Coal to Natural Gas Fuel Switching and CO_2 Emissions Reduction

A thesis presented

by

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To

Applied Mathematics

in partial fulfillment of the honors requirements

for the degree of

Bachelor of Arts

Harvard College

Cambridge, Massachusetts

April 1, 2011

ABSTRACT

US natural gas prices fell in 2009 on account of weak demand and increased supply from shale gas production. The fall in prices led to a reduction in coal-fired electricity generation and a concomitant increase in natural gas-fired electricity generation. Low natural gas prices conjoined with static coal prices and underutilized natural gas power plant capacity to create an environment primed for switching from natural gas to coal. Due to differences in chemical make-ups and plant efficiencies between the two fuels, this switching led to a significant reduction in carbon dioxide emissions. This thesis models how the fuel switching effect occurred and how it translated to an emissions reduction. It also analyzes several hypothetical policies aimed at augmenting the effect to achieve further reductions in emissions. Throughout the analysis, it considers the other impacts—environmental, human health, and economic—of a large-scale shift from a fuel system based on coal to one based on natural gas.

ACKNOWLEDGMENTS

Many people have been supportive and helpful to me in writing this thesis and if this finished product has any worth, much of it is due to them. First of all, I have to thank Mike McElroy and Xi Lu, who have carefully guided me through this whole process. Indeed, this thesis is not the culmination of just several months of research but of more than two years working with and for them as a student, researcher, teaching fellow, and thesis writer. I could not be more grateful to you both. For helpful discussions of this subject matter along the way I have to thank Sierra Peterson, Frank O'Sullivan, David Albin, Sheila Jasanoff, Dale Jorgenson, Gracie Brown, Chris Nielsen, Henry Lee, the Harvard College Environmental Action Committee, and the Future of Energy lecture series. For the unconditional support, my love and gratitude goes to Jay Weiss, Emily Hughes, the Harvard Wrestling team, all my roommates, and most importantly, to my Mom and Dad and my brothers and sister, Spencer, Mikko, Malcolm, and Priscilla.

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Chapter 1: INTRODUCTION

I. Falling Emissions

In 2008, US carbon dioxide (CO_2) emissions from energy departed from their expected trajectory. After having risen at an average annual rate of 1.06% and never having fallen by more than 2% in the previous two decades, CO_2 emissions from energy use fell by 2.95% between 2007 and 2008. The decline in the following year was even greater — emissions from energy fell by 6.94% between 2008 and 2009, the largest drop since the Energy Information Administration (EIA) started recording data in 1949.[1] CO_2 emissions from energy accounted for roughly 80% of total US greenhouse gas (GHG) emissions in 2009. After decades of persistent growth, it appeared that US emissions had finally peaked.

Decreased energy demand due to the global financial crisis caused a decline in emissions, but not enough to account for the entire effect. Total energy demand fell by 4.85% from 2008 to 2009,[2] leaving a third of the 6.94% decline in emissions unexplained. The additional decline resulted from a decrease in the average amount of CO_2 emitted in producing a unit of energy.

In large part, fuel switching from coal to natural gas in the electric power sector drove this change. Natural gas burns more cleanly than coal, releasing fewer emissions per unit of electricity generated. Emissions from the power sector fell by 8.76% from 2008 to 2009.[3] Over the same time period, electricity generation from coal decreased by 11.6% and electricity generation from natural gas rose by 4.3%. Taking into account the 4.1% reduction in annual

[1] United States, Dept. of Energy, Energy Information Administration, *US Carbon Dioxide Emissions in 2009: A Retrospective Review*, 5 May 2010, Web, 22 Mar. 2011.
[2] EIA Data, Total Energy
[3] EPA Data, US GHG Inventory

electric power output,[4] generation from natural gas essentially replaced generation from coal on a one-to-one basis in 2009.

Three main factors contributed to coal to natural gas fuel switching in the electric power sector. First and most important, prices of natural gas fell by nearly half. The average annual price of natural gas delivered to electric power producers fell from $9.26 in 2008 to $4.93 in 2009.[5] This fall in prices resulted from a decline in demand during the recession combined with a large increase in supply due to production of natural gas from shale formations. Second, delivered coal prices remained roughly constant over this time period, in line with a long-term gradual increase.[6] Finally, there was (and is) a significant amount of underutilized high efficiency natural gas power plant capacity on the grid. Natural gas combined cycle plants, which operate at efficiencies upwards of 50% (coal plants and natural gas turbine plants operate at efficiencies around 33%), were utilized at a capacity factor of 40.2% in 2008.[7]

Switching occurs because declining natural gas prices and constant or slightly rising coal prices lower the variable cost of generation from natural gas relative to generation from coal, especially for the most efficient plants. Natural gas is able to take advantage of this improved position by increasing generation at underutilized combined cycle plants. Additional generation from natural gas directly reduces the generation from coal. The 2009 Electric Power Annual report (released in November 2010 by EIA) explains,

> The increase 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. This occurred particularly in the Southeast (Alabama, Arkansas, Florida, Georgia, Mississippi, and South Carolina) and also Pennsylvania. Nationwide, coal-fired electric power generation

[4] EIA Data, Electricity
[5] EIA Data, Natural Gas
[6] EIA Data, Coal
[7] EIA Data, Electricity

> 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.[8]

Electricity generation from efficient natural gas plants emits roughly 60% less CO_2 per unit of electrical energy than generation from coal plants. Because of natural gas' advantage in this respect, fuel switching translates to a deep reduction in CO_2 emissions.

II. Problem Formulation and Previous Research

In this thesis, I model how the coal to natural gas fuel-switching effect occurs and quantify its extent at various prices of coal and natural gas. Linking fuel switching to emissions reduction, I then isolate the effect of falling natural gas prices on the recent emissions reduction in the energy sector and nationwide.

Subsequently, I use the models to demonstrate how targeted federal policies, such as a carbon tax or a subsidy on natural gas, could augment the existing reduction in emissions. I operate under the short-term assumption that power plant capacity does not change, so that switching is only a function of the fuel price differential. I conclude with an analysis of other impacts resulting from a large-scale shift in fuel systems. In summary, this thesis attempts to answer the following questions:

- How have falling natural gas prices, combined with static coal prices and underutilized natural gas capacity, led to a reduction in emissions?
- What further emissions reductions could be achieved in the short term through government policies targeted at altering fuel prices?
- What other impacts are relevant to the decision by policymakers whether to support coal or natural gas?

There has been some prior research in this area. In a 2008 paper, Joseph Cullen analyzed 2005-2007 price and generation data for the ERCOT (Texas) grid. Using a dynamic optimization

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[8] United States, Dept. of Energy, Energy Information Administration, "Electric Power Industry 2009: Year in Review," *Electric Power Annual*, 23 Nov. 2010, Web, 9 Jan. 2011.

model, Cullen concluded that a \$20/ton carbon tax has a minimal effect on coal to gas switching and that it would require a tax on the order of 10 times that size to achieve a significant reduction in emissions.[9] Similarly, a 2009 ERCOT study modeled emissions on the Texas grid at natural gas prices of \$7/MMBTU and \$10/MMBTU and concluded that a carbon tax between \$40/ton and \$60/ton or more would be necessary to return Texas to 2005 emission levels by 2013.[10]

These studies arrived at different conclusions than this thesis because they relied on older data with higher natural gas prices, in the range of \$6/MMBTU to \$12/MMBTU. In the last several years, natural gas from domestic shale formations has fundamentally altered natural gas supply, driving prices into the \$4/MMBTU to \$6/MMBTU range for the foreseeable future. These natural gas prices have transformed the electric power sector, moving natural gas plants into a range where they can compete with coal plants. In this new economic landscape, a carbon tax or other similar price mechanism has a much more significant impact.

Several newer studies reflect this new information. A May 2009 EIA Short Term Energy Outlook report examines the potential for fuel switching in the East South Central and South Atlantic census regions and concludes that switching is likely to occur and lead to a significant increase in power sector natural gas demand.[11] A 2010 MIT study entitled “The Future of Natural Gas” projects that a gradually increasing carbon tax aimed at reducing US GHG emissions to 50% below 2005 levels in 2050 would force coal completely off the electric grid by

[9] Joseph Cullen, “Dynamic Response to Environmental Response in the Electricity Industry,” 12 Dec. 2008: 36, Web.
[10] “Analysis of Potential Impacts of CO2 Emissions Limits on Electric Power Costs in the ERCOT Region,” ERCOT, 12 May 2009, Web.
[11] United States, Dept. of Energy, Energy Information Administration, “The Implications of Lower Natural Gas Prices for the Electric Generation Mix in the Southeast,” Supplement to the *Short Term Energy Outlook*, May 2009, Web. Mar 2011.

2035.[12] Additionally, a 2011 report by Cambridge Energy Research Associates predicts that the power sector's demand for natural gas could nearly double by 2030 given the new price levels.[13]

III. Results

The models for fuel switching and emissions reduction in this thesis show significant effects on emissions both from falling natural gas prices and hypothetical policies supporting natural gas. The models suggest that fuel price changes from 2008 to 2009 were responsible for a 5.15% decrease in power sector CO_2 emissions, which is equivalent to a 2.02% decrease in nationwide GHG emissions.[14] A $10/ton carbon tax would result in a further reduction in power sector emissions of 8.22%, a 3.15% reduction nationwide. Alternatively, a subsidy reducing the price of natural gas $1/MMBTU below current levels would reduce power sector emissions by an additional 1.47%, a 0.57% reduction nationwide.

These emissions reductions are significant. A bill passed in the House of Representatives in the last Congress proposed emissions reduction targets of 17% below 2005 levels by 2020 and 83% below 2005 levels by 2050.[15] These targets are in line with the necessary reductions to avoid serious global warming, according to the international scientific consensus.[16] Fuel

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[12] Ernest J. Moniz et al., *The Future of Natural Gas*, Cambridge: MIT Energy Initiative, 2010, Print.
[13] "Fueling North America's Energy Future: The Unconventional Natural Gas Revolution and the Carbon Agenda, Executive Summary," (Cambridge: IHS Cambridge Energy Resource Associates, 2010), Web, 26 Mar. 2011.
[14] I refer to emissions interchangeably here even though the power sector emissions are primarily CO_2, while nationwide emissions reflect all greenhouse gases and take into account emission sinks. This is acceptable because all emissions, sources and sinks, are denominated in terms of metric tons of carbon dioxide equivalents ($tCO_2eq.$).
[15] United States, Cong. House, *America Clean Energy and Security Act of 2009*, 111th Cong., 1st sess., H.R.2454, 2009, Web, 27 Mar. 2011.
[16] Sujata Gupta and Dennis A. Tirpak, "Chapter 13: Policies, Instruments, and Co-operative Arrangements," *Contribution of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change*, 2007, Web, 28 Mar. 2011, p 776.

switching has and can continue to provide a significant fraction, 20% or more, of the emissions reduction necessary to meet the 2020 target.

IV. Thesis Organization

Chapter 2 reviews the basics of the electric grid and includes a first-pass model of the fuel switching effect based on the dynamics of the merit order. Chapter 3 examines the changes in natural gas and coal prices and gives a background on shale gas production. Chapter 4 presents an econometric model of the fuel switching effect. It begins with the theoretical basis and then constructs an actual model using real data from the Energy Information Administration (EIA). Chapter 5 uses the results from the fuel-switching model to calculate emissions reductions for the actual fuel price changes from 2008 to 2009 and for a range of potential policy options. Chapter 6 offers concluding remarks.

Chapter 2: THE ELECTRICAL GRID AND POWER PRODUCTION

I. Grid Basics

Structure

The United States electric power grid is a complex network of generators, transformers, transmission lines, and distribution systems that stretches across the entirety of the lower 48 states, with interconnections to Canada and Mexico. As a whole, the system ensures that electrical energy is reliably available for residential, commercial, and industrial uses. The grid comprises nearly 18,000 generating facilities connected to consumers by over 275,000 miles of transmission and distribution lines.[17]

The electric power industry has three major components: generation, transmission, and distribution. Generation refers to the actual production of electrical energy at power stations, transmission is the transportation of that electricity at high voltages over long distances, and distribution describes the circulation of electricity to customers on local networks at usable voltages.

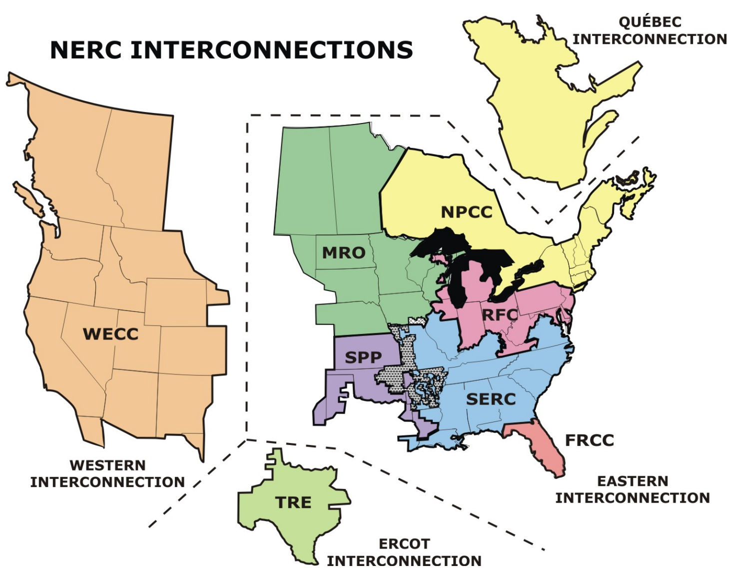
As electricity cannot be economically stored in significant quantities, the grid faces the constant challenge of instantaneously balancing generation with load. To accomplish this goal, the grid is organized into a nested hierarchy of interconnected regions. Various authorities attempt to balance generation and load at each successively larger region. Transmission lines between the regions at each level handle surpluses or shortfalls of electricity as necessary. The North American Electric Reliability Corporation (NERC), an independent non-profit invested with oversight authority by the Energy Policy Act of 2005, operates as the electric reliability

[17] EIA Data: Electricity

organization for the continent, overseeing this hierarchy and ensuring the reliability of the bulk power system.[18]

The national grid is divided into three smaller grids, or interconnections—the Eastern Interconnect, the Western Interconnect, and the Texas Interconnect—which also include large parts of Canada and one utility in Mexico. Transmission between interconnects is limited so they largely operate independently from one another. Within the interconnections, NERC subdivides the grid further into regional entities, as depicted in Figure 2.1 below. The regional entities, of which there are eight in North America, ensure compliance with grid standards. They oversee the system operators—balancing authorities, regional transmission operators (RTOs), independent system operators (ISOs), and reliability coordinators—whose task it is to coordinate electric power production and distribution in their respective regions in order to balance generation with load.[19]

Figure 2.1: Map of North American Grid Divisions, Source: NERC



FRCC—Florida Reliability Coordinating Council
MRO—Midwest Reliability Organization
NPCC—Northeast Power Coordinating Council
RFC—Reliability First Corporation
SERC—SERC Reliability Corporation
SPP—Southwest Power Pool, Inc.
TRE—Texas Reliability Entity
WECC—Western Electricity Coordinating Council

[18] *Understanding the Grid: Reliability Terminology*, NERC, Web, 25 Mar. 2011.
[19] Ibid.

Due to deregulation of the electric power industry over the last two decades, this system is continually evolving in an effort to make the grid accessible to small and large power producers, while ensuring reliability. Traditionally, large-scale utilities were vertically integrated across all three components of the industry—they owned the generating facilities, the transmission lines, and the local distribution networks. In exchange for strong government regulation, they enjoyed monopoly rights to their respective regions and were responsible for balancing within those regions. However, a series of legislative acts and orders from the Federal Energy Regulatory Commission (FERC) in the last quarter of the last century deregulated the electricity markets and encouraged competition by smaller power producers, referred to as non-utility generators. These new policies mandated non-discriminatory access to the transmission and distribution systems and encouraged utilities to sell these assets to ISOs or RTOs, who would assume responsibility for balancing generation and load via a market-based mechanism.[20]

As a result, the electric generating capacity today is a mix of utilities and non-utility generators. Traditional utilities comprise investor-owned utilities, federally-owned facilities such as the Tennessee Valley Authority, publically-owned utilities, and rural electric cooperatives. Non-utility generators are categorized into independent power producers and qualifying facilities based on their size and pricing structure. In 2007, there were more than 3,273 traditional electric utilities and 1,738 non-utility generators. Investor-owned utilities account for only a small percentage of the total number of utilities, but provide 42% of the overall generated electricity. Utilities and non-utility generators own and operate power plants. In 2009, there were over 5,680 power plants in the United States. Each power plant can have one or more generators.[21] In total,

[20] United States, Dept. of Energy, Energy Information Administration, "Electric Power Industry Overview 2007," n.d., Web, 20 Mar. 2011.
[21] Ibid.

there were 17,876 generators in 2009.[22] Revenue from retail electricity sales in 2009 was $353.4 billion.[23]

Generation

Figure 2.2 and Table 2.1 show the amount of electricity generated annually in the US over the past 10 years. As seen in the local maximum and minimum in the graph, electricity generation is correlated with the performance of the economy. Both in 2000 and 2007, when the economy entered recessions, electricity generation declined on the order of 1-4% annually.

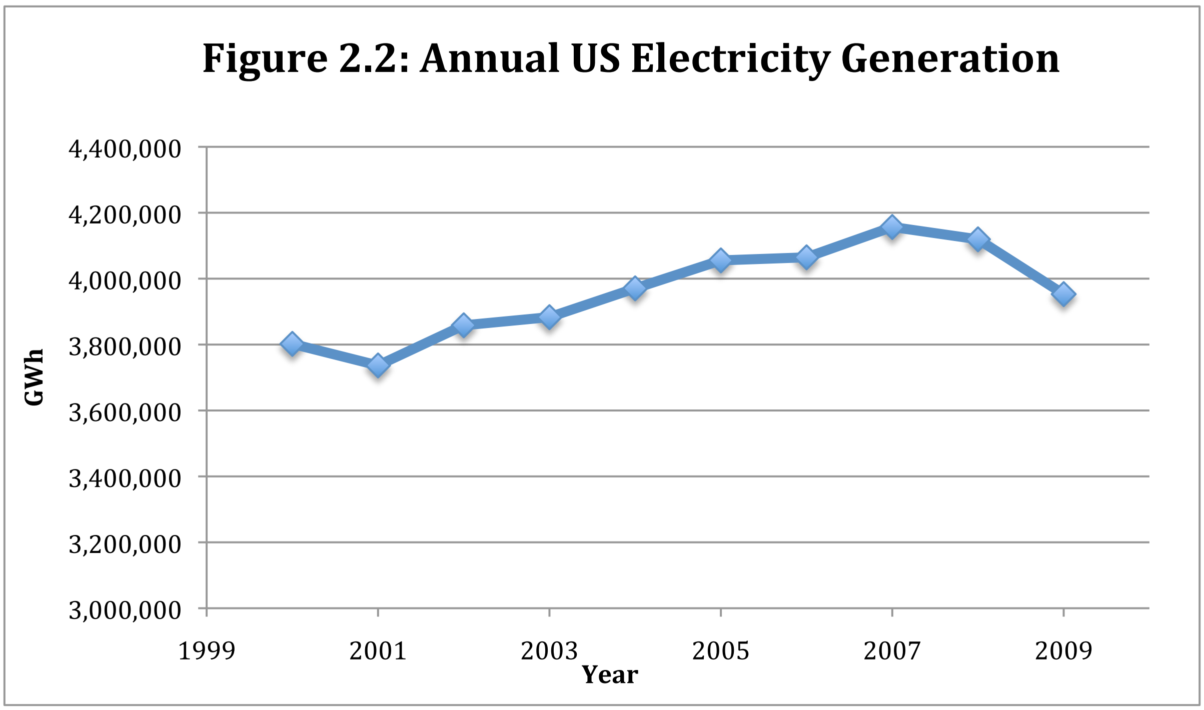
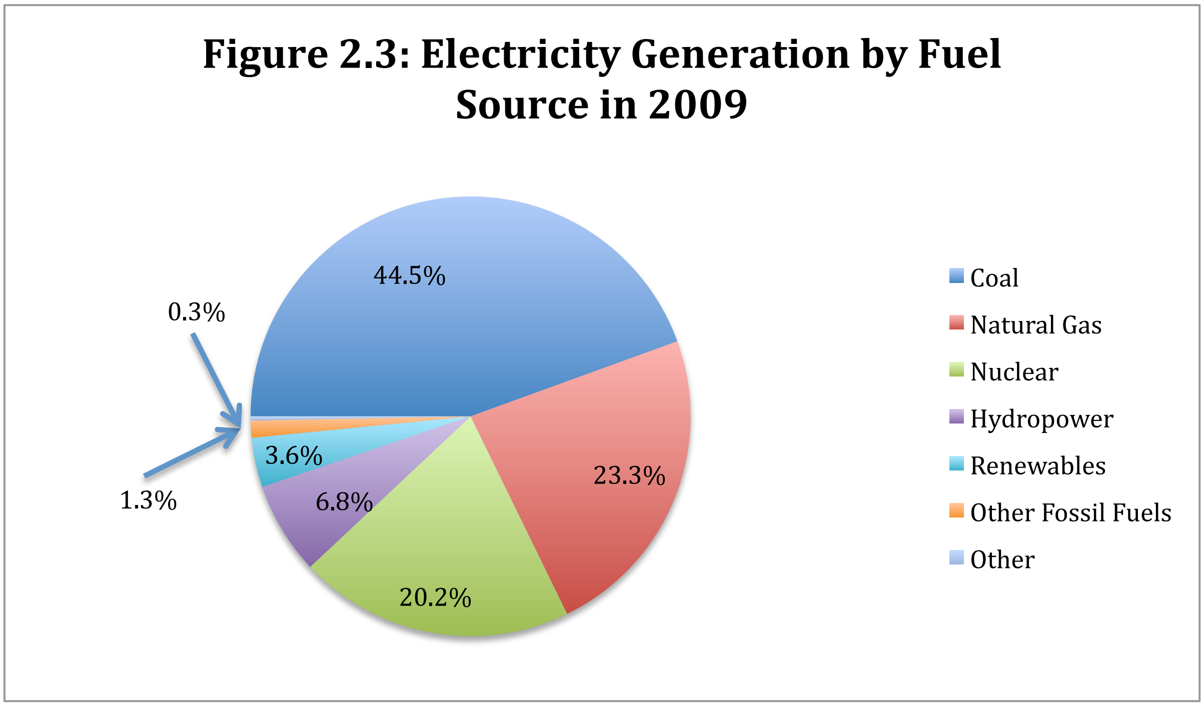


Table 2.1: Annual US Electricity Generation (in GWh), 2000-2009

Year	2000	2001	2002	2003	2004
Generation	3,802,105	3,736,644	3,858,452	3,883,185	3,970,555
Year	2005	2006	2007	2008	2009
Generation	4,055,423	4,064,702	4,156,745	4,119,388	3,953,111

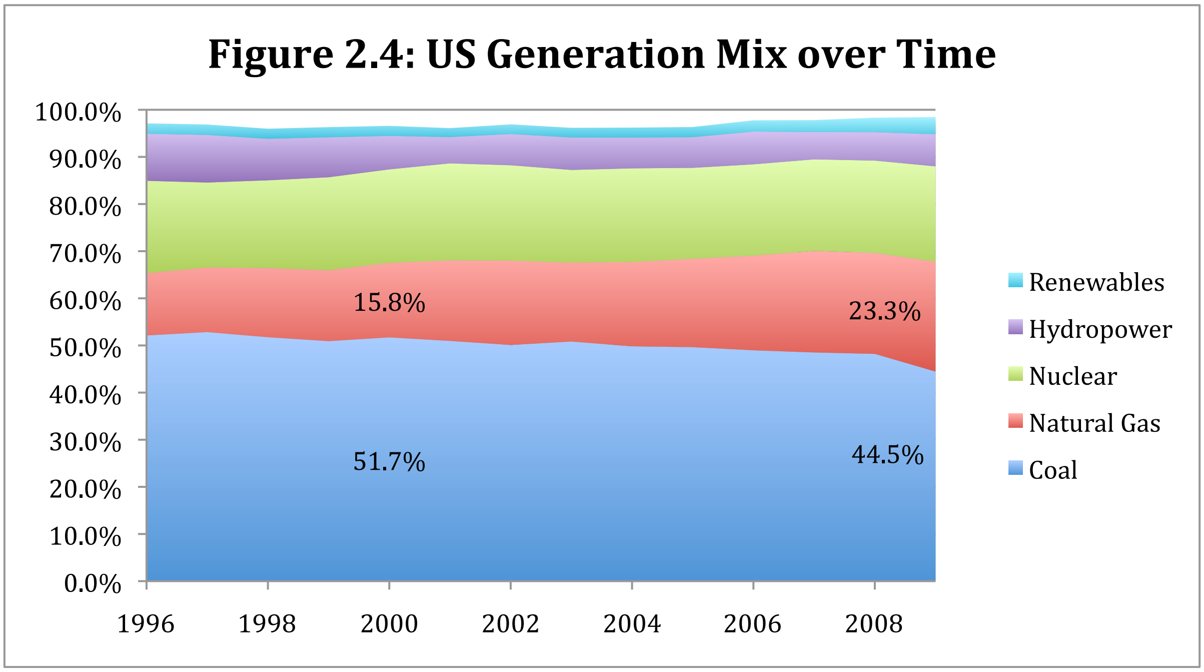
[22] EIA Data, Electricity
[23] Ibid.

