The Intricate Puzzle of Oil and Gas "Reserves Growth"

by David F. Morehouse

Developing the Nation's discovered oil and gas resources for production is a complex process that is often characterized by initial uncertainty as regards the ultimate size or productive potential of the involved reservoirs and fields. Because the geological and hydrological characteristics of the subsurface cannot — for the most part — be directly accessed, indirect techniques and procedures must be used to develop estimates of the size and recoverability of these discovered resources. While new or improved technologies that allow more accurate assessment of the involved parameters have, over time, lessened some of the risks associated with the in-field exploration and development process, significant uncertainties nevertheless remain. Estimates of proved reserves and ultimate recoveries during the early years of a field's or a reservoir's productive life span are, as a result, generally conservative.[1]

Estimates of the volumes that will ultimately be produced from reservoirs and fields tend on average to increase substantially over time. Rather than the discovery of new fields, it is this phenomenon — the increase of estimates of ultimate recovery from a field or group of fields over time due to the extension of proved reservoir area(s), in-field discovery of one or more new reservoirs, and several other factors - - that accounts for the majority of both current domestically-sourced oil and gas supplies and current additions to domestic proved oil and gas reserves. This phenomenon is often called "reserves growth," a colloquial label which is not accurately descriptive of what is actually happening.[2] This article therefore uses the older, more accurate label "ultimate recovery appreciation" (URA) to refer to the phenomenon.

Despite its recognized importance to current domestic oil and gas supply, and its even greater apparent importance to future domestic oil and gas supply, the URA phenomenon is not well understood, and therefore cannot be reliably forecast. Knowledge of how the domestic "inventory" of oil and gas is likely to change over time is a critical input to future energy-related decisions that will be made by individuals, industries, and government policy makers. For that reason the United States Geological Survey (USGS) considers analysis of URA "arguably the most significant research problem in the field of hydrocarbon resources assessment."[3]

This article begins with a background discussion of the methods used to estimate proved oil and gas reserves and ultimate recovery, which is followed by a discussion of the factors that affect the ultimate recovery estimates of a field or reservoir. Efforts starting in 1960 to analyze and project ultimate resource appreciation are then briefly discussed, as are future directions for research regarding the analysis and projection of ultimate recovery appreciation. The terms "estimated ultimate recovery" and "ultimate recovery appreciation" are used throughout the article. They are defined as follows:

- "Estimated ultimate recovery" (EUR) is the sum of the estimate of proved reserves at a specific time and cumulative production up to that time.

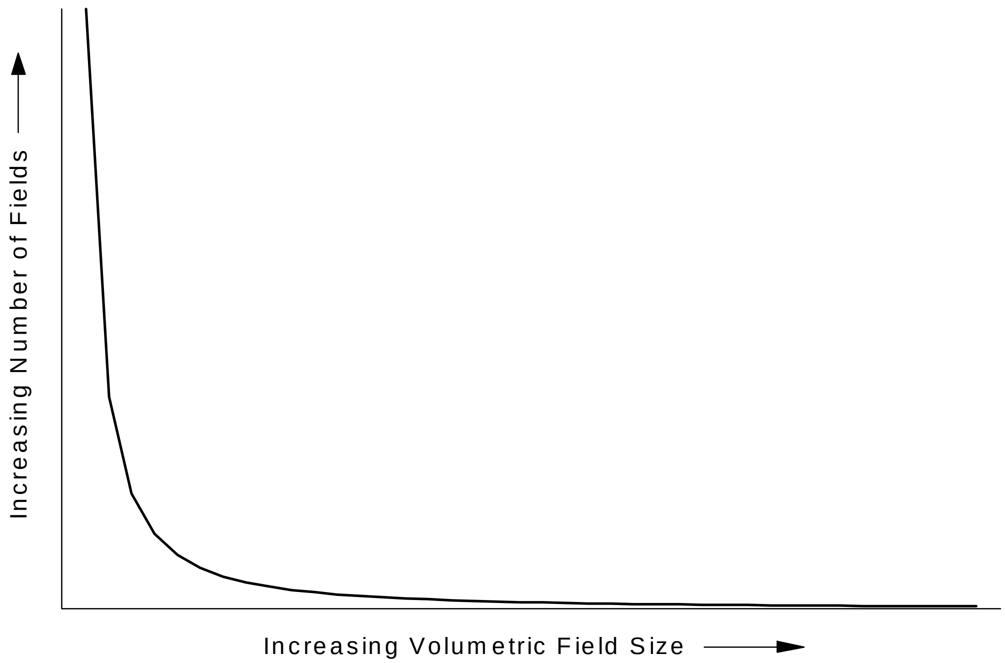
- "Ultimate recovery appreciation" (URA) is the generally observed increase of EUR over time.

Background

A basic rule of thumb in the upstream (or producing) sector of the oil and gas industry is that the best place to find new crude oil or natural gas is near where it has already been found. That is precisely what the industry does most often, for a sound business reason: the financial risk of doing so is far lower than that associated with drilling a rank wildcat hole in a prospective, but previously unproductive, area. On the other hand, there is a definite tradeoff of reward for risk. The returns on drilling investment become ever leaner as more wells are drilled in a particular area because the natural distribution of oil and gas field volumes tends to be approximately log-geometric (or J-shaped as in Figure FE1). There are only a few large fields, whereas there are a great many small ones.[4]

Historically, the largest fields within a given prospective area (and, implicitly, the largest reservoirs within them) are discovered early-on, if for no other reason than that they are most often areally broader targets which even randomly placed boreholes would penetrate early-on. The "biggest found first" phenomenon is clearly evidenced in the oil and gas record of the United States, which is by far the most thoroughly explored oil and gas productive area on Earth. Subsequent to success of the first modern oil well drilled in 1859 in Pennsylvania, randomly sited drilling, and then drilling increasingly

Figure FE1. Approximately Log-Geometric Field Size Distribution



Source: Energy Information Administration, Office of Oil and Gas.

guided by the new and rapidly evolving scientific disciplines of petroleum geology and geophysics, quickly resulted in large domestic discoveries.

