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A SENSITIVITY ANALYSIS OF THE TREATMENT OF WIND ENERGY IN THE AEO99 VERSION OF NEMS

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EXECUTIVE SUMMARY

This study investigates the effect of modeling assumptions about levelized costs and market penetration on the U.S. Department of Energy's *Annual Energy Outlook* (AEO) forecast for wind technologies.

The AEO's annual report of energy supply, demand, and prices through 2020 is based on results from the Energy Information Administration (EIA) National Energy Modeling System (NEMS). NEMS predicts the market penetration of individual energy technologies based on a variety of inputs and assumed changes in these base values over time. The NEMS forecast of technology adoption and use is influenced most strongly by the model's assumptions about the levelized cost of energy for the various technologies. For each year, NEMS allocates a share of the energy market to least-cost technologies; this allocation affects forecasts for future years. NEMS uses cost multipliers and constraints to represent potential physical and economic limitations on growth in capacity; these limitations include depletion of resources, costs of rapid manufacturing expansion, and the stability or instability of the power grid when high levels of generation come from intermittent resources.

In the AEO99 Reference Case version of NEMS, the electric generation supply mix remains fairly steady, and renewable energy technologies such as wind do not achieve significant market share during the forecast period. However, NEMS is also increasingly being used to analyze alternative scenarios (such as low-carbon futures) in which the role of renewables is likely to be enhanced. In these alternative scenarios, the way in which renewable energy technologies are modeled becomes critical.

The structure of NEMS makes cost inputs of primary importance in determining the economic competitiveness of an energy technology. Aside from capital costs, other assumptions embedded in the cost-of-energy equation have generally been considered as secondary in importance. This report examines some of these other assumptions for wind power to determine which ones have the greatest impact on forecasts for this technology. Understanding the relative influence of these assumptions may help suggest areas where NEMS could be refined to increase the accuracy of its representation of the characteristics of renewable technologies.

Wind power was chosen as a case study because it is found over a relatively wide geographic range and is the closest of the renewable technologies to being economically competitive. Because wind power is modeled similarly to some of the other renewable technologies, such as solar thermal and photovoltaics (PV), our findings may be applicable to these areas of NEMS as well. Our sensitivity analysis focused on relaxing assumptions (not including capital cost) to make them less restrictive to wind development. In our initial explorations, we conducted a limited set of runs with more restrictive assumptions and found that those scenarios did not differ much from the Reference Case results. Therefore, we concluded that further restricting the assumptions would not be very instructive.

In this report, we first review the NEMS model structure and input data for wind power. We then present the results of a sensitivity analysis of wind development in NEMS to the assumptions other than capital cost that are used by the model for economic and physical conditions that affect wind resource development. The assumptions we examined include:

- *The National supply curve*, which increases capital cost in response to rapid, short-term growth;
- *The Regional supply curves,* which increase capital cost as more of a region's wind resource is used;
- *The Regional deployment constraint*, which limits new installations in a region to 1 GW/year;
- *The Regional generation constraint*, which limits generation from intermittent renewables to 10 percent of the generation in a region;
- *The Inter-regional transmission constraint,* which specifies that, for most technologies and regions, capacity in one region cannot serve load in another region.

This analysis includes a series of modifications to the AEO99 Reference Case and a $100/ton carbon permit case (roughly equivalent to the Kyoto 1990+24% Scenario).[1] We do not propose the scenarios used to test these assumptions as reasonable alternatives; we are simply using them as a mechanism for exploring some of the assumptions currently used in NEMS.

By adjusting several assumptions, both individually and in tandem, we learned that NEMS wind development forecasts can be significantly affected by constraints related to supply, intermittent power generation, and annual capacity additions as well as by inter-regional transmission limitations and peak load capacity credits. We concluded that, despite the detail with which NEMS characterizes the nation's wind potential, technology, and development, some of the model's assumptions restrict forecasts of wind development more than appears justified based on recent published research on the potential of this technology. These assumptions also interact with other variables for wind and other technologies but we did not explore such potential interactions in this analysis, beyond the assumptions listed above for wind power.

A sensitivity analysis of these assumptions does not significantly alter the penetration of wind in a reference case forecast with fossil fuel prices close to those prevailing in 1999 (when this analysis was conducted). Without significant future reductions in the cost of wind capacity or additional value given to wind as a carbon-free technology, its capacity growth will be limited because wind power is too expensive to compete against other mature technologies such as combined cycles and combustion turbines. However, the assumptions tested in this analysis become important in cases where wind power is economically competitive with other technologies, such as under a carbon permit trading system.

The significance of the assumptions we studied for wind power is only apparent when multiple assumptions are adjusted simultaneously because they overlap in their impact. For example, under a $100/ton carbon permit scenario, the wind capacity projection for 2020 ranges from 15 GW in the base case to 168 GW when the multipliers and constraints examined in this study are removed. If the inter-regional transmission constraint is lifted and it is assumed that capacity

[1]The Kyoto analysis was conducted by EIA to assess the possible effects of reducing U.S. carbon emissions under a carbon permit trading scheme. The 1990 +24% Scenario represents a carbon emissions target for 2020 that is 24% higher than emissions for 1990 (EIA, 1998b).

constructed in one region can serve another region, wind capacity is forecasted to reach 214 GW. Although these upper values should not be viewed as reasonable projections (because they ignore most of factors beyond direct cost that affect wind development), the magnitude of the ranges illustrates the importance of the assumptions governing the growth of wind capacity and resource availability.

Our findings suggest that future research should focus on reducing the many uncertainties related to these assumptions. Because some of the other renewable energy submodules in NEMS are structured much like the Wind Energy Submodule, many of the areas suggested below for future research could also be considered for other renewable technologies in NEMS. We have identified five key areas on which to focus future research:

1. For the *National supply curve*, reexamine the number and size of the short-term supply curve steps that are invoked if annual capacity additions exceed 20 percent of current installed resources.
2. For the *Regional supply curves*, review the allocation of the national wind resource among the five steps of the long-term multiplier. It is important to insure that each step in the supply curve accurately represents the costs for wind development.
3. For the *Regional deployment constraint*, examine the interaction between the 1-GW regional deployment limit and the short-term supply curve cost multipliers. Because these factors represent the same constraint, their combined effect may be greater than intended.
4. For the *Regional generation constraint*, explore the imposition of a graduated cost penalty when the intermittent fraction of regional generation exceeds 10 percent, in contrast to the current binary approach to limiting intermittent technologies.
5. For the *Inter-regional transmission constraint*, consider enabling inter-regional transmission of electricity for wind and other technologies.

Our detailed description of NEMS' model structure and our sensitivity analyses are designed to contribute to the general understanding of how NEMS treats renewable energy technologies such as wind power. We hope that this report will foster further discussion by highlighting key areas of focus for future work to refine the model.

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The listing of individual affiliation for each of our review panel members is for identification purposes only. Although we gladly acknowledge the involvement of the individual members of the peer review panel, we do not mean to imply their endorsement of this report. The final responsibility for the results of the analysis and the content of the report lies solely with the authors.

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INTRODUCTION

The U.S. Department of Energy's *Annual Energy Outlook 1999* (AEO99) presents forecasts of energy supply, demand and prices through 2020 based on results from the Energy Information Administration's (EIA) National Energy Modeling System (NEMS). NEMS is a comprehensive computer model of the domestic energy economy that incorporates economic, regulatory, resource, technological and environmental data on all aspects of energy development and consumption in the United States. Planners and decision-makers in both the public and private sectors refer to forecasts produced by NEMS for analysis of policy initiatives.

The Reference Case forecast of the AEO99 can be viewed as a moderate case in terms of basic economic growth and energy prices assumptions. The economy is assumed to grow at an average annual rate of 2.1 percent over the next 20 years with overall primary energy demand increasing at a lesser rate of 1.1 percent per year, reaching a total of 120 Quads by 2020. In this case, gas and coal prices to consumers actually decrease slightly (0.3 and 1.3 percent, respectively) from their 1997 values, while end-use oil prices increase only 0.3 percent per year. In such a steady environment, there is not much change in the energy mix for new investments in any of the sectors. In this AEO99 Reference Case, wind power is generally too expensive to compete against other technologies such as combined cycles and combustion turbines.

In this study, we review the model structure and input data for wind power in the AEO99 version of NEMS. [1] Several assumptions regarding the physical and economic conditions related to wind technology and resources in NEMS can be key in governing its development. These factors are incorporated either through cost multipliers or as constraints and they include:

- *National supply curve* - increases capital cost in response to rapid, short-term growth
- *Regional supply curves* - increase capital cost as more of a region's wind resource is used
- *Regional deployment constraint* - limits new installations in a region to 1 GW/year
- *Regional generation constraint* - limits generation from intermittent renewables to 10 percent of the generation in a region
- *Inter-regional transmission* - for most technologies and regions, capacity in one region can not serve load in another region.

Most of these constraints and factors do not come into play in the AEO99 Reference Case forecast. Without significant future reductions in the cost of wind capacity or additional value to wind as a carbon-free technology, its capacity growth is very limited because of its basic economics. However, in scenarios where wind power is economically competitive with other technologies, these other factors become important. To assess their relative importance, we conduct a sensitivity analysis of wind development in the model. Our analysis includes a series of modifications to the AEO99 Reference Case, as well as similar modifications to a case in

[1] In other analyses conducted by Lawrence Berkeley National Laboratory (LBNL) and the National Renewable Energy Laboratory (NREL) where structural changes are made to the NEMS code, NEMS is referred to by a new name. In this study, however, we analyze the structure of NEMS and the characterization of wind energy in the model as used for AEO99. We therefore refer to the model as NEMS in this analysis. The AEO2000 has been published since the time of this study and a few of the updates will be noted.

which the capital cost of wind is reduced and a case in which a $100/ton carbon permit is applied (roughly equivalent to EIA's Kyoto 1990+24% Scenario).[2]

In these sensitivity analyses, we examine several factors both individually and in tandem. To assess their full impacts, we generally removed the factors entirely, rather than adjusting their values. We also used scenarios that are not being proposed as reasonable alternatives, but simply function as a mechanism by which to explore some of the assumptions currently active within NEMS. In these cases, we find that, because the constraints and multipliers overlap significantly in their impact, their individual importance is elucidated only when several are removed simultaneously.

The Reference Case projections of the AEO assume continuing market changes and improvement in energy technologies as derived from past trends. Under these conditions, renewable energy technologies, such as wind power, have typically not achieved significant market share during the AEO forecast period. Increasingly, NEMS is being used to analyze alternative scenarios, such as low carbon futures, where the role of renewables is likely to be enhanced. This report explores some of the assumptions used in NEMS regarding wind power to determine their impact on forecasts of this technology and to suggest possible areas in which the model may be refined to better represent the characteristics of renewable technologies.

In addition to reviewing the structure and assumptions of the model, we explored a range of assumptions that are less restrictive to wind. We recognize that a complete analysis of the model would also include a series of parallel cases that test more restrictive assumptions, and suggest such an exercise as an area of future research. Despite our emphasis on less restrictive sensitivity runs, we feel the results elucidate the relative importance of many of the parameters in the model. We hope the description of the model we provide will contribute to the general understanding of how NEMS treats renewable energy technologies such as wind. We also expect this report to foster further discussion by highlighting key areas in which to focus future refinements of the model.

THE REPRESENTATION OF WIND IN NEMS

Model Structure

In NEMS, the Electricity Market Module (EMM) selects new capacity additions to the electric power system at the regional level based on economic and resource analyses of inputs from various submodules. Figure 1 illustrates the function and relationship of these modules. The Renewable Fuels Module (RFM) passes technology and resource data between the EMM and the technology-specific renewable energy submodules. To determine wind power capacity additions, the RFM governs the flow of data between the Wind Energy Submodule (WES) and the EMM. The WES contains detailed U.S. wind energy resource and technology data in a series of input files. Using these data, WES calculates, for each year, the available capacity in

[2]The Kyoto analysis was conducted by EIA to assess the possible effects of reducing U.S. carbon emissions under a carbon permit trading scheme. The 1990 +24% Scenario represented a target in 2020 of carbon emissions 24% higher than were emitted in 1990.

