AN ASSESSMENT OF THE NATURAL GAS RESOURCE BASE OF THE UNITED STATES

by

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for

Office of Policy, Planning, and Analysis
U.S. Department of Energy

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May 2, 1988

This report was prepared under contract no. 80622401 between Argonne National Laboratory and The University of Texas at Austin

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   by Argonne National Laboratory

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   by Bureau of Economic Geology

SUMMARY

The distribution of natural gas in the United States consists of proved reserves in known reservoirs, of inferred reserves and undeveloped resources within these reservoirs, and of undiscovered resources. Beyond proved reserves, all volumes of future natural gas supply are estimates based on information derived from past and current experience in gas production and reservoir development. Even proved reserves are subject to periodic revision. This assessment was conducted starting with an understanding of major components of the natural gas supply derived from existing resource estimates that use established methodologies. In addition to historically defined elements of the resource base, a new component--reserve growth in heterogeneous reservoirs--is quantified in this study.

Resource assessments proceed in their planning and compilation from reasonably well known quantities (proved reserves) to increasingly less well known quantities (undiscovered resources). Further, natural gas reservoirs termed unconventional are typically given separate consideration and include gas in low-permeability reservoirs, gas in shale formations, such as the Devonian of the Eastern U.S., and coalbed methane resources. This approach has been followed in this assessment. Special note was made of Alaskan gas reserves in that they are significant and proven, but transportation for North Slope gas to the Lower 48 states is lacking.

A summary of the results of this assessment shows that a technically recoverable reserve and resource base of 1,059 trillion cubic feet (Tcf) of natural gas exists in the Lower 48 states (table 1). This resource base is made up of proved reserves, inferred reserves, and resources. The latter requires discovery and development, some using improved understanding of reservoir frameworks that must be more fully developed and applied. Of that, 800 Tcf exists or is estimated to exist in conventional reservoirs.

TABLE 1. TOTAL UNITED STATES GAS RESERVES AND RESOURCES ASSESSED

	TECHNICALLY RECOVERABLE GAS, Tcf*	RECOVERABLE GAS BY PRICE**	
		<$3./Mcf	$3.-5./Mcf
LOWER 48 (Conventional)			
PROVED RESERVES, 12/31/86, ONSHORE AND OFFSHORE	159	159	---
INFERRED RESERVES/ PROBABLE RESOURCES, 12/31/86, ONSHORE	85	85	---
INFERRED RESERVES, 12/31/86, OFFSHORE	23	23	---
EXTENDED RESERVE GROWTH IN NONASSOCIATED FIELDS, ONSHORE	119	56	18
GAS RESOURCES ASSOCIATED WITH OIL RESERVE GROWTH***	61	30	11
UNDISCOVERED ONSHORE RESOURCES	219	88	59
UNDISCOVERED OFFSHORE RESOURCES****	134	54	28
SUBTOTAL	**800**	**495**	**116**
LOWER 48 (Unconventional)			
GAS IN LOW-PERMEABILITY RESERVOIRS	180	70	49
COALBED METHANE	48	8	4
SHALE GAS	31	10	5
SUBTOTAL	**1,059**	**583**	**174**
ALASKA			
ALASKA: RESERVES	33	7#	0
ALASKA INFERRED RESERVES (COOK INLET AREA)	3	3	0
ALASKA UNDISCOVERED, ONSHORE AND OFFSHORE	93	2#	2#
SUBTOTAL	**1,188**	**595**	**176**
TOTAL	**1,188**	**595**	**176**

*Volumes of gas judged recoverable with existing technology

**Volumes of gas (Tcf) judged recoverable with existing technology by Review Panel at wellhead prices shown (1987$)

***Judged at oil prices of <$24./bbl and $24.-40./bbl

****Outer Continental Shelf

#Component in southern Alaska

More than half of the total resource evaluated in the Lower 48 states, or 583 Tcf of gas, is judged economically recoverable (including finding costs) at less than \$3.00/Mcf (wellhead price, 1987\$). An additional 174 Tcf of gas is judged economically recoverable in a price range of \$3.00 to \$5.00/Mcf. These judgments of economic recoverability were made by a national Review Panel of natural gas analysts who helped define the course of this study and made critical evaluations of project results (table 2). In all cases, a conservative view is taken of recoverability as well as the total resource accessible at different price ranges. This is particularly true for unconventional resources where the resource base is much greater than the volumes of technically recoverable gas incorporated into this assessment.

The Review Panel acted through a series of judgments made individually and then averaged for each category of natural gas reserve or natural gas resource. The volume of gas judged economically recoverable for each category is the arithmetic mean of the individual estimates after eliminating the highest and the lowest estimate for each price category. The mean estimate and the range of the estimates (less the high and low values) reflect the range of judgment of the Review Panel (table 3).

Key results for each major category of natural gas are:

Proved Reserves

All Lower 48 onshore and offshore gas reserves of 159 Tcf (dry gas basis) are judged economically recoverable at <\$3.00/Mcf wellhead price (1987\$).

Table 2. List of Panelists

Robert J. Finley	Deputy Director The University of Texas at Austin/Bureau of Economic Geology
William L. Fisher	Director The University of Texas at Austin/Bureau of Economic Geology
John D. Grace	Principal Research Geologist Reservoir Assessment and Basin Modeling ARCO
H. William Hochheiser	Physical Scientist U.S. Department of Energy/Office of Geoscience Research
Ted V. Jennings	Geologist Argonne National Laboratory
Robert B. Kalisch	Director Gas Supply and Statistics American Gas Association
Harry C. Kent	Director Potential Gas Agency Colorado School of Mines
Vello A. Kuuskraa	Senior Vice President ICF-Lewin Energy
Charles J. Mankin	Director Oklahoma Geological Survey
Julian G. Martin	Executive Vice President Texas Independent Producers Royalty Owners Association
Paul Martin	Chief, Branch of Offshore Resource Assessment Minerals Management Service
Richard F. Mast	Research Geologist, Branch of Resource Analysis U.S. Geological Survey

Charles Matthews	Senior Petroleum Engineering Consultant Shell Oil Company Member, National Academy of Engineering
Steven E. Plotkin	Senior Analyst Congressional Office of Technology Assessment
Glen E. Schuler	Manager, Economic Planning and Analysis Tenneco, Inc.
William Trapmann	Supervising Economist U.S. Department of Energy/Energy Information and Administration
Thomas J. Woods	Principal Energy Analyst Gas Research Institute

TABLE 3. REVIEW PANEL ASSESSMENT OF ECONOMICALLY RECOVERABLE GAS

RANGE OF ESTIMATES PREPARED BY PROJECT REVIEW PANEL, APRIL 20-21, 1988

ALL NUMBERS EXCEPT THE GAS VOLUMES ARE PERCENTAGES

CATEGORY OF GAS RESOURCE	GAS, Tcf	MEAN % RECOVERABLE <$3./Mcf	MEAN % RECOVERABLE $3.-5./Mcf	RANGE, % <$3./Mcf Low	RANGE, % <$3./Mcf High	RANGE, % $3.-5./MCF Low	RANGE, % $3.-5./MCF High
PROVED RESERVES, 12/31/86, ONSHORE AND OFFSHORE	159	100	---	---	---	---	---
INFERRED RESERVES/ PROBABLE RESOURCES, ONSHORE	85	100	---	---	---	---	---
INFERRED RESERVES, 12/31/86, OFFSHORE	23	100	---	---	---	---	---
EXTENDED RESERVE GROWTH IN NONASSOCIATED FIELDS ONSHORE	119	47	15	43	60	12	30
GAS RESOURCES ASSOCIATED WITH OIL RESERVE GROWTH*	61	49	18	20	60	8	30
UNDISCOVERED ONSHORE RESOURCES	219	40	27	20	50	15	40
UNDISCOVERED OFFSHORE RESOURCES	134	40	21	28	50	15	25
SUBTOTAL	**800**						
GAS IN LOW-PERMEABILITY FORMATIONS	180	39	27	20	45	20	40
COALBED METHANE	48	16	8	5	40	2	20
SHALE GAS	31	33	15	25	40	10	25
SUBTOTAL	**1,059**						
ALASKA: RESERVES	33	PANEL AGREED THAT 7 TCF WAS RECOVERABLE AT <$3.00					
ALASKA INFERRED RESERVES (COOK INLET AREA)	3						
ALASKA UNDISCOVERED, ONSHORE AND OFFSHORE	93	PANEL AGREED THAT 2 TCF WAS RECOVERABLE AT <$3/MCF AND 2 TCF AT $3.-5./MCF					
TOTAL	**1,188**						

*Judged at oil prices of <$24./bbl and $24.-40./bbl

Gas volume shown is the recoverable gas resource or reserve base against which judgements were made
All means and ranges calculated after excluding the highest and lowest estimate in each group
Prices are wellhead prices in 1987$

Inferred Reserves/Probable Resources Onshore

This category is judged on a consensus estimate of 85 Tcf of inferred reserves/probable resources onshore in the Lower 48 states. All gas in this category was judged economically recoverable at <$3.00/Mcf wellhead price (1987$).

Inferred Reserves/Probable Resources Offshore

A total of 23 Tcf of gas in this category in the Lower 48 states is judged 100 percent economically recoverable at <$3.00/Mcf wellhead price in 1987$.

Extended Reserve Growth in Nonassociated Gas Fields, Onshore

Definition of this element of the natural gas resource base forms a major contribution in that it represents gas distributed in known fields recoverable through intensive development of heterogeneous reservoirs. More than 300 plays, or groups of geologically related reservoirs, including some 10,000 fields were evaluated nationally to define a natural gas resource of 105 Tcf in existing fields. This resource is accessed through infill drilling and recompletion of bypassed zones. An additional component of gas reserve growth amounting to 14 Tcf of resources is associated with reserve growth of new pools and extension drilling to develop onshore inferred reserves/probable resources. The total volume resulting from definition of the extended reserve growth potential is 119 Tcf. Of that, 56 Tcf is judged recoverable at less than $3.00/Mcf and 18 Tcf is judged recoverable at $3.00 to $5.00/Mcf (wellhead price, 1987$).

Gas Resources Associated with Oil Reserve Growth

Detailed data on 450 large reservoirs in Texas and an in-depth study of part of the Permian Basin in West Texas were used to extrapolate to the national level (Lower 48, light oil resource base) the increased amounts of associated gas potentially recoverable through oil reserve growth. Oil reserve growth, the improved recovery of mobile oil from known reservoirs, is currently the largest contributor to oil reserve additions. The national resource evaluated by the Review Panel in this category is 61 Tcf, of which 30 Tcf is judged recoverable at <$24.00/bbl and 11 Tcf is judged recoverable at $24.00 to $40.00/bbl (wellhead price, 1987$).

