THE INCLUSION OF ENVIRONMENTAL GOALS IN ELECTRIC RESOURCE EVALUATION: A CASE STUDY IN VERMONT

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Energy development and use impose a broad array of environmental costs on society, including damages to habitats, biota, human health, and amenity. Increasing attention is now being given to the question of how to incorporate these costs in the energy planning and regulatory processes. Within the regulated energy industries, the concept of Integrated Resource Planning (IRP) has been receiving increasing attention at the analytical, policy, and regulatory process levels. The scope of utility resource planning has been broadening significantly, as the old focus on supply planning has been superseded by an integrated approach that emphasizes demand-side measures (e.g., improved efficiency, load shifting, and fuel switching) and non-traditional supply options (e.g., cogeneration, solar, and other renewables). One important extension of the IRP process would be to incorporate the environmental costs of these resource options in the resource evaluation process. The inclusion of environmental costs may result in significant changes in the relative ranking of energy resources.

This paper will address the policy and methodological issues regarding the incorporation of environmental costs in IRP. It will do so by presenting a case study, an analysis of a proposed power purchase from Hydro-Quebec performed on behalf of the Vermont Department of Public Service, in which demand-side management, fuel switching, cogeneration, and efficient new utility resources were evaluated as components of potential resource plans. Emissions of atmospheric pollutants were estimated for each scenario and were ascribed costs for incorporation in the overall economic evaluation. Land use impacts were also evaluated.

INTRODUCTION

Great attention has been given of late to incorporating environmental issues in electric resource planning. As yet, much of this attention has remained at the conceptual level, concerned with general methodologies for evaluating the environmental loadings and impacts associated with electric resources. At this time, there has been only limited application of these concepts within actual electric planning analyses. In this paper, we describe one such application, in which environmental goals were explicitly incorporated in an integrated resource planning (IRP) evaluation.

DESCRIPTION OF THE OVERALL STUDY

On behalf of the Vermont Department of Public Service, a comprehensive evaluation of the Vermont electric system was prepared in order to determine whether a proposed power purchase from Hydro-Quebec was consistent with IRP for Vermont (Docket No. 5330). This planning study (Tellus Institute 1990) included load forecasts, demand side management (DSM) program design, assessment of new power supply options, evaluation of non-utility resources, analysis of transmission needs, and a review of power markets. It also included a detailed analysis of certain environmental loadings associated with alternative resource plans, both with and without the proposed Hydro-Quebec contract. These environmental loadings were explicitly integrated in the overall economic evaluation of the proposed contract and alternative resources.

In this paper, we focus on the environmental analysis embodied in the overall IRP study, while necessarily drawing upon other elements of the study to place that analysis in the appropriate context. We discuss the structure and substance of the environmental analysis as well as alternative approaches to treating environmental issues in IRP. We introduce an approach--the energy/environment target IRP method--that permits straightforward incorporation of environmental goals in energy planning. All resource plans are placed on the same footing with respect to energy and environmental objectives, and both their direct resource costs and environmentally based costs are combined in overall costs for comparison. By including environmental costs, certain options that might otherwise be outside of a least-cost plan might be found desirable.

Of particular interest here is the treatment and environmental performance of DSM, fuel switching, and cogeneration. By expanding the boundaries of electric system planning beyond power supply facilities, and beyond the electric sector itself for certain end-uses, both economies and environmental benefits can be realized.

SELECTION OF ELECTRIC RESOURCES

The existing electric system in Vermont, comprising 24 retail utilities and the Vermont Department of Public Service, serves a winter peak demand of 960 MW and energy requirements of 5271 million KWH, primarily with a mix of nuclear, hydro purchases, coal, and residual oil. Load is projected to grow at an annual rate of about 1.7% for peak and 2.3% for energy over the next 20 years. Peak and energy would reach 1170 MW and 6850 GWH, respectively, in the year 2000 (Tellus Institute 1990).

