THE EFFECTS OF INCREASED CORN-ETHANOL PRODUCTION ON U.S. NATURAL GAS PRICES

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by
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The undersigned, appointed by the Dean of the Graduate School, have examined the thesis entitled

THE EFFECTS OF INCREASED CORN-ETHANOL PRODUCTION ON U.S. NATURAL GAS PRICES

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A candidate for the degree of Master of Science

And hereby certify that in their opinion it is worthy of acceptance.

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A special thanks to my family who has shown me what truly matters in life.

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TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

Table Page

THE EFFECTS OF INCREASED CORN-ETHANOL PRODUCTION ON U.S. NATURAL GAS PRICES

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ABSTRACT

In recent years, there has been a push to increase biofuel production in the United States. The biofuel of choice, it seems, has been ethanol produced from corn. The effects of increased corn-ethanol production on the consumer prices of food and energy continue to be studied and debated. This study examines, in particular, the effects of increased corn-ethanol production on domestic natural gas prices. A structural model of the natural gas market is developed and estimated using two-stage least squares. A baseline projection for the period 2007 to 2015 is determined, and shocks representing the effects of U.S. biofuel policies are applied. The results indicate that the increased level of corn-ethanol production occurring as a result of the current U.S. biofuel policies may lead to natural gas prices that are as much as 6% higher, on average, than if no biofuel policies were in place.

Chapter I

Introduction

It should come as no surprise that agricultural markets and energy markets are related. Energy, from the natural gas used to produce fertilizers to the diesel fuel used to transport grain, is a vital input in agricultural production. In the past, this relationship amounted to little more than a weak correlation between energy and agricultural prices (Tyner and Taheripour, 2008). However, concerns about the environment and the energy independence of the United States have focused public attention on renewable sources of energy including biofuels. Chief among these biofuels at present is ethanol produced from corn. The link between agriculture and energy is now inevitably a much stronger link.

The Energy Independence and Security Act (EISA) of 2007 will require renewable fuel use to increase from 11.1 billion gallons in the calendar year 2009 to 36 billion gallons by 2022. The amount attributable to corn-ethanol could be as high as 10.5 billion gallons in 2009 and 15 billion gallons by 2015. It could remain at that level through 2022. This has sparked debates over the effect of corn-ethanol production on the prices of various consumer goods. Indeed, the food versus fuel debate has received the most attention. Less attention has been paid to the possible effects on consumer energy prices. Wang (2008) showed that ethanol production as mandated would result in lower gasoline prices than would occur otherwise. This study attempts to answer the question, “What effects will increased corn-ethanol production have on natural gas prices?" The primary input in corn ethanol production, after corn, is natural gas. With natural gas poised to become the fossil fuel of choice after oil (Barnes, Hayes, Jaffe, and Victor, 2006), the question is timely and relevant. The answer will shed light on yet another link between agriculture and energy markets. More importantly, policymakers can use this information to make better decisions for the people they represent.

The objectives of this study are threefold:

(I) Determine how much natural gas is used directly and indirectly in the life-cycle of corn-ethanol (i.e. How much energy is used to produce the corn and convert the corn into ethanol?);

(II) Develop a model of the natural gas market that will allow the specific relationship between corn-ethanol production and natural gas prices to be studied; and

(III) Use the model to determine the effects of current U.S. biofuel policies on that relationship.

Chapter 2

Literature Review

There is an abundance of literature that relates to natural gas use in ethanol production, natural gas and energy modeling, and the effects of energy and biofuel policies. Some studies focus on energy consumption by a particular agricultural input such as fertilizer or pesticide. These studies provide a basis for the energy balance studies that examine energy use in corn-ethanol production. In energy balance studies, the authors try to determine if the energy output of corn-ethanol is greater or less than selected energy inputs. To complicate matters, these studies usually vary by scope and assumed inputs.

Models of energy and natural gas markets are quite varied. Large, detailed models are used by agencies like the Energy Information Administration (EIA) and research institutes like the James A. Baker III Institute for Public Policy. Small, simple models are developed and used by individual researchers to explore basic economic relationships.

Both the intended and unintended effects of government policy can be far-reaching. Indeed, it is important to account for these effects when studying energy and agricultural markets.

2.1 Natural gas use in corn and ethanol production

A 1994 report by Bhat, English, Turhollow, and Nyangito sought to "develop current estimates of energy consumption in major fertilizers and pesticides" (p 4). The authors compared three energy use surveys conducted by The Fertilizer Institute in 1979, 1983, and 1987. The surveys reported energy use by type (e.g. natural gas, electricity, etc.) in gigajoules per metric ton (GJ/mt) of fertilizer for the most common forms of nitrogenous fertilizer. Bhat et al. then calculated the weighted average use of each fuel type in GJ/mt of nutrient. Table 2.1 summarizes their findings. The pesticide values belonged to Green (1987) originally and were cited from West and Marland (2002) for this study.

Table 2.1 Natural gas requirements for the production of nitrogenous fertilizers and pesticides

Author(s)	Total Amount	Net Additional Amount
Bhat el al. (1994)	Gigajoules per metric ton of fertilizer	
Ammonia (82-0-0)	40.78	0.00
Urea (46-0-0)	26.02	2.58
Ammonium Nitrate (34-0-0)	18.50	0.81
Urea-AN solutions (30-0-0)	16.11	0.00
Ammonium sulphate (21-0-0)	10.48	0.00
Others (48-0-0)	22.38	not available
	Gigajoules per metric ton of nitrogen	
Weighted Average	51.81	not available
West and Marland (2002)	Gigajoules per metric ton of pesticide	
Herbicide	87.26	not available
Insecticide	97.75	not available
Fungicide	84.44	not available
Additional source: Green (1987)		

The natural gas requirement depends on the amount of nitrogen in the fertilizer. The basic nitrogenous fertilizer is ammonia. In addition to direct application to crops, ammonia is used in the production of other forms of nitrogenous fertilizer. The natural gas requirement for these other forms is represented in large part by the amount of ammonia used. The last column in the table shows how much natural gas is needed in addition to the amount inherent in the ammonia.

The authors studied two fertilizers comprised strictly of phosphate and one potash fertilizer. The amount of natural gas needed to produce single superphosphate was 0.18 GJ/mt. Triple superphosphate required 0.54 GJ/mt. Muriate of potash was the only potassium-based fertilizer analyzed in their study. The most recent data available to the authors at the time of publication was from the year 1985 rather than 1987. In 1985, 1.61 GJ/mt were required for the production of muriate of potash.

In their presentation of energy required for pesticide production, Bhat et al. (1994) aggregated the energy use into one measure. Thus, it was not as helpful in determining only the natural gas requirements. However, those measures were itemized in Green (1987), the source used by Bhat et al. (1994), but they were not available for review. A 2002 article by West and Marland cited the measures from Green (1987) by fuel type. The pesticide numbers in the Table 6.1 include steam energy requirements that West and Marland assumed were met by combustion of natural gas.

In 2002, Shapouri, Duffield, and Wang compared previous life-cycle analyses of ethanol production and updated their own 1995 study. Their purpose was to determine the differences in methods among the studies and provide “a more consistent estimate for the NEV [net energy value] of corn-ethanol” (p 2). According to Shapouri et al., the differences occurred as the result of using different data collection periods, including different types of energy, and differing assumptions about co-product energy credits. Only the first two pertain to this research.

It is no surprise that differences between studies could arise because data in Study X are collected for different a time period than in Study Y. Shapouri et al. understood that studies published at different times will not always have access to the same information. They were trying to stress that authors analyzing the current state of ethanol production should use the most recent data available to them. They pointed out that energy use in agriculture had declined from record levels in the late 1970's while corn yields increased and ethanol production experienced efficiency gains.

"Different types of energy," in this context, refers to primary and secondary types. Shapouri et al. (2002) defined primary energy as energy used directly in the production process including fertilizer use. The definition of secondary energy was energy not directly related to production and includes energy embodied in farm equipment and ethanol facilities. This was a little confusing since it could be argued that the energy embodied in a tractor is as involved in the production process as fertilizer. Shapouri et al. chose to omit secondary energy from their study. They reasoned that it was difficult to measure such energy inputs accurately and, in the case of farm equipment and ethanol facilities, would be very small on a per bushel or per gallon basis when distributed over the life of the equipment. Indeed, this issue of relevance versus practicality is debated frequently in the ethanol energy balance literature. Pimentel (2003) and Pimentel and Patzek (2005) both included secondary energy in their analyses.

To revise their prior study, Shapouri et al. used data from the 1996 Agricultural Resource Management Survey. They focused on the top nine corn producing states.

According to the authors, the states accounted for 80 percent of corn production and 91 percent of ethanol production that year. Input levels were calculated as a weighted average, and the authors used the 3-year weighted average corn yield for those states over the 1995-97 period. Their assumptions about natural gas energy used in the production of fertilizer came from the 2000 Production Cost Survey by The Fertilizer Institute and the GREET model developed by Argonne National Laboratory. Shapouri et al. assumed the natural gas requirements for fertilizer production were 16,857 Btu/lb (39.21 GJ/mt) of nitrogen, 56 Btu/lb (0.3 GJ/mt) of phosphoric acid, and 559 Btu/lb (1.30 GJ/mt) of potash.

These values show an apparent increase in the energy efficiency of fertilizer production when compared to the 1994 study by Bhat et al. Shapouri et al. then used weighted averages of fertilizer application rates, natural gas used for irrigation and drying, and corn yield to determine energy requirements on a per bushel basis. Assuming an average corn yield of 125 bushels per acre, they estimated approximately 19,500 Btu of natural gas were used per bushel of corn produced. The total energy requirement for corn production was estimated to be 57,476 Btu/bu. Table 2.2 summarizes these findings as well as the findings of some of the studies described below.

Natural gas use in ethanol production facilities varies by age of equipment and production process (i.e. old versus new technology, wet versus dry mills). Shapouri et al. (2002) cited from a 2001 survey of ethanol producers average measures of 36,000

Btu of thermal energy used per gallon of ethanol produced by the dry-mill process and 51,060 Btu for the wet-mill process.

Table 2.2 Natural gas requirements in the dry-mill corn-ethanol life cycle

Author(s)	Corn Production	Ethanol Production
Shapouri et al. (2002)	19,500 Btu/bushel (HHV)	36,000 Btu/gallon (HHV)
Graboski (2002)	n/a	39,031 Btu/gallon (LHV)
Pimentel (2003)	n/a	39,076 Btu/gallon (LHV)
Perrin et al. (2009)	n/a	26,300 Btu/gallon* (LHV)

*: Reflects their survey average of 54% of co-products sold as dried DGS and 46% sold as wet DGS
Note: Higher heating values (HHV) include energy in the form of water vapor; lower heating values (LHV) do not. For natural gas, water vapor accounts for about 10% of HHV.

Perrin, Fretes, and Sesmero (2009) surveyed seven recently built or updated dry-mill facilities with at least 50 million gallons of annual production capacity in the north-central U.S. They reported an average natural gas requirement of 26,300 Btu per gallon of denatured ethanol with the two low-cost firms of the survey averaging 24,100 Btu/gal and the two high-cost firms averaging 28,200 Btu/gal. Also, the average amount of co-product sold as dry distiller's grains and solubles (DDGS) was 54% with a range of 0% to 97%.

The authors compared their results to the results of seven similar studies published since the year 2000. The comparisons showed initially that production efficiency had improved. However, Perrin et al. noted that most of the prior studies assumed all the co-product was sold as DDGS, thus incurring a higher natural gas requirement. They demonstrated that a comparable 2007 study yielded natural gas requirements similar to their own when the amount of co-product sold as DDGS was adjusted to 54%. It is unclear whether other studies, when similarly adjusted, would have had the same outcome.

Pimentel (2003) aggregated the energy input values in corn production, so it was unclear how much of the value was attributable to natural gas. For ethanol production, Pimental listed an energy requirement of 39,076 Btu of coal. Since Btu are standard, it is safe to assume the measure could apply to natural gas just as easily as coal. Pimentel and Patzek (2005) was one of the studies reviewed by Perrin et al. and was a revision of the earlier study by Pimentel. Like the 2003 study, the authors aggregated the energy input values in corn production. They assumed that ethanol facilities required approximately 38,240 Btu of steam energy per gallon of ethanol produced. This measure was cited from a 2004 study produced by Illinois Corn. Like before, it is safe to assume that “natural gas” could be substituted for “steam” in this context. Neither study explicitly stated the proportion of co-products sold as DDGS. It appears, as noted by Perrin et al., that both studies assumed all of the co-products were sold as DDGS.

Graboski authored an ethanol energy balance study in 2002 that was unique for its time. It was unique because it was the only one concerned with both the current and future states of the industry rather than “snapshots…of the industry” (Graboski, 2002, p 12). This important consideration was also recognized by Farrell, Plevin, Turner, Jones, O’Hare, and Kammen (2006). For the analysis, Graboski tried to combine the approaches of Shapouri et al. and an earlier study by Pimentel. While much of the analysis seemed quite similar to that of Shapouri et al., Graboski corrected for the underestimated energy inputs in corn production. This included revising the energy use estimated for hybrid seed production, farm labor, machinery, and input transportation and packaging. The revised estimate of the total energy requirement was 51,731 Btu per bushel of corn produced, assuming corn yield of 140.18 bushels per acre. All else equal, the yield assumption used by Shapouri et al. (125 bushels/acre) would increase this estimate to 58,013 Btu/bu. It appeared as though Graboski used the same fertilizer industry statistics as Bhat et al., but without knowing exactly how each type of nitrogen fertilizer was weighted it is not possible to determine how much energy could be directly attributed to natural gas. Graboski adjusted the estimate of thermal energy used by an ethanol facility to 39,031 Btu/gal in dry mills and 55,328 Btu/gal in wet mills.

Graboski (2002) also pointed to an important gap in the current knowledge. As far as this author is aware, there have been no new forward looking energy use analyses since the passing of the EISA 2007. Graboski's assumption that 5 billion gallons of ethanol would produced in 2012 is less than half of the EISA's current mandated level of use for that year. He also assumed that there would not be any efficiency gains in either fertilizer or dry-mill ethanol production, although he assumed there would be efficiency gains in corn production (2002).

To shed some light on the debate over the best energy analysis methods, Jones (1989) was examined. The study identified three key issues with the existing energy analysis literature. The same sticking points continue to exist in the more recent NEV literature. They are system boundary identification, the role of labor, and the role of capital.

The problem relating to system boundary identification appears to be the most pervasive. Indeed, this problem can lead to disputes regarding the other two problems. Jones identified four different boundary levels. The most simplistic level was described by Jones as a "fossil fuel accounting exercise" (1989, p 346). Researchers employing this method care only about direct energy inputs. Process analyses are slightly more complex and try to capture all energy inputs including indirect sources. For this reason, Jones preferred the process analysis method. Most of the studies previously cited have used some form of this analysis. Ecosystem analyses would include solar energy, and thermodynamic analyses would be universal in scale. Jones believed these two levels to be too complex for the energy analysis of an agricultural system.

Disputes over the roles of labor and capital are generally disputes over which indirect sources of energy inputs should be included in a process analysis. Clearly, Pimentel and Patzek (2005) believed energy embodied in labor and capital should be included in an analysis. Shapouri et al. (2002), however, believed the energy from labor and capital to be negligible. Jones described four ways to account for labor. They were as follows: "human metabolic energy expended,… 'lifestyle support' energy requirement,…marginal energy requirement of employment, and…zero energy cost" (1989, p 347). Jones believed the agricultural system being studied determined the most appropriate method (1989).

As an example, Jones compared two agricultural systems in which the main form of labor was different. In the one system, the chief form of labor was manual. In the other system, machinery performed most of the labor. He explained that the metabolic energy requirement would be the most appropriate method for the first system. For the second system, the marginal energy requirement would be the most appropriate method. Jones reasoned that lifestyle support requirements would count some energy inputs twice, and zero energy cost would ignore the inputs required by employment. According to Jones, there is not an adequate way to include the investment value of capital in an energy analysis (1989). It is unclear if that would apply to embodied energy.

Jones declared that the usefulness of energy analyses lies in long term, rather than day-to-day, decision making. Also, general comparisons should be preferred to finely detailed comparisons since the results are influenced by the method used. In general, the technique chosen should be guided by the purpose of the study with an emphasis on the technique with the “minimum acceptable level of complexity” (Jones, 1989, p 353).

Graboski (2002) set the stage for later studies like Farrell et al. (2006) and Liska et al. (2009a) and their development of spreadsheet tools to help analyze the future life-cycle energy requirements of corn-ethanol. There have been several spreadsheet tools developed to aid researchers performing energy analyses of corn-ethanol. The tool developed by Farrell et al. in 2006 was named the ERG Biofuel Analysis Meta-Model (EBAMM). Like Jones (1989), Farrell et al. concluded that variance in system boundaries was the root cause of differences in energy analyses (2006). They developed this model to separate the differences and standardize the boundaries in prior energy balance studies. For instance, they eliminated caloric intake of farm labor and farm labor transportation inputs from the studies that included them, and they added the energy embodied in machinery, capital, and packaging as well as “process water, effluent restoration, and co-product credit[s]” (Farrell et al., 2006, p 2).

The conceptualization of EBAMM was important in the development of the Biofuel and Energy Systems Simulator (BESS) (Liska et al., 2009a). BESS was first released in 2008, and the system boundaries and calculation methods are similar to EBAMM (Liska et al., 2009b). Unlike EBAMM, however, BESS allows users to perform energy analyses of corn-ethanol production using default parameters or parameters of their own choosing. Thus, BESS allows for considerable flexibility and is ideal for the present study.

2.2 Natural gas and energy: Markets and modeling

Kydes and Shaw (1997) discussed the development and structure of the National Energy Modeling System (NEMS). The NEMS is the model used by the EIA to publish its *Annual Energy Outlook* each year. It was developed in 1993 in response to the need for a new national energy model. According to Kydes and Shaw, prior models had become outdated in the presence of a rapidly changing energy sector (1997). NEMS utilizes a modular organization that focuses on domestic energy markets and international energy markets only to the extent that they affect domestic supplies and prices.

On the supply side, natural gas is represented by both supply and transmission modules. The transmission module determines the clearing prices as well as domestic production, imports, and capacity expansion (Kydes and Shaw, 1997). The supply module then determines the availability of domestic production and both pipeline and liquefied natural gas (LNG) imports.

There are four demand modules contained in NEMS. Residential demand is determined for housing types and end uses, and it accounts for changes in housing and appliance stocks and housing "shell" efficiency (Kydes and Shaw, 1997). The industrial demand module is determined for energy- and non-energy intensive manufacturing as well as non-manufacturing industries. Commercial and transportation demand are also determined.

A simple world energy model was developed in Krichene (2002). Krichene used a simultaneous system to model global crude oil and natural gas supply and demand for two periods, 1918 to 1973 and 1973 to 1999. This allowed Krichene to compare estimates before and after the oil price shocks. The model itself assumed rational price expectations and was estimated using two-stage least squares (2SLS) and an error correction model (ECM). The natural gas supply equation was a function of lagged expected own-price, crude oil output, and a price shock dummy. The demand equation was a function of own-price and real GDP. It is unclear why competing product prices were not used in the demand specification.

Table 2.3 summarizes the elasticity estimates of Krichene (2002) and other studies reviewed below. Both estimation methods yielded similar short-run elasticity estimates. The own-price elasticities of demand for natural gas reveal highly inelastic demand. The 2SLS elasticity estimates were -0.39 and -0.01 for the first and second periods, respectively, and the ECM elasticity estimates were -0.15 and -0.04.

Interestingly, only the -0.39 estimate was found to be statistically significant. The real income elasticities of demand were all positive, less than unity, and statistically significant. The short-run own-price elasticities of supply were unusual in that three of the four were both negative and statistically significant. The 2SLS estimates were -0.73 and -0.10 (both statistically significant), and the ECM estimates were -0.56 (statistically significant) and 0.06. Krichene explained that while unusual, these negative supply elasticities could be realistic if producers had the power to take advantage of the highly inelastic demand (2002). The long-run own-price elasticity estimates were both positive.

