ELECTRICITY GENERATING UNIT (EGU) GROWTH MODELING METHOD TASK 2 EVALUATION

FINAL REPORT

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ACRONYMS AND ABBREVIATIONS

ACI	activated carbon injection
AEO	*Annual Energy Outlook*
CENRAP	Central States Regional Air Planning Association
CO	carbon monoxide
CO_2	carbon dioxide
CRA	Charles River Associates
DOE	U.S. Department of Energy
E&MC Group	Economics and Management Consulting Group
EGUs	electricity generating units
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPMM	Electric Power Market Model
FERC	Federal Energy Regulatory Commission
FGD	flue gas desulfurization
FIPS	Federal Information Processing Standard
Hg	mercury
ICF	ICF Consulting, Inc.
IPM	Integrated Planning Model
LADCO	Lake Michigan Air Directors Consortium
lbs/MMBtu	pounds per million British thermal units
LSD	lime spray dryer
LSFO	limestone forced oxidation
MACT	maximum achievable control technology
MANE VU	Mid-Atlantic Northeast Visibility Union
MEL	magnesium enhanced lime
MRN	Multi-Regional National
MW	megawatts
NEMS	National Energy Modeling System
NO_x	oxides of nitrogen
OTAG	Ozone Transport Assessment Group
PM	particulate matter
RPO	Regional Planning Organization
SCC	Source Classification Code
SCR	selective catalytic reduction
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
SOA	secondary organic aerosol
VISTAS	Visibility Improvement – State and Tribal Association of the Southeast
VOC	volatile organic compound
WRAP	Western Regional Air Partnership

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I. INTRODUCTION

The Lake Michigan Air Directors Consortium (LADCO) sought contractor assistance in reviewing growth methodologies for existing and new electricity generating units (EGUs) and other sources, which supply electricity to the electric power grid. Ultimately, the States and Regional Planning Organizations use the results of EGU emission forecasts in urban or regional scale air dispersion modeling exercises to estimate future year air pollutant concentrations, so any growth methods need to supply model-ready emission model inputs. The purpose of this project is to begin to examine EGU growth methods.

The primary pollutants of interest are sulfur dioxide (SO_2), oxides of nitrogen (NO_x), particulate matter (PM), ammonia (NH_3), and mercury (Hg). Carbon dioxide (CO_2) emissions may also be of interest, but are of lesser importance than the other pollutants. Projection years of interest include 2009 (the approximate time for ozone and $PM_{2.5}$ attainment) and 2018 (a longer term regional haze planning horizon). The geographic area of interest is the eastern half of the United States (to capture the trading issues affecting the Midwest States).

This report provides a detailed evaluation of three EGU growth modeling methods of interest to the LADCO States for consideration in developing its own approach. These evaluations address the following attributes of each modeling approach:

- Description of primary analytical modeling methods;
- Geographic areas of application;
- Advantages; and
- Disadvantages.

The material in this Task 2 evaluation is intended to be used to determine which of the currently available modeling approaches might be best suited for use by the LADCO States for future State Implementation Plan (SIP) and air dispersion modeling work. The models evaluated in this report include the Integrated Planning Model (IPM), the National Energy Modeling System (NEMS), and the Electric Power Market Model (EPMM). The evaluation of each model is provided in a separate chapter of this report.

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II. INTEGRATED PLANNING MODEL (IPM) EVALUATION

The IPM is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector. It provides forecasts of least-cost capacity expansion, electricity dispatch, and emission control strategies for meeting energy demand and environmental, transmission, dispatch, and reliability constraints. IPM can be used to evaluate the cost and emissions impacts of proposed policies to limit emissions of SO_2, NO_x, CO_2, and Hg from the electric power sector. IPM is used by EPA to project the impact of emissions policies on the electric power sector in the 48 contiguous States and the District of Columbia. The assumptions underlying EPA's Base Case and associated policy cases were incorporated in IPM under EPA direction by ICF Consulting, Inc. (ICF). IPM was developed by ICF and is used in support of its public and private sector clients. IPM is a registered trademark of ICF.

Past Performance

One of the EGU model evaluation methods of interest to LADCO was to examine the previous ability of the models to prepare emission forecasts that match with actual emissions. Not all of the EGU models of interest have a long enough history to allow such a comparison, but the IPM does. Table 1 compares the estimates of EGU SO_2 and NO_x emissions that were made via IPM for the first U.S. Environmental Protection Agency (EPA) section 812 prospective analysis. This analysis was performed in 1996 and included *with and without* Clean Air Act Amendment emission projections to 2000 and 2010.

Table 1. EGU 2000 Emissions Comparison (thousand tons)

Regional Planning Organization (RPO) Region	Current Estimates of SO_2	IPM Estimated SO_2	SO_2 Difference	Current Estimates of NO_x	IPM Estimated NO_x	NO_x Difference
MANE-VU	1,780	1,448	332	464	437	27
VISTAS	4,204	3,420	784	1,701	1,260	441
Midwest RPO	3,123	2,934	189	1,216	878	338
CENRAP	1,535	1,976	441	1,087	931	156
WRAP	680	713	(33)	650	571	79
Total	11,321	10,490	831	5,117	4,077	1,040

NOTES: MANE VU = Mid-Atlantic Northeast Visibility Union
VISTAS = Visibility Improvement – State and Tribal Association of the Southeast
CENRAP = Central States Regional Air Planning Association
WRAP = Western Regional Air Partnership

The above comparison shows that the IPM model underestimated the actual SO_2 and NO_x emissions in 2000, both at the national and regional levels. For SO_2, it is expected that the primary reason for the difference between model-estimated and actual 2000 emissions is that IPM under-estimated the influence of previous years banking of SO_2 allowances on SO_2 emissions in 2000. This means that EGUs over controlled during Phase I of the Acid Rain Program and used the banked SO_2 allowances in 2000 to avoid having to meet all of their requirements in 2000, had banking not been allowed.

For NO_x, reasons for the IPM model understating actual 2000 EGU NO_x emissions include that one of the assumptions used in the model runs was that a 0.15 pounds per million British thermal units (lbs/MMBtu) NO_x emission limit would be applied throughout the 37-State Ozone Transport Assessment Group (OTAG) region, and that emission reductions as a result of this program would occur in 2000. The OTAG scenario modeling assumptions obviously would be expected to achieve more reductions in 2000 than the NO_x SIP Call rule that was ultimately implemented.

Table 2 provides State-level detail of the IPM versus actual emission comparisons. This helps, in part, to evaluate the hypothesis that IPM underestimated 2000 EGU NO_x emissions because it was applying controls in OTAG States that were not included in the final SIP Call rulemaking. While Table 2 shows that there are a limited number of States in the VISTAS and Midwest RPO regions that are unaffected by the SIP Call, the percentage difference between NO_x SIP Call *affected*, *partially affected*, or *not affected* does not seem to vary according to which of these three categories a State is in. Therefore, it seems logical to conclude that having the IPM model assume that EGU NO_x sources comply with the 0.15 lbs/MMBtu emission limit in the year 2000 is a more significant factor in having lower model predicted EGU NO_x emissions than seen in observed 2000 NO_x emissions, than applying the 0.15 limit to areas that were not ultimately included in the control region.

Ultimately, one of the important questions about IPM (or any of the alternative models) is how well it does at picking the least cost solution to regional NO_x emission reductions across a region? If the actual 2000 NO_x emission estimates include some progress that the States and sources are making in reducing NO_x as a result of the NO_x SIP Call, then the IPM model seems to be capturing the distribution properly. Otherwise, there do not seem to be many conclusions that can be reached about IPM performance via the Table 2 NO_x results.

Converting IPM output files to (SMOKE/IDA) input format modeling files

In order to use IPM results to support regional modeling analyses, the results have to be amended to include emission estimates for the pollutants not addressed by IPM, and to assign the emissions to locations and stack parameters. This post-processing is typically performed for EPA by Pechan.

The information below is provided to explain how the IPM parsed file, a future projection year database created under specific assumptions, is processed and translated into SMOKE/IDA input modeling files. An example with real data is also included for illustrative purposes.

