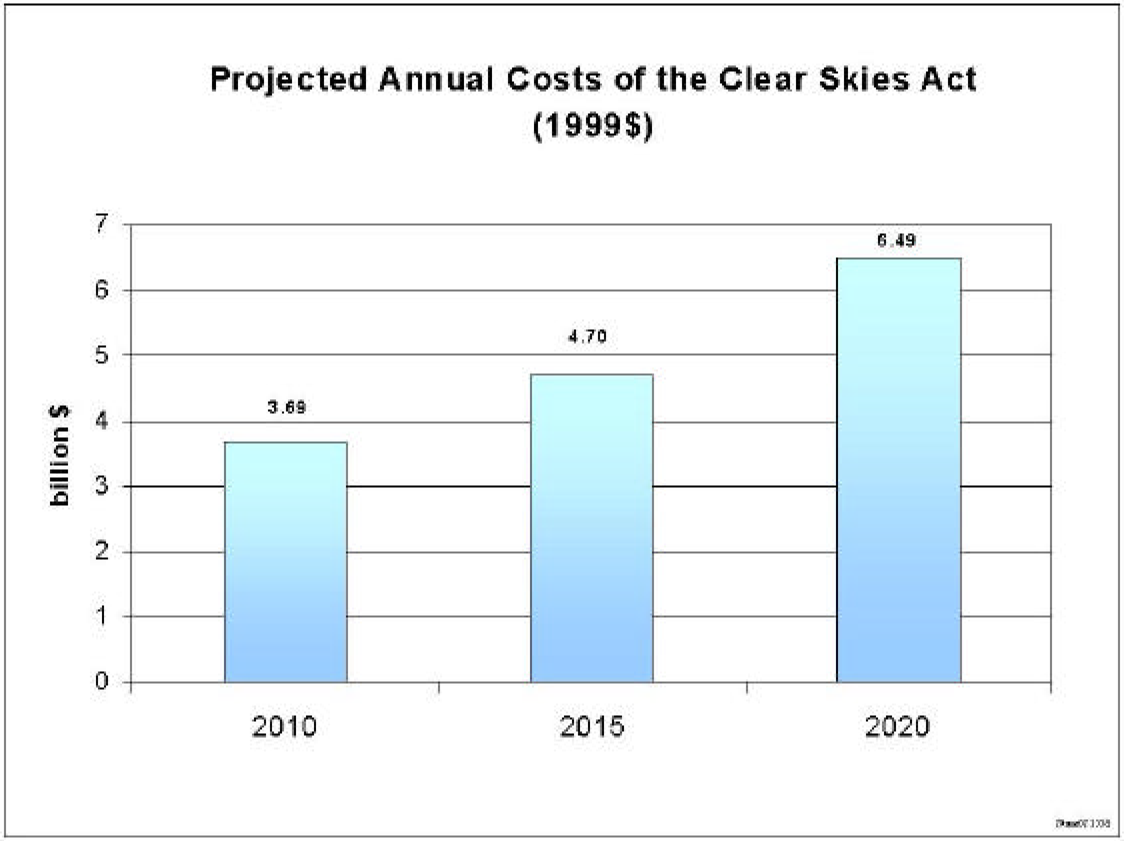
Section C:

Projected Costs

Projected Costs of the Clear Skies Act

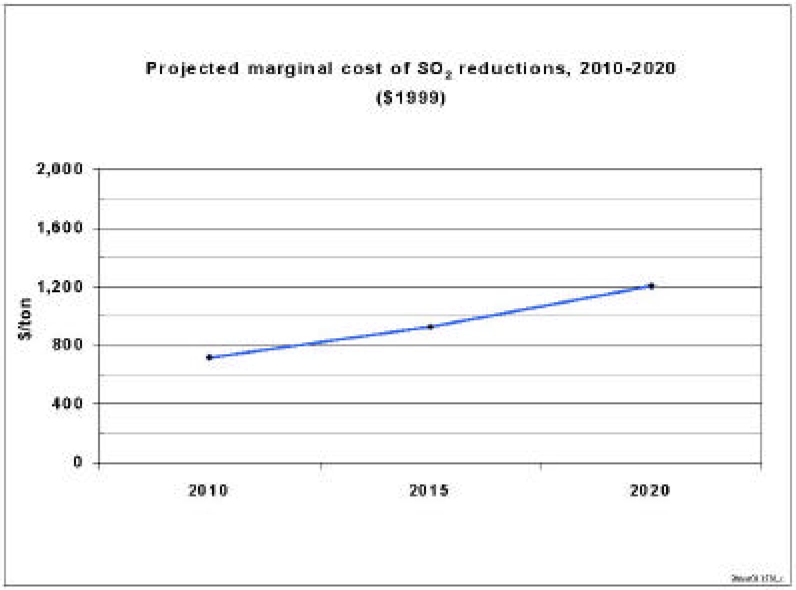


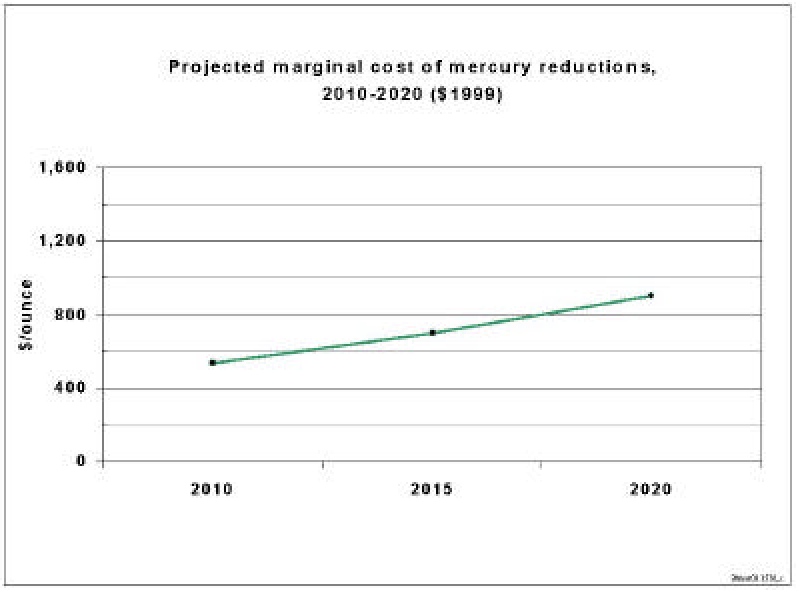
- The net present value (NPV) of the difference in costs between Clear Skies and the EPA Base Case is $65.37 billion ($1999) for the period between 2005 and 2030.

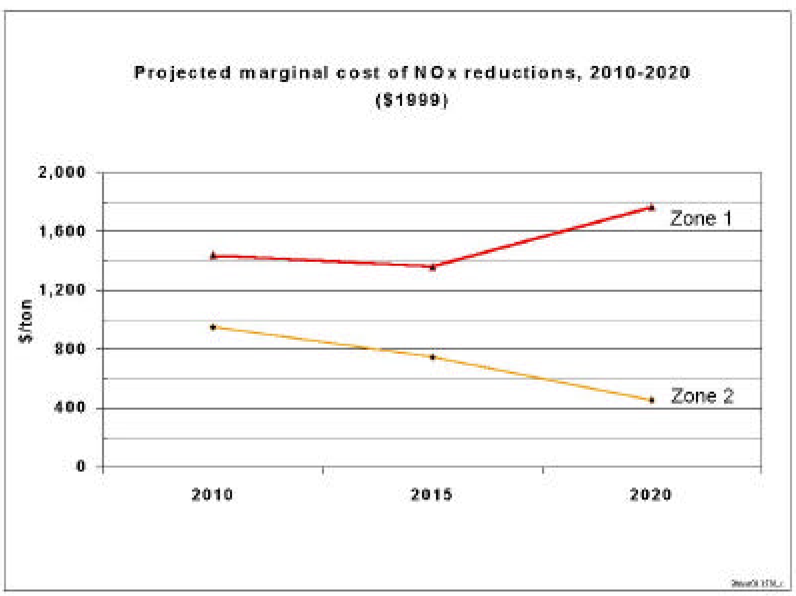
Note: Cost projections are based on modeling using IPM. These projections show the costs to power generators over and above the costs they will incur to meet statutory and regulatory requirements that are already in effect. The projections do not include costs associated with the purchase of allowances from the auction. In the absence of Clear Skies legislation, there are existing statutory provisions that will, in the future, require EPA and states to impose additional requirements (and thus additional costs) on power generators between now and 2020. When compared to existing Clean Air Act requirements, Clear Skies may actually result in cost savings because a cap-and-trade approach is much more efficient than existing regulatory programs. When the Acid Rain Program was implemented using a cap-and-trade program, compliance costs were significantly lower than predicted as sources took advantage of the flexibility provided by a cap and trade program.

