Avoided-Energy-Supply-Component Study Group

Updated Avoided-Energy-Supply Costs

For Demand-Side-Management Screening in New England

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I. Introduction and Summary

A. Purpose of the Study

Avoided-energy-supply components are values for energy supply (electricity generation capacity and energy, and gas commodity and transportation costs) that are avoided by the implementation of demand-side-management programs. This report presents the results of updating the analysis in "Avoided Energy-Supply Costs For Demand-Side-Management Screening in Massachusetts," prepared for the Avoided-Energy-Supply-Component Study Group by Resource Insight and Synapse Energy Economics, July 30, 1999. The Avoided-Energy-Supply-Component Study Group sponsoring this update includes most of the electric and gas utilities serving New Hampshire and Rhode Island, as well as the Massachusetts utilities that sponsored the 1999 AESC study.

This update was undertaken to reflect changes in important inputs to the computation of avoided energy costs. The most important such changes are in current and projected fuel prices, and in the amount of generation being added in New England over the next few years. In addition, New England now has more experience with the operation of the restructured market, allowing this update to model more realistically the bidding behavior of generators and the pricing behavior of power marketers.

The energy-supply components developed in this report are to be used for the purposes of demand-side-management planning, evaluation, and implementation only.

B. Brief Summary of the Approach Taken

This work was performed by Resource Insight, Inc., and its subcontractor, Synapse Energy Economics, in consultation with the Avoided-Energy-Supply-Component Study Group. The Study Group comprises representatives of electric and gas utilities and non-utility parties.

Electric avoided-energy costs at the wholesale level were estimated with a production-costing model through 2012, and projected beyond 2012 from the rate of escalation for new combined-cycle units, which are assumed to set the long-term equilibrium price. Electric capacity costs were estimated from the near-term forward contract prices for capacity and from the costs of new combustion turbines. These wholesale prices were increased to reflect the observed differences between the winning bids for full-requirements retail service (for Massachusetts default service and Rhode Island provider-of-last-resort service) and contemporaneous wholesale forward contract prices. These differences should reflect the costs of ancillary services (which this report does not otherwise include), the incremental cost of a retail load shapes compared to the flat energy blocks traded in the wholesale market, and the supplier's risk of load and price fluctuations.

Avoided costs for gas were computed by updating the projections of wellhead gas costs, scaling the avoided gas costs for various load shapes in proportion to the 1999 results, and adding the delivery costs estimated in the 1999 Study Group Report.

C. Summary of Results

Table ES-1, below, provides the average market price for retail power supply, using the aggregate NEPOOL load shape assumed in the modeling for this report. The load factor for this load is approximately 61%. The cost estimate includes a 16% reserve margin over summer peak, and a 20% retail adder. Nominal prices are computed assuming inflation of 2.5% per annum.

These prices do not include line losses or avoided transmission-and-distribution costs, which are added by each utility.

Table ES-1:
Summary of Projected New England Market Prices for Retail Electric Service

	Average Avoided Power Cost for Retail Service ($/MWh)	
	Year-2000 Dollars	*Nominal Dollars*
2002	$46.83	$49.21
2003	$46.14	$49.68
2004	$46.41	$51.23
2005	$48.84	$55.26
2006	$50.79	$58.90
2007	$53.09	$63.10
2008	$54.31	$66.17
2009	$55.63	$69.47
2010	$57.26	$73.29
2011	$56.90	$74.66
2012	$57.49	$77.31

Table ES-2, below, provides the avoided gas cost for retrofit space-heating measures. These prices do not include avoided distribution costs, which are added by each utility.

Table ES-2:
Summary of Projected New England Market Prices for Natural Gas for a Retrofit-Heating Load Shape

	Avoided Gas Cost ($/MMBtu)	
	Year-2000 Dollars	*Nominal Dollars*
2002	$4.72	$4.96
2003	$4.74	$5.10
2004	$4.67	$5.15
2005	$4.67	$5.28
2006	$4.67	$5.41
2007	$4.67	$5.55
2008	$4.67	$5.68
2009	$4.67	$5.83
2010	$4.67	$5.97
2011	$4.69	$6.16
2012	$4.72	$6.35

D. Comparison to the Results of the 1999 Report

Table ES-3, below, compares the average market price for retail power supply with comparable values from Table 1 of the 1999 Study Group Report. The following factors contribute to the differences:

- averaging in the 1999 report of the production-costing results with the energy prices produced by an equilibrium model (described in the 1999 report),
- use of 1% higher inflation for 1999 in the 1999 report than in this analysis,
- use of a 60% load factor in the 1999 summary versus a 61% load factor here,
- higher fuel-price forecasts now than in 1999,
- effects of the large near-term surplus of generation (which was not fully anticipated in 1999) on the current results,
- recognition in this study that generators do not necessarily bid their energy into the market at cost,
- use of the retail adders in this study versus load weighting of avoided energy costs in the 1999 study.

Table ES-3:
Comparison of Projected New England Market Prices for Retail Electric Service

	Nominal Dollars per MWh		Year-2000 Dollars per MWh	
	1999 Results	*Current Results*	*1999 Results*	*Current Results*
2002	$41.52	$49.21	$39.12	$46.83
2003	$42.72	$49.68	$39.27	$46.14
2004	$44.01	$51.23	$39.47	$46.41
2005	$45.51	$55.26	$39.82	$48.84
2006	$47.20	$58.90	$40.29	$50.79
2007	$48.39	$63.10	$40.30	$53.09
2008	$49.58	$66.17	$40.28	$54.31
2009	$50.52	$69.47	$40.04	$55.63
2010	$51.93	$73.29	$40.15	$57.26

Table ES-4, below, compares the avoided gas cost for retrofit space-heating measures with the comparable values from Table 2 of the 1999 AESC report. These differences are due to the use of (a) 1% higher inflation for 1999 in the 1999 report than in this analysis, and (b) higher gas-price forecasts now than in 1999.

Table ES-4:
Comparison of Projected New England Avoided Gas Costs

	Nominal Dollars per MMBtu		Year-2000 Dollars per MMBtu	
	1999 Results	*Current Results*	*1999 Results*	*Current Results*
2002	$4.35	$4.96	$4.14	$4.72
2003	$4.46	$5.10	$4.14	$4.74
2004	$4.57	$5.15	$4.14	$4.67
2005	$4.68	$5.28	$4.14	$4.67
2006	$4.84	$5.41	$4.17	$4.67
2007	$4.98	$5.55	$4.19	$4.67
2008	$5.14	$5.68	$4.22	$4.67
2009	$5.31	$5.83	$4.25	$4.67
2010	$5.48	$5.97	$4.28	$4.67

II. Fuel Price Update

A. Natural Gas Prices

1. Wellhead Prices

The authors projected wellhead gas costs for calendar year 2002 and 2003 from then-current (September 6, 2001) NYMEX futures prices for gas delivered at the Henry Hub, reduced by 7.6% to reflect recent differentials between Henry Hub prices and average wellhead prices. These prices are included in Appendix A.

Gas-price futures have risen by $0.40–$0.50/MMBtu since we performed our analysis. An update of the gas prices in early November would result in higher prices for 2002–2004 (and to a lesser extent in the extrapolation period to 2009) than in our analysis. Futures prices are inherently volatile, and futures a few months from now may be higher or lower than our projection.

From 2004 through 2010, we held the wellhead gas price constant at the real price for 2010 ($2.69/MMBtu in 1999 dollars) projected by the Energy Information Administration in Annual Energy Outlook 2001 (December 2000, p. 85, Table 17). We escalated real wellhead gas prices at 1% annually thereafter, reflecting the escalation projected in Annual Energy Outlook 2001.

2. Delivered Prices

We added delivery costs averaging $0.80/MMBtu (in 1998 dollars) from the 1999 Study Group Report.