Table 2. State-Level EGU 2000 Emissions Comparison (thousand tons per year)

	SO_2		NO_x		NO_x SIP Call State?	NO_x Percentage Difference
	Current	IPM	Current	IPM		
VISTAS States						
Alabama	512	511	180	141	Partial	27%
Florida	568	394	284	201	None	41%
Georgia	520	434	185	143	Partial	29%
Kentucky	587	380	247	183	All	35%
Mississippi	131	37	62	20	None	210%
North Carolina	453	472	160	145	All	10%
South Carolina	200	164	88	56	All	57%
Tennessee	425	299	156	106	All	47%
Virginia	214	123	81	56	All	45%
West Virginia	593	606	258	209	All	23%
	4,203	3,420	1,701	1,260		
Midwest RPO States						
Illinois	434	663	230	158	All	46%
Indiana	880	610	337	250	All	35%
Michigan	373	365	163	133	Partial	23%
Ohio	1,237	1,060	380	244	All	56%
Wisconsin	198	235	107	93	None	15%
	3,122	2,933	1,217	878		

Initial IPM Parsed File

The IPM parsed output file, representing a given scenario for a specified future year at the unit level, is processed by ICF, then given to EPA and to Pechan in a single Excel file. The records in the IPM file include:

- Existing units (identified by plant name, ORISPL [plant code] and unit ID). Some units may have zero (0) heat input, indicating that they have been retired or are not operating that year; they are not included in the input modeling files that Pechan creates.

- Generic units (both types below are treated the same during Pechan processing).

  - Regional units (identified by a plant name with an IPM subregion, a unit ID, a State, a plant type [turbine, combined cycle], and a fuel type); they come into the file as *planned-committed* units from NEEDS.

  - New units (identified by a plant name of "NEW", a State, a plant type [turbine, combined cycle], and a fuel type); they come into the file as *new* capacity that the IPM model builds in addition to the existing and planned-committed capacity.

The relevant variables in the IPM file include: Year, Unique Id, Plant Name, Plant Type, State Name, State Code, County, County Code, Plant ID (ORISPL), Unit ID, Capacity (MW), Typical July Day Heat Input (BBtu/Day), Typical July Day NO_x (Tons/Day), Fuel Type, Firing Type, Bottom Type, EMF_Controls, Retrofit SO_2/NO_x Controls, Summer Fuel Use (TBtu), Total Fuel Use (TBtu), Total Subbituminous Fuel Use (TBtu), Total Bituminous Fuel Use (TBtu), Total Lignite Fuel Use (TBtu), Summer NO_x Emission (5-month MTon), Total NO_x Emission (Annual MTon), Total SO_2 Emission (Annual MTon), and Total Hg Emission (Annual Ton).

Development of SMOKE/IDA input modeling files

For all units in the final file, Pechan estimates volatile organic compound (VOC), carbon monoxide (CO), PM_{10}, $PM_{2.5}$, and secondary organic aerosol (SOA) annual and winter/summer emissions; speciates Hg (into its elemental, ionic, and particulate components); assigns plant-specific latitude and longitude coordinates (or county centroids as defaults), Standard Industrial Classification (SIC) codes, plant, point, stack, and segment IDs; and assigns stack parameters. In order to do the above, Pechan matches existing units to earlier NEI EGU files to obtain control efficiencies, stack parameters, latitude and longitude coordinates, and Source Classification Code (SCC) (which will establish links to AP-42 emission factors used in emissions [other than SO_2, NO_x, and Hg emissions] calculations); back-calculates fuel usage (by assigning a default SCC-based fuel heat content and using IPM-provided heat input); and uses default stack parameters based on SCC, if needed. Depending on the scenario requirements, Pechan may align the scenario with the base case point source data from the 1996/1999 Hg inventory file, replacing stack parameters, latitude, longitude, and identifying information for records that can be matched.

For *generic* units, Pechan breaks each State's total generic capacity (both generic new and regional units combined) into units of 500 MW for coal steam units, 225 MW for combined cycle units, and 80 MW for gas turbine. Pechan then sites each of these smaller aggregated plant type-fuel type generic units using criteria established about five years ago. Essentially, this entails siting each of these units at an existing "sister" unit in that State, starting with those existing units in attainment areas (based on a dated county attainment status file) and going to those existing units in nonattainment areas in the State, if necessary, and providing the units with default stack parameters and SCCs based on the plant and fuel type. After the generic emissions for all pollutants are calculated (in the same way as for existing units), they are evenly divided among the units within a State. Since none of these newly formed units will match to existing units in any existing files, Pechan provides counties and latitude/longitude coordinates based on their "sister" unit. Additionally, to remain consistent when processing a series of scenarios, any generic units sited that match units sited in earlier scenarios of the series (based on State and unit type) are moved to the earlier determined sites.

The variables that Pechan includes in the Summer SMOKE/IDA input modeling files are as follows (there are other variables which Pechan fills in with defaults or leaves blank to remain consistent with the IDA format for SMOKE processing): State Federal Information Processing Standard (FIPS) Code, County FIPS Code, Plant, Point, Stack, and Segment IDs, Plant Name, SCC, Stack Height (ft), Stack Diameter (ft), Stack Temperature (deg F), Stack Flow (cu ft/sec), Stack Velocity (ft/sec), SIC, Latitude and Longitude (decimal degrees), Annualized Summer VOC, NO_x, CO, SO_2, PM_{10}, $PM_{2.5}$, NH_3, SOA, and Particulate, Ionic, and Elemental Hg (tons/year), Summer Season Day VOC, NO_x, CO, SO_2, PM_{10}, $PM_{2.5}$, NH_3, SOA, and Particulate, Ionic, and Elemental Hg (tons/average summer season day).

For the Winter SMOKE/IDA input modeling file, 7-month winter season emissions are reported.

Example

A specific example scenario illustrates the relationship between the IPM parsed file and the Pechan-created input modeling files. For the IPM parsed output file 2010 Clear Skies Base Case (Scenario #19), existing units represent 73.1 percent of the entire file's generating capacity (MW) and 84.9 percent of total heat input (TBtu), and generic units represent 26.9 percent of the entire file's generating capacity (MW) and 15.1 percent of total heat input (TBtu). For this scenario, coal units represent 51.1 percent of the entire file's generating capacity (MW) and 76.2 percent of total heat input (TBtu), and gas units represent 48.9 percent of the entire file's generating capacity (MW) and 23.8 percent of total heat input (Tbtu).

Table A-1 in Appendix A shows a sample from the initial IPM parsed file for this scenario: 81 records from Wisconsin (77 existing units and 4 generic [2 New and 2 regional] units). Although the IPM parsed file for this scenario contains 230 records for Wisconsin, only these 81 have heat input values; these 81 records were used for Pechan processing.

Table A-2 in Appendix A shows a sample from the SMOKE/IDA input modeling file for scenario #19, 99 records from Wisconsin (77 existing units and 22 generic units). The 77 existing units are the same as the initial IPM parsed file and the 22 generic units are broken out from the 4 generic units in the initial IPM parsed file.

The existing records in the IPM file are matched into an older NEI file on ORISPL (plant ID) and boiler (unit ID) to obtain the SCC, stack parameters, latitude and longitude, PM control efficiencies. Heat (and ash) content are derived from a fuel type-based data file. Using total heat input (from the IPM file) and heat content, the fuel throughput (tons for coal, MMcf for gas) is estimated. Then using SCC, AP-42 uncontrolled emissions factors are obtained, and along with throughput (and ash contents and control efficiencies for PM_{10} and $PM_{2.5}$), VOC, NO_x, CO, SO_2, PM_{10}, $PM_{2.5}$, NH_3, SOA emissions are estimated. Using the IPM-provided fuel type, existing control, and retrofit control information, each boiler with Hg emissions is placed in a category (or "bin") which has corresponding particulate, ionic, and elemental Hg fractions; these fractions are applied to the IPM-provided total Hg emissions to estimate the three speciated Hg emissions. The summer and winter fractions are obtained using the ratio of IPM-provided summer to annual heat input.

For example, as the result of Pechan processing, boiler 5 of the existing Bay Front plant (ORISPL=3982), is the first record in Table A-1 and is transformed into the eighth record in Table A-2. Similarly, the last four records of Table A-1 – all gas burning turbine generics – are aggregated into one 1,715.07 MW gas turbine, then disaggregated into 22 (21 with 80 MW each and 1 with the remaining <80 MW) generic gas turbine units, and transformed into the 25th through 46th records of Table A-2.

Recommended Improvements

Because EPA must compare files across scenarios, the Agency has asked Pechan not to update the many data files (NEI for PM control efficiencies and stack parameters for existing units, AP-42 emission factors, stack parameter defaults, SCCs, latitude/longitude) that we use in development of the modeling files. They have also requested that we not employ an updated methodology so that all file generation is internally consistent. We are particularly concerned about three issues:

- PM estimates. We use "old" PM control efficiencies from an outdated NEI EGU file for estimating PM_{10} and $PM_{2.5}$ future emissions. We believe for estimating future PM emissions, rather than use old PM control efficiencies, we should either (1) use the PM_{10} and $PM_{2.5}$ control efficiencies from the most recent (2001 or 2002) NEI EGU file or (2) develop future PM control and fuel-specific default efficiencies.

