Design of a Multipollutant Control Program: Stakeholder Analysis of Potential Policy Options

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Acknowledgments

This report is based on discussions and analytical work that took place as part of the Center for Clean Air Policy's Air Quality Dialogue on Multipollutant Control Approaches. A list of Dialogue participants, technical advisors and experts is attached. While most participants engaged in discussions of legislation addressing sulfur dioxide, nitrogen oxides, mercury and carbon dioxide, two industry participants declined to participate in discussions pertaining to control options for carbon dioxide.

We would like to thank the participants for the time and ideas they contributed to our effort to advance the state of knowledge on alternative multipollutant policy designs. This report describes new policy design elements and a range of modeling results that can help inform discussions of multipollutant control scenarios for the power sector.

All meetings were held and all analyses were conducted in 2003 prior to the December release of proposed rules by the Environmental Protection Agency on power plant emissions of mercury, sulfur dioxide and nitrogen oxides. The Dialogue participants do not intend this report to signify any endorsement of those proposals.

The Center would also like to thank the following organizations whose financial contributions and in-kind modeling assistance have made our efforts possible: U.S. Environmental Protection Agency (EPA), the Joyce Foundation, Arizona Public Service, Cinergy, Entergy, Exelon, Mirant, NiSource Inc., NRG Energy, PacifiCorp, Peabody, Wisconsin Energy, the Clean Air Task Force, and the New Jersey Department of Environmental Protection. EPA's financial aid and modeling support was restricted to examination of sulfur dioxide, nitrogen oxides and mercury; other sources of support were used to address CO_2 control options.

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Modeling work and policy discussions sought to inform the design of a multipollutant bill for the power sector. This effort was not in any way tied to the MACT regulatory process and did not attempt to model implications of economy-wide carbon control measures.

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I. EXECUTIVE SUMMARY

Over the past year, the Center for Clean Air Policy (CCAP) has hosted the Air Quality Dialogue on Multipollutant Control Approaches for the power sector. This forum, an intensive technical dialogue, brought together multiple stakeholders representing divergent viewpoints to help build a common understanding of alternative multipollutant policy designs and inform the policy debate with new ideas and analyses. Dialogue participants agreed to a series of model runs and underlying assumptions. The policy scenarios selected were not designed to reflect the advocacy positions taken by participating industry and environmental groups but rather to test a range of alternative scenarios that had not been previously modeled. Some of the chosen scenarios responded to individual interests whereas others had more broad-based interest. In addition, Dialogue participants discussed a handful of ideas for policy design that were not modeled.

This forum focused exclusively on the design of a multipollutant bill for the power sector and did not address policy design issues regarding the mercury MACT regulatory process, nor did it look at the effects of economy-wide carbon policies. Conclusions provided in this report are not prescriptions for policy or legislation. Rather, this report summarizes the main analytical findings of the effort and raises questions that will help set the stage for the next round of policy discussions.

The Dialogue, which involved the participation of leading policy makers and stakeholders from state government, industry, the environmental community and academia, applied technical analyses from a variety of sources to help participants understand the effects of various multipollutant policy designs on emissions, program costs, distribution of costs, environmental quality, energy reliability and future penetration of clean and efficient power-generation. As part of the process, the Dialogue sponsored a series of new modeling runs to understand the effects of policy alternatives pertaining to cap levels and timing, technology incentives, and the effects of different assumptions regarding gas prices and load growth. Model runs and assumptions were developed with input from a modeling workgroup and the full stakeholder dialogue. While modeling runs provide valuable insight into potential outcomes attendant to differing policy scenarios, limitations imposed by the model, as well as uncertainties inherent in modeling assumptions, limit the ability of modeling exercises to forecast the future. Accordingly, the results discussed here should not be viewed as dispositive. Rather, what is important in these results is the direction of the findings and the broad picture they paint about the likely impacts of alternative scenarios.

MODELING OVERVIEW

Modeling was conducted by ICF Consulting using the Integrated Planning Model (IPM) platform and modeling assumptions developed by the U.S. Environmental Protection Agency (EPA). The IPM is used extensively by EPA, the private sector, the Western Regional Air Partnership process, the Federal Energy Regulatory Commission, and environmental groups to inform policy design. The IPM is a detailed engineering-economic production-costing model that estimates the marginal cost of emissions reductions for the electricity- generating sector, given the cost and performance characteristics of available options, forecasts for electricity demand, and reliability criteria. The IPM model is capable of simulating single- or multiple-pollutant reduction constraints under cap and trade programs and has been used extensively to analyze alternative multipollutant policy for the electric power sector. The model analysis was run using EPA assumptions, then a combination of EPA and Energy Information Administration (EIA) assumptions agreed to by the Dialogue group. Assumptions involving IGCC and carbon capture and sequestration came from the Air Quality Dialogue process. Policy scenarios and modeling assumptions were developed with input from Dialogue participants.

"CCAP BASE CASE"

The Air Quality Dialogue modified the 2002 EPA analysis of the proposed Clear Skies legislation base case[1] to reflect new information on recent power plant construction and mercury emission modification factors (EMFs). Specifically, EPA developed the modified EMFs for SO_2 and NO_x control technologies with input from the mercury Maximum Achievable Control Technology (MACT) Federal Advisory Committee and they take into account results of the mercury Information Collection Request and other recent test results. During the course of the Dialogue, EPA updated its Base Case to reflect many of the changes adopted by the Air Quality Dialogue. The new EPA modeling is briefly described in the 2003 Technical Support Package for Clear Skies.[2]

The revised CCAP Base Case maintains the standard approach EPA and the U.S. Department of Energy have used for development of a "base case". It includes the assumptions that only promulgated regulations such as the Title IV Acid Rain Trading Program[3] and the NO_x SIP Call[4] are implemented. Provisions of the current Clean Air Act that require further emission reductions but have not yet been implemented through new federal regulations and state implementation plans [SIPs], such as the MACT standard for mercury and tighter SIPs designed to meet the National Ambient Air Quality Standards (NAAQS) for ozone and fine particulates by the current Clean Air Act's attainment deadlines, are not included in the CCAP Base Case. It is recognized, however, that this approach overestimates the emission reductions and the costs of new power plant legislation compared with existing law, because the existing law already requires further, yet-to-be-defined reductions in power plant pollution. Therefore, the "CCAP Base Case" should not be viewed as a "business-as-usual" (BAU) scenario. Rather, it reflects implementation of existing regulations that have already been promulgated, not full implementation of current law. A true "business-as-usual" scenario would reflect these required but still to be implemented reductions.

It would be helpful for EPA or others to model at least two potential BAU scenarios (i.e., high- and low-regulation cases) to bound the likely BAU regulatory and compliance pathways. Given the limited modeling budget for this project, we felt it was beyond the scope of this effort to attempt to model EPA's and the states' future regulatory directions.

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[1] EPA Base Case 2000, Run ID: ipm2000s100d, found at http://www.epa.gov/airmarkets/epa-ipm/results.html.
[2] See http://www.epa.gov/clearskies/03technical_packagetofc.pdf.
[3] Part of the Clean Air Act Amendments of 1990.
[4] The final rule is available at: www.epa.gov/ttn/oarpg/t1/fr_notices/126fina.pdf.

II. THEMES

A number of themes emerged during the discussions, most of which will require further dialogue in subsequent phases of the policy debate. The following sections summarize those themes:

CONTROL TECHNOLOGY

Early penetration of control technologies for mercury and carbon dioxide was seen as desirable by industry as a way to build confidence in the technology, and by environmental groups to boost near-term emissions reductions and to facilitate tighter control levels. In fact, the willingness of a company to accept a given control level is closely related to its perception of the level of risk associated with available or emerging control technologies and the likelihood that they can perform at a reasonable cost. Early demonstration of advanced technologies can help to both drive down costs and improve performance. The Dialogue assessed policy approaches that could be used to encourage application of mercury control technology such as activated carbon injection earlier than the schedule assumed in the Administration's Clear Skies plan. Similarly, the Dialogue assessed approaches to encourage early application of advanced systems for reducing carbon dioxide emissions, including coal gasification, carbon capture and geologic carbon storage.

Modeling runs were conducted of both incentives ("carrots") and requirements ("sticks") to deploy these technologies for removing mercury and CO_2 from the emissions stream. To encourage early penetration of mercury control technologies, the Dialogue modeled a "Technology Incentive Pool," a pool of mercury allowances allocated to early adopters of activated carbon injection (ACI) and other advanced mercury-control technologies. For carbon, the modeling included financing incentives to encourage economic penetration of Integrated Gasification Combined Cycle (IGCC) technology. In some analyses, IGCC incentives were coupled with incentives for retirements of old, inefficient coal plants. In other analyses, IGCC incentives included incentives for carbon capture and sequestration.

These incentives were modeled in combination with emission caps for both mercury and carbon. For mercury, the Dialogue modeled a national 10-ton cap on mercury emissions in 2015, both with and without the technology incentive pool. For carbon dioxide, the modeling included the combination of various carbon caps with financial incentives for IGCC with carbon capture and sequestration. For carbon dioxide, the Dialogue also discussed an alternative to the traditional cap and trade design, which involves infrequent and relatively large step-wise reductions. The alternative scenario is a carbon cap with a regular annual decline, subject to a carbon price circuit breaker. This approach could be applied to other types of emissions as well. No formal modeling of this approach was conducted, however.

CONTROL COST

Another major theme was the cost of control. All participants agreed that one of the great strengths of a multipollutant approach to regulating emissions from electric generators lies in the opportunity it provides generators to create an integrated strategy for control of such pollutants. Participants agreed, assuming appropriate pollution caps and timetables, that, in contrast to the current law's uncoordinated timing of reduction requirements for various pollutants, a multipollutant approach with synchronized deadlines leads to better planning, greater certainty, lower costs, and more environmental benefits per dollar expended. To further minimize the costs of a multipollutant approach, all of the modeling runs evaluated by the Dialogue assume trading for all pollutants evaluated. While the Dialogue agreed to model runs that assume trading, a minority of participants did not support trading for mercury. Cost advantages of trading need to be balanced with concern for local impacts created by trading regimes.

The other key control cost consideration entails the level and timing of requirements. In comparison to the Administration's Clear Skies proposal, we analyzed the potential impact on compliance costs of a number of specific alternative policy scenarios including earlier phase two compliance deadlines and more stringent reduction requirements. We also considered the impacts on compliance cost of a more optimistic projection of mercury-control technology environmental performance to reflect possible advances post-2010. Finally, the group looked at the cost impacts of new incentives to encourage early adoption of advanced technologies, which could help lower costs of meeting more stringent targets in the Phase 2.

EMISSIONS BENEFITS

A third theme related to the health and environmental benefits of various multipollutant control scenarios. In the case of SO_2 and NO_x, the Dialogue considered the health effects of different alternative control scenarios – i.e. impacts on attainment status, numbers of premature deaths and illnesses avoided, and the monetized values of those avoided health effects and considered these benefits in conjunction with the cost information. In the case of mercury and CO_2, the Dialogue considered benefits in terms of emission reductions; due to the difficulties involved, we did not attempt to quantify or monetize the health and environmental benefits of these reductions.

There was concern that the timing of the SO_2 and NO_x requirements in a power sector program be consistent with attainment dates for the National Ambient Air Quality Standards under the current Clean Air Act. The deadline for attainment of the fine particle standard falls in 2009, while the deadline for meeting the eight-hour ozone standard could range from 2007 to 2013. These deadlines can be extended by up to seven years if the states so request and if EPA makes certain findings that technology is not available to comply any earlier. Many states are relying on emissions reductions from upwind power plants as part of their strategies for meeting the PM and ozone standards. Power plant emission reductions alone under the Administration's Clear Skies proposal would be sufficient to bring many areas into attainment, and will contribute to attainment even in areas that need additional reductions. A more aggressive SO_2 cap scenario is projected to bring additional counties into attainment. In most cases, these power plant emission reductions are more cost-effective than those available from other sectors. Unless power sector emissions are reduced on a timetable consistent with the current law's attainment dates, the public may be forced to continue breathing unhealthy air for years beyond those deadlines, or alternatively may pay a higher price to achieve the necessary emission reductions from other sectors.

EFFECTS ON PLANTS IN REGULATED AND DEREGULATED MARKETS

A fourth key theme was the question of whether independent power producers and other power generators operating in deregulated markets face greater challenges than their regulated counterparts in complying with new control requirements. A preliminary analysis of the financial impacts of multipollutant legislation conducted by ICF for EPA on the proposed Clear Skies legislation of 2002[5] suggested that although plants in competitive markets face relatively greater financial effects, nearly all power-generation companies are sufficiently diversified from a fuel type and/or market standpoint that they will be able to bear the new regulation without significant financial problems. However, an updated analysis indicates that plants in competitive markets will benefit overall from Clear Skies due to higher revenues resulting from increasing natural gas prices (and, therefore, higher costs for price-setting natural gas plants) and higher compliance costs for price-setting coal-fired units. The Dialogue did not model the effects of this issue. We will dig further into the impacts of multipollutant regulation on different types of power generators in the next phase of the effort.

We also reviewed a number of analyses of the implications for power plant asset values stemming from the choice of allowance allocation methods. Participants developed a common understanding of the basic effects of different allocation methods on the asset values of power generators using different types of fuels. In particular, presentations focused on the extent to which allowance allocations could over- or under-compensate firms for the change in their net asset value as a result of multi-pollutant caps. This issue will require significant further evaluation to assess whether and to what extent different three- and four- pollutant requirements could disparately impact different regional electricity markets, companies, individual plants, and more broadly, the ongoing transformation of the industry to more competitive market designs.

THE ROLE OF COAL IN THE U.S. ENERGY SUPPLY

Closely linked to the issue of advancing emission-control technology was consideration of the role of coal in the future U.S. energy supply. We examined a number of policy options for encouraging achievement of a zero-emission coal future, enabling coal to continue to play a significant role in meeting world energy and environmental requirements.

The plants most likely to be affected by new multipollutant requirements are small existing coal units (under 300 megawatts [MW]), which together make up about 75 gigawatts of generating capacity. With higher than average heat rates and operating costs, such units are already less competitive in the dispatch order compared to larger coal units and typically operate at capacity factors below 50 percent. New requirements will cost more on a per megawatt-hour (MWh) basis for these smaller units due to the lower economies of scale when adding control technologies to small units, further pushing those units up the cost curve and reducing the amount of time they will run economically. The group agreed that such units should be a focal point of the analysis given their relatively high emissions rates and vulnerability to new requirements.

[5] *Financial Impact of a Multipollutant Emissions Policy*. Report prepared by ICF Consulting for the U.S. Environmental Protection Agency. 2002. Available at: http://www.epa.gov/air/clearskies/pdfs/impactanalysis.pdf.

III. NO_X AND SO_2 POLICY DESIGN

Combustion of fossil fuels from power-generation releases SO_2 and NO_x emissions to the environment, contributing to the formation of ground-level ozone, acid rain, particle formation, and visibility impairment. To protect against adverse effects from SO_2 and NO_x, the federal government and many states have implemented a number of measures to control emissions from power generating facilities. Additional power sector controls can help attain national ambient air quality standards for ozone and fine particles as well as other air quality objectives. As a result, additional limits on SO_2 and NO_x have been proposed as part of a multipollutant approach.

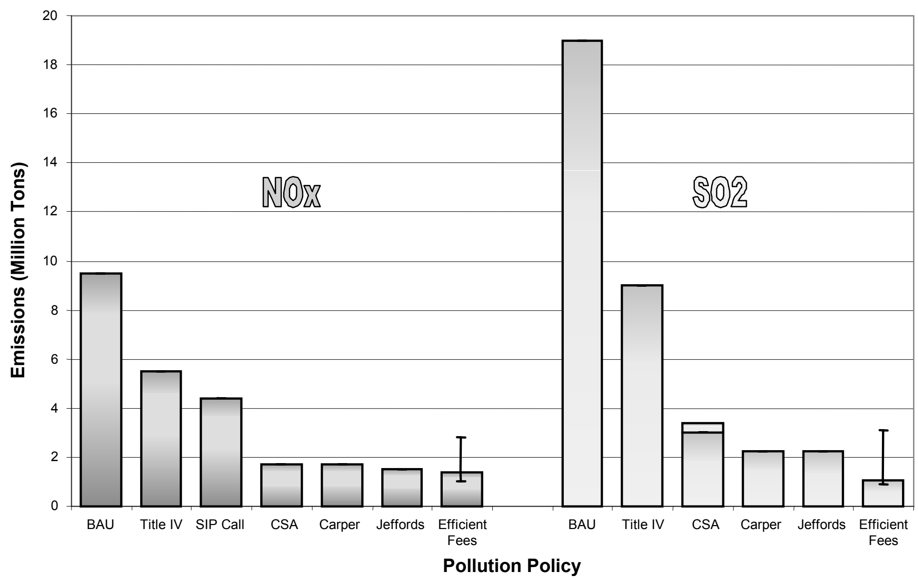
EFFICIENT LEVEL OF CONTROL

Researchers at Resources for the Future presented an analysis of the costs and benefits of SO_2 and NO_x controls that looked at "readily quantifiable" health benefits associated with reducing fine particulates.[6] According to that analysis, the proposed SO_2 and NO_x cap levels in all three legislative proposals (Clear Skies Act [CSI], Carper and Jeffords) fall within the zone in which benefits appear to exceed cost. Importantly, the RFF analysis indicated that deeper SO_2 emissions reductions would also have benefits exceeding costs. [See the "efficient fees" bars (Figure 1)]. Greater emission reductions of both pollutants could be justified by including other emissions reductions benefits beyond those considered "readily quantifiable." On the other hand, costs would increase if the actual requirements used a less efficient design (such as command-and-control style requirements). Moreover, the efficient level of control would change if health benefits from reducing SO_2 were lowered.[7]

[6] Banzaf, HS, Burtraw D, Palmer KL. *Efficient Emissions Fees in the U.S. Electricity Sector*, Resources for the Future Discussion Paper, October 2002. Available at: http://www.rff.org/Documents/RFF-DP-02-45.pdf

[7] The Aries study and others that isolate the effects of different fine particle components may help to refine the estimated benefits from controlling SO_2 emissions from power plants. To the extent that components other than sulfate are responsible for health effects associated with fine particles, this would impact the efficient level of sulfate control. However, an industry representative provided this information after the conclusion of the stakeholder process and other participants in the Air Quality Dialogue did not review these studies.

Figure 1: Electricity-Sector NO_x and SO_2 Emissions in 2020



BAU=business as usual; CSA=Clear Skies Act.
Note: Range on "Efficient Fees" bars indicates the zone within which benefits appear to exceed costs.
Source: Burtraw D, Palmer, KL. *The paparazzi take a look at a living legend: The SO_2 cap-and-trade program for power plants in the United States.* Resources for the Future Discussion Paper 03-15. Washington, DC: Resources for the Future, 2003.

IMPACT OF MORE AGGRESSIVE SO_2 AND NO_X TARGETS AND TIMING

The Dialogue modeled a SO_2 and NO_x control scenario more aggressive than the Clear Skies proposal in a "two-pollutant" or 2P scenario. Under this scenario, NO_x was reduced to 1.7 million tons in 2012 (six years sooner than Clear Skies Act requirements) and SO_2 was reduced to 2.25 million tons in 2015 (25 percent below CSA levels and three years earlier than the CSA final target) with no mercury constraint. The net present value of the added cost of this 2P run ($72.8 billion between 2005 and 2030) was 20 percent higher than the CCAP Clear Skies case and 5 percent higher than the cost of a three-pollutant control scenario that capped NO_x and SO_2 emissions at Clear Skies levels and also capped mercury at 7.5 tons in 2015. Tightening NO_x and SO_2 caps beyond the CSA levels was projected to have little impact on national average wholesale energy prices and natural gas prices (about 1 percent).

