

# CARBON IMPACTS ON OPTIMAL CAPACITY MIX AND GENERATION MIX UNDER VARIOUS POLICY INTERVENTIONS

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### Introduction

The Kyoto protocols, signed in 1997, represent a remarkable coalescence of world powers in the conviction that global warming impacts are a sufficient long-term threat to merit significant near-term adjustments to business as usual (BAU) development scenarios. It is even more amazing that each of the signatories agreed to a quantitative target to be achieved in the 2008 – 2012 period. Although the U.S. commitment remains subject to substantial controversy and still has not been ratified, we have signed an agreement to reduce carbon emissions to a level that is 7.0 percent below 1990 levels in the 2008 – 2012 period.

The 2000 Annual Energy Outlook (AEO2K) by U.S. DOE estimates that total carbon emissions for the U.S. in 2000 will be 1,552 million metric tons compared to the 1,250 million metric tons that will comply with the Kyoto commitment. Ignoring cogeneration, the electric utility sector accounts for approximately 36.5 to 40.5<sup>1</sup> percent of the 1,552 million metric tons. In the AEO2K reference forecast, the average U.S. emissions for 2008 - 2012 will be 1,786 million metric tons of carbon or about 43.0 percent above the agreed limit. Given the difficulty of controlling widespread consumer discretion in the transport sector, it is highly likely that major adjustments will be required in the electric utility sector if the Kyoto target for the U.S. is to be met. It would not be unrealistic to expect that one-half of the adjustment might be required from the electric utilities. Based on DOE forecasts, that would require the electric utility sector to reduce annual carbon emissions by 268 million metric tons<sup>2</sup> in the 2008 – 2012 period.

Estimates of the costs to comply with Kyoto commitments vary dramatically depending on the assumptions made about emissions trading, both within and between countries, and on widely divergent views about the potential for demand versus supply side adjustments. A recent DOE study<sup>3</sup> indicates that carbon prices of more than \$300 per metric ton will be required to achieve the 7.0 percent reduction pledged by the U.S. If that were true, the total cost to the electric utility sector would be in the range of \$80 billion per year. To provide a benchmark for this figure, note that the total revenues for all U.S. investor owned utilities is about \$220 billion per year.

While it is easy to contest any estimate of the direct monetary impact on U.S. electric utilities, it is undeniable that achieving Kyoto targets will require substantial and costly adjustment from this sector. While many countries in Europe have been actively developing strategies for Kyoto compliance, we have not seen a similar sense of urgency among our U.S. utility clients. Many

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<sup>1</sup> The lower figure corresponds to carbon emission factors used by DOE for AEO2K. The higher figure corresponds to emission factors commonly used for Europe.

<sup>2</sup> Note that this corresponds to 983 million metric tons of CO<sub>2</sub>.

<sup>3</sup> U.S. Department of Energy, Energy Information Administration, Office of Integrated Analysis and Forecasting, *Analysis of the Impacts of an Early Start for Compliance with the Kyoto Protocol*, SR/OIAF/99-02 (Washington D.C., July 1999).

assert that the absence of U.S. ratification and of any established policy is sufficient cause to defer active carbon reduction program evaluations. Kyoto requires both compliance by 2008 - 2012 and demonstrable progress on reductions by 2005. This paper argues that it is not premature for U.S. utilities to actively explore the impacts of carbon policy on the value of their assets and on their competitive positions. We routinely recommend that no serious long-term asset sales or acquisitions be made without awareness of the possible impacts of carbon on the values being established for generating assets.

For those that already have an active interest in carbon, this paper addresses the following key questions that will determine how various carbon policies could impact them:

1. What types of carbon transactions are being completed at this time?
2. How are carbon prices being set today for the transactions that are occurring?
3. What are the key differences between carbon taxes, carbon permits and carbon credits in terms of their impacts on electric utilities?
4. How would various market interventions influence the capacity mix selected by utilities?
5. How would various market interventions influence the annual generation mix for utilities?
6. What recommendations can be offered to utilities wishing to develop a strategic position on carbon issues?

The analysis for this paper is intentionally based on simple screening models to keep the results transparent and to focus on policy rather than operational questions. More detailed models are used for specific evaluations but the models used here are sufficient to explore the questions targeted in this paper.

### **“It’s Too Soon to Worry About Carbon”**

The recent DOE study<sup>4</sup> that evaluates the reduction in economic impacts from an early start on carbon compliance shows that it is not too early from a public policy perspective to establish the mechanisms that will allow the U.S. to adhere to its Kyoto commitment. In fact, the DOE study finds that costs of compliance will be significantly lower if we start early on the needed adjustments.

The focus of this paper, however, is on U.S. electric utilities. To enter the inevitable debate on U.S. carbon policy, it is useful, if not essential, to be aware of the mechanisms now being actively promoted and used to transform market decisions toward carbon-friendly technologies.

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<sup>4</sup> Ibid.

Perhaps the best known of the existing agencies focusing on climate change is the Global Environmental Facility (GEF) that uses the World Bank and the United Nations Development Program (UNDP) for project identification, preparation, and implementation. GEF is funded by governments and provides grant support that is carefully designed to induce developers to select projects that reduce carbon emissions compared to a baseline project, which is expected to occur without such supports. The incremental economic costs of the proposed project compared to the baseline is an important, though not absolute, determinant of the amount of grant support that can be given to any specific project. Unit abatement costs (UACs) represent the present value of the incremental costs per ton of CO<sub>2</sub> or carbon reduction over the life cycle of the project. Projects with the lowest and most certain UACs have the best prospects of receiving funding. In general, the size of the grant is intended to equal the incremental cost of the proposed project. More liberal support can be provided for projects that remove barriers to future adoption of carbon-friendly technologies and/or that have exemplary replication potential.

I have been working with the World Bank for several years on identification and preparation of projects that can qualify for some financing from GEF based on carbon reductions. Table 1 provides a sampling of some of the project locations and technologies being evaluated.