Fossil fuels power plants are the primary producers of electricity, though nuclear and hydropower play significant roles as well. Renewable energy sources, such as solar and wind power, are supplying an increasing percentage of national generation but have yet to achieve large-scale market penetration. The pie chart in Figure 2.3 displays the shares of generation by fuel source in 2009.[24]

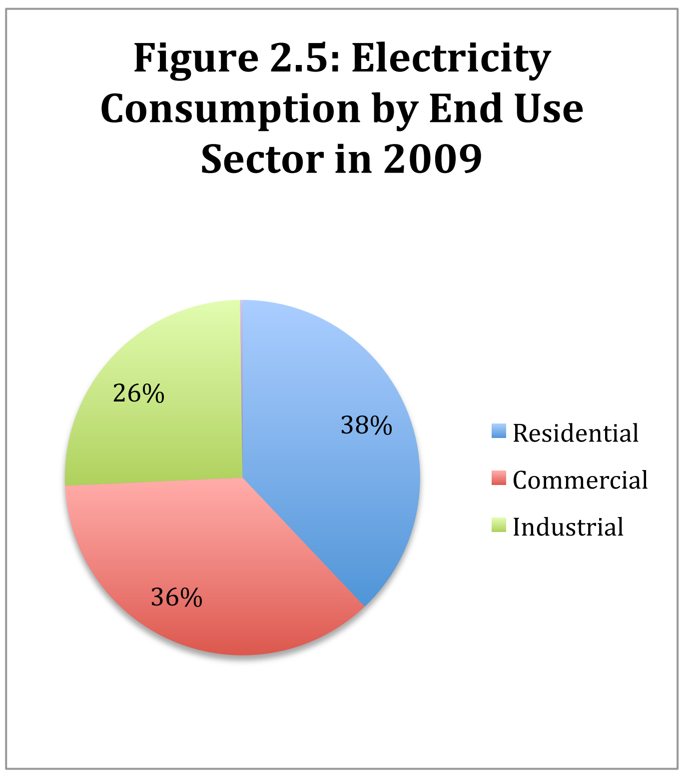


The proportions in this generation mix have not been constant over time. In the last three years, as prices of natural gas have fallen, the share of electric power generation from coal has declined while the share from natural gas has increased. Figure 2.4 shows how these shares of generation have varied over time.[25]

[24] Ibid.
[25] Ibid.



Over the last decade, the generation shares from nuclear and hydropower remained roughly constant. Meanwhile, from 2000 to 2009, the share from coal fell 7.2 percentage points from 51.7% to 44.5%. Over the same time period, the natural gas share rose by 7.5 percentage points from 15.8% to 23.3%.



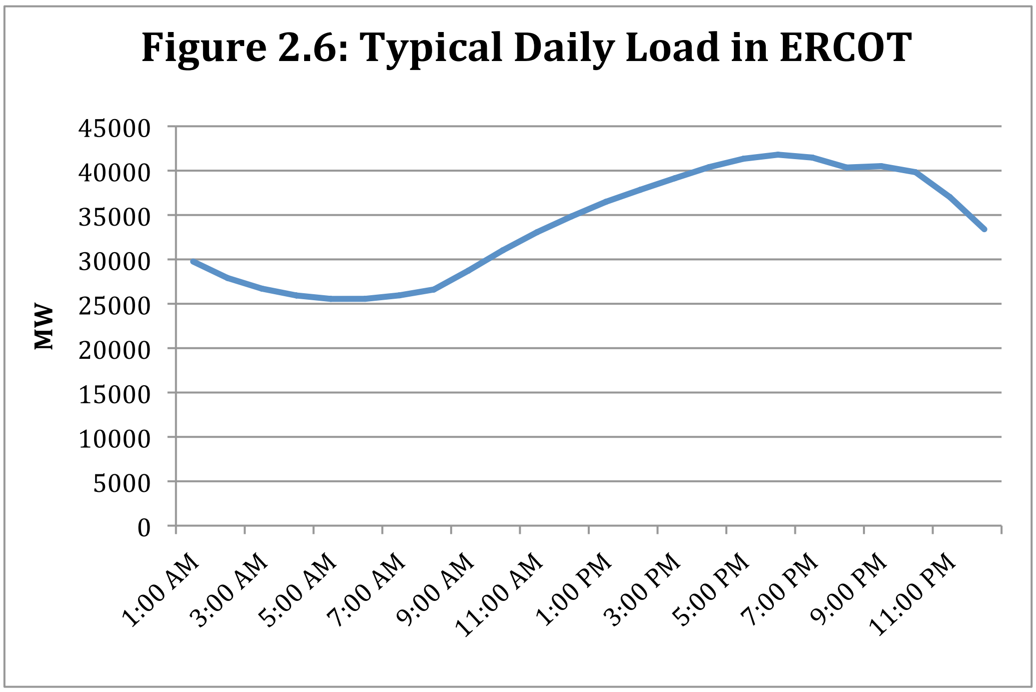
Load

Electricity is used primarily in the residential, commercial, and industrial sectors. Figure 2.5 summarizes the breakdown of end-source uses of electricity by sector.[26]

Electricity loads are highly

[26] Ibid.

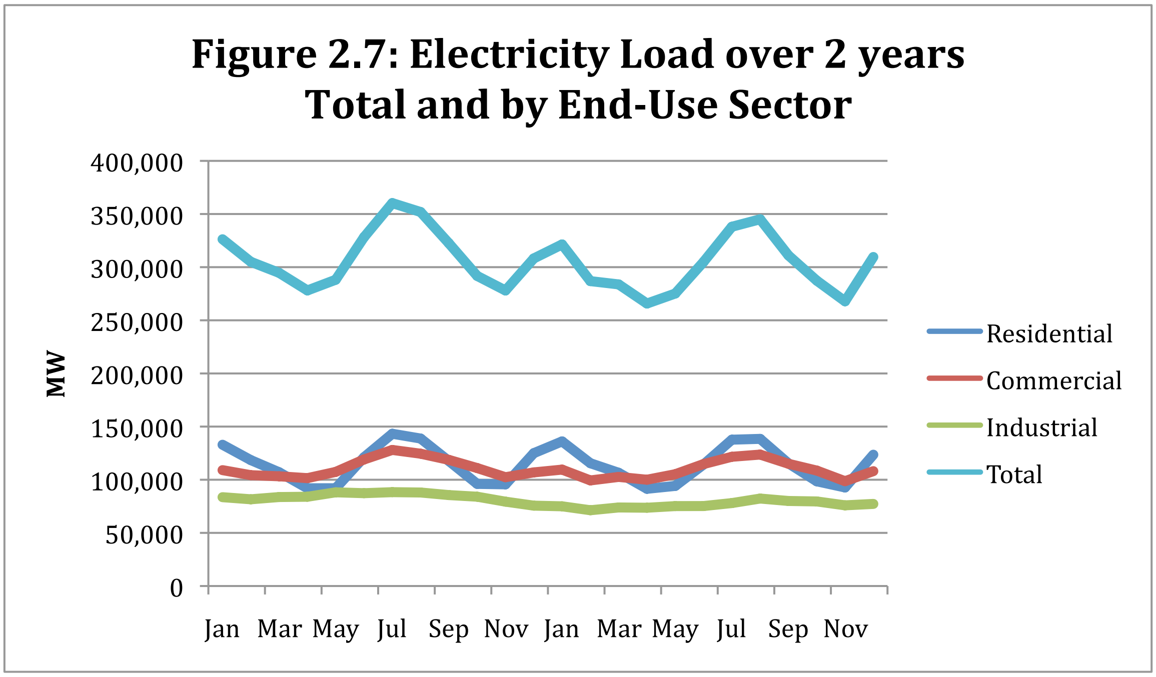
variable in time. Over the course of a 24-hour period, load tends to rise in the late morning and afternoon, peak in the early evening, and return to an overnight low. This shape is based on the different types of consumption patterns. Industrial consumers tend to use power constantly, accounting for the overnight base power load. In contrast, residential and commercial consumers have the largest demand for electricity in the late afternoon and early evening, mostly due to needs for lighting and air-conditioning.[27] Figure 2.6 depicts the load on the ERCOT grid as it changed over the course of a day on May 10, 2009.[28]



Electricity load also varies on a seasonal timescale. Over the course of a year, the load tends to have two peaks, one in December or January and another in late summer. The winter peak reflects a high demand for lighting around the winter solstice and the summer peak reflects the need for air-conditioning during the hottest part of the summer. Figure 2.7 illustrates the pattern for national electricity demand over the two-year period between January 2008 and

[27] H. Lee Willis, *Spatial Electric Load Forecasting*, (CRC Press, 2002), p 148, Web.
[28] ERCOT Data

December 2009.[29] The summer peaks occur in July 2008 and August 2009 and the slightly lower winter peaks occur in January.

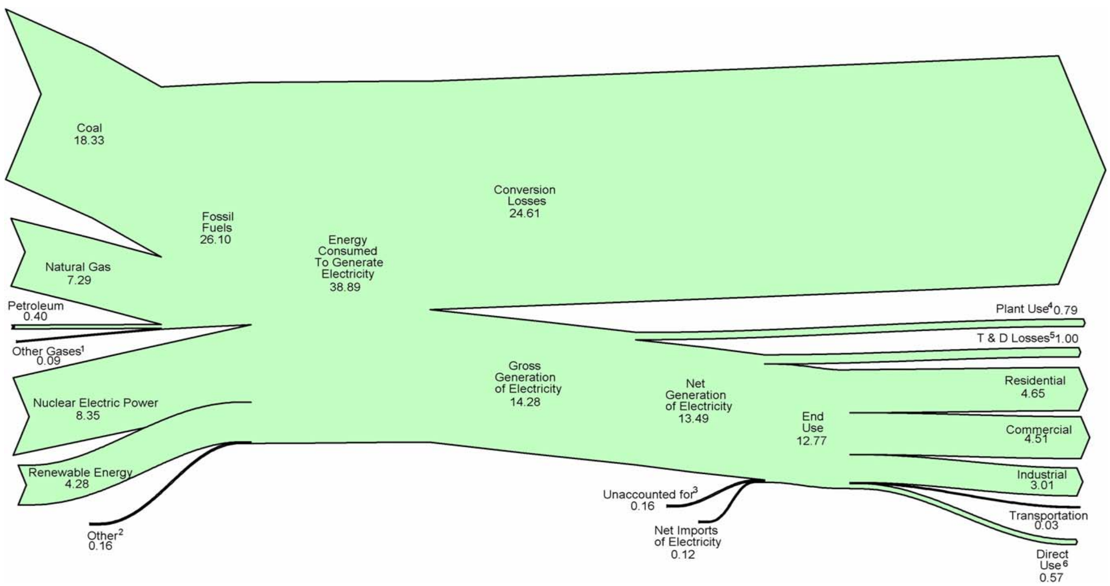


II. Efficiency and Generation Types

Much of the energy that goes into electric power production is lost through inefficiencies in fuel conversions. Fossil fuel energy plants convert the chemical energy of a fuel into electrical energy (via the mechanical energy of expanding steam or exhaust gases) with efficiencies in the range of 25% to 55%. Additional electricity is lost to heat during transmission. The following graph from the EIA's Annual Energy Review demonstrates the flow of energy in the electricity sector, from inputs to final uses.

[29] EIA Data, Electricity

Figure 2.8: Electricity Flow, 2009 (Quadrillion BTU) Source: Annual Energy Review 2009



Only 12.77 out of the overall 38.89 quadrillion BTU utilized to generate electricity reaches consumers and performs useful work. Thus, the sector-wide efficiency is 32.8%.

A number of different fuel sources with varying efficiencies combine to form the electricity generation mix. As explained above, the bulk of electric power generated in the US comes from the combustion of fossil fuels, primarily coal and natural gas. Oil-fired power plants do exist, but they produce a negligible amount of electricity. In addition to fossil fuels, nuclear power and hydropower also provide significant shares of the generation mix and the contribution from non-hydro renewables is growing.

Coal

Coal has been the biggest player in the US electric power sector for some time. Over the last decade, coal-fired power plants have provided between 44% and 52% of the national electric power supply. Coal resources are abundant in the continental US and provide the cheapest fossil fuel on a dollars per MMBTU basis.

Fuel Background

Coal is formed from the incomplete decomposition of vegetable matter in anoxic environments. The coal mined today was formed 350 million years ago in the Carboniferous period. Dead vegetable matter in moist areas such as bogs or marshes did not fully decompose and sedimentation isolated this organic matter underground. Over eons, heat and pressure forced excess water out of the organic matter to produce a compact hydrocarbon complex—coal—capable of being mined and combusted for power.[30]

Depending on the geological conditions at a particular mine, coal also contains a number of impurities, such as sulfur and mercury. Coal is classified based on the degree to which it has been compacted and water has been forced out. In general, the lower the moisture content, the higher the heat content (energy/mass) of the coal, since less energy has to be expended vaporizing water during combustion. The main types of coal are lignite, sub-bituminous coal, bituminous coal, and anthracite. Lignite has the highest moisture, around 45%, and the lowest heat content. At the other end of the spectrum, anthracite has less than 15% moisture and the highest heat content.[31]

Coal is abundant in the United States. At present levels of consumption, domestic coal reserves could last for several hundred years.[32] The most abundant type of coal in the United States is bituminous, found predominantly in the Appalachian mountain range. Bituminous coal emits sulfur dioxide (SO_2) emissions when combusted, which cause human respiratory problems

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[30] Michael B. McElroy, *Energy: Perspectives, Problems, and Prospects*, (Oxford: Oxford University Press, 2010), Print, p 107.
[31] Ibid, p 109.
[32] Ibid, p 106.

and form acid rain. However, there are significant reserves of sub-bituminous coal in the Powder River Basin in Wyoming, which have lower sulfur content.[33] The tradeoff is that sub-bituminous coal also has lower heat content, so more of it must be burned to get the same amount of energy, releasing more CO_2 emissions. Of the coal produced in 2009, 42.4% came from the Powder River Basin and 31.8% came from Appalachia.[34]

<u>Coal Power Plants</u>

A large fraction of coal produced in the US—around 94%—is used for power production.[35] Coal is combusted in steam turbines. Combustion in a boiler converts water into steam, which is forced through a turbine. The turbine rotates a generator shaft to produce electricity. Coal plants are generally on the high end of the capacity spectrum for power plants—the average coal-fired power plant online in 2009 was rated at 238.5 MW with the largest at 1425.6 MW, the William H. Zimmer power station in Ohio.[36] Construction of coal plants requires large capital investments and they are difficult to site. Furthermore, the US fleet of coal power plants is aged. In 2009, 95% of the coal power plant capacity was more than 20 years old and 37.9% was more than 40 years old.[37] Coal power plants have a heat rate of around 10,000 BTU/kWh, which equates to an efficiency of roughly 34%.

<u>Emissions</u>

Coal is the most carbon intensive of the major fossil fuels. When combusted, it emits almost twice as much CO_2 per unit of energy released as natural gas and around 33% more than oil. As a result, coal combustion accounted for 81% of CO_2 emissions from the electric power

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[33] EIA Data, Coal
[34] Ibid.
[35] Ibid.
[36] EIA Data, Electricity, "Form EIA-860"
[37] Ibid.

sector in 2009, while providing only 44.5% of the electric energy.[38] Coal emits several additional harmful pollutants when combusted, including SO_2, nitrogen oxides (NO_x), carbon monoxide (CO), mercury, and particulate matter.

Natural Gas

Natural gas is the other major fossil fuel used in the electric power sector. Unlike coal, it is widely used in other sectors of the economy, mostly for industrial production and for commercial and residential heating. Only 33% of the natural gas consumed in the US is used in the electric power sector.[39] Over the past decade, natural gas-fired power plants have provided between 15% and 24% of the electric power supply. Natural gas emits carbon dioxide when burned, but only half the CO_2 emissions as coal for the same amount of energy input. Natural gas prices are highly volatile, due to difficulty in storage[40] and large fluctuations in demand.

<u>Fuel Background</u>

Natural gas is composed of short hydrocarbon chains, between one carbon (methane) and four carbons (butane) long. Though component ratios vary, the bulk of natural gas—between 70% and 90%—is methane (CH_4). Natural gas, like oil, is formed from dead marine organisms. Millions of years ago, organic matter from these organisms collected on ocean floors and was covered by sediments before full decomposition. Over time, heat and pressure of successive layers of sedimentation broke down this organic matter into simpler and simpler hydrocarbon chains. The longer chains are liquid at standard temperature and pressure and comprise the range

[38] EPA Data, US GHG Inventory
[39] EIA Data, Natural Gas
[40] Helyette Geman, *Commodities and Commodity Derivatives: Modelling and Pricing for Agriculturals, Metals, and Energy*, (Chicester: John Wiley and Sons, Ltd., 2005), Print, p 28.

of petroleum products—oil, waxes, etc. The shortest chains are gaseous at standard temperature and pressure and make up natural gas.[41]

Natural gas is traditionally found in the same wells as oil (as the two substances are different ends of the same hydrocarbon spectrum) but is also found on its own. Natural gas production is prominent in three main world regions: North America, Russia, and the Middle East.[42] In recent years, there have been large discoveries of natural gas in the US in shale formations, providing a relatively low-cost and abundant domestic source of the commodity. The "Shale Gas Revolution" will be discussed in Chapter 3.

Natural Gas Power Plants

Natural gas is combusted to create electricity in gas turbines, steam turbines (similar to those in coal plants), and combined cycle power plants. In a gas turbine, the fuel is mixed with compressed air and then combusted. The hot exhaust gases drive the turbine (cf. the steam turbine, where steam created by the combustion of the fuel drives the turbine). These turbines have a thermal efficiency of roughly 33%.[43] They tend to be smaller units, with lower capital costs than coal-fired power plants. The average size of a gas turbine online in 2009 was 63 MW.[44] Unlike coal-fired plants, gas turbines can be turned on quickly and adjusted easily to meet changing loads.

Combined-cycle power plants couple a gas turbine with a steam turbine. Exhaust gas exiting a gas turbine has a temperature of about 500°C and this waste heat can be captured by passing the exhaust through a heat recovery steam generator. The steam then drives a separate

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[41] McElroy, p 151.
[42] MIT Future of Natural Gas, p 7.
[43] Gilbert M. Masters, *Renewable and Efficient Electric Power Systems*, (Hoboken: John Wiley & Sons, Inc., 2004), Print, p 132.
[44] EIA Data, Electricity, "Form EIA-860"

steam turbine to generate additional electricity, improving the plant's overall electric efficiency. Plants with this design can reach efficiencies of over 50%.[45] Combined-cycle plants tend to be larger than gas turbines, on the order of 200 MW.

Combined cycle power plants accounted for 50.7% of the total natural gas power plant capacity in 2009, gas turbines for 30.2%, and steam turbines for 18.6%.[46]

Emissions

Natural gas is the cleanest burning of the fossil fuels with respect to carbon dioxide. Hydrocarbons with more hydrogen atoms than carbon atoms release a larger fraction of their energy during combustion through water formation rather than CO_2 formation. Thus, hydrocarbons with higher ratios of hydrogen atoms to carbon atoms emit less CO_2 per unit of energy produced than those with lower ratios. Molecules of methane, the primary component of natural gas, have four hydrogen atoms for every carbon atom, the highest possible ratio for a hydrocarbon. Larger hydrocarbons like oil and coal have fewer hydrogen atoms per carbon atom and thus emit more CO_2 per unit of energy produced. This conclusion is borne out in the statistical data shown in Table 2.2.[47]

Table 2.2: Emissions Factors by Fuel Type

Fuel Type	Emissions Factor (kgCO_2/MMBTU)
Coal	
Anthracite	103.69
Bituminous	93.28
Sub-bituminous	97.17
Lignite	97.72
Petroleum	
Crude Oil	74.54
Home Heating Oil	73.15
Natural Gas	
Weighted National Average	53.06

[45] Ibid, p 134
[46] EIA Data, Electricity, "Form EIA-860"
[47] EIA Data, Environment

For the same energy released, natural gas emits around 55% and oil emits around 75% of the CO_2 as coal. Combustion of natural gas also emits NO_x, though far less than coal emits per unit of electricity generated.[48] Methane, a potent greenhouse gas, can be leaked throughout the natural gas production process and add meaningfully to the fuel's climate change impacts.[49]

Nuclear

Nuclear power is electricity produced through fission of radioactive uranium. This process releases large amounts of energy by rearranging the bonds in the nuclei of atoms and heating water into steam to drive a steam turbine, just as in coal-fired power plants. Like coal-fired power plants, nuclear power plants are large and require significant capital outlays for construction. Due to the technicalities of nuclear reactions, they are difficult to start and stop and have low operating costs so often run continuously. Nuclear power plants do not contribute in any significant way to air pollution nor do they emit greenhouse gases. However, they produce a significant amount of radioactive waste, the disposal of which remains a barrier to their wider scale market penetration.[50] In recent years, nuclear power has provided around 20% of the national electric power supply.[51]

Hydropower

Hydropower captures the gravitational potential energy of water to produce electricity. In the water cycle, water is elevated in altitude following evaporation and falls back to the earth through precipitation. Following precipitation, water flows downhill via rivers and streams.

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[48] EPA Data, Air Emissions
[49] EPA Data, US GHG Inventory
[50] McElroy, pp 205-6.
[51] EIA Data, Electricity

Hydropower attempts to harness the power in flowing water by damming rivers and diverting the water flow through a turbine, which rotates a generator shaft to produce electricity.[52] Like nuclear power, hydropower does not contribute significantly to air pollution or greenhouse gas emissions, but the environmental impacts of damming rivers are controversial. Hydropower in the US is largely restricted to the Pacific Northwest and accounts for around 6.5% of the nation's electricity.[53] Though not as variable as solar and wind power, the availability of hydropower depends on precipitation levels. In years of low rain, the electricity available from hydropower is reduced.

