Chapter 3: U.S. Gas Production, Use and Trade: Potential Futures

INTRODUCTION

As discussed in other sections of this report, 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. And we examine how they will interact to shape future U.S. gas use, production and trade over the next few decades.

We investigate the importance of these factors and their uncertainties by applying established models of the U.S. and global economy (see Box 3.1). Alternative assumptions about the future allow us to create a set of scenarios that provides bounds on the future prospects for gas and illustrate the relative importance of different factors in driving the results.

The conditions explored include the High, Mean and Low ranges of gas resource estimates described in Chapter 2. We show the impacts of various policy alternatives, including: no new climate policy; a GHG emission reduction target of 50% by 2050, using a price-based policy (such as a cap-and-trade system or emissions tax) and an emissions policy that uses a set of non-price regulatory measures.

Several assumptions have a particularly important effect on the analysis. Long-term natural gas supply curves, distinguishing the four gas types for the U.S. and Canada, are drawn from Chapter 2. U.S. economic growth is assumed to be 0.9% per year in 2005 to 2010, 3.1% in 2010 to 2020 (to account for recovery) and 2.4% for 2020 to 2050.

BOX 3.1 GLOBAL AND U.S. ECONOMIC MODELS

Projections in this section were made using the MIT Emissions Prediction and Policy Analysis (EPPA) model and the U.S. Regional Energy Policy (USREP) model.[1] Both are multi-region, multi-sector representations of the economy that solve for the prices and quantities of energy and non-energy goods and project trade among regions.

The core results for this study are simulated using the EPPA model — a global model with the U.S. as one of its regions. 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. In the USREP model, foreign trade is represented through import supply and export demand functions, broadly benchmarked to the trade response in the EPPA model. Both models account for all Kyoto gases.

The advantage of models of this type is their ability to explore the interaction of those factors underlying energy supply and demand that influence markets. The models can illustrate the directions and relative magnitudes of influences on the role of gas, providing a basis for judgments about likely future developments and the effects of government policy. However, results should be viewed in light of model limitations. Projections, especially over the longer term, are naturally subject to uncertainty. Also, the cost of technology alternatives, details of market organization and the behavior of individual industries (e.g., various forms of gas contracts, political constraints on trade and technology choice) are beneath the level of model aggregation. The five-year time step of the models means that the effects of short-term price volatility are not represented.

Table 3.1 Levelized Cost of Electricity (2005 cents/kWh)

	Reference	Sensitivity
Coal	5.4	
Advanced Natural Gas (NGCC)	5.6	
Advanced Nuclear[2]	8.8	7.3
Coal/Gas with CCS[3]	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	

Source: EPPA, MIT

Influential cost assumptions are shown in Table 3.1. The first column contains technology costs imposed in the main body of the analysis, as documented in Appendix 3A. The right-most column shows values to be employed in sensitivity tests to be explored later, where we vary the costs of competing generation technologies (nuclear, coal and gas with carbon capture and storage and renewables). The 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 cost of electricity (LCOE[4]) apply to early installations when renewables are at sites with access to the best quality resources and to the grid, and storage or backup 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.

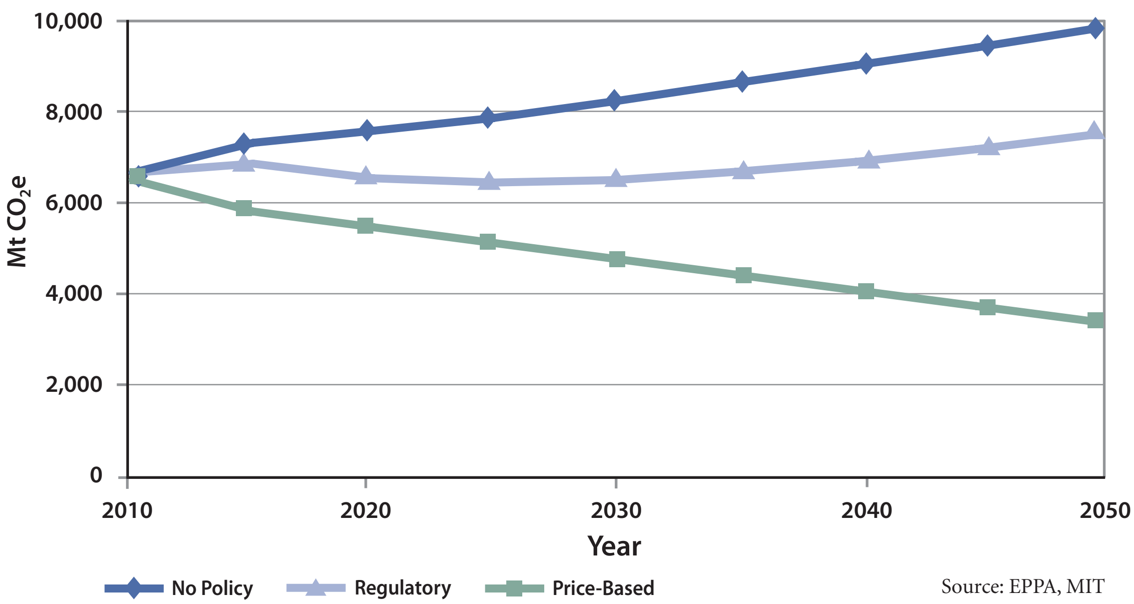
The potential role of compressed natural gas in vehicles is considered separately, drawing on estimates of the cost of these vehicles from Chapter 5 of this report.

We also consider two possible futures for international gas markets: one where they continue in their current pattern of regional trading blocs and an alternative where there develops a tightly integrated global gas market similar to that which now exists for crude oil.

THE ROLE OF U.S. CLIMATE POLICY — THREE ALTERNATIVE SCENARIOS

To explore the future of U.S. gas use in a carbon-constrained world, we analyze three scenarios of greenhouse control, with very different implications for the energy sector as a whole. Scenario 1 establishes a baseline, with no GHG policy measures beyond those in place today. Emissions grow by some 50% over the period, as shown in Figure 3.1. Scenarios 2 and 3 are constructed to span a wide range of possible approaches to climate policy, and potential effects on gas use. Scenario 2 assumes that a price-based policy is imposed on all U.S. GHG emissions with a target of a 50% reduction by 2050, as can be seen in Figure 3.1. Scenario 3 imposes no economy-wide target, but considers two measures proposed for the electric power sector: a renewable energy standard and measures to force retirement of coal-fired power plants. As seen in Figure 3.1, this scenario of a regulatory approach essentially stabilizes U.S. GHG emissions, yielding only about 10% increase by 2050.

Figure 3.1 U.S. Greenhouse Gas Emissions under Alternative Scenarios



Source: EPPA, MIT

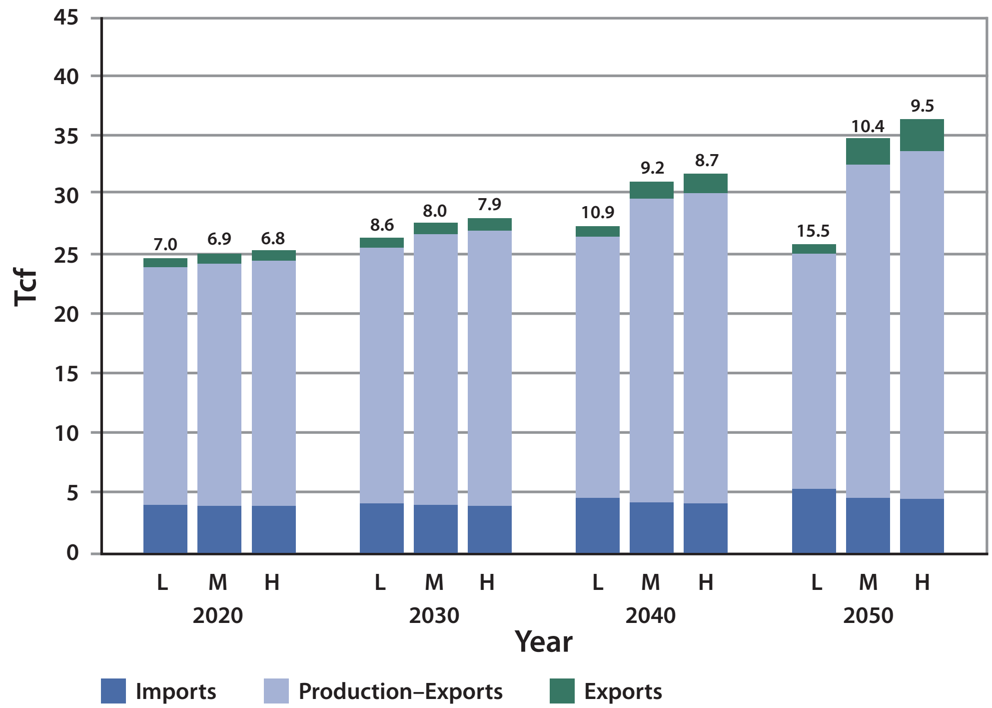
Scenario 1 — No Additional GHG Mitigation Policy

