Chapter 8

Tight Gas

Contents

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INTRODUCTION

"Tight gas" is natural gas that is found in rock formations of extremely low permeability. Such low-permeability formations are found in all gas-producing basins in the United States. Depending on the volume of gas-in-place and the economic viability of its extraction, tight gas formations may constitute a large potential gas resource.

Because of the low permeabilities, fluid flow (both gas and liquid) through tight gas formations is highly restricted. Commercial volumes of gas can only be recovered by artificially fracturing the rock to increase the area of the reservoir in contact with the wellbore. Considerable difficulties in measuring key reservoir parameters in tight formations and establishing the productive areas and zones leads to high uncertainty about the commercial viability of the well until after an expensive fracturing treatment is completed and the well has produced for some time.

The tight gas resource, of all the unconventional natural gas resources, is thought to have the most potential for contributing to U.S. supply in the next 20 years. Low levels of gas have been produced from tight gas formations for many years; significant development began in the early 1970s with the successful use of massive hydraulic fracturing techniques in the Wattenberg Field in Colorado. Incentive prices established in 1979 by the Natural Gas Policy Act (NGPA) increased the relative attractiveness of the resource and promoted development in the early 1980s. Since then, however, interest in gas production from this difficult resource setting has declined as price levels for tight gas dropped in response to the current supply surplus.

CHARACTERISTICS OF THE TIGHT GAS RESOURCE

Tight gas formations are defined in this report as low-permeability sandstone, siltstone, silty shale, and limestone[1] formations deposited in continental, shoreline, or marine environments. Earlier studies have used the terms "tight sands" or simply "tight" formations in addition to tight gas to refer to this resource. Some of the early studies included Devonian shales as tight gas formations, but later studies dealt with the shales separately because of their different production mechanisms and characteristics. This chapter also excludes Devonian shales from the "tight gas" category, treating them in chapter 9 as a separate unconventional resource.

Tight gas reservoirs represent the low permeability end of a continuum of gas-producing reservoirs rather than a unique type. In the past, the cutoff between a conventional and a tight gas reservoir has been somewhat arbitrary, based primarily on the economics of production or requirements for special production techniques. The permeability levels used to define the upper boundary for tight gas have ranged from 0.01 millidarcy (md)[2] to 1 md; most formations identified as tight have permeabilities less than 0.1 md. (For comparison, the permeability of cement is on the order of 0.001 red.) The granting of a special price incentive to tight gas under the NGPA **necessitated a more precise definition.** In 1978, the Federal Energy Regulatory Commission de-

[1] Except for the Edwards Lime format ion in the Southwest, limestone formations have not been Included in tight gas resource assessments. John Sharer, Gas Research Institute, personal communication, 1984,

[2] A millidarcy, abbreviated as "red, " is a standard unit of permeability, which measures the ease with which fluids (liquids and gases) can flow through porous rock.

fined a tight gas reservoir as one having an average permeability of 0.1 md or less at subsurface (in situ) conditions of confining pressure and water saturation, and a maximum production rate prior to stimulation, dependent on depth, of 44 MCF/D at 1,000 ft up to 2,557 MCF/D at 15,000 ft.

The boundary between conventional gas and unconventional tight gas is still changing and will continue to change with changing economics and the further development of production technology for low-permeability reservoirs. Consequently, all estimates of resources and future production from tight formations must be evaluated in the context of their defined boundary conditions. Currently, the American Gas Association is reexamining its definition of the conventional/unconventional boundary. It appears likely that a result of this process will be to transfer resources from the unconventional to the conventional category. The subsequent decline in the projected tight gas potential actually would reflect the recognition that current technology can allow access to a substantial portion of this resource.

In evaluating the potential gas recovery from a well drilled into a tight gas formation, three questions need to be answered: 1) How much gas is present? 2) What conditions exist that control the flow of gas? and 3) Can extraction technology be successfully applied in this setting?

1) How Much Gas is Present?

The occurrence of gas in a given section of a formation is dependent on whether adequate source rocks and appropriate temperature conditions have existed which allowed gas to form. The ability of the gas to migrate and the presence of a trapping and a sealing mechanism are further requirements.

In the case of most tight gas reservoirs, the presence of interbedded organic shales or coal seams ensures an adequate source for gas formation, By the same token, migration is not a problem since the gas does not have to travel far. The low permeability of the formations themselves, together with the overlying shales or other sealing rocks, confine the gas within the sandstones. **In many areas, gas is being produced from nearby** conventional reservoirs, and the required temperature conditions may sometimes be inferred. However, any estimation of potential tight gas resources in unexplored areas should consider these temperature conditions as additional uncertainties.

Some of the tight gas formations deposited under shallow marine conditions, such as those in the Northern Great Plains, may represent an unusual type of natural gas occurrence. In these areas it has been suggested that the methane has formed biogenically (and at low temperatures and pressures) through decomposition of organic material by micro-organisms. s Biogenic gas formation allows gas to be present in areas that otherwise might be assumed not to be gas-bearing, because they have never been exposed to the higher temperatures and pressures generally associated with gas formation (see ch. 3).

Given that gas is present, the amount present in any portion of a tight gas formation is primarily a function of the porosity, temperature, and pressure. These parameters define the space available to be occupied by gas molecules and the amount of gas that can be found in each unit volume of available space. Water saturation is also an important criterion as water competes with gas for the available space.

Porosity is the fraction of the rock that is void **space,** i.e., the space remaining between and within mineral grains, after the grains are packed together. Dissolution and precipitation of material by fluids percolating through the rock may alter the original porosity. Porosity of tight gas formations typically ranges from 3 to 12 percent.[4] Conventional reservoir porosities range from **14** to 25 percent or more.

Pore size is an important determinant of the water saturation of the rock, and thus of gas volume. Very fine grained rocks such as siltstones and chalks, may have high porosities but the individual pores are very small, resulting in a high pore surface area to pore volume ratio. Water

[3]D. D. Rice and E. C. Claypool, "Generation, Accumulation, and Resource Potential of Biogenic Gas," *AAPG Bulletin,* vol. 65, No. 1, January 1981.

[4]That is, 3 to 12 percent of the rock volume is void space.

molecules may be adsorbed on pore surfaces, reducing the volume available to be filled by gas and increasing the water saturation. Because of small pore sizes, tight gas formations are generally characterized by high to very high water sat u rations.

2) How Well Can the Gas Flow?

The most important reservoir characteristic to consider in terms of the recovery of gas from tight gas formations is **permeability** because this ultimately controls how fast the gas can be produced. Permeability is a measure of the ease with which fluids can move through interconnected pores of the reservoir rock in response to a pressure gradient. Thus, a volume of rock can be both porous—have a high percentage of void space—**and** have very low permeability if the individual void spaces are not interconnected or the channels are too narrow to allow gas to move freely. Permeabilities of conventional gas reservoirs range from 1.0 md to several darcies (thousands of millidarcies). In contrast, the permeability of a tight gas reservoir can be as low as 0.00001 md (although at present, recovery generally is limited to reservoirs with permeability greater than about 0.007 red).

The low permeabilities of tight gas formations result from a combination of factors that close off connections between pores, including small grain size, high clay content, and the cementation of grains resulting from the precipitation of dissolved materials.

In very fine grained and recrystallized rocks, where connections between pores are very small, the level of water saturation is a key factor in determining relative gas permeability. Several studies have demonstrated that water saturations on the order of 60 to 70 percent can effectively reduce the permeability to gas to zero.

