STATEMENT OF

MARY J. HUTZLER

DIRECTOR, OFFICE OF INTEGRATED ANALYSIS AND FORECASTING

ENERGY INFORMATION ADMINISTRATION

DEPARTMENT OF ENERGY

BEFORE THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES

U.S. SENATE

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Mr. Chairman and Members of the Committee:

I appreciate the opportunity to appear before you today to discuss the views of the Energy Information Administration (EIA) on prospects for natural gas supply.

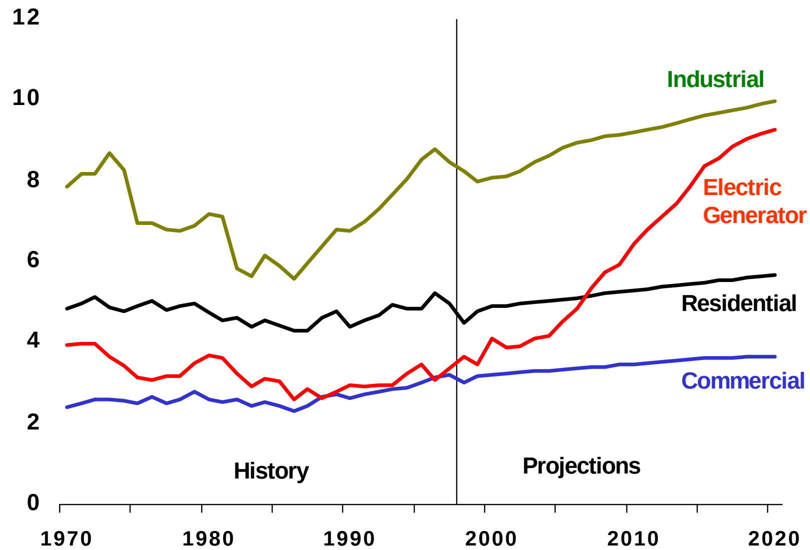
EIA is an independent statistical and analytical agency within the Department of Energy. We are charged with providing objective, timely, and relevant data, analysis, and projections for the use of the Energy Department, other agencies, the Congress, and the public. We do not take positions on policy issues, but we do produce data and analysis reports that are meant to help policy makers decide energy policy. Because we have an element of statutory independence with respect to the analyses that we publish, the views are strictly those of EIA. We do not speak for the Department, nor for any particular point of view with respect to energy policy, and our views should not be construed as representing those of the Department or the Administration.

Today's analysis is based on EIA's Annual Energy Outlook, which provides projections and analysis of domestic energy consumption, supply, prices, and carbon emissions through 2020. These projections are not meant to be exact predictions of the future but represent a likely future, assuming known trends in demographics and technology improvements, and also assuming no change in current law, regulation, and policy. EIA does not propose, advocate, or speculate on changes in laws and regulations. So, one of our key assumptions is that all current laws and regulations remain as they are at the time the projections are made. This means, for example, that none of the provisions of F.E.R.C.'s Order 637 (to improve efficiency in the gas transportation marketplace and protect captive customers from abuses of market power) are assumed in these projections, because, although some elements of the Order were proposed, it did not become an official ruling until February, 2000. Similarly, while state-level electric utility restructuring will probably occur throughout most of the country, we only represent it for States that have actually put restructuring plans in place because implementation plans vary.

History of Natural Gas Supply

The highest recorded U.S. annual consumption of natural gas--22.1 trillion cubic feet (tcf)--occurred a generation ago in 1972 (Figure 1). As close as the Nation came in 1996 and 1997 (within 0.5 percent), the record has yet to be broken. The 1972 peak was followed by a decline to a low of 16.2 tcf in 1986, when the downward trend reversed.

Figure 1. Natural Gas Consumption by Sector, 1970 - 2020 (trillion cubic feet)



What caused natural gas consumption to fall off as sharply as it did between the early 1970's and the mid 1980's, and subsequently almost return to its previous high? The primary reason was heavy regulation of virtually every aspect of the market. Producers were constrained by price controls and end-users were constrained by moratoria placed on the construction of new gas-burning units. The market was unable to send clear signals about the consumers' interest in purchasing and the suppliers' willingness to sell.