Table 2.3 Elasticity estimates from the literature

Author(s)		Own-price		Cross-price		Real income	
		Short run	Long run	Short run	Long run	Short run	Long run
Demand							
Krichene (2002)							
	2SLS	-0.39 and -0.01				0.59 and 0.92	
	ECM	-0.15 and -0.04	-0.70 and -1.1			0.55 and 0.78	1.5 and 2.0
Huntington (2007)		-0.244	-0.668	0.121	0.325		
				Distillate fuel oil			
Uri and Gill (1992)		-0.17	-0.59				
Supply							
Krichene (2002)							
	2SLS	-0.73 and -0.10					
	ECM	-0.56 and 0.06	0.28 to 0.8				

The EIA includes agricultural uses of natural gas in its measures of industrial consumption. Thus, models of industrial natural gas demand provide a reference point for developing more specific models of natural gas demand. In 2007, Huntington developed a single equation model of industrial natural gas demand for the period 1958 to 2003. The equation was represented in the log-log form with autoregressive distributed lag (ADL) relationships. In addition to own-price and a distillate oil price, independent variables included structural output, capacity utilization, heating days, and lagged demand. As per the ADL structure, a one-period lag of each independent variable except capacity utilization was also included in the specification. Huntington estimated own-price elasticities of -0.244 and -0.668 and distillate oil cross-price elasticities of 0.121 and 0.325 in the short- and long runs, respectively.

Huntington also performed some scenario analyses. One scenario tested the assumption of continued natural gas-distillate fuel oil price parity against a price decoupling. In other words, what would happen if natural gas prices and distillate oil prices no longer moved together? Huntington was motivated by the EIA's prediction of a sharp fall in natural gas prices relative to distillate oil prices. There was a large difference in the amount of industrial natural gas consumption under these two assumptions. By 2030, Huntington's model predicted a difference of 3.5 trillion cubic feet per year (Tcf/yr) (2007). The second scenario compared two assumptions regarding the kind of economic growth in the U.S. The first assumption was that growth would occur in energy intensive industries as it did in the late 1980's while the second assumption was that growth would occur in less energy intensive industries as it did in the mid- to late 1990's. Again, the model predicted a difference of approximately 3.5 Tcf/yr.

Huntington identified three limitations of his model. For instance, it could not account for technological progress in individual industries. Also, the structural output and capacity utilization variables represented the manufacturing sector only. Finally, it was a single equation model rather than a simultaneous system of equations (2007).

Uri and Gill (1992) developed a simple, single equation demand model for natural gas by the agricultural sector for the period 1971 to 1989. They were motivated by the lack of research regarding energy consumption in the agricultural sector. Their original specification regressed quantity of agricultural natural gas demand on the residential price of natural gas, a price index of other types of energy, acres irrigated, and average rainfall in the Corn Belt, Lakes, and Northern Plains states weighted by the proportion of total acres planted in each of those regions. Irrigated acres and average rainfall were included to represent the need for natural gas to power irrigation pumps and grain dryers. According to Uri and Gill, those were the two main sources of direct natural gas demand in agriculture (1992). Indirect uses of natural gas in forms such as fertilizer were omitted. The equation was specified with the log-log functional form. It was later determined by a directional causality test that there was no statistically significant evidence of substitution between other energy types and natural gas, so the price index variable was dropped from the final specification. The authors used ordinary least squares (OLS) adjusted for serial correlation to estimate the parameters. They found an own-price elasticity of -0.17 in the short run and -0.59 in the long run.

Time series data are available for several different natural gas prices. The wellhead price, the Henry Hub price, and the delivered prices for each sector are all measured, forecasted, and reported by various entities like the EIA and the New York Mercantile Exchange (NYMEX). Wong-Parodi, Dale, and Lekov (2006) compared the accuracy of two 24-month natural gas price forecasts. Specifically, the authors compared the Henry Hub forward prices reported by the NYMEX and the wellhead price forecasts reported by the EIA. They concluded that the futures price was a little more accurate and unbiased than the EIA forecast.

The choice for a world natural gas price also poses a problem, especially since natural gas trade was, and still is, quite regional in nature. As a result, there are regional reference prices in the global natural gas market. Mazighi (2005) compared two of those prices; the Henry Hub price as reported by the NYMEX and the National Balancing Point (NBP) as reported by the London International Petroleum Exchange (IPE). Mazighi intended to determine which price was most suited to be an international reference price for natural gas in the future, assuming that such a price should exist. The study described several criteria that must be met before such a price can exist. For instance, there must be an organized, though not necessarily physical, market for a standardized good. The word "standardized" refers to goods having "comparable [properties] all around the world" (Mazighi, 2005, p 221). Also, Mazhigi stated the markets must be liquid as well as guided by the basic principles of supply and demand (2005).

Clearly both prices meet the first criteria. Indeed, natural gas is a standard good and the Henry Hub and NBP prices reflect organized markets for that good. The only real difference is that the NYMEX has been trading natural gas since 1990 while the IPE started trading natural gas in 1997 (Mazighi, 2005). Mazighi looked at both the physical and financial liquidity of the two markets. The Henry Hub is a physical location that can receive, store, and distribute natural gas, whereas the NBP is not a physical point but instead refers to a “virtual point” within the UK’s distribution system (Mazighi, 2005). On the NYMEX, natural gas is traded like a commodity with futures contracts and options. On the IPE, prices are determined by physical supply and demand after transmission costs are determined (Mazighi, 2005). Mazighi also noted that the NBP fluctuates more normally than the Henry Hub price (2005). However, Mazighi concluded that the Henry Hub price had the most potential to be an international reference price because of the experience of NYMEX in pricing natural gas and the volume of natural gas traded there (2005).

MacAvoy and Moshkin (2000) explored the effect of regulation on the long-term trend in natural gas prices. According to them, a natural gas price ceiling in place during the 1960’s and 1970’s held prices below the equilibrium level and caused regional supply shortages. Partial deregulation in 1978 then caused some of the prices to increase to the point of being higher than the market clearing level, and the further deregulation in the 1990’s caused the prices to decline (MacAvoy and Moshkin, 2000). Their model was a simultaneous system of supply and sector demand equations. To determine demand for each sector, they estimated total energy demand for that sector followed by the share attributed to natural gas. They determined supply by first estimating total wells and then estimating additions to reserves. A production-reserve ratio was then estimated in order to determine total production. MacAvoy and Moshkin used their completed model to forecast prices for the 1995-2010 period under two scenarios: continued regulation and deregulation. The price they measured was the "average price of outstanding contracts on which there is production" (MacAvoy and Moshkin, 2000, p 320). In 1995, the regulation scenario predicted prices 60% higher than the deregulation scenario. Over the period, both scenarios predicted a decline in prices as well as a narrowing gap between them. By 2010, prices under the regulation scenario were less than 10% higher than the deregulation scenario. MacAvoy and Moshkin concluded that the negative price effects of regulation were moderated over time (2000).

Natural gas trade is an important part of any natural gas model. A 2009 EIA report by Gaul highlighted some of the key natural gas trade statistics for 2007. According to the report, the U.S. continued to be the largest natural gas importer in terms of volume even though net natural gas imports only accounted for 16% of total domestic consumption. Our largest natural gas trading partner was Canada. In 2007, Canada was the world's largest exporter of natural gas, and nearly all of those exports were destined for the U.S. Gaul indicated that Canadian exports are generally on the decline as they exhaust conventional sources and expand their own demand. Mexico, on the other hand, increased their domestic natural gas production. Thus, U.S. natural gas exports to Mexico declined in 2007. LNG imports were higher in 2007 following the general trend. In 2007, they accounted for only 3.7% of U.S. consumption. Though LNG imports had increased in total, Gaul noted that they were quite low during the second half of 2007 as increased competition from Asia pulled supplies away. He also pointed out that the number of countries from which we import LNG increased from four to six. Trinidad and Tobago supplied 58% of our LNG imports in 2007.

The Baker Institute World Gas Trade Model (BIWGTM) was developed in 2006 to forecast the global flows of natural gas to 2040 (Hartley and Medlock). It was designed to produce regional equilibriums in which arbitrage could no longer occur. This was accomplished by using a dynamic spatial general equilibrium framework. The model determined regional prices, production, and demand as well as capacity expansions in both the LNG and pipeline sectors and reserve growth. The BIWGTM used a two-tiered approach to modeling natural gas demand. Researchers would first estimate the total primary energy demand per capita in each region and then estimate the share of that demand attributed to natural gas. In this way, they could constrain the natural gas share and prevent unrealistic swings in demand forecasts over such a long time period (Hartley and Medlock, 2006). The key assumption of the model was that LNG could be traded like a commodity similar to crude oil. According to Hartley and Medlock, this was likely to occur in the long term (2006). Hartley and Medlock identified three reasons for future growth in natural gas trade. In developing countries like China, India, and Mexico the main drivers are economic growth and "expanding power generation requirements" (2006, p 360). In developed countries, increased natural gas demand can also be attributed to environmental concerns.

Mazighi (2003) explored the future of global LNG trade. At that time, Mazighi did not believe LNG had achieved true globalization. For instance, inter-area trade of LNG accounted for only six percent of total LNG trade in 2002 compared to inter-area crude oil trade accounting for 45% of total crude oil trade that same year (Mazighi, 2003). Also, there were three regional LNG pricing structures in the world. In the U.S., LNG price was determined by the Henry Hub price for pipeline gas. In Asia, it was determined by the import price of oil faced by Japan, and in Europe LNG price was similarly determined by the price of an oil basket imported by European countries. The correlation between pipeline gas trade and LNG trade also indicated a lack of globalization. According to Mazighi, LNG was originally used to supplement pipeline gas rather than compete with it (2003). Thus, their trade patterns were correlated. Finally, LNG trade relied heavily on long-term contracts between producers and consumers.

For LNG to become globalized, Mazighi believed four conditions needed to hold. First, excess supplies needed to exist in endowed regions while excess demands existed in unendowed regions. This condition was naturally met. Also, LNG sales would need to rely on short-term contracts or spot sales. The likelihood of this condition being met was improved by a reduction in the operating costs of liquefying and regasifying natural gas. An increase in both open access and uncommitted capacity would be required. The development of globally organized and liquid markets was the final condition mentioned by Mazighi. He concluded there was no guarantee that the conditions would be met by 2010 (Mazighi, 2003).

LNG's future role in the U.S. natural gas market was also explored by Ruester and Neumann (2008). They believed that LNG will be a critical element in our country's energy future. In 2008, there were only 5 operational LNG handling facilities. There were over 40 in various stages of approval; however, Ruester and Neumann believed it unlikely that all of them would be ultimately approved for construction. Barriers to entry discussed by Ruester and Neumann included public resistance to proposed locations, competition with the existing firms, and being overshadowed by volatile oil prices. Nevertheless, the authors indicated that the U.S. will have to meet increased natural gas demand in the face of declining domestic and Canadian production. They noted that, as domestic sources are exhausted and production costs rise, LNG becomes a more viable option. Ruester and Neumann concluded that the best option now is to invest in capacity.

Related to natural gas and energy markets are fertilizer markets. Trends in fertilizer production, consumption, and trade will have important effects on natural gas demand. This is especially true for nitrogenous fertilizers since natural gas is their main production input. Heffer and Prud'Homme (2008) presented a global fertilizer demand and supply outlook. They reported that growth in global nitrogen demand outpaced phosphorous and potash demand in 2006-07. The growth was expected to continue in the future but at a lower rate. The authors expected developing nations in Latin America as well as South and East Asia to provide 84% of the growth in total fertilizer demand. Heffer and Prud'Homme explained that global nitrogen supplies were tight in 2007 as the growth in demand exceeded growth in production. This situation was exacerbated by the ammonia industry utilizing nearly all of the production capacity. Ammonia and urea trade increased in 2007. The growth rates were 1% and 12% respectively. Export growth for ammonia occurred in the Middle East while China became a larger exporter of urea. The U.S. and Asia were key importers in those two markets.

Huang (2009) examined some of the causes of higher fertilizer prices. Rising energy costs clearly contributed to increased fertilizer prices since natural gas prices and nitrogen prices are closely linked. The cost of transporting fertilizer also increased, thus leading to more expensive fertilizer. This increased transportation cost was not entirely the result of higher fuel costs. It was also a response to the inability of transport supply to meet increased transport demand (Huang, 2009). Another key factor on the supply side was the weakening dollar. The weaker dollar caused fertilizer imports to be more expensive for the U.S. For the rest of the world, it caused exports from the U.S. to be less costly. On the demand side, Huang (2009) reported that global population and economic growth would necessitate increased crop production. Recent surges in commodity prices have also contributed to increased crop production. This increase in crop production would require additional fertilizer.

2.3 Policy effects

FAPRI-MU (2008) presented the effects of certain stipulations called for by the Energy Independence and Security Act (EISA) of 2007 and the Food Conservation and Energy Act (FCEA) of 2008. Specifically, they focused on the EISA's mandated biofuel use levels in addition to the FCEA's provisions regarding biofuel blender tax credits and import tariffs. Three of those scenarios are discussed in this study. The first scenario examined the impacts of allowing the tax credits and tariffs to expire with the EISA policies already in place. In other words, it studied the effects of a shift from current biofuel policies to a policy without tariffs and tax credits. In that scenario, ethanol production declined by 11.9%, and ethanol use of corn declined by 11.6%. Corn area planted decreased by 2.0%.

The second scenario examined the impact of removing the EISA mandates while allowing biofuel tax credits and tariffs at their 2008 levels to be extended indefinitely. Like the first scenario, the current policy baseline was the same. Instead, the policy shift removed only the EISA mandates. The results indicated ethanol production was 20.5% lower, ethanol use of corn was 16.3% lower, and corn area fell 1.7%.

The final scenario analyzed the impact of removing the EISA mandates while allowing the tax credits and tariffs to expire on schedule. Again, the baseline policy scenario was the same, but the shift removed all biofuel policies. In this case, the impact was more pronounced. Ethanol production fell 43%, ethanol use of corn was 39.9% lower, and corn area decreased by 5.5%. An interesting feature of these results, as pointed out in the report, is that they are not strictly cumulative. The results of the first two scenarios did not add up to the results of the third. According to the authors, this occurred as a result of the redundant nature of the policies (FAPRI-MU, 2008). In this third scenario, any redundancies that might have occurred were eliminated. Thus, the effect was even larger.

The authors reported that the effects of the policies are quite dependent on petroleum prices. When oil prices remain relatively low, the mandates bolster otherwise low biofuel production and use (FAPRI-MU, 2008). As oil prices rise, the tariffs and tax credits become increasingly effective.

Wiser and Bolinger (2007) reviewed several prior studies to determine if increased use of renewable energy in the electricity generation sector would apply downward pressure on natural gas prices in the long term. They were motivated by the fact that renewable energy could replace traditional fossil fuels like natural gas in electricity generation, thereby reducing aggregate natural gas demand. Furthermore, this reduction in aggregate demand would, *ceteris paribus*, lower natural gas prices. According to the studies they reviewed, Wiser and Bolinger reported that increased renewable energy use would decrease natural gas demand by a range of 1% to 30% (2007). This reduction in natural gas demand would cause a reduction in U.S. average wellhead prices anywhere from 0% to 50%. Although some of the studies reviewed predicted increased electricity prices, Wiser and Bolinger said that most studies predicted net savings to the consumer. Most of the studies predicted savings in the range of 7.5 to 20 dollars per megawatt hour of renewable energy used. To compare these results with other modeling systems, Wiser and Bolinger calculated the price flexibilities presented by the prior studies. The long-run flexibilities ranged from 0.8 to 2.0. EIA estimates fell within this range because most of the prior studies reviewed by Wiser and Bolinger relied on the EIA's NEMS. Four other energy modeling systems also estimated price flexibilities that fell within that range.

Chapter 3

Conceptual Framework

A model of the natural gas market such as this encompasses the theories of production, consumer demand for final goods, and derived demand for inputs. It is assumed that market participants, whether they are a producer or a consumer, act in a rational manner. This implies that producers seek to maximize their profit or, by duality, minimize their cost of producing a given level of output. For a well-behaved, single-output production technology, the profit maximization problem can be set up as:

$$\text{Max}_{\{\mathbf{x}\}}\ \pi(p, \mathbf{w}; \mathbf{x}) = pf(\mathbf{x}) - \mathbf{w}\cdot\mathbf{x}, \ \text{ s.t. } \mathbf{x} \geq \mathbf{0}. \qquad (3.1)$$

In this equation,

p is the output price,

w is a vector of input prices,

f(**x**) is a general production function, and

x is a vector of inputs.

The first order conditions (FOCs) take the form of:

$$pf_i(\mathbf{x}) - w_i = 0, \text{ for } i = 1, 2, \ldots, n. \qquad (3.2)$$

Here,

$f_i(\mathbf{x})$ is the marginal product for input *i* and

w_i is the marginal “wage” for input *i*.

The necessary second order condition (SOC) for maximization is a negative semidefinite Hessian matrix. It is assumed to hold in this model.

(3.2) forms a system of *n* equations with *n* unknowns. Solving this system yields the optimal input vector, $\mathbf{x}^*(p, \mathbf{w})$. The elements within this vector are the optimal demands for each input. When modeling the market for a particular good, these input demands should be accounted for on the demand side. In that context, they are known as derived demands since the overall demand for a good is derived, in part, from the demand for the final product produced by that good (Tomek and Robinson, 2003).

The rational behavior assumption for consumers implies they minimize their expenditure to achieve a given level of utility or maximize their utility subject to a budget constraint. For a well-behaved consumption set and preference ordering, the constrained expenditure minimization problem can be expressed as:

$$\mathrm{Min}_{\{\mathbf{x}\}}\ L(\mathbf{x}, \lambda; \mathbf{p}, u) = \mathbf{p}\cdot\mathbf{x} - \lambda[u(\mathbf{x}) - u], \text{ s.t. } \mathbf{x} \geq \mathbf{0}. \qquad (3.3)$$

The variables are defined as follows:

$\mathbf{x}$ is the commodity bundle,

$\mathbf{p}$ is a vector of commodity prices, and

$u(\mathbf{x})$ is the consumer's utility function.

The FOCs in this case are:

$$p_i - \lambda u_i(\mathbf{x}) = 0, \text{ for } i = 1, 2, \ldots, n \text{ and} \qquad (3.4)$$

$$u(\mathbf{x}) - u = 0.$$

Here,

p_i is the price of commodity *i* and

$u_i(\mathbf{x})$ is the marginal utility for commodity *i*.

The necessary SOC for constrained minimization is a positive semidefinite Hessian matrix. Again, the SOC is assumed to hold in this model.

Functional form specification is an integral part of developing a useful model. Many functional forms are associated with a unique set of benefits. However, many of those benefits also have an associated cost. Choosing the wrong specification can impose unrealistic assumptions on the model and can lead to biased, inconsistent estimators. For instance, a researcher who desires quick and easy elasticity measures might be tempted to choose the log-log form, but the log-log form does not allow those elasticities to vary. Such an assumption can be a problem in some circumstances. Thus, the researcher should be aware of the implications of choosing one particular functional form over another.

Zarnikau (2003) tested the performance of three common parametric functional forms used to model energy demand. The linear, log-log, and translog forms were tested. To test them, Zarnikau used the Nadarya-Watson smoothing technique to obtain non-parametric estimates for cross-sectional electricity demand. These estimates were assumed to represent the actual relationship. Zarnikau calculated the proportion of parametric estimates falling within a 95 percent confidence interval around the non-parametric estimates. The linear form performed the best with 29.3% of the estimates within range, and the translog form performed the worst with only 10.3% within range. Zarnikau noted that poor parametric performance (i.e. low R^2 values) to begin with may have been partly responsible for the results (2003). Also, a time series analysis might have improved the parametric forms' performance, but the smaller sample size would have prevented a non-parametric comparison.

Estimation procedures should also be chosen carefully. In a simultaneous system, ordinary least squares (OLS) estimation generally results in simultaneity bias (Wooldridge, 2006). The bias is the result of the correlation between an endogenous explanatory variable and the error term of a dependent variable it is trying to explain. Researchers have a couple of choices in situations such as this. They can continue with OLS estimation and try to determine the magnitude and direction of the bias, or they can use a different estimation procedure. In all but the simplest simultaneous models, the first option will be too complicated. Thus, choosing another estimation procedure is considered more appropriate.

Two-stage least squares (2SLS) is a common estimation procedure for simultaneous systems. It combines the use of instrumental variables with OLS in a two-step process, hence the name. The first stage involves specifying the reduced-form equation for each of the endogenous explanatory variables in the system by making them functions of the strictly exogenous variables. The predicted values are obtained through OLS estimation and are uncorrelated with the original error term. In the second stage, the original values of the endogenous explanatory variables are replaced with the predicted values obtained in the first stage. Thus, the predicted values act as instrumental variables, and the resulting equations can be estimated with the OLS procedure. Assuming the Gauss-Markov conditions hold, these estimates are consistent and asymptotically efficient.

