Financial Impact Analysis of a Multi-Pollutant Emissions Policy

2003 Update

Prepared by
ICF Consulting
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Organization

- Introduction and Background
- Will 3P Regulations Impact a Firm's Financial Position?
- Will Industry Be Able to Obtain Financing for Required Retrofits?
- Will 3P Regulations Cause Coal Plants to Retire?

Introduction and Background

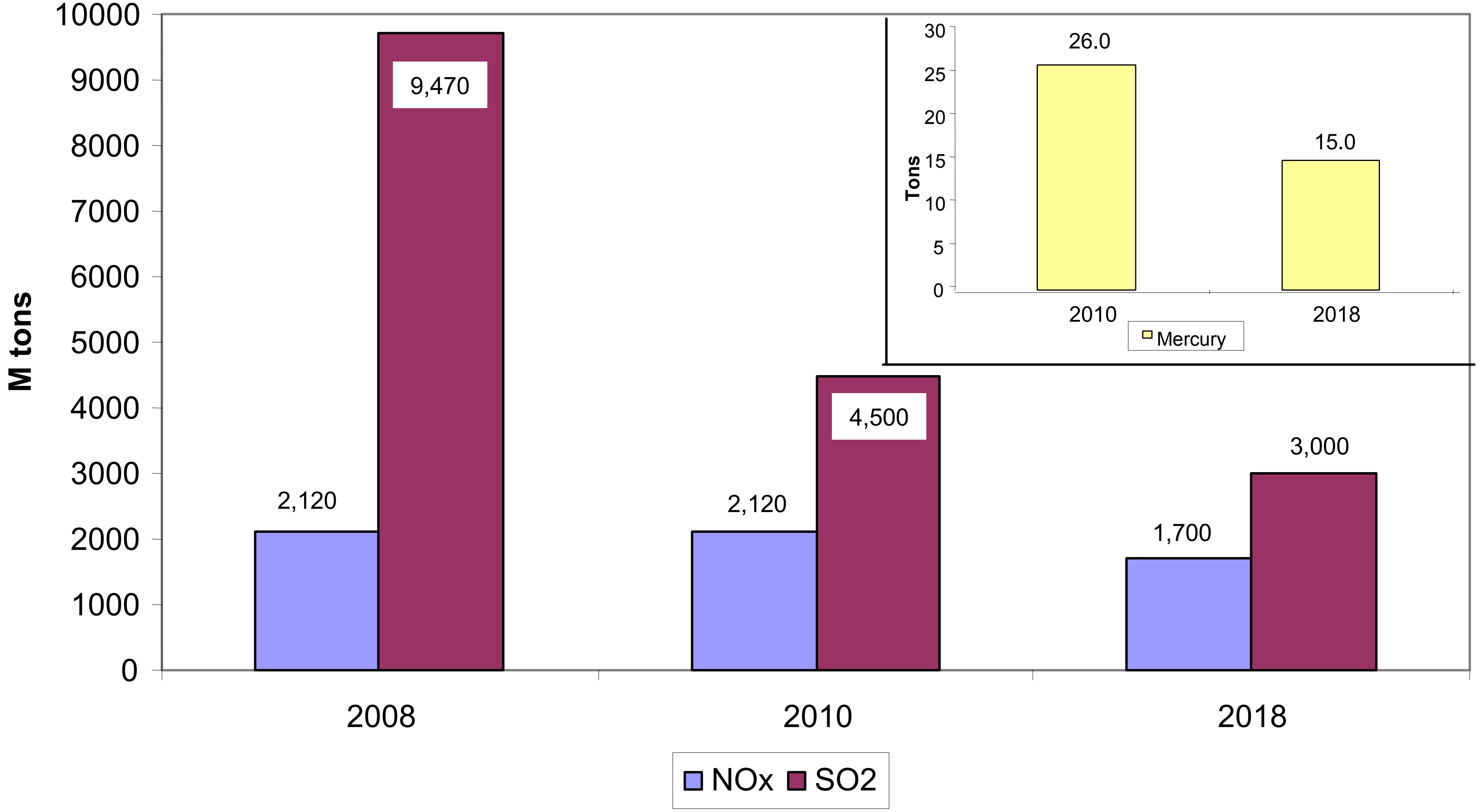
- This briefing summarizes the results of an analysis of the possible implications of a potential multi-pollutant environmental policy (3P policy) addressing sulfur dioxide (SO_2), nitrogen oxides (NO_x) and mercury (Hg) on the electric power industry's operation and financial condition.
- The analysis focused on the answers to three specific questions:

1. Will companies experience financial distress as a result of 3P policies?
2. Can the industry finance required pollution control equipment?
3. Will there be significant retirements of coal-fired power plants?

Introduction and Background
(continued)

- These findings are based on ICF's modeling runs using the Integrated Planning Model (IPM®), a detailed power sector model.
- The IPM model has been used to provide due diligence financing support for tens of billions of dollars of power plant investment. This model has been used for rating agencies, investment banks, developers, and utilities for valuation, pricing and investment studies.
- Information reported in this presentation reflects detailed analysis of EPA's Clear Skies Act 2003 and the corresponding Base Case modeling as illustrated on the next page.

Emission Limits of the 3P Program Analyzed Are Phased in over Time



Notes: Current control policies assumed to be in place prior to 2008.

