Energy Policy 39 (2011) 5309–5321

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

The future of U.S. natural gas production, use, and trade

Sergey Paltsev [a,b,*], Henry D. Jacoby [a], John M. Reilly [a], Qudsia J. Ejaz [a,b], Jennifer Morris [a], Francis O'Sullivan [b], Sebastian Rausch [a], Niven Winchester [a], Oghenerume Kragha [a]

[a] Joint Program on the Science and Policy of Global Change, Massachusetts Institute of Technology, 77 Massachusetts Ave, E19-411, Cambridge, MA 02139-4307, United States
[b] MIT Energy Initiative, Massachusetts Institute of Technology, 77 Massachusetts Ave, E19-307, Cambridge, MA 02139-4307, United States

ARTICLE INFO

Article history:
Received 9 August 2010
Accepted 19 May 2011
Available online 16 June 2011

Keywords:
Natural gas
Climate Policy
International gas trade

ABSTRACT

Two computable general equilibrium models, one global and the other providing U.S. regional detail, are applied to analysis of the future of U.S. natural gas. The focus is on uncertainties including the scale and cost of gas resources, the costs of competing technologies, the pattern of greenhouse gas mitigation, and the evolution of global natural gas markets. Results show that the outlook for gas over the next several decades is very favorable. In electric generation, given the unproven and relatively high cost of other low-carbon generation alternatives, gas is likely the preferred alternative to coal. A broad GHG pricing policy would increase gas use in generation but reduce use in other sectors, on balance increasing its role from present levels. The shale gas resource is a major contributor to this optimistic view of the future of gas. Gas can be an effective bridge to a lower emissions future, but investment in the development of still lower CO_2 technologies remains an important priority. International gas resources may well prove to be less costly than those in the U.S., except for the lowest-cost domestic shale resources, and the emergence of an integrated global gas market could result in significant U.S. gas imports.

1. Introduction

U.S. energy policy is shaped by concerns about energy security, the adequacy of supplies at reasonable and stable prices, and environmental impacts of energy production and use. Natural gas is a relatively clean fuel with lower emissions of greenhouse gases and conventional pollutants than coal and petroleum products. Moreover, newly advanced technologies for exploitation of domestic resources may make increased reliance on gas economic. In this changing resource picture four major areas of uncertainty will combine to determine gas production and use in the U.S.:

- The structure of greenhouse gas policies that may be put into effect in coming years: what form will emissions reductions policies take and how stringent will be the control levels?
- The scale of domestic gas resources: with production from conventional resources falling, will sources such as tight gas, coal bed methane, and shale gas allow U.S. production to continue to grow at stable prices?
- The technology mix in a carbon-constrained world, particularly in the electric sector: how will costs of competitors for natural gas respond to R&D and other efforts to stimulate cost reduction?
- The state of world gas production and trade: will we transition to a fully integrated world market like that for crude oil or will costs and other limits on intercontinental gas transport lead to the persistence of national and regional markets where forces to resolve inter-regional price differences are dampened?

These influences will interact to affect gas prices, use, domestic production, trade, and the need for further development of the natural gas distribution infrastructure in the U.S. They also will act in combination with broader forces affecting energy use including potential new uses for gas, such as compressed natural gas (CNG) vehicles in transportation, domestic economic growth, and changes in world markets that affect the costs of fuels with which gas competes.

Natural gas projections have been the focus of numerous modeling efforts. For example, Aguilera et al. (2009) focus on depletion and future availability of petroleum resources, including natural gas; Hartley and Medlock (2009) examine the impact on primarily European market on different Russian gas supply scenarios and acknowledge the role of shale development for the North American market; Egging et al. (2009) explore the implications of cartel behavior among gas producers; Brown and Yücel (2009) and Aune et al. (2009) investigate issues surrounding the globalization of the natural gas market.

We explore the issues related to natural gas applying first a global economic model that resolves key countries including the

* Corresponding author at: Joint Program on the Science and Policy of Global Change, Massachusetts Institute of Technology, 77 Massachusetts Ave, E19-411, Cambridge, MA 02139-4307, United States. Tel.: +1 617 253 0514; fax: +1 617 253 9845.
E-mail address: paltsev@mit.edu (S. Paltsev).

0301-4215/$ - see front matter © 2011 Elsevier Ltd. All rights reserved.
doi:10.1016/j.enpol.2011.05.033

U.S. and includes details of natural gas resources, energy demand, and competing energy supply technology. We base our projections on re-evaluated estimates of natural gas resources and the costs of extracting them. Then, as a step toward understanding the implications for the adequacy of existing domestic gas infrastructure, we augment results from the global economic model simulations using a U.S. regional model that helps to identify how regional demand and supply may change in the future. Many factors will influence the future role of natural gas in the U.S. energy system. Here we consider the most important of these: greenhouse gas (GHG) mitigation policy, technology development, size of gas resources, and Global Market developments.

2. Study methods and data

2.1. Global and U.S. regional models

Projections are made using the MIT Emissions Prediction and Policy Analysis (EPPA) model and the U.S. Regional Energy Policy (USREP) model. Both are multi-region, multi-sector representations of the economy. The core results for the study are simulated using the EPPA model (Paltsev et al., 2005; Paltsev et al., forthcoming). It is a computable general equilibrium (CGE) model that solves for the prices and quantities of interacting domestic and international markets for energy and non-energy goods as well as for equilibrium in factor markets. The USREP model is nearly identical in structure to EPPA, but represents the U.S. only, segmenting it into 12 single and multi-state regions (Rausch et al., 2009). The foreign sector is represented as export supply and import demand functions rather than a full representation of foreign economies, and interstate capital is mobile reflecting the ease of strongly connected capital markets within the U.S. whereas in the EPPA model international capital flows are restricted.

The way these models represent an economy is shown in Table 1. They include sectors that produce and convert energy, industrial sectors that use energy and produce other goods and services, and households that consume goods and services (including energy) with the non-energy production side of the economy aggregated into the five industrial sectors shown. These and other sectors have intermediate demands for all goods and services determined through an input–output structure. Final demand sectors include households, government, investment goods, and exports. Imports compete with domestic production to supply intermediate and final demands. Demand for fuels and electricity by households includes energy services such as space conditioning, lighting, etc., and a separate representation for Household Transportation (the private automobile) demand. Energy production and conversion sectors include coal, oil, and gas production, petroleum refining, and an extensive set of alternative generation technologies.

Of particular interest in analysis of natural gas are the electricity generation and energy-intensive products sectors and the potential penetration of natural gas into Household Transportation. Energy supply and conversion are modeled in enough detail to identify fuels and technologies with different CO_2 emissions and to represent both fossil and non-fossil technologies. The models include the non-CO_2 Kyoto gases (CH_4, N_2O, HFCs, PFCs, and SF_6).

All fossil energy resources are modeled in EPPA as graded resources whose cost of production rises continuously as they are depleted. In the fossil fuel production sectors, elasticities of substitution are set to generate elasticities of supply that fit the resource grades. Production in any one period is limited by substitution and the value share of the resource that enters the energy sector production functions as a fixed factor. The regional

Table 1
EPPA and USREP model details.

Country or region, EPPA model[a]	**Sectors**	**Factors and natural resources**
United States (USA)	***Non-energy sectors***	Capital
Canada (CAN)	Agriculture	Labor
Japan (JPN)	Services	Crude oil
European Union+ (EUR)	Energy-intensive products	Natural gas
Australia and New Zealand (ANZ)	Other industries products	Coal
Russia (RUS)	Transportation	Shale oil
Rest of Europe and Central Asia (ROE)	Household Transportation	Nuclear
India (IND)	Other household demand	Hydro
China (CHN)	***Energy supply and conversion***	Wind/solar
Brazil (BRA)	Electric generation	Land
Mexico (MEX)	Conventional fossil	
Rest of Latin America (LAM)	Hydro	
Higher income East Asia (ASI)	Existing nuclear	
Rest of Asia (REA)	Wind and solar	
Middle East (MES)	Biomass	
Africa (AFR)	Advanced gas	
	Advanced gas with CCS	
	Advanced coal with CCS	
U.S. Regions, USREP model[b]	Advanced nuclear	
North East	Fuels	
South East	Coal	
North Central	Crude oil, shale oil, refined oil	
South Central	Natural gas, gas from coal	
Mountain	Liquids from biomass	
West	Synthetic gas	

[a] Details of regional groupings is provided in Paltsev et al. (forthcoming)
[b] Details of regional groupings is provided in Rausch et al. (2009).

resource value shares reflect estimated rents. Energy resources are subject to depletion based on physical production of fuel in the previous period (Paltsev et al., 2005). We modify the approach for this study for natural gas supply by creating a two-stage production process. In stage 1 reserves are produced from resources and in stage 2 gas is produced from reserves. We apply this structure to four categories of gas resources: conventional, tight, shale, and coal-bed methane. Natural gas reserves expansion is driven by changes in gas prices, with reserve additions determined by elasticities benchmarked to the gas supply curves described in Section 2.2. On a demand side, elasticities of substitution in production sectors and final demand determine the responsiveness to endogenous price changes. The elasticity values are provided in Paltsev et al. (2005).

Sixteen geographical regions are represented in the EPPA model, as shown in Table 1, including eight of the largest individual countries (USA, Canada, Japan, China, India, Russia, Brazil, and Mexico) and eight aggregate regions. The model computes the trade in all energy and non-energy goods among these regions so that results can be used to explore potential international trade in natural gas. The USREP model is based on a state-level data base, aggregated for this study into the six regions shown in the table.