The flow diagram of this model can be seen in Figure 3.1. There are four direct elements and one indirect element of natural gas supply. The direct elements are domestic natural gas production, natural gas imports, withdrawals from storage, and supplemental fuels. The first three direct elements are self-explanatory, but supplemental fuels needs clarification. Supplemental fuels are synthetic or otherwise unrelated fuels "injected for Btu stabilization…and distributed with natural gas" (EIA, 2008(a), p136). The indirect element of natural gas supply included in this model is net nitrogen fertilizer imports. Since natural gas is such an important input in nitrogenous fertilizer production, nitrogen fertilizer imports can be viewed as an indirect supply of natural gas. This becomes increasingly important if there are low natural gas prices compared to the U.S. in areas that export little natural gas to the U.S. In that situation, U.S. fertilizer production is replaced by fertilizer imports. The net nitrogen imports are expressed in natural gas equivalents.

Natural gas demand is divided into seven sectors: residential, commercial, industrial, electric, transportation, exports, and additions to storage. For this model, industrial demand is broken down into corn production use including the natural gas equivalent of nitrogenous fertilizer, ethanol production use, and other crop use of nitrogenous fertilizers, also expressed in natural gas equivalents. This is possible because industrial natural gas demand includes agricultural uses. Any excess fertilizer demand by crop production will be balanced on the supply side by net nitrogen imports. The remaining industrial demand is combined with transportation use for reasons to be discussed in the next chapter. The wellhead price is used as the reference price.

Additionally, the model will determine the delivered prices for each sector.

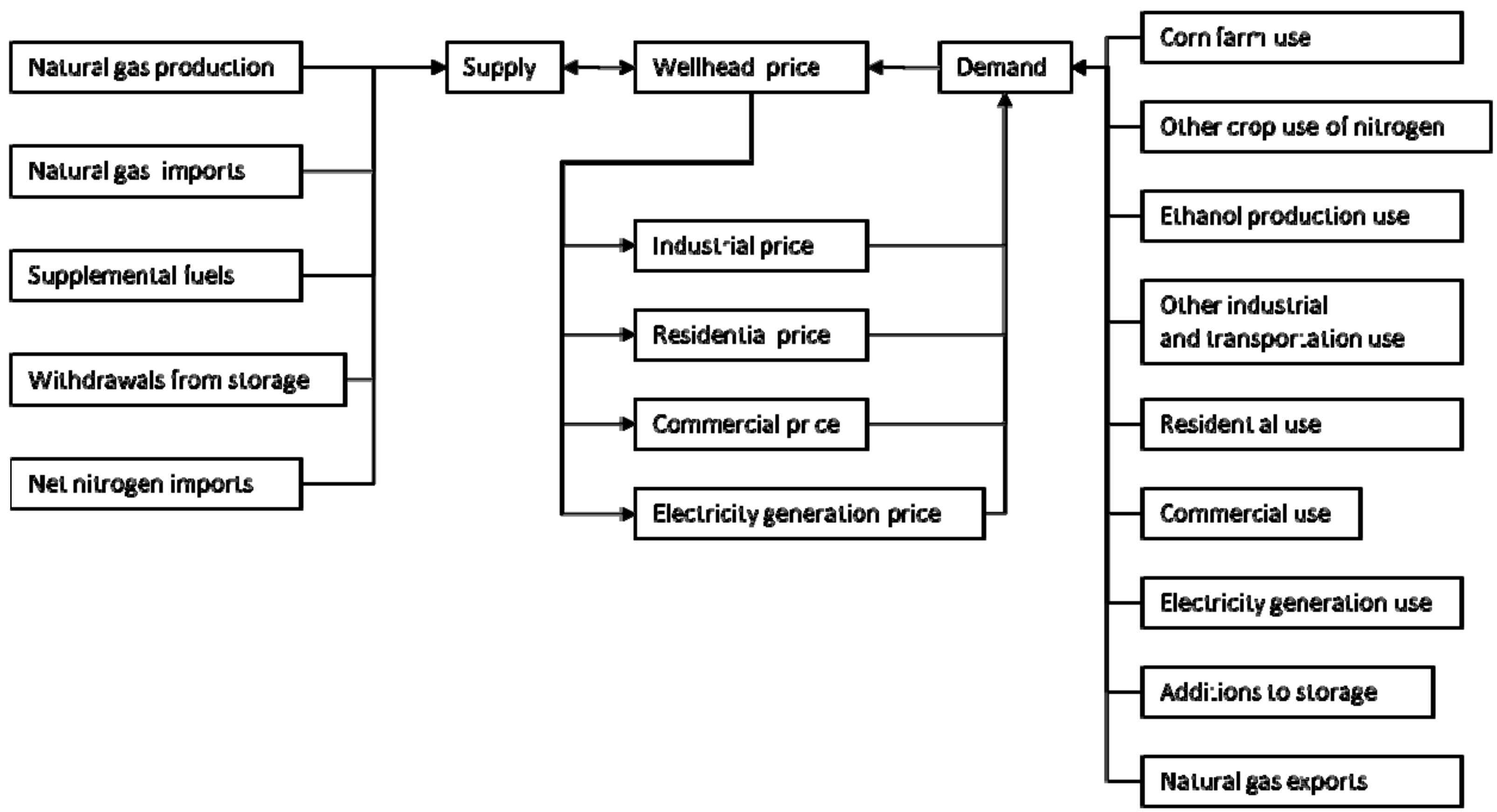

Figure 3.1 Flowchart of the natural gas market

Chapter 4

Methods and Procedures

4.1 Data description

All of the data used in this study were secondary data gathered on an annual basis from a variety of sources. They covered the period from 1984 to 2015. Supply and demand measures as well as prices and operating costs for natural gas and other forms of energy were retrieved from the Energy Information Administration (EIA). The EIA's *Annual Energy Review 2007* (AER 2007) provided the historical data. The 2008 *Annual Energy Outlook* (AEO 2008) provided the forward looking data to 2015. The EIA also reported the Gross Domestic Product (GDP) and domestic population statistics. The 2008 FAPRI Baseline provided the data for crop and ethanol production as well as the producer price index. The nitrogen fertilizer data were supplied by the Economic Research Service (ERS) and the U.S. International Trade Commission (USITC).

The natural gas section of the AER 2007 provided data for the 1984-2006 period. The data gathered included consumption by sector, nominal prices by sector, production, imports, and exports. Data for supply and demand were measured in billions of cubic feet (Bcf). Nominal prices were measured in dollars per thousand cubic feet ($/Mcf). The coal and electricity sections of the AER 2007 provided the related cross-price data. The coal data were reported in dollars per short ton ($/st), and they were not converted to other units. The residential and commercial retail electricity prices were converted from cents per kilowatt-hour, as the EIA reported them, to dollars per kilowatt-hour ($/Kwh). Macroeconomic data including U.S. population, real and nominal GDP, and the GDP deflator were obtained from Appendix D in the AER 2007. Population was reported in millions of people. The GDP numbers were reported in billions of dollars. The base year for real GDP was 2000. The No. 2 distillate fuel oil retail price was retrieved from the Petroleum Navigator on the EIA's main website (http://tonto.doe.gov/dnav/pet/pet_pri_refoth_dcu_nus_m.htm). For this study, it was converted from cents per gallon to dollars per gallon ($/gal).

The reference-case scenario in the AEO 2008 reported the EIA's forecast of these same data out to 2030. However, only the forecasted data to 2015 were required for this study. Nominal prices for natural gas were still listed in $/Mcf, and were forecasted by the EIA to decline. The other supply and demand data were given in trillion cubic feet (Tcf), so they were converted to Bcf. The EIA projected the natural gas supply and demand data, including production and imports, to increase.

A discrepancy measure was forecasted in the AEO 2008, but the withdrawals and additions to storage were not. The discrepancy measure captured the difference between forecasted supply and demand. To maintain consistency across the historical and forecasted time periods, the historical net additions to storage and the balancing adjustments were used to calculate a historical discrepancy measure.

A 2007 report containing natural gas lease and operating costs was available in the Natural Gas Navigator (http://tonto.eia.doe.gov/dnav/ng/ng_pub_publist.asp). The data were provided for the period beginning in 1988. A price index was also provided for years prior to 1988. This index was used to calculate the costs for those years. The costs were reported on an annual basis per well. They were organized by daily production capacity per well and drill depth, including an average cost over all drill depths. To simplify the cost calculations, the average daily production capacity per well was calculated using data from the AER 2007. In 1984, the daily capacity per well was 204.63 Mcf per day (Mcf/day). By 2006, average daily capacity had fallen to 114.908 Mcf/day. There was one cost series for wells averaging 50 Mcf/day and one series for wells averaging 250 Mcf/day. This study used the latter series.

Real prices and costs were obtained by using one of two possible deflators. The producer price index (PPI) deflated prices and costs in the natural gas production equation on the supply side. The price variable in the export and import equations was deflated by the gross domestic product deflator (GDPD) for the United States. The price variables in the other demand sectors were real in that the nominal natural gas prices were deflated by the nominal price of a competing form of energy.

Nitrogen data were gathered from two different sources. Nitrogen use amounts by crop and nitrogen exports were retrieved from the USDA's Economic Research Service (ERS). Export quantities were reported in short tons. Nitrogen use was reported in units of 1000 nutrient tons. Nitrogen import data was obtained from the U.S. International Trade Commission (USITC). The USITC's DataWeb service reported the import quantities back to 1989. Import quantities were in metric tons. To be of use in this model, all of the nitrogen data needed to be converted to natural gas equivalents. The first step in that process was to convert the ERS nitrogen export data from short tons of fertilizer to metric tons of nitrogen. After converting the export data to metric tons, the net nitrogen imports were calculated. The net import data were then backcast to 1985 using the results of a simple OLS regression of net nitrogen imports as a function of industrial natural gas price. The natural gas requirement of 51.81 GJ/mt reported by Bhat et al. (1994) was used to convert net nitrogen imports and nitrogen use by crops to natural gas equivalent in units of Bcf.

The ERS also provided the real GDP data for Canada and Mexico. The data were reported in billions of dollars, and the base year was 2005.

Ethanol production and corn planted acres data were obtained from the 2008 FAPRI Baseline. Ethanol production data were reported in millions of gallons, and corn planted acres data were reported in millions of acres. Before the ethanol production data could be used as an input in the Biofuel and Energy System Simulator (BESS), it needed to be converted to metric units. Thus, ethanol production was converted from millions of gallons to millions of liters.

BESS is a spreadsheet tool that operates in a manner similar to Microsoft Excel. Computations within the simulator are performed with a set of user-defined or default parameters. At the farm level, these parameters specify corn production practices such as input usage, irrigation, and assumed yield. Parameters at the ethanol production level identify the amount of ethanol produced, assumed ethanol yield, energy source(s), and type and amount of co-products sold. BESS uses the metric system of measurement for both input parameters and output. The standard natural gas use parameters listed in the BESS user guide are, after converting to English units, approximately 3051 cubic feet per acre (assuming 125 bu/acre is 25,145 Btu/bu) of corn produced and 27, 591 Btu per gallon of ethanol produced (Liska et al., 2009(b), p 41). These estimates are comparable to those found in the literature for current corn growing practices and state-of-the-art ethanol facilities selling around half of their co-products as DDGS. The data for ethanol and corn production uses of natural gas were calculated in BESS using those standard assumptions. The output listed energy use by source for both corn and ethanol production.

4.2 Model description

The model was a structural equations model. It was estimated over the 1985-2006 period, and a baseline projection for the 2007-2015 period was also determined. Shocks representing future policy effects were then introduced. The resulting forecasts were compared to the baseline projection. Deviations from the baseline scenario will be studied and discussed in a later chapter.

On the supply side, there were equations that estimated natural gas production and natural gas imports. Net nitrogen fertilizer imports represented an indirect source of natural gas. The EIA did not include this indirect source as a part of their natural gas supply numbers. However, much of the natural gas use in corn production is in the form of nitrogen fertilizer. The U.S. has been a major net importer of nitrogen fertilizer for the estimation period of this model. Therefore, net nitrogen fertilizer imports were included. This model assumed they were exogenous. Supplemental fuels represented a small amount of total supply and were exogenous.

Demand sectors representing residential, industrial, commercial, and electricity-generation were estimated in this model. The transportation demand sector is quite small and consists mainly of natural gas used for the distribution of other natural gas. While transportation use is not the same as industrial use, this model combined the two sectors in order to preserve the number of observations. Natural gas exports were also estimated in this model. Ethanol and corn demands for natural gas were removed from the industrial demand measures and were exogenous. Demand for nitrogen fertilizer by crops other than corn was also removed from the industrial demand amount and was exogenous. This variable was included to offset the net nitrogen imports on the supply side. The discrepancy measure was exogenous as well. Variable names, units, and sources are included in Appendix A.

4.2.1 Natural gas demand

Rather than estimate total natural gas demand for the residential sector, this model estimated per capita residential demand. Per capita residential demand is simply total residential demand in cubic feet divided by total population. The per capita residential demand equation was specified as the following:

NGDRESPCUS = *f*(NGPRESUS/ELPRESUS, RGDPPCUS, NGDRESPCUS(t-1), TREND). (4.1)

Per capita residential demand for natural gas was represented as a function of the ratio of residential natural gas and residential electricity prices, real per capita GDP, lagged per capita residential natural gas demand, and a linear trend variable. The own-price effect was expected to be negative. The cross-price effect of the residential electricity price was expected to be positive, *ceteris paribus*, indicating that the two forms of energy would be substitutes in the residential sector. The effect of per capita GDP was expected to be positive.

Industrial and transportation demand for natural gas excluding demand by crop and ethanol production was represented as follows:

NGDOINDUS = *f*(NGPINDUS/DFPUS, RGDPUS, NGDOINDUS(t-1)). (4.2)

Industrial and transportation demand was specified as a function of the price ratio of industrial natural gas and distillate fuel oil, real GDP, and lagged industrial and transportation demand. The effect of the industrial natural gas price was expected to be negative, and the effect of the distillate fuel price was expected to be positive. The income effect of GDP was expected to be positive as well.

The natural gas demand equation for the commercial sector took a form similar to the previous demand equations.

NGDCOMUS = *f*(NGPCOMUS/ELPCOMUS, NGDCOMUS (t-1), TREND). (4.3)

Commercial natural gas demand was represented as a function of the ratio of the commercial natural gas price and the commercial electricity price, lagged commercial demand, and a trend variable. The own- and cross-price effects of the commercial natural gas price and commercial electricity price were expected to be negative and positive, respectively.

Electricity demand for natural gas had the following form:

NGDELUS = *f*(NGPELUS/CLPUS, NGDELUS(t-1), TREND). (4.4)

It was a function of the ratio of the electricity-generation natural gas price and the average U.S. coal price, lagged electricity-generation demand for natural gas, and trend. The electricity-generation price was expected to have a negative own-price effect. The coal price was expected to have a positive cross-price effect.

Natural gas exports were represented as follows:

NGDEXPUS =*f*(NGRPWHDUS, RGDPCA, RGDPMX, NGDEXPUS(t-1), TREND). (4.5)

Exports were a function of the natural gas wellhead price deflated by the U.S. GDP deflator (GDPD), Canada's real GDP, Mexico's real GDP, lagged exports, and a trend variable. The effect of the real natural gas wellhead price was expected to be negative.

Ethanol, corn, and other crop demands for natural gas were three exogenous demands in this model. This is beneficial because it will allow this model to be linked to a larger model, such as the FAPRI model, in the future. The scenario analyses discussed later will involve shocks to the variables representing ethanol and corn demands for natural gas.

4.2.2 Natural gas supply

Natural gas production had the following representation:

NGSPRUS = *f*(NGRPWHDUS, NGRPRCUS, NGSPRUS(t-1)). (4.6)

Natural gas production was a function of the wellhead natural gas price deflated by the PPI, real production costs, and lagged production. The effect of real wellhead price was expected to be positive, and the effect of the production cost was expected to be negative.

Natural gas imports were specified as follows:

NGSIMPUS = *f*(NGRPWHDUS, RGDPCA, NGSIMPUS(t-1), TREND). (4.7)

Imports were a function of the wellhead price deflated by the U.S. GDPD, real Canadian GDP, lagged imports, and a trend variable. The effect of real wellhead price was expected to be positive. This specification is similar to the export equation. However, real Mexican GDP was excluded here because less than 2% of U.S. natural gas imports originate in Mexico. Indeed, the EIA reported that the U.S. did not import any natural gas from Mexico for ten years during the estimation period (Annual Energy Review 2007, 2008(b)).

Net nitrogen imports represented an indirect supply of natural gas. They were exogenous to this system. Supplemental fuels were also exogenous.

4.2.3 Natural gas prices

The price for each demand sector was represented as a function of the nominal wellhead price for natural gas, and a trend variable. The residential, industrial, commercial, electricity-generation, and nitrogen price equations appear in that order below.

NGPRESUS = *f*(NGPWHDUS, TREND). (4.8)

NGPINDUS= *f*(NGPWHDUS, TREND). (4.9)

NGPCOMUS = *f*(NGPWHDUS, TREND). (4.10)

NGPELUS = *f*(NGPWHDUS, TREND). (4.11)

In each case, the effect of the wellhead price was expected to be positive.

4.2.4 Natural gas market clearing identities

The model solved for the natural gas wellhead price by closing on natural gas imports. The following market clearing identity was used.

NGSPRUS + NGSIMPUS + NGSSFUS + NTNIMPUS = NGDTCONUS + NTDOTUS + NGDEXPUS + NGDDISCUS. (4.12)

The sum of natural gas production, imports, supplemental fuels, and net nitrogen imports equals the sum of total natural gas consumption, nitrogen demand by crops other than corn, natural gas exports, and the discrepancy measure.

Total natural gas consumption was calculated as the sum of each sector's demand as well as ethanol and corn production demands for natural gas. This also involved multiplying the per capita residential demand by the total population in billions to get total demand for the residential sector. The identity appears below.

NGDTCONUS = NGDRESPCUS*(POPUS/1000) + NGDOINDUS + NGDCOMUS + NGDELUS + NGDETUS + NGDCRUS. (4.13)

The discrepancy measure refers to the difference between the net change in natural gas storage and the balancing adjustment. The balancing adjustment is used by the EIA to account for differences occurring as the result of "converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merging of different data reporting systems" (EIA, 2008(a), p 185). The calculation of the discrepancy measure is shown below.

NGDDISCUS = NGDADUS – NGSWDUS – NGBALUS. (4.14)

Chapter 5

Empirical Results

The model was estimated using the MODEL procedure in the SAS System. The estimation method was two-stage least squares (2SLS) with a heteroskedasticity consistent covariance matrix estimator (HCCME). The strictly exogenous variables were used as instruments in the first stage of estimation. Second-stage coefficient estimates were estimated for the period 1985 to 2006, and these estimates were used to develop a baseline projection for the period 2007 to 2015.

5.1 Estimation results

The estimation results for the demand equations are summarized Table 5.1, and results for the production and price equations are summarized in Table 5.2. Statistical significance was determined using a one-sided *t*-test for the price variables and a two-sided *t*-test for all other variables. Serial correlation was tested by one of three methods. In the presence of lagged dependent variables, the ordinary Durbin-Watson test is invalid. Therefore, equations containing lagged dependent variables were tested using the Durbin-h test, or when the h-statistic could not be calculated the Durbin-t test was used. Equations without lagged dependent variables were tested using the regular Durbin-Watson test.