Undiscovered Recoverable Onshore Resources, Lower 48 States

Varying estimates exist for this category between the U.S. Geological Survey (USGS) and the Potential Gas Committee (PGC). PGC estimates contain a component of the low-permeability gas resource that is not included in USGS estimates. The difference between the two approaches must be accounted for to make comparable evaluations within this assessment. A weighted average 26 percent low-permeability resource in the PGC estimate of possible and speculative resources was excluded to make a comparable evaluation. The USGS did not include gas from low-permeability formations in their estimate of undiscovered resources, and this adjustment of the PGC estimates places them on the same basis as the USGS estimates. Further, estimates of undiscovered gas resources for the Anadarko Basin in both estimates (25 Tcf for the USGS, and 112 Tcf for PGC) were replaced on a consensus basis by a 1988 estimate of 46 Tcf made by Energy and Environmental Analysis, Inc., for the Gas Research Institute. Setting aside estimates of gas in low-permeability formations and the Anadarko Basin, estimates by the USGS and the PGC are comparable. The resulting estimate on which the Review Panel acted was an undiscovered Lower 48 onshore resource of 219 Tcf. Some 88 Tcf of this resource is judged recoverable in the lower price category (<\$3.00/Mcf) and 59 Tcf in the higher price category (\$3.00 to \$5.00/Mcf).

Undiscovered Offshore Resources

The Review Panel utilized the MMS estimate of 128 Tcf for Federal offshore Lower 48 undiscovered gas resources rather than average the MMS and the PGC estimates. This was done in view of the data base and modeling conducted by the MMS, as well as the fact that the MMS included deep water estimated resources in the Gulf of Mexico and the PGC did not. The Review Panel added 6 Tcf for State offshore to MMS Federal offshore for an undiscovered offshore resource total of 134 Tcf. The judgment of the Review Panel is that 54 Tcf was recoverable at <\$3.00/Mcf and that 28 Tcf was recoverable at \$3.00-\$5.00/Mcf.

Gas in Low-Permeability Formations

Large estimated volumes of in-place gas exist in low-permeability formations in the U.S., but only smaller amounts are considered recoverable with present technology. The Review Panel decided to exclude low-permeability formations of the Northern Great Plains from consideration in this assessment (as described later in this report) in order to maintain a conservative approach to economically recoverable gas. Of a technically recoverable resource base of 180 Tcf, the Review Panel judged 70 Tcf recoverable at <\$3.00/Mcf and 49 Tcf recoverable at \$3.00 to \$5.00/Mcf. Volumes of gas in tight formations assume current technology, but with advanced technology larger volumes of gas could be recovered.

Coalbed Methane

Of 215 Tcf of original gas in place appraised by ICF-Lewin Energy, 90 Tcf is considered technically recoverable. Further, 48 Tcf of that technically recoverable volume is accessible in areas of currently producing basins where production has not yet been developed. The Review Panel considered this volume of gas as the basis for its assessment. Of the 48 Tcf, 8 Tcf is judged recoverable at the lower price (<$3.00/Mcf) and 4 Tcf is judged recoverable at the higher price ($3.00 to $5.00/Mcf) (wellhead price, 1987$).

Shale Gas

ICF-Lewin Energy indicates an appraised resource of 84 Tcf out of an original gas in place of 800 to 1,900 Tcf. Of the appraised resource, 31 Tcf is recoverable using current technology. The Review Panel judged that 10 Tcf of the 31 Tcf resource is recoverable at <$3.00/Mcf and and an additional 5 Tcf is recoverable at $3.00 to $5.00/Mcf.

Other Resources

Gas, natural or synthetic, is available from a variety of other sources but not considered in this analysis. These include gas in water-driven, depleted reservoirs, and mature, saturated in geopressured-geothermal waters, each available through co-production of water and gas. Also not considered is an increment of natural gas potentially available through reserve growth of natural gas fields yet to be discovered. Finally, this analysis does not consider nor address synthetically produced gas from coal and other sources, nor does it consider gas hydrates.

Levels of Uncertainty

Estimations of volumes of natural gas in different categories of the resource base, as well as volumes estimated to be recoverable at different price levels, have varying levels of uncertainty associated with them. Following is a summary of the uncertainty associated with each element of the natural gas base herein considered:

- <u>Proved Reserves, Lower 48: 159 Tcf, all economic at under $3.00/Mcf</u>

  This is the most certain element of the resource base because the definition of proved reserves states that they are the estimated quantities that analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Still, proved reserves from a given field are often adjusted as operating data are accumulated. Since this gas should be recoverable under existing economic conditions, it is all considered to be economic at under $3.00.

- <u>Inferred Reserves/Probable Resources, Lower 48: 108 Tcf, all economic under $3.00/Mcf</u>

  This is gas from the expected expansion of known fields through development drilling of field extensions and pools at other, generally greater depths. This gas is more uncertain than proved reserves since the wells to produce it have mostly not been drilled, but at least we know the reservoirs are there.

- <u>Reserve Growth:</u> <u>Nonassociated Gas: 119 Tcf, 56 Tcf (47%) under $3.00</u>

  <u>Associated Gas: 61 Tcf, 30 Tcf (49%) under $3.00</u>

  This is gas not contacted in existing reservoirs at current fields spacings and completion intervals. It would be recovered by infill drilling and recompletions.

The estimates are based on geologic analysis of the heterogeneity in oil and gas reservoirs and estimates of the amount of uncontacted gas as a function of geologic setting. The extrapolation to the whole U.S. rests on a number of assumptions, here considered conservative. Since the gas occurs in existing reservoirs, it would tend to be relatively inexpensive.

- Undiscovered Resources:

  Lower 48 Onshore: 219 Tcf, 88 Tcf (40%) under $3.00

  Lower 48 Offshore: 134 Tcf, 54 Tcf (40%) under $3.00

  These estimates are based on geologic analysis and judgment by the USGS, the PGC, and the MMS. They are the most uncertain of the resource categories as they include possible undiscovered gas reservoirs in known gas-producing basins and speculative reservoirs in basins that currently do not produce gas. The economic estimates include finding costs, but do not necessarily address the availability of pipelines or markets or the timing of production.

- Alaska: Proved Reserves: 33 Tcf, 7 Tcf under $3.00/Mcf

  Undiscovered Resources: 93 Tcf, 2 Tcf under $3.00/Mcf

  Alaskan North Slope reserves are an exception to the definition of proved reserves in that they are not recoverable at current economics because of lack of transportation. Thus, only the 7 Tcf of southern Alaska reserves is economic under $3.00 Mcf. Similarly, the estimated undiscovered resources would be producible only in southern Alaska, if found.

- Unconventional Gas:

  Tight Formations: 180 Tcf, 70 Tcf (39%) under $3.00/Mcf

  Shale Gas: 31 Tcf, 10 Tcf (33%) under $3.00/Mcf

  Coalbed Methane: 48 Tcf, 8 Tcf (16%) under $3.00/Mcf

The uncertainty associated with these unconventional resources lies somewhere between that of inferred and undiscovered resources. The existence of the resource is fairly certain since the estimates are based mostly on basins with existing production from these formations. The estimates assume only existing technology and thus are fairly conservative. The estimates do not necessarily address the timing of production or the availability of pipeline transportation.

* * * * * *

Finally, it must be emphasized that all elements of the natural gas resource base, except proved reserves, must be converted to reserves before they can be produced and become part of the supply stream. The volume of the resource base that ultimately becomes supply is dependent upon volume of drilling, in turn sensitive to price, technology, and technology development.

INTRODUCTION

This assessment of natural gas resources of the United States incorporates an examination of the traditional resource estimates and of nontraditional resource increments. The latter are derived principally from the expected growth of reserves in existing reservoirs. Existing estimates of natural gas resources are based on different methods and include different segments of the total resource base. This study places existing estimates on a comparable basis so that similarities and differences between estimates of various elements of the resource base can be better determined. Once estimates are appropriately disaggregated into similar elements, the existing total estimates of the U.S. Geological Survey (USGS), Minerals Management Service (MMS), and Potential Gas Committee (PGC) are similar.

This assessment of natural gas reserves and resources examines all major categories of the domestic natural gas supply and further attempts to define availability by wellhead price in 1987 dollars. Gas availability by price was examined through economic modeling by ICF-Lewin Energy using data supplied by the Bureau of Economic Geology for conventional reservoirs. An additional estimate of natural gas reserves and resources attainable at prices of less than $3.00/Mcf and $3.00 to $5.00/Mcf was made for this assessment by a Review Panel of analysts familiar with natural gas supply issues (table 2). These panel members helped guide the study by providing valuable insights and direction as well as data and evaluations of those data necessary for this assessment.

Approach to the Study

The approach to this study was to define all major categories of conventional natural gas reserves and resources, unconventional supplies from low-permeability formations, shale gas and coalbed methane, and nontraditional sources of gas through reserve growth. Data on existing reservoirs and proved reserves were derived from the Significant Oil and Gas Fields of the United States Data Base (NRG Associates, 1985) and the U.S. Department of Energy, Energy Information Administration (EIA). Data on undiscovered gas resources were derived from the USGS, the MMS, and the PGC. Supplementary sources of data included the Gas Research Institute (GRI).

Critical to this study was an understanding of the different definitions of natural gas resources covered within each of these sources of data. In particular, it became evident through the course of this assessment that apparently varying total resource estimates became less divergent as each estimate was disaggregated. For example, the largest difference in undiscovered resources for any region in the Lower 48 states was between the USGS estimate and the PGC estimate for the Anadarko Basin. Selection of a compromise resource value for this assessment was agreed upon by the project Review Panel. Further, recognition of the inclusion of low-permeability gas resources in the PGC estimates but not in the USGS and MMS estimates was equally important in comparing existing estimates.

The purpose of this study is not to duplicate resource estimates that already exist. Rather, it is to explore the assumptions underlying these estimates, define critical differences, and proceed to evaluate systematically the potential for gas reserve growth that can provide additional gas resources. Delineation of these resources is based on new understanding of the complexity of reservoirs, termed reservoir heterogeneity, which derives from the interplay of geologic and engineering characteristics. No part of this assessment would have been possible without the thorough studies that preceded it. Further, the authors of those studies and their organizations provided extensive cooperation in the effort reported here, without which this synthesis could not have been made.

Consideration was given to existing data on the economics of field development in selecting the <$3.00/Mcf price for this assessment. The EIA (1986) reviewed the economics of natural gas resources and considered the gas price required to yield a 15-percent rate of return (ROR) for nonassociated gas field development. The analysis was based on constant 1984 dollars per million Btu, roughly equivalent to price per Mcf.

EIA considered price by field size, depth, and region. As might be expected, the price required to reach a 15-percent ROR for field development increases with depth, decreases with increasing field size, and is generally higher on the West Coast and in the Rocky Mountains than in Texas and Louisiana. While conversion of 1984$ to 1987$ would tend to increase the required price to achieve the stated ROR, drilling costs have decreased in the same period. The price computation used by EIA (1986) uses the developmental well success rate for each depth horizon (to yield dry hole costs) but does not include any lease acquisition or geologic and geophysical costs. Lease acquisition is not a cost for areas already under development, presumably held by production, and available for field drilling. Geologic and geophysical costs to define infill drilling targets would have to be added, however. A representative well for each region was defined using well spacing, recovery per well, initial producing rates, and pressures and production schedules.