Clay content and composition in a formation is another important factor in determining its permeability. Many clays are formed after deposition and tend to grow in such a way as to block pores and pore throats. Certain types of clays are expandable on contact with freshwater. The large volumes of water introduced during drilling into **a** formation by drilling muds and fracturing fluids can cause such clays to swell, further reducing permeability of the formation. Gas and water flow can also reduce permeability by displacing and plugging openings with loosely aggregated or platey clays.

All the factors discussed above affect the matrix permeability of the reservoir rock itself, disregarding any faults or fractures. The **bulk permeability of the entire reservoir,** however, may be greater if there is a well-developed natural fracture system. Natural fractures occur as a result of unequally distributed stresses at any time during or after formation of the rock. They are ubiquitous in all rock formations and occur at all scales. Large fractures may extend for long distances, while microcracks are found at the scale of the smallest grain. At greater depths, under high overburden pressures, most small cracks and some larger fractures are closed. Deposition of crystalline materials by migrating fluids also can seal off fractures. s Nevertheless, the existence of natural fractures is extremely important to the net permeability of tight gas formations.

The flow of gas in tight formations is also a function of the shape of the reservoirs and their lateral continuity—whether or not they exist as continuous bodies spread over large areas or instead occur as multiple smaller, discontinuous units. Lateral continuity and geometry of gas-bearing units control how much gas can find a flow path to the wellbore. Most studies have responded to the differences in these characteristics among the various tight formations by subdividing the formations into two categories commonly referred to as blanket formations and lenticular formations.

Blanket formations consist of continuous gas-bearing deposits that extend laterally over a large area. Blanket reservoir units, 10 to 100 ft thick, may be composed of sandstone, siltstone and silty shale, or chalk or limestone interbedded with very low permeability shales or non marine de-

‘However, if fractures form after hydrocarbons have displaced the water layer, the fractures usually remain open. The mineral saturated water is no longer present to precipitate solid crystals (Ovid Baker, Mobile Research & Development Corp., personal communication, 1984).

posits, including coal seams. Alternatively they can occur as millimeter to centimeter thick sand-rich layers, or "stringers," alternating with clay-rich layers. The bulk of current tight gas production is from reservoirs **in blanket formations.**

Lenticular formations consist of many relatively small, laterally discontinuous sandstone and siltstone units, or "lenses," intermingled with shales and sometimes coal seams. These units are similar in mineral composition to the blanket sandstones except that they tend to have higher clay contents. They **occur stacked vertically one over the other,** in formations hundreds of feet thick. The size, orientation, and geometry of the lenticular units are variable. For example, some, such as units formed by the filling of stream channels, are long and narrow and may have a preferred orientation. Other deposits formed at the bends of stream meanders tend to be shorter and wider and more randomly oriented.

The discontinuous nature of lenticular formations and the variable geometry of the lenses makes them a more difficult resource to quantify, in terms of both gas-in-place and potential for recovery, **For these reasons, despite their extensive occurrence, they have only recently been targeted as a potential resource.**

3) How Will Technology Perform?

The third critical variable for economic recovery of tight gas is the viability of massivescale well stimulation and other extraction technologies **in the geological settings containing tight** gas. Here the issues encompass a large number of specific technology issues ranging from the ability to identify, using well logs, the attractive zones for gas recovery, to developing fluid systems that can help contain a large vertical fracture within a given rock interval. While work is progressing in these areas, much new research and development is required before efficient technologies will exist for tight gas extraction. The key technologies are discussed later **in this chapter.**

GAS-IN-PLACE ESTIMATES[6]

A number of estimates have been made of the resource base and production potential of tight gas formations, beginning in 1972 with the Federal Power Commission's (FPC) National Gas Survey report. In 1978, the Federal Energy Regulatory Commission's (FERC) report updated and expanded on the FPC estimate of the tight gas resource. In 1978 and 1979, Lewin & Associates (Lewin), under contract to the Department of Energy, made a detailed appraisal of 13 tight gas-bearing basins. In 1980, the National Petroleum Council (N PC) published its extensive study on the total U.S. resource in tight formations, combining resource estimates **for 12 basins that had undergone an extensive appraisal, and 101 additional basins whose estimates were based on extrapolation** from the appraised basins. Finally, in 1984, the Gas Research Institute conducted a series of sensitivity analyses of the tight gas re**source base, based** on the NPC methodology.

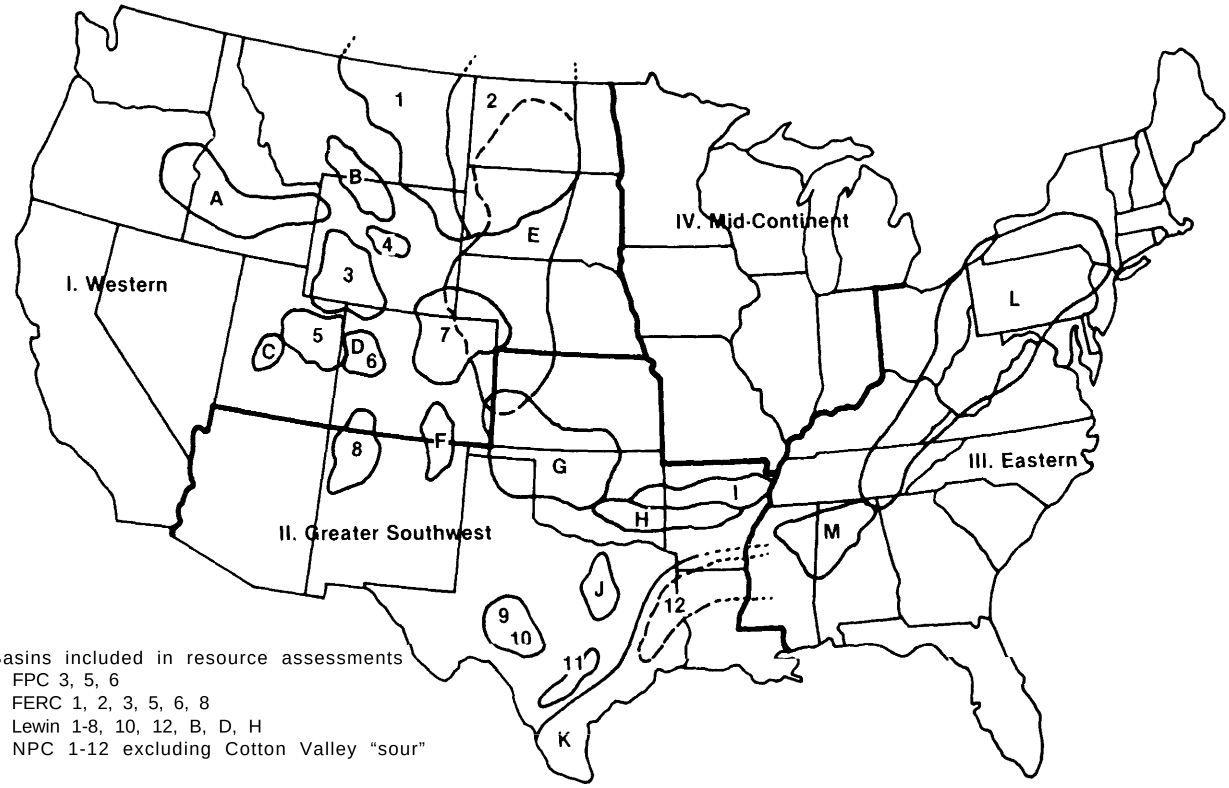
Early estimates of **the tight gas-in-place by the** FPC and FERC only determined the resource **for specific basins. Subsequent estimates expanded the number of basins under consideration and undertook more detailed appraisals within the individual basins as more data became available. The basins included in the various studies are shown in figure** 28. A chronologic representation of the changing resource estimates **for the appraised basins** is given in table 35. Note **that increasing the area under consideration has not necessarily increased the estimated size of the resource.**

Methodologies

The FPC and FERC studies defined the amount of gas within a unit reservoir volume by estimat-

6 In this section, and the section on recoverable resources later in the chapter, OTA has chosen to emphasize the 1980 National Petroleum Council Study on Tight Gas in its discussions of previous resource estimates. This emphasis is based on the excellent reputation of the NPC report, which is widely cited in discussions of the tight gas resource and future production potential, the report's extensive documentation of assumptions and methodology, and the fine level of detail in the basin and subbasin analyses.

