Chapter 5

Gas Production Potential

Chapter 5
Gas Production Potential

There are a variety of alternative approaches to estimating the future gas production potential of the United States, including the use of complex computer programs using econometric, process engineering, or system dynamics approaches to model separately the gas exploration, development, and production processes. Although during the course of this study OTA examined several complex models in detail, we have chosen to use four relatively simple techniques to project future production potential. This approach reflects the high costs of using the complex models and some doubts we entertain about the expected accuracy of these models as forecasting tools. These doubts do not necessarily extend to the usefulness of the models as policy analysis tools; often, these models offer the valuable ability to test alternative policies under carefully controlled conditions. Some of the major natural gas supply models will be discussed in a background document to this technical memorandum.

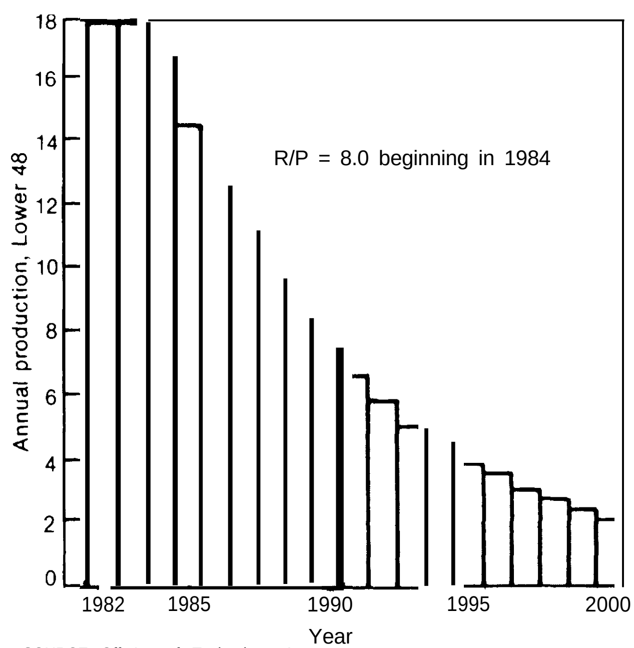
Of the four approaches used by OTA to project the mid- to long-term *(1990* and beyond) production potential for natural gas in the Lower *48* States, three focus specifically on the potential for continued additions to U.S. proved reserves. *The addition of new reserves to the U.S. gas system is the primary determinant of future gas availability.* The importance of new reserves can be illustrated quite simply by drawing the production that would likely result from the *failure* to add to reserve levels and reliance instead on current proved reserves as the sole "inventory" for production to draw on (see fig. 17). Assuming a constant reserves-to-production (R/P) ratio of *8.0,* beginning in 1984, production would immediately begin to drop with shocking rapidity to about 2 trillion cubic feet (TCF) by the end of the century. *

'Conceivably, the initial reduction in production could be slowed by drilling additional development wells, effectively lowering the R 'P ratio. The end result of this strategy would be, however, an even more rapid production collapse occurring a few years later than that shown in figure 17.

Of the three approaches focusing on continued additions to U. S, proved reserves, the first projects future reserves by examining historical trends in all components of reserve additions (new field discoveries, extensions, new pool discoveries, and revisions), examining the underlying causes of the trends, and extrapolating into the future based on OTA's expectations of future conditions. In this extrapolation, we have drawn heavily on the insights gained in our examination of gas resource base assessments. The second approach projects only new field discoveries and then applies a "growth factor" to these discoveries based on historical experience with the growth of new fields and OTA's judgment about how the growth rate may have changed. The third approach is based on a geologist's* region-by-region examination of available gas resources and past exploratory success. In all three cases, production rates are

*Joseph P. Riva, Jr., Congressional Research Service

Figure 17.— Natural Gas Production From 1981 Lower 48 Proved Reserves



SOURCE Off Ice of Technology Assessment

calculated from reserve data by projecting future levels of the R/P ratio.

The fourth approach borrows a method used by M. King Hubbert in 1956, tying future production directly to available resources by drawing freeform plots of the complete natural gas production cycle in such a manner that the cumulative production conforms to existing resource base estimates—in this case, to the estimates of Hubbert, the U.S. Geological Survey (USGS), and the Potential Gas Committee (PGC).

In each of the four approaches, ranges of production potential are estimated based on alternative assumptions about the magnitude of the resource base, efficiency of the exploratory process, and other factors.

[1]Described in M. K. Hubbert, "Techniques of Production as Applied to the Production of Oil and Gas," *Oil and Gas Supply Modeling*, S. I. Gass (ed.), National Bureau of Standards Special Publication 631, May 1982.

OTA's use of four approaches, and alternative assumptions within the approaches, reflects our skepticism of our own and others' ability to project future gas production rates with any precision. A "most likely" or "best" projection was deliberately avoided because we believe that such a projection, beyond 5 years or so into the future, would be futile. Our purpose in this section is to illustrate the plausible *range* of possible future production rates and the general effects on production estimates of different interpretations of the causes of past trends and different assumptions about future conditions. The first approach is our slight favorite, but only because its level of disaggregation forces the analyst to deal more explicitly with the underlying causes of past events. This approach is discussed in the greatest detail.

At the end of the chapter, a variety of gas production forecasts by public agencies, private companies, and institutions are presented and discussed.

APPROACH NUMBER I—PROJECTING TRENDS IN THE INDIVIDUAL COMPONENTS OF RESERVE ADDITIONS

The first approach separately projects trends in reserve additions from new field discoveries, new pool discoveries and extensions, and revisions.

New Field Discoveries

The discovery of gasfields represents the single most important force necessary for building a sustainable natural gas supply because a new gasfield not only adds to *current* reserves but also provides a source of considerably larger additions to future reserves through field growth after the discovery year. Reserve additions attributable to extensions and new pool discoveries and, to an extent, to revisions, are all, in fact, the inevitable consequence of previous new field discoveries. Therefore, if new field discovery rates increase or decrease, then at some point in the near future, reserve additions from extensions and new pool discoveries will almost certainly increase or decrease in a like manner.

Factors Affecting New Field Discoveries

The rate of annual additions to reserves from new field discoveries depends on a variety of factors, but most importantly on:

- *The undiscovered resource base.* —The physical nature of the resource base—including the amount of resources remaining to be found, the distribution of field sizes, the locations of fields, the distribution of types of geological traps (more or less difficult to pinpoint with available exploration techniques), and other physical attributes— is considered by some to be the single most important determinant of future new field discoveries.
- *Exploration technology.—The* rapid advance of exploration technology, e.g., computer-aided seismic technology, affects drilling success rates and, consequently, overall discovery rates. Also, technological improvements have opened up to commercial exploitation some areas whose complex geology had pre-

viously prevented acceptable success rates. Consequently, these improvements have expanded the recoverable resource base. Development of the Western Overthrust Belt is an important example of this effect.

- *Drilling and production* technology.—Improvements in production technology}? create an expanding recoverable resource base and, in turn, an increase in targets for the drill. For example, massive hydraulic fracturing technologies allow exploitation of fields in sands of low permeability that previously would have been subeconomic. Improvements in offshore drilling technology allow exploitation of gasfields in deeper and more hostile waters.
- *Current and perceived future gas prices and other economic variables.* — Such variables affect the propensity to drill and determine where to draw the line between a producible well and a dry hole. In some cases, the higher prices allow the use of well-stimulat ion techniques that would otherwise be too expensive, allowing successful production to be achieved from a well that would otherwise have had too low a flow rate. Additionally, the minimum acceptable reservoir size for production has grown smaller. The *relative* prices of gas and oil are important also because these will determine whether drilling will be preferential y aimed at targets where gas or oil are more likely to be found.
- *Schedules, financial terms, and other aspects of leasing.* —These also determine the number of attractive targets available for exploratory act iv i t y.
- *Industry willingness to take risks.—All* of the above factors and others play a role in determining the propensity of the exploration segment of the industry to assume the risks of wildcat drilling in unproved areas where much of the gas resource potential is thought to exist. Because this type of drilling often involves hostile environments and large capital requirements, much of this drilling is the domain of the major integrated oil companies and the large independents. Consequently, those factors that strongly affect the cash flow, capital availability, and economic incentives for this group of companies are particularly likely to affect the industry's propensity for risk-taking.
- *Historic prices and exploratory experience.* —There always exists an inventory of new field prospects known to explorers through past exploratory activities but undrilled or (in the case of "dry holes") uncompleted because of economic conditions or the availability of more promising prospects elsewhere. The key determinants of the size and character of this ink'enter]' are past exploratory experience and price profiles. The nature of the inventory is, in turn, an important determinant of new field discovery rates in the short-term, especially during the period following a change in price levels or regulatory controls.

Historical Variation of New Field Discoveries

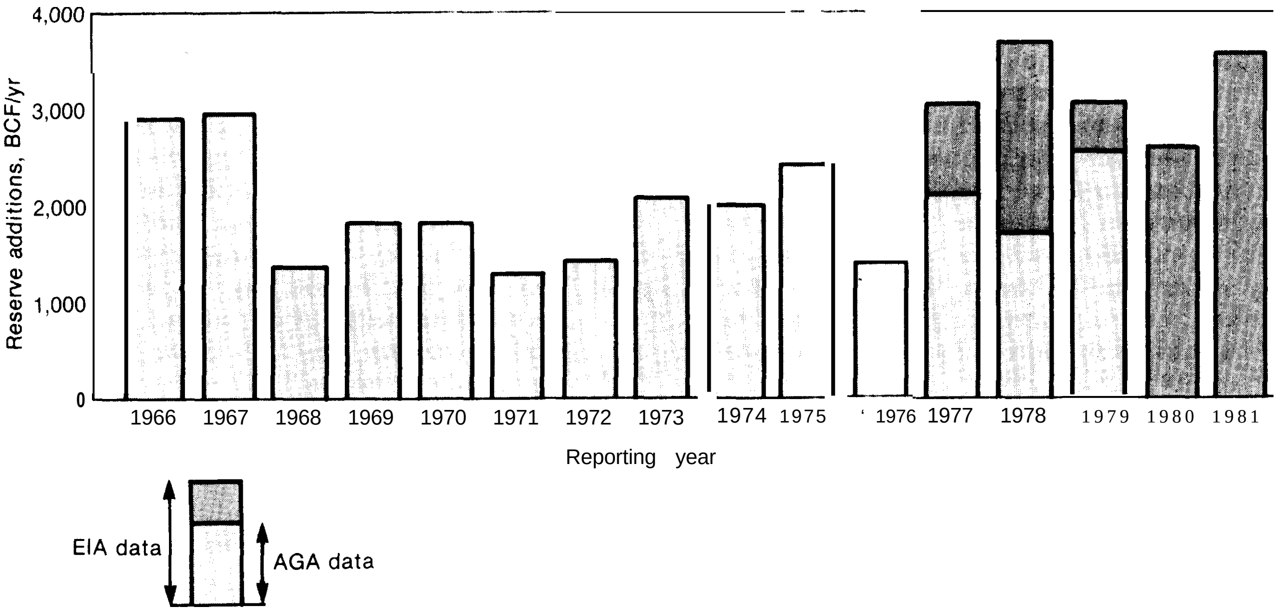
During the 14 years of American Gas Association (AGA) data availability,* the annual additions of new field discoveries in the Lower **48** States have remained fairly steady, if somewhat cyclic, varying between a high of 2.9 TCF and a low of 1.3 TCF. (See fig. 18, which also shows the Energy Information Administration (EIA) data for **1977** to **1981.)** Since **1967,** the last year in which AGA estimated that total reserve additions exceeded product ion, the average of new field discoveries has been 2.0 TCF. Similarly, nonassociated new field discoveries have been equally steady, with a 14-year average of 1.7 TCF. Con-- sequently, new field discoveries played a surprisingly small direct role in annual reserve additions during this period; * * they averaged less than 20 percent of all annual additions from new discoveries and extensions and never exceeded **25** percent in any year.

Although the reserve additions reported as new field discoveries remained steady during this period, the size distribution of the fields discovered did not. As shown earlier in table 12, the average size of new gasfields became considerably smaller (reported year-of-discovery reserves of

*Actually, AGA has compiled reserve additions data since 1947, but only began separate}' estimating new field discoveries in 1 967

''Clearl} they did not play a small *indirect role* since many of the new pool discoveries and extensions in this period represented development of the fields discovered earl ier in the period

Figure 18.–Additions to Lower 48 Natural Gas Proved Reserves: New Field Wildcat Discoveries, 1966-81 (BCF)



SOURCES: Office of Technology Assessment, based on data from Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves-1967 Annual Report*, DOE/EIA-0216 (61), August 1982 and American Petroleum Institute, American Gas Association, and Canadian Petroleum Association, *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31 1979*, VOl 34, June 1980

1.85 billion cubic feet (BCF) per successful new field wildcat in 1979 v. 18.56 BCF per successful new field wildcat in 1966). Furthermore, the lower average did not imply only a reduction in discoveries of giant fields; although this did occur, another change involved a very large increase in the number of very small class E fields* brought into production.