Table 5.1 2SLS results for demand equations

	Estimate	*t*-score	p-value (two-sided)	p-value (one-sided)
Per capita residential demand				
Intercept	15517.23	2.79	0.0121	
Natural gas – electricity price ratio	-40.549	-2.60	0.0180	0.0090
Real per capita GDP	0.04			
Lagged dependent	0.304068	1.14	0.2697	
Trend	-18.0214	-0.38	0.7085	
	Durbin-h = -0.6125	p-value = 0.2701		
Industrial demand				
Intercept	1297.467	1.12	0.2783	
Natural gas – distillate oil price ratio	-182.17	-1.38	0.1826	0.0913
Real GDP	0.04			
Lagged dependent	0.89831	8.99	<0.0001	
	Durbin-h = 1.3524	p-value = 0.0881		
Commercial demand				
Intercept	1623.215	3.59	0.0021	
Natural gas – electricity price ratio	-7.21471	-5.91	<0.0001	<0.00005
Lagged dependent	0.500411	2.57	0.0193	
Trend	32.968	3.85	0.0012	
	Durbin-h = 0.2629	p-value = 0.3963		
Electricity-generation demand				
Intercept	958.1943	1.56	0.1372	
Natural gas – coal price ratio	-420.161	-0.31	0.7581	0.37905
Lagged dependent	0.536715	1.79	0.0897	
Trend	90.31847	2.30	0.0336	
	Durbin-h = 0.4622	p-value = 0.3220		
Export demand				
Intercept	-643.429	-1.85	0.0833	
Real wellhead price	-23.1543	-0.70	0.4929	0.24645
Real GDP (Canada)	1.107355	1.90	0.0754	
Real GDP (Mexico)	-0.06004	-0.06	0.9566	
Lagged dependent	0.842258	4.57	0.0003	
Trend	-16.8011	-1.05	0.3100	
	Durbin- t = 1.1671	p-value = 0.1276		

Per capita residential demand for natural gas was estimated as a function of a price ratio of own- and cross-prices as well as real per capita GDP, a lagged dependent variable, and a trend variable. The coefficient estimate for the price ratio was -40.55, and it was statistically significant at the 1% level. The interpretation of this estimate is that a marginal increase in the ratio of residential natural gas and electricity prices will reduce per capita residential natural gas demand by 40.55 cubic feet (cf), *ceteris paribus*. Since the variable is a ratio, this marginal increase could occur in one of two ways. Residential natural gas prices could increase relative to residential electricity prices, or residential electricity prices could decrease relative to residential natural gas prices. Clearly, this convention requires the two price variables to have equal but opposite effects on per capita residential demand. In this case, the own-price effect is negative, and the cross-price effect is positive. These effects are appropriate according to economic theory.

A RESTRICT statement was used to impose a coefficient value of 0.04 on the real per capita GDP explanatory variable. Prior to the restriction, the estimated value was less than zero. Such a value implied that natural gas was an inferior good, and that implication was not supported by the literature. The value 0.04 was chosen so that the real income elasticity measure would be an appropriate magnitude. Elasticity measures will be discussed in greater detail in a later section.

The lagged dependent variable was predicted to have a positive marginal effect, and the marginal effect of the trend variable was estimated to be negative. The values of the coefficients were 0.30 and -18.02, respectively. In other words, a marginal increase in per capita residential natural gas demand in the prior year would, *ceteris paribus*, increase current per capita residential demand by 0.30 cf. While it was not statistically significant, this estimate had the sign and approximate magnitude supported by theory. The estimated coefficient on the trend variable suggests per capita residential would decrease by 18.02 cf each year, *ceteris paribus*. This coefficient estimate was not statistically significant.

Industrial demand for natural gas was specified as a function of an industrial natural gas to distillate fuel oil price ratio, real GDP, and lagged industrial demand. The marginal effect of the price ratio was estimated to be -182.17. All else held constant, a marginal increase in the price ratio would decrease industrial natural gas demand by 182.17 billion cubic feet (Bcf). Again, the effects of each price variable independent of the other are equal but opposite. Although this estimate had the expected sign according to theory, it was not statistically significant.

As in the residential demand equation, the coefficient for real GDP was less than zero prior to using a RESTRICT statement. In this case, an estimate of 0.04 was also chosen. The effect of the lagged dependent variable was estimated to be 0.90. This means that a marginal increase in industrial demand in the period *t-1* will increase industrial demand in period *t* by 0.90 Bcf, *ceteris paribus*. It was positive and less than unity as expected by theory. This estimate was statistically significant at the 1% level.

Commercial demand for natural gas was estimated as a function of the price ratio between commercial natural gas and commercial electricity prices, a lagged dependent variable, and a trend variable. The marginal effect of the price ratio was estimated to be -7.21. Thus, a marginal increase in the price ratio would, *ceteris paribus*, decrease commercial natural gas demand by 7.21 Bcf. The effect of commercial natural gas price was negative, as expected. The effect of commercial electricity price was positive. The estimate of this coefficient was statistically significant at the 1% level.

The coefficient of the lagged commercial demand variable was estimated to be 0.50. If other variables are held constant, a marginal increase in lagged commercial natural gas demand will increase current commercial natural gas demand by 0.50 Bcf. As expected, it was positive and less than unity. The estimate was statistically significant at the 5% level. The trend variable had an estimated coefficient of 32.77. Thus, commercial natural gas demand was expected to increase by 32.87 Bcf each year, all else held constant. It was statistically significant at the 1% level.

Natural gas demand by the electricity generation sector was estimated as a function of the delivered natural gas price for the electricity generation sector deflated by the coal price, a lagged dependent variable, and a trend variable. The estimated coefficient for the price ratio was -420.16. A marginal increase in the price ratio will reduce natural gas demand by the electricity generation sector by an estimated 420.16 Bcf, *ceteris paribus*. Although it had the correct sign, the estimate was not statistically significant.

The lagged dependent variable had an estimated coefficient of 0.54. Therefore, a marginal increase in the prior year's electricity sector natural gas demand would, all else equal, increase the current year's demand by 0.54 Bcf. The estimate was statistically significant at the 10% level but not the 5% level. The estimated coefficient for the trend variable was 90.32. Each year, natural gas demand by the electricity generation sector is estimated to increase by 90.32 Bcf, *ceteris paribus*. The estimate was statistically significant at the 5% level.

The export demand equation was estimated as a function of the wellhead price for natural gas deflated by the U.S. GDP deflator, the real GDP of Canada, the real GDP of Mexico, and a lagged dependent variable. The marginal effect of the real wellhead price variable was estimated to be -23.15. Holding the other variables constant, a marginal increase in the real wellhead price of natural gas will reduce export demand for natural gas by 23.15 Bcf. This estimate was not statistically significant.

The coefficient for real Canadian GDP was estimated to be 1.11, and the coefficient estimate for real Mexican GDP was -0.06. A marginal increase in Canada's GDP would result in 1.11 Bcf of additional export demand, *ceteris paribus*. A marginal increase in Mexico's GDP was estimated to reduce export demand by 0.06 Bcf, all other variables constant. Neither of these coefficients was statistically significant at the 5% level.

The marginal effect of the lagged dependent variable was estimated to be 0.84. Thus, an increase in natural gas export demand during the prior year will increase current export demand by 0.84 Bcf. This estimate was statistically significant at the 1% level. The trend variable had an estimated coefficient of -16.80. If all other variables were held constant, export demand would decrease by 16.80 Bcf each year. The estimate was not statistically significant.

The natural gas production equation was estimated as a function of the wellhead natural gas price deflated by the producer price index (PPI), total real operating costs, and a lagged dependent variable. The coefficient for real operating costs was estimated to be -19.87, and it was statistically significant at the 1% level. A marginal increase in real operating costs is estimated to decrease natural gas production by 19.87 Bcf. The coefficients for real wellhead price and lagged dependent variables were restricted in this equation to be 200 and 0.9, respectively. Again, the restrictions were used to impose theoretically sound elasticities.

Table 5.2 2SLS results for the production and price equations

	Estimate	*t*-score	p-value (two-sided)	p-value (one-sided)
Production				
Intercept	3124.707	5.12	<0.0001	
Real wellhead price	200			
Real operating costs	-19.866	-2.81	0.0109	0.00545
Lagged dependent variable	0.9			
	Durbin-h = 1.4175	p-value = 0.0782		
Imports				
Intercept	3233.117	4.41	0.0003	
Real wellhead price	190			
Real GDP (Canada)	-5.33934	-4.39	0.0004	
Lagged dependent	0.631134	1.90	0.0733	
Trend	179.8575	2.34	0.0312	
	Durbin-h = -0.6018	p-value = 0.2737		
Residential price				
Intercept	3.228766	13.96	<0.0001	
Wellhead price	1.170959	8.67	<0.0001	<0.00005
Trend	0.066922	4.36	0.0003	
	Durbin-Watson = 1.7425	p-value = 0.1338		
Industrial price				
Intercept	1.23969	24.96	<0.0001	
Wellhead price	1.068694	38.72	<0.0001	<0.00005
Trend	-0.0213	-3.86	0.0011	
	Durbin-Watson = 1.6596	p-value = 0.0882		
Commercial price				
Intercept	2.596079	13.72	<0.0001	
Wellhead price	1.17492	10.48	<0.0001	<0.00005
Trend	0.029824	2.23	0.0378	
	Durbin-Watson = 1.9885	p-value = 0.3459		
Electricity-generation price				
Intercept	0.553957	8.14	<0.0001	
Wellhead price	1.134198	35.57	<0.0001	<0.00005
Trend	-0.02455	-2.58	0.0185	
	Durbin-Watson = 1.8700	p-value = 0.2302		

Natural gas imports were estimated as a function of the wellhead natural gas price deflated by the U.S. GDP deflator, Canada's real GDP, lagged natural gas imports, and a trend variable. The coefficient for real wellhead price was restricted to be 190 for the same reason restrictions were made in other equations. Real Canadian GDP had an estimated coefficient of -5.34, and it was significant at the 1% level. A marginal increase in that variable would decrease U.S. natural gas imports by 5.34 Bcf. The estimated coefficient for the lagged dependent variable was 0.63, and the coefficient for the trend variable was estimated to be 179.86. The latter estimate was statistically significant at the 5% level while the former was not.

All of the delivered price equations were estimated as a function of the wellhead price and a trend variable. The coefficient estimates for the wellhead price in each equation were positive. They ranged from 1.07 in the industrial price equation to 1.17 in both the residential and commercial price equations. The estimated wellhead price coefficient in the electricity generation price equation was 1.13. Each one was statistically significant at the 1% level. Thus, a marginal increase in the wellhead price of natural gas would, *ceteris paribus*, increase the delivered price by 1.07 dollars in the industrial sector, 1.17 dollars in the residential and commercial sectors, and 1.13 dollars in the electricity generation sector.

The coefficients of the trend variables for the residential and commercial price equations were 0.07 and 0.03, respectively. All else equal, residential and commercial prices were estimated to increase by 0.07 and 0.03 dollars. The coefficients for both the industrial and electricity generation sectors were -0.02. It was estimated that the industrial and electricity generation prices would decrease by 0.02 dollars each year, *ceteris paribus*. All four trend estimates were significant at the 5% level, and the estimates for the residential and industrial price trends were also significant at the 1% level.

5.2 Elasticity estimates

Table 5.3 presents the estimated-own price and cross-price elasticities of demand as well as the estimated real income elasticities using period averages. Table 5.4 presents the endpoint elasticity estimates. Estimates for both the short- and long-runs are included as well as estimates using period averages and endpoints. The tables also present the short- and long-run own-price elasticities of production and imports.

The short-run own-price elasticities of demand using period averages were inelastic for every sector. They ranged from -0.02 for electricity generation demand to -0.24 for export demand. These elasticities appear to be similar to those found in the literature. The endpoint elasticities showed a larger range, but each short-run estimate remained inelastic. As expected, both types of estimates became more elastic in the long run. The long-run elasticities using the period averages ranged from -0.04 for electricity generation demand to -1.55 for export demand. The range was slightly narrower for the endpoint elasticities.

The cross-price elasticity estimates in the demand equations were the same in magnitude as the own-price estimates, but they were opposite in direction. The use of a price ratio as an explanatory variable rather than separate own- and cross-prices in the demand equations forced this condition to hold. As a result, the cross-price elasticity estimates revealed substitute relationships between natural gas and each competing good represented.

Table 5.3 Period average elasticity estimates

	Own Price		Cross Price		Real Income	
	Short Run	Long Run	Short Run	Long Run	Short Run	Long Run
Per capita residential demand	-0.1939	-0.2786	0.1939	0.2786	0.0715	0.1028
			Res. Electricity Price			
Industrial demand	-0.1082	-1.0611	0.1082	1.0611	0.04	0.3945
			Distillate Fuel Price			
Commercial demand	-0.2063	-0.4126	0.2063	0.4126		
			Com. Electricity Price			
Electricity-generation demand	-0.0173	-0.0374	0.0173	0.0374		
			Coal Price			
Exports	-0.2442	-1.5454				
Production	0.0241	0.241	-0.0898	-0.898		
			Production Costs			
Imports	0.2021	0.5477				
Residential price	0.4524					
Industrial price	0.7623					
Commercial price	0.5326					
Electricity-generation price	0.9357					

Note: Long-run elasticity estimates were derived by the following formula:
(short-run elasticity estimate)/(1-lagged dependent coefficient estimate)

In the case of per capita residential and industrial natural gas demands, short-run real income elasticities of 0.07 and 0.04 were assumed for each sector, respectively. Estimating the equations without the restrictions led to negative real income elasticity estimates. Such estimates were not supported by the literature. Intuitively, it seemed unreasonable to describe natural gas as an inferior good. Given the assumed short-run elasticities, the long-run real income elasticities were calculated to be 0.10 for the residential sector and 0.39 for the industrial sector. The endpoint elasticity estimates were slightly higher for both the short- and long-runs.

Table 5.4 Endpoint elasticity estimates

	Own Price		Cross Price		Real Income	
	Short Run	Long Run	Short Run	Long Run	Short Run	Long Run
Per capita residential demand	-0.3471	-0.498	0.3471	0.498	0.1036	0.1490
			Res. Electricity Price			
Industrial demand	-0.0908	-0.8898	0.0908	0.8898	0.06	0.5884
			Distillate Fuel Price			
Commercial demand	-0.3226	-0.6452	0.3226	0.6452		
			Com. Electricity Price			
Electricity-generation demand	-0.0191	-0.0412	0.0191	0.0412		
			Coal Price			
Exports	-0.1839	-1.1639				
Production	0.0389	0.389	-0.1427	-1.427		
			Production Costs			
Imports	0.2296	0.6222				
Residential price	0.545					
Industrial price	0.8688					
Commercial price	0.6272					
Electricity-generation price	1.021					

Note: Long-run elasticity estimates were derived by the following formula:
(short-run elasticity estimate)/(1-lagged dependent coefficient estimate)

Without the restriction, the estimate of the short-run own-price elasticity of production would have been negative. The own-price coefficient value of 200 was chosen because a period average elasticity of 0.02 was assumed. This value is about one-third the value of Krichene's 2002 estimate using the error correction model (ECM). The long-run elasticity was calculated to be 0.24 with the assumed short-run elasticity. The end point elasticity estimates were 0.04 in the short-run and 0.39 in the long-run.

There was also an own-price elasticity assumed for imports. Here, the short-run elasticity was assumed to be 0.20 for the period average and 0.23 at the endpoint. An examination of natural gas import and export data revealed that a relatively higher percentage of imports are in the form of liquefied natural gas (LNG). Because LNG trade tends to rely on longer term contracts (Mazighi, 2003), this study assumed that imports would be slightly less responsive to prices in the short-run than exports. The long-run own-price elasticity was estimated to be 0.55 for the period average and 0.62 at the endpoint.

Short-run price transmission elasticities with respect to wellhead price were calculated for each of the price equations estimated. The period average elasticities ranged from 0.45 for the residential price to 0.94 for the electricity-generation price. The endpoint elasticities were slightly larger in magnitude. The range was 0.55 for the residential price to 1.02 for the electricity-generation price.

5.3 Historical fit analysis

Once the coefficient estimates were obtained, the model was dynamically simulated for the 1985-2006 period. A consequence of dynamic, as opposed to static, simulation in the presence of lagged dependent variables was that an error in one period affected both the current and future periods.

The SAS output reported several fit analysis statistics including: the mean error, the mean absolute error, and the root mean square error. These statistics were also presented in their percentage forms. The root mean square error was preferred to the mean and mean absolute errors because it was a more rigorous test of the model's performance. Because the errors were squared, large errors received a heavier penalty than smaller errors. This study focused on the root mean square percent (RMSP) error. The percentage terms were preferred from the reporting perspective because they would be more accessible to those persons unfamiliar with the data. Table 5.5 summarizes the results of the historical fit analysis.

The RMSP errors were reported for the 1985-2006 period, so this was an in-sample test. With the exception of exports, the demand variables showed fairly small RMSP errors. The range was 3.57% for commercial demand to 6.10% for electricity-generation demand. At 32.18%, the RMSP error for exports was the highest of any dependent variable in the model. However, this was not too surprising given that the exports were small at the beginning of the estimation period and much larger at the end of the period. On the supply side, the errors were also fairly small. Imports had the highest error at 9.01%, and the RMSP error for production was 2.77%. The price variables had rather large RMSP errors. The error for wellhead price was 28.99%. Like the export RMSP error, this suggested some prudence would be warranted when forecasting. Because the other price variables were determined in large part by the wellhead price in this model, it was not surprising they had large RMSP errors as well. Their errors ranged from 10.28% for the residential price to 26.08% for the electricity-generation price.

Table 5.5 Root mean square percent error of endogenous variables

		Root Mean Square Percent Error
Demand		
	Per capita residential	3.84
	Industrial	5.12
	Commercial	3.57
	Electricity-generation	6.10
	Exports	32.18
Supply		
	Production	2.77
	Imports	9.01
Prices		
	Wellhead	28.99
	Residential	10.28
	Industrial	19.79
	Commercial	12.72
	Electricity-generation	26.08

Appendix B contains charts comparing the simulated historical results to their actual values. The baseline wellhead price tended to have some large year-to-year fluctuations. That would explain the high RMSP error for that variable. Likewise, the delivered prices all showed that same instability. This situation could be problematic if the fluctuations were large enough to cause negative prices. The demand variables showed decent fit, but each one noticeably missed a couple of turning points. The production variable experienced a similar problem. Imports and exports had trouble matching the historical values with several missed turning points.

Chapter 6

Scenario Analyses

The following three scenarios employed shocks to future values of ethanol and corn production demands for natural gas. The shocks were based on results presented by FAPRI-MU in the 2008 report that was discussed earlier. It was assumed that the average reported shocks occurred at the beginning of the 2007-2015 forecast period and persisted throughout the period. The system was then reevaluated with those shocks in place. The differences between each scenario and the baseline outcomes for the forecast period were calculated and will be discussed below. Tables 6.1, 6.2, and 6.3 summarize the results of the three scenarios.

The baseline forecast was developed by calibrating the model so that the initial values for the variables were equal to the actual observed values. This was to ensure any errors made in the historical simulation would not affect the forecast. Appendix C contains charts comparing the baseline and scenario forecasted values. The wellhead price was projected to fall, and all the other prices were projected to do the same. Natural gas demand in each sector was predicted to rise over the period. However, export demand did not seem to have a definite future trend. Unexpectedly, natural gas production and imports were projected to rise even though wellhead prices were projected to decrease. An examination of the data and the Annual Energy Outlook 2008 (AEO 2008) ruled out any obvious data problem. In fact, the AEO 2008 projected a similar path for natural gas production and imports. According to the Energy

Information Administration (EIA), such a result could be due to another factor such as technological progress influencing the paths (AEO 2008, 2008(a)).

6.1 Scenario 1: EISA in place; allow tariffs and biofuel tax credits expire

According to FAPRI-MU, this scenario would result in an average decline in ethanol production of 11.9% and an average decline in corn production of 2.0%. In this system, the relationship between the ethanol and corn production values and their respective natural gas demands was assumed to be identical in nature. Thus, the declines reported by FAPRI-MU were applied directly to the ethanol and corn production natural gas demands.

Table 6.1 Effects of letting tariffs and tax credits expire on schedule

	2007-2015 Baseline Average	2007-2015 Scenario Average	Absolute Difference	Percent Difference
		Cubic feet		
Per capita residential demand	15910.47	15942.68	32.21	0.20
		Billion cubic feet		
Residential demand	4723.04	4732.60	9.56	0.20
Industrial demand	7764.93	7771.42	6.49	0.08
Commercial demand	3132.54	3139.10	6.56	0.21
Electricity-generation demand	7103.02	7104.36	1.34	0.02
Exports	706.49	707.77	1.28	0.18
Ethanol production	323.63	285.12	-38.51	-11.90
Corn production	274.78	269.28	-5.50	-2.00
Production	18803.00	18794.76	-8.24	-0.04
Imports	4903.95	4893.44	-10.51	-0.22
		Dollars per thousand cubic feet		
Wellhead price	4.67	4.60	-0.07	-1.56
Residential price	12.06	11.97	-0.09	-0.70
Industrial price	5.90	5.83	-0.07	-1.31
Commercial price	10.10	10.02	-0.08	-0.83
Electricity-generation price	5.02	4.94	-0.08	-1.65

In this scenario, the wellhead price was on average 1.56% lower than the baseline wellhead price over the forecast period. The delivered prices for each sector were also lower than their respective baseline prices. The average differences ranged from 0.70% for the residential sector to 1.65% for the electricity-generation sector.