The gas utilities attempted to identify recent market contracts for gas delivery. The only contract for which prices could be provided was for transportation on the Maritimes and Northeast Pipeline. The cost of wellhead gas for that pipeline, from fields off of Nova Scotia, is not likely to be as high as the US wellhead price. (It would be inappropriate to combine the Maritimes and Northern pipeline charges with the average price of wellhead gas.)

The Division of Energy Resources identified projections of delivery prices from *The Weekly Basis*, an electronic newsletter from Silent Sherpa.[1] As of November 1 2001 Silent Sherpa projected delivery prices from Henry Hub to New England retail customers of $1.02/MMBtu for any consecutive twelve-month period from December 2001 through October 2004. For comparison, the delivery costs we used (from the 1999 Study Group Report) from wellhead range from $0.87 in

[1]www.silentsherpa.com/WeeklyBasis.htm.

2002 dollars to \$0.92 in 2004 dollars. Wellhead is also less expensive than Henry Hub, so the total difference in our delivery prices is about \$0.35–\$0.40/MMBtu.

Based on discussions with James Grasso, president of Silent Sherpa, we believe that the delivery costs published in *The Weekly Basis* are drawn from a wide range of prices charged to retail customers. Mr. Grasso expressed his belief that few marketers were active in dealing with retail customers, and that some were charging very large margins. We therefore believe that the published delivery costs are higher than the prices that would be paid by large generators or gas utilities, who are in a better position to negotiate with marketers, and also deal with a wider range of sellers of delivery service.

While Silent Sherpa's estimates of delivery costs may be appropriate for valuing natural gas used by customers buying gas from marketers, we expect that most of the demand-side management undertaken by the utilities will be for customers who buy gas through utilities. Higher gas prices may be appropriate for customers using open access.

The November 8 2001 *Weekly Basis* reports annual average delivery costs of \$0.86/MMBtu, cutting in half the previous week's differential from our estimates.

B. Oil Prices

We set residual and distillate oil prices for 2001 at September, 2001, market prices, as reported by Bloomberg's *Natural Gas Report* 10(1)(9/7/01) using New York Harbor prices and 2% sulfur for residual, and New York and Boston No.-2 Oil prices for distillate.[2] We adopted the projected 2005, 2010, and 2015 prices for deliveries to utilities in Annual Energy Outlook 2001 (p. 131), and interpolated for the remaining years.[3]

As in 1999, we assume an average 10% discount from residual-oil prices for dual-fueled steam-electric plants.

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[2]The September 2001 spot price or New York Harbor residual 2% sulfur oil was \$3.27–\$3.31/MMBtu (*Bloomberg Natural Gas Report* 10(1) (9/7/2001), p. 5.); we used \$3.29/MMBtu. September 2001 citygate prices for distillate no.-2 oil were \$6.06/MMBtu in Boston and \$5.74/MMBtu in New York (*Bloomberg Natural Gas Report* 10(1) (9/7/2001), p. 10.); we used \$6.00/MMBtu

[3]In 1999 dollars per MMBtu, Annual Energy Outlook 2001 (p. 131) projects

	2005	**2010**	**2015**
Distillate	\$4.65	\$4.84	\$5.10
Residual	\$3.52	\$3.88	\$4.00

C. Summary of Fuel Costs

Our updated projections of fuel costs are summarized below in Table 1.

Table 1:
Projected Fuel Costs for New England Generators
(1998 Dollars per MMBtu)

	Natural Gas Wellhead Costs	Residual Oil Costs	Dual Fuel Costs (Residual & Gas)	#2 Oil
2002	$2.70	$3.24	$2.91	$5.34
2003	$2.72	$3.31	$2.98	$4.95
2004	$2.65	$3.39	$3.05	$4.58
2005	$2.65	$3.47	$3.12	$4.58
2006	$2.65	$3.54	$3.18	$4.62
2007	$2.65	$3.61	$3.25	$4.66
2008	$2.65	$3.68	$3.31	$4.69
2009	$2.65	$3.75	$3.37	$4.73
2010	$2.65	$3.82	$3.44	$4.77
2011	$2.68	$3.85	$3.46	$4.82
2012	$2.70	$3.87	$3.48	$4.87

III. Other Updated Inputs to the ELFIN Computation of Wholesale Electric Market Costs

A. New Generator Capacity Additions

Various developers have announced plans to develop some 23,000 MW of generation projects, some of which are still in the planning phase, while others have applications in various stages of the regulatory and permitting process. Approximately 9,000 MW of those projects are under construction and are expected to come on line by the end of 2002. Nearly all of these new units are natural-gas combined-cycle plants. Table 2 summarizes the capacity of new additions used in the production-costing model. That capacity was modeled as generic units, with generic performance factors, rather than on a plant-by-plant basis.

Table 2:
Summary of New Capacity for New England (MW)

Year	New Capacity	Cumulative Additions
2001	3,100	3,100
2002	5,769	8,869

Table 2 is derived from Table 3, below, which summarizes the capacity and expected commercial operation dates (CODs) given in the NE-ISO Regional Transmission Energy Plan draft report RTEP01, Table 3.3.1 (August 2001). The NEPOOL §18.4 interconnection applications for these units have been approved, and they were all under construction as of March 2001.

Except as noted the projected commercial operation dates are from the NE-ISO RTEP report. The projections of state regulatory authorities are similar.

Table 3:
New Capacity for New England by Unit (MW)

Project	Location	Capacity	COD
Millennium	Charlton, Mass.	400	01-04
Westbrook Power	Westbrook, Maine	520	01-04
ANP Blackstone	Blackstone, Mass.	580	01-06
Wallingford Power	Wallingford, Conn.	250	01-06
Milford Power	Milford, Conn.	540	01-09
Lake Road Gen	Killingly, Conn.	810	01-10
ANP Bellingham	Bellingham, Mass.	580	02-01
Sithe Mystic	Everett, Mass.	1,750	02-01
SEI Newington	Newington, NH	525	02-05
AES Londonderry	Londonderry, NH	742	02-06
Sithe Edgar	Weymouth, Mass.	1,500	02-06
Hope Energy	Johnston, RI	500	02-07
Kendall Repowering	Cambridge, Mass.	172	02-07[a]
Total		8,869	

[a]Commercial operation date from Massachusetts Energy Facilities Siting Board

With this magnitude of new additions, summer reserve margins will rise above 40% by 2004 and remain well above 20% throughout the decade.

We did not identify any generator retirements in ELFIN. At this point, we believe that existing units in New England are economic to keep in operation. If power prices were to fall much below the range we have projected, some plants may be retired or mothballed. Specific units may also be retired as a result of future policy decisions or very strict environmental regulations. To the extent that some of the existing generators may be retired, new additions could come on line faster, offsetting the effect of the retirements on market prices.

B. Customer Demand

We took monthly demand and energy requirements from the 2001 CELT Report for 2001 through 2010. This forecast has growth rates of 1.51% for summer peak and 1.54% for energy.[4]

We developed the hourly loads within each month by scaling up the NEPOOL hourly loads for 1997 (used in the 1999 Study Group Report), so that the peak load

[4]"NEPOOL Forecast Report of Capacity, Energy, Loads and Transmission 2001–2010" (2001), p. 10.

and monthly energy matched the CELT projections. The primary secular changes in load shapes over time (e.g., towards a stronger summer peak, or decreased winter heating load) are captured by the growth rates of peak load and energy by month. The actual load shape in any month, or any year, can vary due to such short-term effects as weather. However this analysis does not attempt to capture those random fluctuations. Years with high variability will tend to have higher market energy prices, all else equal, while those with flatter loads will have lower market energy prices.

