THE DEVELOPMENT OF CONSISTENT ESTIMATES OF AVOIDED COSTS FOR BOSTON GAS COMPANY, BOSTON EDISON COMPANY, AND MASSACHUSETTS ELECTRIC COMPANY

A Report to the
Boston Gas Company

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December 22, 1989

Printed on Recycled Paper

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1. INTRODUCTION

This report describes the work of PLC, Inc. to date in preparing consistent estimates of long-run avoided costs for the Boston Gas Company (BGC), the Boston Edison Company (BECo), and the Massachusetts Electric Company (MECo). The objective of this analysis is to produce avoided-cost estimates which can be used to meaningfully evaluate energy-related investments that affect the consumption of both natural gas and electricity.[1] These investments might include:

- the choice of energy sources for end-use equipment in new facilities or for new equipment in existing facilities,
- conservation investments which will reduce the usage of both electricity and gas (e.g., building insulation which will reduce both gas heating and electric cooling loads),
- conservation investments which will reduce the usage of one energy source, but intentionally increase the usage of the other (e.g., the use of electric fans to increase gas furnace combustion or distribution efficiency),
- conservation investments which will reduce usage of one energy source, but incidentally increase usage of the other (e.g., reduction of electric lighting load, which also reduces electric cooling load but increases gas heating load), and
- the replacement of one energy source by the other in existing facilities (i.e., fuel-switching).

The comparison of the avoided costs of BGC to those of BECo and MECo is relevant for all these purposes, since most of the BGC service territory is also served by BECo and MECo.[2]

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[1]We use the term "avoided costs" to mean both the reduction in costs due to lower load, and the increase in costs due to higher load.

[2]It is also true that most of BECo's load is in municipalities served by BGC. MECo serves a much larger geographical area, and the overlap with BGC does not appear to be a large share of MECo territory or load. Of the 74 municipalities BGC serves, 21 (including Boston, which represents 27% of BECo's customers and 27% of BGC customers) are in BECo's service territory, and 32 are in MECo's (including 5 of the 8 cities in which MECo has more than 20,000 customers). The remainder of the BGC communities are served by municipal utilities, except for four towns served by Eastern Edison and one town (of which BGC serves only half) served by Fitchburg G&E. For comparison, BECo serves a total of 40 municipalities, while MECo serves 158, many of which are small,

The avoided-cost estimates previously produced by various utilities differ in many ways. For example, the two electric utilities covered by this study assume different dates at which peaking capacity would be built (1992 for BECo and 1995 for MECo), different technologies for the avoided generation (gas turbine for BECo and combined cycle for MECo), and different technologies for future capacity expansion (gasification coal for BECo and combined cycle repowering for MECo).[3] All three utilities assumed that a reduction in load will permanently avoid the first supply addition whose in-service date is delayed by the load reduction. While this may be a reasonable assumption for BGC (given the fixed schedule on which new pipeline supplies must be accepted or rejected), it is not a reasonable assumption for the electric utilities, which have the option of delaying construction.[4] Load forecasts also differ among utilities, and may rely on different projections for future economic conditions. The utilities also use different methodologies for projecting marginal costs; some of these differences are driven by differences in the utilities and their data, while others are arbitrary.

We have not attempted to eliminate all the differences in the avoided-cost estimation methodologies. We have attempted only a very simple reconciliation in the avoided-cost estimates, to eliminate differences due to different assumptions about the future costs of marginal utility inputs.[5] In essence, we have restated the avoided cost projections from the very different future worlds assumed by the utilities, in terms of inflation rates and of the real prices of fossil fuels, to a common world.

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rural and lack gas service.

[3]Some of the references to MECo actually apply more directly to its wholesale affiliate, New England Power Company (NEPCo), or to other affiliates.

[4]This topic is discussed at greater length in Section 3. The treatment of the avoidable supply may significantly understate BECo's avoided cost. Given their choice of avoidable supplies, the understatement is probably much smaller for MECo, and non-existent for BGC.

[5]We have not attempted the more demanding task of restating the demand forecasts of the utilities, which are influenced to some extent by these and related economic assumptions. The effect of the fuel prices on the forecasts would be fairly small, and would tend to reduce the sensitivity of avoided cost to fuel prices. For example, high fuel prices would tend to reduce loads, which would reduce avoided costs.

In order to make the analysis as robust as possible, we have created three common worlds, based on updated cost projections for each of the three utilities. The BGC cost assumptions are applied to both BECo and MECo, and the cost assumptions for each electric utility are applied to BGC.

1.1 Common Assumptions and Approaches

We have evaluated all utility costs at the end-use level. For the electric utilities, this means at the secondary voltage level. For larger users, power is often delivered at the primary voltage level, or even at transmission voltage, but virtually all power is actually used at secondary voltages (i.e., under 600 volts). Delivery at higher voltage levels saves the utility the costs of transformers, secondary (or even primary) distribution, and the attendant line losses. In such cases, avoided secondary-system costs due to a reduction in load occur within the customer's facility, rather than on the utility system. From a social cost perspective (in which all costs are equally important, whether borne by the utility or by customers) all costs should be evaluated at the secondary level.

The electric utility avoided costs are drawn from analyses which were performed to evaluate contracts with cogenerators and small power producers (collectively, qualifying facilities or QFs). These generators will usually provide energy evenly over the year, so the load decrement representing the QFs is an equal amount in each hour. For evaluating increases or decreases in utility load due to conservation, fuel-switching, or other end-use changes, the load pattern in each rating period should reflect the specific pattern of loads in each period. Each type of end-use load will tend to have its own shape.[6] For average system loads, more energy will be used at high-use times, and less at low-use times, than is modeled in the QF decrement.

In addition, the energy loss multipliers produced by the electric utilities (and used in both their avoided cost computations and ours) are based on the average load in each rating period. The ratio of losses to sales in each hour within the period is assumed to be the same as that ratio at the average load level during the period. The utilities acknowledge that the high-

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[6]For example, within the summer peak period, commercial cooling load will tend to be greatest at the times of highest load and highest cost, the load imposed by exit signs will be flat, and the savings due to an HVAC economizer (which brings in outside air when that is cool enough to provide space chilling) will tend to be greatest at the times of relatively low load and low costs.

load rating periods have higher marginal line losses.[7] The same physical relationship applies within each rating period; the marginal losses will tend to be higher in high-load, high-cost hours and lower in low-load, low-cost hours. By multiplying average avoided cost by the marginal loss percentage at average load, the electric utilities produce loss-adjusted avoided cost estimates which are lower than the actual product of the cost in each hour times the loss multiplier for that hour.

The electric utility marginal costs we used neglect both the correlation of loads with high-cost hours, and the correlation of losses with high-cost hours. Hence, the avoided energy costs for the electric utilities are understated for the purposes to which they are applied here, even if they were totally appropriate for evaluating QFs.[8] The BGC avoided-cost model directly reflects the load shape of weather-sensitive load, and natural gas losses do not appear to vary directly with load,[9] so the BGC avoided-cost estimates does not suffer from these problems.

For each of the three utilities, we have used the cost of capital estimated by that utility in its most recent analyses as the discount rate. The weighted costs of capital range from 11.45% for MECo, to 11.50% for BGC, to 12.16% for BECo. It is not clear that these values are entirely consistent, since the dates of the

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[7]Variable line losses increase roughly as the square of the load on the transmission and distribution system. Hence, losses as a percentage of load (or of generation) rise approximately linearly with load.

[8]The correction in the loss computation would also be appropriate for QF avoided-cost computations.

[9]BGC's cost component which is most likely to follow the increasing marginal pattern of electric losses is not gas losses but compression energy. Resistance-related losses, whether in the flow of electricity or in the flow of a fluid, generally increase as the square of load. BGC assumes that compression costs are a constant amount per MMBTU (i.e., that they increase linearly with load), which probably understates marginal compression costs slightly. However, compression costs are only one portion of total production O&M, all of which BGC assumes varies linearly with load. Some of those production costs probably do not vary at all with load, so the overall treatment of production O&M may be quite reasonable. In any case, compression costs are a small part of BGC's commodity cost (certainly much smaller than the electric utilities' line losses), so this is probably a very minor issue for BGC avoided cost estimates.

estimates are different.[10] We have not attempted to update the costs of capital, for two reasons. First, updating the cost of capital would require updating the carrying charge and revenue requirements computations, since those are determined (in part) by the rate of return. Reproducing and revising the carrying charge computation is generally quite cumbersome. Second, while the use of different costs of capital in the same analysis may be inconsistent, the DPU precedent appears to tolerate such inconsistency for utilities (such as Commonwealth Energy) with generation and distribution subsidiaries with different allowed returns. The DPU has not established rules for the evaluation of projects or programs which affect two or more utilities.

In general, each Massachusetts utility uses its own weighted marginal cost of new capital as its discount rate. However, in DPU 89-21 and in other recent filings, MECo has used an "after-tax" discount rate, which is lower than the weighted cost of capital by the product of the marginal tax rate, the interest rate on debt, and the fraction of marginal capital which is assumed to be debt. In recent cases, MECo has estimated its after-tax cost of capital to be 9.46% - 9.73%. We use 9.73%, the high end of that range which is equivalent to about 11.45% on the pre-tax basis used by BECo, BGC, and virtually all other Massachusetts utilities.[11]

MECo's use of the "after-tax" cost of capital introduces the only major difference in discount rates between the three utilities. Comparing the present value of MECo avoided costs computed with an after-tax discount rate, to the present value of BGC (or BECo) costs computed with a pre-tax discount rate, would provide a misleading picture of the relative costs of the two utilities. Specifically, costs discounted at the after-tax rate would be higher than those discounted at the pre-tax rate. We have therefore restated MECo's discount rate in pre-tax terms.[12] Once this difference is eliminated, the discount rates are quite similar, since BECo uses a 12.16% discount rate and BGC uses an 11.50% discount rate, compared to MECo's 11.45%. With the discount

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[10] The origins of the cost-of-capital estimates are also somewhat different, since BGC's value reflects allowed returns, and BECo's value reflects requested return in a rate case, and the basis for MECo's value (which was taken from Granite State's Least-Cost Plan, and which is consistent with the NEPCo W-10 filing) is not clear.

[11]We do not have enough detail on the 9.46% discount rate to determine the pre-tax equivalent, so we used the pre-tax equivalent of 9.73%.

[12]Using after-tax discount rates would generally improve the cost-effectiveness of conservation, probably including fuel switching.

rates stated on this consistent basis, only minor cost differences are attributable to such underlying financial assumptions as interest rates, return on equity, and capital structure.

1.2 Comparison of the Projections

We use five fuel and inflation forecasts in our analysis. The assumptions for each analysis are displayed in Tables A through E of Attachment 1. Two of these analyses are important only because they form the basis of the electric utility avoided fuel cost estimates which we use as the basis for our projections. For Boston Edison, the 1988 RFP avoided costs are based on July 1987 DRI fuel prices, and BECo's interpretation of DRI inflation projections.[13] We refer to this set of projections as "BECo/DRI 1987." The corresponding starting point for MECo avoided fuel costs is the NEEI projection of September 1987. We call this "NEEI 1987."

The updates to these projections are taken from the most recent available fuel and inflation forecasts by the sources used by the electric utilities. For BECO, the update is from DRI's February 1989 fuel forecast, augmented by DRI February 1989 inflation assumptions filed by BECo in DPU 89-100. We identify this set of projections as "DRI 1989." For MECo, the update is the NEEI September 1988 fuel price projection, which we call "NEEI 1988."[14]

The price projections currently used by BGC are based on the real fuel prices projected by Jensen Associates in May 1989, to which BGC applies an assumed inflation rate of 5%. The same inflation was used to drive the fuel-price projections and for inflation in utility non-fuel costs. We call this set of price projections "BGC/Jensen 1989" or just "Jensen 1989."

1.3 Summary of Results

Tables 1.1 through 1.3 in Attachment 1 show resulting avoided costs for Boston Gas Co., Boston Edison Co., and Massachusetts Electric Co. under various fuel escalation and general inflation assumptions. The summary avoided cost tables, Tables 1.4 through 1.6, clearly demonstrate that natural gas is much cheaper than electricity on a $/MMBTU basis. Consequently, natural gas

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[13]The BECo 1988 avoided cost analysis appears to use different projections of GNP inflation for different purposes. In addition, BECo reports different inflation rates for construction and for O&M. The interpretation of BECo's inflation assumptions is unusually complex.

[14]NEEI's 1989 update is now overdue.

represents an economically superior alternative to electricity even with the lower end-use efficiency of natural gas, and as such should be included in the electric utilities' Least Cost Planning.

In general, the task of putting the various utilities' avoided costs on a comparable basis is an arduous one. To effectively consider all options in a complete least cost strategy, including fuel switching and conservation, it is vital to have a common forecasting methodology among the utilities. Utilities should be required to file their most accurate cost estimates under some uniform set of criteria. Uniform methods for computing load forecasting, avoided capitalized energy costs and fuel costs, marginal energy losses, and discount rates by each utility would considerably facilitate comparison of each utilities' Least Cost Planning.

2. THE BOSTON GAS AVOIDED COST MODEL

The BGC model is essentially the same as that described in the testimony of Gregory O. Tomlinson in DPU 88-67, Phase II. BGC's avoided costs include commodity costs (which reflect both well-head gas prices and commodity-related pipeline charges), supply capacity costs (based on the market price of peaking storage capacity), capitalized energy costs (computed as the difference between Open-Season fixed charges and peaking capacity costs), and BGC's demand-related distribution costs (marginal investment costs, O&M, losses, working capital, etc.). We have left all assumptions as they were stated in DPU 88-67, Phase II, except for updating inflation rates and fuel prices.[15]

The reference run for the BGC model uses the fuel and inflation forecasts provided to BGC by Jensen Associates in May 1989, with interpretations and modifications by BGC. This "Jensen/BGC 1989" run is provided in Attachment 2. Jensen is BGC's standard source for fuel-cost projections. The major assumptions supplied by BGC are a 5% inflation rate for all non-fuel costs, and the treatment of Open Season commodity costs.

Open Season commodity costs are assumed to retain the same relationship (i.e., remain in the same ratio) to the total commodity cost of the F1-Algonquin supply as was assumed in the runs for DPU 88-67, Phase II.

For the BGC avoided cost model, we have continued the prior practice of collapsing avoided demand costs into the avoided costs per MMBTU for each load shape. Given the small number of gas-fired end uses (compared to the wide variety of electric end-uses), and the limited information available on the load shape of conservation measures, this is a useful simplification. If detailed analyses of a wide range of demand-side measures (particularly heating-related measures) are desired, it may be more convenient to break out the capacity charges from the commodity charges.

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[15]The in-service date for BGC's avoidable supply, the Open Season purchase from Canada, has slipped somewhat from the earlier avoided cost estimate. Including this update would probably reduce BGC avoided costs, since the Open Season supplies were originally scheduled to come on line somewhat before they were strictly necessary for BGC's purposes. We have not included this update, since we have not attempted to similarly update the electric utility avoided cost assumptions. Thus, the BGC avoided cost assumptions we derive here may be somewhat overstated by this factor.

2.1 Adapting DRI 1989 Projections for Use in the BGC Model

DRI provides projections of gas purchase costs for each pipeline (Tennessee and Algonquin). We use those costs to drive BGC's commodity costs. We use the two pipeline costs as estimate prices for several supplies. Prices for Champlain, Boundary, and Iroquois are estimated as the DRI F1 pipeline price multiplied by the ratio, in Jensen-89 prices, of the supply to F1. The non-gas portions of the commodity cost are inflated from 1989 levels at the DRI/BECo utility inflation rate.

The resulting BGC avoided cost calculations with DRI/BECo price projections are displayed in Attachment 3.

2.2 Adapting NEEI 1988 Projections for use in the BGC Model

We were not able to determine whether the well-head prices in the NEEI price forecast represented domestic or Canadian supplies, nor whether they represented firm or spot prices. Therefore, we derived well-head gas prices from NEEI's WTI crude-oil prices and Jensen's projected ratios of well-head gas prices to crude oil. The non-gas portion of the commodity cost is inflated from 1989 prices at the NEEI 1988 inflation rate of 5.0%.

The resulting BGC avoided cost calculations with NEEI price projections are displayed in Attachment 4.

3. THE BOSTON EDISON AVOIDED COST MODEL

Electric utility avoided-cost computations generally include three categories of avoidable capacity costs -- generation, transmission, and distribution -- and two types of avoidable energy costs -- fuel and variable O&M, and capitalized energy. Our avoided-cost calculations for each utility are laid out with the capacity costs considered in the first four major tables, and the energy costs considered in the last two major tables.

We modelled BECo's avoided generation costs on BECo's second "Request for Proposals from Qualifying Cogeneration and Small Power Production Facilities" (QF RFP-2). The RFP was issued on 4/14/89; the avoided-cost data were provided to the DPU on 10/25/88. The transmission and distribution costs, and losses, are based on the rate-design portion of BECo's filing in DPU 89-100. The references to DPU 89-100 are to the schedules and workpapers in BECo's "Marginal Cost of Service Study", (Exhibit BE-RDS-4) which accompanies the testimony of Robert D. Saunders (Exhibit BE-RDS-1).

We have organized the tables of the BECo and MECo models to facilitate comparison of the values.[16] Thus, Table 3.1 performs the same computations for BECo as does Table 4.1 for MECo. Where computations are required for only one of the companies, we have labelled those tables with letters (for example, Table 3.1.A), as well as numbers.

The reference run for the BECo model uses the fuel and inflation forecasts provided to BECo by Data Resources, Inc., (DRI) in February 1989. DRI is BECo's standard source for fuel-price projections, and one of BECo's standard sources for inflation projections.[17] This "DRI 1989 Avoided Cost" run is provided in Attachment 5.

Table 3.1.A computes BECo's marginal demand-related costs of transmission and distribution to the secondary level in 1989$ and

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[16]We did not believe that similar comparability between BGC avoided-cost estimation details and those of the electric utilities would be particularly helpful, given the differences in units and industry structure.

[17]BECo sometime uses inconsistent inflation projections by mixing projections from DRI and WEFA. See the testimony of Paul Chernick and Jonathan Wallach on behalf of the Executive Office of Energy Resources, DPU 89-100.

of combustion turbine peaking capacity in 1992$.[18] These are inputs from DPU 89-100. All costs are stated per kW of generation-level coincident peak.

Table 3.1.B calculates the economic (i.e., real-levelized) carrying charges for generation, transmission, and distribution capacity. The economic carrying charge is the ratio of the present value of the revenue requirements of a $1 investment multiplied by the annualization factor. The formula for the annualization factor is

$$\frac{r - I}{1 - \{(1+I)/(1+r)\}^n}$$

where n is the number of years for the cost recovery, r equals the discount rate (for which we used BECo's 12.16%), and I is the inflation rate of 5.8%, from DRI's February 1989 forecast.[19]

Table 3.1 calculates the seasonal allocation of the total annual distribution costs from Table 3.1.A. Costs are escalated at a constant 5.8% in the reference case, but the model allows for different inflation rates in each year, 1989-2011. Table 3.1 allocates 49% of distribution costs to the summer and 51% to the winter, as per DPU 89-100.[20] Finally, Table 3.1 adds in marginal losses of 20.1% in the summer and 20.0% in the winter.[21]

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[18]BECo currently projects that it will need capacity in 1992. Since it is stated in 1992 dollars, the generation cost value produced in Table 3.1.A can appear directly in Table 3.2.

[19]BECo actually uses a variety of inflation rates from the DRI 1989 forecast, from 5.8% to 6.6%. BECo uses the 5.8% value for levelizing its carrying charges, and we accepted this treatment.

[20]Note that "winter" for BECo includes all but the four summer months of June, July, August, and September. BECo's winter is thus equivalent to a combination of MECo's winter (December, January, and February) and spring/fall rating periods. The contribution of loads in different time periods to the need for capacity is a complicated subject. To limit data requirements, we have treated electric utility demand-related costs as flowing from a combination of summer and winter maximum peak loads. The seasonal weights are taken from the utilities' estimates of seasonal contribution to cost causation. Also, we have assumed that all transmission and distribution costs are demand-related, which is a simplification usually assumed by the electric utilities.

[21]The peak losses assigned to distribution are higher than those used for transmission and generation. Most losses occur on the distribution system, and those losses are highest at the distribution system peaks. This treatment is taken from BECo's

Table 3.1 displays the detailed analysis described above for 1989-2011. In order to allow present value comparisons for measures with lifetimes up to 40 years (to 2035), we project the total seasonal costs for each type of capacity (generation, transmission, and distribution), including losses, at the secondary distribution level, using the growth rate from 2001-2011. For the reference run, this is simply the 5.8% rate assumed in the earlier period.

Table 3.2 calculates the seasonal allocation of avoided generation demand costs (in $/kW) at the secondary level, for each year 1989-2011. The initial value for peaking generation capacity in 1992 comes from Table 3.1.A. Generation capacity costs are escalated at 5.8% annually in the reference case. Following BECo's methodology in DPU 89-100, 55% of the total avoided generation cost is allocated to the summer and 45% is allocated to the winter. We also increase the cost per kW in the winter period by the ratio of summer to winter loads, to reflect the fact that the capacity requirement is based on summer peak (as 1.23 MW of capacity per MW of summer peak load), and that there are fewer kW on the winter peak over which the winter share of the cost can be spread.[22] Finally, Table 3.2 adds peak losses of 18.0% in the summer and 18.3% in the winter, from BECo.[23]

Table 3.3 calculates the seasonal allocation of avoided transmission demand costs at secondary levels, in a manner similar to that used in Table 3.2 for generation and Table 3.1 for distribution. Following BECo, we escalate transmission costs at 5.8% annually, assign 55% of the total avoided cost to the summer and 45% to the winter, and add peak losses of 18.0% in the summer and 18.3% in the winter.

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marginal cost analysis.

[22]No similar adjustment appears to be necessary for BECo's transmission and distribution costs. The cost per kW is determined by regressing the incremental costs against the increment in summer peak loads. Since BECo's winter loads have been growing about as fast as its summer loads, in MWs, the incremental $/kW relationship is likely to be similar. In the future, it might be more appropriate to perform these regressions directly with a weighted average of summer and winter peaks, rather than just the summer peak.

[23]BECo estimates that its marginal coincident peak losses (as a percentage of load) are higher at the winter peak than at the summer peak, despite the higher loads and higher temperatures at the summer peak.

Table 3.4 displays the present value of total capacity costs (including generation, distribution, and transmission) to secondary users, for each kilowatt of summer and winter coincident peak load, over various evaluation periods. This figure represents the value of the avoided demand costs which result from one kW of load reduction at the end use, in the indicated season, for the indicated number of years.

Table 3.5 calculates annual avoided energy costs. The DRI-87 avoided fuel and variable O&M costs are taken from BECo's QF RFP-2 (Exhibit A, p. 25, Table 6), and are stated at the generation level. The fuel price update line adjusts the fuel forecast used in the QF filing (DRI's Spring 1987 Forecast) to reflect a more current fuel forecast (DRI's February 1989 forecast). The fuel price update multiplier is computed by comparing fuel savings due to the load decrement used in the RFP expenditures under the two price forecasts. The supporting calculation for the update factor is shown in Attachment 9.

Table 3.5 includes a line for the capitalized energy costs, which are zero for BECo's avoided cost projection.[24] The sum of the updated fuel costs and the capitalized energy costs are split out to time periods using the summer-to-winter cost ratios used by BECo in DPU 89-100.[25]

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[24]BECo's failure to include capitalized energy costs indicates a flaw in the DPU's methodology for computing long-term avoided costs. By including a peaking unit as the first unit in its base expansion plan, and assuming that the peaker is the avoided supply source for the entire period of the analysis, BECo denies conservation and other power suppliers the opportunity to compete against the baseload coal plants it plans for the year 2000 and beyond. However, BECo does include the fuel-cost savings of the coal plants in its avoided fuel costs. Thus, to a large extent, BECo's avoided cost is based on the combination of peaker fixed costs and coal-plant fuel costs. MECo's avoided costs do not appear to suffer substantially from this problem, as will be discussed in Section 4. Since BGC uses a baseload supply as its avoidable supply, its avoided cost calculations are not affected by any similar mismatch of fixed costs and fuel costs.

This problem could be eliminated by requiring all utilities to compute avoided costs based on the changes in optimal supply plans from the base case to the change case. Defining an optimal expansion plan for a change case would be simple for electric utilities, but may be difficult for gas utilities, given the sporadic availability of pipeline capacity expansions.

[25]There is a slight mismatch between the on-peak period definitions used by BECo in RFP-2 (where it uses 8am - 9pm EST, M-F), and in DPU 89-100 (where BECo uses 7am - 9pm in the winter,

The working capital revenue requirement is for a one-month fuel-supply as per DPU 89-100, and is calculated as 16.5% of one month of avoided fuel and variable O&M costs for each of the four periods. For example, the working capital revenue requirement for the summer peak in 1989 is 16.5% of 4.5 cents/kWH divided by 12 months in a year, for a total of .06 cents/kWH.

The total costs in Table 3.5 include the generation-level seasonal avoided costs, plus the working capital revenue requirement and losses. The total costs at the secondary distribution level with losses are projected out to the year 2035 (which would be required to evaluate 40-year investments made in 1995) at the average growth rate from 2000-2008.

Table 3.6 calculates the present value of the avoided energy costs for summer and winter peak and off-peak periods. The "winter" rating period includes the spring and fall seasons, as well. The figure given in each cell of Table 3.6 represents the value of the energy savings which results from one kWh of reduced annual energy usage in the indicated rating period, for each year of the evaluation period (or measure lifetime) listed for that row.

3.1 Adapting Jensen 1989 Projections for the BECo Model

Jensen provides price projections for each grade of oil (#2, and #6 with 0.5%, 1.0%, and 2.2% sulfur) required in the BECo model. Jensen does not provide projections of coal or nuclear fuel costs, so we simply adjusted the DRI 1987 coal prices for the difference in general inflation rates assumed in DRI 1987 (3.9%) and Jensen/BGC 1989 (5.0%). A very small portion of BECo's avoided cost is based on the price of gas burned at the Ocean State Power (OSP) plant. This cost does not appear to follow any of DRI's gas cost projections. Rather, it appears to be more closely linked to the price of 1% sulfur #6 oil. We therefore scaled the OSP gas price by the ratio of Jensen's forecast oil price to that of DRI 1987.

The BECo avoided costs with Jensen/BGC price projections are computed in Attachment 6, which uses the same table-numbering system as does Attachment 5.

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and 9am - 6pm DST, or 8-5 EST, in the summer). We generally use the RFP-2 definition of the peak period.

4. THE MASSACHUSETTS ELECTRIC AVOIDED COST MODEL

The derivation of the avoided costs for Massachusetts Electric Company (MECo) is generally similar to that for BECo. The generation-level inputs come from the avoided costs MECo filed with the DPU in support of its contracts to purchase power from Northeast Landfill and Oxford Cogeneration Associates.[26] These contracts (and the supporting information) were filed in late 1987 through mid-1988, and were based on 1987 fuel-cost projections.

We updated MECo's fuel cost assumptions from NEES's most recent projection of fuel costs ("Review of Energy Market Conditions and Update of Fuel Price Projections," NEEI, 1988).[27] The MECo reference run, based on September 1988 NEEI price forecasts, is shown in Attachment 7. We also updated MECo's generation capacity, (Table 4.1.D), and capitalized energy assumptions with information filed in NEPCo's W-10 rate case before the FERC.[28] We took transmission cost data, (Tables 4.1.A and 4.1.E), from the FERC filing, since NEPCo provides MECo's transmission services. Data on distribution costs (Tables 4.1.A and 4.1.C), and losses come from MECo's recent rate-design proceeding, DPU 89-21.

There are two major differences between the BECo and MECo cost-estimation methodologies. First, MECo's estimates do not repeat the problem in BECo's pricing of power supply energy costs. MECo includes capitalized energy costs which are consistent with the

[26]The documents we reviewed included MECo's response to Information Requests in the Northeast Landfill contract proceeding (about January 1988), Part I of MECo's filing in the Oxford Cogeneration proceeding (June 13, 1988), and MECo's response to Information Requests in the Oxford Cogeneration proceeding (July 26, 1988).

[27]New England Energy, Inc., (NEEI) is MECo's fuel-supply affiliate, and is the standard source of fuel-price projections for the subsidiaries of the New England Electric System (NEES). Other than MECo and NEEI, NEES subsidiaries include Narragansett Electric Company, Granite State Electric Company, and New England Power Company (NEPCo), the wholesale power supplier to MECo, Narragansett, and Granite State.

[28]The NEPCo rate filing (ER 88-630, 88-631, and 89-38, which we collectively refer to as the W-10 proceeding), like the Granite State Least-Cost Plan, computes avoided energy costs based on a proxy unit, which is an over-simplified approach to estimating avoided costs. Also, neither filing included the sensitivity analyses we needed to estimate the relationship between fuel price and avoided costs. Hence, we relied on the avoided energy costs filed by MECo with the DPU in 1987-88.

type of generation technology (combined-cycle gas plants) on which NEPCo intends to rely for baseload energy in the foreseeable future.[29]

Second, MECo appears to understate the cost of distribution facilities per kW of load, by including only the cost of facilities that serve existing customers (and only some of those costs), but dividing that cost by total load growth, including load due to new customers. Similarly, NEPCo excluded half of its transmission investments from its estimate of marginal transmission costs, on the grounds that they were "associated with reliability and regulatory requirements." BECo and BGC, on the other hand, include all distribution and transmission plant as demand-related, except for meters and services. We have corrected this inconsistency by including all non-customer-related plant in MECo's avoided distribution and transmission costs,[30] which brings those costs to a level comparable to those of BECo.

Table 4.1.A and 4.1.B have many blanks, since MECo either does not include these costs, or does not document them. We added Table 4.1.D, which computes the cost of peaking capacity per kilowatt-year, levelized at the inflation rate for utility costs.[31] We have

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[29]The estimated cost of capitalized energy may be somewhat understated, since it is taken from NEPCo's first combined-cycle plant, which would be a conversion of the existing South Street oil-fired plant. Succeeding "green-field" combined cycle plants, which do not have the cost advantages of existing land, turbines, generators, buildings, switch-gear, and the like, are likely to be more expensive than South Street. An optimal supply plan in the change case would defer the in-service date of South Street until the first combined-cycle unit is required, and then defer the in-service date of a more expensive generic unit. The effect of MECo's simplification is probably much smaller than the effect of BECo's elimination of capitalized energy.

[30]Alternatively, the BECo and BGC avoided-cost estimates could be revised downwards to be consistent with the MECo methodology. The better approach seems to be to use the BECo/BGC cost estimation methodology for MECo distribution and transmission costs. Clearly, load-related plant added to serve new customers should be treated in the same fashion as load-related plant added to serve existing customers. The plant that MECo excludes as being related to "reliability" or "regulatory requirements" represents real costs which must be included.

[31]MECo erroneously levelizes the cost at the GNP inflation rate, which is lower and produces a higher first-year cost. The purpose of real-levelizing the carrying costs is to determine the savings from deferring the need for a particular type of capacity. That benefit is determined primarily by the difference between the

restated MECo's O&M and A&G cost estimates in $/kW, rather than as a percentage of plant, as part of our restatement of marginal costs to include all demand-related plant.

With some minor differences, the MECo avoided-cost tables are laid out in the same manner as the corresponding BECo tables. In Table 4.1, we assumed the seasonal split of distribution costs, since MECo did not provide any explicit assumption.[32]

In Tables 4.2 and 4.3, we include in the winter peak allocation those small portions of peak responsibility which MECo assigns to the spring and fall seasons: the bulk of the peak responsibility in the spring/fall season is in the months of November and March, which are more like winter than summer. Note that in Table 4.2, we follow MECo in assuming an avoidable generation capacity cost, priced at market rates, from the beginning of the analysis.[33]

We have not made any adjustment comparable to that in Table 3.2, to reflect the difference between summer and winter loads. MECo and NEPCo maximum winter loads tend to be quite similar to their maximum summer loads.

Table 4.4 calculates the present value of the capacity costs in Tables 4.1 through 4.4 at MECo's discount rate of 11.45%.

In Table 4.5, we start with an estimate of MECo's avoided fuel costs derived from the analysis documented in Attachment 10. We use regression models to describe the relationship between fuel prices in NEEI's 1987 base, low and high fuel-price projections to the corresponding MECo avoided fuel cost estimates. All of our regressions assume linear functional forms and zero intercepts (since avoided cost should double if all fuel prices double), with avoided fuel cost represented as $/kWh, and fuel prices as $/MMBTU. In the period 1987-91, the best fit model predicts avoided fuel cost as a function of oil and coal prices, and of a time variable. For 1992-98 and 1999-2006, gas prices produces better fits than oil

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discount rate and the inflation rate for the cost of the capacity being levelized.

[32]MECo simply divides the annual distribution cost per peak kW by 12, to derive a monthly billing charge.

[33]MECo and its affiliates have made this assumption in all recent filings. Given NEES's reliance on short-term purchases, and the existence of an active market for capacity in New England, this is a reasonable assumption. In fact, BECo also faces the same short-term rates for generation purchases or sales, and should probably include a similar short-term credit for avoidable generation capacity.

prices, so we use coal-price, gas-price and time variables.[34] The time variables pick up the trend in avoided cost, as load growth (and capacity additions) force avoided fuel costs up (and down). In the 1987-1991 period, the capacity additions (presumably Hydro Quebec, Seabrook, and QFs) dominate, and the time variable is slightly negative. In the later periods, load growth dominates and the time trend is slightly positive. The R^2 values for the regressions are 98.7%-99.7%, and the t-statistics of the variables are also generally quite high. The lowest t-statistic is 1.71 for the coal coefficient of the 1992-98 regression; the other t-stats are in the range of 5 to 28.

The regression results can be conceptualized as representing the marginal fuel mix and heat rate for each fuel. For example, the 1992-97 regression implies that each kWh requires 1088 BTU of coal and 10,212 BTU of gas, for an average marginal heat rate of 11,300 BTU/kWh. Coal supplies 9.6% of the marginal fuel, and gas supplies the other 90.4%. The time variable shifts this result down (or up) by 0.12 cents/kWh for each year before (or after) 1995, the middle of the data. Attachment 10 also shows how we evaluate this equation for the NEEI 1988 fuel price update, and for the Jensen 1989 update.

The remainder of Table 4.5 adds working capital and marginal energy losses in the same manner as Table 3.5. Table 4.5.A contains the calculations of marginal losses and energy costs by rating period.

4.1 Adapting Jensen 1989 Projections for the MECo Model

For the MECo model, we needed only 2.2% residual oil, gas, and coal prices. Jensen produces 2.2% residual oil price projections directly. For the gas, we assumed that NEPCo would be buying Open-Season gas at a 100% load factor. Since NEEI 1988 and Jensen/BGC 1989 projections use the same inflation rate, we used NEEI 1988 coal prices for the Jensen 1989 runs, without adjustment.

The resulting MECo avoided costs with Jensen/BGC price projections are computed in Attachment 8, which uses the same table-numbering system as does Attachment 7.

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[34] Oil and gas prices cannot both be used in the same regression, due to their collinearity. One or the other fuel price produces a nonsensical negative coefficient if both are in the same equation. Our updates of the MECo avoided fuel cost require more approximations than do our updates of BECo avoided fuel or BGC avoided commodity.

5. COMPARABLE AVOIDED COST PROJECTIONS

5.1 Summary of Avoided Costs

Table 1.1 in Attachment 1 summarizes the present value of the avoided costs for all three utilities, for projections at the Jensen 1989 fuel prices. The MECo avoided capacity charges are higher than those of BECo for both seasons and all evaluation periods. This is the result of MECo's higher generation cost estimates, especially in early years; its higher marginal losses; and its lower discount rate; partially offset by slightly lower transmission and distribution cost estimates.[35] BECo energy costs start out higher than those of MECo, but MECo costs rise faster than BECo costs. Combined with slightly higher marginal losses, and the lower discount rate, MECo's rising energy costs produce present values which are generally higher than BECo's.

We do not believe that much significance should be attributed to the differences between our estimates of MECo and BECo avoided costs, even with the same set of price inputs (i.e., Jensen 1989). Recall that we were forced to make several approximations in our analysis, and that there are problems in both of the electric utilities' own avoided-cost projections, as well as different assumptions.[36] We would suggest that the MECo and BECo avoided-cost estimates be treated as alternative estimates of generic avoided costs of similarly situated electric utilities.

Nonetheless, we can explain part of the differences between the BECo and the MECo avoided costs. First, the two electric utilities really do have different projections of their avoided energy costs. MECo projects that its avoided energy costs will rise rapidly compared to the cost of its major marginal fuel, natural gas. BECo, by contrast, projects a virtually constant ratio of avoided fuel costs to the price of its dominant fuel, oil, from 1990 through 1999. Starting in 2000, BECo's avoided fuel cost

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[35]There is little justification for substantial differences between the generation capacity cost estimates for the two utilities, at least past 1995, considering the similarity of the peaking units whose costs they are estimating. The DPU may wish to establish a common set of cost assumptions for peaking capacity. The differences in transmission and distribution costs seem plausible, given that BECo's service territory is denser and more difficult to serve.

[36]For example, BECo and MECo assume different costs for the same type of peaking capacity. While we do not have MECo's assumptions regarding power plant performance, the two utilities may also differ in their assumptions regarding the availability and heat rates of common supply resources, such as Ocean States Power, Hydro Quebec, and Connecticut and Massachusetts Yankee.

starts to fall relative to oil prices, due to the introduction of the baseload coal plants, which we discussed in Section 3. It is not clear why the avoided costs of the two electric utilities move so differently with respect to fuel prices in the 1990s.

Second, MECo uses a lower discount rate, so its present values tend to be slightly larger. The higher BECo discount rate would imply that the tax benefit from conservation investments would be larger, and hence that the present value of the cost recovery for a dollar of conservation or fuel-switching investment would be smaller, compared to those for MECo.[37] As a result, the higher MECo avoided costs are partially illusory.

Table 1.2 summarizes the avoided costs of BECo and BGC for the DRI 1989 price projections. Most of the cost components are higher under these assumptions, with greater increases in energy than in demand charges, and greater increases for long evaluation periods than for short evaluation periods. The split between summer and winter baseload gas costs works out slightly differently than under the BGC assumptions, producing lower summer and higher winter baseload gas costs.

Table 1.3 similarly summarizes the avoided costs of MECo and BGC for the NEEI 1988 price projections. The electric capacity costs are the same as in the BGC case, since the inflation rate for utility costs is the same. The energy costs are much lower under the NEEI price projections, so all categories of electric energy costs and total gas costs are reduced from the BGC case, in some cases quite dramatically.

5.2 Comparisons of Avoided Costs

There is no simple relationship between the amount of electricity and the amount of natural gas required to perform a particular end use. Electricity is a premium energy source, which usually has some end-use efficiency advantage compared to direct combustion of gas, or of any other fuel, for that matter. Since the values derived in this report may be used to evaluate many energy choices involving both fuels, it is difficult to define a very meaningful comparison of those costs in the abstract.

In some situations (such as in clothes-drying), slightly more than one BTU of gas energy is required to perform the same task as one BTU of electric energy, where both forms of energy are measured at the point of use. In other situations, a very small amount of electricity can displace large amounts of gas either by increasing the efficiency of gas use (for example, high-efficiency furnaces

[37]See the testimony of Paul Chernick in DPU 88-67, Phase I, and of Gregory O. Tomlinson in DPU 88-67, Phase II, for examples of the present value of an investment in conservation.

generally use more electricity than do standard furnaces for draft-induction fans) or by directly replacing the gas use (such as in chilling). On the other hand, saving a large amount of electricity (as in improved lighting efficiency) may require only a small increase in natural gas usage (as in boiler fuel to replace the lost waste heat from the lights). In many cases, saving electricity (as through reduced cooling load due to more efficient window designs) will also save gas (in reduced space heating loads, due to the new windows), so gas savings should be added to, rather than subtracted from, electric savings.

In addition to the differences in the end-use ratios for gas and electricity in various applications, there will be differences in the load shapes involved, both between applications and between electricity and gas.[38] Hence, any generalized cost comparisons can be only approximate.

Without attempting to model the vast range of interrelationships between gas and electric use, we can simply compare the cost of each energy source as delivered to the end use, for an arbitrary load shape. In Table 1.4, we compare the present values over various numbers of years for each of the three utilities, for baseload avoided costs computed from the Jensen assumptions. The BGC baseload values are taken directly from the avoided-cost runs. For the electric utilities, we estimated the following breakdown of hours into rating periods:

Summer peak:	1032 hours,
Summer off-peak:	1944 hours,
Winter peak:	756 hours,
Winter off-peak:	1404 hours,
Spring/fall peak:	1268 hours, and
Spring/fall off-peak:	2356 hours,

and weighted the present values of avoided cost for each period by the number of hours in each period, to derive a baseload avoided

[38]For example, using one BTU of electricity to save five BTUs of gas in a furnace may be highly advantageous, since the conserved gas will be heavily on-peak for the gas system, and the increased electric usage will be only moderately on-peak for the electric utility. On the other hand, using five BTUs of gas to replace 1 BTU of electricity in a chilling application may also be very cost-effective, since the chilling load would be heavily on the electric peak, at a very low load factor, but totally off-peak for the gas system.

cost. We added one 8760th of the summer and winter peak demand costs, and then multiplied the entire cost by 1,000,000/3413 = 293 to derive an avoided cost in $/MMBTU.

Table 1.5 repeats this comparison for BGC and BECo at DRI 1989 assumptions, while Table 1.6 performs the same comparison for BGC and MECo at NEEI 1988 assumptions.

For any set of fuel and inflation inputs, natural gas is considerably less expensive than electricity, ranging from 20% to 30% of electric costs, to serve baseload uses. For loads which are more on-peak for electricity than for gas (e.g., commercial chilling), the gas:electric price ratio will be even lower. For uses which are more on-peak for gas than for electricity, gas costs will be a larger fraction of electric costs.

