Environmental Challenges and Opportunities of the Evolving North American Electricity Market
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Working Paper

Modeling Techniques and Estimating Environmental Outcomes

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BACKGROUND PAPER

MODELING TECHNIQUES AND ESTIMATING ENVIRONMENTAL OUTCOMES[1]

Introduction

This note has been prepared as a background paper for the Commission for Environmental Cooperation's (CEC) electricity initiative *Environmental Challenges and Opportunities of the Evolving North American Electricity Market*. Its purpose is to provide background information on as well as the results of the various publicly available models that have been used to evaluate the environmental effects of electricity market restructuring in different jurisdictions of North America. The paper is essentially descriptive and, as result, almost all of the information contained in it summarizes information from publicly available documents.

In all, 11 models and 12 modeling exercises are described. The models described are: the Energy Information Administration's (EIA) National Energy Modeling System (NEMS), the Department of Energy's Policy Office Electricity Modeling System (POEMS), the Integrated Planning Model (IPM) used by the US EPA, Resources for the Future's (RFF) Haiku model, the Canadian Energy Research Institute's Energy 2020 Model, the Federal Energy Regulatory Commission's (FERC) use of ICF's Coal and Electric Utilities Model, the Center for Clean Air Policy's use of General Electric's Market Assessment and Portfolio Strategies (GE MAPS) model, the Center for Clean Air Policy's use of GE MAPS in combination with New Energy Associates' Proscreen II, the CEC's use of the Front of Envelope Model, Ontario Power Generation's use of the Utility Fuel Economics Model and National Power Model and, finally, New York State Department of Public Service's (NYDPS) Final Generic Environmental Impact Statement using New Energy Associates' PROMOD.

The reader will immediately notice the heterogeneity of the descriptions of the different models. The reason for this is that many of the models discussed are privately owned and developed. As such, information about their functioning is proprietary. Different private sources provided different amounts of information on the functioning of their models.

Before proceeding to the descriptions and results of the individual models, a comparison of the results of models and modeling exercises used to estimate the environmental effects of electricity market restructuring in the United States is presented in Table 1. This table is intended to provide an estimate of the types of results that have been produced on this topic. This table does not incorporate all the results of all the models described, but only the subset which considers the entire United States and, of those, only the results involving three key air emissions: carbon dioxide (CO_2), sulfur dioxide (SO_2) and nitrogen oxide (NO_x).[2] Some models described in the paper do not appear in the table because either the geographical region of analysis or the results were not comparable.

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[1] Prepared by Zachary Patterson at the CEC Secretariat, with comments from Hillard Huntington. The author wishes to thank Dr. Huntington for his time and help.

[2] Non-air pollution and other environmental problems remain extremely difficult to include in models. What is more, models are not generally designed to model environmental outcomes. Rather, environmental outcomes are usually incorporated as add-ons. As such, there are considerable limitations to the environmental outcomes these models can produce.

Not all of the studies shown in this table directly compare the environmental outcomes of restructured electricity markets to non-restructured markets, most notably, the modeling exercises conducted for Stanford University's Energy Modeling Forum Report #17.[3] However, three different models used in two modeling exercises do compare these outcomes—the NEMS and POEMS models used for the analysis of the Clinton Administration's Comprehensive Electricity Competition Act (CECA), and FERC's Environmental Impact Statement of FERC Order 888. Of these, the overall environmental outcomes as described using CO_2, SO_2 and NO_x as indicators do not tell a straightforward story. For example, the CECA competition analysis suggests an improvement of environmental quality relative to a non-restructured market.[4] The FERC analysis, on the other hand, provides results which imply either an improvement of environmental quality relative to a non-restructured market (the "low" scenario presented in the table) or a deterioration relative to a non-restructured market (the "high" scenario presented in the table).

Table 1. Summary of High and Low Estimates of CO_2, SO_2 and NO_x of Models which have Considered the Environmental Effects of Electricity Market Restructuring in the United States—Estimates for the Year 2010.

	CO_2 (million short tons)		SO_2 ('000 short tons)		NO_x ('000 short tons)	
Model	**High**	**Low**	**High**	**Low**	**High**	**Low**
NEMS CECA	720	662	8,950	9,140	n/a	n/a
NEMS EMF #17	835	759	8,950	9,100	5,990	5,670
POEMS CECA	713	646	8,997	9,024	n/a	n/a
POEMS EMF #17	814	742	9,324	9,353	5,050	4,772
IPM EMF #17	773	723	9,822	9,731	4,231	4,172
Haiku EMF #17	764	695	9,098	9,263	6,193	5,927
FERC 888 FEIS	731	675	9,570	9,563	6,515	5,772

The results reported for "high" and "low" estimates are as follows: for the CECA scenarios, the high estimate is the reference case scenario, whereas the low estimate is the competitive electricity market scenario; for EMF #17, the high scenario is the high electricity demand scenario, the low scenario is the base case scenario (this was used because many of the EMF #17 models did not provide results for the RPS scenario); for the FERC FEIS, the high estimate is the "competition-favors-coal" high price differential scenario, the low estimate is for "competition-favors-gas" constant price differential scenario. Results for the EMF #17 study were made available to the CEC by the Energy Modeling Forum.

As is the case for the exercises from the EMF study, it is difficult to get a sense of what these restructured scenarios tell us about the relative effects of restructured vs. non-restructured electricity markets. This is partly due to the fact that they do not compare restructured vs. non-restructured electricity markets, and partly because (as is explained in the orking paper by Miller et al.) there do not exist any publicly available projections of emissions (apart from CO_2) for the electricity sector into the future.

[3] This modeling exercise uses the assumption of restructured markets as a base case.

[4] Results are clearly influenced by modeling assumptions. For example, the CECA competitive case included financial incentives for renewable energy as well as for national renewable portfolio standards. This may in part explain the positive results for liberalization under this exercise.

This paper describes four other papers that are not included in the above table because their scope of analysis is not the same, that is, the scope is not the entire United States. The results from these studies are mixed as well.

As such, there does not seem to be a firm conclusion from the results of modeling exercises regarding the expected environmental effects of electricity market restructuring. That is, one cannot say that, in general, based on these modeling exercises, electricity restructuring is good (or bad) for the environment. The reason for this is that competition produces complex effects in power markets. Some effects improve the environment, while others degrade it. The model results reflect these conflicting effects. In some models, the effects that improve the environment are stronger while, in other models, the effects that degrade it are stronger.

Factors that might improve the environment include improved heat rates as power firms are induced to find technologies that use less fossil energy. Additionally, competitive markets are likely to encourage more rapid entry by new producers, who will be building mostly gas-fired units that are more energy efficient and cleaner than the retiring units. What is more—although not captured in the models described in this paper—competition might make it easier to implement incentive or economic-based programs, such as tradable permits, than would be the case with traditional cost-of-service regulation.

Factors working in the opposite direction include higher demand caused by lower prices, expansion in transmission that links low-cost coal generation regions to regions importing power, and accelerated depreciation of nuclear plants.

The remainder of this paper provides descriptions of the models and reports the results they produced.

