Analyzing the Effect of Including Environmental Externalities in Utility Planning

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Many state public utility commissions have instituted or are developing policies that address environmental externalities. These rules require electric utilities to consider the "externality costs" of environmental emissions as well as traditional economic costs when evaluating resources as part of an integrated resource plan. The added costs will change the mix of "least-cost" supply technologies and make demand side programs more attractive. The policies vary in their level of complexity and the costs assigned to the externalities. One of the more ambitious policies is that of Massachusetts.

This paper describes an analysis that was performed using a national energy computer model (FOSSIL2, currently used by the Department of Energy) to quantify the impacts of a hypothetical adoption of the Massachusetts externality policy nationwide. First, externality costs applied to only new capacity additions are considered. Then the analysis is expanded beyond the Massachusetts' policy to include existing plants as well. The policy's impacts on emissions, U.S. electricity rates, the mix of utility supply technologies, and energy demand and conservation are examined.

The analysis concludes that including externality costs in new resource acquisitions is significant environmental policy, with extension to existing plants having an even greater impact. U.S. emissions of SO_2, NO_X and CO_2 might be 15 to 30 percent lower by the year 2030, but at the cost of 10 to 24 percent higher electricity rates. The higher rates and increased utility DSM programs increase conservation savings, reducing the electricity growth rate by 0.3 percentage points over the 40 year projection period.

Introduction

Consideration of environmental externalities is becoming an increasingly important factor in the selection of new electricity generation capacity. A recent survey showed that 17 state public utility commissions had instituted or are developing rules addressing environmental externalities as of mid-1991[1]. In general, these rules require electric utilities to consider the "externality costs" of environmental emissions as well as traditional economic costs when evaluating resources as part of an integrated resource or least cost plan.

By definition, an externality is a side-effect causing benefit or damages to others, with no corresponding compensation[2]. Since these side effects are outside--or external to--the price of the good or service, they have come to be referred to as *externalities*. The externality concept is well documented in economics literature, which almost always recommends that wherever possible, such externalities be "internalized"--that is, included in the price of the good or service responsible for the side-effect[3]. The "societal cost" is then defined as the sum of the "private costs" that are included by the market and the external costs that are not.

Currently, state public utility commissions have focused on environmental externalities related to power generation. Although commissions often recognize that other externalities, both positive and negative, are associated with electricity production, the tendency has been to focus on stack gases, such as SO_2, NO_x and CO_2, because they are generally thought to be the most significant externalities for fossil-fueled plants.

A variety of alternative approaches are used to include externalities, including qualitative consideration, generic "cost adders" (for example, a percentage credit given to non-combustion technologies), adjustments the utility's profit or return on equity, relative weights used for ranking, and explicit quantification. Five states, California, Nevada, Massachusetts, New York, and Oregon, have adopted this last method where each emission is assigned an externality cost. Generally the externality costs are used only during the selection process for new resources (whether utility or non-utility owned), and are not paid by the new facility. Additionally, some states are considering applying externality costs to existing resources.

Examples of environmental externality cost estimates by various sources applied to a new coal plant are shown in Table 1. Variations of the estimated costs can be extremely large. For example, the higher values of environmental externality costs associated with a coal plant (shown in Table 1) would almost double the cost of producing power used to evaluate new resources. Externality costs also vary a great deal from study to study -- estimating these costs is clearly not an exact science.

Analyzing the Impacts

In this study, a computer simulation model was used to examine the potential impact of the adoption of environmental externalities in utility planning. The model, FOSSIL2, is a national energy model that is used by the Department of Energy as part of the National Energy Strategy (NES). FOSSIL2 is a useful model for examining the consequences of internalizing environmental externality costs because it explicitly simulates investment in new electric capacity, capital stock turnover, and electricity rates. However, because the model operates at a national level, it cannot represent the complexities of individual utility electricity demand load shapes and dispatching. Utilities are assumed to acquire "least-cost" resources, based on life-cycle costs. By changing the relative costs of generation technologies in the planning stage, the environmental cost adders will change the selected mix of new generation resources to those that have higher private costs but lower societal costs. The resulting increased marginal cost will be reflected in retail electricity rates as new capital stock is added and old stock retires. At the same time, future emission levels will fall as capacity shifts to "cleaner" technologies. Higher electricity prices and altered fuel demands for power generation may also produce "ripple effects" through the rest of the energy system, which can be measured by an integrated all-energy model such as FOSSIL2.