Attachment 1
Assumptions and Summary Tables

TABLE A: DRI-87 PRICES

INFLATION 3.9%	YEAR	atom	coal	dist	gas	res0.5	res1.0	res2.2
	1990	0.59		4.37		3.326	3.095	2.898
	1991	0.60		4.76	2.01	3.667	3.423	3.206
	1992	0.61		5.16	2.28	3.998	3.735	3.498
	1993	0.67		5.54	2.55	4.333	4.047	3.788
	1994	0.67		6.11	2.92	4.831	4.515	4.227
	1995	0.75		6.78	3.42	5.415	5.061	4.737
	1996	0.79		7.53	3.93	6.081	5.682	5.319
	1997	0.83		8.46	4.42	6.914	6.458	6.048
	1998	0.88		9.59	5.18	7.915	7.394	6.920
	1999	0.92		10.94	5.79	9.082	8.483	7.939
	2000	0.97	3.74	12.55	6.75	10.414	9.728	9.107
	2001	1.02	3.99	14.05	7.36	11.664	10.895	10.199
	2002	1.07	4.25	15.76	8.03	13.081	12.218	11.438
	2003	1.13	4.53	17.37	8.74	14.412	13.463	12.603
	2004	1.19	4.82	19.28	9.52	15.997	14.942	13.987
	2005	1.25	5.13	21.29	10.36	17.663	16.499	15.445
	2006	1.31	5.46	23.19	11.26	19.244	17.977	16.827
	2007	1.38	5.81	25.10	12.24	20.828	19.456	18.212
	2008	1.45	6.16	26.81	13.29	22.245	20.779	19.450
	2009	1.53	6.54	28.51	14.43	23.659	22.102	20.691
	2010	1.61	6.92	30.12	15.66	24.994	23.347	21.853

TABLE B: DRI-89 PRICES

INFLATION 3.9%	YEAR	ATOM	COAL	DIST	GAS	RES0.5	RES1.0	RES2.2
	1990	0.59	1.47	4.60		3.16	2.97	2.70
	1991	0.60	1.53	4.97	1.89	3.42	3.22	2.93
	1992	0.61	1.60	5.30	2.12	3.69	3.47	3.16
	1993	0.67	1.68	5.63	2.34	3.96	3.72	3.39
	1994	0.67	1.74	5.99	2.58	4.25	3.99	3.63
	1995	0.75	1.81	6.45	2.93	4.61	4.34	3.95
	1996	0.79	1.90	7.00	3.29	5.05	4.75	4.32
	1997	0.83	2.00	7.73	3.62	5.63	5.29	4.82
	1998	0.88	2.10	8.56	4.14	6.29	5.91	5.37
	1999	0.92	2.21	9.61	4.57	7.12	6.69	6.09
	2000	0.97	2.33	10.74	5.24	8.03	7.55	6.87
	2001	1.02	2.47	12.05	5.74	9.05	8.50	7.74
	2002	1.07	2.60	13.45	6.26	10.14	9.53	8.67
	2003	1.13	2.74	14.94	6.90	11.31	10.63	9.67
	2004	1.19	2.88	16.28	7.41	12.37	11.63	10.58
	2005	1.25	3.04	17.62	7.92	13.44	12.62	11.49
	2006	1.31	3.23	19.00	8.56	14.54	13.66	12.43
	2007	1.38	3.42	20.47	9.29	15.71	14.77	13.44
	2008	1.45	3.63	21.84	10.10	16.82	15.80	14.38
	2009	1.53	3.86	23.20	11.00	17.93	16.85	15.33
	2010	1.61	4.09	24.56	12.00	19.04	17.89	16.28

TABLE C: JENSEN 89 PRICES
INFLATION 5.0%

YEAR	ATOM	COAL @DRI89	COAL @NEEI88	DIST	GAS@ O.S.P.	GAS@ CHAMPLAIN	RES0.5	RES1.0	RES2.2
1990	0.593		1.64	4.02		3.43	3.045	2.899	2.606
1991	0.610		1.67	4.35	1.840	3.67	3.291	3.133	2.816
1992	0.630		1.70	4.66	2.047	4.16	3.522	3.352	3.011
1993	0.692		1.74	4.86	2.204	4.42	3.674	3.496	3.142
1994	0.698		1.77	5.27	2.451	4.73	3.983	3.791	3.403
1995	0.795		1.81	5.73	2.782	5.43	4.325	4.116	3.695
1996	0.842		1.86	6.24	3.097	5.83	4.708	4.477	4.018
1997	0.891		1.92	6.76	3.320	6.25	5.100	4.850	4.351
1998	0.943		1.97	7.31	3.667	6.96	5.505	5.235	4.695
1999	0.996		2.03	7.86	3.843	7.44	5.921	5.630	5.047
2000	1.054	4.058	2.09	8.43	4.186	7.94	6.345	6.033	5.407
2001	1.113	4.347	2.16	9.07	4.383	8.70	6.824	6.488	5.812
2002	1.176	4.654	2.22	9.76	4.583	9.28	7.338	6.975	6.248
2003	1.241	4.985	2.29	10.50	4.868	9.91	7.892	7.500	6.717
2004	1.311	5.324	2.36	11.30	5.139	10.76	8.487	8.066	7.221
2005	1.383	5.686	2.43	12.16	5.447	11.49	9.129	8.675	7.765
2006	1.460	6.075	2.50	13.11	5.825	12.26	9.837	9.346	8.364
2007	1.542	6.482		14.13	6.230	11.329	10.600	10.070	9.009
2008	1.626	6.904		15.23	6.663	12.200	11.422	10.849	9.704
2009	1.716	7.344		16.43	7.127	13.138	12.308	11.689	10.452
2010	1.810	7.803		17.71	7.622		13.263	12.594	11.258

TABLE D: NEEI-88 PRICES
INFLATION 5.0%

YEAR	COAL	GAS	2.2% OIL
1988	1.58	3.07	2.01
1989	1.61	3.14	2.22
1990	1.64	3.22	2.43
1991	1.67	3.28	2.53
1992	1.70	3.36	2.63
1993	1.74	3.50	2.76
1994	1.77	3.71	2.96
1995	1.81	3.98	3.23
1996	1.86	4.31	3.49
1997	1.92	4.63	3.74
1998	1.97	4.90	3.93
1999	2.03	5.14	4.13
2000	2.09	5.33	4.33
2001	2.16	5.53	4.55
2002	2.22	5.73	4.78
2003	2.29	5.95	5.02
2004	2.36	6.17	5.28
2005	2.43	6.41	5.54
2006	2.50	6.67	5.82

TABLE E: NEEI-87 BASE CASE FUEL PROJECTIONS, CURRENT DOLLARS
INFLATION 5.0%

YEAR	COAL	GAS	OIL2.2%
1987	1.58		2.82
1988	1.68		2.69
1989	1.75		2.83
1990	1.82		2.98
1991	1.94	3.74	3.12
1992	2.04	3.82	3.28
1993	2.14	4.04	3.45
1994	2.25	4.11	3.62
1995	2.37	4.19	3.80
1996	2.49	4.37	4.00
1997	2.61	4.53	4.20
1998	2.74	4.71	4.42
1999	2.88	4.85	4.63
2000	3.03	5.05	4.86
2001	3.19	5.20	5.11
2002	3.33	5.44	5.37
2003	3.50	5.54	5.64
2004	3.68	5.73	5.92
2005	3.87	5.94	6.22
2006	4.07	6.15	6.53

TABLE 1.1: SUMMARY OF AVOIDED COSTS AT JENSEN-89 ASSUMPTIONS.

BOSTON GAS COMPANY: PRESENT VALUE $/MMBTU/YEAR

	----HEATING SEASON----		---BASELOAD---			--WATER--
	PROPORTIONAL	INSULATION	ANNUAL	SUMMER	WINTER	HEATING
PV IN 1990						
5 YEARS	25.08	22.81	17.77	14.36	22.45	19.59
7 YEARS	34.52	31.51	24.38	19.68	30.89	26.91
10 YEARS	47.66	43.54	33.68	27.11	42.57	37.18
15 YEARS	66.52	60.86	47.74	38.41	59.20	52.44
20 YEARS	81.94	75.15	60.18	48.49	72.80	65.62
25 YEARS	95.02	87.36	71.15	57.49	84.13	77.12
30 YEARS	106.11	97.78	80.84	65.54	93.56	87.16
40 YEARS	123.50	114.29	96.95	79.13	107.97	103.58

DISCOUNT RATE = 11.5%

BOSTON EDISON COMPANY

A. FUEL COSTS: PRESENT VALUE $/kWH/YR

	SUMMER		WINTER	
YEARS	PEAK	OFF-PEAK	PEAK	OFF-PEAK
5	$0.26	$0.15	$0.19	$0.14
7	$0.35	$0.20	$0.26	$0.19
10	$0.47	$0.27	$0.35	$0.25
15	$0.62	$0.35	$0.47	$0.33
20	$0.74	$0.40	$0.56	$0.38
25	$0.83	$0.43	$0.62	$0.41
30	$0.90	$0.46	$0.67	$0.43
40	$0.99	$0.49	$0.74	$0.46

B. CAPACITY COSTS: PRESENT VALUE $/kW/YR

YEARS	SUMMER	WINTER
5	$461.54	$446.35
7	$618.52	$596.98
10	$818.38	$788.25
15	$1,074.97	$1,033.10
20	$1,259.46	$1,209.40
25	$1,392.71	$1,337.15
30	$1,489.67	$1,430.03
40	$1,611.65	$1,546.71

DISCOUNT RATE = 12.16%

MASSACHUSETTS ELECTRIC COMPANY

A. FUEL COSTS: PRESENT VALUE $/kWH/YR

	SUMMER		WINTER		SPRING/FALL	
YEARS	PEAK	OFF-PEAK	PEAK	OFF-PEAK	PEAK	OFF-PEAK
5	$0.24	$0.16	$0.24	$0.16	$0.22	$0.14
7	$0.36	$0.23	$0.35	$0.23	$0.32	$0.21
10	$0.52	$0.34	$0.51	$0.33	$0.46	$0.30
15	$0.76	$0.49	$0.74	$0.49	$0.68	$0.44
20	$0.96	$0.62	$0.93	$0.61	$0.85	$0.56
25	$1.13	$0.73	$1.10	$0.72	$1.01	$0.66
30	$1.27	$0.82	$1.24	$0.82	$1.14	$0.75
40	$1.50	$0.98	$1.47	$0.97	$1.35	$0.88

B. CAPACITY COSTS: PRESENT VALUE $/kW/YR

YEARS	SUMMER	WINTER
5	$702.13	$590.39
7	$884.07	$743.82
10	$1,119.36	$942.25
15	$1,429.05	$1,203.42
20	$1,658.91	$1,397.27
25	$1,829.53	$1,541.15
30	$1,956.16	$1,647.95
40	$2,119.93	$1,786.05

DISCOUNT RATE = 11.45%

TABLE 1.2: SUMMARY OF AVOIDED COSTS AT DRI-89 ASSUMPTIONS.

BOSTON GAS COMPANY: PRESENT VALUE $/MMBTU/YEAR

	HEATING SEASON		BASELOAD			WATER
	PROPORTIONAL	INSULATION	ANNUAL	SUMMER	WINTER	HEATING
PV IN 1990						
5 YEARS	26.62	24.24	17.73	13.53	23.53	19.95
7 YEARS	36.96	33.77	24.32	18.38	32.61	27.48
10 YEARS	51.67	47.22	33.84	25.33	45.52	38.29
15 YEARS	73.43	67.18	48.20	35.75	64.53	54.51
20 YEARS	91.79	84.17	60.94	44.96	80.71	68.65
25 YEARS	107.94	99.19	72.30	53.15	94.76	81.21
30 YEARS	122.14	112.49	82.44	60.43	106.95	92.36
40 YEARS	145.63	134.66	99.55	72.65	126.74	111.07

DISCOUNT RATE = 11.5%

BOSTON EDISON COMPANY

A. FUEL COSTS: PRESENT VALUE $/kWH/YR

	SUMMER		WINTER	
YEARS	PEAK	OFF-PEAK	PEAK	OFF-PEAK
5	$0.28	$0.16	$0.21	$0.15
7	$0.38	$0.22	$0.29	$0.21
10	$0.52	$0.30	$0.39	$0.28
15	$0.73	$0.41	$0.55	$0.38
20	$0.88	$0.48	$0.66	$0.45
25	$0.98	$0.51	$0.74	$0.48
30	$1.07	$0.54	$0.80	$0.51
40	$1.19	$0.58	$0.89	$0.54

DISCOUNT RATE = 12.16%

B. CAPACITY COSTS: PRESENT VALUE $/kW/YR

YEARS	SUMMER	WINTER
5	$448.01	$433.70
7	$604.24	$583.79
10	$806.91	$778.00
15	$1,074.97	$1,034.11
20	$1,275.17	$1,225.67
25	$1,424.69	$1,369.24
30	$1,536.36	$1,476.47
40	$1,682.05	$1,616.37

TABLE 1.3: SUMMARY OF AVOIDED COSTS AT NEEI-88 ASSUMPTIONS.

BOSTON GAS COMPANY: PRESENT VALUE $/MMBTU/YEAR

	HEATING SEASON		BASELOAD			WATER
	PROPORTIONAL	INSULATION	ANNUAL	SUMMER	WINTER	HEATING
PV IN 1990						
5 YEARS	24.19	21.96	17.07	13.74	21.66	18.85
7 YEARS	33.02	30.08	23.26	18.71	29.57	25.70
10 YEARS	44.96	40.97	31.66	25.36	40.17	34.99
15 YEARS	61.47	56.05	43.88	35.14	54.67	48.27
20 YEARS	74.30	67.85	54.16	43.47	66.10	59.20
25 YEARS	84.66	77.44	62.80	50.55	75.19	68.26
30 YEARS	93.03	85.23	70.05	56.55	82.42	75.79
40 YEARS	105.25	96.68	81.24	66.00	92.76	87.25

DISCOUNT RATE = 11.5%

MASSACHUSETTS ELECTRIC COMPANY

A. FUEL COSTS: PRESENT VALUE $/kWH/YR

	SUMMER		WINTER		SPRING/FALL	
YEARS	PEAK	OFF-PEAK	PEAK	OFF-PEAK	PEAK	OFF-PEAK
5	$0.20	$0.13	$0.19	$0.13	$0.18	$0.12
7	$0.29	$0.19	$0.28	$0.19	$0.26	$0.17
10	$0.42	$0.27	$0.41	$0.27	$0.37	$0.24
15	$0.59	$0.38	$0.57	$0.38	$0.52	$0.34
20	$0.71	$0.46	$0.70	$0.46	$0.64	$0.42
25	$0.81	$0.53	$0.79	$0.52	$0.73	$0.48
30	$0.89	$0.57	$0.86	$0.57	$0.79	$0.52
40	$0.99	$0.64	$0.96	$0.64	$0.88	$0.58

DISCOUNT RATE = 11.45%

B. CAPACITY COSTS: PRESENT VALUE $/kW/YR

YEARS	SUMMER	WINTER
5	$702.13	$590.39
7	$884.07	$743.82
10	$1,119.36	$942.25
15	$1,429.05	$1,203.42
20	$1,658.91	$1,397.27
25	$1,829.53	$1,541.15
30	$1,956.16	$1,647.95
40	$2,119.93	$1,786.05

TABLE 1.4: AVERAGE BASELOAD AVOIDED COSTS AT JENSEN-89 PRICE LEVELS.
$/MMBTU

YEARS	BGC ANNUAL	BECO	MECO
5	17.77	79.68	95.59
7	24.38	107.44	131.40
10	33.68	143.46	180.71
15	47.74	187.95	251.14
20	60.18	219.28	308.31
25	71.15	240.47	355.64
30	80.84	256.65	394.95
40	96.95	276.92	455.12

TABLE 1.5: AVERAGE BASELOAD AVOIDED COSTS AT DRI-89 PRICE LEVELS.
$/MMBTU

YEARS	BGC ANNUAL	BECO
5	17.73	82.81
7	24.32	112.27
10	33.84	152.81
15	48.20	207.96
20	60.94	246.09
25	72.30	271.43
30	82.44	290.84
40	99.55	317.17

TABLE 1.6: AVERAGE BASELOAD AVOIDED COSTS AT NEEI-88 PRICE LEVELS.
$/MMBTU

YEARS	BGC ANNUAL	MECO
5	17.07	86.15
7	23.26	117.42
10	31.66	158.86
15	43.88	214.26
20	54.16	256.08
25	62.80	287.79
30	70.05	311.84
40	81.24	343.93

Attachment 2
BGC Avoided Costs at Jensen 1989

TABLE B: PRESENT VALUE OF TOTAL AVOIDED COSTS

	-----HEATING SEASON-----		---------BASELOAD------------			--WATER--
	PROPORTIONAL	INSULATION	ANNUAL	SUMMER	WINTER	HEATING
PV IN 1989						
5 YEARS	22.33	20.16	15.89	13.19	19.47	17.50
7 YEARS	31.23	28.37	22.06	18.07	27.49	24.35
10 YEARS	43.44	39.59	30.60	24.91	38.34	33.81
15 YEARS	61.00	55.67	43.52	35.28	53.84	47.89
20 YEARS	75.29	68.90	54.95	44.53	66.49	60.04
25 YEARS	87.42	80.20	65.04	52.79	77.03	70.64
30 YEARS	97.70	89.85	73.95	60.17	85.80	79.89
40 YEARS	113.81	105.13	88.76	72.64	99.20	95.02
PV IN 1990						
5 YEARS	25.08	22.81	17.77	14.36	22.45	19.59
7 YEARS	34.52	31.51	24.38	19.68	30.89	26.91
10 YEARS	47.66	43.54	33.68	27.11	42.57	37.18
15 YEARS	66.52	60.86	47.74	38.41	59.20	52.44
20 YEARS	81.94	75.15	60.18	48.49	72.80	65.62
25 YEARS	95.02	87.36	71.15	57.49	84.13	77.12
30 YEARS	106.11	97.78	80.84	65.54	93.56	87.16
40 YEARS	123.50	114.29	96.95	79.13	107.97	103.58
PV IN 1991						
5 YEARS	28.23	25.85	19.83	15.58	25.85	21.93
7 YEARS	38.53	35.37	26.99	21.33	35.00	29.87
10 YEARS	52.67	48.26	37.10	29.42	47.51	40.99
15 YEARS	72.70	66.68	52.40	41.74	65.24	57.48
20 YEARS	89.34	82.12	65.92	52.73	79.86	71.78
25 YEARS	103.45	95.31	77.86	62.54	92.04	84.26
30 YEARS	115.42	106.57	88.40	71.31	102.18	95.15
40 YEARS	134.17	124.41	105.91	86.12	117.67	112.98

TABLE C.1: SUMMARY OF AVOIDED COSTS

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
I. ENERGY COSTS										
A. HEATING SEASON CONSERVATION										
1. PROPORTIONAL	0.00	3.20	3.36	4.95	5.11	5.38	6.59	7.04	7.46	8.59
2. INSULATION	0.00	3.20	3.36	4.95	5.11	5.38	6.59	7.04	7.46	8.59
B. BASELOAD CONSERVATION										
1. ANNUAL	0.00	3.13	3.40	4.38	4.63	4.96	5.63	6.04	6.47	7.12
2. SUMMER	0.00	3.09	3.44	3.61	3.93	4.33	4.73	5.17	5.64	6.05
3. WINTER	0.00	3.06	3.19	5.47	5.64	5.85	6.91	7.28	7.66	8.65
II. CAPACITY COSTS										
A. HEATING SEASON CONSERVATION										
1. PROPORTIONAL	0.00	1.69	1.78	1.87	1.96	2.06	2.16	2.27	2.38	2.50
2. INSULATION	0.00	1.15	1.21	1.27	1.33	1.40	1.47	1.54	1.62	1.70
B. BASELOAD CONSERVATION										
1. ANNUAL	0.00	0.33	0.34	0.36	0.38	0.40	0.42	0.44	0.46	0.48
2. SUMMER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3. WINTER	0.00	0.79	0.83	0.87	0.92	0.96	1.01	1.06	1.12	1.17
III. TOTAL AVOIDED COSTS										
A. HEATING SEASON CONSERVATION										
1. PROPORTIONAL	0.00	4.89	5.14	6.81	7.07	7.43	8.75	9.32	9.84	11.09
2. INSULATION	0.00	4.35	4.57	6.22	6.44	6.78	8.06	8.59	9.08	10.29
B. BASELOAD CONSERVATION										
1. ANNUAL	0.00	3.46	3.74	4.74	5.01	5.36	6.05	6.48	6.93	7.61
2. SUMMER	0.00	3.09	3.44	3.61	3.93	4.33	4.73	5.17	5.64	6.05
3. WINTER	0.00	3.86	4.03	6.34	6.56	6.82	7.92	8.34	8.78	9.82

TABLE C.1: SUMMARY OF AVOIDED COSTS

	1999	2000	2001	2002	2003	2004	2005
I. ENERGY COSTS							
A. HEATING SEASON CONSERVATION							
1. PROPORTIONAL	6.80	7.14	8.54	8.81	9.18	11.02	11.22
2. INSULATION	6.80	7.14	8.54	8.81	9.18	11.02	11.22
B. BASELOAD CONSERVATION							
1. ANNUAL	6.98	7.63	8.35	9.14	10.02	10.99	12.06
2. SUMMER	6.59	7.18	7.83	8.53	9.30	10.13	11.04
3. WINTER	7.27	7.67	8.69	9.20	9.72	10.87	11.52
II. CAPACITY COSTS							
A. HEATING SEASON CONSERVATION							
1. PROPORTIONAL	4.84	5.09	5.34	5.61	5.89	6.02	6.16
2. INSULATION	3.78	3.97	4.17	4.38	4.60	4.72	4.84
B. BASELOAD CONSERVATION							
1. ANNUAL	1.28	1.34	1.41	1.48	1.56	1.60	1.65
2. SUMMER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3. WINTER	3.09	3.25	3.41	3.58	3.76	3.87	3.99
III. TOTAL AVOIDED COSTS							
A. HEATING SEASON CONSERVATION							
1. PROPORTIONAL	11.65	12.23	13.89	14.42	15.07	17.04	17.38
2. INSULATION	10.58	11.11	12.71	13.19	13.78	15.74	16.06
B. BASELOAD CONSERVATION							
1. ANNUAL	8.26	8.98	9.76	10.62	11.57	12.59	13.71
2. SUMMER	6.59	7.18	7.83	8.53	9.30	10.13	11.04
3. WINTER	10.36	10.92	12.10	12.78	13.49	14.74	15.51

TABLE C.2: SUMMARY OF AVOIDED ENERGY COSTS

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
I. COMMODITY COSTS										
A. HEATING SEASON CONSERVATION	0.00	3.20	3.36	-1.46	-1.62	-1.69	-0.82	-0.74	-0.72	0.01
B. BASELOAD CONSERVATION										
1. ANNUAL	0.00	3.13	3.40	2.15	2.29	2.50	3.05	3.33	3.63	4.14
2. SUMMER	0.00	3.09	3.44	3.61	3.93	4.33	4.73	5.17	5.64	6.05
3. WINTER	0.00	3.06	3.19	0.08	-0.02	-0.09	0.67	0.73	0.78	1.43
II. CAPITALIZED ENERGY COSTS										
A. HEATING SEASON CONSERVATION										
1. PROPORTIONAL	0.00	0.00	0.00	6.41	6.73	7.06	7.41	7.79	8.17	8.58
2. INSULATION	0.00	0.00	0.00	6.41	6.73	7.06	7.41	7.79	8.17	8.58
B. BASELOAD CONSERVATION										
1. ANNUAL	0.00	0.00	0.00	2.23	2.34	2.46	2.58	2.71	2.85	2.99
2. SUMMER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3. WINTER	0.00	0.00	0.00	5.39	5.66	5.94	6.24	6.55	6.88	7.22
III. TOTAL AVOIDED ENERGY COSTS										
A. HEATING SEASON CONSERVATION										
1. PROPORTIONAL	0.00	3.20	3.36	4.95	5.11	5.38	6.59	7.04	7.46	8.59
2. INSULATION	0.00	3.20	3.36	4.95	5.11	5.38	6.59	7.04	7.46	8.59
B. BASELOAD CONSERVATION										
1. ANNUAL	0.00	3.13	3.40	4.38	4.63	4.96	5.63	6.04	6.47	7.12
2. SUMMER	0.00	3.09	3.44	3.61	3.93	4.33	4.73	5.17	5.64	6.05
3. WINTER	0.00	3.06	3.19	5.47	5.64	5.85	6.91	7.28	7.66	8.65

TABLE C.2: SUMMARY OF AVOIDED ENERGY COSTS

	1999	2000	2001	2002	2003	2004	2005
I. COMMODITY COSTS							
A. HEATING SEASON CONSERVATION	0.01	0.01	1.05	0.94	0.92	2.35	2.11
B. BASELOAD CONSERVATION							
1. ANNUAL	4.61	5.15	5.74	6.40	7.14	7.97	8.89
2. SUMMER	6.59	7.18	7.83	8.53	9.30	10.13	11.04
3. WINTER	1.55	1.66	2.38	2.58	2.77	3.57	3.86
II. CAPITALIZED ENERGY COSTS							
A. HEATING SEASON CONSERVATION							
1. PROPORTIONAL	6.80	7.14	7.49	7.87	8.26	8.68	9.11
2. INSULATION	6.80	7.14	7.49	7.87	8.26	8.68	9.11
B. BASELOAD CONSERVATION							
1. ANNUAL	2.37	2.48	2.61	2.74	2.88	3.02	3.17
2. SUMMER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3. WINTER	5.72	6.01	6.31	6.62	6.95	7.30	7.66
III. TOTAL AVOIDED ENERGY COSTS							
A. HEATING SEASON CONSERVATION							
1. PROPORTIONAL	6.80	7.14	8.54	8.81	9.18	11.02	11.22
2. INSULATION	6.80	7.14	8.54	8.81	9.18	11.02	11.22
B. BASELOAD CONSERVATION							
1. ANNUAL	6.98	7.63	8.35	9.14	10.02	10.99	12.06
2. SUMMER	6.59	7.18	7.83	8.53	9.30	10.13	11.04
3. WINTER	7.27	7.67	8.69	9.20	9.72	10.87	11.52

TABLE C.3: SUMMARY OF AVOIDED COMMODITY COSTS

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
I. HEATING SEASON CONSERVATION										
A. WITH INTERRUPTIBLE										
1. UNIT COST OF AVOIDED COMMODITY	0.00	3.02	3.17	-1.38	-1.52	-1.59	-0.78	-0.70	-0.68	0.01
2. NON-GAS PRODUCTION O&M LOADING FACTOR	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%
3. A&G NON-PLANT LOADING FACTOR	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%
4. OTHER PRODUCTION O&M	0.000	0.003	0.003	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	0.000
5. TOTAL VARIABLE AVOIDED COMMODITY COST	0.00	3.02	3.17	-1.38	-1.52	-1.59	-0.78	-0.70	-0.68	0.01
6. WORKING CASH ALLOWANCE	0.00	0.27	0.29	-0.12	-0.14	-0.14	-0.07	-0.06	-0.06	0.00
7. WORKING CAPITAL REVENUE REQUIREMENT	0.00	0.04	0.04	-0.02	-0.02	-0.02	-0.01	-0.01	-0.01	0.00
8. LOSS FACTOR	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96
9. HEATING SEASON AVOIDED COMMODITY COST	0.00	3.20	3.36	-1.46	-1.62	-1.69	-0.82	-0.74	-0.72	0.01
II. BASELOAD CONSERVATION										
A. ANNUAL BASELOAD AVOIDED COSTS W/INTERUPTIBLE										
1. UNIT COST OF AVOIDED COMMODITY	0.00	2.95	3.20	2.03	2.16	2.36	2.88	3.14	3.42	3.90
2. NON-GAS PRODUCTION O&M LOADING FACTOR	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%
3. A&G NON-PLANT LOADING FACTOR	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%
4. OTHER PRODUCTION O&M	0.000	0.002	0.003	0.002	0.002	0.002	0.002	0.003	0.003	0.003
5. TOTAL VARIABLE AVOIDED COMMODITY COST	0.00	2.95	3.21	2.03	2.16	2.36	2.88	3.14	3.42	3.90
6. WORKING CASH ALLOWANCE	0.00	0.27	0.29	0.18	0.19	0.21	0.26	0.28	0.31	0.35
7. WORKING CAPITAL REVENUE REQUIREMENT	0.00	0.04	0.05	0.03	0.03	0.03	0.04	0.04	0.05	0.05
8. LOSS FACTOR	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96
9. AVERAGE ANNUAL BASELOAD AVOIDED COMMODITY COST	0.00	3.13	3.40	2.15	2.29	2.50	3.05	3.33	3.63	4.14
B. SUMMER BASELOAD AVOIDED COSTS W/95.11% INTERRUPTIBLE										
1. UNIT COST OF AVOIDED COMMODITY	0.00	2.91	3.24	3.40	3.70	4.08	4.46	4.87	5.31	5.70
2. NON-GAS PRODUCTION O&M LOADING FACTOR	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%
3. A&G NON-PLANT LOADING FACTOR	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%
4. OTHER PRODUCTION O&M	0.000	0.002	0.003	0.003	0.003	0.003	0.004	0.004	0.004	0.005
5. TOTAL VARIABLE AVOIDED COMMODITY COST	0.00	2.92	3.24	3.41	3.71	4.09	4.46	4.88	5.32	5.71
6. WORKING CASH ALLOWANCE	0.00	0.26	0.29	0.31	0.33	0.37	0.40	0.44	0.48	0.51
7. WORKING CAPITAL REVENUE REQUIREMENT	0.00	0.04	0.05	0.05	0.05	0.06	0.06	0.07	0.07	0.08
8. LOSS FACTOR	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96
9. SUMMER BASELOAD AVOIDED COMMODITY COST	0.00	3.09	3.44	3.61	3.93	4.33	4.73	5.17	5.64	6.05
C. WINTER BASELOAD AVOIDED COSTS W/4.89% INTERRUPTIBLE										
1. UNIT COST OF AVOIDED COMMODITY	0.00	2.89	3.01	0.07	-0.02	-0.08	0.63	0.69	0.74	1.35
2. NON-GAS PRODUCTION O&M LOADING FACTOR	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%
3. A&G NON-PLANT LOADING FACTOR	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%
4. OTHER PRODUCTION O&M	0.000	0.002	0.003	0.000	0.000	0.000	0.001	0.001	0.001	0.001
5. TOTAL VARIABLE AVOIDED COMMODITY COST	0.00	2.89	3.01	0.07	-0.02	-0.08	0.63	0.69	0.74	1.35
6. WORKING CASH ALLOWANCE	0.00	0.26	0.27	0.01	0.00	-0.01	0.06	0.06	0.07	0.12
7. WORKING CAPITAL REVENUE REQUIREMENT	0.00	0.04	0.04	0.00	0.00	0.00	0.01	0.01	0.01	0.02
8. LOSS FACTOR	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96
9. WINTER BASELOAD AVOIDED COMMODITY COST	0.00	3.06	3.19	0.08	-0.02	-0.09	0.67	0.73	0.78	1.43

TABLE C.4: CAPITALIZED ENERGY AND PURE PEAKING COSTS

INPUTS:

1. AVOIDABLE SUPPLY	OPEN SEASON									
2. PEAK DAY SUPPLY	34.6									
3. IN-SERVICE DATE	1992									
4. GROSS DEMAND, $1989	$647		647.49	679.86	713.86	749.55	787.03	826.38	867.70	911.08
5. PURE PEAKING COST (DOMAC), $1989	$159		159.12	167.08	175.43	184.20	193.41	203.08	213.24	223.90
6. PEAKING NEED DATE	1999									
7. GNP INFLATION-JENSEN 89		4.0%	4.7%	4.3%	4.3%	4.4%	4.5%	4.6%	4.6%	4.4%
8. GNP INFLATION-BGC 89		5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
9. GNP INFLATION-DRI 89		4.0%	4.0%	4.0%	3.8%	5.6%	4.4%	5.0%	5.6%	5.3%
10. O&M ESCALATION-DRI 89		6.6%	6.6%	6.6%	6.6%	6.6%	6.6%	6.6%	6.6%	6.6%
11. CAPITAL ADDITIONS ESCALATION-DRI 89		6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%
12. GNP INFLATION-NEEI-88		4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
13. CONSTRUCTION INFLATION-NEEI-88		5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%

TABLE C.4: CAPITALIZED ENERGY AND PURE PEAKING COSTS

INPUTS:									
1. AVOIDABLE SUPPLY									
2. PEAK DAY SUPPLY									
3. IN-SERVICE DATE									
4. GROSS DEMAND, $1989	956.64	1004.47	1054.69	1107.43	1162.80	1220.94	1281.99	1346.09	1413.39
5. PURE PEAKING COST (DOMAC), $1989	235.09	246.85	259.19	272.15	285.76	300.04	315.05	330.80	347.34
6. PEAKING NEED DATE									
7. GNP INFLATION-JENSEN 89	4.7%	4.6%	4.6%	4.6%	4.6%	4.5%	4.6%	4.5%	4.6%
8. GNP INFLATION-BGC 89	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
9. GNP INFLATION-DRI 89	5.0%	6.2%	5.2%	6.1%	5.2%	5.5%	5.2%	5.4%	5.2%
10. O&M ESCALATION-DRI 89	6.6%	6.6%	6.6%	6.6%	6.6%	6.6%	6.6%	6.6%	6.6%
11. CAPITAL ADDITIONS ESCALATION-DRI 89	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%
12. GNP INFLATION-NEEI-88	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
13. CONSTRUCTION INFLATION-NEEI-88	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%

TABLE C.4: CAPITALIZED ENERGY AND PURE PEAKING COSTS

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
A. AVOIDED DEMAND COST										
1. $/PEAKDAY MMBTU	0.00	0.00	0.00	749.55	787.03	826.38	867.70	911.08	956.64	1004.47
a. ADJUSTMENT FOR LOSSES AND WORKING CAPITAL	0.00	0.00	0.00	794.23	833.94	875.63	919.42	965.39	1013.66	1064.34
B. PURE PEAKING COST										
1. $/YEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
a. ADJUSTMENT FOR LOSSES AND WORKING CAPITAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2. $/PEAK PERIOD MMBTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3. $/HEATING SEASON MMBTU										
a. PROPORTIONAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
b. INSULATION	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4. $/ANNUAL BASELOAD MMBTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5. $/WINTER BASELOAD MMBTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
C. AVOIDED CAPITALIZED ENERGY COST										
1. $/YEAR	0.00	0.00	0.00	794.23	833.94	875.63	919.42	965.39	1013.66	1064.34
a. PROPORTIONAL	0.00	0.00	0.00	6.41	6.73	7.06	7.41	7.79	8.17	8.58
b. INSULATION	0.00	0.00	0.00	6.41	6.73	7.06	7.41	7.79	8.17	8.58
3. $/ANNUAL BASELOAD MMBTU	0.00	0.00	0.00	2.23	2.34	2.46	2.58	2.71	2.85	2.99
4. $/WINTER BASELOAD MMBTU	0.00	0.00	0.00	5.39	5.66	5.94	6.24	6.55	6.88	7.22

TABLE C.4: CAPITALIZED ENERGY AND PURE PEAKING COSTS

	1999	2000	2001	2002	2003	2004	2005
A. AVOIDED DEMAND COST							
1. $/PEAKDAY MMBTU	1054.69	1107.43	1162.80	1220.94	1281.99	1346.09	1413.39
a. ADJUSTMENT FOR LOSSES AND WORKING CAPITAL	1117.56	1173.43	1232.11	1293.71	1358.40	1426.32	1497.63
B. PURE PEAKING COST							
1. $/YEAR	259.19	272.15	285.76	300.04	315.05	330.80	347.34
a. ADJUSTMENT FOR LOSSES AND WORKING CAPITAL	274.64	288.37	302.79	317.93	333.82	350.52	368.04
2. $/PEAK PERIOD MMBTU	4.04	4.24	4.45	4.68	4.91	5.15	5.41
3. $/HEATING SEASON MMBTU							
a. PROPORTIONAL	2.21	2.33	2.44	2.56	2.69	2.83	2.97
b. INSULATION	1.99	2.09	2.20	2.31	2.42	2.54	2.67
4. $/ANNUAL BASELOAD MMBTU	0.77	0.81	0.85	0.89	0.94	0.98	1.03
5. $/WINTER BASELOAD MMBTU	1.86	1.96	2.05	2.16	2.27	2.38	2.50
C. AVOIDED CAPITALIZED ENERGY COST							
1. $/YEAR	842.92	885.06	929.32	975.78	1024.57	1075.80	1129.59
a. PROPORTIONAL	6.80	7.14	7.49	7.87	8.26	8.68	9.11
b. INSULATION	6.80	7.14	7.49	7.87	8.26	8.68	9.11
3. $/ANNUAL BASELOAD MMBTU	2.37	2.48	2.61	2.74	2.88	3.02	3.17
4. $/WINTER BASELOAD MMBTU	5.72	6.01	6.31	6.62	6.95	7.30	7.66

TABLE C.5: SUMMARY OF CAPACITY COSTS

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
I. AVOIDED LOCAL COSTS										
A. $/YEAR	111.36	116.92	122.77	128.91	135.35	142.12	149.23	156.69	164.52	172.75
B. $/HEATING SEASON MMBTU										
1. PROPORTIONAL	1.61	1.69	1.78	1.87	1.96	2.06	2.16	2.27	2.38	2.50
2. INSULATION	1.10	1.15	1.21	1.27	1.33	1.40	1.47	1.54	1.62	1.70
C. $/ANNUAL BASELOAD MMBTU	0.31	0.33	0.34	0.36	0.38	0.40	0.42	0.44	0.46	0.48
D. $/WINTER BASELOAD MMBTU	0.76	0.79	0.83	0.87	0.92	0.96	1.01	1.06	1.12	1.17
II. AVOIDED PEAKING COSTS										
A. $/YEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1. ADJUSTMENT FOR LOSSES AND WORKING CAPITAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
B. $/HEATING SEASON MMBTU										
1. PROPORTIONAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2. INSULATION	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
C. $/ANNUAL BASELOAD MMBTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
D. $/WINTER BASELOAD MMBTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
III. TOTAL AVOIDED CAPACITY COSTS										
A. $/HEATING SEASON MMBTU										
1. PROPORTIONAL	1.61	1.69	1.78	1.87	1.96	2.06	2.16	2.27	2.38	2.50
2. INSULATION	1.10	1.15	1.21	1.27	1.33	1.40	1.47	1.54	1.62	1.70
B. $/ANNUAL BASELOAD MMBTU	0.31	0.33	0.34	0.36	0.38	0.40	0.42	0.44	0.46	0.48
C. $/WINTER BASELOAD MMBTU	0.76	0.79	0.83	0.87	0.92	0.96	1.01	1.06	1.12	1.17

TABLE C.5: SUMMARY OF CAPACITY COSTS

	1999	2000	2001	2002	2003	2004	2005
I. AVOIDED LOCAL COSTS							
A. $/YEAR	181.39	190.46	199.98	209.98	220.48	220.48	220.48
B. $/HEATING SEASON MMBTU							
1. PROPORTIONAL	2.63	2.76	2.90	3.04	3.20	3.20	3.20
2. INSULATION	1.79	1.88	1.97	2.07	2.17	2.17	2.17
C. $/ANNUAL BASELOAD MMBTU	0.51	0.53	0.56	0.59	0.62	0.62	0.62
D. $/WINTER BASELOAD MMBTU	1.23	1.29	1.36	1.42	1.50	1.50	1.50
II. AVOIDED PEAKING COSTS							
A. $/YEAR	259.19	272.15	285.76	300.04	315.05	330.80	347.34
1. ADJUSTMENT FOR LOSSES AND WORKING CAPITAL	274.64	288.37	302.79	317.93	333.82	350.52	368.04
B. $/HEATING SEASON MMBTU							
1. PROPORTIONAL	2.21	2.33	2.44	2.56	2.69	2.83	2.97
2. INSULATION	1.99	2.09	2.20	2.31	2.42	2.54	2.67
C. $/ANNUAL BASELOAD MMBTU	0.77	0.81	0.85	0.89	0.94	0.98	1.03
D. $/WINTER BASELOAD MMBTU	1.86	1.96	2.05	2.16	2.27	2.38	2.50
III. TOTAL AVOIDED CAPACITY COSTS							
A. $/HEATING SEASON MMBTU							
1. PROPORTIONAL	4.84	5.09	5.34	5.61	5.89	6.02	6.16
2. INSULATION	3.78	3.97	4.17	4.38	4.60	4.72	4.84
B. $/ANNUAL BASELOAD MMBTU	1.28	1.34	1.41	1.48	1.56	1.60	1.65
C. $/WINTER BASELOAD MMBTU	3.09	3.25	3.41	3.58	3.76	3.87	3.99

TABLE C.6: AVOIDED LOCAL COSTS

	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996
A. PLANT INVESTMENT $/PEAKDAY MMBTU										
1. LONG RUN UNIT COSTS	379.19	394.36	410.13	430.64	452.17	474.78	498.52	523.44	549.62	577.10
2. GENERAL PLANT LOADING FACTOR	3.14%	3.14%	3.14%	3.14%	3.14%	3.14%	3.14%	3.14%	3.14%	3.14%
3. UNIT COSTS + LOADING FACTOR	391.10	406.74	423.01	444.16	466.37	489.69	514.17	539.88	566.87	595.22
4. FIXED CHARGE RATE	11.25%	11.25%	11.25%	11.25%	11.25%	11.25%	11.25%	11.25%	11.25%	11.25%
5. A&G EXPENSE PLANT-RELATED LOADING FACTOR	1.07%	1.07%	1.07%	1.07%	1.07%	1.07%	1.07%	1.07%	1.07%	1.07%
6. TOTAL RATE	12.32%	12.32%	12.32%	12.32%	12.32%	12.32%	12.32%	12.32%	12.32%	12.32%
7. ANNUALIZED COST	48.18	50.11	52.11	54.72	57.46	60.33	63.35	66.51	69.84	73.33
B. OPERATING EXPENSES $/PEAKDAY MMBTU										
1. PRODUCTION CAPACITY COSTS	7.27	7.56	7.86	8.26	8.67	9.10	9.56	10.04	10.54	11.06
2. DISTRIBUTION CAPACITY COSTS	27.40	28.50	29.64	31.12	32.67	34.31	36.02	37.82	39.71	41.70
3. A&G EXPENSE NON-PLANT RELATED LOADING FACTOR	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%
4. LOADING	48.39	50.33	52.34	54.96	57.71	60.59	63.62	66.80	70.14	73.65
5. TOTAL CAPACITY EXPENSES	48.39	50.33	52.34	54.96	57.71	60.59	63.62	66.80	70.14	73.65
C. WORKING CAPITAL $/PEAKDAY MMBTU										
1. M&S PREPAYMENTS RATE	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%
2. M&S COST	6.54	6.80	7.07	7.43	7.80	8.19	8.60	9.03	9.48	9.95
3. WORKING CASH O&M	5.97	6.20	6.45	6.78	7.11	7.47	7.84	8.24	8.65	9.08
4. TOTAL WORKING CAPITAL	12.51	13.01	13.53	14.20	14.91	15.66	16.44	17.26	18.13	19.03
D. WORKING CAPITAL REVENUE REQUIRED	1.95	2.03	2.11	2.22	2.33	2.44	2.57	2.69	2.83	2.97
E. SYSTEM SEASONAL CAPACITY RELATED COST	98.53	102.47	106.57	111.90	117.49	123.37	129.53	136.01	142.81	149.95
F. LOSS FACTOR	0.957	0.957	0.957	0.957	0.957	0.957	0.957	0.957	0.957	0.957
G. TOTAL AVOIDED LOCAL COSTS	102.95	107.07	111.36	116.92	122.77	128.91	135.35	142.12	149.23	156.69

TABLE C.6: AVOIDED LOCAL COSTS

	1997	1998	1999	2000	2001	2002	2003	2004	2005
A. PLANT INVESTMENT $/PEAKDAY MMBTU									
1. LONG RUN UNIT COSTS	605.95	636.25	668.06	701.46	736.54	773.36	812.03	812.03	812.03
2. GENERAL PLANT LOADING FACTOR	3.14%	3.14%	3.14%	3.14%	3.14%	3.14%	3.14%	3.14%	3.14%
3. UNIT COSTS + LOADING FACTOR	624.98	656.23	689.04	723.49	759.67	797.65	837.53	837.53	837.53
4. FIXED CHARGE RATE	11.25%	11.25%	11.25%	11.25%	11.25%	11.25%	11.25%	11.25%	11.25%
5. A&G EXPENSE PLANT-RELATED LOADING FACTOR	1.07%	1.07%	1.07%	1.07%	1.07%	1.07%	1.07%	1.07%	1.07%
6. TOTAL RATE	12.32%	12.32%	12.32%	12.32%	12.32%	12.32%	12.32%	12.32%	12.32%
7. ANNUALIZED COST	77.00	80.85	84.89	89.13	93.59	98.27	103.18	103.18	103.18
B. OPERATING EXPENSES $/PEAKDAY MMBTU									
1. PRODUCTION CAPACITY COSTS	11.62	12.20	12.81	13.45	14.12	14.83	15.57	15.57	15.57
2. DISTRIBUTION CAPACITY COSTS	43.79	45.97	48.27	50.69	53.22	55.88	58.68	58.68	58.68
3. A&G EXPENSE NON-PLANT RELATED LOADING FACTOR	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%
4. LOADING	77.33	81.20	85.26	89.52	94.00	98.70	103.63	103.63	103.63
5. TOTAL CAPACITY EXPENSES	77.33	81.20	85.26	89.52	94.00	98.70	103.63	103.63	103.63
C. WORKING CAPITAL $/PEAKDAY MMBTU									
1. M&S PREPAYMENTS RATE	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%
2. M&S COST	10.45	10.97	11.52	12.10	12.70	13.34	14.01	14.01	14.01
3. WORKING CASH O&M	9.53	10.01	10.51	11.04	11.59	12.17	12.78	12.78	12.78
4. TOTAL WORKING CAPITAL	19.99	20.98	22.03	23.14	24.29	25.51	26.78	26.78	26.78
D. WORKING CAPITAL REVENUE REQUIRED	3.12	3.28	3.44	3.61	3.79	3.98	4.18	4.18	4.18
E. SYSTEM SEASONAL CAPACITY RELATED COST	157.45	165.32	173.59	182.27	191.38	200.95	211.00	211.00	211.00
F. LOSS FACTOR	0.957	0.957	0.957	0.957	0.957	0.957	0.957	0.957	0.957
G. TOTAL AVOIDED LOCAL COSTS	164.52	172.75	181.39	190.46	199.98	209.98	220.48	220.48	220.48

