Final Technical Report

Period of Performance 8-30-11 to 7-14-16

PI: John Weyant

Grant Title: Energy Modeling Forum

Grant Number: DE-EI0000065

EMF Report 26
Volume I
September 2013

CHANGING THE GAME?: EMISSIONS AND MARKET IMPLICATIONS OF NEW NATURAL GAS SUPPLIES

Energy Modeling Forum
Stanford University
Stanford, CA 94305-4121

Preface

The Energy Modeling Forum (EMF) was established in 1976 at Stanford University to provide a structural framework within which energy experts, analysts, and policymakers could meet to improve their understanding of critical energy problems. The twenty-sixth EMF study, "Changing the Game?: Emissions and Market Implications of New Natural Gas Supplies," was conducted by a working group comprised of leading international energy analysts and decisionmakers from government, private companies, universities, and research and consulting organizations. The EMF 26 working group met several times and held many extensive discussions over the 2011-2013 period to identify key issues and analyze the detailed results.

This report summarizes the working group's discussions of the modeling results on the role of new natural gas supplies in transforming North American energy markets and emissions. The working group is planning an additional volume of individually contributed papers on most of the models in the study. Inquiries about the study should be directed to the Energy Modeling Forum, Huang Engineering Center, Stanford University, 475 Via Ortega, Stanford, CA 94305-4121, USA (telephone: (650) 723-0645; Fax: (650) 725-5362). Our web site address is: *http://emf.stanford.edu/.*

We would like to acknowledge the different modeling teams that participated in the study. Their willingness to simulate the different cases and to discuss their results in detail contributed significantly to an excellent study.

This volume reports the findings of the EMF working group. It does not necessarily represent the views of Stanford University, members of the Senior Advisory Panel, any reviewers, or any organizations participating in the study or providing financial support.

EMF Sponsorship

Financial support from a wide range of affiliated and sponsoring organizations allows the Forum to conduct broad-based and non-partisan studies. During the period covering the study, the Forum gratefully acknowledges the support for its various studies from the following organizations:

America's Natural Gas Alliance
American Petroleum Institute
Aramco Services
BP America
Central Research Institute of Electric Power Industry, Japan
Chevron
Electric Power Research Institute
Électricité de France
Encana
Environment Canada
Exxon Mobil
Lawrence Livermore National Laboratory
MITRE Corporation
National Energy Policy Institute
Sandia National Laboratory
Southern Company
Statoil Hydro
Talisman Energy
TransCanada
U.S. Department of Energy
U.S. Environmental Protection Agency
Williams Energy

EMF 26 Working Group Participants

Name	Affiliation (at time of study)
Misha Adamantiades	U.S. Environmental Protection Agency
Jeff Amlin	Energy2020 Systematic Solutions, Inc.
Doug Arent	National Renewable Energy Laboratory/JISEA
Amy Jordan Bason	Aramco Services Company
Paul Bernstein	NERA Economic Consulting
David J. Borns	Sandia National Laboratories
Erica Bowman	American Natural Gas Alliance
Carl Calantone	TransCanada Corporation
Daniel Chamberlain	MITRE Corporation
John J. Conti	U.S. Energy Information Administration
Lauren Davis	RTI International
Pat DeLaquil	DecisionWare Group
Allen Fawcett	U.S. Environmental Protection Agency
R. Dean Foreman	Talisman Energy
Donald A. Hanson	Argonne National Laboratory
Stephen Healey	Simon Fraser University
Ken Hoffman	MITRE Corporation
Hillard G. Huntington	Stanford University
Franck Ilmain	Chevron
Mark Jaccard	Simon Fraser University
Nicholas Jones	ExxonMobil
Amit Kanudia	KanORS-EMR
Ozge Kaplan	U.S. Environmental Protection Agency
Tony Knowles	National Energy Policy Institute
Peter H. Kobos	Sandia National Laboratories
Angelina LaRose	U.S. Energy Information Administration
Carol Lenox	U.S. Environmental Protection Agency
Nick Macaluso	Environment Canada
Douglas Meade	University of Maryland / Inforum
Dale Nesbitt	ArrowHead Economics
Chris Nichols	U.S. Department of Energy
Victor Niemeyer	Electric Power Research Institute
Albert M. Passy	Statoil North America
Jotham Peters	Navius Research Inc.
Martin T. Ross	Duke University
Sebastien Rossignol	Électricité de France
Charles G. Rossmann	Southern Company
Ira Shavel	CRA International
David Shin	American Petroleum Institute
A.J. Simon	Lawrence Livermore National Laboratory
David Tsuyuki	Encana

Sugandha Tuladhar	NERA Economic Consulting
Liqing Wang	Navigant Consulting
John Weyant	Stanford University
Alan Wilson	Encana Oil & Gas
Evelyn Wright	KanORS / Decisionware
Yingxia Yang	CRA International
Greg Zwick	TransCanada

Table of Contents

Table of Figures

List of Tables

Study Highlights

This study evaluates the channels through which shale formations and new natural gas supplies can change energy, economic and environmental opportunities within North America. It concludes that continued shale gas development within North America is likely to have more sweeping impacts on future energy prices than on the economy or the environment. This evaluation was conducted by a working group of 50 experts and advisors from a range of diverse universities, research institutes, corporations and government agencies. Support for the study's conclusions came from 14 different expert teams using their own energy-economy models.

Natural gas producers currently receive about $4 per thousand cubic feet, up from about $2.50 about a year ago. Baseline projections in the study anticipate some upward drift in prices that range between $4.03 and $6.24 by 2020 across the models even after adjusting for inflation. More optimistic supply conditions, however, should reduce this price range to $2.67 and $4.95 by lowering production costs.

The upward drift in prices expected by most groups reflects a market where demand for natural gas slowly catches up to the robust supplies of shale gas that have been recorded since 2006.

If the economy should grow faster than anticipated, natural gas prices will be higher but only modestly so. Prices are no more than $0.41 higher by 2020 in any model if the economy grows by 3.0 percent annually rather than 2.5 percent. Additional consumption is not expected to add greatly to the costs of producing more natural gas.

The study underscores that relying upon a single forecast can be very risky. Instead, the study often discusses the impacts in terms of ranges found across the various models. Each expert team holds very different views on fundamental supply and demand conditions that shape the future path for natural gas and competitive fuels.

Shale development also boosts the economy by $70 billion annually over the next several decades. Although this amount appears large, it represents a relatively modest 0.46 percent of the US economy. Today total natural gas expenditures represent about one percent of GDP within this country.

Shale development has relatively modest impacts on carbon dioxide, nitrogen oxide and sulfur dioxide emissions, particularly after 2020. Since 2006, electricity generation has become less carbon intensive as its natural gas share increased from 16 to 24 percent and its coal share decreased from 52 to 41 percent. Over future years, this trend towards reducing emissions becomes less pronounced as natural gas begins to displace nuclear and renewable energy that would have been used otherwise in new powerplants under reference case conditions.

Another contributor to the modest emissions impact is the somewhat higher economic growth that stimulates more emissions. Reinforcing this trend is the greater fuel and power consumption resulting from lower natural gas and electricity prices.

1 Introduction

North American natural gas supplies have expanded significantly since 2006 with the rapid expansion of two processes: horizontal drilling and hydraulic fracturing. Horizontal drilling allows drillers to search for gas laterally after they have drilled vertically often half a mile or more below the earth's surface. Hydraulic fracturing injects pressurized water and small amounts of chemicals and sand into tightly packed rock formations to stimulate the flow of gas. Combined these practices have significantly increased the production which has led to a concomitant reduction in the price of natural gas in North America relative to other fossil fuels and renewable energy sources, setting off a major transition where natural gas is replacing coal in the power sector and impacting the relative competiveness of renewable electricity projects. Unlike many other alternative energy processes like the synthetic fuel dreams of the past, carbon capture and sequestration promises for the future or some wind and solar options in today's markets, the growth in the use of natural gas, as well as upstream investments have not been driven by government mandates, but instead strong commercial interests and entrepreneurial actions. This development has been widely heralded for reducing greenhouse gases and other pollutants as well as for stimulating economic growth. This study sets out to attempt to answer some key questions relative to the medium and long-term potential for natural gas in the US energy economies, impacts on emissions, economic activity and price dynamics.

This report summarizes the work conducted by a working group of about 50 company, government and university experts and advisors that was organized by the Stanford University Energy Modeling Forum. It concludes that continued shale gas development within North America is likely to have more sweeping impacts on future energy prices than on the economy or the environment. The next section begins with an overview of the process adopted by this group. Following sections discuss the implications of expanded shale supplies on economic growth, emissions and the carbon intensity of the fuel supply within the United States through the year 2050. Additional sections describe the impacts on the electric power sectors as well as on the aggregate energy picture. A concluding section highlights the major advantages and limitations of extant large-scale energy models for evaluating the highly complex and risky trends shaped by today's shale gas boom.

2 The EMF Study Design

The Energy Modeling Forum formed a working group of about 50 experts and advisors from companies, government agencies and universities. The group focused on the impacts of the North American natural gas shale revolution on energy markets and various emissions. A comparison of model results facilitated a discussion of the main insights and market risks. Although many organizations often use models to develop forecasts of future conditions, the group focused more effort on understanding key longer-term trends and market risks over the next several decades.[1]

The working group identified the major issues, developed interesting scenarios, and compared and discussed the results from 14 models. It met four times over November 2011-May2013 period.

Modeling teams from 14 different organizations (Table 1) participated in the study. All models integrated information on energy supply and demand to provide prices that reached market balances for each individual fuel. The models used different approaches to determine these prices (See Appendix A). Some models focused on the major inter-industry linkages within the economy. Energy consumption in these models relied upon demand relationships to reveal how energy prices influenced energy demand. Other models placed more emphasis on the competition between explicit technologies for meeting energy service demands.

The study participants considered nine different cases based upon standardized assumptions (See Appendix B). Each modeling team assessed what to include in a baseline scenario for comparing with other cases. They used the 2012 reference case developed by the U.S. Energy Information Administration (EIA) as a guide rather than as a rigid requirement. This case is well known by the public and frequently used by other groups in discussing future energy market conditions. It shows inflation-adjusted oil prices rising by 2.3 percent per year, reaching about $133 per barrel (2010 $) by 2035. The economy grows steadily at 2.5 percent per year over this period. The scenario excludes any new energy policies that restrict fuel use or resource supply development. The other eight alternative cases allow variations in these reference conditions. They represent situations when natural gas is either more or less expensive to produce, when economic growth, technology advances or export expansions allow more energy demand, or when policymakers impose carbon cost constraints on the economy.

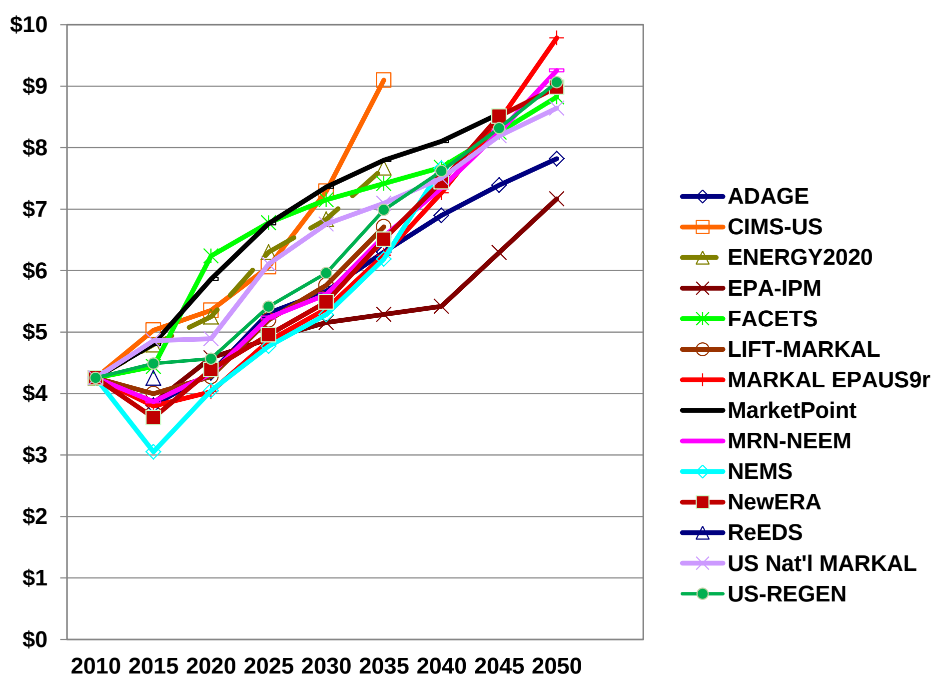
Table 1. Participating Modeling Teams

Model	Institution	More Information
Marketpoint	Deloitte MarketPoint	https://www.deloittemarketpoint.com/models-data/models-data/natural-gas-models
US-REGEN	Electric Power Research Institute	http://globalclimate.epri.com/results_and_publications__US-REGEN.html
MRN-NEEM	Charles River Associates (CRA)	http://www.crai.com/ConsultingExpertise/Content.aspx?tID=828&subtID=842&tertID=894
NewERA	National Economic Research Associates	http://www.nera.com/59_7655.htm
ADAGE	Research Triangle Institute & Duke University	http://www.rti.org/page.cfm?objectid=DDC06637-7973-4B0F-AC46B3C69E09ADA9
LIFT-MARKAL	U Maryland Inforum & MITRE	http://www.inforum.umd.edu/services/models/lift.html
NEMS	US Energy Information Administration	http://www.eia.gov/oiaf/aeo/overview/
CIMS-US	Simon Fraser University	http://www.emrg.sfu.ca/Our-Research/Policy-Modelling
ENERGY2020	Systematic Solutions, Inc.	http://www.arb.ca.gov/cc/scopingplan/economics-sp/models/V1_Overview.pdf
US National MARKAL	DecisionWare, Inc.	http://iea-etsap.org/web/MARKAL.asp#applic
MARKAL EPAUS9r	Environmental Protection Agency (Research Triangle)	http://www.epa.gov/nrmrl/appcd/climate_change/markal.htm
FACETS	KanORS Consultants (India)	http://www.kanors.com/DCM/RES2020/Docs/Index.aspx
EPA-IPM	US Environmental Protection Agency	http://www.epa.gov/airmarkt/progsregs/epa-ipm/index.html
ReEDS	National Renewable Energy Laboratory	http://www.nrel.gov/analysis/reeds/

3 Diverse Natural Gas Market Conditions

Although the reference case projections adopt standardized assumptions about oil prices and economic growth, each model shows a unique path for future natural gas market conditions. By 2035 inflation-adjusted wellhead prices (Figure 1) in 2010 dollars range between $5.30 and $7.80 per thousand cubic feet (Mcf).[2] Higher prices are associated with resource basins that are more expensive to develop, although demand conditions also matter. Within the next five years, many models show a softening of natural gas prices, as demand enters a "catch-up" phase to meet expanding supplies. By 2020 wellhead prices begin rising, as energy consumers start placing greater demands on the natural gas resource base. The Henry Hub wellhead price in June 2013 is approximately $4 per thousand cubic and about 22 percent of the Btu-equivalent imported crude oil costs. The average projected wellhead natural gas price in this study remains at about 21 percent of the Btu-equivalent oil price by 2020 but eventually rises to 29 percent by 2035. Corresponding total natural gas consumption (Figure 2) ranges between 24 and 34 trillion cubic feet (Tcf).

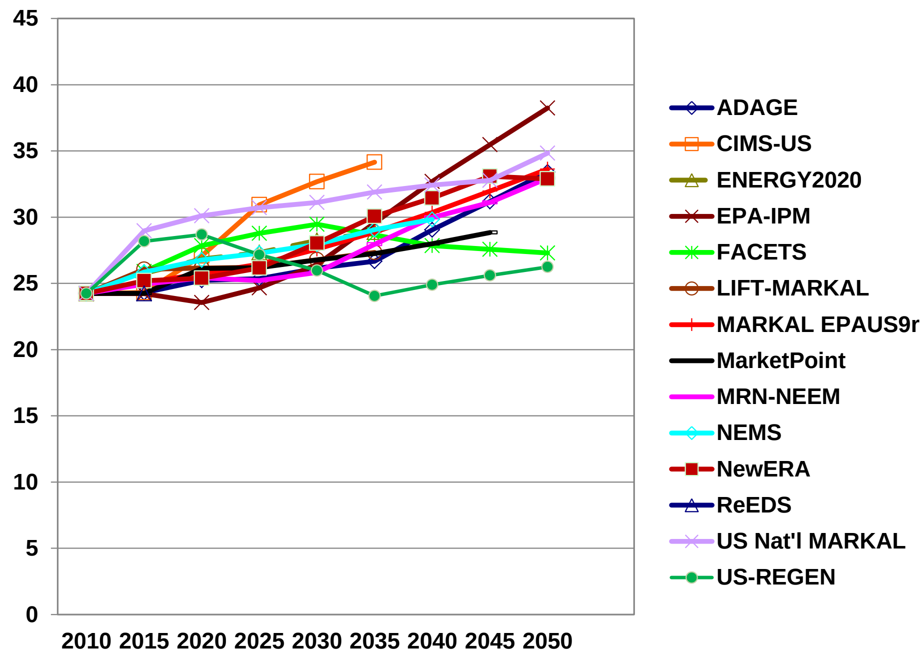
Figure 1. Reference Case Wellhead Price (2010$/Mcf)



Equally important are the nearer-term price projections as well. By 2020 inflation-adjusted wellhead prices in 2010 dollars span $4.03 to $6.24 per thousand cubic feet in 2010 dollars. The lower end of these estimates is approximately the same as current levels (for June 2013) in 2010 inflation-adjusted dollars. The higher end is about 57 percent higher.

