Amount (1)	Percent of Capitalization (2)	Cost Rate (3)	Weighted Cost of Capital (4)	Pre-tax Weighted Cost of Capital (5)
Long Term Debt	$ 523,525	49.2%	6.13%	3.02%	3.02%
Customer Deposits	8,269	0.8%	4.85%	0.04%	0.04%
Preferred Stock	21,027	2.0%	5.05%	0.10%	0.17%
Common Equity	510,800	48.0%	10.00%	4.80%	7.95%
Total	$ 1,063,621	100.0%		7.96%	11.17%

EXHIBIT __ (SAR - 4)
SCHEDULE A - 3

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
LONG TERM DEBT - AVERAGE CAPITALIZATION AND COST
FOR THE TWELVE MONTHS ENDING JUNE 30, 2011
($000)

	Maturity Date (1)	Interest Rate % (2)	Principal Amount Outstanding 6/30/2010 (3)	Charges During Rate Year (4)	Months Outstanding (5)	Average Amount Outstanding During Rate Year (6)	Interest Expense During Rate Year (7)
Long Term Debt							
Outstanding Issues							
1999 NYSERDA Series A Fixed	August 1, 2027	5.45	33,400	-	12	33,400	1,820
1999 NYSERDA Series B Variable	July 1, 2034	2.08	33,700	-	12	33,700	701
1999 NYSERDA Series C Variable	August 1, 2028	2.08	41,150	-	12	41,150	856
1999 NYSERDA Series D Variable	August 1, 2028	2.08	41,000	-	12	41,000	853
1998 NYSERDA Series A Fixed	December 1, 2028	6.50	16,700	-	12	16,700	1,086
2003 MTN Series D @ 4.33%	September 23, 2010	4.33	24,000	(24,000)	3	6,000	260
2002 MTN Series D @ 6.64%	March 28, 2012	6.64	36,000	-	12	36,000	2,390
2004 MTN Series D @ 4.73%	February 27, 2014	4.73	7,000	-	12	7,000	331
2004 MTN Series E @ 4.80%	November 5, 2014	4.80	7,000	-	12	7,000	336
2004 MTN Series E @ 5.05%	November 4, 2019	5.05	27,000	-	12	27,000	1,364
2005 MTN Series E @ 5.84%	December 5, 2035	5.84	24,000	-	12	24,000	1,402
2006 MTN Series E @ 5.76%	November 17, 2031	5.76	27,000	-	12	27,000	1,555
2007 MTN Series F @ 5.80%	March 23, 2037	5.80	33,000	-	12	33,000	1,915
2007 MTN Series F @ 6.03%	September 19, 2017	6.03	33,000	-	12	33,000	1,989
2008 MTN Series F @ 6.85%	November 1, 2013	6.85	30,000	-	12	30,000	2,055
2009 New MTN Issuance	October 1, 2029	6.80	39,600	-	12	39,600	2,693
2010 New MTN Issuance	January 1, 2030	7.20	19,700	-	12	19,700	1,418
2010 New MTN Issuance	September 1, 2030	7.20	-	28,500	10	23,750	1,710
2011 New MTN Issuance	April 1, 2031	7.40	-	16,600	3	4,150	307
Average Long Term Debt Outstanding			473,250			$ 483,150	
Interest Charges for the Rate Year							$ 25,041
Plus: Amortization of Debt Discount and Expense							898
Less: Amortization of Premium on Debt							3
Total Cost of Debt Amount							$ 25,936
% of Average Long Term Debt Outstanding							5.37%

EXHIBIT __ (SAR - 4)
SCHEDULE B - 1

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
LONG TERM DEBT - AVERAGE CAPITALIZATION AND COST
FOR THE TWELVE MONTHS ENDING JUNE 30, 2012
($000)

	Maturity Date (1)	Interest Rate % (2)	Principal Amount Outstanding 6/30/2011 (3)	Charges During Rate Year (4)	Months Outstanding (5)	Average Amount Outstanding During Rate Year (6)	Interest Expense During Rate Year (7)
Long Term Debt							
Outstanding Issues							
1999 NYSERDA Series A Fixed	August 1, 2027	5.45	33,400	-	12	33,400	1,820
1999 NYSERDA Series B Variable	July 1, 2034	3.36	33,700	-	12	33,700	1,132
1999 NYSERDA Series C Variable	August 1, 2028	3.36	41,150	-	12	41,150	1,383
1999 NYSERDA Series D Variable	August 1, 2028	3.36	41,000	-	12	41,000	1,378
1998 NYSERDA Series A Fixed	December 1, 2028	6.50	16,700	-	12	16,700	1,086
2002 MTN Series D @ 6.64%	March 28, 2012	6.64	36,000	(36,000)	9	27,000	1,793
2004 MTN Series D @ 4.73%	February 27, 2014	4.73	7,000	-	12	7,000	331
2004 MTN Series E @ 4.80%	November 5, 2014	4.80	7,000	-	12	7,000	336
2004 MTN Series E @ 5.05%	November 4, 2019	5.05	27,000	-	12	27,000	1,364
2005 MTN Series E @ 5.84%	December 5, 2035	5.84	24,000	-	12	24,000	1,402
2006 MTN Series E @ 5.76%	November 17, 2031	5.76	27,000	-	12	27,000	1,555
2007 MTN Series F @ 5.80%	March 23, 2037	5.80	33,000	-	12	33,000	1,915
2007 MTN Series F @ 6.03%	September 19, 2017	6.03	33,000	-	12	33,000	1,989
2008 MTN Series F @ 6.85%	November 1, 2013	6.85	30,000	-	12	30,000	2,055
2009 New MTN Issuance	October 1, 2029	6.80	39,600	-	12	39,600	2,693
2010 New MTN Issuance	January 1, 2030	7.20	19,700	-	12	19,700	1,418
2010 New MTN Issuance	September 1, 2030	7.20	28,500	-	12	28,500	2,052
2011 New MTN Issuance	April 1, 2031	7.40	16,600	-	12	16,600	1,228
2011 New MTN Issuance	July 1, 2031	7.40	-	4,900	12	4,900	363
2012 New MTN Issuance	March 8, 2032	7.80	-	54,900	4	17,156	1,338
Average Long Term Debt Outstanding			494,350			$ 507,406	
Interest Charges for the Rate Year							$ 28,631
Plus: Amortization of Debt Discount and Expense							904
Less: Amortization of Premium on Debt							3
Total Cost of Debt Amount							$ 29,532
% of Average Long Term Debt Outstanding							5.82%

EXHIBIT (SAR - 4)
SCHEDULE B - 2

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
LONG TERM DEBT - AVERAGE CAPITALIZATION AND COST
FOR THE TWELVE MONTHS ENDING JUNE 30, 2013
($000)

	Maturity Date (1)	Interest Rate % (2)	Principal Amount Outstanding 6/30/2012 (3)	Charges During Rate Year (4)	Months Outstanding (5)	Average Amount Outstanding During Rate Year (6)	Interest Expense During Rate Year (7)
Long Term Debt							
Outstanding Issues							
1999 NYSERDA Series A Fixed	August 1, 2027	5.45	33,400	-	12	33,400	1,820
1999 NYSERDA Series B Variable	July 1, 2034	4.21	33,700	-	12	33,700	1,419
1999 NYSERDA Series C Variable	August 1, 2028	4.21	41,150	-	12	41,150	1,732
1999 NYSERDA Series D Variable	August 1, 2028	4.21	41,000	-	12	41,000	1,726
1998 NYSERDA Series A Fixed	December 1, 2028	6.50	16,700	-	12	16,700	1,086
2004 MTN Series D @ 4.73%	February 27, 2014	4.73	7,000	-	12	7,000	331
2004 MTN Series E @ 4.80%	November 5, 2014	4.80	7,000	-	12	7,000	336
2004 MTN Series E @ 5.05%	November 4, 2019	5.05	27,000	-	12	27,000	1,364
2005 MTN Series E @ 5.84%	December 5, 2035	5.84	24,000	-	12	24,000	1,402
2006 MTN Series E @ 5.76%	November 17, 2031	5.76	27,000	-	12	27,000	1,555
2007 MTN Series F @ 5.80%	March 23, 2037	5.80	33,000	-	12	33,000	1,915
2007 MTN Series F @ 6.03%	September 19, 2017	6.03	33,000	-	12	33,000	1,989
2008 MTN Series F @ 6.85%	November 1, 2013	6.85	30,000	-	12	30,000	2,055
2009 New MTN Issuance	October 1, 2029	6.80	39,600	-	12	39,600	2,693
2010 New MTN Issuance	January 1, 2030	7.20	19,700	-	12	19,700	1,418
2010 New MTN Issuance	September 1, 2030	7.20	28,500	-	12	28,500	2,052
2011 New MTN Issuance	April 1, 2031	7.40	16,600	-	12	16,600	1,228
2011 New MTN Issuance	July 1, 2031	7.40	4,900	-	12	4,900	363
2012 New MTN Issuance	March 1, 2032	7.80	54,900	-	12	54,900	4,282
2013 New MTN Issuance	April 1, 2033	8.10	-	21,500	3	5,375	435
Average Long Term Debt Outstanding			518,150			$ 523,525	
Interest Charges for the Rate Year							$ 31,202
Plus: Amortization of Debt Discount and Expense							886
Less: Amortization of Premium on Debt							3
Total Cost of Debt Amount							$ 32,085
% of Average Long Term Debt Outstanding							6.13%

EXHIBIT (SAR - 4)
SCHEDULE B - 3

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
PREFERRED STOCK - AVERAGE CAPITALIZATION AND COST
FOR THE TWELVE MONTHS ENDING JUNE 30, 2011
($000)

	Dividend Rate % (1)	Principal Amount Outstanding 6/30/2010 (2)	Charges During Rate Year (3)	Average Amount Outstanding During Rate Year (4)	Dividend Amount During Rate Year (5)	Percent (6)
Fixed Rate:	4.50	$ 7,029	$ -	$ 7,029	$ 316	
	4.75	1,998	-	1,998	95	
	4.35	6,000	-	6,000	261	
	4.96	6,000	-	6,000	298	
Total				$ 21,027	$ 970	
Add: Amortization and Redemption Costs					91	
Total Cost of Preferred Stock					$ 1,061	5.05%

EXHIBIT __ (SAR - 4)
SCHEDULE C - 1

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
PREFERRED STOCK - AVERAGE CAPITALIZATION AND COST
FOR THE TWELVE MONTHS ENDING JUNE 30, 2012
($000)

	Dividend Rate % (1)	Principal Amount Outstanding 6/30/2011 (2)	Charges During Rate Year (3)	Average Amount Outstanding During Rate Year (4)	Dividend Amount During Rate Year (5)	Percent (6)
Fixed Rate:	4.50	$ 7,029	$ -	$ 7,029	$ 316	
	4.75	1,998	-	1,998	95	
	4.35	6,000	-	6,000	261	
	4.96	6,000	-	6,000	298	
Total				$ 21,027	$ 970	
Add: Amortization and Redemption Costs					91	
Total Cost of Preferred Stock					$ 1,061	5.05%

EXHIBIT__ (SAR - 4)
SCHEDULE C - 2

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
PREFERRED STOCK - AVERAGE CAPITALIZATION AND COST
FOR THE TWELVE MONTHS ENDING JUNE 30, 2013
($000)

	Dividend Rate % (1)	Principal Amount Outstanding 6/30/2012 (2)	Charges During Rate Year (3)	Average Amount Outstanding During Rate Year (4)	Dividend Amount During Rate Year (5)	Percent (6)
Fixed Rate:	4.50	$ 7,029	$ -	$ 7,029	$ 316	
	4.75	1,998	-	1,998	95	
	4.35	6,000	-	6,000	261	
	4.96	6,000	-	6,000	298	
Total				$ 21,027	$ 970	
Add: Amortization and Redemption Costs					91	
Total Cost of Preferred Stock					$ 1,061	5.05%

EXHIBIT ___ (SAR - 4)
SCHEDULE C - 3

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
CALCULATION OF AVERAGE COMMON EQUITY FOR THE
TWELVE MONTHS ENDING DECEMBER 31, 2009, THE SIX MONTHS ENDING
JUNE 30, 2010 AND THE TWELVE MONTHS ENDING JUNE 30, 2011
($000)

	Common Stock (1)	Retained Earnings (2)	Capital Stock Expense (3)	Total Common Equity (1)+(2)-(3)
Balance - December 31, 2008 - Ratemaking	$ 254,300	$ 119,000	$ 5,000	$ 368,300
Twelve Months Ending December 31, 2009				
January 31	254,300		5,000	
February 28	254,300		5,000	
March 31	254,300		5,000	
April 30	279,300		5,000	
May 31	279,300		5,000	
June 30	279,300		5,000	
July 31	279,300		5,000	
August 31	279,300		5,000	
September 30	279,300		5,000	
October 31	279,300		5,000	
November 30	279,300		5,000	
December 31	318,500		5,000	
Total	$ 3,283,700		$ 60,000	
Average for Twelve Months Ending December 31, 2009	273,642	119,000	5,000	387,642
Adjustment for Retained Earnings	-	5,000	-	5,000
Balance - December 31, 2009 - Ratemaking	273,642	124,000	5,000	392,642
Six Months Ending June 30, 2010				
January 31	318,500		5,000	
February 28	318,500		5,000	
March 31	318,500		5,000	
April 30	318,500		5,000	
May 31	318,500		5,000	
June 30	321,600		5,000	
Total	$ 1,912,600		$ 30,000	
Average for Six Months Ending June 30, 2010	318,800	124,000	5,000	437,800
Adjustment for Retained Earnings	-	9,800	-	9,800
Balance - June 30, 2010 - Ratemaking	318,800	133,800	5,000	447,600
Twelve Months Ending June 30, 2011				
July 31	321,600		5,000	
August 31	321,600		5,000	
September 30	321,600		5,000	
October 31	321,600		5,000	
November 30	321,600		5,000	
December 31	324,800		5,000	
January 31	324,800		5,000	
February 28	324,800		5,000	
March 31	324,800		5,000	
April 30	324,800		5,000	
May 31	324,800		5,000	
June 30	326,700		5,000	
Total	$ 3,881,000		$ 60,000	
Average for Twelve Months Ending June 30, 2011	323,400	133,800	5,000	452,200
Adjustment for Retained Earnings	-	20,400	-	20,400
Balance - June 30, 2011 - Ratemaking	323,400	154,200	5,000	472,600

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
CALCULATION OF AVERAGE COMMON EQUITY FOR THE
TWELVE MONTHS ENDING JUNE 30, 2012 AND THE TWELVE MONTHS
ENDING JUNE 30, 2013
($000)

	Common Stock (1)	Retained Earnings (2)	Capital Stock Expense (3)	Total Common Equity (1)+(2)-(3)
Twelve Months Ending June 30, 2012				
July 31	326,700		5,000	
August 31	326,700		5,000	
September 30	326,700		5,000	
October 31	326,700		5,000	
November 30	326,700		5,000	
December 31	328,600		5,000	
January 31	328,600		5,000	
February 28	328,600		5,000	
March 31	328,600		5,000	
April 30	328,600		5,000	
May 31	328,600		5,000	
June 30	328,600		5,000	
Total	$3,932,800		$ 60,000	
Average for Twelve Months Ending June 30, 2012	327,700	154,200	5,000	476,900
Adjustment for Retained Earnings	-	18,400	-	18,400
Balance - June 30, 2012 - Ratemaking	327,700	172,600	5,000	495,300
Twelve Months Ending June 30, 2013				
July 31	328,600		5,000	
August 31	328,600		5,000	
September 30	328,600		5,000	
October 31	328,600		5,000	
November 30	328,600		5,000	
December 31	328,600		5,000	
January 31	328,600		5,000	
February 29	328,600		5,000	
March 31	328,600		5,000	
April 30	328,600		5,000	
May 31	328,600		5,000	
June 30	328,600		5,000	
Total	$3,943,200		$ 60,000	
Average for Twelve Months Ending June 30, 2013	328,600	172,600	5,000	496,200
Adjustment for Retained Earnings	-	14,600	-	14,600
Balance - June 30, 2013 - Ratemaking	328,600	187,200	5,000	510,800

CENTRAL HUDSON GAS & ELECTRIC CORPORATION

CAPITALIZATION AND CAPITALIZATION RATIOS

Schedule A - Forecast of Capitalization and Capitalization Ratios, 2009 - 2013

Schedule B - Actual Capitalization and Capitalization Ratios, 2004 - 2008

Schedule C - Actual Capitalization and Capitalization Ratios, June 30, 2009

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
CAPITALIZATION AND CAPITALIZATION RATIOS
YEAR ENDING 2009 - 2013
($000)

	2009	2010	2011	2012	2013
Capitalization					
Long Term Debt [1]	$ 453,452	$ 477,649	$ 499,146	$ 518,043	$ 534,240
Unamortized Premium & Discount on Debt - net	(52)	(49)	(46)	(43)	(40)
Total Long Term Debt	453,400	477,600	499,100	518,000	534,200
Preferred Stock	21,027	21,027	21,027	21,027	21,027
Common Stock	318,500	324,800	328,600	328,600	328,600
Retained Earnings	124,000	143,700	164,700	187,200	205,800
Total Common Equity	442,500	468,500	493,300	515,800	534,400
Total Capitalization	$ 916,900	$ 967,100	$ 1,013,400	$ 1,054,800	$ 1,089,600
Short Term Debt	-	-	-	-	-
Total (Financial)	$ 916,900	$ 967,100	$ 1,013,400	$ 1,054,800	$ 1,089,600
Customer Deposits	8,269	8,269	8,269	8,269	8,269
Total (Ratemaking)	$ 925,169	$ 975,369	$ 1,021,669	$ 1,063,069	$ 1,097,869
Capitalization Ratios (Financial)					
Long Term Debt	49.4%	49.4%	49.3%	49.1%	49.0%
Short Term Debt	0.0%	0.0%	0.0%	0.0%	0.0%
Total Debt	49.4%	49.4%	49.3%	49.1%	49.0%
Preferred Stock	2.3%	2.2%	2.1%	2.0%	1.9%
Common Equity	48.3%	48.4%	48.7%	48.9%	49.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%
Capitalization Ratios (Ratemaking)					
Long Term Debt	49.0%	49.0%	48.9%	48.7%	48.7%
Customer Deposits	0.9%	0.8%	0.8%	0.8%	0.8%
Preferred Stock	2.3%	2.2%	2.1%	2.0%	1.9%
Common Equity	47.8%	48.0%	48.3%	48.5%	48.7%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

(1) Includes Current Maturities of Long Term Debt

EXHIBIT __ (SAR - 5)
SCHEDULE A

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
CAPITALIZATION AND CAPITALIZATION RATIOS
YEAR ENDED 2004 - 2008
($000)

	Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008
Capitalization					
Long Term Debt[1]	$ 319,950	$ 343,964	$ 370,961	$ 403,950	$ 433,855
Unamortized Premium & Discount on Debt - net	(67)	(64)	(61)	(58)	(55)
Total Long Term Debt	319,883	343,900	370,900	403,900	433,800
Preferred Stock	21,030	21,027	21,027	21,027	21,027
Common Stock	254,300	254,300	254,300	254,300	254,300
Retained Earnings	25,600	43,300	68,700	92,700	119,000
Total Common Equity	279,900	297,600	323,000	347,000	373,300
Total Capitalization	$ 620,813	$ 662,527	$ 714,927	$ 771,927	$ 828,127
Short Term Debt	12,000	30,000	13,000	42,500	25,500
Total (Financial)	$ 632,813	$ 692,527	$ 727,927	$ 814,427	$ 853,627
Customer Deposits	6,496	7,101	7,954	8,126	8,445
Total (Ratemaking)	$ 627,309	$ 669,628	$ 722,881	$ 780,053	$ 836,572
Capitalization Ratios (Financial)					
Long Term Debt	50.5%	49.7%	51.0%	49.6%	50.8%
Short Term Debt	1.9%	4.3%	1.8%	5.2%	3.0%
Total Debt	52.4%	54.0%	52.7%	54.8%	53.8%
Preferred Stock	3.3%	3.0%	2.9%	2.6%	2.5%
Common Equity	44.2%	43.0%	44.4%	42.6%	43.7%
Total	100.0%	100.0%	100.0%	100.0%	100.0%
Capitalization Ratios (Ratemaking)					
Long Term Debt	51.0%	51.4%	51.3%	51.8%	51.9%
Customer Deposits	1.0%	1.1%	1.1%	1.0%	1.0%
Preferred Stock	3.4%	3.1%	2.9%	2.7%	2.5%
Common Equity	44.6%	44.4%	44.7%	44.5%	44.6%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

(1) Includes Current Maturities of Long Term Debt

EXHIBIT __ (SAR - 5)
SCHEDULE B

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
CAPITALIZATION AND CAPITALIZATION RATIOS
as of June 30, 2009
($000)

	(a) Consolidated Capital CH Energy	Consolidated Percentage	(b) Non-Utility Capital	Non-Utility Percentage	(c) Central Hudson Utility Capital Structure (a - b + CDs)	Utility Percentage
Long Term Debt	$463,896	45.72%	$50,000	29.73%	$413,896	48.42%
Preferred Stock	21,027	2.07%	0	0.00%	21,027	2.46%
Common Equity	529,769	52.21%	118,169	70.27%	411,600	48.15%
Total Capital	$1,014,692	100.00%	$168,169	100.00%	$846,523	
Customer Deposits (CDs)					8,269	0.97%
Total Capital w/ CDs					$854,792	100.00%

CENTRAL HUDSON GAS & ELECTRIC CORPORATION

S&P AND MOODY'S DEBT RATINGS, 1999-2009

Year [1]	S&P Rating [2]	Moody's Rating [2]
1999	A	A3
2000	A	A3
2001	A	A3
2002	A	A2
2003	A	A2
2004	A	A2
2005	A	A2
2006	A	A2
2007	A	A2
2008	A	A2
2009	A	A2

(1) All years shown are ratings at year-end, except 2009, which is June 30
(2) Ratings on Central Hudson's senior unsecured debt

DIRECT TESTIMONY
OF
PAUL E. HAERING

Q. Please state your name and business address for the record.

A. My name is Paul E. Haering. I am employed by Central Hudson Gas & Electric Corporation ("Central Hudson"), and my business address is 284 South Avenue, Poughkeepsie, New York 12601.

Q. What is your educational background?

A. I graduated from Manhattan College in 1986 with a Bachelor of Engineering in Electrical Engineering degree. In 1992, I received a Masters of Electrical Engineering degree from Polytechnic University. In 2007, I received a Masters in Business Administration from Rensselaer Polytechnic Institute

Q. In what capacity are you employed at Central Hudson?

A. I am Vice President of Engineering and Environmental Services. In that capacity I am responsible for the engineering planning and designs for Central Hudson's gas and electric transmission and distribution systems. I am also responsible for the construction, operation, and maintenance of our electrical substations. In addition I have responsibility for our Environmental Affairs and Special Services organizations.

Q. Please summarize your professional experience.

A. I joined Central Hudson in 1986 as a Junior Engineer in the Substation Design Section. In 1989 I was transferred to work as a staff engineer in the

Operations Services Division, which has responsibility for the operation, maintenance, and construction of the Company's substation facilities. In 1994 I was promoted to the position of Operations Supervisor in the Operations Services Division. In 2000, I was transferred to the position of Engineer in the Electric System Protection Section. In 2001, I became Section Engineer for the Distribution Engineering Section. In 2003, I was promoted to the position of Manager of Electric Transmission and Distribution. In 2004, I was promoted to the position of Manger of Electric Engineering Services. In May of 2007 I was named the Assistant Vice President of Engineering and Environmental Services and in December 2007 I was named to my current position.

Q. Have you previously testified before the Commission?

A. Yes. I submitted testimony in cases 05-E-0934, 05-G-0935, 08-E-0887 and 08-G-0888.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony presents the Company's forecast of capital expenditures for the electric, gas and common programs for the period July 1, 2010 through June 30, 2011. This forecast is presented in Exhibit __ (PEH-1).

Q. Was Exhibit __ (PEH-1) prepared by you or under your supervision and direction?

A. Yes.

Q. What is the Capital Forecast set forth in Exhibit___ (PEH-1) based on?

A. The Capital Forecast represents the rate year portion of the Company's most recent Five-Year Capital Plan. The Five-Year Capital Plan I have relied upon was developed by me or under my supervision and direction for purposes as part of our standard annual capital planning process. The entire Five-Year Capital Plan is summarized in Exhibit ___ (PEH-2).

Q. Please explain what is shown on Exhibit __ (PEH-2), Schedule A, entitled "Capital Program – Total."

A. Schedule A is a summary of the Capital Plan for the period 2010 through 2014 and includes the Rate Year ending June 30, 2011. This schedule includes annual totals for each of the three major categories: Electric, Gas and Common. Additional detailed information for each of these three major categories is included in Schedules B through D, respectively. The indicated figures include allowance for funds used during construction (AFUDC).

Q. Referring to Exhibit __ (PEH-2), Schedule B, what is included in the

"Production" category of that schedule?

A. The "Production" category includes construction expenditures for the Central Hudson hydroelectric generating facilities at Sturgeon Pool, Dashville, and High Falls, and the combustion turbine plants at Coxsackie and South Cairo. Expenditures in 2010 of $1,280,000, and 2011 of $1,802,000 are projected for the installation of rubber bladder flashboards for the Sturgeon Pool Dam. This project is the latest in a series of projects that addressed safety, infrastructure and operational efficiency issues at the Sturgeon Pool Dam. The other projects were compliance projects including the pinning of the dam, the installation of a 90% drain, the replacement of the intake rack, and the upgrade of the generators' governors.

Expenditures in 2010 of $177,000, in 2011 of $360,000, in 2012 of $3,488,000 and 2013 of $3,378,000 are projected for fuel modules, stacks, an air compressor at South Cairo, and improved emission controls and monitoring equipment for the combustion turbine plants at Coxsackie and South Cairo. This equipment required to maintain the reliability of service to customers in the Northwest portion of our territory.

Q. Are expenditures included for major rebuilds of existing lines in the "Transmission" category of Schedule B of Exhibit __ (PEH-2)?

A. Yes. It is projected that several existing lines will have construction initiated

or to have come into service during this period.

Several of the major reconductoring / rebuild projects include the "WM" line rebuild, and the "WH-1", "WH-2", "A", and "C" reconductoring projects. The planning and permitting work on the "WM" rebuild project started in 2006. This project is for the rebuild of an 11.5 mile 69 kV Line in Orange County. The project is being driven by a combination of infrastructure needs and local area growth. Expenditures in 2006 were $392,000, in 2007 were $1,246,000, in 2008 were $767,000, and in 2009 are projected to be $1,441,000. Anticipated expenditures for the remainder of the project are $3,386,000 in 2010, $3,331,000 in 2011, and $6,599,000 in 2012 for a total of $16,607,000. These costs are based on the current design, which is subject to change. The final design will be determined coincident with the completion of the permitting process. Increases in the cost of the project have been associated with the length of the permitting process, as well as scope and design changes driven by the permitting process.

The construction of a new (3.5 mile) 115kV line between the East Fishkill and Wiccopee Substations included in the previous forecast has been deferred. The need for the project was to provide a third input into the Southern Dutchess Area to address a post-contingency load serving capability issue. The load in this area includes several large industrial customers. One of these customers recently announced its intention to

cease operation. This has been accounted for in the load forecast for the Southern Dutchess Area. The need for this project may return as the economy improves and/or new businesses occupy vacant manufacturing space in this area, and the project will be reevaluated at such time as that occurs.

The "WH-1", "WH-2", "A", and "C" reconductoring projects are all associated with our Aluminum Conductor Steel Reinforced (ACSR) Conductor Replacement Program. These projects are predicated on conductor failures and subsequent testing of the line conductor. Test results have shown that the existing ACSR conductors on several lines require replacement. The replacement will improve reliability and load serving capability to customers.

The 69 kV "WH-1" and "WH-2" lines are 13.8 miles long each and are located in Ulster and Sullivan County. Anticipated expenditures are $459,000 in 2013 and $4,932,000 in 2014 for a total of $5,391,000.

The 115 kV "A" and "C" lines are a total of 10.8 miles long and are located in Dutchess County (this reconductoring project may be subject to Article VII). Anticipated expenditures are $105,000 in 2012, $107,000 in 2013, $3,288,000 in 2014 and $4,252,000 in 2015 for a total of $7,752,000.

In 2006, Central Hudson performed a LiDAR survey of its entire transmission system. This cutting-edge surveying technology combined with

the use of PLS-CADD modeling technology allowed Central Hudson's engineers to develop very detailed models of the transmission system under varying loading conditions. The study revealed a number of changes in right of way use, ground profiles and encroachments (compared to what was assumed in the original design). Central Hudson has identified 624 spans that do not meet required clearances and will be including in the transmission sag mitigation program. The detailed design work for the mitigation program is being performed on an ongoing basis and as such the program plan and costs continue to be refined. Although originally it was anticipated that 108 spans would be addressed utilizing retensioning, upon analysis of some of the detailed designs it was determined that additional costs would be required to re-tension adjoining spans significantly raising the cost of re-tensioning a span. Based upon this experience, we have reevaluated our mitigation approach and are currently planning to address all 624 spans (1,000 structures) utilizing structure / conductor replacements. Current anticipated expenditures for structure/conductor replacements primarily as a result of this change are $37,781,000 for the five-year program ending in 2013. This amount includes $8,762,000 for work to be completed in 2009.

Q. Referring to Exhibit __ (PEH-2), Schedule B, are there any comments that you would like to make on the "Substation" category?

A. "Substation" expenditures for the period 2010 through 2014 are projected to total $63,634,000. These expenditures are for both the installation of new substations and improvements to existing substations. These projects will reinforce the electric system and provide the capability to reliably serve projected area distribution loads as system growth occurs.

A new Spackenkill Road substation is planned to address demand growth in the Poughkeepsie area. This station will be rated 50 MVA 115-13.8 kV, is currently anticipated to cost $7,033,000 and is planned to go into service in June 2010. No expenditures are included in the rate period beginning July 1, 2010. The new Galeville substation, which was part of the P & MK lines Article VII approval, is a new 30 MVA 115X69-13.8 kV that is being built to address load growth and prepare for the conversion of the existing MK transmission line facilities to 115 kV. It is anticipated that the Galeville project will be completed in June 2010 with a projected cost of $7,703,000. No capital expenditures for this project are included in the rate period beginning July 1, 2010.

Other substation projects include the upgrade / replacement of three substations, and a systematic program to replace circuit breakers.

The Saugerties, Rhinebeck and Grimley Road (Ellenville) Substations are planned to be upgraded / replaced. A new Saugerties station, scheduled for completion in 2012, is planned to address infrastructure and operating

limitations of the existing substation. The new station will be rated 50 MVA, 115X69-13.8 kV and will be initially supplied by 69 kV transmission facilities (this design is consistent with the long range plan for this area which will ultimately have this substation served by 115 kV transmission). The total cost for this project is budgeted at $8,521,000. A 20 MVA 115-13.8 kV transformer primarily serves the Rhinebeck Substation's distribution load. This load is reserved by two 69-13.8 kV transformers. These transformers are over 77 years old and have reached the end of their useful lives. It is planned to replace these two transformers with a second 20 MVA 115-13.8 kV transformer to create a firm 50 MVA substation at Rhinebeck. The total cost of this project is currently estimated at $6,426,000 with an in-service date of 2013. The Grimley Road (Ellenville) project scope is planned to include the replacement of the existing transformers with the transformers from the Galeville Substation, replacement of the wood pole substation structures with steel structures and upgrading protection, control and communications. The total cost of this project is forecasted at $1,522,000 with an in-service date of 2013.

The Coombe Road Substation will relocate our existing Neversink Substation distribution facilities. Load growth in the Town of Neversink and surrounding areas served by the Neversink Substation is driving the need for additional transformer capacity. In addition, as a result of a requirement of

transfer of ownership to the New York City Board of Water Supply of the Neversink Hydro Plant, construction at a new location is planned. This new station will be rated 6 MVA 69-13.8 kV, is anticipated to cost $2,534,000 and is planned to go into service in 2011.

Central Hudson has an ongoing plan to address circuit breaker infrastructure issues. These issues include circuit breakers with duties near or above their interrupting ratings, circuit breakers with poor condition assessments, and circuit breakers that are obsolete. The selection criteria used for this program has identified 152 circuit breakers for replacement, including eight 345kV circuit breakers over the next five years at an estimated cost of $22,433,000. These replacements will improve the reliability of the transmission and distribution system.

As mentioned above, the construction of a new 115kV line between the East Fishkill and Wiccopee Substations has been deferred. Substation expansion projects associated with this project at East Fishkill and Wiccopee have been deferred as well.

Q. Are there any significant programs and or expenditures that are included in the "Distribution Improvements" category?

A. The majority of the expenditures relate to the day-to-day capital requirements for distribution facilities. However, $20,954,000 has been included for

infrastructure improvement programs. Additionally $5,268,000 is included for the construction of distribution facilities associated with the substation reinforcements previously discussed. These amounts in aggregate are consistent with previous projections.

Several infrastructure improvement programs have been identified. These include a program to address 14.4kV paper and lead insulated cable replacement, 14.4kV underground infrastructure, distribution porcelain cutout replacement, distribution pole replacements, Automatic Load Transfer (ALT) switch installations, Distribution Recloser replacements, and other smaller programs.

Central Hudson has approximately 55 miles of 14.4kV paper and lead insulated cables much of which is over 60 years old and is nearing the end of its useful life. Failures of these cables are typically associated with cracks in the lead sheath. Central Hudson has developed a systematic plan to replace the highest priority cables and address underground infrastructure (manholes, pullboxes and ductbanks) as part of this program. The majority of this work is associated with cables that feed the secondary network for the City of Poughkeepsie. Planned expenditures for these projects are $8,225,000 over five years.

Q. Please explain how forecasted construction expenditures were determined

for the electric program categories entitled "New Business", "Transformers", and "Meters" as shown on Schedule B of Exhibit __ (PEH-2).

A. Forecasted expenditures for these categories were trended based on recent actual experience. In general these categories are related to the growth in number of residential customers and residential sales. The forecast overall is lower than the previous forecast due to the economic downturn and lower commodity costs.

Q. Has the Company proposed any projects for which it would plan to seek funding under the American Recovery and Reinvestment Act of 2009 (ARRA)?

A. Yes, the Company has been monitoring the available funding opportunities under the ARRA. The Company has been evaluating both individual projects as well as collaborative opportunities. On July 2, 2009 the Company filed with the Commission an updated list of projects for which the Company is considering applying for funding through the U.S. Department of Energy Smart Grid Investment Grant Program (SGIG).

Q. Could you provide some details on the proposed projects?

A. The first project is a Company proposal for a Smart Grid deployment. The project will create ten Smart Grid electric distribution circuits through the

installation of AMI, distribution equipment upgrades with automatic control and communication capabilities, Home Area Networks, and PHEV charging stations. More details of this are provided in the testimony of the Smart Grid Panel. Additionally the Company is proposing two collaborative projects with the NYISO and the New York State Transmission Owners. One project is a statewide deployment of Phasor Monitoring Units (PMUs) for which the Company has one installation proposed. The second is the installation of additional statewide reactive resources based on an electric system loss analysis performed by the NYISO. The Company has proposed to install 35 MVAr of capacitors as part of this project.

Q. Has the Company included any of the costs of these projects in its Capital Forecast?

A. No. Based on the currently unknown nature of the approval process timing and outcome for federal funding applications for these projects, they have not been included in the Capital Forecast.

Q. Referring to Exhibit __ (PEH-2), Schedule C, what are the major projects identified in the Gas Capital Program.

A. The major projects identified in the Gas Capital Program are the "CH" system reinforcement, three transmission line valve replacements, three

transmission line valve additions, and two new regulator stations (at North Coxsackie and Vail Road), three regulator station re-builds, 3 regulator station upgrades, and a major road rebuild project on Robinson Avenue (NYS Rte 9W) in Newburgh.

Q. Referring to Exhibit __ (PEH-2), Schedule C, are there any comments that you would like to make on the "Transmission" category?

A. "Transmission" expenditures for the period 2010 through 2014 are projected to total $4,448,000. These expenditures are for both the installation of new transmission system components and improvements to the existing transmission system. Many of the capital improvements stem from system load studies or studies performed as part of the pipeline integrity program. Other improvements are from conditions discovered during the operating and maintenance of the system.

Q. Referring to Exhibit __ (PEH-2), Schedule C, are there any comments that you would like to make on the "Regulator" category?

A. "Regulator" expenditures for the period 2010 through 2014 are projected to total $3,465,000. These expenditures are for both the installation of new regulator stations and improvements to existing regulator stations. These projects will reinforce the gas system and provide the capability to reliably

serve projected area distribution loads as system growth occurs.

Q. Are there any specific regulator station projects that are required because of new load development?

A. Yes. The Capital Forecast includes the installation of two new regulator stations related to new load development. These stations are the North Coxsackie and Vail Road regulator stations scheduled for 2011. There are three other stations that are being rebuilt due to load increases, the East Fishkill Regulator station in 2013 to support increased load on the "HH" system in southern Dutchess County, the Hudson River Psychiatric Center in 2013 to provide redundancy to the "HP" system in the Hyde Park area, and the Austin Road station in 2012 in Carmel to provide redundancy to the "SM" system in Mahopac and Carmel.

Q. Please explain how forecasted construction expenditures were determined for the categories entitled "New Business" and "Meters" as shown on Schedule C of Exhibit __ (PEH-2).

A. Forecasted expenditures for these categories are based on the forecasted residential heating customer growth rate for the service territory. Load growth is allocated to gas systems in locations where there is expected residential development or where there are active discussions for commercial

development. Expenditures in these two categories are projected to decrease from prior years based on lower forecasted customer growth.

Q. Please explain how forecast construction expenditures were determined for the category entitled "Distribution Improvements" as shown on Schedule C of Exhibit __ (PEH-2).

A. Forecasted expenditures for this category are based on a combination of distribution improvement initiatives. The category includes service replacements, required cast iron replacement associate with road re-builds or other facility replacements, cast iron or steel main replacements based on system studies, maintenance history, and risk analysis modeling. There are also system reinforcement projects included in this category to ensure system reliability, the most significant of these being the "CH" line reinforcement of the western Orange County area, a continuation of a project started in 2006. The infrastructure replacement projects are reviewed and prioritized based on operating experience and risk reduction. The projected expenditures for the "Distribution Improvements" category total $45,431,000 and reflects a continuation of an accelerated program for gas safety and system reliability improvements. The capital funds related to the replacement of cast iron and steel mains and services is $36,824,000 over the 5-year forecast.

Q. Referring to Exhibit __ (PEH-2), Schedule D, what are the major projects identified in the Common Capital Program.

A. The Lands and Building and Office Categories forecast are primarily replacement of existing small capital components. In addition, the Lands and Buildings category includes some major capital replacements at our facilities, such as roofs, windows, and HVAC equipment. There are also two larger facility projects proposed during the period. The first is the construction of a new customer service facility in 2011 in the New Paltz area. This new facility is part of a broader plan that includes the sale of Central Hudson's Eltings Corners facility (subject to Commission approval pursuant to Section 70). The timing of the sale remains unknown at the time of the preparation of my testimony. The second is an expansion of the Fishkill Operating Headquarters storeroom and vehicle maintenance garage in 2012 and 2013. The Land and Buildings category also includes capital improvements for energy efficiency improvements at existing Company facilities.

The Tools category provides for normal tool replacement only. No new methods of operation are anticipated that would substantially increase this category's spending.

The Transportation and Mobile Tool categories reflect a level required for the normal replacements at the current fleet size.

The I/T and Communication categories reflect expenditures that are consistent with the 5-year I/T Plan. The I/T Plan includes the purchase of a new mainframe in 2012 to replace the mainframe at the Disaster Recovery site, replacement of the map-board and video wall in the system operations center and the continuation of the 5-year PC replacement schedule and the 3-year mobile computer replacement schedule. The Communication Plan consists of the replacement of the voice recording systems in the call center and system operations, and replacement of the telephone system at South Road in 2014.

Q. How did you apportion the forecasted capital requirements in 2010 and 2011 into the July 2010-June 2011 rate year?

A. A detailed capital forecast was prepared for 2010 that identified expenditures for both the first half of the year and the second half of the year. The 2011 forecast was apportioned between the first and second halves of the year. For Gas Production, Transmission, Regulating Stations, New Business and Distribution Improvements categories, the apportionment was based on individual historical trends in expenditures in these categories. For all other categories, one half of the respective annual amount was included.

Q. Does this conclude your direct testimony?

A. Yes.

Exhibits of
Paul E. Haering

EXHIBIT __ (PEH -1)

EXHIBIT __ (PEH –2)
Schedule A
Schedule B
Schedule C
Schedule D

CENTRAL HUDSON GAS & ELECTRIC CORPORATION

CAPITAL PROGRAM - TOTAL

($000)

	Rate Year 7/1/2010 - 6/30/2011
ELECTRIC	$ 58,284
GAS	14,623
COMMON	11,097
CORPORATE TOTAL	$ 84,004

Note: These values include AFUDC

EXHIBIT __(PEH-2)

CENTRAL HUDSON GAS & ELECTRIC CORPORATION

CAPITAL EXPENDITURES PROGRAM

Schedule A – Capital Program - Total

Schedule B – Capital Program - Electric

Schedule C – Capital Program - Gas

Schedule D – Capital Program - Common

CENTRAL HUDSON GAS & ELECTRIC CORPORATION

CAPITAL PROGRAM - TOTAL

($000)

	2010	2011	2012	2013	2014	TOTAL	Rate Year 7/1/2010 - 6/30/2011
ELECTRIC	$ 58,011	$ 60,325	$ 68,690	$ 61,454	$ 60,265	$ 308,745	$ 58,284
GAS	13,536	14,135	16,634	19,748	17,466	81,521	14,623
COMMON	9,496	12,871	12,987	12,759	12,272	60,384	11,097
CORPORATE TOTAL	$ 81,043	$ 87,331	$ 98,312	$ 93,961	$ 90,003	$ 450,650	$ 84,004

Note: These values include AFUDC

Exhibit __ (PEH-2)
Schedule A

CENTRAL HUDSON GAS & ELECTRIC CORPORATION

CAPITAL PROGRAM - ELECTRIC

($000)

	2010	2011	2012	2013	2014	TOTAL	Rate Year 7/1/2010 - 6/30/2011
Production	$ 1,660	$ 2,369	$ 3,698	$ 3,593	$ 1,041	$ 12,361	$ 2,221
Transmission	10,963	12,909	17,543	11,677	9,814	62,905	12,889
Substation	13,377	12,373	13,688	11,716	12,479	63,634	12,241
New Business	6,797	6,981	7,333	7,728	8,497	37,336	6,889
Distribution Improvements	17,524	17,796	18,130	17,998	18,822	90,270	16,249
Transformers	6,182	6,349	6,670	7,028	7,728	33,957	6,265
Meters	1,508	1,549	1,627	1,714	1,885	8,282	1,528
Total	$ 58,011	$ 60,325	$ 68,690	$ 61,454	$ 60,265	$ 308,745	$ 58,284

Note: These values include AFUDC

Exhibit __ (PEH-2)
Schedule B

CENTRAL HUDSON GAS & ELECTRIC CORPORATION

CAPITAL PROGRAM - GAS

($000)

	2010	2011	2012	2013	2014	TOTAL	Rate Year 7/1/2010 - 6/30/2011
Production	$ 253	$ 396	$ 299	$ 215	$ 148	$ 1,311	$ 260
Transmission	886	816	895	1,056	795	4,448	911
Regulating Stations	369	539	756	841	960	3,465	430
New Business	3,256	3,435	3,500	3,948	4,836	18,976	3,319
Distribution Improvements	7,252	7,404	9,610	12,080	9,084	45,431	8,171
Meters	1,519	1,545	1,574	1,609	1,644	7,890	1,532
Total	$ 13,536	$ 14,135	$ 16,634	$ 19,748	$ 17,466	$ 81,521	$ 14,623

Note: These values include AFUDC

Exhibit __ (PEH-2)
Schedule C

CENTRAL HUDSON GAS & ELECTRIC CORPORATION

CAPITAL PROGRAM - COMMON

($000)

	2010	2011	2012	2013	2014	TOTAL	Rate Year 7/1/2010 - 6/30/2011
Lands and Buildings	$ 1,509	$ 3,426	$ 3,214	$ 2,875	$ 1,532	$ 12,556	$ 2,684
Office Equipment	2,548	4,104	4,454	4,526	4,570	20,202	3,427
Tools	799	784	783	724	778	3,868	792
Communication	243	191	194	193	964	1,785	217
Transportation	4,396	4,366	4,343	4,440	4,427	21,974	3,976
Total	$ 9,496	$ 12,871	$ 12,987	$ 12,759	$ 12,272	$ 60,384	$ 11,097

Note: These values include AFUDC

Exhibit __ (PEH-2)
Schedule D

DIRECT TESTIMONY
OF
JOHN J. BORCHERT

Q. Please state your name and business address for the record.

A. My name is John J. Borchert. I am employed by Central Hudson Gas & Electric Corporation "Central Hudson" and my business address is 284 South Avenue, Poughkeepsie, New York 12601.

Q. What is your educational background?

A. I graduated from State University of New York Maritime College in 1985 with a Bachelors of Engineering degree in Electrical Engineering and from Polytechnic University in 1991 with a Master of Science degree in Electrical Engineering. I am a Professional Engineer in the State of New York.

Q. In what capacity are you employed at Central Hudson?

A. I am the Manager of Gas & Mechanical Engineering. In that capacity, I am responsible for the engineering plans and designs for Central Hudson's gas transmission and distribution system and for Central Hudson's Manufactured Gas Plant ("MGP") Site Investigation and Remediation ("SIR") Program.

Q. Please summarize your professional experience.

A. I joined Central Hudson in 1985 as a Junior Engineer in the Electric Planning Section of Engineering performing fuel forecasting, generation planning, and various system studies. In 1989, I was transferred to the Energy Efficiency Division where I developed demand side management programs and

forecasts. In 1995, I was transferred to the position of Power Quality Services Engineer in Customer Service where I was the customer liaison to IBM and other large or high tech customers in the service territory. In 1996, I was transferred to the position of Supervisor of New Business in the Mid-Hudson Division in Customer Service and in 1999 promoted to the position of Customer Service Manager of the Mid-Hudson Division, where I oversaw all aspects of Customer Service Operations for the area. In 2005, I was promoted to my current position of Manager of Gas & Mechanical Engineering.

Q. Have you previously testified before the Commission?

A. Yes. Most recently, I have submitted testimony in Cases 08-E-0887 & 08-G-0888 however; I have also submitted testimony in Cases 92-E-1055 and 92-G-1056, and Cases 05-E-0934 and 05-G-0935.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to describe Central Hudson's program for the investigation and remediation of former manufactured gas plant sites. I will provide 1) an overview of the Central Hudson's MGP SIR Program and 2) cost projections for Central Hudson's MGP Remediation Program expenditures mandated by consent orders, regulations, or agreements.

In addition, I will discuss non labor expense related expenditures linked to the Company's gas leak repair program.

Q. What are the expected expenditures related to the MGP SIR Program?

A. In total, we expect $11.7 million in MGP SIR expenditures in the forecast rate year. The site-by-site rate year forecasts are shown on Exhibit ___ (JJB-1), Schedule A. Exhibit ___ (JJB-1) Schedule A summarizes the non-labor costs for the annual period ending 6/30/11.

I also note that Central Hudson expects to expend an additional $13.9 million for the MGP SIR Program in the two years following the rate year. The increase in rate year and following period expenditures is principally attributable to the continuation of remediation at the Newburgh MGP site that began in 2007 with source removal at the upland "Area A" and will continue through the commencement of a three-year period of remediation at the Newburgh MGP site for Areas "B" and "C", which are in or adjoining the Hudson River.

Q. Please provide an overview of Central Hudson's MGP SIR Program.

A. Central Hudson has an ongoing program for the management of its MGP sites, verifying that the required remedial response measures (site investigations followed, in some cases, by remedial actions) are properly performed for sites containing wastes from a number of former MGP

facilities.

Q. Please provide a brief background on MGP facilities.

A. Manufactured gas plants were operated until the mid 1900s to produce combustible gases from coal and oil for Municipal Street lighting systems and for lighting and other uses in homes and businesses in densely populated regions of the United States. When these plants were removed from service, some by-products of the gas production process remained. The DEC, which regulates the timing and extent of remediation of MGP sites in New York State, has notified Central Hudson that it believes Central Hudson or predecessor organizations at one time owned and/or operated MGPs at eight sites in Central Hudson's franchise territory. The DEC has further requested that Central Hudson investigate and, if necessary, remediate these sites under a Consent Order, Voluntary Clean-up Agreement, or Brownfield Clean-up Agreement. A number of the sites are now owned by third parties and have been redeveloped for other uses.

Q. Please identify the eight MGP sites that have been identified by the DEC for investigation and potential remediation by Central Hudson.

A. There are four sites in Dutchess County (River St. in Beacon, and Bayeux St., Laurel St., and North Water St. in Poughkeepsie); two sites in Ulster County (East Strand in Kingston and Ferry St. in Saugerties); one site in

Greene County (in Catskill); and one site in Orange County (Water St. in Newburgh). The DEC has required Central Hudson to investigate and, when believed necessary by DEC to protect human health and the environment, to undertake remedial actions for these eight sites.

Q. What is the current status of each of these sites?

A. For the Newburgh (Water St.) site the remediation has been completed in one area (Area A) and the final remedial design has been submitted to the NYSDEC for approval for the other two areas (Areas B & C); for Laurel St-Poughkeepsie, the remediation has been completed under a Voluntary Cleanup Agreement and is awaiting NYSDEC review and approval of the remediation work completed; for North Water St-Poughkeepsie the site investigation is currently underway under a NYSDEC-approved Brownfield Clean-up Agreement; for the Kingston site the investigation work is currently underway under a NYSDEC-approved Brownfield Clean-up Agreement; for the Catskill site the investigation is currently underway under a NYSDEC-approved Brownfield Clean-up Agreement; and for the Saugerties (Ferry St.) and the Bayeaux St.-Poughkeepsie sites, Central Hudson has informed DEC that it believes it does not have any liability.

For the Beacon (River St.) site the remediation is complete.

Q. What sites are currently included in the Company's MGP SIR Program?

A. Sites currently included in the SIR Program include: Newburgh, Poughkeepsie-Laurel St., Poughkeepsie-North Water St., Kingston, and Catskill.

Q. Of the $11.7 million in forecast rate year MGP SIR costs, what portion is due to the Newburgh site?

A. As shown on Exhibit ____ (JJB-1), Schedule A, approximately $10.6 million (or 90%) is due to the Newburgh site.

Q. Please explain how you developed the forecast rate year expenditures for the Newburgh site.

A. I have been intimately involved with activities at the Newburgh site since assuming my current position in 2005. Following over 10 years of investigation under the terms of a 1995 DEC Consent Order, the DEC issued a Proposed Remedial Action Plan ("PRAP") in February 2005. DEC held a Public Hearing on the PRAP and has completed a public comment period. DEC issued a Record of Decision ("ROD") in December 2005. The Company requested in April 2006 that the Remedial Design schedule of 180 days as specified in the Consent Order be extended until September 2006 for the upland "source" area of the project and extended until December 2007 for the shore and river areas of the project. The Remedial Work Plan for the remediation of the upland "source" area of the Newburgh Site known as Area

A was filed and approved in November 2006. The work on this area started in November 2006 and was completed in August 2007. The Project Manager for this work reported to me. A construction completion report was submitted to the DEC in February 2008 and approved.

The Company has been working with the DEC to complete the remedial work plan for the shore and river areas, or areas B and C, of the Newburgh site. In December 2008, the Company requested a further extension of the deadline to complete the remedial work plan. The pre-investigation design and remedial work plan for the remaining areas identified by DEC in the ROD were completed under my supervision and direction and a final remedial work plan was submitted to DEC on June 1, 2009. In a letter dated July 10, 2009, the DEC provided comments to the work plan and has indicated that they are prepared to approve the final remediation work plan pending our response to their comments and completion of a citizen participation meeting. Central Hudson has filed responses to the comments on July 24, 2009 and expects the required public meeting to be held by September 15, 2009.

In Exhibit ___ (JJB-1), Schedule B, I have shown a breakdown of the rate year costs forecast for the Newburgh site. This is based on the remedial work plan that was submitted to DEC. The forecasts shown in Exhibit ___ (JJB-1) Schedule B reflect my best current estimates of the activities that will be required at the Newburgh site, the costs for those activities and the timing

of the incurrence of those costs. In Exhibit ____ (JJB-1), Schedule B, I have shown the major activities and costs on a quarterly basis.

Assuming that the remedial work plan is approved by the DEC September 2009, as is currently anticipated, we expect that costs will be incurred in 2009 through 2011 for the remediation project, to be constructed over a three-year period beginning in 2009. Following completion of construction, a post-construction operating and monitoring program is expected to be required.

Q. Please explain how your present forecast for the Newburgh Site for the period July 2010-June 2011 compares to the forecasts that you developed in Cases 08-E-0887 and 08-G-0888 for that same period.

A. The present forecast for the Newburgh site for the period July 2010 – June 2011 projects expenditures of $10,620,000 for this period. The prior forecast shown in my rebuttal testimony and exhibits in Cases 08-E-0887 and 08-G-0888 for the same period showed expenditures of $10,005,000. The schedule of the work to be completed during this time has not changed and the differences in costs are related to refinements in the costs related to construction oversight.

Q. What would happen if the DEC authorization to proceed is not received in 2009, as you have assumed, but sometime in 2010, would that necessarily cause the costs you have forecast to be incurred during the rate year to be

delayed until after the rate year?

A. No. The major activity identified on Exhibit ____ (JJB-1) Schedule B during the second half of 2009 and the first half of 2010 is the pre-construction activities, construction of the access roads, soil/sediment storage areas, and construction of a barrier wall that is needed to permit removal of sediment in the Hudson River. The construction window for the barrier wall placement is between November and April, and the likely duration of the in-river construction portion of the task is approximately 20 weeks. If there were a delay of less than about six months, there should be no significant impact on completing the work planned during the second half of 2009 and the first half of 2010 and the work to be completed during the rate year. If the delay were to be longer than six months, it would shift this work into the rate year and timing of other tasks to complete river work would be shifted out to beyond the rate year, however, there would be little change in the rate year cost projections.

Q. What is the current status of the Laurel St. site?

A. The Company has completed site remediation of the upland "source" area under the terms of a Voluntary Consent Order with DEC. The construction completion report is being prepared for submittal to the DEC. The DEC has informed us that a post-construction operating and monitoring program is required and it is currently being developed by Central Hudson and is

expected to be completed and filed during 2009.

Q. Are other costs expected to be incurred at the Laurel St. site?

A. Yes. It is likely that additional costs will be incurred to conduct additional site investigations the DEC may require for down gradient areas along the property line and under NYS Route 9. It is possible that the additional investigations will indicate that additional remediation may be required.

Q. What is the current status of the North Water St. MGP site?

A. The Company has conducted site investigations at the North Water St. MGP site under the terms of a Voluntary Clean-up Agreement with the DEC. In May 2005, the agreement was converted to a Brownfield Clean-up Agreement. Continued site investigation and remediation is required under the Brownfield Clean-up Agreement. Based on the status of the investigation, which is in the remedial investigation stage, remediation construction is expected to begin in 2013 on the upland "source" area of the site. The proposed remediation action plan, pre-design investigation, and remedial design all remain to be completed prior to any remediation work commencing.

Q. What is the status of the Kingston site?

A. DEC has requested that the Company conduct additional site investigations

and remediation, if necessary, at this site. Based on the status of the investigations at this site, which are in the early site investigation stage, and the time generally required to complete the DEC-required processes, remediation construction is not anticipated to occur prior to the end of 2015. The proposed remediation action plan, pre-design investigation, and remedial design all remain to be completed prior to any remediation work commencing.

Q. What is the status of the Catskill site?

A. DEC has requested that the Company conduct additional site investigations and remediation, if necessary, at this site. Based on the status of the investigations at these sites, which are in the final site investigation stage, and the time generally required to complete the DEC-required processes, remediation construction is anticipated to begin in 2012. The proposed remediation action plan, pre-design investigation, and remedial design all remain to be completed prior to any remediation work commencing.

Q. Have you developed the actual costs incurred by Central Hudson for the MGP SIR Program during the test year?

A. Yes. The actual costs incurred during the period 4/1/06 through 3/31/09 exclusive of Company labor are shown in Columns 2, 4, and 6 of Exhibit ___ (JJB-1), Schedule A, and amount to $12.7 million. On average, this amount

is $4.23 million per year and when adjusted for inflation is $4.3 million per year, which is greater than the existing annual cash rate allowance of $2.815 million for MGP costs.

Q. Have you developed a recommendation for the rate allowance for the costs incurred by Central Hudson for the MGP SIR for the rate period July 1, 2009 through June 30, 2010?

A. Yes. I propose to use the actual three-year average costs from April 1, 2006 through March 31, 2009 of $4.23 million; adjusted for inflation as the basis for the rate allowance. The actual expenditures in excess of the rate allowance should be deferred for future recovery, with carrying charges, per the prior rate plan and the latest Commission Order in June 2009. The proposed treatment of these deferrals is discussed in the testimony of the Revenue Requirements Panel.

Q. Please summarize your expectations of the costs that the Company will incur during the rate year for the MGP SIR Program.

A. My cost forecasts are shown on Schedule A of Exhibit ___ (JJB-1), which summarizes the non-labor costs for the annual period ending 6/30/10. These forecasts are based on the expected scope of activities at each of the five sites and on the expected level of costs for those activities. The unit costs were developed based on my experience in managing the MGP Program

since 2005 and on information provided by the Company's consultants. As discussed previously, the increased level of spending is primarily due to the implementation of the Newburgh Remediation Work Plan. The shoreline and river areas of this remediation project will be completed in 2009, 2010, and 2011. The other major project will be the completion of the investigation and start of the remediation at the North Water Street site. Finally, continuing investigations at the Laurel Street, Kingston, & Catskill sites and ongoing O&M Activity at the sites are also included.

Q. Can you describe Central Hudson's gas leak repair program?

A. Yes, Central Hudson is continuing to propose an enhanced gas leak repair program which will 1) reduce the total leak backlog, 2) align the current leak repair plan with the current Gas Safety target for leak management, and 3) reflect in the Company's rate case forecast and capture in the Rate Plan the trend of the increase in gas leak expenses and the increase in the level of leaks discovered.

Q. What is the current Gas Safety target for gas leak management?

A. The calendar year 2009 Gas Safety Targets are the same as the calendar year 2008 Gas Safety targets set in the prior rate plan that expired in June 2009. For the Leak Management target, Central Hudson will incur a rate adjustment if a year-end 2009 total leak backlog of 250 is exceeded, unless

the Company repairs 340 leaks during the calendar year 2009. The rate adjustment if the target thresholds are not met is 8 basis points.

However, these targets were recently changed and new Gas Safety Targets have been set for calendar year 2010 in the Commission's June 2009 Order. The new gas leak management targets are a repairable leak backlog of 30 leaks at year-end 2010 and total leak backlog of 350 leaks at year-end 2010. The rate adjustment if the target thresholds are not met is 9 basis points for the repairable leak target and 5 basis points for the total leak target.

Q. What are the projected costs for this program?

A. The expense related costs for this program are shown on Exhibit __(JJB-2), Leak Repairs of Distribution Main (Non-Labor). These costs include the increases in gas leak repair costs related to the higher cost of materials for restoration efforts such as paving and blacktop of which the Company cannot control. These costs also include an increase in the number of leaks repaired beginning in 2009 through the use of contractors through 2014. This cost projection will completely replace the non-labor AP costs from the inflation pool.

Q. What is the basis for the leak repair costs projected for the rate period and the period 2010 through 2014?

A. The basis of the leak repair costs for the rate period and the period beyond was an average of the leak repair costs for the period 2006 through 2008, inflated at a rate consistent with the GDP Index.

Q. Is this consistent with gas leak repair expenditures experienced during the test year?

A. No, the test year understates the AP costs related to leak repairs. Several factors caused this test period to be understated. The first is an increase in the number of leaks repair in the last six months of the test period than during the first six months, during the last six months 225 leaks were repaired (62%). Second is a lag in the payment for leaks repaired due to the contract requirement that the leak be repaired, rechecked, and closed before payment is rendered. Third is the restoration costs for leaks repaired during the winter months are not seen until April or May when the restoration can be completed. Finally, is the reduction in fuel costs during the winter reduced our contract repair cost, but now that fuel costs have again increased, contract costs for repairs since the test year have also increased. With this proposed cost projection and basis, Central Hudson is projecting gas leak expenses of $1,370,000 for the rate year, which is lower than the $1,502,000 amount allowed in the recently approved rate case.

Q. What is the growth rate used on the base cost of leak repair established

using the three year average?

A. The growth rate is the same as the inflation rate filed in this case.

Q. Why has the company proposed this increase in the number of leak repairs?

A. The Company has proposed this increase for two reasons. First, there was a substantial increase in the level of leaks discovered from the period 2004 through 2008. The number of leaks discovered increased from 444 in 2004, to 519 in 2005, 649 in 2006, 576 in 2007, and 626 in 2008. Second is that during the period 2004 through 2008, although the Company has consistently repaired between 446 and 544 leaks, during the period 2004 through 2008, Central Hudson experienced an increase of its year-end backlog from 286 to 486 as a result of increased effort and improved methods adopted by the Company to identify leaks. As we have been finding more leaks, we believe that funding an increased annual level of leak repairs is desirable.

Q. Does this conclude your pre-filed testimony?

A. Yes, it does.

Exhibits of
John J. Borchert

EXHIBIT __ (JJB-1)
Schedule A
Schedule B

EXHIBIT __ (JJB-2)

Schedule A of Exhibit __(JJB-1)
Historic and Projected Non-Labor Costs of
Manufactured Gas Plant
Site Investigation and Remediation Program

Site	Actual Costs For Year Ending 3/31/2007	Actual Costs For Year Ending 3/31/2008	Actual Costs For Year Ending 3/31/2009		Projected Costs for Year Ending 12/31/2009	Projected Costs for Year Ending 12/31/2010		Projected Costs for Year Ending 6/30/2011
Newburgh	$1,968	$3,648	$1,650		$3,318	$10,661		$10,620
Laurel St.		$243	$2,866		$1,128	$181		$96
N. Water St.		$151	$558		$1,129	$663		$715
Kingston		$104	$38		$38	$183		$134
Saugerties	$171	$0	$0		$0	$0		$0
Bayeaux St.		$6	$0		$0	$0		$0
Catskill		$310	$98		$145	$98		$178
Beacon		$931	-$42		$9	$0		$0
Total	$2,140	$5,393	$5,168		$5,766	$11,787		$11,744

EXHIBIT__(JJB-1)
Schedule A

Schedule B of Exhibit __(JJB-1)
Projected Non-Labor Costs of the
Newburgh Manufactured Gas Plant
Site Investigation and Remediation Program

Task	2009				
	Q1	Q2	Q3	Q4	Total
Supplemental PID	$ -	$ -	$ -	$ -	$ -
NAPL Recovery/Monitoring	$ 1,640	$ 5,405	$ 6,630	$ 6,630	$ 20,305
Design	$ 153,707	$ 541,509	$ 50,000	$ -	$ 745,216
Const. Support	$ -	$ -	$ 131,250	$ 131,250	$ 262,500
City of Newburgh Engineer	$ -	$ -	$ -	$ 10,000	$ 10,000
NAPL rem/ISCO/IC (B4)	$ -	$ -	$ -	$ -	$ -
Barrier Wall/IC (B7)	$ -	$ -	$ 250,000	$ 1,950,000	$ 2,200,000
Sediment Rem/IC (C5/C5A)	$ -	$ -	$ -	$ -	$ -
Engineering Report	$ -	$ -	$ -	$ -	$ -
O&M	$ -	$ -	$ -	$ -	$ -
DEC Labor	$ 80,074	$ -	$ -	$ -	$ 80,074
Misc & Program Allocation	$ 56,222	$ 47,113	$ 43,615	$ 36,615	$ 183,565
Total	$ 291,643	$ 594,027	$ 481,495	$ 2,134,495	$ 3,501,660

Task	2010				
	Q1	Q2	Q3	Q4	Total
Supplemental PID	$ -	$ -	$ -	$ -	$ -
NAPL Recovery/Monitoring	$ 5,800	$ 5,800	$ 5,800	$ 5,800	$ 23,200
Design	$ -	$ -	$ -	$ -	$ -
Const. Support	$ 131,250	$ 131,250	$ 131,250	$ 131,250	$ 525,000
City of Newburgh Engineer	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 40,000
NAPL rem/ISCO/IC (B4)	$ -	$ -	$ -	$ -	$ -
Barrier Wall/IC (B7)	$ -	$ -	$ -	$ -	$ -
Sediment Rem/IC (C5/C5A)	$ 980,000	$ 3,920,000	$ 3,920,000	$ 980,000	$ 9,800,000
Engineering Report	$ -	$ -	$ -	$ -	$ -
O&M					$ -
DEC Labor	$ -	$ 114,000	$ -	$ -	$ 114,000
Misc & Program Allocation	$ 39,785	$ 39,785	$ 39,785	$ 39,785	$ 159,140
Total	$ 1,166,835	$ 4,220,835	$ 4,106,835	$ 1,166,835	$ 10,661,340

Task	2011				
	Q1	Q2	Q3	Q4	Total
Supplemental PID	$ -	$ -	$ -	$ -	$ -
NAPL Recovery/Monitoring	$ 6,000	$ 6,000	$ 6,000	$ 6,000	$ 24,000
Design	$ -	$ -	$ -	$ -	$ -
Const. Support	$ 131,250	$ 131,250	$ 131,250	$ 131,250	$ 525,000
City of Newburgh Engineer	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 40,000
NAPL rem/ISCO/IC (B4)	$ -	$ -	$ -	$ -	$ -
Barrier Wall/IC (B7)	$ -	$ -	$ -	$ -	$ -
Sediment Rem/IC (C5/C5A)	$ 980,000	$ 3,920,000	$ 3,920,000	$ 980,000	$ 9,800,000
Engineering Report	$ -	$ -	$ -	$ 100,000	$ 100,000
O&M					$ -
DEC Labor	$ -	$ 114,000	$ -	$ -	$ 114,000
Misc & Program Allocation	$ 19,035	$ 19,035	$ 19,035	$ 19,035	$ 76,140
Total	$ 1,146,285	$ 4,200,285	$ 4,086,285	$ 1,246,285	$ 10,679,140

Task	2012				
	Q1	Q2	Q3	Q4	Total
Supplemental PID	$ -	$ -	$ -	$ -	$ -
NAPL Recovery/Monitoring	$ 6,000	$ 6,000	$ 6,000	$ 6,000	$ 24,000
Design	$ -	$ -	$ -	$ -	$ -
Const. Support	$ -	$ -	$ -	$ -	$ -
City of Newburgh Engineer	$ -	$ -	$ -	$ -	$ -
NAPL rem/ISCO/IC (B4)	$ -	$ -	$ -	$ -	$ -
Barrier Wall/IC (B7)	$ -	$ -	$ -	$ -	$ -
Sediment Rem/IC (C5/C5A)	$ -	$ -	$ -	$ -	$ -
Engineering Report	$ -	$ -	$ -	$ -	$ -
O&M	$ 78,750	$ 78,750	$ 78,750	$ 78,750	$ 315,000
DEC Labor	$ -	$ 114,000	$ -	$ -	$ 114,000
Misc & Program Allocation	$ 14,597	$ 14,597	$ 14,597	$ 14,597	$ 58,388
Total	$ 99,347	$ 213,347	$ 99,347	$ 99,347	$ 511,388

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
CASES 09-E-XXXX AND 09-G-XXXX
PROJECTION OF GAS LEAK REPAIRS OF DISTRIBUTION MAIN (NON-LABOR)

PSC ACCOUNT	FUNCTION	DESCRIPTION	Accounts Payable	Journal Voucher	Total	# of Leaks Repaired	Cost Per Repair
Historic Year Ended March 31, 2009:							
887.00	85520	Leak Repairs Distribution Main	732,469	(13,577)	718,892		

For Exhibit PSC Account - 887.00 (Distribution)

						Normalization Adjustment		Adjusted
Breakdown of Repair:								
	(1) Contractor Repair	229,000	0	229,000	95	2,411	843 (3)	3,254
	(2) Other Expenses	503,469	(13,577)	489,892	364	1,346	0	1,346
	Total - Contractor Repair & Other	732,469	(13,577)	718,892				

Projection:

			Contractor Repair - Projection			Other Expenses - Projection			
		(4) Growth Rate	Costs per Leak	# of Leaks Repaired	Gas Leak Repair Expense	Costs per Leak	# of Leaks Repaired	Gas Leak Repair Expense	**Total Contractor & Other**
2009	Over Historic Year @	1.0110	3,289	**131**	430,901	1,361	**419**	570,117	1,001,018
2010	Over 2009 @	1.0130	3,332	**204**	679,744	1,378	**492**	678,148	1,357,892
RYE 6/30/11	Over 2010 @	1.0090	3,362	**204**	685,862	1,391	**492**	684,254	1,370,116
RYE 6/30/12	Over RY1 @	1.0180	3,423	**164**	561,305	1,416	**452**	639,937	1,201,242
RYE 6/30/13	Over RY2 @	1.0190	3,488	**123**	428,977	1,443	**411**	592,946	1,021,923

Footnotes:
Projections are based on premise that backlog of leak repairs is at or below target of 250.
(1) Service provided is excavation repair of pipeline.
(2) Services provided include paving, flagging, materials & permits for the total number of repairs.
(3) Due to timing of billing and favorable pricing, the historic period is not reflective of costs incurred in prior periods and the 2nd quarter of 2009.
Therefore, an average of 2006 through 2008 was used in lieu of the historic period.
(4) Annual growth ratebased on GDP Index .

