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# Prices and Emissions in a Restructured Electricity Market

**Energy Modeling Forum**
**Stanford University**
**Stanford, CA 94305-4026**

# Preface

The Energy Modeling Forum (EMF) was established in 1976 at Stanford University to provide a structural framework within which energy experts, analysts, and policymakers could meet to improve their understanding of critical energy problems. The seventeenth EMF study, Prices and Emissions in a Restructured Electricity Market, was conducted by a working group comprised of leading international energy analysts and decisionmakers from government, private companies, universities, and research and consulting organizations. The EMF 17 working group met three times between January 1999 to June 2000 to discuss key issues and analyze the longer-run implications of restructured electricity markets.

This report summarizes the working group's discussions of the modeling results on U.S. electricity markets. Although international electricity markets were featured prominently in the presentations and discussions, the comparison of model results discussed in this report focuses on the United States. Inquiries about the study should be directed to the Energy Modeling Forum, 406 Terman Engineering Center, Stanford University, Stanford, California 94305, USA (telephone: (650) 723-0645; Fax: (650) 725-5362). Our web site address is: *http://www.stanford.edu/group/EMF*.

We would like to acknowledge Edith Leni and Susan Sweeney for their assistance in the production of this report.

# Contents

# List of Tables



# List of Figures

## Working Group Members

| | |
|---|---|
| Eirik Amundsen | University of Bergen, Norway |
| Ignacio Pérez Arriaga | Universidad Pontificia Comillas (Spain) |
| Hiroshi Asano | Central Research Inst for Electric Power Industry, Japan |
| Ross Baldick | University of Texas |
| Abha Bhargava | Canadian Energy Research Institute |
| Jacqueline Boucher | Electrabel, Belgium |
| John Bower | London Business School |
| Dallas Burtraw | Resources for the Future |
| Hung-po Chao | Electric Power Research Institute |
| John Conti | U.S. Department of Energy |
| David Deangelo | PPL Corporation |
| Max Duckworth | Constellation Power Source |
| Denny Ellerman | Massachusetts Institute of Technology |
| Robert Entriken | Electric Power Research Institute |
| Robert Eynon | U.S. Energy Information Administration |
| Doug Hale | U.S. Energy Information Administration |
| Udi Helman | U.S. Federal Energy Regulatory Commission |
| Ben Hobbs | Johns Hopkins University |
| Bruce Humphrey | Xenergy |
| Hillard Huntington | Stanford University |
| Henry Lee | Harvard University |
| Elliot Lieberman | U.S. Environmental Protection Agency |
| William Meroney | U.S. Federal Energy Regulatory |
| Dale Nesbitt | Altos Management |
| Shmuel Oren | University of California at Berkeley |
| Karen Palmer | Resources for the Future |
| Ken Quinty | PPL Corporation |
| Scott Rogers | University of Toronto |
| Geoffrey Rothwell | Stanford University |
| Alex Rudkevich | Tabor, Caramanis & Associates |
| Hugh Rudnick | Universidad Catolica de Chile |
| Chris Short | Australian Bureau of Agricultural & Resource Economics |
| Yves Smeers | Universite Catholique de Louvain (Belgium) |
| Paul Sotkievicz | University of Florida |
| Russell Tucker | Edison Electric Institute |
| Boddu Venkatesh | ICF Consulting |
| John Weyant | Stanford University |
| Frances Wood | OnLocation, Inc. |
| Assef Zobian | Tabor, Caramanis & Associate |

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King Abdulaziz City for Science and Technology
Mitsubishi Corporation
Natural Resources Canada
New Energy and Industrial Technology Development Organization, Japan
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# EXECUTIVE SUMMARY

## Introduction

Over the last decade many countries and regions have transformed their electricity sectors to make them more competitive. Although the recent modifications of the California market design cast considerable uncertainty about how far this process will evolve, competitive forces are likely to play a more influential role in the sale, transmission and purchase of electricity than they did previously.

This report summarizes the recent findings of the Energy Modeling Forum's working group on electricity prices and emissions in a restructured electricity industry. As in previous EMF studies, the process focused partly on what could be learned from comparing the results of different models.

Although the models were developed for different reasons, they share some common traits that allow their results to be compared. They project regional electricity prices, generation, capacity, consumption, electricity exports and imports, and environmental emissions over at least the next decade and often until 2020. They each have important links to the economy and policy and they emphasize interregional competition between multiple U.S. areas.

The working group considered the five competition scenarios: baseline or reference, high demand, low natural gas prices, expanded transmission, and a renewable portfolio standard (RPS). All of these cases assume that wholesale prices in all regional electricity markets are set equal to the marginal or incremental generation costs immediately in the year 2000. The cases do not show how restructuring would affect electricity decisions relative to a cost-based regulated environment.

## The Baseline Competition Case

In the EMF baseline competition case, gas-fired units owned by electric-generating firms dominate the new capacity additions, providing roughly 84 to 98 percent of the cumulative additions by 2010. Few new coal units are built during this period. Although generators expand existing non-hydroelectric renewable capacity by 33-48% in two models (NEMS and POEMS) over the decade, total capacity for renewables remains a relatively small share of the total.

The technology mix of additional capacity reflects a number of conditions: the type of plants that retire, the relative growth in peak and nonpeak demand, fuel prices, and assumptions about technological progress in various types of units. One critical assumption for the reported simulations is that the natural gas price path remains well below the April 2001 spiked level. The cases implicitly assume that natural gas prices will return to their 1999 levels and rise slightly faster than inflation during the next decade.

Another important caveat is that these models are stronger on economic than on technology factors. These outlooks incorporate thoughtful assumptions about how technology may progress over time, but this single path of technological opportunities is maintained throughout the five cases. In the baseline case, new coal units remain relatively unattractive despite losing significant market share. If the coal-technology producing industry should respond, the mix of capacity could be quite different.

Reflecting standardized economic and energy assumptions across the models, generation grows by 1.3 to 1.6 percent per year in each model, while the growth rate in demand generally ranges from 1.1 to 1.7 percent per year. The projections differ somewhat more in their estimates of peak and nonpeak electricity demands. A key difference concerns their treatment of retail pricing and the ability to use time-of-day rates to shift loads to less busy hours. We recommend strongly that analysts explain clearly how retail pricing has been incorporated in any outlook that they present. Moreover, results will be sensitive to the composition of demand among different customer types. Households, commercial firms, new-technology industry and more traditional firms respond differently to prices and economic activity.

The U.S. average wholesale generation electricity price in the near-term ranges between $25-$34 per megawatt hour (MWH) in 1997 dollars. They tend to fall slightly in real dollars over time to the $25-30 per MWH range in the baseline case, in which generators pay $2.93 to $3.26 per million Btu for natural gas. One model demonstrates a more cyclical response, increasing in 2005 before dropping in 2010. Electricity prices are projected to vary considerably across the 13 regions. In general, the lowest prices are experienced in regions, which have existing low cost coal and nuclear generation sources. Regions more reliant on oil and gas-fired generation and those with higher delivered fuel costs have higher prices. Opportunities for trading can lead to higher or lower prices than otherwise expected. The delivered prices to consumers are based on their patterns of consumption and include transmission and delivery costs.

Some older coal and nuclear plants are being replaced by newer gas technologies in the baseline case. However, by 2010, coal use still remains the dominant fuel, accounting for 19-22 quadrillion BTUs (quads) of a total nonrenewable fuel use of 34-37 quads. Several models call for greater reliance upon natural gas and nuclear than other models, resulting in their estimating smaller increases in carbon emissions.

Economic forces shift the U.S. power sector to greater use of natural gas rather than coal. As a result, in the simulations, annual U.S. emissions for sulfur dioxide, nitrogen oxides, and carbon dioxide from the power sector generally do not keep pace with electricity demand growth over the next decade.

National sulfur dioxide emissions decline by anywhere between 1.0 to 2.5 million metric tons over the 2000-2010 period. This trend reflects the national cap on emissions imposed by the Clean Air Act and that generators are using banked allowances, or allowances earned prior to 2000, during this period.

Nitrogen oxides emissions tend to remain quite steady over the next decade. Most projections of the baseline competition case incorporate no new environmental policies that have not already been approved by policymakers.

Carbon dioxide emissions rise at slower rates (1.3% and 0.9% per annum over the 2000-2010 decade) than electricity generation (1.6% per annum) in 3 of the models. In the other two, emissions are relatively flat between 2000 and 2010. In one case, the slower retirement of nuclear plants contributes to the noticeably slower growth in carbon emissions, while in the other greater retirements of coal capacity is the cause.

**Alternative Competition Cases**

The alternative cases also represent a workably competitive market. Each case shows how market conditions change with other assumptions for baseline demand growth, natural gas prices, transmission fees and capacity, and a renewables portfolio standard (RPS).

The cumulative additions for combined-cycle units over the decade show their largest response to high demand cases, followed by the low gas price case. Changes for other scenarios are minimal.

Natural gas prices and electricity demands are two important influences on the future path for electricity prices. Alternative conditions for electricity transmission and the RPS generally have very modest effects that remain below 5% of the baseline values. These prices are the competitive wholesale levels before any adjustments for stranded costs are added.

The outlooks agree that lower natural gas prices will reduce competitive electricity prices while higher electricity demand will increase electricity prices. However, the pattern across outlooks is rather different. Some outlooks reveal rather large reductions in electricity prices when gas prices fall; the declines in other outlooks are more modest.

Larger changes are seen for some regional electricity prices. The largest gain relative to the baseline (27%) occurs for the midwestern MAIN region in the NEMS model in the high demand case. The largest reduction relative to the baseline (22%) occurs for New York in the RFF model in the low gas price case. While the national prices change by no more than 2% from their baseline levels in the alternative transmission cases, regional prices can increase or decrease by as much as 12 or 13% in these cases. In general, importing regions with higher prices in the baseline case will experience price reductions with more transmission access, while low cost exporting regions will see higher prices.

Higher demands tend to increase the power sector's carbon emissions more than nitrogen oxides or sulfur dioxide emissions in these simulations. Annual carbon emissions for the nation grow by 7-10 percent more than baseline levels by 2010 when energy demands increase by 12 percent. Nitrogen oxides emissions for U.S. grow by approximately 5 percent more by 2010, while U.S. sulfur dioxide emissions remain unchanged.

The lack of new nuclear plants plays an important role in this result. Lower natural gas prices and additional incentives for renewable energy technologies appear to decrease nitrogen oxides and carbon emissions in this sector. National caps tend to keep sulfur dioxide emissions close to their baseline levels.

Sulfur dioxide emissions in 2010 remain relatively similar to baseline levels for most models and cases. By 2010, firms are assumed to have used up their banked allowances and thus annual emissions will be close to the cap of 8.95 million tons per year. Thus, sulfur dioxide emissions do not change much, although the alternative conditions can change the costs of $SO_2$ allowances, which will influence generation costs.

Higher demand conditions increase nitrogen oxides emissions by approximately 5% by 2010 in three of the five models, with the others having no increase or a 20% increase. Unlike sulfur dioxide, these emissions will be pushed higher by increased electricity demand. The nitrogen oxides emissions effect for higher demands is noticeably stronger than the effects in the expanded transmission case as well as in the low transmission fee and higher transmission capacity cases. One model anticipates sharp reductions in nitrogen oxides emissions by the end of the decade when either natural gas prices are lower or when a renewable portfolio strategy (RPS) is implemented.

Carbon emissions in the power sector move strongly with the higher demand conditions. This trend reflects the absence of growth in any new nuclear plants due to a combination of costs and public perceptions. Carbon emissions grow by about 7% to 10% higher than baseline levels and hence increase somewhat less than total electricity demand. The reductions in nitrogen oxides and carbon in the RPS case in one model stem from a decrease in coal capacity and therefore generation, as much as from an increase in renewable generation. In comparison, another model has a greater renewable response to the RPS but smaller gains in emission reductions.

Transmission policy can significantly influence the amount of interregional electricity trade. Expanded transmission capacity and lower transmission fees increase total interregional imports by 23 percent above baseline levels in one model and by 61 percent in another model. Lower transmission fees have a particularly large effect in several models, underscoring the importance of transmission pricing in determining the economic incentive for trade between regions.

Properly functioning prices are the cornerstone of competition's potential efficiency. Competition does not guarantee a certain price, does not require electric loads to be a given magnitude, and does not assure generators that their plants will be used when they want them to be. Participants will need to protect themselves from these business risks. This study's results show how changes in electric load growth, natural gas prices, and transmission costs and expansions could influence conditions in markets where efficient rules have been established.

# PRICES AND EMISSIONS IN A RESTRUCTURED ELECTRICITY MARKET

## Introduction

Over the last decade many countries and regions have transformed their electricity sectors to make them more competitive. Although the recent modifications of the California market design cast considerable uncertainty about how far this process will evolve[1], competitive forces are likely to play a more influential role in the sale, transmission and purchase of electricity than they did previously. These forces are changing the industry in fundamental ways. While they are decoupling generation, transmission, distribution, and retail supply within the industry, they are also fostering much greater interdependence among regions in providing and using electricity. Moreover, these changes are occurring at a time when governments are imposing tighter controls on environmental pollutants.

New structures for organizing the industry have introduced novel ways of operating in electricity markets. They have also created alternative ways of thinking about and planning for successful business strategies. Companies can no longer ignore the potential competition from suppliers or the potential opportunity of servicing customers in other regions. In addition, governments creating market rules in one region need to be aware how their plans work with or against those rules adopted in other regions. They should develop flexible rules that produce meaningful incentives without trying to dictate the outcomes of market processes.

Although modeling competitive electricity markets is in its early stages, these frameworks are already demonstrating their value in terms of helping decision makers to anticipate and plan for widespread structural changes. Uncertainty about how restructuring will unfold and how market participants will respond to more liberalized conditions makes any single forecast of the industry's future highly suspect. But each projection contains some important elements about how competition might operate. While participants cannot predict prices and other market outcomes, they can learn to protect themselves from unexpected swings. This perspective should prepare participants to respond to unexpected developments more quickly and efficiently than otherwise, much like a person driving a car in a city neighborhood who expects the unlikely event that a child will run into the street before his vehicle.

## The EMF Study

This report summarizes the recent findings of the Energy Modeling Forum's working group on electricity prices and emissions in a restructured electricity industry. As in previous EMF studies[2], the process focused partly on what could be learned from comparing the results of different

[1] Poorly designed rules have contributed significantly to California's power crisis. Implementation problems include siting delays for new plants, no long-term contracts, and fixed and subsidized retail prices that do not reflect market conditions.

[2] The EMF 17 working group continued the previous work initiated by the EMF 15 group on a competitive electricity industry. That particular study foresaw the problem of market power, especially when market rules prevented long-term contracts and did not allow the demand side to respond to price. Please see Energy Modeling Forum, *A Competitive Electricity Industry*, Stanford University, Stanford, CA, 1998. The EMF process and some earlier EMF results are described in H.G. Huntington, J.P. Weyant, and J.L. Sweeney. "Modeling for Insights, not Numbers: The Experiences of the Energy Modeling Forum," *OMEGA: The International Journal of Management Science,* Volume 10, No. 5, 1982, pp. 449-462.

models. The critical elements that were analyzed include electricity prices, generation, capacity, interregional trade, and environmental emissions in North American electricity markets.[3] The study drew its members from leading advisors, electricity modelers, and electricity experts from government, companies, universities, and research organizations. Over the period from September 1998 through June 2000, the group met three times to discuss the key issues driving the electricity restructuring topic and how modeling results could help to develop a more comprehensive understanding of the new conditions. Participation by corporate and government advisors helped to define scenarios that would be useful for understanding the interactions among business strategies and public policy.

Although the models were developed for different reasons, they share some common traits that allow their results to be compared. They project regional electricity prices, generation, capacity, consumption, electricity exports and imports, and environmental emissions over at least the next decade and often until 2020. They each have important links to the economy and policy and they emphasize interregional competition between multiple U.S. areas. For this study, these regional U.S. results have been aggregated to the 13 regions linked to NERC regions that are listed in Table 1.[4]

Participating modelers are identified along with their frameworks and organization in Table 2. While EIA's NEMS and CERI's Energy 2020 models are used primarily for developing industry outlooks and special evaluations, RFF's Haiku model was developed as a small, tractable framework for conducting risk assessment and understanding fundamental market uncertainties. MarketPoint is used mainly for such tasks as valuing electricity assets and evaluating other key business strategies. POEMS is based in part upon NEMS but has been restructured to use for electricity policy analysis and business applications. IPM is used both for evaluating policy analysis and for understanding business strategies.

The working group considered the five competition scenarios: baseline or reference, high demand, low natural gas prices, expanded transmission, and a renewable portfolio standard (RPS). These cases are listed in Table 3. The baseline case adopted the economic and energy assumptions from the reference case of the U.S. Energy Information Administration's *Annual Energy Outlook (AEO).*[5] The high demand case examined power market conditions if electricity consumption grew by 1 percent per year more rapidly than in the baseline competition case, for a total of 2.4 to 2.8 percent per year. The low gas price case kept the natural gas price paid by electric utilities in all future years at its projected 2000 inflation-adjusted (or real) level in the baseline case. The high transmission case allowed both expanded physical volume and lower transmission charges between regions of the United States. The renewables portfolio standard (RPS) assumed that the industry must meet a target share of 7.5 percent for renewables excluding hydroelectric power. As explained later, alternative versions of both the high demand and transmission cases were simulated in order to understand better the results obtained in these cases.