The more abundant shale gas represented in the high-shale case substantially reduces the 2020 wellhead prices in many models. Under these conditions, projected 2020 prices could range either above or below 2013 price levels, ranging between $2.67 and $4.95 per thousand cubic feet.

Figure 2. Reference Case Total Natural Gas Consumption (Tcf)

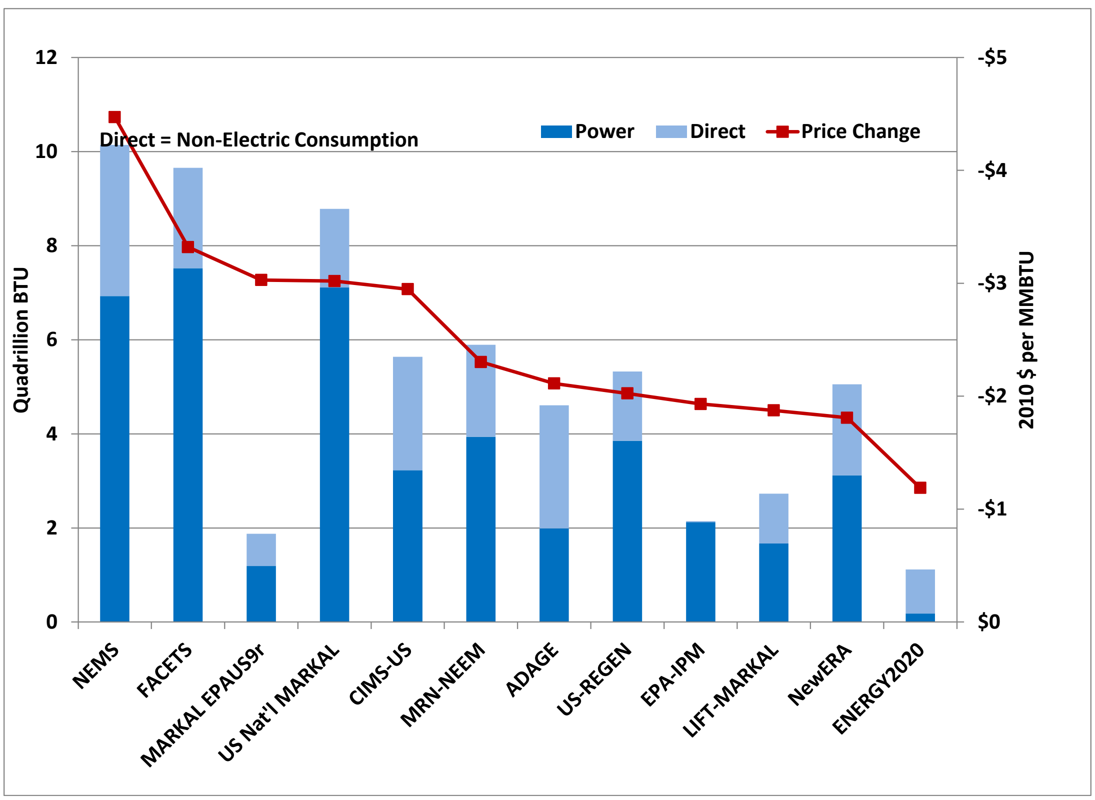


Wellhead natural gas prices are only modestly sensitive to future economic growth. Under the high-economic-growth scenario, inflation-adjusted GDP grows by 3.0 rather than 2.5 percent per year. With baseline resource cost conditions, projected inflation-adjusted prices rise to a range of $4.03 to $6.65 by 2020.

The diversity in model projections is an important result in this study. It represents the uncertainty that various groups have about future natural gas market conditions. Although disparities are often observed in model-comparison studies, the range of results underscores the high degree of uncertainty that experts have about the recent shale gas development. Important factors include the costs of developing additional resources, the flexibility by consumers in seeking new applications for natural gas, and policies that affect fuel choice by electric utilities and end users. Particularly important are regulations that facilitate more or less expansion in nuclear, solar, wind or energy-efficiency opportunities. An advantage of having more diverse conditions is that the study conclusions may be more robust than if the groups had standardized more factors. A disadvantage is that it is more difficult to compare one model structure with another, because it is difficult to diagnose the reasons for differences when many factors vary from each other. For this reason, this report emphasizes the broad conclusions from the model results collectively rather than in how models differ from each other.

This diversity repeats itself when the models applied different resource cost conditions. The working group facilitated a discussion of a high-shale supply case by allowing changes in the ultimately recoverable resource base and the recovery rates per well that reduced natural gas production costs. Although model teams were provided with the assumptions used by the EIA in their AEO2012 projections, each group made its own assessment when implementing this scenario. Although these conditions can be contrasted with the reference case, the working group decided that it would be more useful to use a low-shale supply case as a benchmark for evaluating the impacts due to the shale boom.[3] The reference case already includes much of the newly discovered shale and other natural gas supplies. The low-shale scenario incorporates more pessimistic assumptions about resource availability as well as its ultimate recovery that increases the per-unit cost of developing the resource. The results from this scenario can also be interpreted as the effects of regulatory restrictions on future shale development.

Figure 3. Impact of High Shale on 2035 Electric and Direct Natural Gas Use



In the models production costs will influence wellhead prices in combination with demand conditions. Figure 3 emphasizes the major differences in the way that each model team implemented these conditions. The solid red line and right-hand axis display the difference in the resulting wellhead prices in dollars per Mcf between these two cases for 2035. By 2035 wellhead prices in the high-supply case are between $1 and $4.50 per Mcf below their low-supply paths depending upon the model.

It is not surprising that larger price declines generally encourage more expansion in natural gas consumption. With the models organized from larger to smaller price declines, the stacked bars and left-hand axis indicate the consumption responses in 2035. The lower darker bar represents natural gas consumption in the power sector, while the upper lighter bar represents direct natural gas use in the other, non-electric sectors. Within a model, the power sector response tends to dominate the direct gas use response.

4 Broad Impacts of the Shale Boom

Higher shale resources reduce the costs of natural gas development and expand opportunities throughout the economy. Relative to its path in the low-shale case, the inflation-adjusted gross domestic product (or real GDP) is higher in all models that track the economy's aggregate output. The cumulative aggregation of these GDP gains over all years is significant standing at $1.1 trillion (2010 dollars). (All prices, gross domestic product levels and economic damages from pollution or climate change in this section are adjusted for inflation and expressed in 2010 dollars.) When amortized over the horizon of the study (through 2035 or 2050 depending upon the model), these GDP premiums average $70 billion each year.[4] This amount is about 0.46 percent of $15 trillion, the approximate 2012 GDP level for the United States. Other measures beside the higher GDP level may provide different estimates for the economic gains. See for example Appendix C, which discusses economic welfare gains. The main report uses the GDP estimates because policymakers understood them better than other indicators and the modeling teams have directly reported them.

These gains will be concentrated in a few important sectors, particularly the oil and gas extraction, chemical product and various supporting industries. The shale boom will revitalize these sectors, which were relatively stagnant prior to the first signs of the shale boom in 2006.

Manufacturing in the downstream supply-chain using domestic low-cost plastics and petrochemical products (for local or export markets) may in particular benefit from these developments.

Whether this $70 billion spurt alone will create a resurging US economy, as claimed sometimes in the public press, appears speculative without further research.[5] Although these gains appear large, they are concentrated in a small share of the total economy. A principal reason for this small impact is the size of the oil and gas extraction industry including support activities for mining.[6] Including a portion of these support activities, this sector represented only 0.23 percent of total U.S. employment and 1.44 percent of total U.S. value added in 2011, the latest year for a detailed industrial accounting. The principal industry that will benefit from less expensive natural gas is chemical products, which accounted for 0.57 percent of total employment and 1.68 percent of total value added in that same year. In aggregate, expenditures for natural gas delivered to all end users (including electric powerplants) accounted for 1.08 percent of gross domestic product.[7] Those expenditures are a considerably smaller share than the 4.8 percent allocated for refined petroleum products to final consumers.

Higher economic growth will increase carbon dioxide, sulfur dioxide and nitrogen oxide emissions at the point of delivery (i.e., “downstream”). Less expensive natural gas will also reduce electricity prices and increase total energy and natural gas use, reinforcing this trend. At the same time natural gas may replace other fuels that are more intensive in these pollutants, causing total emissions to decline with more shale development. The natural gas share of total primary energy used for generating electricity rose from 16 to 24 percent over the 2006-2012 period, while the comparable share for coal declined from 52 to 41 percent.[8] If this energy-replacement effect is sufficiently strong in the future, more shale gas development will reduce total emissions.

For consistency with the above economic effects, the study has valued each change in emission types between high- and low-shale cases in monetary terms. The projected change in emissions for each model was multiplied by an estimate of the damage per metric tonne available from other sources on external environmental costs.[9] Although substantial uncertainty exists about the magnitude of each estimate of the per-ton damage, they would have to be several orders of magnitude greater than estimated by various reputable groups before the estimated environmental impacts would be large relative to the economic effects. The estimates of damages from carbon dioxide are based upon carbon costs at the higher end of an uncertain range, reflecting expert opinion that average effects may understate the possibility of abrupt climate change.[10] Sulfur dioxide and nitrogen oxide damages are also uncertain and vary substantially upon the type and location of the application generating the emissions. For this reason, one should view these damage values as providing only an approximate indication of how important these emissions are. A more thorough evaluation would also require estimates for all pollutants and for other greenhouse gases that contribute to global climate change. The study could not include these other considerations because not enough models reported these impacts.

Based upon the damage-per-tonne estimates discussed immediately above, the cumulative change in these emission damages over all years is much smaller than the corresponding change for economic growth. When amortized over the horizon of the study (through 2035 or 2050 depending upon the model), the average emission damages decline by $1 billion (2010 dollars) each year for sulfur dioxide and by $0.25 billion each year for nitrogen oxides. Damages from carbon dioxide emissions, "downstream" at the burnertip, actually increase slightly by $1.8 billion each year when emissions are measured over the full horizon of the study. These results are based upon emission reductions from the models that are discussed later in the report.

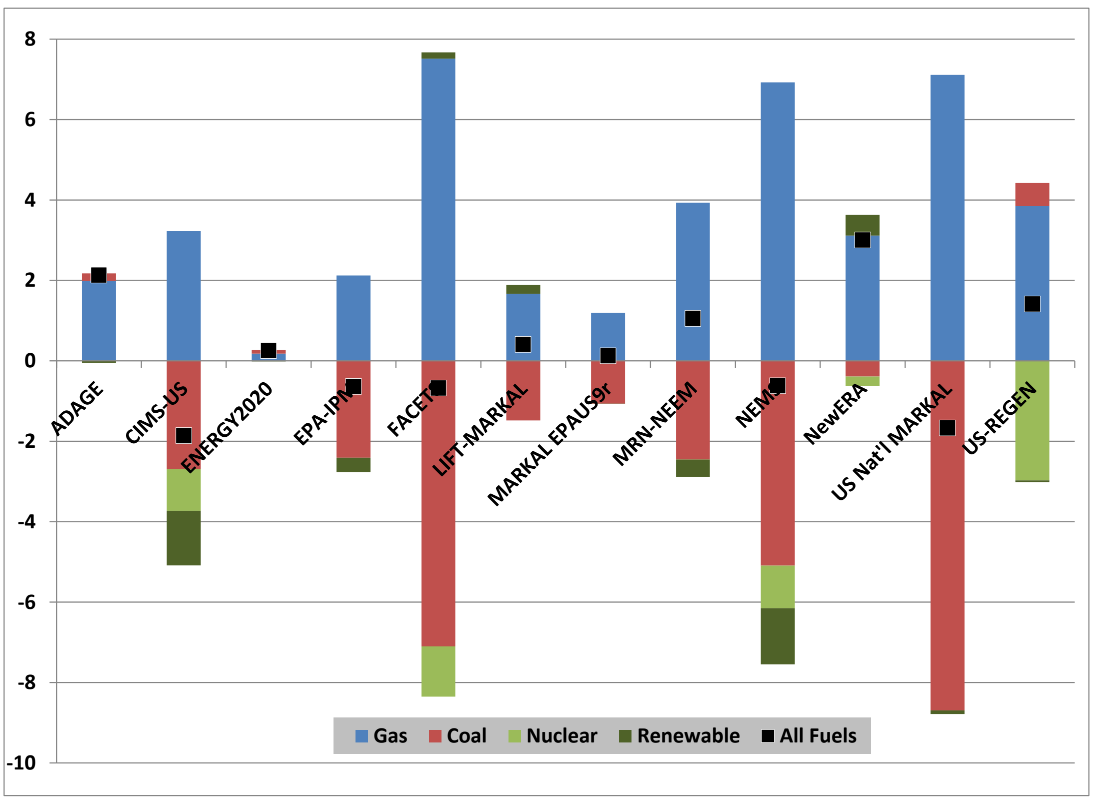
All of these results mask considerable differences between models, some of which show increasing damages and others show decreasing damages. However, even the largest reduction in damages does not alter the conclusion that the economic gains dominate the emission damages in terms of the benefits attributable to shale gas development. The maximum reduction in damages reported for downstream carbon dioxide is $6.9 billion, for nitrogen oxides is $0.9 billion, and for sulfur dioxide is $2.6 billion. The average GDP gain is between 10 and 75 times larger than these estimates.

Developing these shale resources raises a number of other environmental concerns ranging across various chemicals used for the refracturing, drinking water quality, and methane leakages from upstream drilling activities. The social disruption of shale drilling activities on local communities is also a concern. Our report does not contribute any new findings on these public concerns, but many experts think that new regulatory frameworks and monitoring can evolve to manage these risks. Our estimates of higher economic activity due to greater shale supplies suggest that the nation will gain substantially if policymakers can find an approach for managing these environmental and social impacts that will allow shale development to continue.[11]

5 Fuel Shares within the Electric Power Sector

Natural gas has been a strong competitor with coal for electric generation since 2006. The study projections confirm that this fuel competition will continue over the next several decades. Figure 4 reveals the shift in energy use (in quadrillion Btus) between the high-shale and low-shale conditions in 2035. The stacked-bar chart decomposes the change in electric power sector's fuel use into various fuels. Natural gas expansions above the origin (blue bars) are offset by coal contractions below the origin (red bars). Higher shale extraction causes nuclear use to decline in several instances, with a significant reduction in one model (US_REGEN). Several results show natural gas displacing renewable sources when high-shale conditions prevail, although renewables expand along with natural gas in two models (NewERA and LIFT-MARKAL).

Figure 4. Shale Impact on Electric Power Energy Use (Quads), 2035



The fuel mix chosen by the electric sector in the low-shale baseline conditions plays a critical role in determining these responses. The large replacement of coal in more than half the models occurs because regulatory policies and energy-market conditions allow coal to be an important fuel source in the low-shale case even though its share declines over time. In contrast, the smaller coal displacements in the US-REGEN and MARKAL EPAUS9r frameworks result from a more rapid phase-out of coal powerplants even without more optimistic natural gas supply conditions.

There appears to be little agreement about whether total electric fuel use will be higher or lower with more optimistic natural gas supply conditions. The small black square for each model indicates the change in total energy use for electric generation in 2035. More natural gas availability may expand electricity demand through higher economic growth. It also reduces the prices of both natural gas and electricity. If electricity prices fall sufficiently and consumers shift more towards electricity, the power sector may demand more fuel use overall. This response appears to happen in the ADAGE and NewERA projections. Offsetting this effect in NEMS and some other models, however, is the improvement in fuel efficiency when more coal plants that require more heat to produce electricity are displaced by combined-cycle natural gas plants that require less heat.

6 Primary Fuel Shares

An expansion in shale gas supplies also influences fuel choice outside the electric power sector. In the projections these adjustments most frequently occur within the industrial sector. Chemical and related industries that prefer natural gas will grow more strongly when shale supplies are plentiful. In other sectors the projections call for limited natural gas penetration. Heavy trucks powered by LNG engines are promising options, but several factors restrict the expansion of natural gas in light-duty vehicles. The fuel economy gains with hybrids and electric vehicles make it difficult for natural gas vehicles to attract consumers searching for fuel savings. Additionally, there are constraints in delivery infrastructure and vehicle amenities (limited luggage space). In 2035 energy use for transportation changed by less than one quad in the projections when natural gas was more available.

Total natural gas consumption used for both electric and non-electric purposes grows sharply faster with high-shale than with low-shale conditions. Figure 5 shows that total consumption generally grows with both high-shale and low-shale conditions over the 2010-2035 period. Total natural gas consumption usually grows by 0.5 percentage points faster with high-shale than with low-shale conditions, as indicated by the dark and light bars, respectively.