Because of the smaller size of newly discovered fields, a steady expansion of successful exploratory wells was required just to maintain the rather low annual discovery rate of the period. For example, completions of new field (gas) wildcats in the onshore Lower 48 increased from 126 in 1968 to 671 in 1979. Because of the substantial improvements in success rates (see fig. 13) for all new field wildcat drilling (from 8.5 percent in 1968 to 19.0 percent in 1980), however, actual drilling rates did not have to increase in proportion to the rate of completion. From a low of 4,463 wildcat wells in 1971, drilling reached 6,413 wells in 1979 and 8,052 in 1981.

The more recent (1977 to 1981) EIA new field discovery data fig. 18) show considerable year-to-year variation with no apparent trend and are made even more difficult to interpret because of the break with the AGA data series. However, the EIA estimates of new field discoveries were higher during 4 of the 5 years of record than any AGA-recorded discovery rate from 1966 to 1979. Of interest is the source of these discoveries. Although areas like the Western Overthrust Belt and deep Anadarko Basin have been in the forefront of media coverage, most new field discoveries continued to come from more traditional gas-producing areas -- onshore and offshore (Gulf of Mexico) Louisiana and Texas. For example, during both 1980 and "1981 these two States provided two-thirds of the total magnitude of reserve additions from new field discoveries in the Lower 48.

*Class E fields contain less than 6 billion cubic teet of recoverable gas.

2U. S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1980 and 1981, EIA Annual Reports, DOE/EIA-021680 and 81, October 1981 and August 1982.

Implications

The following key issues pertaining to new field discoveries remain essentially unresolved:

- Can the 1968-79 trend in new field discoveries—essentially a steady cycling around an average of 2 TCF/yr or so—be continued well into the future? If optimists about the gas resource potential of small fields are correct, a continuing strong exploratory drilling effort should be able to maintain this level for a number of years. If the pessimists about small fields—and about the remaining resource base in general—are correct, reserve additions from new field discoveries might drop within a few years.
- Do the higher EIA estimates of 1977-81 new field discoveries represent an actual increase, or are they the result of the change in reporting methodology? Does the EIA methodology place more of a newly discovered field's ultimate reserves into the first-year reserve estimate, leaving less room for secondary (extension and new pool wildcat) discoveries? If the EIA values represent a true increase in new field discovery rates, the sustainability of a high rate (perhaps 3.5 TCF/yr) of new field discoveries would seem to depend either on the availability of new giant fields or on extremely high rates of exploratory drilling and the availability of massive numbers of small fields, supported by either or both strong price incentives and continued improvements in exploration technologies (especially in terms of lowering the cost of detailed geological surveys).

The comparison of the three overlapping years of EIA and AGA data in figure 18 is tantalizing because the difference between the two data sets is considerably smaller in 1979 than in 1977 and 1978, and the EIA methodology changed in 1979. Some analysts have chosen to use AGA data until either 1978 or 1979, and EIA data thereafter, assuming that the two series are essentially continuous. However, the coincidence between the 1979 EIA and AGA estimates for new field discoveries may be an accident; the two data sets differ considerably for all of the other reserve addition categories in *1979*.

The failure to resolve the above issues implies that a credible range for future new field discovery rates would be quite wide. Although defining the range is a matter for subjective judgment, OTA would put the range at about 1.5 to *3.5* TCF/yr for the next 10 to 15 years, assuming that *exploratory drilling remains active for the period.* * The range for the next 2 or 3 years should be narrower, however, perhaps 2.0 to 3.5 or 2.5 to 3.5 TCF/yr. The reasoning for these judgments is as follows:

- The high end of the range for the immediate future is based on the distribution of new field sizes. Because the current high discovery rate has not depended on discovering giant fields—notoriously erratic occurrences—but on employing a very large number of exploration teams to discover many medium-sized and small fields, the physical ability of the system to maintain its recent new field discovery rates should logically be quite high unless the gas "bubble' '-and the current slump in drilling and all other exploratory activity—continues.
- To obtain the lower end of the 10- to 15-year range, we assumed that the 1970's AGA data more accurately reflect the likely future and that continuing resource depletion will lead to poorer prospects and a slump from the average of *2.0* TCF/yr during that period. Also, it was assumed that the major reasons for the higher EIA values are methodological and do not reflect an *actual* increase over discovery rates reported by AGA. Consequently, the 1.5 TCF/yr reflects AGA conventions and probable followup field growth. The discovery levels actually *recorded* by EIA would be expected to be higher than this value, but the reserve growth caused by extensions and new pool tests would then be lower than would be predicted by pre-EIA historical experience.
- The higher end of the lo-year range assumes that the EIA data accurately reflect a major upward shift in the finding rate (volume of

* Drilling is now in a substantial slump. The ranges of reserve additions discussed here would be unrealisticall y high if the current "bubble" in gas deliverability y and the related difficulties in marketing new gas were to continue,

gas discovered per unit of exploratory activity). Additionally, it is assumed that continued improvements in exploration and production technologies allow further increases in finding rates and/or that exploratory drilling rates are increased. This end of the range is alined with a large resource base.

Extensions and New Pool Discoveries

As already noted, a new field is generally not sufficiently defined in its year of discovery to allow the "new field discoveries" portion of reported reserve additions to represent all or most of the actual recoverable resource in that field. In the years following discovery, additional exploratory wells are drilled to delineate the full extent of the resources present in the field. Wells that probe the boundaries of reservoirs or fields in order to establish their productive area are called extension wells or extension tests. Wells that search for additional reservoirs within already discovered fields are called new pool tests or new pool wildcats. The reserve additions from extension wells and new pool wildcats represent the results of a secondary or followup discovery process for new fields.

Factors That Affect Extensions and New Pool Discoveries

As with new field discoveries, the major determinants of extensions and new pool discoveries are the magnitude and nature of the "target" (in this case, not the undiscovered recoverable resource base, but only that portion of the remaining resource associated with discovered fields), the technology available to find the gas, and the nature of the incentives to drill:

- The *target.* —The "resource base" for extensions and new pool discoveries is the inventory of discovered but incompletely delineated fields. Limited data from the late 1960's and 1970's indicate that the major part of new field growth has occurred within the first 5 years after discovery. Consequently, unless incentives for gasfield development are lacking, * the magnitude of extensions and new pool discoveries should be strongly *and positively* tied to recent new field discoveries. Additionally, measures that increase current new field discoveries should soon lead to increases in extensions and new pool discoveries as the new fields are further developed.

  Aside from the total gas volume represented by the "target," that is, the inventory of discovered fields, the geological characteristics of the fields will also play an important role in determining future extensions and new pool discoveries. For example, older fields that were incompletely developed because a substantial portion of their in-ground resource was subeconomic* at the time of discovery are now good targets for new exploratory efforts. The size and complexity of newly discovered fields will partially determine the relationship between the initial year-of-discovery reported reserves and the later extensions and new pool discoveries that signify further development of the fields. Because the discovery wells of smaller, less complex fields can generally "prove" a high percentage of their total resource, these fields may offer less opportunity for this later development than was the case with the generally large, complex fields of earlier decades.
- Technology. —The same technological factors that affect new field discoveries affect extensions and new pool discoveries. Computer-assisted seismic technology is considered especially important in allowing extension wells and new pool tests to be drilled with high success rates. Fracturing technologies, by opening up previously uneconomic reservoir margins and tight reservoirs in already discovered fields, expand the target resource available.

  Advancements in exploratory technology have other, varied effects, however. For example, advanced seismic techniques, by offering a highly accurate picture of the potential of new fields shortly after discovery, may encourage a larger proportion of the ultimate recoverable gas to be drilled and "proved" in the initial year-of-discovery, leaving less room for followup discoveries. Advanced

*The current gas "bubble" provides a disincentive for field development.

* Because of the small size or low permeability of the reservoirs or the low quality of the gas.

seismic techniques also may help compress the remaining field delineation into a shorter span of time, leading to increases over expected levels in extensions and new pool discoveries* for a few years after discovery of the field, followed by a later decrease in expected levels of these reserve additions.

Historical Variation of Extensions and New Pool Discoveries

Figure 19 and table 16 illustrate the variation of extensions and new pool discoveries** in the Lower 48 States from 1966 to 1981. Extensions have consistently played the major role in total reserve additions. After declining in the mid to late 1960's, they remained stable around 6,000 BCF/yr from 1969 to 1976 and began to move upwards thereafter. As with the other categories of reserve additions, the shift to EIA data complicates an interpretation of the past few years. According to that data, however, extensions *by themselves* produced reserve additions of 10 TCF in 1981, equaling or surpassing *total* reserve additions in most years of the 1970's.

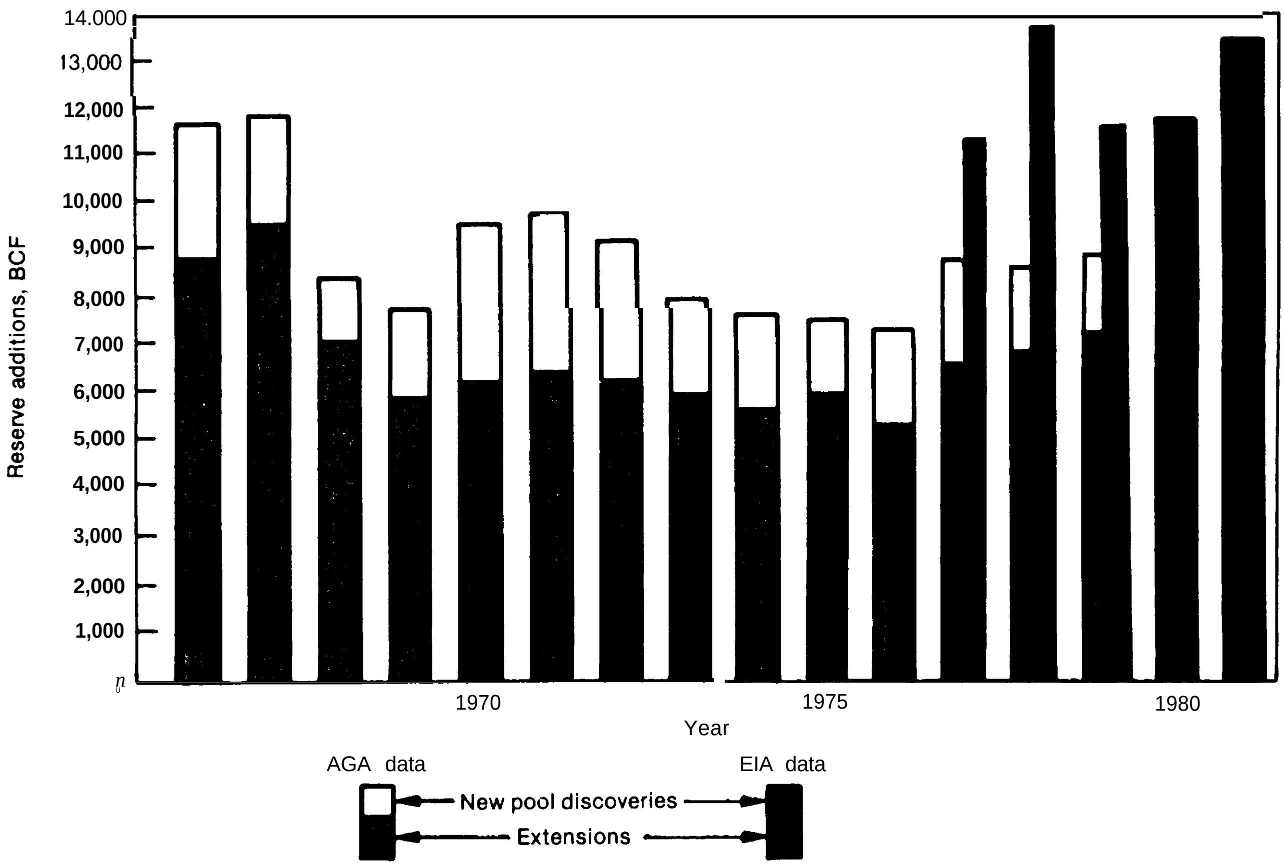
Some of the underlying causes of these trends may be understood by examining the trends in extensions of individual PGC reporting areas.[3] Extensions tend to be concentrated in only a few of

● That is, increases over the discovery rates projected by using historical data.

● *As noted previously, new pool discoveries are reported as "new reservoir discoveries in old fields" in the AGA and EIA reserve reports.

[3]From R. Nehring, "Problems in Natural Gas Reserve, Drilling, and Discovery Data, " contractor report to OTA, 1983.

Figure 19.—Additions to Lower 48 Natural Gas Proved Reserves: Extensions and New Pool Discoveries, 1966-81 (BCF)



SOURCE Office of Technology Assessment

Table 16.—Additions to Lower 48 Natural Gas Proved Reserves: Extensions and New Pool Discoveries 1966-81 (BCF)

Year	Extensions	New pool discoveries	Total
1966	8,767	3,110	11,877
1967	9,472	2,420	11,892
1968	7,037	1,426	8,463
1969	5,800	2,043	7,843
1970	6,146	3,363	9,509
1971	6,375	3,361	9,736
1972	6,154	3,096	9,250
1973	5,931	1,970	7,901
1974	5,693	1,952	7,645
1975	5,926	1,649	7,575
1976	5,337	1,994	7,331
1977	6,569 (8,056)'	2,144 (3,301)	8,713 (1 1,357)
1978	6,720 (9,582)	1,964 (4,277)	8,684 (13,859)
1979	7,112 (8,949)	1,690 (2,566)	8,802 (1 1,515)
1980	(9,046)	(2,577)	(11,623)
1981	(10,485)	(2,994)	(13,429)

[a]The values in parentheses are from EIA data; all other values are AGA reserve data.