- Generics' siting methodology. This needs to be revised. At the very least, we should try to site those regional generics in the IPM subregion that they are named in, rather than just in the State (as is now done for both generic unit types). The entire attainment file and priority numbering also needs to be revisited since individual States and regions may have better methods for siting new units and we should better tailor our siting whenever possible. At present, we use an EPA-approved outdated attainment county file that is matched with utility plants. This file is sorted by State. Within a given State, attainment counties are listed in ascending numeric order of FIPS county code. Within each attainment county, the plants are listed in ascending numeric unique plant ID (ORISPL) order. After all the attainment counties and their plants are listed within a State, the plants within a State are listed for nonattainment counties in the same fashion. Thus, generic units are assigned to sister plants within a State's attainment counties in a rather random fashion.

- Other data files used in the processing. We use outdated files that can and should be updated to reflect the latest versions and to correct any problems that we have noted with these files. Some of these files are seven years old.

Table 3 provides a detailed evaluation of IPM model attributes.

Table 3. EGU Growth Methods - IPM

Model Name: Integrated Planning Model (IPM)
Model Developer: ICF
Primary Sponsor(s): U.S. Environmental Protection Agency (EPA)
Primary Application: Clear Skies Initiative, PM Transport Rule, NO_x SIP Call Regulatory Analysis, Clean Air Power Initiative
Example Geographic Applications (national, regional, State, other): National and regional
Pollutants Addressed: SO_2, NO_x, CO_2, and Hg

A. Description of primary analytical modeling methods: The IPM is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector. It provides forecasts of least-cost capacity expansion, electricity dispatch, and emission control strategies for meeting energy demand and environmental, transmission, dispatch, and reliability constraints.
B. Range of environmental regulatory assumptions
1. Approach to emission trading IPM's objective function is the summation of all the costs incurred by the electricity sector over the entire planning horizon. The total resulting cost is expressed as the net present value of all of the component costs. These costs, which the linear programming formulation attempts to minimize, include the cost of new plant and pollution control construction, fixed and variable operating and maintenance costs, and fuel costs.
2. How does it incorporate unit or State-specific SIP limits? IPM can consider an array of emission constraints for SO_2, NO_x, Hg, and CO_2. Emission constraints can be implemented on a plant-by-plant, regional, or system-wide basis. The constraints can be defined in terms of a total tonnage cap (SO_2 tons) or a maximum emission rate (lbs/MMBtu NO_x). The Version 2.1.6 includes assumptions about anticipated State-specific air regulations in Connecticut, Massachusetts, Missouri, New Hampshire, North Carolina, Texas, and Wisconsin.
3. Known/announced future control installations? The EPA Base Case 2000 includes all planned-committed units that are likely to come on-line before 2005. Planned-committed units are from the NEEDS 2000 database. In EPA Base Case 2000, a planned-committed unit was included only if it had begun construction or secured financing and was expected to be on-line before 2005. NEEDS 2000 does not list planned-committed units on a unit-by-unit basis. All units having similar technologies and located within the same model region are aggregated. For version 2.1.6 of IPM, two sources were used to identify the planned/committed units: RDI New Gen database distributed by Plates and the inventory of planned/committed units assembled by the U.S. Department of Energy (DOE) for the *Annual Energy Outlook* (AEO) 2003. Appendix G in EPA (2003) lists the planned/committed unit information used in Version 2.1.6.
C. General macroeconomic assumptions

Table 3 (continued)

1. Electricity consumption-annual growth rate (%). Does this account for improved energy efficiency with time in projections of future electricity demand?

The electricity sales forecast in the U.S. Energy Information Administration's *Annual Energy Outlook 2003 with Projections to 2025* (DOE, 2003) provided the starting point for the electric load growth assumptions used in IPM. AEO projects electricity consumption to grow at an average annual rate of 1.86 percent in the period 2000 through 2020. Calculations were also performed to account for the documented and projected reductions in consumption due to a series of voluntary programs operated by the U.S. Department of Energy and EPA, collectively known as the Climate Change Action Plan.

D. Fuel options and prices

	Average Mine Month Coal Prices (1999 $/ton)			
	2005	**2010**	**2015**	**2020**
Central and Southern Appalachian	22.37	20.20	18.91	17.15
Central West and Gulf	10.60	9.35	8.39	8.58
Midwest	14.91	13.14	11.81	10.63
Northern Appalachian	18.24	17.00	15.50	14.29
National Average	12.42	11.24	10.25	9.45

U.S. Henry Hub and National Average Delivered Natural Gas Prices (1999 $/MMBtu)

Year	**Henry Hub Gas Price**	**Delivered Gas Price**
2005	2.89	2.95
2010	2.97	3.03
2015	2.96	3.03
2020	2.87	2.94

Crude Oil Prices

Year	**World Oil Price (1999 $/barrel)**
2005	20.8
2010	21.3
2015	21.9
2020	22.4

E. Role of electricity transmission systems or transmission constraints

IPM characterizes the United States by 26 different power market regions, and includes explicit assumptions about the transmission grid connecting the modeled 26 power markets. Inter-regional transmission capability is limited to defined maximum one-directional flows. These values are based on NERC estimates of First Contingency Total Transfer capability for transmission links between regions. IPM uses a factor of 75 percent of the 1999/2000 transmission capabilities. Transmission link wheeling charges are estimated to be 2 miles per kWh in all situations. The Base Case assumes a 2 percent inter-regional transmission loss of energy transferred.

Table 3 (continued)

F. New electricity generating unit technology options/emission/costs

1. Summary Table

	Conventional Pulverized Coal	Integrated Gasification Combined Cycle	Combined Cycle	Advanced Combustion Turbine	Combustion Turbine	Advanced Nuclear	Circulating Fluidized Bed
Size (megawatts [MW])	400	428	400	120	160	600	N/A
Year Available	2010	2010	2010	2005 (2010)	2005 (2010)	2005 (2010)	
Heat Rate (Btu/kWh)	8,689	7,378	7,056	9,384 (8,550)	10,930 (10,450)	10,400 (10,400)	
Capital ($/kW)	1,288	1,443	532	465 (394)	412 (405)	2,465 (2,402)	
Fixed O&M ($/kW/yr)	23.46	32.26	11.73	7.82 (7.82)	9.78 (9.78)	50.97 (50.97)	
Variable O&M ($/MWh)	2.94	1.95	1.95	2.94 (2.94)	3.91 (3.91)	2.03 (2.03)	
SO_2 Rate	95% removal	99% removal				0	
NO_x Rate (lb/MMBtu)	0.11	0.02	0.02		0.08	0	

2. How much new capacity is estimated to be built in each projection year?

For EPA's 2010 Clear Skies Base Case Scenario, IPM built 157 overall generic units with a total capacity of 174,954 MW, which compares with 7,874 existing units with a total capacity of 576,580 MW.

3. How is the need for new capacity determined by the model (and competed with existing technology)?

For a particular technology, one of the 26 regions in the EPA Base Case may be assigned anywhere from 0 to 18 model plants depending on the characteristics of the technology and the region. When it is economically advantageous to do so, IPM builds one or more of these pre-defined model plants by raising its generation capacity from zero during the course of a model run. In determining whether it is economically advantageous to build new plants, IPM takes into account cost differentials among technologies, expected technology cost improvements (based on a plant's age), and regional variations in capital costs that are expected to occur over time.

4. Where are new units located? Is this determined/allocated by State/sub-State/area?

These new units are allocated by region and State.

Table 3 (continued)

5. Are renewable energy sources included in the model forecasts? If so, which technologies? Add information about them to the summary table above, where possible.

The EPA Base Case for IPM includes 7 types of new renewable generating capacity. These include wind, fuel cells, solar photovoltaic, solar thermal, biomass IGCC, geothermal, and landfill gas. The table below summarizes the performance and unit cost assumptions for new capacity from renewable and non-conventional technologies in IPM.

