CENTRAL MAINE
POWER

June 30, 2014

Hon. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Central Maine Power Company,
June 30, 2014 Informational Filing - Annual Update to Formula Rates Effective June 1, 2014.
Docket Nos. ER09-938-000, *et al.*

Dear Secretary Bose:

Central Maine Power Company ("CMP") hereby submits an original and six copies of the Company's Annual Informational Filing, which consists of the annual update to the Commission-approved formula rates in Schedule 21-CMP of the ISO-NE Transmission, Markets, and Services Tariff ("ISO OATT") effective June 1, 2014.

Accordingly, this informational filing reflects actual cost data for calendar year 2013 plus estimated cost data for calendar year 2014 associated with CMP's forecasted transmission plant additions and construction work in progress for CMP's Maine Power Reliability Program ("MPRP"), as well as the annual true-up and associated interest pursuant to 18 CFR § 35.19a of the Commission regulations.

CMP is submitting this filing for informational purposes only in accordance with Section 10.2 of Schedule 21-CMP of the ISO OATT.

This informational filing provides the worksheets reflecting the annual updates for Schedules 1, 13, and 14 and Attachment G and includes the following attachments:

1. Filing Letter;
2. Service List;
3. Certificate of Service;
4. Rates Effective June 1, 2014;
5. Attachment G-R;
6. Attachment G-W;

Printed on recycled paper

83 Edison Drive, Augusta, Maine 04336
Telephone 207-623-3521
www.cmpco.com

IBERDROLA
USA

7. Schedule 1;
8. Update to CCS Charge;
9. Schedule 13;
10. Schedule 14 for Retail Customers; and
11. Schedule 14 for Wholesale Customers.
12. Annual Report of Construction Costs for MRPP

Also included with this filing is a certificate of service that verifies that copies of this filing have been sent to FERC Staff and the Maine Public Utilities Commission.

All correspondence and communications regarding this proceeding should be directed to:

Stephanie T. McNeal
Regulatory Services Department
Central Maine Power Company
83 Edison Drive
Augusta, ME 04336
(207) 621-3871
Facsimile: (207) 626-9577
e-mail: regulatoryservices@cmpco.com

Richard P. Hevey
Legal Department
Central Maine Power Company
83 Edison Drive
Augusta, ME 04336
(207) 621-6546
Facsimile: (207) 621-4714
richard.hevey@cmpco.com

Sincerely,

Richard P. Hevey
Attorney for Central Maine Power
Company

Enclosures
cc: Service List

SERVICE LIST
ANNUAL INFORMATIONAL FILING - UPDATE TO FORMULA RATES
CENTRAL MAINE POWER COMPANY
JUNE 30, 2014

Stephanie McNeal
Regulatory Services Department
Central Maine Power Company
83 Edison Dr
Augusta, ME 04336-0002

Richard P. Hevey
Legal Department
Central Maine Power Company
83 Edison Drive
Augusta, ME 04336-0002

Marc Guerrette
Transmission Services Department
Central Maine Power Company
83 Edison Dr
Augusta, ME 04336-0002

Joseph H. Long
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Harry Lanphear
Maine Public Utilities Commission
18 State House Station
242 State Street
Augusta, ME 04333-0018

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the enclosed documents to be served by mail upon the parties identified on the service list included with this filing.

Dated: June 30, 2014

____

Richard P. Hevey

Attorney for
Central Maine Power Company

CENTRAL MAINE POWER COMPANY
RATES FOR TRANSMISSION AND SCHEDULE 1 SERVICE
Effective June 1, 2014

			LOCAL TRANSMISSION		LOCAL		
			RETAIL	WHOLESALE	SCHEDULE 1		
			(ATT. G-R)	(ATT. G-W)	(SCH. 1)		
1	ANNUAL REVENUE REQUIREMENTS		49,155,775	42,314,984	435,017		
2							
3	Network Load for Rate Design		1,423,745	1,423,745	1,423,745		
4							
5	FIRM POINT TO POINT RATES						
6	Per Year (Line 1 divided by Line 3)	$/kW-Year	34.53	29.72	0.3055		
7	Per Month (Line 6 divided by 12)	$/kW-Month	2.8775	2.4767	0.0255		
8	Per Week (Line 6 divided by 52)	$/kW-Week	0.6640	0.5715	0.0059		
9	Per Day (Line 8 divided by 5)	$/kW-Day	0.1328	0.1143	0.0008		
10							
11	NON-FIRM POINT TO POINT RATES						
12	Per Year (Line 1 divided by Line 3)	$/kW-Year	34.53	29.72	0.3055		
13	Per Month (Line 12 divided by 12)	$/kW-Month	2.8775	2.4767	0.0255		
14	Per Week (Line 12 divided by 52)	$/kW-Week	0.6640	0.5715	0.0059		
15	Per Day (Line 14 divided by 7)	$/kW-Day	0.0949	0.0816	0.0008		
16	Per Hour (Line 15 divided by 24)	$/MWH	3.9542	3.4000	0.0333		
17							
18							
19	Discounts: The $3.00 per kW-year (Wholesale Wheeling Out Rate) for Firm & Non-Firm Point to Point service applicable to Generators						
20	Interconnected with CMP's integrated non-PTF is discounted to $0.00 per kW-Year beginning 3/01/03 until further notice.						
21							
22	NOTE: SCH 1 Rates are the designed the same for both firm and non-firm service, (i.e. daily is based on 7days per week.)						

Central Maine Power
Transmission Revenue Requirements - 2013 Test Year (Adjusted)
Attachment G-R
6/1/2014 - 5/31/2015

Line No.	II. INVESTMENT BASE	Attachment F Reference Section:		Reference
1	Transmission Plant	II (A)(1)(a)	$ 1,248,664,109	w/s 3, line 1 column 5
2	Transmission Related Intangible & General Plant	II (A)(1)(b)	39,015,003	w/s 3, line 4 column 5
3	Transmission Plant Held for Future Use	II (A)(1)(c)	3,365,121	w/s 3, line 5 column 5
4	Total Plant (Lines 1+2+3)		1,291,044,233	
5	Accumulated Depreciation	II (A)(1)(d)	(210,991,767)	w/s 3, line 9 column 5
6	Accumulated Deferred Income Taxes	II (A)(1)(e)	(223,751,761)	w/s 3, line 12 column 5
7	Other Regulatory Assets	II (A)(1)(g)	936,231	w/s 3, line 15 column 5
8	Net Investment (Line 4+5+6+7+8)		857,236,936	
9	Transmission Prepayments	II (A)(1)(h)	564,319	w/s 3, line 16 column 5
10	Transmission Materials and Supplies	II (A)(1)(i)	6,566,596	w/s 3, line 17 column 5
11	Cash Working Capital	II (A)(1)(j)	3,492,564	w/s 3, line 23 column 5
12	MPRP CWIP	II (A)(1)(k)	5,034,097	w/s 3, line 24 column 6
13	Total Investment Base (Line 9+10+11+12)		$ 872,894,512	

	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	II (A)	$ 110,476,567	w/s 2, line 12
15	Depreciation Expense	II (B)	29,234,008	w/s 4, line 3 column 5
16	Amortization of Investment Tax Credits	II (D)	(342,879)	w/s 4, line 4 column 5
17	Municipal Taxes	II (E)	13,630,137	w/s 4, line 5 column 5
18	Operation and Maintenance Expense	II (G)	14,020,713	w/s 4, line 10 column 5
19	Administrative and General Expense	II (H)	13,919,797	w/s 4, line 15 column 5
20	Transmission Related Regulatory Assessments	II (I)	636,510	w/s 4, line 17 column 5
21	Transmission Support Revenues	II (J)	(1,341,553)	w/s 6, line 7
22	Transmission Support Expenses	II (K)	655,602	w/s 7, line 7
23	ISO-NE Transmission Revenues	II (L)	(188,287,366)	
24	Other Wheeling Revenues	II (M)	-	
25	Transmission Rents Received from Electric Property	II (O)	(2,501,247)	w/s 6, line 21
26	Transmission Related Customer Service, Informational Exp. & Sales Exp.		10,249,918	w/s 4, line 16 column 5
27	Forecasted Transmission Revenue Requirement & Annual True Up	II (O)	48,805,568	
28	Total Revenue Requirements (Line 14 thru 28)		49,155,775	
29	Less Wheeling Out Revenues		-	
30	Transmission Revenue Requirement for Retail Transmission-Level Customers		$ 49,155,775	

Central Maine Power
Transmission Revenue Requirements - 2013 Test Year (Adjusted)
Attachment G-R
6/1/2014 - 5/31/2015

Line No.		Capitalization 12/31/2013	Capitalization Ratios	Cost of Capital	Cost of Capital	Equity
1	Long-Term Debt	$ 949,500,000	44.977%	5.111%	2.299%	
2	Preferred Stock	571,300	0.027%	6.000%	0.002%	0.002%
3	Common Equity (less goodwill)	1,160,997,251	54.996%	11.140%	6.127%	6.127%
4	Total Investment Return	$ 2,111,068,551	100.00%		8.428%	6.129%

5 **Cost of Capital Rate=**

6 (a) Weighted Cost of Capital = **8.428%**

7 (b) Federal Income Tax

= (R.O.E. + (PTF Inv. Tax Credit -w/s 1 + Equity AFUDC w/s 13) / PTF Inv. Base) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

= (0.06129 +((342,879) + 410,937) / 872,894,512) x 35.00%)
(1 - 35.0%)

= **3.304%**

8 (c) State Income Tax

= (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)* State Income Tax Rate
(1 - State Income Tax Rate)

= (0.06129 +((342,879) + 410,937) / 872,894,512) + 3.30%)* 8.93%
(1 - 8.93%)

= **0.926%**

9 (a)+(b)+(c) **Cost of Capital Rate** = **12.658%**

		Post-96 (PTF)	**Post 2003 RSP ptf (Incremental Return Calc)**	**Investment Return & Taxes including Incremental Return**	
10	Investment Base	$ 872,894,512	(1,392,908)		
11	x Cost of Capital Rate	12.65820%	1.16056%		
12	= Investment Return and Income Taxes	$ 110,492,733	$ (16,166)	$ 110,476,568	w/s 1 line 14

Central Maine Power
Transmission Revenue Requirements - 2013 Test Year (Adjusted)
Attachment G-R
6/1/2014 - 5/31/2015

Line No.		(1) Total	(2) Wage/Plan Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated		RNS Rate Worksheet or FERC Form 1 Reference for col (1) or (5)
1	**Transmission Plant**	1,248,782,743	100.0000% (b)	1,248,782,743	99.9905%	1,248,664,109	(d)	w/s 9, line 4, column d
2	General Plant	203,839,783	15.3558% (a)	31,301,229	99.9905%	31,298,255		w/s 9, line 7, column d
3	Intangible Plant	50,257,757	15.3558% (a)	7,717,481	99.9905%	7,716,748		w/s 9, line 10, column d
4	Total (line 1+2)	254,097,540		39,018,710		39,015,003		
5	Transmission Plant Held for Future Use	3,365,121		3,365,121		3,365,121		w/s 9, line 5, column d
	Transmission Accumulated Depreciation							
6	Transmission Accum. Depreciation	(190,486,011)	100.0000% (b)	(190,486,011)	99.9905%	(190,467,915)		w/s 9, line 6, column d
7	General Plant Accum. Depreciation	(88,441,236)	15.3558% (a)	(13,580,859)	99.9905%	(13,579,569)		w/s 9, line 9, column d
8	Intangible Plant Accum. Amortization	(45,226,842)	15.3558% (a)	(6,944,943)	99.9905%	(6,944,283)		w/s 9, line 12, column d
9	Total (line 6+7)	(324,154,089)		(211,011,813)		(210,991,767)		
	Transmission Accumulated Deferred Taxes							
10	Accumulated Deferred Taxes (281-283)	(239,095,770)	100.0000% (b)	(239,095,770)	99.9905%	(239,073,056)		FF1 450.1 Notes, Pg. 274.1 L.9, C.k and FF1 450.1 Notes, Pg. 276, L. 19, C. k
11	Accumulated Deferred Taxes (190)	15,322,751	100.0000% (b)	15,322,751	99.9905%	15,321,295		FF1 450.1 Notes, Pg. 234, L. 18, C. c
12	Total (line 8+9)	(223,773,019)		(223,773,019)		(223,751,761)		
	Other Regulatory Assets							
13	FAS 106	6,097,501	15.3558% (a)	936,320				FF1 Pg 232.1, L.37, C.f
14	FAS 109	-	100.0000% (b)	-				See note (c) below
15	Total (line 12+13)	6,097,501		936,320	99.9905%	936,231		
16	Transmission Prepayments	3,675,311	15.3558% (a)	564,373	99.9905%	564,319		w/s 9, line 13
17	Transmission Materials and Supplies	6,567,220	100.0000% (b)	6,567,220	99.9905%	6,566,596		FF1 450.1 Notes, Pg. 227, L. 12, C. c
	Cash Working Capital							
18	Operation & Maintenance Expense					14,020,713		Worksheet 1, Line 18
19	Administrative & General Expense					13,919,797		Worksheet 1, Line 19
20	Net Transmission Support Expense					-		
21	Subtotal (line 18+19+20)					27,940,510		
22						0.125		x 45 / 360
23	Total (line 21 * line 22)					3,492,564		
24	MPRP CWIP	5,034,097		5,034,097		5,034,097		FF1 450.1 Notes,Pg. 200.1 L.11, C.c

(a) Worksheet 5, line 9 - Transmission Wages & Salaries Allocation Factor
(b) Amounts Reported as transmission in FF I .
(c) Amounts reported in FFI for ADITs exclude FAS 109, therefore FAS 109 Reg Asset & Liability also excluded.
(d) Worksheet 5, line 33 - Transmission Network Allocation Factor

Central Maine Power
Transmission Revenue Requirements - 2013 Test Year (Adjusted)
Attachment G-R
6/1/2014 - 5/31/2015

Line No.		(1) Total	(2) Wage/Plant Allocation Factors		(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)		(5) = (3)*(4) PTF Allocated	Worksheet or FERC Form 1 Reference
1	Transmission Depreciation	27,896,816			27,896,816	99.9905%	(e)	27,894,166	w/s 9, line 3 column d
2	Intangible and General Depreciation & Amortization	8,726,146	15.3558%	(a)	1,339,970	99.9905%	(e)	1,339,843	w/s 9, line 20 column d
3	Transmission Depreciation Expense (line 1+2)	36,622,962			29,236,786			29,234,009	
4	Amortization of Investment Tax Credits	(714,950)	47.9585%	(b)	(342,879)			(342,879)	FF1 Pg 266, L.8, C.f
5	Municipal Taxes	13,631,432	100.0000%	(c)	13,631,432	99.9905%	(e)	13,630,137	FF1 450.1 Notes, Pg. 262, L. 14, C. i
	Operation and Maintenance Expense								
6	Operation and Maintenance	143,019,036			143,019,036				w/s 9, line 1 column d
7	Transmission of Electricity by Others - #565	125,338,079			125,338,079				w/s 7, line 26
8	Load Dispatching - #561 - 561.4	3,143,069			3,143,069				FF1 Pg 321, L.84 thru 88, C.b
9	Support Payments (recorded in Accts 566 & 567)	515,843			515,843				w/s 7, line 21 - 22
10	O&M - line 10 less lines 11, 12, & 13	14,022,046	100.0000%	(c)	14,022,046	99.9905%	(e)	14,020,713	
	Administrative and General Expense								
11	A & G subject to Wage & Salaries Allocation Factor	16,041,342	15.3558%	(a)	2,463,276	99.9905%	(e)	2,463,042	w/s 10, line 31
12	A & G subject to Plant Allocation Factor	415,616	47.9585%	(b)	199,323			199,323	w/s 10, line 34
13	A & G directly assigned to transmission	11,258,502	100.0000%	(c)	11,258,502	99.9905%	(e)	11,257,432	w/s 10, line 40
14	RTO Formation Cost	-			-			-	
15	A&G	27,715,460			13,921,101			13,919,797	
16	Transmission Related Customer Service, Informational Exp. & Sales Exp.	27,100,196	37.8223%	(d)	10,249,918			10,249,918	w/s 1, line 26
17	Transmission Related Regulatory Assessments	636,510	100.0000%	(c)	636,510			636,510	FF1 Pg 350, L.20, C.d

(a) Worksheet 5, line 9 - Transmission Wages & Salaries Allocation Factor
(b) Worksheet 5, line 14 - Transmission Plant Allocation Factor
(c) Amounts Reported as transmission in FF I .
(d) Worksheet 5, line 17 - Customer Svc Allocation Factor
(e) Worksheet 5, line 33 - Transmission Network Allocation Factor

Central Maine Power
Transmission Revenue Requirements - 2013 Test Year (Adjusted)
Attachment G-R
6/1/2014 - 5/31/2015

Line No.				Worksheet or FERC Form 1 Reference
	Transmission Wages and Salaries Allocation Factor			
1	Direct Transmission Wages and Salaries	$	2,766,008	w/s 9, line 2
2	Affiliated Company Transmission Wages and Salaries		-	
3	Allocable Portion of Customer-Related Wages and Salaries		3,433,994	line 28 below
4	Total Transmission Wages and Salaries		6,200,001	(line 1+3)
5	Total Wages and Salaries		46,389,250	FF1 Pg 354, L.28, C.b
6	Administrative and General Wages and Salaries		6,013,656	FF1 Pg 354, L.27, C.b
7	Affiliated Company Wages and Salaries less A&G		-	
8	Total Wages and Salaries net of A&G		40,375,594	(line 5-6+7)
9	Percent Allocation		15.3558%	(line 4/8)
	Plant Allocation Factor			
10	Total Transmission Investment (excluding capital leases)		1,248,664,365	line 31 below
11	Transmission Related General and Intangible Plant		39,015,003	ws 3 line 4, col. 5
12	Total Transmission Related Plant		1,287,679,369	
13	Total Plant in Service		2,684,984,908	FF1 Pg 207, L.104, C.g
14	Percent Allocation		47.9585%	(line 12/13)
	Customer Svc & Info Exp & Sales Exp. Allocation Factor			
15	Transmission Revenues	$	175,934,930	FF1 Pg 330, L.11 thru 15, C.
16	Total T&D Revenues including Stranded Costs		465,161,906	FF1 Pg 300, L.10, C.b + line 15 above
17	Percent Allocation		37.8223%	(line 15/16)
	Customer Allocator Wages to Include in Transmission Wage and Salary Allocator			
18	Customer Accounts Expense		7,573,347	FF1 Pg 354, L.24, C.b
19	Customer Service and Informational Expense		311,218	FF1 Pg 354, L.25, C.b
20	Sales Expense		1,545,059	FF1 Pg 354, L.26, C.b
21	Subtotal	$	9,429,624	(line 18+19+20)
	Less:			
22	FERC#905020 ELP		(117,335)	
23	FERC# 908070 DSM		-	
24	FERC# 909010 Advertising		(233,006)	
25	Subtotal	$	(350,341)	(line 22+23+24)
26	Net Customer Allocator Wages		9,079,283	(line 25+21)
27	Customer Allocator		37.8223%	(line 17)
28	Customer Wages to Include in Transmission Wage Allocator	$	3,433,994	(line 27*26)
	Transmission Network Allocation Factor			
29	Total Investment in Transmission Plant		1,248,782,743	w/s 9, line 4
30	Generator leads & Generator Step Up Transformers included in above		118,378	w/s 8
31	Total Investment in Transmission Plant excluding gen leads & step ups	$	1,248,664,365	
32	Total Investment in Transmission Plant from above	$	1,248,782,743	
33	Percent Allocation		99.9905%	(line 31/32)

Central Maine Power
Transmission Revenue Requirements - 2013 Test Year (Adjusted)
Attachment G-R
6/1/2014 - 5/31/2015

Line No.	Party Billed	Facility/Nature of Revenues		PTF	Non-PTF	Total	RNS Rate Worksheet Reference
	Support						
1	MEPCO	Section 375/392		$ (6,531)	$ -	$ (6,531)	
2	Various	Other support revenue and rents		$ -	$ (380,350)	(380,350)	
3	WF Wyman #4 Joint Owners	Sections 164-167		(102,042)	-	(102,042)	
4	WF Wyman #4 Joint Owners	Section 386		(260,097)	(382,255)	(642,352)	
5	FPL			-	(210,278)	(210,278)	
6	PSNH	Section 214 (from Kimball Rd substation)				-	
7		Total Support Revenues		$ (368,670)	$ (972,883)	$ (1,341,553)	ws 1, line 21
	Wheeling						
8	Jurisdictional Sales			$ (175,934,930)	$ -	$ (175,934,930)	FF1 Pg 330, L.11 thru 15, C.n
9	ISO NE RNS Revenues			(199,337,600)	-	(199,337,600)	FF1 450.1 Notes Pg.328, L. 6
10	HVDC - Sch 20A-Central Maine Power			-	(4,323,553)	(4,323,553)	FF1 Pg 330, L.2 thru 4, C.n
11	ISO NE Ancillary Service #1			(4,129,799)	-	(4,129,799)	FF1 450 notes for Pg 328
12	ISO NE Through & Out Revenues			(1,350,029)	-	(1,350,029)	ws15, line 48
13		Total Wheeling Revenues		$ (380,752,358)	$ (4,323,553)	$ (385,075,911)	FF 1 Pg 330 total col n.
14	CMPOATT SCH 9&10 - HVDC	HVDC costs not included in ATRR		-	4,323,553	4,323,553	
15	RNS & Ancillary Revenues	Credited separately on ws 18 (lines 11+14 thru 16)		204,817,428	-	204,817,428	FF1 450.1 Notes Pg.328, L. 6
16	Jurisdictional Sales	(Included in network load of rate divisor)		175,934,930	-	175,934,930	FF1 Pg 330, L.11 thru 15, C.n
17		Sub-total Other Wheeling Revenues		-	-	-	(line 13+14+15+16)
18		Study Revenues		(49,415)	-	(49,415)	FF1 Pg 231, L.22-27, C.d
19		DAF - Schedule 14 & I.A. Related Revenues	456	(2,451,832)	-	(2,451,832)	USS
20		excepted transaction revenues credited to Schedule 1		-	-	-	
21				(2,501,247)	-	(2,501,247)	ws 1, line 25

Central Maine Power
Transmission Revenue Requirements - 2013 Test Year (Adjusted)
Attachment G-R
6/1/2014 - 5/31/2015

Line No.	Party Paid	Facility/Nature of Expenses	RNS Rate Worksheet Reference		PTF		Non-PTF		Total	FERC Account
	Support									
1	Boston Edison	7.1205 % of the cost of service for HQ Ph II, AC		$	34,156		-	$	34,156	566
2	NEP	NEP Ph II, AC -O&M			175,767		-		175,767	566
3		NEP Ph II, AC -RENTS			121,316		-		121,316	567
4		NEP Ph II, AC -INTEREST			139,759		-		139,759	431
5		NEP Ph II, AC -TOTAL	w/s 14, line 7		436,842		-		436,842	
6		NHH- Chester SVC	w/s 9, line 18		184,604		-		184,604	566
7		Total Support Expenses	w/s 1, line 22	$	655,602	$	-		$655,602	
	Wheeling									
8	ISO-NE	Sch 1 - ISO-NE Admin	FF1 450 notes for page 332	$	2,717,803	$	-	$	2,717,803	565
9	ISO-NE	Demand/Load Response	FF1 450 notes for page 332		(265,960)		-		(265,960)	565
10	ISO-NE	Regional Network Transmission Service	FF1 450 notes for page 332		114,698,066		-		114,698,066	565
11	ISO-NE	Sch 1	FF1 450 notes for page 332		2,440,981		-		2,440,981	565
12	ISO-NE	Sch 2 CC	FF1 450 notes for page 332		1,430,000		-		1,430,000	565
13	ISO-NE	Sch 2 VAR Uplift	FF1 450 notes for page 332		1,398,658		-		1,398,658	565
14	ISO-NE	Sch 16	FF1 450 notes for page 332		1,302,151		-		1,302,151	565
15	ISO-NE	Congestion Uplift Expenses	FF1 450 notes for page 332		1,462,107		-		1,462,107	565
16	Bangor Hydro	Firm PTP Res for Energy Transferred to Herman S/S	FF1 page 332.4		255,021		-		255,021	565
17	ISO-NE	Sch 5 NESCO			143,932		-		143,932	565
18	PSNH	Bolt Hill			103,413		-		103,413	565
19		Total Wheeling Expenses	FF1 page 332	$	125,686,173	$	-		$125,686,173	
18		Total Transmission Wheeling/Support Expenses		$	126,341,775	$	-	$	126,341,775	

Line No.					
	SUMMARY BY FERC ACCOUNT:				
19	431			$ 139,759	line 4 above
20	565			125,686,173	FF1 page 332
21	566	NEP AC; Chester; Millstone		360,371	lines 2+6 above
22	567	(Sum of 566+567 to ws 4, line 9)	535,257	155,472	lines 1 + 3 above
23	TOTAL			$ 126,341,775	
24		FERC Form I balance from line 43 above		125,686,173	
25		transmission retail wheeling (line 16 + 90% of line 18)		(348,093)	
26		total to w/s 4, line 7		125,338,080	