TABLE 2: COMMODITY COSTS AS A PERCENTAGE OF CRUDE OIL PRICES JENSEN 1989 INPUTS

SUPPLY	W/HEAD COMMODITY PRICE	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
1. F1	1.955	66%	68%	70%	72%	76%	78%	79%	80%	81%	81%
2. F2	1.955	66%	68%	70%	72%	76%	78%	79%	80%	81%	81%
3. F3	1.955	66%	68%	70%	72%	76%	78%	79%	80%	81%	81%
4. F4		0%									
5. CD6	1.937	65%	68%	70%	72%	76%	78%	79%	80%	81%	81%
6. BOUN	1.649	56%									
7. TGT	1.937	65%	68%	70%	72%	76%	78%	79%	80%	81%	81%
8. STB	1.955	66%	68%	70%	72%	76%	78%	79%	80%	81%	81%
9. SIS	1.955	66%	68%	70%	72%	76%	78%	79%	80%	81%	81%
10. WS	1.955	66%	68%	70%	72%	76%	78%	79%	80%	81%	81%
11. LNG	1.955	66%	68%	70%	72%	76%	78%	79%	80%	81%	81%
12. PROP	3.700	125%	125%	125%	125%	125%	125%	125%	125%	125%	125%
13. SPOT	1.737	58%	60%	61%	64%	69%	73%	75%	75%	76%	77%
14. NOREX	1.937	65%	68%	70%	72%	76%	78%	79%	80%	81%	81%
15. PENN EAST	1.946	66%	68%	70%	72%	76%	78%	79%	80%	81%	81%
16. CHAMPLAIN	1.450	49%									
17. IROQUOIS	1.416	48%									
18. DGAS	1.955	66%	68%	70%	72%	76%	78%	79%	80%	81%	81%
19. DGASBOIL	1.955	66%	68%	70%	72%	76%	78%	79%	80%	81%	81%

ESCALATORS

BOSTON GAS: MAY 1989 JENSEN STUDY

% DIFF										
INFL $'S		6.1%	8.6%	7.3%	4.1%	8.9%	8.9%	9.3%	8.7%	8.2%
1986 $'S		1.3%	3.0%	2.5%	-1.0%	3.9%	3.7%	3.9%	3.5%	3.0%
RACC										
INFL $'S	2.97	3.15	3.42	3.67	3.82	4.16	4.53	4.95	5.39	5.83
1986 $'S	2.68	2.71	2.80	2.87	2.84	2.95	3.06	3.18	3.29	3.39
GNP	4.7%	4.3%	4.3%	4.4%	4.5%	4.6%	4.6%	4.4%	4.7%	4.6%
	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%

TABLE 3: FORECASTED COMMODITY WELLHEAD COSTS JENSEN 1989

SUPPLY	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
1. F1	1.96	2.14	2.40	2.64	2.91	3.25	3.58	3.96	4.36	4.72
2. F2	1.96	2.14	2.40	2.64	2.91	3.25	3.58	3.96	4.36	4.72
3. F3	1.96	2.14	2.40	2.64	2.91	3.25	3.58	3.96	4.36	4.72
4. F4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5. CD6	1.93	2.14	2.40	2.64	2.91	3.25	3.58	3.96	4.36	4.72
6. BOUN	1.65	1.78	1.95	2.28	2.43	2.67	3.16	3.46	3.77	4.22
7. TGT	1.93	2.14	2.40	2.64	2.91	3.25	3.58	3.96	4.36	4.72
8. STB	1.96	2.14	2.40	2.64	2.91	3.25	3.58	3.96	4.36	4.72
9. SIS	1.96	2.14	2.40	2.64	2.91	3.25	3.58	3.96	4.36	4.72
10. WS	1.96	2.14	2.40	2.64	2.91	3.25	3.58	3.96	4.36	4.72
11. LNG	1.96	2.14	2.40	2.64	2.91	3.25	3.58	3.96	4.36	4.72
12. PROP	3.71	3.94	4.28	4.59	4.78	5.20	5.67	6.19	6.73	7.28
13. SPOT	1.72	1.89	2.09	2.35	2.64	3.04	3.40	3.72	4.09	4.49
14. NOREX	1.93	2.14	2.40	2.64	2.91	3.25	3.58	3.96	4.36	4.72
15. PENN EAST	1.96	2.14	2.40	2.64	2.91	3.25	3.58	3.96	4.36	4.72
16. CHAMPLAIN	1.45	1.55	1.68	2.05	2.18	2.36	2.91	3.16	3.42	3.96
17. IROQUOIS	1.42	1.54	1.69	2.00	2.14	2.36	2.83	3.12	3.42	3.84
18. DGAS	1.96	2.14	2.40	2.64	2.91	3.25	3.58	3.96	4.36	4.72
19. DGASBOIL	1.96	2.14	2.40	2.64	2.91	3.25	3.58	3.96	4.36	4.72

TABLE 4: FORECAST COMMODITY "OTHER" COSTS JENSEN 1989

SUPPLY	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
1. F1	0.457	0.480	0.504	0.529	0.555	0.583	0.612	0.643	0.675	0.709
2. F2	0.899	0.944	0.991	1.041	1.093	1.147	1.205	1.265	1.328	1.395
3. F3	1.139	1.196	1.256	1.319	1.384	1.454	1.526	1.603	1.683	1.767
4. F4	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
5. CD6	0.693	0.728	0.764	0.802	0.842	0.884	0.929	0.975	1.024	1.075
6. BOUN	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
7. TGT	0.693	0.728	0.764	0.802	0.842	0.884	0.929	0.975	1.024	1.075
8. STB	0.693	0.728	0.764	0.802	0.842	0.884	0.929	0.975	1.024	1.075
9. SIS	0.901	0.946	0.993	1.043	1.095	1.150	1.207	1.268	1.331	1.398
10. WS	0.665	0.698	0.733	0.770	0.808	0.849	0.891	0.936	0.983	1.032
11. LNG	1.970	2.069	2.172	2.281	2.395	2.514	2.640	2.772	2.911	3.056
12. PROP	0.500	0.525	0.551	0.579	0.608	0.638	0.670	0.704	0.739	0.776
13. SPOT	0.457	0.480	0.504	0.529	0.555	0.583	0.612	0.643	0.675	0.709
14. NOREX	0.693	0.728	0.764	0.802	0.842	0.884	0.929	0.975	1.024	1.075
15. PENN EAST	0.575	0.604	0.634	0.666	0.699	0.734	0.771	0.809	0.850	0.892
16. CHAMPLAIN	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
17. IROQUOIS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
18. DGAS	0.877	0.921	0.967	1.015	1.066	1.119	1.175	1.234	1.296	1.361
19. DGASBOIL	0.457	0.480	0.504	0.529	0.555	0.583	0.612	0.643	0.675	0.709

TABLE D: TOTAL COMMODITY COSTS $/MMBTU JENSEN 1989

SUPPLY	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
1. F1	2.42	2.62	2.90	3.17	3.46	3.83	4.19	4.61	5.04	5.43
2. F2	2.86	3.09	3.39	3.68	4.00	4.39	4.79	5.23	5.69	6.11
3. F3	3.10	3.34	3.65	3.96	4.29	4.70	5.11	5.57	6.05	6.49
4. F4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5. CD6	2.62	2.87	3.16	3.45	3.75	4.13	4.51	4.94	5.39	5.80
6. BOUN	1.65	1.78	1.95	2.28	2.43	2.67	3.16	3.46	3.77	4.22
7. TGT	2.62	2.87	3.16	3.45	3.75	4.13	4.51	4.94	5.39	5.80
8. STB	2.65	2.87	3.16	3.45	3.75	4.13	4.51	4.94	5.39	5.80
9. SIS	2.86	3.09	3.39	3.69	4.00	4.40	4.79	5.23	5.69	6.12
10. WS	2.63	2.84	3.13	3.41	3.71	4.10	4.47	4.90	5.35	5.75
11. LNG	3.93	4.21	4.57	4.92	5.30	5.76	6.22	6.74	7.27	7.78
12. PROP	4.21	4.46	4.83	5.17	5.39	5.84	6.34	6.90	7.47	8.06
13. SPOT	2.18	2.37	2.59	2.88	3.19	3.62	4.01	4.36	4.77	5.20
14. NOREX	2.62	2.87	3.16	3.45	3.75	4.13	4.51	4.94	5.39	5.80
15. PENN EAST	2.52	2.75	3.03	3.31	3.60	3.98	4.35	4.77	5.21	5.61
16. CHAMPLAIN	1.45	1.55	1.68	2.05	2.18	2.36	2.91	3.16	3.42	3.96
17. IROQUOIS	1.42	1.54	1.69	2.00	2.14	2.36	2.83	3.12	3.42	3.84
18. DGAS	2.84	3.06	3.36	3.66	3.97	4.37	4.76	5.20	5.66	6.08
19. DGASBOIL	2.42	2.62	2.90	3.17	3.46	3.83	4.19	4.61	5.04	5.43

TABLE E.1: AVERAGE ANNUAL AVOIDED COMMODITY COST OF BASELOAD CONSERVATION

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
1. BBTU'S OF CONSERVATION	0	12,629	12,629	12,629	12,629	12,629	12,629	12,629	12,629	12,629
2. TOTAL COMMODITY SAVINGS	0	35,839	38,721	25,577	27,318	29,804	36,332	39,658	43,198	49,262
3. AVERAGE ANNUAL AVOIDED COMMODITY COST, $/BBTU	0	2.84	3.07	2.03	2.16	2.36	2.88	3.14	3.42	3.90
4. BASE CASE INTERRUPTIBLE VOLUMES	8,032	8,904	16,231	25,443	24,580	23,186	22,138	20,683	20,250	19,079
CASE 2 INTERRUPTIBLE VOLUMES	8,032	18,053	26,839	25,443	24,580	23,186	22,138	20,683	20,250	19,079
CHANGE IN INTERRUPTIBLE VOLUMES	0	9,149	10,608	0	0	0	0	0	0	0
5. INTERRUPTIBLE SALES MARGIN										
COGENERATION	0.480	0.504	0.529	0.556	0.583	0.613	0.643	0.675	0.709	0.745
C/I	0.200	0.210	0.221	0.232	0.243	0.255	0.268	0.281	0.295	0.310
UTILITY POWER	0.150	0.158	0.165	0.174	0.182	0.191	0.201	0.211	0.222	0.233
6. CHANGE ATTRIBUTABLE TO:										
COGENERATION	0	0	0	0	0	0	0	0	0	0
C/I	0	0	0	0	0	0	0	0	0	0
UTILITY POWER	0	9,149	10,608	0	0	0	0	0	0	0
7. CHANGE IN INTERRUPTIBLE MARGIN	0.000	0.114	0.139	0.000	0.000	0.000	0.000	0.000	0.000	0.000
8. TOTAL AVERAGE ANNUAL AVOIDED COMMODITY COSTS	0.00	2.95	3.20	2.03	2.16	2.36	2.88	3.14	3.42	3.90

TABLE E.2: AVOIDED COMMODITY COST OF HEATING SEASON CONSERVATION

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
1. BBTU'S OF CONSERVATION	0	4,307	4,349	4,409	4,440	4,507	4,554	4,632	4,672	4,725
2. TOTAL COMMODITY SAVINGS	0	12,621	13,209	(2,161)	(2,747)	(3,152)	551	981	1,215	4,525
3. AVOIDED COMMODITY COST, $/BBTU	0	2.93	3.04	-0.49	-0.62	-0.70	0.12	0.21	0.26	0.96
4. BASE CASE INTERRUPTIBLE SALES	8,032	8,904	16,231	25,443	24,580	23,186	22,138	20,683	20,250	19,079
CASE 3 INTERRUPTIBLE SALES	8,032	11,263	19,672	18,411	17,694	16,632	15,782	14,442	14,069	13,042
CHANGE IN INTERRUPTIBLE SALES	0	2,359	3,441	(7,032)	(6,886)	(6,554)	(6,356)	(6,241)	(6,181)	(6,037)
5. INTERRUPTIBLE SALES MARGIN										
COGENERATION	0.480	0.504	0.529	0.556	0.583	0.613	0.643	0.675	0.709	0.745
C/I	0.200	0.210	0.221	0.232	0.243	0.255	0.268	0.281	0.295	0.310
UTILITY POWER	0.150	0.158	0.165	0.174	0.182	0.191	0.201	0.211	0.222	0.233
6. CHANGE ATTRIBUTABLE TO:										
COGENERATION	0	0	0	(7,032)	(6,886)	(6,554)	(6,356)	(6,241)	(6,181)	(6,037)
C/I	0	0	0	0	0	0	0	0	0	0
UTILITY POWER	0	2,359	3,441	0	0	0	0	0	0	0
7. CHANGE IN INTERRUPTIBLE MARGIN	0.000	0.086	0.131	-0.886	-0.905	-0.891	-0.898	-0.910	-0.938	-0.951
8. AVOIDED HEAT SENSITIVE COMMODITY COSTS		3.02	3.17	-1.38	-1.52	-1.59	-0.78	-0.70	-0.68	0.01

TABLE E.3: AVOIDED COMMODITY COSTS DUE TO SUMMER BASELOAD CONSERVATION

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
1. BBTU'S OF CONSERVATION	0	7,404	7,404	7,404	7,404	7,404	7,404	7,404	7,404	7,404
2. TOTAL COMMODITY SAVINGS	0	20,773	23,018	25,192	27,412	30,246	33,023	36,079	39,347	42,218
3. AVOIDED COMMODITY COST, $/BBTU	0	2.81	3.11	3.40	3.70	4.08	4.46	4.87	5.31	5.70
4. ANNUAL CHANGE IN INTERRUPTIBLE MARGIN	0	0.114	0.139	0	0	0	0	0	0	0
5. 95.11 % OF ANNUAL CHANGE	0	0.108	0.132	0	0	0	0	0	0	0
6. TOTAL SUMMER AVOIDED COMMODITY COSTS	0	2.91	3.24	3.40	3.70	4.08	4.46	4.87	5.31	5.70

TABLE E.4: AVOIDED COMMODITY COSTS DUE TO WINTER BASELOAD CONSERVATION

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
1. BBTU'S OF CONSERVATION	5,225	5,225	5,225	5,225	5,225	5,225	5,225	5,225	5,225	5,225
2. TOTAL COMMODITY SAVINGS	0	15,066	15,703	385	(94)	(441)	3,309	3,579	3,851	7,044
3. AVOIDED COMMODITY COST $/BBTU	0	2.88	3.01	0.07	-0.02	-0.08	0.63	0.69	0.74	1.35
4. ANNUAL CHANGE IN INTERRUPTIBLE MARGIN	0	0.114	0.139	0	0	0	0	0	0	0
5. 4.89% OF ANNUAL CHANGE	0	0.006	0.007	0	0	0	0	0	0	0
6. TOTAL WINTER AVOIDED COMMODITY COSTS	0.00	2.89	3.01	0.07	-0.02	-0.08	0.63	0.69	0.74	1.35

TABLE F.1: CHANGE IN COMMODITY COSTS: BASE CASE MINUS CASE 2

SUPPLY	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
1. F1	0	488	536	0	0	0	0	0	0	0
2. F2	0	3,062	2,594	0	36	0	0	0	0	0
3. F3	0	0	0	0	0	0	0	0	0	0
4. F4	0	0	0	0	0	0	0	0	0	0
5. CD6	0	15,541	16,900	0	0	0	81	0	0	0
6. BOUN	0	0	0	0	0	0	0	0	0	0
7. TGT	0	904	938	0	0	0	0	0	0	0
8. STB	0	1,874	1,618	0	0	0	0	0	0	0
9. SIS	0	537	410	0	0	0	0	0	0	0
10. WS	0	1,838	1,852	0	0	0	0	0	0	0
11. LNG	0	4,102	1,818	0	0	0	0	0	7	0
12. PROP	0	(433)	555	0	0	0	0	0	0	0
13. SPOT	0	1,671	980	0	0	0	0	0	0	0
14. NOREX	0	7,650	7,889	0	0	0	0	0	0	0
15. PENN EAST	0	0	4,063	0	0	0	0	0	0	0
16. CHAMPLAIN	0	0	0	13,100	13,930	15,080	18,595	20,192	21,854	25,304
17. IROQUOIS	0	0	0	12,478	13,351	14,724	17,656	19,466	21,337	23,958
18. DGAS	0	9	262	0	0	0	0	0	0	0
19. DGASBOIL	0	0	0	0	0	0	0	0	0	0
20. STORAGE										
LNG	0	(365)	(252)	0	0	0	0	0	(1)	0
STB	0	(715)	(963)	0	0	0	0	0	0	0
SIS	0	(158)	(236)	0	0	0	0	0	0	0
TGT	0	(167)	(245)	0	0	0	0	0	0	0
TOTAL	0	35,839	38,721	25,577	27,318	29,804	36,332	39,658	43,198	49,262
TOTAL W/O STORAGE	0	37,244	40,416	25,578	27,318	29,804	36,332	39,658	43,198	49,262

TABLE F.2: CHANGE IN COMMODITY COSTS, BASE CASE MINUS CASE 3

SUPPLY		1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
1.	F1	0	(1,676)	(1,009)	(1,447)	(1,630)	(1,973)	(2,227)	(2,363)	(2,605)	(2,807)
2.	F2	0	1,442	1,321	(1,197)	(1,139)	(1,019)	(1,211)	(1,480)	(1,764)	(2,018)
3.	F3	0	0	0	0	0	0	0	0	0	0
4.	F4	0	0	0	0	0	0	0	0	0	0
5.	CD6	0	3,800	3,567	(14,425)	(15,496)	(16,480)	(17,756)	(19,420)	(21,066)	(22,445)
6.	BOUN	0	0	0	0	0	0	0	0	0	0
7.	TGT	0	597	803	(183)	(232)	(392)	(465)	(405)	(366)	(440)
8.	STB	0	1,481	1,333	(276)	(319)	(331)	(388)	(558)	(684)	(800)
9.	SIS	0	513	410	(26)	(12)	(4)	0	(16)	0	(55)
10.	WS	0	1,560	1,758	(130)	(141)	(221)	(264)	(284)	(310)	(328)
11.	LNG	0	4,405	1,909	103	111	565	684	862	982	1,120
12.	PROP	0	(433)	787	279	334	0	0	0	0	0
13.	SPOT	0	453	352	(489)	(572)	(703)	(750)	(1,726)	(1,955)	(3,367)
14.	NOREX	0	1,642	1,207	(8,019)	(8,810)	(10,283)	(11,216)	(10,994)	(11,786)	(11,104)
15.	PENN EAST	0	0	1,896	(2,224)	(2,400)	(2,313)	(2,298)	(2,482)	(2,611)	(2,705)
16.	CHAMPLAIN	0	0	0	13,100	13,930	15,080	18,595	20,192	21,854	25,304
17.	IROQUOIS	0	0	0	12,478	13,351	14,724	17,656	19,466	21,337	23,958
18.	DGAS	0	15	313	62	40	35	19	5	0	0
19.	DGASBOIL	0	0	0	0	0	0	0	0	0	0
20.	STORAGE										
	LNG	0	(411)	(269)	(19)	(19)	(86)	(89)	(89)	(91)	(89)
	STB	0	(521)	(737)	178	185	158	166	201	224	229
	SIS	0	(146)	(236)	18	7	2	0	5	0	12
	TGT	0	(100)	(198)	54	64	89	93	68	57	62
	TOTAL	0	12,621	13,209	(2,161)	(2,747)	(3,152)	551	981	1,215	4,525
	TOTAL W/O STORAGE	0	13,799	14,648	(2,394)	(2,985)	(3,315)	381	797	1,026	4,312

TABLE F.3: CHANGE IN COMMODITY COSTS, CASE 4 MINUS CASE 2

SUPPLY		1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
1.	F1	0	2,387	1,667	1,586	1,765	2,114	2,395	2,626	2,927	3,225
2.	F2	0	1,148	850	755	756	690	675	837	905	1,168
3.	F3	0	0	0	0	0	0	0	0	0	0
4.	F4	0	0	0	0	0	0	0	0	0	0
5.	CD6	0	10,242	11,744	12,888	13,986	14,997	16,240	17,761	19,262	20,574
6.	BOUN	0	0	0	0	0	0	0	0	0	0
7.	TGT	0	0	0	(1)	0	0	0	0	16	52
8.	STB	0	0	0	0	0	0	0	0	0	0
9.	SIS	0	0	0	0	0	0	0	0	0	0
10.	WS	0	0	0	0	0	0	0	0	0	0
11.	LNG	0	0	0	0	0	0	0	0	0	0
12.	PROP	0	0	0	0	0	0	0	0	0	0
13.	SPOT	0	1,586	954	882	1,012	1,221	1,368	2,120	2,375	4,037
14.	NOREX	0	5,411	6,240	7,578	8,304	9,779	10,774	10,994	11,786	11,104
15.	PENN EAST	0	0	1,563	1,502	1,589	1,445	1,571	1,742	2,080	2,065
16.	CHAMPLAIN	0	0	0	0	0	0	0	0	0	0
17.	IROQUOIS	0	0	0	0	0	0	0	0	0	0
18.	DGAS	0	0	0	0	0	0	0	0	0	0
19.	DGASBOIL	0	0	0	0	0	0	0	0	0	0
20. STORAGE											
	LNG	0	0	0	0	0	0	0	0	0	0
	STB	0	0	0	0	0	0	0	0	0	0
	SIS	0	0	0	0	0	0	0	0	0	0
	TGT	0	0	0	0	0	0	0	0	(3)	(8)
	TOTAL	0	20,773	23,018	25,192	27,412	30,246	33,023	36,079	39,347	42,218
	TOTAL W/O STORAGE	0	20,773	23,018	25,192	27,412	30,246	33,023	36,079	39,350	42,225

TABLE F.4: CHANGE IN COMMODITY COSTS, BASE CASE MINUS CASE 4

SUPPLY		1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
1.	F1	0	(1,899)	(1,131)	(1,586)	(1,765)	(2,114)	(2,395)	(2,626)	(2,927)	(3,225)
2.	F2	0	1,914	1,744	(755)	(720)	(690)	(675)	(837)	(905)	(1,168)
3.	F3	0	0	0	0	0	0	0	0	0	0
4.	F4	0	0	0	0	0	0	0	0	0	0
5.	CD6	0	5,299	5,156	(12,888)	(13,986)	(14,997)	(16,159)	(17,761)	(19,262)	(20,574)
6.	BOUN	0	0	0	0	0	0	0	0	0	0
7.	TGT	0	904	938	1	0	0	0	0	(16)	(52)
8.	STB	0	1,874	1,618	0	0	0	0	0	0	0
9.	SIS	0	537	410	0	0	0	0	0	0	0
10.	WS	0	1,838	1,852	0	0	0	0	0	0	0
11.	LNG	0	4,102	1,818	0	0	0	0	0	7	0
12.	PROP	0	(433)	555	0	0	0	0	0	0	0
13.	SPOT	0	85	26	(882)	(1,012)	(1,221)	(1,368)	(2,120)	(2,375)	(4,037)
14.	NOREX	0	2,239	1,649	(7,578)	(8,304)	(9,779)	(10,774)	(10,994)	(11,786)	(11,104)
15.	PENN EAST	0	0	2,499	(1,502)	(1,589)	(1,445)	(1,571)	(1,742)	(2,080)	(2,065)
16.	CHAMPLAIN	0	0	0	13,100	13,930	15,080	18,595	20,192	21,854	25,304
17.	IROQUOIS	0	0	0	12,478	13,351	14,724	17,656	19,466	21,337	23,958
18.	DGAS	0	9	262	0	0	0	0	0	0	0
19.	DGASBOIL	0	0	0	0	0	0	0	0	0	0
20.	STORAGE										
	LNG	0	(365)	(252)	0	0	0	0	0	(1)	0
	STB	0	(715)	(963)	0	0	0	0	0	0	0
	SIS	0	(158)	(236)	0	0	0	0	0	0	0
	TGT	0	(167)	(245)	(0)	0	0	0	0	3	8
	TOTAL	0	15,066	15,703	385	(94)	(441)	3,309	3,579	3,851	7,044
	TOTAL W/O STORAGE	0	16,470	17,398	386	(94)	(441)	3,309	3,579	3,849	7,037

TABLE 3.2: SEASONAL ALLOCATION OF AVOIDED GENERATION COSTS ($/kW CP) DRI-89

	1989	1990	1991	1992	1993	1994	1995	1996	1997
[1] GENERATION COST ($/kW CP)	$0.00	$0.00	$0.00	$59.51	$62.97	$66.62	$70.48	$74.57	$78.90
[2] SEASONAL SPLIT ($/kW CP)									
a. SUMMER	$0.00	$0.00	$0.00	$32.73	$34.63	$36.64	$38.77	$41.01	$43.39
b. WINTER	$0.00	$0.00	$0.00	$29.22	$30.85	$32.60	$34.37	$36.25	$38.24
[3] SEASONAL COST ($/kW CP) AT SECONDARY WITH LOSSES									
a. SUMMER	$0.00	$0.00	$0.00	$38.62	$40.87	$43.24	$45.74	$48.40	$51.20
b. WINTER	$0.00	$0.00	$0.00	$34.56	$36.50	$38.57	$40.66	$42.89	$45.24
[4] SEASONAL PEAK FORECAST									
a. NATURAL SUMMER PEAK	2707	2731	2771	2808	2856	2908	2940	2985	3032
b. NATURAL WINTER PEAK	2451	2489	2531	2574	2623	2674	2713	2763	2815
c. RATIO	1.104	1.097	1.095	1.091	1.089	1.088	1.084	1.080	1.077

NOTES:

[1]: FROM TABLE 3.1.A, INFLATES AT 5.8%

[2]: 55% SUMMER, 45% WINTER, TIMES [1] FROM DPU 89-100, Ex RDS-4, SCHEDULE 7.

[2b]: 45% x [1] x [4.c].

[3]: [2] TIMES MARGINAL LOSS FACTOR, 18.0% SUMMER, 18.3% WINTER, FROM DPU 89-100, Ex RDS-4, SCHEDULE 1.

[4] SEASONAL PEAK FORECAST DATA FROM BECo 1988 EFSC, VOL II, Exh II-J-2.

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
[1] GENERATION COST ($/kW CP)	$83.47	$88.31	$93.43	$98.85	$104.59	$110.65	$117.07	$123.86	$131.05	$138.65
[2] SEASONAL SPLIT ($/kW CP)										
a. SUMMER	$45.91	$48.57	$51.39	$54.37	$57.52	$60.86	$64.39	$68.12	$72.08	$76.26
b. WINTER	$40.29	$42.47	$44.77	$47.18	$49.79	$52.69	$55.65	$58.82	$62.34	$66.07
[3] SEASONAL COST ($/kW CP) AT SECONDARY WITH LOSSES										
a. SUMMER	$54.17	$57.31	$60.64	$64.16	$67.88	$71.81	$75.98	$80.39	$85.05	$89.98
b. WINTER	$47.66	$50.24	$52.97	$55.81	$58.90	$62.33	$65.83	$69.58	$73.74	$78.16
[4] SEASONAL PEAK FORECAST										
a. NATURAL SUMMER PEAK	3071	3111	3151	3169	3199	3243	3262	3284	3334	3391
b. NATURAL WINTER PEAK	2863	2911	2959	2988	3024	3065	3088	3112	3154	3202
c. RATIO	1.073	1.069	1.065	1.061	1.058	1.058	1.056	1.055	1.057	1.059

	2008	2009	2010	2011
[1] GENERATION COST ($/kW CP)	$146.69	$155.20	$164.20	$173.72
[2] SEASONAL SPLIT ($/kW CP)				
a. SUMMER	$80.68	$85.36	$90.31	$95.55
b. WINTER	$70.12	$74.55	$79.24	$84.20
[3] SEASONAL COST ($/kW CP) AT SECONDARY WITH LOSSES				
a. SUMMER	$95.20	$100.72	$106.56	$112.74
b. WINTER	$82.95	$88.19	$93.74	$99.61
[4] SEASONAL PEAK FORECAST				
a. NATURAL SUMMER PEAK	3461	3544	3616	3690
b. NATURAL WINTER PEAK	3258	3320	3372	3426
c. RATIO	1.062	1.067	1.072	1.077

TABLE 3.3: SEASONAL ALLOCATION OF AVOIDED TRANSMISSION DEMAND COSTS AT SECONDARY LEVELS DRI 89

	1989	1990	1991	1992	1993	1994	1995	1996	1997
[1] TRANSMISSION COST ($/kW CP)	$24.50	$25.92	$27.42	$29.01	$30.70	$32.48	$34.36	$36.35	$38.46
[2] SEASONAL SPLIT ($/kW CP)									
a. SUMMER	$13.47	$14.26	$15.08	$15.96	$16.88	$17.86	$18.90	$19.99	$21.15
b. WINTER	$11.02	$11.66	$12.34	$13.06	$13.81	$14.61	$15.46	$16.36	$17.31
[3] SEASONAL COST ($/kW CP) AT SECONDARY WITH LOSSES									
a. SUMMER	$15.90	$16.82	$17.80	$18.83	$19.92	$21.08	$22.30	$23.59	$24.96
b. WINTER	$13.04	$13.80	$14.60	$15.45	$16.34	$17.29	$18.29	$19.35	$20.48

NOTES: [1]: FROM TABLE 3.1.A, INFLATES AT 5.8%

[2]: 55% SUMMER, 45% WINTER, TIMES [1], FROM DPU 89-100, Ex RDS-4, SCHEDULE 7.

[3]: [2] TIMES MARGINAL LOSS FACTOR, 18.0% SUMMER, 18.3% WINTER, FROM DPU 89-100, Ex RDS-4, SCHEDULE 1.

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
[1] TRANSMISSION COST ($/kW CP)	$40.69	$43.05	$45.55	$48.19	$50.99	$53.94	$57.07	$60.38	$63.89	$67.59
[2] SEASONAL SPLIT ($/kW CP)										
a. SUMMER	$22.38	$23.68	$25.05	$26.51	$28.04	$29.67	$31.39	$33.21	$35.14	$37.17
b. WINTER	$18.31	$19.37	$20.50	$21.69	$22.94	$24.27	$25.68	$27.17	$28.75	$30.42
[3] SEASONAL COST ($/kW CP) AT SECONDARY WITH LOSSES										
a. SUMMER	$26.41	$27.94	$29.56	$31.28	$33.09	$35.01	$37.04	$39.19	$41.46	$43.87
b. WINTER	$21.66	$22.92	$24.25	$25.65	$27.14	$28.72	$30.38	$32.14	$34.01	$35.98

	2008	2009	2010
[1] BECo AVOIDED FUEL AND O&M COSTS (DR			
a. PEAK	22.84	25.22	21.71
b. OFF-PEAK	12.32	14.65	10.09
[2] FUEL PRICE UPDATE TO DRI-89	76.2%	76.7%	74.6%
[3] AVOIDED CAPITALIZED ENERGY COSTS	0	0	0
[4] UPDATED AVOIDED FUEL AND O&M COSTS PLUS AVOIDED CAPITALIZED ENERGY (cents/kW)			
a. PEAK	17.41	19.33	16.20
b. OFF-PEAK	9.39	11.23	7.53
[5] SEASONAL AVOIDED FUEL AND O&M (cents/kWH)			
a. SUMMER PEAK	20.73	23.02	19.28
b. SUMMER OFF-PEAK	9.76	11.67	7.82
c. WINTER PEAK	15.63	17.36	14.54
d. WINTER OFF-PEAK	9.20	11.00	7.37
[6] WORKING CAPITAL REVENUE REQ.			
a. SUMMER PEAK	0.29	0.32	0.27
b. SUMMER OFF-PEAK	0.13	0.16	0.11
c. WINTER PEAK	0.21	0.24	0.20
d. WINTER OFF-PEAK	0.13	0.15	0.10
[7] TOTAL COST AT GENERATION			
a. SUMMER PEAK	21.01	23.33	19.55
b. SUMMER OFF-PEAK	9.89	11.83	7.93
c. WINTER PEAK	15.85	17.59	14.74
d. WINTER OFF-PEAK	9.33	11.15	7.48
[8] TOTAL COST @ SECONDARY WITH LOSSES			
a. SUMMER PEAK	24.67	27.39	22.94
b. SUMMER OFF-PEAK	11.06	13.23	8.86
c. WINTER PEAK	18.52	20.56	17.22
d. WINTER OFF-PEAK	10.38	12.41	8.32

TABLE 3.6: PRESENT VALUE OF AVOIDED FUEL AND O&M COST ADDERS DRI-89

MAXIMUM INVESTMENT, (PV 1990) ($/kWH)
INVESTMENT IN 1990, SAVINGS BEGIN IN 1991.

	SUMMER		WINTER	
YEARS	PEAK	OFF-PEAK	PEAK	OFF-PEAK
5	$0.28	$0.16	$0.21	$0.15
7	$0.38	$0.22	$0.29	$0.21
10	$0.52	$0.30	$0.39	$0.28
15	$0.73	$0.41	$0.55	$0.38
20	$0.88	$0.48	$0.66	$0.45
25	$0.98	$0.51	$0.74	$0.48
30	$1.07	$0.54	$0.80	$0.51
40	$1.19	$0.58	$0.89	$0.54

NOTES: PV OF LINE 8, TABLE 3.5
DISCOUNT RATE= 12.16%

Attachment 6
BECo Avoided Costs at Jensen 1989

TABLE 3.1.A: COMPUTATION OF MARGINAL DEMAND RELATED COST JENSEN-89 INPUTS

	GENERATION GAS TURBINE (1992$) $/kW OF CAPACITY	TRANSMISSION (1989$) $/kW CP	DISTRIBUTION (1989$) $/kW CP
CAPITAL COSTS			
[1] LONG RUN UNIT INVESTMENT ($/kW)	$366.08	$202.00	$615.00
[2] GENERAL PLANT LOADING	1.0316	1.0316	1.0316
[3] TOTAL INVESTMENT	$377.65	$208.38	$634.43
[4] ECONOMIC CARRYING CHARGE	0.118	0.105	0.111
[5] A&G LOADING (plant)	0.0059	0.0059	0.0059
[6] TOTAL	0.1238	0.1108	0.1168
[7] ANNUALIZED COST ($/kW-YR)	$46.75	$23.10	$74.09
OPERATIONS & MAINTENANCE			
[8] OPERATION & MAINTENANCE	$1.82	$2.43	$20.05
[9] A&G LOADING (non-plant)	1.2578	1.0923	1.4671
[10] TOTAL O&M ($/kW-YR)	$2.29	$2.65	$29.42
WORKING CAPITAL			
[11] MATERIALS & SUPPLIES LOADING FACTOR	0.0346	0.0134	0.0173
[12] M&S EXPENSE	$13.07	$2.79	$10.98
[13] O&M EXPENSE ALLOWANCE	$0.29	$0.33	$3.68
[14] TOTAL CASH WORKING CAPITAL	$13.35	$3.12	$14.65
[15] REVENUE REQUIREMENT FOR CASH WORKING CAPITAL	$2.20	$0.52	$2.42
[16] TOTAL DEMAND COSTS, $/kW-YR OF CAPACITY	$51.24		
[17] TOTAL DEMAND COSTS WITH RESERVE, $/kW-YR CP	$63.02	$26.27	$105.92

NOTES: [1]: FROM BECO; GENERATION -- SCHEDULE 1, p. 3. $0 THROUGH 1991.
TRANSMISSION -- SCHEDULE 2, p. 1.
DISTRIBUTION -- SCHEDULE 3, p. 1.
[2], [5], [9], [11]: BECO SCHEDULE 6, p. 1.
[3]: [1] + [2].
[4]: TABLE 3.1.B.
[6]: [4] + [5].
[7]: [3] * [6].
[8]: BECO; GENERATION --- MCWS-101.
TRANSMISSION -- SCHEDULE 2, p.2.
DISTRIBUTION -- SCHEDULE 3, p.2.
[10]: [8] * [9].
[12]: [11] * [3].
[13]: 0.125 x [10], 45 DAYS CASH ON HAND FOR O&M EXPENSES EQUALS 0.125.
[14]: [12] + [13].
[15]: 0.165 x [14], CALCULATION OF 0.165 IS ON BECo SCHEDULE 6, p. 4.
[16]: [7] + [10] +[15].
[17]: [16] x 1.23, BECO ASSUMES RESERVE REQUIRED FOR NEPOOL OF 23%, $/kW CP, ALL COLUMNS.

TABLE 3.1: SEASONAL ALLOCATION OF DISTRIBUTION COSTS AT SECONDARY JENSEN 89

	1989	1990	1991	1992	1993	1994	1995	1996	1997
[1] DISTRIBUTION COST ($/kW CP)	$105.92	$111.22	$116.78	$122.62	$128.75	$135.19	$141.95	$149.05	$156.50
[2] SEASONAL SPLIT ($/kW CP)									
a. SUMMER	$51.90	$54.50	$57.22	$60.08	$63.09	$66.24	$69.55	$73.03	$76.68
b. WINTER	$54.02	$56.72	$59.56	$62.54	$65.66	$68.95	$72.39	$76.01	$79.81
[3] SEASONAL COST ($/kW CP) AT SECONDARY WITH LOSSES									
a. SUMMER	$62.33	$65.45	$68.72	$72.16	$75.77	$79.56	$83.53	$87.71	$92.10
b. WINTER	$64.83	$68.07	$71.47	$75.04	$78.80	$82.74	$86.87	$91.22	$95.78

NOTES:
[1]: FROM TABLE 3.1.A, INFLATES AT 5.0%.
[2]: 49% SUMMER, 51% WINTER FROM DPU 89-100, Ex RDS-4, SCHEDULE 7.
[3]: LOSSES, SUMMER 20.1%, WINTER 20.0%, FROM DPU 89-100, Ex RDS-4, SCHEDULE 1.

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
[1] DISTRIBUTION COST ($/kW CP)	$164.32	$172.54	$181.17	$190.22	$199.73	$209.72	$220.21	$231.22	$242.78	$254.92
[2] SEASONAL SPLIT ($/kW CP)										
a. SUMMER	$80.52	$84.54	$88.77	$93.21	$97.87	$102.76	$107.90	$113.30	$118.96	$124.91
b. WINTER	$83.80	$87.99	$92.39	$97.01	$101.86	$106.96	$112.31	$117.92	$123.82	$130.01
[3] SEASONAL COST ($/kW CP) AT SECONDARY WITH LOSSES										
a. SUMMER	$96.70	$101.54	$106.61	$111.94	$117.54	$123.42	$129.59	$136.07	$142.87	$150.02
b. WINTER	$100.57	$105.59	$110.87	$116.42	$122.24	$128.35	$134.77	$141.51	$148.58	$156.01

	2008	2009	2010	2011
[1] DISTRIBUTION COST ($/kW CP)	$267.66	$281.05	$295.10	$309.85
[2] SEASONAL SPLIT ($/kW CP)				
a. SUMMER	$131.16	$137.71	$144.60	$151.83
b. WINTER	$136.51	$143.33	$150.50	$158.03
[3] SEASONAL COST ($/kW CP) AT SECONDARY WITH LOSSES				
a. SUMMER	$157.52	$165.39	$173.66	$182.35
b. WINTER	$163.81	$172.00	$180.60	$189.63

TABLE 3.2: SEASONAL ALLOCATION OF AVOIDED GENERATION COSTS ($/kW CP) JENSEN-89

	1989	1990	1991	1992	1993	1994	1995	1996	1997
[1] GENERATION COST ($/kW CP)	$0.00	$0.00	$0.00	$63.02	$66.17	$69.48	$72.96	$76.60	$80.43
[2] SEASONAL SPLIT ($/kW CP)									
a. SUMMER	$0.00	$0.00	$0.00	$34.66	$36.40	$38.21	$40.13	$42.13	$44.24
b. WINTER	$0.00	$0.00	$0.00	$30.94	$32.42	$34.00	$35.58	$37.24	$38.99
[3] SEASONAL COST ($/kW CP) AT SECONDARY WITH LOSSES									
a. SUMMER	$0.00	$0.00	$0.00	$40.90	$42.95	$45.09	$47.35	$49.72	$52.20
b. WINTER	$0.00	$0.00	$0.00	$36.60	$38.36	$40.23	$42.09	$44.06	$46.12
[4] SEASONAL PEAK FORECAST									
a. NATURAL SUMMER PEAK	2707	2731	2771	2808	2856	2908	2940	2985	3032
b. NATURAL WINTER PEAK	2451	2489	2531	2574	2623	2674	2713	2763	2815
c. RATIO	1.104	1.097	1.095	1.091	1.089	1.088	1.084	1.080	1.077

NOTES: [1]: FROM TABLE 3.1.A, INFLATES AT 5.0%

[2]: 55% SUMMER, 45% WINTER, TIMES [1] FROM DPU 89-100, Ex RDS-4, SCHEDULE 7.

[2b]: 45% x [1] x [4.c].

[3]: [2] TIMES MARGINAL LOSS FACTOR, 18.0% SUMMER, 18.3% WINTER, FROM DPU 89-100, Ex RDS-4, SCHEDULE 1.

[4] SEASONAL PEAK FORECAST DATA FROM BECo 1988 EFSC, VOL II, Exh II-J-2.

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
[1] GENERATION COST ($/kW CP)	$84.46	$88.68	$93.11	$97.77	$102.66	$107.79	$113.18	$118.84	$124.78	$131.02
[2] SEASONAL SPLIT ($/kW CP)										
a. SUMMER	$46.45	$48.77	$51.21	$53.77	$56.46	$59.28	$62.25	$65.36	$68.63	$72.06
b. WINTER	$40.77	$42.65	$44.62	$46.66	$48.87	$51.32	$53.80	$56.43	$59.36	$62.44
[3] SEASONAL COST ($/kW CP) AT SECONDARY WITH LOSSES										
a. SUMMER	$54.81	$57.55	$60.43	$63.45	$66.62	$69.95	$73.45	$77.13	$80.98	$85.03
b. WINTER	$48.23	$50.45	$52.78	$55.20	$57.81	$60.71	$63.65	$66.76	$70.22	$73.86
[4] SEASONAL PEAK FORECAST										
a. NATURAL SUMMER PEAK	3071	3111	3151	3169	3199	3243	3262	3284	3334	3391
b. NATURAL WINTER PEAK	2863	2911	2959	2988	3024	3065	3088	3112	3154	3202
c. RATIO	1.073	1.069	1.065	1.061	1.058	1.058	1.056	1.055	1.057	1.059

	2008	2009	2010	2011
[1] GENERATION COST ($/kW CP)	$137.57	$144.45	$151.67	$159.25
[2] SEASONAL SPLIT ($/kW CP)				
a. SUMMER	$75.66	$79.45	$83.42	$87.59
b. WINTER	$65.76	$69.39	$73.19	$77.19
[3] SEASONAL COST ($/kW CP) AT SECONDARY WITH LOSSES				
a. SUMMER	$89.28	$93.75	$98.43	$103.36
b. WINTER	$77.80	$82.08	$86.58	$91.31
[4] SEASONAL PEAK FORECAST				
a. NATURAL SUMMER PEAK	3461	3544	3616	3690
b. NATURAL WINTER PEAK	3258	3320	3372	3426
c. RATIO	1.062	1.067	1.072	1.077

TABLE 3.3: SEASONAL ALLOCATION OF AVOIDED TRANSMISSION DEMAND COSTS AT SECONDARY LEVELS JENSEN 89

	1989	1990	1991	1992	1993	1994	1995	1996	1997
[1] TRANSMISSION COST ($/kW CP)	$26.27	$27.58	$28.96	$30.41	$31.93	$33.52	$35.20	$36.96	$38.81
[2] SEASONAL SPLIT ($/kW CP)									
a. SUMMER	$14.45	$15.17	$15.93	$16.72	$17.56	$18.44	$19.36	$20.33	$21.34
b. WINTER	$11.82	$12.41	$13.03	$13.68	$14.37	$15.09	$15.84	$16.63	$17.46
[3] SEASONAL COST ($/kW CP) AT SECONDARY WITH LOSSES									
a. SUMMER	$17.05	$17.90	$18.79	$19.73	$20.72	$21.76	$22.85	$23.99	$25.19
b. WINTER	$13.98	$14.68	$15.42	$16.19	$17.00	$17.85	$18.74	$19.68	$20.66

NOTES: [1]: FROM TABLE 3.1.A, INFLATES AT 5.0%

[2]: 55% SUMMER, 45% WINTER, TIMES [1], FROM DPU 89-100, Ex RDS-4, SCHEDULE 7.

[3]: [2] TIMES MARGINAL LOSS FACTOR, 18.0% SUMMER, 18.3% WINTER, FROM DPU 89-100, Ex RDS-4, SCHEDULE 1.

