Power Plant Emission Reductions Using a Generation Performance Standard

by
J. Alan Beamon, Tom Leckey, and Laura Martin

There are many policy instruments available for reducing power plant emissions, and the choice of a policy will affect compliance decisions, costs, and prices faced by consumers. In a previous analysis, the Energy Information Administration analyzed the impacts of power sector caps on nitrogen oxides (NO_x), sulfur dioxide (SO_2), and carbon dioxide (CO_2) emissions, assuming a policy instrument patterned after the SO_2 allowance program created in the Clean Air Act Amendments of 1990.[1] This report compares the results of that work with the results of an analysis that assumes the use of a dynamic generation performance standard (GPS) as an instrument for reducing CO_2 emissions.[2] In general, the results of the two analyses are similar: to reduce CO_2 emissions the power sector is expected to turn away from coal-fired generation to natural gas and, to a lesser extent, renewables. However, when a GPS program to reduce CO_2 emissions is assumed, the electricity price impacts of the program are projected to be lower, while natural gas prices, CO_2 allowance prices, and total resource costs for electricity generators are projected to be higher. More generation from renewable fuels is also expected under the GPS program.

Background

In June 2000, former Congressman David M. McIntosh, Chairman of the Subcommittee on National Economic Growth, Natural Resources, and Regulatory Affairs of the Committee on Government Reform, requested that the Energy Information Administration (EIA) analyze the potential impacts of programs to reduce power plant emissions of nitrogen oxides (NO_x), sulfur dioxide (SO_2), carbon dioxide (CO_2), and mercury (Hg) emissions, with and without a renewable portfolio standard (RPS).[3] The first phase of that analysis (referred to in the remainder of this analysis as "Phase I"), looked at the impacts of reducing power sector emissions of NO_x, SO_2, and CO_2.[4] The second phase, which extends the analysis to examine the impacts of reducing Hg emissions and adding a renewable portfolio standard (RPS)—in addition to reducing NO_x, SO_2, and CO_2 emissions—is scheduled for completion in June 2001.

In its original request, the Subcommittee asked EIA to analyze cases with power sector emissions of NO_x and SO_2 capped at 75 percent below their 1997 levels, together with two alternative CO_2 emissions caps—one equal to power sector emissions in 1990 and one reducing those emissions to 7 percent below the 1990 emission level at a later date. Cases were prepared examining the impact of each emission cap by itself and examining them together.[5] The Subcommittee did not specify the policy instrument (emission taxes, emission standards,

[1]Energy Information Administration, *Analysis of Strategies for Reducing Multiple Emissions from Power Plants: Sulfur Dioxide, Nitrogen Oxides, and Carbon Dioxide*, SR / OIAF / 2000-05 (Washington, DC, December 2000).

[2]This analysis was prepared in response to comments received from reviewers of the previous (Phase I) analysis. Independent expert reviewers suggested that alternative policy instruments—particularly a dynamic generation performance standard—for reducing power sector emissions should be analyzed. This report was reviewed by two of those reviewers, Dallas Burtraw and Karen Palmer of Resources for the Future.

[3]A renewable portfolio standard program calls for a share of generation or sales of electricity to come from nonhydroelectric renewable facilities. All suppliers of electricity must either produce the required share themselves or purchase credits from others who produce more than they need.

[4]Energy Information Administration, *Analysis of Strategies for Reducing Multiple Emissions from Power Plants: Sulfur Dioxide, Nitrogen Oxides, and Carbon Dioxide*, SR / OIAF / 2000-05 (Washington, DC, December 2000).

[5]Energy Information Administration, *Analysis of Strategies for Reducing Multiple Emissions from Power Plants: Sulfur Dioxide, Nitrogen Oxides, and Carbon Dioxide*, SR / OIAF / 2000-05 (Washington, DC, December 2000). Readers should refer to the report for a thorough description of the 18 cases analyzed. The analysis in this report is limited to a comparison of the results of selected integrated cases with and without a CO_2 GPS program.

emission cap and trade program, generation performance standard, etc.) to be used to achieve the emission targets. The Phase I analysis used a cap and trade program (with no generation performance standard) for NO_x, SO_2, and CO_2, patterned after the SO_2 allowance program created in the Clean Air Act Amendments of 1990 (CAAA90), which is one of the first large-scale programs in the United States using a cap and trade policy instrument to achieve emission reductions. The CAAA90 SO_2 allowance trading program has generally been viewed as a success.

Under an emission allowance trading system such as that used in the CAAA90 SO_2 program, marketable emission permits (allowances) are allocated at the beginning of the program to power plant operators at no cost (no revenue to be collected by the government). The operators are then free to use the allowances to cover their own emissions, or to sell them to others. The attraction of such a system is that, given a well-functioning allowance market, those with the lowest cost emission reduction opportunities would take advantage of them while selling any unneeded allowances they received to others whose reduction opportunities were more costly. The net result would be compliance with the emission caps at the lowest possible cost. Consumer prices would increase as producers acquired allowances and used more expensive resources to comply with the emission targets.

One concern that has been raised about cap and trade programs is that existing units are granted allowances perpetually, whereas all new units must acquire the allowances they need. In addition, because the allocation of allowances in the CAAA90 SO_2 program was based primarily on the historical amount of fuel consumed, it did not provide any reward for relatively efficient units.