Central Maine Power
Transmission Revenue Requirements - 2013 Test Year (Adjusted)
Attachment G-R
6/1/2014 - 5/31/2015

Property Description	Property Classification	Cost	Worksheet Reference	Reserve	Worksheet Reference	Depreciation	Worksheet Reference
Furniture & Equipment	General	$ 2,480,122		$ 571,026		$ 161,696	
Structure Costs & Map Boards	General	5,250,390		1,984,935		123,453	
UPS	General	284,858		179,776		10,550	
EMS Hardware	General	1,885,690		1,834,871		193,715	
LMS	General	-		-		-	
EBCC	General	-		-		-	
Communication Equipment	General	772,770		641,663		55,873	
PC Equipment	General	-		-		-	
		10,673,830	w/s 9, Line 7B	5,212,271	w/s 9, Line 9B	545,287	w/s 9, Line 8B
EMS Software	Intangibile	7,929,600	w/s 9, Line 10B	7,905,934	w/s 9, Line 12B	5,745	w/s 9, Line 11B
S/S RTU's & Scada	Transmission	4,531,019	w/s 9, Line 4B	1,153,932	w/s 9, Line 6B	113,357	w/s 9, Line 3B
Total Plant Directly Assigned to Schedule 1		$ 23,134,449		$ 14,272,137		$ 664,389	

Generator Leads	Section	Balance
Worumbo	22	11,165
Mechanic Falls Hydro	53A	16,835
Pejepscot Hydro	76C	-
MERC	199	35,766
Fort Halifax	3	3,976
Millstone		-
Total investment in Generator Leads		67,742

Generator Step Up Transformers		
Cape		50,636
Harris		-
Williams		-
Total Investment in Step Ups		50,636
Total Leads & Step Ups	w/s 5, line 30	$ 118,378

Central Maine Power
Transmission Revenue Requirements - 2013 Test Year (Adjusted)
Attachment G-R
6/1/2014 - 5/31/2015

Line No.		A FERC FORM 1 TOTAL	B LESS COST RECOVERED UNDER SCH 1	C ADJUSTMENTS	D ADJUSTED TOTAL	WORKSHEET REFERENCE FOR COL. D
	TRANSMISSION OPERATION & MAINTENANCE EXPENSE					
1	FERC FORM 1, PG 321, LINE 112b	$ 145,865,336	-	$ (2,846,300)	$ 143,019,036	w/s 4, LINE 6
	WAGES & PAYROLL EXPENSES					
2	FERC FORM 1, PG. 354, LINE 21B	4,487,563	(1,721,555)	-	2,766,008	w/s 5, LINE 1
	TRANSMISSION DEPRECIATION EXPENSE					
3	FERC FORM 1, PG. 336, LINE 7B	28,010,173	(113,357)	-	27,896,816	w/s 4, LINE 1
	TRANSMISSION PLANT					
4	FERC FORM 1, PG. 207, LINE 58G	1,253,313,762	(4,531,019)	-	1,248,782,743	w/s 3, LINE 1
	TRANSMISSION PLANT HELD FOR FUTURE USE					
5	FF I, P 214, LINE 47 - (15+16)	3,365,121	-	-	3,365,121	w/s 3, LINE 5
	TRANSMISSION ACCUM. DEPRECIATION					
6	FERC FORM 1, PG 219, LINE 25c	191,639,943	(1,153,932)	-	190,486,011	w/s 3, LINE 6
	GENERAL PLANT					
7	FERC FORM 1, PG 207, LINE 99g	214,513,613	(10,673,830)	-	203,839,783	w/s 3, LINE 2
	GENERAL PLANT DEPRECIATION EXPENSE					
8	FERC FORM 1, PG. 336, LINE 10f	6,750,322	(545,287)	-	6,205,035	(A) see line 20 below
	GENERAL PLANT ACCUM. DEPRECIATION					
9	FERC FORM 1, PG 219, LINE 28c	93,653,507	(5,212,271)	-	88,441,236	w/s 3, LINE 7
	INTANGIBLE PLANT					
10	FERC FORM I, P 205, LINE 5g	58,187,357	(7,929,600)	-	50,257,757	w/s 3, LINE 3
	INTANGIBLE AMORTIZATION					
11	FERC FORM I, PG 336 , LINE 1f	2,526,856	(5,745)	-	2,521,111	(A) see line 20 below
	INTANGIBLE PLANT RESERVE					
12	FERC FORM I, PG 200 , LINE 21c	53,132,776	(7,905,934)	-	45,226,842	w/s 3, LINE 8
	TRANSMISSION PREPAYMENTS					
13	FF1 Pg 111, L.57, C.c	$ 36,673,551	-	$ 32,998,240	$ 3,675,311	w/s 3, LINE 16
	Excluded $32,998,240 of prepaid income taxes reclassified from account 236					
14	HQ PHASE 1 & 2 INVESTMENT (not incl. In line 4)	3,939,400			3,939,400	w/s 14, line 1
15	AC BALANCE	2,261,315			2,261,315	w/s 14, line 1
16	DC BALANCE	$ 1,678,086			$ 1,678,086	w/s 14, line 1
17	HQ PHASE 1 & 2 O&M EXPENSES	3,501,030			3,501,030	w/s 14, line 7
18	BECO AC	34,156			34,156	w/s 14, line 9
19	CHESTER SVC	184,604			184,604	w/s 14, line 8
20	Total HQ	$ 3,719,790			$ 3,719,790	
21	Transmission Wages by FERC Account Number			Sum of (A) =	8,726,146	w/s 4, LINE 2
22						
23	560	$ 338,299				
24	561-561.4 Line	1,721,555				
25	561.5-561.8	101,478				
26	562	587,363				
27	563	60,944				
28	566	-				
29	567	790,903				
30	568	-				
31	569	172,572				
32	570	48,146				
33	571	414,374				
34	572	200,191				
35	573	50,634				
36	564	1,105				
37	FFI page 354.21	$ 4,487,564				

Central Maine Power
Transmission Revenue Requirements - 2013 Test Year (Adjusted)
Attachment G-R
6/1/2014 - 5/31/2015

Line No.	Acc't	Description	Amount	
1	920	Administrative and General Salaries	$ 7,996,238	FF1 Pg 323, L.181, C.b
2	921	Office Supplies and Expenses	3,063,499	FF1 Pg 323, L.182, C.b
3	922	Less Administrative Expenses Transferred	(505,998)	FF1 Pg 323, L.183, C.b
4	923	Outside Services	31,397,588	FF1 Pg 323, L.184, C.b
5	924	Property Insurance	415,616	FF1 Pg 323, L.185, C.b
6	925	Injuries and Damages	1,081,660	FF1 Pg 323, L.186, C.b
7	926	Employee Pensions and Benefits	(6,582,691)	FF1 Pg 323, L.187, C.b
8	928	Regulatory Commissions Expense	9,172,452	FF1 Pg 323, L.189, C.b
9	930.1	General Advertising	655,636	FF1 Pg 323, L.191, C.b
10	930.2	Miscellaneous General Expense	(1,487,452)	FF1 Pg 323, L.192, C.b
11	931	Rents	1,228,520	FF1 Pg 323, L.193, C.b
12	935	Maintenance of General Plant	3,105,466	FF1 Pg 323, L.196, C.b
13		Total Admin & Gen'l Exp.	$ 49,540,534	FF1 Pg 323.197b
14		FERC Reg Comm Exp - Trans (directly assigned) line 41 below	411,066	FF1 Pg 350, L.24 thru 25, C.c
15		FERC assessments - 100% Transmission to w/s 4, line 17	636,510	FF1 Pg 350, L.20, C.d
16		FERC Reg Comm Exp - subject to plant allocation factor (line 33 below)	-	
17		Amortization of RTO Formation Costs (100% Transmission) (line 38 below)	-	0
18		TOTAL FERC ASSESSMENTS (14+15)	$ 1,047,576	
19		State Comm Exp & Assessments - Transmission (directly assigned)	29,474	FF1 Pg 350, L.4, C.c
20		Total State Assessments	8,124,876	FF1 Pg 350, L.3+L.4+L.5+L.6+L.7+L.8+L.9+L.11+L.12+L.13+L.15+L.21, C.c (includes $1.5 mil for MPUC Docket # 2008-255)
21	928	Total Regulatory Commissions Expense: (16+18) & from line 8	$ 9,172,452	FF1 Pg 323, L.189, C.b
22		General Advertising - Transmission related	-	
23		Non-Transmission related General Advertising Exp.	655,636	
24	930.1	Total General Advertising Exp. (line 9)	$ 655,636	
		Summary of Attachment G treatment of A&G		
25		Total A&G	$ 49,540,534	
26	923	less Outside Services	31,397,588	
27	924	less Property Insurance	415,616	MPUC Docket Nos. 2007-215/2008-111
28	926	less pension credit directly assigned to T&D	(6,654,648)	
29	928	less Regulatory Commissions Exp.	9,172,452	
30	930.1	less Non-Trans. General Advertising Exp.	655,636	
31	930.2	less Miscellaneous General Expense	(1,487,452)	
32	920-935	less EPRI Expenses	-	
33		A&G subject to Wages and Salaries Allocation Factor:	$ 16,041,342	w/s 4, line 11
34		Property Insurance	415,616	
35		Regulatory Commissions Exp. - FERC assessments	-	
36		Total A&G subject to Plant Allocation Factor	$ 415,616	w/s 4, line 12
		Items Directly Assigned to Transmission		
37	926010	MRFV - transmission only portion of pension credit	$ (791,903)	MPUC Docket Nos. 2007-215/2008-111
38		State assessments - Transmission (directly assigned)	29,474	FF1 Pg 320, L.4 (c).c
39		Outside Services- Transmission (directly assigned)	11,699,889	FF1 Pg 320, L.184.C.b
40		Miscellaneous General Expense- Transmission (directly assigned)	(90,024)	FF1 Pg 320, L.192.C.b
41		FERC Reg Comm Exp - Trans (directly assigned)	411,066	FF1 Pg 320, L.23+L.24, (c).C
42		total to w/s 4, line 17	$ 11,258,502	w/s 4, line 13

Central Maine Power
Transmission Revenue Requirements - 2013 Test Year (Adjusted)
Attachment G-R
6/1/2014 - 5/31/2015

Line No.	**Customer - Related Expenses Detail** FERC #			Total 2012	To Exclude	Net To Allocate	
1	901	Supervision	FF 1 Pg 322	$ 751,491	$ -	$ 751,491	
2	902	Meter Reading Expense	FF 1 Pg 322	2,433,370	-	2,433,370	
3	903	Customer Records and Collection Expenses	FF 1 Pg 322	15,423,745	-	15,423,745	
4	904	Uncollectible Accounts	FF 1 Pg 322	4,696,302	-	4,696,302	
5	905	Miscellaneous Customer Accounts Expenses	FF 1 Pg 322	5,818,584	4,940,571	878,013	
6	Total Customer Accounts Expenses		FF 1 Pg 322	29,123,492	4,940,571	24,182,921	
7	907	Supervision	FF 1 Pg 322	508	-	508	
8	908	Customer Assistance Expenses	FF 1 Pg 322	434,859	(131)	434,990	
9	909	Informational and Instructional Expenses	FF 1 Pg 322	875,159	875,159	0	
10	910	Miscellaneous Customer Service and Informational Expenss	FF 1 Pg 322	-	-	-	
11	Total Customer Service and Informational Expenses		FF 1 Pg 322	1,310,526	875,028	435,498	
12	911	Supervision	FF 1 Pg 322	6,263	-	6,263	
13	912	Demonstrating and Selling Expenses	FF 1 Pg 322	1,900,769	-	1,900,769	
14	913	Advertising Expenses	FF 1 Pg 322	71,048	-	71,048	
15	916	Miscellaneous Sales Expenses	FF 1 Pg 322	503,697	-	503,697	
16	Total Sales Expenses		FF 1 Pg 322	2,481,777	-	2,481,777	
17	Grand Total Customer-Related Expenses			$ 32,915,795	$ 5,815,599	$ 27,100,196	ws 4, line 16
	Details of Exclusions						
18		Electric Lifeline Program			4,940,571		
19		DSM			(131)		
20		Informational & Instructional			875,159		
21		Total State Related items/programs			$ 5,815,599		

Central Maine Power
Transmission Revenue Requirements - 2013 Test Year (Adjusted)
Attachment G-R
6/1/2013 - 5/31/2014

Line No.	Series	(A) Nominal Interest Rate	(B) Principal	(C) (A)*(B) Annualized Nominal Cost	(D) Expense Premium or Discount	(E) Hedge Activities	(F) (B)-(D)-(E) Net Proceeds	(G) (C)/(F) Embedded Cost Rate	(H) (B)*(G) All Debt Annualized Cost
1	N.H. Business Finance Athority	5.375%	$ 19,500,000	$ 1,048,125	$ 386,087	-	$ 19,113,913	5.484%	$ 1,069,296
2	First Mortgage Bond-Series A	5.700%	150,000,000	8,550,000	1,862,630	6,953,000	141,184,370	6.056%	9,083,867
3	F (Note 1)	5.780%	25,000,000	1,445,000	205,140	2,128,521	22,666,339	6.375%	1,593,773
4	F (Note 2)	5.375%	20,000,000	1,075,000	156,129	-	19,843,871	5.417%	1,083,458
5	F (Note 3)	5.430%	25,000,000	1,357,500	195,140	2,795,719	22,009,141	6.168%	1,541,973
6	F (Note 4)	5.700%	15,000,000	855,000	132,346	-	14,867,654	5.751%	862,611
7	F (Note 5)	5.875%	15,000,000	881,250	132,137	-	14,867,863	5.927%	889,082
8	F (Note 6)	5.300%	30,000,000	1,590,000	230,546	335,500	29,433,954	5.402%	1,620,577
9	F (Note 7)	5.270%	10,000,000	527,000	65,627	175,000	9,759,373	5.400%	539,994
10	F (Note 8)	6.400%	40,000,000	2,560,000	312,089	343,168	39,344,743	6.507%	2,602,635
11	First Mortgage Bond	4.200%	150,000,000	6,300,000	844,040	-	149,155,960	4.224%	6,335,650
12	First Mortgage Bond	5.680%	100,000,000	5,680,000	562,693	-	99,437,307	5.712%	5,712,142
13	First Mortgage Bond	3.070%	125,000,000	3,837,500	676,164	-	124,323,836	3.087%	3,858,371
14	First Mortgage Bond	4.450%	225,000,000	10,012,500	1,195,901	-	223,804,099	4.474%	10,066,002
15			$ 949,500,000	$ 45,718,875	$ 6,956,671	$ 12,730,908	$ 929,812,421	4.917%	$ 46,859,431
16	Less 12/31/2013 Unamort. Loss on Req. Debt (FF I p.111.81.c)						1,801,635		
17	Add Amort. Of Loss on Reaquired Debt (FFI p117.64.c)								575,438
18	Adjusted Balance						$928,010,786 **(I)**		$47,434,869 **(J)**
19	Cost Of Debt (J)/(I)		**5.111%**						

Central Maine Power
Transmission Revenue Requirements - 2013 Test Year (Adjusted)
Attachment G-R
6/1/2014 - 5/31/2015

DERIVATION OF AFUDC INCLUDED IN DEPRECIATION EXPENSE
Source: USS PLANT ACCOUNTING (SAP)

	Vintage	cost	afudc	% of total
1	1953-1970	----------no afudc data available-----------		
2	1971	$ 16,993,929	$ 210,398	1.24%
3	1972	1,354,874	-	0.00%
4	1973	2,530,521	21,837	0.86%
5	1974	3,929,745	200	0.01%
6	1975	4,626,387	38,383	0.83%
7	1976	6,559,880	76,909	1.17%
8	1977	5,885,933	86,351	1.47%
9	1978	17,338,606	444,301	2.56%
10	1979	4,115,534	14,481	0.35%
11	1980	7,717,864	28,543	0.37%
12	1981	3,806,576	45,143	1.19%
13	1982	3,336,346	16,508	0.49%
14	1983	5,462,226	107,741	1.97%
15	1984	6,543,576	188,256	2.88%
16	1985	2,153,012	13,995	0.65%
17	1986	4,063,381	72,616	1.79%
18	1987	6,308,982	70,120	1.11%
19	1988	8,616,426	96,074	1.12%
20	1989	8,190,862	92,568	1.13%
21	1990	18,606,637	300,769	1.62%
22	1991	6,804,433	68,667	1.01%
23	1992	10,041,560	178,995	1.78%
24	1993	5,637,279	121,080	2.15%
25	1994	3,480,922	26,059	0.75%
26	1995	3,820,449	32,298	0.85%
27	1996	2,681,701	20,928	0.78%
28	1997	1,790,063	23,501	1.31%
29	1998	1,477,852	4,185	0.28%
30	1999	1,810,857	10,989	0.61%
31	2000	26,037,439	264,455	1.02%
32	2001	8,983,040	92,232	1.03%
33	2002	8,622,712	117,487	1.36%
34	2003	2,701,882	(16,453)	-0.61%
35	2004	13,379,541	151,747	1.13%
36	2005	10,790,340	187,716	1.74%
37	2006	14,151,218	57,062	0.40%
38	2007	41,386,528	247,340	0.60%
39	2008	84,332,796	3,500,923	4.15%
40	2009	44,549,845	355,246	0.80%
41	2010	20,636,193	558,551	2.71%
42	2011	29,046,140	374,354	1.29%
43	2012	100,664,413	342,000	0.34%
44	2013	61,678,656	823,106	1.33%
45		$ 642,647,156	$ 9,467,661	1.47%

46	Transmission Depreciation Exp from w/s 4	$ 27,894,166
47	AFUDC adj to w/s 2	$ 410,945

Central Maine Power
Transmission Revenue Requirements - 2013 Test Year (Adjusted)
Attachment G-R
6/1/2014 - 5/31/2015

					Phase I				Phase II	
Line No.	HYDRO-QUEBEC CAPITAL LEASES	WS Ref.	TOTAL HQ	TOTAL DC	DC Neetco	DC Vetco	WS Ref.	AC Nep	DC Nhh	DC Neh
1	INVESTMENT-FERC A/C 101.1	w/s 9, line 13	$ 3,939,400	$ 1,678,086	$ -	$ -		$ 2,261,315	$ 695,350	$ 982,736
2	(excluded from transmission plant)									
3	O&M - FERC A/C 566015		$ 1,789,748	$ 1,613,981	$ 152,137	$ 107,943		$ 175,767	$ 638,952	$ 714,949
4	RENTS- FERC A/C 567015		1,353,635	1,232,319	-	-		121,316	464,997	767,322
5	TOTAL O&M		3,143,382	2,846,300	152,137	107,943		297,083	1,103,949	1,482,271
6	INTEREST-FERC A/C 431010		357,648	217,888	8,427	1,221		139,759	46,157	162,083
7	TOTAL	w/s 9, line 16	$ 3,501,030	$ 3,064,188	$ 160,563	$ 109,164		$ 436,842	$ 1,150,106	$ 1,644,354
8	Chester SVC		$ 184,604							
9	BECO AC		34,156							
10	Total HQ		$ 3,719,790							

Central Maine Power
Transmission Revenue Requirements - 2013 Test Year (Adjusted)
Attachment G-R
6/1/2013 - 5/31/2014

: DRAFT INFO FILING

June 1, 2014 89.80

CMP PROJECTED RNS EXPENSE 6/1/14 - 5/31/2015

line #		TOTAL	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY
1	CMP Participant RNS Rate	89.80	7.48	7.48	7.48	7.48	7.48	7.48	7.48	7.48	7.48	7.48	7.48	7.48
2	CMP RNS load 12CP-KW (2012 avg)	1,371,755	1,371,755	1,371,755	1,371,755	1,371,755	1,371,755	1,371,755	1,371,755	1,371,755	1,371,755	1,371,755	1,371,755	1,371,755
3		$ 123,178,612	$ 10,264,884	$ 10,264,884	$ 10,264,884	$ 10,264,884	$ 10,264,884	$ 10,264,884	$ 10,264,884	$ 10,264,884	$ 10,264,884	$ 10,264,884	$ 10,264,884	$ 10,264,884
4														
5	NU Participant RNS Rate	89.80	7.48	7.48	7.48	7.48	7.48	7.48	7.48	7.48	7.48	7.48	7.48	7.48
6	CMP load at Bolt Hill 12CP- KW (2012 avg)	37,550	37,550	37,550	37,550	37,550	37,550	37,550	37,550	37,550	37,550	37,550	37,550	37,550
7		$ 3,371,854	$ 280,988	$ 280,988	$ 280,988	$ 280,988	$ 280,988	$ 280,988	$ 280,988	$ 280,988	$ 280,988	$ 280,988	$ 280,988	$ 280,988
8														
9	BHE Participant RNS Rate	89.80	7.48	7.48	7.48	7.48	7.48	7.48	7.48	7.48	7.48	7.48	7.48	7.48
10	CMP load at Herman 12CP- KW (2012 avg)	5,536	5,536	5,536	5,536	5,536	5,536	5,536	5,536	5,536	5,536	5,536	5,536	5,536
11		$ 497,083	$ 41,424	$ 41,424	$ 41,424	$ 41,424	$ 41,424	$ 41,424	$ 41,424	$ 41,424	$ 41,424	$ 41,424	$ 41,424	$ 41,424
12														
13														
14	**TOTAL RNS EXPENSE**	**$ 127,047,549**	**$ 10,587,296**	**$ 10,587,296**	**$ 10,587,296**	**$ 10,587,296**	**$ 10,587,296**	**$ 10,587,296**	**$ 10,587,296**	**$ 10,587,296**	**$ 10,587,296**	**$ 10,587,296**	**$ 10,587,296**	**$ 10,587,296**
15														
16														
17	CMP PROJECTED RNS REVENUES - 6/1/14 - 5/31/2015													
18														
19	Expected Revenues Collected by ISO:													
20														
21	Pre 1997	$ 344,097,622	$ 28,674,802	$ 28,674,802	$ 28,674,802	$ 28,674,802	$ 28,674,802	$ 28,674,802	$ 28,674,802	$ 28,674,802	$ 28,674,802	$ 28,674,802	$ 28,674,802	$ 28,674,802
22	Post 1996	1,533,596,974	127,799,748	127,799,748	127,799,748	127,799,748	127,799,748	127,799,748	127,799,748	127,799,748	127,799,748	127,799,748	127,799,748	127,799,748
23														
24	Total	$ 1,877,694,596	$ 156,474,550	$ 156,474,550	$ 156,474,550	$ 156,474,550	$ 156,474,550	$ 156,474,550	$ 156,474,550	$ 156,474,550	$ 156,474,550	$ 156,474,550	$ 156,474,550	$ 156,474,550
25														
26	Distribution of Revenues													
27	PRE 1997:													
28	MW-mile %		9.8818%	9.8818%	9.8818%	9.8818%	9.8818%	9.8818%	9.8818%	9.8818%	9.8818%	9.8818%	9.8818%	9.8818%
29	MW-mile weighting		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
30	Rev. Req't %		5.00001%	5.00001%	5.00001%	5.00001%	5.00001%	5.00001%	5.00001%	5.00001%	5.00001%	5.00001%	5.00001%	5.00001%
31	Rev. Req't weighting		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
32														
33	Post 1996													
34	Rev. Req't %		15.28161%	15.28161%	15.28161%	15.28161%	15.28161%	15.28161%	15.28161%	15.28161%	15.28161%	15.28161%	15.28161%	15.28161%
35	Rev. Req't weighting		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
36														
37				**CMP Share of Revenues**										
38	Pre 1997	17,204,907	1,433,742	1,433,742	1,433,742	1,433,742	1,433,742	1,433,742	1,433,742	1,433,742	1,433,742	1,433,742	1,433,742	1,433,742
39	Post 1996	234,358,293	19,529,858	19,529,858	19,529,858	19,529,858	19,529,858	19,529,858	19,529,858	19,529,858	19,529,858	19,529,858	19,529,858	19,529,858
40														
41	**TOTAL RNS REVENUES**	**$ 251,563,200**	**$ 20,963,600**	**$ 20,963,600**	**$ 20,963,600**	**$ 20,963,600**	**$ 20,963,600**	**$ 20,963,600**	**$ 20,963,600**	**$ 20,963,600**	**$ 20,963,600**	**$ 20,963,600**	**$ 20,963,600**	**$ 20,963,600**
42														
43														
44	NET RATE YEAR EXPENSE (REVENUE)	$ (124,515,651)	$ (10,376,304)	$ (10,376,304)	$ (10,376,304)	$ (10,376,304)	$ (10,376,304)	$ (10,376,304)	$ (10,376,304)	$ (10,376,304)	$ (10,376,304)	$ (10,376,304)	$ (10,376,304)	$ (10,376,304)
45														
46														