Renewables

The main domestic sources of non-hydro renewable energy are solar and wind power. Solar power is captured through photovoltaics, which exploit the quantum properties of silicon and other materials to generate an electric current from high-energy photons, and through concentrated solar power, which uses the sun's radiation to heat a fluid and pass it through a turbine to generate electricity. Wind power harnesses the kinetic energy in wind by converting it into the mechanical energy of a spinning turbine blade. The turbine blades turn a generator shaft which produces electricity. Solar power is most prevalent in the Southwest region of the US where the levels of incident sunlight are highest. Wind power is most abundant in the Great Plains region, in states like Iowa and Kansas and in the Texas Panhandle, where the winds are strong and steady. These renewable power sources, especially wind, have exhibited significant growth in recent years, but they still amounted to only 3.6% of the domestic power supply in

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[52] Masters, pp 194-5.
[53] EIA Data, Electricity

2009.[54] Notably, wind and solar power are intermittent energy sources. They do not necessarily provide power when the grid demands it, but instead when the sun is shining or the winds are blowing, respectively.

III. Capacity

Capacity and Capacity Factors

Capacity refers to the maximum amount of power a power plant is capable of producing. Generation, in contrast, is the amount of energy a plant produces over some period of time. This distinction is important in the electric power sector because in many cases, power plants are not always operating at their complete capacity. The amount of electricity that a plant generates annually is often only a fraction of what it would have generated had it been running continuously. For a given plant, this fraction is known as its capacity factor.

Average capacity factors vary significantly across different energy sources. Table 2.3 shows capacity factors for various fuel sources and plant types in 2006 and 2009.[55]

Table 2.3: Capacity Factors

Fuel and Plant Type	Capacity Factor in 2006	Capacity Factor in 2009
Coal	72.6%	63.8%
Natural Gas—Combined Cycle	38.8%	42.5%
Natural Gas—Other	10.7%	9.8%
Hydropower	42.4%	39.8%
Nuclear Power	89.6%	90.3%
Renewables	45.7%	33.8%

The reason that different fuel and plant types operate at different capacity factors depends on dispatch-ability and fixed and variable costs, which will be explored in more detail below. The changes in capacity factors show that trends in nationwide capacity are related to but not congruent to trends in nationwide generation.

[54] Ibid.
[55] Ibid.

Nationwide Capacity over Time

Figures 2.9 and 2.10 show nationwide capacity over time and the changing structure of the capacity mix.[56]

Figure 2.9: US Electric Generating Capacity 2000-2009

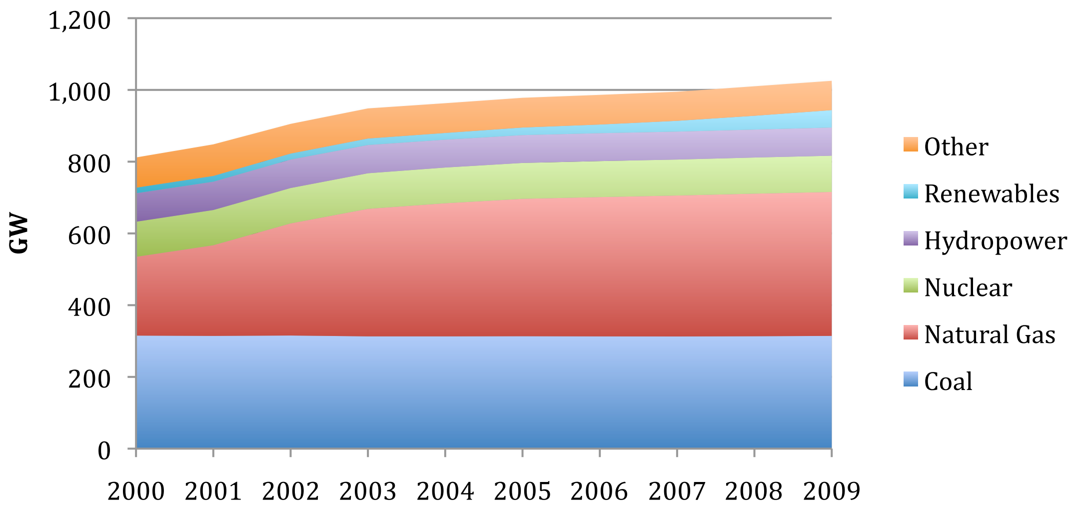
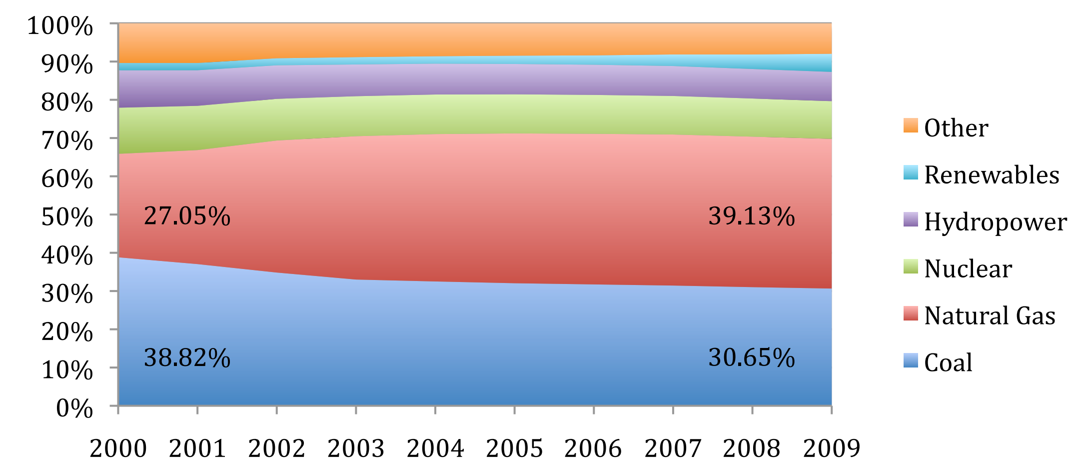


Figure 2.10: Capacity by Fuel Source as a Percentage of Total Capacity



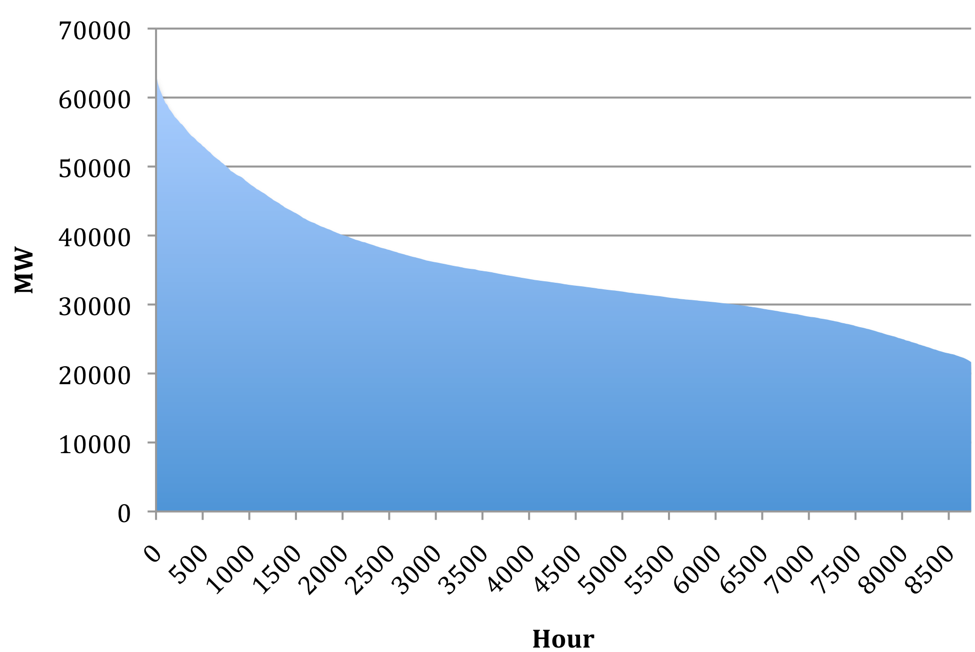
[56] EIA Data, Electricity, Form EIA-860

Over the last decade, national electric power capacity has risen by around 25%, from 800 GW to 1,000 GW. The bulk of that growth in capacity, around 85%, has been in natural gas power plants, with the balance made up by expansion of renewables. As a result, the capacity shares have shifted and natural gas now makes up the largest share of the national capacity at 39.13%, switching places with coal, which has fallen to 30.65%.

Screening Curves

The decision on the optimal capacity mix depends on the shape of the electricity demand curve and the costs that each fuel type faces. As discussed previously, electricity demand is highly variable on both the daily and the seasonal time scale. One can obtain a better sense of the shape of the demand and the capacity needed to meet it by slicing the year into hour-long segments and ordering these segments from the hour of greatest load to the hour of least load. Figure 2.11 displays this load curve (in MW) for the Texas Interconnect (ERCOT) in 2009.

Figure 2.11: ERCOT Hourly Load in 2009



Load varies over the course of the year. The hour of greatest load for ERCOT in 2009, called the peak load, came at 5 pm on July 13 and was almost three times the minimum load.[57] The grid capacity must be sized to meet this peak load (plus some reserves). This means that there are significant portions of the power plant capacity that operate at low capacity factors—running for only a small fraction of the 8,760 hours in a year.

The allocation of different plant types to different sections of the load depends on their fixed and variable costs. Those plants with high fixed costs (capital costs and fixed O&M) and low variable costs (fuel costs and variable O&M) have the lowest total cost at high capacity factors. In contrast, the plants with low fixed costs and high variable costs have the lowest total cost at low capacity factors. This effect is illustrated in Figure 2.12 below. The three screening curves, simulated to represent coal plants, natural gas combined cycle plants, and natural gas turbines, show the total annual cost per kW incurred by a power plant as a function of the number of operational hours per year. The curves are linear functions of hours with fixed costs and variable costs as parameters, according to the following equation.

$$TotalCost[\$/kW-yr] = FixedCosts[\$/kW-yr] + VariableCosts[\$/kWh]*(Hours/Yr)$$

Fixed cost is the sum of a plant's fixed O&M costs and the product of its initial capital cost with its fixed charge rate (which incorporates interest paid on the initial loan, taxes, insurance, and other administrative costs). The variable cost is the sum of the variable O&M and the product of fuel costs (in $/MMBTU) with heat rate (in MMBTU/kWh). The cost numbers

[57] ERCOT Data

used here are based on EIA estimates for each plant type.[58] Cost information is proprietary so a nationwide average of these costs is not public.

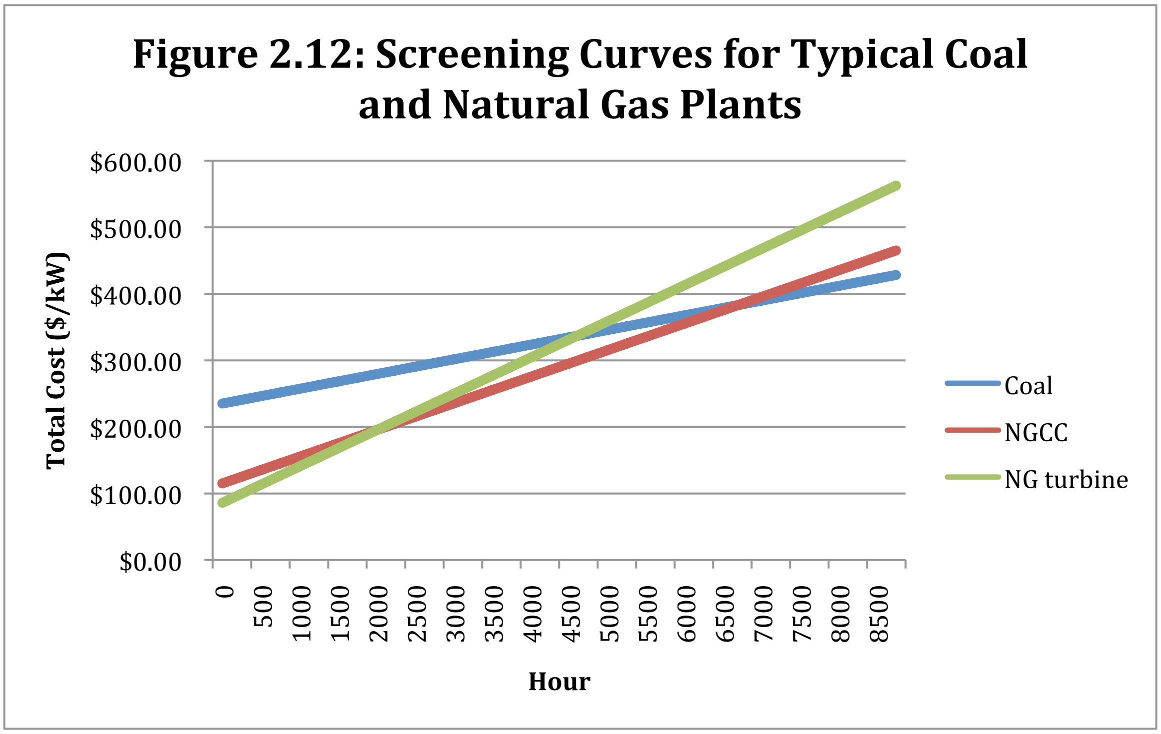
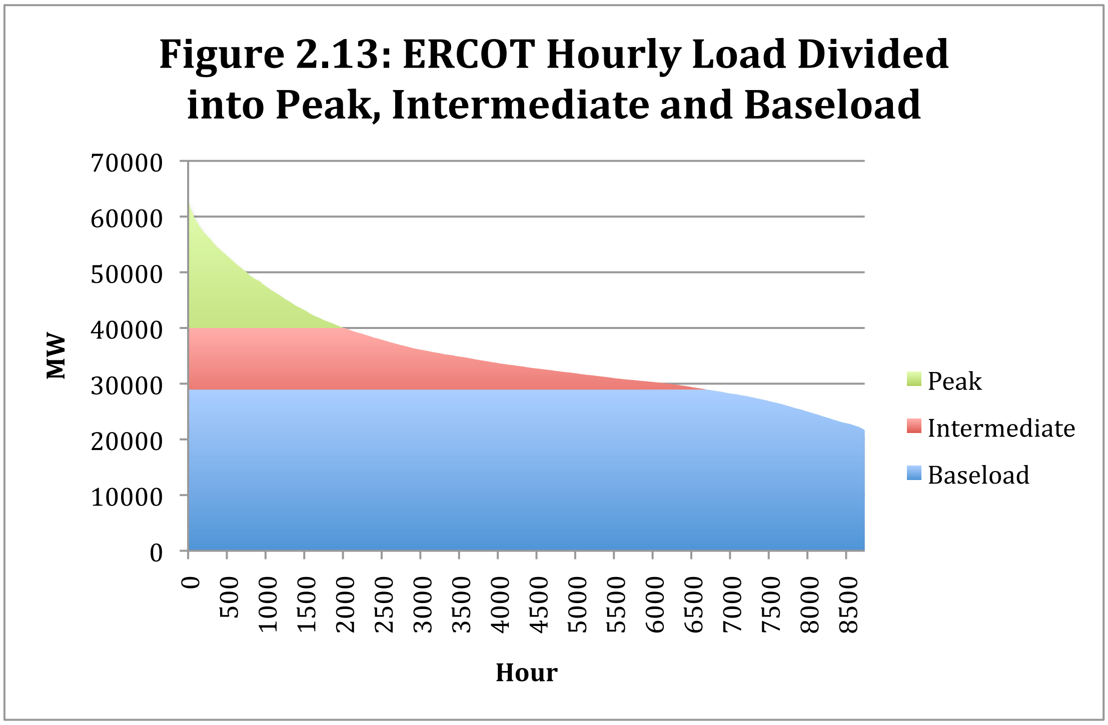


Figure 2.12 shows that different fuel and plant types have the lowest total cost depending on the capacity factor. For plants running from 0 to 2,020 hours per year, natural gas turbines are optimal. Between 2,020 and 6,700 hours per year, natural gas combined cycle plants are optimal and above 6,700 to 8,760 hours per year, coal plants are optimal. By cross-referencing these cutoff points with the hourly load curve, it is possible to map out the optimal capacity mix.

[58] United States, Dept. of Energy, National Renewable Energy Laboratory, "Cost and Performance Assumptions for Modeling Electricity Generation Technologies," Nov. 2010, Web, Feb. 2011.



As shown in Figure 2.13, the load is split into three sections. The rectangular section at the bottom of the curve, which represents the near minimum demand for power throughout the year, is called the baseload. It is met by power plants with high capital costs and low fuel costs, such as coal and nuclear, which run almost continuously. The capacity factor for plants in the baseload is usually above 85%. The middle section is called the intermediate load and is met by power plants with lower capital costs but higher fuel costs. Natural gas combined cycle plants, with their high efficiencies, generally fall in this category and have a capacity factor around 40%. The triangular section at the top is met by peaker plants, those with the lowest capital costs and the highest fuel costs. These are usually gas turbines and their capacity factor is around 10%.[59]

Optimal capacity mix analysis using screening curves and hourly load curves is useful for future planning of capacity expansion. However, it is ineffective in the short run when capacity

[59] Masters, p 144.

is fixed. Variable costs, especially fuel costs, change regularly and shift the slopes and intersection points of the screening curves. For example, a decrease in the price of natural gas lessens the slopes of the natural gas turbine and natural gas combined cycle screening curves, pushing the intersection points with the coal screening curve to the right. This suggests that the breakpoints on the hourly load curve are also pushed to the right and that natural gas takes up a larger share of capacity in the optimal capacity mix. However, changes in the natural gas price happen on the scale of hours and days and weeks, whereas it takes months and years to build power plants. Thus, it is likely that the capacity mix, regionally or nationwide, is often sub-optimal.

IV. Merit Order

To understand which power plants run when load is at different levels, it is necessary to turn to the economic merit order. For a given time and region, the economic merit order is the listing of plants and the power they are willing to supply at various prices. In other words, it is an aggregate supply curve for electric power.

Electric power is sold in two ways: through long-term contracts and on the balancing market. Merit order is relevant in both cases, but it is clearer in the balancing market. In the ERCOT region for example, a large portion—around 95%—of electric power for a given day and hour is sold ahead of time, through long-term bilateral contracts between generators and distributors. The remaining 5% is sold on the balancing market at fifteen-minute intervals. Every hour, generators submit bidding functions which state their willingness and ability to generate additional electric power beyond their planned output at a range of prices. The balancing authority aggregates these bidding functions and balances them against the load every fifteen minutes, essentially intersecting the supply and demand functions to create a market-clearing price, which they send to all the market participants.[60] The generators then come online or increase generation, i.e. are "dispatched", if their marginal costs are less than this price, thereby ensuring that the load is met.

It is possible to simulate the dispatch process to show how the optimal fuel mix responds to changing fuel prices. The following simplified model sets total capacity on a hypothetical grid at 100 MW and distributes capacity among the fuel sources in the following ratio: coal 30%, natural gas combustion turbine 25%, natural gas combined cycle 20%, nuclear 10%, hydropower 10%, wind 4%, solar 1%, roughly equivalent to the present national scenario. Using estimated parameters for variable O&M costs and heat rates based on EIA and National Renewable Energy Laboratory (NREL) data, it is possible to simulate the generation from each type of plant. Table 2.4 summarizes the parameters used in the simulation.[61]

Table 2.4: Parameters for Merit Order Simulation

Plant Type	Capacity (MW)	Plant Size (MW)	Average Variable O&M (Cents/kWh)	Average Heat Rate (BTU/kWh)
Coal	30	5	0.44	10,148
NGCC	20	5	0.20	7,543
NG turbine	25	2.5	0.33	11,497
Nuclear	10	10	0.05	10,460
Hydropower	10	10	0.30	-
Wind	4	4	0	-
Solar	1	1	0	-

In this simulation, there are 6 representative coal plants, 10 natural gas combustion turbines (NGCT), 4 natural gas combined cycle plants (NGCC), 2 hydropower plants, and 1 plant each for nuclear, wind, and solar. The variable O&M costs and average heat rates presented above are the means for each type of plant. These parameters vary across plants to simulate the range of ages and efficiencies within a plant type. For example, coal plant 1 in the scenario has a

[60] Cullen, p 9.
[61] EIA Data, Electricity & "Cost and Performance Assumptions…"

heat rate of 8,804 BTU/kWh, representing a newer, more efficient plant, and coal plant 7 has a heat rate of 11,492 BTU/kWh, representing an older, dirtier plant. I assigned these heat rates and variable O&M costs based on real EIA data, attempting to represent the median 75% of each plant type in terms of performance. I assumed that variable O&M costs co-vary with heat rates because plants that are older and less efficient (higher heat rate) probably also require a higher level of maintenance.

Power plants will run if the market-clearing price is greater than their variable cost. Variable cost is a function of fuel costs, heat rate, and variable O&M costs as follows:

$$VariableCost = (VariableO\,\&\,M) + (HeatRate) * (FuelCosts)$$

Heat rate and variable O&M costs are mostly constant for a given generator, so the generator's place in the economic merit order is mainly based on fluctuations in fuel costs. The economic merit order for several cost scenarios is given in Table 2.5.

Table 2.5: Results for Merit Order Simulation

June 2008 Natural Gas Prices		**September 2009 Natural Gas Prices**		**2009 Prices with $20/ton carbon tax**	
NG Price=$12.06/MMBTU		NG Price=$3.97/MMBTU		NG Price=$3.97/MMBTU	
Coal Price=$2.07/MMBTU		Coal Price=$2.19/MMBTU		Coal Price=$2.19/MMBTU	
Carbon Tax=$0/ton CO2		Carbon Tax=$0/ton CO2		Carbon Tax=$20/ton CO2	
Merit Order	**Var Cost**	**Merit Order**	**Var Cost**	**Merit Order**	**Var Cost**
Wind	0.00	Wind	0.00	Wind	0.00
Solar	0.00	Solar	0.00	Solar	0.00
Hydro 1	0.28	Hydro 1	0.28	Hydro 1	0.28
Hydro 2	0.32	Hydro 2	0.32	Hydro 2	0.32
Nuke 1	0.57	Nuke 1	0.57	Nuke 1	0.57
Coal 1	2.20	Coal 1	2.30	**NGCC 1**	**3.61**
Coal 2	2.33	Coal 2	2.45	**NGCC 2**	**3.93**
Coal 3	2.47	Coal 3	2.59	Coal 1	4.06
Coal 4	2.60	Coal 4	2.73	**NGCC 3**	**4.25**
Coal 5	2.74	**NGCC 1**	**2.82**	Coal 2	4.32
Coal 6	2.87	Coal 5	2.87	**NGCC 4**	**4.58**
NGCC 1	8.21	Coal 6	3.01	Coal 3	4.59
NGCC 2	8.93	NGCC 2	3.07	**NGCT 1**	**4.83**
NGCC 3	9.66	NGCC 3	3.32	Coal 4	4.85
NGCC 4	10.39	NGCC 4	3.57	Coal 5	5.11
NGCT 1	10.90	NGCT 1	3.78	**NGCT 2**	**5.15**
NGCT 2	11.63	NGCT 2	4.03	Coal 6	5.38
NGCT 3	12.37	NGCT 3	4.28	NGCT 3	5.47
NGCT 4	13.10	NGCT 4	4.52	NGCT 4	5.78
NGCT 5	13.83	NGCT 5	4.77	NGCT 5	6.10
NGCT 6	14.57	NGCT 6	5.02	NGCT 6	6.42
NGCT 7	15.30	NGCT 7	5.27	NGCT 7	6.74
NGCT 8	16.03	NGCT 8	5.52	NGCT 8	7.06
NGCT 9	16.77	NGCT 9	5.76	NGCT 9	7.38
NGCT 10	17.50	NGCT 10	6.01	NGCT 10	7.70

In all scenarios, the intermittent renewable sources are at the top of the economic merit order—they are dispatched whenever available. In the scenario with the peak natural gas prices from June 2008, the conventional baseload power sources, coal and nuclear, also are on top. The natural gas combined cycle plants come next, followed finally by the gas turbine plants which have the highest fuel costs and lowest efficiencies. However, in the scenario with the lower natural gas prices from September 2009, the highest efficiency natural gas combined cycle plants (shown in bold) overtake the oldest, most inefficient coal plants in the merit order. In the third scenario, a carbon tax augments this effect—all the combined cycle plants are higher in the merit order than four of the coal plants and the two most efficient combined cycle plants surpass all the coal plants entirely.

