

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

PUBLIC UTILITIES COMMISSION
Investigation of Stranded Costs, Transmission
and Distribution Utility Revenue Requirements,
and Rate Design of Bangor Hydro-Electric
Company - Phase II

REVISED STIPULATION

Docket No. 97-596

The purpose of this Stipulation is to resolve all outstanding issues in this proceeding. The undersigned parties hereby agree to the following:

1. November 24th Order. This Stipulation is intended to address the Phase II issues that arose out of the Commission's Order in this case dated November 24, 1999. Unless otherwise indicated, this Stipulation is based upon and consistent with the findings and conclusions contained in the November 24th Order.

2. Revenue Requirement. The jurisdictional revenue requirement for BHE for the rate year commencing March 1, 2000 is \$103,178,972, as shown on Attachment 1. Schedule P-6-1 showing BHE's electric rate revenues for the rate effective year is also attached. Rate schedules shall be promptly filed with the PUC for final approval which reflect this total revenue requirement.

3. Inter-class Rate Design. Rates for service commencing on or after March 1, 2000 shall be based on the top-down methodology as explained in the November 24th Order. The percentage reduction for each rate class is shown on Attachment 2. For the purpose of implementing the top-down methodology, the following generation rates were used: \$0.041/kWh for the D-5 class; \$0.043/kWh for the D-4 class, and \$0.045/kWh for all other classes. Finally, to offset the increase from \$0.045 per kWh to \$0.049 per kWh in the standard offer rates for the D-1 and D-2 classes established under Docket No. 99-111, the revenues allocated to those two classes were reduced by an offsetting amount: \$1,033,882 for D-1 and \$241,876 for D-2.

4. Intra-class Rate Design. There shall be no change in customer charges or demand charges. The reduction for each class shall be achieved by reducing current bundled energy charges. For those classes with time-of-use or seasonally differentiated energy charges, each energy charge for each time period shall be reduced "across-the-board" by the same percentage. For the D-3 class, current bundled energy charges shall be reduced by the same percentage as used to reduce current bundled energy charges for the D-4 class. The rates are set forth in

Attachment 2A. The parties agree that the Company may restrict the D-1 and D-2 customer classes to those customers with applicable demands of below 500 kW unless such customers were members of said classes on or before February 18, 2000.

5. Amortization. The amortization schedule of certain accounts will take place as set forth in Attachment 3.

A. Amortization of Ultrapower QF Buyout. The existing straight line amortization of the Ultrapower QF Buyout equal to \$1,420,038.32 per month that continues through June 30, 2005 shall be modified to provide an amortization of \$1,420,038.32 per month through December 31, 2004 and an amortization of \$710,019.16 per month for the period January 1, 2005 through December 31, 2005. The unamortized balance shall continue to receive rate base treatment.

B. Amortization of Gain on Sale of Generating Assets. The gain on the sale of generating assets shall be amortized from March 1, 2000 through December 31, 2005 on an uneven basis as shown on Attachment 4. Since the accelerated use of the available value during the first two years increases BHE's revenue requirement in future years, such increases may be mitigated by altering the amortization schedule of BHE's other regulatory assets, including the Ultrapower amortization described in paragraph A of this section. The amount of such alteration, if any, will be determined in a future rate proceeding, including a proceeding pursuant to 35-A M.R.S.A. Section 3208(6). In the event the Ultrapower amortization schedule is adjusted in such future ratemaking proceeding, the so-called "Ultrapower Adjustment" adopted by the Commission in its Order dated May 9, 1995 in Docket No. 95-109 shall be calculated using the amortization schedule described in subparagraph A above, thereby holding BHE's investors harmless from any incremental unamortized balances resulting from the extension of the Ultrapower amortization schedule. As a result of the reduction to the T&D rates of the D-1 and D-2 rate classes in this proceeding that is intended to offset the increased standard offer rate for these classes established by the Commission in Docket No. 99-111, the parties agree that the relative rates of these classes may be modified in a future rate proceeding to reflect a reduced amount of available value to these classes in order to ensure that all classes receive a reasonable share of such available value

6. Accounting Orders. The parties agree that certain costs and revenues cannot be determined with reasonable certainty at this time. In order to assure that ratepayers receive the full benefits of future revenues and pay the full cost of providing service, the Company is hereby authorized to defer, to the extent there is no finding of imprudence, the following revenues and expenses, including carrying costs, for recovery in a future rate proceeding, including, any proceeding pursuant to 35-A M.R.S.A. § 3208(6) for those revenues and expenses which qualify as stranded cost items, to the extent such amounts differ from the estimated amounts of the corresponding specific revenue and expense items reflected in the total revenue requirements in Section 2.

- A. Interim Savings from the Asset Sale. Actual replacement power costs through February 29, 2000 included in the calculation of the Interim Savings from the Asset Sale, including any retroactive modifications to charges such as those proposed in the protest filed at the FERC on February 1, 2000 in Dighton Power Associates Limited Partnerships, et al. v. ISO New England, Docket No. EL00-40-000.
- B. Chapter 380 DSM Expenses. DSM assessments and expenses incurred as a result of the State Planning Office recommendation pursuant to 5 M.R.S.A. § 3305-B. The undersigned agree that what is currently assumed in BHE's jurisdictional revenue requirement is the minimum amount permitted under the foregoing statute, which is 0.5% of BHE's T&D revenue requirement.
- C. Standard Offer. Any over- or under-collection of costs related to the provision of standard offer service according to the terms of Docket No. 99-111.
- D. Graham Station Units 4 and 5. The actual costs and revenues associated with the pending sale of Graham Station Units 4 and 5. BHE's current revenue requirement currently assumes that no revenues will be received by BHE during the rate effect year.
- E. PERC Warrants. The costs associated with the exercise of rights under the PERC stock warrants made after January 20, 2000.
- F. Restructuring. The actual extraordinary expenses that were incurred in preparing for restructuring as authorized in the Commission's September 8, 1999 Accounting Order in this proceeding. As reflected in Exhibits B/D-SC-6-9 and B/D-SC-6-13 (attached hereto as Attachment 5), in calculating the jurisdictional revenue requirement for BHE described in Paragraph 2 above, the parties assumed total deferred costs of \$244,137 related to the special Consumer Education Assessment and \$1,318,465 related to Deferred Cost Associated with System and Other Changes Related to the Advent of Retail Competition and amortized those costs over three (3) years.
- G. Unbundled Special Rate Agreements. As indicated in the Commission's November 24, 1999 Order in this proceeding, BHE has a number of special rate contracts with customers which extend beyond March 1, 2000. For those contracts which call for bundled service ("category 1

contracts”), the parties understand that such contracts must be renegotiated pursuant to 35-A M.R.S.A. § 3204(10) in order to determine an unbundled price for transmission and distribution service.

There is also a second group of contracts, which are those bundled contracts included in the Company’s filing which expire prior to March 1, 2000 (“category 2 contracts”). As described in the November 24 Order in this proceeding, BHE must determine going forward whether to continue offering these customers discounts for T&D service.

(i) In the November 24, 1999 Order, the Commission established February 1, 2000 as the deadline by which it would determine the general reasonableness of contractual T&D rates negotiated pursuant to such contracts. For category 2 contracts, this was to include a preliminary review of each customer’s competitive options according to the terms set forth in the Order. Regarding category 1 contracts, the Commission would focus its review on the customer’s due diligence in procuring competitive generation services. However, because of delays in the procurement activities of such customers, partly as a result of the Commission’s decision in Docket No. 99-111 to reject standard offer bids for BHE’s territory and assign BHE the role of default standard offer provider, BHE has been unable to meet the February 1, 2000 deadline. Consequently, the undersigned agree that the summary review contemplated above will not need to occur.

(ii) Currently, the parties have assumed that BHE will receive \$10,058,946 in non-core T&D revenues related to its category 1 and category 2 contracts. For those contracts for which T&D revenues have not yet been determined, the revenues incorporated within BHE’s revenue requirement in Section 3 were determined in part by (1) backing out from current rates each customer’s expected generation service costs as shown on CW-PH2-3, attached hereto with Attachment 3, and (2) by making certain estimates regarding the unbundled T&D rate for those contracts whose rate varies according to certain indices or other currently unknown measures.

