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ENERGY & ENVIRONMENT DIVISION

Incorporating Global Warming Risks in Power Sector Planning

A Case Study of the New England Region

Volume II: Appendices

F. Krause, J. Busch, and J. Koomey

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INCORPORATING GLOBAL WARMING RISKS IN POWER SECTOR PLANNING

A CASE STUDY OF THE NEW ENGLAND REGION

VOLUME II: APPENDICES

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APPENDIX A: OVERALL CONVENTIONS AND ASSUMPTIONS

Definition and use of resource potentials

The resource potentials in the following appendices are technical-economic potentials that could be mobilized to varying degrees in alternative resource strategies. They reflect some siting and logistic constraints. For example, the wind resource potential is defined on the basis of restrictive siting rules that remove two thirds of the technical potential of that resource (see Appendix L).

In using these technical-economic resource potentials for scenario building, a further limit is placed on the resource by the level of exploitation specified. The maximum utilization level is 75 percent in each case.

Busbar cost calculations

The purpose of cost comparisons in the present analysis is to establish the approximate relative cost of conventional and low carbon resource plans. This comparison is made on the basis of simplified busbar cost calculations and production cost modeling. Real annual costs in the year 2005/10 are compared, rather than net present values of alternative capacity expansion plans. Further details are found in Appendix C.

Below, the various data assumptions for the busbar cost calculations are further explained.

Data and Assumptions Used in Calculating Resource Costs

This appendix summarizes the assumptions and conventions used in developing busbar costs for alternative electricity resources. Unless otherwise specified, assumptions on capital and operating costs and fuel prices are those from New England Power Pool's Generation Task Force Assumptions Book (GTF, 1989), referred to below as GTF. For cogeneration and renewables-based systems, pertinent complementary sources are cited. Important references were technology data compilations in Electric Power Resource Institute (1986, 1989), California Energy Commission (CEC, 1990a), Johannson et al. (1988), and Krause et al. (1992).

Real Discount Rate

The weighted average cost of capital (WACC— in nominal terms) was calculated using the GTF assumptions, and the average inflation rate (as measured by GNP deflator) assumed by GTF (1990-2015) was removed from the nominal WACC using the formula:

(1+WACC)/(1+inflation rate) -1 = real WACC = real discount rate.

The inflation rate is 5.2% and nominal WACC is 11.85%, leading to a real cost of capital of 6.3%. This figure is close to the 6.1% figure developed in the EPRI Technical Assessment Guide (TAG) (EPRI 1986, 1989).

Physical parameters

Where available, lifetime assumptions and plant sizes were taken from GTF for conventional resources.

Construction lead times are presented by GTF as a stream of investment expenditures numbers in a given year after starting the siting/construction process. This parameter was simplified by using a single point value.

Land-use figures for conventional resources are from GTF. Biomass intercooled steam injection gas turbine and cogen land-use numbers are estimates based on other power plants.

Capacity Factor

In all cases except wind, costs are calculated for two capacity factors. One is a typical or average capacity factor (65 percent for utility-owned central stations). The other, the maximum capacity factor, is based on the equivalent availability. Equivalent unplanned outage rates and equivalent availabilities are taken from GTF where available.

Heat Rates

All heat rates are based on higher heating values, and are *average* heat rates. GTF does not calculate average heat rates for its power plants, only heat rates at various load levels. To calculate average heat rates, the GTF full-load heat rates were multiplied by the ratio of average to full-load heat rates from the EPRI TAG for power plants of comparable size. For cogeneration plants, heat rates reflect operating modes.

Capital Recovery Factor

We use the real discount rate as derived above to calculate a capital recovery factor, using the power plant lifetime. To that, we add the technology-specific percentages for federal, state, and local taxes, as given by GTF.

Overnight Capital Cost ($/kW)

These are taken from GTF for conventional resources, and from the sources indicated in each appendix for other resources.

Net Capital Cost Including Interest ($/kW)

This figure is based on the formula in the EPRI TAG to calculate interest, using the real discount rate, the lead time, and the assumption that power plant construction costs are spread evenly over the lead time.

GTF Net Capital Cost Including Interest ($/kW)

GTF (1989) gives capital cost including interest for the conventional utility technologies. When applicable, we use the ratio of GTF's overnight capital costs to capital costs plus interest to scale the net capital costs (including NO_X control operating and maintenance) to the appropriate value. When GTF does not include the technology in its database, we use the EPRI TAG formula mentioned in the previous item.

Startup and inventory ($/kW)

For biomass steam turbine (ST), this number is assumed to be that of the utility conventional combustion cycle plant (from GTF). For biomass intercooled steam injected gas turbine (BISTIG), this number is assumed to be that of the utility integrated coal gasification combined cycle plant (IGACC) (from GTF). For wind, startup is equal to one month of fixed operating and maintenance (O&M). For combined cycle cogeneration (CCC) plants, this number is assumed to be that of the utility advanced combustion cycle plant (from GTF). For industrial gas turbines, this number is assumed to be that of the utility CCC plant (from GTF).

Land ($/kW)

We apply a land cost of $100,000 (1988$) per acre, which is the average New England land cost per acre from GTF. Wind power land costs (rental fees) are based on California data and are included in variable O&M (below).

Fixed O&M and other ($/kW/yr)

These are taken from GTF for conventional resources. Industrial cogeneration has been assigned the fixed O&M of an (advanced combined cycle) ACC plant as given in GTF. Costs for internal combustion engines and for wind are represented as variable costs. Data for biomass plants are taken from Larson (1991).

Incremental O&M (¢/kWh elect.)

For conventional resources, these are as specified by GTF. Wind O&M includes range land rental costs as well as all fixed O&M, based on data from CEC (1990) and U.S. Windpower.

Additional O&M for NOx Control (¢/kWh elect)

These are estimated costs for selective catalytic reduction or equivalent measures that would be required to meet emission standards under stringent Massachusetts rules.

Fuel Price ($/kWh fuel)

Fuel prices for the reference case are based on GTF assumptions, extended to 2020 at the 1990-2009 rates, and levelized over this period using the real discount rate (6.3%) described above. For busbar cost calculations, it is assumed that all combustion turbines (CT), CCCs, and ACC plants use firm gas (no oil for peak gas use periods). The utility gas price is also applied to industrial cogeneration plants. The fuel price for packaged cogeneration in the commercial sector is assumed to be 70 percent higher than the utility gas price, equivalent to the rates currently charged on an annual average basis by Boston Gas Company.

Transmission and Distribution (T&D) Adjustment

Adjustments for T&D losses and costs are not included in the busbar cost of supply options. These adjustments are made in the supply and demand-side resource integration. Avoided T&D costs are estimated in the DSM appendix.

Externality Cost-MA DPU

Externality costs are calculated using direct emissions factors (which do not include emissions from the extraction, processing, and transportation of the relevant fuels). See Appendix D for details.

APPENDIX B: PRODUCTION-COST MODELING OF THE NEPOOL SYSTEM: INPUT ASSUMPTIONS AND BENCHMARKING RESULTS

This appendix describes our methodology for characterizing the existing New England Power Pool (NEPOOL) power system as input to the UPLAN production-cost model. Below we discuss our input assumptions. In a following section, we discuss the results of our exercise in benchmarking our model output to that from NEPOOL.

Input Assumptions

In this section we describe our assumptions and the sources of the data used in modeling the NEPOOL power pool system with the UPLAN model. The data were drawn from a variety of sources, most notably from testimony and background information of Northeast Utilities' (NU) modeling of NEPOOL and their own system; from support documents and briefing materials of the Analysis Group for Regional Electricity Alternative (AGREA) of the Massachusetts Institute of Technology (MIT) Energy Laboratory; and publicly available NEPOOL information, such as the April 1990 Capacity Energy, Loads, and Transmission (CELT) report, the December 1989 Generation Task Force (GTF) report, and others.

Individual Plant Aggregation

Because of a limit on the number of blocks in the UPLAN model, we aggregated individual plants in the NEPOOL system into several generic categories. Our organizing principles for the chosen plant categories were fuel type, technology, size, vintage, and air pollutant emissions characteristics. See Table B.1 for the results of this aggregation.

Heat Rates

Heat rates for oil plants and peaking units (i.e., CTs, Jets, ICUs) are based on incremental heat rates from the NU Polaris input deck. For each plant category, the minimum, 50%, 75%, and full-load average heat rates were averaged over the plants in the NU system. The Medium Coal plant category used the heat rates of the Mt. Tom plant found in the NU Polaris deck. No block detail was available for the Large Coal and Small Coal plant categories; thus, each used an average heat rate drawn from the appropriate coal plants in NU's modeling of the NEPOOL system. The existing combined-cycle plant category used data from EPRI (1989) for block heat rates, scaled to match NU's average heat rates for combined cycle plants.

Maintenance Scheduling

We adopted GTF (NEPLAN, 1989) assumptions for existing system annual average maintenance rates, and apportioned the maintenance systematically across months in order to levelize reserve margin. An exception to this procedure was the treatment of nuclear resources, in which the maintenance schedule of 8.5 weeks/year is spread evenly throughout the months of the year. This approach to nuclear maintenance scheduling reflects a long-term perspective on the nuclear fuel cycle; obviously a given year will deviate from this characterization.

Table B.1. Aggregation of NEPOOL Plants for the UPLAN Model

Category	Size (MW)	Number	Total (MW)
Small Nuclear	600	4	2400
Medium Nuclear	830	2	1660
Large Nuclear	1150	2	2300
Small Coal	75	6	450
Medium Coal	150	4	600
Large Coal	360	5	1800
1950's Oil Steam	100	20	2000
1960's Oil-Steam	300	6	1800
1970s Oil Steam	500	10	5000
Combined Cycle	200	2	400
Peakers	75	22	1650
Storage Hydro	620	1	620
Run-of-River Hydro	800	1	800
Pumped Storage Hydro	1680	1	1680
Thermal Purchases	250	1	250
Hydro-Quebec Purchases	350	1	350
Other Hydro Purchases	500	1	500
Thermal Non-Utility Generation	200	7	1400
Non-Thermal Non-Utility Generation	240	1	240
Total			**25900**

Forced Outages

Nuclear plant forced outage rates (FOR) were adjusted so that, given the maintenance rates, the capacity factor would be in the range of 72%. Coal plant FOR were set at 22% to match actual 1990 NEPOOL generation and 1991 NU modeling of NEPOOL. Other plants used FOR found in GTF (NEPLAN, 1989). In most cases, the FOR we used were comparable to those reported by MIT for similar aggregations of plants (Conners and Andrews, 1990).

Fuel Prices

We used the GTF report (NEPLAN, 1989) for all fuel prices and escalation used in utility-owned generation. These prices (along with all others in our analysis) were input in real 1990 dollars. Existing combined cycle plants, in which distillate fuel is used in place of natural gas during some winter periods when that fuel is in high demand for space heating, are dispatched in the model with a hypothetical fuel priced at three-quarters that of interruptible gas plus one-quarter that of distillate.

Operating and Maintenance (O&M) Costs

By agreement between participating NEPOOL utilities, all O&M costs are considered fixed, with the exception of the peaking units, which include a variable component of O&M costs (Stillinger, 1991). Fixed O&M values were culled from NEPOOL sources. For the Peaker category, we used the variable O&M rate for turbines running on distillate fuel (i.e., 0.3 6 $/MBtu) as shown in the GTF report (NEPLAN, 1989).

Hydro Generation

UPLAN models the monthly variation in hydro generation from user input of monthly capacity factors. Because we lacked complete data on the monthly hydro breakdown for NEPOOL as a whole, we developed a representative hydro "pattern" based upon the hydro resources of three NEPOOL utilities: NU, Central Maine Power (CMP), and Bangor Hydro Electric (BHE). Data from the first utility were drawn from Polaris model input, while data from the latter two utilities came from UPLAN input files obtained from the Maine Public Service Commission. Electricity generated in the region by conventional (i.e., non-pumped-storage) hydro sources in 1988 was 4397 GWhs (EIA, 1990). Our sources account for 2348 GWh, or 53% of the NEPOOL hydro energy. Similarly, in terms of capacity, the region has 1480 MWs of conventional hydro. Of this, we have detailed data on 748 MW, or roughly half.

NEPOOL hydro generation was broken down into three modeling entities: conventional storage, run-of-river, and pumped storage hydro (see below). UPLAN can model hydro dispatch in a peak-shaving mode as either conventional pondage hydro or as pumped storage. Run-of-river hydro was modeled as a must-run resource. The principal UPLAN input for modeling pumped storage is the pumping efficiency. We employed the NU Northfield plant's value of 74%. Northfield constitues 1000 MW of the total 1613 MW of pumped-storage capacity in NEPOOL.

Emission Factors

SO_2 and NO_x emissions factors for existing plants are drawn from MIT/AGREA (1990) and Stillinger (1991). SO_2 emissions are based on the sulfur content of fuels used in aggregated plant types, calculated as a capacity-weighted average. NO_x emissions are based on the type of burner in the aggregated plant categories, also calculated as a capacity-weighted average. Plants built in the 1970s are assumed to meet the New Source Performance Standards (NSPS) emissions standards. Carbon emissions assumed are those that result from direct combustion (i.e., ignoring the fuel cycle or "indirect" emissions) and drawn from California Energy Commission (CEC, 1990).

Operationally, carbon emission factors are placed in the Particulates category of the UPLAN input protocol (as C and not CO_2 because of value limits built into UPLAN).

For new resource SO_2 and NO_x factors, we used those given in MIT/AGREA (1990), with the exception of NO_x emission factors of resources fueled by natural gas or gasified coal. These appear to neglect the application of selective catalytic reduction technology, which is, and we believe will continue to be, a regulatory requirement of plants using such fuels. For these resources, we used the NO_x emission factor developed by the Massachusetts Department of Public Utilities from currently accepted regulatory standards followed by the Massachusetts Department of Environmental Protection (MA DEP) in their interpretation of the best available control technology standard (Heinze-Fry, 1991).

Purchases

Power transactions involving purchases from outside the NEPOOL territory were modeled using similar conventions as MIT/AGREA (1990). These conventions include price assumptions and the split between thermal and non-thermal sources. Non-thermal purchases were dispatched as peak-shaving. Emissions from thermal purchases are based on that of a 200 MW pulverized coal unit burning low sulfur coal with flue gas desulfurization, again following the approach of MIT/AGREA (1990). We used the raw emission rates from the latter document for low sulfur coal with 90% SO_2 reduction as specified for the NSPS in EPRI (1989), and NO_x and carbon as uncontrolled.

Non-Utility Generation (NUG)

The CELT report (1990) gave NUG capacity broken down by thermal and non-thermal categories. NUG forced outage and maintenance rates are based upon the GTF report (1989) weighted by capacity of technologies represented in the NUG categories. Payments to NUGS are based on the contracts held by two entities currently operating in New England, Dartmouth and ENRON, as reported in Kahn et al. (1990). Emissions from thermal NUGs are based on the MA DEP (1990) currently accepted regulations by technology and pollutant. These data were converted into emissions rates per unit fuel input (i.e., lbs/MBtu) by the MA DPU (Heinze-Fry, 1991). For the subset of thermal NUGs that were cogeneration plants, we disaggregated them into those with high, medium, and low steam load situations in order to establish appropriate net heat rates for those plants (see Appendix I). With these net cogeneration heat rates, and assumed heat rates for the remaining NUG capacity, we applied the above MDPU emission rates to arrive at thermal NUG emission factors used as input to the UPLAN model.

Unit Commitment

Using the NEPEX rules for spinning reserve of four-ninths of 150% of the largest thermal generating unit, we employed UPLAN's unit commitment feature to meet this target in dispatching plants on each monthly load duration curve.

Loads

We used hourly load data from Northeast Utilities service territory from 1 July 1989 to 30 June 1990. The data were converted into EEI format and then processed into monthly typical weeks using an endogenous routine of UPLAN. Because EEI data are typically given for calendar years (i.e., January through December) and the Northeast Utilities data spanned two years, some minor transformations were made to the data to create a calendar year of loads while preserving the daily sequence of days of the week (i.e., Mondays through Sundays).

Following the generation of typical weeks, we employed another UPLAN routine for adjusting some of the weekly load shapes to roughly match (i.e., within 2%) the monthly load factors forecast for the CELT report (NEPLAN, 1990). Table B.2 presents the load factors from the raw and adjusted typical weeks of NU load data as compared to the CELT forecast for NEPOOL in 1990 (NEPLAN, 1990).

Table B.2. Load Factors from Monthly Typical Weeks: Northeast Utilities			
Month	**Raw Load Factor**	**Adjusted Load Factor**	**NEPOOL 1990 Load Factor**
January	0.72	0.75	0.76
February	0.65	0.75	0.77
March	0.77	0.76	0.74
April	0.74	0.74	0.74
May	0.66	0.70	0.72
June	0.66	0.66	0.66
July	0.67	0.67	0.67
August	0.70	0.66	0.64
September	0.62	0.65	0.67
October	0.78	0.78	0.77
November	0.72	0.69	0.67
December	0.76	0.74	0.72

For the forecast year 2005, we employed the above typical weeks scaled to match the CELT forecast of energy generation requirement of 151 TWh in that year.

Benchmarking Existing System

The UPLAN characterization of the NEPOOL power system was benchmarked to results from Northeast Utilities' modeling of NEPOOL using the Polaris model (Stillinger, 1991). We compared results for 1991, the base year of NEPOOL modeling by NU. First we compared our characterization of NEPOOL in terms of the capability of projected utility and non-utility resources in 1991. Table B.3 shows the comparison of UPLAN, Polaris, and that reported by NEPOOL in the CELT report (NEPLAN, 1990).

Table B.3. Unit Capabilities Compared (MW)				
	1991 UPLAN (LBL)	**1991 Polaris (NU)**	**90/91 CELT January**	**1991 CELT August**
Nuclear	6360		6645	6382
Coal	2850		2793	2769
Oil/Gas	11050		11598	10789
Sub-total Utility thermal	20260	21188	21036	19940
Conventional Hydro	1420		1427	1416
Pumped Storage	1680		1698	1679
Sub-total Utility Hydro	3100	3099	3125	3095
Purchases	2110	2473	1524	2485
NUGs	1840	1954	1778	1831
TOTAL	27310	28714	27463	27351

Next, we calibrated the UPLAN output to that of NU Polaris modeling of the base year 1991. Our aim in performing the calibration was to replicate key model results of NU's modeling to within a 5-10% range. We concentrated on total production cost, emissions, and generation by fuel type for our calibration. Table B.4 shows the results of this comparison.

Table B.4. Model Output Comparison

	UPLAN (LBL)	Polaris (NU)	Difference (%)
Generation: (GWh)			
Nuclear	43177	43443	-1%
Coal	17417	17462	0%
Oil & Gas	24697	24707	-1%
Conventional Hydro	5929	5019	18%
Pumped Storage	479	1798	-73%
Purchases	11738	11491	2%
NUGs	10230	10245	0%
TOTAL	113995	114165	0%
Production Cost (M$)	2776	2877	-4%
Emissions (k tons):			
SO_2	361	330	10%
NOx	165	150	10%
C	14303	13373	7%

Adjustments were made to the preliminary UPLAN input file in the availabilities of the nuclear, coal, and NUG units in order to bring the UPLAN output into reasonable agreement with the Polaris output. NU assumed rather optimistic performance for the nuclear units, such that the capacity factor for these units reached 78%. Coal plant performance assumed by NU resulted in an overall 70% capacity factor. We calibrated these and the NUG performance to the NU output, while maintaining our original assumptions for the remaining units in the system, leaving the model to determine their energy contribution. Because we modeled all dual oil/gas units in the existing system as oil only, and all distillate/gas units as a fictitious fuel with a hybrid of the distillate and gas prices, we combine all three petroleum fuels together in our comparison to NU. With the exception of hydro generation, the UPLAN model predicts energy generation by fuel type to within 2% of NU's Polaris runs. Total production cost as calculated by UPLAN is 4% lower than Polaris's. SO_2 and NO_x are emitted 10% higher, and carbon 7% higher than Polaris predicts. Since few details were presented by NU on their modeling runs we can only speculate as to why emissions and hydro output differ.

Once the UPLAN file was benchmarked, we made changes to the input file for two principal reasons: 1) to roll back the base year to 1990 from 1991; and 2) to reflect a differing view of likely nuclear performance. To bring the base case year to 1990, in addition to using that year's load forecast and fuel prices, we reduced the amount of NUG capacity, removed the Hydro Quebec Phase II contract from power purchases, and took out the Ocean State combined-cycle unit. National average nuclear plant performance has resulted in capacity factors around 65%. We understand that in New England the nuclear plants have performed above average overall. Thus, our prognosis for NEPOOL nuclear plant performance translates into an average future availability of around 72%.

Future Units

For the base case 2005 resource plan, we based most of our assumptions on future unit characteristics on the GTF report (NEPLAN, 1989). For the composition of the resource mix in 2005 we relied on analysis by New England Governor's Council (NEGC, 1990a,b,c), the details of which were clarified by participants in the analysis (Andrews, 1991). Other appendices describe in greater detail our development of the resource potentials for various alternative resources that form the scenarios presented in the body of this report.

APPENDIX C: FUEL PRICES

Fuel price projections

In this study, the New England Power Pool General Task Force (NEPOOL GTF) assumptions are used for calculating the fuel costs of conventional resources. Levels and trends of biomass fuel prices are discussed in Appendix J. Table C.1 summarizes the fossil fuel price projections for the utility sector as assumed by NEPOOL's generation task force (NEPLAN, 1989) and compares them with the forecast of U.S. DOE (1990). All prices are given in 1989 constant dollars.

It is apparent that the GTF projections are quite comparable to the EIA forecast, and to the forecast of the Gas Research Institute (GRI, 1989). In all cases, gas and oil prices grow by more than four percent per year in real terms. This price rise is projected to continue unabated for thirty years.

Fuel price divergence between coal and gas

While gas (and oil) prices rise rapidly, the projected real escalation of coal prices is very small. As a result, the fuel price advantage of coal grows over time. In the GTF projections, the fuel price ratio of gas to coal is 1.35 in 1990, climbs to 3.3 in 2009, and reaches 5.6 in 2020. This divergence of prices is dampened when fuel costs are levelized over the life of a power plant. The levelized 1990-2020 gas price is only 2.5 times as high as that for coal.

These ratios point to an important issue in making busbar cost comparisons of alternative plants. Given the forecast horizon of Table C.1, only those plants being commissioned now can be compared on a levelized fuel cost basis. As shown in Appendix G, gas-fired advanced combined cycle plants are more advantageous than coal plants in New England when the levelized 1990-2020 gas price is used as a basis for comparison.

For plants that are to be commissioned in future years, the fuel price projections must be extrapolated beyond the year 2020. Assuming that the divergence between coal prices and gas prices continues to grow, the levelized gas price will eventually reach a point where coal plants become cheaper despite their higher capital costs. In principle, then, a comparison of alternative resource plans requires assumptions about gas and coal price trends for thirty years beyond the actual planning horizon, and busbar cost comparisons become correspondingly uncertain.

Backstop effects and impacts of carbon reduction goals

There is reason to question whether these escalation rates for natural gas prices are sustainable over several decades, since new technologies and alternative fuels will act as backstops. Williams and Larson (1988) show how integrated coal gasification combined cycle plants (IGACCs) would likely provide such a backstop function in a conventional planning environment in which no consideration is given to carbon reductions.

We use the GTF assumptions for IGACC coal plants to calculate a backstop gas price at which coal plants and gas plants would break even. This price is about $7/million Btu.

In Table C.1, we show the levelized gas price when prices rise at projected rates until they reach this backstop level. On that basis, the average growth rate over the 1990-2020 period drops from close to 5 percent real to a little more than 3 percent. The 1990-2020 levelized price is $4/million Btu, or about 25 percent lower than the levelized gas price without backstop, which was $ 5.18/million Btu.

In conclusion, a more realistic gas price projection under conventional energy plans might be that gas prices grow at 3 percent real per year, rather than at the 4.5 to 5 percent rates found in the above forecasts.

Whether this backstop function would materialize in New England is unclear. Though one coal gasification plant is being planned by Texaco in Massachusetts, coal-fired power stations face significant siting constraints in that region, and coal gas might not play its competitive role unless it is brought into the region by pipeline.

Impact of carbon reduction strategies

In the context of a carbon reduction strategy, the backstop function of coal gasification will be lost, since the use of coal will have to be avoided. A carbon reduction strategy would increase the price of gas, unless other low-carbon resources are sufficient to limit gas demand to levels assumed in the reference scenario.

However, at the same time that gas prices could be pushed higher than what they would have been in the reference case, coal and oil demand would be reduced, and their prices would be expected to be lower than in the reference case. This would reduce society's fuel bill for coal and oil, which could offset at least part of the impact of higher gas prices. To determine the true net cost of a carbon reduction strategy, these secondary effects have to be taken into account.

3. Treatment of fuel price dynamics in this study

These fuel market dynamics can at best be described qualitatively, as they cannot be reliably quantified. In view of this situation, we proceed as follows:

- — We neglect any backstop effects and use the GTF fuel price forecast for the reference case.
- — As a starting point, we use the same GTF fuel price forecast for the various low-carbon resource mixes.
- — We then examine the degree to which gas demand would rise under various carbon reduction strategies. So long as gas demand changes only modestly, we assume that the GTF fuel price forecast is applicable in these cases as well.
- — In our scenario analysis, we also explore a low price case in which gas and oil prices escalate only 2%/year in real terms.

These reference and low price cases are used in our production cost modeling to capture the effect of fuel price uncertainty on our results.

Table C.1: Comparison of utility fuel price forecasts							
	units	*First year of forecast*	*Last year of forecast*	*Extended to 2020*	*Annual % real growth*	*Levelized fuel price*	*Levelized/ first year*
GTF 1989							
Year		*1990*	*2009*	*2020*			
Firm gas price	$/MMBtu	2.70	7.00	12.15	5.1%	5.18	1.92
Interruptible gas price	$/MMBtu	2.60	6.10	9.99	4.6%	4.62	1.78
Oil #2 price	$/MMBtu	4.00	8.00	11.95	3.7%	6.32	1.58
Oil #6 (med S) price	$/MMBtu	2.80	5.90	9.08	4.0%	4.59	1.64
Coal (med S) price	$/MMBtu	2.00	2.10	2.16	0.3%	2.06	1.03
Nuclear	$/MMBtu	0.70	0.55	0.48	-1.3%	0.61	0.87
GTF 1989 with $7/MMBtu backstop							
Year		*1990*	*2009*	*2020*			
Firm gas price	$/MMBtu	2.70	7.00	7.00	3.2%	4.00	1.48
Interruptible gas price	$/MMBtu	2.60	6.10	7.00	3.4%	3.91	1.51
Oil #2 price	$/MMBtu	4.00	7.00	7.00	1.9%	4.99	1.25
Oil #6 (med S) price	$/MMBtu	2.80	5.90	7.00	3.1%	4.08	1.46
EIA 1990							
Year		*1990*	*2010*	*2020*			
Base Case							
Natural gas price	$/MMBtu	2.39	6.00	9.51	4.7%	4.32	1.81
Oil #6 price	$/MMBtu	2.75	6.21	9.33	4.2%	4.61	1.68
Coal price	$/MMBtu	1.47	1.86	2.09	1.2%	1.69	1.15
High Case							
Natural gas price	$/MMBtu	2.63	6.07	9.22	4.3%	4.47	1.70
Oil #6 price	$/MMBtu	3.11	7.98	12.78	4.8%	5.71	1.84
Coal price	$/MMBtu	1.47	1.85	2.08	1.2%	1.68	1.14
Low Case							
Natural gas price	$/MMBtu	2.17	5.06	7.73	4.3%	3.72	1.71
Oil #6 price	$/MMBtu	2.40	4.58	6.33	3.3%	3.58	1.49
Coal price	$/MMBtu	1.47	1.85	2.08	1.2%	1.68	1.14
EIA 1990, with $7/MMBtu backstop							
Year		*1990*	*2010*	*2020*			
Base Case							
Natural gas price	$/MMBtu	2.39	6.00	7.00	3.6%	3.74	1.56
Oil #6 price	$/MMBtu	2.75	6.21	7.00	3.2%	4.04	1.47
High Case							
Natural gas price	$/MMBtu	2.63	6.07	7.00	3.3%	3.94	1.50
Oil #6 price	$/MMBtu	3.11	7.00	7.00	2.7%	4.32	1.39
Low Case							
Natural gas price	$/MMBtu	2.17	5.06	7.00	4.0%	3.55	1.64
Oil #6 price	$/MMBtu	2.40	4.58	6.33	3.3%	3.58	1.49

Note: All prices are in 1989 $.