The Energy Modeling Forum's Prices and Emissions in a Restructured Electricity Market

In May of 2001, Stanford University's Energy Modeling Forum (EMF) released its 17th report titled *Prices and Emissions in a Restructured Electricity Market*. The paper compares five models' predictions on the environmental outcomes of various scenarios of restructured electricity markets in the United States. It should be noted here that the results from these different models are not projections of the different models. Rather, they are estimates by these models based upon standardized assumptions imposed by the EMF working group. The individual modelers frequently use different assumptions when preparing their own projections. Each of the modeling organizations were asked to adopt roughly 20 common assumptions about the state of the electricity market in the United States to the year 2010, allowing for comparability of assumptions and, more importantly, results. For example, they were asked to assume a perfectly competitive wholesale electricity market starting in the year 2000, and that the retail market would begin to become perfectly competitive in 2000 for all states. Assumptions included common projections for electricity demand and fuel prices (from the Department of Energy's Annual Energy Outlook (AEO) (1999 or 2000), transmission costs, subsidies to renewables, operating and management costs, and a host of other common assumptions. See Table 2 for details.

Table 2. Detailed Assumptions for Baseline Competition Case of EMF #17

Category Input Specification	
Electricity Markets	
	Competitive wholesale
	Competitive retail beginning 2000 for all states
Market structure	Perfect competition
Electricity demand	AEO 1999 (or 2000) Reference Case
Fuel prices	AEO 1999 (or 2000) Reference Case
Cost of Capital	
	Lifetime for new plant is 20 years (17 for wind and solar)
	Debt/equity ratio for new builds is 60/40
	The debt interest rate is 5.5% real and equity is 15% real
Renewables	Extended wind tax credits to 2005
Generation pricing	Marginal cost pricing as defined by each modeler
Ancillary services	Defined by each modeler
Transmission	
Hurdle rate for trading	$1/MWh (1997$)
Organization	Postage Stamp (zonal)
Wheeling fees	$3/MWh (1997$) average between neighboring
NERC regions	
O&M and G&A costs	Savings relative to cost-of-service (COS)
Generation	
O&M	1.8% per year decline, 2000 to 2010
G&A	5% per year decline, 2000 to 2010
Transmission cost reductions	0.75% per year decline, 2000 to 2010
Distribution cost reductions	1.5% per year decline, 2000 to 2010
	Heat rates 0.4% per year improvement for fossil plants, 2000 to 2010
Reserve margins	Goal of 13%–15%, or endogenously derived
Stranded Cost Recovery	
Generation assets	10 year recovery, 10% discount, 100% recovery
Transitional Charges	
Regulatory assets	Recovery of existing regulatory assets
Decommissioning costs	Recovery of required costs
Externality costs	None

Source: EMF 2001.

In addition to the baseline competition assumptions, the different organizations were asked to come up with predictions based on four different future scenarios: a "low gas price" scenario, in which delivered gas prices remain constant at 2000 prices; a high electricity demand scenario, in which electricity demand grows one percent per year faster than AEO predictions; a high transmission scenario, in which transmission capability rises and transmission prices fall; and one with a Renewable Portfolio Standard (RPS) of 7.5 percent non-hydro renewables as a percent of sales by 2010.

The following five models were all compared in EMF #17. As noted in the introduction, some of the models compared in EMF #17 have been used to make estimates in other contexts. For models used for different environment/restructuring exercises, results from all of the exercises in which they were used are reported. Models not compared in EMF #17 are described after the five that were.

The Energy Information Administration's National Energy Modeling System (NEMS)[5]

NEMS models the entire energy sector in the United States by breaking the dynamics of the sector into 12 different modules in five different categories: supply modules, demand modules, conversion modules, a macroeconomic activity module and an international energy module. These 12 modules interact directly or indirectly through one final integrating module, the NEMS integrating module, which controls the NEMS solution process as it iterates to determine a general market equilibrium across all the NEMS modules.

The integrating module executes the system of modules iteratively until it achieves an economic equilibrium of supply and demand in all the consuming and producing sectors. Each module is called in sequence and solved assuming that all other variables in the energy markets are fixed. The procedure continues until the specified convergence variables remain constant within a specified tolerance—a condition defined as convergence.

The NEMS solution algorithm attempts to determine a vector of prices and quantities so supply and demand are matched. Thus, the NEMS integrating algorithm must solve the set of simultaneous equations implied by the supply, demand and conversion models. To this end, it makes use of the Gauss-Seidel algorithm for blocked non-linear simultaneous equations.

Due to the focus of this report, the module of particular interest here is the NEMS Energy Market Module (EMM), which produces most of the results related to the electricity industry.

The EMM interacts with the other modules of NEMS either directly or through the integrating module, and itself comprises four submodels: the Load and Demand-Side Management Submodule (LDSM), the Electricity Finance and Pricing Submodule (EFP), the Electricity Capacity and Planning Submodule (ECP), and the Electricity Fuel Dispatch Submodule (EFD).

The LDSM develops system load shapes for the 13 EMM regions. These are used by the ECP submodule for capacity planning. Selected demand-side management programs are represented as changes in load duration curves, and compared against competing against supply-side options. This module forecasts demand and load shapes for the 13 different NERC regions.

The EFP is mainly a forecasting and accounting submodule which forecasts financial information for electric utilities on an annual basis, given a set of inputs and assumptions concerning forecast capacity expansion plans, operating costs, the regulatory environment and financial data.

The ECP uses a linear programming (LP) formulation to determine planning decisions for the electric power industry. The ECP contains a representation of planning and dispatching in order to examine the tradeoff between capital and operating costs. It simulates least-cost planning and competitive markets by selecting strategies for meeting expected demands and complying with

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[5] EIA 2001, EIA 2000, EIA 1999.

environmental restrictions that minimize the discounted, present value of investment and operating costs. The ECP explicitly incorporates emissions restrictions imposed by the Clean Air Act Ammendments (CAAA) and provides the flexibility to examine potential regulations such as emissions taxes and carbon stabilization.

The EFD uses a linear programming (LP) approach to provide a minimum cost solution to allocating (dispatching) capacity to meet demand. Dispatching involves deciding what generating capacity should operate to meet the demand for electricity, which is subject to seasonal, daily and hourly fluctuations. The objective of the EFD is to provide an economic/environmental dispatching solution. In an economic (least-cost) dispatch, the marginal source of electricity is selected to react to each change in load. In environmental dispatching, the demand for electricity must be satisfied without violating certain emissions restrictions. The EFD integrates the cost-minimizing solution with environmental compliance options to produce the least-cost solution that satisfies electricity demand and restricts emissions to within specified limits.