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
[1] TRANSMISSION COST ($/kW CP)	$40.75	$42.79	$44.93	$47.17	$49.53	$52.01	$54.61	$57.34	$60.20	$63.22
[2] SEASONAL SPLIT ($/kW CP)										
a. SUMMER	$22.41	$23.53	$24.71	$25.94	$27.24	$28.60	$30.03	$31.54	$33.11	$34.77
b. WINTER	$18.34	$19.25	$20.22	$21.23	$22.29	$23.40	$24.57	$25.80	$27.09	$28.45
[3] SEASONAL COST ($/kW CP) AT SECONDARY WITH LOSSES										
a. SUMMER	$26.45	$27.77	$29.16	$30.61	$32.15	$33.75	$35.44	$37.21	$39.07	$41.03
b. WINTER	$21.69	$22.78	$23.92	$25.11	$26.37	$27.69	$29.07	$30.52	$32.05	$33.65

	2008	2009	2010	2011
[1] TRANSMISSION COST ($/kW CP)	$66.38	$69.69	$73.18	$76.84
[2] SEASONAL SPLIT ($/kW CP)				
a. SUMMER	$36.51	$38.33	$40.25	$42.26
b. WINTER	$29.87	$31.36	$32.93	$34.58
[3] SEASONAL COST ($/kW CP) AT SECONDARY WITH LOSSES				
a. SUMMER	$43.08	$45.23	$47.49	$49.87
b. WINTER	$35.34	$37.10	$38.96	$40.90

TABLE 3.4: PRESENT VALUE OF CAPACITY COSTS ($/kW) JENSEN-89

MAXIMUM INVESTMENT, $/kW CP IN 1990
INVESTMENT IN 1990, SAVINGS BEGINS 1991.

YEARS	SUMMER	WINTER
5	$461.54	$446.35
7	$618.52	$596.98
10	$818.38	$788.25
15	$1,074.97	$1,033.10
20	$1,259.46	$1,209.40
25	$1,392.71	$1,337.15
30	$1,489.67	$1,430.03
40	$1,611.65	$1,546.71

NOTES: PV(LINE 3, TABLE 3.1) + PV(LINE 3, TABLE 3.2) + PV(LINE 3, TABLE 3.3).
DISCOUNT RATE= 12.16%

TABLE 3.5: AVOIDED FUEL, O&M, AND CAPITALIZED ENERGY COSTS (cents/kWH), JENSEN-89 INPUTS

	1989	1990	1991	1992	1993	1994	1995	1996	1997
[1] BECo AVOIDED FUEL AND O&M COSTS (DRI-87)									
a. PEAK	3.78	4.18	4.45	5.56	6.12	6.40	7.45	8.09	9.17
b. OFF-PEAK	2.81	3.13	3.13	3.80	4.24	4.31	5.25	5.63	6.45
[2] FUEL PRICE UPDATE TO JENSEN-89	1	93.1%	91.3%	89.9%	87.0%	84.8%	82.7%	80.5%	77.0%
[3] AVOIDED CAPITALIZED ENERGY COSTS	0	0	0	0	0	0	0	0	0
[4] UPDATED AVOIDED FUEL AND O&M COSTS PLUS AVOIDED CAPITALIZED ENERGY (cents/kW)									
a. PEAK	3.78	3.89	4.06	5.00	5.33	5.43	6.16	6.51	7.06
b. OFF-PEAK	2.81	2.91	2.86	3.42	3.69	3.65	4.34	4.53	4.97
[5] SEASONAL AVOIDED FUEL AND O&M (cents/kWH)									
a. SUMMER PEAK	4.50	4.63	4.84	5.95	6.34	6.46	7.33	7.75	8.41
b. SUMMER OFF-PEAK	2.92	3.03	2.97	3.55	3.83	3.80	4.51	4.71	5.16
c. WINTER PEAK	3.39	3.49	3.65	4.49	4.78	4.87	5.53	5.84	6.34
d. WINTER OFF-PEAK	2.75	2.86	2.80	3.35	3.61	3.58	4.25	4.44	4.87
[6] WORKING CAPITAL REVENUE REQ.									
a. SUMMER PEAK	0.06	0.06	0.07	0.08	0.09	0.09	0.10	0.11	0.12
b. SUMMER OFF-PEAK	0.04	0.04	0.04	0.05	0.05	0.05	0.06	0.06	0.07
c. WINTER PEAK	0.05	0.05	0.05	0.06	0.07	0.07	0.08	0.08	0.09
d. WINTER OFF-PEAK	0.04	0.04	0.04	0.05	0.05	0.05	0.06	0.06	0.07
[7] TOTAL COST AT GENERATION									
a. SUMMER PEAK	4.56	4.70	4.91	6.03	6.43	6.55	7.43	7.86	8.52
b. SUMMER OFF-PEAK	2.96	3.07	3.01	3.60	3.89	3.85	4.57	4.77	5.23
c. WINTER PEAK	3.44	3.54	3.70	4.55	4.85	4.94	5.60	5.92	6.43
d. WINTER OFF-PEAK	2.79	2.89	2.84	3.39	3.66	3.63	4.31	4.50	4.93
[8] TOTAL COST @ SECONDARY WITH LOSSES									
a. SUMMER PEAK	5.35	5.51	5.76	7.08	7.54	7.69	8.72	9.22	10.00
b. SUMMER OFF-PEAK	3.31	3.43	3.37	4.02	4.35	4.30	5.11	5.34	5.85
c. WINTER PEAK	4.02	4.14	4.32	5.32	5.66	5.77	6.55	6.92	7.51
d. WINTER OFF-PEAK	3.10	3.22	3.16	3.78	4.08	4.04	4.79	5.01	5.49

NOTES:

[1]: BECo QF RFP-2, Exh A, p. 25, TABLE 6, GENERATION LEVEL, DRI-87 FUEL PRICES

[2]: ADJUSTMENT FOR CURRENT JENSEN-89 FUEL FORECAST.

[3]: BECo ASSUMES NO AVOIDED CAPITALIZED ENERGY COSTS.

[4]: {[1] x [2]} + [3].

[5]: ASSUMES SAME SUMMER/WINTER RATIO FOR ON-PEAK/OFF-PEAK AS IN BECo RDS-4, MCWS-650, SCHEDULE 4.
3.611:2.723 PEAK, 2.178:2.054 OFF-PEAK, SUMMER IS 34.3% OF TOTAL kWH.
SUMMER PEAK 1.190*AVG PEAK, SUMMER OFF-PEAK 1.039*AVG OFF-PEAK
WINTER PEAK 0.898*AVG PEAK, WINTER OFF-PEAK .980*AVG OFF-PEAK.

[6]: ONE-MONTH FUEL SUPPLY: 16.5% * [5]/12.

[7]: [5] + [6].

[8]: INCLUDES LOSSES FROM BECo MCWS-1031
SUMMER PEAK=17.39%, SUMMER OFF-PEAK=11.82%
WINTER PEAK=16.85%, WINTER OFF-PEAK=11.25%.

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
[1] BECo AVOIDED FUEL AND O&M COSTS (DR										
a. PEAK	10.51	11.87	12.19	13.55	14.40	16.66	18.01	20.15	19.63	20.1
b. OFF-PEAK	7.46	8.59	7.67	8.46	9.47	10.22	11.64	12.47	10.98	10.48
[2] FUEL PRICE UPDATE TO JENSEN-89	73.3%	68.6%	65.7%	63.0%	59.8%	58.8%	56.6%	55.4%	58.4%	59.1%
[3] AVOIDED CAPITALIZED ENERGY COSTS	0	0	0	0	0	0	0	0	0	0
[4] UPDATED AVOIDED FUEL AND O&M COSTS PLUS AVOIDED CAPITALIZED ENERGY (cents/kW)										
a. PEAK	7.70	8.15	8.01	8.54	8.61	9.80	10.19	11.17	11.45	11.89
b. OFF-PEAK	5.47	5.90	5.04	5.33	5.66	6.01	6.59	6.91	6.41	6.20
[5] SEASONAL AVOIDED FUEL AND O&M (cents/kWH)										
a. SUMMER PEAK	9.17	9.70	9.53	10.16	10.25	11.67	12.13	13.30	13.64	14.15
b. SUMMER OFF-PEAK	5.68	6.13	5.23	5.54	5.88	6.25	6.84	7.18	6.66	6.44
c. WINTER PEAK	6.92	7.31	7.19	7.66	7.73	8.80	9.15	10.03	10.28	10.67
d. WINTER OFF-PEAK	5.36	5.78	4.94	5.22	5.55	5.89	6.45	6.77	6.28	6.07
[6] WORKING CAPITAL REVENUE REQ.										
a. SUMMER PEAK	0.13	0.13	0.13	0.14	0.14	0.16	0.17	0.18	0.19	0.19
b. SUMMER OFF-PEAK	0.08	0.08	0.07	0.08	0.08	0.09	0.09	0.10	0.09	0.09
c. WINTER PEAK	0.10	0.10	0.10	0.11	0.11	0.12	0.13	0.14	0.14	0.15
d. WINTER OFF-PEAK	0.07	0.08	0.07	0.07	0.08	0.08	0.09	0.09	0.09	0.08
[7] TOTAL COST AT GENERATION										
a. SUMMER PEAK	9.30	9.83	9.66	10.30	10.39	11.83	12.30	13.48	13.82	14.34
b. SUMMER OFF-PEAK	5.76	6.21	5.31	5.61	5.96	6.33	6.94	7.28	6.75	6.53
c. WINTER PEAK	7.01	7.41	7.29	7.77	7.83	8.92	9.28	10.16	10.42	10.82
d. WINTER OFF-PEAK	5.43	5.86	5.00	5.29	5.62	5.97	6.54	6.87	6.36	6.15
[8] TOTAL COST @ SECONDARY WITH LOSSES										
a. SUMMER PEAK	10.91	11.54	11.34	12.09	12.19	13.89	14.44	15.82	16.23	16.84
b. SUMMER OFF-PEAK	6.44	6.94	5.93	6.28	6.67	7.08	7.76	8.14	7.55	7.30
c. WINTER PEAK	8.19	8.66	8.51	9.08	9.15	10.42	10.84	11.88	12.18	12.64
d. WINTER OFF-PEAK	6.04	6.51	5.57	5.89	6.25	6.64	7.28	7.64	7.08	6.85

	2008	2009	2010
[1] BECo AVOIDED FUEL AND O&M COSTS (DR			
a. PEAK	22.84	25.22	21.71
b. OFF-PEAK	12.32	14.65	10.09
[2] FUEL PRICE UPDATE TO JENSEN-89	58.7%	58.2%	65.4%
[3] AVOIDED CAPITALIZED ENERGY COSTS	0	0	0
[4] UPDATED AVOIDED FUEL AND O&M COSTS PLUS AVOIDED CAPITALIZED ENERGY (cents/kW)			
a. PEAK	13.41	14.69	14.19
b. OFF-PEAK	7.23	8.53	6.60
[5] SEASONAL AVOIDED FUEL AND O&M (cents/kWH)			
a. SUMMER PEAK	15.96	17.49	16.90
b. SUMMER OFF-PEAK	7.51	8.87	6.85
c. WINTER PEAK	12.03	13.19	12.74
d. WINTER OFF-PEAK	7.08	8.36	6.46
[6] WORKING CAPITAL REVENUE REQ.			
a. SUMMER PEAK	0.22	0.24	0.23
b. SUMMER OFF-PEAK	0.10	0.12	0.09
c. WINTER PEAK	0.17	0.18	0.18
d. WINTER OFF-PEAK	0.10	0.11	0.09
[7] TOTAL COST AT GENERATION			
a. SUMMER PEAK	16.18	17.73	17.13
b. SUMMER OFF-PEAK	7.62	8.99	6.95
c. WINTER PEAK	12.20	13.37	12.92
d. WINTER OFF-PEAK	7.18	8.48	6.55
[8] TOTAL COST @ SECONDARY WITH LOSSES			
a. SUMMER PEAK	18.99	20.81	20.11
b. SUMMER OFF-PEAK	8.52	10.05	7.77
c. WINTER PEAK	14.26	15.62	15.09
d. WINTER OFF-PEAK	7.99	9.43	7.29

TABLE 3.6: PRESENT VALUE OF AVOIDED FUEL AND O&M COST ADDERS JENSEN-89

MAXIMUM INVESTMENT, (PV 1990) ($/kWH)
INVESTMENT IN 1990, SAVINGS BEGIN IN 1991.

	SUMMER		WINTER	
YEARS	PEAK	OFF-PEAK	PEAK	OFF-PEAK
5	$0.26	$0.15	$0.19	$0.14
7	$0.35	$0.20	$0.26	$0.19
10	$0.47	$0.27	$0.35	$0.25
15	$0.62	$0.35	$0.47	$0.33
20	$0.74	$0.40	$0.56	$0.38
25	$0.83	$0.43	$0.62	$0.41
30	$0.90	$0.46	$0.67	$0.43
40	$0.99	$0.49	$0.74	$0.46

PV OF LINE 8, TABLE 3.5
DISCOUNT RATE= 12.16%

Attachment 7
MECo Avoided Costs at NEEI 1988

TABLE 4.1.A: COMPUTATION OF MARGINAL DEMAND RELATED COSTS

	GENERATION GAS TURBINE (1989$) $/kW OF CAPACITY	TRANSMISSION (1988$) $/kW CP	DISTRIBUTION (1988$) $/kW CP
CAPITAL COST			
[1] LONG RUN UNIT INVESTMENT ($/kW)	SEE TABLE 4.1.D	$211.18	$596.00
[2] GENERAL PLANT LOADING		1	1
[3] TOTAL INVESTMENT		$211.18	$596.00
[4] ECONOMIC CARRYING CHARGE		0.0934	0.1011
[5] A&G LOADING (plant)		0.0000	0.0000
[6] TOTAL		0.0934	0.1011
[7] ANNUALIZED COST ($/kW-YR)		$19.73	$60.28
OPERATIONS & MAINTENANCE			
[8] OPERATION & MAINTENANCE		$3.21	$18.14
[9] A&G LOADING (non-plant)		1.3520	1.4486
[10] TOTAL O&M ($/kW-YR)		$4.34	$26.28
WORKING CAPITAL			
[11] MATERIALS & SUPPLIES LOADING FACTOR		0	0
[12] M&S EXPENSE		$0.00	$0.00
[13] O&M EXPENSE ALLOWANCE		$0.00	$0.00
[14] TOTAL CASH WORKING CAPITAL		$0.00	$0.00
[15] REVENUE REQUIREMENT FOR CASH WORKING CAPITAL		$0.00	$0.00
[16] TOTAL DEMAND COSTS, $/kW-YR OF CAPACITY	$55.73	$24.07	$86.56

NOTES:

[1]: TRANSMISSION -- NEPCo W-10, Ex BL, SCHEDULE 2, p. 5,AND WPNE-BL-2, p. 3.
DISTRIBUTION -- RECORD REQUEST AG-1, DPU 89-21.

[2], [5], [11]: NOT REPORTED.

[3]: [1] + [2].

[4]: TABLE 4.1.B.

[6]: [4] + [5].

[7]: [3] * [6].

[8]: TRANSMISSION -- NEPCo W-10, Ex BL, SCHEDULE 2, p. 5.
DISTRIBUTION -- DPU 89-21, Ex TLS-1, pp. 1 AND 5, 1988 $/kW.

[10]: [8] * [9].

[12]: [11] * [3].

[13]: NOT REPORTED.

[14]: [12] + [13].

[15]: NOT REPORTED.

[16]: [7] + [10] + [15], GENERATION FROM TABLE 4.2.A.

TABLE 4.1.B: CALCULATION OF ECONOMIC CARRYING CHARGES

	GENERATION	TRANSMISSION	DISTRIBUTION
1. RATIO OF PVRR TO INVESTMENT	N/A	1.21	1.31
2. CONSTRUCTION INFLATION RATE (I)		5.0%	5.0%
3. DISCOUNT RATE (r)		11.45%	11.45%
4. USEFUL LIFE (N)		30	30
5. ANNUALIZATION FACTOR		7.75%	7.75%
6. ECONOMIC CARRYING CHARGE		9.34%	10.11%

NOTES:

[1], [3]: TRANSMISSION -- NEPCo W-10, WP NE-BL-2, p. 5, $143.78/$95.91, (r=9.73%).
DISTRIBUTION -- DPU 89-21, MECo WORKPAPER F, p. 4, PV=$534.01/kW MINUS $187.90/kW FOR O&M AND A&G EQUALS $233/kW INCLUDING O&M AND A&G, (r=9.46%).

[5]: (r-I)/{1-[(1+I)/(I+r)]^N}.

[6]: [1] * [5].

TABLE 4.1.C: COMPUTATION OF THE PRESENT VALUE OF 1 kW OF DISTRIBUTION CAPACITY

INVESTMENT	YEAR	TOTAL REV REQ	RATIO OF PVRR TO INVESTMENT
$233.00	0	$0.00	1.31
	1	$65.42	
	2	$64.05	
	3	$62.67	
	4	$61.30	
	5	$59.92	
	6	$58.54	
	7	$57.17	
	8	$55.79	
	9	$54.42	
	10	$53.04	
	11	$51.66	
	12	$50.29	
	13	$48.91	
	14	$47.54	
	15	$46.16	
	16	$44.78	
	17	$43.41	
	18	$42.03	
	19	$40.66	
	20	$39.28	
	21	$38.24	
	22	$37.52	
	23	$36.81	
	24	$36.10	
	25	$35.39	
	26	$34.67	
	27	$33.96	
	28	$33.25	
	29	$32.54	
	30	$31.82	
TOTAL PV AT	11.45%	$464.14	

NOTES: DPU 89-21, Ex TLS-5, WORKPAPER F, p. 4.
TOTAL IS ADJUSTED FOR $19.04/YEAR O&M AND A&G.

TABLE 4.2: SEASONAL ALLOCATION OF AVOIDED GENERATION COSTS, NEEI RATES

	1990	1991	1992	1993	1994	1995	1996	1997	1998
[1] GENERATION ($/kw CP)	$105.00	$110.25	$115.76	$121.55	$127.63	$74.68	$78.42	$82.34	$86.46
[2] WITH RESERVES	$133.88	$139.91	$142.39	$149.51	$156.98	$91.86	$96.45	$101.28	$106.34
[3] SEASONAL SPLIT ($/kW CP)									
a. SUMMER	$72.96	$76.25	$77.60	$81.48	$85.56	$50.06	$52.57	$55.20	$57.96
b. WINTER	$60.91	$63.66	$64.79	$68.03	$71.43	$41.80	$43.89	$46.08	$48.39
[4] SECONDARY WITH LOSSES ($/kW CP)									
a. SUMMER	$93.10	$97.29	$99.02	$103.97	$109.17	$63.88	$67.08	$70.43	$73.95
b. WINTER	$77.36	$80.85	$82.28	$86.39	$90.71	$53.08	$55.74	$58.52	$61.45

NOTES: [1]: 1990-1994 $100/kw 1989$, 1995-2006 $55.73/kw 1989$, FROM STATEMENT BL, SCHEDULE 2, p. 4, AND REVISED p.2, NEPCo W-10 RATE PROCEEDINGS AT FERC INFLATES AT 5.0%

[2]: RESERVES 27.5% IN 1990, 26.9% IN 1991, 23% THEREAFTER FROM STATEMENT BL-REVISED, SCHEDULE 2, p. 4.

[3]: SEASONAL SPLIT 54.5% SUMMER, 45.5% WINTER FROM STATEMENT BL, SCHEDULE 1, p. 8.

[4]: SUMMER LOSSES 27.6%, WINTER LOSSES 27.0%, AS IN TABLE 4.1.

	1999	2000	2001	2002	2003	2004	2005	2006
[1] GENERATION ($/kw CP)	$90.78	$95.32	$100.08	$105.09	$110.34	$115.86	$121.65	$127.73
[2] WITH RESERVES	$111.66	$117.24	$123.10	$129.26	$135.72	$142.51	$149.63	$157.11
[3] SEASONAL SPLIT ($/kW CP)								
a. SUMMER	$60.85	$63.90	$67.09	$70.45	$73.97	$77.67	$81.55	$85.63
b. WINTER	$50.80	$53.34	$56.01	$58.81	$61.75	$64.84	$68.08	$71.49
[4] SECONDARY WITH LOSSES ($/kW CP)								
a. SUMMER	$77.65	$81.53	$85.61	$89.89	$94.38	$99.10	$104.06	$109.26
b. WINTER	$64.52	$67.75	$71.13	$74.69	$78.43	$82.35	$86.46	$90.79

TABLE 4.3: SEASONAL ALLOCATION OF AVOIDED TRANSMISSION COSTS, MECo RATES

	1990	1991	1992	1993	1994	1995	1996	1997	1998
[1] TRANSMISSION ($/kw CP)	$26.54	$27.86	$29.26	$30.72	$32.25	$33.87	$35.56	$37.34	$39.21
[2] SEASONAL SPLIT ($/kW CP)									
a. SUMMER	$18.04	$18.95	$19.89	$20.89	$21.93	$23.03	$24.18	$25.39	$26.66
b. WINTER	$8.49	$8.92	$9.36	$9.83	$10.32	$10.84	$11.38	$11.95	$12.55
[3] SECONDARY WITH LOSSES ($/kW CP)									
a. SUMMER	$23.02	$24.18	$25.38	$26.65	$27.99	$29.39	$30.86	$32.40	$34.02
b. WINTER	$10.78	$11.32	$11.89	$12.48	$13.11	$13.76	$14.45	$15.17	$15.93

NOTES: [1]: SEE TABLE 4.1.A, INFLATES AT 5.0%
[2]: SEASONAL SPLIT 68.0% SUMMER, 32.0% WINTER. SOURCE: STATEMENT BL, SCHEDULE 1, p. 9.
[3]: SUMMER LOSSES 27.6%, WINTER LOSSES 27.0%. SOURCE: SEE TABLE 4.1.

	1999	2000	2001	2002	2003	2004	2005	2006
[1] TRANSMISSION ($/kw CP)	$41.17	$43.22	$45.39	$47.65	$50.04	$52.54	$55.17	$57.92
[2] SEASONAL SPLIT ($/kW CP)								
a. SUMMER	$27.99	$29.39	$30.86	$32.41	$34.03	$35.73	$37.51	$39.39
b. WINTER	$13.17	$13.83	$14.52	$15.25	$16.01	$16.81	$17.65	$18.54
[3] SECONDARY WITH LOSSES ($/kW CP)								
a. SUMMER	$35.72	$37.50	$39.38	$41.35	$43.42	$45.59	$47.87	$50.26
b. WINTER	$16.73	$17.57	$18.44	$19.37	$20.34	$21.35	$22.42	$23.54

TABLE 4.4: PRESENT VALUE OF AVOIDED CAPACITY COSTS ($/kW) MECo RATES

MAXIMUM VALUE, $/kW CP SAVED IN 1990
INVESTMENT IN 1990, SAVINGS BEGIN 1991

YEARS	SUMMER	WINTER
5	$702.13	$590.39
7	$884.07	$743.82
10	$1,119.36	$942.25
15	$1,429.05	$1,203.42
20	$1,658.91	$1,397.27
25	$1,829.53	$1,541.15
30	$1,956.16	$1,647.95
40	$2,119.93	$1,786.05

NOTES: DISCOUNT RATE = 11.45%
PV IN 1990, SUM OF TABLES 1, 2, 3.

TABLE 4.5: AVOIDED ENERGY COSTS (FUEL + CAP EN) MECo RATES (cents/kWH)

	1990	1991	1992	1993	1994	1995	1996	1997
[1] FUEL SAVINGS (c/kWH)	2.58	2.62	3.24	3.51	3.86	4.26	4.73	5.19
[2] CAPITALIZED ENERGY COSTS (c/kWH)	0	0	0	0	0	1.17	1.23	1.29
[3] FUEL SAVINGS + CAP. EN. (c/kWH)	2.58	2.62	3.24	3.51	3.86	5.43	5.96	6.48
[4] SEASONAL AVOIDED ENERGY COSTS								
a. WINTER PEAK	3.16	3.21	3.97	4.31	4.73	6.67	7.31	7.95
b. WINTER OFF-PEAK	2.20	2.23	2.76	2.99	3.29	4.63	5.08	5.53
c. SUMMER PEAK	3.24	3.29	4.07	4.42	4.85	6.83	7.49	8.15
d. SUMMER OFF-PEAK	2.21	2.25	2.78	3.02	3.32	4.67	5.12	5.57
e. SPRING/FALL PEAK	2.94	2.99	3.70	4.01	4.41	6.21	6.81	7.41
f. SPRING/FALL OFF-PEAK	2.02	2.06	2.55	2.76	3.03	4.27	4.68	5.09
[5] WORKING CAPITAL REVENUE REQUIREMENT								
a. WINTER PEAK	0.04	0.04	0.05	0.06	0.07	0.09	0.10	0.11
b. WINTER OFF-PEAK	0.03	0.03	0.04	0.04	0.05	0.06	0.07	0.08
c. SUMMER PEAK	0.04	0.05	0.06	0.06	0.07	0.09	0.10	0.11
d. SUMMER OFF-PEAK	0.03	0.03	0.04	0.04	0.05	0.06	0.07	0.08
e. SPRING/FALL PEAK	0.04	0.04	0.05	0.06	0.06	0.09	0.09	0.10
f. SPRING/FALL OFF-PEAK	0.03	0.03	0.04	0.04	0.04	0.06	0.06	0.07
[6] TOTAL COST AT GENERATION								
a. WINTER PEAK	3.20	3.26	4.03	4.37	4.80	6.76	7.41	8.06
b. WINTER OFF-PEAK	2.23	2.26	2.80	3.04	3.33	4.70	5.15	5.60
c. SUMMER PEAK	3.28	3.34	4.13	4.48	4.91	6.93	7.60	8.26
d. SUMMER OFF-PEAK	2.25	2.28	2.82	3.06	3.36	4.74	5.20	5.65
e. SPRING/FALL PEAK	2.98	3.03	3.75	4.07	4.47	6.30	6.91	7.51
f. SPRING/FALL OFF-PEAK	2.05	2.09	2.58	2.80	3.07	4.33	4.75	5.16
[7] TOTAL COST @ SECONDARY WITH LOSSES						1990$ @4.5%		
a. WINTER PEAK	3.80	3.86	4.78	5.18	5.69	8.01	8.79	9.56
b. WINTER OFF-PEAK	2.51	2.55	3.15	3.42	3.75	5.28	5.80	6.30
c. SUMMER PEAK	3.90	3.96	4.90	5.31	5.83	8.22 5.60	9.01	9.80
d. SUMMER OFF-PEAK	2.53	2.57	3.18	3.44	3.78	5.33 4.24	5.85	6.36
e. SPRING/FALL PEAK	3.48	3.54	4.38	4.75	5.22	7.35	8.06	8.77
f. SPRING/FALL OFF-PEAK	2.29	2.33	2.88	3.12	3.42	4.82	5.29	5.76

NOTES:

[1]: FROM MECo FILING JUNE 13, 1988 RE: PURCHASE POWER AGREEMENT, OXFORD COGEN ASSOCIATES, L.P.
[2]: $8.74/MWH 1989$ FROM 1995, INFLATES AT 5.0%
[3]: [1] + [2].
[4]: SEE TABLE 4.5.A FOR SEASONAL SPLITS.
[5]: [4]/12 * 16.5%.
[6]: [5] + [4].
[7]: SEE TABLE 4.5.B FOR SEASONAL LOSSES.

	1998	1999	2000	2001	2002	2003	2004	2005
[1] FUEL SAVINGS (c/kWH)	5.60	5.82	6.19	6.58	6.96	7.36	7.77	8.20
[2] CAPITALIZED ENERGY COSTS (c/kWH)	1.36	1.42	1.49	1.57	1.65	1.73	1.82	1.91
[3] FUEL SAVINGS + CAP. EN. (c/kWH)	6.95	7.25	7.69	8.15	8.61	9.10	9.59	10.11
[4] SEASONAL AVOIDED ENERGY COSTS								
a. WINTER PEAK	8.53	8.89	9.43	10.00	10.56	11.16	11.76	12.40
b. WINTER OFF-PEAK	5.93	6.18	6.56	6.95	7.34	7.76	8.18	8.62
c. SUMMER PEAK	8.74	9.11	9.67	10.24	10.82	11.44	12.05	12.71
d. SUMMER OFF-PEAK	5.98	6.23	6.61	7.01	7.40	7.82	8.24	8.69
e. SPRING/FALL PEAK	7.95	8.28	8.79	9.31	9.84	10.40	10.96	11.55
f. SPRING/FALL OFF-PEAK	5.46	5.70	6.04	6.40	6.76	7.15	7.54	7.94
[5] WORKING CAPITAL REVENUE REQUIREMENT								
a. WINTER PEAK	0.12	0.12	0.13	0.14	0.15	0.15	0.16	0.17
b. WINTER OFF-PEAK	0.08	0.08	0.09	0.10	0.10	0.11	0.11	0.12
c. SUMMER PEAK	0.12	0.13	0.13	0.14	0.15	0.16	0.17	0.17
d. SUMMER OFF-PEAK	0.08	0.09	0.09	0.10	0.10	0.11	0.11	0.12
e. SPRING/FALL PEAK	0.11	0.11	0.12	0.13	0.14	0.14	0.15	0.16
f. SPRING/FALL OFF-PEAK	0.08	0.08	0.08	0.09	0.09	0.10	0.10	0.11
[6] TOTAL COST AT GENERATION								
a. WINTER PEAK	8.65	9.01	9.56	10.13	10.71	11.31	11.93	12.57
b. WINTER OFF-PEAK	6.01	6.27	6.65	7.04	7.44	7.86	8.29	8.74
c. SUMMER PEAK	8.86	9.24	9.80	10.39	10.97	11.59	12.22	12.88
d. SUMMER OFF-PEAK	6.06	6.32	6.70	7.10	7.50	7.93	8.36	8.81
e. SPRING/FALL PEAK	8.06	8.40	8.91	9.44	9.97	10.54	11.11	11.71
f. SPRING/FALL OFF-PEAK	5.54	5.77	6.13	6.49	6.86	7.25	7.64	8.05
[7] TOTAL COST @ SECONDARY WITH LOSSES								
a. WINTER PEAK	10.25	10.69	11.34	12.01	12.69	13.41	14.14	14.90
b. WINTER OFF-PEAK	6.76	7.05	7.48	7.92	8.37	8.85	9.33	9.83
c. SUMMER PEAK	10.52	10.96	11.63	12.32	13.02	13.76	14.50	15.28
d. SUMMER OFF-PEAK	6.82	7.11	7.54	7.99	8.44	8.92	9.40	9.91
e. SPRING/FALL PEAK	9.41	9.81	10.40	11.02	11.65	12.31	12.97	13.67
f. SPRING/FALL OFF-PEAK	6.17	6.44	6.83	7.24	7.64	8.08	8.51	8.97

	2006
[1] FUEL SAVINGS (c/kWH)	8.65
[2] CAPITALIZED ENERGY COSTS (c/kWH)	2.00
[3] FUEL SAVINGS + CAP. EN. (c/kWH)	10.65
[4] SEASONAL AVOIDED ENERGY COSTS	
a. WINTER PEAK	13.07
b. WINTER OFF-PEAK	9.08
c. SUMMER PEAK	13.39
d. SUMMER OFF-PEAK	9.16
e. SPRING/FALL PEAK	12.17
f. SPRING/FALL OFF-PEAK	8.37
[5] WORKING CAPITAL REVENUE REQUIREMENT	
a. WINTER PEAK	0.18
b. WINTER OFF-PEAK	0.12
c. SUMMER PEAK	0.18
d. SUMMER OFF-PEAK	0.13
e. SPRING/FALL PEAK	0.17
f. SPRING/FALL OFF-PEAK	0.12
[6] TOTAL COST AT GENERATION	
a. WINTER PEAK	13.25
b. WINTER OFF-PEAK	9.21
c. SUMMER PEAK	13.57
d. SUMMER OFF-PEAK	9.28
e. SPRING/FALL PEAK	12.34
f. SPRING/FALL OFF-PEAK	8.49
[7] TOTAL COST @ SECONDARY WITH LOSSES	
a. WINTER PEAK	15.70
b. WINTER OFF-PEAK	10.36
c. SUMMER PEAK	16.11
d. SUMMER OFF-PEAK	10.44
e. SPRING/FALL PEAK	14.41
f. SPRING/FALL OFF-PEAK	9.46

TABLE 4.5.A SEASONAL SPLITS FOR AVOIDED ENERGY COSTS.

		HOURS	AVE LOAD	GWH	Relative Cost OP = 1	Weighted Cost	Relative Cost, Ave = 1
Winter	Peak	806	2868	2312	1.484	3431	1.227
Winter	Off-Peak	1354	2043	2766	1.031	2853	0.853
Summer	Peak	1131	2939	3324	1.521	5055	1.257
Summer	Off-Peak	1797	2060	3702	1.040	3850	0.860
Sprng/Fall	Peak	1352	2672	3613	1.383	4995	1.143
Sprng/Fall	Off-Peak	2320	1883	4369	0.951	4153	0.786
	Peak	sum of above				13481	
	Off-Peak	sum of above				10856	
Average	Peak	3289	2812	9248	1.455	13456	1.203
Average	Off-Peak	5471	1981	10837	1	10837	0.827
	Total	8760	4793	20085	1.210	24293	1.000

NOTES: WINTER: DECEMBER, JANUARY, FEBRUARY
SUMMER: JUNE, JULY, AUGUST, SEPTEMBER
SPRING/FALL: MARCH, APRIL, MAY, OCTOBER, NOVEMBER

TABLE 4.5.B MARGINAL ENERGY LOSSES

SEASON/TIME		TRANSMISSION [1]	PRIMARY [2]	SECONDARY [3]	MARGINAL LOSS MULTIPLIER AT SECONDARY [4]
Winter	Peak	3.7%	9.6%	3.1%	18.5%
Winter	Off-Peak	2.7%	6.6%	2.2%	12.5%
Summer	Peak	3.8%	9.5%	3.2%	18.7%
Summer	Off-Peak	2.7%	6.6%	2.2%	12.5%
Sprng/Fall	Peak	3.5%	8.6%	2.9%	16.8%
Sprng/Fall	Off-Peak	2.4%	6.1%	2.1%	11.5%

NOTES: [1], [2], [3]: MECO LOSS STUDY, DPU 89-21, WORKPAPER E, SCHEDULE 1, p. 1.
[4]: 1/((1-[1])*(1-[2])*(1-[3])-1

TABLE 4.6: PRESENT VALUE OF AVOIDED FUEL AND CAPITALIZED ENERGY COSTS, MECo INPUTS.

MAXIMUM VALUE, $/kW CP SAVED IN 1990
INVESTMENT IN 1990, SAVINGS BEGIN 1991

	WINTER		SUMMER		SPRING/FALL	
YEARS	PEAK	OFF-PEAK	PEAK	OFF-PEAK	PEAK	OFF-PEAK
5	$0.19	$0.13	$0.20	$0.13	$0.18	$0.12
7	$0.28	$0.19	$0.29	$0.19	$0.26	$0.17
10	$0.41	$0.27	$0.42	$0.27	$0.37	$0.24
15	$0.57	$0.38	$0.59	$0.38	$0.52	$0.34
20	$0.70	$0.46	$0.71	$0.46	$0.64	$0.42
25	$0.79	$0.52	$0.81	$0.53	$0.73	$0.48
30	$0.86	$0.57	$0.89	$0.57	$0.79	$0.52
40	$0.96	$0.64	$0.99	$0.64	$0.88	$0.58

DISCOUNT RATE= 11.45%

Attachment 8
MECo Avoided Costs at Jensen 1989

TABLE 4.1.A: COMPUTATION OF MARGINAL DEMAND RELATED COSTS

	GENERATION GAS TURBINE (1989$) $/kW OF CAPACITY	TRANSMISSION (1988$) $/kW CP	DISTRIBUTION (1988$) $/kW CP
CAPITAL COST			
[1] LONG RUN UNIT INVESTMENT ($/kW)	SEE TABLE 4.1.D	$211.18	$596.00
[2] GENERAL PLANT LOADING		1	1
[3] TOTAL INVESTMENT		$211.18	$596.00
[4] ECONOMIC CARRYING CHARGE		0.0934	0.1011
[5] A&G LOADING (plant)		0.0000	0.0000
[6] TOTAL		0.0934	0.1011
[7] ANNUALIZED COST ($/kW-YR)		$19.73	$60.28
OPERATIONS & MAINTENANCE			
[8] OPERATION & MAINTENANCE		$3.21	$18.14
[9] A&G LOADING (non-plant)		1.3520	1.4486
[10] TOTAL O&M ($/kW-YR)		$4.34	$26.28
WORKING CAPITAL			
[11] MATERIALS & SUPPLIES LOADING FACTOR		0	0
[12] M&S EXPENSE		$0.00	$0.00
[13] O&M EXPENSE ALLOWANCE		$0.00	$0.00
[14] TOTAL CASH WORKING CAPITAL		$0.00	$0.00
[15] REVENUE REQUIREMENT FOR CASH WORKING CAPITAL		$0.00	$0.00
[16] TOTAL DEMAND COSTS, $/kW-YR OF CAPACITY	$55.73	$24.07	$86.56

NOTES:
[1]: TRANSMISSION -- NEPCo W-10, Ex BL, SCHEDULE 2, p. 5,AND WPNE-BL-2, p. 3.
DISTRIBUTION -- RECORD REQUEST AG-1, DPU 89-21.
[2], [5], [11]: NOT REPORTED.
[3]: [1] + [2].
[4]: TABLE 4.1.B.
[6]: [4] + [5].
[7]: [3] * [6].
[8]: TRANSMISSION -- NEPCo W-10, Ex BL, SCHEDULE 2, p. 5.
DISTRIBUTION -- DPU 89-21, Ex TLS-1, pp. 1 AND 5, 1988 $/kW.
[10]: [8] * [9].
[12]: [11] * [3].
[13]: NOT REPORTED.
[14]: [12] + [13].
[15]: NOT REPORTED.
[16]: [7] + [10] + [15], GENERATION FROM TABLE 4.2.A.

TABLE 4.1.B: CALCULATION OF ECONOMIC CARRYING CHARGES

	GENERATION	TRANSMISSION	DISTRIBUTION
1. RATIO OF PVRR TO INVESTMENT	N/A	1.21	1.31
2. CONSTRUCTION INFLATION RATE (I)		5.0%	5.0%
3. DISCOUNT RATE (r)		11.45%	11.45%
4. USEFUL LIFE (N)		30	30
5. ANNUALIZATION FACTOR		7.75%	7.75%
6. ECONOMIC CARRYING CHARGE		9.34%	10.11%

NOTES: [1], [3]: TRANSMISSION -- NEPCo W-10, WP NE-BL-2, p. 5, $143.78/$95.91, (r=9.73%).
DISTRIBUTION -- DPU 89-21, MECo WORKPAPER F, p. 4, PV=$534.01/kW MINUS $187.90/kW FOR O&M AND A&G EQUALS $233/kW INCLUDING O&M AND A&G, (r=9.46%).
[5]: (r-I)/{1-[(1+I)/(I+r)]^N}.
[6]: [1] * [5].

TABLE 4.1.C: COMPUTATION OF THE PRESENT VALUE OF 1 kW OF DISTRIBUTION CAPACITY

INVESTMENT		YEAR	TOTAL REV REQ	RATIO OF PVRR TO INVESTMENT
$233.00		0	$0.00	1.31
		1	$65.42	
		2	$64.05	
		3	$62.67	
		4	$61.30	
		5	$59.92	
		6	$58.54	
		7	$57.17	
		8	$55.79	
		9	$54.42	
		10	$53.04	
		11	$51.66	
		12	$50.29	
		13	$48.91	
		14	$47.54	
		15	$46.16	
		16	$44.78	
		17	$43.41	
		18	$42.03	
		19	$40.66	
		20	$39.28	
		21	$38.24	
		22	$37.52	
		23	$36.81	
		24	$36.10	
		25	$35.39	
		26	$34.67	
		27	$33.96	
		28	$33.25	
		29	$32.54	
		30	$31.82	
	TOTAL PV AT			
		11.45%	$464.14	

NOTES: DPU 89-21, Ex TLS-5, WORKPAPER F, p. 4.
TOTAL IS ADJUSTED FOR $19.04/YEAR O&M AND A&G.

Table 4.1.D: Computation of the Present Value of 1 kW Peaking Capacity

	NEPCo Rev Req $/kW-yr	@ 5% Esc.	Real-Levelized	Deflated to 1989$
	[1]	[2]	[3]	[4]
1995	$135	1	$74.68	$55.73
1996	$129	1.05	$78.42	
1997	$124	1.103	$82.34	
1998	$118	1.158	$86.46	
1999	$113	1.216	$90.78	
2000	$108	1.276	$95.32	
2001	$104	1.340	$100.08	
2002	$99	1.407	$105.09	
2003	$94	1.477	$110.34	
2004	$90	1.551	$115.86	
2005	$85	1.629	$121.65	
2006	$81	1.710	$127.73	
2007	$76	1.796	$134.12	
2008	$72	1.886	$140.83	
2009	$67	1.980	$147.87	
2010	$63	2.079	$155.26	
2011	$60	2.183	$163.03	
2012	$57	2.292	$171.18	
2013	$55	2.407	$179.74	
2014	$53	2.527	$188.72	
PV AT 11.45%	$806.45	10.80	$806.45	
in 1989$	$601.78			

Notes: 1. NEPCo W-10, WP NE-BL-2, p. 1.

TABLE 4.1.E: COMPUATAION OF THE PRESENT VALUE OF 1 kW OF TRANSMISSION

INVESTMENT	YEAR	TOTAL REV REQ	RATIO OF PVRR TO INVESTMENT
$95.81	0	$0.00	1.21
	1	$19.70	
	2	$19.11	
	3	$18.51	
	4	$17.92	
	5	$17.33	
	6	$16.74	
	7	$16.15	
	8	$15.56	
	9	$14.97	
	10	$14.38	
	11	$13.79	
	12	$13.20	
	13	$12.60	
	14	$12.01	
	15	$11.42	
	16	$10.83	
	17	$10.24	
	18	$9.65	
	19	$9.06	
	20	$8.47	
	21	$8.02	
	22	$7.71	
	23	$7.41	
	24	$7.10	
	25	$6.79	
	26	$6.49	
	27	$6.18	
	28	$5.88	
	29	$5.57	
	30	$5.26	
TOTAL PV AT	11.45%	$115.57	

SOURCE: MECO WORKPAPER NE-BL-2, p. 5.

Attachment 9
BECo Fuel Cost Update Computation

TABLE A: BASE CASE-CHANGE CASE

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
TOTAL-ATOM	115	609	361	702	491	259	433	246	682	144	636
TOTAL-COAL	0	0	0	0	0	0	0	0	0	0	5294
TOTAL-DIST	8894	9829	28493	37113	29438	41041	42969	47908	61919	67481	49338
TOTAL-GAS	0	559	455	557	638	509	701	619	1101	840	2963
TOTAL-RES.5	4831	4101	913	1081	1028	1376	1457	1652	2070	2366	1868
TOTAL-RES1	36521	37126	37704	36984	44236	49188	54220	65518	67616	83357	70985
TOTAL-RES2.2	1043	2288	2187	2370	2995	2878	3539	3681	4272	4257	7645
TOTAL	51404	54511	70113	78807	78825	95252	103319	119624	137660	158444	138731

TOTAL $/KWH FOR EACH FUEL TYPE. BASE CASE-CHANGE CASE FROM QF-RFP-2.
HEAT RATE * $/MMBTU * GWH

TABLE A: BASE CASE-CHANGE CASE

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
TOTAL-ATOM	712	456	673	450	663	731	1360	1118	679	1607
TOTAL-COAL	5814	5251	6073	5585	6499	19438	22908	22202	20200	41831
TOTAL-DIST	56337	46943	64884	63191	73631	68656	60362	81160	97278	53005
TOTAL-GAS	3303	3374	3710	3835	4265	5879	6334	6684	6972	7495
TOTAL-RES.5	2032	1972	2558	2630	3036	2657	2256	3052	3483	2172
TOTAL-RES1	90471	117907	117827	143555	151146	119194	120523	134335	158974	111258
TOTAL-RES2.2	8729	9721	10460	11657	12596	14339	14827	15973	16997	20324
TOTAL	167398	185623	206186	230904	251837	230893	228570	264524	304583	237691

TABLE B: QF RUN FUEL PRICES

	TYPE OF FUEL	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
atom	CONN YANKEE	0.587	0.598	0.612	0.667	0.667	0.755	0.794	0.835	0.878	0.923	0.971
coal	I.G.C.C. 4 2000											3.741
dist	EDGAR JET	4.372	4.756	5.156	5.544	6.110	6.776	7.532	8.459	9.587	10.942	12.549
gas	OCEAN STATE PWR		2.010	2.280	2.551	2.919	3.420	3.931	4.421	5.180	5.790	6.749
res0.5	WYMAN 4	3.326	3.667	3.998	4.333	4.831	5.415	6.081	6.914	7.915	9.082	10.414
res1.0	MYSTIC 4	3.095	3.423	3.735	4.047	4.515	5.061	5.682	6.458	7.394	8.483	9.728
res2.2	CANAL 1	2.898	3.206	3.498	3.788	4.227	4.737	5.319	6.048	6.920	7.939	9.107

NOTE: PLANTS CHOSEN AS REPRESENTATIVE OF FUEL PRICE, VARIATION IN NUCLEAR FUEL PRICE IS NEGLIGIBLE DUE TO SMALL AMOUNT OF NUCLEAR POWER.