The 1930s was, in hindsight, the peak decade of U.S. crude oil discoveries, while the 1950s was the peak discovery decade for natural gas. The peak discovery year for crude oil was 1967, due entirely to discovery of the Prudhoe Bay Field on the North Slope of Alaska. Had the Prudhoe Bay Field not been discovered, the peak year of crude oil discoveries would have been 1930 when the East Texas Field was found. The peak discovery year for natural gas was 1922 when the Hugoton Field was discovered in southwestern Kansas and the adjacent portions of Oklahoma and Texas.[5] These peak decades resulted in the discovery of fields that jointly account for about 20 percent and 14 percent of the *present* estimates of ultimate recovery for domestic crude oil and natural gas, respectively.[6]

All domestic oil and gas drilling took place onshore in the lower 48 States prior to the 1930s. As applicable technologies originated and advanced and individuals or firms became willing to shoulder a greater risk in search of a greater reward, exploration began to occur in prospective areas that were more environmentally harsh and/or more technologically difficult and, therefore, more expensive to operate in. The sequence was the shallow California offshore beginning in 1932; the shallow Gulf of Mexico in 1937; the deeper outer continental shelf waters of the Gulf of Mexico in 1947; the somewhat deeper offshore California shelf waters in the 1960s; the North Slope of Alaska in the mid-1960s; and finally the deep (over 1,000 feet) Gulf of Mexico in 1976. In each of these “virgin” areas, the early explorers found large new oil or gas fields. Yet the number of wells drilled in them in any given year pales into insignificance in relation to the number of wells drilled in far more thoroughly explored, preponderantly onshore areas in the lower 48 States.

Oil and gas wells are drilled for one of four purposes, the first three of which are considered exploratory and the last, developmental:[7]

1. *To find a new field.* These are called new field tests or wildcat wells.

2. *To find a new reservoir in a previously discovered field.* Such wells are variously called new reservoir tests, new pool wildcats, deeper pool tests or shallower pool tests.

3. *To extend the proved area of a previously discovered reservoir.* These wells are called extension tests or outpost tests.

4. *To exploit a previously discovered and delineated reservoir*. These are called development wells.

The drilling activities associated with these various purposes differ from each other with respect to both magnitude and risk.[8]

In the description of the third exploratory well type appears the word with which much of the remainder of this article is concerned: "proved." Proved reserves of crude oil or natural gas are the *estimated* quantities which, on a particular date, geological and engineering data demonstrate with *reasonable certainty* to be recoverable in the future from known reservoirs *under existing economic and operating conditions.* As noted earlier, estimates of proved reserves tend to be conservative. It is useful to look at some of the reasons why this is the case.

"Reasonable certainty" is a crucial element in the definition of proved reserves because oil and gas reservoirs are not subject to direct visualization or to unlimited and precise measurement of their physical characteristics. The raw data used in estimating proved reserves include engineering and geological data about the reservoir rock and its fluid contents obtained via both direct and indirect measurements, such as:

- Data on the reservoir rock's porosity (the voids or pores that exist between the mineral grains)

- Data on the reservoir rock's permeability (its capacity to conduct fluid flow through the pores) as determined from core analysis or various types of geophysical measurements taken in one or more wells

- Data on the production of fluids from a well or several wells

- Geologic maps of the areal extent, thickness, and continuity of the reservoir rock inferred from well logs and other geophysical and geological data

- Reservoir pressure and temperature data.

When a reservoir is discovered, only data from or closely related to the discovery well are available to the reserves estimator. The initially proved area of the reservoir is frequently estimated on the basis of experience within the same or a similar region. Where there is continuity of the productive formation over a wide geographic area, a relatively large proved area may be initially assigned. Conversely, a relatively small proved area may be assigned when the producing formation is of limited continuity owing to either structural or lithologic factors. When reliable geophysical and geologic data are available, a reasonable estimate of the areal extent of the reservoir can be made on the basis of a relatively small number of extension tests.[9]

More and more data become available as delineation of the reservoir's boundaries via the drilling of extension tests occurs, as development wells are drilled into the reservoir's proved area, and as flow tests are made or actual production commences. Depending on the kind and amount of available data, the estimator will select one of several methods of making a proved reserves estimate. Prior to actual production, it is common to apply either the nominal or volumetric methods. The nominal method bases the reserves estimate on a rule of thumb or an analogy to another reservoir or reservoirs believed to be similar. The more accurate volumetric method applies a rule-of-thumb or analogy-based recovery factor to an in-place volume of oil or gas estimated from the geologic and engineering data.

After production begins, estimates based on production performance data can be made using methods that are generally more accurate than those based strictly on inference from geological and engineering data. They include the production decline method and the reservoir simulation method, which are applicable to both oil and gas reservoirs; the material balance method, which is applicable to oil reservoirs; and the pressure decline method, which is applicable to gas reservoirs. Which of these is selected will depend on the data available and the reservoir's type and production mechanism.

In any case, many judgments are required of the estimator. The determination of rock and fluid properties is to some extent uncertain depending upon the measurement methods employed. The construction of the geologic maps and cross sections and the subsequent determination of the physical size of the reservoir are the major judgmental steps associated with the volumetric method. Estimates made using the material balance, reservoir simulation, and pressure decline methods rely on the estimator's judgments regarding the type of reservoir drive mechanism and the appropriate abandonment conditions. Estimates based on the production decline method are subject to judgment in constructing the trend line, which embodies the estimator's assumptions regarding reservoir performance up to abandonment.

The phrase "under existing economic and operating conditions" is yet another important element of the proved reserves definition. Because of the speculative nature of predicting prices and costs many years into the future, proved reserves are estimated on the basis of the prices, costs, and operating practices in effect on the date of the estimate. However, the wellhead price of crude oil or natural gas has an effect on a reservoir's economic limit, i.e., on the production rate required to meet operating costs. For gas reservoirs, price affects the abandonment pressure used in calculating proved reserves. Should the price of crude oil rise far enough to trigger installation of a secondary or tertiary recovery project in a crude oil reservoir, a significant increase of its proved reserves could result. For either type of reservoir, infill drilling justified by higher prices may in some instances result in a higher recovery factor and a concomitant increase of proved reserves. One thing that is certain is that economic and operating conditions will change post-discovery and so, in concert, will the proved reserves estimates.