Figures 2.14 to 2.16 illustrate how the allocation of plants on the load curve changes, when the results of these simulations are applied to the ERCOT hourly load data.

Figure 2.14: High Natural Gas Prices Scenario

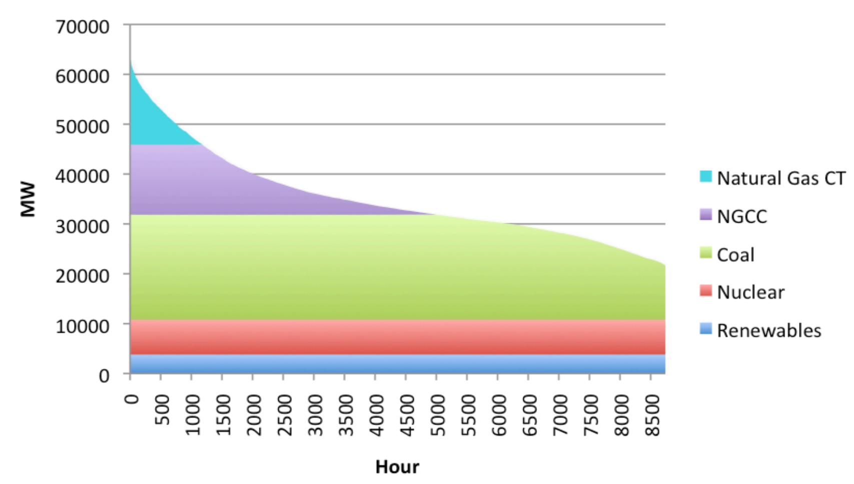
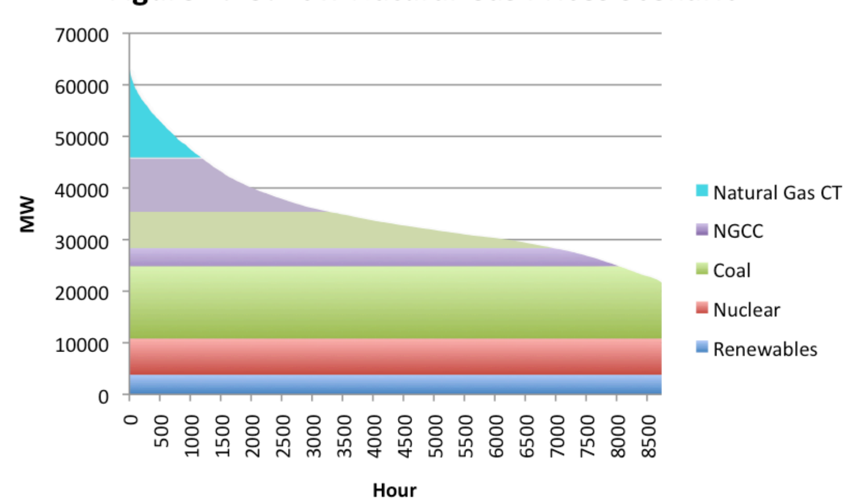
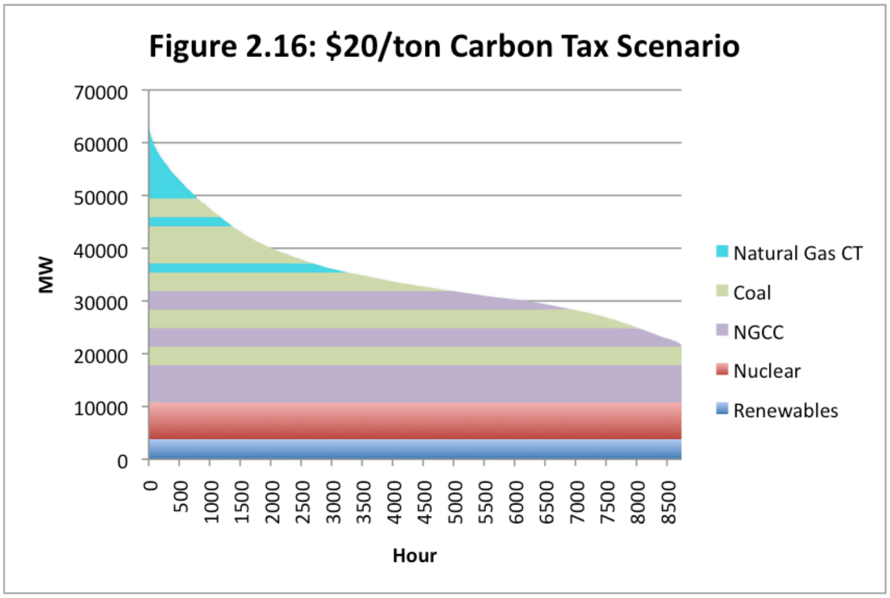


Figure 2.15: Low Natural Gas Prices Scenario





As the figures demonstrate, when the price of natural gas falls (or when the differential between coal and natural gas prices decreases), the high-efficiency natural gas combined cycle plants begin to displace the old, inefficient coal plants in the baseload. These coal plants are forced to operate as intermediate plants at moderate capacity factors. This shift is reflected in the percentage of the generation mix that each fuel source provides, as shown in Table 2.6:[62]

Table 2.6: Generation Mix Under Different Price Scenarios

Scenario	Coal	Nuclear	Natural Gas	Renewables
2008 Natural Gas Prices (high)	55.1%	20.0%	14.1%	10.8%
2009 Natural Gas Prices (low)	51.2%	20.0%	18.0%	10.8%
$20/ton Carbon Tax with '09 prices	28.8%	20.0%	40.3%	10.8%

A moderate carbon tax leads to a major change in the fuel mix. Coal power is reduced significantly and natural gas power almost completely takes its place.

As mentioned above, power plant cost information is proprietary, so no outside observer can know these cost parameters for individual plants or in aggregate. Thus, the parameters used here are only estimates. However, it is a good first-level description of the switching effect that

[62] The renewables (including hydropower) were set at 10.8% of the generation because though they account for 15% of capacity, they are partially or completely intermittent so do not provide their full capacity.

this paper seeks to identify and quantify. Falling natural gas prices, in conjunction with relatively static coal prices and underutilized capacity of high efficiency natural gas combined-cycle power plants, lead to large scale switching from coal to natural gas in the electric power sector.

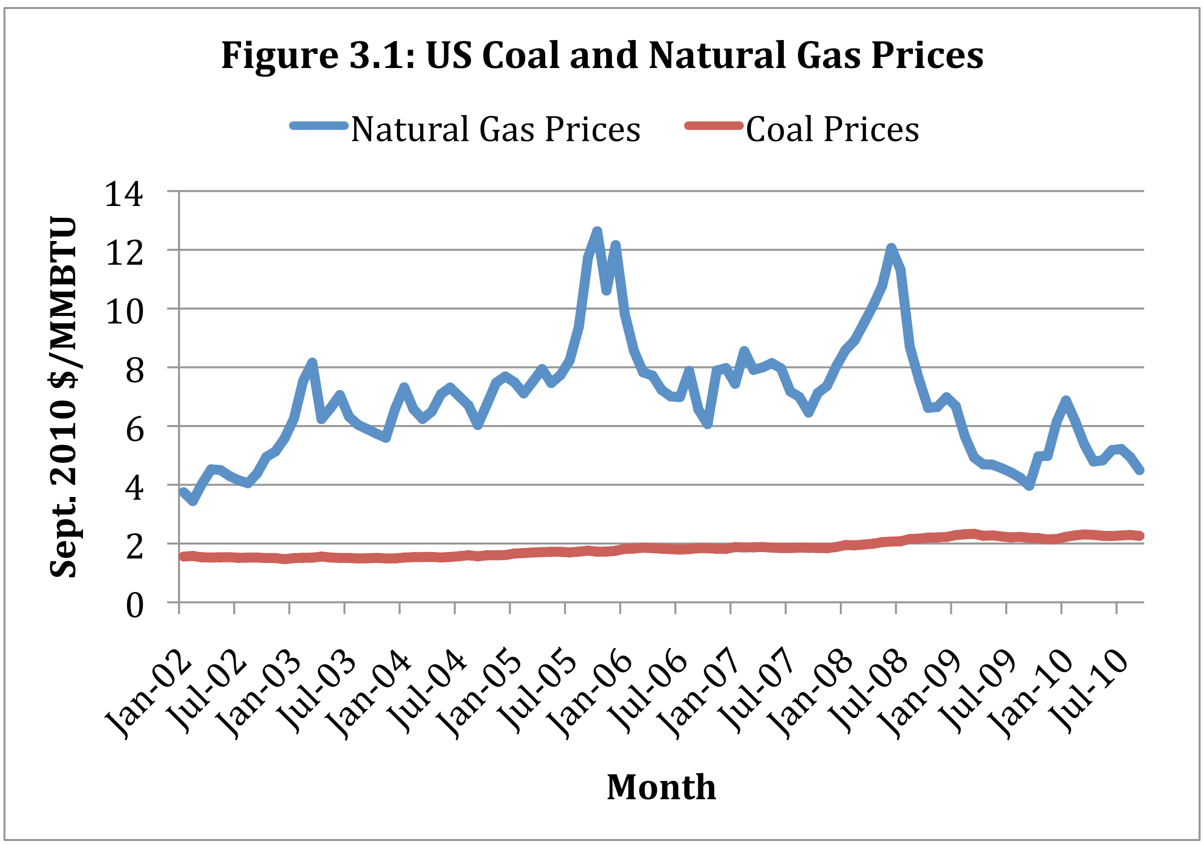
Based on this expected effect and taking individual utilities' cost choices as a black box, Chapter 4 models real observed data to demonstrate exactly how much and in what way the fuel mix changes in response to falling natural gas prices. First, though, it is necessary to understand why those prices fell and so Chapter 3 treats "The Shale Gas Revolution."

Chapter 3: THE SHALE GAS REVOLUTION: RECENT TRENDS IN COAL AND NATURAL GAS PRICES

I. Coal and Natural Gas Prices

Recent Trends

Following wide fluctuations over the course of the decade, US natural gas prices (as paid by electric power producers) fell drastically between 2008 and 2010, from a peak of $12.06/MMBTU in June 2008 to a low of $3.97/MMBTU in September 2009 and settled in September 2010 at $4.50/MMBTU.[63] Figure 3.1 below shows these fluctuations over the last 8 years.



[63] These figures are prices for the whole US, adjusted for inflation to September 2010 dollars and scaled using average energy to volume ratios (prices are reported in dollars/volume), EIA Data, Natural Gas

The graph also depicts the price of coal in dollars/MMBTU (as paid by electric power producers) over the same time period. Strikingly, coal prices exhibit far more stability than natural gas prices, rising gradually from $1.56/MMBTU to $2.26/MMBTU over the 8-year period. There are several reasons for natural gas' higher volatility relative to coal. First, as was explained in the last chapter, coal is used almost entirely (94%) for electric power production. In contrast, natural gas is used for industrial processes and for heating in residential and commercial buildings and so its price fluctuates in response to demands in those sectors. Second, natural gas is not easily stored. Storage facilities are limited and expensive. This leads to high price volatility because there is limited stock inventory to absorb rapid changes in supply and demand.[64] Third, natural gas is the fuel used at the margin in electric power production and so is subject to the demand swings in that even more volatile commodity. Coal, by comparison, provides a relatively predictable amount of baseload power.

Declining Natural Gas Prices

Despite the significant amount of noise in the price of natural gas, the steep decline in prices since mid-2008 seems to represent a long-run shift rather than a temporary aberration. The decline can be attributed partly to decreased demand during the global recession, although consumption of natural gas in the electric power sector rose by 3.0% from 2008 to 2009. Economy-wide natural gas consumption did decline 1.85% between 2008 and 2009, from 23.26 Tcf to 22.83 Tcf.[65] This likely drove prices down, but not enough to explain the entire precipitous decline.

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[64] Geman, p 28, 59
[65] EIA Data, Natural Gas

The additional cause of the fall in prices was on the supply side—beginning in 2006 and 2007, production of natural gas from unconventional sources, primarily shale formations, began to grow rapidly. Spurred by initial successes in the Barnett Shale in Texas, natural gas companies investigated the potential for production in other shale formations around the country. This led to discoveries of large quantities of economically recoverable natural gas in the South, the Northeast, and elsewhere. Natural gas production companies rapidly set up operations to begin production from all these new discoveries. Dry natural gas production rose 6.8% between 2007 and 2009, from 19.27 trillion cubic feet (Tcf) to 20.58 Tcf, an increase of 1.31 Tcf. Dry production of shale gas more than accounted for this increase, ramping up 1.82 Tcf between 2007 and 2009, from 1.29 Tcf to 3.11 Tcf.[66]

This so-called "Shale Gas Revolution" drove natural gas prices down in 2008 and 2009 to their current levels, between $4 and $6/MMBTU. In the face of this new supply and potential further increases in resource estimates, prices are expected to stay in this range for the next decade.[67] Furthermore, the increased supply is expected to stabilize natural gas prices.[68] A low and stable natural gas price changes the playing field for the electric power sector.

II. History of Modern Natural Gas Production

Regulation of Interstate Natural Gas Sales

Natural gas was heavily regulated for a significant period of its history. As natural gas production was becoming a national industry in the first half of the 20th century, Congress passed the 1938 Natural Gas Act to regulate interstate natural gas sales. Through a series of court

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[66] Ibid.
[67] "Annual Energy Outlook 2011, Early Release," *Annual Energy Outlook*, Energy Information Administration, 16 Dec. 2010, Web.
[68] IHS Cambridge Energy Research Associates, p 6.

decisions in the 1940s and 50s, the federal government's regulatory power expanded to the point of setting price ceilings on wellhead prices for interstate gas.[69] Price ceilings had the dual effect of inflating demand and discouraging natural gas companies from investing in exploration to find new gas reserves—there was no incentive to discover gas that would not be economically recoverable at such artificially low prices. By the 1970s, this policy had created a series of natural gas shortages. In response to this, Congress passed the Natural Gas Policy Act of 1978, which raised the price ceilings, and made plans to phase price controls out completely. This Act was the first step toward complete deregulation of the natural gas market, a process which played out through further legislation and FERC orders through the 1980s and 1990s.[70]

Deregulation

It took time for the natural gas market to emerge from the legacy of regulation. Through the last two decades of the 20th century, marketed production of natural gas remained at or below 20 Tcf/yr, never exhibiting significant growth.[71] Finally, in 2000, after never having risen above $3/Mcf (roughly equal to $3/MMBTU) in the years of price setting and afterwards, natural gas wellhead prices rose drastically and hovered between $5 and $8/Mcf for the next several years. This shift upward in prices was necessary to work off the suppressed supply and excess demand from decades of government regulation.[72]

The Shale Gas Revolution

These higher prices in the early 2000s justified exploration for natural gas in unconventional formations. Conventional natural gas is found, often with oil, in highly

[69] "The History of Regulation," NaturalGas.org, n.d. Web. 23 Feb. 2011.
[70] Ibid.
[71] EIA Data, Natural Gas
[72] David Albin, Managing Partner, Natural Gas Partners, Personal Interview, 4 Feb 2010.

permeable underground reservoirs trapped by overlying rock. In contrast, unconventional natural gas is found in low permeability rock, foremost among them shale formations. Previously, companies had overlooked these sources because the low yields from low permeability rock made them uneconomical. At higher prices, however, shale formations were worth investigating. Companies like Mitchell Energy started to expand drilling operations in Texas' Barnett Shale at the beginning of the decade.[73] Over time, specialized drilling techniques—horizontal drilling and hydraulic fracturing—were adapted for the shale plays, lowering production costs. As a result of these technological innovations and sustained elevated prices, shale gas production spread to a number of other shale plays throughout the country, notably the Marcellus Shale in the Northeast, the Antrim Shale in Michigan, and the Fayetteville Shale in Arkansas. The volume of economically recoverable natural gas was far greater than anyone in the industry expected, leading to a drop in prices in 2005[74] and then again, even more drastically, in 2008, when combined with the financial crisis.

Natural gas resource estimates—which account for all technically recoverable resources—were systematically revised upward over the course of the past decade to account for the shale gas discoveries. In 2002, the Potential Gas Committee (PGC), a group operated by the Colorado School of Mines which releases a biennial resource report, estimated the total US natural gas supply at 1,292 trillion cubic feet (Tcf).[75] By 2008, PGC had shifted the total supply estimate upward to 2,080 Tcf, a growth of 788 Tcf. Nearly all of this resource growth was due to shale gas discoveries, estimated at 616 Tcf in PGC's 2008 report.[76] The most recent figures come

[73] Ibid.
[74] Ibid.
[75] Potential Gas Committee, *Potential Supply of Natural Gas in the United States (as of December 31, 2002)*, (Golden: Potential Gas Agency, Colo. School of Mines, 2003), Web.
[76] MIT Future of Natural Gas, p 10.

from EIA's Annual Energy Outlook 2011, which estimates a resource base of 2,552 Tcf, with shale resources of 827 Tcf. This is enough natural gas to provide 110 years of supply at current levels of domestic consumption.[77]

III. Shale Gas Production: Technology and Environmental Impact

Shale Formations

Shale formations, like the other sources of unconventional gas (tight sands and coalbed methane), differ from conventional sources due to their low permeability. Shale is formed from prehistoric clay deposition in wet environments such as tidal flats or deep-water basins. Organic matter is trapped in this clay and subjected to heat and pressure over time to form natural gas, composed mostly of methane. However, unlike the permeable sandstone in which conventional natural gas is found, the fine clay particles compacted into shale have limited horizontal and vertical permeability. As a result, the gas in a shale formation does not naturally collect beneath the overlying layer of impermeable rock, as it does in conventional reservoirs. In order to release shale gas, artificial stimulation is necessary to create fractures through which it can escape.[78]

The shale formations in the US are mostly in the Northeast and the South, the remnants of a shallow sea that covered the Eastern United States 350 million years ago.[79] The major shale formations are shown in Figure 3.2. This map is a little deceptive because the amount of recoverable gas in a shale formation depends not only on its footprint area, but also its thickness,

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[77] *Annual Energy Outlook*.

[78] *Modern Shale Gas Development in the United States: A Primer*, Ground Water Protection Council and ALL Consulting, 2009, Web, p 14.

[79] D.J. Soeder, and W.M. Kappel, *Water Resources and Natural Gas Production from the Marcellus Shale*, U.S. Geological Survey Fact Sheet 2009–3032, 2009, Web.

gas content, porosity, and several other factors. The four largest shale formations, by size of gas resources, are shown in Table 3.1 below.[80]

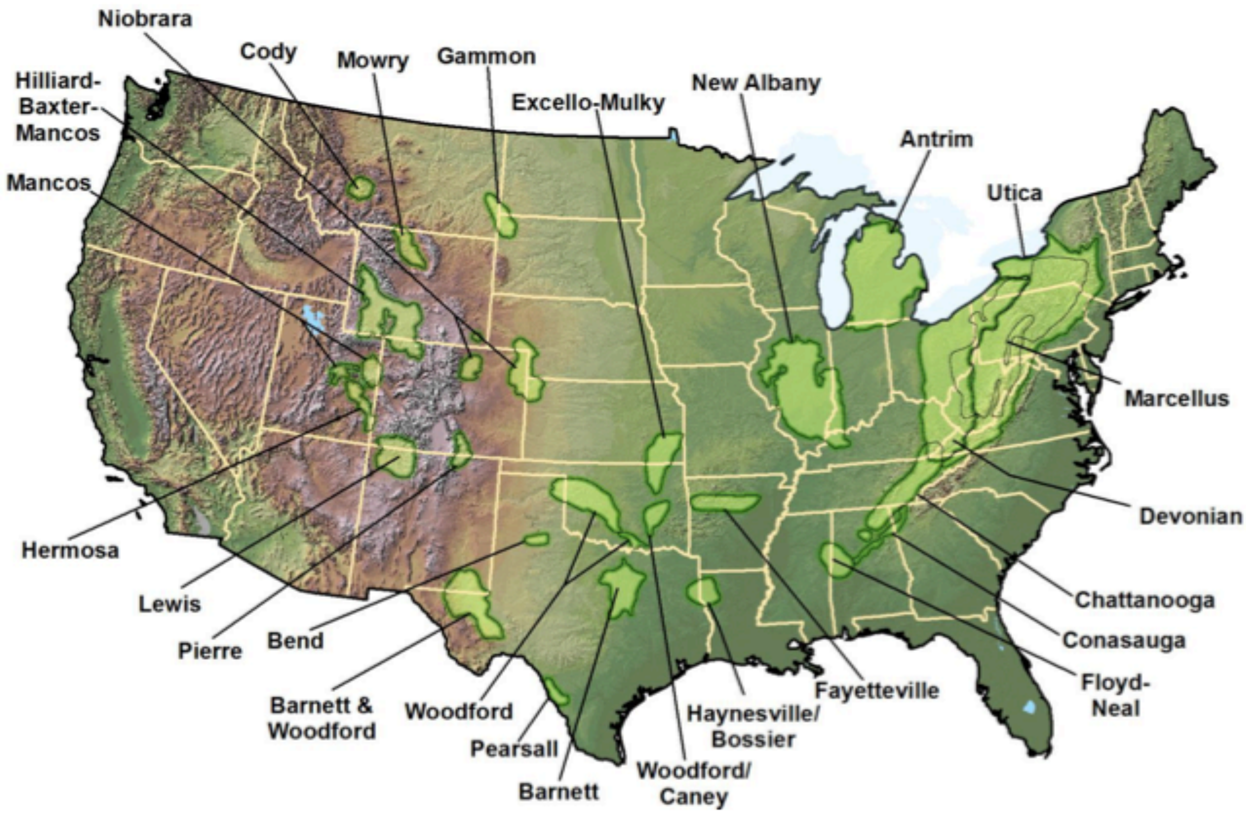

Figure 3.2: Major Shale Gas Formations, Source: Ground Water Protection Council

Table 3.1: Largest US Shale Formations

Shale Formation	**State(s)**	**Estimated Resource Size**
Marcellus	New York, Pennsylvania, West Virginia, Ohio	262 Tcf
Haynesville	Louisiana, Texas	251 Tcf
Barnett	Texas	44 Tcf
Fayetteville	Arkansas, Oklahoma	41.6 Tcf

[80] *Modern Shale Gas Development*, p 8, 17.

Drilling Technologies for Shale Plays

The development of two drilling technologies, horizontal drilling and hydraulic fracturing, have made shale gas production economically feasible.