Figure 28.—Primary Tight Gas Basins



Basins included in resource assessments
FPC 3, 5, 6
FERC 1, 2, 3, 5, 6, 8
Lewin 1-8, 10, 12, B, D, H
NPC 1-12 excluding Cotton Valley "sour"

1. Western Region
1. Northern Great Plains
2. Williston
3. Greater Green River
4. Wind River
5. Uinta
6. Piceance
7. Denver
A. Snake River
B. Big Horn
C. Wasatach
D. Douglas Creek
E. Western Shallow Cretaceus Trend

II. Greater Southwest Region
8. San Juan
9. Val Verde-Ozona Trend
10. Val Verde-Sonora Trend
11. Edwards Lime Trend
12. East Texas/North Louisiana Basin—Cotton Valley Trend
F, Raton
G. Anadarko
H. Ouachita
1. Arkoma
J. Fort Worth
K. Western Gulf Coast

III. Eastern Region
L. Appalachian
M. Black Warrior

NOTE Coastal regions include offshore areas
SOURCE National Petroleum Council

ing average gas-filled porosity[7] and average reservoir temperature and pressure conditions for each of the formations or sections of formations that they evaluated. Using these figures together with the net "pay" (i. e., gas-bearing) thickness and the total productive area of the formation, each study team calculated the total gas-i n-place in the reservoir.

[7]Total porosity times the fraction of void space filled with gas.

The FPC, in its 1972 study, set minimum criteria defining its interpretation of gas that could conceivably be considered as recoverable. It restricted its evaluation to reservoirs with a minimum net pay thickness of 100 ft, less than 65 percent water saturation, 5 to 15 percent porosity, and permeabilities of 0.05 to 0.001 md. It included only formations at depths between 5,000 and 15,000 ft and defined a minimum reservoir size of 12 square miles. It also only considered reservoirs in remote areas, and, among these, only reservoirs not interbedded with high-permeability aquifers.[8] Its study concluded that the three Rocky Mountain Basins alone contained some 600 TCF of tight gas (table 35).

The FERC study used the same methodology as the FPC to calculate the gas-in-place but revised some of the criteria and expanded the area evaluated to include the San Juan Basin and the Northern Great Plains. They included formations with thinner pays (to 20 ft thick) and depths as shallow as 1,500 ft, and allowed lower gas-filled porosities. Despite the expanded area and modified formation parameters, the size of the tight gas resource only increased from 600 to 793 TCF (table 35).

Both the FPC and the FERC recognized that tight gas resources probably existed in other gas-bearing basins. Since little data existed in these areas, however, they felt the size of the additional resource could not be properly evaluated.

The Lewin and NPC studies used considerably more elaborate methodologies to calculate the gas-in-place. Their methods were designed to take into account the variability of physical proper-ties, such as permeability, porosity, and net pay (total thickness of gas-bearing zones), within a format ion.

The Lewin study used available well data to divide each formation into "subareas" based on homogeneous physical characteristics. The potentially productive portion of each subarea was determined by multiplying by the wildcat success rate (fraction of wildcat wells that are commercial successes) for that region, The volume of gas-in-place calculated for each subarea was further adjusted to reflect a log-normal distribution of "pay quality."[9] The Wattenburg Field in the Denver Basin, a relatively well-developed tight sands gasfield, was used as a model to determine a characteristic distribution of pay qualities.

The NPC methodology for calculating the gas-in-place in its appraised basins was similar to the Lewin approach. Instead of using the same pay quality distribution across all fields, however, the NPC determined a distribution of pay quality and other reservoir properties for each individual basin or subbasin based on existing well data. In this way it could calculate the gas-in-place for up to six permeability levels. The NPC study also evaluated a slightly larger area (13,000 more

[8] These last two criteria were included because nuclear explosives were being considered as a stimulation mechanism. The FPC excluded large portions of known tight gas resources which occurred in more populated areas. The FERC study removed these exclusions because by 1978 it seemed evident that nuclear explosives would not be used.

[9] In the Lewin report, pay quality is a function of porosity, permeability, and thickness of the gas-bearing zone.

Table 35.-Tight Gas-in-Place Estimates (in TCF)

Appraised basins	FPC 1973 (gas-in-place)	FERC 1978 (gas-in-place)	Lewin1978 (gas-in-place)	NPC 1980 (gas-in-place)
Northern Great Plains/ Williston	—	130	74	148
Greater Green River	240	240	91	136
Uinta	210	210	50	20
Piceance	150	150	36	49
Wind River	—	—	3	34
Big Horn	—	—	24	—
Douglas Creek	—	—	3	—
Denver	—	—	19	13
San Juan	—	63	15	3
Ozona	—	—	—	1
Sonora	—	—	24	4
Edwards Lime	—	—	—	14
Cotton Valley "sweet"	—	—	67	22
Cotton Valley "sour"	—	—	14	—
Ouachita	—	-	5	—
Total	600	793	423	444

square miles) of potentially productive land than Lewin, although the two sets of appraised basins were similar (Lewin appraised 10 of the 12 NPC basins). In addition, the Lewin study did not evaluate gas-in-place for permeabilities less than 0.001 md, whereas the NPC study included a number of areas with permeabilities as low as 0.0001 md and some areas with permeabilities as low as 0.00001 md. Despite these differences, however, the Lewin and NPC reports do not differ substantially in their total estimates of gas-in-place in the appraised basins (423 v. 444 TCF, respectively). On the other hand, the estimates for individual basins do differ considerably.

In addition to the 12 basin appraisals, the NPC study made the first attempt to estimate the total tight gas resource occurring in all gas-producing basins in the Lower 48 States. To do this it extrapolated the results of its detailed basin appraisals to 101 remaining potential gas-bearing basins. Extrapolated basins were classified according to their similarity to appraised basins; certain formations in the appraised basins were chosen as analogs to formations in the extrapolated basins. The NPC estimated an additional 480 TCF in place in the extrapolated basins as shown in table 36. Its total gas-in-place resource estimate for the U.S. Lower 48 States is 924 TCF.

Estimate Comparison and Discussion of Uncertainties

Appraised Areas

The sequence of gas-in-place estimates for tight gas represents a continuing refinement of the estimation process. Each estimate builds on the former–adding new data and evaluating new areas. In general, the more detailed analyses have tended to produce lower gas-in-place estimates for a particular area. For example, the early FPC and FERC estimates of gas-in-place for the Uinta Basin are 150 TCF. The later Lewin and NPC estimates for the Uinta are only 50 and 20 TCF, respectively. These reductions can be in part accounted for by an increasing realization of high water saturation in the tight gas reservoirs and its negative effect on both gas content and gas permeability.[10] As discussed above, high water saturations tend to reduce the total volume of gas in the reservoir rock as well as restrict the gas flow. The NPC study also reduced the assumed thickness of total pay intervals in the Uinta from a 500- to 1,000-ft range to less than 500 ft, reducing the overall volume of the gas-producing zone and thus the total gas-in-place.