Generation Performance Standard

As with any projections there is considerable uncertainty surrounding the results of EIA's Phase I analysis of power plant emission reductions. Sources of uncertainty include changes in the cost and performance of generating technologies and emissions control technologies, the efficiency and costs of electricity-consuming equipment, the costs of fuels used for power generation (particularly, natural gas), consumer behavior, the outcome of electricity restructuring efforts in each of the States, and the specific approaches (policy instruments) used for implementing the emission reduction programs. The purpose of this study is to analyze the use of an alternative policy instrument for reducing CO_2 emissions.

Historically, the United States has used a variety of emission reduction strategies, including specific emission limits, technology standards, and emissions cap and trade programs. An example of a specific emission limit is the provision of the Clean Air Act that requires all existing fossil-fuel steam generating plants with wall-fired boilers (wall-fired refers to the configuration of the burners in the boiler) to produce no more than 0.45 pounds of NO_x per million British thermal units (Btu) of energy consumed. An example of technology-specific standards is the new source standards that require all new coal-fired power plants to install the best available control technology (scrubbers) to reduce SO_2 emissions. The first large-scale use of an emissions cap and trade program in the United States is the CAAA90 SO_2 allowance program, under which SO_2 emission allowances are allocated to power plants on the basis of their historical fuel consumption. The annual allocation of allowances does not change over time as firms change the use of their plants and new facilities are added.

Several bills that have been introduced in the U.S. Congress contain proposals for a different policy approach to limiting CO_2 emissions from power plants—a dynamic generation performance standard (GPS). In contrast to the CAAA90 SO_2 program, under a dynamic GPS approach (dynamic because it is recalculated every year), allowances would be reallocated each year, based on a plant's megawatthour output. For example, if the national cap on CO_2 emissions were set at 1.914 billion tons (the 1990 CO_2 emission level for the electricity sector) and the total generation from all plants covered under the cap[6] equaled 4 billion megawatthours in a particular year, the GPS would equal 0.479 tons CO_2 (0.119 metric tons carbon equivalent) per megawatthour generated.

The cost and price impacts of a dynamic GPS allowance allocation scheme would differ from those of the program assumed in EIA's Phase I analysis. Under the one-time fixed allowance allocation scheme assumed in the Phase I analysis (referred to in this article as "non-GPS cases"), the full price of emission allowances would be added to the operating costs for all plants producing the targeted emissions. For example, if a plant produced 0.200 metric tons of carbon (0.733 tons CO_2) per megawatthour and the emission allowance price was \$100 per metric ton, the operating costs of that plant would increase by \$20 per megawatthour (\$100 x 0.2). Although firms are given the allowances at no cost under a fixed allowance allocation scheme, each firm will attempt to pass on the full opportunity cost of the allowances in its prices. Thus, supply prices for electricity will increase by the \$20 per megawatthour described above. Consumers will respond to the price increase by

[6]The definition of covered facilities differs among GPS proposals. In some, allowances are allocated to all generators. In others they are allocated only to fossil-fired generators that produce the emissions.

demanding less electricity, and the final price will reflect the new equilibrium price for electricity based on the revised level of demand.

Under the dynamic GPS approach, the impact on the same plant's operating costs would be lower. Using the GPS value above (0.119 metric tons per megawatthour), the same plant producing 0.200 metric tons per megawatthour would need allowances equal to the difference between its emission rate and that year's GPS rate (e.g., 0.200 - 0.119). As a result, the plant's operating costs would increase by only $8 per megawatthour ($100 x [0.200 - 0.119]). If the plant were a price-setting plant, the net effect of the dynamic GPS allowance allocation scheme would be that the full cost of holding allowances for the plant ($20 per megawatthour) would not be passed on to consumers. In effect, the plant would receive an output rebate or subsidy of $12 for each megawatthour produced, and the subsidy would be passed on to consumers in the form of lower electricity prices. In other words, under a GPS allocation scheme the firm has an incentive to increase its output in order to receive additional allowances. To increase its allowance allocation, the firm will not include the full opportunity cost of the allowance in its prices but instead will pass the subsidy on to consumers so that it can raise its own output. Although consumer demand for electricity will decrease by less than in the non-GPS case, equilibrium electricity prices are lower than in the non-GPS case.

Although a dynamic GPS program would be expected to lower the electricity price impact of reducing power sector emissions, it would lead to higher total resource costs, higher CO_2 allowance prices, and higher natural gas prices, because the lower prices for electricity would result in more electricity usage. The increased resource costs would be borne mainly by electricity suppliers, who would have to turn to more expensive resources to comply with the emission caps. The magnitude of the increase in resource costs would depend on the degree to which consumers would have reduced their electricity consumption without the production subsidy, as well as the cost of compliance options faced by suppliers. Especially important would be the sensitivity of the natural gas market to additional demand from the electricity sector.

As one expert puts it, "output based rebating sacrifices some of the efficiencies of market-based environmental policies. Allocating by market share essentially provides a subsidy to output, which creates a bias away from output substitution and toward emissions rate reduction. The result is a higher marginal cost of control, a lower equilibrium output price, and a greater cost to achieving any given level of emissions reduction, compared to an efficient policy. The size of the welfare loss from this distortion depends on how much emissions reduction would normally be performed by output substitution."[7]

All the cases in this analysis assume that allowances will be allocated at no cost and that, as a result, no revenue will be collected by the Government. If an allowance auction or tax instrument were used instead, the Government would collect additional revenue, and those funds could be used to revise existing taxes. Some analysts have argued that such tax effects could be significant.[8]

Analysis Methodology

The cases analyzed for this study are based on the version of EIA's National Energy Modeling System (NEMS) used for the *Annual Energy Outlook 2001*, as was the Phase I analysis, and the results should be compared with those in the corresponding Phase I cases. The reduction programs for NO_x and SO_2 emissions in this study are assumed to be the same as in the Phase I analysis, but a dynamic GPS policy instrument is assumed for reducing CO_2 emissions. Using this approach, CO_2 allowances are reallocated each year, based on a plant's megawatthour output. Each year the average CO_2 emission rate (in tons per megawatthour) necessary to meet the national target is calculated (using the previous year's generation), and generators are allocated enough allowances to cover their emissions if they produce emissions at the GPS target rate.