Reduction in drilling and equipment costs from 1984 to 1987 and dollar conversion between those years should approximately balance, or even make 1987 price-equivalents slightly lower than the 1984 dollars used by EIA (V. Kuuskraa, personal communication, 1988). If so, then development wells for a 1.1- to 4-Bcf field are economic at <$3.00/Mcf (1987$) in South Louisiana, South Texas, West Texas, and the Midcontinent to at least a depth of 12,500 ft and in the Rocky Mountains to at least a depth of 7,500 ft based on the EIA report (1986, table 25). This field size, range of depths, and areal extent cover the bulk of the nonassociated advanced gas resource in terms of its distribution in known fields. Thus, the EIA analysis tends to support the use of a <$3.00/Mcf (1987$) price as a reasonable choice for this assessment. EIA's (1986) prices to yield a 15-percent ROR for a 1.1- to 4-Bcf field range from $1.91/MMBtu in South Louisiana to $2.4/MMBtu in South Texas to $2.62/MMBtu in West Texas for a 12,500-ft well.

The Role of the Review Panel

The national Review Panel of resource analysts (table 2) participating in this study provided critical advice during the course of the study and review during preparation of results. The panel met in Washington, D.C., on March 8, 1988, to set the direction of the effort and in Austin, Texas, April 20-21, 1988, to review results of the resource analysis. Further review of a draft final report was undertaken by each member.

At the Austin meeting, the Review Panel was presented with the basic data, the methodology, and the results from the analysis of each resource category. Where a range of resource options from optimistic (higher resource) to conservative (lower resource) was available, a conservative approach was implemented. This direction was consistently endorsed by the Review Panel in determining the gas resource volumes summarized in table 1.

A further key role of the Review Panel was to make a judgment of the volumes of natural gas in an agreed upon resource base that would be economically recoverable at 1987 wellhead prices of <$3.00/Mcf and at $3.00 to $5.00/Mcf. This judgment was made with economic modeling by ICF-Lewin Energy (appendix 3) as well as economic estimates made by the USGS, MMS, EIA (1986), and Kent and others (1987) as guidelines in determining economically recoverable volumes of parts of the nonassociated and associated gas reserve growth potential. Also, ICF-Lewin Energy provided analysis of technically recoverable volumes of low-permeability gas resources, shale gas resources, and coalbed methane.

Further, some of the economically recoverable gas resource cost relations discussed by the Review Panel were developed using economic analyses from GRI. This was for the offshore new fields and for probable resources (onshore and offshore) from the Hydrocarbon Model developed by Energy and Environmental Analysis, Inc., for GRI. The Review Panel voted on recoverable percentages in each price range for each resource. The highest and lowest individual percentage estimates were discarded from each assessment and the arithmetic mean of the remaining values was used to define the economically recoverable gas in each price range.

Elements of the Resource Base

Each element of the natural gas reserve and resource base is delineated and assessed, and evaluations by the national Review Panel are presented. Detailed information on methodologies, regional results of particular assessments, the economic modeling, and considerations of resource development and technologies are contained in a volume of appendices to this report.

PROVED RESERVES

Proved reserves are "those volumes of oil and gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions" (Energy Information Administration [EIA], 1987). Thus, proved reserves are economically recoverable by definition. For this assessment, and with the concurrence of the Review Panel, 100 percent of Lower 48 states proved natural gas reserves are judged recoverable at less than $3.00/Mcf wellhead price (1987$). The total volume indicated in the Lower 48 states is 158.922 Tcf, or 159 Tcf for summary purposes (EIA, 1987). The distribution of gas reserves in major producing areas is listed in table 4. The basis is total dry gas. Alaskan gas reserves are largely judged not to be available within the price ranges considered in this study (<$3.00/Mcf, $3.00 to $5.00/Mcf) owing to the lack of transportation to market for North Slope Alaskan gas.

TABLE 4. TOTAL DRY NATURAL GAS RESERVES - LOWER 48

Major Producing States	1986 Production Tcf	12/31/86 Proved Reserves Tcf	% Production (cumulative)		% Reserves (cumulative)	
(1) TX (onshore + state offshore)	4.620	40.574	30		26	
(2) Federal Gulf of Mex. (TX, LA, AL)	3.965	32.898	26	(56)	21	(47)
(3) Oklahoma	1.658	16.685	11	(67)	10	(57)
(4) LA (onshore + state offshore)	1.741	12.930	11	(78)	8	(65)
(5) New Mexico	0.628	11.808	4	(82)	7	(72)
(6) Kansas	0.461	10.509	3	(85)	7	(79)
(7) Wyoming	0.402	9.756	3	(88)	6	(85)
TOTAL			88		85	
Total Lower 48 + Federal offshore	15.286	158.922				

WET GAS AFTER LEASE SEPARATION - LOWER 48 (Tcf)

Nonassociated = 139.070

Associated-Dissolved = 28.684 *

Total = 167.754 **

*Alaska associated gas = 30.893 Tcf.

**83% of total wet gas after lease separation is nonassociated gas reserves. The equivalent dry basis is given above.

Source: Energy Information Administration (1987)

PROBABLE RESOURCES OR INFERRED RESERVES

Probable resources in the terminology of the Potential Gas Committee (PGC) and inferred reserves in the terminology of the U.S. Geological Survey (USGS) and Minerals Management Service (MMS) "bridge the boundary between discovered and undiscovered resources" (PGC, 1987). They form "that part of the identified economic resource that will be added to known fields through extensions, revisions and new pay zones" (Dolton and others, 1981). The extension drilling referenced largely involves the future extension of existing pools in known productive reservoirs where the pool has not been completely delineated by development drilling. New pool discoveries, either in shallower or (more likely) in deeper formations also are included.

Inferred reserves are derived by the USGS and MMS, however, from the historical growth of fields recorded through 1979 using data series published jointly by the American Petroleum Institute and the American Gas Association. Through that time very little infill drilling for gas below 640-acre spacing had occurred (see appendix 2, Well Spacing).

The PGC estimates probable resources based on the stage of development of individual fields and does not rely on statistical projections of field growth, although historical precedents of well spacing and recovery are considered. Therefore the PGC estimates generally do not capture those volumes of potential reserve growth in heterogeneous reserves accessible through more intensive field development and recovery.

Onshore Region

The distribution of probable resources/inferred reserves is shown in table 5. The elimination of the low-permeability component from the PGC estimate does much to

TABLE 5. ANALYSIS OF PROBABLE RESOURCES/INFERRED RESERVES

BASED ON PGC AND USGS-MMS DECEMBER 31, 1986 ESTIMATES,Lower 48 (Bcf)

REGION*	PGC	USGS	
Pacific [California]	1,545	2,500	**PGC less tight (37%) = 81 Tcf**
Rocky Mtn. [Rocky Mtn.+Plateau+Basin and Range]	36,551	8,500	**Average of PGC less tight and USGS = 85 Tcf**
P-430+P-440 [Permian]	16,000	13,000	
Midcontinent -(P-430+P-440) [Midcontinent]	31,600	18,300	
Gulf Coast [Gulf Coast]	20,350	41,000	
Atlantic [Eastern+Ill.-Mich.+Warrior]	21,950	5,000	
TOTAL	**127,996**	**88,300**	

ONSHORE PROBABLE RESOURCES/INFERRED RESERVES REPORTED IN THIS ASSESSMENT = 85 Tcf
*USGS areal designations in brackets

OFFSHORE	PGC	MMS	
Gulf	25,235	5,800	
Atlantic	none	none	**KNOWN RESERVES (MMS) = 49.18**
Pacific	237	160 *	**KNOWN RESERVES (PGC) = 34.22**
Subtotal	25,472	5,960	**15 Tcf****
		+ 15,000 **	
		20,960	
		+ 2,000 ***	
TOTAL		**23 Tcf**	

OFFSHORE PROBABLE RESOURCES/INFERRED RESERVE REPORTED IN THIS ASSESSMENT = 23 Tcf
*2 Tcf in Pacific region, no precision to Bcf level implied
**Addition of gas carried by MMS as proven reserve equivalent to part of PGC probable (MMS/EIA difference)
***Addition of gas in state waters

reconcile the PGC and USGS assessments. Inasmuch as the USGS estimate excludes low-permeability resources, this adjustment places both estimates on an equivalent basis. USGS estimates may be conservative because some parts of designated low-permeability formations may produce from conventional permeability reservoirs. Across all onshore regions, the PGC estimated in 1982 that 37 percent of the probable resource in their estimate represented gas in low-permeability reservoirs under conditions similar to current production from such reservoirs. Such occurrences are not judged to require significant advances in technology to recover the gas. Applying this adjustment to a total of approximately 128 Tcf of resource yields a revised PGC estimate of 81 Tcf of onshore conventional Lower 48 probable resources in reservoirs with relatively high permeability. Averaged with 88 Tcf of inferred reserves (USGS estimate) yields an estimate of 85 Tcf of Lower 48 onshore probable resources/inferred reserves. All of this volume is judged by the Review Panel to be economically recoverable at <$3.00/Mcf wellhead price (1987$).

Offshore Region

Inferred reserves and probable resources offshore as reported by the MMS and PGC differ for the Gulf of Mexico and Pacific (table 5). However, this difference is largely related to differences in the accounting of proved reserves (H. Kent and P. Martin, personal communication, 1988). MMS carries 47.04 Tcf of proved reserves for the Gulf of Mexico Federal offshore compared to 32.9 Tcf carried by the Energy Information Administration (EIA; 1987) and 2.14 Tcf for the Pacific Federal offshore compared to 1.33 for EIA, a total difference of 15 Tcf. Because inferred reserves/probable resources are so closely linked to proved reserves, this kind of difference is possible with different resource accounting. If for comparative purposes the 15 Tcf differential between MMS and EIA is credited to the MMS inferred reserve estimate (table 5), differences between the MMS and PGC estimates are slight.

The Review Panel concurred with this adjustment, and further added 2 Tcf of inferred reserves to be the total evaluated to adjust for the volume of gas in state waters that MMS does not include. The total evaluated was 6 Tcf MMS inferred reserves plus 15 Tcf adjustment for proved reserves plus 2 Tcf adjustment for the volume in state waters (total, 23 Tcf). Adjusted, the PGC estimate (25 Tcf) and the MMS estimate (23 Tcf) are comparable.

The Review Panel made an estimate of the economically recoverable offshore gas resource on the basis of 23 Tcf of resource and judged the total to be recoverable at <$3.00/Mcf wellhead price (1987$). The 23 Tcf volume was derived from the sum of 6 Tcf of MMS inferred resource, 15 Tcf of difference in proved reserves between MMS and EIA data, and 2 Tcf of resource in state waters.

EXTENDED RESERVE GROWTH IN NONASSOCIATED GAS RESERVOIRS

Reserve Growth Estimates

Reserve growth of gas fields has historically been calculated from annual tables of ultimate recovery by year of discovery published by the American Petroleum Institute and the American Gas Association. This data series ends in 1979. As such it captures historical and traditional sources of reserve growth such as extensions and new pools. However, through 1977 the vast majority of major nonassociated gas reservoirs were still at 640-acre spacing and some even at 1280 acres (appendix 2, Well Spacing). As a result, these data do not reflect the potential recovery from reservoirs drilled at closer spacing. To affect the tables published in 1979, such infill drilling would have to have occurred by at least 1977 and probably even earlier.