The base case chosen for this externality analysis is similar to the "NES Reference Case" -- the base case forecast used for the 1991 National Energy Strategy. The model and the underlying assumptions for the NES case are described in the technical documentation for the National Energy Strategy[4]. Four policies not included in the NES reference case that were included in our base case and which have a significant impact on the externality analysis are the 1990 Clean Air Act Amendments, utility demand side management (DSM) programs, nuclear plant life extensions, and the availability of new nuclear facilities as a resource option. Our base case assumes that utilities invest in customer conservation that is cost-effective up to 60 percent of the utilities' avoided costs, a level chosen to represent the likely average utility DSM investment. To the degree that externalities raise avoided costs, utilities are assumed to invest in more conservation. The majority of nuclear power plants are assumed to be relicensed for an additional 20 years.

The quantified externality costs for SO_2, NO_x and CO_2 from the Massachusetts DPU[5] were used to create the "Externality" scenarios. Although many believe that the

Table 1. Externality Costs for Major Air Pollutants Associated with an NSPS Coal Plant

	Massachusetts (Tellus/ESRG)		NY State		PACE		BPA		California (PG&E)	
Pollutant	Per Ton	¢/kwh[1]	Per Ton	¢/kwh	Per Ton	¢/kwh	Per Ton	¢/kwh[2]	Per Ton	¢/kwh[3]
CO_2	$22	2.44¢	$1.1	0.1¢	$13.60	1.42¢	NA	NA	$26	2.67¢
SO_2	$1500	0.46¢	$832	0.25¢	$4,060	2.44¢	$1500	0.16¢	$4,060	2.44¢
NO_x	$6500	2.01¢	$1832	0.55¢	$1,640	0.5¢[4]	$844	0.24¢	$7,105	2.13¢
TSP	$4000	0.06¢	$333	0.0005¢	$2,380	.036¢	$1540	0.025¢	$2,380	.036¢
Total		4.97¢		0.91¢		4.40¢		0.43¢		7.28¢

1 10,340 BTU/kwh heat rate assumed.
2 BPA June 25, 1991 planning estimates for area west of Cascades, based on heat rate of 10,856 BTU/kwh and low sulfur coal.
3 10,000 Btu/kwh heat rate assumed.
4 Original Pace report lists 0.005 using emission rate of 0.006 lbs/MMBtu. However, NSPS for NOx for almost all coals is one hundred times greater, at 0.6, so this value was adjusted.

Massachusetts values are too high (for example, a recent RCG/Hagler, Bailly report used in testimony for Massachusetts Electric Company supports substantially lower values[6]), California has proposed higher values, even for outside the Los Angeles area. While all states may not follow the Massachusetts example, this analysis examines the impact that these costs might have if they were adopted nationwide. In addition, nuclear power was assessed an externality cost of 2.9 cents per kilowatt-hour, as estimated by PACE University for New York State.[7] This includes costs for routine operations, accidents, and decommissioning costs that are not internalized. In the first externality scenario presented, externality costs are included in the selection of all new capacity after 1992. In the second externality scenario discussed, the policy is extended to existing resources as well. The externality cases measure the potential impact of the policies and illustrate the logical extension of applying such state policies to the nation as a whole. If states adopt lower values for externality costs, the projected impacts on electricity price and technology selection could be less. States that adopt higher values might see a larger impact.

Environmental Externality Costs Increase the Cost of New Capacity

Environmental externality valuations are sometimes called a "shadow tax" because they are applied in evaluating resource options, but are not actually collected as a real tax would be. However, including externalities for evaluation purposes will lead to retail electricity rate increases nevertheless. Internalizing these environmental externality costs shifts the choice of resources to "cleaner" but more expensive technologies--which increases electricity rates to customers.

When the externality costs are added to the private costs associated with building and operating each generation technology, the "least-cost" option of which technology a utility should choose changes. For example, in the year 2000, the lowest life-cycle private cost technology is projected to be atmospheric fluidized bed coal (AFB) at 7.2 cents/kwh (see Table 2). With a 3.5 cents/kwh externality premium, the societal cost of AFB coal generation rises to 10.7 cents/kwh. In this example, a renewable resource, geothermal power at 9.0 cents/kwh, becomes "least-cost." This would lead to an investment whose private cost is 25 percent higher than would have occurred otherwise. For the gas combined cycle option, which is more universally available, the externality penalty would be 1.2 cents/kwh. Its total societal cost would be 9.1 cents/kwh, which is lower than the coal AFB choice. The marginal private cost increase paid by ratepayers associated with a change in selection from coal to gas is 0.6 cents/kwh or a 9 percent increase in this example.