Emission Limits of the 3P Program Analyzed Are Phased in over Time

- Significant reductions of SO_2, NO_x and Hg are obtained as a result of the 3P programs. The reductions are phased in over time with the lowest emission levels being achieved after 2018.
- Note, this would be the first national program controlling multiple pollutants with a cap and trade mechanism and the first Hg cap and trade program.
- The phased-in implementation of reductions mitigates the program's financial effects.
- However, the economic situation of the power industry is different than during previous major environmental regulatory initiatives in three respects. First, the industry has been partially deregulated. Second, many power companies are currently experiencing financial distress. This distress is, in large part, due to excess additions of new generation capacity. Third, a very large amount of new power plants have been added nearly all of which have been natural gas fired. This may be significant since there is now a large population of new gas plants competing with existing coal plants and the proposed regulations differentially affect coal over gas plants.
- Thus, financial effects are potentially more salient.

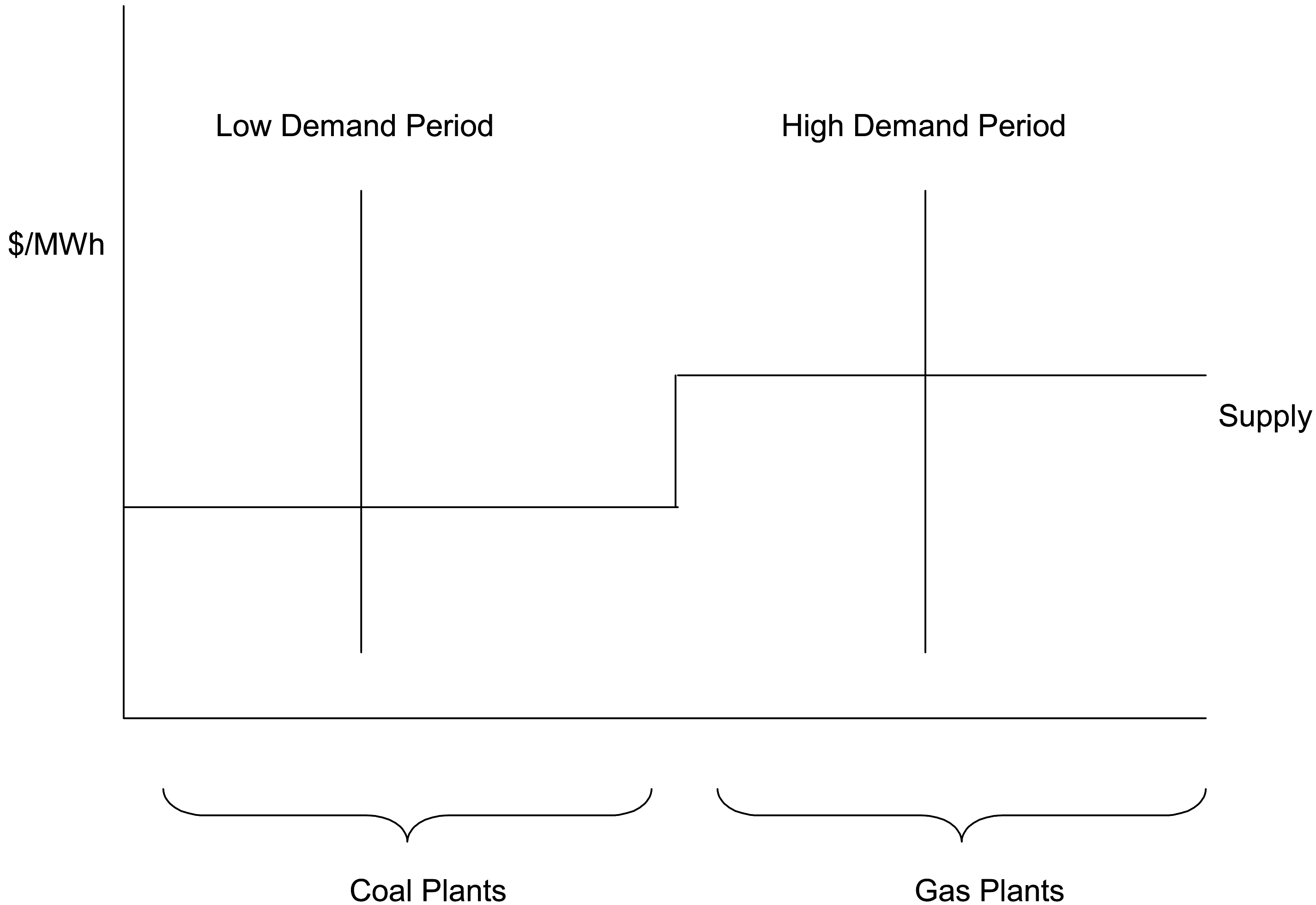
Projected Controls on Coal Capacity under the Examined 3P Case

Control Type	Percent of All Coal Capacity in 2020	
	Base Case	**3P Case**
SO2 Controls	40	68
NOx Controls	47	69
Hg Controls	0	1[1]

Note: Due to installation of scrubbing equipment in the 3P Case, the total amount of coal capacity is slightly reduced from Base Case levels.
[1]Most of the Hg reductions due to this 3P policy case result from the co-benefits of SO_2 and NO_x controls.