All of these cases assume that prices in every regional electricity market are immediately set by

[3] The group also discussed extensively emerging market design issues such as strategic behavior under different constraints, organization of the transmission system operator, and the advantages and disadvantages of considering power transmission flows rather than nodes in managing congestion. The group's discussions of these issues are not covered in this report.

[4] Some variance in reporting of results occurs in CERI's 2020, which reports results for 7 regions in Canada plus an aggregate for US. Although Energy 2020 models the US by each of the 50 States, for the purpose of this exercise, US is aggregated.

[5] The Reference case for Energy 2020 was not completely aligned with the assumptions of AEO99 as provided in Table 4. Specifically, assumptions on electricity demand, heat rate improvements, transmission and distribution COS reductions, and reserve margins are not aligned with the AEO.

**Table 1: U.S. Regions Reported to EMF Working Group**

| NERC Subregion | Subregion Name | Geographic Area |
|---|---|---|
| ECAR | East Central | MI, IN, OH, WV; part of KY, VA, PA |
| ERCOT | Elec Reliability Counc of Texas | Most of TX |
| MAAC | Mid-Atlantic | MD, DC, DE, NJ; most of PA |
| MAIN | Mid-America | Most of IL, WI; part of MO |
| MAPP | Mid-Continent | MN, IA, NE, SD, ND; part of WI, IL |
| NE | New England | VT, NH, ME, MA, CT, RI |
| NY | New York | NY |
| FRCC | Florida | Most of FL |
| STV | Southeast (ex. Florida) | TN, AL, GA, SC, NC; part of VA, MS, KY, FL |
| SPP | Southwest | KS, MO, OK, AR, LA; part of MS, TX |
| NWP | Northwest | WA, OR, ID, UT, MT, part of WY, NV |
| RA | Rocky Mtn & Ariz-NM | AZ, NM, CO, part of WY |
| CNV | California & So. Nevada | CA, part of NV |

**Table 2: EMF 17 Modelers Submitting Results for Standardized Cases**

| ID in Charts | Model Name | EMF Modeler | Organization |
|---|---|---|---|
| NEMS | National Energy Modeling System | Robert Eynon<br>Laura Martin | U.S. Energy Information Administration |
| POEMS | Policy Office Electricity Modeling System | John Conti<br>Frances Wood | US Department of Energy, Policy Office<br>OnLocation Inc. |
| RFF | Haiku | Dallas Burtraw<br>Karen Palmer<br>Ranjit Bharvirkar<br>Anthony Paul | Resources for the Future |
| IPM | IPM | Elliot Lieberman<br>Boddu Venkatesh | U.S. Environmental Protection Agency<br>ICF Consulting, Inc. |
| E2020* | Energy 2020 | Abha Bhargava<br>Christopher Joy | Canadian Energy Research Institute |
| ** | MarketPoint | Dale Nesbitt<br>Ted Forsman | Altos Management Partners |

*Notes:*
* In this study, CERI reported results from Energy 2020 for seven Canadian regions and the United States as a whole.
** MarketPoint results are not compared graphically with the others. This model reported detailed regional results that were not easily aggregated to the core 13 regions shown in Table 2. However, discussion of their results helped to identify the basic principles of competitive markets exhibited by other models.

**Table 3: EMF 17 Cases**

| **Case*** | **Market Assumptions** | **Notes** |
|---|---|---|
| Base Competition | 1999 AEO** Demands and Fuel Prices<br>See Table 4 for other assumptions. | Fully integrated so that demands respond to price. |
| Low Gas Prices | AEO Demands and Fuel Prices + Hold delivered gas prices constant at projected AEO price in 2000 for all classes of customers. | Fully integrated. |
| High Electricity Demands | AEO Demands and Fuel Prices + Increase base electricity growth by 1% per year. | One case allows fuel prices to change incorporating the effects of higher natural gas prices, while the other has fixed (at baseline) natural gas prices. Electricity demands are unresponsive to electricity price changes. |
| High Transmission | Increase transmission capability by 50%.<br>Reduce transmission hurdle rate to $0.10/mWh.<br>Reduce transmission fees by 50%. | Two additional cases separate the change in transmission capacity from the change in the transmission fees and hurdle rate. |
| Renewable Portfolio Standard | Impose an RPS goal of 7.5% non-hydropower renewables (excluding MSW) as a percent of sales by 2010. Assume the RPS requirement expires after 2015. The cost of the credit was capped at $15/mWh. | |

* All cases assume immediate deregulation in all states today.
** Although most models standardized on the 1999 Annual Energy Outlook, the NEMS system used the 2000 version.

incremental or marginal costs in the year 2000[6]. This assumption contrasts with the AEO reference case, which assumed a mixture of deregulation and regulation in the various states. As a result, the EMF scenarios show how changing conditions influence electricity markets in a deregulated environment. The cases do not show how deregulation would affect electricity decisions relative to a regulated environment. The group did not simulate a regulated case because participants had differing opinions of what continued regulation would mean, which regions would be affected, and the degree of market deregulation in a business-as-usual scenario.

A related, important issue concerns the form of the deregulation itself. The group asked the modelers to consider a wholesale electricity market that was workably competitive. Each region had sufficient generators or access to interregional trade that muted the problems of market power being exercised on a consistent basis. This perspective also required that transmission systems within a region were sufficiently efficient in reducing congestion to allow plants to be dispatched on the basis of least cost.[7] Finally, all models, except IPM, allowed demand to respond to prices, with some, but not all, frameworks allowing load shifting in response to time-of-day prices. As a result, the cases are optimistic on the regulatory front by assuming that each government steers its way towards a reasonably competitive market design.

The group did not ask to have different market designs or market imperfections simulated with these models because the systems represented in the current study do not contain the necessary institutional constraints or detailed transmission networks that allow one to consider such issues. The principal advantage of the current models lies in their detailed representation of interregional competition within the electricity industry, with appropriate links to other energy markets and the economy.

[6] As a result, the year 2000 values are hypothetical and do not reflect actual markets outcomes.

[7] POEMS performs the dispatch and trade at the subregional level, with representation of transmission capability among these subregions.

**The Baseline Competition Case**

The EMF baseline competition case combines the reference case economic and energy price assumptions from the *AEO* forecast[8] with the assumption that all U.S. regional markets are immediately competitive with generation prices being set at the incremental production cost of the last unit generating in any period. Models differed in how much fixed operations and maintenance (O&M) costs they incorporated in market prices. Modelers were asked to implement the key assumptions for competition shown in Table 4, unless they had strong reasons for overriding these specifications.

The group was primarily interested in how changes in the economic and energy assumptions influence the competitive electricity market and emissions results. However, it is easier to understand this discussion by first emphasizing a few key characteristics of the baseline case.

*Capacity, Generation, and Demand*

According to the NEMS model, the U.S. electricity industry has about 777 gigawatts[9] of nameplate capacity in 2000. Coal accounts for 39% of total capacity (Figure 1). Gas accounts for 16%, either as combined-cycle units[10] or combustion turbines[11]. Older gas and oil units ("other fossil fuel") amount to 18%, nuclear plants account for

[8] NEMS used *AEO* 2000 assumptions while the other models used *AEO* 1999 assumptions.

[9] Each gigawatt is enough power to meet the demands of a million homes in California.

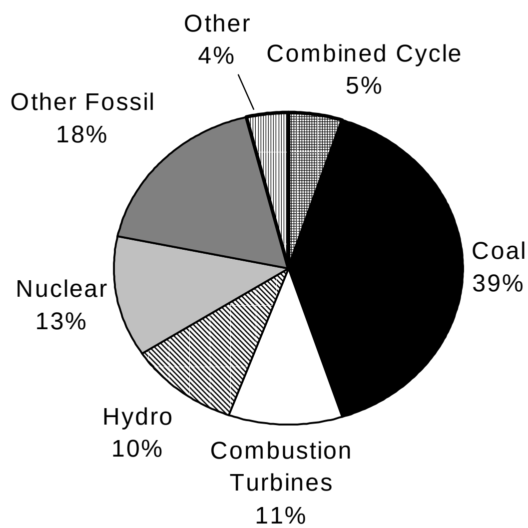
[10] Combined cycle units use a steam turbine to produce electricity from waste heat that exits from a combustion turbine fired by natural gas. This process improves the unit's efficiency.

[11] Gas turbine plants burn natural gas to produce hot gases that turn the turbine.

**Table 4. Detailed Assumptions for Baseline Competition Case**

| Category | Input Specification |
|---|---|
| Electricity Markets | Competitive wholesale<br>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 | Life time for new plant is 20 years (17 for wind & 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 |
| <u>Transmission</u> | |
| - Hurdle rate for trading | $1/MWh (1997$) |
| - Organization | Postage Stamp (zonal) |
| - Wheeling Fees | $3/Mwh (1997$) average between neighboring NERC regions |
| <u>O&M and G&A Costs</u> | 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% (see regional table), or endogenously derived |
| <u>Stranded Cost Recovery</u> | |
| -Generation Assets | 10 year recovery, 10% discount, 100% Recovery |
| <u>Transitional Charges</u> | |
| - Regulatory Assets | Recovery of existing regulatory assets |
| - Decommissioning costs | Recovery of required costs |
| Externality Costs | None |

**Figure 1. Electric Generating Capacity (Percent) in 2000 (NEMS Projection)**




13% and hydroelectric plants account for 10%, with the remaining 4% allocated to the "other" category.

Cumulative capacity additions of all types over the next ten years (until the year 2010) range from 124 to 204 gigawatts, or 16% to 26% of total capacity in 2000 in the four main U.S. models listed at the top of Table 2. Cumulative capacity retirements of all types over this decade vary from 48 to 69 gigawatts, or 6.2% to 8.8% of total capacity in 2000 in these projections.

Gas-fired units owned by electric-generating firms dominate the new additions, providing roughly 84 to 98 percent of the cumulative additions by 2010. Figure 2 shows that electric generators choose almost exclusively from combined-cycle gas units and combustion gas turbines rather than from coal-fired and renewable units. POEMS, RFF and E2020 indicate a preference for combined-cycle plants, while NEMS and IPM tend to select a more even balance between the two types of gas technologies although with a slight preference for combustion turbines. Combined-cycle plants have greater efficiencies and tend to be operated over more hours than combustion turbines, which are used primarily for meeting peak demands. The strong shift towards natural gas may not be as pronounced if gas prices are sustained at the current high prices.

The technology mix of additional capacity is in part linked with the type of plants that retire, as well as the relative growth in peak and nonpeak demand. Demand patterns shifting more towards peak consumption will favor the addition of combustion turbines, if higher electricity prices do not reduce consumption. Patterns shifting more towards baseload use will favor the addition of combined-cycle and coal plants.

Fuel prices will also be important. The preference for gas-fired units in the baseline case may reflect the relatively low gas prices assumed by the AEO99 at the time. If today's higher gas prices prevail for the next decade, the growth in new gas-fired units would be less.

**Figure 2. Cumulative Capacity Additions (GigaWatts) in Baseline Case, 2010**

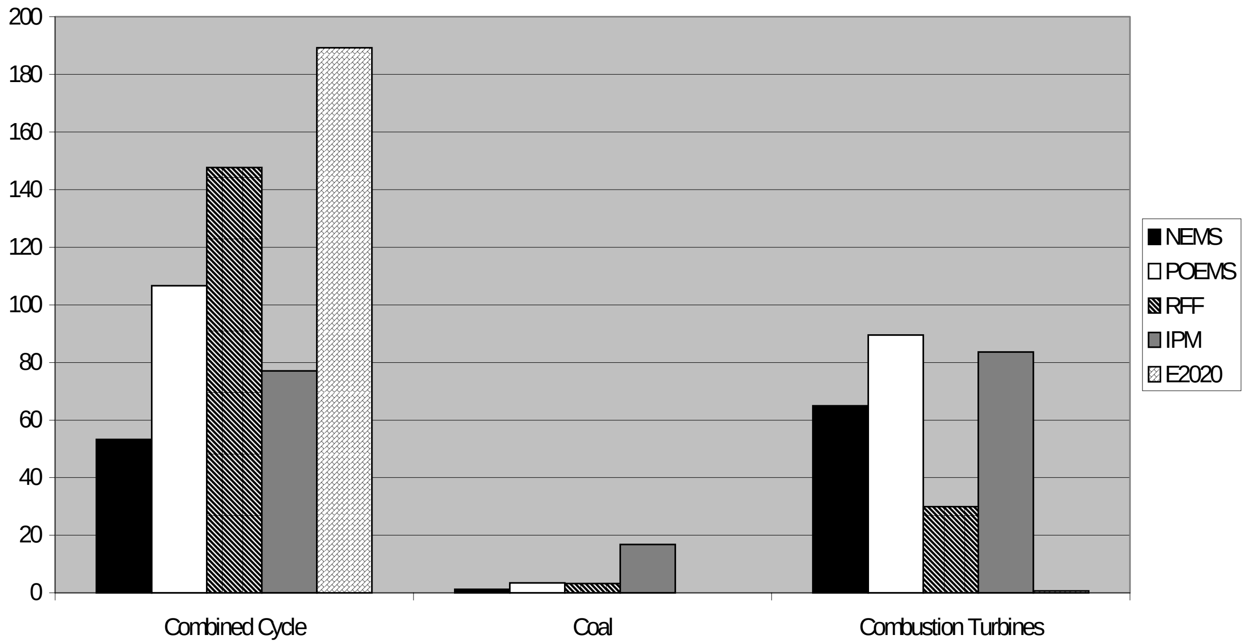



**Figure 3. Cumulative Capacity Additions (GigaWatts) in Baseline Case, 2010**

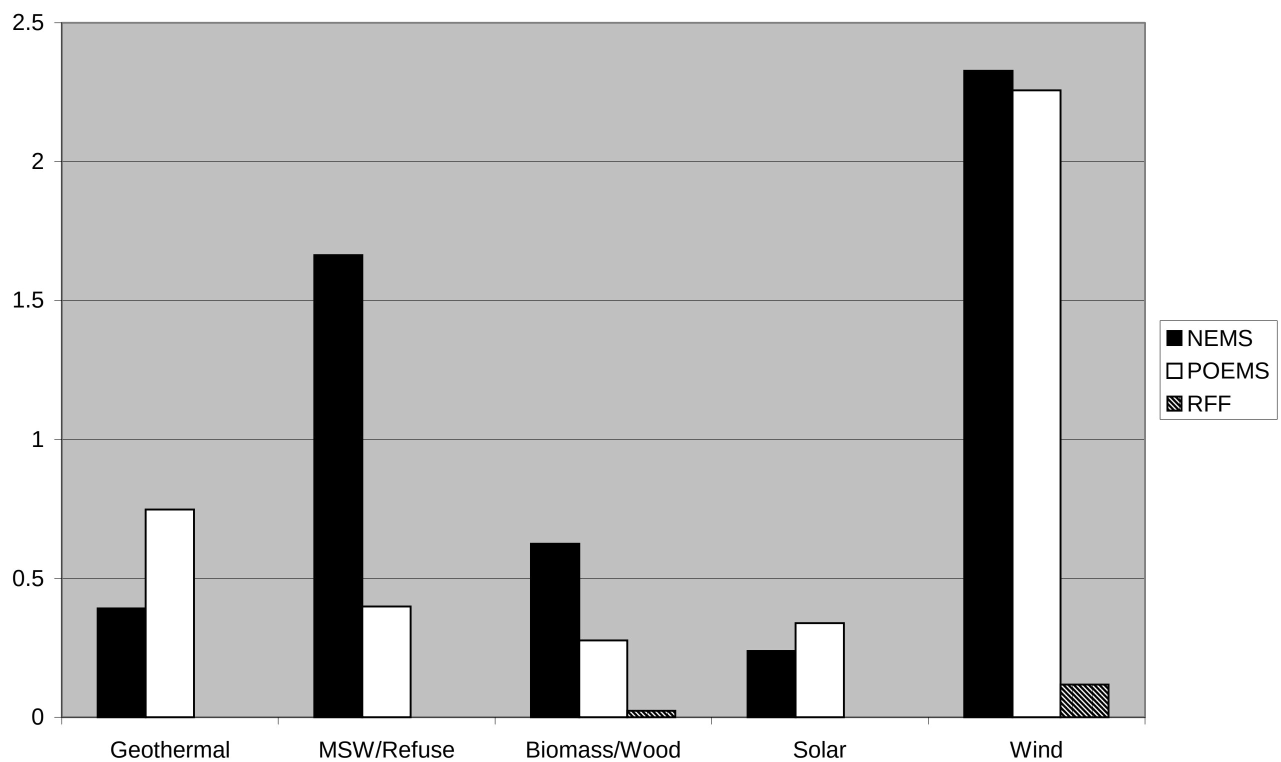
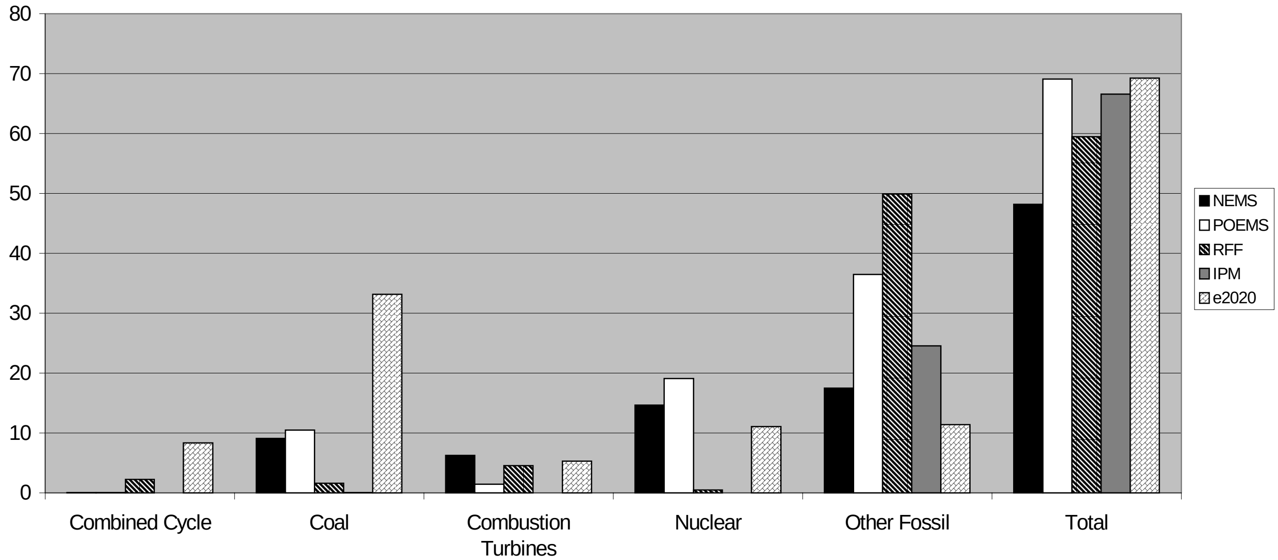