EXHIBIT__(JJB-2)

DIRECT TESTIMONY
OF
CHRISTOPHER D. THOMAS

Q. Please state your name and business address.

A. My name is Christopher D. Thomas and my business address is 284 South Avenue, Poughkeepsie, New York 12601.

Q. By whom are you employed and in what capacity?

A. I am employed by Central Hudson Gas & Electric Corporation ("Central Hudson" or the "Company") as a Tax Specialist in the Tax Department.

Q. Please summarize your educational background and experience.

A. I earned a Bachelor of Science Degree in Accounting from Marist College in 1983. From 1984 to 1987 I worked as a cost accountant at several manufacturing companies. I obtained my Certificate of Management Accounting in 1995. In 1987 I began employment at Central Hudson Gas & Electric Corporation. I have worked in Financial Reporting, Customer Accounting, Budgets, and in 1996 I was transferred to the Tax Department.

Q. What are your responsibilities as Tax Specialist?

A. My responsibilities include preparation of the federal and state tax returns, preparation of the monthly tax accruals, participation in Internal Revenue Service ("IRS") and State tax audits, keeping informed of tax regulations and interpretations and performing tax research.

Q. What is the scope of your testimony in this proceeding?

A. My testimony in this proceeding covers the computation and allocation of Central Hudson's federal and state income tax for the historical and forecast periods.

Q. Was Exhibit___(CDT-1), entitled "Calculation of Federal and State Income Taxes" prepared by you or under your direction?

A. Yes, it was.

Q. What does this exhibit show?

A. This exhibit shows the computation and allocation of the Company's federal and state income tax for the historical period of the twelve months ended March 31, 2009, projections for the calendar years 2009 and 2010 and the rate year for the twelve months ending June 30, 2011.

Q. Please explain the nature of the items included under the heading "Additional Income and Unallowable Deductions" and "Additional Deduction and Nontaxable Income" summarized on Sheet 1 of each of the Schedules in Exhibit___(CDT-1).

A. The items included here are adjustments to book income in order to arrive at taxable income. They are referred to as Schedule M-1 adjustments. The

adjustments to book income are due to (1) timing differences, which relate to items recorded as income or expense on the books of the Company in one period and included in the computation of taxable income in a different period or (2) permanent differences, which relate to items which are recorded for either book or tax purposes but not for both such purposes. An example of a timing difference is the Mortgage Bond Redemption Premium, which is deducted from taxable income when incurred but deducted from book income over the life of the new bond. An example of a permanent difference is the business meals and entertainment expense, which is fully deductible for book purposes but only 50 percent deductible for tax purposes. The 50 percent not allowed for tax purposes is a permanent difference.

Q. Was the calculation of federal and state income tax for the projected periods calculated in the same manner as the historical period?

A. Yes, except for Avoided Cost Capitalized Interest. For the projected periods, the Company is following the treatment for this item as determined by the Commission in Cases 08-E-0887 and 08-G-0888.

Q. Have there been any changes in federal tax law that have impacted federal income taxes since Case 08-E-0887, the Company's last electric rate case or Case 08-G-0888, the Company's last gas rate case?

A. Yes. The "American Recovery and Reinvestment Act of 2009" extends to

2009 and 2010, the one time acceleration of tax depreciation ("bonus depreciation") for specific qualifying property provided for in the "Economic Stimulus Act of 2008".

Q. How were these items treated in the determination of tax expense?

A. Consistent with established accounting methodology, these accelerated depreciation benefits are deferred and amortized over the estimated book lives of the underlying assets.

Q. Have there been any changes in state tax law that have impacted state income taxes since Case 08-E-0887, the Company's last electric rate case or Case 08-G-0888, the Company's last gas rate case?

A. No.

Q. Briefly describe how New York State income tax is calculated.

A. The state tax is calculated using four different methods: the net income method; the minimum taxable income method; the fixed dollar minimum method; and the capital base tax method. The Company's tax liability is the highest of the four taxes is paid. The state income taxes included in Exhibit__(CDT-1) are based on the net income method.

The net income method starts with federal taxable income and is adjusted to exclude state income taxes. New York State tax law provides for

adjustments for qualified public utilities for depreciation on transition property. Transition property is property placed in service prior to January 1, 2000. With respect to such property, a deduction is allowed for the depreciation expense shown on the books and records of the taxpayer rather than the federal depreciation deduction. Additionally, the amortization of certain regulatory assets, deferred prior to January 1, 2000, currently deducted on the books can be deducted from income to arrive at state taxable income. These adjustments have been reflected in the calculation of state income taxes in Exhibit__(CDT-1).

The minimum taxable income method requires the addition of tax preference items, mainly replacing accelerated depreciation with a slower depreciation method to arrive at taxable income. The fixed dollar minimum is a sliding–scale minimum tax based on a corporation's New York receipts and is capped at $5,000. The capital base tax is based on a percentage of average capital and is capped at a maximum of $10 million.

Q. Does this conclude your pre-filed direct testimony?

A. Yes. It does.

Exhibits of
Christopher D. Thomas

EXHIBIT __ (CDT-1)
Schedule A
Schedule B
Schedule C
Schedule D

EXHIBIT __(CDT-1)

CENTRAL HUDSON GAS & ELECTRIC CORPORATION

CALCAULATION OF FEDERAL & STATE INCOME TAXES

Schedule A – Twelve Months Ended March 31, 2009

Schedule B – Twelve Months Ended December 31, 2009

Schedule C – Twelve Months Ended December 31, 2010

Schedule D – Twelve Months Ended June 30, 2011

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
Calculation of Federal Income Taxes
Twelve Months Ended March 31, 2009
($000)

	Electric	Gas	Total
Total Utility Operating Income	$38,505	$9,930	$48,435
Federal Income Tax - Utility Operations	12,623	3,933	16,556
Income Before Federal Income Tax Excluding Interest Charges	51,128	13,863	64,991
Reconciling Amounts			
Additional Income/Unallowable Deductions	83,918	30,190	114,108
Additional Deductions/Nontaxable Income	92,340	25,501	117,841
Taxable Income	42,706	18,552	61,258
Dividend Credit on Preferred Stock	(95)	(32)	(127)
Adjusted Taxable Income	42,611	18,520	61,131
Utility Operations Federal Income Tax			
Current Period Accrual @ 35%	14,919	6,480	21,399
Additional Accrual	(213)	0	(213)
Prior Period Adjustment	(376)	(182)	(558)
Total Account 409.1	14,330	6,298	20,628
Total Provision for Deferred Income Tax Accounts 410.1 & 411.1	(1,707)	(2,365)	(4,072)
Federal Income Tax-Utility Operations	12,623	3,933	16,556

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
Calculation of State Income Taxes
Twelve Months Ended March 31, 2009
($000)

	Electric	Gas	Total
Federal Taxable Income	42,706	18,552	61,258
NYS Adjustments to Federal Taxable Income:			
Additions:			
New York State Income Tax - Current Period	3,379	1,492	4,871
MTA on New York State Income Tax	438	224	662
Fed Depreciation Deduction-Transition Property	19,134	6,475	25,609
Total Additions	22,951	8,191	31,142
Subtractions:			
NYS Depreciation Deduction-Transition Property	16,050	4,400	20,450
Total Subtractions	16,050	4,400	20,450
New York Taxable Income	49,607	22,343	71,950
Utility Operations NYS Income Tax			
Current Period Accrual @ 7.1%	3,523	1,586	5,109
Additional Accrual	-	-	-
Prior Year Adjustments	(144)	(94)	(238)
Total Account 409.1	3,379	1,492	4,871
Total Provision for Deferred Income Tax Accounts 410.1 & 411.1	(578)	(502)	(1,080)
NYS Income Tax - Utility Operations	2,801	990	3,791

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
Federal & State Income Tax Reconciling Amounts & Deferred Taxes
Electric Department
Twelve Months Ended March 31, 2009
($000)

Reconciling Items	Additional Income/ Unallowable Deductions	Additional Deductions/ Nontaxable Income	Federal Deferred Income Taxes Accounts 410.1/411.1	State Deferred Income Taxes Accounts 410.1/411.1
Interest Expense		15,295		
Depreciation	24,116	46,203	8,410	752
Transportation Depreciation	2,953			
Def CBA	1		(1)	(1)
Use of CBA - Economic Development		552	193	25
Use of CBA - Competitive Education	287		(101)	(12)
Use of CBA - Competitive Metering		15	6	1
Storm Damage - December 2008		3,376	1,182	156
Excess Depreciation Reserve		2,839	993	131
Gain on Groveville Hydro		3	1	
Def Revenues - Medicare Act Subsidy	1,058		(370)	(49)
Domestic Production Deduction		65		
Deduction for Bad Debt	5,911	4,987		
Provision for Injuries & Damages	296	1,000		
Worker's Compensation Reserve	391	359		
Property Tax Accrued		488		
Vacation Accrual-Addt'l Tax Deduction		24		
Deferred Directors Compensation	368		(145)	(19)
Officers Life Ins Policy Premium	5			
Officers Life Ins Policy - Buildup CSV		50		
50 Percent Meal Disallowance	196			
Avoided Cost Interest Capitalized	1,066		(27)	(16)
Cost of Removal - Tax Basis		3,190	49	34
Repair Allowance		2,633	(35)	24
Contribution in Aid of Construction	2,305		(640)	(102)
Mortgage Bond Redemption Premium	270		(95)	(7)

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
Federal & State Income Tax Reconciling Amounts & Deferred Taxes
Electric Department
Twelve Months Ended March 31, 2009
($000)

Reconciling Items Continued	Additional Income/ Unallowable Deductions	Additional Deductions/ Nontaxable Income	Federal Deferred Income Taxes Accounts 410.1/411.1	State Deferred Income Taxes Accounts 410.1/411.1
Electric Fuel Costs Deferred	19,832		(6,941)	(914)
MFC overcollection		120	49	7
Powerful Opp Program - Over/Under Coll		903	316	42
Attachment Rents	136		(48)	(7)
Stray Voltage Testing	1,235		(432)	(57)
MGP SIR Costs & Recovery		3,304	1,157	152
Asbestos Litigation		325	113	15
R & D Costs Deferred		607	213	28
SBC/RPS/EEPS Costs Deferred	2,190		(767)	(100)
Def Lost Rev PV Net Metering		38	13	2
Def Revenues - E. Fishkill Substation	1,056		(370)	(49)
MTA Tax		192	68	(12)
Def Elect Serv Quality Incentive Penalty		111	39	5
Unbilled Revenue	1,568		(549)	(72)
Prepaid Insurance		64	363	48
OPEB Expense-Not Funded	3,109		(1,081)	(143)
OPEB Expense-Medicare Act Subsidy		298		
Deferred OPEB Over/Under collected	5,747		(2,012)	(265)
Medicare Act Subsidy-over/under coll		1,292		
Officers Pension Expense FAS87	654		(227)	(30)
Pension Expense-Not Deductible	5,560		(1,946)	(257)
Pension Contribution-deducted prior yr	2,025			
Deferred Pension Exp Over/Under Collected		3,770	1,319	174
Directors Stock Compensation		5	3	
Executive Performance Shares Plan		232	84	11
FAS 123 Fair Value Option Accrual	0		0	
Deferred Property Tax overcollection	1,263		(442)	(58)
NMP2 Deferred Global Settle Costs	320		(111)	(15)
Statutory Rate Adjustment			0	
FIT Research Credit			181	
Amort.Deferred FIT Const. Charges			(109)	
Amort 81-82 ACRS Method Change			(10)	
Total	$83,918	92,340	(1,707)	(578)

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
Federal & State Income Tax Reconciling Amounts & Deferred Taxes
Gas Department
Twelve Months Ended March 31, 2009
($000)

Reconciling Items	Additional Income/ Unallowable Deductions	Additional Deductions/ Nontaxable Income	Federal Deferred Income Taxes Accounts 410.1/411.1	State Deferred Income Taxes Accounts 410.1/411.1
Interest Expense		4,460		
Depreciation	6,340	13,489	3,303	259
Transportation Depreciation	519			
Use of CBA - Economic Development		34	12	2
Use of CBA - Competitive Education	51		(18)	(2)
Residual Gas Deferred Balances	4,329		(1,558)	(205)
Def Revenues - Medicare Act Subsidy	305		(107)	(14)
Deduction for Bad Debt	3,045	2,569		
Provision for Injuries & Damages	50	178		
Worker's Compensation Reserve	66	63		
Property Tax Accrued		181		
Vacation Accrual-Addt'l Tax Deduction		4		
Deferred Directors Compensation	64		(25)	(4)
Officers Life Ins Policy Premium	1			
Officers Life Ins Policy - Buildup CSV		8		
50 Percent Meal Disallowance	40			
Avoided Cost Interest Capitalized	70		(1)	(3)
Cost of Removal - Tax Basis		2,448	499	66
Contribution in Aid of Construction	86		35	3
Mortgage Bond Redemption Premium	96		(34)	(2)

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
Federal & State Income Tax Reconciling Amounts & Deferred Taxes
Gas Department
Twelve Months Ended March 31, 2009
($000)

Reconciling Items	Additional Income/ Unallowable Deductions	Additional Deductions/ Nontaxable Income	Federal Deferred Income Taxes Accounts 410.1/411.1	State Deferred Income Taxes Accounts 410.1/411.1
Gas Costs Deferred	8,121		(2,841)	(376)
MFC overcollection	35		(13)	(2)
Powerful Opp Program - Over/Under Coll		35	11	2
Interruptible AMR Meters		9	3	1
MGP SIR Costs & Recovery		583	204	26
R & D Costs Deferred		86	32	2
SBC/RPS/EEPS Costs Deferred	423		(149)	(19)
Gas Bal Software Maint Costs		41	18	3
MTA Tax		101	36	(6)
Unbilled Revenue	2,509		(878)	(116)
Prepaid Insurance		11	64	8
OPEB Expense-Not Funded	686		(248)	(32)
OPEB Expense-Medicare Act Subsidy		59		
Deferred OPEB Over/Under collected	1,225		(429)	(56)
Medicare Act Subsidy-over/under coll		276		
Officers Pension Expense FAS87	115		(40)	(7)
Pension Expense-Not Deductible	1,312		(459)	(61)
Pension Contribution-deducted prior yr	475			
Deferred Pension Exp Over/Under Coll		821	287	38
Directors Stock Compensation		3		
Executive Performance Shares Plan		42	13	3
Deferred Property Tax overcollection	227		(80)	(10)
Amort 81-82 ACRS Method Change			(2)	
Total	$30,190	$25,501	($2,365)	($502)

EXHIBIT___(CDT-1)

Schedule B
Sheet 1 of 4

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
Calculation of Federal Income Taxes
Twelve Months Ended December 31, 2009
($000)

	Electric	Gas	Total
Total Utility Operating Income	$40,261	$9,430	$49,691
Federal Income Tax - Utility Operations	13,573	3,676	17,249
Income Before Federal Income Tax Excluding Interest Charges	53,834	13,106	66,940
Reconciling Amounts			
Additional Income/Unallowable Deductions	72,092	21,530	93,622
Additional Deductions/Nontaxable Income	112,590	26,438	139,028
Taxable Income	13,336	8,198	21,534
Dividend Credit on Preferred Stock	(95)	(32)	(127)
Adjusted Taxable Income	13,241	8,166	21,407
Utility Operations Federal Income Tax			
Current Period Accrual @ 35%	4,634	2,858	7,492
Additional Accrual	0	0	0
Prior Period Adjustment	0	0	0
Total Account 409.1	4,634	2,858	7,492
Total Provision for Deferred Income Tax Accounts 410.1 & 411.1	8,939	818	9,757
Federal Income Tax-Utility Operations	13,573	3,676	17,249

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
Calculation of State Income Taxes
Twelve Months Ended December 31, 2009
($000)

	Electric	Gas	Total
Federal Taxable Income	13,336	8,198	21,534
NYS Adjustments to Federal Taxable Income:			
Additions:			
New York State Income Tax - Current Period	1,833	(202)	1,631
MTA on New York State Income Tax	-	-	-
Fed Depreciation Deduction-Transition Property	29,931	(5,702)	24,229
Total Additions	31,764	(5,904)	25,860
Subtractions:			
NYS Depreciation Deduction-Transition Property	19,158	5,105	24,263
NYS Transition Property Regulatory Asset Amort.	122	41	163
Total Subtractions	19,280	5,146	24,426
New York Taxable Income	25,820	(2,852)	22,968
Utility Operations NYS Income Tax			
Current Period Accrual @ 7.1%	1,833	(202)	1,631
Additional Accrual	-	-	-
Prior Year Adjustments	-	-	-
Total Account 409.1	1,833	(202)	1,631
Total Provision for Deferred Income Tax Accounts 410.1 & 411.1	1,296	81	1,377
NYS Income Tax - Utility Operations	3,129	(121)	3,008

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
Federal & State Income Tax Reconciling Amounts & Deferred Taxes
Electric Department
Twelve Months Ended December 31, 2009
($000)

Reconciling Items	Additional Income/ Unallowable Deductions	Additional Deductions/ Nontaxable Income	Federal Deferred Income Taxes Accounts 410.1/411.1	State Deferred Income Taxes Accounts 410.1/411.1
Interest Expense		15,560		
Depreciation	25,329	58,179	12,339	1,714
Transportation Depreciation	2,919			
Excess Depreciation Reserve		10,900	3,815	503
Domestic Production Deduction		130		
Property Tax Accrued		261		
Vacation Accrual-Addt'l Tax Deduction		26		
Deferred Directors Compensation		425	149	20
50 Percent Meal Disallowance	227			
Avoided Cost Interest Capitalized	1,023		(299)	(46)
Cost of Removal - Tax Basis		5,739	846	108
Repair Allowance		1,000	(44)	25
Contribution in Aid of Construction	455		14	(9)
Mortgage Bond Redemption Premium	261		(91)	(8)
MGP SIR Costs & Recovery		2,894	1,013	134
Prepaid Insurance		65	23	3
OPEB Expense-Not Funded	8,302	4,792	(1,229)	(162)
OPEB Expense-Medicare Act Subsidy		408		
Officers Pension Expense FAS87	860		(301)	(40)
Pension Expense/Contribution	32,716	12,211	(7,177)	(946)
Amort.Deferred FIT Const. Charges			(109)	
Amort 81-82 ACRS Method Change			(10)	
Total	$72,092	112,590	8,939	1,296

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
Federal & State Income Tax Reconciling Amounts & Deferred Taxes
Gas Department
Twelve Months Ended December 31, 2009
($000)

Reconciling Items	Additional Income/ Unallowable Deductions	Additional Deductions/ Nontaxable Income	Federal Deferred Income Taxes Accounts 410.1/411.1	State Deferred Income Taxes Accounts 410.1/411.1
Interest Expense		4,442		
Depreciation	6,836	16,490	4,145	520
Transportation Depreciation	515			
Residual Gas Deferred Balances	4,420		(1,547)	(204)
Property Tax Accrued		21		
Vacation Accrual-Addt'l Tax Deduction		5		
Deferred Directors Compensation		75	26	3
50 Percent Meal Disallowance	40			
Avoided Cost Interest Capitalized	83		(13)	(3)
Cost of Removal - Tax Basis		988	1	0
Contribution in Aid of Construction	86		35	3
Mortgage Bond Redemption Premium	87		(30)	(2)
MGP SIR Costs & Recovery		513	180	24
Prepaid Insurance		11	4	1
OPEB Expense-Not Funded	1,885	1,078	(282)	(37)
OPEB Expense-Medicare Act Subsidy		92		
Officers Pension Expense FAS87	152		(53)	(7)
Pension Expense/Contribution	7,426	2,723	(1,646)	(217)
Amort 81-82 ACRS Method Change			(2)	
Total	$21,530	$26,438	$818	$81

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
Calculation of Federal Income Taxes
Twelve Months Ended December 31, 2010
($000)

	Electric	Gas	Total
Total Utility Operating Income	$49,010	$12,425	$61,435
Federal Income Tax - Utility Operations	17,369	5,262	22,631
Income Before Federal Income Tax Excluding Interest Charges	66,379	17,687	84,066
Reconciling Amounts			
Additional Income/Unallowable Deductions	73,424	22,195	95,619
Additional Deductions/Nontaxable Income	120,204	24,700	144,904
Taxable Income	19,599	15,182	34,781
Dividend Credit on Preferred Stock	(95)	(32)	(127)
Adjusted Taxable Income	19,504	15,150	34,654
Utility Operations Federal Income Tax			
Current Period Accrual @ 35%	6,826	5,302	12,128
Additional Accrual	0	0	0
Prior Period Adjustment	0	0	0
Total Account 409.1	6,826	5,302	12,128
Total Provision for Deferred Income Tax Accounts 410.1 & 411.1	10,543	(40)	10,503
Federal Income Tax-Utility Operations	17,369	5,262	22,631

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
Calculation of State Income Taxes
Twelve Months Ended December 31, 2010
($000)

	Electric	Gas	Total
Federal Taxable Income	19,599	15,182	34,781
NYS Adjustments to Federal Taxable Income:			
Additions:			
New York State Income Tax - Current Period	872	1,018	1,890
MTA on New York State Income Tax	-	-	-
Fed Depreciation Deduction-Transition Property	12,669	3,508	16,177
Total Additions	13,541	4,526	18,067
Subtractions:			
NYS Depreciation Deduction-Transition Property	20,774	5,339	26,113
NYS Transition Property Regulatory Asset Amort.	84	28	112
Total Subtractions	20,858	5,367	26,225
New York Taxable Income	12,282	14,341	26,623
Utility Operations NYS Income Tax			
Current Period Accrual @ 7.1%	872	1,018	1,890
Additional Accrual	-	-	-
Prior Year Adjustments	-	-	-
Total Account 409.1	872	1,018	1,890
Total Provision for Deferred Income Tax Accounts 410.1 & 411.1	1,538	(16)	1,522
NYS Income Tax - Utility Operations	2,410	1,002	3,412

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
Federal & State Income Tax Reconciling Amounts & Deferred Taxes
Electric Department
Twelve Months Ended December 31, 2010
($000)

Reconciling Items	Additional Income/ Unallowable Deductions	Additional Deductions/ Nontaxable Income	Federal Deferred Income Taxes Accounts 410.1/411.1	State Deferred Income Taxes Accounts 410.1/411.1
Interest Expense		16,512		
Depreciation	26,733	42,249	6,123	927
Transportation Depreciation	2,847			
Excess Depreciation Reserve		16,450	5,758	759
Domestic Production Deduction		194		
Property Tax Accrued		605		
Vacation Accrual-Addt'l Tax Deduction		15		
Deferred Directors Compensation		425	149	20
50 Percent Meal Disallowance	230			
Avoided Cost Interest Capitalized	1,060		(300)	(47)
Cost of Removal - Tax Basis		3,777	198	25
Repair Allowance		1,000	(51)	24
Contribution in Aid of Construction	455		20	(8)
Mortgage Bond Redemption Premium	221		(77)	(8)
MGP SIR Costs & Recovery		8,887	3,110	410
Prepaid Insurance		65	23	3
OPEB Expense-Not Funded	8,302	5,365	(1,028)	(136)
OPEB Expense-Medicare Act Subsidy		408		
Officers Pension Expense FAS87	860		(301)	(40)
Pension Expense/Contribution	32,716	24,252	(2,962)	(391)
Amort.Deferred FIT Const. Charges			(109)	
Amort 81-82 ACRS Method Change			(10)	
Total	$73,424	120,204	10,543	1,538

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
Federal & State Income Tax Reconciling Amounts & Deferred Taxes
Gas Department
Twelve Months Ended December 31, 2010
($000)

Reconciling Items	Additional Income/ Unallowable Deductions	Additional Deductions/ Nontaxable Income	Federal Deferred Income Taxes Accounts 410.1/411.1	State Deferred Income Taxes Accounts 410.1/411.1
Interest Expense		4,599		
Depreciation	7,391	11,401	2,211	283
Transportation Depreciation	502			
Residual Gas Deferred Balances	4,554		(1,594)	(210)
Property Tax Accrued		59		
Vacation Accrual-Addt'l Tax Deduction		3		
Deferred Directors Compensation		75	26	3
50 Percent Meal Disallowance	41			
Avoided Cost Interest Capitalized	84		(12)	(4)
Cost of Removal - Tax Basis		264	(239)	(32)
Contribution in Aid of Construction	86		36	3
Mortgage Bond Redemption Premium	74		(26)	(2)
MGP SIR Costs & Recovery		1,572	550	73
Prepaid Insurance		12	4	1
OPEB Expense-Not Funded	1,885	1,257	(220)	(29)
OPEB Expense-Medicare Act Subsidy		92		
Officers Pension Expense FAS87	152		(53)	(7)
Pension Expense/Contribution	7,426	5,366	(721)	(95)
Amort 81-82 ACRS Method Change			(2)	
Total	$22,195	$24,700	($40)	($16)

EXHIBIT___(CDT-1)

Schedule D
Sheet 1 of 4

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
Calculation of Federal Income Taxes
Twelve Months Ended June 30, 2011
($000)

	Electric	Gas	Total
Total Utility Operating Income	$44,792	$12,016	$56,808
Federal Income Tax - Utility Operations	14,095	4,835	18,930
Income Before Federal Income Tax Excluding Interest Charges	58,887	16,851	75,738
Reconciling Amounts			
Additional Income/Unallowable Deductions	74,281	22,372	96,653
Additional Deductions/Nontaxable Income	115,558	24,723	140,281
Taxable Income	17,610	14,500	32,110
Dividend Credit on Preferred Stock	(95)	(32)	(127)
Adjusted Taxable Income	17,515	14,468	31,983
Utility Operations Federal Income Tax			
Current Period Accrual @ 35%	6,130	5,064	11,194
Additional Accrual	0	0	0
Prior Period Adjustment	0	0	0
Total Account 409.1	6,130	5,064	11,194
Total Provision for Deferred Income Tax Accounts 410.1 & 411.1	7,965	(229)	7,736
Federal Income Tax-Utility Operations	14,095	4,835	18,930

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
Calculation of State Income Taxes
Twelve Months Ended June 30, 2011
($000)

	Electric	Gas	Total
Federal Taxable Income	17,610	14,500	32,110
NYS Adjustments to Federal Taxable Income:			
Additions:			
New York State Income Tax - Current Period	724	957	1,681
MTA on New York State Income Tax	-	-	-
Fed Depreciation Deduction-Transition Property	13,490	3,442	16,932
Total Additions	14,214	4,399	18,613
Subtractions:			
NYS Depreciation Deduction-Transition Property	21,547	5,390	26,937
NYS Transition Property Regulatory Asset Amort.	84	28	112
Total Subtractions	21,631	5,418	27,049
New York Taxable Income	10,193	13,481	23,674
Utility Operations NYS Income Tax			
Current Period Accrual @ 7.1%	724	957	1,681
Additional Accrual	-	-	-
Prior Year Adjustments	-	-	-
Total Account 409.1	724	957	1,681
Total Provision for Deferred Income Tax Accounts 410.1 & 411.1	1,194	(35)	1,159
NYS Income Tax - Utility Operations	1,918	922	2,840

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
Federal & State Income Tax Reconciling Amounts & Deferred Taxes
Electric Department
Twelve Months Ended June 30, 2011
($000)

Reconciling Items	Additional Income/ Unallowable Deductions	Additional Deductions/ Nontaxable Income	Federal Deferred Income Taxes Accounts 410.1/411.1	State Deferred Income Taxes Accounts 410.1/411.1
Interest Expense		18,533		
Depreciation	27,547	43,936	6,552	977
Transportation Depreciation	2,899			
Excess Depreciation Reserve		11,100	3,885	512
Domestic Production Deduction		194		
Property Tax Accrued		641		
Vacation Accrual-Addt'l Tax Deduction		11		
Deferred Directors Compensation		425	149	20
50 Percent Meal Disallowance	232			
Avoided Cost Interest Capitalized	1,049		(291)	(46)
Cost of Removal - Tax Basis		3,826	136	18
Repair Allowance		1,000	(54)	24
Contribution in Aid of Construction	455		22	(8)
Mortgage Bond Redemption Premium	221		(77)	(8)
MGP SIR Costs & Recovery		6,272	2,195	289
Prepaid Insurance		66	23	3
OPEB Expense-Not Funded	8,302	5,064	(1,133)	(149)
OPEB Expense-Medicare Act Subsidy		408		
Officers Pension Expense FAS87	860		(301)	(40)
Pension Expense/Contribution	32,716	24,082	(3,022)	(398)
Amort.Deferred FIT Const. Charges			(109)	
Amort 81-82 ACRS Method Change			(10)	
Total	$74,281	115,558	7,965	1,194

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
Federal & State Income Tax Reconciling Amounts & Deferred Taxes
Gas Department
Twelve Months Ended June 30, 2011
($000)

Reconciling Items	Additional Income/ Unallowable Deductions	Additional Deductions/ Nontaxable Income	Federal Deferred Income Taxes Accounts 410.1/411.1	State Deferred Income Taxes Accounts 410.1/411.1
Interest Expense		5,074		
Depreciation	7,558	11,512	2,215	290
Transportation Depreciation	512			
Residual Gas Deferred Balances	4,554		(1,594)	(210)
Property Tax Accrued		49		
Vacation Accrual-Addt'l Tax Deduction		2		
Deferred Directors Compensation		75	26	3
50 Percent Meal Disallowance	41			
Avoided Cost Interest Capitalized	84		(12)	(4)
Cost of Removal - Tax Basis		275	(235)	(31)
Contribution in Aid of Construction	86		36	3
Mortgage Bond Redemption Premium	74		(26)	(2)
MGP SIR Costs & Recovery		1,107	387	51
Prepaid Insurance		12	4	1
OPEB Expense-Not Funded	1,885	1,239	(226)	(30)
OPEB Expense-Medicare Act Subsidy		92		
Officers Pension Expense FAS87	152		(53)	(7)
Pension Expense/Contribution	7,426	5,286	(749)	(99)
Amort 81-82 ACRS Method Change			(2)	
Total	$22,372	$24,723	($229)	($35)

DIRECT TESTIMONY
OF
THOMAS C. BROCKS

Q. Please state your name and business address.

A. My name is Thomas C. Brocks and my business address is 284 South Avenue, Poughkeepsie, NY 12601.

Q. Please summarize your education and work experience.

A. In 1976 I received a Bachelor of Science Degree in Industrial Relations from LeMoyne College. In 1980 I received a Master of Science Degree in Labor Relations from Pace University. I have worked for Central Hudson Gas & Electric Corporation ("Central Hudson" or the "Company") since July 1980 with the majority of my career being spent in Human Resources. I am currently the Vice President of Human Resources and Chief Ethics and Compliance Officer. During my career I have held positions with responsibility for labor relations, employee relations, employee benefits, compensation, training and development, employment, payroll and safety.

Q. What is the nature of your responsibilities as Vice President of Human Resources and Chief Ethics and Compliance Officer?

A. I am responsible for the staffing of the organization and for the development and administration of all compensation strategies, policies and procedures for all of Central Hudson. In addition, I am responsible for the Company's Ethics and Compliance programs and policies.

Q. Have you previously testified before the Public Service Commission ("Commission")?

A. Yes, I testified in Cases 05-E-05934, 05-G-0935, 08-E-0887 and 08-G-0888 regarding staffing, compensation and benefits.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to address employee compensation, and benefits (health care, pensions and other post employment benefits ("OPEBs") and staffing. I describe the Company's approach to compensation for management employees and why Central Hudson believes that its approach is appropriate. I describe generally the kinds of health and retirement benefits offered by the Company and recent activities to manage these costs. I have also developed a forecast of the rate year staffing level and provided that estimate to the Revenue Requirements Panel.

Q. Has the Company adopted any further structural changes to its pension, OPEBs and health plans subsequent to those you described in Cases 08-E-0887 and 08-G-0888?

A. No, we have not. The cost reductions from those structural changes are reflected in the historic period and, as a result of the Commission's Order in June 2009, also in current rates.

Q. Please describe Central Hudson's compensation strategy and philosophy.

A. Central Hudson believes that there are several components to compensation, each component makes up a portion of the total compensation package, and the entire package (not individual components in isolation) is what is evaluated in the marketplace and therefore represents the fashion in which compensation should be evaluated by the Commission.

Q. Why is it important to Central Hudson to maintain a compensation program that is competitive in the employment market?

A. If Central Hudson does not maintain a compensation program that is competitive in the employment market, it will not be able to retain the high quality employees it currently employs and it will not be able to attract high quality candidates for existing or new requirements. As a result, Central Hudson's operating performance, customer service quality and customer satisfaction would be at needless risk of deterioration.

Q. Please describe Central Hudson's cash compensation program for non-unionized employees and how it manages the costs of the program.

A. Central Hudson has adopted a strategy to compensate employees with base salaries at the 50th percentile of overall compensation for comparable jobs in the Northeast United States. We employ the services of nationally known compensation consultants to establish those salaries.

We believe paying at the median level provides the Company the ability to attract new qualified employees and retain its existing employees.

Q. Is the compensation program for Central Hudson's executives similar to the program described above for the non-unionized employees?

A. Yes, it is. Central Hudson uses a nationally recognized compensation consultant to establish the median level of salaries for Central Hudson's executives. Through the use of this consultant, Central Hudson benchmarks its executive positions to the 50th percentile of overall compensation for comparable jobs in similarly sized companies.

Q. Was a collective bargaining agreement in place between the Company and its union workers during the historic period?

A. Yes. A new collective bargaining agreement was arrived at effective May 1, 2008. The new agreement has a term of three years.

Q. Will a collective bargaining agreement be in place during the forecast rate year?

A. Yes, but it will expire on April 30, 2011.

Q. What are the negotiated wage increases for union employees from the March 31, 2009 end of the historical year through the Rate Year?

A. The current labor agreement provided for a 3.5% wage increase on May 1, 2008 and another 3.5% wage increase on May 1, 2009. They will be followed by increases of 0.5% on November 1, 2009, 3.5% on May 1, 2010, and 0.5% on November 1, 2010.

Q. What are the projected payroll increases for non-union employees?

A. An assumed overall compensation increase of 3.6% from the March 31, 2009 level was employed to forecast the rate year payroll for non-union employees.

In connection with non-union employees, I note that the Company is only requesting revenue requirements associated with base salaries for its Executive and non-Foreman management positions. Central Hudson is not requesting any revenue requirements for "variable," "incentive," "bonus" or "performance-based" management compensation plans. In addition, 2010 executive salaries have been held constant at the 2009 levels. In addition, the Company is requesting revenue requirements for the base salaries and overtime for its management Foreman positions as well as all base wage and overtime compensation for its unionized workforce.

Q. Please describe the Company's staffing levels in the historic year ended March 31, 2009.

A. As of March 31, 2009, there were 840 employees, including officers, full-time management employees and full and part-time union employees.

Q. Do you believe that it will be necessary or desirable for the Company to add employees during the forecast rate year period, the twelve months ending June 30, 2010?

A. Yes. The actual staffing level at May 31, 2009 is 856 and that level that represents an increase of 16 over the level of 840 that existed at the end of the test year and was approved in the Commission's June 2009 rate order. Increases in work tasks as well as regulatory mandates warrant adding 4 employees to the 856. One Financial Analyst will be added to the Financial Planning department and one Cost and Rate Analyst will be added to the Cost and Rate department. In addition two Assistant System Operator position will be added to the System Operations department. I have described these positions in Exhibit___(TCB-1)

Q. Have you assumed that there will be increases or losses of existing employees between the March 30, 2009 end of the historic period and the July 1, 20010 start of the rate year?

A. I have assumed that if there are any increases or losses of existing employees, they will net out to zero.

Q. Do you expect that all of the positions shown in your Exhibit___(TCB-1) will be filled by the start of the rate year?

A. Yes.

Q. Have you provided your forecast of the number of employees to the Revenue Requirements Panel?

A. Yes.

Q. Does this conclude your direct testimony?

A. Yes.

Assistant System Operators (2 positions)

Adding two Assistant System Operators to the Company's System Operations Division is necessary to comply with the recently upgraded NERC Electric Reliability Standards and the Federal DOT proposed rule regarding gas transmission pipeline operations, which will be finalized this fall.
The additional two positions will enhance situational awareness and improve operator response to abnormal conditions that may occur without warning on the electric and gas transmission system. The additional staffing is necessary to comply with these new standards of performance.

Compliance with FERC-approved Electric Reliability Standards is mandatory, and NERC has been designated as the nation's Electric Reliability Organization (ERO) and as such become responsible for enforcement of these standards. Failure to comply with these standards poses serious risks for the Company as a Transmission Owner (TO), including the potential for significant financial penalties imposed by FERC. The existing NPCC list of Bulk Electric System (BES) facilities currently being used for the application of NERC Reliability Standards is under review by FERC. With the completion of this review, the Company expects that more of its transmission lines will be covered by these standards, and as a result, it will be required to register as a Transmission Operator (TOP). Registration as a TOP will significantly increase the number of standards requiring compliance, including standards associated with Operator staffing, training, and certification. Additionally, a major recommendation by the NERC Real-Time Tools Best Practices Task Force is the enhancement of Operator situational awareness, which requires standards and guidelines for the continuous monitoring of current system conditions and future contingencies. Furthermore, the recent US DOT PHMSA (Pipeline and Hazardous Materials Safety Administration) Proposed Rule regarding Control Room Management / Human Factors for Operators of gas pipelines emphasizes the importance of prompt Operator response to abnormal and emergency situations that pose risks to public safety and the environment. The Proposed Rule also identifies a higher level of Operator training required to meet its objectives. The Company, as a gas pipeline Operator, must comply with the rules and regulations required by PHMSA.

As a result of the need to assure compliance with the additional rules and regulations imposed by both NERC and the US DOT, the Company has reevaluated its staffing levels and employee qualifications and responsibilities in the area of Transmission Operations. This reevaluation indicates that an additional two Assistant System Operators are required to enable the Company to comply with the increased number of NERC Reliability Standards associated with mandatory Operator staffing, training, and certification as well as the additional rules proposed by PHMSA. This will allow the Company to staff the Transmission Operations Center with two qualified and certified Transmission System Operators at all times, while at the same time maintaining adequate staffing levels in its Distribution Control Center.

Cost & Rate Analyst (1 position)

The addition of one analyst to the Company's Cost & Rate Group within the Regulatory Affairs Division is necessary to comply with recent orders issued by the New York State Public Service Commission (PSC), to continue to address impacts of current PSC policies, to maintain compliance with NERC Reliability Standards and to comply with FERC requirements.

In its Order, issued and effective June 22, 2009, in Cases 08-E-0887 and 08-G-0888, the PSC approved the implementation of revenue decoupling mechanisms (RDMs) for the Company's electric and gas businesses. These RDMs will require monthly reconciliation of actual delivery revenue for electric and actual use per customer for gas to PSC approved targets, with detailed tracking of differences for refund to or surcharge from customers. The Order's approval of the implementation of an electric bill credit, to be applied on a service class and/or sub-class specific basis, will also require detailed tracking. The Order also required an increased level of detail for certain components of the Company's Energy Cost Adjustment Mechanism (ECAM) and electric Merchant Function Charge (MFC) structure through the implementation of sub-class level factors. As a result, the level of complexity of both the monthly ECAM rate setting and reconciliation processes and the MFC rate setting and monthly tracking processes will increase dramatically.

The expansion of the Hourly Pricing Provision from a minimum customer threshold of 1000 kW to 500 kW, with a detailed implementation plan to be filed on or before August 22, 2009 was also required by the Order. Implementation of this expansion, which is estimated to impact approximately 131 customers, will require installation of meters, rate design for the recovery of meter costs and customer education and outreach, as well as customer support once the program is fully implemented.

The Order also increases cost of service analysis requirements, by requiring the submission of a gas marginal cost of service study and a streamlined (excluding commodity cost/revenue) electric embedded cost of service study with the next gas and electric, respectively, rate case filings.

Finally, the Order also requires the completion and submission of a voltage-specific study of electric losses by January 22, 2009.

On June 19, 2009, the PSC issued an Order in Case 09-M-0311 directing the Company to commence, effective July 1, 2009, collections from electric and gas customers to recover the Temporary State Energy and Utility Service Conservation Assessment pursuant to the Public Service Law Section 18-a(6) as implemented by Chapter 59 of the Laws of 2009. Implementation of this surcharge requires detailed monthly tracking and annual reconciliation and rate design, all on service class and/or sub-class specific basis.

Compliance with current PSC policies has also increased analytical requirements, including increased requirements resulting from increased retail access migration and rate design, rate implementation and customer education and outreach related to AMI/Smart Grid proposals.

Analytical requirements have also increased as a result of continued compliance with certain NERC load forecasting/reporting Reliability Standards, continuous monitoring for revisions to such standards and evaluation of changes/applicability as the Company expands its entity definition.

Finally, the FERC, in Order 714 issued September 19, 2008, has required that all tariffs, tariff revisions and applications for public utilities be filed electronically according to a set of standards developed jointly by FERC and the North American Energy Standards Board. The Company currently has twelve active rate schedules on file with FERC, including the Company's Open Access Transmission Tariff, which will require conversion and maintenance.

The addition of one analyst will enable the Company to comply with additional requirements resulting from recent orders issued by the PSC, address increased requirements resulting from existing PSC policies, maintain compliance with evolving NERC Reliability Standards and comply with new FERC requirements.

Financial Planning Analyst (1 position)

Financial Planning's primary responsibility covers four broad areas: preparing and filing of rate cases, overall responsibility for preparing and reviewing our annual operating budget, overall responsibility for the operation, maintenance and update of the Clarity Budgeting and Reporting system and providing analysis and support for strategic planning efforts. The workload associated with these responsibilities has increased dramatically over the past two years especially in light of likely annual rate case filings and support for a more robust strategic planning effort. This additional workload, as discussed in more detail below, requires the addition of a new Financial Planning Analyst.

Rate Case Filings:
Financial Planning has overall responsibility for the development of rate base and revenue requirements and the coordination of all other witnesses' testimony and exhibits. The timing of the work associated with annual filings requires, during parts of the year, that two cases be work on at the same time. This is coupled with the ever increasing volume of work associated with discovery, analysis of other parties' filing, preparation for and participating in hearings and preparation and review of the various briefs filing during course of a rate case.

Annual Operating Budget/Strategic Planning:
Our annual planning process will be expanded to provide five years of data to support expanded strategic planning efforts. In addition to the requirement for additional data, the Company will be implementing "year-round" budgeting which will require the update, coordination, review and analysis of near-term budgets each quarter rather than once each year.

Clarity Budgeting and Reporting System:
The Clarity System is used to develop the annual operating budgets and is also used to report actual results and budget variations. Clarity is new and is supported and maintained solely by Financial Planning. Clarity development is continuous as is the ever-changing planning and reporting requirements of Central Hudson.

DIRECT TESTIMONY
OF
FORECASTING & RATES PANEL

Q. Please state your names and business address(es).

A. Stacy E. Powers and Amy S. Dittmar, Central Hudson Gas & Electric Corporation ("Central Hudson" or the "Company"), 284 South Avenue, Poughkeepsie, New York 12601.

Q. In what capacity are you employed by Central Hudson?

A. (Powers) I am an Associate Cost and Rate Analyst.

(Dittmar) I am an Associate Cost and Rate Analyst.

Q. Please summarize your education and business experience.

A. (Powers) I received a Bachelor of Science Degree in Business Administration and Accounting from Marist College in 2006. I was employed by Central Hudson in July 2006 as an Assistant Cost and Rate Analyst. I was promoted to my current position of Associate Cost and Rate Analyst in March 2008.

(Dittmar) I received a Bachelor of Science Degree in Financial Economics with a Business Management adjunct from Binghamton University in 2004. I was employed by Central Hudson in February 2006 as an Accounting Clerk in the Plant Accounting Division. I was promoted to the position of Assistant Financial Analyst in May 2006 and subsequently transferred to the position of Assistant Cost and Rate Analyst in January 2008. I was promoted to my current position of Associate Cost and Rate Analyst in January 2009.

Q. Have you previously testified before this Commission?

A. (Powers) Yes. I have testified before this Commission in Case 08-E-0887.
(Dittmar) Yes. I have testified before this Commission in Case 08-G-0888.

Q. What is the purpose of the Forecasting and Rates Panel's testimony in this proceeding?

A. The Panel presents projected inflation rates as well as the following with respect to electric and gas service: 1) historical sales and revenues; 2) the development of the forecast of electric and gas customers, sales and base delivery revenues for all service classes for the period April 1, 2009 through June 30, 2011; 3) development of the projection of interruptible gas sales and revenues, and an overview of the current mechanism for interruptible profit calculation; 4) the interclass revenue allocation of the Company's proposed electric and gas delivery rate changes; 5) the proposed changes in the Company's electric and gas delivery rates and the revenue effect of those changes; 6) the Company's method for collecting purchased power costs from customers; 7) the Company's method for collecting natural gas supply costs from customers; and 8) the electric loss factor and gas factor of adjustment.

Q. With respect to the subject of inflation, what are the projections of the inflation rate and how were they developed?

A. A Gross Domestic Product (GDP) implicit price deflator was developed using the consensus forecast of Blue Chip Economic Indicators included in the April 10, 2009 publication, for 2009 and 2010 forecast figures, and March 10, 2009 publication, for 2011 forecast figures. The forecast for the Rate Year as shown below is an extrapolation of this forecast.

GDP Implicit Price Deflator

Year	Index 2000 = 100	Annual Percent Change
2008	122.4	2.2
12 Months Ended March 2009	122.8	0.3 over 2008
2009	124.1	1.4 over 2008
2010	125.7	1.3 over 2009
Rate Year Ending June 30, 2011	126.8	0.9 over 2010

Q. Now, turning to the subject of electric and gas service, please begin by describing the exhibits which summarize sales, revenue and customer data for recent historical periods and the forecast period.

A. Exhibit__(FRP-1) consists of Schedules A and B for electric and gas, respectively. These schedules present, for the calendar years 2006, 2007 and 2008, and the twelve months ending March 31, 2009 the operating revenues of the Company by prime revenue account, as required by the

Commission's rules. These exhibits also show for each revenue account the kWh or Mcf of electricity or gas delivered (designated as sales), base delivery revenue and the average base delivery revenue per kWh or Mcf sold.

Exhibit__(FRP-2) consists of six schedules. Schedule A presents a summary by customer class of electric sales, base delivery revenues and customers for the twelve-month periods ended March 31, 2009, December 31, 2009, December 31, 2010, and June 30, 2011. Schedule B sets forth monthly electric sales, base delivery revenue and customer data by revenue account for the twelve-months ended March 31, 2009. Schedules C through F contain similar monthly information by service classification for the twelve-month periods ended March 31, 2009, December 31, 2009, December 31, 2010, and June 30, 2011, respectively.

Exhibit__(FRP-3) sets forth six schedules similar to Exhibit__(FRP-2), summarizing gas sales, base delivery revenues and customers for the same time periods.

Q. Were sales to full service customers, or those customers continuing to purchase their energy and/or natural gas requirements from Central Hudson, addressed differently in the forecast than sales to retail access and/or transport customers?

A. No. In prior Central Hudson general rate proceedings, Cases 00-E-1273 and 00-G-1274, the Commission approved the unbundling of commodity supply from delivery, resulting in the same base delivery rates for both full service sales and retail access/transportation customers. Therefore, the sales forecasts reflect total full service and retail access deliveries.

Electric and Gas Sales Forecasts

Q. Were the electric and gas forecasts for firm sales developed in a similar fashion?

A. Yes they were.

Q. Please provide an overview of the process by which the forecast of electric own territory and firm gas sales were developed.

A. Customer forecasts were developed for each electric and gas customer class. For a number of these classes, sales volume forecasts were developed on a sales per customer basis, with total sales specified as a function of sales per customer and customer count. Sales forecasts for the remaining classes were developed on a total class basis.

Q. Why were forecasted sales volumes for certain classes developed on a sales per customer basis?

A. Generally, this approach was applied to the classes with relatively large numbers of customers. Separating total consumption into customer and sales per customer components recognizes that each component is influenced by different factors and provides the opportunity to incorporate more structure into the analysis of total consumption.

Q. What forecasting methodologies were used to project customer and sales levels?

A. Forecasts of customers and sales were developed utilizing various econometric or time series models, or trend projections. The models/forecasts were estimated using actual monthly billed customer and sales data covering the period January 1997 to March 2009.

Estimation periods vary somewhat for the different classes to recognize structural changes to the billing process and data quality issues that can sometimes limit data availability. For example, revisions to billing cycles, in terms of customer composition, and recording of customers' end-use category (residential, commercial, industrial, etc.) can cause shifts in data requiring different estimation periods.

A summary of the methods utilized for each forecast is provided below, with detail regarding model specifications and statistics presented on Exhibit__ (FRP-4) for electric forecasts and Exhibit__(FRP-5) for gas forecasts. Electric forecast results for each class, and in total, are shown on

Exhibit__(FRP-6). Similarly, gas forecast results for each class, and in total, are shown on Exhibit__(FRP-7).

List of Electric Customer and Sales Forecast Methods

Class	Customers	Sales
Res. Heat	time series	econometric (per customer)
Res. Non-Heat	econometric	econometric (per customer)
Com. Demand	econometric	econometric
Com. Non-Dmd.	econometric	econometric (per customer)OPA
Demand	econometric	econometric
OPA Non-Dmd.	econometric	econometric
Ind. Demand	historic constant	econometric (per customer)
Ind. Non-Dmd.	historic constant	econometric (per customer)
SC 13	individual	individual
Area Light	historic constant	fixture specific growth
Street Light	historic constant	fixture specific growth
Traffic Signal	historic constant	historic constant w. trend
Interdepart.	historic constant	historic constant

List of Gas Customer and Sales Forecast Methods

Class	Customers	Sales
Res. Heat	econometric	econometric (per customer)
Res. Non-Heat	time series	econometric (per customer)
Com. Heat	econometric	econometric (per customer)
Com. Non-Heat	time series	econometric (per customer)
OPA	historic w/ additions	econometric (per customer)
Industrial	linear regression	econometric (per customer)
Interdepart.	historic constant	historic constant

Q. Please describe the structures of the models used to develop the electric customer forecasts.

A. Econometric models were constructed to forecast customer levels for the residential non-heat, commercial and other public authority (OPA) demand,

and commercial and OPA non-demand classes. Two types of variables were employed in the specification of these models: economic and binary (or dummy). The model specifications for the residential and OPA customer classes utilize number of households, while the commercial demand and commercial non-demand class models utilize total employment and non-manufacturing employment data, respectively. The model specification for the OPA demand class employs a non-linear regression equation as it reflects the use of an autoregressive ("AR") term. This term captures the impact of all other variables that have not been included in the model due to the inability to identify or quantify such variables or due to the lack of data for such variables.

The residential heat customer forecast was developed applying a linear regression equation to the rolling twelve-month average customer level. The resulting forecast customer level for each calendar year was then allocated to calendar month using the actual two-year average odd/even billing pattern in order to reflect the recent increase in the pattern's amplitude.

Recent changes in categorization of customers' end use have produced significant shifts in the industrial demand and non-demand customer levels due to the relatively small size of these classes. As a result, the forecast customer levels for these classes were maintained at the actual level experienced for the most recent twelve-month period.

As of March 31, 2009, Central Hudson provided transmission or substation service to fifteen customers under the provisions of Service Classification ("S.C.") No. 13. The Company expects to continue providing service to thirteen of these customers, with the remaining two terminating operations.

The Company has experienced little to no customer growth in both S.C. No. 5, area lighting, and S.C. No. 8, street lighting, in recent years. As a result, the forecast customer level for area lighting was maintained at the actual level experienced for the most recent twelve-month period, while the street lighting customer level as of March 31, 2009 was maintained throughout the forecast period.

As approved by the Commission in its Order in Case 00-E-1273, S.C. No. 9, which provides unmetered service, was closed to new customers effective November 1, 2001. Customers requiring service for new traffic signals are now required to take service under S.C. No. 2. Since the closing of this service class, the Company has experienced a minor contraction in the customer level for this class. As a result, the most recent level experienced has been maintained throughout the forecast period.

Q. Please describe the structures of the models utilized to develop the gas customer forecasts.

A. Econometric models were constructed to forecast customer levels for the

residential and commercial heating classes. Two types of variables were employed in the specification of these models: economic and binary (or dummy). The model specification for the residential heating class utilizes number of households while the commercial heating class model utilizes non-manufacturing employment data. The model specification for the commercial heating class employs a non-linear regression equation as it reflects the use of an AR term.

The residential and commercial non-heating class customer forecasts reflect utilization of exponential smoothing models.

The customer forecast developed for the Other Public Authority ("OPA") class assumes that minor growth will continue through the forecast period with the addition of approximately five customers each year. Many schools, hospitals and government offices, which could be included in the OPA classification are coded as commercial heating.

The industrial customer forecast was developed by applying a linear regression equation to the rolling twelve-month average customer level. The resulting forecast customer level for each calendar year was then allocated to calendar month using the average of the actual odd/even billing pattern for calendar years 2004 through 2008.

Q. How do the model structures for electric and gas customer forecasts compare to those approved by the Commission in the Company's last major

rate filing?

A. The Commission's final forecasts in Cases 08-E-0887 and 08-G-0888 were based on the Company's forecast of customers which were developed using the same forecasting methodologies and model structures presented in this proceeding.

Q. What is the source for the economic data utilized in the forecast models?

A. Economic projections for the region served by the Company were based on the April 2009 forecast provided by Moody's Economy.com to the New York Independent System Operator for statewide forecasting. Composite forecast drivers for the Central Hudson region were constructed from four data regions included in the forecast: Albany, Catskills, Dutchess County and Newburgh. The composite economic forecast drivers were calculated as a weighted sum of the regional forecasts, where the weights reflect actual average residential and non-residential sales in the region for calendar years 2006 through 2008.

These data were the latest available to the Panel at the time of the preparation of our analyses. We recommend that the models employed by any party be fully updated, and re-specified if appropriate, to reflect the latest data available at the time of the Commission's decision.

Q. What forecasting methods were used to project sales volumes?

A. Econometric models were constructed to forecast all electric classes excluding S.C. No. 13, area, street and traffic signal lighting and interdepartmental and all firm gas classes excluding interdepartmental and S.C. No. 11. Further, the forecasts developed for the electric residential and commercial classes and all firm gas classes utilize Statistically Adjusted End-Use ("SAE") models.

Q. Please explain the SAE model approach.

A. The SAE approach integrates structural changes in end-use saturation and efficiency trends, as well as addressing the interaction of economic variables, through the construction of end-use variables: heating, cooling and other (base use). These end-use variables include weather, price, economic drivers and end-use saturation and efficiency trends. Additionally, the electric end-use variables constructed for the residential classes reflect changes in housing square footage and thermal shell integrity.

Q. What is the source for end-use saturation and efficiency data?

A. Residential appliance and commercial end-use saturation and efficiency trends are based on Energy Information Administration estimates for the Middle Atlantic Census Region as compiled by Itron, Inc. Where possible, electric estimates are calibrated to Central Hudson's service territory based

on results from the Company's Residential Appliance Saturation Survey series.

Q. What is the basis for the electric price variable?

A. We used the latest information available to us at the time of the preparation of our analyses, with the exception of the New York State Assessment ("NYSA"), which was not included. The historic price series for each class was determined as a function of the total bundled revenue (including delivery and supply) billed to full service customers divided by sales to full service customers in each class. Monthly forecast prices for each class include applicable base delivery charges, including delivery rate increase(s) as filed by the Company in compliance with Case 08-E-0887 effective July 1, 2009 on a temporary basis, pending Commission approval, and a projected delivery rate increase of approximately five percent effective July 1, 2010, as well as Merchant Function Charges ("MFC"), System Benefits Charge ("SBC"), Renewable Portfolio Standard Charge, the Electric Bill Credit, Purchased Power Adjustment, Miscellaneous Charges and Market Price Charge ("MPC"). The MPC, or supply price, was forecasted using monthly regression equations to estimate MPC prices as a function of the on-peak price forecast for NYISO zone G as of July 1, 2009 as obtained from INO.com. The MPC price forecast also includes a market price effect estimate of $2/MWh related to the Regional Greenhouse Gas Initiative

("RGGI") similar to the price forecast utilized by the Company in its most recent general rate proceeding Case 08-E-0887. The price variable is expressed as the CPI-indexed twelve-month moving average on a one-month lag.

Q. What is the basis for the gas price variable?

A. We used the latest information available to us at the time of the preparation of our analyses, with the exception of the NYSA, which was not included. The historic price series for each class was determined as a function of the total bundled revenue (including delivery and supply) billed to full service customers divided by sales to full service customers in each class. Monthly forecast prices for each class include applicable base delivery charges, delivery rate increase(s) as filed by the Company in compliance with Case 08-G-0888 effective July 1, 2009 on a temporary basis, pending Commission approval, and a projected delivery rate increase of approximately four percent effective July 1, 2010, as well as Merchant Function Charges ("MFC"), System Benefits Charge, Renewable Portfolio Standard Charge, an estimate for the Energy Efficiency Portfolio Standard ("EEPS") Charge in Case 07-M-0548, and Gas Supply Charge ("GSC"). The forecast of the GSC, or supply price, reflects utilization of assets currently under contract to Central Hudson, including pipeline transport, storage and commodity supplies, with commodity supply based on New York Mercantile Exchange

("NYMEX") natural gas futures prices as of July 1, 2009. The price variable is expressed as the CPI-indexed twelve-month moving average on a one-month lag.

Q. Why were applicable NYSA Charges not reflected in the forecast for prices?

A. The New York State Assessment Charges filed in compliance with Order in Case 09-M-0311 dated June 19, 2009 and effective July 1, 2009, were filed on a temporary basis. In addition, the Company is currently developing a revised filing which it will file to become effective September 1, 2009. The Company's new NYSA statements will reflect service class specific factors, and for electric sub-class specific factors, as applicable, to reflect voltage level. The Panel determined that it was more efficient to exclude NYSA entirely at this juncture pending the Commission's approval of the revised filing as well as any additional changes regarding implementation of NYSA. Therefore, we recommend that the latest known information available at the time of the Commission's decision be reflected in the final Rate Year forecasts utilized to determine the revenue requirement and rate design.

Q. What economic variables are utilized in the electric sales models?

A. The residential and OPA class models utilize household income and household size, while the commercial and industrial models utilize GDP. As previously noted, these data are part of the forecast supplied by Moody's

Economy.com and subsequently compiled by Central Hudson to correspond more precisely to the Company's service territory.

Q. What economic variables are utilized in the gas sales models?

A. The residential models utilize household income and household size, while the commercial, industrial and OPA models utilize GDP.

Q. How is weather incorporated into the sales models?

A. Monthly actual heating degree days ("HDD") and cooling degree days ("CDD") are transformed into billed HDDs to more closely correspond to the sales billing periods. The sales forecasts are based on normal weather conditions, where the normal weather is determined by a ten-year average of monthly HDD or CDD, as applicable, based on hourly temperature readings obtained from Dutchess County Airport, for the calendar year ending 2008, the latest calendar year for which this information was available at the time of preparation of the Company's sales forecast. We recommend that the latest ten-year average ending December be reflected in the final Rate Year forecasts utilized to determine the revenue requirement and rate design.

Q. Please define a HDD.

A. Weather is expressed in terms of degree days. Electric HDDs are defined as the amount by which 65 degrees Fahrenheit exceeds the average of the high

and low temperatures for a given day. Gas HDDs are defined as the amount by which 65 degrees Fahrenheit exceeds the twenty-four average of temperatures for a given gas day.

Q. Please define a CDD.

A. Electric CDDs are defined as the amount by which the average of the high and low temperatures for a given day exceed 65 degrees Fahrenheit.

Q. Do the sales models contain any other assumptions or variables?

A. Yes. The electric and gas residential and electric OPA sales models include price, income and household size elasticity estimates, while the remaining sales models include price and GDP elasticity estimates. With the exception of the electric and gas residential heat and gas commercial heat and industrial price elasticity parameters developed by the Company, the estimates for these variables have been compiled by Itron. Utilization of binary, or "dummy", variables is reflected in many of the customer and sales models presented here, consistent with standard modeling practices. In many instances, this type of variable was added as a switch to turn various parameters on and off, such as differences in odd/even month billing to reflect bimonthly billing for certain accounts, or to accommodate a specific data point to reduce model error, while maintaining a longer estimation period.

Q. Please discuss the sales forecast for electric S.C. No. 13.

A. The sales forecast for this class has been developed based on discussions with these customers over the period April – July 2009 in which 14 of the existing 15 customers provided the company with either written or verbal general forecasts/indications of future electric consumption. The customers were asked to comment on potential changes in usage, demand, or operations affecting electric consumption for a period of several years, including the rate years.

In addition to customer provided information, the Company also considered historical customer-specific information including, but not limited to, usage, demand and load factor data.

Q. Please describe how the forecast of sales for the street and area lighting classes were developed.

A. Street and area lighting sales were projected by extrapolating inventory trends for existing fixtures. Sales per existing fixture continue to decrease as more efficient sodium lamps are installed as replacements. As a result of the switch to more efficient lighting and no growth in customer level, overall contraction in sales is anticipated for the forecast period.

Q. How were sales under S.C. No. 9 - Traffic Signals forecast?

A. As previously indicated, S.C. No. 9 was closed to new customers effective November 1, 2001. As a result, this service classification has experienced a slight contraction in sales, which has been continued through the forecast period.

Q. How were the Company's interdepartmental sales forecast?

A. Interdepartmental sales were projected by analyzing several years of actual sales data. Both electric and gas interdepartmental sales were held constant throughout the forecast period.

Q. Are the forecasting methodologies utilized by the Company in the preparation of the sales forecasts consistent with those presented by the Company in its last major rate filings?

A. With the exception of the electric small industrial demand sales forecast, which was changed from a total sales to a use-per-customer model in order to better fit historic data, all forecasting methodologies are consistent with those presented by the Company in Cases 08-E-0887 and 08-G-0888.

The Commission's final forecasts in Cases 08-E-0887 and 08-G-0888 were based on Staff's sales models which utilized the Company's indices reflecting Economy.com's forecast of economic data, end-use saturation and efficiency data supplied by Itron and gas and electricity price forecasts (Tr. 1398). Generally, Staff found the Company's sales models acceptable (Tr.

1396). Moreover, Staff portrayed the changes made to the Company's forecasting equations as minor adjustments (Tr. 1397).

Q. Were sales forecasts developed for gas S.C. No.14 or Sales for Resale?

A. No. Historic sales to S.C. No. 14 have been fairly erratic and since this service class is included in the interruptible profit mechanism discussed below a forecast has not been developed for this class. The Company did not prepare a forecast of sales-for-resale, which are commodity sales, since the Company's filing in this proceeding pertains to delivery service. Historic sales for resale are reflected, but associated historic revenues are not, as those revenues are addressed within the Gas Cost Adjustment.

Q. Were any changes made to the sales forecasts to incorporate reductions identified in the on-going EEPS proceeding in Case 07-M-0548?

A. Yes. The electric sales reductions attributable to the EEPS were developed by allocating certain annual reductions identified in the June 23, 2008 Order in Case 07-M-0548 across applicable customer classes and months based on the pre-adjustment forecast.

The gas sales reductions attributable to the EEPS were developed by allocating the annual residential reductions itemized in DPS Staff's Report on Recommendations for the EEPS Proceeding issued March 25, 2008 and the

Straw Proposal issued by the Administrative Law Judges on February 13, 2008 across months based on the pre-adjustment forecast.

Q. Were any additional changes made to forecasted sales external to the models?

A. Yes. Adjustments were made to the electric sales forecast to reflect forecasted sales reductions resulting from increased penetration of residential and non-residential net-metered photovoltaic ("PV") systems.

Q. Why does the forecast reflect sales reductions from increased penetration of net-metered PV systems?

A. Effective August 5, 2008 the Commission raised the overall net-metering ceiling for Central Hudson from 10 MW to 12 MW and enacted new net metering legislation applicable to residential and non-residential service. These governmental actions, together with Central Hudson's active support for solar resources, are expected to produce further sales reductions as new solar installations are made. As a result, it is necessary to build into the sales forecast, and ultimately into base rates, a forecast of sales reductions resulting from the additional PV penetration above the level experienced through March 31, 2009.