Regulations on the price of interstate gas sales were set by the Federal Power Commission (FPC) in the mid 1950's, creating a two-tier market in which interstate gas was regulated and intrastate gas was not. The price ceilings for interstate gas that were set kept prices artificially low, and by the late 1960's prices for intrastate gas began to exceed prices for gas destined for the interstate market. The low prices led to increased demand, but discouraged production, with the exception of what could be sold in the unregulated intrastate market. Shortages of gas that resulted led to industrial sector curtailments in the early 1970's, and, during the extremely cold winter of 1976 to 1977, to curtailments for both the industrial and utility sectors. Many were convinced that the shortages would increase, focusing attention on the issue of supply reliability which was to plague the industry for more than a decade. To help remedy the situation, Congress in 1978 passed the Natural Gas Policy Act (NGPA), the objective of which was to provide a phased decontrol of natural gas wellhead prices. The NGPA placed wellhead price caps on several categories of natural gas, which had escalation factors developed to allow them to rise to a level competitive with other fuels. Rather than remedying the situation, the complexities of the NGPA increased the problem. The escalation clauses were developed under the assumption that oil prices would continue to rise steeply. Price caps for the categories of gas subject to these escalators grew to be priced considerably above, rather than below, the market. These high prices spurred exploration and development. This resulted in high reserve additions, while at the same time the high prices were having a dampening effect on demand. By the early 1980's, the shortage of natural gas had been replaced with a surplus, often referred to as the “gas bubble.” A spot market for gas developed, with spot gas priced below contract gas. Because pipelines were allowed to pass gas costs through to consumers, they had little incentive to try to get access to this lower-priced gas, so average prices to consumers remained above spot prices.

At this point, the Federal Energy Regulatory Commission (FERC), successor to the FPC, intervened with a series of Orders that removed gas costs from minimum bills (Order 380, in 1984), required that pipelines provide open access to transportation services (Order 436, in 1985), and eventually , with Order 636 in 1992, allowed for a major restructuring of interstate pipeline operations. This led to open competition in the industry and a much healthier market that is controlled by supply and demand rather than through heavy regulation. The market has grown steadily since 1986. While there was once speculation as to whether the market would eventually reach 30 tcf, it's now generally viewed as a question of when and how--not if--a 30 tcf market will be achieved.

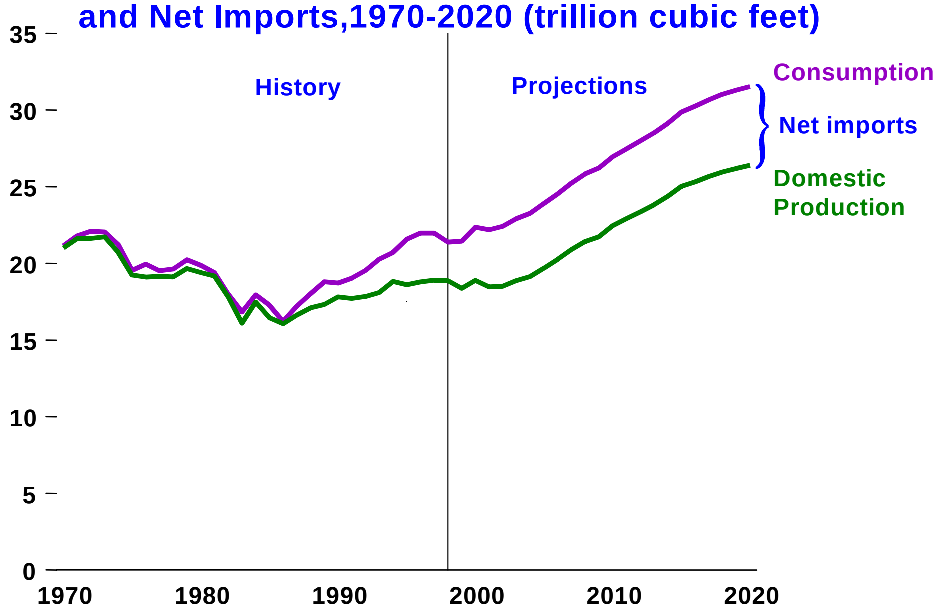
Growing Natural Gas Supply

In 1999, U.S. natural gas consumption was more than 21 tcf and accounted for 23 percent of domestic energy consumption. Gas consumption is expected to grow 1.8 percent annually from 1998 to 2020--faster than any other major fuel source, mainly because of the growth in gas-fired electricity generation. Demand is projected to reach almost 30 tcf in 2015 and continue to rise to almost 32 tcf in 2020. Gas consumption by electricity generators is expected to increase more than two and one half times (compared to current levels), while modest growth is projected in all of the other sectors. As demand increases, pressure on natural gas supply will grow. These demand-side pressures will begin to raise questions like: "Is there enough gas to meet demand at affordable prices?" and "Can we produce the gas fast enough to keep up with demand?"

Even with this projected production increase, technically-recoverable natural gas resources in North America are believed to be adequate to sustain growing production volumes throughout the forecast period without dramatic price increases. (Advances in technology are included in the forecast and current high prices are expected to decline, as discussed below.) Domestic gas production is expected to increase a bit more slowly than consumption over the forecast, rising from 18.7 tcf in 1998 to 25 tcf in 2015, with the difference made up by increased imports. Growing production reflects generally rising wellhead prices, relatively abundant natural gas resources, and improvements in technologies, particularly for producing offshore and unconventional gas.

