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THE COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Petition of Riverside Steam & Electric Company, Inc. for relief pursuant to 220 C.M.R. 8.03(2) and 8.07(2).	D.P.U. 88-123

Motion Of Riverside Steam & Electric Company, Inc.,
For Expedited Discovery on Nuclear Capacity Factor
And For Reconsideration Of Interlocutory Order

AFFIDAVIT OF PAUL L. CHERNICK

I, Paul L. Chernick, hereby state the following to be true:

1. My name is Paul L. Chernick. I am President of PLC, Inc., 18 Tremont Street, Suite 703, Boston, Massachusetts.
2. I received an S.B. degree from the Massachusetts Institute of Technology in June, 1974 from the Civil Engineering Department, and an S.M. degree from the Massachusetts Institute of Technology in February, 1978 in Technology and Policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.
3. I was a Utility Analyst for the Massachusetts Attorney General for over three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and evaluation of power supply options. I then spent five years as a Research Associate at Analysis and Inference, Inc., a Boston consulting firm, where my work included these and other topics, including revenue allocation and ratemaking.
4. Since August of 1986, I have been President of PLC, Inc. In my current position, I have advised a variety of clients on utility matters.
5. I have testified approximately sixty times on utility issues before such agencies as the Massachusetts Energy Facilities

Siting Council, the Maine Public Utilities Commission, the Texas Public Utilities Commission, the Illinois Commerce Commission, the Vermont Public Service Board, the District of Columbia Public Service Commission, the New Mexico Public Service Commission, the Pennsylvania Public Utilities Commission, the Federal Energy Regulatory Commission, the Boston Public Improvements Commission, the Rhode Island Public Utilities Commission, the New Hampshire Public Utilities Commission, the Michigan Public Service Commission, the Connecticut Department of Public Utility Control, the Minnesota Public Utilities Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission.

6. Subjects I have testified on include cost allocation, rate design, marginal cost estimation, long range energy and demand forecasts, costs of nuclear power, conservation costs and potential effectiveness, generation system reliability, fuel efficiency standards, and ratemaking for utility production investments and conservation programs.

7. I have testified approximately 26 times before the Massachusetts Department of Public Utilities (DPU) on topics including rate design, capacity planning, and ratemaking. I testified on avoided cost calculation methodologies and related issues in ratemaking for qualifying facilities (QFs) in the DPU's rulemakings in dockets 535 and 84-276.

8. I am familiar with the factual background of this dispute,

having provided expert analyses for Riverside Steam & Electric (Riverside) in the MDPU proceedings docketed as MDPU 88-19 and 88-123.

9. I have reviewed the avoided cost projections of the Western Massachusetts Electric Company (WMECO), as filed with the DPU in October 1986, December 1987, and August 1988, and those of its sister company Connecticut Light and Power (CLP) to the Connecticut Department of Public Utility Control in April 1988.[1] The avoided fuel costs projected in these filings are displayed in Tables 2 through 5. Both WMECO and CLP are subsidiaries of Northeast Utilities (NU). Due to the NU Generation and Transmission (G&T) Agreement, the incremental costs of WMECO and CLP are identical, and are calculated on the basis of NU combined loads, resources, and dispatch. I have also reviewed information on NU's assumptions for avoided cost calculations, which were not available at the time of Riverside's filings in MDPU 88-19 and 88-123. This information includes Exhibits A-1 and A-2 to the accompanying Motion.

10. Based on my review of the publicly available information, it appears that NU has, since the 12/87 filing, been using nuclear capacity factors which are significantly higher than those it used previously, higher than those it defended in

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1. Hereinafter, these projections are, respectively, referred to as the "10/86," "12/87," "8/88," and "4/88" filings, estimates, or projections.

DPU 88-19, and higher than those approved by the DPU in 88-19. It also appears that NU has assumed, since the 12/87 filing, the future availability of large amounts of economy coal-fired energy from New York, from the PJM (Pennsylvania-New Jersey-Maryland) power pool, and from unspecified sources in New England.