SOURCE. Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves— 1981 Annual Report,* DOE/EIA-0216 *(61),* August 1962; and American Petroleum Institute, American Gas Association, and Canadian Petroleum Association, *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 1979,* vol. *34,* June 1960

these areas. Before 1968, field growth (primarily in relatively deep fields) in the Permian Basin provided a major fraction of total U.S. extensions—e.g., *43* percent in 1966. A sharp decline in Permian Basin reserve growth in 1968 was the primary reason for the general decline in extensions at the same time. The increase in extensions nationwide, beginning in 1977, resulted primarily from increases in:

- Western Overthrust Belt development;
- development of the deep Anadarko Basin;
- tight gas sand development in northeast Texas, Arkansas, and Louisiana; and
- Texas gulf coast development, including offshore fields, the South" Texas Lobo Trend, and tight sands in the Austin Chalk.

Implications

Although the shift in data collection from AGA to EIA complicates interpretation, the sum of extensions and new pool discoveries has apparently been increasing from about 1976 to the present. In the AGA data, however, the increase only takes these "followup" discoveries back toward the levels achieved during the brief surge in new pool discoveries that occurred in the early 1970's. The EIA data show a considerably higher level of "followup" discoveries at about the levels that AGA estimated for 1966 and 1967.

In order to understand the recent variations in extensions and new pool discoveries, it is generally necessary to track the new field discoveries that serve as the "inventory" for the secondary exploration process. There is no obvious trend in the *national* new field discovery pattern (fig. 18) that would explain the recent higher level of secondary discoveries; AGA new field discovery data in the period immediately before this apparent surge in secondary discoveries show no similar increase. Consequently, in order to understand fully the causes of the recent surge, it probably is necessary to undertake a detailed examination of data at the level of individual fields. This is beyond the scope of OTA's study. However, some reasonable hypotheses can be fashioned based on the available data.

One possible explanation for the recent increases in extensions and new pool discoveries is that the increment over "normal" levels represents the delayed development of fields discovered earlier but not developed for economic reasons. The dip in new pool discoveries from about 1973-76 (fig. 19), which occurred despite an earlier period of steady new field discoveries that normally should have maintained steady levels of extensions and new pool discoveries, supports this explanation.

Some field-specific data also support a "delayed development" cause for part of the increases. For example, recent extensions in the Austin Chalk fields in southeast Texas appear to be tied to old fields that were marginally economic when discovered and had never undergone major development before recent price increases encouraged a reexamination. Because these fields were not "new," recent discoveries were probably recorded as extensions and new pool discoveries, even though there was little in the way of previously recorded new field discovery "inventory" to trace as the statistical cause of these secondary discoveries.

Similarly, another of the areas providing a substantial fraction of the increased extensions—the Western Overthrust Belt—probably also followed a delayed pattern of development. In this area, there was little incentive to delineate immediately the first new fields discovered because there was no means to transport the gas. Consequently, a substantial inventory of new fields could have built up until a point was reached where it became clear that the area contained sufficient reserves to justify a pipeline. Attaining this level of reserves would have introduced an incentive for field delineation, and secondary exploration would have then proceeded to cause a surge in extensions.

An additional cause of the recent higher recorded levels of secondary discoveries could be an acceleration in the pace of field-size delineation and development. Such an acceleration would result in the field size growth that in the past might have been spread out over a 60-year span being compressed into a shorter time period, with higher levels of annual reserve additions during this shorter period. Accelerated field size growth would be an expected consequence of higher gas prices, although the recent problems of reduced gas demand would tend to have the reverse effect, that of slowing down the pace of growth.

To summarize, two possible causes for recent increases in extensions and new pool discoveries are an accelerated field development pace and the delayed development of earlier new field discoveries whose development was (at least in part) initially uneconomic. If these are indeed the primary causes of the increases, this has important implications for future reserve additions. First, the faster pace of development means that *fewer* opportunities for field growth will be available in the later years of development; this should tend to decrease future reserve additions unless the rate of new field discoveries increases. Second, unless additional opportunities for growth from older fields are available, this source of "inventory" for extensions and new pool discoveries is unlikely to allow continuation of the currently high-reported levels of reserve additions. Although continuing technological advances and future gas price increases could offer some potential for sustaining reserve additions from older fields, the actual potential for reserve additions from this source is controversial. * In any case, most of any additional reserve growth from older fields seems likely to be attributed to infill drilling and other causes that will be reported as positive revisions rather than as extensions and new pool discoveries.

Recent and future discoveries of new fields still provide the primary source of inventory for future extensions and new pool discoveries. Consequently, future reserve additions from extensions and new pools depend heavily on the meaning of the sharply higher levels of new field discoveries reported during 4 of the past 5 years by EIA. As discussed in the "New Fields" section, OTA suspects that part of the reason why EIA's compilation of new field discoveries is substantially greater in magnitude than the levels shown by AGA is that the EIA data captures some of the reserves that AGA would have reported as second-year extensions, new pool discoveries, or positive revisions. If this is correct, the "growth factor" that should be applied to EIA's new field discovery data to account for field growth after the year of discovery will be smaller than the growth factor applicable to AGA data. For this reason, we do not believe that continuation of high levels of extensions and new pool discoveries is probable under current conditions.

Aside from the effects of the change in reporting, there are other reasons to believe that future levels of extensions and new pool discoveries may drop, First, much of the field growth in the past has come from the giant fields that took years to develop. A large percentage of recent new field discoveries, however, are small, class E (less than 6 BCF of recoverable gas) fields that will require little additional exploratory drilling past the initial wildcat. Second, the suspected acceleration in the pace of field development implies that some of the development that might in the past have taken place in the second year (and that would have been reported as extensions and new pool discoveries) now takes place in the first and will be reported as part of the "new field discoveries" reserve additions. Finally, the high- capital requirements for developing new fields in hostile environments—an increasing part of the remaining resource—demand a more thorough initial

*As discussed in ch. 4 "New Gas From Old Fields.

estimate of reserves, possibly leading to lower (statistical) growth later on.

To conclude, OTA does not believe it is likely that recent reserve additions from extensions and new pool discoveries of 12 to 14 TCF/yr will be sustained in the future even if the gas "bubble" ends and its negative effects on drilling cease. Instead, we project a range of 6 to 11 TCF/yr as an average over the next 10 to 15 years, except that for 1983-85 we project a range of 8 to 12 TCF/yr. The sole possibility of a higher long-term rate of reserve additions from this source lies with the discovery of several new, complex, super giant gasfields with large growth potentials; however, this possibility appears low.

Revisions

Revisions indicate changes in the volume of proved reserves that result from new information gained by drilling and production experience and corrections made to earlier estimates during the reporting year.

The AGA and DOE/EIA reporting of revisions is not identical because EIA has a separate category of "adjustments and corrections" that includes adjustments for changes in data samples, corrections of reporting errors, inclusion of late responses, and other factors. Theoretically, AGA's revisions should be equivalent to the sum of EIA's revisions, adjustments, and corrections. However, the data-gathering and analysis methods used by the two surveys are radically different, and their reserve and reserve addition estimates in the 3 years of overlap do not show good agreement. Consequently, they are not equivalent, although in displaying historical trends AGA revisions will be compared to EIA revisions plus adjustments and corrections.

Factors Affecting Revisions

Generally, revisions occur because of uncertainty associated with estimating the extent of the underground reservoir rock within a trap, the porosity and permeability of that rock, water saturation, pressure, and other physical reservoir characteristics that affect the cumulative volume of production over the life of the reservoir. Revisions tend to be a "catchall" category of reserve additions and deletions, and the many sources of revisions are difficult to separate out of the data. These sources include:

1. new knowledge gained by normal development drilling and production experience (e.g., changes in reservoir pressure-decline trends that indicate that earlier estimates were incorrect);
2. numerical errors in the original compilation of reserve estimates;
3. discoveries for which reporting had been delayed;
4. development drilling on a closer spacing that "discovers" new reserves; *
5. changes in production economics that lower or raise the abandonment pressure of a reservoir or that allow or prevent the use of well-stimulation techniques that increase recovery efficiency;
6. knowledge gained from extension tests that indicate a decrease in the estimated proved area of a reservoir or field (an *increase* would be recorded as an extension); and
7. miscellaneous statistical corrections and adjustments to the data.

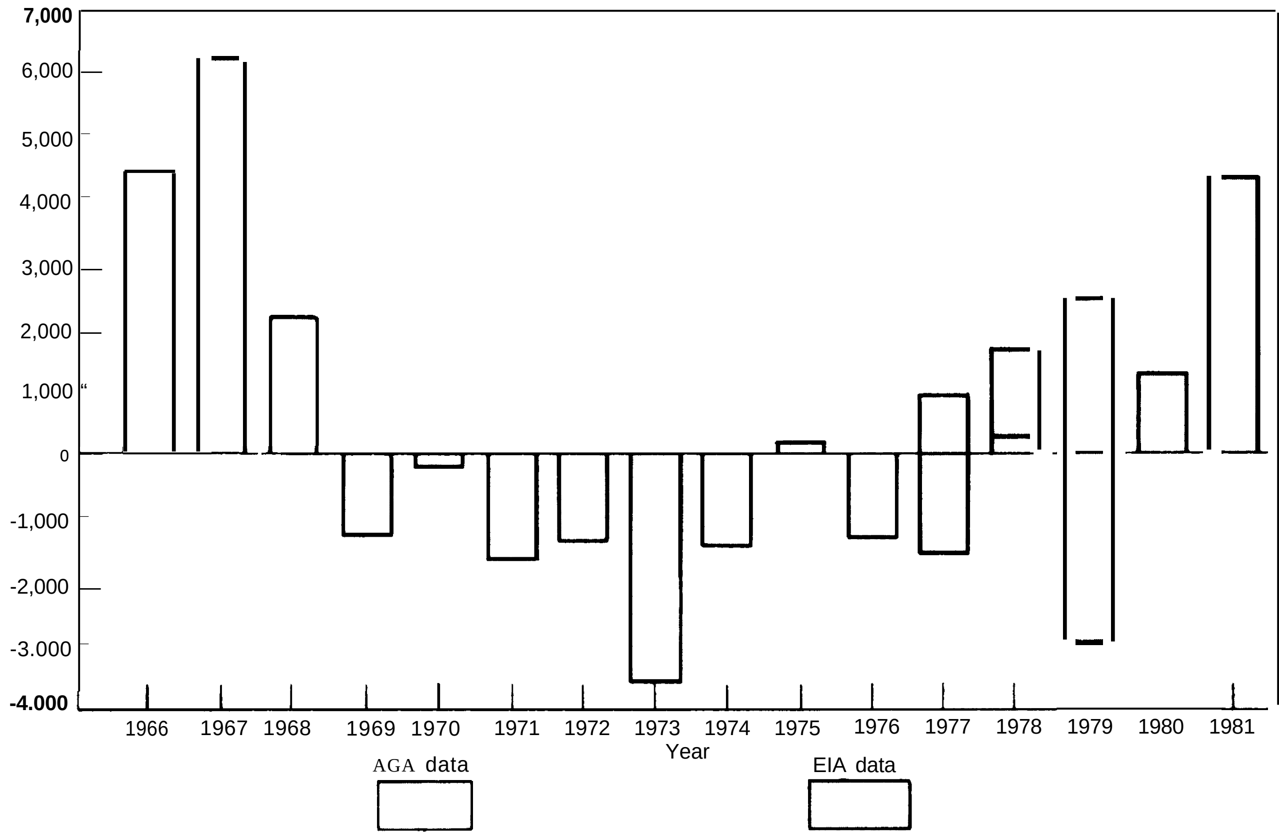
Sources 2, 3, and 7 are considered "Adjustments and Corrections" by EIA and are reported separately.

Historical Variation of Revisions

From 1966 to 1981, net revisions were easily the most volatile of any of the four types of reserve additions. In the data reported by AGA for the contiguous **48** States, revisions varied from **i-6,256** BCF in 1967 to –3,546 BCF in 1973. In the EIA data for the same area, revisions plus adjustments and corrections varied from – 2,911 BCF in 1977 to +4,346 BCF in 1981. Consequently, the year-to-year changes in revisions were the primary determinant of the year-to-year changes in gross reserve additions during the past **16** years. As shown in figure **20,** a series of substantial posi-

*New reserves "discovered" by a development well would be recorded as a revision if the gas is located in a pocket within the established boundaries of a reservoir yet is physically isolated from the reservoir's main drainage system and would not otherwise be produced.