**Figure 4. Cumulative Capacity Retirements (GigaWatts) in Baseline Case, 2000-2010**




Finally, most outlooks must adopt a set of assumptions about technological progress that often remain relatively fixed across scenarios. Changing these assumptions could produce different outlooks. For example, the exclusive choice for combined-cycle plants, especially in E2020, is driven mostly by relatively lower costs for this type of technology. In addition, progress in coal-fired technologies will undoubtedly continue, especially if they are losing market share rapidly. Thus, coal-fired units could be more attractive economically than assumed in these outlooks.

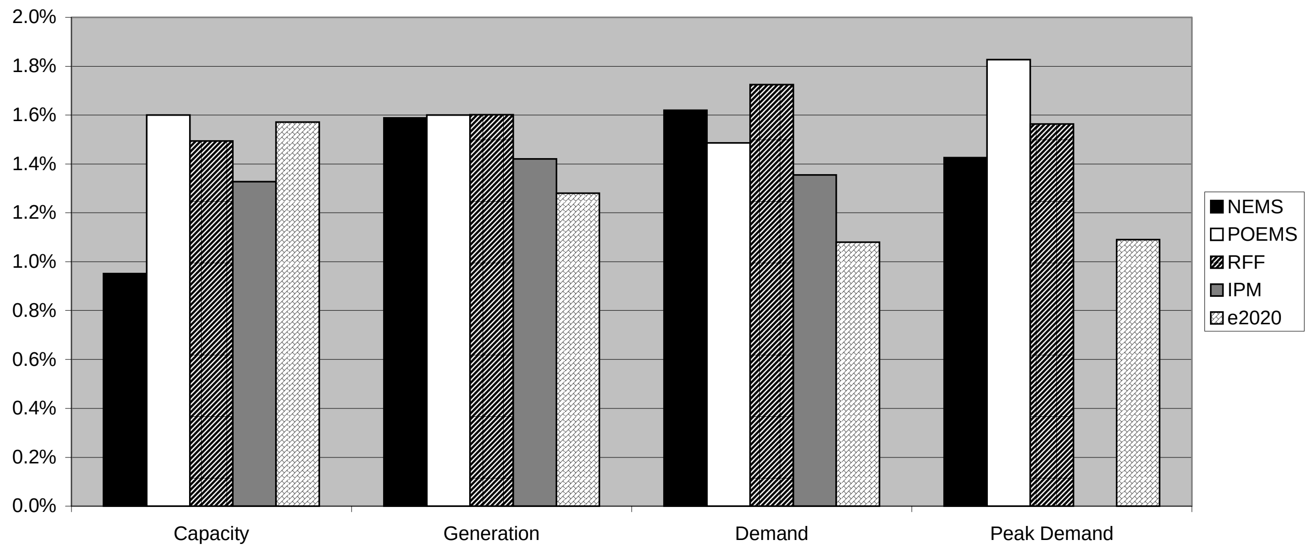
Although generators expand existing non-hydroelectric renewable capacity by 33-48% in two models (NEMS and POEMS) over the decade, total capacity for renewables remains a relatively small share of the total.[12] The scale for renewable capacity additions (Figure 3) is less than 2 percent of the scale for the more traditional sources (Figure 2). All of the projections show more wind-turbine additions than other renewable sources. NEMS also shows some building of municipal system waste and refuse (MSW/refuse) units as well.

Retirements over this decade (Figure 4) are concentrated in the older oil and gas units ("other fossil fuel") and in nuclear plants. Most models retire plants on economic grounds, although some consider scheduled life extensions. In addition to age and licensing agreements, retirements may be more frequent if the model assumes that there is limited rehabilitation of older units. RFF and POEMS project greater retirements of oil and gas units, and these are also the models that project greater combined cycle capacity additions. The low nuclear retirements in RFF will have important implications for environmental emissions, as continued operation of nuclear plants will help to lessen emissions of carbon dioxide, nitrogen oxides, and sulfur dioxide.

Figure 5 shows that the models portray reasonably similar growth rates in U.S. electricity consumption and generation over the 2000-2010 period. Reflecting the attempt to standardize assumptions across the models, generation grows by 1.6 percent per year in three of the models,

[12] The IPM results are not shown in this graph because they are represented in aggregate and not by technology.

**Figure 5. Annual Growth (percent) in Baseline Case, 2000-2010**




while the growth rate in demand generally ranges from 1.5 to 1.7 percent per year. However, both IPM and E2020 indicate slower demand growth rate at 1.4 and 1.1 percent per year[13]. The lower growth in demand in E2020 results from slightly higher prices than in the other models and from a relatively high demand response to price. Moreover, the composition of demand between peak and nonpeak times is also extremely important. The POEMS peak demand[14] grows more rapidly (1.8% per annum) than total demand. This peak-load growth requires greater capacity expansion than in the other projections. On the other hand, capacity tends to be used more intensively over time in NEMS, as demand in the nonpeak hours grows more rapidly than peak demand. Demand during peak hours in this model grows more slowly at 1.4% per annum.

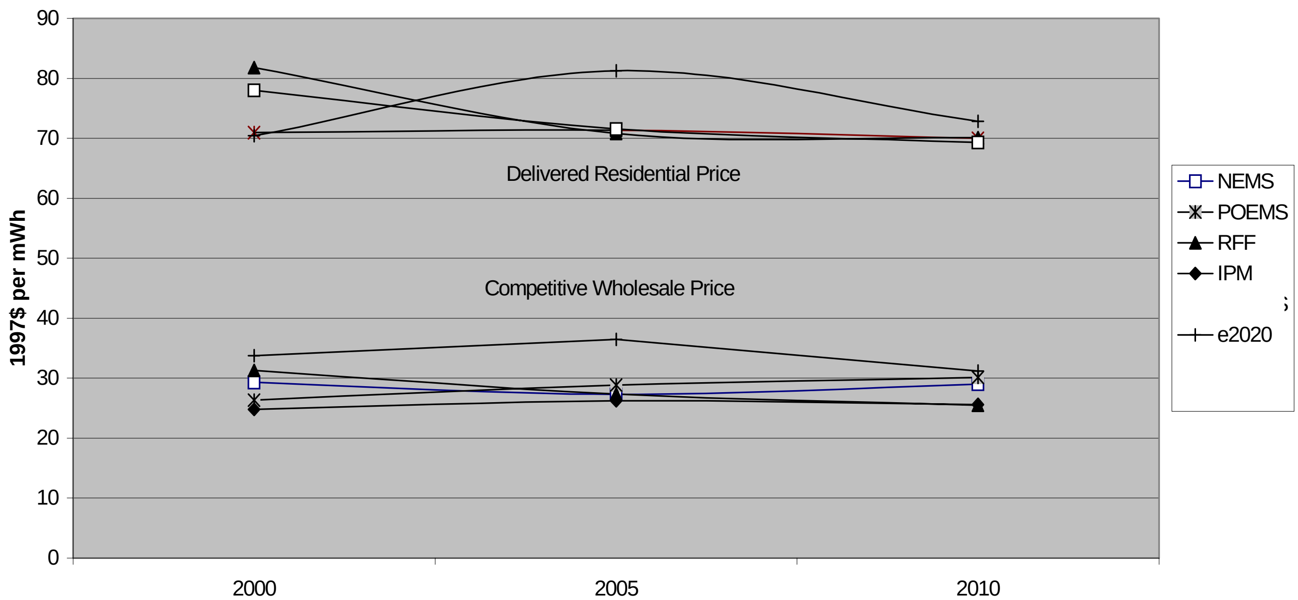
[13] Demand and generation may increase at slightly different rates due to changes in losses, imports and cogenerated electricity sold to the grid.

[14] Peak demand is measured here as the sum of the peaks in each region. Since peaks in each region occur at different hours and on different days, their sum will not be equal to the national peak at a certain hour and day.

The growth in peak demand in POEMS results from the growth of the individual demand end-uses (e.g., lighting, air conditioning, etc.). The peak demand will increase more rapidly than average sales if the demands in those end-uses which contribute the most to peak are increasing more rapidly than those that have a flatter load shape. The residential and commercial loads are increasing somewhat more than industry (especially, heavy industry which tends to have three shifts working throughout the day and therefore flatter loads). The POEMS results in this study, like the IPM results, do not incorporate load shifting in response to time-of-day pricing.

The RFF simulations also do not incorporate time-of-use retail rates for electricity. Each class of consumers faces the annual average electricity price for that class in each time block of the year. The RFF model allows 12 load blocks with the peak block including 1% of the hours in each season (roughly 22 hours for summer and winter and 44 hours for spring/fall). Models with greater details on electricity loads than RFF may show greater peaks and larger peak demands.

**Figure 6. Electricity Prices in Baseline Case, 2000-2010**




The NEMS results for this study assumed full competition, including time-of-use retail pricing for all sectors. Some of the sectors respond to prices by shifting their demand from peak-time periods to off-peak hours. The end-use sectors that were assumed to be able to shift load included water heating and clothes drying in the residential sector, space heating/cooling and water heating in the commercial sector, and shift work in the industrial sector. The assumed elasticity in this model was -0.15, based on the short-run elasticity also used within the NEMS demand models. In addition, load shifting in the commercial sector requires that thermal storage use becomes more widespread.

Load shifting to nonpeak hours reduces not only the peak load but also the amount of new capacity needed. It may also potentially influence the fuel mix of electricity generation and emissions, e.g., away from peaking gas-fired units and towards baseload coal-fired units, although such a trend is not directly observable below because other factors influence this decision, too.

*Electricity Prices*

Figure 6 compares the U.S. average wholesale generation electricity price, which is earned by a generator that operates throughout the year without any downtime.[15] Generators are paying $2.93 to $3.26 per million Btu for natural gas in 2010 in this case. All prices are in 1997 dollars. Electricity prices rise from $26 per megawatt hour (MWH) to $30 per MWH in POEMS, remain relatively steady at $29 per MWH in NEMS and at $25 per MWH in IPM, and fall from $31 to $25 per MWH in the first five years before lev-

[15] Modelers reported both “wholesale” and “delivered to consumers” competitive generation prices. The wholesale prices (reported above) are paid to generators averaged over all hours in the year, in other words paid to a generator which runs all the time ("time weighted average"). The prices to the consumer include losses and are averaged over the amounts purchased in each time period ("quantity weighted average"). These two effects lead to higher prices for the “delivered” than for the “wholesale” concept. In particular, customers buy more power at peak when prices are higher, which raises the average over the one that is time-weighted.

eling off in RFF.[16] The prices in E2020 are more cyclical, increasing from about $34 in 2000 to 36 in 2005 before dropping to about $31 in 2010. The change in E2020's price appears to correspond directly with the tightening of the market. The reserve margins in E2020 are determined endogenously and not set to those specified in AEO99. The reserve margins decrease from 25% in 2000 to 14% in 2003 and then increase to 20% in 2010. There appears to be a 1-2 year lagged price response.

The delivered prices to consumers, also shown in Figure 6, are based on their patterns of consumption and include transmission and delivery costs. IPM results are not shown because the model does not project consumer prices. In addition, consumer prices may include transitional costs for stranded capacity where the book value of the generation assets is higher or lower than the market competitive prices. Projected delivered prices increase less quickly or decrease more quickly compared to the wholesale prices for at least two reasons. The cost of distribution was assumed to decline annually in this scenario. Moreover, the stranded cost charges decline over time in inflation-adjusted terms as well.

In NEMS and POEMS, a total value of stranded costs is determined from the net present value of net cash flows and the net book value. In POEMS positive and negative stranded costs are netted at the company level, while in NEMS they are netted across all plants in a region. This amount is recovered over 10 years in flat nominal dollars each year, which means it declines in inflation-adjusted dollars. Therefore, this component of rates declines over time. RFF calculates stranded cost on a NERC region/subregion basis in the version of the model used for this study. Under this approach, profits earned by some utilities in the region are netted against the stranded costs of others. The net result is always no stranded costs for the region as a whole and thus, there is no stranded cost recovery reflected in retail electricity prices in the RFF results.[17]

Electricity prices are projected to vary considerably across the 13 regions. The wide range of regional wholesale electricity prices is displayed in Figure 7. In general, the lowest prices are experienced in regions, such as ECAR, which have existing low cost coal and nuclear generation sources. Regions more reliant on oil and gas-fired generation and those with higher delivered fuel costs have higher prices. Opportunities for trading can lead to higher or lower prices than otherwise expected. For example, the Northwest region has considerable hydroelectric resources, which without trade would lead to low electricity prices. In all the models[18] except RFF, the NWP prices do not appear to be significantly lower than other regional prices, because other regions set the marginal prices. In POEMS and NEMS delivered prices in NWP are reduced by a credit or discount to account for low cost Federal preference power.

*Fuels Used for Electricity*

The information on additions and retirements indicates that some older coal and nuclear plants are being replaced by newer gas technologies. However, by 2010, coal use still remains the dominant fuel, accounting for 19-22 quadrillion BTUs (quads) of a total nonrenewable fuel use of 34-37 quads (Figure 8). NEMS and POEMS have reasonably similar utility fuel consumption patterns. RFF and E2020 call for greater reliance upon natural gas and RFF calls for more nuclear.

[16] $30 per megawatt-hour would equal 3 cents per kilowatt-hour. These are wholesale electricity prices that exclude transmission and distribution costs.

[17] In subsequent versions of the model, RFF has incorporated stranded costs on a utility by utility basis.

[18] The regional definition of NWP and RA are slightly different in IPM than in the other models. What has been labeled here as NWP is a subset of the full NWP used by others, and the remaining part is included with RA.