Unless gas resources are at the Low end of the resource estimates in Chapter 2, domestic gas use and production are projected to grow substantially between now and 2050. This result is shown in Figure 3.2, from EPPA model simulations, on the assumption that global gas markets remain fragmented in regional trading blocs. Under the Mean resource estimate, U.S. gas production rises by around 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 around 2030 and are in decline by 2050.

The availability of shale gas resources has a substantial effect on these results. If the Mean estimate for other gas resources is assumed, and this same projection is made omitting the shale gas component of supply, U.S. production peaks around 2030 and declines to its 2005 level by 2050.

Given the continued existence of regional trading blocs for gas, there is little change in the role played by imports and exports of gas. Imports (mainly from Canada) are roughly constant over time, though they increase when U.S. resources are Low. Exports (principally to Mexico) are also maintained over the period and grow somewhat if U.S. gas resources are at the High estimate.

Figure 3.2 U.S. Gas Use, Production and Imports & Exports (Tcf), and U.S. Gas Prices above Bars ($/1000 cf) for Low (L), Mean (M) and High (H) U.S. Resources. No Climate Policy and Regional International Gas Markets



Source: EPPA, MIT

Gas prices (2005 U.S. dollars), shown at the top of the bars in Figure 3.2, rise gradually over time as the lower-cost resources are depleted; the lower the resource estimate, the higher the prices. The difference in prices 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 increased the price by 7%. The difference increases somewhat over time, especially for the Low resource case. By 2050, for example, the price is 8% lower if the High resource conditions hold, but 50% higher if domestic resources are at the Low estimate.

Underlying these estimates are developments on the demand side. Under Mean resources, electricity generation from natural gas would rise by about 70% over the period 2010 to 2050 though coal would continue to dominate, with only a slightly growing contribution projected from nuclear power and renewable sources (wind and solar). National GHG emissions rise by about 40% from 2005 to 2050. More detailed results for the scenarios with Mean resources are provided in Appendix 3B.

Scenario 2 — Price-Based Climate Policy

An incentive (or price) based GHG emissions policy that establishes a national price on GHG emissions serves to level the emissions reduction playing field by applying the same penalty to emissions from all sources and all uses.

The policy explored here gradually reduces total U.S. GHG emissions, measured in CO_2 equivalents (CO_2-e)[5], to 50% below the 2005 level by 2050. The scenario is not designed to represent a particular policy proposal and no provision is included for offsets.

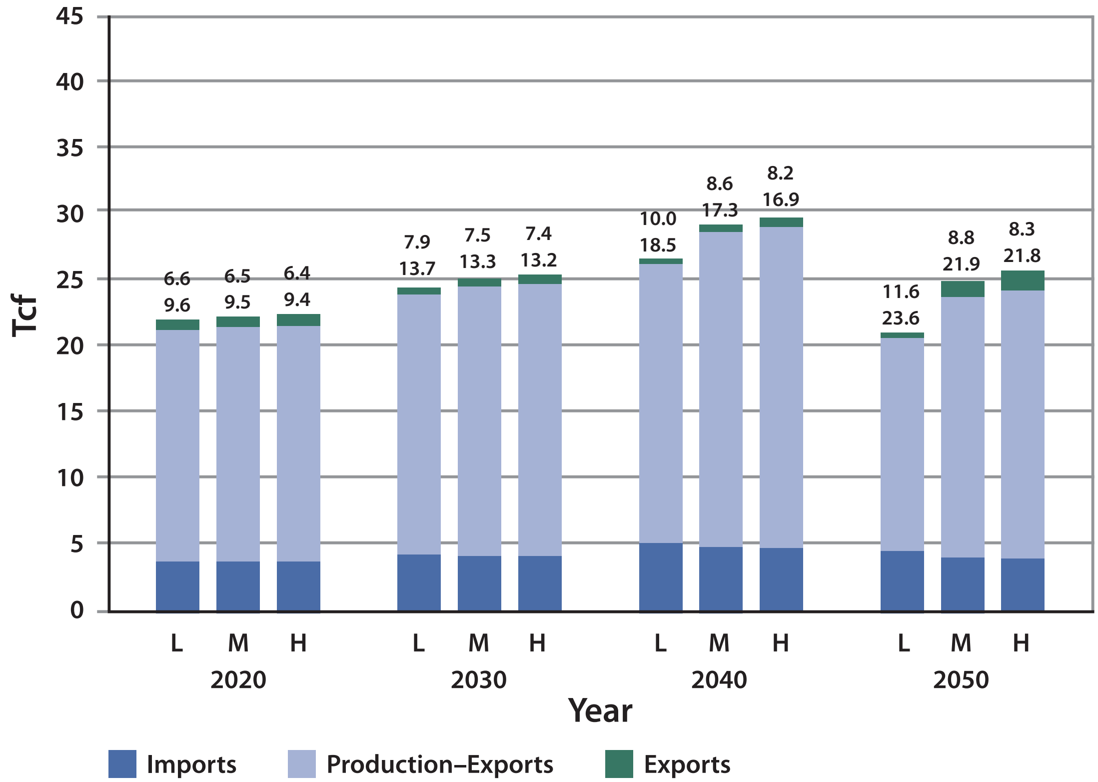
While measures taken abroad are not of direct interest for this study, such policies or the lack of them will affect the U.S. energy system through international trade. If the U.S. were to pursue this aggressive GHG mitigation policy, we assume that it would need to see similar measures being taken abroad. Thus, a similar pattern of reductions is assumed for other developed countries, with lagged reductions in China, India, Russia, Mexico and Brazil that start in 2020 on a linear path to 50% below their 2020 levels by 2070. The rest of the developing countries are assumed to delay action to beyond 2050. We assume no emissions trading among countries.

Even under the pressure of an assumed CO_2 emissions policy, total U.S. gas use is projected to increase up to 2050.

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 (Figure 3.3). Gas production and use grows somewhat more slowly, reducing use and production by a few Trillion cubic feet (Tcf) in 2040 compared with the case without climate policy. After 2040, however, domestic production and use begin to fall. This decline is driven by higher gas prices, Carbon Dioxide (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.

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

Figure 3.3 U.S. Gas Use, Production and Imports & Exports (Tcf), and U.S. Gas Prices ($/1000 cf) for Low (L), Mean (M) and High (H) U.S. Resources, Price-Based Climate Policy and Regional International Gas Markets. Prices are shown without (top) and with (bottom) the emissions charge.