Figure 5. Total US Natural Gas Consumption, 2010-2035 (% per annum)

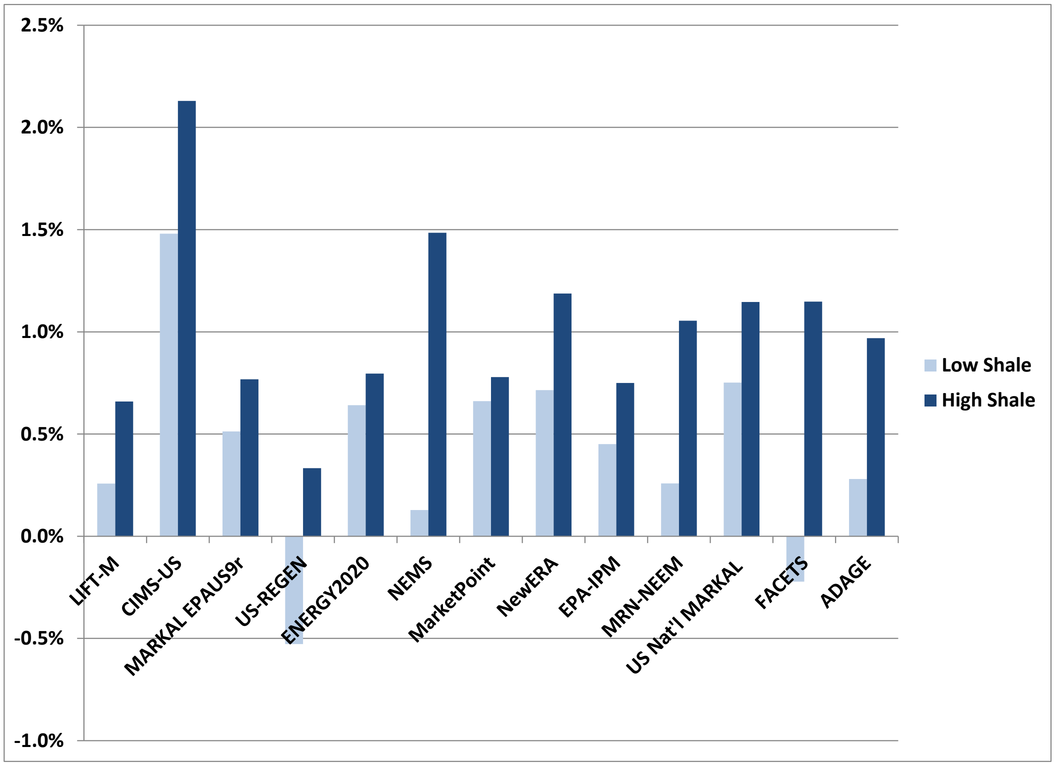
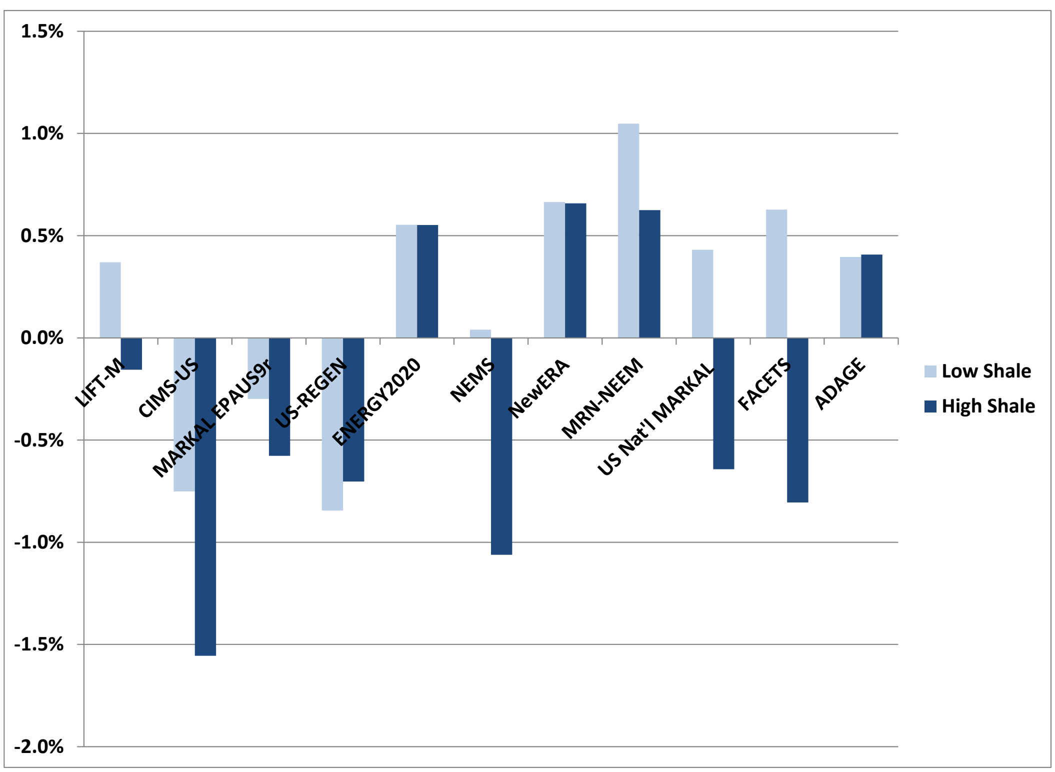


Figure 6. Total US Coal Consumption, 2010-2035 (% per annum)



Total coal consumption used for both electric and non-electric purposes grows slower with high-shale than with low-shale conditions. Figure 6 shows that despite more regulatory controls for water use and cooling, mercury, and cleaner air, total coal consumption grows over the 2010-2035 period in eight of the eleven projections with low-shale conditions. These growth rates often decline when natural gas is more available and less expensive.

The projections in Figure 7 show different patterns for nuclear power's growth rate. It grows strongly in both high and low-shale cases in US-REGEN and mildly in many other projections. It declines in the NewERA, IPM-ERA and US National MARKAL models. Except for the CIMS-US, US-REGEN, FACETS and NEMS results, high-shale conditions do not substantially retard the growth of nuclear power below the low-shale-supply case.

The implications appear mixed for renewable energy sources for electric generation. Figure 8 shows that total renewable consumption grows with both high-shale and low-shale conditions over the 2010-2035 period. Total renewable consumption in half the models grows

Figure 7. Total US Nuclear Consumption, 2010-2035 (% per annum)

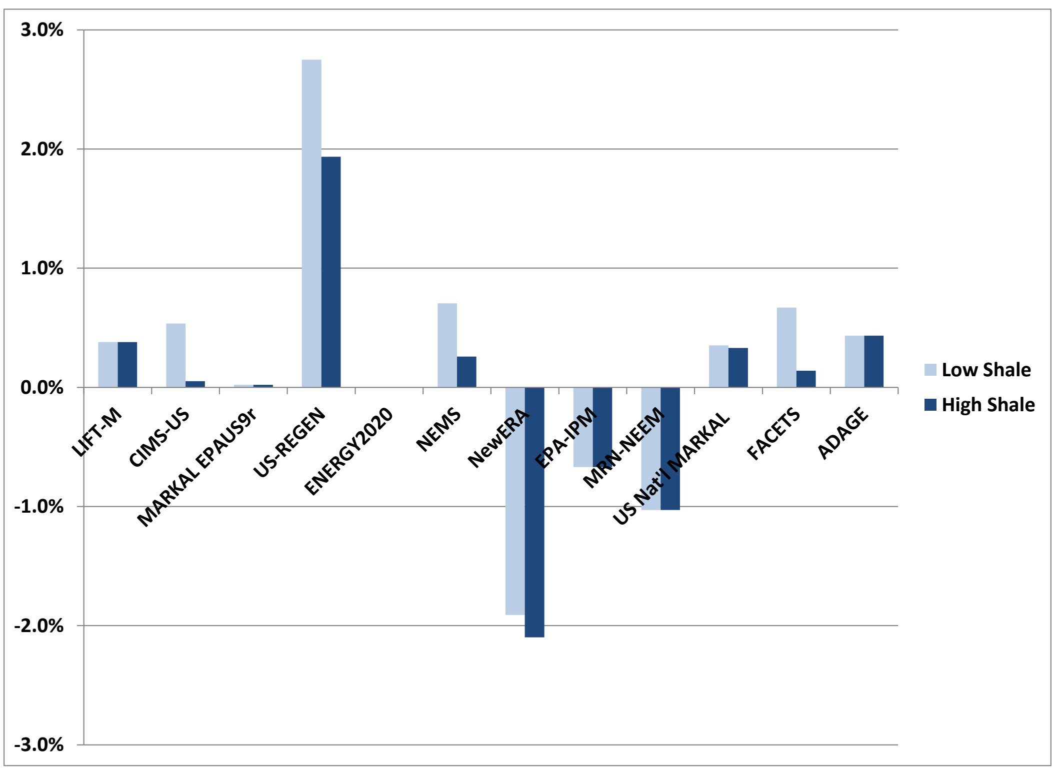
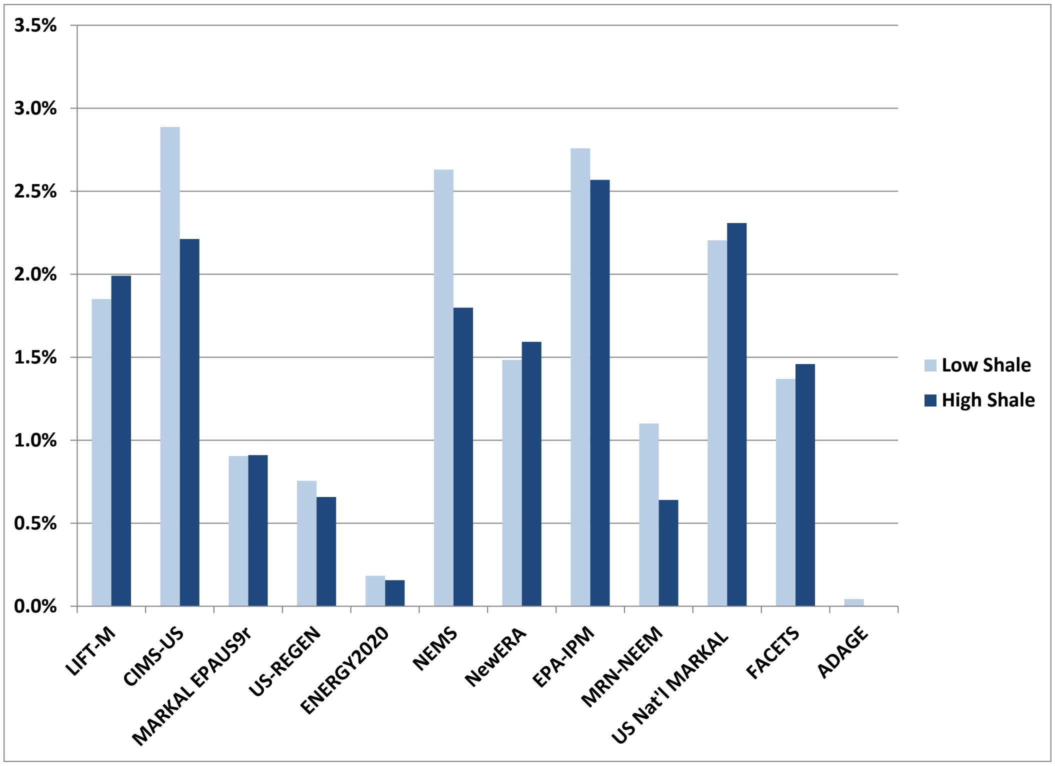


Figure 8. Total US Electric Renewable Consumption, 2010-2035 (% per annum)



more slowly with high-shale than with low-shale conditions, while the other half indicate a faster growth rate. These differences reflect dissimilar assumptions about alternative technology costs for these sources or about how the government implemented renewable portfolio standards or regulated fuel use within the power sector. Future efforts might standardize on these assumptions, but the working group wanted to allow modeling teams some flexibility in interpreting these important technology and policy uncertainties.

Total oil consumption grows much more slowly than for the other energy sources regardless of the natural gas supply conditions. Figure 9 emphasizes this point by using a scale similar to the other fuel charts. Moreover, replacing low-shale with high-shale conditions does not much alter oil consumption growth rates. The limited impact on oil markets reflects the limited penetration by natural gas within the transportation energy sector. All but one model (NEMS) did not incorporate any expansions in tight oil resources from baseline levels in this scenario.

The stacked-bar chart in Figure 10 reveals how the change in the total economy's primary energy use is decomposed by fuel type when natural gas is more available. Primary energy refers to the total energy prior to any transformations like electric generation, which cause some energy

Figure 9. Total US Petroleum Consumption, 2010-2035 (% per annum)

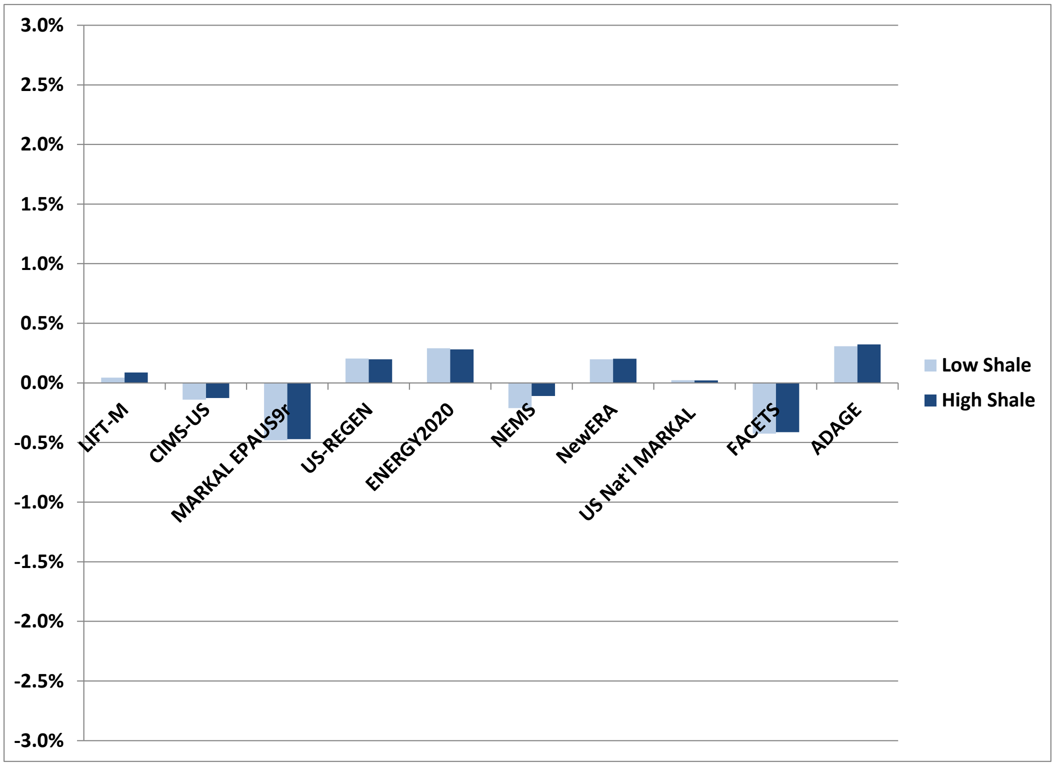
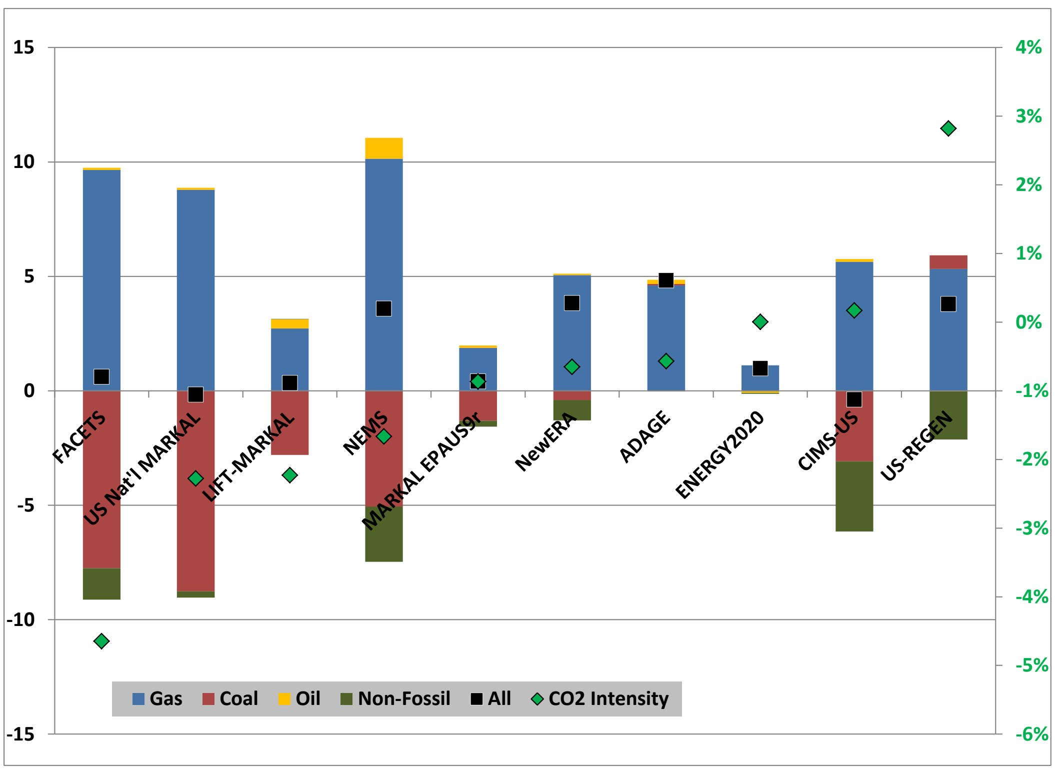


Figure 10. Shale Impact on Total Primary Energy Use (Quads), 2035



losses in the process. Once again, the replacement of coal by natural gas dominates these results. Non-fossil sources are reduced noticeably in about half the projections. These conditions influence oil consumption much less. The solid black box indicates that total energy use in the economy generally increases above the low-shale case level.