Because FOSSIL2 is a national model, the variation in cost among specific sites and regions is taken into account through the use of cost distributions (by using a logit function for market shares). A "knife-edge" change in technology choice will not occur, with all new capacity shifting from fluidized bed coal to geothermal, for example. Therefore, the increase in marginal cost of the U.S. as a whole reflects a shift in market shares, but does not correspond to the shift between two technologies alone. In addition, technology market shares are not static and are projected to change through time. The capital costs of many new advanced technologies are projected to decline, and gas and oil prices are projected to escalate more rapidly than coal prices. Feedback effects, such as higher gas prices resulting from high gas use or higher renewable costs as the lowest cost resources are depleted, will also raise the projected marginal cost increase due to externalities. The result is an overall increase in the U.S. average levelized cost for new generating capacity due to environmental externalities of roughly 12 percent in 2000 and 21 percent by 2030.

Environmental Externality Costs Lead to a Significant Increase in Electricity Prices

An increase in the cost of new capacity translates into higher electricity rates over time. The amount of the future electric rate increase will be small at first, because only marginal or new resource choices are affected. But over the long term, when a greater percentage of the electricity generation mix reflects technology choices with increased resource costs due to externalities, the "externality tax" could be substantial.

Figure 1 demonstrates this stock turnover effect by showing the projected mix of existing versus new generation capacity. In the base case projections, roughly 35 percent of total capacity in place by 2010 will be new construction. By 2030 the fraction of new capacity will have risen to almost 80 percent of the total. If the Massachusetts values for externality costs were adopted nationwide, the 12 to 21 percent increase in the marginal price of new capacity would result in a 2 percent increase in the average electricity price in 2010 and a 10 percent increase in 2030.

However, there is not a one-to-one correspondence between the percent of new construction and the externality effect on the average electricity price. Figure 2 shows the major components leading to the increase in electricity

Table 2. Year 2000 Technology Costs (1990 Cents/Kwh)

	SO2	NOx	CO2	Total Externality Cost	Economic Cost W/O Ext	Societal Cost W/Ext
Externality Costs						
(dollars/ton)	$1,500	$6,500	$22			
Coal Technologies						
Pulverized Coal	0.46	2.01	2.44	4.91	7.49	12.40
AFB	0.22	0.99	2.30	3.52	7.20	10.72
PFB	0.10	0.57	1.98	2.65	7.72	10.37
IGCC	0.02	0.31	2.18	2.51	8.38	10.89
Gas Technologies						
Combined Cycle	0.00	0.26	1.02	1.29	7.85	9.13
STIG/ISTIG	0.00	0.25	0.98	1.23	8.02	9.25
Fuel Cells	0.00	0.02	0.87	0.89	NA	NA
Nuclear	NA	NA	NA	2.90	8.43	11.33
Renewable Technologies						
Geothermal	0.00	0.00	0.00	0.00	8.99	8.99
Biomass	0.00	0.00	0.00	0.00	9.69	9.69
Solar Thermal	0.00	0.00	0.00	0.00	23.96	23.96
Solar/CT	0.00	0.09	0.37	0.46	10.34	10.90
Photovoltaics	0.00	0.00	0.00	0.00	18.94	18.94
Wind	0.00	0.00	0.00	0.00	10.07	10.17
Wind/CT	0.00	0.11	0.46	0.57	8.95	9.52

Note: All technology costs include transmission.

price. The effect of changing the mix of new capacity additions is very small in the near term. Because energy prices are projected to change over the forecast period, gas technologies, which have higher overall life-cycle costs, have lower costs in the early years of their operation. Therefore a shift to greater gas use due to externalities temporarily lowers the average electricity price in the near term, while causing rate increases in the long term.

Roughly half of the price increase is the result of additional demand side management (DSM) programs. With environmental externality costs included for all supply options, more DSM becomes cost-effective. Even though cost-effective utility conservation programs generally lower a utility's revenue requirements, they can lead to higher prices because fixed costs are recovered from the fewer kilowatt-hours that are sold. In this analysis because utilities were assumed to invest up to only 60 percent of the utility avoided cost for conservation, externality cost adders lead to additional conservation investments that are still below the utility avoided costs without externalities included. Therefore the additional conservation investments reduce customer energy service costs, even though they lead to increased rates. However, by 2030 the additional cost of supply offsets the DSM effect, and energy service costs increase. If utilities were assumed to be already paying 100 percent of avoided cost, then energy service costs, as well as rates, would increase with the internalization of externalities. The cost of utility conservation programs is assumed to be recovered through the rate base and applied