This analysis assumes that all generators, including non-CO_2-producing generators, such as nuclear and renewable technologies, are allocated allowances. Non-CO_2-producing generators can sell their allowances to other generators, effectively lowering their operating costs. If CO_2 allowances were not allocated to non-CO_2-producing generators, new renewable generators would be disadvantaged because only fossil generators would receive the production subsidy. This would lead to higher natural gas prices and higher CO_2 allowance prices than in the broad-based GPS program analyzed in this study. Fossil plants with more CO_2 emissions than the average must buy enough allowances to make up the difference between the GPS target emission rate and their actual emission rate. As the earlier example shows, however, the impact of allowance costs on operating costs for those generators would be less under the GPS approach than under the fixed allowance allocation approach used in the Phase I analysis.

[7]C. Fischer, *Rebating Environmental Policy Revenues: Output-based Allocations and Tradable Performance Standards* (Washington, DC: Resources for the Future, January 21, 1999).

[8]L.H. Goulder, I.W.H. Perry, R.C. Williams III, and D. Burtraw, *The Cost-Effectiveness of Alternative Instruments for Environmental Protection in a Second Best Setting* (Washington, DC: Resources for the Future, March 1998).

The GPS approach is modeled by calculating the effective production subsidy that would result from the allowance allocation each year. The subsidy is equal to the average emission rate needed to meet the limit in the given year (in tons per megawatthour) multiplied by the CO_2 allowance price (in dollars per metric ton carbon equivalent). This subsidy (in dollars per megawatthour) is subtracted from the full operating cost of each generator (which includes the costs to purchase allowances for every ton of CO_2 emitted). The adjusted operating cost is then used to set the market-clearing price of electricity. As in the Phase I analysis, it is assumed that generators will include the opportunity costs associated with holding allowances in their operating costs; the difference in the GPS approach is that this cost is reduced by the production subsidy, as long as a plant continues to generate electricity.

In competitive regions, generation prices are assumed to be based primarily on the operating costs of the power plant setting the market-clearing price at any given time. It is assumed that all generation markets behave competitively, and that generators are not able to exert market power. Under the GPS allocation, the market-clearing price will be reduced by the production subsidy that reduces operating costs for all generators. The subsidy will be passed on to consumers, who will see smaller price increases than they would if the full allowance cost were included in the market-clearing price. Even in regions that are not expected to be moving toward full retail competition, the wholesale market is expected to become increasingly competitive, and the opportunity cost of CO_2 allowances is assumed to be included in operating costs. The cost of the subsidy would be borne mainly by power suppliers, who would have to turn to higher cost resources to reduce emissions.

Through the end of 1999, 24 States and the District of Columbia had enacted restructuring legislation or regulatory orders. Together the 24 States accounted for more than 55 percent of sales in 1999. Eighteen other States are studying deregulation. In total, the 42 States that have already taken action or are studying deregulation accounted for more than 88 percent of sales in 1999. In addition, the vast majority of new power plant additions are expected to be built by deregulated entities. Nearly 77 percent of planned additions over the next 4 years reported to EIA are from nonutility entities. However, if a large portion of the generation market remains under cost-of-service pricing over the next 20 years, the zero-cost allocation of allowances could reduce the price impacts from those estimated in this analysis. Essentially, cost-of-service utilities would treat any allowances allocated to them as having zero cost, and they would not reflect any cost for them in their rates.

Results

Table 1 summarizes the results of the analysis. The results are shown for the reference case and four integrated cases—two non-GPS cases using a CO_2 allowance allocation scheme patterned after the CAAA90 SO_2 program and two GPS cases using a dynamic GPS allocation scheme for CO_2 allowances. The two non-GPS cases are from the Phase I analysis and are shown for comparison purposes.

- The non-GPS integrated 1990-7% 2005 case assumes that the power sector must reduce NO_x and SO_2 emissions to 75 percent below their 1997 levels and CO_2 emissions to their 1990 level, all by 2005. In addition, CO_2 emissions in the power sector must be reduced to 7 percent below the 1990 level over the period 2008 to 2012.
- The non-GPS integrated 1990-7% 2008 case makes the same assumptions, but the first compliance dates are delayed until 2008.
- The two GPS integrated cases are the same as the two non-GPS cases except for the use of the dynamic GPS allowance allocation system for CO_2.

In all the integrated cases, meeting the specified emission caps is projected to change the mix of fuels used to generate electricity and to result in higher prices for natural gas and electricity. To meet the combined emission caps, power suppliers are projected to reduce their coal use significantly and to increase their natural gas use. The increased reliance by the power sector on natural gas is projected to lead to higher natural gas prices, which, in turn, contribute to higher electricity prices.

