Chapter 4: Electric Power Generation

INTRODUCTION

The low-carbon emissions and low capital cost of natural gas generation compared to other fossil fuel generation, combined with abundant gas supplies and current relatively low prices, make natural gas an attractive option in a carbon-constrained environment, such as that contemplated in the analysis in Chapter 3. In addition to its increasingly important role as a primary fuel for electricity generation, natural gas will continue to perform a unique function in the power sector by providing both baseload power and the system flexibility that is required to meet variation in power demand and supply from intermittent sources.

The focus of this chapter is on the role of natural gas in helping to reduce CO\textsubscript{2} emissions from the power sector and the interaction of gas use with projected growth in wind and solar generation.

Natural gas provides flexibility to the power system largely through the three types of generation technologies: highly efficient natural gas combined cycle (NGCC) units, steam turbines, and gas turbines. Gas turbines are generally used to meet peak demand levels and to handle weather, time of day, seasonal and unexpected changes in demand. NGCCs and steam turbines can act as baseload or intermediate-load units, although the majority of gas capacity in the U.S. now operates in load-following (intermediate) or peaking service.

Currently, natural gas is second only to coal in total generation, fueling 23% of U.S. electricity production. Natural gas, however, has the highest percentage of nameplate\textsuperscript{1} generation capacity of any fuel, at 41% compared to 31% for coal, which is the next highest (Figure 4.1). This difference between nameplate capacity and generation is

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**Figure 4.1 % Nameplate Capacity Compared to % Net Generation, U.S., 2009\textsuperscript{*}**

*Numbers are rounded
Source: MIT from EIA data
BOX 4.1 MODELS EMPLOYED TO EXAMINE THE U.S. ELECTRICITY SYSTEM

The MARKAL (MARKet ALlocation) model of the U.S. electricity sector enables a granular understanding of generation technologies, time-of-day and seasonal variations in electricity demand and the underlying uncertainties of demand. It was originally developed at Brookhaven National Laboratory (L.D. Hamilton, G. Goldstein, J.C. Lee, A. Manne, W. Marcuse, S.C. Morris, and C-O Wene, “MARKAL-MACRO: An Overview,” Brookhaven National Laboratory, #48377, November 1992). The database for the U.S. electric sector was developed by the National Risk Management Laboratory of the U.S. Environmental Protection Agency (EPA).

The Renewable Energy Deployment System (ReEDS) model is used to project capacity expansions of generation, incorporating transmission network impacts, associated reliability considerations and dispatch of plants as operating reserves. It also captures the stochastic nature of intermittent generation as well as temporal and spatial correlations in the generation mix and demand. It has been developed by the National Renewable Energy Laboratory (NREL) (J. Logan, P. Sullivan, W. Short, L. Bird, T.L. James, M. R. Shah, “Evaluating a Proposed 20% National Renewable Portfolio Standard,” 35 pp. NREL Report No. TP-6A2-45161, 2009).


explained in part by the overbuilding of NGCC units in the mid-1990s. It also shows that NGCC units are operating well below their optimum operating value. Finally, it highlights the unique role of gas and steam turbines, which in 2009 had an average capacity factor of 10% (see Table 4.1). This low-capacity factor illustrates the peaking function of these units, particularly the gas turbines, that are routinely used only to meet peak demand levels and which, absent breakthroughs in storage, are essential for following time-varying electricity demand and accommodating the intermittency associated with wind and solar power.

Historically, because of its higher fuel price compared with nuclear, coal and renewables, natural gas has typically had the highest marginal cost and has been dispatched after other generation sources. Consequently, natural gas has set the clearing price for electricity in much of the country. Lower natural gas prices, the opportunities created by abundant relatively low-cost supplies of unconventional shale gas, increased coal costs and impending environmental regulations that will add to the cost of coal generation are, however, changing the role of gas in power generation.

The Emissions Prediction and Policy Analysis (EPPA) model employed in Chapter 3 is designed to study multi-sector, multi-region effects of alternative policy and technology assumptions, and as a result it only approximates the complexities of electric system dispatch. In this chapter, we analyze in greater depth two of the cases studied there, employing a more detailed model of the electric sector — MARKAL (see Box 4.1). This model is also used to further explore the implications of uncertainty in fuel and technology choices as they influence natural gas demand in this sector, extending the uncertainty analysis in Chapter 3 which considers only the uncertainty in gas resources.
This chapter then considers two questions about gas use in U.S. power generation: (1) What is the potential for reducing CO$_2$ by changing the current generation dispatch order to favor NGCC over coal generation? (2) What will be the effect of increased penetration of wind and solar generation on natural gas power generation?

To answer the first question it is important to understand NGCC utilization patterns. NGGC units are designed to be operated at capacity factors of up to around 85% rather than the current national average of 42%. This suggests possible opportunities for displacing some coal with gas generation, thereby lowering CO$_2$ emissions from the sector. We examine how much of this capacity could actually be applied to this purpose without diminishing system reliability. An important by-product of such a change, also analyzed, would be associated reductions in criteria pollutant emissions.

To explore the second question, the interaction between intermittent renewables and natural gas use is analyzed from two viewpoints: one in the short term when additional intermittent capacity is introduced into a system with other sources fixed; and the other in the longer term when the overall supply structure has time to adjust to growth in intermittent capacity. In this regard, we note that, at a more granular level than is presented in Table 4.1, wind turbines have an average capacity factor of 27%, solar thermal, 19%, and solar PV, 14%, and gas combustion turbines and steam turbines (used to balance load) have average capacity factors of 5% and 14%, respectively.