Table 36.—National Petroleum Council's Gas-in-Place Estimates

	Appraised (12 basins)	Extrapolated (101 basins)	Total (113 basins)
Potential productive area (square miles)	53,000	68,500	121,500
Gas-in-place (TCF).	444	480	924

SOURCE NPC Reporl vol V part I table 1

The NPC estimate represents the most comprehensive estimate of the gas-in-place resource base that exists to date. Because of its level of detail and its attempt to include gas in all gas-bearing basins, it probably represents the best available quantitative assessment of the size of the gas-in-place resource for tight gas. It shares, however, a drawback common to all the estimates: in OTA's opinion, none of the estimates adequately quantifies the extent of the uncertainty associated with the gas-in-place calculation.[11] This may result in the impression that the gas-in-place has been very narrowly defined, whereas the actual range of uncertainty may be quite large.

In most cases the estimators were fully aware of factors contributing to uncertainty. To the extent that their estimates are used by producers and others familiar with the industry, the level of uncertainty may be understood. When the estimates are to be used by those without such a common background, the inherent uncertainties need to be explained in some detail. The following discussion describes the important factors

[10] Strictly speaking, permeability does not affect the magnitude of gas-in-place, whereas gas *content* most certainly does. However, most estimates of gas-in-place do not attempt to Include every molecule of gas, and may exclude gas from formations that have no recoverable gas. Because permeability *does* affect recoverability, an altered estimate of permeability may cause a change In estimated gas-in-place. Nevertheless, gas content is the more closely related of the two variables to gas-in-place.

[11] This statement is not meant to imply that the NPC report did not discuss uncertainty. To the contrary, the technical reports presented substantive discussions of the uncertainties in key parameters, and used probability distributions rather than point estimates in several key calculations. However, these discussions and calculations were not translated into error bands around the report's projections of resources and future production.

contributing to uncertainty and their implications for gas-in-place estimates.

Differences and uncertainties in volumetric estimates of the tight gas resource are often a function of the level of understanding of the geologic history of the basins and the physical characteristics of the formations. Critical parameters include the porosity and water saturation, the areal extent and thickness of the gas-producing portion of a formation, and the actual presence of gas and its geologic origins.

As discussed earlier, porosity and water saturation constrain the amount of gas present in a discrete volume of rock. However, these parameters are extremely difficult to measure accurately and may vary over a wide range within a small area, Available data consist of extrapolations from existing wells and are often insufficient for a valid statistical analysis of a potential producing formation. Furthermore, conventional techniques for measuring and interpreting reservoir parameters, where they have been used in the tight gas intervals, are often not applicable to these types of formations. For example, conventional interpretation of well log data frequently results in higher measured porosities than those actually observed by laboratory analysis of core samples. Errors in porosity measurements can lead to even larger errors in computed levels of water saturation, compounding errors in the estimates of gas-in-place. In the last few years, interpretative techniques have been modified to apply specifically to low-permeability intervals, but these techniques are not yet routinely used.

The extent to which measurement problems of this sort have affected tight gas resource estimates is difficult to determine, although these problems are likely to have been acute for the earlier studies. In the NPC analysis, well performance calculations for future wells were compared with actual well performance in producing wells to check the procedures for estimating porosity and permeability.[12] However, despite recent advances in logging systems and interpretation techniques, there still were severe measurement problems at the time the NPC estimates were developed. In fact, the discussion of measurement problems that appears in the NPC report itself, reproduced in box H, implies that the NPC analysts could not have been overly confident about the precision of their resource calculations.

The areal extent of some tight formations, particularly blanket formations, may be fairly well documented in developed basins from data collected from exploration and development wells drilled for conventional gas resources. Pay thickness may be fairly easy to determine for some blanket formations in which sandstone beds are clearly defined. In other blanket formations, thin gas-bearing sand stringers occur finely interbedded with shales, making determination of the net productive thickness extremely difficult.

The lateral continuity, thus areal extent, of the gas-bearing portions of lenticular formations may be more difficult to determine than for blanket formations since the geometry of the individual lenses cannot be readily understood just by drilling and logging multiple wells within a formation. For example, sand-rich intervals occurring at approximately the same stratigraphic level in two or more wells may or may not represent the same lens (see fig. 29). Extrapolation from mapped surface features of these formations is the best way, at present, to determine dimensions, distribution, and orientations of the sand lenses. However, visible surface manifestations of lenticular formations are not always conveniently present. Another way to approximate the volume of lenticular tight gas formations is to determine an average sand-to-shale ratio based on well log data for a portion of the formation and extrapolate this over the area covered by the formation. The accuracy of this method depends on the number of wells drilled through the formation.

The presence of appropriate source materials and temperatures and/or biologic agents for hydrocarbon generation is a function of the geologic history of a basin. Many tight gas resource estimates consider a large portion of the tight gas interval in the Rocky Mountain Basins to be gas-bearing. There is, however, a dissenting opinion: that temperature, pressure, and source rock composition throughout many lenticular basins, such as the Piceance, were not appropriate for the gen-

[12] Ovid Baker, Mobil Research & Development Corp., personal communication, 1984.

Box H.—What the NPC Report Had to Say About Measuring Key Tight Gas Resource Parameters

"Experience to date indicates a broad variation of the critical parameters even within the same formation. Permeability routinely varies by orders of magnitude; gas-filled porosities can vary by factors of 2 to 5; net pay can vary by factors of 2 to 50. Few data are available on the distribution of lens size and geometry, but extremely wide variations can be expected. Experience indicates that expensive, time-consuming measurements and analyses made for one well may not be sufficiently applicable to another well in the same basin to design a fracture treatment . . . The significance of this is that it substantially reduces the ability to extrapolate from one well to another. Thus, extrapolation over a wide area is difficult.

"In very low-permeability gas reservoirs, existing methods and tools for measuring critical parameters have been found to be inadequate for accurately characterizing the producing formations. Extremely low permeability renders data from drill stem tests nearly useless. Well logging has failed to adequately distinguish gas-productive from water-productive zones. Net pay thickness and gas-filled porosity are measured with very low reliability. Current coring techniques tend to alter the rock properties prior to laboratory testing. Conventional laboratory tests of permeability have been shown to produce results that vastly overstate actual permeability under reservoir conditions of water saturation and pressure. The distortion is greater at lower permeabilities, where recovery is more sensitive to permeability. Laboratory measurements and tests of rock strength and hardness are only now being developed and standardized. No downhole permeability measurement technique has proved reliable in tight formations. Pressure testing of wells in tight formations requires vastly longer time periods than for conventional formations (e.g., weeks v. hours) for comparable precision. Measurements of lens geometry have been limited to studies of outcrops of the formations. The nature and distribution of the subsurface gas-bearing lenses have not been characterized. Reservoir modeling also needs improvement. Competent two-dimensional flow models are available, but three-dimensional models have only begun to be developed and are exceedingly costly to operate.

"Net pay is one of the most important parameters required for reservoir performance evaluation . . . Current methods for determining net pay have a very high probability for error.

"Accurate knowledge of permeability is essential for , . . predicting potential well performance . . . Current methods for obtaining permeability . . . exhibit questionable reliability."