Figure 1. NEMS Model Structure: The EMM, RFM and WES

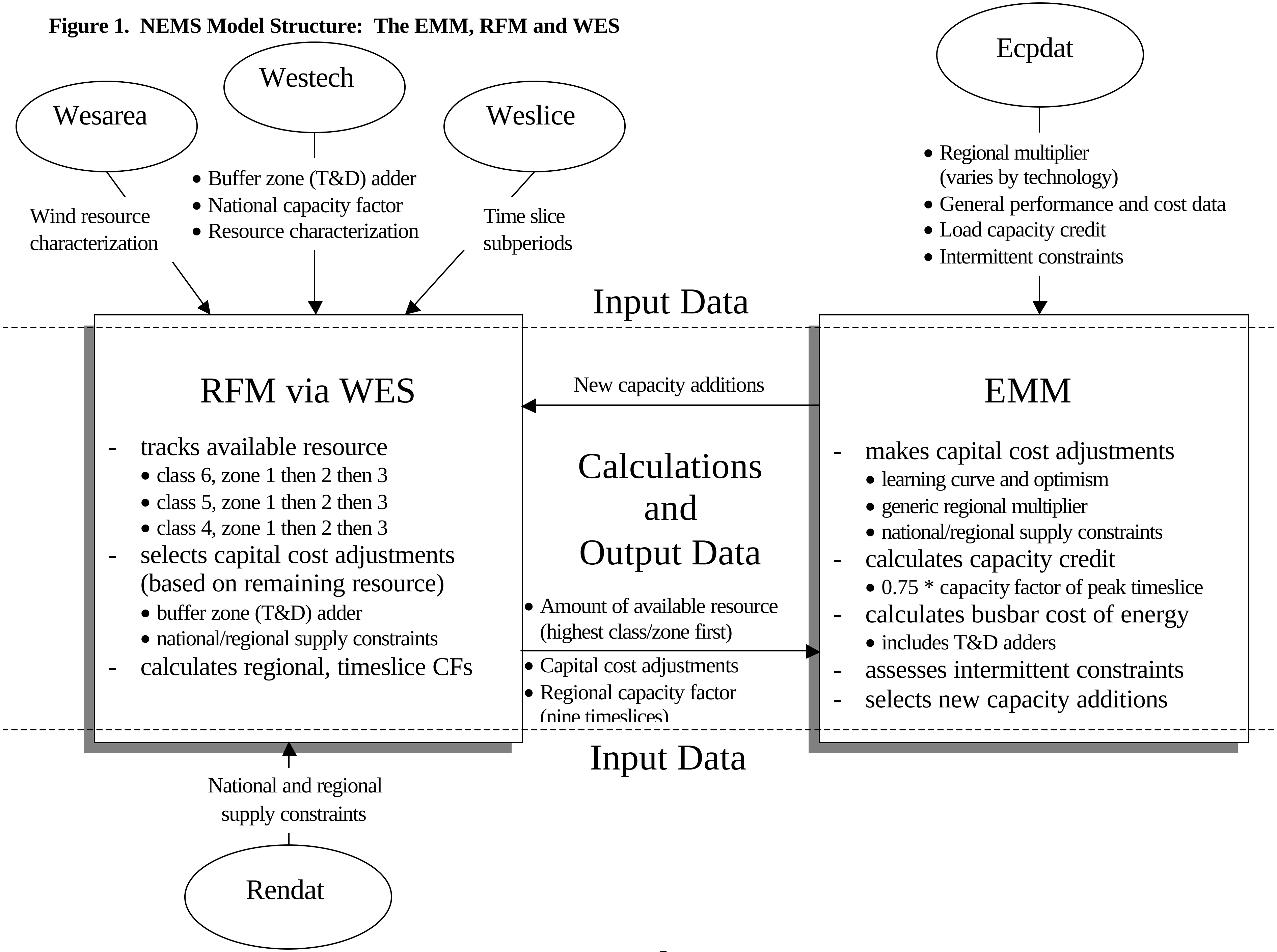
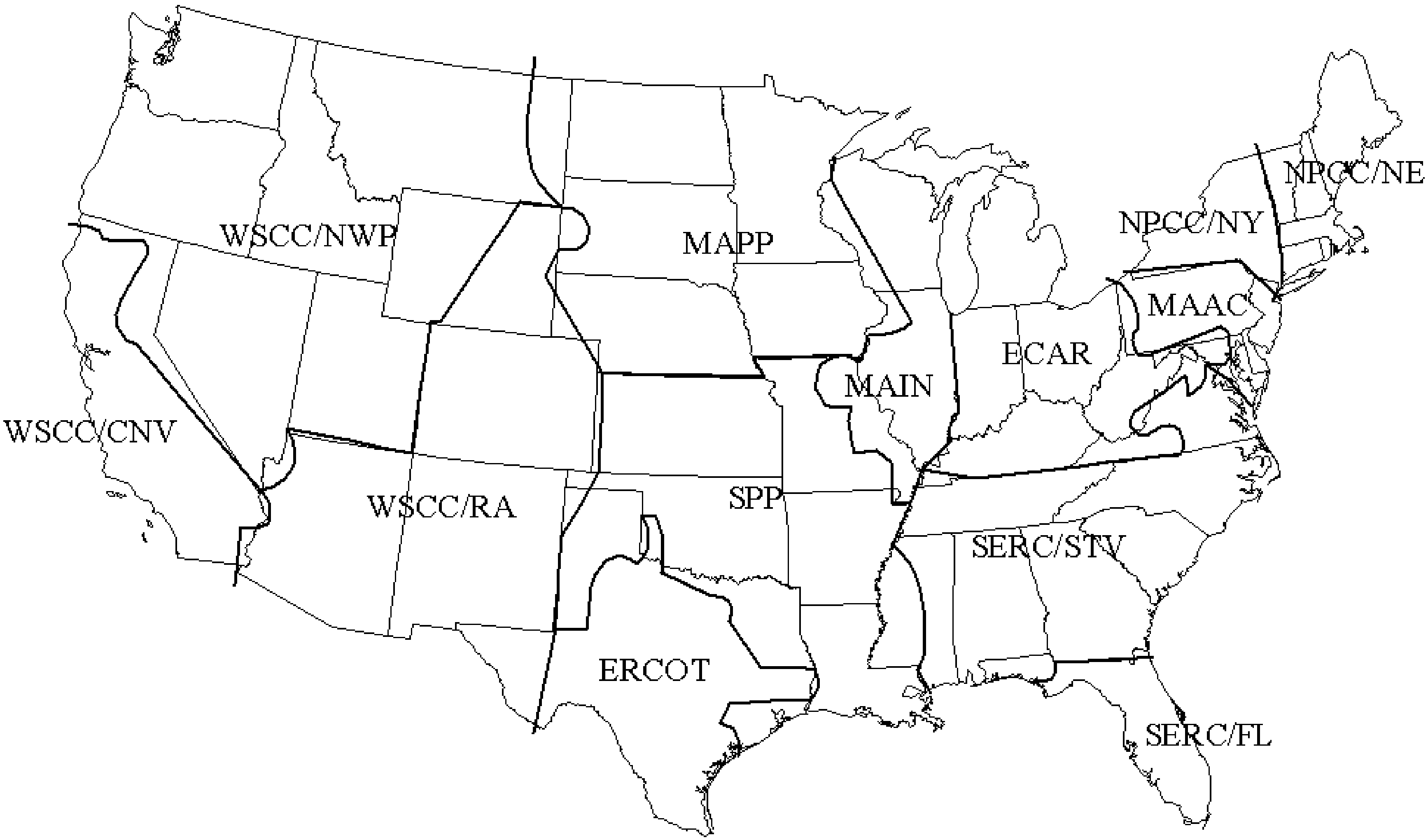


Figure 2. Wind Resource and Electricity Supply Regions in NEMS



Source: The National Energy Modeling System: An Overview 1998, *Energy Information Administration* each region and the capacity factors for each wind class, region and subperiod. All other general technology input data that do not vary by region, including the overnight capital cost, economic life, construction profile, fixed operations and maintenance (O&M) costs, renewable energy production incentives under the Energy Policy Act of 1992 (EPAct), forced outage rates and learning characteristics, are passed directly to the EMM from its Electric Capacity Planning (ECP) data input file, called *ecpdat*.

Input Data

The wind resource data supplied exogenously to NEMS are based on a 1993 Pacific Northwest National Laboratory (PNNL) study which estimated the wind resource potential of available land in the U.S.[1] The model contains a regional description of this wind resource that characterizes the potential energy available in each of three wind classes. These wind classes correspond with the standard definitions of class 6, 5 and 4, as shown in Table 1a.[2] As in the EMM, the wind resource for the continental U.S. is divided into 13 regions (Figure 2). In each region, wind classes are subdivided into three "buffer zones" (zones 1, 2 and 3) which account for the distance between the wind site and the nearest 115 kV or 230 kV transmission line. This structure for assessing the nation's wind resource creates nine wind resource categories per region. The buffer zones, defined in Table 1b, include land within 20 miles of a transmission line as suitable for development. Windy land outside of this area is eliminated. The wind resource potentially available in all wind classes and buffer zones in NEMS totals over 2,500 GW. An output from NEMS of wind energy potential by wind class and buffer zone is shown in Table 2.

Table 1a. Wind Class Definitions in NEMS

NEMS Classification	Standard Terminology	Average Wind Speed
Class 1	Class 6	Above 14.5 mph (6.5 m/s)
Class 2	Class 5	13.4 - 14.5 mph (6.0 - 6.5 m/s)
Class 3	Class 4	12.4 - 13.4 mph (5.6 - 6.0 m/s)

Source: NEMS Renewable Fuels Module Documentation Report: Wind Energy Submodule

Table 1b. Wind Buffer Zone Definitions in NEMS[1]

Buffer Zone	Distance to Transmission Line [2] (miles)
1	0 - 5
2	5 - 10
3	10 - 20

[1]In NEMS, buffer zone refers to the distance to tranmission lines.
[2]Existing 115 kV or 230 kV transmission lines.

Source: wesarea input file

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[1]According to the *Wind Energy Submodule* documentation, available land does not include environmentally protected lands (e.g., parks and wilderness areas), all urban lands, all wetlands, 50 percent of forest lands, 30 percent of agricultural lands, and 10 percent of range and barren lands.
[2]NEMS refers to these classes as 1, 2 and 3, respectively.

Aside from resource characterization, NEMS also contains cost data for wind capacity. For wind and many other renewables, capital cost is particularly important because there are no fuel costs. The capital costs for all technologies in any year and region are a function of many factors, which makes determining the actual cost seen by the model more difficult. NEMS starts with exogenous values and modifies these in the EMM with various multipliers, as described below.

Table 2. Wind Generation Potential by Wind Class and Buffer Zone (GW)[1, 2, 3]

AEO99 REFERENCE CASE

	Wind Class 6			Wind Class 5			Wind Class 4			
Region	buffer zone 1	buffer zone 2	buffer zone 3	buffer zone 1	buffer zone 2	buffer zone 3	buffer zone 1	buffer zone 2	buffer zone 3	Total
ECAR	0.0	0.0	0.0	0.2	0.1	0.2	1.9	0.8	0.9	4
ERCOT	0.0	0.0	0.0	0.0	0.0	0.0	2.5	2.7	5.1	10
MAAC	0.0	0.0	0.0	0.0	0.0	0.0	6.1	2.6	0.9	10
MAIN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
MAPP	0.0	0.0	0.0	35.4	29.1	40.0	579.2	352.8	425.0	1462
NPCC/NY	0.0	0.0	0.0	0.1	0.1	0.1	1.9	0.8	0.5	4
NPCC/NE	0.1	0.0	0.1	1.5	0.9	1.4	2.7	1.6	1.0	9
SERC/FL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
SERC/STV	0.1	0.0	0.0	0.2	0.2	0.2	0.6	0.3	0.3	2
SPP	0.0	0.0	0.0	0.0	0.0	0.0	228.2	134.7	133.0	496
WSCC/NWP	28.1	18.1	26.1	21.1	12.2	17.0	75.9	49.8	67.1	315
WSCC/RA	10.3	5.6	7.9	0.3	0.4	0.7	83.2	50.8	45.7	205
WSCC/CNV	5.7	1.9	0.6	2.4	1.2	0.9	4.8	1.7	1.4	21
U.S.	44	26	35	61	44	60	987	599	681	2537

[1]This wind generation potential is used for the entire forecast period (through 2020).