Without doubt, the most important word in the proved reserves definition is "estimate." Until such time as a reservoir is produced to permanent abandonment, its ultimate recovery volume will be uncertain no matter how much data have been amassed or how well they have been interpreted. Proved reserves can only be estimated, never measured. The proved reserves definitions are intended to result in reliable estimates of the "on-the-shelf inventory" portion of total oil and gas reserves from which production can confidently be expected in the future. One indication that this is indeed the case for the vast majority of U.S. proved reserves estimates is EIA's experience in auditing the estimates submitted to EIA since 1977 by domestic oil and gas well operators on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves." The audits have found that most of the proved reserves estimates submitted to EIA are more than 90 percent certain to be recovered in the future and, in many cases, are more than 95 percent certain to be recovered.[10]

The Importance of Ultimate Recovery Appreciation

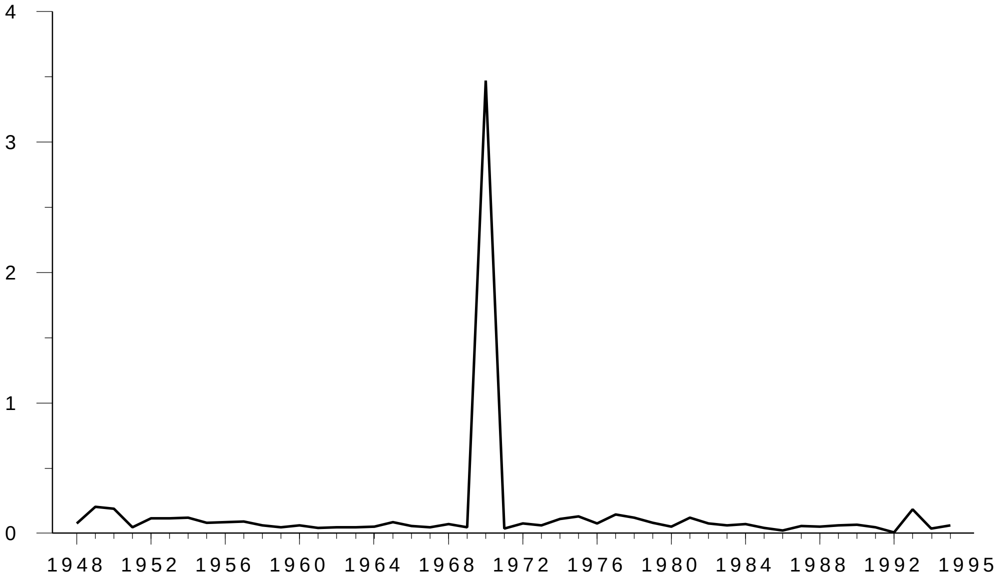
The historical record regarding ultimate recovery appreciation shows that the estimate of ultimate recovery increases over time for most reservoirs, the vast majority of fields, all regions, all countries, and the world. First publicly noted in 1960, it is a major source of both current and expected future oil and gas supplies.[11] In fact, achievement of URA is the principal operational objective of most oil and gas drilling, as well as most upstream industry research and development activity. EIA's proved reserves data indicate that URA is still occurring at low rates in some domestic fields that were found more than a century ago. Most significantly, from 1977 through 1995 approximately 89 percent of the additions to U.S. proved reserves of crude oil and 74 percent of the additions to U.S. proved reserves of dry natural gas were due to URA rather than to the discovery of new oil or gas fields.

Figures FE2 and FE3 provide a comparison of the aforementioned sources of additions to U.S. proved reserves of crude oil and natural gas, expressed as the ratio of those additions from new field discoveries to those due to URA.[12] The towering 1970 peak in both figures reflects booking of proved reserves for the Prudhoe Bay Field.[13] In no other year does the ratio exceed 0.21 for crude oil or 0.89 for natural gas; excluding the 1970 Prudhoe Bay anomaly, the average ratios over the respective periods are 0.08 for crude oil and 0.17 for natural gas. Looked at another way, 93 percent of crude oil reserves additions and 86 percent of natural gas reserves additions during the respective periods were due to URA rather than to the discovery of new fields, excluding Prudhoe Bay.

As stated at the outset, estimated ultimate recovery (EUR) on average appreciates over time. This is well-illustrated by a comparison of the 1977 and 1993 EURs of the 200 U.S. crude oil fields that had the largest 1977 proved reserves (Figure FE4). While EUR had decreased for 23 percent of them by 1993, it had increased for the other 77 percent, and many times over for 32 percent of them. These data also reflect and confirm the essential conservatism of both the definition of proved reserves and the manner in which it is applied in the United States.

The three principal estimators of U.S. oil and gas resources, the Department of the Interior's United States Geological Survey (USGS) and Minerals Management Service (MMS), and the natural gas industry-based Potential Gas Committee (PGC), include estimates of URA in their overall resource estimates. The latest USGS national assessment, based on year-end 1993 data and released in 1995, forecast URAs of 60 billion barrels of crude oil, 13.4 billion barrels of natural gas liquids, and 322 trillion cubic feet of natural gas for the onshore United States and its adjoining State jurisdiction offshore areas in the next 80 years.[14] Of the mean total USGS estimate of resources beyond proved reserves, these quantities represent 65 percent of crude oil resources, 59 percent of natural gas liquids resources, and 34 percent of natural gas resources.

Figure FE2. Ratio of New Field Discoveries to Ultimate Recovery Appreciation for Crude Oil, 1948-1995



Note: URA equals the sum of estimated net revisions, extensions, and new reservoir discoveries in old fields.