The overall IRP analysis considered a variety of new supply and demand side options, including both utility and non-utility resources, to meet the power needs of Vermont over the next twenty years. These included:

- The proposed Hydro Quebec contract[1]
- New utility-owned generating facilities, primarily natural gas combined-cycle and distillate oil combustion turbine, both outfitted with selective catalytic reduction (SCR)[2]
- New non-utility generating facilities, including cogenerators
- Demand-side management programs, including fuel switching from electricity to natural gas[3]

While the focus of our analysis was on the Vermont system itself, we also needed to model external resources in order to capture two effects. First, we needed to account for the fact that the set of new resources in competing resource plans (e.g., plans with and without the proposed contract) might differ, within a given year, in the amount of electricity generated or capacity provided. For this reason, it was necessary to identify the generating resources that would provide the marginal power. We assumed that this power would come from the marginal resources in NEPOOL, since the Vermont utilities are part of that centrally dispatched system.[4] Thus, environmental loadings from NEPOOL

1 *The proposed contract included provisions for up to 340 MW of committed purchases (the "minimum take") and up to 110 MW of additional cancellable capacity. Our analysis focused on the committed purchases.*

2 *Note, however, that use of SCR on oil-fired peakers is unproven.*

3 *We considered a number of DSM programs in our study. In this paper, we refer to a "Strong" DSM program that would provide up to 300 MW of savings (about 21%) off a projected 2010 peak load of 1400 MW. Energy savings were projected to be about 1083 GWH in 2010, or about 12.5% of demand in that year.*

4 *NEPOOL includes virtually all utilities in New England. For the economic analysis, the Vermont system could be modeled in isolation owing to the power-pricing protocols of NEPOOL. Our environmental analysis, however, required that the actual Pool resources and their emissions be estimated.*

marginal resources, as well as from new Vermont resources, were included in the analysis.

Second, we needed to consider what would happen to the proposed contract power, and its impacts on environmental loadings, if Vermont ultimately rejected the contract. We modeled two rejection cases in order to capture the range of possible effects.[5] In one case, we assumed that development at James Bay would be unaffected by Vermont's rejection of the contract. In this case, the "clean" hydropower would be available to displace fossil generation in Canada and New England. For this case, we assumed that 2/3 of the power would flow back into New England, and 1/3 would flow to Ontario Hydro or another utility with similarly "dirty" coal plants. In a second case, we assumed that development at James Bay would be deferred if the contract were rejected. In this case, no hydro power would be "freed up" for fossil displacement by rejection of the contract.[6]

SELECTION OF ENVIRONMENTAL LOADINGS

Within an integrated planning analysis, it would be appropriate, in principle, to include all the environmental impacts associated with electric resources (e.g., air emissions, land use, water emissions, thermal pollution, solid waste generation, noise, traffic, aesthetics, etc.). For purposes of the Vermont analysis, however, it was necessary to limit our focus to a subset of the environmental loadings. We chose to focus on the following air emissions:

Acid Gases:	Sulfur Oxides (SO_x) Nitrogen Oxides (NO_x)
Greenhouse Gases:	Carbon Dioxide (CO_2) Methane (CH_4) Carbon Monoxide (CO) Nitrous Oxide (N_2O)
Other Emissions:	Total Suspended Particulates (TSP) Total Hydrocarbons (THC)

5 *In the original study, we actually modeled a third case that falls between the two described here. There is no need to present that case here.*

6 *After the completion of the study, a Hydro-Quebec witness testified that this would likely be the case.*

In particular, we focused on those emissions that occur during energy conversion (i.e., in the production of electricity or the serving of a direct end-use). Emissions that occur in the rest of the fuel cycle, e.g., upstream--in the extraction, processing, and transport of fuels, and in construction of power plants--or downstream--in the disposal of wastes and decommissioning--were not included.

While the fuel cycle boundaries of our analysis were drawn tightly around the electric generation stage, the geographic boundaries were made more comprehensive. First, by focusing on acid and greenhouse gases, attention to regional and global environmental impacts is expressed in our framework. Second, owing to Vermont's exchanges of power with utilities in Canada, New England, and New York, sources of these pollutants outside of the state that are affected by Vermont's planning and operation are included.

Finally, since hydroelectric development in the James Bay region of Canada would serve most, if not all, of the proposed contract, we also elected to model the land use impacts associated with potential resource options. Analysis of the ecological and socio-economic impacts of hydro-electric development in that region, while relevant to an overall assessment of Hydro-Quebec options, were beyond the scope of our study. However, our results can be used, as we discuss in a later section, to frame the cost to Vermont of avoiding or accepting these impacts.

