Avoided-Energy-Supply-Component Study Group

Avoided Energy-Supply Costs

For Demand-Side-Management Screening in Massachusetts

Prepared for the Avoided-Energy-Supply-Component Study Group by

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Note to the July 30 Final Report

This report includes new tables and other changes since the July 7 edition, incorporating comments from the members of the Avoided-Energy-Supply-Component Study Group.

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Executive Summary and Introduction

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 (DSM) programs. This report presents the findings of an investigation of avoided-energy-supply components for Massachusetts, as well as a discussion of the related research undertaken in the process of developing consensus values for various assumptions and inputs.

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

The major tasks of the Resource Insight team were to (1) review published forecasts of electric generation and gas costs, and (2) support the group in developing a consensus-based projection of avoided energy supply costs by providing background data, analysis, and modeling.

The energy-supply components developed in this report are to be used for the purposes of DSM planning, evaluation, and implementation only. Neither the Study Group nor its members supports in any way the use of the market price projections described herein, nor the inputs to those projections, for any other purpose.

In addition, the development of the final set of quantified values for the analysis and modeling conducted by Resource Insight in the second task was in many respects the result of give and take among the participants of the process. Consequently, none of the individual values used in developing the final results can or should be attributed to individual members of the Study Group. Rather, in the process of seeking a consensus among the parties, each of the utility and non-utility party representatives sought to agree on individual elements of the analysis in order to develop a set of avoided-energy-supply components that all the parties could accept as appropriate for DSM planning, implementation, and evaluation.

A. Electric Consensus Values

The electric values reported in this document are based on consensus inputs to a production-costing model and an equilibrium model. Only the equilibrium model yields capacity prices; these were adopted by the Study Group, except for the year 2000 prices, which were discounted to reflect a short-term capacity surplus in the region. The energy prices projected by the equilibrium model were consistently slightly greater than the energy prices produced by the production cost model. The Study Group chose to average the results of the two methods.

Table 1 presents the Study Group's consensus avoided capacity prices (including reserves) and average energy prices for New England loads. The combined values use a typical load factor of 60% and a reserve margin of 17%, and assume energy savings are proportional to the total load of the New England Power Pool (NEPOOL). This estimate does not include line losses or any externality adder. The consensus values fall within a range of forecasts of market prices surveyed as part of this study and summarized in Section I.F.

Table 1:
Consensus Avoided Electric Supply Costs for New England

	1998 Dollars			Nominal Dollars		
	Capacity and Reserve ($/kW-yr.)	*Energy ($/MWh)*	*Capacity, Reserve, and Energy at 60% Load Factor ($/MWh)*	*Capacity and Reserve ($/kW-yr.)*	*Energy ($/MWh)*	*Capacity, Reserve, and Energy at 60% Load Factor ($/MWh)*
2000	28.91	28.59	34.09	30.37	30.04	35.82
2001	48.18	28.59	37.76	51.89	30.79	40.66
2002	48.18	28.45	37.62	53.19	31.40	41.52
2003	48.18	28.59	37.76	54.51	32.35	42.72
2004	48.18	28.79	37.95	55.88	33.38	44.01
2005	48.18	29.12	38.29	57.27	34.62	45.52
2006	48.18	29.57	38.74	58.70	36.03	47.20
2007	48.18	29.58	38.75	60.17	36.95	48.39
2008	48.18	29.56	38.73	61.67	37.84	49.58
2009	48.18	29.33	38.50	63.22	38.48	50.51
2010	48.18	29.44	38.61	64.79	39.60	51.93

For use in DSM screening, the energy price will have to be differentiated into seasonal peak and off-peak periods, as described in Section I.E, and the capacity price will have to be differentiated into summer and winter periods as described in Section I.C.

Details of the electricity-supply-cost modeling assumptions, methods and results are presented in Section I of this report.

B. Gas Consensus Values

The consultants developed gas costs for three types of load shape: base, weather-sensitive, and water heating. Within the base category, several load-shape subtypes allow for the characterization of DSM measures that have different seasonal savings, but fairly constant savings within any one season. Several different definitions of the seasons are presented, because different companies may use different definitions, or different measures may better fit one seasonal profile than another. Within the weather-sensitive category, two load-shape subtypes differentiate between older and newer buildings.

Table 2 shows the Study Group's consensus values for total avoided delivered gas costs.

Table 2:
Consensus Avoided Delivered Gas Cost (1998 $/MMBtu)

	Baseload							**Weather-Sensitive**		
	Annual	*3-month Winter*	*9-month Summer*	*5-month Winter*	*7-month Summer*	*7-month Winter*	*5-month Summer*	*Old Buildings (269 days)*	*New Buildings (151 days)*	**Water-Heating**
2000	2.94	4.17	2.55	3.65	2.45	3.32	2.43	3.98	4.53	3.20
2001	2.94	4.17	2.55	3.65	2.45	3.32	2.43	3.98	4.53	3.20
2002	2.94	4.17	2.55	3.65	2.45	3.32	2.43	3.98	4.53	3.20
2003	2.94	4.17	2.55	3.65	2.45	3.32	2.43	3.98	4.53	3.20
2004	2.94	4.17	2.55	3.65	2.45	3.32	2.43	3.98	4.53	3.20
2005	2.94	4.17	2.55	3.65	2.45	3.32	2.43	3.98	4.53	3.20
2006	2.97	4.20	2.58	3.68	2.48	3.35	2.46	4.01	4.56	3.23
2007	3.00	4.23	2.61	3.71	2.51	3.38	2.49	4.03	4.59	3.26
2008	3.03	4.27	2.64	3.74	2.54	3.41	2.52	4.06	4.62	3.29
2009	3.06	4.30	2.66	3.77	2.56	3.44	2.54	4.09	4.65	3.32
2010	3.09	4.33	2.69	3.81	2.59	3.47	2.57	4.12	4.68	3.35

Note: The costs for weather-sensitive load (space heating) include 2.5% losses. A portion of these losses flows through to the water-heating costs.

As with the electric costs, these values do not include externalities.

These costs were developed from a combination of wellhead (Henry Hub) prices and transportation costs to New England. Average wellhead prices were based on an average of prominent forecasts; average transportation costs were derived from an independent forecast, a current tariff, and recent historical data. The costs associated with the different load shapes were developed specifically for the Study Group.

The gas-cost analysis is presented in Section II of this report.

I. Marginal Electricity Supply Costs in New England

Following a summary of the Study Group's projection of avoided energy supply costs, Section B summaries the methods and results of the development of the wholesale-price projection.[1] The wholesale prices differ from the electric-generation supply component in that the wholesale prices do not account for load shapes, line losses, or reserve margins. These adjustments, which are a necessary part of the avoided supply component are discussed below in Section C. Section D provide some of the supporting data that the Study Group relied upon in selecting its assumptions. Section E describes additional adjustments or additions required prior to DSM screening. Section F provides recent forecasts of New England market prices, for comparison.

A. Summary of Electric-Generation Capacity and Energy Prices

Table 3 presents the Study Group's consensus avoided capacity prices (including an allowance for a 17% reserve margin) and average energy prices for New England loads. The combined values use a typical load factor of 60%.

Table 3:
Consensus Avoided Electric Supply Costs

	1998 Dollars			Nominal Dollars		
	Capacity and Reserve ($/kW-yr.)	*Energy ($/MWh)*	*Capacity, Reserve, and Energy at 60% Load Factor ($/MWh)*	*Capacity and Reserve ($/kW-yr.)*	*Energy ($/MWh)*	*Capacity, Reserve, and Energy at 60% Load Factor ($/MWh)*
2000	28.91	28.59	34.09	30.37	30.04	35.82
2001	48.18	28.59	37.76	51.89	30.79	40.66
2002	48.18	28.45	37.62	53.19	31.40	41.52
2003	48.18	28.59	37.76	54.51	32.35	42.72
2004	48.18	28.79	37.95	55.88	33.38	44.01
2005	48.18	29.12	38.29	57.27	34.62	45.52
2006	48.18	29.57	38.74	58.70	36.03	47.20
2007	48.18	29.58	38.75	60.17	36.95	48.39
2008	48.18	29.56	38.73	61.67	37.84	49.58
2009	48.18	29.33	38.50	63.22	38.48	50.51
2010	48.18	29.44	38.61	64.79	39.60	51.93

[1]Much of the methodology presented follows that used in the development of wholesale or market prices. Hence, the term "wholesale price" in this report refers to the portion of the avoided-energy-supply component comparable to publicly traded energy and capacity at the generation level, without consideration of load shape, line losses, or reserve margin. Nevertheless, these values should not be confused with actual projections of market price by Resource Insight, its subcontractors, or any member of the Study Group.

B. Derivation of Wholesale Electric Prices

1. *Methods*

The electric energy price forecasts were developed by two different methods—a spreadsheet-based equilibrium model and a special-purpose production-costing (dispatch) model. The Study Group felt both approaches were valid and each emphasized specific aspects of the market dynamics, so it decided to average the annual results of these methods. The dispatch model also supplied time-differentiated energy prices, which are used to shape the average.

Capacity prices are estimated with the equilibrium approach.

a) Equilibrium Market-Price Modeling

Over the long term, the market price of power will be determined by the cost of new resources. Developers will build new plants only when they believe that the market price for electricity will cover the costs (including a return commensurate with risk) of building and running those plants. If the market price is projected to more than cover costs, developers will build more new plants until the market price is driven down to the level of plant cost.

In the short run, the price may differ from the long-term price, exceeding it in periods of capacity shortage (including economic booms and extreme weather) and falling below in periods of excess capacity. Rather than modeling all of the short-run perturbations in market price (many of which are inherently unpredictable), the equilibrium approach projects the market price based on the long-run cost.[2]

The equilibrium model's capacity component is derived from the cost of the cheapest source of new capacity (in dollars per kW-yr.), which is expected to be gas-fired combustion turbine (CT) plants. Capacity prices were developed using a traditional utility revenue-requirements calculation for the combustion turbine and financial assumptions described in Section I.D below.

The energy component of the equilibrium model is derived from the incremental cost of the cheapest source of new energy production (in dollars per MWh), expected to be new gas-fired combined-cycle (CC) plants. While combined-cycle units are more expensive to build than CTs, they run more efficiently and produce energy at a lower cost. Since combined-cycle units are expected to receive capacity revenue based on the cost of CTs, the price of energy is set by the incremental investment and running cost of a combined-cycle plant compared to a CT.

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[2]This is the approach taken in the Massachusetts DPU's rules for RFPs (220 C.M.R. 8.05(3)) in the late 1980s and early 1990s.

Energy prices for new combined-cycle plants were calculated as the sum of fuel costs, variable O&M costs, and capitalized energy costs (the portion of the combined-cycle unit's fixed cost that must be recovered from energy rather than capacity charges). The capitalized energy cost was developed by first performing the traditional revenue-requirements calculation and real-levelization to calculate a fixed charge for the combined-cycle plants. This was multiplied by the estimated capital cost to produce a carrying cost in dollars per kW-yr. The annual fixed O&M (including overheads and capital additions) for the combined-cycle unit was added to this, and—in order to net out the capacity value—the annual CT cost (levelized capital plus fixed O&M) was subtracted. The resulting capitalized energy figure (expressed in dollars per kW-yr.) was then divided by the number of equivalent hours in which the plant would operate, to yield a cost in the form of dollars per kWh, which was then added to the fuel and variable O&M costs.

The inputs to the equilibrium computations are described below in Section I.D. The key drivers for the equilibrium method are as follows:

- Delivered gas price to new gas combined-cycle plants;
- New combined-cycle fixed costs, comprising capital cost, cost of capital, and fixed O&M costs, including overheads and capital additions;
- Variable O&M for new combined-cycle units.

b) The Production-Costing Approach

Production-costing models can be used to estimate the price for energy in the region, based on (1) variable costs, capacity, and reliability of each existing and future plant in the region, (2) regional loads and (3) assumptions about energy supplied or demanded over interconnections with other regions. In a bid-based energy market, such as NEPOOL, assumptions about the behavior of the bidders also affects inputs to the model.

Dispatch of the New England power system to meet loads was simulated using the ELFIN Production Cost Model. ELFIN models energy prices as the cost of the most expensive generator required to serve load at any particular time.

The ELFIN model was developed by the Environmental Defense Fund in the late 1970s and has been widely used in utility-system simulation studies for twenty years. The ELFIN model uses the Baleriaux-Booth algorithm for representing randomly occurring generator outages, and is capable of simulating electric system dispatch at a fine level of detail.

This analysis did not use ELFIN's capacity-expansion capabilities. Instead, the addition of new generators was specified by the consultants, as described in Appendix A.

The planning-assumption inputs to the ELFIN runs are described in Appendix A. The key drivers for the production costing methods are as follows:

- Fuel prices, especially oil
- Market behavior
- Assumed new additions
- Variable O&M, especially for oil plants.

2. New England's Capacity Situation and Emerging Market

This study relies on certain inputs that result from ISO-NE rules and procedures (e.g., the market structure and the Forecast of Capacity, Energy, Load and Transmission (CELT Report)), and assumes that those rules remain stable for the foreseeable future. The basic structure is as follows.

Each NEPOOL participant is required to have installed capacity in all hours of a month at least equal to the participant's non-coincident peak load, plus a monthly reserve requirement. That reserve requirement is set to result in the same level of installed capacity (other than seasonal changes) being required in each month.

The capacity price may be paid through some combination of charges for

- *installed capacity,* in the form of each participant's monthly Capability Responsibility, which is the pool Objective Capability times the participant's share of the sum of non-coincident monthly peaks.
- *operable capability,* in the form of an hourly market administered by the ISO.
- *three kinds of operating reserves* (10-minute spinning, 10-minute non-spinning, and 30-minute), priced in real time.

However, the NEPOOL markets are immature, and it is not clear how important each of these three markets will be in the recovery of capacity costs. This report has not attempted to allocate capacity prices to the various capacity-related ISO-NE services. Since the market opening on May 1, 1999, there is scant market data with which to predict how it will behave.