The advantage of models of this type is their ability to explore ways that domestic and global energy markets will be influenced by the complex interaction of factors like those identified above. Most important for this exploration of the future of natural gas, the models provide a facility for integrating the combined effect of resource estimates, technology, and policy issues. Models of any type have limitations, particularly when applied over a multi-decade horizon. Other input assumptions besides those mentioned above (e.g., about population and overall economic growth, and the ease of an economy's adjustment to price changes) also are subject to uncertainty over decades. There are details of market structure (e.g., various forms of gas contracts, political constraints on trade and technology choice) and of the behavior of individual industries that are beneath the level of aggregation of sectors within the models and reflected only implicitly in the parameters of aggregate production functions for the relatively coarsely resolved sectors. Also, because the models are solved on a 5-year time step they cannot represent the effects of short-term price volatility. Therefore, these model results should be viewed not as predictions where confidence can be attributed to the absolute numbers but rather as illustrations of the directions and relative magnitudes of various influences on the role of gas, and as a basis for forming intuition about likely future developments in a greenhouse-gas-constrained market environment.

2.2. *The representation of gas resources*

Among the important inputs to the EPPA model's sub-model of energy resource development and depletion that were re-evaluated for this study are estimates of the amount of resources and the costs of extracting them (MIT, 2010). Fig. 1 presents global supplies of natural gas by EPPA region and uncertainty range. The Mean global estimate of 16,200 trillion cubic feet (Tcf) is 150 times the global annual natural gas consumption of 108 Tcf in 2009. The range between P90 (90% probability of being exceeded) and P10 (10% probability of being exceeded) is from 12,400 to 20,800 Tcf. The set of natural gas supply functions are based on estimates of recoverable volumes of gas categorized as proved reserves, reserve growth, and undiscovered resources. The proved reserve volumes were taken from figures reported by the US EIA (2009b) and the *Oil and Gas Journal*. The reserve growth estimates were calculated by applying a well cohort analysis methodology (NPC, 2003) using historical U.S. field and well data.

The undiscovered resource estimates were based upon the gas resource assessment work of the USGS (Ahlbrandt et al., 2005), ICF International, and other agencies (e.g., Potential Gas Committee, 2009) that execute geological assessments, along with MIT statistical analysis. For the U.S. and Canada, both conventional and unconventional (tight gas, coal-bed methane, and shale) resource volumes were included in the supply functions. Unconventional gas resources were not included in the supply functions outside the U.S. and Canada because comprehensive assessments of technically recoverable volumes, and the corresponding costs required for their development were not available.

Cost estimates for the different components of the gas supply functions represent the breakeven gas price required to bring that volume of gas to market using the ICF Hydrocarbon Supply Model (Vidas et al., 1993) and ICF World Gas Supply Model, which implement a bottom-up methodology starting at the field or play level. Breakeven gas price calculations account for co-product production on an energy equivalent basis. The components of the breakeven calculation differ depending on which category of gas resource is being analyzed. In the case of proved producing reserves, the breakeven price is simply the operating and maintenance (O&M) cost associated with maintaining production from existing wells. For proved, but not yet producing, reserves and for reserve growth, a discounted cash flow method was used to determine the required breakeven gas price to compensate for the capital spent to develop the resource, and to maintain it during its producing life. The calculation of breakeven prices for undiscovered conventional resources was executed in a manner that includes the cost of gas exploration activity in addition to the development and operating costs at the field level and took into account the size of the field, whether the field was onshore or offshore and what drilling depths were required.

For unconventional resources in the U.S. and Canada a per-well methodology was used, where the well density, the per-well production profile, and recovery rate were defined based on geological analysis of the play. To establish the breakeven gas price and the associated volume of gas for each well, the per-well

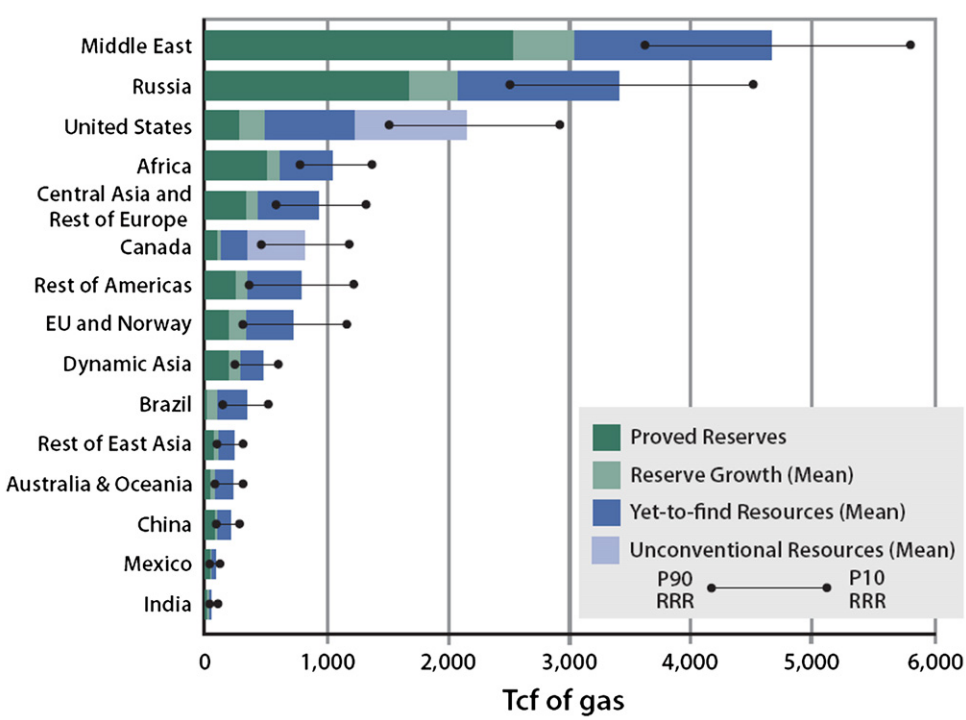

Fig. 1. Global remaining recoverable gas resource (RRR), excluding unconventional gas outside North America (MIT, 2010).

production characteristics were combined with data on drilling and operating costs using a discounted cash flow methodology.

A rate of return of 10% was used, with U.S. and Canadian calculations based on their fiscal regimes. For other regions, the breakeven calculations assumed a 50% tax rate and a 20% royalty rate. Development, exploration, and operating costs were taken from a number of sources, most notably the JAS Survey of Drilling Costs (API, 2006) and the EIA exploration cost database (US EIA, 2009a).

These estimates were made on the basis of costs in 2004, which was near the end of a long period of relatively stable development costs, and alternatively using costs in 2007, which were near their recent peak. These costs are now in a period of decline, which presents a question as to which basis is more appropriate for this analysis. The appropriate basis for our modeling purposes is the 2004 cost basis, for two reasons: (1) in an economic setting, relative prices matter and all other prices and costs in the EPPA and USREP models are on a 2004 basis, and (2) the 2007 conditions likely reflect a short-term response to very tight markets and are thus not representative of likely longer-term conditions, when suppliers of drilling equipment and the like are able to increase supply of this equipment in response to higher prices.

The resulting representation of U.S. gas resource supply to which the EPPA model was benchmarked is illustrated by the curves in Fig. 2, which show the quantity of gas that could be commercial at different extraction cost levels. Fig. 2a shows the relative magnitudes of the Mean estimate of U.S. resources, for current technology at 2004 costs, for the four types of deposits. Uncertainty in these estimates of resources and cost, for the total of the four categories, is shown in Fig. 2b, where the Mean case is the horizontal sum of the resource types in Fig. 2a. High and Low cases have been estimated to represent approximately an 80% confidence interval (i.e., a 10% chance of being above the High case estimate and a 10% chance of being less than the Low). Similar uncertainty ranges hold for the gas resources of all other world regions, though for regions other than the U.S. all gas types are aggregated into a single resource curve. These are long run resource supply curves and are conceptually similar to the "cumulative availability curves" developed by Aguilera et al. (2009). While we have arrived at comparable numbers for the total resource estimates for natural gas, our approaches differ.

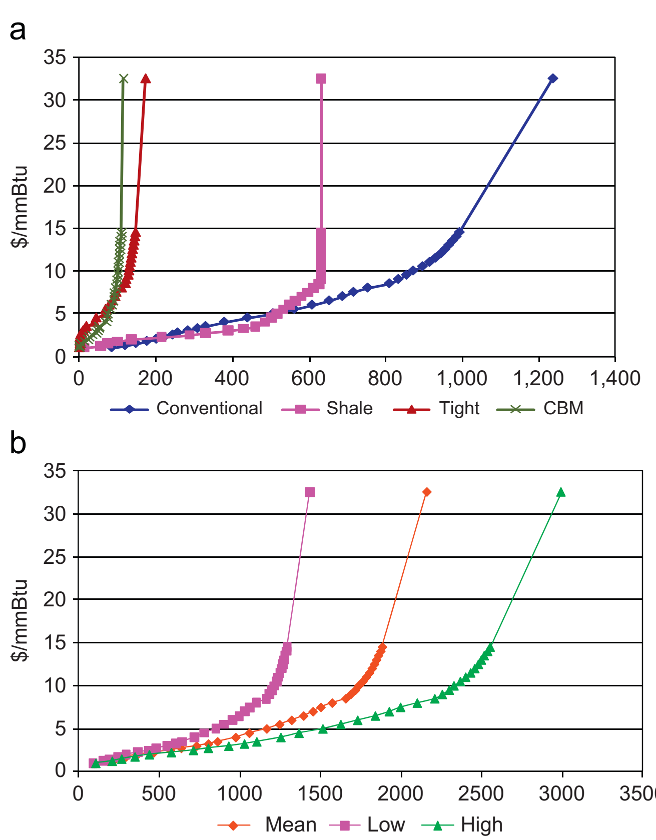

Fig. 2. U.S. natural gas supply functions: (a) mean supply by gas type (Tcf), (b) mean and 80% confidence interval for total U.S. supply (Tcf).