The projections have been reordered to show those with the largest fuel decarbonization beginning on the left side of the figure. This approach defines decarbonization as the ratio of carbon dioxide emissions to primary energy use. The green diamond for each model shows the net impact of more natural gas on the projection's carbon intensity as high-shale replaces low-shale conditions. The three projections with the most decarbonization (FACETS, US National MARKAL, and LIFT-MARKAL) all reveal large shifts away from coal with little or no net increase in primary energy use. Although the NEMS projection also displays a significant shift away from coal, it embodies higher total energy consumption. The stronger net growth in primary energy use in this model tends to dampen the decline in carbon intensity that results from greater natural gas availability. These results serve as a useful precursor to the discussion of carbon dioxide intensities observed in the high-shale and carbon constraint cases.

7 Emissions

Overall shale gas development and use across the breadth of scenarios analyzed have relatively modest impacts on the emissions of carbon dioxide, sulfur dioxide and nitrogen oxides. The implications for carbon dioxide are mixed and depend very much on the model and specific assumptions about the growth of coal, nuclear and renewable energy. It causes small reductions in damages coming from the other two emissions.

Natural gas has lower emissions of carbon dioxide, sulfur dioxide and nitrogen oxides at the burnertip than coal and oil. This substitution will decrease total downstream emissions but other factors caused by more available natural gas may offset it. These effects include higher GDP, more energy use and the displacement of sources with fewer emissions like renewable and nuclear energy.

This section reviews the results for carbon dioxide emissions in greater detail. It compares by model the growth trends for different shale supply conditions with those under a carbon-cost constraint case. The latter scenario provides a useful benchmark for considering the different shale supply cases but is not meant to be a normative policy case. It is well understood that combined action on multiple greenhouse gases is more efficient than focusing upon carbon dioxide alone when mitigating climate change.

This case describes an energy market where politicians adopt a series of unspecified policies that gradually raises the cost of using fossil fuels that are carbon intensive. Although these costs could be passed along through carbon taxes or tradable permits, they could also result from other programs that restrict carbon-based energy sources. These programs are implemented in 2013 and are not allowed to cost more than $25 (2010 dollars) per tonne of carbon dioxide emissions. Over time, they become more severe with inflation-adjusted costs that increment by 5 percent per year to reach $75 (2010 dollars) in 2035. These additional costs discourage the use of carbon-intensive fuels but do not transfer funds towards the government.

Figures 11, 12 and 13 show the annual growth trends covering the 2010-2020, 2010-2035 and 2010-2050 periods, respectively. The bars display total carbon dioxide emissions by model in three separate scenarios: low-shale (light blue bars), high-shale (dark blue bars) and carbon-price (green bars) conditions. In any of the three periods, the difference between the high-shale and low-shale cases is relatively small. Emission growth rates for the reference case are not shown because they track closely those for the two-shale cases. In contrast, emission growth rates for the carbon- price case lie well below the other trends.

The carbon dioxide emission differences due to shale supply conditions are not only smaller than those due to carbon-price impacts, but they are also not uniformly lower in each model for the high-shale relative to the low-shale conditions. In any period some models show a higher emissions growth and other models show a lower emissions growth in the high-shale case.

Whereas Figures 11, 12 and 13 show the rate of growth in emissions in individual cases, it is easier to understand the impact of shale supply on the carbon dioxide trends by decomposing the change in emissions due to different effects. Appendix D provides a more thorough decomposition to show the separate effects of greater GDP, improving primary energy intensity (Btu per dollar of GDP), and the decarbonization of primary energy supply (tonnes of carbon dioxide emissions per Btu). Figure 14 displays a simpler segmentation that underscores the same principles. The change in carbon dioxide emissions due to high-shale supplies for the 2010-2035 period is shown for each model by the dark blue bar. The models are ordered by this variable, with the largest declines appearing on the left side of the figure. The green bar indicates the

Figure 11. Total US CO2 Emissions, 2010-2020 (% per annum)

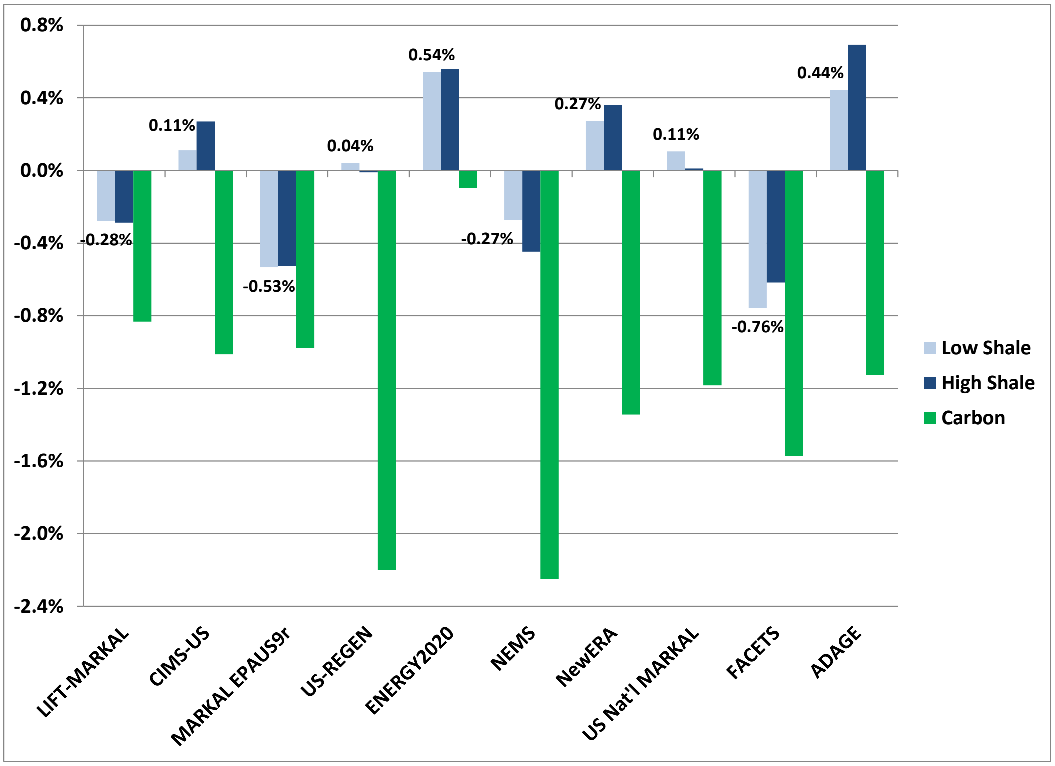


Figure 12. Total US CO_2 Emissions, 2010-2035 (% per annum)

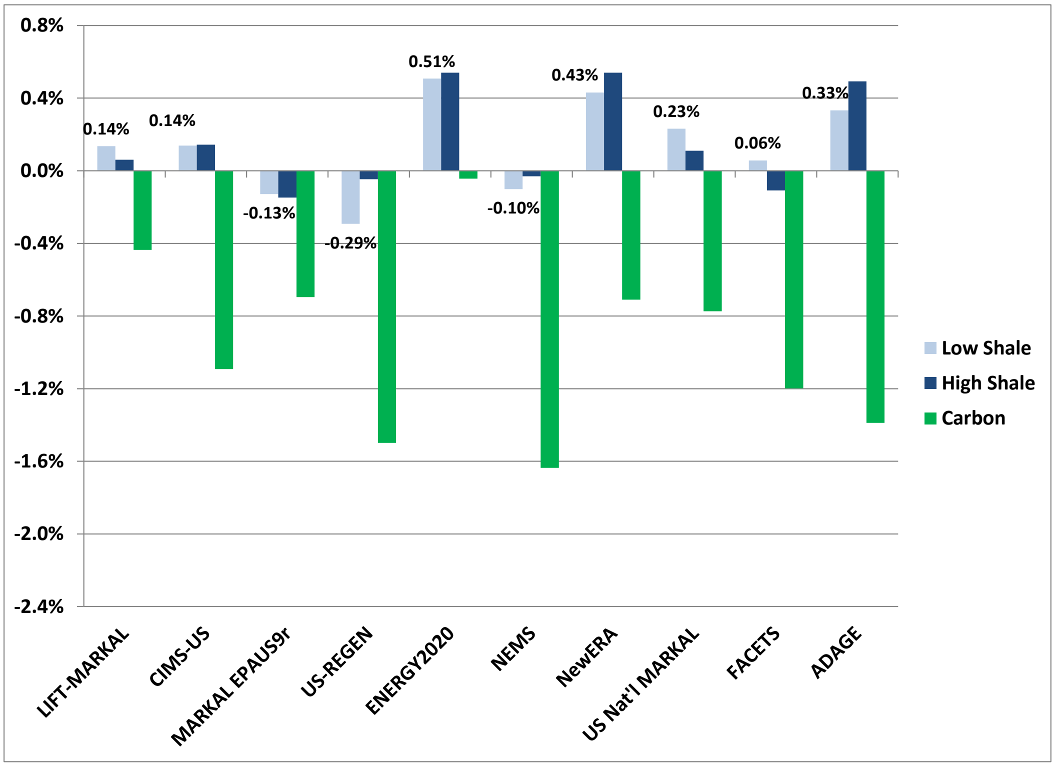


Figure 13. Total US CO_2 Emissions, 2010-2050 (% per annum)

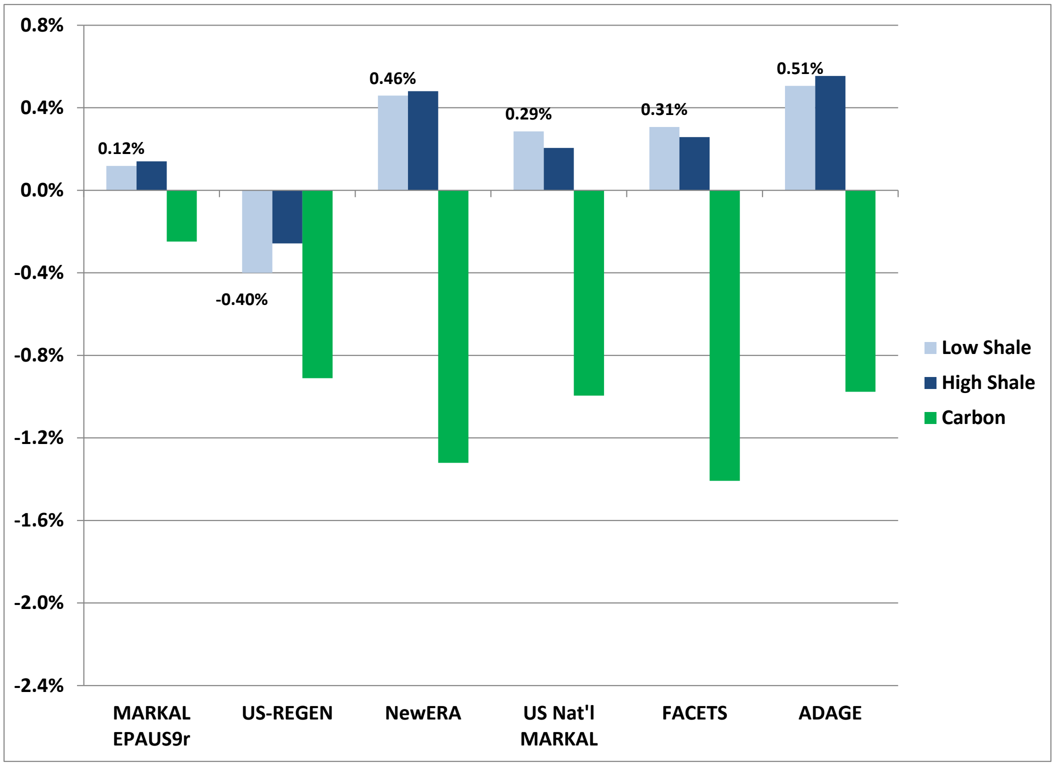
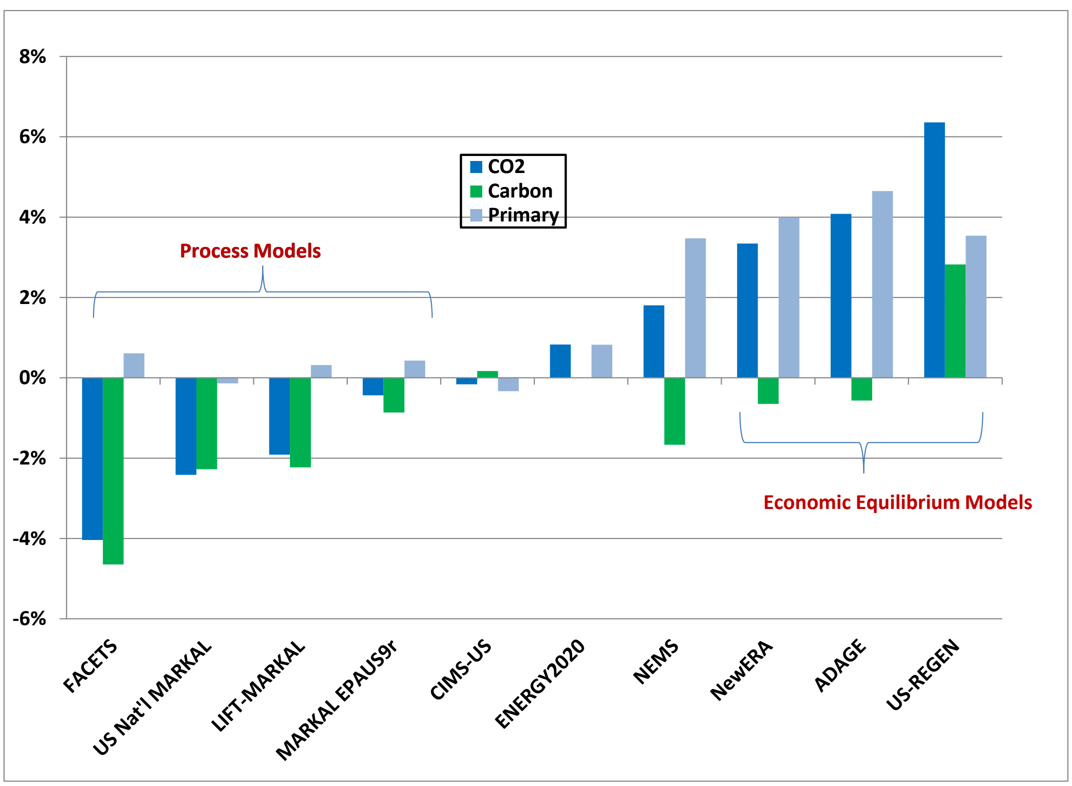


Figure 14. Decomposing CO_2 Emissions Impacts Due to High Shale Supplies, 2035



decarbonization of the primary fuel supply in each model. This bar will be more negative when natural gas replaces coal or oil rather than carbon-free sources. The third, light blue bar represents the increase in primary energy use when natural gas is less expensive. This bar will be more positive when the economy grows more and when energy consumption increases in response to lower natural gas and electricity prices.

Most projections indicate that primary energy will become more decarbonized when natural gas is more available. The one important exception is USREGEN, which expects aggregate energy to become more carbonized as natural gas retards the growth of new nuclear plants.

Decarbonization is the dominant effect in determining carbon dioxide emissions for the projections shown on the left. These models have relatively small expansions in primary energy use due to either economic growth or increasing energy intensity. The four models on the left side are process models that emphasize the competition between explicit technologies for meeting final energy service demands. Although some models like the LIFT-MARKAL framework incorporate a large inter-industry macroeconomic model, these frameworks focus considerable attention on the competition between technologies.

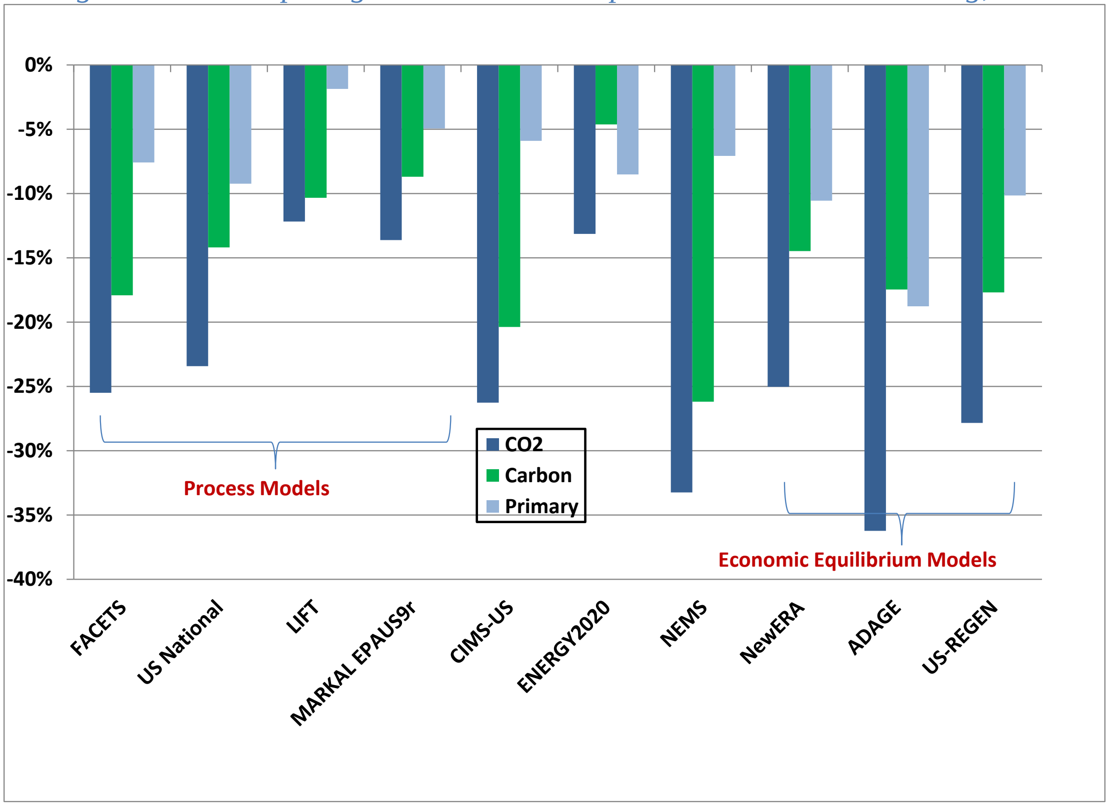
The expansion in primary energy use is the dominant effect in determining carbon dioxide emissions for the projections shown on the right. These models have relatively small decarbonization effects. The three models on the right side are inter-industry, economic equilibrium frameworks that emphasize economic factors and the interrelationships between different markets and sectors within the economy. Although these models are coupled with process models for the electric utility sector, these frameworks focus considerable attention on economic forces and the role for prices.