We selected 1997 data in part because the variability of loads in 1997 was typical of recent years, except for 2000 (the most recent year for which hourly data was available). The year 2000 had a relatively mild summer and thus had much less variability in summer and annual load than the preceding three years. This pattern is illustrated in Table 4:

Table 4:
Ratio of the Standard Deviation of Load to Average Load, by Month and Year

	1997	1998	1999	2000
January	0.162	0.170	0.166	0.170
February	0.162	0.159	0.157	0.152
March	0.167	0.171	0.159	0.156
April	0.167	0.169	0.166	0.165
May	0.182	0.195	0.184	0.186
June	0.219	0.210	0.220	0.204
July	0.219	0.224	0.201	0.191
August	0.194	0.209	0.196	0.209
September	0.199	0.198	0.207	0.194
October	0.186	0.186	0.175	0.179
November	0.179	0.181	0.184	0.169
December	0.169	0.178	0.165	0.155
Annual	0.194	0.198	0.199	0.188

C. Market Behavior

Previous analysis using Synapse Energy Economics' Electric Market Optimization Model (ELMO) indicated that competition among suppliers in New England would not provide sufficient pressure to keep supply bids in line with marginal plant running costs.[5] Recent market behavior indicates that such price behavior can occur in the New England market. Utilities and consumers will pay the market-clearing price for energy as bid by generators, not the theoretical marginal cost of energy. To the extent that generators are able to exercise market power and bid above cost, market prices will exceed marginal cost.

For this analysis, the ELFIN runs include "bid adders" for generator bids into the market. These differ by resource type and by time period. We iterated the model with various adders and selected values that roughly reproduce observed market behavior based on forward contract prices, as explained below.

1. Short-Term Forward Market Prices

As calibration points for the modeling of energy prices we used the latest Natsource electricity futures for New England from September 25, 2001. We were successful in achieving a close match with the prices for 2002.[6]

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[5]ELMO is an optimization model developed by Synapse in 1997 to estimate the potential for market power based on resource ownership. Synapse developed the model to compute the pricing strategies that maximize profits to generation owners. An ELMO analysis of market power in New England identified considerable potential for above-cost energy pricing primarily during tight supply conditions. (Biewald, Bruce, David White, and William Steinhurst. 1997. "Horizontal Market Power in New England Electricity Markets: Simulation Results and a Review of NEPOOL's Analysis." Unpublished paper prepared for the New England Conference of Public Utility Commissioners.) As predicted in that study, market prices have been higher than marginal costs.

[6]The Natsource report on forward contract prices is more comprehensive than other similar data sources available to us. The forward market is only publicly reported through 2004. We calibrated ELFIN to match the forwards in 2002–2004, and to project prices through 2012.

Table 5:
Comparison of New England Forward Prices to ELFIN Results

Period	Hours	Natsource Prices 9/25/01 ($/MWh) Bid	Ask	Average	Average (1998$)	ELFIN Estimate (1998$)
Calendar 2002	peak	$41.60	$42.30	$41.95	$38.41	$38.10
Calendar 2002	off-peak	$29.50	$30.50	$30.00	$27.47	$27.30
Jan-Feb 2002	peak	$44.00	$44.50	$44.25	$40.52	$38.95
July-Aug 2002	peak	$55.25	$55.75	$55.50	$50.82	$49.90
Calendar 2003	peak	$38.00	$39.50	$38.75	$34.61	$37.30
Calendar 2004	peak	$38.00	$39.50	$38.75	$33.77	$37.80

Peak hours are sixteen hours five days per week; off-peak hours are the remainder.

To represent the necessity and ability of generators to recover their fixed as well as variable costs, we used a set of peak and seasonal bid adders as described in Table 6 below to represent cost recovery and market power, as well as to match the prices from Natsource. The primary adders were for the new gas combined-cycle units, which are the lowest-cost marginal units during the summer. During the winter, when gas prices are much higher and the gas combined-cycle units are not the lowest cost units, a nominal adder of $5/MWh was used for all the marginal units to represent a modest fixed-cost recovery. The gas combined-cycle adders are higher in summer than winter because the natural gas prices are so much higher in the winter that there is less opportunity for cost recovery then. An adder of $25/MWh is used for the combustion-turbine units to represent high load-scarcity conditions.

Table 6:
Bid Adders (1998 Dollars per MWh)

	Winter		Summer		Spring & Fall
	Peak	*Off-Peak*	*Peak*	*Off-Peak*	*All*
New Gas CC	$5	$5	$22	—	—
Oil Steam	$5	$5	$15	—	—
Gas Steam	$5	$5	$15	—	—
Coal Steam	—	—	$15	—	—
CTs	$25	$25	$25	$25	$25

IV. Wholesale Electric Market Costs

A. Energy

Table 7 below shows the market prices obtained from the ELFIN model.

Table 7:
Market-Clearing Prices from ELFIN
(Year-2000 Dollars per MWh)

Year	Peak	Off-Peak	Average
2002	$39.6	$28.4	$33.7
2003	$38.8	$28.4	$33.4
2004	$39.3	$28.0	$33.4
2005	$40.4	$28.0	$33.9
2006	$40.9	$28.1	$34.1
2007	$41.8	$28.1	$34.6
2008	$43.7	$28.2	$35.6
2009	$45.5	$28.3	$36.5
2010	$48.0	$28.4	$37.7
2011	$47.0	$28.8	$37.4
2012	$47.5	$29.3	$38.0

As noted above, the ELFIN prices for 2002 through 2004 are similar to current forward prices.

After 2012, we extrapolated the market energy price at the rate of escalation of the energy costs of combined-cycle plants for 2010–15.[7] We estimated the energy costs of the combined-cycle units as their total costs at a 75% capacity factor (roughly the same as the capacity factors of the combined-cycles in the ELFIN runs for 2007–2012), net of a $36/kW-yr. installed-capacity value. That growth rate was 0.655%; it is a reasonable estimate of the continuing growth rate in annual average energy prices, as real gas prices rise over time.

The derivation of this growth rate is show in Appendix B.

However, we noticed that ELFIN's projection of on-peak energy prices grew considerably faster than off-peak prices. The peak price rose at 1.7% annually

[7]New combined-cycle power plants would be added when market prices rise above their costs, but not added when market prices are lower. As a result, market prices should tend to be pushed toward the all-in combined-cycle costs, but will vary above and below that equilibrium price, depending on the balance of supply and demand.

from 2008 to 2012, the off-peak price at 0.80%, and the average price at 1.37%.[8] We used that 5-year growth to allocate the annual compound growth in the cost of the CC between the on-peak period (1.25 times the average growth) and off-peak (0.59 times the average growth). Hence, our projection for annual post-2012 energy price increases at 0.82% for peak energy and 0.38% for off-peak energy.

B. Installed Capacity

We used the Natsource prices for installed-capacity contracts (averaging bid and asked prices) of $1.63/kW-month in 2002 and $1.53/kW-month in 2003.[9] These prices are equivalent to $18.8 and $18.0/kW-yr., respectively, in 2000 dollars. We assumed a small recovery to $18.9/kW-yr. in 2004, and then ramped the price up linearly to $37.8/kW-year in 2007 (all in 2000 dollars). The $37.8/kW-year price ($36/kW-yr in 1998 dollars) appears typical of the market when the market is in balance; it is roughly the cost of a new combustion turbine, minus some minor energy revenues.

We retained the 60:40 summer-winter split of capacity value from the 1999 report.[10] We used reserve margins of 16% above the summer peak and 30% above the winter peak, from ISO-NE Objective Capability Reviews for Power Years 2000–2001 and 2001–2002.[11]

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[8]The average price grew faster in the 2008–2012 period (when New England would still be growing into full utilization of the combined-cycle units added in 2001–2007) than we are projecting for the post-2012 period (when we are expecting additional combined-cycle capacity to slow energy-price escalation).