APPENDIX D: EMISSION FACTORS AND EXTERNALITY SURCHARGES

Fossil carbon burdens: boundary issues

The choice of the accounting system for carbon emissions (and for other environmental impacts) is an important policy issue when implementing externality policies. There are several ways in which the carbon emissions of power plant fuels can be defined:

- Direct emissions at the power plant;
- Direct emissions plus indirect emissions from the entire fuel cycle and its manufactured materials inputs;
- Emissions of carbon plus emissions of other greenhouse gases, notably methane, on a carbon-equivalent basis;
- Inclusion of carbon or carbon-equivalent emissions that are avoided outside the powerplant fuel cycle.

Direct emissions

Table D.1 shows a compilation of direct, indirect, and carbon-equivalent emissions based on Krause et al. (1992). The first data column presents carbon burdens on a direct emissions basis. In current practice, and specifically under the externality valuation systems of the New York Public Service Commission (NY PSC) and the Massachusetts Department of Public Utilities, only direct emissions at the power plant are counted. The New York system only acknowledges carbon dioxide as a greenhouse gas pollutant. The Massachusetts system includes a monetization of power plant methane emissions as well. However, no explicit consideration is given of emissions avoided outside the power plant fuel cycle.

Indirect emissions

Indirect emissions are estimated from process analyses rather than from chemical analysis, and are thus less accurate. They can also be quite region specific, since they incorporate the distances over which power plant fuels and wastes are transported. They also depend on the type of fuel inputs used in fuel cycle operations.[1]

Available analyses show that indirect emissions from the fossil fuel cycles are typically less than ten percent of the direct carbon burden.[2] Carbon burdens associated with inputs into

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[1] These input fuels could themselves vary regionally in terms of their carbon burdens. For example, the nuclear enrichment facilities in the United States are located in states that depend heavily on coal-fired electricity (see below).

[2] See, for example, CEC (1990b) for California, and Fritsche et al. (1989).

the fuel cycle facilities, such as steel or cement for power plants and feedstocks for building insulation materials, are typically an order of magnitude smaller, but can be significant in individual instances.

As an example, Table D.2 shows the indirect carbon burden associated with the nuclear fuel cycle in the United States. The carbon burden is significant on account of the energy-intensive enrichment process. Currently, all enrichment in the United States is done with gas diffusion, and the enrichment facilities are located in utility service territories that rely heavily on coal generation.

Fossil-carbon equivalent emissions

Besides fossil carbon dioxide, the other major greenhouse gases are methane; chlorofluorocarbons (CFCs) and related industrial chemicals; nitrous oxide; and net carbon dioxide releases from the stock of carbon in the terrestrial biosphere. The global warming potential of these gases can be expressed in relative terms or carbon-equivalents (Krause et al. 1989a).

Methane has the greatest potential for affecting rates of global warming. Accounting for the exact contribution of methane is difficult because the scientific knowledge about the carbon equivalence of methane is still imprecise. Based on current estimates, the carbon equivalence of methane on the basis of its atmospheric residence time varies from less than a factor of five to about a factor 30, depending on the time horizon over which warming effects are integrated, and on assumptions about atmospheric chemical processes.[3] Thus, small emissions of methane associated with fuel cycle operations could have a significant impact on the carbon-equivalence of the fuel.

However, significant methane emissions are associated with the gas, oil, and coal fuel cycles. For this reason, the relative ranking of the three major fossil fuels in terms of their carbon versus carbon-equivalent burdens will not be fundamentally altered in most fuel cycles. Anticipated technical efforts to capture more of the methane released from coal seams, from petroleum production and processing, and from natural gas production and distribution, are likely to reduce the significance of these emissions in the future.

Power generation derived from biomass fuels could contribute significant biospheric net carbon emissions if employed on a major scale and if biomass is grown on a non-sustainable basis.[4] CFCs have played a role in some demand-side management (DSM) resources, notably those based on CFC-blown insulating foams, and in efficiency improvements of heat pumps and refrigeration equipment. Substitutes are being implemented that will eliminate these CFC sources.

Emissions avoided outside the powerplant fuel cycle

Cogeneration. The issue of accounting for offsets of carbon or carbon-equivalent emissions arises in several forms. In the case of cogeneration, a portion of the power plant

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[3] For a detailed discussion, see IPCC (1990).

[4] See Krause et al. (1989a), Chapter I.3, for a discussion of the issue of land-use changes in accounting for net carbon emissions from forestry operations.

fuel input is being charged to the displaced boiler. On an energy basis, this effect is typically captured by defining a fuel portion chargeable to power, or a net heat rate.

However, the carbon burden of the displaced boiler fuel may be different from that of the fuel used in the cogenerator. In New England, the displaced fuel would typically be distillate or heavy fuel oil. When the cogenerator fuel is gas, each kWh of power cogenerated thus creates a reduction in carbon emissions in the delivery of thermal energy services. Conversely, when the cogenerator fuel is coal, an increase is caused. Appendix I gives the mathematical formulation for accounting for this factor.

Landfill gas. Landfill methane is derived from the biomass-derived rather than fossil-derived components of landfill. Because the fossil-derived components of landfill, such as plastic and tires, do not decompose anaerobically, landfill gas has no direct fossil carbon burden. Generators fired by landfill gas reduce methane emissions that would otherwise have occured from the anaerobic decomposition of wastes.[5] This leads to a pronounced carbon-equivalent emission credit, shown as a negative carbon-equivalent burden in Table D.1.

Refuse fuel. A similar effect applies in the case of power generation from municipal solid waste. Here, the direct emissions of fossil carbon are significant, since plastics and other fossil-derived materials constitute a significant fraction of the heating value of municipal solid waste (MSW). At the same time, the combustion of MSW fuel avoids landfill gas emissions (see Appendix K for further details).

In this accounting, the net fossil carbon and carbon-equivalent burden depends on the composition of the landfill material, which is a function of the overall utilization of the waste stream, including anticipated trends in recycling. When landfill gas emissions are already being captured and are themselves used for power generation, a further accounting complexity arises. The derivation of the MSW carbon burden shown in Table D.1 is found in Appendix.K.

Finally, power production from MSW could be treated entirely as a by-product of a separate societal activity outside the power sector, i.e., waste disposal and waste reduction through combustion. In that case, all fossil-carbon and carbon-equivalent emissions would be assigned to the activities generating the waste stream, and not to the power sector.

Direct fossil carbon and acid rain emissions by technology

In the present study, only direct emissions are considered, and municipal solid waste is assigned a zero carbon burden. Table D.3 shows the emission burdens of SO_2, NO_x, and CO_2 per unit of electricity for the generating technologies examined in this study. The emission factors for cogeneration power plants and displaced boilers are shown in Table D.4. Boiler emission factors are based on EPA (1985). The methodology for calculating net emissions for cogeneration systems is explained in Appendix I.

The emission burdens for carbon are based on the heat rates, with special treatment of cogeneration plants. The emission burdens for acid rain precursors are based on the input fuel emission factors as given in MIT (1990). In the case of NO_x, selective catalytic reduction (SCR) or its equivalent was assumed. In Massachusetts, SCR is currently

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5 See Appendix K for details.

defined as best available control technology for plants greater than 100 MMBtu/hr (29.3 MW) input. Corresponding emission factors were adopted from Heinze-Frey (1991).

The MDPU surcharges

The application of externality surcharges in power plant cost evaluations was mandated in a recent MA DPU order DPU 89-239 (August 31, 1990). This order required that such surcharges be applied when utilities compare new power plant resource options. Table D.5 compares different estimates of external costs associated with air pollutant emissions.

The values chosen by the MA DPU are roughly 1.5 to 3 times higher than those implied in the environmental portion of the NY Public Service Commission's bidding systems (NY PSC 1989).

Application to existing plants

Though the application of the MDPU surcharges is currently limited to new plants, proposals have been made to apply it to existing plants as well. Below, we calculate the impact of such an extension of the surcharges on the cost of running existing oil and coal plants.

Table D.6 shows emissions factors for existing oil and coal steam plants in the Northeast United States. Tables D.7 and D.8 show the per unit surcharge (in 1989 ¢/kWh) implied by the externality values in Table D.5 and the emissions factors and heat rates in Table D.6.

Results

Even without the surcharge for carbon emissions, the MA DPU externality charges imply hefty increases in power plant variable costs: 2¢/kWh added for an oil steam plant, and 3.5¢/kWh for a coal steam plant.

When the carbon charge is included, the coal plant's external costs rise to almost 6¢/kWh, and the oil plant's external costs jump to more than 4¢/kWh. The externality costs, in combination with fuel costs, would make existing oil and coal plants more expensive on a levelized basis than new gas-fired advanced combustion cycle plants (see Appendix G).

These results compare to external costs of 0.9¢/kWh for the oil plant and 1.5¢/kWh for the coal plant if the values implicit in the NY PSC system are used.

Application to new plants

Table D.9 shows the impact of the MDPU adder on the supply options considered in this study (see Appendices G, I, J, and L). Values are given for the combination of CO_2, SO_2,and NO_x, and for SO_2 and NO_x alone. The table shows that the full adders including carbon dioxide have a pronounced effect on new resource costs:

- Coal-fired plants receive penalties of 2.6-2.8¢/kWh.
- Gas-fired central stations receive surcharges of 1.3-1.5¢/kWh.

- Gas-fired cogeneration systems incur much lower penalties of only 0.4-0.6¢/kWh when thermally optimized, but do only somewhat better than central stations when designed as PURPA machines.
- Biomass-fired cogeneration systems earn externality credits due to the emissions they displace in fossil-fired thermal applications.

These surcharges make current wind turbine and central station biomass technology cheaper than coal plants, but still not competitive with gas ACC plants or cogeneration plants. Further details can be found in Appendices G, I, J, and L.

Table D.1: Carbon burdens and equivalent carbon burdens for various fuels									
Fuel	C burden direct g C/kWh	C burden indirect g C/kWh	C burden total g C/kWh	*Index 1*	*Index 2*	Total CH4 emissions g C.e/kWh	Total equiv. C burden g C.e/kWh	*Index 1*	*Index 2*
Hard coal	91.31			*1.00*	*1.00*			*1.00*	*1.00*
Hard coal to ind. or utility plant	90.33	2.90	93.22	*1.02*	*1.00*	9.53	102.75	*1.13*	*1.00*
Hard coal briquets to sm. cons.	91.31	3.34	94.65	*1.04*	*1.00*	9.42	104.07	*1.14*	*1.00*
Raw lignite	109.96			*1.00*	*1.20*			*1.00*	*1.20*
Lignite to utility plant	109.96	3.14	113.11	*1.03*	*1.21*	0.04	113.14	*1.03*	*1.10*
Lignite products to ind. & sm. cons.	95.24	16.54	111.78	*1.02*	*1.07*	-0.09	111.69	*1.02*	*1.07*
Crude oil	77.69			*1.00*	*0.85*			*1.00*	*0.85*
Heavy fuel oil to ind. or utility plant	76.58	6.28	82.87	*1.07*	*0.89*	2.14	85.01	*1.09*	*0.83*
Light heating oil/diesel to sm. cons.	71.67	6.73	78.40	*1.01*	*0.83*	2.14	80.54	*1.04*	*0.77*
Gasoline to sm. consumers	68.09	6.77	74.86	*0.96*	*0.79*	2.14	77.00	*0.99*	*0.74*
Natural gas	54.00			*1.00*	*0.59*		54.00	*1.00*	*0.59*
Gas to ind. or utility plant	54.00	2.95	56.95	*1.05*	*0.61*	0.52	57.47	*1.06*	*0.56*
Gas to small consumers	54.36	2.90	57.26	*1.06*	*0.60*	3.42	60.68	*1.12*	*0.58*
Fuel wood to sm. consumers	0.00	0.79	0.79	*n.a.*	*0.01*	0.00	0.79	*n.a.*	*0.01*
Municipal waste to utility plants	39.27	0.00	39.27	*n.a.*	*0.43*	0.00	39.27	*n.a.*	*0.43*
Uranium to utility plants	0.00	4.61	4.61	*n.a.*	*0.05*	0.09	4.71	*n.a.*	*0.05*

Notes:

(1) For derivation, see Krause et al. (1992).

(2) Index 2 compares three fuel destinations (direct burdens only; total burdens for large consumers; same for small consumers).

Table D.2: Indirect carbon emissions from nuclear reactors in the U.S.

	Indirect Electricity MWh/reactor-yr	*Indirect Fossil fuels B Btus/reactor-yr*	*Indirect Electricity kWh/kWh.e*	*Indirect Fossil fuels Btus/kWh.e*	*Indirect C from Electricity g/kWh.e*	*Indirect C from Fossil fuels g/kWh.e*	*Total Indirect C g/kWh.e*
Uranium Mining	*3780*	*85*	*0.001*	*12.94*	*0.15*	*0.18*	*0.33*
Construction	370	26	0.000	3.96	0.01	0.06	0.07
Operation	3410	59	0.001	8.98	0.13	0.13	0.26
Milling	*5110*	*83.9*	*0.001*	*12.77*	*0.20*	*0.18*	*0.38*
Construction	160	6.9	0.000	1.05	0.01	0.01	0.02
Operation	4950	77	0.001	11.72	0.19	0.17	0.36
Conversion	*3390*	*290*	*0.001*	*44.14*	*0.13*	*0.62*	*0.75*
Construction	46	4	0.000	0.61	0.00	0.01	0.01
Operation	3344	286	0.001	43.53	0.13	0.61	0.74
Enrichment	*612965*	*87.625*	*0.093*	*13.34*	*24.05*	*0.19*	*24.24*
Construction	1665	15	0.000	2.28	0.07	0.03	0.10
Operation	611300	72.63	0.093	11.05	23.99	0.16	24.14
Fuel Fabrication	*11687*	*8.75*	*0.002*	*1.33*	*0.46*	*0.02*	*0.48*
Construction	37	0.35	0.000	0.05	0.00	0.00	0.00
Operation	11650	8.4	0.002	1.28	0.46	0.02	0.48
Total	*636932*	*555.28*	*0.097*	*84.52*	*24.99*	*1.19*	*26.18*
Construction	2278	52.25	0.000	7.95	0.09	0.11	0.20
Operation	634654	503.03	0.097	76.56	24.90	1.08	25.98

(1) 1000 MWe reactor assumed in ORNL (1980) to operate at 75% capacity factor, yielding 6.57 TWh.
(2) all fossil fuel assumed to be natural gas, as a conservatism.
(3) fossil fuels used as feedstocks have not been included, only fuels directly used for energy.
(4) enrichment assumed to be by gaseous diffusion technology (the only type currently existing in the U.S.)
(5) Carbon emissions factor for electricity is the average for Kentucky and Ohio, the two states with gaseous diffusion enrichment plants operating within their boundaries.
(4) Source for energy use: ORNL 1980.

Table D.3: Direct emission burdens per unit of electricity output.

	Heat Rate *kWh.f/kWh.e*	*Carbon* *g/kWh.e*	*NOx* *g/kWh.e*	*SOx* *g/kWh.e*
Gas CT	3.84	192	0.625	0.004
Gas CCC	2.48	124	0.404	0.002
Gas ACC	2.22	111	0.362	0.002
Coal ST	2.69	240	0.501	0.734
Coal AFB	2.77	247	0.515	0.755
Coal IGACC	2.67	239	0.369	0.730
Nuclear LWR	3.10	0	0.000	0.000
Wind	1.00	0	0.000	0.000
Biomass ST	4.29	0	1.064	0.007
BIG ISTIG	2.38	0	0.591	0.004
BIG ISTIG Cogen	1.85	-25	0.038	-0.197
Ind. GT	2.03	80	-0.048	-0.763
Packaged IC	1.64	62	-0.063	-0.708
Ind. CC	1.71	66	-0.062	-0.717
PURPA CC	2.13	103	0.141	-0.140
Biomass ST cogen	3.00	-198	-0.70	-1.55

Notes:

(1) Heat rates are converted to Btu per kWh of electricity by multiplying by 3412 Btu/kWh.

(2) Negative emissions for cogeneration results from correct accounting for avoided emissions from displaced boiler fuels

Table D.4: Net emission factors for cogeneration systems

	Net heat rate cogen kWh/kWh	EPR cogen kWh/kWh	NOx cogen g/kWh.f	NOx boiler g/kWh.f	SO2 cogen g/kWh.f	SO2 boiler g/kWh.f	Carbon cogen g/kWh.f	Carbon boiler g/kWh.f	Carbon net cogen g/kWh.e	NOx net cogen g/kWh.e	SO2 net cogen g/kWh.e
BIG ISTIG Cogen	1.85	1.49	0.086	0.240	0.000	0.250	0.0	31.9	-25.2	0.038	-0.197
Ind. GT	2.03	0.76	0.086	0.230	0.003	0.500	50.1	63.9	80.4	-0.048	-0.763
Packaged IC	1.64	0.82	0.072	0.198	0.003	0.500	50.1	63.9	62.4	-0.063	-0.708
Ind. CC	1.71	0.81	0.086	0.230	0.003	0.500	50.1	63.9	65.7	-0.062	-0.717
PURPA CC	2.13	4.00	0.086	0.230	0.003	0.500	50.1	63.9	102.6	0.141	-0.140
Biomass ST cogen	3.00	0.19	0.086	0.240	0.000	0.250	0.0	31.9	-197.7	-0.696	-1.548

Table D.5: Value of incremental emissions reductions (1989$/lb)

	SO2 *$/lb SO2*	*NOx* *$/lb NOx*	*CO2* *$/lb C*	*ROG* *$/lb ROG*	*CH4* *$/lb CH4*	*N2O* *$/lb N2O*	*CO* *$/lb CO*	*Particulates* *$/lb PM*
EPRI (1986)								
Low	0.21	0.02	0.00	0.00	0.00	0.00	0.00	0.00
High	0.85	0.23	0.00	0.00	0.00	0.00	0.00	0.00
Best Estimate	0.48	0.07	0.00	0.00	0.00	0.00	0.00	0.00
Hohmeyer (1988)								
Low	0.233	0.292	0.00*	0.233	0.00	0.00	0.00	0.233
High	1.244	1.555	0.00*	1.244	0.00	0.00	0.00	1.244
Chernick et al. (1989)	0.92	1.58	0.042	0.00	0.37	0.00	0.00	0.00
Shilberg et al (1989)								
Outside CA	0.50	1.35	0.027	0.33	0.19	1.85	0.00	0.00
CA Outside SCAQMD	0.90	9.40	0.027	0.57	0.19	1.85	0.00	0.00
CA Inside SCAQMD	9.15	12.25	0.027	8.75	0.19	1.85	0.00	0.00
CEC Staff (1989)	5.75	5.80	0.013	1.65	0.00	0.00	0.00	3.9
Implied in NY PSC System (1989)	0.48	0.94	0.0015	0.00	0.00	0.00	0.00	1.01
MA DPU (1990)	0.75	3.25	0.040	2.65	0.11	1.98	0.43	2

(1) NY PSC #s were derived from the PSC's worksheet, as described in Koomey (1990).
(2) Particulate matter estimates (PM) of CEC are for all particulates less than 10 microns in diameter, while NY PSC and MA DPU systems do not distinguish particulates by size.
(3) ROG = Reactive Organic Gases (essentially equivalent to volatile organic compounds)
(4) Hohmeyer does estimate external costs for global climate change, but the $/lb number for CO2 or other greenhouse gases was not available at press time.

Table D.6: Emissions factors for existing New England power plants						
	Existing coal steam (0.7% S Coal)			*Existing oil steam (1% S Resid. Oil)*		
	lbs/MMBtu	*g/kWh fuel*	*g/kWh elect.*	*lbs/MMBtu*	*g/kWh fuel*	*g/kWh elect.*
Direct Emissions						
SO2	1.13	1.75	5.39	0.80	1.24	3.95
NOx	0.70	1.09	3.34	0.30	0.47	1.48
Carbon	57.6	89.33	274.61	46.4	71.96	228.84
ROG	0.0028	0.00	0.01	0.0051	0.01	0.03
CH4	0.0012	0.0019	0.01	0.0019	0.0029	0.01
N2O		0.00	0.00		0.00	0.00
CO	0.024	0.04	0.11	0.033	0.05	0.16
Particulates	0.1	0.16	0.48	0.09	0.14	0.44
Indirect Emissions						
SO2		0.00	0.00		0.00	0.00
NOx		0.00	0.00		0.00	0.00
Carbon	0.77	1.19	3.67	6.88	10.67	33.93
ROG		0.00	0.00		0.00	0.00
CH4		0.0000	0.00		0.0000	0.00
N2O		0.00	0.00		0.00	0.00
CO		0.00	0.00		0.00	0.00
Particulates		0.00	0.00		0.00	0.00
Total Emissions						
SO2	1.13	1.75	5.39	0.80	1.24	3.95
NOx	0.70	1.09	3.34	0.30	0.47	1.48
Carbon	58.37	90.53	278.28	53.28	82.63	262.77
ROG	0.00	0.00	0.01	0.01	0.01	0.03
CH4	0.00	0.00	0.01	0.00	0.00	0.01
N2O	0.00	0.00	0.00	0.00	0.00	0.00
CO	0.02	0.04	0.11	0.03	0.05	0.16
Particulates	0.10	0.16	0.48	0.09	0.14	0.44

Notes:

(1) Heat rates (HHV) are based on 10,500 Btu/kWh.e for coal plants, and 11,400 Btu/kWh.e for residual oil plants.
(2) Heat rates and emissions are calculated per delivered kWh using T&D losses of 6 percent.
(5) Methane and indirect C emissions from CEC (1990).
(6) Direct Particulates, SO2, and NOx emissions from Connors and Andrews, 1990.
CO and VOC (i.e. ROG) emissions from Bernow et al 1990.

Table D.7: Externality Costs from air emissions from existing New England coal steam plant				
in ¢/kWh delivered	*NY PSC*	*MA DPU Full C charge*	*MA DPU 50% C charge*	*MA DPU No C charge*
Direct Emissions	1.45	5.94	4.72	3.50
SO2	0.57	0.89	0.89	0.89
NOx	0.69	2.39	2.39	2.39
Carbon	0.09	2.44	1.22	0.00
ROG	0.00	0.01	0.01	0.01
CH4	0.00	0.00	0.00	0.00
N2O	0.00	0.00	0.00	0.00
CO	0.00	0.01	0.01	0.01
Particulates	0.11	0.21	0.21	0.21
Indirect Emissions	0.00	0.03	0.02	0.00
SO2	0.00	0.00	0.00	0.00
NOx	0.00	0.00	0.00	0.00
Carbon	0.00	0.03	0.02	0.00
ROG	0.00	0.00	0.00	0.00
CH4	0.00	0.00	0.00	0.00
N2O	0.00	0.00	0.00	0.00
CO	0.00	0.00	0.00	0.00
Particulates	0.00	0.00	0.00	0.00
Total Emissions	1.45	5.97	4.74	3.50
SO2	0.57	0.89	0.89	0.89
NOx	0.69	2.39	2.39	2.39
Carbon	0.09	2.47	1.23	0.00
ROG	0.00	0.01	0.01	0.01
CH4	0.00	0.00	0.00	0.00
N2O	0.00	0.00	0.00	0.00
CO	0.00	0.01	0.01	0.01
Particulates	0.11	0.21	0.21	0.21

(1) externality surcharges calculated using the value of emissions reductions from Table D.5, and the emissions factors from Table D.6.
(2) Value of carbon emissions reductions for MA DPU varied from 100% of MA DPU value to 50% of this value, and then to zero % of this value.

Table D.8: Externality Costs from air emissions from existing New England oil steam plant

in ¢/kWh delivered	*NY PSC*	*MA DPU Full C charge*	*MA DPU 50% C charge*	*MA DPU No C charge*
Direct Emissions	0.90	3.97	2.95	1.93
SO2	0.41	0.65	0.65	0.65
NOx	0.31	1.06	1.06	1.06
Carbon	0.08	2.03	1.02	0.00
ROG	0.00	0.01	0.01	0.01
CH4	0.00	0.00	0.00	0.00
N2O	0.00	0.00	0.00	0.00
CO	0.00	0.02	0.02	0.02
Particulates	0.10	0.20	0.20	0.20
Indirect Emissions	0.01	0.30	0.15	0.00
SO2	0.00	0.00	0.00	0.00
NOx	0.00	0.00	0.00	0.00
Carbon	0.01	0.30	0.15	0.00
ROG	0.00	0.00	0.00	0.00
CH4	0.00	0.00	0.00	0.00
N2O	0.00	0.00	0.00	0.00
CO	0.00	0.00	0.00	0.00
Particulates	0.00	0.00	0.00	0.00
Total Emissions	0.91	4.27	3.10	1.93
SO2	0.41	0.65	0.65	0.65
NOx	0.31	1.06	1.06	1.06
Carbon	0.09	2.33	1.17	0.00
ROG	0.00	0.01	0.01	0.01
CH4	0.00	0.00	0.00	0.00
N2O	0.00	0.00	0.00	0.00
CO	0.00	0.02	0.02	0.02
Particulates	0.10	0.20	0.20	0.20

(1) externality surcharges calculated using the value of emissions reductions from Table D.5, and the emissions factors from Table D.6.
(2) Value of carbon emissions reductions for MA DPU varied from 100% of MA DPU value to 50% of this value, and then to zero % of this value.

Table D.9: Summary of MA DPU externality costs for new power plants					
Resource	*Busbar cost at maximum capacity factor 1990 ¢/kWh*	*MA DPU externalities 1990 ¢/kWh*	*MA DPU externalities (w/o CO2) 1990 ¢/kWh*	*MA DPU externalities % of busbar cost*	*MA DPU externalities (w/o CO2) % of busbar cost*
Gas CT	15.4	2.2	0.5	15%	3%
Gas CCC	6.1	1.5	0.3	24%	5%
Gas ACC	5.6	1.3	0.3	23%	5%
Coal ST	6.7	2.7	0.5	41%	7%
Coal AFB	6.8	2.8	0.5	41%	8%
Coal IGACC	6.7	2.6	0.4	39%	6%
Nuclear LWR	10.2	0.0	0.0	0%	0%
Wind current	8.3	0.0	0.0	0%	0%
Wind advanced	5.2	0.0	0.0	0%	0%
Biomass ST	5.7	0.8	0.8	15%	14%
BIG ISTIG	5.0	0.5	0.4	9%	9%
BIG ISTIG COGEN	3.6	-0.3	-0.3	-9%	-9%
BioST cogen	5.3	0.7	0.0	14%	-1%
Ind. GT	5.1	0.6	-0.2	11%	-3%
Packaged IC	6.1	0.4	-0.2	7%	-3%
Ind. CC	4.6	0.4	-0.2	10%	-4%
PURPA CC	5.4	1.0	0.1	19%	2%

Notes:
(1) See appendices G, I, J, and L for derivation of busbar costs.
(2) Negative emissions for cogeneration results from correct accounting for avoided emissions from displaced boiler fuels

APPENDIX E: COST AND POTENTIAL OF DEMAND-SIDE EFFICIENCY IMPROVEMENTS

Previous studies

About two dozen cost and potential studies for demand-side efficiency and load management (DSM) measures have been conducted in recent years. These studies, which are of varying detail and comprehensiveness, examine the cost and efficiency savings potential by technology in each end-use of electricity for one or several economic sectors. To account for regional differences in climate, and in the statistical weight and base year unit energy consumptions of the various electricity end-uses, DSM potential studies need to be region specific.