An EPA analysis using the REMSAD[11] air quality model considered the impact of proposed Clear Skies SO_2 and NO_x control scenarios on nonattainment for the 8-hour ozone and $PM_{2.5}$ standards. The results show a decrease in the number of counties in nonattainment for both standards in both 2010 and 2020. In the case of $PM_{2.5}$, Clear Skies was found to reduce the number of counties in nonattainment by 42 and 25 in 2010 and 2020, respectively, while in the case of the 8-hour ozone standard, Clear Skies would reduce the number of counties in nonattainment by 3 counties in both the 2010 and 2020 time periods beyond existing

Table 1: Number of Counties in Non-Attainment

Standard	Current	Base Case 2010	Clear Skies 2010	Base Case 2020	Clear Skies 2020	More Stringent SO_2[8] and NO_X 2010	More Stringent SO_2[9] and NO_X 2020
$PM_{2.5}$	129	69	27	43	18	7 additional counties achieve attainment[10]	3 additional counties achieve attainment
8-Hour Ozone	290	47	44	23	20	Not Available	Not Available

requirements (Table 1). A separate assessment conducted by MSB Energy Associates, Inc. for the Clean Air Task Force approximated the $PM_{2.5}$ attainment benefits of SO_2 emissions reductions beyond the Clear Skies Act using linear relationships developed from EPA's modeling work using a methodology suggested by EPA. Specifically, they assumed relationships between national tons of SO_2 emissions and county-level $PM_{2.5}$ concentrations and asthma and mortality emissions factors. They found that the more aggressive SO_2 cap scenario is projected to result in 3 to 7 additional counties meeting attainment beyond what is projected to occur under the Administration's Clear Skies proposal.[12]

Because fine particulate attainment appears to be dependent on the depth and speed of SO_2 reductions from power plants, it may be important to ensure that SO_2 deadlines within a multipollutant control program are consistent with the current law's NAAQS attainment deadlines. The SO_2 reductions under a power-sector multipollutant program would need to be completed by the Clean Air Act's attainment deadlines (2009 to 2016, depending on whether

[8] This scenario capped SO_2 emissions at 4.5 million tons in 2008, 3.5 million tons in 2012 and 2.25 million tons in 2015.
[9] Ibid.
[10] The assessment conducted by MSB Energy Associates, Inc. did not precisely replicate REMSAD modeling results for the Clear Skies run, therefore, the number of counties remaining are not directly comparable to the other numbers in this table. However, as indicated, this study did suggest the relative magnitude of benefits that would be achieved by the more stringent SO_2 and NO_x runs.
[11] Regional Modeling System for Aerosols and Deposition
[12] According to analysis done by MSB Energy Associates, Inc., this translates into an estimated 2,700 to 3,500 avoided deaths per year in 2010 and 2020, valued at roughly $17 to $26 billion annually, and an estimated 23,900 to 44,900 avoided asthma attacks per year in 2010 and 2020.

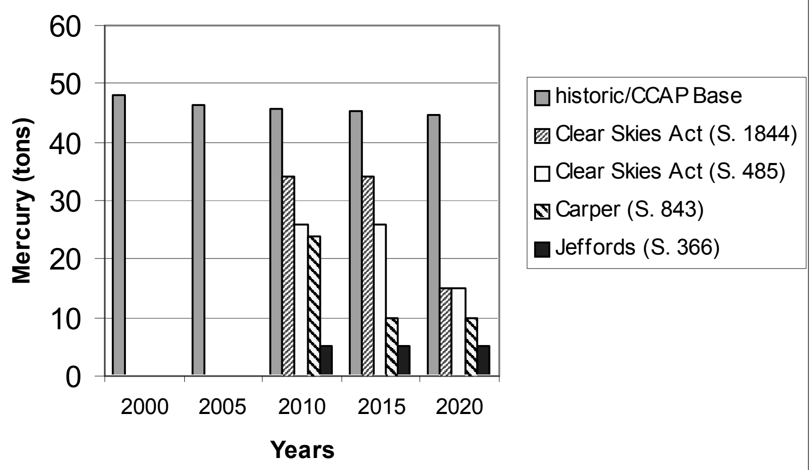
extensions are granted) to assist in meeting the $PM_{2.5}$ standard. A summary of fine particle and ozone attainment deadlines is provided in the Appendix. Under the current Clean Air Act, the deadline for attaining the $PM_{2.5}$ standard is 2009. It can be extended to as late as 2016, but only if findings are made, after notice and public comment, that technology for earlier attainment is not available. No such findings have yet been made.

IV. MERCURY POLICY DESIGN

Mercury is a persistent and bioaccumulative toxic pollutant that poses developmental health risks to fetuses and children through the consumption of fish. To protect against adverse effects from mercury exposure, most states have issued fish consumption advisories recommending that consumers limit their intake of certain types and sizes of fish. In the US, coal-fired power plants are the largest source of US anthropogenic mercury emissions that is still unregulated under the Clean Air Act. Combustion of coal from power-generation releases mercury to the environment. Mercury released to the atmosphere can travel locally, regionally or globally depending on the form of the mercury and climate conditions. Eventually, mercury emissions will deposit in watersheds, lakes, and streams, contributing to bioaccumulation through the food chain from phytoplankton to fish to people. Mercury emissions will be controlled from the power sector through regulations and/or new legislative requirements. See Figure 2 for a summary of mercury emissions levels under legislative proposals.

Extensive modeling was conducted during the course of the dialogue to understand implications of different mercury policy scenarios for the purpose of informing the design of a multipollutant bill. Model runs looked at different mercury control levels and timing, incentives to encourage early deployment of mercury technologies, and sensitivities on technology assumptions, gas price and load growth. Given the limited budget for this effort, we were not able to model every mercury policy design. Further, while all scenarios assumed emissions trading for mercury, it should be clearly stated that there was no consensus on the suitability of mercury trading as a core element of any mercury emissions control regime. Finally, we note that these analyses were conducted before EPA's December 2003 proposals to regulate mercury emissions. The dialogue participants intend no endorsement of EPA's proposals. The modeling conducted for the dialogue may be useful, however, in evaluating those proposals.

Figure 2: Mercury Emissions Levels Under Various Legislative Proposals



Notes: 1. Base Case reflects implementation of the NOx SIP Call and Acid Rain Trading program only. Implementation of new fine particle and ozone transport rules is expected to reduce mercury to 34 tons in 2010. 2. Actual emissions may be higher/lower than shown due to emissions banking.

The modeling runs conducted by the dialogue reference mercury control levels in multipollutant legislation that had been proposed in 2003. Figure 2 shows the mercury emission caps under the main legislative proposals. In addition, we had expected to be able to evaluate a variety of other mercury runs that were to have been developed by EPA for the

Mercury Working Group of the Clean Air Act Advisory Committee. However, these runs were not made available.

MERCURY CO-BENEFITS OF SO_2 AND NO_X CONTROL

Depending on the type of control technologies used and the type of coal being burned, NO_x and SO_2 control can also reduce emissions of mercury.[13] Emission factors are used to represent the ability of various technology and coal combinations to remove mercury. Mercury modeling runs conducted by the Dialogue used the same mercury emissions modification factors (EMFs) used in EPA's 2003 Clear Skies modeling. Previous EPA studies of the Clear Skies Act (using the older EMFs) found that NO_x and SO_2 technologies expected to be applied to comply with the NO_x and SO_2 provisions of the Act resulted in mercury being reduced from 48 tons (current levels) to about 30 tons, four tons over the proposed Clear Skies Phase 1 mercury target of 26 tons in 2010. Modeling conducted using the revised EMF assumptions found that CSI NO_x and SO_2 controls without a mercury constraint reduced mercury emissions to 34 tons in 2010.[14] Most of these "co-benefit" mercury emissions reductions are expected to occur in eastern parts of the country where plants burning high sulfur coals are projected to install scrubbers.

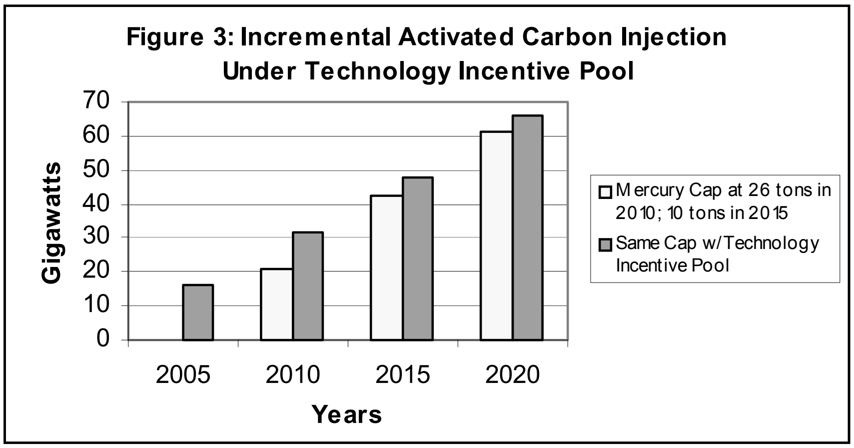
Based on these modeling results, the cost of bridging the gap between the 34-ton co-benefits level to a 26-ton cap in 2010 is estimated at $0.6 billion.[15] On a net present value basis, the difference is $6.7 billion over the 2005 to 2030 study period, or 11 percent of the CSA control costs where mercury is capped at 26 tons in 2010. The incremental costs to go from 34 to 26 tons in 2010 pays for about 6 GW of ACI technology and small amounts (<1 GW apiece) of SCR and scrubber technology. Generation from coal decreases slightly with the incremental mercury control, by about 2 percent.

We also looked at the mercury co-benefits resulting from a more aggressive NO_x and SO_2 control scenario with no mercury constraint.[16] We found that the more aggressive NO_x and SO_2 control scenario is projected to achieve an additional 3.8 tons (11% reduction) of mercury co-benefits in 2010 beyond those achieved by Clear Skies NO_x and SO_2 control levels in the absence of mercury control, at an incremental cost of $19 billion over the 2005 to 2030 study period. While tightening the NO_x and SO_2 caps obviously results in important health and environmental benefits independent of its impact on mercury, it does not appear to be a cost-effective way to reduce mercury emissions as compared to direct reductions in the mercury cap.

[13] For example, NO_x and SO_2 controls more readily remove the more reactive oxidized form of mercury than elemental mercury. Eastern bituminous coals generally have higher proportions of oxidized mercury than western subbituminous and lignite coals, and therefore experience better removal rates with the addition of scrubbers and SCR controls.
[14] Note that the Clear Skies Act of 2003, introduced by Senator Inhofe, Chairman of the Senate Environment and Public Works Committee, modified the first phase mercury target to be equivalent to the 34-ton "co-benefits" level.
[15] These costs may be overestimated given that housekeeping measures, optimization of existing controls for mercury, and other potentially cost-effective mercury-control options that might be used to reduce mercury at the margin are not reflected in the model. However, use of a 90 percent control assumption for ACI technology for all coal types may underestimate actual compliance costs and overestimate control potential.
[16] Under this scenario, NO_x was reduced to 1.7 million tons in 2012 (six years sooner than Clear Skies requirements) and NO_x was reduced to 1.7 million tons in 2015 (25 percent below CSA levels and three years earlier than the CSA final target).

INCENTIVE POOL TO PUSH MERCURY TECHNOLOGY

One of the key reasons for undertaking a multipollutant approach is to provide certainty to generators on future requirements so that they can plan future emissions limits into near-term investment decisions. However, industry uncertainty with respect to the performance of advanced mercury control technologies[17] on specific types of plants—especially those burning subbituminous and lignite coals—presents a barrier to such planning. Despite the desire for additional testing of mercury control technologies, few power generators are willing to make the necessary investments due to what they perceive as the high compliance and financial risks[18] and relatively low returns. In fact, testing done by early actors could ultimately benefit the whole industry, including possible competitors. Participants considered alternative methods of promoting early penetration of advanced mercury control technologies in a way that shares the risk across the industry sector. Advanced technology incentives may be particularly important under a control regime that relies predominantly on mercury "co-benefits" from SO_2 and NO_x technologies in the first control phase.



Specifically, the group discussed policy measures to: 1) encourage early experience with mercury-control technology as a way to build confidence in technology performance and cost, 2) reduce financial and compliance risk, and 3) achieve mercury emissions reductions equal to or beyond the assumed Clear Skies "co-benefits" levels in 2010. We modeled one approach for pushing mercury technology innovation — a "Technology Incentive Pool," whereby a pool of allowances would be allocated to early adopters of new or advanced mercury technologies before the Phase I deadline for mercury reductions.

The analysis assumed that 10 percent of the allowances from the Phase 1 cap (2.6 tons) would be made available each year to units installing advanced mercury control technology between 2006 and 2009.[19] (In the modeling ACI was used as a proxy for all advanced mercury-control

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[17] In this report we used the term "advanced mercury control technology" to refer to control technologies directed specifically at controlling mercury, in contrast to control technologies developed for SO2 or NOx control which also reduce mercury emissions to a limited degree as a co-benefit. The Dialogue Group did not reach any consensus about whether mercury-specific control technologies are or are not demonstrated or available within the meaning of Section 112 of the Clean Air Act.

[18] There is concern the technology won't work as well as anticipated, resulting in having to undertake still additional mercury control measures or purchase of allowances, or that control costs will be higher than anticipated.

[19] Note that although this run design assumed that the allowances for the technology incentive pool would come from within the cap (in order to facilitate comparison with other runs), the policy could be designed such that allowances that are part of the technology incentive pool are additional to the cap. Creating an incentive pool with allowances that are additional to the cap, however, would allow an increase in emissions and would lower the value of allowances, reducing the incentive for advanced technologies.

technologies because it was already included in the model.) The results show an increase in the use of ACI over the study period compared with a scenario that caps mercury emissions at 26 tons in 2010 and 10 tons in 2015, especially in the early years, resulting in a 2 to 6 percent reduction in mercury emissions in each reported run year (2005 to 2020) (Figure 3). The technology incentive pool comes at an increase in incremental system costs of less than one percent ($400 million in total over the 2005 to 2030 period).

Allowances could be distributed to units installing advanced technologies through a reverse auction, or via first come, first served, or pro rata methods. A reverse auction approach would require each interested plant to submit a bid equal to the number of allowances it would be willing to accept to install the advanced mercury technology early. Winning bids would be chosen on the basis of the smallest number of allowances per MW of retrofit to be installed until the entire pool was exhausted. While a reverse auction would achieve the most mercury-reductions per mercury allowance, it may not result in the greatest advances in control technology and it may not achieve progress in technology development in western states where power generators are concerned about the availability of technical solutions. To ensure that advanced technologies are tested on western subbituminous and lignite coals in addition to eastern bituminous coals, one solution would be to establish separate allowance pools for different coal types.

EARLIER AND MORE STRINGENT PHASE 2 MERCURY COMPLIANCE CAPS

As one point of reference, we looked at the mercury levels and timing proposed by the Clear Skies Act using our updated assumptions, as described above, on new generating units and emission modification factors (EMFs). We then looked at three scenarios that implemented incrementally more stringent mercury requirements in Phase 2. These levels were not chosen to match advocacy positions. Rather, these model runs were chosen in an effort to identify a possible middle ground solution as part of a compromise scenario in which a less stringent Phase 1 target is traded off against a more stringent Phase 2 target. The exact estimates cited here should not be viewed as dispositive. What is important is the direction of the findings and the broad picture they paint about the likely effects of various scenarios.

Table 2: Comparison of Three-Pollutant (3P) Scenario Costs and Cumulative Mercury-reductions

	NPV of Incremental 3P (billion 1999$)	Percent Change		Cumulative Hg Redux by 2022 (tons)	% Hg change from CSA
		From CSA	From 2P Case		
2P Case	53.8				
CSA (26 tons in 2010; 15 tons in 2018)	60.5		12.5%	358	
Case 3 (10 t ons in 2018)	63.6	5.1%	18.2%	387	8%
Case 1 (10 tons in 2015)	66.6	10.1%	23.8%	431	20%
Case 4 (7.5 tons in 2015)	70.1	15.9%	30.3%	459	28%

Each change in the timing or level of the mercury cap evaluated by the Air Quality Dialogue resulting in earlier or more aggressive mercury reductions causes a roughly 5 percent increase in the net present value of system costs over the next less stringent case examined. Table 2 shows the increase in system costs and cumulative emissions reductions for the various scenarios analyzed. For example, going from the Clear Skies cap of

15 tons in 2018 to 10 tons in 2018 is projected to increase total system costs by 5.1 percent ($3.1 billion) between 2005 and 2030 and increase cumulative mercury-reductions through 2022 by 8 percent. Likewise, a 10-ton cap in 2015 is projected to increase system costs by 10.1% ($6.1 billion) over the cost of Clear Skies in the 2005 to 2030 timeframe and increase cumulative mercury reductions through 2022 by 20%. To put these costs into perspective, this is comparable to the cost savings achieved by moving the first phase target to 34 tons from 26 tons.

Most commonly, stakeholders and decision makers compare the impact of various alternative mercury-control scenarios in terms of the change made in the total cost of proposed three-pollutant (3P) legislative scenarios. Stakeholders and decision makers usually ask, "How much will this change to mercury requirements increase the total cost of the legislation?" A second approach would be to attempt to isolate the change in mercury costs from the costs of the total 3P package. A limitation of this approach is that when the mercury cap and timing are changed, the model predicts different compliance choices for SO_2 and NO_x, since plants will optimize for the least-cost solution for all three-pollutant reduction requirements. Therefore, it is difficult to apportion costs to individual pollutants. In other words, while costs per ton of mercury control may increase in one run compared to another, costs per ton of SO_2 or NO_x control may decline. Although the total dollar cost differences between the scenarios remains the same, some participants felt it was useful to see that the impacts of a more aggressive mercury control program appear greater in percentage terms when compared only in terms of mercury costs.

According to the modeling, going from the Clear Skies cap of 15 tons in 2018 to a cap of 10 tons in 2018 increases incremental mercury costs from $6.7 billion (the incremental mercury cost under Clear Skies) to $9.7 billion[20], an increase of $3 billion or 46 percent. A 10-ton cap in 2015 results in incremental mercury costs of $12.8 billion, a 92 percent increase from the incremental mercury control costs associated with Clear Skies. Finally, tightening the cap to 7.5 tons in 2015 results in incremental mercury control costs of $15.3 billion, a 129 percent increase from the incremental mercury control costs associated with Clear Skies. These percentage increases are significantly higher than those shown in the table above because the mercury control cost contributes a relatively small share of the total three-pollutant control cost.

Table 3: National Wholesale Electric Prices ($/MWh)

	2015	Percent change From CSA	Percent change From Ref Case	2020	Percent change From CSA	Percent change From Ref Case
Ref. Case	30.14			32.71		
CCAP Clear Skies Act (15 tons in 2018)	31.32		3.9%	33.04		1.0%
Case 3 (10 t ons in 2018)	31.34	0.1%	4.0%	33.03	0.0%	1.0%
Case 1 (10 tons in 2015)	31.36	0.1%	4.0%	33.02	-0.1%	1.0%
Case 4 (7.5 tons in 2015)	31.37	0.2%	4.1%	33.01	-0.1%	0.9%
MWh = megawatt hours						

National wholesale electric prices climb virtually imperceptibly in 2015 as the caps and timing are tightened beyond Clear Skies levels. In 2020 prices are basically flat in all cases compared

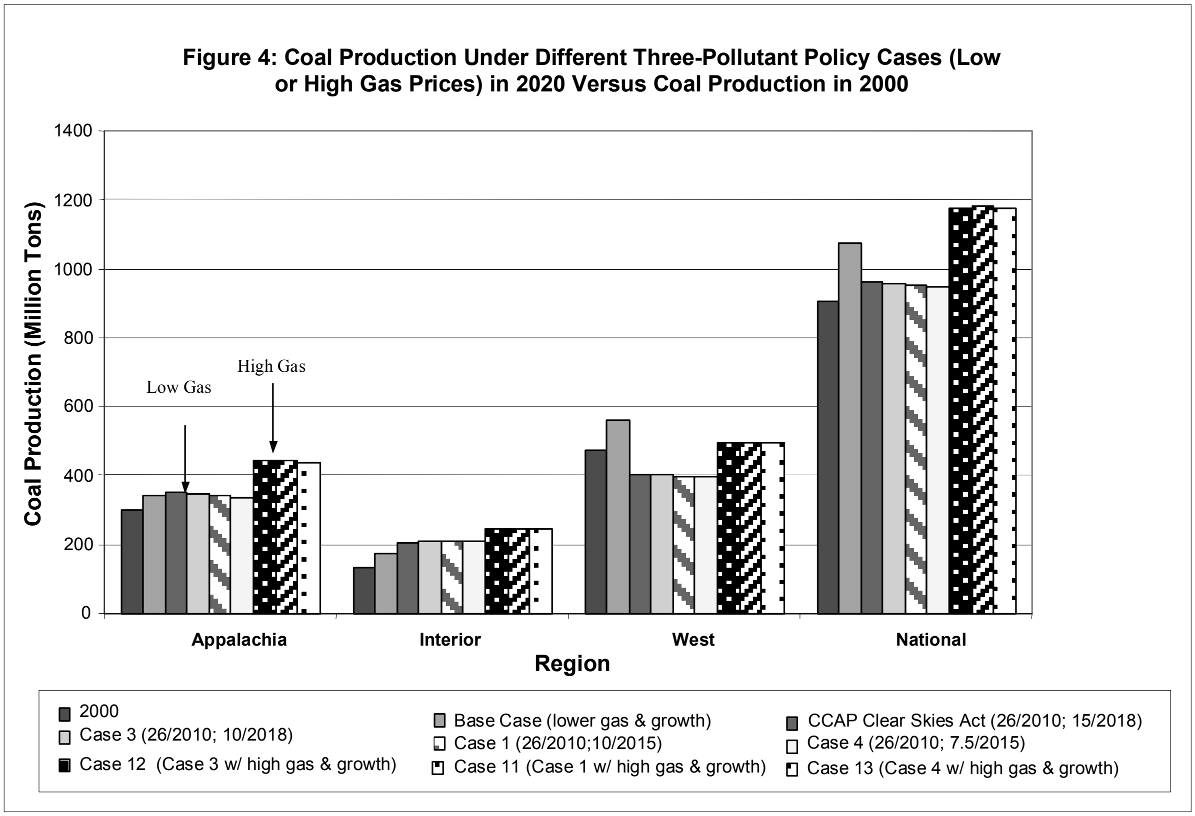
[20] These incremental costs associated with mercury control were calculated by subtracting net present value costs from the full study period (2005 to 2030) associated with a two-pollutant (NO_x and SO_2) scenario from the full three-pollutant (NO_x, SO_2 and Hg) scenario control cost.

with Clear Skies (Table 3). When results for selected heavily coal-fired regions are examined, the same pattern is prevalent. This seemingly counterintuitive outcome can be explained by the observation that natural gas units are on the price-setting margin in most regions, whereas the bulk of controls will be added to coal-fired units. In addition, the modeling indicates that virtually all generators elect to make technology retrofits rather than to switch from coal to gas; wholesale prices are therefore relatively unaffected. Thus, although more stringent mercury scenarios led to additional system-wide pollution control costs, those costs are likely born by some combination of utility shareholders and retail ratepayers and are not passed on in the wholesale electricity market.