11. In the 4/88 and 8/88 avoided cost projections, NU assumes mature capacity factors for the Millstone and Yankee units which average out to 78-80%. (Exhibit A-1, Exhibit A-2, page 2) Neither filing states that these high nuclear capacity factors were used. These assumptions represent a major departure from the 70% mature capacity factor apparently used in previous NU filings, including WMECO's filing in DPU 85-270 (Millstone 3 cost recovery) and WMECO's 10/86 avoided cost projections. The use of a 70% mature nuclear capacity factor was approved by the DPU (for various purposes) in DPU 85-270 and in DPU 88-19.

12. It appears that WMECO also used mature nuclear capacity factors in the 79% range in computing its 12/87 response to the DPU's discovery request in DPU 88-19. WMECO appears to have made this change, even though the DPU request did not ask WMECO to increase projected nuclear capacity factors, and even though no such increase was noted in the response. In fact, four days after the response to DPU discovery was filed, in comments on Riverside's filing, WMECO defended the 70% mature capacity factors, and "what the Company is

using," without ever stating explicitly that it was still using 70%. (Stillinger Comments, December 7, 1987, page 7)

13. As shown in Table 1, the incremental energy rates (IERs) implicit in WMECo's 12/87 filing were dramatically below those in the 10/86 filing, and essentially equivalent to the IERS for the 4/88 and 8/88 filings.[2] Over the period 1990-2006, the average IER for the 10/86 avoided cost estimate is 10,291 BTU/kWh, while those for the 12/87, 4/88, and 8/88 estimates are 8657, 9188, and 8566, respectively. The values after 2006 in the 10/86 filing assume the deferral of a coal-fired combined cycle plant, and are hence not comparable to the values in the later estimates, which assume that no baseload plant is deferrable. The similarity of the 12/87 avoided cost estimate (stated in terms of IER) to that of the 4/88 and 8/88 estimates strongly suggests that it uses the same nuclear capacity factor estimates.[3]

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2. The IER for each year (or a rating period within a year) is the incremental heat rate at which an oil plant burning 1% sulfur #6 fuel oil would have to operate in order to produce the avoided cost reported by WMECO. The IER is thus a measure of avoided cost, restated to be independent of any differences in projected oil prices between avoided cost estimates. Higher nuclear capacity factors tend to reduce the IER, by displacing the most expensive generation on the system, prior to the calculation of savings from the addition of a block of QF capacity.

3. Minor variations in IERs between the 12/87 and 8/88 filings may result from variation in fuel-price ratios, from differing assumptions regarding QF contracts, from differences in load forecasts, and from similar sources. Differences in base-case supply plans may be responsible for the differences in avoided costs around the year 2000 for the 12/87, 4/88, and 8/88 estimates. Alternatively, the decline in nuclear capacity factors CLP predicted in the 4/88 filing for the 1998-2000

14. According to the regression analysis performed by William B. Marcus on earlier NU avoided cost projections, and reproduced as Appendix B to my portion of Riverside's filing in 88-123, each GWH of nuclear energy generation on the NU system reduces NU's estimated IERs by 0.6589 BTU/kWh in the on-peak period, and 0.4712 BTU/kWh in the off-peak period. Using NU's annual values of 4160 hours on-peak and 4600 hours off-peak, the regression results are equivalent to a 0.56 BTU/kWh decrease in average annual IER for each added nuclear GWH. NU's entitlement in the Millstone and Yankee plants totals 2689.3 MW, prior to short-term sales. An average increase in projected nuclear capacity factor of 9 percentage points (from 70% to 79%) is thus equivalent to 2120 GWH annually. The regression results would suggest that this added projected nuclear energy would reduce the projected IER by about 1190 BTU/kWh. For the 1990-2006 period, the 12/87 IERs are 1634 MW lower than the 10/86 IERs, indicating that the change in assumed dispatch is consistent with a radical increase in projected nuclear capacity factors between 10/86 and 12/87.

15. Thus, it appears that the 12/87 avoided costs estimates, on which the DPU based its decision in 88-19, and on which NU based its refusal to renegotiate its contract with Riverside, did not incorporate the 70% mature nuclear

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period may not have been included in WMECO's 12/87 and 8/88 filings.

capacity factors which the DPU approved in 88-19. Roughly speaking, returning the mature nuclear capacity factors to the 70% value approved by the DPU would increase the 12/87 IERs (and hence avoided fuel costs) by about 14%.