(iii) The undersigned further agree that any difference between estimated T&D rates set forth in paragraph (ii), and those rates actually charged by BHE after March 1, 2000 pursuant to either category 1 or 2 contracts, including carrying costs, will be deferred for future recovery as part of BHE's jurisdictional revenue requirement.

H. Gain on the Sale of Gas Pipeline Easements. The revenues received by BHE from the sale of natural gas pipeline easements shall be deferred to the extent similar revenue received by CMP has been deferred for ratemaking purposes.

PROCEDURAL MATTERS

7. The parties to the Stipulation hereby waive any rights that they have under 5 M.R.S.A. §9062(4) and Section 742 of the Commission Rules of Practice and Procedure to the extent necessary to permit the Advisory Staff to discuss this Stipulation and the resolution of this case with the Commissioners at the Commission's scheduled deliberations, without providing to the parties an Examiners Report or the opportunity to file Exceptions.

8. The record on which the parties enter into this Stipulation and on which the Commission may base its determination whether to accept and approve this Stipulation shall consist of all prefiled testimony and exhibits, and all documents and information provided in responses to written and oral data requests and any other material furnished by the Advisory Staff to the Commission, either orally or in writing, to assist the Commission in deciding whether to accept and approve this Stipulation.

9. This Stipulation shall not be considered legal precedent, nor shall it preclude a party from raising any issues in any future proceeding or investigation on similar matters subsequent to this proceeding.

10. This Stipulation represents the full agreement between the parties to the Stipulation and rejection of any part of this Stipulation constitutes a rejection of the whole.

11. If not accepted by the Commission in accordance with the provisions hereof, this Stipulation shall not prejudice the positions taken by any party before the Commission in this proceeding and shall not be admissible evidence therein or in any other proceeding before the Commission.

Respectfully submitted this day of February, 2000

OFFICE OF THE PUBLIC ADVOCATE

By: _____

INDUSTRIAL ENERGY CONSUMERS GROUP

By: _____

BANGOR HYDRO-ELECTRIC COMPANY

By: _____

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SUMMARY OF REVENUE REQUIREMENT

T&D Revenue Requirement	\$63,295,509
Stranded Cost Revenue Requirement	\$39,590,652
Attrition Adjustment	<u>\$300,537</u>
Final Revenue Requirement	\$103,186,698

**RATE EFFECTIVE YEAR
ELECTRIC RATE REVENUES**

LINE #	<u>Customer Rate Class</u>	Rate Effective Year <u>MWh Delivered</u>	Test Year <u>Rate</u>	Adjusted Test Year <u>Rate Change</u>
1	<u>CORE REVENUES</u>			
2	Residential Service	428,866	143.16	-33.28%
3	Residential Water Heat ('97 level)	2,641	140.35	-33.94%
4	Residential Employee ('97 level)	136	126.65	-37.62%
5	Residential Low Income	36,069	115.85	-41.12%
6	Residential TOU	12,004	130.02	-36.64%
7	Residential Heating Service, First Bloc note a	40,576	142.81	-33.36%
8	General Service	143,637	134.54	-35.41%
9	Commercial Water Heating ('97 level)	115	120.46	-39.55%
10	Commercial Space Heating, First Bloc note b	9,359	133.23	-36.24%
11	Com Space Heating (New),NonHeatin note c	1,133	122.15	-39.53%
12	Large Power Secondary D-1	263,041	114.06	-45.32%
13	Primary Power D-4 (includes EFP and QFs)	186,846	95.61	-47.61%
14	Large Power Primary D-2	64,736	103.78	-49.81%
15	Street Lighting	7,035	275.84	-17.27%
16	Muni Lighting (City of Bangor)	1,353	127.21	-37.45%
17	HoltraChem D-5	<u>21,734</u>	77.63	-55.91%
18	CORE ATTRITION YEAR MWh SALES & REVENUE	1,219,280		
19				
	<u>NON CORE REVENUES</u>			
20	Residential Heating Service, Tail Block	25,060	20.00	0.00
21	Residential Thermal Storage	298	2.01	0.00
22	Commercial Space Heating, Tail Block	5,278	20.00	0.00
23	Com Space Heating (New),Heating Season	3,978	35.00	0.00
24	Lincoln Pulp & Paper	97,200	14.70	0.00
25	HoltraChem F-2	216,318	13.00	0.00
26	Great Northern Paper	30,000	5.00	0.00
27	James River Timber	2,466	3.50	0.00
28	James River Old Town	132,534	26.14	0.00
29	Hannaford	18,351	39.59	0.00
30	Wholesale	3,258	24.22	0.00
31	Competitive D-1	16,584	45.03	0.00
32	Competitive D-2	2,795	44.16	0.00
35	Competitive D-4	<u>7,347</u>	40.33	0.00
36	Residential/Gen Service Electric Heat Delta Rev per Formula			
37	NON CORE ATTRITION YEAR MWh SALES & REVENUE	<u>561,468</u>		
38	Unbilled Revenue			
39	TOTAL ATTRITION YEAR MWh SALES & REVENUE	<u>1,780,749</u>		

Exhibit P-6-1
15-Feb-00

Adjusted Test Year <u>Rate/MWh</u>	Rate Effective Year <u>Revenues</u>
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95.52	\$40,964,897
92.71	244,819
79.01	10,762
68.21	2,460,222
82.38	988,903
95.17	3,861,548
86.90	12,481,952
72.82	8,343
84.94	795,020
73.86	83,656
62.37	16,405,095
50.09	9,358,437
52.09	3,371,910
228.20	1,605,477
79.57	107,694
34.22	<u>743,806</u>
	93,492,542

20.00	501,200
2.01	600
20.00	105,568
35.00	139,233
14.70	1,428,840
13.00	2,812,140
5.00	150,000
3.50	8,632
26.14	3,463,868
39.59	726,453
24.22	78,897
45.03	746,861
44.16	123,428
40.33	296,345
	<u>1,246,235</u>
	11,828,299

	<u>58,547</u>
	<u>\$105,379,388</u>

**BANGOR HYDRO-ELECTRIC COMPANY
NET OPERATING EXPENSE - STRANDED COST REVALUATION
DOCKET NO. 97-596
SUPPORT FOR ADJUSTMENT #12 TO
AMORTIZATION OF ASSET SALE**

L I N E		ANALYSIS OF 1998				
	<u>YEAR</u>	<u>BEG. BAL.</u>	<u>1998</u>	<u>1999</u>	<u>1&2/2000</u>	<u>3-12/2000</u>
1	Ultrapower QF Buyout	127,803,445.39	17,040,459.84	17,040,459.84	2,840,076.64	14,200,383.20
2	Beaverwood QF Buyout	18,079,478.66	2,901,981.00	2,761,356.00	507,101.00	3,238,630.00
3	Deferred FASB 106 Costs	434,924.77	70,528.32	70,528.32	11,754.72	58,773.60
4	Seabrook Litigation	371,810.12	25,065.84	25,065.84	4,177.64	20,888.20
5	Low Income Docket No. 97-116	(164,109.53)	(47,859.00)	(54,696.00)	(9,116.00)	(14,566.00)
6	RAR Adjustment	7,065.60	7,065.60	0.00	0.00	0.00
7	DSM NORESCO	1,021,606.00	340,536.00	340,536.00	56,756.00	78,828.00
8	DSM	683,704.32	586,032.96	97,671.36	0.00	0.00
9	Seabrook	30,367,928.65	1,699,050.00	1,699,050.00	283,175.00	1,415,875.00
10	PERC Restructuring	0.00	500,000.00	1,000,000.00	166,666.67	1,358,590.00
11	QF Buyout Bank Debt	892,723.32	357,089.28	357,089.28	59,514.88	119,029.88
12	Interest Rate Cap	317,033.80	126,813.60	126,813.60	21,135.60	42,271.00
13	Call Premiums	240,532.80	46,528.68	46,528.68	7,754.78	38,773.90
14	Low Income Docket No. 97-596	76,601.00	0.00	0.00	0.00	21,278.06
15	Deferred Ice Storm Costs	2,615,366.00	0.00	670,502.00	191,572.00	449,560.00
16	Maine Yankee Deferral	(1,021,759.00)	0.00	282,660.00	80,760.00	(378,430.00)
17	Deferred Restructuring Costs	2,447,871.00	0.00	0.00	0.00	679,960.00