Using a GPS policy instrument to reduce CO_2 emissions leads to significant changes in consumer and supplier efforts to comply with the emission caps. Relative to the findings from the non-GPS integrated cases, a key result of reducing CO_2 emissions through a dynamic GPS is that electricity price impacts are projected to be lower because of the production subsidy inherent in the GPS program (Figure 1). In the non-GPS integrated 1990-7% 2005 case, electricity prices are projected to reach 8.4 cents per kilowatthour (1999 dollars)—an increase of 43 percent over reference case levels—by 2010. In the non-GPS integrated 1990-7% 2008 case, electricity prices are projected to reach 8.2 cents per kilowatthour in 2010, an increase of 39 percent over reference levels. In contrast, electricity prices are projected to reach only 6.9 cents per kilowatthour in 2010 when the emission caps and GPS program are assumed to take effect in 2005 (the GPS integrated 1990-7% 2005 case) and only 6.8 cents per kilowatthour when the caps are assumed to take effect in 2008 (the GPS integrated 1990-7% 2008 case).

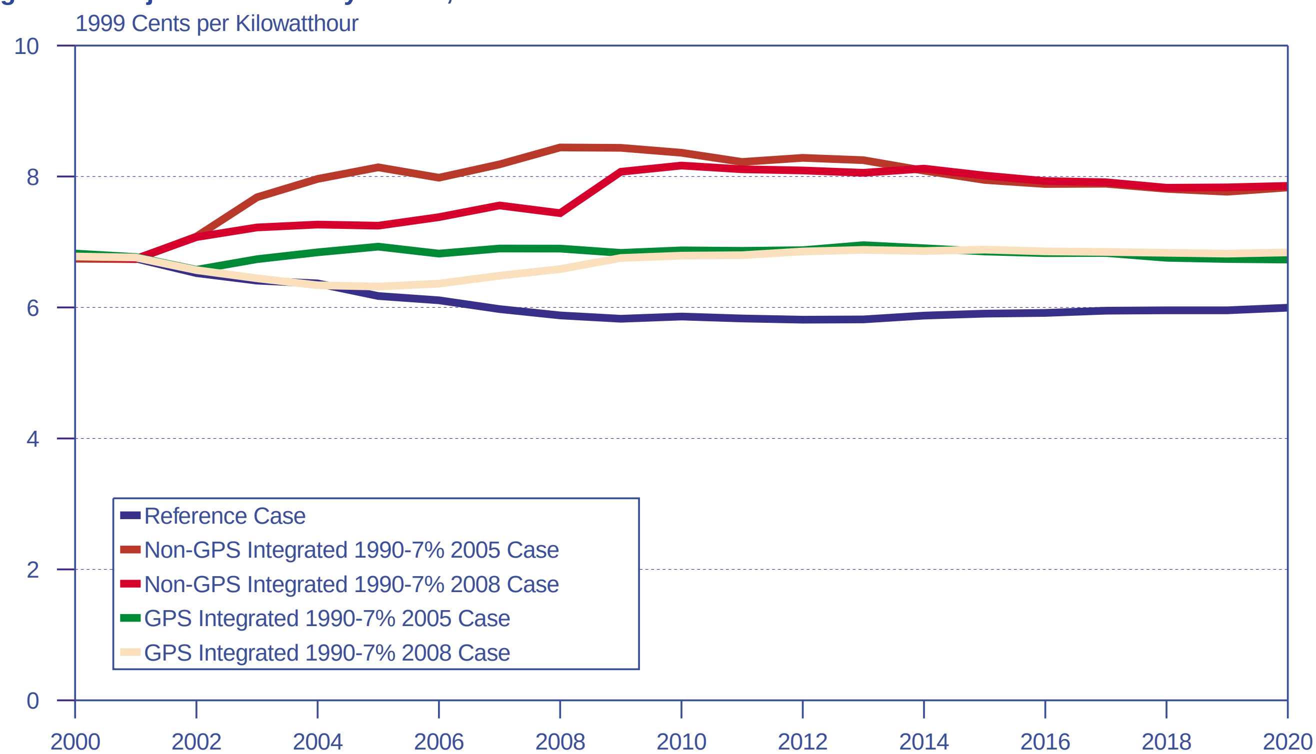
Table 1. Summary of Results: GPS Integrated Cases Compared With Reference and Non-GPS Integrated Cases, 2010 and 2020

Analysis Case	Coal-Fired Generation (Billion Kilowatt-hours)	Gas-Fired Generation (Billion Kilowatt-hours)	Renewable Generation (Billion Kilowatt-hours)	Electricity Sales (Billion Kilowatt-hours)	CO_2 Allowance Price (1999 Dollars per Metric Ton Carbon Equivalent)	Electricity Price (1999 Cents per Kilowatt-hour)	Natural Gas Wellhead Price (1999 Dollars per Thousand Cubic Feet)	Total Electricity Sales (Billion 1999 Dollars)	Non-Electricity Natural Gas Sales[a] (Billion 1999 Dollars)	Total End-Use Electricity and Natural Gas Sales (Billion 1999 Dollars)
2010										
Reference	2,284	1,123	429	4,146	NA	5.86	2.68	243	95	338
Non-GPS Integrated 1990-7% 2005 . . .	1,135	1,839	561	3,832	134	8.36	4.33	320	120	440
Non-GPS Integrated 1990-7% 2008 . . .	1,067	1,935	562	3,868	126	8.17	4.16	316	117	433
GPS Integrated 1990-7% 2005 . . .	1,024	2,070	614	4,062	142	6.87	5.00	279	125	404
GPS Integrated 1990-7% 2008 . . .	1,020	2,118	586	4,070	130	6.79	4.77	276	123	399
2020										
Reference	2,370	1,866	443	4,803	NA	6.00	3.14	288	111	399
Non-GPS Integrated 1990-7% 2005 . . .	852	2,774	677	4,401	130	7.83	4.30	345	133	477
Non-GPS Integrated 1990-7% 2008 . . .	834	2,816	658	4,422	129	7.86	4.42	347	134	482
GPS Integrated 1990-7% 2005 . . .	738	2,851	850	4,724	148	6.73	4.69	318	134	452
GPS Integrated 1990-7% 2008 . . .	739	2,898	806	4,715	147	6.84	4.94	323	137	459

[a]Residential, commercial, and industrial.