Q. Please explain how these adjustments were developed.

A. In developing sales reductions attributable to increased penetration of net-metered PV systems, the Company employed the same methodology approved by the Commission in Case 08-E-0887. The sales reductions attributable to PV penetration are based on a forecast of net-metered PV installations developed by applying a polynomial regression to cumulative kW installed since March 2004, reflecting this date as the date when installations accelerated. This model is presented on Exhibit__(FRP-9). The Company requests recovery of lost revenue associated with any expansion of net metering provisions beyond the provisions reflected in the estimate herein.

Q. What do the final electric and gas sales forecasts show?

A. While the Company continues to experience growth in the number of electric and gas customers, overall use per customer has decreased significantly since 2005 primarily in response to prices. As a result of decreasing use per customer, as well as usage reductions due to the EEPS in Case 07-M-0548 and lost electric sales due to PV net metering, electric and gas sales are forecast to decrease during the Rate Year. Electric own territory sales (excluding unbilled) as shown on Schedule A of Exhibit__(FRP-2) are forecast to decrease by 170,128 MWh, or 3.2 percent, based on the Rate Year ended June 30, 2011 estimate of 5,191,349 MWh as compared to the calendar year 2009 estimate of 5,361,477 MWh. Gas own territory sales (excluding unbilled, Sales for Resale and S.C. No. 14) as shown on

Schedule A of Exhibit__(FRP-3) are forecast to decrease by 388 MMcf, or 2.5 percent, based on the Rate Year ended June 30, 2011 estimate of 14,851 MMcf as compared to the calendar year 2009 estimate of 15,239 MMcf.

Q. Do you have any additional comments to make regarding the topic of sales forecasts?

A. Yes. The models and methods that we have described incorporate a number of assumptions regarding economic activity, prices and consumption patterns, including load factor. To the extent that activity in our service territory, in terms of the level of customers, changes dramatically, or customers change their consumption habits in response to changes in economic/price conditions, these changes should be reflected in the final Rate Year forecasts utilized to determine the revenue requirement and rate design.

Q. How were the revenues associated with the sales forecast for 2009, 2010 and the Rate Year developed?

A. Monthly electric sales were based on an annual historical distribution to allocate revenue account sales to a service class or sub-class basis. Billing demands were projected based on historical load factor trends. The forecasted billing parameters derived were priced at present rates, as filed by

the Company in compliance with Cases 08-E-0887 and 08-G-0888, effective July 1, 2009 on a temporary basis pending Commission approval.

Monthly gas sales, by forecasting group, were allocated between heating and non-heating sub-classes, for the purposes of billing block distribution. The resulting gas sales were spread between blocks based on an O-Give analysis of the actual bill distribution for calendar years 2007 and 2008. The monthly distributions were priced at present rates, effective July 1, 2009 as described above, to obtain total base revenue.

Electric and gas other operating revenues were estimated by extrapolating recent experience and adjusting for known changes.

Q. Were electric S.C. No. 14 revenues excluded from the forecast?

A. No. Historical customers and sales for this service classification were included in the appropriate revenue group forecasts as previously detailed. Due to minimal activity under this service classification, forecasted customers and sales were allocated to the respective parent service classifications as previously detailed.

Q. What assumptions were made with respect to interruptible gas sales and transport service (S.C. Nos. 8 and 9)?

A. Forecasts of sales/deliveries to these customers have been estimated based on historic usage patterns and included on the assumption that they will

continue to take service under the service classification for which they were billed as of March 31, 2009 through the forecast period.

Currently, both the Company's base delivery rates and gas cost adjustment factor include credits derived from the net of fuel revenues received from interruptible sales (S.C. Nos. 8 and 9) and sales to generating facilities (S.C. No. 14). Pursuant to the Order in C.08-G-0888 current base delivery rates include a profit imputation of $1.95 million estimated to be received from such sales. As a result, the Company is permitted to retain the first $1.95 million in net of fuel revenue in each rate year that it may receive from interruptible service and service to generating facilities. If the net of fuel revenue, or profit, is less than $1.95 million in any rate year, the Company is authorized to surcharge firm customers for 90 percent of the shortfall. If the margin exceeds $1.95 million in any rate year, the Company will credit to ratepayers 90 percent of the excess. Any such surcharges or credits are applied through the gas cost adjustment factor.

Q. Please elaborate on the process used to determine interruptible profit and apply the interruptible ratemaking mechanism.

A. This is a two-step process. Step one involves determining the profit (or net of fuel revenue) derived from interruptible service and service to electric generators. The profit is calculated as revenue less revenue tax and fuel cost.

In step two, the imputation is applied by subtracting $1.95 million from the profit as determined in step one. Ninety percent of the resulting shortfall or excess is collected from or returned to customers. The actual monthly net of fuel revenue for the three years ended March 31, 2009 is shown on Exhibit__(FRP-8).

Q. Is the Company proposing any changes to this interruptible profit mechanism?

A. No.

Revenue Allocation

Q. With respect to the subject of revenue allocation, please describe the criteria you have applied in allocating revenues and designing rates.

A. For both electric and gas the Company has historically sought to bring the rates of return of the various service classifications to within 15 percent of the system average rate of return. In this filing, in order to mitigate impacts on those customer classes earning less than 85 percent of the system average rate of return, the maximum increase allocated to all electric and gas service classifications is 1.25 times the overall applicable system increase. The minimum increase allocated to customer classes earning more than 115 percent of the system average rate of return is 0.75 times the overall applicable system increase. The constraints utilized for allocating the electric

and gas revenue increases were based on the electric constraints approved in Case 08-E-0887. The Company is proposing to maintain these constraints for electric service classifications while also utilizing the same constraints for all gas service classifications for consistency purposes.

Q. Were any changes made to forecasted revenues for purposes of revenue allocation and rate design?

A. No.

Q. Please explain Exhibits___(FRP-10) and (FRP-11), relating to the estimated effect of proposed revenue increases.

A. Exhibit___(FRP-10) for electric and (FRP-11) for gas each consist of two schedules that present the details of the proposed interclass revenue allocation. Schedule A details the methodology used to allocate the revenue increases among the various service classifications. Schedule B combines the allocated revenue increases from Schedule A with revenues at present rates to determine total filed base rate revenue by service classification for the Rate Year.

Q. What revenue requirement was used in developing the proposed rate revisions?

A. Electric own territory operating revenue must be increased by $15,207,000 in

the Rate Year in order to meet the Company's costs of providing service. Of that amount, $366,000 (total taxes of $373,000 less $7,000 obtained from other operating revenue increase) represents state and local revenue taxes that would be billed pursuant to the tax surcharge provision of the Company's tariff. The balance of $14,841,000 is to be obtained from S.C. Nos. 1, 2, 3, 5, 6, 8, 9 and 13 rates as explained below.

Gas own territory operating revenue must be increased by $3,997,000 in the Rate Year, in order to meet the Company's costs of providing service. Of that amount $117,000 (total taxes of $120,000 less $3,000 obtained from other operating revenue increase) represents state and local revenue taxes that would be billed pursuant to the tax surcharge provision of the Company's tariff. The balance of $3,880,000, plus $1,950,000 that is offset through imputation to S.C. Nos. 1, 2, 6, 12 and 13 in the rate design process, or a total of $5,830,000 is to be obtained from Service Classification Nos. 1, 2, 6, 12 and 13 rates as explained below.

Q. Please describe your procedure for allocating the Company's proposed revenue increase among the various service classifications.

A. The Company has allocated both the electric and gas proposed increases with reference to the results of the Pro-Forma Rate Year Embedded Cost of Service Studies ("ECOSS"), which are contained in Exhibits__(COSP-1) and (COSP-2), Schedule B and supported by the testimony of the Cost of Service

("COSP") Panel. The revenue allocation methodology is a three-step process.

The first step is to use results from the ECOSS for the Rate Year ending June 30, 2011 to determine what revenue adjustment among service classifications is necessary to have all class rates of return fall within a plus or minus 15 percent tolerance band around the overall rate of return as shown in columns 1-5 of Exhibits__(FRP-10, Schedule A) and (FRP-11, Schedule A).

The second step is to allocate the proposed revenue increase based on total delivery service revenue. The results of Step 2 are shown in column 9 of Exhibits ___(FRP-10, Schedule A) and (FRP-11, Schedule A). After adding the results of the first two steps together in column 10, the third step determines the resulting unconstrained percentage increases for each class as shown in column 11, which are then constrained as previously described.

Q. What were the results you obtained by applying the revenue allocation methodology to the proposed electric revenue increase?

A. Initially the methodology produced unconstrained rate changes for the service classifications ranging from negative 23.27 percent to 53.13 percent. The increases were then adjusted based on the percentage increases for the service classifications relative to the system average increase of 5.93 percent.

For S.C. Nos. 2 (Non Demand), 5, 13 (Substation and Transmission), for which the rate of return fell below the lower tolerance level of 85 percent of the system average, the maximum permissible increase of 1.25 times the average overall increase, or 7.41 percent, was utilized.

For S.C. Nos. 2 (Secondary), 3, 6 and 9, for which the rates of return exceeded the upper tolerance level of 115 percent of the system average, the minimum increase of 0.75 times the average overall increase, or 4.45 percent, was utilized.

Application of these maximum and minimum increases produced a revenue deficiency as compared to the rate increase revenue. This revenue deficiency was then allocated pro-rata among the service classes. The resulting increases are shown in columns 21 and 22 of Exhibit___(FRP-10, Schedule A).

Q. What were the results you obtained by applying the revenue allocation methodology to the proposed gas revenue increase?

A. Initially the methodology produced unconstrained rate changes for the service classifications ranging from negative 13.00 percent to 32.37 percent. The increases were then adjusted based on the percentage increases for the service classifications relative to the system average increase of 8.99 percent.

For S.C. No. 11 – Distribution and S.C. No. 11 - DLM, for which the rate of return fell below the lower tolerance level of 85 percent of the system average, the maximum permissible increase of 1.25 times the average overall increase, or 11.24 percent, was utilized.

For S.C. No. 11 – Transmission, for which the rate of return exceeded the upper tolerance level of 115 percent of the system average, the minimum increase of 0.75 times the average overall increase, or 6.74 percent, was utilized.

Application of the maximum/minimum increase methodology produced a revenue excess as compared to the rate increase revenue. This revenue excess was then allocated pro-rata among the service classes. The resulting increases are shown in columns 21 and 22 of Exhibit __(FRP-11, Schedule A).

Q. Were any adjustments made to the final electric and gas base revenue increases?

A. Yes. For each class, the base revenue increase was reduced by the estimated increase in revenue to be collected through the redesigned Merchant Function Charges for that class calculated as 1) redesigned base MFC rates multiplied by 2) class total deliveries. These adjustments are presented on Schedule A of Exhibits__(FRP-10) and (FRP-11).

Rate Design

Q. Please explain Schedule B of Exhibits__(FRP-10) and (FRP-11), regarding the effects of the proposed electric and gas rates.

A. Schedule B of both exhibits sets forth, by service classification, present base rate delivery revenues, the proposed revenue increase, total proposed delivery revenue and the net effect of the proposed revenue increase.

Q. Are you proposing any structural changes to rate design?

A. Yes. The Company is proposing to eliminate the electric Service Classification No. 6 rate differential between on- and off-peak volumetric rates.

Q. Why has the Company proposed to eliminate this rate differential?

A. Residential time-of-use was implemented while the Company's rates were bundled (commodity and delivery). At that time, the rate differential was established to reflect the differential in commodity. When rates were unbundled in February 2001, the differential was maintained for delivery, but not commodity. Effective July 1, 2007 the commodity rate applicable to S.C. No. 6 customers was separated into on- and off-peak rates in compliance with the Order in Case 05-E-0934 to reflect the differential of procuring commodity during on- and off-peak periods. The Company is proposing to eliminate the volumetric delivery rate differential as there is no cost of service

basis for continuing the differential. The commodity rate continues to be split between on- and off- peak.

Q. Is the Company proposing any other changes to rate design?

A. The Company is proposing to continue to maintain the unbundled rate structure approved by the Commission in the Company's most recent general rate proceeding, Cases 08-E-0887 and 08-G-0888. The Company proposes to update certain rate elements to reflect the results of the ECOSS.

The update to base rates (excluding lost revenue) for the MFC Administration Charge and the MFC Supply Charge as reflected on Schedule A of Exhibits__(FRP-12) and (FRP-13) as well as the update to the billing services credit are based on the results of the ECOSS, as contained in Exhibit __(COSP-1) and (COSP-2), Schedule C. The proposed updates to the billing services credit are shown below.

Billing Services Credit	Per Bill Current	Proposed
Electric	$1.42	$1.42
Gas	$0.98	$1.04

Q. After allocating the proposed electric revenue increase between various service classifications, how did you proceed to design the proposed charges for S.C. Nos. 1 (Residential) and 6 (Residential Time-Of-Use)?

A. For Service Classification No. 1 the monthly customer charge was increased from $18.00 to $22.00. The monthly customer charge for Service Classification No. 6 was increased by approximately the same percentage, from $21.00 to $26.00. These changes are intended to bring the customer charge closer to the embedded costs shown on Schedule C of Exhibit___(COSP-2), and supported by the testimony of the COSP. A flat delivery rate of $0.04494 per kWh was developed to produce the remainder of the Service Classification No. 1 revenue requirement. The on-peak and off-peak delivery rate differentials for Service Classification No. 6 were eliminated, as previously discussed, and a flat delivery rate of $0.04304 per kWh was developed to produce the remainder of the S.C. No. 6 revenue requirement.

Q. Please describe how the charges to S.C. No. 2 – General Service were developed.

A. Customer charges for non-demand, secondary and primary service were all increased to bring them closer to the embedded costs of service, resulting in proposed monthly customer charges as follows: Non-Demand $32.00, Secondary Demand $64.00 and Primary Demand $210.00. For the Non-demand class, a flat delivery rate of $0.00259 per kWh was developed to produce the remainder of the requirement.

Base delivery revenue from the secondary class is primarily driven by demand revenue which currently represents approximately 70 percent of secondary revenue while the volumetric rate contributes only 15 percent of the revenue. A flat demand charge of $8.03 per kW and a flat delivery rate of $0.00524 per kWh were developed for the secondary class by increasing each by approximately 0.4 percent to produce the remainder of the revenue requirement.

Similarly, demand revenue for the primary class currently represents approximately 86 percent of base revenue while the volumetric rate contributes only about 7 percent of the revenue. Therefore, the energy delivery charge and the demand charge for the primary class were each increased by approximately 4.3 percent to produce the remainder of the revenue requirement. This resulted in a flat delivery rate of $0.00141 per kWh and a flat demand charge of $6.57 per kW.

Q. Please describe how the charges to S.C. Nos. 3 and 13 were developed.

A. For both classes the monthly customer charge was increased; from $620.00 to $800.00 for Service Classification No. 3 and from $800.00 to $1,000.00 for Service Classification No. 13 (Substation and Transmission). These changes are intended to bring the customer charge closer to the embedded costs shown on Schedule C of Exhibit___(COSP-2), and supported by the testimony of the COSP.

The overall increase in the customer charge does not produce a significant customer bill impact for either S.C. No. 3, because of the 500 kW minimum bill provision in this service classification, or S.C. No. 13, due to the size of these customers.

A flat demand rate of $8.71 per kW was developed to produce the remainder of the Service Classification No. 3 revenue requirement while maintaining the reactive demand charge approved by the Commission in Case 08-E-0887. S.C. No. 13 Substation and Transmission flat demand rates of $6.64 per kW and $3.59 per kW, respectively, were developed to produce the remainder of the revenue requirement for this class while maintaining the reactive demand charge approved by the Commission in Case 08-E-0887.

Q. To what extent do the proposed changes to customer charges move the Company closer to costs reflected in the ECOSS?

A. The Company is proposing relatively minor movements. The table below shows, for customer classes with the greatest number of customers, the extent to which the current customer charges fall below the indicated costs of service and the movements towards cost that the Company is proposing:

Electric Customer Charges

S.C. No.	Current	Proposed	ECOSS	Current vs ECOSS	Proposed vs ECOSS
1 – NHt	$ 18.00	$ 22.00	$ 29.21	-38%	-25%
2 – ND	$ 30.00	$ 32.00	$ 33.14	- 9%	- 3%
2 – PD	$160.00	$210.00	$398.71	-60%	-47%
2 – SD	$ 50.00	$ 64.00	$ 95.40	-48%	-33%

Gas Customer Charges

S.C. No.	Current	Proposed	ECOSS	Current vs ECOSS	Proposed vs ECOSS
1 & 12 Ht	$17.00	$20.00	$37.01	-54%	-46%
2, 6 & 13 Ht	$30.00	$35.00	$61.06	-51%	-43%

Q. How were proposed charges to S.C. Nos. 5 (Area Lighting) and 8 (Street Lighting) developed?

A. These charges were developed by applying the class increase to each offering across the classes.

Q. Are there any electric service classifications for which the Company is proposing no change at this time?

A. Yes. The Company currently offers standby service under S.C. No. 14. As there is minimal activity under this service classification with respect to the tariff rates, and these rates follow the parent service classification rates/cost

of service, the Company believes that any rate design changes required to this service classification should be made at a later stage in this proceeding.

We are also proposing to maintain the current level of the contract demand charges for S.C. No. 10 at this time as the Company is not supporting a marginal cost of service study in the instant proceeding. The underlying customer charges for this service classification, however, are being updated with the customer charges proposed for S.C. Nos. 2 (Primary), 3 and 13.

Q. After allocating the proposed gas revenue increase between various service classifications, how did you proceed to design the proposed residential rates (S.C. Nos. 1 and 12)?

A. In designing rates for residential customers the initial goal was the keep the increase in the customer charge in line with the customer charge increase approved in Case 08-G-0888. To accomplish this, the minimum charge for the first 200 cubic feet or less was increased from $17.00 to $20.00 per month. The remaining increase was then allocated between the penultimate and tail blocks to maintain similar block ratios as those approved in Case 08-G-0888 while also maintaining similar levels of increase for each block.

Q. Please describe how the charges to Service Classification Nos. 2, 6 and 13 were developed.

A. The primary goal in designing the rates for these classes was to maintain a similar increase in the customer charge in comparison to the residential customer classes.

The first step in the rate design was to increase the minimum charge from $30.00 to $35.00, moving this charge closer to the percentage increase allocated to S.C. Nos. 1 & 12. The next step was to increase the remaining blocks in order to produce block ratios consistent with those approved in Case 08-G-0888 while also maintaining similar rate reductions for each block.

Q. Please describe how the charges to S.C. No. 11 – Transmission, Distribution and DLM were developed.

A. The monthly customer charge for each subclass was increased to $800. Due to the limited number of customers taking service under S.C. No. 11, this proposed increase does not generate a significant amount of revenue. The remaining increase was allocated to the Maximum Daily Quantity (MDQ) charge.

Q. Are there any other gas service classifications for which the Company is proposing revised rates?

A. No. The Company does not currently serve any customers under S.C. Nos. 15 and 16 (Distributed Generation ("DG") – Commercial and Industrial and

DG – Residential, respectively), therefore the Company believes that any rate design changes required to this service classification should be made at a later stage in this proceeding.

Q. Is the Company proposing to update any other delivery rates?

A. Yes. Pursuant to the Commission's Order in Case 08-E-0887, an Electric Bill Credit was implemented July 1, 2009 to return the electric regulatory liability of $36 million to customers over a three year period. For the twelve months ending June 30, 2010, $20 million of that liability will be returned to customers through the Electric Bill Credit factors effective July 1, 2009. The Company is proposing to update the bill credit factors pursuant to the Order in Case 08-E-0887 to return $10 million over the twelve months ending June 30, 2011. These charges are reflected on Schedule B of Exhibit__(FRP-12).

Exhibits

Q. Please explain Exhibits___(FRP-12) and (FRP-13), which set forth a summary of present and proposed rates.

A. Exhibit__(FRP-12) consists of ten schedules. Schedule A and Schedule B set forth the present and proposed MFC Charges, and the proposed EBC, respectively, as previously discussed. Each of the remaining schedules set forth a comparison of the provisions of a present service classification and the proposed superseding service classification.

Exhibit___ (FRP-13) consists of two schedules. As previously noted, Schedule A sets forth present and proposed base MFC charges. Schedule B sets forth a comparison of the provisions of present S.C. Nos. 1, 2, 6, 11, 12 and 13 and the proposed superseding service classifications.

Q. Please explain Exhibits___(FRP-14) and (FRP-15), regarding comparative bills.

A. Exhibit___(FRP-14) provides comparisons of charges for typical usages under S.C. Nos. 1 and 2 at present and proposed rates.

Exhibit___ (FRP-15) provides comparisons of charges for typical usages under S.C. Nos. 1/12 and 2/6/13 at present and proposed rates.

These comparisons were prepared using the monthly Energy Cost Adjustment Mechanism factors effective July 14, 2009 and monthly GSC factors effective July 2, 2009, respectively, in order to develop estimates of full service bills to allow for a more accurate estimate of the utility bill impacts of the proposed rate changes.

Q. How are the Company's energy supply costs recovered from full service customers?

A. From November 2001 to May 1, 2005 all energy costs incurred on behalf of full service customers were fully recovered through the Market Price Charge ("MPC") and Market Price Adjustment ("MPA") components of the

Company's Energy Cost Adjustment Mechanism ("ECAM") or through the Hourly Pricing Provision ("HPP") for S.C. Nos. 2, 3 and 13 customers electing to take service under the terms of the HPP. Effective May 1, 2005, S.C. Nos. 3 and 13 customers continuing to purchase their energy supply requirements from Central Hudson were required to do so under the HPP.

Pursuant to the Order in Case 08-E-0887, the Company will file a Plan for expansion of the HPP to all S.C. No. 2 customers exceeding 500 kW in two consecutive months by August 21, 2009.

Q. Please describe the ECAM.

A. The ECAM consists of four components: the MPC, MPA, the Miscellaneous Charges ("MISC") and Purchased Power Adjustment ("PPA").

The MPC and MPA factors are applicable to all service classifications excluding S.C. Nos. 3 and 13 as previously noted. The MPC charge recovers the Company's cost of electricity supply related purchases, including firm energy, capacity, ancillary charges, risk management fees, and other charges imposed by the New York Independent System Operator ("NYISO"). The MPC also includes working capital carrying charges and an uncollectible allowance. In order to more closely align the MPC with wholesale market prices, energy and capacity purchased under the Purchased Power Agreement with Constellation, is marked to the market using NYISO day-ahead market prices. Energy and capacity purchased

under mandatory IPP contracts and the Company's retained generation is priced at the monthly average of NYISO day-ahead market prices. The MPC charge is calculated on a monthly basis for each MPC group based on actual costs incurred during the previous month allocated over projected deliveries for the collection period. The MPA is the reconciliation mechanism for the MPC. It is also calculated on a monthly basis by MPC group and reconciles actual MPC recoveries with MPC costs.

In addition to the MPC and MPA, there are two other factors that make up ECAM. The MISC factor recovers the cost or benefit of non-avoidable, variable energy related revenues or costs associated with the Company's retained generating facilities and from mandatory IPP purchases. The MISC also includes working capital carrying charges and an uncollectible allowance. The MISC charge or credit is calculated on a monthly basis on the previous month benefit or cost divided by estimated deliveries and is applicable to all energy deliveries as a uniform factor. The Company reconciles MISC recoveries with actual costs or benefits on a three-month lag.

The PPA factor is also applicable to all energy deliveries (excluding NYPA Power For Jobs allocations) as a uniform factor. Effective July 1, 2009, pursuant to the Commission's Order in Case 08-E-0887, service class and sub-class specific PPA factors were implemented. These factor recover the cost or benefit of the Company's PPA with Constellation for energy and capacity from NMP2. As previously indicated, the benefit or cost is

calculated by measuring the difference between the contract price and the actual market price, as included in the MPC. The PPA factor also includes an allowance for uncollectibles. The PPA factor is calculated on a monthly basis based on the cost incurred or benefit realized, as compared to actual market price, during the previous month divided by projected deliveries for the collection period, and is also subject to reconciliation similar to the MISC.

Q. Please provide a brief explanation of the Company's other supply recovery mechanism, the HPP.

A. Since May 1, 2005, the HPP has been the only commodity pricing option available to S.C. Nos. 3 and 13 customers that continue to elect to purchase their energy supply requirements from Central Hudson. Under the HPP, the Company recovers its costs by charging customers for their hourly supply requirements at the NYISO Zone G day-ahead market price, increased to reflect the applicable factor of adjustment. Customers under the HPP plan are also subject to an additional charge, the HPP UCAP charge, to recover costs for energy balancing and other components of electricity supply costs not reflected in the day-ahead market price for energy, such as installed capacity and charges for ancillary services.

Pursuant to the Order in Case 08-E-0887, beginning May 1, 2011, the HPP UCAP Charge will be renamed the HPP Charge and will continue to recover charges for energy balancing, ancillary services, allowances for

working capital and bad debts. This charge will be applied to customer bills on a per kWh basis. In addition, a separate charge, HPP UCAP, will be implemented to recover capacity charges. Each customer's capacity charge will be calculated as the product of the customer's demand during the previous summer's NYCA peak hour and the monthly NYISO Spot Auction price for the NYCA for the prior calendar month. This charge will be applied to customer bills on a per kW basis.

Q. Is the Company proposing any structural changes to the way it recovers purchased electricity costs?

A. No, the Company is seeking to continue to fully recover the costs of electricity purchased for full service customers through the continued application of the provisions of the ECAM and HPP. Continued application of these mechanisms entail the continued use of deferral accounting, as necessary, in recognizing the timing differences that occur between the actual purchases of energy requirements and the collection of costs from customers.

Despite the sale of the Company's fossil and nuclear generating facilities, the unbundling of the supply and delivery function, the implementation of MFCs and the establishment of a mature wholesale electricity market, the Company continues to bear the obligation to forecast, procure, and manage the electricity supply obligation for the great majority of

its customers. The Company continues to source and contract for cost effective supply on behalf of those customers that choose to purchase their supply from the Company. Full recovery of these purchase costs is essential to the financial health and stability of the Company, absent the ability to control generation and wholesale market costs.

Q. How are the Company's natural gas supply costs recovered from full service customers?

A. Gas supply expense (demand and commodity) incurred by the Company to serve full service customers taking service under S.C. Nos. 1 and 2 is recovered through the Gas Supply Charge ("GSC"). The GSC is determined monthly and reconciled annually, for the twelve-month period ending August 31, in accordance with 16 NYCRR §720-6.

Q. Is the Company proposing to revise the electric factor of adjustment?

A. Yes. Currently, the system factor of adjustment of 1.043 is based on the three years ending March 2008, however, pursuant to the Order in Case 08-E-0887, effective July 1, 2009, the Company implemented service-level specific factors of adjustment based on the factors utilized in the Company's ECOS study. As a result, the system factor of adjustment of 1.047 for the three years ending March 2009 has been allocated back to service and/or sub-classes, as shown below, in the same manner as was done in Case 08-

E-0887. Additionally, the aforementioned Order required the Company to submit to the Commission a new loss study by January 22, 2010. The Company proposes to update service-level specific loss factors at a later stage in this proceeding to reflect the loss allocation included in that study.

	RY 1 Sales (kWh)	% Sales	Adjusted FOA	Weighted FOA
S.C. No. 1	2,018,392,000	38.887%	1.0575	0.411207
S.C. No. 2 - ND	153,255,000	2.953%	1.0575	0.031223
S.C. No. 2 - SD	1,446,391,000	27.866%	1.0575	0.294673
S.C. No. 2 - PD	245,144,000	4.723%	1.0390	0.049072
S.C. No. 3	275,997,000	5.317%	1.0390	0.055248
S.C. No. 6	29,000,000	0.559%	1.0575	0.005908
S.C. No. 13 - Sub	165,640,000	3.191%	1.0190	0.032520
S.C. No. 13 - Trans	817,460,000	15.749%	1.0106	0.159167
S.C. No. 9	3,330,000	0.064%	1.0575	0.000678
S.C. No. 5	13,020,000	0.251%	1.0575	0.002653
S.C. No. 8	22,830,000	0.440%	1.0575	0.004651
Total	**5,190,459,000**	**100%**		**1.0470**

Q. Is the Company proposing to revise the gas factor of adjustment?

A. The current factor of adjustment of 1.0117 approved by the Commission in Case 08–G-0888 was based on a three-year average ended August 31, 2008. Similarly, the Company proposes to continue to utilize a three-year average to strike the balance between reflecting current loss activity without producing a high degree of volatility. The Company recommends that this factor be reviewed prior to the Commission's decision in this proceeding to reflect the most recent three years of data ending August 31, 2009, available at the time of the update.

Q. Have Revenue Decoupling Mechanisms ("RDM") been implemented for the Company's electric and gas operations?

A. Yes. Pursuant to the Commission's Order in Cases 08-E-0887 and 08-G-0888, RDMs were implemented for certain electric and gas service classifications effective July 1, 2009.

Q. Is the Company proposing any changes to the electric and gas RDMs currently in place?

A. No. Since the RDMs were implemented July 1, 2009, at the time of this filing, the Company has not yet concluded one billing month under the new mechanisms. As a result, the Company feels it would be premature to propose a change at this time.

Q. Is the Company's gas business subject to a Weather Normalization Clause ("WNC")?

A. Yes. Pursuant to the Commission's Order in Case 08-G-0888, a WNC was implemented for all heating customers taking service under S.C. Nos. 1, 2, 6, 12 and 13.

Q. Is the Company proposing any changes to the WNC currently in place?

A. No. Similar to other New York State utilities, the Company's WNC is effective for the period October 1 – May 31, inclusive. As a result, there has yet to be any activity under the WNC and the Company feels it would be premature to propose a change at this time.

Q. Has the Forecasting & Rates Panel provided additional information for annual periods beyond June 30, 2011?

A. Yes, the Panel has included additional schedules similar to Schedule F of Exhibits__(FRP-2) and (FRP-3) for the twelve month periods ending June 30, 2012 and 2013. These schedules have been provided as additional information to the accompanying filing letter.

Q. Does this conclude your pre-filed direct testimony?

A. Yes, it does.

Exhibits of
Forecasting & Rates Panel

EXHIBIT __ (FRP-1)
Schedules A-B
EXHIBIT__(FRP-2)
Schedules A-F
EXHIBIT __(FRP3)
Schedules A-F
EXHIBIT __ (FRP-4)
Schedules A-B
EXHIBIT __ (FRP-5)
Schedules A-B
EXHIBIT __ (FRP-6)
Sheets 1-14
EXHIBIT __ (FRP-7)
Sheets 1-8
EXHIBIT __ (FRP-8)
EXHIBIT __ (FRP-9)
EXHIBIT __ (FRP-10)
Schedules A-B
EXHIBIT__(FRP-11)
Schedules A-B
EXHIBIT __(FRP12)
Schedules A-J
EXHIBIT __ (FRP-13)
Schedules A-B
EXHIBIT __ (FRP-14)
Schedules A-C
EXHIBIT__(FRP-15)
Schedules A-B

Central Hudson Gas & Electric Corporation

Statement of Operating Revenues

for

2006, 2007, 2008 and
the Twelve Months Ended March 31, 2009

Schedule A	Electric Operating Revenues
Schedule B	Gas Operating Revenues

Central Hudson Gas & Electric Corporation
Statement of Electric Operating Revenues

Acct. No.		Year Ended December 31, 2006 kWh	Total Revenue	Base Revenue	Base Rev. $/kWh	Year Ended December 31, 2007 kWh	Total Revenue	Base Revenue	Base Rev. $/kWh
440	Residential *	2,004,577,384	$ 257,113,991	$ 104,596,595	$ 0.052	2,087,392,163	$ 292,307,419	$ 120,470,675	$ 0.058
442	Commercial and Industrial *	1,720,384,732	$ 161,028,417	$ 41,328,656	$ 0.024	2,295,125,650	$ 229,161,243	$ 48,309,238	$ 0.021
444	Public Street and Highway Lighting	23,235,923	$ 4,325,161	$ 2,802,146	$ 0.121	23,082,124	$ 4,868,218	$ 3,272,262	$ 0.142
445	Other Sales to Public Authorities	287,450,709	$ 27,698,905	$ 6,979,497	$ 0.024	344,003,156	$ 37,189,492	$ 8,876,429	$ 0.026
448	Interdepartmental Sales	920,057	$ 13,974	$ 13,974	$ 0.015	932,586	$ 15,008	$ 15,008	$ 0.016
456.21/25	Residential Retail Access *	25,802,234	$ 1,157,478	$ 1,184,069	$ 0.046	30,785,232	$ 1,610,981	$ 1,663,887	$ 0.054
456.22/26	Commercial Retail Access *	362,616,142	$ 4,852,330	$ 5,219,094	$ 0.014	393,870,213	$ 6,030,124	$ 6,663,832	$ 0.017
456.23	Industrial Retail Access	968,300,037	$ 2,352,644	$ 5,326,409	$ 0.006	395,735,875	$ 2,908,036	$ 3,837,447	$ 0.010
456.24	OPA Retail Access	106,124,738	$ 1,824,305	$ 1,938,969	$ 0.018	60,634,121	$ 1,197,864	$ 1,300,719	$ 0.021
	Total Own Territory	5,499,411,956	$ 460,367,205	$ 169,389,409	$ 0.031	5,631,561,120	$ 575,288,385	$ 194,409,497	$ 0.035
450	Finance Charges on Utility Services	-	$ 2,679,923	$ 2,679,923			$ 2,736,636	$ 2,736,636	
451	Miscellaneous Service Revenues	-	$ 205,750	$ 205,750			$ 227,728	$ 227,728	
454	Rental from Property	-	$ 4,020,877	$ 4,020,877			$ 3,868,339	$ 3,868,339	
456	Other Electric Revenues	-	$ 24,977,765	$ 24,977,765			$ 28,440,276	$ 28,440,276	
	Total Other Operating Revenues	-	$ 31,884,315	$ 31,884,315			$ 35,272,979	$ 35,272,979	
447	Sales for Resale	196,565,213	$ 11,670,768	$ 11,670,768	$ 0.059	153,901,695	$ 6,292,853	$ 6,292,853	$ 0.041
	Total Electric Operating Revenues	5,695,977,169	$ 503,922,288	$ 212,944,492		5,785,462,815	$ 616,854,217	$ 235,975,329	

* Includes Unbilled Sales/Deliveries & Revenue

Exhibit ___(FRP-1)
Schedule A
Sheet 1 of 2

Central Hudson Gas & Electric Corporation
Statement of Electric Operating Revenues

Acct. No.		Year Ended December 31, 2008 kWh	Total Revenue	Base Revenue	Cents per kWh	Twelve Months Ended March 31, 2009 kWh	Total Revenue	Base Revenue	Cents per kWh
440	Residential *	2,003,545,038	$ 326,376,916	$ 127,959,579	$ 0.064	2,008,955,422	$ 342,488,543	$ 130,982,235	$ 0.065
442	Commercial and Industrial *	1,328,799,389	$ 173,862,264	$ 44,095,362	$ 0.033	1,265,378,573	$ 174,648,425	$ 43,365,302	$ 0.034
444	Public Street and Highway Lighting	22,920,784	$ 7,587,993	$ 3,638,007	$ 0.159	22,936,946	$ 5,671,750	$ 3,730,551	$ 0.163
445	Other Sales to Public Authorities	370,394,310	$ 46,662,958	$ 10,222,992	$ 0.028	364,394,472	$ 47,334,350	$ 10,315,229	$ 0.028
448	Interdepartmental Sales	936,654	$ 16,308	$ 16,308	$ 0.017	952,603	$ 17,545	$ 17,545	$ 0.018
456.21/25	Residential Retail Access *	80,320,110	$ 4,551,235	$ 5,018,506	$ 0.062	92,360,000	$ 5,438,283	$ 5,816,476	$ 0.063
456.22/26	Commercial Retail Access *	453,055,396	$ 7,240,539	$ 9,824,641	$ 0.022	493,259,591	$ 9,035,193	$ 11,067,225	$ 0.022
456.23	Industrial Retail Access	1,161,028,517	$ 1,842,055	$ 7,588,125	$ 0.007	1,145,368,026	$ 2,348,779	$ 7,744,733	$ 0.007
456.24	OPA Retail Access	34,090,442	$ 499,946	$ 693,361	$ 0.020	36,874,747	$ 618,519	$ 747,379	$ 0.020
	Total Own Territory	5,455,090,640	$ 568,640,214	$ 209,056,881	$ 0.038	5,430,480,380	$ 587,601,387	$ 213,786,675	$ 0.039
450	Finance Charges on Utility Services		$ 3,379,526	$ 3,379,526			$ 3,585,763	$ 3,585,763	
451	Miscellaneous Service Revenues		$ 253,136	$ 253,136			$ 251,132	$ 251,132	
454	Rental from Property		$ 4,890,356	$ 4,890,356			$ 4,969,383	$ 4,969,383	
456	Other Electric Revenues		$ 18,338,036	$ 18,338,036			$ 13,861,913	$ 13,861,913	
	Total Other Operating Revenues		$ 26,861,054	$ 26,861,054			$ 22,668,191	$ 22,668,191	
447	Sales for Resale	147,044,475	$ 12,676,141	$ 12,676,141	$ 0.086	137,774,698	$ 10,847,899	$ 10,847,899	$ 0.079
	Total Electric Operating Revenues	5,602,135,115	$ 608,177,409	$ 248,594,076		5,568,255,078	$ 621,117,477	$ 247,302,765	

* Includes Unbilled Sales/Deliveries & Revenue

Exhibit ___(FRP-1)
Schedule A
Sheet 2 of 2

Central Hudson Gas & Electric Corporation
Statement of Gas Operating Revenues

Acct No.		Year Ended December 31,2006 Mcf	Total Revenue	Base Revenue	Base Rev. $/Mcf	Year Ended December 31, 2007 Mcf	Total Revenue	Base Revenue	Base Rev. $/Mcf
480	Residential *	4,169,756	$ 68,901,546	$ 21,757,451	$ 5.22	4,652,601	$ 76,044,853	$ 27,528,054	$ 5.92
481	Commercial & Industrial *	3,239,513	$ 42,899,112	$ 10,193,712	$ 3.15	3,396,109	$ 45,289,001	$ 11,582,389	$ 3.41
482	Other Sales-Public Authorities	934,467	$ 11,980,986	$ 4,543,021	$ 4.86	1,149,191	$ 14,132,947	$ 6,005,367	$ 5.23
484	Interdepartmental Sales	25,829	$ 319,226	$ 319,226	$ 12.36	26,280	$ 301,390	$ 301,390	$ 11.47
489.10	Gas Transport. - Cust. Owned Gas	848,838	$ 659,941	$ 659,958	$ 0.78	833,986	$ 708,451	$ 708,451	$ 0.85
489.11	SC 14 Transportation	338,179	$ 53,436	$ 53,438	$ 0.16	592,563	$ 77,590	$ 77,587	$ 0.13
489.09/12	SC 11 Transportation	2,943,133	$ 1,826,553	$ 1,826,610	$ 0.62	2,837,558	$ 1,905,636	$ 1,905,638	$ 0.67
489.13/14/30	Residential Transportation *	456,815	$ 3,012,614	$ 2,192,284	$ 4.80	511,202	$ 2,963,592	$ 2,745,779	$ 5.37
489.19/20/40	Commercial Transportation *	1,427,181	$ 4,729,239	$ 2,846,113	$ 1.99	1,692,840	$ 4,451,082	$ 3,929,991	$ 2.32
489.21	Industrial Transportation	170,451	$ 495,131	$ 286,005	$ 1.68	189,719	$ 412,063	$ 361,911	$ 1.91
489.22	OPA Transportation	58,129	$ 191,748	$ 101,448	$ 1.75	46,974	$ 127,826	$ 111,627	$ 2.38
	Total	14,612,290	$ 135,069,532	$ 44,779,266	$ 3.06	15,929,021	$ 146,414,431	$ 55,258,184	$ 3.47
487	Finance Charges on Utility Services	-	$ 896,905	$ 896,905		-	$ 798,394	$ 798,394	
488	Miscellaneous Service Revenues	-	$ 38,345	$ 38,345		-	$ 32,358	$ 32,358	
493	Rent from Gas Property	-	$ 1,429,596	$ 1,429,596		-	$ 477,504	$ 477,504	
494	Interdepartmental Rents	-	$ -	$ -		-	$ -	$ -	
495	Other Gas Revenues	-	$ 1,256,102	$ 1,256,102		-	$ (191,849)	$ (191,849)	
	Total Other Operating Revenues	-	$ 3,620,948	$ 3,620,948		-	$ 1,116,407	$ 1,116,407	
483	Sales For Resale	2,288,798	$ 16,900,592	$ 16,900,592	$ 7.38	2,325,173	$ 18,218,863	$ 18,218,863	$ 7.84
	Total Gas Operating Revenues	16,901,088	$ 155,591,072	$ 65,300,806	$ 3.86	18,254,194	$ 165,749,701	$ 74,593,454	$ 4.09

* Includes Unbilled Sales/Transport & Revenue

Exhibit ___ (FRP-1)
Schedule B
Sheet 1 of 2

Central Hudson Gas & Electric Corporation
Statement of Gas Operating Revenues

Acct No.		Year Ended December 31, 2008 Mcf	Total Revenue	Base Revenue	Base Rev. $/Mcf	Twelve Months Ended Mar 31, 2009 Mcf	Total Revenue	Base Revenue	Base Rev. $/Mcf
480	Residential *	4,474,266	$ 81,671,510	$ 29,140,449	$ 6.51	4,584,525	$ 87,071,721	$ 29,892,644	$ 6.52
481	Commercial & Industrial *	3,154,531	$ 47,005,226	$ 11,913,730	$ 3.78	3,182,179	$ 48,746,622	$ 11,876,671	$ 3.73
482	Other Sales-Public Authorities	1,198,432	$ 15,864,356	$ 7,348,349	$ 6.13	1,206,199	$ 15,516,357	$ 6,606,051	$ 5.48
484	Interdepartmental Sales	23,648	$ 322,826	$ 322,826	$ 13.65	27,982	$ 391,052	$ 391,052	$ 13.97
489.10	Gas Transport. - Cust. Owned Gas	954,200	$ 927,782	$ 927,779	$ 0.97	1,003,253	$ 1,012,627	$ 1,012,624	$ 1.01
489.11	SC 14 Transportation	540,315	$ 57,718	$ 57,718	$ 0.11	523,289	$ 61,357	$ 61,356	$ 0.12
489.09/12	SC 11 Transportation	2,783,924	$ 1,983,564	$ 1,983,570	$ 0.71	2,688,745	$ 1,984,141	$ 1,984,152	$ 0.74
489.13/14/30	Residential Transportation *	693,376	$ 4,419,862	$ 4,347,217	$ 6.27	755,265	$ 4,874,555	$ 4,689,304	$ 6.21
489.19/20/40	Commercial Transportation *	1,880,722	$ 5,172,888	$ 4,950,609	$ 2.63	2,021,805	$ 5,759,377	$ 5,298,864	$ 2.62
489.21	Industrial Transportation	203,562	$ 459,876	$ 437,689	$ 2.15	198,143	$ 469,365	$ 426,961	$ 2.15
489.22	OPA Transportation	82,783	$ 225,497	$ 208,380	$ 2.52	132,610	$ 354,006	$ 314,702	$ 2.37
	Total Deliveries	15,969,760	$ 158,111,105	$ 61,638,316	$ 3.85	16,323,996	$ 166,241,180	$ 62,554,381	$ 3.83
487	Finance Charges on Utility Services	-	$ 1,008,332	$ 1,008,332		-	$ 1,130,443	$ 1,130,443	
488	Misc. Service Revenues	-	$ 30,564	$ 30,564		-	$ 30,306	$ 30,306	
493	Rent from Gas Property	-	$ -	$ -		-	$ -	$ -	
494	Interdepartmental Rents	-	$ -	$ -		-	$ -	$ -	
495	Other Gas Revenues	-	$ (140,481)	$ (140,481)		-	$ 134,109	$ 134,109	
	Total Other Operating Revenues	-	$ 898,415	$ 898,415		-	$ 1,294,858	$ 1,294,858	
483	Sales For Resale	2,898,722	$ 30,859,536	$ 30,859,536	$ 10.65	3,155,142	$ 36,304,561	$ 36,304,561	$ 11.51
	Total Gas Operating Revenues	18,868,482	$ 189,869,056	$ 93,396,267	$ 4.94	19,479,138	$ 203,840,599	$ 100,153,800	$ 5.14

* Includes Unbilled Sales/Transport & Revenue

Exhibit ___ (FRP-1)
Schedule B
Sheet 2 of 2

Central Hudson Gas & Electric Corporation

Electric Sales, Base Delivery Revenues and Customers

Schedule A	Summary of Electric Sales, Base Revenues and Customers by Service Classification for the Twelve Months Ended March 31, 2009, December 31, 2009, December 31, 2010, and June 30, 2011
Schedule B	Electric Sales, Base Revenues and Customers by Revenue Account - Twelve Months Ended March 31, 2009
Schedule C	Electric Sales, Base Revenues and Customers by Service Classification - Twelve Months Ended March 31, 2009
Schedule D	Electric Sales, Base Revenues and Customers by Service Classification - Twelve Months Ended December 31, 2009
Schedule E	Electric Sales, Base Revenues and Customers by Service Classification - Twelve Months Ended December 31, 2010
Schedule F	Electric Sales, Base Revenues and Customers by Service Classification - Twelve Months Ended June 30, 2011

Central Hudson Gas & Electric Corporation
Summary of Electric Sales (MWh) by Service Classification

	Twelve Months Ended March 31, 2009	2009	2010	Twelve Months Ended June 30, 2011
Service Classification No. 1				
Heating	313,777	320,442	328,680	324,900
EEPS Lost MWh	-	(1,568)	(8,463)	(12,007)
Nonheating	1,779,918	1,818,790	1,784,080	1,766,320
EEPS Lost MWh	-	(10,388)	(44,947)	(59,542)
PV Lost MWh	-	(1,050)	(1,362)	(1,279)
Unbilled	(181)	1,800	(430)	(430)
	2,093,513	2,128,026	2,057,558	2,017,962
Service Classification No. 2				
Nondemand	173,151	172,042	162,400	162,120
EEPS Lost MWh	-	(1,572)	(6,531)	(8,865)
Primary	233,573	247,317	260,850	258,970
EEPS Lost MWh	-	(2,463)	(10,406)	(13,826)
Secondary	1,452,004	1,461,048	1,528,880	1,528,980
EEPS Lost MWh	-	(14,385)	(61,543)	(82,207)
PV Lost MWh	-	(313)	(407)	(382)
Unbilled	(187)	121	(90)	(90)
	1,858,540	1,861,794	1,873,153	1,844,700
Service Classification No. 3	296,315	286,001	293,650	291,670
EEPS Lost MWh	-	(2,798)	(11,817)	(15,673)
	296,315	283,203	281,833	275,997
Service Classification No. 5	13,224	13,287	13,090	13,020
Service Classification No. 6	28,873	28,985	29,000	29,000
Service Classification No. 8	22,937	22,854	22,830	22,830
Service Classification No. 9	3,026	3,345	3,340	3,330
Service Classification No. 13				
Transmission	942,290	856,319	817,460	817,460
Substation	170,810	164,643	165,500	165,640
	1,113,100	1,020,962	982,960	983,100
Interdepartmental	953	941	890	890
Total Own Territory	5,430,480	5,363,398	5,264,654	5,190,829

Central Hudson Gas & Electric Corporation
Summary of Electric Base Delivery Revenues by Service Classification

	Twelve Months Ended March 31, 2009	2009	2010	Twelve Months Ended June 30, 2011
Service Classification No. 1				
Heating	$ 17,931,969	$ 20,332,474	$ 23,501,910	$ 23,293,500
EEPS Lost Revenue	$ -	$ (77,220)	$ (456,730)	$ (647,860)
Nonheating	$ 117,838,945	$ 134,218,465	$ 147,251,500	$ 146,476,990
EEPS Lost Revenue	$ -	$ (519,370)	$ (2,431,220)	$ (3,221,150)
PV Lost Revenue	$ -	$ (52,973)	$ (74,059)	$ (69,527)
Unbilled	$ 497,031	$ 6,181	$ (16,610)	$ (16,610)
	$ 136,267,945	$ 153,907,557	$ 167,774,791	$ 165,815,343
Service Classification No. 2				
Nondemand	$ 9,983,516	$ 11,212,636	$ 12,244,960	$ 12,285,550
EEPS Lost Revenue	$ -	$ (23,120)	$ (74,610)	$ (101,170)
Primary	$ 3,888,604	$ 4,426,470	$ 4,966,870	$ 4,937,120
EEPS Lost Revenue	$ -	$ (43,380)	$ (185,270)	$ (244,270)
Secondary	$ 45,759,860	$ 48,818,403	$ 53,669,550	$ 53,788,690
EEPS Lost Revenue	$ -	$ (434,830)	$ (1,870,640)	$ (2,495,270)
PV Lost Revenue	$ -	$ (29,157)	$ (38,702)	$ (36,348)
Unbilled	$ 29,785	$ 27,447	$ (1,570)	$ (1,570)
	$ 59,661,765	$ 63,954,469	$ 68,710,588	$ 68,132,732
Service Classification No. 3	$ 5,377,191	$ 5,546,172	$ 5,962,180	$ 5,926,380
EEPS Lost Revenue	$ -	$ (53,740)	$ (230,540)	$ (305,410)
	$ 5,377,191	$ 5,492,432	$ 5,731,640	$ 5,620,970
Service Classification No. 5	$ 1,054,949	$ 1,467,242	$ 1,628,700	$ 1,625,120
Service Classification No. 6	$ 1,533,611	$ 1,651,499	$ 1,785,870	$ 1,785,870
Service Classification No. 8	$ 3,730,551	$ 4,040,126	$ 4,285,330	$ 4,291,090
Service Classification No. 9	$ 219,542	$ 211,852	$ 202,380	$ 202,350
Service Classification No. 13				
Transmission	$ 4,361,726	$ 4,485,569	$ 4,843,740	$ 4,843,740
Substation	$ 1,561,850	$ 1,751,574	$ 2,002,290	$ 2,003,720
	$ 5,923,576	$ 6,237,143	$ 6,846,030	$ 6,847,460
Interdepartmental	$ 17,545	$ 10,998	$ 3,020	$ 3,020
Total Own Territory	$ 213,786,675	$ 236,973,318	$ 256,968,349	$ 254,323,955

Central Hudson Gas & Electric Corporation
Summary of Electric Customers by Service Classification

	Twelve Months Ended March 31, 2009	2009	2010	Twelve Months Ended June 30, 2011
Service Classification No. 1				
Heating	25,023	25,676	25,891	25,874
Nonheating	227,312	227,950	229,709	230,550
Unbilled	-	-	-	-
	252,335	253,626	255,600	256,424
Service Classification No. 2				
Nondemand	29,059	28,813	28,816	28,937
Primary	168	169	169	171
Secondary	11,781	11,742	11,909	12,111
Unbilled	-	-	-	-
	41,008	40,723	40,895	41,219
Service Classification No. 3	34	32	32	32
Service Classification No. 5	4,563	4,563	4,563	4,563
Service Classification No. 6	1,578	1,566	1,575	1,575
Service Classification No. 8	206	207	207	207
Service Classification No. 9	306	297	297	297
Service Classification No. 13				
Transmission	9	7	6	6
Substation	7	7	7	7
	16	14	13	13
Interdepartmental	1	1	1	1
Total Own Territory	300,046	301,029	303,182	304,331

Central Hudson Gas & Electric Corporation
Statement of Electric Sales, Revenues and Customers by Revenue Account
Twelve Months Ended March 31, 2009

Acct. No.		April 2008	May 2008	June 2008	July 2008	August 2008	September 2008	October 2008	November 2008	December 2008	January 2009	February 2009	March 2009	Total
	Sales (MWh)													
440	Residential *	164,741	129,429	139,430	169,384	191,625	176,236	147,136	144,755	168,113	199,662	203,199	175,244	2,008,955
442	Commercial and Industrial *	106,461	103,140	109,763	122,593	119,765	111,925	94,249	97,264	101,868	102,399	103,942	92,020	1,265,379
444	Public Street and Highway Lighting	1,722	1,541	1,380	1,486	1,665	1,853	2,123	2,290	2,513	2,411	2,018	1,935	22,937
445	Other Sales to Public Authorities	30,587	28,432	29,697	31,688	28,746	29,553	28,035	31,250	31,666	32,394	32,823	29,523	364,394
447	Sales for Resale	13,456	13,554	8,119	9,579	9,426	8,507	9,281	12,218	14,342	12,050	12,749	14,496	137,775
448	Interdepartmental Sales	62	59	70	82	75	69	73	71	71	90	254	(23)	953
456.21/25	Residential Retail Access *	6,256	5,151	5,661	7,087	8,196	8,022	7,071	7,176	8,285	9,889	10,384	9,183	92,360
456.22/26	Commercial Retail Access *	31,393	33,063	38,127	46,674	43,859	44,907	39,825	41,147	42,255	45,484	45,759	40,766	493,260
456.23	Industrial Retail Access	91,647	98,162	104,451	108,886	105,025	99,443	99,111	92,345	91,423	88,585	80,213	86,078	1,145,368
456.24	OPA Retail Access	2,364	2,349	2,325	2,809	2,850	2,586	2,326	2,496	3,824	4,075	3,925	4,946	36,875
	Total Sales	448,688	414,879	439,023	500,269	511,232	483,099	429,230	431,003	464,360	497,039	495,266	454,167	5,568,255
	Base Revenues ($)													
440	Residential *	$ 10,126,808	$ 8,741,262	$ 9,146,523	$ 11,011,476	$ 11,919,554	$ 11,482,951	$ 10,247,568	$ 10,203,311	$ 11,302,886	$ 12,568,321	$ 12,675,297	$ 11,556,278	$ 130,982,235
442	Commercial and Industrial *	$ 3,496,109	$ 3,486,362	$ 3,713,030	$ 4,011,682	$ 3,981,633	$ 3,875,651	$ 3,495,224	$ 3,486,047	$ 3,555,086	$ 3,443,560	$ 3,452,339	$ 3,368,579	$ 43,365,302
444	Public Street and Highway Lighting	$ 288,282	$ 288,236	$ 287,987	$ 320,151	$ 317,014	$ 323,301	$ 319,414	$ 318,181	$ 312,139	$ 318,140	$ 320,021	$ 317,685	$ 3,730,551
445	Other Sales to Public Authorities	$ 822,033	$ 803,798	$ 859,594	$ 895,259	$ 820,777	$ 905,537	$ 1,065,936	$ 664,865	$ 879,073	$ 878,961	$ 895,401	$ 823,995	$ 10,315,229
447	Sales for Resale	$ 1,255,195	$ 1,430,849	$ 1,092,022	$ 1,131,020	$ 837,481	$ 680,512	$ 612,292	$ 751,517	$ 862,447	$ 916,528	$ 624,955	$ 653,081	$ 10,847,899
448	Interdepartmental Sales	$ 986	$ 925	$ 1,120	$ 1,580	$ 1,437	$ 1,313	$ 1,391	$ 1,359	$ 1,346	$ 1,717	$ 4,819	$ (448)	$ 17,545
456.21/25	Residential Retail Access *	$ 370,753	$ 336,894	$ 363,507	$ 452,424	$ 498,878	$ 509,281	$ 476,467	$ 483,738	$ 529,349	$ 594,378	$ 620,339	$ 580,468	$ 5,816,476
456.22/26	Commercial Retail Access *	$ 637,358	$ 695,939	$ 808,907	$ 950,042	$ 958,446	$ 1,025,843	$ 971,772	$ 1,001,552	$ 989,139	$ 1,026,808	$ 1,019,994	$ 981,425	$ 11,067,225
456.23	Industrial Retail Access	$ 568,629	$ 621,141	$ 681,372	$ 728,368	$ 696,734	$ 707,101	$ 676,589	$ 677,497	$ 635,805	$ 574,391	$ 575,809	$ 601,297	$ 7,744,733
456.24	OPA Retail Access	$ 44,083	$ 44,832	$ 49,713	$ 56,692	$ 59,984	$ 57,661	$ 54,396	$ 53,163	$ 71,431	$ 73,266	$ 71,393	$ 110,765	$ 747,379
	Total Base Revenues	$ 17,610,236	$ 16,450,238	$ 17,003,775	$ 19,558,694	$ 20,091,938	$ 19,569,151	$ 17,921,049	$ 17,641,230	$ 19,138,701	$ 20,396,070	$ 20,260,367	$ 18,993,125	$ 224,634,574
	Customers													
440	Residential	244,017	243,532	243,186	244,608	242,438	241,031	241,017	241,980	244,700	242,668	241,073	244,774	242,919
442	Commercial and Industrial	41,266	39,023	41,013	39,222	40,320	38,166	39,872	38,218	40,754	37,569	39,612	38,336	39,448
444	Public Street and Highway Lighting	205	205	205	205	206	206	206	206	206	206	207	207	206
445	Other Sales to Public Authorities	3,716	3,291	3,676	3,284	3,665	3,268	3,673	3,290	3,757	3,216	3,634	3,247	3,475
447	Sales for Resale	4	5	4	5	5	4	4	4	4	3	5	4	4
448	Interdepartmental Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
456.21/25	Residential Retail Access	8,352	9,225	9,365	10,092	9,766	10,641	10,611	11,511	10,839	11,192	10,715	12,056	10,364
456.22/26	Commercial Retail Access	2,241	2,465	2,731	2,824	3,115	3,237	3,624	3,627	3,963	3,751	3,968	3,888	3,286
456.23	Industrial Retail Access	117	120	132	133	148	149	171	161	175	165	176	158	150
456.24	OPA Retail Access	137	154	141	198	189	214	192	215	204	222	212	273	196
	Average Customers	300,055	298,020	300,453	300,571	299,852	296,916	299,370	299,212	304,602	298,992	299,602	302,943	300,049

* Includes Unbilled

Exhibit ___(FRP-2)
Schedule B

Central Hudson Gas & Electric Corporation
Summary of Electric Sales (MWh) by Service Classification
Twelve Months Ended March 31, 2009

	April 2008	May 2008	June 2008	July 2008	August 2008	September 2008	October 2008	November 2008	December 2008	January 2009	February 2009	March 2009	Total
Service Classification No. 1													
Heating	31,804	22,823	17,205	18,284	18,031	17,054	15,863	19,973	28,876	40,547	42,468	40,847	313,777
Nonheating	135,999	122,260	129,522	160,493	175,073	161,531	136,604	129,279	146,735	162,727	166,347	153,347	1,779,918
Unbilled	2,140	(10,891)	(1,858)	(2,657)	6,171	5,153	1,356	2,283	(38)	5,272	3,569	(10,682)	(181)
	169,943	134,192	144,870	176,120	199,275	183,738	153,824	151,534	175,574	208,546	212,384	183,512	2,093,513
Service Classification No. 2													
Nondemand	15,156	12,197	13,195	13,723	15,352	13,258	12,955	12,468	15,105	15,795	17,715	16,232	173,151
Primary	18,190	18,471	19,696	21,511	21,072	20,015	18,720	19,247	19,333	19,284	19,558	18,477	233,573
Secondary	111,335	111,162	121,938	140,600	131,990	129,032	110,048	116,303	121,347	122,073	127,346	108,829	1,452,004
Unbilled	51	331	(789)	65	(491)	600	(782)	733	(947)	887	(344)	498	(187)
	144,732	142,161	154,040	175,900	167,923	162,905	140,940	148,751	154,839	158,039	164,275	144,036	1,858,540
Service Classification No. 3	23,475	22,976	25,352	27,549	26,498	25,156	23,835	24,403	25,470	26,307	22,035	23,259	296,315
Service Classification No. 5	1,005	919	804	857	939	1,046	1,188	1,297	1,422	1,400	1,181	1,166	13,224
Service Classification No. 6	2,823	1,923	1,990	2,171	2,461	2,172	1,984	1,857	2,556	2,837	3,351	2,748	28,873
Service Classification No. 8	1,722	1,541	1,380	1,486	1,665	1,853	2,123	2,290	2,513	2,411	2,018	1,935	22,937
Service Classification No. 9	285	283	285	283	285	283	285	277	(68)	275	276	274	3,026
Service Classification No. 13													
Transmission	76,892	82,799	86,725	89,978	86,935	82,697	81,507	74,855	74,394	71,735	64,253	69,521	942,290
Substation	14,293	14,474	15,387	16,263	15,750	14,675	14,190	13,449	13,247	13,349	12,491	13,243	170,810
	91,185	97,272	102,112	106,240	102,685	97,371	95,697	88,304	87,641	85,084	76,744	82,764	1,113,100
Interdepartmental	62	59	70	82	75	69	73	71	71	90	254	(23)	953
Total	435,233	401,326	430,904	490,690	501,806	474,593	419,950	418,785	450,018	484,989	482,517	439,671	5,430,480

Exhibit ___(FRP-2)
Schedule C
Sheet 1 of 3

Central Hudson Gas & Electric Corporation
Summary of Electric Base Delivery Revenues by Service Classification
Twelve Months Ended March 31, 2009

	April 2008	May 2008	June 2008	July 2008	August 2008	September 2008	October 2008	November 2008	December 2008	January 2009	February 2009	March 2009	Total
Service Classification No. 1													
Heating	$ 1,611,386	$ 1,278,305	$ 1,041,859	$ 1,135,889	$ 1,144,533	$ 1,144,782	$ 1,071,486	$ 1,280,358	$ 1,647,457	$ 2,167,556	$ 2,219,608	$ 2,188,750	$ 17,931,969
Nonheating	$ 8,743,793	$ 8,186,281	$ 8,512,253	$ 9,953,578	$ 10,967,192	$ 10,590,555	$ 9,561,146	$ 9,271,682	$ 10,134,800	$ 10,709,397	$ 10,861,250	$ 10,347,018	$ 117,838,945
Unbilled	$ 84,190	$ (421,963)	$ (69,406)	$ 341,077	$ 267,685	$ 213,575	$ 58,543	$ 97,757	$ 1,202	$ 226,914	$ 152,429	$ (454,972)	$ 497,031
	$ 10,439,369	$ 9,042,623	$ 9,484,706	$ 11,430,544	$ 12,379,410	$ 11,948,912	$ 10,691,175	$ 10,649,797	$ 11,783,459	$ 13,103,867	$ 13,233,287	$ 12,080,796	$ 136,267,945
Service Classification No. 2													
Nondemand	$ 807,477	$ 715,129	$ 777,474	$ 772,829	$ 874,303	$ 807,963	$ 847,226	$ 800,408	$ 908,331	$ 858,190	$ 940,618	$ 873,568	$ 9,983,516
Primary	$ 293,265	$ 304,763	$ 328,086	$ 356,929	$ 347,187	$ 359,635	$ 338,010	$ 333,850	$ 318,559	$ 297,543	$ 305,629	$ 305,148	$ 3,888,604
Secondary	$ 3,433,304	$ 3,529,110	$ 3,882,367	$ 4,229,206	$ 4,125,146	$ 4,166,015	$ 3,998,443	$ 3,557,671	$ 3,823,495	$ 3,689,096	$ 3,713,928	$ 3,612,079	$ 45,759,860
Unbilled	$ (19,817)	$ 26,360	$ (33,700)	$ 54,722	$ (32,259)	$ 33,858	$ (38,223)	$ 37,307	$ (42,240)	$ 41,396	$ (30,842)	$ 33,223	$ 29,785
	$ 4,514,229	$ 4,575,362	$ 4,954,227	$ 5,413,686	$ 5,314,377	$ 5,367,471	$ 5,145,456	$ 4,729,236	$ 5,008,145	$ 4,886,225	$ 4,929,333	$ 4,824,018	$ 59,661,765
Service Classification No. 3	$ 401,268	$ 413,534	$ 453,429	$ 483,455	$ 463,241	$ 470,806	$ 423,157	$ 489,854	$ 474,505	$ 471,162	$ 426,143	$ 406,637	$ 5,377,191
Service Classification No. 5	$ 83,155	$ 85,442	$ 82,781	$ 89,135	$ 88,465	$ 91,655	$ 87,803	$ 87,317	$ 87,274	$ 90,898	$ 86,437	$ 94,587	$ 1,054,949
Service Classification No. 6	$ 139,997	$ 102,048	$ 106,883	$ 115,620	$ 133,214	$ 122,126	$ 113,709	$ 107,196	$ 136,649	$ 145,389	$ 168,056	$ 142,724	$ 1,533,611
Service Classification No. 8	$ 288,282	$ 288,236	$ 287,987	$ 320,151	$ 317,014	$ 323,301	$ 319,414	$ 318,181	$ 312,139	$ 318,140	$ 320,021	$ 317,685	$ 3,730,551
Service Classification No. 9	$ 16,819	$ 16,270	$ 15,915	$ 18,729	$ 19,461	$ 18,517	$ 19,049	$ 18,667	$ 9,763	$ 17,667	$ 31,556	$ 17,129	$ 219,542
Service Classification No. 13													
Transmission	$ 347,056	$ 370,948	$ 387,301	$ 406,527	$ 391,610	$ 403,259	$ 375,145	$ 359,253	$ 348,588	$ 318,800	$ 316,228	$ 337,011	$ 4,361,726
Substation	$ 123,880	$ 124,001	$ 137,404	$ 148,247	$ 146,228	$ 141,279	$ 132,458	$ 128,853	$ 114,386	$ 125,677	$ 119,532	$ 119,905	$ 1,561,850
	$ 470,936	$ 494,949	$ 524,705	$ 554,774	$ 537,838	$ 544,538	$ 507,603	$ 488,106	$ 462,974	$ 444,477	$ 435,760	$ 456,916	$ 5,923,576
Interdepartmental	$ 986	$ 925	$ 1,120	$ 1,580	$ 1,437	$ 1,313	$ 1,391	$ 1,359	$ 1,346	$ 1,717	$ 4,819	$ (448)	$ 17,545
Total Base Revenue	$ 16,355,041	$ 15,019,389	$ 15,911,753	$ 18,427,674	$ 19,254,457	$ 18,888,639	$ 17,308,757	$ 16,889,713	$ 18,276,254	$ 19,479,542	$ 19,635,412	$ 18,340,044	$ 213,786,675

Exhibit ___(FRP-2)
Schedule C
Sheet 2 of 3

Central Hudson Gas & Electric Corporation
Summary of Electric Customers by Service Classification
Twelve Months Ended March 31, 2009