Table 4.1 2009 Average Capacity Factors by Select Energy Source, U.S. (numbers rounded)

<table>
<thead>
<tr>
<th>Source</th>
<th>All Energy Sources</th>
<th>Hydroelectric Conventional</th>
<th>Other Renewables</th>
<th>Natural Gas Other</th>
<th>Natural Gas CC</th>
<th>Nuclear</th>
<th>Petroleum</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>64</td>
<td>40</td>
<td>34</td>
<td>10</td>
<td>42</td>
<td>90</td>
<td>8</td>
</tr>
</tbody>
</table>

Study of these two questions is approached with the use of two additional electric sector models, each designed to simulate the power system and its operations in detail over a range of conditions and timescales (see Box 4.1), enabling the following analyses:

- An examination of reliability and transmission constraints, which helps to isolate and understand the total generation required at points in time to meet demand for electricity and maintain operating reserve capacity and adequate installed capacity margins. We employ ReEDS for this analysis, which uses multiple time periods for any given year and reports results by geographic regions.

- An exploration of annual scenarios at the hourly level, which takes into consideration details of real-time problems, such as uncertainty and variability in demand and in generation patterns for intermittent technologies, and start-up and shut-down characteristics for plant cycling. Here we use the Memphis model.
ELECTRICITY SYSTEM OVERVIEW

The electricity system is complex; this overview of how the system works, including the regimes under which power plants operate and the hierarchy of decision-making that influences the capacity and generation mixes, is intended to enhance the understanding of the implications of the modeling and analysis discussed later in the chapter.

Electricity is produced from diverse energy sources, varied technologies and at all scales. Sources for electric generation include a mix of renewables (sun, wind, hydro resources, among others), fossil fuels (oil, natural gas, coal) and uranium. As such, the generation of electricity comprises a variety of technologies with the type of fuel being used, and characterized by a wide range of investment and operating costs. Conventional power plants are operated under different regimes, mainly depending on their variable operating costs and operating flexibility.

- **Baseload plants** are characterized by expensive capital costs and low variable costs, and they are operated most of the time during the year. They tend to be inflexible plants as they cannot easily change their operational level over a wide usage.

- **Peaking plants** are characterized by low capital costs and higher variable costs, and they are operated a few hours per year when the electric load is the highest. They can be characterized as flexible plants because of their quick operating response.

- **Intermediate plants** have variable costs that fall in between those of peaking and baseload technologies, and they are operated accordingly. They can be characterized as cycling plants, i.e., plants that operate at varying levels during the course of the day and perhaps shut down during nights and weekends.

The expansion planning and operation of electric power systems involve several decisions at different timescales, generally based on economic efficiency and system reliability criteria. This process has a hierarchical structure, where the solutions adopted at higher levels are passed on to the lower levels incorporating technical or operational restrictions at that level:

- **Long-term** decisions are part of a multi-year process (3 years up to 10 or more years) that involves investments in generation and network required to expand the system.

- **Medium-term** decisions are taken once the expansion decisions have been made. They are part of an annual process (up to 3 years) that determines the generation unit and grid maintenance schedule, fuel procurement and long-term hydro resource scheduling.

- **Short-term** decisions are taken on a weekly time frame. They determine the hourly production of thermal and hydroelectric plants for each day of the week (or month), subject to availability of the plants and to hydro production quotas determined at the upper decision level, and considering not only variable operating costs, but also the technology’s own technical characteristics such as start-up and shut-down cost and conditions, a plant’s technical minima and ramping times. In addition, these short-term decisions are subject to generating reserve capacity needed to immediately respond to unexpected events.

- **Real-time** decisions involve the actual operation of the system (seconds to minutes). They involve the economic dispatch of generation units, the control of frequency so that production and demand are kept in balance at all times, while maintaining the system components within prescribed safe tolerances of voltages and power flows, accounting also for possible contingencies.
Finally, meeting reliably the consumption of electric power at all times requires having both adequate installed capacity and secure operation procedures. A reliable operation involves using ancillary services at different levels, maintaining sufficient capacity in reserve (quick-start units, spinning reserves) and with enough flexibility to respond to deviations in the forecast of demand or intermittent generation, and to unexpected events, such as the sudden loss of lines or generation plants.

**THE ROLE OF GAS GENERATION UNDER A CO₂ LIMIT**

The EPPA model simulations in Chapter 3 provide insights into both the economy-wide use of natural gas and its market share in electric power under various assumptions about greenhouse gas (GHG) mitigation. Application of the MARKAL model, with its greater electric sector detail, provides a check on the adequacy of the EPPA approximations for the power sector. MARKAL considers a more complete listing of the generation alternatives, and it addresses the variation in the level of electricity demand, as a result of the diurnal, weekly and seasonal cycles (which EPPA only roughly approximates). This variation is important because different technologies are needed to run different numbers of hours per year — a pattern that changes over years with demand growth and new investment. Also, the MARKAL model allows for a more complete exploration of uncertainty in gas use in the power sector.

For consistency with the analysis in Chapter 3, certain MARKAL inputs are taken from the EPPA model results, including electricity demand, supply curves for natural gas and coal and the reference costs of generation technologies. Also, two of the same policy cases are considered: Scenario A, which assumes no new GHG policy; and Scenario B, which imposes a Price-Based mitigation measure. For the Price-Based case, a cap on CO₂ emissions for the electric sector in MARKAL is set based on the results for that scenario in Chapter 3.