Electricity-generation demand had the lowest average increase over the baseline at 0.02%, and commercial demand saw the largest average increase at 0.21%. On average, natural gas production was 0.04% lower than baseline production, and imports were 0.22% lower.

6.2 Scenario 2: Remove EISA; extend tariffs and biofuel credits indefinitely

In this scenario, FAPRI-MU reported that ethanol production would be an average of 20.5% lower than the baseline amounts. Corn production would be an average of 1.7% lower than the baseline amounts. The effect on ethanol production was larger in magnitude than Scenario 1, but the effect on corn production was lower in magnitude. Without knowing the relative impacts of corn and ethanol production on natural gas demand, it would be difficult to guess whether the effects in this scenario are greater or less than those of the first scenario. During the forecast period, the demands for natural gas by corn and ethanol production were balanced. On average, ethanol production required 50 billion cubic feet (Bcf) more natural gas than corn production in a given year during that time. Thus, one would logically expect the results of this scenario to be similar to those of Scenario 1 but with larger effects in magnitude.

The wellhead price in Scenario 2 was an average of 2.52% lower than the baseline wellhead price. The delivered prices were all lower by more than 1% on average. Again, the residential sector showed the smallest average price change of

1.12%, and the electricity-generation sector showed the largest with average difference of 2.67%.

Table 6.2 Effects of removing EISA mandates, tariffs and tax credits extended

	2007-2015 Baseline Average	2007-2015 Scenario Average	Absolute Difference	Percent Difference
		Cubic feet		
Per capita residential demand	15910.47	15962.45	51.98	0.33
		Billion cubic feet		
Residential demand	4723.04	4738.47	15.43	0.33
Industrial demand	7764.93	7775.42	10.49	0.14
Commercial demand	3132.54	3143.12	10.58	0.34
Electricity-generation demand	7103.02	7105.18	2.16	0.03
Exports	706.49	708.55	2.06	0.29
Ethanol production	323.63	257.28	-66.35	-20.50
Corn production	274.78	270.10	-4.68	-1.70
Production	18803.00	18789.71	-13.29	-0.07
Imports	4903.95	4887.00	-16.95	-0.35
		Dollars per thousand cubic feet		
Wellhead price	4.67	4.55	-0.12	-2.52
Residential price	12.06	11.92	-0.14	-1.12
Industrial price	5.90	5.78	-0.12	-2.12
Commercial price	10.10	9.97	-0.13	-1.35
Electricity-generation price	5.02	4.89	-0.13	-2.67

The effects on demand and supply were larger than Scenario 1 as well. Commercial demand for natural gas was, on average, 0.34% higher than the baseline in this scenario. The average difference between the scenario and baseline electricity-generation demands increased to 0.03%. Natural gas production, on the other hand, was an average of 0.07% lower than the baseline. Natural gas imports were 0.35% lower than the baseline, on average.

6.3 Scenario 3: Remove EISA; allow tariffs and tax credits to expire

If this scenario were to occur, FAPRI-MU reported the 2008-2017 average change in ethanol production would be -43% and the average change in corn production would be -5.5%. The effects of removing any redundant support by the policies are clearly seen. The effects in this scenario were expected to be larger in magnitude than the sums of the effects from the first two scenarios.

Table 6.3 Effects of removing EISA mandates, tariffs and tax credits expire

	2007-2015 Baseline Average	2007-2015 Scenario Average	Absolute Difference	Percent Difference
		Cubic feet		
Per capita residential demand	15910.47	16023.39	112.92	0.71
		Billion cubic feet		
Residential demand	4723.04	4756.56	33.52	0.71
Industrial demand	7764.93	7787.70	22.77	0.29
Commercial demand	3132.54	3155.52	22.98	0.73
Electricity-generation demand	7103.02	7107.73	4.71	0.07
Exports	706.49	710.98	4.49	0.64
Ethanol production	323.63	184.47	-139.16	-43.00
Corn production	274.78	259.66	-15.12	-5.50
Production	18803.00	18774.12	-28.88	-0.15
Imports	4903.95	4867.12	-36.83	-0.75
		Dollars per thousand cubic feet		
Wellhead price	4.67	4.42	-0.25	-5.47
Residential price	12.06	11.76	-0.30	-2.44
Industrial price	5.90	5.64	-0.26	-4.61
Commercial price	10.10	9.81	-0.29	-2.93
Electricity-generation price	5.02	4.74	-0.28	-5.80

The wellhead price in this scenario was 5.47% lower than the baseline wellhead price, on average. Indeed, the difference was greater than the value of 4.08% obtained by adding the results of Scenarios 1 and 2. Moreover, the delivered prices for the residential and electricity-generation sectors were an average 2.44% and 5.80% lower than the baseline prices, respectively.

In this case, the average difference between commercial demand and the baseline grew to 0.73%. Electricity-generation demand was an average of 0.07% higher than the baseline export demand. Natural gas production under the scenario was, on average, 0.15% lower than baseline natural gas production while imports were 0.75% lower.

Chapter 7

Summary and Conclusions

7.1 Summary

This study attempted to accomplish three objectives. The first objective was to determine how much natural gas was used in the life-cycle of corn based ethanol. That information, in addition to knowledge about the natural gas and fertilizer markets, was used to construct a model of the natural gas market in a way that would reveal the effects of ethanol and corn production on natural gas prices. The final objective was to use the natural gas model to analyze U.S. biofuel policy and answer the primary research question, "What are the effects of increased corn-ethanol production on natural gas prices?"

The model itself was a structural equations model. On the demand side, equations were estimated for natural gas demand by sector and for exports. Supply equations for natural gas production and imports were also estimated. Price equations were specified and estimated for each sector. The wellhead natural gas price was determined by market closure.

The two-stage least squares (2SLS) method was employed to estimate the coefficients in this system. 2SLS was chosen to avoid the bias that occurs when estimating a system of simultaneous equations with ordinary least squares (OLS). The Durbin-Watson, Durbin-h, and Durbin-t tests were used to test for serial correlation.

The results of those tests revealed that serial correlation did not pose a serious problem.

The SAS System was used to perform the testing and estimation. Preliminary estimation indicated that certain parameters would need to be restricted. These restricted values were chosen to provide theoretically sound elasticities. Short-run own-price elasticities of demand were fairly inelastic with electricity-generation demand being the most inelastic and export demand the least inelastic. Recall that the cross-price elasticities for each demand variable were of equal magnitude as the own-price elasticities, but because price ratios were used, the cross-price elasticities had the opposite sign. The long-run own- and cross-price elasticities of demand were more elastic than the short-run elasticities. The short-run own-price elasticities of natural gas production and imports were determined, in part, by their restricted coefficients. They were both inelastic. The long-run own-price elasticities of supply were also more elastic than the short-run.

The estimated coefficients were used to develop a historical simulation for the 1985-2006 period. The fit of this historical simulation was analyzed using the root mean square percent (RMSP) error. This analysis showed that the model simulated the actual demand variables, except exports, pretty well. The RMSP error was roughly between 3% and 6%. The RMSP for exports, however, was 32%, and for the wellhead price it was 29%. The other price variables also had fairly high RMSP errors as a result. Therefore, some caution should be used when discussing forecasted outcomes.

A baseline projection was developed for the 2007-2015 period. When that was completed, shocks were introduced to the exogenous natural gas demands by corn and ethanol production. The shocks were based on the impacts of removing certain U.S. biofuel policies as reported by FAPRI-MU in 2008. They were assumed to be persistent. That is, they were introduced in the year 2007 and persisted for each remaining year of the forecast.

The first scenario examined the effect of letting the biofuel tariffs and tax credits expire with the EISA mandates in place. According to FAPRI-MU, this would result in an 11.9% decrease in ethanol production and a 2.0% decline in corn production. Applying those shocks resulted in lower price and supply paths and higher demand paths relative to the baseline projection.

In the second scenario, the shocks represented the effect of removing the EISA mandates while extending the tariffs and tax credits. Here, the effect on ethanol production was larger than in Scenario 1, but the effect on corn production was smaller. In this model, the resulting forecast was similar to the forecast of Scenario 1. Once again, the price and supply paths were predicted to be lower than the baseline forecast, and the demand paths were predicted to be higher.

The shocks for the third scenario were based on the effect of removing the EISA mandates in addition to letting the tariffs and tax credits expire. Here, the effects on corn and ethanol production were larger in magnitude than summing the effects of Scenario 1 and Scenario 2. Like the previous scenarios, this model projected lower paths for the price and supply variables relative to the baseline, and the demand paths were projected to be higher than the baseline projection.

7.2 Conclusions

The findings of this study showed that the effects of increased corn-ethanol production on natural gas prices could be fairly substantial. According to the third scenario, removing U.S. biofuel policies would result in average forecasted natural gas prices that ranged from 2% to 6% lower than the baseline average forecast. In other words, corn-ethanol production under current U.S. biofuel policies could result in natural gas prices 2% to 6% higher than if there were no U.S. biofuel policies in place.

Forecasted annual per capita expenditure on natural gas by the residential sector in Scenario 3 would be an average of 3.44 dollars less than the baseline. In total, that would amount to just over a billion dollars. The industrial and electricity-generation sectors would spend just under two billion dollars less in the third scenario. The commercial sector would save just under a billion dollars.

In relation to studies such as Wang (2008), in which it appeared that consumers may enjoy a price benefit at the gas pumps as a result of increased ethanol production, this study showed that increased ethanol production could cost consumers more as they try to meet other energy needs. Here, the inelasticity of demand prevents baseline natural gas consumers from reducing their natural gas demand enough to offset the price increase caused by increased ethanol production. In other words, consumers would be spending more money on natural gas while consuming less of it as a result of current biofuel policies.

Policymakers who are concerned with the impact of increased corn-ethanol production on consumer prices may not be too worried by these results. However, these results did not show the specific price transmissions from other sectors that could affect the consumer. Higher natural gas prices would cause higher production costs in the industrial and commercial sectors. As a result, consumers might face higher prices for the goods and services from those sectors.

That being said, there are certain considerations to be made. Remember there is not a specific mandated level of use for corn-ethanol, and the shocks in this study assumed changes in ethanol production were realized only by adjustments to corn-ethanol production. If advanced forms of ethanol are produced in large enough quantities, corn-ethanol production may decline in spite of the policies. In that case, the actual effects on natural gas prices could be much lower. It will depend on the amount of natural gas used in the advanced ethanol production processes.

Similarly, the only crop production numbers that were changed in the scenarios were the corn planted area numbers. This ignored any area substitution among crops. Essentially, the model assumed farmland that dropped out of corn production became idle and no longer required natural gas inputs. This assumption is unlikely to hold in all cases. There will be some crop substitution made in many cases, and the production of those crops will require natural gas. Thus, the effects of may be overstated if the demand for natural gas by the other crops is large enough to compensate for lower corn production. Future work on this project will include a way to account for crop substitution.

Another important consideration is the high RMSP errors for the price equations. The differences between the baseline and scenario averages could be larger or smaller than those currently reported. Given that the forecast errors could be different in each scenario, it is unclear what the exact effect would be. The direction and magnitude of the errors in each scenario would be the deciding factors.

Also, there is the issue of elasticities. Several elasticities were assumed in this model. In particular, the own-price elasticities of both production and imports were assumed. This means that all the supply side responses to natural gas price changes in the scenarios were imposed. Moreover, the real income elasticities for residential and industrial demands were assumed. Therefore, the results presented in this study will have some sensitivity to the chosen elasticity estimates. Future work with this model will need to include a sensitivity analysis to examine the effects of a range of elasticity measures.

Finally, it is important to remember that this is only a partial equilibrium model. Future research would include linking this model to models of other markets including the ethanol, corn, and fertilizer markets. In those models, ethanol production, corn production, and fertilizer demands and imports would be determined endogenously. Linking to the entire FAPRI model would be ideal as it would allow a more comprehensive dynamic analysis.

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Appendix A

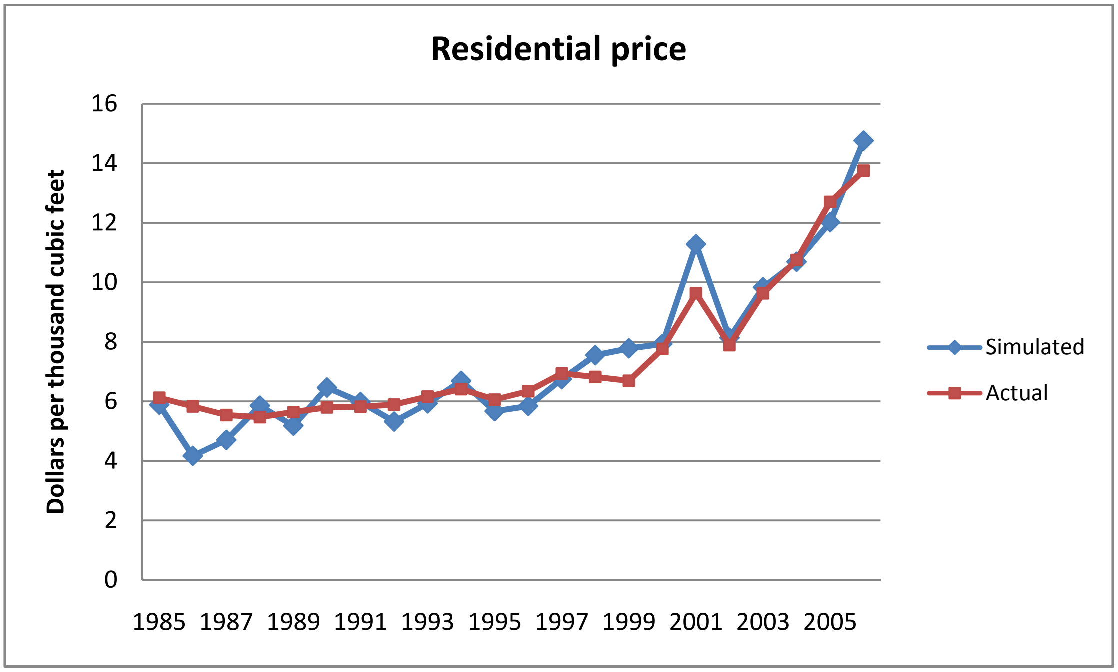
Data names, units, and sources

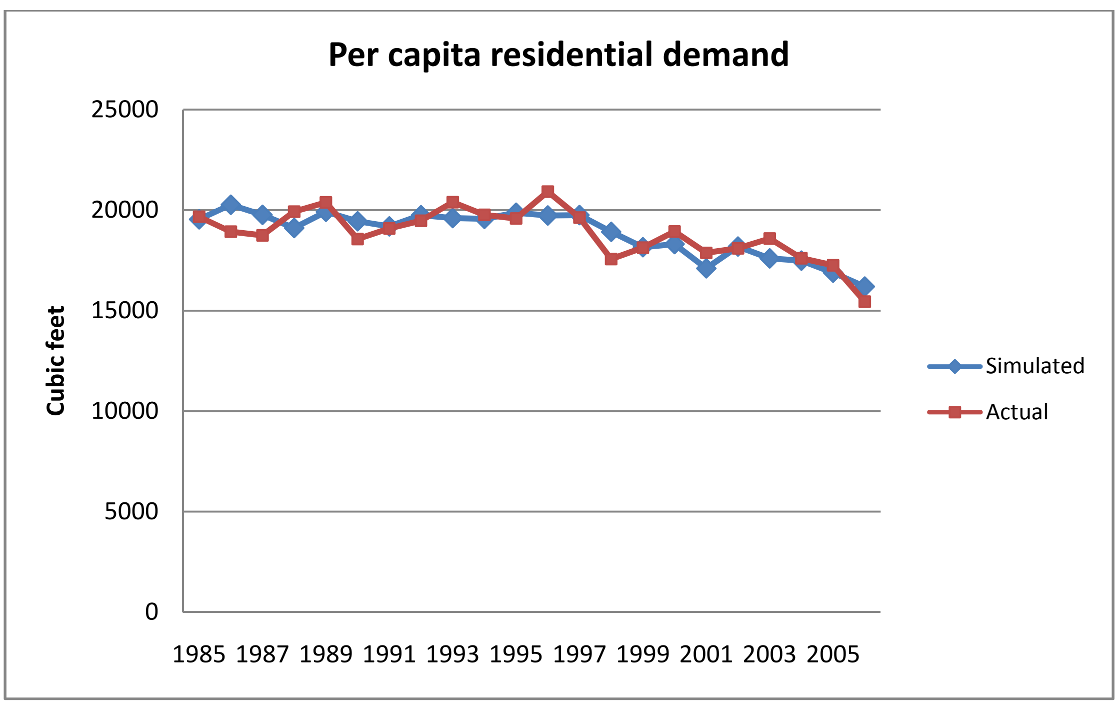
Description	Name	Units	Source
Residential natural gas demand	NGDRESPCUS	Billion cubic feet	Energy Information Association
Industrial and transportation natural gas demand	NGDOINDUS	Billion cubic feet	Energy Information Association
Commercial natural gas demand	NGDCOMUS	Billion cubic feet	Energy Information Association
Electricity generation natural gas demand	NGDELUS	Billion cubic feet	Energy Information Association
Natural gas exports	NGDEXPUS	Billion cubic feet	Energy Information Association
Ethanol production demand for natural gas	NGDETUS	Billion cubic feet	Calculated
Corn production demand for natural gas	NGDCRUS	Billion cubic feet	Calculated
Total natural gas consumption	NGDTCONUS	Billion cubic feet	Calculated
Nitrogen demand by other crops	NTDOTUS	Billion cubic feet	Calculated
Discrepancy measure	NGDDISCRUS	Billion cubic feet	Energy Information Association
Additions to storage	NGDADUS	Billion cubic feet	Energy Information Association
Balancing measure	NGBALUS	Billion cubic feet	Energy Information Association
Natural gas production	NGSPRUS	Billion cubic feet	Energy Information Association
Natural gas imports	NGSIMPUS	Billion cubic feet	Energy Information Association
Supplemental fuels	NGSSFUS	Billion cubic feet	Energy Information Association
Withdrawals from storage	NGSWDUS	Billion cubic feet	Energy Information Association
Net nitrogen imports	NTNIMPUS	Billion cubic feet	Calculated
Wellhead natural gas price	NGPWHDUS	Dollars per thousand cubic feet	Energy Information Association