When demand and supply are balanced, and the mix of installed capacity is balanced between peaking and baseload capacity, the market price of capacity would be expected to approximate the annualized cost of a CT peaking unit. When the region has surplus capacity, the market price of capacity would normally be lower than the equilibrium price.

In the early 1990s, projections of load and capacity indicated that New England would have 1,000–2,000 MW of excess capacity for five to ten years. Between

1989 and 1993, the market price of capacity fell from essentially full equilibrium price to just a few dollars per kilowatt-year.

Today, NEPOOL expects a capacity surplus for 1999–2000. That is, NEPOOL projects that a few hundred megawatts of capacity will be available in excess of that needed to meet its planning target of one day of emergency responses in ten years.

The New England Power Pool's reliability targets currently require installed summer capacity about 6% above annual peak.[3]

The Power Pool's 1999 CELT projects that, with the return to service of Millstone 2 and the completion of capacity under construction or fully licensed, installed reserve margins will exceed 6% in 1999–2001. Depending on the rates at which load grows, new capacity is built, and existing plants are retired, the amount of capacity proposed in New England could extend the period of surplus installed capacity for many years.[4]

Capacity can have value even with an excess of installed capacity. The amount of excess capacity expected in this period is less extreme than in the early 1990s. In addition, NEPOOL now has requirements and a market for operable capacity, and market-based (rather than cost-based) pricing of the operating reserves. The installed capacity market is set up to allocate whatever capacity is installed among market participants, and may therefore maintain a market value for installed capacity, even if the pool has more than its target for installed capacity.

For example, in April 1999, the market-clearing price was $1.24/kW-month, even with 360 MW of excess installed capacity.[5] The preliminary operable-capacity clearing prices for June 8, 1999, alone, were nearly $10/kW. In addition, the market prices for operating reserves have exceeded $1/kW-day (and sometimes several dollars per kW-day) on several days in May and June of 1999.

To account for NEPOOL's capacity surplus and recognize other complex pricing arrangements and uncertainties in future markets, the Study Group chose to discount the capacity price from equilibrium levels by 80% in 1999 and 40% in 2000.

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[3]The 6%-reserve values include generation in New England, plus a few hundred MW of purchases. This target does not include inter-regional tieline capacity. Including the capability supplied by the Hydro Quebec (HQ) Phase I & II intertie (1,800 MW summer) and other interties (1,000 MW summer), the total required reserve is about 19%.

[4]Developers have proposed more than 20,000 MW of new capacity within NEPOOL. Only a small portion of this would be required to maintain adequate reserves over the next decade.

[5]This is the most recent month for which the ISO has conducted the after-the-fact clearing of the installed-capacity market.

3. *Summary of Wholesale Market Results*

Table 4 presents the Study Group's consensus wholesale capacity prices and baseload (100% operating factor) energy prices.[6] The consensus energy price is the average of the results of the equilibrium and production-costing computations.

Table 4:
Consensus Wholesale Electricity Prices

	1998 Dollars					Nominal Dollars		
	Energy ($/MWh)			Capacity ($/kW-yr.)	Combined Capacity & Energy ($/MWh)	Capacity ($/kW-yr.)	Energy ($/MWh)	Combined Capacity & Energy ($/MWh)
	Production Costing	Equilibrium	Consensus					
2000	28.20	26.84	27.52	24.71	30.34	25.96	28.91	31.88
2001	28.20	26.84	27.52	41.18	32.22	44.35	29.64	34.70
2002	27.90	26.84	27.37	41.18	32.07	45.45	30.21	35.40
2003	28.20	26.84	27.52	41.18	32.22	46.59	31.14	36.45
2004	28.60	26.84	27.72	41.18	32.42	47.75	32.15	37.60
2005	28.90	26.84	27.87	41.18	32.57	48.95	33.13	38.72
2006	29.40	27.05	28.23	41.18	32.93	50.17	34.40	40.12
2007	29.20	27.25	28.23	41.18	32.93	51.43	35.26	41.13
2008	29.00	27.39	28.20	41.18	32.90	52.71	36.10	42.12
2009	28.50	27.60	28.05	41.18	32.75	54.03	36.80	42.97
2010	28.50	27.81	28.16	41.18	32.86	55.38	37.87	44.19

These values are comparable to the market-price forecasts discussed in Section I.F. They do not include the effects of load shapes and reserve requirements, and are therefore less than the values in Table 1 and Table 3.

C. Computing DSM Avoided Costs from Wholesale Prices

A number of adjustments and additional inputs are necessary to turn the consensus wholesale prices, described above, into avoided supply components that are useful for DSM screening. This section describes the adjustments that have been made in this project. Other adjustments are utility-specific or beyond the scope of this project, and are described in Section I.E below.

1. *Required Capacity Reserve Margin*

The *wholesale* prices for capacity derived in this report reflect the cost of a kilowatt of supply. However, power suppliers will need to meet a reserve

[6]The reference to baseload identifies these market prices as around-the-clock, not load-following. Most loads will have greater avoided energy costs, and greater avoided capacity costs per MWh than most loads avoided by DSM.

requirement; that is, they will have to maintain (or purchase) installed capacity and operable capacity in excess of their peak load. As a result, each kilowatt of DSM load reduction saves more than a kilowatt of supply, since the load reduction also allows the power supplier to avoid the reserves that would otherwise be required. The Study Group agrees that avoided capacity costs should reflect the required reserve margin, and will be calculated as the wholesale capacity prices times one plus the required reserve margin.

However, the ISO has not projected future installed reserve requirements, and the Study Group has not fully considered what level of required reserves it expects. The production-costing runs used in this study assumed a long-term expansion plan designed to maintain a reserve at least equal to 17%. Consistent with the modeling, the assumed 17% reserve requirement has been added to the capacity and total avoided cost in Table 1 and Table 3 and the seasonal capacity prices in Table 5, below.

2. Seasonal Allocation of Capacity Avoided Costs

Demand-side-management screening requires identification of the seasons that will count towards the capacity value. The New England Power Pool's competitive markets for generation capacity (installed, operable, three kinds of operating reserves, and automatic generator control) are complex and still evolving, and the seasonal pattern of pricing is not clear.

At this point, any determination of the monthly distribution of capacity value should be considered tentative. The Study Group accepted an allocation of 60% of the capacity value to summer peak and 40% to winter peak as reasonable.[7] Table 5Table 5, below, presents these seasonal values, including the allowance for the reserve margin.

In NEPOOL, the annual peak occurs in the summer, and as a result, the total avoided capacity cost was developed in terms of avoided costs per summer kW.

The consultants normalized the seasonally allocated capacity costs for a typical DSM measure whose savings follow the system load shape as follows. The winter

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[7]Logically, summer prices should be higher, since that is when NEPOOL's capacity situation has been tightest. Payments for operable capacity and operating reserves are likely to be higher in the summer months. On the other hand, ISO-New England is requiring participants to have essentially the same amount of installed capacity throughout the year, so monthly installed capacity prices could be fairly level across months. Depending on how much of the capacity price is recovered through installed capacity, operable capacity, and operating reserve charges, the seasonal pattern in capacity value may be flat or skewed strongly towards the summer.

capacity value was calculated as the product of 40% of the total capacity value (in dollars per summer kW) and the ratio of summer peak demand to winter peak demand (in the year 2000).

Table 5:
Avoided Electric Capacity Cost by Seasonal Peak

	1998$ per Summer Peak kW	1998$ per Winter Peak kW	Nominal $ per Summer Peak kW	Nominal $ per Winter Peak kW
2000	17.35	12.92	18.23	13.57
2001	28.91	21.53	31.13	23.19
2002	28.91	21.53	31.91	23.77
2003	28.91	21.53	32.71	24.36
2004	28.91	21.53	33.53	24.97
2005	28.91	21.53	34.36	25.59
2006	28.91	21.53	35.22	26.23
2007	28.91	21.53	36.10	26.89
2008	28.91	21.53	37.01	27.56
2009	28.91	21.53	37.93	28.25
2010	28.91	21.53	38.88	28.96

Note: Winter values equal 40% of the total annual value, multiplied by the ratio of year-2000 NEPOOL summer peak (22,450 MW) to winter peak (20,100 MW).

The application of the seasonal values is discussed below in Section I.E.1.

3. Load-Weighted Avoided Energy Cost

The wholesale energy prices (such as those reported in Table 4) are for energy delivered equally in all hours. Actual DSM measures will have a variety of load shapes, few of which will be totally flat. If a single set of avoided energy costs are to be applied to all DSM, those avoided costs should reflect the shape of the average DSM measure, which is likely to resemble the average load shape. Table 1 provides projections of load-weighted energy prices, which are roughly 4% greater than hourly-weighted energy prices, to reflect the differences between those two results in the ELFIN runs.[8]

Table 6 provides load-weighted peak period and off-peak period energy prices for each month 2000–2010, where the peak period is Monday–Friday from 8 AM to 9

[8]For each month, ELFIN reports hour-weighted energy prices for the on-peak period, the off-peak period, and all hours. The ELFIN model also reports the average price received by generators (which is also the load-weighted price) over the course of the year. The load-weighted average price is about 4% more than the hour-weighted average price for the entire year. However, if the on-peak and off-peak prices (each of which represents an hour-weighted average within the period) are weighted by load in those periods, the resulting average is about 2% greater than the annual hour-weighted average price. Thus, it was necessary to add an average of approximately 2% to the on-peak and off-peak prices in order to produce average annual prices that match the load-weighted averages from ELFIN.

PM, as previously used by DOER. For most DSM screening tools, these monthly values must be aggregated to a few seasonal periods. This process is described below in Section I.E.2.

Table 6:
Load-Weighted Avoided Energy Components by Month and Period

1998 $/MWh

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2000	*Peak*	30.5	31.6	36.4	27.4	31.6	31.3	41.3	35.8	30.3	27.0	28.7	29.8
	Off-Peak	26.7	27.6	26.1	24.2	24.3	25.4	25.7	26.9	23.5	24.6	24.8	26.7
2001	*Peak*	30.4	31.8	30.6	27.4	31.5	31.7	41.2	36.2	30.7	27.3	29.0	30.1
	Off-Peak	27.5	28.2	26.2	24.1	24.8	25.3	25.9	26.6	23.8	24.7	24.8	27.4
2002	*Peak*	30.7	31.4	30.6	27.7	33.3	32.1	39.3	35.4	30.8	27.2	29.1	30.3
	Off-Peak	28.1	28.5	26.2	24.1	21.9	25.2	25.6	26.4	22.7	24.5	24.6	28.1
2003	*Peak*	31.1	32.1	31.1	27.6	33.2	32.4	39.8	35.6	30.4	27.3	29.5	30.7
	Off-Peak	28.3	28.6	26.7	24.3	21.9	25.2	25.2	26.0	22.5	24.7	24.8	28.3
2004	*Peak*	31.6	32.3	31.4	27.9	32.5	32.0	41.0	36.8	31.5	27.5	29.8	31.2
	Off-Peak	28.4	28.6	26.5	24.2	21.8	25.0	25.3	26.0	22.6	24.7	24.9	28.5
2005	*Peak*	32.3	33.2	32.2	28.1	33.1	32.6	42.8	38.3	31.7	27.6	30.7	32.1
	Off-Peak	28.5	28.7	26.6	24.0	21.8	24.9	25.1	25.7	22.5	24.5	24.4	28.7
2006	*Peak*	33.6	34.5	33.1	28.5	32.6	33.5	46.1	39.3	32.1	28.1	31.5	33.0
	Off-Peak	28.8	29.0	27.2	23.3	21.8	23.2	26.0	25.5	22.3	24.8	24.5	28.9
2007	*Peak*	34.4	35.2	34.3	28.8	32.8	34.8	45.5	38.5	32.2	28.9	32.0	33.7
	Off-Peak	29.1	29.4	27.4	22.9	21.8	22.9	23.6	23.9	22.1	24.0	24.3	29.3
2008	*Peak*	34.4	35.1	34.8	28.8	33.3	34.7	45.9	39.0	31.3	28.7	32.3	33.7
	Off-Peak	29.4	29.7	27.4	22.6	21.0	22.8	23.4	24.1	21.4	23.8	24.2	29.6
2009	*Peak*	33.6	34.5	34.5	35.1	32.6	34.0	44.2	37.7	31.6	28.3	30.8	33.1
	Off-Peak	29.7	30.0	26.3	22.5	20.9	21.9	22.9	23.7	21.4	23.4	23.7	29.8
2010	*Peak*	34.5	35.0	34.9	31.0	33.0	34.0	45.4	38.1	31.7	28.6	31.7	33.6
	Off-Peak	30.0	30.3	26.3	22.6	21.1	21.9	22.5	23.8	21.6	23.3	24.0	30.2