The net present value calculations are also based on IPM. See chapter 7, table 7.1 of the IPM documentation for more information on the discount rates used for various plant types. (www.epa.gov/airmarkets/epa-ipm/index.html#documentation).

Projected Allowance Prices under Clear Skies







Note: under the Clear Skies Act, the marginal costs of SO_2 and NOx reductions are well below $2,000/ton and the marginal cost of mercury reductions are below $1,000/ounce.

The dollar value is the projected allowance price, representing the marginal cost (i.e., the cost of reducing the last ton) of emissions reductions. Marginal costs are based on modeling using IPM.

Distribution of Allowances under Clear Skies

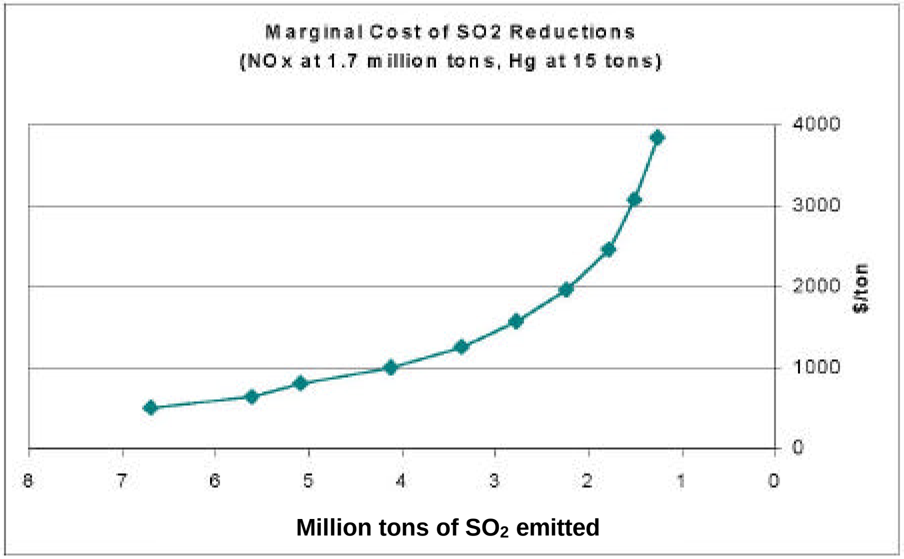
- **The distribution of allowances under the Clear Skies Act occurs through the combination of an auction and an allocation:**
  - During the first year of the new trading program, 99% of the SO_2, NOx and mercury allowances would be allocated to affected units with an auction for the remaining 1%.
  - Each subsequent year, an additional 1% of the allowances for twenty years, and then an additional 2.5% thereafter, will be auctioned until eventually all the allowances are auctioned.
- **For the first twenty years of the trading programs, the majority of allowances are distributed *for free* via the allocation. Because of the time value of money, allowances allocated for these earlier years are generally more valuable in the allowance market than allowances allocated for later years.**
  - EPA analyzed the net present value (NPV) of the stream of allowances that would be distributed through 2030, as well as through 2061.