**Figure 7. Regional Competitive Wholesale Electricity Price in Baseline Case, 2010**

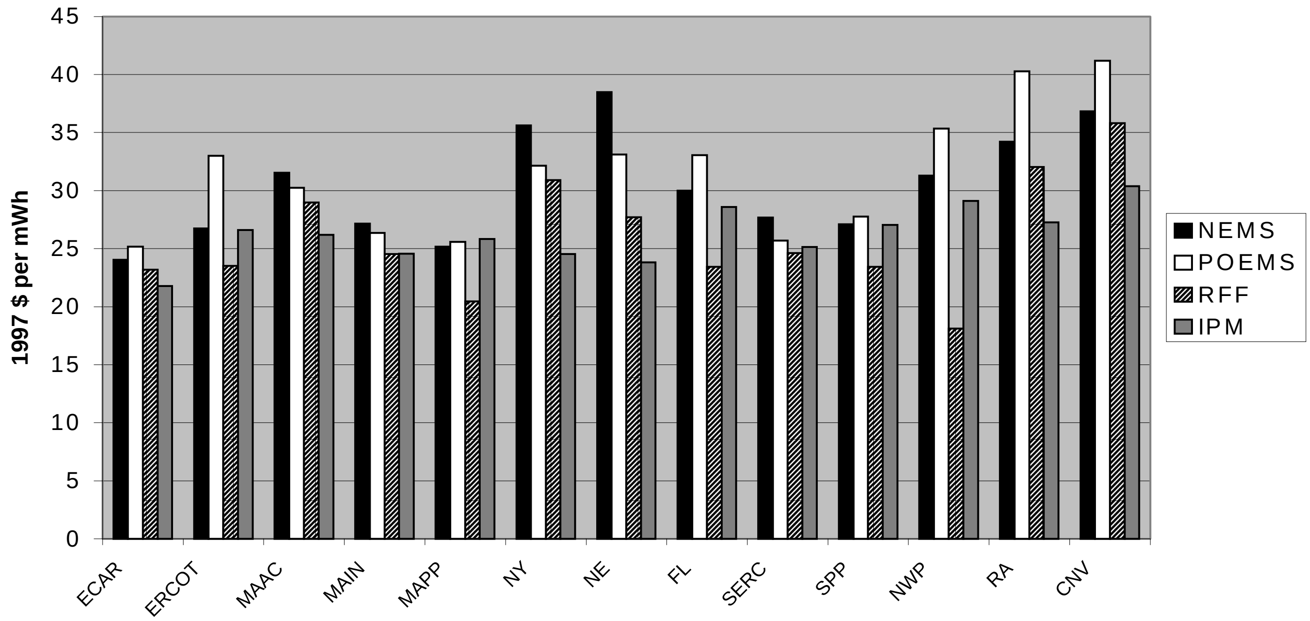
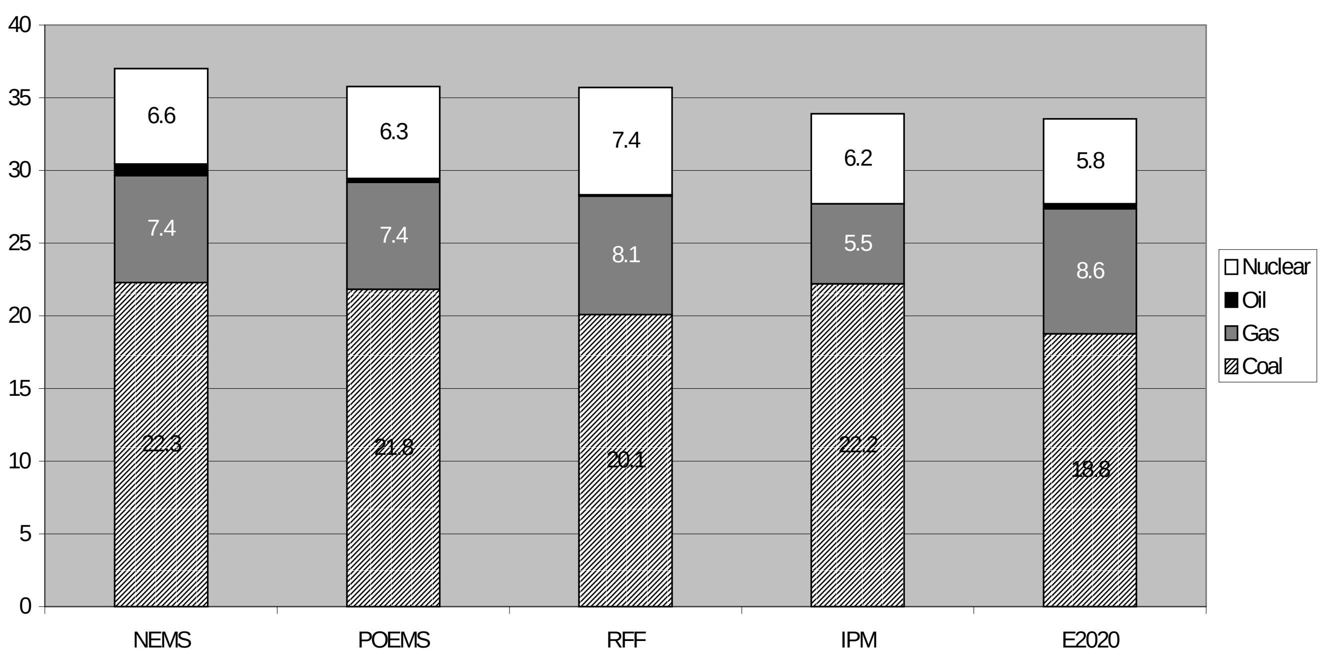



**Figure 8. Fuel Consumption (Quadrillion BTUs) for Electricity in Baseline, 2010**



IPM registers lower total fuel use, primarily in its lower use of natural gas.

A number of factors contribute to these fuel use patterns. The pattern of end-use loads or demands has an important role. If peak demand grows rapidly and is not strongly responsive to rising prices during the peak period, generators will be encouraged to build natural gas plants with low capital costs that can be operated over fewer hours to meet the higher demand. Coal plants with higher capital costs and lower operating costs might be built to meet demands of longer duration or base loads.

The dispatch of existing and new units is determined by relative operating costs and by the opportunities to trade among regions. Operating costs are affected by heat rates, which measures how much energy is used to generate a kilowatt hour of electricity. Assumptions about improvements in existing plant heat rates and the heat rates of new plants might therefore affect the dispatch choice. Industry restructuring may introduce pricing reforms that will change the load pattern and will bring forth competitive pressures that will encourage cost-cutting operations and purchasing new units with improved heat rates. These heat rates directly affect the amount of fuel required for generation. Although these factors are difficult to disentangle, they will strongly shape the industry's response to future conditions.

Moreover, the share of operations and maintenance (O&M) costs assumed to be included in the bid prices vary among the models. When a model assumes that more O&M costs are passed through to the bid price, units with higher O&M costs will be dispatched less frequently than those with lower O&M costs. This effect could influence fuel use in the power sector.

Although the RFF coal prices remain lower relative to gas prices than for the other projections, they indicate more natural gas use for electric power. RFF has slightly more optimistic assumptions about technological change in combined-cycle units than those found in NEMS and POEMS. As a result, more new plants are built and these units are fired by natural gas. The RFF model can not directly simulate reductions in costs of building new plants as a result of prior learning as is done in NEMS and POEMS. Instead, the model tries to incorporate this effect by assuming lower costs initially that, over several years, will approximate the effect of learning on costs found in other models.

These developments, the past and future improvements of gas turbine technologies, and higher cost of capital in competitive markets expand the use of gas in combined-cycle units over coal to meet baseload demand, even though fuel prices paid by generators tend to move slightly in favor of coal over time. While inflation-adjusted (or real) coal prices remain relatively stable over the decade, natural gas prices tend to rise. In 2000, coal prices delivered to generators in most models are approximately 40-45% of the comparable gas price (Figure 9). By 2010, they decline to about 30-35% of the gas price.

*Emissions*

This shift in the U.S. power sector to natural gas rather than coal causes annual U.S. emissions for sulfur dioxide, nitrogen oxides, and carbon dioxide from the power sector to grow more slowly than electricity demand over the next decade.

Figure 10 reveals that the national sulfur dioxide annual emissions decline by anywhere between 1.0 to 2.5 million metric tons over the 2000-2010 period. This trend reflects the national cap on emissions imposed by the Clean Air Act and that generators are using banked allowances, or allowances earned prior to 2000, during this period. The similarity across different projections reflects

**Figure 9. Coal-Gas Price Ratio for Utilities in Baseline Case, 2000-2010**

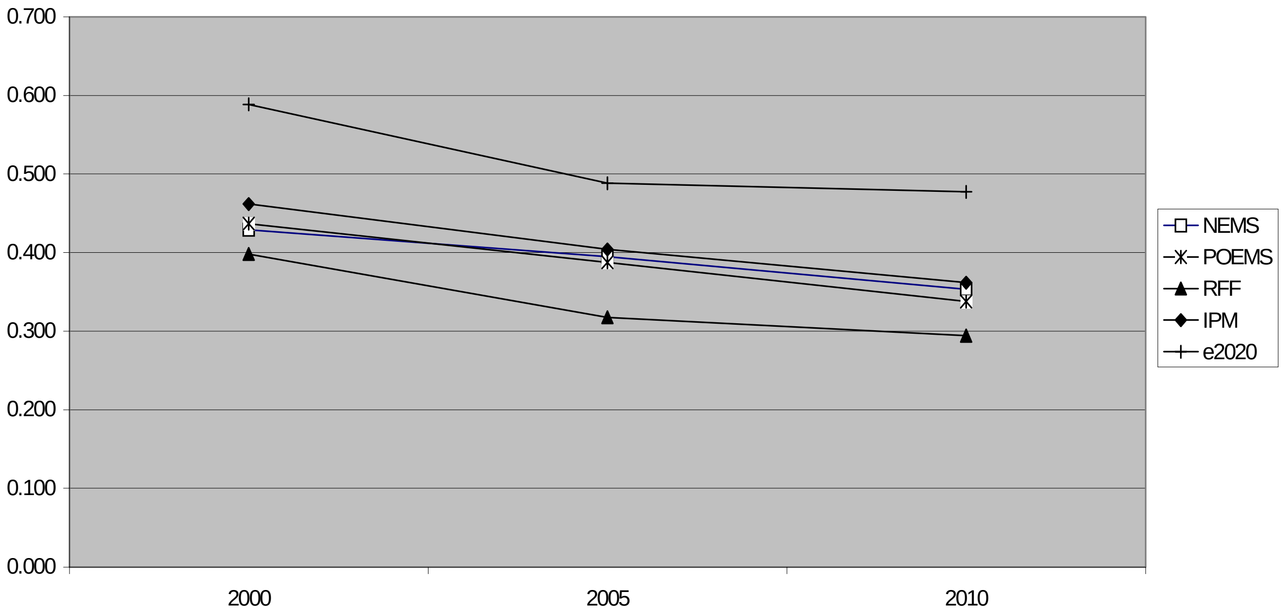



**Figure 10. Sulfur Dioxide Emissions in Baseline Case, 2000-2010**

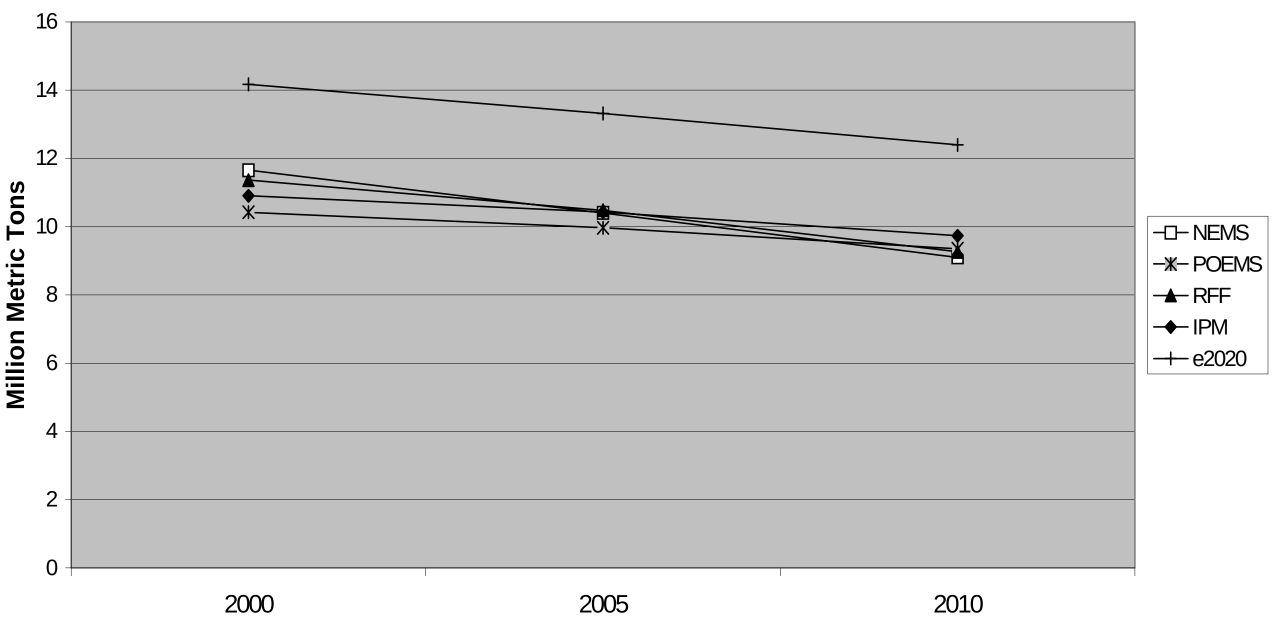
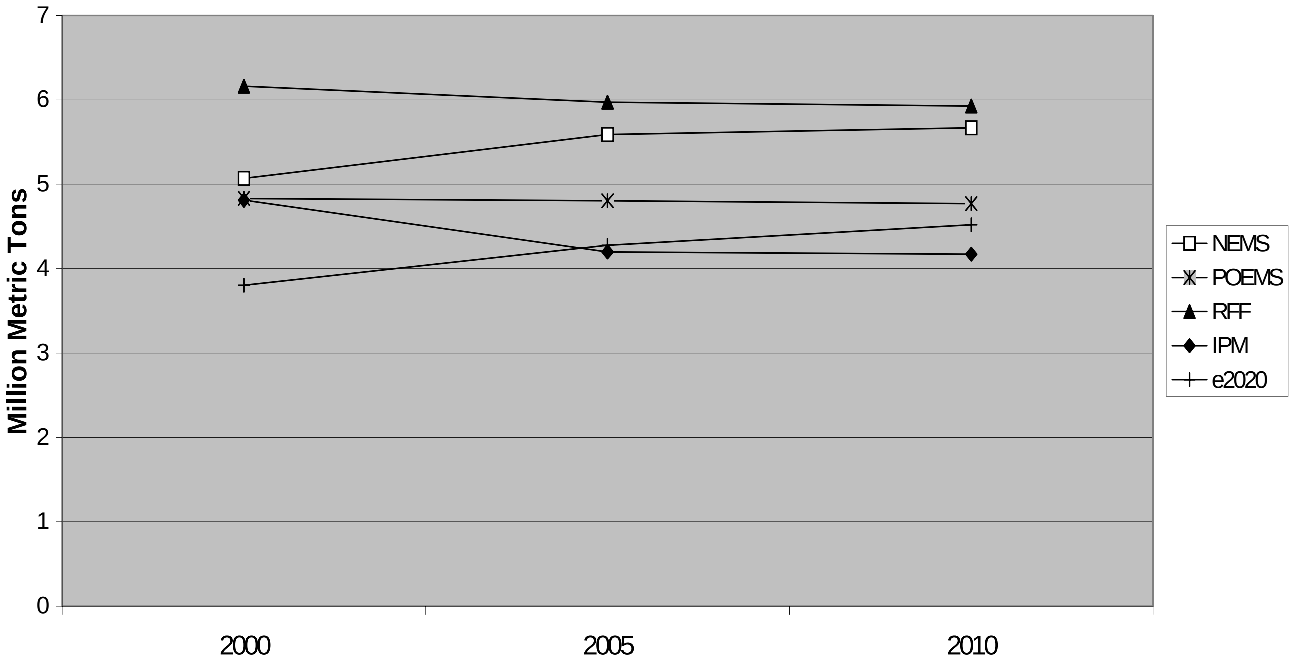


**Figure 11. Nitrogen Oxide Emissions in Baseline Case, 2000-2010**




the national caps that have already been imposed on these emissions in the baseline conditions. No national cap is specified in E2020 and therefore the base level emissions are higher across the entire time period. However, similar amounts of reductions over time are achieved.

Nitrogen oxides emissions in Figure 11 tend to remain quite steady over the next decade, except for the increase between 2000 and 2005 in NEMS and Energy 2020. The RFF emissions remain more than 1 million metric tons (or approximately 25%) above the POEMS emissions throughout the decade. The NEMS emissions remain between the RFF and POEMS emission paths. These three projections of the baseline competition case incorporate no new environmental policies that have not already been approved by policymakers.[19] At the end of the decade, nitrogen oxides emissions increase by 0.6 million metric tons (or 11.8%) above 2000 levels in NEMS and decrease by 0.2 million metric tons (3.8%) in RFF. However, the lower IPM trend incorporates the summer peak $NO_x$ restrictions and reveals a decline of about 0.6 million metric tons (13.3%) of $NO_x$ emissions over the decade.