Aguilera et al. (2009) apply the reserve growth to undiscovered volumes (that also include the basins un-assessed by USGS). In comparison, in our calculations we use larger estimates of the proved reserves for conventional gas and include unconventional gas (nearly 1400 Tcf) in U.S. and Canada. We apply reserve growth only to the proved reserves. In addition, we use costs at the field level which accounts for the size[1] and location (basin, onshore vs. offshore) leading to the curves more representative of marginal costs. We include exploration costs for undiscovered conventional fields by using a discovery process model. We also develop uncertainty ranges for the supply projections, while Aguilera et al. (2009) provide only Mean estimates.

It is important to note that in the economic model production in any period is subject to dynamic processes that add reserves from resources and deplete reserves and resources. These features slow development, allocating the available resource over time while creating resource rents. As a result the gas price in any period is higher than the extraction cost of the least cost resource available at that time.[2] Uncertainty in the similar supply functions for oil and coal is not considered in this study.

2.3. *Other influential assumptions*

2.3.1. *Growth assumption and technology costs*

Several assumptions are important. U.S. economic growth is assumed to be 0.9% per year in 2005–2010, 3.1% in 2010–2020 (to account for recovery) and 2.4% for 2020–2050. Influential cost assumptions are shown in Table 2. The first column contains technology costs imposed in the main body of the analysis, as documented in Electronic Annex 1 in the online version of this article, and the right-most column shows values to be employed in sensitivity tests to be explored later. Nuclear power, coal, and gas generation with CO_2 capture and storage (CCS), and natural gas combined cycle (NGCC) plants are modeled as perfect substitutes for other conventional generation. Some estimates for coal or gas with CCS suggest even higher costs for early installations, but here we assume these costs apply to the *n*th plant, after experience is gained with the technology.

The costs for wind and solar imply that wind is near competitive in the base year and that solar costs three times that of conventional coal-fired electricity at that time. These intermittent renewables (wind and solar) are distinguished by scale. At low penetration levels they enter as imperfect substitutes for conventional electricity generation, and the estimates of the levelized

[1] Another detail is that here we use a different distribution for the sizes of undiscovered fields than the USGS. We use the linear-ratio model that increases the number of smaller fields relative to the lognormal distribution that the USGS employs. This leads to higher estimates for the undiscovered resources.

[2] Economic rents occur when prices are above the cost of production, and in resource markets the emergence of rent is conventionally attributed to three sources: Hotelling, Ricardian, and monopoly. Hotelling rents occur because holders of the resource expect prices to rise in the future and hold back on production today. Ricardian rents occur because resources are graded and there are limits to how fast the least costly resources can be developed and produced. Monopoly rents may also be present because of non-competitive behavior. The EPPA and USREP model structures embed estimates of the current rents in different resources based on existing data without explicitly identifying the underlying reason for them. The reserve-proving and energy production processes in the model restrict the rate of development and thus create persistent rents.

Table 2
Levelized cost of electricity (2005 cents/kWh).

	Reference	Sensitivity
Coal	5.4	
Advanced natural gas (NGCC)	5.6	
Advanced nuclear[a]	8.8	7.3
Coal/gas with CCS[b]	9.2/8.5	6.9/6.6
Renewables		
Wind	6.0	
Biomass	8.5	
Solar	19.3	
Substitution elasticity (wind, biomass, solar)	1.0	3.0
Wind+gas backup	10.0	

[a] Reference costs are based on the data for capital and O&M cost from U.S. Energy Information (US EIA, 2010). The lower sensitivity estimate is based on the 2010 update of the 2003 MIT study of the Future of Nuclear Power (MIT, 2009).

[b] Reference costs are based on the *Annual Energy Outlook* (US EIA, 2010; see endnote 3). The lower sensitivity estimate for coal with CCS draws on MIT study of the Future of Coal (2007), for gas with CCS on McFarland et al. (2009).

cost of electricity (LCOE[3]) apply to early installations when renewables are at sites with access to the best quality resources and to the grid and storage or back-up is not required. Through the elasticity of substitution the model imposes a gradually increasing cost of production as their share increases, to be limited by the cost with backup. These energy sector technologies, like others in the model, are subject to cost reductions over time through improvements in labor, energy, and (where applicable) land productivity.

2.3.2. *Representation of international gas markets*

Assumptions about the structure of international gas markets also influence the prospects for U.S. natural gas, and we explore two ways they may evolve over coming decades. Current trade is concentrated within three regional markets, those circled in Fig. 3 which highlights North American trade (U.S., Canada, and Mexico); trade among Europe, Russia, and North Africa; and Asia/Middle East trade links among Japan, China, Indonesia, Australia, and other Asian countries. We represent current regional markets by modeling gas as an imperfect substitute among the regions (Armington trade structure). With the Armington trade, supply, and demand changes in one region are not fully transmitted to other regions, and prices among regions can diverge. This formulation tends to preserve existing trade relationships and to limit expansion of trade to regions with which there is currently little or no trade. In the discussion to follow this case is referred to as a Regional Markets case and most of the analysis below assumes this trade pattern is sustained over the study period.

However, if demand and supply changes in regions lead to wide price divergence it becomes more likely that trade patterns will change over time to take advantage of price differentials, and what could develop is a more globally integrated market akin to the one that emerged in recent decades for oil. The gas market has been slower to develop than that for oil – due to the scale economies and lumpiness of investment in LNG and long-distance pipeline transport – but economic incentives for this evolution are present. To represent globally integrated natural gas market, where gas prices equalize among regions, except for differences in transportation costs between exporters and importers (Heckscher–Ohlin trade structure), we develop the Global Market scenario, which is explored in Section 5.

[3] LCOE is the cost of electricity per kWh that over the life of the plant fully recovers operating, fuel, capital costs, and financial costs.

2.4. *Scenarios considered*

We consider a number of scenarios to investigate the implications for gas of different future energy and CO_2 policies and of uncertainty in other factors to which gas use and production is sensitive. These alternative assumptions include:

- No New Climate Policy which takes account of the Energy Independence and Security Act of 2007 (EISA) and the American Recovery and Reinvestment Act of 2009 (ARRA) – as they mandate biofuels, CAFE standards, and subsidies to renewables – but it does not consider greenhouse gas reduction proposals in the Congress as of spring 2010 or potential regulations under the Clean Air Act.
- A Price-Based Greenhouse Gas (GHG) Emissions Policy which imposes an economy-wide price on GHGs that gradually reduces emissions to 50% below 2005 by 2050. Similar reductions are imposed in other developed countries and with China, India, Russia, Mexico, and Brazil beginning in 2020 on a linear path to 50% below their 2020 levels by 2070. The rest of the developing countries delay action to beyond 2050.

These scenarios are simulated to 2050, and alternative cases consider the effects of the 80% confidence interval of estimated of gas resources, and the influence of alternative assumptions about the evolution of global gas markets. In addition, we explore:

- A Regulatory Climate Policy which gradually retires coal power plants and phases in a renewable electricity portfolio standard requiring renewable to supply 25% of electric generation.

Because running all possible combinations of these alternative policies and sensitivities would create a prohibitively large number of possible scenarios, we investigate a selective set that highlight key determinants of the future role of natural gas.

In the discussion below we report all results in terms of constant 2005 dollars.

3. U.S. natural gas with no additional Climate Policy

Even absent additional greenhouse gas mitigation the future role of natural gas in the U.S. will be influenced by the extent and cost of domestic gas resources, and the nature of the international gas market (explored in Section 5). Unless gas resources are at the Low end of the resource estimates in Fig. 2, domestic gas use and production are projected to grow substantially between now and 2050 (Fig. 4). Under the Mean resource estimate U.S. gas production rises by roughly 40% between 2005 and 2050, and by a slightly higher 45% under the High estimate. It is only under the Low resource outcome that resource availability substantially limits growth in domestic production and use. In that case, gas production and use plateau near 2030 and are in decline by 2050. U.S. imports remain roughly the same regardless of the magnitude of domestic resources, and a small quantity of exports (mainly to Mexico) is sustained. Details of this EPPA projection, and selected others for results below, all assuming Mean gas resources, are provided in Electronic Annex 2 in the online version of this article.

Natural gas prices are shown at the top of the bars in 2005 U.S. dollars. They rise over time as the lower-cost resources are depleted, and the lower the resource estimate the higher the projection of U.S. gas price. The difference across the range of resource scenarios is not great for most periods. In 2030, for example, the High resource estimate yields a price 2% below that for the Mean estimate while the Low resource condition increases the price by 7%. The difference increases somewhat over time,

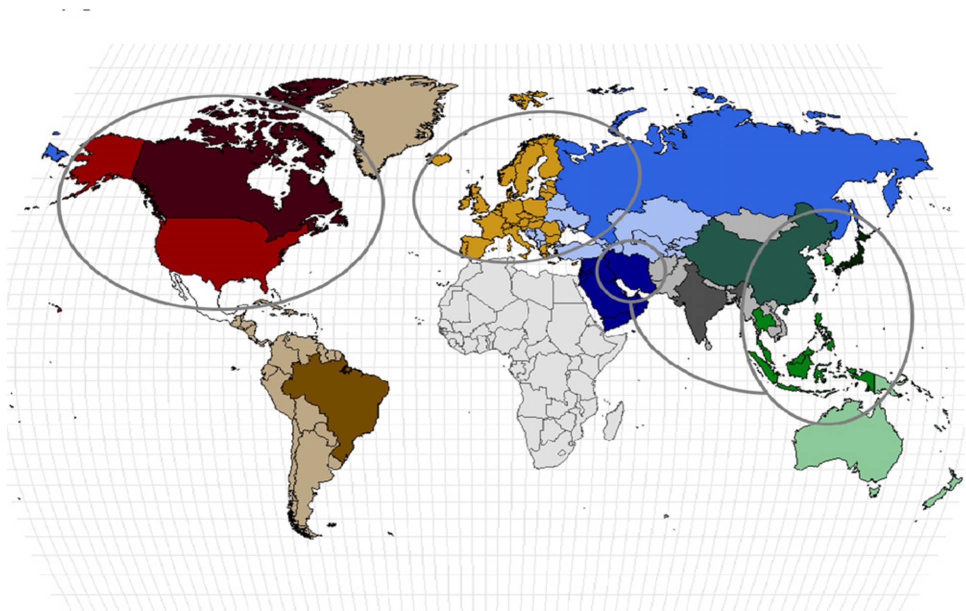

Fig. 3. Regional Gas Markets.