Nominal $/MWh

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2000	*Peak*	32.0	33.2	38.3	28.8	33.2	32.8	43.4	37.6	31.8	28.4	30.1	31.3
	Off-Peak	28.0	29.0	27.5	25.4	25.6	26.7	27.0	28.2	24.7	25.8	26.0	28.0
2001	*Peak*	32.7	34.3	33.0	29.5	34.0	34.2	44.3	39.0	33.1	29.4	31.2	32.4
	Off-Peak	29.6	30.4	28.2	25.9	26.7	27.3	27.9	28.7	25.6	26.6	26.7	29.5
2002	*Peak*	33.8	34.6	33.7	30.6	36.7	35.4	43.4	39.1	34.0	30.0	32.1	33.4
	Off-Peak	31.0	31.4	29.0	26.6	24.2	27.8	28.3	29.2	25.0	27.0	27.1	31.0
2003	*Peak*	35.2	36.3	35.2	31.2	37.5	36.6	45.0	40.3	34.4	30.9	33.4	34.7
	Off-Peak	32.0	32.4	30.2	27.5	24.8	28.5	28.5	29.4	25.5	27.9	28.1	32.0
2004	*Peak*	36.6	37.5	36.4	32.4	37.7	37.2	47.5	42.6	36.5	31.9	34.5	36.1
	Off-Peak	32.9	33.1	30.8	28.1	25.3	29.0	29.3	30.1	26.2	28.7	28.8	33.0
2005	*Peak*	38.4	39.4	38.3	33.4	39.3	38.8	50.9	45.5	37.7	32.8	36.5	38.2
	Off-Peak	33.9	34.2	31.6	28.6	26.0	29.6	29.8	30.6	26.7	29.1	29.0	34.1
2006	*Peak*	41.0	42.0	40.4	34.7	39.7	40.9	56.2	47.9	39.1	34.2	38.4	40.1
	Off-Peak	35.0	35.4	33.1	28.4	26.5	28.2	31.7	31.0	27.2	30.2	29.8	35.2
2007	*Peak*	43.0	43.9	42.8	36.0	41.0	43.4	56.8	48.1	40.3	36.1	40.0	42.1
	Off-Peak	36.4	36.8	34.3	28.6	27.2	28.6	29.5	29.8	27.6	30.0	30.3	36.6
2008	*Peak*	44.0	45.0	44.5	36.9	42.6	44.4	58.7	49.9	40.1	36.7	41.3	43.1
	Off-Peak	37.7	38.0	35.0	28.9	26.9	29.2	29.9	30.8	27.4	30.5	31.0	37.9
2009	*Peak*	44.1	45.3	45.3	46.1	42.8	44.7	58.0	49.5	41.5	37.1	40.5	43.5
	Off-Peak	39.0	39.3	34.5	29.5	27.4	28.8	30.0	31.2	28.1	30.6	31.2	39.2
2010	*Peak*	46.4	47.0	46.9	41.7	44.3	45.7	61.0	51.2	42.6	38.4	42.6	45.2
	Off-Peak	40.3	40.7	35.3	30.4	28.3	29.5	30.2	32.0	29.0	31.3	32.3	40.6

4. *Projection of Avoided Costs beyond 2010*

This report provides avoided-cost projections for the period 2000–2010. Beyond 2010, avoided costs should be projected to grow at the average annual rate for the five years from 2005 to 2010. For any given component, that annual average growth rate should be calculated as

$$\left(\frac{\mathrm{AESC}_{2010}}{\mathrm{AESC}_{2005}}\right)^{1/5}$$

D. The Estimation Procedure in Depth

1. *Key Costs of the New Entrants*

Table 7 outlines many of the key characteristics of the new combined-cycle units and CTs. The basis for each of these inputs is discussed in more detail immediately below. The cost of firm gas burned by combined-cycle units is discussed in the gas-cost section, Section II. All costs in the table are shown in 1998 dollars and are projected to rise with 2.5% annual inflation.[9] No changes in the real costs or performance of new technologies are modeled, although the assumptions for the new units do allow for some improvement from recent norms.[10]

Table 7:
Characteristics of the New Generating Units

	Capital Costs *($/kW)*	**Fixed Operating Costs** *($/kW-yr.)*	**Variable O&M** *($/MWh)*	**Heat Rate** *(Btu/kWh)*	**Book Life** *(Years)*	**Tax Life** *(Years)*
CC	597	25.00	1.02	6,975	30	20
CT	360	5.79	*not used*	*not used*	25	15

[9]The statement of costs in constant 1998 dollars is for convenience in comparison and computation. The various costs are derived from the most recent available historical data, or from projected costs for future plants, as described below.

[10]The expectation of falling costs of future price-setting generation would tend to cause developers of power plants to demand greater short-term returns, to ensure that their investment would be recovered. As a result, less new generation would be built and near-term prices would be greater than in a situation in which market participants expected stable costs. Consequently, an expectation of falling costs of new capacity might well result in no change in the total market value of existing plants.

a) Capital Costs

All of the capital-cost assumptions were developed after reviewing the costs and performance of recent actual installations and projections by plant developers for projects that have received financing. In considering the values reported, Resource Insight has attempted to put them on a consistent basis.[11] The capital costs reported in Table 7 are expressed in terms of the cost per summer kW. The combined-cycle costs drive the total cost of energy and capacity combined. The values for the CTs primarily determine the split between energy and capacity prices, and are therefore less important than the values for combined-cycle units.

(1) Combined-Cycle Units

Based on a review of cost-estimates for combined-cycle plants under construction or in development in New England, the Study Group selected a capital cost of $597/kW (in 1998 dollars). This cost is about 10% less than the average among the most reliable estimates available, and was intended in part to capture the potential savings associated with the use of brownfields sites and some optimism about cost reductions from technological progress and competitive efficiencies.[12]

The estimates reviewed by the Study Group are summarized in Table 8, below, which separates the more reliable estimates from less-reliable ones, which are from press releases. The Study Group regards information from SEC-regulated filings or financing announcements to be more credible than press releases because they balance the optimism of developers with their consideration of risks of legal liability. Press releases report a wide range of construction costs for other proposed New England power plants. Some of these estimates appear to be very preliminary, optimistic, or incomplete.

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[11]Published costs may appear to differ greatly from one another due to omission of such factors as owner's costs, installation costs, transmission interconnection costs, and the impact of wear and temperature on unit capacity. Likewise, in order to compare different sources of combined-cycle heat rates, the values must be normalized to reflect differences in reporting conventions, such as full-load heat rate versus annual average heat rate, lower versus higher heating value, ambient temperature, and cooling systems.

[12]There is a widespread expectation that future combined-cycle designs, especially for larger units, will be less expensive than the plants currently under construction. The data on the costs of new technology have yet to indicate any such trend. The capital cost for the first 500-MW GE H–technology combined-cycle plant (the successor to the F- and G-class plants of the 1990s and early 2000s), at Baglan Bay in Wales, is projected to be £300 million, which is equivalent to $500 million, or about $979/kW.

Table 8:
Recent Announcements of Combined-Cycle Capital Costs

Developing Company	Summer Capacity (MW)	ISD	Location		Price ($millions)	$/kW	$/kW (1996$)	Source of Estimate
Reliable Combined Cycle Estimates								
Energy Management Inc.	238	Apr 00	Rumford	ME	160	672	622	10K
Energy Management Inc.	239	Jul 00	Tiverton	RI	173	724	670	10K
Energy Management Inc.	168	May 99	Dighton	MA	120	714	677	10K
Calpine	486	Nov 00	Westbrook	ME	300	617	571	10K
Duke & UI	480	Jun 99	Bridgeport	CT	291	606	575	Financing
Power Development Corp. and El Paso	266	Mar 99	Agawam	MA	190	714	677	Financing
US Generating	360	*Jul 00*	Charlton	MA	205	569	527	Regulatory Filing
US Generating	729	*Jul 01*	Killingly	CT	491	674	608	Regulatory Filing
Power Development Corp. and El Paso	245	Jan 01	Westfield	MA	200	816	737	Cancellation Report
Average of Reliable Estimates							**629**	
Combined Cycle Estimates From Press Releases								
AES Corp.	648	Jul 01	Londonderry	NH	200	309	279	Press Release
ANP	765	Jul 00	Gorham	ME	270	353	326	Press Release
ANP	522	*Jul 00*	Blackstone	MA	300	575	532	Press Release
ANP	522	*Jul 00*	Bellingham	MA	300	575	532	Press Release
Consolidated Edison	504	Jul 01	Newington	NH	188	372	336	Press Release
Casco Bay Energy Co.	450	Apr 00	Veazie	ME	221	491	454	Press Release
US Generating	429	*Jul 01*	Somerset	MA	300	699	631	Press Release
Average Press Release Estimates							**441**	

Note: Dates in italics are approximate (e.g, when only the year was stated, July 1 was assumed).

The average of the reliable estimates from Table 8, $629/kW (in 1996 dollars), was discounted by about 10% to $566/kW to reflect the potential cost reduction through brownfields developments, and escalated by 2.5% for two years, resulting in the consensus capital cost of $597/kW.[13]

The decision not to consider the immature projections (the second group of Table 8) in selecting the capital cost is supported by the data in Table 9, which provides six examples of the increase in estimates of a project's capital costs as the project proposal matures. The early announcements often use inflated capacity values, and may include only the costs of major equipment. As projects move closer to completion, developers often find that they must add investments for water supply, more-expensive cooling equipment, and other costly auxiliary equipment.

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[13]One of the least-expensive plants listed in Table 2 is the Bridgeport plant, which reuses the site, cooling system, transmission, and other assets of the Bridgeport 1 steam plant. (The cost of losing the capacity of Unit 1 might be added to the cost of the plant.) New generation on such brownfield sites may be generally less expensive than plants at new sites.

Table 9:
Combined-Cycle Cost Trends

Developing Company	Claimed MW	Summer MW	Winter MW	Location	Price ($ millions)	$/kW (Claimed)	$/kW (Summer)	Source
Duke and UI	520	480	520	Bridgeport CT	260	500	542	Power Eng. 5/98
Duke and UI	520	480	520	Bridgeport CT	291	560	606	EUW 5/5/95. Calculated from UI's investment and %
Energy Management	265	238	265	Tiverton RI	160	604	672	EPD 12/2/98
Energy Management	265	238	265	Tiverton RI	173	653	727	Calpine 98 10k
Energy Management	169	166	185	Dighton MA	70	414	422	Clark Reports 2/8/96
Energy Management	169	166	185	Dighton MA	115	680	693	Globe 7/24/98
Energy Management	169	166	185	Dighton MA	120	710	723	Calpine 98 10K
Reliant	500	450	500	Johnston RI	250	500	556	BBJ 7/24-7/30/98
Reliant	500	450	500	Johnston RI	260	520	578	Providence Journal 5/20/99
US Generating	400	360	400	Charlton MA	150	375	417	Telegram & Gazette 6/18/96
US Generating	360	360	400	Charlton MA	205	569	569	EFSB Order 11/3/97

(2) Combustion Turbines

The Study Group selected a combustion-turbine capital cost of $360/kW (in 1998 dollars), following the review of recent announcements of new combustion turbines.

Table 10:
Recent Announcements of Combustion Turbines Costs

Sponsor	Project Name		Capacity (MW) Summer	Capacity (MW) Announced	In-Service Date	Announced Cost: Nominal $ Million	Announced Cost: 1998$ per Summer kW	Announced Cost: 1998$ per Announced kW
Peoples, Dominion	Elwood Energy	IL	493	600	Jun-99	$200	$396	$326
VEPCo	n/a	VA	740	900	Sep-00	$291	$373	$306
Illinois Power	n/a	Il	145	176	Jun-99	$82	$554	$455
MCN	Cobisa-Person	NM	115	140	May-00	$60	$498	$410
Western Resources	Gordon Evans	KN	247	300	Jun-00	$120	$464	$381
Southern	Neenah	WI	247	300	Jun-00	$100+	$387+	$318
AES/Commonwealth Chesapeake	Accomack County	VA	247	300	Dec-99	$100	$391	$322
Indianapolis P&L	n/a	IL	164	200	Sep-00	$60	$346	$284
TVA	n/a	TN	559	680	Jul-00	$240	$409	$336
Polsky for Alliant	Christiana	WI	432	525	Jun-00	$140	$309	$254
MW-Weighted Average			3,388	4,121	Apr-00	$1,393	$393+	
Simple Average							$413+	$339+

Notes
Announced capacities are assumed to be winter capacities. Summer capacities are estimated as 82% of winter capcities, based on the ratio of seasonal capacities reported 1998 Tampa Electic 10-Year Plan, page IV-7. $/kW costs are calculated as total announced cost, divided by either announced or summer capacity, as indicated. Earlier announcements by Vepco and Peoples for the same projects listed have been omitted.

Table 10 lists these data. Since no combustion turbines are in development in New England, these units are primarily in the Midwest and South, where land and construction labor tend to be less expensive (and siting easier) than in New England. On average, these plants are reported by their sponsors to cost about $339/kW in 1998 dollars. However, many of the announced capacities probably reflect winter or nominal ratings, both of which are greater than summer ratings.

After adjusting these cost figures for lower summer capacity ratings, the cost is more than $400/kW. These announced costs may also be understated, because, as noted above, plant developers often have an incentive to understate costs in order to limit their property-tax assessments.[14] The $360/kW value was chosen to reflect the uncertainties in the capacity ratings and in the quality of the data.

b) Operating Costs

The Study Group set total operating costs for new combined-cycle plants at $31/kW-yr. (in 1998 dollars). Of this, $25/kW-yr. was considered fixed, and $6/kW-yr. (applied as $1.02/MWh) was considered variable. The total value is about 20% less than recent average historical experience for the combined-cycle units constructed after 1990 that report to FERC. The Study Group adopted the lower value after considering competitive pressures and projections from the 1999 Annual Energy Outlook (AEO) from the Energy Information Administration and the NEPOOL Generation Task Force (GTF) "Summary of the Generation Task Force Long-Range Study Assumptions" (August 1993). The split between fixed and variable costs was based on the GTF and more recent utility projections of variable O&M.

The Study Group set total operating costs for the new combustion turbine units to $5.79/kW-yr. (in 1998 dollars), all of which was treated as fixed.

This figure was developed by

- averaging the total 1992–96 non-fuel O&M reported to FERC for all post-1990 CTs that report to FERC ($3.76/kW-yr. in 1998 dollars),
- adding 15% overheads,
- adding experience-weighted average net capital additions for the same set of units ($1.47/kW-yr.).

The 15%-overhead adder reflects administrative and general (A&G) costs, including payroll taxes, benefits, personnel expenses, legal, and the like. This overhead adder represents a significant improvement from utility experience, including generation-only companies (which typically have A&G costs for more than 25% of O&M). Not much information is available on the overhead costs of competitive generation companies, but the Study Group believes that the competitive pressures of the markets would bring A&G rates down.

[14]The Study Group did not find any CT cost estimates for actual planned plants in financial filings or other sources, and thus was forced to rely on the press-release data.