FUEL SWITCHING UNDER MERCURY SCENARIOS

In our modeling, no significant fuel switching from coal to gas occurred in any of the mercury scenarios. In fact, the 7.5-ton case resulted in less than 2 percent fuel switching away from coal. In all cases national coal use increased from 2000 levels (Figure 4). However, these results are potentially sensitive to assumptions on the effectiveness of mercury-control technologies on western subbituminous and lignite coals. In the event that mercury-control technologies cannot achieve 90 percent control effectiveness on western coals at the assumed cost, we would expect more fuel switching from coal to gas or to eastern bituminous coals. Conversely, if mercury-control technologies become more advanced and exceed 90 percent control, even greater reductions would be possible without inducing fuel switching. Moreover, the impact on competition between regional coal markets is affected only marginally by tightening the cap and timing of mercury-controls. In general, interior coal production rises slightly (1 to 3 percent), whereas Appalachian and western coal production declines by a similar amount (2 to 4 percent and within 1 percent, respectively) compared with their projected levels under a Clear Skies policy scenario.

Changing assumptions about the relative level of natural gas prices and about the relative growth rate in demand for electricity have a more pronounced effect on both national and regional coal production than changes in a second-phase mercury target. Assuming future natural gas prices at levels projected by the Energy Information Administration (i.e., gas prices higher than EPA estimates but lower than current market prices) results in growth in national and regional coal production relative to historic production levels in 2000. Assuming lower natural gas prices and load forecasts still results in growth in coal production over 2000 levels, but of a much smaller size. National coal production is projected to grow by 30 percent with EIA's assumptions and only 5 percent with lower price and load forecasts. (See sensitivity run results for details on gas price and load growth assumptions.)



EFFECTS OF PHASE 1 TARGET WITH BANKING

We modeled a scenario without a Phase 1 cap on mercury (assuming co-benefits associated with SO_2 and NO_X controls) coupled with a 10-ton cap taking hold in either 2013 (a more aggressive Phase 2 scenario) or 2018. The purpose of this scenario was to test the cost and emissions implications of trading off a Phase 1 cap for a more stringent Phase 2 cap. The idea was that such a scenario would give added time to develop control technologies before a binding cap comes into effect.

By removing the Phase 1 cap from the policy scenario, we effectively removed the ability and incentive for firms to bank emissions reductions achieved below that cap level for later use to assist in compliance with the binding cap in 2013 or 2018. The net cost savings were insignificant and, as expected with any one-phase program, the modeling showed a spike in costs just before the compliance year. From a benefits standpoint, the lack of a Phase 1 cap was significant. Lacking any requirement or incentive for early action, the modeling projects that firms would delay any action until the approach of the binding cap, resulting in 16% fewer reductions in mercury emissions on a cumulative basis through 2022 than a comparable scenario that included a Phase 1 cap. These results affirm that for any given tonnage cap in the 2013 to 2018 timeframe, a two phase program with an earlier binding cap and emissions banking can provide important benefits over achieving the same target in one step. Of course, the relative advantages of banking would depend on the chosen cap levels and timing.

POTENTIAL OF ADVANCED TECHNOLOGIES TO REDUCE COSTS OF MORE STRINGENT MERCURY CAPS

Cap-and-trade programs, with or without incentives for new technology investment, can encourage development and deployment of new emissions-reduction technology. A cap-and-trade system for mercury would be likely to encourage more rapid technological advancements in emissions control. Since the model is not set up to show potential technology advancements resulting from new mercury cap requirements and the resulting policy implications, we therefore simulated this technology learning effect with scenarios that assumed lower costs for mercury control options already in the model—ACI and scrubber technology. In the first advanced technology scenario, we assumed that scrubbers achieve 95 percent (or better) removal rates for all technologies and fuels (instead of 16 to 97 percent removal rates) at a 5 percent increase in variable operating cost. In a second advanced technology scenario, we made the same assumptions about scrubber technology and also assumed that ACI technology achieves a 95% removal rate (instead of 90%). Our advanced technology scenarios were applied to a case that capped mercury emissions at 10 tons in 2015.

The advanced technology scenarios we modeled enabled achievement of mercury cap levels at lower overall cost. The resulting incremental costs for achieving a three-pollutant control scenario with a 10-ton Hg target in 2015 (assuming technology innovation) are about the same as the projected costs of the Clear Skies Act (when no technology innovation is assumed), which caps mercury at 15 tons in 2018. Due to enhanced early action under the advanced technology scenario, cumulative mercury emissions reductions are relatively high (460 tons between 2005 and 2022, or 28 tons greater than the comparison scenario with a 10-ton Hg target in 2015). These results suggest that if technology improves in response to the incentives inherent in a cap and trade program, it would be possible to make greater mercury-reductions at costs similar to those currently projected for Clear Skies. Although technology for mercury control is not currently available at the assumed costs, history has shown that new control requirements create incentives for technology innovation.

SENSITIVITY RUN RESULTS

Sensitivity runs were conducted to understand the potential impacts of higher gas price and load growth assumptions on cases looking at earlier and more stringent Phase 2 mercury targets. Our sensitivity cases assumed gas prices of $3.01/mmbtu and $3.35/mmbtu in 2010 and 2020, respectively, instead of $2.55/mmbtu and $2.50/mmbtu. Moreover, our sensitivity runs used a 1.8 percent per year on average load growth, consistent with AEO 2003 projections, instead of 1.2 percent per year.[21]

The sensitivity cases show higher coal use in response to higher gas prices and load growth, and most of this increase is in eastern coals. As expected, use of natural gas declines. To reduce emissions associated with higher coal use, more plants retrofit with scrubbers, selective catalytic reduction (SCR) and ACI.

[21] Note that EPA's latest CSA runs assume that power demand increases by 1.55% per year and assume higher gas prices.

In comparison with the lower gas price and load growth runs, the cost of the sensitivity runs are higher in early years but lower in the later years (2015+) due to the construction of more natural gas combined-cycle units (rather than combustion turbines) in the base case. As a result, older coal plants are used less in the policy cases without needing any new capital investments, leading to lower-cost emissions reductions. The sensitivity runs have a higher net present value cost over the 2005 to 2030 timeframe than their paired runs (Table 4).

Table 4: Net Present Values of Total Incremental Costs of the Sensitivity Mercury Runs With Higher Gas Prices and Load Growth

Sensitivity Run	Net Present Values (billion 1999$, b/w 2005-2030)	Paired Run	Net Present Values (billion 1999$, b/w 2005-2030)
Case 12 (10 tons in 2018)	67.7	Case 3 (10 tons in 2018)	63.6
Case 11 (10 tons in 2015)	71.3	Case 1 (10 tons in 2015)	66.6
Case 13 (7.5 tons in 2015)	75.0	Case 4 (7.5 tons in 2015)	69.1

STATE AND LOCAL OPTIONS TO SET MORE STRINGENT MERCURY TARGETS

A key concern relates to the effect on local mercury contamination of allowing mercury trading. As compared to a program that requires maximum available control technology on all mercury-emitting power plants, the Clear Skies proposal and proposed mercury rule would allow mercury emissions trading. Holding the stringency of the two approaches constant (i.e, assuming they each result in the same national tonnage of mercury emissions), a program that allows trading could result in a significantly different geographic pattern of mercury emissions compared with one that does not allow trading. Some areas that currently experience the most mercury loadings could receive much less mercury reduction benefit under a trading plan than under a no-trading plan.

One option to addressing concerns about local contamination is to disallow mercury emissions trading altogether; however, that option was not evaluated in our modeling efforts. Another option is to continue to rely on states' authority to set plant-specific requirements for power plant mercury emissions. The administration's proposed Clear Skies legislation and mercury regulation would not alter that authority. However, under Clear Skies, a state would not be able to restrict trading to upwind sources. Therefore, even with more stringent state requirements, the same number of total emissions would occur nationally. The main difference would be fewer emissions occurring in states opting for greater restrictions. In contrast, under the proposed mercury regulation, a state could opt not to use emissions trading altogether or could decide to issue fewer allowances, resulting in fewer total allowances in the trading program.

In addition, several possible modifications to CSA could be made to assure that reductions in local mercury contamination are not lost due to trading, including: adopting a minimum 70 percent plant specific requirement or a minimum plant specific emissions rate limit in the legislation; allowing local and state overrides of trades, and creating regional trading limits.

V. CARBON DIOXIDE POLICY DESIGN

A second focus of the Air Quality Dialogue related to the design of options for reducing carbon dioxide (CO_2) emissions from power plants in the context of a power sector multipollutant bill. Options examined were a cap on carbon emissions, a technology incentive program, and combinations of the two. When asked what they felt was the single most important element to getting legislation enacted, Air Quality Dialogue participants identified CO_2 control as one of the two most important issues in the design of a multipollutant approach. Some participants were exclusively interested in an incentive-based approach, whereas others were interested in CO_2 caps or blended policies. Table 5 shows the CO_2 cap levels or incentives under the current legislative proposals. The key points from the CO_2 discussions and analysis are described in the remainder of this section.

Table 5: Key CO_2 Provisions of Current Legislative Proposals

	Phase 1	Phase 2	Offsets	Integrated Gasification Combined Cycle Incentives
Senate energy bill (H.R. 6)				Investment and production credit for advanced clean coal technologies
Carper bill (S. 843)	2006 levels by 2009	2001 levels by 2013	Unlimited offsets under recognized programs	
Jeffords bill (S. 366)	1990 levels by 2009		Credits can be purchased from capped industry	Allowances provided for advanced coal technology
McCain-Lieberman 2002 (S. 139)*	2000 levels by 2010	1990 levels by 2016	Up to 15% of compliance via offsets in Phase I; 10% in Phase II	
McCain-Lieberman 2003 (S. 139)*	2000 levels by 2010		Up to 15% of compliance via offsets	

*Both McCain-Lieberman bills are economy-wide; we applied the economy-wide target levels to the electricity sector in our modeling.

ROLE OF THE CO_2 POLICY "TOOLKIT"

Dialogue participants discussed a number of measures in the policy "toolkit," such as cap-and-trade, cap level, offsets, allowance allocation, technology incentives, price escape valve, declining cap with price circuit breakers, and policies and measures (e.g., renewable portfolio and energy efficiency programs). A limited number of tools were analyzed in the modeling, either in individual packages or in combined approaches. Results from the various scenarios are described below. Other tools were discussed during the course of several meetings but were not analyzed in the modeling due to time and resource constraints. Greater discussion and analysis of different combinations of tools would be desirable in future dialogues in order to develop a comprehensive plan that achieves significant emissions reductions while minimizing costs to various stakeholders.

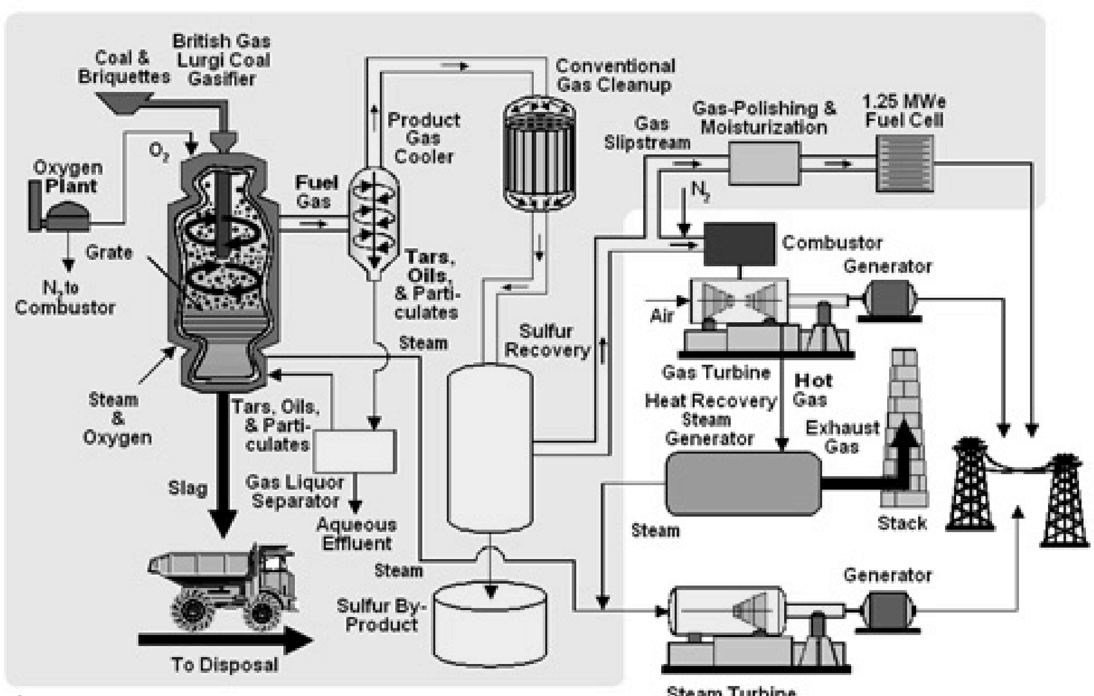
ROLE OF ADVANCED TECHNOLOGY

An important theme arising from the CO_2 discussions was that of the role that advanced technology will need to play in addressing climate change. Power generators are looking for a solution that will provide compliance certainty into the foreseeable future and minimize costs and disruptions to energy markets. The coal industry is interested in developing technological solutions that will enable continued use of its product under a future climate regime. Environmental groups are looking for policies that stop the growth of CO_2 and other greenhouse gases and encourage movement toward aggressive GHG stabilization targets.

As technologies are developed, the “first movers” (i.e., entities that first test the technology) often assume 100 percent of the risk and receive less than 100 percent of the benefits that arise from testing, improving, and reducing the cost of the next generation of the technology. One of the main issues pursued by the Dialogue was to consider approaches (e.g., carrots and sticks) to encourage technological development, cost reduction and early adoption of advanced technologies. The Dialogue focused on incentives for integrated gasification combined cycle (IGCC), an advanced coal technology, with CO_2 capture and sequestration—technologies that have drawn significant interest from industry and environmental groups and have yet to be the subject of extensive integrated analysis. While there was also interest in looking at incentives for other power sector technologies, potentially including the deployment of more renewables, improved methods to extract and transport natural gas, broader use of combined heat and power, advances in energy efficiency within power plants and more demand-side management throughout the economy, time and resources did not allow for a full evaluation of all available advanced technologies for mitigating CO_2 emissions. Other advanced technologies will be discussed in future Dialogues.

IGCC uses a chemical process that gasifies coal to produce gas (primarily hydrogen and carbon monoxide), which is then burned like natural gas to produce electricity (see Figure 5). Compared with conventional coal technologies, such as pulverized coal, IGCC is more efficient

Figure 5: The Integrated Gasification Combined Cycle Process



Source: National Energy Technology Laboratory for electricity production and generates minimal emissions of SO_2 and mercury. IGCC technology has been widely applied in the chemical and refining industries for production of multiple fuels and products, but its application in the power-generation sector is still limited as a result of the technology's high capital costs, concerns in some quarters about the lack of demonstrated reliability and the lack of experience with integration of the gasification and chemical processes and geologic sequestration. IGCC produces a concentrated stream of CO_2, which could be captured and disposed of in geological formations, such as depleted oil and gas fields, saline aquifers, and unmineable coal seams (the so-called CO_2 capture and sequestration process).

The IGCC, carbon capture and sequestration, and enhanced oil recovery technology cost and performance characteristics used in modeling conducted by the Air Quality Dialogue were based on assumptions agreed to by the Dialogue group (Table 6). Note that in our modeling, we did not assume improvements in the cost and performance of IGCC and carbon capture and sequestration technologies, whereas other technologies in the IPM are assumed to improve over time. Based on the current pace of IGCC technology development, our assumptions were perhaps optimistic in early periods in the model (e.g., 2010), but they were most likely conservative with regard to potential technological learning by 2015.

Table 6: IGCC Technology Assumptions Used in Modeling

	IGCC	IGCC–CCS	IGCC–CCS and EOR Credit
Heat rate (Btu/kWh)	7,590	9,311	9,311
Includes heat rate penalty (%)		*22.7*	*22.7*
Total plant capital cost ($/kW)[22]	$1,248.00	$1,678.00	$1,678.00
Operation and maintenance ($/MWh)	$8.90	$12.02	$12.02
Sequestration cost ($/ton CO_2)	N/A	$13.61	$3.63
Environmental performance			
SO_2 (% reduction from fuel input)	98	98	98
NO_X (lbs/MMBtu)	0.024	0.024	0.024
CO_2 (% reduction from fuel input)	N/A	90	90
Hg (% reduction from fuel input)	95	95	95
CCS=CO_2 capture and sequestration; EOR=enhanced oil recovery; IGCC=integrated gasification combined cycle; kWh=kilowatt hours; MMBtu=million metric British thermal units			

A promising near-term carbon sequestration option is that of using CO_2 in enhanced oil recovery operations, whereby CO_2 is injected into existing or depleted oil fields for incremental oil production and, potentially, can be permanently sequestered. According to estimates by independent industry experts and the National Energy Technology Laboratory (NETL), oil production from enhanced oil recovery could increase to 0.5 million barrels per day in 2010 and 1 million barrels per day in 2020 from the current production level of 216,000 barrels per day,

[22] Includes overnight engineering costs only. "All-in" capital costs would be higher. This capital cost figure is likely to be optimistic in the early periods in the model (e.g., 2010) but conservative with regard to potential technology learning by 2015.

given projected oil prices and assuming CO_2 is commercially available.[23] Enhanced oil recovery is projected to rise to 2 million barrels per day by 2050. A typical IGCC plant with a size of 400 MW and CO_2 removal efficiency of 90 percent will capture 2.5 million tons of CO_2 per year. NETL's estimates of future enhanced oil recovery production suggest that all the CO_2 from 7 to 12 GW of new IGCC with carbon capture and sequestration could be used in enhanced oil recovery in 2010 and 14 to 24 GW of IGCC with carbon capture and sequestration could be used in 2020. Our analysis considered IGCC incentives at levels less than this technical potential—4.38 GW in 2010 and a total of 8.75 GW in 2020—and limited the total penetration of IGCC with enhanced oil recovery in our modeling scenarios to levels within the technical potential—17.5 GW in 2020 (Table 7).

Table 7: CO_2 Used for Enhanced Oil Recovery (EOR) (GW)

	2010	2020
Technical potential for EOR	7 to 12	14 to 24
EOR penetration assumed in modeling runs as a result of incentives	4.38	8.75
Maximum economic penetration of EOR in CO_2 cap cases	—	17.5

The Air Quality Dialogue sponsored several modeling runs to understand the incentives needed to boost IGCC technology and its role in achieving emissions reductions. The runs sought to shed light on a number of policy-relevant questions, such as:

- What financial incentive levels are needed to encourage and deploy IGCC and IGCC with carbon capture and sequestration in the absence of a cap on CO_2 emissions?
- How do needed incentive levels for IGCC with carbon capture and sequestration change when incentives are coupled with a CO_2 cap?
- What is the impact on CO_2 emissions of different IGCC and carbon capture and sequestration incentive policies, with and without a CO_2 cap?
- How do incentives for IGCC with carbon capture and sequestration affect the cost of meeting a CO_2 cap?
- How does IGCC technology penetration affect conventional pollutant emissions?