SOURCE: National Petroleum Council, *Unconventional* Gas *Sources: Tight* Gas *Reservoirs,* Part 1, December 1980,

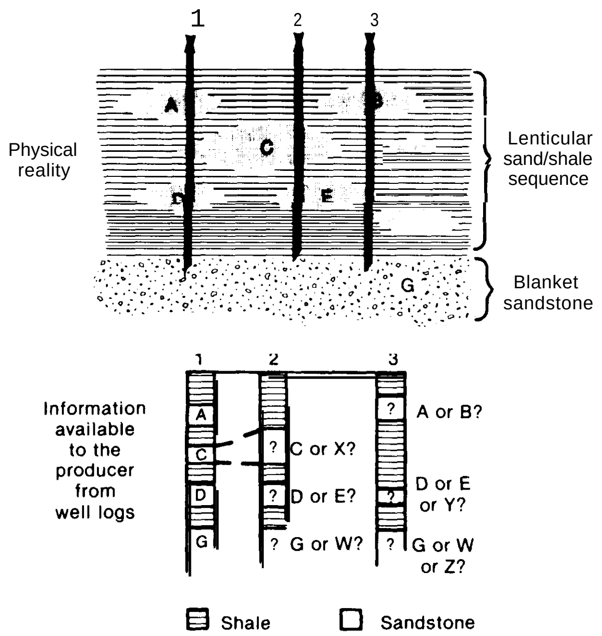
eration of large quantities of gas.[13] This opinion holds that only a small proportion of the thousands of feet of vertical section of tight sandstones is actually gas-bearing. If confirmed, this would substantially reduce the estimated gas-in-place, and make basins like the Piceance much less attractive for potential production. Similarly, the NPC estimate of the gas-in-place in the Denver Basin included a caveat that as much as 30 percent of the estimated gas-in-place in that basin may not actually exist. Temperature and pressure conditions in the northern part of the basin may never have been high enough to generate gas. The volumetric estimate of gas-in-place in the Denver Basin is based on gas contents extrapolated from the known gas-bearing portions of the formations occurring in the southern part of the basin.

The most controversial of the appraised areas is the Northern Great Plains, estimated by the NPC to have nearly 150 TCF of gas-in-place in shallow formations. Two-thirds of this gas is estimated to be technically recoverable. The controversy centers around the origin of the gas, whether it is early thermogenic or biogenic,[14] and

[13] J.W. Crafton, "Fracturing Technologies for Gas Recovery From Tight Sands," contractor report to OTA, September 1983.

[14] That is, formed by physical processes associated with high temperatures (thermogenic) or else by biological processes, usually anaerobic digestion (biogenic).

Figure 29.—Problems With Reservoir Mapping in Lenticular Formations



Note that A & B and D & E are stratigraphically at the same level, but are distinct units.

SOURCE: Office of Technology Assessment.

if biogenic, whether it formed during deposition and burial of the sediments in the basin (75 million to 100 million years ago) or more recently.[15] The theory accepted by the NPC, based on a study by the USGS,[16] is that it is old biogenic gas, and is ubiquitous throughout the region. Further, the NPC assumed that gas migration and loss to the atmosphere has not significantly depleted these resources.

As discussed in a dissent to the NPC estimate of Northern Great Plains gas-in-place, alternate theories of recent biogenic or early thermogenic formations imply a far lower volume of gas generated and only localized accumulation, implying in turn a lower gas-in-place, on the order of 10 to 20 TCF.[17] Even if the gas is old biogenic gas, some argue that there is likely to have been significant gas loss since the time of formation, unless sealing mechanisms have been unusually effective.

Given the large discrepancies in estimates of gas-in-place, and the important implications for the natural gas resource base, the questions associated with the origin of the Northern Great Plains gas and its preservation need to be resolved.

As might be expected, dissent from the NPC estimates is not restricted to those who are more pessimistic or are simply skeptical of the accuracy of the estimates. For example, several panelists at OTA's Workshop on Unconventional Gas Sources felt that the NPC's resource estimates reflected an **overly conservative approach** which tended to discount or dismiss resource potential unless there existed definitive evidence of its existence. It was claimed that, in some basins where extensive drilling records were available, NPC geologists assigned either zero or a heavily discounted value of gas-in-place to sections where there had been no "gas shows, " even when the "no shows" resulted simply from a lack of drilling. A case in point is the Denver Basin, mentioned previously; in this basin, the NPC assumed that only 1,600 of a total of 45,000 sections, or 3.6 percent, are gas-bearing. In the words of one of these critics, this approach "places an unjustified premium on the exploration technology and wisdom of our predecessors in the petroleum business."[18]

In the opinion of these same critics, the conservatism displayed in the NPC study's estimates of productive **area is duplicated** in its estimates of the **thickness** of the gas-bearing rock in the productive formations. For example, in the NPC analysis of the Piceance Basin, one of the lenticular basins where high gas-in-place estimates have been questioned, the four gas-bearing formations have a total thickness averaging about 6,400 ft but are assigned estimated "net pay ranges, " or gas-filled thicknesses, of:

Formation	Net *pay range (ft)*
1. Ft. Union.	12-80
2. Corcoran Cozette	16-70
3. Mesaverde.	20-200
4. Lower Cretaceous-Jurassic .	7-35

[15] If formed recently, less gas would be expected because the conditions necessary for methane-forming bacteria to reach underground sediments are not commonly available. National Petroleum Council, *Unconventional Gas Sources, Tight Gas Reservoirs, Part II,* appendix, December 1980.

[16] D. D. Rice and G. W. Shurr, "Shallow, Low-Permeability Reservoirs of Northern Great Plains—Assessment of Their Natural Gas Resources," *AAPG Bulletin,* vol. 64, No. 7, July 1980, pp. 969-987.

[17] National Petroleum Council, *Unconventional Gas Sources, Tight Gas Reservoirs, Part II,* appendix, December 1980.

[18] Ovid Baker, Mobil Research & Development Corp., letter of Aug 3, 1984, to OTA.

The ranges are not additive, but **at no point does the NPC assume that the gas-filled portion of the formations occupy more than** 6 **percent of the total thickness of sediment.**

It is unlikely at this time that the existing arguments about the relative "optimism" or "conservatism" of the NPC's estimate of gas-in-place can be resolved. In OTA's opinion, **the** NPC **estimate of gas-in-place for the appraised basins, excluding the Northern Great Plains, probably should still serve as a reasonable "most likely" estimate, even though a considerable error band—at least +/- 100 TCF—must be assigned to the estimate. As for the Northern Great Plains, there appears to be a substantial possibility** that the NPC estimate is too high, but the evidence is by no means conclusive.

Extrapolated Areas

In the NPC analysis, the uncertainties that apply to the appraised basins are magnified in the extrapolated basins. Not only is there a lack of exploration and production data for these basins, but also the gas-in-place estimates were not generated by geologists experienced in those basins, as was the case for the appraised basins. Extrapolations were made by assigning gas-in-place values to the estimated productive area in each extrapolated basin using formations in appraised basins as analogs. In some cases this approach has a high potential for error, since different parts of the country have undergone significantly different geological histories which may have affected the amount of gas formed and preserved, but which could not be properly accounted for in the estimation process.

For example, the Eastern region (primarily the Appalachian and Black Warrior basins) was estimated to contain 49 TCF in shallow formations based on analogies with formations in the Northern Great Plains. However, the Northern Great plains estimates assume a biogenic origin for the gas, leading to the large volumes of gas-in-place. Even if biogenic gas formed in the Appalachian and Black Warrior basins, given their age (300 million to 400 million years relative to 75 million to 100 million years) and complex geologic history, it is unlikely that much biogenic gas would have been preserved to the present day. Therefore, the gas content per unit rock appears unlikely to be the same in the two regions.

There was widespread agreement among the NPC study participants interviewed by OTA that the gas-in-place estimates for the extrapolated basins were highly uncertain.