Net imports are expected to rise to make up the difference between domestic production and consumption, and they are generally expected to be priced competitively relative to domestic sources (Figure 2). Net imports are expected to climb from 3.1 tcf in 1998 to 4.9 tcf in 2015–somewhat faster than the growth in overall consumption, accounting for 16 percent of total consumption in 2015.

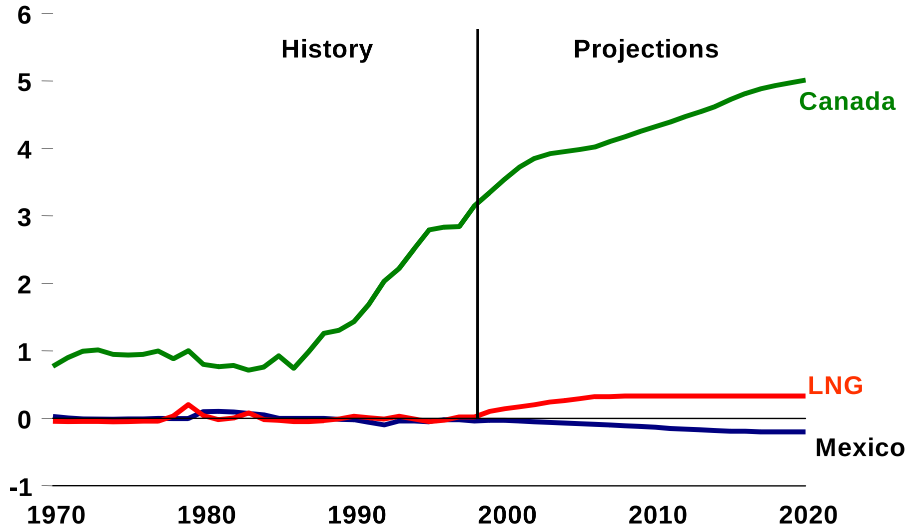
Figure 2. Natural Gas Production, Consumption, and Net Imports,1970-2020 (trillion cubic feet)



Most of the increase is attributable to imports from Canada, primarily from western Canada, although some new gas is also expected from Sable Island in the offshore Atlantic (Figure 3). Canadian resources are adequate to sustain production for many years. The Canadian Gas Potential Committee indicates that there is an estimated 184 tcf of marketable discovered and undiscovered natural gas in the Western Canada Sedementary Basin.[1]

[1] Canadian Gas Potential Committee, Natural Gas Potential in Canada (Calgary: University of Calgary, 1997), p. 1.

Figure 3. Natural Gas Net Imports, 1970-2020
(trillion cubic feet)



In addition, interest in developing the MacKenzie Delta/Beaufort Sea region of the Northwest Territories has recently begun to increase. The Canadian National Energy Board estimates the undiscovered marketable potential for natural gas in the region at 55 tcf. With most Canadian oil- and gas-producing regions less mature than those in the United States, the potential for additional low-cost production is strong, and imports from Canada are projected to remain competitive with U.S. domestic supplies in the forecast.

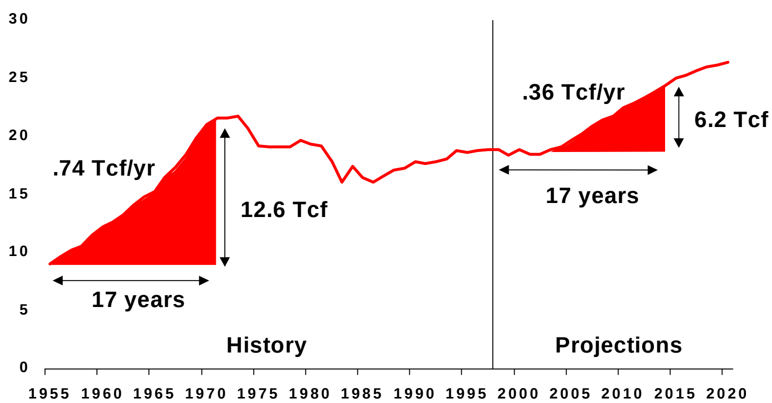
Mexico also has a considerable natural gas resource base, but gas trade with Mexico is expected to consist primarily of exports. Conversion of power plants from heavy fuel oil to natural gas, in compliance with Mexico's environmental regulations, is expected to gain momentum and it is unlikely that indigenous natural gas production can be increased enough to satisfy rising demand.

LNG provides another source of gas imports; however, given the projected relatively low natural gas prices in the lower-48 markets, LNG is expected to supply just 0.33 tcf, or 1 percent of U.S. gas consumption in 2015. LNG imports in the future could rise above the forecast given the opening of the currently mothballed facilities at Cove Point, Maryland and/or Elba Island, Georgia. Total available import capacity including these facilities is 0.84 tcf, so LNG is not expected to become a major source of supply in the forecast period.