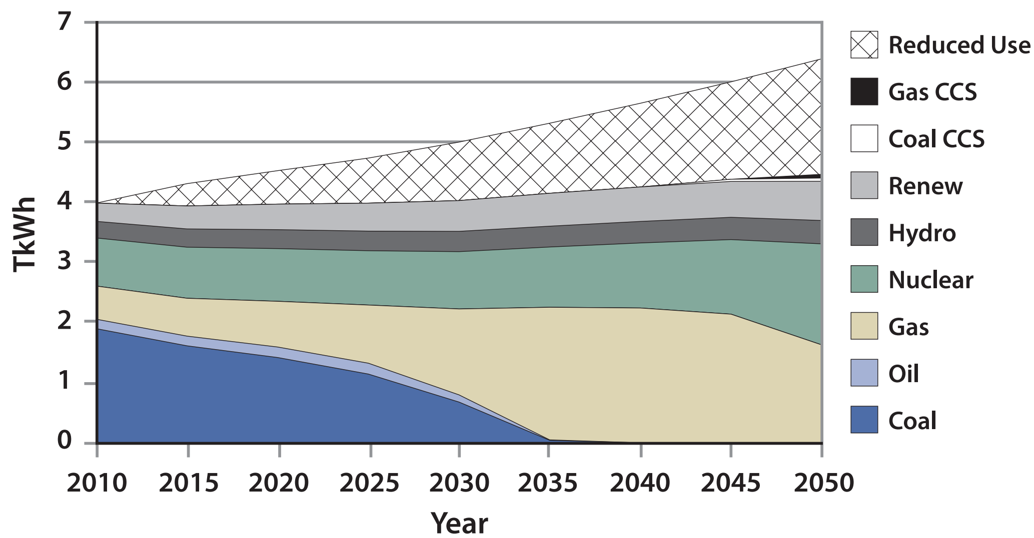


Source: EPPA, MIT

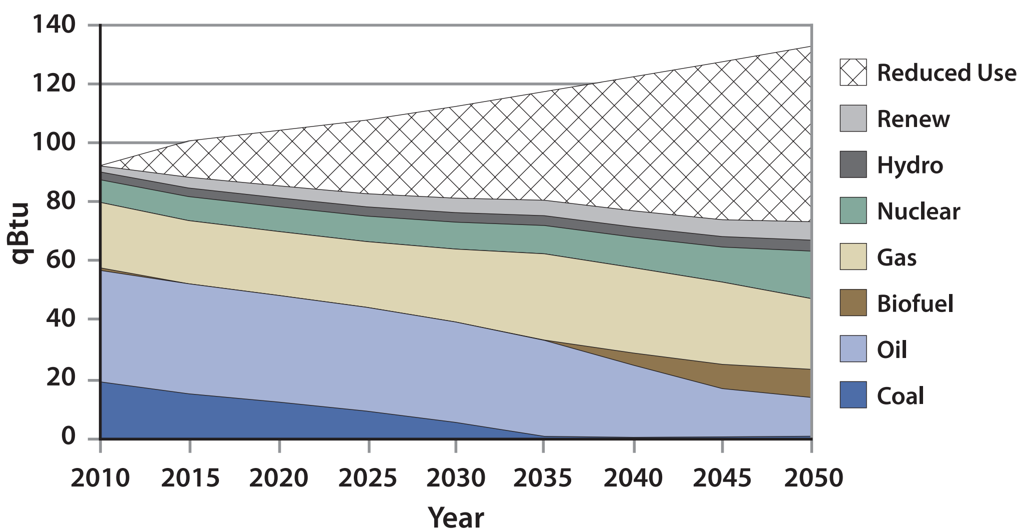
A major effect of the economy-wide, price-based GHG policy is to reduce energy use (Figure 3.4). The effect in the electric sector is to effectively flatten demand, holding it near its current 4 Trillion killowatt hour (TkWh) level (Figure 3.4a). Based on the cost assumptions underlying the simulation (see Appendix 3A) nuclear, Carbon Capture and Storage (CCS) and renewables are relatively expensive compared with generation from gas. Conventional coal is driven from the generation mix by the CO_2 prices needed to meet the economy-wide emissions reduction targets. 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 energy (Figure 3.4b) the demand reduction effect is even stronger, leading to a decline in U.S. energy use of nearly 20 quadrillion (10^{15}) British thermal units (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 around 40% in 2040.

Figure 3.4 Energy Mix under a Price-Based Climate Policy, Mean Natural Gas Resources

3.4a Electric Sector (TkWh)



3.4b Total Energy Use (qBtu)



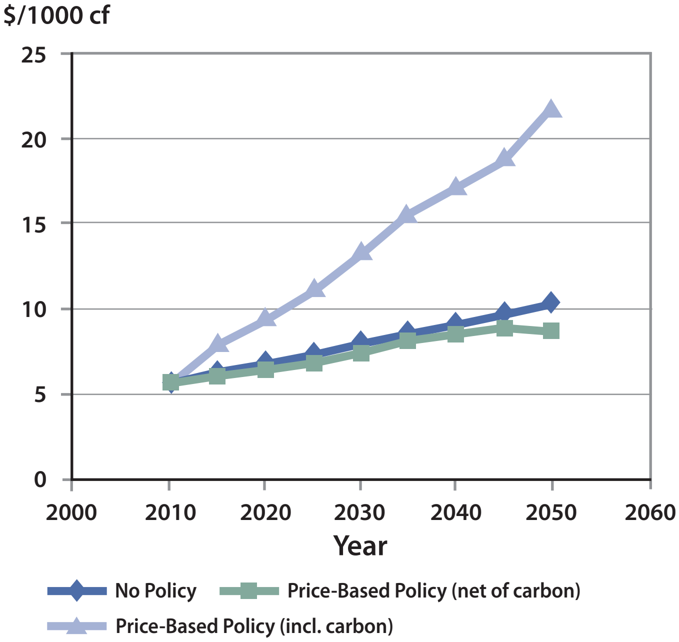
Source: EPPA, MIT

Under this policy scenario, the U.S. emissions price is projected to rise to $106 per ton CO_2-e in 2030 and to $240 by 2050. The macroeconomic effect is to lower U.S. Gross Domestic Product (GDP) by 1.7% in 2030 and 3.5% in 2050. (Other measures of cost are provided in Appendix 3A.) A selection of resulting U.S. domestic prices is shown in Figure 3.5. 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 (Figure 3.5a). The CO_2 charge is nearly half of the user price of gas.[6]

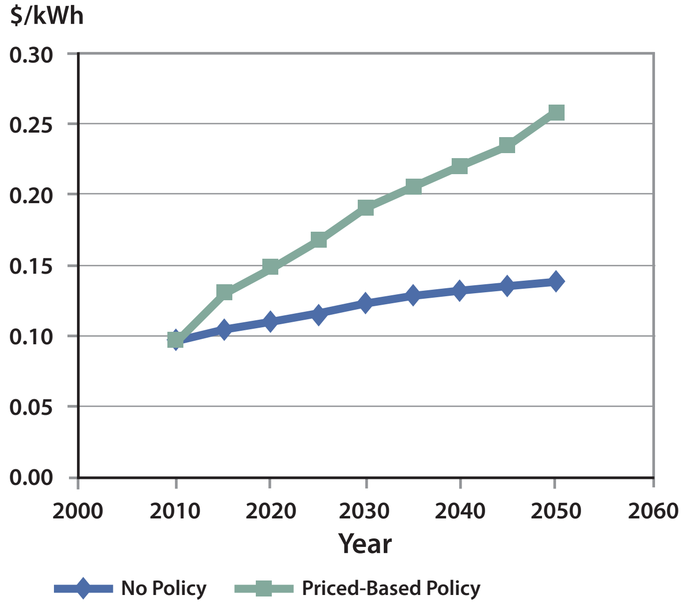
Even in the No-Policy case, electricity prices are projected to rise by 30% in 2030 and about 45% over the period to 2050 (Figure 3.5b). The assumed emissions mitigation policy is projected to cause electricity prices to rise by almost 100% in 2030 and by two and one-half times by 2050 compared with current prices.