TECHNOLOGY

The characteristics of the tight gas resource base present gas producers with a variety of important problems in locating and exploiting this gas. Many of these problems result from the very low permeability of the tight gas reservoirs and the consequent need to use fracturing to achieve commercial levels of gas production. For example, full exploitation of the lenticular reservoirs requires the ability to contact lenses remote from the wellbore, yet our current ability to predict or control fracture length and direction is poor. In addition, the presence of water-sensitive clays raises the potential for formation damage from the fracturing fluids. Difficulties in accurately measuring reservoir characteristics greatly complicate fracture placement and add to the economic risk of stimulation. Also, the depth and structure of some of the tight formations lead to extremely demanding requirements for fracture fluids and proppants. In this section, these problems and the technologies available to overcome them are briefly discussed. A longer discussion of fracturing technologies is presented in appendix B.

Hydraulic Fractures

Gas flows from a reservoir towards a well bore because of a pressure difference between the reservoir and the well bore. The rate of flow is dependent on the difference in pressure and the permeability of the formation. Fracturing is designed to increase flow rates by cracking the reservoir rock, exposing more of the reservoir surface to the lower wellbore pressure. Hydraulic fracturing is accomplished by pumping large volumes of fluid down the wellbore, increasing the pressure on the rock formation until it breaks down and fractures. Because the fractures would tend to close when the fluid is removed—especially in deep reservoirs where the pressure of the rock is great—sand or other materials are added to the fluid. Left behind when the fluid is removed, these "proppants" are wedged into the fractures and prevent them from closing,

Hydraulic fractures tend to be unidirectional, generally extending out in opposite directions from the wellbore. By convention, their length is measured along one wing (see fig. 30). Their direction and orientation (vertical, horizontal, or inclined) are controlled by the regional stress regime and the depth of the target formation. Induced fractures at depths greater than 2,000 ft are oriented in the vertical plane. At shallower depths, such as might be found in the biogenic gas reservoirs of the Northern Great Plains, fracture orientation may be horizontal.

Table 37 illustrates the need for fractures in tight formations and the substantial benefits that may be gained from larger fractures. As shown in the table, a well in a highly permeable (10 md) reservoir can drain all the gas in two sections, or 1,280 acres, of a field over a 15-year production life. An unfractured[19] well in a tight (0.001 md) blanket sand can drain only about 20 acres of the field during a 30-year production life, and during that time would average less than **40** MCF/D of gas production, a very low rate. A massive hydraulic fracture creating a 1,000-ft fracture would increase the average production rate by nearly fivefold and allow complete drainage of the field with six wells per section rather than nearly 30 with unfractured wells. An advanced technology producing a 4,000-ft fracture would increase the average production rate by a factor of 15 and allow the tight field to be drained with a 320-acre (two wells per section) spacing, a fairly common spacing in **conventional** gasfields.

Successful fracturing in tight formations is complex and faces substantial obstacles. A few critical points should be understood. First, the great majority of tight gas recovery heretofore has been restricted to areas "characterized by thick, fairly uniform, blanket-type formations , . . (where) . . . only a limited knowledge of the formation characteristics is necessary to stimulate economic production rates."[20] The majority of the resource, however, is more complex, and greater understanding of the geology and production mechanics is critical .21 Second, although fracturing dates from the 1800s, and **hydraulic** fracturing dates from 1947 and has the benefit of the experience gained by thousands of separate fracturing treatments, the type of massive hydraulic fracture needed to begin to fully exploit the tight resource has only been developed in the last 10 years or so. The process is not fully understood and extrapolation to new geologic situations is difficult.

[19]Actually, the process of "completing" the well involves an explosive perforation of the well lining that creates a small fracture, here assumed to be 100 ft in length.

[20]Gas Research Institute, *Status Report." GRI's Unconventional Natural Gas Subprogram,* December 1983,

[21]Ibid.

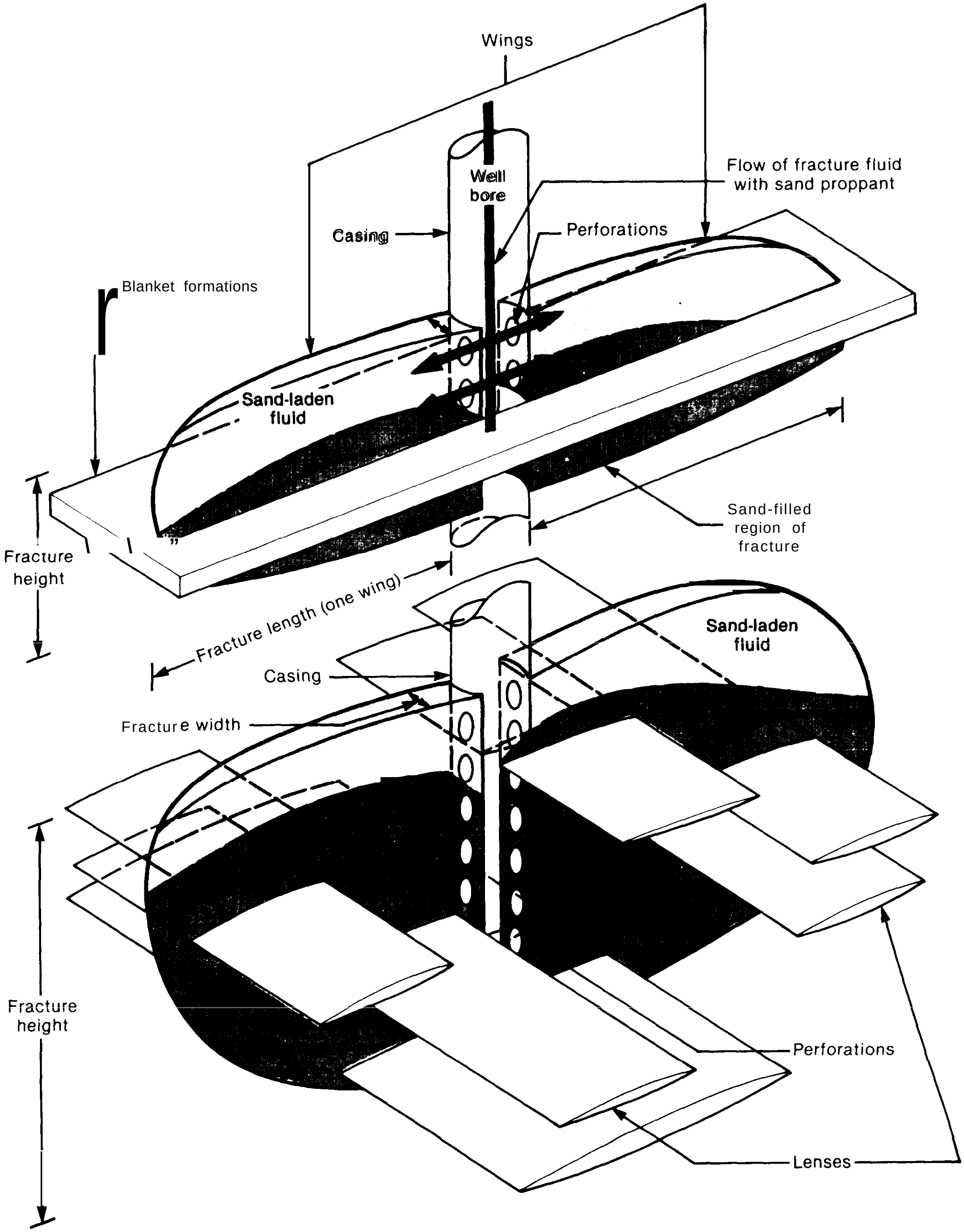
Table 37.—Conventional and Tight Gas Wells Compared

Type well	Perm. (red.)	Fracture length (ft)	Ultimate production (MMCF)	Production life (years)	Wells per section to produce (all gas)	Reservoir area Exposed by fracture (sq. ft)
Conventional	10	100	31,700	15	0.5	34,000
Tight—unfractured	0.001	100	390	30	29	34,000
Tight—present technology ., .	0.001	1,000	1,838	*30*	*6*	*340,000*
Tight—advanced technology .	0.001	4,000	6,015	30	2	1,360,000

NOTES Net pay = 85 ft.
Initial pressure = 5,500 psi
Maximum recovery, gas/section =16 BCF for conventional,
11 BCF for tight gas wells.