All the model runs discussed in this section add CO_2 policies to a three-pollutant control scenario, referred to as the "3P Reference Case," in which NO_x and SO_2 control levels are equivalent to those proposed in the Clear Skies Initiative and mercury emissions are capped at 26 tons in 2010 and 10 tons in 2015. The modeling used EIA assumptions on natural gas price and load growth. Moreover, all the CO_2 runs include a demand response to changes in the price of power. Finally, as in the three-pollutant runs, we assume a competitive power market. Detailed descriptions of the model run scenarios and assumptions are provided in the Appendix.

It is important to recognize that the estimates generated by the model are subject to uncertainties arising from the assumptions used. The estimates cited here should not be viewed as dispositive. Rather, what is important is the direction of the findings and the broad picture they paint about the likely effects of various scenarios.

[23] Kuuskraa V. CO_2 EOR Technologies. Presentation at New Markets for CO_2: Second Annual Conference on Carbon Sequestration. 2003.

IGCC INCENTIVE[24] POLICIES WITHOUT A CO_2 CAP

Our analysis evaluated two incentive-based policy packages for IGCC technologies without CO_2 caps. The first policy package, "IGCC Incentive Package with Coal Retirements," combines incentives for IGCC with incentives for retiring older, less efficient coal plants. Specifically, this scenario assumes a total penetration of 35 GW of IGCC—a capacity level roughly equivalent to half of existing small (i.e., under 300 MW) and less efficient pulverized coal plants—coupled with retirement of 17.5 GW of coal plants. The 35 GW of IGCC were divided into three bundles: 17.5 GW IGCC without any carbon capture and sequestration, 8.75 GW IGCC with carbon capture and sequestration, and 8.75 GW IGCC with carbon capture and sequestration and credits for enhanced oil recovery[25]. Half of each technology bundle was assumed to enter the market in the 2008 to 2012 timeframe, with the remainder entering the market between 2013 and 2017. This scenario tied incentives for IGCC with carbon capture and sequestration to a "retooling" of generation away from the least efficient coal-fired power plants, reflecting congressional discussions on tax incentives for IGCC coupled with coal retirements contained in the energy legislation under discussion at the time of the analysis.[26]

The second policy package, "IGCC with Carbon Sequestration Incentive Package," provided incentives for IGCC with carbon capture and sequestration (with and without credits for enhanced oil recovery), but without incentives for retiring existing coal capacity. This program was designed to analyze the impact of a purely incentive-based approach without a requirement for coal retirements. This option contained the same amount of IGCC with carbon capture and sequestration as in the first incentive-based policy package. Specifically, we analyzed two separate bundles of IGCC capacity, including 8.75 GW of IGCC with carbon capture and sequestration and credits for enhanced oil recovery, and 8.75 GW of IGCC with carbon capture and sequestration without credits for enhanced oil recovery. Half of each technology bundle was assumed to enter the market in the 2008 to 2012 timeframe, with the remainder entering the market between 2013 and 2018.

[24] Note: In these scenarios, we forced in desired technology to determine the needed size of the incentives.
[25] The availability of enhanced oil recovery was restricted to five states believed to be most promising for this application, including Texas, California, New Mexico, Louisiana and Wyoming.
[26] The energy bill passed by the Senate in 2003 (i.e., H.R. 6) dropped the provision requiring coal retirements.

Incentives Needed to Support IGCC Packages

Table 8: Incentives Needed to Encourage IGCC and Coal Retirements Without a CO_2 Cap	
Technology or Incentive Program	**Incentive Level ($/MWh)**
IGCC only (without CCS)	$0 to $1.72
IGCC with CCS and credits for EOR (under IGCC/Retirement Package)	$0.69 to $2.48
IGCC with CCS and credits for EOR (under IGCC/CCS Package)	$0 to $4.29
California System Benefit Charge Fund: new renewable energy reverse auction program	$7.50 to $15.00
Coal Retirements (under IGCC/ Retirement Package)	$13.92 to $15.72
Federal tax credit for electricity produced from renewable resources	$17.00
IGCC with CCS, without credits for EOR (under IGCC/CCS Package)	$15.33 to $28.28
IGCC with CCS, without credits for EOR (under IGCC/Retirement Package)	$22.42 to $34.78
CCS=CO_2 capture and sequestration; EOR=enhanced oil recovery; IGCC=integrated gasification combined cycle.	

We found that relatively small incentives are projected to be needed on a generation basis ($/MWh) to encourage IGCC alone ($0 to $1.72 per MWh) and IGCC with carbon capture and sequestration and credits for enhanced oil recovery ($0 to $4.29 per MWh). Relatively larger incentives are needed to encourage retirements of coal plants ($13.92 to $15.72 per MWh) and IGCC with carbon capture and sequestration without credits for enhanced oil recovery ($15.33 to $34.78 per MWh) (Table 8). Note that the actual incentives needed to encourage IGCC with carbon capture and sequestration may be higher in the early years and lower in the later years, because we assumed relatively aggressive improvement in performance and cost before 2010 and no improvement after 2010. To give some context to these projections, on a (per megawatt-hour of) generation basis, IGCC with carbon capture and sequestration and credits for enhanced oil recovery is projected to cost substantially less than the cost of the federal tax credit for electricity produced from renewable resources (e.g., wind energy production), whereas IGCC with carbon capture and sequestration without access to enhanced oil recovery credits is projected to cost more than the renewable energy incentive program.

Interestingly, the incentives needed to encourage IGCC with carbon capture and sequestration, both with and without credits for enhanced oil recovery, were lower when coal retirements were also part of the package since the retirements create demand for new generation. The total incentives needed under the retirements package were more than those needed to support IGCC with carbon capture and sequestration.

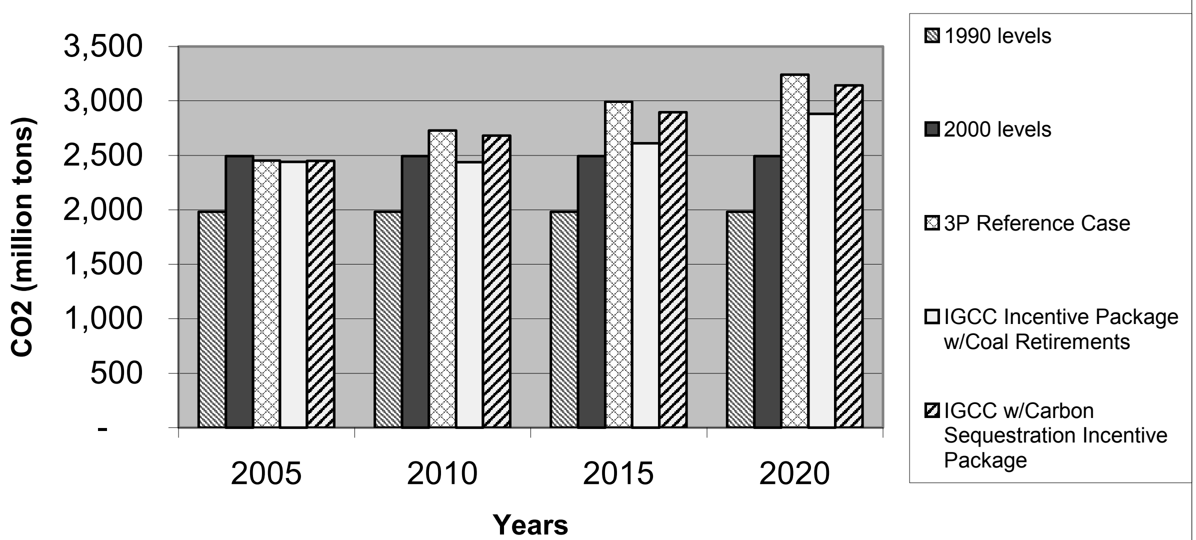
CO_2 Emissions Under IGCC Incentives (without CO_2 caps)

The IGCC Incentive Package with Coal Retirements is projected to reduce CO_2 emissions to 11 percent below the 3P reference case scenario in both 2010 and 2020.[27] This scenario reduced emissions to 2% below 2000 levels[28] in 2010 and is projected to reduce emissions to 16% above 2000 levels in 2020. Emissions increase after 2010 because the assumed growth in electricity demand outweighs emissions benefits from coal retirements and penetration of IGCC with

[27] In the "3P Reference Case," NO_x and SO_2 control levels are equivalent to those proposed in the Clear Skies Initiative and mercury emissions are capped at 26 tons in 2010 and 10 tons in 2015. The modeling used EIA assumptions on natural gas price and load growth.
[28] 2000 levels modeled by ICF consulting were 2,492 tons. This level is considerably higher than AEO's estimate of year 2000 emissions for this sector.

carbon capture and sequestration. We found that 17.5 GW of coal retirements have a much bigger impact on CO_2 emissions reductions than do 17.5 GW of new IGCC and carbon capture and sequestration technology. The IGCC incentive scenario without mandatory retirements leads to a reduction in CO_2 emissions below the 3P reference case levels of 2 percent to 3 percent in the 2010 to 2020 time frame (Figure 6). Even though IGCC with carbon capture and sequestration generates very low CO_2 emissions, it largely replaces new natural gas combined-cycle units, which also have relatively low emissions of CO_2. Therefore, in and of itself, this package should not be viewed as a way to reduce CO_2 emissions in the near term.

Figure 6: CO_2 Emissions Under IGCC Incentive Cases



The IGCC Incentive Package with Coal Retirements also helps reduce the cost to industry of achieving 3P caps. For example, it helps reduce mercury allowance costs by about 20 percent over the study period, and it significantly reduces allowance costs for SO_2 and NO_X (allowance costs for NO_X are roughly 30 percent lower in the eastern region and 60 percent lower in the western region). However, we again found that the reductions in mercury, SO_2, and NO_X allowance prices are largely due to coal retirements rather than IGCC penetration. Even though IGCC results in very low mercury emissions, the IGCC largely replaces new natural gas combined-cycle units, which are also very low emitters of mercury.

Costs of IGCC Incentive Packages Without CO_2 Caps

As noted in the earlier section, the net present value of total system costs for the 3P reference case comes to $71.3 billion. The incremental net present value of total system costs[29] to support the full IGCC Incentive Package with Coal Retirements is projected to be $38.5 billion dollars, a 54 percent increase over the cost of the 3P Reference Case, and resulting a total system cost for the multipollutant program of $109.8 billion dollars. The cost to support the more limited IGCC

[29] This calculation was made over a 30-year period to 2003 using a real discount rate of 5.34%.

with Carbon Sequestration Incentive Package is projected to be $8.2 billion dollars, a 12 percent increase over the 3P Reference Case, and resulting in a total control cost for the multipollutant program of $79.5 billion dollars. The difference in the net present values of the two IGCC incentive scenarios results mainly from the cost of building additional capacity needed to compensate for forced coal retirements. (Table 9).

Table 9: Net Present Value (NPV) of Increase in System Costs from IGCC Incentive Cases (billions)		
	NPV of costs from 2005 to 2030	% of 3P Reference Case Costs
3P Reference Case	$71.3	0
IGCC Incentive Package with Coal Retirements	$38.5	54
IGCC with Carbon Sequestration Incentive Package	$8.2	12
IGCC= integrated gasification combined cycle.		

The annual payments required to support the different technology incentive packages in the 2010 and 2015 timeframes range from $40 to $130 million[30] in the case of IGCC with carbon capture and sequestration and access to EOR credits, to $750 million to $1.73 billion in the case of IGCC with carbon capture and sequestration without access to EOR credits[31], to $1.93 to $1.96 billion for the combination of IGCC technology (without sequestration) and coal retirements[32]. These figures can be compared with the estimated $328 million annual cost in 2010 of the federal tax credit for electricity produced from certain renewable resources. (Table 10).

Table 10: Annual Payments for Various IGCC Technologies Under IGCC Incentive Scenarios (billion $1999)		
	2010	**2015**
IGCC (8.75 GW in 2008–2012; 17.5 GW in 2013–2017)	0.11	0.0
Coal Retirements (8.75 GW in 2008–2012; 17.5 GW in 2013–2017)	1.85	1.93
IGCC+CCS (4.375 GW in 2008–2012; 8.75 GW in 2013–2017)	0.75 to 0.87	1.37 to 1.73
IGCC+CCS w/EOR (4.375 GW in 2008–2012; 8.75 GW in 2013–2017)	0.08 to 0.13	0.04 to 0.10
CCS=CO_2 capture and sequestration; EOR=enhanced oil recovery; IGCC=integrated gasification combined cycle.		

Based upon the assumptions modeled, national average wholesale energy prices with the IGCC Incentive Package with Coal Retirements are expected to be about 15 percent higher than the 3P reference case in 2010, declining to about 2 percent above the 3P reference case levels in 2020. This energy price increase and subsequent leveling off relative to the 3P reference case results from forcing retirements in 2010 of the equivalent of 17.5 GW of relatively low cost, coal-fired generation. With higher fuel prices, the natural gas that displaces older coal generation will increase marginal generation costs and electricity prices. In comparison, under the incentive-only package, national wholesale energy prices are roughly 1 percent below 3P reference case levels in 2010 and 2020 (Table 11).

[30] This level of annual funding supports 880 MW per year of IGCC with carbon capture and sequestration with EOR credits in 2008 to 2017.
[31] This level of annual funding supports 880 MW per year of IGCC with carbon capture and sequestration without EOR credits in 2008 to 2017.
[32] This level of annual funding supports 1.75 GW per year of IGCC (without carbon capture and sequestration) and 1.75 GW per year of forced coal retirements in 2008 to 2017.

Table 11: National Wholesale Electric Prices Under IGCC Incentive Cases ($/MWhr)				
	2010	**% Change from 3P Ref Case**	**2020**	**% Change from 3P Ref Case**
3P Reference Case	27.1		29.1	
IGCC Incentive Package w/Coal Retirements	31.2	15.2%	29.7	2.3%
IGCC w/Carbon Sequestration Incentive Package	26.7	-1.7%	28.9	-0.6%
IGCC=Integrated Gasification Combined Cycle.				

The impact of IGCC incentive programs on regional wholesale electricity prices varies widely. In the IGCC Incentive Package with Coal Retirements, some states (e.g., Arizona and New Mexico) experience higher than average increases in wholesale electricity prices (a 23 percent increase in 2010), whereas other states (e.g., California and Texas) experience lower than average increases (1 to 4 percent in 2010 and 2020).[33] A number of factors contribute to these differences, including the location of retired coal units, new natural gas units and new IGCC plants with carbon capture and sequestration, and the availability of enhanced oil recovery. Because of all the competing factors, potential for enhanced oil recovery is not the main factor influencing the impact on wholesale electricity prices.

In the IGCC with Carbon Sequestration Incentive Package, the availability of credits for enhanced oil recovery appears to have a neutral to positive near-term effect on regional wholesale energy prices. While national average wholesale energy prices decline by 2 percent in 2010, regional wholesale prices decrease by 1 percent to 5 percent in the regions in which enhanced oil recovery credits are available. In 2015 and after, the impact of IGCC incentives on wholesale electricity prices is minimal, both nationally and in the regions with access to credits for enhanced oil recovery. Some regions without enhanced oil recovery availability had more significant increases in wholesale energy prices whereas others saw little change. In New England (NEPOOL), for example, the impact on wholesale energy prices is 8 percent higher than the national average in 2010 and 5 percent higher than the national average in 2020. In contrast, the impact on the Midwest (ECAR) region was similar to the national average. This can be explained by the fact that virtually no IGCC plants are projected to be located in New England while a number are expected in the ECAR region.

Coal and Natural Gas Market Impacts

Encouraging deployment of new, efficient IGCC units at the level evaluated by the Dialogue (17.5 GW) has little effect on national coal generation and consumption in each year evaluated (1 percent or less). Coal retirements, however, reduce coal generation and consumption below the 3P Reference Case but still result in an increase in consumption nationally from year 2000 levels. Specifically, the IGCC Incentive Package with Coal Retirements results in a decline in coal generation of 13 and 10 percent in 2010 and 2020 versus the 3P Reference Case with similar (13 and 12 percent) declines in coal consumption. This decline in coal consumption is roughly consistent across the major coal supply regions. The slightly higher percent decline in coal consumption in 2020 as compared with the decline in coal-fired power generation results from the fact that the new IGCC units use less coal per unit of electricity produced. When compared

[33] National average wholesale energy prices increase by 15 percent in 2010 and 2 percent in 2020.

against 2000 coal consumption, this scenario results in a national decrease (3 percent) in coal consumption in 2010 and an increase (14 percent) by 2020. Natural gas generation increases under the retirement scenario by 24 percent in 2010 and 14 percent in 2020 from the 3P Reference Case as some retired coal plants are replaced by natural gas combined cycle units. The IGCC with Carbon Sequestration Incentive Package, in contrast, leads to a decrease in natural gas generation of one percent or less.

Building Confidence in IGCC: Providing Early Incentives

One potentially promising way to encourage near-term introduction of IGCC is to support IGCC with enhanced oil recovery. The enhanced oil recovery would provide commercial value for CO_2 and IGCC projects, making them potentially more cost competitive with other plant types. In fact, the modeling predicts that IGCC with carbon capture and sequestration, where CO_2 can be used for enhanced oil recovery, will be economically competitive with natural gas combined cycle by 2018 even without a cap on CO_2 emissions. The analysis also predicts that IGCC with carbon capture and sequestration and credits for enhanced oil recovery will require a much smaller incentive ($0.43 to $0 per kWh from 2008 to 2020) than IGCC with carbon capture and sequestration and without enhanced oil recovery ($2.83 to $1.53 per kWh). Annual payments to make IGCC with carbon capture and sequestration and enhanced oil recovery competitive under the scenarios modeled are projected to be $80 million to $130 million in 2010 and $40 million to $100 million in 2015.[34] To overcome other (non-cost) barriers to implementation and penetration of IGCC technology, the government may want to provide slightly more funding. This option could be a relatively low cost path to achieve early testing of new technologies.

Note, however, that while enhanced oil recovery opportunities could be helpful to proving IGCC and carbon capture and sequestration technology and minimizing the cost of initial penetration, the availability is limited both geographically and as a result of the volatility of the price of oil.

CAPS WITH AND WITHOUT TECHNOLOGY INCENTIVES

In addition to incentive programs, we modeled cap and trade systems for reducing emissions of carbon dioxide. In total, we analyzed three different CO_2 cap cases:

- The first scenario (Case 2) had a phased CO_2 cap that limited emissions to 2005 levels by 2008, 2001 levels by 2012, and ultimately achieved 1990 levels in 2016[35], but included no incentives for advanced IGCC technology and presumed no availability of enhanced oil recovery credits for carbon sequestered by new IGCCs.[36] This scenario allowed the

[34] In each case, reported incentive levels are sufficient to encourage 4.375 GW in the 2008 to 2012 period and another 4.375 GW in the 2013 to 2017 period.

[35] These phased CO_2 caps reflect a blend of cap levels proposed in earlier versions of the Carper and McCain-Lieberman bills. We modeled the Carper cap levels as proposed in the 2002 version of the bill (S. 185), which was later revised in 2003 with slight modifications. In addition, this case analyzed the original final carbon cap level in the McCain-Lieberman bill (1990 levels by 2016) (S. 139). ICF used 2455 MMTons of CO_2 as the 2005 cap, 2451 MMTons of CO_2 as the 2001 cap, and 1981 MMTon of CO_2 as the 1990 cap.

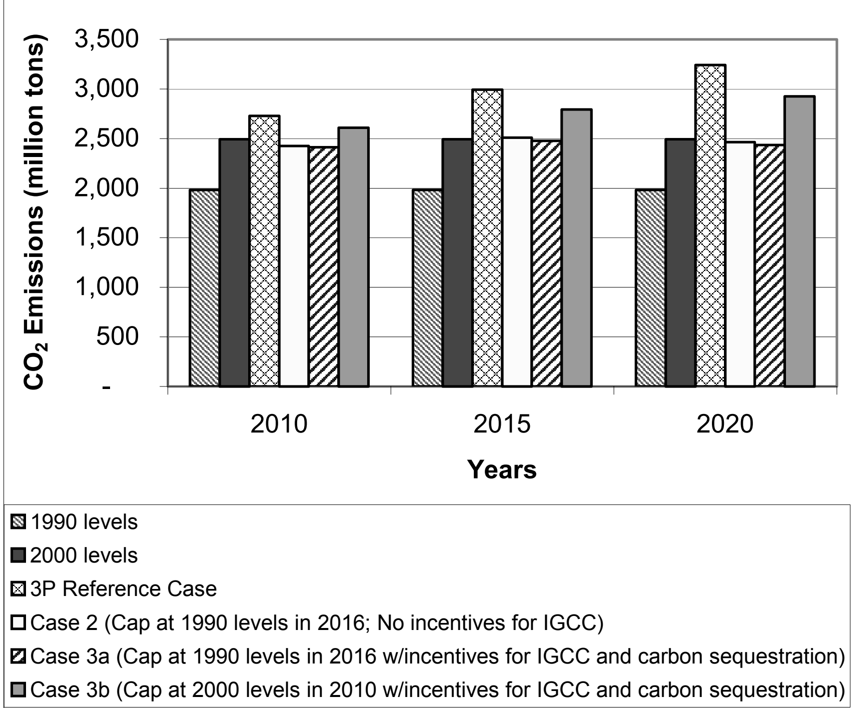
[36] The scenario included only IGCC options characterized by EPA cost and performance assumptions.

use of off-system reductions, or offsets[37], to be used for 15 percent of compliance prior to 2016 and 10 percent of compliance after 2016.

