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Costs of NOx Control Strategies on Electric Power Generation Using the Integrated Planning Model

DRAFT

The Implementation Strategies and Issues Work Group (ISI) of the Ozone Transport Assessment Group (OTAG) requested that the U.S. Environmental Protection Agency (EPA) use the Integrated Planning Model (IPM) to analyze the costs for the electric power industry of NOx control strategies during the Round 3 geographic analyses. The strategy options covered NOx emissions during the summer season. ISI asked the Agency to use control technology cost and performance information that the Control Technologies and Options Work Group (CTO) collected and developed throughout 1996. Initially, an ad hoc work group of CTO determined how OTAG's cost assumptions should be used in IPM, while the Trading/Incentives Work Group specified the actual control strategies that EPA analyzed. CTO also requested that EPA use IPM to analyze a rated-based approach to NOx control in OTAG using two different sets of NOx control cost and performance assumptions.

Brief descriptions of what IPM is and how EPA uses the model, the direction that ISI provided the Agency on this analysis, the coverage and structure of the analysis, and the results follow below. The EPA papers for OTAG that provide more details on the analyses are referenced below.[1]

What IPM Is and How EPA Uses the Model

Over the last 18 months, EPA has used the Integrated Planning Model (IPM) of ICF Resources Incorporated to analyze the emissions reductions and costs of air pollution control options for the electric power industry for NOx, SOx, and several other air pollutants.[2] The Agency selected IPM, because it is a well-established utility planning model used for a wide range of electric power generation applications by many different types of clients.[3] The Model is run for EPA by ICF Resources, who has extensive expertise on the electric power industry, fuel suppliers, and the affects pollution controls can have on their operations. IPM also has the unique capability of analyzing cap-and-trade programs covering summer season and annual emissions for multiple pollutants. The Model was used to support the Clean Air Power Initiative (CAPI). Throughout 1996, EPA also used IPM to analyze a wide range of issues for the Trading/Incentives Work Group.[4]

1The references cited below, as well as the briefings of the results presented this Spring to ISI and the Policy Group and segments of the results of the actual IPM runs are available at EPA's Clean Air Power Initiative web site. The address is: http://www.epa.gov/capi.

2IPM is a dynamic linear programming model that considers how to minimize the costs of operating the electric power system over the forecast period subject to technical operating constraints electric generation units and pollution control constraints specified by the user. EPA's use of the model always has SOx constraints specified for the CAAA Title IV Allowance Trading Program and other pollution control constraints, such as a cap on the level of summer NOx emissions in states within OTAG.

3Users of IPM or its results include the Edison Electric Institute, the Electric Power Research Institute, Tennessee Valley Authority, National Coal Association, U.S. Department of Energy, Center for Economic Development, Southern Company, Carolina Power and Light, US Gen, ENRON, and CINERGY. The national version of IPM was initially developed by EEI. It was used by EEI and the National Coal Association for estimation of costs and emission reductions for cap-and-trade programs to control summer season NOx in the Ozone Transport Region in 1994.

4The results of the analysis that EPA prepared for OTAG's Trading/Incentives Work Group are summarized in that group's final OTAG report in a section entitled "Findings from the OTAG Cap-and-Trade Analyses."

In all analyses, EPA had ICF Resources set up and run IPM based on the Agency's assumptions of how the electric power industry will operate when deregulation occurs over the next 15 years. The Agency conducted extensive research to develop the best assumptions possible on electric generation unit operating characteristics, air emissions, and pollution control costs and performance.[5] The NOx control technology assumptions that the Agency uses were developed for EPA by Bechtel Corporation, who has designed electric power generation units and installed NOx control systems on generation units.[6]

All of EPA's assumptions in IPM have had external review during CAPI.[7] The NOx control assumptions were subjected to an additional special peer review process last year. IPM received a favorable review from the Department of Energy. When ISI was considering using IPM for analysis of NOx control options, EPA made several presentations at OTAG meetings and to utility representatives (arranged by the Utility Air Regulatory Group (UARG)) to explain the model and its key assumptions. The Agency went back through the data sets it uses for fossil generation units during January and February 1997 and carefully rechecked their soundness when a comparison was done between EMS 95 NOx Emissions Inventory Baseline and EPA's IPM Baseline for 2007.[89] On an ongoing basis, EPA has checked it electric demand, generation capacity expansion, operation, and fuel price assumptions against the forecasts and assumptions of the Energy Information Administration, Gas Research Institute, Data Resources Incorporated, and Cambridge Energy Research Associates. The Agency has found that its assumptions are within the range of other leading forecasting groups.