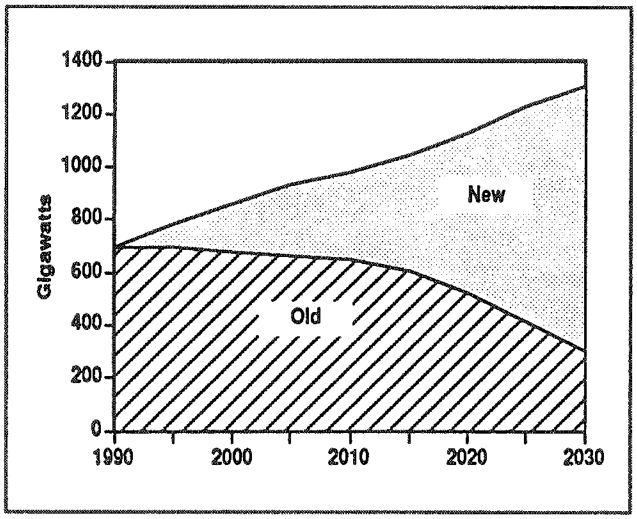

Figure 1. Total Capacity

to all customers. If DSM costs were expensed, the price effect would be larger in the near term, while smaller in the long term.

An additional, but small, effect leading to higher electricity rates is higher gas prices that result from higher gas demand. The base case price projection is very similar to the DOE NES reference case, because most of the underlying assumptions are the same. The natural gas price delivered to electric utilities is projected to escalate form $2.23 per million Btu in 1990 to $ 6.30 per MMBtu in 2010 to $8.91 per MMBtu in 2030. In this externality scenario, greater generation of electricity from natural gas

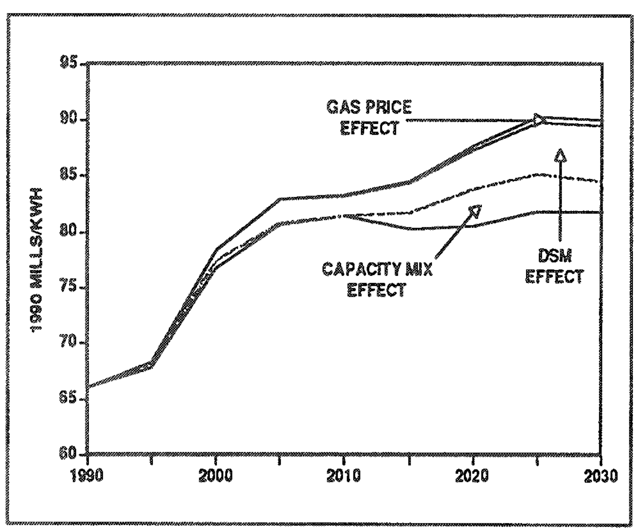

Figure 2. Components of Average Utility Price Between Base and Externality Case

creates more upward pressure on the gas price, given the same assumption about gas supplies and drilling costs, and the gas price is projected to increase to $9.54 per MMBtu in 2030.

The gradual nature of the electricity price increase and small near term effect could be part of the reason that this policy appears attractive politically. In addition, the externality values assigned in terms of dollars per ton of pollutant are likely not have much meaning to ratepayers. Only when translated into electricity prices and monthly energy bills can the public, as ratepayers and citizens, determine whether the cost of environmental control is worthwhile. In general, consumers have determined that any price increase is generally unacceptable or at least hard fought. For example, there have been debates over whether a rate penalty is acceptable for increased DSM programs, and if so, what level of rate increase is tolerable. For another comparison, the recently-passed Clean Air Act Amendments are expected to increase electric rates by 1 to 2 percent over the next 10 to 20 years, for the U.S. as a whole.[8] Of course, these price impacts vary greatly by region, with some seeing much higher increases. On average the effect of environmental externality policies on rates could be much greater than DSM programs or the Clean Air Act, and the magnitude of the effect also will likely vary by region.

Externality Costs Increase Utility DSM Investments

The demand for electricity is reduced when externality costs are applied to new capacity additions, as a result of both higher electricity prices and larger utility DSM programs. The growth rate of demand for the first 20 year period is projected to be 1.5 percent per year with externalities versus 1.9 percent in the base case. The long term rate from 2010 to 2030 is projected to be 1.6 percent compared to 1.7 percent. By 2030 total demand is projected to be reduced by 580 billion kilowatt-hours or 10 percent. Because the base case assumes that all utilities adopt DSM programs that pay up to 60 percent of their avoided costs for conservation, the incremental effect of the externality costs is simply to make more conservation cost-effective. If an externality policy were to encourage utilities to consider conservation programs that would not have otherwise implemented any, then the impact of the externality policy on electricity demand would be greater.