Carbon dioxide emissions in Figure 12 rise in NEMS and POEMS but at slower rates (1.3% and 0.9% per annum over the 2000-2010 decade) than electricity generation (1.6% per annum). Emissions grow by 95 million metric tons in NEMS and by 65 million metric tons in POEMS and IPM over the decade. The RFF emissions are relatively stable throughout the ten years. The

[19] Hence, the projections, except those of IPM, ignored the restrictions on summer-peak $NO_x$ emissions in 19 eastern states that were imposed by the Ozone Transport Rule (OTR) established by the Clean Air Act Amendments of 1990 and by State Implementation Plans (SIP) Call policies, which were being challenged in court at the time of this study.
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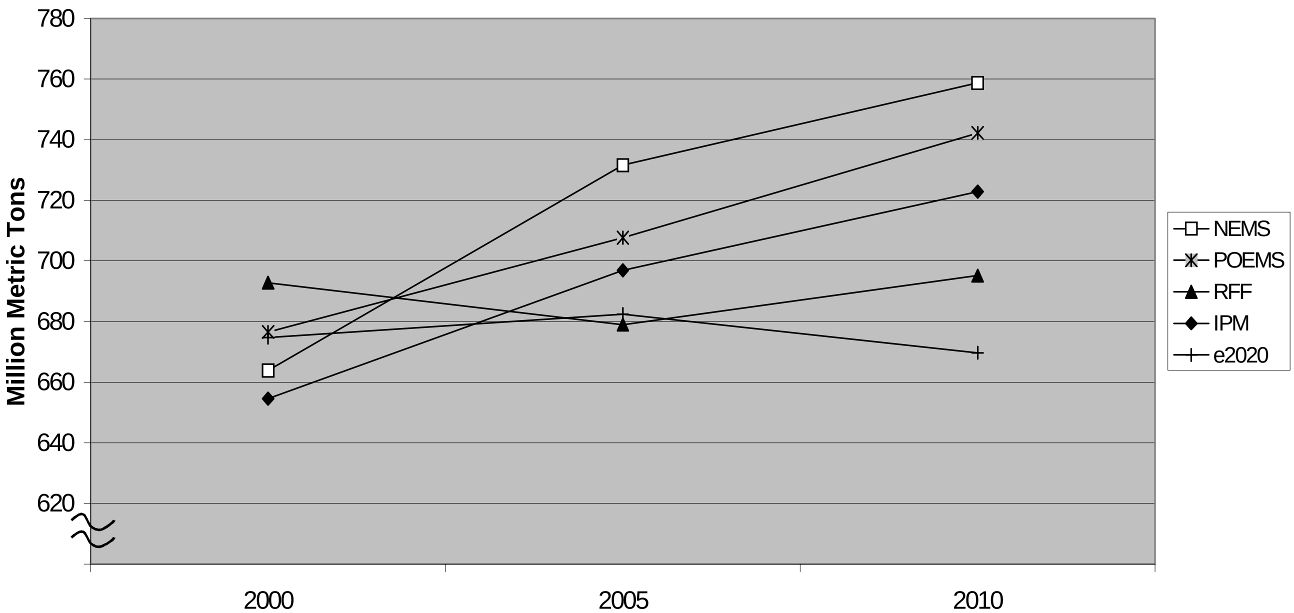
**Figure 12. Carbon Emissions in Baseline Case, 2000-2010**




slower retirement of nuclear plants in this projection contributes to this noticeably slower growth in carbon emissions. The initial drop in RFF emissions from 2000 to 2005 is due to a shift from oil to gas generation and to more efficient units, as a large share of oil and gas steam plants retire. The E2020 carbon emissions are relatively stable over the forecast period, decreasing by 5 million metric tons in 2010 relative to 2000. This is largely due to a shift towards gas-generated power and slower electricity demand growth than the other models.

*Interregional Electricity Trade*

The projections expect similar volumes of total electricity trade among the 13 different regions for which all models report results. These regions are based upon those used by the North American Electric Reliability Council (NERC) shown in Figure 13. There is no trend towards increasing electricity trade over time in these baseline projections. It should be emphasized that these trade estimates ignore any imports and exports between power control areas or between companies within these large regions. They are also annual averages that do not reflect seasonal conditions.

By 2010, NEMS projects 259 billion kWh of imports into these NERC-related regions from one of the other areas, POEMS projects 209 billion kWh, RFF expects 238 billion kWh, and IPM anticipates 171 billion kWh. As a percent of total U.S. generation, these estimates range from 4.1% to 6.2%. However, Figure 14 shows that the regional patterns for interregional imports do vary among projections. For example, relative to the other projections, RFF calls for more imports into the midwestern states represented by ECAR and the eastern MAAC region and fewer imports into Illinois and Wisconsin represented by the MAIN region and into California and Nevada within the

**Figure 13. Electricity Market Module Regions**

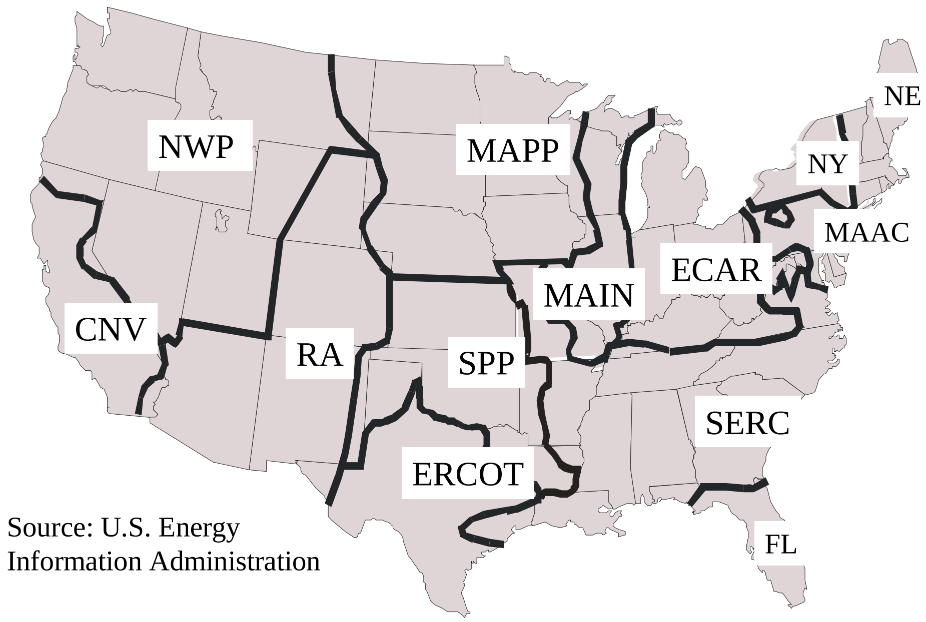
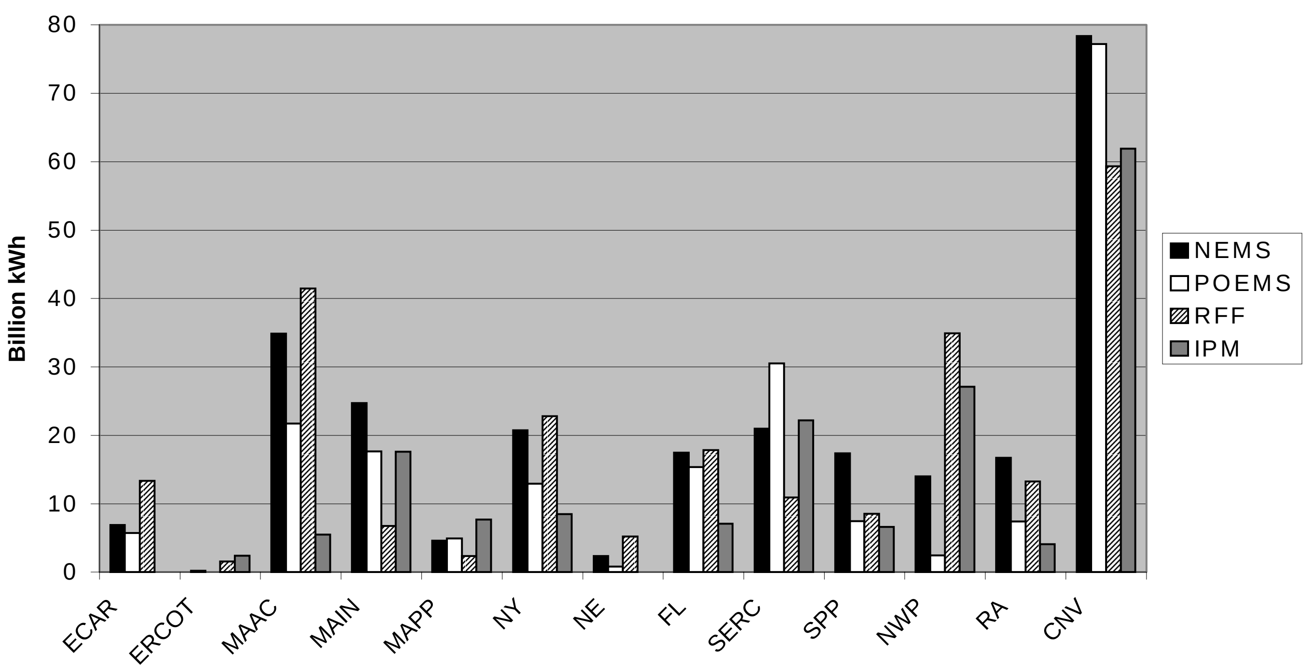



**Figure 14. Interregional Imports in Baseline Case, 2010**



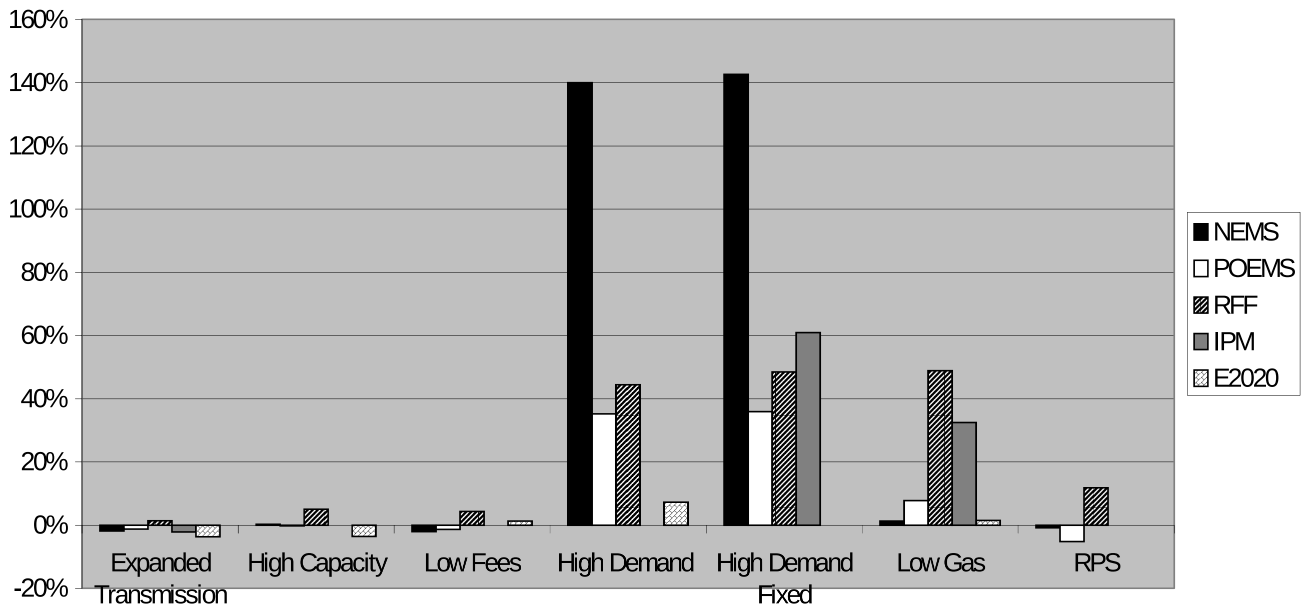
WSCC region. IPM projects considerably less trade in the Eastern Interconnection regions.[20]

These four U.S. outlooks anticipate that electricity imports from our North American neighbors, Canada and Mexico, will range from 29 to 44 billion kWh in 2010. The lower end of these estimates are only slightly higher than the 25 billion kWh that the Canadian Energy Research Institute (CERI) is projecting for Canadian exports to the United States. The latter estimate, of course, excludes the Mexican exports included in the U.S. projections. The similarity between estimates from some U.S. models and a Canadian model probably reflects that these models are projecting international electricity trade on the basis of current permits.

## Alternative Competition Cases

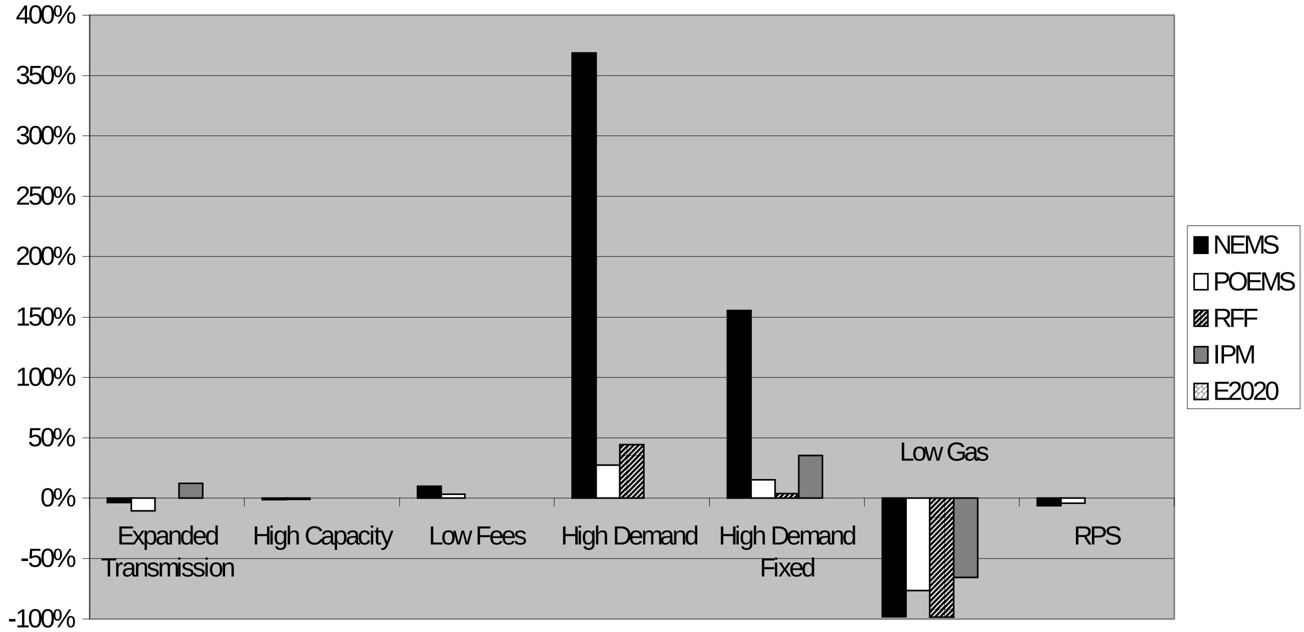
The alternative cases show how competitive market conditions change with other assumptions for baseline demand growth, natural gas prices, transmission fees and capacity, and a renewables portfolio standard (RPS). Often, changes in assumed conditions will lead to several effects that can be difficult to discern. Therefore, to help understand these cases, the group also requested that the modelers run additional cases for the expanded transmission case and for the higher demand case. The two additional transmission cases considered the effects of lower transmission fees and higher transmission capacity separately. The additional high electricity demand case kept natural gas prices at their baseline levels, rather than allowing them to rise with the additional load growth. All models except IPM reported the additional transmission and high demand cases. IPM also did not report the RPS case.

**Figure 15. Percent Changes in Combined Cycle Cumulative Additions from Baseline Case, 2000-2010**




[20] The IPM results for the Western regions are not quite comparable with the other models due to a different regional definition (see footnote 18).

**Figure 16. Percent Change in Coal Capacity Cumulative Additions from Baseline Case, 2000-2010**




*Capacity Additions*

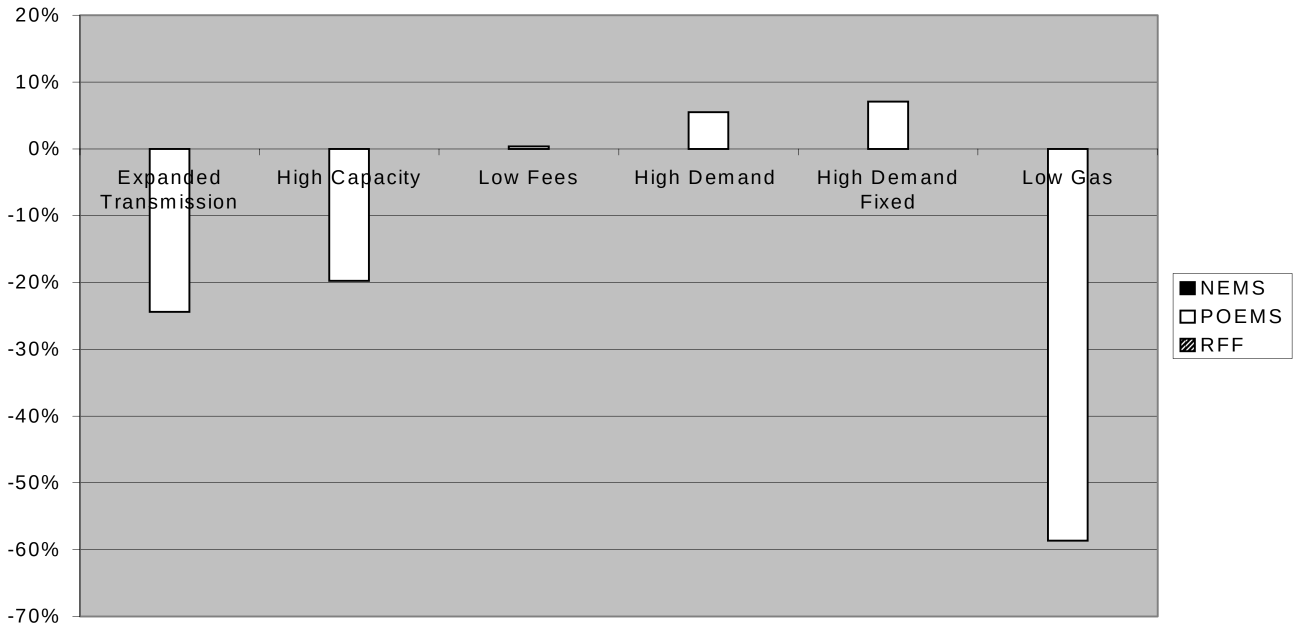
The cumulative additions for combined-cycle units (Figure 15) over the decade remain within 10 percent or less of the baseline competition case for all cases except the high demand cases and the RFF and IPM lower natural gas price case.[21] Combined-cycle plants dominate new capacity additions under the baseline conditions. Their prospects do not change much for any of the models in any of the expanded transmission cases.