OTAG's Directions for the IPM Runs

From January to March 1997, an Ad Hoc Work Group of CTO met to decide how to use OTAG's cost and technology performance assumptions in IPM and discuss issues that work group members raised about other assumptions in the model.[10] From April to May 1997, the Ad Hoc Work

5The set of assumptions that the Agency uses in IPM are provided in EPA's Analyzing Electric Power Generation under the CAAA, July 1996.

6The cost equations and performance rates for the NOx control technologies are briefly presented in EPA's Analyzing Electric Power Generation under the CAAA, July 1996 and EPA's paper for OTAG entitled "Using the Integrated Planning Model to Estimate the Costs of NOx Control Strategies on Electric Power Generation in OTAG's Round 3 Analysis," May 1997. The technical rationale supporting these cost and performance assumptions can be found in Bechtel Corporation, "Investigation of Performance and Cost of NOx Controls as Applied to Group 2 Boilers Revised Draft Report,", August 1996 and Bechtel Corporation, "Cost Estimates for Selected Applications of NOx Control Technologies on Stationary Combustion Boilers", March 1996.

7During CAPI, the Agency made changes to its analytic approach and assumptions concerning deregulated operations of the electric power system in the United States based on review comments of the Utility Air Regulatory Group (UARG), Edison Electric Institute, National Mining Association, the Coalition of Gas-Based Environmental Solutions, and the Center for Clean Air Policy.

8Details of how EPA used IPM to estimate daily summer NOx emissions for the OTAG Base Case for 2007 can be found in EPA, "Forecast of Average Daily NOx Emissions in July by Electric Generation Units in the OTAG Base Case Using the Integrated Planning Model (IPM)," December 1996.

9EPA made presentations of a paper entitled "Use of the Integrated Planning Model (IPM) for OTAG Analysis", February 1997, at the Philadelphia meeting before ISI and OTAG's Regional and Urban Scale Modeling Work Group.

10Participants in the work group initially included Ned Helme from the Center for Clean Air Policy (chair) and technical experts from the Utility Air Regulatory Group (UARG), Southern Company, New Hampshire, Northeast States for Coordinated Air Use Management, the Institute for Clean Air Companies (ICAC), and EPA. In April 1997, Steve Gerritson of Lake Michigan Air Directors Consortium, Robert Lopez of the Wisconsin DNR, and representatives from Southern Ohio Edison and the Midwest Ozone Group (MOG) joined the group.

Group met again to decide how to set up two more IPM runs and to compare the results from another analysis using the Control Cost Optimization and Rate Impact Estimation Matrix (OTAG Cost Matrix), developed by Robert Lopez of the Department of Natural Resources, Wisconsin, and presented separately in this report. CTO decided that the results produced by IPM were to serve as OTAG's estimates of the costs for the electric power industry of alternative control strategies once the "backstop" analysis using the Cost Matrix further confirmed the reliability of the results produced by IPM.

Decisions on Cost Assumptions

The original cost and performance assumptions that CTO compiled and developed were range estimates of high and low cost-effectiveness (dollars per ton of NOx removed) for various NOx control technologies linked to potential market penetration assumptions. The assumptions were catalogued in three documents that CTO prepared over time:

- Utility Air Regulatory Group, Electric Utility Nitrogen Oxides Reduction Technology Options for Application by the Ozone Transport Assessment Group, January 1996.
- Colburn, Ken, State's Report on Electric Utility Nitrogen Oxides Reduction Technology Options for Application by the Ozone Transport Assessment Group, April 11, 1996.
- Lopez, Robert, Version 9 Control Cost Optimization and Rate Impact Estimation Matrix, December 1, 1996, (large spreadsheet which provided cost ranges for control technologies from information in the above documents and further discussions within CTO. This would later be replaced with Version 12 that is presented in a separate section of this report).