Figure 20.—Additions to Lower 48 Natural Gas Proved Reserves: Revisions As Reported,[a] 1966-81 (BCF)



[a]NOTE EIA plots for revisions t adjustments and corrections

SOURCES Off Ice of Technology Assessment based on data from Energy Information Administration *U S Crude Oil, Natural Gas and Natural Gas Liquids Reserves– 1981 Annual Report*, DO E/EIA-0216 (81) August 1982 and American Petroleum Institute American Gas Association, and Canadian Petroleum Association, Reserves o f *Crude Oil Natural Gas Liquids and Natural Gas in the United States **and Canada as o f** December* 31, 1979 VOl 34, June 1980

tive revisions in the mid-1960's changed to net negative revisions in almost every year in the 1970's, particularly in the onshore contiguous 48 States. As discussed later, understanding the role of these revisions is important in interpreting reserve changes during this period.

The largest negative revisions in the 1970's were reported in onshore south Louisiana and Texas Railroad Commission Districts 1, 2, 3, 4, and 6. Together, they contributed a total of over 30 TCF and proved to be remarkably persistent, continuing throughout the 1970's in both the AGA and EIA data. They were concentrated in older fields that had been producing for one to three decades before the revisions began.

The negative revisions in these six areas appear to be causally related to a situation that encouraged optimism in reserve calculations. During the 1930's, 1940's, and 1950's, exploration for natural gas in and adjacent to the gulf coast was highly successful. As a result, much more gas was discovered than could be produced, given the small size of the national natural gas market at the time. The transmission companies, having contracted for reserves with a productive capacity substantially exceeding what they could market, developed a system for prorating production among operators on a basis of remaining reserves (i. e., the larger an operator's reserves, the more gas the transmission companies would buy). This created a strong incentive for the operators to provide the most optimistic estimates of reserves they could justify. By 1970, following years of increasing production and gradual depletion, the operators were beginning to realize that reserves were overstated.

The size, timing, and geographic distribution of the reported negative revisions that followed depended primarily on when each major operating company recognized the problem and how they decided to revise their estimates downward, choosing to take them all at once or spreading them out over several years.[4]

Implications

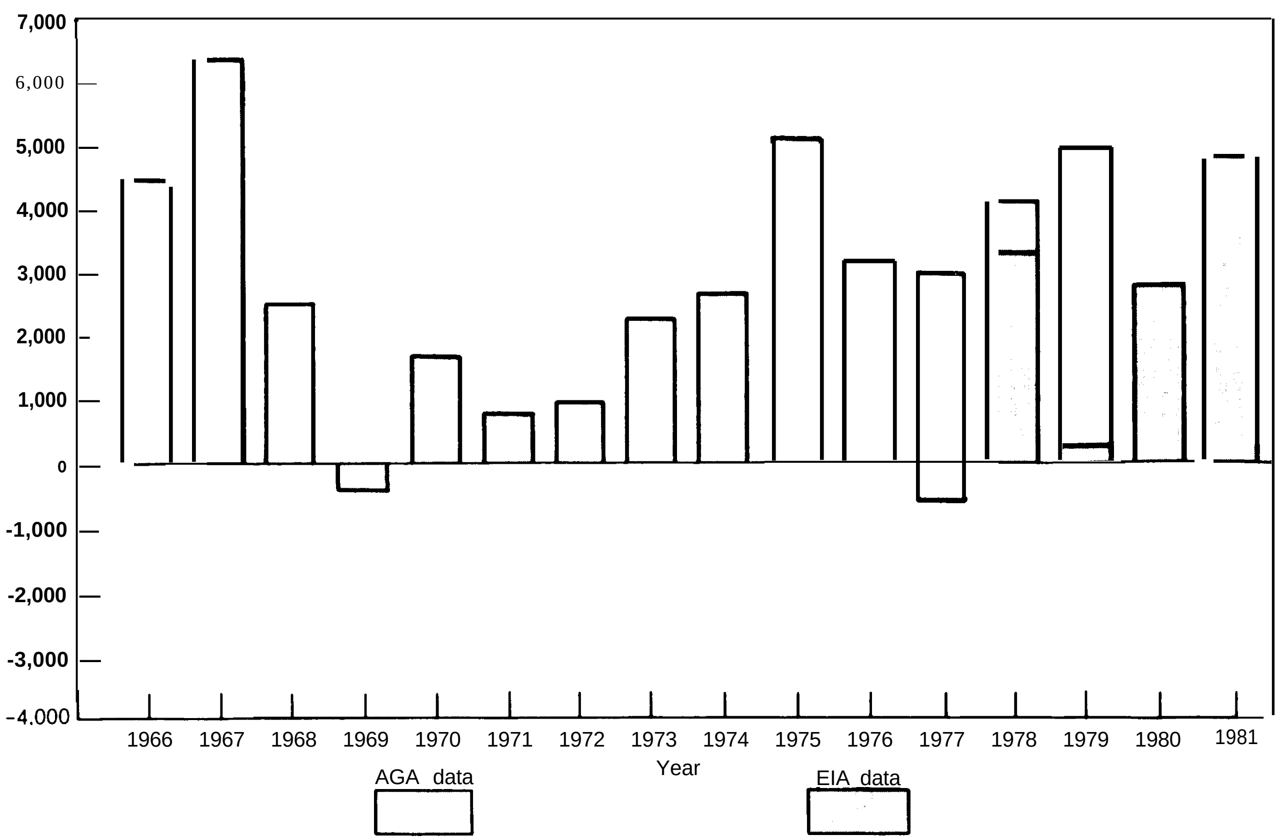
An argument can be made that the historical record, erratic as it seems, supports the idea of generally positive revisions in the long-term. This is based on the view that the large but localized negative revisions of the 1970's appear to have ended. The trends in revisions for the areas outside the source area for the negative revisions seem far more positive.[5] For example, if the gulf coast revisions were subtracted from the total Lower 48 revisions, as shown in figure 21, the "amended revisions" would appear to support a projection of positive future revisions. On the other hand, an examination of the sources of revisions indicates that extreme caution should be used in forecasting the direction of future revisions.

Of the seven sources of revisions listed previously, the second and seventh are essentially random. The others either will always yield positive revisions, will always yield negative revisions, or may have a bias in one direction or the other. The first source, drilling and production experience, would be random if there were no incentives to be either pessimistic or optimistic in reserve

[4] Ibid.

[5] T. J. Woods, "On Natural Gas Trends, " Gas Research Institute, 1982; "R. Nehring, contractor report to OTA, op. cit.

Figure 21.—Additions to Lower 48 Natural Gas Proved Reserves: Revisions As Amended,[a] 1966-81 (BCF)



[a]NOTE: EIA plots are for revisions + adjustments and corrections.

SOURCE Off Ice of Technology Assessment

calculations. However, the requirement to raise capital for field development or to meet minimum reserve requirements for a new pipeline are powerful incentives for optimistic reserve estimates. A tendency toward optimistic estimates would result in mostly negative revisions from drilling and production experience. The large negative revisions of the 1970's in the gulf coast and adjacent provinces appear to have resulted from just such a tendency.

The fifth source, changes in production economics, also could be random in that gas prices could rise faster (yielding positive revisions) or slower (negative revisions) than the costs of operating fields and enhancing production. Although rigid price controls or the competition of low-priced alternative fuels could conceivably lead to negative revisions from this source, it seems more likely that most such revisions would be positive, especially if gas becomes scarcer. In support of this argument, the growth in reserves attributed to well reworking, infill drilling, and lowered abandonment pressures—growth that would be reported as positive revisions—is seen by some analysts as an extremely important component of future reserve additions (see ch. 4, section on "New Gas From Old Fields").

Of the remaining sources of revisions, the third and fourth will always yield positive revisions, and the sixth always will yield negative revisions. *

The confusing mix of "positive," "negative," and "random" sources of revision make it extremely difficult to predict how revisions will behave in the future. Also, revisions data do not indicate which previous years' data are being revised. Consequently, it is difficult to know the causes of past revisions—a necessary prerequisite for intelligent forecasting. For these reasons, some analysts disregard revisions entirely in their trend analyses and implicitly assume they will not be a significant component of future reserve additions.

A reasonable range of average yearly revisions for the next 10 to 15 years appears to be O to 2 TCF/yr, with the positive tendency based on OTA's belief that there may be some significant potential from the growth of older fields due to lowered abandonment pressures, infill drilling, and the like.

Reserves= to= Production Ratio

Because the reserves-to-production ratio (R/P) measures the rate at which gas is produced from discovered reservoirs, it represents the analytical link between projections of new discoveries and forecasts of gas production.

Factors Affecting R/P

At the level of the individual production firm, the selection of a production rate—and, consequently, the selection of the R/P—represents an economic tradeoff between the cost of drilling additional wells and installing additional gas-gathering and processing facilities (i. e., the cost of increasing production), on the one hand, and the cost of holding reserves in the ground, on the other, Consequently, factors such as exploration and development costs, present and expected future gas prices, and interest rates all affect the R/P. For example, increases in current prices will theoretically lead to faster production, while expectations of real increases in future prices can cause production to be delayed.[6]

In oil production, it is well known that too fast a production rate—too low an R/ P—can cause a premature decline in production and a loss of potentially recoverable reserves. For example, in a reservoir whose pressure is supplied mainly by water that displaces the oil as it is produced (a "water-drive" reservoir), an overly rapid rate of production can cause the encroaching water to flow around less-permeable sections of the reservoir, leaving behind the oil in these sections. When the water reaches the well, the added costs of water separation and disposal can cause premature abandonment.[7]

*The sixth, knowledge gained from extension tests, yields only negative revisions because an ***increase*** in reserves caused by this source would be reported as an extension

[6]Douglas Bohi and Michael Toman, "Understanding Nonrenewable Resource Supply Behavior, " *Science*, vol. 219, Feb. 25, 1983.

[7]P. A. Stockil (cd.}, *Our Industry Petroleum* (London: British Petroleum Co.Ltd., 1977).

Because gas flows more easily than oil, there is far more leeway in gas production, and production rates frequently can vary over a wide range. There are, however, the same kinds of physical limits to gas production as to oil production, Although some loss of ultimately recoverable gas from the well may be acceptable to the producer in exchange for a more rapid payback (from the higher flow rate), the potential for large losses will serve to limit flow rates.

Aside from the obvious economic factors and physical limitations to avoid resource loss, several other factors affect R/P:

- Technology. —The major technology affecting R/P may be rock-fracturing methods. The use of massive hydraulic fracturing and other fracturing techniques can open up low-permeability rock and cause marginal wells with low-flow rates to become rapid producers. The availability of sophisticated seismic exploratory techniques has reduced overall drilling costs—enhancing the incentive to drill additional wells to expand production—by increasing the success ratio; it also has helped improve the placement of successful wells to maximize production.
- Geology. —The rate of gas flow is directly dependent on the permeability of the gas reservoir formation and on its pressure and thickness. Although fracturing can partly compensate for low permeability, wells in tight gas formations generally produce much more slowly than do wells in more permeable rock because the fractures do not reach all of the tight reservoir rock. Similarly, gas in deep over-pressure formations will for short periods of time produce far more rapidly than in shallow, low-pressure formations;* in fact, the high pressures in such formations have caused severe technical problems in fields such as the Fletcher Field in southwestern Oklahoma, where wells and drilling equipment have been destroyed by failure to control the enormous pressures built up deep underground.[8] Also, field size distributions may affect R/P because smaller fields, which will be of increasing importance in future reserve additions, may be produced faster than large, complex fields.
- Field *Maturity.* —Early in a field's lifetime, R/Ps are typically very high because the major focus is on reserve delineation rather than development; during this period, pipeline and gas-processing capacity may be nonexistent or minimal and markets may be undeveloped. As pipeline capacity is added and sales contracts signed, the R/P will decrease rapidly. As the field tends toward depletion, the R/P may rise again as gas pressures drop and as drilling gravitates to the marginal, low-permeability formations. However because, the R/P will equal **1.0** in the last year of a field's production, the R/P will decrease during the very last years of the field.
- *Conservation Regulations.* —Some gas-producing States directly regulate production-related variables such as well spacing and flow rates. These regulations are intended to promote efficient development of reserves to prevent loss of ultimate recovery. Their origin lies in the disruption caused by the discovery of the east Texas field in 1930 and the large oversupply and resulting wasteful gas-production practices that followed. '
- Market Demand. —When the market is demand-limited (deliverability exceeds demand), as it is today, the R/P no longer provides a measure of gas-production capacity. Low demand can raise the R/P.
- *Reserve Requirements.* —The substantial capital requirements of gas transmission and distribution systems has led the transmission and distribution companies as well as Government regulatory agencies to pursue long-term contracts requiring high R/P's and high reserve requirements for pipeline approvals. These requirements do not apply, however, to mature areas where pipeline capacity is already in place.

* However, once the "propping effect" of the gas under pressure is removed by partial production, the permeability of the reservoir may be reduced to "tight-gas" levels, and productions will slow.

"'Fletcher Area Underscores Perils in Deep Gas Reservoirs, " *Oil and Gas Journal,* Feb. 7, 1983, p. 25,

'R. E. Megill, *An introduction to Exploration Economics* (Tulsa, Okla.: Petroleum Publishing Company, 1971).