- The second cap scenario we evaluated (Case 3a), combined the cap and offset provisions listed above with incentives for IGCC and carbon capture and sequestration. Specifically, we evaluated incentives needed to achieve a total of 17.5 GW of IGCC with carbon capture and sequestration by 2015, half with access to enhanced oil recovery credits, and half without, similar to the IGCC incentive scenarios discussed earlier. The maximum penetration (through a combination of incentives and economic penetration) of IGCC–CCS with enhanced oil recovery credits was limited to 17.5 GW in order to not exceed the estimated maximum potential of enhanced oil recovery, described above under the discussion of advanced technologies.
- In our third cap scenario (Case 3b), we evaluated the impacts of a CO_2 cap at 2000 levels[38] in 2010 combined with incentives for IGCC with carbon capture and sequestration. In this scenario, offsets could be used to meet 15 percent of compliance--equivalent to the cap levels and offset restrictions recently proposed in the 2003 McCain-Lieberman bill (S.139), but applied to the power sector only. The IGCC incentives used in this scenario are the same as those used in Case 1a, discussed above.

Originally, we envisioned being able to compare our CO_2 cap cases with results of analysis on the Carper bill (which proposed a cap of 2006 levels by 2009 and 2001 levels by 2013 with unlimited offsets); however, those results were not available for comparison.

Figure 7: On-System CO_2 Emissions from Carbon Cap Cases



CO_2 Emissions With a CO_2 Cap

The CO_2 caps modeled by the Air Quality Dialogue all achieve emissions reductions from the three-pollutant reference case, though the actual on-system emissions levels are higher than the stated

[37] Offsets are emissions reductions purchased from outside the electricity sector (e.g., carbon sequestration) and used for compliance with the electricity-sector carbon cap.
[38] The 2000 cap level used by ICF was 2,492 MMTons of CO_2.

cap levels due to use of offsets and emissions banking. We found that Cases 2 and 3a, which cap CO_2 at 1990 levels by 2016, resulted in an 11 to 25 percent reduction in CO_2 emissions in 2010 and 2020 from the 3P Reference Case, whereas Case 3b, which caps emissions at the 2000 level in 2010, resulted in a 4 to 10 percent reduction. On-system emissions under case 3b increase over time despite a hard cap on carbon emissions due to use of flexibility mechanisms.[39] (Figure 7).

System Costs with a CO_2 Cap

As noted in the earlier section, the net present value of total system costs for the 3P reference case comes to $71.3 billion over the full 2005 to 2030 study period. The incremental system costs of the CO_2 cap cases range from $29.0 billion under Case 3b, which caps emissions at the 2000 level in 2010, to an estimated $86.2 to $96.4 billion under Cases 2 and 3a that cap CO_2 emissions at 1990 levels in 2016. The total cost of a four-pollutant control program with the CO_2 cap cases modeled by the Air Quality Dialogue ranges from $100.3 billion to $167.7 billion. The resulting cost increase from the three-pollutant control scenario ranges from 41 percent to 135 percent. (Table 12).

Table 12: Net Present Value (NPV) of Increase in System Costs from Carbon Cap Cases (billions)		
	NPV of costs from 2005 to 2030	% of 3P Reference Case Costs
3P Reference Case	$71.3	0
Case 2 (Cap at 1990 levels in 2016; No incentives for IGCC)	$96.4	135%
Case 3a (Cap at 1990 levels in 2016 w/incentives for IGCC and carbon sequestration)	$86.2	121%
Case 3b (Cap at 2000 levels in 2010 w/incentives for IGCC and carbon sequestration)	$29.0	41%
IGCC= integrated gasification combined cycle.		

As expected, national wholesale energy prices are lower under the less stringent cap than under the more stringent cap (Table 13). National wholesale electricity prices under Case 3b are projected to be 5 percent higher than the 3P reference case levels in 2010 and 8 percent higher in 2020, whereas wholesale electricity prices under the CO_2 cap cases achieving 1990 levels by 2016 are projected to be 25 to 29 percent higher than under the 3P reference case in 2010 and 31 to 36 percent higher in 2020. These projected price increases assume a demand response to higher energy prices.

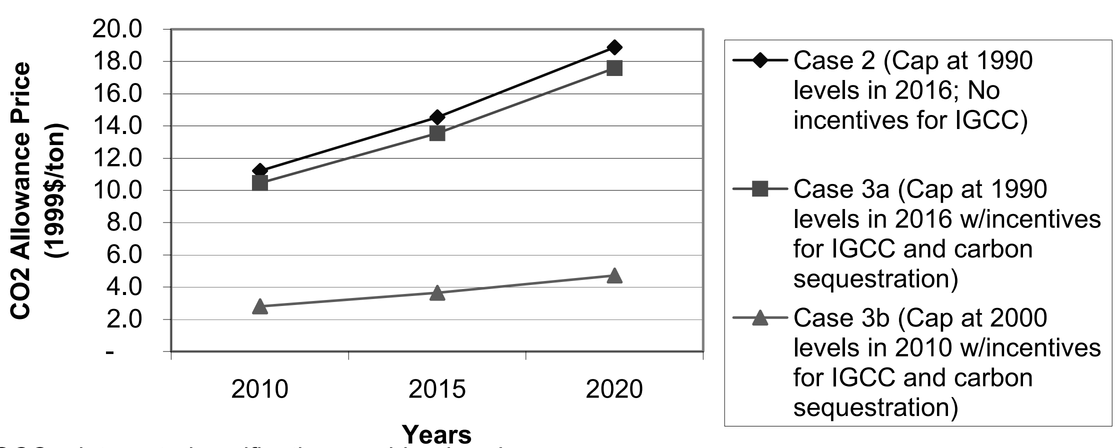
[39] 1990 and 2000 levels modeled by ICF consulting were 1,981 and 2,492 tons, respectively. These levels are considerably higher than AEO's estimates of 1990 and 2000 emissions for this sector.

Table 13: National Wholesale Electric Prices ($/MWhr) under CO_2 Cap Cases				
	2010	% change from 3P Ref Case	2020	% change from 3P Ref Case
3P Reference Case	27.1		29.1	
Case 2 (Cap at 1990 levels in 2016; No incentives for IGCC)	35.0	29.1%	39.4	35.6%
Case 3a (Cap at 1990 levels in 2016 w/incentives for IGCC and carbon sequestration)	34.0	25.3%	38.0	30.7%
Case 3b (Cap at 2000 levels in 2010 w/incentives for IGCC and carbon sequestration)	28.6	5.5%	31.3	7.6%
IGCC=Integrated Gasification Combined Cycle.				

CO_2 Allowance Prices

Allowance prices for CO_2, an indicator of the cost of a CO_2-control program, are significantly lower under Case 3b than under the cases that cap CO_2 at 1990 levels by 2016, with or without IGCC incentives. Allowance prices for Case 3b, which allows 15 percent of compliance to be met with offsets, are $2.80 per ton in 2010 and $4.70 per ton in 2020, compared with $10.50 to $11.20 per ton in 2010 and $17.60 to $18.90 per ton in 2020 under the cases that cap CO_2 at 1990 levels by 2016. (Figure 8).

Figure 8: CO_2 Allowance Prices Under Carbon Cap Cases With and Without IGCC Incentives



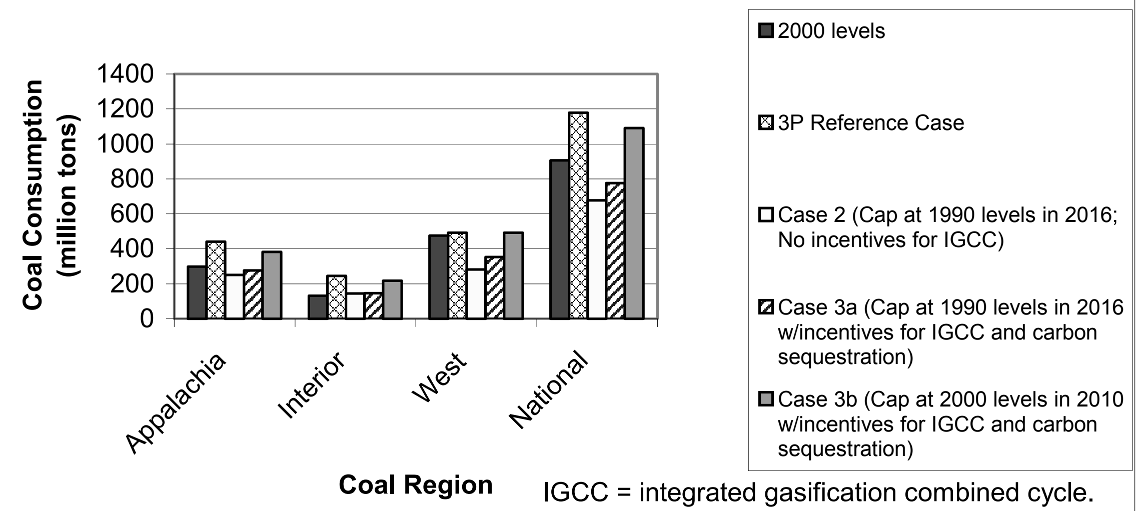
IGCC = integrated gasification combined cycle.

Coal and Natural Gas Market Impacts with a CO_2 Cap

The CO_2 cap scenarios modeled all result in a decline in coal generation compared with the 3P Reference Case, though Case 3b (cap at 2000 levels in 2010) results in an increase in coal generation compared to 2000 levels. The presence of an IGCC incentive package helps to moderate reductions in coal generation. For example, whereas Case 2 (CO_2 cap at 1990 levels by 2016 without IGCC incentives) led to reductions in coal generation on the order of 16 to 41 percent between 2010 and 2020, Case 3a (CO_2 cap at 1990 levels by 2016 with IGCC incentives) results in a decline in coal generation on the order of 13 to 33 percent. Natural gas generation increases under all three cap scenarios, on the order of 20 to 50 percent for Cases 2 and 3a and by 2 to 11 percent under Case 3b.

Similarly, the CO_2 cap scenarios modeled result in very different impacts on fuel consumption. Case 3b more than maintains historic levels of coal consumption. In fact, coal consumption increases overall to 9 percent above 2000 levels in 2010 and 21 percent above 2000 levels in 2020. (Figure 9). However, compared with the 3P reference case, coal production under Case 3b shows a decline in consumption (3 percent below 2010 levels and 8 percent below 2020 levels)

Figure 9: Impact on Coal Markets of Carbon Cap Cases With and Without IGCC Incentives in 2020



IGCC = integrated gasification combined cycle.

because of greater construction of base and intermediate load natural gas units (instead of peaking units) and due to the greater efficiency of the new IGCC units in their use of coal. Note that the West is the only region in which coal production is at similar levels under both Case 3b and the 3P reference case. Natural gas consumption under this CO_2 cap scenario is comparable to the 3P reference case in 2010 and results in a 9 percent increase in 2020 over the 3P reference case.

In contrast, Case 3a (cap at 1990 levels in 2016 with IGCC incentives) results in a decline in coal consumption to 5 percent below 2000 levels in 2010 and 14 percent below 2000 levels in 2020. Case 2 (cap at 1990 levels in 2016 without IGCC incentives) results in an even greater decline in coal consumption (to 8 percent below 2000 levels in 2010 and 25 percent below 2000 levels in 2020). Both cases show substantial increases in natural gas consumption.

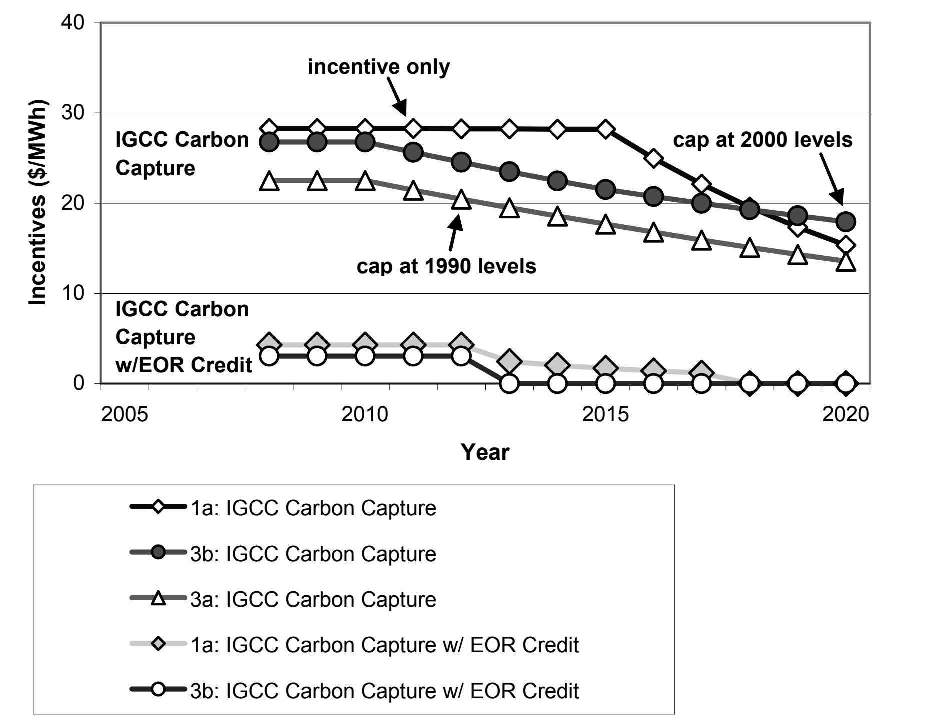
Effects of Including IGCC Incentives in a CO_2 Cap

Results from other CO_2 cap modeling runs of caps at 1990 levels in 2016 conducted by the Dialogue[40] provide some insight as to the effects of including incentives for IGCC with carbon capture and sequestration in a CO_2 cap. The CO_2 cap with IGCC incentives costs more than a parallel scenario without IGCC incentives, but results in lower wholesale power prices and helps to maintain coal generation. The system cost premium of adding IGCC incentives to the CO_2 cap is roughly $20 billion over the 30-year study period. This higher cost of the cap plus incentive scenario pays for about 65 GW of IGCC and carbon capture technology, results in a 4 percent increase of coal-fired power generation, and lowers national wholesale electricity prices by 1 to 4 percent as IGCC penetration alleviates pressure on natural gas generation and the associated higher fuel costs.

Incentive Levels to Encourage IGCC–CCS Under CO_2 Caps

A CO_2 cap helps to lower the incentives needed to encourage IGCC in most of the years modeled (Figure 10). As noted earlier, the incentive needed to encourage IGCC with carbon capture and sequestration where there is no credit for enhanced oil recovery and no cap on carbon dioxide emissions is projected to range from $28.28 per MWh in 2010 to $15.33 per MWh in 2020. A cap on carbon dioxide emissions can help lower the costs of the incentive needed to encourage deployment of IGCC with carbon capture and sequestration.

Figure 10: Effect of Various Carbon Cap Levels on Incentives Needed to Support IGCC With Carbon Capture



For example, the cap of 2000 levels by 2010 lowers the necessary incentive to support IGCC and

[40] These runs were not discussed earlier because they do not include restrictions on the availability of enhanced oil recovery. However, these runs can be compared to each other to understand the relative cost implications of a cap alone and a cap in combination with an incentive program.

carbon capture technology by 5 percent to \$26.79 per MWh in 2010 (but not in 2020). The more aggressive Case 2 lowers the incentive needed by 11 to 20 percent, to \$22.51 per MWh in 2010 and \$13.58 per MWh in 2020. Similarly, CO_2 caps reduce the incentives needed for IGCC with carbon capture and sequestration with credit for enhanced oil recovery. Without a CO_2 cap, the incentives needed to encourage IGCC with carbon capture with access to enhanced oil recovery are projected to range from \$4.29 to \$0 in 2010 and 2020, respectively. (Starting in 2018, the technology is projected to become economic vis-à-vis natural gas combined cycle.) Under Case 3b, the required incentive is just \$3.04 in 2010 and the technology becomes competitive in 2013. Under Case 2, IGCC with carbon capture and credits for enhanced oil recovery is cost competitive throughout the study period.

The annual payment for IGCC and carbon capture incentives under the cap at 2000 levels in 2010 come to \$0.91 billion in 2010 and \$1.32 billion in 2015, whereas the annual payment for IGCC and carbon capture incentives under the Case 2 are \$0.69 billion per year in 2010 and \$1.08 billion in 2015—24 percent and 18 percent lower, respectively, than the less stringent case.

Sources of Funding for IGCC Under a CO_2 Cap

The Dialogue discussed a number of tools to provide incentives for IGCC with carbon capture and sequestration, including a production tax credit, a "line charge," and allowance allocation (or revenue recycling from an allowance auction). The method of financing the IGCC incentive will greatly affect the distribution of the costs among various constituencies (e.g., ratepayers, shareholders, and taxpayers). Our modeling results assume that the cost of the IGCC incentives is covered within the electricity system [e.g., through an electricity "line charge" or allowance allocation (or revenues from an allowance auction)]. If the cost of the incentives is covered outside of the electricity sector, however, (e.g., through tax credits from the general treasury), energy price and electricity system cost increases shown in this modeling would be greatly reduced. The distribution of costs among generators and consumers would depend on how the incentive was structured and which companies chose to build the IGCC and carbon capture facilities and thus receive the bonus allowances or funds from the "line charge" pool.

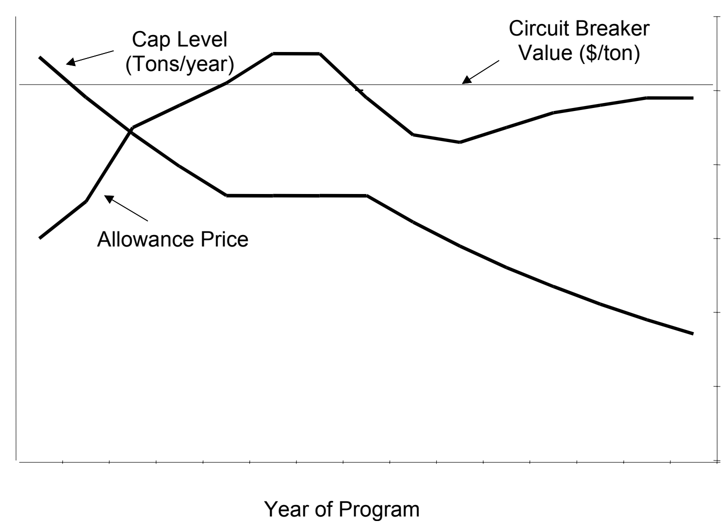
For scenarios in which IGCC and carbon capture incentives are coupled with a CO_2 cap, the group discussed the possibility of using allowance allocations (or the revenues from an allowance auction) to pay for the IGCC incentives. For example, at a CO_2 allowance price of \$17.60 per ton in 2020, as is projected to occur in the Case 2 with IGCC Incentives scenario, about 3 percent of allowances are needed to fully fund the IGCC and carbon capture and sequestration incentive package (17.5 GW). As the cap becomes less stringent, a larger share of the allowances would be needed to fund the IGCC incentives because the value of each allowance would be lower. In Case 3b (2000 levels by 2010), with a CO_2 allowance price of \$4.70 per ton, 9 percent of allowances would be needed to fully fund the IGCC and carbon capture and sequestration incentive package. Note that the actual cost of the incentive program would be higher to account for administrative and transaction costs and would depend on the chosen implementation mechanism. The mercury section of this report suggests some of the options that could be used to implement an allowance-based scheme to create the incentives.

In the modeling, we analyzed an approach whereby the funds for IGCC incentives are incurred directly in the electricity sector through a "generation performance standard." As a result of this modeling assumption, the total system costs and the effects on electricity prices shown in the analysis are higher than if the costs of the IGCC were incurred outside of the sector, such as through an investment tax credit.