- Under this 3P scenario, it is expected that power companies will install incremental SO_2 controls at 86 GW of generating capacity. Incremental NO_x controls and incremental Hg controls are projected to be installed at 67 GW and 4 GW of generating capacity, respectively.
- The impact of the 3P policy in terms of installation of controls is felt as early as 2005 for some units. However, 45 percent of the incremental capital investment resulting from the 3P policy does not occur until after 2010.

Deregulated Wholesale Prices Reflect Marginal Costs



Deregulated Wholesale Prices Reflect Marginal Costs

- Since US wholesale power markets are assumed to operate as competitive deregulated markets, prices are set by the marginal cost of serving demand. Shifts in the variable costs of marginal units resulting from the 3P policy will shift the market price. All units will receive a market price equal to the marginal unit's cost at the time they are dispatched.
- In periods in which natural gas fueled plants are on the margin, prices reflect the marginal costs of these plants. In a hypothetical case in which gas plants are always on the margin and their costs are unchanged, prices do not change. Thus, even if coal plant costs rise they may not be able to pass their cost through to the market.
- As it turns out, this worst-case scenario from the perspective of coal plants does not occur, and in fact, wholesale market prices do provide substantial cost pass through potential.

Wholesale Prices Only Moderately Affected

Year	National Average Firm Wholesale Market All-Hours Price (1999$/MWh)		
	Base Case	3P Case	Change
2005	23.2	24.3	+1.1 (4.6%)
2010	25.4	27.2	+1.8 (6.7%)
2015	29.9	31.3	+1.4 (4.5%)
2020	31.6	32.6	+1.0 (3.0%)
Annuity 2005-2020	26.2	27.6	+1.4 (5.5%)

Notes: The firm wholesale price is the annual average hourly energy price plus the annual capacity price at a 100 percent load factor. All US wholesale power markets are assumed to operate as deregulated competitive markets.

Wholesale Prices Only Moderately Affected (continued)

- As a result of the 3P case, the average national wholesale power price (including energy and capacity) on an annuity basis increases 5.5 percent.
- This reflects two factors.
  - First, natural gas prices increase roughly $0.09/MMBtu (3 percent) in real 1999 dollars on a levelized basis under the Clear Skies case. Thus, in hours in which gas plants are on the margin, prices rise.
  - Second, coal power plant variable costs (i.e., fuel, variable O&M and the cost of emission allowances, but not including the allocation of emission allowances) increase 8 percent. Thus, when coal plants are on the margin, prices also increase.
- The 5.5 percent increase can be thought of as the average of the increase due to increasing coal and gas plant costs.

Wholesale Prices Only Moderately Affected (continued)

- Wholesale power price movements will be sensitive to the response of gas prices to increased demand for gas and, in turn, the sensitivity of wholesale prices to changes in gas price. The larger the increase in wholesale prices due to shifts in the gas price, the larger the level of costs deregulated coal plants will be able to recover. The opposite also holds true.
- Coal power plants thus face two negative developments. First, wholesale power prices have increased less than their variable costs. Second, they must also recover increases in their fixed costs (e.g., capital and fixed O&M).
- On the other hand, coal plants are also allocated emission allowances. These revenues can help offset the effects of costs increases.
- Regulated units are assumed to be able to pass full costs (including fixed and capital) through to customers via the rate base. However, deregulated units receive competitive market prices and are not guaranteed cost recovery. Hence, competitive wholesale market prices more directly influence deregulated plants.

Retail Power Price Increases Even Smaller

Year	National Average Price (1999$/MWh)					
	Firm Wholesale Market All-Hours Price			Retail Price		
2005	23.2	24.3	+1.1 (4.6%)	58.5	59.3	+0.8 (1.3%)
2010	25.4	27.2	+1.8 (6.7%)	59.5	61.1	+1.6 (2.6%)
2015	29.9	31.3	+1.4 (4.5%)	62.2	63.9	+1.7 (2.8%)
2020	31.6	32.6	+1.0 (3.0%)	63.9	65.2	+1.3 (2.0%)
Annuity 2005-2020	26.2	27.6	+1.4 (5.5%)	60.2	61.5	+1.4 (2.2%)

Notes: Firm wholesale prices represent annual average hourly energy price plus the annual capacity price at a 100 percent load factor. For deregulated market areas, the generation component of retail prices is based the load weighted wholesale energy price (rather than average hourly marginal price) plus the load weighted capacity price. For areas not currently deregulated, the generation component of the retail price is based on estimates of the cost-of-service derived from a combination of IPM and EIA cost information (AEO2002). For additional information on retail price derivation, see EPA Technical Support Document, July 2003 (http://www.epa.gov/clearskies/technical.html).

Retail Power Price Increases Even Smaller (continued)

- Retail electricity price increases due to the Clear Skies Act are similar on an absolute $/MWh basis to the increases in wholesale prices, but much smaller on a percentage basis. This is because the non-generation components of customer rates (e.g., transmission and distribution) are unchanged. On an annuity basis, the national average retail rate increases 2.2 percent as compared to the average wholesale market price increase of 5.5 percent.
- In regulated states, full generation costs are recovered from ratepayers. In deregulated states, wholesale prices are expected to be recovered from wholesale power purchasers and ultimately passed on to end-users.
  - For regulated markets, the generation component of the retail price is based on estimates of the cost-of-service derived from a combination of IPM and EIA cost information (AEO2002). A probability of deregulation is also assumed to determine an expected retail rate.
- Thus, in different states, customers see different rates of increase on the generation side due to the Clear Skies Act. Nonetheless, the absolute increase is similar and the retail increase is still small on a percentage basis.