Figure 3.5 U.S. Natural Gas and Electricity Prices under Alternative Policy Scenarios, Mean Gas Resources

3.5a Natural Gas Prices ($/1000 cf)



3.5b Electricity Prices ($/kWh)



Source: EPPA, MIT

As noted earlier, a set of alternative cost assumptions was explored for low-carbon technologies in the electricity sector, including less costly CCS, nuclear and renewables (Table 3.1).

The biggest projected impact on gas use in electricity results from an assumption of low-cost nuclear generation.

Of these, the biggest impact on gas use in electricity results from 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.

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 displaces nuclear power which by that time starts to replace gas in the electric sector. With less-costly CCS, gas use increases in the electric sector by nearly 3 Tcf. This is because both gas generation with CCS 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.[7]

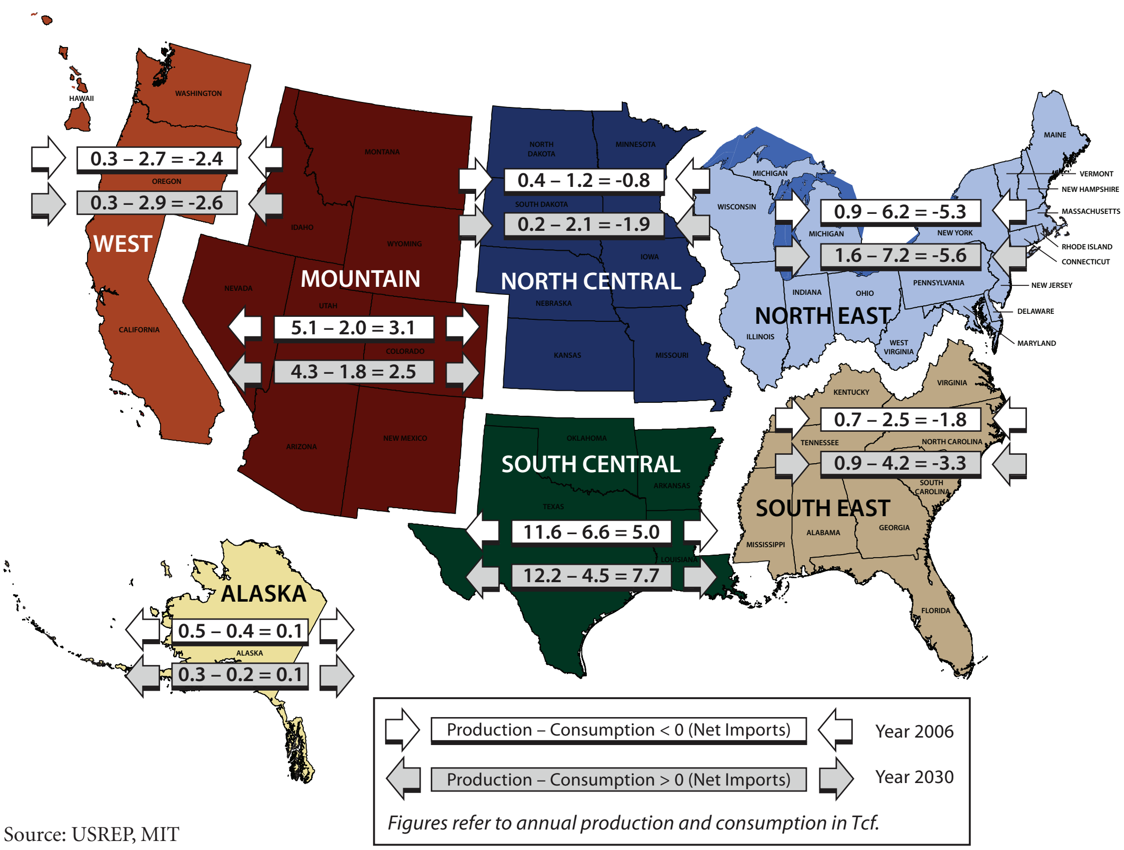
Many other combinations of technological uncertainties could be explored. For example, a breakthrough in large-scale electric storage would improve the competitiveness of intermittent sources. A major insight to be drawn from these few model experiments, however, is that, under a policy based on emissions pricing to mitigate greenhouse gas emissions, natural gas is in a strong competitive position unless competing technologies are much less expensive than we now anticipate.

The simulations shown in Figures 3.3–3.5 do not include the Compressed Natural Gas (CNG) vehicle. When this policy case is repeated with this technology included, applying optimistic cost estimates drawn from Chapter 4 of this report, the result depends on the assumption about the way competing biofuels, and their potential indirect land-use effects, are accounted. Even with advanced biofuels credited as a zero-emissions option, however, CNG vehicles rise to about 15% of the private vehicle fleet by 2040 to 2050. 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.[8]

Some U.S. regions that have not traditionally been gas producers have significant shale gas resources, and the extent to which these resources are developed is material to the patterns of production and distribution of gas in the U.S. To identify regional patterns of production and use within the U.S., we apply the USREP model and report results for seven regions of the country for 2006 and 2030 under the 50% climate policy target and the Mean gas resources (Figure 3.6). Gas production increases most in those regions with the new shale resources — by more than 78% in the Northeast region (New England through the Great Lakes States) and by about 50% in the South Central area that includes Texas. In regions without new shale resources,

Some U.S. regions that have not traditionally been gas producers do have significant shale gas resources, and the extent to which these resources are developed is material to the patterns of production and distribution of gas in the U.S.

Figure 3.6 Natural Gas Production and Consumption by Region in the U.S., 2006 and 2030, Price-Based Policy Scenario, Mean Gas Resources



Source: USREP, MIT

production changes little, showing slight increases or decreases. In the Northeast, the production increase comes close to matching the projected growth in gas use.

The most substantial potential need for additional interregional gas flows, on the regional definition of Figure 3.6, is from the Texas/South Central region which increases net exports by a combined 2.7 Tcf, with shipment to other regions except the Northeast.[9] Compared to the 2030 interregional flows absent climate policy, the assumed emissions target lowers the need for new capacity largely because of the expansion of supply in the Northeast.

Among the most obvious measures that could have a direct impact on CO_2 emissions would be those requiring renewable energy and one encouraging a phase-out of existing coal-fired power plants.

Scenario 3 — Regulatory Emissions Reductions

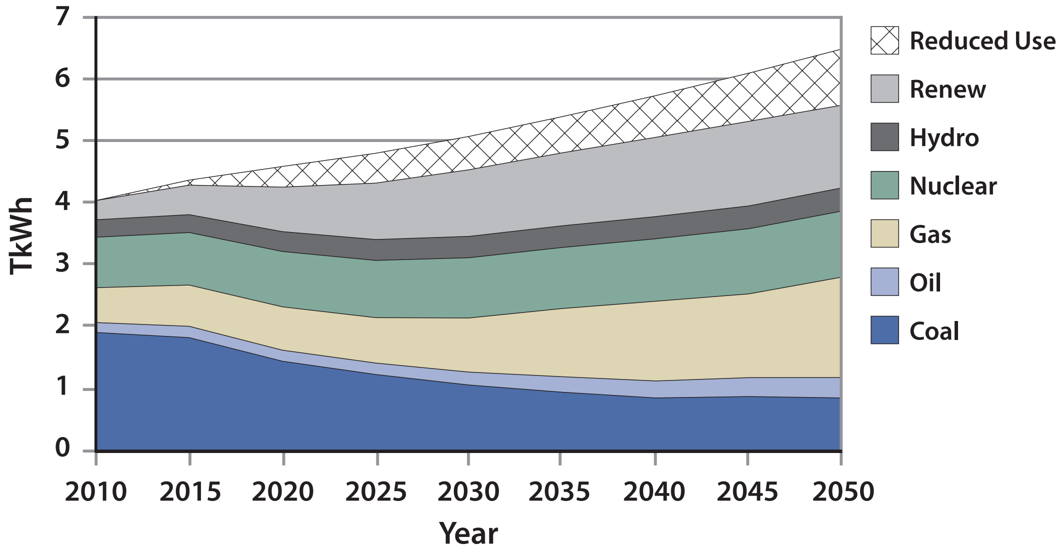
If emissions reductions are sought by regulatory and/or subsidy measures, with no price on emissions, many alternatives are available. Among the most obvious measures that could have a direct impact on CO_2 emissions would be those requiring renewable energy and one encouraging a phase-out of existing coal-fired power plants.