Source: National Energy Modeling System, runs MCBASE.D121300A, FDP7B05.D121300B, FDP7B08.D121500A, FDP75FEE.D021101B, and FDP7FEEG.D011801A.

Figure 1. Projected Electricity Prices, 2000-2020



Source: National Energy Modeling System, runs MCBASE.D121300A, FDP7B05.D121300B, FDP7B08.D121500A, FDP75FEE.D021101B, and FDP7FEEG.D0111801A.

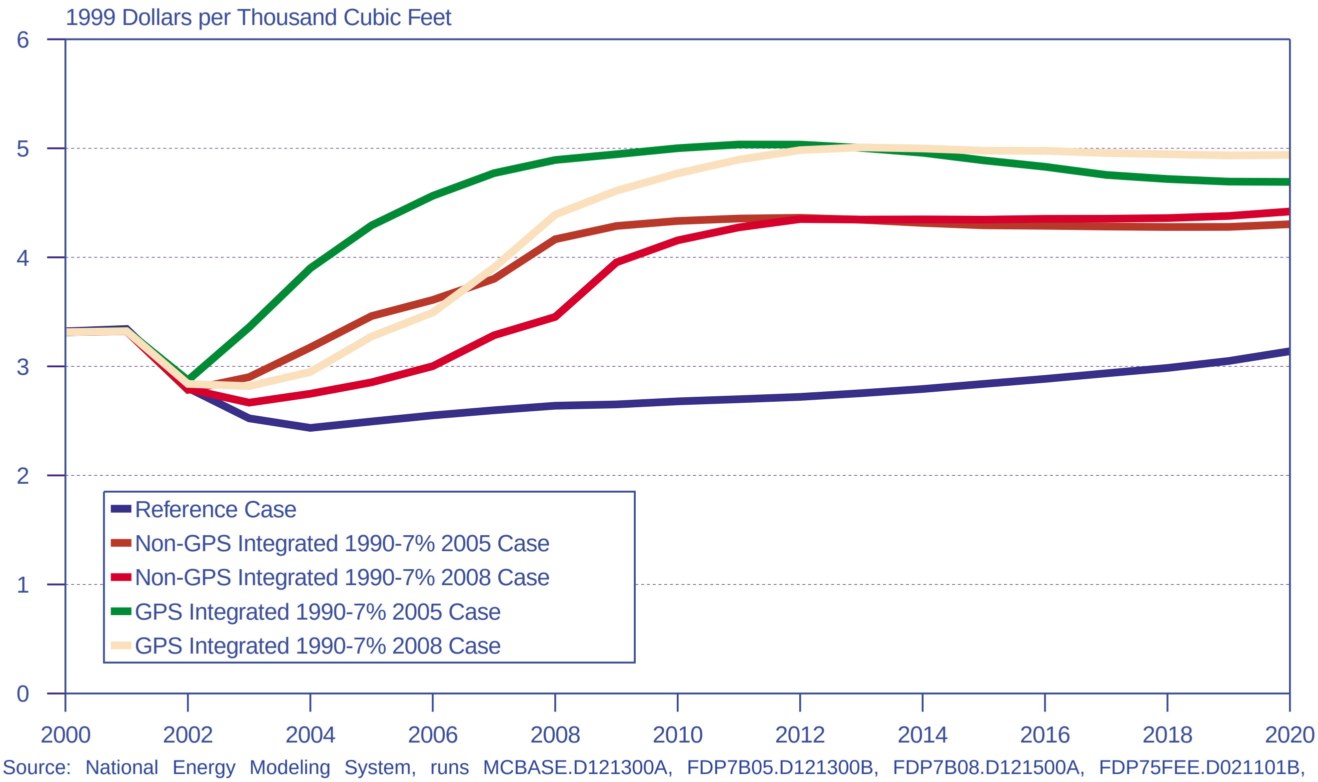
Because the impacts on electricity prices are expected to be more modest in the GPS integrated cases, consumers have less incentive to alter their electricity consumption patterns than they do in the non-GPS integrated cases. As a result, in the GPS integrated cases, the demand for electricity is projected to be only slightly below the reference case level. In the reference case, electricity demand is projected to grow by 1.8 percent per year on average between 2000 and 2020. In the non-GPS integrated 1990-7% 2005 case, the projected growth rate for electricity demand is reduced to 1.4 percent per year between 2000 and 2020, but in the GPS integrated 1990-7% 2005 case it is close to that in the reference case, at 1.7 percent per year. In the two non-GPS integrated cases, demand for electricity is projected to be reduced by about 7 to 8 percent from the reference levels in both 2010 and 2020. But with electricity prices projected to be only 16 to 17 percent above the reference case level in the two GPS integrated cases, electricity demand is projected to be only about 2 percent less than in the reference case.

Generally, consumers might be expected to be more responsive to a 16- to 17-percent increase in electricity prices, but in the GPS integrated cases natural gas prices are projected to be higher than in the non-GPS integrated cases, and there is less incentive for end-use consumers to switch from electricity to natural gas. Without sufficient consumer response, the burden to reduce CO_2 emissions is projected to fall chiefly on electricity suppliers, and as a result the changes in the generation fuel mix are expected to be more significant than they would be under a non-GPS allocation scheme.