Within this assessment some 10,000 fields distributed across the U.S. in 334 groups of geologically related reservoirs, termed plays, were evaluated for increased recovery on the basis of their geological complexity. Onshore nonassociated gas reservoirs appraised from the data base represent 90 percent of Lower 48 onshore nonassociated gas reserves. A geological assessment of the reserve growth capacity of these reservoirs was made on a disaggregated basis. An average 16.7 percent of estimated ultimate recovery (EUR) forms the resource target for nonassociated gas reserve growth. The result is a reserve growth potential of 105 Tcf when extrapolated across the full Lower 48 onshore nonassociated gas reserve base.

An additional increment of this element of gas reserve growth will come from more intensive development of inferred reserves/probable resources. Given an average reserve growth factor of 16.7 percent of estimated ultimate recovery, an additional increment of 14.2 Tcf of gas forms a resource target through the growth of probable resources/inferred reserves. For purposes of judging economically recoverable gas, the review panel combined this 14 Tcf of gas with the 105 Tcf of reserve growth potential to form a resource base of 119 Tcf.

Because few major gas reservoirs are developed at spacings below 640 acres per well and even fewer below 320 acres per well (see appendix 2, Well Spacing), it is judged that there is minimal overlap with probable resources/inferred reserves. The latter are derived from historical reserve appreciation factors.

Economic Access to Nonassociated Gas Reserve Growth

The Review Panel was asked to judge the economic recoverability of this nonassociated gas reserve growth resource. This judgment was made after review of ICF-Lewin's economic evaluations (appendix 3). The price categories used were <$3.00/Mcf and $3.00 to $5.00/Mcf wellhead price in 1987$. The judgment was made on a resource base of 119 Tcf consisting of 105 Tcf of nonassociated gas reserve growth from existing reservoirs and 14 Tcf from reserve growth of current probable, or inferred, resources. The mean results of the Review Panel's judgment were that 47 percent, or 56 Tcf of gas, is economically recoverable at <$3.00/Mcf and that an additional 15 percent, or 18 Tcf, is economically recoverable at $3.00 to $5.00/Mcf. These percentages were computed after deleting the high and the low estimate in each price category. The range of estimates was 43 to 60 percent for the lower price category and 12 to 30 percent for the higher.

Explanation of Project Approach to Reservoir Heterogeneity

Abundant case studies and specific examples of reservoir heterogeneity for oil reservoirs clearly show that these reservoirs are more complex and compartmentalized than previously thought. Thus, poorly drained or entirely uncontacted reservoir compartments are left as targets for infill drilling and recompletion of wells in all but the simplest reservoirs with the most efficient drive mechanisms. This complexity is not surprising given the average 38-percent primary and secondary recovery across Texas oil reservoirs, a subset of national reservoirs that accounts for one-third of U.S. production.

Although affected by the greater mobility of gas in the reservoir, the same factors of reservoir heterogeneity applicable to oil reservoirs apply to gas resources. Current estimates of gas resources by the U.S. Geological Survey, the Minerals Management Service, and the Potential Gas Committee do not reflect the potential for field reserve growth through recompletion of bypassed zones and infill drilling to incompletely contacted or totally isolated reservoir compartments because this element of reserve growth has not been part of the historical natural gas mix. Development of gas reservoirs by these methods will be guided by an increasing availability of case studies on the geology and engineering properties of complex reservoirs and the relation of these properties to hydrocarbon producibility. Few such studies exist for gas reservoirs; however, when taken with oil reservoir case studies and fundamental understanding of reservoir sedimentology, a hierarchy of reservoir complexity can be defined. This hierarchy can be defined separately for carbonate and sandstone reservoirs as one major division in reservoir type; that approach has been taken for this study.

For both sandstones and carbonates, major depositional reservoir types are listed in descending order of geologic complexity (tables 6 and 7). For sandstones, complex, fine-grained submarine fan systems represent a high degree of facies variation that is compounded by fine grain size, which limits the extent of a well's drainage radius. An example is the Spraberry Formation, a submarine fan system deposited in the deep central part of the Midland Basin of West Texas. On the opposite end of the scale are massive barrier-core deposits that consist of thick buildups of sandstone representing ancient barrier-island systems. The resulting reservoirs parallel the margin of ancient basins and can be found, for example, in the Frio Formation of the Gulf Coast Basin in Texas. Within these end members some 22 different sandstone reservoir types were rated for their relative degree of complexity and given a heterogeneity rank on a scale of 1 to 10 (table 6).

The same approach was taken for the ordering of 12 types of carbonate reservoirs that as a group are more heterogeneous than sandstones. Biogenic deposition (carbonate-secreting organisms) and chemical precipitation as a mode of deposition, combined with later chemical modification, led to greater complexity of the carbonate group. Restricted carbonate platforms have rapidly changing depositional environments related to water depth with a tendency toward precipitation of gypsum and even salt (halite) as the platform grades into evaporitic flats. Multiple cycles tend to occur as in the San Andres/Grayburg carbonates of the Permian Basin in West Texas. On the other end of the scale, larger reef systems can have less internal complexity than other carbonate types as they build vertically, but even these never become as homogeneous as the least complex sandstone reservoirs. Thus, both lithologic types, sandstones and carbonates, do not have equally ranked end members.

Associated with each reservoir type and its related degree of heterogeneity is a gas reserve growth factor (tables 6 and 7). This factor is our judgment of the

TABLE 6. SANDSTONE DEPOSITIONAL SYSTEMS

System	Heterogeneity Rank	Reserve Growth Factor*
Submarine slope/fan/canyon fill, silty to muddy	9.0	25
Fractured shales**	9.0	15
Braided streams	8.0	20
Fine-grained meanderbelt	8.0	20
Tidal deposits	8.0	20
Overwash/backbarrier	8.0	20
Fluvial/deltaic sandstone on carbonate shelf	8.0	20
Deep-water siliceous shales/cherts	8.0	20
Alluvial fan	7.5	20
Fluvial-dominated delta	7.5	20
Coarse-grained meanderbelt	7.0	20 ***La Gloria Field, Texas: 26***
Fan delta	7.0	20
Shelf sandstones	7.0	20
Shelf sandstone on mixed shelves	7.0	20
Submarine slope/fan/canyon fill, sandy	7.0	20 ***Port Arthur Field, Texas: 25***
Lacustrine sandstone/deltas	6.0	17
Barrier shoreface	6.0	17
Eolian	4.5	15
Wave-modified delta	4.5	15 ***Julian Field, Texas: 28***
Wave-dominated delta	3.0	8
Strandplain, sandy	2.5	5
Barrier core	2.0	5

*Percent of Estimated Ultimate Recovery
**Less incremental gas available because of lack of matrix porosity

TABLE 7. CARBONATE DEPOSITIONAL SYSTEMS

System	Heterogeneity Rank	Reserve Growth Factor*
Evaporitic flats (sabkhas)	9.0	25
Restricted platform, shoaling cycles, dolomitized	8.5	22 ***Hugoton Field, Kansas: 25***
Open shelves, extensive diagenesis	8.0	22
Shelf-edge reefs, drapes	8.0	22
Shelf edge, slope, basinal	8.0	22
Karstic overprints	8.0	22
Unconformity	8.0	22
Open shelves, platforms, ramps	7.0	20
Small atolls, pinnacle reefs	7.0	20
Oolitic bars and barriers	6.0	17
Large atolls, pinnacle reefs	5.0	15
Chalks**	3.0	15

*Percent of Estimated Ultimate Recovery
**Reserve Growth Factor remains high owing to low permeability

percent of conventional estimated ultimate recovery from a field that is a resource target for advanced gas recovery. These increments of gas obviously parallel the heterogeneity rank in their distribution. The volume of original gas in place (OGIP) represented by each factor is correspondingly smaller. For example, a 20-percent growth factor for a 100-Bcf reservoir whose conventional recovery is 65 percent of OGIP (65 Bcf) represents 0.2 X 65 Bcf = 13 Bcf, or 13 percent of OGIP. Note that more heterogeneous reservoirs will have lower EUR measured by standard methods and will therefore have more potential for reserve growth. The assignment of growth factors is supported by studies of the gas reservoirs with their associated incremental gas resource target noted in italics for the appropriate depositional system. Further guidance was taken from the distribution of unrecovered mobile oil in 450 of the largest oil reservoirs in Texas analyzed by the Bureau of Economic Geology (Galloway and others, 1983; Tyler and others, 1984; Fisher and Finley, 1986). The factors assigned are considered conservative and represent the judgment of a group of reservoir geology specialists at the Bureau. Higher values than those assigned were derived from several case studies, but agreement on the overall hierarchy of heterogeneity rank was not changed as the result of a single case study in a particular depositional system.

For the economic modeling conducted by ICF-Lewin Energy for this study, additional judgments were required to define how much of the incremental gas resource could be captured with additional wells in each square mile of reservoir area. The modeling is for blanket, or uniform, infilling only, and cannot consider strategically placed wells. This determination represents the production function for advanced gas recovery used in the economic model (table 8). The percent recovery for the high heterogeneity class may be optimistic for the 320-acre well, and it may be appropriate to distribute more of this resource into closer spacing categories. Future analyses

TABLE 8. PRODUCTION FUNCTIONS BY HETEROGENEITY CLASS FOR ADVANCED GAS RESOURCE (AGR) RECOVERY

Assumes Wells Beyond One per Section (640-acre spacing) by Blanket Infilling for Purposes of Economic Modeling

HIGH HETEROGENEITY

SPACING	PERCENT OF AGR RECOVERY
320	40
160	30
80	10
40	5

MODERATE HETEROGENEITY

SPACING	PERCENT OF AGR RECOVERY
320	50
160	30
80	5
40	5

LOW HETEROGENEITY

SPACING	PERCENT OF AGR RECOVERY
320	60
160	25
80	5
40	5

should address this question in light of actual field studies and experience likely to be gained in the near future. Note that the production functions are conservative in that an unrecovered increment of advanced gas resource of 15 percent remains for the high heterogeneity class, 10 percent for the intermediate heterogeneity class, and 5 percent for the low heterogeneity class. Thus, the production functions do not assume perfect ability to contact all compartments in heterogeneous reservoirs. The production functions were derived through consultation between Bureau of Economic Geology geological and engineering staff and the resource analysts at ICF-Lewin Energy.

ASSOCIATED GAS RESERVE GROWTH POTENTIAL

During the recent period of stabilization of oil production in the Lower 48 states, from 1979 through 1984, 92 percent of onshore oil reserve additions came from reserve growth, that is, additions other than new field discoveries. Oil reservoirs contributing to this reserve growth contain considerable volumes of associated gas as solution gas and as free gas. Flow rates of many in-field development wells and increased understanding of reservoir heterogeneity indicate that previously untapped reservoir compartments are being drained for the first time during much of this development. Thus, substantial gas volumes remain to be recovered.