18	Overaccumulated Depreciation	(3,561,483.00)	(1,483,951.00)	(1,780,742.00)	(296,790.00)	0.00
19	SUBTOTAL	180,612,739.90	22,169,341.12	22,682,822.92	3,924,538.93	21,329,844.84
20	Net Asset Sale Gain	(28,937,558.00)	0.00	0.00	0.00	(4,913,000.00)
21	NEW SUBTOTAL	151,675,181.90	22,169,341.12	22,682,822.92	3,924,538.93	16,416,844.84
22	Return on Balance -Excl. Ultrapower at 12.38%	N/A	2,608,763.20	2,792,415.29	455,610.23	2,275,348.34
23	Return on Ultrapower Balance at 7.49%		5,316,094.95	4,560,507.58	686,624.72	3,118,295.56
23	Revised Purchased Power	N/A	11,674,331.00	11,474,331.00	1,879,055.17	9,395,275.83
24	TOTAL	N/A	41,768,530.27	41,510,076.79	6,945,829.04	31,205,764.57

YEAR	<u>BEG. BAL.</u>	<u>1998</u>	<u>1999</u>	<u>1&2/2000</u>	<u>3-12/2000</u>
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25 *-1998 &1999 Known Purchase Power is assumed to be at Year 2000 Level.

26 **RATE BASE- ULTRAPOWER**

27	BEGINNING BALANCE		76,019,875.39	65,931,925.55	55,843,977.71	54,162,653.07
28	ENDING BALANCE		65,931,925.55	55,843,977.71	54,162,653.07	45,756,029.87
29	AVG UNAMORTIZED BALANCE		70,975,900.47	60,887,951.63	55,003,315.39	49,959,341.47
30	<u>RATE BASE- Excluding Ultrapower **</u>					
31	BEGINNING BALANCE		20,475,189.15	21,669,612.18	23,442,105.00	22,946,800.51
32	ENDING BALANCE		21,669,612.18	23,442,105.00	22,946,800.51	21,602,191.66
33	AVG UNAMORTIZED BALANCE		21,072,400.66	22,555,858.59	23,194,452.75	22,274,496.09

34 Grossed Up COC, Excluding Ultrapower 12.38%

35 **PURCHASED POWER:**

36	BASE CASE PURCHASE POWER	N/A	11,674,331.00	11,674,331.00	1,945,721.83	9,728,609.17
37	PPLG HQ SUPPORT PAYMNTS	N/A	0.00	(200,000.00)	(66,666.67)	(333,333.33)
38	REVISED PURCHASE POWER	N/A	11,674,331.00	11,474,331.00	1,879,055.17	9,395,275.83

	BEG. BAL.	1998	1999	1&2/2000	3-12/2000	
39	<u>Def'd Income Taxes- Excluding Ultrapower</u>					
40	BASE CASE DEFERRED IT	(14,758,854.09)	(16,139,780.78)	(13,272,565.88)	(12,987,276.08)	(10,937,509.06)
41	ASSET SALE DEFERRED IT *	11,362,306.73	11,362,306.73	11,362,306.73	11,362,306.73	9,434,392.49
42	REVISED DEFERRED IT	<u>(3,396,547.36)</u>	<u>(4,777,474.05)</u>	<u>(1,910,259.15)</u>	<u>(1,624,969.35)</u>	<u>(1,503,116.57)</u>
43	<u>Def'd Income Taxes-Ultrapower</u>					
44	BASE CASE DEFERRED IT	<u>(51,783,570.00)</u>	<u>(44,831,060.00)</u>	<u>(37,878,548.00)</u>	<u>(36,719,796.00)</u>	<u>(30,926,036.00)</u>
	<u>BEG. BAL.</u>	<u>1998</u>	<u>1999</u>	<u>1&2/2000</u>	<u>3-12/2000</u>	
43	<u>PERC Rate Base Changes</u>					
44	BEGINNING BALANCE		0.00	7,704,231.00	12,251,872.00	12,555,740.00
45	ENDING BALANCE		7,704,231.00	12,251,872.00	12,555,740.00	13,305,740.00
46	AVG UNAMORTIZED BALANCE		3,852,115.50	9,978,051.50	12,403,806.00	12,930,740.00

* - Asset Sale Gain Deferred Income Taxes Calculated Excluding the Impact of the Equity Component of Carrying Costs on the Def. Asset Sale Gain, as I

** - The RATE BASE Excluding Ultrapower includes the changes in the PERC restructuring cost deferred balance as a result of the payments associated v
and the value of the actual warrants exercised in 1999.

COMPANY
VENUE REQUIREMENT

BLACK/DAWES
 EXHIBIT B/D-SC-6-12B
 Adjustment #12 NOE
 15-Feb-00
Phase II Revised

NO NOE
LOSS GAIN

KNOWN AND MEASURABLE CHANGES
THRU 2006 - ASSET SALE CASE

<u>1&2/2001</u>	<u>3-12/2001</u>	<u>1&2/2002</u>	<u>3/12/02</u>	<u>2003</u>	<u>2004</u>	<u>1-6/2005</u>	<u>7-12/2005</u>
2,840,076.64	14,200,383.20	2,840,076.64	14,200,383.20	17,040,459.84	17,040,459.84	4,260,113.26	4,260,113.25
647,726.00	3,238,630.00	647,726.00	3,238,630.00	897,698.66	0.00	0.00	0.00
11,754.72	58,773.60	11,754.72	58,773.60	70,528.32	11,754.85	0.00	0.00
4,177.64	20,888.20	4,177.64	20,888.20	25,065.84	25,065.84	12,532.92	12,532.92
(2,913.00)	(14,566.00)	(2,913.00)	(14,566.00)	(2,913.53)	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15,766.00	78,828.00	15,766.00	78,828.00	15,763.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
283,175.00	1,415,875.00	283,175.00	1,415,875.00	1,699,050.00	1,699,050.00	849,525.00	849,525.00
271,718.00	1,358,590.00	271,718.00	1,358,590.00	1,630,308.00	1,630,308.00	815,154.00	815,154.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7,754.78	38,773.90	7,754.78	38,773.90	7,888.86	0.00	0.00	0.00
4,255.61	21,278.06	4,255.61	21,278.06	4,255.61	0.00	0.00	0.00
89,912.00	449,560.00	89,912.00	449,560.00	224,780.00	0.00	0.00	0.00
(75,686.00)	(378,430.00)	(75,686.00)	(113,529.00)	0.00	0.00	0.00	0.00
135,992.00	679,960.00	135,992.00	679,960.00	136,007.00	0.00	0.00	0.00

0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4,233,709.39	21,168,543.96	4,233,709.39	21,433,444.96	21,748,891.60	20,406,638.53	5,937,325.18	5,937,325.17
(739,600.00)	(3,345,160.00)	(907,000.00)	(2,637,500.00)	(9,030,600.00)	(8,164,200.00)	336,000.00	463,502.00
3,494,109.39	17,823,383.96	3,326,709.39	18,795,944.96	12,718,291.60	12,242,438.53	6,273,325.18	6,400,827.17
421,578.22	2,070,187.98	374,888.79	1,776,050.32	2,059,255.76	2,315,099.56	1,144,571.46	1,038,182.33
560,693.50	2,488,639.49	434,762.29	1,858,983.41	1,538,158.40	782,571.11	180,964.99	159,541.24
1,764,785.17	8,823,925.83	2,104,837.50	10,524,187.50	23,230,959.00	24,206,153.00	12,174,556.50	12,174,556.50
6,241,166.28	31,206,137.26	6,241,197.97	32,955,166.18	39,546,664.77	39,546,262.21	19,773,418.13	19,773,107.24