47	PROJECTED RNS REVENUES	$ 251,563,200	line 41 above			
48	2012 THROUGH & OUT REVENUES	1,350,029	ws 6, line 16	CY	CY	CY
49	TOTAL REGIONAL REVENUES	252,913,229		TY incetives	ATU incentive	FTPA incentives
50	LESS:					
51	ROE ADDER - 50bp	4,252,106		$ 3,334,400	$ (150,588)	$ 1,068,293
52	ROE ADDER - 100bp	486,417		546,507	(255,049)	194,959
53	ROE ADDER - 125bp	9,016,451		5,841,625	1,064,465	2,110,360
54	MPRP CWIP INCENTIVE	50,870,888		75,826,631	1,798,850	(26,754,592)
55	TOTAL CREDIT FOR REGIONAL REVS	$ 188,287,367	w/s 1, L. 23			

Central Maine Power
Transmission Revenue Requirements - 2013 Test Year (Adjusted)
Attachment G-R
6/1/2013 - 5/31/2014

Line #		Transition Schedule						
1	Transition Year	1	2	3	4	5	6	7-11
2	From / to	3/1/97- 2/28/98	3/1/98 - 2/28/99	3/1/99 - 2/28/00	3/1/00 - 2/28/01	3/1/01 - 2/28/02	3/1/02 - 2/28/03	Thereafter
3								
4	% of Local Charges to be paid by PTF connected loads	100%	80%	60%	40%	20%	20%	0%
5								
6	12 month average PTF Connected Load	49,448	39,558	29,669	19,779	9,890	9,890	-
7	12 month average Non PTF Connected Load	1,423,745	1,423,745	1,423,745	1,423,745	1,423,745	1,423,745	1,423,745
8								
9	avg load (See Sch. 12, sec B.1. & D.2)	1,473,193	1,399,645	1,388,456	1,377,267	1,366,078	1,366,078	1,354,889

Line #			
10	**Network Load for rate year (6/1/13-5/31/14) rate design:**		
11	Non PTF Connected Load (line 7)		1,423,745
12	PTF Connected Load (line 6 for years 7 and out)		-
13	Total Local Network Load		1,423,745
14			
15	ATRR ws 1, line 28	$	49,155,775
16			
17	Rate $/kW-yr (line 15/13)	$	34.53
18			
19	RATE DESIGN FORMULA:		
20	ATRR/(NPTFNL+(PTFNL X ATYP)) where:		
21		ATRR = Annual Transmission Revenue Requirement	
22		NPTFNL = Non-PTF Network Load	
23		PTFNL = PTF Network Load	
24		ATYP = Applicable Transition Year Percentage (Sch. 11)	
25			

Line #	RATE DESIGN PROOF:		Total			Rate		ATYP		Network load		# months
27	Recovery from Non-PTF connected Customers	$	49,155,775	=	$	34.526	x	100%	x	1,423,745	x	12/12
28	Recovery from PTF Connected Customers -last 9 months of Transition yr 10		-	=	$	34.526	x	0%	x	49,448	x	9/12
29	Recovery from PTF Connected Customers -1st 3 months of Transition yr 11		-	=	$	34.526	x	0%	x	49,448	x	3/12
30												
31	Total Recovery	$	49,155,775									
32	Rounding differences		0									

Line #			
33	FIRM POINT TO POINT RATES: (See Sch. 7 for Wheeling Out Rate)		
34	Per Year (Line 17)	$	34.5257
35	Per Month (Line 34 divided by 12 months)	$	2.8771
36	Per Week (Line 34 divided by 52 weeks)	$	0.6640
37	Per Day (Line 36 divided by 5 days)	$	0.1328
38			
39	NON-FIRM POINT TO POINT RATES:		
40	Per Year (Line 17)	$	34.5257
41	Per Month (Line 40 divided by 12 months)	$	2.8771
42	Per Week (Line 40 divided by 52 weeks)	$	0.6640
43	Per Day (Line 42 divided by 7days)	$	0.0949
44	Per Hour (Line 43 divided by 24 hours)	$	0.0040

Central Maine Power
Transmission Revenue Requirements - 2013 Test Year (Adjusted)
Attachment G-R
6/1/2014 - 5/31/2015

Line No.	I.viii	FORECASTED TRANSMISSION REVENUE REQUIREMENTS	Forecast Period	Attachment K Reference Section:	Amount	Reference
1		Forecasted Rev Req'ts for FTPA		I.vii	$ 56,688,031	line 6 below
2		Forecasted Rev Req'ts for FCWIP		I.vii	190,121	line 9 below
3		Forecasted Transmission Revenue Requirements (Lines 1 + 2)			$ 56,878,152	
4		Forecasted Transmission Plant Additions	2014	I.iii	$ 369,082,105	
5		Carrying Charge Factor		I.v	15.36%	line 21 below
6		Total Forecasted Revenue Requirements (Lines 1*2)			$ 56,688,031	
7		Forcasted MPRP CWIP (FCWIP)	2014	I.iv	$ 1,375,816	Annual Report of Construction Costs
8		MPRP Cost of Capital Rate (MCOC)		I.vi	13.82%	line 24 below
9		Forecasted Rev Req'ts for FCWIP (Lines 4*5)			$ 190,121	
	II.	CARRYING CHARGE FACTOR				
10		Investment Return and Associated Income Taxes		(A)	$ 109,780,917	w/s 21, line 13
11		Depreciation Expense		(B)	29,234,008	w/s 1, line 15
12		Amortization of Investment Tax Credits		(C)	(342,879)	w/s 1, line 16
13		Municipal Taxes		(D)	13,630,137	w/s 1, line 17
14		Operation and Maintenance Expense		(E)	14,020,713	w/s 1, line 18
15		Administrative and General Expense		(F)	13,919,797	w/s 1, line 19
16		Transmission Related Regulatory Assessments		(G)	636,510	w/s 1, line 20
17		Transmission Support Expenses		(H)	655,602	w/s 1, line 22
18		Transmission Related Customer Service, Informational Exp. & Sales Exp.		(M)	10,249,918	w/s 1, line 26
19		Total Expenses (Lines 10 thru 18)			$ 191,784,723	
20		Transmission Plant		(A)(1)(a)	$ 1,248,664,109	w/s 1, line 1
21		Carrying Charge Factor (Lines 19/20)			15.36%	
		DERIVATION OF MPRP COST OF CAPITAL RATE (MCOC)				
22		Cost of Capital Rate - 11.14% ROE			12.65820%	w/s 2, line 9
23		Cost of Capital Rate - 1.25% bp ROE adder for MPRP			1.16056%	w/s 2, line 11
24		MPRP Cost of Capital Rate (MCOC) (Lines 21 x 22)			13.81876%	
	III.	ANNUAL TRUE-UP				
25		ATRR for True-up = 2012 Actual		Attachment K	188,637,573	w/s 19, line 29
26		ATRR subject to True-up = '11 TY + '12 Forecast - (as billed)			196,449,827	w/s 19, line 29
27		Under / (Over) (Lines 24-25)			$ (7,812,253)	
28		Interest			(260,330)	w/s 20, line 13
29		Total True Up and associated interest (Lines 26+27)			$ (8,072,584)	
30		Net Forecasted Revenue Requirement and Prior Year True-up (Lines 3 + 28)			$ 48,805,568	ws 1, line 27

Central Maine Power
Transmission Revenue Requirements - 2013 Test Year (Adjusted)
Attachment G-R
6/1/2014 - 5/31/2015

Line No.	I. ANNUAL TRUE-UP	Rate Year	Attachment G	Reference
1	ATRR for True-up = 2013 Actual	6/1/2014 - 5/31/2015	$ 188,637,573	
2	ATRR subject to True-up = 2012 TY + 2013 Forecast (as billed)	6/1/2013 - 5/31/2014	$ 196,449,827	
3	Annual True-up (Line 1 - Line 2)		$ (7,812,253)	w/s 19, line 29

Central Maine Power
Transmission Revenue Requirements - 2013 Test Year (Adjusted)
Attachment G-R
6/1/2014 - 5/31/2015

	INVESTMENT BASE	*Formula Reference Section:*	Difference	6/1/2014 - 5/31/2015 2013 TY	6/1/2013 - 5/31/2014 2012 TY + 2013 Forecast
1	Transmission Plant	II (A)(1)(a)	$ 356,130,974	$ 1,248,664,109	$ 892,533,135
2	Transmission Related Intangible & General Plant	II (A)(1)(b)	2,090,819	39,015,003	36,924,184
3	Transmission Plant Held for Future Use	II (A)(1)(c)	(31,191)	3,365,121	3,396,312
4	Total Plant (Lines 1+2+3)		358,190,602	1,291,044,233	932,853,631
5	Accumulated Depreciation	II (A)(1)(d)	(15,774,773)	(210,991,767)	(195,216,994)
6	Accumulated Deferred Income Taxes	II (A)(1)(e)	(88,344,243)	(223,751,761)	(135,407,518)
7	Other Regulatory Assets	II (A)(1)(f)	(255,001)	936,231	1,191,232
8	Net Investment (Line 4+ 5+6+7)		253,816,585	857,236,936	603,420,351
9	Transmission Prepayments	II (A)(1)(g)	154,202	564,319	410,117
10	Transmission Materials and Supplies	II (A)(1)(h)	(841,301)	6,566,596	7,407,897
11	Cash Working Capital	II (A)(1)(i)	1,201,496	3,492,564	2,291,068
12	MPRP CWIP	II (A)(1)(j)	(427,412)	5,034,097	5,461,509
13	Transmission Investment Base (Line 8+9+10+11+12)		$ 253,903,570	$ 872,894,512	$ 618,990,942
	REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	II (A)	$ 30,821,399	$ 110,476,567	$ 79,655,168
15	Depreciation Expense	II (B)	9,709,555	29,234,008	19,524,453
16	Amortization of Investment Tax Credits	II (C)	(49,915)	(342,879)	(292,964)
17	Municipal Taxes	II (D)	4,378,513	13,630,137	9,251,624
18	Operation and Maintenance Expense	II (E)	1,923,801	14,020,713	12,096,912
19	Administrative and General Expense	II (F)	7,688,167	13,919,797	6,231,630
20	Transmission Related Regulatory Assessments	II (G)	(6,925)	636,510	643,435
21	Transmission Support Expenses	II (H)	(27,748)	655,602	683,350
22	Transmission Support Revenues	II (I)	24,897	(1,341,553)	(1,366,449)
23	ISO-NE Transmission Revenues	II (J)	-	-	-
24	Other Wheeling Revenues	II (K)	(147,801)	(2,501,247)	(2,353,446)
25	Transmission Rents Received from Electric Property	II (L)	-	-	-
26	Transmission Related Customer Service, Informational Exp. & Sales Exp.	II (M)	(848,399)	10,249,918	11,098,317
27	Total costs for True-up purposes		53,465,545	188,637,573	135,172,029
28	Forecasted Transmission Revenue Requirements - 2013	II (N)	(61,277,798)	-	61,277,798
29	Annual True-up	II (N)	$ (7,812,253)	$ 188,637,573	$ 196,449,826
30	Reconciliation to LNS ATRR:				
31	Line 29 Above		$ (7,812,253)	$ 188,637,573	$ 196,449,826
32	ISO-NE Transmission Revenues	II (J)	(62,492,511)	(188,287,366)	(125,794,855)
33	Pro Forma RTO Formation Cost Adj.	II (F)(3)	-	-	-
34	Annual True-Up	II (N)	16,555,673	(7,812,253)	(24,367,926)
35	Interest on Annual True-up up	II (N)	551,690	(260,330)	(812,021)
36	2014 Forecasted Transmission Revenue Requirements	II (N)	56,878,152	56,878,152	-
37	LNS ATRR		$ 3,680,750	$ 49,155,775	$ 45,475,024

Central Maine Power
Transmission Revenue Requirements - 2013 Test Year (Adjusted)
Attachment G-R
6/1/2014 - 5/31/2015

Undercollection / (Overcollection)
(7,812,253)

	Initial Billing Period	Local		FERC Monthly Interest Rate	Local
1	June 2013	$ (7,812,253)		0.27%	$ (21,093)
2	July 2013	(7,833,347)		0.28%	(21,933)
3	August 2013	(7,833,347)		0.28%	(21,933)
4	September 2013	(7,833,347)		0.27%	(21,150)
5	October 2013	(7,898,363)		0.28%	(22,115)
6	November 2013	(7,898,363)		0.27%	(21,326)
7	December 2013	(7,898,363)		0.28%	(22,115)
8	January 2014	(7,963,920)		0.28%	(22,299)
9	February 2014	(7,963,920)		0.25%	(19,910)
10	March 2014	(7,963,920)		0.28%	(22,299)
11	April 2014	(8,028,427)		0.27%	(21,677)
12	May 2014	(8,028,427)		0.28%	(22,480)
13			Total Interest		$ (260,330)
14			True-Up		(7,812,253)
15			Total True-Up & Interest		$ (8,072,584)

Central Maine Power
Transmission Revenue Requirements - 2013 Test Year (Adjusted)
Attachment G-R
6/1/2014 - 5/31/2015

Investment Base Calculation for Incremental Return and Associated Income Taxes for Post-2003 PTF, MPRP PTF and MPRP CWIP

Line No.		TOTAL MPRP	MPRP CWIP	MPRP Non-PTF
1	MPRP CWIP	$ 5,034,097	$ 5,034,097	$ -
2	MPRP PTF Investment	26,472,757	-	26,472,757
3	Depreciation Reserve	(823,589)	-	(823,589)
4	Accumulated Deferred Income Taxes	(32,076,174)	-	(32,076,174)
5	INVESTMENT BASE	$ (1,392,908)	$ 5,034,097	$ (6,427,006)
		w/s 2 line 10		
6	Cost of Capital Rate - 1.25% bp ROE adder for MPRP (w/s 2 line 8)		12.65820%	
7	MPRP Cost of Capital Rate (MCOC)(6+7)		1.16056%	
8			13.81876%	
	MPRP CWIP - Base (5 x 6)			
9	MPRP CWIP - Incremental (5 x 7)		637,226	
10	Investment Return and Income Taxes - MPRP CWIP (9+10)		58,424	
11			$ 695,650	
	Investment Return and Income Taxes - Total		110,476,567	w/s 1, line 14
12	Less Inv Return&Taxes- MPRP CWIP (11)		695,650	
13	Investment Return and Income Taxes - excluding CWIP		$ 109,780,917	
			w/s 17, line 10	

CENTRAL MAINE POWER COMPANY
TRANSMISSION REVENUE REQUIREMENTS - 2013 TEST YEAR (ADJUSTED)
Attachment G-W
6/1/2014 - 5/31/2015

Line No.	INVESTMENT BASE	Formula Reference *Section:*		AMOUNT	Reference
1	Transmission Plant	II (A)(1)(a)	$	1,248,664,109	Worksheet 3, line 1 column 5
2	Transmission Related Intangible & General Plant	II (A)(1)(b)		17,405,806	Worksheet 3, line 4 column 5
3	Transmission Plant Held For Future Use	II (A)(1)(c)		3,365,121	Worksheet 3, line 5 column 5
4	Total Plant (Lines 1+2+3)			1,269,435,036	
5	Transmission Related Depreciation Reserve	II (A)(1)(d)		(199,624,244)	Worksheet 3, line 9 column 5
6	Transmission Related Accumulated Deferred Taxes	II (A)(1)(e)		(223,751,761)	Worksheet 3, line 12 column 5
7	Other Regulatory Asssets / Liabilities	II (A)(1)(f)		417,682	Worksheet 3, line 15 column 5
8	Net Investment (Line 4+ 5+6+7)			846,476,713	
9	Transmission Prepayments	II (A)(1)(g)		251,761	Worksheet 3, line 16 column 5
10	Transmission Materials & Supplies	II (A)(1)(h)		6,566,596	Worksheet 3, line 17 column 5
11	Transmission Related Cash Working Capital	II (A)(1)(i)		3,278,113	Worksheet 3, line 23 column 5
12	MPRP CWIP	II (A)(1)(j)		5,034,097	Worksheet 3, line 24 column 6
13	Transmission Investment Base (Line 8+9+10+11+12)		$	861,607,280	
	REVENUE REQUIREMENTS				
14	Investment Return and Associated Income Taxes	II (A)	$	109,052,373	Worksheet 2, line 11
15	Transmission Depreciation Expense	II (B)		28,491,911	Worksheet 4, line 3 column 5
16	Transmission Related Amort of Investment Tax Credits	II (C)		(337,125)	Worksheet 4, line 4 column 5
17	Transmission Related Municipal Tax Expense	II (D)		13,630,137	Worksheet 4, line 5 column 5
18	Transmission Operation & Maintenance Expense	II (E)		13,672,653	Worksheet 4, line 10 column 5
19	Transmission Related Administrative & General Expense	II (F)		12,552,251	Worksheet 4, line 15 column 5
20	Transmission Related Regulatory Assessments	II (G)		636,510	Worksheet 4, line 17 column 5
21	Transmission Support Expenses	II (H)		655,602	Worksheet 7, line 11
22	Transmission Support Revenues	II (I)		(1,341,553)	Worksheet 6, line 7
23	ISO-NE Transmission Revenues	II (J)		(188,287,366)	Worksheet 14, line 55
24	Other Wheeling Revenues	II (K)		-	
25	Transmission Rents Received from Electric Property	II (L)		(2,501,247)	Worksheet 6, line 35
26	Forecasted Transmission Revenue Requirement & Annual True Up	II (M)		56,090,838	Worksheet 16, line 29
27	Total Transmission Revenue Requirements (Line 14 thru 26) Retail Distribution - level customers			42,314,984	
28	Less Wheeling Out Revenues			-	
29	Transmission Revenue Requirement for Retail Transmission - level Customers		$	42,314,984	

CENTRAL MAINE POWER COMPANY
TRANSMISSION REVENUE REQUIREMENTS - 2013 TEST YEAR (ADJUSTED)
Attachment G-W
6/1/2014 - 5/31/2015

		CAPITALIZATION 12/31/2013	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION	
1	LONG-TERM DEBT (ws 11)	$ 949,500,000	44.977%	5.111%	2.299%		
2	PREFERRED STOCK (FF 1 page 112.3c)	571,300	0.027%	6.000%	0.002%	0.002%	
3	COMMON EQUITY (FF 1 p. 112.16c less line 3c less goodwill of $302,129,279)	1,160,997,251	54.996%	11.140%	6.127%	6.127%	
4	TOTAL INVESTMENT RETURN	$ 2,111,068,551	100.00%		8.428%	6.129%	
4a	MPRP New Inv Adder Calc. (125 bp)		54.996%	1.25%	0.687%	0.687%	1.161% including FIT&SIT

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 8.428%

6 (b) Federal Income Tax =

(R.O.E. + (Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp) / (Inv. Base) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

= (0.0613 +((337,125) + 410,937) / 861,607,280) x 0.35)
(1 - 0.35)
ws 1, line 15 w/s 12, L. 47

= 3.305%

7 (c) State Income Tax =

(R.O.E. + (Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp) / PTF Inv. Base) + Federal Income Tax)* State Income Tax Rate
(1 - State Income Tax Rate)

= (0.0613 +((337,125) + 410,937) / 861,607,280) + 0.0330484)* 0.0893
(1 - 0.0893)

= 0.926%

8 (a)+(b)+(c) Cost of Capital Rate = 12.659%

			MPRP Non-PTF (Incremental Return Calc)	**Total Investment Return & Taxes including Incremental Return**	
		ws 1, line 13	ws 21, line 5		
9	INVESTMENT BASE	$ 861,607,280	$ (1,392,908)		
10	x Cost of Capital Rate	12.659%	1.161%		
11	= Investment Return and Associated Income Taxes	109,068,539	$ (16,166)	$ 109,052,373	worksheet 1, line 14

CENTRAL MAINE POWER COMPANY
TRANSMISSION REVENUE REQUIREMENTS - 2013 TEST YEAR (ADJUSTED)
Attachment G-W
6/1/2014 - 5/31/2015

Line No.			(1) Total	(2) Wage/Plant Allocation Factors		(3) = (1)*(2) Transmission Allocated	(4) (see note)		(5) = (3) x (4) Network Transmisson Allocated	Worksheet or FERC Form 1 Reference for col (1)
1	**Transmission Plant**	$	1,248,782,743	100.00% (b)	$	1,248,782,743	99.9905%	$	1,248,664,109	ws 9, line 4
2	General Plant		203,839,783	6.8507% (a)		13,964,452	99.9905%		13,963,125	ws 9, line 6
3	Intangible Plant		50,257,757	6.8507% (a)		3,443,008	99.9905%		3,442,681	ws 9, line 9
4	**Transmission Related Intangible & General Plant (line 2+3)**	$	254,097,540		$	17,407,460		$	17,405,806	
5	**Transmission Plant Held for Future Use**		3,365,121	100.00% (b)		3,365,121			3,365,121	Page 214, line 47 - line 14 - line 15
6	Transmission Accum. Depreciation	$	(190,486,011)	100.00% (b)	$	(190,486,011)	99.9905%	$	(190,467,915)	ws 9, line 5
7	General Plant Accum.Depreciation		(88,441,236)	6.8507% (a)		(6,058,844)	99.9905%		(6,058,268)	ws 9, line 8
8	Intangible Plant Accum. Amortization		(45,226,842)	6.8507% (a)		(3,098,355)	99.9905%		(3,098,061)	ws 9, line 11
9	**Transmission Related Depreciation Reserve (line 6+7+8)**	$	(324,154,089)		$	(199,643,210)		$	(199,624,244)	
10	Accumulated Deferred Taxes (281-283)		(239,095,770)	100.00% (b)		(239,095,770)	99.9905%		(239,073,056)	FF1 450.1 Notes Pg. 274.1 L.9, C.k and FF1 450.1 Notes Pg. 276, L.19, C.k
11	Accumulated Deferred Taxes (190)		15,322,751	100.00% (b)		15,322,751	99.9905%		15,321,295	FF1 450.1 Notes, Pg. 234, L. 18, C. c
12	**Transmission Related Accumulated Deferred Taxes (line 10+11)**	$	(223,773,019)		$	(223,773,019)		$	(223,751,761)	
13	FAS 106		6,097,501	6.8507% (a)		417,722				FF1 Pg 232.1, L.37, C.f
14	FAS 109		-	100.00% (c)		-				See Note (C) below
15	**Other Regulatory Assets/Liabilities (line 13+14)**	$	6,097,501		$	417,722	99.9905%	$	417,682	
16	**Transmission Prepayments**	$	3,675,311	6.8507% (a)		251,785	99.9905%	$	251,761	w/s 9, line 12
17	**Transmission Materials and Supplies**	$	6,567,220	100.00% (b)		6,567,220	99.9905%	$	6,566,596	See P. 450 notes for Page 227.12c
18	Operation & Maintenance Expense					13,672,653				Worksheet 1, Line 18
19	Administrative & General Expense					12,552,251				Worksheet 1, Line 19
20	Net Transmission Support Expense					-				Worksheet 1, Lines 21 & 22
21	Subtotal (line 18+19+20)					26,224,904				
22						0.125				45 / 360
23	Total (line 21 x line 22)				$	3,278,113	100.00%	$	3,278,113	
24	**MPRP CWIP**	$	5,034,097	100.00% (b)	$	5,034,097	100.00%	$	5,034,097	FF1 450.1 Notes,Pg. 200.1 L.11, C.c

(a) Worksheet 5, line 9 - Transmission Wages & Salaries Allocation Factor
(b) Amounts Reported as transmission in FF I .
(c) Amounts reported in FFI for ADITs exclude FAS 109, therefore FAS 109 Reg Asset & Liability also excluded.
(4) Worksheet 5, line 37 - Transmission Network Allocation Factor

CENTRAL MAINE POWER COMPANY
TRANSMISSION REVENUE REQUIREMENTS - 2013 TEST YEAR (ADJUSTED)
Attachment G-W
6/1/2014 - 5/31/2015

Line No.		(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) (see note)	(5) = (3) x (4) Network Transmisson Allocated	Worksheet or FERC Form 1 Reference for col (1)
1	Transmission Depreciation	$ 27,896,816	100.00% (c)	$ 27,896,816	99.9905%	$ 27,894,166	ws 9, line 3
2	Intangible and General Depreciation & Amortization	8,726,146	6.8507% (a)	597,802	99.9905%	597,745	ws 9, line 22
3	**Transmission Depreciation Expense (line 1+2)**	36,622,962		28,494,618		28,491,911	
4	**Transmission Related Amort. of ITC**	(714,950)	47.1537% (b)	(337,125)	100.00%	(337,125)	FF I page 266, line 8f (Acc't 411.4)
5	**Transmission Related Municipal Tax Expense**	13,631,432	100.00% (c)	13,631,432	99.9905%	13,630,137	See p. 450 note for pp. 262 & 263 line 14i
6	Transmission Operation and Maintenance	143,019,036					ws 9, line 1
7	Transmission of Electricity by Others - #565	125,686,172					ws 7, line 51
8	Load Dispatching - #561-561.4	3,143,069					FF I page 321, lines 84 thru 88, C. b
9	Support Payments (recorded in Accts 566 & 567)	515,843					ws 7, line 44 + line 45
10	**Transmission O&M (line 6 less lines 7, 8, & 9)**	$ 13,673,953	100.00% (c)	$ 13,673,953	99.9905%	$ 13,672,653	
11	A & G subject to Wage & Salaries Allocation Factor	16,041,342	6.8507% (a)	1,098,944	99.9905%	1,098,840	ws 10, line 32
12	A & G subject to Plant Allocation Factor	415,616	47.1537% (b)	195,978	100.00%	195,978	ws 10, line 35
13	A & G directly assigned to transmission	11,258,502	100.00% (c)	11,258,502	99.9905%	11,257,432	ws 10, line 45
14	Amortization of RTO Formation Costs	-	100.00% (d)	-	100.00%	-	ws 10, line 38
15	**Transmission Related Admin & Gen'l (lines 11+12+13)**	$ 27,715,460		$ 12,553,424		$ 12,552,251	
16	**Reserved**						
17	**Transmission Related Regulatory Assessments**	$ 636,510	100.00% (c)	$ 636,510	100.00%	$ 636,510	

(a) Worksheet 5, line 9 - Transmission Wages & Salaries Allocation Factor
(b) Worksheet 5, line 14 - Transmission Plant Allocation Factor
(c) Amounts Reported as transmission in FF I .