With the higher projections for electricity demand in the GPS integrated cases, natural gas prices are projected to increase more than they would in the non-GPS integrated cases (Figure 2). In the GPS integrated 1990-7% 2005 case, wellhead natural gas prices are projected to reach $5.00 per thousand cubic feet in 2010 and $4.69 per thousand cubic feet in 2020, significantly higher than projected in the non-GPS integrated 1990-7% 2005 case ($4.33 in 2010 and $4.30 in 2020). The price effects translate readily to an altered consumption pattern.

Whereas price changes for natural gas and electricity in the non-GPS integrated cases force reductions in industrial consumption of both electricity and natural gas relative to reference case levels, the GPS integrated cases project slight increases in industrial electricity consumption relative to the reference case, while industrial gas consumption is projected to be lower. The smaller electricity price and larger natural gas price impacts in the GPS integrated cases relative to the non-GPS cases reduce the incentive for industrial customers to lower their electricity usage or switch to natural gas. Essentially, relative to the reference case, higher natural gas prices encourage industrial consumers to switch to electricity, which more than offsets the conservation encouraged by higher electricity prices. Although the GPS prompts industrial consumers to reduce natural gas

Figure 2. Projected Wellhead Natural Gas Prices, 2000-2020



Source: National Energy Modeling System, runs MCBASE.D121300A, FDP7B05.D121300B, FDP7B08.D121500A, FDP75FEE.D021101B, and FDP7FEEG.D0111801A.

consumption by about 10 percent in 2010 relative to the reference case, increased natural gas consumption by electricity generators—projected to be as much as 92 percent higher than the reference case level in 2010 (as compared with an increase of 76 percent relative to the reference case in the non-GPS integrated cases in 2020)—more than offsets the industrial sector reduction. In the GPS integrated 1990-7% 2005 case, the projected wellhead price of natural gas in 2010 exceeds the reference case price by 87 percent and exceeds the price in the non-GPS integrated 1990-7% 2005 case by 15 percent.

The difference in expected changes to the generation fuel mix between the GPS and non-GPS integrated cases illustrates the effect of the output subsidy (Table 1). Despite much higher natural gas prices, natural-gas-fired electricity generation is projected to be higher in the GPS integrated cases than in the non-GPS integrated cases, especially in the early years of the forecast. In 2010, the GPS integrated 1990-7% 2005 case projects 2,070 billion kilowatthours of gas-fired generation, 13 percent higher than the 1,839 billion kilowatthours projected in the non-GPS integrated 1990-7% 2005 case. By 2020, the difference between the two cases is only 4 percent (77 billion kilowatthours of gas-fired generation), with increased generation from renewable sources expected to make up most of the difference. Renewable generation is only slightly higher in the GPS cases than in the non-GPS cases in 2010, but by 2020 increased generation from new, dedicated biomass and wind plants in the GPS integrated 1990-7% 2005 case leads to projected renewable generation of 850 billion kilowatthours, a 26-percent increase over the projection in the non-GPS integrated 1990-7% 2005 case.

Coal-fired generation is projected to drop even more dramatically in the GPS cases than in the non-GPS cases. The reference case projects 2,370 billion kilowatthours of coal-fired electricity generation in 2020, which is reduced to 825 billion kilowatthours in the non-GPS integrated 1990-7% 2005 case and to 738 billion kilowatthours in the GPS integrated 1990-7% 2005 case (13 percent lower than in the non-GPS case). Nuclear generation in 2020 is projected to be about 2 percent higher in both the GPS cases than in the non-GPS cases, because most existing units are projected to operate longer.

As indicated above, a key difference between the GPS and non-GPS integrated cases is in the projections for renewable electricity generation (Table 2). Because of the increased pressure on suppliers to find ways to reduce their emissions in the GPS integrated cases and the impact that it has on natural gas prices, suppliers are projected to turn increasingly to renewables, especially in the later years of the projections. Increased use of natural gas still is expected to be the most widely used compliance option, but the role played by renewables is expected to grow in the GPS integrated cases. For example, in 2020, generation from wind plants is expected to be 55 billion kilowatthours (423 percent) higher in the non-GPS integrated 1990-7% 2005 case than in the reference case, and in the GPS integrated 1990-7% 2005 case the corresponding difference is projected to be 112 billion kilowatthours (860 percent higher than in the reference case and 83 percent higher than in the non-GPS integrated 1990-7% case).

Table 2. Renewable Generation by Fuel in the Non-GPS Integrated and GPS Integrated Cases
(Billion Kilowatthours)

Fuel	Reference Case	Non-GPS Integrated 1990-7% 2005 Case	Non-GPS Integrated 1990-7% 2008 Case	GPS Integrated 1990-7% 2005 Case	GPS Integrated 1990-7% 2008 Case
2010					
Hydropower	303	308	308	309	308
Geothermal Energy	25	93	102	131	116
Municipal Solid Waste	29	35	35	35	35
Biomass	57	107	99	107	104
Solar Thermal	1	1	1	1	1
Solar Photovoltaic	1	1	1	1	1
Wind	12	15	15	29	20
Total	**429**	**561**	**562**	**614**	**586**
2020					
Hydropower	302	307	307	308	308
Geothermal Energy	25	97	102	133	116
Municipal Solid Waste	33	39	39	39	39
Biomass	66	162	141	241	222
Solar Thermal	1	1	1	1	1
Solar Photovoltaic	2	2	2	2	2
Wind	13	68	65	125	118
Total	**443**	**677**	**658**	**850**	**806**

Source: National Energy Modeling System, runs MCBASE.D121300A, FDP7B05.D121300B, FDP7B08.D121500A, FDP75FEE.D021101B, and FDP7FEEG.D011801A.