16. In addition to the change in nuclear capacity factors, it appears that NU has made inappropriate and speculative assumptions regarding the availability of coal-fired economy (unscheduled, uncontracted) energy from other utilities. None of the avoided cost filings provides any statement regarding the magnitude or price of anticipated purchases of coal-fired energy. Nonetheless, the 4/88 and 8/88 filings were based on the assumption that NU could and would purchase large amounts of coal-fired power from other utilities, rising from about 300 GWH in 1990 to nearly 2000 GWH in 1998. See Exhibit A-2, page 3. This latter figure is equivalent to over 300 MW of nuclear capacity at a 70% capacity factor. I have not seen any data on NU assumptions regarding coal-fired purchases after 1998, but the trend in the assumed purchases in the 1990s was strongly upward, suggesting that post-1998 volumes might be even larger.[4]

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4. While NU's insistence on maintaining the confidentiality of its production costing inputs makes the publicly available information regarding NU's other recent assumptions much more limited, it also appears that NU has been making two other highly implausible assumptions which it has not documented or justified. First, NU has apparently assumed that large amounts of economy oil-fired energy will be available from the west, and from other utilities within New England, throughout the forecast period. Second, NU has apparently assumed that the cost of oil-fired and coal-fired power from other utilities will escalate much more slowly than NU's own fuel costs, with

17. DPU regulations (220 CMR 8.05(2)(c)) specifically require that where "data and assumptions used in the [avoided cost] calculation are different from those used in the most recent demand forecast and resource supply plan filed with the Energy Facilities Siting Council ("EFSC"), the utility must provide a full explanation for the differences." The 4/87 EFSC filing (the most recent as of the 12/87 avoided cost calculations) provides no projection of the availability of coal-fired energy to NU, or its use by NU. The only reference in that filing to bulk power purchases is found on page III-8, which states in part that "In 1986, NU purchased about 500,000 MWh of economic coal-fired energy. . . It is anticipated that future purchases of coal power from the west will be reduced from levels experienced in prior years because of the addition of Millstone Unit 3." The 1986 and 1988 EFSC filings contained similar statements, with different historical power purchase reports. Hence, NU's incorporation of these large power purchases in its avoided cost calculations violate the filing requirements of 220 CMR 8.05.

18. The fact that NU has not changed its reporting of projected coal sales from 1986 through 1988 should imply that NU has

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even oil-fired energy increasing at less than the rate of inflation. Since other utilities will use up their most economical resources as loads grow, the cost of economy power purchases should increase faster than NU's fuel price projections, not slower.

not significantly changed its projections for the amount of such power it will purchase. However, it appears likely that NU has changed its projections, since the decrease in the IERs from 10/86 to 12/87 is about 440 BTU/kWh higher than can be explained from the change in nuclear capacity factors. From the regression analysis, we estimate that the 440 BTU/kWh differential could be explained by average annual coal purchases of about 785 GWH.

19. NU assumes that the economy purchases of coal-fired energy will increase steadily throughout the forecast period. (Exhibit A-2, page 3) In the forecast period, most utilities to the west project gradually falling reserve margins, as their loads grow. Thus, the amount of power available for purchase should decline, not rise, and the price of the power available should rise, further reducing the amount which is economical for NU.

20. NU projects rising economy coal purchases from within New England. Given the shortage of base-load capacity in the region, and the lack of plans for additional construction of baseload plants, the availability of economy coal energy would be expected to fall, rather than rise.

21. The hypothesized coal purchases are uncommitted resources, for which NU has no contractual rights.[5] It is far from

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5. No such commitments are shown in Chapter V of the 1986 through 1988 NU Power Facilities Forecast filings with the EFSC (Table E-24). No such commitments are noted in the revisions to the EFSC filings described in the avoided cost filings.

certain that other utilities will have low-cost coal power available. If they do have power, the utilities in New York and PJM may well offer the power first within their own power pools, both for contractual reasons and to avoid transmission charges. Even for sales within New England, sellers would be expected to prefer to enter these split-savings economy transactions with utilities having higher decremental costs than NU, such as Boston Edison. Finally, even if NU were the economically preferred purchaser, transmission constraints may prevent purchases from the west. NU has predicted in its current Connecticut rate case that New York utilities will be seeking to sell large amounts of firm power in New England, reducing the already limited transmission capacity available for economy interchange.