[2]Wind classes 6, 5 and 4 correspond to classes 1, 2, and 3 in NEMS, respectively. See Table 1a for wind class definitions.

[3]In the NEMS framework, buffer zone refers to the distance from transmission lines. See Table 1b for wind buffer zone definitions.

The initial values for these economic data for wind are shown in Table 3 (in 1997$). One key input parameter to note is the construction lead time of three years. This delay influences the build decisions for wind, as for other technologies, in several ways. Most directly, it affects the cost calculation of wind by discounting the effect of learning, and it also has repercussions in the functioning of the supply constraints applied to wind power, both discussed later.

NEMS also starts with exogenous values for the capacity factor by wind class. These national annual capacity factors, shown in Table 4, are input in five-year intervals. Yearly values are linearly interpolated from these five-year increments. The capacity factor inputs, based on two 1990 Science Applications International Corporation studies, are predicted to increase as the technology advances. The highest capacity factor, class 6 in 2020, is predicted to reach 40 percent. Class 5 and 4 wind resources in this same year are given a 37 percent and a 34 percent capacity factor, respectively.

Power plants that are reported by generators as under development or are mandated by states are specified exogenously in NEMS and referred to as “planned additions.” Of the 800 MW of wind that is added between 2000 and 2020 in the AEO99 Reference Case, over 700 MW are planned additions. Only a fraction of the wind capacity added in the Reference Case is added by the model logic as a result of the technology's economics.

Table 3. Initial Wind Cost Variable Input Values

Variable	Initial Value	Source
Overnight Capital Cost (1)	$725/kW (2)	EIA Internal Review (3)
Fixed O&M	$25.94/kW (4)	EPRI 1993 Technical Assessment Guide
Variable O&M	$0/kW	EPRI 1993 Technical Assessment Guide
Construction Lead Time	3 years	EPRI 1993 Technical Assessment Guide
Capacity Credit	0.75 * Capacity Factor	EIA Internal Review
Production Credit	1.63 ¢/kWh (5) through 1999(6) 0 ¢/kWh 2000 - 2020	Energy Policy Act of 1992

(1) Actually the fifth-of-a-kind overnight capital cost.
(2) Converted to 1997$ from NEMS input value of $540 in 1987$ using a GDP implict price deflator. In the AEO2000, EIA has updated the capital cost to $916/kW (1997$).
(3) Based on discussions with industry, government and national laboratory sources.
(4) Converted to 1997$ from NEMS input value of $19.31 in 1987$.
(5) Converted to 1997$ from NEMS input value of 1.21 ¢/kWh in 1987$.
(6) If a plant is built in or before 1999, it receives this credit for 10 years. If it is built in 2000 or later, it receives no production credit.

Source: ecpdat input file

Table 4. National Capacity Factors by Wind Class[1]

	Capacity Factor		
Year	Class 6	Class 5	Class 4
1990	0.26	0.23	0.20
1995	0.30	0.27	0.24
2000	0.32	0.29	0.26
2005	0.34	0.31	0.28
2010	0.36	0.33	0.30
2015	0.38	0.35	0.32
2020	0.40	0.37	0.34

[1]Wind classes 6, 5 and 4 correspond to classes 1, 2 and 3 in NEMS, respectively. See Table 1a for wind class definitions.

Source: westech input file

Calculations and Outputs

The Wind Energy Submodule (WES)

The WES both determines the potential wind resource and tracks the remaining wind resource as capacity is built. In addition, the WES calculates all wind-specific regionally varying components affecting the cost of wind generation, specifically the capacity factor and the transmission and distribution (T&D) adder. The WES also supplies capital cost multipliers for wind each year to the EMM that are based on the available resource, according to both national and regional supply curves. This section describes each of these functions.

A primary role of the WES is to tabulate the available wind capacity data for the EMM and track resource development. Available wind capacity for the current year is determined, by wind class and then buffer zone, such that all class 6 (buffer zone 1 first, then zone 2, then zone 3) resources are depleted before any class 5 or 4 resources are developed. Once the EMM builds new wind capacity, wind energy supplies are accordingly reduced in the WES.

Table 5. EMM Time Slices for Wind Capacity Factors

Time slice	Month	Time of day
1	June - September	7:00 - 18:00
2	June - September	5:00 - 7:00, 18:00 - 24:00
3	June - September	0:00 - 5:00
4	December - March	7:00 - 18:00
5	December - March	5:00 - 7:00, 18:00 - 24:00
6	December - March	0:00 - 5:00
7	April - May, October - November	7:00 - 18:00
8	April - May, October - November	5:00 - 7:00, 18:00 - 24:00
9	April - May, October - November	0:00 - 5:00

Source: weslice input file

The WES also calculates regional, time-dependent capacity factors based on national capacity factor inputs. These time-dependent capacity factors are based on what NEMS terms time slices, which divide the year into three seasonal and three hourly subperiods (Table 5). Each time slice is assigned an “energy fraction” multiplier that equals the fraction of the annual generation expected during that season and time-of-day category in a given region. The multipliers for all of the energy fraction time slices in a given region sum to 1.00. Each time slice is also assigned a “time fraction” multiplier that corresponds to the number of hours in each time period relative to the total hours in a year. The ratio of energy fraction to time fraction in each time slice, which is used as a capacity factor multiplier in NEMS, is listed by region in Table 6. The regional, time slice capacity factors calculated in the WES are the product of the national average capacity factor and the regional capacity factor multiplier:

$$\text{regional time slice capacity factor}_{r,y,c} = \text{national capacity factor}_{y,c} * \text{energy fraction}_r / \text{time fraction}_r$$

where r = region, y = year, and c = wind class.

This structure results in a total of nine time slice capacity factors for each wind class, region and year. The regional time slice capacity factors are then averaged to produce a single average capacity factor for each region, in each year, based on the best available wind class that can be developed that year. The averages of the time slice capacity factors for each region in the AEO99 Reference Case are summarized in Table 7.

Table 6. Capacity Factor Multiplier[1] by Time Slice[2] and Region

Region	Time Slice[2] 1	2	3	4	5	6	7	8	9	avg	min	max
ECAR	1.21	0.41	0.31	1.36	1.05	1.01	1.42	0.79	0.67	0.92	0.31	1.42
ERCOT	0.96	0.90	0.71	1.16	0.90	0.87	1.25	0.97	0.91	0.96	0.71	1.25
MAAC	0.76	0.49	0.56	1.39	1.22	1.26	1.21	0.91	1.00	0.98	0.49	1.39
MAIN	1.03	0.54	0.34	1.36	1.01	0.96	1.44	0.88	0.73	0.92	0.34	1.44
MAPP	1.07	0.51	0.51	1.18	0.95	0.96	1.44	0.96	0.90	0.94	0.51	1.44
NY	0.96	0.37	0.26	1.64	1.27	1.25	1.24	0.77	0.57	0.92	0.26	1.64
NE	1.04	0.51	0.43	1.33	1.04	1.03	1.37	0.87	0.81	0.94	0.43	1.37
FL	0.73	0.65	0.59	1.32	1.10	1.12	1.21	1.06	1.00	0.97	0.59	1.32
STV	1.25	0.55	0.43	1.52	0.86	0.87	1.40	0.67	0.59	0.90	0.43	1.52
SPP	0.96	0.90	0.71	1.16	0.90	0.87	1.25	0.97	0.91	0.96	0.71	1.25
NWP	0.95	0.58	0.44	1.35	1.14	1.14	1.27	0.87	0.79	0.95	0.44	1.35
RA	1.04	0.63	0.56	1.34	0.92	0.99	1.32	0.84	0.87	0.94	0.56	1.34
CNV	1.13	1.81	1.56	0.64	0.70	0.61	0.74	1.05	0.94	1.02	0.61	1.81

[1]The capacity factor multiplier is used to derive a specific capacity factor from the average capacity factor (by wind class) for each of the nine time slices. The capacity factor multiplier equals the energy fraction[3] divided by the time fraction for each time slice.

[2]Time Slice Definitions:

Slice	Months	Hours	Num Hours	Num Months	percent of year
1	June-Sept	7:00-18:00	11	4	15%
2	June-Sept	5:00-7:00,18:00-24:00	8	4	11%
3	June-Sept	0:00-5:00	5	4	7%
4	Dec-March	7:00-18:00	11	4	15%
5	Dec-March	5:00-7:00,18:00-24:00	8	4	11%
6	Dec-March	0:00-5:00	5	4	7%
7	April-May,Oct-Nov	7:00-18:00	11	4	15%
8	April-May,Oct-Nov	5:00-7:00,18:00-24:00	8	4	11%
9	April-May,Oct-Nov	0:00-5:00	5	4	7%

[3]The energy fraction multiplier equals the fraction of the annual generation expected during that season and time slice, defined as follows:

Region	Time Slice 1	2	3	4	5	6	7	8	9	SUM
ECAR	0.19	0.05	0.02	0.21	0.12	0.07	0.22	0.09	0.05	1.00
ERCOT	0.15	0.10	0.05	0.18	0.10	0.06	0.19	0.11	0.06	1.00
MAAC	0.12	0.06	0.04	0.21	0.14	0.09	0.19	0.10	0.07	1.00
MAIN	0.16	0.06	0.02	0.21	0.11	0.07	0.22	0.10	0.05	1.00
MAPP	0.16	0.06	0.04	0.18	0.11	0.07	0.22	0.11	0.06	1.00
NY	0.15	0.04	0.02	0.25	0.14	0.09	0.19	0.09	0.04	1.00
NE	0.16	0.06	0.03	0.20	0.12	0.07	0.21	0.10	0.06	1.00
FL	0.11	0.07	0.04	0.20	0.12	0.08	0.19	0.12	0.07	1.00
STV	0.19	0.06	0.03	0.23	0.10	0.06	0.22	0.08	0.04	1.00
SPP	0.15	0.10	0.05	0.18	0.10	0.06	0.19	0.11	0.06	1.00
NWP	0.15	0.07	0.03	0.21	0.13	0.08	0.20	0.10	0.06	1.00
RA	0.16	0.07	0.04	0.20	0.10	0.07	0.20	0.09	0.06	1.00
CNV	0.17	0.20	0.11	0.10	0.08	0.04	0.11	0.12	0.07	1.00

Table 7. Wind Average Regional Capacity Factors[1]

AEO99 REFERENCE CASE

Region	1995	2000	2005	2010	2015	2020
ECAR	0.26	0.29	0.31	0.33	0.35	0.37
ERCOT	0.23	0.26	0.28	0.30	0.32	0.34
MAAC	0.23	0.26	0.28	0.30	0.32	0.34
MAIN	0.23	0.26	0.27	0.29	0.31	0.33
MAPP	0.26	0.29	0.31	0.33	0.35	0.37
NPCC/NY	0.26	0.29	0.30	0.32	0.34	0.36
NPCC/NE	0.29	0.31	0.33	0.35	0.37	0.39
SERC/FL	0.23	0.26	0.28	0.30	0.32	0.34
SERC/STV	0.29	0.32	0.34	0.36	0.38	0.37
SPP	0.23	0.26	0.28	0.30	0.32	0.34
WSCC/NWP	0.29	0.31	0.33	0.35	0.37	0.39
WSCC/RA	0.29	0.32	0.34	0.36	0.37	0.39
WSCC/CNV	0.29	0.31	0.33	0.35	0.37	0.39

[1]The NEMS Renewable Fuels Module (RFM) estimates a wind capacity factor for each of nine separate time-of-year sl
A time-of-year slice is defined by one of 3 time-of-day periods and one of 3 month-of-year periods (3 x 3 = 9 slices)
The average regional capacity factor represents the average of these values, weighted by the amount of time in ea

Because transmission and distribution from remote wind sites represent an additional cost important to wind, the WES is also responsible for determining a wind-specific transmission cost adder. This value is taken directly from the *westech* input file and varies both regionally and by buffer zone. The transmission cost adder for each region is shown by buffer zone in Table 8. This value can increase the overnight capital cost of wind by up to 10 percent.