[9]The relevant data, from Natsource's September 25 2001 report (table titled "NEPOOL PTF Seller's Choice") are as follows in dollars per MWh. January-February 2002 bid $150, ask $1.75. July-August 2002 bid $150, ask $1.75. 2003 bid $1.40, ask $1.65.

[10]In 1999, the Study Group discussed reasons for the installed-capacity pricing to be skewed toward the summer, and reasons for it to be uniform through the year, and settled on the 60:40 split as a reasonable estimate of the effects of rules that were then yet to be developed. Those rules are still in flux, and are likely to change again if ISO-NE merges into a super-regional RTO.

[11]Coste, Wayne, Carissa Sedlacek, and Jolene Wescott. 2000. "Review of NEPOOL Object Capability for Power Year 2000–2001 for NEPOOL Power Supply Planning Committee." Unpublished report approved by the NEPOOL Power Supply Planning Committee June 2, 2000. Supplemented by "Revised Objective Capability Values for the 2001/2002 Power Year," August 9 2001 memorandum from Paul Shortley to the NEPOOL Participants Committee.

V. Retail Avoided Electric-Supply Costs

A. Retail Adders

We compared prices quoted in the wholesale market for energy and capacity to winning bids for competitive full-requirements services, such as default service in Massachusetts and provider-of-last-resort service in Rhode Island. We expected to find that the retail prices were higher than could be explained from the wholesale prices, to reflect the higher energy costs of an uneven retail load shape, the costs of ancillary services (which we did not price separately), and the risks of uncertain future load.

The tables in Appendix C add up our estimates for the wholesale market costs that we believe were expected at the time the utilities received their bids from suppliers. We received usable data from three utilities—Fitchburg Gas and Electric, Massachusetts Electric, and Narragansett Electric—including the winning bid prices, the date of the bids, the losses assumed, and some information on the shape of the loads.[12] We had a total of seven bids to work with: two six-month rounds from FG&E; one six-month round from Massachusetts Electric, differentiated into prices for three classes; and a four-month and a six-month bid for Narragansett. The six-month bid for Narragansett was for a level price over that period, while all the rest were for separate prices for each month.

We estimated the monthly load factor and the percentage of energy that would be used in the peak period for each month of each bid, from the load data provided to us.[13] We included only peaks falling between the hours of 11 AM and 5 PM in estimating load factor, to minimize the effect of spurious peaks at odd hours that would not be coincident with the peak of a diversified marketer.[14] For similar reasons, we adjusted the load factors of the three Massachusetts Electric classes upward to reflect the diversity in their peaks. We estimated the wholesale forward contract prices for installed capacity, flat on-peak energy, and flat off-peak energy from such sources as the Natsource broker sheet, Bloomberg's *Natural Gas Report,* and Platt's *Power Market Week* database. In some cases all these values were projected in publications available to us; in other cases, we had to interpolate

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[12]NStar also provided some data, but not enough to be useable.

[13]Rather than identify specific holidays, we simply shifted 4% of on-peak MWh to the off-peak period. This method will introduce some random fluctuations in individual months, but should provide reasonable estimates over the course of the year

[14]ISO-NE ICAP requirements are computed from the monthly peak of each load-serving entity, not the load coincident with system peak.

and extrapolate values. We included the monthly reserve margins required by ISO NE, and assumed that the marketer would pay the Schedule-1 and Schedule-9 ISO transmission charges.[15] Finally, we included whatever loss factor the utility reported that it added to the metered load.[16]

Table 8, below, summarizes the results. The retail:wholesale ratios for individual months range from 1.08 to 1.34, while the ratios for individual bids range from 1.11 to 1.22. The ratios show a decided upward trend as the interval from bid to delivery rises. The ratios for power to be delivered one or two months after the bid date average about 1.1, while the ratios for 7 and 8 months out are 1.19 and 1.20. Assuming that marketers are offering prices that are locked in for a year or more, starting a month or two into the future, a ratio of 1.2 would be appropriate to apply to competitive market bids.[17]

We applied the 1.2 ratio to all wholesale market prices to develop retail avoided energy-supply costs. The retail adder might be higher for some cost components (such as capacity and on-peak summer energy) than for others. The available data are not sufficient to support disaggregation of the adder between components.

[15]Those embedded charges are not included in the final retail avoided costs. Each utility should include appropriate avoided transmission-and-distribution costs in screening.

[16]Note that there are no loses in the FG&E computation. That company informed us that it pays marketers for default service per kWh delivered to its transmission system from the PTF, not per kWh sold.

[17]The adder might be a bit higher, since the average 20% differential is computed for the entire observed wholesale and retail price, including the regulated transmission charges, for which the marketer bears little risk.

Table 8: Ratios of Retail to Wholesale Prices

Bid Date	Class	Months Between Bid and Delivery 1	2	3	4	5	6	7	8	9	10	Months to Mid bid	Bid Average	Company Average
Fitchburg Gas & Electric														
7/30/2000														
Delivery Date						Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01			
Ratio	All					1.18	1.11	1.13	1.25	1.34	1.30	7.5	1.22	
3/30/2001														
Delivery Date				Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01					
Ratio	All			1.14	1.18	1.19	1.13	1.10	1.10			5.5	1.14	
														1.18
Narragansett Electric														
4/24/2001														
Delivery Date		May-01	Jun-01	Jul-01	Aug-01									
Ratio	All	1.08	1.09	1.18	1.11							2.5	1.11	
8/14/2001														
Delivery Date		Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02							
Ratio	All	1.19	1.15	1.16	1.19	1.14	1.13					3.5	1.16	
														1.14
Mass Electric														
3/8/2001														
Delivery Date			May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01						
Ratio	Res		1.12	1.22	1.15	1.13	1.14	1.21				4.5	1.16	
Ratio	Com		1.11	1.21	1.14	1.13	1.11	1.13				4.5	1.14	
Ratio	Ind		1.19	1.25	1.19	1.16	1.16	1.20				4.5	1.19	
Simple Average												4.5		1.16
Average of Monthly Ratios		1.08	1.13	1.20	1.15	1.16	1.13	1.16	1.17	1.34	1.30		1.16	1.16
Running Average			1.10	1.14	1.14	1.14	1.14	1.14	1.15	1.17	1.18			

B. Summary of Avoided Electric Costs

Table 9 summarizes the annual electric avoided costs for annual capacity, including a 16% reserve margin Table 10 summarizes monthly on-peak and off-peak energy. Both include a 20% retail adder and 3.96% inflation from 1998 dollars to 2000 dollars. The wholesale equivalents of these tables are provided in Appendix D.

Table 9:
Seasonal Capacity Cost (Year-2000 Dollars per kW-yr. of Load)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Post-2011
Summer	$15.69	$15.79	$26.32	$31.59	$31.59	$31.59	$31.59	$31.59	$31.59	$31.59	$31.59
Winter	$11.72	$11.80	$19.67	$23.60	$23.60	$23.60	$23.60	$23.60	$23.60	$23.60	$23.60

.