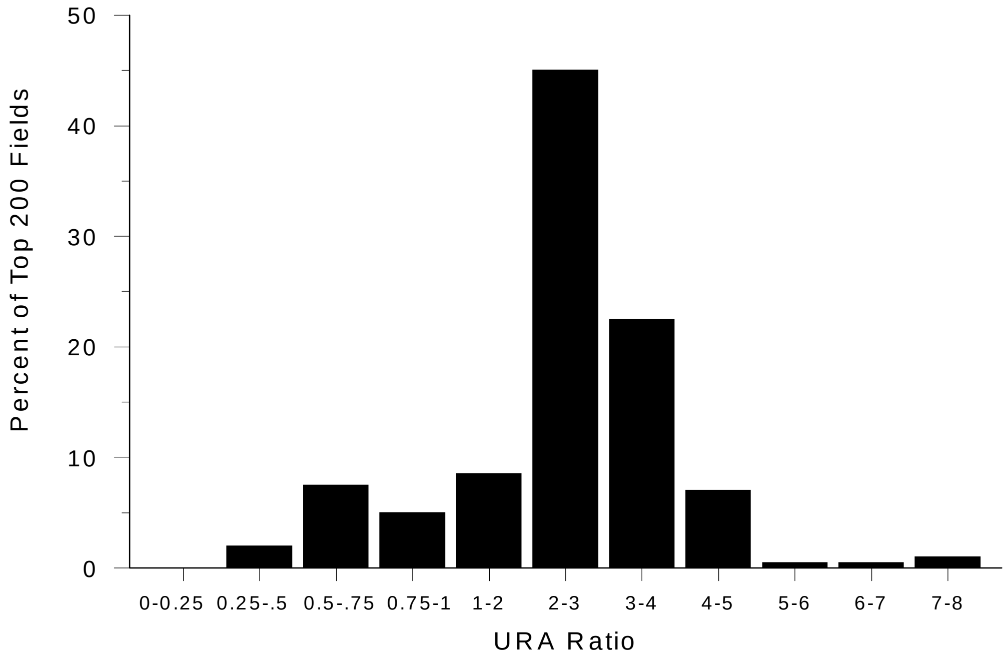
Sources: **Pre-1970:** American Petroleum Institute, American Gas Association, Canadian Petroleum Association, *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 1979* (Washington, DC, June 1980), Table II, p. 24, Table VII-1, p. 155, and Table VII-2, p. 116. **1970-1980 arithmetically linked as shown in:** Energy Information Administration (EIA), *Two Approaches to the Linkage of U.S. Oil and Gas Reserves Estimates*, DOE/EIA-0452 (Washington, DC, July 1984). **Post-1980:** EIA, *U.S. Crude Oil, Natural Gas and Natural Gas Liquids Reserves*, 1995 Annual Report, DOE/EIA-0216(95) (Washington, DC, November 1996), Tables D1 and D3.

Figure FE3. Ratio of New Field Discoveries to Ultimate Recovery Appreciation for Natural Gas, 1966-1995

Note: URA equals the sum of estimated net revisions, extensions, and new reservoir discoveries in old fields.

Sources: **Pre-1970:** American Petroleum Institute, American Gas Association, Canadian Petroleum Association, *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 1979* (Washington, DC, June 1980), Table II, p. 24, Table VII-1, p. 155, and Table VII-2, p. 116. **1970-1980 arithmetically linked as shown in:** Energy Information Administration (EIA), *Two Approaches to the Linkage of U.S. Oil and Gas Reserves Estimates*, DOE/EIA-0452 (Washington, DC, July 1984). **Post-1980:** EIA, *U.S. Crude Oil, Natural Gas and Natural Gas Liquids Reserves*, 1995 Annual Report, DOE/EIA-0216(95) (Washington, DC, November 1996), Tables D1 and D3.

Figure FE4. 1993 URA Ratios of the 200 U.S. Fields That Had the Largest 1977 Proved Liquid Hydrocarbon Reserves



Note: Proved liquid reserves = proved crude oil reserves + proved lease condensate reserves. URA Ratio = (1978 through 1993 liquids production plus 1993 proved liquid reserves)/1977 proved liquid reserves.
Source: Energy Information Administration, Oil and Gas Integrated Field File.

The PGC uses the term “probable resources” for its estimate of URA. The latest mean PGC estimate of probable gas resources, based on data at year-end 1996, was 216.2 trillion cubic feet for the United States inclusive of the Federal jurisdiction Outer Continental Shelf. This represents 20.2 percent of the mean total PGC gas resource estimate and is about 61 percent of the combined USGS and MMS estimates of gas URA.[15] [16]

The USGS, MMS, and PGC resource estimates for natural gas are developed using different data and different methods. The fact that the two principal estimates of gas URA differ by more than 100 trillion cubic feet is of less significance than the fact that in both instances URA represents a major portion of the remaining (as-yet untapped) domestic natural gas resource base.

What Is Known About the URA Process

The URA phenomenon is known to be principally the result of three factors. The primary factor is lack of adequate geotechnical information at the time of field discovery. Second are "systemic factors" embodying the net effect of the industry's post-discovery field delineation, field development, and production monitoring processes, as modulated by its reserves recognition practices. Third, there are factors, such as the occurrence of technological progress, that probably have differential effects on the process from field to field depending principally on field size, on location relative to the operating environment, markets, and transportation facilities, and on specific reservoir characteristics within a field.

Put formally, it is well established that only a handful of events can cause URA to occur in a field:

1. The proved area of a reservoir in the field is increased by successful extension test drilling (or perhaps, in some cases, what is really just development drilling done by a conservative booker). These positive changes to proved reserves are recorded as *extensions* in the annual EIA reserves survey.

2. A new, economically productive reservoir is discovered in the field. These positive changes are recorded as such in the annual EIA reserves survey.

3. A production performance-based re-evaluation of the field's proved reserves is undertaken that results in a larger proved reserves estimate. These changes are recorded as *positive revisions* in the annual EIA reserves survey.[17]

4. The field's proved reserves estimate is increased in response to the implementation or planned implementation of some recovery factor-boosting engineering change, ranging from a favorable well recompletion to the adoption of tertiary recovery methods. These changes are also recorded as *positive revisions* in the annual EIA reserves survey.

5. The field's proved reserves estimate is increased due to one or more successful new completions within existing wells that tap a by-passed (behind-the-pipe) zone not previously booked as proved reserves. These changes are also recorded as *positive revisions* in the annual EIA reserves survey.

6. A favorable long-term change of wellhead or lease border product prices relative to production costs results in a longer-than-previously-anticipated field economic lifetime, reflected as an increase of proved reserves. These changes are also recorded as *positive revisions* in the annual EIA reserves survey.

Several observations can be made about these causes of URA. Significant periods of elapsed time, ranging from months to a decade, are associated with the occurrence of all of them except cause 6. New investment is a prerequisite for the occurrence of all except causes 3 and 6. Only causes 1 and 2 (and sometimes 4 and 5) are related to drilling activity. Put conversely, at least half of the factors that can cause URA are unrelated to drilling activity.

There are also a number of factors that can modulate the rate at which URA occurs, individually or in concert. These include:

- *The prevailing economic environment*. All else equal, and given adequate demand, the advent of a higher price/cost ratio should accelerate URA, and the converse.

- *Physical complexity of the field.* The more complex a field is either structurally or sedimentologically, the more effort and elapsed time will be needed to fully "prove it up."