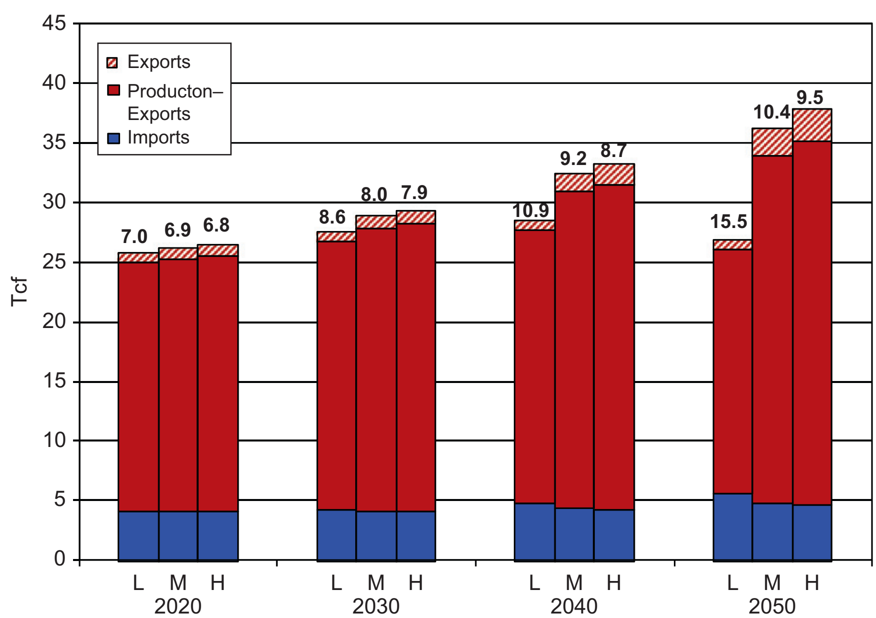

Fig. 4. U.S. gas use, production and imports and exports (Tcf), and U.S. gas prices above bars (2005 $/1000 cf) for Low, Mean, and High U.S. resources. No Climate Policy and Regional Gas Markets.

especially for the Low resource case. By 2050 the price is 8% lower if the High resource conditions hold, but 50% higher if domestic resources are at the Low estimate.

Because shale gas resources are the largest contributor to the recent re-evaluation of U.S. gas resources they have a substantial effect on these results. In this no-policy case, with Mean resources, U.S. gas production rises by 42% between 2005 and 2050. If this projection is made without shale resources, production peaks in the vicinity of 2030 and declines back to its 2005 level by 2050. The reduction in domestic gas production is then reflected in U.S. gas use which rises by 35% with the shale resources, but by only 8% without them.

U.S. energy use by source under the no-additional-policy assumption, and the Mean resources is shown in Fig. 5. Electricity generation from natural gas (Fig. 5a) would rise by about two-thirds over the period 2005–2050. Coal would continue to dominate electric generation, with only a slightly growing contribution from nuclear power and renewable sources (wind and solar). Similarly for total U.S. primary energy (Fig. 5b), gas use would rise by about half over the period, but would remain a roughly constant fraction of total energy use.

4. Effects of GHG mitigation on U.S. gas production and use

In recent years attention has been devoted to the use of GHG emissions pricing, achieved by implementing a cap-and-trade system though often supplemented by regulation and subsidies. Another possibility is a variety of other energy policies, perhaps motivated in large part by climate concerns, directed at specific

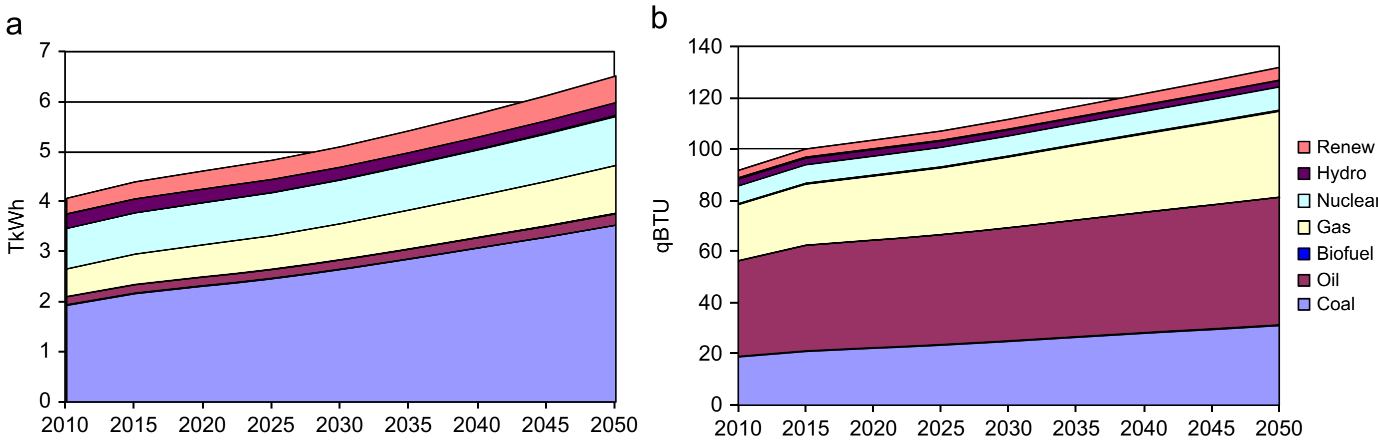

Fig. 5. U.S. electric generation and total energy use by source, no-policy case with Mean gas resources: (a) electric generation (TkWh) and (b) total energy use (quadrillion Btu).

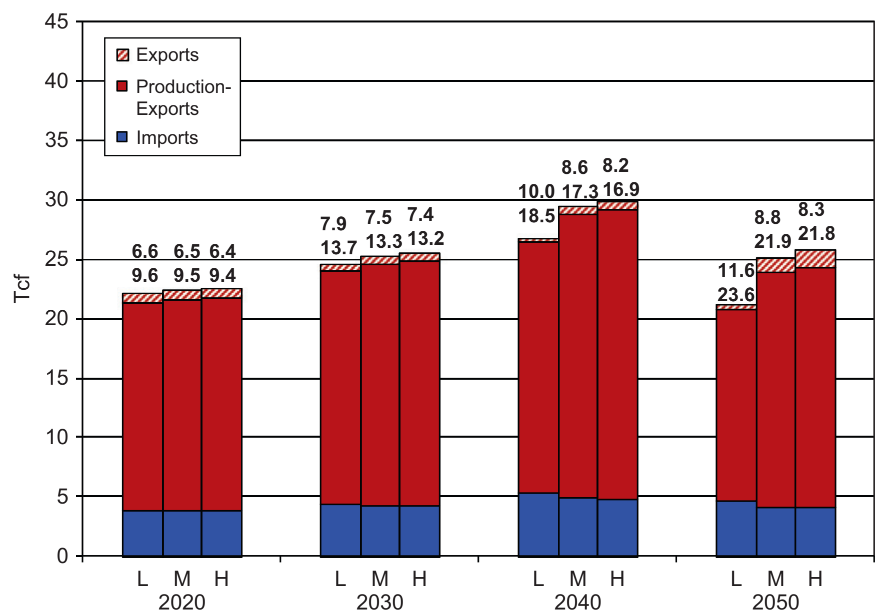

Fig. 6. U.S. gas use, production and imports and exports (Tcf), and U.S. gas prices (2005 $/1000 cf) for Low, Mean and High U.S. resources. Price-based Climate Policy and Regional Gas Markets. Prices are shown without (top) and with (bottom) the emissions charge.

technologies, especially those in electric generation. An incentive-based policy like a cap-and-trade system can vary from stringent to modest depending on what emissions cap or tax is set, how many offsets are allowed, and other possible cost-containment features. Similarly, there are endless variants of technology-based policies that might specify best available technology, create incentives for phase out of dirtier technologies, or require a certain percentage of clean technologies such as in a renewable energy standard. We consider the implications of one representation of each of these broad mitigation alternatives: first via a price-based approach and then applying a regulatory alternative.

4.1. Mitigation applying a price-based measure

The futures of gas under a price-based GHG policy is explored using the simple emissions control scenario described in Section 2.4 under which the U.S. reduces its total emissions to 50% below the 2005 level by 2050. It is assumed that other countries take mitigation actions abroad because it seems unlikely that the U.S. would follow through on such a policy unless others participated as well, and actions abroad can affect the U.S. through international trade effects. The scenario is not designed to represent any specific policy proposal, and no provision is included for offsets.

4.1.1. Gas production, use & trade, and resulting prices

Fig. 6 presents the same information for the Climate Policy case as was presented in Fig. 4 for the no-new-policy scenario, adding the gas price at both producer and consumer levels (i.e., including the CO_2 penalty). The broad features of U.S. gas markets under the assumed emissions restriction are not substantially different from the no-policy scenario, at least through 2040. Gas production and use grow somewhat more slowly, reducing use and production by a few Tcf in 2040 compared with the case without Climate Policy.