This analysis of associated gas reserve growth makes use of data from the Atlas of Major Texas Oil Reservoirs (Galloway and others, 1983), which covers 450 of the largest reservoirs in the state, each with cumulative production of 10 million barrels or more. These reservoirs are divided into 49 plays with similar depositional systems, hydrocarbon source, and trapping style. For each play, an average initial gas-oil ratio (GOR) is given that is a good average measure of the GOR to be expected during development of in-field oil resources.

The volume of the oil reserve growth resource target in Texas also has been calculated from Oil Atlas data. The largest portion of this target resides in the Permian Basin, where complex carbonate reservoirs are predominantly solution gas drive mechanisms. The expected range of GOR that might be applied to the range of reservoir types in different geographic regions is 700 to 1,000 Scf/Stb. This range represents carbonate reservoirs outside Texas (700 Scf/Stb) to an overall Texas estimated value (1,000 Scf/Stb). The resulting estimated gas resource to be recovered through oil reserve growth is therefore 25 to 35 Tcf (table 9).

TABLE 9. ANALYSIS OF ASSOCIATED GAS RESERVE GROWTH POTENTIAL

TEXAS

Region	RRC Districts	Oil Reserve Growth Target, Bbbl
Gulf Coast	2+3+4	4.6
East Texas	5+6	1.2
North Texas	7B+9	3.7
Permian	8+8A	23.7
Panhandle	10	1.8
SUM		**35**

*Based on 450 oil fields in Texas, grouped by play and region

Estimated range of GOR = 700 to 1000**

Estimated range of Associated Gas Reserve Growth Potential in Texas:

35 Bbbl x 700 Scf/Stb = 25 Tcf

35 Bbbl x 1000 Scf/Stb = 35 Tcf

**Expected GOR in Scf/Stb; about 1,000 Scf/Stb for Texas, 700 Scf/Stb carbonate reservoirs outside Texas

U.S.

Total U.S. Lower 48 Discovered Light Oil Resource..............................	**363 Bbbl**
Total Texas Discovered Light Oil Resource..	**150 Bbbl**
Ratio of National Lower 48 Discovered to Texas Discovered Resource.....	**2.42**
Estimate of Lower 48 Associated Gas Resource From Oil Reserve Growth: (2.42 times lower limit of Texas estimate [25 Tcf])	**61**

To extrapolate this result to the Lower 48 states requires a ratio of the discovered light oil resource in Texas (150 Bbbl) to the discovered light oil resource in the extrapolated region (363 Bbbl) (table 9). The ratio of 2.42 may then be multiplied by the lower limit of the expected Texas resource to give a Lower 48 states estimate of 60.5, or 61, Tcf of associated gas reserve growth potential. Texas contains a diversity of reservoir types and, except for coarse-grained submarine fan systems in California and shelf-bar systems in the Rocky Mountain region, is a reasonable sample of national reservoir types.

The Review Panel believes that oil prices will be the controlling factor in the recovery of the associated gas through oil reserve growth. Therefore, the panel estimated volumes of oil and associated gas economically recoverable at oil prices of <$24.00/bbl and at $24.00 to $40.00/bbl in 1987$. At less than $24.00/bbl, 49 percent, or 30 Tcf, was judged recoverable, and at $24.00 to $40.00/bbl, an additional 18 percent, or 11 Tcf, was judged recoverable. The range of estimates was 20 to 60 percent recovery at <$24.00/bbl and an additional 8- to 30-percent recovery at $24.00 to $40.00/bbl after deleting the highest and lowest estimate in each category.

UNDISCOVERED GAS RESOURCES

Undiscovered gas resources have been estimated by the U.S. Geological Survey (USGS) and Minerals Management Service (MMS) in an update of the 1981 USGS Circular 860, and by the Potential Gas Committee (PGC) as part of their ongoing biennial assessment (see appendix 1, Methods). For onshore and state waters, the USGS has adopted a play-based approach for significant fields in their current estimate using the Significant Oil and Gas Fields of the United States Data Base produced by Nehring and Associates (NRG Associates, 1985) as a major source of data. The MMS approach for evaluation of offshore resources employs input of geological and geophysical factors into a mathematical model followed by a Monte Carlo simulation. A second model is used to evaluate economics for those prospects found to be hydrocarbon bearing on a Monte Carlo trial (Cooke, 1985). The approach of the PGC centers on estimates of numbers and sizes of undiscovered fields and pools, volumes of gas-bearing rock, yield factors, probability of trap existence and trap fill, and other parameters that stem from the judgment of individuals with knowledge of the region being evaluated. Each of these methods is different in its approach and execution.

Onshore Resources

A further consideration is that different portions of the onshore resource base may be included or excluded by definition at the start of the analysis. In the 1988 update of the 1981 analysis, the USGS rigorously excluded tight, or low-permeability, gas reservoirs by definition. Without some correction for this resource category, the estimates of the USGS and PGC cannot be reasonably compared. A further complication arises in that geographic areas by which results are reported do not match precisely for onshore USGS and PGC areas, but for purposes of this assessment the major focus is on the larger components of the total resource. The PGC estimates were adjusted for the inclusion of tight-formation resources using a resource-volume weighted average for the possible and speculative resource categories. On average, 26 percent of these resources is attributed to tight reservoirs on the basis of individual estimates of 19 percent for possible resources and 36 percent for speculative resources given in the 1982 PGC resource estimate.

The most significant difference between the USGS and PGC estimates for onshore areas exists for the Anadarko Basin region of Oklahoma. Resource estimates vary from 25 Tcf by the USGS to 112 Tcf by the PGC.

The USGS and PGC onshore resource estimates (less Anadarko Basin) differed by only 15 Tcf (table 10). The Review Panel utilized an onshore undiscovered resource base of 173 Tcf of resources, the average of the USGS and PGC estimates, exclusive of the Anadarko Basin. An estimate of 46 Tcf from a study by Energy and Environmental Analysis, Inc., supported by the Gas Research Institute (Hugman and Vidas, 1988) was accepted by the Review Panel as a compromise volume for purposes of determining economically recoverable undiscovered gas resources in the Anadarko Basin. The Review Panel judged that 40 percent of a total of 219 Tcf of Lower 48 onshore resources, or 88 Tcf, is economically recoverable and discoverable at <$3.00/Mcf (1987$). An additional 27 percent of the total resource, or 59 Tcf, is judged economically recoverable and discoverable at $3.00 to $5.00/Mcf (1987$). The range of estimates for <$3.00/Mcf was 20 to 50 percent recoverable and for $3.00 to $5.00/Mcf was 15 to 40 percent. The highest and lowest estimates in each category were removed to define the average and range of percentage economic recoveries.

TABLE 10. COMPARISON OF USGS (DRAFT) AND PGC (1988) UNDISCOVERED ONSHORE GAS RESOURCES

As of December 31, 1986, (Tcf) Mean (USGS) and Most Likely (PGC) Values

	USGS	PGC	
TOTAL U.S.	254	400.3	
LESS ALASKA	-57.9	-44.1	
LESS ANADARKO BASIN	-25.1	-111.7	
SUBTOTAL	171	244.5	
LESS STATE OFFSHORE	- 6	-63.6	LESS 26 PERCENT TIGHT GAS RESOURCE
TOTAL	**165**	**181**	

AVERAGE OF USGS AND PGC ONSHORE LOWER 48 RESOURCES LESS ANADARKO BASIN = 173 TCF

GAS RESEARCH INSTITUTE ESTIMATE OF ANADARKO BASIN RESOURCES = 46 TCF

TOTAL LOWER 48 ONSHORE RESOURCE ESTIMATE FOR THIS ASSESSMENT = 219 TCF
(173 + 46 = 219)

Offshore Resources

Existing estimates of Federal offshore undiscovered Lower 48 gas resources range from 110 Tcf (PGC) to 128 Tcf (MMS) (table 11). The MMS estimate includes resources judged to occur beneath very deep waters in the Gulf of Mexico. These deep-water resources were not included in the PGC estimate, but are judged by the Review Panel to be significant, and the MMS estimate of 128 Tcf was therefore endorsed. State offshore waters contribute 6 Tcf for a total 134-Tcf undiscovered Lower 48 offshore gas resource. The Review Panel judged that 40 percent, or 54 Tcf, is available at <$3.00/Mcf (1987$) and that an additional 21 percent, or 28 Tcf, is available at $3.00 to $5.00/Mcf (1987$) on a resource base of 134 Tcf. The highest and lowest estimates were removed from each category to define the range and average. The range of estimates exclusive of these high and low values was 28 to 50 percent discoverable and recoverable for the <$3.00/Mcf price and 15 to 25 percent recoverable for the $3.00 to $5.00/Mcf category. It should be noted that the updated (1988) estimates by the USGS and MMS report volumes recoverable at different prices. However, their price ranges are based only on cost of development. The Review Panel, however, elected to make estimates reflecting both finding and development costs.

TABLE 11. COMPARISON OF MMS (DRAFT) AND PGC OFFSHORE LOWER 48 GAS RESOURCES

As of December 31, 1986 (Bcf except where indicated), Mean (MMS) and Most Likely (PGC) values

REGION	MMS*	USGS,Tcf **	PGC***
Gulf	103,340	5	76,725
Atlantic	17,030	0	15,450
Pacific	8,010	1	17,741
Total	**128,380**	**6**	**109,916**

MMS Federal Offshore + 6 Tcf State Offshore = 134 Tcf Total Offshore for This Assessment

*MMS undiscovered recoverable
**State offshore from USGS
***Sum of PGC possible and speculative

UNDISCOVERED SMALL FIELD RESOURCES

In a draft of current (1988) analysis, the U.S. Geological Survey (USGS) has estimated the number of small fields remaining to be discovered. Fields in the Lower 48 onshore are listed in table 12 and include a total of 75,542 fields, about one-third of which are nonassociated gas. Within the latter fields are an estimated 21.6 Tcf of nonassociated gas and 435 MMbbl of natural gas liquids (NGL). Conversion of the NGL to gas equivalent yields 2.54 Tcf of gas; the Btu equivalent of these liquids would contribute to the economics of field development. An additional 7.1 Tcf of associated gas is carried in the total of the small oil fields. The small fields defined by the USGS were included in their overall resource estimate and are not to be considered as a separate additional resource. Although the Potential Gas Committee (PGC) did not make a separate estimate of small fields, the resource contained in such fields is also included in the overall PGC resource estimate. The number of small fields indicates the importance of technical efficiency in access to this resource.

Other estimates of small fields suggest that the total number may be larger than indicated above. If the total number of small fields were more on the order of 110,000 as others have suggested, and half of these fields contained nonassociated gas equivalent to 90 percent of their total hydrocarbons on a Btu basis, then the estimate of small field gas would double to about 50 Tcf. This alternative was not used or considered in this assessment.