Performance and Unit Cost Assumptions for New Capacity from Renewable and Non-Conventional Technologies in IPM

	Biomass Gasification Combined Cycle	Wind	Fuel Cells	Solar Photovoltaic	Solar Thermal	Geothermal	Landfill Gas
Size (MW)	100	50	10	5	100	100	100
First Year Available	2010	2005	2005	2005	2005	2005	2005
Lead Time (years)	4	3	2	2	3	4	1
Vintage #1 (years covered)	2010-2030	2005-2030	2005-2014	2005-2030	2005-2030	2005-2030	2005-2030
Vintage #2 (years covered)	–	–	2015-2030	–	–	–	–
Availability	87.7%	90%	90.7%	90%	90%	87%	85%
Generation Capability	Economic Dispatch	Generation Profile	Economic Dispatch	Generation Profile	Generation Profile	Economic Dispatch	Economic Dispatch
Vintage #1							
Heat Rate (Btu/kWh)	8,219	0	5,574	0	0	32,391	10,000
Capital ($/kW)	1,490	1,031-2,625	2,175	2,576	3,187	1,846-6,174	1,299
Fixed O&M ($/kW/yr)	44.81	26.41	15.00	9.97	47.40	62.40-2010.50[3]	78.58
Variable O&M ($/MWh)	5.34	0.00	2.06	0.00	0.00	0.00	10.48
Vintage #2							
Heat Rate (Btu/kWh)	–	–	5,361	–	–	–	–
Capital ($/kW)	–	–	1,566	–	–	–	–
Fixed O&M ($/kW/yr)	–	–	15.00	–	–	–	–
Variable O&M ($/MWh)	–	–	2.06	–	–	–	–

NOTES: Capital costs for wind plants vary by wind class and cost class; Capital and fixed O&M costs for geothermal plants are site specific.

Table 3 (continued)

G. Emission control technology performance and costs

Emission Control Performance Assumptions

	SO_2 Scrubbers			NO_x Post-Combustion Controls				Hg		Other Controls	
	Limestone Forced Oxidation (LSFO)	Magnesium Enhanced Lime (MEL)	Lime Spray Dryer (LSD)	Selective Catalytic Reduction (SCR)	Selective Non-Catalytic Reduction (SNCR)	Gas Reburn		Activated Carbon Injection (ACI)	ACI + Fabric Filters*	Combustion Optimization	Biomass Cofiring
						Low NO_x	High NO_x				
Percent Removal	95%	96%	90%	Coal: 90% Gas: 80%	Coal: 35% Gas: 50%	40%	50%	80%	N/A	0.5% heat rate improvement 20% NO_x reduction	
Capacity Penalty	-2.1%	-2.1%	-2.1%								
Heat Rate Penalty	+2.1%	+2.1%	+2.1%								
Fuel Use Impacts						16% gas use	16% gas use				
Cost											
Capital ($/kW)	$201	$195	$156	$80	$9.9-19.5	$33.3	$33.3	13.48		2.5	1-31
Fixed O&M ($/kW/yr)	8	9	5	0.53	0.14-0.25	0.50	0.50	2.21		6.4	0.15-1.57
Variable O&M (mills/kWh)	1	1	2	0.37	0.84-1.31	–	–	0.61		–	–
Applicable Population	Coal boilers >100 MW	Coal boilers <550 MW and >100 MW	Coal boilers >550 MW	Coal boilers >100 MW All oil/gas steam units	All coal and oil/gas steam units	All coal steam units with NO_x rates higher than 0.5 lbs/MMBtu and without post-combustion controls	All coal steam units with NO_x rates higher than 0.5 lbs/MMBtu and without post-combustion controls	All coal units >25 MW		Coal boilers > 100 MW	All coal units

NOTE: List co-control pollutant benefits for technologies that have them. Hg emission factors used in IPM vary based on the burner type, particulate control, NO_x Post-Combustion Controls, and SO_2 Post-Combustion Controls.

*Either fabric filters or electrostatic precipitators (or both) are modeled as existing pollution control technologies in IPM, with ACI added to obtain Hg control.

Table 3 (continued)

H. Existing EGU plants/unit data sources and attributes IPM uses the NEEDS database as its source for data on all currently operating and planned-committed units. The current version of NEEDS is NEEDS 2000. NEEDS 2000 contains unit-level information and describes the unit's location (model region, State, and county), capacity, plant type, pollution control equipment for SO_2, NO_x, and PM, boiler configurations, Hg emission modification factors, and SO_2 and NO_x emission rates. Version 2.1.6 of the IPM model also includes some updates to NEEDS 2000. The three primary updates have been to planned/committed capacity, 2002 information of SO_2, NO_x, and PM controls, and revisions to some mercury emission rate estimates.
1. Level of aggregation-model input While IPM includes all the EGU units in the NEEDS database, an aggregation scheme clusters actual units into model plants, and IPM uses only the model plants in the actual modeling. This aggregation makes the model computations more manageable, while capturing the essential characteristics of the generating units. Aggregations are based on location, size, technology, efficiency, fuel choices, unit configuration, emission rates, and environmental regulations. PM currently uses 1,385 model plants to represent 12,283 existing units.
2. Level of aggregation-model output IPM takes the model plant-level computations and assigns their emissions and generation (heat input) to existing units and new generic units.
I. Geographic specificity Unit-level for existing plants/units, and State-level for new generic units.
J. Temporal specificity of assumption and results Typical July day and summer (5 month) NO_x emissions. Annual SO_2 and NO_x emissions.
K. Financial data Capital charge rates and real discount rates vary by plant type. Capital charge rates vary from 12.0 percent to 19.0 percent, while the discount rates are in the range of 5.34 to 6.74 percent. The default discount rate for all non-capital expenditures is 5.34 percent. In addition, a default discount rate of 5.34 percent is used in computing the annual increase in allowance price for cap-and-trade programs when banking is used as a compliance strategy.

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III. NATIONAL ENERGY MODELING SYSTEM (NEMS) EVALUATION

The Energy Information Administration (EIA) of DOE produces the AEO every year. The AEO 2003 includes projections of energy supply, demand, and prices through the year 2025. These projections are developed using a model called the National Energy Modeling System (NEMS). This model is modularly designed, with one of the modules being the electricity market module. This electricity market module represents generation, transmission, and pricing of electricity, subject to delivered prices for coal, petroleum products, and natural gas; costs of generation by centralized renewables; macroeconomic variables for costs of capital and domestic investment; and electricity load shapes and demand. There are three primary sub-modules – capacity planning, fuel dispatching, and finance and pricing.

Table 4 summarizes the attributes of the DOE NEMS.

NEMS is a Fortran-based model. The source code is available from DOE's ftp site at: ftp://ftp.eia.doe.gov/pub/oiaf/aeo/aeo2004.zip. The code is contained in about 57 individual Fortran program files, along with numerous input files. In most cases, these input files are text files that can easily be updated or revised. For example, the emmcntl.txt file contains many of the input parameters used in the electricity market module. One of these is a matrix listing the allowable coal plant retrofit control configurations including allowable combinations of SO_2 retrofit controls, NO_x retrofit controls, spray coolers, and fabric filters. A similar matrix is provided for New Source Review plants.

The archive file contains brief instructions for running the PC-compatible NEMS program. These instructions explain how to run a subset of the modules contained in NEMS. This makes it possible for a user to run just the electricity market module and submodules, relying on previously calculated data output from the other modules to be used as input to the electricity market module. For example, if a user desires to run only the electricity market module after changing some of the parameters of the unit-level plant data file, coal prices used in this new run would be those output during DOE's reference case run for the AEO 2004.

Table 5 lists the data fields contained in the NEMS electricity market module unit level input file. In addition to the fields listed in this table, this input file contains several fields for plant and unit identifiers. The source of the data in this file is a combination of information contained in DOE and Federal Energy Regulatory Commission (FERC) forms submitted annually by certain electric utilities. This input file contains data on plant operation and equipment design, fuel consumption and quality, boiler/generator configuration, and control equipment from Form EIA-767. Data in this file from planned units are obtained from Form EIA-860. Generation and fuel consumption data are obtained from Form EIA-759. Data on operating costs of utilities are obtained from FERC forms. The input data file used for the AEO 2004 projections contains 21,155 individual unit records. The data from this file are used by the model to determine capacity and NO_x emissions in the projection years.