22. The DPU has clearly indicated that future electric power supplies should only be included in the calculation of avoided costs to the extent that they "can be reasonably relied on." (DPU 86-218-A, at 14; DPU 88-83, at 10) Thus, QF energy production is included only for those projects with long-run power purchase agreements (220 CMR 8.05(2)(c)), and only for those agreements "approved by the Department" (220 CMR 8.05(3)(b)(3)(a); DPU 86-217). In DPU 88-83, the DPU further restricted the use of both QF and utility contracts to half of contracted purchases. NU's projected low-cost fossil fuel purchases can not be relied

on.

23. The DPU requires in 220 CMR 8.05(3)(a)(5) that the "utility must support its computation of ceiling price schedules," e.g., avoided cost projections. NU does not appear to have made any attempt to support the inclusion of large economy energy purchases in its computation of avoided costs, and indeed has not revealed to the DPU the existence of this assumption.

24. NU, by assuming large speculative purchases of economy energy, has violated several requirements of DPU regulations and precedent. Most importantly, by failing to point out the use of this assumption, NU has prevented meaningful DPU review of its avoided cost projections, including those filed in 12/87 in response to the DPU discovery in 88-13, those used in negotiating with the Riverside project early in 1988, and those filed in 8/88 and approved by the DPU in 86-218-C (October 1988).

SIGNED UNDER PAINS AND PENALTIES OF PERJURY THIS 4th DAY OF November, 1988.

Paul L. Chernick

Paul L. Chernick

TABLE 1: SUMMARY OF INCREMENTAL ENERGY RATES

	IER 10/86 [1]	IER 12/87 [2]	IER 4/88 [3]	IER 8/88 [4]
1990	9,043	8,501	8,743	8,406
1991	9,745	8,478	8,228	8,357
1992	9,339	7,189	7,889	8,342
1993	9,898	8,572	8,889	8,698
1994	10,124	8,254	8,169	7,980
1995	10,056	8,915	8,875	8,610
1996	10,217	8,031	8,494	8,170
1997	10,576	9,975	9,378	8,623
1998	10,915	8,713	9,920	8,891
1999	11,083	9,026	10,776	9,674
2000	11,709	9,469	11,454	9,882
2001	11,392	8,601	9,384	6,508
2002	11,418	8,577	9,319	6,896
2003	9,357	8,697	9,208	9,331
2004	9,842	8,668	9,196	9,294
2005	10,075	8,774	9,153	9,069
2006	10,158	8,731	9,124	8,891
2007		8,882	9,090	9,044
2008		9,000	9,070	9,292
2009		8,986	9,080	8,740
2010		8,875	9,086	
2011		9,048	9,069	
2012		9,231		
2013		8,807		
2014		8,718		
2015		8,678		
2016		8,780		
2017		8,950		
2018		9,130		
2019		9,295		
2020		9,494		
AVERAGES:				
1990-2000	10,246	8,648	9,165	8,694
1990-2006	10,291	8,657	9,188	8,566
1990-2010		8,710	9,168	8,635

NOTES:

[1]: FROM TABLE 2.

[2]: FROM TABLE 3.

[3]: FROM TABLE 4.

[4]: FROM TABLE 5.

TABLE 2: IER, USING 10/86 AVOIDED COSTS

YEAR	-FUEL AND O&M COSTS (CENTS/KWH)- ON-PEAK	OFF-PEAK	REFERENCE --1%S #6 oil-- (CENTS/MMBTU)	--INCREMENTAL ENERGY RATES (IER)-- ON-PEAK	OFF-PEAK	AVERAGE
	[1]	[2]	[3]	[4]	[5]	[6]
1986	3.1	2.3	249.0	12,450	9,237	10,763
1987	2.7	2.2	235.9	11,446	9,326	10,333
1988	2.9	2.3	258.2	11,232	8,908	10,011
1989	3.2	2.5	278.9	11,474	8,964	10,156
1990	3.2	2.3	301.6	10,610	7,626	9,043
1991	3.6	2.9	331.7	10,853	8,743	9,745
1992	3.8	3.0	361.9	10,500	8,290	9,339
1993	4.3	3.5	392.0	10,969	8,929	9,898
1994	4.9	4.0	437.3	11,205	9,147	10,124
1995	5.4	4.5	490.0	11,020	9,184	10,056
1996	6.2	5.1	550.3	11,267	9,268	10,217
1997	7.3	6.0	625.7	11,667	9,589	10,576
1998	8.5	7.2	716.2	11,868	10,053	10,915
1999	10.0	8.3	821.7	12,170	10,101	11,083
2000	12.4	9.8	942.4	13,158	10,399	11,709
2001	13.6	10.6	1055.5	12,885	10,043	11,392
2002	15.3	11.9	1183.6	12,927	10,054	11,418
2003	14.2	10.4	1304.3	10,887	7,974	9,357
2004	16.4	12.3	1447.6	11,329	8,497	9,842
2005	19.2	13.3	1598.2	12,014	8,322	10,075
2006	20.0	15.6	1741.5	11,484	8,958	10,158
AV. 1990-2006	9.9	7.7	841.3	11,577	9,128	10,291