	April 2008	May 2008	June 2008	July 2008	August 2008	September 2008	October 2008	November 2008	December 2008	January 2009	February 2009	March 2009	Average
Service Classification No. 1													
Heating	24,477	25,795	24,370	25,912	24,350	25,563	24,151	25,586	24,200	25,764	23,847	26,259	25,023
Nonheating	227,004	225,857	227,333	227,746	227,012	225,039	226,657	226,827	230,521	227,049	227,154	229,544	227,312
Unbilled	-	-	-	-	-	-	-	-	-	-	-	-	-
	251,481	251,652	251,703	253,658	251,362	250,602	250,808	252,413	254,721	252,813	251,001	255,803	252,335
Service Classification No. 2													
Nondemand	29,925	27,737	30,165	28,243	30,000	27,685	29,916	28,011	30,960	27,811	30,067	28,189	29,059
Primary	166	142	167	167	169	173	169	175	172	173	171	173	168
Secondary	11,618	11,741	11,615	11,840	11,494	11,782	11,699	12,026	12,069	11,707	11,774	12,009	11,781
Unbilled	-	-	-	-	-	-	-	-	-	-	-	-	-
	41,709	39,620	41,947	40,250	41,663	39,640	41,784	40,212	43,201	39,691	42,012	40,371	41,008
Service Classification No. 3	34	34	34	34	34	34	34	34	34	34	34	34	34
Service Classification No. 5	4,611	4,603	4,594	4,525	4,655	4,545	4,625	4,470	4,536	4,410	4,483	4,694	4,563
Service Classification No. 6	1,683	1,573	1,638	1,567	1,600	1,558	1,582	1,557	1,589	1,521	1,548	1,518	1,578
Service Classification No. 8	205	205	205	205	206	206	206	206	206	206	207	207	206
Service Classification No. 9	311	311	311	311	311	311	311	301	296	299	297	297	306
Service Classification No. 13													
Transmission	10	10	10	9	9	9	9	8	8	8	8	8	9
Substation	7	7	7	7	7	7	7	7	7	7	7	7	7
	17	17	17	16	16	16	16	15	15	15	15	15	16
Interdepartmental	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Customers	300,052	298,016	300,450	300,567	299,848	296,913	299,367	299,209	304,599	298,990	299,598	302,940	300,046

Exhibit ___(FRP-2)
Schedule C
Sheet 3 of 3

Central Hudson Gas & Electric Corporation
Summary of Electric Sales (MWh) by Service Classification
Twelve Months Ended December 31, 2009

	January 2009	February 2009	March 2009	April 2009	May 2009	June 2009	July 2009	August 2009	September 2009	October 2009	November 2009	December 2009	Total
Service Classification No. 1													
Heating	40,547	42,468	40,847	30,330	23,650	18,100	18,740	18,950	19,870	17,800	20,770	28,370	320,442
EEPS Lost MWh	-	-	-	(243)	(188)	(145)	(148)	(152)	(156)	(142)	(165)	(229)	(1,568)
Nonheating	162,727	166,347	153,347	137,320	128,510	136,010	161,760	182,590	174,820	145,740	128,870	140,750	1,818,790
EEPS Lost MWh	-	-	-	(1,070)	(999)	(1,057)	(1,257)	(1,418)	(1,357)	(1,131)	(1,002)	(1,097)	(10,388)
PV Lost MWh	-	-	-	(124)	(132)	(131)	(101)	(105)	(106)	(114)	(114)	(123)	(1,050)
Unbilled	5,272	3,569	(10,682)	380	(9,780)	(2,990)	(1,800)	6,850	7,410	2,150	2,900	(1,480)	1,800
	208,546	212,384	183,512	166,593	141,061	149,787	177,194	206,715	200,481	164,303	151,259	166,191	2,128,026
Service Classification No. 2													
Nondemand	15,795	17,715	16,232	15,610	12,140	12,960	13,480	15,520	13,080	13,240	11,810	14,460	172,042
EEPS Lost MWh	-	-	-	(200)	(157)	(167)	(174)	(200)	(169)	(170)	(152)	(183)	(1,572)
Primary	19,284	19,558	18,477	19,555	20,048	21,025	22,510	22,960	21,550	21,270	20,050	21,030	247,317
EEPS Lost MWh	-	-	-	(253)	(259)	(272)	(292)	(298)	(280)	(276)	(260)	(273)	(2,463)
Secondary	122,073	127,346	108,829	109,220	111,130	121,200	135,060	135,260	133,820	119,570	112,010	125,530	1,461,048
EEPS Lost MWh	-	-	-	(1,424)	(1,449)	(1,581)	(1,763)	(1,764)	(1,746)	(1,560)	(1,461)	(1,637)	(14,385)
PV Lost MWh	-	-	-	(37)	(39)	(39)	(30)	(31)	(32)	(34)	(34)	(37)	(313)
Unbilled	887	(344)	498	-	490	(860)	130	(530)	830	(810)	890	(1,060)	121
	158,039	164,275	144,036	142,471	141,904	152,266	168,921	170,917	167,053	151,230	142,853	157,830	1,861,794
Service Classification No. 3	26,307	22,035	23,259	21,600	22,480	23,100	24,920	25,640	24,430	23,630	23,500	25,100	286,001
EEPS Lost MWh	-	-	-	(282)	(293)	(301)	(325)	(335)	(319)	(308)	(307)	(328)	(2,798)
	26,307	22,035	23,259	21,318	22,187	22,799	24,595	25,305	24,111	23,322	23,193	24,772	283,203
Service Classification No. 5	1,400	1,181	1,166	990	890	790	860	960	1,060	1,220	1,320	1,450	13,287
Service Classification No. 6	2,837	3,351	2,748	2,840	1,940	2,000	2,180	2,480	2,180	2,000	1,860	2,570	28,985
Service Classification No. 8	2,411	2,018	1,935	1,710	1,540	1,370	1,480	1,660	1,830	2,110	2,280	2,510	22,854
Service Classification No. 9	275	276	274	280	280	280	280	280	280	280	280	280	3,345
Service Classification No. 13													
Transmission	71,735	64,253	69,521	73,690	79,640	74,860	77,930	74,900	71,550	70,170	64,240	63,830	856,319
Substation	13,349	12,491	13,243	12,980	13,500	13,630	15,970	15,480	14,340	13,880	13,040	12,740	164,643
	85,084	76,744	82,764	86,670	93,140	88,490	93,900	90,380	85,890	84,050	77,280	76,570	1,020,962
Interdepartmental	90	254	(23)	60	60	70	70	90	70	60	60	80	941
Total	484,989	482,517	439,671	422,932	403,002	417,852	469,480	498,787	482,955	428,575	400,385	432,253	5,363,398

Exhibit ___(FRP-2)
Schedule D
Sheet 1 of 3

Central Hudson Gas & Electric Corporation
Summary of Electric Base Delivery Revenues by Service Classification
Twelve Months Ended December 31, 2009

	January 2009	February 2009	March 2009	April 2009	May 2009	June 2009	July 2009	August 2009	September 2009	October 2009	November 2009	December 2009	Total
Service Classification No. 1													
Heating	$ 2,167,556	$ 2,219,608	$ 2,188,750	$ 1,740,230	$ 1,468,890	$ 1,203,640	$ 1,318,850	$ 1,426,150	$ 1,562,960	$ 1,425,500	$ 1,612,210	$ 1,998,130	$ 20,332,474
EEPS Lost Revenue	$ -	$ -	$ -	$ (10,590)	$ (8,140)	$ (6,300)	$ (7,120)	$ (7,890)	$ (8,390)	$ (7,620)	$ (8,830)	$ (12,340)	$ (77,220)
Nonheating	$ 10,709,397	$ 10,861,250	$ 10,347,018	$ 9,725,200	$ 9,335,170	$ 9,671,790	$ 11,329,520	$ 13,482,090	$ 13,648,540	$ 12,085,600	$ 11,168,420	$ 11,854,470	$ 134,218,465
EEPS Lost Revenue	$ -	$ -	$ -	$ (46,610)	$ (43,730)	$ (46,120)	$ (60,770)	$ (74,250)	$ (73,360)	$ (61,130)	$ (54,260)	$ (59,140)	$ (519,370)
PV Lost Revenue	$ -	$ -	$ -	$ (5,412)	$ (5,770)	$ (5,749)	$ (5,494)	$ (5,729)	$ (5,760)	$ (6,189)	$ (6,210)	$ (6,660)	$ (52,973)
Unbilled	$ 226,914	$ 152,429	$ (454,972)	$ 16,260	$ (416,580)	$ (127,970)	$ (77,040)	$ 264,750	$ 286,400	$ 83,100	$ 112,090	$ (57,200)	$ 6,181
	$ 13,103,867	$ 13,233,287	$ 12,080,796	$ 11,419,078	$ 10,327,840	$ 10,689,291	$ 12,497,946	$ 15,085,121	$ 15,410,390	$ 13,519,261	$ 12,823,420	$ 13,717,260	$ 153,907,557
Service Classification No. 2													
Nondemand	$ 858,190	$ 940,618	$ 873,568	$ 892,090	$ 783,340	$ 841,180	$ 897,630	$ 1,065,600	$ 978,600	$ 1,045,870	$ 964,950	$ 1,071,000	$ 11,212,636
EEPS Lost Revenue	$ -	$ -	$ -	$ (3,780)	$ (3,030)	$ (3,220)	$ (3,170)	$ (2,340)	$ (1,920)	$ (1,920)	$ (1,700)	$ (2,040)	$ (23,120)
Primary	$ 297,543	$ 305,629	$ 305,148	$ 329,270	$ 355,980	$ 368,570	$ 401,250	$ 420,510	$ 438,100	$ 407,260	$ 399,570	$ 397,640	$ 4,426,470
EEPS Lost Revenue	$ -	$ -	$ -	$ (3,980)	$ (4,600)	$ (4,730)	$ (4,980)	$ (4,990)	$ (5,430)	$ (4,980)	$ (4,840)	$ (4,850)	$ (43,380)
Secondary	$ 3,689,096	$ 3,713,928	$ 3,612,079	$ 3,563,210	$ 3,736,740	$ 3,973,040	$ 4,351,850	$ 4,615,140	$ 4,651,430	$ 4,456,460	$ 4,163,480	$ 4,291,950	$ 48,818,403
EEPS Lost Revenue	$ -	$ -	$ -	$ (42,000)	$ (44,160)	$ (47,220)	$ (50,240)	$ (52,580)	$ (53,150)	$ (50,480)	$ (46,630)	$ (48,370)	$ (434,830)
PV Lost Revenue	$ -	$ -	$ -	$ (3,294)	$ (3,519)	$ (3,509)	$ (2,875)	$ (2,998)	$ (3,008)	$ (3,233)	$ (3,243)	$ (3,478)	$ (29,157)
Unbilled	$ 41,396	$ (30,842)	$ 33,223	$ -	$ 9,270	$ (16,260)	$ 2,460	$ (9,190)	$ 14,390	$ (14,050)	$ 15,430	$ (18,380)	$ 27,447
	$ 4,886,225	$ 4,929,333	$ 4,824,018	$ 4,731,516	$ 4,830,021	$ 5,107,851	$ 5,591,925	$ 6,029,152	$ 6,019,012	$ 5,834,927	$ 5,487,017	$ 5,683,472	$ 63,954,469
Service Classification No. 3	$ 471,162	$ 426,143	$ 406,637	$ 389,780	$ 419,560	$ 426,020	$ 486,950	$ 507,080	$ 504,860	$ 477,970	$ 509,160	$ 520,850	$ 5,546,172
EEPS Lost Revenue	$ -	$ -	$ -	$ (4,950)	$ (5,170)	$ (5,320)	$ (6,140)	$ (6,480)	$ (6,580)	$ (6,060)	$ (6,400)	$ (6,640)	$ (53,740)
	$ 471,162	$ 426,143	$ 406,637	$ 384,830	$ 414,390	$ 420,700	$ 480,810	$ 500,600	$ 498,280	$ 471,910	$ 502,760	$ 514,210	$ 5,492,432
Service Classification No. 5	$ 90,898	$ 86,437	$ 94,587	$ 124,880	$ 124,420	$ 123,950	$ 132,830	$ 134,300	$ 135,770	$ 138,110	$ 139,580	$ 141,480	$ 1,467,242
Service Classification No. 6	$ 145,389	$ 168,056	$ 142,724	$ 150,340	$ 111,400	$ 115,100	$ 125,320	$ 148,160	$ 136,920	$ 129,630	$ 121,690	$ 156,770	$ 1,651,499
Service Classification No. 8	$ 318,140	$ 320,021	$ 317,685	$ 315,730	$ 315,590	$ 315,450	$ 356,110	$ 356,160	$ 356,210	$ 356,290	$ 356,340	$ 356,400	$ 4,040,126
Service Classification No. 9	$ 17,667	$ 31,556	$ 17,129	$ 14,760	$ 14,760	$ 14,760	$ 16,870	$ 16,870	$ 16,870	$ 16,870	$ 16,870	$ 16,870	$ 211,852
Service Classification No. 13													
Transmission	$ 318,800	$ 316,228	$ 337,011	$ 376,700	$ 374,180	$ 372,980	$ 427,370	$ 410,520	$ 426,720	$ 394,470	$ 379,370	$ 351,220	$ 4,485,569
Substation	$ 125,677	$ 119,532	$ 119,905	$ 125,690	$ 126,030	$ 134,950	$ 184,420	$ 174,290	$ 168,040	$ 159,300	$ 159,710	$ 154,030	$ 1,751,574
	$ 444,477	$ 435,760	$ 456,916	$ 502,390	$ 500,210	$ 507,930	$ 611,790	$ 584,810	$ 594,760	$ 553,770	$ 539,080	$ 505,250	$ 6,237,143
Interdepartmental	$ 1,717	$ 4,819	$ (448)	$ 1,090	$ 1,090	$ 1,270	$ 240	$ 310	$ 240	$ 200	$ 200	$ 270	$ 10,998
Total Base Revenue	$ 19,479,542	$ 19,635,412	$ 18,340,044	$ 17,644,614	$ 16,639,721	$ 17,296,302	$ 19,813,841	$ 22,855,483	$ 23,168,452	$ 21,020,968	$ 19,986,957	$ 21,091,982	$ 236,973,318

Exhibit ___(FRP-2)
Schedule D
Sheet 2 of 3

Central Hudson Gas & Electric Corporation
Summary of Electric Customers by Service Classification
Twelve Months Ended December 31, 2009

	January 2009	February 2009	March 2009	April 2009	May 2009	June 2009	July 2009	August 2009	September 2009	October 2009	November 2009	December 2009	Average
Service Classification No. 1													
Heating	25,764	23,847	26,259	25,289	26,563	25,182	26,712	25,143	26,536	25,121	26,539	25,160	25,676
Nonheating	227,049	227,154	229,544	227,402	227,085	227,635	227,384	227,869	227,678	228,225	228,026	230,348	227,950
Unbilled	-	-	-	-	-	-	-	-	-	-	-	-	-
	252,813	251,001	255,803	252,691	253,648	252,817	254,096	253,012	254,214	253,346	254,565	255,508	253,626
Service Classification No. 2													
Nondemand	27,811	30,067	28,189	29,804	27,655	29,767	27,619	29,688	27,598	29,777	27,626	30,151	28,813
Primary	173	171	173	169	159	169	168	168	170	169	172	166	169
Secondary	11,707	11,774	12,009	11,744	11,713	11,710	11,732	11,535	11,722	11,731	11,740	11,783	11,742
Unbilled	-	-	-	-	-	-	-	-	-	-	-	-	-
	39,691	42,012	40,371	41,717	39,527	41,646	39,519	41,391	39,490	41,677	39,538	42,100	40,723
Service Classification No. 3	34	34	34	32	31	32	31	31	31	31	33	30	32
Service Classification No. 5	4,410	4,483	4,694	4,611	4,603	4,594	4,525	4,655	4,545	4,625	4,470	4,536	4,563
Service Classification No. 6	1,521	1,548	1,518	1,605	1,545	1,605	1,545	1,605	1,545	1,605	1,545	1,605	1,566
Service Classification No. 8	206	207	207	207	207	207	207	207	207	207	207	207	207
Service Classification No. 9	299	297	297	297	297	297	297	297	297	297	297	297	297
Service Classification No. 13													
Transmission	8	8	8	6	6	6	6	6	6	6	6	6	7
Substation	7	7	7	7	7	7	7	7	7	7	7	7	7
	15	15	15	13	13	13	13	13	13	13	13	13	14
Interdepartmental	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Customers	298,990	299,598	302,940	301,174	299,872	301,212	300,234	301,212	300,343	301,802	300,669	304,297	301,029

Exhibit ___(FRP-2)
Schedule D
Sheet 3 of 3

Central Hudson Gas & Electric Corporation
Summary of Electric Sales (MWh) by Service Classification
Twelve Months Ended December 31, 2010

	January 2010	February 2010	March 2010	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010	October 2010	November 2010	December 2010	Total
Service Classification No. 1													
Heating	41,100	43,070	43,020	31,840	24,730	18,770	19,360	19,500	20,270	17,980	20,820	28,220	328,680
EEPS Lost MWh	(1,057)	(1,107)	(1,103)	(827)	(634)	(486)	(495)	(506)	(517)	(465)	(534)	(732)	(8,463)
Nonheating	156,490	159,460	146,900	134,380	125,980	134,110	161,070	182,650	174,320	144,090	126,560	138,070	1,784,080
EEPS Lost MWh	(3,943)	(4,030)	(3,704)	(3,390)	(3,172)	(3,377)	(4,057)	(4,595)	(4,384)	(3,626)	(3,187)	(3,482)	(44,947)
PV Lost MWh	(127)	(118)	(136)	(136)	(145)	(145)	(81)	(86)	(88)	(96)	(98)	(106)	(1,362)
Unbilled	1,510	2,710	(8,290)	380	(9,780)	(2,990)	(1,800)	6,850	7,410	2,150	2,900	(1,480)	(430)
	193,973	199,985	176,687	162,247	136,979	145,882	173,997	203,813	197,011	160,033	146,461	160,490	2,057,558
Service Classification No. 2													
Nondemand	15,080	16,870	14,390	14,430	11,210	12,040	12,730	14,830	12,500	12,730	11,440	14,150	162,400
EEPS Lost MWh	(607)	(678)	(579)	(581)	(450)	(484)	(512)	(597)	(503)	(511)	(461)	(568)	(6,531)
Primary	22,410	21,230	21,680	20,760	21,120	21,950	23,350	23,600	21,970	21,560	20,180	21,040	260,850
EEPS Lost MWh	(889)	(842)	(861)	(828)	(843)	(878)	(935)	(944)	(879)	(862)	(806)	(839)	(10,406)
Secondary	134,520	127,760	120,920	116,500	117,940	127,650	141,280	140,390	137,890	122,600	114,250	127,180	1,528,880
EEPS Lost MWh	(5,414)	(5,142)	(4,868)	(4,690)	(4,748)	(5,138)	(5,688)	(5,651)	(5,550)	(4,935)	(4,599)	(5,120)	(61,543)
PV Lost MWh	(38)	(35)	(41)	(41)	(43)	(43)	(24)	(26)	(26)	(29)	(29)	(32)	(407)
Unbilled	850	(470)	450	-	490	(860)	130	(530)	830	(810)	890	(1,060)	(90)
	165,912	158,693	151,091	145,550	144,676	154,237	170,331	171,072	166,232	149,743	140,865	154,751	1,873,153
Service Classification No. 3	25,260	23,580	23,910	22,990	23,750	24,200	25,880	26,390	24,930	23,950	23,680	25,130	293,650
EEPS Lost MWh	(1,016)	(949)	(962)	(925)	(955)	(974)	(1,042)	(1,062)	(1,003)	(964)	(953)	(1,012)	(11,817)
	24,244	22,631	22,948	22,065	22,795	23,226	24,838	25,328	23,927	22,986	22,727	24,118	281,833
Service Classification No. 5	1,370	1,150	1,110	980	880	790	850	950	1,050	1,210	1,310	1,440	13,090
Service Classification No. 6	2,840	3,360	2,750	2,840	1,940	2,000	2,180	2,480	2,180	2,000	1,860	2,570	29,000
Service Classification No. 8	2,400	2,000	1,940	1,710	1,540	1,370	1,480	1,660	1,830	2,110	2,280	2,510	22,830
Service Classification No. 9	270	280	270	280	280	280	280	280	280	280	280	280	3,340
Service Classification No. 13													
Transmission	64,820	58,000	63,280	67,120	72,920	68,700	77,930	74,900	71,550	70,170	64,240	63,830	817,460
Substation	13,040	12,550	13,380	13,170	13,800	13,950	16,000	15,510	14,370	13,910	13,060	12,760	165,500
	77,860	70,550	76,660	80,290	86,720	82,650	93,930	90,410	85,920	84,080	77,300	76,590	982,960
Interdepartmental	80	120	70	60	60	70	70	90	70	60	60	80	890
Total	468,949	458,769	433,526	416,022	395,870	410,505	467,956	496,083	478,500	422,502	393,143	422,829	5,264,654

Exhibit ___(FRP-2)
Schedule E
Sheet 1 of 3

Central Hudson Gas & Electric Corporation
Summary of Electric Base Delivery Revenues by Service Classification
Twelve Months Ended December 31, 2010

	January 2010	February 2010	March 2010	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010	October 2010	November 2010	December 2010	Total
Service Classification No. 1													
Heating	$ 2,718,430	$ 2,788,940	$ 2,823,730	$ 2,187,580	$ 1,826,230	$ 1,478,490	$ 1,538,490	$ 1,517,260	$ 1,584,490	$ 1,434,620	$ 1,614,270	$ 1,989,380	$ 23,501,910
EEPS Lost Revenue	$ (57,190)	$ (59,690)	$ (59,680)	$ (44,590)	$ (34,520)	$ (26,190)	$ (26,630)	$ (27,270)	$ (27,820)	$ (25,050)	$ (28,630)	$ (39,470)	$ (456,730)
Nonheating	$ 12,668,900	$ 12,839,410	$ 12,183,350	$ 11,489,250	$ 11,031,390	$ 11,480,970	$ 12,935,790	$ 14,111,780	$ 13,657,900	$ 12,031,710	$ 11,078,120	$ 11,742,930	$ 147,251,500
EEPS Lost Revenue	$ (213,150)	$ (218,000)	$ (200,150)	$ (183,390)	$ (172,040)	$ (182,320)	$ (219,640)	$ (248,850)	$ (236,990)	$ (195,850)	$ (172,580)	$ (188,260)	$ (2,431,220)
PV Lost Revenue	$ (6,906)	$ (6,445)	$ (7,386)	$ (7,386)	$ (7,888)	$ (7,877)	$ (4,409)	$ (4,686)	$ (4,788)	$ (5,218)	$ (5,310)	$ (5,760)	$ (74,059)
Unbilled	$ 58,360	$ 104,740	$ (320,410)	$ 14,690	$ (378,000)	$ (115,560)	$ (69,570)	$ 264,750	$ 286,400	$ 83,100	$ 112,090	$ (57,200)	$ (16,610)
	$ 15,168,444	$ 15,448,955	$ 14,419,454	$ 13,456,154	$ 12,265,172	$ 12,627,513	$ 14,154,031	$ 15,612,984	$ 15,259,192	$ 13,323,312	$ 12,597,960	$ 13,441,620	$ 167,774,791
Service Classification No. 2													
Nondemand	$ 1,021,190	$ 1,085,750	$ 994,590	$ 1,058,380	$ 958,230	$ 1,032,150	$ 976,250	$ 1,063,280	$ 974,590	$ 1,043,490	$ 964,760	$ 1,072,300	$ 12,244,960
EEPS Lost Revenue	$ (6,940)	$ (7,740)	$ (6,600)	$ (6,600)	$ (5,110)	$ (5,570)	$ (5,910)	$ (6,830)	$ (5,800)	$ (5,800)	$ (5,230)	$ (6,480)	$ (74,610)
Primary	$ 382,160	$ 368,930	$ 375,290	$ 405,360	$ 435,770	$ 447,290	$ 446,540	$ 435,180	$ 448,560	$ 415,480	$ 405,030	$ 401,280	$ 4,966,870
EEPS Lost Revenue	$ (14,010)	$ (14,140)	$ (13,650)	$ (15,180)	$ (16,530)	$ (16,620)	$ (16,900)	$ (16,270)	$ (16,480)	$ (15,530)	$ (15,160)	$ (14,800)	$ (185,270)
Secondary	$ 4,343,880	$ 4,178,260	$ 4,210,970	$ 4,262,700	$ 4,442,240	$ 4,681,130	$ 4,794,940	$ 4,791,260	$ 4,788,950	$ 4,568,770	$ 4,249,700	$ 4,356,750	$ 53,669,550
EEPS Lost Revenue	$ (149,520)	$ (147,030)	$ (143,290)	$ (147,730)	$ (154,950)	$ (164,530)	$ (168,680)	$ (169,060)	$ (168,600)	$ (159,500)	$ (146,820)	$ (150,930)	$ (1,870,640)
PV Lost Revenue	$ (3,611)	$ (3,366)	$ (3,857)	$ (3,857)	$ (4,123)	$ (4,123)	$ (2,312)	$ (2,445)	$ (2,496)	$ (2,732)	$ (2,772)	$ (3,008)	$ (38,702)
Unbilled	$ 14,740	$ (8,150)	$ 7,800	$ -	$ 8,500	$ (14,910)	$ 2,250	$ (9,190)	$ 14,390	$ (14,050)	$ 15,430	$ (18,380)	$ (1,570)
	$ 5,587,889	$ 5,452,514	$ 5,421,253	$ 5,553,073	$ 5,664,027	$ 5,954,817	$ 6,026,178	$ 6,085,925	$ 6,033,114	$ 5,830,128	$ 5,464,936	$ 5,636,732	$ 68,710,588
Service Classification No. 3	$ 501,690	$ 480,700	$ 456,330	$ 465,200	$ 496,690	$ 500,230	$ 505,190	$ 521,590	$ 514,900	$ 484,550	$ 513,010	$ 522,100	$ 5,962,180
EEPS Lost Revenue	$ (19,450)	$ (18,540)	$ (17,590)	$ (18,030)	$ (19,320)	$ (19,220)	$ (19,470)	$ (20,160)	$ (20,000)	$ (18,800)	$ (19,700)	$ (20,260)	$ (230,540)
	$ 482,240	$ 462,160	$ 438,740	$ 447,170	$ 477,370	$ 481,010	$ 485,720	$ 501,430	$ 494,900	$ 465,750	$ 493,310	$ 501,840	$ 5,731,640
Service Classification No. 5	$ 139,810	$ 136,590	$ 136,000	$ 134,100	$ 132,640	$ 131,320	$ 132,200	$ 133,660	$ 135,130	$ 137,470	$ 138,940	$ 140,840	$ 1,628,700
Service Classification No. 6	$ 168,320	$ 194,350	$ 164,040	$ 169,610	$ 125,500	$ 129,640	$ 136,930	$ 152,470	$ 136,920	$ 129,630	$ 121,690	$ 156,770	$ 1,785,870
Service Classification No. 8	$ 357,250	$ 357,140	$ 357,120	$ 357,060	$ 357,010	$ 356,960	$ 356,990	$ 357,040	$ 357,090	$ 357,170	$ 357,220	$ 357,280	$ 4,285,330
Service Classification No. 9	$ 16,840	$ 16,870	$ 16,840	$ 16,870	$ 16,870	$ 16,870	$ 16,870	$ 16,870	$ 16,870	$ 16,870	$ 16,870	$ 16,870	$ 202,380
Service Classification No. 13													
Transmission	$ 358,740	$ 355,300	$ 376,300	$ 413,260	$ 451,220	$ 418,540	$ 438,900	$ 421,620	$ 438,240	$ 405,110	$ 389,580	$ 376,930	$ 4,843,740
Substation	$ 152,860	$ 157,260	$ 158,310	$ 170,280	$ 167,990	$ 171,170	$ 189,750	$ 179,620	$ 173,380	$ 164,630	$ 164,950	$ 152,090	$ 2,002,290
	$ 511,600	$ 512,560	$ 534,610	$ 583,540	$ 619,210	$ 589,710	$ 628,650	$ 601,240	$ 611,620	$ 569,740	$ 554,530	$ 529,020	$ 6,846,030
Interdepartmental	$ 270	$ 410	$ 240	$ 200	$ 200	$ 240	$ 240	$ 310	$ 240	$ 200	$ 200	$ 270	$ 3,020
Total Base Revenue	$ 22,432,663	$ 22,581,549	$ 21,488,297	$ 20,717,777	$ 19,657,999	$ 20,288,080	$ 21,937,809	$ 23,461,929	$ 23,045,076	$ 20,830,270	$ 19,745,658	$ 20,781,242	$ 256,968,349

Exhibit ___(FRP-2)
Schedule E
Sheet 2 of 3

Central Hudson Gas & Electric Corporation
Summary of Electric Customers by Service Classification
Twelve Months Ended December 31, 2010

	January 2010	February 2010	March 2010	April 2010	May 2010	June 2010	July 2010	August 2010	September 2010	October 2010	November 2010	December 2010	Average
Service Classification No. 1													
Heating	26,886	24,915	26,963	25,254	26,527	25,148	26,676	25,108	26,500	25,087	26,503	25,126	25,891
Nonheating	228,348	228,937	230,159	229,281	229,040	229,590	229,377	229,882	229,653	230,143	229,907	232,191	229,709
Unbilled	-	-	-	-	-	-	-	-	-	-	-	-	-
	255,234	253,852	257,122	254,535	255,567	254,738	256,053	254,990	256,153	255,230	256,410	257,317	255,600
Service Classification No. 2													
Nondemand	28,255	29,726	27,633	29,743	27,627	29,771	27,651	29,751	27,683	29,886	27,761	30,308	28,816
Primary	166	169	168	170	161	171	170	171	172	171	175	169	169
Secondary	11,789	11,785	11,832	11,857	11,864	11,893	11,945	11,778	11,987	12,018	12,048	12,110	11,909
Unbilled	-	-	-	-	-	-	-	-	-	-	-	-	-
	40,210	41,680	39,633	41,770	39,652	41,835	39,766	41,700	39,842	42,075	39,984	42,587	40,895
Service Classification No. 3	31	31	31	32	32	32	31	31	32	32	33	31	32
Service Classification No. 5	4,410	4,483	4,694	4,611	4,603	4,594	4,525	4,655	4,545	4,625	4,470	4,536	4,563
Service Classification No. 6	1,545	1,605	1,545	1,605	1,545	1,605	1,545	1,605	1,545	1,605	1,545	1,605	1,575
Service Classification No. 8	207	207	207	207	207	207	207	207	207	207	207	207	207
Service Classification No. 9	297	297	297	297	297	297	297	297	297	297	297	297	297
Service Classification No. 13													
Transmission	6	6	6	6	6	6	6	6	6	6	6	6	6
Substation	7	7	7	7	7	7	7	7	7	7	7	7	7
	13	13	13	13	13	13	13	13	13	13	13	13	13
Interdepartmental	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Customers	301,948	302,169	303,543	303,071	301,917	303,322	302,438	303,499	302,635	304,085	302,960	306,594	303,182

Central Hudson Gas & Electric Corporation
Summary of Electric Sales (MWh) by Service Classification
Twelve Months Ended June 30, 2011

	July 2010	August 2010	September 2010	October 2010	November 2010	December 2010	January 2011	February 2011	March 2011	April 2011	May 2011	June 2011	Total
Service Classification No. 1													
Heating	19,360	19,500	20,270	17,980	20,820	28,220	40,670	42,370	42,110	31,040	24,160	18,400	324,900
EEPS Lost MWh	(495)	(506)	(517)	(465)	(534)	(732)	(1,788)	(1,863)	(1,849)	(1,381)	(1,061)	(816)	(12,007)
Nonheating	161,070	182,650	174,320	144,090	126,560	138,070	153,670	156,280	143,510	131,030	123,210	131,860	1,766,320
EEPS Lost MWh	(4,057)	(4,595)	(4,384)	(3,626)	(3,187)	(3,482)	(6,622)	(6,757)	(6,190)	(5,656)	(5,306)	(5,680)	(59,542)
PV Lost MWh	(81)	(86)	(88)	(96)	(98)	(106)	(111)	(105)	(121)	(122)	(132)	(133)	(1,279)
Unbilled	(1,800)	6,850	7,410	2,150	2,900	(1,480)	1,510	2,710	(8,290)	380	(9,780)	(2,990)	(430)
	173,997	203,813	197,011	160,033	146,461	160,490	187,329	192,635	169,170	155,291	131,091	140,641	2,017,962
Service Classification No. 2													
Nondemand	12,730	14,830	12,500	12,730	11,440	14,150	14,870	16,760	14,380	14,460	11,230	12,040	162,120
EEPS Lost MWh	(512)	(597)	(503)	(511)	(461)	(568)	(1,014)	(1,144)	(982)	(987)	(765)	(821)	(8,865)
Primary	23,350	23,600	21,970	21,560	20,180	21,040	22,320	20,980	21,310	20,350	20,730	21,580	258,970
EEPS Lost MWh	(935)	(944)	(879)	(862)	(806)	(839)	(1,495)	(1,407)	(1,429)	(1,372)	(1,400)	(1,458)	(13,826)
Secondary	141,280	140,390	137,890	122,600	114,250	127,180	135,690	128,000	120,580	116,010	117,680	127,430	1,528,980
EEPS Lost MWh	(5,688)	(5,651)	(5,550)	(4,935)	(4,599)	(5,120)	(9,223)	(8,699)	(8,196)	(7,885)	(7,999)	(8,662)	(82,207)
PV Lost MWh	(24)	(26)	(26)	(29)	(29)	(32)	(33)	(31)	(36)	(37)	(39)	(40)	(382)
Unbilled	130	(530)	830	(810)	890	(1,060)	850	(470)	450	-	490	(860)	(90)
	170,331	171,072	166,232	149,743	140,865	154,751	161,965	153,989	146,077	140,539	139,927	149,209	1,844,700
Service Classification No. 3	25,880	26,390	24,930	23,950	23,680	25,130	25,160	23,300	23,480	22,560	23,370	23,840	291,670
EEPS Lost MWh	(1,042)	(1,062)	(1,003)	(964)	(953)	(1,012)	(1,711)	(1,585)	(1,597)	(1,534)	(1,589)	(1,621)	(15,673)
	24,838	25,328	23,927	22,986	22,727	24,118	23,449	21,715	21,883	21,026	21,781	22,219	275,997
Service Classification No. 5	850	950	1,050	1,210	1,310	1,440	1,360	1,130	1,100	970	870	780	13,020
Service Classification No. 6	2,180	2,480	2,180	2,000	1,860	2,570	2,840	3,360	2,750	2,840	1,940	2,000	29,000
Service Classification No. 8	1,480	1,660	1,830	2,110	2,280	2,510	2,400	2,000	1,940	1,710	1,540	1,370	22,830
Service Classification No. 9	280	280	280	280	280	280	270	270	270	280	280	280	3,330
Service Classification No. 13													
Transmission	77,930	74,900	71,550	70,170	64,240	63,830	64,820	58,000	63,280	67,120	72,920	68,700	817,460
Substation	16,000	15,510	14,370	13,910	13,060	12,760	13,060	12,570	13,400	13,190	13,830	13,980	165,640
	93,930	90,410	85,920	84,080	77,300	76,590	77,880	70,570	76,680	80,310	86,750	82,680	983,100
Interdepartmental	70	90	70	60	60	80	80	120	70	60	60	70	890
Total	467,956	496,083	478,500	422,502	393,143	422,829	457,573	445,789	419,940	403,026	384,239	399,249	5,190,829

Exhibit ___(FRP-2)
Schedule F
Sheet 1 of 3

Central Hudson Gas & Electric Corporation
Summary of Electric Base Delivery Revenues by Service Classification
Twelve Months Ended June 30, 2011

	July 2010	August 2010	September 2010	October 2010	November 2010	December 2010	January 2011	February 2011	March 2011	April 2011	May 2011	June 2011	Total
Service Classification No. 1													
Heating	$ 1,538,490	$ 1,517,260	$ 1,584,490	$ 1,434,620	$ 1,614,270	$ 1,989,380	$ 2,694,500	$ 2,750,430	$ 2,773,840	$ 2,143,650	$ 1,794,730	$ 1,457,840	$ 23,293,500
EEPS Lost Revenue	$ (26,630)	$ (27,270)	$ (27,820)	$ (25,050)	$ (28,630)	$ (39,470)	$ (96,420)	$ (100,490)	$ (100,200)	$ (74,470)	$ (57,410)	$ (44,000)	$ (647,860)
Nonheating	$ 12,935,790	$ 14,111,780	$ 13,657,900	$ 12,031,710	$ 11,078,120	$ 11,742,930	$ 12,549,040	$ 12,699,760	$ 12,031,620	$ 11,338,970	$ 10,910,740	$ 11,388,630	$ 146,476,990
EEPS Lost Revenue	$ (219,640)	$ (248,850)	$ (236,990)	$ (195,850)	$ (172,580)	$ (188,260)	$ (358,710)	$ (365,370)	$ (334,760)	$ (305,700)	$ (287,110)	$ (307,330)	$ (3,221,150)
PV Lost Revenue	$ (4,409)	$ (4,686)	$ (4,788)	$ (5,218)	$ (5,310)	$ (5,760)	$ (6,046)	$ (5,688)	$ (6,588)	$ (6,650)	$ (7,172)	$ (7,212)	$ (69,527)
Unbilled	$ (69,570)	$ 264,750	$ 286,400	$ 83,100	$ 112,090	$ (57,200)	$ 58,360	$ 104,740	$ (320,410)	$ 14,690	$ (378,000)	$ (115,560)	$ (16,610)
	$ 14,154,031	$ 15,612,984	$ 15,259,192	$ 13,323,312	$ 12,597,960	$ 13,441,620	$ 14,840,724	$ 15,083,382	$ 14,043,502	$ 13,110,490	$ 11,975,778	$ 12,372,368	$ 165,815,343
Service Classification No. 2													
Nondemand	$ 976,250	$ 1,063,280	$ 974,590	$ 1,043,490	$ 964,760	$ 1,072,300	$ 1,024,240	$ 1,090,720	$ 1,001,360	$ 1,066,450	$ 966,850	$ 1,041,260	$ 12,285,550
EEPS Lost Revenue	$ (5,910)	$ (6,830)	$ (5,800)	$ (5,800)	$ (5,230)	$ (6,460)	$ (11,610)	$ (12,980)	$ (11,280)	$ (11,160)	$ (8,650)	$ (9,440)	$ (101,170)
Primary	$ 446,540	$ 435,180	$ 448,560	$ 415,480	$ 405,030	$ 401,280	$ 381,170	$ 365,620	$ 369,840	$ 398,610	$ 429,080	$ 440,730	$ 4,937,120
EEPS Lost Revenue	$ (16,900)	$ (16,270)	$ (16,480)	$ (15,530)	$ (15,160)	$ (14,800)	$ (23,610)	$ (23,220)	$ (22,450)	$ (25,160)	$ (26,990)	$ (27,700)	$ (244,270)
Secondary	$ 4,794,940	$ 4,791,260	$ 4,788,950	$ 4,568,770	$ 4,249,700	$ 4,356,750	$ 4,393,960	$ 4,203,570	$ 4,220,260	$ 4,268,480	$ 4,455,630	$ 4,696,420	$ 53,788,690
EEPS Lost Revenue	$ (168,680)	$ (169,060)	$ (168,600)	$ (159,500)	$ (146,820)	$ (150,930)	$ (254,530)	$ (248,220)	$ (241,580)	$ (248,500)	$ (261,350)	$ (277,500)	$ (2,495,270)
PV Lost Revenue	$ (2,312)	$ (2,445)	$ (2,496)	$ (2,732)	$ (2,772)	$ (3,008)	$ (3,161)	$ (2,977)	$ (3,448)	$ (3,478)	$ (3,744)	$ (3,775)	$ (36,348)
Unbilled	$ 2,250	$ (9,190)	$ 14,390	$ (14,050)	$ 15,430	$ (18,380)	$ 14,740	$ (8,150)	$ 7,800	$ -	$ 8,500	$ (14,910)	$ (1,570)
	$ 6,026,178	$ 6,085,925	$ 6,033,114	$ 5,830,128	$ 5,464,938	$ 5,636,732	$ 5,521,199	$ 5,364,363	$ 5,320,502	$ 5,445,242	$ 5,559,326	$ 5,845,085	$ 68,132,732
Service Classification No. 3	$ 505,190	$ 521,590	$ 514,900	$ 484,550	$ 513,010	$ 522,100	$ 500,270	$ 475,380	$ 448,730	$ 457,220	$ 489,800	$ 493,640	$ 5,926,380
EEPS Lost Revenue	$ (19,470)	$ (20,160)	$ (20,000)	$ (18,800)	$ (19,700)	$ (20,260)	$ (32,640)	$ (30,880)	$ (29,290)	$ (29,820)	$ (32,030)	$ (32,360)	$ (305,410)
	$ 485,720	$ 501,430	$ 494,900	$ 465,750	$ 493,310	$ 501,840	$ 467,630	$ 444,500	$ 419,440	$ 427,400	$ 457,770	$ 461,280	$ 5,620,970
Service Classification No. 5	$ 132,200	$ 133,660	$ 135,130	$ 137,470	$ 138,940	$ 140,840	$ 139,240	$ 135,870	$ 135,440	$ 133,530	$ 132,060	$ 130,740	$ 1,625,120
Service Classification No. 6	$ 136,930	$ 152,470	$ 136,920	$ 129,630	$ 121,690	$ 156,770	$ 168,320	$ 194,350	$ 164,040	$ 169,610	$ 125,500	$ 129,640	$ 1,785,870
Service Classification No. 8	$ 356,990	$ 357,040	$ 357,090	$ 357,170	$ 357,220	$ 357,280	$ 358,210	$ 358,100	$ 358,080	$ 358,020	$ 357,970	$ 357,920	$ 4,291,090
Service Classification No. 9	$ 16,870	$ 16,870	$ 16,870	$ 16,870	$ 16,870	$ 16,870	$ 16,840	$ 16,840	$ 16,840	$ 16,870	$ 16,870	$ 16,870	$ 202,350
Service Classification No. 13													
Transmission	$ 438,900	$ 421,620	$ 438,240	$ 405,110	$ 389,580	$ 376,930	$ 358,740	$ 355,300	$ 376,300	$ 413,260	$ 451,220	$ 418,540	$ 4,843,740
Substation	$ 189,750	$ 179,620	$ 173,380	$ 164,630	$ 164,950	$ 152,090	$ 153,070	$ 157,470	$ 158,500	$ 170,480	$ 168,290	$ 171,490	$ 2,003,720
	$ 628,650	$ 601,240	$ 611,620	$ 569,740	$ 554,530	$ 529,020	$ 511,810	$ 512,770	$ 534,800	$ 583,740	$ 619,510	$ 590,030	$ 6,847,460
Interdepartmental	$ 240	$ 310	$ 240	$ 200	$ 200	$ 270	$ 270	$ 410	$ 240	$ 200	$ 200	$ 240	$ 3,020
Total Base Revenue	$ 21,937,809	$ 23,461,929	$ 23,045,076	$ 20,830,270	$ 19,745,658	$ 20,781,242	$ 22,024,243	$ 22,110,585	$ 20,992,884	$ 20,245,102	$ 19,244,984	$ 19,904,173	$ 254,323,955

Exhibit ___ (FRP-2)
Schedule F
Sheet 2 of 3

Central Hudson Gas & Electric Corporation
Summary of Electric Customers by Service Classification
Twelve Months Ended June 30, 2011

	July 2010	August 2010	September 2010	October 2010	November 2010	December 2010	January 2011	February 2011	March 2011	April 2011	May 2011	June 2011	Average
Service Classification No. 1													
Heating	26,676	25,108	26,500	25,087	26,503	25,126	26,850	24,880	26,927	25,220	26,492	25,114	25,874
Nonheating	229,377	229,882	229,653	230,143	229,907	232,191	230,154	230,667	231,851	230,935	230,656	231,189	230,550
Unbilled	-	-	-	-	-	-	-	-	-	-	-	-	-
	256,053	254,990	256,153	255,230	256,410	257,317	257,004	255,547	258,778	256,155	257,148	256,303	256,424
Service Classification No. 2													
Nondemand	27,651	29,751	27,683	29,886	27,761	30,308	28,438	29,933	27,862	29,996	27,906	30,070	28,937
Primary	170	171	172	171	175	169	169	172	171	173	164	174	171
Secondary	11,945	11,778	11,987	12,018	12,048	12,110	12,138	12,157	12,225	12,274	12,301	12,346	12,111
Unbilled	-	-	-	-	-	-	-	-	-	-	-	-	-
	39,766	41,700	39,842	42,075	39,984	42,587	40,745	42,262	40,258	42,443	40,371	42,590	41,219
Service Classification No. 3	31	31	32	32	33	31	32	32	32	32	32	32	32
Service Classification No. 5	4,525	4,655	4,545	4,625	4,470	4,536	4,410	4,483	4,694	4,611	4,603	4,594	4,563
Service Classification No. 6	1,545	1,605	1,545	1,605	1,545	1,605	1,545	1,605	1,545	1,605	1,545	1,605	1,575
Service Classification No. 8	207	207	207	207	207	207	207	207	207	207	207	207	207
Service Classification No. 9	297	297	297	297	297	297	297	297	297	297	297	297	297
Service Classification No. 13													
Transmission	6	6	6	6	6	6	6	6	6	6	6	6	6
Substation	7	7	7	7	7	7	7	7	7	7	7	7	7
	13	13	13	13	13	13	13	13	13	13	13	13	13
Interdepartmental	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Customers	302,438	303,499	302,635	304,085	302,960	306,594	304,254	304,447	305,825	305,364	304,217	305,642	304,331

Exhibit ___(FRP-2)
Schedule F
Sheet 3 of 3

Central Hudson Gas & Gas Corporation

Gas Sales, Base Delivery Revenues and Customers

Schedule A	Summary of Gas Sales, Base Revenues and Customers by Service Classification for the Twelve Months Ended March 31, 2009, December 31, 2009, December 31, 2010, and June 30, 2011
Schedule B	Gas Sales, Base Revenues and Customers by Revenue Account - Twelve Months Ended March 31, 2009
Schedule C	Gas Sales, Base Revenues and Customers by Service Classification - Twelve Months Ended March 31, 2009
Schedule D	Gas Sales, Base Revenues and Customers by Service Classification - Twelve Months Ended December 31, 2009
Schedule E	Gas Sales, Base Revenues and Customers by Service Classification - Twelve Months Ended December 31, 2010
Schedule F	Gas Sales, Base Revenues and Customers by Service Classification - Twelve Months Ended June 30, 2011

Central Hudson Gas & Electric Corporation
Summary of Gas Sales, Base Revenues and Customers By Service Classification
Twelve Months Ended March 31, 2009, December 31, 2009, 2010 and June 30, 2011

	Twelve Months Ended Mar. 31, 2009	Twelve Months Ended Dec. 31, 2009	Twelve Months Ended Dec. 31, 2010	Twelve Months Ended Jun. 30, 2011
Sales & Transport (Mcf)				
Service Classification Nos. 1 & 12				
Heat	5,205,820	5,152,835	5,031,180	5,018,090
Nonheating	202,917	199,906	186,833	181,308
Unbilled	(57,945)	(57,974)	(14,610)	(14,610)
Case 07-M-0548 EEPS Adjustment	-	(10,890)	(22,360)	(22,340)
	5,350,792	5,283,876	5,181,043	5,162,448
Service Classification Nos. 2, 6 & 13				
Heat	5,246,144	5,086,403	4,938,638	4,996,633
Nonheating	817,906	793,762	757,762	756,114
Unbilled	(14,823)	(11,606)	(5,600)	(5,600)
	6,049,227	5,868,559	5,690,800	5,747,147
Service Classification No. 8	680,708	581,338	526,690	526,690
Service Classification No. 9	1,003,253	1,089,472	1,142,480	1,142,480
Service Classification No. 11	2,688,745	2,321,866	2,229,377	2,229,377
Service Classification No. 14	523,289	1,262	-	-
Sales for Resale	3,155,142	970,488	-	-
Interdepartmental	27,982	24,789	22,650	22,650
Total Sales & Transport	19,479,138	16,141,650	14,793,040	14,830,792
Base Revenue ($)				
Service Classification Nos. 1 & 12				
Heat	$ 32,149,819	$ 34,565,502	$ 40,180,620	$ 40,155,130
Nonheating	$ 2,555,436	$ 2,720,071	$ 2,978,880	$ 2,917,140
Unbilled	$ (66,071)	$ (613,337)	$ (211,530)	$ (211,530)
Case 07-M-0548 EEPS Adjustment	$ -	$ (65,940)	$ (127,620)	$ (127,510)
	$ 34,639,184	$ 36,606,296	$ 42,820,350	$ 42,733,230
Service Classification Nos. 2, 6 & 13				
Heat	$ 15,512,137	$ 16,258,849	$ 18,195,040	$ 18,421,280
Nonheating	$ 2,245,882	$ 2,403,295	$ 2,616,770	$ 2,612,170
Unbilled	$ (12,199)	$ (66,910)	$ (55,930)	$ (55,930)
	$ 17,745,820	$ 18,595,234	$ 20,755,880	$ 20,977,520
Service Classification No. 8	$ 6,720,193	$ 3,097,372	$ 757,380	$ 757,380
Service Classification No. 9	$ 1,012,624	$ 1,119,766	$ 1,192,660	$ 1,192,660
Service Classification No. 11	$ 1,984,152	$ 2,049,617	$ 2,010,840	$ 2,010,840
Service Classification No. 14	$ 61,356	$ 5,285	$ -	$ -
Sales for Resale	$ 36,304,561	$ -	$ -	$ -
Interdepartmental	$ 391,052	$ 240,009	$ 54,270	$ 54,270
Total Own Territory	$ 98,858,942	$ 61,713,579	$ 67,591,380	$ 67,725,900
Customers				
Service Classification Nos. 1 & 12				
Heat	54,018	54,150	54,579	54,813
Nonheating	9,446	9,281	9,021	8,878
	63,464	63,431	63,599	63,691
Service Classification Nos. 2, 6 & 13				
Heat	9,366	8,969	8,778	8,906
Nonheating	1,281	1,257	1,252	1,253
	10,647	10,226	10,031	10,159
Service Classification No. 8	43	37	33	33
Interdepartmental	1	1	1	1
Total Sales & Transport Customers	74,155	73,695	73,664	73,883

Central Hudson Gas & Electric Corporation
Summary of Gas Sales, Base Revenues, and Customers By Revenue Account
Twelve Months Ended March 31, 2009

Acct. No.		April 2008	May 2008	June 2008	July 2008	August 2008	September 2008	October 2008	November 2008	December 2008	January 2009	February 2009	March 2009	Total
	Sales (Mcf)													
480	Residential	490,623	241,949	111,221	97,557	83,967	80,698	125,936	367,882	593,800	816,282	902,555	672,055	4,584,525
481	Commercial & Industrial	333,089	180,239	111,838	84,659	84,947	91,253	114,672	242,793	400,606	557,691	575,473	404,919	3,182,179
482	Public Authorities	110,695	48,796	29,416	35,822	(6,522)	16,152	57,052	111,531	175,171	243,149	212,704	172,234	1,206,199
483	Sales For Resale	267,290	134,943	265,686	45,033	263,231	300,345	340,116	332,661	235,349	323,366	357,281	289,841	3,155,142
484	Interdepartmental	2,490	665	531	1,128	420	74	169	1,894	4,342	5,158	6,366	4,746	27,982
489.09	SC 11 DLM Transportation	62,834	44,644	19,605	33,832	32,330	34,776	52,080	83,722	108,352	131,602	104,630	97,197	805,604
489.10	Gas Transport. - Cust. Owned Gas	46,408	62,453	46,470	45,926	50,610	50,804	88,297	113,003	152,730	90,793	110,313	145,446	1,003,253
489.11	SC 14 Transportation	21,548	7,363	122,338	269,556	62,856	27,048	10,242	-	1,076	1,196	66	-	523,289
489.12	SC 11 Transportation	156,950	123,064	134,375	175,637	117,847	113,967	136,988	161,458	211,990	189,791	213,405	147,669	1,883,141
489.13/14/30	Residential Transportation	85,304	44,008	16,744	7,253	17,638	10,320	20,902	63,114	99,133	136,543	145,330	108,978	755,265
489.19/20/40	Commercial Transportation	180,575	125,942	88,593	83,604	75,533	80,133	103,366	168,972	243,484	304,361	322,998	244,244	2,021,805
489.21	Industrial Transportation	12,960	19,228	10,294	9,128	9,768	9,332	9,785	17,181	22,434	24,016	28,199	25,819	198,143
489.22	OPA Transportation	5,815	3,181	2,205	956	818	1,572	4,085	13,981	20,511	28,268	28,896	22,323	132,610
	Total Sales	1,776,580	1,036,475	959,316	890,089	793,441	816,474	1,063,690	1,678,191	2,268,978	2,852,217	3,008,215	2,336,472	19,479,138
	Base Revenues													
480	Residential	$ 3,012,657	$ 1,984,431	$ 1,361,344	$ 1,281,516	$ 1,193,492	$ 1,179,053	$ 1,404,766	$ 2,527,066	$ 3,416,592	$ 4,219,359	$ 4,589,399	$ 3,722,969	$ 29,892,644
481	Commercial & Industrial	$ 1,353,861	$ 854,914	$ 582,674	$ 490,124	$ 520,421	$ 472,273	$ 581,584	$ 917,489	$ 1,325,372	$ 1,701,013	$ 1,754,847	$ 1,322,099	$ 11,876,671
482	Public Authorities	$ 710,642	$ 275,590	$ 129,987	$ 142,900	$ 46,652	$ 78,297	$ 414,524	$ 668,523	$ 927,458	$ 1,148,498	$ 1,177,822	$ 885,158	$ 6,606,051
483	Sales For Resale	$ 2,957,203	$ 1,645,175	$ 3,472,764	$ 617,601	$ 2,725,874	$ 2,704,083	$ 2,645,314	$ 3,270,046	$ 3,367,276	$ 4,506,161	$ 4,755,167	$ 3,637,897	$ 36,304,561
484	Interdepartmental	$ 33,118	$ 9,965	$ 9,171	$ 21,438	$ 5,907	$ 930	$ 2,086	$ 27,921	$ 62,007	$ 73,029	$ 84,629	$ 60,851	$ 391,052
489.09	SC 11 DLM Transportation	$ 58,450	$ 53,106	$ 45,750	$ 49,929	$ 49,488	$ 50,207	$ 55,290	$ 64,587	$ 71,829	$ 78,653	$ 70,709	$ 68,531	$ 716,529
489.10	Gas Transport. - Cust. Owned Gas	$ 52,637	$ 63,967	$ 47,128	$ 45,742	$ 50,558	$ 50,557	$ 87,006	$ 109,606	$ 145,387	$ 102,103	$ 114,988	$ 142,945	$ 1,012,624
489.11	SC 14 Transportation	$ 1,987	$ 664	$ 12,465	$ 26,635	$ 10,603	$ 2,438	$ 923	$ 260	$ 96	$ 108	$ 5,177	$ -	$ 61,356
489.12	SC 11 Transportation	$ 106,126	$ 104,547	$ 103,511	$ 106,711	$ 99,998	$ 103,405	$ 105,021	$ 106,331	$ 108,379	$ 107,358	$ 109,270	$ 106,966	$ 1,267,623
489.13/14/30	Residential Transportation	$ 464,841	$ 324,754	$ 219,686	$ 153,552	$ 195,847	$ 171,463	$ 275,932	$ 405,960	$ 534,467	$ 667,320	$ 706,686	$ 568,796	$ 4,689,304
489.19/20/40	Commercial Transportation	$ 466,910	$ 337,972	$ 253,383	$ 235,102	$ 221,008	$ 231,871	$ 309,027	$ 445,075	$ 618,980	$ 758,148	$ 801,253	$ 620,135	$ 5,298,864
489.21	Industrial Transportation	$ 27,860	$ 41,271	$ 22,417	$ 19,922	$ 21,271	$ 20,371	$ 21,358	$ 37,004	$ 48,230	$ 51,678	$ 60,409	$ 55,150	$ 426,961
489.22	OPA Transportation	$ 15,207	$ 9,191	$ 6,313	$ 3,654	$ 3,209	$ 5,266	$ 11,079	$ 33,179	$ 47,061	$ 64,080	$ 65,254	$ 51,209	$ 314,702
	Total Base Revenues	$ 9,261,519	$ 5,705,547	$ 6,266,593	$ 3,194,826	$ 5,144,328	$ 5,070,214	$ 5,913,910	$ 8,613,047	$ 10,673,134	$ 13,477,508	$ 14,295,610	$ 11,242,706	$ 98,858,942
	Customers													
480	Residential	59,545	51,276	58,896	51,530	58,680	50,835	58,400	51,381	59,909	51,748	60,388	52,137	55,394
481	Commercial & Industrial	8,651	7,481	8,429	7,431	8,193	7,140	8,205	7,287	8,615	7,357	8,617	7,359	7,897
482	Public Authorities	724	682	704	662	692	654	718	685	735	679	723	680	695
484	Interdepartmental	1	1	1	1	1	1	1	1	1	1	1	1	1
489.13/14/30	Residential Transportation	7,716	7,900	8,116	8,058	8,015	8,064	8,023	8,191	8,041	8,041	8,235	7,809	8,017
489.19/20/40	Commercial Transportation	1,918	1,887	2,040	1,943	2,095	2,008	2,157	2,091	2,182	2,048	2,184	2,062	2,051
489.21	Industrial Transportation	25	33	31	30	32	32	32	33	32	31	32	33	31
489.22	OPA Transportation	63	64	55	62	54	73	72	79	72	77	73	79	69
	Average Customers	78,643	69,324	78,272	69,717	77,762	68,807	77,608	69,748	79,587	69,982	80,253	70,160	74,155

Exhibit___(FRP-3)
Schedule B

Central Hudson Gas & Electric Corporation
Statement of Gas Sales, Base Revenues and Customers By Service Classification
For the Twelve Months Ended March 31, 2009

	April 2008	May 2008	June 2008	July 2008	August 2008	September 2008	October 2008	November 2008	December 2008	January 2009	February 2009	March 2009	Total
Sales & Transport (Mcf)													
Service Classification Nos. 1 & 12													
Heating	694,132	372,375	214,914	119,270	103,347	78,534	131,809	241,618	607,058	762,205	1,056,305	824,253	5,205,820
Non-Heating	23,824	15,081	13,596	9,938	8,165	6,377	9,088	12,318	21,745	24,624	33,796	24,366	202,917
Unbilled	(140,778)	(100,615)	(100,008)	(24,348)	(9,903)	6,054	6,043	177,544	65,579	167,870	(39,622)	(65,762)	(57,945)
	577,178	286,841	128,502	104,859	101,609	90,966	146,939	431,480	694,382	954,699	1,050,480	782,858	5,350,792
Service Classification Nos. 2, 6 & 13													
Heating	536,397	299,528	195,657	158,768	106,579	136,866	179,258	390,592	668,410	891,103	971,357	711,629	5,246,144
Non-Heating	66,577	60,134	57,140	48,945	43,582	44,965	55,829	65,956	77,561	111,452	104,716	81,049	817,906
Unbilled	(22,830)	(16,203)	(25,919)	(5,192)	(1,618)	721	3,043	23,939	14,811	29,310	(6,747)	(8,139)	(14,823)
	580,144	343,458	226,878	202,521	148,543	182,552	238,130	480,487	760,782	1,031,865	1,069,327	784,539	6,049,227
Service Classification No. 8	61,737	33,045	14,932	11,598	15,995	15,942	50,728	73,486	99,975	123,746	96,348	83,176	680,708
Service Classification No. 9	46,408	62,453	46,470	45,926	50,610	50,804	88,297	113,003	152,730	90,793	110,313	145,446	1,003,253
Service Classification No.11	219,784	167,708	153,980	209,469	150,177	148,743	189,068	245,180	320,342	321,393	318,035	244,866	2,688,745
Service Classification No. 14	21,548	7,363	122,338	269,556	62,856	27,048	10,242	-	1,076	1,196	66	-	523,289
Sales for Resale	267,290	134,943	265,686	46,033	263,231	300,345	340,116	332,661	235,349	323,366	357,281	289,841	3,155,142
Interdepartmental	2,490	665	531	1,128	420	74	169	1,894	4,342	5,158	6,366	4,746	27,982
Total Sales & Transport	1,776,580	1,036,475	959,316	890,089	793,441	816,474	1,063,690	1,678,191	2,268,978	2,852,217	3,008,215	2,335,472	19,479,138
Base Revenue													
Service Classification Nos. 1 & 12													
Heating	$ 3,737,521	$ 2,422,689	$ 1,871,577	$ 1,329,850	$ 1,307,504	$ 1,115,206	$ 1,461,073	$ 1,938,232	$ 3,542,825	$ 3,980,095	$ 5,229,471	$ 4,213,776	$ 32,149,819
Non-Heating	$ 259,347	$ 192,928	$ 214,155	$ 168,140	$ 185,404	$ 149,661	$ 186,817	$ 182,717	$ 252,516	$ 233,027	$ 299,170	$ 231,554	$ 2,555,436
Unbilled	$ (513,565)	$ (301,754)	$ (501,507)	$ (61,447)	$ (102,475)	$ 86,637	$ 34,288	$ 815,406	$ 162,603	$ 682,259	$ (221,317)	$ (145,199)	$ (66,071)
	$ 3,483,303	$ 2,313,863	$ 1,584,225	$ 1,436,543	$ 1,390,433	$ 1,351,504	$ 1,682,178	$ 2,936,355	$ 3,957,944	$ 4,895,381	$ 5,307,324	$ 4,300,131	$ 34,639,184
Service Classification Nos. 2, 6 & 13													
Heating	$ 1,572,885	$ 955,196	$ 712,844	$ 587,086	$ 483,499	$ 529,949	$ 662,789	$ 1,177,513	$ 1,889,447	$ 2,376,426	$ 2,606,661	$ 1,957,842	$ 15,512,137
Non-Heating	$ 190,492	$ 164,200	$ 162,633	$ 135,664	$ 129,373	$ 126,772	$ 156,751	$ 178,998	$ 216,204	$ 286,302	$ 280,271	$ 218,222	$ 2,245,882
Unbilled	$ (75,790)	$ (24,905)	$ (81,277)	$ (3,536)	$ (18,425)	$ 15,149	$ 17,029	$ 83,086	$ 20,040	$ 92,601	$ (36,835)	$ 664	$ (12,199)
	$ 1,687,587	$ 1,094,491	$ 794,200	$ 719,214	$ 594,447	$ 671,870	$ 836,569	$ 1,439,597	$ 2,125,691	$ 2,755,329	$ 2,850,097	$ 2,176,728	$ 17,745,820
Service Classification No. 8	$ 881,108	$ 419,769	$ 197,379	$ 171,013	$ 217,020	$ 135,220	$ 499,523	$ 658,344	$ 834,525	$ 959,386	$ 998,249	$ 748,657	$ 6,720,193
Service Classification No. 9	$ 52,637	$ 63,967	$ 47,128	$ 45,742	$ 50,558	$ 50,557	$ 87,006	$ 109,606	$ 145,387	$ 102,103	$ 114,988	$ 142,945	$ 1,012,624
Service Classification No.11	$ 164,576	$ 157,653	$ 149,261	$ 156,640	$ 149,486	$ 153,612	$ 160,311	$ 170,918	$ 180,208	$ 186,011	$ 179,979	$ 175,497	$ 1,984,152
Service Classification No. 14	$ 1,987	$ 664	$ 12,465	$ 26,635	$ 10,603	$ 2,438	$ 923	$ 260	$ 96	$ 108	$ 5,177	$ -	$ 61,356
Sales for Resale	$ 2,957,203	$ 1,645,175	$ 3,472,764	$ 617,601	$ 2,725,874	$ 2,704,083	$ 2,645,314	$ 3,270,046	$ 3,367,276	$ 4,506,161	$ 4,755,167	$ 3,637,897	$ 36,304,561
Interdepartmental	$ 33,118	$ 9,965	$ 9,171	$ 21,438	$ 5,907	$ 930	$ 2,086	$ 27,921	$ 62,007	$ 73,029	$ 84,629	$ 60,851	$ 391,052
Total Base Revenue	$ 9,261,519	$ 5,705,547	$ 6,266,593	$ 3,194,826	$ 5,144,328	$ 5,070,214	$ 5,913,910	$ 8,613,047	$ 10,673,134	$ 13,477,508	$ 14,295,610	$ 11,242,706	$ 98,858,942
Customers													
Service Classification Nos. 1 & 12													
Heating	56,751	50,677	56,574	51,053	56,354	50,493	56,248	51,141	57,635	51,401	58,309	51,583	54,018
Non-Heating	10,559	8,557	10,490	8,593	10,389	8,461	10,221	8,491	10,362	8,445	10,365	8,417	9,446
	67,310	59,234	67,064	59,646	66,743	58,954	66,469	59,632	67,997	59,846	68,674	60,000	63,464
Service Classification Nos. 2, 6 & 13													
Heating	9,876	8,876	9,772	8,880	9,606	8,679	9,694	8,881	10,147	8,921	10,087	8,973	9,366
Non-Heating	1,399	1,162	1,406	1,167	1,387	1,145	1,392	1,183	1,391	1,162	1,442	1,136	1,281
	11,275	10,038	11,178	10,047	10,993	9,824	11,086	10,064	11,538	10,083	11,529	10,109	10,647
Service Classification No. 8	57	51	29	23	25	28	52	51	51	52	49	50	43
Interdepartmental	1	1	1	1	1	1	1	1	1	1	1	1	1
Average Customers	78,643	69,324	78,272	69,717	77,762	68,807	77,608	69,748	79,587	69,982	80,253	70,160	74,155

Exhibit___(FRP-3)
Schedule C

Central Hudson Gas & Electric Corporation
Summary of Gas Sales, Base Revenues and Customers By Service Classification
For the Twelve Months Ending December 31, 2009