To illustrate how this 15% overhead adder might be achievable, Table 11 provides some information on the overheads of major New England generating utilities. Typically, the pension and benefit portion of A&G is about 16% of production O&M, and payroll taxes are another 3%, for direct labor overheads of 19% (See "Total Direct Labor-Related A&G" in Table 11). However, for some companies in some years, these overheads have been as little as 12%. The ratios may be somewhat smaller for competitive power producers. The other overhead costs (legal, regulatory, public relations, and similar administrative tasks) are only partially incremental with the number of sites or MW a company operates, and hence only a fraction of the allocated costs reported by utilities ("Pensions and Benefits" and "Payroll Taxes" in Table 11) should be included. Overall, the Study Group believes that a 15% overhead adder for incremental plants is not an unreasonable target in competition.

Table 11:
Overhead Costs at Major New England Generation Utilities
As Percent of Production Non-Fuel O&M

		Pensions and Benefits	Payroll Taxes	Total Direct Labor-Related A&G	Other A&G	Total
		[1]	[2]	[3]	[4]	[5]
BECo	1995	16%	4%	21%	23%	44%
	1996	15%	4%	19%	13%	32%
	1997	17%	4%	21%	15%	36%
Canal	1995	9%	3%	12%	22%	33%
	1996	18%	3%	20%	20%	40%
	1997	12%	3%	15%	19%	34%
Montaup	1995	16%	3%	19%	16%	35%
	1996	18%	3%	21%	29%	50%
	1997	12%	3%	14%	15%	29%
NEPCo	1995	20%	2%	22%	33%	55%
	1996	17%	2%	19%	30%	49%
	1997	20%	2%	22%	30%	52%

Notes: *All data from FERC Form 1. O&M excludes purchased power.*
[1] Allocated on wages and salaries.
[2] Allocated on wages and salaries.
[3] [1] + [2]
[4] Excluding advertising and property insurance.
[5] [3] + [4]

Since the new CT would not operate many hours, the equilibrium model assumed that it would have no variable operating costs. Although this is not literally correct, the total variable operating costs for a CT do tend to be very small, because it operates in so few hours. For the ELFIN dispatch model, existing CTs were assumed to have operating costs, but no new CT were modeled, so there was no need to specify a variable operating cost.

c) Heat Rate

The Study Group selected an annual average heat rate of 6,975 Btu/kWh (HHV).This value represents an improvement of approximately 3% beyond the best reported performance for any unit in any full year: Florida Power & Light's Martin County 3 & 4 achievement of 7,172 Btu/kWh in 1995. The 3% decrease in heat rate reflects modest expectations for future technological improvements.

In comparing this heat-rate projection to reports of anticipated efficiencies of future combined-cycle units, it is important to recognize that real operating conditions will cause most plants to have higher heat rates (i.e., lower efficiency) than is anticipated under optimal conditions. The following factors raise heat rates from theoretically achievable values:[15]

- the energy used in operating plant auxiliaries;
- the loss of efficiency due to the use of evaporative or dry cooling, rather than the more efficient once-through water cooling;
- the effect of ambient temperatures higher than the standard conditions;
- the effects of part load operation and start-up energy costs, due to economic dispatch and outages;
- fouling of turbine blades and other equipment between maintenance outages;
- unrecoverable wear and tear, especially on turbine blades.

Cumulatively, these effects can be significant. While Siemens reports that its v84.2 turbine produces a combined-cycle heat rate of 6,630 at lower heat value—the equivalent of 7,293 Btu/kWh at higher heat value—the operators of two combined-cycle plants that use the v84.2 (Bergen and Manchester St.) report heat rates of 7,865–8,089 Btu/kWh.

d) Plant Lives

For combined-cycle plants, a thirty-year recovery period was assumed. Thirty years is shorter than the book life assumed by traditional utilities, but longer than typical financing periods for merchant plants. Pressure on developers to repay debt over fifteen–twenty-five years, and to maintain adequate coverage ratios above debt-service costs, will require higher annual fixed charges than would longer

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[15]Some reported heat rates (especially from international sources) use the lower heating value of the fuel, excluding the 10% of the energy in natural gas that is bound up in the vaporization of the water produced by combustion. Common U.S. practice is to report fuel prices and heat rates at higher heating values, which are 10% lower than the same inputs at lower heating value.

financing periods.[16] For the combustion turbine, a twenty-five-year book life was assumed. Consistent with current federal tax code, the financing costs reflect accelerated depreciation over tax lives of twenty and fifteen years for the CC and CT units, respectively.

e) Financial Assumptions

General inflation is assumed to be 2.5% per year.

For the new combined-cycle units and CTs, the Study Group selected the following capital structure.

Table 12:
Assumed Capital Structure of the New Units

	Share	Rate
Equity	25%	15.0%
Debt	75%	7.5%

This structure is highly leveraged, although less so than that of many traditional independent power producers with long-term power-purchase contracts with utilities.

Compare this to the financial structure of merchant plant operators expected by such rating agencies as Standard and Poor's, by many utilities, and by cost-of-capital experts; see Table Appendix C–1. The current capital structures of some merchant-plant owners, such as National Power, PowerGen, and PG&E's USGenNE subsidiary, which purchased NEPCo's generation assets, are provided in Table Appendix C–2. While the Study Group's assumptions incorporate a greater percentage of debt than suggested by the data in Appendix C, the inferred increased riskiness of the investment is somewhat offset by a higher return on equity.

The model used a federal income-tax rate of 34% and a state-income tax rate of 8%, yielding a combined tax rate of 39.3% and an after-tax cost of capital of just less than 7.2%.[17]

These assumptions, combined with property taxes (assumed to be 2% of initial plant investment) and the new units' book-life and tax-life assumptions, yield real-

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[16]For example, Standard and Poor's expects a 4.25 coverage ratio to be typical for BBB-rated merchant plants.

[17]The 8% state income-tax rate is the New England average income tax rate for utilities from the NEPOOL Generation Task Force's "Summary of the Generation Task Force Long-Range Study Assumptions," August 1993, Exhibit 16.

levelized carrying-charge rates of 9.5% for the combined-cycle plants and 10.0% for the combustion-turbine plants.

2. *Additional Assumptions Used in the Production-Costing Model*

Since ELFIN models each unit in NEPOOL individually, it requires many additional inputs. The inputs to the analysis of market prices include new generator additions, fuel costs, variable O&M costs, heat rates, non-utility generation, loads, imports, outage rates and air emissions. The modeling assumptions are described in Appendix A.

3. *Computation of Equilibrium Results*

a) Capacity Price

The computation of the capacity price started with the $360/kW construction cost described above. Given the financial assumptions in Section I.D.1.e) above, the required real-levelized fixed charge rate over the book life of the CT is about 10%, resulting in a carrying charge of $35.38/kW-yr. (in 1998 dollars). Including the annual fixed O&M charges of $5.79/kW-yr. (with A&G), the total capacity cost is $41.18/kW-yr. (in 1998 dollars).

b) Energy Price

The computation of the equilibrium energy price is described in Section I.B.1, as the sum of fuel costs, variable O&M costs, and capitalized energy costs (the portion of the combined-cycle unit's capital cost and fixed O&M that must be recovered from energy rather than capacity charges). This computation is presented in Table 13. Fuel costs are the product of heat rate, defined above, and gas costs, as determined below in Section II. The results vary by year, due to changes in gas prices over time.

Table 13:
Calculation of Equilibrium Wholesale Electricity Prices (1998 Dollars)

	Calculation of Capacity Cost			Calculation of Equilibrium Energy Cost									
	Annual CT Capital Charge ($/kWyr)	CT Fixed O&M ($/kWyr)	Capacity Price ($/kWyr)	Annual CC Capital Charge ($/kWyr)	CC Fixed O&M ($/kWyr)	CC Fixed Costs above Capacity Value ($/kWyr)	CC Fixed Costs above Capacity Value ($/MWh)	CC Variable O&M ($/MWh)	CC Fuel ($/MMBtu)	CC Fuel ($/MWh)	CC Energy Cost ($/MWh)	Pure Baseload Energy Cost ($/MWh)	Combined Baseload Energy and Capacity ($/MWh)
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
2000	35.38	5.79	41.18	56.23	25.00	40.06	5.14	1.02	2.98	20.79	26.94	26.84	31.54
2001	35.38	5.79	41.18	56.23	25.00	40.06	5.14	1.02	2.98	20.79	26.94	26.84	31.54
2002	35.38	5.79	41.18	56.23	25.00	40.06	5.14	1.02	2.98	20.79	26.94	26.84	31.54
2003	35.38	5.79	41.18	56.23	25.00	40.06	5.14	1.02	2.98	20.79	26.94	26.84	31.54
2004	35.38	5.79	41.18	56.23	25.00	40.06	5.14	1.02	2.98	20.79	26.94	26.84	31.54
2005	35.38	5.79	41.18	56.23	25.00	40.06	5.14	1.02	2.98	20.79	26.94	26.84	31.54
2006	35.38	5.79	41.18	56.23	25.00	40.06	5.14	1.02	3.01	20.99	27.15	27.05	31.75
2007	35.38	5.79	41.18	56.23	25.00	40.06	5.14	1.02	3.04	21.20	27.36	27.25	31.95
2008	35.38	5.79	41.18	56.23	25.00	40.06	5.14	1.02	3.06	21.34	27.50	27.39	32.09
2009	35.38	5.79	41.18	56.23	25.00	40.06	5.14	1.02	3.09	21.55	27.71	27.60	32.30
2010	35.38	5.79	41.18	56.23	25.00	40.06	5.14	1.02	3.12	21.76	27.92	27.81	32.51

Column Notes

[1] CT capital cost, adjusted to start-of-year, multiplied by carrying charge rate. $360 ÷ (1+2.5%)^.5 × 10.0%.
[2] Assumed. See text.
[3] [1] + [2]
[4] CC capital cost, adjusted to start-of-year, multiplied by carrying-charge rate. $597 ÷ (1+2.5%)^.5 × 9.5%.
[5] Assumed. See text.
[6] [4]+[5]-[3]
[7] [6], expressed as dollars per MWh: [6] ÷ 8,760 ÷ 89% capacity factor × 1,000
[8] Assumed. See text.
[9] Delivered gas price. See text.
[10] [9] × 6,975 Btu/kWh ÷ 1,000
[11] [7] + [8] + [10]
[12] [11], adjusted based on 1997 lambdas from 99% operating factor (89% capacity factor) to 100% operating factor (operating at full ability, 90% capacity factor).
[13] [12] + [3] ÷ 8,760 × 1,000

E. Additional Inputs Required for DSM Screening

1. *Determining the Time of Peak-Demand Savings*

Every NEPOOL participant needs installed capacity every month (and other types of capacity every hour), based on the participant's non-coincident peak. This means that, in principle, different power suppliers could have different hours in a month that are critical for determining capacity costs. A marketer serving mostly large offices would need to maintain a reserve margin over its 2-PM peak, while a marketer serving mostly residential customers would need to maintain reserves over its 6-PM peak.

Sooner or later, NEPOOL participants are likely to work out a way to transfer load, so as to avoid this problem, and the critical period for capacity in each month will coincide with NEPOOL's peak hours. In addition, operable-capacity and operating-reserve charges will tend to be greatest in NEPOOL's peak hours in the month. In the interim, the distribution utility's peak hours represent as good a proxy as any available for the time at which demand will affect the capacity costs incurred by electric customers.

Therefore, each distribution utility should estimate seasonal (summer or winter) DSM capacity savings for a measure or program as the savings at the utility's summer peak hour and winter peak hour.

2. *Seasonal Costing Periods*

This report does not compute seasonal energy prices for any particular definition of the seasons. The various utilities use different seasonal definitions in their DSM measure data and their screening tools; none of the preferred seasonal definitions was the same as DOER's periods.

Seasonal peak and off-peak prices can be computed for any desired seasonal definition by weighting the monthly prices by monthly energy output, for whatever months are selected for the season. Since usage varies across months, simple averages of monthly prices will misstate (and generally understate) average prices in the season. For convenience, Table 14 provides the monthly period weights, as a percentage of annual energy output, to be applied to the monthly energy costs in Table 6, above.

Table 14:
Monthly Weighting Factors to Develop Seasonal Energy Components

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Peak	4.21%	3.84%	3.89%	3.42%	3.76%	3.88%	4.30%	4.32%	3.76%	3.50%	3.62%	4.09%
Off-Peak	5.06%	4.69%	4.67%	4.08%	3.75%	4.21%	4.48%	4.70%	4.11%	4.32%	4.31%	5.03%

3. Line Losses

Line losses have not been developed in this project, but should be added to both avoided capacity and energy costs. Losses vary among distribution utilities. Where possible, marginal losses should be estimated separately for each energy period and for peak demand.

4. Externalities

For both energy and capacity values, under the "Proposed Guidelines: Cost Effectiveness, Monitoring and Evaluation Issues, and Shareholder Incentives," filed by various parties in DTE 98-100, an externality adder would be applied to all avoided energy supply costs. This adder is not included in the values presented in this report.

5. Avoided Transmission and Distribution

The avoided costs in this report do not include any avoided transmission or distribution costs. Estimates of avoided T&D costs should be included in the avoided costs used in screening DSM measures and programs.

F. Comparison to Sources of Electricity Market Prices in New England

The consensus wholesale price forecasts in Table 4 may be compared to other available forecasts and to current market prices. This section presents some such forecasts and prices for comparison.

1. Forecasts of Market Prices

Resource Insight surveyed forecasts of electricity market prices prepared in 1998 and 1999 (some of which are based on 1997 inputs). These forecasts are summarized below in Table 15.[18] Appendix B provides additional information about these forecasts, to the extent that it is publicly available. Table Appendix B–1 provides time-differentiated projections, and differentiation into energy and capacity components, where available. Table Appendix B–2 specifies the input

[18]In its June 25, 1997, memo that developed the Avoided Generation Component currently in use, DOER presented market-price estimates from two utilities, two consultants to non-utility parties, and two methods developed by participants in the process. The external sources are now outdated: two (by Northeast Utilities and Resource Insight) have been superceded by other projections presented in this report, and another (NEES) is now considered obsolete by the sponsoring utility. Only the projection by LaCapra Associates does not appear to have been formally withdrawn or replaced. Nonetheless, that projection is now quite old, and is not included it in this survey.

assumptions to these forecasts where they are available. Appendix B also describes the source of the forecasts.