The Ad Hoc Work Group decided to rely primarily on EPA's NOx control cost and performance assumptions for the initial cap-and-trade analysis, which were within the range of estimates provided in the above documents. For most NOx control technologies, all, or part of OTAG's cost and performance assumptions for NOx control technologies were in a narrow range. In areas where UARG and the Institute for Clean Air Companies (ICAC) saw major differences in EPA's assumptions and the ones that they had submitted to OTAG for consideration, the Group initially decided to do sensitivity analyses that used their alternative assumptions for an analysis of one of the control strategies. The main differences between the UARG and ICAC assumptions and EPA's assumptions are summarized below.

UARG and ICAC Assumptions

There are three major differences between EPA's and UARG's assumptions. UARG believes that the capital costs of selective catalytic reduction (SCR) technology for coal-fired units will be higher than EPA assumes. This occurs because UARG's experts (unlike EPA) believe that there will not be economies of scale in retrofitting coal-fired units. EPA assumes economies of scale for units up to 500 MWs. In fact, UARG's experts believe there will be increasing costs per production unit (i.e., kilowatt) to install SCR for units larger than 500 MWs with flue gas desulfurization.) UARG also believes that selective non-catalytic reduction (SNCR) technology will not be as effective as EPA assumes. The Agency assumes 40 percent NOx reduction for units with NOx less than .5 lbs of NOx/MMBtus of heat input and 35 percent for units with greater than .5 NOx.[11] UARG provided SNCR assumptions of 34-36 percent reductions for units between 100-200 MWs with graduated decreases in performance levels until units between 400-500 MWs provide a 21-23 percent NOx reduction, for units with NOx level less than or greater than .5 pounds of NOx per MM Btus, respectively.

There are three major differences between EPA's and ICAC's assumptions. ICAC believes that a hybrid technology (combining elements of SCR and SNCR) will be commercially available before 2007 which approaches the reduction performance of SCR at a lower capital cost, although it will have higher operating and maintenance costs. ICAC believes that this hybrid is often going to be a more cost-effective choice than SCR. ICAC believes that SCR technology will provide greater reductions than EPA is assuming for coal-fired units with NOx rates greater than 0.5 pounds of NOx per million Btus of heat input. Finally, ICAC also believes that SCR can get greater NOx reductions when it is placed on gas-fired units.

Decisions on Model Runs

EPA initially committed to conduct cost analysis through nine IPM computer runs of Round 3 geographic strategies. The Trading/Incentives Work Group decided what the Agency should analyze for seven of the runs.[12] It requested analysis of six cap-and-trade strategies based on the NOx emissions levels set for each of the Fine Grid Zones and the Coarse Grid for the Round 3, Runs B, G, and I. The Work Group also requested an analysis of a rate-based control strategy using the NOx emissions rates that are in the Round 3, Run G strategy. CTO added two sensitivity runs of one of the cap-and-trade alternatives using the ICAC and UARG assumptions. EPA was able to do three more IPM runs to address the "leakage" issue, which the Trading/Incentives Work Group asked EPA to examine in its analysis. One of these runs considered having one NOx emissions cap of 606 thousand tons over the Fine Grid Zones, based on the levels of control that were in Round 3, Run I, for the five zones. Coincidently, this **Modified Run I cap-and-trade run represents the likely upper bound cost of implementing the recommendations the Policy Group has made to EPA for the control of emissions from the electric power industry to address the ozone transport problem.**

Rate-Based Approaches

CTO and the Trading/Incentives Work Group requested that EPA provide analyses of rate-based controls for Run G and Run I reflecting a command-and-control approach that states in OTAG could adopt to implement the recommendations they could make on controls on electric power generation. EPA set up simple rate-based systems which provided for generation units in each OTAG Zone and the Coarse Grid meeting the rates specified for OTAG for that zone for coal and oil/gas fired units. Tables 1 and

11EPA bases its SNCR performance assumptions on continuous emissions monitoring (CEM) data submitted to EPA by utilities under 40 CFR Part 75.

12Like COT, the Trading/Incentives Work Group set up an ad hoc Work Group to decide which runs should be done and how they should be set up. The chair of the group was Dennis Koepke of the Wisconsin DNR. There were participants from UARG, Southern Company, TVA, and EPA.

2 show those rates.[13] For the rate-based approach using Run G, OTAG had the Agency use the EPA NOx control assumptions. For the rate-based approach using Run I, EPA used UARG's and ICAC's NOx control assumptions in IPM in separate runs.