Sales & Transport (Mcf)	January	February	March	April	May	June	July	August	September	October	November	December	Total
Service Classification Nos. 1 & 12													
Heat	762,205	1,058,304	824,252	667,456	359,506	224,762	118,684	110,417	91,883	132,380	241,204	563,781	5,152,835
Nonheating	24,524	33,796	24,366	22,995	15,135	13,450	9,409	8,264	6,544	9,167	11,621	20,534	199,906
Unbilled	167,870	(39,622)	(65,762)	(135,400)	(95,410)	(103,990)	(9,810)	(10,800)	5,910	480	167,410	60,950	(57,974)
Case 07-M-0548 EEPS Adjustment	-	-	-	(2,900)	(1,560)	(980)	(520)	(480)	(400)	(570)	(1,050)	(2,430)	(10,890)
	954,699	1,050,478	782,857	552,151	277,671	133,242	117,763	107,601	103,937	141,457	419,185	642,835	5,283,876
Service Classification Nos. 2, 6 & 13													
Heat	891,103	971,357	711,629	494,502	304,774	170,018	146,088	117,327	133,738	180,842	351,936	613,090	5,086,403
Nonheating	111,452	104,716	81,049	73,691	48,371	55,725	38,267	46,372	38,623	56,458	56,010	83,028	793,762
Unbilled	29,310	(6,747)	(8,139)	(24,060)	(16,520)	(23,100)	(2,550)	(1,790)	820	530	26,010	14,630	(11,606)
	1,031,865	1,069,327	784,539	544,133	336,625	202,643	181,805	161,909	173,179	237,830	433,956	710,748	5,868,559
Service Classification No. 8	123,746	96,348	83,176	40,272	19,532	9,221	6,303	11,821	12,347	40,601	59,091	78,880	581,338
Service Classification No. 9	90,793	110,313	145,446	66,920	73,960	51,070	50,290	53,810	53,250	96,660	125,480	171,480	1,089,472
Service Classification No. 11	321,393	318,035	244,866	188,530	143,828	111,395	115,418	111,791	114,237	161,443	212,112	278,818	2,321,866
Service Classification No. 14	1,196	66	-	-	-	-	-	-	-	-	-	-	1,262
Sales for Resale	323,366	357,281	289,841	-	-	-	-	-	-	-	-	-	970,488
Interdepartmental	5,158	6,366	4,295	2,300	850	40	80	60	80	140	1,430	3,990	24,789
Total Sales & Transport	2,852,216	3,008,214	2,335,020	1,394,306	852,466	507,611	471,659	446,992	457,030	678,131	1,251,254	1,886,751	16,141,650
Base Revenue ($)													
Service Classification Nos. 1 & 12													
Heat	$ 3,980,095	$ 5,229,471	$ 4,213,776	$ 3,690,540	$ 2,405,270	$ 1,935,490	$ 1,403,310	$ 1,618,240	$ 1,508,640	$ 1,883,880	$ 2,461,790	$ 4,235,000	$ 34,565,502
Nonheating	$ 233,027	$ 299,170	$ 231,554	$ 250,030	$ 189,850	$ 209,160	$ 170,740	$ 213,680	$ 183,940	$ 229,640	$ 214,120	$ 295,160	$ 2,720,071
Unbilled	$ 682,259	$ (221,317)	$ (145,199)	$ (947,800)	$ (610,990)	$ (1,154,290)	$ (141,260)	$ (168,540)	$ 99,290	$ 6,970	$ 1,724,320	$ 463,220	$ (613,337)
Case 07-M-0548 EEPS Adjustment	$ -	$ -	$ -	$ (16,120)	$ (9,470)	$ (6,430)	$ (3,500)	$ (3,140)	$ (2,680)	$ (3,820)	$ (6,830)	$ (13,950)	$ (65,940)
	$ 4,895,381	$ 5,307,324	$ 4,300,131	$ 2,976,650	$ 1,774,660	$ 983,930	$ 1,429,290	$ 1,660,240	$ 1,789,190	$ 2,116,670	$ 4,393,400	$ 4,979,430	$ 36,606,296
Service Classification Nos. 2, 6 & 13													
Heat	$ 2,376,426	$ 2,806,661	$ 1,957,842	$ 1,462,700	$ 962,730	$ 641,140	$ 625,670	$ 638,380	$ 678,420	$ 845,920	$ 1,338,020	$ 2,124,940	$ 16,258,849
Nonheating	$ 286,302	$ 280,271	$ 218,222	$ 207,890	$ 139,890	$ 161,310	$ 125,990	$ 168,270	$ 141,640	$ 198,200	$ 193,260	$ 282,030	$ 2,403,295
Unbilled	$ 92,601	$ (36,835)	$ 664	$ (86,620)	$ (64,430)	$ (103,950)	$ (11,730)	$ (8,770)	$ 3,650	$ 2,330	$ 96,240	$ 49,740	$ (66,910)
	$ 2,755,329	$ 2,850,097	$ 2,176,728	$ 1,583,970	$ 1,038,190	$ 698,500	$ 739,930	$ 797,880	$ 823,910	$ 1,046,450	$ 1,627,540	$ 2,456,710	$ 18,595,234
Service Classification No. 8	$ 959,386	$ 998,249	$ 748,857	$ 56,610	$ 26,080	$ 10,970	$ 8,580	$ 13,350	$ 16,080	$ 57,940	$ 85,330	$ 116,140	$ 3,097,372
Service Classification No. 9	$ 102,103	$ 114,988	$ 142,945	$ 74,850	$ 72,790	$ 51,370	$ 50,100	$ 52,860	$ 52,880	$ 97,990	$ 129,690	$ 177,200	$ 1,119,766
Service Classification No. 11	$ 186,011	$ 179,979	$ 175,497	$ 167,570	$ 167,570	$ 167,570	$ 167,570	$ 167,570	$ 167,570	$ 167,570	$ 167,570	$ 167,570	$ 2,049,617
Service Classification No. 14	$ 108	$ 5,177	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,285
Sales for Resale	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Interdepartmental	$ 73,029	$ 84,629	$ 60,851	$ 5,510	$ 2,040	$ 100	$ 190	$ 140	$ 190	$ 340	$ 3,430	$ 9,560	$ 240,009
Total Own Territory	$ 8,971,347	$ 9,540,443	$ 7,604,809	$ 4,865,160	$ 3,081,330	$ 1,912,440	$ 2,395,860	$ 2,692,040	$ 2,849,820	$ 3,486,960	$ 6,406,960	$ 7,906,610	$ 61,713,579
Customers													
Service Classification Nos. 1 & 12													
Heat	51,402	58,311	51,584	56,770	50,846	56,816	50,911	56,881	51,013	57,003	51,137	57,125	54,150
Nonheating	8,445	10,365	8,417	10,336	8,399	10,237	8,398	10,124	8,283	10,023	8,241	10,100	9,281
	59,847	68,676	60,001	67,106	59,245	67,053	59,309	67,005	59,296	67,026	59,378	67,225	63,431
Service Classification Nos. 2, 6 & 13													
Heat	8,921	10,087	8,973	9,524	8,524	9,293	8,381	9,010	8,307	9,161	8,287	9,163	8,969
Nonheating	1,162	1,442	1,136	1,364	1,119	1,375	1,121	1,353	1,113	1,379	1,122	1,399	1,257
	10,083	11,529	10,109	10,888	9,643	10,668	9,502	10,363	9,420	10,540	9,409	10,562	10,226
Service Classification No. 8	52	49	50	33	33	33	33	33	33	33	33	33	37
Interdepartmental	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Sales & Transport Customers	69,983	80,255	70,161	78,028	68,922	77,755	68,845	77,402	68,750	77,600	68,821	77,821	73,695

Exhibit__(FRP-3)
Schedule D

Central Hudson Gas & Electric Corporation
Summary of Gas Sales, Base Revenues and Customers By Service Classification
For the Twelve Months Ending December 31, 2010

Sales & Transport (Mcf)	January	February	March	April	May	June	July	August	September	October	November	December	Total
Service Classification Nos. 1 & 12													
Heat	718,083	963,570	781,500	693,070	377,563	231,444	120,814	111,783	92,574	133,311	242,557	564,911	5,031,180
Nonheating	21,176	26,388	23,314	22,800	14,837	13,141	8,877	7,914	6,344	9,079	11,260	19,703	186,833
Unbilled	125,540	(22,040)	2,350	(135,400)	(95,410)	(103,990)	(9,810)	(10,600)	5,910	480	167,410	60,950	(14,610)
Case 07-M-0548 EEPS Adjustment	(3,190)	(4,280)	(3,470)	(3,080)	(1,680)	(1,930)	(540)	(500)	(410)	(590)	(1,080)	(2,510)	(22,360)
	861,609	965,638	803,694	577,390	295,310	139,565	119,341	108,597	104,418	142,280	420,147	643,054	5,181,043
Service Classification Nos. 2, 8 & 13													
Heat	782,981	866,795	718,828	511,972	313,364	174,839	147,882	118,780	135,840	184,873	358,872	623,812	4,938,838
Nonheating	83,907	95,830	76,050	76,255	49,422	56,603	38,607	46,639	38,806	56,702	56,105	83,036	757,762
Unbilled	22,680	(3,230)	980	(24,060)	(16,520)	(23,100)	(2,550)	(1,790)	820	530	26,010	14,630	(5,600)
	889,568	959,195	795,858	564,167	346,268	208,342	183,939	163,629	175,466	242,105	440,987	721,278	5,690,800
Service Classification No. 8	98,611	79,220	79,791	40,272	19,532	9,221	6,303	11,821	12,347	40,601	59,091	78,880	526,690
Service Classification No. 9	118,050	128,810	152,700	66,920	73,960	51,070	50,290	53,810	53,250	96,660	125,480	171,480	1,142,480
Service Classification No. 11	273,790	292,706	225,309	188,530	143,828	111,395	115,418	111,791	114,237	161,443	212,112	278,818	2,229,377
Service Classification No. 14	-	-	-	-	-	-	-	-	-	-	-	-	-
Sales for Resale	-	-	-	-	-	-	-	-	-	-	-	-	-
Interdepartmental	4,670	5,110	3,900	2,300	850	40	80	60	80	140	1,430	3,990	22,650
Total Sales & Transport	2,246,298	2,430,879	2,052,252	1,439,579	879,746	519,633	475,371	449,708	459,798	683,229	1,259,247	1,897,500	14,793,040
Base Revenue ($)													
Service Classification Nos. 1 & 12													
Heat	$ 4,791,310	$ 6,087,410	$ 5,110,430	$ 4,855,350	$ 3,195,820	$ 2,524,410	$ 1,717,870	$ 1,738,680	$ 1,525,000	$ 1,901,420	$ 2,481,290	$ 4,251,630	$ 40,180,620
Nonheating	$ 268,250	$ 337,380	$ 274,210	$ 306,410	$ 231,320	$ 253,420	$ 195,250	$ 218,330	$ 178,300	$ 223,680	$ 207,470	$ 284,850	$ 2,978,880
Unbilled	$ 841,120	$ (138,850)	$ 15,260	$ (947,800)	$ (810,990)	$ (1,154,290)	$ (141,260)	$ (168,540)	$ 99,290	$ 6,970	$ 1,724,320	$ 483,220	$ (211,530)
Case 07-M-0548 EEPS Adjustment	$ (17,310)	$ (22,590)	$ (18,650)	$ (17,110)	$ (10,210)	$ (6,750)	$ (3,640)	$ (3,260)	$ (2,740)	$ (3,940)	$ (7,010)	$ (14,410)	$ (127,620)
	$ 5,883,380	$ 6,263,350	$ 5,381,270	$ 4,196,850	$ 2,605,940	$ 1,616,790	$ 1,768,220	$ 1,785,210	$ 1,799,850	$ 2,128,130	$ 4,406,070	$ 4,985,290	$ 42,820,350
Service Classification Nos. 2, 8 & 13													
Heat	$ 2,580,530	$ 2,841,050	$ 2,405,370	$ 1,856,610	$ 1,228,610	$ 841,230	$ 718,870	$ 650,310	$ 686,270	$ 861,180	$ 1,363,230	$ 2,161,780	$ 18,195,040
Nonheating	$ 274,100	$ 316,120	$ 254,590	$ 262,780	$ 175,870	$ 201,860	$ 142,160	$ 170,690	$ 142,170	$ 198,870	$ 193,570	$ 281,990	$ 2,616,770
Unbilled	$ 74,840	$ (10,680)	$ 3,230	$ (86,620)	$ (64,430)	$ (103,950)	$ (11,730)	$ (8,770)	$ 3,850	$ 2,330	$ 99,240	$ 49,740	$ (55,930)
	$ 2,929,470	$ 3,148,510	$ 2,663,190	$ 2,032,770	$ 1,340,050	$ 939,140	$ 849,300	$ 812,230	$ 832,290	$ 1,062,380	$ 1,653,040	$ 2,493,510	$ 20,755,880
Service Classification No. 8	$ 146,900	$ 117,000	$ 102,400	$ 56,810	$ 28,080	$ 10,970	$ 8,580	$ 13,350	$ 16,050	$ 57,940	$ 85,330	$ 116,140	$ 757,380
Service Classification No. 9	$ 143,460	$ 139,450	$ 150,020	$ 74,850	$ 72,790	$ 51,370	$ 50,100	$ 52,860	$ 52,860	$ 97,990	$ 129,690	$ 177,200	$ 1,192,860
Service Classification No. 11	$ 167,570	$ 167,570	$ 167,570	$ 167,570	$ 167,570	$ 167,570	$ 167,570	$ 167,570	$ 167,570	$ 167,570	$ 167,570	$ 167,570	$ 2,010,840
Service Classification No. 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales for Resale	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Interdepartmental	$ 11,190	$ 12,240	$ 9,340	$ 5,510	$ 2,040	$ 100	$ 190	$ 140	$ 190	$ 340	$ 3,430	$ 9,560	$ 54,270
Total Own Territory	$ 9,281,970	$ 9,848,120	$ 8,473,790	$ 6,534,160	$ 4,214,470	$ 2,785,940	$ 2,843,960	$ 2,831,360	$ 2,868,860	$ 3,514,350	$ 6,445,130	$ 7,949,270	$ 67,591,380
Customers													
Service Classification Nos. 1 & 12													
Heat	51,255	57,259	52,079	57,383	51,504	57,486	51,603	57,584	51,683	57,650	51,751	57,706	54,579
Nonheating	8,360	10,116	8,224	10,020	8,143	9,922	8,141	9,811	8,028	9,711	7,985	9,785	9,021
	59,615	67,375	60,303	67,403	59,647	67,408	59,744	67,395	59,711	67,361	59,736	67,491	63,599
Service Classification Nos. 2, 8 & 13													
Heat	8,569	9,143	8,456	9,150	8,278	9,145	8,306	8,998	8,344	9,241	8,399	9,311	8,778
Nonheating	1,142	1,402	1,135	1,365	1,120	1,375	1,122	1,354	1,114	1,379	1,123	1,398	1,252
	9,711	10,545	9,591	10,515	9,398	10,520	9,428	10,352	9,458	10,620	9,522	10,709	10,031
Service Classification No. 8	33	33	33	33	33	33	33	33	33	33	33	33	33
Interdepartmental	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Sales & Transport Customers	69,360	77,954	69,928	77,952	69,079	77,962	69,206	77,781	69,203	78,015	69,292	78,234	73,664

Exhibit__(FRP-3)
Schedule E

Central Hudson Gas & Electric Corporation
Summary of Gas Sales, Base Revenues and Customers By Service Classification
For the Twelve Months Ending June 30, 2011

Sales & Transport (Mcf)	July	August	September	October	November	December	January	February	March	April	May	June	Total
Service Classification Nos. 1 & 12													
Heat	120,814	111,783	92,574	133,311	242,557	564,911	719,040	961,658	776,220	688,069	374,976	230,177	5,018,090
Nonheating	8,877	7,914	6,344	9,079	11,260	19,703	20,275	27,110	22,105	21,796	14,213	12,632	181,308
Unbilled	(9,810)	(10,600)	5,910	480	167,410	60,950	125,540	(22,040)	2,350	(135,400)	(95,410)	(103,990)	(14,610)
Case 07-M-0548 EEPS Adjustment	(540)	(500)	(410)	(590)	(1,080)	(2,510)	(3,200)	(4,280)	(3,470)	(3,060)	(1,670)	(1,030)	(22,340)
	119,341	108,597	104,418	142,280	420,147	643,054	861,655	962,448	799,205	571,405	292,109	137,789	5,162,448
Service Classification Nos. 2, 6 & 13													
Heat	147,882	118,780	135,840	184,873	358,872	623,612	797,572	881,869	731,331	519,191	319,133	177,878	4,996,833
Nonheating	38,607	46,639	38,806	56,702	56,105	83,036	83,840	95,315	75,677	75,829	49,163	56,395	756,114
Unbilled	(2,550)	(1,790)	820	530	26,010	14,630	22,680	(3,230)	980	(24,060)	(16,520)	(23,100)	(5,600)
	183,939	163,629	175,466	242,105	440,987	721,278	904,092	973,954	807,988	570,960	351,776	210,973	5,747,147
Service Classification No. 8	6,303	11,821	12,347	40,601	59,091	78,880	98,611	79,220	70,791	40,272	19,532	9,221	526,690
Service Classification No. 9	50,290	53,810	53,250	96,660	125,480	171,480	118,050	128,810	152,700	66,920	73,960	51,070	1,142,480
Service Classification No. 11	115,418	111,791	114,237	161,443	212,112	278,818	273,790	292,706	225,309	188,530	143,828	111,395	2,229,377
Service Classification No. 14	-	-	-	-	-	-	-	-	-	-	-	-	-
Sales for Resale	-	-	-	-	-	-	-	-	-	-	-	-	-
Interdepartmental	80	60	80	140	1,430	3,990	4,670	5,110	3,900	2,300	850	40	22,650
Total Sales & Transport	475,371	449,708	459,798	683,229	1,259,247	1,897,500	2,260,868	2,442,248	2,059,893	1,440,387	882,055	520,488	14,830,792
Base Revenue ($)													
Service Classification Nos. 1 & 12													
Heat	$ 1,717,870	$ 1,738,680	$ 1,525,000	$ 1,901,420	$ 2,481,290	$ 4,251,630	$ 4,806,050	$ 6,086,090	$ 5,101,180	$ 4,835,340	$ 3,187,480	$ 2,523,100	$ 40,155,130
Nonheating	$ 195,250	$ 218,330	$ 178,300	$ 223,680	$ 207,470	$ 284,850	$ 258,510	$ 324,670	$ 262,930	$ 295,180	$ 223,090	$ 244,880	$ 2,917,140
Unbilled	$ (141,280)	$ (168,540)	$ 99,290	$ 6,970	$ 1,724,320	$ 483,220	$ 841,120	$ (138,850)	$ 15,280	$ (947,800)	$ (810,990)	$ (1,154,290)	$ (211,530)
Case 07-M-0548 EEPS Adjustment	$ (3,640)	$ (3,280)	$ (2,740)	$ (3,940)	$ (7,010)	$ (14,410)	$ (17,360)	$ (22,590)	$ (18,650)	$ (17,010)	$ (10,150)	$ (6,750)	$ (127,510)
	$ 1,768,220	$ 1,785,210	$ 1,799,850	$ 2,128,130	$ 4,406,070	$ 4,985,290	$ 5,888,320	$ 6,249,320	$ 5,360,740	$ 4,165,710	$ 2,589,430	$ 1,606,940	$ 42,733,230
Service Classification Nos. 2, 6 & 13													
Heat	$ 718,870	$ 650,310	$ 686,270	$ 861,180	$ 1,363,230	$ 2,161,780	$ 2,630,190	$ 2,893,150	$ 2,451,160	$ 1,887,970	$ 1,256,400	$ 860,770	$ 18,421,280
Nonheating	$ 142,160	$ 170,690	$ 142,170	$ 198,870	$ 193,570	$ 281,990	$ 273,930	$ 317,230	$ 253,550	$ 261,570	$ 175,090	$ 201,350	$ 2,612,170
Unbilled	$ (11,730)	$ (8,770)	$ 3,850	$ 2,330	$ 96,240	$ 49,740	$ 74,840	$ (10,860)	$ 3,230	$ (86,620)	$ (84,430)	$ (103,950)	$ (55,930)
	$ 849,300	$ 812,230	$ 832,290	$ 1,062,380	$ 1,653,040	$ 2,493,510	$ 2,978,960	$ 3,199,720	$ 2,707,940	$ 2,062,920	$ 1,347,060	$ 958,170	$ 20,977,520
Service Classification No. 8	$ 8,580	$ 13,350	$ 16,080	$ 57,940	$ 85,330	$ 116,140	$ 146,900	$ 117,000	$ 102,400	$ 56,610	$ 26,080	$ 10,970	$ 757,380
Service Classification No. 9	$ 50,100	$ 52,860	$ 52,860	$ 97,990	$ 129,690	$ 177,200	$ 143,460	$ 139,450	$ 150,020	$ 74,850	$ 72,790	$ 51,370	$ 1,192,660
Service Classification No. 11	$ 167,570	$ 167,570	$ 167,570	$ 167,570	$ 167,570	$ 167,570	$ 167,570	$ 167,570	$ 167,570	$ 167,570	$ 167,570	$ 167,570	$ 2,010,840
Service Classification No. 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales for Resale	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Interdepartmental	$ 190	$ 140	$ 190	$ 340	$ 3,430	$ 9,560	$ 11,190	$ 12,240	$ 9,340	$ 5,510	$ 2,040	$ 100	$ 54,270
Total Own Territory	$ 2,843,960	$ 2,831,360	$ 2,868,860	$ 3,514,350	$ 6,445,130	$ 7,949,270	$ 9,336,400	$ 9,885,300	$ 8,498,010	$ 6,533,170	$ 4,224,970	$ 2,795,120	$ 67,725,900
Customers													
Service Classification Nos. 1 & 12													
Heat	51,603	57,584	51,683	57,650	51,751	57,706	51,803	57,762	52,560	57,830	51,929	57,889	54,813
Nonheating	8,141	9,811	8,028	9,711	7,985	9,785	8,100	9,803	7,966	9,708	7,887	9,611	8,878
	59,744	67,395	59,711	67,361	59,736	67,491	59,903	67,565	60,526	67,538	59,816	67,500	63,691
Service Classification Nos. 2, 6 & 13													
Heat	8,306	8,998	8,344	9,241	8,399	9,311	8,749	9,356	8,696	9,422	8,578	9,474	8,906
Nonheating	1,122	1,354	1,114	1,379	1,123	1,398	1,143	1,402	1,136	1,365	1,119	1,376	1,253
	9,428	10,352	9,458	10,620	9,522	10,709	9,892	10,758	9,832	10,787	9,697	10,850	10,159
Service Classification No. 8	33	33	33	33	33	33	33	33	33	33	33	33	33
Interdepartmental	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Sales & Transport Customers	69,206	77,781	69,203	78,015	69,292	78,234	69,829	78,357	70,392	78,359	69,547	78,384	73,883

Exhibit__(FRP-3)
Schedule F

Central Hudson Gas & Electric Corporation

Electric Model Specifications and Statistics

Schedule A	**Customer Models**
Sheet 1	Residential Non-Heat
Sheet 2	Residential Heat
Sheet 3	Commercial Demand
Sheet 4	Commercial Non-Demand
Sheet 5	OPA Demand
Sheet 6	OPA Non-Demand

Schedule B	**Sales Models**
Sheet 1	Residential Heat Average Use
Sheet 2	Residential Non-Heat Average Use
Sheet 3	Commercial Demand
Sheet 4	Commercial Non-Demand Average Use
Sheet 5	OPA Demand
Sheet 6	OPA Non-Demand
Sheet 7	Industrial Demand Average Use
Sheet 8	Industrial Non-Demand Average Use

Electric Model Specifications and Statistics
Residential Non-Heat Customer Model

Estimation Begins:	2001:1
Estimation Ends:	2009:3

Regression Statistics

Iterations	1
Adjusted Observations	99
Deg. of Freedom for Error	88
R-Squared	0.973
Adjusted R-Squared	0.970
Durbin-Watson Statistic	2.121
Mean Abs. % Err. (MAPE)	0.36%

Variable	Coefficient	StdErr	T-Stat	P-Value
EconT.HHs_Ind	196,753.547	1,423.667	138.202	0.00%
BinaryT.Jan01	15,704.627	1,195.104	13.141	0.00%
BinaryT.Nov02	(4,570.671)	1,110.545	(4.116)	0.01%
BinaryT.Apr02	3,707.245	1,114.990	3.325	0.13%
BinaryT.Jul06	(3,638.996)	1,116.010	(3.261)	0.16%
BinaryT.Aug06	3,889.333	1,115.617	3.486	0.08%
BinaryT.Mar	1,446.295	389.236	3.716	0.04%
BinaryT.TrendBef06	1,041.850	105.886	9.839	0.00%
BinaryT.Dec	1,792.038	410.522	4.365	0.00%
BinaryT.Trend_Aft06	1,100.552	84.009	13.100	0.00%
BinaryT.Jan_Bef09	6,517.048	435.718	14.957	0.00%

Electric Model Specifications and Statistics
Residential Heat Customer Model

Linear Regression Model	
Estimation Begins (rolling 12 month average):	2002:1
Estimation Ends (rolling 12 month average):	2009:3

Regression Statistics

Observations	87
R-Squared	0.865
Adjusted R-Squared	0.863

Variable	**Coefficient**
CONST	26,734.0000
Variable	(2.9405)

Electric Model Specifications and Statistics
Commercial Demand Customer Model

Estimation Begins:	2001:1
Estimation Ends:	2009:3

Regression Statistics

Iterations	1
Adjusted Observations	99
Deg. of Freedom for Error	89
R-Squared	0.972
Adjusted R-Squared	0.969
Durbin-Watson Statistic	1.783
Mean Abs. % Err. (MAPE)	1.03%

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	(6,691.048)	1,789.202	(3.740)	0.03%
BinaryT.Nov07	(430.910)	134.325	(3.208)	0.19%
BinaryT.Dec07	352.585	134.385	2.624	1.03%
BinaryT.Jan08	368.860	134.446	2.744	0.74%
BinaryT.May03	(442.590)	133.655	(3.311)	0.14%
BinaryT.Jan05	551.603	133.975	4.117	0.01%
BinaryT.Mar07	546.082	134.012	4.075	0.01%
BinaryT.Aug	(144.805)	49.072	(2.951)	0.41%
BinaryT.TrendVar	238.158	9.840	24.204	0.00%
EconT.TotEmp_Ind	13,614.529	1,814.599	7.503	0.00%

Electric Model Specifications and Statistics
Commercial Non-Demand Customer Model

Estimation Begins:	2001:1
Estimation Ends:	2009:3

Regression Statistics

Iterations	1
Adjusted Observations	99
Deg. of Freedom for Error	87
R-Squared	0.952
Adjusted R-Squared	0.946
Durbin-Watson Statistic	1.801
Mean Abs. % Err. (MAPE)	0.76%

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	12,501.403	1,149.978	10.871	0.00%
BinaryT.Jan	628.212	101.268	6.203	0.00%
BinaryT.Feb	1,990.559	96.492	20.629	0.00%
BinaryT.Apr	2,011.216	101.027	19.908	0.00%
BinaryT.Jun	1,975.036	100.998	19.555	0.00%
BinaryT.Aug	1,921.921	101.008	19.027	0.00%
BinaryT.Oct	2,005.644	101.032	19.852	0.00%
BinaryT.Dec	2,361.358	101.074	23.363	0.00%
BinaryT.TrendBef07	(47.376)	9.740	(4.864)	0.00%
BinaryT.Trend_Aft08	35.897	8.500	4.223	0.01%
EconT.NonManEmp_Ind	12,473.807	1,114.254	11.195	0.00%
BinaryT.Jan01	854.964	281.616	3.036	0.32%

Electric Model Specifications and Statistics
OPA Demand Customer Model

Estimation Begins:	2000:1
Estimation Ends:	2009:3

Regression Statistics

Iterations	6
Adjusted Observations	110
Deg. of Freedom for Error	97
R-Squared	0.932
Adjusted R-Squared	0.924
Durbin-Watson Statistic	2.109
Mean Abs. % Err. (MAPE)	1.06%

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	(2,102.419)	259.793	(8.093)	0.00%
BinaryT.Jul_a05	23.477	8.320	2.822	0.58%
BinaryT.Feb	(18.373)	5.249	(3.500)	0.07%
BinaryT.Aug	(18.102)	5.551	(3.261)	0.15%
BinaryT.Nov	(14.312)	5.606	(2.553)	1.23%
BinaryT.Mar00	58.216	16.091	3.618	0.05%
BinaryT.May03	(49.918)	15.814	(3.157)	0.21%
BinaryT.Mar07	84.116	15.963	5.269	0.00%
BinaryT.Nov07	(54.557)	16.781	(3.251)	0.16%
BinaryT.Jan05	68.256	15.949	4.280	0.00%
BinaryT.Mar05	51.965	15.976	3.253	0.16%
EconT.HHs_Ind	3,345.415	253.289	13.208	0.00%
AR(1)	0.610	0.077	7.888	0.00%

Electric Model Specifications and Statistics
OPA Non-Demand Customer Model

Estimation Begins:	2001:1
Estimation Ends:	2009:3

Regression Statistics

Iterations	1
Adjusted Observations	99
Deg. of Freedom for Error	85
R-Squared	0.985
Adjusted R-Squared	0.982
Durbin-Watson Statistic	2.286
Mean Abs. % Err. (MAPE)	0.86%

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	2,632.705	268.207	9.816	0.00%
BinaryT.EvenYrs_Aft00	361.491	5.177	69.822	0.00%
BinaryT.Dec07	82.252	24.925	3.300	0.14%
BinaryT.Feb06	(95.239)	24.831	(3.836)	0.02%
BinaryT.Jul06	(87.137)	24.851	(3.506)	0.07%
BinaryT.Mar03	68.166	24.762	2.753	0.73%
BinaryT.Jan01	148.716	25.478	5.837	0.00%
BinaryT.Trend_A05	3.873	0.785	4.937	0.00%
BinaryT.Nov07	(93.342)	24.921	(3.746)	0.03%
BinaryT.Apr06	(82.476)	24.839	(3.320)	0.13%
EconT.HHs_Ind	(846.013)	263.289	(3.213)	0.19%
BinaryT.Jan05	90.085	25.000	3.603	0.05%
BinaryT.May07	(65.773)	24.888	(2.643)	0.98%
BinaryT.Sep07	(61.513)	24.909	(2.470)	1.56%

Electric Model Specifications and Statistics
Residential Heat Average Use Model

Estimation Begins:	1998:1
Estimation Ends:	2009:3

Regression Statistics

Iterations	26
Adjusted Observations	135
Deg. of Freedom for Error	126
R-Squared	0.991
Adjusted R-Squared	0.990
Durbin-Watson Statistic	1.873
Mean Abs. % Err. (MAPE)	3.08%

Variable	Coefficient	StdErr	T-Stat	P-Value
ResHtVarsCR.XHeat	0.001	-	59.408	0.00%
ResHtVarsCR.XCool	0.001	-	17.795	0.00%
ResHtVarsCR.XOther	0.404	0.019	21.051	0.00%
BinaryT.Jan	(65.858)	12.980	(5.074)	0.00%
BinaryT.Apr	(62.914)	13.096	(4.804)	0.00%
BinaryT.May	(68.425)	13.140	(5.207)	0.00%
BinaryT.Nov	(96.350)	13.794	(6.985)	0.00%
BinaryT.Dec	(90.064)	15.093	(5.967)	0.00%
MA(1)	0.367	0.083	4.425	0.00%

Electric Model Specifications and Statistics
Residential Non-Heat Average Use Model

Estimation Begins:	1999:1
Estimation Ends:	2009:3

Regression Statistics

Iterations	10
Adjusted Observations	122
Deg. of Freedom for Error	110
R-Squared	0.974
Adjusted R-Squared	0.971
Durbin-Watson Statistic	1.944
Mean Abs. % Err. (MAPE)	1.71%

Variable	Coefficient	StdErr	T-Stat	P-Value
ResNHVarsCR.XHeat	0.963	0.070	13.839	0.00%
ResNHVarsCR.XCool	0.844	0.061	13.879	0.00%
ResNHVarsCR.XOther	0.955	0.028	34.430	0.00%
BinaryT.Jan	(26.973)	4.390	(6.145)	0.00%
BinaryT.Apr	(22.505)	4.055	(5.550)	0.00%
BinaryT.May	(26.102)	4.371	(5.971)	0.00%
BinaryT.Jul	36.376	6.919	5.258	0.00%
BinaryT.Aug	62.730	11.598	5.408	0.00%
BinaryT.Sep	40.236	8.779	4.583	0.00%
BinaryT.Nov	(31.770)	5.611	(5.663)	0.00%
BinaryT.Dec	(31.560)	5.767	(5.472)	0.00%
AR(1)	0.876	0.054	16.231	0.00%

Electric Model Specifications and Statistics
Commercial Demand Sales Model

Estimation Begins:	1998:1
Estimation Ends:	2009:3

Regression Statistics

Iterations	1
Adjusted Observations	135
Deg. of Freedom for Error	124
R-Squared	0.946
Adjusted R-Squared	0.941
Durbin-Watson Statistic	2.110
Mean Abs. % Err. (MAPE)	2.10%

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	22,350.230	2,845.170	7.855	0.00%
DmdVarsCR.XOther_ComDmd	7.126	0.240	29.635	0.00%
DmdVarsCR.XCool_ComDmd	0.003	-	27.245	0.00%
BinaryT.May	(7,095.504)	1,038.262	(6.834)	0.00%
BinaryT.Oct	(3,587.335)	1,013.366	(3.540)	0.06%
BinaryT.Mar07	7,876.310	3,098.337	2.542	1.23%
BinaryT.Nov	(7,235.663)	1,047.553	(6.907)	0.00%
BinaryT.Apr	(7,052.415)	1,051.809	(6.705)	0.00%
BinaryT.Jun00	8,066.793	3,217.601	2.507	1.35%
BinaryT.Jun	(3,442.068)	1,036.429	(3.321)	0.12%
BinaryT.Feb	2,657.024	1,021.850	2.600	1.05%

Electric Model Specifications and Statistics
Commercial Non-Demand Average Use Model

Estimation Begins:	2001:1
Estimation Ends:	2009:3

Regression Statistics

Iterations	14
Adjusted Observations	99
Deg. of Freedom for Error	85
R-Squared	0.933
Adjusted R-Squared	0.923
Durbin-Watson Statistic	1.946
Mean Abs. % Err. (MAPE)	2.53%

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	1,179.585	61.528	19.172	0.00%
NonDmdVarsCR.XHeat_ComND	0.001	-	9.933	0.00%
NonDmdVarsCR.XCool_ComND	0.003	-	8.789	0.00%
NonDmdVarsCR.XOther_ComND	(11.315)	0.958	(11.817)	0.00%
BinaryT.Jan	96.753	10.722	9.023	0.00%
BinaryT.Feb	71.973	9.123	7.890	0.00%
BinaryT.Jun	(28.438)	8.000	(3.555)	0.06%
BinaryT.Nov	(48.898)	7.023	(6.963)	0.00%
BinaryT.May	(29.101)	9.149	(3.181)	0.21%
BinaryT.Apr02	(62.989)	19.864	(3.171)	0.21%
BinaryT.May02	(62.952)	20.888	(3.014)	0.34%
BinaryT.Feb02	(50.865)	19.853	(2.562)	1.22%
BinaryT.May06	(66.347)	20.074	(3.305)	0.14%
MA(1)	0.284	0.111	2.557	1.24%

Electric Model Specifications and Statistics
OPA Demand Sales Model

Estimation Begins:	1997:1
Estimation Ends:	2009:3

Regression Statistics

Iterations	1
Adjusted Observations	147
Deg. of Freedom for Error	134
R-Squared	0.916
Adjusted R-Squared	0.909
Durbin-Watson Statistic	2.136
Mean Abs. % Err. (MAPE)	2.24%

Variable	Coefficient	StdErr	T-Stat	P-Value
CRWthrT.HDD	6.764	0.300	22.513	0.00%
CRWthrT.CDD	20.134	1.784	11.288	0.00%
EconT.Dmd_Econ_Ind	237.998	2.507	94.935	0.00%
BinaryT.Apr	(896.825)	274.150	(3.271)	0.14%
BinaryT.Aug	(1,659.079)	349.469	(4.747)	0.00%
BinaryT.Jun03	(2,727.223)	894.984	(3.047)	0.28%
BinaryT.Jul03	(3,877.287)	898.154	(4.317)	0.00%
BinaryT.May03	4,577.044	895.855	5.109	0.00%
BinaryT.Dec03	3,469.286	890.021	3.898	0.02%
BinaryT.Feb07	3,422.135	898.431	3.809	0.02%
BinaryT.Trend_A03	176.479	16.045	10.999	0.00%
BinaryT.Mar07	(3,346.079)	896.620	(3.732)	0.03%
BinaryT.Nov01	2,728.217	895.821	3.045	0.28%

Electric Model Specifications and Statistics
OPA Non-Demand Sales Model

Estimation Begins:	2002:1
Estimation Ends:	2009:3

Regression Statistics

Iterations	1
Adjusted Observations	87
Deg. of Freedom for Error	75
R-Squared	0.935
Adjusted R-Squared	0.925
Durbin-Watson Statistic	2.071
Mean Abs. % Err. (MAPE)	3.33%

Variable	Coefficient	StdErr	T-Stat	P-Value
EconT.NonDmd_Econ_Ind	10.478	0.155	67.417	0.00%
CRWthrT.HDD	0.448	0.020	22.774	0.00%
BinaryT.Feb	63.348	26.002	2.436	1.73%
BinaryT.Mar03	236.219	63.403	3.726	0.04%
BinaryT.Mar08	198.391	62.521	3.173	0.22%
BinaryT.Apr03	244.265	62.709	3.895	0.02%
BinaryT.May	(130.485)	24.717	(5.279)	0.00%
BinaryT.Aug	331.654	26.408	12.559	0.00%
BinaryT.Oct_05	187.228	61.959	3.022	0.35%
BinaryT.Nov	(232.792)	24.562	(9.478)	0.00%
BinaryT.Dec06	(206.583)	61.894	(3.338)	0.13%
BinaryT.Trend_A04	(7.258)	1.519	(4.780)	0.00%

Electric Model Specifications and Statistics
Industrial Demand Average Use Model

Estimation Begins:	2004:1
Estimation Ends:	2009:3
Regression Statistics	
Iterations	10
Adjusted Observations	62
Deg. of Freedom for Error	58
R-Squared	0.905
Adjusted R-Squared	0.900
Durbin-Watson Statistic	1.960
Mean Abs. % Err. (MAPE)	2.56%

Variable	**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
CRWthrT.CDD	0.025	0.002	10.200	0.00%
EconT.SmlDmd_Mult	48.059	1.636	29.367	0.00%
BinaryT.TrendVar	(1.368)	0.167	(8.211)	0.00%
AR(1)	0.408	0.122	3.344	0.15%

Electric Model Specifications and Statistics
Industrial Non-Demand Average Use Model

Estimation Begins:	1999:1
Estimation Ends:	2009:3

Regression Statistics

Iterations	8
Adjusted Observations	122
Deg. of Freedom for Error	111
R-Squared	0.953
Adjusted R-Squared	0.949
Durbin-Watson Statistic	2.262
Mean Abs. % Err. (MAPE)	9.45%

Variable	Coefficient	StdErr	T-Stat	P-Value
CRWthrT.CDD	0.001	-	4.114	0.01%
CRWthrT.HDD	-	-	6.442	0.00%
BinaryT.Jan01	0.381	0.071	5.350	0.00%
BinaryT.Feb01	(0.278)	0.071	(3.925)	0.02%
EconT.NonDmd_Mult	0.641	0.037	17.437	0.00%
BinaryT.Dec04	(0.367)	0.065	(5.611)	0.00%
BinaryT.Sep06	2.411	0.071	34.064	0.00%
BinaryT.Oct06	(1.913)	0.071	(26.978)	0.00%
BinaryT.Jan08	0.388	0.066	5.930	0.00%
BinaryT.TrendVar	(0.030)	0.004	(7.615)	0.00%
AR(1)	0.422	0.086	4.892	0.00%

Central Hudson Gas & Electric Corporation

Gas Model Specifications and Statistics

Schedule A	**Customer Models**
Sheet 1	Residential Heat
Sheet 2	Residential Non-Heat
Sheet 3	Commercial Heat
Sheet 4	Commercial Non-Heat
Sheet 5	Industrial

Schedule B	**Sales Models**
Sheet 1	Residential Heat Average Use
Sheet 2	Residential Non-Heat Average Use
Sheet 3	Commercial Heat Average Use
Sheet 4	Commercial Non-Heat Average Use
Sheet 5	OPA Average Use
Sheet 6	Industrial Average Use

Gas Model Specifications and Statistics
Residential Heat Customer Model

Estimation Begins:	2001:1
Estimation Ends:	2009:3

Regression Statistics

Iterations	1
Adjusted Observations	99
Deg. of Freedom for Error	84
R-Squared	0.985
Adjusted R-Squared	0.983
Durbin-Watson Statistic	1.772
Mean Abs. % Err. (MAPE)	0.63%

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	(72,530.013)	3,938.310	(18.417)	0.00%
EconVars.Households_Ind	116,035.866	3,774.789	30.740	0.00%
BinaryVars.OddMonths_01	1,129.853	267.802	4.219	0.01%
BinaryVars.Jan_01	4,986.988	497.188	10.030	0.00%
BinaryVars.EvenMonths_06	4,479.344	203.071	22.058	0.00%
BinaryVars.EvenMonths_Aft06	5,937.411	161.100	36.855	0.00%
BinaryVars.Mar	699.426	169.677	4.122	0.01%
BinaryVars.EvenMonths_01_04	1,853.580	151.398	12.243	0.00%
BinaryVars.EvenMonths_05	3,181.301	201.873	15.759	0.00%
BinaryVars.Jan_02	2,702.027	479.081	5.640	0.00%
BinaryVars.Jan_03	2,088.082	467.130	4.470	0.00%
BinaryVars.Jan_04	1,436.206	461.207	3.114	0.25%
BinaryVars.Jan_05	2,058.148	459.600	4.478	0.00%
BinaryVars.Jan_06	2,682.261	459.702	5.835	0.00%
BinaryVars.Jan_08	1,757.931	463.471	3.793	0.03%

Gas Model Specifications and Statistics
Residential Non-Heat Customer Model

Exponential Smoothing Model	
Estimation Begins:	2001:1
Estimation Ends:	2009:3

Regression Statistics

Iterations	1
Adjusted Observations	97
Deg. of Freedom for Error	94
R-Squared	0.976
Adjusted R-Squared	0.976
Durbin-Watson Statistic	1.990
Mean Abs. % Err. (MAPE)	1.08%

Variable	**Coefficient**
Simple	0.001
Trend	14.601
Seasonal	0.533

Gas Model Specifications and Statistics
Commercial Heat Customer Model

Estimation Begins:	2001:1
Estimation Ends:	2009:3

Regression Statistics

Iterations	8
Adjusted Observations	98
Deg. of Freedom for Error	88
R-Squared	0.969
Adjusted R-Squared	0.966
Durbin-Watson Statistic	2.394
Mean Abs. % Err. (MAPE)	1.15%

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	(8,317.542)	1,285.283	(6.471)	0.00%
EconTrans.NonManEmp_Ind	15,052.889	1,224.389	12.294	0.00%
BinaryVars.EvenMonths_Aft00	813.298	19.846	40.981	0.00%
BinaryVars.Jan	251.948	39.252	6.419	0.00%
BinaryVars.Aug	(163.678)	39.090	(4.187)	0.01%
BinaryVars.Mar	151.073	38.418	3.932	0.02%
BinaryVars.Dec_07	392.372	98.477	3.984	0.01%
BinaryVars.Dec_08	509.014	98.394	5.173	0.00%
BinaryVars.Feb_09	511.248	98.771	5.176	0.00%
AR(1)	0.666	0.086	7.792	0.00%

Gas Model Specifications and Statistics
Commercial Non-Heat Customer Model

Exponential Smoothing Model	
Estimation Begins:	2001:1
Estimation Ends:	2009:3

Regression Statistics

Iterations	1
Adjusted Observations	97
Deg. of Freedom for Error	94
R-Squared	0.947
Adjusted R-Squared	0.946
Durbin-Watson Statistic	2.344
Mean Abs. % Err. (MAPE)	1.97%

Variable	**Coefficient**
Simple	0.155
Trend	-
Seasonal	0.423

Gas Model Specifications and Statistics
Industrial Customer Model

Linear Regression Model	
Estimation Begins (rolling 12 month average):	2002:1
Estimation Ends (rolling 12 month average):	2009:3
Regression Statistics	
Observations	87
R-Squared	0.948
Adjusted R-Squared	0.947

Variable	**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
CONST	314.1197	0.6060	518.570	0.00%
Variable	(0.4707)	0.0120	(39.369)	0.00%

Gas Model Specifications and Statistics
Residential Heat Average Use Model

Estimation Begins:	1997:1
Estimation Ends:	2009:3

Regression Statistics

Iterations	20
Adjusted Observations	147
Deg. of Freedom for Error	138
R-Squared	0.995
Adjusted R-Squared	0.995
Durbin-Watson Statistic	1.908
Mean Abs. % Err. (MAPE)	5.03%

Variable	Coefficient	StdErr	T-Stat	P-Value
ResSpHtVars.XHeat	-	-	86.451	0.00%
ResSpHtVars.XOther	0.029	0.007	4.382	0.00%
BinaryVars.Aug	1.361	0.159	8.554	0.00%
BinaryVars.Sep	1.043	0.143	7.302	0.00%
BinaryVars.Nov	(1.031)	0.120	(8.621)	0.00%
BinaryVars.May	(0.582)	0.122	(4.765)	0.00%
BinaryVars.Jul	0.817	0.139	5.876	0.00%
BinaryVars.Feb	0.686	0.122	5.609	0.00%
MA(1)	0.330	0.084	3.919	0.01%

Gas Model Specifications and Statistics
Residential Non-Heat Average Use Model

Estimation Begins:	1999:1
Estimation Ends:	2009:3

Regression Statistics

Iterations	15
Adjusted Observations	111
Deg. of Freedom for Error	101
R-Squared	0.981
Adjusted R-Squared	0.979
Durbin-Watson Statistic	1.715
Mean Abs. % Err. (MAPE)	5.07%

Variable	Coefficient	StdErr	T-Stat	P-Value
ResNHtVars.XOther	0.058	0.005	11.190	0.00%
BinaryVars.Nov_06	(0.292)	0.078	(3.759)	0.03%
ResNHtVars.HUseMul	0.002	-	15.946	0.00%
BinaryVars.Mar_07	0.217	0.078	2.775	0.66%
BinaryVars.Feb_Mar_05	0.188	0.055	3.410	0.09%
BinaryVars.Dec_02	(0.316)	0.078	(4.050)	0.01%
BinaryVars.Jun_02	(0.215)	0.078	(2.775)	0.66%
BinaryVars.Jan_09	0.346	0.102	3.375	0.11%
BinaryVars.Feb_09	0.376	0.104	3.608	0.05%
SAR(1)	0.825	0.056	14.742	0.00%

Gas Model Specifications and Statistics
Commercial Heat Average Use Model

Estimation Begins:	2000:1
Estimation Ends:	2009:3

Regression Statistics

Iterations	7
Adjusted Observations	110
Deg. of Freedom for Error	102
R-Squared	0.989
Adjusted R-Squared	0.989
Durbin-Watson Statistic	2.006
Mean Abs. % Err. (MAPE)	6.24%

Variable	Coefficient	StdErr	T-Stat	P-Value
StructureVars.Heat_SpHt	0.054	0.001	95.433	0.00%
BinaryVars.Aug	8.009	1.120	7.148	0.00%
BinaryVars.Sep	8.835	1.235	7.154	0.00%
BinaryVars.Apr	(7.568)	1.023	(7.398)	0.00%
StructureVars.Other_SpHt	44.483	7.199	6.179	0.00%
BinaryVars.May_03	(7.878)	2.760	(2.854)	0.52%
BinaryVars.Jul	9.655	1.285	7.516	0.00%
AR(1)	(0.364)	0.098	(3.719)	0.03%

Gas Model Specifications and Statistics
Commercial Non-Heat Average Use Model

Estimation Begins:	2000:1
Estimation Ends:	2009:3

Regression Statistics

Iterations	1
Adjusted Observations	111
Deg. of Freedom for Error	100
R-Squared	0.892
Adjusted R-Squared	0.881
Durbin-Watson Statistic	2.069
Mean Abs. % Err. (MAPE)	10.67%

Variable	Coefficient	StdErr	T-Stat	P-Value
BinaryVars.ShiftJun02	12.129	1.273	9.531	0.00%
BinaryVars.Sep_06	14.139	4.810	2.940	0.41%
BinaryVars.Jan_03_04	14.026	3.552	3.949	0.01%
BinaryVars.Feb_Mar05	19.143	3.543	5.403	0.00%
BinaryVars.Nov03_04	15.457	3.468	4.457	0.00%
BinaryVars.Jul_04	20.527	4.849	4.233	0.01%
StructureVars.Heat_GS	0.016	0.001	18.152	0.00%
StructureVars.Other_GS	168.063	12.939	12.989	0.00%
BinaryVars.Oct_03	(13.892)	4.831	(2.876)	0.49%
BinaryVars.ShiftMay05	7.864	1.152	6.825	0.00%
BinaryVars.Jan_09	16.160	4.835	3.343	0.12%

Gas Model Specifications and Statistics
OPA Average Use Model

Estimation Begins:	2001:1
Estimation Ends:	2009:3

Regression Statistics

Iterations	1
Adjusted Observations	99
Deg. of Freedom for Error	89
R-Squared	0.993
Adjusted R-Squared	0.992
Durbin-Watson Statistic	2.037
Mean Abs. % Err. (MAPE)	9.96%

Variable	Coefficient	StdErr	T-Stat	P-Value
StructureVars.Heat_SpHt	0.143	0.001	113.230	0.00%
BinaryVars.Summer_2	9.048	1.419	6.377	0.00%
BinaryVars.Jan	20.120	2.913	6.907	0.00%
BinaryVars.Feb_01	(23.618)	7.233	(3.265)	0.16%
BinaryVars.Feb_03	(51.305)	7.286	(7.042)	0.00%
BinaryVars.Mar_03	(29.152)	7.191	(4.054)	0.01%
BinaryVars.Apr	(16.214)	2.760	(5.875)	0.00%
BinaryVars.May	(21.624)	2.556	(8.460)	0.00%
BinaryVars.Dec	11.349	2.760	4.112	0.01%
BinaryVars.Mar_05	21.544	7.148	3.014	0.34%

Gas Model Specifications and Statistics
Industrial Average Use Model

Estimation Begins:	2002:1
Estimation Ends:	2009:3

Regression Statistics

Iterations	7
Adjusted Observations	86
Deg. of Freedom for Error	77
R-Squared	0.968
Adjusted R-Squared	0.965
Durbin-Watson Statistic	2.222
Mean Abs. % Err. (MAPE)	10.34%

Variable	Coefficient	StdErr	T-Stat	P-Value
StructureVars.Heat_Ind	0.144	0.006	26.005	0.00%
StructureVars.Other_Ind	655.926	71.810	9.134	0.00%
BinaryVars.Dec_03	(51.749)	14.467	(3.577)	0.06%
BinaryVars.Sep_04	41.584	12.864	3.233	0.18%
BinaryVars.Apr	(45.031)	5.566	(8.090)	0.00%
BinaryVars.May	(22.238)	5.572	(3.991)	0.02%
BinaryVars.Nov_03	73.140	14.463	5.057	0.00%
BinaryVars.Feb_04	40.870	13.029	3.137	0.24%
AR(1)	0.646	0.086	7.552	0.00%

Central Hudson Gas & Electric Corporation

Electric Forecast Results*

Sheet 1	Residential Heat
Sheet 2	Residential Non-Heat
Sheet 3	Commercial Demand
Sheet 4	Commercial Non-Demand
Sheet 5	OPA Demand
Sheet 6	OPA Non-Demand
Sheet 7	Industrial Demand
Sheet 8	Industrial Non-Demand
Sheet 9	Service Class 13
Sheet 10	Area Lighting
Sheet 11	Street Lighting
Sheet 12	Traffic Signals
Sheet 13	Interdepartmental
Sheet 14	Total Own Territory

*Results do not include post-forecast adjustments for EEPS in Case 07-M-0548 and PV Net Metering

Electric Forecast Results
Residential Heat

	Custs	Change	Actual MWh	Change	Norm MWh	Change	Actual MWh/Cust	Norm MWh/Cust
2002	26,638		325,390		334,724		12.22	12.57
2003	26,641	3	361,680	36,290	347,479	12,755	13.58	13.04
2004	26,612	(29)	351,250	(10,430)	356,306	8,827	13.20	13.39
2005	26,586	(26)	358,740	7,490	342,933	(13,373)	13.49	12.90
2006	26,477	(109)	324,690	(34,050)	334,938	(7,995)	12.26	12.65
2007	26,449	(28)	336,160	11,470	339,874	4,936	12.71	12.85
2008	26,462	13	331,790	(4,370)	332,214	(7,660)	12.54	12.55
***2009**	26,431	(31)	336,360	4,570	330,310	(1,904)	12.73	12.50
2010	26,416	(15)			339,360	9,050		12.85
Rate Year	26,399				335,590			12.71

*2009 data represents 3 months actual/normal and 9 months forecast

Electric Forecast Results
Residential Non-Heat

	Custs	Change	Actual MWh	Change	Norm MWh	Change	Actual MWh/Cust	Norm MWh/Cust
2002	212,658		1,546,210		1,552,477		7.27	7.30
2003	215,400	2,742	1,617,990	71,780	1,617,013	64,536	7.51	7.51
2004	217,898	2,498	1,656,420	38,430	1,671,245	54,232	7.60	7.67
2005	220,957	3,059	1,794,990	138,570	1,712,197	40,952	8.12	7.75
2006	223,143	2,186	1,713,970	(81,020)	1,729,813	17,616	7.68	7.75
2007	225,399	2,256	1,775,550	61,580	1,772,125	42,312	7.88	7.86
2008	227,248	1,849	1,756,450	(19,100)	1,764,189	(7,936)	7.73	7.76
***2009**	228,095	847	1,810,060	53,610	1,797,590	33,401	7.94	7.88
2010	230,078	1,983			1,780,720	(16,870)		7.74
Rate Year	230,918				1,762,980			7.63

*2009 data represents 3 months actual/normal and 9 months forecast

Electric Forecast Results
Commercial Demand

	Custs	Change	Actual MWh	Change	Norm MWh	Change	Actual MWh/Cust	Norm MWh/Cust
2002	8,311		1,276,390		1,272,397		153.58	153.10
2003	8,585	274	1,284,510	8,120	1,292,205	19,808	149.62	150.52
2004	9,026	441	1,322,430	37,920	1,327,458	35,253	146.51	147.07
2005	9,452	426	1,385,400	62,970	1,353,133	25,675	146.57	143.16
2006	9,761	309	1,354,960	(30,440)	1,355,482	2,349	138.81	138.87
2007	9,900	139	1,419,080	64,120	1,418,573	63,091	143.34	143.29
2008	10,037	137	1,387,070	(32,010)	1,395,324	(23,249)	138.20	139.02
***2009**	9,988	(49)	1,396,450		1,397,000	1,676	139.81	139.87
2010	10,145	157			1,467,050	70,050		144.61
Rate Year	10,344				1,471,690			142.27

*2009 data represents 3 months actual/normal and 9 months forecast

Electric Forecast Results
Commercial Non-Demand

	Custs	Change	Actual MWh	Change	Norm MWh	Change	Actual MWh/Cust	Norm MWh/Cust
2002	25,882		182,010		182,361		7.03	7.05
2003	25,973	91	186,330	4,320	185,570	3,209	7.17	7.14
2004	25,996	23	181,410	(4,920)	182,252	(3,318)	6.98	7.01
2005	26,220	224	187,770	6,360	183,752	1,500	7.16	7.01
2006	26,451	231	176,390	(11,380)	177,846	(5,906)	6.67	6.72
2007	26,862	411	180,350	3,960	180,333	2,487	6.71	6.71
2008	27,229	367	176,560	(3,790)	177,241	(3,092)	6.48	6.51
***2009**	26,943	(286)	175,970	(590)	175,500	(1,741)	6.53	6.51
2010	26,955	12			166,080	(9,420)		6.16
Rate Year	27,077				166,010			6.13

*2009 data represents 3 months actual/normal and 9 months forecast

Electric Forecast Results
OPA Demand

	Custs	Change	Actual MWh	Change	Norm MWh	Change	Actual MWh/Cust	Norm MWh/Cust
2002	1,259		359,390		360,266		285.46	286.15
2003	1,297	38	371,530	12,140	369,790	9,524	286.45	285.11
2004	1,341	44	377,520	5,990	378,952	9,162	281.52	282.59
2005	1,384	43	391,800	14,280	385,318	6,366	283.09	278.41
2006	1,384	-	374,260	(17,540)	377,072	(8,246)	270.42	272.45
2007	1,367	(17)	384,770	10,510	384,772	7,700	281.47	281.47
2008	1,392	25	385,350	580	386,339	1,567	276.83	277.54
***2009**	1,404	12	385,490	140	384,540	(1,799)	274.57	273.89
2010	1,418	14			399,550	15,010		281.77
Rate Year	1,423				398,100			279.76

*2009 data represents 3 months actual/normal and 9 months forecast

Electric Forecast Results
OPA Non-Demand

	Custs	Change	Actual MWh	Change	Norm MWh	Change	Actual MWh/Cust	Norm MWh/Cust
2002	1,964		15,920		16,039		8.11	8.17
2003	1,967	3	17,070	1,150	16,854	815	8.68	8.57
2004	1,938	(29)	15,210	(1,860)	15,223	(1,631)	7.85	7.86
2005	1,943	5	16,010	800	16,002	779	8.24	8.24
2006	1,940	(3)	14,990	(1,020)	15,181	(821)	7.73	7.83
2007	1,965	25	15,680	690	15,675	494	7.98	7.98
2008	1,978	13	15,370	(310)	15,313	(362)	7.77	7.74
***2009**	1,974	(4)	15,150	(220)	15,090	(223)	7.67	7.64
2010	1,975	1			15,380	290		7.79
Rate Year	1,976				15,290			7.74

*2009 data represents 3 months actual/normal and 9 months forecast

Electric Forecast Results
Industrial Demand

	Custs	Change	Actual MWh	Change	Norm MWh	Change	Actual MWh/Cust	Norm MWh/Cust
****2002**	561		284,650		284,650		507.40	507.40
****2003**	576	15	295,080	10,430	295,080	10,430	512.29	512.29
****2004**	576	-	287,110	(7,970)	287,110	(7,970)	498.45	498.45
2005	566	(10)	268,440	(18,670)	262,354	(24,756)	474.28	463.52
2006	571	5	245,740	(22,700)	244,705	(17,649)	430.37	428.56
2007	550	(21)	240,350	(5,390)	240,094	(4,611)	437.00	436.53
2008	550	-	227,500	(12,850)	227,503	(12,591)	413.64	413.64
***2009**	547	(3)	212,510	(14,990)	211,790	(15,713)	388.50	387.18
2010	547	-			216,790	5,000		396.33
Rate Year	547				209,840			383.62

*2009 data represents 3 months actual/normal and 9 months forecast
**2002 through 2004 actual data shown in place of normal due to model estimation beginning in 2005

Electric Forecast Results
Industrial Non-Demand

	Custs	Change	Actual MWh	Change	Norm MWh	Change	Actual MWh/Cust	Norm MWh/Cust
2002	458		2,920		2,930		6.38	6.40
2003	454	(4)	2,960	40	2,959	29	6.52	6.52
2004	458	4	2,860	(100)	2,903	(56)	6.24	6.34
2005	473	15	3,040	180	2,958	55	6.43	6.25
2006	462	(11)	2,740	(300)	2,764	(194)	5.93	5.98
2007	706	244	4,490	1,750	4,487	1,723	6.36	6.36
2008	601	(105)	3,680	(810)	3,687	(800)	6.12	6.13
***2009**	566	(35)	2,860	(820)	2,840	(847)	5.05	5.02
2010	567	1			2,610	(230)		4.60
Rate Year	567				2,460			4.34

*2009 data represents 3 months actual/normal and 9 months forecast

Electric Forecast Results
Service Class 13**

	Custs	Change	Actual MWh	Change	Norm MWh	Change
2002	17		1,164,812		1,164,812	
2003	20	3	1,199,482	34,670	1,199,482	34,670
2004	20	-	1,255,800	56,318	1,255,800	56,318
2005	20	-	1,280,683	24,883	1,280,683	24,883
2006	18	(2)	1,259,242	(21,441)	1,259,242	(21,441)
2007	17	(1)	1,227,874	(31,368)	1,227,874	(31,368)
2008	16	(1)	1,135,886	(91,988)	1,135,886	(91,988)
***2009**	14	(2)	1,020,960	(114,926)	1,020,960	(114,926)
2010	13	(1)			982,960	(38,000)
Rate Year	13				983,100	

*2009 data represents 3 months actual/normal and 9 months forecast
**SC 13 sales are not normalized

Electric Forecast Results
Area Lighting**

	Custs	Change	Actual MWh	Change	Norm MWh	Change	Actual MWh/Cust	Norm MWh/Cust
2002	4,545		12,093		12,093		2.66	2.66
2003	4,646	101	12,586	493	12,586	493	2.71	2.71
2004	4,696	50	12,982	396	12,982	396	2.76	2.76
2005	4,706	10	13,167	185	13,167	185	2.80	2.80
2006	4,644	(62)	13,315	148	13,315	148	2.87	2.87
2007	4,653	9	13,391	76	13,391	76	2.88	2.88
2008	4,594	(59)	13,262	(129)	13,262	(129)	2.89	2.89
***2009**	4,563	(31)	13,287	25	13,287	25	2.91	2.91
2010	4,563	-			13,090	(197)		2.87
Rate Year	4,563				13,020			2.85

*2009 data represents 3 months actual/normal and 9 months forecast
**Lighting sales are not normalized

Electric Forecast Results
Street Lighting**

	Custs	Change	Actual MWh	Change	Norm MWh	Change	Actual MWh/Cust	Norm MWh/Cust
2002	201		23,630		23,630		117.56	117.56
2003	201	-	23,582	(48)	23,582	(48)	117.32	117.32
2004	201	-	23,286	(296)	23,286	(296)	115.85	115.85
2005	201	-	23,189	(97)	23,189	(97)	115.37	115.37
2006	201	-	23,236	47	23,236	47	115.60	115.60
2007	203	2	23,082	(154)	23,082	(154)	113.70	113.70
2008	205	2	22,921	(161)	22,921	(161)	111.81	111.81
***2009**	207	2	22,854	(67)	22,854	(67)	110.41	110.41
2010	207	-			22,830	(24)		110.29
Rate Year	207				22,830			110.29

*2009 data represents 3 months actual/normal and 9 months forecast
**Lighting sales are not normalized

Electric Forecast Results
Traffic Signals**

	Custs	Change	Actual MWh	Change	Norm MWh	Change	Actual MWh/Cust	Norm MWh/Cust
2002	320		3,509		3,509		10.97	10.97
2003	319	(1)	3,498	(11)	3,498	(11)	10.97	10.97
2004	315	(4)	3,459	(39)	3,459	(39)	10.98	10.98
2005	314	(1)	3,439	(20)	3,439	(20)	10.95	10.95
2006	313	(1)	3,433	(6)	3,433	(6)	10.97	10.97
2007	313	-	3,425	(8)	3,425	(8)	10.94	10.94
2008	309	(4)	3,052	(373)	3,052	(373)	9.88	9.88
***2009**	297	(12)	3,345	293	3,345	293	11.26	11.26
2010	297	-			3,340	(5)		11.25
Rate Year	297				3,330			11.21

*2009 data represents 3 months actual/normal and 9 months forecast
**Lighting sales are not normalized

Electric Forecast Results
Interdepartmental**

	Custs	Actual MWh	Change
2002	1	867	
2003	1	1,004	137
2004	1	1,012	8
2005	1	955	(57)
2006	1	920	(35)
2007	1	933	13
2008	1	937	4
***2009**	1	941	4
2010	1	890	(51)
Rate Year	1	890	

*2009 data represents 3 months actual/normal and 9 months forecast
**Interdepartmental sales are not normalized

Electric Forecast Results
Total Own Territory Sales (Excludes Unbilled)

	Custs	Change	Actual MWh	Change	Norm MWh	Change	Actual MWh/Cust	Norm MWh/Cust
****2002**	282,815		5,197,791		5,210,755		18.38	18.42
****2003**	286,080	3,265	5,377,302	179,511	5,367,102	156,347	18.80	18.76
****2004**	289,078	2,998	5,490,749	113,447	5,517,988	150,886	18.99	19.09
2005	292,823	3,745	5,727,623	236,874	5,580,080	62,092	19.56	19.06
2006	295,366	2,543	5,507,886	(219,737)	5,537,947	(42,133)	18.65	18.75
2007	298,385	3,019	5,625,135	117,249	5,624,638	86,691	18.85	18.85
2008	300,622	2,237	5,459,828	(165,307)	5,477,868	(146,770)	18.16	18.22
***2009**	301,030	408	5,396,237	(63,591)	5,376,047	(101,821)	17.93	17.86
2010	303,182	2,152			5,410,650	34,603		17.85
Rate Year	304,332				5,385,130			17.69

*2009 data represents 3 months actual/normal and 9 months forecast

Exhibit ___(FRP-7)

Central Hudson Gas & Electric Corporation

Gas Forecast Results*

Sheet 1	Residential Heat
Sheet 2	Residential Non-Heat
Sheet 3	Commercial Heat
Sheet 4	Commercial Non-Heat
Sheet 5	OPA
Sheet 6	Industrial
Sheet 7	Interdepartmental
Sheet 8	Total Own Territory

*Results do not include post-forecast adjustments for EEPS

Gas Forecast Results
Residential Heat

	Custs	Change	Actual Mcf	Change	Norm Mcf	Change	Actual Mcf/Cust	Norm Mcf/Cust
2002	46,463		4,334,501		4,620,825		93.29	99.45
2003	47,596	1,133	5,260,247	925,746	4,838,243	217,418	110.52	101.65
2004	48,808	1,212	5,014,217	(246,030)	5,008,697	170,453	102.73	102.62
2005	50,360	1,552	5,072,412	58,195	5,028,746	20,049	100.72	99.86
2006	51,694	1,334	4,510,474	(561,938)	4,716,606	(312,139)	87.25	91.24
2007	52,848	1,154	4,897,110	386,636	4,943,466	226,860	92.66	93.54
2008	53,866	1,018	4,976,396	79,286	4,886,584	(56,882)	92.38	90.72
***2009**	54,099	233	5,139,756	163,360	4,962,561	75,977	95.01	91.73
2010	54,529	431			5,019,467	56,906		92.05
RY	54,763				5,006,228			91.42

*2009 data represents 3 months actual/normal and 9 months forecast

Gas Forecast Results
Residential Non-Heat

	Custs	Change	Actual Mcf	Change	Norm Mcf	Change	Actual Mcf/Cust	Norm Mcf/Cust
2002	10,785		197,746		205,113		18.34	19.02
2003	10,562	(223)	221,411	23,665	211,418	6,305	20.96	20.02
2004	10,325	(237)	206,863	(14,548)	206,984	(4,434)	20.04	20.05
2005	10,129	(196)	209,100	2,237	208,033	1,050	20.64	20.54
2006	9,929	(200)	196,243	(12,857)	200,280	(7,753)	19.76	20.17
2007	9,757	(172)	199,091	2,848	200,309	28	20.40	20.53
2008	9,537	(220)	200,992	1,901	199,286	(1,022)	21.07	20.90
***2009**	9,276	(261)	200,486	(506)	197,123	(2,164)	21.61	21.25
2010	9,016	(260)			186,342	(10,781)		20.67
RY	8,873				180,819			20.38