Some of the more detailed studies are available for the U.S. residential sector (Koomey et al., 1991), Texas (Hunn et al., 1986), Michigan (Krause et al., 1988), and New York (Miller et al., 1989). A translation of the findings from the earlier studies to the New England region was undertaken in NEEPC (1987).

In the present study, we update the NEEPC analysis on the basis of the most recent study by Miller et al. for New York. For the purpose of assessing the DSM potential in New England, this study offers the advantages of comprehensiveness (coverage of both industrial, residential, and commercial sector), proximity to the New England (NE) region, and similarity of diverse, pooled utility systems. In the next section, we describe the methodology and findings from the NY study, and our approach for adapting their savings and incremental costs for New England.

The DSM technical potential in New York

The electricity savings potential as analyzed by Miller et al. (1989) for NY is based on the stock of buildings and equipment as of 1986. Sixty-two efficiency measures were applied to three sectors: residential, commercial, and industrial. The large majority of the measures are commercially available at this time. Most second generation DSM technologies and concepts that are expected to become commercially available were not included. For the residential and commercial sectors, the savings from most measures were calculated through the use of a building energy simulation model, allowing quantification of savings interactions among end-uses.

Cost-effectiveness of the measures were evaluated by calculating the marginal cost of saved energy (CSE). This levelized cost is based on the incremental cost of the conservation measure above that of less efficient measures. The cost of saved energy does not yet include program costs that might be applied to encourage the measure's adoption and to verify savings. Nor does it include cost savings due to avoided transmission and distribution investments (see below). Cost-effectiveness is examined from three perspectives: utility (10 percent real), consumer (6 percent real), and societal (3 percent real).

Major findings

The technical potential savings for New York are shown in the first set of columns of Table E.1 by sector and end-use, along with the CSE from the consumer's perspective. In Table

E.2, the measures are sorted in order of increasing CSE and show the average savings per conservation measure implied by the aggregated end-use totals shown in the previous table.

Overall, the NY study found that full adoption of the evaluated measures would reduce electricity consumption by 38%. On a sectoral basis, the technical savings potential is 37% for residential customers, 50% for commercial customers, and 22% for industrial customers. The amount of the technical savings potential that is cost-effective varies with the perspective. The consumer and societal perspectives (at 6% and 3% discount rates, respectively) show cost-effective potential savings of around 34%, whereas from the utility perspective (at 10% discount rate), they are slightly less, at 28%.

Adaptation to New England

The general approach in adapting the above technical savings potential for New York to New England is to use the end-use savings on a percentage basis from the former and apply them to the end-use shares of the latter. Miller et al. reported their results as absolute savings by measure (e.g., storm windows or ASD on fan motors) and sector (i.e., residential, commercial, and industrial). We regrouped these into end-use categories by sector and converted them into percentage savings for the sector as a whole as shown in Table E.1. The sectoral and end-use category shares of electricity consumption in New England were taken from NEEPC (1987) and NEPOOL's 1990 CELT load forecast documentation.

Based on the 1990 CELT forecast of electricity demand for New England for the year 2005, and the NY savings above, a 2005 electricity savings potential was calculated for the NE region.[1] The marginal costs of saved energy, presented in the NY study by individual technology rather than by end-use, were aggregated as the savings weighted average CSE by end-use and applied to the NE savings estimates.[2] In this manner, a supply curve was constructed (Table E.1).

Findings for New England

The overall and sectoral savings in percentage terms are shown in Table E.3. Weighted average savings are 33 percent overall, slightly lower than the 38 percent found for the New York mix of end-uses.

In the period between 1990 and 2005, NEPOOL's 1990 CELT report projects net generation requirements to grow from 112 TWh to about 160 TWh. This is in the absence

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[1] The New York study covers only existing buildings. For New England, the savings potential in existing buildings, expressed in percentage terms, was applied to new buildings as well, and so were the average costs obtained for retrofit measures. In practice, savings in new buildings could be larger or smaller, and the unit cost of savings could vary correspondingly. Our estimate could be improved in this regard, but such a refinement was beyond the scope of this study.

[2] Of the three cost perspectives in the New York study, the customer perspective discount rate at 6% is almost identical with the real discount rate of 6.3% used here. Therefore, the measure costs as calculated under the "customer" perspective are shown. Because utility program costs are typically expensed and profit incentives are only a small fraction of DSM savings, utility taxes are not applied, and only the capital recovery factor is used in calculating CSE's.

of utility DSM programs beyond the small contribution already in place in 1990 (see below). Applying the 33 percent savings factor to this forecast, the technical-economic savings potential becomes 53 TWh (Table E.4).

Note that the DSM potential as calculated relies almost entirely on currently commercial technologies. Most second generation DSM technologies and concepts were not taken into account. For comparison, the earlier 1987 NEEPC study found a technical savings potential in NE of 53 TWh by 2005 using commercially available technology, and of 81 TWh with potentially available technology.

DSM achievable potential

The difficulty and cost of applying end-use efficiency measures increases as the full technical-economic potential is approached. Reasons for this phenomenon are variations in retrofit problems by building type, differences in the immediate appeal of end-use technologies, inertia of existing installation, design, and retail trades, and outreach efforts required to directly reach those customer groups that tend to show the least response to utility incentive programs. As a result, only a portion of the technical-economic potential can be expected to be implemented through utility DSM programs, though that portion is likely to rise with utility program experience, and as utilities are allowed to share in the savings from such programs.

At the same time, a broad penetration of efficiency measures can be achieved through standards, such as the federal appliance efficiency standards. When standards are combined with utility programs, a more effective mobilization of demand-side resources can be achieved.

Estimates of the achievable potential of demand-side resources were first developed in Krause et al. (1988) based on early program experience. Subsequent in-depth analyses of exemplary program designs and resulting penetration levels for lighting programs (Krause et al., 1989b) and more broadly across all end-uses (Nadel 1990) have improved the understanding of what is achievable through well-run utility programs. In New England and other parts of the Northeastern United States, utilities also have created a database on program experience (NORDAX).

Based on these analyses, including program experience in New England itself, Nadel and Tress (1990) estimated in a follow-up study to the NY potential analysis that with best utility programs, and with new efficiency standards for appliances and lighting equipment, the achievable portion of the technical conservation potential for New York is 80 percent. Here, utility programs alone would contribute half of the achievable potential, and standards and market forces the rest. Our method of scenario construction, in which contributions from each constrained resource are limited to 75 percent of the calculated technical-economic potential, is compatible with this analysis.

Impact of current utility DSM plans

As of 1990, NEPOOL's CELT report (NEPLAN, 1990) indicates plans to implement DSM programs that would achieve about 8 TWh in electricity demand reduction, bringing the forecast down to 151 TWh for 2005.[3] A somewhat larger role for DSM is foreseen in the 1991 CELT report (NEPOOL, 1991), which indicates an energy impact of 10.5 TWh in 2006.

Some member utilities are considerably more ambitious. New England Electric System (NEES), the leading large NEPOOL utility in DSM implementation, aims to meet one-third of its demand growth over fifteen years with DSM resources and is spending 5 percent of total revenues on these programs (Destribats et al., 1991).

Precedents already exist in New England and elsewhere for still larger DSM expenditures. Several municipal utilities in the New England region are spending up to ten percent or more of their revenue on DSM, including, in some cases, fuel switching.[4] Outside the region, the largest private investor-owned utility in the nation, Pacific Gas and Electric Company, is planning to meet 75 percent of its demand growth with DSM resources over the next ten years.

Treatment of DSM potential in this study

Table E.4 summarizes the method of calculating the total DSM potential, and of accounting for DSM resources projected by NEPOOL. The table shows that in NEPOOL's 1990 CELT forecast, about 15 percent of the total 2005 DSM resource (and about 30 percent of the DSM resource that can be reached through programs rather than standards) is being utililized. At the maximum DSM contribution assumed in our scenarios, NEPOOL's 2005 demand is reduced by 25 percent to about 120 TWh.

DSM load factor

End-uses with more baseload-like loadshapes (refrigeration, water heating, motors) constitute about one third of the total savings potential (Table E.1). This fraction is comparable to the baseload fraction in total system load, but the derivation of DSM on the total system load curve is more complex. For one, the conservation resources of Table E.1 would likely be deployed in combination with load control programs such as cycling and storage.

We do not model these impacts in our analysis. It is simply assumed that, on average, demand-side efficiency resources will have the same load factor as the system as a whole. While this is a sufficient approximation for the purposes of this study, more detailed modeling approaches based on end-use loadshape impacts should be used where greater precision is required.[5]

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3 According to the 1990 CELT report, utility DSM programs had contributed an estimated 1 TWh to total loads. Revisions in the 1991 report suggest a 1990 contribution of close to 3 TWh. Similarly, the 1991 forecast raises the DSM contribution in 2006 to about 10.5 TWh. We did not adjust our modeling runs to these 1991 data.

4 Examples are the Taunton Municipal Utility and the Burlington Electric Department (see also Appendix F).

5 As emphasized in more detailed modeling studies by Connors and Andrews (1990), currently planned, limited contributions from DSM to NEPOOL loads have a low load factor. Under these circumstances, the shift of generation to cleaner plants can actually be delayed relative to a business-as-usual resource plan.

DSM technology costs

In the past, engineering estimates for technology costs have often differed from experience with real utility programs. The most comprehensive recent analysis is that by Nadel and Keating (1991) which examines 42 impact evaluations conducted on utility programs. The results of this analysis show that engineering estimates have been either too optimistic or too pessimistic depending on the situation. There are more examples of cases where engineering estimates were too optimistic.

Table E.7 summarizes the results of our technology cost estimates for New England in the 25%, 50%, and 75% cases, for high and low resource cost assumptions. The high resource cost assumptions represent the averages adopted from the New York analyses with an additional 20% cost added to account for uncertainty in the cost and performance estimates.

DSM program costs

Utility programs bring with them administrative costs for marketing, customer contacts, audits, trade ally recruitment, issuing of rebates, monitoring, and evaluation. Unlike incentive payments to customers, which are a transfer payment, these utility program administrative costs represent a true societal cost of DSM, and must be included in assessments based on the total resource cost perspective. As utilities receive a share of the DSM savings as a profit incentive, an additional cost arises for verifying reported program savings.

DSM resource potentials cannot be fully mobilized by incentive programs alone. As the cumulative participation rates of programs increase, free rider fractions also rise (Krause et al. 1989b), and reaching remaining customers becomes more difficult. At the same time, the broad market penetration of the sponsored efficiency devices forms a basis for introducing regulatory standards that make these efficiency oportunities to all consumers.

Utility incentives programs can also be supplanted by energy service companies (ESCOs). The administration, and savings verification costs of utility programs, ESCO programs, and state standards can vary significantly, and a disaggregated treatment is required. Below, we develop high and low cost estimates for these components of DSM resource costs.

Utility programs

We include program administrative costs on the basis of in-depth case study analyses as found in Krause et al. (1989b). That study finds that on a levelized basis, program administrative costs in twelve lighting programs ranged from 0.1 to 0.8 ¢/kWh saved. These figures from first-generation programs cover the full range of program types, including aggressive direct installation programs.

The study shows that there seems to be no definite relationship between program administration costs and the amount of per-customer savings obtained. That is, higher

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For the scenarios considered in this study, where much larger DSM contributions are considered, the DSM load factor will be significantly higher, and will eventually approximate the system load factor.

savings balance the higher outreach costs in more aggressive programs. The above cost range does not take into account the feedback effect on future programs of the experience gained to date. This feedback effect might well lower future program administration costs.

In considering the average cost of program administration across the entire DSM potential in New England, it is important to account for the fact that only half of this potential would be realized through utility programs. The other half would be implemented through efficiency standards (Nadel and Tress, 1990).

Costs of verification and savings guarantees

The program administration costs from utility experience typically do not include the cost of guaranteeing the savings as estimated in engineering calculations. As utilities begin to receive a share of DSM savings as a profit incentive, the issue of savings verification will gain prominence.

An upper limit for the cost of guaranteed performance can be gleaned from the experience to date with DSM resource bidding in New England and elsewhere. Bidding programs and performance subcontracting programs typically involve performance guarantees on the part of the energy service company executing the program. An analysis of the cost of DSM resources acquired through such bidding mechanisms (Goldman and Busch, 1991) suggests that requirements for performance guarantees can add significantly (as much as 1 to 2¢/kWh) to the cost of DSM resources,[6] though it is difficult to distinguish the impact of verification requirements from other contractual features or high rates of profit.

These figures are likely to represent an upper limit. As experience is gained with the reliability of engineering estimates, as savings verification methods become more refined, and as the need for elaborate verification becomes better understood on a case-by-case basis, these costs may well drop significantly.[7] Also, utilities may be in a better position to verify savings cheaply, on account of their access to billing information and other customer data.

Administration and verification costs for state efficiency standards

Less data are available on the cost of state efficiency standards than on utility program costs. Experience in California suggests that implementation costs in mils/kWh for appliance efficiency standards to date have been very low because enforcement is simple.[8] Enforcement is most complex in the case of commercial buildings, where complex and highly project-specific designs are involved. In the case of building efficiency standards,

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6 This estimate is obtained by subtracting from total-resource-cost DSM bids the cost of the technology alone.

7 Goldman and Busch (1991) already see a downward trend in the cost of DSM resources acquired through bidding when comparing more recent contracts with earlier ones. This downward trend is related, in part, to lower avoided cost ceilings, but shows that the excess cost charged by energy service companies over the cost of the technology resource itself is quite pliable.

8 Krause et al. (1988) estimate a cost of about 1 mil/kWh based on data from the California Energy Commission.

about 2 million dollars were spent to train California's ca. 5000 building officials in enforcement. Relative to the estimated savings from these standards, the cost per kWh is in the range of several mils.

Treatment of program costs in this study

We define a low and a high case. We also account for the fact that the time horizon in this study is quite long, i.e., 15-20 years. Such a span allows for significant improvements in program delivery. In the low case, utility program administrative costs are 0.3¢/kWh, compared to 0.8¢/kWh in the high case. For standards, the low case administrative costs are 0.1¢/kWh, compared to 0.4¢/kWh in the high case. When weighted with their contribution to the total achievable DSM potential, the range becomes 0.2 to 0.6¢/kWh (Table E.7). These costs are added to the DSM technology costs as defined in Table E.1.[9]

The costs of savings verification and O&M are treated in an analogous manner. To calculate the weighted average costs, energy service company (ESCO) bid costs are given a weight of 25%, utility program costs are given a weight of 25% and efficiency standards costs are given a weight of 50%. The weighted average for verification and O&M is 0.45¢/kWh in the low cost case and 1¢/kWh in the high cost case.

In total, program, administration, and verification costs increase the resource cost of efficiency improvements by 0.6¢/kWh in the low case and by 1.6¢/kWh in the high case .

Correction for avoided T&D costs

The transmission and distribution (T&D) benefits of DSM programs have been a topic of utility and regulatory interest for some time. Traditionally, marginal T&D costs have been calculated using the so-called NERA methodology (NERA, 1977). More recently, sophisticated small area load forecasting techniques have been developed (EPRI, 1990), but few utilities have applied these more sophisticated techniques to date.

NERA methodology

The NERA methodology makes use of regression analysis to derive marginal costs from historic system-average T&D investments per kW load growth.

This approach brings with it a number of problems. A key uncertainty is whether the methodology actually yields true marginal costs: will the same load-correlated costs that were incurred in the past also be needed in the future? For example, if reserve margins were not at their target levels during the historical periods over which T&D investments

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[9] This correction in absolute terms rather than in percentage terms is suggested by the same research. For the lighting efficiency measures examined, which had total resource costs ranging from 0.7 to 3¢/kWh, program costs amounted to typically 10-30 percent of technology measure costs. However, higher technology measure costs as found in other end-uses and listed in Table E.2, do not necessarily mean higher program administration costs. Program administration costs are more customer-related than correlated with the levelized cost of a measure. The application of a percentage correction rather than an absolute correction is likely to be less accurate

were analyzed, marginal costs calculated from historical data may be different from those that would be applicable over the longer term when such targets would presumably be met.

A second issue relates specifically to DSM programs: what portion of marginal T&D costs is load related and what portion is customer related in the secondary distribution system? In the NERA methodology, marginal customer-related costs are distinguished from demand-related costs using the concept of a mininimum distribution system, but such a construct is a poor substitute for actual data. The NERA costs also depend on conventions concerning the use of historic or replacement costs in deriving marginal costs from past investment time series, and on both diversity factors and energy and power losses in the grid.

Conventional NERA estimates for New England

Marginal T&D cost estimates for NEPOOL as a whole were not available to us. We estimate approximate marginal T&D costs based on data from several sources. Baughman (1979) gives levelized average transmission and distribution costs by U.S. region as developed from utility industry statistics for a utility sector model. For the New England region, this figure is 0.45¢/kWh for transmission, and 0.06¢/kWh for substations in 1972 dollars, and assuming a 13.5 percent fixed charge rate. We assume that these are the only demand-related costs , and treat other costs for pole lines, transformers, and meters as customer related. Converting to 1990 dollars using the producer price index for electrical equipment, and adjusting to our somewhat lower fixed charge rate, yields a cost of 1.13¢/kWh.

Chernick (1991) provides a compilation of recent marginal T&D cost studies from five New England and four other Northeast utilities (Table E.5). The average cost is $27/kW-yr for transmission, $55/kW-yr for primary distribution, and $49/kW-yr for secondary distribution (in 1991 dollars based on real fixed charge rates without inflation). If one ignores in-house distribution savings of industrial and large commercial customers, secondary distribution costs would be affected mainly by DSM programs for residential customers. Using this conservatism, we weigh the secondary distribution costs by the share of residential energy savings in the total savings potential as shown in Table E.3. The real average cost for the T&D system as a whole is then $98/kW-yr. Assuming that the average load factor of the DSM resource is 65 percent, this translates into a T&D credit of 1.7¢/kWh.[10]

The cost estimates by the nine utilities bear out a significant variability of estimates (see Table E.5). This variability is attributable, in part, to differences in time horizons, treatment of historical inflation, use of past and future years versus only historical years, line losses by voltage level, cost of capital differences, above-ground and underground installation, differences in system loads, and coincidences by territory.

Small area forecasting methodology

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[10] This calculation assumes a real fixed charge rate of 12.2 percent, and the GDP deflator.

Beginning in the late 1970s, the Electric Power Research Institute (EPRI) sponsored a number of studies aimed at developing T&D impacts of changes in end-use loads on the basis of spatially disaggregated bottom-up analyses of coincident loads (EPRI, 1980; EPRI, 1990a). These methods make use of computerized approaches to small area load forecasting (Willis and Northcote-Green, 1984; Willis et al. 1986). They not only improve the understanding of system-average marginal T&D costs, but also allow the determination of differences in these costs within the service territory. These differences can be used for geographically targeted DSM programs.

The methodology relies on small-area load curves (EPRI, 1990). These are constructed on the basis of load shapes for different customer subclasses and their present and projected geographical distribution in the service area. Data bases on the geographic distribution of customers are developed from various mapping techniques, including satellite images, and are converted into composite load densities (kVA/acre). Customer load shapes are developed from end-use based projections of future saturations in end-use equipment, usage, and efficiency. An optimized T&D system is then designed.

DSM program impacts modify the customer class load shapes and the coincidence of loads. They thus lead to a different optimization of the T&D system. By comparing the new optimization with the previous one, the T&D cost impacts of the DSM resource can be calculated. Spatial frequency analysis is used as a screening tool in comparing the two cases.

A geographically disaggregated assessment of T&D benefits differs from the conventional assessment of DSM in important respects. In conventional practice, the T&D component of avoided costs is calculated on a system-average basis and is added to the generation component, which is inherently a system-average cost. Benefit/cost ratios are then determined on that basis for an average DSM program (system-wide application).

When load growth is broken out by sub-area, avoided T&D costs can be calculated on a local basis. Over a specified planning horizon, one can expect to find substantial avoided-cost benefits in some regions, and no such benefits in others. Examples for the former might be areas where peak loads are approaching maximum feeder and substation capacity, rapidly growing suburbs built into the green field, or customers at the end of long distribution lines. By contrast, DSM programs might avoid or defer little T&D investment in city areas where growth is stagnant and ample distribution capacity exists, or in other areas with overbuilt T&D capacity. The variability of T&D benefits is reflected, in part, by the variability in benefit/cost ratios when one and the same DSM program is applied and evaluated in different subareas.

Utility service territories differ in terms of their urban/rural patterns, experience varying magnitudes of growth and migration, and currently have varying reserve margins in their T&D systems. It is therefore necessary to analyze T&D marginal costs for each system and subarea. System-average T&D benefits may vary significantly from utility to utility. Below, we summarize findings from a case study in New England.

New England case study results

In New England, ABB Power Systems, Incorporated recently used a spatial analysis to determine the T&D impacts of cycling and conservation DSM options of the Central Maine Power (CMP) service territory. Results of this project have not been finalized at the time of this writing. Initial findings (Willis, 1991) for the service territory's 14 transmission areas as a whole indicate that DSM T&D benefits are positive and substantial in almost all subareas of the service territory. Contrary to conventional wisdom, some of the highest marginal T&D costs were found in the urban area of Portland, due to high residential and commercial customer growth in the northwestern part of the city.

Benefit/cost ratios were calculated from the total resource cost perspective, using the net present value of avoided generation, transmission, and distribution costs until the year 2000 (Willis, 1991). A 20 percent adder for program administration costs was also included. The value of avoided T&D capacity was calculated using both system-wide averages derived with the NERA methodology and detailed engineering estimates for each feeder. The latter method resulted in T&D benefits that were slightly higher (by about 5-10 percent).

The typical findings are illustrated by results for a specific transmission area (ABB, 1991). In that area, projected-year 2000 load growth of 7.5 MW would be reduced by 80 percent or 5.7 MW if a package of five cycling and six conservation programs were implemented.[11] It was found that the six efficiency programs achieved an average benefit/cost ratio of 0.89 without the T&D benefits, compared to a benefit/cost ratio of 1.3 when T&D benefits were included. Put another way, the area T&D savings of the package increased the dollar savings from avoided generation costs alone by 45 percent (Table E.6). For the cycling and efficiency programs in combination, the average benefit/cost ratio became 1.5.

These findings, which reflect the broad relationships found for the service territory as a whole,[12] have an important implication:

- T&D benefits can be large enough to make DSM programs highly cost-effective even when these programs avoid no more than short-run marginal cost in power generation.

These case study figures can be translated into approximate benefits expressed in cents per kWh. Based on an average cost of 2.5-3¢ per kWh saved[13] for the DSM programs in Table E.6, a T&D benefit of approximately 40 percent (see Table E.6) translates into about 1-1.2 ¢/kWh for the above service area.

Similarly, the relationship of T&D savings to generating costs can be translated into a cents per kWh figure. According to CMP's 1991 avoided cost schedule, the minimum avoided energy cost is 2.56¢/kWh (CMP, 1991). Based on the relationship between generation and T&D costs of Table E.6, this avoided cost translates into 1.15¢/kWh.

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11 The conservation programs were lighting upgrades (residential, commercial, industrial), water heater wraps (residential, commercial), and fan motor efficiency improvements (industrial-commercial). See Table E.6.

12 The DSM ratios found for the Boothbay transmission area lean toward the lower bound of the range of benefit/cost ratios found in the service territory as a whole (Lee Willis, ABB Power Systems, Inc., personal communication, June 1991).

13 Personal communication with Lee Willis, ABB Power Systems, Pittsburgh, PA, June 1991.

Preliminary findings of the CMP study also suggest that targeting DSM programs to specific sub-areas could increase the net benefits of DSM resources by 20 to 25 percent over blanket application, due to the elimination of high near-term T&D investments. An example of such an opportunity is the high-growth area of the city of Portland, where avoided T&D costs were found to be as high as 50 mils/kWh saved.[14] In areas such as these, T&D benefits alone are sufficient to economically justify DSM programs.

Other studies on geographically disaggregated DSM benefits

Significant potential T&D benefits from targeting DSM to specific areas were also identified by Orans (1991) for the service territory of Pacific Gas and Electric Company (PG&E). He calculates marginal T&D costs in the 25 local transmission areas and almost 200 distribution planning areas of the utility's service territory. A major portion of the service territory faces marginal costs in excess of $100/kW-year, with some areas reaching several hundred dollars per kW-year. When DSM programs are targeted to such areas, they earn correspondingly larger credits. Like the CMP study, Orans (1991) finds that in some cases, deferrals of T&D investments alone could economically justify DSM programs.

Treatment of T&D credits in this study

To reflect the uncertainty from the current lack of a New England-wide analysis, we define a high and a low estimate. The high estimate of 0.8 ¢/kWh is below both the conventional NERA figures and the preliminary estimates derived from the in-depth CMP analysis. As a low estimate, we assume a credit of only 0.2 ¢/kWh.

This credit is applied to both the utility program and the standards-based portion of the DSM resource, as well as to fuel switching resources (see Appendix A.6). Tie-in costs for generating plants, and unaccounted commercial and industrial sector savings in secondary (in-house) distribution are neglected as a conservatism, and so are savings from targeted application.

These estimates are probably too low. Both the above analysis and environmental issues suggest that T&D avoided costs could be significantly higher. Siting new transmission lines in New England has become increasingly difficult due to public opposition to their environmental and land-use effects. Future projects could experience real cost escalations related to widening corridors, more expensive routing, and other modifications.[15]

Similarly, the rising trend of public demands for environmental quality suggests that more transmission and distribution lines might have to be run underground in the future. This could further increase marginal T&D costs, since such lines are several times as expensive as overhead lines.

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14 Personal communication with Lee Willis, ABB Power Systems, Pittsburgh, PA, June 1991.

15 Transmission tie-ins for new generation plants are a further cost component that needs to be incorporated. When preparing integrated resource plans, utilities often include these investments as part of the cost of generation plant rather than T&D expenditure. These tie-ins may cost in the neighborhood of 100-200 $/kW (Krause et al., 1988). In this study, they were not included in the estimates of power generation costs from new plants.

Cost summary

The summary supply curve of DSM resources for New England is shown in Table E.7 and the more detailed supply curve is shown in Table E.8. Both the high and the low estimate are shown. As can be seen, there is a significant, (about 2 ¢/kWh) uncertainty in the cost of DSM resources, but this uncertainty occurs within a cost range that is still favorable when compared to new power supplies (see Appendices G through L).

In practice, DSM resources are not necessarily mobilized in the cost-ordered manner suggested by the supply curve. Often, packages of measures and packages of programs are being used to improve marketing efficiency and to take account of opportunity costs. Such packaging may become more prevalent as utilities seek to capture a larger fraction of DSM resources in a shorter period of time by increasing per-customer savings.

The impact of rising resource contributions from DSM efficiency improvements on their cost is difficult to predict for other reasons. Learning effects will reduce program administration costs over time, while rising penetration levels will increase the cost of reaching remaining customers. Higher-cost measures will eventually have to be pursued, but efficiency potentials are likely to be replenished through innovation.