Historical Variation of R/P*

The early years of gas discovery in this country were marked by lack of a gas-distribution network, substantial discoveries of gas as a low-valued or even unwanted byproduct of oil exploration, and the eventual discovery of enormous reserves (e. g., the **1922** discovery of the giant Hugoton field in Kansas) that overwhelmed existing demand. The combination led to very high R/Ps in the 1920-40 period, followed by an era of continued decline.

In the early years of the post-World War II growth, as new pipeline systems were constructed, previously unproductive proved reserves were developed. This activity increased the level of production without adding substantially to the volume of proved reserves, thus lowering the R/P. Later in the 1960's and 1970's, when the natural gas market had become supply constrained, production was again maintained by further development and a lowering of the R/P. At this time, however, the ability to obtain greater production from a given volume of proved reserves was improved by a geographical shift in production to the Gulf of Mexico and encouraged by economic changes that favored more rapid extraction rates.

The decline in R/P from **1946** to 1981 for the Lower 48 States is shown in figure 22. The AGA data cover the period 1946 through 1979, while DOE EIA includes only the 5 years from **1977** through **1981. * ***

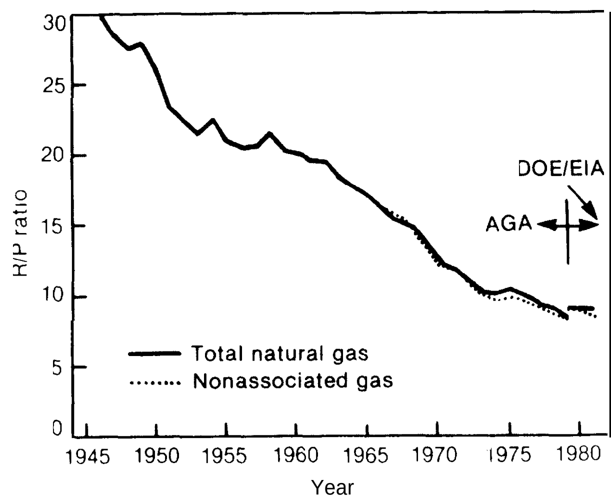
The AGA data show strong year-to-year declines in the R/P over virtually the entire 34-year period of available data. Recently, the rate of decline eased from an average of over 0.8 per year between 1966 and 1974, to an average of 0.5 per year during the 1975-79 period. DOE/EIA estimated dry gas data show a further easing of the decline rate to about 0.2 per year between 1977 and 1981.

Currently, the lowest R/P for the nonassociated gas of a major producing State is 6.6 in Louisiana.

* Based on Jensen Associates, Inc., *Understanding Natural Gas Supply in the U. S.*, April 1983, contractor report to OTA

•'These displayed ratios are developed using the year-end reserves estimate for the year prior to the production period This approach to calculating the R P stems from a belief that production in a given year is more likely to be representative of reserves that are available at the beginning of the year

Figure 22.— Reserve-to-Production Ratios for Natural Gas in the Lower 48 States



SOURCE Off Ice of Technology Assessment based on data from Energy Infer mation Administration, *U S Crude Oil, Natural Gas and Natural* ***Gas Liquids Reserves— 1981 Annual Report*.** DOEIE!A-0216 (81) August 1982, and American Petroleum Institute, American Gas Association and Can ad ian Petroleum Association Reserves *of* ***Crude*** *Oil Natural* **Gas** *Liquids, and Natural* **Gas** *in the United States and Canada as of December 31, 1979* vol 34, June 1980

The lowest R/P for any geographical subdivision published by the 1981 DOE/EIA reserves report was a 4.0 for the State domain of the Texas offshore. The total Texas and Louisiana offshore, representing 33 percent of Lower 48 State production, stood at 6.5 in 1981. With the Gulf of Mexico excluded, the balance of the Lower 48 States had a 1981 R/P of 9.8. Contrasting strongly with the lower R/P's of the gulf coast would be that of 17.2 for the heavily depleted reservoirs of Kansas and 20.1 in Wyoming, where field development for newly discovered reserves was incomplete in 1981.

Implications

These examples of R/Ps for different areas of the United States during 1981 may indicate that the Lower 48 State R/P could move further downward in future years if gas supplies were found in areas with combinations of high-reservoir permeabilities and economics that favor extensive field development. * This is in fact what happened

* Some opinion exists, however, that some of the lower R P's are due to underreporting of reserves rather than to extremely rapid production If true, this might indicate less potential for further lowering the national R P

throughout the 1970's as the Gulf of Mexico became an increasingly large component of the total supply. Between 1973 and 1981 the gulf's share of production grew from 20 to 33 percent.

An additional factor that might tend to push the R/P downwards is a continuation of current discovery trends towards smaller field sizes. It is widely believed that smaller fields will be delineated, developed, and produced over shorter periods of time than was historically the case with the mix of field sizes discovered until now.

On the other hand, some factors could cause the R/P to reverse and begin to climb upward. Future production trends may tend to increase the shares of gas from tighter, lower permeability reservoirs and other sources more expensive to develop, which could lead to slow rates of production from proved reserves. For example, both the deep Tuscaloosa trend and the Western Overthrust Belt are expected to have relatively high R/Ps; field development and gas-processing costs for these areas are too high to allow rapid depletion at current gas prices.[10] In addition, the R/P might tend to increase if future reserve additions were below annual production rates because the production capability (as a percentage of remaining reserves) of reservoirs tends to decline with their age,* and a rate of reserve additions that is below replacement levels will lead to an increasing average age for U.S. gas reservoirs.[11]

It is important to note that the balance between demand and supply will also play a critical role in determining the R/P. Because the purpose of this evaluation is to examine the potential for gas supply *if gas is highly sought after*, gas production—and, consequently R/P—is assumed to be based on a supply-limited situation.** This situation would tend to intensify the incentives to develop fields rapidly and to maximize production (minimize R/P). Rapid field development should not be expected, however, if the current gas "bubble" of oversupply continues. In this case, field development and production are likely to be slowed.

In conclusion, expected R/Ps in 15 to 20 years may range from values below today's levels—perhaps 7.0, or even somewhat lower—to levels slightly higher than today's—perhaps 9.5. Part of the future trend will be caused by the geologic nature of new discoveries and their geographic environment. These factors can be manipulated somewhat but are more likely to be imposed by the random success of future exploration. Because the R/P is also strongly affected by the willingness to drill development wells and to take other (expensive) production-enhancing measures, large increases in gas prices would tend to drive the R/P down to its lower limit. The lower value obviously can occur only with high gas demand, an assumption of this study. If gas demand were poor, the R/P could exceed 9.5 for a while. Eventually, however, the lack of exploration incentives would move proved reserves back into balance with production requirements.

Production Scenarios

Table 17 summarizes the ranges of reserve additions and R/P's projected for Lower 48 natural gas development, Tables 18 and 19 present production and reserves projections that represent the two extremes of the ranges in table 17. The first projection assumes an optimistic exploration future and rapid production of newly found reserves—predicated upon high gas prices, high demand, and an avoidance of large reserve additions in low-permeability areas that are hard to develop rapidly. The second projection assumes low finding rates and an increase in low-permeability reserves where production rates are limited. Because each projection represents a convergence of events of relatively low probability—e.g., the lowest rates of new field discoveries, extensions and new pool discoveries, zero revisions, and an upturn in R/P—the projections should be viewed as approximately bounding the range of production and proved reserve levels, rather than as identifying likely values.

[10] E.F. Hardy and C. p. Neill, testimony to the Subcommittee on Fossil and Synthetic Fuels, Committee on Energy and Commerce, U.S. House of Representatives, June 1, 1981.

*Up to a point. During the last few years of a reservoir's life, its R/P must decrease because, in the last year, it will be 1.0. The last year's production will use up the entire remaining reserve.

[11] Ibid.

**That is, a situation where additional supplies at prevailing prices would be easily absorbed.

Table 17.—Summary of Projections of Components of Reserve Additions and R/Ps

New field discoveries	1983-85	2.0-3.5 TCF/yr
	1986-2000	1.5-3,5 TCF/yr
Extensions and new pool discoveries	1983-85	8.0-12 TCF/yr
	1986-2000	6,0-11 TCF/yr
Revisions	1983-2000	0-2.0 TCF/yr
R/P	2000	7,0-9.5
Scenario 1A: reserve additions	1983-85	17.5 TCF/yr
	1986-2000	16.5 TCF/yr
R/P	2000	7.0
Scenario 1B: reserve additions	1983-85	10.5 TCF/yr
	1986-2000	7.5 TCF/yr
R/P	2000	9.5

SOURCE Office of Technology Assessment

Table18.— Lower 48 States Natural Gas Production and Reserves 1981-2000 (in TCF)
SCENARIO 1A: Optimistic Exploration, Rapid Production

Year	Production	Reserve additions	Proved reserves	R/P[a]
1981 (actual)	18.5	21.5	168.6	9.0
1982 (approximate)	17.3	19.2[b]	170,7	9.75
1983	18.0	17,5	170,2	9.50
1984	18.9	17,5	168,8	9.0
1985	19.2	17.5	167.1	8.8
1986	19,4	16.5	164.2	8.6
1987	19.3	16.5	161.4	8.5
1988	19.5	16,5	158,4	8.3
1989	19.6	16,5	155,3	8.1
1990	19.4	16,5	152.4	8.0
1991	19,3	16.5	149.6	7.9
1992	19,2	16.5	146.9	7.8
1993	19,1	16.5	144.3	7.7
1994	19.0	16.5	141.8	7.6
1995	18.9	16,5	139.4	7.5
1996	18.8	16.5	137,1	7.4
1997	18.8	16.5	134.8	7.3
1998	18.7	16.5	132.6	7,2
1999	18,7	16.5	130,4	7.1
2000	18.6	16.5	128.3	7,0

Cumulative production after 1982 = 342.4 = 44% of USGS remaining resource.

[a] R/P calculated by dividing previous year's (yearend) reserves by production in the listed year
[b] American Gas Association "Preliminary Findings Concerning 1982 Natural Gas Reserves," *Energy Analysis*, Apr 29, 1983

SOURCE Office of Technology Assessment

Table 19.–Lower 48 States Natural Gas Production and Reserves 1981-2000 (in TCF)
SCENARIO 1 B: Pessimistic Exploration, Slowed Production

Year	Production	Reserve additions	Proved reserves	R/P[a]
1981 (actual).	18.5	21.5	168.6	**9.0**
1982 (approximate).	17,3	19.2[b]	170.7	**9.75**
1983	18.0	10.5	163.2	**9.50**
1984 .., ...	18.1	10.5	155.6	**9.3**
1985	16.9	10.5	149.2	**9.2**
1986	16.4	7.5	140.3	**9.1**
1987	15.4	7.5	132.4	**9.1**
1988	14.6	7.5	125.3	**9.1**
1989, ...	13.8	7.5	119.0	**9.1**
1990	12.9	7,5	113.6	**9.2**
1991	12.4	7.5	108,7	**9.2**
1992	11,8	7.5	104.4	**9.2**
1993	11,2	7.5	100.7	**9.3**
1994	10.8	7.5	97.4	**9.3**
1995	10.5	7.5	94.4	**9.3**
1996	10,0	7.5	91.9	**9.4**
1997	9.8	7.5	91.9	**9.4**
1998	9.5	7.5	87.6	**9.4**
1999, ...,.., ...	9.2	7.5	85.9	**9.5**
2000	9.0	7.5	84.4	**9.5**

Cumulative production after 1982 = 230 TCF = 300/0 of USGS remaining resource.

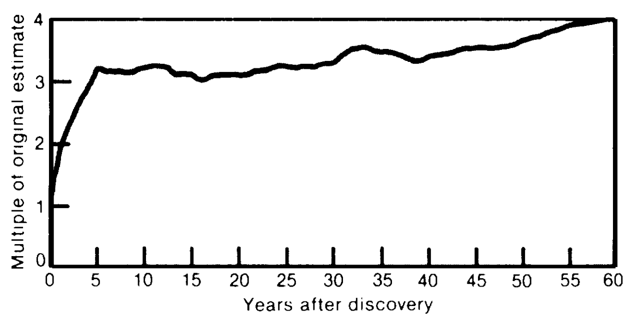
[a]R/P calculated by dividing previous years (yearend) reserves by production In the listed Year
[b]American Gas Association Preliminary Findings Concerning 1982 Natural Gas Reserves, *Energy Analysis* Apr 29 1983
SOURCE Office of Technology Assessment

APPROACH NUMBER 2–PROJECTING NEW POOL DISCOVERIES, EXTENSIONS, AND REVISIONS AS A SINGLE GROWTH FACTOR

The preceding approach is designed to allow a projection of future gas reserves based on separate estimates of new field discoveries, extensions, new pool discoveries, and revisions. An alternative method is to project only new field discoveries and apply a "growth factor" to these discoveries that combines the effects of the other three categories of reserve additions.