Table 8. Transmission Extension Costs[1] by Region and Buffer Zone[2]

Region	Transmission and Distribution Adder (1997$/kW) Buffer Zone 1 0 - 5 Miles	Buffer Zone 2 5 - 10 Miles	Buffer Zone 3 10 - 20 Miles
ECAR	10.9	32.6	65.3
ERCOT	11.0	33.0	66.1
MAAC	14.8	44.3	88.7
MAIN	10.2	30.6	61.3
MAPP	10.5	31.4	62.9
NY	12.1	36.3	72.5
NE	11.7	35.1	70.1
FL	8.3	25.0	50.0
STV	13.4	40.3	80.6
SPP	13.0	39.1	78.2
NWP	11.6	34.7	69.3
RA	8.5	25.4	50.8
CNV	14.5	43.5	87.0

[1]This tranmission extension cost is added to the capital cost of wind. It is speci
to wind, and additional to the standard T&D cost applied to all technologie
[2]In NEMS, buffer zone refers to the distance from transmission lines.

Source: westech input file

Finally, in each forecast year, the WES selects the appropriate set of short- and long-term supply curve multipliers that are applied to the capital cost of wind (referred to as elasticities in NEMS), based on the current installed capacity by region. These values are passed to the EMM where they are used in creating three supply steps. The short-term supply constraints are applied nationally and represent manufacturing, siting and construction limitations to rapid expansion relative to existing capacity. The short-term wind capital cost multipliers are designed to increase the capital cost by 1 percent for every 1 percent ordered that exceeds 20 percent of the prior year's installed wind capacity. Because there is a three-year construction period, this penalty occurs much more readily than if the cost were applied when the annual growth rate was higher than 20 percent.While this was EIA's intent, the implementation in NEMS diverges from this description and the penalty is effectively much larger than 1 percent for each 1 percent in orders above 20 percent. The linear program used for capacity expansion decisions in NEMS uses only three supply steps which are defined by the 20 percent and a maximum order amount, set at 300 percent in the AEO99 Reference Case. The first step, which has no cost penalty, is the size of 20 percent of last year's capacity. The second step is equal to half way between the 20 percent and 300 percent, or 140 percent of capacity. Within this step, the average increase in installations above 20 percent is 70 percent, so the cost penalty associated with this step is assumed to be 70 percent (in keeping with the concept of a 1 percent increase in cost for every 1 percent in orders greater than 20 percent of existing installations). While mechanically sound, this means that the first time the orders exceed 20 percent of the installations in place in the previous year, the capital cost of wind increases by 70 percent. This cost increase effectively eliminates any further wind development in that year.[3]

The long-term cost multipliers are applied regionally and are based primarily on assumptions about local resource development. These supply constraints account for any site-specific considerations that increase wind plant development costs other than average annual wind speed and interconnection distance, including (1) all other natural resource limitations, such as slope or icing, (2) costs of upgrading the existing transmission and distribution network, and (3) all market constraints, such as environmental, cultural and alternative land use issues. The reasoning behind the increase in cost is that the best sites would be used first within a region and successive sites would be more expensive. The cost multipliers may also reflect a perceived uncertainty associated with the PNNL wind resource estimates. EIA uses the California and Northwest estimates as the basis for distributing wind resources for other regions.[4] The regional supply multipliers are composed of five different steps, determined by the fraction of the wind resource that has been depleted (Table 9). In successive steps, the capital cost of wind is increased by 20 percent, 50 percent, 100 percent and 200 percent. In each forecast year, the applicable multiplier associated with current resource depletion is passed to the ECP and added to each of the short-term multiplier steps. While the multiplier associated with each step is uniform across regions, the capacity development at which they are applied varies. The regions with the most wind potential (i.e., MAPP and SPP) have the steepest steps.

[3]The maximum order amount has been reduced to 100 percent in the AEO2000 in order to reduce the step size and decrease the cost penalty of the initial step. In addition, the share of capacity that can be ordered at no additional cost was increased to 30 percent and the cost penalty was reduced to 0.5 percent.

[4]For AEO2000, EIA has increased the proportions of total wind resources in the lowest cost categories for the CNV and ERCOT regions.

Table 9. Wind Long-term Supply Curve Specification[1] by Share of Regional Wind Potential

AEO99 REFERENCE CASE

Region	Regional Supply Curve Specification														
	STEP 1			STEP 2			STEP 3			STEP 4			STEP 5		
	cap cost	resource threshold[3]		cap cost	resource threshold[3]		cap cost	resource threshold[3]		cap cost	resource threshold[3]		cap cost	resource threshold[3]	
	multiplier	%	GW	multiplier	%	GW	multiplier	%	GW	multiplier	%	GW	multiplier	%	GW
ECAR	1.0	0%	0	1.2	10%	0.4	1.5	20%	0.8	2.0	30%	1.2	3.0	40%	1.6
ERCOT	1.0	0%	0	1.2	15%	1.5	1.5	25%	2.6	2.0	48%	4.9	3.0	93%	9.6
MAAC	1.0	0%	0	1.2	10%	1.0	1.5	20%	1.9	2.0	30%	2.9	3.0	40%	3.8
MAIN*	1.0	0%	0	1.0	40%	0.0	1.0	50%	0.0	1.0	60%	0.0	1.0	70%	0.0
MAPP	1.0	0%	0	1.2	1%	7.3	1.5	2%	21.9	2.0	5%	65.8	3.0	8%	109.6
NY	1.0	0%	0	1.2	10%	0.4	1.5	20%	0.7	2.0	40%	1.4	3.0	60%	2.1
NE	1.0	0%	0	1.2	10%	0.9	1.5	20%	1.8	2.0	40%	3.7	3.0	60%	5.5
FL*	1.0	0%	0	1.0	10%	0.0	1.0	20%	0.0	1.0	30%	0.0	1.0	50%	0.0
STV	1.0	0%	0	1.2	10%	0.2	1.5	20%	0.4	2.0	40%	0.7	3.0	60%	1.1
SPP	1.0	0%	0	1.2	1%	2.5	1.5	2%	7.4	2.0	5%	22.3	3.0	8%	37.2
NWP	1.0	0%	0	1.2	3%	7.9	1.5	7%	21.4	2.0	10%	30.3	3.0	10%	31.9
RA	1.0	0%	0	1.2	2%	4.1	1.5	4%	8.2	2.0	8%	16.4	3.0	18%	36.9
CNV	1.0	0%	0	1.2	12%	2.5	1.5	16%	3.2	2.0	19%	3.9	3.0	23%	4.7
total	-	-	0	-	-	29	-	-	70	-	-	153	-	-	244

[1]In a given year, the regional supply constraint multiplier is applied to the effective capital cost of wind.[2] The appropriate capital cost multiplier is dependent on the amount of existing wind capacity in a given region relative to the total available wind resource in that region. The capital cost multiplier for step N is used if the ratio of existing regional capacity to regional renewable potential is greater than the resource threshold for step N, but less than the resource threshold for step N+1.

[2]The effective capital cost of wind is the overnight capital cost of wind (exogenous) modified by learning curve multiplier and generic regional cost multipliers.

*Capital cost multiplier in regions 4 and 8 always equals 1.0 because there is no wind resource in those regions.

[3]Resource threshold is expressed as a percentage of total wind resource in a given region and in absolute capacity values.

Although implemented at the regional level, the severity of these multipliers is most easily seen at the national level. These steps are structured such that only 1.5 percent of the total national potential wind resource in NEMS is available in the first block (no cost multiplier), 1.6 percent in the second block (20 percent cost multiplier), and 3.3 percent in the third block (50 percent cost multiplier). The remainder, 3.5 percent in the fourth block (100 percent cost multiplier) and over 90 percent in the last block (200 percent cost multiplier), is allocated such that capital cost essentially eliminates this resource from potential development.

The Electricity Market Module

The EMM determines new capacity addition projections based on capacity, performance and cost data by region for each technology. The factors that are evaluated to determine the market share allocated to wind include general cost and performance values (supplied by the ECP), regional capacity factor values and available capacity (both supplied by the WES).

Table 10. Factors Affecting Capital Cost[1]

Variable	Value for Wind	Source
Regional Multipliers	varies: 0.86 to 1.12	EIA Internal Review[2]
Elevation Multiplier	1.0	EIA Internal Review
Project Contingency Multiplier	1.073	EIA Internal Review
Optimism Factor	1.0	EIA Internal Review
Learning Curve Multiplier	starts at 1.434 (in 1995) reaches 1.0 in 2000 0.925 in 2020 (Case 0) or 0.62 in 2020 (Case 123458)	EIA Internal Review
Regional Long-Term Supply Multipliers	5 steps: costs increase by 20%, 50%, 100%, 200%	Argonne National Laboratory
National Short-Term Supply Multipliers	1% for every 1% capacity addition that exceeds 20% of the previous year's total installed capacity	EIA Internal Review

[1] Values listed are for wind, although these multipliers also exist for other technologies.

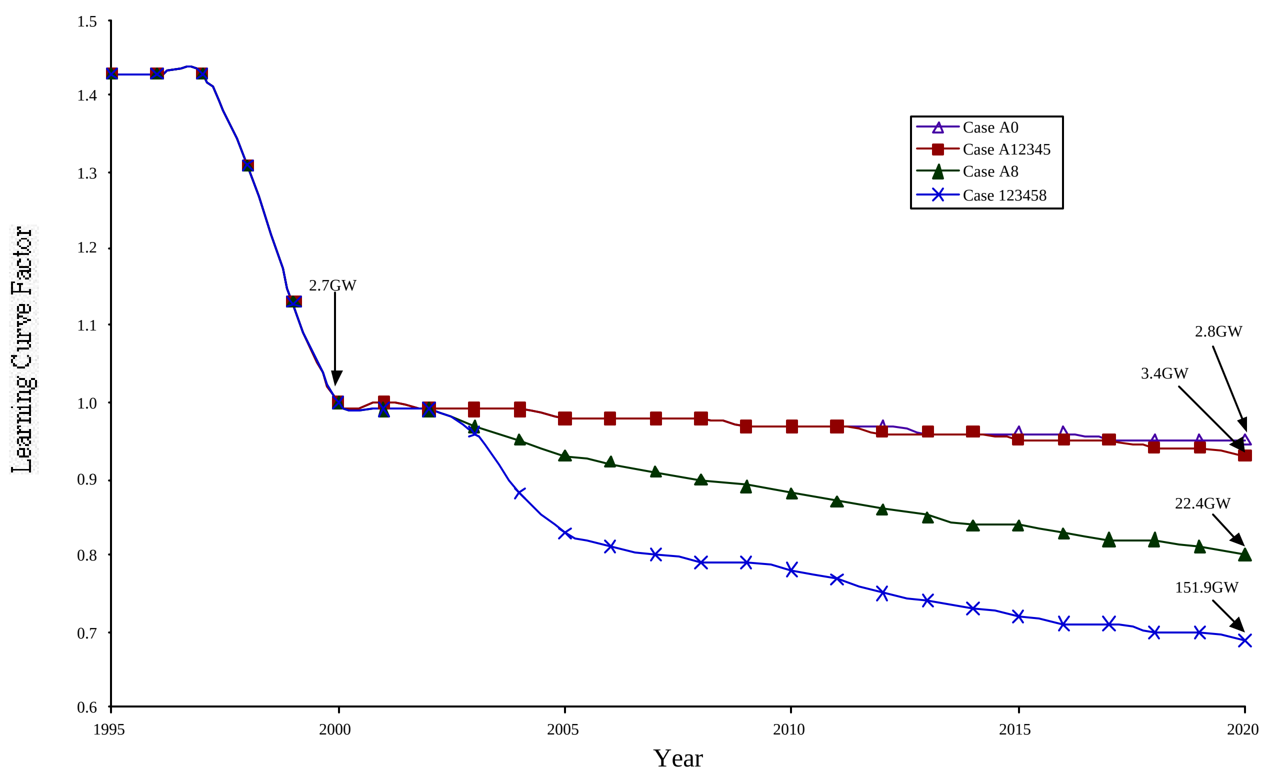
[2] Based on discussions with industry, government and national laboratory sources.