In Table 15 the forecasts are organized into the following four broad groups based on the method with which the forecast was derived:

- Forecasts based on production-costing models include those sponsored by CL&P, WMECo, CommElectric, and CMP. The results of the ELFIN model presented above fall into this category.
- Forecasts based on the costs of new capacity include one by the Tellus Institute and one by Resource Insight. The capacity values and the equilibrium energy prices presented in this report fall into this category.
- Forecasts derived from the sale price of New England generation assets were developed by the Tellus Institute separately for the sales of generating plant by CMP, NEP, and BECo.
- Forecasts derived from judgmental adjustments to other forecasts were available from Fitchburg and from Exeter Associates.

Most of the forecasts explicitly reflect competitive conditions, although it is generally not possible to determine exactly how the authors' assumptions differ from what they would have used for projecting prices in a regulated environment. However, Tellus seems to have assumed regulatory conditions in two respects. First, Tellus' projections of market prices from the asset sales assume that future O&M and generation for existing plants will equal 1996 costs, without any adjustment for competitive efficiencies (which would reduce costs) or competitive financing (which would increase costs). Second, Tellus' equilibrium projection uses regulated financing; using competitive financing would increase costs.

Table 15:
Comparison of Market-Price Forecasts

Total Combined Capacity and Energy (Nominal Dollars per MWh)

	Production-Cost Models				Equilibrium Models		Asset-Sale			Judgment	
	CL&P	WMECo	ComElec	CMP	Resource Insight	Tellus Equilibrium	Tellus CMP	Tellus BECo	Tellus NEP	FG&E	Exeter Assoc
Date	Mar 99	97/98	Apr 97	Dec 97	Apr 99	Apr 98	Apr 98	Apr 98	Apr 98	1998	Apr 99
Load Shape	Baseload	Baseload	Baseload	Baseload	Baseload	CMP	CMP	BECo	NEP	Baseload	Baseload
2000	26.3	33.5	33.0	35.3	38.8	34.3	54.1	54.2	37.8	33.0	31.6
2001	27.4	33.2	34.0	38.0	39.8	35.4	55.8	55.9	39.0	34.0	32.9
2002	29.1	33.7	35.1	40.9	40.8	36.4	57.4	57.5	40.1	35.0	34.9
2003	30.9	34.7	36.2	42.8	41.8	37.5	59.2	59.3	41.3	36.0	37.1
2004	33.3	35.0	37.3	44.8	42.8	38.6	60.9	61.0	42.6	37.1	
2005	36.5	35.8	38.4	47.0	43.9	39.8	62.8	62.9	43.9	38.2	
2006	37.3	37.0	39.7	49.2	45.2	41.0	64.6	64.8	45.2	39.4	
2007	38.3	38.1	41.1	51.5	46.6	42.2	66.6	66.7	46.5	40.5	
2008	39.2	39.2	42.6	54.0	48.0	43.5	68.6	68.7	47.9	41.8	
2009	40.2	40.4	44.1	56.6	49.5	44.8	70.6	70.8	49.4	43.0	
2010	41.2	41.6	45.6	58.2	51.0	46.1	72.8	72.9	50.9	44.3	
2011	42.2	42.9	47.1	59.8	52.6	47.5	74.9	75.1	52.4	45.6	
2012	43.3	44.1	48.6	61.5	54.2	48.9	77.2	77.3	53.9	47.0	
2013	44.3	45.5	50.4	63.3	55.9	50.4	79.5	79.7	55.6	48.4	
2014	45.5	46.8	52.1	65.1	57.6	51.9	81.9	82.0	57.2	49.9	
2015	46.6	48.2	54.0	67.4	59.4	53.5	84.3	84.5	58.9	51.4	

Notes

Capacity prices per MWh are derived assuming a capacity factor of 80%.

See Appendix B to this report for the forecast details and assumptions and an annotated list of sources.

2. Comparisons to Actual Prices and Forward Contracts

The consensus energy-price projections can also be compared to a variety of market data.

These projected market prices are significantly greater than the New England system marginal costs as recorded in the hourly marginal cost (lambda*)* data for 1995–97. One major explanation for the projected increase is that substantial costs for NOx emissions are included in the ELFIN analysis (see Appendix A). In addition, the NEPOOL lambda did not have to support the costs of new capacity, the costs of which were recovered from ratepayers. In the market, prices can rise well above the costs recorded in the NEPOOL-lambda data.

The projections are significantly less than the actual New England energy market prices since the hourly market began on May 1 of this year. The ELFIN results fit the May values almost exactly, but fail to reflect the much greater average prices in June, due largely to hot days with large amounts of capacity unavailable. Table 16 compares the monthly ELFIN results for 2000 to actual monthly market prices for May and June.

Table 16:
Comparison of ELFIN Projections to Monthly Average

	Hour-Weighted Average Prices	
	Actual 1999	ELFIN Projection for 2000, in 1999$
May	$28.2/MWh	$28.1/MWh
June	$48.6/MWh	$28.6/MWh

The difference for June, the consultants believe, is mostly due to ELFIN simulating a market in which supply bids are based almost entirely upon marginal running costs The actual market, however, is subject to tight capacity situations in which prices have little to do with short-run marginal costs.

The on-peak market prices from ELFIN can also be compared to the on-peak forward contract prices for NEPOOL energy reported by Bloomberg's *Natural Gas Report* (June 25, 1999). Since the ELFIN peak period is 13 hours long (reflecting the periods traditionally used in DSM analysis by Massachusetts utilities), while the Bloomberg period is 16 hours long, an adjustment to the ELFIN results is necessary to put the two sources in comparable terms. Bloomberg does not report trades in off-peak energy.

Table 17:
Comparison of ELFIN Projections to Forward Contract Prices

	ELFIN On-Peak Hour-Weighted		Bloomberg On-Peak Price
	13-Hour Peak	*Plus 3 Off-Peak Hours*	*16-Hour Peak Period*
January–March 2000	\$34.74	\$33.55	\$30.80–32.20
Calendar Year 2000	\$33.73	\$32.47	\$35.00–37.00
Calendar Year 2001	\$34.25	\$33.07	\$35.00–36.75

Table 17 indicates that ELFIN's projections are somewhat greater than actual recent contracts for the first quarter of 2000; this appears to be due to maintenance scheduling in March. Otherwise, ELFIN's projections are less than actual contract prices. The consensus energy prices are 2.4% less than the ELFIN results, and would thus be even further below actual annual contract prices: roughly 10–12% less.

Since no public source is available for the contract pricing of off-peak energy or capacity, the overall prices in this report cannot be compared to the forward market. Nor are prices available for contracts beyond 2001.

II. Marginal Gas Commodity and Demand Costs

A. Summary of Avoided Gas Costs

Avoided gas costs were developed for three types of load shapes: base, weather-sensitive, and water heating. Within the base category, several load-shape subtypes allow for the characterization of DSM measures that have different seasonal savings, but fairly constant savings within any one season. Several different definitions of the seasons are presented, because different companies use different definitions and different measures may better fit one seasonal profile than another. Within the weather-sensitive category, two load-shape subtypes differentiate between older and newer buildings.

Table 18 provides projections of total avoided delivered gas costs for each year, 2000–2010.

Table 18:
Annual Delivered Gas Cost

1998 $/MMBtu

	Baseload							Weather-Sensitive		
	Annual	*3-month Winter*	*9-month Summer*	*5-month Winter*	*7-month Summer*	*7-month Winter*	*5-month Summer*	*Old Buildings (269 days)*	*New Buildings (151 days)*	**Water-Heating**
2000	2.94	4.17	2.55	3.65	2.45	3.32	2.43	3.98	4.53	3.20
2001	2.94	4.17	2.55	3.65	2.45	3.32	2.43	3.98	4.53	3.20
2002	2.94	4.17	2.55	3.65	2.45	3.32	2.43	3.98	4.53	3.20
2003	2.94	4.17	2.55	3.65	2.45	3.32	2.43	3.98	4.53	3.20
2004	2.94	4.17	2.55	3.65	2.45	3.32	2.43	3.98	4.53	3.20
2005	2.94	4.17	2.55	3.65	2.45	3.32	2.43	3.98	4.53	3.20
2006	2.97	4.20	2.58	3.68	2.48	3.35	2.46	4.01	4.56	3.23
2007	3.00	4.23	2.61	3.71	2.51	3.38	2.49	4.03	4.59	3.26
2008	3.03	4.27	2.64	3.74	2.54	3.41	2.52	4.06	4.62	3.29
2009	3.06	4.30	2.66	3.77	2.56	3.44	2.54	4.09	4.65	3.32
2010	3.09	4.33	2.69	3.81	2.59	3.47	2.57	4.12	4.68	3.35

Nominal $/MMBtu

	Baseload							Weather-Sensitive		
	Annual	*3-month Winter*	*9-month Summer*	*5-month Winter*	*7-month Summer*	*7-month Winter*	*5-month Summer*	*Old Buildings (269 days)*	*New Buildings (151 days)*	**Water-Heating**
2000	3.09	4.38	2.68	3.83	2.57	3.49	2.55	4.18	4.76	3.36
2001	3.17	4.49	2.75	3.93	2.64	3.58	2.62	4.29	4.88	3.45
2002	3.25	4.60	2.81	4.03	2.70	3.66	2.68	4.39	5.00	3.53
2003	3.33	4.72	2.89	4.13	2.77	3.76	2.75	4.50	5.13	3.62
2004	3.41	4.84	2.96	4.23	2.84	3.85	2.82	4.62	5.25	3.71
2005	3.49	4.96	3.03	4.34	2.91	3.95	2.89	4.73	5.38	3.80
2006	3.62	5.12	3.14	4.48	3.02	4.08	3.00	4.89	5.56	3.94
2007	3.75	5.28	3.26	4.63	3.13	4.22	3.11	5.03	5.73	4.07
2008	3.88	5.47	3.38	4.79	3.25	4.37	3.23	5.20	5.91	4.21
2009	4.01	5.64	3.49	4.95	3.36	4.51	3.33	5.37	6.10	4.36
2010	4.16	5.82	3.62	5.12	3.48	4.67	3.46	5.54	6.29	4.51

Note: The costs for weather-sensitive load (space heating) include 2.5% losses. A portion of these losses flows through to the water-heating costs.

Table 19 summarizes the elements contributing to avoidable delivered gas costs for the year 2000.

Table 19:
Avoided Delivered Gas Costs in the Year 2000 by Load Shape

	Market Price (1998 $/MMBtu)			
	Wellhead	*Delivery*	*Reserve*	*Total*
Baseload				
Annual	$2.14	$0.80	—	$2.94
3-month winter	$2.35	$1.82	—	$4.17
9-month summer	$2.08	$0.47	—	$2.55
5-month winter	$2.24	$1.41	—	$3.65
7-month summer	$2.08	$0.37	—	$2.45
7-month winter	$2.20	$1.12	—	$3.32
5-month summer	$2.08	$0.35	—	$2.43
Heating Loads				
Old buildings (269 days, 63°)	$2.13	$1.52	$0.33	$3.98
New buildings (151 days, 48°)	$2.13	$2.01	$0.39	$4.53
Water Heating	—	—	—	$3.20

As described in Section II.D, below, these costs were developed by combining the wellhead gas costs developed in Section II.B with the delivery and reserve costs developed in Section II.C. The avoided-gas-cost components developed in this report, like those developed for avoided electricity supply, are to be used for the purposes of DSM planning, evaluation, and implementation only. Neither the Study Group nor its members supports in any way the use of the projections described herein, or the inputs to those projections, for any other purpose.

B. Wellhead (Henry Hub) Prices

For input to both gas and electric avoided costs, the year-2000 Henry Hub annual-average cost of gas is projected to be $2.14/MMBtu (1998 dollars), rising with inflation through 2005, and at 1.35% above inflation thereafter.

Resource Insight developed annual average gas prices at Henry Hub based on a review of seven forecasts. The forecasts are listed below, and their projections, in 1998 dollars per MMBtu, are presented below in Table 20. The Study Group reviewed the average forecast prepared by Resource Insight and accepted it as a reasonable forecast of gas commodity costs.

Table 20:
Forecasts of Gas Prices at Henry Hub (1998$/MMBtu)

	EVA Firm July 98	AEO98 Dec 97	AEO99 Nov 98	WEFA Early 98	WEFA99 Mar 99	DRI Apr 98	GRI 1997	Average of EVA, AEO99, and WEFA	Used in Developing Model Input
1995				1.72			1.76		
1996		2.31		2.62	2.63	2.65			
1997	2.56	2.31	2.29	2.55	2.66	2.56			
1998	2.25	2.16	2.05	2.14	2.11	2.30			
1999	2.26	2.16	2.18	2.18	1.87	2.26		2.21	2.14
2000	2.09	2.16	2.17	2.16	2.29	2.24	2.07	2.14	2.14
2001	2.01	2.15	2.19	2.12	2.20	2.19		2.11	2.14
2002	2.02	2.15	2.19	2.12				2.11	2.14
2003	2.04	2.16	2.20	2.14				2.13	2.14
2004	2.06	2.17	2.22	2.15				2.14	2.14
2005	2.08	2.17	2.28	2.17		2.14	1.99	2.18	2.15
2006	2.10	2.18	2.36	2.19				2.22	2.17
2007	2.14	2.21	2.41	2.21				2.26	2.20
2008	2.18	2.23	2.44	2.23				2.28	2.23
2009	2.22	2.27	2.46	2.25				2.31	2.26
2010	2.27	2.32	2.49	2.28		2.36	2.03	2.35	2.29
2011	2.31	2.33	2.50	2.30				2.37	2.33
2012	2.36	2.37	2.52	2.33				2.41	2.36
2013	2.40	2.38	2.55	2.35				2.43	2.39
2014	2.45	2.39	2.59	2.38				2.47	2.42
2015	2.50	2.41	2.63	2.41		2.63	2.07	2.51	2.45
2016	2.52	2.43	2.67	2.43				2.54	2.49
2017	2.55	2.45	2.69	2.46				2.57	2.52
2018	2.57	2.50	2.70	2.48				2.59	2.55
2019	2.60	2.53	2.71	2.52				2.61	2.59
2020	2.63	2.59	2.70	2.55		2.93		2.62	2.62
2005–2020 average annual change									1%

Notes: The AEO98 and AEO99 projections are a volume-weighted average of AEO's forecast of Gulf offshore and onshore wellhead prices. The equilibrium and ELFIN model inputs were based on the average of the three forecasts, smoothed as shown in the final column.