DEVELOPMENT OF LOADING COEFFICIENTS

Loading coefficients for land use, expressed in acres per MW, were developed from the US DOE (1983) and MEOS (1986) figures. The land use impacts of resource plans were expressed in acre-years, the cumulative land area allocated to electricity production times the number of years of such allocation.

Emissions factors for most new electric resources, expressed in lbs per MMBtu of fuel input, were derived from a data base that summarizes EPA, DOE, and other estimates of environmental loadings (Tellus Institute 1989). NEPOOL heat rate estimates were then used to convert these factors to lbs/MWH emissions coefficients. Emissions from the Hydro-Quebec purchase itself were assumed to be zero, since that power is to be provided primarily by hydro-electricity.[7] Emissions coefficients for the Ontario Hydro system (to which some power would flow in one rejection scenario) were based on a 50-50 mix of scrubbed and unscrubbed coal plants.

[7] *In testimony filed after our original analysis was completed, a number of parties argued that some fossil power might be necessary to serve the contract in its early years. Some parties also argued that flooding for hydro development would result in releases of carbon dioxide and methane over the next several decades from loss of standing biomass and/or the loss of future CO_2 uptake. This impact is relevant to the analysis of Vermont resource plans only for the case in which rejection of the contract affects development at James Bay. We found that the magnitude of these two effects is relatively small; e.g., the annualized carbon emissions from biomass loss in James Bay is about 200 pounds per MWH, about one tenth that of a new combined cycle gas plant. Their impact on the overall results is given in Rosen (1990).*

The process by which these emissions factors were developed need not concern us here; the interested reader is referred to Tellus Institute (1990). What is of interest are the processes by which we determined emissions coefficients for the less-simple electric resources: cogenerating facilities, DSM devices, fuel switching options, and the NEPOOL margin. Emissions coefficients for these resources, as well as for more conventional supply resources, are listed in Table 1.

Cogeneration Offsets

Cogeneration facilities produce usable thermal energy in addition to their output of electricity. Therefore, they require special treatment in the development of their emissions factors. Since these dual purpose facilities provide useful energy in addition to their output of electricity, it would not be correct to attribute all their air emissions to the production of electricity. We therefore adjusted their emissions coefficients in order to account for the commercial and industrial boiler emissions that

Table 1. Environmental Loadings

	EMISSIONS IN POUNDS PER MWH								LAND USE (acres/MW)
Resource	SO_x	NO_x	CO_2	CH_4	TSP	CO	THC	N_2O	
Hydro Quebec	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	190.00
Natural Gas Comb. Cycle (CC)	0.00	0.64	953	0.11	0.01	0.51	0.01	0.06	1.00
Natural Gas CC, Cogen 1	-0.68	0.31	719	0.10	-0.03	0.45	0.01	0.03	1.00
Natural Gas CC, Cogen 2	-2.24	0.02	682	0.09	-0.12	0.45	0.01	0.01	1.00
Distillate Comb. Turbine (CT)	2.36	1.14	1828	0.02	0.33	1.29	0.40	0.24	0.10
Coal Fluidized Bed	5.31	5.37	2078	0.01	0.29	0.29	0.03	0.31	1.00
Coal Fluidized Bed, Cogen 1	4.43	4.95	1778	0.01	0.23	0.22	0.02	0.27	1.00
Wood Steam	0.13	2.27	3010	0.46	0.43	4.26	1.42	0.46	0.67
NEPOOL Margin	12.14	5.11	1813	0.02	0.84	0.54	0.11	0.34	0.10
Ontario Hydro Margin	12.10	2.97	2320	0.01	1.21	0.24	0.03	0.33	0.00
Non-Fuel Switching DSM	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00
Fuel Switching (R/C WH)	0.00	0.47	153	0.00	0.02	0.02	0.01	0.00	0.00
Fuel Switching (CSH)	0.75	0.52	625	0.04	0.07	0.14	0.07	0.10	0.00
Fuel Switching (RSH)	0.30	0.33	655	0.02	0.08	0.09	0.05	0.03	0.00

Notes: Natural Gas CC, Cogen 1 is a cogenerating CC that displaces a mix of residual, distillate, and natural gas fuels in industrial boilers. Natural Gas CC, Cogen 2 displaces only residual oil. Coal Fluidized Bed, Cogen 1 displaces the same mix of fuels as the Natural Gas CC, Cogen 1.