To explore this prospect, we formulate a scenario with a renewable energy standard (RES) mandating a 25% 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. This case results in approximately a 50% reduction in carbon emissions in the electricity sector by 2050, but it does not provide incentives to reduction in non-electric sectors so these measures only hold total national GHG emissions to near the 2005 level, as shown in Figure 3.1.

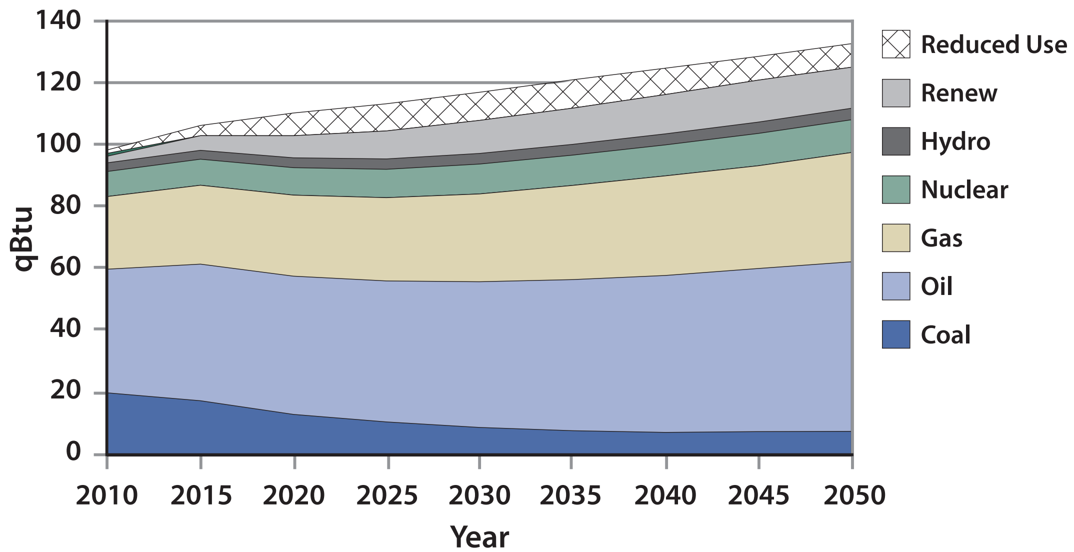
One evident result of these mitigation measures is that the reduction in energy demand is less than under the assumed price-based policy, either in the electric sector (Figure 3.7a) or in total energy (Figure 3.7b). Also, the measures represented here achieve less emissions reduction in the electricity sector than does the price-based policy. In the price-based policy, reductions in the electricity sector are about 70% by 2050, even though the national target is only a 50% reduction, because it is less costly to abate there than in the rest of the economy. The difference in total national energy use is more dramatic (Figure 3.7b compared with Figure 3.4b) because the all-sector effect of the universal GHG price is missing.

Figure 3.7 Energy Mix under a Regulatory Policy, Mean Gas Resources

3.7a Electric Sector (TkWh)



3.7b Total Energy Use (qBtu)



Source: EPPA, MIT

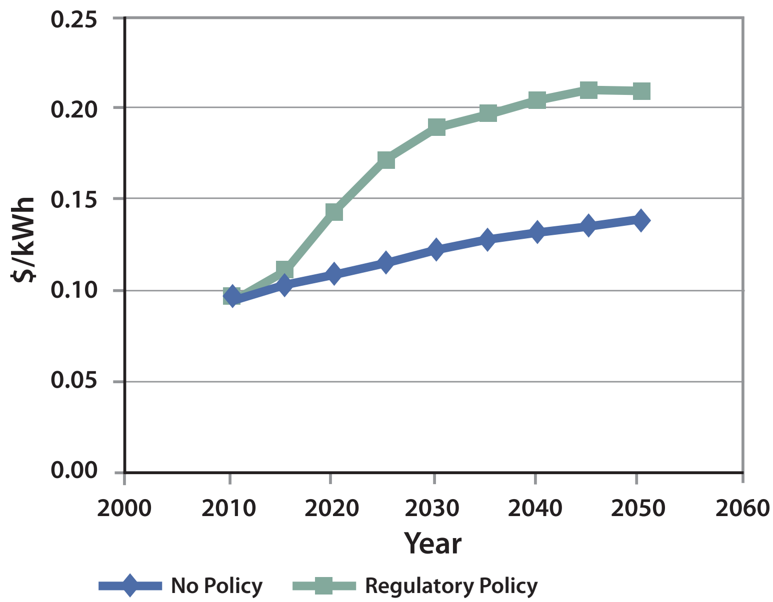
These regulatory measures yield a projection of total U.S. gas use very similar to that under a no-policy assumption, shown in Figure 3.2. Under the Mean resource estimate the 2050 level is almost identical between the two scenarios (see Appendix 3B), and the figure would look essentially the same for the High and Low cases as well. Also, U.S. natural gas prices are essentially the same with these regulatory measures as in the case without additional GHG-policy shown in Figure 3.5a (again see Appendix 3B for a comparison). Electricity prices do differ from the no-policy scenario, however, as higher generation costs are passed along to consumers. The result is presented in Figure 3.8, where by 2050 the coal and renewable regulations raise the electricity price by 50% over its level without GHG policy.

In this case, the effects on natural gas, compared to a no-policy assumption, are concentrated in the electric sector as the non-electric sectors face roughly the same gas price in both cases.

Natural gas remains resilient under a wide range of potential approaches to U.S. climate policy.

In the electric sector, the forced expansion of renewables tends to squeeze out gas-based electric generation, particularly in the early decades of the period, while the reduction in coal use opens up opportunities for gas. The net result is a pattern of gas use over time not different from the no-policy case, as noted earlier. Naturally, the net impact on gas use in the electric sector depends on the stringency of the two regulatory measures and their relative pace of implementation, and compared to the assumed price-based approach, they have the potential to reduce the use of gas in the sector. Nonetheless, for this regulatory scenario, like the more ambitious policy-based case, U.S. natural gas demand remains resilient, continuing to make a major contribution to national energy use.

Figure 3.8 Electricity Prices ($/kWh) under No-Policy and Regulatory Scenarios, Mean Gas Resources



Source: EPPA, MIT

THE ROLE OF INTERNATIONAL GAS MARKETS

Currently world gas trade is concentrated in three regional markets: North America; Europe — served by Russia and Africa; and Asia — with a link to the Middle East. There are significant movements of gas within each of these markets, but limited trade among them.

Different pricing structures hold within these regional markets. For some transactions, prices are set in liquid competitive 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.

These relatively isolated, regionalized markets could be sustained for many more decades. On the other hand, it is possible that LNG or pipeline transport could grow, linking these three regions, with the effect of increasing interregional gas competition, loosening price contracts tied to oil products and moderating the price deviations among the regions.

Such a process could go in many directions depending 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 non-conventional sources elsewhere. To the extent the structure evolves in this direction, however, there are major implications for U.S. natural gas production and use.