Resource Insight reviewed the following forecasts:

- Energy Information Administration. December 1998. "Annual Energy Outlook 1999 with Projections to 2020" DOE/EIA-0383(99). Washington: U.S. DOE.
- Energy Information Administration. December 1997. "Annual Energy Outlook 1998 with Projections to 2020" DOE/EIA-0554(98). Washington: U.S. DOE.
- Standard & Poor's DRI. April 1998. "World Energy Service U.S. Outlook, April 1998." Lexington, Mass.: Standard & Poor's DRI.

- Gas Research Institute. 1997. “Baseline Projection Data Book, 1998 Edition” Vol. 2 of “GRI Baseline Projection of U.S. Energy Supply and Demand to 2015” GRI-97/0368. Chicago: GRI.
- WEFA Group. Early 1998. “Natural Gas Outlook.” Eddystone, Penn.: WEFA Group.
- WEFA Natural Gas Monthly. March 1999. (This is a short-term forecast, through 2001.)
- Energy Ventures Analysis. July 1998. “Vermont Updated Energy Price Forecast” Technical Report 32. Arlington, Va.: EVA.

All of the forecasts of gas prices at Henry Hub fall within a fairly close range; see Table 20. The most recent of the long-term forecasts, AEO99, remains in line with the earlier forecasts. An average of the EVA, AEO99 and WEFA98 forecasts determined the annual-average wellhead gas price input to the avoided cost estimates.[19]

Inspection of monthly prices (recent actuals, projections, and futures) suggests that the wellhead commodity price is typically slightly greater in the winter than for the year as a whole, and that the rest of year is very slightly less than the average. As a result, the seasonal baseload avoided costs reflect wellhead gas costs that are 10% higher than annual baseload ($2.35/MMBtu in 1998 dollars) in December through February, and 3% lower in all other months ($2.08/MMBtu in 1998 dollars).

C. Delivery Costs to New England

1. Baseload Delivery Prices

The delivery cost for 365-day baseload gas is projected to be $0.80/MMBtu (in 1998 dollars, rising with inflation). The baseload price sets the avoided baseload gas cost. For the equilibrium model of electric avoided costs, this baseload delivery cost was increased by 5% to $0.84/MMBtu (in 1998 dollars). This increase reflects the likelihood of scheduled maintenance occurring in the spring and fall (when delivery costs are relatively low), and the possibility that some portion of the delivery costs are fixed and cannot be recovered through resale when the plant is down, especially for forced outages.

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[19]The earlier AEO and the short-term WEFA forecasts were excluded to avoid redundancy. The relatively high GRI forecast and low DRI forecasts were also excluded, although adding them into the average changes it very little.

This value is based on the price of firm gas purchased by New England plants in 1997–98, and on the only two estimates of annual costs of firm gas delivered to New England that Resource Insight was able to find. These estimates are as follows:

- The $0.77/MMBtu Tennessee tariff supplied by Boston Gas,
- The roughly $0.85/MMBtu estimate (in 1998 dollars) of firm delivery costs from EVA's 1998 Forecast.[20]

Although several of the other forecasts projected delivered costs to New England, those projections are not useful for at least one of the following reasons:

- The costs are specific to a customer class's load shape, and hence difficult to convert to a consistent measure of cost.
- They include distribution rates, which are not relevant for avoided costs.
- They include interruptible sales, which is also not relevant for most gas DSM, or new gas combined-cycle plants.[21]
- The forecast's author has disavowed them, which is the case for EIA's projections of delivery costs to New England. According to Phyllis Martin of EIA, "We have looked at the New England regional results, and we agree that they are too low. Our efforts for the AEO99 were focused on the national results, and we will be spending more time calibrating the regional results for the AEO2000" (e-mail from Phyllis Martin, May 28, 1999).

2. *Seasonal Delivery Prices*

For the electric avoided costs, it was necessary to differentiate the annual gas-delivery cost by month. The analysis described in this section yielded the following monthly delivery prices, which were used in the ELFIN model.

- Winter (December, January, February): $1.82/MMBtu
- Shoulder (November, March): $0.81/MMBtu
- Non-heating (April to October): $0.35/MMBtu.

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[20]The three New England power plants that burn firm gas and (at least until recently) reported to FERC—New Boston, Manchester Street, and Ocean States—report firm gas purchases of $1.13, 98¢, and 68¢/MMBtu above Henry prices, respectively, averaged over the available data since January 1997.

[21]While many existing steam plants burn a mix of interruptible gas and oil, those plants are modeled as burning oil at a discount, as discussed above, rather than modeling the two fuels separately (which no production-costing model seems to do very well).

The computation began with the following values:

- $0.80/MMBtu for 365-day baseload gas delivery
- $2.50/MMBtu for 60-day storage, from the Tioga cost estimate provided by Boston Gas.
- $0.35/MMBtu for market prices for delivery from Henry Hub to New England in the 214 days of the non-heating months of April to October, based on utility reports of market prices to FERC.

Next, the $2.50 average for the top 60 days was split into $3/MMBtu for the top 30 days (roughly propane costs), and $2/MMBtu for the next 30 days.

Delivery costs for two more intervals were interpolated: the third highest-cost 30 days ($1.02/MMBtu) and the rest of the heating period (60¢/MMBtu). This resulted in a total of five price intervals.

Finally, using Boston Gas's data on normal sendout (which follows weather conditions very closely), days from the five price intervals were assigned to months; the daily prices were averaged to get the monthly prices reported at the top of this section. The number of days of each interval in each month, and the resulting monthly prices, are shown below in Table 21.

Table 21:
Development of Monthly Gas Prices

	Days by Month and Interval					Total	Monthly Delivery	Monthly Average
	Top 30	*2nd 30*	*3rd 30*	*Shoulder*	*Off-Peak*	**Days**	**Cost**	**Price**
Delivery Price	$3.00	$2.00	$1.02	$0.60	$0.35			
Month								
November	0	2	1	16	11	30	18.47	$0.62
December	5	7	11	8	0	31	44.98	$1.45
January	14	8	3	6	0	31	64.65	$2.09
February	9	10	5	4	0	28	54.48	$1.95
March	2	3	10	13	3	31	31.02	$1.00
April	0	0	0	12	18	30	13.50	$0.45
May	0	0	0	0	31	31	10.85	$0.35
June	0	0	0	0	30	30	10.50	$0.35
July	0	0	0	0	31	31	10.85	$0.35
August	0	0	0	0	31	31	10.85	$0.35
September	0	0	0	0	30	30	10.50	$0.35
October	0	0	0	2	29	31	11.35	$0.37
Total Days	30	30	30	61	214	365		
Average Prices for Various Loadshapes								
Sept-May Baseload								$0.96
Annual Baseload								$0.80
Summer								$0.35
Elfin Winter (Dec-Feb)								$1.82
Elfin shoulder (Nov and Mar)								$0.81
Elfin Summer (Apr-Oct)								$0.37

Notes
Monthly delivery cost is the sum of the products of the days per interval and the interval prices. Monthly average price is monthly delivery cost, divided by total days per month.

D. Avoided Gas Costs by Load Shape

Avoided gas costs were developed for three load shapes: base, weather-sensitive, and water heating. The final results of these analyses are tabulated in Section II.A, above.

1. *Avoided Baseload Costs*

Baseload DSM avoids baseload supply, which was modeled as the Tennessee pipeline resource plus average annual Henry Hub price. The avoided cost is thus $2.94 ($0.80 plus $2.14, respectively) in 2000, rising to $3.09/MMBtu in 2010 (all in 1998 dollars).

The computation for seasonally-differentiated baseload gas (which may be useful for summer gas cooling, summer pilot shut-offs, replacement of winter pilots with electronic ignitions, and a few other end-uses and measures) is the same as the computation for seasonal gas price used in Table 21. The following table summarizes seasonal baseload avoided capacity costs for three definitions of winter. The electric production-costing model used the monthly costs associated with the three-month winter.

Table 22:
Delivery Costs for Baseload Gas by Duration of Winter Period Used

Winter Months	Winter	Summer
3 Dec-Feb	$1.82	$0.47
5 Nov-Mar	$1.41	$0.37
7 Oct-April	$1.12	$0.35

These delivery costs were then added to the seasonal wellhead costs.

2. Avoided Weather-Sensitive Costs

Avoided capacity costs were estimated for weather-sensitive loads (mostly space-heating loads) in a manner similar to that used for seasonal baseload costs. The difference between baseload and weather-sensitive loads is that more of the weather-sensitive load occurs in the high-cost days. As a first approximation, the weather-sensitive load pattern was estimated by subtracting a baseload level of sendout from normal daily firm sendout, using Boston Gas's estimates of normal-year sendout for 1998–99. The weather-sensitive sendout on each day were then matched to the appropriate price interval, assuming that the days with the highest New England firm sendout also have the highest market gas delivery prices. The weather-sensitive delivery price is the product of the daily sendout times the daily price, divided by total sendout.

Using Boston Gas's average daily sendout for July as a measure of baseload gives a total of 269 days with weather-sensitive load. This is about the annual number of days with average temperatures under 63º F, a standard reference point for computing heating degree-days. The market price for the average MMBtu sent out in this period is $1.48/MMBtu. This seems to be a reasonable estimate of the average value of gas costs avoided by conservation measures for older, leaky, poorly insulated buildings with high balance points.

In thermally tighter buildings, especially in new construction, the balance point will be lower, efficiency measures will matter in fewer days, and conservation savings from the same measure will be smaller. On the other hand, the avoided costs will be higher: space-heating conservation measures in buildings with a 48º F balance point, requiring heat on only 151 days, will save $1.96/MMBtu on those colder days.

These computations are summarized in Table 23.

Table 23:
Summary of Average Delivery Costs for Weather-Sensitive Sendout

	Interval						Average Delivery
	Top 30	2nd 30	3rd 30	Shoulder	Off-Peak	**Total**	**Cost**
Delivery Cost	$3.00	$2.00	$1.02	$0.60	$0.35		
269-day load (for old buildings)							
Number of days	30	30	30	61	118	269	
% of sendout	24%	19%	16%	25%	15%	100%	$1.48
151-day load (for new buildings)							
Number of days	30	30	30	61		151	
% of sendout	38%	26%	19%	18%		100%	$1.96

This analysis may understate load-weighted market price in at least two ways (even assuming that the initial assignment of prices to load intervals was correct).

- It ignores the variation of loads and market price within the pricing intervals. In the highest-load days within each interval (e.g., the second thirty days), the market delivery price is likely to be greater than average for the interval. Thus, the sendout-weighted price will tend to be more than computed here. This factor would add a few percent to the estimates of average market price.
- It computed costs for normal winter weather. In colder winters, more peaking resources will need to be used, increasing total and average costs. In warmer weather, total costs are somewhat less, but many of the costs incurred to meet normal weather (or even acquired as insurance against design weather) cannot be recaptured. For example, capacity charges must be paid even if storage is not fully utilized, and unused storage gas and LNG are often dumped in the spring at low prices. This analysis has not attempted to compute the additional average cost of the asymmetry in the effects of colder and warmer weather.

These understatements are offset by the lack of perfect correlation of market price with Massachusetts's weather and heating load. Some of the days with the highest market delivery prices may be only moderately cold in New England; the high price may result from demand in the Mid-Atlantic or the Midwest.

The weather-sensitive delivery costs are added to the summer wellhead gas cost, since weather-sensitive load is largely served from storage.

a) Reserve Capacity for Weather-Sensitive Load

In addition to the costs of delivering gas in a normal winter, gas suppliers need to have available capacity to meet peak day and peak season demand with design weather. The difference between normal and extreme weather is great. Boston Gas estimates that effective degree days (EDD) (adjusting for wind speed, length of cold snaps, and other factors) average 49 in the top 30 days of a normal year (the amount of capacity implicitly included in the delivery cost estimates) and 83 on the design day. This 34 additional EDDs comprise 0.67% of the EDD in the top 151 days, or 0.57% of the EDD in the top 269 days.

Using Boston Gas's 1995 marginal-cost study, propane-air capacity (generally the least-cost capacity capable of serving a large part of the design winter) was estimated to cost $57/MMBtu-day in 1998 dollars. That translates to $0.38/MMBtu for 151-day measures, or $0.32/MMBtu for 269-day measures.

3. Avoided Gas Costs for Water-Heating Loads

Each MMBtu of water-heating load was assumed to be equivalent to the combination of 0.75 MMBtu of baseload and 0.25 MMBtu of 269-day weather-sensitive load. The avoided costs were calculated as a weighted average of these two elements.

E. Computing DSM Avoided Costs from Wholesale Prices

The estimates of delivery costs already include transmission gas usage, so it need not be added. Physical losses of gas in distribution are not generally load-related. Rather, most gas that is physically lost in distribution is either used by load-independent equipment, or lost due to construction work and pipe failures.

However, one component of unaccounted-for gas is related to load. Most small gas meters, such as those used for residential customers, measure volume without compensating for temperature (and hence density). It is likely that a significant portion of the 3.3% loss factor Boston Gas uses is due to the fact that most space-heating gas is delivered at a temperature lower than the 59º F standard. In the summer, gas may be delivered at higher temperatures, so baseload gas may be properly metered.

Therefore, 2.5% losses were added to the wellhead and delivery costs of space-heating loads for DSM screening purposes. Since the avoided-cost components for weather-sensitive load contribute to the estimated avoided cost for water-heating load, this loss factor slightly increases the water-heating avoided cost. These losses are reflected in Table 2, Table 18, and Table 19.