R/C WH = Residential Small Commercial Water Heating
CSH = Commercial Space Heating
RSH = Residential Space Heating

The wood steam coefficients assume unsustainable wood consumption. Sustainable burning would have substantially lower CO_2 emissions.

are avoided because of their steam output. In order to calculate these emissions offsets, we developed emissions coefficients for medium-sized industrial boilers fueled by natural gas, distillate (#2) oil, and residual (#6) oil. Since the actual identity and fuel type of future QF and IPP resources is uncertain, we modeled two generic QF/IPP scenarios for this particular analysis:

Scenario 1: All facilities are natural gas combined cycle with cogeneration. All avoided boilers are assumed to be fueled by residual oil.

Scenario 2: Facilities are 50 percent natural gas combined cycle, half with cogeneration and half without; 25 percent coal atmospheric fluidized bed with cogeneration; 25 percent wood fired generation. The cogeneration is assumed to avoid a mix of boilers characteristic of the region (EIA 1989): 41 percent natural gas, 33 percent distillate oil, and 25 percent residual oil.

These two scenarios are used illustrate a range of the environmental benefits/costs that may result from the QF/IPP development assumed in this IRP study.

In each scenario, determining the actual level of emissions avoided by the cogenerator required that we also know the overall steam efficiencies for the cogenerator type and for the avoided boiler. For the cogenerator, we assumed that 25% of the heat remaining after electricity production would be turned into useable steam. Thus, for a gas combined-cycle cogenerator with a heat rate of 8,214 Btu/kWh, the overall thermal efficiency (i.e., the fraction of energy input used for thermal end-uses) would be about 15% [= (1 - 3412/8214) * .25]. For industrial boilers, we assumed an overall efficiency of 75%.

Given the gross emissions from a cogenerator (E_g, measured in lbs/MMBtu), its overall thermal efficiency (S_c), the gross emissions from the average avoided boiler (E_b, in lbs/MMBtu) and its overall thermal efficiency (S_b), we can calculate the cogenerator's "net" emissions (E_n, in lbs/MMBtu) as:

$$E_n = E_g - E_b * (S_c/S_b), \qquad (1)$$

where, in general, S_c = (1 - 3412/Heat Rate) x F, and F is the fraction of thermal energy not used for electricity production that is captured for thermal end-uses.

By multiplying this factor by the cogenerator's electric heat rate, we can then determine the facility's emissions coefficient in lbs/MWH.

NEPOOL Margin

Since different resource plans for Vermont imply different levels of generation from the rest of the NEPOOL system, it was necessary to consider how emissions from NEPOOL as a whole would vary under different resource plans. Based on a dispatch analysis of the NEPOOL system, we estimated the fraction of the NEPOOL margin that would be made up of various resources: residual oil steam (78%), distillate oil steam (less than 1%), natural gas steam (3%), distillate combustion turbines (17%), and natural gas combustion turbines (2%). Based on emissions coefficients for each individual resource type, we used these fractions to develop a weighted average emissions rate to represent the NEPOOL margin.[8]

For the land use impact associated with capacity differences, we assumed that the NEPOOL margin was peaking capacity, with a land use factor of 0.10 acres per MW.

Demand-Side Management

The environmental benefits of DSM are reduced emissions from avoided electricity production and reduced land use from avoided capacity construction. DSM resources that embodied efficiency

8 *The emission rates for the NEPOOL system margin can be thought of as short-term* avoided emissions, *directly analogous to short-term avoided costs. Long-term avoided emissions are associated with different long-term resource plans. If costs are ascribed to these avoided emissions, adding the resultant* avoided emissions costs *to the direct avoided costs gives total (energy plus emissions) avoided costs.*

improvements were assumed to have emissions coefficients of exactly zero. This is consistent with our focus on the emissions that occur only during the conversion stage of electricity production. Fuel switching programs (for example, switching from electricity to natural gas for residential water heating) cause increased emissions at the end-use; these emissions were counted as an environmental cost of DSM.[9] We considered three types of fuel switching programs:

- Residential Space Heating: From electricity to natural gas (13%), propane (52%), and distillate oil (35%).
- Residential/Small Commercial Water Heating: From electricity to natural gas (25%) and propane (75%).
- Commercial Space Heating: From electricity to natural gas (13%) and distillate oil (87%).