Source: ecpdat and westech input files

The ECP provides the EMM with nationally consistent cost data for wind. As with all generation technologies, the input values for these variables are then modified by optimism (always 1.0 for wind because it is a conventional technology), learning and other multipliers. Table 10 details many of the key multipliers that are applied to the capital cost of wind as a result of model calculations. With the exception of the short- and long-term supply curves, these multipliers are not addressed in any detail here. It should also be noted that these multipliers are applied to all technologies, although the values listed in Table 10 are unique to wind. The learning curve for wind in NEMS is applied nationally and is based on both domestic and, indirectly, international wind development. Capital costs are assumed to be reduced by 8 percent for each doubling of capacity from the first to the fifth unit and then decrease by 5 percent for each doubling thereafter. [1, 2] Figure 3 tracks the learning curve multiplier over time in the AEO99 Reference Case and in several of the sensitivity analysis cases. In the AEO99 Reference Case, the learning curve multiplier is greater than 1.00 during the early years (starting at 1.43 in 1990), drops fairly quickly to 1.00 by the year 2000, and then slowly flattens to 0.92 by the year 2020. This scaling is in keeping with the fact that the input values in the *ecpdat* file – as well as those reported in the AEO99 documentation – are fifth-of-a-kind costs. Thus, in the Reference Case, wind's capital cost in 1990 is actually 143 percent higher than the *ecpdat* input value and by 2020 the capital cost of wind is only 92 percent of the input value. In a case in which all constraints and multipliers have been removed and the overnight capital cost has been reduced by half (Case 123458), resulting in 152 GW of installed wind capacity by 2020, the learning multiplier reaches 0.62, a 38 percent decrease in capital cost from the input value.

Figure 3. Wind Learning Curve Factors through Time

WITH TOTAL INSTALLED CAPACITY NOTED IN 2000 AND 2020



[1]One unit of wind is a 50 MW wind plant.

[2]U.S. Department of Energy, Energy Information Administration, *Assumptions to the Annual Energy Outlook 1999*, December 1998.

Although the cost of wind is decreasing over time as a result of learning, the construction lead-time for wind causes NEMS to use the cost of wind in one year to determine what is ready for operation three years later. This time-lag may slightly disadvantage wind because the majority of its construction delay is attributable more to siting and permitting than turbine construction, which actually happens later in the process. This situation is in contrast to more traditional technologies where plant construction can begin more immediately and, therefore, costs are more justifiably based on the year the plant is ordered. The construction lead time effectively discounts the cost reduction attributed to learning.

Along with the general cost and performance inputs, the *ecpdat* input file also provides a regional multiplier, based on labor and equipment costs, to the EMM, where it is applied to the capital cost. Every technology in NEMS is subject to this regional multiplier, although the multiplier does vary by technology. For example, the regional multiplier for wind in the MAPP region is 1.01 while for wind in the CNV region it is 1.07. As a result, the ratio of the costs for wind in the two regions is generally 1.059. The capital costs, excluding the short-term cost multipliers, are output in the EMMREPT report, along with the values for the various regional and national multipliers. Table 11 shows the costs for a subset of scenarios (explored later in this report) for MAPP and CNV as well as the value of the long-term cost multiplier in CNV. The cost declines over time in these cases are due to the learning multiplier. In the permit cases, when more wind capacity is built, the cost declines are greater due to increased learning. Some of the sensitivity cases discussed later also illustrate the impact of the long-term resource cost multipliers.

Table 11. Wind Capital Costs (1997$/kW)

EXCLUDING SHORT-TERM COST MULTIPLIERS

	2000	*2005*	*2010*	*2015*	*2020*
MAPP Region					
Reference 0	785	753	742	735	726
Permit 0	785	752	723	681	649
Permit 1	785	752	723	681	649
Permit 2	785	752	723	645	598
Permit 5	785	751	714	603	545
CNV Region					
Reference 0	832	797	786	778	769
Permit 0	832	797	766	866	825
Permit 1	832	797	766	721	688
Permit 2	832	797	765	683	634
Permit 5	832	796	757	639	577
Long-Term Cost Multiplier in CNV					
Reference 0	1.00	1.00	1.00	1.00	1.00
Permit 0	1.00	1.00	1.00	1.20	1.20
Permit 1	1.00	1.00	1.00	1.00	1.00
Permit 2	1.00	1.00	1.00	1.00	1.00
Permit 5	1.00	1.00	1.00	1.00	1.00

Table 12. Wind Regional Effective Load-Carrying Capability[1, 2]
AEO99 REFERENCE CASE

Region	1995	2000	2005	2010	2015	2020
ECAR	0.24	0.26	0.28	0.30	0.31	0.33
ERCOT	0.17	0.18	0.20	0.21	0.23	0.24
MAAC	0.13	0.15	0.16	0.17	0.18	0.19
MAIN	0.18	0.20	0.21	0.23	0.24	0.26
MAPP	0.21	0.23	0.24	0.26	0.28	0.29
NPCC/NY	0.19	0.21	0.22	0.23	0.25	0.26
NPCC/NE	0.23	0.25	0.26	0.28	0.29	0.31
SERC/FL	0.13	0.14	0.15	0.16	0.17	0.18
SERC/STV	0.27	0.30	0.31	0.33	0.35	0.34
SPP	0.17	0.18	0.20	0.21	0.23	0.24
WSCC/NWP	0.25	0.27	0.29	0.30	0.32	0.34
WSCC/RA	0.23	0.25	0.26	0.28	0.29	0.31
WSCC/CNV	0.25	0.27	0.28	0.30	0.32	0.34

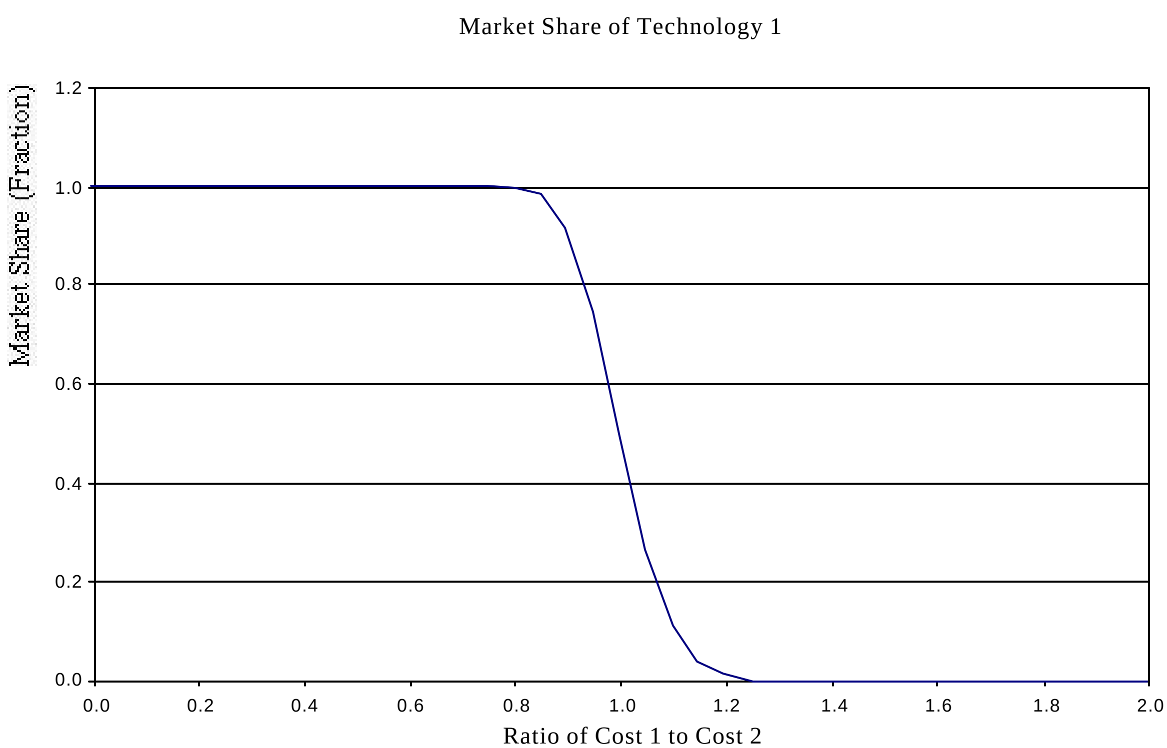
[1]Effective Load-Carrying Capability (ELCC) represents the reliability benefit from an intermittent resource, expressed as kW of effective load-carrying capability per kW of installed capacity.
[2]ELCC equals 75% of the capacity factor of a region at the peak time period (always time slice 1).

Another function of the EMM is to assess a capacity credit for each technology based at least partially on its reliability as a peak energy resource. The effective load-carrying capability of wind as an intermittent generation source is determined in NEMS by a scaling factor called the Load Capacity Credit (LCC). This capacity credit determines the amount of duplicate capacity that must be built to guarantee power for potentially unserviced load that could result from the intermittency of the wind resource. The additional capacity serves as reserve to be used when the wind resource is unavailable. The EMM assesses an LCC that is equal to 75 percent of the capacity factor of the peak time period in that wind region and class. This LCC means, for example, that for a 33 percent peak capacity factor, the effective load-carrying capability would be 0.33 x 0.75 kW/kW installed, or 0.25 kW/kW installed. This devaluation of the capacity credit of wind significantly reduces the economic competitiveness of this technology in NEMS. Table 12 contains the average regional effective load-carrying capabilities in five-year steps. The capacity values in each region increase over time, from a low of 0.14 in 2000 to as high as 0.34 in 2020.

Also incorporated in the EMM are two constants that function as upward bounds on regional wind power development in a given year. The first of these regional bounds, the intermittency generation limit, is designed to limit the contribution of intermittent renewable energy technologies (solar, wind and photovoltaics (PV) only) to 10 percent of total generation in a region. This constraint is imposed due to concerns about system reliability and availability of these intermittent technologies. While the fraction of intermittent power allowed in a region has been limited in previous versions of NEMS, the former bound was 1.5 percent of peak power. The option to apply the limit to peak, capacity, or generation, or to switch it off, is a new feature of the AEO99 version of NEMS. The second regional bound, a maximum annual deployment constraint, prevents more than 1 GW of capacity additions in any one year in any region. This constraint appears to be an older version of the short-term elasticity concept, but it is still active.