*2009 data represents 3 months actual/normal and 9 months forecast

Gas Forecast Results
Commercial Heat

	Custs	Change	Actual Mcf	Change	Norm Mcf	Change	Actual Mcf/Cust	Norm Mcf/Cust
2002	7,364		3,541,792		3,728,716		480.96	506.34
2003	7,537	173	4,116,225	574,433	3,805,630	76,914	546.14	504.93
2004	7,747	210	3,995,862	(120,363)	3,986,326	180,695	515.79	514.56
2005	7,994	247	4,091,435	95,573	4,056,136	69,810	511.81	507.40
2006	8,217	223	3,650,967	(440,468)	3,843,736	(212,400)	444.32	467.78
2007	8,423	206	4,017,463	366,496	4,012,460	168,723	476.96	476.37
2008	8,539	116	3,996,501	(20,962)	3,934,703	(77,756)	468.02	460.78
***2009**	8,131	(409)	3,980,427	(16,074)	3,853,657	(81,046)	489.57	473.98
2010	7,931	(199)			3,802,879	(50,778)		479.48
RY	8,060				3,867,631			479.84

*2009 data represents 3 months actual/normal and 9 months forecast

Gas Forecast Results
Commercial Non-Heat

	Custs	Change	Actual Mcf	Change	Norm Mcf	Change	Actual Mcf/Cust	Norm Mcf/Cust
2002	1,144		450,045		458,399		393.40	400.70
2003	1,159	15	544,946	94,901	531,191	72,792	470.19	458.32
2004	1,161	2	573,096	28,150	572,648	41,458	493.62	493.24
2005	1,169	8	618,453	45,357	616,735	44,087	529.04	527.58
2006	1,149	(20)	581,296	(37,157)	589,627	(27,109)	505.91	513.17
2007	1,144	(5)	624,162	42,866	623,995	34,368	545.60	545.45
2008	1,162	18	637,496	13,334	635,018	11,023	548.54	546.41
***2009**	1,145	(17)	630,881	(6,616)	625,675	(9,343)	550.99	546.44
2010	1,146	1			612,309	(13,366)		534.34
RY	1,146				611,092			533.28

*2009 data represents 3 months actual/normal and 9 months forecast

Gas Forecast Results
OPA

	Custs	Change	Actual Mcf	Change	Norm Mcf	Change	Actual Mcf/Cust	Norm Mcf/Cust
2002	694		764,650		811,005		1,101.80	1,168.60
2003	709	15	895,858	131,208	814,603	3,598	1,263.55	1,148.95
2004	700	(9)	854,174	(41,684)	852,167	37,564	1,220.25	1,217.38
2005	714	14	861,728	7,554	853,712	1,545	1,206.90	1,195.68
2006	706	(8)	734,536	(127,192)	778,154	(75,558)	1,040.42	1,102.20
2007	719	13	817,265	82,729	815,557	37,403	1,136.67	1,134.29
2008	734	15	809,801	(7,464)	795,637	(19,920)	1,103.27	1,083.97
***2009**	738	4	842,211	32,410	813,954	18,317	1,141.21	1,102.92
2010	744	6			837,729	23,775		1,125.98
RY	747				838,811			1,122.91

*2009 data represents 3 months actual/normal and 9 months forecast

Gas Forecast Results
Industrial

	Custs	Change	Actual Mcf	Change	Norm Mcf	Change	Actual Mcf/Cust	Norm Mcf/Cust
2002	306		626,921		638,116		2,048.76	2,085.35
2003	304	(2)	623,075	(3,846)	588,921	(49,195)	2,049.59	1,937.24
2004	298	(6)	565,347	(57,728)	564,479	(24,442)	1,897.14	1,894.22
2005	296	(2)	529,730	(35,617)	526,361	(38,118)	1,789.63	1,778.25
2006	286	(10)	406,165	(123,565)	423,405	(102,956)	1,420.16	1,480.44
2007	276	(10)	444,728	38,563	444,555	21,150	1,611.33	1,610.71
2008	276	-	431,003	(13,725)	425,760	(18,795)	1,561.61	1,542.61
***2009**	268	(8)	439,143	8,140	428,739	2,979	1,638.59	1,599.77
2010	263	(5)			455,686	26,947		1,732.65
RY	260				447,568			1,721.42

*2009 data represents 3 months actual/normal and 9 months forecast

Gas Forecast Results
Interdepartmental

	Custs	Change	Actual Mcf	Change	Norm Mcf	Change	Actual Mcf/Cust	Norm Mcf/Cust
2002	1		23,715		23,715		23,715.00	23,715.00
2003	1	-	27,799	4,084	27,799	4,084	27,799.00	27,799.00
2004	1	-	24,311	(3,488)	24,311	(3,488)	24,311	24,311
2005	1	-	27,062	2,751	27,062	2,751	27,062	27,062
2006	1	-	21,576	(5,486)	21,576	(5,486)	21,576	21,576
2007	1	-	21,311	(265)	21,311	(265)	21,311	21,311
2008	1	-	21,217	(94)	21,217	(94)	21,217	21,217
***2009**	1	-	24,789	3,572	24,789	3,572	24,789	24,789
2010	1	-			22,650	(2,139)		22,650
RY	1				22,650			22,650

*2009 data represents 3 months actual/normal and 9 months forecast

Gas Forecast Results
Total Firm Sales

	Custs	Change	Actual Mcf	Change	Norm Mcf	Change
2002	66,757		9,939,370		10,485,890	
2003	67,868	1,111	11,689,561	1,750,191	10,817,806	331,916
2004	69,040	1,172	11,233,870	(455,691)	11,215,612	397,806
2005	70,663	1,623	11,409,920	176,050	11,316,786	101,174
2006	71,982	1,319	10,101,257	(1,308,663)	10,573,385	(743,401)
2007	73,168	1,186	11,021,130	919,873	11,061,652	488,267
2008	74,116	948	11,073,406	52,276	10,898,206	(163,447)
***2009**	73,658	(458)	11,257,693	184,287	10,906,498	8,292
2010	73,630	(27)			10,937,062	30,564
RY	73,850				10,974,799	

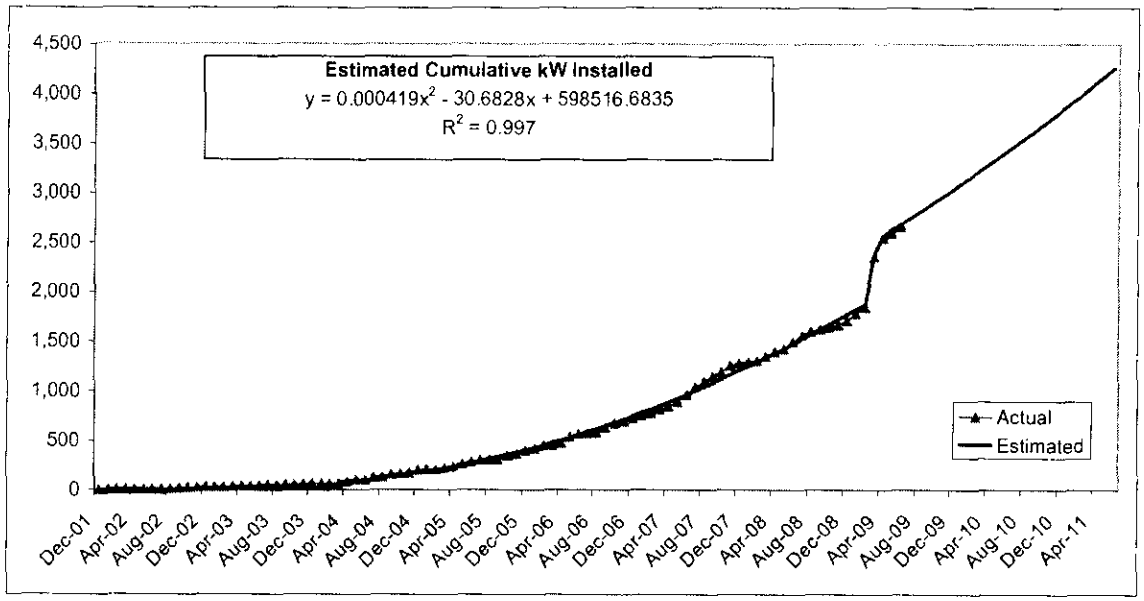
*2009 data represents 3 months actual/normal and 9 months forecast

Central Hudson Gas & Electric Corporation

Actual Monthly Net of Fuel Revenue

		January	February	March	April	May	June	July	August	September	October	November	December	Total
2006	S.C. No. 8	$ 230,076	$ 98,144	$ 53,152	$ 33,114	$ 75,926	$ 38,194	$ 59,530	$ 14,251	$ 61,794	$ 179,321	$ 148,715	$ 141,011	$ 1,133,228
	S.C. No. 9 - Standby	$ -	$ 16,025	$ 6,210	$ 488	$ 2,885	$ 334	$ 3,867	$ 263	$ 365	$ 8,771	$ 12	$ 488	$ 39,728
	S.C. No. 9 - Trans.	$ 37,877	$ 48,550	$ 95,723	$ 64,738	$ 48,031	$ 37,252	$ 36,118	$ 37,231	$ 37,220	$ 58,831	$ 67,620	$ 86,249	$ 655,439
	Curtailment Penalty	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Imbalance Penalty	$ -	$ 464	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 464
	Dynegy	$ 952	$ -	$ -	$ 934	$ 4,822	$ 7,187	$ 15,958	$ 826	$ -	$ 2,013	$ -	$ -	$ 32,692
	Dynegy Standby	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Dynegy OBA Penalty	$ 7,955	$ -	$ -	$ 205	$ 715	$ -	$ 845	$ -	$ -	$ -	$ -	$ 10,755	$ 20,475
	Danskammer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Danskammer Tolling	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Roseton	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Roseton Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Turbine	$ -	$ -	$ -	$ 10	$ -	$ -	$ 3,260	$ 6,910	$ -	$ -	$ -	$ -	$ 10,179
	Total	$ 276,860	$ 163,183	$ 155,085	$ 99,488	$ 132,378	$ 82,967	$ 119,597	$ 59,481	$ 99,379	$ 248,937	$ 216,347	$ 238,503	$ 1,892,206
2007	S.C. No. 8	$ 316,415	$ 69,694	$ 286,838	$ 119,631	$ 58,126	$ 35,208	$ 32,876	$ 27,686	$ 34,552	$ 88,036	$ 180,096	$ 382,851	$ 1,611,989
	S.C. No. 9 - Standby	$ 840	$ 73	$ 1,249	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,162
	S.C. No. 9 - Trans.	$ 70,239	$ 49,196	$ 108,589	$ 58,743	$ 37,897	$ 35,075	$ 36,390	$ 34,920	$ 36,034	$ 43,070	$ 85,291	$ 101,523	$ 696,967
	Curtailment Penalty	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 394	$ -	$ 394
	Imbalance Penalty	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 71	$ 71
	Dynegy	$ -	$ -	$ 71	$ -	$ -	$ 20,044	$ 5,496	$ 22,327	$ 4,515	$ 7,120	$ 2,165	$ -	$ 61,738
	Dynegy Standby	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Dynegy OBA Penalty	$ 795	$ -	$ 4,290	$ -	$ -	$ 9,890	$ -	$ -	$ -	$ 860	$ -	$ -	$ 15,835
	Danskammer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Danskammer Tolling	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Roseton	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Roseton Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Turbine	$ -	$ 1,133	$ 2,475	$ -	$ -	$ -	$ 2,366	$ -	$ 7,172	$ -	$ -	$ -	$ 13,146
	Total	$ 388,290	$ 120,096	$ 403,513	$ 178,374	$ 96,023	$ 100,217	$ 77,128	$ 84,912	$ 82,274	$ 119,086	$ 267,947	$ 484,445	$ 2,402,303
2008	S.C. No. 8	$ 296,610	$ 201,342	$ 200,493	$ 245,954	$ 21,067	$ 7,584	$ 10,479	$ 49,961	$ (5,952)	$ 102,882	$ 73,746	$ 110,167	$ 1,314,333
	S.C. No. 9 - Standby	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	S.C. No. 9 - Trans.	$ 74,474	$ 79,527	$ 115,774	$ 43,339	$ 51,509	$ 37,811	$ 36,497	$ 40,374	$ 40,321	$ 89,387	$ 87,154	$ 115,067	$ 791,234
	Curtailment Penalty	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Imbalance Penalty	$ 211	$ 138	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 349
	Dynegy	$ 186	$ -	$ 1,460	$ 1,984	$ 663	$ 12,444	$ 29,925	$ 7,250	$ 2,435	$ 922	$ 260	$ 97	$ 57,626
	Dynegy Standby	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Dynegy OBA Penalty	$ -	$ -	$ -	$ 250	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 250
	Danskammer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Danskammer Tolling	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Roseton	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Roseton Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Turbine	$ -	$ -	$ 2,089	$ 57	$ -	$ 1,834	$ 5,300	$ 1,544	$ -	$ -	$ -	$ -	$ 10,824
	Total	$ 371,481	$ 281,007	$ 319,816	$ 291,584	$ 73,238	$ 59,673	$ 82,201	$ 99,129	$ 36,804	$ 173,191	$ 161,160	$ 225,331	$ 2,174,616
2009	S.C. No. 8	$ 16,206	$ 426,337	$ 383,075										$ 825,618
	S.C. No. 9 - Standby	$ -	$ -	$ -										$ -
	S.C. No. 9 - Trans.	$ 83,930	$ 93,009	$ 113,309										$ 290,248
	Curtailment Penalty	$ -	$ -	$ -										$ -
	Imbalance Penalty	$ 50	$ 281	$ -										$ 331
	Dynegy	$ 108	$ 6	$ -										$ 114
	Dynegy Standby	$ -	$ -	$ -										$ -
	Dynegy OBA Penalty	$ -	$ 5,165	$ -										$ 5,165
	Danskammer	$ -	$ -	$ -										$ -
	Danskammer Tolling	$ -	$ -	$ -										$ -
	Roseton	$ -	$ -	$ -										$ -
	Roseton Adjustment	$ -	$ -	$ -										$ -
	Turbine	$ -	$ -	$ 900										$ 900
	Total	$ 100,293	$ 524,798	$ 497,284	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,122,376

Central Hudson Gas & Electric Corporation
Cumulative PV Net Metered kW Installed



Cumulative Residential kW Installed

	January	February	March	April	May	June	July	August	September	October	November	December
2009	1,372.24	1,420.41	1,815.89	1,983.14	2,026.56	2,069.14	2,113.80	2,159.08	2,203.43	2,249.94	2,295.52	2,343.19
2010	2,391.54	2,435.74	2,485.25	2,533.69	2,584.43	2,634.09	2,686.07	2,738.66	2,790.10	2,843.92	2,896.59	2,951.56
2011	3,007.16	3,057.98	3,114.80	3,170.40	3,228.38	3,285.13	3,344.42	3,404.25	3,462.84	3,523.91	3,583.66	3,645.95

Cumulative Non-Residential kW Installed

	January	February	March	April	May	June	July	August	September	October	November	December
2009	409.89	424.28	542.41	592.37	605.34	618.06	631.40	644.92	658.17	672.06	685.68	699.91
2010	714.36	727.56	742.35	756.82	771.97	786.81	802.33	818.04	833.41	849.48	865.21	881.64
2011	898.24	913.42	930.40	947.00	964.32	981.27	998.98	1,016.85	1,034.36	1,052.60	1,070.44	1,089.05

Lost kWh - Residential
(in excess of 800 kW prior to July 1, 2009)
(in excess of 1,340 kW after July 1, 2009)
(in excess of 2,360 kW after July 1, 2010)

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2009	70,650	67,880	112,100	123,600	131,780	131,380	101,090	105,320	105,930	113,800	114,250	122,520	1,300,300
2010	127,030	118,470	135,790	135,790	145,050	144,860	81,170	86,090	87,960	95,920	97,590	105,980	1,361,700
2011	111,170	104,700	121,230	122,340	131,840	132,720	142,680	148,270	148,780	159,450	159,710	170,850	1,653,740

Lost kWh - Non-Residential
(in excess of 800 kW prior to July 1, 2009)
(in excess of 1,340 kW after July 1, 2009)
(in excess of 2,360 kW after July 1, 2010)

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2009	21,100	20,280	33,480	36,920	39,360	39,240	30,190	31,460	31,640	33,990	34,130	36,600	388,390
2010	37,950	35,390	40,560	40,560	43,330	43,270	24,250	25,710	26,270	28,650	29,150	31,660	406,750
2011	33,210	31,270	36,210	36,540	39,380	39,640	42,620	44,290	44,440	47,630	47,700	51,030	493,960

Lost Revenue (Including Rev Tax) - Residential
(in excess of 800 kW prior to July 1, 2009)
(in excess of 1,340 kW after July 1, 2009)
(in excess of 2,360 kW after July 1, 2010)

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2009	$ 3,090	$ 2,967	$ 4,900	$ 5,412	$ 5,770	$ 5,749	$ 5,494	$ 5,729	$ 5,760	$ 6,189	$ 6,210	$ 6,660	$ 63,930
2010	$ 6,906	$ 6,445	$ 7,386	$ 7,386	$ 7,888	$ 7,877	$ 4,409	$ 4,686	$ 4,788	$ 5,218	$ 5,310	$ 5,760	$ 74,059
2011	$ 6,046	$ 5,688	$ 6,588	$ 6,650	$ 7,172	$ 7,212	$ 7,755	$ 8,062	$ 8,092	$ 8,665	$ 8,686	$ 9,289	$ 89,905

Lost Revenue (Including Rev Tax) - Non-Residential
(in excess of 800 kW prior to July 1, 2009)
(in excess of 1,340 kW after July 1, 2009)
(in excess of 2,360 kW after July 1, 2010)

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2009	$ 1,882	$ 1,811	$ 2,987	$ 3,294	$ 3,519	$ 3,509	$ 2,875	$ 2,998	$ 3,008	$ 3,233	$ 3,243	$ 3,478	$ 35,837
2010	$ 3,611	$ 3,366	$ 3,857	$ 3,857	$ 4,123	$ 4,123	$ 2,312	$ 2,445	$ 2,496	$ 2,732	$ 2,772	$ 3,008	$ 38,702
2011	$ 3,161	$ 2,977	$ 3,448	$ 3,478	$ 3,744	$ 3,775	$ 4,051	$ 4,215	$ 4,225	$ 4,532	$ 4,542	$ 4,859	$ 47,007

Central Hudson Gas & Electric Corporation

Estimated Effect of Poposed Electric Revenue Increase

Schedule A	Electric Interclass Revenue Allocation
Schedule B	Determination of Rate Case Revenue with Proposed Revenue Increase

Central Hudson Gas & Electric Corporation

Electric Revenue Allocation
Min .75x, Max 1.25x

Twelve Months Ending June 30, 2011

	(1) Initial Net Income	(2) Rate of Return	(3) 6.28% +/- 15%	(4) Adj Net Income	(5) Adj to Initial Net Income	(6) (5)-(1) Difference	(7) (6)/ 60385 Adj FIT/SIT	Excludes Revenue Taxes (8) Base Rates	(9) Base Rev (2) Increase	(10) (7)+(9) Total Increase	(11) (10)/(8) % Increase Unadjusted
Total	$ 43,593	6.28%		$ 43,188	$ 43,593			$ 250,398	$ 14,841	$ 14,841	5.93%
SC 1 Residential	$ 28,454	6.15%	6.15%	$ 28,454	$ 28,734	$ 280	$ 464	$ 162,161	$ 9,611	$ 10,075	6.21%
SC 2 Non Demand	$ (508)	-1.10%	5.34%	$ 2,465	$ 2,469	$ 2,997	$ 4,964	$ 12,156	$ 720	$ 5,684	46.76%
SC 2 Secondary	$ 12,060	11.64%	7.22%	$ 7,495	$ 7,509	$ (4,511)	$ (7,471)	$ 51,141	$ 3,031	$ (4,440)	-8.68%
SC 2 Primary	$ 676	5.35%	5.35%	$ 676	$ 683	$ 7	$ 11	$ 4,682	$ 278	$ 289	6.16%
SC 3 Primary	$ 1,210	8.91%	7.22%	$ 981	$ 990	$ (220)	$ (364)	$ 5,608	$ 332	$ (31)	-0.56%
SC 5 Area Lighting	$ 257	4.76%	5.34%	$ 400	$ 404	$ 47	$ 78	$ 1,585	$ 94	$ 172	10.86%
SC 6 Residential TOU	$ 389	8.34%	7.22%	$ 337	$ 340	$ (49)	$ (81)	$ 1,745	$ 103	$ 23	1.30%
SC 8 Street Lighting	$ 612	6.57%	6.57%	$ 612	$ 618	$ 6	$ 10	$ 4,281	$ 254	$ 264	6.16%
SC 9 Traffic Signals	$ 82	17.14%	7.22%	$ 26	$ 26	$ (56)	$ (59)	$ 202	$ 12	$ (47)	-23.27%
SC 13 Substation	$ 291	4.01%	5.34%	$ 387	$ 391	$ 100	$ 166	$ 1,006	$ 118	$ 284	14.23%
SC 13 Transmission	$ (39)	-0.12%	5.34%	$ 1,335	$ 1,348	$ 1,378	$ 2,281	$ 4,833	$ 286	$ 2,568	53.13%

	(12) % Increase Constrained	(13) % Increase Unadjusted	(14) (6)*(12) $ Increase Constrained	(15) (6)*(13) $ Increase Unadjusted	(16) (14)+(15) Total	(17) (10)-(16) Revenue Shortfall	(18) (16)+(17) Revenue $ Increase	(19) (18)/(8) Revenue % Increase	(20) Revenue Adjustment	(21) (18)+(20) Adj $ Increase	(22) (21)/(8) Final % Increase	(23) (18)/(18) System Increase as a % of System
			$ 4,134	$ 10,627	$ 14,761	$ 80	$ 14,841	5.93%		$ 14,841	5.93%	100.00%
SC 1 Residential	0.00%	6.21%	$ -	$ 10,075	$ 10,075	$ 55	$ 10,130	6.25%		$ 10,130	6.25%	68.25%
SC 2 Non Demand	7.41%	0.00%	$ 901	$ -	$ 901	$ 5	$ 905	7.45%		$ 905	7.45%	6.10%
SC 2 Secondary	4.45%	0.00%	$ 2,273	$ -	$ 2,273	$ 12	$ 2,286	4.47%		$ 2,286	4.47%	15.40%
SC 2 Primary	0.00%	6.16%	$ -	$ 289	$ 289	$ 2	$ 290	6.20%		$ 290	6.20%	1.95%
SC 3 Primary	4.45%	0.00%	$ 249	$ -	$ 249	$ 1	$ 251	4.47%		$ 251	4.47%	1.69%
SC 5 Area Lighting	7.41%	0.00%	$ 118	$ -	$ 118	$ 1	$ 118	7.45%		$ 118	7.45%	0.80%
SC 6 Residential TOU	4.45%	0.00%	$ 78	$ -	$ 78	$ 0	$ 78	4.47%		$ 78	4.47%	0.53%
SC 8 Street Lighting	0.00%	6.16%	$ -	$ 264	$ 264	$ 1	$ 265	6.19%		$ 265	6.19%	1.79%
SC 9 Traffic Signals	4.45%	0.00%	$ 9	$ -	$ 9	$ 0	$ 9	4.47%		$ 9	4.47%	0.06%
SC 13 Substation	7.41%	0.00%	$ 148	$ -	$ 148	$ 1	$ 149	7.45%		$ 149	7.45%	1.00%
SC 13 Transmission	7.41%	0.00%	$ 358	$ -	$ 358	$ 2	$ 360	7.45%		$ 360	7.45%	2.43%

	Increase	
Avg.		5.93%
Min	0.75x	4.45%
Max	1.25x	7.41%

Adjustment for Revenue Unbundled to MFCs

	Base Rev (2) Increase	Delivery MWh	RY MFC Admin/ kWh	Est MFC Admin Revenue	RY MFC Supply/ kWh	Est MFC Supply Revenue	Total Estimated MFC Revenue	MFC Revenue from Current Base Rates	MFC Adjustment to Rate Increase	Adj Base Rev Increase	Adj Increase as % of System	Final % Increase	Current MFC Admin/ kWh	Current MFC Supply/ kWh
Total	$ 14,841			$ 6,874		$ 9,467	$ 16,341	$ 14,099	$ (2,242)	$ 12,599	100.00%	5.03%		
SC 1 Residential	$ 10,130	2,018,392	$ 0.00292	$ 5,894	$ 0.00396	$ 7,993	$ 13,887	$ 12,090	$ (1,797)	$ 8,333	66.14%	5.14%	$ 0.00209	$ 0.00396
SC 2 Non Demand	$ 905	153,255	$ 0.00433	$ 664	$ 0.00580	$ 889	$ 1,553	$ 1,218	$ (335)	$ 570	4.53%	4.69%	$ 0.00283	$ 0.00512
SC 2 Secondary	$ 2,286	1,448,391	$ 0.00019	$ 275	$ 0.00026	$ 376	$ 651	$ 564	$ (87)	$ 2,199	17.45%	4.30%	$ 0.00014	$ 0.00025
SC 2 Primary	$ 290	245,144	$ 0.00002	$ 5	$ 0.00002	$ 5	$ 10	$ 7	$ (3)	$ 287	2.28%	6.13%	$ 0.00001	$ 0.00002
SC 3 Primary	$ 251	275,997	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 251	1.99%	4.47%	$ -	$ -
SC 5 Area Lighting	$ 118	13,020	$ -	$ -	$ 0.01077	$ 140	$ 140	$ 137	$ (3)	$ 115	0.92%	7.26%	$ -	$ 0.01055
SC 6 Residential TOU	$ 78	29,000	$ 0.00125	$ 36	$ 0.00169	$ 49	$ 85	$ 68	$ (17)	$ 61	0.48%	3.50%	$ 0.00081	$ 0.00152
SC 8 Street Lighting	$ 265	22,830	$ -	$ -	$ 0.00026	$ 6	$ 6	$ 6	$ -	$ 265	2.10%	6.19%	$ -	$ 0.00026
SC 9 Traffic Signals	$ 9	3,330	$ -	$ -	$ 0.00274	$ 9	$ 9	$ 9	$ -	$ 9	0.07%	4.47%	$ -	$ 0.00270
SC 13 Substation	$ 149	165,840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 149	1.18%	7.45%	$ -	$ -
SC 13 Transmission	$ 360	817,460	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 360	2.86%	7.45%	$ -	$ -

Central Hudson Gas & Electric Corporation
Electric Interclass Revenue Allocation
Determination of Base Rate Revenue with Proposed Revenue Increase
Twelve Months Ending June 30, 2011

	Present Rate Base Revenues ($000)						Proposed Revenue Increase ($000)				Total Revenue After Increase ($000)				
	Sales MWh	Revenue Tax Factor	Base Rates	MFC Revenue	Revenue Tax	Total	Base Rates	MFC Revenue	Revenue Tax	Total	Base Rates	MFC Revenue	Revenue Tax	Total	Percent Total Increase
Service Classification No. 1															
Residential	2,018,392	0.02280	$ 150,070	$ 12,090	$ 3,672	$ 165,832	$ 8,332	$ 1,797	$ 251	$ 10,380	$ 158,402	$ 13,887	$ 3,923	$ 176,212	6.26%
Service Classification No. 2															
Non-demand	153,255	0.00230	$ 10,938	$ 1,218	$ 28	12,184	$ 570	$ 335	$ 22	$ 927	$ 11,509	$ 1,553	$ 50	$ 13,112	7.61%
Demand - Secondary	1,446,391	0.00230	$ 50,576	$ 564	$ 117	51,257	$ 2,198	$ 87	$ 57	$ 2,342	$ 52,774	$ 651	$ 174	$ 53,599	4.57%
Demand - Primary	245,144	0.00230	$ 4,675	$ 7	$ 11	$ 4,693	$ 289	$ 3	$ 7	$ 299	$ 4,964	$ 10	$ 18	$ 4,992	6.37%
	1,844,790		$ 66,190	$ 1,790	$ 155	$ 68,134	$ 3,057	$ 424	$ 86	$ 3,568	$ 69,247	$ 2,214	$ 241	$ 71,702	5.24%
Service Classification No. 3															
Large Primary	275,997	0.00230	$ 5,608	$ -	$ 13	$ 5,621	$ 252	$ -	$ 6	$ 258	$ 5,859	$ -	$ 19	$ 5,879	4.59%
Service Classification No. 5															
Area Lighting	13,020	0.02280	$ 1,452	$ 137	$ 36	$ 1,625	$ 115	$ 3	$ 3	$ 121	$ 1,567	$ 140	$ 39	$ 1,746	7.45%
Service Classification No. 6															
Residential Time of Use	29,000	0.02280	$ 1,678	$ 68	$ 40	$ 1,786	$ 61	$ 17	$ 2	$ 81	$ 1,740	$ 85	$ 42	$ 1,866	4.51%
Service Classification No. 8															
Street Lighting	22,830	0.00230	$ 4,275	$ 6	$ 10	$ 4,291	$ 265	$ (0)	$ 7	$ 272	$ 4,540	$ 6	$ 17	$ 4,563	6.33%
Service Classification No. 9															
Traffic Signals	3,330	0.00230	$ 193	$ 9	$ 1	$ 202	$ 9	$ (0)	$ -	$ 9	$ 202	$ 9	$ 1	$ 212	4.64%
Service Classification No. 13															
Substation	165,640	0.00230	$ 1,999	$ -	$ 5	$ 2,004	$ 148	$ -	$ 4	$ 152	$ 2,147	$ -	$ 9	$ 2,156	7.58%
Transmission	817,460	0.00230	$ 4,708	$ -	$ 135	$ 4,844	$ 359	$ -	$ 9	$ 368	$ 5,068	$ -	$ 144	$ 5,212	7.60%
	983,100		6,708	0	$ 140	$ 6,847	$ 507	$ -	$ 13	$ 520	$ 7,215	$ -	$ 153	$ 7,368	7.60%
Total Filed Rates	5,190,459		$ 236,173	$ 14,100	$ 4,066	$ 254,339	$ 12,599	$ 2,241	$ 368	$ 15,208	$ 248,772	$ 16,341	$ 4,434	$ 269,548	5.98%
Interdepartmental	890		$ 3		$ -	$ 3	$ (1)	$ -	$ -	$ (3)	$ 2	$ -	$ -	$ -	
SC No. 1 Unbilled	(430)		$ (17)			$ (17)	$ (3)	$ -	$ -	$ (3)	$ (19)	$ -	$ -	$ (19)	
SC No. 2 Unbilled	(90)		$ (2)			$ (2)	$ 1	$ -	$ -	$ 1	$ (0)	$ -	$ -	$ (0)	
Other Revenues	0	0.00837	$ 8,366		$ 70	$ 8,436	$ 224	$ -	$ 7	$ 231	$ 8,590	$ -	$ 77	$ 8,667	
Total	5,190,829		$ 244,524	$ 14,100	$ 4,136	$ 262,760	$ 12,821	$ 2,241	$ 375	$ 15,435	$ 257,345	$ 16,341	$ 4,511	$ 278,195	5.87%

Revenue Tax on Increase	$ 373
Total Revenue Increase	$ 15,430
Revenue Tax Rate	2.48%

Exhibit ___ (FRP-10)
Schedule B

Central Hudson Gas & Electric Corporation

Estimated Effect of Poposed Gas Revenue Increase

Schedule A	Gas Interclass Revenue Allocation
Schedule B	Determination of Rate Case Revenue with Proposed Revenue Increase

Central Hudson Gas & Electric Corporation

Gas Revenue Allocation

Min .75x, Max 1.25x

Twelve Months Ending June 30, 2011

	(1) Initial Net Income	(2) Rate of Return	(3) 6.34% +/- 15%	(4) Adj Net Income	(5) Adj to Initial Net Income	(6) (5)-(1) Difference	(7) (6)/.60385 Adj FIT/SIT	Excludes Revenue Taxes (8) Base Rates	(9) Base Rev Increase	(10) (7)+(9) Total Increase	(11) (10)/(8) % Increase Unadjusted
Total	$ 12,046	6.34%		$ 11,920	$ 12,046			$ 64,846	$ 5,830	$ 5,830	8.99%
SC 1& 12 Residential Heat	$ 8,256	7.24%	7.24%								
SC 1& 12 Residential Nonheat	$ (101)	-0.77%	5.39%								
Total SC 1 & 12 Residential	$ 8,155	6.42%	6.42%	$ 8,155	$ 8,241	$ 86	$ 143	$ 41,866	$ 3,764	$ 3,907	9.33%
SC 2, 6, & 13 Com & Ind Heat	$ 2,812	5.30%	5.39%								
SC 2, 6, & 13 Com & Ind Nonheat	$ 689	12.04%	7.29%								
Total SC 2, 6, & 13	$ 3,502	5.96%	5.96%	$ 3,502	$ 3,539	$ 37	$ 61	$ 20,980	$ 1,886	$ 1,947	9.28%
SC 11 Transmission	$ 315	15.92%	7.29%	$ 144	$ 146	$ (169)	$ (281)	$ 1,276	$ 115	$ (166)	-13.00%
SC 11 Distribution	$ 5	1.74%	5.39%	$ 15	$ 15	$ 10	$ 17	$ 73	$ 7	$ 24	32.37%
SC 11 DLM	$ 70	3.59%	5.39%	$ 104	$ 105	$ 36	$ 59	$ 652	$ 59	$ 118	18.12%

	(12) % Increase Constrained	(13) % Increase Unadjusted	(14) (8)*(12) $ Increase Constrained	(15) (8)*(13) $ Increase Unadjusted	(16) (14)+(15) Total	(17) (10)-(16) Revenue Shortfall	(18) (16)+(17) Revenue $ Increase	(19) (18)/(8) Revenue % Increase	(20) Revenue Adjustment	(21) (18)+(20) Adj $ Increase	(22) (21)/(8) Final % Increase	(23) (19)/(19) System Increase as a % of System
			$ 167	$ 5,854	$ 6,022	$ (192)	$ 5,830	8.99%	$ -	$ 5,830	8.99%	100.00%
SC 1& 12 Residential Heat												
SC 1& 12 Residential Nonheat												
Total SC 1 & 12 Residential	0.00%	9.33%	$ -	$ 3,907	$ 3,907	$ (124)	$ 3,782	9.03%	$ -	$ 3,782	9.03%	64.86%
SC 2, 6, & 13 Com & Ind Heat												
SC 2, 6, & 13 Com & Ind Nonheat												
Total SC 2, 6, & 13	0.00%	9.28%	$ -	$ 1,947	$ 1,947	$ (62)	$ 1,886	8.99%	$ -	$ 1,886	8.99%	32.34%
SC 11 Transmission	6.74%	0.00%	$ 86	$ -	$ 86	$ (3)	$ 83	6.53%	$ -	$ 83	6.53%	1.43%
SC 11 Distribution	11.24%	0.00%	$ 8	$ -	$ 8	$ (0)	$ 8	10.88%	$ -	$ 8	10.88%	0.14%
SC 11 DLM	11.24%	0.00%	$ 73	$ -	$ 73	$ (2)	$ 71	10.88%	$ -	$ 71	10.88%	1.22%

			$	(191.59)
			$	6,021.59
	Increase			-3.18%
Avg.		8.99%		
Min	0.75x	6.74%		
Max	1.25x	11.24%		

Adjustment for Revenue Unbundled to MFCs

	Base Rev Increase	MFC Admin Mcf	MFC Admin per Ccf	Est MFC Admin Revenue	MFC Supply Mcf	MFC Supply per Ccf	Est MFC Supply Revenue	Total Estimated MFC	MFC Revenue at present MFC Rates	MFC Adjustment to Rate Increase	Adj Base Rev Increase	% Increase Excl. MFC
Total	$ 5,830			$ 1,741			$ 2,223	$ 3,964	$ 3,427	$ (537)	$ 5,293	8.7%
SC 1 & 12	$ 3,782	5,177,058	$ 0.02900	$ 1,501	5,177,058	$ 0.02123	$ 1,099	$ 2,600	$ 2,333	$ (267)	$ 3,515	9.0%
SC 2, 6, & 13	$ 1,886	5,775,404	$ 0.00415	$ 240	5,775,404	$ 0.01947	$ 1,124	$ 1,364	$ 1,094	$ (270)	$ 1,616	8.2%
SC 11 Transmission	$ 83										$ 83	6.5%
SC 11 Distribution	$ 8										$ 8	10.9%
SC 11 DLM	$ 71										$ 71	10.9%

Exhibit __ (FRP-11)
Schedule A

Central Hudson Gas & Electric Corporation
Determination of Base Rate Revenue with Proposed Revenue Increase
Twelve Months Ending June 30, 2011

	Revenue at Present Rates ($000)							Proposed Revenue Increase ($000)				Total Revenue After Increase ($000)				
	Customer Months	Sales (Mcf.)	Revenue Tax Factor	Base Rates	MFC	Revenue Tax	Total	Base Rates	MFC	Revenue Tax	Total	Base Rates	MFC	Revenue Tax	Total	% Overall Increase
S.C. Nos. 1 & 12 - Billed	784,274	5,177,058	0.02578	$ 39,532	$ 2,333	$ 1,079	$ 42,945	$ 2,594	$ 267	$ 87	$ 2,948	$ 42,126	$ 2,600	$ 1,166	$ 45,892	6.86%
S.C. No. 2, 6 & 13 - Billed	121,905	5,752,754	0.00516	$ 19,835	$ 1,090	$ 108	$ 21,033	$ 587	$ 270	$ 26	$ 883	$ 20,423	$ 1,360	$ 134	$ 21,916	4.20%
S.C. No. 11 - Transmission	36	1,355,420	0.00516	$ 1,276	$ -	$ 7	$ 1,282	$ 83	$ -	$ 3	$ 86	$ 1,359	$ -	$ 10	$ 1,369	6.73%
S.C. No. 11 - Distribution	12	62,720	0.00516	$ 73	$ -	$ 0	$ 73	$ 8	$ -	$ -	$ 8	$ 81	$ -	$ 0	$ 81	10.82%
S.C. No. 11 - DLM	12	811,237	0.00516	$ 652	$ -	$ 3	$ 655	$ 71	$ -	$ 2	$ 73	$ 723	$ -	$ 5	$ 728	11.13%
Unbilled	-	(20,210)		$ (267)	$ -	$ -	$ (267)	$ -	$ -	$ -	$ -	$ (267)	$ -	$ -	$ (267)	0.00%
Total Firm	886,239	13,138,979		$ 61,101	$ 3,423	$ 1,198	$ 65,721	$ 3,343	$ 537	$ 118	$ 3,998	$ 64,444	$ 3,960	$ 1,316	$ 69,719	6.08%
																--
																--
Interdepartmental	12	22,650		$ 50	$ 4	$ -	$ 54	$ -	$ -	$ -	$ -	$ 50	$ 4	$ -	$ 54	
Interruptible	648	1,669,170		$ 1,940	$ -	$ 10	$ 1,950	$ -	$ -	$ -	$ -	$ 1,940	$ -	$ 10	$ 1,950	
Total Own Territory	886,899	14,830,799		$ 63,091	$ 3,427	$ 1,208	$ 67,725	$ 3,343	$ 537	$ 118	$ 3,998	$ 66,434	$ 3,964	$ 1,326	$ 71,723	5.90%

Revenue Tax on Increase	$ 120
Total Revenue Increase	$ 4,076
Revenue Tax Rate	3.03%

Exhibit ___ (FRP-11)
Schedule B

Central Hudson Gas & Electric Corporation

Summary of Present and Proposed Electric Rates

Schedule A	Merchant Function Charges
Schedule B	Electric Bill Credit
Schedule C	Service Classification No. 1
Schedule D	Service Classification No. 2
Schedule E	Service Classification No. 3
Schedule F	Service Classification No. 5
Schedule G	Service Classification No. 6
Schedule H	Service Classification No. 8
Schedule I	Service Classification No. 9
Schedule J	Service Classification No. 13

Central Hudson Gas & Electric Corporation

Electric Commodity Related Merchant Function Charges
($/kWh)

Present Base MFC Rates

	MFC Administration Charge	MFC Supply Charge	MFC Total
S.C. No. 1	$ 0.00209	$ 0.00390	$ 0.00599
S.C. No. 2 ND	$ 0.00283	$ 0.00512	$ 0.00795
S.C. No. 2 PD	$ 0.00001	$ 0.00002	$ 0.00003
S.C. No. 2 SD	$ 0.00014	$ 0.00025	$ 0.00039
S.C. No. 3	$ -	$ -	$ -
S.C. No. 5	$ -	$ 0.01055	$ 0.01055
S.C. No. 6	$ 0.00081	$ 0.00152	$ 0.00233
S.C. No. 8	$ -	$ 0.00028	$ 0.00028
S.C. No. 9	$ -	$ 0.00270	$ 0.00270
S.C. No. 13 S	$ -	$ -	$ -
S.C. No. 13 T	$ -	$ -	$ -

Proposed Base MFC Rates

	MFC Administration Charge	MFC Supply Charge	MFC Total
S.C. No. 1	$ 0.00292	$ 0.00396	$ 0.00688
S.C. No. 2 ND	$ 0.00433	$ 0.00580	$ 0.01013
S.C. No. 2 PD	$ 0.00002	$ 0.00002	$ 0.00004
S.C. No. 2 SD	$ 0.00019	$ 0.00026	$ 0.00045
S.C. No. 3	$ -	$ -	$ -
S.C. No. 5	$ -	$ 0.01077	$ 0.01077
S.C. No. 6	$ 0.00125	$ 0.00169	$ 0.00294
S.C. No. 8	$ -	$ 0.00028	$ 0.00028
S.C. No. 9	$ -	$ 0.00274	$ 0.00274
S.C. No. 13 S	$ -	$ -	$ -
S.C. No. 13 T	$ -	$ -	$ -

Central Hudson Gas & Electric Corporation

Electric Bill Credit

Present EBC Rates

	Bill Credit Per kWh	Bill Credit Per kW
S.C. No. 1	$ (0.00682)	$ -
S.C. No. 2 ND	$ (0.00658)	$ -
S.C. No. 2 PD	$ (0.00131)	$ -
S.C. No. 2 SD	$ (0.00209)	$ -
S.C. No. 3	$ -	$ (0.52)
S.C. No. 5	$ (0.00917)	$ -
S.C. No. 6	$ (0.00345)	$ -
S.C. No. 8	$ (0.01185)	$ -
S.C. No. 9	$ (0.00354)	$ -
S.C. No. 13 S	$ -	$ (0.59)
S.C. No. 13 T	$ -	$ (0.31)

Proposed EBC Rates

	Bill Credit Per kWh	Bill Credit Per kW
S.C. No. 1	$ (0.00348)	$ -
S.C. No. 2 ND	$ (0.00371)	$ -
S.C. No. 2 PD	$ (0.00063)	$ -
S.C. No. 2 SD	$ (0.00104)	$ -
S.C. No. 3	$ -	$ (0.29)
S.C. No. 5	$ (0.00469)	$ -
S.C. No. 6	$ (0.00197)	$ -
S.C. No. 8	$ (0.00574)	$ -
S.C. No. 9	$ (0.00180)	$ -
S.C. No. 13 S	$ -	$ (0.31)
S.C. No. 13 T	$ -	$ (0.16)

Central Hudson Gas & Electric Corporation

Summary of Present and Proposed Electric Rates

Single Phase Residential Service

Service Classification No. 1 - P.S.C. No. 15

Present Rate		Proposed Rate	
Monthly Charge	$ 18.00	Monthly Charge	$ 22.00
Monthly Energy Delivery Charge per kWh	$ 0.04691	Monthly Energy Delivery Charge per kWh	$ 0.04494

Minimum Monthly Charge:

The Customer Charge

Minimum Monthly Charge:

The Customer Charge

Central Hudson Gas & Electric Corporation

Summary of Present and Proposed Electric Rates

General Service

Service Classification No. 2 - P.S.C. No. 15

Present Rate			Proposed Rate		
Monthly Charge			Monthly Charge		
Non-Demand Metered		$ 30.00	Non-Demand Metered		$ 32.00
Demand Metered	Primary	$ 160.00	Demand Metered	Primary	$ 210.00
	Secondary	$ 50.00		Secondary	$ 64.00
Monthly Energy Delivery Charge per kWh			Monthly Energy Delivery Charge per kWh		
Non-Demand Metered		$ 0.00340	Non-Demand Metered		$ 0.00259
Demand Metered	Primary	$ 0.00135	Demand Metered	Primary	$ 0.00141
	Secondary	$ 0.00522		Secondary	$ 0.00524
Monthly Demand Delivery Charge			Monthly Demand Delivery Charge		
Demand Metered	Primary	$ 6.30	Demand Metered	Primary	$ 6.57
	Secondary	$ 8.00		Secondary	$ 8.03
Minimum Monthly Charge:			Minimum Monthly Charge:		
The Customer Charge Plus Basic Demand Charge			*The Customer Charge Plus Basic Demand Charge*		
Applicability: All purposes except customers whose maximum demand exceeds 1,000 kW in two consecutive months.			Applicability: All purposes except customers whose maximum demand exceeds 1,000 kW in two consecutive months.		

Central Hudson Gas & Electric Corporation

Summary of Present and Proposed Electric Rates

Large Power Primary Service

Service Classification No. 3 - P.S.C. No. 15

Present Rate			Proposed Rate		
Monthly Charge	$	620.00	Monthly Charge	$	800.00
Monthly Energy Delivery Charge per kWh	$	-	Monthly Energy Delivery Charge per kWh	$	-
Monthly Demand Delivery Charge			Monthly Demand Delivery Charge		
Basic Demand per kW	$	8.42	Basic Demand per kW	$	8.71
Reactive Demand per Rkva	$	0.83	Reactive Demand per Rkva*	$	0.83
Minimum Monthly Charge:			Minimum Monthly Charge:		
The Customer Charge Plus Basic Demand Charge			*The Customer Charge Plus Basic Demand Charge*		

Central Hudson Gas & Electric Corporation

Summary of Present and Proposed Electric Rates

Area Lighting

Service Classification No. 5 - P.S.C. No. 15

Lamp and Fixture Charge

Lumens	Type	Annual kWh	Present Monthly Base Rate	Proposed Monthly Base Rate
First Light				
7,000	Mercury	832	$ 7.43	$ 7.97
20,000	Mercury	1,820	$ 10.42	$ 11.18
60,000	Mercury	4,320	$ 17.20	$ 18.45
5,800	Sodium	344	$ 6.27	$ 6.73
16,000	Sodium	721	$ 7.65	$ 8.21
27,000	Sodium	1,264	$ 9.51	$ 10.20
50,000	Sodium	1,984	$ 11.39	$ 12.22
140,000	Sodium	4,656	$ 20.27	$ 21.74
50,000	Sodium - Floodlight	1,984	$ 11.67	$ 12.52
20,500	Metal Halide	1,200	$ 9.60	$ 10.30
36,000	Metal Halide	1,856	$ 10.91	$ 11.70
36,000	Metal Halide - Floodlight	1,856	$ 11.26	$ 12.08
110,000	Metal Halide - Floodlight	4,400	$ 19.05	$ 20.43

Lamp, Fixture and Pole Package Charge

Lumens	Type	Annual kWhrs	Present Monthly Base Rate	Proposed Monthly Base Rate
14,000	Metal Halide	820	$ 21.22	$ 22.76
20,500	Metal Halide	1,200	$ 24.96	$ 26.77
36,000	Metal Halide	1,856	$ 29.78	$ 31.94
5,800	Sodium - Colonial Post Top	344	$ 12.90	$ 13.84

Central Hudson Gas & Electric Corporation

Summary of Present and Proposed Electric Rates

Area Lighting

Service Classification No. 5 - P.S.C. No. 15

Decorative and Specialty Lighting

Lumens	Type	Annual kWhrs	Present Monthly Base Rate	Proposed Monthly Base Rate
5,800	Sodium - Acorn	344	$ 9.96	$ 10.68
6,000	Induction - Acorn	340	$ 13.11	$ 14.06
14,000	Metal Halide - Acorn	820	$ 9.94	$ 10.66
16,000	Sodium - Victorian	721	$ 10.31	$ 11.06
27,000	Sodium - Highway Setback	1,264	$ 9.42	$ 10.10
50,000	Sodium - Highway Setback	1,984	$ 8.83	$ 9.47
20,500	Metal Halide - Highway Setback	1,200	$ 10.44	$ 11.20
36,000	Metal Halide - Highway Setback	1,856	$ 11.80	$ 12.66
27,000	Sodium - Teardrop	1,264	$ 17.77	$ 19.06
50,000	Sodium - Teardrop	1,984	$ 19.86	$ 21.30
20,500	Metal Halide - Teardrop	1,200	$ 18.43	$ 19.77
36,000	Metal Halide - Teardrop	1,856	$ 19.91	$ 21.36

Decorative and Specialty Lighting - Supporting Equipment

Type	Present Monthly Base Rate	Proposed Monthly Base Rate
Standard Wooden Utility Pole	$ 6.16	$ 6.61
Fluted Decorative Fiberglass Pole (area lighting)	$ 20.10	$ 21.56
Fiberglass Pole up to 20' (decorative other than highway)	$ 17.81	$ 19.10
Fiberglass Pole for Highway Setback (30' mounting height)	$ 17.81	$ 19.10
Decorative Arm for Decorative Teardrop Lighting	$ 8.55	$ 9.17

Central Hudson Gas & Electric Corporation

Summary of Present and Proposed Electric Rates

Residential Time-of-Use Service

Service Classification No. 6 - P.S.C. No. 15

Present Rate		Proposed Rate	
Monthly Charge	$ 21.00	Monthly Charge	$ 26.00
Monthly Energy Delivery Charge per kWh			
On-Peak	$ 0.07892	Monthly Energy Delivery Charge per kWh	$ 0.04304
Off-Peak	$ 0.02630		
Minimum Monthly Charge:		Minimum Monthly Charge:	
The Customer Charge		*The Customer Charge*	
Rating Periods		Rating Periods	
On-Peak: Customer choice of: 8am - 8pm OR 9am - 9pm OR 10am - 10pm, excluding six designated holidays		Single energy delivery charge no longer split into on-peak and off-peak rating periods.	
Off-Peak: All other hours including all hours of the following holidays: New Year's Day, Memorial Day, Fourth of July, Labor Day, Thanksgiving Day, Christmas Day			

Central Hudson Gas & Electric Corporation

Summary of Present and Proposed Electric Rates

Public Street and Highway Lighting

Service Classification No. 8 - P.S.C. No. 15

Company Owned and Maintained

Lumens	Type	Annual kWh	Present Annual Base Rate	Proposed Annual Base Rate
Standard Lights				
5,800	Sodium Vapor	344	$ 133.17	$ 141.41
16,000	Sodium Vapor	720	$ 148.02	$ 157.18
27,000	Sodium Vapor	1,264	$ 179.46	$ 190.57
50,000	Sodium Vapor	1,984	$ 202.39	$ 214.92
140,000	Sodium Vapor	4,656	$ 335.15	$ 355.90
20,500	Metal Halide	1,200	$ 204.17	$ 216.81
36,000	Metal Halide	1,856	$ 198.14	$ 210.40
Non-Standard Lights				
1,000	Incandescent	368	$ 107.51	$ 114.16
2,500	Incandescent	756	$ 142.20	$ 151.00
4,000	Incandescent	1,180	$ 170.62	$ 181.18
6,000	Incandescent	1,620	$ 195.45	$ 207.55
15,000	Incandescent	2,480	$ 253.35	$ 269.03
3,600	Mercury Vapor	504	$ 136.80	$ 145.27
7,000	Mercury Vapor	832	$ 148.16	$ 157.33
11,000	Mercury Vapor	1,184	$ 160.71	$ 170.66
15,000	Mercury Vapor	1,820	$ 187.51	$ 199.12
20,000	Mercury Vapor	1,820	$ 187.51	$ 199.12
60,000	Mercury Vapor	4,320	$ 275.10	$ 292.13
Lamp, Fixture and Pole Package				
5,800	Sodium Vapor - Colonial Post Top	344	$ 288.24	$ 306.08
5,800	Sodium Vapor	344	$ 363.35	$ 385.84
16,000	Sodium Vapor	720	$ 376.62	$ 399.93
14,000	Metal Halide	820	$ 415.12	$ 440.82
20,500	Metal Halide	1,200	$ 429.02	$ 455.58
36,000	Metal Halide	1,856	$ 454.31	$ 482.43
Standard Decorative and Special Purpose Luminaires				
5,800	Sodium Vapor - Acorn	344	$ 168.49	$ 178.92
6,000	Induction - Acorn	340	$ 228.54	$ 242.69
14,000	Metal Halide - Acorn	820	$ 213.24	$ 226.44
16,000	Sodium Vapor - Victorian	720	$ 217.11	$ 230.55
27,000	Sodium Vapor - Highway Setback	1,264	$ 206.01	$ 218.76
50,000	Sodium Vapor - Highway Setback	1,984	$ 231.62	$ 245.96
20,500	Metal Halide - Highway Setback	1,200	$ 236.04	$ 250.65
36,000	Metal Halide - Highway Setback	1,856	$ 229.85	$ 244.08
50,000	Sodium Vapor - Floodlight	1,984	$ 214.36	$ 227.63
36,000	Metal Halide - Floodlight	1,856	$ 205.46	$ 218.18
110,000	Metal Halide - Floodlight	4,400	$ 352.93	$ 374.78
27,000	Sodium Vapor - Teardrop	1,264	$ 248.19	$ 263.55
50,000	Sodium Vapor - Teardrop	2,480	$ 291.14	$ 309.16
20,500	Metal Halide - Teardrop	1,200	$ 268.93	$ 285.58
36,000	Metal Halide - Teardrop	1,856	$ 275.68	$ 292.74

Central Hudson Gas & Electric Corporation

Summary of Present and Proposed Electric Rates

Public Street and Highway Lighting

Service Classification No. 8 - P.S.C. No. 15

Customer Owned/Company Maintained

Lumens	Type	Annual kWh	Present Annual Base Rate	Proposed Annual Base Rate
Standard Lights				
6,000	Induction	340	$ 39.68	$ 42.14
5,800	Sodium Vapor	344	$ 45.25	$ 48.05
16,000	Sodium Vapor	720	$ 58.20	$ 61.80
27,000	Sodium Vapor	1,264	$ 76.93	$ 81.69
50,000	Sodium Vapor	1,984	$ 102.07	$ 108.39
140,000	Sodium Vapor	4,656	$ 199.72	$ 212.08
14,000	Metal Halide	820	$ 65.94	$ 70.02
20,500	Metal Halide	1,200	$ 79.69	$ 84.62
36,000	Metal Halide	1,856	$ 99.98	$ 106.17
110,000	Metal Halide	4,400	$ 212.73	$ 225.90
Non-Standard Lights				
9,500	Sodium Vapor	584	$ 53.52	$ 56.83
1,000	Incandescent	368	$ 66.42	$ 70.53
2,500	Incandescent	756	$ 88.04	$ 93.49
4,000	Incandescent	1,180	$ 103.47	$ 109.87
6,000	Incandescent	1,620	$ 134.34	$ 142.66
10,000	Incandescent	2,480	$ 163.96	$ 174.11
7,000	Mercury Vapor	832	$ 61.39	$ 65.19
11,000	Mercury Vapor	1,184	$ 73.86	$ 78.43
15,000	Mercury Vapor	1,820	$ 99.07	$ 105.20
20,000	Mercury Vapor	1,820	$ 99.07	$ 105.20
60,000	Mercury Vapor	4,320	$ 186.17	$ 197.69

Other Charges

Type	Present Base Rate	Proposed Base Rate
Pre-attachment survey fee	$ 7.30	$ 7.30
Annual pole rental (company sole owned)	$ 5.70	$ 6.05
Annual pole rental (company joint owned)	$ 2.85	$ 3.03

Central Hudson Gas & Electric Corporation

Summary of Present and Proposed Electric Rates

Public Street and Highway Lighting

Service Classification No. 8 - P.S.C. No. 15

Company Owned and Maintained

Lumens	Type	Annual kWh	Present Annual Base Rate	Proposed Annual Base Rate
Standard Lights				
5,800	Sodium Vapor	344	$ 20.11	$ 21.35
9,500	Sodium Vapor	584	$ 28.38	$ 30.14
16,000	Sodium Vapor	720	$ 33.06	$ 35.11
27,000	Sodium Vapor	1,264	$ 51.81	$ 55.02
50,000	Sodium Vapor	1,984	$ 76.60	$ 81.34
140,000	Sodium Vapor	4,656	$ 168.65	$ 179.09
8,500	Metal Halide	520	$ 26.18	$ 27.80
14,000	Metal Halide	820	$ 36.52	$ 38.78
20,500	Metal Halide	1,200	$ 49.60	$ 52.67
36,000	Metal Halide	1,856	$ 72.19	$ 76.66
110,000	Metal Halide	4,400	$ 159.83	$ 169.72
Non-Standard Lights				
1,000	Incandescent	368	$ 20.94	$ 22.24
2,500	Incandescent	756	$ 34.31	$ 36.43
6,000	Incandescent	1,620	$ 64.07	$ 68.04
7,000	Mercury Vapor	832	$ 36.92	$ 39.21
11,000	Mercury Vapor	1,184	$ 49.05	$ 52.09
20,000	Mercury Vapor	1,820	$ 70.96	$ 75.35

Other Charges

Type	Present Base Rate	Proposed Base Rate
Pre-attachment survey fee	$ 7.30	$ 7.30
Annual pole rental (company sole owned)	$ 5.70	$ 6.05
Annual pole rental (company joint owned)	$ 2.85	$ 3.03

Public Street and Highway Lighting - Supporting Equipment

Type	Present Base Rate	Proposed Base Rate
Standard Company Pole (street lighting)	$ 49.81	$ 52.89
Mastarms greater than 14'	$ 28.13	$ 29.87
Fluted Decorative Fiberglass Pole	$ 260.17	$ 276.27
Fiberglass Pole up to 20' (decorative lighting)	$ 230.59	$ 244.86
Fiberglass Pole for Highway Setback (30' mounting height)	$ 230.59	$ 244.86
Decorative Arm for Decorative Teardrop Lighting	$ 110.73	$ 117.58

Central Hudson Gas & Electric Corporation

Summary of Present and Proposed Electric Rates

Single Phase Residential Service

Service Classification No. 9 - P.S.C. No. 15

Present Rate		
Monthly Charge	$	2.66
Monthly Energy Delivery Charge per kWh	$	-

Proposed Rate		
Monthly Charge	$	2.79
Monthly Energy Delivery Charge per kWh	$	-

Minimum Monthly Charge:

The Customer Charge

Minimum Monthly Charge:

The Customer Charge

Central Hudson Gas & Electric Corporation

Summary of Present and Proposed Electric Rates

Large Power Substation & Transmission Service

Service Classification No. 13 - P.S.C. No. 15

Present Rate			Proposed Rate		
Monthly Charge	$	800.00	Monthly Charge	$	1,000.00
Monthly Energy Delivery Charge per kWh			Monthly Energy Delivery Charge per kWh		
Substation	$	-	Substation	$	-
Transmission	$	-	Transmission	$	-
Monthly Demand Delivery Charge			Monthly Demand Delivery Charge		
Basic Demand per kW			Basic Demand per kW		
Substation	$	6.21	Substation	$	6.64
Transmission	$	3.34	Transmission	$	3.59
Reactive Demand per Rkva	$	0.83	Reactive Demand per Rkva*	$	0.83
Minimum Monthly Charge:			Minimum Monthly Charge:		
The Customer Charge Plus Basic Demand Charge			*The Customer Charge Plus Basic Demand Charge*		

Central Hudson Gas & Electric Corporation

Summary of Present and Proposed Gas Rates

Schedule A	Merchant Function Charges
Schedule B	Residential Service Service Classification Nos. 1 & 12
	Commercial and Industrial Service Service Classification Nos. 2, 6 & 13
	Firm Transportation Service Service Classification No. 11 Transmission Distribution Distribution Large Mains (DLM)

Central Hudson Gas & Electric Corporation

Gas Commodity Related Merchant Function Charges
($/Ccf)

Present Base MFC Rates

MFC Group	Applicable to S.C. No.	MFC Administration Charge	MFC Supply Charge	MFC Total
MFC-1	1, 12 & 16	$ 0.02536	$ 0.01970	$ 0.04506
MFC-2	2, 6, 13 & 15	$ 0.00372	$ 0.01523	$ 0.01895

Proposed Base MFC Rates

MFC Group	Applicable to S.C. No.	MFC Administration Charge	MFC Supply Charge	MFC Total
MFC-1	1, 12 & 16	$ 0.02900	$ 0.02123	$ 0.05023
MFC-2	2, 6, 13 & 15	$ 0.00415	$ 0.01947	$ 0.02362

Central Hudson Gas & Electric Corporation

Summary of Present and Proposed Gas Rates

Residential Delivery Service
Service Classification Nos. 1 & 12 - P.S.C. No. 12

Present Rate - Monthly Charge		Proposed Rate - Monthly Charge	
Cubic Feet	Rate per 100 Cubic Feet	Cubic Feet	Rate per 100 Cubic Feet
200 or Less	$17.00	200 or Less	$20.00
Next 4,800	$0.6845	Next 4,800	$0.6922
Additional	$0.3944	Additional	$0.3989

Commercial and Industrial Delivery Service
Service Classification Nos. 2, 6 & 13 - P.S.C. No. 12

Present Rate - Monthly Charge		Proposed Rate - Monthly Charge	
Cubic Feet	Rate per 100 Cubic Feet	Cubic Feet	Rate per 100 Cubic Feet
200 or Less	$30.00	200 or Less	$35.00
Next 9,800	$0.4727	Next 9,800	$0.4721
Next 490,000	$0.2704	Next 490,000	$0.2700
Additional	$0.2206	Additional	$0.2203

Firm Transportation
Service Classification No. 11 - P.S.C. No. 12

Present Rate - Monthly Charge		Proposed Rate - Monthly Charge	
Transmission:			
Customer Charge	$600.00	Customer Charge	$800.00
Mcf of MDQ	$7.73	Mcf of MDQ	$8.20
Distribution:			
Customer Charge	$600.00	Customer Charge	$800.00
Mcf of MDQ	$15.53	Mcf of MDQ	$16.84
Distribution - Large Mains (DLM):			
Customer Charge	$600.00	Customer Charge	$800.00
Mcf of MDQ	$9.21	Mcf of MDQ	$10.19

Central Hudson Gas & Electric Corporation

Comparison of Present and Proposed Electric Rates

Schedule A	Service Classification No. 1
Schedule B	Service Classification No. 2
Sheet 1	Non-Demand
Sheet 2	Secondary Demand
Sheet 3	Primary Demand
Schedule C	Rates Utilized in Development of Typical Bills

Central Hudson Gas & Electric Corporation

Comparison of Present and Proposed Electric Rates

S.C. No. 1 - Non Heating

	20% Below Average	15% Below Average	10% Below Average	5% Below Average	Average	5% Above Average	10% Above Average	15% Above Average	20% Above Average
kWh	500	530	560	590	620	650	680	710	740
Present Bill	$ 77.57	$ 81.12	$ 84.67	$ 88.22	$ 91.77	$ 95.31	$ 98.86	$ 102.41	$ 105.96
Proposed Bill	$ 82.82	$ 86.44	$ 90.05	$ 93.67	$ 97.29	$ 100.91	$ 104.53	$ 108.15	$ 111.77
$ Increase	$ 5.25	$ 5.32	$ 5.39	$ 5.46	$ 5.53	$ 5.59	$ 5.66	$ 5.73	$ 5.80
% Increase	6.77%	6.56%	6.36%	6.19%	6.02%	5.87%	5.73%	5.60%	5.48%

EBC Reduction	$ 1.67	$ 1.77	$ 1.87	$ 1.97	$ 2.07	$ 2.17	$ 2.27	$ 2.37	$ 2.47
Delivery Rate Increase	$ 3.58	$ 3.55	$ 3.52	$ 3.49	$ 3.46	$ 3.42	$ 3.39	$ 3.36	$ 3.33
Total $ Increase	$ 5.25	$ 5.32	$ 5.39	$ 5.46	$ 5.53	$ 5.59	$ 5.66	$ 5.73	$ 5.80

S.C. No. 1 - Heating

	20% Below Average	15% Below Average	10% Below Average	5% Below Average	Average	5% Above Average	10% Above Average	15% Above Average	20% Above Average
kWh	800	860	910	960	1,010	1,060	1,110	1,160	1,210
Present Bill	$ 113.06	$ 120.16	$ 126.07	$ 131.99	$ 137.91	$ 143.82	$ 149.74	$ 155.65	$ 161.57
Proposed Bill	$ 119.00	$ 126.24	$ 132.27	$ 138.30	$ 144.33	$ 150.36	$ 156.39	$ 162.43	$ 168.46
$ Increase	$ 5.94	$ 6.08	$ 6.20	$ 6.31	$ 6.43	$ 6.54	$ 6.66	$ 6.77	$ 6.89
% Increase	5.26%	5.06%	4.91%	4.78%	4.66%	4.55%	4.45%	4.35%	4.26%

EBC Reduction	$ 2.67	$ 2.87	$ 3.04	$ 3.21	$ 3.37	$ 3.54	$ 3.71	$ 3.87	$ 4.04
Delivery Rate Increase	$ 3.27	$ 3.21	$ 3.16	$ 3.10	$ 3.06	$ 3.00	$ 2.95	$ 2.90	$ 2.85
Total $ Increase	$ 5.94	$ 6.08	$ 6.20	$ 6.31	$ 6.43	$ 6.54	$ 6.66	$ 6.77	$ 6.89

Note: The Increase shown is a result of the expiration of $10 million of the $20 million Electric Bill Credit pursuant to Commission Order in C.08-E-0887 and the base delivery rate increases proposed by the Company as shown on Exhibit__(FRP-12), both effective July 1, 2010.