Growing Domestic Production

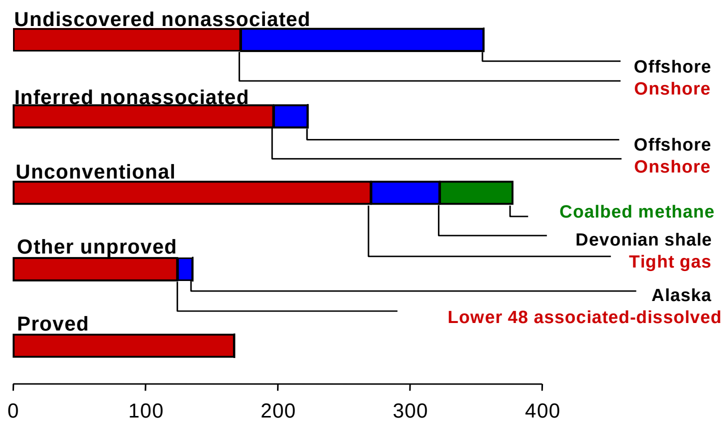
To satisfy a 30 tcf market in 2015, annual domestic natural gas production will need to increase by 6.2 tcf (Figure 4). Thus, over the next 17 years production increases must average about 360 billion cubic feet (bcf) per year. From 1955 to 1972, the industry increased production at twice this rate. Of course, conditions are different from what they were in those earlier years. Undiscovered field sizes in mature producing areas are smaller, and larger prospects are located in more remote areas. On the other hand, the average real price of natural gas in 1999 was more than three times higher than it was in 1955, real exploration and production costs are lower, technology is significantly more advanced, and the regulatory environment is much more favorable to gas production.

Figure 4. Natural Gas Production,1955 - 2020
(trillion cubic feet)



Current estimates of technically-recoverable natural gas resources[2] indicate that the resource base is expected to be adequate to sustain growing production volumes for many years, based primarily on the assessments done by the U.S. Geological Survey for onshore regions and by the Minerals Management Service for offshore areas. As of January 1, 1998, technically recoverable resources were 1,259 tcf (Figure 5). Resources include not only proved reserves, which were 167 tcf, but inferred reserves from known fields, undiscovered conventional resources from new fields, and undeveloped resources of unconventional gas. Inferred reserves, representing the expected growth from previously discovered fields, totaled 223 tcf, most of that located in onshore areas. Conventionally recoverable resources in lower-48 undiscovered fields not associated with oil deposits accounted for 356 tcf of the total. Undeveloped resources of

Figure 5. Technically Recoverable U.S. Natural Gas Resources as of January 1, 1998 (trillion cubic feet)



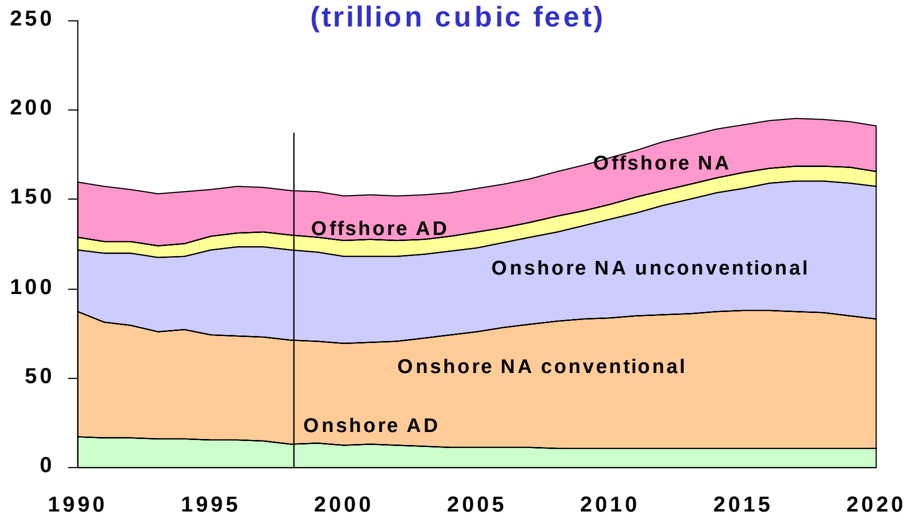
unconventional gas from tight sands formations, coalbeds, and shales total 378 tcf. Gas associated with oil makes up most of the balance of the total technically recoverable resource base.

[2]Technically recoverable resources are resources in accumulations producible using current recovery technology but without reference to economic profitability. Economic considerations imbedded in the discovery and reserve growth functions within the EIA modeling methodology determine the profitability of those technically recoverable resources that are converted into proved reserves.

Reserves are anticipated to be more than adequate throughout most of the forecast period. Although falling prices in 1998 caused production to exceed reserve additions, rising prices in the forecast after 2003 are projected to cause reserve additions generally to exceed production until close to the end of the forecast period, even with the expected increases in demand. This leads to a growth in end-of-year reserves throughout much of the forecast period (Figure 6). Relatively high levels of annual reserve additions through 2015 reflect increased exploratory and developmental drilling as a result of higher prices, as well as productivity gains from technology improvements.