Will Companies Experience Financial Distress under a 3P Policy?

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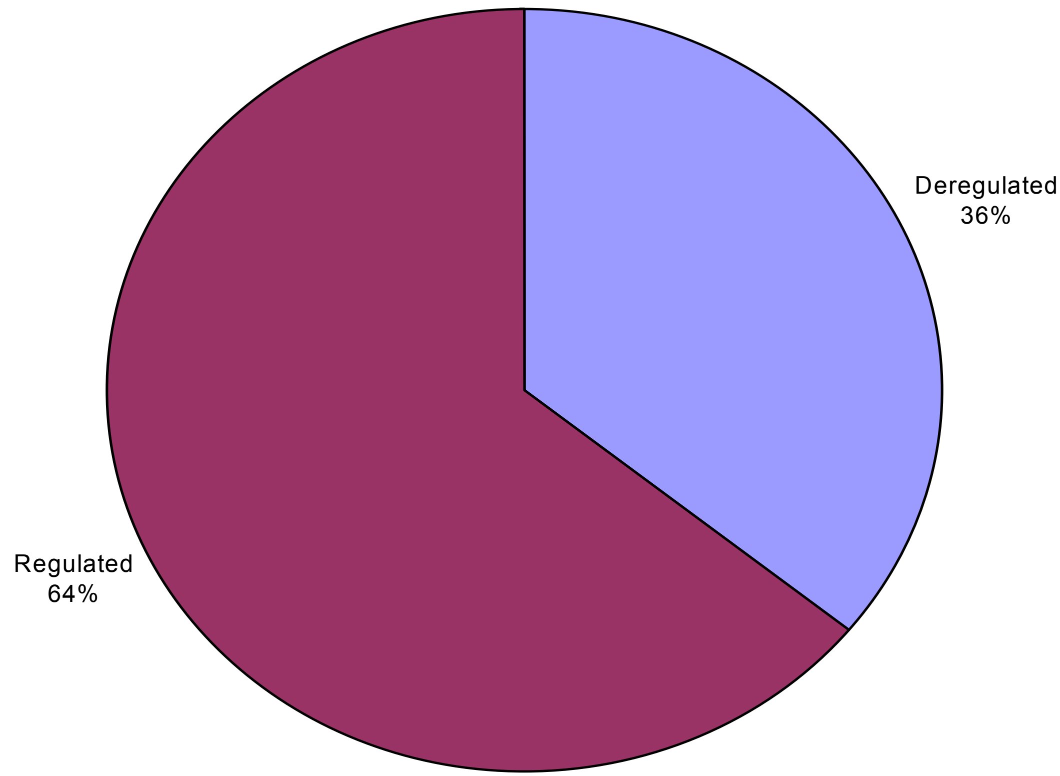
Financial Effects

- These are two principal metrics used by the financial community: (1) the change in total plant or company value (i.e., change in discounted net cash flow), and (2) the change in plant or company debt service coverage ratios. Both approaches are approximated in this analysis.
- In our analysis, companies are assumed to be credit worthy and have a manageable amount of debt by 2005 under the Base Case. Specifically, companies are assumed to have a 2.8 coverage ratio (cash available to cover debt) starting in 2005. Further, companies are assumed to refinance to maintain a 2.8 level over time in the Base Case.[1]
- This is not only reasonable given the time before most effects occur, but is also necessary to separate out the effects of 3P versus other issues (e.g., current excessive reliance on debt financing).
- The analysis also assumed that in regulated states, retail rate caps would either end by 2005 or be reset based on new conditions. This is increasingly reasonable over time as many existing rate caps are due to expire within the next few years.
- Lastly, this analysis also assumes no binding price caps will occur in the time horizon in deregulated wholesale markets. This is also reasonable for a long-term analysis.

[1] Except as noted later.

The Financial Impact of 3P Policies Could Be an Issue for Owners of Already Deregulated Coal Plants



Total US Coal Capacity = 306 GW

Source: Based on data as modeled in IPM® for the EPA Base Case.

The Financial Impact of 3P Policies Could Affect Owners of Already Deregulated Coal Plants (continued)

- Of 306 GW of coal capacity in the US, 36 percent or about 110 GW is considered deregulated.
- Regulated power plants can pass economically justified costs through to ratepayers. Even in deregulated states there are some publicly owned or operated units which price on a cost-plus franchise basis; these units are treated as regulated in this analysis. Thus, 64 percent of the coal plants will experience no direct financial distress due to regulated cost recovery mechanisms.
- The assumption that utilities can pass environmental control costs to rate payers reflects past successes by utilities in this regard, the modest size of the required customer electric rate increases, legal requirements for cost recovery, the relatively unambiguous nature of the requirement, and the assumption that current retail rate caps will not be in place in the long run.