**Table 1 Representative Carbon Projects**

<b>Country</b>	<b>Technologies</b>	<b>Grant/Investment (MUSD)</b>
<b>Czech Republic</b>	Geothermal	\$0.5/\$4.0
	Waste Heat Cogeneration	\$5.8/\$22.0
	IGCC – Lignite	\$25.0/\$150.0
	Energy Efficiency	\$9.0/\$45.0
<b>Slovak Republic</b>	Industrial Cogeneration	\$2.2/\$18.9
	Geothermal	\$0.4/\$5.1
	Geothermal District Heat	Very Large Project TBD
<b>Poland</b>	Biomass	\$0.4/\$2.7
	Geothermal District Heat	\$5.0/\$100.0
	Geothermal	\$2.5/\$6.5
<b>Hungary</b>	Biomass	\$2.2/\$24.2
	Small Hydro	\$0.2/\$1.1
<b>Kazakhstan</b>	Large Hydro	TBD/\$100.0
	Wind	TBD
<b>Russia</b>	Gas Flaring	TBD
	Wind	TBD
	Biomass	TBD
<b>Slovenia</b>	Biomass Revolving Fund	TBD
	Energy Efficiency	TBD

Although variations are considerable, one can usefully characterize the GEF program as a grant-based program that provides support equal to 15 to 25% of investment costs for projects that offer low cost, highly probable carbon reductions.

The primary difficulty for GEF is the scarcity of available funds relative to the total need to accomplish Kyoto commitments. Both fund limitations and administrative burdens suggest that GEF can only play a small, though very beneficial role in making climate change happen. In large part, GEF money can be thought of as *seed funding* that would be difficult to raise from purely commercial sources.

The second World Bank program has a different focus than GEF. The Prototype Carbon Fund (PCF) was founded in the belief that global carbon markets are both the most efficient and most probable way of mobilizing sufficient funds to finance the additional costs of energy supplies with less carbon emissions. For a market in carbon credits to materialize, two preconditions are essential. First, binding commitments must be established for reductions by country. This was achieved at Kyoto in late 1997. Second, internationally acceptable verification procedures must be established so that marketable instruments can be created and traded. The PCF has been funded by a blend of private and public investments with the primary mission of demonstrating how a carbon market can work. Unlike GEF, PCF will actually purchase carbon reductions and take ownership of the credits. Successful operation of the PCF in the carbon pre-market is expected to facilitate formation of a long-term market with virtually unlimited funding for profitable trading of carbon derivatives. The equilibrium price in this market will be paid for all transactions regardless of the incremental cost of the reductions achieved – also in sharp contrast to GEF procedures. Because of potential conflicts between GEF and PCF, GEF has been given right of first refusal on all projects brought to the Bank.

Beyond these international programs that are funneled through the World Bank and UNDP, there are numerous bilateral initiatives. Activities implemented jointly (AIJ) is a popular focus in Europe.<sup>5</sup> Without formal establishment of an international market, countries with high UACs can choose to buy credits from specific projects in other countries where the costs of compliance are much lower. The European Union has commissioned a multi-million dollar study by a consortium of consultants to assess the potential and mechanics of AIJ.

The Dutch have also been working intensively on development of a tendering process (ERUPT) whereby they will openly accept bids for emission reduction units (ERUS) to be delivered in the 2008 – 2012 period. Since the Netherlands is so completely reliant on gas for their energy supplies, carbon reductions there will be quite expensive, hence their interest in discovery through tenders of cost-effective purchases from other sources.

In summary, there are a variety of approaches being tried and applied with substantially different intents and methods. This classroom of experience can be valuable to those wishing to develop a well-reasoned position on carbon issues and policy.

### **What Will Carbon Prices Be?**

Many in the electric utility business feel that their response to new carbon mandates will be immediately clear as soon as the Kyoto protocols are translated to carbon prices. Economic dispatch and optimal capacity mix problems can then be easily solved with existing tools, for this

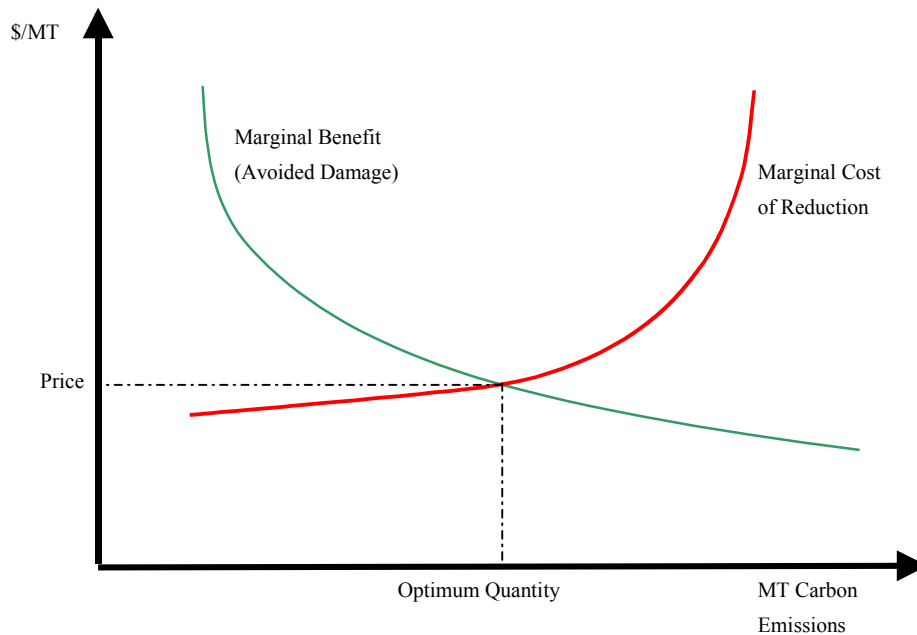
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<sup>5</sup> Some U.S. utilities have experimented with AIJ projects. Wisconsin Electric, for example, invested a small amount in a project in Decin, Czech Republic on an AIJ basis.

merely represents a change in the relative price of fuels. Experience with the various market interventions that are actively being explored suggests that this is an oversimplification. Nevertheless, it is important to consider the alternative prices being considered and the methods used to estimate such prices. It is also important to recognize that carbon prices might be manifested in the form of carbon taxes or in the form of the prices for tradable carbon allowances, much like the existing markets for SO<sub>2</sub> credits.