After 2040, however, domestic production and use begin to fall. The decline is driven by higher gas prices, CO_2 charge inclusive, that gas users would see. The price reaches about $22 per thousand cubic feet (cf) with well over half of that price reflecting the CO_2 charge. While gas is less CO_2-intensive than coal or oil, at the reduction level required by 2050 its CO_2 emissions are beginning to represent an emissions problem. Nonetheless, even under the pressure of the assumed emissions

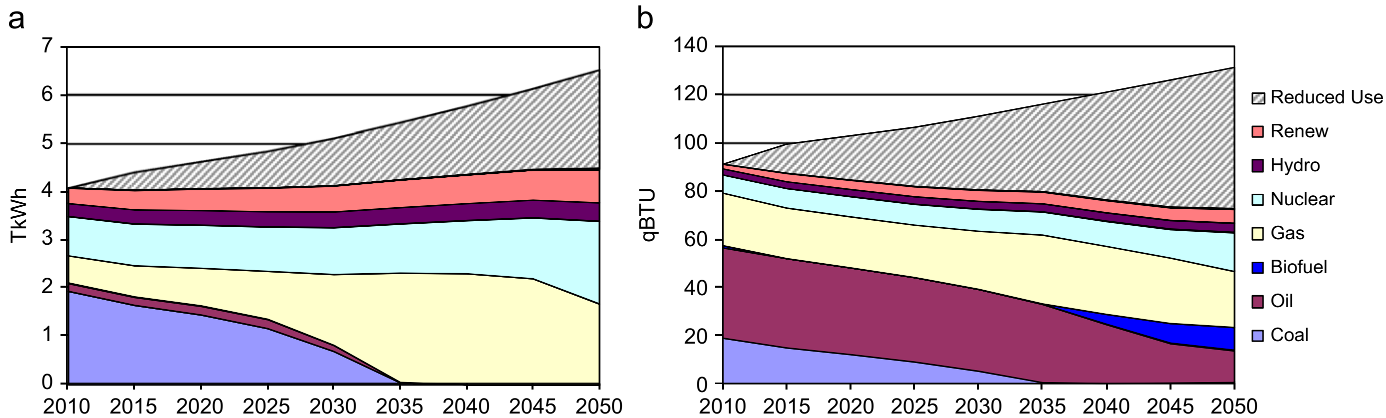

Fig. 7. Energy mix under a price-based Climate Policy, Mean gas resources: (a) electric generation (Tkwh) and **(b)** total energy use (quadrillion Btu).

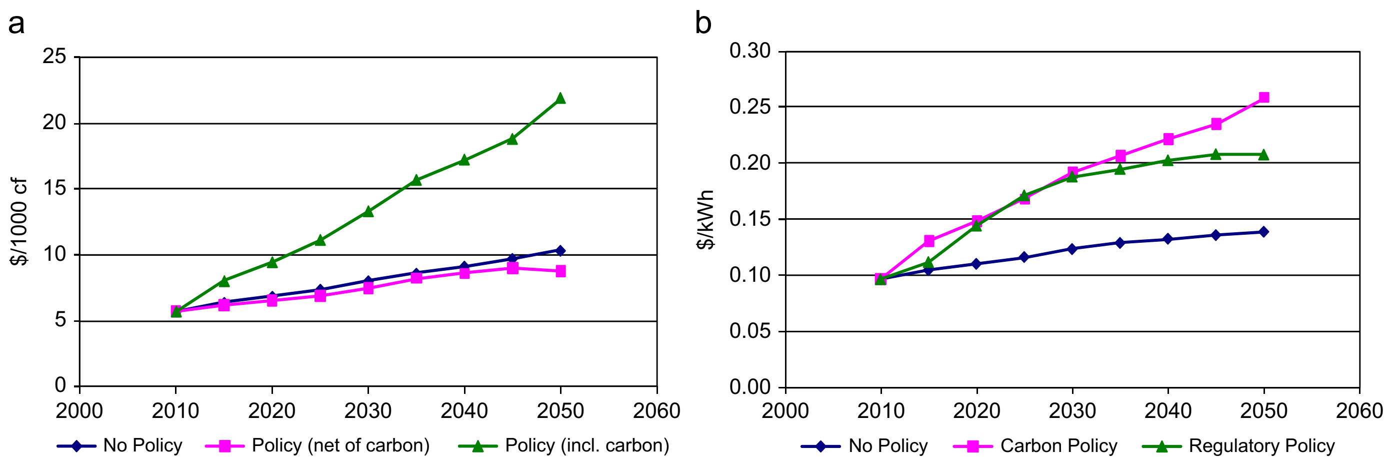

Fig. 8. U.S. natural gas and electricity prices, Mean gas resources: (a) natural gas prices (2005 $/1000 cf), (b) electricity prices (2005 $/kWh).

policy, total gas use is projected to increase from 2005 to 2050 even for the Low estimate of domestic gas resources.

4.1.2. Energy quantities and prices

A major effect of the energy-wide, price-based mitigation is to reduce energy use (Fig. 7). The effect on the electric sector (Fig. 7a) is to flatten demand. Nuclear, coal, or gas with CCS and renewables are relatively expensive compared with gas generation without CO_2 storage. (Coal and gas with CCS begin to enter the generation mix between 2040 and 2050 but are too small to show in the figure.) Conventional coal is driven from the generation mix by the CO_2 prices needed to meet the economy-wide emissions reduction targets, to be replaced mainly by natural gas. Natural gas is the substantial winner in the electric sector: the substitution effect, mainly gas generation for coal generation, outweighs the demand reduction effect.

For total primary energy (Fig. 7b) the projected demand reduction is even stronger, leading to a decline in U.S. energy use of nearly 20 quadrillion (10^{15}) Btu. The reduction in coal use is evident, and oil and current-generation biofuels (included in oil) begin to be replaced by advanced biofuels. Because national energy use is substantially reduced, the share represented by gas is projected to rise from about 20% of the current national total to approximately 40% in 2040.

The U.S. GHG emissions price projected under this scenario is approximately $100 per ton CO_2-e in 2030 and approaching $240 by 2050. The macroeconomic effect is to lower U.S. GDP by nearly 2% in 2030 and somewhat over 3% in 2050. A selection of resulting U.S. domestic prices is shown in Fig. 8. Natural gas prices, exclusive of the CO_2 price, are reduced slightly by the mitigation policy, but the price inclusive of the CO_2 charge is greatly increased (Fig. 8a). The CO_2 charge is nearly half of the user price of gas. Even in the no-policy case electricity prices are projected to rise by 30% in 2030 and about 45% over the period to 2050 (Fig. 8b). The assumed emissions mitigation policy is projected to cause electricity prices to rise by almost 100% in 2030 and more than double by 2050 compared with current prices. (Also shown in the figure is the electricity price increase under a sample regulatory regime, to be discussed below.)

Because of the estimated abundance of gas and limited opportunities for gas–oil substitution the current price premium in the U.S. of oil products over gas (on an energy basis) is maintained and even grows over time. One substitution option not modeled here is the possibility of conversion of gas to liquids,[4] which might become economic and perhaps be further stimulated by security concerns, even though making no contribution to CO_2 reduction. Such a development would raise U.S. gas use and prices, and lower oil demand with some moderating effect on the world oil price.

4.1.3. Policy effects on gas use by sector and U.S. gas transport infrastructure

The 50% price-based mitigation policy will re-allocate gas use among economic activities. Fig. 9 shows the gas use by sector as

[4] A potential interplay between gas and oil via gas-to-liquids is discussed in Burden et al. (2009).

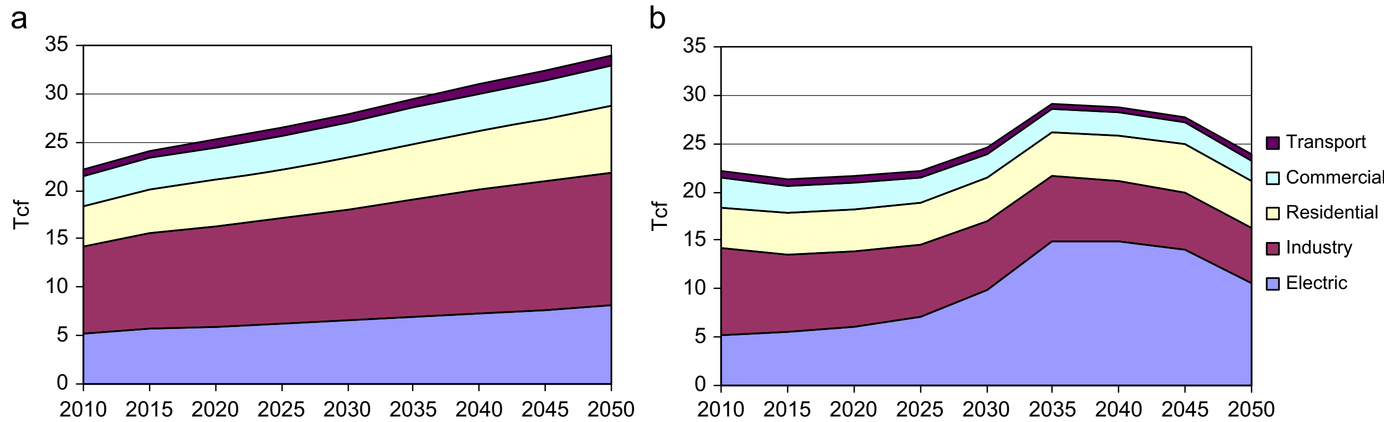

Fig. 9. Influence of policy on gas use by sector, Mean gas resources (quadrillion Btu), (a) no-policy reference case, (b) price-based policy.

defined in the EPPA model for the Mean resource case. (energy-intensive industry products and other industry products are aggregated into a single industry sector.) Transportation includes both commercial transportation and private vehicles; the scenario does not allow for CNG vehicles (explored below) and so they have no effect on gas use. In the no-policy case (Fig. 9a) the greatest increase in gas use is in the industry sector and secondarily in residential use. Under assumed price-based emissions mitigation on the other hand (Fig. 9b), gas use is reduced somewhat especially in the latter years. A prominent feature is the shift of gas to electric generation from other sectors.