- *Technological advancement*. The advent of a new technology that increases the recovery factor, reduces recovery cost, or reduces risk should accelerate URA. The difficult analytical problem here is determining the rate and the degree of "market penetration," particularly when the indicated "market" for a particular technology is rather local or regional in nature.

- *The risk preferences of operating firms*. These are in part reflected by their booking practices.[18]

- *The local quasi-physical operating environment*. This includes natural environment-related matters (e.g., deep water, Arctic conditions, etc.), the availability of necessary equipment and services, field location relative to the extant operational support and product transportation infrastructures, delays resulting from regulatory oversight and compliance, and so forth.

While the causes of URA are well known, analysis of their impact on the actual rate of appreciation and of their interactions has been hampered by a lack of sufficiently detailed serial EUR data.

Attempts to Analyze and Project URA

The First Analysis

J.R. Arrington, a Canadian petroleum engineer, was the first to address the URA phenomenon publicly. He noted that — with proper data — statistical estimates of ultimate recovery for a reservoir and, by aggregation, for a field, could be constructed by analogy to the known past appreciation behavior of similar reservoirs. The required data were annual reservoir-by-reservoir series that allocated each year's net change to the proved reserves estimate back to the year of reservoir discovery. Using his company's proprietary reservoir data, Arrington calculated the percentage change in proved reserves experienced in each successive post-discovery year. The annual changes were typically found to decrease as time passed, reflecting in cumulative form an asymptotic approach to the ultimately recoverable oil or gas volume(s). Arrington did not provide a mathematical equation descriptive of the process, but did provide a tabular example of how to calculate the annual appreciation ratios which reduces to:

$$RR_{(t,t+1)} = \frac{EUR_{(n,n+t+1)}}{EUR_{(n,n+t)}}$$

where,

- RR is the revision ratio (appreciation factor) between successive post-discovery years
- EUR is estimated ultimate recovery
- t is the number of years after discovery (the revision number)
- n is the discovery year to which the EUR is credited

Arrington used a visually smoothed curve through 3-year weighted averages of these ratios to approximate the path of appreciation over time.

Statistical Analyses

Two decades later followed a series of 12 publicly available studies involving the statistical estimation of URA for either the entire United States or the lower 48 States.[19] These studies were most often conducted with the intent of quantifying the phenomenon in order to be able to project it within the context of some larger study of overall future oil and gas resources. They were not the principal focus, and none of them fully took into consideration the mechanics of the underlying process. Instead, each study empirically fitted a different mathematical equation to part or all of the available serial EUR data. While differently formulated, all of the equations used had in common the desired general form: rapid increase of the expected URA early-on, whether expressed as a function of time or drilling activity level or both, followed by successively lower rates of increase, such that the estimated URA asymptotically approached an upper bound.

One of the difficulties facing many of the researchers was the lack of serial field- and/or reservoir-specific EUR data. These data were unavailable outside of oil and gas well operators' proprietary files until 1990. Before then, the publicly available serial EUR data consisted of State- or State subdivision-wide estimates of the ultimate recovery of crude oil by year of discovery ranging from a pre-1920 group category through 1979 as prepared by the American Petroleum Institute (API) in the years 1966 through 1979, and like estimates for non-associated, associated-dissolved, and total natural gas as prepared by the American Gas Association (AGA). The authors of the first nine post-Arrington URA studies had no option but to rely on these data.

Most of the studies found one or more serious faults with these data, among which were:

- Appreciation rates were highly erratic in the early years, which was deemed to reflect data series “start-up problems.”
- For some unknown reason, the appreciation rates for pre-1947 fields were six times larger than for post-1947 fields.
- The assignment of discoveries to the proper year was clearly arbitrary in some instances.
- The AGA’s associated-dissolved gas EUR series was physically unreasonable relative to the corresponding API crude oil EUR series.
- All of the remaining (i.e., “good”) data still exhibited a high variance, which required statistical smoothing to render it suitable for analytical use.

Because of these data limitations, any embedded relationships to causative factors such as geology perforce were both coincidental and deeply “buried.”

The two most recent URA studies have instead relied primarily or solely, respectively, on the field-by-field EUR data series contained in EIA’s Oil and Gas Integrated Field File (OGIFF), which became available in 1990. OGIFF presently provides annual EUR data for fields covering more than 90 percent of the Nation’s proved reserves from 1977 through 1995. The OGIFF EUR data are derived from confidential Form EIA-23 survey data and public State and Federal production data obtained via Petroleum Information/Dwights LLC.[20]

The first of these studies, performed by the National Petroleum Council for natural gas URA only, spliced the pre-1977 API/AGA EUR data series to the 1977 and subsequent EIA EUR series. The volumetric discontinuity between the two series was resolved by elevating the former to match the latter in 1977. This was also the first and only study of URA which fitted an empirical function to the EUR data that depended on both elapsed post-discovery time and a measure of drilling activity. The resulting forecast of URA was much higher than predicted in any of the previous studies.

The most recent study was performed by the USGS as a part of its 1996 National Assessment of U.S. oil and gas resources located onshore and in State-jurisdiction offshore waters. It relied solely on the EIA OGIFF EUR data and used a growth function dependent only on elapsed post-discovery time. The USGS investigators found it necessary to subdivide the EUR data into two classes: a “normally behaving” fields class which covered 86 percent of the oil and gas at year-end 1990; and an “outlier” field class which accounted for the rest. Included within the “outliers” were such fields as the heavy oil fields in California that had been returned to major production levels from near-moribund status by the introduction of tertiary recovery methods in the 1970s and 1980s, and early low-permeability gas field discoveries in the Appalachian Basin that were not fully developed until special pricing and tax incentives appeared in the same period.

The USGS’s growth function performed reasonably well in reproducing the URA behavior of the normally behaving class of fields over the 1997 through 1990 period (oil projection 12.0 billion barrels versus 12.2 billion barrels actual; gas projection 83.5 trillion cubic feet versus 87.9 trillion cubic feet actual). Unfortunately, the same was not true for the outlier fields. Unlike the normally behaving fields, the URA paths of these fields showed no sign of approaching an upper bound. In absence of knowledge as to how to model their behavior, fairly conservative estimates were made for the URA of this category of fields. This treatment of the outlier fields clearly left something to be desired inasmuch as, while these fields do not hold the bulk of reserves, they account for the bulk of URA activity.