The EMM employs a two-step process when determining market shares for individual energy technologies. In each year, a linear programming (LP) optimization is performed first, where the future cost of the electricity supply over the planning horizon is minimized based on expected future electricity demands, the cost of alternative technologies and expected future energy prices, subject to a variety of conditions. Next, the technology-specific deployment decision is modified by an algorithm that gives some share to technologies that were close to being least-cost but were not selected in the optimization. Figure 4 shows an example of the effect of this market sharing for a case in which there are just two technologies. As is evident from the curve, the fraction of the market allocated to technologies that are not the least-cost option quickly becomes insignificant, the farther these options are from the most competitive. This market sharing approach prevents "knife-edge" solutions, and makes the effects of constraints less distinct. The market sharing does not substantially change the market fraction selected by the LP for each technology, but does allow slightly more expensive nascent technologies to gain some share. In the AEO99 Reference Case, most of the endogenous market share for renewables is provided by this algorithm. In the Permit 0 case, sharing results in more installed wind capacity during the early years (prior to 2006) and less in later years, for an overall reduction in capacity of about 8 percent, or 1.1.GW, over the forecast period.

Figure 4. Example of Market Sharing



SENSITIVITY ANALYSIS

We tested the sensitivity of the model to many of these parameters by varying the same assumptions in three sets of runs: scenarios based on the Reference Case minus planned additions, scenarios with a half capital cost minus planned additions, and scenarios with a $100/ton carbon permit price including planned additions. Table 13 lists the different parameters that were tested under the various scenarios.

In each of the reference-based cases in which a constraint or multiplier was relaxed individually, wind capacity additions increase only slightly, if at all. More significant effects of the constraints are demonstrated when multiple constraints are removed simultaneously, or when individual constraints are removed combined with a reduced capital cost or a $100/ton carbon permit price. The results of these scenarios are described in detail below.

Table 13. Variables Modified for Sensitivity Analysis

Scenario number	Scenario Name	Variables Modified: Variable	New Value	Reference Value
0	No Planned Additions[1]	Planned Additions PLNTDAF input file	0 MW	707 MW
1	Regional Supply Curves	Long-term Elasticity RENDAT input file	1.0 for all steps[2]	1.0 - 3.0 (5 steps)
2	National Supply Curve	Short-term Elasticity RENDAT input file	1% per 100% addition[3]	1% per 1% addition induced at 20% of previous year's capacity
3	Maximum Annual Deployment Limit	Upper Bound WESAREA input file	10 GW	1 GW
4a 4c	Capacity Credit	Load Capacity Credit CREDIT	1.00 1.25	0.75 0.75
5	Intermittent Generation Limit	Intermittent Upward Bound UPINTBND	1.00	0.10
6	Inter-regional Transmission	Code change/regional variables ECPDAT input file	allowed	not allowed
7	Learning-by-Doing	Learning Curve UPLRNCR	1.00	1.43 - 0.92
8	Capital Cost	Overnight Capital Cost UPOVR	$270/kW[4]	$540/kW[4]

[1]For all Permit cases, planned additions were included.
[2]In the Permit cases, this constraint was relaxed by increasing the step thresholds to 0.9, 0.96, 0.98 and 0.99 instead of the resource-based values shown in Table 9.
[3]In the Permit cases, the penalty remained 1% per 1% addition but the threshold was changed to when builds exceed 300% of the previous year's capacity.
[4]Values are in 1987$.

Reference Case and Sensitivities

In the AEO99 Reference Case, 0.8 GW of wind energy are added between 2000 and 2020, of which less than 100 MW are from unplanned additions. Unplanned additions refer to the capacity that is selected for development by the model logic and therefore are of greatest interest in this analysis. To eliminate any confusion about the effects of our changes, we ran a new reference case (Case 0) without the planned additions for wind from 2000 to 2020. In this case, only 15 MW of wind are added between 2000 and 2020. The model-derived capacity additions are less than in the Reference Case because the planned additions were contributing to learning and therefore were reducing future capital costs. The capacity additions that result from each of the simulations in which constraints were relaxed, also run without planned additions, are shown in Table 14. The first half of Table 14 gives the actual capacity additions while the second half shows these additions indexed to Case 0.

To test the effects of the various assumptions on Case 0, scenarios were run in which five factors were changed individually. These runs included removing the long- and short-term supply curve multipliers entirely (Cases 1 and 2),[3] increasing the 1 GW annual deployment limit (Case 3), raising the capacity credit (Cases 4a and 4c),[4] and eliminating the intermittent generation limit (Case 5). While installed wind capacity is somewhat affected, the changes are not significant in any of the cases because, in Case 0, wind does not penetrate into the electric-generation mix enough to be affected by these assumptions.

A sixth simulation (Case 7) was run to test the effect of the learning curve on projected wind additions. In this scenario, the learning-by-doing multiplier found in the EMM was set equal to 1.00 in all years. Surprisingly, this adjustment had a slight but positive effect on installed capacity in comparison to Case 0. Because the learning curve in NEMS is structured so that the input cost is the fifth-of-a-kind and the multiplier to the capital cost is greater than 1.00 prior to the year 2000, our method for eliminating the learning curve multiplier actually lowers the capital cost in the short term. Substantially more effort would be required to attempt short circuiting the curve midway through the forecast, although the results would more clearly illustrate the effects of learning-by-doing if the multiplier was only eliminated starting in 2000.

Scenario Combination

The results of a run in which each of these constraints (with the exception of the learning multiplier) were removed in the same scenario (Case 12345) are also shown in Table 14. In this case, installed wind capacity was up 21 percent to 3.42 GW by 2020. This total is only slightly higher than that in Case 4c, implying that in Case 0, the 0.75 capacity credit is the main factor influencing wind development.

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[3]These were also removed together in Case 12.

[4]In two separate cases, the capacity credit was raised to 100 percent (Case 4a) and 125 percent (Case 4c). See Lilienthal (1990) for a discussion about the potential capacity value of wind if peak loads and output are well matched.

Table 14. Total Installed Wind Capacity through Time (GW)[1]
REFERENCE CASE MINUS PLANNED ADDITIONS SCENARIOS

		2000	2005	2010	2015	2020
0	reference case minus planned additions	2.68	2.68	2.68	2.69	2.83
1	negated long-term supply curves (regional)	2.68	2.68	2.68	2.69	2.85
2	negated short-term supply curve (national)	2.68	2.68	2.68	2.69	2.95
12	negated long- and short-term supply curves	2.68	2.68	2.68	2.70	2.97
3	negated regional deployment limit	2.68	2.68	2.68	2.69	2.84
4a	raised CC scaling factor (1.0)	2.68	2.68	2.68	2.75	3.00
4c	raised CC scaling factor (1.25)	2.68	2.68	2.70	2.88	3.41
5	raised intermittent generation limit (1.0)	2.68	2.68	2.68	2.69	2.83
7	negated learning by doing	2.68	2.68	2.68	2.70	2.90
12345	1, 2, 3, 4c, 5	2.68	2.68	2.70	2.89	3.42
8	lowered capital cost by 50%	2.70	4.44	7.70	13.39	22.43
Indexed Capacity (case 0 capacity = 1.0)						
0	reference case minus planned additions	1.00	1.00	1.00	1.00	1.00
1	negated long-term supply curves (regional)	1.00	1.00	1.00	1.00	1.01
2	negated short-term supply curve (national)	1.00	1.00	1.00	1.00	1.04
12	negated long- and short-term supply curves	1.00	1.00	1.00	1.00	1.05
3	negated regional deployment limit	1.00	1.00	1.00	1.00	1.00
4a	raised CC scaling factor (1.0)	1.00	1.00	1.00	1.02	1.06
4c	raised CC scaling factor (1.25)	1.00	1.00	1.01	1.07	1.20
5	raised intermittent generation limit (1.0)	1.00	1.00	1.00	1.00	1.00
7	negated learning by doing	1.00	1.00	1.00	1.00	1.02
12345	1, 2, 3, 4c, 5	1.00	1.00	1.01	1.07	1.21
8	lowered capital cost by 50%	1.01	1.66	2.87	4.98	7.93

[1]In all cases, all wind planned additions with online years after the year 1999 are removed from the forecast (-700MW).

<u>Reduced Capital Cost Scenarios (Case 8)</u>

Because capital cost plays such a significant role in determining the cost of wind in NEMS, we ran a simulation (also without planned additions) with a reduced capital cost input value. The objective of the scenario was to determine the importance of other assumptions concerning wind development. When such an extreme case of reducing the overnight capital cost of wind in the input file by half (before learning-by-doing and other factors are assessed) is tested, wind energy experiences tremendous expansion, starting almost immediately. By 2020, approximately eight times the wind capacity, nearly 22.5 GW, is predicted to be developed in comparison to Case 0.

Reduced Capital Cost and Sensitivities

We then used the half capital cost to further test the effects of the assumptions about wind energy development. These results are presented in Table 15. Most dramatic of the individual effects was the response of the model to the national supply curve with this new capital cost (Case 82).

Table 15. Total Installed Wind Capacity through Time[1]

HALF CAPITAL COST MINUS PLANNED ADDITIONS SCENARIO

		2000	*2005*	*2010*	*2015*	*2020*
Installed Capacity						
81	8 and 1	2.70	4.46	7.74	13.19	22.01
82	8 and 2	2.71	8.31	15.61	30.62	46.74
812	8 and 12	2.71	7.38	16.76	32.85	52.36
83	8 and 3	2.70	4.47	7.84	13.68	22.80
84a	8 and 4a	2.74	4.60	7.71	13.38	23.25
84c	8 and 4c	2.74	4.67	7.84	13.67	24.03
85	8 and 5	2.70	4.47	7.83	14.27	24.62
87	8 and 7	2.81	4.99	8.32	13.86	21.94
123458	1, 2, 3, 4c, 5 and 8	2.74	18.96	38.05	97.79	151.90
Indexed Capacity (case 0 capacity = 1.0)						
81	8 and 1	1.01	1.66	2.89	4.90	7.78
82	8 and 2	1.01	3.10	5.82	11.38	16.52
812	8 and 12	1.01	2.75	6.25	12.21	18.50
83	8 and 3	1.01	1.67	2.93	5.09	8.06
84a	8 and 4a	1.02	1.72	2.88	4.97	8.22
84c	8 and 4c	1.02	1.74	2.93	5.08	8.49
85	8 and 5	1.01	1.67	2.92	5.30	8.70
87	8 and 7	1.05	1.86	3.10	5.15	7.75
123458	1, 2, 3, 4c, 5 and 8	1.02	7.07	14.20	36.35	53.67
Indexed Capacity (case 8 capacity = 1.0)						
8	lowered capital cost by 50%	1.00	1.00	1.00	1.00	1.00
81	8 and 1	1.00	1.00	1.01	0.99	0.98
82	8 and 2	1.00	1.87	2.03	2.29	2.08
812	8 and 12	1.00	1.66	2.18	2.45	2.33
83	8 and 3	1.00	1.01	1.02	1.02	1.02
84a	8 and 4a	1.01	1.04	1.00	1.00	1.04
84c	8 and 4c	1.01	1.05	1.02	1.02	1.07
85	8 and 5	1.00	1.01	1.02	1.07	1.10
87	8 and 7	1.04	1.12	1.08	1.04	0.98
123458	1, 2, 3, 4c, 5 and 8	1.01	4.27	4.94	7.30	6.77

[1]In all cases, all wind planned additions with online years after the year 1999 are removed from the forecast (-700MW).

Negating the national supply curve and assuming that there is no cost penalty of ordering large quantities of wind capacity resulted in a 110 percent increase in installed capacity over Case 8 – to more than 47 GW in 2020. Curiously, eliminating regional supply curves (Case 81) reduced the total capacity relative to the Case 8, by 6 percent; this result, however, may be an artifact of our methodology.[5] When both supply curves were eliminated (Case 812), installed capacity

[5]Our method of relaxing this constraint, which effectively eliminates the steps of the multiplier, changes the LP's market sharing allocation to wind.

increased by more than 145 percent. When the capital cost is reduced, the combined effect of removing the supply curves is greater than the sum of their individual effects.

As in Case 0, removing the maximum annual deployment limit alone (Case 83) had only a minimal effect on installed capacity. Raising the capacity credit scaling factor 1.0 (Case 84a) also resulted in a similarly small, 4 percent increase in capacity over Case 8, while raising the intermittency generation limit with the lower capital cost (Case 85) resulted in a 10 percent increase in installed capacity, relative to Case 8.