The difference in response among sectors represents the combination of a substitution effect (gas against more CO_2-intensive fuels) and an energy use reduction effect because the gas price, inclusive of the CO_2 charge, is higher. In the electricity sector, where gas is an effective substitute for coal, the substitution effect outweighs the demand reduction effect and so gas use increases. Carbon pricing increases electricity price less than direct fuel prices. Gas use is reduced in other uses where its competition is petroleum fuels or electricity where its carbon advantage is less. While there is a substitution effect, it is weaker and is outweighed by the demand reduction effect caused by higher prices.

Considering the aggregation of sectors in the EPPA model the absolute values of these effects should not be accorded great weight. But they do suggest the trends to be expected from a price-based policy: that is, gas will find its greatest economic value in displacing coal in the electric sector, and the higher prices needed to achieve this result will lead to gas being shifted out of other sectors, with the greatest percentage effect expected in trade-exposed sectors, which by the EPPA aggregation points to the industrial sectors in contrast to commercial, service, and household users.

The changing sources of gas within the U.S. may require changes in the existing transportation infrastructure, either more or different pipelines within the U.S. or more LNG facilities. To explore this prospect we consider the regional shifts in production and consumption within the U.S. employing the USREP model described in Section 2. Gas production increases most in those regions with the new shale resources. It increases by more than 150% in the Northeast region (New England through the Great Lake States), by just about 50% in the South Central area that includes Texas, and 30% in the Mountain states. In regions without new shale resource production changes very little—slight increases or decreases. Under the no-new-policy case the Northeast production increase comes close to matching the growth in consumption, so this result suggests little need for additional gas transportation infrastructure into this large-demand region. (However, we do not model changes in intra-regional flows and investments may be needed to connect new producing areas to existing distribution networks.) The biggest gas transportation implications would appear to be additional capacity to move gas from the Texas/South Central region and the Mountain states. These two regions increase their net exports by a combined 4 Tcf. The greater capacity would need to go to all other regions except the Northeast. Under Climate Policy, those regions with the largest shale gas resources (Northeast and South Central) show increases in production but not nearly as large as in the no-new-policy case. Other regions show little change or a reduction in production. The possible new gas transportation requirements are less than in the no-new-policy case, but many of the general patterns are the same.[5]

4.1.4. *Sensitivity to costs of competing technologies*

Another influence on the future of natural gas is the costs of competing supplies, particularly in the electric power sector. Here we focus on three technologies to which gas use is particularly sensitive: cheaper renewable sources, lower-cost coal and gas with CCS, and lower-cost nuclear power. Also, we explore the prospect of gas use in household transportation. Because it would be difficult to construct an "equivalent" cost reduction applying to all of these technologies we explore the effect of one scenario of cost reduction for each, to give an impression of how energy markets would adjust and the effect on natural gas.

The results are shown in Table 3. To explore the effect of cheaper renewables we assume that an elasticity parameter that represents the ease of integrating wind into the grid is increased from 1.0 to 3.0, as shown in Table 2. This change assumes the variability in the wind resource, and the need to match production with the load requires less cost than in the base case. Lower-cost renewables yield a reduction in gas use in the electric sector by 1.8 Tcf in 2030, but total gas use falls by only 1.2 Tcf. In 2050 a difference in gas use is smaller, 0.5 Tcf and 0.1 Tcf, respectively, as availability of cheaper renewables does not require an increase in nuclear power that by that time starts to replace gas in electric sector.

To explore the effect of cheaper base-load generation the cost of coal and gas generation with CCS is lowered by about 25%

[5] National gas production and use with the USREP model differs slightly from the EPPA projections. In the no-new-policy case, gas production and use is slightly higher than in the EPPA simulations, and in the climate policy case it is a bit lower. The USREP model captures inter-regional differences in coal and gas prices and better reflects differences in renewable costs among regions than does the nationally aggregated EPPA model, but it does not explicitly represent foreign trading partners. The variation in results introduced by these differences in structure is well within the range of other uncertainties.

Table 3
Sensitivity to technology costs, price-based policy, Mean gas resources.

	2005		2030		2050	
	Elec.	Total	Elec.	Total	Elec.	Total
Gas use (Tcf)						
Ref technology	5.6	22.0	10.0	24.6	10.6	23.9
More renewables	5.6	22.0	8.1	23.4	10.2	23.8
Cheap CCS	5.6	22.0	10.5	25.5	13.6	28.2
Cheap nuclear	5.6	22.0	9.4	24.5	3.4	18.5
CNG	5.6	22.0	9.9	25.3	10.0	24.5
Gas price ($/1000 cf), net of CO_2 charge						
Ref technology		5.5		7.5		8.8
More renewables		5.5		7.5		8.6
Cheap CCS		5.5		7.6		9.3
Cheap nuclear		5.5		7.5		8.2
CNG		5.5		7.6		8.9
Gas price ($/1000 cf), inclusive of CO_2 charge						
Ref technology		5.5		13.3		21.9
More renewables		5.5		12.5		21.2
Cheap CCS		5.5		12.9		19.4
Cheap nuclear		5.5		12.8		18.4
CNG		5.5		13.4		23.2

(Table 2). At the higher-cost reference assumptions this technology does not become competitive until too late in the simulation period to have an effect on coal use. With less-costly CCS gas use increases in the electric sector, by nearly 3 Tcf, because both gas and coal generation with CCS become economic and share the low-carbon generation market (with about 25% of electricity produced by gas with CCS by 2050 and another 25% by coal with CCS). Gas use in the economy as a whole increases even more, by 4.2 Tcf.

The biggest impact on gas use in electricity results from the low-cost nuclear generation. Focusing on 2050, when the effects of alternative assumptions are the largest, a low-cost nuclear assumption reduces annual gas use in the electric sector by nearly 7 Tcf. Economy-wide gas use falls by only about 5 Tcf, however, because the resulting lower demand for gas in electricity leads to a lower price and more use in other sectors of the economy.

Many other combinations of technological uncertainties could be explored, perhaps without adding to the insight to be drawn from these few model experiments: under a price-based mitigation policy natural gas is in a strong competitive position unless competing technologies are much cheaper than we now anticipate. Also, because of its use in almost all sectors, the development of lower-cost competitors in any one sector, such as electric generation, leaves gas at a lower price absorbing at least some of the freed-up supply in other uses.

The simulations above do not include the CNG vehicle. This policy case was simulated with this technology included, applying optimistic estimates of the cost penalty of the natural gas vehicle and the pace of development of fueling infrastructure (Kragha, 2010). The result depends on assumptions about the way competing biofuels, and their potential indirect land-use effects, are accounted (Melillo et al., 2009). Even with advanced biofuels credited as a zero-emissions option, however, CNG vehicles rise to about 15% of the private vehicle fleet by 2040–2050—which is projected to be much more efficient than today. They consume about 1.5 Tcf of gas at that time which, because of the effect of the resulting price increase on other sectors, adds approximately 1.0 Tcf to total national use.[6]

[6] Substitution for motor fuel is the likely target of possible expansion of gas-to-liquids technology. Its market penetration would depend on competition not

4.2. Effects of a regulatory approach to emissions mitigation

If emissions reductions are to be sought by means of regulatory and/or subsidy measures, with no price on emissions, many alternatives are available. Among the most obvious measures that could have a direct impact on CO_2 emissions, would be those requiring renewable energy or encouraging a phase-out of existing coal-fired power plants. To explore this prospect we formulate a scenario with a renewable energy standard (RES) mandating a 25% renewable share of electric generation by 2030, and holding at that level through 2050, and measures to force retirement of coal fired power plants starting in 2020, so that coal plants accounting for 55% of current production are retired by 2050. Mean gas resources are assumed, as are the reference levels of all technology costs. The case results in approximately a 50% CO_2 emissions reduction in the electricity sector by 2050, but it does not provide incentives to reduce emissions in non-electric sectors, so these measures only hold national emissions to near the 2005 level up to 2040 slightly rising afterwards mostly due to increased oil use.

The resulting projection of the role of natural gas is shown in Fig. 10. One evident result in comparison with Fig. 7 is that the level of demand reduction in the electric sector is less than under the assumed price-based policy (Fig. 10a). The lower reduction results from the lower electricity price, shown in Fig. 8b, which carries no CO_2 charge and only reflects the increased cost of generation imposed by the regulatory requirement. The difference in reduction in the national total (Fig. 10b) is more dramatic compared with Fig. 7b because the all-sector effect of the universal greenhouse-gas price is missing.

In the electric sector the rapid expansion of renewables tends to squeeze out gas-based generation in the early decades of the period. Of course, as can be seen in the figure, the impact on gas use depends heavily on the relative pace of implementation of the two regulatory measures in this experiment. Regarding total all-sector gas use, this set of assumption leads to a circumstance where gas continues to make a major contribution to national energy use, though potentially less than if all energy sources face the same penalties for their GHG emissions.