Current Coal Capacity in Deregulated States by State

State	Coal Plants	Public/Regulated Coal Capacity (MW)	Private/Deregulated Coal Capacity (MW)	Total Coal Capacity (MW)
Ohio	30	541	21,716	22,257
Texas	20	2,391	17,011	19,402
Pennsylvania	38	0	18,894	18,894
Illinois	25	1,184	13,798	14,982
Michigan	23	824	10,848	11,671
Virginia	21	0	5,615	5,615
Arizona	6	3,330	1,871	5,201
Maryland	8	0	4,814	4,814
New York	16	50	3,930	3,980
New Jersey	7	23	1,993	2,016
Massachusetts	3	0	1,666	1,666
Delaware	4	0	994	994
Connecticut	3	0	574	574
New Hampshire	2	0	569	569
Oregon	1	0	508	508
Maine	2	0	90	90
Total	**177**	**8,343**	**104,890[1]**	**113,233**

[1] Approximately 4.6 GW of additional coal capacity is included in the total for deregulated. This represents 0.5 GW in California where deregulation is suspended, 2.3 GW in Montana where deregulated is delayed but the majority of coal plants were sold, and the capacity at Big Cajun in Louisiana.

- Currently deregulated coal plants are not geographically dispersed; five states account for 75 percent of the capacity (Ohio, Texas, Pennsylvania, Illinois, Michigan).

Deregulated Coal Capacity Value May Be Compensated for 3P Impacts

- In the future, more existing U.S. coal plants could be deregulated. Even so, currently-regulated plants are still likely to be insulated from financial impacts. This is because knowing that 3P programs will affect their deregulated value and coverage ratios once they are deregulated, these plants should be able to obtain compensation via greater stranded cost recovery.
- Thus, we conclude that the impact of 3P regulations will only place at risk already-deregulated power plants[1].
- Given that regulated facilities will not be largely affected by 3P policies due to the possibility of recovering costs through their rate base, the rest of this document is focused largely on the financial impact to deregulated companies.

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[1] Note, this analysis conservatively assumes that pending environmental regulations were not originally factored in during the stranded cost review of already-deregulated units. Also, if there were re-regulation of already-deregulated coal plants, the financial effect would also be less than shown here.

Financial Distress Is Measured by Change in Value and Change in Debt Service Coverage Ratio (DSCR)

- One simplified view of financial distress for already-deregulated coal plants would be to simply determine the change in value (i.e., change in discounted cash flow) due to the environmental regulations. However, large changes in Debt Service Coverage Ratios (DSCR) also can be an important measure of financial distress. Hence, we reviewed both.
- DSCRs are used as a metric to judge the liquidity of a company and potential risk to investors. The DSCR refers to the ratio of dollars available from cash flow to repay or service debt (principal and interest). Lower ratios indicate greater risk of inability to repay debt or default.
- For this analysis, ICF assumed a starting or Base Case coverage ratio of 2.8 (net revenues or cash flow is 2.8 times debt service requirements) across companies for all years and examined the extent to which coverage ratios would be affected by the 3P policy[1]. This starting DSCR is not inconsistent with the long-term historical average for many companies and, as mentioned, ensures that this analysis is able to separate the effects of the 3P program from other problems.

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[1] Except as noted.

Financial Distress Is Measured by Change in Value and Change in Debt Service Coverage Ratio (DSCR) (continued)

- Companies with coverage ratios of about 2.5 to 2.8 are considered to be "investment grade", particularly those with coal plants. Coverage ratios of 2.0 to 2.5 are generally considered positive, but require firms be more closely scrutinized. Coverage ratios of 1.5 to 2.0 can be disruptive. Coverage ratios below 1.5 can be catastrophic to corporate viability.
- ICF analyzed the financial impact on earnings over a 15-year horizon and accounted for allocation of emission permits on an input basis.[1]
- The change in the net present value (NPV) of all generation assets was calculated based on the difference between the EPA Base Case and the 3P policy case. This method approximates a discounted cash flow analysis approach. However, the analysis presented herein is performed before taxes, interest and depreciation. The change in NPV calculated herein reflects the impact of the policy on the value of the sector's generation assets[2].
- Similarly, the change in DSCR across cases was also calculated.

[1] A forecast of near-term fuel input was used to allocate allowances. The initial allowance auction was assumed to begin in 2010 at 1 percent. An increasing share of the total allocation was assumed to be auctioned, reaching a level of 11 percent by year 2020.

[2] New units (i.e., plants built by the model beyond current mix) were not considered in the analysis. Since these are forecasted to be gas plants, which likely benefit from 3P, the change in total NPV could have been more positive than estimated here.

The Effects of Clear Skies on Deregulated Coal Plants' NPV

Parameter	Normalized[1] Change in Dollars	Percent Change
Change in Electricity Revenues[2]	+1.7	+6%
Change in Costs Plus Change in Net Allowance Transactions[3]	-1.0	-4%
Change in Net Revenues	+0.7	+8%

[1] Dollar value is normalized such that total change in costs plus the change in net allowance position due to the Clear Skies Act is equal to –1.
[2] Includes energy and capacity revenues
[3] Total change in fuel, variable O&M, Fixed O&M, and capital costs plus allowance allocations revenues less allowance expenditures.