There have been two widely publicized applications of NEMS greater competition in the

Table 3. Key Assumptions of CECA Modeling

	CECA	CECA
Transmission Hurdle Rate	$3 per MWh	$1.5 per MWh
Transmission Wheeling Fees	80% FERC Order 888	50% FERC Order 888
Generation	Improvement plant mix only	Improve 50%–75% from values to those of top of comparable
Generation G&A	1% per year	5% per year (2000–2010)
Transmission	No	0.75% per year (2000–2010)
Distribution	No	1.5% per year (2000–2010)
Reserve	8%*, except FL @ 4%	8%*, except FL @ 4%
Fossil Plant Availability	85%	89%
Heat	Improvement plant mix only	Improve 50% from values to those of top of comparable plants

EIA analysis solves for reserve margin endogenously, but on average it was eight percent.
Source: Bradley 2001.

electricity market. The first was used to evaluate the environmental effects of the Clinton Administration's Comprehensive Electricity Competition Act (CECA). The second application was for EMF study #17.

The first analysis was conducted by the EIA (1999). Two scenarios were developed, a reference case and a CECA competitive case. The key assumptions used in the different scenarios are produced in Table 3. In addition to these assumptions, in the reference case, electricity prices were based on the average cost of service, whereas, in the competitive case, electricity prices consisted of the marginal cost of generation, ancillary charges, an RPS premium (where applicable), a Public Benefits Charge and stranded cost recovery. Assumptions that were common to the two scenarios were electricity demand growth rates and fuel prices from the AEO 1999.

The key results predicted by NEMS were that between 2000 and 2015:

Reference Case:

- Total capacity increases from 779 GW to 927 GW.
- Natural gas/oil combined cycle combustion capacity increases from 35 GW to 170 GW.
- Nuclear capacity falls from 95 GW to 56 GW.
- Coal capacity falls marginally from 310 GW to 306 GW.
- Coal generation increases from 1,992 to 2,192 billion kWh.
- Natural gas generation increases from 372 to 1,259 billion kWh.
- Renewable generation increases from 54 to 69 billion kWh.
- No significant change in NO_x or SO_2, because of the assumption of implementation of the NO_x State Implementation Plan (SIP) Call and of the Clean Air Act's Acid Rain Program.
- Carbon emissions increase from 595 to 711 million metric tonnes (Mt).

Competitive Case:

- Total capacity increases from 782 GW to 909.58 GW.
- Natural gas/oil combined cycle combustion capacity increases from 35 GW to 119 GW.
- Nuclear capacity falls from 95 GW to 53 GW.
- Coal capacity falls marginally from 310 GW to 302 GW.
- Coal generation increases from 2,037 to 2,213 billion kWh.
- Natural gas generation increases from 349 to 904 billion kWh.
- Renewable generation increases from 69 to 238 billion kWh
- No significant change in NO_x or SO_2 because of the assumption of implementation of the NO_x SIP Call and of the Clean Air Act's Acid Rain Program.
- Carbon emissions increase from 600 to 662 Mt.

The most recent application of NEMS to analyze environmental effects of electricity deregulation was its use for EMF #17. The key environmental predictions to flow from NEMS, using the assumptions of EMF #17, follow. Please note that the reason SO_2 emissions remain the same in all scenarios is because one assumption of the EMF study was that national caps would constrain emissions to the same level.

Baseline Scenario:

- Cumulative capacity additions of 52, 2 and 63 GW for combined cycle gas, coal and combustion turbines, respectively, by 2010.
- Cumulative capacity additions of 0.4, 1.7, 0.6, 0.3 and 2.3 GW of geothermal, landfill gas, biomass, solar and wind production, respectively, by 2010.
- Overall cumulative capacity retirements of 48 GW and of 9 GW for coal, 7 GW for combustion turbines, 15 GW for nuclear and 18 GW for other fossil fuel sources by 2010.[6]
- A reduction in SO_2 emissions from 11.5 million Mt in 2000 to 9 Mt in 2010.
- An increase in NO_x emissions from 5.1 Mt in 2000 to 5.7 Mt in 2010.
- An increase in carbon emissions from 663 Mt in 2000 to 759 Mt in 2010.

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[6] Numbers may not sum to totals given due to rounding.

Low Gas Price Scenario:
- Combined cycle capacity additions are one percent higher than the base case.
- Coal capacity additions are 100 percent lower than in the base case.
- As a result, gas fuel consumption for electricity generation rises 11 percent above the base case, and coal consumption decreases by one percent.
- SO_2 emissions are unchanged from the base case.
- NO_x emissions are 0.5 percent higher than in the base case.
- CO_2 emissions are 0.3 percent higher than in the base case.

High Electricity Demand Scenario:
- Combined cycle capacity additions are 142 percent higher than the base case.
- Coal capacity additions are 358 percent higher than in the base case.
- As a result, gas fuel consumption for electricity generation rises 29 percent above the base case and coal consumption increases by five percent.
- SO_2 emissions are unchanged from the base case.
- NO_x emissions are six percent higher than in the base case.
- CO_2 emissions are 10 percent higher than in the base case.

Expanded Transmission Scenario:
- Combined cycle capacity additions are one percent lower than the base case.
- Coal capacity additions are unchanged from the base case.
- As a result, gas fuel consumption for electricity generation falls one percent below the base case, and coal consumption increases by one percent.
- SO_2 emissions are unchanged from the base case.
- NO_x emissions are one percent higher than in the base case.
- CO_2 emissions are one percent higher than in the base case.

RPS scenario:
- Combined cycle capacity additions fall by one percent from the base case.
- Coal capacity additions fall by five percent from the base case.
- Natural gas consumption for electricity generation falls one percent below the base case, and coal consumption decreases one percent below the base case.
- SO_2 emissions are unchanged from the base case.
- NO_x emissions increase by less than one percent relative to the base case.
- CO_2 emissions decrease by 1.5 percent.

The Department of Energy's Policy Office Electricity Modeling System (POEMS)[7]

POEMS is essentially a modified version of the EIA's NEMS. The modification involves the replacement of the Electricity Market Module (EMM) of NEMS with TRADELEC™, a module developed by OnLocation, Inc., of Virginia.

The main difference between TRADELEC™ and the EMM is that TRADELEC™ provides an alternative electricity model with more detail and disaggregation than NEMS. In particular the EMM constrains electricity market analysis to 13 regions, whereas the regional unit of analysis

[7]DOE 1999

for TRADELEC™ is the power control area (PCA), of which there are 114. TRADELEC™ articulates in a very similar way with the rest of NEMS as does the EMM.

There have been two widely publicized applications of POEMS. The first was to evaluate the environmental effects of the Clinton Administration's Comprehensive Electricity Competition Act (CECA), the second was in EMF #17.

The first analysis was conducted by DOE (1999). Two scenarios were developed and were the same as described above for EIA (1999). The key assumptions used in the different scenarios were also the same as those of the CECA NEMS study and are shown in Table 3 above.

For the most part, the results of the POEMS model for the CECA modeling exercise were very similar to the results from NEMS, except that POEMS predicted the retirement of more oil and gas steam plants and replaced them with combined cycle natural gas plants. This resulted in lower overall annual carbon emissions than NEMS.