5. The role of international gas markets

Gas is priced under different conventions in different regions. In some situations prices are set in spot markets; in others they are dominated by contracts linking gas prices to prices of crude oil and oil products. As a result, gas prices can differ substantially among the regions. Here we consider a case where those institutional differences disappear. The main reason that we might expect such a change in market structure is that price differences among regions become so large that profits can be made above the cost of transport. The magnitude of supply from abroad would depend on the development of supply capacity by those nations with very large resources (mainly Russia and countries in the Middle East), or perhaps the expansion of nonconventional sources elsewhere, and as influenced by national and industry policies regarding trade and contract forms. To the extent the structure evolves in this direction; however, there are major implications for U.S. natural gas production and use. To investigate the potential evolution of an integrated Global Market akin to crude oil, we simulate a case where gas prices are equalized in

(*footnote continued*)
only with oil products but also with direct gas use, biofuels, and electricity which reduce CO_2 emissions while liquids from gas would not.

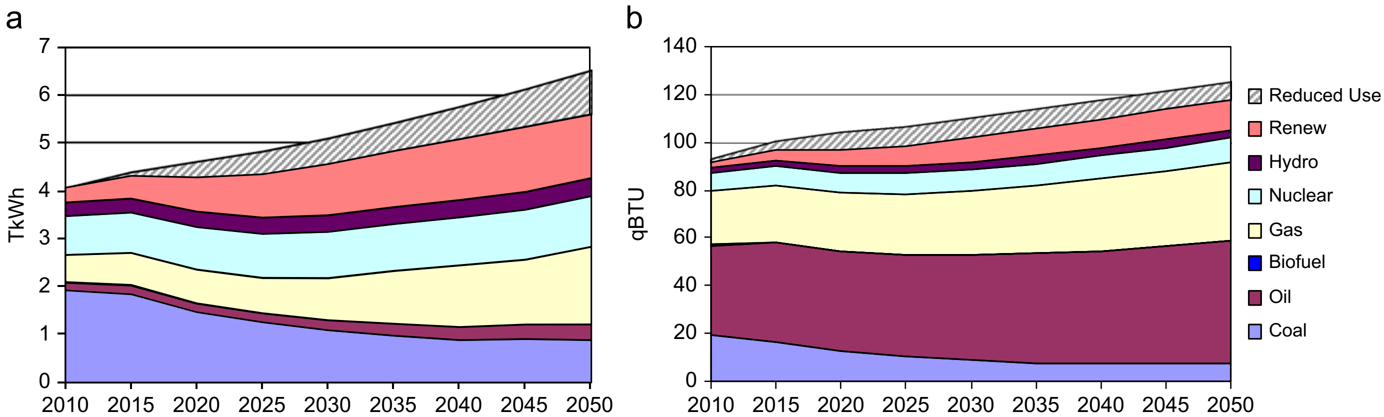

Fig. 10. Energy mix under a regulatory policy, Mean gas resources: (a) electric generation (TkWh), (b) total energy use (quadrillion Btu).

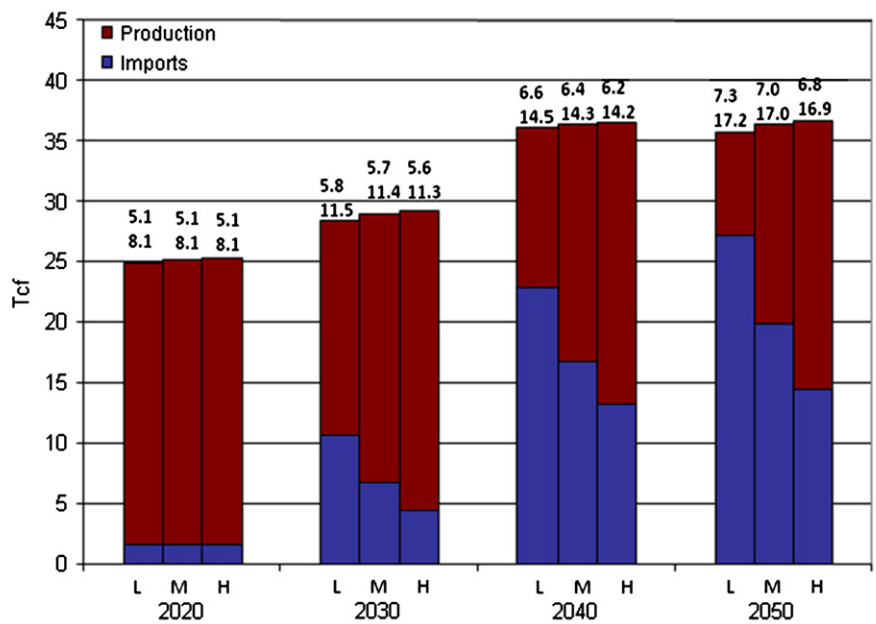

Fig. 11. U.S. gas use, production and imports and exports (Tcf), and U.S. gas prices ($/1000 cf) for Low, Mean and High U.S. resources price-based Climate Policy and global gas markets. Prices are shown without (top) and with (bottom) the emissions charge.

all markets except for fixed differentials that reflect transport costs.[7]

Projected effects on U.S. production and trade are shown in Fig. 11 for the 50% price-based GHG reduction and High, Mean, and Low gas resources cases. This result may be compared with the Regional Markets case shown in Fig. 6. Beginning in the period 2020–2030, the cost of U.S. gas begins to rise above that of supplies from abroad and the U.S. becomes more dependent on imports of gas. By 2050, the U.S. depends on imports for about 50% of its gas in the Mean resource case. U.S. gas use rises to near the level in the no-policy case because prices are lower. U.S. gas use and prices are much less affected by the level of domestic resources, because the effect on prices is moderated by the availability of imports. The development of an efficient international market, with decisions about supply and imports made on an economic basis, would have complex effects: it would benefit the U.S. economically, limit the development of domestic resources, and lead to growing import dependence.

Possible international gas trade flows that are consistent with U.S. and global demand under the Regional and Integrated Global Market are shown in Fig. 12. A no-new-policy case is shown. Under Regional Market conditions (Fig. 12a) trade flows are large within gas market regions but small among them. To avoid a cluttered map, small trade flows (less than 1 Tcf) are not shown in the figure, but to be seen are U.S. imports from Canada, the imports to the EU from Russia and Africa and the imports into Asia from Australia and the Middle East. Trade flows can be particularly sensitive to the development of transportation infrastructure and political considerations, and so projections of bilateral trade in gas are particularly uncertain. The Regional Markets case tends to increase trade among partners where trade already exists, locking in patterns determined in part by historical political considerations.

[7] In the Global Markets case (Heckscher–Ohlin assumption) the EPPA model does not resolve bilateral trade flows. Exports go into an international pool and importing countries import from the pool, taking account of transportation cost. In this method countries cannot simultaneously export and import, so in the scenarios we resolve only the net trade—gross trade could be somewhat larger, although for energy there is in general not a large difference between net and gross trade.

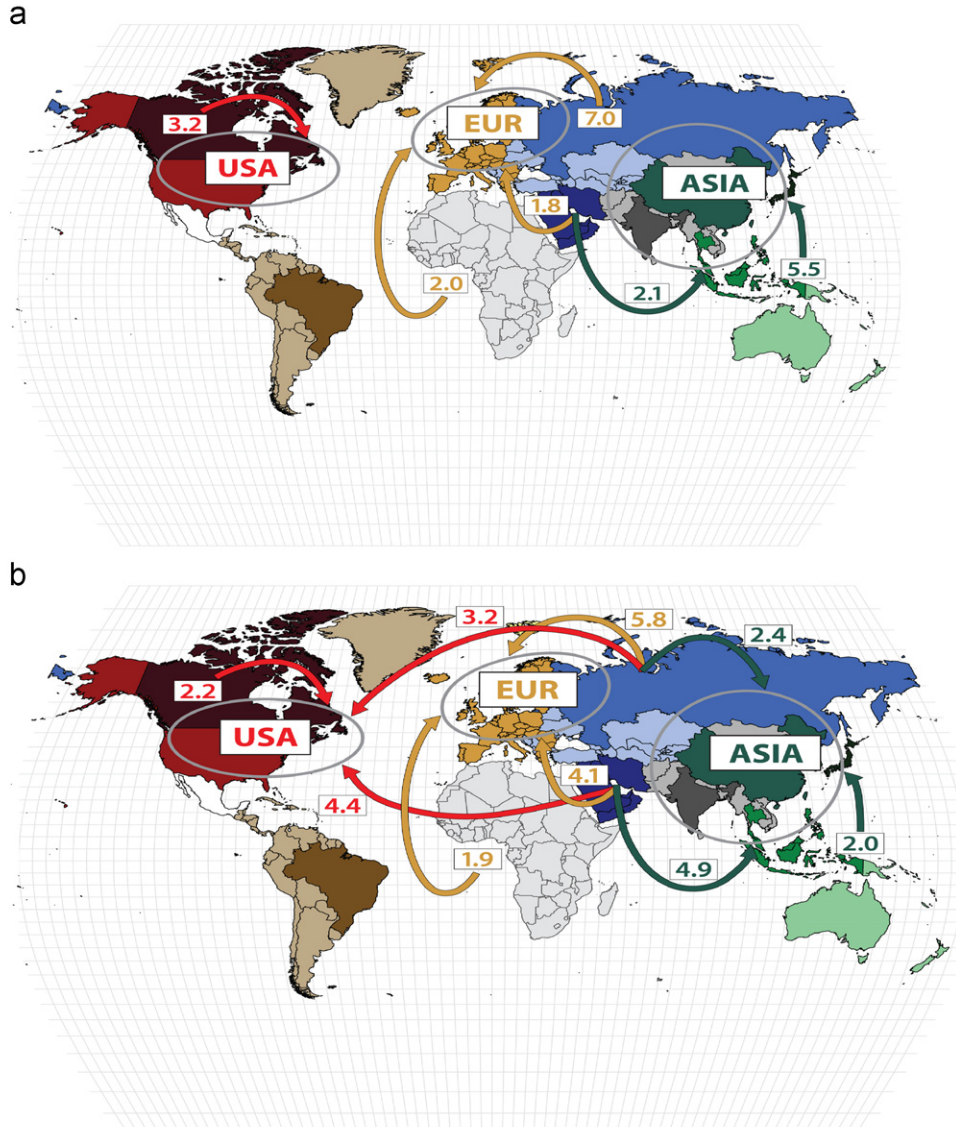

Fig. 12. Major trade flows of natural gas among the EPPA regions in 2030, No New Policy (Tcf): (a) Regional Markets, (b) Global Market.