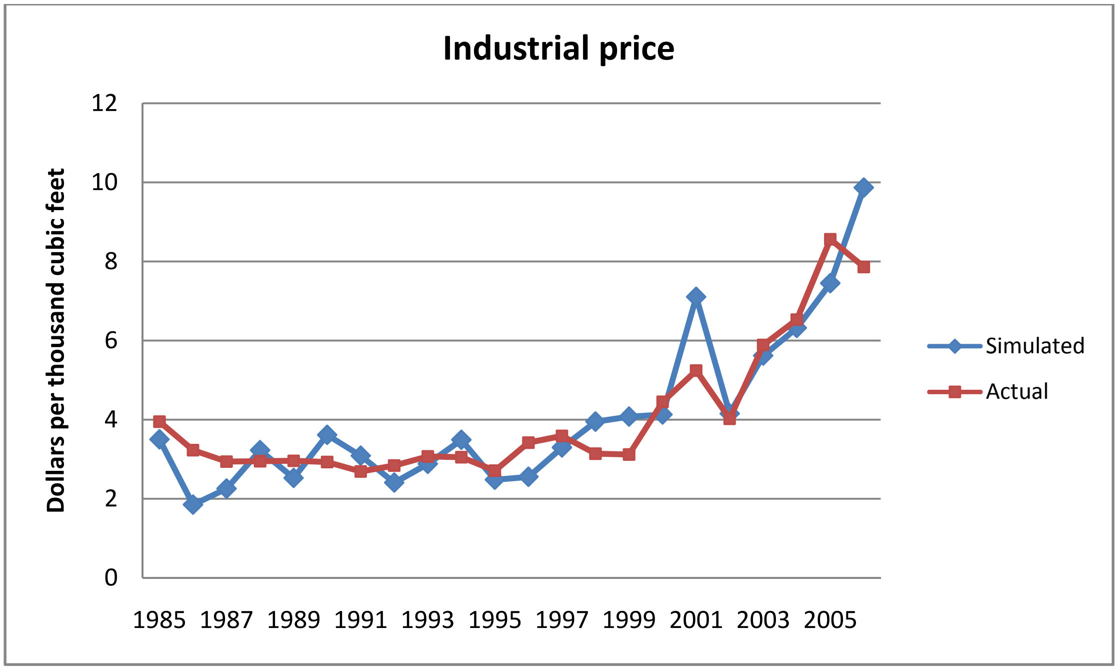
Description	Name	Units	Source
Residential natural gas price	NGPRESUS	Dollars per thousand cubic feet	Energy Information Association
Industrial natural gas price	NGPINDUS	Dollars per thousand cubic feet	Energy Information Association
Commercial natural gas price	NGPCOMUS	Dollars per thousand cubic feet	Energy Information Association
Electricity generation natural gas price	NGPELUS	Dollars per thousand cubic feet	Energy Information Association
Production costs	NGPRCUS	Cents per thousand cubic feet	Calculated
Residential electricity price	ELPRESUS	Dollars per kilowatt-hour	Energy Information Association
Commercial electricity price	ELPCOMUS	Dollars per kilowatt-hour	Energy Information Association
Distillate fuel price	DFPUS	Dollars per gallon	Energy Information Association
Coal price	CLPUS	Dollars per ton	Energy Information Association
Real U.S. gross domestic product	RGDPUS	Billion dollars (2000=Base)	Energy Information Association
Real per capita U.S. gross domestic product	RGDPPCUS	Dollars (2000=Base)	Energy Information Association
Real Canadian gross domestic product	RGDPCA	Billion dollars (2005=Base)	Economic Research Service
Real Mexican gross domestic product	RGDPMX	Billion dollars (2005=Base)	Economic Research Service
Producer Price Index	PPIUS	Index (2000=Base)	FAPRI-MU
U.S. gross domestic product deflator	GDPDEFUS	Index (2000=Base)	Energy Information Administration
U.S. population	POPUS	Millions	Energy Information Administration
Linear trend	TREND		Calculated

Appendix B

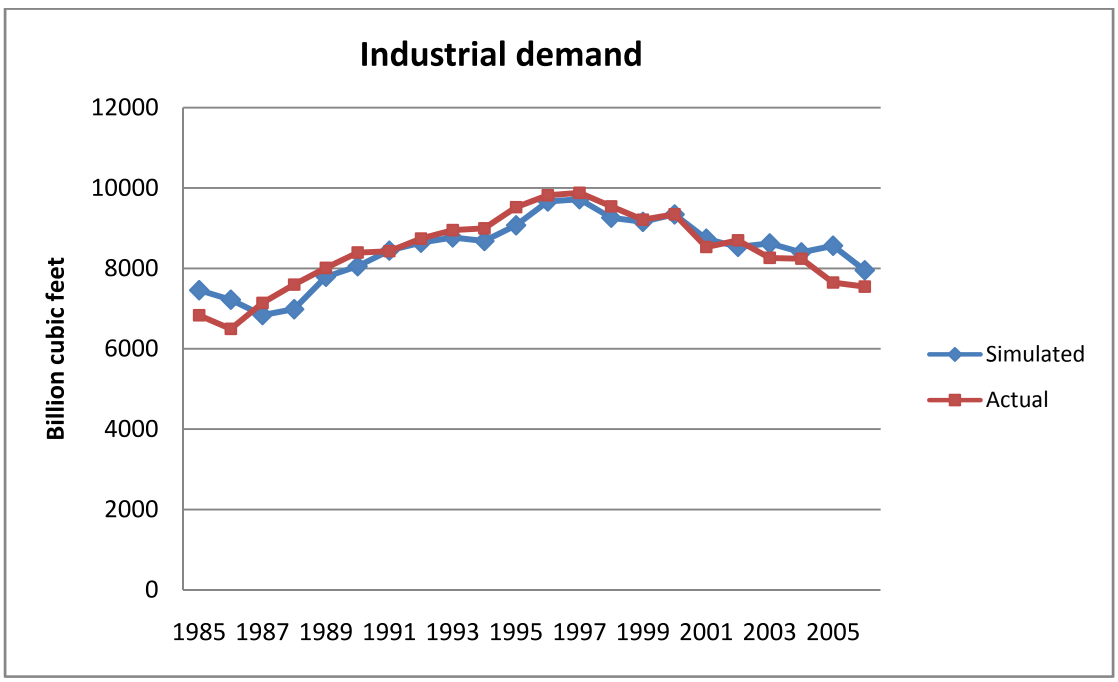
Charts comparing simulated to actual value



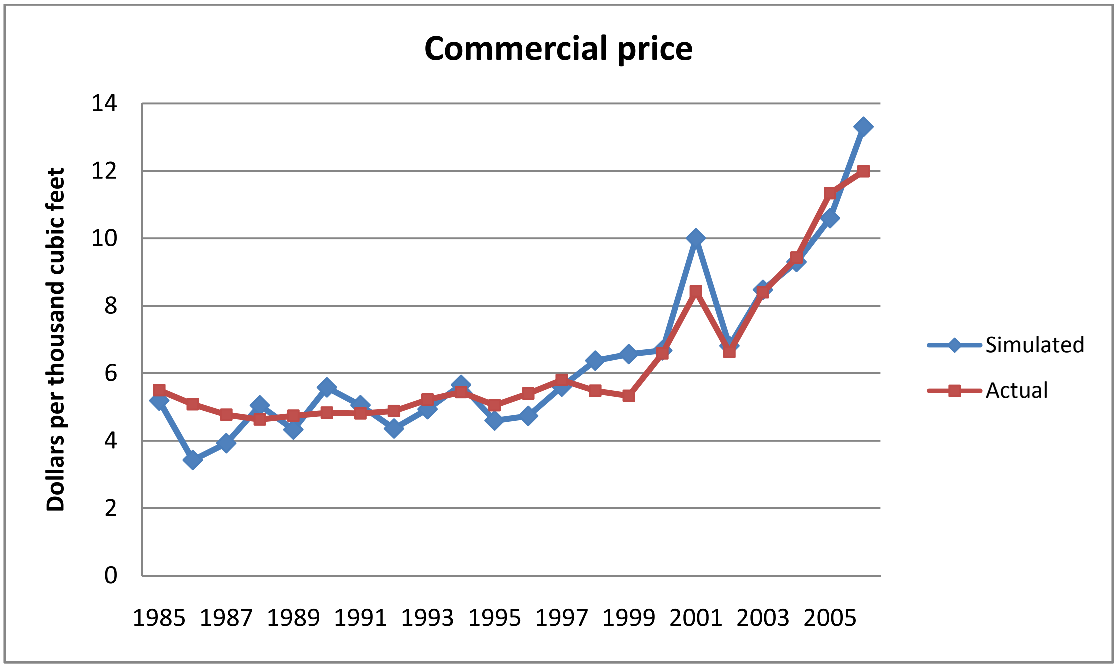




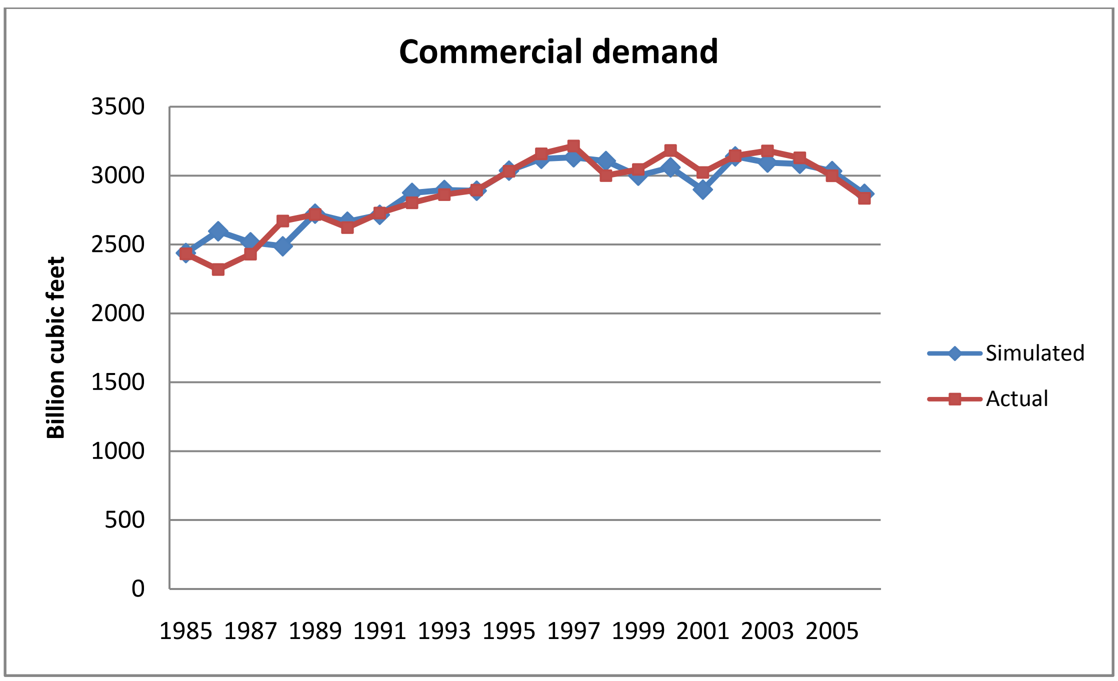
Industrial price
Dollars per thousand cubic feet
12
10
8
6
4
2
0
1985 1987 1989 1991 1993 1995 1997 1999 2001 2003 2005
Simulated
Actual



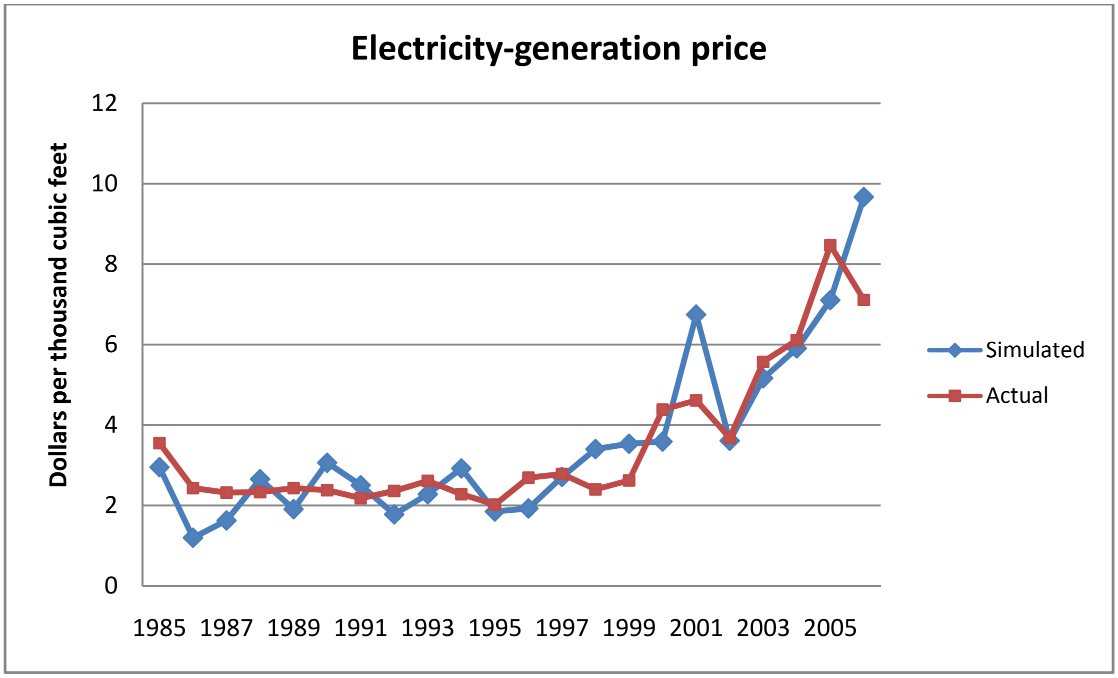
Industrial demand
Billion cubic feet
12000
10000
8000
6000
4000
2000
0
1985 1987 1989 1991 1993 1995 1997 1999 2001 2003 2005
Simulated
Actual

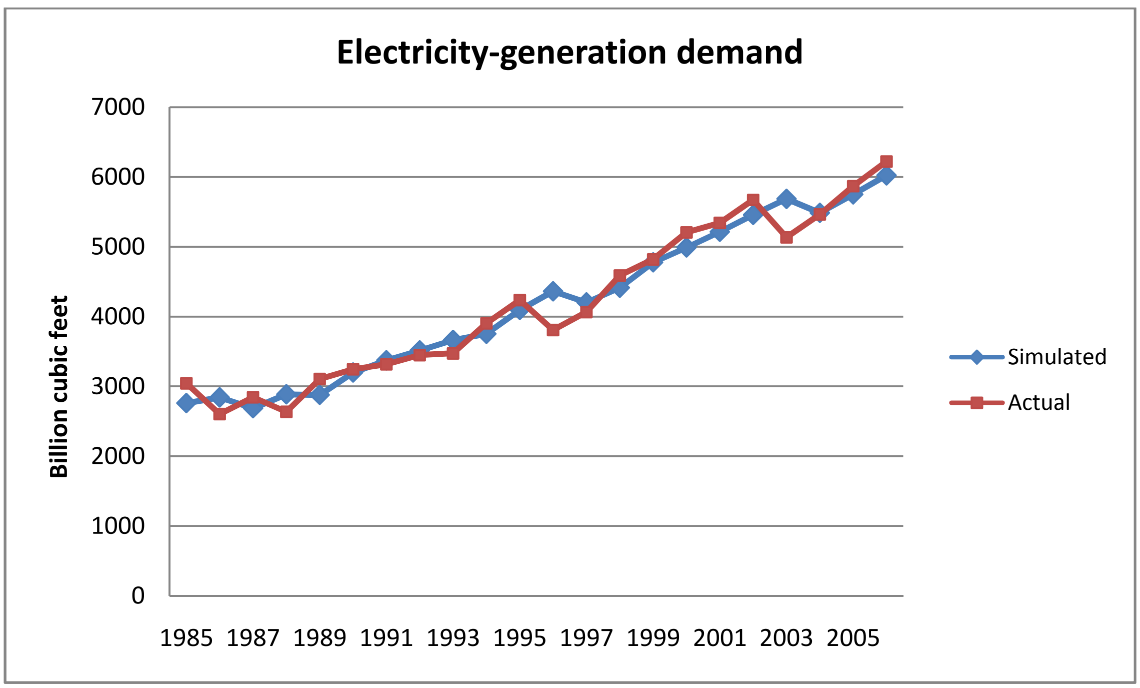


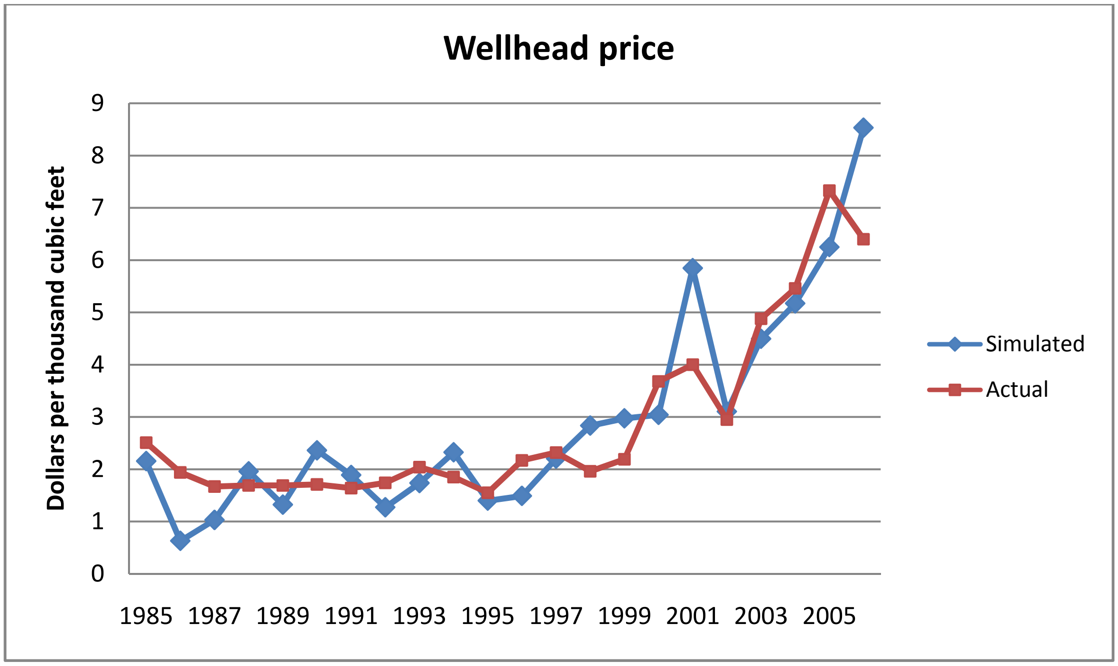
Commercial price
Dollars per thousand cubic feet
14
12
10
8
6
4
2
0
1985 1987 1989 1991 1993 1995 1997 1999 2001 2003 2005
Simulated
Actual

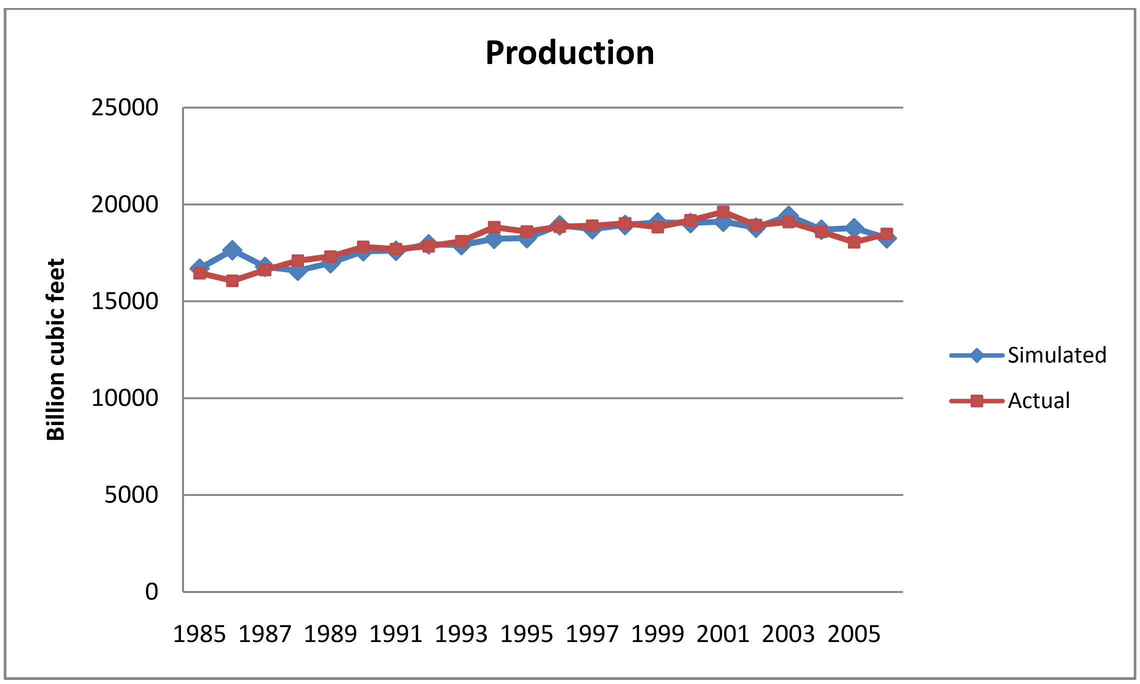


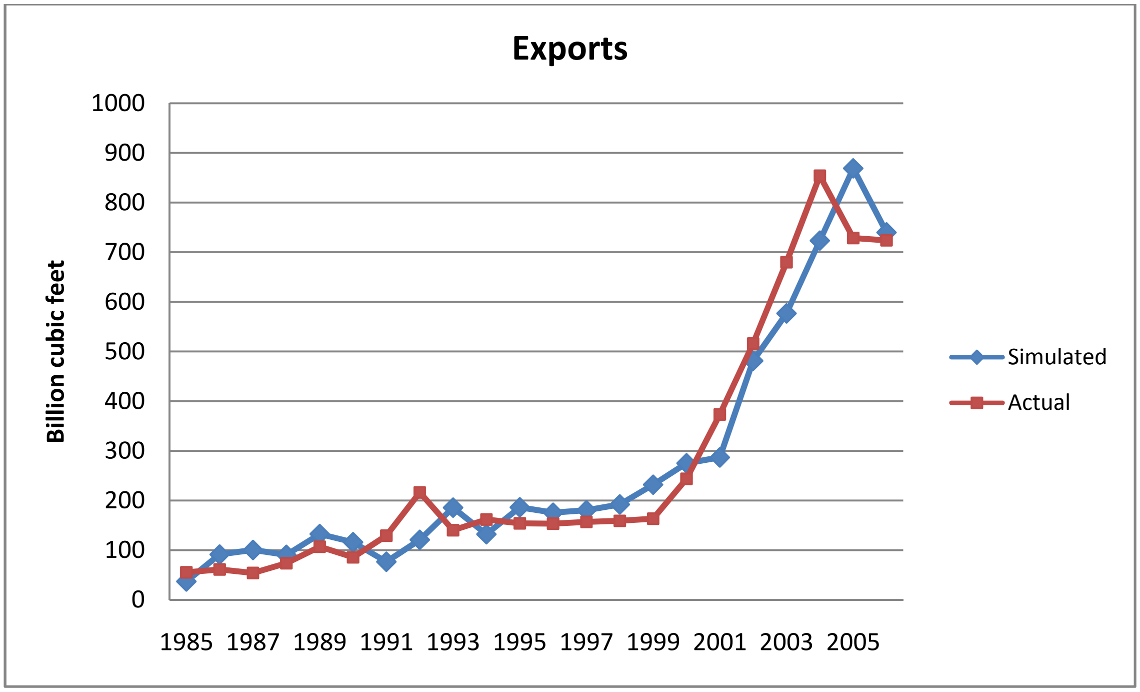
Commercial demand
Billion cubic feet
3500
3000
2500
2000
1500
1000
500
0
1985 1987 1989 1991 1993 1995 1997 1999 2001 2003 2005
Simulated
Actual