TABLE B: QF RUN FUEL PRICES

	TYPE OF FUEL	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
atom	CONN YANKEE	1.021	1.074	1.129	1.187	1.248	1.313	1.381	1.452	1.527	1.606
coal	I.G.C.C. 4 2000	3.988	4.250	4.533	4.822	5.130	5.461	5.806	6.164	6.536	6.924
dist	EDGAR JET	14.054	15.761	17.369	19.277	21.285	23.190	25.098	26.805	28.512	30.120
gas	OCEAN STATE PWR	7.360	8.029	8.740	9.520	10.359	11.260	12.241	13.289	14.429	15.659
res0.5	WYMAN 4	11.664	13.081	14.412	15.997	17.663	19.244	20.828	22.245	23.659	24.994
res1.0	MYSTIC 4	10.895	12.218	13.463	14.942	16.499	17.977	19.456	20.779	22.102	23.347
res2.2	CANAL 1	10.199	11.438	12.603	13.987	15.445	16.827	18.212	19.450	20.691	21.853

TABLE C1: DRI 89 PRICES

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
ATOM	0.59	0.60	0.61	0.67	0.67	0.75	0.79	0.83	0.88	0.92	0.97
COAL	1.47	1.53	1.60	1.68	1.74	1.81	1.90	2.00	2.10	2.21	2.33
DIST	4.60	4.97	5.30	5.63	5.99	6.45	7.00	7.73	8.56	9.61	10.74
GAS		1.89	2.12	2.34	2.58	2.93	3.29	3.62	4.14	4.57	5.24
RES0.5	3.16	3.42	3.69	3.96	4.25	4.61	5.05	5.63	6.29	7.12	8.03
RES1.0	2.97	3.22	3.47	3.72	3.99	4.34	4.75	5.29	5.91	6.69	7.55
RES2.2	2.70	2.93	3.16	3.39	3.63	3.95	4.32	4.82	5.37	6.09	6.87

TABLE C1: DRI 89 PRICES

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
ATOM	1.02	1.07	1.13	1.19	1.25	1.31	1.38	1.45	1.53	1.61
COAL	2.47	2.60	2.74	2.88	3.04	3.23	3.42	3.63	3.86	4.09
DIST	12.05	13.45	14.94	16.28	17.62	19.00	20.47	21.84	23.20	24.56
GAS	5.74	6.26	6.90	7.41	7.92	8.56	9.29	10.10	11.00	12.00
RES0.5	9.05	10.14	11.31	12.37	13.44	14.54	15.71	16.82	17.93	19.04
RES1.0	8.50	9.53	10.63	11.63	12.62	13.66	14.77	15.80	16.85	17.89
RES2.2	7.74	8.67	9.67	10.58	11.49	12.43	13.44	14.38	15.33	16.28

TABLE C2: JENSEN 89 PRICES	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
atom	0.593	0.610	0.630	0.692	0.698	0.795	0.842	0.891	0.943	0.996	1.054
coal											4.058
dist [1]	4.020	4.350	4.659	4.860	5.271	5.728	6.240	6.764	7.306	7.860	8.430
gas [2]		1.840	2.047	2.204	2.451	2.782	3.097	3.320	3.667	3.843	4.186
res0.5 [1]	3.045	3.291	3.522	3.674	3.983	4.325	4.708	5.100	5.505	5.921	6.345
res1.0 [1]	2.899	3.133	3.352	3.496	3.791	4.116	4.477	4.850	5.235	5.630	6.033
res2.2 [1]	2.606	2.816	3.011	3.142	3.403	3.695	4.018	4.351	4.695	5.047	5.407

NOTES:

[1]: DISTALLATE AND RESIDUAL OILS: WELLHEAD + TRANSPORTATION PRICE, CURRENT DOLLARS
[2]: GAS: INITIAL VALUE TAKEN FROM DRI, INFLATES AT THE RATIO OF JENSEN89/DRI-87 RES1.0
[1], [2]: AFTER 2005, ALL OIL ESCALATE AT AVG COMPOUND GROWTH RATE FOR PAST 10 YEARS

TABLE C2: JENSEN 89 PRICES	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
atom	1.113	1.176	1.241	1.311	1.383	1.460	1.542	1.626	1.716	1.810
coal	4.347	4.654	4.985	5.324	5.686	6.075	6.482	6.904	7.344	7.803
dist [1]	9.069	9.757	10.498	11.297	12.156	13.106	14.130	15.234	16.425	17.709
gas [2]	4.383	4.583	4.868	5.139	5.447	5.825	6.230	6.663	7.127	7.622
res0.5 [1]	6.824	7.338	7.892	8.487	9.129	9.837	10.600	11.422	12.308	13.263
res1.0 [1]	6.488	6.975	7.500	8.066	8.675	9.346	10.070	10.849	11.689	12.594
res2.2 [1]	5.812	6.248	6.717	7.221	7.765	8.364	9.009	9.704	10.452	11.258

TABLE D1: PRICE RATIO DRI 89/DRI 87

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
ATOM	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
COAL											62.3%
DIST	105.2%	104.5%	102.8%	101.6%	98.0%	95.2%	92.9%	91.4%	89.3%	87.8%	85.6%
GAS		94.1%	92.9%	91.9%	88.4%	85.8%	83.6%	81.9%	79.9%	78.9%	77.6%
RES0.5	95.0%	93.3%	92.3%	91.4%	88.0%	85.1%	83.0%	81.4%	79.5%	78.4%	77.1%
RES1.0	96.0%	94.1%	92.9%	91.9%	88.4%	85.8%	83.6%	81.9%	79.9%	78.9%	77.6%
RES2.2	93.2%	91.4%	90.3%	89.5%	85.9%	83.4%	81.2%	79.7%	77.6%	76.7%	75.4%

NOTE: DRI-89 PRICES / DRI-87 PRICES.

TABLE D1: PRICE RATIO DRI 89/DR

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
ATOM	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
COAL	61.9%	61.2%	60.4%	59.7%	59.3%	59.2%	58.9%	58.9%	59.1%	59.1%
DIST	85.7%	85.3%	86.0%	84.5%	82.8%	81.9%	81.6%	81.5%	81.4%	81.5%
GAS	78.0%	78.0%	79.0%	77.8%	76.5%	76.0%	75.9%	76.0%	76.2%	76.6%
RES0.5	77.6%	77.5%	78.5%	77.3%	76.1%	75.6%	75.4%	75.6%	75.8%	76.2%
RES1.0	78.0%	78.0%	79.0%	77.8%	76.5%	76.0%	75.9%	76.0%	76.2%	76.6%
RES2.2	75.9%	75.8%	76.7%	75.6%	74.4%	73.9%	73.8%	73.9%	74.1%	74.5%

TABLE D2: PRICE RATIO JENSEN 89/DRI 87

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
atom	101.1%	102.0%	103.0%	103.8%	104.6%	105.3%	106.0%	106.7%	107.3%	107.9%	108.5%
coal											108.5%
dist	92.0%	91.5%	90.4%	87.7%	86.3%	84.5%	82.8%	80.0%	76.2%	71.8%	67.2%
gas		91.5%	89.8%	86.4%	84.0%	81.3%	78.8%	75.1%	70.8%	66.4%	62.0%
res0.5	91.5%	89.8%	88.1%	84.8%	82.4%	79.9%	77.4%	73.8%	69.6%	65.2%	60.9%
res1.0	93.7%	91.5%	89.8%	86.4%	84.0%	81.3%	78.8%	75.1%	70.8%	66.4%	62.0%
res2.2	89.9%	87.8%	86.1%	83.0%	80.5%	78.0%	75.5%	71.9%	67.8%	63.6%	59.4%

NOTE: JENSEN 89 PRICES / DRI-87 PRICES.

TABLE D2: PRICE RATIO JENSEN 89

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
atom	109.0%	109.5%	110.0%	110.4%	110.8%	111.2%	111.6%	112.0%	112.4%	112.7%
coal	109.0%	109.5%	110.0%	110.4%	110.8%	111.2%	111.6%	112.0%	112.4%	112.7%
dist	64.5%	61.9%	60.4%	58.6%	57.1%	56.5%	56.3%	56.8%	57.6%	58.8%
gas	59.5%	57.1%	55.7%	54.0%	52.6%	51.7%	50.9%	50.1%	49.4%	48.7%
res0.5	58.5%	56.1%	54.8%	53.1%	51.7%	51.1%	50.9%	51.3%	52.0%	53.1%
res1.0	59.5%	57.1%	55.7%	54.0%	52.6%	52.0%	51.8%	52.2%	52.9%	53.9%
res2.2	57.0%	54.6%	53.3%	51.6%	50.3%	49.7%	49.5%	49.9%	50.5%	51.5%

TABLE E1: DRI-89 $

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
ATOM	115	609	361	702	491	259	433	246	682	144	636
COAL	0	0	0	0	0	0	0	0	0	0	3297
DIST	9358	10271	29289	37689	28858	39069	39934	43781	55285	59269	42225
GAS	0	526	423	512	564	437	586	507	880	663	2300
RES0.5	4590	3825	842	988	904	1172	1210	1345	1645	1855	1441
RES1.0	35046	34928	35033	33999	39095	42184	45330	53665	54042	65736	55091
RES2.2	972	2091	1976	2121	2572	2400	2875	2934	3315	3265	5767
TOTAL	50081	52250	67924	76011	72485	85520	90368	102478	115849	130931	110757

NOTE: TABLE D x TABLE A.

TABLE E1: DRI-89 $

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
ATOM	712	456	673	450	663	731	1360	1118	679	1607
COAL	3601	3212	3671	3336	3852	11498	13493	13076	11929	24711
DIST	48304	40060	55811	53366	60953	56252	49231	66126	79155	43221
GAS	2577	2632	2930	2985	3262	4467	4808	5083	5315	5743
RES0.5	1576	1529	2007	2034	2310	2007	1702	2307	2640	1654
RES1.0	70583	91968	93035	111737	115615	90569	91493	102145	121197	85254
RES2.2	6624	7369	8026	8818	9371	10592	10943	11809	12593	15141
TOTAL	133978	147225	166153	182725	196025	176115	173029	201665	233509	177330

TABLE E2: JENSEN 89 $	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
atom	116	621	372	729	513	273	459	262	732	155	690
coal	0	0	0	0	0	0	0	0	0	0	5743
dist	8179	8989	25744	32536	25393	34694	35599	38312	47186	48473	33145
gas	0	512	409	481	535	414	552	465	779	558	1838
res0.5	4423	3681	804	917	848	1099	1128	1218	1440	1542	1138
res1.0	34208	33981	33842	31952	37142	40002	42728	49205	47865	55319	44024
res2.2	938	2010	1882	1966	2411	2245	2674	2648	2898	2706	4539
TOTAL	47864	49794	63053	68581	66843	78728	83140	92111	100900	108754	91118

NOTE: TABLE D x TABLE A.

TABLE E2: JENSEN 89 $	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
atom	776	499	740	497	735	813	1518	1253	763	1811
coal	6337	5749	6678	6167	7204	21624	25573	24867	22696	47144
dist	36353	29060	39219	37031	42051	38802	33983	46126	56040	31164
gas	1967	1926	2067	2070	2242	3041	3224	3352	3443	3648
res0.5	1189	1106	1401	1395	1569	1358	1148	1567	1812	1152
res1.0	53875	67307	65637	77498	79470	61966	62376	70138	84075	60015
res2.2	4975	5310	5575	6018	6333	7127	7335	7969	8586	10470
TOTAL	105471	110958	121317	130677	139604	134732	135158	155272	177416	155403

TABLE F1: FUEL UPDATE RATIO	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
TOTAL(DRI-89)/TOTAL (DRI-87)	97.4%	95.9%	96.9%	96.5%	92.0%	89.8%	87.5%	85.7%	84.2%	82.6%	79.8%

TABLE F1: FUEL UPDATE RATIO	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
TOTAL(DRI-89)/TOTAL (DRI-87)	80.0%	79.3%	80.6%	79.1%	77.8%	76.3%	75.7%	76.2%	76.7%	74.6%

TABLE F2: FUEL UPDATE RATIO	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
TOTAL(JENSEN)/TOTAL(DRI)	93.1%	91.3%	89.9%	87.0%	84.8%	82.7%	80.5%	77.0%	73.3%	68.6%	65.7%

TABLE F2: FUEL UPDATE RATIO	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
TOTAL(JENSEN)/TOTAL(DRI)	63.0%	59.8%	58.8%	56.6%	55.4%	58.4%	59.1%	58.7%	58.2%	65.4%

FUEL MIX REGRESSIONS FOR LOW, BASE, AND HIGH FUEL PRICE FORECASTS, NEEI 9/87.

TABLE 1: FUEL REGRESSIONS FOR YEARS 1987-1991

CALCULATED VALUE	AVOIDED ENERGY COST	2.2% OIL	COAL	GAS	TIME	YEAR	PRICE FORECAST
0.0248150	0.02417	2.16	1.58	0	-2	1987	LOW
0.0253200	0.02538	2.24	1.69	0	-1	1988	LOW
0.0257709	0.02617	2.33	1.75	0	0	1989	LOW
0.0262545	0.02628	2.43	1.82	0	1	1990	LOW
0.0269029	0.02683	2.53	1.94	3.26	2	1991	LOW
0.0307232	0.03006	2.82	1.58	0	-2	1987	BASE
0.0293347	0.02967	2.69	1.68	0	-1	1988	BASE
0.0302286	0.03086	2.83	1.75	0	0	1989	BASE
0.0311918	0.03119	2.98	1.82	0	1	1990	BASE
0.0322527	0.03193	3.12	1.94	3.74	2	1991	BASE
0.0320607	0.03172	2.97	1.58	0	-2	1987	HIGH
0.0334401	0.03409	3.15	1.69	0	-1	1988	HIGH
0.0349223	0.03571	3.34	1.81	0	0	1989	HIGH
0.0365402	0.0364	3.54	1.94	0	1	1990	HIGH
0.0383025	0.03763	3.76	2.07	4.37	2	1991	HIGH

Regression Output:

Constant	0
Std Err of Y Est	0.000522
R Squared	0.986757
No. of Observations	15
Degrees of Freedom	12

	OIL	COAL	TIME
X Coefficient(s)	0.008950	0.002776	-0.00054
Std Err of Coef.	0.000353	0.000575	0.000096

FUEL MIX REGRESSIONS FOR LOW, BASE, AND HIGH FUEL PRICE FORECASTS, NEEI 9/87.

TABLE 1: FUEL REGRESSIONS FOR YEARS 1987-1991

CALCULATED VALUE	AVOIDED ENERGY COST	2.2% OIL	COAL	GAS	TIME	YEAR	PRICE FORECAST
0.0248150	0.02417	2.16	1.58	0	-2	1987	LOW
0.0253200	0.02538	2.24	1.69	0	-1	1988	LOW
0.0257709	0.02617	2.33	1.75	0	0	1989	LOW
0.0262545	0.02628	2.43	1.82	0	1	1990	LOW
0.0269029	0.02683	2.53	1.94	3.26	2	1991	LOW
0.0307232	0.03006	2.82	1.58	0	-2	1987	BASE
0.0293347	0.02967	2.69	1.68	0	-1	1988	BASE
0.0302286	0.03086	2.83	1.75	0	0	1989	BASE
0.0311918	0.03119	2.98	1.82	0	1	1990	BASE
0.0322527	0.03193	3.12	1.94	3.74	2	1991	BASE
0.0320607	0.03172	2.97	1.58	0	-2	1987	HIGH
0.0334401	0.03409	3.15	1.69	0	-1	1988	HIGH
0.0349223	0.03571	3.34	1.81	0	0	1989	HIGH
0.0365402	0.0364	3.54	1.94	0	1	1990	HIGH
0.0383025	0.03763	3.76	2.07	4.37	2	1991	HIGH

Regression Output:

Constant	0
Std Err of Y Est	0.000522
R Squared	0.986757
No. of Observations	15
Degrees of Freedom	12

	OIL	COAL	TIME
X Coefficient(s)	0.008950	0.002776	-0.00054
Std Err of Coef.	0.000353	0.000575	0.000096

TABLE 2: FUEL REGRESSIONS FOR YEARS 1992-1997

CALCULATE VALUE	AVOIDED ENERGY COST	2.2% OIL	COAL	GAS	TIME	YEAR	PRICE FORECAST
0.030918	0.03162	2.63	2.04	3.18	-3	1992	LOW
0.033516	0.03419	2.73	2.14	3.30	-2	1993	LOW
0.034997	0.03678	2.84	2.25	3.31	-1	1994	LOW
0.036481	0.03708	2.95	2.36	3.32	0	1995	LOW
0.039302	0.03917	3.07	2.49	3.46	1	1996	LOW
0.041413	0.04131	3.20	2.61	3.53	2	1997	LOW
0.043633	0.04353	3.32	2.74	3.61	3	1998	LOW
0.037462	0.03599	3.28	2.04	3.82	-3	1992	BASE
0.041031	0.03956	3.45	2.14	4.04	-2	1993	BASE
0.043121	0.04312	3.62	2.25	4.11	-1	1994	BASE
0.045348	0.04413	3.80	2.37	4.19	0	1995	BASE
0.048598	0.0473	4.00	2.49	4.37	1	1996	BASE
0.051616	0.05063	4.20	2.61	4.53	2	1997	BASE
0.054873	0.05406	4.42	2.74	4.71	3	1998	BASE
0.044695	0.04462	3.99	2.22	4.51	-3	1992	HIGH
0.049343	0.0492	4.23	2.33	4.83	-2	1993	HIGH
0.052365	0.05402	4.49	2.45	4.99	-1	1994	HIGH
0.055496	0.05534	4.76	2.57	5.16	0	1995	HIGH
0.059450	0.05979	5.05	2.70	5.41	1	1996	HIGH
0.063718	0.06443	5.36	2.84	5.69	2	1997	HIGH
0.068197	0.0694	5.68	2.98	5.99	3	1998	HIGH

Regression Output:

Constant	0
Std Err of Y Est	0.001014
R Squared	0.991029
No. of Observations	21
Degrees of Freedom	18

	COAL	GAS	TIME
X Coefficient(s)	0.001088	0.010212	0.001259
Std Err of Coef.	0.000635	0.000357	0.000113

TABLE 3: FUEL REGRESSIONS FOR YEARS 1998-2006

CALCULATED VALUE	AVOIDED ENERGY COST	2.2% OIL	COAL	GAS	TIME	YEAR	PRICE FORECAST
0.04540	0.04754	3.46	2.88	3.65	-3	1999	LOW
0.04834	0.04988	3.59	3.02	3.74	-2	2000	LOW
0.05089	0.05231	3.74	3.18	3.79	-1	2001	LOW
0.05431	0.05447	3.89	3.34	3.92	0	2002	LOW
0.05627	0.05680	4.05	3.50	3.91	1	2003	LOW
0.05901	0.05939	4.20	3.68	3.97	2	2004	LOW
0.06188	0.06196	4.37	3.87	4.04	3	2005	LOW
0.06501	0.06462	4.55	4.06	4.13	4	2006	LOW
0.05828	0.05731	4.63	2.88	4.85	-3	1999	BASE
0.06235	0.06071	4.86	3.03	5.05	-2	2000	BASE
0.06598	0.06471	5.11	3.19	5.20	-1	2001	BASE
0.07057	0.06890	5.37	3.33	5.44	0	2002	BASE
0.07377	0.07258	5.64	3.50	5.54	1	2003	BASE
0.07783	0.07659	5.92	3.68	5.73	2	2004	BASE
0.08220	0.08107	6.22	3.87	5.94	3	2005	BASE
0.08669	0.08560	6.53	4.07	6.15	4	2006	BASE
0.07439	0.07419	6.03	3.13	6.27	-3	1999	HIGH
0.07995	0.07938	6.39	3.28	6.60	-2	2000	HIGH
0.08522	0.08530	6.78	3.45	6.90	-1	2001	HIGH
0.09159	0.09158	7.20	3.62	7.30	0	2002	HIGH
0.09660	0.09729	7.63	3.81	7.57	1	2003	HIGH
0.10272	0.10362	8.10	4.00	7.94	2	2004	HIGH
0.10919	0.11065	8.59	4.20	8.34	3	2005	HIGH
0.11624	0.11782	9.11	4.41	8.79	4	2006	HIGH

Regression Output:

Constant	0
Std Err of Y Est	0.001181
R Squared	0.996660
No. of Observations	24
Degrees of Freedom	21

	COAL	GAS	TIME
X Coefficient(s)	0.003688	0.010715	0.001442
Std Err of Coef.	0.000309	0.000187	0.000109

TABLE 4: AVOIDED ENERGY COSTS
BASE CASE FUEL PRICES, CURRENT$, $/MMBTU

YEAR	ESTIMATED AVOIDED ENERGY COST 9/88 FUEL PROJECTION		AVOIDED ENERGY COST 9/87 FUEL PROJECTION		ESTIMATED AVOIDED ENERGY CO 9/87 FUEL
	[1]	[2]	[3]	[4]	[5]
1988	0.0229		0.0297		0.0293
1989	0.0243	1.062	0.0309	1.040	0.0302
1990	0.0258	1.058	0.0312	1.011	0.0312
1991	0.0262	1.017	0.0319	1.024	0.0323
1992	0.0324	1.237	0.0360	1.127	0.0375
1993	0.0351	1.084	0.0396	1.099	0.0410
1994	0.0386	1.098	0.0431	1.090	0.0431
1995	0.0426	1.105	0.0441	1.023	0.0453
1996	0.0473	1.110	0.0473	1.072	0.0486
1997	0.0519	1.097	0.0506	1.070	0.0516
1998	0.0560	1.078	0.0541	1.068	0.0549
1999	0.0582	1.041	0.0573	1.060	0.0583
2000	0.0619	1.064	0.0607	1.059	0.0624
2001	0.0658	1.062	0.0647	1.066	0.0660
2002	0.0696	1.058	0.0689	1.065	0.0706
2003	0.0736	1.058	0.0726	1.053	0.0738
2004	0.0777	1.055	0.0766	1.055	0.0778
2005	0.0820	1.055	0.0811	1.058	0.0822
2006	0.0865	1.055	0.0856	1.056	0.0867

[1]: CALCULATED USING FUEL MIX FROM REGRESSIONS WITH 87 PRICES AND 9/88 FUEL PRICES.
[2]: ANNUAL AVERAGE GROWTH RATE OF AVOIDED ENERGY COST.
[3]: AVOIDED ENERGY COSTS, 9/87 PRICES.
[4]: ANNUAL AVERAGE GROWTH RATE OF AVOIDED ENERGY COST.
[5]: CALCULATED USING FUEL MIX FROM REGRESSIONS WITH 87 PRICES AND 9/87 FUEL PRICES.

JENSEN FUEL COST INPUTS

TIME INPUT	YEAR	OIL	COAL	GAS	AVOIDED ENERGY COSTS 1987 FUEL PRICES	ESTIMATED AVOIDED ENERGY COSTS JENSEN-89 PRICES
0	1990	2.606	1.64	3.41	0.03119	0.027773
1	1991	2.816	1.67	3.64	0.03193	0.029337
-3	1992	3.011	1.70	4.10	0.03599	0.039981
-2	1993	3.142	1.74	4.34	0.03956	0.043660
-1	1994	3.403	1.77	4.62	0.04312	0.047892
0	1995	3.695	1.81	5.29	0.04413	0.055969
1	1996	4.018	1.86	5.66	0.0473	0.061050
2	1997	4.351	1.92	6.04	0.05063	0.066305
3	1998	4.695	1.97	6.71	0.05406	0.074473
-3	1999	5.047	2.03	7.15	0.05731	0.079769
-2	2000	5.407	2.09	7.60	0.06071	0.086304
-1	2001	5.812	2.16	8.32	0.06471	0.095631
0	2002	6.248	2.22	8.85	0.0689	0.102966
1	2003	6.717	2.29	9.41	0.07258	0.110746
2	2004	7.221	2.36	10.20	0.07659	0.120865
3	2005	7.765	2.43	10.85	0.08107	0.129578
4	2006	8.364	2.50	11.55	0.0856	0.138712

GAS PRICE IS CHAMPLAIN COMMODITY CHARGE + ANNUAL DEMAND CHARGE/365
$647.49 FROM BOSGASAC
OIL IS RES2.2%, REFINERY + TRANSPORTATION COST
COAL IS THE 9/88 NEEI COAL PRICE

APPENDIX C

DPU 89-23 PC

8/B

ANALYSIS OF FUEL SUBSTITUTION AS AN ELECTRIC CONSERVATION OPTION

BASED ON THE AVOIDED COSTS OF BOSTON GAS COMPANY, BOSTON EDISON COMPANY, AND MASSACHUSETTS ELECTRIC COMPANY

A Report to the
Boston Gas Company

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Eric Espenhorst

PLC, Inc.

December 22, 1989

Printed on Recycled Paper

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1. INTRODUCTION AND SUMMARY

1.1 Introduction

This report examines the economics of replacing appliances and equipment which operate on electricity with equivalent end-use equipment operating on natural gas. The approach used in this report can be applied to decisions on equipment for new construction and renovation, on new equipment for new or expanded uses within existing buildings, on replacement of existing equipment on a normal schedule,[1] and on the replacement of existing equipment on an accelerated basis. For convenience, we refer to all of these situations as "fuel switching," but not all applications will involve the switching of an existing fuel.

We consider fuel-switching from electric end-uses on the systems of both Boston Edison (BECo) and Massachusetts Electric (MECo) to gas-fired end uses on the Boston Gas (BGC) system, using system avoided cost estimates for each utility, as developed elsewhere.[2] Fuel-switching is evaluated for three different fuel price and inflation projections, reflecting the estimates used by each of the three utilities (or updates from each utility's standard sources). For each comparison, the same fuel and inflation scenario is used to drive the avoided cost computation for each of the three utilities.

This report presents computations of the cost-effectiveness of fuel-switching both residential end uses (space heating, water heating, clothes drying, and cooking), and commercial space cooling and associated space and water heating. Due to the differences in the methodological issues raised by the residential and commercial end uses, we have separated the analyses. This methodology is applicable to all end uses. Section 2 discusses the inputs we have used for load levels and load shapes in the residential class, while Section 3 presents the actual comparisons of system costs for residential end uses.

Section 4 presents generic data on commercial cooling load shapes, load levels, and costs. Section 5 presents case studies drawn from published reports and from BGC internal analyses, and computes the system costs and building-specific costs for a range

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[1] By a "normal" schedule, we mean at the time when the equipment wears out, ceases to operate effectively, is obsolete, or would otherwise typically be replaced in kind.

[2] See Chernick and Espenhorst (1989). We use the term "system" avoided costs to include only the costs of construction and operating the utilities' common plant. This cost category does not include all social costs, such as the cost of installing the end-use equipment.

of fuel choices. The analysis concentrates on chilling energy choice, but also considers one example of heating energy choice.

This report deals only with the conversion of electric end-uses to natural gas. Given the currently projected avoided costs and efficiency ratios, virtually all bulk switching of residential and commercial loads should flow in this direction.[3] However, many gas conservation measures (such as condensing furnaces) will require increased electrical usage for fans, pumps, and controls. The cost-effectiveness of these inter-fuel substitutions should be analyzed in a manner similar to that used in this report. Similarly, fuel-switching of industrial processes may be economical in either direction, depending on end-use efficiencies; these potential conversions should be analyzed in a framework similar to that which is used here.

1.2 Summary

Counting only the utility system costs, gas is substantially less expensive than electricity for each of the applications we review: residential ranges, dryers, water heaters, and space heating; and commercial chilling and space heating.

The total cost-effectiveness of switching from electricity to gas is potentially sensitive to the cost of the conversion. For the residential sector, water-heating conversions appear to be clearly cost-effective so long as the building has gas service, and may be cost-effective even if a service is required. The same is true for space heating. Range and dryer conversions are likely to be cost-effective in many situations.

In the commercial sector, fuel-switching of chillers appears to be generally cost-effective in new buildings, in existing buildings where additional cooling must be added, or in existing buildings where electric chillers are close to the end of their useful lives. Additionally, fuel-switching of existing chillers on an accelerated basis may also be cost-effective, depending in part on the efficiency of the existing equipment. The gas chiller system must be chosen to fit the energy requirements of the specific building. Fuel-switching may not be cost-effective in some small, high load-factor applications without a waste-heat load, especially where the gas service is very expensive.

The single commercial space-heating conversion we examined was also extremely cost-effective.

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[3]Some isolated residential applications, such as the rare gas-fired refrigeration, may be cost-effective to switch in the opposite direction.

In addition to the direct-cost social benefits of fuel-switching to Massachusetts, the substitution of direct gas use for electricity generated from coal, oil, or even natural gas will have substantial environmental benefits. The reduction of oil imports due to fuel switching would also have significant economic benefits, on a regional and national level. These externalities are discussed in Chernick and Caverhill (1989).

This study strongly supports the conclusion that Massachusetts electric utilities (at least BECo and MECo) should include fuel-switching in their demand-side programs. The DPU's precedents have clearly established the responsibility of utilities to minimize the social costs of meeting their customers' energy needs. Given the high benefit-cost ratios for many of the fuel-switching applications, the inclusion of fuel-switching in the electric utility demand-side programs is required by those precedents. Fuel-switching services should be offered to electric customers on the same terms, and should be paid for by the same mechanisms, as are applied to other efficiency measures, including direct services and incentives for storage cooling, efficient new-building design, building retrofits, and appliance efficiency. The logic behind the electric utility paying for reductions in its customers' energy usage is the same, whether the product reducing electric usage is provided by the suppliers of high-efficiency lighting or by the suppliers of gas chillers and of natural gas.

Since the fuel switching would primarily reduce the cost of serving electric customers, the cost of the fuel-switching program should be borne by the electric utility and its customers. The portion of the conversion cost which can be assumed by the participant will probably vary with the type of conversion. The excellent economics of commercial gas chilling, combined with its low market penetration, suggest the existence of a market failure, which the electric utility can correct by paying a portion of the cost of chilling conversions.

2. RESIDENTIAL APPLIANCE END-USE PATTERNS

To analyze the system cost-effectiveness of fuel switching, we need estimates of the amount of electricity used by a particular appliance, the composition of that electric use by season and time of day (e.g., by rating period), and the contribution of each end use to summer and winter peak loads. We also need to know how much gas will be required to replace the electric load, and we must select a load shape to approximate the cost of providing the additional gas.[4]

So far as we have been able to determine, neither BECo or MECo (or any other NEES company) has published data on the load shapes of various end uses. However, NEPOOL has released such data for the load shapes used in NEPOOL's own load forecasting model. We use these data extensively.

2.1 Load Factors

Table 2.1 presents data from NEPOOL's Massachusetts load-forecasting model for six end-use categories: ranges, controlled and uncontrolled water heaters, dryers, heat pumps, and resistance space heating.[5] These data include the annual consumption per appliance, the total contribution by each appliance type to the NEPOOL peak load (summer and winter), and the number of installed appliances.[6] From these values, we compute the load factor and peak contribution (in kW per MWH of annual energy) for each appliance type, based on each of the seasonal peaks.

The data in Table 2.1 represents the data on which the NEPOOL utilities have traditionally relied. Unfortunately, most of this data is neither local nor recent. For example, the data for ranges

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[4]Both the electric rating periods and the gas load shape must be consistent with the estimates developed in Chernick and Espenhorst (1989).

[5]Controlled water heaters are largely shut off for some of the peak hours, usually by a time clock.

The specific NEPOOL model runs available were from 1985. So far as we can determine, NEPOOL has assumed the same load shape by end use since the model was first constructed in 1977.

[6]Various utilities (and other sources) report summer peak load data for peaks in July or in August. Actual utility and NEPOOL summer peaks in any year may occur from June through September, depending on weather patterns and other factors. Similarly, winter peak is reported as December or January, although the peak may also occur in February. These differences in the timing of peaks are unlikely to substantially affect the results reported here.

are from 33 single-family houses (with an average of 4.5 people per house) in 1966 in Baltimore, the data for dryers are from a similar sample for 1968, the data for controlled water heaters are from 30 households in Philadelphia in 1966, and those for uncontrolled water heaters are from 23 single-family houses in 1962 in Baltimore. Differences in climate, housing stock, technology (e.g., improvements in water heater efficiency and the introduction of microwaves), and demographic patterns (e.g., two-income families, small numbers of children) make the application of these data in the 1990s to Massachusetts utilities somewhat suspect. In addition, the hours of each utility's peak seasonal load may differ slightly from the hour of NEPOOL peak load.

The Joint Utility Monitoring Project (JUMP), sponsored by several Massachusetts electric utilities, has developed estimates for load curves for some appliances, including ranges, dryers, and uncontrolled water heaters, based on recent metered load data (Applied Energy Group, 1989). Some odd results suggest that the data may be subject to either sampling problems or monitoring equipment errors.[7] The sample ranged from 39 to 51, depending on the appliance, but the number of useable observations was 25-40, depending on the appliance and the analysis. No utility appears to have utilized the JUMP data for any public purpose to date.

In addition, the JUMP data is presented in a very odd form. The report lists non-coincident peak load of each appliance (e.g., each range) and the coincident load of all appliances of each type (e.g., all ranges), which are useless measures for virtually any utility purpose other than sizing service drops. The interesting peak load data, such as appliance load coincident with building peak, line transformer peak, distribution substation peak, total distribution peak, or total system peak, are not reported (and may not have been collected). However, this is the only recent measured data for appliance end-use, at least for New England.

Table 2.1.A presents JUMP data on average appliance energy usage and peak loads at summer and winter peak hours, for average days in broadly defined summer (May-September) and winter (October-February) periods. We cannot determine how these peak loads might be related to the peak loads on system peak days, or to peak loads on typical days in peak months. However, the JUMP report provides graphs of usage on high-load days, from which we estimated the high-use peak loads shown in Table 2.1.B.

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[7] For example, JUMP reports average usage for refrigerators which is almost twice the value reported by most utilities and other sources. For water heating usage, the JUMP value is about 20% lower than either MECo or BECo estimates. Since water heater usage estimates are generally based on billing data for specific rates and specifically coded customers, they tend to be more reliable than other electric usage estimates.

In many cases, the JUMP data provide very different estimates of coincident peak contribution than does the NEPOOL data. For some appliances and seasons, the JUMP data shows higher peak contributions, while for others it shows lower contributions. The general tendency is for winter peak contribution to be higher in the JUMP data, and for summer peak to be higher in the NEPOOL data.[8] One of the largest differences is in summer peak contribution by water heaters, for which the NEPOOL data indicated a kW/MWH ratio of 0.14, while the JUMP data indicated a ratio (for its long "summer" period) of 0.09. However, a 1987-88 study of 100 water heaters by MECo's Rhode Island affiliate (Narragansett Electric) reports water heater loads for our summer and winter coincident peaks of 0.9 and 1.8 kW, or about three times the JUMP average load data.[9] Given these inconsistencies, we are reluctant to adjust peak contributions based on the JUMP data.

It is likely that the NEPOOL data understates winter peak contributions, and it is possible that NEPOOL data slightly overstates summer peak contributions. This direction of load changes is consistent with demographic trends since the 1960s. However, we will continue using the NEPOOL data, pending resolution of the outstanding questions regarding the JUMP results.

2.2 Average Electric Use and Contribution to Peak

Each of the electric utilities has its own estimates of average energy usage per appliance, and presents these estimates in its annual reports to the Energy Facilities Siting Council. Corresponding values for peak contribution by appliance are either not generated or not provided by the utilities. Hence, we have combined each utility's annual usage estimate with the NEPOOL load factor data, to produce an estimate of the peak contributions by appliance.

Table 2.2 multiplies the NEPOOL kW/MWH figures from Table 2.1 by BECo estimates of annual usage in order to estimate the kW peak contribution of each end use on the BECo system. Table 2.3 performs the same computation for MECo energy usage estimates. Note that the two utilities present different categories of data for water and space heating. First, most of MECo water heating is controlled, while essentially all of BECo water heating is uncontrolled. Second, BECo presents space heating usage

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[8]As noted above, the long time periods over which the JUMP data is averaged may introduce some distortion.

[9]Narragansett average water heater usage is perhaps 20% higher than the average in the JUMP data, but this explains very little of the difference in peak contribution.

disaggregated between single- and multi-family dwellings, and between resistance heating and heat pumps, while MECo presents a single average value.[10] Since space heating energy usage varies widely with dwelling size and configuration, and since that usage would be estimated on a site-specific basis in any actual fuel-switching program, the values provided here are primarily illustrative.[11] Thus, we have not attempted to estimate a wider range of space heating values for MECo.

The estimates of energy usage for any particular type of appliance vary widely between Tables 2.1, 2.1.A, 2.2, and 2.3. This is particularly true for ranges, for which the average-usage estimates vary from 431 kWh to 1136 kWh.[12] This variability may reflect the differences in service territories, in housing stocks, and in the dates of the estimates. For the most part, however, the variation reflects real uncertainties about the electricity usage by individual appliances.

2.3 Time-of-Use Energy Splits

Our next task is to estimate the split of the electricity consumption by rating period. We used NEPOOL data to estimate the split for ranges, dryers, and water heaters. For space heating, we did not have comparable NEPOOL data and used simpler assumptions. We followed the general convention of the Massachusetts electric utilities and defined the peak period to run from 8 a.m. to 9 p.m. EST on weekdays, with all other hours being off-peak.[13]

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[10]We have estimated the MECo heat pump and resistance values from MECo's assumptions that heat pumps represent 5% of electric space-heating installations, and that a heat pump uses 70% as much energy as does resistance heating.

[11]In particular, properly designed new buildings may require very little space heating energy. The economics of gas space heating in these truly super-insulated buildings will tend not to be as favorable as in conventional buildings, since the cost of a boiler and heat-distribution system will be offset by smaller energy savings. In these buildings, water heating, rather than space heating, will be the major energy load.

[12]DOE (1980) estimates about 800 kWh for an electric range.

[13]Utility data on hourly loads is generally labelled by the time at the end of each interval. Thus, the 8am - 9pm on-peak period would correspond to hours ending 9am to 9pm. BECo has proposed a more complex definition of peak and off-peak hours, with different seasonal patterns, but this proposal has not yet been accepted by the DPU.

Tables 2.4 through 2.7 present NEPOOL hourly summer and winter weekday load shapes for ranges, dryers, controlled water heaters, and uncontrolled water heaters, respectively. Each table shows the split of energy usage between peak and off-peak hours, taking into account weekends and holidays, for summer, winter, and the spring/fall shoulder period.[14]

Table 2.7.A provides the monthly usage splits and on-peak/off-peak splits for the JUMP data. These results are essentially the same as the NEPOOL data.[15] We decided to continue using the NEPOOL data, since the differences are trivial.

The NEPOOL data we have seen provides only peak-day load shapes for space-heating and space-cooling loads, which they model as being weather-sensitive. We could not use that data for this analysis, which requires year-round data, and were forced to look elsewhere for space heating usage patterns.

We based our estimate of the distribution of space-heating usage across seasons on the distribution of heating degree-days. From ASHRAE data,[16] Boston has 3043 heating degree-days in December-February (the electric companies' winter period), out of a total of 5634 degree-days, or 54%. However, the electric heating load is more heavily weighted toward the winter months than would be implied by the distribution of heating degree-days. The balance point (the temperature at which heating is first required) for electrically-heated dwellings is well below the 65 degree base used in computing the heating degree-days. The lower balance point reduces the energy consumption in mild shoulder months by a larger fraction than it reduces the energy consumption in cold winter months. To reflect this relationship, we assumed that 65% of the heating energy is used in the winter months, with the other 35% consumed in the spring/fall months.[17]

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[14]We assume that the spring/fall load shapes are equivalent to an average of summer and winter load shapes.

[15]The JUMP on-peak period starts one hour later than the on-peak period we used in our analysis of NEPOOL data.

[16]Our immediate source was Anderson and Riordan (1976).

[17]BGC's data on weather-sensitive sendout by month is not particularly relevant to estimating the seasonal split of electric space-heating consumption, since electrically heated buildings tend to be better insulated (given the higher cost of electric heat and the recent vintage of most electrically-heated buildings) and thus to have lower balance points than gas-heated buildings.

We base the split of space-heating electricity consumption between peak and off-peak hours on the assumptions in MECo's September 15, 1989 filing for pre-approved contract cost recovery of its conservation programs. MECo assumes that 70% of the savings from its residential space-heating conservation program will be in the on-peak period. Small portions of the savings in this program are from lighting (8.7%) or water heating (14%) improvements. MECo expects the savings from its water heater conservation program to be 54% on-peak, and those from its low-income lighting program (Energy Fitness) to be 60% on-peak. Thus, of the 77.3% of the savings which result from space-heating improvements, 74% must be in the peak hours, to produce the 70% on-peak average. These percentages seem very high,[18] so we assumed that 65% of space-heating energy usage was in the peak hours.

2.4 Relative End-use Efficiency of Electric and Gas Equipment

Gas appliances generally use more energy at the end use point than do equivalent electric appliances.[19] The difference in efficiency results from such sources as inefficiencies in heat transfer from the gas flame to the working medium (e.g., the air in a furnace, the pot of a stove-top, or the water in a boiler or water heater), operating flue losses, and standby losses through the heat-exchange surfaces.

Table 2.8 presents comparable estimates for the efficiency of electric and gas-fired equipment for each of the residential end uses. For water heating and space heating, Table 2.8 lists both standard-efficiency and high-efficiency models. Where practical, both the gas efficiency and the electric efficiency are taken from the same source for comparability. Notes to Table 2.8 provide estimates from Arthur D. Little, Inc. (1988) which produce similar efficiency ratios. The standard efficiencies for water heaters and gas space heating equipment are taken from the recently enacted

[18]Less than half of all hours are in the on-peak period, and daylight hours will generally have lower heating loads than nighttime hours, due to higher ambient temperatures and solar gain. Significant temperature setbacks may occur during the middle of weekdays, in some homes which are unoccupied for most of the day. On the other hand, occupancy (which creates heat from people and appliances, decreasing load on the heating system) will tend to be higher on weekends and holidays, and nighttime temperature setbacks will also decrease off-peak usage.

[19]The most efficient gas units may use less than low-efficiency electric units, but this is not a representative comparison.

National Appliance Efficiency Standards (NAES).[20] The high-efficiency electric space-heating equipment is a heat-pump, at the heating season performance factor implied by BECo's estimates of average usage for resistance and heat-pump systems.[21]

The last column of Table 2.8 shows the ratio of gas use to electric use implied by the efficiencies presented in that table. In each case, gas requires more energy at the end use than does electricity, with the increment ranging from 8% for dryers to 96% for ranges.[22]

Tables 2.9 and 2.10 compute gas consumption, from the electric consumption values assumed for each of the electric utilities. Table 2.9 presents this computation for BECo assumptions, while Table 2.10 presents the comparable analysis for MECo. In each table, the first column presents the kWh usage of each electric end-use estimated by the utility.[23] The second column converts this

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[20]The efficiencies listed are the lowest allowed by law. Averages will be higher, even for routine applications. We are only interested in the ratio of gas efficiency to electric efficiency. The ratios we compute will be representative, so long as the percentage by which typical gas appliances exceed NAES standards is equal to the percentage by which electrical appliances exceed their NAES requirements.

[21]BECo estimates that heat pumps use 75% as much energy as do resistance systems, while MECo estimates a 70% ratio. Heat pumps are available with rated efficiencies higher than those assumed by the utilities, but the actual efficiency of heat pumps in Massachusetts' cold climate may be much lower than the rated efficiency. Since temperatures at peak are generally rather low, the peak use is not likely to be very much lower than in Tables 2.2 and 2.3, even for high-efficiency air-to-air heat pump systems.

[22]The notes to Table 2.8 give some comparisons to ADL data on electric and gas appliance efficiencies. The estimates used by Krause, et al., (1988) produce slightly higher ratios for ranges (2.1) and dryers (1.2). The Krause estimates for water heating imply a gas:electric use ratio of 2.34, but this estimate depends on an electric water heater usage (3753 kWh/year) which is much lower than the estimates of either BECo or MECo, and a gas usage (30 MMBTU/year) which is much higher than BGC's estimates, even for heating customers. The authors do not cite any source for their estimates, so we have not been able to evaluate the basis for these figures, and have not used them.