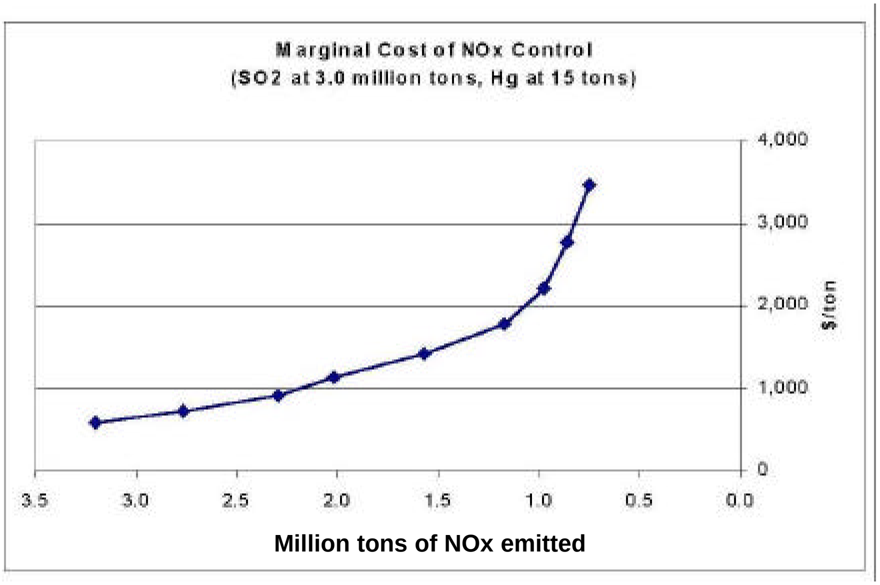
Despite the prevalence of the auction in the later years, EPA's analysis shows that the vast majority of the net present value of the allowances is distributed for free via allocation:

-- For the period between 2008/2010 and 2030, 90-92% of the total NPV is allocated.
-- For the period between 2008/2010 and 2061, approximately 80% of the total NPV is allocated.

Note: The net present value calculations are based on allowances prices in IPM.

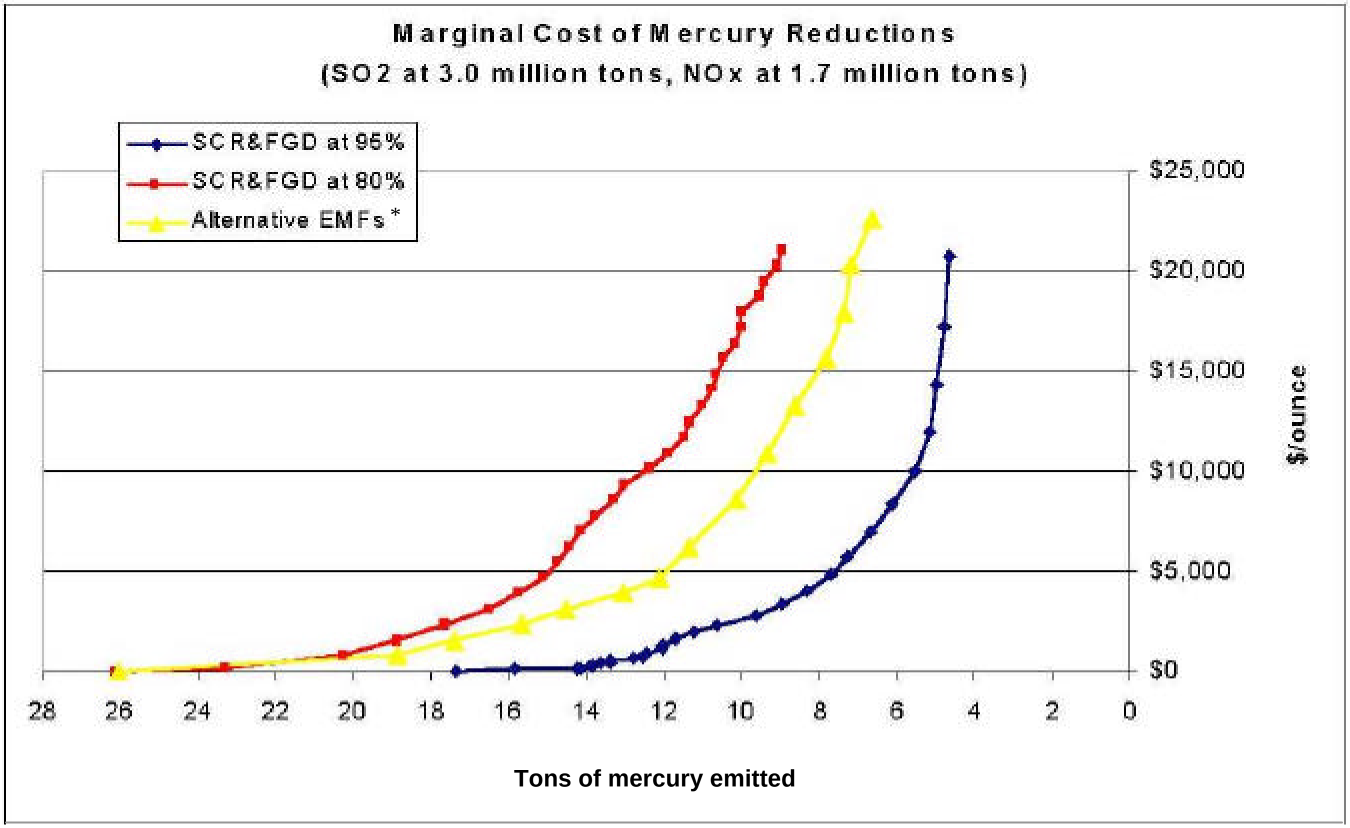
Marginal Costs for SO_2 and NOx reductions