DECLINING CAP AND CIRCUIT BREAKER

Air Quality Dialogue participants indicated interest in the declining cap and price circuit breaker approach proposed by Joel Bluestein of Energy and Environmental Analysis, Inc. The key feature of this proposal is a cap that declines gradually at a pre-established rate as long as allowance costs remain at or below an established, "circuit breaker" price. When allowance costs exceed the circuit breaker price, the cap level remains constant until allowance prices again fall below the circuit breaker price (Figure 11). It is anticipated that the higher prices would lead to technology advancements, which in turn would bring down the compliance cost. This gradual rate of decline is expected to aid price discovery, minimize risk, provide a driver for new technology, and establish a signal to meet environmental goals, including long-term environmental objectives.

Figure 11: Circuit Breaker Operation



Further consideration is needed of ways to analyze this declining cap and circuit breaker approach with a power-sector dispatch model and, potentially, other modeling systems.

VI. CONCLUSIONS

SO_2 AND NO_X CONCLUSIONS

Analyses and discussion occurring within the Air Quality Dialogue addressed the targets and timing of SO_2 and NO_x emissions reductions. The main findings and conclusions are as follows:

- Modeling results show that tightening SO_2 and NO_x caps beyond the Clear Skies Act levels (to 2.25 million tons SO_2 in 2015, and moving the NO_x target of 1.7 million tons from 2018 to 2012) is projected to have little impact on national average wholesale energy prices and natural gas prices (within 1 percent), although it would result in an increase in total incremental costs ($1.15 billion, or 41 percent in 2010).[41]
- More stringent SO_2 controls are expected to increase the number of areas in attainment for fine particles and, according to the analysis by Resources for the Future, would have benefits exceeding costs.[42]
- Because fine particulate attainment appears to be dependent on the depth and speed of SO_2 reductions from power plants, it may be important to ensure that SO_2 deadlines within a multipollutant control program are consistent with the current law's NAAQS attainment deadlines.

MERCURY CONCLUSIONS

Dialogue participants focused their attention on mercury technologies, cap levels and timing. There was substantial interest in understanding the effects of different mercury control scenarios designed to advance development and deployment of mercury technologies on the one hand, and to understand implications of more aggressive control strategies on the other.

The strongest theme to emerge from the first phase of the Air Quality Dialogue is the importance of encouraging technological innovation and greater certainty on control costs to winning broad support for a strong emission-reduction program for mercury in the context of a multipollutant bill. Dialogue participants expressed interest in early deployment of ACI and other advanced technologies in the first phase of the mercury-control program as a way to potentially reduce costs, improve performance, and encourage greater penetration of such technologies in the second phase of the program, as well as to achieve earlier reductions in mercury emissions. Generators expressed the concern that they might be reluctant to deploy such less certain technologies in the first phase of a mercury-control program because of financial and compliance risks associated with testing mercury technologies that would ultimately benefit the whole industry, including possible competitors.

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[41] As noted earlier, the quantitative estimates developed in the modeling should be viewed as approximations indicative of the direction of likely cost impacts rather than as precise point estimates. In addition, the reference case used for comparison with alternate policy scenarios is based on currently implemented regulations and does not include any of the expected future EPA regulatory changes (such as mercury MACT and implementation of a fine particulate standard). Hence, it is recognized by dialogue participants that this approach overestimates both the emission reductions and the costs of new power plant legislation compared to existing law.

[42] New preliminary research on the contribution of SO_2 emissions to fine particulate health impacts could affect this conclusion.

The modeling conducted for the Dialogue quantifies the projected cost and benefits of incentive approaches to early deployment and of tighter cap levels and timing. Main findings are as follows:

- As a way to spread the risk of early deployment of advanced mercury-control technologies, a special pool of allowances could be created as an incentive to generators to deploy such technologies. The modeling suggests that creation of a Technology Incentive Pool of 2.6 tons of mercury allowances, available to generators who elect to apply activated carbon injection or other advanced technologies in the pre-2010 period (before Phase 1) would encourage significant penetration of such technologies for less than a 1 percent increase in total costs for the 3P package ($400 million in net present value terms). Allowances for the technology incentive pool could be subtracted from the Phase 1 allocation to all generators (the option modeled) or provided by increasing the Phase 1 allocation by 10 percent (2.6 tons).
- Tightening the mercury emissions-reduction cap from 15 tons in 2018 to 10 tons in 2018 is projected to increase total 3P compliance costs by approximately 5 percent ($3.1 billion in net present value terms). Further tightening the cap by advancing the compliance date to 2015 would add approximately another 5 percent to total 3P costs, and reducing the cap to 7.5 tons in the same compliance period would increase total 3P costs by an additional 4 percent. In addition, even the most aggressive of these options (7.5 tons cap in 2015) has almost no impact on wholesale electricity prices both nationally (within 0.2 percent) and regionally (-1.5 to 2.1 percent), reflecting how the cost may not be passed on directly to wholesale electricity consumers. Cumulative mercury emission reductions increase between 8 and 28 percent through 2022 with these more aggressive caps and timetables. Moreover, the impact of such changes on national and regional coal production is slight (-1 to 5 percent).
- Modeling of the impact of assumed improvements in the performance and cost of mercury-reduction technology suggest that if the mercury-reduction program follows the pattern of previous SO_2 and NO_x cap-and-trade programs, savings in technology costs could be significant. Implementation of the early technology incentive pool could be an important stimulus to such innovation. If, instead, the Phase 1 target is set at a pure "co-benefits" level (i.e., at the mercury-emission level expected to be achieved as a result of deployment of only scrubbers for SO_2 control and selective catalytic reduction for NO_x control), then it is difficult to see how, in the Phase 1 the "early learning" needed to advance the technology will occur. The modeling suggests that the projected cost of implementing Clear Skies might well be a reasonable estimate for the cost of slightly more stringent Phase 2 mercury-reduction targets and timetables, once likely technological innovation is factored in.

CO_2 CONCLUSIONS

As with mercury, the strongest theme to emerge from the first phase of the Air Quality Dialogue regarding policy options was the importance of encouraging technological innovation and greater certainty in compliance costs. Two key sets of options were the focus of the analysis and discussion: 1) incentives for technologies that remove and sequester CO_2 from coal and 2) caps on CO_2 emissions. The CO_2 caps could be combined with technology incentives or with CO_2 price-based circuit breaker provisions.

The modeling centered on incentive scenarios, cap scenarios, and combinations of the two approaches. The declining cap with circuit breaker provision was not modeled due to limitations in the applicability of the modeling platform to such options. The results of the modeling suggest the following conclusions:

1. IGCC incentives coupled with incentives for coal plant retirements result in higher system costs and wholesale electricity prices than an incentive program without coal plant retirements. However, IGCC incentives combined with incentives for coal plant retirements produce significantly more CO_2 emission reductions than does an IGCC incentive package without coal plant retirements.
2. Adding incentives for IGCC with carbon capture and sequestration to CO_2 caps is slightly more expensive than CO_2 caps alone, but leads to greater coal consumption.
3. CO_2 caps lower the incentives needed to finance IGCC with carbon capture and sequestration. The more stringent the cap, the lower the expenditures required to finance the incentives.
4. IGCC with carbon capture and sequestration in areas where there is credit for enhanced oil recovery operations represents an attractive near-term incentive scenario; it would require lower incentive payments per MWh than are currently provided by the federal government to promote wind energy. While enhanced oil recovery represents a small share of the total carbon sequestration opportunity, enhanced oil recovery can be used in the near-term to build experience with IGCC-CCS technology and to reduce the costs for future broad-based applications of IGCC with carbon capture and sequestration.
5. A cap at 2000 emission levels by 2010 in which offsets may be used to meet 15 percent of the cap, coupled with incentives for IGCC with carbon capture and sequestration, (Case 3b) is projected to achieve a 4 to 10 percent reduction in CO_2 emissions from the electricity sector in 2010 and 2020 while raising system costs by roughly 2 percent and national wholesale prices by 5 to 8 percent above the 3P reference case.
6. A CO_2 cap proposal that ultimately achieves 1990 levels by 2016 in which offsets may be used to meet 15 percent of the cap through 2015 and 10 percent of the cap in 2016 and later, with a similar incentive program for IGCC with carbon capture and sequestration, (Case 3a) is projected to achieve an 11 to 25 percent reduction in CO_2 emissions from the electricity sector in 2010 and 2020 while raising system costs by 5 to 8 percent and national wholesale prices by 25 to 31 percent above the 3P reference case.
7. A cap set at 2000 levels by 2010 is projected to result in an increase in coal production of 21% above 2000 production levels by 2020.

This analysis provides a good initial evaluation of the potential of various incentives to promote IGCC and carbon capture and sequestration technology. A critical unanswered question is that of how to finance the incentives. The Dialogue considered three major options: federal tax credits, bonus allowances for technology deployment, and a federal line charge on electricity.

The next phase of the Air Quality Dialogue will explore these options in more detail. The next phase of the Dialogue may also address other elements of the broader "toolkit" for reducing greenhouse gases, including policies and measures to encourage or require development and deployment of energy efficiency and renewable energy.

VII. APPENDIX

APPENDIX 1: ABOUT THE INTEGRATED PLANNING MODEL

The Air Quality Dialogue's analysis of multipollutant and technology incentive policy scenarios was conducted using ICF's Integrated Planning Model (IPM). The IPM is a detailed engineering-economic production-costing model that estimates the marginal cost of emissions reductions for the electricity-generating sector. The model uses a linear programming formulation to select investment options and dispatch generating resources by minimizing the net present value of capital and operational costs, given the cost and performance characteristics of available options, forecasts of electricity demand, and reliability criteria.

The IPM model is capable of simulating single- or multiple-pollutant reduction constraints under cap-and-trade programs, or technology-based standards (e.g., Best Available Control Technology [BACT], Maximum Achievable Control Technology [MACT]) and has been used by the U.S. Environmental Protection Agency (EPA) and many private-sector clients to analyze alternative approaches for reducing multiple emissions from electricity generation. IPM determines the least-cost means of meeting emissions reduction policy requirements and forecasts allowance prices, compliance costs, and unit dispatch and retrofit decisions for each boiler and generator in the North American Electric Reliability Council (NERC) regions. Allowance prices in the electricity sector are determined, excluding technologies that remove emissions from the post-combustion process, by the increased system costs of building and operating less carbon-intensive generation as well as existing unit dispatch changes.

For more details on the IPM model, see Documentation of EPA Modeling Applications (V.2.1) Using the Integrated Planning Model, U.S. EPA Office of Air and Radiation, March 2002.

Information on IPM is also available at: www.epa.gov/airmarkets/epa-ipm.

APPENDIX 2: FINE PARTICLE AND OZONE ATTAINMENT DEADLINES

Table A.1: Fine Particulate Attainment Deadlines Under National Ambient Air Quality Standards (NAAQS)	
Date	**NAAQS Compliance Deadline**
December 31, 2009	Statutory deadline, 5 years after designation of non-attainment areas or sooner if feasible (need to comply "as expeditiously as practicable")
December 31, 2014	5-year extension possible if showing made; Full 5-years is not automatic—need to comply "as expeditiously as practicable"
December 31, 2015	Attainment deadline if granted additional one-year extension
December 31, 2016	Attainment deadline if granted final one-year extension
2018	**Phase 2 CSA Deadline for SO_2**

Table 4.2: 8-Hour Ozone Attainment Deadlines, Subpart 1*	
Date	**NAAQS Compliance Deadline**
April 15, 2009	Statutory deadline, 5 years after designation of non-attainment areas or sooner if feasible (need to comply "as expeditiously as practicable")
April 15, 2014	A 5-year extension is possible if a showing is made. A Full 5-year extension is not automatic—need to comply "as expeditiously as practicable."
April 15, 2015	Attainment deadline if granted additional one-year extension
April 15, 2016	Attainment deadline if granted final one-year extension
2018	**Phase 2 CSA Deadline for NO_x**
NAAQS=National Ambient Air Quality Standards. *Under EPA's draft implementation rule, this provision may apply just to those areas that are in attainment for the 1-hour ozone standard but in nonattainment for the 8-hour standard.	

Table 4.3: 8-Hour Ozone Attainment Deadlines, Subpart 2*	
Date	**NAAQS Compliance Deadline**
2007	Marginal
2010	Moderate
2013	Serious
2018	**Phase 2 CSA Deadline for NO_x**
2019-2021	Severe
NAAQS=National Ambient Air Quality Standards. *Under EPA's draft implementation rule, may apply to all areas OR just those areas in non-attainment for the 1-hour standard and the 8-hour standard. Dates shown are for compliance with the 8-hour standard. The one-hour standard must be achieved by 2010 in all cases.	

APPENDIX 3: 3P CASE SUMMARY AND MODELING RESULTS

Case Name	SO_2	NOx	Mercury	Notes
CCAP Base	Title IV	NOx SIP call	No constraint	
CCAP CSA	4.5 million tons in 2010, 3.0 million tons in 2018	2.1 million tons in 2008, 1.7 million tons in 2018 (two zones)	26 tons in 2010, 15 tons in 2018	
Case 1	CSA Caps and Timing		26 tons in 2010, 10 tons in 2015	
Case 2	CSA Caps and Timing		10 tons in 2013	
Case 3	CSA Caps and Timing		26 tons in 2010, 10 tons in 2018	
Case 4	CSA Caps and Timing		26 tons in 2010, 7.5 tons in 2015	
Case 5	CSA Caps and Timing		10 tons in 2018	
Case 6	4.5 million ton in 2008, 3.5 million ton in 2012, 2.25 million ton in 2015	2.1 million ton in 2008, 1.7 million ton in 2012	No constraint	
Case 7	2.25 million tons in 2011	1.6 million tons in 2011	7.5 tons in 2013	
Case 8 - Advanced Technology #1	CSA Caps and Timing		26 tons in 2010, 10 tons in 2015	wet FGD 90% removal for all coals, 90% ACI
Case 9 - Advanced Technology #2	CSA Caps and Timing		26 tons in 2010, 10 tons in 2015	wet FGD 90% removal for all coals, 95% ACI
Case 10 - Technology Incentive Pool	CSA Caps and Timing		23.4 tons in 2010, 10 tons in 2015	
CCAP Base w/EIA growth and gas	Title IV	NOx SIP call	No constraint	
Case 11- Case 1 with EIA growth and gas	CSA Caps and Timing		26 tons in 2010, 10 tons in 2015	
Case 12 - Case 3 with EIA growth and gas	CSA Caps and Timing		26 tons in 2010, 10 tons in 2018	
Case 13 - Case 4 with EIA growth and gas	CSA Caps and Timing		26 tons in 2010, 7.5 tons in 2015	
Case 14 - with EPA growth and gas	CSA Caps and Timing		No constraint	
Case 15 - with EIA growth and gas	CSA Caps and Timing		No constraint	

	215b_b1				215b_b2				215b_b3b			
	CCAP Basecase				**CCAP CSA**				**Case 1**			
Total Incremental Costs (billion 1999$)	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**
	none				1.0	3.4	4.8	6.5	1.0	3.7	5.5	7.2
EMISSIONS AND ALLOWANCE PRICES	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**
SO_2												
Emissions at Affected Plants [MTons]	10,300	9340	8810	8810	8005	6,048	5,096	4,267	8,048	6,005	4,931	4,151
Allowance Price [1999 US$/Ton]	295	362	468	454	487	599	777	1,008	481	591	767	995
NOx EAST												
Emissions at Affected Plants [MTons]	473	473	473	473	473	1,582	1,522	1,222	473	1,582	1,504	1,240
Allowance Price [1999 US$/Ton]	1,940	2,062	2,137	2,193	1,904	1,052	1,011	1,311	1,941	967	919	1,192
NOx WEST												
Emissions at Affected Plants [MTons]					0	538	538	538	0	538	538	538
Allowance Price [1999 US$/Ton]					0	424	484	400	0	273	251	326
Mercury												
Emissions at Affected Plants [tons]	46.3	45.6	45.2	44.7	41.1	26.0	23.1	17.9	41.1	22.7	17.1	12.6
Allowance Price [1999 US$/lb]					0	33,840	36,210	46,970	0	41,010	53,200	69,000
CO_2												
Emissions at all units (million metric tonnes)	2,299	2,416	2,542	2,636	2,262	2,322	2,441	2,523	2,259	2,316	2,436	2,517
					0.01608	0.03907	0.03964	0.04302	0.01755	0.041655	0.041985	0.04529
Incremental Retrofits (GW)	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**
FGD					20	40	56	78	19	41	59	80
SCR					0	31	36	56	0	31	36	53
ACI					0	6	11	29	0	21	43	62
Generation Mix (1000 GWh)	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**
Coal	2089	2130	2182	2213	2,037	1,997	2,040	2,051	2034	1989	2030	2042
Gas/oil	909	1093	1299	1493	944	1,207	1,422	1,635	943	1210	1432	1644
Nuclear	552	539	536	518	568	559	555	536	572	563	555	536
Hydroelectric	269	269	269	269	269	269	269	269	269	269	269	269
Other	127	112	108	109	127	113	108	109	127	113	108	109
Coal Production (million tons)	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**
Appalachia	333	333	342	341	318	315	343	349	318	318	338	340
Interior	181	173	172	172	193	196	198	206	191	199	205	211
West	489	522	548	562	459	411	417	405	461	406	407	399
National	1,002	1,027	1,062	1,074	971	922	957	960	970	923	950	950

	215b_b4b Case 2				215b_b5b Case 3				215b_b6b Case 4			
Total Incremental Costs (billion 1999$)	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**
	1.3	2.6	7.7	7.6	1.0	3.4	5.2	6.7	0.9	3.9	5.7	7.4
EMISSIONS AND ALLOWANCE PRICES	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**
SO_2												
Emissions at Affected Plants [MTons]	7,832	6,659	4,306	4,022	8,046	6,055	5,018	4,231	8,094	5,875	4,923	4,099
Allowance Price [1999 US$/Ton]	523	643	834	1,082	482	593	769	998	474	582	755	980
NOx EAST												
Emissions at Affected Plants [MTons]	473	1,582	1,344	1,302	473	1,582	1,500	1,244	473	1,582	1,500	1,244
Allowance Price [1999 US$/Ton]	1,903	1,320	733	951	1,890	1,066	960	1,245	1,940	942	901	1,169
NOx WEST												
Emissions at Affected Plants [MTons]	0	538	522	533	274	538	538	538	0	538	538	538
Allowance Price [1999 US$/Ton]	0	1,002	177	230	0	401	368	312	0	310	403	286
Mercury												
Emissions at Affected Plants [tons]	40.9	32.1	10.0	10.0	41.2	25.4	20.4	15.3	41.1	20.4	15.6	10.9
Allowance Price [1999 US$/lb]	0	0	126,400	81,920	0	34,440	44,670	57,940	0	47,080	61,070	79,210
CO_2												
Emissions at all units (million metric tonnes)	2,260	2,336	2,417	2,510	2,261	2,321	2,436	2,522	2,258	2,315	2,434	2,509
Incremental Retrofits (GW)	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**
FGD	21	29	72	82	19	40	58	78	19	44	59	80
SCR		30	44	46		31	36	53		30	35	51
ACI		1	82	82		8	24	43		32	54	72
Generation Mix (1000 GWh)	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**
Coal	2034	2021	2001	2032	2036	1995	2031	2049	2035	1988	2029	2030
Gas/oil	947	1182	1454	1647	945	1208	1430	1637	942	1212	1432	1654
Nuclear	568	559	561	543	568	559	555	537	572	563	556	538
Hydroelectric	269	269	269	269	269	269	269	269	269	269	269	269
Other	127	113	108	109	128	113	108	109	128	113	108	109