There are two basic approaches to establishing the value of carbon reductions. Economists have been active over the last decade in trying to estimate the complex linkages among emissions, concentrations, temperature changes, and economic damages associated with such temperature changes. Once economic damages can be reasonably estimated, the optimum world level of emissions can be determined using conventional cost/benefit logic. The equilibrium prices and quantities of carbon emissions would be determined by increasing carbon reductions to the point at which marginal costs and marginal benefits (damage reductions) are equated. Figure 1 illustrates this conceptual solution. Given the difficulty of accurately assessing damage from sea level changes, land use changes, human displacement, ecosystem losses, etc. over a very long horizon, it is not surprising that estimated benefits from given carbon reductions vary widely. Fankhauser (1995) provides a very useful summary and the probabilistic ranges presented in Table 2.

**Figure 1 World Economic Optimum Emissions**



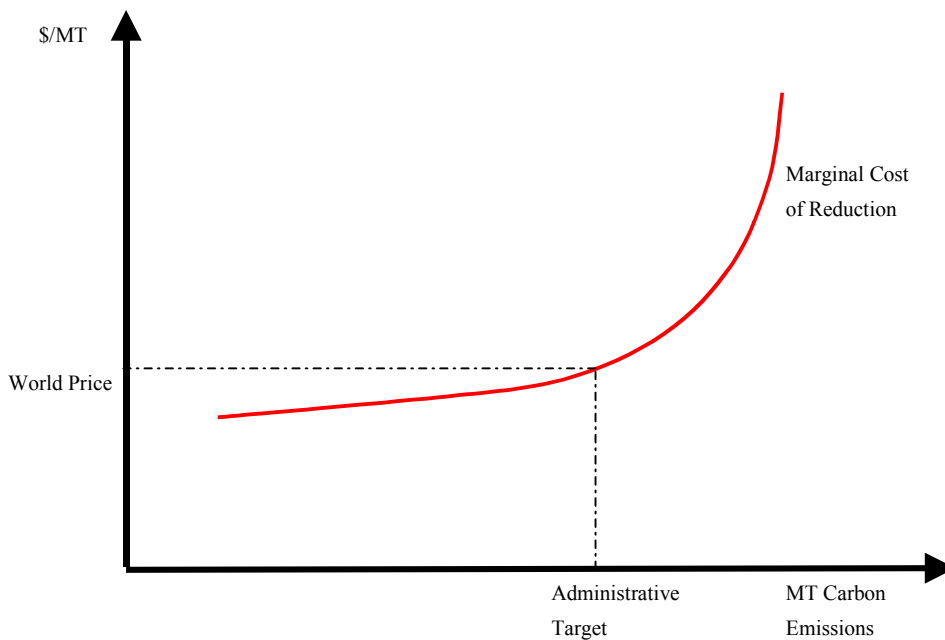
**Table 2 Marginal Social Costs of Carbon Emissions (\$/MT C)**

Period	2001 – 2010	2011 – 2020	2021 – 2030
Mean	\$22.8	\$25.3	\$27.8
5 <sup>th</sup> Percentile	\$7.4	\$8.3	\$9.2
95 <sup>th</sup> Percentile	\$52.9	\$58.4	\$64.2
Standard Devtn	\$16.0	\$17.5	\$19.0

These costs can be thought of as differences between the present worth of an emissions stream of X MT of carbon and a second stream of X+1 MT of carbon over a long future horizon. The values increase over time primarily because of expected growth in world population and incomes. The range of \$7.4 to \$52.9 per MT for the current period testifies to the inherent uncertainty of such estimates. Nevertheless, figures near the mean estimates have been adopted as policy guides by agencies actively supporting carbon reduction projects. GEF and PCF, for example, have a general guideline of \$10 to \$20 per ton of carbon as the line of demarcation for low-cost carbon reductions. They have been willing to give grants and purchase emission credits at prices in this range.

The second approach to valuing carbon reductions is more pragmatic and avoids the difficult task of assessing the benefits of carbon reductions. The cost curve from Figure 1 is still required. In principle, this curve represents a rank ordering of all possible carbon reduction projects in the world. This curve is coupled with an administratively determined emissions level to determine the world price of carbon emissions, as shown in Figure 2. This solution is exactly what has been implemented by the Kyoto agreements which set emission limits for each signatory for the 2008 – 2012 period and thus effectively for the world.

**Figure 2 Administrative Carbon Pricing**



Juxtaposing the \$300 per ton DOE estimate and the roughly \$25 per ton benefit estimates, one might wonder if the Kyoto targets have been set below the economic optimum quantities. In fact, the DOE estimates represent the marginal cost of compliance IF the U.S. were to comply solely through domestic adjustments. That is, they do not assume that the U.S. would purchase lower-cost credits from countries where carbon reductions can be made more cost effectively. Russia, for example, has huge emission credits available at very low cost largely because of the economic collapse that occurred since the benchmark year of 1990.

The effective conclusions that we can usefully draw from this pricing discussion include:

- The DOE estimates of restricted domestic cost of compliance with the Kyoto agreements are dramatically higher than the best available estimates of the benefits from reduced emissions.
- The DOE estimates would involve financial impacts of an unacceptable magnitude for U.S. electric utilities.
- U.S. compliance with Kyoto will then require acquisition of carbon credits abroad through trading mechanisms or through AIJ projects.
- It is not unreasonable to consider a price of \$20 per MT of carbon emissions in planning near-term generation capacity additions<sup>6</sup>. For illustrative purposes in this paper, this carbon price is assumed.