Table 4. EGU Growth Methods – NEMS

Model Name: Electricity Market Module of the National Energy Modeling System (NEMS)
Model Developer: EIA
Primary Sponsor(s): DOE
Primary Application: To project the energy, economic, environmental, and security impacts on the United States of alternative energy policies and of different assumptions about energy markets.
Example Geographic Applications (national, regional, State, other): National, regional
Pollutants Addressed: SO_2, NO_x, CO_2, Hg

A. Description of primary analytical modeling methods: NEMS is an energy-economy modeling system of U.S. energy markets for the midterm period through 2025. The projections use a market-based approach to energy analysis, balancing energy supply and demand, and accounting for economic competition energy fuels and sources. The model is modular by sector with information flowing between modules. The most relevant module for this LADCO project is the Electricity Market Module. This module represents generation, transmission, and pricing of electricity, costs of generation, macroeconomic variables for capital and domestic investment costs, and electricity load shapes and demand. New generating technologies and environmental compliance options compete directly in capacity expansion and dispatch decisions.
B. Range of environmental regulatory assumptions NEMS includes the Clean Air Act Title IV SO_2 and NO_x provisions, the NO_x SIP Call, planned flue gas desulfurization (FGD) retrofits, including the Clean Smokestacks bill in North Carolina, the Energy Policy Act of 1992, the Public Utility Holding Company Act, and Federal Energy Regulatory Commission (FERC) Orders 888 and 889.
1. Approach to emission trading In NEMS, utilities are assumed to comply with the Title IV SO_2 allowance program, meeting the overall emission cap. Existing units have the following options in NEMS: retrofit FGD, transfer or purchase SO_2 allowances, lower capacity utilization rate, or switch to low sulfur coal. NEMS assumes that the allowance market operates without regulation and that States do not regulate the type of coal to be used. Banking of SO_2 allowances is also considered in NEMS, using a multi-year framework.
2. How does it incorporate unit or State-specific SIP limits? Title IV NO_x limits are applied by boiler type. NO_x SIP Call reductions are applied by meeting emission caps at the State level through retrofitting SCR on existing units.
3. Known/announced future control installations? Known scrubber retrofit plans are modeled.
C. General macroeconomic assumptions Macroeconomic variables are determined in the Macroeconomic Activity Module. Key variables determined in this module include gross domestic product, interest rates, disposable income, and employment. The module uses proprietary models developed by Global Insight including the Macroeconomic Model of the U.S. Economy.
1. Electricity consumption-annual growth rate (%) AEO projects electricity consumption to grow at an average annual rate of 1.86 percent in the period 2000 through 2020.

Table 4 (continued)

D. Fuel options and prices				
	Average Mine Month Coal Prices (2001 $/ton)			
	2005	**2010**	**2015**	**2020**
Appalachian	26.01	24.86	24.80	24.69
Interior	19.39	18.54	18.26	18.25
Northern Great Plains	6.09	5.71	6.00	6.40
Other West and Non-Contiguous	19.14	17.89	17.83	17.79
National Average	16.50	14.99	14.67	14.38

U.S. Wellhead and National Average Delivered Natural Gas Prices (2001 $/1000 ft^3)		
Year	**Wellhead Gas Price**	**Delivered Gas Price**
2005	2.90	3.33
2010	3.30	3.86
2015	3.59	4.21
2020	3.72	4.38

Crude Oil Prices	
Year	**World Oil Price (2001 $/barrel)**
2005	23.27
2010	23.99
2015	24.72
2020	25.48

E. Role of electricity transmission systems or transmission constraints

The Electricity Fuel Dispatch submodule of NEMS divides the United States into 13 electricity supply regions. The transmission network used by this submodule allows electricity to be traded across regions. The dispatch and network configuration is similar to real-time capacity allocation. Units are dispatched by time slice using available capacity, optimizing on minimum costs until demand is satisfied and environmental and load constraints are met. The Electricity Fuel Dispatch submodule uses a linear programming least-cost algorithm in this modeling of electricity dispatch. Dispatch and trade decisions are made by region. Generators are assumed to be able to service a load anywhere within a region, thus ignoring transmission and engineering constraints that may limit dispatching of specific plants. Constraints related to inter-regional transmission electricity account for the loss of electricity occurring in the transmission of power between regions, and an inter-regional transmission capacity limit.

Table 4 (continued)

F. New electricity generating unit technology options/emission/costs

	Conventional Pulverized Coal (Scrubbed)	Integrated Gasification Combined Cycle	Conventional Gas/Oil Combined Cycle	Advanced Combustion Turbine	Combustion Turbine	Advanced Nuclear
Size (MW)	600	500	250	230	160	1,000
Year Available*	2006	2006	2005	2004	2004	2007
Heat Rate (Btu/kWh) in 2002**	9,000 (8,600)	8,000 (7,200)	7,500 (7,000)	9,394 (8,550)	10,939 (10,450)	10,400 (10,400)
Capital - 2001 $ ($/kW)	1,154	1,367	536	460	409	2,117
Fixed O&M ($/kW/yr)	24.52	33.72	12.26	8.17	10.22	53.48
Variable O&M (mills/kWh)	3.07	2.04	2.04	3.07	4.09	0.43
SO_2 Rate (lb/MMBtu)						
NO_x Rate (lb/MMBtu)	0.11	0.02	0.02	0.08	0.08	

*First year new unit could be completed, given an order date of 2002.
**Heat rates in parentheses represent n^{th}-of-a-kind heatrate.

Table 4 (continued)

G. Emission control technology performance and costs

Emission Control Performance Assumptions (Retrofits)

	SO_2 Scrubbers			NO_x Post-Combustion Controls				Hg	Other Controls	
	Limestone Forced Oxidation (LSFO)	Magnesium Enhanced Lime (MEL)	Lime Spray Dryer (LSD)	SCR	SNCR	Gas Reburn: Low NO_x	Gas Reburn: High NO_x	Activated Carbon Injection	Combustion Optimization	Biomass Cofiring
Percent Removal	95%			90%						
Capacity Penalty										
Heat Rate Penalty										
Fuel Use Impacts										
Cost										
Applicable Population										
Capital Cost $/kW										
300 MW	267			93						
500 MW	204			82						
700 MW	168			75						
Retrofit Factor	1.3			1.3						

NOTE: The costs of these control measures are calculated using EPA's CUECOST3.xls model (as updated 2/9/2000).

Table 4 (continued)

H. Existing EGU plants/unit data sources and attributes The existing facility data used in the electricity market module are obtained from several different survey forms that certain electric utilities are required to submit annually. Form EIA-767 contains data on plant operation and equipment design, fuel consumption and quality, boiler/generator configuration, and control equipment from power plants with a nameplate capacity of 100 MW or more and a subset of these data from units with a nameplate capacity between 10 and 100 MW. Data on planned units are obtained from Form EIA-860. Monthly data on net generation and fuel consumption are collected in Form EIA-759. Data on operating costs of utilities are obtained from FERC Form 1. Plants are retired when it is no longer economical to continue running them. If new replacement capacity can lower the overall cost of producing electricity. Average capital additions are applied to all existing plants: $11/kW-oil/gas steam plants; $6/kW-combined cycle plants; all CT-$16/kW for coal plants; $18/kW-nuclear plants. Costs are added to existing plants regardless of age. After 30 years of age, an additional $5/kW capital charge is added to fossil fuel plants and $50/kW charge is added to nuclear plants. This is used to represent further investments related to aging, such as: major repairs or retrofits, decreases in plant performance, and increased maintenance costs.
1. Level of aggregation-model input Starts with unit-level input. Units are then aggregated to 32 different types of existing coal steam plants plus 20 additional plant types.
2. Level of aggregation-model output Data are output nationally or by the 13 NERC regions and subregions used within NEMS. NEMS does not output unit-specific data.
I. Geographic specificity 13 NERC regions and subregions.
J. Temporal specificity of assumption and results Emission data are output annually, but within the model, electricity loads are segmented into 3 seasons (summer, winter, off-peak), each with 3 daily periods (daytime, morning/evening, and night).
K. Financial data

Table 4 (continued)

L. Model Availability The NEMS model is fully documented and archived with the archive including the source language, input files, and output files needed to replicate the AEO reference case runs. Certain portions of the model are proprietary, such as the Global Insights, Inc. macroeconomic model and the optimization modeling libraries. These proprietary data are not included in the archives. NEMS can be run by organizations outside of DOE on a high-powered PC if the necessary proprietary software is installed. The model is currently installed and used in organizations like Oak Ridge National Laboratory and other national laboratories, the Electric Power Research Institute, the National Renewable Energy Laboratory, and several private consulting firms.