Externalities Significantly Change the Mix of New Supply Side Resources

If externality values such as those currently in use in Massachusetts were adopted nationwide, the fuel mix of new capacity additions would likely change dramatically. Because coal-fired generation has the highest CO_2 emissions per kilowatt-hour of electricity generated, coal is particularly sensitive to the estimate of CO_2 externality costs, and coal additions would be markedly reduced. Renewable capacity additions would be increased greatly, and natural gas-fired generation additions increased moderately as compared to the base case, as shown in Figure 3. Nuclear power fares slightly worse due to the 2.9 cents per kilowatt-hour externality assessment. The projected increase in fuel mix towards renewables is primarily for wind and solar thermal and, to a lesser extent, geothermal and biomass. This shift in capacity reflects the imposition of high externality costs on emissions of carbon dioxide, which affects all fossil fuel generation options, and SO_2, which primarily affects coal-fired generation. However, even with externality costs, market share for coal is projected to increase at the end of the 40-year period due to rising natural gas prices and the prior development of most of the cost-effective renewable resources.

This change in new capacity additions would affect future installed generating capacity, as shown in Figure 4. The fuel mix shift projected for new capacity is reflected in total generating capacity, but is diluted by the existing stock. Coal capacity is projected to increase from current levels but more slowly than total projected stock. Some of the new coal capacity in the base and externality cases scenarios results from conversions of natural gas combined cycles plants to coal gasification (IGCC). Renewable capacity in 2030 is projected to be about 180 GW greater in the externality case compared to the base case, and oil/gas capacity is higher by about 40 GW. In 2030 the renewables capacity in the externality case is comprised of roughly 70 GW solar thermal, 85 GW wind, 10 GW photovoltaics, 120 GW hydro and pumped storage, 40 GW geothermal, and 35 GW of biomass/waste. The investment in additional DSM programs and an increase in electricity rates due to externality policy is projected to reduce the demand for electricity and therefore the need for new generation capacity. Total capacity is projected to be roughly 130 GW or 10 percent lower by 2030 than in the Base Case.

The projected impact of considering environmental externalities on future electricity generation, as shown in Figure 5, is not exactly the same as that on capacity, but a similar shift of fuels occurs. For example, generation from oil and gas is projected to increase more than does oil and gas capacity because more gas capacity is constructed as baseload. In addition, because many of the renewable energy sources (solar and wind) are intermittent with correspondingly low capacity factors, gas turbines are used for backup power for some technologies. The low capacity factors of renewables also mean they contribute a smaller share of generation than of capacity.

The projected impact of environmental externality cost adders on the fuel and technology mix of future electricity capacity and generation is large--much larger than expected from the recently-passed Clean Air Act Amendments. For example, EIA projects a shift of only 3 GW away from coal in new capacity additions by 2010