Natural gas price changes are important in shifting the mix or quantity of capacity additions in RFF and IPM. In IPM the mix of additions shifts from 84 percent gas technologies to 93 percent and the mix between the combined cycles and turbines shifts to a greater reliance on combined cycles. In RFF, additions are dominated by combined cycles in both cases (over 80% of total), but low gas prices create greater capital stock turnover, and total additions by 2010 increase 41 percent relative to the Base case. For both NEMS and POEMS, low gas prices increase retirements and additions only modestly and the share of combined cycle additions changes little.

However, total demand is the dominating factor in NEMS for cumulative combined-cycle additions. For NEMS the very significant proportional increase in additions due to high growth is primarily the result of relatively low additions in the baseline case, and to a lesser extent, due to a shift in the mix of additions to greater use of combined cycles and fewer combustion turbines.

[21] The RFF RPS case is also almost 12% above the baseline competition case.

**Figure 17. Percent Change in Wind Capacity Cumulative Additions from Baseline Case, 2000-2010**




E2020 demonstrates smaller response for capacity additions, and much of it is in combined cycle plants. High demand generates the largest response at approximately 7 percent. Changes for other scenarios are minimal.

Perhaps reflecting the models' assumptions that coal technology does not progress significantly, the cumulative additions for coal capacity over the decade are relatively small in the baseline case. With higher demand conditions, these additions over the decade expand by at least 25% in each model (with the exception of E2020) and by more than 350% in the NEMS projections (Figure 16). Higher demands expand total capacity additions, including coal capacity. Because gas prices increase in integrated high demand case, the coal share while still small increases slightly. Lower natural gas prices almost eliminate any new coal capacity in NEMS and RFF, and strongly reduce it in POEMS and IPM.

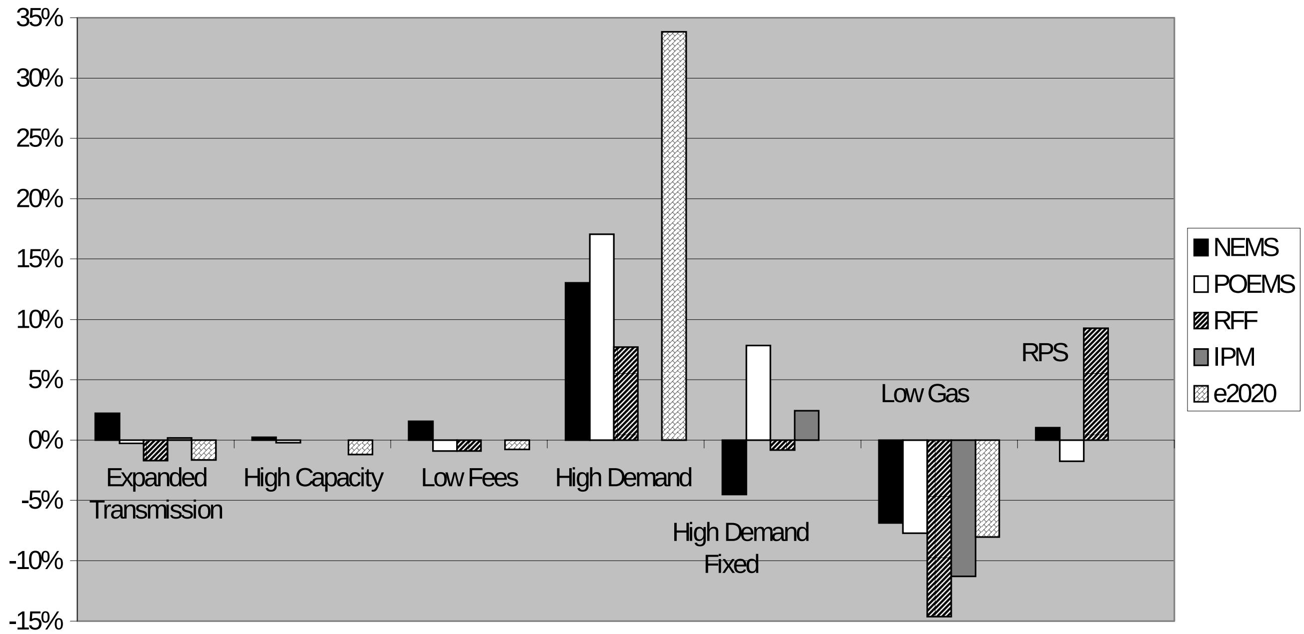
Wind capacity additions over the decade increase dramatically from 2.3 gigawatts in the baseline competition case to 8.0 gigawatts in the RPS case in POEMS. They also increase strongly in RFF as well, from 0.1 gigawatts in the baseline competition case to 4.6 gigawatts in the RPS case. However, Figure 17 indicates that wind capacity additions in RFF do not change across the other cases, nor do they change in any case in NEMS. As a result, only POEMS reveals any fluctuations in wind capacity additions across all cases.[22] This figure indicates that expanded transmission facilities (especially, higher capacity) and lower natural gas prices (in addition to the RPS conditions described above) significantly reduce cumulative wind capacity additions in POEMS.

*Electricity Prices*

Figure 18 reveals that natural gas prices and electricity demands are two important influences on the future path for electricity prices. The only

[22] IPM did not report wind capacity separately.

**Figure 18. Percent Change in Competitive Wholesale Electricity Price from Baseline Case, 2010**




other significant change at the national level occurs with the RPS case in the RFF model. Otherwise, the alternative conditions for electricity transmission and the RPS generally have very modest effects that remain below 5% of the baseline values.

Larger changes are seen for some regional electricity prices. The largest gain relative to the baseline (27%) occurs for the midwestern MAIN region in the NEMS model in the high demand case. The largest reduction relative to the baseline (22%) occurs for New York in the RFF model in the low gas price case. While the national prices change by no more than 2% from their baseline levels in the alternative transmission cases, regional prices can increase or decrease by as much as 12 or 13% in these cases.

In general, importing regions with higher prices in the baseline case will experience price reductions with more transmission access, while low cost exporting regions will see higher prices. As discussed in the section on the baseline case, these prices are the competitive wholesale levels before any adjustments for stranded costs are added.

The outlooks agree that lower natural gas prices will reduce competitive electricity prices while higher electricity demand will increase electricity prices. However, the pattern across outlooks is rather different. RFF and IPM reveal rather large reductions in electricity prices when gas prices fall; the declines in NEMS, POEMS and E2020 are more modest. By contrast, the NEMS and POEMS electricity price increases are greater when electricity demands grow more vigorously, while the RFF and IPM price increases are more modest. The increase in E2020 electricity prices is much larger than other models, because total available capacity is fixed, resulting in higher prices and declining reserve margins.

Several factors could be contributing to the higher electricity prices in the high electricity demand case. First, the industry could be pushed out further along its supply stack and forced to use more

**Table 5. Percent Change in Generation and Electricity Price in the High-Demand Cases (from the Baseline Case), 2010**

| | High Demand with Fixed Price | | High Demand with Integrated Price | |
|---|---|---|---|---|
| | Generation | Price | Generation | Price |
| NEMS | 12.54 | -4.53 | 12.54 | 13.04 |
| POEMS | 10.41 | 7.83 | 10.45 | 17.05 |
| RFF | 10.71 | -0.82 | 12.82 | 7.70 |
| IPM | 10.33 | 2.44 | | |
| E2020 | | | 13.21 | 33.81 |

expensive units to meet the higher demand. Second, the addition of new capacity will create higher demand for fuel by generators and this increased consumption could bid fuel prices higher. Both limits on the gas resource base and gas pipeline bottlenecks could induce these higher prices. In using more natural gas, the power sector must shift gas away from other end-use sectors as well as encourage more natural gas production. These two factors will both lead to higher competitive electricity prices than under the baseline conditions.

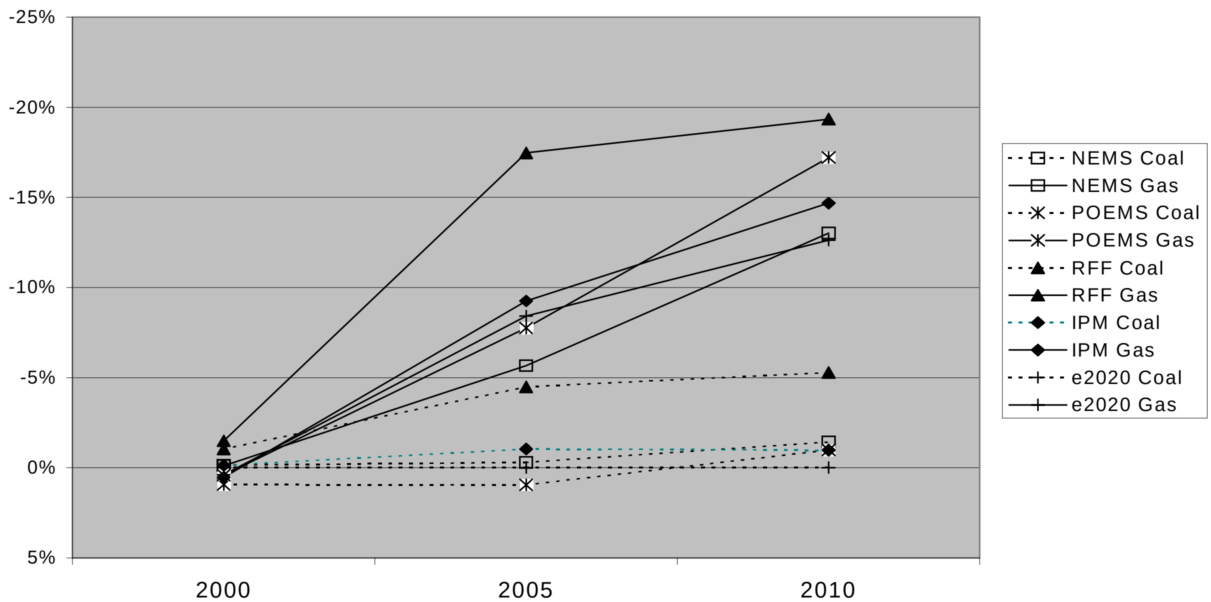
Several other factors are also changing the average electricity price between these two cases. Even if the demand curve is shifted outward by the same proportion in all hours and days, prices could move upward more quickly during peak times and loads could be shifted away from these high-price periods. As a result, electricity use might grow more rapidly in nonpeak than in peak times, thereby decreasing the average price as consumption was shifted between periods. Another complication lies in the effect of higher demand on changing retirements and additions, both of which will influence the shape of the supply stack between the two cases.

When demands are increased and natural gas prices are fixed at their baseline values, the results show what happens to electricity prices when the increased fuel costs are ignored. POEMS shows a 7.5% increase and IPM a 2.4% increase in wholesale competitive electricity prices, which is consistent with the view that costs will rise as the industry moves further out on its supply stack. NEMS reveals a decrease of almost 5% by the end of the decade, which could be due to shifts in the supply stack attributable to retirements and additions. There is virtually no change in RFF's electricity price, and E2020 did not report results for this case. The POEMS increase is less than the 10.5% increase in total electricity demand in that model.

These results demonstrate that natural gas conditions can have a significant effect on electricity prices. In an effort to achieve greater consistency in the demand shock, the modelers in this study did not allow these higher electricity prices to reduce the use of power. In actual electricity markets and when these models are usually simulated, however, the higher power prices would offset some, but not all, of the initial growth in electricity consumption. Under these conditions, both electricity consumption and gas use by the power sector would be lower, as would the price of natural gas and electricity.

Given the important qualifications on which factors are changed in this case, the high-demand cases also reveal some information about how much electricity prices will respond relative to electricity generation when the desire for elec-

**Figure 19. Percent Change in Fuel Prices for Generation in Low Gas Price Case from Baseline Case, 2000-2010**



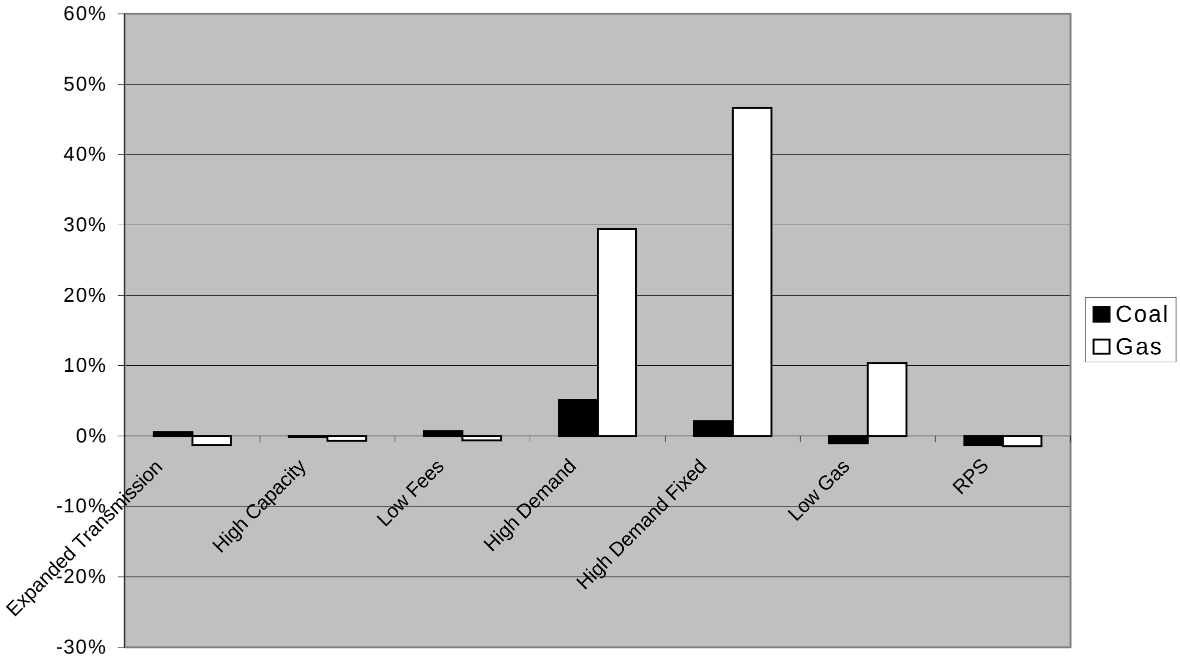

tricity expands. Table 5 shows that total generation and the competitive wholesale electricity price each rise by about 12.5-13% above baseline levels in NEMS in the high-demand case with integrated fuel prices (the last set of columns). Thus, the inferred supply response or elasticity is near unity in this model.[23] Prices increase the most in E2020; generation increases are not that high, indicating a much lower supply elasticity. Similarly, prices increase more than generation in POEMS, inferring a lower supply elasticity, although the gap between the change in price and generation is much smaller than in E2020. Prices increase less than generation in RFF, inferring a higher supply elasticity.

The first set of columns in Table 5 shows the same computations when higher demands are allowed but natural gas prices are kept at their baseline levels. The results show a much lower increase in electricity prices when natural gas prices do not increase. As a result, the inferred elasticity is much greater. In fact, there is a decline in the NEMS competitive wholesale electricity price in this case, while the RFF price remains virtually unchanged. This result probably reflects the influence of retirements and additions on the supply stack in the two cases.

Competitive wholesale electricity prices fall below baseline levels in the lower gas price case as shown in Figure 18. Figure 19 shows that natural gas prices in RFF fall sharply to more than 15% below baseline values in 2005 and almost reach 20% below baseline by 2010 because they rose more quickly in their baseline case. (The figure shows decreases as negative values that increase as you move upward in the chart.) The

[23] The price elasticity of electricity supply is defined as the percentage change in electricity quantity supplied divided by the percentage change in price, holding other factors constant. Clearly, these other factors that are held constant will certainly influence the measured response. Thus, the reader is discouraged from computing implicit elasticities from the numbers in Table 5 as being a model's elasticity.

**Figure 20. Percent Change in Fuel Consumption for Electricity Generation in NEMS from the Baseline Case, 2010**




natural gas prices relative to the baseline case fall more slowly in the other models, although the changes in gas price trends move closer to each other by the end of the decade. Moreover, the RFF coal prices also decline more than 5% below the baseline by 2010. The downward pressure on fuel prices paid by the power sector contributes to the relatively strong decline in competitive power prices in that model shown in Figure 18.