Horizontal drilling refers to the practice of drilling vertically down to the target depth of the shale formation and then angling the drill bit sideways to drill horizontally through the shale formation. This process is depicted in Figure 3.3.

A horizontal well exposes more of the shale formation than a vertical well. Since the target gas has limited lateral permeability, drilling horizontally is essential for reaching more of the gas and optimizing recovery. Furthermore, a single horizontal well can cover the same area as several vertical wells and multiple horizontal wells can be drilled from the same well pad. This improves drilling economics and reduces environmental impacts, since fewer drilling sites mean fewer access roads, processing facilities, and pipelines.[81]

The key to accessing natural gas in shale is stimulating the formations. This is done through hydraulic fracturing, or "hydro-fracking".

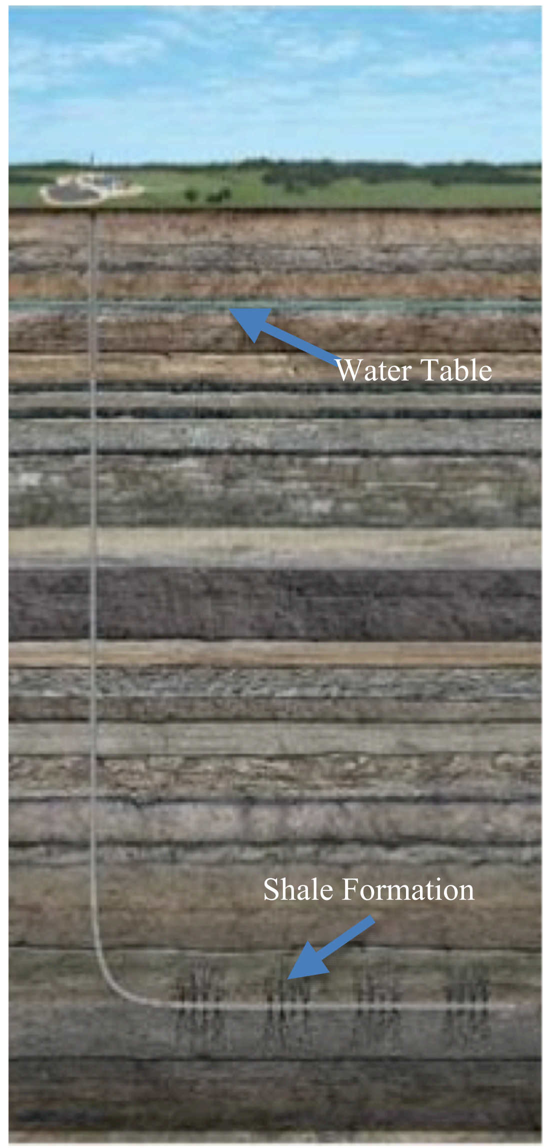

Figure 3.3: Horizontal Drilling
Source: Ground Water Protection Council

[81] Ibid, p 47-8.

Once the well has been fully drilled and the well walls have been reinforced with several layers of cement and steel casing, millions of gallons of fracture fluid are injected into the well at high pressure, creating fractures in the shale and liberating the natural gas. The fracture fluid is made up of water, sand, and chemical additives. The sand functions as a proppant—once the fluid has made cracks in the shale, sand flows in to hold the cracks open. The chemical additives serve a variety of purposes and usually make up less than 2% of the mixture. Some additives work to reduce friction, others prevent the sand from settling in the fracture fluid, and the rest serve a myriad of other purposes based on the specific geological characteristics of the well. Generally, different sections of the horizontal well are fractured in separate stages and each stage requires a number of cycles of fracturing fluid.[82]

Environmental Concerns

Shale gas production presents many of the same environmental concerns as conventional oil and gas production, as well as some concerns unique to its technology, specifically hydraulic fracturing. The concerns fall in five main areas:

- Water use
- Protection of groundwater
- Wastewater management
- Air pollution
- Land use impacts and other local community impacts

Drilling and hydraulic fracturing are water-intensive operations. Depending on geological characteristics, between 2 and 4 million gallons of water are needed per well.[83] The bulk of this water is used during the hydro-fracking process, though a significant amount is needed during drilling as well. Considered from the perspective of an entire water basin, this is not an

[82] Ibid, p 58-61.
[83] Ibid, p 64.

inordinate amount of water. Estimates suggest that large-scale natural gas production would require between 0.1% and 0.8% of the annual water budget in each relevant basin. However, drilling and hydraulic fracturing processes take place over a short period of time—20-30 days—so large one-time water withdrawals could overwhelm local water systems, especially during seasons of low water flow.[84]

Much of the controversy surrounding shale gas production has been centered on ground and surface water contamination. The shale formations are at depths on the scale of 1,000 to 10,000 feet below the surface, so it is often necessary to drill through the water table (usually between 100 and 1,000 feet below the surface) to reach the shale gas. The wells are lined with several nested layers of steel casing and cement to isolate the fluids in the well—fracture fluids and natural gas—from the ground water. This basic system is illustrated in Figure 3.4.

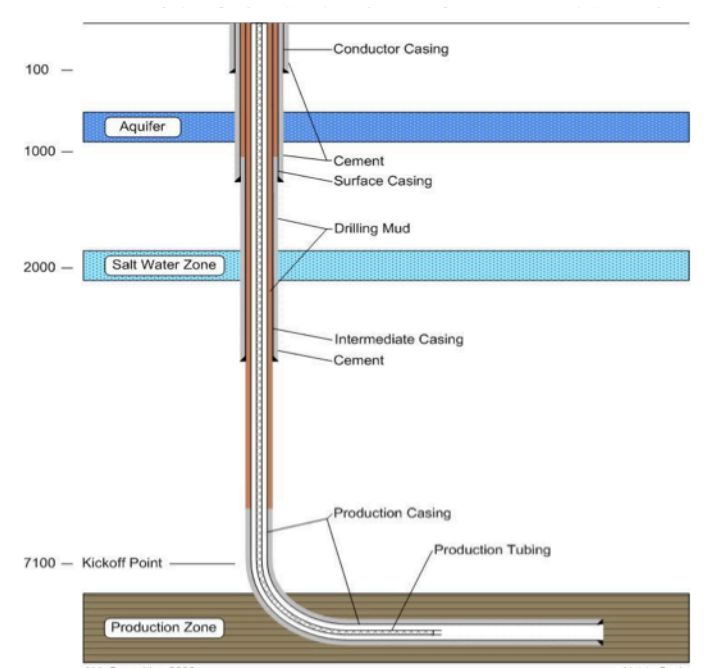

Figure 3.4: Cement Casing in Natural Gas Wells
Source: Ground Water Protection Council

Conductor casing prevents the top of the well from caving in, surface casing isolates the well from freshwater zones, and intermediate casing protects the well from saltwater or overpressurized zones.[85] During drilling, tests are regularly conducted to ensure the integrity of the casing

[84] Ibid, p 65.
[85] Ibid, p 52.

structure and the seal of the cement with the well walls. Industry analysis suggests that the probability of groundwater contamination due to corrosion of properly cemented casing is on the order of 2×10^{-8}. [86] Furthermore, the groundwater is usually separated from the shale formation by several thousand feet of solid rock.

Careful management of wastewater removed from the well is essential to avoiding water contamination. Wastewater includes both flowback—recovered fracture fluids—and produced water—naturally occurring water in the well. Thus, wastewater contains any chemicals originally in the fracture fluid plus chemicals added through interaction with the shale, including dissolved toxic metals, salts, and naturally occurring radioactive material (NORM).[87] Several methods are used to dispose of wastewater. In most cases, it is stored in lined containment pits immediately after removal from the well. In urban locations, steel storage tanks may be used for this purpose.[88] Wastewater can then be treated at conventional wastewater treatment plants, injected into underground wells, or recycled. Conventional treatment of shale gas wastewater is difficult due to the high levels of contaminants and total dissolved solids, though there has been some development of shale gas specific wastewater treatment.[89]

Wastewater can be injected into porous and permeable rock formations thousands of feet below the water table. However, these injection sites must be available and challenges exist in transporting wastewater from drilling sites to disposal sites. Finally, there are emerging practices of recycling wastewater or treating it on-site to a level at which it can be effectively reused.[90]

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[86] Ibid, p 53.
[87] David M. Kargbo, Ron G. Wilhelm and David J. Campbell, "Natural Gas Plays in the Marcellus Shale: Challenges and Potential Opportunities," *Environmental Science and Technology*, 44 (2010): 5679-5684, Web, p 5681.
[88] *Modern Shale Gas Development*, p 55.
[89] Kargbo et al., p 5681.
[90] *Modern Shale Gas Development*, p 68.

The air pollution concerns for shale gas are consistent with those across the entire oil and gas industry. Energy-intensive drilling, pumping, and processing equipment emit large quantities of CO_2, NO_x and volatile organic compounds (VOCs), which together cause tropospheric ozone problems. Near some rural natural gas drilling sites in Sublette County, Wyoming, ozone levels comparable with those in downtown Los Angeles have been recorded.[91] Additionally, there are significant leaks of methane throughout the natural gas production process, though EPA is working with industry to mitigate this problem.[92]

Developing sites for drilling and processing necessitates clearing land, building roads, and constructing pipelines and processing facilities, all with potential negative impacts for wildlife and local communities. Horizontal drilling cuts down on the number of well sites needed to cover an area and so minimizes these effects. During drilling operations, dust and noise can pose additional problems for local ecologies and human communities.

Regulatory Structure

Shale gas faces the same regulatory structure as the rest of the oil and gas industry. The Environmental Protection Agency (EPA) administers most of the laws affecting natural gas production. EPA generally sets federal minimum standards and allows states to implement these standards with additional state-specific requirements as necessary. This fits shale gas production well as geological considerations differ across regions.[93]

The major statutes affecting shale gas production are the Clean Water Act which regulates surface discharges of water and stormwater runoff, the Safe Drinking Water Act which

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[91] Derek Farr, "Sublette Nonattainment Recommended," *Sublette Examiner*, 18 Mar. 2009, Web, 18 Mar 2011.
[92] Kargbo et al., p 5682.
[93] *Modern Shale Gas Development*, p 25.

regulates underground injection of hazardous fluids, and the Clean Air Act which regulates air emissions from production equipment.[94]

However, through a clause built into the Energy Policy Act of 2005 (commonly known as the Halliburton Loophole) hydraulic fracturing operations were exempted from regulation under certain clauses of the Safe Drinking Water Act.[95] As a result, natural gas production companies do not have to report the chemicals used in their fracture fluids.

Controversy

There has been considerable controversy over shale gas production, centering on the use of hydraulic fracturing and the dangers it poses for water contamination. Over the past year and a half, a number of media sources have heightened their coverage of the shale gas boom, especially in the Marcellus Shale in New York, Pennsylvania, and West Virginia, a region which has not previously seen such elevated levels of natural gas drilling. Filmmaker Josh Fox released a documentary film at the Sundance Film Festival in January 2010 called *Gasland*, which criticized shale and natural gas drilling. The documentary was well-received, winning a Special Jury Prize at Sundance and an Academy Award nomination.[96] It prompted a rebuttal from an industry PR group, Energy in Depth, who published a point-by-point refutation of the film's claims in June 2010.[97] In response, Fox and his crew published "Affirming Gasland" in September 2010, which refuted the industry's claims.[98]

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[94] Ibid.
[95] United States, Cong. House, *Energy Policy Act of 2005: Sec. 322*, 109th Cong., 1st sess., H.R.6, 2005, Web, 26 Mar. 2011.
[96] "About the Film", *Gasland the Movie*, n.d. Web, 26 Mar. 2011.
[97] "Debunking Gasland," *Energy in Depth*, 9 Jun. 2010, Web, 18 Mar. 2011.
[98] Josh Fox et al., *Affirming Gasland*, Jul. 2010, Web, 18 Mar. 2011.

More recently, the New York Times published an extensive article, "Regulation Lax as Gas Wells' Tainted Water Hits Rivers," on February 27, 2011 which relied on the leak of a number of EPA documents to claim that state regulators in Pennsylvania and elsewhere are ill-equipped to deal with the wastewater from shale gas wells.[99] The article cites a number of pollutants in the produced water from the hydro-fracking process, focusing on high levels of radioactive material which conventional water treatment plants are not designed to remove. Former Pennsylvania Governor Edward Rendell and former Secretary of the Pennsylvania Department of Environmental Protection John Hanger responded to the article in a March 2 op-ed piece, claiming that drilling in Pennsylvania is highly regulated through inspections, issues of violations, and fines and that regulation had strengthened under their watch.[100]

Most of the controversy focuses on if and how drinking water sources are contaminated by the drilling process. The debate quickly becomes an argument over who lays claim to the best science—the affected residents, the activists, industry, or the state and federal regulatory bodies. The natural gas industry and the activist community tend to take opposite sides on the main issues, while the regulatory bodies and the affected residents, who benefit from local investment but feel the cost of air and water pollution, fall somewhere in between. The sides disagree on several main points:

- The extent of state and federal regulation of natural gas drilling
- The health impacts of the chemicals used in the fracture fluids
- Whether natural gas from the shale formation can migrate upward to contaminate aquifers
- The effectiveness of wastewater pits
- The suitability of wastewater treatment plants for natural gas produced water and flowback

[99] Ian Urbina, "Regulation Lax as Gas Wells' Tainted Water Hits Rivers," *New York Times* 27 Feb. 2011: A1, Web, 18 Mar. 2011.
[100] Edward G. Rendell and John Hanger, "Natural Gas Drilling, in the Spotlight," *New York Times* 6 Mar. 2011: WK9, Web, 18 Mar. 2011.

- Whether hydro-fracking was responsible for several publicized incidents of water contamination, specifically in Dimock, PA, Dunkard Creek, PA, Fort Lipton, CO, and West Divide Creek, CO

Regulatory structures for shale gas production exist, but are not perfect. As indicated earlier, hydraulic fracturing is exempted from certain clauses under the Safe Drinking Water Act, but overall shale gas production is regulated under all the major environmental statutes. State agencies also exercise significant regulatory authority over natural gas drilling. A 2009 Ground Water Protection Council report examined regulations in the 27 predominant oil and gas states and concluded that most states had significant regulations on well permitting, well construction, reporting on well treatment (fracking), wastewater pit lining, and spill remediation.[101]

There have been a number of documented instances of groundwater contamination associated with natural gas drilling in shale. In many of these cases, including in Dimock, PA and West Divide Creek, CO, state officials concluded that faulty well construction was the cause of contamination.[102] There does not appear to be an inherent problem with the hydro-fracking technology, rather there have been isolated incidents where poor cementing and inadequate well integrity testing allowed for contamination. With improved technology and increased oversight, these problems can be controlled.

Issues remain for the management of well wastewater. The toxic chemicals from the fracture fluids pose a significant health risk if they leak into drinking water. Furthermore, conventional treatment plants are unable to process the elevated levels of toxic metals and radioactive material in some wastewater (179 wells out of 71,000 in Pennsylvania returned high levels of radioactive material in a recent analysis) and so this material is injected untreated into

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[101] *State Oil and Natural Gas Regulations Designed to Protect Water Resources*, Ground Water Protection Council, 2009, Web, 18 Mar. 2011.
[102] Mike Soraghan, "NATURAL GAS: Groundtruthing 'Gasland'" *Greenwire*, E&E Publishing, LLC, 24 Feb. 2011, Web, 18 Mar. 2011.

rivers.[103] However, technological improvements such as recycling waste water and replacing some of the fracture fluid chemicals with less toxic substitutes show promise in mitigating these impacts.[104]

Further understanding of shale gas drilling and development of adequate regulatory structures, especially in regions where natural gas drilling is relatively new, will help foster an environment where shale gas production can occur without negative impact on either the environment or human health.

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[103] Urbina, *NY Times*
[104] Kargbo et al., p 5682.

Chapter 4: THE POWER MIX AS A FUNCTION OF NATURAL GAS PRICES: ECONOMETRIC MODELS

I. Motivation

Increases in shale gas production have helped drive natural gas prices down and will maintain them at low levels. These low natural gas prices enable the highest-efficiency combined cycle plants to challenge the lowest-efficiency coal plants for places in the baseload. The simulation at the end of Chapter 2 illustrates how the fuel-switching process functions under a declining price differential between coal and natural gas. However, that simulation was based on rough estimates—power plant cost data is proprietary—so it is difficult to accurately model the shape and extent of the effect from that angle. However, data on average fuel costs and power generation from each fuel source are available. Taking each individual generator's cost-based generation decision as a black box, it is possible to relate the common fuel price with aggregate generation from all the plants in a given area. This chapter attempts to model this relationship between price inputs and generation output, using real data for coal and natural gas prices and coal's share of generation in each census region on a monthly timescale.

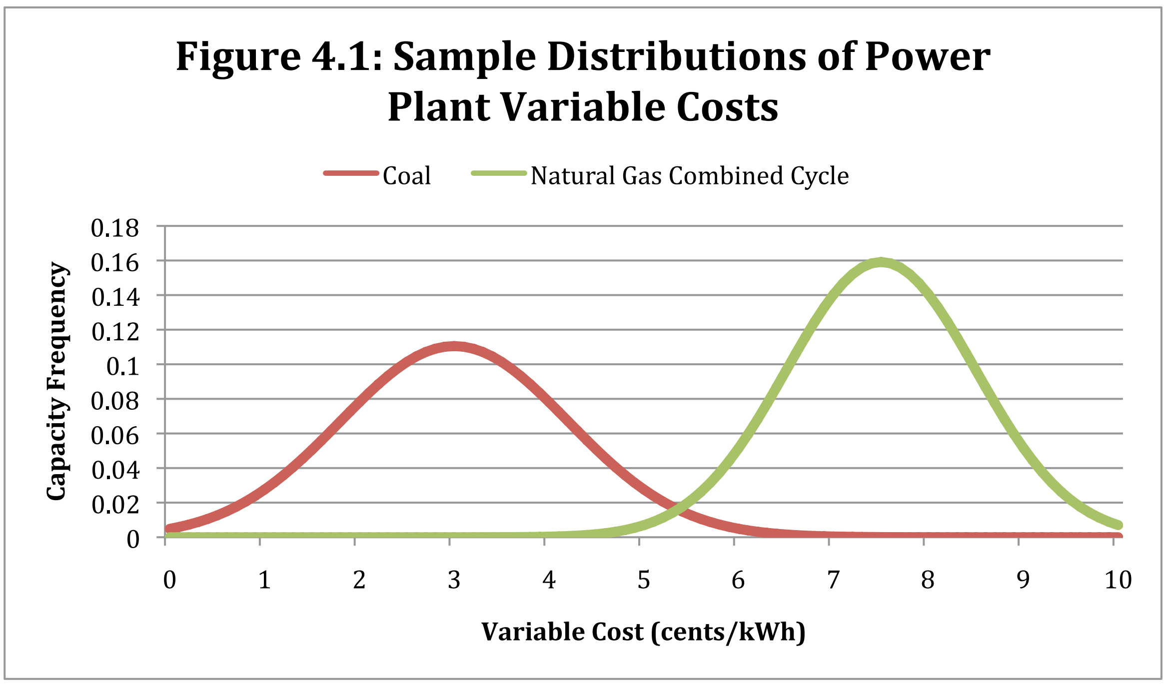
II. Theoretical Underpinnings

The merit order determines whether or not a generator produces electricity at a given price level. A generator's position in the merit order is based on its variable cost of production—the plants with low variable costs come online before those with higher variable costs.

This analysis assumes that a generator's heat rate and variable O&M costs do not change over time or generation levels. This is not a perfect assumption—the heat rates of coal plants are much higher during start-up, for example[105]—but it suffices for this analysis.

[105] Cullen, p 18.

However, these parameters will not be the same for all generators of a given type. Rather, they may be expected to vary significantly across plants since older and more inefficient plants likely have higher variable O&M costs and higher heat rates. For example, a coal generator built in 1960 likely has poorer performance parameters than a coal generator built in 1990. It is assumed that for each generator type (coal, natural gas combined-cycle, etc.) that these parameters are independent, normally distributed random variables[106] and thus for a given fuel price, the variable cost is normally distributed. Figure 4.1 depicts theoretical plots of these variable cost distributions for coal and natural gas combined cycle plants.



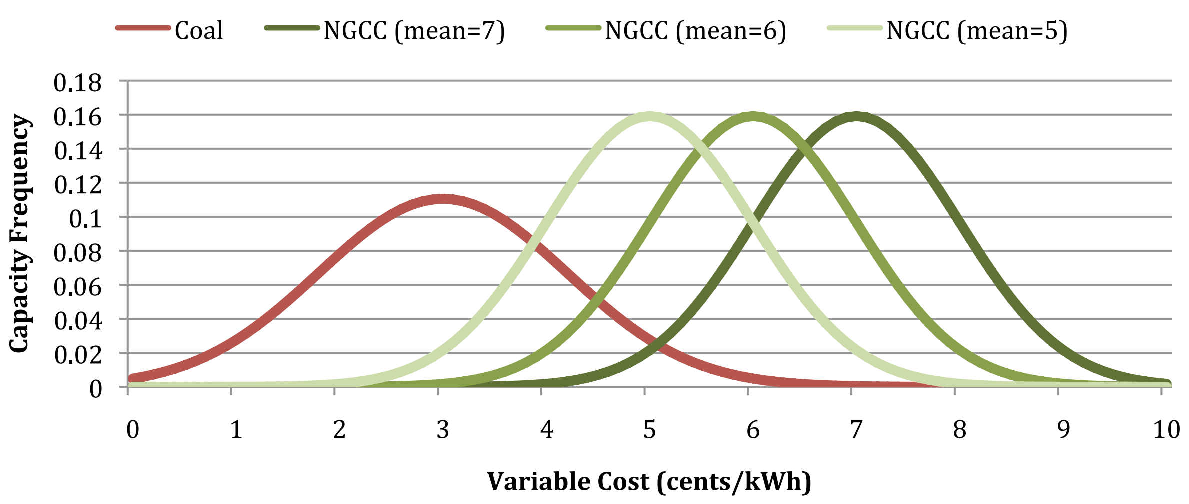
The area under each curve represents the total capacity of each fuel type. Every unit of capacity of each type—that is, every power plant—is situated along the x-axis at its variable cost of production. Moving in the direction of increasing variable costs, the area under the curves are

[106] Again, this is probably not a perfect assumption. Variable O&M costs and heat rates are likely correlated, as both will be high for old, inefficient plants. This correlation leads to a fat-tailed distribution, which augments the fuel-switching effect. Thus, the assumption that each are independent and normally distributed represents a conservative lower bound.

arranged in the merit order. Thus, the overlap between the two curves (at 5-6 cents/kWh in this graph) represents the portion of the natural gas combined-cycle capacity that has a lower variable cost than some portion of the coal capacity, sitting higher than that capacity in the merit order. This natural gas capacity is able to displace the overlapping coal capacity. It takes the place of the corresponding megawatts of coal in the baseload, forcing the coal to a lower capacity factor, as seen in the simulation in Chapter 2. Thus, an increase in the area of overlap between the two distributions is proportional to a reduction in generation from coal.

As natural gas fuel prices decrease, the mean of the natural gas combined cycle distribution decreases as well since variable costs are linear in fuel costs. Thus, the natural gas distribution curve shifts to the left and the area of overlap between the two curves increases, as pictured in Figure 4.2.