Table 5. Data Contained in NEMS Unit Level Data Input File

Name Plate Actually Owned By Identified Co.
Summer Capacity Owned
Winter Capacity Owned
Average Heatrate
Percent Sold to Grid
Variable O&M Cost (87$/MWH)
Fixed O&M Cost (87$/MW)
General and Administrative Expenses (87$/MW)
Annual Investment in Capital Additions (87$/MW)
Scrubber Efficiency in Removing SO2
Average Capacity Factor
Cost per KW for Retrofit of Scrubber
Sequestration Efficiency in Removing CO2
Fuel Shares
Monthly Capacity Factors
Number of Units in Plant Record
NOX Emission Rate lbs/MMBtu
NOX Emission Rate lbs/MMBtu before OTR Retrofits
NOX Combustion Controls - Overnight Cost
NOX Combustion Controls - Fixed O&M
NOX Combustion Controls - Variable O&M
NOX Combustion Controls - Reduction Factor
NOX SNCR Controls - Overnight Cost
NOX SNCR Controls - Fixed O&M
NOX SNCR Controls - Variable O&M
NOX SNCR Controls - Reduction Factor
NOX SCR Controls - Overnight Cost
NOX SCR Controls - Fixed O&M
NOX SCR Controls - Variable O&M
NOX SCR Controls - Reduction Factor
Asset Value
Book CWIP
???? CWIP
Plant Cost
Lev. Cost for Nuc. Life. Ext (Phase 1)
Lev. Cost for Nuc. Life. Ext (Phase 2)
Lev. Cost for Nuc. Life. Ext (Phase 3)
Initial Plant Group
Plant Group
Plant Subgroup
On-Line Year (9999 If Not Specified)
On-Line Month (12 If Not Specified)
Retire Year (9999 If Not Specified)
Retire Month (12 If Not Specified)
Out-of-Service Year (9999 If Not Specified)
Out-of-Service Month (12 If Not Specified)

Table 5 (continued)

In Service Year (9999 If Not Specified)	
In Service Month (12 If Not Specified)	
Scrubber On-Line Year	
Scrubber Group	
Refurbishment Date	
Nuclear Endog. Ret Switch (0=no, 1=yes)	
Plant Vintage	0 = Cancelled or Retired <1990 1 = On Line by or before 1990 2 = Planned Additions 3 = Unplanned Additions 4 = Repowering (Before) 5 = Repowering (After) 6 = Planned Retrofit (Before) 7 = Planned Retrofit (After) 8 = Unplanned Retrofit (Before) 9 = Unplanned Retrofit (After)
NEMS Fuel Codes	
EFD Plant Type Code	
NEMS Region Code for Location of Plant	
NEMS Region Code for Unit Owner	
Census Region Number	
Natural Region Number	
Coal Region Number	
Financial Type Number for EFP	
Plant Type Number for ECP	
Ownership Type 1=Private, 2=Public, 3=NUG	
Must Run Code 1 = Yes, 0 = No	
Phase 1 Unit (1 = Yes, 0 = No)	
NOX Combustion Controls	(0 = None, 1 = Existing, 2 = CAA, 3 = OTAG, 4 = New)
NOX Post Combustion Controls	(0 = None, 1 = Existing SNCR 2 = Existing SCR 3 = CAA SNCR 4 = CAA SCR 5 = OTAG SNCR 6 = OTAG SCR 7 = New)
2-Digit State Abbreviation for Plant Location	
NOX Emission Control Technology	
Boiler Firing Type Code	
Boiler Bottom Type Code	
Scrubber Type W - Wet, D - Dry, N - None	
Particulate Control E - Cold Side ESP, B - Bag House, N - None / Other	
Activated Carbon Injection A - Activated Carbon Injection, P - ACI + Spray Cooling + Fabric Filter, N - None	

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IV. ELECTRIC POWER MARKET MODEL (EPMM) EVALUATION

Table 6 summarizes the attributes of the Electric Power Market Model (EPMM). Charles River Associates (CRA) and Economics and Management Consulting Group (E&MC Group) provide an integrated modeling framework that can combine a detailed simulation of EGU operations and investments with simulation of how impacts of electricity sector policies would propagate to other sectors and to consumers in regional economies of the United States.

The electric sector analyses performed by CRA and E&MC Group integrate two models: one is a macro-model that is designed to capture the important features of State, regional, and national economies. The second is the EPMM, which uses a detailed database of all U.S. power plants to provide quantitative analyses of costs and changes within the electricity sector from various air pollution control strategies. CRA's Multi-Regional National (MRN) model is used at two stages in an analysis: (a) it provides economic and policy inputs to a detailed, plant-specific model of the electricity industry and (b) it quantifies the economic impacts that the electricity sector has on the rest of the economy.

There is little published information about EPMM, because the model serves the private sector (electric utility industry) market. Therefore, the information in Table 6 was provided by Anne Smith of CRA. Table B-1 in Appendix B provides some sample results reporting from a recent EPMM analysis.

Table 6. EGU Growth Methods - EPMM

Model Name: EPMM (integrated with MRN macroeconomic model)
Model Developer: Charles River Associates
Primary Sponsor(s): Multiple
Primary Application: Multi-pollutant analysis, asset valuation, etc.
Example Geographic Applications (national, regional, State, other): All
Pollutants Addressed: NO_x, SO_2, CO_2, Hg. (Others can be added as desired)

A. Description of primary analytical modeling methods: Linear programming; model identifies capacity builds, unit dispatch, fuel choices and retrofit control choices that minimize total costs of serving regional electricity demands while accounting for all the key system and environmental constraints. All the system decisions are optimized with respect to year and location.
B. Range of environmental regulatory assumptions Any that are considered important. To date, we have developed data and model changes to reflect many existing State-level regulations (e.g., NC Clean Smokestacks Law), the WRAP program, SIP Call and Title IV in our reference case. We can layer any desired additional environmental policies onto this reference set. EPMM currently estimates emissions of NO_x, SO_2, Hg and CO_2 from all units in the United States and Canada. Other emissions could be added if viewed as important. Because the modeling system has a macroeconomic dimension, it can directly simulate the effect of economy-wide CO_2 caps on utility sector responses. (Other modeling systems such as IPM can directly assess CO_2 policies that apply only to the electric sector.)
1. Approach to emission trading A cap is represented as a constraint on emissions. It can be assigned to any subset of units or regions. It can be seasonal, as is the SIP Call cap. The model finds the least-cost way to simultaneously meet that cap, plus any other caps, plus all electricity system constraints. Because of the presence of all the other constraints, the least-cost way to meet the cap in EPMM is different from that which would emerge from a simplistic engineering approach that creates a marginal cost curve based on the control options for that pollutant of all the capped units, and then controls those units that fall on the low side of the cap. Rather, control choices simultaneously account for multiple pollutant policies and represent the least-cost way to achieve the full set.
2. How does it incorporate unit or State-specific SIP limits? Existing limits of this sort are largely captured in the fact that all existing control technologies are in place before the first model year, and are not allowed to be “removed” or “turned off”. If other forms of limitations (such as maximum hours per year of generation) are important, these can be added to the model as desired.
3. Known/announced future control installations? Any known future control installations can be added to the model. Some are already in the model, in that State-specific programs can be included in the reference case.

Table 6 (continued)

C. General macroeconomic assumptions

Macroeconomic growth is reflected in EPMM in how electricity demand is projected to grow in each subregion. Technology costs (e.g., capital cost of new capacity or of retrofits) can vary by region, reflecting different labor and materials costs). These can also be allowed to change over time, to reflect either technological change or changing forecasted macroeconomic conditions. Fuel prices also reflect macroeconomic forecasts, and vary by region, season, and time to capture such forecasts. Which forecast is used is up to the client, but when clients have no preferences of their own, we usually use NERC demand forecasts, AEO fuel price forecasts, and EIA technology cost information. It should be noted that EPMM is also integrated with the MRN macroeconomic model, and initial demand and price forecasts may be adjusted by "feedback" from the MRN model. For example, if EPMM projects a substantial increase in the cost of electricity in a region as a result of a policy that has been simulated, the initial electricity demand input for that region may be adjusted downward by the MRN model to reflect a macroeconomic-scale response to cost increases in that region. This will in turn modify the set of technological control responses from EPMM. The models iterate until the sector and macroeconomic conditions are consistent under the new policy.

1. Electricity consumption-annual growth rate (%). Does this account for improved energy efficiency with time in projections of future electricity demand?

This is a client choice. Yes it can account for energy efficiency improvements, and most off-the-shelf forecasts (such as NERC) do incorporate such trends in their forecasts.

D. Fuel options and prices.

EPMM coal prices are stated as FOB prices for each coal type (rank, SO_2 and Hg contents) that come from each coal-mining State. To these prices, a transport cost is added that is specified for each origin State and destination demand region. The actual assumptions are a client choice. We can, however, provide a set based on spot-price data reported to FERC. Units used are $/MMBtu not $/ton. Escalation rates can be specified for the FOB prices (a negative escalation rate can be used to reflect efficiency improvements in mining, which has been the recent trend). Major demand changes for coal may lead to a price-elasticity response from iteration with the MRN macroeconomic component of the model set.