Under the “Proposed Guidelines: Cost Effectiveness, Monitoring and Evaluation Issues, and Shareholder Incentives,” filed by various parties in DTE Docket No. 98-100, an externalities adder would be applied to all avoided energy-supply costs. This adder is not included in the consensus gas values presented in this report.

Beyond 2010, avoided costs for each load shape should be projected to grow at the average annual rate for the five years from 2005 to 2010. Section I.E explains the formula used to determine these rates.

Appendix A: Additional Assumptions Used in the ELFIN Dispatch Model

Since ELFIN models each unit in NEPOOL individually, it requires many additional inputs. The inputs to the analysis of market prices include new generator additions, fuel costs, variable O&M costs, heat rates, non-utility generation, loads, imports, outage rates and air emissions. The values used in this modeling exercise are described below.

The below planning assumptions are used solely for this study and the development of avoided-energy-supply components. Their use here does not indicate support by the parties to the Study Group for these assumptions to be used for any other purpose.

A. New Generator Capacity Additions

Capacity additions in New England were assumed to be entirely gas-fired combined-cycle generators, since there are currently about 23,000 MW of such projects in various stages of planning, permitting, or construction in the region.[22] (Other than a small wind development, no non-combined-cycle generation projects have requested an SIIS.[23]) These combined-cycle plants were added in 250-MW increments in order to achieve the reserve margin projected for the year 2000 in the April 1999 CELT report (16.9% including purchases from Hydro Quebec).

The summer reserve margin in this analysis stays in the 17%-to-18% range through 2010. Total net additions through 2010 are 7,000 MW (including 1,250 MW added between the summer 1999 and summer 2000 peak periods). The schedule of these additions, specified as the cumulative number of generic 250 MW units brought online in January 1 or the year listed, is indicated in Table Appendix A–1.

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[22]About 1,000 of these MW are under construction, another 3,000 MW have a completed System Impact and Interconnection Study (SIIS) from ISO-NE. Developers of the remaining 19,000 MW have applied for an SIIS.

[23]If energy prices decline, but a need for peaking capacity remains, some combined-cycle projects can be constructed as CTs, by delaying installation of the heat-recovery steam generator.

Table Appendix A–1:
Additions of Combined-Cycle Generators in 250-MW Units

	Units Added *(Cumulative)*
2000	5
2001	7
2002	10
2003	12
2004	14
2005	16
2006	18
2007	21
2008	23
2009	26
2010	28

No generator retirements were specified in ELFIN. In general, the analysis suggests that the existing units in New England are economic to operate on a going-forward basis, and that they will not be retired unless there are specific policy decisions to retire specific units or very strict environmental regulations are applied. To the extent that some of the existing generators may be retired, new additions should come online faster than in Table Appendix A–1, offsetting the effect of the retirements on market prices.

B. Fuel Costs

The fuel cost inputs are summarized in Tables Appendix A–2 and A–3. Their derivation is explained following the tables.

Table Appendix A–2:
Fuel Price Input Assumptions by Fuel

	Year-2000 Price *(1998$/MMBtu)*	**Escalation**
Coal	Varies by plant	-1.0% real
Natural Gas:		
Commodity Cost	2.14	+1.0% real after 2005 (zero before)
Delivery—Winter	1.82	Zero real escalation
Delivery—Spring and Fall	0.81	Zero real escalation
Delivery—Summer	0.35	Zero real escalation
Distillate Oil	3.81	+1.5% real
Residual Oil	2.02	Varies. See annual values below.
Residual—Low Sulfur	+0.15	

Table Appendix A–3:
Residual Oil Annual Fuel Prices

	Residual-Oil Costs *($/MMBtu)*	**Dual-Fuel (Residual & Gas) Costs** *($/MMBtu)*
2000	2.02	1.82
2001	2.10	1.89
2002	2.18	1.96
2003	2.27	2.04
2004	2.35	2.12
2005	2.45	2.21
2006	2.59	2.33
2007	2.73	2.46
2008	2.71	2.44
2009	2.67	2.40
2010	2.71	2.44

1. Coal-Price Forecast

Historical, 1997 plant-specific coal prices from the Utility Data Institute (UDI) database (compiled from utility FERC-Form-1 filings) were used as the starting price in the model. These prices were assumed to decline 1% annually, in real terms, as projected by the AEO.

Coal prices are plant specific, varying significantly with the transportation arrangements and fuel-type requirements (sulfur content, ash content, ash melting point) of each plant (or in some cases, each unit). Coal is not on the margin very much in New England, and no proposed New England power plants would burn coal, so coal prices do not affect the marginal electricity price much.

2. Gas-Price Forecast

The derivation of the price forecast for firm gas delivered to New England power plants is described in Section II.D.1.

3. Oil-Price Forecast

Table Appendix A–4 tabulates projections of residual-oil prices from WEFA, EVA, AEO98, AEO99, GRI, and DRI. These projections of residual oil vary widely; in 2010, for example, they range from $2.15/MMBtu to $3.57/MMBtu. The AEO98 forecast was the highest, and among the earliest, of the 1998 forecasts, while the AEO99 forecast reflects recent expectations of reduced OPEC market power and increased production. The AEO99 forecast is the basis for the inputs to the avoided cost runs, with one adjustment. AEO99 projects a drop in price to $1.82/MMBtu in 2000. That price drop seems excessive from today's prices, which are over $2.00/MMBtu. Therefore a higher value of $2.02/MMBtu in 2000, converging to the AEO99 value in 2005 was used. The modified AEO forecast lies in the middle of the range of forecasts reviewed.

Table Appendix A–4:
Forecasts of Price of Residual Oil Delivered to NE Utilities (1998$/MMBtu)

	WEFA Early 98	GRI 1997	DRI Apr 98	EVA July 98	AEO98 Dec 97	AEO99 Nov 98	ELFIN Input
1995	2.71	3.42		2.66	2.76		
1996	3.16		3.16	3.11	3.16		
1997	3.00		2.78	2.70		2.75	2.75
1998	2.72		2.24	2.03		1.97	1.97
1999	2.90		2.36	1.98		2.03	2.03
2000	2.91	2.99	2.36	1.99	3.04	1.82	2.02
2001	2.94		2.37	2.08		1.97	2.10
2002	2.96			2.07		2.05	2.18
2003	2.99			2.04		2.25	2.27
2004	3.01			2.04		2.37	2.35
2005	3.04	2.91	2.57	2.04	3.30	2.45	2.45
2006				2.06		2.59	2.59
2007				2.08		2.73	2.73
2008				2.10		2.71	2.71
2009				2.12		2.67	2.67
2010	3.07	2.91	2.88	2.15	3.57	2.71	2.71
2011				2.19		2.72	2.72
2012				2.22		2.77	2.77
2013				2.26		2.83	2.83
2014				2.29		2.89	2.89
2015	3.10	2.91	3.23	2.32	3.71	2.77	2.77
2016				2.35		2.89	2.89
2017				2.39		2.90	2.90
2018				2.42		2.92	2.92
2019				2.46		2.95	2.95
2020	3.14			2.50	3.88	2.97	2.97
2000–2020 average annual change						2.48%	

Note: The ELFIN input value is a modified version of the AEO99 forecast.

The projections of the price of distillate delivered to New England utilities also vary widely, as shown below in Table Appendix A–5. For the avoided-cost runs, the year-2000 starting price is $3.81/MMBtu, rising annually at a real rate of increase of 1.63%. This increase is based on an average of four forecasts, WEFA98, DRI, EVA, and AEO99. $3.81/MMBtu is essentially the same starting point as AEO 99, but with a slower escalation rate.

Table Appendix A–5:
Forecasts of Price of Distillate Oil Delivered to NE Utilities (1998$/MMBtu)

	WEFA Early 98	DRI Apr 98	EVA July 98	AEO99 Nov 98	ELFIN Input
1995	4.10		4.07		
1996		5.10			
1997				4.50	
1998	4.20	3.76	2.94	3.55	3.61
1999				3.70	3.71
2000	4.43	3.94	3.07	3.81	3.81
2001				4.03	3.87
2002				4.20	3.94
2003				4.41	4.00
2004				4.58	4.06
2005	4.59	4.27	3.21	4.79	4.13
2006	0.00			4.90	4.20
2007				5.03	4.27
2008				5.04	4.34
2009				5.07	4.41
2010	4.71	4.74	3.38	5.09	4.48
2000–2010 average annual change					1.6%

Note: The ELFIN input value is the average of the four other forecasts.

Dual-fueled steam plants, which can burn either residual oil or gas, were assigned an average fuel price 10% lower than the price of residual oil. This estimate is based on a simple analysis that took the lower of the two fuels for each week, based on prices reported for New York City. (Both oil and gas will be a bit more expensive in New England, and the price differentials will vary with the plant site and the sulfur content of the oil it burns.) The 10% benefit of dual-fuel capability approximates the average benefit for 1994–98. During periods of very low oil prices (1998, for example), the benefit of dual-fuel operation essentially vanishes; during 1995, on the other hand, the advantage was over 20%.

C. Variable O&M costs

Table Appendix A–6, below, shows variable O&M costs for existing plants by plant type, Except for the CTs, the variable O&M was based on Dr. Howard Pifer's testimony on behalf of Potomac Edison in Case No. 8797 (page 30). The variable O&M cost for the new generic combined-cycle generators is described above in Section I.D.1.

Table Appendix A–6:
Variable O&M Costs by Plant Type

	Costs
Nuclear Units	$0.59/MWh
Unscrubbed Coal	$1.96/MWh
Scrubbed Coal	$2.95/MWh
Natural Gas	$1.23/MWh
Residual Oil	$1.88/MWh
Distillate Oil	$1.47/MWh
Internal Combustion	$12/MWh
Combustion Turbines	$3/MWh

D. Heat Rates

Heat rates for existing generators were based on full-load heat-rate data from EIA for 1997. Full load heat rates for steam plants were adjusted upward by 8% to reflect actual operating averages, based on an analysis of the UDI station-level data.

Fossil steam units larger than 100 MW were broken into five capacity blocks with the heat rate for the first four blocks set at one half of one percent below the annual average, and the heat rate for the last block set at 2 percent above the average.

E. Non-Utility Generation

Non-utility generation (NUG) inputs were developed based EIA generating unit data and the total available resources (Section VI) in the 1999 CELT report. Because the EIA and CELT data sources reported ownership for different time periods, the NUG capacity used in the modeling was adjusted to be consistent with the Summer and Winter reserve margins reported for 2000 in the 1999 CELT Report. See Table Appendix A–7.

Table Appendix A–7:
Inputs for Non-Utility Generators

	Capacity *(MW)*	Cost *($/MWh)*	Forced Outage Rate	Scheduled Outage Rate	Target Capacity Factor
Hydro Group	780	1	6.5%	10%	67%
Thermal Group	Summer : 1,840 Winter : 2,940	20	9%	9%	82%

F. Loads

Monthly demand and energy requirements were taken from the April, 1999 CELT Report for 1999 and 2000, with annual growth rates of 1.93% for peak and 2.11% for energy applied thereafter.

Hourly loads for the year 1997—the most recent year for which a full year of data was available—were used as the basis for the load curves for ELFIN.

G. Outage Rates

Outage rates for future units were based upon the most recent available EPRI Technical Assessment Guide. For New combined-cycle units, the forced-outage rate was 4.6% and the scheduled-outage rate was 6.9%.

For existing nuclear units, projected capacity factors of 81% were used. For existing non-nuclear units, equivalent forced and scheduled outage rates by fuel type and size category were developed from national averages for 1993–97 reported in the Generation Availability Data System of the North American Electric Reliability Council.

H. Air-Emissions Rates and Costs

Power generation entails environmental costs, many of which are mitigated in ways that internalize some of the costs. For example,

- Power plant pollution control and low-impact cooling technologies, which raise construction costs, heat rate, and fixed and variable operation and maintenance costs.
- Cleaner fuels such as low-sulfur oil and coal, which command higher prices and impose higher fuel costs.
- Emission allowances for pollutants such as NOx and SO_2, which are exchanged under regional cap and trade systems.

Pollution control and cooling technologies are reflected in the estimates of capital cost, O&M, and heat rate discussed above. Fuel sulfur content is reflected in generator fuel costs. This section explains the Study Group's treatment of emissions-allowance costs.[24]

The requirement for allowances to cover SO_2 emissions was ordained by the passage of the Clean Air Act Amendments in 1990, and has been included in

[24]The emissions-related costs reflected in this report, including allowances, are internalized in the costs for electricity production. These are not externalities, which are defined as costs that are not internalized in market prices.

generation-planning analyses by most utilities ever since.[25] The NOx-allowance system has been developed more recently, but is now firmly established for the Ozone Transport Region (OTR, comprising the New England and mid-Atlantic states). The EPA's efforts to establish comparable NOx limits and trading schemes covering the Midwest and Southeast are currently under appeal. NOx allowances have generally been incorporated in at least some Northeastern utilities' projections of production costs at least since 1997.

In this analysis, SO_2 allowances are priced based on current allowance market prices of about $200/ton in 1998 dollars, consistent with EPA reports of prices in early 1999 of $200–$219/ton.

NOx emissions are priced at $2,500/ton in the ozone season (May through September) and $350/ton during other months, for an annualized average of $1,246/ton. Recently NOx allowances have been trading at much higher prices: $5,100/ton–$5,500/ton reported in the May 5 and May 10, 1999 issues of *Bloomberg Power Lines,* and as much as $5,100/ton for OTR 1999 allowances reported in the most recent trades in Cantor-Fitzgerald's on-line *NOx Budget Market Bulletin* (6/22/99). In addition, *NOx Budget Market Bulletin* reports NOx-reduction credits in Massachusetts and Connecticut selling at $1,000/ton in the ozone season and $650–$700/ton in the non-ozone season.