Figure 4.2: Distributions of Variable Costs for Power Plants under Declining Natural Gas Prices



The convolution of two distributions at a given value is equal to the area of overlap between them when their means are separated by that value.[107] Furthermore, the convolution of two Gaussian distributions is itself a Gaussian of the form:

$$(f \otimes g)(x) = \frac{1}{\sqrt{2\pi(\sigma_1^2 + \sigma_2^2)}} e^{-\frac{(x-(\mu_1+\mu_2))^2}{2(\sigma_1^2+\sigma_2^2)}}$$

where $(f \otimes g)$ is the convolution, μ and σ are the means and standard deviations, and x is the horizontal shift.[108]

Thus, the reduction in generation from coal is proportional to a Gaussian distribution (the area of overlap), which is a function of the distance between the means. The distance between the means is the difference between the average variable cost of generation from each fuel type. This difference is dependent on fuel costs and constants (average heat rate and average variable O&M for each fuel type.) The constants in the exponent either scale the fuel costs or drop down to join the leading constant. Thus, the reduction in generation from coal is of the form:

$$Coal\mathrm{Re}\,duct = b * e^{-c*FuelCost^2}$$

where *FuelCost* is a linear function of natural gas prices and coal prices and *b* and *c* are constants. This is by no means ironclad, but it offers a rough sense of the functional form of the fuel-switching behavior. Assuming that the percentage of coal is constant when natural gas prices are high, a model for the percentage of coal in the fuel mix is of the form:

$$\%Coal = a - b * e^{-c*FuelCost^2}$$

where *a* is the percentage of coal in the limit of high natural gas prices, *b* scales the Gaussian to connect fuel switching with reduction in actual generation and *c* accounts for the heat rates and other constants in the exponent. The shape of this model is shown in Figure 4.3. (For simplicity,

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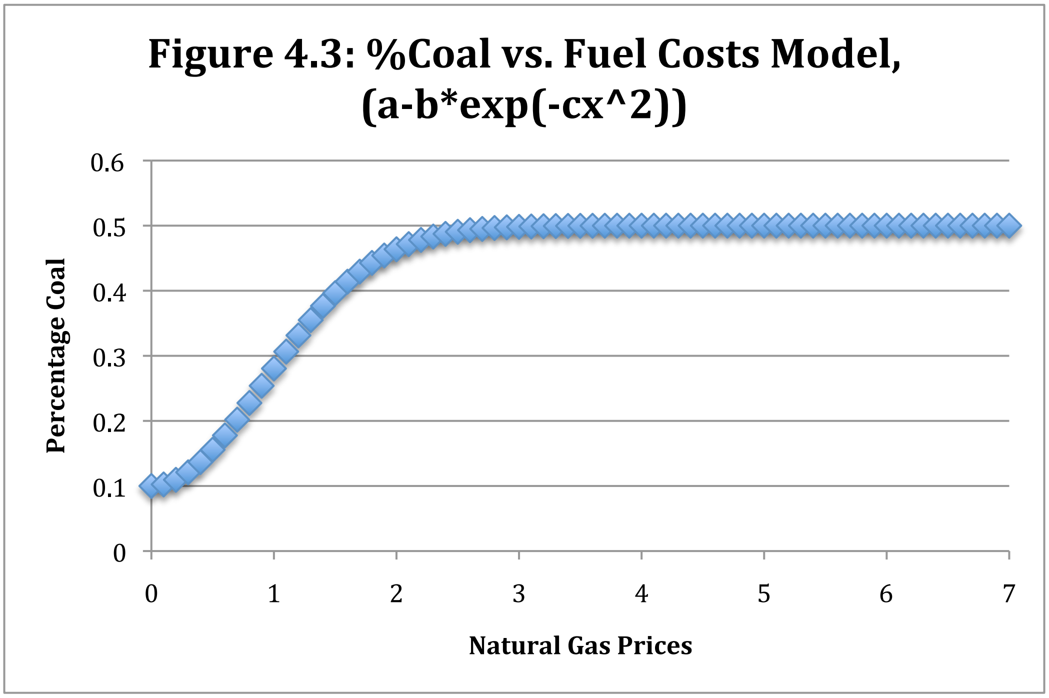
[107] Adrian Down, *Convolutions and Fresnel Diffraction*, 24 Apr. 2006, Web, 23 Mar. 2011.
[108] *Convolution*, Wolfram MathWorld, 16 Mar. 2011, Web, 26 Mar. 2011.

coal prices are held constant and natural gas prices are allowed to vary in the figure, but both vary in the actual model).



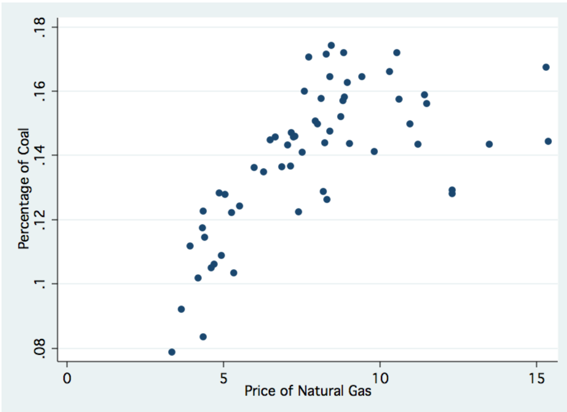
Intuitively, this shape makes sense. As long as natural gas prices are high enough that the variable cost distributions do not significantly overlap, coal contributes a constant share to the power mix, that is, a well-defined fraction of the baseload. It only competes with nuclear and renewables, which are roughly constant in capacity and generation. When natural gas prices fall to the point that the distributions begin to significantly overlap, natural gas plants can displace an increasing amount of coal out of the baseload. This reduction is limited only by the size of the existing natural gas capacity.

III. Price and Generation Data

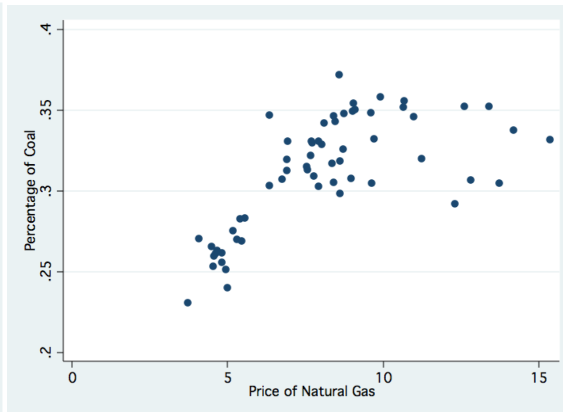
The real data are consistent with this theoretical basis. Figure 4.4 shows a scatterplot for each census region, plotting coal-fired generation as a percentage of total generation against the price of natural gas over the five-year period October 2005 to September 2010.

Figure 4.4: Percentage Coal vs. Price of Natural Gas Scatterplots

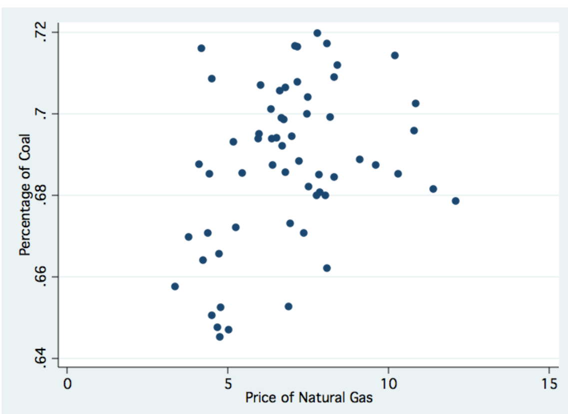
Region 1 – New England



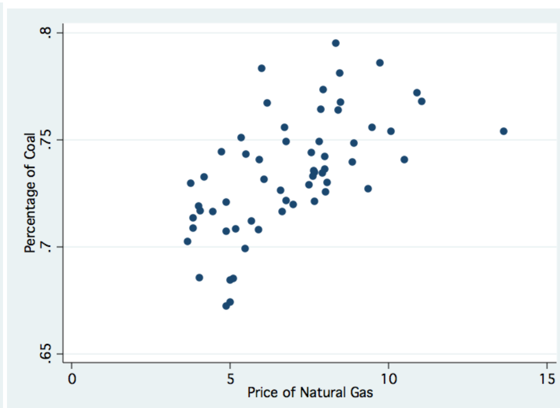
Region 2 – Mid-Atlantic



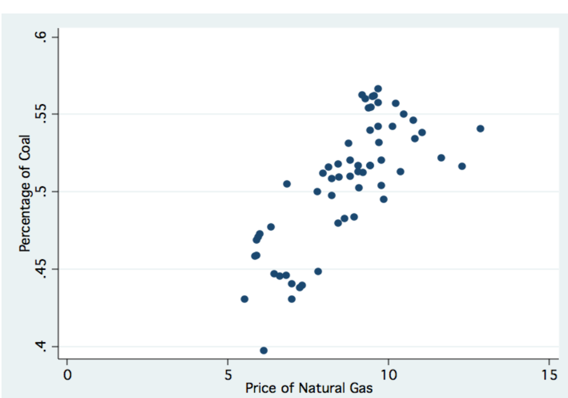
Region 3 – East North Central



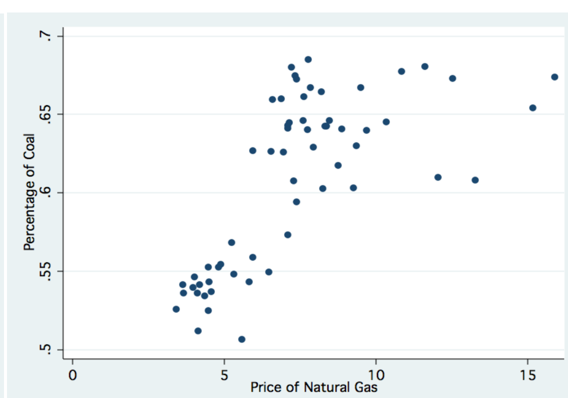
Region 4 – West North Central



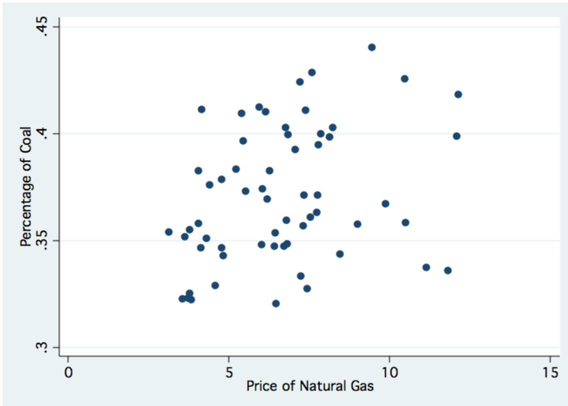
Region 5 – South Atlantic



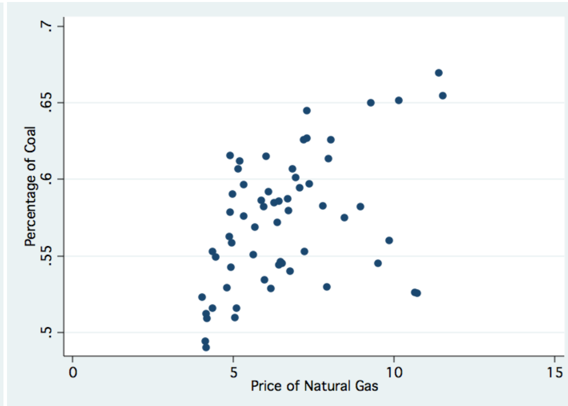
Region 6 – East South Central



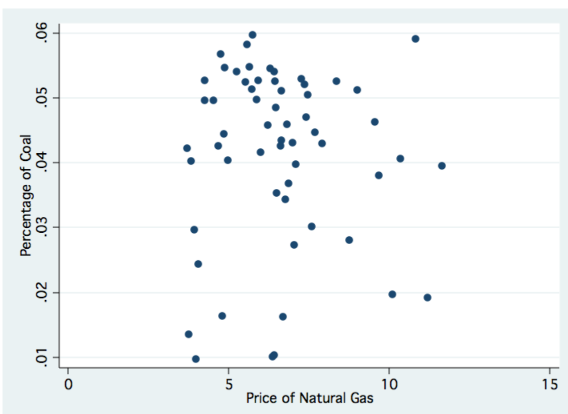
Region 7 – West South Central



Region 8 – Mountain



Region 9 – Pacific



Overall, it appears that as natural gas prices decline (and as coal prices remain roughly constant) the percentage of electricity produced by coal is at first roughly flat and then, upon reaching a threshold price point, decreases significantly. This effect is consistent with the theoretical prediction, though it is more apparent in some regions than others. The effect is especially pronounced in the Mid-Atlantic, South Atlantic, and East South Central regions. In other regions, like the Pacific region or West South Central, the effect is either muted or absent. It appears that the threshold in the price of natural gas comes at around $4-$6/MMBTU, below which switching between coal and natural gas increases rapidly. However, these scatter plots only show the data with respect to one independent variable, natural gas prices. The inclusion of other variables in the models below, such as coal prices and capacity levels, adds further nuance to the analysis.

IV. National Model

I conducted an econometric analysis to fit models to the observed data. I tried linear models, natural log models, and polynomial models. The best fitting model was achieved using a polynomial approximation of the theoretical prediction, and so those are the results I present here, along with the most basic linear model for comparison.

Data

<u>Regions:</u>

Data by state exist, but are sparse, so I aggregated the state data into census region data. The ideal scenario would be to use NERC regions, but those regions cut across state lines and are not available for all the variables. Census regions provide a rough approximation of the NERC regions. The following are the census regions:

1—New England (CT, MA, ME, NH, RI, VT)
2—Mid Atlantic (NY, NJ, PA)
3—East North Central (IL, IN, MI, OH, WI)
4—West North Central (IA, KS, MN, MO, NE, ND, SD)
5—South Atlantic (DE, DC, FL, GA, MD, NC, SC, VA, WV)
6—East South Central (AL, KY, MS, TN)
7—West South Central (AR, LA, OK, TX)
8—Mountain (AZ, CO, ID, MT, NV, NM, UT, WY)
9—Pacific (CA, OR, WA, AK, HI)

Thus, there are 9 regions.

Time:

The data are available monthly, from October 2005 to September 2010. This temporal resolution is based on the EIA reporting requirement applicable to power plants.

Thus, there are 60 monthly periods over 5 years.

Variables:

For this time span and these regions, I consider the following variables:

% Coal (coal) – Computed by dividing the electricity generated from coal in a given region and month by the total electricity generated in that region and month. Data source is Form EIA-923 (formerly Forms EIA-906 & EIA-920).

Price of Coal (prcoal) – Reported data by state and census region on the price of coal ($/MMBTU) as paid by electric power producers in a given month, adjusted for inflation. Data source is Electric Power Monthly (EIA). Also computed were the square, 4^{th} power, and 6^{th} power of the price (prcosq, prcoqu, prcosi).

Price of Natural Gas (prnatgas) – Computed as weighted averages of state-level data on delivered price of natural gas to electric power producers ($/Mcf). Adjusted for inflation and scaled by average Mcf/MMBTU ratios. Data Source is direct from EIA, Natural Gas. Also computed were the square, 4^{th} power, and 6^{th} power of the price (prngsq, prngqu, prngsi).

Capacity Variables (capcoal, capngcc, caphyd, capnuke, caprenew) – Computed as the ratio of the capacity from each major type of generation (Coal, Natural Gas Combustion Turbine, Natural Gas Combined Cycle, Hydropower, Nuclear, Renewables) divided by the total capacity in a given region and month. Net summer capacity figures were used for the months May-November and net winter capacity figures were used for the months December-April. Data source is Form EIA-860.

Fraction of Peak Load (fracpeak) – Computed as the generation in a given month and region divided by the maximum power generated in the time span from six months before the end of that month to six months after. The monthly resolution of the generation data only captured the seasonal variation in the actual variable, i.e., fracpeak is lower in the fall and higher in the middle of the summer. It does not capture the daily variation, which has a significant effect on what types of plants are used and for how long.

Models

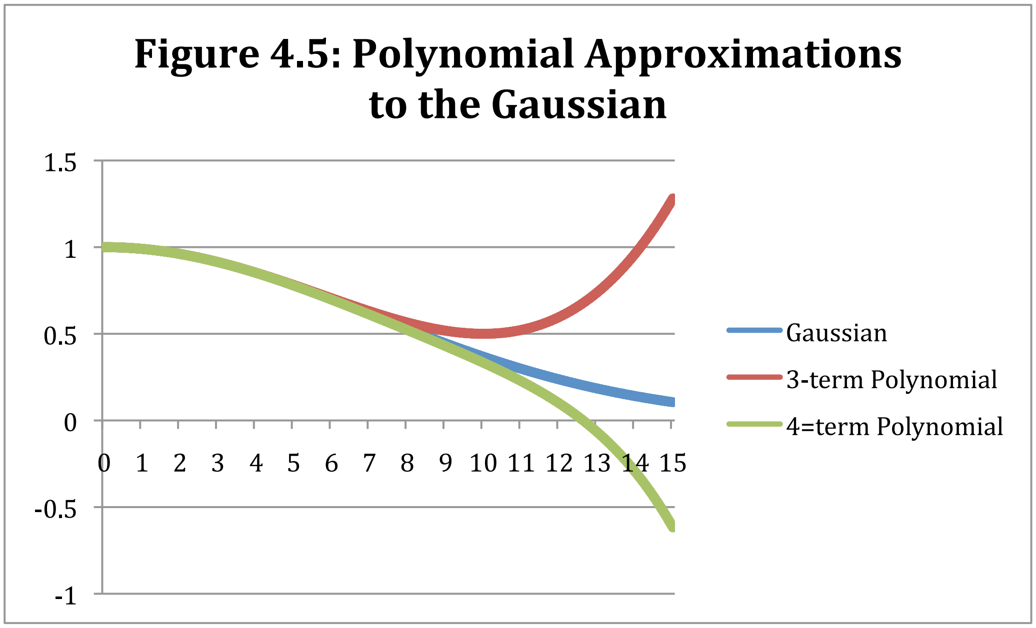
I began with a linear model, although the theory and the data suggest the effect is highly non-linear. I then tried natural log and polynomial models to attempt to capture this non-linearity. Ideally, it would be possible to directly model the negative Gaussian function suggested by theory, but the technicalities of the econometric analysis make this too complicated. However, it is possible to model the Taylor approximation of the function. The Taylor series for an exponential around x=0 (the Maclaurin series) is:

$$e^t = 1 + t + \frac{t^2}{2!} + \frac{t^3}{3!} + \ldots$$

Thus, when $t = -cx^2$, the series becomes:

$$e^{-cx^2} = 1 - cx^2 + \frac{c^2x^4}{2} - \frac{c^3x^6}{6} + \ldots$$

This is a good approximation on the scale relevant to the model—x=0 to x=10—when c is small. For x much larger than this, the two equations rapidly diverge. Figure 4.5 shows e^{-cx^2} and its polynomial approximations with three and four terms for c=0.01.



Therefore, I fit a polynomial model of the form:

$$\%Coal = d + f * FuelCost^2 + g * FuelCost^4 + h * FuelCost^6$$

since *x* corresponds to *FuelCost.* I only model the percentage of coal in the power mix, assuming that any reduction in generation from coal plants is equal to the increase in generation from natural gas combined cycle plants. This assumption is valid because the natural gas combined cycle plants are adjacent to the coal plants in the merit order and so fuel switching between them happens on a one-to-one basis.

Both coal prices and natural gas prices are components of the fuel cost. The natural gas prices vary much more significantly and are more useful in designing a model over a range of prices. Nevertheless, the coal prices are important to the fuel choice and are a relevant piece of the model in assessing policy options. For simplicity, the coal and natural gas prices are allowed to enter the polynomial separately. That is, there are squared, 4th power, and 6th power terms for coal and natural gas prices, but no natural gas price times coal price terms. It is difficult to model the coal prices due to their narrow window of data ($1.14/MMBTU to $3.81/MMBTU). In designing this side of the model, I tried several different combinations of polynomial terms for coal and balanced goodness-of-fit with reasonable expectation for the effect of coal prices outside of the $1 to $4 range. The constant term *a* from the theoretical model, which represents the percentage of coal in the generation mix at high natural gas prices, is subsumed into *d*. However, this starting coal percentage depends on the capacity mix, so I split the constant *d* into a linear function of capacity variables and a new constant.

Regressions

Thus, using the panel data in region and month, the regressions fit models of the form:

$$\%Coal_{r,m} = \beta * f(NatGasPrices_{r,m}, CoalPrices_{r,m}) + \delta * Capacity_{r,m} + c_r + u_{r,m}$$

where *r* indexes by region and *m* indexes by month, *f* is a function of the fuel costs (linear, natural log, polynomial), β is the vector of coefficients for the terms in *f*, *Capacity* is a vector of capacity data with coefficients in δ, *c* is an unobserved effect that is constant in time and *u* is the idiosyncratic error. This is a standard unobserved effects model of the form,

$$y_{it} = \overrightarrow{x_{it}} * \vec{\beta} + c_i + u_{it}$$

with the explanatory variables divided into key variables—fuel costs—and control variables—capacity and fraction of peak. Unobserved effects panel data models make it possible to remove c_i from the regression through differencing, thereby removing a potential source of omitted variable bias. However, this process requires strict exogeneity of the explanatory variables, meaning that there can be no correlation between the idiosyncratic error u_{it} and the explanatory variables x_{it} for any time periods s and t.[109] This assumption is somewhat questionable for the data, except that many potentially problematic effects are fixed in time and so are part of c_i, not u_{it}. For example, it might be expected that the balancing authority's willingness to use reserves versus relying on demand side reduction at peak load would be correlated with prices and would affect generation shares. However, this is a quality of the balancing authority that is unchanging in time. Similarly, a region's proximity to key coal mines or natural gas wells is certainly correlated with its prices and probably affects the generation share, yet the distances are fixed in time so are not part of the idiosyncratic error. Thus, strict exogeneity is assumed.

A central question in using unobserved effects panel data models is whether to use a random effects model or a fixed effects model. The central difference is that fixed effects models treat c_i as a parameter to be estimated while random effects models treat it as a random variable. This entails the additional assumption on random effects models that c_i is uncorrelated with x_{it}.[110] Stronger assumptions on the data are required to conduct random effects models, so they are considered a special case of fixed effects models. If the random effects assumptions hold, the random effects estimators converge toward the fixed effects estimators, as the number of time periods goes to infinity. Thus, it is possible to test whether the random effects assumptions are valid by comparing the estimators, a process called the Hausman test. It is only necessary to conduct the Hausman test on the key policy variables because only their coefficients are relevant to the conclusions.[111]

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[109] Jeffrey M. Wooldridge, *Econometric Analysis of Cross Section and Panel Data*, 1st ed. (Cambridge: The MIT Press, 2001), p 247.
[110] Ibid, p 257.
[111] Ibid, p 289.

I ran Hausman tests on the models presented and found that the random effects assumption held for both. The results are summarized in Table 4.1. The null hypothesis in each case is that the random effects estimators are consistent.