Efficient access to small fields less than 1 MMboe will depend on such improved technologies as low-cost, high-resolution seismic data, improved well placement based on advanced depositional and structural modeling, and possibly better drilling and formation evaluation techniques. The timing of implementation of these techniques will

TABLE 12. ANALYSIS OF UNDISCOVERED SMALL FIELDS BASED ON DRAFT 1988 USGS DATA (small field resource included as a component of total resource)

FIELD CLASS	FIELD SIZE, LIMITS, Mmboe	TOTAL FIELDS, NONASSOC. GAS	TOTAL FIELDS, OIL	FIELD SIZE, Mmboe*
1	.032-.063	10,486	22,260	0.046
2	.063-.125	6,794	13,480	0.088
3	.125-.250	4,287	7,777	0.175
4	.250-.500	2,595	4,222	0.35
5	.500-1.00	1,607	2,024	0.7
TOTAL		25,769	49,763	

*Field size is taken as 1.4 times the lower class boundary

Total Gas as Calculated by USGS = 29 Tcf
Total Nonassociated Gas as Calculated by USGS = 22 Tcf

depend on demand for gas resources and the degree to which advanced recovery research and development makes these techniques available to the large number of small companies and independent operators who are most likely to put them to active use.

RESERVE GROWTH OF UNDISCOVERED NONASSOCIATED RESOURCES

Assessment of the gas reserve growth potential of current nonassociated gas reservoirs suggests the potential for a significant resource of gas to be gained through increased understanding of reservoir heterogeneity. This advanced gas recovery component totals some 105 Tcf of potential gas reserve growth, with an additional 14 Tcf (approximately) to be added to current inferred reserves/probable resources. The understanding of reservoir complexity gained through exploitation of this resource will no doubt be transferred into the development of future discoveries.

Estimates of the field size and depth distribution for undiscovered resources have been made in 1988 by the U.S. Geological Survey, by Geological Exploration Associates Ltd. based on work by Kent and Finney (1988), and by the Potential Gas Committee. All sources suggest that a significant portion of undiscovered resources will be in modest-sized fields (class 6 [1 to 2 Bcf] to 11 [32 to 64 Bcf]) as well as in small fields (smaller than class 6). Modest-sized fields, and those large fields remaining to be discovered, will be exploitable to a greater degree using concepts of advanced recovery than will small fields effectively drained by few wells. Assessment of reserve growth potential of undiscovered resources will be accomplished with some confidence as additional case studies of gas reserve growth are made.

Acceptance of gas reserve growth from known reservoirs would be an important first step before reassessment of expected yields from undiscovered fields. Overall, given that predictions of undiscovered resources are made with an historical understanding of gas recoveries, the direction for yields from future discoveries is likely to be positive, especially for larger fields. Improved recovery technologies will certainly be a part of this process in conjunction with a more thorough understanding of depositional heterogeneity. However, this category of resource was not quantified in this assessment and is not part of the total natural gas resource reported here.

RESOURCES IN LOW-PERMEABILITY RESERVOIRS

A significant natural gas resource occurs in formations with low permeability. These so-called tight formations are generally artificially stimulated by hydraulic fracturing in order to produce gas at economic rates. The Federal Energy Regulatory Commission (FERC) defines a low-permeability gas reservoir as one having an average in situ permeability within the pay zone of 0.1 md (millidarcy) or less. Furthermore, the production rate in an unstimulated well cannot exceed a flow rate specified by the FERC for different depth intervals and cannot produce more than 5 barrels of oil per day (Potential Gas Committee, 1981). In this report, shale gas reservoirs are treated separately even though they might fulfill the FERC definition of a tight reservoir.

Low-permeability gas formations have traditionally been divided into blanket and lenticular reservoirs. Blanket reservoirs are 10 to 100 ft thick and extend laterally over a large area; they are composed of sandstone, siltstone, shale, chalk, or limestone. Lenticular formations, generally sandstone or siltstone, contain thick gas-bearing intervals, with laterally discontinuous beds scattered through the section. The National Petroleum Council (NPC, 1980) estimated that more than 40 percent of recoverable gas in tight formations is contained in lenticular reservoirs and that the balance is in blanket reservoirs.

Most of the low-permeability gas reservoirs in the continental U.S. occur in the western states. Estimates by the NPC (1980) of the gas in place in tight formations were made by studying in detail certain basins that were believed to contain 35 percent of the low-permeability gas resource (the appraised basins), and then extrapolating to the remaining potential low-permeability gas areas using basin analogs. The basins or formations appraised in detail were the Northern Great Plains/Williston, Greater Green River, Uinta, Piceance, Wind River, Denver, San Juan, Val Verde (Sonora/Ozona), Edwards Lime, and Cotton Valley. These appraised areas/formations were estimated to contain 444 Tcf of gas in place in tight reservoirs, and the extrapolated areas were estimated to contain an additional 480 Tcf of gas in tight reservoirs (table 13). The estimated volume of technically and economically recoverable low-permeability gas ranges from 192 to 574 Tcf (NPC, 1980) (table 13). The low estimate assumes a price of $2.50/Mcf and a base technology; the high estimate assumes a price of $9.00/Mcf and advanced technology.

A current study by ICF-Lewin Energy (1988) estimates that there is a volume of 433 Tcf in the appraised basins (the same ones evaluated in the NPC study) and another 512 Tcf in extrapolated areas, for a total of 945 Tcf of gas in place in tight formations in the continental U.S. (table 13). The areas of the country containing low-permeability gas resources that were evaluated by extrapolation were divided into four regions. The gas in place estimated for the four regions is as follows: western (79 Tcf); greater southwest (188 Tcf); mid-continent (8 Tcf); and eastern (238 Tcf). The amount of technically recoverable gas in the appraised basins ranges from 108 to 170 Tcf (table 13); the low estimate assumes current technology, and the high estimate assumes advanced technology. The technically recoverable gas in the extrapolated areas ranges from 134 Tcf (current technology) to 228 Tcf (advanced technology).

For this assessment the Review Panel initially considered a volume of technically recoverable low-permeability gas resources of 240 Tcf using current and forseeable technology to be a conservative estimate. These resources could include most of the 63.6 Tcf of low-permeability formation gas resources adjusted out of the PGC estimates. A small percentage of the PGC low-permeability formation resources would

TABLE 13. RESOURCE ESTIMATES OF NATURAL GAS IN LOW-PERMIABILITY FORMATIONS FOR THE CONTINENTAL UNITED STATES

SOURCE OF ESTIMATE	TOTAL GAS IN PLACE	TECHNICALLY RECOVERABLE GAS
NATIONAL PETROLEUM COUNCIL, 1980		
• APPRAISED BASINS	444 TCF	97 - 271 TCF
• EXTRAPOLATED BASINS	480 TCF	95 - 303 TCF
• TOTAL	924 TCF	192 - 574 TCF
ICF-LEWIN, 1988		
• APPRAISED BASINS	433 TCF	108 - 170 TCF
• EXTRAPOLATED BASINS	512 TCF	134 - 228 TCF
• TOTAL	945 TCF	242 - 398 TCF

FOR THIS ASSESSMENT

Technically Recoverable Gas = 240 Tcf - 60 Tcf (Northern Great Plains) = 180 Tcf occur in shale gas reservoirs. The potential of technically recoverable gas is 400 Tcf with advanced technology, but this volume of gas is not considered here.

According to ICF-Lewin Energy, economic model evaluations for price ranges considered in this study show that 162 Tcf of low-permeability gas is economically recoverable in the Lower 48 states at less than $5.00/Mcf (1987$). Furthermore, two-thirds of that volume (105 Tcf) is recoverable at less than $3.00/Mcf (1987$) with current technology (table 14). That technology assumes a maximum fracture half-length of 400 ft, a fracture conductivity of 400 md-ft, and a maximum number of wells per section of 4. The economic constraints that apply to these determinations are a 10-percent rate of return, no depletion allowance, and an 80-percent development drilling success rate (ICF-Lewin Energy, 1988). Because improvements in hydraulic fracturing technology are actively being pursued by industry, service companies, and the Gas Research Institute, increasing quantities of the large low-permeability gas resource are expected to become economically accessible. For example, in the appraised basins, economically recoverable gas available at $2.00/Mcf (1987$) (different price assumption than that for this study) that is now estimated at 44 Tcf will more than double to 93 Tcf with advanced technology. The assumptions for advanced technology include a maximum fracture half-length of 1,000 ft, a fracture conductivity of 800 md-ft, and a maximum number of wells per section of 8. In contrast, assumptions of advanced technology made by the NPC in 1980 involved a fracture half-length of 4,000 ft and well spacings in some cases even closer than 80 acres per well.

All of the above technically and economically recoverable low-permeability gas volumes include gas in the Northern Great Plains region where a relatively shallow, low-pressure resource of mostly biogenic gas exists. The Review Panel excluded 60 Tcf of Northern Great Plains gas from its assessment of technically recoverable gas in

TABLE 14. ESTIMATED UNCONVENTIONAL NATURAL GAS POTENTIAL - CURRENT TECHNOLOGY*

RESOURCE	GIP (TCF)	ECONOMICALLY RECOVERABLE RESOURCE			
		$3/MCF (TCF)	$3-5/MCF (TCF)	$5-10/MCF (TCF)	TOTAL (TCF)
TIGHT GAS SANDS					
• APPRAISED	433	56	19	33	108
• EXTRAPOLATED	512	49	38	46	133
• TOTAL	945	105	57	79	241

* FROM ECONOMIC MODELING BY ICF-LEWIN ENERGY, 1988.

order to maintain a conservative approach. Therefore, 180 Tcf rather than 240 Tcf was evaluated. Of 180 Tcf of low-permeability gas resources, the Review Panel judged, on average, that 39 percent, or 70 Tcf, is recoverable at <$3.00/Mcf (1987$) and that an additional 27 percent, on average, or 49 Tcf, is recoverable at $3.00 to $5.00/Mcf (1987$). These percentages were determined after eliminating the highest and lowest estimate in each price category. After eliminating those two values, the range was 20 to 45 percent for the <$3.00/Mcf category and 20 to 40 percent for the $3.00 to $5.00/Mcf category.

COALBED METHANE

Coalbed methane is gas found in coal seams in sedimentary basins across the United States. Coal seams east of the Mississippi River (eastern coals) are generally Pennsylvanian in age, whereas those of the western United States are mostly Cretaceous or early Tertiary in age. Coal forms when peat (plant remains) is buried and subjected to high temperatures and pressures for an extended period of time (millions of years). Methane is a major product formed as a result of this coalification process.

Some coalbed methane escapes from the coal seam and makes its way into adjacent sandstone reservoir beds. In this case the coal is only the source for the gas, and the accumulation in the sandstone is a conventional resource and is included in the resource estimates of both the PGC and the USGS. In other cases the methane is retained within the coal seam, and the coal is both the source and the reservoir for the gas. The conditions of accumulation and recovery of the resource in the latter situation are only now beginning to be understood, and the technology of recovery is currently under development. The resource within the coal seams is the subject of this section, and estimates of this resource are not included in either the PGC or USGS resource estimates.

Coalbed Methane Resources

The existing range in estimations of coalbed methane resources in the United States, 72 to 860 Tcf (table 15), reflects in large part the uncertainties associated with a little-evaluated resource. The parameters that control the occurrence,

TABLE 15. COALBED METHANE RESOURCE ESTIMATES (TCF) FOR THE UNITED STATES

(Modified from Rightmire, 1984; Tables 1 and 2.) The Rightmire (1984) estimate is for only 14 U.S. coal basins.