Emissions factors, expressed in lbs/MMBtu of fuel input, for each type of heating unit were based on standard furnaces and water heaters. Aggregate emissions coefficients for each program were then developed as the weighted average of the individual emissions coefficients. Fuel switching "heat rates" were then developed based on (1) the efficiency of the end-use conversion device and (2) electric losses in transmission and distribution. For example, given an average space heater efficiency of 80% and a line loss factor of 7.9%, we calculated a space heating fuel switching "heat rate" of 3,953 Btu/kWh, calculated as:

$$3{,}953 \text{ Btu/kWh} = 3412 \text{ Btu/kWh} / (1.079 * 0.80) \quad (2)$$

By multiplying these heat rates by the lbs/MMBtu emissions factors, emissions coefficients in lbs/MWH were calculated for the fuel switching programs.

9 *The environmental benefits would be the avoided emissions from reduced electricity generation which, in general, would be greater owing to its lower thermodynamic efficiency and somewhat dirtier fuel mix.*

VALUATION OF ENVIRONMENTAL LOADINGS

In order to incorporate environmental loadings and goals directly in our overall economic analysis, we decided to use the not-uncontroversial approach of developing monetary costs for air emissions. We did *not* attempt to value land use impacts. Monetization of land use is problematic because some environmental costs are already internalized in land costs (after all, land is a market good) and because of inter-regional difficulties, among other reasons. Before presenting our actual derivation of emissions costs, we will discuss briefly the range of methodologies that we considered.

Valuation Methodologies

The art and science of attributing costs to environmental impacts are still in their developing stages. Two general approaches have been taken to the problem, one emphasizing the costs associated with environmental damage and/or its remediation, the other emphasizing the costs to prevent it.

While significant efforts have been made using the damage costing approach (see, e.g., ECO Northwest et al. 1984, 1986, 1987; Hall et al. 1989; Hohmeyer 1988), we believe that they do not provide a suitable basis for establishing policies in New England at this time. While we did review some such estimates, it soon became clear that such impacts and their costs are inherently complex and uncertain, are qualitatively and quantitatively site-specific, and depend not only on scientific and economic analysis but also on public perception and values. The *direct* ascription of costs to certain impacts--e.g., loss of species, degradation of habitats, loss of human life, disturbance of cultures--is itself controversial and arguably inappropriate. In our opinion, neither the science nor the economics of environmental damages are sufficiently developed at this time, nor is public policy discussion sufficiently advanced, to assign acceptable damage costs to the air pollutants modeled in our Vermont analysis.

While abatement costs are generally well understood, particularly in comparison with damage costs, there is *no reason* to expect that they bear any simple relation to the damage costs for which they are used as proxies. They may be inappropriate for representing both the overall and relative magnitudes of damages associated with different pollutants. Thus, their use as a surrogate for the actual health, socio-economic, and ecological damages associated with environmental loadings could result in inappropriate ranking of alternative resources and resource plans.

Because of this problem with simple cost of control valuation, a more nuanced control cost approach has been proposed, based on the notion of regulators' "revealed preferences" (Schilberg et al. 1989) or "shadow pricing" (Chernick and Caverhill 1989). In this approach, existing and proposed environmental regulations are analyzed in order to estimate the value that society implicitly places on specific environmental impacts. For example, acid rain legislation may be analyzed in order to estimate the costs society is willing to impose on itself to reduce emissions of SO_x. In analyzing the regulations, we can identify the highest (or marginal) cost reduction strategy required by the regulations. If we assume that regulators are "rational", this can then be taken as an estimate of the value that they (and society) have placed on air emissions. At the very least, it can be argued that this value represents the "revealed preferences" of regulators, and that, to be consistent, it ought to be applied when decisions affecting these environmental impacts are made.