(4) Worksheet 5, line 37 - Transmission Network Allocation Factor

CENTRAL MAINE POWER COMPANY
TRANSMISSION REVENUE REQUIREMENTS - 2013 TEST YEAR (ADJUSTED)
Attachment G-W
6/1/2014 - 5/31/2015

Line No.				Worksheet or FERC Form 1 Reference
	Transmission Wages and Salaries Allocation Factor			
1	Direct Transmission Wages and Salaries	$	2,766,008	ws 9, line 2
2	Affiliated Company Transmission Wages and Salaries		-	
3			-	
4	Total Transmission Wages and Salaries (line 1+2+3)		2,766,008	
5	Total Wages and Salaries		46,389,250	Page 354.28b
6	Administrative and General Wages and Salaries		6,013,656	Page 354.27b
7	Affiliated Company Wages and Salaries less A&G		-	
8	Total Wages and Salaries net of A&G (line 5-6+7)	$	40,375,594	
9	Percent Allocation (line 4/8)		6.8507%	
	Transmission Plant Allocation Factor			
10	Total Transmission Investment	$	1,248,664,365	line 17 below
11	Transmission Related General & Intangible Plant		17,405,806	ws 3 line 4
12	Total Transmission Related Investment	$	1,266,070,172	
13	Total Plant in Service	$	2,684,984,908	Page 207.104g
14	Percent Allocation (line 12/13)		47.1537%	
	Transmission Network Allocation Factor			
15	Total Investment in Transmission Plant	$	1,248,782,743	ws 9, line 4E
16	Generator leads & Generator Step Up Transformers included in above		118,378	ws 8
17	Total Investment in Transmission Plant excluding gen leads & step ups	$	1,248,664,365	
18	Total Investment in Transmission Plant from above	$	1,248,782,743	
19	Percent Allocation (line 17/18)		99.9905%	

CENTRAL MAINE POWER COMPANY
TRANSMISSION REVENUE REQUIREMENTS - 2013 TEST YEAR (ADJUSTED)
Attachment G-W
6/1/2014 - 5/31/2015

	Party Billed	Facility/Nature of Revenues	FERC Account	PTF	Non-PTF	Total	Worksheet Reference
		Support					
1	MEPCO	Section 375/392	454	$ (6,531)	$ -	$ (6,531)	
2	Various	Other support revenue and rents	454	-	(380,350)	(380,350)	
3	WF Wyman #4 Joint Owners	Sections 164-167	454	(102,042)	-	(102,042)	
4	WF Wyman #4 Joint Owners	Section 386	454	(260,097)	(382,255)	(642,352)	
5	PSNH	Section 214 (from Kimball Rd substation)	454	-	-	-	
6	FPL I.A. SCH L	Sections 82 & 222	454	-	(210,278)	(210,278)	
7		Total Support Revenues		$ (368,670)	$ (972,883)	$ (1,341,553)	ws 1, line 22
8							
9		**Wheeling**					
10	Jurisdictional Sales		456	$ (175,934,930)	$ -	$ (175,934,930)	FF1 p330 lines11 thru 15
11	ISO NE RNS REVENUES		456	(199,337,600)	-	(199,337,600)	FFI 450 notes for p328
12	Sch 9&10 - HVDC		456	-	(4,323,553)	(4,323,553)	FF1 p330 lines 2 thru 4
13			456	-	-	-	
14	ISO NE Ancillary Service #1		456	(4,129,799)	-	(4,129,799)	FFI 450 notes for p328
15			456	-	-	-	
16	ISO NE Through & Out Revenues		456	(1,350,029)	-	(1,350,029)	ws 14, line 48
17			456	-	-	-	
18			456	-	-	-	
19			456	-	-	-	
20			456	-	-	-	
21			456	-	-	-	
22	Madison Electric (Northeast Utilities) Expired 12/03		456	-	-	-	
23		Total Wheeling Revenues		$ (380,752,358)	$ (4,323,553)	$ (385,075,911)	**FERC Form 1 page 330**
24							
25							
26							
27	CMPOATT SCH 9&10 - HVDC	HVDC costs not included in ATRR		$ -	$ 4,323,553	$ 4,323,553	line 12
28							
29	NEPOOL RNS & Ancillary Revenues	(lines 11+14 thru 16)Credited separately on ws 14		204,817,428	-	204,817,428	FF1 p328, L. 6
30	Jurisdictional Sales	(Included in network load of rate divisor)		175,934,930	-	175,934,930	FF1 p330 lines 11 thru 15
31		Sub-total Other Wheeling Revenues		-	-	-	(line 23+27+29+30)
32		Study Revenues		(49,415)	-	(49,415)	FFI 231 lines 22 thru 27
33		DAF - Schedule 14 & I.A. Related Revenues	456	(2,451,832)	-	(2,451,832)	
34		excepted transaction revenues credited to Schedule 1		-	-	-	
35		Total Rents		$ (2,501,247)	$ -	$ (2,501,247)	ws 1, line 25

CENTRAL MAINE POWER COMPANY
TRANSMISSION REVENUE REQUIREMENTS - 2013 TEST YEAR (ADJUSTED)
Attachment G-W
6/1/2014 - 5/31/2015

	Party Paid	Facility/Nature of Expenses	FERC Account		PTF	Non-PTF		Total	W/S REF.
		Support							
1	Boston Edison	7.1205 % of the cost of service for HQ Ph II, AC	567	$	34,156		$	34,156	
2	NEP	NEP Ph II, AC -O&M	566 see W/S 14		175,767			175,767	
3	NEP	NEP Ph II, AC -RENTS	567 see W/S 14		121,316			121,316	
4	NEP	NEP Ph II, AC -INTEREST	431		139,759			139,759	
5	NEP	NEP Ph II, AC -TOTAL			436,842			436,842	w/s 13, line 10
6	NEP	NHH- Chester SVC	566		184,604			184,604	w/s 9, line 17
7	Northeast Utilities	Millstone Transmission Facilities	566		-	-		-	
8	MEPCo	Orrington Substation	565			-		-	
9		Less non ptf portion of Millstone from above				-		-	
10									
11		Total Support Expenses		$	655,602	$ -	$	655,602	w/s 1, line 21
12									
13		**Wheeling**							
14	ISO-NE	Sch 1 - ISO-NE Admin	565	$	2,717,803		$	2,717,803	FF1 450 notes for page 332
15	ISO-NE	Demand/Load Response	565		(265,960)			(265,960)	FF1 450 notes for page 332
16	ISO-NE	Regional Network Transmission Service	565		114,698,066			114,698,066	FF1 450 notes for page 332
17	ISO-NE	Sch 1	565		2,440,981			2,440,981	FF1 450 notes for page 332
18	ISO-NE	Sch 2 CC	565		1,430,000			1,430,000	FF1 450 notes for page 332
19	ISO-NE	Sch 16	565		1,302,151			1,302,151	FF 1 450 notes for page 332
20	ISO-NE	Congestion Uplift Expenses	565		1,462,107			1,462,107	FF 1 450 notes for page 332
21	Bangor Hydro	Firm PTP Res for Energy Transferred to Herman S/S	565		255,021			255,021	FF 1 page 332.4
22	ISO-NE	Sch 5 NESCO	565		143,932			143,932	FF 1 450 notes for page 332
23									
24									
25									
26									
27	ISO-NE	Sch 2 VAR Uplift	565		1,398,658			1,398,658	FF1 450 notes for page 332
28									
29									
30									
31									
32									
33									
34									
35	PSNH	Bolt Hill	565		103,413			103,413	
36									
37		Total Wheeling Expenses			$125,686,173	$0		$125,686,173	
38									
39		Total Transmission Wheeling/Support Expenses			$126,341,775	$0		$126,341,775	
40									
41		SUMMARY BY FERC ACCOUNT:							
42		431					$	139,759	line 4 above
43		565						125,686,173	**FF1 page 332**
44		566	NEP AC; Chester; Millstone					360,371	lines 2+6 above
45		567	(Sum of 566+567 to ws 4, line 9)			535,257		155,472	lines 1 + 3 above
46		TOTAL						$126,341,775	
47									
48									
49			FERC Form I balance from line 43 above					125,686,173	
50			transmission retail wheeling					-	
51			total to w/s 4, line 7				$	125,686,173	

CENTRAL MAINE POWER COMPANY
TRANSMISSION REVENUE REQUIREMENTS - 2013 TEST YEAR (ADJUSTED)
Attachment G-W
6/1/2014 - 5/31/2015

Data per CMP detailed property records

PROPERTY DESCRIPTION	PROPERTY CLASSIFICATION	COST	ref	RESERVE	ref	DEPRECIATION	ref
Furniture & Equipment	General	$ 2,480,122		$ 571,026		$ 161,696	
Structure Costs & Map Boards	General	5,250,390		1,984,935		123,453	
UPS	General	284,858		179,776		10,550	
EMS System	General	1,885,690		1,834,871		193,715	
EMS Hardware	General	-		-		-	
LMS	General	-		-		-	
EBCC	General	-		-		-	
Communication Equipment	General	772,770		641,663		55,873	
PC Equipment	General	-		-		-	
		10,673,830	w/s 9, Line 6D	5,212,271	w/s 9, Line 8D	545,287	w/s 9, Line 7D
EMS Software	Intangibile	7,929,600	w/s 9, Line 9D	7,905,934	w/s 9, Line 11D	5,745	w/s 9, Line 10D
S/S RTU's & Scada	Transmission	4,531,019	w/s 9, Line 4D	1,153,932	w/s 9, Line 5D	113,357	w/s 9, Line 3D
Total Plant Directly Assigned to Schedule 1		$ 23,134,449		$ 14,272,137		$ 664,389	

Generator Leads	Section	Balance
Worumbo	22	$ 11,165
Mechanic Falls Hydro	53A	16,835
Pejepscot Hydro	76C	-
MERC	199	35,766
Fort Halifax	3	3,976
Millstone		-
Total investment in Generator Leads		67,742

Generator Step Up Transformers		
Cape		50,636
Harris		-
Williams		-
Total Investment in Step Ups		50,636
Total Leads & Step Ups		$ 118,378

CENTRAL MAINE POWER COMPANY
TRANSMISSION REVENUE REQUIREMENTS - 2013 TEST YEAR (ADJUSTED)
Attachment G-W
6/1/2014 - 5/31/2015

		FERC FORM 1 REFERENCE	A FERC FORM 1 TOTAL	B LESS HQ DC WS13, line 7	C Other	D LESS COST RECOVERED UNDER SCH 1	E ADJUSTED TOTAL		WORKSHEET REFERENCE FOR COL. E
1	Transmission O&M	FERC FORM 1, PG 321, LINE 112b	$ 145,865,336	$ (2,846,300)	$ -	$ -	$ 143,019,036	1	WS 4, LINE 6
2	Salaries & Wages	FERC FORM 1, PG. 354, LINE 21B	4,487,563	-	-	(1,721,555)	2,766,008	2	WS 5, LINE 1
3	Transmission Depreciation	FERC FORM 1, PG. 336, LINE 7B	28,010,173	-	-	(113,357)	27,896,816	3	WS 4, LINE 1
4	Transmission Plant	FERC FORM 1, PG. 207, LINE 58G	1,253,313,762	-	-	(4,531,019)	1,248,782,743	4	WS 3, LINE 1
4a	Transmission Plant Held for Future Use	FF I, P 214, LINE 47 - (15+16)	3,365,121	-	-	-	3,365,121	4a	WS 3, LINE 5
5	Transmission Depreciation Reserve	FERC FORM 1, PG 219, LINE 25c	191,639,943	-	-	(1,153,932)	190,486,011	5	WS 3, LINE 6
6	General Plant	FERC FORM 1, PG 207, LINE 99g	214,513,613	-	-	(10,673,830)	203,839,783	6	WS 3, LINE 2
7	General Depreciation Exp.	FERC FORM 1, PG. 336, LINE 10f	6,750,322	-	-	(545,287)	6,205,035	7	(A) see line 22 below
8	Gen'l Deprec. Res.	FERC FORM 1, PG 219, LINE 28c	93,653,507	-	-	(5,212,271)	88,441,236	8	WS 3, LINE 7
9	Intangible Plant	FERC FORM I, P 205, LINE 5g	58,187,357	-	-	(7,929,600)	50,257,757	9	WS 3, LINE 3
10	Intangible Amortization	FERC FORM I, PG 336 , LINE 1f	2,526,856	-	-	(5,745)	2,521,111	10	(A) see line 22 below
11	Intangible Plant Reserve	FERC FORM I, PG 200 , LINE 21c	53,132,776	-	-	(7,905,934)	45,226,842	11	WS 3, LINE 8
12	Transmission Prepayments	FF1 Pg 111, L.57, C.c	36,673,551	-	(32,998,240)	-	3,675,311		
13	HQ PHASE 1 & 2 INVESTMENT (not incl. In line 4)		3,939,400				3,939,400	12	WS 13, line 1
14	AC BALANCE		2,261,315				2,261,315	13	WS 13, line 1
15	DC BALANCE		$ 1,678,086				$ 1,678,086	14	WS 13, line 1
16	HQ PHASE 1 & 2 O&M EXPENSES		3,501,030				3,501,030	15	WS 13, line 10
17	BECO AC		34,156				34,156	16	WS 13, line 13
18	CHESTER SVC		184,604				184,604	17	WS 7, line 6
19	Total HQ		$ 3,719,790				$ 3,719,790	18	WS 13, line 15

Excluded $32,998,240 of prepaid income taxes reclassified from account 236

	Transmission Wages by FERC Account Number						
20				Sum of (A) =	8,726,146	20	WS 4, LINE 2
21	560		$ 338,299			21	
22	561-561.4	Line 2d	1,721,555			22	Line 2 D above
23	561.5-561.8		101,478			23	
24	562		587,363			24	
25	563		60,944			25	
26	566		-			26	
27	567		790,903			27	
28	568		-			28	
29	569		172,572			29	
30	570		48,146			30	
31	571		414,374			31	
32	572		200,191			32	
33	573		50,634			33	
34	564		1,105			34	
35	FFI page 354.21		$ 4,487,564			35	Line 2 A above

CENTRAL MAINE POWER COMPANY
TRANSMISSION REVENUE REQUIREMENTS - 2013 TEST YEAR (ADJUSTED)
Attachment G-W
6/1/2014 - 5/31/2015

Administrative and General Expense Detail

	Acc't	Description		Amount	W/S or FF I REF.
1	920	Administrative and General Salaries	$	7,996,238	FF1 Pg 323, L.181, C.b
2	921	Office Supplies and Expenses		3,063,499	FF1 Pg 323, L.182, C.b
3	922	Less Administrative Expenses Transferred		(505,998)	FF1 Pg 323, L.183, C.b
4	923	Outside Services		31,397,588	FF1 Pg 323, L.184, C.b
5	924	Property Insurance (see line 32 below)		415,616	FF1 Pg 323, L.185, C.b
6	925	Injuries and Damages		1,081,660	FF1 Pg 323, L.186, C.b
7	926	Employee Pensions and Benefits		(6,582,691)	FF1 Pg 323, L.187, C.b
8	928	Regulatory Commissions Expense		9,172,452	FF1 Pg 323, L.189, C.b
9	930.1	General Advertising		655,636	FF1 Pg 323, L.191, C.b
10	930.2	Miscellaneous General Expense		(1,487,452)	FF1 Pg 323, L.192, C.b
11	931	Rents		1,228,520	FF1 Pg 323, L.193, C.b
12	935	Maintenance of General Plant		3,105,466	FF1 Pg 323, L.196, C.b
13		Total Admin & Gen'l Exp.	$	49,540,534	
14		FERC Reg Comm Exp - Trans (directly assigned) line 41 below	$	411,066	FF1 Pg 350, L.24 thru 25, C.c
15		FERC assessments - 100% Transmission to w/s 4, line 17		636,510	FF1 Pg 350, L.20, C.d
16		FERC Reg Comm Exp - subject to plant allocation factor (line 33 below)		-	
17		Amortization of RTO Formation Costs (100% Transmission) (line 38 below)		-	
18		TOTAL FERC Reg Comm Exp and Assessments	$	1,047,576	
19		State assessments - Transmission (directly assigned) (line 40 below)	$	29,474	FF1 Pg 350, L.4, C.c
20		Total State Assessments and Other		8,124,876	FF1 Pg 350, L.3+L.4+L.5+L.6+L.7+L.8+L.9+L.11+L.12+ L.13+L.15+L.21, C.c (includes $1.5 mil for MPUC Docket # 2008-255)
21	928	Total Regulatory Commissions Expense: (lines 18+20) & from line 8 above	$	9,172,452	FF1 Pg 323, L.189, C.b
22		General Advertising - Transmission related		-	
23		Non-Transmission related General Advertising Exp.		655,636	
24	930.1	Total General Advertising Exp. (line 9 above)	$	655,636	
		Summary of Attachment G treatment of A&G			
25		Total A&G (line 13 above)	$	49,540,534	
26	923	less Outside Services		31,397,588	
27	924	less Property Insurance (line 5 above)		415,616	
28	928	less Regulatory Commissions Exp. (line 21 above)		9,172,452	
28	930.1	less Non-Trans. General Advertising Exp. (line 9 above)		655,636	
29	930.2	less Miscellaneous General Expense		(1,487,452)	
30	920-935	less EPRI Expenses		-	
31	926	less pension credit directly assigned to T&D		(6,654,648)	MPUC Docket Nos. 2007-215/2008-111
32		A&G subject to Wages and Salaries Allocation Factor:	$	16,041,342	w/s 4, line 11
33		Property Insurance (line 5 above)		415,616	
34		Regulatory Commissions Exp (line 16 above)		-	
35		Total A&G subject to Plant Allocation Factor	$	415,616	w/s 4, line 12
36		Amort of Def' RTO Formation and Assoc. CC included in 928 (line 17 above)		-	
37		928 Adjustment for Book Amortization of RTO Formation Costs		-	
38		Rate Year Pro forma Amort of Def' RTO Formation and Assoc CC		-	
39		Total RTO Formation & Assoc CC assigned 100% to Transmission		-	w/s 4, line 14
		Items Directly Assigned to Transmission			
40	926010	MRFV - transmission only portion of pension credit	$	(791,903)	MPUC Docket Nos. 2007-215/2008-111
41		State assessments - Transmission (directly assigned) (Line 19 above)		29,474	FF1 Pg 350,L.4, C.c
42		Outside Services- Transmission (directly assigned)		11,699,889	FF1 Pg 320,L.184, C.b
43		Miscellaneous General Expense- Transmission (directly assigned)		(90,024)	FF1 Pg 320,L.192, C.b
44		FERC Reg Comm Exp - Trans (directly assigned) (Line14 above)		411,066	FF1 Pg 350,L.23&24, C.c
45		total to w/s 4, line 13	$	11,258,502	w/s 4, line 13

CENTRAL MAINE POWER COMPANY
TRANSMISSION REVENUE REQUIREMENTS - 2013 TEST YEAR (ADJUSTED)
Attachment G-W
6/1/2014 - 5/31/2015

Line No.	Series	(A) Nominal Interest Rate	(B) Principal	(C) (A)*(B) Annualized Nominal Cost	(D) Expense Premium or Discount	(E) Hedge Activities	(F) (B)-(D)-(E) Net Proceeds	(G) (C)/(F) Embedded Cost Rate	(H) (B)*(G) All Debt Annualized Cost
1	N.H. Business Finance Athority	5.375%	$ 19,500,000	$ 1,048,125	$ 386,087	$ -	$ 19,113,913	5.484%	$ 1,069,296
2	First Mortgage Bond-Series A	5.700%	150,000,000	8,550,000	1,862,630	6,953,000	141,184,370	6.056%	9,083,867
3	F (Note 1)	5.780%	25,000,000	1,445,000	205,140	2,128,521	22,666,339	6.375%	1,593,773
4	F (Note 2)	5.375%	20,000,000	1,075,000	156,129	-	19,843,871	5.417%	1,083,458
5	F (Note 3)	5.430%	25,000,000	1,357,500	195,140	2,795,719	22,009,141	6.168%	1,541,973
6	F (Note 4)	5.700%	15,000,000	855,000	132,346	-	14,867,654	5.751%	862,611
7	F (Note 5)	5.875%	15,000,000	881,250	132,137	-	14,867,863	5.927%	889,082
8	F (Note 6)	5.300%	30,000,000	1,590,000	230,546	335,500	29,433,954	5.402%	1,620,577
9	F (Note 7)	5.270%	10,000,000	527,000	65,627	175,000	9,759,373	5.400%	539,994
10	F (Note 8)	6.400%	40,000,000	2,560,000	312,089	343,168	39,344,743	6.507%	2,602,635
11	First Mortgage Bond	4.200%	150,000,000	6,300,000	844,040	-	149,155,960	4.224%	6,335,650
12	First Mortgage Bond	5.680%	100,000,000	5,680,000	562,693	-	99,437,307	5.712%	5,712,142
13	First Mortgage Bond	3.070%	125,000,000	3,837,500	676,164	-	124,323,836	3.087%	3,858,371
14	First Mortgage Bond	4.450%	225,000,000	10,012,500	1,195,901	-	223,804,099	4.474%	10,066,002
15			$ 949,500,000	$ 45,718,875	$ 6,956,671	$ 12,730,908	$ 929,812,421	4.917%	$ 46,859,431
16	Less 12/31/2013 Unamort. Loss on Req. Debt (FF I p.111.81.c)						1,801,635		
17	Add Amort. Of Loss on Reaquired Debt (FFI p117.64.c)								575,438
18	Adjusted Balance						$928,010,786 (I)		$47,434,869 (J)
19	Cost Of Debt (J)/(I)		**5.111%**						

CENTRAL MAINE POWER COMPANY
TRANSMISSION REVENUE REQUIREMENTS - 2013 TEST YEAR (ADJUSTED)
Attachment G-W
6/1/2014 - 5/31/2015

DERIVATION OF AFUDC INCLUDED IN DEPRECIATION EXPENSE
Source: USS PLANT ACCOUNTING (SAP)

	Vintage	cost	afudc	% of total
1	1953-1970	----------no afudc data available-----------		
2	1971	$ 16,993,929	$ 210,398	1.24%
3	1972	1,354,874	-	0.00%
4	1973	2,530,521	21,837	0.86%
5	1974	3,929,745	200	0.01%
6	1975	4,626,387	38,383	0.83%
7	1976	6,559,880	76,909	1.17%
8	1977	5,885,933	86,351	1.47%
9	1978	17,338,606	444,301	2.56%
10	1979	4,115,534	14,481	0.35%
11	1980	7,717,864	28,543	0.37%
12	1981	3,806,576	45,143	1.19%
13	1982	3,336,346	16,508	0.49%
14	1983	5,462,226	107,741	1.97%
15	1984	6,543,576	188,256	2.88%
16	1985	2,153,012	13,995	0.65%
17	1986	4,063,381	72,616	1.79%
18	1987	6,308,982	70,120	1.11%
19	1988	8,616,426	96,074	1.12%
20	1989	8,190,862	92,568	1.13%
21	1990	18,606,637	300,769	1.62%
22	1991	6,804,433	68,667	1.01%
23	1992	10,041,560	178,995	1.78%
24	1993	5,637,279	121,080	2.15%
25	1994	3,480,922	26,059	0.75%
26	1995	3,820,449	32,298	0.85%
27	1996	2,681,701	20,928	0.78%
28	1997	1,790,063	23,501	1.31%
29	1998	1,477,852	4,185	0.28%
30	1999	1,810,857	10,989	0.61%
31	2000	26,037,439	264,455	1.02%
32	2001	8,983,040	92,232	1.03%
33	2002	8,622,712	117,487	1.36%
34	2003	2,701,882	(16,453)	-0.61%
35	2004	13,379,541	151,747	1.13%
36	2005	10,790,340	187,716	1.74%
37	2006	14,151,218	57,062	0.40%
38	2007	41,386,528	247,340	0.60%
39	2008	84,332,796	3,500,923	4.15%
40	2009	44,549,845	355,246	0.80%
41	2010	20,636,193	558,551	2.71%
42	2011	29,046,140	374,354	1.29%
43	2012	100,664,413	342,000	0.34%
44	2013	61,678,656	823,106	1.33%
		$ 642,647,156	$ 9,467,661	1.47%
45				
46	Transmission Depreciation Exp from w/s 4			27,894,166
47				
48	AFUDC adj to w/s 2			$ 410,945