Table 10:
Avoided Retail Energy Components by Period (Year-2000 Dollars per MWh)

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2002	*Peak*	48.4	48.8	36.2	32.1	58.9	61.0	64.1	60.4	42.5	31.4	37.5	48.2
	Off-Peak	46.9	46.9	29.1	28.8	30.8	30.7	30.6	31.3	29.2	28.9	28.9	46.9
2003	*Peak*	48.5	48.7	36.8	31.3	58.1	59.6	63.2	59.8	38.7	30.4	34.2	48.2
	Off-Peak	47.0	47.0	29.1	29.1	30.8	30.7	30.6	31.1	29.4	29.1	29.1	47.2
2004	*Peak*	49.4	49.3	37.8	31.6	58.0	59.5	61.5	59.1	39.8	30.6	39.9	48.3
	Off-Peak	46.5	46.5	28.6	28.4	30.3	30.2	29.9	30.7	28.8	28.4	28.4	46.5
2005	*Peak*	50.5	50.1	41.9	31.9	59.1	60.5	62.4	59.1	41.5	31.4	43.8	49.3
	Off-Peak	46.5	46.5	28.6	28.4	30.2	30.1	29.9	30.8	28.8	28.6	28.6	46.7
2006	*Peak*	51.9	52.0	40.8	32.4	60.5	61.5	63.0	59.4	46.3	32.4	37.2	50.3
	Off-Peak	46.7	46.5	28.7	28.4	30.2	30.2	29.9	30.9	28.8	28.7	28.7	46.7
2007	*Peak*	52.6	52.8	43.7	34.6	61.5	62.6	63.5	59.6	46.8	33.9	39.3	51.0
	Off-Peak	46.7	46.7	28.9	28.4	30.1	30.2	29.9	31.1	28.8	28.8	28.8	46.8
2008	*Peak*	54.5	54.3	47.0	40.7	63.9	62.1	67.4	59.9	48.0	36.9	41.2	52.6
	Off-Peak	46.9	46.8	29.2	28.4	30.1	30.2	29.9	31.2	28.8	28.8	28.9	47.0
2009	*Peak*	55.8	59.4	50.1	38.9	65.6	62.1	67.6	60.3	50.5	48.7	42.8	53.9
	Off-Peak	47.0	46.9	30.2	28.6	30.1	30.3	29.9	31.4	28.8	28.9	28.9	47.2
2010	*Peak*	61.1	61.1	51.1	63.5	63.9	62.4	68.1	60.9	53.8	42.0	44.9	58.3
	Off-Peak	47.3	47.2	30.7	28.6	30.1	30.3	29.9	31.6	28.8	29.1	29.1	47.4
2011	*Peak*	62.6	62.9	54.4	42.3	68.0	63.1	69.1	61.7	40.0	44.0	48.3	59.8
	Off-Peak	47.8	47.7	32.1	29.2	30.2	30.7	30.2	31.9	29.1	29.6	29.4	47.8
2012	*Peak*	65.0	64.4	55.4	45.7	63.0	63.4	70.2	62.6	40.8	45.7	47.3	60.8
	Off-Peak	48.3	47.9	32.9	29.8	30.3	30.9	30.3	32.3	29.3	31.8	30.2	48.2
Post-2012													
	Peak	0.82%											
	Off-Peak	0.38%											

VI. Avoided Costs for Natural-Gas Utilities

In estimating the gas-utility avoided costs for various load shapes, we started with the wellhead gas prices we had estimated in the 1999 Study Group Report for each load shape. We computed the ratio of the load-shape prices to the annual average prices, as shown in Table 11:

Table 11:
Relative Costs of Natural Gas for Various Load Shapes
(Source: 1999 AESC Report)

	$/MMBtu	Ratio to Annual Average
Seasonal Base Loads		
Annual Average	$2.14	
3-month Winter	$2.35	1.098
9-month Summer	$2.08	0.972
5-month Winter	$2.24	1.047
7-month Summer	$2.08	0.972
7-month Winter	$2.20	1.028
5-month Summer	$2.08	0.972
Heating Loads		
Old buildings retrofit (269-day heating season, 63°F balance point)	$2.13	0.995
New buildings (151-day heating season, 48°F balance point)	$2.13	0.995

We then computed the updated avoided cost for each load shape by multiplying the updated annual average wellhead price by the appropriate ratio (from Table 11, above), adding the delivery costs and (for weather-sensitive loads) peaking reserves from the 1999 report, and adding 3.96% inflation from 1998 dollars to 2000 dollars. As in the 1999 report, we estimated the avoided cost for water-heating loads as 0.75 times the avoided costs for annual average load and 0.25 times the avoided costs for the retrofit heating shape.

These costs are shown below in Table 11.

Table 12:
Total Delivered Natural-Gas Costs (1998 Dollars per MMBtu)

	Annual Average	3-Month Winter	9-Month Summer	5-Month Winter	7-Month Summer	7-Month Winter	5-Month Summer	Heating Retrofit	New Heating	Water Heating
Including delivery and reserves of:	$0.80	$1.82	$0.47	$1.41	$0.37	$1.12	$0.35	$1.85	$2.38	
2002	$3.50	$4.78	$3.09	$4.24	$2.99	$3.90	$2.97	$4.54	$5.07	$3.76
2003	$3.52	$4.81	$3.11	$4.26	$3.01	$3.92	$2.99	$4.56	$5.09	$3.78
2004	$3.45	$4.73	$3.05	$4.18	$2.95	$3.84	$2.93	$4.49	$5.02	$3.71
2005	$3.45	$4.73	$3.05	$4.18	$2.95	$3.84	$2.93	$4.49	$5.02	$3.71
2006	$3.45	$4.73	$3.05	$4.18	$2.95	$3.84	$2.93	$4.49	$5.02	$3.71
2007	$3.45	$4.73	$3.05	$4.18	$2.95	$3.84	$2.93	$4.49	$5.02	$3.71
2008	$3.45	$4.73	$3.05	$4.18	$2.95	$3.84	$2.93	$4.49	$5.02	$3.71
2009	$3.45	$4.73	$3.05	$4.18	$2.95	$3.84	$2.93	$4.49	$5.02	$3.71
2010	$3.45	$4.73	$3.05	$4.18	$2.95	$3.84	$2.93	$4.49	$5.02	$3.71
2011	$3.48	$4.76	$3.07	$4.21	$2.97	$3.87	$2.95	$4.51	$5.04	$3.74
2012	$3.50	$4.79	$3.10	$4.24	$3.00	$3.90	$2.98	$4.54	$5.07	$3.76
2013	$3.53	$4.82	$3.13	$4.27	$3.03	$3.93	$3.01	$4.57	$5.10	$3.79
2014	$3.56	$4.85	$3.15	$4.30	$3.05	$3.96	$3.03	$4.60	$5.12	$3.82
2015	$3.59	$4.88	$3.18	$4.33	$3.08	$3.98	$3.06	$4.62	$5.15	$3.84
2016	$3.62	$4.91	$3.21	$4.36	$3.11	$4.01	$3.09	$4.65	$5.17	$3.87
2017	$3.65	$4.94	$3.24	$4.39	$3.14	$4.04	$3.12	$4.68	$5.20	$3.90
2018	$3.68	$4.97	$3.27	$4.42	$3.16	$4.07	$3.14	$4.71	$5.23	$3.93
2019	$3.71	$5.00	$3.30	$4.45	$3.19	$4.10	$3.17	$4.74	$5.25	$3.95
2020	$3.74	$5.03	$3.33	$4.48	$3.22	$4.12	$3.20	$4.76	$5.28	$3.98
2021	$3.77	$5.06	$3.36	$4.52	$3.25	$4.15	$3.23	$4.79	$5.31	$4.01
2022	$3.80	$5.09	$3.39	$4.55	$3.28	$4.18	$3.26	$4.82	$5.33	$4.04
Post-2012 escalation	0.8%	0.6%	0.9%	0.7%	0.9%	0.7%	0.9%	0.6%	0.5%	0.7%

Appendix A: Gas Futures Prices

Table Appendix A-1: NYMEX Gas Futures Prices, September 6, 2001

Contract Date	$/MMBtu	Contract Date	$/MMBtu	Contract Date	$/MMBtu
Jan-02	3.23	Jan-03	3.57	Jan-04	3.60
Feb-02	3.20	Feb-03	3.45	Feb-04	3.47
Mar-02	3.12	Mar-03	3.37	Mar-04	3.34
Apr-02	3.03	Apr-03	3.13	Apr-04	3.14
May-02	3.06	May-03	3.18	May-04	3.13
Jun-02	3.10	Jun-03	3.17	Jun-04	3.17
Jul-02	3.15	Jul-03	3.19	Jul-04	3.22
Aug-02	3.15	Aug-03	3.21	Aug-04	3.25
Sep-02	3.18	Sep-03	3.22	Sep-04	3.30
Oct-02	3.17	Oct-03	3.22	Oct-04	*3.23*
Nov-02	3.37	Nov-03	3.37	Nov-04	*3.38*
Dec-02	3.51	Dec-03	3.53	Dec-04	*3.54*

Source: New York Mercantile Exchange closing prices as reported by ino.com

October, November, and December prices were extrapolated from the corresponding month in 2003, times ratio of average price in January–September 2004 to the average price in January–September 2003.