The underlying technology mix computed by the more-detailed electric sector model can be illustrated by annual load duration curves, which show the mix of generation dispatched at different times to meet changes in the level of electricity demand in the contiguous U.S. electric system over the course of a year. These curves for the year 2030, with and without a policy of carbon constraints, are shown in Figure 4.2. In the absence of a carbon policy (Panel a), generation from hydro, coal and nuclear occur at all times of the year while generation from wind and hydro are supplied whenever they are available.⁶

Without a carbon policy (Panel a), natural gas generation from combined cycle and steam turbines occurs for less than half of the time over the course of the year during periods of higher demand; and natural gas combustion turbines are used for only a few hours per year at the peak demand hours.

Under the carbon price policy (Panel b), NGCC technology largely substitutes for coal to provide baseload generation along with nuclear generation.
Figure 4.2 Time blocks approximation to the Load Duration Curve for the (a) No Policy and (b) 50% Carbon Reduction Policy Scenarios in 2030. Three seasons have been considered: summer, winter and spring/autumn. Within each season, there are four blocks: peak time, daytime PM, daytime AM, and nighttime, as shown in the graphs. The peak time block is very narrow.

Source: MIT analysis
The change over time in the energy mix in the electric sector is shown in Figure 4.3 for both the No Policy and the Price-Based cases. In the No Policy case, under reference assumptions for fuel prices, electricity demand and technology costs — and mean gas resources — these results show the same pattern of increasing gas use as the simulation studies in Chapter 3. The gas use in this sector in 2025 is essentially the same in the two studies. Toward the end of the simulation period, MARKAL projects one-quarter to one-third more gas-based generation than EPPA, though gas generation is still small relative to coal.

Under the Price-Based policy the overall pattern of change remains the same as in EPPA: coal is forced out and replaced by gas. In the period to 2025 MARKAL projects a more rapid phase-out of coal than does EPPA, in part because MARKAL is a forward-looking model and sees higher prices in the future whereas the recursive dynamic (myopic) EPPA model does not. Farther out in time coal is no longer in the mix, and under a continuously tightening CO₂ constraint conventional gas generation begins to be replaced by non-carbon generation sources such as nuclear, renewables and/or coal or gas with carbon capture and sequestration (CCS).

The EPPA model expands nuclear generation whereas MARKAL introduces natural gas with CCS, yielding about a one-quarter greater level of gas use. The outlook for gas in this sector is consistently positive across the two studies, and the difference in details of load dispatch is to be expected for models of such different mathematical structure, and well below the level of uncertainty in either (see Figure 4.3).
The systems studies in Chapter 3 consider only uncertainty in the estimates of gas resources (Figures 3.2, 3.3 and 3.0). Applying the MARKAL model and the reference assumptions discussed above, a study was carried out of the effect on gas use of uncertainties not only in resources but in other prices, electricity demand and technology costs. The same two cases were considered: No Policy; and the Price-Based policy. Here we describe results for a 50% confidence interval: i.e., a 25% chance of gas use above the high level as shown, and a 25% chance of use below the low level. Details of the analysis are provided in Appendix 4B.

By 2030, with no additional mitigation policy, the gas demand by the electric sector runs 17% above and 19% below the mean value of 6.3 trillion square feet (Tcf) (50% confidence interval). The main factors leading to this range are the demand for electricity, the prices of natural gas and coal and the costs of new technologies, in particular the cost of new coal steam and IGCC technologies.

Under the Price-Based policy the uncertainty is substantially greater, ranging from 47% above to 42% below the mean value of 12.8 Tcf (50% confidence interval). The main influence behind this greater uncertainty is in the costs of technologies that might substitute at large scale for fossil-based generation, such as wind, solar and advanced nuclear generation technologies. The share of natural gas in the generation mix is a result of the interplay between technologies that both compete with and complement each other at the same time as they supply different segments of demand over the year.

The uncertainty ranges given here are intended to caution the reader against giving too much weight to the actual numbers in future projections in this chapter and elsewhere in the report. Rather, the critical insights are about the trends and relationships, which are more robust across a wide range of possible futures.

**NEAR-TERM OPPORTUNITIES FOR REDUCING CO\textsubscript{2} EMISSIONS BY ENVIRONMENTAL DISPATCH**

Near-term opportunities for CO\textsubscript{2} emission reductions in the power sector are limited by the current generation mix and transmission infrastructure, the cost of renewables and other low-emission sources and technologies, as well as the lag times associated with siting and building any new generation capacity. The re-ordering of generation between coal and gas units (modeled here as a form of environmental dispatch forced by a CO\textsubscript{2} constraint) may be the only option for large-scale CO\textsubscript{2} emissions reduction from the power sector which is both currently available and relatively inexpensive.

As noted, the current fleet of NGCC units has an average capacity factor of 41%, relative to a design performance of approximately 85%. An electric system requires capacity to meet peak demands occurring only a few hours per year, plus an operating reserve, so the system always includes some generation units that run at capacity factors below their design value. However, the U.S. has enough spare capacity in other technologies to allow dispatching more NGCC generation, displacing coal and reducing CO\textsubscript{2} emissions, without major capital investment. An additional benefit of this approach would be to substantially reduce emissions of air pollutants such as sulfur dioxide (SO\textsubscript{2}), nitrogen oxide (NO\textsubscript{x}), mercury (Hg) and particulates.

**NGCC Potential if Fully Dispatched**

Figure 4.4 suggests the scale and location of the potential for shifting among generation units. Plotted there is the geographic distribution of fully-dispatched NGCC potential (FDNP), defined as the difference between the electricity that would be produced by NGCC plants at an 85% capacity factor and their actual 2008 generation. Figure 4.4 also shows the geographic distribution of coal generation, divided into
less and more efficient units where a “less efficient” unit is defined as one with a heat rate over 10,000 Btu/kWh.