See Exhibit__(FRP-14, Schedule C) for rates used in the development of these bills

EXHIBIT__(FRP-14)
Schedule A

Central Hudson Gas & Electric Corporation

Comparison of Present and Proposed Electric Rates

S.C. No. 2 - Non Demand

	20% Below Average	15% Below Average	10% Below Average	5% Below Average	Average	5% Above Average	10% Above Average	15% Above Average	20% Above Average
kWh	350	370	400	420	440	460	480	510	530
Present Bill	$ 56.91	$ 58.45	$ 60.75	$ 62.28	$ 63.82	$ 65.35	$ 66.88	$ 69.18	$ 70.72
Proposed Bill	$ 60.41	$ 62.03	$ 64.45	$ 66.07	$ 67.69	$ 69.31	$ 70.93	$ 73.36	$ 74.98
$ Increase	$ 3.49	$ 3.58	$ 3.71	$ 3.79	$ 3.88	$ 3.96	$ 4.05	$ 4.17	$ 4.26
% Increase	6.14%	6.12%	6.10%	6.09%	6.07%	6.06%	6.05%	6.03%	6.02%

EBC Reduction	$ 1.00	$ 1.06	$ 1.15	$ 1.21	$ 1.26	$ 1.32	$ 1.38	$ 1.46	$ 1.52
Delivery Rate Increase	$ 2.49	$ 2.52	$ 2.56	$ 2.58	$ 2.62	$ 2.64	$ 2.67	$ 2.71	$ 2.74
Total $ Increase	$ 3.49	$ 3.58	$ 3.71	$ 3.79	$ 3.88	$ 3.96	$ 4.05	$ 4.17	$ 4.26

See Exhibit__(FRP-14, Schedule C) for rates used in the development of these bills

EXHIBIT__(FRP-14)
Schedule B
Sheet 1 of 3

Central Hudson Gas & Electric Corporation
Comparison of Present and Proposed Electric Rates

S.C. No. 2 - Secondary Demand

	kWh									
kW	500	750	1,000	2,000	2,500	5,000	7,500	10,000	15,000	20,000
5										
Present Bill	$ 127.50	$ 146.14	$ 164.78	$ 239.32	$ 276.60					
Proposed Bill	$ 142.25	$ 161.17	$ 180.09	$ 255.77	$ 293.61					
EBC Reduction	$ 0.53	$ 0.79	$ 1.05	$ 2.10	$ 2.63					
Delivery Rate Increase	$ 14.22	$ 14.25	$ 14.27	$ 14.35	$ 14.39					
Total $ Increase	$ 14.75	$ 15.04	$ 15.32	$ 16.45	$ 17.02					
Total % Increase	11.57%	10.29%	9.30%	6.87%	6.15%					
10										
Present Bill	$ 167.60	$ 186.24	$ 204.88	$ 279.42	$ 316.70					
Proposed Bill	$ 182.50	$ 201.43	$ 220.35	$ 296.03	$ 333.87					
EBC Reduction	$ 0.53	$ 0.79	$ 1.05	$ 2.10	$ 2.63					
Delivery Rate Increase	$ 14.37	$ 14.40	$ 14.42	$ 14.50	$ 14.54					
$ Increase	$ 14.90	$ 15.19	$ 15.47	$ 16.60	$ 17.17					
% Increase	8.89%	8.15%	7.55%	5.94%	5.42%					
15										
Present Bill			$ 244.98	$ 319.53	$ 356.80	$ 543.17	$ 729.54			
Proposed Bill			$ 260.60	$ 336.28	$ 374.12	$ 563.32	$ 752.52			
EBC Reduction			$ 1.05	$ 2.10	$ 2.63	$ 5.25	$ 7.88			
Delivery Rate Increase			$ 14.57	$ 14.65	$ 14.69	$ 14.90	$ 15.10			
$ Increase			$ 15.62	$ 16.75	$ 17.32	$ 20.15	$ 22.98			
% Increase			6.38%	5.24%	4.85%	3.71%	3.15%			
20										
Present Bill				$ 359.63	$ 396.90	$ 583.27	$ 769.64	$ 956.01		
Proposed Bill				$ 376.53	$ 414.37	$ 603.57	$ 792.77	$ 981.97		
EBC Reduction				$ 2.10	$ 2.63	$ 5.25	$ 7.88	$ 10.50		
Delivery Rate Increase				$ 14.80	$ 14.84	$ 15.05	$ 15.25	$ 15.47		
$ Increase				$ 16.90	$ 17.47	$ 20.30	$ 23.13	$ 25.97		
% Increase				4.70%	4.40%	3.48%	3.01%	2.72%		
30										
Present Bill					$ 477.10	$ 663.47	$ 849.84	$ 1,036.21	$ 1,408.95	
Proposed Bill					$ 494.87	$ 684.07	$ 873.28	$ 1,062.48	$ 1,440.88	
EBC Reduction					$ 2.63	$ 5.25	$ 7.88	$ 10.50	$ 15.75	
Delivery Rate Increase					$ 15.14	$ 15.35	$ 15.55	$ 15.77	$ 16.18	
$ Increase					$ 17.77	$ 20.60	$ 23.43	$ 26.27	$ 31.93	
% Increase					3.72%	3.11%	2.76%	2.53%	2.27%	
40										
Present Bill						$ 743.67	$ 930.04	$ 1,116.41	$ 1,489.15	$ 1,861.89
Proposed Bill						$ 764.58	$ 953.78	$ 1,142.98	$ 1,521.38	$ 1,899.79
EBC Reduction						$ 5.25	$ 7.88	$ 10.50	$ 15.75	$ 21.00
Delivery Rate Increase						$ 15.65	$ 15.85	$ 16.07	$ 16.48	$ 16.90
$ Increase						$ 20.90	$ 23.73	$ 26.57	$ 32.23	$ 37.90
% Increase						2.81%	2.55%	2.38%	2.16%	2.04%
50										
Present Bill						$ 823.88	$ 1,010.25	$ 1,196.62	$ 1,569.35	$ 1,942.09
Proposed Bill						$ 845.08	$ 1,034.28	$ 1,223.48	$ 1,601.89	$ 1,980.29
EBC Reduction						$ 5.25	$ 7.88	$ 10.50	$ 15.75	$ 21.00
Delivery Rate Increase						$ 15.95	$ 16.16	$ 16.37	$ 16.78	$ 17.20
$ Increase						$ 21.20	$ 24.04	$ 26.87	$ 32.53	$ 38.20
% Increase						2.57%	2.38%	2.25%	2.07%	1.97%
100										
Present Bill						$ 1,224.89	$ 1,411.26	$ 1,597.63	$ 1,970.37	$ 2,343.10
Proposed Bill						$ 1,247.59	$ 1,436.80	$ 1,626.00	$ 2,004.40	$ 2,382.80
EBC Reduction						$ 5.25	$ 7.88	$ 10.50	$ 15.75	$ 21.00
Delivery Rate Increase						$ 17.46	$ 17.66	$ 17.87	$ 18.29	$ 18.70
$ Increase						$ 22.71	$ 25.54	$ 28.37	$ 34.04	$ 39.70
% Increase						1.85%	1.81%	1.78%	1.73%	1.69%

Note: The increase shown is a result of the expiration of $10 million of the $20 million Electric Bill Credit pursuant to Commission Order in C.08-E-0887 and the base delivery rate increases proposed by the Company as shown on Exhibit__(FRP-12), both effective July 1, 2010.

See Exhibit__(FRP-14, Schedule C) for rates used in the development of these bills

Central Hudson Gas & Electric Corporation
Comparison of Present and Proposed Electric Rates

S.C. No. 2 - Primary Demand

kW	kWh 500	750	1,000	2,000	2,500	5,000	7,500	10,000	15,000	20,000
5										
Present Bill	$ 225.85	$ 242.79	$ 259.72	$ 327.47	$ 361.34					
Proposed Bill	$ 277.71	$ 294.83	$ 311.96	$ 380.45	$ 414.70					
EBC Reduction	$ 0.34	$ 0.51	$ 0.68	$ 1.36	$ 1.70					
Delivery Rate Increase	$ 51.52	$ 51.53	$ 51.55	$ 51.62	$ 51.66					
Total $ Increase	$ 51.86	$ 52.04	$ 52.23	$ 52.98	$ 53.36					
Total % Increase	22.96%	21.44%	20.11%	16.18%	14.77%					
10										
Present Bill	$ 257.43	$ 274.37	$ 291.30	$ 359.04	$ 392.92					
Proposed Bill	$ 310.64	$ 327.77	$ 344.89	$ 413.38	$ 447.63					
EBC Reduction	$ 0.34	$ 0.51	$ 0.68	$ 1.36	$ 1.70					
Delivery Rate Increase	$ 52.87	$ 52.89	$ 52.91	$ 52.98	$ 53.01					
Total $ Increase	$ 53.21	$ 53.40	$ 53.59	$ 54.34	$ 54.71					
Total % Increase	20.67%	19.46%	18.39%	15.13%	13.92%					
15										
Present Bill			$ 322.88	$ 390.62	$ 424.49	$ 593.85	$ 763.20			
Proposed Bill			$ 377.82	$ 446.31	$ 480.56	$ 651.79	$ 823.02			
EBC Reduction			$ 0.68	$ 1.36	$ 1.70	$ 3.40	$ 5.10			
Delivery Rate Increase			$ 54.26	$ 54.33	$ 54.37	$ 54.55	$ 54.73			
Total $ Increase			$ 54.94	$ 55.69	$ 56.07	$ 57.95	$ 59.83			
Total % Increase			17.01%	14.26%	13.21%	9.76%	7.84%			
20										
Present Bill				$ 422.20	$ 456.07	$ 625.43	$ 794.78	$ 964.13		
Proposed Bill				$ 479.25	$ 513.49	$ 684.73	$ 855.96	$ 1,027.19		
EBC Reduction				$ 1.36	$ 1.70	$ 3.40	$ 5.10	$ 6.80		
Delivery Rate Increase				$ 55.68	$ 55.72	$ 55.90	$ 56.08	$ 56.26		
Total $ Increase				$ 57.04	$ 57.42	$ 59.30	$ 61.18	$ 63.06		
Total % Increase				13.51%	12.59%	9.48%	7.70%	6.54%		
30										
Present Bill					$ 519.23	$ 688.59	$ 857.94	$ 1,027.29	$ 1,365.99	
Proposed Bill					$ 579.36	$ 750.59	$ 921.82	$ 1,093.05	$ 1,435.52	
EBC Reduction					$ 1.70	$ 3.40	$ 5.10	$ 6.80	$ 10.20	
Delivery Rate Increase					$ 58.43	$ 58.61	$ 58.79	$ 58.97	$ 59.33	
Total $ Increase					$ 60.13	$ 62.01	$ 63.89	$ 65.77	$ 69.53	
Total % Increase					11.58%	9.00%	7.45%	6.40%	5.09%	
40										
Present Bill						$ 751.74	$ 921.10	$ 1,090.45	$ 1,429.15	$ 1,767.85
Proposed Bill						$ 816.46	$ 987.69	$ 1,158.92	$ 1,501.38	$ 1,843.85
EBC Reduction						$ 3.40	$ 5.10	$ 6.80	$ 10.20	$ 13.60
Delivery Rate Increase						$ 61.31	$ 61.49	$ 61.67	$ 62.03	$ 62.39
Total $ Increase						$ 64.71	$ 66.59	$ 68.47	$ 72.23	$ 75.99
Total % Increase						8.61%	7.23%	6.28%	5.05%	4.30%
50										
Present Bill						$ 814.90	$ 984.26	$ 1,153.61	$ 1,492.31	$ 1,831.01
Proposed Bill						$ 882.32	$ 1,053.55	$ 1,224.79	$ 1,567.25	$ 1,909.71
EBC Reduction						$ 3.40	$ 5.10	$ 6.80	$ 10.20	$ 13.60
Delivery Rate Increase						$ 64.02	$ 64.20	$ 64.38	$ 64.74	$ 65.10
Total $ Increase						$ 67.42	$ 69.30	$ 71.18	$ 74.94	$ 78.70
Total % Increase						8.27%	7.04%	6.17%	5.02%	4.30%
100										
Present Bill						$ 1,130.70	$ 1,300.05	$ 1,469.40	$ 1,808.11	$ 2,146.81
Proposed Bill						$ 1,211.65	$ 1,382.88	$ 1,554.12	$ 1,896.58	$ 2,239.04
EBC Reduction						$ 3.40	$ 5.10	$ 6.80	$ 10.20	$ 13.60
Delivery Rate Increase						$ 77.55	$ 77.73	$ 77.91	$ 78.27	$ 78.63
Total $ Increase						$ 80.95	$ 82.83	$ 84.71	$ 88.47	$ 92.23
Total % Increase						7.16%	6.37%	5.77%	4.89%	4.30%

Note: The Increase shown is a result of the expiration of $10 million of the $20 million Electric Bill Credit pursuant to Commission Order in C.08-E-0887 and the base delivery rate increases proposed by the Company as shown on Exhibit__(FRP-12), both effective July 1, 2010.

See Exhibit__(FRP-14, Schedule C) for rates used in the development of these bills

Central Hudson Gas & Electric Corporation

Comparison of Present and Proposed Electric Rates

Rates Utilized in Development of Typical Bills

	SC 1	SC 2 ND	SC 2 SD	SC 2 PD
Market Price Charge	$ 0.06215	$ 0.06215	$ 0.06215	$0.05932
Market Price Adjustment	$ 0.00542	$ 0.00542	$ 0.00542	$0.00507
Purchased Power Adjustment	$ 0.00070	$ 0.00076	$ 0.00080	$ 0.00077
Miscellaneous Charges	$ (0.00411)	$ (0.00411)	$ (0.00411)	$ (0.00411)
System Benefits Charge	$ 0.00377	$ 0.00377	$ 0.00377	$ 0.00377
MFC Admin Charge	$ 0.00209	$ 0.00283	$ 0.00014	$ 0.00001
MFC Supply Charge	$ 0.00403	$ 0.00569	$ 0.00033	$ 0.00003
MFC Transition Adjustment	$ 0.00012	$ 0.00049	$ 0.00006	$ -
New York State Assessment*	$ 0.00267	$ 0.00267	$ 0.00267	$ 0.00267
Electric Bill Credit	$ (0.00682)	$ (0.00658)	$ (0.00209)	$ (0.00131)
Weighted Revenue Tax - Commodity	0.252%	0.252%	0.252%	0.252%
Weighted Revenue Tax - Delivery	2.252%	0.252%	0.252%	0.252%
MFC Admin Charge - Proposed	$ 0.00292	$ 0.00433	$ 0.00019	$ 0.00002
MFC Supply Charge - Proposed*	$ 0.00409	$ 0.00637	$ 0.00034	$ 0.00003
Electric Bill Credit - Proposed	$ (0.00348)	$ (0.00371)	$ (0.00104)	$ (0.00063)

In order to only show the impact of base rate increases, annual bills under proposed rates do not reflect annual changes to the SBC, or any increases related to the EEPS charge in Case 07-M-0548. NYSA has been included at current rates but is subject to change on September 1, 2009 as discussed in the FRP Testimony.

*The MFC Supply Charge includes 50 percent of forecast net lost revenues associated with customer migration and therefore is subject to change each year based on the calculation of actual net lost revenues. Current allocation of MFC Lost Revenue Charge included in Proposed MFC Supply.

Central Hudson Gas & Electric Corporation

Comparison of Bills Under Present and Proposed Rates

Schedule A	Service Classification Nos. 1 & 12
Schedule B	Service Classification Nos. 2, 6 & 13

Central Hundson Gas & Electric Corporation

Comparison of Bills Under Present and Proposed Rates

P.S.C. No. 12 - Gas
Service Classification Nos. 1 & 12

Monthly Usage Ccf	Monthly Bill Present	Monthly Bill Proposed	Change in Monthly Bill Amount	Change in Monthly Bill Increase
2	$ 18.88	$ 21.97	$ 3.09	16.35%
4	21.74	24.85	3.11	14.33%
6	24.59	27.73	3.14	12.77%
8	27.44	30.60	3.17	11.54%
10	30.29	33.48	3.19	10.54%
15	37.41	40.67	3.26	8.71%
20	44.54	47.87	3.33	7.47%
25	51.67	55.06	3.39	6.56%
30	58.79	62.25	3.46	5.88%
35	65.92	69.44	3.52	5.35%
40	73.05	76.64	3.59	4.91%
50	87.30	91.02	3.72	4.26%
60	98.58	102.40	3.82	3.88%
80	121.13	125.15	4.02	3.32%
100	143.69	147.90	4.22	2.94%
130	177.52	182.03	4.52	2.54%
170	222.63	227.54	4.91	2.21%
200	256.46	261.67	5.21	2.03%
300	369.23	375.43	6.20	1.68%
1000	1,158.64	1,171.78	13.14	1.13%
Average Annual Heating Customer @ 910 Ccf Per Year				
910	1,349.87	1,397.08	47.21	3.50%

Weighted Revenue Tax Factor:	Delivery		0.02513
	Commodity		0.00513
Gas Supply Charge (per Ccf):		$	0.64017
New York State Assessment Surcharge:		$	0.03001

		Present (Exhibit__(FRP-13), Schedule A)	Proposed	
Merchant Function Charge (per Ccf):	MFC Admin	$ 0.02536	$ 0.02900	
	MFC Supply *	$ 0.02144	$ 0.02297	**
	Transition Adj.	$ 0.00148	$ 0.00148	***

*The MFC Supply Charge includes 50 percent of forecast net lost revenues associated with customer migration and therefore is subject to change each year based on the calculation of actual net lost revenues.
** Current allocation of MFC Lost Revenue Charge included in Proposed MFC Supply
*** Proposed Transition Adj. Rate reflects current Transition Adjustment rate

In order to only show the impact of base rate increases, annual bills under proposed rates do not reflect annual changes to the SBC, or any increases related to the EEPS charge in Case 07-M-0548. NYSA has been included at current rates but is subject to change on September 1, 2009 as discussed in the FRP Testimony

Central Hundson Gas & Electric Corporation

Comparison of Bills Under Present and Proposed Rates

P.S.C. No. 12 - Gas
Service Classification Nos. 2, 6 & 13

Monthly Usage Ccf	Monthly Bill Present	Monthly Bill Proposed	Change in Monthly Bill Amount	Change in Monthly Bill Increase
2	$ 31.56	$ 36.60	$ 5.04	15.95%
10	41.00	46.07	5.07	12.36%
30	64.58	69.73	5.15	7.97%
50	88.17	93.40	5.23	5.93%
100	147.13	152.57	5.44	3.69%
150	195.93	201.58	5.65	2.88%
200	244.72	250.59	5.87	2.40%
250	293.52	299.60	6.08	2.07%
300	342.32	348.61	6.29	1.84%
400	439.91	446.63	6.72	1.53%
500	537.50	544.65	7.15	1.33%
600	635.09	642.68	7.58	1.19%
800	830.28	838.72	8.44	1.02%
1000	1,025.47	1,034.76	9.30	0.91%
1500	1,513.43	1,524.87	11.44	0.76%
2000	2,001.39	2,014.98	13.59	0.68%
3000	2,977.32	2,995.20	17.88	0.60%
5000	4,929.17	4,955.64	26.47	0.54%
7500	7,243.85	7,281.29	37.45	0.52%
10000	9,558.52	9,606.95	48.43	0.51%
12000	11,410.26	11,467.47	57.21	0.50%
14000	13,262.00	13,328.00	66.00	0.50%
16000	15,113.74	15,188.52	74.78	0.49%
20000	18,817.22	18,909.57	92.35	0.49%
Average Annual Heating Customer @ 4800 Ccf Per Year				
4800	5,278.91	5,359.60	80.68	1.53%

Weighted Revenue Tax Factor:	Delivery		0.00513
	Commodity		0.00513
Gas Supply Charge (per Ccf):		$	0.64017
New York State Assessment Surcharge:		$	0.03001

		Present (Exhibit__(FRP-13), Schedule A)	Proposed (Exhibit__(FRP-13), Schedule A)	
Merchant Function Charge (per Ccf):	MFC Admin	$ 0.00372	$ 0.00415	
	MFC Supply *	$ 0.02282	$ 0.02706	**
	Transition Adj.	$ 0.00380	$ 0.00380	***

*The MFC Supply Charge includes 50 percent of forecast net lost revenues associated with customer migration and therefore is subject to change each year based on the calculation of actual net lost revenues.
** Current allocation of MFC Lost Revenue Charge included in Proposed MFC Supply
*** Proposed Transition Adj. Rate reflects current Transition Adjustment rate

In order to only show the impact of base rate increases, annual bills under proposed rates do not reflect annual changes to the SBC, or any increases related to the EEPS charge in Case 07-M-0548. NYSA has been included at current rates but is subject to change on September 1, 2009 as discussed in the FRP Testimony.

DIRECT TESTIMONY
OF
COST OF SERVICE PANEL

Q. Please state your name and business address.

A. Glynis L. Bunt and Lauren M. Guido, Central Hudson Gas & Electric Corporation ("Central Hudson" or the "Company"), 284 South Avenue, Poughkeepsie, New York 12601.

Q. In what capacity are you employed by Central Hudson?

A. (Bunt) I am Director of Cost, Rates and Forecasts.

(Guido) I am an Assistant Cost and Rate Analyst.

Q. Please summarize your education and experience.

A. (Bunt) I received an Associate in Science Degree in Business Administration from Dutchess Community College in 1984. In 1986, I graduated from the State University of New York at New Paltz with a Bachelor of Science Degree in Business Administration. I received a Master of Business Administration Degree with a concentration in Finance from Marist College in January 1994. Following about one year of employment as an internal auditor for a retail chain I was employed by Central Hudson in June 1987 as an Accounting Trainee in the Internal Audit Division. I was promoted to Assistant Auditor in 1989 and subsequently transferred to the position of Assistant Financial Analyst in the Financial Planning Division later that year. I was promoted to Associate Financial Analyst in 1991, to Regulatory and

Financial Analyst in 1993 and to Senior Regulatory and Financial Analyst in 1996. I was transferred to the position of Rates and Forecasts Analyst in the Cost and Rate Division in 1997 and promoted to my current position in September 2002.

(Guido) I received an Associate in Science Degree in Business Administration from Ulster County Community College in 2005. In 2007, I graduated from the State University of New York at New Paltz with a Bachelor of Science Degree with a double major in Marketing and Management. I received a Master of Business Administration Degree with a concentration in Management from the State University of New York at New Paltz in May 2009. I was employed by Central Hudson in January 2008 as an Assistant Cost and Rate Analyst.

Q. Have you previously testified before this Commission?

A. (Bunt) Yes. I have testified before this Commission in Cases 95-G-1034, 05-E-0934, 05-G-0935, 08-E-0887 and 08-G-0888, and have submitted an affidavit in 07-M-1139.

(Guido) No.

Q. What is the purpose of your testimony in this proceeding?

A. Our testimony presents Cost of Service (COS) information regarding the Company's gas and electric operations. We have prepared four separate

embedded COS studies (fully allocated and unbundled per Case 00-M-0504 Unbundling Track guidelines): a historical study and a pro forma study of gas operations; and, a historical study and a pro forma study of electric operations. In addition, as discussed later, we have prepared a hypothetical historical delivery-only electric study. The historical studies pertain to the calendar year ended December 31, 2007. The pro forma studies pertain to the Rate Year of the twelve months ending June 30, 2011.

Q. Have you prepared any exhibits to support your testimony?

A. Yes. We have prepared Exhibits (COSP-1), (COSP-2) and (COSP-3) which include the following schedules:

Exhibit (COSP-1)-Gas Department Embedded Study:

Schedule A - Gas Department Rate of Return Statement for the Historical Year 2007;

Schedule B - Gas Department Rate of Return Statement for the Pro Forma Rate Year 7/2010-6/2011;

Schedule C - Gas Department Levelized Revenue Requirement for the Pro Forma Rate Year 7/2010-6/2011 with a targeted ROR to illustrate a potential rate structure with unbundled components.

Exhibit (COSP-2)-Electric Department Embedded Study:

Schedule A - Electric Department Rate of Return Statement for the Historical

Year 2007;

Schedule B - Electric Department Rate of Return Statement for the Pro Forma Rate Year 7/2010-6/2011;

Schedule C - Electric Department Levelized Revenue Requirement for the Pro Forma Rate Year 7/2010-6/2011 with a targeted ROR to illustrate a potential rate structure with unbundled components.

Exhibit (COSP-3)-Electric Department Delivery-Only Hypothetical Embedded Study:

Page 1 of 2 - Electric Department Delivery-Only Hypothetical Rate of Return Statement

Page 2 of 2 – Summary of Assumptions

Q. What is the purpose of an embedded cost of service study?

A. The basic purpose is to determine the earned rate of return (ROR) on rate base by service class in order to evaluate the relationship between current rates being charged to each customer class and the costs incurred to serve each customer class. Basically, revenues less expenses divided by rate base yields the ROR, an estimate of net income received for each dollar invested to provide service.

Q. What is the difference between a historical COS and a pro forma COS?

A. A historical COS uses actual data as recorded on the Company's books for a particular calendar year, in this case 2007. A pro forma COS utilizes rate year forecasts for system loads, revenues, expenses, and rate base to develop an estimated ROR by service class. Together, the historical and pro forma studies allow for a comparison of realized to expected rates of return based on the current rate structure, which became effective as of July 1, 2009.

Q. What is the intent of the historical year COS studies?

A. To document actual realized rate base, revenues and expenses by rate class that are reconcilable to Central Hudson's Annual Report to the State of New York Public Service Commission (PSC); and, to facilitate the unbundling of rates by reference to actual calendar year labor and expenses by PSC account and Central Hudson function number.

Q. What is the primary purpose of the rate year COS studies?

A. To provide a frame of reference and guidance for the design of cost-based delivery service rates that will produce relative ROR uniformity among the various rate classes and a fair rate of return on the Company's investments.

Q. Please outline the methods used to prepare an embedded cost of service.

A. The basic procedure is to allocate rate base, expenses, and revenue among

the various service classes via a three step process of (1) functionalization, (2) classification of investment and expenses; then, (3) allocation of those "costs" among the service subclasses.

Q. Please explain what is meant by the term "functionalization".

A. Functionalization characterizes the analysis and re-grouping of the various plant investment and expenses according to the activity or "function" for which the cost was incurred rather than by the FERC/PSC account number to which it was booked. The conventional "functions" are production-related, transmission-related, distribution-related or customer-related (PTDC).

Q. How did you determine the function of a cost?

A. Company accounting records and data maintained for engineering purposes are the principal sources of information used in the functionalization process. Personnel from the Company's accounting and engineering areas also provided assistance in identifying the particular function or functions of specific investments.

Q. Would you please provide an example of a functionalized cost?

A. Costs recorded in the Electric Plant Account 353, Transmission Station Equipment, averaged about $83.5 million in 2007. Records as to the type and location of the equipment represented by this investment indicate that

about $1.3 million served a production function; $66.3 million served a power supply transmission function; $15.7 million - a distribution function and about $100,000 served a specific class of customers. As a result, the $1.3 million would be functionalized to production, the $66.3 million to transmission, the $15.7 million to distribution, and the $100,000 is specifically assigned to a specific class of customers.

Q. Please explain what is meant by the term "classification".

A. Classification refers to the process of separating the functionalized costs into amounts related to demand, energy or number of customers. Demand-related costs vary in proportion to the rate (in kW or Mcf) at which customers utilize electricity or natural gas. Energy-related costs vary in proportion to the total volume of the electricity or natural gas delivered. Customer-related costs vary in proportion to the number of customers served. A smaller, fourth category of costs, specifically-assigned, defines costs that can be attributed to a particular service class of customers.

Q. Regarding your example of the functionalization of Electric Account 353, how did you proceed to classify these costs?

A. Since virtually all of the equipment included in Account 353 must be sized to meet the expected maximum collective demand of all customers, the non-specific functional categories (production, power supply transmission and

distribution) were classified as demand-related investment. The remainder, about $100,000, was specifically assigned.

Q. Please explain what is meant by the term "allocation".

A. Allocation refers to the process of distributing the functionalized and classified costs among the service classes on the basis of service class contribution to peak[1] demand (in kW); or, class contribution to total volume of electricity delivered (i.e. energy in MWh); or, class contribution to total number of customers; or, by direct assignment to a specific rate class when appropriate.

Q. Continuing with your Account 353 example, how was the plant investment ultimately allocated?

A. Investments functionalized as “production” and "power supply transmission" were allocated to the various service classes on the basis of their respective contribution to the average of the summer and winter coincident peak demands. Investment functionalized as "distribution-related" was allocated per class contribution to the class non-coincident peak demand at the

1 Several types of 'demand' allocators are used: Summer/Winter Coincident Peak (CP) demand, Class NCP (non-coincident peak kW); Sigma NCPi (sum of individual customer's peak demand).

substation level of service. Investments functionalized as "specific" were directly assigned to the rate classes of customers to be served by that investment.

Q. What major sources of information were used to develop the historical cost of service studies?

A. The "Electric Utility Cost Allocation Manual" dated January 1992 by the National Association of Regulatory Utility Commissioners was used as the basic reference on cost of service methodology. Company accounting and engineering records yielded additional information for the functionalization and classification of various costs. The Company's Annual Report to the PSC for the year ended December 31, 2007 was the principal source for Income Statement items and Operation & Maintenance expenses. The Company developed electric demand allocators from a comprehensive load research program. Finally, Company billing records yielded number of customers, kWh/Mcf sold/delivered and revenues by rate code and service class.

Q. What major sources of information were used to develop the rate year pro forma cost of service studies?

A. The Company's Revenue Requirements Panel provided rate year income statements for both gas and electric, which included estimates for future rate

base, O&M, depreciation and amortization and other operating expenses. The Company's Forecasting & Rates Panel provided revenue, sales and customer forecasts. Details regarding future plant investments, depreciation reserve and taxes came from the Accounting department. Rate year demand allocators were developed by applying the ratio of historical kWh/customer/class: kW/customer/class to the forecast kWh/customer/class. Application of historical COS results to rate year data yields an expected ROR on rate base by customer class, given currently effective rates. A comparison of class ROR to the system average ROR will indicate which rates need to be adjusted in order to improve the system average ROR and/or reduce interclass subsidies.

Q. How many service classes and subclasses do your studies address?

A. The electric department COS studies address twelve subclasses: SC1-residential general/non-heating, SC1-residential heating, SC6-residential time-of-use, SC2-small general service non-demand metered, SC2-small general service secondary demand metered, SC2-small general service primary demand metered, SC3-large general primary, SC13-large general substation, SC13-large general transmission, SC5-area lighting, SC8-street lighting and SC9-traffic signals.

The gas department COS studies address nine subclasses: SC1-residential heating, SC1-residential non-heating, SC2-commercial/industrial heating,

SC2-commercial/industrial non-heating, SC8 & 9-interruptible, SC11dlm-firm distribution large mains, Interdepartmental (Central Hudson's own use of gas), SC11t-firm transmission and SC11d-firm distribution.

Q. With respect to the specific process, how did you classify production plant in the Electric COS studies?

A. Consistent with the decision in Case 00-E-1273, hydroelectric production plant was classified energy-related; combustion turbines were classified demand-related.

Q. How did you classify production plant in the Gas COS studies?

A. As in Cases 90-G-0673, 92-G-1056, 95-G-1034, 00-G-1274, 05-G-0935 and 08-G-0888, gas production plant was classified 100% demand-related since the Company's gas production investment is in propane peaking facilities utilized to meet anticipated winter peak demand.

Q. Have you made any significant changes to the manner in which the Company functionalized, classified or allocated items as compared to the approach filed by the Company in Cases 08-E-0887 and 08-G-0888?

A. Yes, consistent with the Commission's Order in Case 08-E-0887, the allocation of procurement costs in the instant electric historic and pro forma COS studies has been changed. Previously, procurement costs were

allocated volumetrically on total energy deliveries. In the instant case, procurement costs have been allocated based on average number of billed customers in order to reflect an allocator that does not vary with volume, as prescribed by the Commission.

The gas historical and pro forma COS studies submitted in the instant case reflect gas mains costs allocated on the basis of 65% demand and 35% customer as prescribed by the Commission in the determination of rates in Case 08-G-0888. The studies also allocate the costs of the two downstream meters at West Point across the customer classes, including West Point, also as prescribed by the Commission in Case 08-G-0888. Additionally, the gas pre-allocator CSTMRS (total number of customers in the customer class divided by the total number of customers on the system) has been substituted for the pre-allocator CSTMRS2 (number of Metretek and Power Spring metered customers in the customer class divided by the total number of customers on the system having such demand meters). Finally, the development of the gas pro forma net plant by functional category in the new study reflects the functional detail underlying the net plant forecast developed by the Accounting Panel, consistent with the method utilized for the development of the electric pro forma net plant by functional category. This differs from the method utilized in Case 08-G-0888, wherein the gas pro forma net plant by functional category was developed by apportioning plant to functional category based on the historic COS plant balances.

Q. How are the costs of gas distribution mains less than six inches in diameter treated in the new studies?

A. Gas mains of less than six inches in diameter are allocated to customers other than the SC11dlm-firm distribution large mains class and the SC11t-firm transmission class.

Q. Please describe the distribution mains allocator utilized for the SC11dlm-firm distribution large mains class.

A. The distribution mains allocator utilized for this class has been adjusted to remove costs related to distribution mains less than 6-inches in diameter.

Q. Earlier in your testimony you made reference to unbundled functions and Case 00-M-0540. Please describe the requirements for unbundling and the results.

A. The Unbundling Track of Case 00-M-0504 required Central Hudson to file fully allocated embedded COS studies with unbundled rates based on those studies. In compliance, the Company filed such studies in Cases 05-E-0934, 05-G-0935, 08-E-0887 and 08-G-0888 that led to the implementation and continuation of the unbundled Merchant Function Charges (MFCs) that currently appear on customers' bills.

Q. Are the COS studies that you are sponsoring fully unbundled?

A. Yes. The electric and gas embedded COS studies prepared for this rate case identify the revenue requirements for bundled and unbundled components. Cost-based potential MFCs for customers taking commodity service from an Energy Services Company (ESCO) have been updated and are shown in Exhibit__(COSP-1) Schedule C for gas customers and Exhibit__(COSP-2) Schedule C for electric customers.

Q. How many cost components have you unbundled?

A. Four for the gas department and seven for the electric department.

Q. Could you please identify each of the unbundled components and explain the different number of unbundled functions for gas and electric?

A. The unbundled components common to both gas and electric departments include: procurement; credit & collections; bill printing, mailing and receipt services (BPRS); and, competitive energy services (CES). The unbundled components unique to the electric department include meter ownership, meter services and meter data services. The PSC has not yet mandated competitive metering for gas customers.

Q. How do these categories compare to the categories adopted by the Commission in its June 2009 rate order in Cases 08-E-0887 and 08-G-0888?

A. These categories are the same as those adopted by the Commission in its June 2009 rate order in Cases 08-E-0887 and 08-G-0888.

Q. Could you please identify the kinds of costs that are included in each of the unbundled component's revenue requirements?

A. Procurement includes shares of common plant, labor & expenses, including credit and collections costs related to commodity, for the acquisition of commodity for Central Hudson customers, allocated shares of call center costs and allocated shares of PSC accounts 905, 908 and Administrative & General O&M accounts 920 through 932 proportionate to full service credit & collections expenses.

The Credit & Collections (for delivery service) revenue requirement includes a share of account 904 (Uncollectible Accounts) proportionate to bad debt on delivery service as well as allocated shares of call center, credit and collections, bill complaints, and shares of 905, 908 & 920 through 932 proportionate to labor & expenses concerning delivery service credit & collections.

The BPRS revenue requirements and unbundled costs include labor and expenses attributable to the cash processing department, the annual charges of the vendor currently contracted by Central Hudson to print and mail bills plus allocated shares of call center costs and shares of expenses booked to

PSC accounts 905, 908 & 920 through 932.

CES includes the labor and expenses of any marketing efforts and advertising expenses related to sales promotions, plus an allocated share of call center costs and shares of expenses booked to PSC accounts 905, 908 & 920 through 932.

Regarding the unbundled components unique to the electric department: meter ownership reflects the service class average meter cost and average initial installation costs for non-demand meters but only the class average meter cost for demand metered customers; meter services reflect the class average avoidable maintenance expense per meter; and, meter data services reflect the class average meter reading cost.

Q. Please briefly describe the methods used to assign labor and expenses to each of the unbundled functions.

A. The analysis began with the compilation of year 2007 labor expenses (by internal area and function number) as recorded in each PSC account greater than or equal to 900.00; roughly 300 function numbers in the electric department and 200 in the gas department. Most areas within Central Hudson use 900 series accounts only for overhead-type functions (e.g., general office salaries); consequently, these labor expenses were temporarily functionalized as PTDC-related for later functionalization on labor sub-total across all functions. Several areas, however, use 900 series

accounts to record virtually all expenses. Labor and expenses in each of these areas were examined in detail and unbundled as appropriate.

Briefly, all labor and expenses booked to account 902, meter reading, were unbundled for the electric department but left bundled with customer accounts expenses for the gas department. Expenses booked to PSC account 904, Uncollectibles, were split proportionately between commodity-related bad debt and delivery service-related bad debt. Expenses booked to PSC account 903 by the call center were allocated to the various bundled and unbundled functions per surveys of call types from customers. Credit & collections costs booked to 903 were split like uncollectibles: to commodity-related procurement vs. delivery-service-related expenses. With the exception of bill printing and mailing vendor costs, most labor and expenses booked to PSC account 905 were functionalized per the unbundled subtotal of 902 & 903 labor. As previously mentioned, vendor charges for printing and mailing bills to customers were unbundled to the BPRS function together with labor and expenses from our cash processing department (from accts 903, 905, 908 and some A&G accounts). Marketing labor and expenses (within 908 & 912) were unbundled to CES together with advertising related to sales promotions (within PSC account 916) and shares of call center costs from several accounts.

Q. How would customers be able to avoid the unbundled costs and MFCs that you have described and shown in Schedule C of Exhibits (COSP-1) and (COSP-2)?

A. The complete array of unbundled costs could be avoided by customers who contract with an ESCO for commodity service, choose to have a single bill issued by the ESCO (an ESCO that agrees to assume all credit and collections costs); and, if an electric customer, contracts with a third party for all metering services.

Q. Are any current retail access/delivery service customers avoiding the full range of unbundled components?

A. No, not at this time. Currently, we have no retail access customers who have chosen to have a single bill issued by the ESCO. We do have customers who have chosen a single bill issued by Central Hudson and they receive a BPRS credit but the ESCO reimburses Central Hudson for that cost. Moreover, a customer would not be able to avoid the full range of unbundled components unless the billing ESCO assumed all uncollectibles, credit and collections responsibilities.

Q. Please briefly describe the results of the Gas Department COS studies.

A. Schedule A (the historical study) and Schedule B (the pro forma study) of Exhibit __ (COSP-1) summarize the rates of return for the system and for

service subclasses. Line 9 on each of the schedules details Rate Base by service class; Line 12 shows Total Operating Revenues; Line 18 shows Total Operating Expenses; Line 19 shows Operating Income (line 12 less line 18); and, Line 20 shows Rates of Return (line 19 divided by line 9).

The Index of Return, Line 21, indicates the relative degree of difference between the system total ROR and the ROR of each service class (100 signifies a ROR equal to the System ROR; 85 and 115 respectively indicate a ROR 15% less than and 15% greater than the System ROR).

The results from the historical gas COS study show the rates of return from four of the seven rate classes (excluding SC8&9 - interruptible and Interdepartmental) to be below the system average ROR.

The results shown in Exhibit __(COSP-1), Schedule B, the pro forma rate year gas COS study, reveal the system average ROR at 6.34%, below the 7.28% allowed for the rate year under the Order in Case 08-G-0888 issued and effective June 22, 2009, with four of seven classes also below the system average ROR.

Exhibit__(COSP-1) Schedule C Page 1 of 2 shows the approximate gas department revenue requirements by function to achieve a system average ROR of 7.58%, from each customer class. Exhibit__(COSP-1) Schedule C Page 2 of 2 develops (from Page 1) bundled delivery service rates (lines 53,

54 & 55) for each service class and potential credits for each of the unbundled components (lines 56-59). Finally, lines 60-63 develop delivery service rates with unbundled Merchant Function Charges (MFCs) for Administration (MFC_A) and Supply (MFC_B) for each rate class.

Q. What customers might be eligible to avoid MFC_A and MFC_B?

A. Any Retail Access customer of an ESCO that provided a single bill and assumed all credit and collection responsibilities would be eligible to avoid both MFC_A and MFC_B. A gas customer electing Retail Access service, with dual billing or single billing from Central Hudson, would be eligible to avoid only the Supply Charge, MFC_B (the Procurement and CES unbundled components; re: line 62).

Q. Please briefly describe the results of the Electric Department embedded COS (ECOS) studies.

A. Exhibit__(COSP-2) Schedule A (the historical year electric study) and Exhibit__(COSP-2) Schedule B (the pro forma study) similarly summarize the rates of return for the electric system and show the allocation of Rate Base, Revenues, Operating Expenses and resultant ROR by each customer rate classification.

Again, the Index of Return indicates the relative degree of difference between the system total ROR and the ROR of each service class (100

signifies a ROR equal to the System ROR; 85 and 115 respectively indicate a ROR 15% less than and 15% greater than the System ROR).

The results from the 2007 electric department COS study reveal indexes below 85 for the SC5 & SC8 lighting classes, SC1-Non-heat, and SC2-non-demand. All other classes had RORs above the 2007 system average ROR.

Exhibit__(COSP-2) Schedule B details the pro forma delivery service forecasted costs and expected revenues as allocated by the embedded electric cost of service study to the rate classes; and, the estimated rates of return by class. Schedule B shows the SC2 non-demand, SC13 substation, SC13 transmission and the SC5 lighting classes to be below a system index of 85, SC2 primary-demand is at the system index of 85, and all other classes are above an index of 85.

Exhibit__(COSP-2) Schedule C shows the revenue required to produce a targeted system average ROR of 7.58% from each service class (i.e. "levelized" revenue requirements), together with a potential rate structure for delivery service with potential credits for each of the unbundled components. The levelized bundled rates are shown in lines 60 through 62 and the unbundled credits potentially available to any retail access electric customer shown in lines 63 through 69.

Q. What might be the minimum Merchant Function Charge that a retail access electric customer might avoid?

A. An electric customer choosing an ESCO for commodity service with a two bill option or a single bill from Central Hudson would be eligible for MFC_B (reflecting the procurement credit shown on line 63 and the CES credit shown on line 69). The combined backout expressed in $/kWh is shown in line 73.

Q. What might be the maximum delivery MFC that a retail access electric customer could avoid?

A. An electric customer choosing an ESCO for commodity service that issued a single bill and assumed all credit and collections responsibilities for delivery service would be eligible to avoid both the Supply and the Administrative Merchant Function Charges (respectively MFC_B and MFC_A shown in Schedule C, page 2, lines 73 and 74).

Q. Are there any differences between the 2007 historical COS studies and the rate year studies?

A. Yes, the historical studies include rate base, revenues and expenses associated with commodity purchases of electricity and gas as well as delivery service rate base, revenues, and expenses. In contrast, the rate year studies contain neither fuel-related expenses nor expenses for the

purchase of electric or gas commodities.

Q. Has the Commission addressed these differences?

A. Yes. In its Order in Case 08-E-0887 the Commission required that the Company submit a delivery-only historic embedded cost of service study with its next electric rate filing. As a result, we have prepared such a study, which is summarized in Exhibit__(COSP-3). However, preparation of this study required that a number of gross simplifying assumptions be made regarding the identification and separation of revenues, certain expense items including federal and state income tax, and adjustments to rate base. As a result, we do not believe that the study accurately depicts historic results that may have been achieved if Central Hudson operated as a delivery-only company.

Q. Please discuss the preparation of a gas marginal cost of service study.

A. In its June 2009 Order, the Commission required that the Company file a gas marginal COS study with its next gas rate filing. The Commission also recognized that the Company might not have adequate time to complete such a study prior to its next filing. As Central Hudson has not previously been required to file a marginal COS study, such studies require a significant amount of time to prepare, and the Order requiring such a study was only issued June 22, 2009, we have not been able to complete a gas marginal COS study in time to include it with this filing, but believe that we could

submit such a study by December 1, 2009. Since the stated use for the study is in relation to the gas tail block rate design, this schedule should allow adequate time for consideration of the study in this case.

Q. Does this conclude your pre-filed direct testimony?

A. Yes.

Exhibits of
COST OF SERVICE PANEL

EXHIBIT __ (COSP-1)
Schedules A-C

EXHIBIT__(COSP-2)
Schedules A-C

EXHIBIT __(COSP-3)

EXHIBIT__(COSP-1)

CENTRAL HUDSON GAS & ELECTRIC CORPORATION

GAS DEPARTMENT

Embedded Cost of Service Studies

Schedule A – Rate of Return Statement for the Historical Year 2007

Schedule B – Rate of Return Statement for Rate Year # 1, 7/10 – 6/11

Schedule C, pg. 1– Levelized Revenue Requirements @ 7.58% ROR for Rate Year #1

Schedule C, pg. 2– Unbundled Revenue Requirements with Backout Credits

Gas Department 2007 Rate of Return Statement

			Residential		Commercial / Industrial		SC8/9	Firm		Firm	Firm
	Rate Base:	Total System	Heating	Non-heat	Heating	Non-heat	Interruptible	SC11 dlm	Intrdprtmntl	SC11 t	SC11 d
1	Gross Plant in Service	$ 259,679,369	$ 140,319,400	$ 17,906,088	$ 71,544,888	$ 7,436,723	$ 1,748,198	$ 2,898,119	$ 13,069,218	$ 4,017,141	$ 739,594
2	less: Accum. Provisions for Depr. & Amort.	$ 95,813,000	$ 45,714,208	$ 5,515,056	$ 24,923,566	$ 2,558,359	$ 530,154	$ 1,146,094	$ 13,302,675	$ 1,868,657	$ 254,231
3	Net Plant in Service	$ 163,866,369	$ 94,605,192	$ 12,391,032	$ 46,621,322	$ 4,878,364	$ 1,218,044	$ 1,752,025	$ (233,457)	$ 2,148,484	$ 485,363
4	plus: Construction Work in Progress	$ 7,353,000	$ 4,245,117	$ 556,009	$ 2,091,989	$ 218,902	$ 54,656	$ 78,617	$ (10,476)	$ 96,407	$ 21,779
5	plus: Working Capital	$ 23,730,249	$ 11,923,028	$ 826,515	$ 8,857,418	$ 821,343	$ 940,665	$ 74,748	$ 169,597	$ 97,620	$ 19,314
6	less: Accumulated Deferred Income Taxes	$ 27,270,000	$ 15,000,341	$ 1,815,815	$ 8,168,913	$ 839,323	$ 175,925	$ 400,278	$ 113,863	$ 669,029	$ 86,512
7	plus: Deferred Charges	$ 4,267,000	$ 2,430,668	$ 311,139	$ 1,233,487	$ 128,305	$ 30,357	$ 51,980	$ (5,357)	$ 73,343	$ 13,078
8	less: Other Rate Base Deductions	$ 13,907,249	$ 7,937,719	$ 990,251	$ 4,101,068	$ 421,633	$ 167,594	$ 126,289	$ (15,706)	$ 141,677	$ 36,723
9	Total Rate Base	$ 158,039,369	$ 90,265,945	$ 11,278,629	$ 46,534,234	$ 4,785,957	$ 1,900,202	$ 1,430,804	$ (177,849)	$ 1,605,147	$ 416,300
	Revenues:										
10	Sales, Transport & Divry Srvc Revenues	$ 145,945,217	$ 74,330,740	$ 4,397,589	$ 52,925,779	$ 5,412,902	$ 6,655,279	$ 516,810	$ 301,390	$ 1,258,150	$ 146,578
11	Miscellaneous Revenues	$ 19,804,484	$ 9,005,651	$ 376,102	$ 8,664,903	$ 1,280,324	$ -	$ -	$ 477,504	$ -	$ -
12	Total Operating Revenues	$ 165,749,701	$ 83,336,391	$ 4,773,691	$ 61,590,682	$ 6,693,226	$ 6,655,279	$ 516,810	$ 778,894	$ 1,258,150	$ 146,578
	Expenses:										
13	Operation and Maintenance	$ 137,892,300	$ 68,003,166	$ 4,012,162	$ 53,416,238	$ 4,887,384	$ 6,120,315	$ 273,976	$ 747,153	$ 363,495	$ 68,410
14	Depreciation and Amortization	$ 6,147,731	$ 3,424,069	$ 424,223	$ 1,813,600	$ 187,252	$ 41,265	$ 83,314	$ 23,721	$ 131,175	$ 19,113
15	Taxes Other than Income	$ 7,512,657	$ 4,153,914	$ 487,496	$ 2,369,897	$ 272,244	$ 47,344	$ 66,766	$ 13,568	$ 83,084	$ 18,344
16	Federal Income Tax	$ 3,653,670	$ 1,985,163	$ (112,395)	$ 997,527	$ 408,225	$ 126,479	$ 24,687	$ (6,414)	$ 219,264	$ 11,133
17	NYS Income Tax	$ 511,831	$ 275,495	$ (43,770)	$ 133,434	$ 80,774	$ 25,982	$ 1,677	$ (5,798)	$ 42,440	$ 1,598
18	Total Operating Expenses	$ 155,718,188	$ 77,841,807	$ 4,767,716	$ 58,730,696	$ 5,835,879	$ 6,361,385	$ 450,421	$ 772,230	$ 839,457	$ 118,597
19	Net Operating Income (line12 less line 18)	$ 10,031,513	$ 5,494,584	$ 5,975	$ 2,859,986	$ 857,347	$ 293,894	$ 66,389	$ 6,664	$ 418,693	$ 27,981
20	Rate of Return (line 19 divided by line 9)	6.35%	6.09%	0.05%	6.15%	17.91%	15.47%	4.64%	-3.75%	26.08%	6.72%
21	Index (Class ROR divided by System ROR)	100	96	1	97	282	244	73	(59)	411	106

Exhibit__(COSP-1)
Schedule A

Gas Department RY 7/10-6/11 Rate of Return Statement

			Residential		Commercial / Industrial		SC8/9	Firm		Firm	Firm
	Rate Base:	Total System	Heating	Non-heat	Heating	Non-heat	Interruptible	SC11 dlm	Intrdprtmntl	SC11 t	SC11 d
1	Gross Plant in Service	$ 311,390,000	$ 176,611,223	$ 19,748,481	$ 83,197,317	$ 9,134,735	$ -	$ 3,601,637	$ 13,982,845	$ 4,664,446	$ 449,316
2	less: Accum. Provisions for Depr. & Amort.	$ 105,053,822	$ 53,616,345	$ 5,767,394	$ 26,488,877	$ 2,885,150	$ -	$ 1,323,458	$ 12,791,673	$ 2,037,374	$ 143,552
3	Net Plant in Service	$ 206,336,178	$ 122,994,878	$ 13,981,087	$ 56,708,440	$ 6,249,586	$ -	$ 2,278,180	$ 1,191,172	$ 2,627,072	$ 305,764
4	plus: Construction Work in Progress	$ 8,577,000	$ 5,112,662	$ 581,167	$ 2,357,261	$ 259,783	$ -	$ 94,700	$ 49,515	$ 109,202	$ 12,710
5	plus: Working Capital	$ 8,809,000	$ 5,047,626	$ 579,604	$ 2,509,267	$ 283,079	$ -	$ 95,801	$ 157,235	$ 124,182	$ 12,205
6	less: Accumulated Deferred Income Taxes	$ 37,035,000	$ 21,098,715	$ 2,213,580	$ 10,777,152	$ 1,170,254	$ -	$ 587,595	$ 152,417	$ 976,417	$ 58,870
7	plus: Deferred Charges	$ 3,473,000	$ 1,972,192	$ 205,381	$ 1,006,390	$ 108,789	$ -	$ 58,067	$ 18,270	$ 98,230	$ 5,682
8	less: Other Rate Base Deductions	$ 127,000	$ 76,280	$ 8,815	$ 34,469	$ 3,816	$ -	$ 1,285	$ 838	$ 1,313	$ 184
9	Total Rate Base	$ 190,033,178	$ 113,952,363	$ 13,124,843	$ 51,769,737	$ 5,727,167	$ -	$ 1,937,868	$ 1,262,937	$ 1,980,955	$ 277,307
	Revenues:										
10	Sales, Transport & Divry Srvc Revenues	$ 67,993,360	$ 40,918,936	$ 2,949,488	$ 19,312,754	$ 2,747,072	$ -	$ 655,200	$ 54,270	$ 1,282,320	$ 73,320
11	Miscellaneous Revenues	$ 1,329,300	$ 953,072	$ 53,438	$ 287,607	$ 35,184	$ -	$ -	$ -	$ -	$ -
12	Total Operating Revenues	$ 69,322,660	$ 41,872,008	$ 3,002,926	$ 19,600,360	$ 2,782,256	$ -	$ 655,200	$ 54,270	$ 1,282,320	$ 73,320
	Expenses:										
13	Operation and Maintenance	$ 35,787,000	$ 20,134,342	$ 2,322,673	$ 10,655,346	$ 1,225,206	$ -	$ 372,943	$ 518,692	$ 511,260	$ 46,539
14	Depreciation and Amortization	$ 7,571,000	$ 4,376,503	$ 471,483	$ 2,166,039	$ 236,272	$ -	$ 109,573	$ 29,746	$ 169,566	$ 11,818
15	Taxes Other than Income	$ 8,157,000	$ 4,970,392	$ 514,812	$ 2,200,078	$ 247,234	$ -	$ 76,168	$ 47,310	$ 90,913	$ 10,093
16	Federal Income Tax	$ 4,839,178	$ 3,459,527	$ (170,966)	$ 1,235,227	$ 321,792	$ -	$ 26,035	$ (201,304)	$ 168,579	$ 288
17	NYS Income Tax	$ 922,151	$ 675,403	$ (34,394)	$ 229,459	$ 62,312	$ -	$ 967	$ (38,052)	$ 26,711	$ (255)
18	Total Operating Expenses	$ 57,276,329	$ 33,616,168	$ 3,103,606	$ 16,486,148	$ 2,092,817	$ -	$ 585,687	$ 356,392	$ 967,028	$ 68,483
19	Net Operating Income (line12 less line 18)	$ 12,046,331	$ 8,255,840	$ (100,680)	$ 3,114,212	$ 689,439	$ -	$ 69,513	$ (302,122)	$ 315,292	$ 4,837
20	Rate of Return (line 19 divided by line 9)	6.34%	7.24%	-0.77%	6.02%	12.04%	0.00%	3.59%		15.92%	1.74%
21	Index (Class ROR divided by System ROR)	100	114	(12)	95	190	-	57		251	28

Exhibit__(COSP-1)
Schedule B

Levelized RY Gas Revenue Requirement @ Target ROR = 7.58%

				Residential		Commercial / Industrial		SC8/9	Firm		Firm	Firm
			Total System	Heating	Non-heat	Heating	Non-heat	Interruptible	SC11 dlm	Intrdprtmntl	SC11 t	SC11 d
	Production:											
1	Demand - Capacity	DFWPK	$ 1,017,864	$ 501,045	$ 13,468	$ 455,297	$ 45,268	$ -	$ -	$ 2,787	$ -	$ -
2	Demand - Generation	DAVGMCF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Commodity	COMMOD	$ (68,693)	$ (26,637)	$ (967)	$ (26,641)	$ (4,031)	$ -	$ (3,752)	$ (105)	$ (6,269)	$ (290)
4	Procurement	DAVGMCF	$ 2,066,784	$ 944,677	$ 34,285	$ 944,844	$ 142,978	$ -	$ -	$ -	$ -	$ -
5	Total Production		$ 3,015,955	$ 1,419,085	$ 46,786	$ 1,373,500	$ 184,214	$ -	$ (3,752)	$ 2,682	$ (6,269)	$ (290)
	Transmission & Subtransmission:											
6	Supply Trans - Reg Stations	DWPK	$ 4,118,350	$ 1,735,850	$ 46,660	$ 1,577,359	$ 156,828	$ -	$ 175,233	$ 9,654	$ 406,162	$ 10,605
7	Supply Trans - Lines	DWPK	$ 12,737	$ 5,368	$ 144	$ 4,878	$ 485	$ -	$ 542	$ 30	$ 1,256	$ 33
8	Common Trans - Reg Stations	DWPK	$ 1,485,413	$ 626,089	$ 16,829	$ 568,924	$ 56,565	$ -	$ 63,203	$ 3,482	$ 146,495	$ 3,825
9	Common Trans - Lines	DWPK	$ 245	$ 103	$ 3	$ 94	$ 9	$ -	$ 10	$ 1	$ 24	$ 1
10	T&D Equip for Spfc Cstmrs @ Trans PSI	STSUB	$ 216,048	$ 12,659	$ 419	$ 12,561	$ 1,294	$ -	$ 50,598	$ 916	$ 137,600	$ -
11	Specific Iroquois Lines	STLNS	$ 425,661	$ -	$ -	$ -	$ -	$ -	$ -	$ 425,661	$ -	$ -
12	General Reg Stations / Lines	DWPK	$ 3,147,386	$ 1,326,597	$ 35,659	$ 1,205,472	$ 119,853	$ -	$ 133,919	$ 7,378	$ 310,403	$ 8,104
13	Total Transmission & Subtransmission		$ 9,405,840	$ 3,706,667	$ 99,715	$ 3,369,289	$ 335,035	$ -	$ 423,505	$ 447,121	$ 1,001,941	$ 22,567
	Bulk Distribution:											
14	Distribution Reg Stations	DMAINS	$ 2,245,920	$ 1,082,039	$ 29,085	$ 983,244	$ 97,758	$ -	$ 41,165	$ 6,018	$ -	$ 6,610
15	Bulk Mains & Mtr Stations - Demand	DMAINS	$ 17,108,249	$ 8,242,410	$ 221,557	$ 7,489,838	$ 744,672	$ -	$ 313,577	$ 45,840	$ -	$ 50,355
16	Bulk Mains & Mtr Stations - Customer	CMAINS	$ 9,212,134	$ 6,837,224	$ 1,107,428	$ 1,110,941	$ 156,245	$ -	$ 47	$ 125	$ -	$ 125
17	(reserved for future use) - Demand	DSPFC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Dist Equip of Spfc Customers (SC8 & SC11)	CORUPT	$ 408,546	$ 176,588	$ 7,054	$ 184,704	$ 27,464	$ -	$ -	$ -	$ -	$ 12,735
19	Bulk Services Demand	DSRVCS	$ 807,827	$ 396,461	$ 10,657	$ 360,263	$ 35,819	$ -	$ -	$ 2,205	$ -	$ 2,422
20	Bulk Services Customer	CSECY	$ 11,101,638	$ 8,239,762	$ 1,334,597	$ 1,338,831	$ 188,296	$ -	$ -	$ 150	$ -	$ -
21	(reserved for future use) - Demand	DSVCES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	Specific Services - Customer (SC8 & SC11)	CORUPT	$ 26,507	$ 12,322	$ 492	$ 12,888	$ 1,916	$ -	$ -	$ -	$ -	$ 889
23	Total Bulk Distribution		$ 40,912,820	$ 24,986,807	$ 2,710,871	$ 11,480,709	$ 1,252,171	$ -	$ 354,790	$ 54,338	$ -	$ 73,135
24	Meters & Regulators	CMTRS	$ 7,193,271	$ 3,599,295	$ 623,989	$ 2,462,492	$ 280,306	$ -	$ 5,962	$ 204,594	$ 12,475	$ 4,158
25	Industrial Reg Stations	CINSTP	$ 111,849	$ -	$ -	$ 98,426	$ 13,423	$ -	$ -	$ -	$ -	$ -
26	Firm Customers Mtr / Reg Installations	CINSTX	$ 2,909,634	$ 2,159,301	$ 349,743	$ 350,852	$ 49,345	$ -	$ 197	$ 39	$ 118	$ 39
27	Miscellaneous Revenues	DRMISC	$ (1,329,300)	$ (953,072)	$ (53,438)	$ (287,607)	$ (35,184)	$ -	$ -	$ -	$ -	$ -
28	Uncollectibles, Credit & Collections on Delivery	CODBT	$ 1,741,044	$ 1,292,135	$ 209,288	$ 209,952	$ 29,528	$ -	$ 24	$ 24	$ 71	$ 24
29	Bill Printing, Mailing & Receipt Services	CNBLS	$ 528,051	$ 344,487	$ 55,797	$ 111,947	$ 15,745	$ -	$ 13	$ 13	$ 38	$ 13
30	Customer Account Services (901-905)	CUSTAC	$ 4,371,537	$ 2,893,625	$ 468,682	$ 884,025	$ 124,331	$ -	$ 471	$ 6	$ 298	$ 99
31	Competitive Energy Services	CUSVCS2	$ 156,636	$ 103,479	$ 16,761	$ 31,886	$ 4,484	$ -	$ 10	$ 2	$ 11	$ 4
32	Sales & Customer Service (907-916)	CUSVCS3	$ 1,495,529	$ 1,033,323	$ 167,368	$ 258,328	$ 36,332	$ -	$ 34	$ 28	$ 87	$ 29
33	Sales, Transport & Divry Srvc Revenues	RSALES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	Total Levelized Revenue Requirement from Rates		$ 70,512,866	$ 40,585,133	$ 4,695,559	$ 20,343,798	$ 2,289,731	$ -	$ 781,252	$ 708,846	$ 1,008,769	$ 99,779
35	Demand		$ 30,585,700	$ 13,926,623	$ 374,482	$ 12,657,930	$ 1,258,552	$ -	$ 778,247	$ 503,971	$ 1,001,941	$ 81,955
36	Commodity		$ 1,998,091	$ 918,040	$ 33,318	$ 918,203	$ 138,947	$ -	$ (3,752)	$ (105)	$ (6,269)	$ (290)
37	Customer		$ 39,258,375	$ 26,691,541	$ 4,341,197	$ 7,055,272	$ 927,416	$ -	$ 6,757	$ 204,980	$ 13,098	$ 18,114
38	Revenue		$ (1,329,300)	$ (953,072)	$ (53,438)	$ (287,607)	$ (35,184)	$ -	$ -	$ -	$ -	$ -
39	Check		0.00	(0.00)	0.00	-	0.00	-	(0.00)	(0.00)	0.00	(0.00)

				Residential		Commercial / Industrial		SC8/9	Firm		Firm	Firm	
			Total System	Heating	Non-heat	Heating	Non-heat	Interruptible	SC11 dlm	Intrdprtmntl	SC11 t	SC11 d	
	Revenue Requirements for bundled functions @ ROR on RB =	**7.58%**											
40	Demand-related functions	L 35	$ 30,585,700	$ 13,928,623	$ 374,482	$ 12,657,930	$ 1,258,552	$ -	$ 778,247	$ 503,971	$ 1,001,941	$ 81,955	
41	Commodity-related functions	L 36-L45	$ (68,693)	$ (26,637)	$ (967)	$ (26,641)	$ (4,031)	$ -	$ (3,752)	$ (105)	$ (6,269)	$ (290)	
42	Customer-related functions	L37-L38-L46:48	$ 35,503,344	$ 23,998,369	$ 4,005,914	$ 6,413,881	$ 842,475	$ -	$ 6,711	$ 204,942	$ 12,978	$ 18,074	
43	sub-total		$ 66,020,351	$ 37,900,355	$ 4,379,429	$ 19,045,169	$ 2,096,995	$ -	$ 781,206	$ 708,808	$ 1,008,650	$ 99,739	
44	Revenue Requirements for Unbundled Functions												
45	Procurement function	L 4	$ 2,066,784	$ 944,677	$ 34,285	$ 944,844	$ 142,978	$ -	$ -	$ -	$ -	$ -	
46	DS Uncollectibles, Credit & Collections function	L 28	$ 1,741,044	$ 1,292,135	$ 209,288	$ 209,952	$ 29,528	$ -	$ 24	$ 24	$ 71	$ 24	
47	Bill Printing, Mailing & Receipt function	L 29	$ 528,051	$ 344,487	$ 55,797	$ 111,947	$ 15,745	$ -	$ 13	$ 13	$ 38	$ 13	
48	Competitive Energy Services function	L 31	$ 156,636	$ 103,479	$ 16,761	$ 31,886	$ 4,484	$ -	$ 10	$ 2	$ 11	$ 4	
49	sub-total		$ 4,492,515	$ 2,684,778	$ 316,129	$ 1,298,629	$ 192,735	$ -	$ 46	$ 38	$ 119	$ 40	
50	Total Delivery Service Revenue Requirement	L43+L49	$ 70,512,866	$ 40,585,133	$ 4,695,559	$ 20,343,798	$ 2,289,731	$ -	$ 781,252	$ 708,846	$ 1,008,769	$ 99,779	
	RY Billing Units												
51a	GAS Deliveries @ meter (SC8&9 sales to SC1 & 2), Mcf		14,851,002	5,758,687	208,997	5,759,705	871,586	0	811,237	22,650	1,355,420	62,720	
51b	GAS Deliveries @ meter, Mcf		14,851,002	4,995,750	181,308	4,996,633	756,114	1,669,170	811,237	22,650	1,355,420	62,720	
52	Number of Customers		73,855	54,813	8,878	8,906	1,253	0	1	1	3	1	
	Levelized Full Service DS Rates based on RY @ ROR =	**7.58%**											
53	for Demand-related functions, Rate, $ / Mcf	L35 / L51a	$ 2.06	$ 2.42	$ 1.79	$ 2.20	$ 1.44	$ -	$ 0.96	$ -	$ 0.74	$ 1.31	
54	Energy functions $ / Mcf @ mtr (excluding commodity chgs)	L36 / L51a	$ 0.1345	$ 0.1594	$ 0.1594	$ 0.1594	$ 0.1594	$ -	$ (0.0046)	$ -	$ (0.0046)	$ (0.0046)	
55	Customer Rate, $ / mo	L37+ L38/L52/12	$42.80	$39.13	$40.25	$63.32	$59.36	$0.00	$563.08	$0.00	$363.82	$1,509.50	
	Potential Backout Credits available to Customers												
56	Procurement $ / Mcf at meter	L45 / L51b	$ 0.1392	$ 0.1891	$ 0.1891	$ 0.1891	$ 0.1891	$ -	$ -	$ -	$ -	$ -	
57	Divry Srvc Uncollectibles, Credit & Collections Rate $ / month	L46 / L52 / 12	$1.96	$1.96	$1.96	$1.96	$1.96	$0.00	$0.00	$0.00	$0.00	$0.00	
58	Bill Printing & Receipt Services Rate $ / month	L47 / L52 / 12	$0.60	$0.52	$0.52	$1.05	$1.05	$0.00	$0.00	$0.00	$0.00	$0.00	
59	Competitive Energy Services Rate $ / month	L48 / L52 / 12	$0.18	$0.16	$0.16	$0.30	$0.30	$0.00	$0.00	$0.00	$0.00	$0.00	
	Delivery Service Rates and MFCs @ ROR =	**7.58%**											
60	Energy Rate (Net of Procurement) in $ / Mcf	L40+L41 / L51b	$ 2.0549	$ 2.7828	$ 2.0601	$ 2.5280	$ 1.6592	$ -	$ -	$ -	$ -	$ -	
61	Customer Rate (Net of CES & UCC) in $ / month	L55- L57- L59	$40.66	$37.01	$38.13	$61.06	$57.10	$0.00	$0.00	$0.00	$0.00	$0.00	
62	Supply Charge (Procurement + CES) in $ / Mcf	L45+L48 / L51b	$ 0.1497	$ 0.2098	$ 0.2815	$ 0.1955	$ 0.1950	$ -	$ -	$ -	$ -	$ -	MFC_B
63	Admin. Charge: (Uncollectibles Credit & Collections) in $ / Mcf	L46 / L51b	$ 0.1172	$ 0.2586	$ 1.1543	$ 0.0420	$ 0.0391	$ -	$ -	$ -	$ -	$ -	MFC_A
	Current (Jul 09) Delivery Service Rates												
64	First Block			First 2 Ccf or less	$ 17.00	first 2 Ccf or less	$ 30.00		$ 600.00	customer chg	$ 600.00	$ 600.00	
65	Second Block			next 48 Ccf	$ 0.6845	next 98 Ccf	$ 0.4727		$ 9.21	Mcf of MDQ/mo	$ 7.73	$ 15.53	
66	Third Block			additional gas	$ 0.3944	next 4900 Ccf	$ 0.2704		$ 1.00	Excess MDQ	$ 1.00	$ 1.00	
67	Fourth Block					additional gas	$ 0.2206						