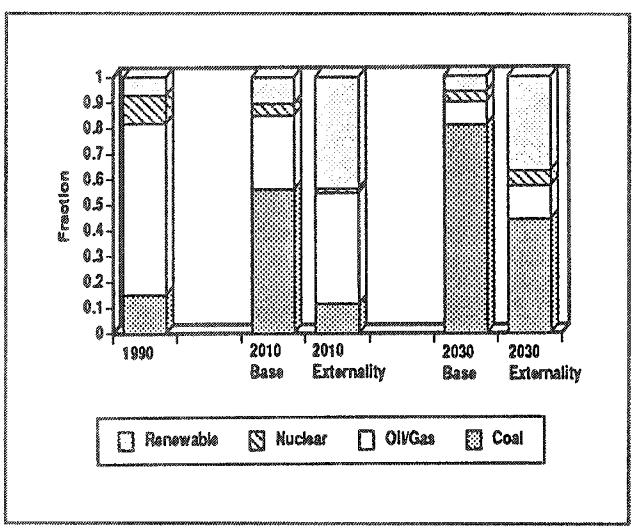

Figure 3. New Capacity Market Share: Base and Externality Cases

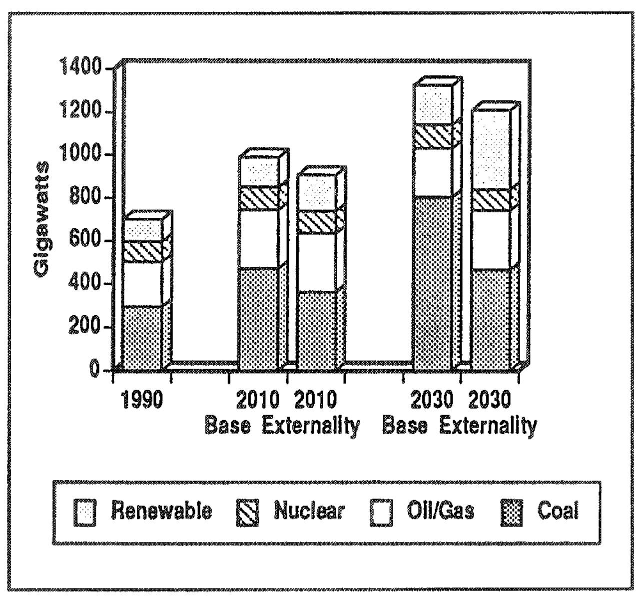

Figure 4. Total Capacity: Base and Externality Cases

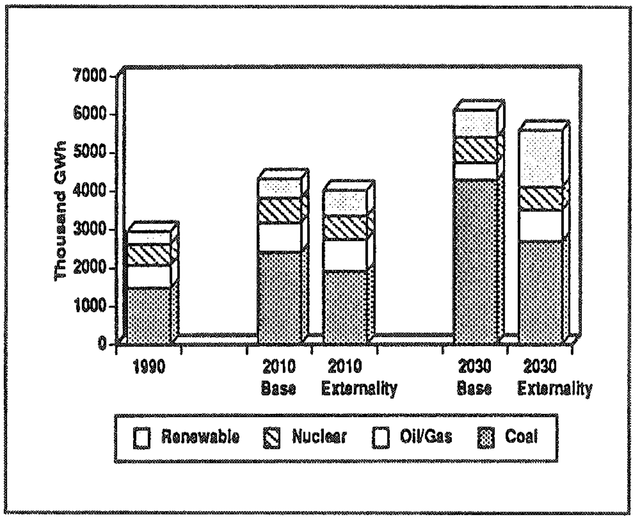

Figure 5. Electricity Production: Base and Externality Cases

due to the Clean Air Act, most of which goes to gas.[9] The shift to renewables projected in this analysis to result from the consideration of externalities would be unprecedented.[10]

Adding Externality Costs to Planning Reduces SO_2 and NO_x in the Long Term, But Not in the Near Term

The implicit purpose of accounting for environmental externalities is to reduce overall air emissions. However, an externalities policy that affects only new sources (while leaving existing sources unaffected) is effective in reducing emissions only in the long term. As shown in Table 3, accounting for environmental externalities (using Massachusetts' cost estimates) for new plants would not significantly reduce future SO_2 and NO_x emissions in the near term. Emissions from new plants are already controlled at low levels, and incorporating external environmental costs does not make a significant difference in overall air emissions for a while. However, a significant reduction might occur in the long term, when the mix of capacity has been altered. Because of this large, long term impact, externality costing should be considered major environmental policy.

For SO_2, there is virtually no change in emissions projected in 2010 and a 2.3 million ton utility reduction projected in 2030. This assumes that there will not be a shift to higher sulfur coal or lower removal rates by scrubbers in existing plants when the 8.9 million ton ceiling on SO_2 allowances created by the Clean Air Act Amendments is no longer binding. The Clean Air Act Amendment passed in 1990 internalizes SO_2 externalities for new power plants. It does this by requiring all plants to have an "allowance" for each ton of SO_2 emitted (after the year 2000). An allowance is an SO_2 offset--new projects that emit SO_2 have the choice of how much SO_2 to remove at the plant through technology choices (for example scrubbers, fluidized beds, or low-sulfur coal) versus how much to purchase reductions made at someone else's plant (an allowance). The combination of the two must reduce the net SO_2 emissions from the new plant to zero. Therefore after the year 2000, it is unnecessary (and unfair) to attribute an externality cost for SO_2 to a new power plant which must comply with the 1990 Clean Air Act Amendment, unless there is a significant regional pollution problem. A policy such as that in Massachusetts double-counts the SO_2 externality costs of the plant, which have already been internalized.[11] Contrary to the assumptions of this analysis, emission levels might reach an equilibrium at the capped level even with externality costs (implying no further reductions from externalities). On the other hand, if the externality cost assigned to SO_2 is much higher than the cost of reducing SO_2 emissions (which is likely to be the case with the Massachusetts values), developers of coal fired power projects may choose to continue reducing emissions beyond what the new Clean Air Act requires, in order to minimize the externality penalty assigned to them. How older plants react to reduced demand for allowances will be the key to whether total SO_2 emissions are reduced beyond the 8.9 million ton cap.