	215b_b7b				215b_b8b				215b_b10			
	Case 5				**Case 6**				**Case 7**			
Total Incremental Costs (billion 1999$)	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**
	1.3	2.7	4.0	8.4	2.8	4.0	5.6	7.3	1.90	2.11	9.24	9.12
EMISSIONS AND ALLOWANCE PRICES	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**
SO_2												
Emissions at Affected Plants [MTons]	7,790	6,610	5,523	3,504	5,867	4,813	4,242	3,144	6,769	6,007	3,317	3,157
Allowance Price [1999 US$/Ton]	517	636	825	1,070	720	885	1,148	1,489	603	741	961	1,246
NOx EAST												
Emissions at Affected Plants [MTons]	473	1,582	1,582	1,162	473	2,020	1,700	1,700	473	473	1,600	1,600
Allowance Price [1999 US$/Ton]	1,941	1,307	1,317	869	1,784	1,072	1,340	1,357	1,900	1,943	949	803
NOx WEST												
Emissions at Affected Plants [MTons]	0	538	538	534								
Allowance Price [1999 US$/Ton]	0	971	1,002	33								
Mercury												
Emissions at Affected Plants [tons]	40.8	32.8	31.2	10.0	37.7	30.2	28.3	27.0	38.2	37.7	7.5	7.5
Allowance Price [1999 US$/lb]	0	0	0	105,800					0	0	165,500	129,500
CO_2												
Emissions at all units (million metric tonnes)	2,261	2,341	2,468	2,515	2,239	2,327	2,440	2,532	2,251	2,354	2,411	2,499
									0.0207	0.0259	0.0516	0.05218
Incremental Retrofits (GW)	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**
FGD	22	30	50	97	49	63	75	106	37	43	100	105
SCR	0	29	30	58	0	32	54	52	0	0	63	61
ACI	0	1	1	75					0	1	95	95
Generation Mix (1000 GWh)	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**
Coal	2,034	2,027	2,076	2,031	1,995	1,994	2,023	2,047	2,017	2,039	1,994	2,017
Gas/oil	947	1,177	1,386	1,655	985	1,209	1,439	1,639	963	1,165	1,460	1,661
Nuclear	568	558	554	536	568	559	555	537	552	539	536	518
Hydroelectric	269	269	269	269	269	269	269	269	269	269	269	269
Other	127	113	108	109	128	113	108	109	144	133	135	136

	215b_b12b				215b_b14b				215b_b13b			
	Case 8				**Case 9**				**Case 10**			
									5%	5%	-3%	-2%
Total Incremental Costs (billion 1999$)	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**
	0.87	3.13	4.77	6.48	0.89	3.15	4.72	6.39	1.02	3.86	5.34	6.99
EMISSIONS AND ALLOWANCE PRICES	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**
SO_2												
Emissions at Affected Plants [MTons]	8,201	6,292	4,955	4,136	8,168	6,235	4,982	4,202	7,913	5,665	4,896	4,115
Allowance Price [1999 US$/Ton]	466	573	743	963	473	581	754	977	497	612	772	1,002
NOx EAST												
Emissions at Affected Plants [MTons]	473	1,582	1,558	1,186	473	1,582	1,558	1,186	473	1,582	1,499	1,245
Allowance Price [1999 US$/Ton]	1,914	1,235	1,269	1,646	1,899	1,235	1,272	1,650	1,932	933	927	1,202
NOx WEST												
Emissions at Affected Plants [MTons]	0	538	538	538	0	538	538	538	0	538	536	540
Allowance Price [1999 US$/Ton]	0	664	708	837	0	664	744	837	0	269	237	308
Mercury								**Case 1:**	41.1	22.7	17.1	12.6
Emissions at Affected Plants [tons]	31.6	21.7	17.2	13.5	31.6	21.8	17.3	13.4	39.8	21.4	16.8	12.2
Allowance Price [1999 US$/lb]	0	32,610	42,290	54,860	0	30,220	39,200	50,850	0	42,930	54,200	70,300
CO_2								**% change**	3%	6%	2%	3%
Emissions at all units (million metric tonnes)	2,267	2,333	2,455	2,539	2,267	2,334	2,459	2,545	2,265	2,327	2,447	2,532
Incremental Retrofits (GW)	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**
FGD	18	37	63	85	18	38	63	85	21	50	63	84
SCR	0	28	28	57	0	28	29	58	0	34	39	55
ACI	0	10	19	29	0	9	20	31	16	31	48	66
Generation Mix (1000 GWh)	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**
Coal	2,044	2,015	2,059	2,074	2,045	2,016	2,066	2,082	2,039	2,002	2,047	2,063
Gas/oil	937	1,188	1,402	1,612	937	1,187	1,396	1,603	947	1,206	1,420	1,628
Nuclear	568	559	555	536	568	559	555	536	563	554	550	532
Hydroelectric	269	269	269	269	269	269	269	269	269	269	269	269
Other	127	113	108	109	127	113	108	109	127	113	108	109
Coal Production (million tons)	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**
Appalachia	320	325	329	347	320	327	343	348	318	330	344	351
Interior	192	206	208	220	192	204	206	223	191	197	206	212
West	462	421	421	411	462	422	427	414	461	407	408	401
National	974	952	958	978	974	953	976	985	970	934	958	964

	215b_b17b				215b_b11b_CCAP_2C				215b_b15			
	CCAP Basecase w/EIA gas and growth				**Case 11**				**Case 12**			
Total Incremental Costs (billion 1999$)	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**
	none				1.53	4.31	5.14	6.79	1.57	4.01	4.81	6.24
EMISSIONS AND ALLOWANCE PRICES	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**
SO_2												
Emissions at Affected Plants [MTons]	9,790	9,570	8,886	8,813	7,322	5,912	5,114	4,140	7,240	6,034	5,271	4,100
Allowance Price [1999 US$/Ton]	319	392	508	553	540	664	861	1,117	549	674	874	1,134
NOx EAST												
Emissions at Affected Plants [MTons]	473	473	473	473	473	1,582	1,521	1,223	473	1,582	1,522	1,222
Allowance Price [1999 US$/Ton]	1,887	2,151	2,293	2,273	1,807	1,000	964	1,250	1,793	1,042	1,012	1,313
NOx WEST												
Emissions at Affected Plants [MTons]					0	538	538	538	0	538	538	538
Allowance Price [1999 US$/Ton]					0	526	434	380	0	449	505	473
Mercury												
Emissions at Affected Plants [tons]	44.4	46.7	46.0	45.8	39.0	21.3	17.7	12.7	38.5	24.1	20.3	15.3
Allowance Price [1999 US$/lb]					0	44,690	57,970	75,190	0	36,840	47,790	61,980
CO_2												
Emissions at all units (million metric tonnes)	2,252	2,512	2,738	2,973	2,320	2,554	2,823	3,077	2,225	2,476	2,717	2,940
					-0.0303	-0.0165	-0.031	-0.0349	0.012	0.0146	0.00781	0.01124
Incremental Retrofits (GW)	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**
FGD					23	59	75	102	25	57	72	103
SCR					0	43	51	75	0	43	51	75
ACI					0	34	48	70	0	22	36	51
Generation Mix (1000 GWh)	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**
Coal	2,026	2,213	2,425	2,650	1,980	2,157	2,374	2,585	1,980	2,160	2,380	2,587
Gas/oil	946	1,140	1,336	1,549	985	1,187	1,385	1,614	985	1,185	1,380	1,612
Nuclear	594	601	602	601	601	609	602	601	601	609	602	601
Hydroelectric	269	269	269	269	269	269	269	269	269	269	269	269
Other	126	113	109	109	126	114	108	110	126	114	108	110
Coal Production (million tons)	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**
Appalachia	326	351	381	419	305	358	392	442	305	357	390	443
Interior	177	181	182	183	195	226	236	246	195	219	233	242
West	466	542	598	634	447	435	482	492	447	445	488	492
National	969	1,073	1,160	1,236	947	1,018	1,109	1,179	947	1,021	1,111	1,177

	215b_b19				215b_b18b				215b_b20			
	Case 13				**Case 14 - 2P**				**Case 15 - 2P**			
					-59.5%	16.5%	21.4%	26.1%				
Total Incremental Costs (billion 1999$)	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**
	1.64	4.64	5.49	7.13	1.63	2.85	3.81	4.78	2.04	3.27	3.66	4.86
						0.6	0.1647					
EMISSIONS AND ALLOWANCE PRICES	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**
SO_2												
Emissions at Affected Plants [MTons]	7,223	5,730	5,083	4,196	7,381	6,156	5,317	4,505	6,555	6,274	5,531	4,507
Allowance Price [1999 US$/Ton]	549	675	876	1,136	555	682	884	1,147	626	769	997	1,294
NOx EAST												
Emissions at Affected Plants [MTons]	473	1,582	1,503	1,241	473	1,582	1,582	1,162	473	1,582	1,582	1,162
Allowance Price [1999 US$/Ton]	1,813	957	872	1,131	1,874	1,272	1,296	1,632	1,655	1,339	1,340	1,622
NOx WEST												
Emissions at Affected Plants [MTons]		538	538	529		538	538	538	265	538	538	538
Allowance Price [1999 US$/Ton]	0	473	365	284	0	664	685	685	0	685	727	727
Mercury												
Emissions at Affected Plants [tons]	38.4	18.9	14.8	11.3	40.6	34.0	32.8	30.0	38.1	35.2	34.4	31.3
Allowance Price [1999 US$/lb]	0	52,340	67,890	88,060								
CO_2												
Emissions at all units (million metric tonnes)	2,225	2,472	2,714	2,939	2,262	2,351	2,485	2,561	2,225	2,496	2,728	2,953
	0.01212	0.01612	0.00901	0.0113								
Incremental Retrofits (GW)	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**
FGD	25	62	76	99	29	40	57	77	37	51	64	92
SCR	0	43	53	74	0	32	32	65	0	38	38	74
ACI	0	46	66	84								
Generation Mix (1000 GWh)	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**
Coal	1,980	2,153	2,373	2,586	2,034	2,041	2,099	2,101	1,978	2,187	2,397	2,608
Gas/oil	986	1,191	1,387	1,614	948	1,162	1,362	1,584	987	1,159	1,363	1,591
Nuclear	601	609	602	601	568	559	555	537	601	609	602	601
Hydroelectric	269	269	269	269	269	269	269	269	269	269	269	269
Other	126	114	108	110	127	113	108	109	126	114	108	111
Coal Production (million tons)	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**
Appalachia	304	356	396	437	316	331	351	359	306	359	400	455
Interior	196	226	238	245	196	195	194	196	199	206	209	217
West	447	435	475	492	460	450	460	448	442	486	525	529
National	947	1,017	1,108	1,174	972	975	1,005	1,003	948	1,051	1,134	1,200

Net Present Value [$billion ($1999)] for period 2005 to 2030	
CCAP CSA	60.5
Case 1	66.6
Case 2	70.1
Case 3	63.6
Case 4	69.1
Case 5	63.3
Case 6	72.8
Case 7	82.8
Case 8	60.9
Case 9	60.7
Case 10	67.0
Case 11	71.3
Case 12	67.7
Case 13	75.0
Case 14	53.8
Case 15	

Cumulative SO2 Emissions Reductions from Basecase through 2022 (million tons)		Cumulative NOx Emissions Reductions from Basecase through 2022 (million tons)		Cumulative Hg Emissions Reductions from Basecase through 2022 (tons)	
CCAP CSA	64.630	CCAP CSA	31.286	CCAP CSA	358
Case 1	66.121	Case 1	31.304	Case 1	431
Case 2	67.269	Case 2	31.818	Case 2	434
Case 3	65.042	Case 3	31.295	Case 3	387
Case 4	66.933	Case 4	31.313	Case 4	459
Case 5	64.145	Case 5	31.307	Case 5	324
Case 6	87.104	Case 6	33.048	Case 6	276
Case 7	82.988	Case 7	34.233	Case 7	439
Case 8	64.182	Case 8	31.259	Case 8	460
Case 9	64.101	Case 9	31.262	Case 9	460
Case 10	66.333	Case 10	29.651	Case 10	427
				Case 14	211
Note: Model run years were grouped differently for Case 10. As a result, cumulative benefits are not directly comparable.					

APPENDIX 4: 4P CASE SUMMARY AND MODELING RESULTS

<table>
<tr><th>Case Name</th><th>Common Elements</th><th>Carbon Policy</th><th>Existing Coal Constraints</th><th>IGCC Capacity Incentives</th></tr>
<tr><td>EPA 3P Reference Case</td><td rowspan="6">EPA 3P Run Mercury caps set to 26 tons in 2010 and 10 tons in 2015

EIA AEO 2003 electric demand and gas price assumptions
EIA estimated demand response of -0.15 short-term, -0.35 long-term</td><td>None</td><td>None</td><td>None</td></tr>
<tr><td>1</td><td>None</td><td>Generation equivalent* of 17.5 GW of existing coal capacity under 300 MW forced to retire</td><td>Generation equivalent* of:
17.5 GW IGCC
8.75 GW IGCC with CCS
8.75 GW IGCC CCS and EOR
Generation requirement forced in, half in 2008-2012, half in 2013-2017</td></tr>
<tr><td>1a</td><td>None</td><td>None</td><td>Generation equivalent* of:
8.75 GW IGCC with CCS
8.75 GW IGCC CCS and EOR
Generation requirement forced in, half in 2008-2012, half in 2013-2017</td></tr>
<tr><td>2</td><td>Carper/McCain-Lieberman: 2005 levels by 2008; 2001 levels by 2012; 1990 levels by 2016

Compliance Limited to off-system reductions:
15% prior to 2016, 10% after 2016</td><td rowspan="3">None</td><td>None. (No IGCC with CCS allowed to come on-line)</td></tr>
<tr><td>3a</td><td></td><td rowspan="2">Generation equivalent* of:
8.75 GW IGCC with CCS
8.75 GW IGCC CCS and EOR
Generation requirement forced in, half in 2008-2012, half in 2013-2017 (EOR Limited to 17.5 GW Total Capacity)</td></tr>
<tr><td>3b</td><td>2000 levels by 2010 with 15% of compliance limited to off-system reductions</td></tr>
</table>

* Generation equivalent calculated based on 80% capacity factor.

Compliance (MW)

Case EPA 3P Cumulative (MW)

Retrofit Type	2005	2010	2015	2020
ACI	-	33,691	47,698	70,180
Scrubber	23,943	70,558	95,105	121,960
SCR	23,306	107,037	124,082	151,146
SNCR	-	5,360	5,675	7,024
Retire Coal	925	925	925	925
Retire Other	33,609	29,206	24,570	22,700
Repower	-	4,157	4,157	4,157

Case 1 Cumulative (MW)

Retrofit Type	2005	2010	2015	2020
ACI	-	20,079	38,280	54,401
Scrubber	13,719	31,467	41,107	59,597
SCR	23,929	49,074	54,060	73,192
SNCR	146	3,519	3,519	3,519
Retire Coal	14,379	18,336	18,336	18,336
Retire Other	39,380	34,977	30,341	28,471
Repower	-	22,369	23,203	23,203

Case 1a Cumulative (MW)

Retrofit Type	2005	2010	2015	2020
ACI	-	33,267	49,201	72,449
Scrubber	23,784	66,674	91,274	116,747
SCR	23,141	100,859	121,116	147,864
SNCR	-	4,922	4,922	6,203
Retire Coal	869	869	869	869
Retire Other	34,936	30,533	25,897	24,027
Repower	-	4,372	4,689	4,689

Case 2 Cumulative (MW)

Retrofit Type	2005	2010	2015	2020
ACI	-	16,780	30,215	33,088
Scrubber	11,835	27,655	36,756	41,421
SCR	23,040	50,859	52,643	53,576
SNCR	146	195	195	415
Retire Coal	10,925	11,360	11,360	11,360
Retire Other	29,926	25,523	21,887	21,887
Repower	-	18,747	19,313	19,313

Case 3b Cumulative (MW)

Retrofit Type	2005	2010	2015	2020
ACI	-	23,708	48,331	65,865
Scrubber	21,368	58,461	81,071	108,636
SCR	22,655	88,868	109,730	134,592
SNCR	-	5,651	5,651	6,469
Retire Coal	1,643	1,643	1,643	1,643
Retire Other	34,130	29,727	25,091	23,221
Repower	-	6,421	7,142	7,907

Generation (GWh)

Case EPA 3P

Capacity Type	2005	2010	2015	2020
Coal	1,975,372	2,152,539	2,207,282	2,207,496
Gas	921,013	1,102,943	1,327,652	1,575,941
Nuclear	600,862	608,659	602,199	601,453
Oil/Gas Steam	64,188	84,554	57,727	38,315
Other	350,877	354,987	356,133	357,124
IGCC	4,702	4,702	167,217	377,600
Grand Total	**3,917,014**	**4,308,384**	**4,718,210**	**5,157,929**

Case 1

Capacity Type	2005	2010	2015	2020
Coal	1,968,184	1,745,688	1,697,483	1,686,320
Gas	923,295	1,365,134	1,626,145	1,803,925
Nuclear	607,362	615,307	608,843	608,079
Oil/Gas Steam	61,068	55,575	52,910	34,577
Other	351,471	356,662	356,827	355,662
IGCC	4,702	127,342	346,977	636,859
Grand Total	**3,916,082**	**4,265,708**	**4,689,185**	**5,125,422**

Case 1a

Capacity Type	2005	2010	2015	2020
Coal	1,972,102	2,116,702	2,178,991	2,176,912
Gas	922,073	1,087,840	1,320,307	1,577,438
Nuclear	600,862	608,659	602,199	601,453
Oil/Gas Steam	63,693	69,750	54,106	34,727
Other	350,692	354,754	356,232	356,702
IGCC	4,702	66,022	199,485	401,249
Grand Total	**3,914,124**	**4,303,727**	**4,711,320**	**5,148,481**

Case 2

Capacity Type	2005	2010	2015	2020
Coal	1,975,527	1,799,975	1,736,326	1,526,477
Gas	896,387	1,394,549	1,822,897	2,344,818
Nuclear	627,500	647,648	655,864	654,613
Oil/Gas Steam	61,318	37,900	31,989	16,756
Other	351,072	357,065	364,971	390,621
IGCC	4,702	4,702	4,702	4,702
Grand Total	**3,916,506**	**4,241,839**	**4,616,749**	**4,937,987**

Case 3a

Capacity Type	2005	2010	2015	2020
Coal	1,971,585	1,801,720	1,736,741	1,532,771
Gas	901,837	1,335,460	1,691,841	2,192,180
Nuclear	625,537	645,762	654,041	652,797
Oil/Gas Steam	61,721	39,425	30,756	18,129
Other	351,063	356,262	358,476	372,972
IGCC	4,702	68,865	157,965	197,369
Grand Total	**3,916,445**	**4,247,494**	**4,629,820**	**4,966,218**

Case 3b

Capacity Type	2005	2010	2015	2020
Coal	1,964,634	2,043,788	2,120,329	2,121,384
Gas	924,638	1,129,617	1,386,987	1,752,762
Nuclear	609,032	629,679	635,826	634,733
Oil/Gas Steam	61,165	61,608	50,270	29,955
Other	350,673	354,559	355,304	354,883
IGCC	4,702	66,022	140,224	197,369
Grand Total	**3,914,844**	**4,285,273**	**4,688,940**	**5,091,086**

Capacity Additions (MW)

Case EPA 3P Incremental (MW)

Capacity Type	2005	2010	2015	2020
Combined Cycle	-	8,771	23,822	38,648
Combustion Turbine	-	2,189	30,468	33,093
Geothermal	-	-	-	-
IGCC Repower	-	-	21,653	28,030
IGCC Carbon Capture	-	-	-	-
IGCC Carbon Capture w/ EOR Credit	-	-	-	-
Landfill Gas	-	-	-	-
Nuclear	-	-	-	-
Wind	-	-	-	-
Grand Total	**-**	**10,960**	**75,943**	**99,771**

Case EPA 3P Cumulative (MW)

Capacity Type	2005	2010	2015	2020
Combined Cycle	-	8,771	32,593	71,241
Combustion Turbine	-	2,189	32,657	65,750
Geothermal	-	-	-	-
IGCC Repower	-	-	21,653	49,683
IGCC Carbon Capture	-	-	-	-
IGCC Carbon Capture w/ EOR Credit	-	-	-	-
Landfill Gas	-	-	-	-
Nuclear	-	-	-	-
Wind	-	-	-	-
Grand Total	**-**	**10,960**	**86,903**	**186,674**

Case 1 Incremental (MW)

Capacity Type	2005	2010	2015	2020
Combined Cycle	-	6,969	45,433	33,070
Combustion Turbine	-	-	-	27,511
Geothermal	-	-	-	-
IGCC Repower	-	8,170	21,094	38,622
IGCC Carbon Capture	-	4,085	4,085	-
IGCC Carbon Capture w/ EOR Credit	-	4,085	4,085	-
Landfill Gas	-	-	-	-
Nuclear	-	-	-	-
Wind	-	-	-	-
Grand Total	**-**	**23,309**	**74,696**	**99,203**

Case 1 Cumulative (MW)

Capacity Type	2005	2010	2015	2020
Combined Cycle	-	6,969	52,402	85,472
Combustion Turbine	-	-	-	27,511
Geothermal	-	-	-	-
IGCC Repower	-	8,170	29,264	67,886
IGCC Carbon Capture	-	4,085	8,170	8,170
IGCC Carbon Capture w/ EOR Credit	-	4,085	8,170	8,170
Landfill Gas	-	-	-	-
Nuclear	-	-	-	-
Wind	-	-	-	-
Grand Total	**-**	**23,309**	**98,006**	**197,209**

Case 1a Incremental (MW)