	Average Mine Month Coal Prices (1999 $/ton)			
	2005	**2010**	**2015**	**2020**
Central and Southern Appalachian				
Central West and Gulf				
Midwest				
Northern Appalachian				
National Average				

Table 6 (continued)

U.S. Henry Hub and National Average Delivered Natural Gas Prices (1999 $/MMBtu)		
Year	**Henry Hub Gas Price**	**Delivered Gas Price**
2005		
2010		
2015		
2020		
Gas prices are specified as a price in $/MMBtu in each of the 28 demand regions, and may be specified to vary by season, if the client wishes. If the client wishes, the price track can be specified as just a Henry Hub forecast, and we can use historical price differentials to convert this to a price for each of the 28 regions. Any forecast can be used, but we recommend that the base case assumptions adhere to well-considered standard forecasts such as AEO or National Petroleum Council produce. Major demand changes for coal may lead to a price-elasticity response from iteration with the MRN macroeconomic component of the model set.		

Crude Oil Prices Same choices as gas prices above.	
Year	**World Oil Price**
2005	
2010	
2015	
2020	
E. Role of electricity transmission systems or transmission constraints There is a limited capacity for power to be transmitted from each region into each of the other regions. This limitation is based on NERC data. (In fact, the subregions of EPMM are defined specifically along the NERC reporting lines so that transmission constraint data can be obtained readily.) Sensitivity analyses of the effect of increased transmission capacity can be performed, but the model does not endogenously alter this capacity.	

Table 6 (continued)

F. New electricity generating unit technology options/emission/costs

1. Summary Table: The model currently has all of these (except CFB), and a few variations on them, and renewables. Assumptions are based on EIA data, but all assumptions are subject to client review, if desired. Additional technologies can be added. The cost data vary by subregion. No particular size limitations are applied when new capacity is built.

	Conventional Pulverized Coal	Integrated Gasification Combined Cycle	Combined Cycle	Advanced Combustion Turbine	Combustion Turbine	Advanced Nuclear	Circulating Fluidized Bed
Size (MW)							
Year Available							
Heat Rate (Btu/kWh)							
Capital ($/kW)							
Fixed O&M ($/kW/yr)							
Variable O&M ($/MWh)							
SO_2 Rate (lb/MMBtu)							
NO_x Rate (lb/MMBtu)							

2. How much new capacity is estimated to be built in each projection year? New capacity builds are endogenously determined. The quantity, and the mix, depend on the scenario. We generally see the quantity of new capacity following the assumed electricity demand growth rates, once any excess capacity is depleted. The mix (coal versus gas, CC versus GT, etc.) tends to be what responds to variations in environmental policy.

3. How is the need for new capacity determined by the model (and competed with existing technology)? New capacity is built when it is forecasted to produce a positive net present value of cash flow. Revenues come from dispatch and from serving capacity requirements. It competes against existing technology in terms of its ability to be dispatched, which is based on the lowest operating cost to meet demand in each segment of the load duration curve for the region. Operating cost includes fuel, control technology operating costs, and (for any emissions of the unit that are under a cap-trade program) emissions costs. If after netting capacity revenues from its costs, a potential new unit cannot compete in dispatch sufficiently to make revenues to cover the residual costs, it will not be built.

Table 6 (continued)

4. Where are new units located? Is this determined/allocated by State/sub-State/area? Determined according to the above endogenous process, and the net effect determines the subregion where it is located simultaneously with the quantity and type.

5. Are renewable energy sources included in the model forecasts? If so, which technologies? Add information about them to the summary table above, where possible. Yes. We currently have data for wind, co-fired biomass, full biomass, and geothermal.

Table 6 (continued)

G. Emission control technology performance and costs

These are also decided in collaboration with the client. Model run time and memory set limits on how many can be included in any one scenario. Generally we run the model with wet , SCR, SNCR, LNB and an ACI+COHPAC form of Hg control with endogenously-determined, continuously-variable Hg control levels. We have at times also included dry , but this has tended not to affect results enough to warrant the added run time that it imposes. We could also add an ACI-only option, or a FF-only, but have found that doing so is not important to the model results if Hg cap-and-trade is in the policy scenario. (Simple back-of-envelope calculations explain why this is the case.)

With regard to Hg control, EPMM has a unique feature that allows us to address maximum achievable control technology (MACT)-style Hg constraints that exactly meet the MACT requirement at each unit without excess operating costs. EPMM identifies the exact way to operate the Hg control equipment to just meet the MACT limit; this means that the “single” Hg control option actually provides an infinite array of percentage removal options from 1% removal of Hg up to the maximal % removal (e.g., up to 90% removal for some cases). Other models, such as IPM, are only able to offer 2 or 3 discrete Hg control levels, such as either 60% or 90% removal, but nothing in-between. This strongly limits their ability to simulate alternative MACT constraints. EPMM is not limited in this way.

The data that we usually use to reflect these technologies is based on EPA assumptions. We frequently adjust the assumptions to reflect client views on the matter. We have actively followed the Hg control technology development, as this is the area where clients usually want to diverge from EPA assumptions. We can help clients understand the choices and supporting evidence regarding Hg control technology assumptions. We use whatever assumptions the client wants to rely on.

Emission Control Performance Assumptions

	SO_2 Scrubbers			NO_x Post-Combustion Controls				Hg		Other Controls	
	Limestone Forced Oxidation (LSFO)	Magnesium Enhanced Lime (MEL)	Lime Spray Dryer (LSD)	SCR	SNCR	Gas Reburn		Activated Carbon Injection (ACI)	ACI + Fabric Filters	Combustion Optimization	Biomass Cofiring
						Low NO_x	High NO_x				
Percent Removal											
Capacity Penalty											
Heat Rate Penalty											
Fuel Use Impacts											
Cost											
Applicable Population											

NOTE: List co-control pollutant benefits for technologies that have them.

Table 6 (continued)

This is (as usual) a client choice. The model incorporates a full matrix of co-benefits. Any technology can control any of the 4 pollutants. Generally, however, the focus has been on how equipment that is originally designed to control SO_2, NO_x or PM affects Hg. Co-control applies to existing PM controls in place as well as to the technologies that are currently options for future retrofits. We can fill the co-benefits matrix to reflect EPA assumptions, industry assumptions, no co-control at all, or any other set of choices. Co-control assumptions vary with the rank of the coal (bituminous, subbituminous, or lignite). We are deeply familiar with the underlying science and data supporting alternative co-control assumptions and can assist clients in choosing among the alternative assumptions, if they wish. Alternatively, we can simply adopt whatever assumptions they direct us to use.

V. SUMMARY AND CONCLUSIONS

Prior to the NO_x SIP Call, State's treatment of EGU growth forecasts has typically been to develop and apply growth and control factors to State and sub-state areas to estimate source-specific EGU emissions. Growth factors for SIC code 4911 (Electric Utility Services) have been developed from either Bureau of Economic Analysis projections, or EPA's Economic Growth Analysis System (EGAS). The Bureau of Economic Analysis provides State-level earnings projections. EGAS 4.0 provides State-level estimates as well, with nonattainment area level projections for serious and severe ozone nonattainment areas. Control factors typically reflect the average expected reduction in the State (or sub-state area). This approach does not capture the emission trading possibilities that will occur under an emission cap. In addition, this method ignores the fact that the new EGUs that come on-line after the inventory base year are likely to have different emission characteristics and locations than the set of existing EGUs.

The models that are available and have been used historically to produce EGU emissions and growth forecasts, such as IPM, NEMS, and EPMM, have been designed and implemented to provide national and regional level results. These models have proven to be valuable tools for providing assessments of SO_2 and NO_x allowance prices, compliance costs by region and State, coal markets analysis, etc. During the 1990s, EPA recognized the value in using the IPM model results to provide inputs to air quality model simulations of various EGU control policy scenarios. In some sense, this stretched the model from a situation where it performed well at estimating regional results, to a situation where it was being used to provide plant- and unit-level emission estimates. IPM was primarily being used to provide regional air dispersion modeling inputs, which was an acceptable use of these EGU emission forecasts, but the unit-level emission estimates were never published, or scrutinized Then, when the NO_x SIP Call analysis was performed, and since, there has been interest, and associated scrutiny of plant- and unit-level emission forecasts. The result is that for SIP-type applications, the IPM model has been extended to a use which is beyond its capabilities. One of the key issues addressed in this report chapter is whether models such as IPM, NEMS, or EPMM can be revised or augmented in a way that meets States' requirements for future SIP and air dispersion modeling work.