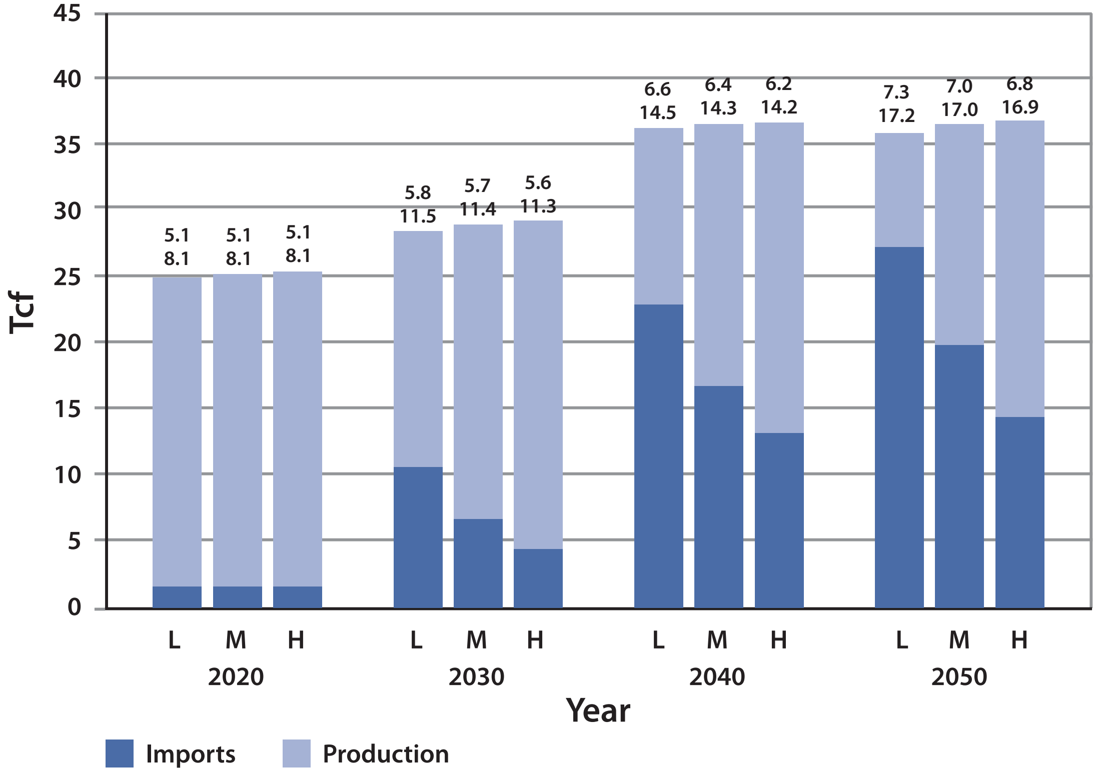
To investigate the end-effect of possible evolution of an integrated global market akin to crude oil, we simulate a scenario where market integration and competition lead to equalization of gas prices among markets except for fixed differentials that reflect transport costs.

In this scenario, gas suppliers and consumers are assumed to operate on an economic basis. That is, no effective gas cartel is formed, and suppliers exploit their gas resources for maximum national economic gain.

Projected effects on U.S. production and trade are shown in Figure 3.9 for the 50% reduction and High, Mean and Low gas resources cases. This result may be compared with the Regional Markets case shown in Figure 3.3.

In 2020, U.S. net imports are lowered to 1.6 Tcf (versus 4.1 Tcf in the Regional Markets case). Because in the Integrated Global Market scenario the EPPA model resolves for the net trade only, a decrease in net imports might be interpreted as a potential for small gas exports from the U.S. while keeping imports constant. Beginning in the period 2020 to 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. In the Mean resource case, the U.S. depends on imports for about 50% of its gas by 2050 and U.S. gas use rises to near the level in the no-policy case, because prices are lower. As the emergence of an integrated global market would lead ultimately to greater reliance on imports, U.S. gas use — and prices — are much less affected by the level of domestic resources. Thus, the development of a highly integrated international market, with decisions about supply and imports made on an economic basis, would have complex effects: it would benefit the U.S. economically, limiting the development of domestic resources but would lead to growing import dependence.

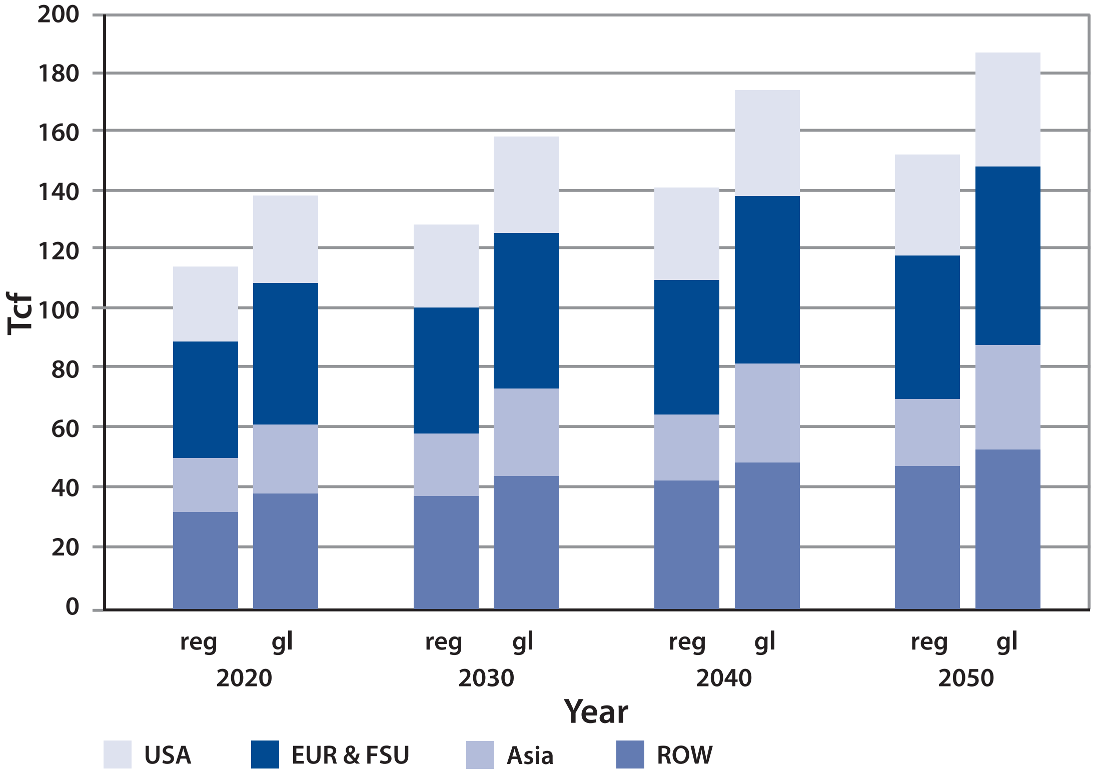
Figure 3.9 U.S. Gas Use, Production and Imports & Exports (Tcf) and U.S. Gas Prices ($/1000 cf) for Low (L), Mean (M) and High (H) U.S. Resources, Price-Based Climate Policy and Global Gas Markets. Prices are shown without (top) and with (bottom) the emissions charge.



Source: EPPA, MIT

In the Regional Markets case, global demand for gas increases from the current demand of about 100 Tcf, to about 150 Tcf by 2050. In the Integrated Global Markets scenario, gas availability increases globally, reducing gas prices, and as a result, gas demand rises to about 190 Tcf in 2050. Figure 3.10 shows the projected increase in gas use. In the Regional Markets case, gas use in U.S. and Asia grows by around 50% from 2010 to 2050, while in Europe and countries of the former Soviet Union it increases by about 35%. Assumption of an Integrated Global Market changes the growth in Asia to 135%, while U.S. and European use grows by about 70%. A growth in the Rest of the World (ROW) is mostly driven by an increase in the gas usage in the Middle East and the rest of Americas, where assumptions about the different market structures affect the results to a lesser degree.