NOTES:

[1] WMECO Long-term Avoided Costs, October 1, 1986; Table 1-A, column (a).

[2] Ibid., column (e).

[3] Ibid., Exhibit 2.

[4] [1]/[3]*1,000,000.

[5] [2]/[3]*1,000,000.

[6] ([4]*4160+[5]*4600)/8760.

TABLE 3: IER, USING 12/87 AVOIDED COSTS

Year	Avoided Cost on-peak	Avoided Cost off-peak	reference 1%S $/bbl	IER BTU/kWh on-peak	IER BTU/kWh off-peak	Average of IER
1990	3.8	2.5	22.81	10,362	6,817	8,501
1991	3.9	2.9	24.76	9,797	7,285	8,478
1992	3.7	2.5	26.56	8,665	5,855	7,189
1993	4.5	3.4	28.46	9,835	7,431	8,572
1994	4.5	3.6	30.35	9,222	7,378	8,254
1995	5.2	4.1	32.25	10,029	7,908	8,915
1996	5.1	3.9	34.62	9,163	7,007	8,031
1997	7.1	5.6	39.36	11,220	8,850	9,975
1998	7.1	5.6	45.06	9,801	7,730	8,713
1999	8.5	6.6	51.70	10,226	7,940	9,026
2000	10.6	7.6	59.28	11,122	7,974	9,469
2001	10.6	7.9	66.40	9,930	7,400	8,601
2002	12.0	8.7	74.46	10,024	7,268	8,577
2003	13.1	10.0	82.05	9,931	7,581	8,697
2004	15.0	10.6	91.06	10,246	7,241	8,668
2005	16.6	12.0	100.55	10,269	7,423	8,774
2006	17.9	13.1	109.56	10,162	7,437	8,731
2007	19.4	14.7	118.57	10,177	7,711	8,882
2008	21.0	15.9	126.63	10,315	7,810	9,000
2009	22.4	16.8	134.69	10,344	7,758	8,986
2010	23.4	17.5	142.28	10,230	7,650	8,875
2011	25.3	18.9	150.82	10,434	7,795	9,048
2012	26.8	20.8	159.36	10,460	8,118	9,231
2013	26.9	21.2	168.84	9,910	7,810	8,807
2014	28.0	22.4	178.80	9,740	7,792	8,718
2015	30.3	23.0	189.71	9,934	7,541	8,678
2016	32.4	24.5	200.14	10,069	7,614	8,780
2017	34.9	26.4	211.53	10,262	7,763	8,950
2018	37.5	28.4	222.91	10,464	7,925	9,130
2019	40.3	30.5	235.24	10,656	8,065	9,295
2020	43.3	32.8	247.57	10,879	8,241	9,494
AV. 1990-2006	8.78	6.51	54.08	10,000	7,443	8,657