In many regions FDNP generation matches well with less efficient coal capacity, suggesting opportunities for displacing emissions-intensive units, while other locations show few such opportunities. For example, Southeastern states such as Texas, Louisiana, Mississippi, Alabama and Florida appear to have relatively larger opportunities, while those in Midwestern states such as Illinois, Indiana and Ohio are relatively smaller.

Possible Contribution of NGCC Capacity to a CO₂ Reduction Goal

Figure 4.4 represents only the average potential available over the course of the year, aggregated by state, therefore providing an upper limit of the substitution potential; it does not equate to “surplus” generation capacity. For this discussion, “surplus” is defined as the amount of NGCC generation that can be used over the course of one year to replace coal while respecting transmission limits, operation constraints and demand levels at any given time.
To account for a number of system characteristics that may better identify the range of opportunities for fuel substitution, we apply the ReEDS model (see Box 4.1). This model is well suited for examination of reliability and transmission constraints, demand fluctuations and reserve capacity margins that will limit these opportunities. Also, as noted, ReEDS reports results by geographic regions. This enables us to identify opportunities to change the fuel dispatch order nationwide, and provides insights into five regions of the country: the Electric Reliability Council of Texas (ERCOT), Midwest Independent Transmission Operator (MISO), Pennsylvania-New Jersey-Maryland (PJM), New England (ISO-NE) and Florida Reliability Coordinating Council (FRCC). Each region has different generation costs, fuel mixes and ability to trade electricity:

- ERCOT is essentially electrically isolated from the rest of the country;
- MISO and PJM are heavily interconnected; they import and export electricity from each other, but have a relatively small amount of NGCC surplus;
- ISO-NE and FRCC have surplus NGCC but New England has relatively little coal generation, whereas Florida has a significant percentage of inefficient coal capacity that might be a candidate for displacement.

We analyze the potential for a version of environmental dispatch by running the ReEDS model for the year 2012 in three scenarios: CO₂ unconstrained, a 10% reduction in U.S. electric sector CO₂ emissions, and a 20% reduction. Runs for the year 2012 are used because the model does not invest in new capacity in this time period; as such, CO₂ reductions are attributable to shift of generation among existing units.

Figure 4.5 illustrates the changes in generation by technology under the three scenarios. In the 20% CO₂ reduction scenario, the NGCC fleet has an average capacity factor of 87%, displaces

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**Figure 4.5 Generation by Technology under Various CO₂ Constraints, U.S., 2012**

![Figure 4.5](image-url)
about one-third of 2012 coal generation (700 terawatt-hours (TWh)) and increases gas consumption by 4 Tcf.9

In Figure 4.5, as the carbon constraint increases, most of the electricity generation by technology does not change. Coal and natural gas are the exceptions: as the carbon constraint increases, coal generation significantly declines, and NGCC proportionally increases.

Although NGCC displacement of coal generation is nearly one-for-one at the national level, the change in generation and emissions is not uniform across regions. Figure 4.6 shows regional results, comparing coal generation in the absence of a CO₂ target to surplus NGCC generation in a 20% reduction scenario.

In Figure 4.6, the left bars represent the amount of regional coal generation absent carbon constraints, using ReEDS 2012 forecasts. This is the “business as usual” scenario. The right bars represent the amount of additional NGCC generation that is available for dispatch in the current system after satisfying all system requirements. This additional amount of generation is calculated as the difference between the NGCC generation dispatched in the base case and in the 20% CO₂ reduction scenario. The largest potential for substitution of NGCC for coal generation is in PJM, although in both PJM and MISO coal continues to dominate.

A closer look at how the imposition of a CO₂ limit would shift generation among units can be seen in the revised unit dispatch at different demand levels. For this analysis, we look at ERCOT, a system that is isolated from the rest of the U.S. and, in our re-dispatch scenarios, has regional percentage of CO₂ reductions that tracks national reductions. Because of these similarities to the country, and because of the greater availability of operations information from ERCOT, an analysis of ERCOT, using
ReEDS provides additional details about fuel switching on a more granular timescale.

Figure 4.7 illustrates how existing capacity would be dispatched to meet 2012 projected demand for the highest peak, average and low demand situations, with and without the CO$_2$ target to force a change in unit dispatch. The figure shows an unconstrained base case and a case with a 20% CO$_2$ reduction. The average profile shows the generation dispatch for all technologies across an entire year (8,760 hours), not a single time slice.

In Figure 4.7, the red line represents 17 time periods of demand for the year, sorted from greatest to least demand. The bar graphs to the right of the nameplate capacity bar show the dispatch profile in those time periods under two carbon scenarios: no reduction and 20% reduction.

Not surprisingly, the results indicate that the greatest opportunities for displacement of coal generation exist during average and low demand periods. Figure 4.7 also shows that coal generation is dispatched in every time period, indicating that not enough NGCC surplus exists in ERCOT to completely displace coal;
conversely, surplus NGCC capacity exists and can displace some coal capacity in all demand periods examined, even during the super peak, although the amount is small.

**Effect of System Re-Dispatch on Criteria Pollutants**

The Clean Air Act (CAA) requires power plant controls on SO$_2$, NOx, particulates and Hg. According to the EPA, “60% of the uncontrolled power plant units are 31 years or older, [some] lack advanced controls for SO$_2$ and NOx, and approximately 100 gigawatts (GW) out of total of [more than 300] GW of coal are without SO$_2$ scrubbers.”