<u>1&2/2001</u>	<u>3-12/2001</u>	<u>1&2/2002</u>	<u>3/12/02</u>	<u>2003</u>	<u>2004</u>	<u>1-6/2005</u>	<u>7-12/2005</u>
37,446,930.85	37,447,303.54						
45,756,029.87	44,074,705.23	35,668,082.03	33,986,757.39	25,580,134.19	15,492,186.35	5,404,238.51	4,260,113.25
44,074,705.23	35,668,082.03	33,986,757.39	25,580,134.19	15,492,186.35	5,404,238.51	4,260,113.25	(0.00)
44,915,367.55	39,871,393.63	34,827,419.71	29,783,445.79	20,536,160.27	10,448,212.43	4,832,175.88	2,130,056.62
21,602,191.66	21,321,674.11	19,210,488.27	18,959,595.74	15,813,652.16	17,453,807.59	19,946,831.58	18,145,659.25
21,321,674.11	19,210,488.27	18,959,595.74	15,813,652.16	17,453,807.59	19,946,831.58	18,145,659.25	16,406,094.15
21,461,932.88	20,266,081.19	19,085,042.01	17,386,623.95	16,633,729.88	18,700,319.58	19,046,245.42	17,275,876.70
1,831,451.83	9,157,259.17	2,171,504.17	10,857,520.83	23,630,959.00	24,606,153.00	12,374,556.50	12,374,556.50
(66,666.67)	(333,333.33)	(66,666.67)	(333,333.33)	(400,000.00)	(400,000.00)	(200,000.00)	(200,000.00)
1,764,785.17	8,823,925.83	2,104,837.50	10,524,187.50	23,230,959.00	24,206,153.00	12,174,556.50	12,174,556.50

1&2/2001	3-12/2001	<u>1&2/2002</u>	<u>03-12/2002</u>	2003	2004	1-6/2005	7-12/2005
(10,527,555.01)	(8,477,504.57)	(8,106,390.40)	(6,004,082.46)	(5,093,518.18)	(4,669,438.18)	(4,457,398.59)	(4,245,358.59)
9,147,953.64	7,859,718.12	7,474,344.17	6,321,654.41	2,729,077.32	0.00	0.00	189,108.82
(1,379,601.37)	(617,786.45)	(632,046.23)	317,571.95	(2,364,440.86)	(4,669,438.18)	(4,457,398.59)	(4,056,249.78)
(29,767,284.00)	(23,973,524.00)	(22,814,772.00)	(17,021,012.00)	(10,068,500.00)	(3,115,988.00)	0.00	0.00

<u>1&2/2001</u>	<u>3-12/2001</u>	<u>1&2/2002</u>	<u>03-12/2002</u>	<u>2003</u>	<u>2004</u>	<u>1-6/2005</u>	<u>7-12/2005</u>
13,305,740.00	13,555,740.00	14,305,740.00	14,555,740.00	15,055,740.00	15,055,740.00	15,055,740.00	15,055,740.00
13,555,740.00	14,305,740.00	14,555,740.00	15,055,740.00	15,055,740.00	15,055,740.00	15,055,740.00	15,055,740.00
13,430,740.00	13,930,740.00	14,430,740.00	14,805,740.00	15,055,740.00	15,055,740.00	15,055,740.00	15,055,740.00

**Deferred Taxes are not Provided for on AFUDC Equity.
with the restructuring**

0.00
3,354,423.84
N/A
3,354,423.84
1,849,686.17
(0.00)
21,589,013.00
26,793,123.01
<u>2006</u>
(0.00)
(0.00)
(0.00)
16,406,094.15
13,475,750.31
14,940,922.23
21,989,013.00
(400,000.00)
21,589,013.00

2006

(3,821,278.59)

189,108.82

(3,632,169.78)

0.00

2006

15,055,740.00

15,055,740.00

15,055,740.00

**EXHIBIT CW-PH2-9
BANGOR HYDRO-ELECTRIC COMPANY
DOCKET 97-596
ENERGY REVENUE UNBUNDLING
BHE RATE DESIGN SUMMARY**

Classes	Adjusted Test Year Core Energy Sales	Current Bundled Revenues	Current Customer Charge Revenues	Current Demand Revenues	Current Bundled Energy Revenues	Proposed Class Revenue Decrease	Unbundled Energy Revenues	% of Unbundled Energy Rev to Bundled Energy Rev
Residential Service	420,334,419	\$60,994,009	\$0	\$0	\$60,994,009	\$20,650,455	\$40,343,553	66.1%
Residential Water Heat	2,640,724	\$375,670	\$0	\$0	\$375,670	\$129,735	\$245,935	na
Residential Employee	136,208	\$17,486	\$0	\$0	\$17,486	\$6,692	\$10,794	61.7%
Residential Low Income	35,657,266	\$4,186,986	\$0	\$0	\$4,186,986	\$1,751,793	\$2,435,194	58.2%
Residential TOU	12,356,205	\$1,628,446	\$90,858	\$0	\$1,537,588	\$607,043	\$930,544	60.5%
Residential Heating	39,853,713	\$5,768,971	\$0	\$0	\$5,768,971	\$1,957,958	\$3,811,013	na
Total Residential	510,978,535	\$72,971,568	\$90,858	\$0	\$72,880,710	\$25,103,677	\$47,777,033	65.6%
General Service	142,988,624	\$19,499,342	\$2,028,356	\$0	\$17,470,985	\$7,024,836	\$10,446,149	59.8%
Commercial Water Heating	114,572	\$13,989	\$0	\$0	\$13,989	\$5,629	\$8,360	na
Commercial Space Heating	8,471,389	\$1,128,670	\$97,128	\$0	\$1,031,542	\$416,188	\$615,354	na
Commercial Space Htg New	1,068,986	\$130,577	\$0	\$0	\$130,577	\$52,518	\$78,059	na
Total Commercial	152,643,570	\$20,772,577	\$2,125,484	\$0	\$18,647,093	\$7,499,170	\$11,147,923	59.8%
Large Power Secondary D-1	258,470,583	\$29,885,481	\$532,776	\$5,451,685	\$23,901,020	\$13,732,189	\$10,168,831	42.5%
Primary Power D-4	186,186,172	\$18,045,440	\$15,168	\$3,192,450	\$14,837,822	\$8,740,536	\$6,097,287	41.1%
Cur High Tension D-5	21,696,500	\$1,707,152	\$0	\$0	\$1,707,152	\$971,171	\$735,981	43.1%
Large Power Primary D-2	60,468,884	\$6,360,552	\$38,714	\$1,034,012	\$5,287,826	\$3,212,629	\$2,075,197	39.2%
Total Power	526,822,139	\$55,998,625	\$586,658	\$9,678,147	\$45,733,820	\$26,656,525	\$19,077,296	41.7%
Street & Area Lighting	7,473,735	\$2,089,613	\$0	\$0	\$2,089,613	\$367,174	\$1,722,438	82.4%
Street Light Energy	1,353,463	\$174,517	\$0	\$0	\$174,517	\$66,494	\$108,024	61.9%
Total Lighting	8,827,198	\$2,264,130	\$0	\$0	\$2,264,130	\$433,668	\$1,830,462	80.8%
Total	1,199,271,442	\$152,006,901	\$2,803,000	\$9,678,147	\$139,525,753	\$59,693,040	\$79,832,714	57.2%

LARGE POWER SECONDARY AND PRIMARY BILLING DEMAND and CUSTOMER CHARGE SUMMARY

	Unscaled Winter Demand	Unscaled non-Winter Demand	Test Year Revenue based Scaling factor	Scaled Winter Demand	Scaled non-Winter Demand	Winter Demand Rate	non-Winter Demand Rate	Annual Demand Revenue	Test Year Number of Customers	Current Monthly Customer Charges	Annual Customer Revenues
Large Power Secondary D-1	266,766	629,812	1.02764789182	274,141	647,225	\$6.50	\$5.67	\$5,451,685	1,124	\$39.50	\$532,776
Large Power Primary D-2	55,528	126,847	1.01963286033	56,618	129,338	\$6.11	\$5.32	\$1,034,012	98	\$32.92	\$38,714