### **Carbon Taxes, Permits and Credits**

There is no way to reasonably anticipate how the U.S. may choose to deliver the committed quantities of carbon credits if and when the agreement is ratified. Three concepts have sufficient precedent, however, to warrant consideration. Carbon taxes are being used in Europe and are commonly discussed in the U.S. as corrective policy tools for markets that fail to recognize the environmental externalities associated with combustion of fossil fuels. The intent would be to intervene in fuel markets through carbon taxes to the extent necessary to induce the amount of efficiency improvements and fuel switching needed to reduce carbon emissions by the desired amount. Since this intervention is not envisaged as a source of public sector revenue generation, most proposals call for a return of carbon tax revenues to the general public through lump sum rebates of personal income taxes or through reductions in social security taxes.

Carbon permits could be patterned after the SO<sub>2</sub> permit trading program, which has been widely heralded as an example of enlightened environmental regulation. Utilities would each be given allowances for so many tons of CO<sub>2</sub> emissions per year. Any utility wishing to exceed their allowance could only do so through purchase of permits from other sources. Given the global nature of climate change concerns, this program would most likely operate on an international basis. Assuming that both carbon taxes and carbon permits would reflect a common world

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<sup>6</sup> For a coal plant with a heat rate of 10,500 BTU/kWh and coal at \$1.15 per MMBTU, this carbon price would mean an increase of 49% in fuel costs per kWh.

carbon price, there would be little difference in economic incentives for the tax and the permit programs. In one case, excess emissions would require payment of taxes while in the other case, excess emissions would require purchase of permits at the same cost. The PCF, discussed above, is attempting to demonstrate the practicality of a world market in carbon credits.

Carbon credits or *carrots* also have well-established precedents in the history of U.S. environmental policy. Much of the mandated improvements in water quality were accompanied by Federal cost sharing up to a certain percent of total project investment costs. The GEF approach in which they have been willing to give grants to projects equal to the incremental economic cost of clean projects compared to the most probable baseline is a useful model for carrot interventions.

All three of these measures can be made to look alike through creative design. In practice, however, they commonly differ in the following ways:

- Grants or credits are often paid up front at the time that a project is being developed and are equal to the present worth of cost increments that may occur over the life cycle of the project. Taxes and purchases or sales of carbon permits, however, tend to align monetary transfers with delivery of reductions and may even come after the reduction has been achieved and verified.
- Taxes or permit prices are likely to be set by policy or in national or international auctions that will yield a single carbon price applicable to all transactions for a given time period. The single price applies to all projects regardless of the specific costs of achieving the carbon reduction. GEF, in contrast, commits to give grants equal to no more than the incremental cost of a specific project. Thus, the dollar per ton figure can vary widely across projects.

It is useful to consider two classes of carbon reduction projects that involve higher than baseline costs but lower than baseline carbon emissions. In the first instance, the investment costs of the proposed project would exceed those of the baseline project but the annual fuel and operating costs would be lower. Renewable energy and energy efficiency projects are good examples. In the second class, proposed investment costs are lower but operating costs are higher than for the baseline. Installations of gas-fired boilers rather than compliant coal boilers for district heating systems are good examples of this class.

For the first class, the incentive should be paid up front when the higher cost investment is being made to assure that the desired system is installed. For the second class, taxes or permits may be better aligned with the operating cost variances. Failure to properly align incentives with cost variances requires the project developer to use precious financing to align resources with need. While this can often be done, there is some peril that the right project will be built but not operated properly or vice versa due to discrepancies between disbursements and applications of funds.

## **Carbon Policy Impacts on Electric Utilities**

A paper of this length and scope cannot adequately assess all dimensions of carbon policy in the huge U.S. electric utility sector. The more modest objective of illustrating methods of assessment and estimating some quantitative benchmarks is, however, useful and attainable.

Simple and well-known screening models have been applied to a hypothetical greenfield utility for my illustrations. Greenfield in this context means that no existing capacity is assumed. Therefore, all needed capacity to meet load and reserve requirements is to be acquired at new investment costs over the twenty-year period of analysis. Capacity is treated as fungible, which can be rationalized in one of two ways. If a utility were building this capacity, our assumptions are equivalent to asserting that all excess capacity can be sold at cost in every year. Alternatively, we can view the capacity costs as purchases from new capacity that is coming on line in every year. These would be extreme assumptions if one were focussing on quantitative precision. For illustrative purposes, however, such assumptions do no violence to the methodological illustrations. In our work with U.S. utilities, we can often begin with established system models to provide a more realistic basis for carbon policy evaluation. The insights developed here are still essential to understanding and measuring impacts for specific environments.

Two fundamental policy assumptions have been contrasted in my analysis. First, I assume a carbon tax of \$20 per MT is imposed immediately and maintained over the next 20 years. As discussed above, this would not be different in principle from the establishment of a carbon credit market in which the invariant world price of carbon is \$20 per MT. A far more severe policy disallows any additional coal-fired capacity or coal-fired generation beyond that chosen in the first year. Gas-fired combined cycle generation replaces all of the reduced capacity and output from the coal-fired units.

The benchmark utility used for illustration has a peak load of 10,000 MW with annual energy requirements of 46,000 GWh, which implies an annual load factor of 52.5%. The minimum load is about 3,200 MW. Annual load growth over the 21-year horizon is assumed to be 2.0%. Generating units considered are limited to conventional pulverized coal, gas-fired combined cycle and gas-fired combustion turbines. The key parameters for the carbon impact model are summarized in Table 3.