If an efficient Global Market is assumed to develop, then substantial flows among current trading regions would result. As in the Global Market scenario we do not resolve bilateral trade flows (see footnote 7), the flows pictured in Fig. 12b are consistent with demand and supply and net exports in each region but there are other flows that are also consistent. Here we show the U.S. to import from the Middle East as well as from Canada and Russia, and movements from the Middle East to Asia and Europe would increase—implying a substantial expansion of LNG facilities. Russian gas would begin to move into Asian markets, via some combination of pipeline transport and LNG.

The precise patterns of trade that might develop to 2030 and beyond will be influenced by the economics of the energy industry, as captured by the EPPA model, and also by national decisions regarding gas production and imports. Therefore, the numbers shown are subject to a number of uncertainties, prominent among which is the willingness of Middle-East and Russian suppliers to produce and export. If potential supplies are not forthcoming then global prices would be higher and the U.S. would import less than projected, or perhaps increase exports.

The broad insight to be drawn from these simulations is nonetheless evident: to the degree that economics is allowed to determine the global gas market, trade in this fuel is likely to increase over coming decades. A few years ago there was significant development of LNG capacity in the U.S. on the expectation that U.S. resources were limited and likely more expensive than international supplies. Had that expectation proved correct, the world might have proceeded faster toward the development of a more broadly integrated Global Market.

6. A summary of results

The easiest generalization of this exploration of the future of natural gas is that the outlook for gas over the next several decades is highly favorable. Shale gas resources add significantly to the U.S. resource base and allow production to increase, whereas in their absence production would likely decline or at best sustain current levels. Naturally the gas resource base and costs of accessing it are uncertain. The upside uncertainty has less of an impact on domestic production levels because at the Mean estimate of resources supply is adequate to meet growing demand at moderate prices through 2050. Even at the pessimistic end of estimates, however, in the absence of additional GHG mitigation U.S. gas production and use is projected to be higher in 2050 than today.

A stringent policy of greenhouse gas reduction, if pursued with a price-based policy that would yield a level playing field for competing energy sources, would favor gas relative to other fossil fuels. The share of gas in total energy use is projected to be larger with such a policy, though overall energy use would be lower. Only under the Low end of the range of domestic resources would gas use in 2050 be lower than today. Regulatory energy policies that might be driven in part by efforts to lower CO_2 emissions could be less favorable for natural gas depending on the relative stringency and timing of the regulations.

With or without GHG emissions mitigation the changing distribution of U.S. gas production, particularly the exploitation of shale resources, will require some expansion in the long-distance pipeline network, primarily to accommodate shipment of gas out of the South Central region to areas other than the North East, though the imposition of emissions mitigation reduces the need such changes in this system.

Gas competes most strongly in the electric power sector, especially under Climate Policy, because it has much lower CO_2 emissions than coal. The technology is well-known and inexpensive compared with alternatives such as nuclear, CCS, or renewables. On a level playing field, only with significant cost breakthroughs or very stringent CO_2 reduction targets would these alternative sources compete effectively with gas over the next few decades. Thus in the electric generation sector natural gas is a bridge fuel under Climate Policy, providing a cleaner alternative to coal. With continued tightening of CO_2 constraints beyond 2050, however, the CO_2 emissions from gas generation eventually will require adoption of other, still-lower carbon emitting generation technologies. The shale gas resource is far from a panacea over the longer term and investment in the development of still lower CO_2 technologies remains an important priority.

If a more tightly integrated world gas market develops and low cost conventional resources in the Middle East and Russia are accessible to the market, then economic conditions would favor increasing U.S. LNG imports even with large resources of domestic shale. While some of the shale resources can compete with these low cost foreign sources, much of the resource is expected to be more costly to produce and so would not compete purely on economic grounds.

Acknowledgments

We are thankful to Tony Meggs and Gordon Kaufman for their valuable contribution. This analysis was carried out as part of an interdisciplinary study, The Future of Natural Gas, which was supported principally by the American Clean Skies Foundation, with additional support from the Hess Corporation, the Agencia Nacional de Hidrocarburos (Columbia), the Energy Futures Coalition, and the MIT Energy Initiative. Development of the economic models applied in the study was supported by the U.S. Department of Energy, the U.S. Environmental Protection Agency, the Electric Power Research Institute, and by a consortium of industry and foundation sponsors (for complete list see http://globalchange.mit.edu/sponsors/current.html).

Appendix A. Supporting information

Supplementary data associated with this article can be found in the online version at doi:10.1016/j.enpol.2011.05.033.

References

Aguilera, R., Eggert, R., Gustavo Lagos, C., Tilton, J., 2009. Depletion and the future availability of petroleum resources. Energy Journal 30 (1), 141–174.

Ahlbrandt, T., Charpentier, R., Klett, T., Schmoker, J., Schenk, C., Ulmishek, G., 2005. Global Resource Estimates from Total Petroleum Systems. American Association of Petroleum Geologists.

API, 2006. American Petroleum Institute. Joint Association Survey on Drilling Costs, Washington, D.C.

Aune, F., Rosendahl, K., Sagen, E., 2009. Globalisation of natural gas markets—effects on prices and trade patterns. Energy Journal, Special Issue on World Natural Gas Markets and Trade, 39–53.

Brown, S., Yücel, M., 2009. Market arbitrage: European and North American natural gas prices. Energy Journal, Special Issue on World Natural Gas Markets and Trade, 167–185.

Burden, J., Pepper, W., Aggarwal, V., 2009. The impact of high oil prices on global and regional natural gas and LNG markets. Energy Journal, Special Issue on World Natural Gas Markets and Trade, 55–71.

Egging, R., Holz, F., Von Hirschhausen, C., Gabriel, S., 2009. Representing GASPEC with the World Gas Model. Energy Journal, Special Issue on World Natural Gas Markets and Trade, 97–117.

Hartley, P., Medlock, K., 2009. Potential futures for Russian natural gas exports. Energy Journal, Special Issue on World Natural Gas Markets and Trade, 73–95.

Kragha, O., 2010. Economic implications of natural gas vehicle technology in U.S. private automobile transportation. MS Thesis, Master of Science in Technology and Policy, Massachusetts Institute of Technology, Cambridge, MA.

MIT, 2007. The Future of Coal: An Interdisciplinary MIT Study. Massachusetts Institute of Technology, Cambridge, MA.

MIT, 2009. Update of the 2003 Future of Nuclear Power: An Interdisciplinary MIT Study. Massachusetts Institute of Technology, Cambridge, MA.

MIT, 2010. The Future of Natural Gas: An Interdisciplinary MIT Study Interim Report. Massachusetts Institute of Technology, Cambridge, MA.

McFarland, J., Paltsev, S., Jacoby, H., 2009. Analysis of the coal sector under carbon constraints. Journal of Policy Modeling 31 (1), 404–424.

Melillo, J., Reilly, J., Kicklighter, D., Gurgel, A., Cronin, T., Paltsev, S., Felzer, B., Wang, X., Sokolov, A., Schlosser, C.A., 2009. Indirect emissions from biofuels: how important? Science 326, 1397–1399.

NPC [National Petroleum Council], 2003. Balancing Natural Gas Policy—Fueling the Demands of a Growing Economy.

Paltsev, S., Reilly, J., Jacoby, H., Eckaus, R., McFarland, J., Sarofim, M., Asadoorian, M., and Babiker, M., 2005. The MIT Emissions Prediction and Policy Analysis (EPPA) Model: Version 4. MIT Joint Program on the Science and Policy of Global Change, Report 125, Cambridge, MA. Available at: 〈http://globalchange.mit.edu/files/document/MITJPSPGC_Rpt125.pdf〉.

Paltsev, S., Reilly, J., Jacoby, H., Morris, J., Karplus, V., Gurgel, A., Eckaus, R., ,and Babiker, M., (forthcoming). The MIT Emissions Prediction and Policy Analysis (EPPA) Model: Version 5. MIT Joint Program on the Science and Policy of Global Change, Report, Cambridge, MA.

Potential Gas Committee, 2009. Potential Supply of Natural Gas in the United States—Report of the Potential Gas Committee (December 31, 2008). Gas Agency, Colorado School of Mines.

Rausch, S., Metcalf, G., Reilly, J., and Paltsev, S., 2009. Distributional impacts of a U.S. greenhouse policy: a general equilibrium analysis of carbon pricing. MIT Joint Program on the Science and Policy of Global Change, Report 182, Cambridge, MA. Available at: 〈http://globalchange.mit.edu/files/document/MITJPSPGC_Rpt182.pdf〉.

US EIA [Energy Information Administration], 2009a. Annual Energy Review 2008.

US EIA [Energy Information Administration], 2009b. U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves Report Available at:〈http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/crude_oil_natural_gas_reserves/cr.html〉.

US EIA [Energy Information Administration], 2010. Annual Energy Outlook 2010 Early Release.

Vidas, E., Hugman, R., Haverkamp, D., 1993. Guide to the hydrocarbon supply model: 1993 update. Gas Research Institute Report GRI-93/0454.