Table E.1 End Use Savings from New York Adapted for New England

	ENERGY							
	NEW YORK				NEW ENGLAND			
End Use	*1986 Sales (%)*	*1986 Savings Potential (GWh/yr)*	*Sectoral Savings Potential (%)*	*Wtd. Avg. CSE at 6% ($/kWh)*	*1985 Sales (%)*	*Forecast Year Savings (GWh/yr)*	*Sectoral Savings Potential (%)*	*Wtd. Avg. CSE at 6% ($/kWh)*
RESIDENTIAL:	35%	12652	37%	0.035	36%	18021	31%	0.034
Freezer	4.4%	761	2%	0.009	4.3%	1242	2%	0.009
Refrigerator	27.3%	4522	13%	0.011	19.2%	5313	9%	0.011
Range	4.3%	286	1%	0.023	7.8%	867	2%	0.023
Water Heater	8.6%	712	2%	0.026	15.9%	2199	4%	0.026
Lighting	15.3%	3710	11%	0.038	9.3%	3767	7%	0.038
Space Heating	12.2%	1187	3%	0.041	13.1%	2129	4%	0.041
Clothes Dryer	5.2%	858	2%	0.065	7.0%	1929	3%	0.065
Room A/C	4.9%	322	1%	0.138	3.0%	329	1%	0.138
Central A/C	1.8%	294	1%	0.229	0.9%	246	0%	0.229
TV	9.3%				6.0%			
Clothes Washer					0.9%			
Dish Washer					1.8%			
Heating Aux.					2.8%			
Misc.	6.8%				8.0%			
TOTAL	100%				100%			
COMMERCIAL:	40%	20014	50%	0.028	33%	24341	46%	0.027
Refrigeration		440	1%	0.007	10.0%	583	1%	0.007
Lighting	32.9%	8634	22%	0.025	43.0%	14950	28%	0.025
Cooling					12.0%			
Ventilation					10.0%			
Heating					11.0%			
All HVAC	54.3%	10940	27%	0.032	33.0%	8808	17%	0.032
Water Heating					3.0%			
Cooking					2.0%			
Misc.	12.8%				10.0%			
TOTAL	100%				101%			
INDUSTRIAL:	21%	4485	22%	0.055	28%	10398	23%	0.052
Lighting	7.0%	523.4	3%	0.026	13.4%	2239	5%	0.026
Motors/Process					36.4%			
Motors/Other					35.5%			
All Motors	78.0%	3961.2	19%	0.059	71.9%	8159	18%	0.059
Electrolysis					4.8%			
Process Heat					8.5%			
Space Heating					1.5%			
Misc.	15.0%							
TOTAL	100%				100%			

Table E.2 New York Conservation Potentials Study Results

End Use	*Average Savings Per Measure*	*Number of Measures Applied to End Use*	*Total end-use savings*	*Weighted Average CSE at 6% ($/kWh)*
Com. Refrigeration	n/a	3	50%	0.007
Res. Freezer	17%	3	50.0%	0.009
Res. Refrigerator	16%	3	47.9%	0.011
Res. Range	10%	2	19.2%	0.023
Com. Lighting	10%	7	72.4%	0.025
Res. Water Heater	12%	2	23.9%	0.026
Ind. Lighting	3%	4	11.7%	0.026
Com. HVAC	5%	12	55.5%	0.032
Res. Lighting	12%	6	70.1%	0.038
Res. Space Heating	7%	7	47.7%	0.041
Ind. Motors	n/a	n/a	n/a	0.059
Res. Clothes Dryer	48%	1	47.7%	0.065
Res. Room A/C	6%	3	19.0%	0.138
Res. Central A/C	9%	5	47.2%	0.229

Table E.3. Savings by sector

Sector	*New England*	*New York*
Residential	12%	13%
Commercial	16%	20%
Industrial	7%	5%
TOTAL for System	35%	38%

Table E.4 Calculation of electricity demand in 2005/10			
	Energy (TWh)	*Demand Index*	*DSM utilization Index*
1990 NEPOOL Electricity Demand	112	*70*	
2005 NEPOOL Forecast w.o. DSM	160	*100*	
2005/10 technical savings potential @ 33%	53		*100*
2005 NEPOOL DSM forecast	8		*15*
DSM resource not captured	45		*85*
2005 NEPOOL demand forecast w. DSM	152	*95*	
2005/10 demand w. 75% of DSM potential	120	*75*	

Notes:

(1) NEPOOL forecast data are based on 1990 CELT report.
(2) Due to uncertainties in load growth, NEPOOL's 1990 forecast is interpreted as applying to 2005/10.

Table E.5: Estimated demand-related marginal T&D costs for a sample of utilities in the Northeast

	1991$/kW-yr (peak demand coincident at the point of generation)									
	PepCo	BECo	EECo	NEPCo/MECo	Citizen's VT	Central VT	NYSEG	Con Ed	Comm Ed	**Average**
Transmission	21	26	not estimd.	18	60	17	39	32	31	**27**
Primary distribution	70	57	72	21	68	38	44	35	87	**55**
Secondary distribution	92	52	110	44	6	11	24	47	58	**49**

Notes:

(1) Company estimates as compiled by Chernick (1991).

(2) All values based on real fixed charge rates (without inflation).

(3) Values are not necessarily derived with consistent assumptions.

Table E.6: Avoided T&D costs in a case study transmission area of Central Maine Power Co.

Program	*DSM cost* *1000 $*	*Avoided gen. cost* *1000 $*	*Avoided transm. cost* *1000 $*	*Avoided distr. cost* *1000 $*	*T&D benefit rel. to DSM cost* *fraction*	*T&D benefit rel. to gen. cost* *fraction*
Residential lighting	196	165	72	64	0.69	0.82
Commercial lighting	113	98	10	15	0.22	0.26
Industrial lighting	19	11	5	4	0.47	0.82
C&I motor fan efficiency	184	180	19	29	0.26	0.27
Res. water heater wrap	49	39	4	6	0.20	0.26
Comml. water heater wrap	13	18	2	3	0.38	0.28
All programs	574	511	112	121	0.41	0.46

Notes:

(1) Source: ABB (1991).
(2) All data are for the Boothbay transmission area of Central Maine Power.
(3) Costs are present values in 1990 dollars, based on ABB (1991).
(4) DSM costs are total resource costs including a 20 percent adder for administration.
(5) DSM costs are based on a 6.75% real discount rate.
(6) Avoided costs are based on Schedule 91-A Interim of Central Maine Power Co.

Table E.7 Components of DSM Costs (1990 ¢/kWh)

	Low		*High*	
DSM Technology Cost				
@ 25% utilization	*1.2*		*1.4*	
@ 50% utilization	*2.1*		*2.5*	
@ 75% utilization	*2.5*		*3.0*	
Program Administration Cost (weighted)	*0.2*		*0.6*	
Utility Programs		0.3		0.8
State Standards/Codes		0.1		0.4
Verification and O&M Cost (weighted)	*0.45*		*1*	
ESCO Bids		1		2
Utility Programs		0.5		1
State Standards/Codes		0.15		0.5
TOTAL GROSS DSM Resource Costs				
@ 25% utilization	*1.85*		*3.0*	
@ 50% utilization	*2.75*		*4.1*	
@ 75% utilization	*3.15*		*4.6*	
Transmission & Distribution Credit	*-0.8*		*-0.2*	
TOTAL NET DSM Resource Costs				
@ 25% utilization	*1.05*		*2.8*	
@ 50% utilization	*1.95*		*3.9*	
@ 75% utilization	*2.35*		*4.4*	
Shareholder financial incentives (for rate impact calculation only)	*0.24*		*0.35*	

Notes:

(1) For administrative costs, standards-based costs and program-based costs are weighted 1:1

(2) For verification and O&M costs, energy service company (Esco) bid costs are given a weight of 25%, utility program costs are given a weight of 25% and efficiency standards costs are given a weight of 50%.

Table E.8: Supply curve of DSM efficiency resources in New England

Savings in 2005/10 GWh/yr	*CSE marginal at 6% $/kWh*	*Savings 2005/10 Cumul. GWh/yr*	*Savings 2005/10 Cumul. fraction*	*CSE average $/kWh*	*Low Ave CSE w. T&D plus Admin. $/kWh*	*High Ave CSE w. T&D plus Admin. $/kWh*
583	0.007	583	1%	0.007	0.005	0.023
1242	0.009	1825	3%	0.009	0.007	0.024
5313	0.011	7138	14%	0.010	0.008	0.026
867	0.023	8004	15%	0.012	0.010	0.028
14950	0.025	22954	44%	0.020	0.018	0.038
2199	0.026	25153	48%	0.021	0.019	0.039
2239	0.026	27392	52%	0.021	0.019	0.039
8808	0.032	36200	69%	0.024	0.022	0.043
3767	0.038	39967	76%	0.025	0.023	0.044
2129	0.041	42096	80%	0.026	0.024	0.045
8159	0.059	50256	95%	0.031	0.029	0.051
1929	0.065	52185	99%	0.032	0.030	0.053
329	0.138	52514	100%	0.033	0.031	0.054
246	0.229	52760	100%	0.034	0.032	0.055

Notes:

(1) Savings and costs of saved energy (CSE) from Table E.1. High cost case technology costs are increased by 20% relative to Table E.1 to reflect uncertainty in these costs.
(2) Low CSE based on low estimate for admin., verif., and T&D corrections from Table E.7.
(3) High CSE based on high estimate for admin., verif., and T&D corrections from Table E.7.

APPENDIX F: FUEL SWITCHING

In principle, fuel switching opportunities at the point of end use exist both from direct fuels to electricity and from electricity to gas. This appendix focuses on fuel switching opportunities that could lower carbon emissions. The following measures are examined:

- Switching electric space heating to gas or propane
- Switching electric water heating to gas or propane
- Switching electric dryers and stoves to gas or propane
- Switching air conditioners and chillers from electric drives to gas engines and/or gas-fired absorption chillers.

Carbon benefits of fuel switching to gas

In most heating applications, fuel switching from electricity to direct fuels at the point of end-use saves considerable amounts of carbon. The present carbon intensity of New England Power Poool (NEPOOL) electricity generation is about 150 gC/kWh.e, as compared to 50 gC/kWh for gas. At this intensity, space and water heaters save carbon as long as their efficiency exceeds 33 percent. Efficiencies in the 65-75 percent range are now standard for gas equipment, and condensing pulse combustion space and water heaters reach higher heating value efficiencies in excess of 90 percent. Significant economic cost advantages often accompany such large carbon benefits (see below).

Such decisive carbon benefits, however, are elusive in air conditioning applications. In large commercial buildings, an engine-driven chiller with a coefficient of performance (COP) of 1.4-2 is about as carbon intensive as an electric chiller with a typical COP of 5.5, which is 5.5/3=1.83 on a carbon-corrected basis. Similarly, a residential absorption chiller with a COP of 0.5-0.7 at best matches electric air conditioners with typical COPs of 2 or more.

While efficiency improvements in absorption chilling can be expected, this is also true for electric air conditioners. The eventual balance between the two end-use technologies cannot be predicted at this time. For the time being, it is plausible to assume that from a carbon standpoint, electric and gas air conditioning are a draw. Trade-offs can therefore be based on economics and other factors.

Current fuel switching programs in New England

With the exception of recent activities by several smaller utilities in Vermont, no major end-use fuel switching programs have been undertaken either by electric or gas utilities in New England so far. Three winter-peaking utilities in Vermont (Burlington Electric Department, Stowe Municipal Utility, and Ludlow Municipal Utility) have programs that promote the use of gas or propane instead of electricity. The extent and form of the fuel switching promotion varies. Between the various programs, the following activities are being pursued:

- Evaluation of customer potential for fuel switching and other DSM measures (all).
- Audits, technical assistance, and construction management for fuel switching projects in homes, motels, condominiums, etc. (all)
- Incentive payments of 35¢/kWh of first-year savings.
- Completed projects for fuel switching to gas as part of housing rehabilitation for low-income households (BED);
- Longer-range plans calling for the conversion of 80 percent of residential electric space heating customers (BED);
- Mandatory residential demand rates for customers with loads greater than 10 kW (Stowe);

One utility, Burlington Electric Department, is poised to spend a significant portion of its sales revenues on fuel switching. With sales of about 35 million dollars, the utility has taken up a $11 million bond to finance a major DSM and fuel switching program over the next three and a half years. The current program plan calls for total residential sector expenditures of 2 million dollars in the first year, and more than half of this sum is to be used for fuel switching.[1]

So far, BED has contributed to a rehabilitation project for 336 low-income units, and completed a pilot program of space-heating fuel switching using through-the-wall heaters. These were installed in 44 households with unit energy consumptions ranging from 4000 to 18000 kWh.e/yr. BED converted 50 units so far in its own residential fuel switching program.

An important goal in Vermont's fuel switching and DSM programs are winter peak savings, since the state's utilities are winter peaking. Electric space heating has been discouraged for several years in Vermont, and its saturation is therefore less than 10 percent, significantly lower than the 16 percent average in New England as a whole.

Potential of low carbon fuel switching resources

The bulk of low carbon fuel switching opportunities are in driers and space and water heating. Within the scope of this study, we focus on the potential for fuel switching in residential water heating and driers. Such estimates are the most easily quantifiable from available statistics. This analysis will need to be complemented by a more comprehensive assessment to capture the full low-carbon fuel switching resource. As in the case of electric DSM resources, it is important to distinguish between the technical potential of fuel switching, and the achievable economic potential. Issues of program cost-effectiveness, penetration rates, customer acceptance, and distributional equity have to be taken into account.

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[1] Personal communication with Sean Foley, Burlington Electric Department, Burlington, VT, and Blair Hamilton, Vermont Energy Investment Corporation, Burlington, VT.

Water heating

The maximum technical potential for water-heater fuel switching is defined by the current saturation of electric water heaters. This saturation was 31 percent in 1990, equivalent to 1.57 million customers.[2]

A second statistic is the number of space heating gas customers in New England that do not have gas water heating. Fully 69 percent of New England's 1.8 million residential gas customers could switch to gas water heating.[3] In the first approximation, these 1.25 million customers are currently relying on electric water heating, but have access to gas. In our simplified estimate, they represent 80 percent of the total electric water heating fuel switching potential. The remaining 20 percent could switch to gas by using propane, as some households are doing already.

The resulting electric load that could potentially be switched is shown in Table F.1, along with the NEPOOL average annual consumption for electric water heating .[4] Converting all electric water heating residential customers to gas would reduce the region's electric load by 7.3 TWh.

Space heating

About 16 percent of NEPOOL residential customers have electric space heating systems, with an average 1990 annual energy consumption of 5610 kWh.[5] Technological improvements and more efficient building shells are projected to reduce this figure to 4610 kWh/yr in 2005, with saturation reaching 21 percent. If all electric customers could be switched to gas, the maximum potential electric load reduction in 2005/10 would be 4.1 TWh.

Dryers

The saturation of dryers is projected to increase from 62 percent in 1990 to 73 percent in 2005 in the NEPOOL forecast. Efficiency is expected to increase, so that the unit energy consumption will decline from 740 to 650 kWh/yr. The maximum electric load reduction is 2.2 TWh in 2005.

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2 Total residential electric customers include second homes. For the purpose of the present context, only primary residences matter. The residential customer figure on that basis was 5.05 million in 1990. Personal communication with Don Bourcier, NEPLAN.

3 Statistics on gas customers were obtained from the New England Gas Association

4 This figure is the one used in the NEPOOL load forecast for that year. It is an average of the controlled and uncontrolled and storage water heaters. Personal communication, Don Bourcier, NEPLAN.

5 The unit energy consumptions and saturations by system type were as follows: baseboard (6000 kWh, 12%), storage (5400 kWh, 0.2%), single family homes with wood stoves (4850 kWh, 2.2%), and heat pumps (3760 kWh, 1.6%). Personal communication, Don Bourcier, NEPLAN.

Cost-effectiveness of fuel switching

The basic data and assumptions are shown in Table F.3 and F.4. Conversion costs are based on an analysis by Vermont Energy Investment Corporation (VEIC, 1990), which was commissioned by several utilities participating in Vermont's collaborative resource planning process. These costs are similar to, or somewhat higher than, costs reported in other studies (Krause et al., 1988) and should thus be conservative. The gas price is based on the 1990 average New England residential gas price as listed in GRI (1989), which is 7.15 $/million Btu. This price is escalated using the real gas price escalation rate of 5.1% used by GTF for utility gas prices, and levelized over the life of the furnace or appliance. Total investment including installation costs is levelized over a weighted average life that reflects the longer economic utility of one-time building modifications such as chimneys, vents, and black pipe.

The resulting levelized cost of fuel switching in ¢/kWh.e is then corrected for avoided T&D costs and program administration costs (see Appendix E). Generation cost credits for peak load reduction are not taken into account. These can be substantial (see VEIC, 1990; Chernick, 1990) and should be more carefully evaluated.

The high case data for administration costs are taken from BED's pilot program results, which were $477 per customer.[6] This administrative cost is allocated to the three end-uses in proportion to their UECs. The resulting levelized program administration costs are in good agreement with the range of costs given in Appendix E. In the low case, administration costs are reduced by the direct involvement of gas companies.[7] Guaranteed savings costs are not applied to fuel switching programs.

The point of reference for the costs in Table F.4 are the levelized long-run avoided costs of the utility, not residential customer rates. Against a range of 5-7¢/kWh in real terms (1990 dollars), the results show that the conversion of water heaters and dryers is cost-effective to cost-competitive for the average customer. In the case of space heating, cost-effectiveness would be reached only with larger customers in colder regions, and when using through-the-wall retrofits rather than central systems.[8]

Several qualifications should be added to this estimate. First, the cost calculation is for a hypothetical average customer facing average New England gas rates. This calculation would be the basis of a resource estimate only if equity considerations are given weight.[9]

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6 Sean Foley, personal communication.

7 BED did not promote the conversion of dryers or water heaters in its program. However, some local gas and propane companies pursued gas water heater fuel switching without BED incentives once the BED program had started. With learning effects, the low administration cost figure can be considered a good estimate for an expanded program.

8 Assuming that the same electricity savings are achieved.

9 Some utilities have found that strict eligibility cut-offs on the basis of billing data and audits can lead to significant dissatisfaction among customers with the utility's service.

Real customers have electricity uses that vary with household size and personal habits. When a distribution curve of unit energy consumptions is used, only a portion of the total number of customers would be at or below the cost calculated in Table F.4.[10] Electric space heating customers in the three southern states face much less severe winters than those in Vermont, New Hampshire, and Maine.

Furthermore, the above calculation uses a busbar cost model that is geared toward the average long-run cost of electricity. It does not take into account seasonal and time of use rates or demand charges for either electricity or gas. A more fine-grained analysis should be undertaken. It could alter the figures shown in the table.

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[10] BED found 80 percent of its customers eligible for through-the-wall space heating fuel switching (Sean Foley, BED, personal communication). However, in the service territories of other Vermont utilities, only 15-50 percent would qualify. The UEC distribution is skewed, with most customers below the average. The same effect also applies to water heating customers (Blair Hamilton, VEIC, personal communication).

Table F.1: Residential electricity use in dryers, space heating, and water heating, NEPOOL						
	UEC 1990 kWh.e/yr	*Saturation 1990*	*UEC 2005 kWh.e/yr*	*Saturation 2005*	*Total use 1990 TWh/yr*	*Total use 2005 TWh/yr*
Water heaters	4300	31.5%	4200	35.3%	6.8	7.3
Space heating	5610	16.0%	4610	21.0%	4.5	4.1
Clothes dryers	740	62.0%	650	73.0%	2.3	2.2

Notes:

(1) Unit energy consumption (UEC) and saturation data from NEPLAN 1990 forecast documentation.
(2) Excludes second homes; 1990 population increases by 10 percent by 2005.

Table F.2: Residential gas customers without gas water heating			
	All million	*SH only %*	*SH only million*
Connecticut	0.423	67.5%	0.300
Maine	0.012	45.0%	0.005
Massachusetts	1.104	63.0%	0.780
New Hampshire	0.63	13.5%	0.009
Rhode Island	0.185	58.5%	0.137
Vermont	0.017	81.0%	0.015
New England	1.803	69.1%	1.246

Notes:

(1) Based on data provided by the New England Gas Association.
(2) For comparison, 1.57 million electric customers (31%) had electric water heating.

Table F.3: First cost of fuel switching measures

	First cost	*Gas pipe & flue*	*Labor*	*Total*
Electric WH	285	0	105	390
Gas/propane WH	425	150	115	690
Extra cost gas WH	140	150	10	300
Extra cost gas dryer	30	85	0	115
Extra cost gas space heat				
Through the wall				2200
Central, rental units				3600
Central, owner-occupied				5100

Notes:

(1) Cost data for through the wall heaters based on BED 1990 pilot program results.
(2) Other cost data developed by VEIC (1990) for Vermont Collaborative.
(3) Costs are based on bulk contracting through a utility program.

Table F.4: Cost of fuel switching for dryers, space heating, and water heating

		Water heater	*Dryer*	*Space heating central*	*Space heating through wall*
Appliance life		10	10	20	15
Weighted investment life		15	17	25	23
Electricity displaced (2005)	kWh.e/yr-customer	4200	650	8000	8000
Efficiency gas appliance		0.65	0.65	0.75	0.7
Gas required	kWh.f/yr	6462	1000	10667	11429
Base year gas price	$/million Btu	7.15	7.15	7.15	7.15
Real escalation rate		5.1%	5.1%	5.1%	5.1%
Levelized gas price	¢/kWh.f	3.01	3.01	3.69	3.34
Annual fuel cost	1990 $/yr	194	30	394	382
Capital cost	1990 $	300	105	5100	2200
Capital recovery factor		0.105	0.097	0.080	0.084
Annualized capital cost	1990 $/yr	31.50	10.19	410.40	185.52
Fuel switching cost, fuel	¢/kWh.e	4.63	4.63	4.92	4.78
Fuel switching cost, capital	¢/kWh.e	0.75	1.57	5.13	2.32
Total	¢/kWh.e	5.38	6.19	10.05	7.09
System costs					
Levelized avoided T&D costs, low	¢/kWh	-1.00	-1.00	-1.00	-1.00
Levelized avoided T&D costs, high	1990 $/customer	-0.2	-0.2	-0.2	-0.2
Levelized program costs, low	¢/kWh	0.2	0.2	0.2	0.2
Levelized program costs, high	¢/kWh	0.51	0.51	0.33	0.39
Net fuel switching cost low	**¢/kWh**	**4.6**	**5.4**	**9.2**	**6.3**
Net fuel switching cost high	**¢/kWh**	**5.7**	**6.5**	**10.2**	**7.3**

Notes:

(1) Base year gas price is 1990 New England retail avg. as given in GRI (1989).
(2) Fuel price levelized using a real discount rate of 6.3% over relevant equipment lifetime.
(3) Capital recovery factor based on weighted avg. life for appliance and installation investment.
(4) High program administration costs based on BED fuel switching pilot program, allocated by UEC.
(5) Low program costs based on implementation by gas companies.
(6) High and low T&D credits from Appendix E.
(7) Space heating UECs are higher than implied in Table E.1 to illustrate costs for larger customers and colder regions.

APPENDIX G: CONVENTIONAL UTILITY GENERATION

The conventional plants covered in this appendix include the following:

— Combustion turbines (CT)

— Conventional and advanced combined cycles (CACC)

— Coal-fired atmospheric fluidized bed plants

— Integrated coal gasification combined cycles (ICGCC)

— Nuclear lightwater reactors

Because the fuels used in these plants are available outside New England, no resource potentials in the narrow sense can be defined for them. However, de facto constraints related to siting, accident risk, and other environmental issues could limit the deployment of these plants. For gas-fired plants, current supply constraints in New England are discussed in Appendix H.

The busbar costs for these resources are shown in Table G.1. The cost and performance data are based on New England Power Pool's General Task Force assumptions (NEPLAN, 1989). An exception is the heat rate of the integrated gasification advanced combined cycle (IGACC), which reflects more advanced hot gas clean-up designs that are also assumed in costing biomass gasification plants (see Appendix J).

A further modification is the additional operating and maintenance (O&M) cost for more stringent NO_x control than federally required. Costs for selective catalytic reduction and other low-NO_x techniques are in flux.[1] The figures shown in the table are estimates that anticipate some cost reductions for these control technologies. Coal plants, with significant embedded nitrogen levels in the fuel, are charged six mils. Gas-fired combined cycles, which can make use of steam injection and direct combustion technology, are charged three mils.

The GTF assumptions lead to a clear cost advantage for IGACC plants. Even when very low-cost imported coal is assumed, an IGACC plant cannot compete with a gas plant under GTF assumptions. This advantage is further augmented when externality costs are added. The favorable economics of gas-fired plants are reflected in current utility resource plans, which emphasize gas ACC technology. Nuclear reactors, though not affected by the Massachusetts externality adders, are the least economical baseload option, even when compared to coal plant costs including adders.

[1] See, for example, the energy technology status report of the California Energy Commission (CEC, 1990a).

Table G.1: Busbar costs of conventional electric generation technologies							
	Gas CT	*Gas CCC*	*Gas ACC*	*Coal ST*	*Coal AFB*	*Coal IGACC*	*Nuclear LWR*
PHYSICAL PARAMETERS							
Total Electric Capacity (MWe)	150.1	231.6	222.3	600	600	205	1150
Lifetime (Years)	25	35	35	35	35	35	39
Construction Lead Time (Years)	3	3	3	6	5	4	7
Land Used (acres onsite and offsite)	6	11	11	215	226	100	503
Ave Capacity Factor	10%	65%	65%	65%	65%	65%	65%
Equivalent Unplanned Outage Rate	3.5%	5.5%	5.5%	7.8%	10.2%	10.7%	10.0%
Equivalent Availability	92.4%	90.5%	90.5%	80.6%	81.3%	85.5%	72.0%
Heat Rate (kWh heat in/kWh elect. out)	3.84	2.48	2.22	2.69	2.77	2.45	3.10
Efficiency	26.1%	40.3%	45.0%	37.2%	36.2%	40.8%	32.2%
FIXED COSTS							
Capital Recovery Factor	0.134	0.130	0.130	0.130	0.130	0.130	0.120
Overnight Capital Cost ($/kW)	380	490	480	1300	1400	1700	3500
Additional NOx Control Cost ($/kW)	75	75	75	75	75	75	0
Net Capital Cost ($/kW)	455	565	555	1375	1475	1775	3500
Net Cap Cost Including Interest ($/kW)	484	601	591	1611	1673	1950	4236
GTF Net Cap Cost Incl. Interest ($/kW)	467	646	636	1798	1896	2088	5100
Startup ($/kW)	20.34	19.66	19.33	39.19	40.65	46.97	87.38
Inventory ($/kW)	7.95	29.89	27.13	28.17	28.96	9.49	170.62
Land ($/kW)	4.35	5.17	5.38	38.98	40.98	53.07	47.59
Total: Startup, Inventory, Land ($/kW)	33	55	52	106	111	110	306
Annualized Capital Cost ($/kW/yr)	67.0	90.7	89.1	246.7	260.0	284.7	646.0
Fixed O&M ($/kW/yr)	0.64	11.34	11.80	27.54	24.72	46.18	61.98
Total Fixed Costs ($/kW/yr)	*67.7*	*102.1*	*100.9*	*274.2*	*284.7*	*330.8*	*708.0*
Total Fixed Costs (¢/kWh)	*7.7*	*1.8*	*1.8*	*4.8*	*5.0*	*5.8*	*12.4*
VARIABLE COSTS							
Incremental O&M (¢/kWh elect.)	0.47	0.20	0.20	0.66	0.64	0.35	0.00
Addl O&M for NOx Control (¢/kWh elect)	0.20	0.30	0.30	0.60	0.60	0.60	0.00
Fuel Price ($/kWh fuel)	0.0177	0.0177	0.0177	0.0070	0.0070	0.0070	0.0021
Fuel Cost (¢/kWh elect.)	6.8	4.4	3.9	1.9	1.9	1.7	0.6
Total Variable Costs (¢/kWh)	*7.5*	*4.9*	*4.4*	*3.1*	*3.2*	*2.7*	*0.6*
T&D Adjustment	1	1	1	1	1	1	1
DELIVERED COST (¢/kWh)							
Fixed @ avg. capacity factor	*8.0*	*1.7*	*1.7*	*4.4*	*4.5*	*5.5*	*10.6*
Fixed @ max. capacity factor	*0.9*	*1.2*	*1.2*	*3.5*	*3.6*	*4.2*	*9.6*
Variable	*7.5*	*4.9*	*4.4*	*3.1*	*3.2*	*2.7*	*0.6*
Externality Cost-MA DPU	*2.2*	*1.5*	*1.3*	*2.7*	*2.8*	*2.6*	*0.0*
Externality Cost-MA DPU w/o CO2	*0.5*	*0.3*	*0.3*	*0.5*	*0.5*	*0.4*	*0.0*
credit for fuel flex.	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*-0.2*	*0.0*
Total @ avg. capacity factor	***15.4***	***6.6***	***6.1***	***7.5***	***7.7***	***8.0***	***11.3***
Total w/MA DPU	***17.7***	***8.0***	***7.4***	***10.3***	***10.5***	***10.6***	***11.3***
Total w/MA DPU w/o CO2	***15.9***	***6.9***	***6.4***	***8.0***	***8.2***	***8.4***	***11.3***
Total @ max. capacity factor	***15.4***	***6.1***	***5.6***	***6.7***	***6.8***	***6.7***	***10.2***
Total w/MA DPU	***17.7***	***7.6***	***6.9***	***9.4***	***9.6***	***9.3***	***10.2***
Total w/MA DPU w/o CO2	***15.9***	***6.4***	***5.9***	***7.2***	***7.3***	***7.1***	***10.2***

(1) Capital cost, O&M cost, and performance data from GTF(1989) and EPRI (1989). All costs in 1990$.