**Table 3 Model Inputs**

<b>Loads</b>						
MW		10,000				
GWh		46,000				
Annual Load Factor		52.5%				
Annual Growth Rate		20%				
<b>Fuel Prices</b>	\$/MMBTU		Escalation			
Coal	\$1.15		1.30%			
Gas	\$4.03		3.60%			
<b>Technology</b>	Heat Rate	Efficiency	CO <sub>2</sub> MT/MWh In	Ce MT/MWh In	Life Yrs	
Pulverized Coal	10,340	33.0%	0.35	0.289	30	
Gas Combined Cycle	6,820	50.0%	0.20	0.109	20	
Gas Combustion Turbine	12,000	28.4%	0.20	0.192	20	
<b>Technology</b>	Investment \$/kW	Escalation	Variable OM \$/MWh	Escalation		
Pulverized Coal	\$1,250	2.50%	\$2.00	2.50%		
Gas Combined Cycle	\$600	2.75%	\$3.00	2.50%		
Gas Combustion Turbine	\$400	2.75%	\$4.00	2.50%		
<b>Technology</b>			Fixed OM \$/kW-yr	Escalation		
Pulverized Coal			\$37.50	2.50%		
Gas Combined Cycle			\$18.00	2.75%		
Gas Combustion Turbine			\$18.00	2.75%		
<b>Discount Rate</b>		12.0%				

A graphic presentation of a well-known screening model is the simplest way to illustrate the impacts of a carbon tax on both capacity and dispatch decisions. The top panel of Figure 3 represents each of the three available technologies as a straight-line graph against the hours in the year. The intercept represents annual fixed costs consisting of both annualized investment costs and fixed operation and maintenance costs. These costs would continue in the short term whether or not the plant is actually operated. The slope of the line represents all operating costs that increase in proportion to the number of hours the plant is run. The predominant variable operating cost is fuel. The two intersections of the three technology lines identify the operating hours for each. These intersections are projected onto a load duration curve shown in the bottom panel of Figure 3 to define both the amount of capacity of each type that is desired and the amount of energy that should come from each type of unit to assure least cost operation.

A carbon tax would increase the cost of using both coal and gas, but the impact on coal is much larger than on gas since the relative carbon content is much higher. The red lines in Figure 3 yield the new least cost solution with a carbon tax. Note that the rotation of the coal line is greater than for either of the gas technologies. The following impacts of a carbon tax are immediately evident:

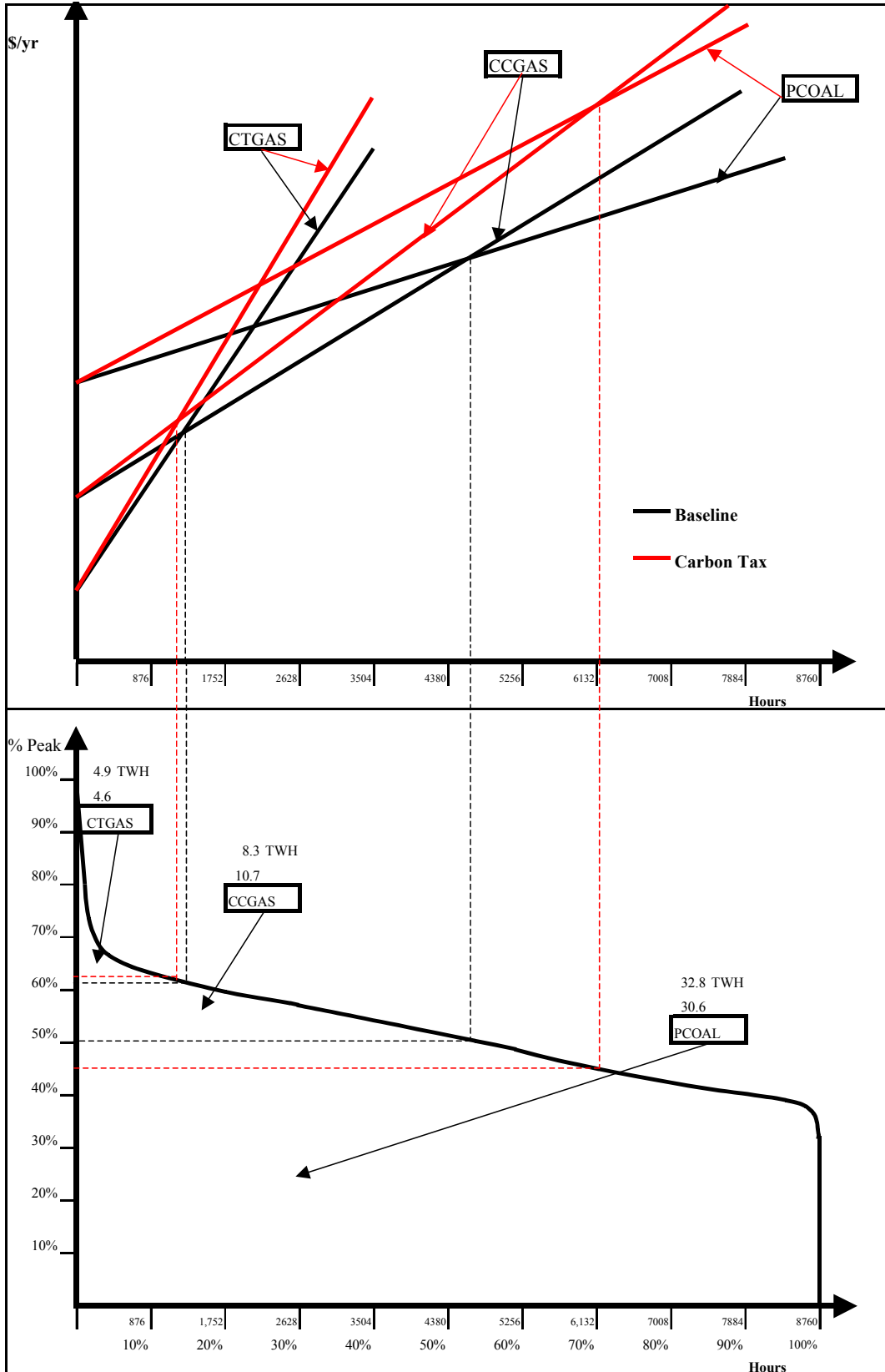
- Economic optimization will require a flight from more expensive technologies. In this instance, both the amount of coal-fired capacity acquired and the amount of electricity generated from coal are reduced as a result of the carbon tax. For the year shown, the reduction in coal-fired capacity is 393 MW and the reduction in coal-fired generation is 2.1 TWh. Both capacity and energy from the gas-fired combustion turbines will also decrease. This is because the combined cycle technology uses gas

more efficiently than the combustion turbines. Combustion turbine capacity for the year illustrated is reduced by 59 MW while energy is reduced by 0.3 TWh.