Appendix B:
Derivation of Growth Rate for Combined-Cycle Costs

Table Appendix B-1:
Summary of Growth Rates in All-In Combined-Cycle Costs

	Average Elfin CC Fuel Price	Annual Energy Costs		
		($/kW-yr.)		
	($/MMBtu)	Fuel	Total	($/MWh)
2008	$3.44	$158	$233	$35.43
2009	$3.44	$158	$233	$35.43
2010	$3.44	$158	$233	$35.43
2011	$3.47	$159	$234	$35.64
2012	$3.50	$160	$236	$35.85
2013	$3.54	$162	$237	$36.09
2014	$3.57	$164	$239	$36.34
2015	$3.61	$165	$240	$36.59
2016	$3.64	$167	$242	$36.84
Annual Growth 2010–2016	0.96%			0.65%

Table Appendix B-2: Assumptions and Intermediate Results

Capital Cost	$650/kW
Fixed O&M	$32.6/kW-yr
Variable O&M	$1.25/Mwh
Heat Rate	6975 Btu/kWh
Carrying Charge	10.67%
Annual Capital Cost	$69.4/kW-yr[a]
NOx Rate	0.28 lbs./MWh
NOx Cost	$1,000/ton
NOx Price Adder	$0.14/MWh[b]
ICAP	$36/kW-yr.
Fixed Costs	$66.0/kW-yr.[c]
Capacity Factor	75%
Variable O&M/kW-yr.	$8.2/kW-yr.[d]
NOx Cost/kW-yr.	$0.9/kW-yr.[e]
Total Non-Fuel	$75.1/kW-yr.[f]

[a] Capital Cost × Carrying Charge

[b] NOx rate × NOx cost

[c] Annual Capital Cost + Fixed O&M - ICAP

[d] Variable O&M Capacity Factor × 8.76

[e] NOx Price Adder × Capacity Factor * 8.76

[f] Fixed Coasts + Variable O&M/kW-yr. + NOx Cost/kW-yr.

Appendix C: Computation of Retail Adders

Table Appendix C-1: Fitchburg Gas & Electric Computation of Retail Adder

(Default Price Set At or About 7/30/2000)

	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01
Retail Price ($/MWh)	80.4	97.9	96.0	77.5	74.1	79.0
Calculation of Wholesale Prices						
Peak Energy ($/MWh)[a]	$68.8	$92.8	$84.5	$63.4	$57.0	$63.3
Off-Peak Energy ($/MWh)[b]	$52.9	$67.2	$65.6	$43.0	$36.1	$40.1
ICAP ($/kW-month)[c]	$1.85	$1.85	$1.85	$1.85	$1.85	$1.85
NEPOOL PTF ($/kW-yr.)[d]	$15.59	$15.59	$15.59	$15.59	$15.59	$15.59
On-Peak[c]	49%	50%	53%	53%	51%	56%
Monthly Load Factor[c]	68%	64%	61%	63%	70%	69%
Reserve Requirement[e]	1.35	1.31	1.37	1.44	1.64	1.49
All Wholesale Costs ($/MWh)[f]	$68.2	$87.8	$85.0	$62.2	$55.3	$60.9
Retail:Wholesale Ratio (Average 1.22)	1.18	1.11	1.13	1.25	1.34	1.30

Notes

[a] Power Market Week's Price Index Database for 9/22/00–9/29/00; Bloomberg 9/29/00

[b] Peak times the off-peak/peak ratio of the same month of the previous year, from NEPOOL hourly data as aggregated by www.isoanalysis.com.

[c] Forward prices for Year 2001 from Natsource 11/00

[d] The sum of ISO NE's "RNS Rates for June '01" (in its "NEPOOL Transmission Tariff Schedule 9—Regional Network Service") and the line 20 of "Summary" in its "NEPOOL Transmission Tariff Schedule 1—Scheduling, System Control and Dispatch Service." The ISO's Transmission Settlement Subcommittee approved these rates on June 1 2001.

[e] From "Review of NEPOOL Object Capability for Power Year 2000–2001," cited in footnote 11 (p. 14) of this update.

[f] Calculated as the sum of the following times 1 plus losses:

- Peak energy times percent on peak
- Off-peak energy times percent not on peak
- Hourly ICAP divided by monthly load factor times reserve requirement times 1,000
- Hourly NEPOOL PTF divided by monthly load factor times reserve requirement times 1,000

Table Appendix C-2:
Fitchburg Gas & Electric Computation of Retail Adder
(Default Price Set At or About 3/30/2001)

	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01
Retail Price ($/MWh)	$83.8	$104.4	$110.8	$68.1	$70.5	$67.7
Calculation of Wholesale Prices						
Peak Energy ($/MWh)[a]	$76.0	$101.0	$101.0	$57.8	$56.3	$56.3
Off-Peak Energy ($/MWh)[a]	$48.0	$51.0	$51.0	$40.0[b]	$40.0	$40.0
ICAP ($/kW-month)[a]	$2.84	$4.13	$4.13	$2.84	$2.84	$2.84
NEPOOL PTF ($/kW-yr.)[c]	$15.59	$15.59	$15.59	$15.59	$15.59	$15.59
On-Peak[d]	55%	51%	58%	54%	55%	55%
Monthly Load Factor[e]	66%	67%	64%	65%	52%	62%
Reserve Requirement[f]	1.26	1.16	1.16	1.31	1.61	1.49
All Wholesale Costs ($/MWh)[g]	$73.5	$88.6	$92.7	$60.4	$64.1	$61.3
Retail:Wholesale Ratio (Average 1.18)	1.14	1.18	1.19	1.13	1.10	1.10

Notes

[a] Natsource 3/29/01

[b] Natsource did not provide a September value. The fourth-quarter monthly value is used.

[c] The sum of ISO NE's "RNS Rates for June '01" (in its "NEPOOL Transmission Tariff Schedule 9—Regional Network Service") and the line 20 of "Summary" in its "NEPOOL Transmission Tariff Schedule 1—Scheduling, System Control and Dispatch Service." The ISO's Transmission Settlement Subcommittee approved these rates on June 1 2001.

[d] From the same month in 2000 as provided by the Fitchburg Gas & Electric Company.

[e] From the same month in 2000 as computed from date provided by the Fitchburg Gas & Electric Company.

[f] From "Review of NEPOOL Object Capability for Power Year 2000–2001" and "Revised Objective Capability Values for the 2001/2002 Power Year," cited in footnote 11 (p. 14) of this update.