(2) Fuel prices are levelized over the period 1990-2020 using a 6.3% real discount rate, and are derived from the fuel price forecast in GTI

(3) Maximum capacity factor is based on equivalent availability, except for combustion turbine.

APPENDIX H: GAS SUPPLY CONSTRAINTS IN NEW ENGLAND

The gas supply issue

An important factor in New England electricity planning is the future availability of natural gas. The amount of gas could be made available, and at what price, is not only important in the context of carbon reduction strategies, but also for the realization of current New England utility resource plans.[1]

There are two views on the availability of gas in New England for the next ten to twenty years. In the optimistic view, New England will be able to import as much gas as it needs to meet both power sector and thermal demands. Factors favoring such an outcome are that major low cost gas reserves exist in Canada, and that the United States and Canadian pipeline system is becoming progressively more integrated and flexible in moving large quantities of gas.

In the pessimistic view, siting constraints, competition with other large markets for Canadian gas (e.g., California), and other factors will constrain gas availability in New England.

In a lower limit scenario, the expansion of gas supplies to the New England region will be more or less limited to those four pipeline projects that are already under way and/or were approved by the FERC in its recent "Open Season" proceedings.[2]

Gas supply and carbon reduction strategies

A carbon reduction strategy could be more dependent on sufficient gas supplies than conventional supply strategies. Conventional strategies principally include the option to bridge gas supply deficits with coal-fired plants, though major siting constraints apply to coal plants as well. Given this situation, it is instructive to compare the lower limit gas supply represented by the four open season projects with the gas demand implied in various carbon reduction strategies. This comparison can indicate the degree to which such strategies might be exposed to the risk of uncertain gas availability.

To make such a comparison, it is necessary to establish what fraction of the four pending gas supply projects in New England could be available for power production, given

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[1] A recent review of New England gas supply issues is found in NEGC (1990a). For previous assessments, see NECGA (1988) and Schleede (1988).

[2] The projects considered likely to succeed are the Iroquois system, the Niagara Spur, and the Texas East CD-1 project. In addition, the NOREX system was approved in 1989 and is expected to be completed by the end of 1990.

competing uses for the gas they will supply. Translating the capacity of these projects into their gas-fired power production equivalents involves various assumptions, including:

- — The growth of firm non-generation demand in the region;
- — The gas DSM resources that might be mobilized by applying integrated resource planning to gas utilities;
- — The degree to which firm, seasonal firm, or interruptible supply contracts will be used for gas-fired generating plants;
- — The net heat rates of the gas-fired generating technologies employed.

A simplified analysis of these factors is presented below.

The New England gas supply situation

Status quo gas supply

Important data for the following discussion are summarized in Table H.1. Despite rapid growth,[3] the contribution of gas to total primary energy use in New England remains far below the national average (13.3 percent in 1987 compared to 23 percent nationwide).

In 1987, about 384 billion cubic feet (Bcf) of natural gas were sold in New England, of which 76 percent were firm capacity sales. The dominant sector was residential, with a 42 percent share, followed by the commercial sector with 26 percent. Industry accounted for only 15 percent of total sales. About half the supply to the industrial sector was interruptible.

Gas used for generation accounted for the remaining 17 percent of sales. Eighty-five percent of this gas was used by utility power plants, and all of it on an interruptible basis. Non-utility generation, mostly industrial cogeneration qualifying facilities (QFs), accounted for the remainder. In 1988, utilities significantly reduced their gas purchases to take advantage of low oil prices.

Installed pipeline capacity for firm delivery was about 1.6 Bcf/day in 1987. The annual load factor was 65 percent. By 1988, New England's gas system was operating close to its firm capacity limit.

Additional supply capacities on the way

The New England Governors' Conference (NEGC, 1990) estimates that four major supply projects already approved by the Federal Energy Regulatory Commission (FERC) will be successful. These will add an additional capacity of 0.65 Bcf/day to New England's gas supply system. At a constant load factor of 65 percent, this capacity represents energy in the amount of about 155 Bcf/yr. About sixty percent of the additional capacity (0.4 Bcf/day) has been contracted for by New England's local distribution companies (LDCs).

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[3] Between 1975 and 1987, gas use grew by an average of 3.5%/yr in New England.

The remaining 0.25 Bcf/day has been contracted for by utilities, cogenerators, and independent power producers.

Growth in gas demand for non-generation applications

Projections of 1987-2000 demand growth in the New England region are available from DRI and GRI. Both forecasts differentiate between the residential, commercial, industrial, and power generation sectors. The trends forecast for non-generation gas uses are similar. The residential sector shows the greatest growth in both forecasts, while industrial sector growth is small or zero.

Averaged over all sectors but excluding generation, the DRI forecast assumes a growth of 1.2%/yr for non-generation applications. The GRI forecast is based on a non-generation growth of 2.0%/yr. The 2005 demand forecast for non-generation applications shown in Table H.1 is calculated by averaging the DRI and GRI assumptions for each sector. This results in an average growth rate of 1.5%/yr for non-generation applications.

Gas available for power generation

In absolute terms, this growth results in non-generation requirements of 95 Bcf/yr in 2005. With the 60 Bcf/yr of gas requirements for power generation projects that have already been assigned capacity from the four current gas supply projects, total generation gas demand is 155 Bcf/yr before further gas generation capacity is considered. This total just matches the total gas supply that would be available in the region after the four projects have been added. Without gas DSM, but with the gas that was being used for power generation in 1987, the total gas available for electricity production would be 124 Bcf (see Table H.1).

Gas-fired power generation could be pursued in existing plants by converting them to gas or by repowering them with combined cycle technology. In both cases, the vintage of existing plants and their location relative to the gas grid are limiting factors. As the NEGC estimated (1990), some 3600 MW of oil plants could be converted to gas. About 2400 MW would be suitable for repowering. This would result in a repowered capacity of about 7200 MW.

Power generation potential with gas DSM and fuel switching

Before building new pipeline projects, the supply situation for power projects could be improved if gas utilities were to limit the demand growth in non-generation uses. Because residential and most commercial gas customers are on a firm supply basis, demand-side management in these sectors could be particularly effective in stretching pipeline and storage capacities.

For illustrative purposes, Table H.1 therefore includes a calculation in which non-generation gas demand is kept roughly constant at base-year levels.[4] In that case, the supply available for electricity production would almost double to 220 Bcf/yr.

A third column in Table H.1 shows a calculation in which the same gas DSM is assumed, but all residential electric water heating and electric dryers are switched to gas (for a discussion of fuel switching potentials, see Appendix F.6). The gas supplies required for this end-use conversion are about 47 bcf/yr.

Gas heat rates

In translating these figures into power generation, we assume that all gas-fired power plants except IPP projects with firm capacity gas contracts will be supplied on a seasonal firm basis. Seasonal firm contracts have already emerged in New England (NEGC, 1990). They offer an effective means for local distribution companies to improve their load factors and stretch pipeline peak capacity to serve more firm customers. Power projects would burn distillate fuel for a certain number of days during the winter season.

The number of days of secondary fuel operation required by local distribution companies before making part of their capacity available for power production depends on the number of gas plants sharing available pipeline capacity. In air pollution non-attainment areas, distillate oil operation may be limited to 30 days per year under current regulations. Local distribution companies appear to be favoring 300-day seasonal firm contracts (NEGC, 1990).

For the purpose of the following exploration, it is assumed that gas supply for power generation will be on a 330-day firm basis on average. This means that in the first approximation, the amount of gas burned per kWh of electricity (the gas heat rate) is 35/365=9.6 percent lower than the nominal heat rate. Both utility and non-utility gas capacity is assumed to operate in this manner. Possible future improvements in the gas system load factor, which would increase the gas power production potential for a given pipeline capacity, are neglected.

The electrical efficiency of cogeneration power plants is assumed to be the same as that of existing utility capacity and oil plants that could be converted to gas (heat rate of about 10,300 Btu/kWh). After subtracting generation with distillate oil, the gas heat rate for both is 9300 Btu/kWh.[5] Based on the same calculation, advanced combined cycle units and intercooled steam injected gas turbine (ISTIG) plants, the gas heat rate would be 6850 Btu/kWh.

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[4] We did not analyze the cost and technical feasibility of this DSM goal in detail. Such an analysis should be done to refine this calculation.

[5] IPP projects with firm gas contracts and using current combined cycle technology have about the same total heat rate, and an identical gas heat rate. With these assumptions, 1987 gas sales would yield 7 TWh, close to actual generation, which was 7.4 TWh including secondary fuels.

Power generation with gas DSM

Table H.1 then shows how much extra power could be generated from the four additional pipeline projects. An important conclusion arises from comparing results with and without gas DSM:

- If gas demand for non-generation uses was stabilized through DSM programs, gas-fired electricity production in New England could be almost doubled over what it would be otherwise.

Simple fuel conversion, while attractive on a first cost basis, would be the least efficient use of available gas supplies. The figures also imply that even with gas DSM, only a fraction of the suitably located existing plants could be converted or repowered as base to intermediate-load plants with available supplies.

Supplies would be greatly stretched if used in more efficient plants. If used for advanced combined cycles, they would be sufficient to provide about 42 percent of the approximately 45 TWh demand growth projected for 2005.[6]

The gas input into cogeneration plants would be higher, but this gas would in effect displace large amounts of oil in non-generation uses, or free gas that was already being used there for other uses.

Industrial gas-fired cogeneration would yield less electricity from the same amount of gas than advanced central stations. However, the carbon burden of thermally optimized cogeneration would be lower (see Appendix I). In the future, European-style district heating plants using ACC or ISTIG technology could produce electricity nearly as efficiently as ACC central stations, while offering a significant carbon burden advantage.

Impact of fuel switching at the point of end-use

In the hypothetical case where gas is set aside for switching residential water heaters and dryers to gas (see Appendix F), the remaining gas for power generation is reduced by about half. Gas-fired generation would contribute 28 percent of the 1990-2005 demand increment if used in ACC plants.

Summary

In our analysis, gas supplies are treated as unconstrained. The above in-depth analysis of the four current pipeline projects has an illustrative function only. Still, it bears a clear message:

- New England will need to initiate projects for obtaining additional gas supplies, and it will need to integrate gas supply and demand-side planning with electricity planning.

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[6] Net load growth plus eight percent line losses. See NEPLAN (1990).

- This observation is true even before carbon reduction goals are considered.

Whether carbon reduction goals would worsen this predicament depends on the resource mix used to achieve such reductions. Gas demand impacts may not be large if New England's DSM and renewable resource potentials reduce demand for gas-fired generation technologies sufficiently.

Table H.1: Minimum potential for gas-fired electricity production in New England					
	Units	*1987/88 status quo*	*2005 w. approved projects no gas DSM*	*2005 w. approved projects plus gas DSM*	*2005 apprvd projcts plus DSM plus fuel sw.*
Gas supply capacity					
Existing capacity	Bcf/day	1.619	1.619	1.619	1.619
New capacity	Bcf/day		0.65	0.65	0.65
assigned to LDCs	Bcf/day		0.4	0	0
assigned to generation projects	Bcf/day		0.25	0.65	0.65
Total system capacity	Bcf/day	1.619	2.919	2.919	2.919
Annual load factor		*65%*	*65%*	*65%*	*65%*
Gas demand/supply balance					
Demand: Non-generation customers	Bcf/yr	319	414	319	367
Residential	Bcf/yr	161	226		
Commercial	Bcf/yr	99	123		
of which interruptible	Bcf/yr	17			
Industrial	Bcf/yr	59	66		
of which interruptible	Bcf/yr	30			
Demand: identified generation projects	Bcf/yr	65	124	124	124
Utility power generation	Bcf/yr	55	69		
Non-utility power generation	Bcf/yr	10	55		
Total identified demand	Bcf/yr	384	539	443	491
Total supply	Bcf/yr	384	538	538	538
Surplus potentially avail. for addl. generation	Bcf/yr	0	0	95	47
Gas-fired power generation					
Existing and pending gas-fired plants					
Utility and IPP plants (8500 Btu gas/kWh)	TWh/yr	6.0	7.5	7.5	7.5
Cogen plants (9300 Btu gas/kWh)	TWh/yr	1.0	5.7	5.7	5.7
Total electricity	TWh/yr	7.0	13.2	13.2	13.2
Gas generation as a fraction of el. growth	%		*0.14*	*0.14*	*0.14*
Max. addnl. electr. production based on					
– Conversion of ex. oil plants (9300 Btu gas/kWh)					
Electricity (incl. generation fr. second. fuel)	TWh/yr		0.0	9.4	4.7
Gas generation as a fraction of el. growth	%		*0.14*	*0.35*	*0.24*
C burden incl. secondary fuel and T&D losses	*g C/kWh*			*140*	*140*
– Addl. ind. cogeneration (9300 Btu gas/kWhe)					
Electricity (incl. generation fr. second. fuel)	TWh/yr		0.0	9.8	4.9
Gas generation as a fraction of el. growth	%		*0.14*	*0.36*	*0.25*
C burden incl. secondary fuel and T&D losses	*g C/kWh*			*90*	*90*
– Adv. ACC/ISTIG plants (6850 Btu gas/kWhe)					
Electricity (incl. generation fr. second. fuel)	TWh/yr		0.0	12.8	6.4
Gas generation as a fraction of el. growth	%		*0.14*	*0.42*	*0.28*
C burden incl. secondary fuel and T&D losses	*g C/kWh*			*113*	*113*

Notes to Table H.1:

(1) Gas demand based on ave. of DRI and GRI New England forecast growth rates.
(2) Data on existing and pending supply projects from New England Governors' Conference (NEGC 1990a).
(3) Projects assumed to be completed include NOREX, Iroquois, Niagara spur, and Texas Eastern.
(4) DSM is assumed to reduce demand growth in non-generation applications by half.
(5) Net growth in final electricity is 45 TWh between 1987 and 2005.
(6) Total net heat rates are higher than gas heat rates by factor 365/330, except for firm contract IPPs.
(7) Cogeneration net C burden based on Appendix I.
(8) Fuel switching assumes full conversion of all electric water heating and electric dryers.
(9) Maximum addnl. generation based on using all gas beyond base year level in plants of each type.

APPENDIX I: COGENERATION POTENTIAL IN NEW ENGLAND

Estimating the cogeneration resource potential is an involved task. Estimating the potentials and costs of carbon reduction within that resource potential is even more difficult, for in addition to characterizing the cogeneration potential in terms of costs, capacity, and total electricity generation, we must also determine:

- which cogeneration systems can provide carbon savings relative to central stations, notably utility-scale gas-fired advanced combined cycles (ACC). Key parameters are the input fuel, the overall efficiency, and the displaced boiler fuel in thermal applications;
- efficiency levels and carbon burdens of currently existing, planned, and forecast cogeneration capacity; and
- the impact of requirements for low carbon burdens on the cost and potential of cogeneration projects.

Such an analysis goes beyond the scope of the present study. Because the resource potential of cogeneration in New England appears to be substantial, however, efforts were made to derive an order-of-magnitude figure using simplified assumptions. These simplified estimates are described below.

Net heat rates and carbon burdens

Net heat rates

The *net heat rate* of a cogeneration power plant is the amount of fuel needed to cogenerate a unit of electricity. It is analogous to the heat rate of central stations. The net electric heat rate is based on allocating to the electrical side all fuel inputs in excess of those that would be required in a conventional boiler to produce the same thermal output. It can be written as:

$$N = \frac{(T_c - T_b)}{EPR} \qquad (1)$$

where

T_c is the total heat rate of the cogenerator (kWh.fuel/kWh.th),

T_b is the heat rate of the conventional boiler (kWh.fuel/kWh.th), and

EPR is the electricity production rate (kWh.e/kWh.th).

Conventional fossil-fired central stations based on steam turbine/boiler technology require typically 2.5-3.0 kWh of fuel per kWh of electricity. Cogeneration systems mainly built for power production ("PURPA-machines") tend to have net heat rates in that same range.

By contrast, cogeneration systems optimized for self-generation can achieve net heat rates as low as 1.0-2.0, depending on load matching, total system efficiency, and technology.

Carbon burdens

The carbon burden of a unit of electricity from cogeneration can be calculated as follows (Krause et al., 1992):

$$C_{cogen} = N * C_{cogen} + \frac{(C_b - C_{cogen})}{BE * EPR} \qquad (2)$$

where

N is the net heat rate of the cogenerator ($kWh.f/kWh_e$),

BE is the efficiency of the displaced boiler, and

C_b, and C_{cogen} are the total carbon burdens of the various fuels (g/kWh_f).

In the equation, the first term represents the cogenerator carbon burden when the carbon burden of the displaced boiler fuel and the fuel used in the cogeneration plant are the same. The second term represents the correction for the case where the two fuels are different.

The operating mode with the lowest carbon burden for cogenerated electricity is in thermal load following (TLF). If electric loads are followed (ELF), the net heat rate will rise, and so will carbon burdens.

PURPA operating standard and efficiency requirements

Under the Public Utility Regulatory Policy Act (PURPA) of 1978, cogeneration facilities are characterized by an "operating standard." This operating standard is defined as follows:

$$OS = \frac{UO_{th}}{(UO_{th} + UO_e)} \qquad (3)$$

where

UO_{th} is the annual average useful thermal output, and

UO_e is the annual average electrical output of the cogeneration system.

The minimum operating standard for oil- and gas-fired cogeneration units under PURPA requires that thermal output be at least 20 percent of total useful output, and that electrical output plus one half of the useful thermal output ("PURPA efficiency") equal at least 42.5 percent of fuel inputs on a lower heating value (LHV) basis (FERC, 1981).[1] When the

[1] Because Federal Energy Regulatory Commission rules are expressed on a lower heating value basis while power plant performance data are typically expressed on a higher heating value basis, we show both values in Table I.1 Total first-law efficiencies and electrical efficiencies are expressed on a HHV basis.

20 percent operating standard is not met, the electric-plus-50%-of-thermal output requirement rises to 45 percent. This efficiency standard is designed to assure that oil- and gas-fired cogeneration units achieve net electric heat rates comparable to those of conventional central stations.

Carbon burdens under alternative operating standards

Table I.1 shows the direct carbon burden of alternative cogeneration systems when thermally optimized, and when configured to just meet minimum PURPA efficiency requirements.[2] The efficiency of the displaced boiler is assumed to be 85 percent. All cogenerators are gas-fired. Gas is assumed to be 330 days per year firm, supplemented by 35 days of distillate combustion during the gas system winter peak period. The electricity production rate is calculated using the relationships of equations (1) and (2). Carbon burdens are calculated, respectively, for displacing gas, coal, and the weighted average mix of direct fuel use in the industrial and commercial sectors of New England. The latter is within ten percent of the carbon burden of light heating oil.[3]

Several observations can be made:

- Thermally optimized systems have operating standards in excess of 50 percent, compared to a minimum operating standard of 15 percent for oil- and gas-fired units, and of 5 percent for coal-fired units.[4]
- For cogenerators displacing the New England mix of thermal end-use fuels, the PURPA efficiency requirements do not ensure any significant gain over the carbon burden of a utility-scale ACC plant. In most cases, the carbon burden of the cogenerator is actually about ten percent higher.
- Thermally optimized gas-fired cogeneration improves on the carbon burden of a gas-fired utility ACC plant by about 25-40 percent when displacing the New England mix of thermal end-use fuels.
- Even when displacing boilers and furnaces that are already fired with gas, thermally optimized cogeneration improves on the carbon burden of

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2 Performance data for prototypical industrial cogeneration systems were obtained from John Kovacek, General Electric Co., Applications Division, Schenactedy, N.Y.

3 Based on data from EIA (1990), the industrial sector consumed 33 percent of direct fuel energy as heavy fuel oil, 22 percent as light fuel oil, 38 percent as gas, and seven percent as coal. In the commercial sector, the proportions were 17, 37, 45, and 1 percent.

4 An additional condition is that the PURPA efficiency (based on electrical output plus one half the useful thermal output) is at least 42.5 percent. For oil- and gas-fired units, an operating standard as low as five percent is permissible so long as the PURPA efficiency is at least 45 percent. See FERC (1981).

a utility ACC plant as long as electrical efficiencies[5] of more than 25 percent are realized.

The effects of the displaced fuel and of the thermal output fraction are graphically illustrated in Figure 1. The figure shows the direct carbon burden of cogenerated electricity as a function of the thermal output fraction, for a 56 MW gas-fired combined cycle plant.

Carbon burden of packaged engine/chiller systems

In commercial buildings, internal combustion engines can be used not only to generate electricity and heat, but also to displace electric air conditioning. In one configuration, the internal combustion (IC) engine drives a generator, and heat outputs are used for space and water heating and for an absorption chiller cycle.

Equation 2 can be modified to describe this system by introducing a term that corrects for the difference in carbon burden between the displaced electric air conditioner and the IC engine system. Table I.2 shows the net carbon burden of a typical large system in which 40 percent of the thermal output is used in a two-stage absorption chiller with a coefficient of performance (COP) of 1.0, and displaces outputs from a high efficiency (85%) fuel boiler and an electric chiller with a COP of 5.5.

As the table shows, the carbon burden of such a system is still about 12-28 percent lower than that of a gas-fired ACC central station, even when the electricity driving the air conditioner is itself generated in a gas-fired ACC (115 gC/kWh).

Carbon burdens of electricity from currently existing cogeneration capacity

The operating standards of recent cogeneration projects are reviewed in an analysis by Capehart and Capehart (1991), who examine the 1988 to July 1990 FERC applications. The sample comprised 143 applications representing about 9300 MW.

The authors find that only 29.2 percent of these facilities meet an operating standard greater than 25 percent, and only 11.6 percent meet a standard of more than 50 percent. That is, about 70 percent of recent cogeneration projects were PURPA machines. These figures assume that the facility is operated as stated in the FERC application. No verification of actual performance was undertaken.

These figures comprise coal-fired, oil-fired, gas-fired, and biomass-fired units, and combined cycle, gas turbine, and steam turbine plants. No disaggregation by fuel type or technology is given. Based on these data, the following observations can be made:

- At least 70 percent or more of recent cogeneration projects are more carbon-intensive than gas-fired ACC central stations.

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[5] Electrical efficiency refers here to the calculated efficiency when all fuel inputs are allocated to the electricity output of the cogenerator. This figure depends on the thermal output insofar as thermal output affects the performance of the generator cycle.

- At most about 12 percent of recent cogeneration projects offer substantially lower carbon burdens than gas-fired ACC central stations.

The prevalence of PURPA machines in recently built capacity is also reflected in the fact that very low operating standards (down to the PURPA all-fuel minimum of five percent) were encountered in every size class from less than 1 MW to 350 MW. The average operating standard falls off precipitously as size increases: from the 50 percent range for small (<1 MW to 10 MW) facilities to the 15-20 percent range for the larger facilities that contributed the bulk of the sample MW. For the 10-50 MW range, the average was 35-40 percent (Capehart and Capehart, 1991).

At the same time, the same analysis shows that current technology can be applied in high efficiency configurations. Projects with operating standards of 70 to 90 percent were found in all size classes. Typically, such projects are steam turbines built mainly for self-generation rather than sale to the grid. These and on-site packaged cogeneration systems (typically less than 1 MW) in commercial and industrial buildings, are most economical in the self-generation mode.

Cogeneration carbon burdens in New England

No formal analysis of New England's cogeneration projects was available, and no such analysis was undertaken in the present study. However, some data for a sample of projects were obtained by telephone from staff of Northeastern Utilities (NU) and New England Electric System (NEES). These data and the findings of Capehart and Capehart (1991) were used to estimate the carbon burden of cogeneration projects as listed by the New England Governor's Conference (NEGC, 1990b).

From these rough estimates it appears that existing, committed, and proposed gas-fired projects in New England nearly match the carbon burden of gas-fired ACC central stations. Most existing and proposed gas-fired projects are smaller than 70 MW. Several existing and proposed gas-fired combined cycle district heating plants and a few industrial plants appear to be efficient and have carbon burdens well below those of ACC central stations. A detailed analysis of FERC applications for current and proposed projects would allow more precise estimates.

Busbar costs of electricity production from cogeneration

Table I.3 shows busbar costs for four systems:

- — an industrial gas turbine with heat recovery steam generator (HRSG);
- — a packaged reciprocating engine for commercial building applications;
- — an industrial combined cycle; and
- — a combined cycle sized to meet the same thermal load at more than twice the electric output.

The cost and performance assumptions are based on data provided by manufacturers and other sources.[6] It is assumed that the cogeneration system is part of a new building or industrial plant or is installed as part of a routine replacement. Capital and operating cost credits for avoided boiler or furnace investments are taken into account,[7] and so are extra variable costs for stringent NO_x control.[8] As a conservatism, we neglect the transmission and distribution (T&D) credits earned by on-site systems.[9]

The busbar figures show that the four gas-fired cogeneration systems could produce electricity at costs ranging from 4.6 to 6.1¢/kWh at maximum capacity factor.

Impact of low carbon configurations on cogeneration busbar costs

The carbon burden difference between thermally optimized cogeneration systems and PURPA systems is greatest for combined cycle plants. The two combined cycle systems shown in Table I.3 illustrate the trade-offs involved in building a plant designed for thermally optimized operation versus designs for high electric output for sale to the grid. The 122 MW combined cycle is designed for an operating standard of 28 percent, compared to 55 percent for the 56 MW unit. The capital cost for this PURPA-like machine is 21 percent lower than that for the thermally optimized cogeneration plant, but the heat rate is 25 percent higher.

Table I.3 shows that the bona fide cogeneration plant of smaller size has, at 4.6¢/kWh, a fifteen percent lower busbar cost than the PURPA machine. The heat rate advantage of the smaller plant is more important than the capital cost advantage of the larger plant. Without the credits for displaced boilers, the total costs of the two systems would be just about equal.

This cost relationship changes significantly when the Massachusetts externality surcharges are added. Assuming that a capital cost credit applies, the disadvantage of the less efficient

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[6] The data for industrial steam and gas turbine systems were provided by General Electric's Applications Division. The data on IC engines were taken from Kostrzewa and Davidson (1988) and GRI (1989). Cost estimates for the industrial systems are feasibility grade estimates. They are installed costs for green field plants excluding interest during construction, escalation, or "soft" costs for permits, etc. They do include unfired HSRG units where applicable, steam, and feedwater systems, including make-up water systems, step-up transformer, control room, interface hardware, plant security, fire protection, and shop areas for maintenance and spare parts.