The most recent application of POEMS to analyze environmental effects of electricity deregulation was its use for EMF #17. The key environmental predictions to flow from the NEMS using the assumptions of EMF #17 are:

Baseline Scenario:
- Cumulative capacity addition of 107, 2 and 90 GW for combined cycle gas, coal and combustion turbines, respectively, by 2010.
- Cumulative capacity additions of 0.75, 0.4, 0.25, 0.3 and 2.25 GW for geothermal, landfill gas, biomass, solar and wind production, respectively, by 2010.
- Overall cumulative capacity retirements of 69 GW and of 11 GW for coal, 2 GW for combustion turbines, 19 GW for nuclear and 36 GW for other fossil fuel sources by 2010.
- A reduction of SO_2 emissions from 10.5 million Mt in 2000 to 9.5 Mt in 2010.
- NO_x emissions remain stable at around 4.9 Mt until 2010.
- An increase of carbon emissions from 677 Mt in 2000 to 741 Mt in 2010.

Low Gas Price Scenario:
- Combined cycle capacity additions are eight percent higher than the base case.
- Coal capacity additions are 75 percent lower than in the base case.
- Wind capacity additions are 58 percent lower than in the base case (POEMS is the only model to report on wind capacity in this context).
- Gas fuel consumption for electricity generation rises 16 percent above the base case, and coal consumption decreases by two percent.
- SO_2 emissions are unchanged from the base case.
- NO_x emissions are one percent lower than in the base case.
- CO_2 emissions are unchanged from the base case.

High Electricity Demand Scenario:
- Combined cycle capacity additions are 38 percent higher than the base case.
- Coal capacity additions are 20 percent higher than in the base case.
- Wind capacity additions are six percent higher than in the base case (POEMS is the only model to report on wind capacity in this context).
- Natural gas fuel consumption for electricity generation rises 31 percent above the base case, and coal consumption increases by five percent.
- SO_2 emissions are unchanged from the base case.

- NO_x emissions are six percent higher than in the base case.
- CO_2 emissions are 9.5 percent higher than in the base case.

Expanded Transmission Scenario:
- Combined cycle capacity additions are essentially unchanged from the base case.
- Coal capacity additions are 10 percent lower than in the base case.
- Wind capacity additions are 25 percent lower than in the base case (POEMS is the only model to report on wind capacity in this context).
- Natural gas consumption for electricity generation falls one percent below the base case, and coal consumption increases by one percent.
- SO_2 emissions are unchanged from the base case.
- NO_x emissions are two percent higher than in the base case.
- CO_2 emissions are one percent higher than in the base case.

RPS scenario:
- Combined cycle capacity additions fall by five percent from the base case.
- There is little expected change to coal capacity additions from the base case.
- Natural gas consumption for electricity generation falls four percent below the base case, and coal consumption decreases two percent below the base case.
- SO_2 emissions are unchanged from the base case.
- NO_x emissions increase by one percent relative to the base case.
- CO_2 emissions decrease by three percent.

The Environmental Protection Agency's Use of the Integrated Planning Model (IPM)[8]

The IPM[9] is a dynamic electric utility planning model. It is fundamentally a linear programming model whose objective function is to minimize the net present value of the sum of all the costs associated with electricity production for a determined level of detail and a determined planning horizon.

In addition to costs associated with electricity production itself, costs associated with demand-side management can be incorporated into the objective function. Since it is a linear programming model, the objective function is subject to a series of linear constraints which include: reserve margin constraints (given reserve margins must be maintained); demand constraints (electricity demand must be met); capacity constraints (supply cannot be greater than total generation capacity); turn down/area protection constraints (can incorporate whether some generating units can be shut down or need to be operated continuously at a given capacity); emissions constraints (constraints on various types of emissions at determinable levels of aggregations—regional basis, plant by plant); transmission constraints (e.g., between regions linked by transmission lines); and demand-side market penetration constraints (constraints on the effectiveness of demand-side management initiatives).

The model is considered "dynamic," in the sense that that capital costs are discounted to a base year. In addition to the discounting of costs, the model can also incorporate other types of future

[8] EIA 1996.

[9] The IPM was developed by ICF Consulting and is run for the Agency using EPA's assumptions about the electric power system and fuel supply.

information, such as estimated demand or prices for a given period, incorporated within the time horizon in the objective function.

The most recent and widely publicized application of the IPM to analyze environmental effects of electricity deregulation was its use for EMF #17. The key environmental predictions to flow from the IPM using the assumptions of EMF #17 are:

Baseline Scenario:
- Cumulative capacity additions of 78, 18 and 82 GW for combined cycle gas, coal and combustion turbines, respectively, by 2010.
- Overall cumulative capacity retirements of 67 GW and of 25 GW for non-gas, -coal and -nuclear fossil fuel sources by 2010 (IPM does not specify retirements by technology).
- A reduction of SO_2 emissions from 11 million Mt in 2000 to 9.8 Mt in 2010.
- A reduction of NO_x emissions from 4.7 Mt in 2000 to 4.2 Mt in 2010.
- An increase of carbon emissions from 655 Mt in 2000 to 722 Mt in 2010.

Low Gas Price Scenario:
- Combined cycle capacity additions are 33 percent higher than the base case.
- Coal capacity additions are 60 percent lower than in the base case.
- As a result, gas fuel consumption for electricity generation rises 23 percent above the base case and coal consumption decreases by eight percent.
- SO_2 emissions are unchanged from the base case.
- NO_x emissions are 2.5 percent lower than in the base case.
- CO_2 emissions are three percent lower than in the base case.

High Electricity Demand Scenario:
- Combined cycle capacity additions are 62 percent higher than the base case.
- Coal capacity additions are 32 percent higher than in the base case.
- Natural gas consumption for electricity generation rises 40 percent above the base case and coal consumption increases by two percent.
- SO_2 emissions are unchanged from the base case.
- NO_x emissions are two percent higher than in the base case.
- CO_2 emissions are seven percent higher than in the base case.

Expanded Transmission Scenario:
- Combined cycle capacity additions are one percent lower than in the base case.
- Coal capacity additions are 10 percent higher than in the base case.
- As a result, gas fuel consumption for electricity generation falls 2.5 percent below the base case, and coal consumption increases by one percent.
- SO_2 emissions are unchanged from the base case.
- NO_x emissions are one percent higher than in the base case.
- CO_2 emissions are one percent higher than in the base case.

The IPM did not consider the RPS scenario.

Resources for the Future's Haiku Model[10]

The RFF Haiku Model is a simulation model of regional electricity markets and interregional electricity trade, with an integrated algorithm for NO_x and SO_2 emission control technology choice.[11] The model simulates changes in electricity markets stemming from public policy associated with increased competition or environmental regulation. The model simulates electricity demand, electricity prices, the composition of electricity supply, interregional electricity trading activity, and emissions of key pollutants such as NO_x and CO_2 from electricity generation in different regions. Two components of the Haiku model are the Intra-regional Electricity Market Component and the Interregional Power Trading Component.

Regional markets reach equilibrium by equating supply and demand locally. Using data from the U.S. Energy Information Administration (EIA), the demand component classifies annual electricity demand by three customer types (residential, commercial and industrial), by three seasons (summer, winter, fall/spring), and by four time blocks (super-peak, peak, shoulder and baseload hours). Demand is represented by a price-sensitive demand function where each customer class/season/time block has its own demand function with a unique set of parameters.