USGS has used afield-growth approach to calculate the amount of gas remaining to be discovered in the inventory of identified fields.[12] In that application, a curve was constructed that alescribes the reserve growth in initial discoveries that occurs after the year of discovery, averaged over all discovered fields nationwide and over 9 of the 14 discovery years where appropriate data were available (1966-79). This curve, illustrated in figure 23, shows a 60-year growth in reserves to about four times the initial (discovery year) estimate of gas volumes discovered. The curve shows that most of this growth occurs in the first 5 years

Figure 23.—The Growth of Year-of-Discovery Estimates of the Amount of Recoverable Natural Gas Discovered in the Lower 48 States



SOURCE: D. H. Root, "Estimation of Inferred Plus Indicated Reserves for the United States," app. F in *Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States*, U.S. Geological Survey Circular 860, 1981.

after the discovery year. In the USGS calculation, the curve was applied to the initial discoveries reported in every discovery year, assuming that reserve growth patterns of recently discovered fields would be the same as the patterns of much older discoveries. The gas volumes calculated in this manner—gas that is difficult to classify as

[12]U.S. Geological Survey Circular 860, app. F.

discovered or undiscovered—are called "inferred reserves" by USGS.

This method may be extended to project how the first-year estimates of reserve additions from future new field discoveries will grow in the years following the discovery year. However, certain adjustments have to be made. First, a growth factor calculated by tracking "initial discoveries" data must be increased if it is to apply directly to new *field* discovery data. This is because the discovery data[13] includes not only new field discoveries, but also "certain hydrocarbon accumulations which are significant from the standpoint that advances in exploration technology resulted in the discovery of such reservoirs."[14] Consequently, the year-of-discovery values are larger than those of "new field discoveries, " and the later expansion is lower because some technology-based expansions are excluded. Adjusting the calculated growth factor to account only for growth of new fields may raise the factor by about **20** percent.

Second, for the method to be credible, the assumption that the historical growth curve will continue to be valid must be relaxed somewhat. Many of the factors affecting the growth of recoverable reserves in newly discovered fields have changed; consequently, it appears likely that the growth curve has changed as well. The development of a credible forecasting procedure depends on defining a new curve or family of curves that logically fit these changed conditions.

Table 20 lists the arguments—some speculative—that support an increase or decrease (over historical levels of field growth) in the ultimate magnitude of reserve growth in new fields. *

USGS's estimate is not the only available estimate of field growth. Table 21 presents three other estimates, with ultimate growth ranging from 3.5 to 6.3 times the initial year-of-discovery estimate.

[13]The data came from table XIV of *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada*, vols. 21-34, 1966 through 1979, American Gas Association/American Petroleum Institute/Canadian Petroleum Association.

[14]Ibid.

[15]Robert Paszkiewicz, Jensen Associates, personal communication.

*These conditions are the same as those affecting revisions, extensions, and new pool discoveries.

Table 20.—Arguments[a] for the Question, "Will the Reserve Growth in New Fields Be Larger or Smaller Than the Growth Recorded in Previously Discovered Fields?"

A. New fields will grow more

1. Recent increases in real gas prices are leading to greater recovery factors for gasfields—from closer spacing of development wells, extensions into less-permeable margins of reservoirs, exploitation of smaller pools, lowering of abandonment pressures, and reworking of older wells. Together, they increase the ultimate recovery (reported cumulative production at field abandonment).
2. The historical growth factor does not accurately reflect the actual field growth. The large negative revisions in onshore south Louisiana and Texas have artificially depressed reported field-growth rates, Because these revisions were due to a unique set of circumstances, they are unlikely to recur, and reported growth rates should increase.

B. New Fields Will Grow Less:

1. Part of the reason that the levels of new field discoveries reported by EIA were higher than those reported by AGA during the 3 years the two reports overlapped is probably that EIA reported reserve additlons during the discovery year that AGA did not report until the second year, Therefore, when EIA-reported trends are used to project future new field discoveries, the growth factor used should be smaller than the historical average, which was derived from AGA data
2. The historical growth factor was derived from data developed during a time when giant gasfields dominated gas reserves, Giant fields with multiple pools take many years to develop and are generally believed to have greater relative growth than small fields. Present and future field sizes will be smaller and should be expected to have smaller growth factors and faster development,
3. Improvements in seismic and other exploration technology, as well as in reservoir engineering, allow clearer initial delineation of field boundaries and other field characteristics and more accurate first-year reserve estimates, This should leave less room for growth.
4. Increased gas prices have led to acceleration of field development. Some of the development that might previously have taken place in the second year now takes place in the first year and is reported as part of the initial new field discovery reserve data
5. High capital requirements to develop new fields in hostile environments—an increasing feature of today's resource base— require a more accurate first-year estimate of reserves, leading to lower "growth" later on.

[a]Some of these arguments are speculative For example, in B 1 OTA has not determined the cause of the AGA/EIA differences in reported new field discoveries

SOURCE Office of Technology Assessment

In order to use the "growth-factor" approach to project future gas production, Jensen Associates, Inc., an OTA contractor, constructed a simple model that applied growth curves similar to

Table 21.—Alternative Estimates of Growth Factors for Initial Reserve Estimates for Gasfields

Author	Suggested growth factors
1. USGS (Root) (1981)	4.0, all fields
2. Haun (1981)	4.0, fields younger than 48 years 5.0, fields older than 48 years
3. Hubbert (1974)	3.5, all fields
4. Marsh (1971)	5.0, fields younger than 28 years 6.3, fields older than 28 years

1 D H Root, "Estimation of Inferred Plus Indicated Reserves for the United States," app F in G L Dolton, et al, *Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States*, U S Geological Survey Circular 660, 1981
2 J D Haun, "Future of Petroleum Exploration in the United States," *AAPG Bulletin 656(10), 1981*
3 M K Hubbert, "U S Energy Resources, A Review as of 1972," S Res 45, ser No 93-40 (92.75), Committee on Interior and Insular Affairs, U S Senate 1974, cited in Haun, ibid
4 G R Marsh, "How Much 011 Are We Really Finding" *Oil and Gas Journal*, Apr 5, 1971, cited in Haun, op cit

SOURCE Office of Technology Assessment

that in figure 23 to both known fields and to projected levels of new field discoveries. A growth curve that reached a factor of 4.0 in 60 years was applied to all pre-1982 discoveries, while curves with 30-year growth periods were applied to discoveries from 1982 on. The period of 30 years was selected to reflect OTA's belief that the pace of field development has quickened. The choice is a guess because data sufficient to calculate a new timetable are not available. The uncertainty in the ultimate value for the growth factor is reflected in a range of values from 3.0 to 5.0. In OTA's opinion, 5.0 represents an optimistic upper-bound on future growth in new fields.

Tables 22 through 24 present the results of three scenarios representing the search for reasonable upper- and lower-bounds on future gas production.* For each scenario, the "growth-curve" methodology was applied only to nonassociated gas. Associated gas was projected separately by applying a gas-to-oil production ratio of 1.3 MCF per barrel of crude oil to the EIA's 1981 oil production forecast.[16]

*The production projections in the three tables should be viewed as slightly pessimistic. This is because they are based on projected 1982 nonassociated reserve additions of 8.7- 10.2 TCF, whereas preliminary reports (based on the annual reports of the major oil and gas companies) indicate that actual 1982 additions may have been significantly higher, perhaps as high as 15 or 16 TCF.

[16]U. S, Department of Energy, 1981 *Annual Report to Congress*, vol. 3, p. 62.

Table 22.–Lower 48 States Natural Gas Production and Reserves, 1982-2000 (in TCF)–Scenario 2A: Very Optimistic[a]

Year	Total gas production	Nonassociated gas: Production	Nonassociated gas: Reserve additions	Nonassociated gas: Proved reserve	Nonassociated gas: R/P	Assoc./dissolved gas[b] production
1982	18.7	15.7	10.2	132.8	8.8	3.0
1983	18.2	15.3	11.7	129.2	8.7	2.9
1984	18.0	15.2	13.0	127.0	8.5	2.9
1985	18.0	15.2	14.8	126.6	8.3	2.8
1986	18.3	15.5	15.5	126.7	8.2	2.8
1987	18.6	15.8	15,8	126.6	8.0	2,7
1988	18.9	16.2	15,9	126.3	7.8	2,7
1989	19,3	16.5	16,0	125.7	7.6	2.7
1990	19,5	16.8	16.0	124.9	7.5	2.7
1991	19,7	17.1	16,1	123.9	7,3	2.6
1992	19,8	17.3	16,2	122.8	7.2	2.6
1993	19.8	17.3	16,2	121.7	7.1	2.5
1994	19,7	17.2	16,3	120.8	7.1	2.5
1995	19,6	17.2	15,3	119.0	7.0	2.4
1996	19.3	16.9	15.4	117.4	7.0	2.4
1997	19.1	16,8	15.4	116.0	7.0	2.4
1998	19.0	16.6	15.4	114.8	7.0	2.3
1999	18.8	16.5	15.5	113.8	7.0	2.3
2000	18.7	16.4	15.5	112.9	6.9	2.3

Cumulative production after 1982 = 342.4 TCF = 44°/0 USGS remaining resource.

Note Rows and columns may not add exactly due to rounding
[a]Assumptions Nonassociated gas new field discovery rate = *3,000* BCF/yr
Growth factor = 50
Additional growth from price rises for old gas = 1000 BCF/yr from 1985 to 1995
[b]Associated/dissolved gas—gas found in the same reservoir with oil

SOURCE Jensen Associates Inc contract submission to the Office of Technology Assessment, 1983

Table 23.— Lower 48 States Natural Gas Production and Reserves, 1982-2000 (in TCF)— Scenario 2B: Pessimistic[a]

Year	Total gas product ion	Nonassociated gas Product ion	Reserve additions	Proved reserve	RIP	Assoc./dissolved gas[b] production
1982	18.7	15.7	8.7	131,3	8.8	3.0
1983	18,0	15.1	8.4	124.6	8.7	2.9
1984	17.4	14,6	8.3	118.4	8.5	3.0
1985	16.9	14,1	8.3	112,6	8.4	2.8
1986	16,4	13.6	8,2	107.2	8.3	2.8
1987	15.9	13.2	7,6	101.7	8.1	2,7
1988	15.4	12.7	7.6	96.6	8.0	2,7
1989	15,0	12.3	7,7	92.0	7.9	2.7
1990	14.6	11,9	7,7	87.7	7.7	2,7
1991	14.2	11,6	7.7	83.8	7.6	2,6
1992	13.8	11.2	7.7	80.3	7.5	2.6
1993	13,4	10.9	7,7	77.1	7,4	2.5
1994	13.0	10,5	7.7	74.4	7.3	2,5
1995	12.6	10,2	7.2	71.4	7.3	2.4
1996	12,2	9.8	7.2	68.8	7.3	2.4
1997	11.8	9.5	7.1	66.5	7,3	2.4
1998	11,5	9.2	7.1	64.4	7.2	2.3
1999	11,2	8.9	7.1	62.6	7.2	2,3
2000	11.0	8.7	7.1	61.0	7,2	2.3

Cumulative production after 1982 = 254 TCF = 330/0 USGS remaining resource.

Note Rows and columns may not add exactly due to rounding
[a]Assumptions Nonassociated gas new field discovery rate 1,500 BCF/yr
Growth factor 40
Additional growth from price rises for old gas 500 BCF/yr from 1985 to 1995
[b]Associated dissolved gas–gas found in the same reservoir with oil

SOURCE Jensen Associates Inc contract submission to the Office of Technology Assessment, 1983

Table 24.–Lower 48 States Natural Gas Production and Reserves, 1982-2000 (in TCF)– Scenario 2C: Very Pessimistic[a]

Year	Total gas production	Nonassociated gas Production	Reserve additions	Proved reserve	R/P	Assoc./dissolved gas[b] production
1982	18.5	15.5	8.7	131.3	8.9	3.0
1983	17,7	14.8	8.0	124.7	8.9	2.9
1984	16.9	14.0	7.5	118.1	8.9	2.9
1985	16.1	13.3	6.4	111.2	8.9	2.8
1986	15.3	12,5	6.1	104.9	8.9	2.8
1987	14.5	11.8	5.4	98.5	8.9	2.7
1988	13.8	11.1	5.4	92.8	8.9	2.7
1989	13,1	10.4	5.4	87.9	8.9	2.7
1990	12.5	9.9	5.5	84.4	8.9	2.7
1991	12.0	9.4	5.5	79.6	8.9	2.6
1992	11,5	8.9	5.5	76.1	8.9	2.6
1993	11.1	8.6	5.5	73.1	8.9	2.5
1994	10.7	8.2	5.6	70.5	8.9	2.5
1995	10,4	7.9	5.6	68.1	8.9	2.4
1996	10.1	7.7	5.5	66.0	8.9	2.4
1997	9.8	7,4	5.5	64.1	8.9	2.4
1998	9,5	7.2	5.5	62.4	8.9	2.3
1999	9.3	7.0	5.5	60.9	8.9	2.3
2000	9.1	6.8	5.5	59.6	8.9	2.3

Cumulative production after 1982 = 223.4 TCF = 29% USGS remaining resource.

Note Row; and columns may not add exactly due to rounding
[a]Assumptions Nonassociated gas new field discovery rate = 1,500 BCF/yr
Growth factor = 30
No additional growth from price rises for old gas
[b]Associated/dissolved gas—gas found in the same reservoir with oil

SOURCE Jensen Associates, Inc., contract submission to the Office of Technology Assessment, 1983

APPROACH NUMBER 3–REGION-BY-REGION REVIEW OF RESOURCES AND EXPLORATORY SUCCESS*

Using a region-by-region review to project future gas production involves a geologist's examination of a variety of factors affecting production in 10 individual regions of the Lower 48 States and his subjective evaluation of their future production potential.