- The population of already-deregulated coal plants experiences a positive impact due to Clear Skies. The NPV of their net revenues increases eight percent.
- The above table shows that for every $1 increase in costs (including net allowance transactions) there is a $1.7 increase in revenues from wholesale power sales at deregulated coal plants. Hence, net revenues of deregulated coal units increase by $0.7 for every $1 increase in costs due to Clear Skies.
- As noted earlier, deregulated coal plant variable costs (fuel, variable non-fuel O&M and emission allowance costs) increase 8 percent. Deregulated coal plant costs including all elements (i.e., variable plus capital and fixed O&M) increase 9 percent. However, costs only increase 3.9 percent once allocated allowances are factored in, and hence, the increase in revenues from power sales is greater than the net increase in costs after factoring in allowances. Also, a percent increase in revenues has a larger effect on net revenues than a percent increase in costs since revenues are higher than costs.

The Effects of Clear Skies on Deregulated Coal Plants' NPV (continued)

- As noted earlier, wholesale power price increases are sensitive to the change in natural gas prices resulting from Clear Skies.
- Natural gas prices increase roughly $0.09/MMBtu (3 percent) on a levelized basis under the Clear Skies case.
- In the event that natural gas prices are less sensitive to increased gas demand resulting from the 3P policy, the value of coal plants could experience a significantly smaller increase or even a modest decrease in value.
- The financial impacts of the Clear Skies Act are also sensitive to the allocation of emission allowances. In this scenario, 11 percent[1] of allowances are auctioned by 2020. If fewer allowances are allocated without charge and a greater number are auctioned at the market price, deregulated coal plants could be adversely affected. The opposite is also true.
- This holds true since compliance and operating decisions for individual units are not affected by the allocation of allowances to these units. Hence, the costs of compliance at deregulated coal units remain unchanged regardless of permit allocation decisions.

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1. Assuming an initial auction of 1 percent in 2010 and an additional 1 percent each year through 2020.

Financial Metrics – Changes in Value and DSCR Due to the 3P Program (%) – EPA's Modeling of the Clear Skies Act of 2003

Category – U.S. Total	Percent Change in Value (NPV)
All Regulated Plants	+[1]
All Deregulated Coal Plants[2]	+8
All Deregulated Non-Coal Plants[2]	+16
Sample Portfolio of Deregulated Assets[3]	+4

[1]Change in NPV for regulated assets would equal the original book value plus the change in investments over the original book value and would thus be positive, particularly for coal plants. Although it is known that this value will be positive, it is not possible to determine an exact change in value without an analysis of embedded costs for each unit.

[2] Changes in value for deregulated plants reflect changes in capital investment costs, FOM and VOM, as well as changes in revenues based on competitive wholesale power prices and allocation of allowances.

[3] The sample portfolio shown is comprised of Midwest deregulated coal assets (7.0 GW) and Midwest deregulated non-coal assets (5.1 GW).

Financial Effects Metrics – Change in Value and DSCR – EPA's Modeling of the Clear Skies Act of 2003

- The regulated assets of companies increase in value by an amount equal to the environmental control investment. Also, regulated rates increase to cover costs and generate required returns on the investments. Hence, coverage ratios would be unchanged since the revenue-to-debt service ratio on new investments is the same as under the Base Case.
- The deregulated non-coal assets (e.g., nuclear, hydro, oil and gas plants) increased in value to a greater extent than the average deregulated coal plant. This is because the increase in power prices, though less than the increase in coal costs, was higher than the increase in compliance costs for these plants. Some oil and gas units were adversely affected.
- The value of regulated coal plants (i.e., primarily coal plants in regulated states) would increase by 9.8 percent (versus 8 percent for deregulated coal plants) if their cost recovery mechanism were market, not cost-of-service based. As noted, cost pass-through ensures increased value equal to the increase in capital investment[1].

[1] It is possible that regulated companies making off-system sales might lose some revenue. This study assumes off-system sales offset ratepayer costs 100 percent, or that on-system load growth eliminates most of this potential. Thus, no financial effects are experienced.

Changes in Value of Deregulated Coal Units Due to the 3P Program (%)

Category	Change in Value (NPV)[1]
All Deregulated Coal Plants – Average[2]	+8
Best 10%[3]	+66
Best 25%[3]	+37
Worst 25%[3]	-20
Worst 10%[3]	-57
Sample Portfolio of Deregulated Assets[4]	+4

[1] Value shown is calculated as the total percentage change in NPV from 2005 to 2020 for the portfolio of units in the category as listed.
[2]Does not exclude units that become uneconomic due to 3P.
[3] Units are ranked from highest to lowest according to the change in NPV from the Base to 3P Case. The 29 coal units that become uneconomic due to the 3P case are excluded. The categories reflect a total of 431 coal units in deregulated states. The Best 10th and 25th percentiles are based on the top 43 and 108 units, respectively, with the most positive change in NPV due to 3P. The Worst 10th and 25th percentiles are based on the 43 and 108 units, respectively, which exhibit the greatest negative change in NPV due to 3P.
[4] The sample portfolio shown was comprised of Midwest deregulated coal assets (7.0GW) and Midwest deregulated non-coal assets (5.1 GW).

- In this analysis, some individual deregulated assets experience a large adverse impact as shown by the spread of plus 66 to minus 57 percent NPV. However, the impact is likely to be muted on a portfolio basis; the sample portfolio shown, which includes deregulated coal and non-coal assets, experiences only a 4 percent change in NPV.
- The portfolios of some owners will be affected more than others. However, even the most adversely affected owners are not expected to experience severe distress when considering full portfolios especially, but not limited to portfolios with some regulated capacity.