Uncertainty with regard to estimates of the Nation's natural gas resources has always been an issue in projecting production, and could affect production and prices. The uncertainty surrounding recoverable gas resource estimates is reflected in the differing views on the subject. For example, an April 1998 study by the Gas Research Institute (GRI), contending that the industry has "significantly underestimated" the growth potential of existing fields in the Midcontinent, onshore Gulf Coast, East Texas, and San Juan Basin areas, proposes higher resource estimates for those areas.

Figure 6. Lower 48 Natural Gas End-of-Year Reserves (trillion cubic feet)



Over the forecast period, increased U.S. natural gas production comes primarily from lower-48 onshore conventional nonassociated sources (Figure 7). Conventional onshore production accounted for 35 percent of total U.S. domestic production in 1998 and is expected to increase to 40 percent in 2015. Offshore production, mainly from wells in the Gulf of Mexico, also rises. Innovative, cost-saving technology and large oil and gas finds, particularly in the deep waters of the Gulf, have encouraged interest in this area. Much of the gas production in deep waters is expected to be associated with oil wells. Lower-48 offshore Gulf Coast production was 5.6 tcf in 1998—a little lower than the previous year, because of lower prices. Rocky Mountain (primarily unconventional sources) and onshore Gulf of Mexico regions account for just over half of the incremental production needed between 1998 to 2015, as improvements in technologies continue. Increased production from the offshore Gulf Coast and onshore Southwest regions account for almost a third of the total increase in the same period. Although offshore Gulf Coast production grows in the projections, picking up after 2001 as a result of further deepwater exploration and development, production from the offshore Gulf of Mexico is constrained by depletion effects.

Figure 7. Natural Gas Production by Source, 1970-2020 (trillion cubic feet)

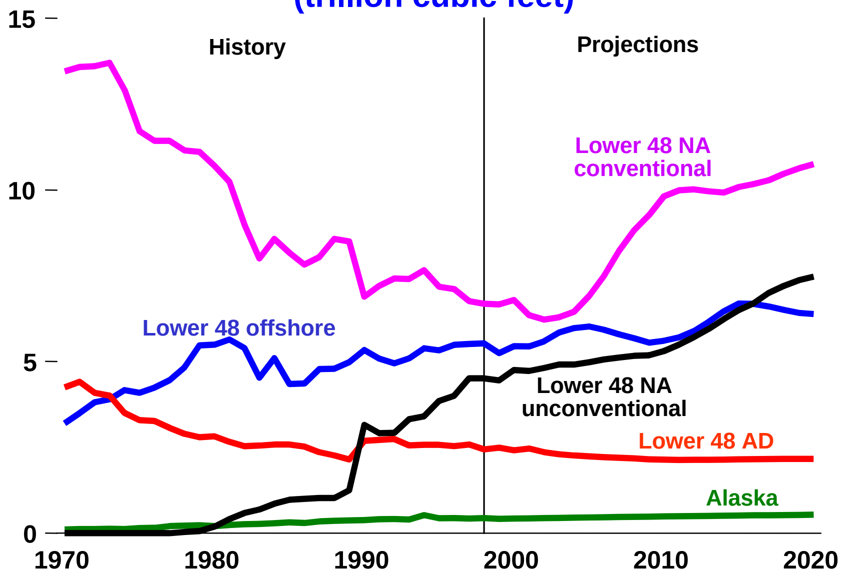
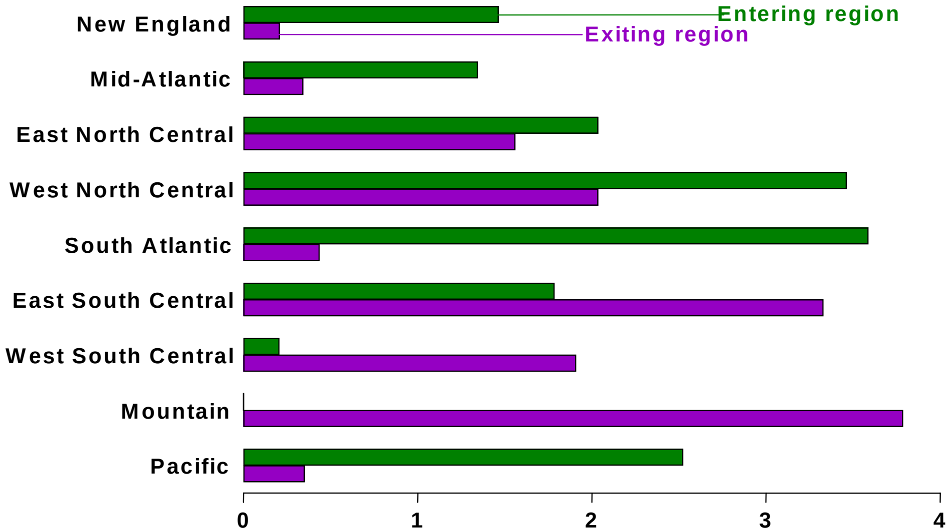