[7] Capital cost credits are based on information by manufacturers (Kovacek, 1991) and on costs of displaced boiler equipment (GRI, 1989). Additional sources are discussed in Krause, et al. (1992). The capital cost credit is 30 percent for thermally optimized industrial systems, and 20 percent for commercial building IC engines. For the industrial PURPA machine, the capital cost credit is reduced in proportion to the reduction in thermal output.

[8] Emissions are controlled to 25 ppmv with dry low NO_x controls. The extra operating costs are for additional measures required to meet more stringent demands.

[9] Such T&D credits could be large, insofar as the failure of individual cogeneration units is expected to occur randomly, leading to a low coincidence of outage demand on the T&D system.

PURPA system grows by six mils with carbon dioxide and by three mils when only SO_2 and NO_x emissions are valued.

This calculation suggests the following:

- Designing cogeneration systems for low carbon emissions does not necessarily increase their busbar cost (capital cost credit does not apply), and could well decrease it (capital cost credit applies).
- Monetized adders result in a robust busbar cost advantage of thermally optimized systems.

However, cost neutrality or a busbar cost advantage for thermally optimized systems does not necessarily mean an economic advantage for the project developer. In many cases, the preference for PURPA machines over thermally optimized, low carbon cogeneration appears to be shaped more by the opportunity for buy-back rate and avoided cost arbitrage than by any generating cost advantages of the PURPA plant.

Since this opportunity for arbitrage grows with the amount of power sold to the grid, the carbon burden of cogeneration under the current regulatory regime is strongly influenced by trends in avoided costs and buy-back rates. Conversely, the impact of changes in regulations requiring higher operating standards on cogeneration capacity growth will depend on the avoided cost trends that were assumed in the reference cogeneration capacity projections.

Economic and market potential of industrial cogeneration

Forecasts of future industrial cogeneration resources, including regionalized projections for New England are available from the Gas Research Institute (GRI). GRI's 1991 Baseline Projections contain cogeneration forecasts to 2010 based on EEA's ISTUM model (GRI/EEA, 1991). These projections do not take into account the potential impact of independent power producers on avoided costs and buy-back rates.

In a separate projection, GRI analyzed the impact of independent power producers (IPPs) on the cogeneration market for the period to 2010. This analysis is based on a similar cogeneration forecasting model developed by HBI and contains a regional forecast for New England as well (GRI/HBI, 1991). To be able to interpret these cogeneration projections, one must understand how they are derived.

Both cogeneration projections make use of economic forecasts disaggregated by two-digit SIC codes, and assume flat to slightly declining real electricity rates, combined with gas prices rising at GRI's projected average rate of about 4.4%/year in real terms in the period to 2010. The projections further draw on data bases by industry sector of electric to thermal energy consumption ratios, of industrial plants by steam capacity, and of installed boiler capacity by industry, technology, and fuel type.

Prototypical cogeneration facilities are analyzed by industry for each type and size of stylized steam and electric load. The most important technologies examined are coal-fired conventional or atmospheric fluidized bed boilers; and oil- or gas-fired steam turbines, gas turbines, reciprocating engines, and combined cycles. The cogeneration systems are configured as bona fide cogeneration plants, i.e., with high (65-75%) overall efficiency.[10] PURPA machines and IPP units are not included.

The economics of these cogeneration systems are then evaluated using regional energy prices and buy-back rates. The HBI analysis explicitly takes into account the potential impact of IPPs on avoided costs. These data are used to calculate economic potentials. Steam loads that are already being cogenerated are subtracted. A market penetration analysis translates these figures into market potentials.

GRI /EEA 1991 baseline projections

The results of this projection are shown in Table I.4. According to the 1989 GRI baseline projections, total New England industrial cogeneration in 2010 would be 27.5 TWh. This compares to a total of 5.6 TWh from cogeneration and self-generation capacity at the end of 1989.[11] Most (57 percent) of the additional fossil-fired generation would be from gas. Net additions would be about 21.9 TWh: 18.6 TWh from fossil fuels and 3.3 TWh from biomass and other fuels.

With a 75 percent capacity factor, the growth in energy production translates into a total capacity addition for New England of about 3330 MW by 2010. 1390 MW are from gas, 500 MW from biomass, 840 MW are from oil, and 600 MW from coal.

GRI/HBI 1991 forecast

The GRI/HBI forecast for 2005 projects about 3000 MW of new industrial cogeneration capacity for New England beyond projects already in place in 1990. Annual capacity additions average about 220 MW per year during the 1990s, and slow to about 170 MW/yr in the remaining years of the forecast period. In the first part of the forecast period, gas-fired units dominate. After that, the cogeneration fuel mix is projected to gradually shift to coal. Competitive bidding and IPP projects are found to reduce future cogeneration markets by 12 percent nationally relative to the GRI baseline projection.

Accounting issues

The figures of the New England Governor's Conference (NEGC, 1990) and the GRI projections include cogeneration electricity that is used within the firm only (referred to here as "self-generated electricity"), notably the large self-generation capacity in the pulp and

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[10] Personal communications with Joel Bluestein, EEA, and Hugh McDermott, HBI.

[11] This base year figure was calculated as follows: According to power sales data in NEPOOL's 1990 CELT report (NEPLAN, 1990), the average capacity factor of existing non-utility generating plants was 81 percent. This capacity factor was applied to the 532 MW of cogeneration facilities selling to utilities as listed in NEGC (1989). The self-generation capacity (facilities not selling to utilities) of 660 MW was assigned an average capacity factor of 70 percent. Because the self-generation capacity contains a substantial amount (198 MW) of hydro capacity, the latter capacity factor may be still too high.

paper industry in Maine.[12] In the convention of NEPOOL's CELT report, this portion of cogenerated power is netted from the load forecasts.[13] To avoid double counting, the GRI figures in Table I.4 are adjusted downward by the projected electricity generation from cogeneration plants in the paper industry.

Most paper industry cogeneration occurs within the service territory of Central Maine Power (CMP). CMP expects an increase in pulp and paper industry electrical loads within its territory of about 1.25 TWh/yr between 1991 and 2005, and 1.5 TWh by 2010.[14] Extrapolating these figures to a statewide basis, an estimated 2.1 TWh of pulp and paper industry load growth would occur by 2005, and 2.5 TWh by 2010.[15]

Subtracting these figures from the GRI forecast yields a net contribution over the 1990 base year of 19.4 TWh by 2010. This is equivalent to about 3000 MW at a 75 percent capacity factor.

Comparison with currently proposed NE projects

NEPOOL's 1990 CELT report lists 1915 MW of committed and proposed cogeneration capacity (895 MW of committed cogeneration QF resources and 1020 MW from uncommitted projects that are planned or proposed). Committed and proposed gas-fired cogeneration capacity is about 1200 MW; coal-fired projects are about 500 MW.

A significant increase in cogeneration capacity occurred between 1989 and 1990. According to NEGC's 1989 and 1990 compilations, cogeneration capacity almost doubled, from 532 MW to 1003 MW. Virtually all the increase was from plants selling to utilities. The major increases came from coal (238 MW), gas (161 MW), and biomass (89 MW).

Economic and market potential of non-industrial cogeneration

Besides industrial applications, two further important cogeneration markets are on-site packaged cogeneration in commercial and institutional sectors, and district heating schemes. Both technologies compete in many applications.

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12 For details, see NEPOOL's CELT report (NEPLAN, 1990), and the compilation of self-generation capacity by the New England Governor's Conference (NEGC, 1990b). The CELT report showed industrial cogeneration only when there was a power sales contract with a utility.

13 A large amount of existing self-generation is netted from NEPOOL loads. See NEPLAN (1990). According to Central Maine Power, net utility sales to the industry are projected to decrease by 0.35 TWh between 1990 and the 2005/10 period. For more details, see the 1988-2018 long-range industrial forecast of the company (CMP, 1990).

14 CMP assumes standard steam turbine technology will continue to be used in the paper mills. Advanced biogasification technology could be used to increase electricity production ratios (see Appendix J).

15 CMP represents 54 percent of Maine's total pulp mill capacity, and 64 percent of paper mill capacity. The pulp capacity share is to grow to 60 percent, while that of the paper capacity is to stay constant over the long-term (RISI, 1990).

Many on-site packaged cogeneration systems are designed to also provide air conditioning using absorption chillers. Similarly, district heating plants can be designed to provide steam for on-site turbine-based chillers and for absorption chillers, or chilled water that is centrally produced. These systems compete with high-efficiency air conditioning, thermal energy storage, and high-efficiency boilers and water heaters.

On-site packaged cogeneration

Nationally, some 700 commercial cogeneration systems under 5 MW were operating in 1989, with a total capacity of 268 MW. Another 139 MW were under development. While the larger systems (1-5 MW) represented only 12 percent of all projects, they contributed about 70 percent of the total capacity (GRI, 1990). An additional 1700 MW existed in systems larger than 5 MW, including those installed in college campuses and other large facilities (GRI, 1990).

Currently available national assessments of the commercial cogeneration market differ widely. Projections by GRI foresee an installed electric capacity of 7100 MW by 2000, and 11600 MW by 2010 (GRI, 1991), including systems larger than 5 MW. This is equivalent to a 5.8 percent cogeneration share in commercial sector electricity supplies, compared to 1.7 percent in 1990. Estimates for the national market for smaller systems in 2000 range from 1900 MW to 5200 MW (Limaye, 1988). These projections are market potentials based on scaling up recent activity, and apply the short payback requirements that are commonly found in commercial building energy-efficiency investments.

Resource and market potentials

The purely technical potential of on-site cogeneration in commercial and institutional sector buildings is very large, probably of the order of 50-60 GW.[16] Until now, assessments of the economic cogeneration potential in commercial buildings have been hampered by insufficient data about the cooling, heating, and electric loads in U.S. commercial building stock. A recent analysis conducted by Lawrence Berkeley Laboratory (Huang et al., 1990) greatly improves the commercial building load characterization. In that analysis, buildings with the most favorable cogeneration conditions and statistically significant shares of commercial sector energy use were found to be the following: hospitals, large hotels, extended-hour sit-down restaurants, fast-food restaurants, and large office buildings.

This analysis has not yet been fully utilized to arrive at improved estimates of the economic potential of packaged cogeneration. The Gas Research Institute is conducting an assessment with HBI that aims to calculate the U.S. market potential in the twenty metropolitan areas analyzed by LBL. However, this analysis looks at cogeneration feasibility on the basis of status quo market conditions, in which investors require very short payback times and face a number of regulatory and institutional hurdles.[17]

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[16] Based on potential sites as quoted in Limaye (1988).

[17] For a discussion of these hurdles, see, e.g., GRI (1990). As shown in that report, programs to overcome these hurdles on the part of gas utilities have been limited to date, both in number and in terms of

In the ongoing GRI/HBI analysis, payback periods for on-site cogeneration is found to be 3.5-10 years against electric rates in the Boston Edison service territory, with the bulk below five years. Market shares are allocated on the basis of statistical distributions of life cycle costs for cogeneration systems and competing technologies. Because competing technologies have often lower payback times and life-cycle costs, cogeneration technologies are projected to win only a small market share, and only very small market potentials are predicted.[18]

In the context of this study, the more relevant figure is the total resource potential available at costs of about 6-7.0¢/kWh (see Table I.3), irrespective of competing non-electric technologies, but taking account of electrical efficiency improvements in air conditioning and lighting.

In the absence of published estimates of this potential, we assume the economic commercial sector packaged cogeneration potential in New England scales in proportion to the share of the region in total U.S. power sales. Using the 1991 GRI national baseline projection of 11,600 MW as a basis, this yields an estimate of about 370 MW. To allow for electrical efficiency improvements, we discount this figure to 250 MW.

District heating

Several district heating systems exist in the New England region. The largest existing cogeneration systems are the Capitol District and O'Brian plants in Hartford, with a total installed capacity of 110 MW. Another 115 MW combined cycle plant is being planned by Boston Thermal Corporation, which serves the downtown area of that city.

The Hartford Capitol District plant is a state-of-the-art system that exemplifies the high efficiency that can be achieved with district heating plants. The overall efficiency of the system is 65 percent, the operating standard is 46 percent, and the PURPA efficiency is 50 percent.[19]

According to information from staff of the Hartford and Boston district heating utilities, their currently existing or planned electric capacities could be economically expanded by a third, equivalent to an additional 75 MW, for a total of 300 MW in these two cities. In buildings where hydronic systems still exist, district heating companies have found that retrofits to steam can be done with short, one to two year payback times. Also, steam has a good market potential in new construction on account of avoided first costs for equipment, e.g., boiler rooms and exhaust stacks.

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incentives offered. Notably, no significant relief for the high first cost of cogeneration units has been offered by programs to date.

18 For example, the market potential in the Boston Gas service area has been identified as about 95 mostly small projects with a total capacity of 13 MW by 1998 (personal communication with Hugh McDermott, HBI, and Ken Cheo, Boston Gas Company). Scaled to New England on the basis of gas customers, the total market potential for 2000 would be about 50-60 MW in the region.

19 Personal communication with Eric Rorstrom, Northeastern Utilities.

Other potential candidates for expanding district heating are university campuses and cities such as New Haven, Springfield, Stamford, and Providence. Scaling from the Boston and Hartford systems by population, these cities would add a potential of 180 MW.

An additional potential could become available where district heating can economically include loads from residential and smaller commercial customers, as widely done in Europe.[20] Lack of a tradition of publicly funded district heating utilities, and capital market and institutional barriers were cited as reasons for the lack of such cogeneration in New England.

Based merely on the above figures, an additional district heating capacity of 370 MW could be installed. There is some overlap between the building loads that would be served by the above commercial-sector oriented district heating systems and those that could be served by smaller on-site cogeneration systems. For the purposes of this study, we assume that the additional potential from district heating is 250 MW. The combined additional potential for both district heating and on-site cogeneration is estimated as 500 MW.

Impact of carbon reduction goals on the cogeneration potential in New England

Policies that favor or require low-carbon generating sources (reduction targets, higher minimum efficiency requirements, or externality adders) will shift the competition between cogeneration and central station generation into an arena in which the reference parameters are the costs and carbon burdens of a gas-fired utility-scale ACC plant. In the context of a carbon reduction strategy, projects fired by coal or oil will become less viable on account of high carbon burdens. Gas-fired projects that are mainly aimed at power sales to the grid (PURPA machines) will become less viable.

Because the cogeneration systems modeled in the GRI forecasts are thermally optimized (65-70 percent overall efficiency), the industrial sector projections of total capacity as shown in Table I.4 also define the cogeneration resource size for the present context. The same holds for thermally oriented district heating and packaged cogeneration systems. The average cost of that resource, however, and therefore the interpretation of the forecast as a market potential, might change.

The major coal share of projected cogeneration capacity in the GRI forecasts (see above) is based on a greater attractiveness of coal-fired units in later years of the forecasting period. This dynamic results from the projection of relatively stable coal prices combined with significant real escalation of gas prices (GRI/HBI, 1991). A carbon reduction strategy would effectively eliminate coal-fired systems.

The elimination of oil and coal as a competitive fuel in most cogeneration applications would be matched by a corresponding loss of competitiveness of these fuels in utility or

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20 According to experience in Germany, district heating is not economically limited to downtown areas. For example, the city of Flensburg, with about 100,000 inhabitants, achieved a 95 percent conversion to district heating. Most suburbs were connected at grid costs per unit of delivered energy that were no higher than those for downtown customers. See Krause et al. (1992) for further details.

IPP investments. In effect, the competition would narrow to the scale versus heat rate issues analyzed above. On the basis of that analysis, most steam loads that had previously been projected to be cogenerated on the basis of oil or coal might be cogenerated by gas if gas is available.

A further factor is that gas-fired cogeneration systems have higher electricity to steam ratios than the steam turbines used with coal. A shift of steam loads from coal to gas would thus increase electricity production. This aspect could make cogeneration projects more dependent on utility buy-back rates, notably in industries where electricity to steam ratios are low.

Obviously, gas and biomass supply constraints could hamper the development of low-carbon cogeneration facilities. However, these fuel availability constraints are not unique to cogeneration. They also apply to utility capacity expansion, and will have to be addressed in any resource plan for the region (see also Appendix H and Appendix J). The gas-fired cogeneration potential as estimated in this section is to be understood as an unconstrained potential.

Finally, significant capital allocation barriers exist within many industrial firms that have not traditionally engaged in cogeneration. In a strategy aimed at mobilizing low carbon resources, the development of gas-fired cogeneration could be augmented through a changed interpretation of best available control technology (BACT) for industrial boiler emissions. Industrial producers would be required to submit cogeneration feasibility studies for every permitted boiler or process.[21]

In view of these factors, it is difficult to derive more than a very crude estimate for the New England economic potential of low-carbon, gas-fired industrial cogeneration. For the purposes of this study, we use a gas-fired, thermally optimized potential of 2000 MW for the 2005/10 period. The potential of biomass-fired cogeneration is discussed in Appendix J.

[21] Such a requirement was recently introduced in the state of Hessen in Germany.

Fig. I.1: C-burden of a 56 MW cogeneration CC plant

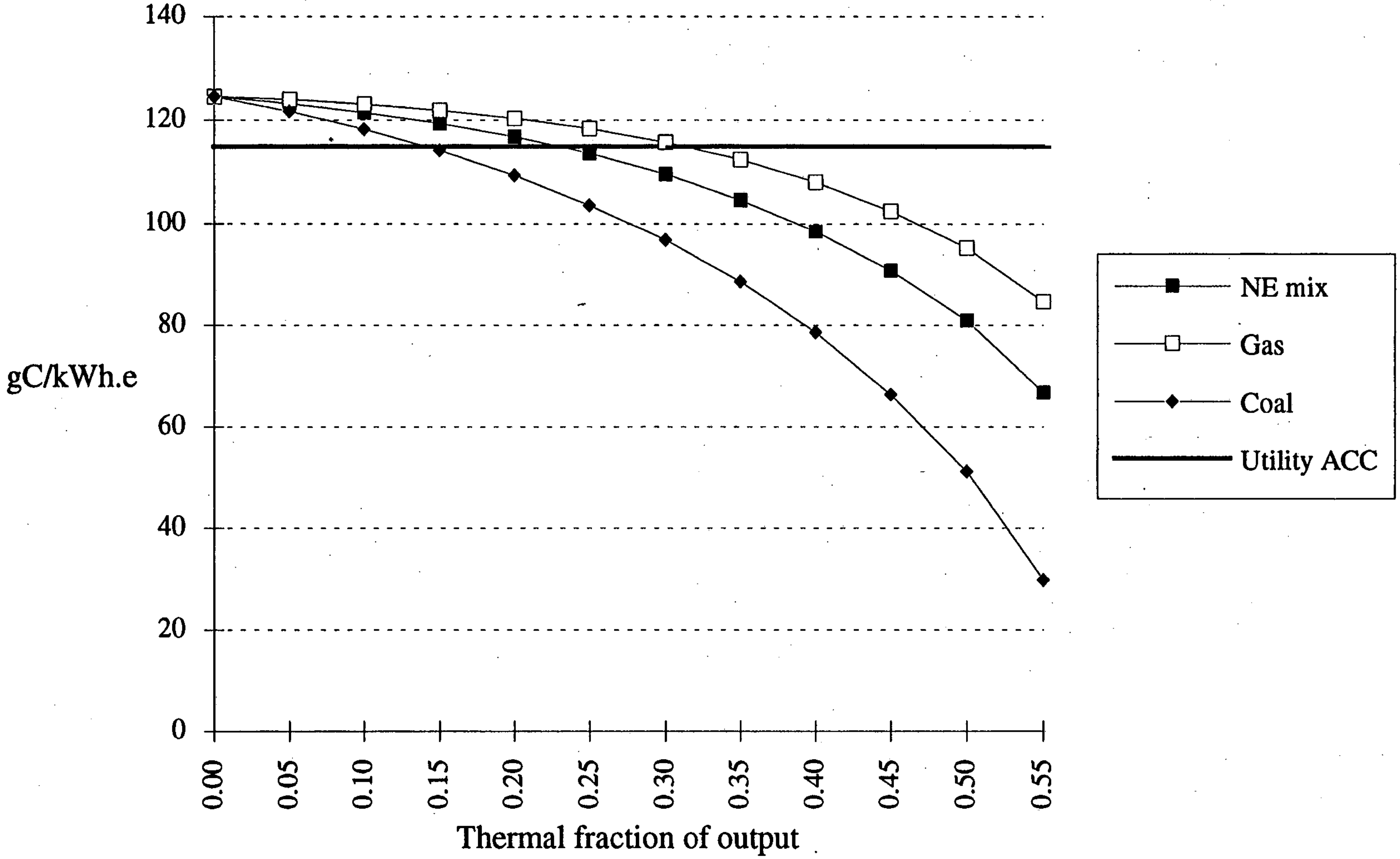

Table I.1: Carbon burdens of thermally optimized and PURPA cogeneration systems

System	Size MW	Thermal output quality psig/deg F	Thermal output Fth fraction HHV	Electrical efficiency Ee HHV	Electr. prod. ratio EPR kWh/kWh HHV	Net heat rate N kWh/kWh HHV	PURPA efficiency Epurpa LHV	Total efficiency Etot HHV	C-burden gas displcg NE mix gC/kWh HHV	C-burden gas displcg gas gC/kWh HHV	C-burden gas displcg coal gC/kWh HHV
Thermally optimized systems											
Combined cycle	56	150	0.554	32.3%	0.81	1.63	58.2%	72.4%	67	85	30
Industrial GT	38	150	0.569	27.9%	0.76	2.03	51.5%	71.9%	86	105	47
Extract.-cond. ST	60	80	0.708	19.0%	0.41	2.41	46.8%	72.4%	90	124	17
Back-pressure ST	43	80	0.735	17.6%	0.36	2.42	46.7%	73.8%	85	125	3
Back-pressure ST	6.2	80	0.800	13.4%	0.25	2.76	44.7%	74.4%	85	143	-34
Commercial IC	1	low T	0.550	32.5%	0.82	1.64	58.2%	80.2%	72	85	31
PURPA systems											
Combined cycle	56	150	0.000	41.5%	n.a.	2.41	46.1%	41.5%	125	125	125
Industrial GT	38	150	0.425	27.9%	1.35	2.71	42.5%	53.9%	130	140	108
Extract.-cond. ST	60	80	0.652	19.7%	0.53	2.86	42.5%	63.0%	121	148	65
Back-pressure ST	43	80	0.701	17.6%	0.43	2.92	42.5%	65.4%	118	151	48
Back-pressure ST	6.2	80	0.788	13.4%	0.27	3.10	42.5%	70.1%	108	160	-3
Commercial IC	1	low T	0.260	32.5%	2.85	2.66	42.5%	48.8%	134	138	122
Reference system											
Utility-scale CC	220	none		45.0%	n.a.	2.22	n.a.	45.0%	115	115	115

(1) PURPA efficiency based on lower heating value, following the FERC convention.
(2) All other efficiencies, and C-burdens, based on higher heating values, following US utility convention.
(3) Plant performance data for 56 MW combined cycle from General Electric Co.
(4) Carbon burdens based on direct emissions only. C-burden for gas based on 330 day/yr firm, 35 days/yr oil #2.
(5) Weighted ave C-burden of New Endland direct fuel consumption mix in 1988: 63.9 g/kWh.f industrial, 60.7 g/kWh.f commercial.

Table I.2: Carbon burden of gas absorption chiller/IC engine cogeneration systems					
	Units	*El. C-burden 250 gC/kWh* *Boiler fuel #2 oil*	*Boiler fuel gas*	*El. C-burden 115 gC/kWh* *Boiler fuel #2 oil*	*Boiler fuel gas*
Net carbon burden	g C/kWh.e	63	83	78	98

Notes:

(1) COP of displaced electric chiller is 5.5, of gas chiller 1.0.
(2) Efficiency of displaced boiler is 80 percent HHV.
(3) Electrical efficiency of IC engine is 30 percent, total efficiency 75 percent.
(4) 40 percent of thermal output is used for chilling, the rest for space and water heating.
(5) Carbon burden of IC system based on firm gas supply.

Table I.3: Busbar costs of cogeneration technologies

	Ind. GT	*Packaged IC*	*Ind. CC*	*PURPA CC*
PHYSICAL PARAMETERS				
Total Electric Capacity (MWe)	38	0.5	56	122
Lifetime (Years)	30	20	30	30
Construction Lead Time (Years)	2	1	2	2
Land Used (acres onsite and offsite)	0	0	0	0
Capacity Factor	65%	65%	65%	65%
Equivalent Unplanned Outage Rate	3.0%	3.0%	3.0%	3.0%
Equivalent Availability	92.0%	95.0%	92.0%	92.0%
Heat Rate (kWh heat in/kWh elect. out)	2.03	1.64	1.71	2.13
Efficiency	49.3%	61.0%	58.5%	46.9%
FIXED COSTS				
Capital Recovery Factor	0.127	0.141	0.127	0.127
Overnight Capital Cost ($/kW)	758	1200	766	606
Credits for displaced boiler/htg system	-227	-240	-230	-91
Net capital Cost ($/kW)	531	960	536	515
Cap Cost Including Interest ($/kW)	547	960	553	531
GTF Net Cap Cost Incl. Interest ($/kW)				
Startup ($/kW)	19.7	0.0	19.3	19.7
Inventory ($/kW)	29.9	0.0	27.1	29.9
Land ($/kW)	0	0	0	0
Total: Startup, Inventory, Land ($/kW)	50	0.00	46	50
Annualized Capital Cost ($/kW/yr)	75.8	135.8	76.2	73.8
Fixed O&M ($/kW/yr)	10.9	0.0	11.8	10.9
Staff ($/kW/yr)	13.0	0.0	13.0	13.0
Total Fixed Costs ($/kW/yr)	*99.8*	*135.8*	*101.0*	*97.8*
Total Fixed Costs (¢/kWh)	*1.8*	*2.4*	*1.8*	*1.7*
VARIABLE COSTS				
Incremental O&M (¢/kWh elect.)	0.2	1.2	0.2	0.2
Addl O&M for NOx Control (¢/kWh elect)	0.30	0.00	0.30	0.30
O&M credit f. boiler/heating system	-0.2	-0.2	-0.2	-0.1
Fuel Price ($/kWh fuel)	0.0177	0.0301	0.0177	0.0177
Fuel Cost (¢/kWh elect.)	3.6	4.9	3.0	3.8
Total Variable Costs (¢/kWh)	*3.9*	*5.9*	*3.3*	*4.2*
T&D Adjustment	1	1	1	1
DELIVERED COST (¢/kWh)				
Fixed @ avg. capacity factor	*1.8*	*2.4*	*1.8*	*1.7*
Fixed @ max. capacity factor	*1.2*	*1.6*	*1.3*	*1.2*
Variable	*3.9*	*5.9*	*3.3*	*4.2*
Externality Cost-MA DPU	*0.6*	*0.4*	*0.4*	*1.0*
Externality Cost-MA DPU w/o CO2	*-0.2*	*-0.2*	*-0.2*	*0.1*
Total @ avg. capacity factor	*5.6*	*8.3*	*5.1*	*5.9*
Total w/MA DPU	*6.2*	*8.8*	*5.5*	*6.9*
Total w/MA DPU w/o CO2	*5.5*	*8.2*	*4.9*	*6.0*
Total @ max. capacity factor	*5.1*	*7.6*	*4.6*	*5.4*
Total w/MA DPU	*5.7*	*8.0*	*5.0*	*6.4*
Total w/MA DPU w/o CO2	*5.0*	*7.4*	*4.4*	*5.5*

Notes:

(1) Cost and performance data for industrial systems from General Electric Co., Applications Division.

(2) Cost and performance data for commercial sector IC system from engine manufacturers and GRI (1989).