Table 7 lists some of the primary model attributes that are of interest to the LADCO States and summarizes how the models address them. All are large complex models that require a sophisticated user to prepare model inputs, run the models, and perform results interpretation. IPM and EPMM are proprietary models, which if LADCO was interested in running, they would either have to contract directly with the model developers, or establish a licensing agreement with these firms in order to use them. If the LADCO States are interested in having a complete EGU model at their disposal, then it is recommended that the DOE NEMS model be considered the primary option. However, due to the complexity of this model and the interactions between the various submodules, it is unlikely that any one State agency would have the necessary resources available to devote to understanding the model sufficiently to modify the underlying data or computer code. This may be more feasible as an RPO-based or inter-RPO effort.

Table 7. Model Comparison Summary Table

Model/Attributes	**IPM**	**NEMS**	**EPMM**
Geographic areas of application - United States-eastern United States	United States and regional applications	United States	United States and regional applications
Ability to provide air quality modeling inputs	Yes, after post-processing	Not as currently configured	This should be possible although the model has not been used this way previously
Pollutants	SO_2, NO_x, Hg, CO_2	SO_2, NO_x, Hg, CO_2	SO_2, NO_x, Hg, CO_2
Emissions time reporting	Annual, 5-month ozone season, summer day (NO_x)	Annual	Annual
Level at which simulations are performed	Model plant	Model plant	Model plant
Level at which results are reported	Plant/unit for existing, model plant for new	By 13 NERC regions and sub-regions	
Does it consider cap-and-trade regulation?	Yes	Yes	Yes
Publicly available?	No	Yes (some portions proprietary)	No
Model developer/owner	ICF	DOE	CRA
Transparent code	No	Available	No
Transparent data	For the most part	Yes	No

None of the models provide air quality modeling inputs directly. As described in Chapter II, Pechan has developed a routine for post-processing the IPM output file to produce IDA files for EPA. This routine adds pollutant emissions not already provided by IPM and assigns locations and stack parameters to all EGU emissions. It is expected that similar routines could be developed to be applied to the results of the NEMS and EPMM models to develop model-ready input files, if necessary. At the moment, IPM has a long history of providing results that have been used in air quality models that the other models do not have.

Regardless of which model LADCO selects for future EGU growth modeling, there are needed improvements and updates which should be made to the post-processing routine so that it includes the latest available information on emission factors and siting criteria. In the process of making these updates, more of this process can be computerized, although there are parts of this routine that may not be able to be readily accomplished via computer code.

The EPMM model developers/users employ their model to serve the private utility market. Therefore, EPMM has much less documentation available to us than the other two models. CRA believes that the EPMM is comparable to IPM in its computation methods. However, it is difficult to verify this. Recent national analyses of potential greenhouse gas policies have used EPMM, and there has been some speculation that the differences in model results between EPMM and other published studies is in some of the model input assumptions. However, we have not found any comparisons of EPMM with other criteria air pollutant EGU model in the literature.

A. RECOMMENDATIONS FOR IMPROVING IPM POST PROCESSING

The IPM post processing approved by EPA and developed by Pechan almost seven years ago is based on nationally applied procedures. Modifying the post processing procedures for a region such as the LADCO States should include state inputs and any plans that are specific to a LADCO State. Recommended tasks for improving IPM post processing include the following:

1. Update the base year data file from 1996 to represent 2002 EGU characteristics for post processing. This file is used to obtain data elements for existing units in the IPM scenario file.

2. Update the latitude-longitude/county centroid file used in post processing. At present, a dated latitude-longitude file is used in post processing siting. However, this data file should be replaced by an updated latitude-longitude data file that has been quality assured/quality controlled and combines several more recent latitude-longitude data sources.

3. Update the SCC file (which includes SCC-based default heat and ash content, as well as default stack parameters) used in post processing. Within the last year, the number of SCCs has increased; these SCCs as well as default heat content, ash content, and stack parameters should be added to the present data file. Additionally, a review should be made of the

default values used in the old SCC file to determine if there are updated default values for the original SCCs that could be included.

4. Review and update any other data files used in IPM postprocessing if the review results indicate that more recent information is available from another source.

5. Develop a new method for obtaining projection year PM_{10} and $PM_{2.5}$ control efficiencies. At present, control efficiencies from a 1996 EGU file are used for the projection years. The best approach to obtain projection year PM control efficiencies would be to consult with States and/or LADCO and the electric generating companies, who may be able to provide future default PM control efficiencies by fuel type and/or information about plant-specific projection year controls. Since the IPM scenario files that are provided by EPA do not include projected PM controls, this could require a considerable amount of effort. A simplified, less costly approach for obtaining projection year PM_{10} and $PM_{2.5}$ control efficiencies for existing units would be to use those in the 2002 EGU data file as surrogates.

6. Develop a new methodology for siting new units. One sub-task is to review 1990 to 2002 new EGU plant and generator sitings within each LADCO State to analyze whether the States/electric generating companies have formulated a general plan for adding new capacity and selecting sites for new EGU plants and/or generators. Another sub-task is to interview selected electric generating companies, the State Public Service Commission, and other agencies involved in siting new EGUs to identify the criteria that they use for choosing the sites for a State's new EGU plants and/or generators.

   After all the information is gathered, a report would be prepared that outlines potential new methodological siting approaches that can be codified for electronic implementation, given the available resources. A meeting with the States, LADCO, and the contractor would be held to discuss alternative siting methodologies, with the goal of reaching agreement on new siting methodologies to be selected for implementation; the methodologies may differ from State to State. This task is expected to require considerable effort.

7. Add the information needed to estimate EGU emissions for all PM components of interest. At present, only filterable PM_{10} and $PM_{2.5}$ emissions are estimated. However, with the increased interest in primary PM_{10} and $PM_{2.5}$ emissions, these additional emissions should be estimated by first calculating PM condensable values.

8. Review mercury speciation methodology. At present, based on information provided by EPA, units with mercury emissions are categorized into *bins* based on the unit's fuel type and control device information. Each bin is associated with a speciation fraction for elemental, ionic, and particulate mercury that is applied to the total mercury emissions provided in the IPM scenario. The binning procedure, as well as the speciation fractions, were last reviewed by EPA over 2.5 years ago.

9. Once improvements have been agreed upon and translated into software code, the new post processing procedures should be tested by taking a previously post processed scenario and applying the new post processing software code. The old and new data files should be compared to determine the reasonableness of emissions, other data elements of interest, and new units' siting changes.

B. ADDITIONAL WORK STEPS NEEDED TO USE NEMS IN EGU EMISSION PROJECTIONS

This section lists the steps and processes that would need to be undertaken to efficiently use the NEMS model projections as the starting point for preparing emissions model-ready EGU files. This procedure would give LADCO the ability to revise the input EGU data as needed, as well as other key parameters affecting emissions, such as control efficiencies for new or retrofit emission controls, run NEMS to provide projections of generation and key pollutant emissions, and then post-process the data output from NEMS into a format usable by an emissions model.

The following steps are recommended for achieving this goal:

1. Review the NEMS code and associated data files. Identify program files related to and used in the Electricity Market Module and submodules. Identify data files used by these program files and list the parameters that are set in each data file. Prepare a memorandum describing the procedures performed in each of the relevant modules and listing the data parameters that are set in each file.

2. Determine the input data desired to be updated by LADCO or the States (e.g., SO_2 control efficiency or unit level input data) and identify the NEMS files that contain these input data fields. Develop an interface to allow users to update the selected data fields, with routines incorporated for checking for valid input values and ranges before allowing updated data to be included.

3. Modify the NEMS code to retain data for existing units in a less aggregated manner, with larger units retained at the unit level.

4. Develop a NEMS post-processor for existing and planned units. This post-processor would need to perform tasks similar to the steps that are currently performed in the IPM post-processing. Match existing and planned unit data output by the modified NEMS to the unit identifiers needed for emissions modeling. Disaggregate the smaller units that were combined for the NEMS processing and match with appropriate unit identifiers. Match each unit with the appropriate stack parameters and latitude/longitude fields. Calculate emissions for pollutants not included in NEMs, and ozone season day emissions, if needed.

5. Develop NEMS post-processor for generic units. Break generic generation into individual units. Develop siting methodology for generic units including process for determining the amount of generation from regional level to allocate to each State in the region. Calculate

emissions for each generic unit. Assign unit identifiers, stack parameters, and latitude/longitude to each generic unit.

6. Develop program to automate process of updating NEMS input files, running selected NEMS modules, performing necessary post-processing, and developing model-ready EGU data files in necessary data formats.

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