Note: Analysis uses the Technology Retrofit and Updating Model which tends to over predict SO_2 marginal costs because it has fewer degrees of freedom than IPM (see Section G for a description of this model); costs projected by IPM would be lower. Analysis assumes that NOx and Hg emissions are at the levels of the caps.

Marginal Costs for Mercury Reductions



- Selective Catalytic Reduction (SCR) and Flue Gas Desulfurization (FGD) -- more commonly known as scrubbers -- are post-combustion NOx and SO_2 controls, respectively.

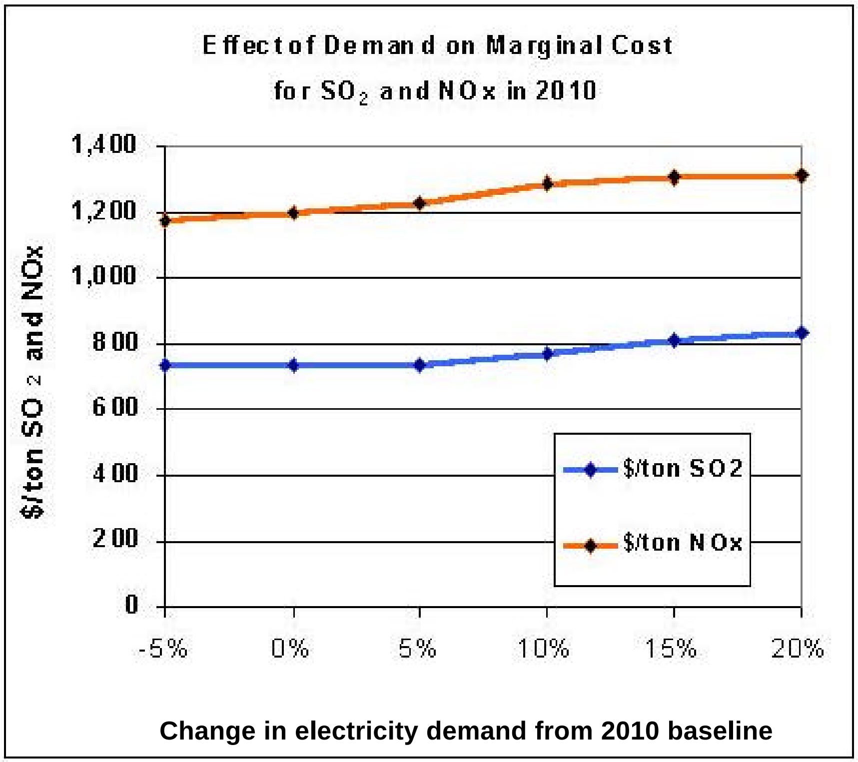
Note: Curves are based on different assumptions regarding the Hg removal efficiency of a combination of SCR and FGD. Analysis uses the Technology Retrofit and Updating Model which tends to over predict Hg marginal costs because it has fewer degrees of freedom than IPM (see Section G for a description of this model); costs projected by IPM would be lower.