STUDY	YEAR	GAS IN PLACE	RECOVERABLE
Rightmire; DOE MRCP (TRW)	1984	134 - 402	- -
Kuuskraa and Meyer	1980	- 550	40 - 60
National Petroleum Council	1980	- 398	- 45
Sharer and Rasmussen (GRI)	1980	- 500	10 - 60
Rosenberg and Sharer (GRI)	1979	72 - 860	16 - 487
FERC	1978	300 - 850	- -

abundance, and economic recovery of the resource are poorly understood. Most resource estimates have been made from regional data bases. Estimations of recoverable and economic resources require information not inherent to data bases used to calculate in-place resources.

Because coal seams are the reservoirs for coalbed methane, several of the gas-in-place estimates reported in table 15 were based on U.S. Geological Survey (Averitt, 1975) estimates of coal resources in the United States. Using these coal resource figures (tonnages) and an average gas content of 200 cf of methane per ton of coal, Federal Energy Regulatory Commission (FERC, 1978) calculated 300 Tcf of gas in place in coalbed methane in coal seams less than 3,000 ft deep and 550 Tcf of gas in place in seams deeper than 3,000 ft. In other studies based on the same coal resource figures, the authors assigned average gas contents on the basis of coal rank (Kuuskraa and Meyer, 1980; National Petroleum Council [NPC], 1980) or on the basis of coal rank and depth (Sharer and Rasmussen, 1980), and some authors adjusted their estimates to allow for that gas that escaped from shallow coal seams (NPC, 1980). In final analysis, all of these estimates, which inherited the uncertainties of the original coal resource estimate, are fairly close, but their high and low estimates vary by as much as an order of magnitude.

A recent study of coalbed methane resources (Rightmire, 1984) (table 16) evaluated 14 coal basins. The estimate is based on coal tonnage calculations made during the course of the study and on analyses of the methane content of coal seams in the respective basins. However, not all coal seams in the studied basins were evaluated, and several coal basins were not included in the study, so the sum of the basin estimates is not a United States total. In view of the range (134 to 402 Tcf) of the estimate and the apparent subjectivity involved in the method of analysis, it appears that this estimate is no more certain than those that preceded it.

Most recently, the Gas Research Institute contracted ICF-Lewin Energy to study the coalbed methane resources in the Northern Appalachian (50 to 100 Tcf; Kelafant and others, 1987), Black Warrior (19.8 Tcf; McFall and others, 1986a), San Juan (56 Tcf; Kelso and others, 1987), and Piceance Creek (84 Tcf; McFall and others, 1986b) Basins. These evaluations were made with more extensive data bases than previous studies, especially with regard to number of analyses of methane content of coal seams. The resource estimates for the Northern Appalachian and Piceance Creek Basins are similar to those of previous studies. However, resources estimates for the Black Warrior and San Juan Basins are nearly twice the size of the earlier estimates (table 16).

If coalbed methane resources are poorly quantified, then recoverable and economic resources are even less certain because of limited production experience and sparse data (Office of Technology Assessment [OTA], 1985) and poor understanding of geologic controls on producibility. The recoverable resources reported in table 15 were derived by a variety of methods, all with shortcomings (see review by OTA, 1985). The disparity between regional <u>resources</u> (gas in place) and <u>economically recoverable resources</u> is evident from a study by ICF-Lewin Energy (personal communication, 1988) that included appraised areas of current coalbed methane production in the eastern and western United States. The study indicates that 7 percent of the in-place gas is economically recoverable at $3/Mcf (1987$), and 8.5 percent is economically recoverable at $5/Mcf. Further, the ICF-Lewin analysis suggests economic resources are more limited by technological and geological factors than by price.

Regional resource estimates for coalbed methane, like those for shale gas reservoirs, are based on volumetric calculations of the reservoir rock. The volume of coal is calculated by summing the thicknesses of coal seams in individual boreholes, posting these values on maps, and contouring the values to get areal distributions of net coal thickness. Thickness is multiplied by area to determine volume, which is

TABLE 16. COALBED METHANE RESOURCES (TCF) FOR 14 U.S. COAL BASINS

(Modified from Rightmire, 1984; and OTA, 1985.)

REGION	BASIN	STATES	GAS IN PLACE
EASTERN UNITED STATES			
	Northern Appalachian	KY, MD, TN, VA	61.0 - 61.0
	Central Appalachian	KY, MD, OH, PA, WV	10.0 - 48.0
	Illinois	IL, IN, KY	5.2 - 21.1
	Black Warrior	AL, MS	5.0 - 10.0
	Arkoma	AR, OK	1.6 - 3.6
	Richmond	VA	0.7 - 1.4
	EASTERN SUBTOTAL		83.5 - 145.1
WESTERN UNITED STATES			
	Piceance Creek	CO	30.0 - 110.0
	San Juan	CO, NM	1.8 - 31.0
	Powder River	MT, WY	5.9 - 39.4
	Greater Green River	CO, WY	0.2 - 30.9
	Western Washington	WA	3.6 - 24.0
	Raton Mesa	CO, NM	8.0 - 18.4
	Wind River	WY	0.5 - 2.2
	Uinta	CO, UT	0.2 - 0.8
	WESTERN SUBTOTAL		50.2 - 256.7
TOTAL (FOR 14 BASINS)			133.7 - 401.8

multiplied by specific gravity to arrive at coal tonnage. Tonnage is then multiplied by gas content of the coal (cf/ton) to derive coalbed methane resources. The estimate thus derived provides an assessment of the gas resource and serves as the foundation for the subsequent estimate of recoverable or economic resources. The evaluation of economic resources, however, must consider several additional geologic factors beyond those influencing gas in place. These factors are discussed below along with an explanation of how they are accounted for in the ICF-Lewin Energy estimates of recoverable coalbed methane.

First, coal is not the homogeneous, continuous reservoir that is suggested by the coal isopach maps used in volumetric studies. Instead, coal occurs in individual non-communicating beds separated by other rock units. Furthermore, coal seams do not extend across entire basins; they are compartmentalized reservoirs. Coal seams have maximum unbroken extents of tens of miles, and they are bounded by facies changes or faults. Because of this, the net pay isopach maps constructed as part of the ICF-Lewin basin analyses need to be, and have been, adjusted in the calculation of recoverable gas. This is accomplished through two methods. First, a history match of actual production data from densely drilled areas in the Warrior and San Juan Basins establishes what volume of coal has actually been contacted by the induced fracture and thus the total coal thickness established from the geologic analysis is adjusted downward. Second, the isopach maps do not include thin, discontinuous coal seams and thus they are not part of the analysis of recoverable gas.

Second, deeply buried coal seams are characterized by severely reduced permeabilities and thus reduced recoverability. This geologic phenomenon is incorporated into the economic analysis through the development of basin-specific correlations relating in-situ permeability to depth. These correlations are derived from laboratory test data and from history matching actual coal seam production data. However, additional research and field testing are greatly needed in this area.

Third, localized geologic phenomena such as natural degasification and fracture spacing and orientation can greatly influence coalbed methane recovery. The ICF-Lewin estimates attempt to incorporate the influence of these geologic factors by using reservoir simulation on a township-by-township basis to estimate recoverable coalbed methane. Townships characterized by shallow or thin coals are excluded from the analysis, as are areas where the gas content of the coal is known to be anomalously low. In addition, depending on data availability, each township is assigned a unique value for fracture spacing and orientation. Again, additional research is needed to better understand the evolution and distribution of fracture patterns in most U.S. coal basins, particularly in areas characterized by the enhanced permeability resulting from closely spaced fractures.

The ICF-Lewin (1988) estimates for recoverable coalbed methane are based on currently available geologic and engineering data and are completed within the context of the current understanding of the factors which control coalbed methane accumulation and recovery. However, improved geologic understanding of the occurrence, distribution, and producibility of the coal resource, particularly site-specific geologic studies, may well show the current estimates of economically recoverable coalbed methane to be conservative.

Economically Recoverable Coalbed Methane

The Review Panel considered a technically recoverable coalbed methane resource of 48 Tcf. This was based on the expansion of present resource development into new areas of currently producing basins using current technology. Of the 48 Tcf, the Review Panel judged that, on average, 16 percent, or 8 Tcf, was recoverable at <$3.00/Mcf, and that 8 percent, or 4 Tcf, was recoverable at $3.00 to $5.00/Mcf (1987$). These percentages are after removal of the high and low estimates for each price category. The range of estimates was 5 to 40 percent for the low price and 2 to 20 percent for the higher price, also after removal of the high and low estimates.

SHALE GAS

Occurrence

Shale gas is methane that occurs in Devonian through Mississippian age formations, primarily in the Appalachian, Illinois, and Michigan Basins of the eastern United States. The Appalachian Basin has the greatest resources and production. The color of Devonian shales varies with organic carbon content, which is commonly 5 to 25 percent (Potential Gas Committee [PGC], 1981). They are broadly classified as black, brown, or gray, with the darker color resulting from greater organic carbon content. The shales, initially clays deposited on the seafloor, have undergone burial, compaction, and thermal maturation, producing methane from the organics in the process. Because of low shale permeability, the gas did not migrate; organic shales are both the source rock and the reservoir for Devonian shale gas. Methane content ranges from 0.003 to 1.110 cf and averages 0.4 cf per cubic foot of shale in the Appalachian and Illinois Basins (Science Applications, Inc., 1980). Methane occurs adsorbed on the organic matter in the shale and as free gas in pores and fractures.

Shale Gas Resources

Estimates of shale gas resources (table 17) range from 387 to 3,900 Tcf (gas in place) for all U.S. basins and 206 to 2,579 Tcf (gas in place) for the Appalachian Basin, which is the largest eastern shale basin, both areally and in terms of shale gas resources; estimates of shale gas show 86 Tcf in the Illinois Basin and 76 Tcf in the Michigan Basin (National Petroleum Council [NPC], 1980). The disparity in estimates is due, in part, to variations in the methods of determining the gas content, reservoir

TABLE 17. DEVONIAN SHALE RESOURCE ESTIMATES (TCF)
(MODIFIED FROM OTA, 1985; PGC, 1981)

SOURCE	YEAR	BASIN	GAS IN PLACE	RECOVERABLE
Zielinski and McIver	1982	Appal.	1440 - 2579	-
Charpentier and Others	1982	Appal.	557 - 1131	-
NPC	1980	Appal.	225 - 1861	- 50
		Ill.	- 86	-
		Mich.	- 76	-
		TOTAL	387 - 2023	-
Kuuskraa and Meyer	1980	Appal.	400 - 2000	10 - 50
		Other	- 1900	-
		TOTAL	2300 - 3900	-
FERC	1978	Appal.	285	60
Smith	1978	Appal.	206 - 903	-

potential, and drainage efficiency for the shales (PGC, 1981). The Charpentier and others (1982), NPC (1980), and Zielinski and McIver (1982) studies (table 17) all calculated gas in place by multiplying gas content, shale content, and areal extent (volumetrics). However, different methods were used to arrive at shale thickness and gas content. For example, NPC (1980) used an average gas content derived from off-gassing of shale. Charpentier and others (1982) calculated gas contents of shale using a variety of data sources. Zielinski and McIver (1982) calculated gas contents for shales and verified their results by comparison with off-gassed samples collected in a pressurized core barrel. They concluded that off-gassed values reported in some studies were erroneously low because of escaped gas.