The model plants that populate the supply component of the model are constructed using information at the generating unit level on generating capacity and engineering characteristics drawn from three different EIA databases: EIA 860, EIA 759 and EIA 767. This information is aggregated from the "constituent plant" to the "model plant" level based on the fuel type (including the coal-demand region where a plant is located), technology (including whether the plant had a scrubber installed in 1997 or not) and vintage of each unit. The model plant definitions used in this model are adapted from those developed by the U.S. EPA for the Clean Air Power Initiative project (EPA 1998). As a part of that project, EPA's contractor, ICF, Inc., developed prototypical operating cost information for each model plant category. This information is combined with regional fuel cost, the costs associated with endogenously selected NO_x control technologies (and, in the case of emission allowance trading, the cost of NO_x allowances) and unit availability (reflecting planned and unplanned outages) to develop regional supply curves. The geographic location of each model plant is determined by generation weighting the latitude and longitude information for each constituent plant. Each region has up to 45 model plants.

Interregional power trading is determined as the trade necessary to equilibrate differences in regional equilibrium electricity prices (gross of transmission costs and power losses) across different NERC regions. These transactions are constrained by the assumed level of available interregional transmission capability as reported by NERC, and they reflect interregional transmission losses and transmission fees.

The model contains emission factors for NO_x, SO_2 and CO_2 for each model plant, based on information from U.S. EPA and EIA on plant performance and total emissions. Electric power industry-wide emissions of SO_2 are capped under Title IV of the 1990 Clean Air Act Amendments and, therefore, would not be affected by restructuring, but the capability of representing alternative emission policies is available. Information on the costs of NO_x emission control, which is the focus of the current project, is obtained for all generating facilities and aggregated to the model plant level. NO_x control strategies are chosen endogenously, based on cost minimization, and the costs of these controls feed into the calculation of NERC region-wide

[10] RFF 2000.

[11] The Haiku model was developed to contribute to integrated assessment with support from EPA, the U.S. Department of Energy, and Resources for the Future.

electricity supply functions. This interaction between endogenously chosen emission control technologies and emission factors with electricity supply allows analysis of the effect of alternative environmental policies on interregional power trading and other market outcomes, as well as their effect on emissions.

The most recent and widely publicized application of Haiku to analyze environmental effects of electricity deregulation was its use for EMF #17. The key environmental predictions to flow from Haiku using the assumptions of EMF #17 are:

Baseline Scenario:

- Cumulative capacity addition of 148, five and 32 GW for combined cycle gas, coal and combustion turbines, respectively, by 2010.
- Cumulative capacity additions of 0.05 and 0.1 GW for biomass/wood and wind power, respectively, by 2010.
- Overall cumulative capacity retirements of 2, 1.5, 2.5 and 50 GW for combined cycle, coal, combustion turbine and "other fossil fuel" sources by 2010.
- A reduction of SO_2 emissions from 11.5 million Mt in 2000 to 9.1 Mt in 2010.
- A reduction of NO_x emissions from 6.1 Mt in 2000 to 5.9 Mt in 2010.
- A marginal increase in carbon emissions by 2010.

Low Gas Price Scenario:

- Combined cycle capacity additions are 48 percent higher than the base case.
- Coal capacity additions are 99 percent lower than in the base case.
- As a result, gas fuel consumption for electricity generation rises 58 percent above the base case, and coal consumption decreases by 20 percent.
- SO_2 emissions are unchanged from the base case.
- NO_x emissions fall by 18 percent relative to the base case.
- CO_2 emissions fall by 7.5 percent relative to the base case.

High Electricity Demand Scenario:

- Combined cycle capacity additions are 50 percent higher than in the base case.
- Coal capacity additions are estimated to be five percent higher than in the base case.
- As a result, gas fuel consumption for electricity generation rises 46 percent above the base case and coal consumption decreases by five percent.
- SO_2 emissions are unchanged from the base case.
- NO_x emissions are estimated to decrease by two percent.
- CO_2 emissions are estimated to increase by 4.6 percent.

Expanded Transmission Scenario:

- Combined cycle capacity additions are one percent higher than the base case.
- No expected change in coal capacity additions from the base case.
- As a result, gas fuel consumption for electricity generation rises one percent above the base case, and coal consumption decreases slightly—less than one percent—below the base case.
- SO_2 emissions are unchanged from the base case.
- NO_x emissions are unchanged.
- CO_2 emissions are unchanged.

RPS scenario:

- Combined cycle capacity additions are 12 percent higher than the base case.

- No expected change in coal capacity additions from the base case.
- Natural gas consumption for electricity generation rises 9.5 percent above the base case and coal consumption decreases 11 percent below the base case.
- SO_2 emissions are unchanged from the base case.
- NO_x emissions decrease nine percent below the base case.
- CO_2 emissions decrease by 7.5 percent.

Canadian Energy Research Institute's (CERI) Energy 2020

As mentioned in the introduction, obtaining information on some of the models was not possible due to the proprietary nature of the models. There is a fair bit of information on what Energy 2020's capabilities are, there was not, however very much documentation on the underlying functioning of the model itself. As such, only its results are presented.

Baseline Scenario:
- Cumulative capacity addition of 190 GW for combined cycle gas, no coal additions, and only a marginal increase in combustion turbines by 2010.
- Overall cumulative capacity retirements of 69 GW with eight GW for combined cycle gas, 34 GW for coal, six GW for combustion turbines, 11 GW for nuclear and 11 GW for other fossil fuel sources by 2010.
- A reduction of SO_2 emissions from 14.1 million Mt in 2000 to 12.3 Mt in 2010.
- NO_x emissions rise from 3.9 Mt to 4.6 Mt in 2010.
- Carbon emissions fall marginally from 676 Mt in 2000 to 675 Mt in 2010.

Low Gas Price Scenario:
- Combined cycle capacity additions are one percent higher than the base case.
- Coal capacity additions are 100 percent lower than in the base case.
- Natural gas consumption for electricity generation rises four percent above the base case and coal consumption decreases marginally.
- SO_2 emissions are unchanged from the base case.
- NO_x emissions are 2.5 percent higher than in the base case.
- CO_2 emissions are one percent higher than the base case.

High Electricity Demand Scenario:
- Combined cycle capacity additions are eight percent higher than the base case.
- Coal capacity additions are unchanged from the base case.
- Natural gas consumption for electricity generation rises 41 percent above the base case, and coal consumption increases by two percent.
- SO_2 emissions are unchanged from the base case.
- NO_x emissions are 21 percent higher than in the base case.
- CO_2 emissions are 11 percent higher than in the base case.

Expanded Transmission Scenario:
- Combined cycle capacity additions decline by four percent from the base case.
- Coal capacity additions are unchanged from the base case.
- As a result, gas fuel consumption for electricity generation falls two percent below the base case, and coal consumption is unchanged.
- SO_2 emissions are unchanged from the base case.
- NO_x emissions are one percent lower than in the base case.

- CO_2 emissions are one percent lower than in the base case.

Energy 2020 did not consider the RPS scenario.