Table 4.2 contains results from ReEDS under the three scenarios that indicate the potential effects of the CO$_2$ constraint (also shown) on emissions of SO$_2$, NOx and Hg. (The model does not project particulate emissions, which also would be reduced.) While ReEDS does not fully model the trading markets for SO$_2$ and NOx, it makes a reasonable approximation by capping national emissions levels and making economically efficient dispatch decisions under these constraints. In all three simulations the cap for SO$_2$ emissions is based on the 2005 Clean Air Interstate Rule (CAIR) interpolated for 2012.

Changes to the dispatch order of generation, from coal to gas, would lower prices in the SO$_2$ market, and might even yield a reduction in national emissions below the CAIR limit, as shown with a 4% change in Case 2. Importantly, the reductions in NOx and Hg emissions could be substantial, by as much as one-third under the more stringent CO$_2$ limit.

Table 4.3 shows the corresponding emissions profiles by region for CO$_2$ and Hg. (ReEDS does not provide adequate regional detail for SO$_2$ and NOx). Each region acts in its own best economic interests under the given constraints. And, because of variation in generation costs, installed capacity and transmission differences between regions, some regions have comparative advantage dispatching less CO$_2$ intensive generation. Depending on the regulatory structure, regions with these advantages may produce more electricity, export it and/or sell credits (assuming a cap-and-trade approach); and regions which typically deploy technologies that are more CO$_2$ intensive take opposite actions. This leads to uneven emissions effects on individual regions.

A 20% emissions reduction in electric sector CO$_2$ emissions through coal-to-gas displacement would represent mitigation of 8% of the U.S. total. The ReEDS model does not provide

<table>
<thead>
<tr>
<th></th>
<th>Base Case</th>
<th>Case 1 – 10% CO$_2$ Reduction</th>
<th>Case 2 – 20% CO$_2$ Reduction</th>
<th>% Reduction from Base Case for Case 1</th>
<th>% Reduction from Base Case for Case 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO$_2$ (million metric tons)</td>
<td>2,100</td>
<td>1,890</td>
<td>1,680</td>
<td>—</td>
<td>4%</td>
</tr>
<tr>
<td>SO$_2$ (million tons)</td>
<td>5.66</td>
<td>5.66</td>
<td>5.46</td>
<td>—</td>
<td>4%</td>
</tr>
<tr>
<td>NOx (million tons)</td>
<td>4.66</td>
<td>3.92</td>
<td>3.16</td>
<td>16%</td>
<td>32%</td>
</tr>
<tr>
<td>Hg (tons)</td>
<td>48</td>
<td>40</td>
<td>32</td>
<td>17%</td>
<td>33%</td>
</tr>
</tbody>
</table>

Source: MIT analysis

Table 4.2 National Emissions for CO$_2$-Reduction Scenarios
an accurate estimate of the national economic cost of this option, but an approximation can be made by comparing the break-even CO₂ price at which the cost of NGCC generation equals the cost of coal generation, given their different variable operations and maintenance costs, heat rates and CO₂ emissions rates. The result is an implicit cost of about $16 per ton CO₂.

More analysis is required to determine whether, because of the geographic differences between NGCC and coal units, some new transmission infrastructure may be necessary. Nonetheless, a more complete analysis is very likely to prove the cost of this option to be low compared to most other mitigation options. For example, one estimate of the per-ton CO₂ emissions avoidance cost estimate to retrofit a typical sub-critical coal plant with post-combustion CSS is $74 per ton. The displacement of coal generation with NGCC generation should be pursued as the most practical near-term option for significantly reducing CO₂ emissions from power generation.

In sum, there is sufficient surplus NGCC capacity to displace roughly one-third of U.S. coal generation, reducing CO₂ emissions from the power sector by 20% and yielding a major contribution to control of criteria pollutants. This would require an incremental 4 Tcf per year of natural gas, which corresponds to a cost of $16 per ton of CO₂ in delivered coal prices and the decrease in delivered natural gas prices, combined with surplus capacity at highly efficient gas-fired combined-cycle plants resulted in coal-to-gas fuel switching. Nationwide, coal-fired electric power generation declined 11.6 percent from 2008 to 2009, bringing coal’s share of the electricity power output to 44.5 percent, the lowest level since 1978.”

It should also be noted that coal-to-gas fuel switching is already occurring. According to the Energy Information Agency (EIA), “The increase

Table 4.3 Emissions of Select Regions Before and After Re-Dispatch, 2012

<table>
<thead>
<tr>
<th>Base Case</th>
<th>MISO</th>
<th>ERCOT</th>
<th>PJM</th>
<th>FRCC</th>
<th>ISO-NE</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂ (million metric tons)</td>
<td>543</td>
<td>153</td>
<td>446</td>
<td>67.2</td>
<td>19</td>
</tr>
<tr>
<td>Hg (tons)</td>
<td>13.4</td>
<td>2.77</td>
<td>11</td>
<td>1.32</td>
<td>0.138</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Case 2 – 20% CO₂ Reduction</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂ (million metric tons)</td>
</tr>
<tr>
<td>Hg (tons)</td>
</tr>
<tr>
<td>% Hg reduction</td>
</tr>
</tbody>
</table>

Source: MIT Analysis
**INTERMITTENT RENEWABLE ELECTRICITY SOURCES AND NATURAL GAS DEMAND**

In this section, we explore the impacts of the introduction of significant amounts of intermittent wind and solar electricity generation on natural gas generation and overall natural gas demand.