Table 4.1: Hausman Tests

Model	**χ^2 value**	**P > χ^2**	**Reject null?**
Linear	1.80 (m=2)	0.4064	No
Polynomial	0.49 (m=4)	0.974	No

Random effects regressions were conducted on the panel data. Reported standard errors are heteroskedastic and adjusted for clustering on region. All reported parameters are significant at the 5% level unless otherwise noted. Standard deviations are reported in parentheses. Regression 1 is a linear model without any control variables. Regression 2 is the polynomial approximation of the theoretical model without any control variables. Regression 3 is the linear model with control variables and regression 4 is the polynomial approximation model with control variables.[112]

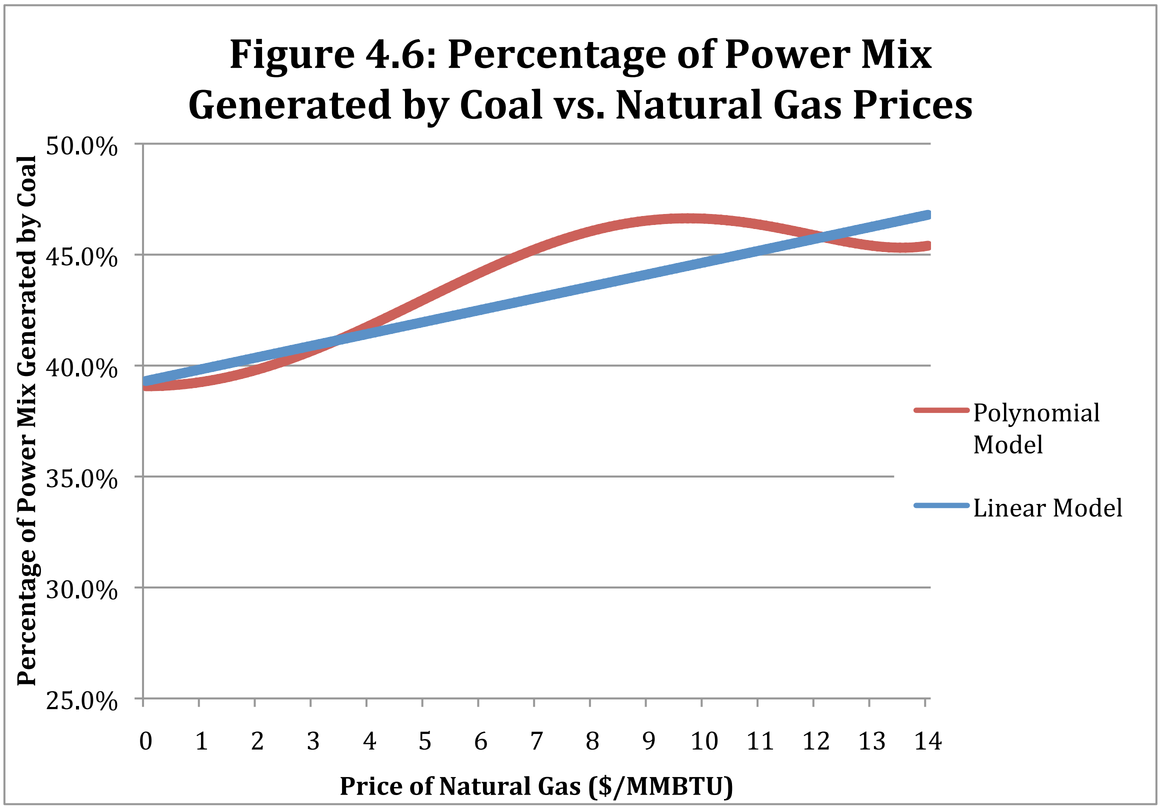
[112] I also ran regressions on models with the price differential between coal and natural gas as the key independent variable. I found that constraining the parameters on the price of coal and price of natural gas to be opposite of each other (which using their difference as a regressor effectively does) deprived them of a lot of their explanatory power. Theoretically, it makes sense that they should not be opposites of each other, but rather related by the ratio of their respective heat rates, since the product of the heat rate and the fuel cost drives a plant's variable cost.

Table 4.2: National Model Regression Results

Regressor	(1)	(2)	(3)	(4)
Price of Natural Gas	0.00395 (0.000663)		0.00528 (0.000762)	
(Price of Natural Gas)^2		0.00134 (0.000234)		0.00194 (0.000251)
(Price of Natural Gas)^4		-1.06e-5 (2.32e-6)		-1.56e-5 (2.57e-6)
(Price of Natural Gas)^6		2.57e-8 (6.51e-9)		3.75e-8 (7.43e-9)
Price of Coal	-0.0531 (0.00594)		-0.00920 (0.00398)	
(Price of Coal)^2		-0.0145 (0.00344)		0.0139 (0.00312)
(Price of Coal)^4		0.000345 (0.000188)*		-0.00109 (0.000224)
Natural Gas Combined Cycle Capacity			-0.493 (0.0603)	-0.426 (0.0555)
Coal Capacity			0.935 (0.0455)	0.988 (0.0421)
Hydropower Capacity			-0.555 (0.0466)	-0.558 (0.0424)
Nuclear Capacity			-1.08 (0.0805)	-1.09 (0.0754)
Renewable Capacity			-0.667 (0.151)	-0.404 (0.146)
Fraction of Peak			-0.0731 (0.0197)	-0.0905 (0.0164)
Constant	0.525 (0.0699)	0.460 (0.0879)	0.483 (0.0414)	0.391 (0.0390)
R^2	0.2060	0.2106	0.9830	0.9855
N	451	451	451	451

*p=0.066

As the shift in R^2 values reveals, much of the variance in generation across time and regions is due to variance in capacity levels. However, when these variables are held constant and the prices of natural gas and coal are allowed to vary, the shape of the %coal curve in fuel costs is very significant. It was found that the polynomial approximation for the differenced Gaussian best fit the data. The polynomial model is not perfect. For example, there is no actual reason for the coal percentage to peak at $9/MMBTU. Rather, this reflects the behavior of polynomials. Nevertheless, it reveals the general shape of the fuel switching behavior. The models are graphed in Figure 4.6 using simulated capacity and coal price data.



V. Regional Models

Using the national model and regional parameters, it is possible to estimate the percentage coal levels at various prices of coal and natural gas for different regions. Ultimately, I am interested in the fuel switching effect—the percentage of total generation that switches between coal and natural gas as the fuel prices change and capacity is constrained. This is equal to the difference between the final and initial coal percentages. Table 4.3 shows the modeled switching effect from the polynomial model using price changes between 2008 and 2009 alongside the observed switching effect for that time period.

Table 4.3: Modeled and Actual Switching Effects, 2008-2009

Region	2008 NG Price	2009 NG Price	2008 Coal Price	2009 Coal Price	Modeled Effect	Actual Effect
New England	$10.24	$5.02	$2.96	$3.39	-5.77%	-2.94%
Mid-Atlantic	$10.39	$5.22	$2.33	$2.48	-3.19%	-4.41%
EN Central	$8.92	$4.63	$1.91	$2.08	-3.62%	-1.33%
WN Central	$7.68	$4.47	NA	NA	-3.50%	-2.02%
S. Atlantic	$10.16	$7.31	$2.93	$3.33	-2.95%	-6.99%
ES Central	$9.57	$4.38	$2.26	$2.50	-4.22%	-9.11%
WS Central	$8.50	$4.06	$1.66	$1.75	-4.28%	-1.48%
Mountain	$8.02	$4.67	$1.52	$1.55	-3.43%	-1.82%
Pacific	$8.19	$4.46	$2.22	$2.29	-3.78%	-0.53%

The national model roughly estimates the size and shape of the fuel switching effect. However, it is not very precise in differentiating between regions. The national model constrains all regions to the same fuel-switching curve. The only difference between regions is the starting and ending points of the fuel prices. In reality, regional curves vary significantly. The scatterplots above demonstrate that the percentage coal curves vary in steepness and threshold switching price from region to region. This reflects a difference in a region's "fuel-switchability." Fuel-switchability appears to be highest in those regions where there is significant capacity of both coal and natural gas combined cycle plants—something for electricity production to switch out of and something to switch into. Table 4.4 below summarizes the relevant capacities for the nine census regions.

Table 4.4: Regional Power Plant Capacities

Region	2008 Natural Gas Combined Cycle Capacity	2008 Coal Capacity
New England	34.2%	8.7%
Mid-Atlantic	19.8%	23.0%
EN Central	10.5%	50.5%
WN Central	6.8%	48.2%
S. Atlantic	16.0%	35.4%
ES Central	17.2%	42.5%
WS Central	32.4%	20.4%
Mountain	22.4%	40.1%
Pacific	19.4%	2.4%

The regions where coal to natural gas fuel switching was highest between 2008 and 2009—South Atlantic and East South Central—have natural gas combined cycle capacities greater than 15% and coal capacities greater than 35%. The Mid-Atlantic region, with a coal capacity of 23%, also experienced significant fuel switching. In contrast, regions like East and West North Central have limited natural gas capacity to switch into and so the reduction in generation from coal is muted. On the other side of the spectrum, regions like New England, West South Central, and the Pacific have limited coal capacity and already rely heavily on natural gas or other power sources and so do not have much coal to replace.

The only anomaly to this pattern is the Mountain region, which has high natural gas and coal capacity but sees little fuel switching. This is the case for several reasons. First, coal production over the past several decades has shifted from Appalachia to the Powder River Basin in Wyoming and other locations in the Upper Great Plains. This shift has occurred because of the 1990 Amendments to the Clean Air Act, which tightened regulations on sulfur dioxide emissions and increased the demand for low-sulfur coal from the West.[113] As a result, the cheapest coal in the country comes from the Mountain region. Furthermore, this shift from East to West in coal production means that the oldest coal-fired power plants are located near the coal production centers in the East, whereas the relatively newer coal plants are in the West. As explored above, it is expected that the oldest, most inefficient plants are displaced out of the baseload first. This age differential explains why the switching effect is greatest in states like Pennsylvania or Georgia which have very old coal plants far from the new sources of coal and muted in a state like Wyoming which has newer plants and more proximate coal.

[113] McElroy, p 117.

The level of generation from renewables in a region is also important. Though the nationwide contribution of renewables to total electricity generation remains low, it is significant in certain regions. Wind power in prominent in Texas, which is in the West South Central region, and in the Great Plains states, which are in the West North Central region. Additionally, solar power has ramped up in California and the Southwest, which are in the Mountain and Pacific regions. In the short-term, the addition of intermittent power sources like wind and solar to the grid requires that more natural gas capacity is kept as reserves (to compensate for the times when the sun is not shining or the wind is not blowing) and thus reduces its ability to take a spot in the baseload.[114] Thus, the fuel switching effect is diminished in these regions.

All these factors point to a heterogeneity in the fuel-switching curves across regions. To accommodate this, I ran separate regressions for each region. This comes at a sacrifice of the unobserved effects model's advantages, but ultimately achieves a better fit. The results from regressions of the regional data on the polynomial model are presented in Table 4.5. Though capacity variables were included in the regression, I report only the parameters on the fuel price variables for simplicity. The parameters are all significant at a 5% level unless otherwise noted.

Table 4.5: Results from Regional Models

Region	**1**	**2**	**3***	**4**	**5**
Regressor					
(Price of Natural Gas)^2	0.00233	0.00232	0.00231	0.000739	0.00234
(Price of Natural Gas)^4	-1.97e-5	-1.77e-5	-3.2e-5	-3.74e-6	-8.89e-6
(Price of Natural Gas)^6	4.86e-8	4.01e-8	1.26e-7	0	0
(Price of Coal)^2	0	0	-0.0383	0	-0.0129
(Price of Coal)^4	0	-0.0007	0	0	0
R^2	0.7781	0.8728	0.5739	0.6654	0.8394

*p=0.061 for parameter on Fraction of peak (not reported here)

[114] Xi Lu, Michael B. McElroy, and Nora Sluzas, "Costs For Integration of Wind on an Hourly Basis into the Future ERCOT System and Related Costs for Savings in Emissions of CO_2," *Environmental Science and Technology* 45.7 (2011): 3160-3166.

Region	6	7	8	9
Regressor				
(Price of Natural Gas)^2	0.00358	0.000236	0	0.000625
(Price of Natural Gas)^4	-2.47e-5	0	0	-4.06e-6
(Price of Natural Gas)^6	5.13e-8	0	0	0
(Price of Coal)^2	0	0	-0.0402	0.0277
(Price of Coal)^4	0	0	0	-0.00358
R^2	0.8842	0.4529	0.5164	0.4008

These models fit the observed data more accurately. Table 4.6 shows the actual changes alongside predicted changes in coal percentage from 2008 to 2009 using real price inputs and assuming constrained capacity. The models are not perfect, but are much closer-fitting than the national model, in absolute and relative terms. Figures 4.7 and 4.8 show the fitted line together with the scattered data for the Mid-Atlantic region and the East South Central region. These curves are fitted only for the changes in fuel prices, so do not take into account the effects of capacity changes present in the scattered data. Nevertheless, the fit on both is convincing

Table 4.6: Modeled and Actual Switching Effects (Regional Models), 2008-2009

Region	Regional Models Fuel Switching Effect	Actual Effect
New England	-3.71%	-2.94%
Mid-Atlantic	-4.92%	-4.41%
EN Central	-3.43%	-1.33%
WN Central	-1.73%	-2.02%
S. Atlantic	-7.99%	-6.99%
ES Central	-9.99%	-9.11%
WS Central	-1.32%	-1.48%
Mountain	-0.32%	-1.82%
Pacific	-1.54%	-0.53%

Figure 4.7: Regional Model with Scattered Data—Mid-Atlantic Region

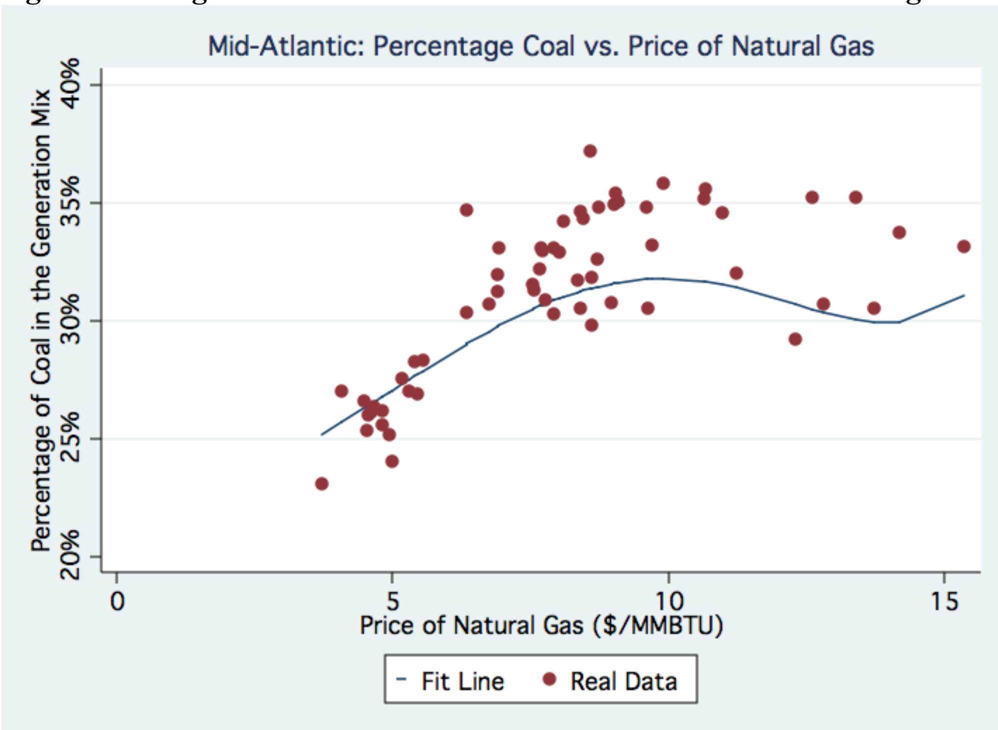
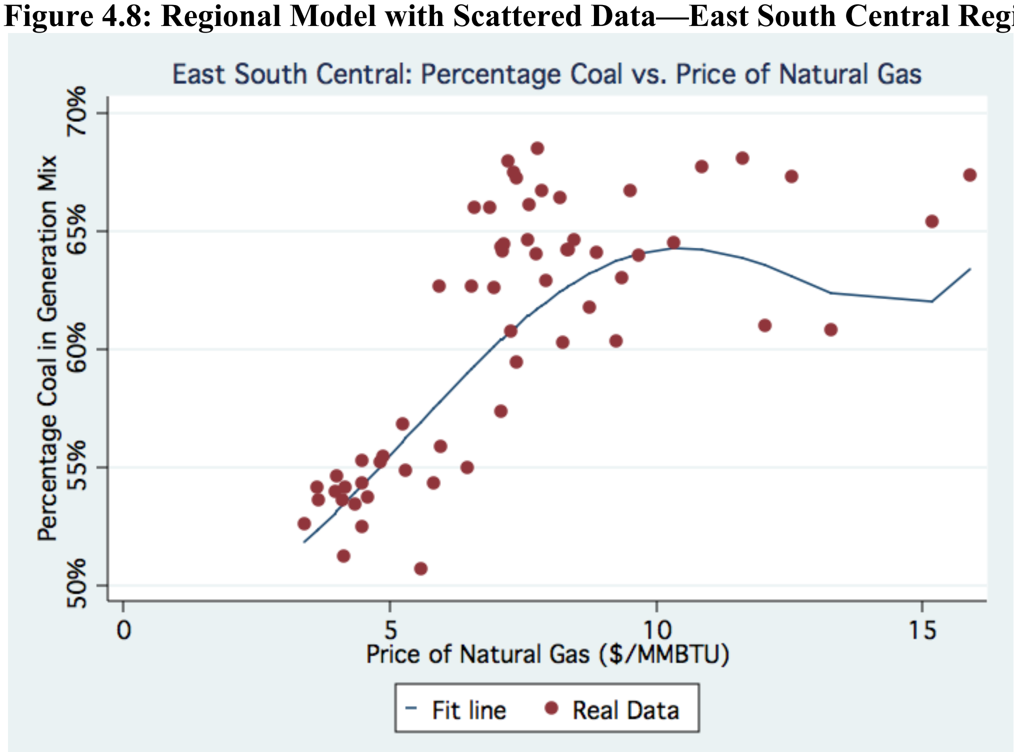


Figure 4.8: Regional Model with Scattered Data—East South Central Region



Chapter 5: REDUCTIONS IN CARBON DIOXIDE EMISSIONS THROUGH FUEL SWITCHING

I. Emissions Model

As detailed in Chapter 2, the combustion of coal emits almost twice as much carbon dioxide per unit of energy released as the combustion of natural gas. Furthermore, natural gas combined cycle plants tend to be around 30% more efficient than coal plants in converting fuel inputs into electricity outputs. Thus, replacing a unit of electricity from a coal-fired power plant with a unit of electricity from a natural gas-fired combined cycle plant results in a significant reduction in CO_2 emissions per unit of electricity. Rough numbers illustrating this effect are shown in Table 5.1.[115]

Table 5.1: CO_2 Emissions per Unit of Electricity

	Average Emissions Factor ($kgCO_2$/MMBTU)	Average Heat Rate (MMBTU/MWh)	Emissions/Electricity (tCO_2/MWh)
Natural Gas	53.06	7.543	0.400
Coal	95.43	10.148	0.968
Natural Gas as a % of Coal	55.6%	74.3%	41.3%

On average, coal to natural gas fuel switching leads to a 58.7% reduction in emissions per unit of electricity. The initial reductions are even greater than this because the most efficient (low heat rate) natural gas plants replace the most inefficient (high heat rate) coal plants first.

In 2008, CO_2 emissions from coal accounted for 83% of CO_2 emissions from electric power production and 32.5% of all GHG emissions.[116] Thus, if all coal-fired electricity generation were switched over to natural gas, nationwide GHG emissions would be reduced by 19.1%. This is an upper bound, but it offers a sense of the scope of emissions reductions that are possible through the fuel-switching effect.

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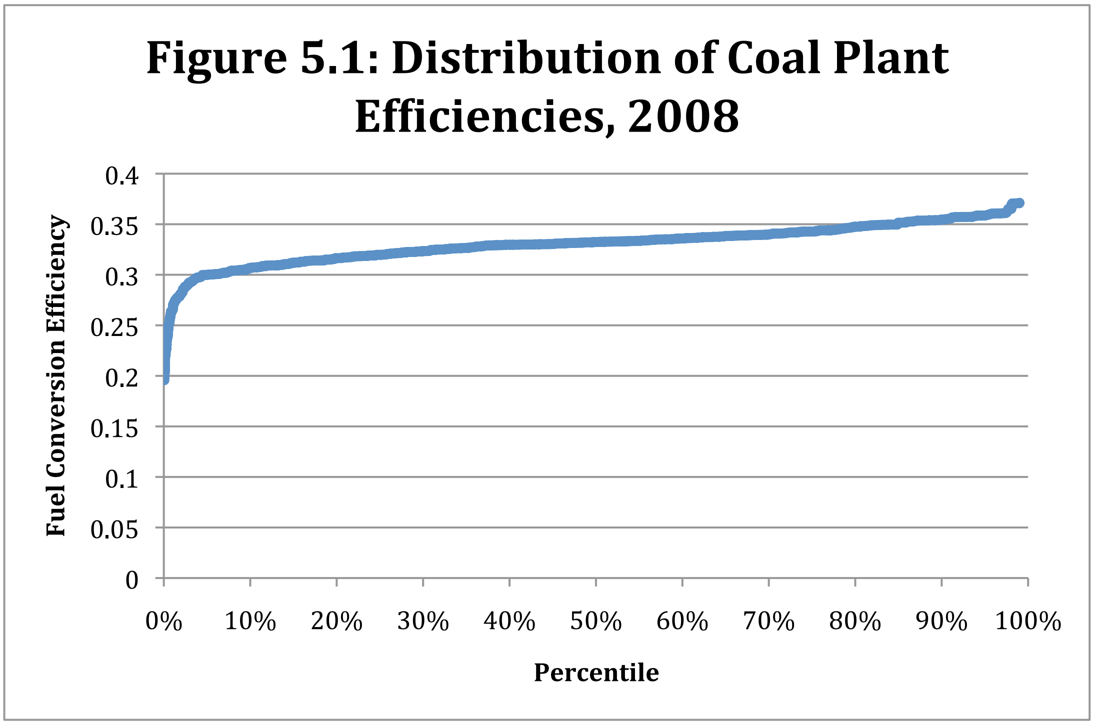
[115] EIA Data, Electricity, The emissions factor for coal is a weighted average based on Chapter 2 values and 2009 production.
[116] EPA, US GHG inventory

Using the fuel-switching model from the previous chapter, I analyzed how fuel price movements and targeted policies changing these prices translate into emissions reductions. Ultimately, the model gives the reduction in emissions as a function of changes in the fuel prices. Taking the regional fuel-switching model as an input, it looks like this:

$$ER(\tau_{coal},\tau_{ng}) = \sum_r \Delta\%Coal_r(\tau_{coal},\tau_{ng}) * TotalGen_r * (\frac{3.413}{\eta_{coal}} * f_{coal} - \frac{3.413}{\eta_{ng}} * f_{ng})$$

ER stands for CO_2 emissions reduction in metric tons and the τ's represent the changes in each of the fuel prices in \$/MMBTU. A sum is taken over the emissions reduction in every census region *r*. Regional emissions reductions are calculated by multiplying the regional fuel switching effect, *Δ%Coal*, by the total electricity generation in the region to obtain the amount of electricity in MWh that switches from coal to natural gas. This amount is then multiplied by the difference in CO_2 emissions per unit of electricity in tCO_2/MWh for coal and natural gas, thus subtracting the added emissions due to generating the electricity with natural gas from the emissions reduction due to removing generation from coal. The emissions per unit of electricity figures are the product of the heat rate and the emissions factor, *f*, in tCO_2/MMBTU. The heat rate is 3.413 MMBTU/MWh divided by the plant efficiency, η.