FERC 888 Final Environmental Impact Assessment using ICF's Coal and Electric Utilities Model (CEUM)[12]

Table 4. Key Assumptions from the FERC FEIS Modeling

<table>
<tr><th rowspan="3"></th><th colspan="6">Base Case</th><th colspan="3">Proposed Rule</th></tr>
<tr><th colspan="3">Constant Price</th><th colspan="3">High Price Differential</th><th rowspan="2">Low Response</th><th rowspan="2">Favors Coal</th><th rowspan="2">Favors Gas</th></tr>
<tr><th>2000</th><th>2005</th><th>2010</th><th>2000</th><th>2005</th><th>2010</th></tr>
<tr><td>Delivered Coal Price</td><td>1.15</td><td>1.09</td><td>1.01</td><td>1.18</td><td>1.17</td><td>1.09</td><td colspan="3" rowspan="2">Uses Base Case Assumptions</td></tr>
<tr><td>Delivered Gas Price</td><td>1.67</td><td>1.62</td><td>1.57</td><td>2.48</td><td>2.78</td><td>2.98</td></tr>
<tr><td>Transmission Barriers</td><td colspan="6">Usage price gradually falls to .5 mill/kWh by 2010</td><td colspan="3">Usage price falls to 0.5 mill/kWh by 2000</td></tr>
<tr><td>Competitive Reserve Margins</td><td colspan="6">Fall to 15% gradually by 2005</td><td>Fall to 15% gradually by 2005</td><td colspan="2">Fall to 15% gradually by 2005 13% by 2010</td></tr>
<tr><td>Fossil Plant Availability</td><td colspan="6">Rise to 85% in 2005</td><td>Rise to 85% in 2005</td><td>Rise to 85% in 2000, 90% in 2005</td><td>Rise to 85% in 2005</td></tr>
<tr><td>Heat Rates for Existing Fossil Fuel Plants</td><td colspan="6">Heat rates degrade over time</td><td>Heat rates degrade over time</td><td>Heat rates do not degrade over time</td><td>Heat rates degrade over time</td></tr>
<tr><td>New Combined Cycle Gas Plants</td><td colspan="6">Heat rates set at 7500 Btu/kWh</td><td colspan="2">Heat rates set at 7500 Btu/kWh</td><td>Heat rates improve to 6800 Btu/kWh</td></tr>
</table>

Source: Bradley 2001.

FERC chose to use ICF's Coal and Electric Utilities Model (CEUM)[13] to undertake its environmental effect assessment of FERC order 888. The model was used to capture (1) changes in generating capacity and generation; (2) changes in emissions of SO_2, NO_x, total suspended particulates and CO_2; and (3) savings from more efficient dispatch and construction of generating units. FERC used the Urban Airshed Model (UAM-V) to determine downwind air quality effects.

The CEUM is the integrating model of ICF's system of models and databases pertaining to the coal and electric utility industries. The CEUM forecasts key attributes of the coal and electric utility industries, and generates an equilibrium solution through a standard linear programming formulation. The objective function of the linear program minimizes the total costs of generating and distributing electricity plus delivered coal costs to non-utility sectors. Transmission, environmental and other constraints can be added to the linear program. The level of analysis is 47 different demand regions and 40 coal supply regions.

FERC designed two base case scenarios and three proposed rule scenarios. Table 4 outlines the key assumptions in the FERC modeling. The scenarios as listed in the FEIS are:

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[12] Bradley 2001; FERC 1996.

[13] The CEUM was a precursor to ICF's IPM, referred to earlier in the paper.

a high price differential base case, in which natural gas is assumed to become substantially more expensive compared with coal than it is today; a constant price differential case, in which natural gas is assumed to maintain essentially the same price relative to coal as it had for the last 10 years; a low-response scenario, in which the proposed rule is assumed to lead to no efficiency gains as a result of increased competition in the industry (for this scenario, the same fuel price assumptions are made as for the high price differential base case); a competition-favors-coal scenario, in which the proposed rule is assumed to result in efficiency gains in the electric industry generally, in ways that tend to favor coal (for this scenario, the same fuel price assumptions are made as in the high price differential base case); and, finally, a competition-favors-gas scenario, in which the proposed rule is assumed to result in efficiency gains in the electric industry generally, in ways that tend to favor natural gas (for this scenario, the same fuel price assumptions are made as in the constant price differential base case).

FERC emphasized that the biggest uncertainty is the competitiveness of coal and natural gas due to: (1) future coal and natural gas prices; (2) whether competition will stimulate investment in efficiency measures at coal and/or natural gas facilities; and (3) whether other public policies, such as air emission reduction strategies and global climate change policies, are implemented that will affect the competitiveness of the different fuels.

FERC based its electricity demand growth rate assumptions on North American Electric Reliability Council (NERC) 1994 Electricity Supply and Demand forecasts. In the 1995–2000 timeframe, electricity sales and peak demand were projected to grow 1.8 percent annually, and 1.7 percent annually over the 2001–2010 timeframe.

FERC determined the effect of the proposed rule by comparing the base cases to three proposed rule scenarios. Under the two base cases, future fuel prices had little effect on determining the fuel type of new generation additions. Under both base cases, natural-gas-fired capacity was predicted to double between 1993 and 2010. With the implementation of the proposed rule, coal generation capacity increases one percent if conditions favor coal generation and does not change with favorable natural gas conditions. With the implementation of the proposed rule, natural gas generation capacity decreases four percent if conditions favor coal generation and increases three percent with favorable natural gas conditions. The lower generation capacity additions over the base cases are attributed to the lower reserve margins assumptions under of the proposed rule. Both hydropower and nuclear generation capacity and generation factors were assumed to remain constant through the timeframe.

With the implementation of the proposed rule, coal generation increases four percent if conditions favor coal generation and declines three percent with favorable natural gas conditions. With the implementation of the proposed rule, natural gas generation capacity decreases eight percent if conditions favor coal generation and increases four percent with favorable natural gas conditions. The FERC modeling indicated sensitivity to fuel prices for interregional trade patterns. In particular, the east north central region (i.e., coal-fired dominant region) is a net exporter in coal-favoring scenarios and a net importer in natural-gas-favoring scenarios.

SO_2 emission levels are relatively unchanged under any scenario, due to the implementation of Phase II of the acid rain program, which went into effect January 1, 2000. One of FERC's arguments regarding the NO_x effect is that NO_x emissions will increase regardless of the implementation of the proposed rule. In comparing the two base cases, with a constant price differential between coal and natural gas, and high price differential favoring coal, NO_x emissions grow by 10 percent. When the scenarios are added to the mix, NO_x emissions under the coal-favorable scenario increase only slightly—one percent in 2010 (over the high price differential base case). Under the favorable natural gas conditions, NO_x emissions decrease by two to three percent in 2010, due to the displacement of more coal generation.

On a regional basis, FERC argues that, again, changes in NO_x emissions in 2010 are slight (-1%–4%) under the coal-favorable scenario, with the exception of the Pacific region. There, a 13-percent increase is due to increased coal-fired generation capacity and the fact that baseline emissions are low. These regional emission changes were then modeled with the UAM-V, which showed localized effects of improving to slightly decreasing ozone attainment.