CENTRAL MAINE POWER COMPANY
TRANSMISSION REVENUE REQUIREMENTS - 2013 TEST YEAR (ADJUSTED)
Attachment G-W
6/1/2014 - 5/31/2015

					Phase I			Phase II			
	HYDRO-QUEBEC CAPITAL LEASES	WS Ref.	TOTAL HQ	TOTAL DC	DC Neetco	DC Vetco	WS Ref.	AC Nep	DC Nhh	DC Neh	
1	INVESTMENT-FERC A/C 101.1	w/s 9, line 13	$ 3,939,400	$ 1,678,086	$ -	$ -		$ 2,261,315	$ 695,350	$ 982,736	1
2	(excluded from transmission plant)										2
3											3
4	O&M - FERC A/C 566015		$ 1,789,748	$ 1,613,981	$ 152,137	$ 107,943		$ 175,767	$ 638,952	$ 714,949	4
5	RENTS- FERC A/C 567015		1,353,635	1,232,319	-	-		121,316	464,997	767,322	5
6											6
7	TOTAL O&M		3,143,382	2,846,300	152,137	107,943	WS 9 L.16	297,083	1,103,949	1,482,271	7
8	INTEREST-FERC A/C 431010		357,648	217,888	8,427	1,221		139,759	46,157	162,083	8
9											9
10	TOTAL	w/s 9, line 16	$ 3,501,030	$ 3,064,188	$ 160,563	$ 109,164		$ 436,842	$ 1,150,106	$ 1,644,354	10
11											11
12	Chester SVC		184,604								12
13	BECO AC		34,156								13
14											14
15	Total HQ	w/s 9, line 19	$ 3,719,790								15

CENTRAL MAINE POWER COMPANY
TRANSMISSION REVENUE REQUIREMENTS - 2013 TEST YEAR (ADJUSTED)
Attachment G-W
6/1/2014 - 5/31/2015

source: PTOAC DRAFT INFO FILING

June 1, 2014 89.80

line #	CMP PROJECTED RNS EXPENSE 6/1/13 - 5/31/2014	TOTAL	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY
1	CMP Participant RNS Rate	$ 89.80	$ 7.48	$ 7.48	$ 7.48	$ 7.48	$ 7.48	$ 7.48	$ 7.48	$ 7.48	$ 7.48	$ 7.48	$ 7.48	$ 7.48
2	CMP RNS load 12CP-KW (2013 avg)	1,371,755	1,371,755	1,371,755	1,371,755	1,371,755	1,371,755	1,371,755	1,371,755	1,371,755	1,371,755	1,371,755	1,371,755	1,371,755
3		123,178,647	10,264,887	10,264,887	10,264,887	10,264,887	10,264,887	10,264,887	10,264,887	10,264,887	10,264,887	10,264,887	10,264,887	10,264,887
4														
5	NU Participant RNS Rate	$ 89.80	$ 7.48	$ 7.48	$ 7.48	$ 7.48	$ 7.48	$ 7.48	$ 7.48	$ 7.48	$ 7.48	$ 7.48	$ 7.48	$ 7.48
6	CMP load at Bolt Hill 12CP- KW (2013 avg)	37,550	37,550	37,550	37,550	37,550	37,550	37,550	37,550	37,550	37,550	37,550	37,550	37,550
7		3,371,854	280,988	280,988	280,988	280,988	280,988	280,988	280,988	280,988	280,988	280,988	280,988	280,988
8														
9	BHE Participant RNS Rate	$ 89.80	$ 7.48	$ 7.48	$ 7.48	$ 7.48	$ 7.48	$ 7.48	$ 7.48	$ 7.48	$ 7.48	$ 7.48	$ 7.48	$ 7.48
10	CMP load at Herman 12CP- KW (2013 avg)	5,536	5,536	5,536	5,536	5,536	5,536	5,536	5,536	5,536	5,536	5,536	5,536	5,536
11		497,113	41,426	41,426	41,426	41,426	41,426	41,426	41,426	41,426	41,426	41,426	41,426	41,426
12														
13														
14	**TOTAL RNS EXPENSE**	**$ 127,047,614**	**$ 10,587,301**	**$ 10,587,301**	**$ 10,587,301**	**$ 10,587,301**	**$ 10,587,301**	**$ 10,587,301**	**$ 10,587,301**	**$ 10,587,301**	**$ 10,587,301**	**$ 10,587,301**	**$ 10,587,301**	**$ 10,587,301**
15														
16														
17	CMP PROJECTED RNS REVENUES - 6/1/13 - 5/31/2014													
18														
19	Expected Revenues Collected by ISO:													
20														
21	Pre 1997	$ 344,097,622	$ 28,674,802	$ 28,674,802	$ 28,674,802	$ 28,674,802	$ 28,674,802	$ 28,674,802	$ 28,674,802	$ 28,674,802	$ 28,674,802	$ 28,674,802	$ 28,674,802	$ 28,674,802
22	Post 1996	1,533,596,974	127,799,748	127,799,748	127,799,748	127,799,748	127,799,748	127,799,748	127,799,748	127,799,748	127,799,748	127,799,748	127,799,748	127,799,748
23														
24	Total	$ 1,877,694,596	$ 156,474,550	$ 156,474,550	$ 156,474,550	$ 156,474,550	$ 156,474,550	$ 156,474,550	$ 156,474,550	$ 156,474,550	$ 156,474,550	$ 156,474,550	$ 156,474,550	$ 156,474,550
25														
26	Distribution of Revenues													
27	PRE 1997:													
28	MW-mile %		9.8818%	9.8818%	9.8818%	9.8818%	9.8818%	9.8818%	9.8818%	9.8818%	9.8818%	9.8818%	9.8818%	9.8818%
29	MW-mile weighting		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
30	Rev. Req't %		4.84691%	4.84691%	4.84691%	4.84691%	4.84691%	4.84691%	4.84691%	4.84691%	4.84691%	4.84691%	4.84691%	4.84691%
31	Rev. Req't weighting		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
32														
33	Post 1996													
34	Rev. Req't %		14.29630%	14.29630%	14.29630%	14.29630%	14.29630%	14.29630%	14.29630%	14.29630%	14.29630%	14.29630%	14.29630%	14.29630%
35	Rev. Req't weighting		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
36														
37				**CMP Share of Revenues**										
38	Pre 1997	$ 17,204,907	$ 1,433,742	$ 1,433,742	$ 1,433,742	$ 1,433,742	$ 1,433,742	$ 1,433,742	$ 1,433,742	$ 1,433,742	$ 1,433,742	$ 1,433,742	$ 1,433,742	$ 1,433,742
39	Post 1996	234,358,293	19,529,858	19,529,858	19,529,858	19,529,858	19,529,858	19,529,858	19,529,858	19,529,858	19,529,858	19,529,858	19,529,858	19,529,858
40														
41	**TOTAL RNS REVENUES**	**$ 251,563,200**	**$ 20,963,600**	**$ 20,963,600**	**$ 20,963,600**	**$ 20,963,600**	**$ 20,963,600**	**$ 20,963,600**	**$ 20,963,600**	**$ 20,963,600**	**$ 20,963,600**	**$ 20,963,600**	**$ 20,963,600**	**$ 20,963,600**
42														
43														
44	NET RATE YEAR	$ 124,515,586	$ 10,376,299	$ 10,376,299	$ 10,376,299	$ 10,376,299	$ 10,376,299	$ 10,376,299	$ 10,376,299	$ 10,376,299	$ 10,376,299	$ 10,376,299	$ 10,376,299	$ 10,376,299
45														
46														
47	PROJECTED RNS REVENUES	$ 251,563,200	line 41 above											
48	2013 THROUGH & OUT REVENUES	1,350,029	ws 6, line 16											
49	TOTAL REGIONAL REVENUES	252,913,229												
50	LESS:													
51	ROE ADDER - 50bp	4,247,088												
52	ROE ADDER - 100bp	477,918												
53	ROE ADDER - 125bp	9,051,922												
54	MPRP CWIP INCENTIVE	50,848,934												
55	TOTAL CREDIT FOR REGIONAL REVS	$ 188,287,367	w/s 1, L. 23											

CENTRAL MAINE POWER COMPANY
TRANSMISSION REVENUE REQUIREMENTS - 2013 TEST YEAR (ADJUSTED)
Attachment G-W
6/1/2014 - 5/31/2015

Line #		Transition Schedule						
1	Transition Year	1	2	3	4	5	6	7-11
2	From / to	3/1/97- 2/28/98	3/1/98 - 2/28/99	3/1/99 - 2/28/00	3/1/00 - 2/28/01	3/1/01 - 2/28/02	3/1/02 - 2/28/03	Thereafter
3								
4	% of Local Charges to be paid by PTF connected loads	100%	80%	60%	40%	20%	20%	0%
5								
6	12 month average PTF Connected Load	49,448	39,558	23,735	9,494	1,899	380	-
7	12 month average Non PTF Connected Load	1,423,745	1,423,745	1,423,745	1,423,745	1,423,745	1,423,745	1,423,745
8								
9	avg load (See Sch. 12, sec B.1. & D.2)	1,473,193	1,463,304	1,447,480	1,433,239	1,425,644	1,424,125	1,423,745

Line #			
10	**Network Load for rate design:**		
11	Non PTF Connected Load (line 7)		1,423,745
12	PTF Connected Load (line 6 for years 7 and out)		-
13	Total Local Network Load		1,423,745
14			
15	ATRR ws 1, line 28	$	42,314,984
16			
17	Rate $/kW-yr (line 15/13)	$	29.72
18			
19	RATE DESIGN FORMULA:		
20	ATRR/(NPTFNL+(PTFNL X ATYP)) where:		
21		ATRR = Annual Transmission Revenue Requirement	
22		NPTFNL = Non-PTF Network Load	
23		PTFNL = PTF Network Load	
24		ATYP = Applicable Transition Year Percentage (Sch. 11)	
25			

Line #	RATE DESIGN PROOF:		Total			Rate		ATYP		Network load		# months
27	Recovery from Non-PTF connected Customers	$	42,314,984	=	$	29.7209	x	100%	x	1,423,745	x	12/12
28	Recovery from PTF Connected Customers -last 9 months of Transition yr 1(		-	=	$	29.7209	x	0%	x	49,448	x	9/12
29	Recovery from PTF Connected Customers -1st 3 months of Transition yr 11		-	=	$	29.7209	x	0%	x	49,448	x	3/12
30												
31	Total Recovery	$	42,314,984									
32	Rounding differences		0									

Line #			
33	FIRM POINT TO POINT RATES: (See Sch. 7 for Wheeling Out Rate)		
34	Per Year (Line 17)	$	29.7209
35	Per Month (Line 34 divided by 12 months)	$	2.4767
36	Per Week (Line 34 divided by 52 weeks)	$	0.5716
37	Per Day (Line 36 divided by 5 days)	$	0.1143
38			
39	NON-FIRM POINT TO POINT RATES:		
40	Per Year (Line 17)	$	29.7209
41	Per Month (Line 40 divided by 12 months)	$	2.4767
42	Per Week (Line 40 divided by 52 weeks)	$	0.5716
43	Per Day (Line 42 divided by 7days)	$	0.0817
44	Per Hour (Line 43 divided by 24 hours)	$	0.0034

CENTRAL MAINE POWER COMPANY
TRANSMISSION REVENUE REQUIREMENTS - 2013 TEST YEAR (ADJUSTED)
Attachment G-W
6/1/2014 - 5/31/2015

Line No.			Forecast Period	Attachment K Reference		Amount	Reference
	I.viii	FORECASTED TRANSMISSION REVENUE REQUIREMENTS		*Section:*			
1		Forecasted Rev Req'ts for FTPA		I.vii	$	52,520,384	line 6 below
2		Forecasted Rev Req'ts for FCWIP		I.vii		190,128	line 9 below
3		Forecasted Transmission Revenue Requirements (Lines 1 + 2)			$	52,710,512	
Line No.							
4		Forecasted Transmission Plant Additions	2014	I.iii	$	369,082,105	
5		Carrying Charge Factor		I.v		14.23%	line 20 below
6		Total Forecasted Revenue Requirements (Lines 1*2)			$	52,520,384	
7		Forcasted MPRP CWIP (FCWIP)	2014	I.iv	$	1,375,816	
8		MPRP Cost of Capital Rate (MCOC)		I.vi		13.82%	line 23 below
9		Forecasted Rev Req'ts for FCWIP (Lines 4*5)			$	190,128	
	II.	CARRYING CHARGE FACTOR					
10		Investment Return and Associated Income Taxes		(A)	$	108,356,696	Worksheet 20, line 14
11		Transmission Depreciation Expense		(B)		28,491,911	Worksheet 1, line 15
12		Transmission Related Amort of Investment Tax Credits		(C)		(337,125)	Worksheet 1, line 16
13		Transmission Related Municipal Tax Expense		(D)		13,630,137	Worksheet 1, line 17
14		Transmission Operation & Maintenance Expense		(E)		13,672,653	Worksheet 1, line 18
15		Transmission Related Administrative & General Expense		(F)		12,552,251	Worksheet 1, line 19
16		Transmission Related Regulatory Assessments		(G)		636,510	Worksheet 1, line 20
17		Transmission Support Expenses		(H)		655,602	Worksheet 1, line 21
18		Total Expenses (Lines 10 thru 17)			$	177,658,635	
19		Transmission Plant		(A)(1)(a)	$	1,248,664,109	Worksheet 1, line 1
20		Carrying Charge Factor (Lines 18/19)				14.23%	
		DERIVATION OF MPRP COST OF CAPITAL RATE (MCOC)					
21		Cost of Capital Rate - 11.14% ROE				12.65873%	ws 2
22		Cost of Capital Rate - 1.25% bp ROE adder for MPRP				1.16056%	ws 2
23		MPRP Cost of Capital Rate (MCOC) (Lines 21 + 22)				13.81929%	
	III.	ANNUAL TRUE-UP					
24		ATRR for True-up = 2012 Actual		Attachment K	$	174,511,512	ws 17
25		ATRR subject to True-up = '11 TY + '12 Forecast - (as billed)				171,240,197	ws 17
26		Under / (Over) (Lines 24-25)			$	3,271,315	
27		Interest				109,011	ws 19
28		Total True Up and associated interest (Lines 26+27)			$	3,380,327	
29		Net Forecasted Revenue Requirement and Prior Year True-up (Lines 3 + 28)			$	56,090,838	
						ws 1, line 26	

CENTRAL MAINE POWER COMPANY
TRANSMISSION REVENUE REQUIREMENTS - 2013 TEST YEAR (ADJUSTED)
Attachment G-W
6/1/2014 - 5/31/2015

2013 True-up (2012 TY + 2013 forecast - 2013 TY Actual)

	I. ANNUAL TRUE-UP			Att G-W
1	ATRR for True-up = 2012 Actual	ws 18 line 27(b)	$	174,511,512
2	ATRR subject to True-up = '11 TY + '12 Forecast - (as billed)	ws 18 line 27(c)		171,240,197
3	Annual True-up (Line 1 - Line 2)	Difference	$	3,271,315
				To worksheet 19

CENTRAL MAINE POWER COMPANY
TRANSMISSION REVENUE REQUIREMENTS - 2013 TEST YEAR (ADJUSTED)
Attachment G-W
6/1/2014 - 5/31/2015

		Formula Reference *Section:*	*Difference* (a)	6/1/2014-5/31/2015 2013 TY (b)	6/1/2013-5/31/2014 2012 TY + 2013 Forecast (c)
	INVESTMENT BASE				
1	Transmission Plant	II (A)(1)(a)	$ 356,130,974	$ 1,248,664,109	$ 892,533,135
2	Transmission Related Intangible & General Plant	II (A)(1)(b)	1,695,422	17,405,806	15,710,384
3	Transmission Plant Held For Future Use	II (A)(1)(c)	-	3,365,121	3,365,121
4	Total Plant (Lines 1+2+3)		357,826,396	1,269,435,036	911,608,640
5	Transmission Related Depreciation Reserve	II (A)(1)(d)	(15,415,976)	(199,624,244)	(184,208,268)
6	Transmission Related Accumulated Deferred Taxes	II (A)(1)(e)	(88,344,242)	(223,751,761)	(135,407,518)
7	Other Regulatory Asssets / Liabilities	II (A)(1)(f)	(89,160)	417,682	506,842
8	Net Investment (Line 4+ 5+6+7)		253,977,018	846,476,713	592,499,695
9	Transmission Prepayments	II (A)(1)(g)	77,265	251,761	174,495
10	Transmission Materials & Supplies	II (A)(1)(h)	(841,301)	6,566,596	7,407,897
11	Transmission Related Cash Working Capital	II (A)(1)(i)	1,512,162	3,278,113	1,765,951
12	MPRP CWIP	II (A)(1)(j)	(427,412)	5,034,097	5,461,509
	Transmission Investment Base (Line 8+9+10+11)		$ 254,297,733	$ 861,607,280	$ 607,309,548
	REVENUE REQUIREMENTS				
13	Investment Return and Associated Income Taxes	II (A)	$ 30,888,896	$ 109,052,373	$ 78,163,477
14	Transmission Depreciation Expense	II (B)	9,615,725	28,491,911	18,876,186
15	Transmission Related Amort of Investment Tax Credits	II (C)	(50,847)	(337,125)	(286,278)
16	Transmission Related Municipal Tax Expense	II (D)	4,378,513	13,630,137	9,251,624
17	Transmission Operation & Maintenance Expense	II (E)	1,892,103	13,672,653	11,780,551
18	Transmission Related Administrative & General Expense	II (F)	10,205,193	12,552,251	2,347,057
19	Transmission Related Regulatory Assessments	II (G)	(6,925)	636,510	643,435
20	Transmission Support Expenses	II (H)	(27,748)	655,602	683,350
21	Transmission Support Revenues	II (I)	24,897	(1,341,553)	(1,366,449)
22	ISO-NE Transmission Revenues	II (J)	-	-	-
23	Other Wheeling Revenues	II (K)	(147,801)	(2,501,247)	(2,353,446)
24	Transmission Rents Received from Electric Property	II (L)	-	-	-
25	Total costs for True-up purposes		56,772,006	174,511,512	117,739,506
26	Forecasted Revenue Requirements - 2013	II (M)	(53,500,691)	-	53,500,691
27	Annual True-up	II (M)	$ 3,271,315	$ 174,511,512	$ 171,240,197
28	Reconciliation to LNS ATRR:				
29	Line 27 Above		$ 3,271,315	$ 174,511,512	$ 171,240,197
30	ISO-NE Transmission Revenues	II (J)	(62,492,511)	(188,287,366)	(125,794,855)
31	Annual True-Up	II (M)	16,968,593	3,271,315	(13,697,277)
32	Interest on Annual True-up up	II (M)	565,450	109,011	(456,439)
33	2014 Forecast	II (M)	52,710,512	52,710,512	-
34	LNS ATRR		$ 11,023,359	$ 42,314,984	$ 31,291,625

CENTRAL MAINE POWER COMPANY
TRANSMISSION REVENUE REQUIREMENTS - 2013 TEST YEAR (ADJUSTED)
Attachment G-W
6/1/2014 - 5/31/2015

CMP
FERC Interest Calculation associated with Annual True Up - Under / (Over)
Transmission Revenue Requirements

Undercollection / (Overcollection) From worksheet 17
3,271,315

Initial Billing Period	Balance	FERC Monthly Interest Rate	Interest
June 2013	$ 3,271,315	0.27%	$ 8,832.55
July 2013	3,280,148	0.28%	9,184.41
August 2013	3,280,148	0.28%	9,184.41
September 2013	3,280,148	0.27%	8,856.40
			-
October 2013	3,307,373	0.28%	9,260.64
November 2013	3,307,373	0.27%	8,929.91
December 2013	3,307,373	0.28%	9,260.64
			-
January 2014	3,334,824	0.28%	9,337.51
February 2014	3,334,824	0.25%	8,337.06
March 2014	3,334,824	0.28%	9,337.51
			-
April 2014	3,361,836	0.27%	9,076.96
May 2014	3,361,836	0.28%	9,413.14
Total Interest			$ 109,011
			3,271,315
Total True Up & Interest			$ 3,380,327
			ws 16

CENTRAL MAINE POWER COMPANY
TRANSMISSION REVENUE REQUIREMENTS - 2013 TEST YEAR (ADJUSTED)
Attachment G-W
6/1/2014 - 5/31/2015

Investment Base Calculation for Incremental Return and Associated Income Taxes for Non-Pool Supported MPRP and MPRP CWIP

		TOTAL MPRP	MPRP CWIP	MPRP Non-PTF
1	MRPP Non-PTF related CWIP	$ 5,034,097	$ 5,034,097	$ -
2	MPRP Non-PTF Investment	26,472,757	-	26,472,757
3	Depreciation Reserve	(823,589)	-	(823,589)
4	Accumulated Deferrred Income Taxes	(32,076,174)	-	(32,076,174)
5	INVESTMENT BASE	$ (1,392,908)	$ 5,034,097	$ (6,427,006)
		w/s 2 line 9		
6	Cost of Capital Rate - 11.64% ROE (w/s 2 line 33)		12.65873%	
7	Cost of Capital Rate - 1.25% bp ROE adder for MPRP (w/s 2 line 8)		1.16056%	
8	MPRP Cost of Capital Rate (MCOC)(6+7)		13.81929%	
9	MPRP CWIP - Base (5 x 6)		$ 637,253	
10	MPRP CWIP - Incremental (5 x 7)		58,424	
11	Investment Return and Income Taxes - MPRP CWIP (9+10)		$ 695,677	
12	Investment Return and Income Taxes - Total		$ 109,052,373	w/s 1, line 14
13	Less Inv Return&Taxes- MPRP CWIP (11)		695,677	
14	Investment Return and Income Taxes - excluding CWIP		$ 108,356,696	
			w/s 16, line 10	

CENTRAL MAINE POWER COMPANY
LOCAL SCHEDULE 1 REVENUE REQUIREMENTS
2013 TEST YEAR

Line No.	II. INVESTMENT BASE	Formula Reference Section:		Reference
1	Local Control Center Plant		$ 23,134,449	Worksheet 3, line 1 column 3
2	Intangible Plant		2,140,980	Worksheet 3, line 2 column 3
3	General plant		8,683,575	Worksheet 3, line 3 column 3
4	Local Control Center Related Plant (Lines 1+2+3)	II (A)(1)(a)	33,959,004	
5	Local Control Center Related Depreciation Reserve	II (A)(1)(b)	(19,966,397)	Worksheet 3, line 9 column 3
6	Local Control Center Related Accumulated Deferred Taxes	II (A)(1)(c)	(5,680,743)	Worksheet 3, line 14 column 3
7	Local Control Center Related Other Regulatory Asssets / Liabilities	II (A)(1)(d)	3,714,182	Worksheet 3, line 20 column 3
8	Net Investment (Line 4+7-6-5)		12,026,046	
9	Local Control Center Related Prepayments	II (A)(1)(e)	46,309	Worksheet 3, line 22 column 3
10	Local Control Center Related Materials & Supplies	II (A)(1)(f)	133,354	Worksheet 3, line 24 column 3
11	Local Control Center Related Cash Working Capital	II (A)(1)(g)	478,958	Worksheet 3, line 31 column 3
12	Local Control Center Investment Base (Line 8 + 9+10+11)		$ 12,684,667	
	II. REVENUE REQUIREMENTS			
13	Return and Associated Income Taxes	II (A)	$ 1,599,911	Worksheet 2, line 44
14	Depreciation Expense	II (B)	1,036,122	Worksheet 4, line 4 column 3
15	Amortization of Investment Tax Credits	II (C)	(9,008)	Worksheet 4, line 6 column 3
16	Municipal Tax Expense	II (D)	176,916	Worksheet 4, line 8 column 3
17	Payroll Tax Expense	II (E)	-	Worksheet 4, line 10 column 3
18	Operation & Maintenance Expense	II (F)	3,143,069	Worksheet 4, line 17 column 3
19	Administrative & General Expense	II (G)	688,598	Worksheet 4, line 23 column 3
20	Support Revenue	II (H)	(412,306)	Worksheet 12
21	Total Revenue Requirements (Line 13 thru 20)		$ 6,223,302	
22	Local Control Center Wages and Salaries Allocation Factor	I (A)(2)	100.00%	Worksheet 5, line 20
23	Transmission Related Revenue Requirement (Line 21 X 22)		$ 6,223,302	
24	OATT Sch 1 revenues (regional)	III (1)	$ (4,129,799)	Att. G - ws 6, line 14 (less 46,979 50bp RTO adder)
25	Schedule 1 related Short term, non-firm, & penalty revenues	III (2)	-	
26	CCS revenues	III (3)	-	
27	Schedule 1 related Wheeling out revenues	III (4)	-	
28	Prorated Excepted Transaction Revenues	III (5)	-	
29	Local Schedule 1 Revenue Requirement for Retail Distribution Level Customers		$ 2,093,503	
	Less:			
30	CCS revenues	III (2)	(510,817)	
31	Schedule 1 related Wheeling out revenues	III (3)	(1,147,670)	
32	Local Schedule 1 Revenue Requirement for Retail Transmission Level & Wholesale Customers		$ 435,016	