I added further nuance to the model by not holding the heat rate constant over all plants of a given type. Rather, in the fuel-switching effect, the most efficient natural gas plants replace the most inefficient coal plants first. Thus, the average heat rate of the switched plants depends on the extent of the fuel switching. For initial switching, the average heat rate of the displaced coal plants will be very high, but for more elevated levels of switching the average heat rate will converge toward the average heat rate of all coal plants. Figure 5.1 displays the distribution of heat rates for US coal plants in 2008.



Thus, efficiency η for coal can be modeled as a function η(Percentile). It is difficult to decide exactly what percentile sets the efficiency because the generation is reduced at a range of coal plants with different efficiencies under the fuel switching effect. The generation from coal displaced as a percentage of total generation from coal—*(-Δ%Coal)/(%Coal)*—functions as a suitable approximation. This modeling is further improved by computing these efficiency curves on a regional level to reflect the fact that some regions, like the South, have more older, inefficient coal plants than other regions.

It is more difficult to compute the efficiency curves for natural gas combined cycle plants because the reported data divide the combined cycle plants into their gas turbine and steam turbine components. Natural gas combined cycle plants have a maximum efficiency of around

51%-54%[117] and a fleet-wide average efficiency of 45.2%[118]. For simplicity, the efficiency of the displacing NGCC plants was assumed to be 53% in all instances. Thus, the improved model is:

$$ER(\tau_{coal},\tau_{ng}) = \sum_r \Delta\%Coal_r(\tau_{coal},\tau_{ng}) * TotalGen_r * (\frac{3.413}{\eta_{coal,r}(\frac{-\Delta\%Coal_r}{\%Coal_r})} * f_{coal} - \frac{3.413}{\eta_{ng}} * f_{ng})$$

Using this emissions reduction model and the levels of fuel switching from 2008 to 2009 modeled in Chapter 4, I calculated the nationwide emissions reductions due to fuel switching in this period. Table 5.2 below summarizes this calculation.

Table 5.2: Nationwide Emissions Reductions

Region	**Coal to Gas Switching Effect**	**Emissions Reductions (tCO_2)**	**Percentage of 2008 Nationwide Power Sector Emissions**	**Percentage of 2008 Total Nationwide Emissions**
New England	-3.71%	-3,343,205	-0.14%	-0.06%
Mid-Atlantic	-4.92%	-13,982,624	-0.59%	-0.23%
EN Central	-3.43%	-17,180,890	-0.73%	-0.29%
WN Central	-1.73%	-5,129,465	-0.22%	-0.09%
South Atlantic	-7.99%	-43,424,028	-1.84%	-0.72%
ES Central	-9.99%	-26,962,255	-1.14%	-0.45%
WS Central	-1.32%	-6,582,169	-0.28%	-0.11%
Mountain	-0.32%	-1,110,365	-0.05%	-0.02%
Pacific	-1.54%	-4,024,723	-0.17%	-0.07%
Total		*-121,739,722*	*-5.15%*	*-2.02%*

Thus, the emissions reductions from fuel switching accounted for a 2.02% reduction in total emissions from 2008 to 2009, around a third of the total 6.59% decrease over this time period. Emissions from electricity decreased by 8.76% in 2009 (accounting for 3.43 percentage points of the nationwide decline in emissions) at the same time that electricity generation fell by 4.10%. The emissions reduced from fuel switching account for a 5.15% decrease in emissions

[117] "Gas Turbine and Combined Cycle Products," *GE Energy*, n.d., Web, 30 Mar. 2011. The most efficient combined cycle plants available are the F-class and H-class technologies. GE reports the low heating value (LHV) efficiencies for these plants at 56%-60%. Since the coal efficiencies are calculated using high heating values (HHV), I scaled the natural gas efficiencies by the appropriate factor for natural gas, 0.901, so that they are HHV efficiencies as well.

[118] EIA Data, Electricity

from electricity. Together, these effects add up to a 9.25% decrease, roughly in line with the actual 8.76% decrease. Thus, the modeled fuel-switching effect fits well with the reduction in generation—as a substitution effect and an income effect, respectively—to explain the overall decline in power sector emissions.

II. Policy Scenarios

I model three policy scenarios to examine how targeted changes in fuel prices might augment the existing emissions reduction contributed by coal to gas switching. Specifically, I consider a carbon tax at two different levels, the complete removal of fossil fuel subsidies, and the addition of a natural gas subsidy. Each of these mechanisms increases the price of coal relative to natural gas. In each case, it is assumed that the capacity of all power plant types is constrained so that only changes in the fuel price influence changes in the generation mix.

Carbon Tax

A carbon tax increases the price of a fuel in proportion to the amount of carbon dioxide produced when that fuel is combusted. So, a carbon tax would raise the price of both coal and natural gas, but it would raise the price of coal more since coal has a higher emissions factor (the amount of carbon in coal per unit of chemical energy). The increase in prices is in proportion to the fuel's emissions factor. For example, a $20/tCO_2$ tax results in the following price increases:

$$\$20/tCO_2 * (0.05306tCO_2/MMBTU) = \$1.0612/MMBTU \text{ (natural gas)}$$
$$\$20/tCO_2 * (0.09543tCO_2/MMBTU) = \$1.9086/MMBTU \text{ (coal)}$$

Theoretically, the impacts of a carbon tax and a cap-and-trade system are identical—both operate to impose a price on carbon and the market adjusts in response to this price's effect on individual goods. In practice, however, the effects of a tax system and a cap-and-trade system diverge due to the uncertainty in the marginal cost and marginal benefit curves. A tax sets a price on emissions and leaves the quantity of reduced emissions uncertain while a cap-and-trade system sets the quantity of emissions and leaves the price of reduction uncertain.[119] I focus on a carbon tax here, because it is necessary to have a fixed price as an input to the fuel switching model. Emissions reductions for a \$5/tCO_2 tax and a \$10/tCO_2 tax are presented in Tables 5.3 and 5.4.

Table 5.3: \$5/tCO_2 tax

Region	**Coal to Gas Switching Effect**	**Emissions Reductions (tCO_2)**	**Percentage of 2009 Nationwide Power Sector Emissions**	**Percentage of 2009 Total Nationwide Emissions**
New England	0.38%	419,713	0.02%	0.01%
Mid-Atlantic	-2.30%	-6,630,074	-0.31%	-0.12%
EN Central	-8.22%	-34,808,246	-1.62%	-0.62%
WN Central	0.14%	587,184	0.03%	0.01%
South Atlantic	-3.86%	-20,002,939	-0.93%	-0.36%
ES Central	0.63%	3,579,260	0.17%	0.06%
WS Central	0.05%	267,274	0.01%	0.00%
Mountain	-6.86%	-17,772,935	-0.83%	-0.32%
Pacific	-4.29%	-14,781,352	-0.69%	-0.26%
Total		*-89,142,115*	*-4.14%*	*-1.58%*

Table 5.4: \$10/tCO_2 tax

Region	**Coal to Gas Switching Effect**	**Emissions Reductions (tCO_2)**	**Percentage of 2009 Nationwide Power Sector Emissions**	**Percentage of 2009 Total Nationwide Emissions**
New England	0.75%	833,247	0.04%	0.01%
Mid-Atlantic	-6.28%	-16,441,484	-0.76%	-0.29%
EN Central	-18.20%	-73,813,260	-3.43%	-1.31%
WN Central	0.29%	1,188,038	0.06%	0.02%
South Atlantic	-8.32%	-42,007,889	-1.95%	-0.75%
ES Central	1.27%	7,217,469	0.34%	0.13%
WS Central	0.11%	551,472	0.03%	0.01%
Mountain	-15.55%	-39,722,081	-1.84%	-0.71%
Pacific	-14.82%	-14,781,352	-0.69%	-0.26%
Total		*-176,975,841*	*-8.22%*	*-3.15%*

[119] Martin L. Weitzman, “Prices vs. Quantities,” *The Review of Economic Studies*, 41.4, 1974, Web.

Removal of Fossil Fuel Subsidies

The Obama Administration has advocated removing tax breaks for large corporations, including fossil fuel producers, in order to raise revenue and level the playing field.[120] According to a 2007 EIA study, electricity production from coal is subsidized at $0.44/MWh and electricity production from natural gas is subsidized at $0.25/MWh.[121] Thus, removing all subsidies would be relatively advantageous to natural gas. These subsidy figures are scaled by the respective average heat rates and added to the fuel prices.

Table 5.5: Removal of Fuel Subsidies

Region	**Coal to Gas Switching Effect**	**Emissions Reductions (tCO_2)**	**Percentage of 2009 Nationwide Power Sector Emissions**	**Percentage of 2009 Total Nationwide Emissions**
New England	0.05%	52,656	0.00%	0.00%
Mid-Atlantic	-0.14%	-406,945	-0.02%	-0.01%
EN Central	-0.66%	-2,887,213	-0.13%	-0.05%
WN Central	0.02%	72,497	0.00%	0.00%
South Atlantic	-0.31%	-1,600,209	-0.07%	-0.03%
ES Central	0.08%	443,157	0.02%	0.01%
WS Central	0.01%	32,465	0.00%	0.00%
Mountain	-0.55%	-1,439,317	-0.07%	-0.03%
Pacific	-0.19%	-14,781,352	-0.69%	-0.26%
Total		*-20,514,261*	*-0.95%*	*-0.36%*

Natural Gas Subsidy

Finally, the government could directly subsidize natural gas production in order to make it more competitive with coal. Modeled below are the results from a $0.50/MMBTU subsidy, a $1.00/MMBTU subsidy, and a $2.00/MMBTU subsidy. Due to adjustments in the market, the actual subsidy would have to be larger than these values. These models determine the effect of a

[120] Jessica Leber, "Obama's Budget Pushes Clean Technologies, Cuts Clean Coal Technologies," *ClimateWire*, 1 Feb. 2011, Web, 26 Mar. 2011.
[121] United States, Dept. of Energy, Energy Information Administration, *Federal Financial Interventions and Subsidies in Energy Markets 2007: Executive Summary*," 2007, Web, 15 Mar 2011, p xvi.

larger subsidy which reduces the fuel price by the given amount of \$/MMBTU. It is assumed that coal prices remain constant.

Table 5.6: \$0.50/MMBTU subsidy

Region	**Coal to Gas Switching Effect**	**Emissions Reductions (tCO_2)**	**Percentage of 2009 Nationwide Power Sector Emissions**	**Percentage of 2009 Total Nationwide Emissions**
New England	-0.72%	-691,734	-0.03%	-0.01%
Mid-Atlantic	-0.75%	-2,659,664	-0.12%	-0.05%
EN Central	-0.53%	-3,205,995	-0.15%	-0.06%
WN Central	-0.26%	-1,133,524	-0.05%	-0.02%
South Atlantic	-1.03%	-5,703,993	-0.26%	-0.10%
ES Central	-1.15%	-3,176,161	-0.15%	-0.06%
WS Central	-0.09%	-457,715	-0.02%	-0.01%
Mountain	0.00%	0	0.00%	0.00%
Pacific	-0.20%	-575,163	-0.03%	-0.01%
Total		*-17,603,948*	*-0.82%*	*-0.31%*

Table 5.7: \$1.00/MMBTU subsidy

Region	**Coal to Gas Switching Effect**	**Emissions Reductions (tCO_2)**	**Percentage of 2009 Nationwide Power Sector Emissions**	**Percentage of 2009 Total Nationwide Emissions**
New England	-1.43%	-1,292,387	-0.06%	-0.02%
Mid-Atlantic	-1.49%	-4,464,705	-0.21%	-0.08%
EN Central	-1.09%	-5,293,408	-0.25%	-0.09%
WN Central	-0.49%	-1,616,340	-0.08%	-0.03%
South Atlantic	-2.06%	-11,062,254	-0.51%	-0.20%
ES Central	-2.22%	-6,040,563	-0.28%	-0.11%
WS Central	-0.17%	-855,316	-0.04%	-0.02%
Mountain	0.00%	0	0.00%	0.00%
Pacific	-0.39%	-1,115,785	-0.05%	-0.02%
Total		*-31,740,759*	*-1.47%*	*-0.56%*

Table 5.8: $2.00/MMBTU subsidy

Region	**Coal to Gas Switching Effect**	**Emissions Reductions (tCO_2)**	**Percentage of 2009 Nationwide Power Sector Emissions**	**Percentage of 2009 Total Nationwide Emissions**
New England	-2.74%	-2,374,769	-0.11%	-0.04%
Mid-Atlantic	-2.86%	-8,234,681	-0.38%	-0.15%
EN Central	-2.15%	-10,132,854	-0.47%	-0.18%
WN Central	-0.89%	-2,857,671	-0.13%	-0.05%
South Atlantic	-4.08%	-21,097,040	-0.98%	-0.38%
ES Central	-4.04%	-10,952,766	-0.51%	-0.19%
WS Central	-0.29%	-1,470,176	-0.07%	-0.03%
Mountain	0.00%	0	0.00%	0.00%
Pacific	-0.72%	-1,908,203	-0.09%	-0.03%
Total		*-59,028,160*	*-2.74%*	*-1.05%*

III. Discussion

Results

The various policy options all reduce carbon dioxide emissions, at levels ranging from 0.82% to 8.22% of power sector emissions (0.31% to 3.15% of total emissions). Table 5.9 summarizes these options.

Table 5.9: Policy Options

Policy	**Power Sector Emissions Reduction**	**Nationwide Emissions Reduction**
Carbon Tax		
$5/$tCO_2$	*-4.14%*	*-1.58%*
$10/$tCO_2$	*-8.22%*	*-3.15%*
Removal of Fuel Subsidies	*-0.95%*	*-0.36%*
Natural Gas Subsidy		
$0.50/MMBTU	*-0.82%*	*-0.31%*
$1.00/MMBTU	*-1.47%*	*-0.56%*
$2.00/MMBTU	*-2.74%*	*-1.05%*

These represent significant reductions in emissions. For comparison, the Waxman-Markey climate change bill, which passed in the House of Representatives in 2009 and was supported by the White House, set a target of reducing nationwide emissions from all sources to

17% below 2005 levels by 2020.[122] A \$10/tCO_2 tax would achieve roughly 19% of that reduction through fuel switching (not including reduced demand) in a very short time.

The carbon tax is the most effective of the policy options. By raising the price of coal significantly, it places the two fuels on an almost even footing. In this position, natural gas is able to replace large fractions of production from coal. Removal of fossil fuel subsidies also raises the price of coal, but does not cause a large switching effect. A natural gas subsidy leaves the price of coal steady and tries to push the price of natural gas down into a range where it can compete. Though it requires a major subsidy to make this happen, it does result in a significant reduction in emissions. The main coal to natural gas switching under these policies occurs in the South and the Mid-Atlantic regions as before, and there is significant switching in the East North Central region as well.

Limitations of the Model

It is important to note that the conclusions from these models—the fuel switching and the emissions reduction models—are based on extrapolations beyond the range of real data. As such, their accuracy depends on how well the models reflect reality, not just how well they fit the existing data. I attempted to design the models to achieve a best fit to the data and to provide sensible and meaningful results when extended outside of the data range. This was particularly difficult with the coal price components of the model. The data for coal were restricted to a relatively narrow range in each region and this lack of variance makes it challenging to model a robust trend. I rejected several iterations of regional models with better fits because they implied that coal use increased significantly at high prices of coal, a nonsensical result. This was due in large part to the divergent nature of the Maclaurin series at high values of x, as explored in

[122] *America Clean Energy and Security Act of 2009*

Chapter 4. Thus, the coal models and the resulting emissions reduction models, especially the models of the carbon taxes since they model large increases in the coal price, present estimates, but are expected to be informative nonetheless.

Another limitation of the model is that the regional apportionment uses census regions, which only roughly conform to electric usage patterns. It would be better to use NERC regions because that would model switching on a self-enclosed electric grid. As it is, in the Pacific region for example, fuel switching clearly does not occur between a coal plant in California and a natural gas plant in Hawaii. However, this is a limitation of the EIA data as presented, specifically the price data. A subsequent iteration of the model might try to correct this for more precise results.

Other Contributing Factors

A May 2009 EIA Short Term Energy Outlook report concluded that fuel switching was likely to occur in the East South Central and South Atlantic regions. However, the report identified several uncertainties which could suppress or delay the switching effect, namely power producers' contractual obligations for delivered coal, limited capacity in natural gas pipelines or the electric grid system, and the limited availability of natural gas combined cycle plant capacity.[123]

Of particular importance is the availability of combined cycle capacity. This enters the model as a control variable and as a determinant of the shape of the fuel-switching curve. Notably, the differenced Gaussian that I derive as a theoretical basis for the model does not decline to negative infinity as the natural gas price goes to zero. Rather, the model shallows out and can intercept the y-axis above the origin depending on the relative sizes of the *a* and *b*

[123] *Short Term Energy Outlook*, p 2.

parameters. This reflects the fact that the quantity of coal capacity switched out is limited by the availability of natural gas capacity to take its place. As discussed in Chapter 2, the most significant switching occurs in those regions with abundant coal and natural gas capacity. Ultimately, though, capacity imposes a limit in every region so that the highest levels of switching may be curtailed until new plants are built.

However, a positive feedback in the system helps address this issue. A 2009 Energy Policy paper argues (as does this thesis) that internalizing the cost of emissions rearranges the merit order and forces traditional baseload power, such as coal plants, to the margin of demand. The coal plants are not well equipped to turn on and off frequently because of their high start-up costs and the wear and tear on the machinery while ramping up generation. They perform optimally when running continually at their rated power. The paper concludes that these cycling costs significantly increase the cost of generation from coal, counteracting the benefits of reduced emissions.[124]

However, the Energy Policy paper operates under the assumption of short-term constrained capacity. Relaxing that assumption and considering the situation in the medium-term suggest a different effect. Coal power plants operating in the intermediate or peaking sections of the demand curve represents a highly sub-optimal capacity allocation of the grid, not only because of cycling costs but also because of coal's high fixed costs. This situation creates a large incentive for the construction of new capacity, specifically natural gas combined cycle plants, which can serve the intermediate level demand at a lower total cost than coal. Thus, there are two stages to the fuel switching process. In the short-term, old, inefficient coal plants are forced higher in the demand curve to a lower capacity factor. In the medium-term, they are displaced off

[124] Eleanor Denny and Mark O'Malley, "The Impact of Carbon Prices on Generation-Cycling Costs" *Energy Policy* 37 (2009): 1204-1212.

the grid entirely by the arrival of new combined cycle capacity. The emissions reduction estimates in this short-term model, then, likely underestimate the eventual reductions in the medium to long-term.

Chapter 6: CONCLUSION

Low natural gas prices brought on by the “Shale Gas Revolution” have driven an ongoing transformation in the electric power sector. As natural gas prices fall and coal prices rise or stay constant, the most efficient natural gas plants are increasingly able to displace the most inefficient coal plants from the baseload, leading to a reduction in generation from coal compensated by an increase in generation from natural gas.

The fuel-switching model indicates that changes in the prices of coal and natural gas from 2008 to 2009 led to significant switching in almost every census region. The effect was greatest in regions with high capacities of both coal and natural gas combined cycle power plants. In the East South Central and South Atlantic regions, 9.99% and 7.99% of total generation switched from coal to natural gas, respectively. The effect was also significant in the Mid Atlantic region, where 4.92% of the total generation switched from coal to gas.

This effect is not temporary. Natural gas prices are expected to remain in the $4/MMBTU to $6/MMBTU range and the bulk of new capacity projected to come online over the next few years is expected to be natural gas-fired.[125]

In 2009, fuel switching translated to a reduction in CO_2 emissions from the power sector of 5.15%, equivalent to a nationwide GHG emissions reduction of 2.02%. Combined with a 4.10% reduction in electricity generation due to reduced demand, this result is consistent with the observed 8.76% reduction in power sector emissions in 2009.

Emissions reductions were greatest in the South Atlantic and East South Central regions, where the fuel switching effect was largest and the displaced coal plants tended to be older and

[125] IHS Cambridge Energy Research Associates, p 7.

more inefficient. There were also significant reductions in the Mid-Atlantic and East North Central regions.

Targeted policies in support of natural gas could augment the existing fuel switching effect, leading to a deeper total emissions reduction. A carbon tax of $5/t$CO_2$ would result in a 4.14% reduction from 2009 power sector emissions (a 1.58% reduction in nationwide emissions); a $10/t$CO_2$ tax would lead to an 8.22% reduction (a 3.15% reduction in nationwide emissions). Alternatively, a subsidy that lowers gas prices by $1.00/MMBTU would reduce power sector emissions by 1.47% (0.56% nationwide) and a subsidy that lowers prices by $2.00/MMBTU would reduce power sector emissions by 2.74% (1.05% nationwide).

These results represent a lower bound on emissions reduction. Coal plants forced into lower capacity factor positions in the generation curve experience problems with cycling (turning on and off to meet marginal demand), which will increase their O&M costs. They will be susceptible to replacement by new natural gas capacity, forcing them off the grid entirely and leading to further emissions reductions than those modeled here. Subsequent iterations of the model might attempt to account for this capacity replacement effect.

Furthermore, natural gas is superior to coal in a number of respects other than CO_2 emissions. Natural gas burns much more cleanly than coal, only emitting NO_x and methane in significant quantities when combusted. By comparison, coal combustion emits NO_x and methane at higher rates than natural gas and also emits SO_2, mercury, particulate matter, CO, and toxic metals.[126] These air pollutants have dangerous impacts on human health—SO_2, particulate matter, and CO are damaging to the respiratory system and mercury consumption can cause birth

[126] EPA, eGRID2010

defects and lower IQ.[127] Furthermore, coal mining often causes surface water contamination through acid mine drainage and seepage from abandoned mines.[128] There remain some water pollution issues with natural gas drilling, but improved technologies and regulatory structures are expected to address these problems.

The transition to a natural gas fuel system, in addition to these environmental and health benefits, is also expected to create jobs and spur domestic investment. Due to decades of mechanization in the coal industry, there are only an estimated 180,000 blue-collar coal jobs in the whole nation today.[129] In contrast, a recent study from Penn State estimated that shale gas development would create over 200,000 jobs and add nearly $20 billion to the economy by 2020 in the state of Pennsylvania alone.[130] Similar studies for West Virginia, Texas, and Louisiana project proportionally large job creation and investment numbers in those states.[131] Furthermore, a shift to a larger natural gas share in electric generation mix would require the construction of new plants, pipelines, and other infrastructure, creating additional jobs and investment.

The electric power sector has reached a critical juncture. Natural gas is in a position to replace coal as the dominant source of electricity generation and has already begun to do so. The new range of natural gas prices offers an opportunity to shape America's energy system for decades to come. Small changes in the price of natural gas translate into deep levels of coal to natural gas fuel switching. This presents a low-cost option for making significant reductions in

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[127] "Toxic Air: The Case for Cleaning Up Coal-fired Power Plants," *American Lung Association*, March 2011, Web, 18 Mar 2011

[128] Nick Price and Logan Yonavjak, "Mountaintop Removal Cuts Through Southern Forests," *World Resources Institute*, 30 Jul. 2010, Web, 18 Mar. 2011.

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[130] Timothy J. Considine, Robert Watson, and Seth Blumsack, "The Economic Impacts of the Pennsylvania Marcellus Shale Natural Gas Play: An Update," *Department of Energy and Mineral Engineering*, Pennsylvania State University, 24 May 2010, Web, 20 Mar 2011.

[131] *Interstate Oil and Gas Compact Commission*, Web, 20 Mar. 2011.

CO_2 emissions while increasing the overall efficiency of the electricity grid, creating jobs, spurring domestic investment, cleaning up the nation's air and water and improving human health. Using targeted economics and careful politics, we can capitalize on this opportunity to create great benefit for the environment, the economy, and our society.

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