The CEUM model also examined other pollutant effects. For example, mercury and total suspended emissions each increase by two percent under the coal-favorable scenario. CO_2 emissions are expected to remain relatively constant because total fossil fuel generation is expected to remain constant.

FERC also found that the effect on water resources was slight overall, but that there would be regional effects. For example, under a coal-favorable scenario, water consumption in the South Atlantic increases by 20 cfs in 2010 and correlates directly with generation levels. Increased coal production is also expected to increase water degradation, although not significantly. Other effects FERC examined include land requirements, waste and socioeconomic effects.

Center for Clean Air Policy using GE MAPS (Market Assessment and Portfolio Strategies) and Proscreen II (Now Strategist)[14]

In 1995, the Center for Clean Air Policy (CCAP) initiated the Air Quality and Electric Restructuring Dialogue to (1) identify and quantify air quality effects that may result from electric utility restructuring, and (2) develop mitigation measures within the electric restructuring framework. The Center chose to develop a case study of the New York Power Pool and formed a dialogue workgroup consisting of individuals from the utility, and from the regulatory and environmental sectors.

The CCAP analysis used the Proscreen II integrated corporate planning model and the Multi-Area Production Simulation (MAPS) model to analyze the New York case study. Proscreen II is a proprietary computer program of Energy Management Associates and was used to determine capacity expansion dates, and establish revenue requirement levels and retirement schedules for existing electric generating plants.

MAPS is proprietary software of the General Electric Company. It is effectively an electricity dispatch model which models the location of demand and generation recognizing transmission and other constraints, but does not explicitly model the construction of new power plants. As such, any information on new power plants is added to the model exogenously.

The underlying objective of the computer simulation is to determine, for each simulation hour, the lowest bid production cost for producing electricity in sufficient quantities needed to meet customer demand and operating reserve levels, and, at the same time, meet all security constraints imposed on the electricity system for reliability purposes.

The calculation of lowest-bid production cost reflects current electricity deregulation market objectives of compensating electricity producers based on the value of their output. Value is determined by market clearing prices reflecting the highest accepted bid in each simulated control area or sub-area, adjusted for losses and transmission congestion costs. This cost is referred to as

[14] CCAP 1997.

the Locational Based Marginal Price (LBMP). This pricing mechanism has been authorized in deregulated electricity markets by the Federal Energy Regulatory Commission, including the NYCA and PJM systems. It provides energy output, fuel consumption, production costs, air emissions and transmission flows.

The New York State Energy Research and Development Authority headed the modeling efforts. The first step was to develop a reference case scenario, using forecasting data from the Energy Planning Board. Parameters within the model were then changed to determine their effect on revenue and air quality. In the last step, the CCAP analysis analyzed measures to create "emission neutrality" under electric restructuring. Table 5 highlights some of the modeling parameters that were examined.

The key assumptions used in the model related to:

Electricity demand growth. The CCAP analysis assumed that peak demand growth would increase approximately 1.3 percent per year between 1993 and 2001. However, demand-side management and more stringent building energy-efficiency standards offset this growth. This reduced the annual increase in peak demand to 0.8 percent.

Fuel prices. Fuel prices were based on the 1994 State Energy Plan.

Reserve margins. A 22 percent reserve margin is used for the reference case. It is assumes that all new generation capacity will be natural-gas-fired capacity. Nuclear facilities are assumed to operate until their operating licenses expired (except for the high retirement scenario).

Table 5: CCAP Modeling Parameter Changes

1.	Change in reserve margin from 22% to 20%, 15% or 10%
2.	Change in retirement schedule
3.	Change in IPP contract schedule
4.	Change in load shape (decrease peak load by 2.5% or by 5%)
5.	Increase in electricity demand
6.	Increase in imported power
7.	A combination of lower reserve margin, increase retirements, shave peak load and increase imported power
8.	Increase American Electric Power coal unit capacity factor to 80%
9.	Changes in electric industry structure

Source: Bradley 2001.

The reference case indicates a need for an additional 140 MW of capacity in 1999; 1,672 MW in 2005 and 6,300 MW to meet the reserve margin requirement. Natural-gas-fired generation in 2011 increase by 25 percent when coal, oil and nuclear plants are retired, compared to the no-action case. However, under a scenario in which transmission lines are increased to allow for increased imports, and a reduced reserve margin is instituted, natural gas generations in-state fall 15 percent as compared to the no-action case.

The analysis incorporates the Federal Acid Rain Program and the OTC NO_x Budget program (Phase I) emission caps. Reducing the reserve margin delays the need for additional capacity, thus increasing SO_2 emissions (6%) and NO_x emissions (8%) in 2011 over the reference case. In all scenarios, SO_2 emission levels in the state are below acid rain allocations.

However, these numbers fail to capture the increase in emissions from associated importation of electricity. Under the multiparameter changing scenario #7, in 2011, 20,000 GWh of electricity are imported from the midwestern electricity control area, ECAR. This translates into an increase of 17,233 tons of ozone season NO_x (50% increase over the reference case), and an 87,000 ton increase of SO_2 (34% increase over the reference case) in 2011. CCAP also modeled a case study of the effects from increased capacity factors at American Electric Power's coal-fired units—

classified by CCAP as a plausible extreme due to the company's economic advantage of low cost generation. The findings were similar to the increases found under scenario #7.

CCAP also tracked changes in CO_2 emission levels, finding a pattern similar to that for SO_2 and NO_x emissions, with an initial drop from 1993 levels but increasing after 1999, reflecting the growth of electricity demand and the retirement of nuclear facilities. The assessment also calculated changes in PM and mercury levels, but they were small.

CEC Model: (Front of Envelope Model)[15]

CEC-sponsored the development of a Front of the Envelope (FOE) model, which provides a relatively accessible tool for weighing selected effects of changes in the regulation of electricity markets in North America.

The FOE model involves an extremely simple partial-equilibrium model, whose results are used to make some simplified calculations of emissions under various combinations of deregulation scenarios and exogenously specified changes in patterns of power generation. The model was formulated and solved using GAMS.

Several key assumptions of this model were used, which simplified the model tremendously. First, there are no transmission losses or constraints that are explicitly modeled; second, no distinction is made between peak and base demand for electricity; third, substitution between fuel sources is not endogenous but is exogenously specified in different scenarios; finally, electricity supply in each region is assumed to arise from a constant elasticity supply curve.

Different parameters are used in estimating environmental effects. In the CEC model, three scenarios are applied: minimal, mid-range and full levels of deregulation. And three different energy mixes are used: one in which the energy mix remains the same (status quo); an optimistic scenario, in which the share of electricity produced by natural gas-powered generators is increased by one percent; and a less-optimistic scenario, in which the energy share from coal increases by one percent. Numerous other assumptions and constraint parameters are included in the CEC model. Among the key findings of the CEC (2000) model are:

- Deregulation increases overall emissions of NO_x, SO_2 and CO_2 in North America, fundamentally because of a shift in the production of energy between regions. Energy production increases in regions where energy prices are relatively low, and decreases in regions where they are high. Production is shifted to both relatively clean and relatively dirty regions. However, the increases in emissions in dirty regions is far greater than the decreased emissions caused from a shift to the cleaner regions, because dirtier regions produce far more emissions per unit of electricity generated than in the cleaner regions where production also increases. The model estimates that deregulation would result in an increase of NO_x from 13,646 to 13,653 thousand short tons, of SO_2 from 7,827 to 7,831 and of carbon from 657 to 658 million short tons.
- A shift in the fuel mix to natural gas works to decrease emissions: NO_x to 13,574 thousand short tons, SO_2 to 7,739 thousand short tons, and carbon to 656 million short tons.