This analysis first explores the short-term effects of intermittent wind and solar generation on gas generation and demand, a scenario which assumes that the capacity from technologies — other than wind or solar — is fixed. Some European countries already approximate this situation, where substantial volumes of wind or solar generation have been installed during the last few years. Also in some U.S. states, the proportion of intermittent generation exceeds 10% and the dispatch of existing conventional generation units has had to adjust accordingly.

We then turn to longer-term impacts, where the deployment of intermittent generation is assumed to take place gradually, possibly in response to government policies that, for example, set a mandatory target for renewable generation. Over time, capacity additions and retirements of other technologies are made as the system adjusts to intermittent generation.

**Effects in the Short Term**

To elucidate the short-term effects, we use:

- a 2030 projected generation portfolio as the base case, obtained from the ReEDS CO2 Price-Based policy scenario (see Box 4.1); and
- the Memphis model (see Box 4.1) applied to daily dispatch patterns for ERCOT which, as noted earlier, is an isolated system that can be studied without the complicating influence of inter-regional transmission.

With this 2030 generation portfolio as our reference point, we examine the daily dispatch patterns of all generation technologies, including natural gas, when greater or lesser levels of wind or solar electricity generation are made available to be dispatched and the capacities of the other technologies are held constant.

**Wind generation.** The results for varying levels of wind generation are seen in:

- Figure 4.8a, the base case, which is a representative day for ERCOT;
- Figure 4.8b, when wind produces half the amount of generation as in the base case; and
- Figure 4.8c, where wind produces twice the amount of generation as in the base case.
Figure 4.8 Impact of Wind on a One-Day Dispatch Pattern for ERCOT

4.8a Wind Base Case

4.8b Wind 0.5

4.8c Wind 2.0

Source: MIT Analysis
In Figure 4.8a, the base case depicts the estimated existing contribution from wind in ERCOT in 2030. The nighttime load (roughly hours 01 through 04) is met by nuclear and coal baseload plus wind generation. There is no appreciable output from gas between hours 01 and 04 because it has higher variable costs than nuclear and coal and it gets dispatched last. Natural gas also has the flexibility to cycle. In hours 05 through 23, when overall demand increases during the early morning and decreases in the late evening, NGCC generation adjusts to match the differences in demand.

As depicted in Panel 4.8b, when less wind is dispatched, the NGCC capacity is more fully employed to meet the demand, and the cycling of these plants is significantly reduced. The baseload plants continue to generate at full capacity.

In Panel 4.8c with twice as much wind as the base case, natural gas generation is reduced significantly; the gas capacity that is actually used is forced to cycle completely. Baseload coal plants are also forced to cycle because of the relatively low nighttime demand; coal plant cycling can increase CO₂, SO₂ and NOx emissions.

**Solar Generation.** Like wind, for solar there are figures depicting: a base case in ERCOT (Figure 4.9a); a case where solar provides half the amount of generation as the base case (Figure 4.9b); and a case where solar provides twice the generation seen in the base case (Figure 4.9c).

The pattern with solar is somewhat different than for wind. The solar generation output basically coincides with the period of high demand, roughly between hours 06 and 22. As seen in the base case Figure 4.9a, this is also when NGCC capacity gets dispatched. The natural gas plants are used more when solar output is less (see Figure 4.9b). Conversely, when solar is used more, less gas is dispatched (see Figure 4.9c).

The baseload plants are largely unaffected and cycling is not a problem for them, since there is no intermittent solar-based generation during the low-demand night hours.

In sum, our short-term analysis shows that the most significant impacts of a quick deployment of additional wind or solar at any given future year will most likely be both a reduction in production from, and an increase in cycling of, gas-fueled NGCC plants; there is a less significant fall in production for the much-less-employed, single-cycle gas turbines and steam gas units.

**[In the short term]….the most significant impacts of a quick deployment of additional wind or solar … will most likely be both a reduction in production from, and an increase in cycling of, gas-fueled NGCC plants….**

The displacement of gas is greater for solar than for wind, since solar production has a stronger correlation with demand than does wind generation.

Large wind penetrations may also displace some coal production and result in some cycling of these plants. No impact on nuclear production is expected with the average U.S. technology mix.
Figure 4.9 Impact of Solar CSP (no storage) on One-day Dispatch Pattern for ERCOT

Source: MIT Analysis
Effects in the Long Term

To explore the effects of the penetration of intermittent generation over the long term, we examine two policy scenarios, both with a system expansion to 2050 and a target leading to a 70% reduction of CO$_2$ emissions in the U.S. power sector.

We look at two different versions of the 70% reduction case because the means by which the target is implemented — through different mitigation policy instruments — has an effect on how the system responds to more or less expensive renewable generation. The two policy instruments we examine are:

- the imposition of a CO$_2$ price to achieve the CO$_2$ emissions reduction target; and
- the imposition of an emissions constraint to achieve the same target.

We then analyze how the electric system, and gas use over time, would differ if the capital costs of solar or wind generation capacity were higher or lower than the reference levels for the two base cases. Again the ReEDS model is employed.\textsuperscript{17}

In the ReEDs simulations of both policy scenarios, the generation mix evolves over time, similar to that shown in Chapter 3, Figures 3.4a and 3.4b. During the early-to-middle decades of the simulation period the dominant event is the substitution of coal generation by NGCC units. At the same time, wind generators, with gas turbine back-up, begin to be deployed as a baseload technology.\textsuperscript{18}

This combination of wind production and flexible generation capacity competes with potential new nuclear capacity and also erodes NGCC production. Wind impacts the preferred new baseload generation technology, the one that is most economic but for which expansion is not subject to environmental or other limits. Late in the period, conventional coal production has been replaced, economically-competitive wind resources start becoming exhausted and nuclear plus some solar penetration begins.