The regional volumetrics approach is adequate for resource (gas-in-place) estimates, but it is unsatisfactory for determining technically and economically recoverable shale gas, as is evidenced by the few existing reports for these values. The method does not consider important geological variables, such as the extent and density of natural fractures or the presence of silt lenses that affect permeability and, hence, economic production.

For a 40-quadrant area (23,000 mi^2) in a productive region, ICF-Lewin Energy evaluated technically and economically recoverable shale gas in four productive horizons, applying a set of technological, geological, and economic assumptions. They found that, with current technology, 21 percent of the in-place gas is technically recoverable. At \$3/Mcf (1987\$), 14 percent is economically recoverable, and at \$5/Mcf, 18 percent is economically recoverable. Although methods are unavailable for extrapolating estimates of technically and economically recoverable Devonian shale gas, studies directed at such methods are in progress (ICF-Lewin Energy, personal communication, 1988).

Economically Recoverable Shale Gas

The Review Panel considered a technically recoverable shale resource of 31 Tcf. This was based on the expansion of present resource development into new areas using current technology. Of the 31 Tcf, the Review Panel judged that, on average, 33 percent, or 10 Tcf, is recoverable at <$3.00/Mcf and that an additional 15 percent, or 5 Tcf, is recoverable at $3.00 to $5.00/Mcf (1987$). All prices are wellhead prices. These percentages were determined after eliminating the highest and lowest estimate in each price category. The range of estimates was 25 to 40 percent for the <$3.00/Mcf category and 10 to 25 percent for the $3.00 to $5.00/Mcf category.

OTHER UNCONVENTIONAL GAS SOURCES

Near-Term Producibility

Of the three resource types reviewed here (co-production, geopressured-geothermal, and gas hydrates), only elements of the co-production resource are economically recoverable at 1987 gas prices. Improvements in disposal well technology, conversion to co-production practices before abandonment (with plugging and possible mechanical damage), and careful review of reservoir volumes and production histories now lead to economic co-production projects. Near-term applications will expand in the Gulf Coast region with consequent improved reservoir recovery efficiencies where water-drive mechanisms result in low efficiencies. The review panel determined that none of the three types covered in this section offers a near-term definable resource whose cost of production can be evaluated for this assessment.

Co-Production Gas

Co-production refers to the production of natural gas from formations that will not yield gas unless a large amount of water is produced with it. Co-production includes three main types of gas production (Gas Research Institute [GRI], 1986): (1) production from watered-out gas reservoirs, (2) gas previously bypassed because of associated water, and (3) aquifers containing dissolved gas, including geopressured-geothermal reservoirs. Co-production gas occurs as mobile, immobile, and solution gas. Mobile gas is gas that is free to move through the reservoir to the well bore, immobile gas is trapped gas that is not free to move to the well bore, and solution gas is dissolved in the brine (GRI, 1986). All three types of co-production provide gas that would not ordinarily be produced by conventional production methods.

Wells in watered-out reservoirs are usually shut-in and abandoned because of the costs associated with low gas production and the need for brine disposal. However, one-third to one-half of the original gas may remain in the reservoir, much of it as immobile gas that is not free to move to the well bore. By reentering an existing, watered-out well, much of the remaining gas can be recovered by co-production of gas with high-volume brine production. The objective is to produce at a high enough rate to lower the brine level and the reservoir pressure so that the immobile gas expands until it becomes mobile again (GRI, 1986). The trapped gas is then free to migrate to the well bore with the produced water. In a geopressured reservoir, the pressure may be sufficient to produce brine without mechanical pumping; in a hydropressured reservoir, pumping is required for brine production.

A preliminary estimate of the co-production resource in the continental U.S. is 8,990 Tcf of co-production gas in place (table 18), of which 384 Tcf is technically recoverable (GRI, 1986). The estimated volume of co-production gas that is economically recoverable is 50 Tcf (GRI, 1986); this figure includes co-production gas in Alaska. No separate estimate of economically recoverable co-production gas was made for the continental U.S. alone. This estimate of economically recoverable co-production gas assumes production of 100 standard cubic feet of gas per barrel of brine produced (P. L. Randolph, personal communication, 1988). The greatest volume of technically recoverable co-production gas resource is located along the Gulf Coast of Texas (177 Tcf) and Louisiana (167 Tcf). There is an estimated volume of 33 Tcf of economically recoverable co-production gas in the Texas and Louisiana Gulf Coast, assuming that the ratio of economically recoverable to technically recoverable co-

Table 18. OTHER UNCONVENTIONAL GAS RESOURCE ESTIMATES FOR THE CONTINENTAL UNITED STATES

Resource Type	Gas-In-Place	Ultimately Recoverable Resource	Economically Recoverable	Source of Estimate
Co-Production	8,990 Tcf onshore only	384 Tcf onshore only	50 Tcf (includes Alaska) onshore only	Gas Research Institute, 1986
Geopressured-Geothermal	3,100 Tcf* onshore only	97 Tcf* onshore only	Not estimated	Wallace and others, 1979
	2,800 Tcf* offshore only	53 Tcf* offshore only	Not estimated	
	1,100 Tcf* onshore only	50 Tcf* onshore only	Not estimated	Kuuskraa and Meyer, 1980
	690 Tcf# all sandstones	21-35 Tcf# all sandstones	Not estimated	Gregory and others, 1980
	325 Tcf# sandstones >30 ft	10-16 Tcf# sandstones >30ft	Not estimated	
Gas Hydrates	4,200-21,000 Tcf@ offshore only	Not estimated	Not estimated	Trofimuk and others, 1977
	2,700 Tcf@ offshore only	Not estimated	Not estimated	McIver, 1979; Chersky and Makogon, 1970
	6,700,000 Tcf@ offshore only	Not estimated	Not estimated	Dobrynin and others, 1979

* Gulf Coast only

@ Includes Alaska shelf areas

\# Texas onshore only, >8,000 ft

production gas is the same throughout the continental U.S. In the Gulf Coast, the target reservoirs occur at depths from near surface to 6,100 m (20,000 ft); geopressured reservoirs occur at depths greater than about 2,500 to 2,750 m (8,000 to 9,000 ft). Other areas of the continental U.S. with technically recoverable co-production gas include California (26 Tcf), the Rocky Mountains (9 Tcf), and the Mid-Continent (5 Tcf).

Geopressured-Geothermal Gas Resources

Natural gas (mostly methane) that occurs dissolved in geopressured-geothermal reservoirs is a special subset of the co-production resource. Methane solubility is a function of temperature, pressure, and salinity, but typical saturation levels of geopressured brines are 20 to 40 standard cubic feet of gas per barrel of brine (Potential Gas Committee [PGC], 1981). The major geopressured-geothermal regime in the United States occurs along the Texas-Louisiana Gulf Coast at depths greater than about 2,500 to 2,750 m (8,000 to 9,000 ft). Other areas of the country that may contain geopressured-geothermal gas resources are the Arkoma, Big Horn, Wind River, Green River, Piceance, Uinta, San Joaquin, and Mississippi Salt Basins (PGC, 1981).

No estimates have been made for geopressured-geothermal gas resources in the entire continental U.S. Instead, because the Gulf Coast contains by far the major geopressured-geothermal resource in the country, all estimates have focused on this area alone (table 18). Recent estimates indicate that there are in the range of 1,000 to 3,000 Tcf of dissolved gas in place (table 18) in the onshore U.S. Gulf of Mexico and about 3,000 Tcf offshore in geopressured-geothermal reservoirs (Wallace and others, 1979; Kuuskraa and Meyer, 1980). The amount of ultimately recoverable gas in onshore areas has been estimated as 97 Tcf by Wallace and others (1979) but only

50 Tcf by Kuuskraa and Meyer (1980). An estimated 53 Tcf is recoverable offshore (table 18) (Wallace and others, 1979).

A detailed study of sandstone volume and methane solubility in deep geopressured reservoirs of the Texas Gulf Coast indicates that the total volume of dissolved methane in Tertiary sandstones below 2,500 m (8,000 ft) is 690 Tcf in Texas alone (table 18) (Gregory and others, 1980). The total in-place volume of solution methane in "effective" Tertiary sandstones (sandstones that are greater than 9 m [30 ft] thick below 2,500 m [8,000 ft]) is 325 Tcf. The recoverable volumes of dissolved methane in Texas range from 21 to 35 Tcf in all sandstones and from 10 to 16 Tcf in effective sandstones, assuming a recovery factor of 3 to 5 percent of the methane in place (Gregory and others, 1980). The amount of geopressured-geothermal gas that is economically recoverable at $1.40 to $1.80 is negligible (P. L. Randolph, personal communication, 1988), assuming methane solubility of 25 standard cubic feet of gas per barrel of brine.

Gas Hydrates

Gas hydrates are an icelike mixture of gas and water in which gas molecules are trapped by a framework of water molecules (PGC, 1981). Large quantities of natural gas can potentially be trapped in gas hydrates, and they could be a greater resource per unit volume than conventional free-gas reservoirs at depths less than 1,500 m (5,000 ft). Gas hydrates form in high-pressure - low-temperature environments such as permafrost or within marine seafloor sediments. The only permafrost areas in the United States that may contain gas hydrates occur in Alaska. Estimates of the volume of gas in gas hydrates in Alaskan permafrost areas range from 11 to 25,000 Tcf (PGC, 1981). Gas hydrates have also been inferred to exist in the following offshore areas around the continental U.S.: (1) Atlantic Ocean in the New Jersey Baltimore Canyon area and the Blake-Bahama Outer Ridge area; (2) Pacific Ocean in the California/Oregon Continental Slope area; and (3) Gulf of Mexico in the Louisiana Green Canyon area (Morgantown Energy Technology Center, 1985).

Gas hydrates theoretically should form at the sediment-water interface below about 500 m (1,600 ft) of water, and the thickness of the gas hydrate accumulation increases with the thickness of the water column. The presence of gas hydrates in submarine sediments has been inferred primarily from geophysical evidence, by recognizing a bottom-simulating seismic reflector believed to be caused by a layer of gas hydrate. In addition, some geochemical evidence exists to support the hypothesis that gas hydrates occur in ocean sediments (Morgantown Energy Technology Center, 1985). Deep Sea Drilling Project cores from the Blake Ridge contained higher volumes of gas than would be expected if only free gas were present. Gas hydrates were drilled by the Glomar Challenger off the Pacific coast of Mexico, near Acapulco; the gas hydrate was observed on the ship deck before it decomposed.

Several estimates have been made of the volume of gas hydrate resources on the offshore shelf areas of the U.S. (table 18). The estimates in table 18 include gas hydrates in the area along the Alaskan shelves but not in onshore Alaskan permafrost. Resource estimates range from 2,700 to 6,700,000 Tcf of gas in place within gas hydrates in submarine sediments along U.S. shelf areas (table 18). However, no gas hydrates have ever been produced from offshore sediments, and no estimates have been made for the amount of gas that is technically recoverable from offshore U.S. gas hydrates.

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