Because consumers are not expected to reduce their use of electricity significantly in the GPS integrated cases, electricity suppliers would have to take additional steps to reduce CO_2 emissions, and CO_2 allowance prices would be higher than projected in the non-GPS integrated cases (Figure 3). In the non-GPS integrated cases, the CO_2 allowance price peaks at $139 per metric ton (1999 dollars per metric ton carbon equivalent) in 2009; in the GPS integrated cases it peaks at $153 per ton in 2016. The CO_2 allowance price reaches a peak later in the GPS cases because of the greater pressure on suppliers to find ways to reduce emissions even as the demand for electricity continues to rise. The higher CO_2 allowance prices in the GPS integrated cases stem from increased natural gas generation, combined with the higher marginal cost of compliance for the efficient coal plants that remain in the dispatch.

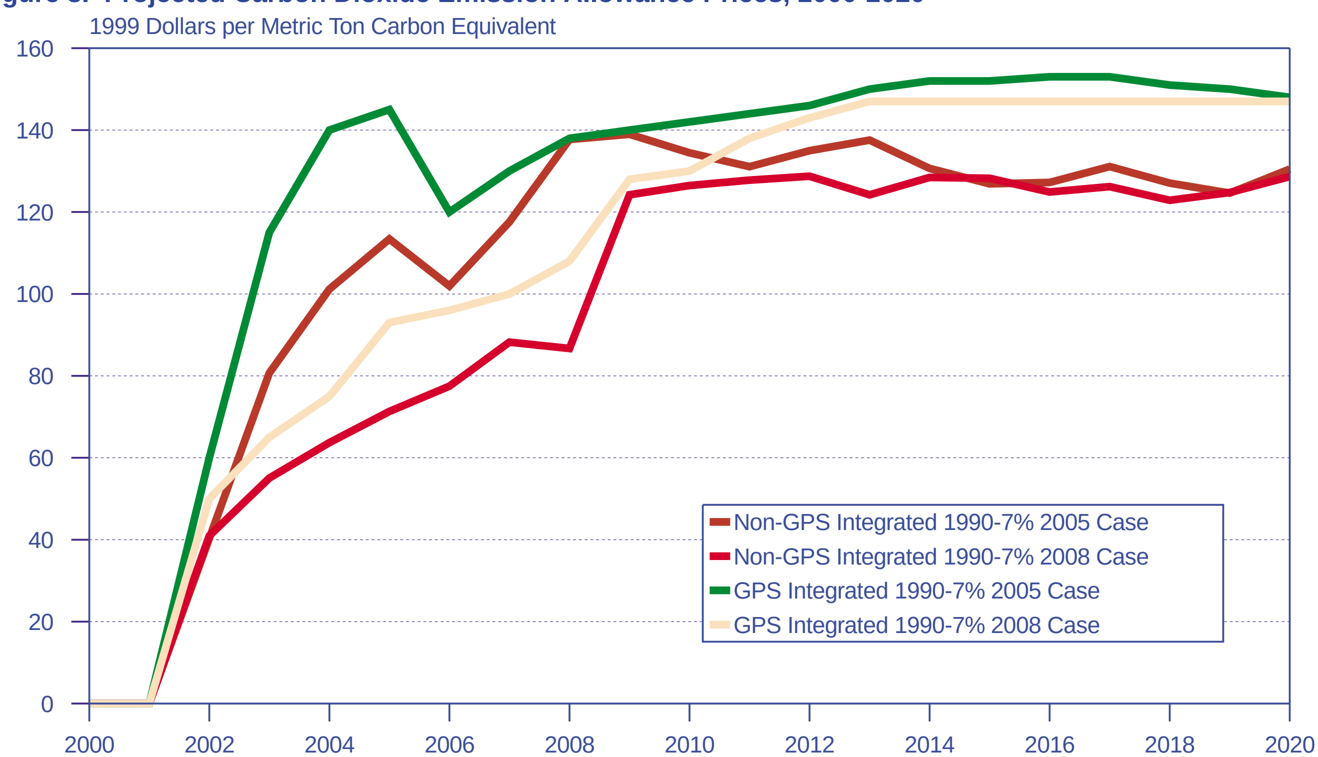
The Nation's electricity bill to all customer groups—residential, commercial, and industrial customers—is projected to be lower in the GPS integrated cases than in the non-GPS integrated cases. By 2010, electricity sales in the GPS integrated 1990-7% 2005 case is projected to be $279 billion, higher than the reference case projection of $243 billion but 13 percent below the projection of $320 billion in the non-GPS integrated 1990-7% 2005 case. In the GPS cases, lower electricity prices are expected to offset higher electricity usage, resulting in reduced revenues for electricity generators. At the same time, however, total resource costs for the electricity industry—the combination of fuel costs, capital costs, and operations and maintenance costs (excluding the costs of emission allowances)—are expected to be higher under a dynamic GPS allowance allocation scheme (Figure 4).