Utility Carbon Dioxide Emissions Would Be Significantly Reduced But the U.S. Would Not Achieve Carbon Stabilization

The biggest reduction in emissions is projected for carbon dioxide. There are at this time no government regulations that directly control the level of CO_2 emissions. Accounting for CO_2 "externalities" would therefore in effect be the first attempt to regulate CO_2 emissions. As mentioned earlier, the externality cost assigned to CO_2 by Massachusetts is large--it might add 30 percent to the planning cost of a coal-fired plant and 15 percent to a gas combined cycle plant, in 2000 for example. Implementing an externalities policy would shift investment in new power plants away from fossil fuels and toward sources without CO_2, such as conservation or renewables. Because nuclear plants are assessed 2.9 cents per kilowatt-hour externality cost, nuclear power does not contribute to this shift. Table 3 shows that this shift in resource investments could reduce CO_2 emissions from power plants by roughly 350 million tons of carbon dioxide per year or 30 percent by 2030, which is significantly larger than the 10 percent electricity demand reduction. The decline in total

Table 3. Emission Reductions Relative to the Base Case

	SO2		NOx		CO2	
	2010	2030	2010	2030	2010	2030
Million Tons/Year						
Electricity Generation	0.2	2.3	0.6	2.6	165.0	349.9
Total U.S.	0.2	2.2	0.6	2.5	157.3	329.0
Percent						
Electricity Generation	2.3%	26.8%	9.3%	34.6%	15.3%	32.2%
Total U.S.	1.1%	13.1%	3.4%	11.2%	6.0%	14.5%

U.S. emissions in tons is slightly smaller than the utility reduction because of offsetting projected increases in emissions from direct energy consumption. In addition because utilities are projected to account for less than half of U.S. emissions in 2030, the percentage reduction is much smaller for the U.S. as a whole, 15 percent. In this projection, total U.S. carbon emissions still rise roughly 50 percent from current levels by 2030 (compared to over a 75 percent rise without an externality policy). The emission reductions are gradual, since they occur as new "cleaner" technologies make up more of the total generation capacity and additional conservation is implemented.

Applying Externality Costs to Existing Plants Creates a Larger Near Term Impact

The application of externality costs to only new construction decisions is projected to have a limited impact over the next 20 years in terms of electricity price increases, total capacity fuel mix, or emissions. In part this is because utilities currently plan to life-extend much of their older existing capacity which reduces the need for new capacity. If externality cost adders are applied to life-extension decisions under integrated resource planning, there could be a more significant near term impact. The Massachusetts' externality cost estimates are high enough to make most coal life-extensions more costly on a societal cost basis than building new non-coal-fired capacity. However, life-extensions for most oil/gas plants and relicensing of nuclear plants remain cost-effective. As a result of the additional application of externality costs and therefore not extending the older coal plants, more new capacity would be constructed over the next two decades.

The next logical step is to apply externality costs to existing capacity by adding these costs to dispatching decisions. Once many of the older and dirtier coal plants have retired through reducing life-extensions, this may not have a significant impact. However, because the model used to test this policy is national in scope and does not have a detailed dispatching sector, the results can be only approximate. The focus of the dispatch decision is the relative mix of oil and gas versus coal generation. Additional demand-side management as a dispatching response was not considered. Due to the regional concentrations of coal and oil/gas plants, the potential for altering the generation mix on a national level is limited. In addition, over the long term with relatively high gas prices projected after 2010, environmental dispatch is likely to have little effect because coal plants are projected to be cheaper to operate even when externality costs are included. Compared with the decision to build new coal plants, coal operating costs remain more competitive with gas even with externalities because coal's most expensive component is the initial capital investment.

The average electricity price increase resulting from externalities would be more immediate and much larger in the near term if the policy affects existing plants, as seen in Figure 6. The average electric rate is projected to be 17 percent higher in 2000 as a result of eliminating most coal life-extensions and creating a greater need for new construction in the near term. At the same time the new additions are more expensive due to the selection of resources including externality costs. When environmental cost dispatching is adopted as well, the price might be even 6 percent higher or 24 percent above the base case. However, by 2030 prices are essentially the same as when externality costs are applied only to new resources.

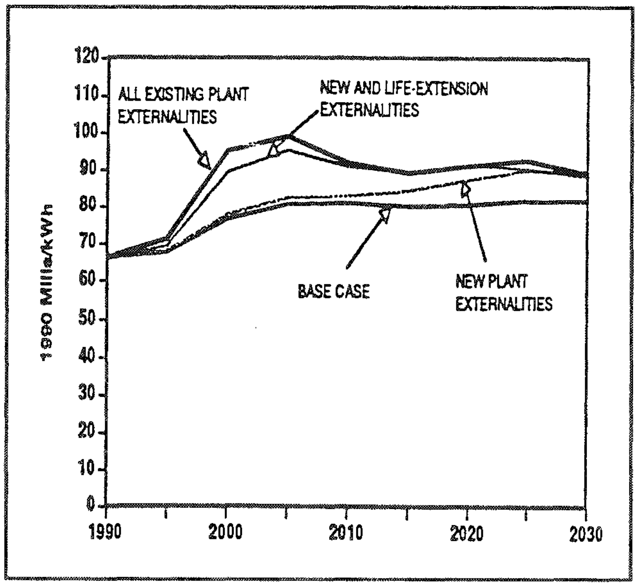

Figure 6. Average Electricity Price

Extending the externality policy to existing plants leads to a further reduction in the demand for electricity in the near term. The growth rate from 1990 to 2010 might be only 1.2 percent per year. The increased conservation is the result of higher electricity rates, not utility DSM programs because the avoided cost remains essentially the same.