LARGE POWER SECONDARY AND PRIMARY BILLED ENERGY SUMMARY and UNBUNDLED ENERGY RATE DETERINATION

	Unscaled Winter Energy	Unscaled non-Winter Energy	Test Year Revenue based Scaling factor	Scaled Winter Energy	Scaled non-Winter Energy	% Unbundled Energy Rev to Bundled Energy Rev	current winter energy rate	current non-winter energy rate	proposed winter energy rate	proposed non-winter energy rate
Large Power Secondary D-1	79,404,340	173,273,458	1.02764789182	81,599,703	178,064,104	42.5%	\$0.10079	\$0.08785	\$0.04288	\$0.03738
Large Power Primary D-2	19,011,653	40,243,617	1.01963286033	19,384,906	41,033,714	39.2%	\$0.09580	\$0.08356	\$0.03760	\$0.03279

PRIMARY POWER TOU BILLING DEMAND SUMMARY

	Unscaled Winter Peak Billed Demand	Unscaled Winter Shoulder Billed Demand	Unscaled non-Winter Peak Billed Demand	Unscaled non-Winter Shoulder Billed Demand	Scaled Winter Peak Billed Demand	Scaled Winter Shoulder Billed Demand	Scaled non-Winter Peak Billed Demand	Scaled non-Winter Shoulder Billed Demand	Winter Peak Demand Rate	Winter Shoulder Demand Rate	non-Winter Peak Demand Rate	non-Winter Shoulder Demand Rate	Annual Demand Revenues
primary voltage customers	48,574	46,191	225,324	214,309	53,069	50,466	246,176	234,142	\$8.45	\$3.97	\$4.13	\$1.30	\$1,969,874
high voltage customers	40,575	29,172	132,040	114,692	44,330	31,872	144,259	125,306	\$8.20	\$3.85	\$4.01	\$1.26	\$1,222,576
total all customers	89,149	75,363	357,364	329,001	97,399	82,337	390,435	359,448					\$3,192,450
venue based scaling factor =	1.09254239232744												

PRIMARY POWER TOU CUSTOMER CHARGE SUMMARY

test year number of customers =	32
current monthly customer charge =	\$39.50
annual customer charge revenues =	\$15,168

POWER POWER TOU BILLED ENERGY SUMMARY

	Unscaled Winter Peak Billed Energy	Unscaled Winter Shoulder Billed Energy	Unscaled Winter Offpeak Billed Energy	Unscaled non-Winter Peak Billed Energy	Unscaled non-Winter Shoulder Billed Energy	Unscaled non-Winter Offpeak Billed Energy	Scaled Winter Peak Billed Energy	Scaled Winter Shoulder Billed Energy	Scaled Winter Offpeak Billed Energy	Scaled non-Winter Peak Billed Energy	Scaled non-Winter Shoulder Billed Energy	Scaled non-Winter Offpeak Billed Energy
primary voltage customers	12,454,320	12,890,390	17,581,943	27,008,790	26,460,190	35,800,647	13,606,873	14,083,298	19,209,018	29,508,248	28,908,879	39,113,725
high voltage customers	2,605,600	3,001,600	4,293,350	9,033,425	9,816,625	14,757,725	2,846,728	3,279,375	4,690,667	9,869,400	10,725,079	16,123,440
total all customers	15,059,920	15,891,990	21,875,293	36,042,215	36,276,815	50,558,372	16,453,601	17,362,673	23,899,685	39,377,648	39,633,958	55,237,165

POWER POWER TOU UNBUNDLED ENERGY RATE DETERINATION

	Current Winter Peak Energy Price	Current Winter Shoulder Energy Price	Current Winter Offpeak Energy Price	Current non-Winter Peak Energy Price	Current non-Winter Shoulder Energy Price	Current non-Winter Offpeak Energy Price	Proposed Winter Peak Energy Price	Proposed Winter Shoulder Energy Price	Proposed Winter Offpeak Energy Price	Proposed non-Winter Peak Energy Price	Proposed non-Winter Shoulder Energy Price	Proposed non-Winter Offpeak Energy Price
primary voltage customers	\$0.09580	\$0.08355	\$0.06871	\$0.08346	\$0.08267	\$0.06719	\$0.03937	\$0.03433	\$0.02823	\$0.03430	\$0.03397	\$0.02761
high voltage customers	\$0.09293	\$0.08104	\$0.06665	\$0.08096	\$0.08019	\$0.06517	\$0.03819	\$0.03330	\$0.02738	\$0.03327	\$0.03295	\$0.02678
to bundled energy price ratio =	41.1%											

GENERAL SERVICE and COMMERCIAL SPACE HEATING RATE CUSTOMER CHARGE SUMMAR

	general service	commercial space heating
test year number of customers =	12,530	600
current monthly customer charge =	\$13.49	\$13.49
annual customer charge revenues=	\$2,028,356	\$97,128

GENERAL SERVICE, COMMERCIAL WATER HEATING
and both COMMERCIAL SPACE HEATING CLASSES
ENERGY RATE DETERMINATION

	% of Unbundled Energy Rev to Bundled Energy Rev	current energy rate	proposed energy rate
General Service	59.8%	\$0.12215	\$0.07304
Commercial Water Heating ¹	NA	\$0.12215	\$0.07304
Commercial Space Heating - head block only ¹	NA	\$0.12215	\$0.07304
Commercial Space Htg New - head block only ¹	NA	\$0.12215	\$0.07304

HOLTRACHEM FIRM UNBUNDLED ENERGY RATE DETERINATION

Unscaled Winter Energy	Unscaled non-Winter Energy	Test Year Revenue based Scaling factor	Scaled Winter Energy	Scaled non-Winter Energy	% Unbundled Energy Rev to Bundled Energy Rev	current winter energy rate	current non-winter energy rate	proposed winter energy rate	proposed non-winter energy rate	unbundled energy (total) revenues
7,145,000	14,551,500	1.000342734681	7,147,449	14,556,487	43.1%	\$0.08372	\$0.07617	\$0.03609	\$0.03284	\$735,981

STREET AND AREA LIGHTING AND MUNICIPAL LIGHTING CLASSES ENERGY RATE and MONTHLY CHARGE DETERMINATION

	Average kWh per Month	Current Street and Area Lighting Total Monthly Charge	Current Periodic Service Street and Area Lighting Total Monthly Charge	Average Revenue per kWh Reduction ²	Street and Area Lighting Reduction of Total Monthly Charge ³	Proposed Street and Area Lighting Monthly Customer Charge	Proposed Periodic Service Street and Area Lighting Monthly Customer Charge	Current Municipal Street Lighting Rate	Proposed Municipal Street Lighting Rate
High-Pressure Sodium Vapor 4000 Lumens	20	\$8.29	\$14.33	\$0.04913	\$0.98	\$7.31	\$13.35	\$0.12910	\$0.07991
High-Pressure Sodium Vapor 5800 Lumens	29	\$10.67	\$17.94	\$0.04913	\$1.42	\$9.25	\$16.52	\$0.12910	\$0.07991
High-Pressure Sodium Vapor 9500 Lumens	41	\$14.81	\$23.75	\$0.04913	\$2.01	\$12.80	\$21.74	\$0.12910	\$0.07991
High-Pressure Sodium Vapor 16000 Lumens	60	\$19.50	\$29.94	\$0.04913	\$2.95	\$16.55	\$26.99	\$0.12910	\$0.07991
High-Pressure Sodium Vapor 27500 Lumens	111	\$29.31	\$43.32	\$0.04913	\$5.45	\$23.86	\$37.87	\$0.12910	\$0.07991
High-Pressure Sodium Vapor 50000 Lumens	171	\$48.42	\$70.18	\$0.04913	\$8.40	\$40.02	\$61.78	\$0.12910	\$0.07991
Mercury Vapor 3500 Lumens	45	\$10.46	\$17.61	\$0.04913	\$2.21	\$8.25	\$15.40	\$0.12910	\$0.07991
Mercury Vapor 7000 Lumens	80	\$16.56	\$26.40	\$0.04913	\$3.93	\$12.63	\$22.47	\$0.12910	\$0.07991
Mercury Vapor 11000 Lumens	105	\$22.00	\$33.29	\$0.04913	\$5.16	\$16.84	\$28.13	\$0.12910	\$0.07991
Mercury Vapor 20000 Lumens	167	\$30.16	\$43.44	\$0.04913	\$8.20	\$21.96	\$35.24	\$0.12910	\$0.07991
Mercury Vapor 56000 Lumens	402	\$71.58	\$97.63	\$0.04913	\$19.75	\$51.83	\$77.88	\$0.12910	\$0.07991
Incandescent 1000 Lumens	22	\$7.26	\$13.52	\$0.04913	\$1.08	\$6.18	\$12.44	\$0.12910	\$0.07991
Incandescent 2500 Lumens	50	\$12.13	\$18.42	\$0.04913	\$2.46	\$9.67	\$15.96	\$0.12910	\$0.07991
Incandescent 4000 Lumens	74	NA ¹	NA ¹		NA ¹	NA ¹	NA ¹	\$0.12910	\$0.07991
Incandescent 6000 Lumens	107	\$22.91	\$33.64	\$0.04913	\$5.26	\$17.65	\$28.38	\$0.12910	\$0.07991