Reducing CO_2 emissions in the non-GPS integrated cases is expected to increase resource costs for electricity generators by $35 to $38 billion over the reference case levels in 2020. In the GPS integrated cases, however, total resource costs in 2020 are projected to increase by $69 to $72 billion relative to the reference case, about $34 billion more than in the non-GPS integrated cases. About half the increased cost is expected to come from greater expenditures on natural gas. A smaller portion is attributable to increased capital expenditures on new plants, including 25 gigawatts of relatively expensive dedicated biomass plants capacity. Increased expenditures on biomass fuel also account for part of the increase in total resource costs. The higher resource costs projected in the GPS cases are a measure of the inefficiency introduced by the production subsidy associated with the dynamic GPS.

Summary

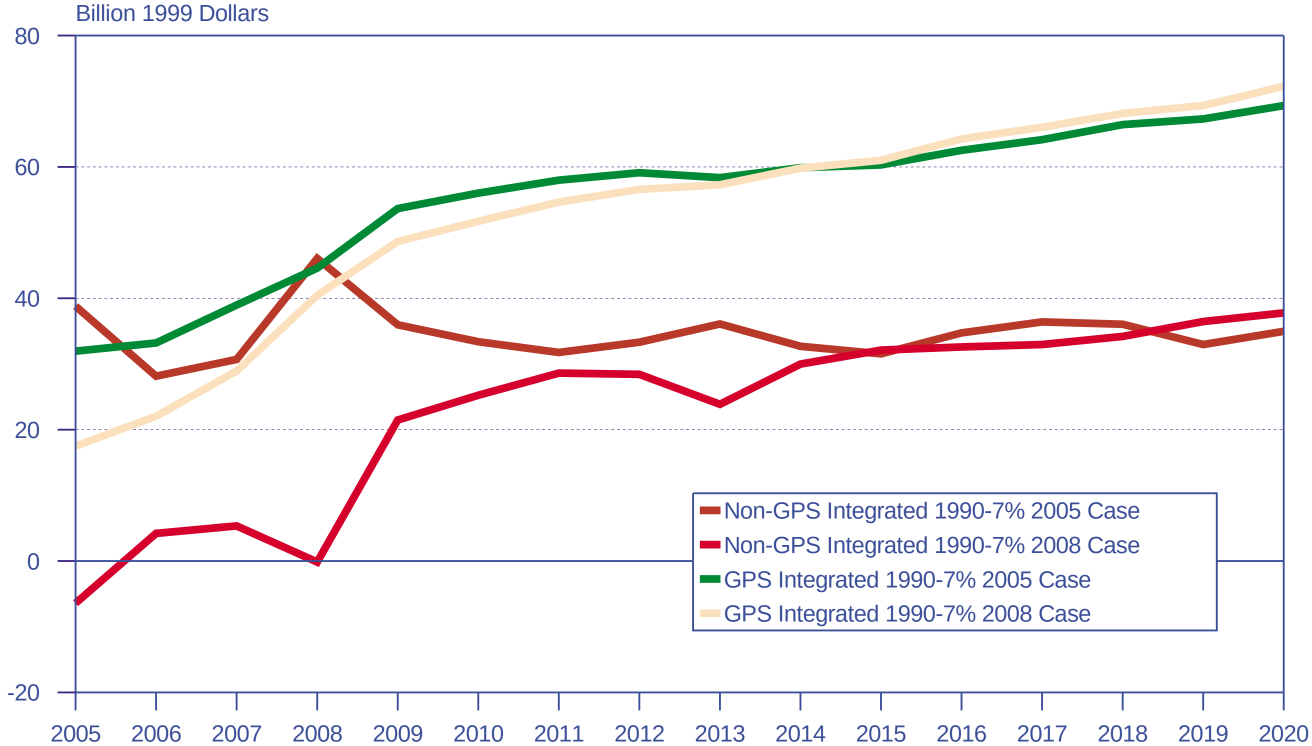
This report compares the projected impacts of two alternative policy instruments for reducing CO_2 emissions from electricity generation. Both systems use a cap and trade emission allowance system, but the allowance

Figure 3. Projected Carbon Dioxide Emission Allowance Prices, 2000-2020



Source: National Energy Modeling System, runs MCBASE.D121300A, FDP7B05.D121300B, FDP7B08.D121500A, FDP75FEE.D021101B, and FDP7FEEG.D0111801A.

Figure 4. Projected Changes in Total Resource Costs Relative to the Reference Case, 2005-2020



Source: National Energy Modeling System, runs MCBASE.D121300A, FDP7B05.D121300B, FDP7B08.D121500A, FDP75FEE.D021101B, and FDP7FEEG.D0111801A.

allocation schemes are different. The first approach, from EIA's Phase I analysis, uses a cap and trade system patterned after the CAAA90 SO_2 allowance program. The second uses a dynamic GPS allowance allocation system for CO_2 emissions. In many respects the results of the two instruments are similar: to reduce CO_2 emissions, the power generation sector is expected to turn away from coal to natural gas and, to a lesser extent, renewables. When a GPS CO_2 program is used, however, the impacts of the program on end-use electricity prices are projected to be lower; natural gas prices, CO_2 allowance prices, and total resource costs for electricity generators are expected to be higher; and generation from renewable fuels is expected to increase.

The higher total resource costs projected under a dynamic GPS allowance system result from the production subsidy inherent in the GPS program, which reduces the incentives for consumers to find ways to reduce their electricity consumption. The size of the increase in resource costs in the GPS analysis cases relative to the projected resource costs in the non-GPS cases depends on the extent to which emissions are projected to be reduced in the non-GPS cases as a result of consumer efforts to reduce electricity consumption when they are faced with the full price impacts of the emission reduction program without the production subsidy, as well as the price responses in the natural gas and renewable fuel markets to increased demand in the electricity generation sector.