Models appearing in the center of this figure combine economic factors and explicit technologies. They show more moderate impacts on carbon dioxide emissions.

Comparisons with the carbon-price case are useful. Identical in format to Figure 14, Figure 15 summarizes the 2035 impacts of carbon pricing when reference conditions prevail. Notice that both decarbonization and the primary energy effect both place large downward pressure on carbon dioxide emissions for most models. The major difference from Figure 14 is twofold. First, carbon dioxide emissions fall much more precipitously below the reference case path in Figure 15. And second, the introduction of a carbon price reduces primary energy use through both economic growth and energy intensity rather than increases it. The light blue bars in Figure 15 extend downward rather than upward.

Although shale expansion reduces carbon dioxide emissions in some models, its impacts are not the same as an integrated climate policy if the public is concerned about global climate change risks over the long run.

Figure 15. Decomposing CO_2 Emissions Impacts Due to Carbon Pricing, 2035



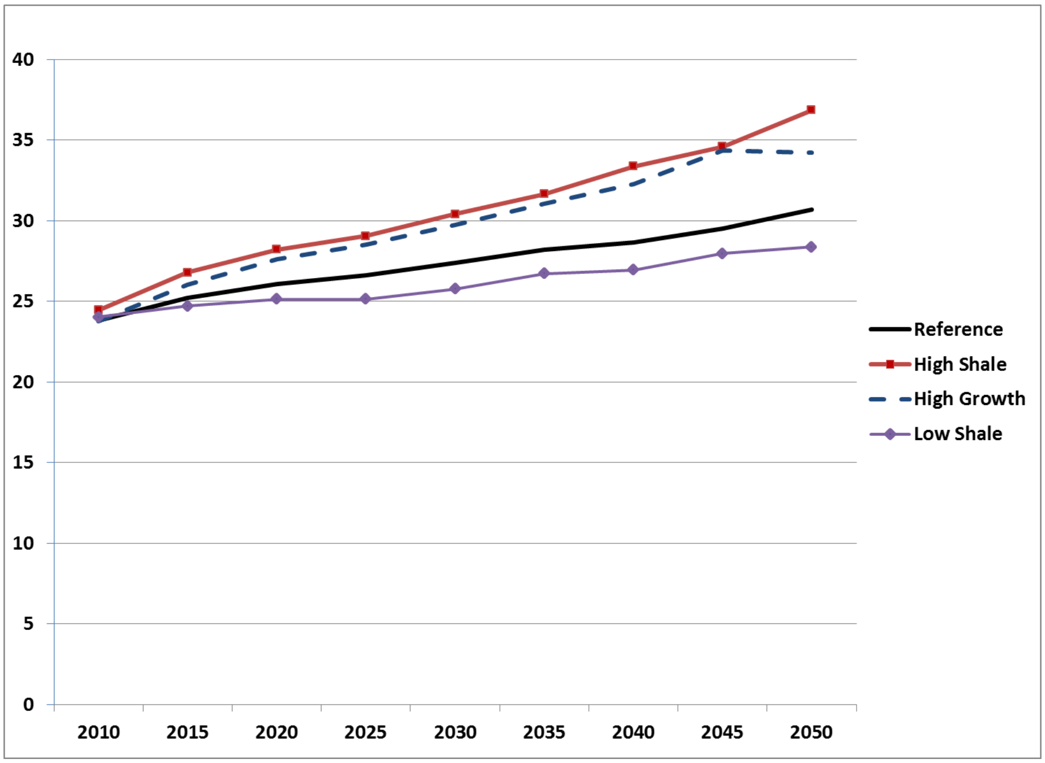
8 Market Expansions and Natural Gas Prices

Natural gas prices are currently low relative to the costs for other fuels. Many potential users are reluctant to invest in new capital equipment and infrastructure, however, because they fear that expanding demand can significantly raise future natural gas prices. If energy producers can easily extract additional supplies without much additional cost, future natural gas prices may not escalate quickly as new demands enter the market. Conversely, prices may rise quickly if producers find that new supplies are costly and future production from existing wells decline rapidly.

The study included several cases when the annual economic growth rate increased from 2.7 to 3.2 percent. The faster economic growth rate influenced certain key manufacturing sectors more than other sectors. For example, the chemical industry in the faster growth case grew proportionally faster than other industries at an annual rate of 1.5 rather than 1.2 percent.

Higher economic growth raises natural gas consumption above the reference path in all models. Figure 16 compares the average projection for these conditions with those for the high-

Figure 16. Average U.S. Natural Gas Consumption (Tcf), 2010-2050

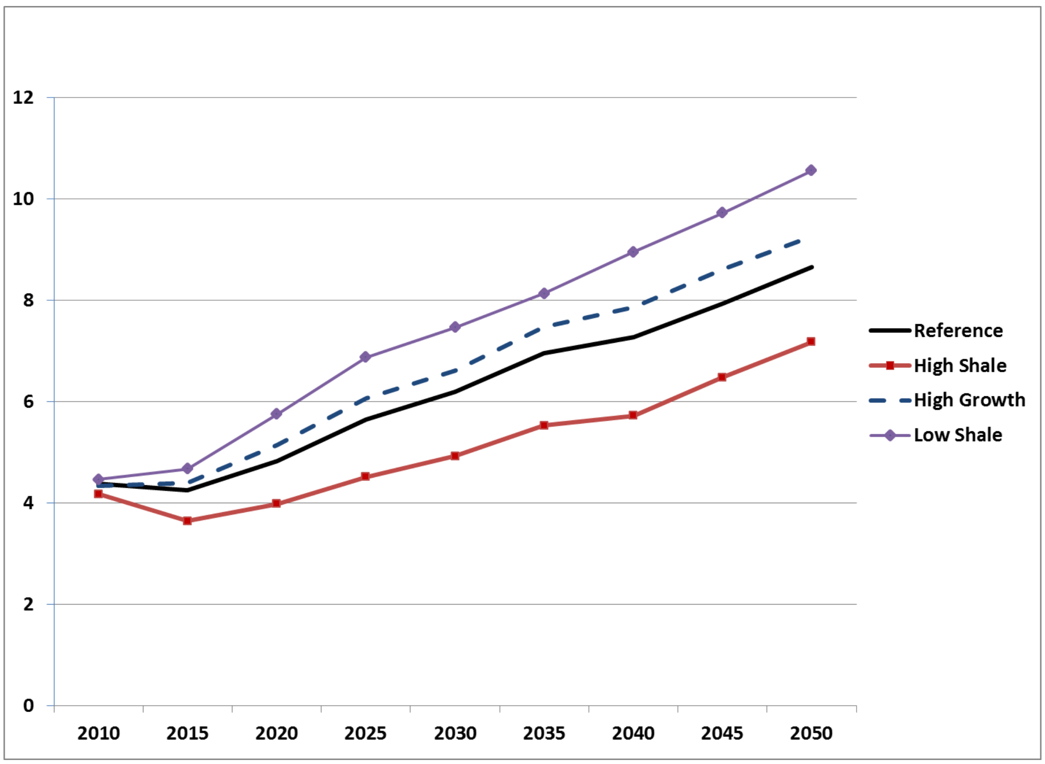


shale, low-shale and reference conditions. The average high-growth consumption pattern tracks the high-shale consumption path quite closely through the 2010-2050 period. Average consumption rises in all four cases, even when natural gas production is constrained in the low-shale conditions.

An additional economic growth of 0.5 percent per year raises the average wellhead price from $7 to about $7.50 in 2035. Natural gas prices rise above the reference path in all models but by varying amounts in the high-growth case. Figure 17 compares the average price projection for these conditions with those for the high-shale, low-shale and reference conditions. Even with some softening over the next five years, the average natural gas wellhead price rises over the full period in all four cases. This trend applies even for favorable technological and geological conditions in the high-shale case.

It is interesting that the high-growth and high-shale conditions produce similar shifts in the average consumption paths but quite different price responses. The average high-growth price pattern in Figure 17 shifts upward from reference levels (the solid black line) by much less than the high-shale price pattern moves downward. Generally, prices do not rise as much in the high-demand projections because natural gas production tends to respond considerably less to changes in the price level than does consumption.

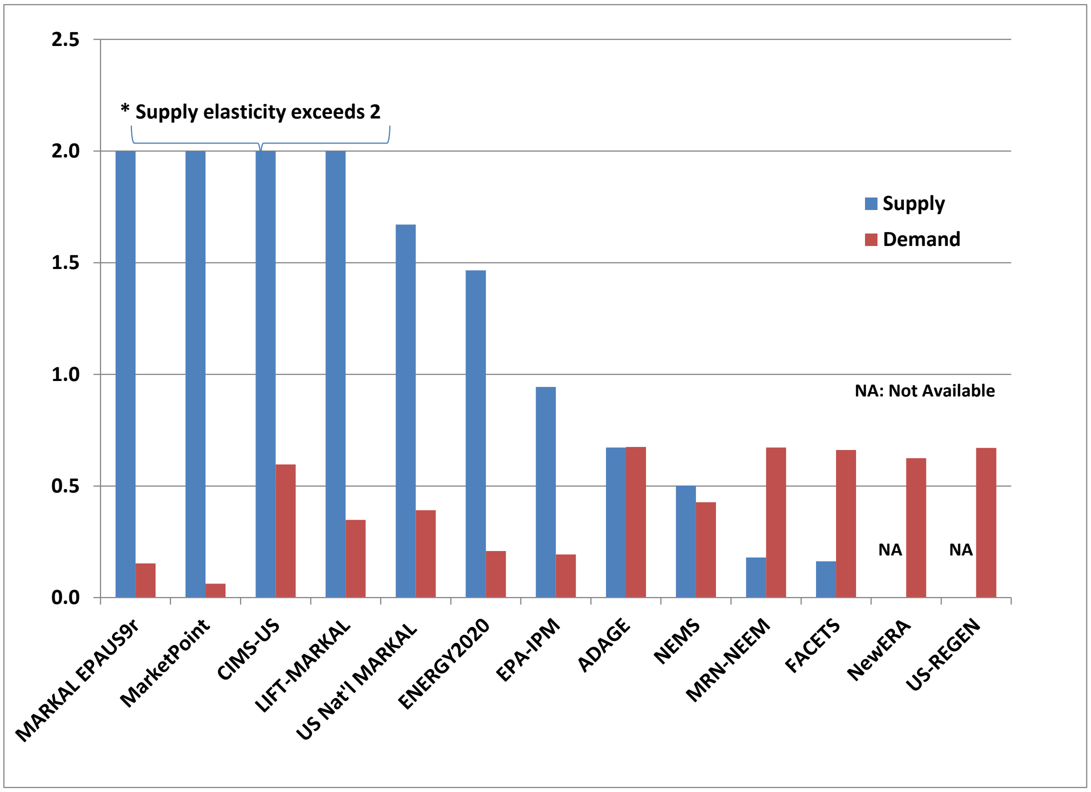
Figure 17. Average U.S. Wellhead Gas Price (2010$/Mcf), 2010-2050



These trends can be observed from Figure 18, which compares the response of each model's natural gas supply and demand to price changes as derived from a comparison of scenario results for 2035. Results from the high-shale case are compared to their counterparts in the reference scenario to derive the *demand* response of total consumption to changes in the wellhead price. Results from the high-growth case are compared to their counterparts in the reference scenario to derive the *supply* response of total U.S. production and imports to changes in the wellhead price. These responses are reported as inferred price elasticities that show the ratio of the percentage change in total natural gas use or availability to the percentage change in wellhead prices, where an estimate of 0.5 indicates that the percent change in supply or demand amounts to half of the percent change in wellhead price. The derived supply response in some models appears very high because their results reveal very small price changes due to high economic growth that may be misleading for computing elasticities. For this reason, the figure truncates any large responses at the value, two. See Appendix E for further review.

Higher exports also increase the demand for natural gas, although its impact can be somewhat different from the high-growth case. The study included a high-export case patterned after one set of conditions evaluated by the U.S. Energy Information Administration (2012).[12] Beginning in 2015, exports gradually expanded by one billion cubic feet per day until the increase reached six billion cubic feet per day in 2020. The 2020 expansion represents about 10 percent of a total market comprising 22 trillion cubic feet annually. Modelers allowed these exports to occur regardless of world market conditions.

Figure 18. Inferred Price Elasticities for 2035 by Model (Relative to Reference Case)



Although only three models simulated these conditions, their results suggest modest natural gas price increases due to an expanding export market. Wellhead prices are 2.5 to 9 percent higher in 2020, resulting in price increments between $0.14 and $0.39 per Mcf in 2010 dollars. Estimates range between 2.6 and 6.3 percent ($0.17 to $0.33) in 2025 and 2.8 and 7.1 percent in 2030 ($0.20 to $0.48).

The study also evaluated several advanced end-use natural gas technologies in another high-demand case. These cases were simulated by the process models with explicit technologies that included the following five models: CIMS-US, EPA-IPM, LIFT-MARKAL, MARKAL-EPAUS9r and US National MARKAL. Lower costs increased potential natural gas use by options primarily in the transportation sector, such as LNG trains and heavy-duty trucks. The scenario also included more favorable economic conditions for gas-to-liquid (GTL) processes that manufactured diesel fuel from natural gas. It also evaluated some additional advancements for stationary fuel cells providing heat and power in residential and commercial buildings. Average natural gas use for transportation increased gradually to 1.1 quads (approximately 3.1 billion cubic feet per day) by 2035 as a result of these higher potentials. Projections ranged from near zero to 2.9 quads across the five models.

9 Modeling Advantages and Remaining Challenges

This study coordinated the efforts of 14 different modeling teams to provide a deeper understanding of the impacts of new natural gas shale developments on North American energy markets. The frameworks used for this analysis have important advantages for long-term policymaking and strategic planning. Although models and quantification are not necessary to discuss these issues, they do provide a consistent framework for evaluating energy markets, the environment and the economy. Users of these models can evaluate alternative strategies and technologies under diverse conditions. Such results provide an opportunity to formulate more robust plans for identifying market risks and improving important public and private decisions. The need for structured thinking becomes particularly key when important uncertainties like new oil price regimes or new resources emerge on the energy landscape.

During the study, working group participants also became aware of several areas where the models should be improved. With time, it is expected that the modeling groups will make these improvements. Below are a few initial topics for consideration.

Most but not all models provide a richer explanation of energy demand rather than resource costs. To some extent, this problem also exists outside of the modeling community, as only now are independent groups beginning to evaluate the opportunities to apply new drilling techniques to areas where the resource basins are poorly understood.

Even within the demand sectors, however, the working group discussed whether the frameworks were representing enough flexibility in choosing different fuels, particularly outside of the electric power sector. The current gap between natural gas and other fuel prices may induce many more new technical options to replace other fuels with natural gas. More extensive interfuel substitution may be as important as lower-cost resource basins in determining future natural gas market conditions. Although natural gas has largely displaced the direct use of oil products as fuels in residential, commercial, and some industrial end use sectors over a long period, there is likely to be continuing interfuel substitution, particularly in surface transportation and within the chemical industry.

By design, this study focused on North America and did not incorporate important global dimensions of the shale gas boom. Many modeling teams in this study are beginning to explore these international issues by developing other systems with a world focus. Future efforts need to place these North American developments in the context of global markets, both for oil and natural gas. Location and regional costs become very important within the world natural gas market, which may lead to the United States shifting its natural gas supply towards pipeline trade into Mexico rather than LNG exports for the European and Asian markets.

Appendix A: Model Types

The models adopt either an economic equilibrium, engineering process, or some blended or hybrid approach for representing energy supply, demand and prices in the United States. An economic equilibrium system will solve for multiple spatial and temporal markets throughout the economy, while an engineering process approach solves the low-cost strategy for choosing between competing technologies for meeting a similar end-use demand service.

Table A-1 collates key model traits for the various systems, although most systems are not purely process or economic. For example, the University of Maryland and MITRE analysts have combined process detail from the MARKAL model with the LIFT inter-industry economic model. Similarly, ADAGE, NewERA, MRN-NEEM and US-REGEN developed originally as inter-industry equilibrium systems but now include detailed processes for sectors like electric generation.