For this approach, the gas resource base was assumed to be a compromise between the assessments of USGS and PGC. For each region, a resource value was selected by examining the field size and number implications of the two assessments and choosing the value that seemed more realistic. Then, future additions to proved reserves were estimated, based on a subjective evaluation of the following factors:

- *Difficulty and expense of development.* —Based on expected field sizes, depths, known geology.
- *Announced leasing schedules.*
- *"Maturity" of province.* —The percent of total expected resources that have already been developed.
- Recent development *history.* —Especially, the rates of entry into proved reserves of the remaining resources.

For each region, it was generally considered unlikely that a very high percentage of the remaining undiscovered resource—say, **50** percent or greater—could be transferred into proved reserves by **2000,** and this situation acted as a strict limit on production in some regions, for example, in the "west Texas and eastern New Mexico" region. * *

Tables 25 and 26 present two scenarios of future gas production and reserve additions based on the above approach. Scenario 3A projects that one-

*The analysis described in this section was performed by Joseph P. Riva, Jr., Specialist in Earth Sciences, Congressional Research Service (CRS). Riva's full report, which is part of CRS's participation in this study, will be incorporated in a background document to this technical memorandum.

* ● To stabilize current gas production to the end of the century in this region, *96* percent of the estimated undiscovered gas in the region would have to be discovered by *2000.* From 1970 to 1981, 23 percent of the inferred reserves plus undiscovered resources were added to reserves.

Table 25.—Lower 48 States Natural Gas Production and Reserves, 1982-2000 (in TCF)—Scenario 3A

Year	Production	Reserve additions	Proved reserves	R/P
1981.	18.5	21.6	168.6	9
1982	18.6	10.9	160.9	9
1983 ...., ...	17.6	10.9	154.2	9
1984 ..., ...	16.8	11.2	148.5	9
1985, ...	16.1	11.2	143.5	9
1986	15.7	11.2	139.0	9
1987	15.3	11.2	135.0	9
1988 .., ...	15.1	11.2	131.0	9
1989, ...	14.7	11.2	127.4	9
1990 ...., ...	14,5	11.2	124,1	9
1991 .., ., ...	14.3	11.2	121.0	8
1992	14,2	11,2	118.0	8
1993 ....., ...	14.0	11.2	115.2	8
1994 ..., ...	13.7	**10.1**	111.6	8
1995 ...., ...	13,5	10.1	108.2	8
1996 ...., ...	13.4	10.3	105.1	8
1997	13.3	10.3	102.1	8
1998 ......, ...	13.0	10.3	99.4	8
1999	12.8	10.3	97.0	8
2000	12.6	10.3	94.6	8

Cumulative production after 1982 = 260.6 = 34°/0 USGS remaining resource.

SOURCE J P Riva, Jr *A Projection of Conventional Natural Gas Production in the Lower 48 States to the Year 2000* Congressional Research Service/Library of Congress, June 10. 1983

Table 26.— Lower 48 States Natural Gas Production and Reserves, 1982-2000 (in TCF)—Scenario 3B

Year	Production	Reserve additions	Proved reserves	R/P
1981	18.5	**21.6**	**168.6**	9
1982	18.7	**12.1**	**161.9**	9
1983 ...., ...	18.0	**12.1**	**156.0**	9
1984	17.3	**12.1**	**150.8**	9
1985, ...	16.8	**12.1**	**146.1**	9
1986. , ...	16,2	**12.1**	**142.0**	9
1987	15.8	**12.1**	**138.3**	9
1988, ...	15.4	**12.1**	**135.0**	9
1989, ...	15.0	**12.1**	**132.1**	9
1990. , ...	15.1	**12.1**	**129.1**	8.5
1991 .., ...	15.6	**12.1**	**125.5**	8
1992 ..., ...	15.7	**12.1**	**121.9**	8
1993 ..., ...	15,2	**12.1**	**118.8**	8
1994	14.8	**12.1**	**116.0**	8
1995 ...., ...	14.5	**12.1**	**113.6**	8
1996	14,2	**12.1**	**111.5**	8
1997	13.9	**12.1**	**109,7**	8
1998	13.7	**12.1**	**108.0**	8
1999 ...., ...	13,5	**12.1**	**106.6**	8
2000	13.3	**12.1**	**105.4**	8

Cumulative production after 1982 = 274 = 35°/0 USGS remaining resource.

SOURCE J P Riva, Jr A *Projection of Conventional Natural Gas Production in the Lower 48 States to the Year 20@* Congressional Research Ser. vice/Library of Congress, June 10, 1983 quarter of the gas estimated to be available in undiscovered fields at the end of 1981 will be discovered by 2000. This compares to 55 percent of the undiscovered gas being discovered between 1945 and 1981, a period when larger prospects were available, but also when gas discovery rates may have been hampered by low regulated prices. In this scenario, gas production is projected to increase in the Rocky Mountains and Great Plains region, the Eastern Interior region, and the Appalachian region; in addition; production begins in Oregon-Washington and on the Atlantic continental shelf. However, major production decreases are projected for west Texas and eastern New Mexico, the midcontinent, and the gulf coast, all critical gas producers today.

Scenario 3B assumes that exploration becomes more efficient and that 35 percent of the resources in undiscovered fields can be discovered by 2000. Even under this more optimistic scenario, however, gas production will decline to 13.3 TCF by **2000.**

APPROACH NUMBER 4–GRAPHING THE COMPLETE PRODUCTION CYCLE

Projecting future gas production by graphing the complete production cycle is based on the expectation of M. King Hubbert that the complete cycle of production will somewhat resemble a bell-shaped curve and that knowing the area under the curve-the total recoverable resource—allows a reasonable facsimile of the entire curve to be drawn, once about a third or more of the production cycle has been completed. Hubbert used this approach in 1956[17] to show that then-current estimates of the remaining oil resource base implied that oil production was on the verge of peaking and then declining.

In this application, gas production values for 1900-82 were plotted, and three freeform curves were extended from the 1982 production rate such that the area under the curves equaled the remaining gas resources estimated by, respectively, Hubbert, USGS, and PGC (see table 5). These curves are shown in figure 24.

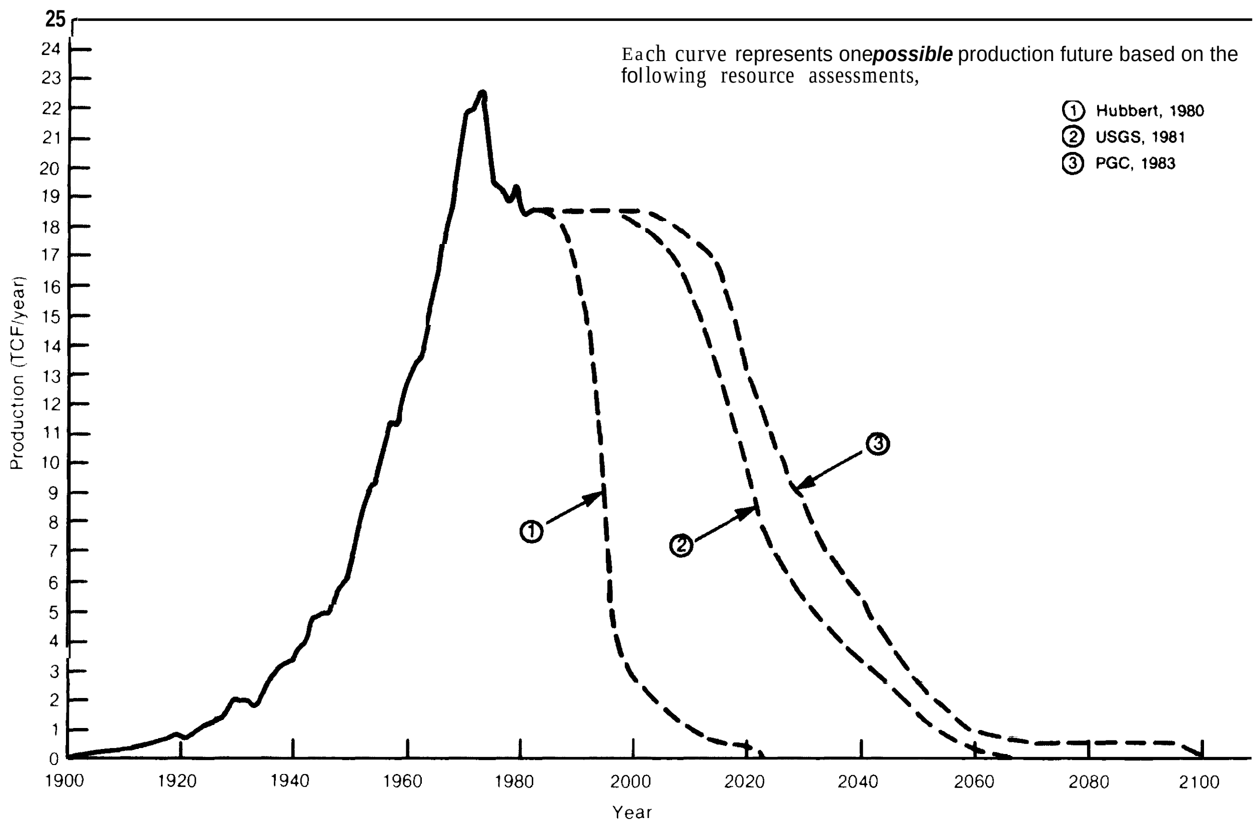
The curves show that Hubbert's assessment implies an extraordinarily sharp decline in production, so that by 2000 the total Lower 48 production rate would be about 3 TCF. Since there is little flexibility in drawing this curve, it appears unlikely that the range of uncertainty due to the selection of the curve's shape is greater than about **2 to 5** TCF in 2000.

The curves representing the USGS and PGC gas resource assessments were drawn so that the declining portion of the curve resembles a mirror image of the ascending portion. Both curves show production rates staying steady at least until 2000. A plausible physical interpretation of the curves is that they represent a resource base that still retains a substantial number of large fields amenable to rapid rates of production. Furthermore, the shape of the curves is clearly alined with high demand for gas and prices that encourage substantial development drilling as well as vigorous exploratory efforts.

The USGS and PGC curves obviously can be redrawn to reflect different conceptions of how the production cycle might unfold. However, the necessity of maintaining existing production trends in the early years and of tapering-off gradually as the resource is depleted limits the options. Figure 25 shows the original USGS curve and a second curve that reflects a different conception, that of a production decline that commences earlier but proceeds at a more gradual rate. This second curve might reflect a future where industrial demand for gas declines and exploratory activity and development drilling proceed at a lower level, It might also reflect a resource base whose fields are smaller, in more difficult to develop locations, and of lower average permeability.

[17] M K Hubbert, Nuclear Energy and Fossil Fuels, " in American **Petroleum** Institute, *Drilling and Production Practice* (1956), cited in M. K Hubbert, "Techniques of Prediction as Applied to the Production of Oil and Gas," *Oil and Gas Supply Modeling*, S. I. **Gass** (ed.), National Bureau of Standards Special Report 631, May 1982.

Figure 24.— Future Production Curves for Conventional Natural Gas in the Lower 48 States



SOURCE: Office of Technology Assessment.