Figure 8. Pipeline Capacity Expansion by Census Division, 1998-2015 (billion cubic feet per day)



Pipeline and Transportation Issues

With the significant increase in annual production projected for the Rocky Mountain and Gulf Coast onshore production regions between 1998 and 2015—1.57 and 1.64 tcf, respectively--- considerable pipeline expansion will be required (Figure 8). For the Rocky Mountain region, an area that has long experienced bottlenecks in pipeline capacity that have prevented full use of its production capacity, the additional projected production represents a 54 percent increase from 1998 levels.

Much of the forecasted expansion is either already in progress or scheduled to be completed within the next two years. Several pipeline projects recently completed will provide producers in the Rocky Mountain region with new access to customers in the Midwest. KN Interstate's new Pony Express project and the Trailblazer system expansion provide access from the Wyoming and Montana production regions, and Transwestern Pipeline and El Paso Natural Gas expansions have increased the capacity to move supplies out of New Mexico's San Juan Basin. Transwestern also expanded its Gallup, New Mexico compressor station which further increased its capacity. The completion last year of a large scale gathering system in the Powder River Basin significantly increased access to supplies, as did the Frontrunner intrastate expansion. To utilize the new gathering system, both Wyoming Interstate and Colorado Interstate pipelines increased their capacity. Along with increases in capacity, significant increases in flows from the region to markets on the east and west coasts are expected between 1998 and 2015.

There has been considerable pipeline expansion in the Gulf Coast offshore region area, but much of it is for gathering systems and short-haul pipelines to move supplies onshore, rather than major interstate pipeline expansions. The greatest recent increase in pipeline capacity has been to increase import capacity between the United States and Western Canada. Capacity almost doubled between 1990 and 1998, with the major expansion being the Northern Border expansion through Montana into the Midwest. Other major expansions are the Alliance Pipeline, also providing access to Western Canada, and the Maritime and Northeast system to transport Sable Island supplies to markets in New England.

Natural Gas Drilling Activity

One of the key activities in producing natural gas is drilling. With prices providing an economic incentive and generally declining drilling costs, successful lower-48 natural gas well completions are expected to reach 16,200 in 2015. This level of drilling is below the level reached in 1981 of more than 20,000 successful gas wells, but represents approximately a 54 percent increase over 1998 levels.

Although the number of available drilling rigs has been generally declining since 1982, price increases are a powerful incentive for increased drilling and the purchase of new drilling equipment. The number of available drilling rigs increased by almost 16 percent annually between 1974 and 1982--from 1,767 to 5,644--as natural gas prices more than quadrupled in real terms and oil prices more than doubled. The rigs needed over the forecast period are assumed to be constructed, with the total rig count projected to increase from 1,705 in 1998 to 2,053 in 2015. The increase in rigs is tempered by the fact that technological improvements make it possible to drill faster and thus individual rigs can be more productive than in the past. Given the historical response to prices, even prices below current levels are likely to provide sufficient incentive for the needed drilling rigs available.

The U.S. natural gas rig count on June 30 was a record high of 718 rigs, and exploration and production budgets for many natural gas producers are reportedly expected to increase in the latter part of 2000 and into 2001, spurred by the incentive of higher prices. Although the effects of increased drilling for gas will probably not appear in the form of increased production until after the next heating season, overall, the natural gas industry is thought to be in a position to meet the supply requirements for a market of 30 tcf, with adequate supplies available from numerous sources at the prices projected in the AEO2000 reference case. As long as the industry can be assured that the demand will be there, the economic incentive of a competitive market will assure that the necessary investments in infrastructure, rigs, drilling, and manpower will be made over time.

Natural Gas Prices

According to EIA's Short-Term Energy Outlook, the average wellhead price for natural gas is expected to average $3.03 per thousand cubic feet in 2000 (in 1998 dollars). In nominal terms, this represents the highest annual wellhead price on record; in real (inflation-adjusted) terms, this projected price would be the highest annual average price since 1985. Over the past 2 months, natural gas prices in the spot market have averaged over $4.00 per thousand cubic feet, though over the past week they have fallen below this figure to the $3.70 to $3.80 per thousand cubic feet range. Although EIA believes these higher prices will not remain in the long-term, a break from higher natural gas wellhead prices may not develop until next spring. Several years of relatively low prices have slowed down exploration and drilling for new sources of supply. Recent higher prices have caused drilling to rebound, but new domestic supplies are not likely to augment production until after the next heating season. Given the assumption that the current price regime will generate greater success by Canadian suppliers in filling new export capacity on the Alliance pipeline, we expect higher net imports to help alleviate the tight supply situation. Hot summer weather in portions of the country that consume large amounts of gas-generated electricity has contributed to a low storage injection rate. Natural gas that would normally be injected into storage has, to some extent, been used (indirectly through electric generators) to run air conditioners. EIA anticipates that prices will be high through the summer and into the winter, as gas demand growth for electric generation is projected to remain high through 2000.