CENTRAL MAINE POWER COMPANY
LOCAL SCHEDULE 1 REVENUE REQUIREMENTS
2013 TEST YEAR

Line		CAPITALIZATION 12/31/2013	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION	
1	LONG-TERM DEBT	$ 949,500,000	44.977%	5.111%	2.299%		Worksheet 9
2	PREFERRED STOCK	571,300	0.027%	6.000%	0.002%	0.002%	FF 1 pp. 112.3d
3	COMMON EQUITY	1,160,997,251	54.996%	11.140%	6.127%	6.127%	FF 1 p. 112.14d less line 3d less goodwill
4							
5	TOTAL INVESTMENT RETURN	$ 2,111,068,551	100.00%		8.428%	6.129%	

6
7
8
9 **Cost of Capital Rate=**
10
11 (a) Weighted Cost of Capital = **8.428%**
12
13 Local Control Center Inv. | Equity AFUDC
14 (b) Federal Income Tax = (R.O.E. + (Tax Credit -w/s 1, line 15 + w/s 10, line 47) / Local Control Center Inv. Base) x Federal Income Tax Rate)
15 (1 - Federal Income Tax Rate)
16
17 = (0.0613 +((9,008) + 1,670) / 12,684,667) x 0.35)
18 (1 - 0.35)
19
20 = **3.269%**
21
22 Local Control Center Inv. | Eq. AFUDC
23 (c) State Income Tax = (R.O.E. + ((Tax Credit + of Deprec. Exp.) / Local Control Center Inv. Base) + Federal Income Tax)* State Income Tax Rate
24 (1 - State Income Tax Rate)
25
26 = (0.0613 +((9,008) + 1,670) / 12,684,667) + 0.0326908)* 0.0893
27 (1 - 0.0893)
28
29 = **0.916%**
30
31
32
33 (a)+(b)+(c) Cost of Capital Rate = **12.613%**
34
35
36
37
38 **Local Control Center**
39
40 INVESTMENT BASE $ 12,684,667
41
42 x Cost of Capital Rate **12.613%**
43
44 = Investment Return and Income Taxes $ 1,599,911
ws 1, line 13

CENTRAL MAINE POWER COMPANY
LOCAL SCHEDULE 1 REVENUE REQUIREMENTS
2013 TEST YEAR

Line No.		(1) Total	(2) Allocation Factors	(3) = (1)*(2) Local Control Center Allocated	Schedule 1 Rate Worksheet or FERC Form 1 Reference for col (1) or (3)
1	Local Control Center Plant	$ 23,134,449	100.00%	$ 23,134,449	Worksheet 6, line 15
2	Intangible Plant	50,257,757	4.26% (a)	2,140,980	Worksheet 6, line 4
3	General Plant	203,839,783	4.26% (a)	8,683,575	Worksheet 6, line 1
4	**Total Local Control Center Related Plant**	$ 277,231,989		33,959,004	
5					
6	Local Control Center Accumulated Depreciation	(14,272,137)	100.00%	(14,272,137)	Worksheet 6, line 15
7	Intangible Accumulated Amortization	(45,226,842)	4.26% (a)	(1,926,663)	Worksheet 6, line 6
8	General Accumulated Depreciation	(88,441,236)	4.26% (a)	(3,767,597)	Worksheet 6, line 3
9	**Total Local Control Center Related Depreciation Reserve**	$ (147,940,215)		$ (19,966,397)	
10					
11					
12	Accumulated Deferred Taxes (281-283)	(507,110,770)	1.26% (b)	(6,389,596)	Worksheet 11, line 3
13	Accumulated Deferred Taxes (190)	56,258,195	1.26% (b)	708,853	Worksheet 11, line 2
14	**Total Local Control Center Related Accumulated Deferred Taxes**	$ (450,852,575)		$ (5,680,742)	
15					
16					
17					
18	FAS 106	6,097,501	4.26% (a)	259,754	Page 232.1, lines 37, C. f
19	FAS 109	274,160,955	1.26% (b)	3,454,428	FF1 Pg 232.2, L.2, C.f - FF1 Pg 278, L.26, C.f
20	**Total Local Control Center Related Other Regulatory Assets/Liabilities**	$ 280,258,456		$ 3,714,182	
21					
22	**Local Control Center Related Prepayments**	3,675,311	1.26% (b)	46,309	Page 111.57c - $32,998,240 for accrued taxes
23					
24	**Local Control Center Related Materials and Supplies**	10,583,658	1.26% (b)	133,354	Worksheet 11, line 4
25					
26					
27	Operation & Maintenance Expense			3,143,069	Worksheet 1, Line 18
28	Administrative & General Expense			688,598	Worksheet 1, Line 19
29	Subtotal (line 27+28)			3,831,667	
30				0.125	x 45 / 360
31	**Local Control Center Related Cash Working Capital**			$ 478,958	

(a) Worksheet 5, line 11
(b) Worksheet 5, line 28

CENTRAL MAINE POWER COMPANY
LOCAL SCHEDULE 1 REVENUE REQUIREMENTS
2013 TEST YEAR

Line No.		(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Local Control Center Allocated	Worksheet or FERC Form 1 Reference for col (1)
1	Local Control Center Depreciation Expense	$ 664,389	100.00%	$ 664,389	Worksheet 6, line 15
2	Intangible Amortization	2,521,111	4.26% (a)	107,399	Worksheet 6, line 5
3	General Depreciation	6,205,035	4.26% (a)	264,334	Worksheet 6, line 2
4	**Total Local Control Center Depreciation Expense**	$ 9,390,535		$ 1,036,123	
5					
6	**Local Control Center Related Amortization of ITC**	(714,950)	1.26% (b)	(9,008)	Page 266.8.f
7					
8	**Local Control Center Related Municipal Taxes Expense**	14,040,985	1.26% (b)	176,916	w/s 11, line 5
9					
10	**Local Control Center Related Payroll Tax Expense (c)**	-	4.26% (a)	-	
11					
12					
13	System Control and Load Dispatch - #556	-			Page 321.77b
14	Load Dispatching - #561 - 561.4	3,143,069			Page 321.84 thru 88 & ws 7
15	Load Dispatching - #581	-			581 excluded from Transmission
16					
17	**Local Control Center Related Operations & Maintenance Exp.**	$ 3,143,069	100.00%	$ 3,143,069	
18					
19					
20	A & G subject to Wage & Salaries Allocation Factor	16,041,342	4.26% (a)	683,361	Worksheet 8, line 33
21	A & G subject to Plant Allocation Factor	415,616	1.26% (b)	5,237	Worksheet 8, line 36
22	A & G directly assigned to Local Control Center	-	100.00%	-	
23	**Local Control Center Related Administrative & General Exp.**	$ 16,456,958		$ 688,598	

(a) Worksheet 5, line 11
(b) Worksheet 5, line 28
(c) Payroll taxes - FERC Form 1, page 263 lines 3,5&9 col i&l are recorded in acc't 184
and then cleared and properly functionalized to the appropriate accounts based on the distribution of labor.

CENTRAL MAINE POWER COMPANY
LOCAL SCHEDULE 1 REVENUE REQUIREMENTS
2013 TEST YEAR

Line No.		formula reference			Sch. 1 Rate Worksheet or FERC Form 1 Reference
1					
2	**Wages and Salaries Allocation Factor**	I(A)(1)		2013	
3					
4	Total Local Control Center Direct Wages and Salaries		$	1,721,555	ws 7, line 5(c)
5					
6	Total Wages and Salaries			46,389,250	Page 354.28b
7	Administrative and General Wages and Salaries			6,013,656	Page 354.27b
8	Affiliated Company Wages and Salaries less A&G			-	
9	Total Wages and Salaries net of A&G (line 6 - 7 + 8)		$	40,375,594	
10					
11	Percent Allocation (line 4/9)			**4.26%**	
12					
13					
14	**Local Control Center Wages and Salaries Allocation Factor**	I(A)(2)			
15					
16	Total Transmission Local Control Center Direct Wages and Salaries		$	1,721,555	ws 7, line 5(c)
17					
18	Total Local Control Center Direct Wages and Salaries		$	1,721,555	Line 4 above
19					
20	Percent Allocation (line 16/18)			**100.00%**	ws 1, line 22
21					
22					
23	**Local Control Center Plant Allocation Factor**	I(A)(3)			
24					
25	Total Investment in Local Control Center Related Plant		$	33,959,004	ws 3, line 4
26	Total Plant in Service		$	2,684,984,908	Page 207.104g
27					
28	Percent Allocation (line 25/26)			**1.26%**	

CENTRAL MAINE POWER COMPANY
LOCAL SCHEDULE 1 REVENUE REQUIREMENTS
2013 TEST YEAR

		FERC Form 1 Reference	FERC FORM 1 TOTAL	less amounts directly assigned to Sch 1.	ADJUSTED TOTAL	ref
1	General Plant	FERC FORM 1, PG 207, LINE 99g	$ 214,513,613	$ 10,673,830	$ 203,839,783	w/s 3, line 3 col. 1
2	General Depreciation Exp.	FERC FORM 1, PG. 336, LINE 10f	6,750,322	545,287	6,205,035	w/s 4, line 3 col. 1
3	Gen'l Deprec. Res.	FERC FORM 1, PG 219, LINE 28c	93,653,507	5,212,271	88,441,236	w/s 3, line 8 col. 1
4	Intangible Plant	FERC FORM 1, PG 205 line 5g	58,187,357	7,929,600	50,257,757	w/s 3, line 2 col. 1
5	Intangible Amortization	FERC FORM 1, PG 336 Line 1f	2,526,856	5,745	2,521,111	w/s 4, line 2 col. 1
6	Intangible Plant Reserve	FERC FORM 1 PG200 line 21c	53,132,776	7,905,934	45,226,842	w/s 3, line 7 col. 1

	PROPERTY DESCRIPTION	PROPERTY CLASSIFICATION	COST	ref	RESERVE	ref	DEPRECIATION	ref
7	Furniture & Equipment	General	$ 2,480,122		$ 571,026		$ 161,696	
8	Structure Costs & Map Boards	General	5,250,390		1,984,935		123,453	
9	UPS	General	284,858		179,776		10,550	
10	EMS Hardware		1,885,690		1,834,871		193,715	
11	Communication Equipment	General	772,770		641,663		55,873	
12			10,673,830		5,212,271		545,287	
13	EMS Software	Intangible	7,929,600		7,905,934		5,745	
14	S/S RTU's & Scada	Transmission	4,531,019		1,153,932		113,357	
15	Totals Directly Assigned to Schedule 1		$ 23,134,449		$ 14,272,137		$ 664,389	
			w/s 3, line 1, col 1		w/s 3, line 6, col 1		w/s 4, line 1, col 1	

CENTRAL MAINE POWER COMPANY
LOCAL SCHEDULE 1 REVENUE REQUIREMENTS
2013 TEST YEAR

	FERC ACCT		TOTAL EXPENSE	P/R OH & OTHER EXPENSES	SALARIES & WAGES
			(a)	(b)	©
1	561.1 Load Dispatch-Reliability	Page 321.85b	$ 673,046	$ 253,749	$ 419,297
2	561.2 Load Dispatch-Monitor & Operate Transmission System	Page 321.86b	2,456,517	1,154,259	1,302,258
	561.3 Load Dispatch-Transmisssion Service & Scheduling	Page 321.87b	13,506	13,506	-
3	561.4 Scheduling, System Control & Dispatch Services	Page 321.88b	-	-	-
4					
5	TOTAL		$ 3,143,069	$ 1,421,514	$ 1,721,555
6					

CENTRAL MAINE POWER COMPANY
LOCAL SCHEDULE 1 REVENUE REQUIREMENTS
2013 TEST YEAR

Administrative and General Expense Detail

	Acc't	Description	Amount	W/S or FF I REF.
1	920	Administrative and General Salaries	$ 7,996,238	
2	921	Office Supplies and Expenses	3,063,499	
3	922	Less Administrative Expenses Transferred	(505,998)	
4	923	Outside Services	31,397,588	
5	924	Property Insurance (see line 32 below)	415,616	
6	925	Injuries and Damages	1,081,660	
7	926	Employee Pensions and Benefits	(6,582,691)	
8	928	Regulatory Commissions Expense	9,172,452	
9	930.1	General Advertising	655,636	
10	930.2	Miscellaneous General Expense	(1,487,452)	
11	931	Rents	1,228,520	
12	935	Maintenance of General Plant	3,105,466	
13		Total Admin & Gen'l Exp.	$ 49,540,534	Page 323.197b
14		FERC Reg Comm Exp - T (directly assigned)	-	FF1 p 350
15		FERC assessments - 100% Transmission	-	FF1 p 350
16		FERC Reg Comm Exp - subject to plant allocation factor	411,066	FF1 p 350
17		Amortization of RTO Formation Costs (100% Transmission)	636,510	FF1 p 350
18		TOTAL FERC Reg Comm Exp and Assessments directly assigned to T	1,047,576	
19		State assessments - Transmission (directly assigned) (line 40 below)	29,474	FF1 p 350
20		Total State Assessments and Other Assessments	8,124,876	FF1 p 350
21	928	Total Regulatory Commissions Expense: (lines 18+20) & from line 8 above	$ 9,172,452	FF1 p 350
22		General Advertising - Transmission related	-	
23		Non-Transmission related General Advertising Exp.	655,636	
24	930.1	Total General Advertising Exp. (line 9 above)	$ 655,636	
		Summary of Attachment G treatment of A&G		
25		Total A&G (line 13 above)	49,540,534	
26	923	less Outside Services	31,397,588	
27	924	less Property Insurance (line 5 above)	415,616	
28	928	less Regulatory Commissions Exp. (line 21 above)	9,172,452	
29	930.1	less Non-Trans. General Advertising Exp. (line 9 above)	655,636	
30	930.2	less Miscellaneous General Expense	(1,487,452)	
31	920-935	less EPRI Expenses	-	
32	926	less pension credit directly assigned to T&D	(6,654,648)	MPUC Docket Nos. 2007-215/2008-111
33		A&G subject to Wages and Salaries Allocation Factor:	$ 16,041,342	to ws 4, line 20, col. 1
34		Property Insurance (line 5 above)	415,616	
35		Regulatory Commissions Exp (line 14 above)	-	
36		Total A&G subject to Plant Allocation Factor	$ 415,616	w/s 4, line 21
37		Amort of Def' RTO Formation and Assoc. CC included in 928 (line 17 above)	-	
38		928 Adjustment for Book Amortization of RTO Formation Costs	-	
39		Rate Year Pro forma Amort of Def' RTO Formation and Assoc CC	-	ws 21
40		Total RTO Formation & Assoc CC assigned 100% to Transmission	-	Att G-R w/s 4, line 14
		Items Directly Assigned to Transmission		
41	926010	MRFV - transmission only portion of pension credit	(791,903)	MPUC Docket Nos. 2007-215/2008-111
42		State assessments - Transmission (directly assigned) (Line 19 above)	29,474	FF1 Pg 350,L.4, C.c
43		Outside Services- Transmission (directly assigned)	11,699,889	FF1 Pg 320,L.184, C.b
44		Miscellaneous General Expense- Transmission (directly assigned)	(90,024)	FF1 Pg 320,L.192, C.b
45		FERC Reg Comm Exp - Trans (directly assigned) (Line14 above)	411,066	FF1 Pg 350,L.23&24, C.c
46		Total to Attachment G-R w/s 4, line 13	$ 11,258,502	

CENTRAL MAINE POWER COMPANY
LOCAL SCHEDULE 1 REVENUE REQUIREMENTS
2013 TEST YEAR

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
			(A)*(B)			(B)-(D)-(E)	(C)/(F)	(B)*(G)
Series	**Nominal Interest Rate**	**Principal**	**Annualized Nominal Cost**	**Expense Premium or Discount**	**Hedge Activities**	**Net Proceeds**	**Embedded Cost Rate**	**All Debt Annualized Cost**
N.H. Business Finance Athority	5.375%	$ 19,500,000	$ 1,048,125	$ 386,087	-	$ 19,113,913	5.484%	$ 1,069,296
First Mortgage Bond-Series A	5.700%	150,000,000	8,550,000	1,862,630	6,953,000	141,184,370	6.056%	9,083,867
F (Note 1)	5.780%	25,000,000	1,445,000	205,140	2,128,521	22,666,339	6.375%	1,593,773
F (Note 2)	5.375%	20,000,000	1,075,000	156,129	-	19,843,871	5.417%	1,083,458
F (Note 3)	5.430%	25,000,000	1,357,500	195,140	2,795,719	22,009,141	6.168%	1,541,973
F (Note 4)	5.700%	15,000,000	855,000	132,346	-	14,867,654	5.751%	862,611
F (Note 5)	5.875%	15,000,000	881,250	132,137	-	14,867,863	5.927%	889,082
F (Note 6)	5.300%	30,000,000	1,590,000	230,546	335,500	29,433,954	5.402%	1,620,577
F (Note 7)	5.270%	10,000,000	527,000	65,627	175,000	9,759,373	5.400%	539,994
F (Note 8)	6.400%	40,000,000	2,560,000	312,089	343,168	39,344,743	6.507%	2,602,635
First Mortgage Bond	4.200%	150,000,000	6,300,000	844,040	-	149,155,960	4.224%	6,335,650
First Mortgage Bond	5.680%	100,000,000	5,680,000	562,693	-	99,437,307	5.712%	5,712,142
First Mortgage Bond	3.070%	125,000,000	3,837,500	676,164	-	124,323,836	3.087%	3,858,371
First Mortgage Bond	4.450%	225,000,000	10,012,500	1,195,901	-	223,804,099	4.474%	10,066,002
		$ 949,500,000	$ 45,718,875	$ 6,956,671	$ 12,730,908	$ 929,812,421	4.917%	$ 46,859,431
Less 12/31/2013 Unamort. Loss on Req. Debt (FF I p.111.81.c)						1,801,635		
Add Amort. Of Loss on Reaquired Debt (FFI p117.64.c)								575,438
Adjusted Balance						$928,010,786		$47,434,869
						(I)		**(J)**
Cost Of Debt (J)/(I)		**5.111%**						

CENTRAL MAINE POWER COMPANY
LOCAL SCHEDULE 1 REVENUE REQUIREMENTS
2013 TEST YEAR

Source: USS

Line	Vintage	Cost	AFUDC	% of Total
	Transmission Assets:			
1	1953-1970	**no afudc data available**		
2	1971	16,993,929	210,398	1.24%
3	1972	1,354,874	-	0.00%
4	1973	2,530,521	21,837	0.86%
5	1974	3,929,745	200	0.01%
6	1975	4,626,387	38,383	0.83%
7	1976	6,559,880	76,909	1.17%
8	1977	5,885,933	86,351	1.47%
9	1978	17,338,606	444,301	2.56%
10	1979	4,115,534	14,481	0.35%
11	1980	7,717,864	28,543	0.37%
12	1981	3,806,576	45,143	1.19%
13	1982	3,336,346	16,508	0.49%
14	1983	5,462,226	107,741	1.97%
15	1984	6,543,576	188,256	2.88%
16	1985	2,153,012	13,995	0.65%
17	1986	4,063,381	72,616	1.79%
18	1987	6,308,982	70,120	1.11%
19	1988	8,616,426	96,074	1.12%
20	1989	8,190,862	92,568	1.13%
21	1990	18,606,637	300,769	1.62%
22	1991	6,804,433	68,667	1.01%
23	1992	10,041,560	178,995	1.78%
24	1993	5,637,279	121,080	2.15%
25	1994	3,480,922	26,059	0.75%
26	1995	3,820,449	32,298	0.85%
27	1996	2,681,701	20,928	0.78%
28	1997	1,790,063	23,501	1.31%
29	1998	1,477,852	4,185	0.28%
30	1999	1,810,857	10,989	0.61%
31	2000	26,037,439	264,455	1.02%
32	2001	8,983,040	92,232	1.03%
33	2002	8,622,712	117,487	1.36%
34	2003	2,701,882	(16,453)	-0.61%
35	2004	13,379,541	151,747	1.13%
36	2005	10,790,340	187,716	1.74%
37	2006	14,151,218	57,062	0.40%
38	2007	41,386,528	247,340	0.60%
39	2008	84,332,796	3,500,923	4.15%
40	2009	44,549,845	355,246	0.80%
41	2010	20,636,193	558,551	2.71%
	2011	29,046,140	374,354	1.29%
42	2012	100,664,413	342,000	0.34%
	2013	61,678,656	823,106	1.33%
43	totals	$ 642,647,156	$ 9,467,661	**1.47%**
44				
45	Transmission Plant related Depreciation Expense:		$ 113,357	From Worksheet 6, line 11
46				
47	AFUDC Adjustment		**$ 1,670**	To Worksteet 2

Note: No AFUDC was capitalized related to general plant investments, as they were purchased and not constructed.

CENTRAL MAINE POWER COMPANY
LOCAL SCHEDULE 1 REVENUE REQUIREMENTS
2013 TEST YEAR

Line #	Description	FERC FORM 1 REF.	FERC FORM I Bal.	Less Amounts Assigned to Transmission	Amount for Schedule 1	Sch. 1 w/s ref
1	Accumulated Deferred Income Taxes:					
	190	Page 234.8c	$ 71,580,946	$ 15,322,751	$ 56,258,195	w/s 3, line 9
2	Adjusted Total		71,580,946	15,322,751	56,258,195	
	282	Page 113.63c	(579,202,621)	223,917,228	(355,285,393)	
	283	Page 113.64c	(167,003,919)	15,178,542	(151,825,377)	
3	subtotal 281-283		(746,206,540)	239,095,770	(507,110,770)	w/s 3, line 8
4	Materials & Supplies	Page 110.48.c	17,150,878	6,567,220	10,583,658	w/s 3, line 21
	Total Real and Personal Propoerty 408.1	Page 263.14 i	27,672,417	13,631,432	14,040,985	
	Less Sales & Use Taxes		-	-	-	
5	Property Taxes		$ 27,672,417	$ 13,631,432	$ 14,040,985	w/s 4, line 7

CENTRAL MAINE POWER COMPANY
LOCAL SCHEDULE 1 REVENUE REQUIREMENTS
2013 TEST YEAR

FERC	Description / Source		Amount
454	BANGOR HYDRO - MSA	$	(261,352)
454	NEW ENGLAND POWER MICRO		(19,497)
454	MEPCO - APEX		(131,457)
		$	(412,306)

CENTRAL MAINE POWER COMPANY
ANNUAL UPDATE TO CCS CHARGE
EFFECTIVE 6/1/14

2013 Local Sch. 1 Rev. Req't Effective 6/1/14	$ 2,093,503			
2012 Local Sch. 1 Rev. Req't Effective 6/1/13	$ 3,847,991			
Change 6/1/13 to 6/1/14	$ (1,754,488)	-45.59%		

CCS CHARGE:	As Updated Effective 6/1/13	$ Change	As Updated Effective 6/1/14	% Change
Fixed Charge	16,808	(7,663)	9,145	-45.59%
Variable Charge:				
Generators > 500 MW	0.28	(0.13)	0.15	-45.59%
Generators ≤ 500 MW	0.37	(0.17)	0.20	-45.59%

CENTRAL MAINE POWER
SCHEDULE 13
2013 TEST YEAR

CIACs and contributions rec'd on meter property = 117,380

Line No.	INVESTMENT BASE	Formula Reference Section:	Amount	adjustments	Capital related	O&M related	Total	Reference
1	Meter Plant	II (A)(1)(a)	$ 59,345,979	-	59,345,979	-	59,345,979	Worksheet 3, line 1 column 3
2	General Plant	II (A)(1)(b)	15,337,109	-	-	15,337,109	15,337,109	Worksheet 3, line 3 column 3
3	Total Plant (Lines 1+2)		74,683,088	-	59,345,979	15,337,109	74,683,088	
4	Accumulated Depreciation	II (A)(1)(c)	(14,792,583)	-	(8,138,176)	(6,654,407)	(14,792,583)	Worksheet 3, line 8 column 3
5	Accumulated Deferred Income Taxes	II (A)(1)(d)	(12,540,464)	-	(9,965,123)	(2,575,341)	(12,540,464)	Worksheet 3, line 13 column 3
6	Other Regulatory Asssets / Liabilities	II (A)(1)(e)	8,084,569	-	6,059,736	2,024,833	8,084,569	Worksheet 3, line 20 column 3
7	Net Investment (Line 3+4+5+6)		55,434,610	-	47,302,416	8,132,194	55,434,610	
8	Prepayments	II (A)(1)(f)	276,534	-	-	276,534	276,534	Worksheet 3, line 22 column 3
9	Materials & Supplies	II (A)(1)(g)	294,384	-	-	294,384	294,384	Worksheet 3, line 24 column 3
10	Cash Working Capital	II (A)(1)(h)	925,344	-	-	925,344	925,344	Worksheet 3, line 31 column 3
11	Total Investment Base (Line 7+8+9+10)		$ 56,930,873	$ -	$ 47,302,416	$ 9,628,457	56,930,873	

Line No.	REVENUE REQUIREMENTS	Formula Reference	Amount	adjustments	Capital related	O&M related	Total	Reference
12	Investment Return and Income Taxes	II (A)	$ 7,189,658	-	5,973,704	1,215,954	7,189,658	Worksheet 2, line 44
13	Depreciation Expense	II (B)	3,419,912	2,953,039	-	466,873	3,419,912	Worksheet 4, line 4 column 3
14	Investment Tax Credit	II (C)	(19,886)	-	(15,802)	(4,084)	(19,886)	Worksheet 4, line 8 column 3
15	Municipal Taxes	II (D)	390,550	-	-	390,550	390,550	Worksheet 4, line 10 column 3
16	Payroll Taxes	II (E)	-	-	-	-	-	Worksheet 4, line 12 column 3
17	Operation & Maintenance Expense	II (F)	6,184,229	-	-	6,184,229	6,184,229	Worksheet 4, line 17 column 3
18	Administrative & General Expense	II (G)	1,218,527	-	-	1,218,527	1,218,527	Worksheet 4, line 23 column 3
19	Total Revenue Requirements (Lines 12 thru 18)		$ 18,382,990	$ 2,953,039	$ 5,957,902	$ 9,472,049	18,382,990	
	Annual Carrying Charge				**11.63%**	**15.93%**		
	Monthly Carrying Charge				**0.97%**	**1.33%**		

Pursuant Schedule 13, capital related excludes depreciation expense on meter plant as depreciation on meter DAF will be tracked and charged separately, in addition to the capital related carrying charge.