Most models represent all major energy sources, although one system (MarketPoint) is a detailed global natural gas framework. Most models focus upon all sectors, although ReEDS and EPA-IPM focus primarily upon the electric power sector. EPA-IPM, MarketPoint and NEMS track total natural gas resources available for all future years at a very disaggregated level. Most other models represent production conditions through supply curves that reveal the costs of producing different natural gas volumes in each year. Table A-1 tries to compare the main features with broad summary terms without being too explicit. For example, all models have some agents who will adjust to meet what future conditions they expect. Decisions will be based upon adapting these expectations based upon past experience or complete knowledge about how future events will materialize. Some models adopt both types of anticipation, as indicated in the footnote to the table. Table 1 in the main report provides links for accessing more information about each model.

Table A- 1. Model Types

Model	Type	Look-Ahead	Markets	Spatial	Demand Approach	Gas Supply
Marketpoint	Market Equilibrium	Foresight	Natural Gas	World (but Regional)	Elasticity	Resource Base
US-REGEN	Interindustry Equilibrium	Foresight	Economy	Regional	Elasticity	Price Level
MRN-NEEM	Interindustry Equilibrium	Foresight	Economy	Regional	Elasticity	Supply Curves
NewERA	Interindustry Equilibrium	Foresight	Economy	Regional	Elasticity	Supply Curves
ADAGE	Interindustry Equilibrium	Foresight	Economy	Regional	Elasticity	Supply Curves
NEMS	Process-Economy	Adaptation*	All Fuels	Regional	Process	Resource Base
CIMS-US	Process-Economy	Adaptation*	All Fuels	National	Process	Supply Curves
ENERGY2020	Process-Economy	Adaptation*	All Fuels	Regional	Process	Supply Curves
LIFT-MARKAL	Process-Economy	Foresight	Economy	National	Process	Supply Curves
US National MARKAL	Process (Optimization)	Foresight	All Fuels	National	Process	Supply Curves
MARKAL EPAUS9r	Process (Optimization)	Foresight	All Fuels	Regional	Process	Supply Curves
FACETS	Process (Optimization)	Foresight	All Fuels	Regional	Process	Supply Curves
EPA-IPM	Process (Optimization)	Foresight	Gas-Electricity	Regional	Elasticity	Resource Base
ReEDS	Process (Optimization)	Foresight	Gas-Electricity	Regional	Elasticity	Supply Curves

* Some agents adapt to recent past experience while others have foresight.

Appendix B: EMF 26 Study Design

This study design contains assumptions for nine cases for the EMF 26 study. It is anticipated that each case can be easily implemented in most models once modelers have established a reference case.

The nine cases include (1) a reference, (2) a high-shale estimated ultimate recovery (EUR) supply, (3) a low-shale EUR supply, (4) a high-economic growth, (5) a high-natural gas demand, (6) a combination, high-shale EUR, high-economic growth scenario, (7) a carbon-constraint case, (8) a combined, carbon-constraint and high-shale EUR case and (9) a high-export scenario. Modelers also have the option to simulate a modeler's choice case.

1. Reference Case Assumptions

Modeling teams are not required to standardize on the reference case assumptions when their model determines a variable endogenously or when they believe strongly in a different outlook for a factor such as electricity sales or economic growth. If a model incorporates substantially different oil price and economic growth trends relative to AEO assumptions, please report these variables as output. Otherwise, it is recommended that the modeling team do their best to achieve some degree of standardization with the following AEO 2012 trends:

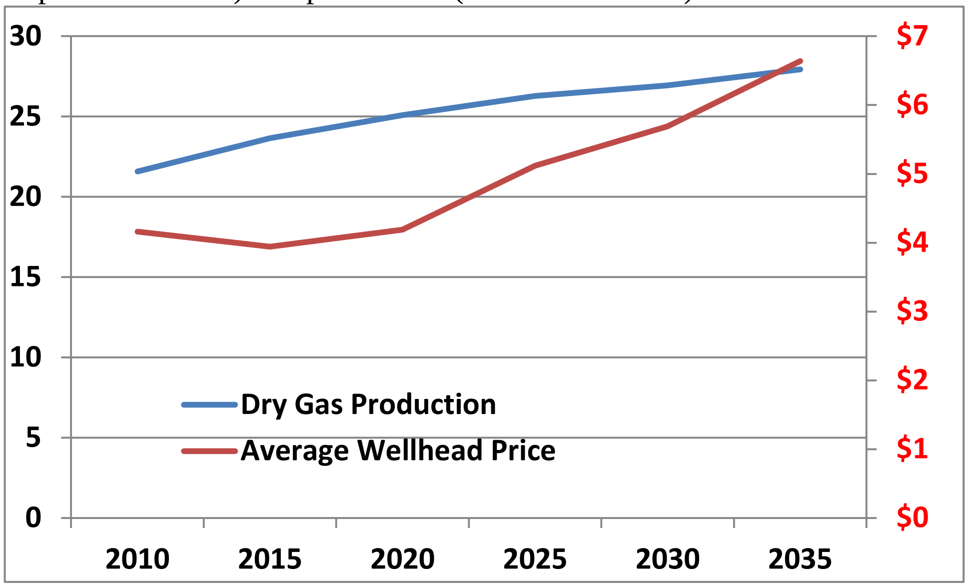
Variable	Units	2010	2035	% p.a.
Imported Crude Oil (dollars per barrel)	2010$/barrel	75.87	132.95	2.3%
Coal, Delivered (dollars per million Btu)	2010$/mmbtu	2.38	2.94	0.9%
Real Gross Domestic Product	2005$	13088	24539	2.5%
Total Electricity Use	billion kwh	3877	4716	0.8%
Liquefied Natural Gas Imports	Tcf	0.43	0.24	-2.3%
Liquefied Natural Gas Exports	Tcf	0.06	0.9	11.1%

Please reference the AEO 2012 projections for specific regional prices and other variables where relevant for your model. If your model is calibrated to the AEO 2011 projections, you may still be able to standardize on the above energy price and economic growth paths. If that is not possible, please use the 2011 projections as assumptions.

For reference to those models that would like exogenous natural gas supply estimates for the reference case, we also provide the following dry gas production (Tcf) and wellhead price (2010$/mmbtu) estimates from the AEO 2012 reference case:

Variable	Unit	2010	2015	2020	2025	2030	2035
Dry Gas Production	Tcf	21.58	23.65	25.09	26.28	26.94	27.93
Average Wellhead Price	2010$/Mcf	4.16	3.94	4.19	5.12	5.69	6.64

If horizons extend beyond 2035, teams will need to extrapolate beyond that year. Efforts to extend these trends may find helpful the chart below indicating the 2010-2035 wellhead price (2009 dollars per million Btu) and production (trillion cubic feet) reference trends.



Additional information about natural gas production by source is shown below for the AEO 2012 reference case.

Table. Natural gas production by source in AEO2012 Reference case, 1990-2035 (trillion cubic feet)

	Alaska	Coalbed methane	Lower 48 offshore	Lower 48 onshore conventional	Tight gas	Shale gas
2010	0.36	1.99	2.56	6.00	5.68	4.99
2015	0.29	1.83	1.88	5.33	6.08	8.24
2020	0.27	1.79	2.34	4.94	6.06	9.69
2025	0.25	1.77	2.38	4.44	6.17	11.26
2030	0.25	1.74	2.58	3.88	6.07	12.42
2035	0.23	1.76	2.72	3.45	6.14	13.63

http://www.eia.gov/oiaf/aeo/tablebrowser/ contains a full set of AEO 2012 reference case estimates and their relationship to AEO 2011 reference levels.

2. High Shale EUR Supply Assumptions

Total natural gas supply conditions are based upon the case labeled as high estimated ultimate recovery (EUR) per well in the AEO 2012 projections. The expected cumulative production of shale gas wells over their lifetimes is increased by 50 percent more than in the reference case. These conditions result in lower drilling costs resulting from greater shale gas extraction.

Models that represent shale gas resources explicitly can choose to represent these above conditions directly in their framework to the extent possible. Further information is contained in U.S. Energy Information Administration, *Annual Energy Outlook 2012 with Projections to 2035*, DOE/EIA-0383(2012),| June 2012, pp. 56-64. Otherwise, models including those with more aggregated natural gas supply conditions should represent these additional sources by **<u>decreasing the height of the total</u>** U.S. natural gas supply curve for each year **<u>by a given percent</u>** below their reference case values beginning in 2015. Supply curve shifts reduce wellhead costs for each level of natural gas production. For example, if the incremental cost of producing 25 Tcf was $10 in the reference case, the incremental cost of producing the same 25 Tcf would be $7.50 after the supply curve has been shifted downward by 25%.

This shift is based upon the percent change in prices and total dry production from the reference to the high shale EUR case in the AEO 2012, as shown in the table immediately below. If the supply curves are relatively flat and costs remain the same as production expands, these EIA wellhead price changes will be reliable estimates of how much the supply curve shifts. Otherwise, these wellhead price changes will understate the size of the supply curve shift, but there is no way of knowing the extent of the bias without more information about the shape of the supply curve -- how much costs change as production is increased.

Table. Wellhead Price and Production Effects of High Shale (EUR) Case

	2015	2020	2025	2030	2035
Henry Hub Price	-9%	-13%	-17%	-18%	-21%
US Dry Production	3%	5%	6%	7%	7%

3. <u>Low Shale EUR Assumptions</u>

Total natural gas supply conditions are based upon the case labeled as low estimated ultimate recovery (EUR) per well in the AEO 2012 projections. The expected cumulative production of shale gas wells over their lifetimes is decreased by 50 percent less than in the reference case. These conditions result in higher drilling costs resulting from less shale gas extraction.

Models that represent shale gas resources explicitly can choose to represent these above conditions directly in their framework to the extent possible. Further information is contained in U.S. Energy Information Administration, *Annual Energy Outlook 2012 with Projections to 2035*, DOE/EIA-0383(2012), June 2012, pp. 56-64. Otherwise, models including those with more aggregated natural gas supply conditions should represent these additional sources by **<u>increasing the height of the total</u>** U.S. natural gas supply curve for each year **<u>by a given percent</u>** above their reference case values beginning in 2015.

This shift is based upon the percent change in prices and total dry production from the reference to the low shale EUR case in the AEO 2012, as shown in the table immediately below.

Table. Wellhead Price and Production Effects of Low Shale (EUR) Case

	2015	2020	2025	2030	2035
Henry Hub Price	7%	15%	21%	23%	11%
US Dry Production	-4%	-6%	-8%	-10%	-7%

4. <u>High Economic Growth Assumptions</u>

Natural gas demand conditions are changed to reflect higher economic growth. Inflation-adjusted (real) gross domestic product grows more rapidly in each industry. Reference and high-growth output growth (% per annum, 2010-2035) are shown in the table below and on the next page. If your model uses a different economic growth path from the AEO 2012 case, please add the difference between the high growth and reference growth rates in this table to your baseline economic growth rate. For example, if your reference case growth rate for real GDP is 3.2% per annum, please use 3.2% + (3.0%-2.5%) = 3.7% in your high growth case.

Economic Growth Rates for Reference and High Growth Cases
(% per annum, 2010-2035)

	Reference	**High growth**
Real Gross Domestic Product	**2.5%**	**3.0%**
Value of Shipments (billion 2005 dollars)		
Service Sectors	2.0%	2.2%
Total Industrial	1.6%	2.2%
Agriculture, Mining, and Construction	1.7%	2.4%
Manufacturing	1.6%	2.1%
Energy-Intensive	1.0%	1.2%
Non-Energy-Intensive	1.9%	2.5%
Total	1.9%	2.2%
Nonmanufacturing Sector Shipments		
Agriculture/Forestry/Fishing/Hunting	0.8%	1.0%
Mining	0.7%	0.9%
Construction	2.3%	3.2%
Manufacturing Sector Shipments		
Food Products	1.5%	1.6%
Beverages and Tobacco Products	0.0%	0.7%
Textile Mills and Products	-2.6%	-1.1%
Apparel	-8.3%	-9.9%
Wood Products	1.5%	1.9%
Furniture and Related Products	0.7%	2.0%
Paper Products	1.4%	1.7%
Printing	-0.1%	0.2%
Chemical Manufacturing	1.2%	1.5%
Bulk Chemicals	0.8%	0.9%
Inorganic	-1.2%	-1.0%
Organic	1.2%	1.3%
Resin, Synthetic Rubber, and Fibers	1.1%	1.2%
Agricultural Chemicals	-0.7%	-0.7%
Other Chemical Products	1.6%	2.0%
Petroleum and Coal Products	0.0%	0.3%
Petroleum Refineries	0.0%	0.3%

Other Petroleum and Coal Products	0.3%	0.7%
Plastics and Rubber Products	1.3%	1.5%
Leather and Leather Products	-3.7%	-3.2%
Stone, Clay, and Glass Products	1.2%	2.8%
Glass and Glass Products	1.0%	1.8%
Cement and Lime	2.1%	2.8%
Other Nonmetallic Mineral Products	1.2%	3.1%
Primary Metals Industry	1.0%	1.7%
Iron and Steel Mills and Products	0.8%	1.9%
Alumina and Aluminum Products	1.1%	1.2%
Other Primary Metal Products	1.2%	1.5%
Fabricated Metal Products	1.2%	1.9%
Machinery	1.8%	3.1%
Computers and Electronics	2.6%	3.2%
Transportation Equipment	2.8%	3.2%
Electrical Equipment	1.8%	3.0%
Miscellaneous Manufacturing	2.8%	3.2%

5. High Natural Gas Demand Case

Natural gas demand conditions are changed to reflect more optimistic natural gas demand growth potential.

Natural gas demand is increased by:

- Increased market penetration of both light- and heavy-duty natural gas vehicles
- Higher natural gas use in rail and marine transportation applications
- Increased economic growth rates in energy intensive industries
- Expanded use of gas-to-liquids technology

See technology details provided in spreadsheets on EMF website at http://emf.stanford.edu/research/emf_26/

6. High Economic Growth Case with High Shale EUR

The high economic growth case as above is combined with the high-shale EUR supply assumptions.

7. Carbon Constraint Case

Reflecting the current U.S. political climate, the carbon constraint case will reflect unspecified policy constraints rather than an explicit carbon tax or fee for a tradable permit. Although it is based upon the AEO carbon fee case, this study will not discuss these results as the impact of carbon fees or taxes. This case provides considerable insight for understanding the response to other fuel prices as well as to natural gas prices when carbon dioxide is constrained. Reference case assumptions are combined with an additional cost on carbon dioxide. The following assumptions apply:

- No carbon costs exist prior to 2013.
- The carbon cost (2010$) equals $25 per metric ton carbon dioxide in 2013.
- The carbon cost rises by approximately 5% more than inflation (real) each year, following approximately this path

		2013	**2015**	**2020**	**2025**	**2030**	**2035**
Carbon costs (fees)	2010$/tonne	25	28	36	46	60	77

- The carbon costs are revenue neutral in that all carbon revenues remain within the private sector and do not flow to the government. This assumption will be equivalent to a carbon tax with lump-sum redistribution in computable general equilibrium models.

8. Carbon Fee Case with High Shale EUR

Within policymaking and corporate circles, considerable uncertainty exists about whether natural gas consumption would increase if greater natural gas supply was combined with tightened constraints on carbon dioxide emissions. Although some modelers believe that they already know how natural gas markets will fare under these conditions in their own model, wider appreciation of these results across a diverse set of models appears lacking. See, for example, National Petroleum Council, *Prudent Development – Realizing the Potential of North America's Abundant Natural Gas and Oil Resources*, September 15, 2011, chapter 4, page 7 and Figure 4-4.

The same carbon fee as above is combined with the high-supply case.

9. High Export Case

The high export case allows increased exports resulting from higher world natural gas demand and increased investment in LNG export facilities within North America. This case follows the export case with ***low levels and slow penetration*** evaluated in the recent EIA analysis of natural gas exports. Natural gas exports from North America through liquefied natural gas terminals begin to expand by 1 billion cubic feet per day (Bcf/d) above reference levels in 2015. This expansion increases by 1 Bcf/d each year until 2020. Thereafter, the total expansion remains at 6 billion cubic feet per day (2.19 trillion cubic feet per year) higher than the reference level. These expansions are summarized in the table below:

	2015	2016	2017	2018	2019	2020	2050
Bcf/d	1	2	3	4	5	6	6
Tcf/yr	0.37	0.73	1.10	1.46	1.83	2.19	2.19

Allow these expansions to occur in the US Gulf of Mexico region (Texas and Louisiana).
The above volumes are gross estimates that include additional natural gas consumed during the liquefaction process (about 10 percent of the total).

For models that require cost estimates, the approximate costs for liquefaction facilities in the Gulf Coast region is approximately $3 per million BTU, the additional transportation cost to Europe is approximately $1 per million BTU, and the additional transportation cost to Asia is approximately $2 per million BTU. These estimates are guidelines only, as the precise costs will depend upon the specific source and destination of the LNG flows.

International natural gas models should try to force in extra world demand or higher supply costs elsewhere that will achieve these export levels to the extent that is reasonable. It would be extremely helpful if you could explain these additional conditions and the extent to which you think that they are possible.

International Energy and Economic Conditions

The purpose of the EMF 26 study is to evaluate how ***changed North American*** natural gas supplies and economic conditions affect domestic energy markets. It does not try to evaluate how ***changed global*** natural gas supplies and economic conditions affect domestic energy markets. North American models without global interactions cannot address the second issue.