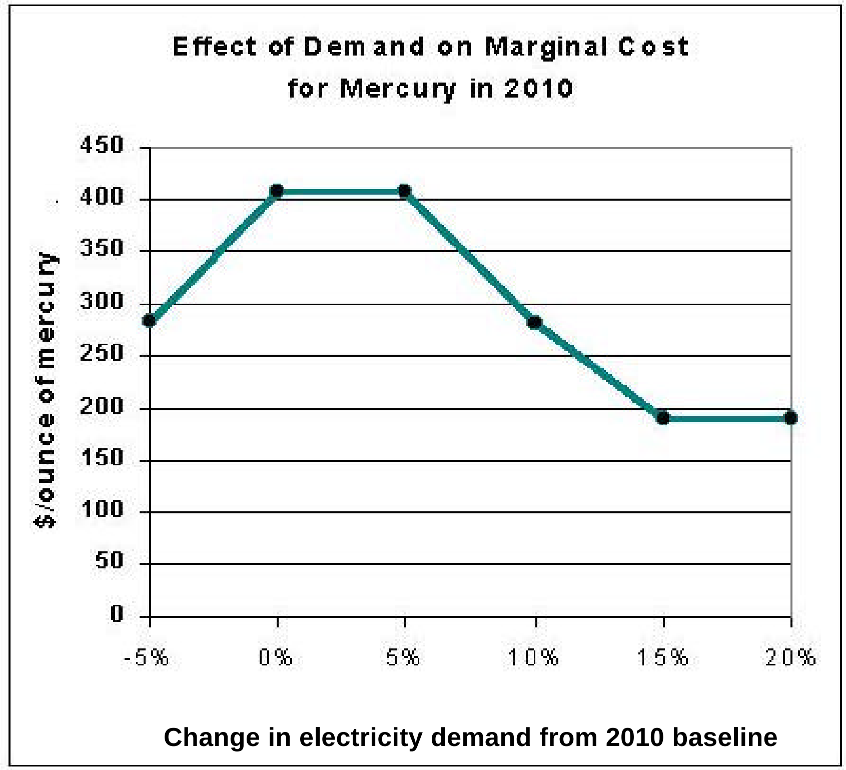
In the IPM model, EPA assumes that mercury removal efficiencies for control technology configurations vary depending on coal type and control technology. See the IPM documentation, chapter 5, table 5.7a (http://www.epa.gov/airmarkets/epa-ipm/index.html#documentation) for more information and 5.3.2 for a definition of "Alternative Emission Modification Factors (EMFs)". An EMF is the ratio of outlet mercury concentration to inlet mercury concentration; EMF's capture the mercury reductions attributable to different unit configurations and different configurations of SO_2, NOx, and particulate controls.

Varying Industry Growth Rates

• If electricity demand were 15-20% higher than assumed in the Integrated Planning Model, the marginal cost of controlling SO_2 and NOx would be approximately 10% higher, though the marginal cost of mercury would be lower.

• As demand rises, there is greater constraint on sources under the NOx cap than under the mercury cap since new gas-fired generating capacity has some NOx emissions, but no mercury emissions. The decline in the marginal costs of mercury abatement arises because of the increased use of the NOx controls, which enables the mercury cap to be achieved at a lower cost.