CO$_2$ Price-Based Case. In the CO$_2$ Price-Based case, the nature of the system adjustments in these simulations can be illustrated using an example of the changes that would be brought about by lower-cost wind capacity. First, the increased intermittent renewable generation needs to be accompanied by flexible back-up capacity, albeit with low utilization levels. In the U.S., spare capacity of gas-fueled plants is enough to meet this requirement initially, but eventually additional investment is needed (gas turbines in these scenarios).

As this combination of new intermittent renewable and flexible electricity plants grows, it starts to replace the expansion and utilization of baseload generation technologies, nuclear or fossil generation with CCS (coal without CCS has already been forced out of the system by its CO$_2$ emissions). However, these classic baseload technologies are not increasing; therefore, the low-cost renewable capacity plus flexible generation increases in baseload and even in mid-merit service, at the expense of gas generation.
This interaction can be illustrated with a summary of what happens in the base case system for the ERCOT region when different renewable costs are simulated, therefore changing the intermittent generation penetration levels.

The results in Figure 4.10 are plotted to highlight the way cumulative gas generation changes with different assumptions about wind-generation costs and the corresponding wind-generation levels. The figure shows the total generation in TWh by type of generation technology over the simulation period from 2005 to 2050 and assumes the underlying emissions target is imposed by a CO₂ price. It illustrates that the displacement of gas by wind takes place through changed patterns of investment and generation over many years.

As Figure 4.10 shows, increased cumulative wind generation, as a consequence of lower wind investment costs, or an aggressive renewable portfolio standard, has a direct impact on the new investment and associated production by natural gas, equal to almost one TWh of reduced natural gas generation for one TWh of wind output. This happens because NGCC is the technology that is most vulnerable to wind competition, both before and after coal has been driven out of the market. It should also be noted that, while the cumulative generation of gas turbines (Gas-CT in Figure 4.10) does not change enough to show in the graph, gas turbine capacity actually increases substantially to support the additional wind contribution.

Figure 4.10 Cumulative Generation in ERCOT in the Period 2005–2050 for All Technologies Given Alternative Levels of Wind Penetration (TWh)
In Figure 4.10, the horizontal axis is cumulative wind output, the vertical axis is the cumulative output for all technologies, including wind (if the two axes were plotted to the same scale the function for wind would be a 45˚ line). The base-case level of wind generation is indicated with a vertical line, so that output to the right of that point results from lower capital costs and the output to the left results from higher capital costs.

Figure 4.10 also shows that the difference in cumulative generation by the other technologies is not much affected by changes in the contribution of wind generation. It should be repeated that this is a result for ERCOT. The differences in generation mix in other regions will vary, though viewed at the national level the pattern is very similar to that shown here.19

**CO\textsubscript{2} Cap Case.** The result differs somewhat if emissions mitigation is accomplished by a CO\textsubscript{2} cap instead of a price. The fixed CO\textsubscript{2} constraint implies that an increment in wind output that displaces NGCC production and investment also reduces the need for other low-CO\textsubscript{2} baseload capacity to reduce the emissions.

Cheaper wind creates slack under the emissions constraint, which may be filled by whatever is the cheapest generation source. In some simulations, this cheap generation comes from otherwise almost-idle coal-fired plants. Thus, as a minor perverse effect, under the CO\textsubscript{2} constraint more wind can imply a small increment of additional coal production — a condition that does not occur when coal is burdened by a CO\textsubscript{2} price.

The case of solar generation without storage is similar to wind in many respects. However, since the production profile of solar has a high level of coincidence with the daily demand and has a more stable pattern, an increment in solar generation does not require back-up from flexible gas plants as much as wind does. In fact, solar can partially fulfill a peaking plant role.

In summary, our analysis of gradual and sustained “long term” penetration of wind and solar shows that large-scale penetration of wind generation, when associated to flexible natural gas plants, will assume a mostly baseload role, and will reduce the need for other competing technologies such as nuclear, coal or even gas-fueled combined cycles, if expansion with coal and nuclear technologies does not take place.

**Our analysis shows that a gradual and sustained “long term” substantial penetration of wind, when associated with flexible natural gas plants, will assume a mostly baseload role, and will reduce the need for other competing technologies such as nuclear, coal or even gas-fueled combined cycles. This effect is less pronounced in the case of solar.**

because of economic, environmental or any other reasons. This effect is less pronounced in the case of the solar technology, because of its characteristic daily production pattern.

Although our analysis has been limited to a few alternative scenarios, we can observe a consistent pattern for the impact of intermittent renewable generation: We see that an increase of wind or solar output systematically results in a proportionally significant reduction of natural gas fueled production, while, at the same time, the total installed capacity of flexible generation (typically also natural gas fueled plants) is maintained or increased.

Precise numerical estimations and any second order impacts are heavily dependent on the specific energy policy instruments and the assumptions on the future costs of fuels and technologies.
The detailed operational analysis of plausible future scenarios with large presence of wind and solar generation reveals the increased need for natural gas capacity (notable for its cycling capability and lower capital cost) to provide reserve capacity margins. This does not however necessarily translate into a sizeable utilization of these gas plants.

Additional Implications

In deregulated wholesale markets with substantial penetration of renewables, the volatility of marginal prices can be expected to increase. Also, mid-range technologies, of which NGCC is the most likely candidate, will see their output reduced. The uncertainty regarding the adequate technology mix, and the economics of such a mix under the anticipated future prices and operating conditions, raises concern about attracting sufficient investment in gas-fueled plants under a competitive market regime.