CENTRAL MAINE POWER
SCHEDULE 13
2013 TEST YEAR

			CAPITALIZATION 12/31/2013	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
1	LONG-TERM DEBT	w/s 9	$ 949,500,000	44.977%	5.111%	2.299%	
2	PREFERRED STOCK	page 112.3c	571,300	0.027%	6.000%	0.002%	0.002%
3	COMMON EQUITY	page 112.16c less line 3c, less goodwill of $302,129,279	1,160,997,251	54.996%	11.140%	6.127%	6.127%
4	TOTAL INVESTMENT RETURN		$ 2,111,068,551	100.00%		8.428%	6.129%

Cost of Capital Rate=

5	(a) Weighted Cost of Capital	=	**8.43%**									
					Meter Inv.		Equity AFUDC					
6	(b) Federal Income Tax	= (	R.O.E. +	(	Tax Credit -w/s 1	+	) /	Meter Inv. Base)	x	Federal Income Tax Rate	)	
7		(	1						-	Federal Income Tax Rate	)	
8												
9		= (	0.0613	+(	(19,886)	+	0) /	56,930,873)	x	0.35	)	
10		(	1						-	0.35	)	
11		=	**3.28%**									
					Meter Inv.		Eq. AFUDC					
12	(c) State Income Tax	= (	R.O.E. +	(	(Tax Credit	+	of Deprec. Exp.) /	Meter Inv. Base)	+	Federal Income Tax	)*	State Income Tax Rate
13		(	1						-	State Income Tax Rate	)	
14		= (	0.0613	+(	(19,886)	+	0) /	56,930,873)	+	0.0328142	)*	0.0893
15		(	1						-	0.0893	)	
16		=	**0.92%**									
17	(a)+(b)+(c) Cost of Capital Rate	=	**12.63%**									

			Meter
18	INVESTMENT BASE	$	56,930,873
19	x Cost of Capital Rate		**12.63%**
20	= Investment Return and Income Taxes	$	7,189,658

CENTRAL MAINE POWER
SCHEDULE 13
2013 TEST YEAR

Line No.		(1) Total	(2) Allocation Factors	(3) = (1)*(2) Meter Allocated	Worksheet or FERC Form 1 Reference for col (1) or (3)
1	Meter Plant	59,345,979	100.00%	59,345,979	Worksheet 6, line 3, col. a
2					
3	General Plant	203,839,783	7.52% (a)	15,337,109	Worksheet 6, line 7, col. a
4					
5	Accumulated Depreciation				
6	Meter Accumulated Depreciation	(8,138,176)	100.00%	(8,138,176)	Worksheet 6, line 3, col. B
7	General Plant Accumulated Depreciation	(88,441,236)	7.52% (a)	(6,654,407)	Worksheet 6, line 7, col. B
8	Total Acccumulated Depreciation	(96,579,412)		(14,792,583)	
9					
10	Accumulated Deferred Taxes				
11	Accumulated Deferred Taxes (281-283)	(507,110,770)	2.78% (b)	(14,105,286)	Worksheet 10, line 2, col F
12	Accumulated Deferred Taxes (190)	56,258,195	2.78% (b)	1,564,822	Worksheet 10, line 1, col F
13	Total (line 8+9)	(450,852,575)		(12,540,464)	
14					
15					
16					
17	Other Regulatory Assets / Liabilities				
18	FAS 106	6,097,501	7.52% (a)	458,782	Page 232.1, line 37f
19	FAS 109	274,160,955	2.78% (b)	7,625,787	FF1 Pg 232.2, L.2, C.f - FF1 Pg 278, L.26, C.f
20	Total (line 12+13)	280,258,456		8,084,569	
21					
22	Prepayments	3,675,311	7.52% (a)	276,534	Page 111.57c - $32,998,240 for accrued taxes
23					
24	Total Materials and Supplies	10,583,658	2.78% (b)	294,384	Worksheet 10, line 3, col F
25					
26	Cash Working Capital				
27	Operation & Maintenance Expense			6,184,229	Worksheet 1, Line 17
28	Administrative & General Expense			1,218,527	Worksheet 1, Line 18
29	Subtotal (line 18+19+20)			7,402,756	
30				0.125	x 45 / 360
31	Total (line 21 * line 22)			925,344	ws 1, line 10

(a) Worksheet 5, line 10
(b) Worksheet 5, line 23

CENTRAL MAINE POWER
SCHEDULE 13
2013 TEST YEAR

Line No.		(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Meter Allocated	Worksheet or FERC Form 1 Reference for col (1)
1	Meter Depreciation Expense				
2	Meter Depreciation Expense	$ 2,953,039	100.00%	$ 2,953,039	Worksheet 6, line 3, col. D
3	General Plant Deprec. Expense	6,205,035	7.52% (a)	466,873	Worksheet 6, line 7, col. D
4		9,158,074		3,419,912	
5					
6					
7					
8	Amortization of Investment Tax Credits	(714,950)	2.78% (b)	(19,886)	Page 266, line 8f (acc't 411.4)
9					
10	Property Taxes	14,040,985	2.78% (b)	390,550	Worksheet 10, line 4
11					
12	Payroll Taxes (c)	-	7.52% (a)	-	
13					
14	Operation and Maintenance				
15	Meter Expense - Ferc # 586	6,184,229			Page 322.140b & worksheet 7, line 1, col a
16	Maintenance of Meter - Ferc # 597	-			Page 322.153b & worksheet 7, line 2, col a.
17	O&M (line 15 + 16)	$ 6,184,229	100.00%	$ 6,184,229	
18					
19	Administrative and General				
20	A & G subject to Wage & Salaries Allocation Factor	16,041,342	7.52% (a)	1,206,967	Worksheet 8, line 31
21	A & G subject to Plant Allocation Factor	415,616	2.78% (b)	11,560	Worksheet 8, line 34
22	A & G directly assigned to Meter	-	100.00%	-	Worksheet 8, line 14
23	A&G (line 20+21+22)	$ 16,456,958		$ 1,218,527	

(a) Worksheet 5, line 10
(b) Worksheet 5, line 23
(c) Payroll taxes - FERC Form 1, page 263 lines 3,5&9 col i&l are recorded in acc't 184
and then cleared and properly functionalized to the appropriate accounts.

CENTRAL MAINE POWER
SCHEDULE 13
2013 TEST YEAR

Line No.			Worksheet or FERC Form 1 Reference
1			
2	**Wages and Salaries Allocation Factor**	2013	
3			
4	Total Meter Direct Wages and Salaries	3,037,916	Ws 7, Line 4, col. C
5			
6	Total Wages and Salaries	46,389,250	Page 354.28b
7	Administrative and General Wages and Salaries	6,013,656	Page 354.27b
8	Total Wages and Salaries net of A&G (line 6 - 7)	40,375,594	
9			
10	Percent Allocation (line 4/8)	**7.52%**	
11			
12			
13			
14			
15	**Plant Allocation Factor**		
16			
17	Total Investment in Meter Plant	59,345,979	Ws 3, Line 1, Col. 3
18	Allocated General Plant	15,337,109	Ws 3, Line 3, Col. 3
19	Total Meter Plant	74,683,088	
20			
21	Total Plant in Service	2,684,984,908	Page 207.104g
22			
23	Percent Allocation (line 19/21)	**2.78%**	

CENTRAL MAINE POWER
SCHEDULE 13
2013 TEST YEAR

		12/31/2013				
1	PROPERTY DESCRIPTION	COST	RESERVE	NBV	2013 DEPRECIATION	
2		(a)	(b)	(c)	(d)	
3	Meter Plant	$ 59,345,979	$ 8,138,176	$ 51,207,803	$ 2,953,039	Note 1
4					w/s 4, line 2, col 1.	
5	Total General Plant	214,513,613	93,653,507	120,860,106	6,750,322	Note 2
6	Direct Assigned to Schedule 1	10,673,830	5,212,271	5,461,559	545,287	Schedule 1, Worksheet 6
7	Net General Plant	$ 203,839,783	$ 88,441,236	$ 115,398,547	$ 6,205,035	
		w/s 3, line 3, col 1.	w/s 3, line 7, col 1.		w/s 4, line 3, col 1.	

Note 1: Meter Plant, Reserve & Depreciation from Plant Accounting

Note 2: General Plant Balance from FERC Form 1, page 207, line 99, column g
General Plant Accum. Deprec. From FERC Form 1, page 219, line 28, column c
General Plant Deprec. Expense from FERC Form 1, page 336, line 10, column f

CENTRAL MAINE POWER
SCHEDULE 13
2013 TEST YEAR

	FERC ACCT	TOTAL EXPENSE	OTHER EXPENSES	SALARIES & WAGES	Worksheet or FERC Form 1 Reference
		(a)	(b)	(c)	
1	586 - Meter Expense	$ 6,184,229	$ 3,146,313	$ 3,037,916	Page 322.140
2	597 - Maintenance of Meters	-	-	-	Page 322.153
3					
4	TOTAL	$ 6,184,229	$ 3,146,313	$ 3,037,916	
				w/s 5, line 4	

CENTRAL MAINE POWER
SCHEDULE 13
2013 TEST YEAR

	Acc't	Description	Amount	Reference
1	920	Administrative and General Salaries	7,996,238	
2	921	Office Supplies and Expenses	3,063,499	
3	922	Less Administrative Expenses Transferred	(505,998)	
4	923	Outside Services	31,397,588	
5	924	Property Insurance	415,616	
6	925	Injuries and Damages	1,081,660	
7	926	Employee Pensions and Benefits	(6,582,691)	
8	928	Regulatory Commissions Expense	9,172,452	
9	930.1	General Advertising	655,636	
10	930.2	Miscellaneous General Expense	(1,487,452)	
11	931	Rents	1,228,520	
12	935	Maintenance of General Plant	3,105,466	
13		Total Admin & Gen'l Exp.	49,540,534	Page 323.197b
14		FERC assessments -Meter related(directly assigned)	-	
		FERC assessments - (directly assigned to transmission)	1,047,576	FF1 page 350
15		FERC assessments - subject to plant allocation factor	-	FF1 page 350
16		TOTAL FERC ASSESSMENTS (14+15)	1,047,576	FF1 page 350
17		State assessments - Meter (directly assigned)	-	
18		Total State Assessments	8,124,876	FF1 page 350
19	928	Total Regulatory Commissions Expense: (16+18) & from line 8	9,172,452	FF1 page 350
20		General Advertising - Transmission related	655,636	
21		Non-Satellite related General Advertising Exp.	-	
22	930.1	Total General Advertising Exp. (line 9)	655,636	
		Summary of Schedule 13 Treatment of A&G		
23		Total A&G (line 13)	49,540,534	
24	923	less Outside Services	31,397,588	
25	924	less Property Insurance (line 5)	415,616	
26	928	less Regulatory Commissions Exp. (line 19)	9,172,452	
27	930.1	less Non-Trans. General Advertising Exp. (line 9)	655,636	
28	930.2	less Miscellaneous General Expense	(1,487,452)	
29	920-935	less EPRI Expenses	-	
30		less amounts assigned 100% to t & d	(6,654,648)	
31		A&G subject to Wages and Salaries Allocation Factor:	16,041,342	to worksheet 4, line 20, column 1
32		Property Insurance (line 5)	415,616	
33		Regulatory Commissions Exp. - FERC assessments (line 15)	-	
34		Total A&G subject to Plant Allocation Factor	415,616	to worksheet 4, line 21, column 1

CENTRAL MAINE POWER
SCHEDULE 13
2013 TEST YEAR

	Series	(A) Nominal Interest Rate	(B) Principal	(C) (A)*(B) Annualized Nominal Cost	(D) Expense Premium or Discount	(E) Hedge Activities	(F) (B)-(D)-(E) Net Proceeds	(G) (C)/(F) Embedded Cost Rate	(H) (B)*(G) All Debt Annualized Cost
1	N.H. Business Finance Athority	5.375%	$ 19,500,000	$ 1,048,125	$ 386,087	-	$ 19,113,913	5.484%	$ 1,069,296
2	First Mortgage Bond-Series A	5.700%	150,000,000	8,550,000	1,862,630	6,953,000	141,184,370	6.056%	9,083,867
3	F (Note 1)	5.780%	25,000,000	1,445,000	205,140	2,128,521	22,666,339	6.375%	1,593,773
4	F (Note 2)	5.375%	20,000,000	1,075,000	156,129	-	19,843,871	5.417%	1,083,458
5	F (Note 3)	5.430%	25,000,000	1,357,500	195,140	2,795,719	22,009,141	6.168%	1,541,973
6	F (Note 4)	5.700%	15,000,000	855,000	132,346	-	14,867,654	5.751%	862,611
7	F (Note 5)	5.875%	15,000,000	881,250	132,137	-	14,867,863	5.927%	889,082
8	F (Note 6)	5.300%	30,000,000	1,590,000	230,546	335,500	29,433,954	5.402%	1,620,577
9	F (Note 7)	5.270%	10,000,000	527,000	65,627	175,000	9,759,373	5.400%	539,994
10	F (Note 8)	6.400%	40,000,000	2,560,000	312,089	343,168	39,344,743	6.507%	2,602,635
11	First Mortgage Bond	4.200%	150,000,000	6,300,000	844,040	-	149,155,960	4.224%	6,335,650
12	First Mortgage Bond	5.680%	100,000,000	5,680,000	562,693	-	99,437,307	5.712%	5,712,142
13	First Mortgage Bond	3.070%	125,000,000	3,837,500	676,164	-	124,323,836	3.087%	3,858,371
14	First Mortgage Bond	4.450%	225,000,000	10,012,500	1,195,901	-	223,804,099	4.474%	10,066,002
15									
16			$ 949,500,000	$ 45,718,875	$ 6,956,671	$ 12,730,908	$ 929,812,421	5.148%	$ 46,859,431
17									
18	Less 12/31/2013 Unamort. Loss on Req. Debt (FF I p.111.81.c)						1,801,635		
19	Add Amort. Of Loss on Reaquired Debt (FFI p117.64.c)								575,438
20	Adjusted Balance						$928,010,786		$47,434,869
21							**(I)**		**(J)**
22	Cost Of Debt (J)/(I)		**5.111%**						

CENTRAL MAINE POWER
SCHEDULE 13
2013 TEST YEAR

a	b		c	d	e	f	g
Line #	Description		FERC FORM 1 REF.	FERC FORM I Bal.	Less Amounts Assigned to Transmission	Amount Subject to Allocation for Meters	w/s ref
	Accumulated Deferred Income Taxes:						
1		190	Line 7 below	71,580,946	15,322,751	56,258,195	w/s 3, line 12
		282	Page 113.63c	(579,202,621)	(223,917,228)	(355,285,393)	
		283	Page 113.64c	(167,003,919)	(15,178,542)	(151,825,377)	
2	subtotal 281-283			(746,206,540)	(239,095,770)	(507,110,770)	w/s 3, line 11
3	Materials & Supplies		Page 227.12c	17,150,878	6,567,220	10,583,658	w/s 3, line 24
	Total Real and Personal Property - 408		Page 263.14.i	27,672,417	13,631,432	14,040,985	
	less Sales and Use Taxes			-	-	-	
4	Property Taxes			27,672,417	13,631,432	14,040,985	w/s 4, line 10
5	Total per FF 1		Page 234.8c	71,580,946			
6	Deferred Gain on Asset Sale		Page 234.1c	-			
7	Adjusted Total		Line 5 - line 6	71,580,946			

CENTRAL MAINE POWER COMPANY
SCHEDULE 14 (for Retail Customers)
2013 TEST YEAR

CIACs and contributions rec'd on transmission property = 56,219,523

Line No.	II. INVESTMENT BASE	Formula Reference Section:		Total	adjustments	Capital related	O&M related	Total
1	Transmission Plant	II (A)(1)(a)	$	1,248,664,109	-	1,248,664,109	-	1,248,664,109
2	Transmission Related Intangible & General Plant	II (A)(1)(b)		39,015,003	-	-	39,015,003	39,015,003
3	Transmission Plant Held For Future Use	II (A)(1)(c)		3,365,121	-	3,365,121	-	3,365,121
4	Total Transmission Related Plant (Lines 1+2+3)			1,291,044,233	-	1,252,029,230	39,015,003	1,291,044,233
5	Transmission Related Accumulated Depreciation & Amortization	II (A)(1)(d)		(210,991,767)	-	(190,467,915)	(20,523,852)	(210,991,767)
6	Transmission Related Accumulated Deferred Income Taxes	II (A)(1)(e)		(223,751,761)	-	(216,990,044)	(6,761,717)	(223,751,761)
7	Other Regulatory Asssets	II (A)(1)(f)		936,231	-	-	936,231	936,231
8	Net Investment (Line 4-5-6+7)			857,236,936	-	844,571,271	12,665,665	857,236,936
9	Transmission Prepayments	II (A)(1)(g)		564,319	-	-	564,319	564,319
10	Transmission Materials & Supplies	II (A)(1)(h)		6,566,596	-	-	6,566,596	6,566,596
11	Transmission Related Cash Working Capital	II (A)(1)(i)		3,492,564	-	-	3,492,564	3,492,564
12	Total Transmission Investment Base (Line 8+9+10+11)		$	867,860,415	$ -	$ 844,571,271	$ 23,289,144	$ 867,860,415
	II. REVENUE REQUIREMENTS							
13	Investment Return and Associated Income Taxes	II (A)	$	109,780,917	-	106,834,932	2,945,985	109,780,917
14	Transmission Related Depreciation & Amortization Expense	II (B)		29,234,008	27,894,166	-	1,339,842	29,234,008
15	Transmission Related Amort of Investment Tax Credits	II (C)		(342,879)	-	(332,517)	(10,362)	(342,879)
16	Transmission Related Municipal Taxes	II (D)		13,630,137	-	-	13,630,137	13,630,137
17	Transmission Operation & Maintenance Expense	II (E)		14,020,713	-	-	14,020,713	14,020,713
18	Transmission Related Administrative & General Expense	II (F)		13,919,797	-	-	13,919,797	13,919,797
19	Transmission Related FERC Assessments	II (G)		636,510	-	-	636,510	636,510
20	Transmission Related Customer Service, Info Exp. & Sales Exp.	II (M)		10,249,918	-	-	10,249,918	10,249,918
21	Totals		$	191,129,121	$ 27,894,166	$ 106,502,415	$ 56,732,541	$ 191,129,121
22	Annual Carrying Charge					**10.03%**	**4.35%**	
23	Monthly Carrying Charge					**0.84%**	**0.36%**	

Pursuant Schedule 14, capital related excludes transmission depreciation expense as depreciation on DAF will be tracked and charged separately, in addition to the capital related carrying charge.

CENTRAL MAINE POWER COMPANY
SCHEDULE 14 (for Wholesale Customers)
2013 TEST YEAR

CIACs and contributions rec'd on transmission property = 56,219,523

Line No.	II. INVESTMENT BASE	Formula Reference Section:		Total	adjustments	Capital related	O&M related	Total
1	Transmission Plant	II (A)(1)(a)	$	1,248,664,109	-	1,248,664,109	-	1,248,664,109
2	Transmission Related Intangible & General Plant	II (A)(1)(b)		17,405,806	-	-	17,405,806	17,405,806
3	Transmission Plant Held For Future Use	II (A)(1)(c)		3,365,121	-	3,365,121	-	3,365,121
4	Total Transmission Related Plant (Lines 1+2+3)			1,269,435,036	-	1,252,029,230	17,405,806	1,269,435,036
5	Transmission Related Accumulated Depreciation & Amortization	II (A)(1)(d)		(199,624,244)	-	(190,467,915)	(9,156,329)	(199,624,244)
6	Transmission Related Accumulated Deferred Income Taxes	II (A)(1)(e)		(223,751,761)	-	(220,683,798)	(3,067,963)	(223,751,761)
7	Other Regulatory Asssets	II (A)(1)(f)		417,682	-	-	417,682	417,682
8	Net Investment (Line 4-5-6+7)			846,476,714	-	840,877,518	5,599,196	846,476,714
9	Transmission Prepayments	II (A)(1)(g)		251,761	-	-	251,761	251,761
10	Transmission Materials & Supplies	II (A)(1)(h)		6,566,596	-	-	6,566,596	6,566,596
11	Transmission Related Cash Working Capital	II (A)(1)(i)		3,278,113	-	-	3,278,113	3,278,113
12	Total Transmission Investment Base (Line 8+9+10+11)		$	856,573,184	$ -	$ 840,877,518	$ 15,695,666	$ 856,573,184
	II. REVENUE REQUIREMENTS							
13	Investment Return and Associated Income Taxes	II (A)	$	108,356,696	-	106,371,191	1,985,505	108,356,696
14	Transmission Related Depreciation & Amortization Expense	II (B)		28,491,911	27,894,166	-	597,745	28,491,911
15	Transmission Related Amort of Investment Tax Credits	II (C)		(337,125)	-	(332,503)	(4,622)	(337,125)
16	Transmission Related Municipal Taxes	II (D)		13,630,137	-	-	13,630,137	13,630,137
17	Transmission Operation & Maintenance Expense	II (E)		13,672,653	-	-	13,672,653	13,672,653
18	Transmission Related Administrative & General Expense	II (F)		12,552,251	-	-	12,552,251	12,552,251
19	Transmission Related FERC Assessments	II (G)		636,510	-	-	636,510	636,510
20	Transmission Related Customer Service, Info Exp. & Sales Exp.			-	-	-	-	-
21	Totals		$	177,003,033	$ 27,894,166	$ 106,038,688	$ 43,070,179	$ 177,003,033
22	Annual Carrying Charge					**10.02%**	**3.30%**	
23	Monthly Carrying Charge					**0.84%**	**0.28%**	

Pursuant Schedule 14, capital related excludes transmission depreciation expense as depreciation on DAF will be tracked and charged separately, in addition to the capital related carrying charge.

Annual Report of MPRP Construction Costs for the 2014 FERC Informational Filings

CENTRAL MAINE POWER
Maine Power Reliability Program

Burns & McDonnell
SINCE 1898

TABLE OF CONTENTS

Page No.

PART I – SUMMARY OF CONSTRUCTION COSTS FOR FERC INFORMATIONAL FILINGS

Summary of MPRP Costs for the 2013 FERC Informational Filings

1. **The actual amount of CWIP recorded each month for the MPRP project for the most recent calendar year.**

   Attachment 1 provides the actual amount of CWIP recorded each month for the MPRP project for 2013.

   The Lewiston Loop represents a collection of projects within the MPRP that were classified as Deferred by the Maine Public Utilities Commission (MPUC) Order on June 10, 2010. CMP continued with planning and preliminary engineering for the Lewiston Loop and on August 23, 2013 received a Certificate of Public Convenience and Necessity (CPCN) from the MPUC. The Lewiston Loop projects are reclassified from Deferred to Approved in this report with additional estimated costs identified during the regulatory approval process assigned as Scope Change. Costs incurred during the regulatory approval process have been reclassified as CWIP.

2. **Forecast of the year end MPRP CWIP balance for the current calendar year.**

   CMP estimates the year-end 2014 MPRP CWIP balance will be $323,050,642 for PTF facilities with $6,409,913 for non-PTF facilities.

3. **A summary and detail of accounting transfers between MPRP CWIP and Plant in Service.**

   Attachment 1 provides a summary of the MPRP monthly account additions and reclassifications between CWIP and Plant in Service for the MPRP in 2013.

4. **A statement of the current status of the MPRP projects and estimated in-service dates for the program.**

   Below is a summary of the actual and forecast annual in-service values and costs for the MPRP categorized by PTF, Non-PTF, distribution, retirement and general plant.