Further adding to the situation, several new gas-fired power plants are expected to come on line this summer, and many plants that were previously used for peaking only are now serving as baseload generators, causing an increase in overall natural gas demand. Underground storage levels are currently 19 percent below year-ago levels, putting upward pressure on the price as we enter the time of year in which injections into storage usually occur. However, average daily net injections in the first two weeks of July were 24 percent above the 5-year (1995-1999) average for the month and 59 percent ahead of last year's rate. If injections continue at historically average rates through the remainder of the refill season, gas inventories would be 2,856 billion cubic feet on November 1, which is 4 percent below the 5-year (1995-1999) average of 2,985 billion cubic feet.

Concerns regarding possible high summer demand in conjunction with the relatively low level of storage had been putting upward pressure on price. Until recently, high prices appear to have been discouraging a higher rate of storage injections. For the remainder of this year at least, it is clear that the overall domestic supply situation remains tight and prices will be above what were previously expected. Producers are expected to increase production to meet the demand increases, but this cannot be done overnight. Thus, while prices are expected to remain higher than last year for the short-term, over the longer term we anticipate that they will move downward before beginning to rise again reaching $2.81 per thousand cubic feet (1998 dollars) in 2020 in the AEO reference case.

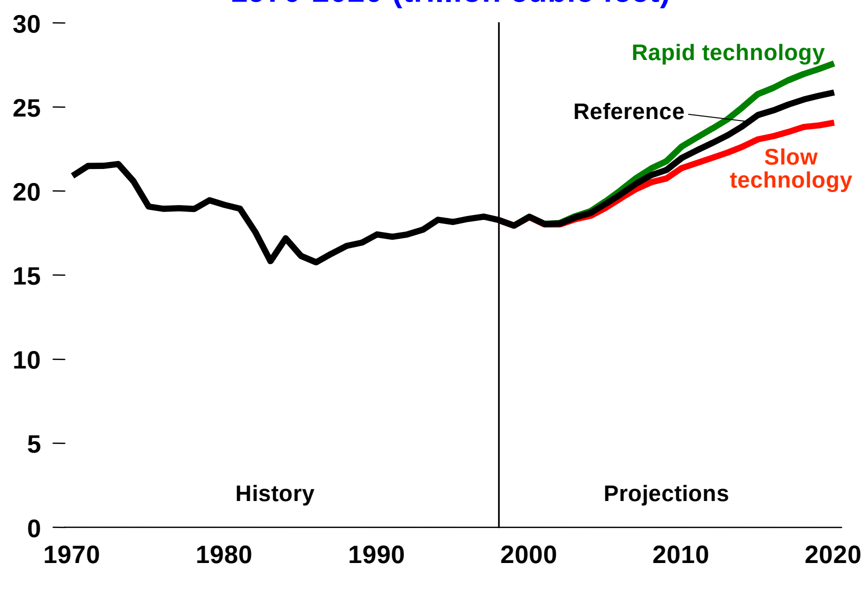
Technological Development

Technology improvements have both reduced effective exploration and development costs, and increased the recoverability of in-place resources. Major advances in data acquisition, data processing, and the use of technology to display and integrate seismic data with other geologic data--combined with lower cost computer power and experience gained using new techniques--have exerted downward pressure on costs. One significant cost-saving technology, adopted in the later part of the 1980s, was horizontal drilling. Drilling a horizontal, as opposed to a conventional vertical well, enables more of the reservoir to be exposed to the wellbore since most reservoirs are wider than they are deep. Another substantial boost to successful exploration and development has come from the increased use of three dimensional seismology to more effectively delineate prospective areas of a formation. Additionally, the introduction of subsea well technologies, tension leg platforms, and production spars have opened up vast new and promising areas for exploration in the deepwater areas of the offshore that had been inaccessible. The AEO reference case assumes that improvements in technology will continue at historical rates. To assess the potential effects of faster and slower rates of improvement, rapid and slow technology cases are also examined, with the same resource base as in the reference case. Rapid technology improvements could yield benefits in the form of both lower prices and increased production to meet higher consumption requirements.

Production from unconventional gas resources (tight sands, shales, and coalbeds), an increasingly important source of supply, is responsive to changes in the assumed levels of technological progress. Whereas the reference case projects total U.S. natural gas production in 2015 at 25.0 tcf, the rapid technology case projects 26.3 tcf of production in 2015, with the increase coming primarily from offshore and unconventional sources (Figure 9). More significantly, this higher production is available at lower prices, reflecting the lower costs and higher efficiencies that result from increased technological gains. In the slow technology case, prices are higher than in the reference case, and production in 2015 only reaches 23.6 tcf.