Finally, eliminating learning-by-doing (Case 87) does lower installed capacity slightly, by 2 percent in 2020. The effect of this multiplier, however, is probably dampened by the fact that it was turned off prior to the year 2000 in the scenario, making costs lower in the near term.

Scenario Combination

When all of these factors were removed in a single scenario (Case 123458), wind experienced tremendous expansion, reaching nearly 152 GW (over a 500 percent increase) by 2020. While illustrating that this combined effect is much greater than the sum of the individual effects, this high projection is not a reasonable one because of its extreme assumptions. The following carbon permit scenarios help further demonstrate the impact of multiple, overlapping constraints acting together when wind is economically competitive.

Carbon Permit Scenarios

We executed a similar set of scenarios while introducing a $100/ton carbon permit (Permit 0), roughly equivalent to the Kyoto 1990+24% case executed by EIA, to more completely examine the synergistic effects of these mulitpliers and constraints, as well as to examine some of the model interactions and results in greater detail. As previously stated, the purpose of removing various multipliers was to understand which assumptions are the most important in affecting projections. As a result, the scenarios discussed here are not intended to reflect best estimates or even necessarily represent reasonable projections.

In these scenarios, planned additions from AEO99 were kept intact, and once a constraint was removed, it remained inactivated in subsequent cases. Table 16 details the structure of these runs. Most importantly, we found in these cases that the effect of the individual constraints was damped compared with their combined effect. As multiple constraints were removed in a given run, the forecast wind capacity changed dramatically. An additional function of NEMS that was explored in this set of runs is the possibility of allowing inter-regional transmission. This concept is explained in detail below.

An alternative method for exploring the effects of individual assumptions is shown in the "X" cases. In these cases, only one constraint was activated and all others were relaxed. The effects

Table 16. Permit Scenarios Modifications

Case	Modification
Permit 0	$100/ton carbon permit
Permit 1	Permit 0 + relaxed long-term supply constraint by region
Permit 2	Permit 1 + removed national short-term supply constraint
Permit 3	Permit 2 + removed 1GW/year annual deployment limit
Permit 4	Permit 3 + capacity credit increased from 0.75 to 1.0
Permit 5	Permit 4 + removed regional 10% intermittent generation limit
Permit 6	Permit 5 + enabled inter-regional construction
Permit 1X	Permit 5 + default long-term supply constraint
Permit 2X	Permit 5 + short-term supply constraint with smaller steps

of the individual factors in the X cases are more profound than in the cases with multiple assumptions unaltered.

A summary for the national wind capacity projections across all of these cases is provided in Table 17. More detailed capacity and generation projections in these scenarios are shown in Table 18 for the carbon permit cases for the years 2015 and 2020. The projections for all the technology types are shown, so the impact of additional wind capacity can be seen on the rest of the electricity system. The regional capacity for wind is shown as well.

Table 17. Total Installed Wind Capacity (GW)
CARBON PERMIT SCENARIOS

	2000	*2005*	*2010*	*2015*	*2020*
Permit 0	2.80	3.35	4.84	8.85	15.42
Permit 1	2.80	3.35	4.81	8.71	15.62
Permit 2	2.80	3.37	5.79	20.59	45.72
Permit 3	2.80	3.37	9.89	42.72	62.52
Permit 4	2.80	3.44	11.96	48.11	64.16
Permit 5	2.80	3.44	11.91	58.57	168.30
Permit 6	2.80	3.35	6.28	52.42	214.40
Permit 1X	2.80	3.44	8.34	42.50	93.16
Permit 2X	2.80	3.31	4.88	11.12	34.29

$100/ton Carbon Permit (Permit 0)

Imposing a carbon permit price beginning in 2006 and linearly ramping it to $100/ton by 2010 leads to 15.4 GW of wind capacity by 2020. The comparable reference without any permit cost was 3.6 GW. In contrast, when the various physical and economic conditions that potentially affect wind development, as enumerated in Table 16, are ignored under the $100/ton carbon permit price (as in Permit 5), 168 GW of wind capacity are installed by 2020.

Table 18. Total Installed Capacity (GW) in $100/Ton Carbon Permit Scenarios by Technology and Region

	2015									2020								
	Permit 0	Permit 1	Permit 2	Permit 3	Permit 4	Permit 5	Permit 1X	Permit 2X	Permit 6	Permit 0	Permit 1	Permit 2	Permit 3	Permit 4	Permit 5	Permit 1X	Permit 2X	Permit 6
Electric Capacity by Technology																		
Non Renewable Technologies																		
Coal Steam	248.0	247.6	248.1	247.8	248.9	246.7	248.8	246.5	247.1	247.9	247.6	247.5	247.8	248.3	240.7	244.3	246.4	238.2
Other Fossil Steam	45.5	48.5	43.4	43.4	39.3	39.3	45.2	47.8	38.3	45.5	48.3	43.0	42.5	36.7	32.6	41.3	47.1	25.9
Combined Cycle	200.2	199.7	198.2	197.8	199.5	201.2	196.1	204.1	201.8	221.4	221.4	216.6	215.5	217.9	216.3	212.8	232.2	212.5
Combustion Turbine/Diesel	150.1	150.2	153.7	153.0	148.7	150.4	150.6	147.9	148.0	186.3	182.0	189.7	184.3	187.5	182.6	186.5	174.9	186.4
Nuclear Power	76.8	76.8	76.8	76.8	76.8	76.8	76.8	76.8	76.8	76.8	76.8	76.8	76.8	76.8	76.8	76.8	76.8	76.8
Pumped Storage	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Non-Renewable	742.1	744.3	741.7	740.3	734.7	735.9	739.0	744.6	733.5	799.4	797.6	795.1	788.4	788.7	770.5	783.2	798.9	761.3
Renewable Technologies																		
Conventional Hydropower	79.71	79.71	79.71	79.71	79.71	79.71	79.71	79.71	79.71	79.83	79.83	79.83	79.83	79.71	79.71	79.71	79.83	79.71
Geothermal	4.04	4.06	4.02	3.87	3.91	3.90	3.90	3.53	3.48	4.81	4.81	4.83	4.57	4.55	4.50	4.57	4.27	4.18
Municipal Solid Waste	4.17	4.17	4.17	4.17	4.17	4.17	4.17	4.01	4.01	4.27	4.27	4.27	4.27	4.27	4.27	4.27	4.09	4.09
Wood and Other Biomass	6.70	6.75	6.80	6.73	6.54	6.47	6.48	6.91	6.94	23.47	24.08	22.01	20.69	21.13	17.57	17.60	22.94	17.12
Solar Thermal	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52
Solar Photovoltaic	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64
Wind	8.85	8.71	20.59	42.72	48.11	58.57	42.50	11.12	52.42	15.42	15.62	45.72	62.52	64.16	168.30	93.16	34.29	214.40
Total Renewable	104.40	104.30	116.20	138.10	143.40	153.80	137.70	106.20	147.50	129.00	129.80	157.80	173.00	175.00	275.50	200.50	146.60	320.60
TOTAL	*846.5*	*848.6*	*857.9*	*878.4*	*878.1*	*889.7*	*876.7*	*850.8*	*881.0*	*928.4*	*927.4*	*952.9*	*961.4*	*963.7*	*1046.0*	*983.7*	*945.5*	*1081.9*
Wind Capacity by Region																		
ECAR	0.00	0.00	0.18	0.18	0.24	0.18	0.23	0.05	0.26	0.17	0.08	1.91	0.36	1.51	0.36	0.63	0.50	4.52
ERCOT	0.19	0.19	1.20	2.20	2.35	2.36	2.20	0.19	2.28	0.19	0.19	3.08	4.61	4.67	4.68	4.38	0.19	12.09
MAAC	0.00	0.00	0.06	2.32	2.65	2.16	0.68	0.03	0.06	0.00	0.00	3.35	7.47	7.39	7.40	3.77	0.03	4.80
MAIN	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	4.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	29.76
MAPP	0.70	0.70	2.72	5.90	5.67	7.34	7.26	0.71	9.45	1.19	0.72	6.10	6.19	6.19	25.82	23.78	0.71	25.89
NPCC/NY	0.01	0.01	0.09	0.07	0.08	0.08	0.08	0.02	0.03	0.01	0.01	1.81	0.25	1.77	1.71	0.39	0.02	1.35
NPCC/NE	0.27	0.27	0.70	0.42	1.37	1.55	1.56	0.31	0.49	0.27	0.27	1.74	3.67	2.52	2.43	2.18	0.31	4.60
SERC/FL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SERC/STV	0.19	0.19	0.43	0.43	0.48	0.48	0.32	0.31	0.32	0.26	0.58	1.07	0.97	1.07	1.08	0.59	0.31	1.16
SPP	0.00	0.00	1.27	7.27	11.21	10.69	4.17	0.05	2.54	0.01	0.01	5.24	13.52	13.54	56.12	12.92	0.05	40.18
WSCC/NWP	0.16	0.07	3.27	9.80	9.87	11.31	13.28	0.14	4.55	4.23	1.31	7.85	10.17	10.19	37.25	25.14	6.14	23.59
WSCC/RA	4.80	3.98	5.07	5.06	5.17	13.14	9.51	2.17	9.48	5.42	5.44	5.43	5.50	5.52	19.65	14.46	13.84	25.14
WSCC/CNV	2.51	3.29	5.59	9.04	8.99	9.25	3.19	7.11	18.95	3.65	6.99	8.11	9.77	9.74	11.78	4.91	12.17	41.29
TOTAL	*8.9*	*8.7*	*20.6*	*42.7*	*48.1*	*58.6*	*42.5*	*11.1*	*52.4*	*15.4*	*15.6*	*45.7*	*62.5*	*64.2*	*168.3*	*93.2*	*34.3*	*214.4*

Regional Supply Curves (Permit 1, Permit 1X)

In the Permit 1 and 1X cases, the regional multipliers, which increase costs according to the fraction of wind resource already developed, were essentially removed while still retaining the steps associated with the transmission buffer zones and wind classes.[1] In the Permit 1 case, there is slightly less wind capacity in 2015 and then slightly more in 2020, and the regional distribution is different compared to Permit 0. For example, there is more wind capacity in CNV and less in MAPP and NWP in 2020. This response indicates that the regional multipliers were constraining the growth in CNV. The capital costs in Table 17 confirm that the cost multiplier is 20 percent for CNV in Permit 0. The fact that the total national capacity does not change very much and the wind additions in other regions decline shows that something else, such as the short-term supply curve, is limiting the total.

The effect of the regional resource supply curves is more evident when these multipliers are used while all the other multipliers and constraints have been removed (Permit 1X). In this case, the total wind capacity in 2020 is reduced by 45 percent from 168 GW to 93 GW. Not surprisingly, the amount of wind resource assumed available at base cost in each region is an important assumption in projecting installed wind capacity.

National Supply Curve (Permit 2, Permit 2X)

The Permit 2 case confirms that the short-term supply curve was limiting wind additions in the Permit 1 case. In addition to removing the long-term supply curves, the short-term multipliers were minimized in the Permit 2 case.[2] The effect of relaxing this multiplier is significant, especially in the later years 2015 and 2020. Instead of 9 GW of wind in 2015 in Permit 0 and Permit 1, 21 GW are projected in Permit 2. Similarly, without the multiplier, 46 GW are projected in 2020 as compared to only 16 GW when the multiplier was active.