MPRP In-Service, Retirement and General Plant Projections ($ in thousands)

Year	CMP PTF	BHE/MEPCO PTF	CMP Non-PTF	CMP Distribution	Retirement	General Plant	Total
2009	$22,435	$0	$0	$0	$0	$0	$22,435
2010	$4,674	$0	$709	$0	$0	$0	$5,383
2011	$26,798	$0	$2,453	$1,948	$3,636	$0	$34,835
2012	$213,016	$0	$13,260	$1,835	$11,567	$1,113	$240,791
2013	$311,360	$17,058	$10,050	$1,892	$5,048	-$912	$344,496
2014	$278,209	$9,500	$2,423	$300	$3,500	$1,500	$295,432
2015	$376,264	$9,986	$6,154	$4,918	$1,250	$250	$398,822
2016	$62,821	$0	$5,831	$2,700	$500	$100	$71,952
Total:	**$1,295,577**	**$36,544**	**$40,880**	**$13,593**	**$25,501**	**$2,051**	**$1,414,146**

The total cost estimate for projects within the MPRP (as included in the ISO-NE Transmission Cost Allocation approval) that are approved by the MPUC, including scope change and contingency, is $1,424,538,000. The current forecast anticipates that the Program can be constructed within the original cost estimate and the addition of the revised Lewiston Loop estimates prepared during the regulatory process.

Additional projects related to the MPRP that are still in the Planning and Regulatory approval process are estimated at $84,202,000. These projects currently include:

1. Sections 80 rebuild (Mid-Coast)
2. Section 84 rebuilds
3. New 115kV Section 244 (Mid-Coast)
4. Various line upgrades and substation expansions

Portions of the projects listed above will need to be constructed under the classifications of “Remote Ends” or “Line Terminations”. Those project costs are incorporated in the project forecast contained in the prior table.

5. Project cost estimates in a format similar to ISO-NE annual cost updates.

Attachment 2 provides cost estimate updates for MPRP projects approved by the MPUC, additional projects that are undergoing continued planning, preliminary engineering and regulatory approval and the combined cost estimates for the MPRP as a whole.

ATTACHMENT 1 – MONTHLY CWIP AND PLANT IN-SERVICE BALANCES

Central Maine Power Company
FERC Informational Filing Attachment 1
MPRP 2013 Monthly CWIP and In-Service Transmission Balances

	Total As of 12/31/2012	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
CWIP Balance	573,703,068	580,568,367	588,948,841	607,690,424	618,498,857	634,447,957	520,938,263	538,064,163	539,856,132	533,441,206	557,058,059	521,606,101	504,215,352
In Service	282,877,805	296,522,644	310,557,300	312,237,607	318,052,856	319,076,108	448,958,973	453,662,566	458,893,396	502,232,851	504,722,064	565,893,467	604,756,159
Transmission balances only	-												

ATTACHMENT 2 – PROJECT COST ESTIMATE UPDATE SHEETS

FIGURE 1 – TOTAL MPRP PROJECT FORECAST

APPROVED AND ADDITIONAL PROJECT COST ESTIMATE UPDATE SHEET

Transmission Owner:	**Central Maine Power Co.**	**RSP Project #:**	**Various**
Project Name:	**MPRP**	**Estimate Grade:**	**D (Construction)**
Base Estimate:	**$ 1,284,307**	**PPA Approval:**	
TCA Application #:	**CMP-08-TCA-01 & CMP-10-TCA-01**	**Date:**	**5/31/2014**

1. Project Scope Summary

Central Maine Power is modernizing its 40 year-old bulk power transmission system by investing between $1.4 and $1.5 billion in new construction. The proposed improvements are intended to maintain reliability over the coming decades and to provide the infrastructure necessary to facilitate the state's emerging wind, hydro, biomass and tidal energy industries. The Maine Power Reliability Program will improve the company's electric transmission network primarily between the towns of Eliot and Orrington where it interconnects to transmission systems in northern and eastern Maine. The Program is segregated into logical construction areas referred to as the Northern Loop, Central Loop, Southern Loop and Southern Connector.

2. Project Update

The MPRP received its ISO-NE determination letter in January 2010. The Certificate of Public Convenience and Necessity (CPCN) from the Maine Public Utilities Commission (MPUC) was approved with stipulation on June 10, 2010 followed by subsequent approvals in 2011 and 2013. Approvals by the Maine Department of Environmental Protection (MDEP) were received on April 5, 2010 and the by the Army Corps of Engineers (ACOE) on July 21, 2010. Approximately 96% of materials have been received with substation and transmission line construction progressing as planned. The Outage Sequence Plan continues to influence the construction and energization schedules. Program risk is evaluated and adjusted monthly. Current forecasts reflect contract amounts, approved change orders, T&M contract projections and anticipated future risk. The values represented in this update include projections of costs associated with Lewiston Loop, which received its CPCN in August 2013.

3. Project Cost Summary

Central Maine Power - Maine Power Reliability Program							
Project MPRP Components	Base Estimate	Base Estimate With Contingency	Scope Change	Actual Costs	Project Forecast	Estimated % Completion	Forecast vs. Estimate
2.2.1 New 345KV Lines	$ 387,999	$ 448,684	$ -	$ 338,063	$ 458,056	74%	$ 9,372
2.2.2 New 115KV Lines	$ 183,591	$ 212,473	$ 6,741	$ 136,365	$ 230,458	59%	$ 17,985
2.2.3 New 345KV Substations	$ 236,352	$ 273,467	$ -	$ 186,394	$ 195,273	95%	$ (78,194)
2.2.4 New 115KV Substations	$ 18,433	$ 21,316	$ 5,914	$ 11,364	$ 26,491	43%	$ 5,175
2.2.5 345 KV Substations Expansions/Modifications	$ 77,846	$ 90,059	$ -	$ 76,129	$ 86,250	88%	$ (3,809)
2.2.6 115 KV Substations Expansions/Modifications	$ 30,988	$ 36,841	$ 3,562	$ 31,585	$ 53,534	59%	$ 16,693
2.2.7 Lines Rerates, Relocations, Rebuilds	$ 349,098	$ 403,936	$ 5,747	$ 295,035	$ 448,286	66%	$ 44,350
Grand Total	**$ 1,284,307**	**$ 1,486,776**	**$ 21,964**	**$ 1,074,935**	**$ 1,498,348**	**71.74%**	**$ 11,572**

Note: PTD Through the First Quarter of 2014

4. Project Forecast

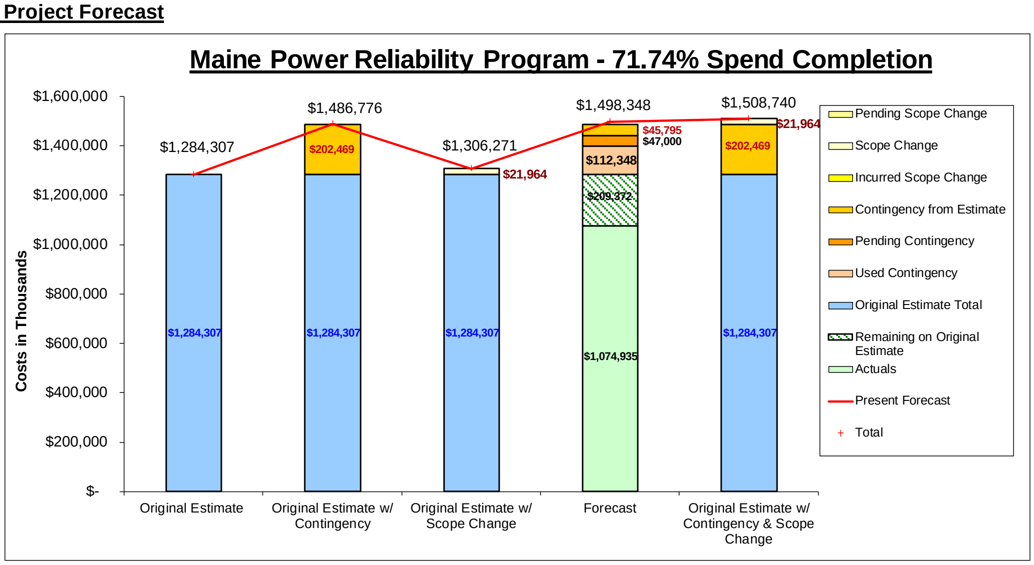


FIGURE 2 – MPRP PROJECTS APPROVED BY THE MPUC

APPROVED MPRP PROJECT COST ESTIMATE UPDATE SHEET

Transmission Owner:	**Central Maine Power Co.**	**RSP Project #:**	**Various**
Project Name:	**MPRP**	**Estimate Grade:**	**D (Construction)**
Base Estimate:	**$ 1,211,893**	**PPA Approval:**	
TCA Application #:	**CMP-08-TCA-01 & CMP-10-TCA-01**	**Date:**	**5/31/2014**

1. Project Scope Summary

Central Maine Power is modernizing its 40 year-old bulk power transmission system by investing between $1.4 and $1.5 billion in new construction. The proposed improvements are intended to maintain reliability over the coming decades and to provide the infrastructure necessary to facilitate the state's emerging wind, hydro, biomass and tidal energy industries. The Maine Power Reliability Program will improve the company's electric transmission network primarily between the towns of Eliot and Orrington where it interconnects to transmission systems in northern and eastern Maine. The Program is segregated into logical construction areas referred to as the Northern Loop, Central Loop, Southern Loop and Southern Connector.

2. Project Update

The MPRP received its ISO-NE determination letter in January 2010. The Certificate of Public Convenience and Necessity (CPCN) from the Maine Public Utilities Commission (MPUC) was approved with stipulation on June 10, 2010 followed by subsequent approvals in 2011 and 2013. Approvals by the Maine Department of Environmental Protection (MDEP) were received on April 5, 2010 and the by the Army Corps of Engineers (ACOE) on July 21, 2010. Approximately 96% of materials have been received with substation and transmission line construction progressing as planned. The Outage Sequence Plan continues to influence the construction and energization schedules. Program risk is evaluated and adjusted monthly. Current forecasts reflect contract amounts, approved change orders, T&M contract projections and anticipated future risk. The values represented in this update include projections of costs associated with Lewiston Loop, which received its Certificate of Public Convenience and Necessity (CPCN) in August 2013.

3. Project Cost Summary

Central Maine Power - Maine Power Reliability Program $/1000

Project MPRP Components	Base Estimate	Base Estimate With Contingency	Scope Change	Actual Costs	Project Forecast	Estimated % Completion	Forecast vs. Estimate
2.2.1 New 345KV Lines	$ 387,999	$ 448,684	$ -	$ 338,063	$ 458,056	74%	$ 9,372
2.2.2 New 115KV Lines	$ 157,214	$ 181,802	$ 6,741	$ 136,288	$ 199,787	68%	$ 17,985
2.2.3 New 345KV Substations	$ 236,352	$ 273,467	$ -	$ 186,394	$ 195,273	95%	$ (78,194)
2.2.4 New 115KV Substations	$ 18,433	$ 21,316	$ 5,914	$ 11,364	$ 26,491	43%	$ 5,175
2.2.5 345 KV Substations Expansions/Modifications	$ 70,160	$ 81,122	$ -	$ 76,129	$ 77,313	98%	$ (3,809)
2.2.6 115 KV Substations Expansions/Modifications	$ 29,769	$ 35,424	$ 3,562	$ 31,538	$ 52,117	61%	$ 16,693
2.2.7 Lines Rerates, Relocations, Rebuilds	$ 311,966	$ 360,759	$ 5,747	$ 294,949	$ 405,109	73%	$ 44,350
Grand Total	**$ 1,211,893**	**$ 1,402,574**	**$ 21,964**	**$ 1,074,725**	**$ 1,414,146**	**76.00%**	**$ 11,572**

Note: PTD Through the First Quarter of 2014 (includes Bangor Hydro Orrington investments)

4. Project Forecast

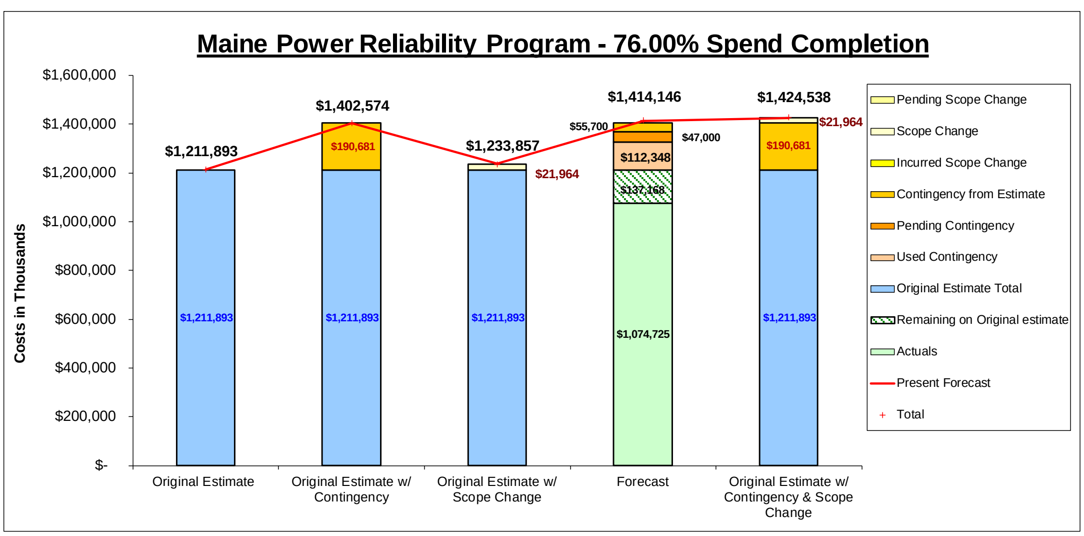


FIGURE 3 – ADDITIONAL MPRP PROJECTS PENDING MPUC APPROVAL

ADDITIONAL PROJECTS COST ESTIMATE UPDATE SHEET

Transmission Owner:	**Central Maine Power Co.**	**RSP Project #:**	**Various**
Project Name:	**Maine Power Reliability Program**	**Estimate Grade:**	**D (Construction)**
Base Estimate:	**$ 72,414**	**PPA Approval:**	
TCA Application #:	**CMP-08-TCA-01 & CMP-10-TCA-01**	**Date:**	**5/31/2014**

1. Project Scope Summary

Central Maine Power is modernizing its 40 year-old bulk power transmission system by investing between $1.4 and $1.5 billion in new construction. The proposed improvements are intended to maintain reliability over the coming decades and to provide the infrastructure necessary to facilitate the state's emerging wind, hydro, biomass and tidal energy industries. The Maine Power Reliability Program will improve the company's electric transmission network primarily between the towns of Eliot and Orrington where it interconnects to transmission systems in northern and eastern Maine. The Program is segregated into logical construction areas referred to as the Northern Loop, Central Loop, Southern Loop and Southern Connector.

2. Project Update

The MPRP received its ISO-NE determination letter in January 2010. The Certificate of Public Convenience and Necessity (CPCN) from the Maine Public Utilities Commission (MPUC) was approved with stipulation on June 10, 2010 followed by subsequent approvals in 2011 and 2013. Approvals by the Maine Department of Environmental Protection (MDEP) were received on April 5, 2010 and the by the Army Corps of Engineers (ACOE) on July 21, 2010. Since the 2013 cost update, ISO-NE has cancelled the Raven Farm autotransformer and 115kV switchyard. The values represented in the deferred project update include estimates and forecasts of project costs, or portions thereof, that are currently being pursued within the planning and regulatory process.

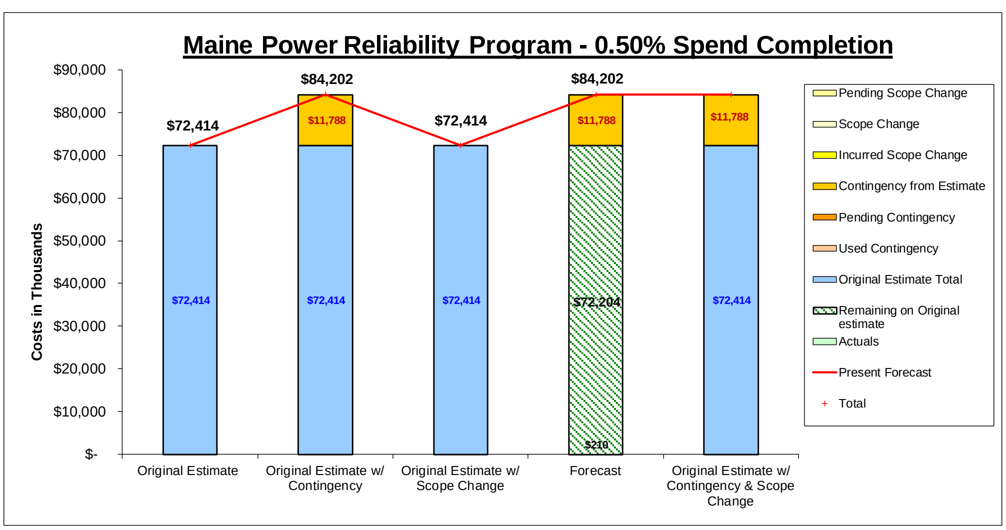
3. Project Cost Summary

Central Maine Power - Maine Power Reliability Program

Project Maine Power Reliability Program Components	Base Estimate	Base Estimate With Contingency	Scope Change	Actual Costs	Project Forecast	Estimated % Completion	Forecast vs. Estimate
2.2.1 New 345KV Lines	$ -	$ -	$ -	$ -	$ -	0%	$ -
2.2.2 New 115KV Lines	$ 26,377	$ 30,671	$ -	$ 77	$ 30,671	0%	$ -
2.2.3 New 345KV Substations	$ -	$ -	$ -	$ -	$ -	0%	$ -
2.2.4 New 115KV Substations	$ -	$ -	$ -	$ -	$ -	0%	$ -
2.2.5 345 KV Substations Expansions/Modifications	$ 7,686	$ 8,937	$ -	$ -	$ 8,937	0%	$ -
2.2.6 115 KV Substations Expansions/Modifications	$ 1,219	$ 1,417	$ -	$ 47	$ 1,417	3%	$ -
2.2.7 Lines Rerates, Relocations, Rebuilds	$ 37,132	$ 43,177	$ -	$ 86	$ 43,177	0%	$ -
Grand Total	**$ 72,414**	**$ 84,202**	**$ -**	**$ 210**	**$ 84,202**	**0.50%**	**$ -**

Note: PTD Through the First Quarter of 2014

4. Project Forecast



APPENDIX A – PROGRAM COST SUMMARY

MAINE POWER RELIABILITY PROGRAM (MPRP)
Program Cost Summary $/1000
as of 31-May-14

Approved Projects

Calendar Year	*Pre 2014 Total*	*2014*													*2015 Total*	*2016 Total*	*TOTAL*
		January	*February*	*March*	*April*	*May*	*June*	*July*	*August*	*September*	*October*	*November*	*December*	*2014 Total*			
Material	$ 173,308	$ 61	$ 1,337	$ (1,144)	$ 2,368	$ 1,045	$ 856	$ 812	$ 1,050	$ 626	$ 505	$ 375	$ 262	$ 8,155	$ 8,155	$ 2,616	$ 192,233
Labor	$ 511,162	$ 6,926	$ 13,523	$ 17,060	$ 9,989	$ 9,291	$ 8,824	$ 5,854	$ 5,814	$ 3,119	$ 2,744	$ 1,953	$ 1,316	$ 86,413	$ 55,288	$ 10,253	$ 663,115
Right of Way (net)	$ 40,343	$ 118	$ 98	$ 44	$ -	$ 55	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 315	$ 120	$ 200	$ 40,978
Engineering / Permitting / Indirects	$ 290,391	$ 4,039	$ 1,995	$ 1,632	$ 2,808	$ 2,073	$ 1,269	$ 1,066	$ 2,051	$ 1,615	$ 1,093	$ 950	$ 1,226	$ 21,817	$ 12,603	$ 11,550	$ 336,361
Escalation (Future Spend)	$ -	$ -	$ -	$ -	$ -	$ 125	$ 125	$ 125	$ 125	$ 125	$ 125	$ 125	$ 125	$ 1,001	$ 10,000	$ 1,051	$ 12,052
AFUDC (Distribution)	$ 198	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 10	$ 10	$ 5	$ 223
Contingency	$ 140,760	$ -	$ -	$ -	$ -	$ 444	$ 444	$ 444	$ 444	$ 444	$ 444	$ 444	$ 444	$ 3,554	$ 13,401	$ 11,470	$ 169,185
Total	**$ 1,156,161**	**$ 11,145**	**$ 16,954**	**$ 17,592**	**$ 15,166**	**$ 13,035**	**$ 11,519**	**$ 8,302**	**$ 9,485**	**$ 5,930**	**$ 4,912**	**$ 3,848**	**$ 3,375**	**$ 121,264**	**$ 99,577**	**$ 37,145**	**$ 1,414,146**

Additional Projects

Calendar Year	*Pre 2014 Total*	*2014*													*2015 Total*	*2016 Total*	*TOTAL*
		January	*February*	*March*	*April*	*May*	*June*	*July*	*August*	*September*	*October*	*November*	*December*	*2014 Total*			
Material	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,100	$ 8,617	$ 21,717
Labor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,893	$ 13,697	$ 27,590
Right of Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Engineering / Permitting / Indirects	$ -	$ -	$ -	$ -	$ -	$ 159	$ 161	$ 39	$ 39	$ 21	$ 21	$ 21	$ 21	$ 481	$ 5,859	$ 9,200	$ 15,540
Escalation (Future Spend)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,843	$ 1,422	$ 3,265
AFUDC (Lewiston Loop)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contingency	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,070	$ 7,020	$ 16,090
Total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 159**	**$ 161**	**$ 39**	**$ 39**	**$ 21**	**$ 21**	**$ 21**	**$ 21**	**$ 481**	**$ 43,765**	**$ 39,956**	**$ 84,202**

Total Projects

Calendar Year	*Pre 2014 Total*	*2014*													*2015 Total*	*2016 Total*	*TOTAL*
		January	*February*	*March*	*April*	*May*	*June*	*July*	*August*	*September*	*October*	*November*	*December*	*2014 Total*			
Material	$ 173,308	$ 61	$ 1,337	$ (1,144)	$ 2,368	$ 1,045	$ 856	$ 812	$ 1,050	$ 626	$ 505	$ 375	$ 262	$ 8,155	$ 21,255	$ 11,233	$ 213,950
Labor	$ 511,162	$ 6,926	$ 13,523	$ 17,060	$ 9,989	$ 9,291	$ 8,824	$ 5,854	$ 5,814	$ 3,119	$ 2,744	$ 1,953	$ 1,316	$ 86,413	$ 69,181	$ 23,950	$ 690,705
Right of Way	$ 40,343	$ 118	$ 98	$ 44	$ -	$ 55	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 315	$ 120	$ 200	$ 40,978
Engineering / Permitting / Indirects	$ 290,391	$ 4,039	$ 1,995	$ 1,632	$ 2,808	$ 2,232	$ 1,430	$ 1,105	$ 2,090	$ 1,636	$ 1,114	$ 971	$ 1,247	$ 22,298	$ 18,462	$ 20,750	$ 351,901
Escalation (Future Spend)	$ -	$ -	$ -	$ -	$ -	$ 125	$ 125	$ 125	$ 125	$ 125	$ 125	$ 125	$ 125	$ 1,001	$ 11,843	$ 2,473	$ 15,317
AFUDC	$ 198	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 10	$ 10	$ 5	$ 223
Contingency	$ 140,760	$ -	$ -	$ -	$ -	$ 444	$ 444	$ 444	$ 444	$ 444	$ 444	$ 444	$ 444	$ 3,554	$ 22,471	$ 18,490	$ 185,275
Total	**$ 1,156,161**	**$ 11,145**	**$ 16,954**	**$ 17,592**	**$ 15,166**	**$ 13,194**	**$ 11,680**	**$ 8,341**	**$ 9,524**	**$ 5,951**	**$ 4,933**	**$ 3,869**	**$ 3,396**	**$ 121,745**	**$ 143,342**	**$ 77,101**	**$ 1,498,348**

APPENDIX B – MPRP COSTS THROUGH 2013 FOR CWIP FILING

CMP MPRP Costs For 2014 CWIP Filing

	PTF	Non-PTF	Transmission Totals
A. 2013 Ending Balances			
Plant In-Service	$ 578,283,402	$ 26,472,757	$ 604,756,159
CWIP	$ 499,181,255	$ 5,034,097	$ 504,215,352
Retirement and Salvage Cost			
Total through 2013	**$ 1,077,464,657**	**$ 31,506,854**	**$ 1,108,971,511**
B. 2014 Additions or Adjustments			
Plant In-Service	$ 278,208,797	$ 2,423,000	$ 280,631,797
CWIP	$ (176,130,613)	$ 1,375,816	$ (174,754,797)
Retirement and Salvage Cost			
Total Projected in 2014	**$ 102,078,184**	**$ 3,798,816**	**$ 105,877,000**
C. Projected 2014 Ending Balances			
Plant In-Service	$ 856,492,199	$ 28,895,757	$ 885,387,956
CWIP	$ 323,050,642	$ 6,409,913	$ 329,460,555
Retirement and Salvage Cost	$ -	$ -	
Total Projected through 2014	**$ 1,179,542,841**	**$ 35,305,670**	**$ 1,214,848,511**