[23]We have restricted this analysis to the four residential end uses for which fuel-switching is most likely to be economical on a significant scale in Eastern Massachusetts. Space cooling and even refrigeration are potentially subject to switching, as well.

value to MMBTUs. The third column repeats the usage ratio from Table 2.8. The fourth column multiplies the electric usage in MMBTUs by the usage ratio, to derive the usage of the gas version of the appliance in MMBTUs. The last columns provide, for comparison, BGC's estimate of its customers' average usage for that end use.[24]

We have not attempted to formally reconcile the BGC average usage estimates with the average gas usages derived from BECo and MECo electric use estimates. Differences in housing type, housing age, dwelling size, equipment age,[25] and demographics can produce widely divergent average usage values. In addition, the end-use estimates for any of the three utilities are largely guesses, based on data which is often difficult to interpret.[26] Considering the numerous potential sources of differences, the estimates are surprisingly close. BGC's estimates of dryer usage are very high compared to the estimates of electric dryer usage, but this may result from the age of BGC's current dryer stock and demographic factors. We expected the difference between gas heating usage estimates based on electric-heating usage values and BGC's estimates of its current customers' average space-heating usage. The current gas-heated homes are generally older, less well insulated, and less weather-tight than the electric homes, and their heating systems are less efficient than those which would be installed in a conversion.

Our primary objective is to develop consistent estimates of electric and gas usage, so that some meaningful analyses of fuel switching can be performed. To that end, we have concentrated on deriving reasonable usage ratios, and have relied on the electric utility estimates of electric appliance usage to drive the gas

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[24]Note that we do not need breakdowns of the usage pattern of each gas appliance, since we have already estimated avoided costs for specific patterns. We assume that ranges and dryers are baseload uses, that space heating follows the BGC average weather-sensitive load, and that water heating follows the water-heating load shape we synthesized in DPU 88-67, Phase II (25% weather-sensitive, 75% baseload). More detailed analysis of gas end-use load shapes would be justified if fuel-switching appeared to be only marginally cost-effective.

[25]For example, most of the existing appliances on the BGC system probably have pilot lights, which will be rare for the efficient new equipment used in fuel switching programs.

[26]For example, BGC's data indicates that customers with some combination of appliances use much less gas than the sum of the usage by customers with each of the appliances separately. These counter-intuitive results may be due to data problems or due to correlation with other factors (e.g., housing type).

appliance usage estimates, ensuring consistency. To the extent that usage is understated, the economic advantages of switching from electric to gas will be understated, and vice versa. We have not been able to thoroughly evaluate the electric utility average-use estimates on which we have relied. However, for space-heating and water-heating conversions, site-specific estimates will generally be available from audits or engineering models, so the values presented herein are largely illustrative. For ranges and dryers, the electric utility estimates are towards the low end of the range of estimates we have seen, suggesting that they are more likely to be understated than overstated.

In addition to the distribution of loads over time, the analysis requires an estimate of the lifetime of each fuel-switching measure. A full analysis of this issue is complicated, since a typical conversion involves:

- adding conversion equipment (e.g., services, piping) with very long lives (40 years or more),
- adding gas appliances with shorter lives (10-25 years),
- avoiding replacing the existing electric equipment when it would have worn out (perhaps 5-10 years hence), and
- substituting the cost and replacement schedule for electric equipment with those for gas equipment (which may have different capital costs and different average lives).

To simplify this generic analysis, we used a single lifetime for all parts of each conversion. Table 2.11 presents the lifetime estimates for each appliance type from DOE (1980), and our selected life for analytical purposes.[27]

[27]Krause, et al., (1988) use 13 years for the lifetime of water heaters, and 18 years for dryers and ranges. They assume that the conversions (as opposed to the specific appliance) will last 30 years.

3. COST-EFFECTIVENESS OF RESIDENTIAL FUEL SWITCHING

3.1 System Cost Comparisons

Tables 3.1 through 3.4 calculate the total electric system avoided cost savings as a result of fuel-switching, the corresponding increase in BGC system costs, and the net system savings. Each table performs the comparison for all four end uses (sometimes with variants), for switching load from one of the electric utilities to BGC. The comparisons are performed using the avoided costs developed from the fuel and inflation forecasts used by the electric utility, and using the avoided costs developed from the fuel and inflation forecasts used by BGC.

Each of the Tables has three parts. Part A computes the total electricity savings as the sum of energy and capacity savings. Sections 1 and 2 of Part A of each table display the total energy reduction due to fuel switching each end use, the disaggregation of that total reduction by rating period, and the assumed contribution to summer and winter peak loads in kW. Section 3 of Part A of each table lists the measure life assumed, from Table 2.11. Sections 4 and 5 reproduce from Chernick and Espenhorst (1989), the present value of saving one kWh or one kW in that rating period, for the stated lifetime. Section 6 provides the product of each kWh or kW reduction, multiplied by the avoided cost for that type of reduction, and the sum of those values.

Part B of each of Tables 3.1 to 3.4 calculates the added gas cost which results from switching from electricity to gas.[28] The present value figures are from the BGC avoided-cost model, as presented in Chernick and Espenhorst (1989). Part C of each table summarizes the reduction in electric system costs and the increase in gas system costs, and computes the net utility system savings from conversion and the ratio of gas to electric system costs.

Depending on the electric utility involved and the fuel price projection used, switching residential electric end-uses to gas is worth about \$300-\$700 for each range, \$400-500 for each dryer, \$1,500-\$2,400 for uncontrolled water heating, \$1,000-\$1,400 for controlled water heating, and \$4900-\$8500 for a variety of space heating applications. The figures for space heating are very sensitive to the level of existing electric usage, and will vary widely from one application to another. The difference in dollar terms is very small, and results from different end-usage patterns and variability in electric avoided costs.

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[28]This calculation excludes customer-related costs (services and meters) and other installation costs.

3.2 Total Cost Comparisons

The results presented in Tables 3.1-3.4 do not represent complete cost-effectiveness analyses. Selecting one energy source over the other for a particular end use may result in several types of differential costs or savings. For the selection of gas over electricity, the added costs (or savings) might include some or all of the following:

- a gas line extension,
- addition of a gas service line,
- addition of gas distribution within the building,
- addition of a distribution system for hot water or air (for space heating, or for conversion of multi-family buildings from individual electric water heaters to a central gas-fired boiler),
- addition of a flue or vent (for space heating or water heating),
- reduction in the electric service line,
- reduction of internal wiring sizes,
- changes in maintenance costs,
- increased cost of end-use equipment,[29] and
- conversion costs (e.g., early replacement of appliances, repair of interior surfaces damaged in running gas or hot water lines).

These costs will be quite specific to each particular application. They will depend on whether the fuel-switching occurs in a new, rehabbed, or existing building, whether gas is already available in the building or on the street, the age of the electric equipment, the design of the building, and whether a flue already exists. The savings shown in Tables 3.1 to 3.4 must be compared

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[29]Many gas appliances are more expensive than corresponding electrical appliances. This is especially true for baseboard heating versus gas furnaces or boilers. The choice of the replacement equipment should reflect the lowest total social cost from the converted system: the lowest total cost will often require fairly efficient (and thus fairly expensive) equipment.

to the costs of performing the fuel conversion to determine whether the conversion is cost-effective.[30]

Krause, et al. (1988) provide estimates for the incremental cost of gas water heaters, dryers, or ranges, for situations in which existing electric appliances are near the end of their useful lives and will soon need to be replaced. Their conversion costs are thus greater than the incremental cost of choosing gas in new construction (where the wiring costs of the electric appliances are avoidable), and lower than the cost of early replacement of functioning electric appliances (where more of the gas appliance's cost must be included in the calculation). Krause et al. estimate that installation will cost about $186/appliance, assuming that the building already has gas service (and a flue for the water heater).[31] They also estimate incremental purchase costs of gas appliances over comparable electric appliances, of $130 for ranges, $40 for dryers, and $50 for water heaters, based on prices in the Montgomery Ward catalog. They thus estimate total conversion costs as $316 for ranges, $226 for dryers, and $236 for water heaters. For the ranges, Krause's conversion-cost estimate is between 50% and 100% the avoided system costs, depending on the base usage of the range. This suggests that conversion may be cost-effective for large households, but not for small ones. The conversion cost is about half of system savings for the dryers, and about 10-20% of the avoided system costs for water heaters.

Wisconsin Public Service Company (WPS) is more optimistic than Krause with respect to the costs of fuel-switching. WPS estimates $300 for a range (essentially the same as Krause), $100 for a dryer, and $50 for hot water (EWU, 1987). These may reflect incremental costs in new construction, where the costs of a larger service and of internal 220 V wiring are avoidable. Dryer and water-heater fuel-switching would be overwhelmingly cost-effective, given these costs.

We compared the appliance-cost differentials in Krause, et al., to prices in 1989 Sears catalogs. This source shows no price differential between common gas (30 gallon) and electric (40

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[30]In addition, externalities and non-price factors should be reflected in the decision, to the extent practical. Most environmental externalities and oil-import effects will further favor gas over electricity.

[31]These estimates appear to be based on water heater conversion costs in about 1987$. The cost of installation for the range might be higher than assumed by Krause, et al., since the appliance is typically further from the gas service line.

gallon) water heaters.[32] For any of a range of features, gas dryers cost $40 more than the corresponding electric dryers.[33] Ranges are much more difficult to compare, due to the variety of features available in one or both fuels: styling, waist-level broiler, under-oven storage, oven timer controls, and fancy burners (e.g., solid burners on electric ranges, thermostatic burners on gas ranges). Depending on how one defines equivalence between gas and electric ranges, the price differential might be as low as zero, or as high as $130. The Krause figures appear to be reasonable for dryers, but they overstate water heater cost differentials and appear rather high for ranges.

If the electric appliances are not approaching the point at which they would require routine replacement, a larger fraction of the cost of the gas appliance must be included in the net cost of the conversion. This consideration may not be critical for economics of the water heater, but may be important for ranges and dryers.

We have found several sources which provide fuel-switching costs for space heating, either for new installations or for actual conversions. We have information on space-heating capital costs in new construction from two New England utilities. In a study for Northeast Utilities, Fleming (1986) estimates an incremental cost of gas space-heating over baseboard resistance electric space-heating in a new single-family home as $1,700 for a forced-air system and $4,500 for a hydronic heating system.[34] MECo's 1988 EFSC filing (Volume I, p. 62) reports space-heating capital costs of $5,220 for gas, $5,000 for a heat pump, and $1,500 for resistance.[35] MECo's data thus suggests an increment for gas over resistance of $3,700 which is consistent with Fleming's estimates for hydronic systems.

We also have data on retrofit or conversion costs from several sources. CECARF (1989) reports than standard fossil heating

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[32]Electric water heaters are generally sized larger than gas water heaters, to compensate for slower heat recovery.

[33]This comparison is facilitated by Sears' practice of offering gas and electric versions of dryer models, which appear to be identical down to the catalog numbering system.

[34]These figures are for annual fuel use efficiencies (AFUEs) of 78%-80%, or essentially minimum efficiencies under the NAES. Fleming estimates a cost of about $1200 extra for a condensing furnace or boiler at 90%-93% AFUE.

[35]MECo also suggests that resistance faces code-related differential costs of about $1,200, but the discussion of this point is unclear.

equipment (installed) costs $1,700 for furnaces and $2,500 for boilers, with an additional $700 for high-efficiency equipment. The furnace costs, plus the cost of gas service lines, would be reasonable estimates of the costs of conversion in homes having ductwork for heat pumps or central air-conditioning.

WPS provides estimates of $2,500 for conversion from electric to standard-efficiency space heating, or $4,000 for high-efficiency space heating, both in a commercial application saving 14,000 kWh/year (EWU, 1987). Lipsey (1989) reports an incremental cost of $1,600 for converting from heat-pump to integrated gas space-heating, where conversion of domestic water-heating from electric to gas was already planned.

The most comprehensive survey of actual conversion costs we have found is an unpublished study by Vermont Energy Investment Corporation (VEIC). The VEIC results are summarized in Table 3.5. Roughly speaking, conversion costs are $3,000-$6,400 for single-family homes and about $2,500 for multi-family buildings.[36] Since these homes were in Vermont, the energy usage is considerably higher than for Massachusetts electrically-heated homes, at about 11,000-24,000 kWh for the single-family homes and 5,000 kWh for the multi-family homes.[37]

Virtually all of the space-heating conversion cost estimates are considerably smaller than the system savings from conversion. Even at the average space heating usage assumed by MECo, and at the low fuel prices projected by NEEI, the system savings for resistance heating are approximately $6,300. Assuming that one half of MECo's electric heating customers have single-family homes and that the other half have multi-family buildings,[38] and that conversions average $2,500 for multi-family and $5,000 for single family (or $3,750 overall), the net benefit of conversion is about $2,500/unit. Depending on how many of the conversions included water heating, and how many of the water heaters were controlled, the water heating system savings would add another $500 to $2,000

[36] One of the multi-family conversions involved a cogeneration facility.

[37] Most of the single-family home values include water-heating savings. For the multi-family value, we have used the building with no water-heating conversion. Three of the single-family homes used wood along with the electric heat; including the wood use at 3500 BTU/cord produces equivalent electric energy use of 17,000 - 24,000 kWh.

[38] Approximately 75% of BECo's heating customers are in multi-family buildings.

in savings.[39] Range and dryer conversions would further increase these savings. Thus, the cost of fuel switching appears to be lower than the savings, for a variety of space-heating applications, even with worst-case avoided-cost assumptions.

While site-specific analyses should be required before investment decisions are made, especially for heating conversions, multi-family applications, and where services or line extensions are required, the results in this section strongly suggest that residential fuel-switching will be cost-effective in most situations. Typical Boston Gas service additions cost about $1,000 for single-family homes and $1,200 for multi-family buildings. Where extension of gas mains is required, the cost for a typical single-family project, to serve 16 houses, is about $14,000 or $900 per house. A typical main extension to serve 50 units in multi-family housing costs $37,000 or $740 per apartment. Even under the least favorable avoided-cost projections, typical service and main investments are smaller than the benefits of typical conversions.

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[39] The $500 value assumes that only half the units (e.g., the single-family homes) convert their water heating, and that all of the water heaters were controlled. The $2,000 value assumes 100% water-heating conversion and no control.

4. COMMERCIAL CHILLING USAGE PATTERNS AND NON-FUEL COSTS

Compared to residential appliances, commercial chilling loads and the costs of chilling equipment are more variable across applications, in largely predictable ways. While the concept of a typical range, or dryer, or water heater is very useful, chilling installations are more appropriately addressed on an individual basis.

Chilling loads to be met by any particular installation may vary by over an order of magnitude, from under 100 tons to over 2000 tons. Some buildings (such as offices) operate only 10-12 hours weekdays, and therefore may have virtually all of their loads in the peak rating periods and have low load factors. Other buildings, such as hospitals and hotels, operate continuously, and have much less of their loads in the peak hours and much higher load factors. All other things being equal, large buildings, with large internal heat gains (such as computer facilities) and large solar gains, and with low needs for external air, will require chilling over a larger portion of the year than will small buildings with low internal and solar gains, and/or which use large amounts of outside air (e.g., hospitals or laboratories). Some chiller applications involve a small unit added to an existing chiller facility (to accommodate growth or replace a retired unit), while others involve an entirely new facility or a total replacement of existing equipment. Additionally, gas chilling equipment can be used with electric equipment in a peak-shaving role, in which the gas chiller operates during the on-peak hours for electric energy, or during the hours in which the building might establish a monthly billing demand peak, and the electric chiller carries most of the off-peak load (and any on-peak load in excess of the gas unit's capacity).

The relative costs of gas and electric chilling systems vary in many ways with the time pattern of usage. Electric energy is particularly expensive in daily peak periods. Coincident peak electric loads are very expensive to serve. Gas becomes relatively expensive for cooling loads which overlap the heating season. Gas chilling equipment experiences little or no efficiency penalty at partial load, compared to electric. The size of the chilling system is also important, since gas equipment has a larger capital cost (in $/ton) for small capacities than for large capacities.

Auxiliary services which may be performed by a gas chiller vary with the site and the situation. Absorption chillers can be set up to operate as heaters, eliminating the cost and space required for a separate boiler. This is a valuable benefit where space is at a premium, and where hydronic heating is planned, already exists, or is feasible. Engine-driven chillers produce exhaust at a temperature high enough to generate steam or very hot water as an essentially free by-product, greatly reducing the cost of chiller operation where such heat is useful during the cooling season (as in hospitals and restaurants).

Despite these differences, it is possible to make some generalizations regarding the load and cost characteristics of commercial chilling. First, we have load shape data from NEPOOL and BECo. Table 4.1 displays the total energy consumption and total peak load contribution for cooling (and heating) for offices and stores (the only commercial loads NEPOOL models), from the NEPOOL 1985 model documentation.[40] Table 4.1 also computes the load factor and kW/MWH peak factor for each building type and end use. The chilling load factors are much lower (and the peak factors are therefore much higher) than is true for the residential end uses in Tables 2.1 and 2.1.A: commercial chilling uses 1.4-1.9 kW of coincident summer peak for each MWH of annual consumption, compared to 0.11-0.16 summer kW/MWH for the residential end uses. The commercial chilling load factors are 5.9% - 8.2%.

BECo does not directly provide an estimate of commercial cooling load factor. However, BECo's 1988 EFSC forecast documentation does provide information from which this parameter can be derived. BECo reports that commercial baseload (non-heating, non-cooling) sales in 1987 were 5394 GWH, of which 7% was in July, 3.44% of the July use was in the peak day, and 5% of the peak day use was in the peak hour, which implies that the commercial baseload contribution to peak was 649 MW. The total commercial-class contribution to peak is reported to be 1679 MW, so commercial cooling must have contributed 1030 MW. Since BECo gives a 1987 commercial cooling estimate of 884 GWH, this implies a kW/MWH ratio of 1.165, or a load factor of 9.8%. This is a somewhat better load factor than is used by the NEPOOL model, but it may be consistent with NEPOOL's estimates, considering that BECo's load must include large amounts of high load-factor cooling at hospitals, computer facilities, hotels, and educational buildings, none of which are explicitly modelled by NEPOOL. BECo's estimate is also consistent with the estimate by Madison Gas and Electric (MG&E) of 1.15 kW/MWH or a load factor of 9.9% (EWU, 1987).

In addition to the BECo and NEPOOL data, we have reviewed several studies of gas and electric chilling options (Kunkle and Darrow, 1987; Neumann, et al., 1989; Carver, 1989; AGA, 1988; AGA, 1989; EWU, 1987; and several analyses of specific buildings). Our sources generally agree that chilling load factors are in the range of 7-22%, with office buildings at the low end and with university buildings and hospitals at the high end. On-peak energy shares a range which extends from over 95% for some office buildings down to about 50% for hospitals.

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[40]We include heating here, because the choice of chilling energy also often influences the choice of heating energy.

Table 4.2 summarizes some of the buildings for which we were able to review data on chiller fuel choice. For each building, the table lists information on the building, the reason for chiller choice (e.g., new construction, routine replacement, early replacement, additional space or cooling load added, or the desire to reduce operating costs) in the original study, the characteristics of the candidate electric and gas chillers, load characteristics, and cost data. The table allows for a listing of a second alternative system, which may be a second all-gas technology, or may be a hybrid gas/electric solution. Some buildings are listed more than once, because we have data on more than two alternatives to the same electric base case, or because the available analyses use different base cases.

On the cost side, the studies we have reviewed are generally in agreement on the coefficients of performance (COPs) of various types of chillers:

- Electric centrifugal chiller COPs are in the range of 4.0-6.0 (depending on the quality of the chiller and its duty cycle, among other things) for 0.6-0.8 kW/Ton,[41]

- Double-effect absorption gas chiller COPs are about 1.0, or about 12 kBTU/Ton-hour.

- Engine-driven gas chiller COPs are about 1.4-2, or about 6-9 kBTU/Ton-hour.

In general, gas-fired absorption chiller systems tend to be about $100-$400/Ton more expensive than centrifugal electric systems, including additional cooling tower capacity.[42] The additional cooling tower capacity is required by the lower end-use efficiency of gas chillers, which therefore produce more waste heat

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[41]Chiller efficiency may also vary with the working fluid used. Centrifugal chillers generally use chlorofluorocarbons (CFCs), which are important greenhouse gases and are also the major threat to the ozone layer. Absorption chillers do not use CFCs. The chilling unit "ton" is equivalent to 12,000 BTU/hour (the rate at which heat is absorbed by ice melting at the rate of one ton/day).

[42]For example, MG&E assumes that fuel-switching to reduce peak load by 317 kW, implying about 500 T of chilling, would cost about $59,000 ($120/T) in new construction, and about 10% more for retrofit (EWU, 1987). These figures can be higher if large changes in the heating system, and especially piping systems, are included in the choice of a gas chiller. Those additional costs are properly part of the heating system cost, and will only be incurred if justified by the heating-cost savings.

than electric chillers. Engine-driven gas chillers tend to run \$200-\$500/Ton more than electric chillers.[43] Gas chillers are also usually assumed to be somewhat more expensive to operate and maintain than electric chillers. Some of the additional costs result from the higher waste-heat rejection rates, which will require more make-up water, and may require more pumping energy than electric units.[44] These cost disadvantages may be partially balanced by the fact that gas chillers (especially absorption units) are quieter than electric units, and that the absorption units require significantly less space than do the electric units.

The average lives of chilling conversions may well exceed 20 years, but we will use 20 years as a conservative (i.e., pessimistic) value, for the purposes of this fuel-switching analysis. This is the value used by MG&E (EWU, 1987), for commercial chilling conversions in both new construction and retrofit situations.

[43]The most expensive engine-driven chillers use heat recovery to drive additional absorption chilling, and thus have COPs at the high end of the range.

[44]Resizing pumps and piping can reduce the electric energy penalty of the cooling tower.

5. COST-EFFECTIVENESS OF FUEL SWITCHING FOR COMMERCIAL CHILLING

This cost-effectiveness analysis for commercial chilling is patterned after that for the residential end uses in Section 3. The avoided costs come from the same source as for the residential analysis, although most of the gas is priced at summer baseload costs, which were not used in the residential analysis. Any gas chilling load in the December-March period is treated as winter baseload, which somewhat overstates its cost. Chilling load in the winter months will be inversely correlated with heating load, and will contribute less to peak-season costs (for capacity, capitalized energy, and commodity costs) than will winter baseload.

Another complication of this analysis is that the chilling systems may have differences in maintenance costs.[45] To convert the extra maintenance costs of gas chillers to a present value, we multiply the first-year cost by a factor of 11.5, which is the present value of a dollar per year for 20 years, deflated at a 6% real discount rate. The 6% real discount rate is equivalent to a 11.3% nominal discount rate and a 5% inflation rate.[46]

For illustrative purposes, we have analyzed the cost-effectiveness of fuel-switching for chilling at two commercial chilling installations. We selected these applications to represent a range of important parameters.

The first building (Building 1 in Table 4.2), is a large office building which operates only during normal business hours on weekdays. This is a hypothetical building modelled by Kunkle and Darrow, with a load factor comparable to that which NEPOOL assumes for offices. We examine both peak-shaving and full-gas chilling

[45]Such differences may exist for residential systems, especially for heating systems, but we did not model them.

[46]The use of different discount rate for the various utilities make the choice of an exact value for this parameter somewhat difficult. In the longer term, the DPU should probably specify a common social discount rate to be used by each of the utilities in assessing the social cost-effectiveness of conservation and fuel-switching options. Fortunately, this present-value factor is not very sensitive to the nominal discount rate (it is only 12.5 at a 5% real rate, for example), and its magnitude is not crucial to these analyses described below.

options,[47] and a gas space and water heating case. In all cases, the gas chiller is an absorption unit.

The results for the office building cases are shown in Tables 5.1 through 5.4, for the four fuel cost comparisons. Depending on the cost case, the system cost savings of the peak shaving option is $330,000-$460,000 with just the chilling function, and $2,000,000-$3,000,000 with both chilling and heating. For full gas chilling, the system cost savings are $800,000-$1,200,000 for chilling alone, and $2,500,000-$3,700,000 for combined heating and cooling.

These savings swamp the incremental costs of gas chilling and/or heating equipment. Kunkle and Darrow (1987) estimate the incremental cost of the conversions as ranging from $58,000 for the chiller-only peaking case, to $210,000 for the full-cooling-plus-heating case. The conversions would be highly cost-effective, even if these cost estimates are quite optimistic. The results are also insensitive to reasonable changes in load shape (<u>e.g.</u>, if a small part of the electric cooling load were met by off-peak energy, or if the load factor were somewhat higher).

The second building (Building #6 in Table 4.2) is a hospital building, with continuous use and high water-heating requirements. The cooling load to be added is on the order of 120-150 tons, and the chiller will operate essentially full-time during the chilling season (only 47% of kWh in the on-peak period) at a very high load factor (22%). We compare electric chillers to three gas-fired alternatives: an engine chiller alone, an engine chiller with heat recovery for water heating, and an absorption chiller.

The results for the hospital cases are shown in Tables 5.5 through 5.8, for the four fuel-cost comparisons. Depending on the cost assumptions, the system cost savings of the engine chiller alone are $90,000-$160,000, while with credit for the water-heating energy, the savings rise to $150,000-$230,000. The savings for the absorption chiller are $30,000-$90,000.

Even at a fairly high incremental cost, such as $500/ton or $75,000 total, the free-standing engine is cost-effective, and the engine with heat-recovery is extremely cost-effective.

The 120 ton absorption chiller would probably cost $35,000-$40,000 more than the electric chiller (based on the estimate for Building #5 in Table 4.2), which is within the range of system

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[47] In these cases, the gas chiller is not changing the costs of heating. This situation would arise if the building used the same heating fuel (either electric or gas heat), regardless of chiller fuel. If the heating fuel were gas, the chiller would avoid the need for a boiler.

savings. Fuel-switching design teams will probably find that small, high load-factor applications without waste-heat recovery opportunities will be among the most challenging design situations for cost-effective gas chilling systems.[48]

In any specific application, care should be taken to select the least-cost option, including high-efficiency electric chilling; gas co-generation driving absorption chilling; steam-driven chilling; direct gas firing of absorption, engine, and desiccant chillers (at a range of efficiencies, as applicable); hybrid gas and electric systems; water-heating heat-recovery options; and combined cooling and heating equipment. However, it appears from our initial results that gas chilling will be preferable to electric chilling in most new construction and routine replacements, unless the cost of the gas service extension is very high. In addition, the system cost savings are so large that early replacements may be cost-effective in many situations.

[48]The BECo avoided costs appear to be understated (See Chernick and Espenhorst, 1989).

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TABLE 2.1: NEPOOL DATA ON RESIDENTIAL END-USE LOAD FACTORS

APPLIANCE	AVERAGE USE (kWH)	NUMBER OF APPLIANCES (1000s)	PEAK CONTRIBUTION (MW) DEC 7 P.M.	AUG 1 P.M.	LOAD FACTOR DEC	AUG	KW/ MWH DEC	AUG
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
RANGE	693	1,262	234.4	97.2	42.6%	102.7%	0.268	0.111
DRYER	663	1,469	137.1	150.8	81.1%	73.7%	0.141	0.155
WATER HEATER								
CONTROLLED	4,562	157	37.4	8.2	218.6%	997.1%	0.052	0.011
UNCONTROLLED	4,147	106	65.1	61.4	77.1%	81.7%	0.148	0.140
HEAT PUMP HEATING	2,923	42.6	63.8	--	22.3%	--	0.512	--
RESISTANCE HEATING	5,066	200	422.4	--	27.4%	--	0.417	--

NOTES: [1], [2], [3], [4]: NEPOOL 1985 FORECAST DOCUMENTATION FOR MASSACHUSETTS IN 1990.
[5]: [1] x [2]/([3] x 8760).
[6]: [1] x [2]/([4] x 8760).
[7]: 1000 x [3]/([1] x [2]).
[8]: 1000 x [4]/([1] x [2]).

TABLE 2.1.A: JUMP LOAD DATA, AVERAGE DAYS

APPLIANCE	AVERAGE USE (kWH)	PEAK CONTRIBUTION (kW) WINTER 7 P.M.	SUMMER 1 P.M.	LOAD FACTOR WINTER	SUMMER	KW/MWH WINTER	SUMMER
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
RANGE	482.6	0.155	0.035	35.5%	157.4%	0.321	0.073
DRYER	894.47	0.15	0.13	68.1%	78.5%	0.168	0.145
WATER HEATER UNCONTROLLED	3551.96	0.595	0.31	68.1%	130.8%	0.168	0.087

NOTES: [1], [2], [3]: MASSACHUSETTS JOINT UTILITY END-USE MONITORING PROJECT, FEBRUARY, 1989,
SUMMER: MAY THROUGH SEPTEMBER, WINTER: OCTOBER THROUGH FEBRUARY.
[4]: [1] / ([2] x 8760).
[5]: [1] / ([3] x 8760).
[6]: 1000 x [2] / [1].
[7]: 1000 x [3] / [1].

TABLE 2.1.B: JUMP DATA, APPLIANCE PEAK

APPLIANCE	AVERAGE USE (kWH)	CONTRIBUTION (kW) DEC 7 P.M.	AUG 1 P.M.	LOAD FACTOR DEC	AUG	KW/MWH DEC	AUG
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
RANGE	482.6	0.6	0.05	9.2%	110.2%	1.243	0.104
DRYER	894.47	0.22	0.36	46.4%	28.4%	0.246	0.402
WATER HEATER UNCONTROLLED	3551.96	0.6	0.6	67.6%	67.6%	0.169	0.169

NOTES: [1]: MASSACHUSETTS JOINT UTILITY END-USE MONITORING PROJECT, FEBRUARY, 1989.
[2], [3]: MASSACHUSETTS JOINT UTILITY END-USE MONITORING PROJECT, FEBRUARY, 1989, FIG I-3.
[4]: [1] / ([2] x 8760).
[5]: [1] / ([3] x 8760).
[6]: 1000 x [2] / [1].
[7]: 1000 x [3] / [1].

TABLE 2.2 PEAK CONTRIBUTIONS BY APPLIANCES, BECo ESTIMATES

APPLIANCE	AVERAGE ANNUAL USAGE (kWH)	KW/MWH DEC	KW/MWH AUG	KW PEAK CONTRIBUTION DEC	KW PEAK CONTRIBUTION AUG
	[1]	[2]	[2]	[3]	[3]
RANGE	1,123	0.27	0.11	0.30	0.12
DRYER	949	0.14	0.15	0.13	0.15
WATER HEATER [4]					
CONTROLLED	--				
UNCONTROLLED	4,259	0.15	0.14	0.63	0.59
HEAT PUMP HEATING					
SINGLE-FAMILY	9,236	0.51		4.73	
MULTI-FAMILY	2,336	0.51		1.20	
RESISTANCE HEATING					
SINGLE-FAMILY	12,315	0.42		5.13	
MULTI-FAMILY	3,114	0.42		1.30	

NOTES:

[1]: BECo 1988 EFSC FORECAST, DATA FOR 1990.
[2]: TABLE 2.1.
[3]: [1] x [2]/1000.
[4]: THE NARRAGANSETT LOAD CONTROL STUDY REPORTS PEAK CONTRIBUTION OF 1.8 kW WINTER OF 1.2 kW SUMMER FOR UNCONTROLLED WATER HEATERS.

TABLE 2.3: PEAK CONTRIBUTIONS BY APPLIANCES, MECo ESTIMATES

APPLIANCE	AVERAGE ANNUAL USAGE (kWH)	KW/MWH DEC	KW/MWH AUG	KW PEAK CONTRIBUTION DEC	KW PEAK CONTRIBUTION AUG
	[1]	[2]	[2]	[3]	[3]
RANGE	431	0.27	0.11	0.12	0.05
DRYER	823	0.14	0.15	0.12	0.13
WATER HEATER [4]					
CONTROLLED	4,978	0.05	0.01	0.26	0.06
UNCONTROLLED	4,555	0.15	0.14	0.67	0.64
RESISTANCE HEATING	7,197	0.42		3.00	
HEAT PUMP HEATING	5,038	0.51		2.58	

NOTES:

[1]: NEES 1988 EFSC FILING, HEAT PUMP AND RESISTANCE HEATING DERIVED FROM 7088 AVERAGE, SEE TEXT.

[2]: TABLE 2.1.

[3]: [1] x [2]/1000.

[4]: THE NARRAGANSETT LOAD CONTROL STUDY REPORTS PEAK CONTRIBUTIONS OF 1.8 kW WINTER AND 0.9 kW SUMMER WITHOUT CONTROL, AND 1.2 kW WINTER AND 0.65 kW SUMMER WITH CONTROL.

TABLE 2.4: ELECTRICITY CONSUMPTION FOR RANGE USE BY RATING PERIOD

RANGE, AUGUST

	MON	TUFR	SAT	SUN
1 AM	10,419	10,419	9,551	9,551
2 AM	7,814	7,814	6,946	6,946
3 AM	7,814	7,814	6,946	6,946
4 AM	10,419	10,419	9,551	9,551
5 AM	13,024	13,024	11,287	12,156
6 AM	31,258	31,258	23,443	23,443
7 AM	63,384	63,384	38,204	39,072
8 AM	91,168	91,168	60,779	63,384
9 AM	63,384	63,384	84,222	86,827
10 AM	56,437	56,437	92,036	110,270
11 AM	63,384	63,384	68,593	134,582
12 PM	83,354	83,354	76,408	158,025
1 PM	79,881	79,881	84,222	142,396
2 PM	78,144	78,144	80,749	110,270
3 PM	72,935	72,935	79,881	103,324
4 PM	118,953	118,953	122,426	125,899
5 PM	243,984	243,984	223,145	190,151
6 PM	263,085	263,085	240,510	197,097
7 PM	157,157	157,157	143,264	204,911
8 PM	75,539	75,539	68,593	110,270
9 PM	33,862	33,862	31,258	79,012
10 PM	18,234	18,234	17,365	39,072
11 PM	18,234	18,234	16,497	17,365
12 MIDNIGHT	13,024	13,024	11,287	12,156
peak:9-9 [1]	1,390,099	1,390,099		
off-peak [2]	284,792	284,792	1,607,163	1,992,676
Total [3]	1,674,891	1,674,891	1,607,163	1,992,676
%peak	83.0%	83.0%		
% off-peak	17.0%	17.0%		

RANGE, DECEMBER

	MON	TUFR	SAT	SUN
1 AM	13,024	13,024	11,287	12,156
2 AM	8,683	8,683	7,814	8,683
3 AM	8,683	8,683	7,814	8,683
4 AM	13,024	13,024	11,287	12,156
5 AM	15,629	15,629	13,892	15,629
6 AM	38,204	38,204	26,048	31,258
7 AM	77,276	77,276	44,282	51,228
8 AM	112,007	112,007	70,330	81,617
9 AM	77,276	77,276	98,114	112,007
10 AM	69,462	69,462	106,797	142,396
11 AM	78,144	78,144	79,881	172,785
12 PM	102,456	102,456	88,563	204,043
1 PM	98,114	98,114	98,114	183,205
2 PM	96,378	96,378	93,773	142,396
3 PM	88,563	88,563	92,036	132,845
4 PM	146,737	146,737	142,396	163,235
5 PM	300,421	300,421	259,612	243,984
6 PM	323,864	323,864	278,714	254,403
7 PM	192,756	192,756	166,708	264,822
8 PM	92,905	92,905	80,749	142,396
9 PM	41,677	41,677	35,599	101,587
10 PM	23,443	23,443	19,970	51,228
11 PM	22,575	22,575	19,102	22,575
12 MIDNIGHT	15,629	15,629	13,892	15,629
	1,708,753	1,708,753		
	348,177	348,177	1,866,774	2,570,946
	2,056,930	2,056,930	1,866,774	2,570,946
	83.1%	83.1%		
	16.9%	16.9%		

NUMBER OF DAYS					
IN 4 MOS [4]	17	69	18	20	
peak:9-9	23631683	95916831	0	0	119548514
off-peak	4841464	19650648	28928934	39853520	93274566

NUMBER OF DAYS						GRAND
IN 3 MOS [5]	14	49	13	14		TOTAL
peak:9-9	23922542	83728897	0	0	107651439	227199953
off-peak	4874478	17060673	24268062	35993244	82196457	175471023
						402670976

SEASONAL SUMMARY

	SUMMER	SPR/FALL [6]	WINTER	TOTAL
PEAK	119548514	164427354	107651439	391627306
OFF-PEAK	93274566	126793651	82196457	302264674
				693891981 GRAND TOTAL

summer	
peak:9-9 [7]	17.2%
off-peak [8]	13.4%
winter	
peak:9-9 [9]	15.5%
off-peak [10]	11.8%
Spring/fall	
peak:9-9 [11]	23.7%
off-peak [12]	18.3%

NOTES:

[1]: PEAK HOURS, HOURS ENDING 9 a.m TO 9 p.m. EST WEEKDAYS, OR HOURS ENDING 9 a.m. TO 9 p.m.
[2]: OFF-PEAK HOURS, ALL OTHER HOURS.
[3]: [1] + [2].
[4]: APPROXIMATE NUMBER OF EACH TYPE OF DAY IN 4 MONTH SUMMER.
[5]: APPROXIMATE NUMBER OF EACH TYPE OF DAY IN 3 MONTH WINTER.
[6]: SPRING/FALL CALCULATED AS WEIGHTED AVERAGE OF SUMMER AND WINTER,
S/F= 5/2 * (W/3 + S/4).
[7]: SUMMER PEAK HOURS / GRAND TOTAL.
[8]: SUMMER OFF-PEAK HOURS / GRAND TOTAL.
[9]: WINTER PEAK HOURS / GRAND TOTAL.
[10]: WINTER OFF-PEAK HOURS / GRAND TOTAL.
[11]: SPRING/FALL PEAK HOURS / GRAND TOTAL.
[12]: SPRING/FALL OFF-PEAK HOURS / GRAND TOTAL.

TABLE 2.5: ELECTRICITY CONSUMPTION OF CLOTHES DRYERS BY RATING PERIODS

DRYER, AUGUST

	MON	TUFR	SAT	SUN
1 AM	51,089	33,875	33,875	17,934
2 AM	35,868	23,912	23,912	11,956
3 AM	29,890	19,927	19,927	9,963
4 AM	25,905	17,934	17,934	7,971
5 AM	23,912	15,941	15,941	7,971
6 AM	23,912	15,941	15,941	7,971
7 AM	29,890	19,927	19,927	9,963
8 AM	33,875	21,919	21,919	11,956
9 AM	87,677	57,787	57,787	29,890
10 AM	101,625	65,758	67,750	33,875
11 AM	109,596	71,736	73,728	35,868
12 NOON	115,574	75,721	77,714	37,860
1 PM	101,625	65,758	67,750	33,875
2 PM	79,706	51,809	53,802	25,905
3 PM	65,758	41,846	43,838	21,919
4 PM	57,787	37,860	37,860	19,927
5 PM	51,809	33,875	33,875	17,934
6 PM	43,838	27,897	29,890	13,949
7 PM	35,868	21,919	23,912	11,956
8 PM	29,890	19,927	19,927	9,963
9 PM	57,787	37,860	37,860	19,927
10 PM	73,728	47,824	47,824	23,912
11 PM	65,758	41,846	43,838	21,919
12 MIDNIGHT	57,787	37,860	37,860	19,927
peak:9-9 [1]	938,540	609,753		
off-peak [2]	451,614	296,906	924,591	464,291
Total [3]	1,390,154	906,659	924,591	464,291
%peak	67.5%	67.3%		
% off-peak	32.5%	32.7%		

DRYER, DECEMBER

	MON	TUFR	SAT	SUN
1 AM	47,824	35,868	39,853	25,905
2 AM	35,868	27,897	29,890	19,927
3 AM	27,897	19,927	21,919	15,941
4 AM	23,912	17,934	19,927	13,949
5 AM	19,927	15,941	17,934	11,956
6 AM	23,912	17,934	19,927	13,949
7 AM	31,882	23,912	25,905	17,934
8 AM	59,780	43,838	47,824	31,882
9 AM	71,736	53,802	59,780	39,853
10 AM	79,706	59,780	65,758	43,838
11 AM	111,589	83,691	91,662	61,772
12 PM	135,500	101,625	111,589	75,721
1 PM	111,589	83,691	91,662	61,772
2 PM	95,647	71,736	77,714	53,802
3 PM	71,736	53,802	59,780	39,853
4 PM	67,750	51,809	55,794	37,860
5 PM	67,750	49,816	55,794	37,860
6 PM	67,750	49,816	55,794	37,860
7 PM	79,706	59,780	65,758	43,838
8 PM	103,618	77,741	85,684	57,787
9 PM	79,706	59,780	65,758	43,838
10 PM	71,736	53,802	59,780	39,853
11 PM	63,765	47,824	51,809	35,868
12 MIDNIGHT	55,794	41,846	45,831	31,882
peak:9-9	1,143,783	856,869		
off-peak	462,297	346,723	1,323,126	894,700
Total	1,606,080	1,203,592	1,323,126	894,700
%peak	71.2%	71.2%		
% off-peak	28.8%	28.8%		

NUMBER OF DAYS IN 4 MOS [4]	17	69	18	20		NUMBER OF DAYS IN 3 MOS [5]	14	49	13	14	TOTAL	GRAND TOTAL
peak:9-9	15955180	42072957	0	0	58028137	peak:9-9	16012962	41986581	0	0	57999543	116027680
off-peak	7677438	20486514	16642638	9285820	54092410	off-peak	6472158	16989427	17200638	12525800	53188023	107280433
												223308113

summer	
peak:9-9 [7]	15.0%
off-peak [8]	14.0%
winter	
peak:9-9 [9]	15.0%
off-peak [10]	13.8%
Spring/fall	
peak:9-9 [11]	21.9%
off-peak [12]	20.2%

SEASONAL SUMMARY

SUMMER	SPR/FALL [6]	WINTER	TOTAL	
58028137	84600538	57999543	200628218	
54092410	78131109	53188023	185411541	
			386039759	GRAND TOTAL

NOTES:

[1]: PEAK HOURS, HOURS ENDING 9 a.m TO 9 p.m. EST WEEKDAYS, OR HOURS ENDING 9 a.m. TO 9 p.m.
[2]: OFF-PEAK HOURS, ALL OTHER HOURS.
[3]: [1] + [2].
[4]: APPROXIMATE NUMBER OF EACH TYPE OF DAY IN 4 MONTH SUMMER.
[5]: APPROXIMATE NUMBER OF EACH TYPE OF DAY IN 3 MONTH WINTER.
[6]: SPRING/FALL CALCULATED AS WEIGHTED AVERAGE OF SUMMER AND WINTER,
S/F= 5/2 * (W/3 + S/4).
[7]: SUMMER PEAK HOURS / GRAND TOTAL.
[8]: SUMMER OFF-PEAK HOURS / GRAND TOTAL.
[9]: WINTER PEAK HOURS / GRAND TOTAL.
[10]: WINTER OFF-PEAK HOURS / GRAND TOTAL.
[11]: SPRING/FALL PEAK HOURS / GRAND TOTAL.
[12]: SPRING/FALL OFF-PEAK HOURS / GRAND TOTAL.