Figure 3.10 Gas Use (Tcf) in Regional Markets (reg) and Integrated Global Markets (gl) scenarios for USA, Asia, Europe and former Soviet Union (EUR+FSU) and the Rest of the World (ROW)



Source: EPPA, MIT

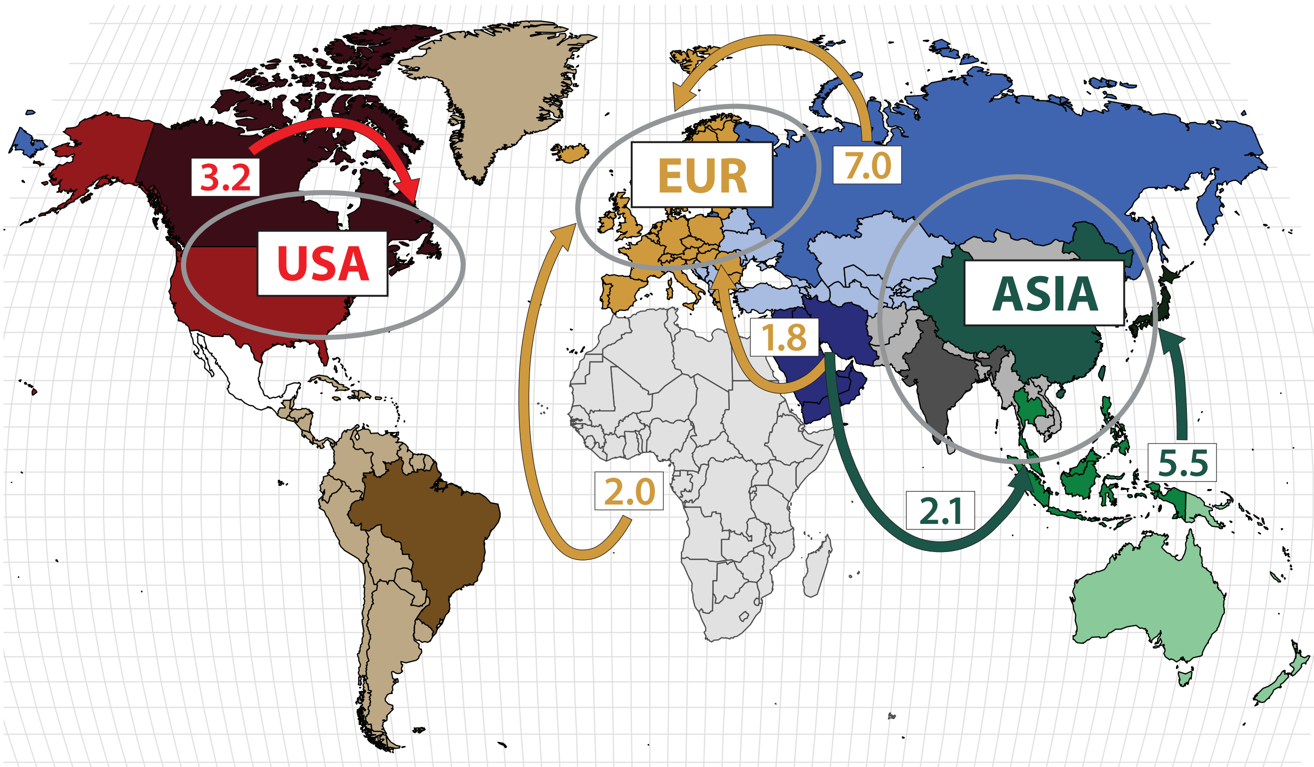
Possible international gas trade flows that are consistent with U.S. and global demand under the Regional and Integrated Global Markets cases are shown in Figure 3.11. Under Regional Market conditions (Figure 3.11a), we can see that trade flows are large within gas market regions but small among them. To avoid a cluttered map, small trade flows (less than 1 Tcf) are not shown. Except for the "Middle East to Europe" flow of 1.8 Tcf, interregional movements among the three regions specified above are less than 0.6 Tcf in any direction in 2030.

Trade flows can be particularly sensitive to the development of transportation infrastructure and political considerations, and so projections of bilateral trade in gas are highly 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.

If a highly integrated Global Market is assumed to develop (Figure 3.11b), a very different pattern of trade emerges. The U.S. is projected 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.

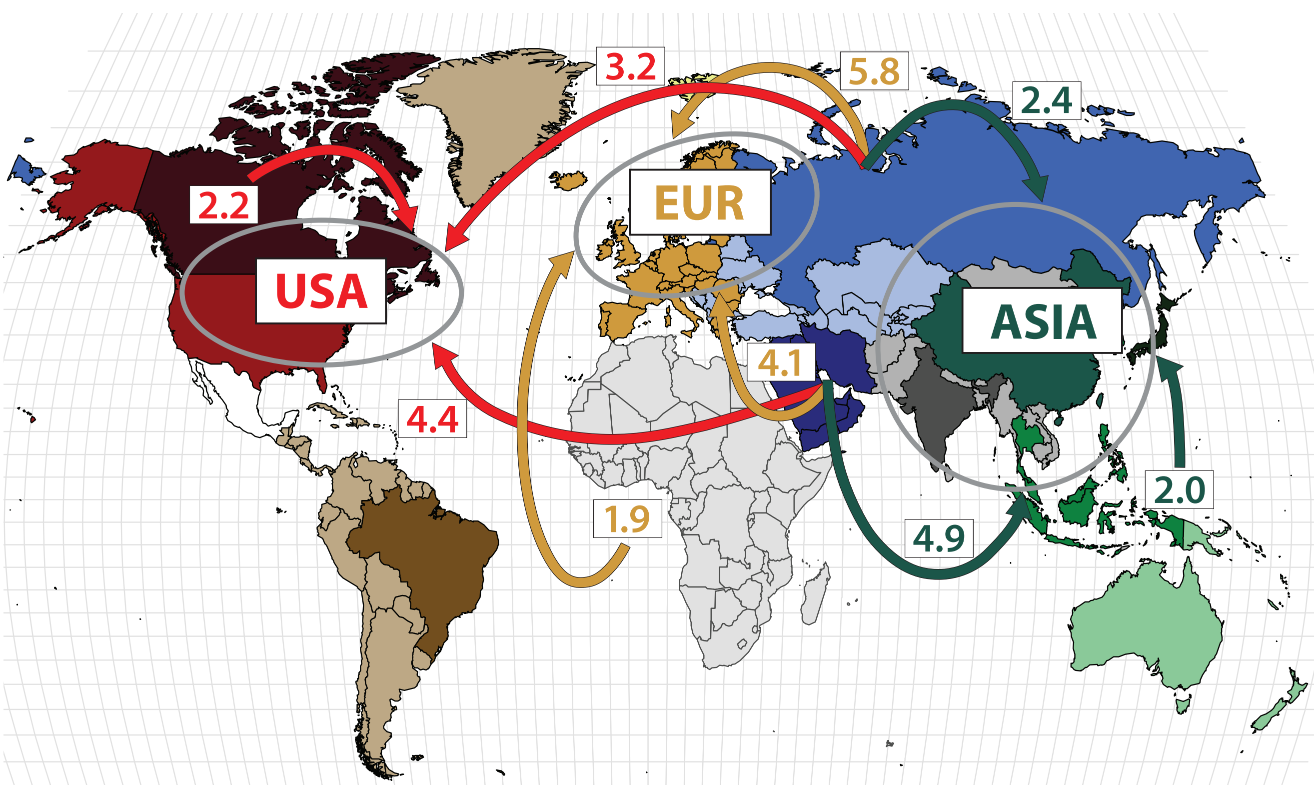
Figure 3.11 Major Trade Flows of Natural Gas among the EPPA Regions in 2030, No New Policy (Tcf)

3.11a Regional Markets



Source: EPPA, MIT

3.11b Global Market



Source: EPPA, MIT

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, imports and transport infrastructure. 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 on the modeled economic basis.[10] If potential supplies are not forthcoming, then global prices would be higher and the U.S. would import less than projected and perhaps increase exports. The broad insight to be drawn is nonetheless evident: to the degree that economics are allowed to determine the global gas market, trade in this fuel is set to increase over coming decades, with implications for investment and potential concerns about import dependence.