(3) Full capital cost credit applies in new plants or when replacing existing boilers and heating systems.

(4) O&M costs for IC engine based on manufacturer service contracts.

(5) All costs in 1990 $.

Table I.4: Potential growth of cogeneration in New England, 1990-2010

		Existing cogen capacity		*Potential additional cogeneration capacity in 2010*				
		NEGC 1990		*GRI/EEA 1991 incl. self-generation*		*C reduction strategy excl. self-gen./ NEPOOL loads*		*C-burden*
Sector, fuel, and technology		*MW.e*	*TWh.e*	*MW.e*	*TWh.e*	*MW.e*	*TWh.e*	*gC/kWh.e*
Industrial sector		873	5.7	3330	21.9	3150	20.7	88.2
Coal	ST	43	0.3	600	3.9	79	0.5	270
Oil	ST, GT	426	2.8	840	5.5	26	0.2	210
Gas	ST, GT, CC	102	0.7	1390	9.1	2915	19.2	90
Biomass/other	ST	302	2.0	500	3.3	130	0.9	-50
Biomass/other	BIG/GT/ISTIG					190	1.2	-25
Commercial sector		120	1.3	370	2.3	500	3.1	75
On-site		10	0.65			250	1.5	75
District heating		110	0.65			250	1.5	75
Total		993	7.0	3700	24.1	3650	23.8	86.5

Notes:

(1) GRI forecast includes 2.5 TWh of paper industry cogeneration netted from NEPOOL loads.

(2) Under C reduction strategy, oil- and coal-fired capacity is limited to NEPLAN (1990) existing and committed resources.

APPENDIX J: BIOMASS RESOURCES IN NEW ENGLAND

Biomass-fired generation could make a significant contribution to New England's power supplies. More than 80 percent of New England's land area is forested. The following discussion therefore focuses on forest-derived biomass, but also covers other waste sources.

In characterizing the economic potential for power production from biomass resources, the following analytic steps are required:

- Identifying the future mix of land use, in terms of conventional forestry activities aimed mainly at non-energy products and energy plantations;
- Determining environmentally sustainable and economic levels of forestry biomass harvest;
- Calculating the amount of forestry and other biomass residues available for energy production and accounting for competing uses;
- Estimating the cost of biomass chip fuels from forestry harvest residues, and the feedback effects on biomass fuel prices from energy and competing uses;
- Using biomass power plant technology data to calculate potential power production and costs.

A key issue in developing the region's forestry biomass resources for energy purposes is the integration of biomass use for fuels with biomass use for other applications, and the environmentally sound integration of forestry commodity production with other forestry functions (wildlife habitat, recreation).

A detailed assessment of these issues is beyond the scope of this report. For the purposes of this study, we estimate the economic biomass energy potential in New England using a number of simplifying assumptions.

Forms of biomass fuel production

Two modes of large-scale biomass fuel exploitation have been proposed and analyzed in terms of their potential:

- the production of fuelwood chips from short-rotation plantations based on fast-growing species such as hybrid poplar, and
- the use of improved management of existing forests to increase commercial yields and biomass residues available for fuelwood chip production.

The ecological impacts of fast rotation forestry on wildlife habitats and soils are less understood than those of conventional practice. Fast rotation energy plantations thus carry higher ecological risks than the intensive management of existing forests. In order to avoid overstating the sustainable biomass fuel potential, the following discussion is limited to the latter approach.

Below, we estimate fuel and power generation potentials of biomass chip production from conventional forestry and from utiliziation of wastes from the forest products industries (e.g., lumber mills and paper mills). In a separate section, we also examine the electricity production potential from municipal solid wastes and landfill and sewer gas.

Current utilization of forestry-based biomass fuel resources in New England

An analysis of biomass fuel use by fuel category and application was conducted by Donovan Associates (1990) for Maine. The study covered both thermal uses and uses for power generation. Paper companies own cogeneration plants fueled by a mixture of oil, coal, hydro, black liquor, mill residue, and wood chips. Data on the relative proportions of use of these fuels are poor. Donovan Associates attempted to estimate the amount of biomass chips and mill residues used in these self-generation plants as well, but data uncertainties appear to be significant.

For lack of state-by-state data on thermal biomass applications for New England as a whole, scaling to New England was done through the following steps: To calculate biomass fuel use in existing thermal applications, we extrapolate the Maine data to the region in proportion to state-by-state timberland areas.[1] To calculate fuel use in existing biomass-fired power plants, total kWh generation figures as given in NEPOOL's 1990 CELT report are converted into input energy using a heat rate of 15640 Btu/kWh for the generating plant, and a HHV for biomass fuels of 4950 Btu/lb.[2]

The resulting New England figures are shown in Table J.1. Total biomass fuel consumption in New England is estimated at 13 million tons per year. This total consists of about 9 million tons for thermal end-uses, and about about 4 million tons in power plants. Firewood consumption grows by 50 percent during the 1990s, and is assumed to double by 2010, as projected in RISI (1990). Firewood (chunkwood) consumption is shown for completeness only. It is accounted for as a separate forest product in total timber harvest projections and does not affect the biomass residue potentials calculated here.

Existing biomass-fired plants

Inventories of biomass-fired power plants in New England were recently prepared by the New England Governors' Conference (NEGC, 1990), by Donovan Associates (1990), and

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1 Since biomass fuel use and commercial forestry management appear to be less widespread in the densely populated southern states, this procedure probably overestimates total biomass use in thermal applications.

2 The heat rate is taken from EPRI's technology assessment guide (EPRI, 1989). The tonnages of biomass fuel consumption given in Donovan Associates (1990) are somewhat higher than those calculated here. These figures imply a somewhat lower heating value for biomass chips.

by the State Planning Office of Maine (Connors, 1991). NEPOOL's CELT forecast lists existing, committed, and uncommitted biomass plants.

The total non-utility capacity in place in November of 1989 was 530 MW including 97 MW of capacity listed as not selling to utilities. The total grew to 802 MW by the end of 1990.[3] Most biomass-fired power generation capacity is located in Maine, where NEGC (1990) lists 636 MW, including 99 MW of plants not selling power to utilities. Biomass cogeneration capacity grew by about 90 MW, from 189 MW in 1989 to 278 MW in 1990.

Future biomass fuel resources from forestry residues

Lumber mill residues

Currently available mill residue and other waste supplies are already largely being used for energy purposes. In the first approximation, future lumber mill residue potentials will vary in proportion to lumber harvests. A detailed analysis by Seymour and Lemin (1990), finds that the long-term sustainable limit for sawtimber harvesting in Maine is 33 percent above the 1981-85 level.

This long-term figure may not be fully realized if sawtimber harvesting is constrained by sluggish demand. For the near term, the slowdown in construction activity in the New England region has led to lower growth forecasts. For example, Seymour and Lemin project a four percent drop in the Maine sawtimber harvest for 2000. According to another analysis (RISI, 1990), annual removals of sawtimber from Maine forests are projected to grow by 10 percent between 1989 and 2010. In Table J.1, the potential of available mill residues for energy use (both thermal and power generation) is scaled up by 10 percent.

Paper mill process wastes

The availability of biomass wastes (bark and black liquor) from within the paper industry will vary with overall pulp production growth in that sector. The 1990 RISI analysis of the pulp and paper industry projects that pulp production from virgin wood fibre harvested in Maine will grow by 30 percent between 1990 and 2010, from 2.618 million short tons to 3.394 million short tons. This growth is lower than the predicted growth in paper production, due to a significant increase in recycled fibre and pulp imports. Paper production is projected to grow by 40 percent over the same period.

Central Maine Power projects paper industry electricity consumption to grow in proportion to the 40 percent paper production increment, assuming constant electricity inputs (1640 kWh per ton of paper). At the same time, power generation by the industry in its service territory is projected to grow by 1.9 TWh or 69 percent between 1990 and 2010, from 2.726 TWh to 4.603 TWh (CMP, 1990). The implied specific generation is 1890 kWh per short ton in 1990, and 2260 kWh/short ton in 2010.

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[3] NEPOOL's 1990 CELT report counts only 13 plants as contributing to its generating capability. A number of cogeneration plants are fully or partially netted from loads. The reference case modeled in this study only includes those biomass units that were listed in the CELT report as operating by June 1990.

These figures compare with estimates of electricity production levels in a stylized pulp mill of 535 to 1684 kWh per ton of pulp when only bark and black liquor are used (Larson, 1991). The higher electricity outputs in Maine reflect the use of fuels other than process wastes, notably purchased coal, oil, biomass chips, and lumber mill wastes. According to information provided by energy managers at two mills, about half the input energy for electricity generation is currently derived from oil and coal.

In the following analysis, it is assumed that the projected increase in power generation by the paper industry will be mainly achieved through the use of more efficient steam turbine cogeneration systems and through utilization of hog fuel and black liquor supplies that increase with timber throughput.[4] Paper industry growth is assumed to have no net impact on biomass fuel resources available outside the industry.[5]

Harvested biomass chip fuel production

The key question for expanded use of biomass-fired power generation is the size of the biomass fuel resource that could be sustainably harvested at competitive economic cost and with low environmental and other indirect impacts.

A detailed analysis of sustainable pulpwood, timberwood, and biomass residue harvests is available only for the state of Maine (Seymour and Lemin, 1989). Seymor and Lemin analyze sustainable harvesting levels on the basis of conventional Maine forestry practices that only partially rely substantially on intensive management techniques (e.g., thinning stands and culling) commonly used in other U.S. regions. The study finds that forest management will need to be improved to meet projected demands for pulpwood and sawtimber products in a sustainable manner. Once improved, they find that 18.9 million tons per year of biomass residues could be harvested in the form of biomass chips, compared to current consumption of biomass chips for energy purposes of about three million tons per year.

It is not possible to simply extrapolate the results from this analysis to the New England region as a whole. Though Maine contains only 53 percent of New England's timber lands, the ownership structure of forests in other states inhibits the same level of commercial exploitation. As a basis for a more realistic estimation of the Maine potential, we therefore use U.S. forestry data for actual timber harvests in the six states.[6] These data show that harvests in Maine constituted about 72 percent of the total New England harvest

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4 For example, Boise Cascade recently installed new steam boilers generating steam at 1325 lbs, compared to 400-700 lbs for the old boilers. Power capacity increased from 18 MW to 85 MW while steam production was increased by only about 15 percent (Robert Stickney, personal communication). Also, plans are under way to convert the Portland oil pipeline to gas, which would allow the use of more efficient combined cycle generating equipment.

5 Purchased biomass supplies would increase if biogasification/steam injection gas turbine (BIG/STIG) technology is introduced and steam loads are to be met. See Larson (1991) for an analysis of the fuel mixes of alternative cogeneration systems in a prototypical 1000 ton pulp/day plant.

6 Personal communication with Eric Wharton, U.S. Forest Service, Radnor, PA. Data were based on 1981-1984 harvesting surveys. See Wharton (1982) for details.

in the early to mid-1980s. The corresponding scaling factor is 1.38. On that basis, we estimate a long-term sustainable forest residue potential for biomass chip fuels of 26 million green tons per year.

Projections of total timber removals for the 1990-2020 period (RISI, 1990) indicate that the Maine harvesting level in that period will be in excess of the long-term sustainable potential, due to a temporal transient. As a conservatism, we calculate the biomass power potential on the basis of the long-term sustainable limit only.

Current and future biomass fuel prices

Recent trends in fuel prices and industry structure

Over the last ten years, the number of chip contractors supplying wood fuel has risen from a handful to more than 70 in Maine alone. There is strong competition among chip suppliers, and prices for biomass fuels have decreased considerably in real terms despite a major expansion of supplies: Over the last ten years, prices have remained at about 18 $/dry ton (nominal) for fuel chips.[7]

The distribution of commercial forestry land in Maine is reflected in the market shares of small private and large corporate owners. The large corporate holdings in the north of the state and the smaller holdings near the population centers in the south and southeast of the state supply about half of the total chip demand. Based on current biomass fuel consumption rates, feedstocks for fuel chips remain in abundant supply from either supplier group. No competing demand for greenwood feedstocks has arisen from pulp production.[8]

Wastes from lumber mills are somewhat cheaper than greenwood chips. Because these wastes represent a disposal problem for saw mills, they are often available at low cost at these mills. They are shipped to either free-standing or pulp mill cogeneration power plants. Their commodity price is mainly determined by transportation costs.

Projected fuel prices

Forestry experts in Maine expect no real price increase in biomass chip fuels so long as production remains within the physical limits of the above supply potentials. This projection is based on benefits derived by forestry owners when residues are converted into fuels, and on the relative lack of competing non-energy uses for forestry residues. Biomass availability is not seen as a price factor because only a small portion of total forestry land is currently being managed to yield biomass fuels.

At the moment, yields of lumber and pulpwood, along with the speed at which stands reach maturity, are limited by the natural tendency of forests to grow densely. To optimize yields

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[7] Jim Connors, Maine State Planning Office, personal communication.

[8] See RISI (1990) for an analysis and projection of forest products and timber supplies.

requires thinning stands, which is not economically viable if there is no commercial use for the removed trees. These thinnings, and diseased trees and slash that would otherwise be left to decompose in the forest, become a commodity when biomass fuels are used. This creates the triple benefit of greater yields, earlier maturity, and an additional source of income.

Saw mills and paper mills require trees of certain minimum size and maturity. They cannot make use of branches, crowns, bark, culling trees, and other "non-growing stock." By contrast, woodfuel chips can be produced from trees of any size and maturity, as well as from tree portions such as crowns, branches, etc.

In addition, paper industry analysts predict that pulpwood chip prices in Maine will be depressed due to greatly increased recycling of paper (RISI, 1990). This market development is likely to limit real price increases in biomass fuel chip prices.

Biomass power plant technologies and costs

The busbar costs of alternative biomass-fired power plants are shown in Table J.2.

Current technology

Current biomass power generation technology is based on steam turbines and boilers similar to those used for burning coal. Fluidized bed designs are proving especially attractive for QF projects. Data from EPRI (1989) and from a study of completed free-standing QF projects conducted by Donovan Associates (1990) for Central Maine Power indicate power plant costs (including interest during construction) of about 1700 to 2200 $/kW.

In the case of cogeneration facilities, a capital and operating cost credit is applied to account for avoided costs for boilers, fuel handling, and other process equipment that would have to be purchased anyway.

Existing free-standing biomass-fired plants show a range of typically 10-40 MW, with power plant efficiencies in the 17-23 percent range. Recently added paper mill cogeneration capacity under contract to utilities ranges from about 20 to 75 MW in size. The larger turbines are typically supplied with steam from several boilers, some of which are fired by fossil fuels.

Fuel transportation limits

The cost of transportation for supplying plants of current size and efficiency has turned out to be less of a factor in biomass fuel costs than originally believed. Because of a constant flow of trucking services between pulp mills, saw mills, lumber and pulp and paper consumers, and logging sites, ample opportunities exist for backhaul of fuel chips, wastes, and power plant ashes. Biomass power plants in Maine draw their fuel chip supplies from areas within a radius of 50 miles or more, and waste fuels are sometimes hauled over distances of more than 100 miles one way (Connors, 1991).

Advanced, biogasification-based technology

The principal handicap of current biomass generation technology is that it is based on steam turbines and boilers with severe cost and efficiency penalties at small (less than 50 MW) scale. This handicap could be overcome with biomass gasifiers (BIGs) coupled to industrial gas turbines (GT) or aeroderivative STIG or ISTIG turbines (Larson et al., 1988).

The gasifier technology is analogous to that used in coal gasification technology. The use of air-blown rather than oxygen-blown gasification and steam injection gas turbines rather than combined cycles leads to efficient plants at much smaller (50-100 MW) scale. Because of their high efficiency (about 42 percent on a HHV basis for a 110 MW BIG/ISTIG plant), turbine systems of this scale are compatible with biomass transport limitations.

The technology is of particular interest to the pulp and paper industry, where the gasifier would eliminate the need for Tomlinson recovery boilers. These boilers are prone to explosion accidents.[9]

Biomass gasification systems offer the potential for significantly lower unit capital costs. After reaching commercial maturation, the technology is estimated to cost $1150/kW, for BIG/STIGs, and $890/kW for BIG/ISTIGs in 1990 dollars (Larson, 1991). In Table J.2, this estimate is increased by 40 percent to $1250/kW as a conservatism, and to account for higher costs in the near term. When used for cogeneration in the pulp and paper industry, a capital and operating cost credit of $250/kW is applied.[10]

Unlike current biomass boilers, GT, STIG and ISTIG systems require pre-dried fuels of at most 25 and 15 percent moisture content, respectively. The drying of wood chips from 50 percent to 20 percent moisture content is estimated to add $0.55/GJ to the cost of wood chip fuel (Larson, 1991).

Remaining technical problems, apart from assembly of a commercial ISTIG unit, are quite analogous to those surrounding the gasification of coal, and NO_x clean-up of the hot gas. However, biomass fuels are more easily gasified and contain less embedded nitrogen than coal. On the other hand, biomass fuels contain high volatile alkali levels, which make the elimination of corrosive alkali deposits on gas turbine blades a special requirement. Finally, feeding biomass fuels into pressurized reactors takes a little more energy than feeding coal.

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[9] Such an explosion occured in the Old Town mill of James River Co. in Maine in 1987. The pulp mill had to operate at only 40 percent capacity for five months, and significant production losses were incurred (RISI ,1990).

[10] The biogasifier cost is essentially offset by the avoided cost of the Tomlinson boiler. See Larson (1991) for details.

Commercialization prospects

A detailed discussion of current commercialization efforts in the United States and Europe is given in Larson (1991). In the United States, the Department of Energy announced a major new program initiative to commercialize the BIG/GT technology by the late 1990s. In New England, the Vermont Department of Public Service, in cooperation with Burlington Electric Company and other in-state utilities, is exploring the possibility of a commercial demonstration plant based on BIG/GT technology and wood chips from forestry management operations. General Electric Company is proposing to test biomass fuels for biogasification projects at its Schenactady facility in New York state. In Europe, the Finnish manufacturer Ahlstrom is planning a 6-10 MW BIG/GT demonstration plant in Sweden. If the commercialization of BIG technologies proceeds as planned, rapid growth in biomass power plant capacity could occur by the late 1990s.

Total future biomass power potential

In Table J.1, we estimate that the long-term biomass fuel potential after accounting for projected thermal uses and fuel for already existing and planned biomass power plants is about 19.6 million green tons per year. Depending on which technology is used to convert this resource, an additional 18.5 (conventional technology) to 31.1 TWh (advanced technology) of electricity could be produced from biomass chips.

Table J.1: Biomass fuel use and power generation potential in New England

		1988/90	*1995/2000*	*2005/10 Conv. plants*	*2005/10 Adv. plants*
Electricity needed to meet NEPOOL CELT loads	*TWh/yr*	*110*	*140*	*159*	*159*
Sustainable supply potential					
Biomass chips	10^6 tons/yr			26.1	26.1
Mill residue and recycled wastes	10^6 tons/yr			5.3	5.3
Chunkwood	10^6 tons/yr			5.5	5.5
Total				36.9	36.9
Biomass fuel consumption					
Thermal end-uses					
Harvested biomass chips	10^6 tons/yr	0.4	0.4	0.4	0.4
Chunkwood	10^6 tons/yr	2.9	4.3	5.5	5.5
Mill residue and other wastes	10^6 tons/yr	3.3	3.5	3.6	3.6
Subtotal		6.6	8.2	9.6	9.6
Power generation					
Existing CELT capability plants	10^6 tons/yr	3.4	3.4	3.4	3.4
Existing plants netted from CELT loads	10^6 tons/yr	0.9	0.9	0.9	0.9
Committed	10^6 tons/yr		1.5	1.5	1.5
Uncommitted			1.9	1.9	1.9
Total biomass fuel use in identified plants	10^6 tons/yr	10.9	16.0	17.3	17.3
Surplus potentially avail. for addl. generation	10^6 tons/yr			19.6	19.6
Biomass-fired power generation					
Power from ex. and pending biomass plants					
Existing counted in CELT	TWh/yr	2.4	2.4	2.4	2.4
Existing netted from CELT	TWh/yr	0.6	0.6	0.6	0.6
Committed	TWh/yr		1.1	1.1	1.1
Planned	TWh/yr		1.4	1.4	1.4
Total electricity	TWh/yr	3.0	5.4	5.4	5.4
Fraction of CELT demand met by identified plants		*0.022*	*0.039*	*0.034*	*0.034*
Max. addnl. electr. production					
All remaining biomass used by					
Conventional ST plants (23.3% efficiency HHV)	TWh/yr			13.7	
Fraction of growth potentially met w. conv. plants				*0.28*	
Biogasification/ISTIG (42.9% efficient HHV)	TWh/yr				26.8
Fraction of growth potentially met w. adv. plants					*0.60*
Total electricity from biomass plants	**TWh/yr**	**2.4**	**4.8**	**18.5**	**31.6**
Fraction of CELT demand potentially met		*0.022*	*0.034*	*0.117*	*0.200*

(1)Biomass chip potential based on Seymour and Lemin (1989) for Maine, scaled to total New England harvest data from U.S. Forest Servic
(2) Mill residue and recycled wastes from Donovan Associates (1990) for Maine, scaled with total New England harvest.
(3) Based on 326 MW of existing, 144 MW of committed, and 194 MW of planned biomass power projects (NEPLAN, 1990).
(4) NEPLAN (1990) nets 91 MW of net summer capacity and 626 GWh of electricity production from NEPOOL loads.
(5) Net growth in final electricity is 45 TWh between 1990 and 2005.
(6) Heat rates for conventional plants from EPRI (1986, 1989).
(7) Heat rates for biomass gasification plants based on Larson (1991).

Table J.2: Busbar costs of biomass-fired technologies

	Biomass ST	*BIGISTIG*	*BIGISTIG COGEN*	*Biomass ST COGEN*
PHYSICAL PARAMETERS				
Total Electric Capacity (MWe)	24	114	97	24
Lifetime (Years)	35	30	30	30
Construction Lead Time (Years)	3	3	3	3
Land Used (acres onsite and offsite)	20.5	20.5	0	0
Ave Capacity Factor	65%	65%	65%	65%
Equivalent Unplanned Outage Rate	8.0%	4.9%	4.9%	3.0%
Equivalent Availability	85.9%	90.3%	90.3%	92.0%
Heat Rate (kWh heat in/kWh elect. out)	4	2.33	2.64	3.00
Efficiency	0.23	42.9%		
FIXED COSTS				
Capital Recovery Factor	0.124	0.127	0.127	0.127
Overnight Capital Cost ($/kW)	2161	1280	1250	2161
Credits for displaced boiler/htg system			-250	-500
Net capital Cost ($/kW)	2161	1280	1000	1661
Cap Cost Including Interest ($/kW)	2300	1362	1064	1767
GTF Net Cap Cost Incl. Interest ($/kW)	2300	1362		
Startup ($/kW)	20	47	35	16
Inventory ($/kW)	30	18	9	24
Land ($/kW)	93	20	0	0
Total: Startup, Inventory, Land ($/kW)	142	84	44	40
Annualized Capital Cost ($/kW/yr)	302	184	141	230
Fixed O&M ($/kW/yr)	53	53	53	53
Total Fixed Costs ($/kW/yr)	*355*	*237*	*194*	*283*
Total Fixed Costs (¢/kWh)	*6.2*	*4.2*	*3.4*	*5.0*
VARIABLE COSTS				
Incremental O&M (¢/kWh elect.)	0.53	0.53	0.53	0.53
Addl O&M for NOx Control (¢/kWh elect)	0.30			0.30
O&M credit f. boiler/heating system			-0.2	-0.2
Fuel Price ($/kWh fuel)	0.0061	0.0081	0.0041	0.0031
Fuel Cost (¢/kWh elect.)	2.6	1.9	1.1	0.9
Total Variable Costs (¢/kWh)	*3.5*	*2.4*	*1.4*	*1.8*
T&D Adjustment	1	1	1	1
DELIVERED COST (¢/kWh)				
Fixed @ avg. capacity factor	*6.2*	*4.2*	*3.4*	*5.0*
Fixed @ max. capacity factor	*4.7*	*3.0*	*2.4*	*3.5*
Variable	*3.5*	*2.4*	*1.4*	*1.8*
Externality Cost-MA DPU	*0.8*	*0.5*	*-0.3*	*0.7*
Externality Cost-MA DPU w/o CO2	*0.8*	*0.4*	*-0.3*	*0.0*
Total @ avg. capacity factor	***9.7***	***6.6***	***4.8***	***6.7***
Total w/MA DPU	***10.5***	***7.0***	***4.5***	***7.5***
Total w/MA DPU w/o CO2	***10.5***	***7.0***	***4.5***	***6.7***
Total @ max. capacity factor	***8.2***	***5.4***	***3.9***	***5.3***
Total w/MA DPU	***9.0***	***5.9***	***3.5***	***6.0***
Total w/MA DPU w/o CO2	***9.0***	***5.9***	***3.5***	***5.2***

(1) Capital cost, O&M cost, and performance data from EPRI (1986), GTF (1989), and Larson (1991). Costs in 1990$.
(2) ISTIG systems require pre-drying of fuel chips. Fuel costs for cogen systems are partially process wastes. See Larson (1991
(3) Capital and O&M credits of about 20 percent are based on cost of Tomlinson boiler, see Larson (1991).
(4) Capital cost for BIGSTIG system includes 40 percent surcharge over mature costs given by Larson (1991).

APPENDIX K: POTENTIAL POWER PRODUCTION FROM MUNICIPAL SOLID WASTE

New England has been in the forefront of power production from municipal solid waste. According to data from EPA and state waste management agencies, New England burned about 40 percent of its solid waste stream in 1990.[1] In the nation as a whole, only about 10-15 percent each of MSW are currently burned and recycled (OTA, 1989). Most of this combustion was in power plants. Total installed refuse plant capacity was 439 MW in 1990 (NEGC,1990). Only about 10 MW were cogenerating heat.

In the context of a carbon reduction strategy, two issues arise:

- Does municipal solid waste offer any carbon benefits? And,
- How far can MSW-fired power production be expanded in New England?

Direct carbon burden of municipal solid waste fuel

Estimates of the total carbon burden of municipal solid waste (MSW) can be made from heating value data and carbon content data for refuse fuels. These measurements can vary greatly, however. Higher heating values as received range from 2200 to 5000 Btu/lb, with moisture contents of 25-50 percent, and non-combustables of 25-50 percent (Robinson, 1987; ASME, 1987). On a dried basis, HHV are typically 6000 to 6600 Btu/lb. Refuse-derived fuels with residual moisture content of about five percent show values of 8000-10500 Btu/lb.

The National Bureau of Standards (NBS) has developed a standard reference material (SRM 1657) with a HHV of 5963 Btu/lb on a dry basis. From ultimate chemical analysis, unprepared solid waste contains about 25-30 percent carbon by weight. Trends toward increasing removal of inorganic fractions due to recycling suggest that the higher value might be more representative in the future. Using the NBS heating value and a 30 percent carbon burden, one obtains a total direct carbon burden of 22 g/kWh.fuel.

Of the total carbon content of MSW, only a certain fraction is from fossil-based materials. In the first approximation, the fossil carbon burden of MSW can be represented by the contribution of plastic materials. Plastic materials currently represent a small fraction (about 7-10 percent by weight) of MSW. However, their heating value is substantially larger than that of other refuse materials. On a weighted average basis, plastic materials currently have a higher heating value of about 17600 Btu/lb. This is equivalent to 29 percent of the NBS figure of 5963 Btu/lb for total refuse. With growing recycling and other trends, this share is expected to increase further (Artz, 1991). We use a figure of 6600 Btu/lb for the calculations below.

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[1] Based on data obtained from Ron Jennings, U.S. EPA, Boston Office, personal communication.