While the revealed preferences method does have a number of difficulties[10], we believe that in some instances it is a useful way to estimate the values that society places on air emissions. Indeed, in some of our more recent work (Shimshak et al. 1990), we explicitly recommended that Massachusetts adopt the "revealed preferences" approach in order to include environmental costs in an all resources bidding system.[11]

For the purposes of the Vermont study, however, we decided to use a different costing methodology that relies upon abatement cost estimates. In this approach, it is recognized that the valuation of environmental impacts is so fraught with difficulty that, at this time, public policy on the environment should precede and motivate technical analysis. For that reason, emissions reductions should be taken as *goals* of the resource evaluation process, rather than given values as outputs of that process. The resource evaluation process can then be seen as attempting to meet two goals: satisfying Vermont's electricity requirements and keeping emissions below a specified emissions target. The least-cost resource plan, including supply technologies, demand side options, non-utility resources, fuel switching, and pollution control techniques (or offsets), would have to satisfy these criteria. Naturally, different plans which meet the criteria would have different costs and uncertainties. However, by using this approach planners, regulators, and the public would be informed about the overall costs that would be required to meet the two criteria, and the additional costs that would be incurred as a consequence of setting alternate environmental targets.[12]

Derivation of Emissions Costs Using the Environmental Standards Approach

The environmental target established for all scenarios in the Vermont IRP study was *no net new*

10 It assumes that regulators have made a rational assessment of society's "costs" and "benefits". These costs can be either higher or lower than actual damage costs, either through insufficient information, or because a risk-averse or risk-accepting margin is adopted. Moreover, society's revealed preferences can change over time as information, analysis, and values change. Thus, a limitation of this approach is that past or current revealed preferences may bear little relation to actual impacts and their current value to society, or the value that further attention, scrutiny, and public debate might reveal. Both the acid rain policy debate of the last decade and a half and the nascent greenhouse gas discussion are examples.

11 It should be noted, however, that, ideally, one would not simply accept a single point value based on current revealed preferences, but would instead explore a range of such values and the direct cost implications of moving along that range.

12 This approach puts the environmental targets forward as a matter of environmental policy and places the burden of proof on those who would argue that the costs are too high or the benefits too low.

emissions for the Vermont system (including the impacts of unpurchased HQ power and the NEPOOL margin). Thus, we did not value emissions from the resources considered, since we assumed that no net emissions would occur; instead of estimating costs associated with air emissions externalities, we estimated the costs of avoiding the externalities. A range of estimates of pollution abatement costs were obtained from the literature to reflect the potential mix of options that could be used to achieve this target. The *average* of high and low abatement costs across a range of technologies and modalities for emissions reduction were used here instead of New England-specific abatement costs. In the case of acid gases, this is consistent with emerging national strategies for achieving reduction targets at the lowest feasible costs (e.g., through emissions trading). However, it would not be feasible for the region to always find the lowest cost abatement technique elsewhere, since other utility systems would also be seeking to employ these lowest cost solutions. A similar phenomenon of abatement cost increases could occur for afforestation for taking up carbon in net biomass increases, as increasing amounts of land are brought under biomass production. Thus, we have taken the low and high abatement cost estimates to reflect a realistic range of options and their costs.[13]

13 *Note that our usage of average abatement costs differs substantially from the usages in New York (New York State Energy Office et al. 1989 and Putta 1989) and in California (Therkelsen 1990; CEC 1990). In our case, we require that emissions be abated, while in the New York and California applications emissions are still assumed to occur. Average abatement costs are not the correct measure to use for valuing unabated emissions. See Bernow and Marron (1990).*

Table 2 summarizes the results of our review of the literature. The low SO_x abatement cost estimates are based on the use of low sulfur fuels, while the high cost estimates are based on scrubber retrofits. Similarly, low NO_x abatement cost estimates are based on low NO_x burner retrofits, while the high estimates are based on the costs of selective catalytic reduction. The costs of all of the greenhouse gases were based on uptake of carbon in afforestation,[14] with global warming potentials based on estimated long term contributions.[15] Use of these figures captures only the greenhouse effect; other environmental effects, for example health effects associated with CO, are not included. Note that, because of a lack of information, no cost figures were developed for hydrocarbon emissions; as a result, hydrocarbons were implicitly valued at $0. This omission clearly understates the environmental costs associated with electric resources. For more information on the derivation of these cost figures, see Tellus Institute (1990).