TABLE 4: IER, USING 4/88 AVOIDED COSTS

YEAR	-FUEL AND O&M COSTS (CENTS/KWH)- ON-PEAK	OFF-PEAK	REFERENCE --1%S #6 oil-- (CENTS/MMBTU)	--INCREMENTAL ENERGY RATES (IER)-- ON-PEAK	OFF-PEAK	AVERAGE
	[1]	[2]	[3]	[4]	[5]	[6]
1988	4.1	3.1	266.6	15,379	11,628	13,409
1989	3.4	2.5	303.9	11,188	8,226	9,633
1990	3.7	2.2	333.1	11,108	6,605	8,743
1991	3.7	2.4	366.7	10,090	6,545	8,228
1992	3.8	2.6	401.8	9,457	6,471	7,889
1993	4.6	3.1	428.9	10,725	7,228	8,889
1994	4.8	2.8	459.0	10,458	6,100	8,169
1995	5.3	3.6	496.6	10,673	7,249	8,875
1996	5.6	3.7	541.8	10,336	6,829	8,494
1997	6.8	4.6	601.9	11,298	7,642	9,378
1998	7.8	5.6	669.8	11,645	8,361	9,920
1999	9.2	7.2	756.3	12,164	9,520	10,776
2000	11.0	8.6	850.3	12,937	10,114	11,454
2001	10.7	7.4	955.6	11,197	7,744	9,384
2002	11.9	8.2	1068.5	11,137	7,674	9,319
2003	13.1	9.0	1188.9	11,019	7,570	9,208
2004	14.3	9.8	1298.1	11,016	7,549	9,196
2005	15.4	10.6	1407.1	10,944	7,533	9,153
2006	16.6	11.4	1520.1	10,920	7,500	9,124
2007	17.8	12.3	1640.4	10,851	7,498	9,090
2008	19.0	13.1	1753.2	10,837	7,472	9,070
2009	20.2	14.0	1866.2	10,824	7,502	9,080
2010	21.5	14.8	1979.1	10,864	7,478	9,086
2011	22.7	15.7	2097.7	10,821	7,484	9,069
AV. 1990-2006	8.7	6.0	785.0	11,007	7,543	9,188

NOTES
[1]: NU 4/88 AVOIDED COST FILING, WORKSHEET IV-10-B, Column 1.
[2]: Ibid., Column 2.
[3]: Ibid., Exhibit IV-1.
[4]: [1]/[3]*1,000,000.
[5]: [2]/[3]*1,000,000.
[6]: ([4]*4160+[5]*4600)/8760.

TABLE 5: IER, USING 8/88 AVOIDED COSTS

YEAR	-FUEL AND O&M COSTS (CENTS/KWH)- ON-PEAK	OFF-PEAK	REFERENCE --1%S #6 oil-- (CENTS/MMBTU)	--INCREMENTAL ENERGY RATES (IER)-- ON-PEAK	OFF-PEAK	AVERAGE
	[1]	[2]	[3]	[4]	[5]	[6]
1989	3.5	2.5	289.5	12,090	8,636	10,276
1990	3.4	2.0	317.0	10,726	6,309	8,406
1991	3.5	2.3	343.4	10,192	6,698	8,357
1992	3.7	2.5	368.0	10,054	6,793	8,342
1993	4.1	2.8	392.9	10,435	7,126	8,698
1994	4.3	2.5	420.4	10,228	5,947	7,980
1995	4.6	3.3	455.0	10,110	7,253	8,610
1996	5.0	3.2	496.3	10,075	6,448	8,170
1997	5.7	3.9	551.4	10,337	7,073	8,623
1998	6.4	4.6	613.5	10,432	7,498	8,891
1999	7.7	5.8	692.8	11,114	8,372	9,674
2000	8.8	6.7	778.9	11,298	8,602	9,882
2001	6.8	4.7	875.4	7,768	5,369	6,508
2002	7.8	5.8	978.8	7,969	5,926	6,896
2003	12.0	8.5	1089.1	11,018	7,805	9,331
2004	13.1	9.2	1189.1	11,017	7,737	9,294
2005	14.0	9.6	1288.9	10,862	7,448	9,069
2006	14.9	10.1	1392.3	10,702	7,254	8,891
2007	15.9	11.5	1502.6	10,582	7,653	9,044
2008	17.6	12.5	1605.9	10,960	7,784	9,292
2009	18.3	11.9	1709.3	10,706	6,962	8,740
AV. 1990-2006	7.4	5.1	720.2	10,255	7,039	8,566

NOTES

[1]: WMECO QF RFP 8/88, Table 1-B, column (a).
[2]: Ibid., Column (f).
[3]: Ibid., Exhibit 1.
[4]: [1]/[3]*1,000,000.
[5]: [2]/[3]*1,000,000.
[6]: ([4]*4160+[5]*4600)/8760.