Capacity Type	2005	2010	2015	2020
Combined Cycle	-	6,683	25,484	35,463
Combustion Turbine	-	915	28,794	37,369
Geothermal	-	-	-	-
IGCC Repower	-	-	9,612	26,881
IGCC Carbon Capture	-	4,084	4,085	-
IGCC Carbon Capture w/ EOR Credit	-	4,085	4,085	-
Landfill Gas	-	-	-	-
Nuclear	-	-	-	-
Wind	-	-	-	-
Grand Total	**-**	**15,767**	**72,060**	**99,713**

Case 1a Cumulative (MW)

Capacity Type	2005	2010	2015	2020
Combined Cycle	-	6,683	32,167	67,630
Combustion Turbine	-	915	29,709	67,078
Geothermal	-	-	-	-
IGCC Repower	-	-	9,612	36,493
IGCC Carbon Capture	-	4,084	8,169	8,169
IGCC Carbon Capture w/ EOR Credit	-	4,085	8,170	8,170
Landfill Gas	-	-	-	-
Nuclear	-	-	-	-
Wind	-	-	-	-
Grand Total	**-**	**15,767**	**87,827**	**187,540**

Case 2 Incremental (MW)

Capacity Type	2005	2010	2015	2020
Combined Cycle	-	7,506	68,492	87,089
Combustion Turbine	-	-	1,226	8,736
Geothermal	-	-	-	-
IGCC Repower	-	-	-	-
IGCC Carbon Capture	N/A	N/A	N/A	N/A
IGCC Carbon Capture w/ EOR Credit	N/A	N/A	N/A	N/A
Landfill Gas	-	-	144	2,260
Nuclear	-	-	-	-
Wind	-	-	-	-
Grand Total	**-**	**7,506**	**69,862**	**98,085**

Case 2 Cumulative (MW)

Capacity Type	2005	2010	2015	2020
Combined Cycle	-	7,506	75,998	163,087
Combustion Turbine	-	-	1,226	9,962
Geothermal	-	-	-	-
IGCC Repower	-	-	-	-
IGCC Carbon Capture	N/A	N/A	N/A	N/A
IGCC Carbon Capture w/ EOR Credit	N/A	N/A	N/A	N/A
Landfill Gas	-	-	144	2,404
Nuclear	-	-	-	-
Wind	-	-	-	-
Grand Total	**-**	**7,506**	**77,368**	**175,453**

Case 3b Incremental (MW)

Capacity Type	2005	2010	2015	2020
Combined Cycle	-	3,988	46,932	58,513
Combustion Turbine	-	-	5,467	5,095
Geothermal	-	-	-	-
IGCC Repower	-	-	-	-
IGCC Carbon Capture	-	4,085	4,085	-
IGCC Carbon Capture w/ EOR Credit	-	4,085	5,801	7,614
Landfill Gas	-	-	-	144
Nuclear	-	-	-	-
Wind	-	-	-	-
Grand Total	**-**	**12,158**	**62,285**	**71,366**

Case 3b Cumulative (MW)

Capacity Type	2005	2010	2015	2020
Combined Cycle	-	3,988	50,920	109,433
Combustion Turbine	-	-	5,467	10,562
Geothermal	-	-	-	-
IGCC Repower	-	-	-	-
IGCC Carbon Capture	-	4,085	8,170	8,170
IGCC Carbon Capture w/ EOR Credit	-	4,085	9,886	17,500
Landfill Gas	-	-	-	144
Nuclear	-	-	-	-
Wind	-	-	-	-
Grand Total	**-**	**12,158**	**74,443**	**145,809**

Emissions

Case EPA 3P

Emissions	2005	2010	2015	2020
SO2 [MTons]	7,468	6,059	5,261	4,286
NOX [MTons]	3,664	2,186	2,125	1,826
CO2 [MMTons]	2,453	2,727	2,992	3,240
MER [Tons]	39	21	18	13

Case 1

Emissions	2005	2010	2015	2020
SO2 [MTons]	8,588	5,780	4,849	4,121
NOX [MTons]	3,632	2,179	2,075	1,843
CO2 [MMTons]	2,440	2,436	2,611	2,882
MER [Tons]	41	22	17	13

Case 1a

Emissions	2005	2010	2015	2020
SO2 [MTons]	7,455	5,998	5,259	4,319
NOX [MTons]	3,658	2,186	2,123	1,828
CO2 [MMTons]	2,449	2,680	2,897	3,141
MER [Tons]	39	21	18	13

Case 2

Emissions	2005	2010	2015	2020
SO2 [MTons]	8,671	6,432	5,320	3,983
NOX [MTons]	3,659	2,198	2,124	1,793
CO2 [MMTons]	2,435	2,426	2,509	2,465
MER [Tons]	40	22	18	13

Case 3a

Emissions	2005	2010	2015	2020
SO2 [MTons]	8,654	6,429	5,309	4,008
NOX [MTons]	3,655	2,198	2,137	1,777
CO2 [MMTons]	2,433	2,412	2,475	2,435
MER [Tons]	40	22	18	12

Case 3b

Emissions	2005	2010	2015	2020
SO2 [MTons]	7,612	6,060	5,323	4,302
NOX [MTons]	3,648	2,185	2,125	1,835
CO2 [MMTons]	2,440	2,609	2,794	2,926
MER [Tons]	39	22	17	13

Capacity Prices (1999$/kWh), Energy Prices (1999$/MWh), Firm Prices (1999$/MWh)

Case EPA 3P

National	2005	2010	2015	2020
Capacity Prices (1999$/kW-yr)	0	20	33	43
Energy Prices (1999$/MWh)	22.5	27.1	29.5	29.1
Firm Prices (1999$/MWh)	22.5	29.4	33.2	34.0

Case 1

National	2005	2010	2015	2020
Capacity Prices (1999$/kW-yr)	0	7	26	41
Energy Prices (1999$/MWh)	22.3	31.2	31.1	29.7
Firm Prices (1999$/MWh)	22.3	32.0	34.0	34.4

Case 1a

National	2005	2010	2015	2020
Capacity Prices (1999$/kW-yr)	0	17	33	44
Energy Prices (1999$/MWh)	22.4	26.7	29.5	28.9
Firm Prices (1999$/MWh)	22.5	28.6	33.2	33.9

Case 2

National	2005	2010	2015	2020
Capacity Prices (1999$/kW-yr)	0	7	28	42
Energy Prices (1999$/MWh)	22.1	35.0	37.2	39.4
Firm Prices (1999$/MWh)	22.1	35.8	40.4	44.3

Case 3a

National	2005	2010	2015	2020
Capacity Prices (1999$/kW-yr)	1	7	28	42
Energy Prices (1999$/MWh)	22.1	34.0	36.0	38.0
Firm Prices (1999$/MWh)	22.2	34.7	39.2	42.8

Case 3b

National	2005	2010	2015	2020
Capacity Prices (1999$/kW-yr)	-	16	32	45
Energy Prices (1999$/MWh)	22.3	28.6	30.9	31.3
Firm Prices (1999$/MWh)	22.3	30.5	34.6	36.4

Wholesale Energy Prices – EOR Regions (1999$/MWh)

Case EPA 3P

Region	2005	2010	2015	2020
CALI	29.7	33.8	35.1	34.5
AZNM	18.7	23.0	31.8	33.2
RMPA	16.3	21.3	29.8	31.3
ERCOT	22.8	29.4	31.8	32.3
ENTERGY	18.3	22.2	25.5	31.9

Case 1

Region	2005	2010	2015	2020
CALI	29.4	34.1	35.3	34.5
AZNM	18.8	28.2	33.4	33.6
RMPA	16.3	29.0	31.6	31.8
ERCOT	22.5	30.6	32.5	32.8
ENTERGY	18.1	24.6	26.7	31.8

Case 1a

Region	2005	2010	2015	2020
CALI	29.7	32.4	35.3	34.6
AZNM	18.7	21.9	32.0	33.1
RMPA	16.3	21.0	29.8	31.3
ERCOT	22.7	29.1	31.8	32.3
ENTERGY	18.3	21.9	25.3	31.8

Case 2

Region	2005	2010	2015	2020
CALI	29.3	38.7	41.6	44.9
AZNM	18.6	29.4	39.4	42.8
RMPA	16.0	28.7	37.4	40.9
ERCOT	22.9	35.3	38.4	42.0
ENTERGY	18.2	31.2	34.7	42.1

Case 3b

Region	2005	2010	2015	2020
CALI	29.5	33.9	36.3	36.8
AZNM	18.6	23.5	33.4	35.2
RMPA	16.1	22.4	30.9	33.4
ERCOT	22.6	30.8	33.2	34.4
ENTERGY	18.1	23.9	26.1	33.8

Wholesale Energy Prices – Select Regions (1999$/MWh)

Case EPA 3P

Region	2005	2010	2015	2020
ECAR	19.7	27.7	32.5	33.7
NEPOOL	27.3	34.2	35.9	37.3
WEST	25.5	29.1	32.7	33.1

Case 1

Region	2005	2010	2015	2020
ECAR	19.5	32.4	34.5	34.8
NEPOOL	27.4	38.5	39.8	39.0
WEST	25.4	31.7	33.6	33.4

Case 1a

Region	2005	2010	2015	2020
ECAR	19.7	27.2	32.6	33.5
NEPOOL	27.3	36.8	38.6	39.0
WEST	25.5	28.2	32.8	33.1

Case 2

Region	2005	2010	2015	2020
ECAR	18.8	34.6	40.3	44.0
NEPOOL	27.4	42.3	45.1	48.6
WEST	25.2	34.7	39.6	43.0

Case 3b

Region	2005	2010	2015	2020
ECAR	19.4	29.5	34.5	36.0
NEPOOL	27.2	38.2	39.9	41.1
WEST	25.3	29.7	34.0	35.2

Gas Prices (1999$/MMBtu)

Case EPA 3P

Year	Price (1999$/MMBtu)
2005	2.57
2010	3.01
2015	3.25
2020	3.35

Case 1

Year	Price (1999$/MMBtu)
2005	2.54
2010	3.19
2015	3.35
2020	3.43

Case 1a

Year	Price (1999$/MMBtu)
2005	2.57
2010	2.96
2015	3.25
2020	3.35

Case 2

Year	Price (1999$/MMBtu)
2005	2.53
2010	3.15
2015	3.44
2020	3.77

Case 3b

Year	Price (1999$/MMBtu)
2005	2.55
2010	3.01
2015	3.25
2020	3.41

Gas Consumption (TBtu)

	2005	2010	2015	2020
Case EPA 3P	6,953	8,388	9,623	10,993
Case 1	6,953	9,946	11,525	12,408
Case 1a	6,953	8,142	9,542	10,993
Case 2	6,775	9,905	12,474	15,528
Case 3b	6,953	8,321	9,899	11,992

Allowance Prices (1999$/Ton)

Case EPA
3P

Year	SO2 Title IV	East Annual NOX	West Annual NOX	Mercury (1999$/lb)
	Allowance Prices (1999$/ton)			
2005	540	1,807	-	-
2006	540	1,807	-	-
2007	569	1,558	-	-
2008	599	1,344	526	44,690
2009	630	1,159	526	44,690
2010	664	1,000	526	44,690
2011	699	992	506	47,077
2012	737	985	487	49,592
2013	776	978	469	52,240
2014	817	971	451	55,031
2015	861	964	434	57,970
2016	907	1,015	422	61,065
2017	956	1,069	411	64,326
2018	1,007	1,127	400	67,761
2019	1,060	1,187	390	71,379
2020	1,117	1,250	380	75,190

Case 1

Year	Allowance Prices (1999$/ton)				Incentive Price (1999$/MWh)			
	SO_2 Title IV	East Annual NO_X	West Annual NO_X	Mercury (1999$/lb)	IGCC Repower	IGCC Carbon Capture	IGCC Carbon Capture w/ EOR Credit	Coal Forced Offline
2005	396	2,010	-	-	-	-	-	-
2006	396	2,010	-	-	-	-	-	-
2007	417	1,584	-	-	-	-	-	-
2008	439	1,248	255	36,170	1.72	24.49	2.48	15.05
2009	462	984	255	36,170	1.72	24.49	2.48	15.05
2010	487	775	255	36,170	1.72	24.49	2.48	15.05
2011	513	743	232	38,102	1.72	24.06	1.92	15.18
2012	540	712	210	40,138	1.72	23.64	1.49	15.31
2013	569	682	191	42,282	-	23.23	1.16	15.45
2014	599	653	174	44,541	-	22.82	0.90	15.58
2015	631	626	158	46,920	-	22.42	0.69	15.72
2016	665	659	135	49,424	-	24.48	0.78	15.34
2017	701	695	116	52,062	-	26.72	0.87	14.97
2018	738	732	99	54,840	-	29.18	0.97	14.61
2019	777	771	85	57,767	-	31.86	1.08	14.26
2020	819	812	72	60,850	-	34.78	1.21	13.92

Case 1a

Year	Allowance Prices (1999$/ton)				Incentive Price (1999$/MWh)	
	SO2 Title IV	East Annual NOX	West Annual NOX	Mercury (1999$/lb)	IGCC Carbon Capture	IGCC Carbon Capture w/ EOR Credit
2005	541	1,813	-	-	-	-
2006	541	1,813	-	-	-	-
2007	570	1,558	-	-	-	-
2008	600	1,339	515	45,390	28.28	4.29
2009	632	1,151	515	45,390	28.28	4.29
2010	665	989	515	45,390	28.28	4.29
2011	701	981	515	47,815	28.26	4.29
2012	738	973	515	50,369	28.25	4.29
2013	778	965	461	53,060	28.23	2.45
2014	819	957	444	55,894	28.22	2.04
2015	863	949	428	58,880	28.20	1.69
2016	909	1,000	412	62,024	24.96	1.40
2017	957	1,053	397	65,336	22.10	1.17
2018	1,009	1,109	382	68,824	19.56	-
2019	1,062	1,169	368	72,499	17.32	-
2020	1,119	1,231	371	76,370	15.33	-

Case 2

Year	Allowance Prices (1999$/ton)				
	SO2 Title IV	East Annual NOX	West Annual NOX	Carbon	Mercury (1999$/lb)
2005	399	1,802	-	-	-
2006	399	1,802	-	-	-
2007	420	1,738	-	-	-
2008	442	1,676	262	11.2	42,430
2009	465	1,616	262	11.2	42,430
2010	490	1,558	262	11.2	42,430
2011	516	1,296	262	11.8	44,695
2012	544	1,078	262	12.4	47,081
2013	573	897	-	13.1	49,594
2014	603	746	-	13.8	52,241
2015	636	621	-	14.6	55,030
2016	670	654	-	15.3	57,969
2017	705	689	-	16.1	61,065
2018	743	726	-	17.0	64,326
2019	783	764	-	17.9	67,761
2020	825	805	-	18.9	71,380

Case 3a

Year	Allowance Prices (1999$/ton)					Incentive Price (1999$/MWh)	
	SO2 Title IV	East Annual NOX	West Annual NOX	Carbon	Mercury (1999$/lb)	IGCC Carbon Capture	IGCC Carbon Capture w/ EOR Credit
2005	398	1,826	-	-	-	-	-
2006	398	1,826	-	-	-	-	-
2007	419	1,734	-	-	-	-	-
2008	441	1,647	253	10.5	42,050	22.51	-
2009	464	1,564	253	10.5	42,050	22.51	-
2010	489	1,485	253	10.5	42,050	22.51	-
2011	515	1,264	253	11.0	44,295	21.45	-
2012	542	1,077	253	11.6	46,660	20.44	-
2013	571	917	36	12.2	49,151	19.48	-
2014	602	781	19	12.9	51,776	18.56	-
2015	634	665	10	13.6	54,540	17.69	-
2016	668	700	5	14.3	57,452	16.78	-
2017	703	737	3	15.0	60,519	15.91	-
2018	741	777	1	15.8	63,751	15.09	-
2019	781	818	1	16.7	67,154	14.32	-
2020	822	862	-	17.6	70,740	13.58	-

Case 3b

Year	Allowance Prices (1999$/ton)					Incentive Price (1999$/MWh)	
	SO2 Title IV	East Annual NOX	West Annual NOX	Carbon	Mercury (1999$/lb)	IGCC Carbon Capture	IGCC Carbon Capture w/ EOR Credit
2005	517	1,801	-	-	-	-	-
2006	517	1,801	-	-	-	-	-
2007	544	1,568	-	-	-	-	-
2008	573	1,366	345	2.8	43,170	26.79	3.04
2009	603	1,190	345	2.8	43,170	26.79	3.04
2010	635	1,036	345	2.8	43,170	26.79	3.04
2011	669	1,017	345	3.0	45,474	25.64	3.04
2012	705	999	345	3.1	47,902	24.54	3.04
2013	742	980	403	3.3	50,459	23.48	-
2014	782	963	425	3.5	53,153	22.48	-
2015	824	945	448	3.6	55,990	21.51	-
2016	868	996	472	3.8	58,981	20.74	-
2017	914	1,049	497	4.0	62,132	19.99	-
2018	963	1,105	523	4.3	65,451	19.28	-
2019	1,014	1,164	551	4.5	68,947	18.59	-
2020	1,068	1,226	332	4.7	72,630	17.92	-

Total System Costs (Million 1999$)

Case EPA 3P

	2005	2010	2015	2020
Variable O&M	6,799	8,687	9,639	10,806
Fixed O&M	21,768	22,703	23,627	25,032
Fuel	43,118	51,078	56,722	61,630
Capital	975	4,315	13,870	25,191
Total	72,660	86,783	103,859	122,660

Case 1

	2005	2010	2015	2020
Variable O&M	6,665	7,788	8,698	9,759
Fixed O&M	21,250	21,792	22,648	23,836
Fuel	42,670	54,186	60,603	64,355
Capital	764	7,295	18,343	30,665
Total	71,348	91,060	110,292	128,615

Case 1a

	2005	2010	2015	2020
Variable O&M	6,790	8,724	9,762	10,895
Fixed O&M	21,746	22,683	23,610	25,001
Fuel	43,051	49,937	56,538	61,616
Capital	971	6,014	15,420	26,490
Total	72,558	87,358	105,330	124,001

Case 2

	2005	2010	2015	2020
Variable O&M	6,676	7,570	8,081	8,489
Fixed O&M	21,976	22,779	24,104	25,551
Fuel	42,160	53,143	63,322	76,314
Capital	759	3,603	10,601	18,657
Offsets	-	4,126	5,350	3,740
Total	71,570	91,221	111,457	132,750

Case 3a

	2005	2010	2015	2020
Variable O&M	6,666	7,706	8,102	8,104
Fixed O&M	21,840	22,714	23,965	25,324
Fuel	42,247	51,687	60,166	71,592
Capital	736	5,383	14,396	23,337
Offsets		3,842	4,982	3,483
Total	71,489	91,331	111,611	131,840

Case 3b

	2005	2010	2015	2020
Variable O&M	6,757	8,486	9,376	9,711
Fixed O&M	21,828	22,915	24,198	25,668
Fuel	42,796	50,022	56,973	64,415
Capital	948	5,811	14,249	23,684
Offsets	-	1,051	1,363	1,768
Total	72,328	88,285	106,158	125,246

Net Present Value of Total System Costs

Change from EPA (EIA Growth) 3P Case (Billion Year 1999 $)
30-year NPV, Discounted at Real Discount Rate of 5.34% to 2003

Billion 2000$	NPV
Case 1	38.5
Case 2	96.4
Case 3	58.6
Case 1a	8.2
Case 2a	47.6
Case 3a	86.2
Case 3b	29.0

Coal Consumption (Million Tons)

Case 1

	2005	2010	2015	2020
Appalachia	314	294	337	397
Interior	194	192	188	209
West	433	395	415	426
National	940	881	940	1,032

Case 2

	2005	2010	2015	2020
Appalachia	316	296	291	251
Interior	184	179	161	144
West	433	356	342	281
National	933	831	794	677

Case 3

	2005	2010	2015	2020
Appalachia	318	327	351	323
Interior	187	187	174	159
West	436	413	435	484
National	940	926	960	965

Case 1a

	2005	2010	2015	2020
Appalachia	304	357	395	442
Interior	195	226	236	244
West	447	447	485	497
National	946	1,030	1,116	1,183

Case 2a

	2005	2010	2015	2020
Appalachia	317	305	310	277
Interior	187	186	171	155
West	433	396	454	509
National	937	887	934	941

Case EPA 3P

	2005	2010	2015	2020
Appalachia	305	358	392	442
Interior	195	226	236	246
West	447	435	482	492
National	947	1,018	1,109	1,179

Case 3a

	2005	2010	2015	2020
Appalachia	318	305	309	276
Interior	183	181	165	146
West	432	376	393	353
National	933	862	868	775

Case 3b

	2005	2010	2015	2020
Appalachia	308	353	374	382
Interior	192	209	217	218
West	441	424	469	491
National	941	987	1,061	1,091