Consistent with our assumption that the emissions abatement costs will actually be incurred as abatement technologies are implemented, we chose to use our estimate of the Vermont Joint Owners weighted

14 *The CO_2 cost figures are based on estimates of reforestation costs; since there are no existing CO_2 regulations, they are not based on "regulators revealed preferences". In later work (Shimshak et al. 1990; Bernow and Marron 1990), we have concluded that the CO_2 numbers presented here are somewhat low, although the $7 figures is the same as that recently adopted in California (CEC 1990).*

15 *We used the following global warming potentials (by weight): $CO_2 = 1.0$, $CO = 2.2$, $CH_4 = 10$, $N_2O = 180$; these are based on Lashof and Ahuja (1990).*

Table 2. Environmental Abatement Costs in 1989$/ton (Tellus Institute 1990)

Emission	Low	Medium	High
NO_x	200	2,600	5,000
SO_x	200	850	1,500
CO_2	3	7	11
TSP	220	360	500
THC	n/a	n/a	n/a
CO	7	15	24
CH_4	30	70	110
N_2O	540	1,260	1,980

cost of capital (about 10.5%) as the discount rate in this analysis. Use of this discount rate was appropriate for abatement costs that will actually be incurred, just as construction and fuel costs are incurred.

RESULTS

Results for the Hydro Quebec Contract

The principal results of the Vermont analysis are presented in Table 3 for two cases: one in which rejection of the contract does not cause Hydro-Quebec development to be deferred and one in which rejection causes a deferral. Note that the deferral assumption *only* affects the emissions costs in the cases in which the HQ contract is assumed to be rejected. For each deferral case, two scenarios were analyzed: Low Fuel prices and High Fuel prices.[16] Note that the variation in fuel prices has a significant impact on direct ratepayer revenue requirements (roughly $500 million in the Hydro-Quebec Out case), but only a small impact on emissions costs (the difference is only about $4 to $7 million between scenarios). Emissions costs in the low fuel price cases are slightly lower than in the high fuel price cases because of slightly greater use of new, "clean" facilities and a corresponding reduction in use of existing facilities.

In both fuel price scenarios, revenue requirements are *lower* for resource plans including the contract. In the non-deferral case, emissions costs *with* the proposed contract are actually higher than they are when the contract is rejected. This slightly counter-intuitive result (why would purchasing hydro power *increase* emissions costs?) is explained by the fact that, in this case, the power would reduce emissions even more if it were used to back down existing generation in New England and Ontario Hydro, rather than mostly new facilities in Vermont. In the low fuel price scenario, this emissions cost differential more than offsets the revenue requirement savings, and thus the contract appears uneconomic in this instance. In the high fuel price scenario, however, the direct economic benefits of the contract outweigh the emissions costs differential. In the deferral cases, finally, emissions costs greatly favor the contract, and thus the net results also favor the contract.

Of course, the net economic results do not include many other impacts, most notably the issue of land use (and related environmental and socio-cultural

[16] *In the study, many other scenarios were also modeled, but they are of little concern here. See Tellus Institute (1990).*

Table 3. Results of the Analysis

Scenario	Revenue Requirement	Emissions Costs	Total Costs	Land Use (Thousand acre-yrs)
No Deferral of Hydro-Quebec Development:				
Low Fuel: HQ In	7871	395	8266	1413.8
HQ Out	7914	331	8245	1416.3
High Fuel: HQ In	8184	399	8583	1417.4
HQ Out	8409	336	8745	1418.8
Deferral of Hydro-Quebec Development:				
Low Fuel: HQ In	7871	395	8266	1413.8
HQ Out	7914	579	8493	18.8
High Fuel: HQ In	8184	399	8583	1417.4
HQ Out	8409	586	8995	19.2

(All costs are in millions of 1989 present value dollars) impacts) that arises for the deferral case. The economic results can be used, however, to provide a framework for evaluating these concerns. For the Low Fuel price scenario, for example, we can pose the following question: Do we believe that the environmental impacts associated with 1.4 million acres-years of land use (roughly 47,000 acres per year for 30 years) are worth more than $43 million in direct economic and $184 million in emissions costs savings? If so, we should reject the contract despite these savings. Similarly, we can ask whether Vermont is willing to increase its incremental electric costs by about 2.7% (227/8266) in order to avoid these other impacts.