Electricity-generation price
Dollars per thousand cubic feet
12
10
8
6
4
2
0
1985 1987 1989 1991 1993 1995 1997 1999 2001 2003 2005
Simulated
Actual

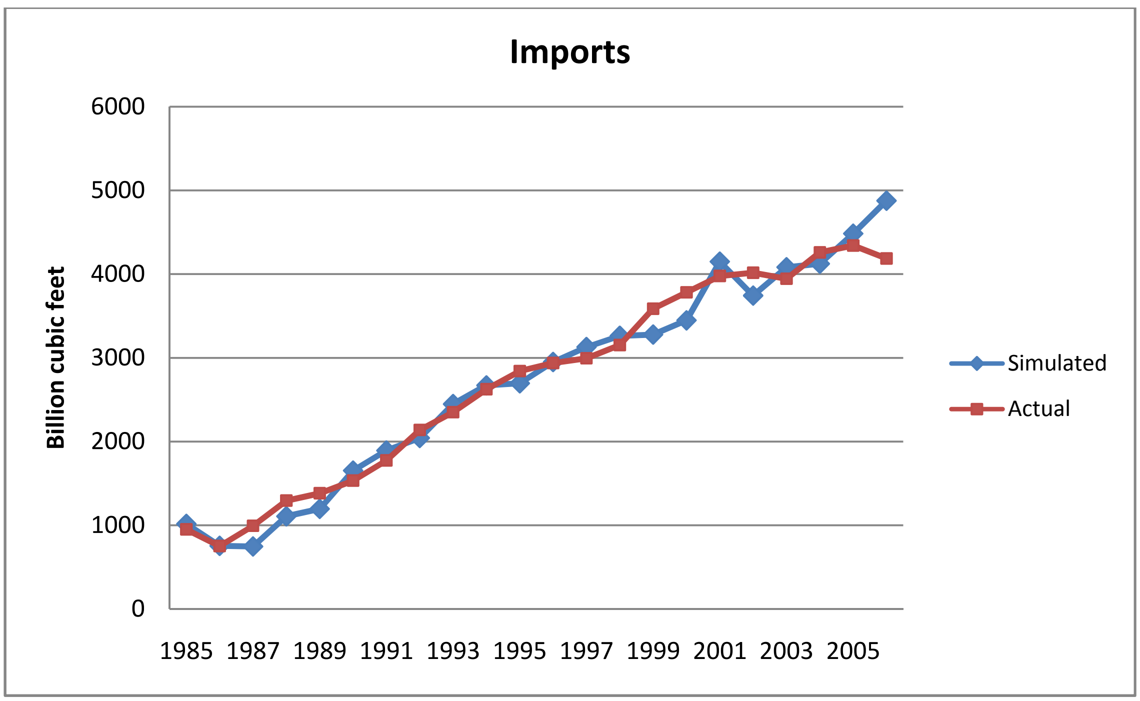

Electricity-generation demand
Billion cubic feet
7000
6000
5000
4000
3000
2000
1000
0
1985 1987 1989 1991 1993 1995 1997 1999 2001 2003 2005
Simulated
Actual


Wellhead price
Dollars per thousand cubic feet
9
8
7
6
5
4
3
2
1
0
1985 1987 1989 1991 1993 1995 1997 1999 2001 2003 2005
Simulated
Actual


Production
Billion cubic feet
25000
20000
15000
10000
5000
0
1985 1987 1989 1991 1993 1995 1997 1999 2001 2003 2005
Simulated
Actual



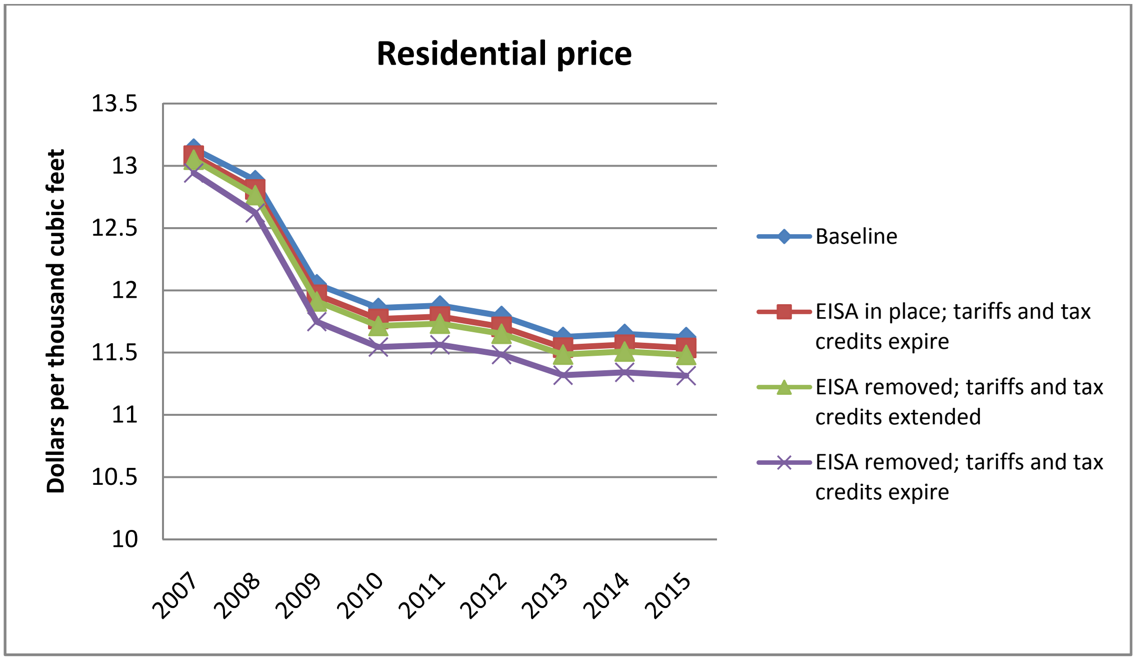
Exports
Billion cubic feet
1000
900
800
700
600
500
400
300
200
100
0
1985 1987 1989 1991 1993 1995 1997 1999 2001 2003 2005
Simulated
Actual

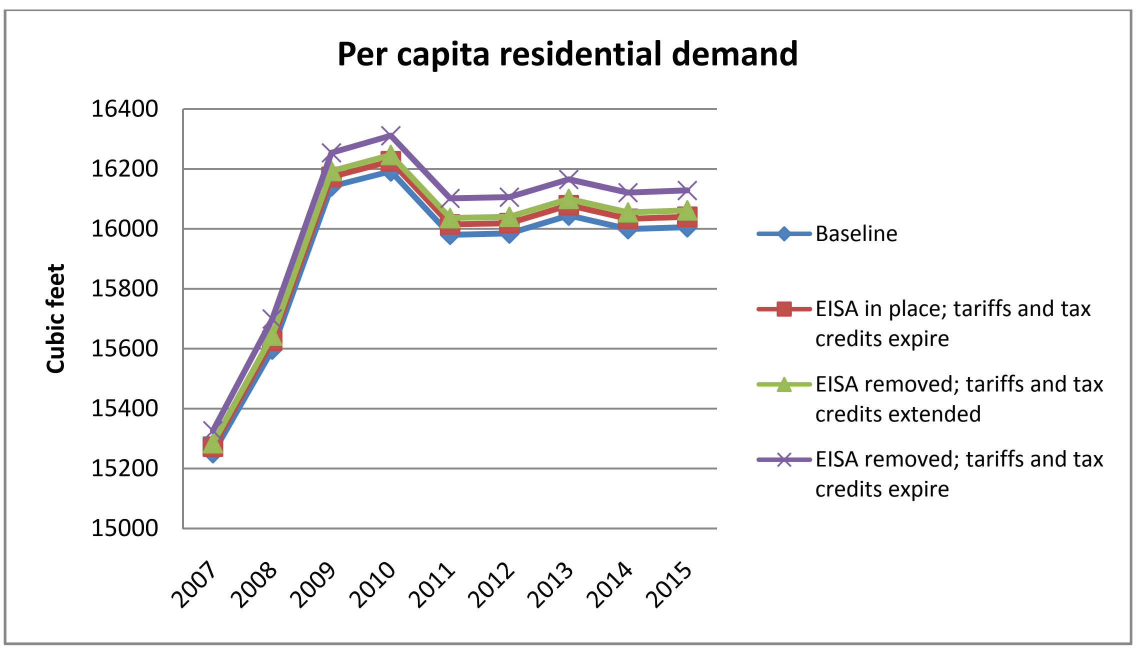


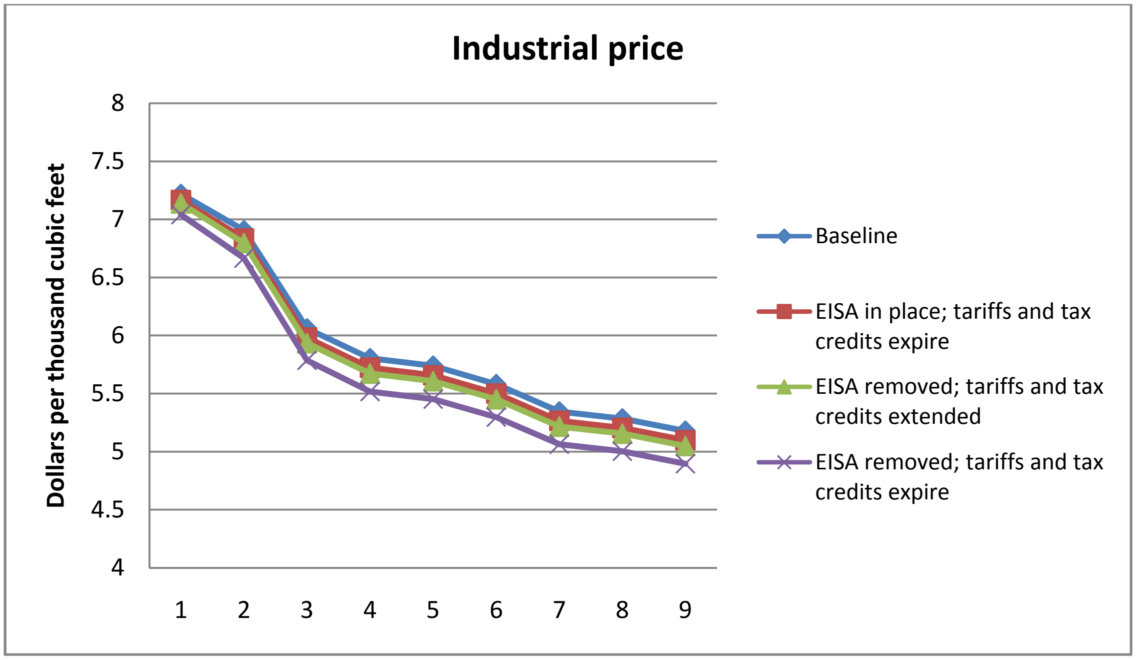
Imports
Billion cubic feet
6000
5000
4000
3000
2000
1000
0
1985 1987 1989 1991 1993 1995 1997 1999 2001 2003 2005
Simulated
Actual

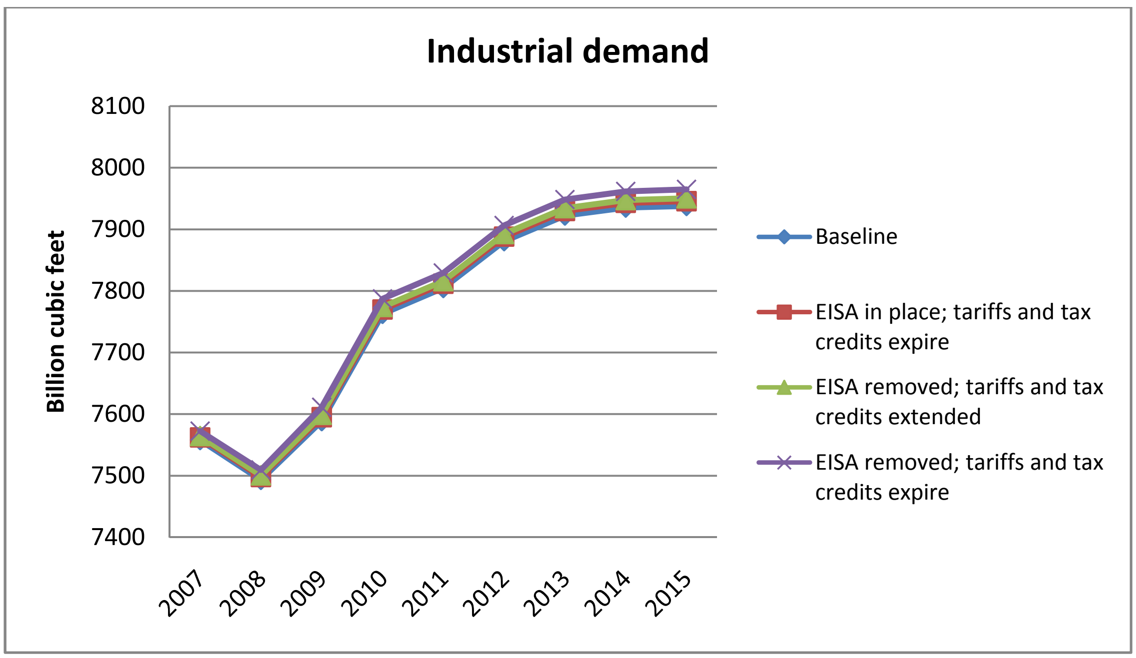
Appendix C

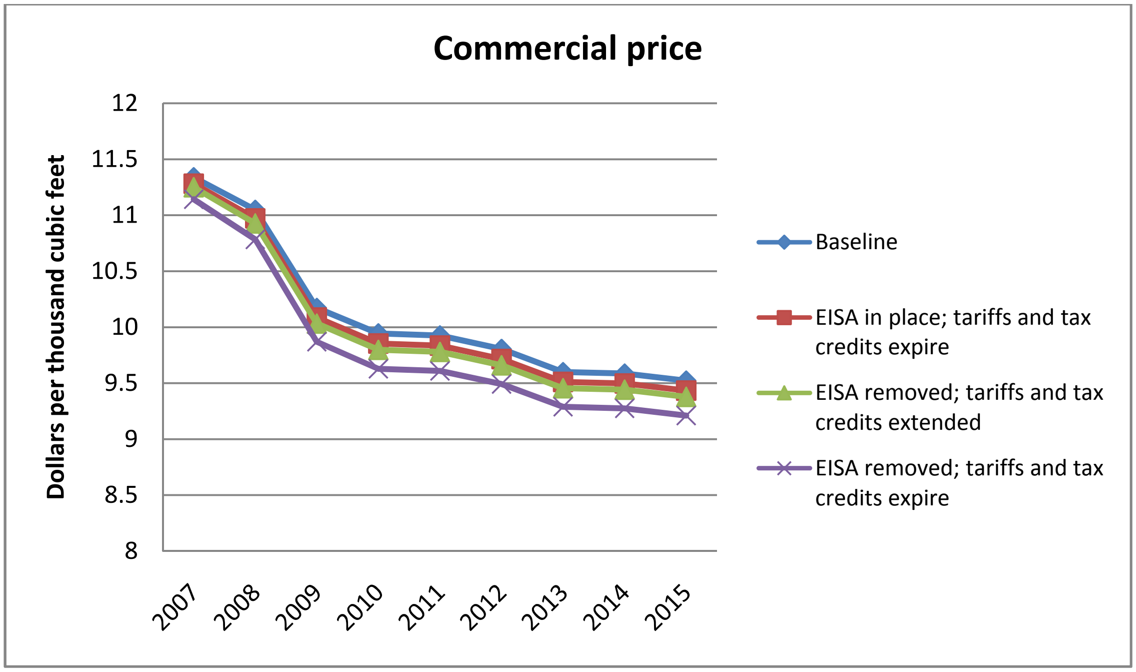
Charts comparing baseline forecasts to scenario forecasts