In the reference case, international models should adopt global economic and energy assumptions consistent with their North American conditions. In the alternative cases, international models should not change exogenous information that influences global natural gas supplies, carbon constraints or economic growth outside of North America. The only exception would be the high export case where additional economic growth and demand outside of North America creates additional demand for North American exports.

Modeler Choice Case

Modelers are encouraged to simulate another case that might serve as a good example for other modeling teams to consider in the next round. Carefully thinking through the precise scenario assumptions increases the likelihood that other teams will find it useful to simulate. Examples of these scenarios could include any of the following conditions:

- Combined high natural gas demand and Federal Clean Energy Standards
- Combined high natural gas demand, Federal Clean Energy Standards, and high shale EUR conditions
- Alternative high and low shale supplies
- Alternative high-demand conditions
- Alternative combined high-demand and high-supply conditions
- Alternative combined low-demand and low-supply conditions
- Transportation policies promoting increased natural gas demand
- An expansion or contraction of global natural gas supplies
- A lower or higher oil price path

Output Variables with EIA Estimate for 2010

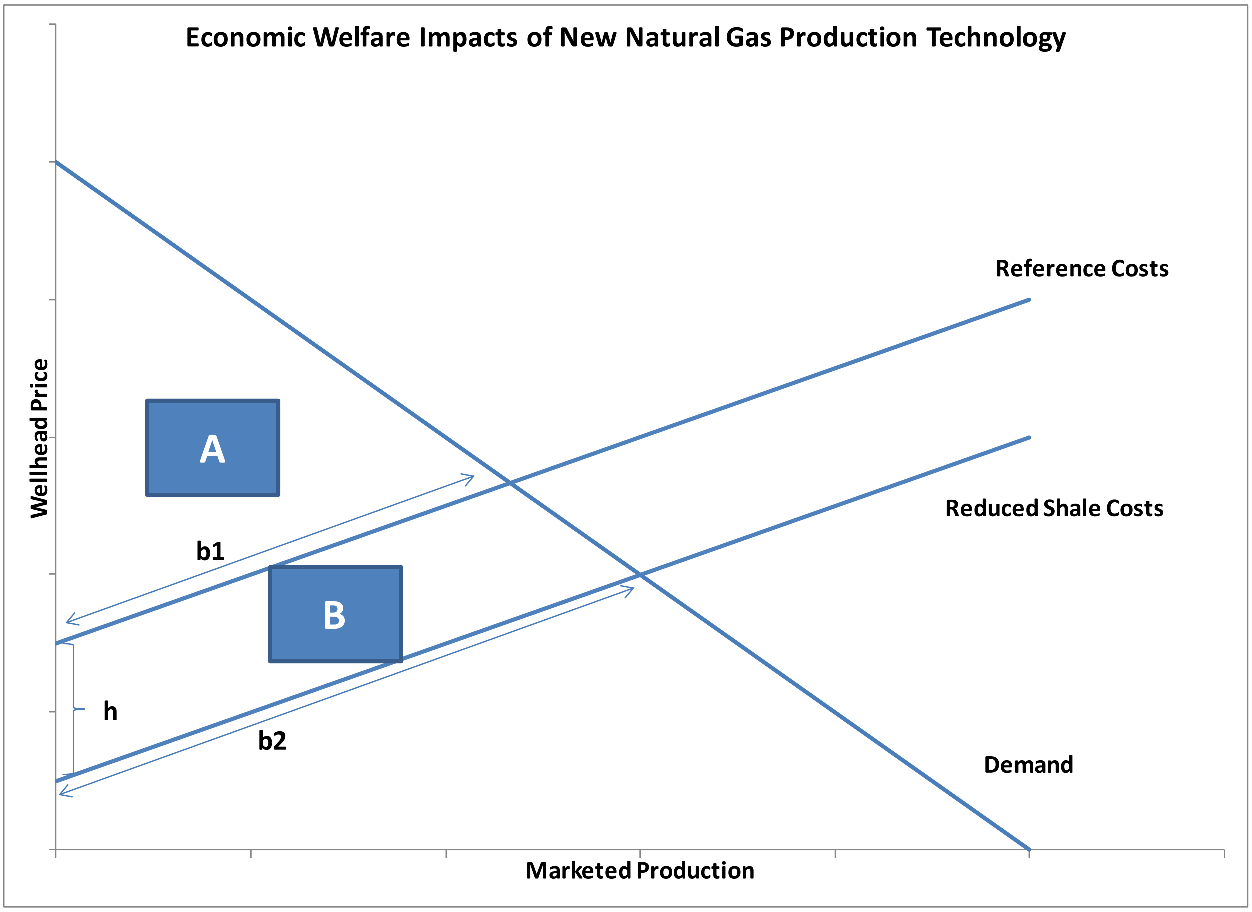
Modelers are asked to report the variables listed on the next page in five-year intervals between 2010 and 2050 (or your ending year). The EMF Excel template for reporting results will be provided soon. Please return results by October 29 to hillh@stanford.edu.

Sector	Variable	Units	2010	Notes
USA	Real GDP	billion 2005$	13088	
USA	Imported Crude Price	2010$/barrel	75.87	
USA	Gas Wellhead Price	2010$/Mcf	4.16	Henry Hub price permissible
USA	Electricity Price	2010¢ /KWH	9.8	Average delivered price permissible
USA	Gasoline Price	2010$/mmbtu	22.59	
Electricity	Natural Gas Price	2010$/mmbtu	5.14	Average delivered price (all users) permissible
Electricity	Coal Price	2010$/mmbtu	2.25	Average delivered price (all users) permissible
Primary	Petroleum/Liquids	quadrillion Btu	37.25	Ethanol, biodiesel, coal synthetic liquids
Primary	Natural Gas	quadrillion Btu	24.71	
Primary	Coal	quadrillion Btu	20.76	Excludes coal synthetic liquids and gas
Primary	Nuclear	quadrillion Btu	8.44	
Primary	Hydropower	quadrillion Btu	2.51	
Primary	Biomass	quadrillion Btu	2.88	Exc. energy content liquids from wood, waste
Primary	Other Renewable	quadrillion Btu	1.34	Excludes hydropower and biomass
Primary	Total	quadrillion Btu	98.16	
Electricity	Natural Gas	quadrillion Btu	7.54	
Electricity	Coal	quadrillion Btu	19.13	
Electricity	Nuclear	quadrillion Btu	8.44	
Electricity	Renewable	quadrillion Btu	3.85	
Electricity	Total	quadrillion Btu	39.63	
Residential	Liquids	quadrillion Btu	1.22	
Residential	Natural Gas	quadrillion Btu	5.06	
Residential	Electricity	quadrillion Btu	4.95	
Residential	Total Delivered	quadrillion Btu	11.66	
Commercial	Liquids	quadrillion Btu	0.72	
Commercial	Natural Gas	quadrillion Btu	3.29	
Commercial	Electricity	quadrillion Btu	4.54	
Commercial	Total Delivered	quadrillion Btu	8.71	
Industrial	Liquids	quadrillion Btu	8.05	
Industrial	Natural Gas	quadrillion Btu	8.14	Includes lease & plant fuel
Industrial	Coal	quadrillion Btu	1.56	
Industrial	Biofuels	quadrillion Btu	0.84	
Industrial	Renewable	quadrillion Btu	1.5	
Industrial	Electricity	quadrillion Btu	3.28	
Industrial	Total Delivered	quadrillion Btu	23.37	
Transportation	Liquids	quadrillion Btu	26.88	
Transportation	Natural Gas	quadrillion Btu	0.69	Includes pipelines & compressed natural gas
Transportation	Electricity	quadrillion Btu	0.02	
Transportation	Total Delivered	quadrillion Btu	27.59	
Emissions	CO2	million tonnes	5633.6	metric tonnes
Emissions	NOx	Thou. Tons	16339	Value for 2008 (US Statistical Abstract)
Emissions	SO2	Thou. Tons	11429	Value for 2008 (US Statistical Abstract)
USA	Dry Gas Production	Tcf	21.58	
USA	Total Imports	Tcf	3.71	
USA	LNG Imports	Tcf	0.43	
USA	Total Exports	Tcf	1.14	
USA	LNG Exports	Tcf	0.06	

Appendix C: Welfare Gains

Another measure of the gains in economic opportunities is economic welfare. Welfare gains include not only the production and consumption of goods and services sold in markets but also the reduction in pollution damages as well as the value of other non-marketed services like household activities and leisure. Lower natural gas costs increase opportunities to produce either more energy or other goods & services.

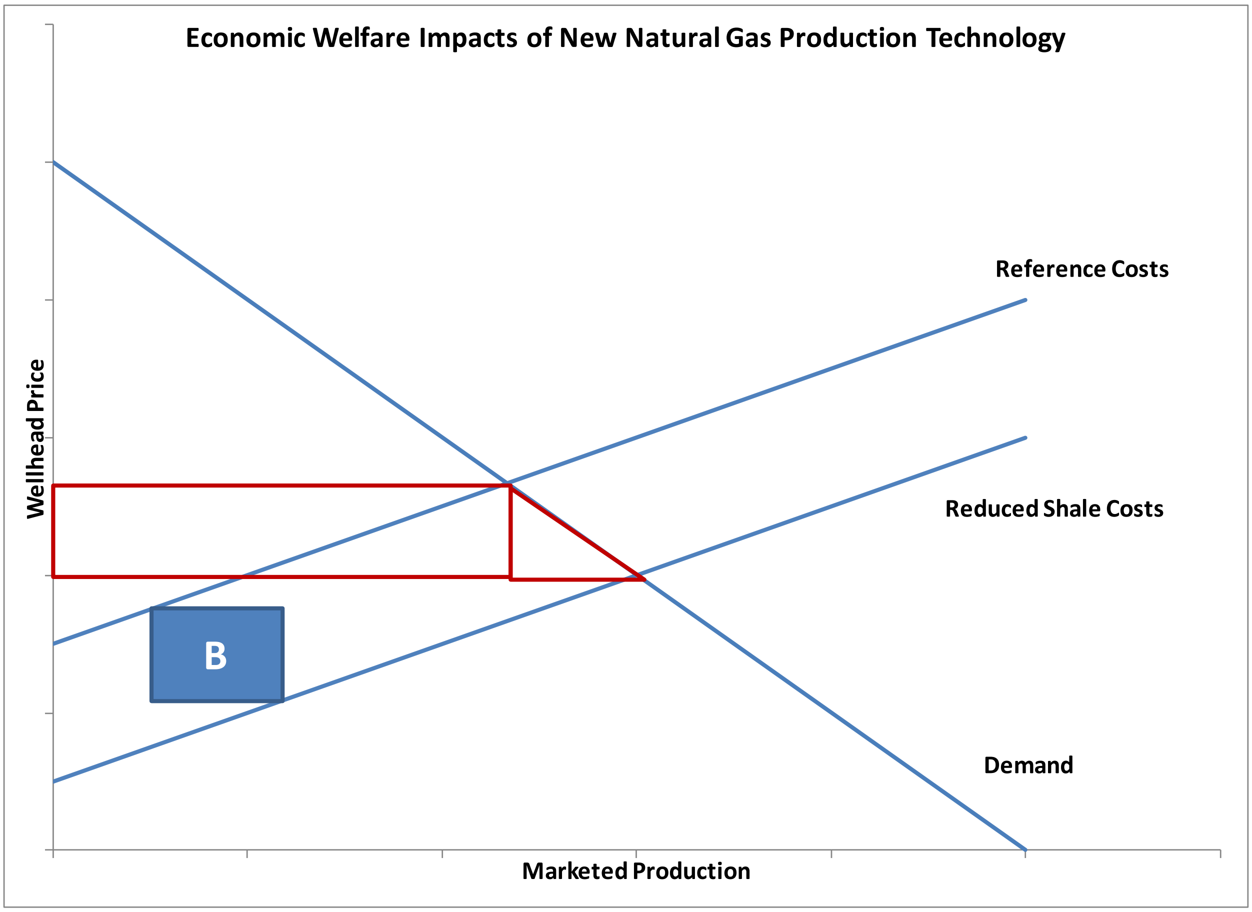
Figure C- 1. An Intuitive Explanation for Benchmarking the Welfare Gains,



Total welfare before the shale "gale" equals the area under the demand curve and above the reference-cost curve indicated by the triangular area, A, in Figure C-1. After nature and human technology combine to reduce the cost of extracting natural gas, total welfare increases by the reduction in costs indicated by the trapezoidal area, B. This area is not a transfer of wealth within society as often happens when policymakers adopt taxes or subsidies. Instead, it represents a transfer from "nature" to society for the benefit of all citizens. This area equals the trapezoid's height, h, times the average of the shorter and longer base lines, b1 and b2.

Although the study lacks all the information required to compute area B exactly for each model, a minimum value can be derived as a benchmark. Each model provides the two equilibrium price-quantity points for reference and shale cost conditions; hence, these points do not change in the explanation given below. As the supply curves become flatter in Figure C-1 above, the distances b1 and b2 decline. Figure C-2 below shows the welfare impact when the supply curves are completely flat. Under these conditions, the welfare impacts are simply the gains in consumer surplus resulting from the reduced costs in natural gas production as determined by the price change. Although the models do not have perfectly flat supply curves, many models show very little price response when markets need to produce more gas supply to balance conditions.

Table C- 1. Welfare Gains with Flat Natural Gas Supply Curves



The total society will gain at least as much as what natural gas consumers realize. It may gain more than this amount if producers can successfully extract some of the benefits for themselves. This situation will happen when they earn rents on inframarginal supplies that cost producers less than the market-clearing price.

Natural gas consumers will gain on each unit of natural gas used an amount approximately equal to the wellhead natural gas price decrease. The cumulative aggregation of these cost reductions over all years is also large. When amortized over the horizon of the study (through 2035 or 2050 depending upon the model), these premiums average $153 billion each year. This amount is about 1 percent of $15 trillion, the approximate 2012 GDP level for the United States.

The main report does not discuss these welfare gains for several reasons. If the shale gas development simply flattened the resource cost curve in the relevant area rather than shifting it rightward by a uniform amount, the welfare gains may be less than computed above. Additionally, these computations are best done within each model, applying the actual supply and demand curves used in that system. Adopting this approach, however, introduces another complication because each model may compute welfare effects differently, depending upon whether the effects include capital cost dynamics and the terminal value of the resource base and other long-lived indicators.

Appendix D: Decomposition of Carbon Dioxide Emissions

The carbon dioxide trends can be better understood by decomposing them into separate effects. The first three columns of Table D-1 report the change in real GDP, primary energy use and carbon dioxide emissions in 2035 due to higher shale supplies. Lower natural gas prices stimulate real GDP slightly in proportional terms with an average impact of 0.6 percent in 2035. They also encourage more energy-intensive processes. When combined with the favorable economic growth effects, they increase total primary energy consumption in the second column by an average of 1.7 percent in 2035. The impacts on carbon dioxide emissions can be either smaller or greater in any model but average an increase of 0.75 percent in 2035. Similar results apply for 2050 for a smaller set of models whose horizons extend through the longer period.

The last two columns display changes in energy and carbon intensities due to the shale expansion. The change in energy intensity measures the difference between the change in primary energy and the change in real GDP. When averaged across all projections, it tends to be 1.4 percent higher with high-shale supplies in 2035. The change in carbon intensity represents the decarbonization of the total primary fuel supply, measured by the difference between the change in carbon dioxide emissions and the change in primary energy. When averaged across all projections, it tends to be 1 percent lower with high-shale supplies in 2035. The three models with large decarbonization trends (FACETS, US National MARKAL and LIFT-MARKAL) projected large coal displacement in Figure 10 of the main report. These three models are process-based systems, while many of the others are either energy-economy or inter-industry equilibrium frameworks.

Table D- 1. GDP, Energy and Carbon Impacts Due to High Shale Supplies, 2035

(% Deviation from Low Shale Supply Case)

	2035			Intensity	
	GDP	Primary	CO2	Energy	Carbon
ADAGE	0.43%	4.65%	4.08%	4.21%	-0.57%
CIMS-US	#N/A	-0.33%	-0.16%	-0.33%	0.17%
ENERGY2020	#N/A	0.83%	0.83%	0.83%	0.00%
FACETS	#N/A	0.61%	-4.04%	0.61%	-4.65%
LIFT-MARKAL	0.75%	0.32%	-1.91%	-0.44%	-2.23%
MARKAL EPAUS9r	#N/A	0.43%	-0.44%	0.43%	-0.86%
NEMS	1.22%	3.47%	1.81%	2.25%	-1.67%
NewERA	0.17%	3.99%	3.34%	3.82%	-0.65%
US National MARKAL	#N/A	-0.14%	-2.42%	-0.14%	-2.28%
US-REGEN	0.36%	3.54%	6.36%	3.18%	2.82%
Average	0.59%	1.74%	0.75%	1.44%	-0.99%
Median	0.43%	0.72%	0.33%	0.72%	-0.76%

Energy intensity = Primary - GDP, or Primary when GDP impact is #NA
Carbon intensity = CO2 -
Primary.

Comparisons with the carbon-constraint case are useful. Identical in format to Table D-1, Table D-2 summarizes the 2035 impacts of carbon constraints when reference conditions prevail. The impacts are an order of magnitude greater than for the shale expansion in Table D-1. Unlike the shale expansion, the carbon constraint causes a reduction in real GDP in all results. The average impact registers reductions of 0.8 percent in real GDP, 8.4 percent in primary energy consumption and 26.8 percent in carbon dioxide emissions. Changes in the energy intensity and the decarbonization of the total fuel supply both move strongly negatively in the final two columns.