- The reductions from the coal units and from the combustion turbines must be offset by an increase of 452 MW of combined cycle capacity and generation of 2.4 TWh.

The simple carbon model used for this paper repeats the analysis illustrated in Figure 3 for each of 21 years to obtain estimates of the lifecycle costs and carbon emissions under alternative generation plans and policy interventions. The incremental costs of power supply over that horizon can then be compared with the emission reductions achieved to determine whether this is a cost-effective method of achieving such reductions. The complete data regarding the impacts of a carbon tax are provided in Table A-1 at the end of the paper and are summarized in Table 4.

**Figure 3 Illustrative Impacts of Carbon Tax**



**Table 4 Carbon Tax Impact Summary**  
**(All \$ Figures are Present Values in MUSD Except as Noted)**

		<b>Baseline</b>	<b>Proposed</b>	<b>Difference</b>
<b>Fixed Costs</b>		\$13,992	\$13,796	\$(196)
<b>Variable Costs</b>		\$10,746	\$11,002	\$255
<b>Total Costs</b>		\$24,738	\$24,798	\$60
<b>Emissions (MMMT)</b>				
	<b>CO<sub>2</sub></b>	1,106	1,083	22
	<b>Ce</b>	302	296	6
<b>Unit Abatement</b>	<b>\$/MT</b>			
	<b>CO<sub>2</sub></b>			\$2.71
	<b>Ce</b>			\$9.93

The cost impacts are intuitive. Fixed costs decrease since less expensive combined cycle units displace more costly coal units. This impact is much greater than the small substitution of combined cycle units for combustion turbines. Variable costs increase as more expensive gas is substituted for coal. To some extent this impact is mitigated because combined cycle efficiencies are considerably higher than for conventional coal-fired plants. The net incremental cost of the revised generation plan is \$60 million. Carbon reductions for the 20-year period are 22 million metric tons of CO<sub>2</sub> or 6 million tons of carbon equivalent. Combining these figures yields attractive unit abatement costs that are well below the expected world price of carbon. From a national-global perspective, the adjustments in utility capacity and generation decisions induced by the carbon tax would seem attractive. Carbon reductions are achieved at a cost below \$10 per MT while we have indicated above that the expected global social benefits are probably in excess of \$20 per MT.

Carbon credits at \$20 per ton would have identical impacts on utility resource selection as the carbon tax that has been illustrated. If we assume that the utility is selling its output at a retail price of \$80 per MWh, the tax or credit costs would increase electric prices by about 7.7%. The primary differences between those solutions would relate to the recipients of the payments for taxes or for credits. Tax payments would generate large revenue streams that could be divided in different ways between utilities and taxpayers. Credit purchases would provide an equivalent revenue stream to any worldwide project developer with verifiable credits for sale. These distribution issues are complex and merit separate discussion.

Carbon grants or carrots could work in the following way if GEF procedures were implemented by the U.S. GEF would consider this project as a cost-effective reduction of Ce emissions since the incremental costs are below the \$10 per ton limit. Since the utility would have incremental costs of \$60 million in choosing the cleaner proposed option over the baseline, GEF would normally provide a \$60 million grant to the utility to induce them to choose the cleaner option.

The remaining problem that is not evident from these results is that carbon emissions from this utility remain at an average level of 14.1 million MT of Ce per year over the horizon considered.

Whether this would be a sufficient reduction for this utility could only be determined by comparison with their 1990 levels of emissions.

The second case examined assumes that a more aggressive response from this utility is required if U.S. Kyoto commitments are to be met. In this instance I have assumed that the first year selection of coal capacity and generation remains fixed throughout the 21-year period. In this case, the share of coal-fired capacity falls from 46.1% to 35.1% while the share of combined cycle capacity increases from 9.4% to 20.4%. The share of coal-fired energy falls from 75.9% to 58.0% while combined cycle energy climbs from 14.0% to 31.9%. Detailed cost and emission results for this case are presented in Table A-2 and are summarized in Table 5.

**Table 5 Coal Moratorium Impact Summary  
(All \$ Figures are Present Values in MUSD Except as Noted)**

	<b>Baseline</b>	<b>Proposed</b>	<b>Difference</b>
<b>Fixed Costs</b>	\$13,992	\$13,213	\$(779)
<b>Variable Costs</b>	\$10,746	\$12,219	\$1,474
<b>Total Costs</b>	\$24,738	\$25,433	\$695
<b>Emissions (MMMT)</b>			
<b>CO<sub>2</sub></b>	1,106	965	140
<b>Ce</b>	302	263	38
<b>Unit Abatement \$/MT</b>			
<b>CO<sub>2</sub></b>			\$4.95
<b>Ce</b>			\$18.15

In this case, the carbon reductions are more than six times larger but the incremental costs increase from \$60 to \$695 million. The unit abatement costs remain below the best estimates of the social value of reductions so this adjustment would still be viewed positively from a national-global perspective. The critical policy question would be how to induce the utility to adopt this more costly solution. A tax designed to yield this particular solution would have to be applied to coal rather than to carbon. A grant based on current GEF criteria would only yield \$380 million compared to the incremental cost of \$695 million and would not be sufficient alone to lead the utility to this result. Since the social benefits exceed the incremental costs, a case could be made for a more generous grant mechanism. Carbon credits could also work in this instance, since the utility could generate carbon reductions at a cost (\$18.15/MT) below the expected world market price (\$20/MT) at which they could sell those credits. The most likely policy stance for this type of adjustment would involve some combination of carrots and sticks.