Results for Efficient Resources

Based on the emissions coefficients and the average abatement costs, it is possible to estimate the emissions costs associated with specific electric resources. Table 4 presents disaggregated emissions costs for a variety of resources. These figures illustrate the significant environmental benefits associated with cogeneration and demand-side management. Note, for example, that the fuel switching programs, which increase emissions at the end use, still have lower emissions costs (per MWH) than a non-cogenerating natural gas combined-cycle facility. Note also how the emissions costs of cogenerating facilities vary significantly depending on the type of steam boilers that are displaced.

The results in Table 4 can be used to make a head-to-head gross emissions comparison of DSM options and various supply resources. They do not, however, give an exact picture of DSM's environmental benefits, since DSM will back down a mix of facilities (e.g., a mix of new gas CC, new distillate CT, and old residual oil steam). In order to capture this effect, we analyzed the overall dispatch of the Vermont system with different amounts of DSM. All DSM programs were found to provide net emissions benefits. Table 5 presents these benefits in levelized cents per kWh, and as percentages of utility avoided costs (which were calculated based on changes in the entire Vermont system). Non-fuel switching programs were found to save from 1.40 to 2.13 cents per kWh of emissions costs, roughly 18% of utility avoided costs. Not surprisingly, fuel switching programs produced lower net savings, both in absolute terms (0.99 to 1.24 cents per kWh) and as a percentage of utility avoided costs (9% to 15%).

CONCLUSION

In this study we have adopted the energy/environment target IRP approach, simultaneously meeting end-use energy requirements and emissions targets. The environmental credits found for DSM indicate that additional DSM investments, beyond those considered in this study, may be effective for achieving even lower cost resource plans that meet both energy needs and the emissions constraints.

Table 4. Emissions Costs for Electric Resources in 1989$/MWH

	--- Natural Gas CC ---			-- Coal AFB --			-- Fuel Switching DSM --			
	Non-Cogen	Cogen 1	Cogen 2	Non-Cogen	Cogen 1	Dist. CT	Water Heat	Commer SH	Resid SH	Other DSM
NO_x	$0.83	$0.40	$0.03	$ 6.98	$ 6.44	$1.48	$0.61	$0.68	$0.43	$0.00
SO_x	0.00	-0.29	-0.95	2.26	1.88	1.00	0.00	0.13	0.13	0.00
CO_2	3.34	2.52	2.39	7.27	6.22	6.40	2.93	2.19	2.29	0.00
TSP	0.00	-0.01	-0.02	0.05	0.04	0.06	0.02	0.01	0.01	0.00
CO	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00
CH_4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N_2O	0.04	0.02	0.01	0.20	0.17	0.15	0.01	0.06	0.02	0.00
Total:	$4.21	$2.65	$1.45	$16.76	$14.75	$9.10	$3.57	$3.26	$2.88	$0.00

As noted in Table 1, the Cogen 1 facilities displace a mix of residual, distillate, and natural gas in industrial boilers, while Cogen 2 displaces only residual oil.

CC = Combined Cycle, AFB = Atmospheric Fluidized Bed, CT = Combustion Turbine

Table 5. Avoided Costs (direct economic and environmental) for DSM (Nichols 1990)

Program	Avoided Utility Costs	Avoided Emissions Costs	Total Avoided Costs	Emissions Cos as a % of Utility Costs
Water Heat Fuel Switching	8.19	1.24	9.43	15%
Resid. ESH Fuel Switching	11.37	1.07	12.44	9%
Commer. ESH Fuel Switching	11.33	0.99	12.32	9%
Non-Fuel Switching	7.73 to 11.72	1.40 to 2.13	9.13 to 13.85	18%

We should reiterate that these cost adders are based on an estimate of average abatement costs. As we discussed above, this is appropriate, insofar as you accept the premise that a "no new net emissions" policy will in fact we applied to the resource plans considered in this analysis. If such a policy of "internalizing" emissions were not carried out, then the costs associated with avoided air emissions could be significantly higher (insofar as the average cost of abatement is likely significantly less than actual damage costs). As a result, the environmental benefits of DSM and cogeneration would appear even larger (using the high cost figures, for example, the environmental costs and benefits in Tables 4 and 5 would appear about 1.5 to 2 times larger).

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