Table D- 2. GDP, Energy and Carbon Impacts Due to Carbon Constraint, 2035

(% Deviation from Reference Case)

	2035			Intensity	
	GDP	Primary	CO2	Energy	Carbon
ADAGE	-1.13%	-18.76%	-36.23%	-17.63%	-17.47%
CIMS-US	#N/A	-5.89%	-26.27%	-5.89%	-20.37%
ENERGY2020	#N/A	-8.51%	-13.14%	-8.51%	-4.62%
EPA-IPM	#N/A	#N/A	-58.51%	#N/A	#N/A
FACETS	#N/A	-7.59%	-25.50%	-7.59%	-17.91%
LIFT-MARKAL	-0.74%	-1.86%	-12.18%	-1.11%	-10.32%
MARKAL EPAUS9r	#N/A	-4.94%	-13.62%	-4.94%	-8.69%
MarketPoint	#N/A	#N/A	#N/A	#N/A	#N/A
MRN-NEEM	-0.86%	#N/A	#N/A	#N/A	#N/A
NEMS	-0.74%	-7.07%	-33.25%	-6.33%	-26.18%
NewERA	-0.50%	-10.55%	-25.03%	-10.04%	-14.48%
ReEDS	#N/A	#N/A	#N/A	#N/A	#N/A
US National MARKAL	#N/A	-9.23%	-23.42%	-9.23%	-14.19%
US-REGEN	-0.97%	-10.15%	-27.85%	-9.18%	-17.70%
Average	-0.83%	-8.45%	-26.82%	-7.99%	-15.19%
Median	-0.80%	-8.05%	-25.50%	-7.59%	-15.97%

Energy intensity = Primary - GDP, or Primary when GDP impact is #NA
Carbon intensity = CO2 - Primary.

Appendix E: Inferred Price Elasticities of Supply and Demand

Supply Elasticity, High Growth versus Reference

Model	2015	2020	2025	2030	2035	2040	2045	2050
ADAGE	-0.413	1.115	0.649	0.672	0.629	0.338	0.061	-0.028
CIMS-US	#NC	#NC	4.104	4.403	2.113	#N/A	#N/A	#N/A
ENERGY2020	7.147	2.110	1.712	1.466	1.373	#N/A	#N/A	#N/A
EPA-IPM	0.122	0.914	0.678	0.943	0.859	0.793	0.688	0.643
FACETS	0.125	0.497	0.146	0.163	0.630	#NC	2.537	1.371
LIFT-MARKAL	3.363	2.136	2.517	3.685	7.171	#N/A	#N/A	#N/A
MARKAL EPAUS9r	#NC	6.048	5.900	6.002	6.014	6.053	6.110	6.902
MarketPoint	3.071	3.698	4.376	5.177	5.322	4.848	4.599	#N/A
MRN-NEEM	0.356	0.241	0.214	0.180	0.179	0.208	0.267	0.551
NEMS	0.108	0.281	0.409	0.502	0.534	0.650	#N/A	#N/A
US National MARKAL	#NC	0.446	1.055	1.671	1.176	1.268	1.703	1.653
US-REGEN	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
Average	1.735	1.749	1.978	2.260	2.364	2.023	2.281	1.849
Median	0.241	1.015	1.055	1.466	1.176	0.793	1.703	1.007

#NA = not available; #NC = not computed because price change is very small.

Supply Elasticity, Shale Growth versus High Shale

Model	2015	2020	2025	2030	2035	2040	2045	2050
ADAGE	-0.049	0.929	0.716	0.756	0.788	0.620	0.527	0.462
CIMS-US	#NC	#NC	5.050	2.382	1.657	#N/A	#N/A	#N/A
ENERGY2020	7.147	2.131	1.711	1.450	1.359	#N/A	#N/A	#N/A
EPA-IPM	0.158	0.673	0.726	0.996	1.096	1.132	0.952	0.871
FACETS	0.354	0.625	0.256	0.808	0.695	#NC	0.735	0.928
LIFT-MARKAL	0.974	1.262	2.032	2.978	6.001	#N/A	#N/A	#N/A
MARKAL EPAUS9r	#NC	#NC	#NC	#NC	#NC	#NC	#NC	#NC
MarketPoint	3.205	3.127	2.562	3.407	2.990	3.368	4.715	#N/A
MRN-NEEM	0.495	0.424	0.386	0.368	0.322	0.291	0.284	0.272
NEMS	0.146	0.581	1.071	0.576	0.848	0.696	#N/A	#N/A
US National MARKAL	#NC	0.655	0.274	0.410	1.065	0.864	1.129	0.983
US-REGEN	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
Average	1.554	1.219	1.479	1.413	1.682	1.162	1.390	0.703
Median	0.424	0.801	0.898	0.902	1.081	0.780	0.844	0.871

#NA = not available; #NC = not computed because price change is very small.

Demand Elasticity, High Shale versus Reference

Model	2015	2020	2025	2030	2035	2040	2045	2050
ADAGE	-0.503	-0.393	-0.320	-0.380	-0.430	-0.469	-0.456	-0.455
CIMS-US	-0.930	-0.550	-0.178	-0.448	-0.450	#N/A	#N/A	#N/A
ENERGY2020	#NC	-0.111	-0.163	-0.227	-0.284	#N/A	#N/A	#N/A
EPA-IPM	-0.435	-0.355	-0.264	-0.296	-0.254	-0.222	-0.196	-0.189
FACETS	-0.392	-0.406	-0.454	-0.572	-0.885	-1.230	-1.222	-1.226
LIFT-MARKAL	-0.360	-0.317	-0.293	-0.375	-0.362	#N/A	#N/A	#N/A
MARKAL EPAUS9r	0.003	-0.019	-0.062	-0.088	-0.115	-0.147	-0.180	-0.211
MarketPoint	-0.086	-0.086	-0.083	-0.080	-0.079	-0.082	-0.079	#N/A
MRN-NEEM	-0.504	-0.476	-0.549	-0.637	-0.578	-0.576	-0.725	-0.826

NEMS	-0.348	-0.439	-0.450	-0.498	-0.527	-0.599	#N/A	#N/A
NewERA	-0.731	-0.681	-0.650	-0.531	-0.596	-0.688	-0.725	-0.994
US Nat'l MARKAL	-0.398	-1.228	-0.508	-0.664	-1.183	-1.418	-1.646	-1.836
US-REGEN	-0.378	-0.337	-0.802	-1.092	-0.827	-1.086	-1.182	-1.084
Average	-0.422	-0.415	-0.368	-0.453	-0.505	-0.652	-0.712	-0.853
Median	-0.395	-0.393	-0.320	-0.448	-0.450	-0.587	-0.725	-0.910

#NA = not available; #NC = not computed because price change is very small.

Demand Elasticity, Low Shale versus Reference

Model	2015	2020	2025	2030	2035	2040	2045	2050
ADAGE	-0.297	-0.292	-0.408	-0.423	-0.675	-0.714	-1.141	-2.111
CIMS-US	-0.142	-0.138	-0.371	-0.359	-0.596	#N/A	#N/A	#N/A
ENERGY2020	#NC	-0.115	-0.151	-0.192	-0.209	#N/A	#N/A	#N/A
EPA-IPM	-0.352	-0.354	-0.178	-0.243	-0.193	-0.162	-0.160	-0.158
FACETS	-0.239	-0.295	-0.453	-0.621	-0.661	-0.703	-0.737	-0.772
LIFT-MARKAL	-0.241	-0.154	-0.142	-0.152	-0.348	#N/A	#N/A	#N/A
MARKAL EPAUS9r	-0.052	-0.081	-0.117	-0.141	-0.153	-0.179	-0.205	-0.236
MarketPoint	-0.063	-0.063	-0.065	-0.066	-0.062	-0.059	-0.057	#N/A
MRN-NEEM	-0.431	-0.417	-0.436	-0.440	-0.672	-1.000	-1.521	-2.195
NEMS	-0.225	-0.247	-0.283	-0.317	-0.427	-0.519	#N/A	#N/A
NewERA	-0.536	-0.463	-0.419	-0.517	-0.625	-0.799	-1.268	-1.090
US Nat'l MARKAL	-0.814	-0.391	-0.383	-0.432	-0.391	-0.348	-0.400	-0.421
US-REGEN	-0.421	-0.277	-0.483	-0.483	-0.670	-0.449	-0.491	-0.488
Average	-0.318	-0.253	-0.299	-0.337	-0.437	-0.493	-0.665	-0.934
Median	-0.269	-0.277	-0.371	-0.359	-0.427	-0.484	-0.491	-0.630

#NA = not available; #NC = not computed because price change is very small.

Demand Elasticity, Shale Growth versus High Shale

Model	2015	2020	2025	2030	2035	2040	2045	2050
ADAGE	-0.445	-0.365	-0.441	-0.509	-0.591	-0.835	-1.110	-1.381
CIMS-US	-0.104	-0.106	-0.151	-0.250	-0.396	#N/A	#N/A	#N/A
ENERGY2020	#NC	-0.113	-0.163	-0.226	-0.271	#N/A	#N/A	#N/A
EPA-IPM	-0.314	-0.616	-0.325	-0.364	-0.214	-0.152	-0.143	-0.143
FACETS	-0.343	-0.387	-0.509	-0.644	-0.984	-1.523	-1.330	-1.229
LIFT-MARKAL	0.028	-0.087	-0.164	-0.196	-0.185	#N/A	#N/A	#N/A
MARKAL EPAUS9r	0.007	0.003	-0.032	-0.033	-0.035	-0.068	-0.105	-0.118
MarketPoint	-0.085	-0.084	-0.086	-0.083	-0.082	-0.083	-0.076	#N/A
MRN-NEEM	-0.411	-0.474	-0.499	-0.630	-0.651	-0.930	-1.451	-2.262
NEMS	-0.321	-0.389	-0.412	-0.487	-0.587	-0.809	#N/A	#N/A
NewERA	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
US Nat'l MARKAL	#NC	-0.291	-0.494	-0.498	-0.451	-0.349	-0.288	-0.147
US-REGEN	-0.137	-0.176	-0.388	-0.566	-0.578	-0.598	-0.519	-0.423
Average	-0.213	-0.257	-0.305	-0.374	-0.419	-0.594	-0.628	-0.814
Median	-0.226	-0.234	-0.356	-0.426	-0.423	-0.598	-0.404	-0.423

#NA = not available; #NC = not computed because price change is very small.

References

Alley, Richard B. (2000). *The Two-Mile Time Machine: Ice Cores, Abrupt Climate Change, and Our Future*, Princeton, N.J: Princeton University Press.

Citi GPS: Global Perspectives & Solutions (2012), "Energy 2020: North America, the New Middle East?" March.

Credit Suisse (2012), "The Shale Revolution," Securities Research & Analytics, 13 December. http://www.credit-suisse.com/researchandanalytics.

Ebinger, Charles, Kevin Massy and Govinda Avasarala (2012). "Liquid Markets: Assessing the Case for U.S. Exports of Liquefied Natural Gas," Policy Brief 12-01, Brookings Institution, Washington, DC, May.

EIA (2011). *Annual Energy Outlook 2011*, U.S. Energy Information Administration, Report Number: DOE/EIA-0383(2011), April.

EIA (2012). "Effect of Increased Natural Gas Exports on Domestic Energy Markets," U.S. Energy Information Administration, January.

Howarth, RW, Santoro, R and Ingraffea, A (2011). Methane and the greenhouse-gas footprint of natural gas from shale formations, *Climatic Change*, June, 106(4): 679-690.

Interagency Working Group on Social Cost of Carbon (2010), Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Washington, DC: United States Government.

Jiang, Mohan, W Michael Griffin, Chris Hendrickson, Paulina Jaramillo, Jeanne VanBriesen and Aranya Venkatesh, (2011), Life Cycle Greenhouse Gas Emissions of Marcellus Shale Gas, Environmental Research Letters, 6(3): 034014. ISSN: 1748-9326.

Krupnick, Alan, Hal Gordon, and Sheila Olmstead (2013), "Pathways to Dialogue: What the Experts Say about the Environmental Risks of Shale Gas," RFF Report, Washington, DC, February.

Medlock, Kenneth B. (2012), "US LNG Exports: Truth and Consequence," Baker Institute for Public Policy, Rice University, Discussion Paper.

Medlock, Kenneth B., Amy Myers Jaffe and Peter R. Hartley (2011), "Shale Gas and U.S. National Security," Baker Institute for Public Policy, Rice University, Discussion Paper.

MIT (2011). "The Future of Natural Gas: An Interdisciplinary MIT Study," Report. Massachusetts Institute of Technology Energy Initiative, Cambridge, MA.

National Research Council (2010). *Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use,* Washington, DC: National Academies Press.

National Petroleum Council (2011), *Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources*, Washington, DC.

NERA Economic Consulting (2012), "Macroeconomic Impacts of LNG Exports from the United States," Washington, DC.

Paltsev, Sergey, Henry D. Jacoby, John M. Reilly, Qudsia J. Ejaz, Jennifer Morris, Francis O'Sullivan, Sebastian Rausch, Niven Winchester, and Oghenerume Kragha (2011). "The Future of U.S. Natural Gas Production, Use, and Trade, *Energy Policy*," 39(9): 5309-5321, September.

U.S. Department of Energy (2011), Secretary Energy Advisory Board, "Second Ninety Day Report," Washington, DC, November.

Endnotes

[1] The current study provides a unique opportunity to compare results across multiple modeling teams using standardized assumptions for each case. Other major modeling studies that have applied models to the natural gas shale prospects include Paltsev, Jacoby, Reilly, Ejaz, Morris, O'Sullivan, Rausch, Winchester, and Kragha (2011) as well as Medlock, Jaffe and Hartley (2011).

[2] Modeling teams reported results for five-year intervals in order to focus on the longer-term trends in market conditions. As a result, the figures in this report do not reveal short-run perturbations that shift conditions within intervening years. The chart includes a price for CIMS-US that exceeds the upper end ($7.80) of this range but this cost is for electric utilities. In December 2012, this price was about $1 per million cubic feet above the average wellhead price. This report consistently uses the electric utility price for natural gas for this model only, because it is important to understand how prices and quantities respond to alternative energy and economic conditions.

[3] Through 2030, nuclear generation is virtually the same in the low-shale as in the reference case, differing by 4 percent at most in any model. Renewable generation varies slightly more through 2030 in these two cases but by no more than 7 percent. Differences after 2030 become more pronounced.

[4] For each $1 per thousand cubic feet decrease in wellhead gas prices, the average GDP for all models reporting this effect increases by $55 billion in 2020.

[5] See Citi GPS (2012) for a more optimistic evaluation or Credit Suisse (2012) for a more guarded (but still positive) assessment. If natural gas resources are developed consistent with the EMF high-shale conditions, this activity will expand output and employment in the oil and gas extraction industry, in some important end-use sectors like the chemical industry, and in a range of supporting sectors throughout the economy. This expansion will be facilitated by a shift of skilled labor, capital and materials from other sectors. This release of these inputs will cause output in other sectors to expand less rapidly than otherwise. There are also likely to be further economic adjustments. If reduced energy imports increase the value of the US dollar, other US export industries may lose some competitive advantages on international markets. Additionally, higher costs for labor and capital may slow the expansion in goods and services that are not traded internationally. On net, a rise in the economy's total output is expected, although it will be smaller than the increase in the expanding sectors alone.

[6] Oil and gas extraction activity is the sum of oil and gas extraction (NAICS code 211) and a proportional share of supporting activities for mining (NAICS code 213). The latter share is the percent of oil and gas extraction and other mining accounted for by the former. The US Bureau of Economic Analysis is the source for the output and employment estimates.

[7] The US Energy Information Administration is the source for the energy expenditure estimates.

[8] US Energy Information Administration, *Monthly Energy Review*, Washington, DC, July 2013.

[9] Interagency Task Force (2010) provides estimates of the damages from carbon dioxide emissions, while the National Research Council (2010) provides estimates of the damages from the other two gases. Damages from carbon dioxide emissions represent higher-than-expected impacts from temperature change. They are based upon the 95th percentile cost estimate at a 3 percent discount rate. When converted to inflation-adjusted 2010 dollars, they begin at $68 per metric tonne of carbon dioxide and increase over time to reach $142 per metric tonne by 2050. Damages for the other two gases apply to coal power plant operations and remain constant in 2010 dollars at $1672 per metric tonne of nitrogen oxides and $ 6060 per metric tonne of sulfur dioxide through the study's horizon.

[10] See Alley (2000).

[11] MIT (2011), National Petroleum Council (2011) and U.S. Department of Energy (2012) all emphasize that governments should and can effectively monitor and regulate the pressing environmental issues. Howarth, Santoro, and Ingraffea (2011) argued that upstream shale gas production might cause methane leakages that are very much more serious than for other fossil fuel production. Countering this conclusion is the sensitivity analysis provided by Jiang, Griffin, Hendrickson, Jaramillo, VanBriesen and Venkatesh (2011). Krupnick, Gordon, and Olmstead (2013) survey the views of experts on the range of important environmental issues associated with shale gas development.

[12] The Energy Modeling Forum plans to compare results from world natural gas models in future efforts. US Energy Information Administration (2012), Medlock (2012), and NERA Economic Consulting (2012) have evaluated the potential for US exports to be globally competitive. See also Ebinger, Massy and Avasarala (2012) for a review of other studies on the topic, including several by different consulting groups.