TABLE 1
Summer NOx Emission Limitations for Existing Coal-Fired and Selected Oil/Gas-Fired Units under a Rate-Based Approach Using Round 3, Run G Strategy*

Area	Coal-Fired Units Pounds of NOx/MM Btus of Heat Input	Oil/Gas-Fired Steam and Combined-Cycle Units Pounds of NOx/MM Btus of Heat Input
Zone 1	.20	.20
Zone 2	.20	.20
Zone 3	.20	.20
Zone 4	.25	.20
Zone 5	.20	.20
Coarse Grid	CAAA Title IV Rates	Uncontrolled

* New sources are subject to Best Available Control Technology requirements.

TABLE 2
Summer NOx Emission Limitations for Existing Coal-Fired and Selected Oil/Gas-Fired Units under a Rate-Based Approach Using Round 3, Run I Strategy*

Area	Coal-Fired Units Pounds of NOx/MM Btus of Heat Input	Oil/Gas-Fired Steam and Combined-Cycle Units Pounds of NOx/MM Btus of Heat Input
Zone 1	.15	.15
Zone 2	.15	.15
Zone 3	.15	.15
Zone 4	.20	.20
Zone 5	.15	.15
Coarse Grid	.35	.20

* New sources are subject to Best Available Control Technology requirements.

13EPA assumed combustion turbines used for peaking would not be controlled, because there rates are very low and the operate only a limited amount of the summer season.

Cap-and-Trade Approaches

The Trading/Incentives Work Group requested that EPA use IPM to analyze six different cap-and-trade programs. For the cap-and-trade approaches, EPA either:

(1) set up unconstrained trading under one NOx emissions cap that covered all of the areas where OTAG wanted controls in place. For three of the options, EPA set up one trading zone cap in IPM covering all of the Fine Grid zones in Runs B and G, or all the OTAG's states for Run I, or

(2) established five to six NOx emissions caps that covered each of the five Fine Grid zone in all runs and the Coarse Grid in Run I, where only intra-zonal trading was allowed. For these remaining three options, EPA set up five to six trading zones in IPM to cover cap-and-trade programs for Runs B, G, and I.

All the cap-and-trade options allowed for banking of summer NOx emissions and later use of them within any zone where there was a single trading zone cap and the same zone where they were initially banked when there was multiple zone caps. Results were reported for years 2007 and 2012 (so that the influence of banking could be observed). Tables 3, 4, and 5 show the summer NOx emissions levels that were used to set emissions caps for each individual zone, or that were summed to provide one emissions cap in the options analysis.

CTO asked EPA to examine the sensitivity of these results based on EPA cost assumptions to alternative assumptions provided by ICAC and UARG. A sensitivity analysis was done using the Run I / One cap for All of OTAG option with these alternative assumptions. For the sensitivity analysis done to examine the "leakage issue," EPA also conducted an analysis of a cap-and-trade approach that would have a single NOx emissions cap of 606 thousand tons for the Fine Grid zones based on emissions levels for these Zones in Run I (see Table 5).

TABLE 3
Summer NOx Emission Caps for Run B Cap-and-Trade Options

Areas	-- OTAG Control Level Basis for Summer NOx Cap -- OTAG Level__ - Based on Using Less Stringent of .x lbs of NOx/MM Btus, or x% of 1990 Rates for All Coal-Fired Units*	Summer NOx Cap 1,000 Tons
Zone 1	Level 2a - .25 lbs of NOx, or 65% reduction	235
Zone 2	Level 1 - .35 lbs of NOx, or 55% reduction	474
Zone 3	Level 2a - .25 lbs of NOx, or 65% reduction	191
Zone 4	Level 1 - .35 lbs of NOx, or 55% reduction	220
Zone 5	Level 2a - .25 lbs of NOx, or 65% reduction	52
All Zones	Not Applicable	1,171
Coarse Grid	CAAA Title IV Controls	N/A

* The NOx rate for gas-fired units in the Fine Grid is .20 lbs of NOx/MM Btus and there is no Coarse Grid rate.