The changes in capacity and generation mix resulting from the application of externality costs to existing facilities are also greatest in the near term. With externality costs applied to life-extensions, in the year 2000 projected coal capacity is 130 GW lower, oil and gas capacity 90 GW higher, and renewables 30 GW higher than when externalities are applied only to new construction decisions. By 2030, when life-extended plants would have retired in any case, the capacity mix is similar to the new resource externality case. The addition of an environmental cost dispatching policy primarily affects the generation mix in 2000. Generation from coal capacity might be reduced by 30 percent, oil/gas generation might be increased by 8 percent, and renewables increase by 7 percent compared to applying externalities to just new capacity and life-extensions. Total generation is projected to be 3 percent lower overall due to higher electricity rates. The long term generation differences are minimal.

The projected emissions mirror the capacity and generation changes. U.S. carbon dioxide emissions would be reduced 16 percent below the base case in 2000 compared to only a 3 percent reduction when externalities are only applied to new capacity additions. Although in 2000 this would mean emissions would be 6 percent below current levels, emissions would still rise after the year 2000 and reductions would be roughly equivalent to those from the new plant only externality policy case by 2030 (see Figure 7). SO_2 and NO_x emissions would also be lower in the near term, if externalities were applied to existing capacity (by 28 percent and 20 percent respectively in 2000).

Conclusion

Accounting for environmental externalities in utility resource planning could have a major impact on the future fuel and technology mix of generating capacity and on the price of electricity. For example, the impact of externalities cost adders could be significantly greater than that estimated to result from the 1990 Clean Air Act Amendments, if all states followed Massachusetts' lead. The Clean Air Act Amendments enacted after years of analytical and political scrutiny, are estimated to increase the overall average price of electricity by a few percent on average. This analysis suggests that the effect of externality costs (as valued in Massachusetts) could cause electricity rates to rise on average roughly 10 to 24 percent, depending on whether the policy is applied to only new plants or all plants. Investments in new generating capacity would shift dramatically away from coal and towards conservation and renewables. As a result, total emissions would be reduced significantly over the long term, although not necessarily in the short term. Clearly, accounting for externalities is a major policy decision that requires serious scrutiny before it is widely adopted.

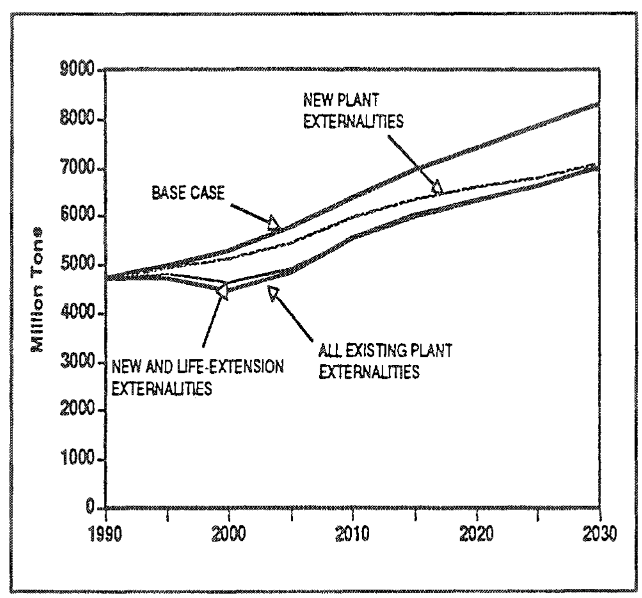

Figure 7. U.S. Carbon Dioxide Emissions

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Endnotes

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8. Burkhardt, David A. *Acid Rain: What the Final Bill Looks Like*, (Public Utilities Fortnightly, December 6, 1990).

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10. This projected reliance on renewables is highly dependent on assumptions about the resource size and cost of renewable technologies. If the assumptions of improving renewable technologies used in this analysis prove to be wrong, there is likely to be greater reliance on gas-fired technologies.

11. Hutchinson, Mark A. "Emissions Caps, Externalities, and Double Counting: Why Certain Externalities should Not Be Included in New Resource Planning," *DSM and the Global Environment*, April 1991. Note that the Massachusett's policy was enacted prior to the passage of the Clean Air Act Amendments.