There are reasons to expect that these prices will decline somewhat over time as the ozone-trading region expands and as further controls—such as SCR—are installed at plants in the region. Expanding the NOx cap-and-trade system to the Midwest would increase the available supply of relatively low-cost NOx emissions (although it will also increase the demand for reductions). Recent data support this position. For example, Cantor-Fitzgerald reports that OTR NOx allowances for 2000–2002 were selling for $2,500/ton earlier in 1999, when 1999 allowances were $4,000/ton. Assuming that the sales price reflects a discount rate of 8%, that would imply that the parties to the transaction expected prices on the order of $2,900/ton in 2000–2002.

The Study Group selected the NOx allowance prices based on the current values and projected reductions.

Emissions rates for NOx and SO_2 for existing plants are based upon 1998 EPA data. These may decrease for some units as further emission controls are added to the plants.

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[25]SO_2 trading values were incorporated in some of the forecasts previously relied upon by the DOER in setting statewide avoided generation costs in 1997.

I. Imports

The following assumptions were made regarding imports of power into the New England Region.

The Hydro Quebec Phase I and II intertie has an import capacity of 1,500 MW Summer and 525 MW Winter (Section 1 of 1998 CELT), with energy limited to 7,000 GWh per annum.

Hydro Quebec's Vermont purchase capacity (including Highgate, block loading, and a portion of the Phase I and II intertie) is 442 MW, with energy limited to a 71% capacity factor.

Additional imports of 1,250 MW (as suggested in the January 23, 1998 Market Reliability Planning Committee Minutes, page 4) are available from New York and New Brunswick. This capacity is modeled in five blocks at prices from $70/MWh to $110/MWh. Each block is assigned a forced outage rate of 50%.

J. Market Behavior

The ELFIN runs include a token recognition of the opportunities for generators to raise prices in tight demand situations. This behavior is reflected in high prices for peak power over the New York and New Brunswick interties ($70/MWh to $110/MWh) and in a substantial adder ($50/MWh) to the variable cost of existing combustion turbines.

Previous analysis using Synapse Energy Economics' Electric Market Optimization Model indicated that during peak load periods competition among suppliers would not provide pressure to keep supply bids in line with marginal plant running costs.[26] Recent market behavior indicates that the type of price behavior seen in the earlier modeling analysis can occur in the New England market—in the first two months of market operation, prices have frequently been well above the highest marginal cost for any generator in the pool. (See Table 16, on page 27 of this report.)

The impact of the intertie pricing and CT-bid adder on the overall annual market prices in these ELFIN runs is small, since these resources are on the margin (i.e., setting the market price) for only a very small number of the hours in the year (significantly less than 1 percent). They do not produce hourly prices as high as those seen on high-cost days in the actual market.

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[26]See "Horizontal Market Power in New England Electricity Markets: Simulation Results and a Review of NEPOOL's Analysis," prepared by Synapse Energy Economics for the New England Conference of Public Utility Commissioners, June 11, 1997.

Appendix B:
Market Price Forecasts

Works Cited in Table 15:

Central Maine Power. 1997/98. Forecast presented in MPUC Docket No. 97-580. R. J. Rudden Associates "mid" market price projection, provided in response to discovery request OPA 13-2 in Docket No. 97-580.

Commonwealth Electric. 1997/98. Forecast presented in MDTE Docket No. 97-111. This projection was prepared by ICF Resources, Incorporated, "Forecast of Marginal Energy and Capacity Prices on the New England Power Pool," April 18, 1997. Provided in response to record request AG-RR-25 in DPU-DTE 97-111.

Fitchburg Gas & Electric. 1997/98. Forecast presented in MDTE Docket No. 97-115. This projection was provided in FG&E's response to data request DTE 2-6, without any documentation, and FG&E has stated that it is not based on a detailed analysis. The summary table assumes that the energy prices are for baseload, and include capacity, but not reserves.

Western Massachusetts Electric Company. Circa 1997. Projection from MDTE Docket No. 97-120 WMECo response to IR AG 3-18, in MDTE Docket No. 97-120. The forecast was expressed in terms of an 80% load factor in the Direct Testimony of Jonathan Wallach and Paul Chernick, Exhibit JFW/PLC-10, in the same case.

Connecticut Light & Power. 1999. Schedule D of the Company's filing in CDPUC 99-02-05. The projection was developed by PHB Hagler Bailly; its details and underlying assumptions are confidential. The overall dollars-per-MWh values for baseload NUG energy were provided in the nonconfidential Schedule D.

Tellus Institute. 1998. Direct Testimony of Richard Rosen, ExhibitsRAR-15, pages 3, 5 and 9, and Exhibit RAR-17, pages 1 and 6, in MPUC Case No. 97-580. Four different forecasts were presented. For three of these forecasts, Tellus backed out the market prices implicit in the asset sales of CMP, BECo, and NEP.

Exeter Associates. 1999. Testimony of Matthew I. Kahal in CDPUC Case No. 99-02-05. The basis for Mr. Kahal's short-term market price is not documented in his testimony.

Resource Insight. 1999. Direct Testimony of Paul Chernick in CDPUC 99-02-05 and CDPUC 99-03-04. This testimony was filed under a protective agreement, but the forecast is not confidential.

Table Appendix B–1:
Comparison of Detailed Market-Price Forecasts

	RII				FG&E			WMECo				CMP				ComElectric				
	Capacity ($/kW)	Capacity ($/MWh)	Energy ($/MWh)	Total ($/MWh)	On-Peak ($/MWh)	Off-Peak ($/MWh)	All-Hours ($/MWh)	Capacity ($/kW)	Capacity ($/MWh)	Energy ($/MWh)	Total ($/MWh)	Capacity ($/kW)	Capacity ($/MWh)	Energy ($/MWh)	Total ($/MWh)	Capacity ($/kW)	Capacity ($/MWh)	Peak Energy ($/MWh)	Off-Peak Energy ($/MWh)	All-Hours Energy ($/MWh)
2000	50	7.1	31.7	38.8	36.0	30.0	33.0	55	7.8	25.7	33.5	49	6.9	28.4	35.3	45	6.4	28.8	25.0	26.6
2001	51	7.3	32.5	39.8	37.0	31.0	34.0	57	8.1	25.1	33.2	57	8.2	29.8	38.0	46	6.6	29.7	25.8	27.4
2002	53	7.5	33.3	40.8	38.0	32.0	35.0	59	8.4	25.3	33.7	66	9.4	31.4	40.9	48	6.8	30.7	26.6	28.3
2003	54	7.7	34.1	41.8	39.0	33.0	36.0	61	8.7	26.0	34.7	68	9.7	33.1	42.8	49	7.0	31.8	27.3	29.2
2004	55	7.9	35.0	42.8	40.1	34.1	37.1	63	9.0	26.0	35.0	70	10.0	34.8	44.8	51	7.2	32.9	28.0	30.0
2005	57	8.1	35.8	43.9	41.2	35.2	38.2	65	9.3	26.5	35.8	72	10.3	36.6	47.0	52	7.4	34.1	28.7	30.9
2006	58	8.3	36.9	45.2	42.4	36.4	39.4	67	9.6	27.4	37.0	75	10.6	38.6	49.2	54	7.7	35.4	29.7	32.1
2007	59	8.5	38.1	46.6	43.5	37.5	40.5	69	9.8	28.3	38.1	77	11.0	40.6	51.5	55	7.9	36.7	30.7	33.2
2008	61	8.7	39.4	48.0	44.8	38.8	41.8	71	10.1	29.1	39.2	79	11.3	42.7	54.0	57	8.1	38.1	31.8	34.4
2009	62	8.9	40.6	49.5	46.0	40.0	43.0	73	10.4	30.0	40.4	81	11.6	45.0	56.6	59	8.4	39.6	32.9	35.7
2010	64	9.1	41.9	51.0	47.3	41.3	44.3	75	10.7	30.9	41.6	84	12.0	46.2	58.2	61	8.6	41.1	34.0	37.0
2011	66	9.4	43.2	52.6	48.6	42.6	45.6	77	11.0	31.8	42.9	86	12.3	47.5	59.8	62	8.9	42.5	35.1	38.2
2012	67	9.6	44.6	54.2	50.0	44.0	47.0	80	11.4	32.8	44.1	89	12.7	48.8	61.5	64	9.2	44.1	36.2	39.5
2013	69	9.8	46.0	55.9	51.4	45.4	48.4	82	11.7	33.8	45.5	92	13.1	50.2	63.3	66	9.4	45.7	37.5	40.9
2014	71	10.1	47.5	57.6	52.9	46.9	49.9	84	12.0	34.8	46.8	94	13.5	51.6	65.1	68	9.7	47.3	38.9	42.4
2015	72	10.3	49.1	59.4	54.4	48.4	51.4	87	12.4	35.8	48.2	97	13.9	53.5	67.4	70	10.0	49.1	40.4	44.0

Notes:

Capacity prices per MWh are derived assuming a capacity factor of:	80%
For FGE All-Hours $/MWh, on-peak energy weighted:	50%
For ComElectric All-Hours $/MWh, on-peak energy weighted:	41.7%

Table Appendix B–2:
Assumptions Underlying Market-Price Forecasts

	RII	ICF	Tellus	CMP	WMECo
Years dollars	1998, exc. Gas	1996	1996		
Inflation	2.5%	3%	3%	3%	3%
Load Growth		1.8%			
Capacity Need Date	1998	1998	1996		1998
Commodity Gas Price	(in 1997$)				
2000	2.11	1.90	2.08		
2005	2.11	2.05	2.11		
2010	2.25	2.15	2.24		
2015	2.40	2.26	2.30		
Gas Delivery Cost	0.84		1.02		
Residual Price					
2000		3.07			2.93
2005		3.23			2.99
2010		3.40			3.07
2015		3.57			3.13
Distillate Price					
2000		4.05			
2005		4.22			
2010		4.39			
2015		4.57			
Nuclear Capacity Factor		74%			
Canadian Hydro Purchases		9.9 TWh			
Pool Reserve Margin		18%	20%		
New CC:					
Capital Cost ($/kW)	605	450	383		
Heat rate (Btu/kWh)	7200	6700	6500		
Fixed O&M ($/kW/yr)	32.2	17.1	11.7		
Variable O&M ($/MWh)	1.24	1	0.2		
Availability or Capacity Factor	86%	90%			
Capital Charge Rate	11.05%	12.7%	10.5%		
New CT:					
Capital Cost ($/kW)	350	300	275		
Heat rate (Btu/kWh)		11000	11900		
Fixed O&M ($/kW/yr)	5.93	1.9	9.4		
Variable O&M ($/MWh)		1	0.1		
Availability		92			
Capital Charge Rate	11.38%	12.7%			

Missing information may not have been used or may not be available.

Appendix C:
Capital Cost and Capital Structure

Table Appendix C–1:
Experts' Estimates of the Capital Structure and Costs for Merchant Generators

	Source	Percent Debt	Return on Debt	Return on Equity	Pre-Tax Cost of Capital	After-Tax Cost of Capital	Notes
1	Joseph Graves	40%	8.5%	12.5%	10.9%	9.6%	
2	Jerome Haas	55%	8.5%	13.0%	10.5%	8.7%	
3	Stephen Hill	40%	7.23%	12.00%	10.1%	9.0%	
4	James Rothschild	45%	7.52%	11.75%	9.8%	8.5%	
5	Howard Pifer	40%				9.3%	ATCC may use different tax rate
6	R. Craig Evans	40%	7.06%				Investment grade debt
7	Standard & Poor's	35%					A-rated debt
8	Standard & Poor's	45%					BBB-rated debt
9	Standard & Poor's	20-30%					IPPs with contracts

Additional notes and source notes by line number:

After-tax cost of capital reflects a combined income tax rate of 39.28%.

1 Direct Testimony of Joseph S. Graves (PHB) on behalf of the Potomac Electric Power Company in Maryland PSC Case No. 8796 (July, 1998), pp. 41-42.

2 Prepared Direct Testimony of Jerome E. Haas (NERA) on behalf of Baltimore Gas & Electric Company in Maryland PSC Case No. 8794. July 1, 1998. Page 16.

3 Testimony of Stephen G. Hill on Behalf of the Maryland Office of People's Counsel in Maryland PSC Case Nos. 8794 and 8804. December 22, 1998.

4 Direct Testimony of James A. Rothschild, on behalf of the Connecticut Office of Consumer Counsel, in Connecticut DPUC Docket No. 99-02-05, April 1999.

5 Direct Testimony of Dr. Howard Pifer (PHB) on behalf of Potomac Edison Company in Maryland PSC Case No, 8797. July 1, 1998. Page 38.

6 Testimony of R. Craig Evams (Delmarva) on behalf of Delmarva Power & Light Company in Maryland PSC Case No. 8795. July 1, 1998. Page 6. Evans' estimate of return on equity was confidential. "With estimates of debt levels from 25% to 65%, the Company chose 40% as a reasonable level of debt investment. This will allow the company who builds the next generation facility to retain investment quality debt ratings on the bonds…"

7 Standard and Poor's Global Sector Review, (October, 1997).

8 Standard and Poor's Global Sector Review, (October, 1997).

9 Standard and Poor's Industry Comment, (September, 1997).

Table Appendix C–2:
Capital Structures of Merchant Generators as of Mid-1999

	Market Equity Capitalization	Long-Term Debt	Percent Debt	Notes
PowerGen				
12/31/98	£5,128 M	£2,853 M	36%	
3/31/98	£5,386 M	£818 M	13%	
3/31/97	£3,780 M	£849 M	18%	
National Power				
3/31/99	£6,131 M	£2,849 M	32%	
3/31/98	£7,464 M	£3,049 M	29%	
3/31/97	£5,897 M	£2,697 M	31%	
USGen NE				
12/31/97	$1,000 M	$750 M	43%	PG&E 1997 10K. Some of the debt is from affiliates, and may require further equity
1998	$1,555 M	$575 M	27%	S&P CreditWire 9/4/98
12/31/1998	$10,284 M	$1,978 M	16%	PG&E 10K: book equity. Includes other non-utility operations
12/31/1998	$15,367 M	$1,978 M	11%	Equity at market