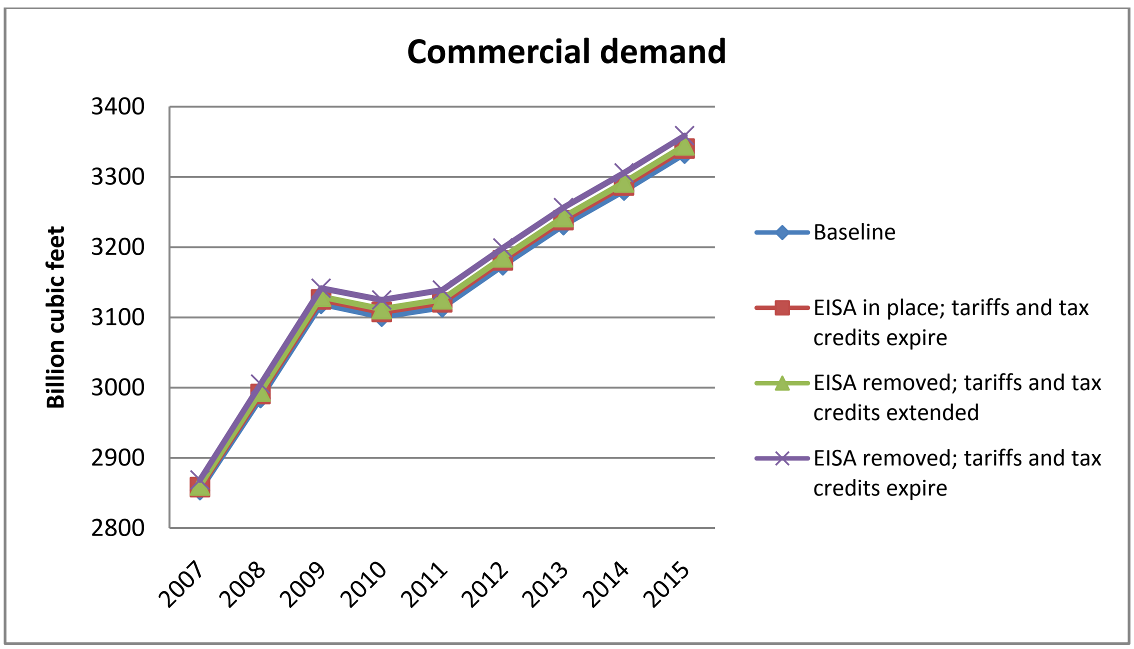


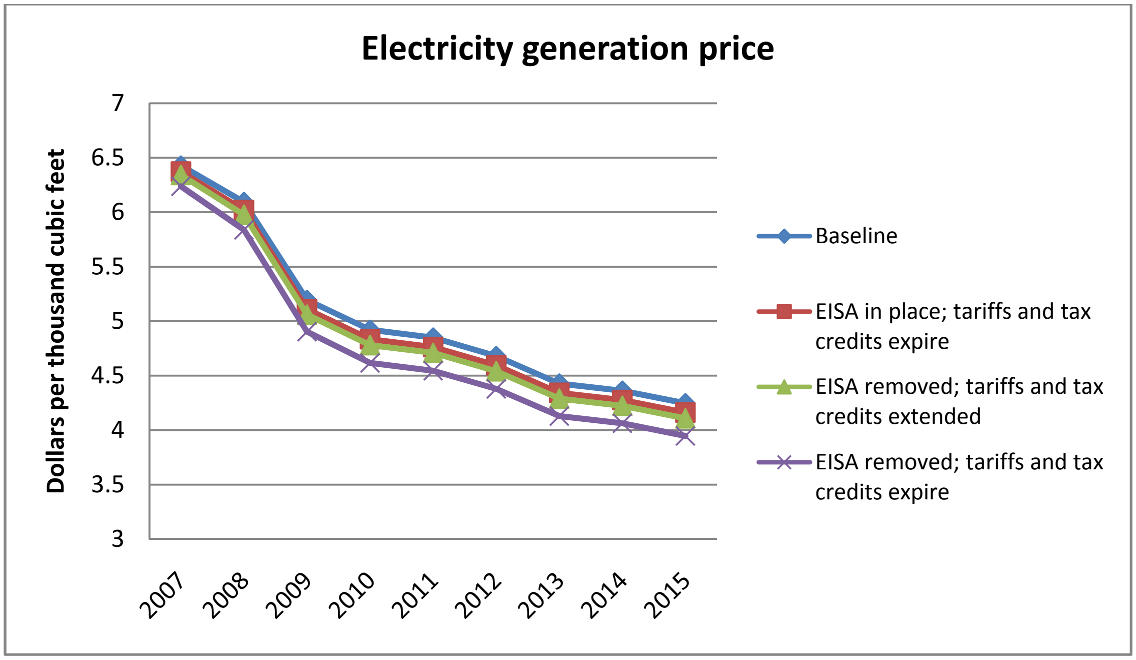


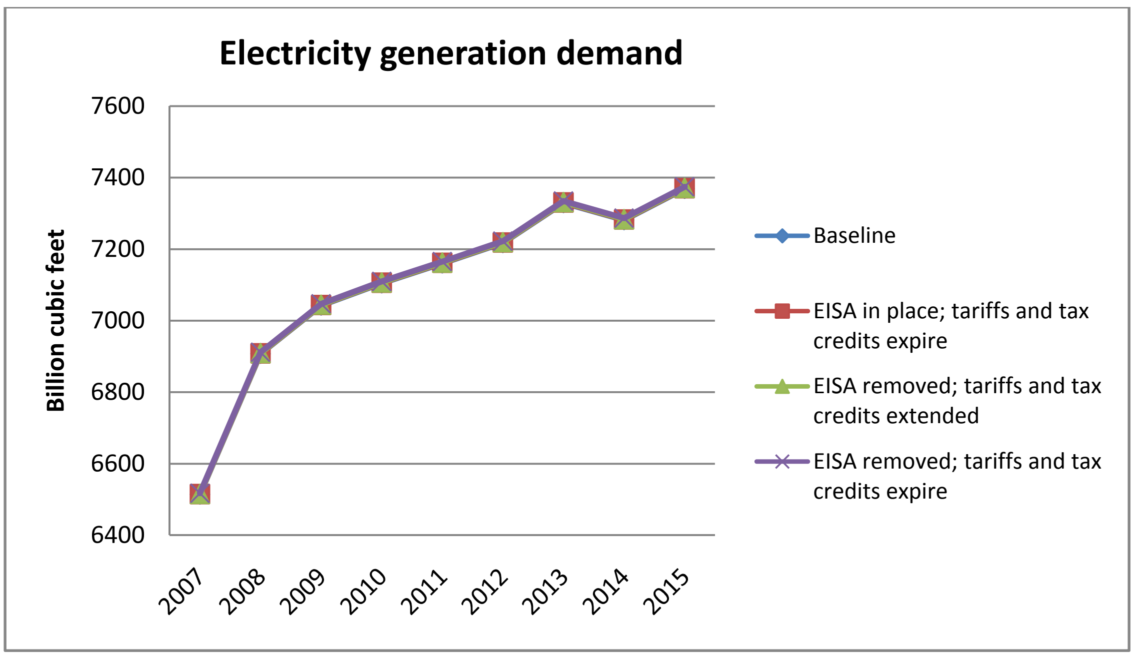

Industrial price
Dollars per thousand cubic feet
8
7.5
7
6.5
6
5.5
5
4.5
4
1
2
3
4
5
6
7
8
9
Baseline
EISA in place; tariffs and tax credits expire
EISA removed; tariffs and tax credits extended
EISA removed; tariffs and tax credits expire

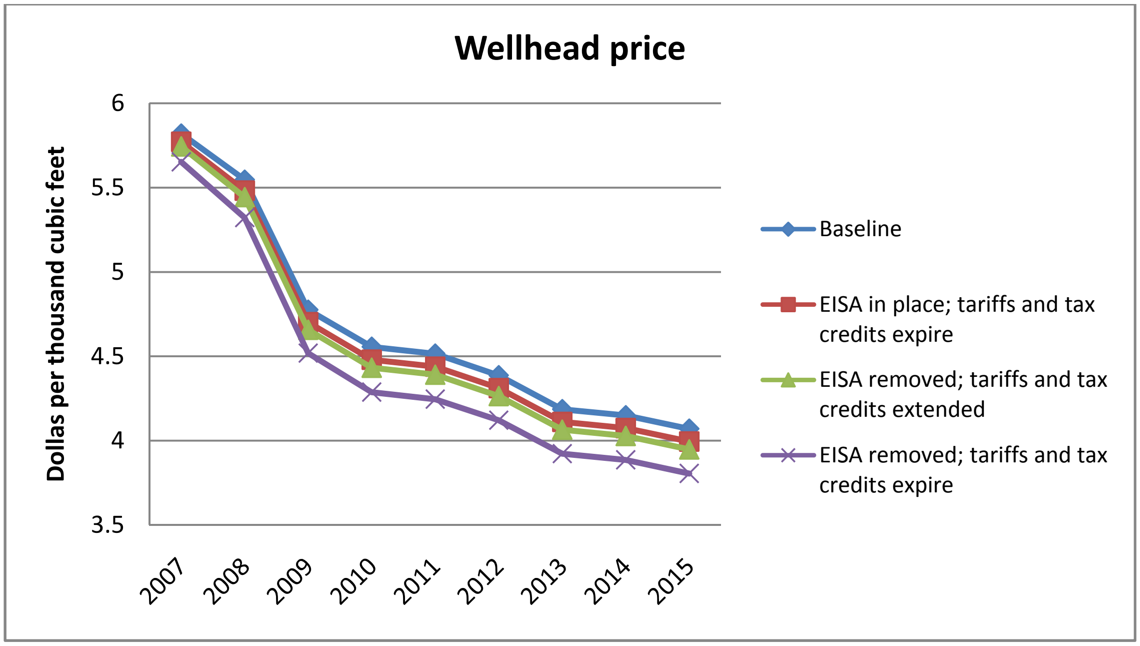

Industrial demand
Billion cubic feet
8100
8000
7900
7800
7700
7600
7500
7400
2007
2008
2009
2010
2011
2012
2013
2014
2015
Baseline
EISA in place; tariffs and tax credits expire
EISA removed; tariffs and tax credits extended
EISA removed; tariffs and tax credits expire


Commercial price
Dollars per thousand cubic feet
12
11.5
11
10.5
10
9.5
9
8.5
8
2007
2008
2009
2010
2011
2012
2013
2014
2015
Baseline
EISA in place; tariffs and tax credits expire
EISA removed; tariffs and tax credits extended
EISA removed; tariffs and tax credits expire

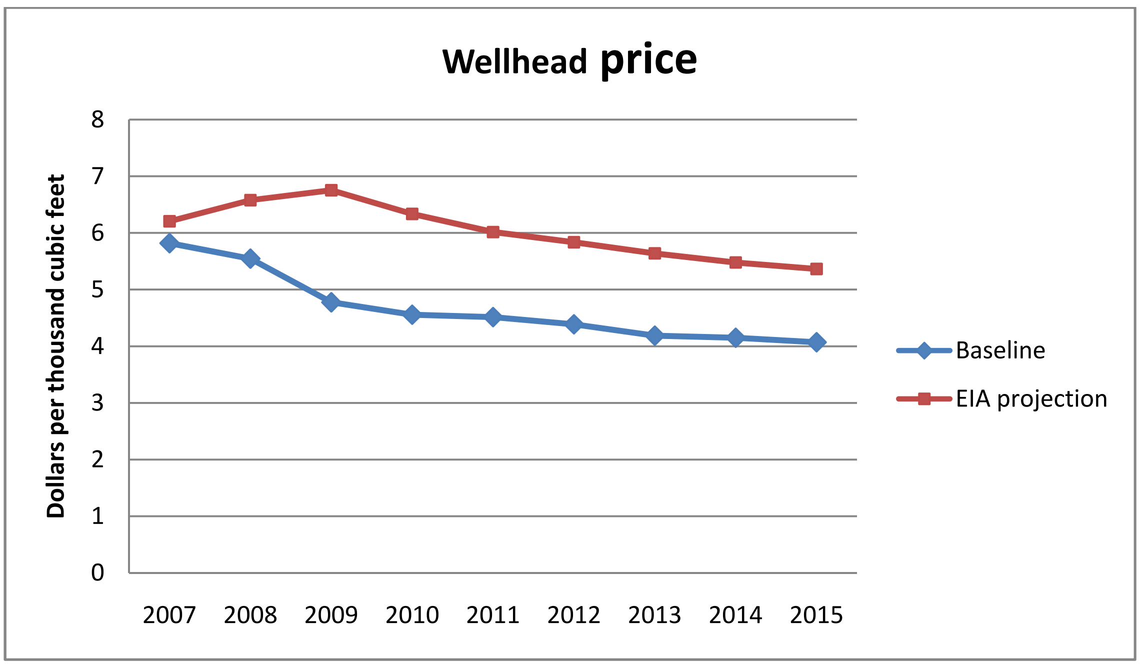

Commercial demand
Billion cubic feet
3400
3300
3200
3100
3000
2900
2800
2007
2008
2009
2010
2011
2012
2013
2014
2015
Baseline
EISA in place; tariffs and tax credits expire
EISA removed; tariffs and tax credits extended
EISA removed; tariffs and tax credits expire


Electricity generation price
Dollars per thousand cubic feet
7
6.5
6
5.5
5
4.5
4
3.5
3
2007
2008
2009
2010
2011
2012
2013
2014
2015
Baseline
EISA in place; tariffs and tax credits expire
EISA removed; tariffs and tax credits extended
EISA removed; tariffs and tax credits expire

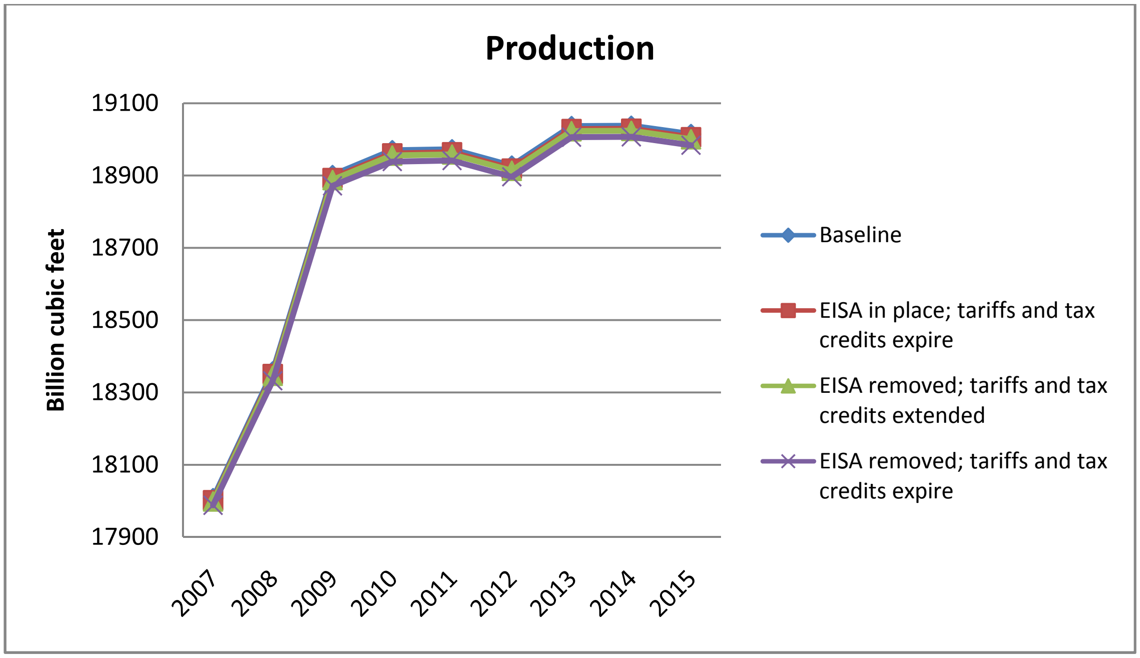

Electricity generation demand
Billion cubic feet
7600
7400
7200
7000
6800
6600
6400
2007
2008
2009
2010
2011
2012
2013
2014
2015
Baseline
EISA in place; tariffs and tax credits expire
EISA removed; tariffs and tax credits extended
EISA removed; tariffs and tax credits expire



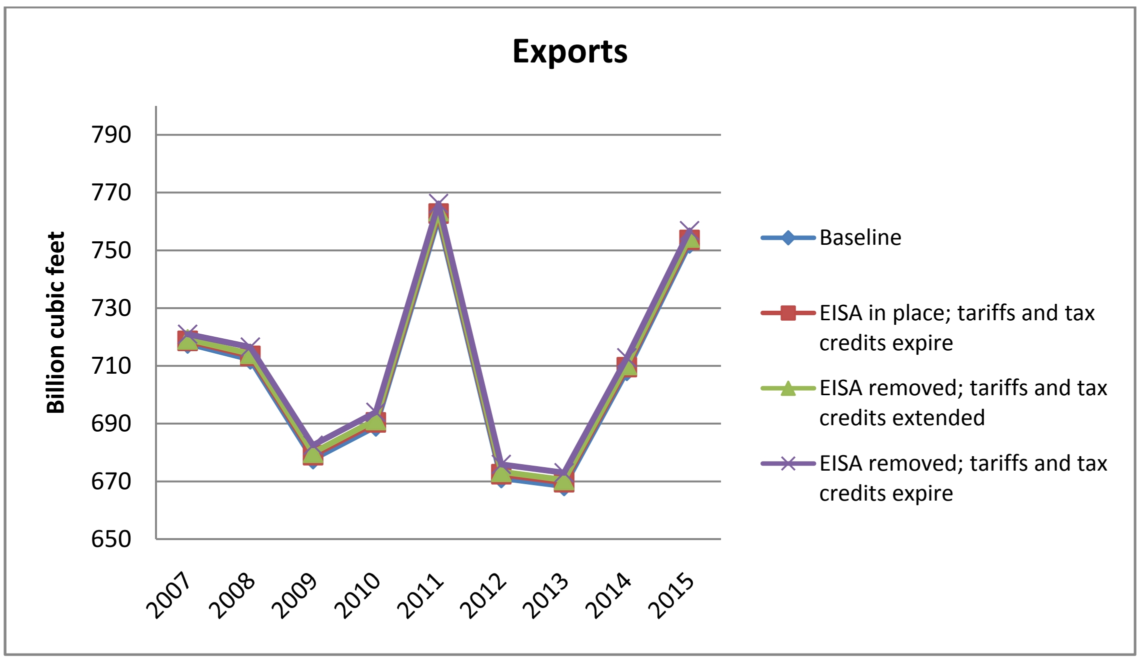
Wellhead price
Dollas per thousand cubic feet
6
5.5
5
4.5
4
3.5
2007
2008
2009
2010
2011
2012
2013
2014
2015
Baseline
EISA in place; tariffs and tax credits expire
EISA removed; tariffs and tax credits extended
EISA removed; tariffs and tax credits expire



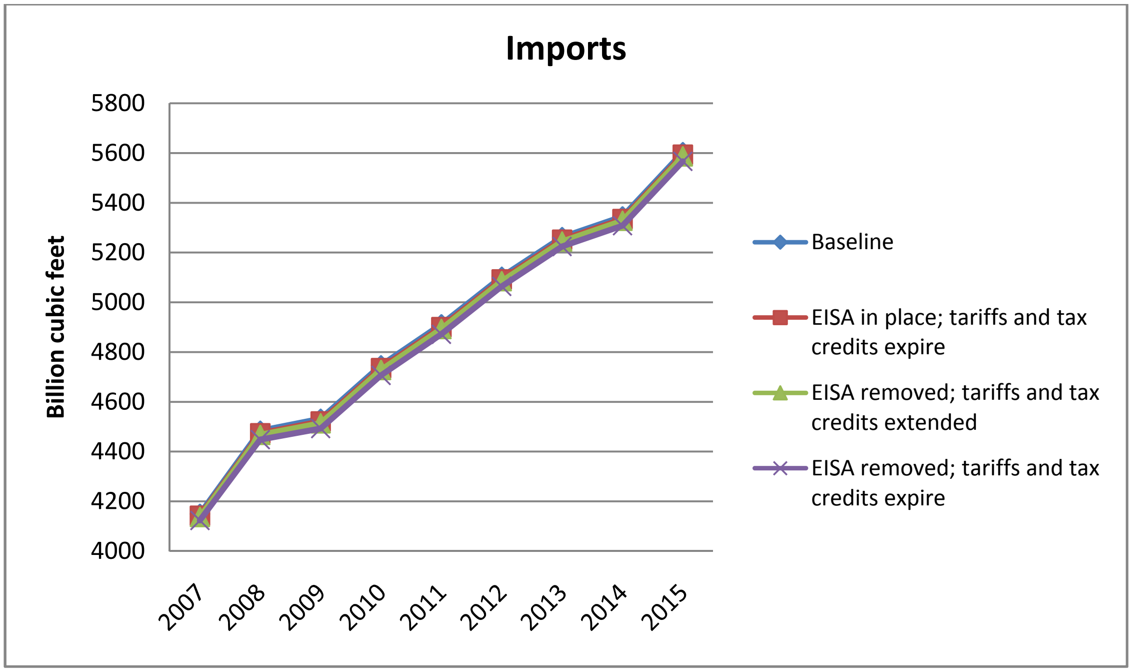
Wellhead price
Dollars per thousand cubic feet
8
7
6
5
4
3
2
1
0
2007
2008
2009
2010
2011
2012
2013
2014
2015
Baseline
EIA projection



Production
Billion cubic feet
19100
18900
18700
18500
18300
18100
17900
2007
2008
2009
2010
2011
2012
2013
2014
2015
Baseline
EISA in place; tariffs and tax credits expire
EISA removed; tariffs and tax credits extended
EISA removed; tariffs and tax credits expire



Exports
Billion cubic feet
790
770
750
730
710
690
670
650
2007
2008
2009
2010
2011
2012
2013
2014
2015
Baseline
EISA in place; tariffs and tax credits expire
EISA removed; tariffs and tax credits extended
EISA removed; tariffs and tax credits expire


Imports
Billion cubic feet
5800
5600
5400
5200
5000
4800
4600
4400
4200
4000
2007
2008
2009
2010
2011
2012
2013
2014
2015
Baseline
EISA in place; tariffs and tax credits expire
EISA removed; tariffs and tax credits extended
EISA removed; tariffs and tax credits expire