Using data for the carbon composition of typical plastic polymers (ASME, 1987), one obtains a weighted average carbon burden for this fossil-based waste component that is about as high as that for oil. The direct plus indirect carbon burden is 78 g/kWh for distillate fuel oil. With this value as a proxy for plastics, and a 35 percent heating value contribution from plastics and other fossil-based materials, one obtains a net direct fossil carbon burden of 28 gC/kWh for refuse. This figure is significantly lower than the equivalent gross fossil carbon burden of about 70 g/kWh.

Credit for avoided landfill methane emissions

The combustion of municipal solid wastes avoids the anaerobic decomposition of the same materials in landfills. MSW fuel must therefore be credited with the CO_2-equivalent of the avoided landfill methane emissions. This equivalence depends on the amount of methane that would have been produced per unit of landfilled solid waste.

Net carbon burden of landfill gas

Landfill gas consists mainly of approximately equal portions of methane and carbon dioxide, with small admixtures of halogen and sulfur-containing gases. When used for power production, the methane fraction is converted to CO_2 and water while the carbon dioxide fraction is passed through the combustor as an inert gas. It can therefore be omitted from the carbon burden analysis of landfill gas. When stripped of the carbon dioxide, landfill gas becomes pipeline grade gas with a heating value comparable to that of natural gas, which also consists mainly of methane. In first approximation, then, the gross carbon burden of landfill gas becomes that of natural gas.

The carbon dioxide output of the landfill generator would have occurred as well under natural, mostly aerobic decomposition of the landfill materials, though the emissions would have been stretched over a number of years. For the purposes of the present study, this temporal difference can be ignored. The direct carbon burden of landfill gas is then zero.

CO_2-equivalence of avoided landfill methane emissions

The CO2-equivalence of the CH_4 portion in the landfill gas mixture is uncertain, but is estimated as 21 times the CO_2 portion (IPCC, 1990). When this methane is combusted to carbon dioxide, the warming potential represented by the landfill methane is correspondingly reduced. This leads to a twenty-one-fold CO_2-equivalence credit per unit of combusted landfill methane.[2] The net carbon burden of landfill gas then is 19 x (-50 gCequ./kW.f) = –530 gCequ./kWh.f.

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[2] Without the transformations during manufacture, consumption, and landfilling, most (though not all) of the biomass-derived components of solid waste would have decomposed aerobically to carbon dioxide, rather than anaerobically under the sealed conditions of a landfill. For the purpose of the present approximate calculation, it is assumed that all biomass derived materials would have decayed into carbon dioxide. The carbon dioxide emitted by the landfill gas generator does not add any net emissions of CO_2, because it, too, would have been emitted under aerobic conditions. The net carbon credit is thus ten times the methane consumed.

Total methane yields in the literature range from 31 to 94 liters of methane per kg of solid waste (EMCON Associates, 1980). For the purpose of this analysis, a yield of 62.5 liters CH_4 per kg of refuse is assumed. With this assumption, and a 21:1 warming equivalence between CO_2 and CH_4 (IPCC, 1990), the CO_2-equivalent credit for avoided methane is about –164 gC/kWh of refuse fuel.

Net MSW carbon burden

Combined with the direct carbon burden of 27.5 gC/kWh, the net carbon burden of MSW fuel is –137 gC/kWh.f. This negative value indicates that the combustion of MSW in power plants can bring substantial greenhouse gas benefits.

Potential for expansion of power production from refuse

The future availability of municipal solid waste for combustion, and therefore the power generation potential from trash to energy plants, is shaped by a number of factors. These include:

- Population growth
- Growth trends in per capita trash generation
- Expected closure of most existing landfills
- More stringent and costly environmental control requirements for new landfills
- State waste agency goals of increased recycling
- Changes in waste composition and heating value

About two thirds of the more than 500 New England landfills are scheduled to be shut down over the next 10 years. Reasons include exhaustion of capacity, and ground and surface water contamination. New landfills will be difficult to site and much more expensive to operate than existing ones. In response, New England's waste management agencies have set targets to recycle as much as 50 percent of municipal solid waste by the mid-1990s.

This recycling effort will impact the composition of the MSW fuel. This, in turn, will lead to changes in the heating value and moisture content of the fuel. The fuel moisture content affects the lower heating value, and thus the efficiency at which MSW fuel is converted in boilers and power plants.

Unfortunately, no precise estimates are available of the impact of these developments on the potential for power generation from municipal solid waste. Also, baseline per capita waste generation data are generally unreliable and vary significantly from community to community.[3] For the purpose of this study, the technical potential for power generation

[3] For example, estimates from Maine indicate that small rural communities (less than 1000 inhabitants) produce only 2.7 lbs MSW/cap-day, or about half as much as urban communities (more than 10,000 inhabitants) at 5 lbs/cap-day (MWMA, 1990). The same value of 5 lbs/cap-day is reported for Boston

from municipal solid waste is therefore conservatively estimated on a "back-of-the-envelope" basis, using the following assumptions:

— New England's population will grow to 14.2 million in 2010.[4]

— Gross trash generation per capita is 5 lbs/cap-day, and remains constant over the next 20 years.[5]

— The maximum fraction available for combustion is 40 percent, with the remainder either recycled and composted or landfilled.[6]

— The heating value of MSW is 6000 Btu/lb in 1990 and increases to 6500 Btu/lb by 2010.[7]

— The average efficiency of trash-to-energy steam turbine plants in 1990 is calculated from the above assumptions and data, using the reported installed refuse power plant capacity and capacity factors.[8] It is estimated to be 17 percent.[9]

— This efficiency is assumed to increase by 10 percent by 2010, due to improved fuel quality.

(OTA, 1989). While this rural-urban difference can be generalized, values for communities of the same type vary significantly, in part due to definitional differences (OTA, 1989).

4 As projected by the U.S. Bureau of Census (1990).

5 The zero growth assumption is conservative. The historical per capita growth rate during 1970-1986 was 0.7 percent per year, which would increase trash generation by 15 percent over 20 years (U.S. EPA, 1988a,b; OTA, 1989).

6 The 40 percent ceiling is equal to the estimated weighted average MSW fraction currently burned in New England. It also corresponds to the future disposal pattern of recently issued recycling-oriented waste management plans. For example, the waste management plan of Maine (MWMA, 1990) foresees a 50 percent recycling fraction combined with a 40 percent fraction for incineration, with the remainder going to landfill.

7 The 1990 figure is based on OTA (1989) and estimates by Artz (1991). Artz predicts a 10-20 percent increase in post-recovery HHV as recycling fractions are increased. The removal of yard wastes into separate composting streams and the increased use of garbage disposals for food wastes are predicted to eliminate most of the low-Btu, high moisture components of MSW. At the same time, the ratio of organic to inorganic components is rising, and the percentage of high Btu plastics is on the increase as well. This average predicted trend could, of course, be reversed in individual circumstances, depending on current recycling patterns and compositions.

8 Based on the small power report of the New England Governor's Conference, (NEGC, 1990), 395 MW were operating and 58 MW were under construction at the end of 1989. The average capacity factor was about 73 percent.

9 The design average efficiency of a 45 MW plant as given in EPRI's technology assessment guide is about 20 percent. Many MSW plants are considerably smaller and have significantly lower efficiencies. Current average efficiency is likely to be about 15 percent.

With these assumptions, the power generation potential from New England's municipal solid waste is calculated as shown in Table K.1. It shows that MSW power production could be expanded by about 25 percent, adding another 120 MW of capacity at a 75 percent capacity factor.

Conclusion

The principal conclusion from this approximate calculation is that in the context of current recycling-oriented waste management goals, not enough fuel will be available for a major expansion of refuse power generation. However, existing refuse plants could make an additional contribution to carbon reductions if their waste heat were more effectively used for district heating or other cogeneration purposes.

Table K.1: Power production potential of municipal solid waste

	Units	*1990*	*2010*
MSW per capita before recovery	lbs/cap-day	5	5
Population in New England	million	13.05	14.24
Total MSW generation	million lbs/yr	23811	25993
Fraction recycled		*0.10*	*0.50*
Fraction landfilled		*0.50*	*0.10*
Fraction for power generation		*0.40*	*0.40*
Total MSW avail. for power generation	million lbs/yr	9524	10397
Ave HHV MSW as received	Btu/lb	6000	6500
Total available input energy	TWh/yr	16.74	19.79
Percent converted to electricity		16.4%	18.1%
Total potential power production	TWh.e/yr	2.7	3.6
Total potential capacity @ 75% CF	MW	430	544
Index		*1.00*	*1.27*

(1) Historic waste generation data estimated from historic landfill trends as given in U.S. EPA (1988b).

APPENDIX L: WIND RESOURCE POTENTIAL

The technical potential of wind power in New England is large. However, significant potential siting constraints must be taken into account. To date, the experience of the region with commercial-scale applications of wind power technology is very limited. Meanwhile, a second generation of wind turbines is under commercial development in Europe, Japan, and in the United States. The cost and performance gains from this development will make the wind resource in New England more attractive to utilities.

Wind resource potential

Elliott et al. (1990) and Elliot (1990) estimate the technical potential for electricity production from wind power in each of the fifty states in the United States. They compiled estimates of windspeeds from a variety of sources (Elliott et al., 1986), normalized them to 50m height, calculated the number of square kilometers associated with wind speeds in a given power class, created four cases in which different amounts of land were excluded from consideration for environmental or other reasons, and calculated the power in the wind and the potential power output.

Table L.1 classifies by wind power class the land areas of each of the states in the New England Region. Wind resource classes are defined in terms of a range of mean wind power density (in units of W/m^2), or an equivalent mean wind speed at the specified height above ground (Elliott et al., 1986).[1] Wind power densities for each wind class are also shown in Table L.1.

Wind classes 5, 6, and 7 can be exploited economically using current technology, while wind classes 3 and 4 in most cases would require more advanced technology. The highest grade developable wind resources in New England are found mainly in the mountaineous regions of Maine, New Hampshire, and Vermont. A number of sites, including Mt. Cardigan, Bolt Mountain, Mt. Success, Mt. Berlin, and Wildcat Mountain, show very high (16-19 mph) average wind speeds.

Siting constraints

To quantify potential electricity generation, Elliott et al. define four exclusion classes, based on their assessment of siting constraints. Exclusion level one ignores all environmental and siting constraints on wind plants, and therefore represents the maximum technical potential. Exclusion level two excludes 100% of "environmentally sensitive land," defined as parks, monuments, wildlife refuges, and recreation areas. Exclusion level three excludes all land excluded in Level 2, and also excludes all urban land, 50% of forest land, 30% of agricultural land, and 10% of range land. Exclusion level four is the most restrictive, excluding all land from wind turbine siting except for 90% of range land. Elliott et al. believe that exclusion level three is the most realistic. For the purposes of this discussion, we focus mainly on exclusion levels three and four.

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[1]Because the power density rises with the cube of the wind speed, sites with the same average wind speed can have vastly different wind power densities, depending on the distribution of wind speeds. Elliott et al. (1986) convert average wind speeds to power densities assuming a Rayleigh distribution, which is a good approximation in many cases, and a conservative assumption in extreme cases.

Sites available in wind power classes 5, 6, and 7 are strongly affected by siting constraints, being reduced by a factor of two by exclusion level two constraints, a factor of three by level three constraints, and a factor of six by level four constraints. Power class 3 and 4 resources are less affected by land exclusions than the power classes with higher power densities.

Power production potential

In Tables L.2 and L.3 we have converted the land estimates in Table L.1 into potential electric power production, using the assumptions of Elliott et al. (1990) and Elliot (1990). The capacity factor is assumed to be 25 percent, and the wind turbine hubs to be located 50 meters above the ground.[2]

Table L.2 shows that even under the most severe siting constraints, electric power generation from currently economic wind power class 5 and 6 resources is roughly 6 TWh. This is equivalent to about 5% of 1990 final electricity use in New England. Under the less restrictive level three exclusion class, class 5 and 6 wind power resources could potentially supply 13 TWh, or about 11% of 1990 final electricity use in New England. Table L.3 disaggregates these results to each state in New England.

Coincidence with system peak

Diurnal wind speed data from more than a year's worth of measurement for Green Mountain Power Company's experimental site at Mt. Equinox (U.S. Windpower, 1991) show that the wind speeds and electric system winter and summer peaks can be highly coincident in New England sites. In the summer (July), wind speeds show a pronounced mid-day lull, in which wind speeds drop to about 60 percent of their maximum. Beginning at 3 pm, the wind picks up strongly. By 5 pm, it is within 20 percent of its maximum. In the winter (December), the mid-day lull is much smaller, and in the evening period, wind speeds are within a few percent of their diurnal maximum.

Wind power costs

Cost estimates for current and next generation wind turbines are shown in Table L.4. Current technology figures are based on field experience in California, which represents more than 90 percent of the world's operating experience with the technology. Installed costs of $1000/kW, operating and maintenance costs of 1.2¢/kWh, availabilities in excess of 95 percent, and capacity factors of up to 35 percent have been achieved (EPRI, 1990b).[3] An average maintenance cost of 1.4¢/kWh and a capacity factor of 25 percent is assumed here for power class 6 sites. For power class 5 sites, the capacity factor is 15 percent lower. This performance is roughly equivalent to measured results from California's Altamont site.[4] Rental payments to land owners on which wind turbines are installed (typically 2-3 percent of power sales revenues) are included in operating and maintenance costs, again based on California's commercial experience.

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[2] Transmission and distribution losses from the turbine to the grid are assumed to be 25%.

[3] Due to the prevalence of older machines, the average capacity factor in California had reached only 19 percent in 1989. In Denmark, where development began later, a capacity factor of 24.3 percent was achieved, see Krause et al. (1992) for further discussion.

[4] Personal communication with Robert Guertin, VP Engineering, U.S. Windpower.

In 1988, the Electric Power Research Institute, Pacific Gas and Electric Company, and U.S. Windpower formed a consortium to develop a second-generation wind turbine in a five-year program. The overall funding for this ongoing program is about $20 million, most of which is provided by U.S. Windpower, the only integrated wind power firm in the United States. The new 300 kW turbine will have variable speed electronics to capture the energy of wind gusts. This will increase energy capture by 10 percent or more, while also reducing dynamic stress on the turbine, and thus extending its life. Capital costs are expected to be reduced to $750/kW in mass production, and operating and maintenance costs are expected to decline significantly due to reduced strain on mechanical components, fewer parts, and less labor when serving fewer larger units in the field. Based on estimates provided by U.S. Windpower, a capacity factor of 30 percent is assumed for a power class 6 site, and a 15 percent lower factor for a class 5 site.[5]

A further advantage of the new variable-speed turbine is that the electronic controller can be set to provide or consume reactive power, depending on grid needs. Industry experts predict that much greater amounts of wind capacity will be able to be accommodated on a typical utility system than is currently possible without threatening power quality disturbances (EPRI, 1990b).

An indication of the potential cost-effectiveness and perceived near-term viability of the new wind turbine is given by the fact that a 100 MW windfarm in the Solano site in California (80 percent coincidence between wind and utility summer peak) was bid at about 5¢/kWh by U.S. Windpower for 1995 in a competitive bidding process of Sacramento Municipal Utility District, and was selected as one of the seven finalists.

Remoteness costs

Windplant sites in New England may be less accessible than in the Western United States, where expanses of open land often simplify access by road. Also, the three major California sites are in passes that are close to transmission lines, a favorable factor that could be less prevalent in New England's mountainous sites. Finally, the harsh winter season adds additional winter costs. We assume a $250/kW remoteness surcharge for New England wind sites.

Total busbar costs

Table L.4 shows electricity costs for current and future wind turbines in class 5 and 6 sites. The figures bear out that wind power could be cost-competitive with advanced gas-fired central stations (see Appendix G).

Current status of wind generation in New England

Overall, wind power development in New England has not reached a significant scale. In New England, performance tests of wind turbines have recently been undertaken by Green Mountain Power (GMP) on Mt. Equinox in Vermont. The utility conducted a two-turbine research project to test wind plant reliability in the harsh climate of New England (Winer, 1990). This experiment dispelled initial concerns about problems of ice build-up on the turbine blades. The Green Mountain site also proved a site with a very favorable wind regime, with a remarkably steady availability of wind power. The utility is in the process of signing up land for a 30 MW windfarm.

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[5] Personal communication with Robert Guertin, VP Engineering, U.S. Windpower.

At this time, a number of other high potential sites in New England are being evaluated in depth for their practical development potential. A first large-scale (250 MW) commercial windfarm is being proposed by U.S. Windpower in the Rumford area of Maine. An arrangement is being investigated in which a paper mill in Rumford would make available a suitable site on its commercial forest land in return for a rental payment. Existing transmission capacity appears sufficient on account of the mill's own power production and needs.

Table L.1: Land Areas associated with different wind power classes in the New England Region

	Wind Power Class 3	4	5	6	7
Wind power density (W/sq m) @ 50 m	350	450	550	700	900
Wind power intercepted (MW/sq km land)	5.5	7.07	8.64	11	14.14
Annual average power output (MW/sq km land)	1.03	1.33	1.62	2.06	2.65
Land Area for exclusion level 1 (sq km)					
Connecticut	1060	100	8	0	0
Massachusetts	4835	343	654	267	0
Maine	10861	1201	481	178	14
New Hampshire	348	351	313	91	6
Rhode Island	211	32	0	0	0
Vermont	249	446	421	41	0
New England Total	**17564**	**2473**	**1877**	**577**	**20**
Land Area for exclusion level 2 (sq km)					
Connecticut	895	65	5	0	0
Massachusetts	3682	189	297	120	0
Maine	9517	573	280	105	8
New Hampshire	276	210	182	49	3
Rhode Island	101	14	0	0	0
Vermont	193	266	240	23	0
New England Total	**14664**	**1317**	**1004**	**297**	**11**
Land Area for exclusion level 3 (sq km)					
Connecticut	507	33	2	0	0
Massachusetts	2009	121	246	119	0
Maine	5287	435	148	57	4
New Hampshire	141	109	95	25	1
Rhode Island	86	14	0	0	0
Vermont	111	142	128	12	0
New England Total	**8141**	**854**	**619**	**213**	**5**
Land Area for exclusion level 4 (sq km)					
Connecticut	107	4	0	0	0
Massachusetts	590	65	208	119	0
Maine	1107	316	18	9	0
New Hampshire	20	12	10	1	0
Rhode Island	77	14	0	0	0
Vermont	20	17	14	1	0
New England Total	**1921**	**428**	**250**	**130**	**0**

(1) wind power densities at 50 meter hub height are estimated assuming Rayleigh distribution. Estimated power output assumes 10 rotor diameter spacing between turbines in a given row, and 5 rotor diameter spacing between turbine rows. Power density is that intercepted by wind machines so spaced over 1 square km. Capacity factor is assumed to be 25%, and transmission losses to the busbar are also 25%

(2) exclusion level 1 = no exclusions of land area for any reason.

(3) exclusion level 2 = 100% of environmentally sensitive land excluded, including parks, monuments, wildlife refuges, and recreation areas.

(4) exclusion level 3 = exclusions as in level 2; also excludes all urban land, 50% of forest land, 30% of agricultural land, and 10% of range land.

(5) exclusion level 4 = exclusions as in level 2; also excludes all urban, agricultural, and forest land, and 10% of range land (as in exclusion level 3).

(6) Wind power classes 5, 6, and 7 can be tapped economically using current technology. Classes 3 and 4 may be tapped using advanced turbines currently under development.

Table L.2: Potential wind electricity production in the New England region

	Wind Power Class				
	3	*4*	*5*	*6*	*7*
Wind power density (W/sq m) @ 50 m	350	450	550	700	900
Wind power intercepted (MW/sq km land)	5.5	7.07	8.64	11	14.14
Annual average power output (MW/sq km land)	1.03	1.33	1.62	2.06	2.65
Potential electricity production (TWh)					
Exclusion class 1	158	29	27	10	0
Exclusion class 2	132	15	14	5	0
Exclusion class 3	73	10	9	4	0
Exclusion class 4	17	5	4	2	0
Potential electricity production (% of 1990)					
Exclusion class 1	141%	26%	24%	9%	0%
Exclusion class 2	118%	14%	13%	5%	0%
Exclusion class 3	66%	9%	8%	3%	0%
Exclusion class 4	15%	4%	3%	2%	0%
Potential electricity production (% of 2005)					
Exclusion class 1	106%	19%	18%	7%	0%
Exclusion class 2	88%	10%	9%	4%	0%
Exclusion class 3	49%	7%	6%	3%	0%
Exclusion class 4	12%	3%	2%	2%	0%

(1) potential electricity production calculated from data in Table L.1.
(2) Exclusion classes defined in Table L.1.
(3) Wind power classes 5, 6, and 7 can be tapped economically using current technology.
Classes 3 and 4 may be tapped using advanced turbines currently under development
(4) 1990 final electricity use = 112 TWh. 2005 projected final electricity use = 150 TWh.

Table L.3: Potential wind electricity production in the New England region by state

	Wind Power Class									
	Three		*Four*		*Five*		*Six*		*Seven*	
	TWh	*%1990*	*TWh*	*%1990*	*TWh*	*%1990*	*TWh*	*%1990*	*TWh*	*%1990*
New England Total--Level 1	**158.5**	**141%**	**28.8**	**25.7%**	**26.6**	**23.8%**	**10.4**	**9.3%**	**0.5**	**0.4%**
Connecticut	9.6	8.5%	1.2	1.0%	0.1	0.1%	0.0	0.0%	0.0	0.0%
Massachusetts	43.6	39.0%	4.0	3.6%	9.3	8.3%	4.8	4.3%	0.0	0.0%
Maine	98.0	87.5%	14.0	12.5%	6.8	6.1%	3.2	2.9%	0.3	0.3%
New Hampshire	3.1	2.8%	4.1	3.7%	4.4	4.0%	1.6	1.5%	0.1	0.1%
Rhode Island	1.9	1.7%	0.4	0.3%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Vermont	2.2	2.0%	5.2	4.6%	6.0	5.3%	0.7	0.7%	0.0	0.0%
New England Total--Level 2	**132.3**	**118%**	**15.3**	**13.7%**	**14.2**	**12.7%**	**5.4**	**4.8%**	**0.3**	**0.2%**
Connecticut	8.1	7.2%	0.8	0.7%	0.1	0.1%	0.0	0.0%	0.0	0.0%
Massachusetts	33.2	29.7%	2.2	2.0%	4.2	3.8%	2.2	1.9%	0.0	0.0%
Maine	85.9	76.7%	6.7	6.0%	4.0	3.5%	1.9	1.7%	0.2	0.2%
New Hampshire	2.5	2.2%	2.4	2.2%	2.6	2.3%	0.9	0.8%	0.1	0.1%
Rhode Island	0.9	0.8%	0.2	0.1%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Vermont	1.7	1.6%	3.1	2.8%	3.4	3.0%	0.4	0.4%	0.0	0.0%
New England Total--Level 3	**73.5**	**65.6%**	**9.9**	**8.9%**	**8.8**	**7.8%**	**3.8**	**3.4%**	**0.1**	**0.1%**
Connecticut	4.6	4.1%	0.4	0.3%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Massachusetts	18.1	16.2%	1.4	1.3%	3.5	3.1%	2.1	1.9%	0.0	0.0%
Maine	47.7	42.6%	5.1	4.5%	2.1	1.9%	1.0	0.9%	0.1	0.1%
New Hampshire	1.3	1.1%	1.3	1.1%	1.3	1.2%	0.5	0.4%	0.0	0.0%
Rhode Island	0.8	0.7%	0.2	0.1%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Vermont	1.0	0.9%	1.7	1.5%	1.8	1.6%	0.2	0.2%	0.0	0.0%
New England Total--Level 4	**17.3**	**15.5%**	**5.0**	**4.5%**	**3.5**	**3.2%**	**2.3**	**2.1%**	**0.0**	**0.0%**
Connecticut	1.0	0.9%	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Massachusetts	5.3	4.8%	0.8	0.7%	3.0	2.6%	2.1	1.9%	0.0	0.0%
Maine	10.0	8.9%	3.7	3.3%	0.3	0.2%	0.2	0.1%	0.0	0.0%
New Hampshire	0.2	0.2%	0.1	0.1%	0.1	0.1%	0.0	0.0%	0.0	0.0%
Rhode Island	0.7	0.6%	0.2	0.1%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Vermont	0.2	0.2%	0.2	0.2%	0.2	0.2%	0.0	0.0%	0.0	0.0%

(1) wind power potential calculated as in Table L.2, using the assumptions from Table L.1. 1990 final electricity use in New England = 112 TWh.

Table L.4: Busbar costs of conventional and advanced wind generation technologies

	Current technology		*Advanced technology*	
PHYSICAL PARAMETERS				
Wind power class	*6*	*5*	*6*	*5*
Total Electric Capacity (MWe)	0.2	0.2	0.4	0.4
Lifetime (Years)	30	30	30	30
Construction Lead Time (Years)	1	1	1	1
Ave Capacity Factor	25%	21%	30%	26%
Equivalent Unplanned Outage Rate	5.0%	5.0%	5.0%	5.0%
Equivalent Availability	95.0%	95.0%	95.0%	95.0%
Heat Rate (kWh heat in/kWh elect. out)	1.00	1.00	1.00	1.00
Efficiency	100.0%	100.0%	100.0%	100.0%
FIXED COSTS				
Capital Recovery Factor	0.122	0.122	0.122	0.122
Overnight Capital Cost ($/kW)	1000	1000	750	750
Addl. remoteness costs (road and transm. access)	250	250	250	250
Net Capital Cost ($/kW)	1250	1250	1000	1000
Net Cap Cost Including Interest ($/kW)	1250	1250	1000	1000
GTF Net Cap Cost Incl. Interest ($/kW)	1250	1250	1000	1000
Startup ($/kW)	10.80	10.80	8.10	8.10
Inventory ($/kW)				
Land ($/kW)				
Total: Startup, Inventory, Land ($/kW)	11	11	8	8
Annualized Capital Cost ($/kW/yr)	153.2	153.2	122.5	122.5
Fixed O&M ($/kW/yr)	n/a	n/a	n/a	n/a
Total Fixed Costs ($/kW/yr)	*153.2*	*153.2*	*122.5*	*122.5*
Total Fixed Costs (¢/kWh)	*7.1*	*8.2*	*4.7*	*5.4*
VARIABLE COSTS				
Incremental O&M (¢/kWh elect.)	1.20	1.20	0.75	0.75
Rental payment for site use	0.20	0.20	0.20	0.20
Fuel Price ($/kWh fuel)	0	0	0	0
Fuel Cost (¢/kWh elect.)	0	0	0	0
Total Variable Costs (¢/kWh)	*1.4*	*1.4*	*1.0*	*1.0*
T&D Adjustment	1	1	1	1
DELIVERED COST (¢/kWh)				
Fixed @ avg. capacity factor	*7.1*	*8.2*	*4.7*	*5.4*
Fixed @ max. capacity factor	*7.1*	*8.2*	*4.7*	*5.4*
Variable	*1.4*	*1.4*	*1.0*	*1.0*
Externality Cost-MA DPU	*0.0*	*0.0*	*0.0*	*0.0*
Externality Cost-MA DPU w/o CO2	*0.0*	*0.0*	*0.0*	*0.0*
credit for fuel flex.	*0.0*	*0.0*	*0.0*	*0.0*
Total @ avg. capacity factor	***8.5***	***9.6***	***5.6***	***6.3***
Total w/MA DPU	***8.5***	***9.6***	***5.6***	***6.3***
Total w/MA DPU w/o CO2	***8.5***	***9.6***	***5.6***	***6.3***
Total @ max. capacity factor	***8.5***	***9.6***	***5.6***	***6.3***
Total w/MA DPU	***8.5***	***9.6***	***5.6***	***6.3***
Total w/MA DPU w/o CO2	***8.5***	***9.6***	***5.6***	***6.3***

(1) all costs in 1990$.

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