A problem common to all of the empirical statistical studies of URA is that given the:

- high variance of the serial EUR data,
- loose connection to causality provided by either elapsed time or a gross measure of drilling activity, and
- aggregation of disparate geologies that accompanies use of EUR data sets inclusive of large geographic areas,

one can "drive" any number of differently formulated but similarly shaped curves through the data with little objective assurance that the results are either significantly unique or even appropriate.[21] At the same time, many of the outlier fields, particularly those with high appreciation rates, are not being well represented.

A graphic illustration of the very broad URA data dispersion that occurs when grouping fields across geologic types and geographic areas was provided by the National Petroleum Council (NPC) and is reproduced with minor modification in Figure FE5. The NPC plotted cumulative growth rates versus time since discovery for a geologically and geographically diverse group of 97 nonassociated gas fields that had discovery dates ranging from 1928 to 1988, along with the NPC’s URA predictions (based on application of its URA model to the combined API/AGA and EIA OGIFF data series) for 1922, 1950, and 1970 discoveries.[22]

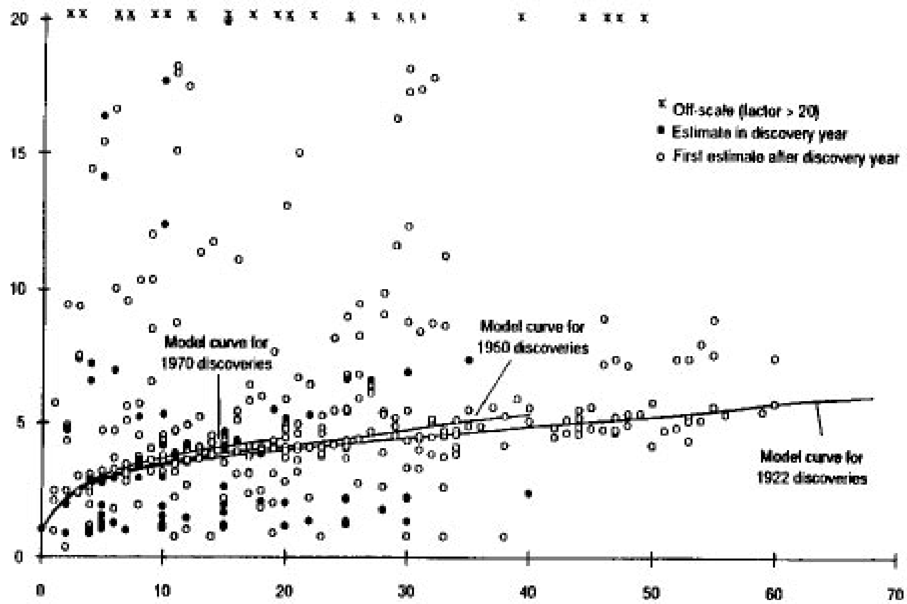
Nonstatistical Analyses

Aside from the empirical statistical URA studies, the natural gas industry-based Potential Gas Committee (PGC) has estimated the Nation's "probable resources" of natural gas (definitionally equivalent to its estimated URA) biennially since 1964, excepting 1974.[23] The PGC estimates are developed via a subjective but straight-forward and reservoir-specific volumetric method. To estimate the probable resources associated with the additional development of an already discovered reservoir, PGC's local estimating committee members use the known productive area of the reservoir as an analog to develop a yield factor, which is then applied to an estimate of the as-yet undeveloped reservoir volume. The resulting volume is then risked via multiplication by the estimated probability of existence of the additional reservoir volume. A similar scheme is used for undiscovered probable gas resource estimates — those involving new reservoir discoveries in a known field. The principal differences are that the estimate is additionally risked for the existence of the new reservoir's trap and the analog that is used may be drawn from another field located in the same geologic province.[24] The PGC's estimates of future URA are, therefore, independent of the EUR data series that all others have relied upon in investigating and projecting URA.

Overall Evaluation

In summary, much of the analytical effort to date can be characterized as a series of creative attempts to get around the high variance present in the API/AGA EUR data. The product of most of the analysis has been more-or-less arbitrary approximations of central URA tendencies lacking corresponding error measures. Evaluation of the existing body of work on URA analysis and forecasting, inclusive of the nature of the data that have supported it, suggests that:

Figure FE5. Observed Growth Factors and URA Model Projections for the NPC Sample Fields



Source: Energy Information Administration, Office of Oil and Gas. Derived from National Petroleum Council, "Report of the Reserves Appreciation Subgroup fo the Source and Supply Task Group, 1992 National Petroleum Council Natural Gas Study" (Washington, DC, August 1992), unpublished open file text, Figure 14.

- Caution should be exercised in placing faith in any of the existing empirically determined URA estimates, particularly in absence of an explicit associated measure of uncertainty.

- Given the apparent importance of URA to future domestic oil and gas supply, continued study of the URA phenomenon, in greater detail than in the past, is both necessary and justified.

Future Directions

The appropriate direction for further study can in part be ascertained directly from the report of the first URA study. Having relied on reservoir-by-reservoir data from his own company's files, Arrington noted:

> "The amount of [post-first booking] growth is a function of knowledge and size of the virgin reservoir. The greater the knowledge of a new reservoir, the more accurate will be the initial estimate. Large fields normally have greater increases percentagewise than small fields. The philosophy of the estimating group also affects the rate of revision. If a conservative policy is followed in booking unproven reserves, the future changes in [proved] reserves obviously will be higher than for a more optimistic estimating group. Regardless of the factors affecting it, growth is normal although the amount varies from area to area and with various estimating groups."

Thus, Arrington's initial work indicated that factors other than elapsed post-discovery time and / or drilling effort had significant effects on the ultimate recovery appreciation phenomenon. To improve on the former analyses, any new study of URA must seek to account for those factors. Specifically and to the maximum extent possible this will require the development of means to account separately for the effects on the URA process of economic change, technological advancement, and differential proved reserves booking practices.

EIA and the USGS are collaborating on work to provide a more complete and better understanding of the process and factors that drive URA. EIA currently has in-progress some of the rigorous statistical groundwork required to develop a means of capturing the effect of both industry-specific and general economic conditions. A corollary requirement will be the prior separation of the available serial EUR data into homogenously behaving units according to some criterion or set of criteria that provides a link to the known URA causative or modulatory factors. Several important questions relating to the applicability of the available data remain to be answered.

Are Field-level EUR Data Sufficient to the Task?