## **Conclusions and Recommendations**

This paper argues that the impacts of the Kyoto agreements on the U.S. electric utility sector are of sufficient potential magnitude and immediacy to merit more attention than the topic seems to be getting. I have also suggested that planning against an assumed carbon price of \$20 per MT of Ce is a useful starting point in mapping a utility position on carbon policy. Finally, I have contrasted policy instruments including taxes, tradable credits, and grants as interventions that

could be used to induce utilities to behave in ways that will deliver the committed reductions. My quantitative results from a simple capacity expansion and production cost model provide a frame of reference that should also illustrate the issues in choosing among carbon policies and strategies.

My conviction is that utilities would be well-served to begin formulating carbon strategies that address the following questions:

1. How would current capacity acquisition and planned production decisions be changed by establishment of a carbon tax of \$20 per MT?
2. How would current capacity acquisition and planned production decisions be changed by establishment of a world market in carbon credits that settled on a trading price of \$20 per MT?
3. What amount of carbon credits would my utility need to purchase for different possible allowances that my utility could be given?
4. Would it be useful to identify sources of bilateral credits that could possibly be acquired early at less than the expected world market price?
5. How would carbon policy influence my utility's enthusiasm for renewable energy and energy efficiency projects?
6. What position should my utility adopt regarding the relative efficacy of taxes, credits and grants related to carbon?
7. How could my utility establish the baseline against which carbon reductions should be measured?
8. Could my utility make money by producing carbon reductions at costs below the likely sales price?
9. What is the potential impact of possible carbon policies on the value of my generating assets?
10. How would various carbon policies influence the market price forecasts that my utility uses to make resource acquisition or sale decisions?

This paper does not attempt to answer these questions in any generic way. The more modest objective here has been to stimulate interest in carbon issues that are admittedly complex and to suggest that due diligence in the utility community will not allow carbon blindness to continue indefinitely. Unless the entire Kyoto protocol collapses, the U.S. will face substantial and costly adjustments in the electric utility sector. Policies that deliver those adjustments could vary widely in terms of impact on each specific utility. In that light, it seems desirable for utilities to be able to articulate well-reasoned positions on the issues addressed in this paper.

## References

Fankhauser, Samuel, *Valuing Climate Change: The Economics of the Greenhouse*, Earthscan Publications Ltd., London, 1995.

U.S. Department of Energy, Energy Information Administration, Office of Integrated Analysis and Forecasting, *Analysis of the Impacts of an Early Start for Compliance with the Kyoto Protocol*, SR/OIAF/99-02 (Washington D.C., July 1999).

**Table A-1  
Carbon Tax Impacts**

Technology	Baseline						Carbon Tax						
	MW		GWh		Capacity Factors		MW		GWh		Capacity Factors		
	Yr 1	Average	Yr 1	21 Years	Yr 1	Yr 21	Yr 1	Average	Yr 1	21 Years	Yr 1	Yr 21	
Pulverized Coal	4,957	6,504	32,766	900,494	75.5%	75.2%	4,564	6,264	30,644	869,454	76.6%	75.2%	
Gas Combined Cycle	1,356	1,327	8,299	166,344	69.8%	65.5%	1,808	1,618	10,711	202,451	67.6%	66.0%	
Gas Combustion Turbine	3,687	4,447	4,935	119,195	15.3%	13.9%	3,628	4,396	4,646	114,128	14.6%	13.6%	
Reserves	1,500	1,842					1,500	1,842					
Total	11,500	14,119	46,000	1,186,033			11,500	14,119	46,000	1,186,033			
Technology	CO <sub>2</sub> Million MT		Ce Million MT				CO <sub>2</sub> Million MT		Ce Million MT		Differences MMT		
	Yr 1	21 Years	Yr 1	21 Years			Yr 1	21 Years	Yr 1	21 Years	CO <sub>2</sub> 21 Yrs	Ce 21 Yrs	
	Pulverized Coal	34.8	955.1	9.5	260.5			32.5	922.2	8.9	251.5	32.9	9.0
Gas Combined Cycle	3.3	66.5	0.9	18.1			4.3	80.9	1.2	22.1	-14.4	-3.9	
Gas Combustion Turbine	3.5	83.8	0.9	22.9			3.3	80.3	0.9	21.9	3.6	1.0	
Total	41.5	1,105.5	11.3	301.5			40.1	1,083.4	10.9	295.5	22.1	6.0	
Technology	Fixed Costs MUSD		Variable Costs MUSD		Total Costs MUSD		Fixed Costs MUSD		Variable Costs MUSD		Total Costs MUSD		
	Yr 1	PV 21 Yrs	Yr 1	PV 21 Yrs	Yr 1	PV 21 Yrs	Yr 1	PV 21 Yrs	Yr 1	PV 21 Yrs	Yr 1	PV 21 Yrs	
	Pulverized Coal	\$ 792.3	\$ 9,554.6	\$ 455.1	\$ 5,095.0	\$ 1,247.4	\$ 14,649.6	\$ 729.5	\$ 9,111.7	\$ 425.7	\$ 4,876.9	\$ 1,155.2	\$ 13,988.6
Gas Combined Cycle	\$ 112.2	\$ 1,117.7	\$ 253.0	\$ 2,603.0	\$ 365.2	\$ 3,720.7	\$ 149.6	\$ 1,394.8	\$ 326.5	\$ 3,218.2	\$ 476.1	\$ 4,613.0	
Gas Combustion Turbine	\$ 286.1	\$ 3,319.7	\$ 258.4	\$ 3,048.2	\$ 544.5	\$ 6,367.9	\$ 282.8	\$ 3,289.9	\$ 243.3	\$ 2,906.4	\$ 526.1	\$ 6,196.3	
Total	\$ 1,190.6	\$ 13,992.0	\$ 966.6	\$ 10,746.1	\$ 2,157.1	\$ 24,738.2	\$ 1,161.9	\$ 13,796.4	\$ 995.4	\$ 11,001.6	\$ 2,157.4	\$ 24,797.9	
Summary		Baseline	Proposed	Difference									
Fixed Costs MUSD	PV 21 Yrs	\$ 13,992.0	\$ 13,796.4	\$ (195.7)									
Variable Costs MUSD	PV 21 Yrs	\$ 10,746.1	\$ 11,001.6	\$ 255.4									
Total Costs MUSD	PV 21 Yrs	\$ 24,738.2	\$ 24,797.9	\$ 59.7									
CO <sub>2</sub> Emissions MMT	Total 21 Yrs	1,105.5	1,083.4	22.1									
Ce Emissions	Total 21 Yrs	301.5	295.5	6.0									
Unit Abatement Costs													
	CO <sub>2</sub>	\$/MT		\$	2.71								
	Ce	\$/MT		\$	9.93								
Carbon Taxes MUSD	Total 21 Yrs	\$ 5,915.4											
	PV 21 Yrs	\$ 2,173.4											