TABLE 4
Summer NOx Emission Caps for Run G Cap-and-Trade Options

Areas	-- OTAG Control Level Basis for Summer NOx Cap -- OTAG Level__ - Based on Using Less Stringent of .x lbs of NOx/MM Btus, or x% of 1990 Rates for All Coal-Fired Units*	Summer NOx Cap 1,000 Tons
Zone 1	Level 2b - .20 lbs of NOx, or 75% reduction	179
Zone 2	Level 2b - .20 lbs of NOx, or 75% reduction	281
Zone 3	Level 2b - .20 lbs of NOx, or 75% reduction	169
Zone 4	Level 2a - .25 lbs of NOx, or 65% reduction	167
Zone 5	Level 2b - .20 lbs of NOx, or 75% reduction	41
All Zones	Not Applicable	837
Coarse Grid	CAAA Title IV Controls	N/A

* The NOx rate for gas-fired units in the Fine Grid is .20 lbs of NOx/MM Btus and there is no Coarse Grid rate.

TABLE 5
Summer NOx Emission Caps for Run I Cap-and-Trade Options

Areas	-- OTAG Control Level Basis for Summer NOx Cap -- OTAG Level__ - Based on Using Less Stringent of .x lbs of NOx/MM Btus, or x% of 1990 Rates for All Coal-Fired Units*	Summer NOx Cap 1,000 Tons
Zone 1	Level 3 - .15 lbs of NOx, or 85% reduction	124
Zone 2	Level 3 - .15 lbs of NOx, or 85% reduction	190
Zone 3	Level 3 - .15 lbs of NOx, or 85% reduction	135
Zone 4	Level 2b - .20 lbs of NOx, or 75% reduction	127
Zone 5	Level 3 - .15 lbs of NOx, or 85% reduction	31
Coarse Grid	Level 1 - .35 lbs of NOx, or 55% reduction	414
All Otag Areas	Not Applicable	1,020

* The NOx rate for gas-fired units in the Fine Grid is the same rate as coal-fired units and .20 for the Coarse Grid.

Coverage and Structure of Analysis

EPA used IPM to estimate annual incremental compliance costs of alternative NOx control strategies for electric generation units in states that are within OTAG. These costs were estimated by considering the difference in the electricity production costs of a NOx control strategy run and the OTAG

Base Case forecast that IPM provided.[14] All the analyses assumed that OTAG would recommend seasonal controls for the summer, rather than annual controls to address the ozone transport question. EPA assumed that the summer season was from May 1st through September 30th (153 days). The analyses covered power generation by electric utilities and independent power producers and cogenerators who sell power to the national power grid under firm contracts that were reported to the North American Electric Reliability Council (NERC) in the 37 states that are in OTAG.

IPM contains a set of "model plants" which represent similar types of electric generation units that collectively meet the nation's electric demand in the future at the least-cost given whatever NOx controls are imposed on generation units within OTAG. To conduct the analysis, EPA had ICF reconfigure the model plants from how they were set up in 1996 for CAPI to fit the type of Round 3 analysis that OTAG is conducting. For OTAG's Round 3 analysis, the model plants are composed of similar plants within each of the five OTAG zones and the Coarse Grid (and do not represent units in more than one zone). For coal-fired and oil/gas steam units, the model plants also are stratified by size -- composed of like units under 200 megawatts (MWs), units between 200-400 MWs, and units over 400 MWs.

Results

The main results of the analysis for the rate-based control and cap-and-trade options are in Tables 6 and 7, respectively.[15] In order to place the results in perspective, it is important to recognize that Run B was the least stringent of the eight Round 3 NOx control strategies. Run I was the most stringent control strategy. As mentioned earlier, the Modified Run I provides a reasonable approximation of the upper bound cost of what OTAG recommended EPA do in setting NOx budgets for each state, if they are implemented through a cap-and-trade program with a single cap.

The simple rate-based approaches for Run I produce reductions that are close to the cap-and-trade results for the Run I / 1 Cap for All of OTAG option. Therefore, it is reasonable to compare the annual incremental costs in 2007 to see how much more expensive a rate-based approach is over a cap-and-trade alternative using either ICAC, or UARG, NOx control cost assumptions. The cap-and-trade approaches are between 20 to 25 percent cheaper than the rate-based approach. The simple rate-based approach to Run G leads to a much lower reduction in NOx levels than the cap-and-trade approach for Run G. In this case, it is better to compare the cost-effectiveness estimates of the two cases to judge how much less expensive the cap-and-trade approach can be.

14The Base Case forecast of NOx emissions for 2007 and 2012 is explained in the EPA, "Base Case Forecast of NOx Emissions from Electric Power Generation in OTAG Using IPM," March 1997.