Notes: ¹ the 4000 lumen incandescent lamp is not available to Street and Area Lighting customers

² average revenue per kWh reduction is equal to the ratio of the core class revenue reduction divided by the class adjusted test year energy sales, quantities are given in CW-PH2-5

³ the Street and Area Lighting total monthly charge reduction was calculated by multiplying the revenue reduction per kWh for the class as given in Exhibit CW-PH2-5 for each light, respectively

o bundled energy price ratio =

82.4%

o bundled energy price ratio =

61.9%

RESIDENTIAL LOW INCOME CLASSES ENERGY RATE and MINIMUM CHARGE DETERMINATION

	% of Unbundled Energy Rev to Bundled Energy Rev	current mininum charge	proposed mininum charge	current headblock energy rate	proposed headblock energy rate	current tailblock energy rate	proposed tailblock energy rate
Residential Low Income - 0% to 50% of FPG ¹	58.2%	\$14.22	\$9.41	na	na	\$0.07845	\$0.04563
Residential Low Income - 51% to 75% of FPG ¹	58.2%	\$14.22	\$9.41	\$0.14224	\$0.09408	\$0.09775	\$0.05685
Residential Low Income - 76% to 100% of FPG ¹	58.2%	\$14.22	\$9.41	\$0.14224	\$0.09408	\$0.10755	\$0.06255
Residential Low Income - 101% to 150% of FPG ¹	58.2%	\$14.22	\$9.41	\$0.14224	\$0.09408	\$0.10979	\$0.06385

Note: ¹ the minimum charge and the headblock rate were set equal to the Residential Service minimum charge and rate, respectively, as per the existing convention

RESIDENTIAL SERVICE, RESIDENTIAL WATER HEATING
and RESIDENTIAL SPACE HEATING
ENERGY RATE DETERMINATION

	% of Unbundled Energy Rev to Bundled Energy Rev	current energy rate	current minumum charge	proposed energy rate	proposed minumum charge
Residential Service	66.1%	\$0.14224	\$14.22	\$0.09408	\$9.41
Residential Water Heat ¹	NA	\$0.14224	\$0	\$0.09408	\$0
Residential Heating - head block only ¹	NA	\$0.14224	\$14.22	\$0.09408	\$9.41

Note: ¹ this rate was set equal to the Residential Service rate as per the existing convention

RESIDENTIAL TOU UNBUNDLED ENERGY RATE DETERMINATION

	Winter Peak Rate	Winter Shoulder Rate	Winter Offpeak Rate	non-Winter Peak Rate	non-Winter Shoulder Rate	non-Winter Offpeak Rate
current prices	\$0.17781	\$0.15698	\$0.09040	\$0.15278	\$0.13495	\$0.07788
proposed prices	\$0.10761	\$0.09500	\$0.05471	\$0.09246	\$0.08167	\$0.04713

o bundled energy price ratio = 60.5%

RESIDENTIAL TOU UNBUNDLED CUSTOMER CHARGE DETERMINATION

test year number of customers =	797
current monthly customer charge =	\$9.50
annual customer charge revenues =	\$90,858

RETIRED EMPLOYEE ENERGY RATE DETERMINATION

% of Unbundled Energy Rev to Bundled Energy Rev	current energy rate	current mininum charge	proposed energy rate	proposed mininum charge
61.7%	\$0.12717	\$12.72	\$0.07850	\$7.85

BANGOR HYDRO-ELECTRIC COMPANY
NET OPERATING EXPENSE - STRANDED COST REVENUE REQUIREMENT
DOCKET NO. 97-596
SUPPORT FOR ADJUSTMENT #12 TO NOE
AMORTIZATION OF ASSET SALE GAIN