*Fuels*

Changes in electricity demands and natural gas prices dominate the response of combined-cycle capacity additions in the alternative competition cases. This same pattern is observed for the fuels used by the power sector in these cases. In general the percent change in gas consumption will be greater than a percent change in coal, because the base coal consumption is substantially larger.

In Figure 20, NEMS shows natural gas use in the power sector increasing by 45% above the baseline when demands are increased and natural gas prices are fixed at the baseline levels. This increment declines to 30% above the baseline levels when natural gas prices are allowed to increase as well. The higher gas prices discourage gas use in the power sector.[24] In this model, lower gas prices cause 10% more gas consumption by the power sector relative to the baseline case.

In Figure 21, POEMS displays a similar pattern, although the estimates vary somewhat. The high demand case with fixed prices results in a 36% increase in gas consumption in the power sector above the baseline when fuel prices are fixed and a 31% increase in the integrated high demand case with rising gas prices. Gas use for generation increases by 15% above the baseline when gas prices fall below the baseline.

The RFF results in Figure 22 show a substantially larger adjustment in coal and gas generation in the low gas price case than in the other cases. The power sector's gas use in 2010 expands by

[24] For reasons given in the previous section, if the modelers had allowed electricity consumption to decline with higher electricity prices, natural gas use would have declined more but electricity prices would not have risen as much.

**Figure 21. Percent Change in Fuel Consumption for Electricity Generation in POEMS from the Baseline Case, 2010**

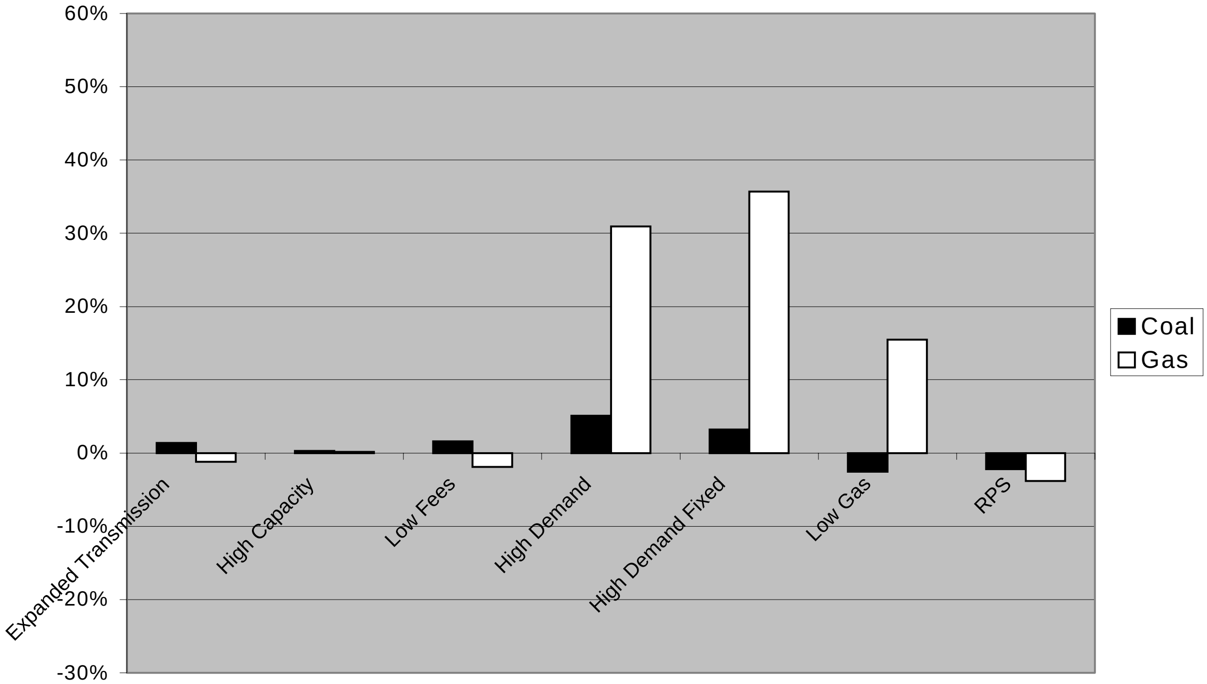



**Figure 22. Percent Change in Fuel Consumption for Electricity Generation in RFF from the Baseline Case, 2010**

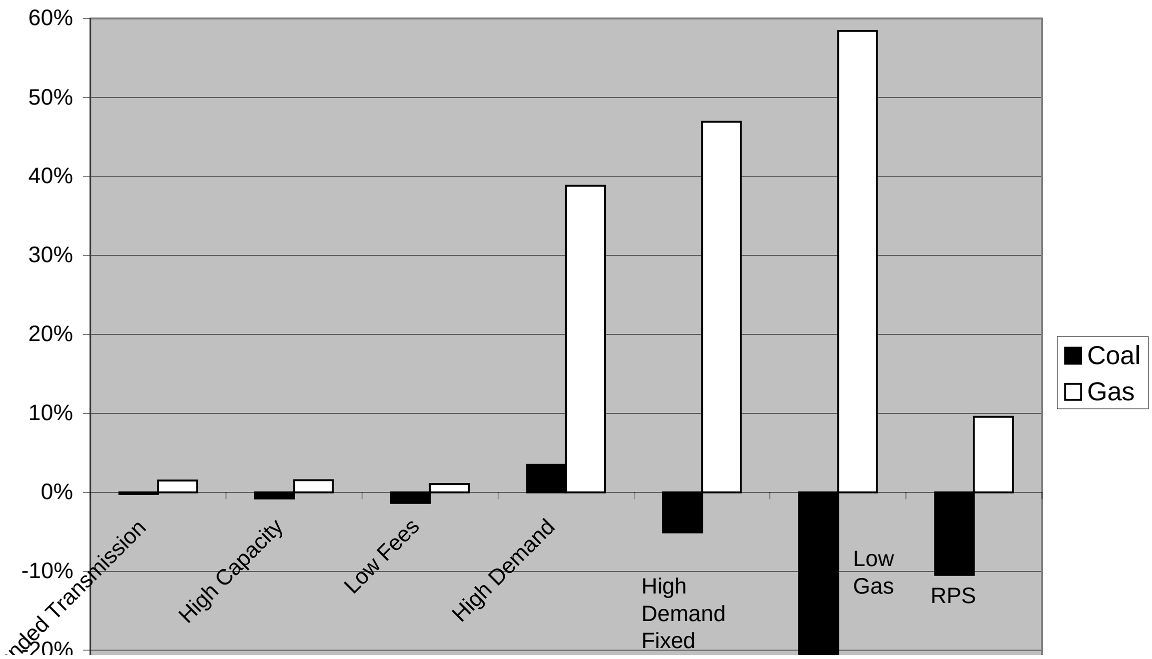


**Figure 23. Percent Change in Fuel Consumption for Electricity Generation in IPM from the Baseline Case, 2010**

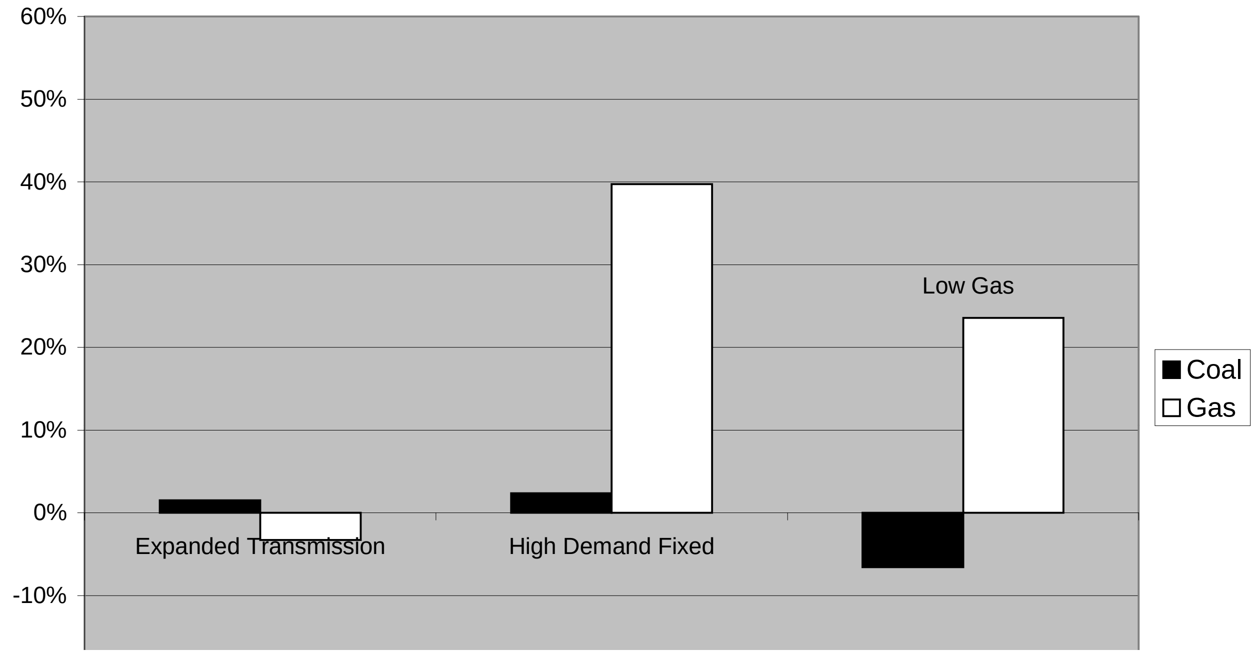



**Figure 24. Percent Change in Fuel Consumption for Electricity Generation in ENERGY2020 from the Baseline Case, 2010**

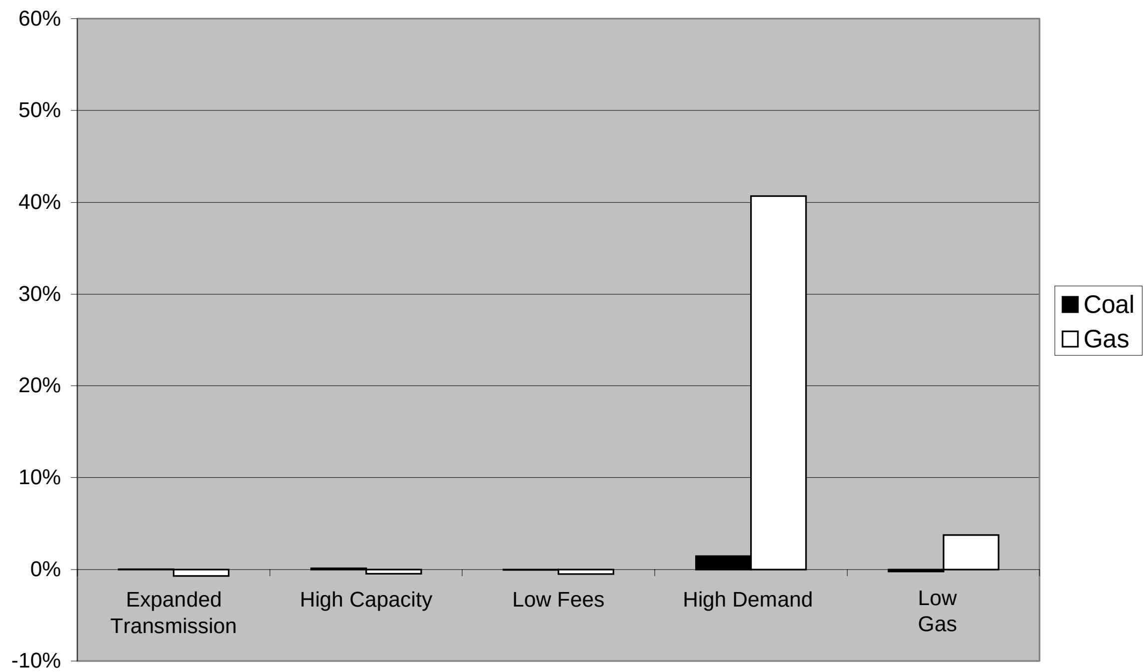
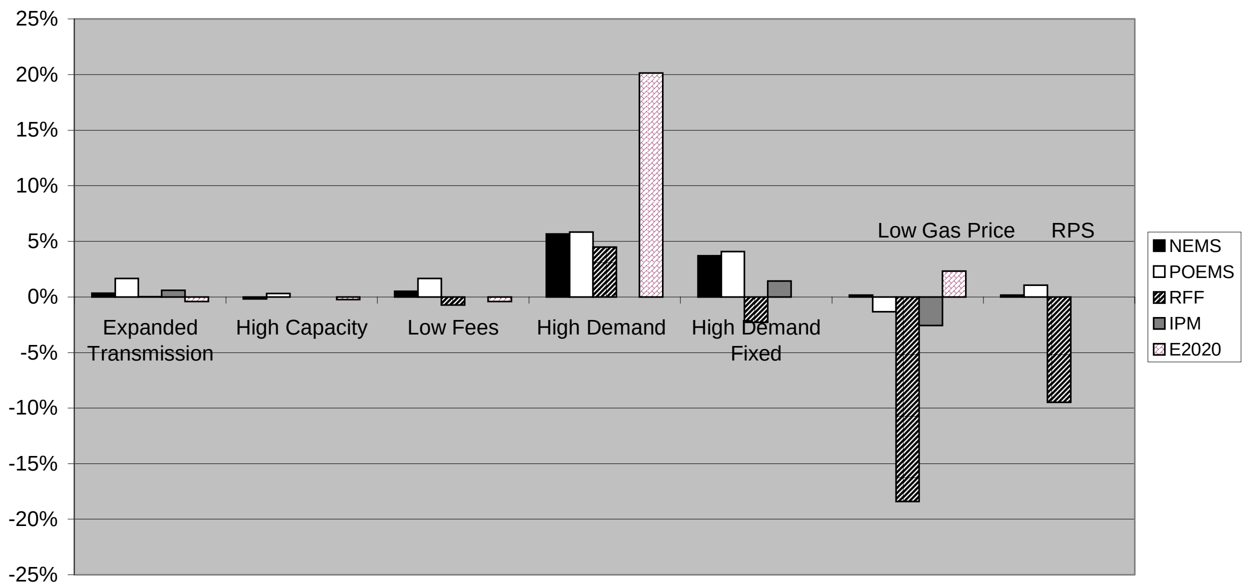


**Figure 25. Change from Baseline (%) in Nitrogen Oxide Emissions, 2010**




58% above the baseline while its coal use contracts by 22%. This gas expansion is stronger than that observed for the high-demand case.

The expansion in natural gas generation in the IPM results in Figure 23 is stronger for the high demand case with fixed prices than for the lower natural gas price case. However, the model's response to gas prices is in between the NEMS and POEMS results.

In Figure 24 showing E2020 results, high demand generates a 41% increase for gas use in the electricity sector, which is similar to the other models. However, the model's response to low gas price is minimal at 3.7%.

In all but RFF, the increased transmission cases lead to a modest shift from gas to coal generation. As new gas construction changes the existing regional endowment of capacity, this shift towards coal becomes less pronounced and the changes appear less in 2010 than in 2000 and 2005.

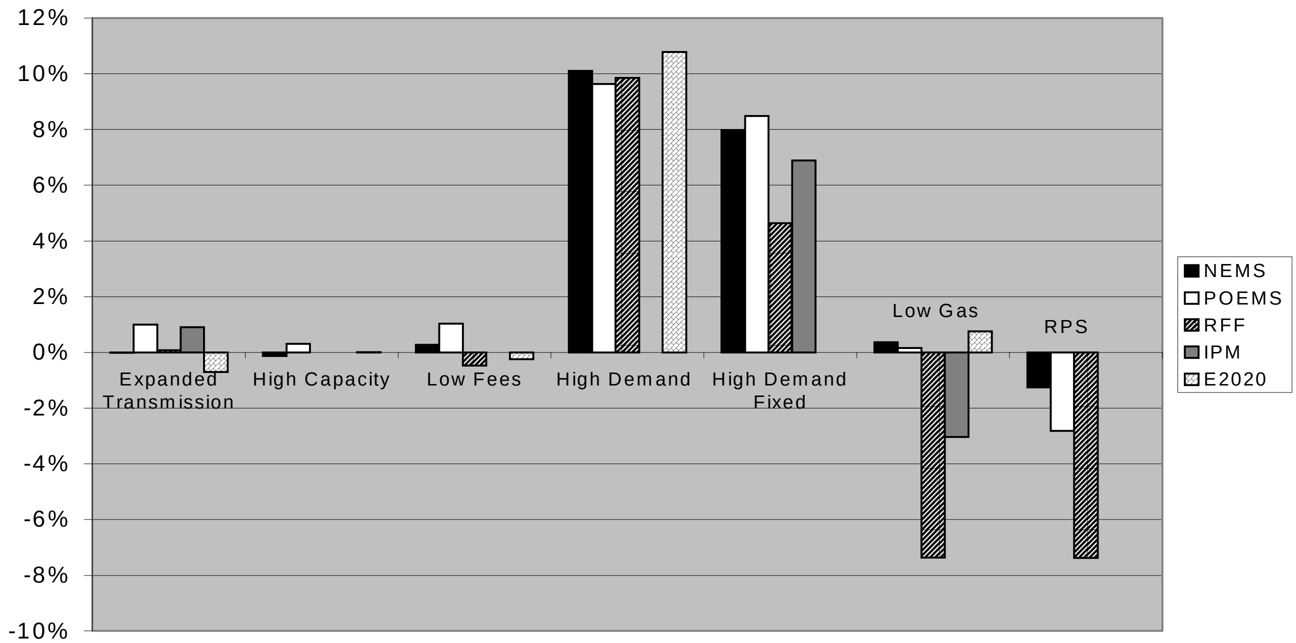
*Emissions*

Higher demands tend to increase the power sector's carbon emissions more than nitrogen oxides or sulfur dioxide emissions in these simulations. Annual carbon emissions for the nation grow by 7-10 percent more than baseline levels by 2010 when energy demands increase by 12 percent. Nitrogen oxides emissions for U.S. grow by approximately 5 percent more by 2010, while U.S. sulfur dioxide emissions remain unchanged.