Coverage Ratios of Deregulated Units Under the 3P Program

Category	Base Case Simple Average Annual DSCR 2005-2020	3P Case Simple Average Annual DSCR 2005 – 2020
All Deregulated Coal Plants – Average[1]	2.8	3.0
Best 10%[2]	2.7	4.5
Best 25%[2]	2.8	3.7
Worst 25%[2]	2.8	2.4
Worst 10%[2]	2.1	0.3
Sample Portfolio of Deregulated Assets[3]	2.8	2.6

[1] Does not exclude units that become uneconomic due to 3P.
[2] Units are ranked from highest to lowest according to the change in NPV from the Base to 3P Case. The 29 coal units that become uneconomic due to the 3P case are excluded. The categories reflect a total of 431 coal units in deregulated states. The Best 10th and 25th percentiles are based on the top 43 and 108 units, respectively, with the most positive change in NPV due to 3P. The Worst 10th and 25th percentiles are based on the 43 and 108 units, respectively, which exhibit the greatest negative change in NPV due to 3P.
[3] The sample portfolio shown was comprised of Midwest deregulated coal assets (7.0GW) and Midwest deregulated non-coal assets (5.1 GW).

Coverage Ratios of Deregulated Units Under the 3P Program

- In the Base Case, most deregulated coal plants are assumed to have a DSCR of 2.8 on average and in each year. One category of plants that has lower coverage ratios is the Best 10%. This group makes substantial capital investments in the Base Case that lower their coverage modestly to an annual average of 2.7.
  - In the Base Case, capital investments for environmental controls are significant; $12 billion cumulatively versus $34 billion in the 3P case (though not all concentrated in this category).
- The second category that does not maintain a 2.8 DSCR in the Base Case is the Worst 10%. In some early years, these plants cannot cover any debt because their cash flows are negative. Thus, the 2.1 is the average of a zero ratio in some years, and a positive 2.8 in others.
- In the 3P Case, the average coverage ratio for all deregulated coal improves from 2.8 to 3.0. The increase in revenues available to cover debt exceeds the increase in debt service associated with added capital investments.
- As is the case for the NPV of net revenues, there is a range of effects across the deregulated coal plant population. However, only in the case of the Worst 10% is the decrease significant.
- The effect on companies is expected to be modestly negative or positive due to the portfolio effect. In the sample portfolio, the coverage ratio falls modestly from 2.8 to 2.6. No financial harm would be incurred by this portfolio. The effects would be even less if the portfolio were to include regulated assets.

Can Power Companies Finance Required Pollution Control Equipment?

Ability to Finance Investments (Market Efficiency)

- A second question arises related to financing 3P investments. Specifically, can companies access the capital required for forecast pollution control investments.
- This is referred to as a market efficiency problem since efficient markets should ensure that capital needed for economic, i.e., profitable, activities is available.
- In the context of regulated assets, the issue relates to whether companies will be allowed to earn their required rates of return. This can be thought of as whether state regulation of utilities works. We assume that state regulation functions to provide cost-plus recovery for investments in required pollution controls. This reflects past success by utilities, the modest size of the required customer rate increases, legal requirements for cost recovery, and the relatively unambiguous nature of the requirement. Indeed, financial effects as opposed to rate effects have only become relevant as a result of industry deregulation.
- In the context of deregulated assets, the issue is whether the financial markets work well enough to support the continued operation of economic investments.

Recent Power Plant Investment 1998 - 2002

Investment Category	Investment Expense[1] (billions of dollars)
Debt Capital (Bond) Markets	39
Equity Markets	20
Bank Finance	29
Total	88

Note: All values shown in billions of dollars in real 1999 year dollars.
[1]The majority of this is deregulated – i.e., non-rate based power plants.
Source: Estimated from personal discussions with financial institution agents.

Projected Controls on Coal Capacity under the 3P Policy Case

- For the 3P policy analyzed, there are significant capital investments, and hence, financing needs. There is a projected 71 percent increase in capacity retrofit with FGD (flue gas desulfurization) or scrubbers for SO_2 and an additional 47 percent increase in capacity retrofit with NO_x controls. Hg controls will be installed for the first time on a distinct minority of coal plants. Little or no change is anticipated for oil- and gas-fired, nuclear, large hydroelectric or renewable capacity.
- The total amount of new financing required for the purchase of new pollution control equipment ($22 billion real 1999 dollars) appears able to be financed primarily in light of the attractive economics of the continued operation of existing coal power plants. Forty-five percent of these costs are incurred after 2010.
- Secondary reasons to expect that the necessary financing is possible include:
  - The even larger investments in power plants recently financed as shown in the table
  - The history of successful financing or funding of past pollution control requirements including 101 GW of scrubbers and 75 GW of NO_x controls

Investments in Pollution Control Equipment Less than Anticipated New Power Plant Investment Costs

- Another perspective is that this is a large, capital-intensive industry that historically has successfully accessed the capital markets. Projections through 2020 indicate that significant investment will continue to occur in new power plant construction. Thus, pollution control equipment is only part of the total capital requirements of the industry.
- Forecast total capital requirements – $72 Billion[1]
  - New power plant investment – $50 Billion
  - Incremental due to controls – $22 Billion
- Percent increase in pollution control investments over Base Case levels by 2020 – 184 percent.