This issue is presently being addressed by several European countries with significant penetration of wind generation, where the patterns of production of NGCC and single cycle gas turbines and also of some baseload technologies, have already had major impacts. Similar situations are developing in some parts of the U.S. Presently there is no consensus on a suitable regulatory response to this situation, which could include enhancements of any capacity mechanisms such as those already in place in most U.S. wholesale markets, new categories of remunerated ancillary services or other instruments.

RECOMMENDATION

In the event of a significant penetration of intermittent renewable production in the generation technology mix, policy and regulatory measures should be developed to facilitate adequate levels of investment in natural gas generation capacity to ensure system reliability and efficiency.

Although limited in scope, our analysis shows the diversity and complexity of the impacts that a significant penetration of intermittent generation (mostly wind and solar, in practice) have on the technology mix and the operation of any considered power system. The possible future emergence of electricity storage options, as well as enhanced demand responsiveness, will also affect the need for flexible generation capacity, which is presently fueled by natural gas. The level and volatility of future energy prices will determine the volume and nature of investment in future generation under market conditions. Other regulatory frameworks should also be considered.

These complicated implications and trade-offs cannot be spelled out without the help of suitable computer models. The accuracy of the estimates of future fuel utilization and the adequate technology mix critically depends on the performance of these models. Unfortunately, the state-of-the-art computer models that simulate and optimize the capacity expansion and the operation of power systems and electricity markets — such as ReEDS or Memphis — are still in a development phase and fall short of the requirements to incorporate intermittent generation, storage and demand response realistically, under a variety of energy policies and regulatory environments.
RECOMMENDATION

A comprehensive appraisal of the economic, environmental and reliability implications of different levels of significant penetration of renewable generation should be performed for power systems with different generation technology portfolios and under different energy policy scenarios.

The information obtained from this appraisal should inform a central piece in the design of energy policies that contemplate mandating large amounts of solar or wind generation.

Additional efforts should be made to expand or develop the sophisticated computation electric system models that are needed for this task.
NOTES

1 Nameplate capacity is the nominal, maximum instantaneous output of a power plant.

2 Absent other considerations, generation units are normally dispatched in economic merit order, i.e., those with lower variable operating costs first.

3 Channele Wirmin, EIA, private communication.


6 Hydroelectric generation, shown in Figure 4.2 as constant over demand periods, will in fact tend to be concentrated in particular seasons and peak periods of the day. The MARKAL model does not represent this detail, though its inclusion would have only a small effect on the figure as it aggregates all the national hydroelectric facilities.

7 The same change in unit dispatch could be approached using various forms of direct regulation, options not studied here.

8 The ReEDS model captures key characteristics of the electricity network’s transmission constraints and reliability requirements by splitting the country into 134 geographic partitions. Each partition balances demand and supply of electricity by independently generating, importing, and exporting electricity. Collectively, subsets of these balancing areas constitute the independent system operators (ISOs) and regional transmission organizations (RTOs).

9 As noted in the introduction of this section, the expected maximum capacity factor for an NGCC plant is 85%. The EIA projects that this could increase to 87% by 2016 (http://www.eia.doe.gov/oiaf/aeo/pdf/2016levelized_costs_aeo2010.pdf). The average fleet capacity factor of 87% from ReEDS for the 20% CO₂ reduction scenario approaches the upper generation threshold of the country’s current NGCC fleet.

10 Although the trend for NGCC displacement of coal generation remains the same for this updated scenario, these results are numerically different than the results presented in the interim report. The interim report showed opportunities for coal displacement in all time periods. The difference stems from assumptions about how much NGCC capacity exists in ERCOT. The NGCC capacity numbers used for this 2012 simulation are more conservative, and projected forward from 2006 EIA capacity and generation data (2006 is the start year for ReEDS).


12 For a variety of reasons, deployment of required controls has been delayed, largely by court findings of legal flaws in various rulemakings. The New Transport Rule, which will replace Clean Air Interstate Rule (CAIR) in place today, is expected to be finalized in mid-2011 and will be implemented over time, with most coverage finalized by 2014. The Transport Rule will cover SO₂ and NOx. EPA released a proposed rule for mercury emissions from coal and oil-fired power plants in March, 2011 and plans to finalize the rule by the end of the year. A final rule on CO₂ for power plants is expected sometime in 2012.

13 This break-even price assumes a NGCC variable O&M cost of $3.20/MWh, fuel price of $5.38/mmBtu, heat rate of 6.04 mmBtu/MWh, and CO₂ emissions of 0.053 tons/mmBtu. For coal, the calculation assumes a variable O&M cost of $4.30/MWh, fuel price of $2.09/mmBtu, heat rate of 10 mmBtu/MWh, and CO₂ emissions of 0.098 tons/mmBtu. The cost of NGCC and coal generation break-even when the sum of the variable O&M cost and price per ton CO₂ multiplied by the amount of CO₂ emitted are equal to each other, for the respective fuels. Start-up and shut-down costs, ramp rates, associated changes in emissions, and other costs that have not been fully modeled are not included in this calculation.


15 EIA AEO 2010.


18 The ReEDS simulations of this level of mitigation show a greater penetration of renewable generation than do the results of the EPPA model shown in Chapter 3, but the difference is not an important influence on the insights to be drawn from these calculations.

19 Details of these cases are provided by Yao and Pérez-Arriaga, op cit.