No new nuclear plants play an important role in this result. Lower natural gas prices and additional incentives for renewable energy technologies appear to decrease nitrogen oxides and carbon emissions in this sector. National caps tend to keep sulfur dioxide emissions close to their baseline levels in all scenarios.

Sulfur dioxide emissions in 2010 remain relatively similar to baseline levels for most models and cases. By 2010, firms do not change their

**Figure 26. Change from Baseline (%) in Carbon Emissions, 2010**




emissions levels much from the baseline, although the alternative conditions can change the costs of $SO_2$ allowances, which will influence generation costs.

Figure 25 reveals that the higher demand conditions increase nitrogen oxides emissions by approximately 5% by 2010 in three of the four models. Unlike sulfur dioxide, these emissions will be pushed higher by increased electricity demand. The nitrogen oxides emissions effect for higher demands is noticeably stronger than the effects in the expanded transmission case as well as in the low transmission fee and higher transmission capacity cases. RFF anticipates sharp reductions in nitrogen oxides emissions by the end of the decade when either natural gas prices are lower or when a renewable portfolio strategy (RPS) is implemented.

Carbon emissions in the power sector move with the higher demand conditions as shown in Figure 26. This trend reflects the absence of growth in any new nuclear plants due to a combination of costs and public perceptions. Carbon emissions grow by about 7% to 10% higher than baseline levels and hence increase somewhat less than total electricity demand.[25] Electricity demand is 13.7% higher than 2010 baseline levels in E2020, 12.5% higher in NEMS, 10.5% higher in POEMS, and 10.3% higher in RFF. The latter model (RFF) shows stronger reductions in carbon emissions with lower natural gas prices or with the RPS than do the other models. The reductions in nitrogen oxides and carbon in the RPS case in RFF stem from a decrease in coal capacity and therefore generation, as much as from an increase in renewable generation. In comparison, POEMS has a greater renewable response to the RPS but smaller gains in emission reductions.

[25] Constraints on carbon emissions could be imposed by pricing carbon through taxes or allowances, as has been analyzed by the Energy Modeling Forum Working Group 16. See Weyant, John P. (1999), editor, The *Costs of the Kyoto Protocol: A Multi-Model Evaluation*, *Energy Journal*, special issue.

*Interregional Electricity Trade*

Transmission policy can significantly influence electricity markets that are undergoing restructuring. The expanded transmission case establishes both higher transmission capacity and lower transmission fees. These conditions encourage more aggregate trading between all regions in the various projections shown in Figure 27. Total interregional imports increase by 23 percent above baseline levels in RFF and by 61 percent in NEMS. The increase is greatest (85%) for IPM, although that model had a lower baseline level of interregional imports.

The chart also shows that lower transmission fees dominate the effects of the expanded transmission case in NEMS and POEMS. These results underscore the importance of transmission pricing in determining the economic incentive for trade between regions, and that fees can be more constraining on trade than physical limits. In the weaker total effect in RFF, higher transmission capacity appears to be more important than lower fees, at least at an aggregate level.

These results have noticeable regional differences as well. No one regional pattern flows through all the outlooks. Figure 28 shows how the expanded transmission case affects imports into each major region by 2010. For example, California imports over 15 million kWh more than in the baseline case in NEMS and more than 35 million additional kWh in POEMS. Most of the smaller NEMS effect is due to lower transmission fees (Figure 29), while most of the larger POEMS effect is attributable to higher transmission capacity (Figure 30).

**Conclusion**

Properly functioning prices are the cornerstone of competition's potential efficiency. Competition does not guarantee a certain price, does not require electric loads to be a given magnitude, and does not assure generators that their plants will be used when they want them to be. Participants will need to protect themselves from these business risks. This study's results show how changes in electric load growth, natural gas prices, and transmission costs and expansions could influence conditions in markets where efficient rules have been established.

Electricity demand and natural gas prices will be important drivers for the power sector over this next decade as the industry undergoes further restructuring. For one of the scenarios in this study, total annual electricity demand was increased by 1% per year above the baseline levels. The projected response was a 10-14% increase in total electricity consumption over the decade and an increase in the competitive delivered price of electricity of between 7.7 and 17% above baseline levels after 10 years for most models except E2020, which has an increase of 33%. These adjustments incorporated higher natural gas prices that were necessary to keep gas flowing into the power sector to support this expansion. The cases assume that there are no severe limitations on large-scale natural gas pipeline expansion. Ignoring these higher gas prices, the competitive delivered electricity price would be no more than 7.8% higher than baseline in any of the projections. Thus, higher natural gas prices may contribute to higher electricity prices over the next decade if expanded electricity demand or more stringent environmental policy encourage more natural gas generation.

Lower natural gas prices with the same electric demand growth will reduce electricity prices and will help to stimulate natural gas use that may provide environmental benefits in terms of reduced carbon and sulfur dioxide but also costs in terms of. nitrogen oxides Thus, uncertainty about the cost of finding additional natural gas supply

**Figure 27. Change in Interregional Imports, 2010**

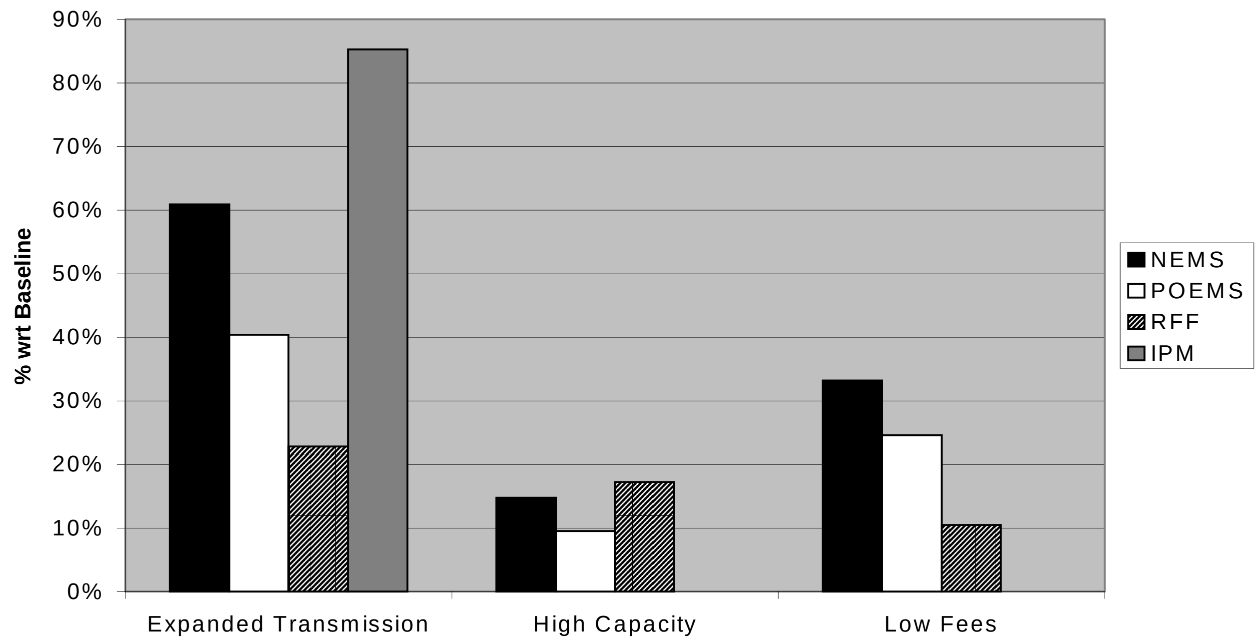



**Figure 28. Change in Interregional Imports in Expanded Transmission (wrt Baseline), 2010**

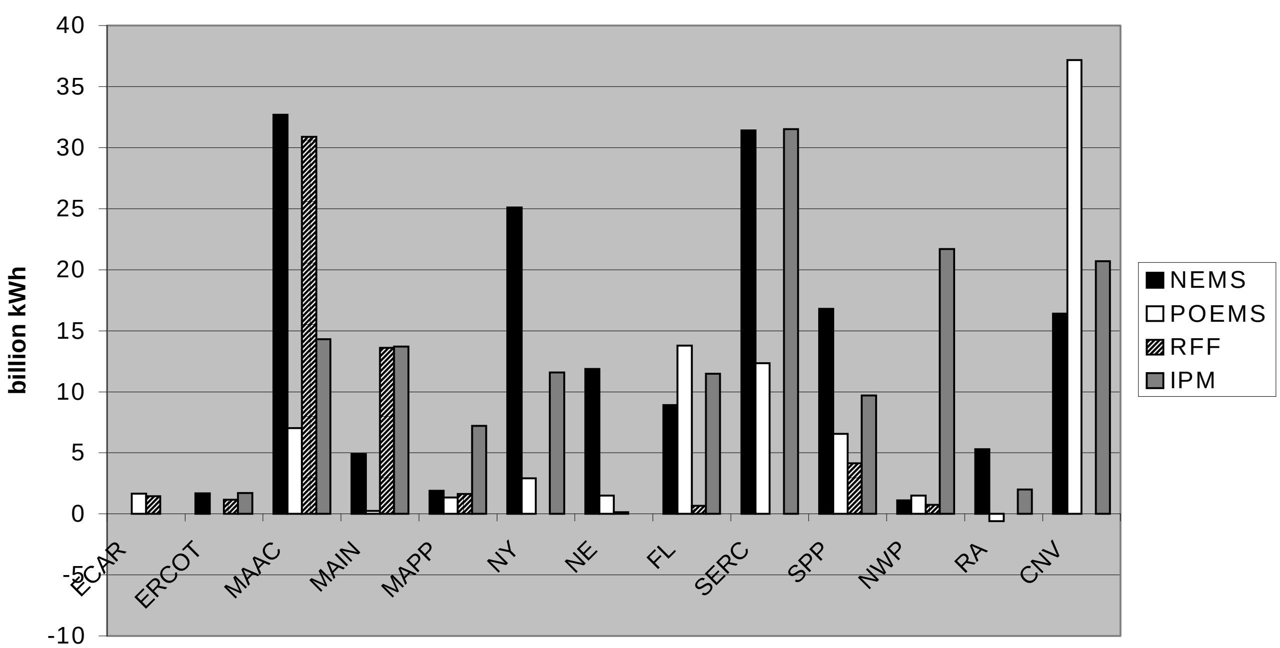


**Figure 29. Change in Interregional Imports in Low Transmission Fees wrt Baseline, 2010**

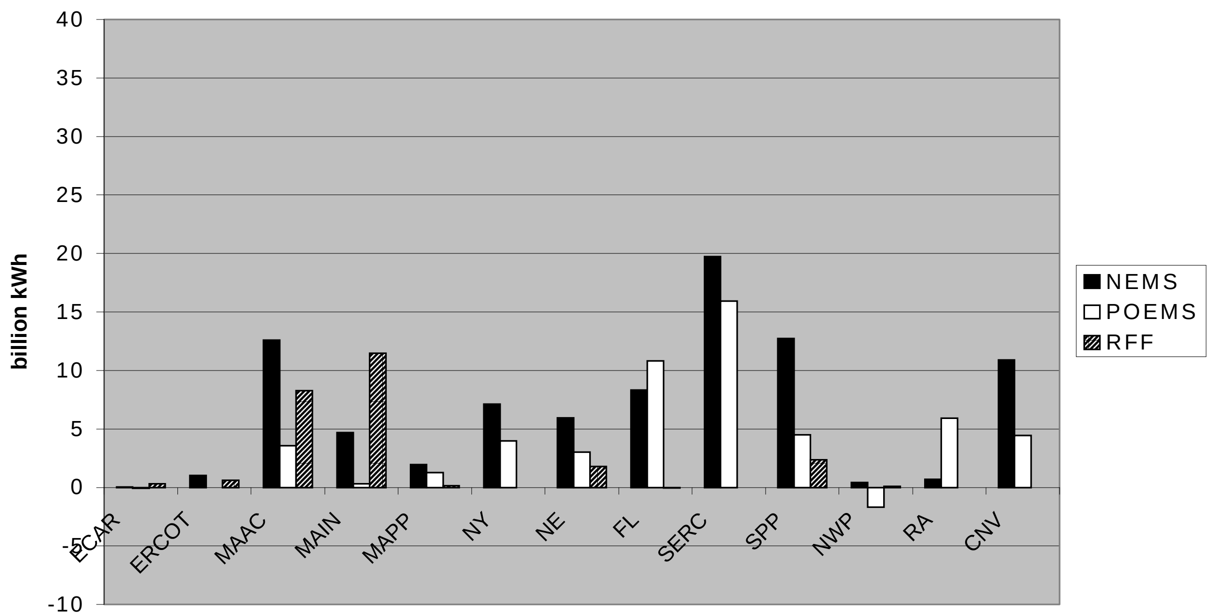
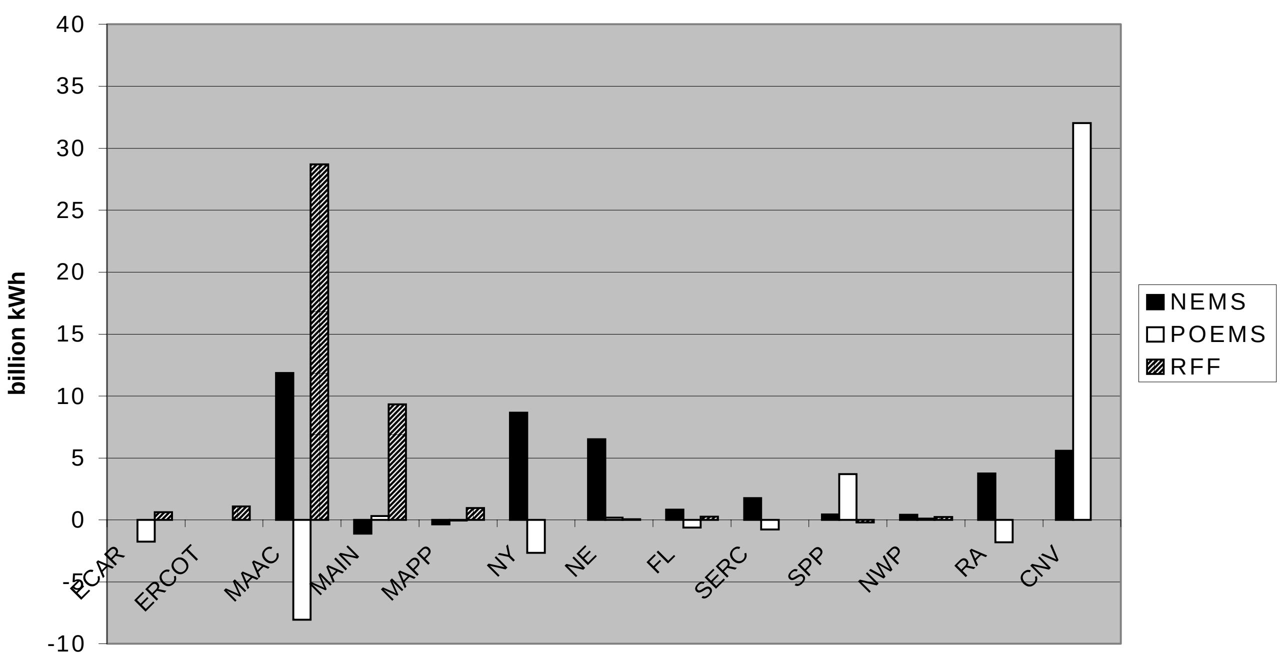



**Figure 30. Change in Interregional Imports in High Transmission Capacity wrt Baseline , 2010**



will be an important unknown for understanding the electricity industry's future.

National sulfur emissions within the power sector are expected to decline over the next decade as utilities use banked allowances or cleaner coal under the national cap for these emissions. This program was implemented in two phases. Unused emission allowances in the first phase (when the cap was less stringent) could be saved or "banked" for use in the second phase. In contrast, the $NO_x$ cap is implemented in one phase, which reduces the incentive to bank. Instead, firms must comply with the $NO_x$ cap immediately and are unlikely to accumulate banked allowances for the future. In summary, banking will play a more minor role for this emission than it has in the SO2 program.

As a result, both nitrogen oxides and carbon emissions in the power sector are expected to grow but by less than electric loads or demand. Moreover, faster economic growth will mean higher emissions for these two pollutants.