TABLE 2.6: ELECTRICITY CONSUMPTION OF CONTROLLED WATER HEATERS BY RATING PERIOD

WATER HEATER, CONTROLLED, AUGUST (kWH)

	MON	TUFR	SAT	SUN
1 AM	174,278	155,971	151,578	133,271
2 AM	144,987	129,610	126,681	111,303
3 AM	101,784	90,800	88,603	77,618
4 AM	57,848	51,990	50,526	44,668
5 AM	54,919	49,061	48,329	42,471
6 AM	72,494	65,171	62,974	55,652
7 AM	116,429	103,981	101,052	88,603
8 AM	159,633	142,791	139,129	122,287
9 AM	203,568	181,600	177,207	155,239
10 AM	229,197	205,033	199,907	175,010
11 AM	220,410	196,978	191,852	168,420
12 NOON	188,923	168,420	164,026	144,255
1 PM	174,278	155,971	151,578	133,271
2 PM	144,987	129,610	126,681	111,303
3 PM	130,342	116,429	113,500	99,587
4 PM	8,787	8,055	7,323	6,590
5 PM	2,929	2,929	2,929	2,197
6 PM	17,574	15,377	15,377	13,181
7 PM	23,432	20,503	20,503	17,574
8 PM	23,432	20,503	20,503	17,574
9 PM	29,290	25,629	24,897	21,968
10 PM	35,148	30,755	30,755	26,361
11 PM	377,846	337,572	328,784	288,510
12 MIDNIGHT	493,543	440,820	429,836	377,114
peak:9-9 [1]	1,397,149	1,247,037		
off-peak [2]	1,788,909	1,598,522	2,774,530	2,434,027
Total [3]	3,186,058	2,845,559	2,774,530	2,434,027
% peak	43.9%	43.8%		
% off-peak	56.1%	56.2%		

WATER HEATER, CONTROLLED, DECEMBER (kWH)

	MON	TUFR	SAT	SUN
1 AM	383,704	347,091	335,375	318,533
2 AM	319,265	289,242	279,723	265,810
3 AM	84,942	76,887	74,690	71,029
4 AM	63,707	57,848	55,652	52,723
5 AM	59,313	54,187	51,990	49,794
6 AM	53,455	48,329	46,865	43,936
7 AM	159,633	144,255	139,862	132,539
8 AM	213,087	192,584	185,994	177,207
9 AM	266,542	240,913	232,858	221,142
10 AM	309,013	279,723	270,204	256,291
11 AM	319,997	289,975	279,723	265,810
12 NOON	309,013	279,723	270,204	256,291
1 PM	255,559	231,394	223,339	212,355
2 PM	229,929	207,962	201,371	191,120
3 PM	180,868	164,026	158,168	150,845
4 PM	10,252	9,519	9,519	8,787
5 PM	6,590	5,858	5,858	5,126
6 PM	19,039	17,574	16,842	16,110
7 PM	21,236	19,039	18,306	17,574
8 PM	21,236	19,039	18,306	17,574
9 PM	25,629	23,432	21,968	21,236
10 PM	33,684	30,755	30,023	28,558
11 PM	319,265	289,242	279,723	265,810
12 MIDNIGHT	468,646	423,978	410,065	389,562
peak:9-9	1,974,903	1,788,177		
off-peak	2,158,701	1,954,398	3,616,628	3,435,762
Total	4,133,604	3,742,575	3,616,628	3,435,762
% peak	47.8%	47.8%		
% off-peak	52.2%	52.2%		

NUMBER OF DAYS IN 4 MOS [4]	17	69	18	20	TOTAL
peak:9-9	23751533	86045553	0	0	109797086
off-peak	30411453	110298018	49941540	48680540	239331551

NUMBER OF DAYS IN 3 MOS [5]	14	49	13	14	TOTAL	GRAND TOTAL
peak:9-9	27648642	87620673	0	0	115269315	225066401
off-peak	30221814	95765502	47016164	48100668	221104148	460435699
						685502100

summer	
peak:9-9 [7]	9.3%
off-peak [8]	20.2%
winter	
peak:9-9 [9]	9.7%
off-peak [10]	18.7%
Spring/fall	
peak:9-9 [11]	13.9%
off-peak [12]	28.2%

SEASONAL SUMMARY

	SUMMER	SPR/FALL [6]	WINTER	TOTAL
PEAK	109797086	164680941	115269315	389747342.
OFF-PEAK	239331551	333835676	221104148	794271375.
				1184018717 GRAND TOTAL

NOTES:

[1]: PEAK HOURS, HOURS ENDING 9 a.m TO 9 p.m. EST WEEKDAYS, OR HOURS ENDING 9 a.m. TO 9 p.m.
[2]: OFF-PEAK HOURS, ALL OTHER HOURS.
[3]: [1] + [2].
[4]: APPROXIMATE NUMBER OF EACH TYPE OF DAY IN 4 MONTH SUMMER.
[5]: APPROXIMATE NUMBER OF EACH TYPE OF DAY IN 3 MONTH WINTER.
[6]: SPRING/FALL CALCULATED AS WEIGHTED AVERAGE OF SUMMER AND WINTER,
S/F= 5/2 * (W/3 + S/4).
[7]: SUMMER PEAK HOURS / GRAND TOTAL.
[8]: SUMMER OFF-PEAK HOURS / GRAND TOTAL.
[9]: WINTER PEAK HOURS / GRAND TOTAL.
[10]: WINTER OFF-PEAK HOURS / GRAND TOTAL.
[11]: SPRING/FALL PEAK HOURS / GRAND TOTAL.
[12]: SPRING/FALL OFF-PEAK HOURS / GRAND TOTAL.

TABLE 2.7: ELECTRICITY CONSUMPTION FOR UNCONTROLLED WATER HEATERS BY RATING PERIODS

WATER HEATER, UNCONTROLLED, AUGUST

		MON	TUFR	SAT	SUN
1 AM		62,516	56,117	38,888	33,966
2 AM		58,086	51,687	30,520	26,582
3 AM		53,164	47,256	29,043	25,597
4 AM		48,241	42,826	15,260	13,291
5 AM		50,210	44,795	22,151	19,690
6 AM		53,164	47,256	20,675	18,213
7 AM		86,637	77,284	69,408	61,040
8 AM		96,482	86,145	79,253	69,408
9 AM		105,835	94,513	99,928	87,261
10 AM		108,788	97,466	115,188	191,404
11 AM		110,757	98,943	127,986	112,234
12 NOON		96,482	86,145	122,079	107,312
1 PM		72,361	64,485	97,466	85,652
2 PM		58,086	51,687	93,036	81,714
3 PM		53,164	47,256	70,392	61,532
4 PM		66,454	59,071	58,578	51,194
5 PM		75,807	67,931	66,947	58,578
6 PM		95,005	84,668	83,683	73,346
7 PM		109,281	97,466	95,990	84,176
8 PM		107,312	95,990	94,513	82,699
9 PM		104,358	93,036	83,683	73,346
10 PM		101,404	90,575	69,408	61,040
11 PM		93,528	83,683	58,578	51,194
12 MIDNIGHT		81,714	73,346	52,671	46,272
peak:9-9	[1]	1,163,690	1,038,657		
off-peak	[2]	785,146	700,970	1,695,324	1,576,741
Total	[3]	1,948,836	1,739,627	1,695,324	1,576,741
%peak		59.7%	59.7%		
% off-peak		40.3%	40.3%		

WATER HEATER, UNCONTROLLED, DECEMBER

	MON	TUFR	SAT	SUN
1 AM	75,807	73,838	41,842	39,873
2 AM	69,900	68,423	35,442	33,473
3 AM	63,993	62,516	38,888	36,919
4 AM	61,532	60,547	32,981	31,504
5 AM	60,547	59,071	34,458	32,489
6 AM	63,993	62,516	36,427	34,458
7 AM	98,943	96,974	86,145	82,207
8 AM	133,401	125,525	102,881	97,959
9 AM	148,661	132,416	134,878	128,478
10 AM	153,583	136,847	163,921	155,552
11 AM	121,587	108,296	156,045	148,168
12 NOON	108,788	96,974	132,909	126,017
1 PM	102,389	91,067	119,618	113,711
2 PM	97,466	86,637	110,757	105,342
3 PM	95,005	84,176	92,052	87,129
4 PM	89,590	79,745	88,606	84,176
5 PM	87,129	77,776	83,191	78,761
6 PM	98,451	87,621	99,435	94,513
7 PM	115,188	102,389	130,447	124,048
8 PM	147,676	130,940	137,339	130,447
9 PM	140,785	125,525	121,587	115,680
10 PM	134,386	119,618	88,606	84,176
11 PM	133,893	114,203	75,315	71,377
12 MIDNIGHT	122,079	102,389	66,454	63,009
	1,506,298	1,340,409		
	1,018,474	945,620	2,210,224	2,099,466
	2,524,772	2,286,029	2,210,224	2,099,466
	59.7%	58.6%		
	40.3%	41.4%		

NUMBER OF DAYS IN 4 MOS [4]	17	69	18	20	TOTAL
peak:9-9	19782730	71667333	0	0	91450063
off-peak	13347482	48366930	30515832	31534820	123765064

NUMBER OF DAYS IN 3 MOS [5]	14	49	13	14	TOTAL	GRAND TOTAL
peak:9-9	21088172	65680041	0	0	86768213	178218276
off-peak	14258636	46335380	28732912	29392524	118719452	242484516
						420702792

summer		
peak:9-9	[7]	12.6%
off-peak	[8]	17.0%
winter		
peak:9-9	[9]	11.9%
off-peak	[10]	16.3%
Spring/fall		
peak:9-9	[11]	17.8%
off-peak	[12]	24.3%

SEASONAL SUMMARY

SUMMER	SPR/FALL [6]	WINTER	TOTAL	
91450063	129463133.5	86768213	307681409	
123765064	176286041.6	118719452	418770557	
			726451967	GRAND TOTAL

NOTES:

[1]: PEAK HOURS, HOURS ENDING 9 a.m TO 9 p.m. EST WEEKDAYS, OR HOURS ENDING 9 a.m. TO 9 p.m.
[2]: OFF-PEAK HOURS, ALL OTHER HOURS.
[3]: [1] + [2].
[4]: APPROXIMATE NUMBER OF EACH TYPE OF DAY IN 4 MONTH SUMMER.
[5]: APPROXIMATE NUMBER OF EACH TYPE OF DAY IN 3 MONTH WINTER.
[6]: SPRING/FALL CALCULATED AS WEIGHTED AVERAGE OF SUMMER AND WINTER,
S/F= 5/2 * (W/3 + S/4).
[7]: SUMMER PEAK HOURS / GRAND TOTAL.
[8]: SUMMER OFF-PEAK HOURS / GRAND TOTAL.
[9]: WINTER PEAK HOURS / GRAND TOTAL.
[10]: WINTER OFF-PEAK HOURS / GRAND TOTAL.
[11]: SPRING/FALL PEAK HOURS / GRAND TOTAL.
[12]: SPRING/FALL OFF-PEAK HOURS / GRAND TOTAL.

TABLE 2.7A: JUMP TIME OF USE SPLITS

APPLIANCE:	RANGE		DRYER		UNCONTROLLED WATER HEATER	
	kWH	PEAK kWH	kWH	PEAK kWH	kWH	PEAK kWH
MONTH						
JANUARY	48.51	23.58	80.77	39.79	332.29	124.42
FEBRUARY	43.35	22.30	72.15	38.52	313.38	128.83
MARCH	43.02	24.59	69.21	39.43	341.96	131.62
APRIL	40.62	21.84	82.81	47.52	312.40	124.25
MAY	37.63	19.61	78.23	41.17	321.12	114.85
JUNE	28.52	15.01	69.04	34.56	225.64	81.16
JULY	32.77	17.76	66.01	32.97	277.05	109.54
AUGUST	33.94	16.19	70.60	32.26	270.70	97.19
SEPTEMBER	38.00	20.14	65.48	34.39	252.47	102.82
OCTOBER	41.69	22.32	94.04	40.05	296.13	115.85
NOVEMBER	48.99	27.90	75.23	34.01	299.13	113.14
DECEMBER	45.56	26.13	70.91	32.81	309.67	132.44
TOTAL	482.60	257.37	894.47	447.49	3551.96	1376.11
kWH						
SUMMER	133.23	69.10	271.13	134.18	1025.86	390.71
WINTER	137.42	72.01	223.83	111.12	955.34	385.69
SPRING/FALL	211.95	116.26	399.52	202.18	1570.74	599.71
% OF TOTAL						
SUMMER	27.6%	14.3%	30.3%	15.0%	28.9%	11.0%
WINTER	28.5%	14.9%	25.0%	12.4%	26.9%	10.9%
SPRING/FALL	43.9%	24.1%	44.7%	22.6%	44.2%	16.9%

	RANGE		DRYER		WATER HEATER	
	OFF-PEAK	PEAK	OFF-PEAK	PEAK	OFF-PEAK	PEAK
SUMMER	13.3%	14.3%	15.3%	15.0%	17.9%	11.0%
WINTER	13.6%	14.9%	12.6%	12.4%	16.0%	10.9%
SPRING/FALL	19.8%	24.1%	22.1%	22.6%	27.3%	16.9%

TABLE 2.8: EFFICIENCY ESTIMATES

APPLIANCE/END USE	UNITS	GAS RATING	ELECTRIC RATING	GAS:ELECTRIC USE RATIO
(a)	(b)	(c)	(d)	(e)
1. RANGE	ANNUAL MMBTU	5.3	2.7	1.96
2. DRYER	ENERGY FACTOR	2.4	2.6	1.08
3. STANDARD WATER HEATER	ENERGY FACTOR	54.4%	88.1%	1.62
4. EFFICIENT WATER HEATER	ENERGY FACTOR	63.0%	95.0%	1.51
5. STANDARD SPACE HEATING	AFUE	78.0%	100.0%	1.28
6. EFFICIENT SPACE HEATING	AFUE	93.0%	133.0%	1.43

NOTES:

1. (c) DOE (1980), BASE WITHOUT PILOT: 3 MMBTU FOR OVEN, 2.3 MMBTU FOR STOVE.
   (d) DOE (1980), BASE: 416.7 kWH FOR OVEN, 360.6 FOR STOVE.
   (e) ADL ASSUMES EFFICIENCIES OF 26% FOR GAS, 49% FOR ELECTRIC, OR A 1.885 USE RATIO.
2. (c) AND (d) FOE (1980), BASE LINE, Lbs of clothes dried/kWH input.
   (e) ADL ASSUMES 60% EFFICIENCY FOR GAS, 66% FOR ELECTRIC, OR A 1.10 RATIO.
3. (c) NATIONAL APPLIANCE EFFICIENCY STANDARDS FOR 1990, 40 GALLON.
   (d) NATIONAL APPLIANCE EFFICIENCY STANDARDS FOR 1990, 50 GALLON.
   SIZES FROM DOE (1980).
4. (c) AND (d): LOW END OF LISTINGS IN ACEEE (1988).
5. (c) NATIONAL APPLIANCE EFFICIENCY STANDARDS, 1992.
   (d) RESISTANCE
6. (c) CONDENSING FURNACE: LOW END OF ACEEE (1988); ADL SUGGESTS 94%.
   (d) HEAT PUMP: BECo 1988 EFSC FILING, p. E-18.

TABLE 2.9: GAS CONSUMPTION ESTIMATES ON BECo SYSTEM.

	ELECTRIC kWH USAGE	ELECTRIC MMBTU	USAGE RATIO	GAS USE MMBTU	BOSTON GAS 1987 ESTIMATES HEATING CUSTOMERS	BOSTON GAS 1987 ESTIMATES NON-HEATING CUSTOMERS	MOST RECENT ESTIMATES
	[1]	[2]	[3]	[4]	[5]	[5]	[6]
1. RANGE	1,123	3.8	1.96	7.53	10.7	5.5	10.0
2. DRYER	949	3.2	1.08	3.51	10.0	5.3	9.3
3. STANDARD WATER HEATER	4,259	14.5	1.62	23.55	24.4	16.9	24.8
4. STANDARD SPACE HEATING	12,315	42.0	1.28	53.90	110.0		94.2
5. EFFICIENT SPACE HEATING	9,236	31.5	1.43	45.09			

NOTES:
[1]: kWH USAGE ESTIMATE BY BECo FROM TABLE 2.2.
[2]: [1] * .003413.
[3]: USAGE RATIO FROM TABLE 2.8
[4]: [2] * [3].
[5]: MMBTU, FROM BGC 1986 "RESIDENTIAL SATURATION SURVEY," FEBRUARY 1987.
[6]: UNPUBLISHED BGC ESTIMATES. CORRESPONDING VALUES FOR UNITS WITHOUT PILOTS WOULD BE 7.7 MMBTU FOR RANGES, AND 89.6 MMBTU FOR SPACE HEATING.

TABLE 2.10: GAS CONSUMPTION ESTIMATES ON MECo SYSTEM

	ELECTRIC kWH USAGE	ELECTRIC MMBTU	USAGE RATIO	GAS USE MMBTU	BOSTON GAS 1987 ESTIMATES HEATING CUSTOMERS	BOSTON GAS 1987 ESTIMATES NON-HEATING CUSTOMERS	MOST RECENT ESTIMATES
	[1]	[2]	[3]	[4]	[5]	[5]	[6]
1. RANGE	431	1.47	1.96	2.89	10.7	5.5	10.0
2. DRYER	823	2.81	1.08	3.04	10.0	5.3	9.3
3. UNCONTROLLED WATER HEATER	4,555	15.55	1.62	25.18	24.4	16.9	24.8
4. CONTROLLED WATER HEATER	4,978	16.99	1.62	27.51			
5. STANDARD SPACE HEATING	7,197	24.56	1.28	31.49	110.0		94.2
6. EFFICIENT SPACE HEATING	5,038	17.19	1.43	24.59			

NOTES:
[1]: kWH USAGE ESTIMATE BY MECo FROM TABLE 2.3.
[2]: [1] * .003413.
[3]: USAGE RATIO FROM TABLE 2.8.
[4]: [2] * [3].
[5]: FROM BGC 1986 "RESIDENTIAL SATURATION SURVEY," FEBRUARY 1987.
[6]: UNPUBLISHED BGC ESTIMATES. CORRESPONDING VALUES FOR UNITS WITHOUT PILOTS WOULD BE 7.7 MMBTU FOR RANGES, AND 89.6 MMBTU FOR SPACE HEATING.

TABLE 2.11: ASSUMED AVERAGE APPLIANCE LIFETIME (years)

SOURCE:	SPACE HEATING	WATER HEATING	CLOTHES DRYING	COOKING
DOE ELECTRIC	20	10	14	14
DOE GAS	20	10	11	14
PLC, Inc.	20	10	10	15
WISCONSIN PS	20	10	12	15
CEC	20-22.4 yr*	11	12.3	19.1

NOTE: DOE DATA FROM DOE (1980), VOLUME 4, p.4-4.
WISCONSIN PUBLIC SERVICE DATA FROM ADVANCE PLAN 5.

CEC: California Energy Demand
1989-2009
Vol II: p. 2-26

* heater

TABLE 3.1: FUEL-SWITCHING ANALYSIS: BECo VS. BGC AVOIDED COSTS, DRI-89 PRICE ASSUMPTIONS

SECTION A: TOTAL ELECTRIC SAVINGS

FUEL USE:	RANGE	DRYER	UNCONTROLLED WATER HEATER	SINGLE-FAMILY SPACE-HEAT HEAT PUMP	SINGLE-FAMILY SPACE-HEAT RESISTANCE
1. ELECTRICITY CONSUMPTION - TOTAL	1,123	949	4,259	9,236	12,315
a. SUMMER PEAK	193	142	537		
b. SUMMER OFF-PEAK	150	133	724		
c. WINTER PEAK	440	350	1,265	6,003	8,005
d. WINTER OFF-PEAK	338	323	1,729	3,233	4,310
2. PEAK DEMAND					
a. SUMMER	0.12	0.15	0.59		
b. WINTER	0.30	0.13	0.63	4.73	5.13
3. MEASURE LIFE (YEARS)	15	10	10	20	20
4. PV $/kWH					
a. SUMMER PEAK	$0.73	$0.52	$0.52	$0.88	$0.88
b. SUMMER OFF-PEAK	$0.41	$0.30	$0.30	$0.48	$0.48
c. WINTER PEAK	$0.55	$0.39	$0.39	$0.66	$0.66
d. WINTER OFF-PEAK	$0.38	$0.28	$0.28	$0.45	$0.45
5. PV $/kW					
a. SUMMER	$1,075	$807	$807	$1,275	$1,275
b. WINTER	$1,034	$778	$778	$1,226	$1,226
6. AVOIDED ELECTRIC COSTS					
a. CAPACITY COSTS	$445	$222	$971	$5,800	$6,293
b. ENERGY COSTS	$574	$343	$1,485	$5,414	$7,219
c. TOTAL COSTS	$1,020	$566	$2,455	$11,214	$13,512

NOTES: [1]: ASSUMED TIME PERIOD SPLITS - BECo WINTER=MECo WINTER+MECO SPRING/FALL.
RANGE = 17.2%, 13.4%, 39.2%, 30.1%, TABLE 2.4.
DRYER = 15.0%, 14.0%, 36.9%, 34.0%, TABLE 2.5.
SPACE HEAT = WINTER HOURS = 65%, 35%, SEE TEXT.
WATER HEAT = 12.6%, 17.0%, 29.7%, 40.6%, TABLE 2.7.

[2]: TABLE 2.2.
[3]: TABLE 2.11.
[4]: AVOIDED COST TABLE 3.4.
[5]: TABLE 3.6.
[6.a]: 2a*5a+2b*5b.
[6.b]: 1a*4a+1b*4b+1c*4c+1d*4d.
[6.c]: [6.a] + [6.b].

TABLE 3.1: FUEL-SWITCHING ANALYSIS: BECo VS. BGC AVOIDED COSTS, DRI-89 PRICE ASSUMPTIONS

SECTION B: ADDED GAS COSTS, DRI-89 INPUTS

				SPACE HEAT	
	RANGE	DRYER	WATER HEAT	CONDENSING	STANDARD
1. GAS CONSUMPTION-TOTAL (MMBTU)	7.53	3.51	23.55	45.09	53.90
2. GAS USE PROFILE	BASE	BASE	WATER HEAT	WEATHER-SENSITIVE	
3. MEASURE LIFE (YEARS)	15	10	10	20	20
4. PV $/MMBTU	$48.20	$33.84	$38.29	$91.79	$91.79
5. GAS COST	$363	$119	$902	$4,139	$4,948

NOTES: [1]: TABLE 2.9.
[3]: TABLE 2.11.
[4]: BOSTON GAS COSTS AT DRI-89 RATES.
[5]: [1] x [4].

SECTION C: SYSTEM COST SUMMARY, DRI-89 INPUTS

				SINGLE-FAMILY SPACE-HEAT	
				HEAT PUMP	RESISTANCE
			UNCONTROLLED	COMPARED TO	
	RANGE	DRYER	WATER HEATER	CONDENSING	STANDARD
1. REDUCED ELECTRIC COST	$1,020	$566	$2,455	$11,214	$13,512
2. ADDED GAS COST	$363	$119	$902	$4,139	$4,948
3. SYSTEM SAVINGS	$657	$447	$1,554	$7,075	$8,564
4. RATIO GAS:ELECTRIC COSTS	35.6%	21.0%	36.7%	36.9%	36.6%

NOTES: [1]: FROM FUEL SWITCHING TABLE 3.1.A.
[2]: FROM FUEL SWITCHING TABLE 3.1.B.
[3]: [1] - [2].
[4]: [2] / [1].

TABLE 3.2: FUEL-SWITCHING ANALYSIS: BECo VS. BGC AVOIDED COSTS, JENSEN-89 PRICE ASSUMPTIONS

SECTION A: TOTAL ELECTRIC SAVINGS				SINGLE-FAMILY SPACE-HEAT	
FUEL USE:	RANGE	DRYER	UNCONTROLLED WATER HEATER	HEAT PUMP	RESISTANCE
1. ELECTRICITY CONSUMPTION - TOTAL	1,123	949	4,259	9,236	12,315
a. SUMMER PEAK	193	142	537		
b. SUMMER OFF-PEAK	150	133	724		
c. WINTER PEAK	440	350	1,265	6,003	8,005
d. WINTER OFF-PEAK	338	323	1,729	3,233	4,310
2. PEAK DEMAND					
a. SUMMER	0.12	0.15	0.59		
b. WINTER	0.30	0.13	0.63	4.73	5.13
3. MEASURE LIFE (YEARS)	15	10	10	20	20
4. PV $/kWH					
a. SUMMER PEAK	$0.62	$0.47	$0.47	$0.74	$0.74
b. SUMMER OFF-PEAK	$0.35	$0.27	$0.27	$0.40	$0.40
c. WINTER PEAK	$0.47	$0.35	$0.35	$0.56	$0.56
d. WINTER OFF-PEAK	$0.33	$0.25	$0.25	$0.38	$0.38
5. PV $/kW					
a. SUMMER	$1,075	$818	$818	$1,259	$1,259
b. WINTER	$1,033	$788	$788	$1,209	$1,209
6. AVOIDED ELECTRIC COSTS					
a. CAPACITY COSTS	$445	$226	$984	$5,723	$6,209
b. ENERGY COSTS	$491	$309	$1,335	$4,568	$6,091
c. TOTAL COSTS	$936	$534	$2,319	$10,291	$12,300

NOTES:
[1]: ASSUMED TIME PERIOD SPLITS - BECo WINTER=MECo WINTER+MECO SPRING/FALL.
RANGE = 17.2%, 13.4%, 39.2%, 30.1%, TABLE 2.4.
DRYER = 15.0%, 14.0%, 36.9%, 34.0%, TABLE 2.5.
SPACE HEAT = WINTER HOURS = 65%, 35%, SEE TEXT.
WATER HEAT = 12.6%, 17.0%, 29.7%, 40.6%, TABLE 2.7.
[2]: TABLE 2.2.
[3]: TABLE 2.11.
[4]: AVOIDED COST TABLE 3.4.
[5]: TABLE 3.6.
[6.a]: 2a*5a+2b*5b.
[6.b]: 1a*4a+1b*4b+1c*4c+1d*4d.
[6.c]: [6.a] + [6.b].

TABLE 3.2: FUEL-SWITCHING ANALYSIS: BECo VS. BGC AVOIDED COSTS, JENSEN-89 PRICE ASSUMPTIONS

SECTION B: ADDED GAS COSTS, JENSEN-89 INPUTS

	RANGE	DRYER	WATER HEAT	SPACE HEAT CONDENSING	SPACE HEAT STANDARD
1. GAS CONSUMPTION (MMBTU)	7.53	3.51	23.55	45.09	53.90
2. GAS USE PROFILE	BASE	BASE	WATER HEAT	WEATHER-SENSITIVE	
3. MEASURE LIFE (YEARS)	15	10	10	20	20
4. PV $/MMBTU	$47.74	$33.68	$37.18	$81.94	$81.94
5. GAS COST	$359	$118	$876	$3,695	$4,417

NOTES: [1]: TABLE 2.9.
[3]: TABLE 2.11.
[4]: BOSTON GAS COSTS AT JENSEN-89 RATES.
[5]: [1] x [4].

SECTION C: SYSTEM COST SUMMARY, JENSEN-89 INPUTS

	RANGE	DRYER	UNCONTROLLED WATER HEATER	SINGLE-FAMILY HEAT PUMP COMPARED TO CONDENSING	SPACE-HEAT RESISTANCE COMPARED TO STANDARD
1. REDUCED ELECTRIC COST	$936	$534	$2,319	$10,291	$12,300
2. ADDED GAS COST	$359	$118	$876	$3,695	$4,417
3. SYSTEM SAVINGS	$577	$416	$1,444	$6,596	$7,883
4. RATIO GAS:ELECTRIC COSTS	38.4%	22.1%	37.7%	35.9%	35.9%

NOTES: [1]: FROM FUEL SWITCHING TABLE 3.1.A.
[2]: FROM FUEL SWITCHING TABLE 3.1.B.
[3]: [1] - [2].
[4]: [2] / [1].

TABLE 3.3: FUEL-SWITCHING ANALYSIS: MECo VS. BGC AVOIDED COSTS-NEEI RATES

A. TOTAL ELECTRIC SAVINGS FUEL USE:	RANGE	DRYER	CONTROLLED WATER HEATER	UNCONTROLLED WATER HEATER	RESISTANCE HEATING	HEAT PUMP HEATING
1. ELECTRICITY CONSUMPTION - TOTAL	431	823	4,978	4,555	7,197	5038
a. WINTER PEAK	67	123	483	542	3,041	2,129
b. WINTER OFF-PEAK	51	114	931	742	1,637	1,146
c. SUMMER PEAK	74	123	463	574		
d. SUMMER OFF-PEAK	58	115	1,006	774		
e. SPRING/FALL PEAK	102	180	692	811	1,637	1,146
f. SPRING/FALL OFF-PEAK	79	166	1,404	1,107	882	617
2. PEAK DEMAND						
a. SUMMER	0.05	0.13	0.06	0.64		
b. WINTER	0.12	0.12	0.26	0.67	3.00	2.58
3. MEASURE LIFE (YEARS)	15	10	10	10	20	20
4. PV $/kWH						
a. WINTER PEAK	$0.57	$0.41	$0.41	$0.41	$0.70	$0.70
b. WINTER OFF-PEAK	$0.38	$0.27	$0.27	$0.27	$0.46	$0.46
c. SUMMER PEAK	$0.59	$0.42	$0.42	$0.42	$0.71	$0.71
d. SUMMER OFF-PEAK	$0.38	$0.27	$0.27	$0.27	$0.46	$0.46
e. SPRING/FALL PEAK	$0.52	$0.37	$0.37	$0.37	$0.64	$0.64
f. SPRING/FALL OFF-PEAK	$0.34	$0.24	$0.24	$0.24	$0.42	$0.42
5. PV $/kW						
a. SUMMER	$1,429	$1,119	$1,119	$1,119	$1,659	$1,659
b. WINTER	$1,203	$942	$942	$942	$1,397	$1,397
6. ELECTRIC SAVINGS						
a. CAPACITY COSTS	$207	$252	$309	$1,348	$4,192	$3,607
b. ENERGY COSTS	$203	$271	$1,512	$1,441	$4,279	$2,995
c. TOTAL COSTS	$411	$523	$1,820	$2,788	$8,471	$6,602

NOTES:

[1]: ASSUMED TIME PERIOD SPLITS
RANGE = 15.5%, 11.8%, 17.2%, 13.4%, 23.7%, 18.3%, TABLE 2.4.
DRYER = 15.0%, 13.8%, 15.0%, 14.0%, 21.9%, 20.2%, TABLE 2.5.
SPACE HEAT = 42.25%, 22.75%, 0%, 0%, 22.75%, 12.25%, SEE TEXT.
WATER HEAT CONTROLLED= 9.7%, 18.7%, 9.3%, 20.2%, 13.9%, 28.2%, TABLE 2.6.
UNCONTROLLED= 11.9%, 16.3%, 12.6%, 17.0%, 17.8%, 24.3%, TABLE 2.7.

[2]: TABLE 2.3.

[3]: DOE (1980), p.4-4.

[4]: TABLE 3.6.

[5]: AVOIDED COST TABLE 3.4.

[6.a]: 2a*5a+2b*5b.

[6.b]: 1a*4a+1b*4b+1c*4c+1d*4d+1e*4e+1f*4f.

[6.c]: [6.a] + [6.b].

TABLE 3.3: FUEL-SWITCHING ANALYSIS: MECo ELECTRIC AVOIDED COSTS-MECo RATES

B: ADDED GAS COSTS, NEEI INPUTS

	RANGE	DRYER	WATER HEATING CONTROLLED	WATER HEATING UNCONTROLLED	RESISTANCE HEATING	HEAT PUMP HEATING
1. GAS CONSUMPTION (MMBTU)	2.89	3.04	27.51	25.18	31.49	24.59
2. GAS USE PROFILE	BASE	BASE	WATER HEAT	WATER HEAT	WEATHER-SENSITIVE	
3. MEASURE LIFE (YEARS)	15	10	10	10	20	20
4. PV $/MMBTU	$43.88	$31.66	$34.99	$34.99	$74.30	$74.30
5. GAS COST	$127	$96	$963	$881	$2,340	$1,827

NOTES:
[1]: TABLE 2.10.
[3]: TABLE 2.11.
[4]: FROM BOSTON GAS AVOIDED COST MODEL, NEEI PRICES.
[5]: [1] x [4].

C: SUMMARY TABLE

	RANGE	DRYER	CONTROLLED WATER HEATER	UNCONTROLLED WATER HEATER	RESISTANCE HEATING	HEAT PUMP HEATING
1. REDUCED ELECTRIC COSTS	$411	$523	$1,820	$2,788	$8,471	$6,602
2. ADDED GAS COSTS	$127	$96	$963	$881	$2,340	$1,827
3. SYSTEM SAVINGS	$284	$426	$858	$1,907	$6,131	$4,775
4. RATIO GAS:ELECTRIC COSTS	30.9%	18.4%	52.9%	31.6%	27.6%	27.7%

NOTES:
[1]: FROM FUEL SWITCHING TABLE 3.3 SEC A.
[2]: FROM FUEL SWITCHING TABLE 3.3 SEC B.
[3]: [1] - [2].
[4]: [2] / [1].

TABLE 3.4: FUEL-SWITCHING ANALYSIS: MECo VS BGC AVOIDED COSTS JENSEN RATES

A. TOTAL ELECTRIC SAVINGS FUEL USE:	RANGE	DRYER	CONTROLLED WATER HEATER	UNCONTROLLED WATER HEATER	RESISTANCE HEATING	HEAT PUMP HEATING
1. ELECTRICITY CONSUMPTION	431	823	4,978	4,555	7,197	5,038
a. WINTER PEAK	67	123	483	542	3,041	2,129
b. WINTER OFF-PEAK	51	114	931	742	1,637	1,146
c. SUMMER PEAK	74	123	463	574		
d. SUMMER OFF-PEAK	58	115	1,006	774		
e. SPRING/FALL PEAK	102	180	692	811	1,637	1,146
f. SPRING/FALL OFF-PEAK	79	166	1,404	1,107	882	617
2. PEAK DEMAND						
a. SUMMER	0.05	0.13	0.06	0.64		
b. WINTER	0.12	0.12	0.26	0.67	3.00	2.58
3. MEASURE LIFE (YEARS)	15	10	10	10	20	20
4. PV $/kWH						
a. WINTER PEAK	$0.74	$0.51	$0.51	$0.51	$0.93	$0.93
b. WINTER OFF-PEAK	$0.49	$0.33	$0.33	$0.33	$0.61	$0.61
c. SUMMER PEAK	$0.76	$0.52	$0.52	$0.52	$0.96	$0.96
d. SUMMER OFF-PEAK	$0.49	$0.34	$0.34	$0.34	$0.62	$0.62
e. SPRING/FALL PEAK	$0.68	$0.46	$0.46	$0.46	$0.85	$0.85
f. SPRING/FALL OFF-PEAK	$0.44	$0.30	$0.30	$0.30	$0.56	$0.56
5. PV $/kW						
a. SUMMER	$1,429	$1,119	$1,119	$1,119	$1,659	$1,659
b. WINTER	$1,203	$942	$942	$942	$1,397	$1,397
6. ELECTRIC SAVINGS						
a. CAPACITY COSTS	$207	$252	$309	$1,348	$4,192	$3,607
b. ENERGY COSTS	$262	$337	$1,879	$1,791	$5,731	$4,012
c. TOTAL COSTS	$470	$589	$2,188	$3,139	$9,924	$7,619

NOTES: [1]: ASSUMED TIME PERIOD SPLITS
RANGE = 15.5%, 11.8%, 17.2%, 13.4%, 23.7%, 18.3%, TABLE 2.4.
DRYER = 15.0%, 13.8%, 15.0%, 14.0%, 21.9%, 20.2%, TABLE 2.5.
SPACE HEAT = 42.25%, 22.75%, 0%, 0%, 22.75%, 12.25%, SEE TEXT.
WATER HEAT CONTROLLED=9.7%, 18.7%, 9.3%, 20.2%, 13.9%, 28.2%, TABLE 2.6.
UNCONTROLLED=11.9%, 16.3%, 12.6%, 17.0%, 17.8%, 24.3%, TABLE 2.7.

[2]: TABLE 2.3.
[3]: DOE (1980), p.4-4.
[4]: TABLE 3.6.
[5]: AVOIDED COST TABLE 3.4.
[6.a]: 2a*5a+2b*5b.
[6.b]: 1a*4a+1b*4b+1c*4c+1d*4d+1e*4e+1f*4f.
[6.c]: [6.a] + [6.b].

TABLE 3.4: FUEL-SWITCHING ANALYSIS: MECo ELECTRIC AVOIDED COSTS JENSEN RATES

B: ADDED GAS COSTS, JENSEN-89 PRICES

	RANGE	DRYER	WATER HEATING CONTROLLED	WATER HEATING UNCONTROLLED	RESISTANCE HEATING	HEAT PUMP HEATING
2. GAS CONSUMPTION (MMBTU)	2.89	3.04	27.51	25.18	31.49	24.59
3. GAS USE PROFILE	BASE	BASE	WATER HEAT	WATER HEAT	WEATHER-SENSITIVE	
4. MEASURE LIFE (YEARS)	15	10	10	10	20	20
5. PV $/MMBTU	$47.74	$33.68	$37.18	$37.18	$81.94	$81.94
6. GAS COST	$138	$102	$1,023	$936	$2,580	$2,015

NOTES: [1]: TABLE 2.10.
[3]: TABLE 2.11.
[4]: FROM BOSTON GAS AVOIDED COST MODEL, JENSEN-89 PRICES.
[5]: [1] x [4].

C: SUMMARY TABLE

	RANGE	DRYER	CONTROLLED WATER HEATER	UNCONTROLLED WATER HEATER	RESISTANCE HEATING	HEAT PUMP HEATING
1. REDUCED ELECTRIC COSTS	$470	$589	$2,188	$3,139	$9,924	$7,619
2. ADDED GAS COSTS	$138	$102	$1,023	$936	$2,580	$2,015
3. SYSTEM SAVINGS	$332	$486	$1,165	$2,203	$7,343	$5,604
4. RATIO GAS:ELECTRIC COSTS	29.3%	17.4%	46.8%	29.8%	26.0%	26.4%

NOTES: [1]: FROM FUEL SWITCHING TABLE 3.4 SEC A.
[2]: FROM FUEL SWITCHING TABLE 3.4 SEC B.
[3]: [1] - [2].
[4]: [2] / [1].

TABLE 3.5: SUMMARY OF SELECTED VEIC ELECTRIC HEAT CONVERSION CASE STUDIES

CASE STUDY #	NUMBER OF UNITS	CON-VERSION FROM	CON-VERSION TO	DHW INCLUDED?	FLOOR AREA (S.F.)	CONVERSION COST	COST PER SQUARE FOOT	FIRST YR REDUCED kWh	WOOD SAVED (CORDS)
1	34	ELEC	GAS	NO	20800	$83,552	$4.02	172288	
2	32	ELEC	PROPANE COGEN	YES	25600	$80,857	$3.16	261840	
3	1	ELEC/WOOD	GAS	YES	865	$4,418	$5.11	11330	1.5
4	1	ELEC/WOOD	PROPANE	YES	1920	$2,964	$1.54	6898	5.0
5	1	ELEC	OIL	NO	1152	$3,700	$3.21	23070	
6	1	ELEC	GAS	YES	1640	$6,350	$3.87	19510	
7	1	ELEC/WOOD	PROPANE	YES	960	$3,985	$4.15	5250	4.0
8	1	ELEC	GAS	YES	1176	$4,975	$4.23	11062	

TABLE 4.1: NEPOOL DATA ON COMMERCIAL END-USE LOAD FACTORS

	TIME OF PEAK	ENERGY (MWH)	PEAK (kW)	LOAD FACTOR	kW/MWH
STORES HEATING	6 p.m.	90,107	37,642	27.3%	0.418
OFFICE HEATING	6 p.m.	120,989	52,349	26.4%	0.433
STORES COOLING	2.p.m.	237,420	461,356	5.9%	1.943
OFFICE COOLING	2.p.m.	347,380	483,239	8.2%	1.391

TABLE 4.2: DESCRIPTION OF STUDIES COMPARING ELECTRIC AND GAS CHILLERS

SITE	BUILDING 1A	BUILDING 1B	BUILDING 2	BUILDING 3
1. BUILDING DESCRIPTION				
A. TYPE	OFFICE	OFFICE	OFFICE	OFFICE
B. SIZE (SQ FT)	500,000	500,000	140,000	
C. HVAC ADDED FOR:	NEW BLDG	NEW BLDG	NEW BLDG	REPLACEMENT
2. ELECTRIC CHILLER				
A. TONNAGE	1000	1000	320	2000
B. TYPE	CENTRIFUGAL	CENTRIFUGAL	CENTRIFUGAL	CENTRIFUGAL
C. ANNUAL ENERGY (KWH)	419,774	419,774	271,023	1,012,973
D. PEAK DEMAND (KW)	700 [30]	700 [30]	193	1130
E. % ENERGY ON-PEAK	100.0%	100.0%	~79% [32]	95.6%
F. LOAD FACTOR	6.85%	6.85%	16.03%	10.23%
G. EFFICIENCY (COP)	~5.0	~5.0	5.0 [29]	5.2-5.8
3. BASE CASE HEATING				
SPACE HEAT				
A. SOURCE	GAS BOILER	ELECTRIC	ELECTRIC	
B. ANNUAL ENERGY	7,996 MMBTU	1,883,250 KWH	527,395 KWH	
WATER HEAT				
C. SOURCE	GAS BOILER	ELECTRIC	ELECTRIC	
D. ANNUAL ENERGY	637 MMBTU	149,285 KWH		
PUMPS & OTHER AUXILIARIES				
E. ANNUAL ENERGY (KWH)	78,663			
4. ALTERNATIVE GAS CHILLER				
A. TONNAGE	1000	1000	320	2000
B. TYPE	ABSORPTION	ABSORPTION	ABSORPTION	ABSORPTION
C. ANNUAL ENERGY (MMBTU)	7,329	7,329	5,033	21,141
D. ANNUAL ENERGY (KWH)	26,665 [30]	26,665 [30]	19,797 [33]	
E. PEAK DEMAND (KW)	5.3 [30]	5.3 [30]	14.1 [33]	
F. EFFICIENCY (COP)	~.97	~.97	0.92 [29]	.92-.95
5. ALTERNATIVE HEATING				
SPACE HEAT				
A. SOURCE	GAS CHILLER	GAS CHILLER	ELECTRIC	
B. ANNUAL ENERGY	7,996 MMBTU	7,996 MMBTU	2,222 MMBTU	
WATER HEAT				
C. SOURCE	GAS CHILLER	GAS CHILLER	ELECTRIC	
D. ANNUAL ENERGY	637 MMBTU	637 MMBTU		
PUMPS & OTHER AUXILIARIES				
E. ANNUAL ENERGY (KWH)	78,663	78,663	53,154 [34]	
6. INCREMENTAL CAPITAL COST				
A. GAS CHILLER	$155,000	$155,000	$70,000	
B. COOLING TOWER	$20-$50/TON [26]	$20-$50/TON [26]	$8,000	
C. GAS HEATING PIPING		$0.11-$1.00/SQ FT [27]	$134,000 [28]	
D. GAS BOILER	$45-$50/TON CREDIT			
E. GAS SERVICE			$5,000	$50,000-$100,000
F. TOTAL INCREMENTAL COST	$110,000 [26]	$210,000 [26] [27]	$258,495 [28]	
7. INCREMENTAL GAS MAINTENANCE COST			$2,500	

SITE	BUILDING 1A	BUILDING 1B	BUILDING 2	BUILDING 3
******************				
HVAC SECOND OPTION				
******************				
8. 2ND OPTION GAS CHILLER				
A. TONNAGE	400	400		700
B. TYPE	ABSORPTION	ABSORPTION		ABSORPTION
C. ANNUAL ENERGY (MMBTU)	1280	1280		12,810
D. ANNUAL ENERGY (KWH)	910 [31]	910 [31]		
E. PEAK DEMAND (KW)	2.1 [31]	2.1 [31]		
F. EFFICIENCY (COP)	~.97	~.97		0.92
G. INCREMENTAL CAPITAL COST	$58,000 [26]	$163,000 [26] [27]		
H. INCREMENTAL MAINTENANCE COST				
9. 2ND OPTION ELECTRIC CHILLER				
A. TONNAGE	600	600		2000
B. TYPE	CENTRIFUGAL	CENTRIFUGAL		CENTRIFUGAL
C. ANNUAL ENERGY (KWH)	347,995	347,995		373,641
D. PEAK DEMAND (KW)	422 [31]	422 [31]		667
E. % ENERGY ON-PEAK	100.00%	100.00%		97.4%
F. LOAD FACTOR	9.41%	9.41%		6.39%
G. EFFICIENCY (COP)	5.0	5.0		5.2-5.8
10. 2ND OPTION HEATING				
SPACE HEAT				
A. SOURCE	GAS CHILLER	GAS CHILLER		
B. ANNUAL ENERGY	7,996 MMBTU	7,996 MMBTU		
WATER HEAT				
C. SOURCE	GAS CHILLER	GAS CHILLER		
D. ANNUAL ENERGY	637 MMBTU	637 MMBTU		
PUMPS & OTHER AUXILIARIES				
E. ANNUAL ENERGY (KWH)	78,663	78,663		

SITE	BUILDING 4	BUILDING 5	BUILDING 6A	BUILDING 6B
1. BUILDING DESCRIPTION				
A. TYPE	OFFICE	COLLEGE	HOSPITAL	HOSPITAL
B. SIZE (SQ FT)		40,000		
C. HVAC ADDED FOR:	OPERATING SAVINGS [24]	NEW BLDG	ADDITION	ADDITION
2. ELECTRIC CHILLER				
A. TONNAGE	5 UNITS @300	150	150	120
B. TYPE	CENTRIFUGAL	CENTRIFUGAL	CENTRIFUGAL	CENTRIFUGAL
C. ANNUAL ENERGY (KWH)	686,432	160,230	170,457	136,347
D. PEAK DEMAND (KW)	903 [25]	141	88	71
E. % ENERGY ON-PEAK	80.2%	61.4%	46.9%	46.9%
F. LOAD FACTOR	8.68%	12.95%	22.08%	22.08%
G. EFFICIENCY (COP)	4.0 [29]	4.0-5.0	5.0-5.6	5.0-5.6
3. BASE CASE HEATING				
SPACE HEAT				
A. SOURCE		2 GAS BOILERS		
B. ANNUAL ENERGY				
WATER HEAT				
C. SOURCE			OIL	OIL
D. ANNUAL ENERGY				
PUMPS & OTHER AUXILIARIES				
E. ANNUAL ENERGY (KWH)				
4. ALTERNATIVE GAS CHILLER				
A. TONNAGE	320 [24]	150	150	120
B. TYPE	ABSORPTION [24]	ABSORPTION	ENGINE DRIVEN	ABSORPTION
C. ANNUAL ENERGY (MMBTU)		2,700	1,743 [22]	2,751
D. ANNUAL ENERGY (KWH)				
E. PEAK DEMAND (KW)				
F. EFFICIENCY (COP)	1.02 [29]	0.92	1.4-2.1 [23]	0.92
5. ALTERNATIVE HEATING				
SPACE HEAT				
A. SOURCE		GAS CHILLER [21]		
B. ANNUAL ENERGY				
WATER HEAT				
C. SOURCE			HEAT RECOVERY/OIL	OIL
D. ANNUAL ENERGY			[22]	
PUMPS & OTHER AUXILIARIES				
E. ANNUAL ENERGY (KWH)				
6. INCREMENTAL CAPITAL COST				
A. GAS CHILLER	$150,000 [24]	$40,000		
B. COOLING TOWER		$16,000		
C. GAS HEATING PIPING				
D. GAS BOILER		$9,500 CREDIT		
E. GAS SERVICE				
F. TOTAL INCREMENTAL COST		$43,500 [35]		
7. INCREMENTAL GAS MAINTENANCE COST			$2,609	

SITE	BUILDING 4	BUILDING 5	BUILDING 6A	BUILDING 6B
******************				
HVAC SECOND OPTION				
******************				
8. 2ND OPTION GAS CHILLER				
A. TONNAGE	150 [24]	150		
B. TYPE	ENGINE DRIVEN [24]	ENGINE DRIVEN		
C. ANNUAL ENERGY (MMBTU)		1,394		
D. ANNUAL ENERGY (KWH)				
E. PEAK DEMAND (KW)				
F. EFFICIENCY (COP)	1.48 [29]	1.4-2.1		
G. INCREMENTAL CAPITAL COST	$96,000 [24]	$78,000		
H. INCREMENTAL MAINTENANCE COST	$0.012/TON-HOUR [24]			
9. 2ND OPTION ELECTRIC CHILLER				
A. TONNAGE				
B. TYPE				
C. ANNUAL ENERGY (KWH)				
D. PEAK DEMAND (KW)				
E. % ENERGY ON-PEAK				
F. LOAD FACTOR				
G. EFFICIENCY (COP)				
10. 2ND OPTION HEATING				
SPACE HEAT				
A. SOURCE		2 GAS BOILERS		
B. ANNUAL ENERGY				
WATER HEAT				
C. SOURCE				
D. ANNUAL ENERGY				
PUMPS & OTHER AUXILIARIES				
E. ANNUAL ENERGY (KWH)				

NOTES:

Line

2F: [2C]/([2D]*8760).