15Details on these results can be found in EPA, "Round 3 Analysis of Cap-and-Trade Strategies to Lower NOx Emissions from Electric Power Generation in OTAG, March 25, 1997; EPA, "NOx Control Choices in the OTAG Cap-and-Trade Options" (Excel spreadsheet table), April 8, 1997; EPA, "Analysis of Rate-Based Controls in OTAG Using Round 3, Run G Control Levels;" and EPA, "Analysis of Rate-Based Controls in OTAG Using Round 3, Run I Control Levels," May 1997.

TABLE 6
Results of the Rate-Based Options Analysis for 2007

Round 3 Basis for Rate-based Controls/ Assumptions	Summer NOx Emissions (1,000 tons)	Annual NOx Emissions (1,000 tons)	Incremental Annual Costs (Billion 95$)	Cost Per Ton of NOx Reduced
Base Case	**2,180**	**4,989**	NA	NA
Run G - EPA	1,301	3,863	$2.00	$1,800
Run I - ICAC	985	3,482	$2.06	$1,350
Run I - UARG	982	3,476	$3.48	$2,300

Limitations

The following limitations should be recognized in reviewing the results:

- All the results are influenced by EPA's assumptions on how units will operate under deregulation, forecasted future fuel prices, and electric generation technology improvements.

- Today's costs are used in estimating costs that are not incurred until at least 2007. Technology performance is likely to be better and costs are likely to be lower in the future.

- Only Phase I of the Ozone Transport Commission's MOU is considered part of the baseline; the Phase II and III requirements are built into the OTAG NOx control strategies.

- The cost-effectiveness numbers cannot be directly compared to other OTAG cost estimates for controls where trading is also allowed, because these other estimates do not factor in the cost savings from trading. A simple rough comparison can be made by making a downward adjustment in the costs of the other control measures by the same amount that trading reduces the costs for utility control strategies.

- All the cap-and-trade analyses assume an orderly retrofitting of electric generation units with NOx controls and that the market will be very effective at enabling power plants that have the lowest NOx control costs to take actions to reduce emissions while the remaining units purchase allowances from them. To the extent that the market is less than perfect (and all other things being equal), the costs for cap-and-trade approaches will be greater than estimated.

TABLE 7
Results of the Cap-and-Trade Options Analysis for 2007 and 2012

Control Basis / Cap(s) / Assumptions / Cap(s) Amount (1,000 tons) *In all but regular Run I: cap(s) cover Fine Grid*	**Summer NOx Emissions (1,000 tons)**		**Annual NOx Emissions (1,000 tons)**		**Incremental Annual Costs (Billion 95$)**		**Cost Per Ton of NOx Reduced**	
	2007	**2012**	**2007**	**2012**	**2007**	**2012**	**2007**	**2012**
Base Case	**2,180**	**2,171**	**4,989**	**4,982**	**NA**	**NA**	**NA**	**NA**
Run B / 1 Cap for 5 Fine Grid Zones / EPA / 1,171	1,909	1,898	4,515	4,458	$.42	$.35	$900	$650
Run B / 5 Caps for 5 Fine Grid Zones / EPA / 1,171	1,898	1,836	4,501	4,433	$.43	$.39	$900	$750
Run G / 1 Cap for 5 Fine Grid Zones / EPA / 837	1,577	1,526	4,181	4,125	$.91	$.81	$1,150	$950
Run G / 5 Caps for 5 Fine Grid Zones / EPA / 837	1,567	1,516	4,171	4,114	$.93	$.84	$1,150	$1,000
Run I / 1 Cap for All OTAG / EPA / 1,020	1,020	994	3,565	3,497	$1.98	$1.66	$1,400	$1,100
Run I / 6 Caps: Fine and Coarse Grid Zones / EPA / 1,020	1,020	980	3,567	3,487	$2.03	$1.78	$1,450	$1,200
Run I / 1 Cap for All OTAG / ICAC / 1,020	1,020	996	3,570	3,505	$1.63	$1.42	$1,150	$950
Run I/1 Cap for All OTAG / UARG / 1,020	1,020	1,020	3,563	3,521	$2.71	$2.19	$1,900	$1,500
Modified Run I / 1 Cap for Fine Grid Zones / EPA / 606	**1,349**	**1,294**	**3,950**	**3,887**	**$1.48**	**$1.33**	**$1,450**	**$1,200**