BLACK/DAWES
EXHIBIT B/D-SC-6-12B
Adjustment #12 NOE
15-Feb-00
Phase II Revised

ANALYSIS OF KNOWN AND MEASURABLE CHANGES 1998 THRU 2006 - ASSET SALE CASE															
YEAR	BEG. BAL.	1998	1999	1&2/2000	3-12/2000	1&2/2001	3-12/2001	1&2/2002	3/12/02	2003	2004	1-6/2005	7-12/2005	2006	
1	Ultrapower QF Buyout	127,803,445.39	17,040,459.84	17,040,459.84	2,840,076.64	14,200,383.20	2,840,076.64	14,200,383.20	2,840,076.64	14,200,383.20	17,040,459.84	17,040,459.84	4,260,113.26	4,260,113.25	0.00
2	Beaverwood QF Buyout	18,079,478.66	2,901,981.00	2,761,356.00	507,101.00	3,238,630.00	647,726.00	3,238,630.00	647,726.00	3,238,630.00	2,901,981.00	2,901,981.00	0.00	0.00	0.00
3	Deferred PASB 106 Costs	434,924.77	70,528.32	70,528.32	11,754.72	11,754.72	11,754.72	11,754.72	11,754.72	11,754.72	70,528.32	70,528.32	0.00	0.00	0.00
4	Seabrook Litigation	371,810.12	25,065.84	25,065.84	4,177.64	20,888.20	4,177.64	20,888.20	4,177.64	20,888.20	25,065.84	25,065.84	12,532.92	12,532.92	25,065.84
5	Low Income Docket No. 97-116	(164,109.53)	(47,859.00)	(54,695.00)	(9,116.00)	(14,566.00)	(2,913.00)	(14,566.00)	(2,913.00)	(14,566.00)	(47,859.00)	(47,859.00)	0.00	0.00	0.00
6	RAR Adjustment	7,065.60	7,065.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7,065.60	7,065.60	0.00	0.00	0.00
7	DSM NORESCO	1,021,606.00	340,536.00	340,536.00	56,756.00	78,828.00	15,766.00	78,828.00	15,766.00	78,828.00	340,536.00	340,536.00	0.00	0.00	0.00
8	DSM	683,704.32	586,032.96	97,671.36	0.00	0.00	0.00	0.00	0.00	0.00	586,032.96	586,032.96	0.00	0.00	0.00
9	Seabrook	30,367,928.65	1,699,050.00	1,699,050.00	283,175.00	1,415,875.00	283,175.00	1,415,875.00	283,175.00	1,415,875.00	1,699,050.00	1,699,050.00	849,525.00	849,525.00	1,699,050.00
10	PERC Restructuring	0.00	500,000.00	1,000,000.00	166,666.67	1,358,590.00	271,718.00	1,358,590.00	271,718.00	1,358,590.00	1,630,308.00	1,630,308.00	815,154.00	815,154.00	1,630,308.00
11	QF Buyout Bank Debt	892,723.32	357,089.28	357,089.28	59,514.88	119,029.88	0.00	0.00	0.00	0.00	357,089.28	357,089.28	0.00	0.00	0.00
12	Interest Rate Cap	317,033.80	126,813.60	126,813.60	21,135.60	0.00	42,271.00	0.00	0.00	0.00	126,813.60	126,813.60	0.00	0.00	0.00
13	Call Premiums	240,532.80	46,528.68	46,528.68	7,754.78	38,773.90	7,754.78	38,773.90	7,754.78	38,773.90	46,528.68	46,528.68	0.00	0.00	0.00
14	Low Income Docket No. 97-596	76,601.00	0.00	0.00	0.00	21,278.06	4,255.61	21,278.06	4,255.61	21,278.06	76,601.00	76,601.00	0.00	0.00	0.00
15	Deferred Ice Storm Costs	2,615,366.00	0.00	670,502.00	191,572.00	449,560.00	89,912.00	449,560.00	89,912.00	449,560.00	2,615,366.00	2,615,366.00	0.00	0.00	0.00
16	Maine Yankee Deferral	(1,021,759.00)	0.00	282,660.00	80,760.00	(378,430.00)	(75,686.00)	(378,430.00)	(75,686.00)	(378,430.00)	(1,021,759.00)	(1,021,759.00)	0.00	0.00	0.00
17	Deferred Restructuring Costs	2,447,871.00	0.00	0.00	0.00	679,960.00	135,992.00	679,960.00	135,992.00	679,960.00	2,447,871.00	2,447,871.00	0.00	0.00	0.00
18	Overaccumulated Depreciation	(3,561,483.00)	(1,483,951.00)	(1,780,742.00)	(296,790.00)	0.00	0.00	0.00	0.00	0.00	(1,483,951.00)	(1,483,951.00)	0.00	0.00	0.00
19	SUBTOTAL	180,612,739.90	22,169,341.12	22,682,822.92	3,924,538.93	21,329,844.84	4,233,709.39	21,168,543.96	4,233,709.39	21,433,444.96	22,169,341.12	22,169,341.12	5,937,325.18	5,937,325.17	3,354,423.84
20	Net Asset Sale Gain	(28,937,558.00)	0.00	0.00	0.00	(739,600.00)	(739,600.00)	(3,345,160.00)	(907,000.00)	(2,637,500.00)	(28,937,558.00)	(28,937,558.00)	0.00	0.00	N/A
21	NEW SUBTOTAL	151,675,181.90	22,169,341.12	22,682,822.92	3,924,538.93	20,590,244.84	3,494,109.39	17,823,383.96	3,326,709.39	18,795,944.96	22,169,341.12	22,169,341.12	6,273,325.18	6,273,325.18	3,354,423.84
22	Return on Balance- Excl. Ultrapower at 12.38%	N/A	2,608,763.20	2,792,415.29	455,610.23	2,275,348.34	421,578.22	2,070,187.98	374,888.79	1,776,050.32	2,608,763.20	2,608,763.20	1,144,571.46	1,038,182.33	1,849,686.17
23	Return on Ultrapower Balance at 7.49%	N/A	5,316,094.95	4,560,507.58	686,634.72	3,118,295.56	560,693.50	2,488,639.49	434,762.29	1,858,983.41	5,316,094.95	5,316,094.95	782,571.11	159,541.24	(0.00)
23	Revised Purchased Power	N/A	11,674,331.00	11,474,331.00	1,879,055.17	9,395,275.83	1,764,785.17	8,823,925.83	2,104,837.50	10,524,187.50	11,674,331.00	11,674,331.00	24,206,153.00	12,174,556.50	21,589,013.00
24	TOTAL	N/A	41,768,530.27	41,510,076.79	6,945,829.04	31,205,764.57	6,241,166.28	31,206,137.26	6,241,197.97	32,955,166.18	41,768,530.27	41,768,530.27	19,773,418.13	19,773,107.24	26,793,123.01
	YEAR	BEG. BAL.	1998	1999	1&2/2000	3-12/2000	1&2/2001	3-12/2001	1&2/2002	3/12/02	2003	2004	1-6/2005	7-12/2005	2006
25	*-1998 & 1999 Known Purchase Power is assumed to be at Year 2000 Level.						37,446,930.85	37,447,303.54							
26	RATE BASE- ULTRAPOWER														
27	BEGINNING BALANCE		76,019,875.39	65,931,925.55	55,843,977.71	54,162,653.07	45,756,029.87	44,074,705.23	35,668,082.03	33,986,757.39	25,580,134.19	15,492,186.35	5,404,238.51	4,260,113.25	(0.00)
28	ENDING BALANCE		65,931,925.55	55,843,977.71	54,162,653.07	45,756,029.87	44,074,705.23	35,668,082.03	33,986,757.39	25,580,134.19	15,492,186.35	5,404,238.51	4,260,113.25	(0.00)	(0.00)
29	AVG UNAMORTIZED BALANCE		70,975,900.47	60,887,951.63	55,003,315.39	49,959,341.47	44,915,367.55	39,871,393.63	34,827,419.71	29,783,445.79	20,536,160.27	10,448,212.43	4,832,175.88	2,130,056.62	(0.00)
30	RATE BASE- Excluding Ultrapower **														
31	BEGINNING BALANCE		20,475,189.15	21,669,612.18	23,442,105.00	22,946,800.51	21,602,191.66	21,321,674.11	19,210,488.27	18,959,595.74	15,813,652.16	17,453,807.59	19,946,831.58	18,145,659.25	16,406,094.15
32	ENDING BALANCE		21,669,612.18	23,442,105.00	22,946,800.51	21,602,191.66	21,321,674.11	19,210,488.27	18,959,595.74	15,813,652.16	17,453,807.59	19,946,831.58	18,145,659.25	16,406,094.15	13,475,750.31
33	AVG UNAMORTIZED BALANCE		21,072,400.66	22,555,858.59	23,194,452.75	22,274,496.09	21,461,932.88	20,266,081.19	19,085,042.01	17,386,623.95	16,633,729.88	18,700,319.58	19,046,245.42	17,275,876.70	14,940,922.23
34	Grossed Up COC, Excluding Ultrapower	12.38%													
35	PURCHASED POWER:														
36	BASE CASE PURCHASE POWER	N/A	11,674,331.00	11,674,331.00	1,945,721.83	9,728,609.17	1,831,451.83	9,157,259.17	2,171,504.17	10,857,520.83	23,630,959.00	24,606,153.00	12,374,556.50	12,374,556.50	21,989,013.00
37	PPLG HQ SUPPORT PAYMNTS	N/A	0.00	(200,000.00)	(66,666.67)	(333,333.33)	(66,666.67)	(333,333.33)	(66,666.67)	(333,333.33)	(400,000.00)	(400,000.00)	(200,000.00)	(200,000.00)	(400,000.00)
38	REVISED PURCHASE POWER	N/A	11,674,331.00	11,474,331.00	1,879,055.17	9,395,275.83	1,764,785.17	8,823,925.83	2,104,837.50	10,524,187.50	23,230,959.00	24,206,153.00	12,174,556.50	12,174,556.50	21,589,013.00
	BEG. BAL.	1998	1999	1&2/2000	3-12/2000	1&2/2001	3-12/2001	1&2/2002	03-12/2002	2003	2004	1-6/2005	7-12/2005	2006	
39	Def'd Income Taxes- Excluding Ultrapower														
40	BASE CASE DEFERRED IT	(14,758,854.09)	(16,139,780.78)	(13,272,565.88)	(12,987,276.08)	(10,937,509.06)	(10,527,555.01)	(8,477,504.57)	(8,106,390.40)	(6,004,082.46)	(5,093,518.18)	(4,669,438.18)	(4,457,398.59)	(4,245,358.59)	(3,821,278.59)
41	ASSET SALE DEFERRED IT *	11,362,306.73	11,362,306.73	11,362,306.73	11,362,306.73	9,434,392.49	9,147,953.64	7,859,718.12	7,474,344.17	6,321,654.41	2,729,077.32	0.00	0.00	189,108.82	189,108.82
42	REVISED DEFERRED IT	(3,396,547.36)	(4,777,474.05)	(1,910,259.15)	(1,624,969.35)	(1,503,116.57)	(1,379,601.37)	(617,786.45)	(632,046.23)	(317,571.95)	(2,364,440.86)	(4,669,438.18)	(4,457,398.59)	(4,056,249.78)	(3,632,169.78)
43	Def'd Income Taxes-Ultrapower														
44	BASE CASE DEFERRED IT	(51,783,570.00)	(44,831,060.00)	(37,878,548.00)	(36,719,796.00)	(30,926,036.00)	(29,767,284.00)	(23,973,524.00)	(22,814,772.00)	(17,021,012.00)	(10,068,500.00)	(3,115,988.00)	0.00	0.00	0.00
	BEG. BAL.	1998	1999	1&2/2000	3-12/2000	1&2/2001	3-12/2001	1&2/2002	03-12/2002	2003	2004	1-6/2005	7-12/2005	2006	
43	PERC Rate Base Changes														
44	BEGINNING BALANCE		0.00	7,704,231.00	12,251,872.00	12,555,740.00	13,305,740.00	13,555,740.00	14,305,740.00	14,555,740.00	15,055,740.00	15,055,740.00	15,055,740.00	15,055,740.00	15,055,740.00
45	ENDING BALANCE		7,704,231.00	12,251,872.00	12,555,740.00	13,305,740.00	13,305,740.00	14,305,740.00	14,555,740.00	15,055,740.00	15,055,740.00	15,055,740.00	15,055,740.00	15,055,740.00	15,055,740.00
46	AVG UNAMORTIZED BALANCE		3,852,115.50	9,978,051.50	12,403,806.00	12,930,740.00	13,430,740.00	13,930,740.00	14,430,740.00	14,805,740.00	15,055,740.00	15,055,740.00	15,055,740.00	15,055,740.00	15,055,740.00