SOURCE: R. W. Veatch, Jr and O Baker, "How Technology and Price Affect U S Tight Gas Potential, " *Petroleum Engineer International, January 1983.*

Figure 30.—Conceptual Fractures Created by Massive Hydraulic Fracturing in Blanket and Lenticular Formations



SOURCE: National Petroleum Council, *Unconventional Gas Sources Tight Gas Reservoirs, Part /,* December 1980

Third, aside from the difficulty of **forecasting** what a fracture will do, it is hard to tell in any detail what a fracture **has done** even after it has been completed and the well is producing (or has proved to be unproductive). In addition, as with any new and rapidly developing technology, state-of-the-art techniques are not necessarily standard practice in commercial ventures. For these reasons, our extensive experience in fracturing has not been as much benefit in projecting future performance as might have been expected.

Despite these difficulties, however, well service companies and producers have been responding vigorously to the various problems encountered in tight formations and have developed a number of variations to the standard fracture treatments. Of particular importance are the development of new fracture fluids and proppants which can increase fracturing efficiency and fracture conductivity. In addition, improved techniques for fracture containment (i. e., keeping the fracture within the gas-bearing layer), fracture prediction, and onsite monitoring will result in more accurate production estimates, greatly reducing the risk of developing these high-cost resources.

Proppants.–Development of new proppants is an important area of innovation by the service companies in response to a need for material that will not crush at high pressures and is light enough for the fluid to transport to the end of the fracture. Recent developments include ceramic beads and resin-coated sands that have lower densities than bauxite–the material currently used in high pressure situations—and thus can be more efficiently transported by the fluid. They appear to have sufficient strength for most fracture applications.

Fracturing Fluids.–The need for a fracture fluid that simultaneously can avoid formation damage (clay swelling, etc.) and maintain a high capacity to carry proppants in suspension into the fracture has led to the development of very sophisticated fluids. A particularly significant development is "cross-l inking,' which temporarily increases the viscosity of the fluid—and thus its fracturing and proppant-carrying capability–by linking together polymer chains. After emplacement of the proppant, this viscous fluid alters to a low-viscosity fluid so that it can flow back to the wellbore, minimizing formation damage.

Fracture Containment.–A common problem in thin blanket sands is the difficulty of keeping the fracture within the blanket, or pay zone, so that it does not waste its energy fracturing nonproductive rock or actually cause reserves to be lost by fracturing into a water zone or fracturing the reservoir "cap." In general, readily available techniques have not been successful at containing fractures within the pay zone. New techniques have been proposed (including careful placement of the fracture initiation point, very careful control of the fracturing fluid viscosity and pressure, and use of floating proppants to seal off upper non producing portions of the fracture) and are being tested, as discussed in app. B.

Fracture Prediction. -Understanding the mechanisms of fracturing and thus being able to predict fracture behavior is critical to reducing the economic risk of tight sands development to manageable levels. The state of the art of fracture prediction, however, comes from sophisticated mathematical models and laboratory experiments with very little field verification.

Current practice in the field is to use relatively simple analytical models against which to compare fracture behavior, proppant placement, tracture length, and well performance. These simple models will often be inadequate in complex tight gas situations, but the more sophisticated models currently available are expensive, time-consuming, and dependent on input data that often are not readily obtained. And, although laboratory experiments allow interesting possibilities for tightly controlled conditions and parametric analysis, it is difficult to be confident that field-scale fractures will behave in the same manner as the small-scale laboratory fractures.

Field-scale testing, using experimental wells or excavating a created fracture, can overcome some of these problems but is extremely expensive. Only a few field-scale tests have been completed and ongoing projects have been curtailed due to Federal funding cuts. Nevertheless, they are providing valuable information on actual fracture configuration.

The difficulties of fracture prediction are particularly acute in the early stages of field development, when theoretical models and analogy with other fields provide the only forecasting guides, Continued development of the field provides data for performance matching of prospective sites with producing wells, and the percentage of successful well stimulations should increase with experience, As discussed below, however, this learning process may be disrupted by problems associated with monitoring fracturing success and interpreting well performance.

Monitoring Fracture Behavior.–The ability to monitor fracture behavior is critical to tight sands development for two reasons. First, it is the means by which the existing experience in fracturing can be translated into an ability to predict fracture behavior for new wells. The **inability to measure what** has actually occurred underground in past fracture treatment is responsible for our poor predictive capability. Second, it is critical to field development, because knowing fracture location is necessary in planning additional wells so as to minimize interference between wells. Most of the technologies under development to monitor fractures in the field are adaptations of existing geophysical and well logging techniques, They are discussed in greater detail in appendix B. Some success has been realized in determining fracture height adjacent to the borehole, and in some cases, total fracture length and propagation direction. Problems still exist in determining propped length of the fracture and vertical growth[22] at a distance from the wellbore.

Most of these technologies are still experimental and costly, and are difficult to use. However, fracture diagnostics has received major attention from service companies in the past few years, and innovation has been rapid. improvement and widespread commercial use of these monitoring techniques would have a major effect in lowering the economic risk of tight sands development.

[22]Vertical growth is an important parameter because of the desirability of keeping the fracture within the pay interval. See *Fracture Containment* above.

Current Fracturing Success.—In tight gas formations, improved fracturing technologies, developed in blanket sands, have for the most part realized considerable success. Increased fracture lengths in blanket formations often appear to be attainable simply by increasing the volume of fluid and proppant pumped. Fractures over 2,000 ft long have been reported.[23] Where design lengths have not been achieved, failure can generally be attributed to fracturing out of the pay interval, inadequate proppant transport, or extensive formation damage.

An additional but less obvious major problem may still exist in blanket formations. Because massive hydraulic fracturing in low-permeability formations is still a relatively new technology, there are no data on whether the permeability of the fractures can be maintained through time. There is concern that the fractures may close or become plugged before the 30-year production histories are complete. Counteractive measures, such as periodic cleanup treatments or multiple small fracture treatments over the life of the wells, have not been evaluated in terms of their costs, risks, and effect on well performance.

The overall success rate of massive hydraulic fracturing in tight formations is likely to improve to the extent that new technologies are developed to counteract problems such as formation damage and inadequate proppant transport. A certain number of reservoirs, however, may never be amenable to production using massive hydraulic fracturing. For example, adequate fracture containment in some reservoirs may never be possible due to the intrinsic characteristics of the rock. If reservoir boundary layers are substantially weaker than the reservoir rock, the fracture will grow vertically at the expense of horizontal growth. In effect, much of the fluid and proppant is being used to create a fracture in a nonproductive interval. Recovery from such reservoirs cannot be based on the creation of 1,000-ft fractures. More work needs to be done in identifying such formations and determining the optimal fracture treatment to maximize recovery at minimum cost.

[23]B.A.Matthews, W. K. Miller, and B. W. Schlottman, "Record Massive Hydraulic Fracturing Treatment Pumped In East Texas Cotton Valley Sands," *Oil and Gas Journal,* Oct. 4, 1982, pp. 94-98.