[1] 2005-2020 forecast period.

Will There Be Significant Retirements of Coal-fired Plants?

Coal Plants Will Be Economic

(Real $/MWh) – Illustrative

Going Forward Cost Item	Base Case Average U.S. Coal Plant	Base Case New Gas-Fired Combined Cycle	Difference
Levelized Capital[1]	0.5	12.3	+11.8
Fuel[2]	10.1	24.4	+14.3
Non-Fuel Variable O&M[2]	2.3	2.0	-0.3
Emission Allowance Costs[3]	2.5	0.6	-1.9
Fixed O&M[4]	4.4	2.1	-2.3
Total	19.8	41.4	+21.6

Note: Data shown for 2020.

[1] Combined cycle capital cost of $535/kW at 12.9 percent capital charge rate and 64 percent capacity factor. Coal capital costs represent total capital investment spread across all coal plants.

[2] Illustrative.

[3] Allowance costs are based on average emissions for all coal plants. The average annual SO2 emission rate is 0.73 lbs/MMBtu and the average annual NOx emission rate is 0.32 lbs/MMBtu. Costs represent the costs of base case pollutant programs spread across all coal plants.

[4] Coal unit FOM assumes 83 percent capacity factor; combined cycle FOM assumes 64 percent capacity factor.

- This analysis evaluated whether coal plants would remain economic and profitable after 3P legislation and therefore continue to operate. Coal plants would be uneconomic only if the costs of replacement power, such as a new combined cycle facility, were lower than the costs of continued operation including environmental compliance costs.
- The illustration above indicates that the typical coal plant would not retire unless a cost increase of over 100 percent from Base Case levels were to occur. The 3P policies analyzed add only 9 percent to the cost of coal plants (on a levelized basis 2005-2020), much less than the cost differential between the typical existing coal-fired and new gas-fired facilities. Also, there were some offsetting revenue increases from power price increases and allocated emission allowances.
- Exceptions can occur due to cost differences, e.g., higher coal costs than typical or lower gas plant costs. Exceptions can also arise when excess capacity is available, and hence, replacement power is available for some period at variable costs. However, these exceptions are rare due to the large cost advantage of coal plants and the temporary and limited extent of excess capacity.
- Therefore, we conclude that nearly all existing coal units remain competitive and will continue to operate under the 3P policy analyzed.

Change in Forecast of Uneconomic Coal Units and Utilization Are Small

	Year			Total/ Average
	2010	2015	2020	
Cumulative Coal Retirements (MW)				
Base Case	1,001	1,001	1,001	1,001
3P Case	6,174	6,174	6,174	6,174
Incremental Closures Due to 3P	5,173	5,173	5,173	5,173
Average Coal Unit Capacity Factor (%)				
Base Case	81%	83%	84%	82%
3P Case	81%	82%	82%	82%

Note: Due to installation of scrubbing equipment in the 3P Case the total amount of coal capacity is slightly reduced from Base Case levels.

- A key effect of 3P policies is an increase in the variable costs of operating existing coal units; there are also smaller variable cost increases at some gas units.
- Nonetheless, the dispatch of existing coal units is not significantly affected.
- Note, additional factors affecting the viability of coal plants, such as localized reliability requirements and local considerations that may lead to continued operation, were not considered as part of this analysis.

Uneconomic Coal Units

- Of the 5.2 GW identified as uneconomic in the 3P case:
  - 724 MW are lignite-fired and have not been given an alternative fuel option in the analysis. In fact, higher rank coals may be an option.
  - Most of these units are a part of larger facilities that include other units remaining on-line. Only four facilities are projected to become uneconomic in their entirety (i.e., all units). Only one of the four facilities is larger than 110 MW.
  - The uneconomic units are distributed over seventeen states – the state with the most uneconomic capacity has only 17 percent of the total.
  - The uneconomic coal units are generally the smallest and/or most inefficient units that are displaced by recently built natural gas capacity. Sensitivity analysis shows that without the recent overbuilding of this capacity, no units would be uneconomic.
- If higher gas prices or load growth, such as those used by EIA in the AEO 2003, were assumed, the amount of capacity currently identified as uneconomic would be reduced.

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Conclusions

- Financial impacts of the Clear Skies Act of 2003 program on the power industry are likely to be limited and will not affect the financial stability of companies. Although some already-deregulated coal plants (the most vulnerable population of power plants) are adversely affected, on average, the value and coverage ratios of these plants increase. Further, portfolio effects mitigate these adverse effects, especially for companies with regulated, and non-coal deregulated power plants.
- The small financial impact results from the phased-in nature of the program, the continued cost plus regulation of most U.S. coal plants and other factors such as modestly higher deregulated and regulated prices, and allocation of allowances to power plant owners.
- The industry will be able to finance the $22 billion of required incremental investment. The requirement is phased in, and only moderate in size relative to recent and future power industry capital requirements. Also, the Clear Skies Act does not adversely affect the financial condition of the industry.
- About 5.2 GW of coal capacity that become uneconomic due to the 3P policy in this analysis may in fact turn out to be economic as a hedge on shifting natural gas prices or necessary to ensure local reliability.