EXHIBIT__(COSP-2)

CENTRAL HUDSON GAS & ELECTRIC CORPORATION

ELECTRIC DEPARTMENT

Embedded Cost of Service Studies

Schedule A – Rate of Return Statement for the Historical Year 2007

Schedule B – Rate of Return Statement for Rate Year # 1, 7/10 – 6/11

Schedule C, pg. 1– Levelized Revenue Requirements @ 7.58% ROR for Rate Year #1

Schedule C, pg. 2– Unbundled Revenue Requirements with Backout Credits

Electric Department 2007 Rate of Return Statement

			Residential			Small General Service			Large General Service			SC5 Area	SC8 Street	SC9 Traffic
	Rate Base:	Total System	SC1 Non-heat	SC1 Heat	SC6 TOU	SC2 non-dmnd	SC2 sec-dmnd	SC2 pri-dmnd	SC3 Primary	SC13 Subs	SC13 Trans	Lighting	Lighting	Lighting
1	Gross Plant in Service	$ 841,316,671	$ 489,227,071	$ 67,526,136	$ 6,444,856	$ 59,003,014	$ 122,907,662	$ 13,243,150	$ 18,175,419	$ 8,610,642	$ 34,803,407	$ 9,390,348	$ 11,527,286	$ 457,678
2	less: Accum. Provisions for Depr. & Amort.	$ 259,703,270	$ 148,059,727	$ 20,548,963	$ 1,982,083	$ 17,762,692	$ 39,662,036	$ 4,377,740	$ 6,033,077	$ 2,847,822	$ 12,091,930	$ 2,723,169	$ 3,475,003	$ 139,029
3	Net Plant in Service	$ 581,613,401	$ 341,167,344	$ 46,977,173	$ 4,462,773	$ 41,240,323	$ 83,245,627	$ 8,865,411	$ 12,142,343	$ 5,762,820	$ 22,711,477	$ 6,667,179	$ 8,052,283	$ 318,649
4	plus: Construction Work in Progress	$ 32,990,000	$ 19,224,127	$ 2,661,621	$ 254,315	$ 2,294,942	$ 4,738,772	$ 519,969	$ 721,777	$ 347,067	$ 1,401,195	$ 382,015	$ 426,233	$ 17,967
5	plus: Working Capital	$ 32,389,000	$ 18,615,036	$ 2,534,181	$ 240,566	$ 2,312,052	$ 5,191,918	$ 512,462	$ 670,065	$ 272,778	$ 1,182,314	$ 284,285	$ 554,242	$ 19,100
6	less: Accumulated Deferred Income Taxes	$ 75,995,000	$ 42,613,247	$ 5,915,190	$ 580,581	$ 5,117,899	$ 11,787,085	$ 1,387,630	$ 1,913,984	$ 905,365	$ 3,833,533	$ 812,561	$ 1,088,042	$ 39,883
7	plus: Deferred Charges	$ (40,844,000)	$ (23,909,916)	$ (3,304,963)	$ (315,380)	$ (2,857,829)	$ (5,811,328)	$ (633,430)	$ (878,071)	$ (421,682)	$ (1,679,320)	$ (477,581)	$ (532,257)	$ (22,241)
8	less: Other Rate Base Deductions	$ (7,380,000)	$ (4,229,995)	$ (589,411)	$ (57,271)	$ (510,710)	$ (1,113,129)	$ (119,143)	$ (163,033)	$ (80,258)	$ (314,042)	$ (83,131)	$ (116,107)	$ (3,770)
9	Total Rate Base	$ 537,533,401	$ 316,713,339	$ 43,542,233	$ 4,118,963	$ 38,382,299	$ 76,691,033	$ 7,995,923	$ 10,905,163	$ 5,135,876	$ 20,096,175	$ 6,126,468	$ 7,528,567	$ 297,362
	Revenues:													
10	Electric Delivery Revenues	$ 575,273,377	$ 249,924,255	$ 42,410,839	$ 4,381,978	$ 22,696,503	$ 142,492,954	$ 15,388,300	$ 20,758,588	$ 1,733,686	$ 68,259,412	$ 1,920,627	$ 4,868,264	$ 437,970
11	Other Revenues	$ 41,580,840	$ 17,573,331	$ 2,897,447	$ 293,767	$ 1,602,364	$ 9,492,155	$ 1,107,947	$ 1,636,885	$ 732,631	$ 5,552,620	$ 324,992	$ 339,912	$ 26,788
12	Total Operating Revenues	$ 616,854,217	$ 267,497,587	$ 45,308,286	$ 4,675,745	$ 24,298,868	$ 151,985,109	$ 16,496,246	$ 22,395,473	$ 2,466,317	$ 73,812,032	$ 2,245,619	$ 5,208,176	$ 464,759
	Expenses:													
13	Operation and Maintenance	$ 510,766,394	$ 218,071,294	$ 35,885,969	$ 3,631,792	$ 23,363,035	$ 121,984,958	$ 14,124,688	$ 18,116,719	$ 1,241,610	$ 68,015,721	$ 1,802,234	$ 4,190,237	$ 338,137
14	Depreciation and Amortization	$ 22,251,467	$ 13,001,075	$ 1,790,476	$ 170,183	$ 1,577,234	$ 3,225,254	$ 342,277	$ 467,040	$ 220,917	$ 878,934	$ 250,494	$ 315,411	$ 12,172
15	Taxes Other than Income	$ 27,063,824	$ 12,733,029	$ 1,701,652	$ 200,535	$ 1,331,622	$ 5,893,758	$ 745,898	$ 1,078,947	$ 425,189	$ 2,733,011	$ 58,003	$ 149,932	$ 12,249
16	Federal Income Tax	$ 13,755,420	$ 5,069,942	$ 1,545,695	$ 181,527	$ (926,540)	$ 5,943,393	$ 340,388	$ 782,073	$ 149,949	$ 538,680	$ 2,373	$ 97,863	$ 30,077
17	NYS Income Tax	$ 3,243,229	$ 1,189,484	$ 356,436	$ 41,774	$ (204,726)	$ 1,403,842	$ 81,079	$ 181,568	$ 34,534	$ 125,190	$ (2,574)	$ 29,662	$ 6,961
18	Total Operating Expenses	$ 577,080,333	$ 250,064,823	$ 41,280,229	$ 4,225,812	$ 25,140,624	$ 138,451,204	$ 15,634,329	$ 20,626,347	$ 2,072,198	$ 72,291,536	$ 2,110,529	$ 4,783,106	$ 399,596
19	Net Operating Income (line12 less line 18)	$ 39,773,884	$ 17,432,764	$ 4,028,057	$ 449,933	$ (841,756)	$ 13,533,905	$ 861,917	$ 1,769,127	$ 394,119	$ 1,520,496	$ 135,090	$ 425,070	$ 65,162
20	Rate of Return (line 19 divided by line 9)	7.40%	5.50%	9.25%	10.92%	-2.19%	17.65%	10.78%	16.22%	7.67%	7.57%	2.21%	5.65%	21.91%
21	Index (Class ROR divided by System ROR)	100	74	125	148	(30)	238	146	219	104	102	30	76	296

Exhibit_(COSP-2)
Schedule A

Electric Department RY#1 7/10-6/11 Rate of Return Statement

			Residential			Small General Service			Large General Service			SC5 Area	SC8 Street	SC9 Traffic
	Rate Base:	Total System	SC1 Non-heat	SC1 Heat	SC6 TOU	SC2 non-dmnd	SC2 sec-dmnd	SC2 pri-dmnd	SC3 Primary	SC13 Subs	SC13 Trans	Lighting	Lighting	Lighting
1	Gross Plant in Service	$ 1,038,725,000	$ 603,417,853	$ 83,116,492	$ 6,975,211	$ 68,322,060	$ 158,305,203	$ 19,698,527	$ 21,193,811	$ 11,329,413	$ 40,973,675	$ 11,010,731	$ 13,842,551	$ 539,473
2	less: Accum. Provisions for Depr. & Amort.	$ 295,695,177	$ 169,884,012	$ 23,487,209	$ 1,980,252	$ 19,230,150	$ 46,331,464	$ 5,818,155	$ 6,259,905	$ 3,337,036	$ 12,337,371	$ 2,984,923	$ 3,892,088	$ 152,611
3	Net Plant in Service	$ 743,029,823	$ 433,533,841	$ 59,629,283	$ 4,994,959	$ 49,091,910	$ 111,973,738	$ 13,880,372	$ 14,933,906	$ 7,992,377	$ 28,636,304	$ 8,025,809	$ 9,950,463	$ 386,862
4	plus: Construction Work in Progress	$ 31,130,000	$ 18,109,978	$ 2,504,178	$ 210,663	$ 2,023,158	$ 4,684,962	$ 593,146	$ 643,673	$ 348,697	$ 1,260,437	$ 342,973	$ 391,855	$ 16,280
5	plus: Working Capital	$ 36,990,000	$ 21,747,356	$ 2,900,848	$ 237,972	$ 2,623,641	$ 5,733,584	$ 648,866	$ 661,774	$ 317,902	$ 1,154,093	$ 326,350	$ 617,706	$ 19,908
6	less: Accumulated Deferred Income Taxes	$ 122,866,000	$ 69,432,857	$ 9,603,564	$ 824,862	$ 7,862,045	$ 19,601,065	$ 2,617,946	$ 2,817,985	$ 1,503,501	$ 5,551,960	$ 1,258,820	$ 1,729,134	$ 62,260
7	plus: Deferred Charges	$ 7,695,000	$ 4,440,333	$ 615,315	$ 52,094	$ 493,270	$ 1,182,030	$ 151,600	$ 164,863	$ 88,791	$ 326,531	$ 82,135	$ 94,044	$ 3,995
8	less: Other Rate Base Deductions	$ 1,857,000	$ 1,264,764	$ 160,781	$ 11,292	$ 149,571	$ 185,048	$ 17,027	$ 17,449	$ 4,412	$ 15,728	$ 21,654	$ 7,895	$ 1,377
9	Total Rate Base	$ 694,121,823	$ 407,133,887	$ 55,885,279	$ 4,659,533	$ 46,220,363	$ 103,788,202	$ 12,639,010	$ 13,568,782	$ 7,239,854	$ 25,809,676	$ 7,496,791	$ 9,317,038	$ 363,407
	Revenues:													
10	Electric Delivery Revenues	$ 254,320,935	$ 143,171,971	$ 22,643,372	$ 1,785,870	$ 12,184,099	$ 51,255,891	$ 4,692,742	$ 5,620,970	$ 2,003,720	$ 4,843,740	$ 1,625,120	$ 4,291,090	$ 202,350
11	Other Revenues	$ 8,369,485	$ 4,140,455	$ 844,976	$ 54,241	$ 351,171	$ 873,827	$ 59,223	$ 71,832	$ 118,687	$ 1,646,572	$ 205,274	$ 1,210	$ 2,017
12	Total Operating Revenues	$ 262,690,420	$ 147,312,426	$ 23,488,348	$ 1,840,111	$ 12,535,271	$ 52,129,718	$ 4,751,965	$ 5,692,802	$ 2,122,407	$ 6,490,312	$ 1,830,394	$ 4,292,300	$ 204,367
	Expenses:													
13	Operation and Maintenance	$ 143,685,000	$ 84,728,972	$ 10,991,966	$ 883,199	$ 10,827,112	$ 23,077,351	$ 2,395,511	$ 2,302,401	$ 961,300	$ 3,584,349	$ 985,163	$ 2,868,327	$ 79,250
14	Depreciation and Amortization	$ 27,563,000	$ 16,234,165	$ 2,232,855	$ 185,739	$ 1,841,545	$ 4,037,086	$ 495,138	$ 532,719	$ 289,274	$ 1,013,442	$ 312,790	$ 373,726	$ 14,521
15	Taxes Other than Income	$ 31,831,000	$ 15,667,704	$ 2,090,476	$ 212,609	$ 1,504,241	$ 7,015,236	$ 978,884	$ 1,108,970	$ 523,436	$ 2,421,053	$ 71,106	$ 223,171	$ 14,115
16	Federal Income Tax	$ 14,101,101	$ 6,903,777	$ 2,243,482	$ 146,541	$ (892,647)	$ 5,042,939	$ 189,058	$ 467,863	$ 59,585	$ (369,503)	$ 96,214	$ 184,933	$ 28,858
17	NYS Income Tax	$ 1,917,703	$ 873,715	$ 379,300	$ 23,340	$ (236,990)	$ 876,768	$ 17,511	$ 71,196	$ (1,698)	$ (129,254)	$ 8,304	$ 30,192	$ 5,317
18	Total Operating Expenses	$ 219,097,804	$ 124,408,332	$ 17,938,079	$ 1,451,429	$ 13,043,263	$ 40,049,381	$ 4,076,202	$ 4,483,149	$ 1,831,897	$ 6,520,086	$ 1,473,577	$ 3,680,349	$ 142,061
19	Net Operating Income (line12 less line 18)	$ 43,592,616	$ 22,904,094	$ 5,550,269	$ 388,682	$ (507,992)	$ 12,080,337	$ 675,763	$ 1,209,653	$ 290,510	$ (29,774)	$ 356,817	$ 611,951	$ 62,306
20	Rate of Return (line 19 divided by line 9)	6.28%	5.63%	9.93%	8.34%	-1.10%	11.64%	5.35%	8.91%	4.01%	-0.12%	4.76%	6.57%	17.14%
21	Index (Class ROR divided by System ROR)	100	90	158	133	(18)	185	85	142	64	(2)	76	105	273

Exhibit__(COSP-2)
Schedule B

	Levelized Electric RY #1 Revenue Requirement @	Target ROR	7.58%													
				Residential			Small General Service			Large General Service			SC5 Area	SC8 Street	SC9 Traffic
	Production:		Total System	SC1 Non-heat	SC1 Heat	SC6 TOU	SC2 non-dmnd	SC2 sec-dmnd	SC2 pri-dmnd	SC3 Primary	SC13 Subs	SC13 Trans	Lighting	Lighting	Lighting
1	Demand - Capacity	DSUWN	$ 6,440,018	$ 2,894,635	$ 515,977	$ 46,457	$ 250,565	$ 1,472,759	$ 232,660	$ 259,550	$ 124,279	$ 613,145	$ 9,946	$ 17,442	$ 2,604
2	Demand - Generation	DAVGKW	$ 7,238,711	$ 2,417,780	$ 443,569	$ 41,111	$ 217,260	$ 2,050,458	$ 337,569	$ 380,054	$ 220,801	$ 1,074,566	$ 18,458	$ 32,365	$ 4,721
3	Commodity	COMMOD	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Procurement	CUNITS	$ 8,646,875	$ 6,550,610	$ 735,144	$ 44,750	$ 822,187	$ 344,097	$ 4,856	$ 904	$ 199	$ 170	$ 129,636	$ 5,881	$ 8,439
5	Total Production		$ 22,325,603	$ 11,863,024	$ 1,694,690	$ 132,319	$ 1,290,012	$ 3,867,314	$ 575,085	$ 640,509	$ 345,279	$ 1,687,881	$ 158,040	$ 55,688	$ 15,763
	Transmission & Subtransmission:														
6	Power Supply Trans - Subs	DSUWN	$ 19,313,348	$ 8,680,891	$ 1,547,394	$ 139,322	$ 751,433	$ 4,416,742	$ 697,737	$ 778,379	$ 372,709	$ 1,838,797	$ 29,827	$ 52,309	$ 7,809
7	Power Supply Trans - Lines	DSPK	$ 36,122,938	$ 17,099,155	$ 1,765,528	$ 234,275	$ 1,511,778	$ 8,556,262	$ 1,278,337	$ 1,473,989	$ 710,308	$ 3,479,796	$ -	$ -	$ 13,510
8	Common Trans - Subs	DNCPTS	$ 232,109	$ 56,171	$ 10,127	$ 1,070	$ 5,966	$ 28,362	$ 4,198	$ 56,881	$ -	$ 68,371	$ 339	$ 584	$ 40
9	Common Trans - Lines	DNCPTL	$ 374,079	$ 104,064	$ 18,762	$ 1,982	$ 11,052	$ 52,544	$ 7,778	$ 10,297	$ -	$ 165,818	$ 627	$ 1,082	$ 73
10	Specific - Subs	STSUB	$ 2,287,778	$ -	$ -	$ -	$ -	$ -	$ -	$ 18,513	$ 458,614	$ 1,810,651	$ -	$ -	$ -
11	Specific - Lines	STLNS	$ 181,061	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 181,061	$ -	$ -	$ -
12	General Subtrans Lines	DNCPGT	$ 1,595,928	$ 712,497	$ 129,635	$ 11,979	$ 68,228	$ 362,733	$ 60,817	$ 62,173	$ 29,663	$ 145,708	$ 4,353	$ 7,633	$ 508
13	Total Transmission & Subtransmission		$ 60,107,241	$ 26,652,778	$ 3,471,446	$ 388,627	$ 2,348,457	$ 13,416,644	$ 2,048,867	$ 2,400,233	$ 1,571,294	$ 7,690,202	$ 35,146	$ 61,607	$ 21,940
	Bulk Distribution:														
14	Distribution Substations	DSUBS	$ 20,982,753	$ 10,308,885	$ 1,875,644	$ 173,327	$ 987,164	$ 5,248,267	$ 879,942	$ 899,567	$ 429,181	$ -	$ 62,983	$ 110,438	$ 7,355
15	Primary Lines - Demand	DPRIM	$ 18,170,322	$ 9,113,538	$ 1,658,157	$ 153,229	$ 872,700	$ 4,639,714	$ 777,910	$ 795,259	$ -	$ -	$ 55,680	$ 97,632	$ 6,503
16	Primary Lines - Customer	CPRIM	$ 39,806,028	$ 30,157,127	$ 3,384,392	$ 206,018	$ 3,785,113	$ 1,584,124	$ 22,357	$ 4,164	$ -	$ -	$ 596,808	$ 27,077	$ 38,849
17	Line Transformers - Demand	DTRNSF	$ 5,617,889	$ 3,445,449	$ 598,548	$ 45,614	$ 319,842	$ 1,175,794	$ -	$ -	$ -	$ -	$ 11,372	$ 19,941	$ 1,328
18	Line Transformers - Customer	CSECY	$ 6,431,716	$ 4,875,930	$ 547,203	$ 33,310	$ 611,993	$ 256,128	$ -	$ -	$ -	$ -	$ 96,494	$ 4,378	$ 6,281
19	Secondary Lines - Demand	DSECY	$ 6,120,983	$ 3,923,775	$ 669,701	$ 46,756	$ 359,993	$ 1,095,293	$ -	$ -	$ -	$ -	$ 8,872	$ 15,557	$ 1,036
20	Secondary Lines - Customer	CSECY	$ 20,199,866	$ 15,313,662	$ 1,718,580	$ 104,615	$ 1,922,064	$ 804,411	$ -	$ -	$ -	$ -	$ 303,057	$ 13,749	$ 19,727
21	Services - Demand	DSVCES	$ 2,856,370	$ 2,241,450	$ 382,566	$ 26,709	$ 205,646	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	Services - Customer	CSVCES	$ 1,991,596	$ 1,628,440	$ 107,298	$ 9,448	$ 246,411	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	Total Bulk Distribution		$ 122,177,523	$ 81,008,254	$ 10,942,088	$ 799,026	$ 9,310,926	$ 14,803,731	$ 1,680,208	$ 1,698,990	$ 429,181	$ -	$ 1,135,267	$ 288,772	$ 81,080
24	Meter Installations, CTs & PTs	CMTRS2	$ 6,680,890	$ -	$ -	$ -	$ -	$ 5,900,860	$ 445,836	$ 214,450	$ 55,589	$ 64,155	$ -	$ -	$ -
25	Installations on Customer Premises - Plant	CINSTP	$ 642,235	$ 115,320	$ 31,685	$ 1,204	$ -	$ -	$ -	$ -	$ -	$ -	$ 494,025	$ -	$ -
26	Installations on Customer Premises - Exp	CINSTX	$ 6,976,932	$ 4,474,285	$ 653,972	$ 49,219	$ 425,070	$ 1,243,712	$ 108,361	$ -	$ -	$ -	$ 22,313	$ -	$ -
27	Street Lighting	CLGTNG	$ 3,754,247	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,754,247	$ -
28	Meter Ownership (re: line 24)	CMTRS	$ 2,954,418	$ 1,954,311	$ 227,104	$ 49,166	$ 402,094	$ 304,208	$ 9,730	$ 4,111	$ 1,216	$ 2,479	$ -	$ -	$ -
29	Meter Services / Maintenance (re: line 24)	CMTRS3	$ 4,349,625	$ 2,630,582	$ 309,027	$ 87,621	$ 587,961	$ 694,407	$ 22,210	$ 9,384	$ 2,775	$ 5,659	$ -	$ -	$ -
30	Meter Reading (902)	CMTRS4	$ 10,803,270	$ 7,258,841	$ 814,625	$ 49,589	$ 1,822,158	$ 762,599	$ 10,763	$ 60,136	$ 13,224	$ 11,335	$ -	$ -	$ -
31	DS Uncollectibles, Credit & Collections (903, 904, 905)	CODBT	$ 6,869,325	$ 5,292,097	$ 593,907	$ 36,153	$ 664,227	$ 277,989	$ 3,923	$ 731	$ 161	$ 138	$ -	$ -	$ -
32	Bill Printing, Mailing & Receipt Services (903, 905)	CNBLS	$ 2,988,831	$ 1,965,089	$ 220,533	$ 13,424	$ 493,289	$ 206,448	$ 2,914	$ 543	$ 119	$ 102	$ 77,778	$ 3,529	$ 5,063
33	Customer Account Services (901-905)	CUSTAC	$ 13,344,527	$ 7,697,883	$ 1,184,297	$ 91,947	$ 684,276	$ 2,535,305	$ 229,183	$ 273,974	$ 97,651	$ 236,024	$ 93,470	$ 209,726	$ 10,789
34	Competitive Energy Services	CUSVCS2	$ 809,647	$ 627,784	$ 70,453	$ 4,289	$ 66,907	$ 28,001	$ 395	$ 74	$ 16	$ 14	$ 10,549	$ 479	$ 687
35	Sales & Customer Services (907-916)	CUSVCS3	$ 8,853,362	$ 6,673,452	$ 760,558	$ 51,472	$ 863,056	$ 344,624	$ 6,383	$ 3,335	$ 1,309	$ 5,741	$ 128,977	$ 5,868	$ 8,587
36	OTHER Revenues	OSALES	$ (8,369,485)	$ (4,140,455)	$ (844,976)	$ (54,241)	$ (351,171)	$ (873,827)	$ (59,223)	$ (71,832)	$ (118,687)	$ (1,646,572)	$ (205,274)	$ (1,210)	$ (2,017)
37	Sales Revenues	RSALES													
38	Total Levelized Electric RY #1 Revenue Requirement @		$ 265,268,191	$ 154,073,245	$ 20,129,411	$ 1,699,815	$ 18,607,262	$ 43,512,016	$ 5,084,635	$ 5,234,636	$ 2,399,125	$ 8,057,158	$ 1,950,291	$ 4,378,705	$ 141,892
39	Demand-related		$ 120,295,576	$ 58,580,509	$ 9,172,039	$ 880,720	$ 5,344,367	$ 27,048,471	$ 3,939,379	$ 4,354,608	$ 2,124,753	$ 8,303,347	$ 183,999	$ 322,617	$ 40,766
40	Energy-related		$ 15,885,586	$ 8,968,389	$ 1,178,713	$ 85,862	$ 1,039,447	$ 2,394,555	$ 342,425	$ 380,959	$ 221,000	$ 1,074,736	$ 148,094	$ 38,246	$ 13,159
41	Commodity-related		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
42	Customer-related		$ 137,456,515	$ 90,664,802	$ 10,623,635	$ 787,474	$ 12,574,620	$ 14,942,816	$ 862,054	$ 570,901	$ 172,059	$ 325,647	$ 1,823,472	$ 4,019,052	$ 89,984
43	Revenue		$ (8,369,485)	$ (4,140,455)	$ (844,976)	$ (54,241)	$ (351,171)	$ (873,827)	$ (59,223)	$ (71,832)	$ (118,687)	$ (1,646,572)	$ (205,274)	$ (1,210)	$ (2,017)
	Check		-	-	-	-	-	-	-	-	-	-	-	-	-

				Residential			Small General Service			Large General Service			SC5 Area	SC8 Street	SC9 Traffic
			Total System	SC1 Non-heat	SC1 Heat	SC6 TOU	SC2 non-dmnd	SC2 sec-dmnd	SC2 pri-dmnd	SC3 Primary	SC13 Subs	SC13 Trans	Lighting	Lighting	Lighting
	Revenue Requirements for bundled functions @ ROR on RB =	**7.58%**													
44	Demand-related functions	L 39-f43	$ 117,953,291	$ 58,364,077	$ 8,915,923	$ 878,123	$ 5,327,608	$ 26,948,245	$ 3,920,168	$ 4,331,549	$ 2,010,179	$ 6,710,186	$ 183,999	$ 322,617	$ 40,616
45	Energy-related functions	L40 - L48	$ 7,238,711	$ 2,417,780	$ 443,569	$ 41,111	$ 217,260	$ 2,050,458	$ 337,569	$ 380,054	$ 220,801	$ 1,074,566	$ 18,458	$ 32,365	$ 4,721
46	Customer-related functions	L42-f43-49.54	$ 102,657,218	$ 67,013,569	$ 7,799,430	$ 495,608	$ 8,203,698	$ 11,895,878	$ 772,129	$ 447,177	$ 150,478	$ 253,103	$ 1,529,945	$ 4,013,835	$ 82,368
47	sub-total		$ 227,849,220	$ 127,795,425	$ 17,158,922	$ 1,414,843	$ 13,748,566	$ 40,894,581	$ 5,029,866	$ 5,158,780	$ 2,381,459	$ 8,037,855	$ 1,732,402	$ 4,368,817	$ 127,705
	Revenue Requirements for Unbundled Functions														
48	Procurement function	L 4	$ 8,646,875	$ 6,550,610	$ 735,144	$ 44,750	$ 822,187	$ 344,097	$ 4,856	$ 904	$ 199	$ 170	$ 129,636	$ 5,881	$ 8,439
49	Meter Ownership function	L 28	$ 2,954,418	$ 1,954,311	$ 227,104	$ 49,166	$ 402,094	$ 304,208	$ 9,730	$ 4,111	$ 1,216	$ 2,479	$ -	$ -	$ -
50	Meter Services function	L 29	$ 4,349,625	$ 2,630,582	$ 309,027	$ 87,621	$ 587,961	$ 694,407	$ 22,210	$ 9,384	$ 2,775	$ 5,659	$ -	$ -	$ -
51	Meter Reading function	L 30	$ 10,803,270	$ 7,258,841	$ 814,625	$ 49,589	$ 1,822,158	$ 782,599	$ 10,763	$ 60,136	$ 13,224	$ 11,335	$ -	$ -	$ -
52	DS Uncollectibles, Credit & Collections function	L 31	$ 6,869,325	$ 5,292,097	$ 593,907	$ 36,153	$ 664,227	$ 277,989	$ 3,923	$ 731	$ 161	$ 138	$ -	$ -	$ -
53	Bill Printing, Mailing & Receipt function	L 32	$ 2,988,831	$ 1,965,089	$ 220,533	$ 13,424	$ 493,289	$ 206,448	$ 2,914	$ 543	$ 119	$ 102	$ 77,778	$ 3,529	$ 5,063
54	Competitive Energy Services function	L 34	$ 809,647	$ 627,784	$ 70,453	$ 4,289	$ 66,907	$ 28,001	$ 395	$ 74	$ 16	$ 14	$ 10,549	$ 479	$ 687
55	sub-total		$ 37,421,991	$ 26,279,314	$ 2,970,794	$ 284,991	$ 4,858,823	$ 2,617,750	$ 54,790	$ 75,883	$ 17,709	$ 19,897	$ 217,964	$ 9,889	$ 14,188
56	Total Delivery Service Revenue Requirement	L47 + L55	$ 265,271,211	$ 154,074,739	$ 20,129,716	$ 1,699,834	$ 18,607,389	$ 43,512,331	$ 5,084,657	$ 5,234,662	$ 2,399,168	$ 8,057,752	$ 1,950,365	$ 4,378,706	$ 141,893
	Billing Units														
57	Average Monthly Sigma NCPi @ meter, kW		1,952,640	1,069,547	167,584	12,630	84,323	372,498	53,119	52,594	25,392	114,953	0	0	0
58	Deliveries as measured @ meter, MWh		5,190,459	1,705,499	312,893	29,000	153,255	1,446,391	245,144	275,997	165,640	817,460	13,020	22,830	3,330
59	Number of Customers		304,329	230,550	25,874	1,575	28,937	12,111	171	32	7	6	4,563	207	297
	Levelized Full Service DS Rates based on ROR =	**7.58%**													
60	Demand Rate, $ / kW / month	L44 / L57 / 12	$5.03	$0.00	$0.00	$0.00	$0.00	$6.03	$6.15	$6.86	$6.60	$4.86	$0.00	$0.00	$0.00
61	Energy Rate $ / kWh @ mtr (excluding commodity chgs)	L40 / L58	$ 0.00306	$ 0.03948	$ 0.03226	$ 0.03324	$ 0.04155	$ 0.00156	$ 0.00140	$ 0.00138	$ 0.00133	$ 0.00131	$ 0.02551	$ 0.01581	$ 0.01615
62	Customer Rate, $ / mo	L42-f43/L59/12	$35.99	$31.35	$32.32	$38.93	$35.25	$97.50	$400.81	$1,366.90	$1,999.86	$3,789.29	$29.56	$1,617.49	$24.72
	Potential Backout Credits available to Customers														
63	Procurement $ / kWh delivered @ Meter level	L48 / L58	$ 0.00167	$ 0.00384	$ 0.00235	$ 0.00154	$ 0.00536	$ 0.00024	$ 0.00002	$ 0.00000	$ 0.00000	$ 0.00000	$ 0.00996	$ 0.00026	$ 0.00253
64	Meter Ownership Rate $ / month	L49 / L59 / 12	$0.81	$0.71	$0.73	$2.60	$1.16	$2.09	$4.74	$10.76	$14.47	$34.43	$0.00	$0.00	$0.00
65	Meter Services Rate $ / month	L50 / L59 / 12	$1.19	$0.95	$1.00	$4.64	$1.69	$4.78	$10.83	$24.57	$33.03	$78.59	$0.00	$0.00	$0.00
66	Meter Reading Rate $ / month	L51 / L59 / 12	$2.96	$2.62	$2.62	$2.62	$5.25	$5.25	$5.25	$157.42	$157.42	$157.42	$0.00	$0.00	$0.00
67	Divry Srvc Uncollectibles, Credit & Collections Rate $ / month	L52 / L59 / 12	$1.88	$1.91	$1.91	$1.91	$1.91	$1.91	$1.91	$1.91	$1.91	$1.91	$0.00	$0.00	$0.00
68	Bill Printing & Receipt Services Rate $ / month	L53 / L59 / 12	$0.82	$0.71	$0.71	$0.71	$1.42	$1.42	$1.42	$1.42	$1.42	$1.42	$1.42	$1.42	$1.42
69	Competitive Energy Services Rate $ / month	L54 / L59 / 12	$0.22	$0.23	$0.23	$0.23	$0.19	$0.19	$0.19	$0.19	$0.19	$0.19	$0.19	$0.19	$0.19
	Delivery Service Rates and MFCs @ ROR =	**7.58%**													
70	Demand Rate, $ / kW / month	L 60	$5.03	$0.00	$0.00	$0.00	$0.00	$6.03	$6.15	$6.86	$6.60	$4.86	$0.00	$0.00	$0.00
71	Energy Rate (Net of Procurement) in $ / kWh	L61 - L63	$ 0.00139	$ 0.03564	$ 0.02991	$ 0.03170	$ 0.03618	$ 0.00142	$ 0.00138	$ 0.00138	$ 0.00133	$ 0.00131	$ 0.01555	$ 0.01555	$ 0.01361
72	Customer Rate (Net of CES & UCC) in $ / month	L62- L67- L69	$33.89	$29.21	$30.18	$36.79	$33.14	$95.40	$398.71	$1,364.79	$1,997.76	$3,787.19	$29.36	$1,617.30	$24.53
73	Supply Charge (Procurement + CES) in $ / kWh	(L48+L54) / L58	$ 0.00182	$ 0.00421	$ 0.00257	$ 0.00169	$ 0.00580	$ 0.00026	$ 0.00002	$ 0.00000	$ 0.00000	$ 0.00000	$ 0.01077	$ 0.00028	$ 0.00274
74	Admin. Charge: (Uncollectibles Credit & Collections) in $ / kWh	L52 / L58	$ 0.00132	$ 0.00310	$ 0.00190	$ 0.00125	$ 0.00433	$ 0.00019	$ 0.00002	$ 0.00000	$ 0.00000	$ 0.00000	$ -	$ -	$ -
	Current (Jul '09) Delivery Service Rates														
75	Demand Rate, $ / kW / month			$0.00	$0.00	$0.00	$0.00	$8.00	$6.30	$8.42	$6.21	$3.34	$0.00	$0.00	$0.00
76	Energy Rate $ / kWh (excluding commodity chgs)			$ 0.04691	$ 0.04691	07892/.02630	$ 0.00340	$ 0.00522	$ 0.00135	$ -	$ -	$ -	rates based on lamp type		
77	Customer Rate, $ / mo			$18.00	$18.00	$21.00	$30.00	$50.00	$160.00	$620.00	$800.00	$800.00	$0.00	$0.00	$0.00

MFC_a
MFC_A

EXHIBIT__(COSP-3)

CENTRAL HUDSON GAS & ELECTRIC CORPORATION

ELECTRIC DEPARTMENT

Electric Department Delivery-Only Hypothetical Embedded Study

Page 1 of 2: Electric Department Delivery-Only Hypothetical Rate of Return Statement

Page 2 of 2: Summary of Assumptions

Electric Department Delivery-Only HYPOTHETICAL Rate of Return Statement

			Residential			Small General Service			Large General Service			SC5 Area	SC8 Street	SC9 Traffic
	Rate Base:	Total System	SC1 Non-heat	SC1 Heat	SC6 TOU	SC2 non-dmnd	SC2 sec-dmnd	SC2 pri-dmnd	SC3 Primary	SC13 Subs	SC13 Trans	Lighting	Lighting	Lighting
1	Gross Plant in Service	$ 841,316,671	$ 489,227,071	$ 67,526,136	$ 6,444,856	$ 59,003,014	$ 122,907,662	$ 13,243,150	$ 18,175,419	$ 8,610,642	$ 34,803,407	$ 9,390,348	$ 11,527,286	$ 457,678
2	less: Accum. Provisions for Depr. & Amort.	$ 259,703,270	$ 148,059,727	$ 20,548,963	$ 1,982,083	$ 17,762,692	$ 39,662,036	$ 4,377,740	$ 6,033,077	$ 2,847,822	$ 12,091,930	$ 2,723,169	$ 3,475,003	$ 139,029
3	Net Plant in Service	$ 581,613,401	$ 341,167,344	$ 46,977,173	$ 4,462,773	$ 41,240,323	$ 83,245,627	$ 8,865,411	$ 12,142,343	$ 5,762,820	$ 22,711,477	$ 6,667,179	$ 8,052,283	$ 318,649
4	plus: Construction Work in Progress	$ 32,990,000	$ 19,224,127	$ 2,661,621	$ 254,315	$ 2,294,942	$ 4,738,772	$ 519,969	$ 721,777	$ 347,067	$ 1,401,195	$ 382,015	$ 426,233	$ 17,967
5	plus: Working Capital	$ 32,126,856	$ 18,515,767	$ 2,516,317	$ 238,713	$ 2,302,446	$ 5,123,359	$ 504,169	$ 659,393	$ 272,568	$ 1,138,409	$ 283,651	$ 553,143	$ 18,923
6	less: Accumulated Deferred Income Taxes	$ 75,995,000	$ 42,613,247	$ 5,915,190	$ 580,581	$ 5,117,899	$ 11,787,085	$ 1,387,630	$ 1,913,984	$ 905,365	$ 3,833,533	$ 812,561	$ 1,088,042	$ 39,883
7	plus: Deferred Charges	$ (40,844,000)	$ (23,909,916)	$ (3,304,963)	$ (315,380)	$ (2,857,829)	$ (5,811,328)	$ (633,430)	$ (878,071)	$ (421,582)	$ (1,679,320)	$ (477,581)	$ (532,257)	$ (22,241)
8	less: Other Rate Base Deductions	$ (7,380,000)	$ (4,230,871)	$ (589,465)	$ (57,273)	$ (510,854)	$ (1,112,634)	$ (119,073)	$ (162,948)	$ (80,294)	$ (313,500)	$ (83,169)	$ (116,148)	$ (3,770)
9	Total Rate Base	$ 537,271,257	$ 316,614,947	$ 43,524,422	$ 4,117,112	$ 38,372,837	$ 76,621,979	$ 7,987,560	$ 10,894,405	$ 5,135,702	$ 20,051,729	$ 6,125,871	$ 7,527,508	$ 297,185
	Revenues:													
10	Electric Delivery Revenues	$ 194,379,244	$ 105,038,768	$ 16,356,535	$ 1,680,849	$ 8,781,290	$ 43,167,590	$ 3,372,014	$ 5,309,453	$ 1,430,059	$ 4,788,739	$ 1,000,995	$ 3,272,051	$ 180,901
11	Other Revenues	$ 41,623,263	$ 17,614,425	$ 2,881,257	$ 292,281	$ 1,644,335	$ 9,532,308	$ 1,104,058	$ 1,634,352	$ 731,802	$ 5,496,048	$ 325,323	$ 340,259	$ 26,816
12	Total Operating Revenues	$ 236,002,507	$ 122,653,192	$ 19,237,792	$ 1,973,129	$ 10,425,625	$ 52,699,898	$ 4,476,072	$ 6,943,805	$ 2,161,860	$ 10,284,787	$ 1,326,319	$ 3,612,310	$ 207,716
	Expenses:													
13	Operation and Maintenance	$ 129,216,049	$ 73,585,877	$ 9,884,301	$ 934,433	$ 9,381,303	$ 22,196,974	$ 2,053,937	$ 2,582,324	$ 935,517	$ 4,111,899	$ 879,086	$ 2,589,940	$ 80,459
14	Depreciation and Amortization	$ 22,251,467	$ 13,001,075	$ 1,790,476	$ 170,183	$ 1,577,234	$ 3,225,254	$ 342,277	$ 467,040	$ 220,917	$ 878,934	$ 250,494	$ 315,411	$ 12,172
15	Taxes Other than Income	$ 27,063,824	$ 13,071,791	$ 1,734,988	$ 203,829	$ 1,349,922	$ 5,811,841	$ 715,832	$ 1,050,903	$ 439,078	$ 2,432,356	$ 63,794	$ 176,700	$ 12,791
16	Federal Income Tax	$ 13,999,942	$ 4,826,623	$ 1,513,043	$ 178,850	$ (901,566)	$ 6,147,845	$ 369,143	$ 821,040	$ 144,996	$ 779,966	$ 1,136	$ 88,746	$ 30,120
17	NYS Income Tax	$ 3,460,228	$ 1,229,778	$ 360,447	$ 42,227	$ (184,416)	$ 1,470,987	$ 90,300	$ 193,284	$ 34,545	$ 187,239	$ (1,522)	$ 30,335	$ 7,023
18	Total Operating Expenses	$ 195,991,510	$ 105,715,143	$ 15,283,255	$ 1,529,522	$ 11,222,477	$ 38,852,900	$ 3,571,489	$ 5,114,590	$ 1,775,053	$ 8,390,394	$ 1,192,988	$ 3,201,133	$ 142,565
19	Net Operating Income (line12 less line 18)	$ 40,010,997	$ 16,938,049	$ 3,954,537	$ 443,607	$ (796,852)	$ 13,846,998	$ 904,583	$ 1,829,215	$ 386,807	$ 1,894,393	$ 133,331	$ 411,178	$ 65,151
20	Rate of Return (line 19 divided by line 9)	7.45%	5.35%	9.09%	10.77%	-2.08%	18.07%	11.32%	16.79%	7.53%	9.45%	2.18%	5.46%	21.92%
21	Index (Class ROR divided by System ROR)	100	72	122	145	(28)	243	152	225	101	127	29	73	294

These results are hypothetical only and do not necessarily depict the results that may have been achieved if Central Hudson operated as a delivery-only company.

Exhibit__(COSP-3)
Page 1 of 2

Electric Department Delivery-Only Hypothetical Embedded Study
Summary of Assumptions

Changes from historical study (COSP-2):

1 Eliminated commodity working capital
2 Removed commodity related revenue (This impacted the RSALES & OSALES allocators)
3 Removed commodity expense
4 Adjusted FIT/SIT calculations to remove commodity related Schedule M adjustments

Comparison of impact on system is provided below:

	Total	Delivery Only	Difference
Total Rate Base	$ 537,533,401	$ 537,271,257	$ 262,144
Total Revenues	$ 616,854,217	$ 236,002,507	$ 380,851,710
Operating Expenses:			
Operation and Maintenance	$ 510,766,394	$ 129,216,049	$ 381,550,345
Depreciation and Amortization	$ 22,251,467	$ 22,251,467	$ -
Taxes Other than Income	$ 27,063,824	$ 27,063,824	$ -
Federal Income Tax	$ 13,755,420	$ 13,999,942	$ (244,523)
New York State Income Tax	$ 3,243,229	$ 3,460,228	$ (216,999)
Total Operating Expenses	$ 577,080,334	$ 195,991,510	$ 381,088,824
Net Operating Income	$ 39,773,884	$ 40,010,997	$ (237,114)
Rate of Return by Function	7.399%	7.447%	

These results are hypothetical only and do not necessarily depict the results that may have been achieved if Central Hudson operated as a delivery-only company.

DIRECT TESTIMONY
OF
DONALD L. DUBOIS

Q. Please state your name and business address.

A. My name is Donald L. DuBois, Jr. and my business address is 284 South Avenue, Poughkeepsie, NY 12601.

Q. By whom are you employed and in what capacity?

A. I am employed by Central Hudson Gas & Electric Corporation, as the Manager of Electric T & D and Quality/Productivity Initiatives.

Q. What are your responsibilities in your current position?

A. I have several responsibilities related to the electric transmission and distribution system. I have responsibility for Electric Transmission & Distribution Maintenance, Construction and Operations. I have overall responsibility for matters pertaining to stray voltage testing, standby, and mitigation activities at Central Hudson as well as responsibility for vegetation management activities at Central Hudson including electric transmission and distribution, and gas transmission. I am also responsible for implementing the corporate Quality and Productivity Initiative.

Q. Please summarize your educational background and professional experience.

A. I received a Bachelor of Science Degree in Mechanical Engineering from Union College in 1986. Since 1986, I have been continuously employed

by Central Hudson, with assignments in its Production, Mechanical Engineering, Gas & Mechanical Engineering, Fuels Resources, Operation Services, and Customer Services Groups. Prior to my current assignment I served as the Manager of System Construction.

Q. Have you previously testified before this Commission?

A. Yes, I testified in Central Hudson Cases 00-E-1273 and 00-G-1274, as the Director of Fuels Resources and in Central Hudson Cases 05-E-0934 and 05-G-0935, as the Manager of System Construction. Most recently I testified in Central Hudson Cases 08-E-0887 and 08-G-0888, as the Manager of Electric T & D and Quality/Productivity Initiatives.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony will address the actual expenditures for the twelve months ended March 31, 2008, and the projected expenditures for the rate year for Central Hudson's 1) Stray Voltage Program, 2) Electric Transmission Right of Way ("ROW") Management Program, 3) Electric Distribution Line Clearance Program, and 4) Transmission Enhanced Infrastructure Maintenance.

Stray Voltage Testing Program

Q. Please describe generally what you will address concerning stray voltage?

A. I will discuss Central Hudson's implementation of the annual stray voltage

testing program which was required by the Commission in its Order Instituting Safety Standards (issued and effective January 5, 2005) and the Order Adopting Changes to Electric Safety Standards (issued and effective December 15, 2008). I will describe the magnitude of Central Hudson's stray voltage program, what facilities have been tested, and the results of those tests. Additionally, and I will address the actual expenditures for the twelve months ended March 31, 2009, and the projected expenditures for the rate year.

Q. Please describe the magnitude of the stray voltage testing program at Central Hudson.

A. The Commission's Order issued January 5, 2005, requires that stray voltage testing be performed on all electric facilities that are capable of conducting electricity and are publicly accessible. The testing is required on distribution and transmission poles that have a down ground, guy wire or metal riser pipe, pad-mounted transformers and switchgear, underground equipment including manhole and pull-box covers, substation fences, metal streetlight poles, whether they are Company-owned or not, and metal traffic signal poles and devices.

The Commission's Order issued December 15, 2008, changed the definition of "finding" and "mitigation" and instituted requirements to perform additional testing to determine the extent of stray voltage and these changes in scope have increased the costs of the stray voltage program.

With regard to the number of facilities that require testing in the Central Hudson service territory, the approximate numbers of pieces of equipment that are part of the annual testing program are summarized in Table 1 below:

Table 1

Distribution Poles	209,148
Transmission Structures	8,663
Padmounted Transformers/Switchgear	13,133
Manholes/ Pullboxes	1,236
Substation Fences	104
Company Owned Metal Streetlight Poles	185
Municipal Owned Metal Streetlight Poles	5,306
Traffic Signal Poles/ Devices	827

Q. How is the Company executing this annual testing program?

A. Central Hudson manages a group of contractors to meet the annual testing requirements. Since 2007, the stray voltage testing program had operated on a designated twelve-month term, beginning on December 1, and ending November 30. The 2008 program began December 2, 2007 and was completed on November 11, 2008. The Order Adopting Changes to the Electric Safety Standards established the twelve-month term coincident with the calendar year beginning with the 2009 program. Contractors are currently performing all phases of testing which include distribution poles, transmission poles, and pad-mounted equipment, streetlights and traffic signal poles, manhole/pullboxes, and substation

fences. In 2007, Central Hudson transitioned the Stray Voltage Testing Program from the previous circuit-based data collection methodology to a geographical "grid" based method. This decreased the amount of overlapping with multiple field testers, since now each field tester became responsible for a specific geographical area. Field testers utilize a PDA (hand held data collection unit) that has a built in GPS based interactive map showing the individual field tester's real time location as well as each facility to be tested within their geographic "grid."

Although the 2005 Order only required mitigation of stray voltage findings greater than or equal to 8 volts, Central Hudson has mitigated any stray voltage finding of 4.5 volts or greater during the 2005, 2006, 2007, and 2008 testing cycles. The stray voltage testing contractor has been required to standby or guard any finding of 4.5 volts or greater until a crew arrives to eliminate the stray voltage or make the area safe. It is not uncommon to have the testing contractor on standby for a period of two hours. The cases that have required mitigation on average have taken approximately four hours to remedy.

Central Hudson is utilizing a separate contractor to perform the data management function, which includes the uploading and downloading of test records from the field data collection devices, addressing issues related to the field data collection hardware and software and reporting on test results and progress.

An independent contractor is responsible for implementing the Quality Assurance program that is required by the Order.

Q. How has the Order Adopting Changes to Electric Safety Standards affected the annual testing program?

A. The December 15, 2008 Order changed the definition of "finding" to be any confirmed voltage reading on an electric facility greater than or equal to 1 volt measured using a volt meter and a 500 ohm shunt resistor. The change in threshold voltage from 8 Volts to 1 Volt has increased contractor standby costs.

The Order Adopting Changes has also changed the testing protocols by requiring the additional testing for stray voltage on all metallic structures within 30 feet of an electric facility where stray voltage was measured. This subtle change has the potential to significantly increase the cost of performing the stray voltage testing depending on the number of locations where stray voltage is identified.

An additional change, to the definition of "mitigation", now requires Central Hudson to take the necessary actions to effectively eliminate the stray voltage findings (repair and test until less than 1 volt is observed). This change has increased the number of locations that require mitigation as well as the extent of the mitigation.

Q. Could you provide a summary of the results and actual expenditures by category for the stray voltage testing program since 2005?

A. The results are summarized in Table 2 below:

Table 2

	2005/2006			2007			2008		
	Visits	Between 1V and 8V	8V and Over	Visits	Between 1V and 8V	8V and Over	Visits	Between 1V and 8V	8V and Over
Distribution Poles	214,319	324	0	205,870	627	2	209,148	507	1
Transmission Structures	8,566	179	0	8,594	343	2	8,663	6	0
Padmounted Transformers/Switchgear	12,669	0	0	12,508	8	0	13,133	11	0
Manholes/ Pullboxes	2,483	0	0	1,220	0	0	1,236	0	0
Substation Fences	219	4	0	107	0	0	104	0	0
Company Owned Metal Streetlight Poles	370	1	0	185	0	0	185	0	0
Municipal Owned Metal Streetlight Poles	10,705	14	7	5,278	1	4	5,306	6	2
Traffic Signal Poles	1,582	0	0	811	0	0	827	0	0
Totals	250,913	522	7	234,573	979	8	238,602	530	3

The actual expenditures for each category by calendar year are summarized in Table 3 below:

Table 3

Category	2005/2006 Cycle 2005 Actual Expenditures	2005/2006 Cycle 2006 Actual Expenditures	2007 Cycle Actual Expenditures	2008 Cycle Actual Expenditures
Distribution Overhead & Underground Testing	$915,831	$449,720	$1,772,866	$1,247,811
Street Lights/Traffic Signals Testing	$51,985	$41,365	$22,608	$30,561
Transmission Testing	$51,528	$116,778	$87,903	$100,518
QA/QC	$21,723	$25,855	$37,619	$43,113
Stand-By			$11,362	$1,257
Mitigation				
Total	$1,041,067	$633,718	$1,932,358	$1,423,260

Q. What were the actual costs for the stray voltage program during the twelve-month period ending March 31, 2009?

A. Actual costs were $1,044,717 as shown on Exhibit DLD-1. Please note that the costs for the twelve months ending March 31, 2009 do not represent the annual costs for performing the required testing due to the changes in the designated twelve month term as described above. In addition, the standby and mitigation costs during the historical period do not reflect the increased costs associated with the compliance with the Order Adopting Changes to Electric Safety Standards that were implemented by Central Hudson following December 15, 2008.

Q. Please describe the activities that comprise the Stray Voltage Testing Program and how the rate year forecast was developed for each activity as reflected in Exhibit DLD-1.

A. There are six activities that comprise Central Hudson's stray voltage testing program as reflected in Exhibit DLD-1.

Stray Voltage – Distribution Overhead and Underground includes the testing of the electric distribution system to include the manhole and pull box covers that comprise our network systems. The forecasted expenditures for this activity were developed based on the contractor bid pricing for this testing and adjusted for the anticipated testing to be completed during the period from January 1, 2010 through June 30, 2010. The cost of testing equipment and data management associated with the distribution system is also included in this forecast.

Stray Voltage – Streetlights/Traffic Signals was broken out as a separate activity because in many cases the locations to be tested are either comprised of facilities not owned by Central Hudson or, as in the case of streetlights, require special testing protocols. The testing of streetlights must be performed when the fixture is energized which requires the work to be performed after normal working hours which is slightly more expensive. Since the number of locations is fairly consistent from year to year, the forecast for this activity reflects the application of the average yearly escalation factor to the forecasted expenditures for this activity from the prior rate period.

Stray Voltage - Transmission includes the testing of all electric transmission facilities. The forecast for this activity reflects the application of the average yearly escalation factor to the forecasted expenditures for this activity from the prior rate period.

Quality Assurance/Quality Control is performed by an independent contractor and covers all three activities outlined above. The same methodology utilized to forecast the cost for streetlights/ traffic signals and transmission was used to forecast the cost for this activity.

Stray Voltage Standby is required whenever there is a stray voltage finding. Typically the contractor performing the testing guards or barricades the location until someone can respond to evaluate and mitigate the finding. A period of two hours per standby has been used to forecast the cost for this item. The estimated number of findings utilized in

the prior rate period forecast was based on the average number of findings during 2007 and 2008 above 1 volt. In recognition of the impact associated with the mitigation work that will be completed within the next year, the expected number of findings for the forecasted rate period reflects a significant reduction from the prior rate period.

Stray Voltage Mitigation is required whenever there is a confirmed stray voltage finding. The cases that have required mitigation on average have taken four hours to remedy. The estimated number of locations requiring mitigation utilized in the prior rate period forecast was based on the average number of findings during 2007 and 2008 above 1 volt. The estimated number of locations requiring mitigation for this rate period reflects a significant reduction from the prior rate period in recognition of the mitigation work that will be completed prior to the rate year.

Electric Transmission ROW Management Program

Q. Have you developed the actual costs of Central Hudson's Electric Transmission ROW management in the twelve-month period ending March 31, 2008?

A. Yes. The costs of the Electric ROW Management Plan for the period ending March 31, 2009 are summarized on Exhibit DLD-2.

Q. Please describe the scope of Electric Transmission ROW Maintenance activity for the future rate year that is reflected in Exhibit DLD-2.

A. Central Hudson's Long Range Transmission ROW Management Plan as

revised and filed on December 12, 2007 outlines the work to be performed and is the basis for the forecasted expenditures reflected in Exhibit DLD-2. The Staff of the Department of Public Service reviewed and approved the Plan revisions as indicated by letter dated January 7, 2008, from Secretary, Jaclyn A. Brilling. This Plan identifies a total of 587 miles and 9,485 acres of electric transmission ROW to be maintained on a five-year cycle (equating to approximately 118 miles and 1,897 acres per year).

Q. Please describe the activities that comprise the Company's Electric Transmission ROW Maintenance and how the rate year forecast was developed for each activity as reflected in Exhibit DLD-2.

A. There are six activities that comprise Central Hudson's Electric Transmission ROW Maintenance as reflected in Exhibit DLD-2. Routine ROW Maintenance – Electric Transmission includes a number of cost components that need to be discussed independently to understand the proposed rate year expenditures. Most of these cost components are being dictated and impacted by the PSC Order Requiring Enhanced Transmission Right – of- Way Management Practices by Electric Utilities in Case 04-E-0822 (Transmission ROW Order). The side trimming operations which are required to maintain the edge of the electric transmission ROW were suspended for the last maintenance cycle and replaced by the ROW Edge Reclamation initiative which was just recently completed in June of 2009. Reinstating the side trimming operations significantly increases the Routine ROW Maintenance cost forecast

compared to the period when ROW Edge Reclamation was taking place. To develop the forecast for side trimming, it is estimated that 10% of the ROW on an annual basis can be considered clear and that the remainder will require side trimming.

Although mowing and access roads was a separate activity for the last rate filing, this work is actually performed in conjunction with the routine ROW floor work and as such should be included as a component of Routine ROW Maintenance.

The projected cost to complete the Routine Electric Transmission ROW Maintenance, which includes maintaining the ROW floor, performing limited mowing and access road work, completing the required side trimming, and applying the appropriate herbicide to 20% of the total ROW miles and acres each year (5 year cycle) will require annual expenditures of $1,355,867 for rate year ending June 30, 2011 based on recent bids to complete this work.

The Electric Transmission ROW Edge Encroachment Reclamation work was completed in June 2009 and I have assumed that further edge reclamation work will not be required in the rate year (ending June 2011).

Since the danger trees are by definition located outside of the ROW, removal from private property requires Central Hudson in most cases to negotiate permission to remove the identified trees. Although this could result in higher costs for the Danger Tree Removal activity, the number of danger trees identified for removal has been decreasing resulting in a

slightly lower forecast than the historical period expenditures. Work to be performed as part of the Hot Spot Trimming activity is identified through routine inspection as well as during the stray voltage testing program. The comprehensive ground inspections and quarterly aerial patrols are utilized to identify maintenance items associated with the infrastructure and to identify mid-cycle vegetation clearance issues that are addressed as part of the Hot Spot Trimming Program. To take advantage of the synergies associated with performing the required stray voltage testing of the transmission structures not scheduled for comprehensive inspection in a given year, hot spot trimming crews are trained to perform the required stray voltage testing as part of their substation – to - substation vegetation patrols. The costs associated with this patrol are allocated to either the stray voltage testing program or the hot spot trimming program based on the extent of the mid – cycle hot spot trimming required. The forecasted expenditures for the Hot Spot Trimming activity reflect the application of the average yearly escalation factor to the forecasted expenditures for this activity from the prior rate period.

As indicated above, the Mowing and Access Road activity has been incorporated into the Routine ROW Maintenance activity.

Q. How did you determine the costs for the Legal and Environmental category?

A. Based on my experience with our current clearing programs the

acquisition of additional ROW width and danger tree removals as mandated by the Commission involve the potential for impacts to residential properties along our ROWs, and resolving homeowner concerns is generally time consuming and expensive. The number of areas that have been identified on the 115 kV lines where there are ROW easement restrictions will necessitate the use of contractors to assist in the survey and property assessments. The areas where additional ROW width is successfully acquired can be capitalized but the areas where easements cannot be obtained will be charged to this activity. The work plan for completing the survey and property assessment work associated with the 115 kV line ROW easement restrictions will extend through 2013. Based on this work plan it has been forecasted that expenditures will be $16,000 per quarter beginning January 1, 2010.

Distribution Line Clearance Program

Q. Please describe the scope of Electric Distribution Line Clearance Program for the future rate year that is reflected in Exhibit DLD-3.

A. Central Hudson retained an independent consulting firm to analyze distribution line clearance practices from an electric reliability perspective. Based on a review of Central Hudson's tree related outage data it was determined that most of the outages were being caused by tree or limb failure not growth contact and the consultant recommended that Central Hudson establish greater clearances by reducing the overhang and

removal of tall growing species from within the ROW (Modified Enhanced Trimming). This methodology was implemented in March of 2007 and has become the standard for our routine line clearance program on single-phase as well as three-phase lines. It was also confirmed that continuation of the Enhanced Line Clearance Program on the worst performing (prioritized by tree-caused customer interruptions) three-phase lines to include expanding the hazard/danger tree removal initiative on a system basis would improve reliability.

The time required to provide increased side clearances, reduce the overhang, and remove the tall growing species from within the ROW was initially estimated to take twenty–five percent longer to complete than standard box trimming. Based on the consultant's conclusions that only a small percentage of Central Hudson's tree related outages are caused by growth contacts, the decision was made to extend the trimming cycle from 3 years to 4 years in order to offset the increased costs associated with performing this additional work. The increase in tree density associated with transitioning to a four - year cycle is beginning to impact the cost per mile for both on-road and off-road line clearance.

The consultant also concluded that performing Enhanced Line Clearance on three-phase lines would reduce tree-related interruptions compared to standard three-phase box trimming. It was recommended that Enhanced Trimming be conducted on an additional 760 miles of three-phase lines. Through June 30, 2009, Central Hudson has completed 339 miles of

enhanced line clearance and is required to complete an additional 150 miles by June 30, 2010. Exhibit DLD-3 includes the forecasted funding to complete an additional 100 miles of enhanced line clearance during the rate period. The reason for this reduction from 150 miles to 100 miles will be discussed later in this testimony but will result in completing the remaining 300 enhanced line clearance miles over three years instead of two.

Q. Please describe the activities that comprise the Company's Electric Distribution Line Clearance Program as reflected in Exhibit DLD-3.

A. As shown on Exhibit DLD-3, I have broken the Distribution Line Clearance Program costs down into six activities: Trimming – Scheduled On-Road, Trimming - Scheduled Off-Road, Trimming – Danger Trees, Flagging Line Clearance, Trimming – Trouble Orders, and Enhanced Line Clearance.

Q. Please describe those activities.

A. The On - Road and Off - Road trimming is sometimes referred to as the "routine" portions of the program, and the Trouble Orders and Danger Tree elements as "off-cycle" portions of the program. The routine portions are conducted on a four - year cycle basis, which equates to 1,363 (5,452/4) miles of on-road and 426 (1,703/4) miles of off-road clearing per year.

The off-cycle portions depend on the actual number of Trouble Orders created, and Danger Trees identified during the year. Trouble Orders identify tree related conditions requiring off-cycle attention and typically

follow a storm event. Localized wind events or lightning strikes can damage tree limbs that are or will make contact with our electrical facilities. These would be examples of trouble order conditions. The Enhanced Line Clearance program targets completing a more aggressive ground to sky line clearance (including tree removals and complete over-hang removal) on both the on-road and off-road three-phase mainline sections of the worst performing circuits from a tree-related outage perspective. Continued funding of the enhanced line clearance program is desirable from a tree-related outage perspective. Line Clearance Flagging costs are accounted for independently of the on-road line clearance, enhanced line clearance, danger tree removal, and trouble order costs, but are directly related to performing these work functions. Appropriate signage and flagging continue to be required to meet local town, county, state and federal guidelines for work zone safety when performing work to include trimming operations along or across any roadway. Work zone safety continues to be a paramount concern and providing trained and qualified flagging personnel is an integral part of performing distribution line clearance activities along state, county, and town roads. The rate year cost levels for these activities are based on current market conditions, based on the assumption that the work would be performed, and staffed as needed, through temporary employment with compensation paid on an hourly basis.

Q. What were the actual costs for the Distribution Line Clearance Program during the twelve-month period ending March 31, 2009?

A. As shown on Exhibit DLD-3 expenditures for the historical period were $9,185,910. Please note that the costs for the twelve months ending March 31, 2009 include the costs of completing 105 miles of Enhanced Line Clearance during this period.

Q. Please describe how the rate year forecast for the Distribution Line Clearance Program was developed for each activity as reflected in Exhibit DLD-3.

A. The two factors that determined the forecasted cost for the on-road, off-road, and enhanced line clearance activities were cost per mile and miles to be completed during the forecasted period.

There are approximately 5,452 total on-road system miles and 2,753.6 miles have been completed since we transitioned to modified enhanced trimming in March of 2007. Based on the expenditures allocated to the on-road activity for the rate period ending June 30, 2010, it is projected that there will be 1,831.8 miles remaining to be completed during the forecasted rate period. Utilizing the 2009 average cost per mile of $4,445 and adjusting the cost based on the escalation factors indicated on Exhibit DLD-3 resulted in the rate year forecasted expenditures of $8,707,462 for on-road line clearance.

Using the same methodology for off-road line clearance, there are approximately 1,703 total off-road system miles and 892.6 miles have

been completed since we transitioned to modified enhanced trimming in March of 2007. Based on the expenditures allocated to the off-road activity for the rate period ending June 30, 2010, it is projected that there will be 501.4 miles remaining to be completed during the forecasted rate period. Utilizing the 2009 average cost per mile of $8,307 and adjusting the cost based on the escalation factors indicated on Exhibit DLD-3 resulted in the rate year forecasted expenditures of $4,303,516 for off-road line clearance.

There were 33.7 miles (roughly one third of the annual rate case required miles) of enhanced line clearance completed during the first four months of 2009 at a cost of $389,235 resulting in an average cost per mile of approximately $11,551. The average cost per mile for 2010 is calculated by applying the escalation factor indicated on Exhibit DLD-3. Multiplying this average cost by 50 miles results in forecasted expenditures of $580,600 for the July 1, 2010 through December 31, 2010 period. Escalating this forecasted cost by the factor indicated on Exhibit DLD-3 results in forecasted expenditures of $602,650 for the January 1, 2011 through June 30, 2011 period for Rate Year forecasted expenditures of $1,183,250 to complete 100 miles as indicated on Exhibit DLD-3. The reduction from 150 miles to 100 miles for the rate period is intended to reduce the incremental line clearance expenditures associated with the additional on-road and off-road miles proposed to be completed during this period and reflects consideration relative to crew availability.

Danger Tree forecasted expenditures were developed by escalating the 2009 budget of $883,410 by the escalation factor indicated on Exhibit DLD-3 resulting in anticipated expenditures of $927,139 in 2010 and $962,370 in 2011. Subtracting the anticipated expenditures for the period January 1, 2010 through June 30, 2010 from the total anticipated expenditures in 2010 resulted in forecasted expenditures of $480,580 for the period July 1, 2010 through December 31, 2010. Dividing the anticipated expenditures for 2011 by 2 resulted in forecasted expenditures from January 1, 2011 to June 30, 2011 of $481,185. Total forecasted expenditures for the rate period are $961,765 as indicated on Exhibit DLD-3.

Trouble Order forecasted expenditures were developed by escalating the July 1, 2009 through December 31, 2009 budget of $35,790 by the escalation factor indicated on Exhibit DLD-3 resulting in anticipated expenditures of $37,562 for the period of July 1, 2010 through December 31, 2010. Subtracting the July 1, 2009 through December 31, 2009 budget from the current rate allowance provides the anticipated expenditures for the period January 1, 2010 through June 30, 2010 of $58,936. Escalating these expenditures by the factor indicated on Exhibit DLD-3 results in anticipated expenditures of $61,176 for the period January 1, 2011 through June 30, 2011 resulting in forecasted expenditures of $98,738 for the rate period as indicated on Exhibit DLD-3.

The forecasted expenditures for flagging were developed by calculating an

average flagging cost per mile for the first four months of 2009 for both On-Road and Enhanced Line Clearance. These average costs per mile were then escalated by the factors indicated on Exhibit DLD-3 to determine the average cost per mile for 2010 and 2011 for both Enhanced and On-Road. Multiplying the average cost by the planned miles resulted in forecasted expenditures of $710,483 for the July 1, 2010 through December 31, 2010 period and $735,714 for the January 1, 2011 through June 30, 2011 period. The total forecasted expenditures for flagging during the rate period are $1,446,197 based on the assumption that 80% of the flagging costs are associated with On-Road line clearance program.

Transmission Enhanced Infrastructure Maintenance

Q. Is the Company continuing its Transmission Enhanced Infrastructure Maintenance efforts?

A. Yes. The four new or expanded programs identified during the last rate filing include changes to electric transmission survey methods, fund inspection and repair of transmission towers, additional Osmose pole treatment, and a transmission tower painting program. These items are summarized on Exhibit DLD-4 and will require funding of $700,000, as I have provided to the Revenue Requirements Panel. These items are required to adequately assess and maintain our electric transmission system on an ongoing basis.

Q. Does this conclude your pre-filed direct testimony?

A. Yes.