* - Asset Sale Gain Deferred Income Taxes Calculated Excluding the Impact of the Equity Component of Carrying Costs on the Def. Asset Sale Gain, as Deferred Taxes are not Provided for on AFUDC Equity.

** - The RATE BASE Excluding Ultrapower includes the changes in the PERC restructuring cost deferred balance as a result of the restructuring and the value of the actual warrants exercised in 1999.

BANGOR HYDRO-ELECTRIC COMPANY
NET OPERATING EXPENSE - STRANDED COST REVENUE REQUIREMENT
DOCKET NO. 97-596
SUPPORT FOR ADJUSTMENT #12 TO NOE
AMORTIZATION OF ASSET SALE GAIN

BLACK/DAWES
EXHIBIT B/D-SC-6-12A
Adjustment #12 NOE
15-Feb-00
Phase II Revised

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1 SUMMARY OF AMORTIZATION OF ASSET SALE GAIN:

2 NET ASSET SALE GAIN @ 2/29/99 (28,937,558.00) Includes Carrying Costs and Interim Savings
3 GROSS UP COST OF CAPITAL 12.38%

4 STRAIGHT LINE @ 64 MOS (452,149.34)

PERIOD	MONTHLY AMORTIZATION	AVG MONTHLY REVENUE REQ	AMORTIZATION USED IN PERIOD	ANNUALIZED REVENUE REQ
5 3-12/2000	(491,300.00)	3,120,576.46	(4,913,000.00)	37,446,917.48
6 1-2/2001	(369,800.00)	3,120,583.14	(739,600.00)	37,446,997.69
7 3-12/2001	(334,516.00)	3,120,613.73	(3,345,160.00)	37,447,364.71
8 1-2/2002	(453,500.00)	3,120,598.98	(907,000.00)	37,447,187.81
9 3-12/2002	(263,750.00)	3,295,516.62	(2,637,500.00)	39,546,199.42
10 2003	(752,550.00)	3,295,555.40	(9,030,600.00)	39,546,664.77
11 2004	(680,350.00)	3,295,521.85	(8,164,200.00)	39,546,262.21
12 1-6/2005	56,000.00	3,295,569.69	336,000.00	39,546,836.25
13 7-12/2005	77,250.00	3,295,517.87	463,502.00	39,546,214.48
14 2006	N/A	2,232,760.25	N/A	26,793,123.01

TOTAL (28,937,558.00)

15
16 RATE EFFECTIVE YEAR REVENUE REQUIREMENT \$46,329,770.72 Reference B/D-SC-6-12B
17 REVISED RATE EFFECTIVE YEAR REV. REQUIRE. 37,446,930.85 Reference B/D-SC-6-12B
REDUCTION IN REVENUE REQUIREMENT \$8,882,839.87

18
19 **RATE EFFECTIVE YEAR AMORTIZATION:**
20 March - December 2000 (\$491,300 X 10 Months) (\$4,913,000)
January - February 2001 (\$369,800 X 2 Months) (739,600)
21 Total Rate Effective Year Amortization (\$5,652,600)

BANGOR HYDRO-ELECTRIC COM
NET OPERATING EXPENSE - STRANDED COST RE
DOCKET NO. 97-596

L I N E			
	<u>Revenue:</u>		
1	General Base Revenue		
2	Other		
3	Total Revenue	\$0	1
	<u>Operating Expenses:</u>		2
4	Purchased Power		3
5	Wages		4
6	Operation		5
7	Maintenance		6
8	Fringe Benefits		7
9	Uncollectible Revenues		8
10	Depreciation & Amortization		9
11	Amortization of Seabrook Unit 1		10
12	Amortization of Contract Buyouts/Restructurings		11
13	Other Amortizations	96,396	12
14	Property & Excise Taxes		13
15	Payroll Taxes		14
16	Interest on Consumers' Deposits		15
17	Total Operating Expenses	\$96,396	16
18	Net Operating Expense (Pre-Inc Taxes)	(\$96,396)	17
	<u>Income Tax Expenses:</u>		18

19	Federal and State Income Taxes:	\$0	
20	Deferred Income Taxes:	0	
21	Investment Tax Credit:	0	
22	Total Income Tax Expense	\$0	
24	Net Operating Expense	(\$96,396)	

MPANY
VENUE REQUIREMENT

BLACK/DAWES
EXHIBIT B/D-SC-6-9
Adjustment # 9 NOE
18-Jan-2000
Phase II

Description of Adjustment

To record the amortization of the MPUC Consumer Education Assessment of \$239,233, to be billed to the Company in May 1998, 1999 and 2000, over a three year period. Also to record the amortization of the State Planning Office Conservation Program Fund Assessment to be billed to the Company in December 1999 and 2000.

CONSUMER EDUCATION ASSESSMENT:

May 1998 Assessment for Bangor Hydro	<u>\$119,633</u>
Total 1998 Assessment	800,000
Bangor Hydro's Share of Assessment	<u>14.95%</u>
Total 1999 Assessment	\$600,000
Muliplied by Bangor Hydro's Share	<u>15.65%</u>
May 1999 Assessment for Bangor Hydro	<u>\$93,903</u>
Total 2000 Assessment	\$200,000
Muliplied by BHE's Share (Ave. of 1998-99)	<u>15.30%</u>
May 2000 Assessment for Bangor Hydro	<u>\$30,601</u>
Total Bangor Hydro Assessment (Line 1 + Line 6 + Line 9)	<u>\$244,137</u>
<u>STATE PLANNING OFFICE CONSERV. ASSESSMENT:</u>	
December 1999 Assessment for Bangor Hydro	<u>\$21,472</u>
Total 1999 Assessment	137,255
Bangor Hydro's Share of Assessment	<u>15.64%</u>
Total 1999 Assessment	\$150,702
Muliplied by Bangor Hydro's Share	<u>15.65%</u>
Dec. 2000 Assessment for Bangor Hydro	<u>\$23,586</u>
Total Bangor Hydro Assessment (Line 14 + Line 18)	<u>\$45,058</u>
Grand Total of BHE Assessments (Line 12 +Line 20)	\$289,195
Divided by 36 Month Amortization Period	<u>36</u>
Monthly Amortization	\$8,033
Muliplied by 12 months in rate effect. year	<u>12</u>
Rate Effective Year Amortization	<u><u>\$96,396</u></u>

Federal and State Income Taxes	\$0
Deferred Income Taxes	
Investment Tax Credit	
	<u>\$0</u>
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13	Other Amortizations	719,556		
14	Property & Excise Taxes			
15	Payroll Taxes			
16	Interest on Consumers' Deposits			
17	Total Operating Expenses	\$719,556		
18	Net Operating Expense (Pre-Inc Taxes)	(\$719,556)		
	<u>Income Tax Expenses:</u>			
19	Federal and State Income Taxes:	\$0	Federal and State Income Taxes	\$0
20	Deferred Income Taxes:	0	Deferred Income Taxes	
21	Investment Tax Credit:	0	Investment Tax Credit	
22	Total Income Tax Expense	\$0		<u>\$0</u>
24	Net Operating Expense	(\$719,556)		