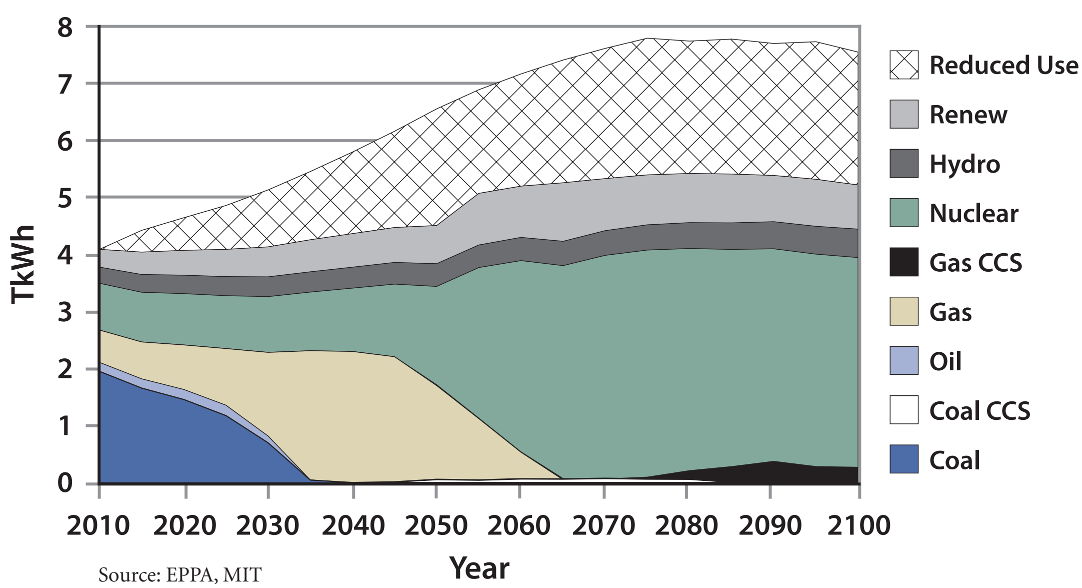
The assumptions about the gas markets also affect the carbon price and GDP impacts in the GHG mitigation scenario. While the difference is small initially (in 2030, a U.S. carbon price is decreased from $106 to $103 per ton CO_2-e and U.S. GDP loss is decreased from 1.7% to 1.6%), it grows over time (in 2050, a U.S. carbon price is decreased from $240 to $180 and U.S. GDP loss is decreased from 3.5% to 2.6%).

LONGER-TERM PROSPECTS FOR GAS UNDER DEEPER EMISSIONS CUTS

While current investment and policy decisions appropriately focus on a shorter horizon, policy decisions related to atmospheric stabilization of GHG concentrations inevitably involve a very long-term perspective. Though gas frequently is touted as a "bridge" to the future, continuing effort is needed to prepare for that future, lest the gift of greater domestic gas resources turn out to be a bridge with no landing point on the far bank.

To explore this issue, we conducted model simulations extending the horizon to 2100 assuming GHG emissions cuts that deepen to 80% below 2005 levels. The result is that, until gas with CCS begins to penetrate after 2060, the cost of CO_2 emissions from gas generation becomes too high to support its use in generation (Figure 3.12). Nuclear is cheaper than coal or gas with CCS for much of the period and so it expands to meet the continuing electricity demand. Different cost assumptions well within the range of uncertainty would lead to a different mix of low-CO_2 generation sources, but the picture for gas without CCS would remain the same.

Figure 3.12 Energy Mix in Electric Generation under a Price-Based Climate Policy, Mean Natural Gas Resources and Regional Natural Gas Markets (TkWh)



Source: EPPA, MIT

One implication of this longer-term experiment is that while we might rely on plentiful supplies of domestic gas in the near term, this must not detract us from preparing for a future with even One implication of this longer-term experiment is that while we might rely on plentiful supplies of domestic gas in the near term, this must not detract us from preparing for a future with even greater GHG emissions

To the degree that economics are allowed to determine the global gas market, trade in this fuel is set to increase over coming decades, with implications for investment and import dependence.

constraints. Barriers to the expansion of nuclear power or coal and/or gas generation with CCS must be resolved over the next few decades so that over time these energy sources will be able to replace natural gas in power generation. Without such capability, it would not be possible to sustain an emissions mitigation regime.

CONCLUSIONS

The outlook for gas over the next several decades is in general very favorable. In the electric generation sector, given the unproven and relatively high cost of other low-carbon generation alternatives, gas could well be the preferred alternative to coal.

A multi-sector GHG pricing policy would increase gas use in generation but reduce its use in other sectors, on balance increasing gas use substantially from the present level. A regulatory approach, applied to renewable and coal use in the electric sector, could lead to even greater growth in gas use while having a more limited effect on national GHG emissions. Most important, in all cases studied — no new climate policy and a wide range of approaches to GHG mitigation — natural gas is positioned to play a growing role in the U.S. energy economy.

International gas resources are likely 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.

The shale gas resource is a major contributor to domestic resources but far from a panacea over the longer term. Under deeper cuts in CO_2 emissions, cleaner technologies are needed. Gas can be an effective bridge to a lower CO_2 emissions future but investment in the development of still lower CO_2 technologies remains an important priority.

NOTES

[1]Citations to documentation of the EPPA model and features related to this study are provided in Paltsev, S., H. Jacoby, J. Reilly, O. Kragha, N. Winchester, J. Morris and S. Rausch, 2010: The Future of U.S. Natural Gas Production, Use, and Trade. MIT Joint Program on the Science and Policy of Global Change, *Report 186*, Cambridge, MA. The USREP model is described by Rausch, S., G. Metcalf, J. Reilly and S. Paltsev, 2010: Distributional Impacts of Alternative U.S. Greenhouse Gas Control Measures. MIT Joint Program on the Science and Policy of Global Change, *Report 185*, Cambridge, MA.

[2]Reference costs from the U.S. EIA (see Appendix 3A). The lower sensitivity estimate is based on Update of the 2003 Future of Nuclear Power: An Interdisciplinary MIT study, Massachusetts Institute of Technology, Cambridge, MA.

[3]Reference costs from the U.S. EIA (see Appendix 3A). The lower sensitivity estimate for coal with CCS draws on The Future of Coal: An Interdisciplinary MIT study, Massachusetts Institute of Technology, Cambridge, MA; that for gas with CCS comes from McFarland, J., S. Paltsev and H. Jacoby, 2009: Analysis of the Coal Sector under Carbon Constraints, *Journal of Policy Modeling*, 31(1), 404–424.

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

[5]CO_2 equivalent emissions for all greenhouse gases are calculated using 100-year global warming potentials (GWPs). See Appendix 1A for discussion. The simulations in this chapter account for fugitive methane emissions from the gas supply system.

[6]Because of the 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, 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.

[7]For more details about sensitivity tests see Paltsev, S., H. Jacoby, J. Reilly, Q. Ejaz, F. O'Sullivan, J. Morris, S. Rausch, N. Winchester and O. Kragha. 2010: The Future of U.S. Natural Gas Production, Use and Trade, MIT Joint Program on the Science and Policy of Global Change, *Report 186*, Cambridge, MA.

[8]Substitution for motor fuel is the likely target of possible expansion of gas-to-liquids technology (see Chapter 4). Its market penetration would depend on competition not only with oil products but also with direct gas use, biofuels and electricity which reduce CO_2 emissions while liquids from gas would not.

[9]Gas production and use with the USREP model is somewhat lower than the EPPA projection. Compared to EPPA, the USREP model has the advantage of capturing inter-regional differences in coal and gas prices, and better reflecting differences in renewable costs among regions, but it does not represent foreign trading partners. This variation introduced by the different model structures is well within the range of other uncertainties.

[10]For additional scenarios about the long-term prospects for Russian natural gas, see Paltsev S., (2011). Russia's Natural Gas Export Potential up to 2050. MIT Joint Program on the Science and Policy of Global Change Report (forthcoming).