[g] Calculated as the sum of the following times 1 plus losses:

- Peak energy times percent on peak
- Off-peak energy times percent not on peak
- Hourly ICAP divided by monthly load factor times reserve requirement times 1,000
- Hourly NEPOOL PTF divided by monthly load factor times reserve requirement times 1,000

Table Appendix C-3:
Narragansett Electric Computation of Retail Adder
(Default Price Set At or About 8/14/2001)

	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02
Retail Price ($/MWh)	$56.74	$56.74	$56.74	$56.74	$56.74	$56.74
Calculation of Wholesale Prices						
Peak Energy ($/MWh)[a]	$44.3	$44.3	$44.3	$44.3	$50.5	$50.5
Off-Peak Energy ($/MWh)[a]	$32.3	$33.5	$33.5	$33.5	$30.5	$30.5
ICAP ($/kW-month)[a]	$1.60	$1.60	$1.60	$1.60	$1.50	$1.5
NEPOOL PTF ($/kW-yr.)[b]	$15.59	$15.59	$15.59	$15.59	$15.59	$15.59
On-Peak[c]	0.48	0.49	0.50	0.46	0.50	0.50
Monthly Load Factor[c]	76%	75%	83%	83%	82%	79%
Reserve Requirement[d]	1.31	1.67	1.52	1.35	1.30	1.36
Losses	8%	8%	8%	8%	8%	8%
All Wholesale Costs ($/MWh)[e]	$47.8	$49.5	$48.7	$47.5	$49.6	$50.4
Retail:Wholesale Ratio (Average 1.16)	1.19	1.15	1.16	1.19	1.14	1.13

Notes

[a]Bloomberg 8/17/01

[b]The sum of ISO NE's "RNS Rates for June '01" (in its "NEPOOL Transmission Tariff Schedule 9—Regional Network Service") and the line 20 of "Summary" in its "NEPOOL Transmission Tariff Schedule 1—Scheduling, System Control and Dispatch Service." The ISO's Transmission Settlement Subcommittee approved these rates on June 1 2001.

[c]From the same month in 2000, from data provided by NGrid.

[d]From "Review of NEPOOL Object Capability for Power Year 2000–2001" and "Revised Objective Capability Values for the 2001/2002 Power Year," cited in footnote 11 (p. 14) of this update.

[e]Calculated as the sum of the following times 1 plus losses:

- Peak energy times percent on peak
- Off-peak energy times percent not on peak
- Hourly ICAP divided by monthly load factor times reserve requirement times 1,000
- Hourly NEPOOL PTF divided by monthly load factor times reserve requirement times 1,000

Table Appendix C-4:
Narragansett Electric Computation of Retail Adder
(Default Price Set At or About 4/24/2001)

	May-01	Jun-01	Jul-01	Aug-01
Retail Price ($/MWh)	58.82	81.02	103.99	99.81
Calculation of Wholesale Prices				
Peak Energy ($/MWh)[a]	$56.9	$73.6	$99.0	$99.0
Off-Peak Energy ($/MWh)[a]	$37.0	$44.5	$51.3	$51.3
ICAP ($/kW-month)[a]	$0.4	*$3.00*	$3.00	$3.0
NEPOOL PTF ($/kW-yr.)[b]	$15.59	$15.59	$15.59	$15.59
On-Peak[c]	0.50	0.50	0.46	0.50
Monthly Load Factor[c]	73%	73%	75%	78%
Reserve Requirement[d]	1.49	1.30	1.16	1.16
Losses	8%	8%	8%	8%
All Wholesale Costs ($/MWh)[e]	$54.3	$74.3	$88.4	$90.2
Retail:Wholesale Ratio (Average 1.11)	1.08	1.09	1.18	1.11

Notes

[a] Natsource 4/24/01; Bloomberg 4/27/01

[b] From Schedule 9 Rate.xls

[b] The sum of ISO NE's "RNS Rates for June '01" (in its "NEPOOL Transmission Tariff Schedule 9—Regional Network Service") and the line 20 of "Summary" in its "NEPOOL Transmission Tariff Schedule 1—Scheduling, System Control and Dispatch Service." The ISO's Transmission Settlement Subcommittee approved these rates on June 1 2001.

[d] From "Review of NEPOOL Object Capability for Power Year 2000–2001," cited in footnote 11 (p. 14) of this update.

[e] Calculated as the sum of the following times 1 plus losses:

- Peak energy times percent on peak
- Off-peak energy times percent not on peak
- Hourly ICAP divided by monthly load factor times reserve requirement times 1,000
- Hourly NEPOOL PTF divided by monthly load factor times reserve requirement times 1,000

Table Appendix C-5:
Mass Electric Computation of Residential Retail Adder
(Default Price Set At or About 3/8/2001)[a]

	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01
Retail Price ($/MWh)	78.1	93.9	113.6	111	75.4	75.7
Calculation of Wholesale Prices						
Peak Energy ($/MWh)[b]	$57.0	$76.6	$101.0	$101.0	$55.5	$49.1
Off-Peak Energy ($/MWh)[b]	$40.3	$45.3	$51.3	$51.3	$40.5	$35.8
ICAP ($/kW-month)[b]	$3.18	$3.18	$3.50	$3.50	$3.18	$3.18
NEPOOL PTF ($/kW-yr.)[c]	$15.59	$15.59	$15.59	$15.59	$15.59	$15.59
On-Peak[d,e]	61%	45%	56%	60%	55%	55%
Monthly Load Factor[d,f]	55%	62%	54%	64%	59%	59%
Reserve Requirement[g]	1.49	1.30	1.16	1.16	1.31	1.67
Losses	9%	9%	9%	9%	9%	9%
All Wholesale Costs ($/MWh)[h]	$71.2	$78.0	$100.7	$100.4	$67.3	$63.5
Retail:Wholesale Ratio (Average 1.14)	1.10	1.20	1.13	1.11	1.12	1.19

Notes

[a] These data comprise data from the former Massachusetts Electric and Eastern Edison service territories.

[b] Natsource 3/8/01; Bloomberg, 3/7/01

[c] The sum of ISO NE's "RNS Rates for June '01" (in its "NEPOOL Transmission Tariff Schedule 9—Regional Network Service") and the line 20 of "Summary" in its "NEPOOL Transmission Tariff Schedule 1—Scheduling, System Control and Dispatch Service." The ISO's Transmission Settlement Subcommittee approved these rates on June 1 2001.

[d] September and October interpolated from data provided from NGrid for August 2001 and November 2000.

[e] Reduced 4% to account for holidays.

[f] Reflects inter-class diversity.

[g] From "Review of NEPOOL Object Capability for Power Year 2000–2001" and "Revised Objective Capability Values for the 2001/2002 Power Year," cited in footnote 11 (p. 14) of this update.

[h] Calculated as the sum of the following times 1 plus losses:

- Peak energy times percent on peak
- Off-peak energy times percent not on peak
- Hourly ICAP divided by monthly load factor times reserve requirement times 1,000
- Hourly NEPOOL PTF divided by monthly load factor times reserve requirement times 1,000

Table Appendix C-6:
Mass Electric Computation of Commercial Retail Adder
(Default Price Set At or About 3/8/2001)[a]

	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01
Retail Price ($/MWh)	81	101	119	118.2	77.3	73.5
Calculation of Wholesale Prices						
Peak Energy ($/MWh)[b]	$57.0	$76.6	$101.0	$101.0	$55.5	$49.1
Off-Peak Energy ($/MWh)[b]	$40.3	$45.3	$51.3	$51.3	$40.5	$35.8
ICAP ($/kW-month)[b]	$3.18	$3.18	$3.50	$3.50	$3.18	$3.18
NEPOOL PTF ($/kW-yr.)[c]	$15.59	$15.59	$15.59	$15.59	$15.59	$15.59
On-Peak[d,e]	60%	53%	59%	61%	60%	60%
Monthly Load Factor[d,f]	49%	51%	47%	51%	54%	56%
Reserve Requirement[g]	1.49	1.30	1.16	1.16	1.31	1.67
Losses	9%	9%	9%	9%	9%	9%
All Wholesale Costs ($/MWh)[h]	$73.0	$83.4	$104.8	$104.5	$69.5	$65.0
Retail:Wholesale Ratio (Average 1.14)	1.11	1.21	1.14	1.13	1.11	1.13

Notes

[a] These data comprise data from the former Massachusetts Electric and Eastern Edison service territories.