All of the causative factors and some of the modulatory factors operate at the level of the individual reservoir. EIA collected annual reservoir-by-reservoir estimates of proved reserves and reserves changes beginning with 1977, but was required to cease their collection in 1979 in order to reduce respondent burden. It is unclear whether EIA's field-level reserves data series will prove sufficient to allow the development of a definitive understanding of the URA phenomenon. The potentially deleterious effect of reserves estimate aggregation has been well-illustrated by the striking difference between the results of the early USGS URA studies based on the State-level API/AGA EUR data and the most recent USGS study based on regional aggregates of the EIA OGIFF field-level reserves data. The USGS's inferred reserves estimates went up 267 percent for crude oil, 335 percent for natural gas liquids, and 326 percent for natural gas. Thus, determining whether or not field-by-field reserves estimates will suffice is a crucial matter that needs to be addressed early.

Are the Available EUR Data Adequately Representative?

The available serial data bearing on domestic ultimate recovery appreciation are incomplete. EIA has complete appreciation histories for relatively few fields, and most of the Nation's significant fields are not among them. Through October 1996, 45,992 distinct oil and gas fields had been officially recognized in the United States. OGIFF contains data covering about 39,000 of them. Of those fields, only 10,109 were discovered during the life span of the API/AGA series. Only about 13,000 new field discoveries occurred during the life span of the EIA ultimate recovery estimate series. Since, as previously indicated, the largest fields are on average found early during the exploration history of any particular geographic area, the more recent the discoveries are, the smaller they tend to be. And since, as Arrington first noted, large and small fields do not appreciate similarly, a question arises as to data applicability to the older, larger fields.

Is the URA Process (or Are its Components) Time-invariant?

On a field-by-field basis only an 18-year data window on the appreciation behavior of domestic fields is available. This window records only mid- to late-stage appreciation behavior for most fields including nearly all of the most significant fields. Relative field size aside, whether the early stage appreciation behavior of the older fields is well enough approximated by the early stage appreciation behavior of the recently discovered fields for which EIA has data is unclear. Thus far, all of the statistical URA analysts have bypassed addressing this question by making the implicit assumption that appreciation behavior is invariant over time or measure of effort, which is clearly not a satisfactory approach.

Can the Available Serial EUR Data be Adequately Parsed?

An important undertaking in the further study of URA will be the development of criteria for the categorization of domestic fields into homogeneously behaving groups which relate to identifiable characteristics such as field geologic type, field complexity, field location, field vintage, and so forth. Even if empirical methods prove to be the only applicable means of URA analysis given the available EUR data, adroit sub-setting of those data should by itself yield significant improvement over the present URA estimates.

Conclusion

The ultimate recovery appreciation phenomenon is, in effect, an intricate puzzle. It will not be a fast or easy one to put together. Nevertheless, the large — and for the most part unquantified — uncertainties associated with the currently available estimates of this key component of the remaining domestic crude oil and natural gas resource bases need to be far better understood and reduced insofar as possible. They fundamentally affect crucial projections of our Nation's future domestic oil and gas supplies. The collaborative effort now being undertaken by the EIA and the USGS is aimed at achieving these objectives.

End Notes

1. The natural "package" in which oil and gas is found is a *reservoir*, defined as a porous and permeable underground formation containing an individual and separate natural accumulation of producible hydrocarbons which is confined by impermeable rock or water barriers and is characterized by a single natural pressure system. A *field* is an area consisting of one or more reservoirs all grouped on, or related to, the same individual geological structural feature and/or stratigraphic condition. Thus, there may be two or more reservoirs in a field that are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or both.

2. For a particular reservoir or field over a particular period of time it is entirely possible for the estimate of proved reserves to *decrease* as a result of production while the estimate of ultimate recovery *increases* for some reason. In such instances, the proved reserves decrease is smaller than the one which would have been booked absent the occurrence of URA.

3. United States Geological Survey, *The Importance of Reserves Growth for the Nation's Supply of Natural Gas,* Fact Sheet FS-202-96(Washington, DC, October 1996).

4. Lawrence J. Drew, *Undiscovered Mineral and Petroleum Deposits: Assessment & Controversy*, (New York: Plenum Publishing Corporation, 1997), Chapter 3.

5. Energy Information Administration, *U.S. Oil and Gas Reserves by Year of Discovery,* DOE/EIA-0534 (Washington, DC, August 1990), p. 5.

6. Energy Information Administration, *U.S. Oil and Gas Reserves by Year of Discovery,* Table 1, pp. 6-7.

7. Ignoring miscellaneous wells such as those drilled only to ascertain subsurface stratigraphy or for production-related purposes such as the injection or reinjection of fluids.

8. In the 78 years for which overall drilling statistics are available (1918-1995), 2,803,732 holes were drilled for oil or gas in the United States, 67.4 percent of which were successful. For the 52-year period in which both overall and exploratory drilling statistics are available (1944-1995), 2,177,094 holes were drilled for oil or gas, of which 65.3 percent were successful. Just 499,819, or 22.9 percent of these holes were exploratory; of which only 109,643, or 21.9 percent were successful. About 56 percent of the exploratory holes were new field tests, of which only 13 percent were successful. Oil and gas wells do not, of course, last forever. According to the Interstate Oil and Gas Compact Commission, by year-end 1994 about 55 percent of all successful oil or gas wells drilled in the United States had been plugged and abandoned because they had reached their economically productive limit.

   Source: DeGolyer & MacNaughton, *20th Century Petroleum Statistics*, 52nd Ed. (Dallas, TX, November 1996), pp. 28-29, and Interstate Oil and Gas Compact Commission, *Produce or Plug: The Dilemma Over the Nation's Idle Oil and Gas Wells* (December 1996), p. 5.

9. There are relatively unusual situations where data from a single well will, or must, suffice. These include small reservoirs that cannot economically support production from more than one well, or a larger reservoir where such factors as its shape or high bulk permeability of the reservoir rock allow a single well to drain the reservoir efficiently. Nongeotechnical considerations, such as a legal requirement to prove the commercial viability of a lease in order to hold it beyond an impending expiration date, may also occasionally cause the booking of proved reserves based on a single well.