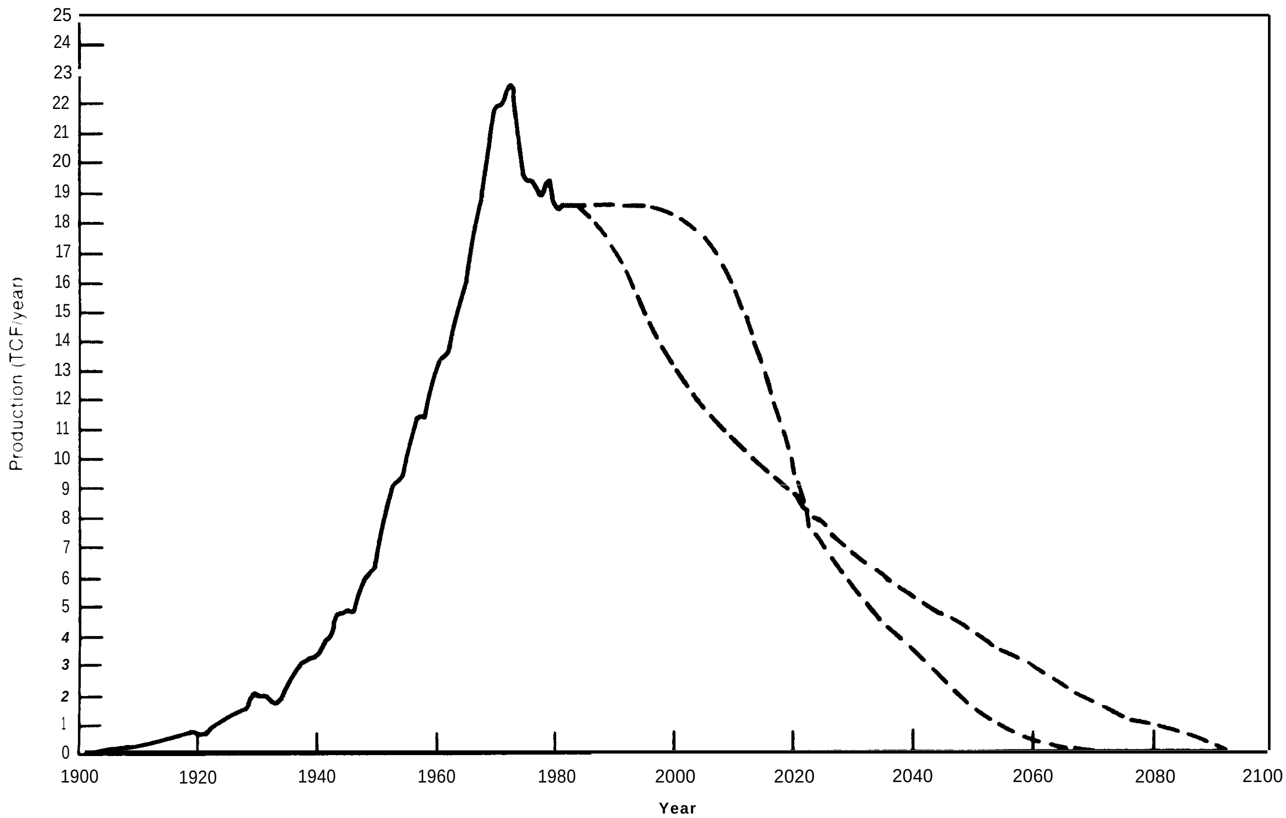
A RANGE FOR FUTURE GAS PRODUCTION

In comparing figures 24 and 25 to the production projections produced by the alternative methods, some interesting conclusions can be drawn. *First, the higher end of the production ranges, which shows essentially stable production levels out to 2000, appears to be quite compatible with the USGS and PGC curves,* as drawn in figure 24. It should be remembered, however, that there are interpretations of the detailed physical nature of the gas resource base that, while compatible with the *overall magnitude* and even the regional estimates of USGS or PGC, could be completely *incompatible* with the high year 2000 production projection. The second curve in figure 25 displays such an alternative interpretation, and there are more radical possibilities as well. *

*One such possibility would be a resource base that, while large, had most of its resources in hard-to-find, slow-to-produce fields. The future production "cycle" would then show a significant production drop in the next 20 to 30 years, followed by a very long period of low but stable production.

A second conclusion is that the lower end of the production range—about 9 TCF by 2000—is really much too optimistic for a believer of the Hubbert or RAND resource estimate. This is because the assumptions of the lower end of the range, while appearing to be pessimistic to a "resource optimist, " may actually appear somewhat optimistic to a "resource pessimist ." This end of the range assumes that the fairly low new field discovery rates of the early 1970's are more realistic as a long-term average than are the higher rates of the last few years, *but it ignores the possibility that even these low rates might go down still farther as resource depletion continues.* Consequently, the true production implication of

Figure 25. —Two Production Futures, One Resource Base: Alternative Representations of Future Production of Conventional Natural Gas in the Lower 48 States, Based on the USGS (1981) Resource Assessment (mean estimate)



SOURCE Office of Technology Assessment

the range of resource base estimates cited in table 5 is likely to be a year **2000** range of about 4 to 19 TCF rather than the range of 9 to 19 TCF expressed by the first three projection approaches. *

As discussed in chapter 4, OTA believes that the Hubbert and RAND estimates are overly pessimistic and that a more likely lower bound for the remaining recoverable gas resources is about 400 TCF rather than Hubbert's 244 TCF or RAND's 283 TCF. This higher value is compatible with a **2000** production rate of 9 TCF. Consequently, in our opinion, *a reasonable range for Lower 48 conventional natural gas production for the year 2000 is 9 to 19 TCF.* Similarly, *a reasonable range for 1990 is 13 to 20 TCF.*

Finally, figure 24 illustrates an important point about the current "optimistic" assessments of the recoverable resource base: that these, too, imply an inevitable decline in conventional gas production, although the date of decline is perhaps **20** or 30 years later than that dictated by a pessimistic (400 TCF) resource base assessment. It must be stressed, however, that the additional **20** years or so of leeway implied by the more optimistic assessments may yield sufficient changes in prices and technology to allow either or both the entry of nonconventional gas sources to the market and the movement of large amounts of conventional resources from "subeconomic" to "economic."

'It is important to remember that the kind of radical drop in production dictated by the most pessimistic of the resource base estimates will likely violate their baseline assumptions of maintenance of existing cost price relationships — except for Hubbert's assessment (Hubbert believes his methodolog, "captures" future changes in price cost relationships and technology). Although many present gas customers can switch without extreme difficulty to 011 products or to elect ricity (assure ing supplies of these are available), a rapid drop in production would still tend to push gas prices sharply upwards. This in turn would tend to increase the resource base by moving subeconom ic resources into the economic, recoverable category.

24-358 0 - 83 - 8

These potential sources of gas production are outside the boundaries of the resource base assessments and production forecasts discussed in this technical memorandum, but conceivably they could be extremely important to future U.S. gas production.

PUBLIC AND PRIVATE SECTOR FORECASTS OF FUTURE GAS PRODUCTION

Comparisons of alternative gas production forecasts have many of the same problems as those of comparing gas resource base estimates (see ch. 3, table 4). The economic, regulatory, and other "scenario" conditions assumed for the forecasts are not always made clear. Because the range of reasonable future values/assumptions for these conditions are so broad, it is probably safe to assume that there are major scenario differences between different forecasts. The resources measured may differ, with some forecasts including only "conventional" gas and others including all methane sources, especially gas from tight sands. The extent to which some of the commonly used resource base estimates (which are important variables in some of the forecasts, directly determining finding rates or defining an upper limit for cumulative discoveries) contain unconventional resources is not always clear. For example, the PGC acknowledges that as much as 20 percent of its estimated "potential resource" is in tight sands, 'a but other estimates do not specify such a percentage. Consequently, even the forecasters, themselves, do not always know how much tight gas is incorporated in their production forecasts. *

Table 27 presents the results of 21 public and private sector production forecasts of conventional Lower 48 gas production.** Four of the forecasts explicitly include tight sands and/or Devonian shale; these are noted on the table.

A striking feature of the table is that all but one of the forecasts project substantial declines in gas production, most within 10 years and all but the one "dissenter" by 1995. It is important to recognize that these forecasters include some prominent gas "optimists," including AGA. Consequently, much of the current optimism about gas's future apparently stems from projections of supplementary supply from unconventional sources, from Alaska, from Mexico and Canada, and from LNG imports. Chapter 6 provides a brief discussion of the potential from all of these sources except unconventional production. *

The extent of agreement about future gas production displayed in table 27 is in sharp contrast to the very wide range projected by OTA. For the year 2000, a range of 11 to 15 TCF/yr—an extremely narrow range, given different base assumptions, forecasting methods, etc.—would encompass 13 of the 14 estimates available for that date. In contrast, OTA believes that an appropriate range for year 2000 production is 9 to 19 TCF/yr. Part of this difference may be attributed to the fact that most of the values in the table represent forecasts of "most likely" gas production rates, and there may be a tendency for such estimates to cluster together. In conjunction with this possibility, a lack of documentation for many of the forecasts makes it unclear whether they are all independent, original estimates. Some may simply be averages of other forecasts, reflecting the "conventional wisdom. "

Of particular interest is a comparison of AGA's year 2000 estimate—12 to 14 TCF/yr—and the production implications of the AGA-supported PGC's gas resource assessment. PGC's assessment seems most compatible with production levels of 15 or 16 TCF/yr, or higher. If the AGA production forecast is intended to be associated with the PGC resource base, then AGA is using a most pessimistic interpretation of the resource base, at least

"Potential Gas Agency, News Release, Feb. *26, 1983.*

● Further, there may not be agreement as to what constitutes "tight gas. " For example, the Federal Energy Regulatory Commission includes a maximum permeability of 0.1 millidarcies in its definition, while the National Petroleum Council used 1 millidarcy as the limit in its report on unconventional gas sources.

*● Including associated 'dissolved gas (gas colocated with oil), on a dry basis.

● Unconventional gas potential will be discussed in the final report from this study.

Table 27.–A Comparison of Conventional Lower 48 Natural Gas Supply Forecasts (TCF)

Company	1985	1990	1995	2000
I. Gulf	19.4	18.8	16.7	13 8
2. Texaco	18.9	16.1	14.0	13.0
3. Chevron.	18,2	18.0	165	14.0
4. Exxon	—	14.6	—	14.1
5. Sheila..	17.0	13.9	11.5	8.9
6. Conoco[b]	19,0	18.0	—	14,6
7. Union.	19,2	18.0	—	—
9. Standard Oil (Indiana)[c]	18,5	17.7	16.5	15.5
10. Tenneco	18.0	15.4	13.5	11.9
11 AIR	15.5	13,6	—	—
12, AGE	16.0-18.0	15.0-17.0	13,5-15,5	12,0-14.0
13. GRI	17.9	15,1	12.8	116
14. DOC[c] ...	—	—	—	12.8
15. GAO	16.5	148	14.0	13.5
16. E. Erickson	17.4-18.5	—	—	—
17, ERA	17,3	149	14.0	—
18. ICF	16,1	14.3	12.4	—
19. IEA/OECD[b]	16.5-18.0	14,0-17.0	—	11-15
20. Chase Bank[b] .,	18,3	17,7	—	—
Average	18.1	16.6	153	143

aMarketed **gas** rather than actual total (dry) production Excludes increased production from fields that are 'forever controlled under NGPA and that Shell believes could be obtained with decontrol
bNumbers include tight sands
cAverages include Interpolated data

REFERENCES

1 Gulf 011 Corp , US Energy Analysis Task Group Pittsburg Pa *US Env(ronmenfa/Assessment 1982 Scenarios* June 1982 Business as Usual scenario(In eludes Lower 48 and southern Alaska)

'2 Texaco Inc Economics Division Finance and Economics Department, White Plains NY *United States* Energy *Outlook* 19802000 February 1981 (Forecast of Marketed Productlon)

"3 Standard 011 Co of California Economics Department San Francisco Calif Preliminary forecast from forthcoming publication

4 Exxon Co USA Houston Tex Energy *Outlook 1980-2000* December 1980

"5 Shell Oil Co Exploration and Production Economics Department Houston, Tex *National Energy Outlook to the Year 2000* July 1982 (Fall 1981 Analysis Dry Marketed Gas)

"6 Conoco Inc Coordinating and Planning Department Stamford Corm *World Energy Outlook* Through 2000 January 1982

"7 Union Oil Co 011 and Gas Division Planning and Valuation Los Angeles Calif

"8 Marathon 011 Co Economics Department Findlay Ohio

"9 Standard 011 Co (Indiana) Chicago Ill Amoco's forecast Includes nonhydrocarbon gases and is specifically done on a dry gas basis Its 1985 forecast number is demand-constrained

"1O Tennessee Gas Transmission Co Economic Analysis and Long Range Planning Department Houston Tex *Energy 1982-2000* August 1982

"11 American Natural Resources Co Detroit Mich *United States Energy Outlook* 1980.2000

12 American Gas Association Gas Supply Committee Arlington Va *The Gas Energy Supply Outlook 1980-2000* January 1982

"13 Gas Research Institute Washington DC ***Gas Research** Insights* October 1982

14 US Department of Commerce Washington DC *US Energy* for *the* Rest *of the* Century July 1982

15 General Accounting Office Washington DC *Analysis of* Current *Trends in US Petroleum* and *Natural Gas Production.* Dec 7 1979

16 Dr Edward W Erickson for Natural **Gas** Supply Association *Natural Gas Policy Act A Pragmatic Analysis* January 1981

17 Energy Information Administration US Department of Energy Washington DC *1981 Annual Report to Congress.* February 1982

18 ICF Inc Washington DC "The Economics of Gas Supply" **as** published in *The Energy Journal,* vol *3, No 4* October 1982

19 international Energy Agency OECD *World Energy Outlook,* Paris 1982

20 Chase Manhattan Bank Energy Economics Division New York Best estimate forecast from forthcoming publication

SOURCE Jensen Associates Inc *Understanding* Natural Gas *Supply* In the *United States* Contractor Report to the Office of Technology Assessment April 1983

from the standpoint of maintaining production rates at high levels during the next few decades.

OTA undertook to evaluate and compare both the general methodologies associated with these forecasts and, in a few cases, the specific assumptions and methodological decisions made by individual forecasters. However, many of the forecasts are based, in large part, on proprietary information, and needed details were unavailable. Also, several of the forecasts made by the large energy companies depend heavily on judgmental procedures rather than on formal computerized models, and these forecasts would have been difficult to document and evaluate even if the companies had desired public scrutiny of this sort. In addition, several of the models ostensibly available for public scrutiny do not, in fact, have adequate documentation. A background document to this report will present OTA's staff review of modeling methodologies and of some specific models. The document will also present a review of modeling methodology by James Jensen, president of Jensen Associates, an OTA contractor.