[b] Natsource 3/8/01; Bloomberg, 3/7/01

[c] The sum of ISO NE's "RNS Rates for June '01" (in its "NEPOOL Transmission Tariff Schedule 9—Regional Network Service") and the line 20 of "Summary" in its "NEPOOL Transmission Tariff Schedule 1—Scheduling, System Control and Dispatch Service." The ISO's Transmission Settlement Subcommittee approved these rates on June 1 2001.

[d] September and October interpolated from data provided from NGrid for August 2001 and November 2000.

[e] Reduced 4% to account for holidays.

[f] Reflects inter-class diversity.

[g] From "Review of NEPOOL Object Capability for Power Year 2000–2001" and "Revised Objective Capability Values for the 2001/2002 Power Year," cited in footnote 11 (p. 14) of this update.

[h] Calculated as the sum of the following times 1 plus losses:

- Peak energy times percent on peak
- Off-peak energy times percent not on peak
- Hourly ICAP divided by monthly load factor times reserve requirement times 1,000
- Hourly NEPOOL PTF divided by monthly load factor times reserve requirement times 1,000

Table Appendix C-7:
Mass Electric Computation of Industrial Retail Adder
(Default Price Set At or About 3/8/2001)[a]

	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01
Retail Price ($/MWh)	77.1	95.5	112.2	111.6	73.9	70.8
Calculation of Wholesale Prices						
Peak Energy ($/MWh)[b]	$57.0	$76.6	$101.0	$101.0	$55.5	$49.1
Off-Peak Energy ($/MWh)[b]	$40.3	$45.3	$51.3	$51.3	$40.5	$35.8
ICAP ($/kW-month)[b]	$3.18	$3.18	$3.50	$3.50	$3.18	$3.18
NEPOOL PTF ($/kW-yr.)[c]	$15.59	$15.59	$15.59	$15.59	$15.59	$15.59
On-Peak[d,e]	56%	51%	53%	57%	56%	55%
Monthly Load Factor[d,f]	70%	71%	64%	65%	68%	72%
Reserve Requirement[g]	1.49	1.30	1.16	1.16	1.31	1.67
Losses	6%	6%	6%	6%	6%	6%
All Wholesale Costs ($/MWh)[h]	$64.9	$76.1	$94.5	$96.4	$63.7	$58.9
Retail:Wholesale Ratio (Average 1.19)	1.19	1.25	1.19	1.16	1.16	1.20

Notes

[a] These data comprise data from the former Massachusetts Electric and Eastern Edison service territories.

[b] Natsource 3/8/01; Bloomberg, 3/7/01

[c] The sum of ISO NE's "RNS Rates for June '01" (in its "NEPOOL Transmission Tariff Schedule 9—Regional Network Service") and the line 20 of "Summary" in its "NEPOOL Transmission Tariff Schedule 1—Scheduling, System Control and Dispatch Service." The ISO's Transmission Settlement Subcommittee approved these rates on June 1 2001.

[d] September and October interpolated from data provided from NGrid for August 2001 and November 2000.

[e] Reduced 4% to account for holidays.

[f] Reflects inter-class diversity.

[g] From "Review of NEPOOL Object Capability for Power Year 2000–2001" and "Revised Objective Capability Values for the 2001/2002 Power Year," cited in footnote 11 (p. 14) of this update.

[h] Calculated as the sum of the following times 1 plus losses:

- Peak energy times percent on peak
- Off-peak energy times percent not on peak
- Hourly ICAP divided by monthly load factor times reserve requirement times 1,000
- Hourly NEPOOL PTF divided by monthly load factor times reserve requirement times 1,000

Appendix D:
Wholesale Avoided Electric Costs

Table Appendix D-1:
Seasonal Wholesale Capacity Cost
(Year-2000 Dollars per kW-yr.)

	Summer	Winter
2002	$11.27	$7.51
2003	$10.82	$7.21
2004	$11.35	$7.56
2005	$15.13	$10.09
2006	$18.91	$12.61
After 2006	$22.69	$15.13

Table Appendix D-2:
Wholesale Market Energy Components by Month and Period (Year-2000 Dollars per MWh)

		Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2002	*Peak*	$39.6	$40.3	$40.6	$30.1	$26.7	$49.1	$50.8	$53.4	50.3	35.4	26.2	31.3	40.1
	Off-Peak	$28.4	$39.1	$39.1	$24.2	$24.0	$25.7	$25.6	$25.5	26.1	24.3	24.1	24.1	39.1
2003	*Peak*	$33.7	$40.4	$40.5	$30.7	$26.1	$48.4	$49.7	$52.7	49.8	32.2	25.4	28.5	40.1
	Off-Peak	$38.8	$39.2	$39.2	$24.2	$24.2	$25.7	$25.6	$25.5	25.9	24.5	24.2	24.2	39.3
2004	*Peak*	$28.4	$41.2	$41.1	$31.5	$26.3	$48.3	$49.6	$51.3	49.3	33.2	25.5	33.3	40.2
	Off-Peak	$33.4	$38.8	$38.8	$23.8	$23.7	$25.3	$25.2	$24.9	25.6	24.0	23.7	23.7	38.8
2005	*Peak*	$39.3	$42.1	$41.8	$34.9	$26.6	$49.3	$50.4	$52.0	49.3	34.6	26.2	36.5	41.1
	Off-Peak	$28.0	$38.8	$38.8	$23.8	$23.7	$25.2	$25.1	$24.9	25.7	24.0	23.8	23.8	38.9
2006	*Peak*	$33.4	$43.2	$43.3	$34.0	$27.0	$50.4	$51.3	$52.5	49.5	38.6	27.0	31.0	41.9
	Off-Peak	$40.4	$38.9	$38.8	$23.9	$23.7	$25.2	$25.2	$24.9	25.8	24.0	23.9	23.9	38.9
2007	*Peak*	$28.0	$43.9	$44.0	$36.4	$28.8	$51.3	$52.2	$52.9	49.7	39.0	28.3	32.7	42.5
	Off-Peak	$33.9	$38.9	$38.9	$24.1	$23.7	$25.1	$25.2	$24.9	25.9	24.0	24.0	24.0	39.0
2008	*Peak*	$40.9	$45.4	$45.2	$39.2	$33.9	$53.2	$51.8	$56.1	49.9	40.0	30.8	34.3	43.9
	Off-Peak	$28.1	$39.1	$39.0	$24.3	$23.7	$25.1	$25.2	$24.9	26.0	24.0	24.0	24.1	39.2
2009	*Peak*	$34.1	$46.5	$49.5	$41.8	$32.4	$54.7	$51.8	$56.3	50.2	42.1	40.5	35.7	44.9
	Off-Peak	$41.8	$39.2	$39.1	$25.2	$23.8	$25.1	$25.3	$24.9	26.2	24.0	24.1	24.1	39.3
2010	*Peak*	$28.1	$50.9	$50.9	$42.6	$52.9	$53.2	$52.0	$56.8	50.7	44.8	35.0	37.4	48.5
	Off-Peak	$34.6	$39.4	$39.3	$25.6	$23.8	$25.1	$25.3	$24.9	26.3	24.0	24.2	24.2	39.5
2011	*Peak*	$43.7	$52.2	$52.4	$45.3	$35.2	$56.7	$52.6	$57.6	51.5	33.4	36.7	40.2	49.8
	Off-Peak	$28.2	$39.8	$39.7	$26.7	$24.3	$25.2	$25.6	$25.2	26.6	24.2	24.6	24.5	39.8
2012	*Peak*	$35.6	$54.2	$53.6	$46.2	$38.0	$52.5	$52.8	$58.5	52.2	34.0	38.0	39.4	50.6
	Off-Peak	$45.5	$40.2	$39.9	$27.4	$24.8	$25.3	$25.8	$25.3	26.9	24.4	26.5	25.2	40.1
Post-2012														
	Peak	0.82%												
	Off-Peak	0.38%												