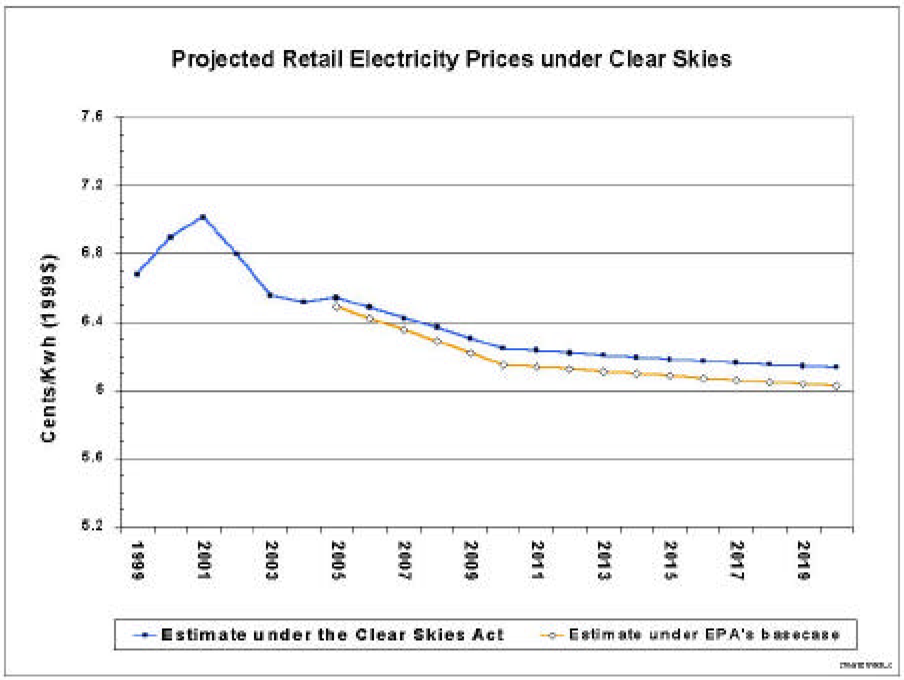


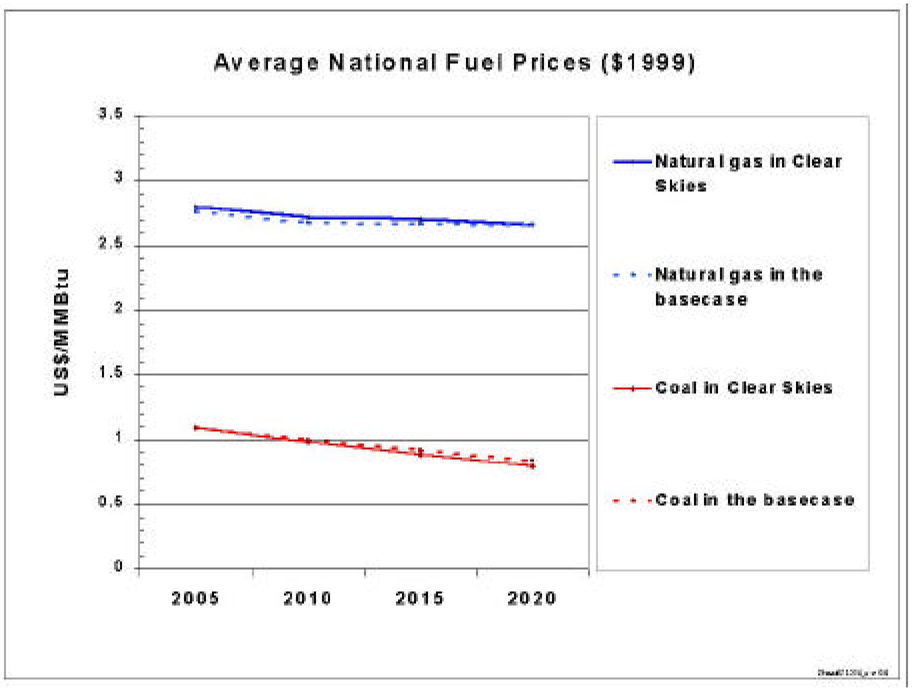


Note: The projected *emissions* under the Clear Skies Act in 2010 were used for this analysis. Analysis uses the Technology Retrofit and Updating Model (see Section G for a description).

Impact on Electricity Prices and Fuel Prices

- Retail electricity prices are expected to gradually decline *with or without* Clear Skies because of efficiency improvements and ongoing restructuring in the electricity generating sector.





Note: Retail prices through 2003 are from AEO2000. Prices for the period after 2003 were calculated using the Retail Electricity Price Model (see Section G for a description of the Model).

The coal price represents an average minemouth price across all twelve grades of coal in the model. The natural gas price is the Henry Hub price. Average national fuel prices are EPA's estimates.