Offshore gas production in the Gulf of Mexico is expected to grow from 5.5 tcf in 1998 to a peak of 6.7 tcf in 2015 in the reference case and 5.9 tcf in the slow technology case. In the rapid technology case,

Figure 9. Lower 48 Natural Gas Production in Three Cases, 1970-2020 (trillion cubic feet)

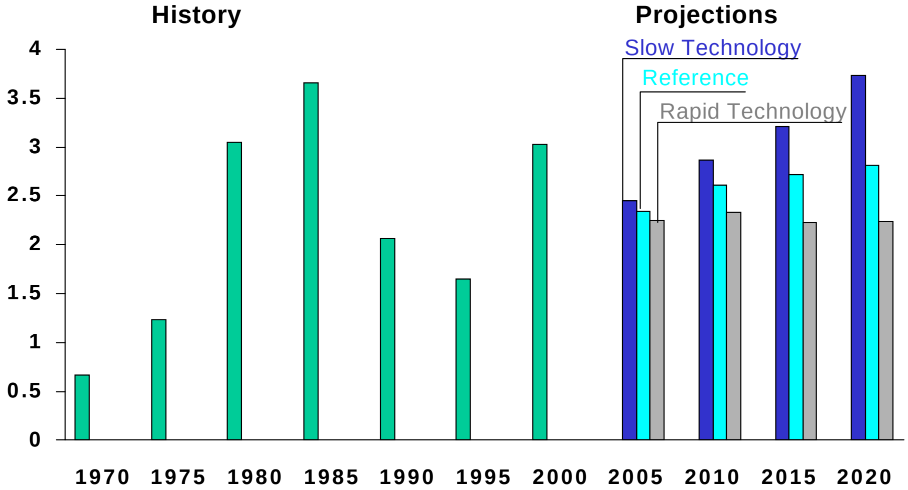


however, offshore Gulf of Mexico production exceeds this peak, growing to 7.5 tcf in 2015, and cumulative offshore production between 1998 and 2015 is 109.9 tcf, compared with 104.5 tcf in the reference case and

98.9 tcf in the slow technology case. The rapid technology assumption has a similar, but less dramatic, effect on unconventional gas recovery (UGR). Cumulative UGR production between 1998 and 2015 is 96.3 tcf in the rapid technology case, compared with 93.7 tcf in the reference case and 90.6 tcf in the slow technology case. Virtually all of the increase in cumulative total production in the high technology case over the reference case comes from UGR and offshore production. In the slow technology case, the drop in production from UGR and offshore sources exceeds the drop in total cumulative production by slightly over 6 tcf. Changes in production in the alternative technology cases reflect the benefits of lower costs and higher finding rates for conventionally recoverable gas, as well as an array of technological enhancements for unconventional gas recovery.

The natural gas price projections are highly sensitive to changes in assumptions about technological progress. Reference case wellhead prices for natural gas in the lower-48 States are projected to increase on average by 1.7 percent a year from 1998 to 2020 reaching $2.81 per thousand cubic feet in 1998 dollars (Figure 10). The increase reflects rising demand for natural gas and the impact of the progression of discoveries from larger and more profitable fields to smaller, less economical ones. Lower-48 wellhead prices increase at an average annual rate of 3.0 percent in the slow technology case, compared with 0.6 percent in the rapid technology case, over the projection period. In the rapid technology case, average natural gas wellhead prices are projected to reach $2.23 in 2015, which is $0.48 less than the reference case price. These relatively large differences in price among cases arise because substantial shifts in supply result from the variance in technological progress, under conditions of moderate demand responsiveness.

Figure 10. Lower 48 Natural Gas Wellhead Prices in Three Cases, 1970 - 2020 (1998 dollars per thousand cubic feet)



Summary

Overall, the natural gas industry is expected to be in a position to meet the supply requirements for a 30 tcf market, with adequate supplies available from numerous sources at competitive prices. While recent high natural gas prices resulting from the tight supply situation will most likely continue for the short-term, over the longer term EIA anticipates that they will move downward before beginning a rise along the lines forecast in the AEO Reference case. Technology improvements that have occurred since the 1970's have both reduced effective exploration and development costs and increased the recoverability of in-place resources. Improvements are expected to continue, which will make it possible to produce more of the resource base.

Much of the pipeline expansion needed to meet a 30 tcf market is either already completed or scheduled to be completed within the next two years. Several new expansions provide producers in the Rocky Mountain region with access to customers in the Midwest, and recent Gulf Coast area projects have provided gathering systems and short-haul pipelines to access new supplies. These are the two areas of the country from which most of the incremental production is forecast to come. Expansion of capacity between the

United States and Canada has significantly increased, providing greater access to Western Canadian supplies and new access to Sable Island supplies.