10. Confirming EIA's reserves auditing experience, the Society of Petroleum Engineers and the World Petroleum Congress in March 1997 moved formally to define proved reserves as 90 percent or more assured of future recovery regardless of whether the estimate is deterministically or probabilistically constructed or stated. This decision was made after years of debate between reserves estimators who favored the established deterministic style estimates and others who favored the introduction of probabilistic reserves estimates. See: Society of Petroleum Engineers, "SPE/WPC Reserves Definitions Approved," *Journal of Petroleum Technology* (Tulsa, OK, May 1997), pp. 527-528.

11. J.R. Arrington, “Predicting the size of crude reserves is key to evaluating exploration programs,” *The Oil and Gas Journal*, Vol. 58, No. 9 (Tulsa, OK, February 1960), pp. 130-134.

12. The figures cover the years in which both year-end proved reserves and the components of reserves change during the year have been nationally estimated: 1948-1995 for crude oil, and 1966-1995 for natural gas.

13. Most of the proved natural gas reserves of the Prudhoe Bay Field were de-booked by EIA in 1978 pending emergence of a viable market for them.

14. United States Geological Survey, *1995 National Assessment of United States Oil and Gas Resources*, Circular 1118, US Government Printing Office (Washington, DC, 1995), p. 2.

15. Potential Gas Agency, *Potential Supply of Natural Gas in the United States, Report of the Potential Gas Committee (December 31, 1996)*, Colorado School of Mines (Golden, CO, March 1997), Table 8, p. 20.

16. The Minerals Management Service has estimated ultimate recovery appreciations of 2.2 billion barrels of crude oil and 32.7 trillion cubic feet of natural gas for Federal jurisdiction Gulf of Mexico fields. Source: Minerals Management Service, *Assessment of the Undiscovered Hydrocarbon Potential of the Nation’s Outer Continental Shelf,* MMS 96-0034 (Washington, DC, June 1996), Table 3, p. 18.

17. The survey also collects data on downward or negative revisions, but since these do not cause URA, they are not considered here.

18. Firms vary in their booking practices in response to their (or their investors') risk aversion preferences and in accord with their interpretations of generally accepted petroleum engineering and financial accounting standards. Some firms, particularly the smallest ones, will fully book as soon as an estimate has been made. Others will await the making of a business commitment to field development, or will “book up” in parallel to the making of business commitments to specific stages of a field's development. The most conservative firms have been known to delay reserves booking until at least some production facilities have been successfully installed. Differential booking effects may also exist that depend upon where a field is located relative to the existing production and transportation infrastructure, certain environmental considerations, and other factors. For example, onshore in the lower 48 States, booking delays can typically range from a few months to more than a year. Offshore in the Gulf of Mexico, booking delays can range up to a few years. In Arctic Alaska, the delay for crude oil booking can easily be on the order of 10 years.

19. They are:

    J.J. Arps, M. Mortada, and A.E. Smith, "Relationship Between Proved Reserves and Exploratory Effort," *Journal of Petroleum Technology* (June 1971), pp. 671-675.

    G. Rogge Marsh, "How much oil are we really finding?," *The Oil and Gas Journal* (April 1971), pp. 100-104.

    Chester R. Pelto, "Forecasting Ultimate Oil Recovery," SPE Paper 4261 in *Symposium on Petroleum Economics and Evaluation*, Society of Petroleum Engineers, Dallas Section (Dallas, TX, 1973), pp. 45-52.

    M. King Hubbert, "U.S. Energy Resources, a Review as of 1972, Part 1" in U.S. Congress, Senate, *A National Fuels and Energy Policy Study,* 93rd Cong., 2d sess., Committee on Interior and Insular Affairs Print Serial No. 93-40(92-75), pp. 111-119 and pp. 138-143.

    D.A. White, R.W. Garrett, Jr., G.R. Marsh, R.A. Baker, and H.M. Gehman, "Assessing Regional Oil and Gas Potential" in *Methods of Estimating the Volume of Undiscovered Oil and Gas Resources*, Amer. Assn. of Petr. Geol. Studies in Geology No. 1 (Tulsa, OK, 1975), pp. 147-149.

R.F. Mast and Janet Dingler, "Estimates of Inferred + Indicated Reserves for the United States by States" in United States Geological Survey, *Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States*, Circular 725 (Washington, DC, 1975), pp. 73-78.

D.H. Root, "Estimation of Inferred Plus Indicated Reserves for the United States," in United States Geological Survey, *Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States*, Circular 860 (Washington, DC, 1981), pp. 81-87.

David H. Root, "Historical Growth of Estimates of Oil- and Gas-Field Sizes," in U.S. Department of Commerce, National Bureau of Standards, *Proceedings of a Symposium on Oil and Gas Supply Modeling, July 18-20, 1980* (Washington, DC, May 1982), pp. 350-268.

D.H. Root, "Inferred and Indicated Reserves," Section II. H. in *National Assessment of Undiscovered Conventional Oil and Gas Resources*, United States Geological Survey Open File Report 88-373 (an unpublished 1988 working paper), pp. 81-89.

National Petroleum Council, *Report of the Reserves Appreciation Subgroup of the Source and Supply Task Group, 1992 National Petroleum Council Natural Gas Study* (Washington, DC, August 1992), pp. 169, unpublished open file text.

E.D. Attanasi and D.H. Root, “The enigma of oil and gas field growth,” *American Association of Petroleum Geologists Bulletin*, Vol. 78, No. 3 (Tulsa OK, 1994), pp. 321-332.

20. For detailed information about the Oil and Gas Integrated Field File see: Energy Information Administration, *U.S. Oil and Gas Reserves by Year of Discovery*, DOE/EIA-0534 (Washington, DC, August 1990).

21. For example, where GF equals cumulative appreciation factor and t equals the elapsed post-discovery years, both of the following equations, which have not been used, will fit the data just as well as any of the equations that have:

$$GF_t = a + \frac{b}{t} + \frac{c}{t^2}$$

and

$$GF_t = \frac{(a + ct)}{(1 + bt)}$$

where a, b, and c are regression coefficients.

22. National Petroleum Council, *Report of the Reserves Appreciation Subgroup of the Source and Supply Task Group, 1992 National Petroleum Council Natural Gas Study*, Figure 14, p. 63. Reproduced with permission as Figure FE5.

23. Potential Gas Agency, *Potential Supply of Natural Gas in the United States (December 31, 1996)* (Golden, CO, March 1997), 130 pp.

24. Energy Information Administration, *An Examination of Domestic Natural Gas Resource Estimates*, SR/RNGD/89-01 (Washington, DC, February 1989), p. 64.