The effect of the national supply curve and its implementation can have a tremendous effect on otherwise high growth scenarios. When the multiplier is applied using the default step sizes in a case which otherwise has all the other multipliers and constraints removed, projected 2020 wind capacity is essentially the same as in Permit 0, compared to 168 GW with all removed. The penalty of ordering more than 20 percent of the previous year's capacity is so high that no more than that capacity is selected. When the step size, and therefore the penalty, is reduced by lowering the maximum order rate to 60 percent (from 300 percent) and all other constraints are

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[1]In these cases, the steps of the multiplier were preserved. The percent of capacity that could be built at the base cost was increased to 90 percent of the resource in a region. The costs were then stepped up by 20 percent. When 96 percent of the capacity was used the costs increased to 50 percent. For each of the last one percent steps, the costs increased further. These multipliers were kept at the high end for two reasons. The first is that because three resource steps are passed to the ECP, they need to have different costs. If not, the market sharing algorithm sees them as equivalent and will give all three some share if wind is close to being cost effective. The second reason is to help insure that the market sharing recognizes when the regional resource is almost used up.

[2]The percent of capacity that could be built in any year without a cost penalty was increased from 20 percent to 300 percent of existing capacity. The cost penalty was retained to ensure that the market sharing would see different costs for the three steps of wind supply. Otherwise it would give each of three steps the same share if wind is close to being cost effective.

removed (Permit 2X), projected wind capacity in 2020 is 34 GW. This reflects the LP choosing the full 60 percent each year beginning in 2012, although the actual share is slightly lower due to the market sharing.

Annual Regional Deployment Limits (Permit 3)

With the relatively rapid growth in wind capacity in the Permit 2 case, some regions were being affected by the limit of 1 GW of wind additions per year in any region. Relaxing this bound by allowing up to 10 GW of new capacity per year and adjusting the previous supply constraints, increases wind capacity as early as 2010 in the Permit 3 case. By 2020 wind capacity is projected to be 62.5 GW, which is 16.8 GW greater than in Permit 2. The upper bound appears to affect the timing of the deployment as well as simply capping the additions in a given year. The regions that gain in capacity vary over time. In 2010, RA and CNV both gain in capacity, while capacity in NWP declines slightly. In 2015, the increased capacity occurs in six regions. Interestingly, there are a few regions that add less wind without this constraint, especially New England in 2015 and ECAR and NY in 2020, compared to Permit 2. It is not clear why some regions add less wind capacity when this bound is raised.

Capacity Credit (Permit 4)

The Permit 4 scenario tests the implications of wind also being given credit for providing 100 percent of its derated capacity at peak (equal to the peak capacity factor times the nameplate capacity). In this scenario, wind capacity is projected to be 13 percent higher in 2015 and 3 percent higher in 2020 compared to Permit 3. In both years, more oil and gas steam plants are retired as a result of the increased capacity credit for wind, implying that these were previously providing value for reserve. The effect on combustion turbines is less clear. In some years and cases these increase and in some they decrease.

Regional Intermittent Generation Limit (Permit 5)

Finally, the 10 percent intermittent generation limit of the LP was also removed in Permit 5. In this scenario, wind capacity is projected to be 168 GW by 2020, more than double that in Permit 4. The largest gains are in MAPP, SPP and the three WSCC regions, as shown in Table 18.

In several regions the share of generation provided by intermittent capacity is very significant. By 2020 in the Permit 5 case, MAPP and SPP generate roughly 40 percent of their electricity from intermittent sources. This scenario is clearly a very optimistic and unrealistic one, but illustrates the importance of the various assumptions associated with making projections using NEMS.

Inter-regional Transmission (Permit 6)

The capacity expansion module of the EMM includes a feature that allows the construction of new capacity in one region to serve another region. In the AEO99 Reference Case, this option is incorporated only for coal plants that can be constructed in neighboring regions to sell into California. With continued deregulation, the construction of merchant plants that are not tied to a specific service territory will likely increase the amount of capacity that is built in one region and transmitted to another. For wind, this could mean that greater use of resources in areas of low demand growth would be feasible. In this sensitivity case, we have allowed coal, combined cycles and wind plants to also be constructed in neighboring regions. Additional transmission costs of 50 percent are included in the capital costs for the plants, and 5 percent additional transmission losses to transmit between regions are assumed.

With our first set of cases allowing inter-regional trade, we uncovered a problem with the way the model tracked the use of wind resources in a region when this option is used. Instead of decrementing the wind resource in the region where the wind capacity was being built, the model was attributing it to the region where the electricity was sold. This allowed it to overbuild in some regions, while constraining it needlessly in others. The cases shown here reflect the revised model code where the regional accounting has been changed.

When inter-regional transmission is allowed and the supply multipliers and other constraints have been relaxed, construction favors natural gas combined cycles through 2015 and wind capacity is slightly lower. By 2020, when gas prices and price expectations are higher and wind costs are lower due to greater learning, wind capacity increases from 168 GW to 214 GW. Table 19 compares wind capacity additions by region for the Permit 5 and Permit 6 cases. Additions are shown for both the region in which the wind resource is used and the region in which the capacity is constructed. The difference between these is not necessarily the amount built within a region for that region's use because a region may be both an importer and an exporter.

Table 19. Regional Wind Capacity Additions 1995-2020 (GW)

			Permit 6	
Region	Resource Base	Permit 5 Total	Built In Region	Built For Region
ECAR	4.0	0.4	2.4	4.5
ERCOT	10.3	4.5	8.9	11.9
MAAC	9.6	7.4	6.6	4.8
MAIN	0.0	0.0	0.0	29.7
MAPP	1461.5	25.1	62.2	25.2
NPCC/NY	3.5	1.7	1.8	1.3
NPCC/NE	9.2	2.2	3.5	4.3
SERC/Florida	0.0	0.0	0.0	0.0
SERC/STV	1.8	1.1	1.1	1.2
SPP	495.9	56.1	40.4	40.2
WSCC/NWP	315.4	37.2	58.1	23.6
WSCC/RA	204.9	19.6	23.7	25.1
WSCC/CNV	20.7	9.7	2.1	39.2
TOTAL	*2536.8*	*164.9*	*211.0*	*211.0*

Much more capacity is constructed in the west and in MAPP compared to Permit 5. The greatest inter-regional transmission is from MAPP to MAIN and from NWP to CNV. In fact, more wind capacity is built in NWP for CNV than is built within CNV, which is a bit surprising. However, CNV has the highest regional cost multiplier, and the additional transmission cost from NWP to CNV is not that much greater than the transmission cost assumed within CNV. As a result, in many years it appears to be slightly less expensive to build in NWP and transmit to CNV than to build there. This highlights the importance of the inter-regional transmission costs. For this case, it was simply assumed that the transmission costs would be 50 percent higher than the costs within the exporting region.

The intermittent generation limit appears to apply to the region in which the renewable capacity is constructed rather than the region where the generation is sold. Which region is more appropriate for the constraint depends on the view of whether the potential reliability problems with large portion of intermittents is due to voltage stability issues associated with injection of power into the grid or due to concerns about coincident outages that would leave customers without power. This issue would need to be addressed if inter-regional transmission is allowed.

Impacts on Installed Capacity of Other Technologies

In each of the various scenarios, the capacity of technologies other than wind is affected, although not always uniformly. However, as seen in Table 18, there is generally a very small impact on conventional capacity relative to the increases in wind capacity. For example, 2020 wind capacity increases by 104 GW between Permit 4 and Permit 5, yet non-wind capacity only declines by 22 GW. This response is due to the difference in capacity factors and capacity credits between wind and conventional capacity.

RECOMMENDATIONS

The effects of several of the assumptions examined in this report are quite significant in governing the deployment of wind capacity in NEMS and the results of the sensitivity analyses help rank the relative importance of these factors in terms of their impact on technology development. Based on our findings, we can recommend several areas in which to focus future work on the NEMS model itself as well as areas in which model input data may require revision. First, the relevance of each of the cost multipliers should be evaluated. Redundant factors may need to be revised or eliminated. For example, both the 1 GW maximum annual deployment limit and the short-term supply curve are designed to moderate growth. Both are probably not needed. However, in several of the permit and half capital cost cases, wind capacity increases at rates of up to 50 percent per year and in some regions and years provides up to 100 percent of new capacity additions. Under these conditions, it is not unreasonable to assume that wind development costs would increase. Because the growth multipliers are so influential, further research may be necessary to determine if the current penalties are the most appropriate. In addition, the number and size of the steps used in the LP may need to be reexamined, when an order exceeds 20 percent of current resources. [3]

Similarly, the long-term supply curves increase the overnight capital cost by 200 percent for over 90 percent of the nation's potential wind power, which significantly reduces the amount of wind power that can be economically developed. Only 1.5 percent of the potential wind resource in

[3]The maximum order amount has been reduced to 100 percent in the AEO2000 in order to reduce the step size and decrease the cost penalty of the initial step. In addition, the share of capacity that can be ordered at no additional cost was increased to 30 percent and the cost penalty was reduced to 0.5 percent.

NEMS is available without a long-term supply cost penalty. A different allocation of wind resource among the long-term supply constraint steps should be explored. In addition, the wind resource availability itself may need to be reexamined. For example, the California and Northwest studies which EIA has used to develop the regional cost multipliers in those regions show more wind resources than the current resource base in NEMS for these regions. [4] NREL is also working on updating the wind potential in several regions and is finding that there may be more resource than previously estimated.

While there is a legitimate concern about how much intermittent capacity a region can absorb without jeopardizing reliability, the absolute cutoff on intermittent generation at 10 percent of a region's total may not be the best approach. Ideally, it could be replaced with a more gradual cost penalty. For example, a reduction of the capacity credit of the plant may be a more appropriate mechanism to regulate this constraint. If this strategy is pursued, the percent of generation at which this constraint is currently invoked could also be reviewed. Current research suggests that intermittents may contribute in the range of 20–40 percent, and even up to 50 percent of generation (Grubb, 1998), without compromising the reliability of the power system, if loads are well matched.

It may also be appropriate to expand the option to permit inter-regional transmission for wind and other technologies, considering the probability that this practice will become more common under deregulation and the fact that this function has already been implemented for a limited case (coal in California). Including inter-regional transmission for wind would need to be part of a peer-reviewed process to evaluate transmission costs associated with such siting.

Of course, any structural or data inputs changes made regarding wind capacity should also be evaluated for application to other renewable technologies. Many of these technologies have the same or similar cost multipliers. Consistent treatment might lead to greater capacity for biomass or solar while reducing wind capacity in carbon permit scenarios. Further work could also extend the sensitivity cases to other generating technologies in NEMS, since most of the parameters examined are common to all technologies. A comprehensive analysis would also include the effects on wind of changes made to assumptions regarding other technologies.

CONCLUSIONS

A variety of assumptions are made in the AEO99 version of NEMS that represent potential economic and physical limitations to the growth in wind capacity. While these factors have little effect on the AEO99 Reference Case, they make a dramatic difference when wind is more attractive, such as under a carbon permit trading system. With $100/ton carbon permits, the wind capacity projection for 2020 ranges from 15 GW in the base case to 214 GW when all the multipliers and constraints examined in this study are removed.

The upper end of this range is not intended to be viewed as a reasonable projection, but its magnitude illustrates the importance of the parameters governing the growth of wind capacity

[4] For AEO2000, EIA has increased the proportions of total wind resources in the lowest cost categories for the CNV and ERCOT regions.

and resource availability. These findings suggest that future research should focus on the many uncertainties related to these parameters. To begin with, the interaction between the 1 GW regional deployment limit and the short-term cost multipliers may be exerting a larger effect on wind than intended, and the code may need to be modified to achieve the intended effect. The potential also exists for coding changes that would enable inter-regional transmission of electricity for wind and other technologies. In addition, the allocation of the national wind resource among the five steps of the long-term supply curves should be reviewed. It is important to insure that each step in the supply curve accurately represents the costs for wind development. Finally, the imposition of a graduated cost penalty should be explored when the intermittent fraction of regional generation exceeds a set amount (currently 10 percent), as opposed to the binary approach currently employed. Because some of the other renewable energy submodules are structured in a similar manner to the Wind Energy Submodule, many of these areas of suggested research could also be considered for other renewable technologies in NEMS.

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