[15] CEC 2000. Copies available from the CEC upon request.

- The reduction in emissions due to a shift towards more natural gas generation becomes smaller as the electricity market becomes more deregulated because of the above mentioned tendency for liberalization to increase emissions.
- An increase of one percent in the share of electricity produced by coal generators increases emissions in all regions and in North America as a whole: NO_x to 13,885 thousand short tons (2 percent increase), SO_2 to 7,968 thousand short tons (2 percent increase), and carbon to 667 million short tons (2 percent increase).
- The reduction of the marginal costs increases total generation production and increases emissions: NO_x to 13,657, SO_2 to 7,833 thousand short tons, and carbon to 658 million short tons.
- Because the difference between long-run and short-run estimates are simply larger absolute values for demand and supply elasticities, the above-mentioned patterns are exacerbated in the long run—deregulation causes emissions to increase more in the long run than in the short run.

Ontario Power Generation's Use of Utility Fuel Economics Model and National Power Model[16]

The modeling work by Hill & Associates relies on two components: the Utility Fuel Economics Model (UFEM) and the National Power Model (NPM). Integration of the models is done sequentially. The NPM models the dispatching of plants in economically optimal conditions (with regulatory and other constraints), and the total generating output is fed into the UFEM. The UFEM then estimates new fuel or cleanup options—including new fuel and technological constellations—which are fed back into the NPM model.

Modeling work by PHB Hagler Baily uses a GE MAPS (described above) model to estimate changes in the Eastern Interconnection electricity system of the United States, with Ontario included, for the period 2005–2012. Two scenarios are used:

1. The *Base Case* assumes implementation of Phase II of the Clean Air Act Amendments (CAAA). In 2000, SO_2 was limited to 0.55 kg/mmBTU and NO_x was limited to 0.18–0.21 kg/mmBTU, depending on boiler type. For the 11 states in the Ozone Transport Commission (OTC), further emission reductions were imposed. The Base Case scenario assumes that Ontario imposes an emissions cap of 175,000 metric tonnes for SO_2 and 58,000 for NO_x. (Since the parameters of the study were set, the Ontario government has imposed emissions caps of 158,000 metric tonnes for SO_2 and 55,000 for NO_x.)
2. The *NAAQS Case* assumes more stringent NO_x State Implementation Plan (SIP) Call commitments by states to meet National Ambient Air Quality Standards (NAAQS) targets.

Among the results of the contrasting scenarios run under the model, the NAAQS increases capital and operating costs, relative to the base case, by $one billion per year to 2007. (These costs are over and above the mitigation costs of Phase II of the CAAA.) On an aggregate level, this increase will have a marginal effect on total generating costs in the United States. However, the

[16] Plagiannakos 2000. Available online at <http://www.cec.org/programs_projects/trade_environ_econ/pdfs/Plagiann.pdf>.

additional costs are concentrated in the coal-dominated Midwest and the southeastern United States.

Focusing on the ECAR (East Central Area Reliability) region, the study notes that, even with the advent of Phase II of the CAAA, SO_2 emissions are not expected to fall significantly, given the extent of SO_2 banking accumulated under Phase I commitments (about nine million Mt in 1999). Once banked, SO_2 credits are exhausted and new scrubbers are built between 2002 and 2007, the ECAR coal-fired emissions drop in response to Phase II constraints. By contrast, under Phase II, NO_x emissions from coal-fired plants are reduced immediately by approximately eight percent.

The model suggests that electricity "transfers out" from ECAR to other regions could decrease by more than 50 percent from a baseline of 28 TWh in 1998 to less than 13 TWh by 2010. The model assumes that the main reason for this decrease is the NO_x SIP Call limits that come into effect before 2005.

New York State Department of Public Service's (NYDPS) Final Generic Environmental Impact Statement Using New Energy Associates' PROMOD[17]

This study was conducted to establish the environmental effects on the state of New York of the transition to a more competitive electricity industry in New York. PROMOD was used to this end. PROMOD predicts future operating costs, system reliability, and emissions of NO_x, SO_2 and CO_2. Due to its proprietary nature, information on the functioning and underlying model of PROMOD was unavailable. However, one thing that was ascertained through the New Energy promotional literature and in conversation with New Energy staff is that, effectively, PROMOD is an electricity dispatch model whose functions are similar to those of GE MAPS. That is, PROMOD models the location of demand and generation while recognizing transmission and other constraints, but does not explicitly model the construction of new power plants.

The FEIS considered a no-action base case and two competitive alternatives. The no-action base case assumed that generation, transmission, distribution and energy services remain bundled. It also recognized, however, that more independent power producers, power marketers/brokers and external generators would sell electricity to the power grid.

In the wholesale competition alternative, generation became separate from transmission and distribution businesses, and incorporated a system benefit charge to fund socially beneficial programs.

The retail competition alternative assumed the electricity market would split into four enterprises: (1) generation, (2) transmission, (3) distribution, and (4) energy/customer service. The transmission and distribution businesses would continue to be regulated, and a system benefit charge was incorporated to support socially beneficial programs.

Assumptions common to all the models included a 1.1 percent annual growth rate in electricity peak demand and a 23.5 percent minimum reserve margin to determine when new generation capacity/imports were necessary. All new generation capacity was assumed to be natural-gas-fired. The model relied on NY Power Pool data for generating related data.

[17] Bradley 2001; New Energy Associates 2001; NYDPS 1996.

The base case predicted the need for 6,400 MW of additional capacity by the end of 2012. These needs fluctuated a great deal, depending upon assumptions regarding nuclear retirement and load demands. Two scenarios focused on the changes in the generation mix. Under scenario #3, where IPPs were dispatched in order of operating costs, coal generation was predicted to increase around 31,000 GWhs due to its lower cost. Under scenario #5, high electricity demand and the retirement of nuclear capacity, natural-gas-fired plants increased generation by 12 percent compared with the base case.

With respect to emissions, under the no-action scenario, SO_2 was forecast to increase by 50,000 tons per year through 2012 (due to increased sales), while NO_x was estimated to decrease by 38,000 tons (due to implementation of the OTC). In the majority of the scenarios, the SO_2 increase occurred sooner under the competitive scenarios. The FEIS found that a goal to stabilize 1990 CO_2 emission levels would be difficult under the base case and competitive scenarios. The no-action alternative provided cumulative CO_2 emission estimates of eight percent above current rates through 2012. Effects on particulate matter were very closely related to results for NO_x. Mercury was considered, and competition was expected to have little effect (one percent decrease).

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