**Table A-2  
Coal Moratorium Impacts**

Technology	Baseline						No New Coal					
	MW		GWh		Capacity Factors		MW		GWh		Capacity Factors	
	Yr 1	Average	Yr 1	21 Years	Yr 1	Yr 21	Yr 1	Average	Yr 1	21 Years	Yr 1	Yr 21
Pulverized Coal	4,957	6,504	32,766	900,494	75.5%	75.2%	4,957	4,957	32,766	688,080	75.5%	75.5%
Gas Combined Cycle	1,356	1,327	8,299	166,344	69.8%	65.5%	1,356	2,874	8,299	378,758	69.8%	72.2%
Gas Combustion Turbine	3,687	4,447	4,935	119,195	15.3%	13.9%	3,687	4,447	4,935	119,195	15.3%	13.9%
Reserves	1,500	1,842	-	-			1,500	1,842				
<b>Total</b>	<b>11,500</b>	<b>14,119</b>	<b>46,000</b>	<b>1,186,033</b>			<b>11,500</b>	<b>14,119</b>	<b>46,000</b>	<b>1,186,033</b>		
Technology	CO <sub>2</sub> Million MT		Ce Million MT				CO <sub>2</sub> Million MT		Ce Million MT		Differences MMT	
	Yr 1	21 Years	Yr 1	21 Years			Yr 1	21 Years	Yr 1	21 Years	CO <sub>2</sub> 21 Yrs	Ce 21 Yrs
	Pulverized Coal	34.8	955.1	9.5	260.5			34.8	729.8	9.5	199.0	225.3
Gas Combined Cycle	3.3	66.5	0.9	18.1			3.3	151.4	0.9	41.3	-84.9	-23.2
Gas Combustion Turbine	3.5	83.8	0.9	22.9			3.5	83.8	0.9	22.9	0.0	0.0
<b>Total</b>	<b>41.5</b>	<b>1,105.5</b>	<b>11.3</b>	<b>301.5</b>			<b>41.5</b>	<b>965.1</b>	<b>11.3</b>	<b>263.2</b>	<b>140.4</b>	<b>38.3</b>
Technology	Fixed Costs MUSD		Variable Costs MUSD		Total Costs MUSD		Fixed Costs MUSD		Variable Costs MUSD		Total Costs MUSD	
	Yr 1	PV 21 Yrs	Yr 1	PV 21 Yrs	Yr 1	PV 21 Yrs	Yr 1	PV 21 Yrs	Yr 1	PV 21 Yrs	Yr 1	PV 21 Yrs
	Pulverized Coal	\$ 792.3	\$ 9,554.6	\$ 455.1	\$ 5,095.0	\$ 1,247.4	\$ 14,649.6	\$ 792.3	\$ 7,888.4	\$ 455.1	\$ 4,249.5	\$ 1,247.4
Gas Combined Cycle	\$ 112.2	\$ 1,117.7	\$ 253.0	\$ 2,603.0	\$ 365.2	\$ 3,720.7	\$ 112.2	\$ 2,005.2	\$ 253.0	\$ 4,922.3	\$ 365.2	\$ 6,927.5
Gas Combustion Turbine	\$ 286.1	\$ 3,319.7	\$ 258.4	\$ 3,048.2	\$ 544.5	\$ 6,367.9	\$ 286.1	\$ 3,319.7	\$ 258.4	\$ 3,048.2	\$ 544.5	\$ 6,367.9
<b>Total</b>	<b>\$ 1,190.6</b>	<b>\$ 13,992.0</b>	<b>\$ 966.6</b>	<b>\$ 10,746.1</b>	<b>\$ 2,157.1</b>	<b>\$ 24,738.2</b>	<b>\$ 1,190.6</b>	<b>\$ 13,213.3</b>	<b>\$ 966.6</b>	<b>\$ 12,219.9</b>	<b>\$ 2,157.1</b>	<b>\$ 25,433.2</b>
<b>Summary</b>		Baseline	Proposed	Difference								
Fixed Costs MUSD	PV 21 Yrs	\$ 13,992.0	\$ 13,213.3	\$ (778.7)								
Variable Costs MUSD	PV 21 Yrs	\$ 10,746.1	\$ 12,219.9	\$ 1,473.8								
Total Costs MUSD	PV 21 Yrs	\$ 24,738.2	\$ 25,433.2	\$ 695.1								
CO <sub>2</sub> Emissions MMT	Total 21 Yrs	1,105.5	965.1	140.4								
Ce Emissions	Total 21 Yrs	301.5	263.2	38.3								
Unit Abatement Costs												
	CO <sub>2</sub>	\$/MT		\$ 4.95								
	Ce	\$/MT		\$ 18.15								