8: If a 2nd Option Chiller is specified for both gas and electric (lines 8 and 9), the 2nd option is a hybrid system utilizing both types of chillers. If no 2nd Option electric chiller is specified (line 9 is blank), 2nd Option Gas Chiller (line 8) can be compared with Electric Chiller (line 2) or Alternative Gas Chiller (line 4). See also Note [24].

9: See line 8.

9F: [9C]/([9D]*8760).

Other Notes

[21]: For emergency purposes, a stand-by boiler is also specified.

[22]: Heat recovery from engine jacket water will be used to displace production from oil-fired hot water boilers. 9387.3 therms of heat will be recovered annually. This will displace 13410.4 therms of oil (assuming a boiler efficiency of 70%).

[23]: Cooling COP does not include effect of heat recovery. See Note [22].

[24]: Building 4 is an existing building with sufficient chiller capacity; the base case is continued operation of the current chillers. The alternatives evaluated involve addition of a new, more efficient chiller to be operated with the existing chillers as a means of reducing operating costs. Thus, the options described on lines 4 and 8 can be compared, but these can not be compared with that on line 2. All capital cost of the alternative chillers is incremental, since the base case (line 2) involves no capital costs. However, the incremental capital cost data on lines 6A and 8G includes chiller purchase cost only. No installation, overhead, cooling tower, or other costs are included.

[25]: Peak demand calculated by multiplying peak tonnage reported (1026) by efficiency reported (0.88 kW/ton).

[26]: Hitachi produces a condenser upgrade option which improves the condensing heat exchanger on the chiller, allowing higher operating temperature, reduced flow rate, and higher efficiency. With this upgrade, incremental capital cost is $20/ton. Without this upgade, incremental cost is on the order of $40-$50/ton. For Buildings 1A and 1B, the incremental cooling tower cost appears to have been been included in the incremental chiller cost estimates reported on lines 6A and 8G.

[27]: This case includes cost of substituting gas space and water heating for electric. Based on a draft study (cited on page 24 of Kunkle and Darrow (1987), an incremental piping cost of $0.11/square foot is estimated. The incremental cost of a 4 pipe system and boiler could be as high as $1.00/square foot (Id. at page 26).

[28]: This case includes cost of substituting gas space heating for electric.

[29]: Efficiency converted to COP as follows: COP = Cooling output/energy input.
For example, the COP of .7 kw/ton = 12,000 Btu/.7*3413 = 5.0.
Similarly, the COP of .13 therm/ton-hour = 12,000 Btu/.13*100000 = 0.92.

[30]: Line 4D includes all cooling-related electric use. Line 4E includes only the increase in electric demand stemming from the greater cooling tower requirements of the gas chiller. Line 2D is calculated as the difference between total building demand with an electric chiller and with a gas chiller, plus line 4E. Thus, to the extent that Line 4E underestimates the total electric demand of gas cooling, Line 2D is also underestimated.

[31]: Lines 4E, 8D, & 8E include only the increase in electric energy and demand stemming from the greater cooling tower requirements of the gas chiller. Line 9D is calculated as the difference between total building demand with a 1000 ton gas chiller and with a 400 gas and a 600 ton electric chiller, plus the difference between lines 4E and 8E. Thus, to the extent that Lines 4E & 8E underestimate the total electric demand of gas cooling, Line 9D is is also affected.

[32]: Estimated based on rates and average cost per kwh reported for operating electric chiller.

[33]: Estimated based on rates, reported electric cost of operating gas chiller, and split of demand and energy costs reported for electric chiller.

[34]: Estimated based on rates, reported electric cost of operating gas heat, and split of demand and energy costs reported for electric heat.

[35]: Total incremental cost includes an additional $17,000 of installation and pumps and pipes. However, the gas absorption chiller does not require sound attenuation, resulting in a $20,000 credit.

TABLE 5.1: LARGE OFFICE BUILDING FUEL-SWITCHING ANALYSIS: BECO ELECTRIC COSTS/DRI PRICES
PART A: ELECTRIC AVOIDED COSTS

MEASURE	400 TON GAS PEAK SHAVE AC	1000 TON GAS FULL LOAD AC	GAS SPACE & WATER HEAT
1. ELECTRICITY CONSUMPTION SAVED (kWH)			
a. SUMMER PEAK	45,726	307,499	48,747
b. SUMMER OFF-PEAK	0	0	4,662
c. WINTER PEAK	2,215	2,144	716,861
d. WINTER OFF-PEAK	0	0	482,923
e. SPRING/FALL PEAK	22,927	83,465	434,778
f. SPRING/FALL OFF-PEAK	0	0	265,903
2. PEAK DEMAND SAVED (kW)			
a. SUMMER	276	695	0
b. WINTER	0	0	1191
3. MEASURE LIFE (YEARS)	20	20	20
4. PV $/kWH			
a. SUMMER PEAK	$0.88	$0.88	$0.88
b. SUMMER OFF-PEAK	$0.48	$0.48	$0.48
c. WINTER PEAK	$0.66	$0.66	$0.66
d. WINTER OFF-PEAK	$0.45	$0.45	$0.45
e. SPRING/FALL PEAK	$0.66	$0.66	$0.66
f. SPRING/FALL OFF-PEAK	$0.45	$0.45	$0.45
5. PV $/kW			
a. SUMMER	$1,275.17	$1,275.17	$1,275.17
b. WINTER	$1,225.67	$1,225.67	$1,225.67
6. ELECTRIC SAVINGS			
a. CAPACITY COSTS	$351,590	$885,682	$1,459,773
b. FUEL COSTS	$56,833	$327,101	$1,142,189
c. TOTAL COSTS	$408,422	$1,212,783	$2,601,962

NOTES:
[1]: From Kunkle and Darrow (1987).
[2]: Summer: Demand reduction in July.
Winter: Assume gas cooling results in no electric demand reduction on peak days.
For electric heating, demand reduction in January.
[4]: Chernick and Espenhorst (1989). 20 year PV in 1990. Winter prices apply for Spring/Fall.
[5]: Chernick and Espenhorst (1989). 20 year PV in 1990.
[6.a]: 2a*5a+2b*5b.
[6.b]: 1a*4a+1b*4b+1c*4c+1d*4d+1e*4e+1f*4f.
[6.c]: [6.a] + [6.b].

TABLE 5.1: LARGE OFFICE BUILDING FUEL-SWITCHING ANALYSIS: BECO ELECTRIC COSTS/DRI PRICES
PART B: ADDED GAS COSTS

MEASURE	400 TON GAS PEAK SHAVE AC	1000 TON GAS FULL LOAD AC	GAS SPACE & WATER HEAT
1. GAS CONSUMPTION ADDED (MMBTU)			
a. SUMMER BASE	1229	7246	
b. WINTER BASE	50	83	
c. WEATHER-SENSITIVE			7996
d. WATER HEAT			637
2. MEASURE LIFE (YEARS)	20	20	20
3. PV $/MMBTU			
a. SUMMER BASE	$44.96	$44.96	$44.96
b. WINTER BASE	$80.71	$80.71	$80.71
c. WEATHER-SENSITIVE	$91.79	$91.79	$91.79
d. WATER HEAT	$68.85	$68.85	$68.85
4. GAS COST ADDED	$59,332	$332,491	$777,790
5. MAINTENANCE COST ADDED			
6. TOTAL COST ADDED	$59,332	$332,491	$777,790

NOTES: [1]: From Kunkle and Darrow (1987).
[3]: Chernick and Espenhorst (1989). 20 year PV in 1990.
[4]: 1a*3a+1b*3b+1c*3c+1d*3d.
[5]: Not estimated by Kunkle and Darrow (1987).
[6]: [4] + [5].

TABLE 5.1: LARGE OFFICE BUILDING FUEL-SWITCHING ANALYSIS: BECO ELECTRIC COSTS/DRI PRICES
PART C: SUMMARY TABLE

MEASURE	400 TON GAS PEAK SHAVE AC	1000 TON GAS FULL LOAD AC	GAS SPACE & WATER HEAT
1. REDUCED ELECTRIC COSTS	$408,422	$1,212,783	$2,601,962
2. ADDED GAS COSTS	$59,332	$332,491	$777,790
3. SYSTEM SAVINGS	$349,091	$880,292	$1,824,172
4. RATIO GAS:ELECTRIC COSTS	14.5%	27.4%	29.9%

NOTES: [1]: TABLE 5.1 PART A.
[2]: TABLE 5.1 PART B.
[3]: [1] - [2].
[4]: [2] / [1].

TABLE 5.2: LARGE OFFICE BUILDING FUEL-SWITCHING ANALYSIS: BECO ELECTRIC COSTS/JENSEN PRICES
PART A: ELECTRIC AVOIDED COSTS

MEASURE	400 TON GAS PEAK SHAVE AC	1000 TON GAS FULL LOAD AC	GAS SPACE & WATER HEAT
1. ELECTRICITY CONSUMPTION SAVED (kWH)			
a. SUMMER PEAK	45,726	307,499	48,747
b. SUMMER OFF-PEAK	0	0	4,662
c. WINTER PEAK	2,215	2,144	716,861
d. WINTER OFF-PEAK	0	0	482,923
e. SPRING/FALL PEAK	22,927	83,465	434,778
f. SPRING/FALL OFF-PEAK	0	0	265,903
2. PEAK DEMAND SAVED (kW)			
a. SUMMER	276	695	0
b. WINTER	0	0	1191
3. MEASURE LIFE (YEARS)	20	20	20
4. PV $/kWH			
a. SUMMER PEAK	$0.74	$0.74	$0.74
b. SUMMER OFF-PEAK	$0.40	$0.40	$0.40
c. WINTER PEAK	$0.56	$0.56	$0.56
d. WINTER OFF-PEAK	$0.38	$0.38	$0.38
e. SPRING/FALL PEAK	$0.56	$0.56	$0.56
f. SPRING/FALL OFF-PEAK	$0.38	$0.38	$0.38
5. PV $/kW			
a. SUMMER	$1,259.46	$1,259.46	$1,259.46
b. WINTER	$1,209.40	$1,209.40	$1,209.40
6. ELECTRIC SAVINGS			
a. CAPACITY COSTS	$347,258	$874,771	$1,440,395
b. ENERGY COSTS	$47,917	$275,490	$967,409
c. TOTAL COSTS	$395,175	$1,150,261	$2,407,805

NOTES: [1]: From Kunkle and Darrow (1987).
[2]: Summer: Demand reduction in July.
Winter: Assume gas cooling results in no electric demand reduction on peak days.
For electric heating, demand reduction in January.
[4]: Chernick and Espenhorst (1989). 20 year PV in 1990. Winter prices apply for Spring/Fall.
[5]: Chernick and Espenhorst (1989). 20 year PV in 1990.
[6.a]: 2a*5a+2b*5b.
[6.b]: 1a*4a+1b*4b+1c*4c+1d*4d+1e*4e+1f*4f.
[6.c]: [6.a] + [6.b].

TABLE 5.2: LARGE OFFICE BUILDING FUEL-SWITCHING ANALYSIS: BECO ELECTRIC COSTS/JENSEN PRICES
PART B: ADDED GAS COSTS

MEASURE	400 TON GAS PEAK SHAVE AC	1000 TON GAS FULL LOAD AC	GAS SPACE & WATER HEAT
1. GAS CONSUMPTION ADDED (MMBTU)			
a. SUMMER BASE	1229	7246	
b. WINTER BASE	50	83	
c. WEATHER-SENSITIVE			7996
d. WATER HEAT			637
2. MEASURE LIFE (YEARS)	20	20	20
3. PV $/MMBTU			
a. SUMMER BASE	$48.49	$48.49	$48.49
b. WINTER BASE	$72.80	$72.80	$72.80
c. WEATHER-SENSITIVE	$81.94	$81.94	$81.94
d. WATER HEAT	$65.62	$65.62	$65.62
4. GAS COST ADDED	$63,273	$357,408	$696,972
5. MAINTENANCE COST ADDED			
6. TOTAL COST ADDED	$63,273	$357,408	$696,972

NOTES: [1]: From Kunkle and Darrow (1987).
[3]: Chernick and Espenhorst (1989). 20 year PV in 1990.
[4]: 1a*3a+1b*3b+1c*3c+1d*3d.
[5]: Not estimated by Kunkle and Darrow (1987).
[6]: [4] + [5].

TABLE 5.2: LARGE OFFICE BUILDING FUEL-SWITCHING ANALYSIS: BECO ELECTRIC COSTS/JENSEN PRICES
PART C: SUMMARY TABLE

MEASURE	400 TON GAS PEAK SHAVE AC	1000 TON GAS FULL LOAD AC	GAS SPACE & WATER HEAT
1. REDUCED ELECTRIC COSTS	$395,175	$1,150,261	$2,407,805
2. ADDED GAS COSTS	$63,273	$357,408	$696,972
3. SYSTEM SAVINGS	$331,902	$792,853	$1,710,832
4. RATIO GAS:ELECTRIC COSTS	16.0%	31.1%	28.9%

NOTES: [1]: TABLE 5.2, PART A.
[2]: TABLE 5.2, PART B.
[3]: [1] - [2].
[4]: [1] / [2].

TABLE 5.3: LARGE OFFICE BUILDING FUEL-SWITCHING ANALYSIS: MECO ELECTRIC COSTS/NEEI PRICES
PART A: ELECTRIC AVOIDED COSTS

MEASURE	400 TON GAS PEAK SHAVE AC	1000 TON GAS FULL LOAD AC	GAS SPACE & WATER HEAT
1. ELECTRICITY CONSUMPTION SAVED (kWH)			
a. SUMMER PEAK	45,726	307,499	48,747
b. SUMMER OFF-PEAK	0	0	4,662
c. WINTER PEAK	2,215	2,144	716,861
d. WINTER OFF-PEAK	0	0	482,923
e. SPRING/FALL PEAK	22,927	83,465	434,778
f. SPRING/FALL OFF-PEAK	0	0	265,903
2. PEAK DEMAND SAVED (kW)			
a. SUMMER	276	695	0
b. WINTER	0	0	1191
3. MEASURE LIFE (YEARS)	20	20	20
4. PV $/kWH			
a. SUMMER PEAK	$0.71	$0.71	$0.71
b. SUMMER OFF-PEAK	$0.46	$0.46	$0.46
c. WINTER PEAK	$0.70	$0.70	$0.70
d. WINTER OFF-PEAK	$0.46	$0.46	$0.46
e. SPRING/FALL PEAK	$0.64	$0.64	$0.64
f. SPRING/FALL OFF-PEAK	$0.42	$0.42	$0.42
5. PV $/kW			
a. SUMMER	$1,658.91	$1,658.91	$1,658.91
b. WINTER	$1,397.27	$1,397.27	$1,397.27
6. TOTAL ELECTRIC SAVINGS			
a. CAPACITY COSTS	$457,395	$1,152,213	$1,664,149
b. ENERGY COSTS	$48,689	$273,243	$1,150,639
c. TOTAL COSTS	$506,084	$1,425,455	$2,814,788

NOTES: [1]: From Kunkle and Darrow (1987).
[2]: Summer: Demand reduction in July.
Winter: Assume gas cooling results in no electric demand reduction on peak days.
For electric heating, demand reduction in January.
[4]: Chernick and Espenhorst (1989). 20 year PV in 1990.
[5]: Chernick and Espenhorst (1989). 20 year PV in 1990.
[6.a]: 2a*5a+2b*5b.
[6.b]: 1a*4a+1b*4b+1c*4c+1d*4d+1e*4e+1f*4f.
[6.c]: [6.a] + [6.b].

TABLE 5.3: LARGE OFFICE BUILDING FUEL-SWITCHING ANALYSIS: MECO ELECTRIC COSTS/NEEI PRICES
PART B: ADDED GAS COSTS

MEASURE	400 TON GAS PEAK SHAVE AC	1000 TON GAS FULL LOAD AC	GAS SPACE & WATER HEAT
1. GAS CONSUMPTION ADDED (MMBTU)			
a. SUMMER BASE	1229	7246	
b. WINTER BASE	50	83	
c. WEATHER-SENSITIVE			7996
d. WATER HEAT			637
2. MEASURE LIFE (YEARS)	20	20	20
3. PV $/MMBTU			
a. SUMMER BASE	$43.47	$43.47	$43.47
b. WINTER BASE	$66.10	$66.10	$66.10
c. WEATHER-SENSITIVE	$74.30	$74.30	$74.30
d. WATER HEAT	$59.20	$59.20	$59.20
4. GAS COST ADDED	$56,765	$320,476	$631,795
5. MAINTENANCE COST ADDED			
6. TOTAL COST ADDED	$56,765	$320,476	$631,795

NOTES: [1]: From Kunkle and Darrow (1987).
[3]: Chernick and Espenhorst (1989). 20 year PV in 1990.
[4]: 1a*3a+1b*3b+1c*3c+1d*3d.
[5]: Not estimated by Kunkle and Darrow (1987).
[6]: [4] + [5].

TABLE 5.3: LARGE OFFICE BUILDING FUEL-SWITCHING ANALYSIS: MECO ELECTRIC COSTS/NEEI PRICES
PART C: SUMMARY TABLE

MEASURE	400 TON GAS PEAK SHAVE AC	1000 TON GAS FULL LOAD AC	GAS SPACE & WATER HEAT
1. REDUCED ELECTRIC COSTS	$506,084	$1,425,455	$2,814,788
2. ADDED GAS COSTS	$56,765	$320,476	$631,795
3. SYSTEM SAVINGS	$449,319	$1,104,979	$2,182,992
4. RATIO GAS:ELECTRIC COSTS	11.2%	22.5%	22.4%

NOTES: [1]: TABLE 5.3 PART A.
[2]: TABLE 5.3 PART B.
[3]: [1] - [2].
[4]: [1] / [2].

TABLE 5.4: LARGE OFFICE BUILDING FUEL-SWITCHING ANALYSIS: MECO ELECTRIC COSTS/JENSEN PRICES
PART A: ELECTRIC AVOIDED COSTS

MEASURE	400 TON GAS PEAK SHAVE AC	1000 TON GAS FULL LOAD AC	GAS SPACE & WATER HEAT
1. ELECTRICITY CONSUMPTION SAVED (kWH)			
a. SUMMER PEAK	45,726	307,499	48,747
b. SUMMER OFF-PEAK	0	0	4,662
c. WINTER PEAK	2,215	2,144	716,861
d. WINTER OFF-PEAK	0	0	482,923
e. SPRING/FALL PEAK	22,927	83,465	434,778
f. SPRING/FALL OFF-PEAK	0	0	265,903
2. PEAK DEMAND SAVED (kW)			
a. SUMMER	276	695	0
b. WINTER	0	0	1191
3. MEASURE LIFE (YEARS)	20	20	20
4. PV $/kWH			
a. SUMMER PEAK	$0.96	$0.96	$0.96
b. SUMMER OFF-PEAK	$0.62	$0.62	$0.62
c. WINTER PEAK	$0.93	$0.93	$0.93
d. WINTER OFF-PEAK	$0.61	$0.61	$0.61
e. SPRING/FALL PEAK	$0.85	$0.85	$0.85
f. SPRING/FALL OFF-PEAK	$0.56	$0.56	$0.56
5. PV $/kW			
a. SUMMER	$1,658.91	$1,658.91	$1,658.91
b. WINTER	$1,397.27	$1,397.27	$1,397.27
6. TOTAL ELECTRIC SAVINGS			
a. CAPACITY COSTS	$457,395	$1,152,213	$1,664,149
b. ENERGY COSTS	$65,445	$368,138	$1,529,418
c. TOTAL COSTS	$522,840	$1,520,351	$3,193,567

NOTES: [1]: From Kunkle and Darrow (1987).
[2]: Summer: Demand reduction in July.
Winter: Assume gas cooling results in no electric demand reduction on peak days.
For electric heating, demand reduction in January.
[4]: Chernick and Espenhorst (1989). 20 year PV in 1990.
[5]: Chernick and Espenhorst (1989). 20 year PV in 1990.
[6.a]: 2a*5a+2b*5b.
[6.b]: 1a*4a+1b*4b+1c*4c+1d*4d+1e*4e+1f*4f.
[6.c]: [6.a] + [6.b].

TABLE 5.4: LARGE OFFICE BUILDING FUEL-SWITCHING ANALYSIS: MECO ELECTRIC COSTS/JENSEN PRICES
PART B: ADDED GAS COSTS

MEASURE	400 TON GAS PEAK SHAVE AC	1000 TON GAS FULL LOAD AC	GAS SPACE & WATER HEAT
1. GAS CONSUMPTION ADDED (MMBTU)			
a. SUMMER BASE	1229	7246	
b. WINTER BASE	50	83	
c. WEATHER-SENSITIVE			7996
d. WATER HEAT			637
2. MEASURE LIFE (YEARS)	20	20	20
3. PV $/MMBTU			
a. SUMMER BASE	$48.49	$48.49	$48.49
b. WINTER BASE	$72.80	$72.80	$72.80
c. WEATHER-SENSITIVE	$81.94	$81.94	$81.94
d. WATER HEAT	$65.62	$65.62	$65.62
4. GAS COST ADDED	$63,273	$357,408	$696,972
5. MAINTENANCE COST ADDED			
6. TOTAL COST ADDED	$63,273	$357,408	$696,972

NOTES: [1]: From Kunkle and Darrow (1987).
[3]: Chernick and Espenhorst (1989). 20 year PV in 1990.
[4]: 1a*3a+1b*3b+1c*3c+1d*3d.
[5]: Not estimated by Kunkle and Darrow (1987).
[6]: [4] + [5].

TABLE 5.4: LARGE OFFICE BUILDING FUEL-SWITCHING ANALYSIS: MECO ELECTRIC COSTS/JENSEN PRICES
PART C: SUMMARY TABLE

MEASURE	400 TON GAS PEAK SHAVE AC	1000 TON GAS FULL LOAD AC	GAS SPACE & WATER HEAT
1. REDUCED ELECTRIC COST	$522,840	$1,520,351	$3,193,567
2. ADDED GAS COST	$63,273	$357,408	$696,972
3. SYSTEM SAVINGS	$459,566	$1,162,943	$2,496,594
4. RATIO GAS:ELECTRIC COSTS	12.1%	23.5%	21.8%

NOTES: [1]: TABLE 5.4, PART A.
[2]: TABLE 5.4, PART B.
[3]: [1] - [2].
[4]: [2] / [1].

TABLE 5.5: HOSPITAL FUEL-SWITCHING ANALYSIS: BECO ELECTRIC COSTS/DRI PRICES
PART A: ELECTRIC AVOIDED COSTS

BASE CASE ELECTRIC CHILLER/NATURAL GAS BOILER FOR HOT WATER HEATING

MEASURE	150 TON GAS ENGINE DRIVEN CHILLER	120 TON GAS ABSORPTION CHILLER
1. ELECTRICITY CONSUMPTION SAVED (kWH)		
a. SUMMER PEAK	63,242	50,594
b. SUMMER OFF-PEAK	75,616	60,502
c. WINTER PEAK	0	0
d. WINTER OFF-PEAK	0	0
e. SPRING/FALL PEAK	16,575	13,288
f. SPRING/FALL OFF-PEAK	14,932	11,963
2. PEAK DEMAND SAVED (kW)		
a. SUMMER	88	71
b. WINTER	0	0
3. MEASURE LIFE (YEARS)	20	20
4. PV $/kWH		
a. SUMMER PEAK	$0.88	$0.88
b. SUMMER OFF-PEAK	$0.48	$0.48
c. WINTER PEAK	$0.66	$0.66
d. WINTER OFF-PEAK	$0.45	$0.45
e. SPRING/FALL PEAK	$0.66	$0.66
f. SPRING/FALL OFF-PEAK	$0.45	$0.45
5. PV $/kW		
a. SUMMER	$1,275.17	$1,275.17
b. WINTER	$1,225.67	$1,225.67
6. ELECTRIC SAVINGS		
a. CAPACITY SAVINGS	$112,215	$90,537
b. ENERGY SAVINGS	$109,608	$87,717
c. TOTAL SAVINGS	$221,823	$178,254

NOTES: [2]: Summer: Demand reduction in July.
Winter: Assume gas cooling results in no electric demand reduction on peak days.
At this building, there is no cooling in winter months.
[4]: Chernick and Espenhorst (1989). 20 year PV in 1990. Winter costs apply for Spring/Fall.
[5]: Chernick and Espenhorst (1989). 20 year PV in 1990.
[6.a]: 2a*5a+2b*5b.
[6.b]: 1a*4a+1b*4b+1c*4c+1d*4d+1e*4e+1f*4f.
[6.c]: [6.a] + [6.b].

TABLE 5.5: HOSPITAL FUEL-SWITCHING ANALYSIS: BECO ELECTRIC COSTS/DRI PRICES
PART B: ADDED GAS COSTS

BASE CASE ELECTRIC CHILLER/NATURAL GAS BOILER FOR HOT WATER HEATING

MEASURE	150 TON GAS ENGINE DRIVEN CHILLER W/ HEAT RECOVERY			120 TON GAS ABSORPTION CHILLER
	COOLING	HEAT RECOVERY	TOTAL	
1. GAS CONSUMPTION ADDED (MMBTU)				
a. SUMMER BASE	1,743	(1,341)	402	2,751
b. WINTER BASE				
c. WEATHER-SENSITIVE				
d. WATER HEAT				
2. MEASURE LIFE (YEARS)	20	20	20	20
3. PV $/MMBTU				
a. SUMMER BASE	$44.96	$44.96	$44.96	$44.96
b. WINTER BASE	$80.71	$80.71	$80.71	$81.15
c. WEATHER-SENSITIVE	$91.79	$91.79	$91.79	$92.73
d. WATER HEAT	$68.65	$68.65	$68.65	$69.02
4. GAS COST ADDED	$78,382	($60,293)	$18,089	$123,672
5. MAINTENANCE COST ADDED	$30,004		$30,004	
6. TOTAL COST ADDED	$108,385	($60,293)	$48,092	$123,672

NOTES: [3]: Chernick and Espenhorst (1989). 20 year PV in 1990.
[4]: 1a*3a+1b*3b+1c*3c+1d*3d.
[5]: For engine driven chiller, 20 year PV of base year maintenance cost increase of $2609.
[6]: [4] + [5].

TABLE 5.5: HOSPITAL FUEL-SWITCHING ANALYSIS: BECO ELECTRIC COSTS/DRI PRICES
PART C: SUMMMARY TABLE

BASE CASE ELECTRIC CHILLER/NATURAL GAS BOILER FOR HOT WATER HEATING

MEASURE	150 TON GAS ENGINE DRIVEN CHILLER		120 TON GAS ABSORPTION CHILLER
	COOLING	COOLING & HEAT RECOVERY	
1. REDUCED ELECTRIC COSTS	$221,823	$221,823	$178,254
2. ADDED GAS COSTS (TOTAL)	$108,385	$48,092	$123,672
3. SYSTEM SAVINGS	$113,437	$173,730	$54,582
4. RATIO GAS:ELECTRIC COSTS	48.9%	21.7%	69.4%

NOTES: [1]: TABLE 5.5, PART A.
[2]: TABLE 5.5, PART B.
[3]: [1] - [2].
[4]: [2] / [1].

TABLE 5.6: HOSPITAL FUEL-SWITCHING ANALYSIS: BECO ELECTRIC COSTS/JENSEN PRICES
PART A: ELECTRIC AVOIDED COSTS

BASE CASE ELECTRIC CHILLER/NATURAL GAS BOILER FOR HOT WATER HEATING

MEASURE	150 TON GAS ENGINE DRIVEN CHILLER	120 TON GAS ABSORPTION CHILLER
1. ELECTRICITY CONSUMPTION SAVED (kWH)		
a. SUMMER PEAK	63,242	50,594
b. SUMMER OFF-PEAK	75,616	60,502
c. WINTER PEAK	0	0
d. WINTER OFF-PEAK	0	0
e. SPRING/FALL PEAK	16,575	13,288
f. SPRING/FALL OFF-PEAK	14,932	11,963
2. PEAK DEMAND SAVED (kW)		
a. SUMMER	88	71
b. WINTER	0	0
3. MEASURE LIFE (YEARS)	20	20
4. PV $/kWH		
a. SUMMER PEAK	$0.74	$0.74
b. SUMMER OFF-PEAK	$0.40	$0.40
c. WINTER PEAK	$0.56	$0.56
d. WINTER OFF-PEAK	$0.38	$0.38
e. SPRING/FALL PEAK	$0.56	$0.56
f. SPRING/FALL OFF-PEAK	$0.38	$0.38
5. PV $/kW		
a. SUMMER	$1,259.46	$1,259.46
b. WINTER	$1,209.40	$1,209.40
6. ELECTRIC SAVINGS		
a. CAPACITY SAVINGS	$110,832	$89,422
b. ENERGY SAVINGS	$92,002	$73,627
c. TOTAL SAVINGS	$202,834	$163,049

NOTES: [2]: Summer: Demand reduction in July.
Winter: Assume gas cooling results in no electric demand reduction on peak days.
At this building, there is no cooling in winter months.
[4]: Chernick and Espenhorst (1989). 20 year PV in 1990. Winter costs apply for Spring/Fall.
[5]: Chernick and Espenhorst (1989). 20 year PV in 1990.
[6.a]: 2a*5a+2b*5b.
[6.b]: 1a*4a+1b*4b+1c*4c+1d*4d+1e*4e+1f*4f.
[6.c]: [6.a] + [6.b].

TABLE 5.6: HOSPITAL FUEL-SWITCHING ANALYSIS: BECO ELECTRIC COSTS/JENSEN PRICES
PART B: ADDED GAS COSTS

BASE CASE ELECTRIC CHILLER/NATURAL GAS BOILER FOR HOT WATER HEATING

MEASURE	150 TON GAS ENGINE DRIVEN CHILLER W/ HEAT RECOVERY COOLING	HEAT RECOVERY	TOTAL	120 TON GAS ABSORPTION CHILLER
1. GAS CONSUMPTION ADDED (MMBTU)				
a. SUMMER BASE	1,743	(1,341)	402	2,751
b. WINTER BASE				
c. WEATHER-SENSITIVE				
d. WATER HEAT				
2. MEASURE LIFE (YEARS)	20	20	20	20
3. PV $/MMBTU				
a. SUMMER BASE	$48.49	$48.49	$48.49	$48.49
b. WINTER BASE	$72.80	$72.80	$72.80	$72.80
c. WEATHER-SENSITIVE	$81.94	$81.94	$81.94	$81.94
d. WATER HEAT	$65.62	$65.62	$65.62	$65.62
4. GAS COST ADDED	$84,536	($65,027)	$19,509	$133,382
5. MAINTENANCE COST ADDED	$30,004		$30,004	
6. TOTAL COST ADDED	$114,540	($65,027)	$49,512	$133,382

NOTES: [3]: Chernick and Espenhorst (1989). 20 year PV in 1990.
[4]: 1a*3a+1b*3b+1c*3c+1d*3d.
[5]: For engine driven chiller, 20 year PV of base year maintenance cost increase of $2609.
[6]: [4] + [5].

TABLE 5.6: HOSPITAL FUEL-SWITCHING ANALYSIS: BECO ELECTRIC COSTS/JENSEN PRICES
PART C: SUMMMARY TABLE

BASE CASE ELECTRIC CHILLER/NATURAL GAS BOILER FOR HOT WATER HEATING

MEASURE	150 TON GAS ENGINE DRIVEN CHILLER		120 TON GAS ABSORPTION CHILLER
	COOLING	COOLING & HEAT RECOVERY	
1. REDUCED ELECTRIC COSTS	$202,834	$202,834	$163,049
2. ADDED GAS COSTS (TOTAL)	$114,540	$49,512	$133,382
3. SYSTEM SAVINGS	$88,295	$153,322	$29,667
4. RATIO GAS:ELECTRIC COSTS	56.5%	24.4%	81.8%

NOTES: [1]: TABLE 5.5, PART A.
[2]: TABLE 5.5, PART B.
[3]: [1] - [2].
[4]: [2] / [1].

TABLE 5.7: HOSPITAL FUEL-SWITCHING ANALYSIS: MECO ELECTRIC COSTS/NEEI PRICES
PART A: ELECTRIC AVOIDED COSTS

BASE CASE ELECTRIC CHILLER/NATURAL GAS BOILER FOR HOT WATER HEATING

MEASURE	150 TON GAS ENGINE DRIVEN CHILLER	120 TON GAS ABSORPTION CHILLER
1. ELECTRICITY CONSUMPTION SAVED (kWH)		
a. SUMMER PEAK	63,242	50,594
b. SUMMER OFF-PEAK	75,616	60,502
c. WINTER PEAK	0	0
d. WINTER OFF-PEAK	0	0
e. SPRING/FALL PEAK	16,575	13,288
f. SPRING/FALL OFF-PEAK	14,932	11,963
2. PEAK DEMAND SAVED (kW)		
a. SUMMER	88	71
b. WINTER	0	0
3. MEASURE LIFE (YEARS)	20	20
4. PV $/kWH		
a. SUMMER PEAK	$0.71	$0.71
b. SUMMER OFF-PEAK	$0.46	$0.46
c. WINTER PEAK	$0.70	$0.70
d. WINTER OFF-PEAK	$0.46	$0.46
e. SPRING/FALL PEAK	$0.64	$0.64
f. SPRING/FALL OFF-PEAK	$0.42	$0.42
5. PV $/kW		
a. SUMMER	$1,658.91	$1,658.91
b. WINTER	$1,397.27	$1,397.27
6. ELECTRIC SAVINGS		
a. CAPACITY SAVINGS	$145,984	$117,783
b. ENERGY SAVINGS	$96,565	$77,281
c. TOTAL SAVINGS	$242,549	$195,064

NOTES: [2]: Summer: Demand reduction in July.
Winter: Assume gas cooling results in no electric demand reduction on peak days.
At this building, there is no cooling in winter months.
[4]: Chernick and Espenhorst (1989). 20 year PV in 1990.
[5]: Chernick and Espenhorst (1989). 20 year PV in 1990.
[6.a]: 2a*5a+2b*5b.
[6.b]: 1a*4a+1b*4b+1c*4c+1d*4d+1e*4e+1f*4f.
[6.c]: [6.a] + [6.b].

TABLE 5.7: HOSPITAL FUEL-SWITCHING ANALYSIS: MECO ELECTRIC COSTS/NEEI PRICES
PART B: ADDED GAS COSTS

BASE CASE ELECTRIC CHILLER/NATURAL GAS BOILER FOR HOT WATER HEATING

MEASURE	150 TON GAS ENGINE DRIVEN CHILLER W/ HEAT RECOVERY COOLING	HEAT RECOVERY	TOTAL	120 TON GAS ABSORPTION CHILLER
1. GAS CONSUMPTION ADDED (MMBTU)				
a. SUMMER BASE	1,743	(1,341)	402	2,751
b. WINTER BASE				
c. WEATHER-SENSITIVE				
d. WATER HEAT				
2. MEASURE LIFE (YEARS)	20	20	20	20
3. PV $/MMBTU				
a. SUMMER BASE	$43.47	$43.47	$43.47	$43.47
b. WINTER BASE	$66.10	$66.10	$66.10	$66.10
c. WEATHER-SENSITIVE	$74.30	$74.30	$74.30	$74.30
d. WATER HEAT	$59.20	$59.20	$59.20	$59.20
4. GAS COST ADDED	$75,784	($58,295)	$17,489	$119,573
5. MAINTENANCE COST ADDED	$30,004		$30,004	
6. TOTAL COST ADDED	$105,788	($58,295)	$47,493	$119,573

NOTES: [3]: Chernick and Espenhorst (1989). 20 year PV in 1990.
[4]: 1a*3a+1b*3b+1c*3c+1d*3d.
[5]: For engine driven chiller, 20 year PV of base year maintenance cost increase of $2609.
[6]: [4] + [5].

TABLE 5.7: HOSPITAL FUEL-SWITCHING ANALYSIS: MECO ELECTRIC COSTS/NEEI PRICES
PART C: SUMMMARY TABLE

BASE CASE ELECTRIC CHILLER/NATURAL GAS BOILER FOR HOT WATER HEATING

MEASURE	150 TON GAS ENGINE DRIVEN CHILLER		120 TON GAS ABSORPTION CHILLER
	COOLING	COOLING & HEAT RECOVERY	
1. REDUCED ELECTRIC COSTS	$242,549	$242,549	$195,064
2. ADDED GAS COSTS (TOTAL)	$105,788	$47,493	$119,573
3. SYSTEM SAVINGS	$136,761	$195,056	$75,491
4. RATIO GAS:ELECTRIC COSTS	43.6%	19.6%	61.3%

NOTES: [1]: TABLE 5.5, PART A.
[2]: TABLE 5.5, PART B.
[3]: [1] - [2].
[4]: [2] / [1].

TABLE 5.8: HOSPITAL FUEL-SWITCHING ANALYSIS: MECO ELECTRIC COSTS/JENSEN PRICES
PART A: ELECTRIC AVOIDED COSTS

BASE CASE ELECTRIC CHILLER/NATURAL GAS BOILER FOR HOT WATER HEATING

MEASURE	150 TON GAS ENGINE DRIVEN CHILLER	120 TON GAS ABSORPTION CHILLER
1. ELECTRICITY CONSUMPTION SAVED (kWH)		
a. SUMMER PEAK	63,242	50,594
b. SUMMER OFF-PEAK	75,616	60,502
c. WINTER PEAK	0	0
d. WINTER OFF-PEAK	0	0
e. SPRING/FALL PEAK	16,575	13,288
f. SPRING/FALL OFF-PEAK	14,932	11,963
2. PEAK DEMAND SAVED (kW)		
a. SUMMER	88	71
b. WINTER	0	0
3. MEASURE LIFE (YEARS)	20	20
4. PV $/kWH		
a. SUMMER PEAK	$0.96	$0.96
b. SUMMER OFF-PEAK	$0.62	$0.62
c. WINTER PEAK	$0.93	$0.93
d. WINTER OFF-PEAK	$0.61	$0.61
e. SPRING/FALL PEAK	$0.85	$0.85
f. SPRING/FALL OFF-PEAK	$0.56	$0.56
5. PV $/kW		
a. SUMMER	$1,658.91	$1,658.91
b. WINTER	$1,397.27	$1,397.27
6. ELECTRIC SAVINGS		
a. CAPACITY SAVINGS	$145,984	$117,783
b. ENERGY SAVINGS	$130,045	$104,075
c. TOTAL SAVINGS	$276,029	$221,858

NOTES: [2]: Summer: Demand reduction in July.
Winter: Assume gas cooling results in no electric demand reduction on peak days.
At this building, there is no cooling in winter months.
[4]: Chernick and Espenhorst (1989). 20 year PV in 1990.
[5]: Chernick and Espenhorst (1989). 20 year PV in 1990.
[6.a]: 2a*5a+2b*5b.
[6.b]: 1a*4a+1b*4b+1c*4c+1d*4d+1e*4e+1f*4f.
[6.c]: [6.a] + [6.b].

TABLE 5.8: HOSPITAL FUEL-SWITCHING ANALYSIS: MECO ELECTRIC COSTS/JENSEN PRICES
PART B: ADDED GAS COSTS

BASE CASE ELECTRIC CHILLER/NATURAL GAS BOILER FOR HOT WATER HEATING

MEASURE	150 TON GAS ENGINE DRIVEN CHILLER W/ HEAT RECOVERY			120 TON GAS ABSORPTION CHILLER
	COOLING	HEAT RECOVERY	TOTAL	
1. GAS CONSUMPTION ADDED (MMBTU)				
a. SUMMER BASE	1,743	(1,341)	402	2,751
b. WINTER BASE				
c. WEATHER-SENSITIVE				
d. WATER HEAT				
2. MEASURE LIFE (YEARS)	20	20	20	20
3. PV $/MMBTU				
a. SUMMER BASE	$48.49	$48.49	$48.49	$48.49
b. WINTER BASE	$72.80	$72.80	$72.80	$72.80
c. WEATHER-SENSITIVE	$81.94	$81.94	$81.94	$81.94
d. WATER HEAT	$65.62	$65.62	$65.62	$65.62
4. GAS COST ADDED	$84,536	($65,027)	$19,509	$133,382
5. MAINTENANCE COST ADDED	$30,004		$30,004	
6. TOTAL COST ADDED	$114,540	($65,027)	$49,512	$133,382

NOTES: [3]: Chernick and Espenhorst (1989). 20 year PV in 1990.
[4]: 1a*3a+1b*3b+1c*3c+1d*3d.
[5]: For engine driven chiller, 20 year PV of base year maintenance cost increase of $2609.
[6]: [4] + [5].

TABLE 5.8: HOSPITAL FUEL-SWITCHING ANALYSIS: MECO ELECTRIC COSTS/JENSEN PRICES
PART C: SUMMMARY TABLE

BASE CASE ELECTRIC CHILLER/NATURAL GAS BOILER FOR HOT WATER HEATING

MEASURE	150 TON GAS ENGINE DRIVEN CHILLER		120 TON GAS ABSORPTION CHILLER
	COOLING	COOLING & HEAT RECOVERY	
1. REDUCED ELECTRIC COSTS	$276,029	$276,029	$221,858
2. ADDED GAS COSTS (TOTAL)	$114,540	$49,512	$133,382
3. SYSTEM SAVINGS	$161,490	$226,517	$88,476
4. RATIO GAS:ELECTRIC COSTS	41.5%	17.9%	60.1%

NOTES: [1]: TABLE 5.5, PART A.
[2]: TABLE 5.5, PART B.
[3]: [1] - [2].
[4]: [2] / [1].