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Lenticular reservoirs represent a situation where new technologies have not been effective. The NPC-estimated base technology (1,000-ft fractures) is not yet the acknowledged state of the art, nor is there substantive evidence that fractures will penetrate lenses not actually intersected by the well bore. Where large-scale fracture treatments have been attempted in lenticular formations, results have been disappointing. Commercial flow rates were not attained. Insufficient data were collected both before and after treatment to evaluate why fracture treatments failed,[24]

Currently, most producers have returned to less expensive shorter fractures. In some cases they are drilling wells in areas with thick vertical sequences of lenticular sands and stimulating multiple pay intervals by fracturing each interval with fractures on the order of 100 to **500** ft long,

Although per well stimulation costs are lower in this case, cumulative production per well may be less, since a smaller gas-bearing area is in contact with the well bore. This technique may limit the potential recovery from lenticular formations, particularly in the short term. However, there are some data indicating that, over the long term, gas flow from wells in lenticular reservoirs, with relatively short fractures, may not exhibit the expected production decline rates of a limited reservoir.[25] Because the nature of natural fracture systems and gas flow behavior in lenticular formations is not well understood, it may be premature to draw conclusions about the long-term gas recovery of alternative fracturing strategies in these formations.

Reservoir Characterization Technologies

Techniques and instrumentation to quantify more accurately the physical properties of the reservoirs and to help determine their relationship to one another are crucial to designing more efficient stimulations and making accurate estimates of reserves and recovery rates for economic analysis, Accurate reservoir characterization reduces both the costs and risks of field development.

Conventional methods for determining reservoir parameters include: geologic mapping of exposed areas of the reservoir formation, laboratory analysis of core samples and detailed subsurface correlation of reservoirs, well logging, and well tests. Considerable data have been collected using each of these techniques. Problems with the techniques themselves have been identified. Only limited progress has been made to date in modifying existing techniques and developing new techniques to overcome their problems.

Laboratory analysis of core samples recovered from a well provides the best estimate of reservoir properties at that particular site. The data can be correlated with information from other wells to derive a broader regional picture of the subsurface conditions. Date from laboratory analyses can also aid in the interpretation of well logs.

Most samples for laboratory analysis are recovered using conventional coring techniques, The depth of recovery is known, and temperature and pressure information often is available. The recovered samples are subjected to a range of laboratory tests to determine porosity, pore volume, permeability, water saturation, mechanical rock properties, and mineralogy.[26] Electrical and gamma-ray logs are also run on the samples for correlation with well logs.

Because small changes in reservoir properties can substantially alter estimates of the recoverable gas, the laboratory measurements need to give an accurate picture of actual reservoir conditions. Alteration of the physical properties of the rock during its collection represents an important problem for tight formations, contributing to inaccuracies in measurements of permeability, water saturation and other parameters.[27]

[24] An alternative explanation of the production failure (instead of failure of the fractures to reach design lengths) is that the fractures may have achieved design lengths but that other problems, such as water infiltration, and production problems caused by backflow of the sand proppant, were primarily responsible for the disappointing gas flows. The originator of this explanation concurs, however, that the "wells have not been tested and studied sufficiently to decide if the fractures are successful or not." Ovid Baker, Mobil Research & Development Corp., personal communication, 1984.

[25] D.H. Stright, Jr., and J. 1. Gordon, "Decline Curve Analysis in Fractured Low Permeability Gas Wells in the Piceance Basin, " *SPE/DOE Symposium on Low Permeability Gas Reservoirs,* SPE/DOE 11640, 1983, pp. 351-356.

26A. R. Sattler, "The Multiwell Experiment Core Program, " *SPE/DOE Symposium on Low Permeability Gas Reservoirs,* SPE/DOE 11763, 1983, pp. 437-442.

[27] National petroleum Council, *Unconventional/Gas sources: Executive Summary,* December 1980.

Techniques for unaltered core recovery exist (e.g., the use of pressurized core barrels), but at present are too expensive and too unreliable for routine use. The available techniques are most practical for research purposes or possibly for use in the early stages of developing a large field, to assist in planning a development strategy,

Well logs are among the more commonly used techniques to determine reservoir properties. They are comparatively inexpensive to use, and results generally can be obtained quickly. Unfortunately, many of the logging techniques used in conventional reservoirs have given inaccurate results in the unconventional formations,[28] partly because some conventional methods of log analysis are not appropriate for low-permeability formations and partly because some analysts are not properly accounting for the low-permeability conditions .29

The complex mineralogic content, including clays and cement, and poorly defined interfaces between producing and nonproducing zones in tight formations distort log responses. Resulting porosity and water saturation measurements may be too low or too high. Often the precision of the tools is not sufficient for these reservoirs; e.g., a small error in porosity measurement can result in a large error in inferred fluid saturation. Failure to distinguish gas-productive from water-productive zones, a common problem,[30] drastically complicates the selection of fracture locations.

A prototype logging tool has recently been developed using nuclear magnetic resonance (NMR) to determine porosity, fluid saturation, pore size distribution, and bulk permeability of a formation. Laboratory tests of the tool have been successful; however, the time required to obtain accurate measurements (on the order of several days) is likely to severely restrict its commercial application.[31] NMR logs may end up being most useful on experimental wells where they would be used to gather baseline data for extrapolation. In the long term, it may be a less expensive technology for obtaining reservoir data than coring.

Another approach to improved logging is to use available equipment with specialized interpretive techniques to account for the log distortions associated with the tight formations. An example of new interpretive techniques is a system called "TITEGAS," which is based on equations which define the response of conventional logging tools.[32] The system deals primarily with data from density, neutron, and resistivity logs and makes a number of claims to accurately measure, among other parameters, porosity, gas saturation, clay content, and the presence of natural fractures in complex, tight formations.

Improved interpretation of conventional logs clearly is an important element of better reservoir characterization for tight formations. The need for new interpretive techniques is not clear, however. OTA found some in the research community who felt that, with available techniques, it was now possible to accurately measure reservoir characteristics in most tight gas situations; they blamed current problems on the failure of most practitioners to assimilate the latest advances.[33] There are many others who conclude that logging of tight formations is still error-prone and basically unreliable.

Well tests are also frequently used to empirically determine breakdown pressures (e.g., the pressure required to initially fracture a formation) and gas flow rates. From these data, such reservoir properties as in-situ stress and gas permeability can be inferred. Creation of small-scale fractures is particularly useful in determining the difference in the stress characteristics of the rock in the producing and non producing intervals, which in turn allows prediction of fracture containment.

[28] G. C. Kukal, et al., "Critical Problems Hindering Accurate Log Interpretation of Tight Gas Sand Reservoirs," *SPE/DOE Symposium on Low Permeability Gas Reservoirs*, SPE/DOE 11620, 1983.

[29] S. A. Holditch, Texas A&M University, personal communication, 1984.

[30] National petroleum Council, *Unconventional Gas Sources: Executive Summary*, December 1980.

[31] K. H. Frohne, Morgantown Energy Research Center, personal communication, 1984.

[32] G. C. Kukal, "A Systematic Approach for the Effective Log Analysis of Tight Gas Sands," 1984 *SPE/DOE/GRI Unconventional Gas Recovery Symposium*, SPE/DOE/GRI 12851, Pittsburgh, PA, May 13-15, 1984.

[33] S. A. Holditch, Texas A&M University, personal communication, 1984.

Pressure-transient testing is the most common technique used to get a rough estimate of gas permeability prior to stimulation. These tests consist of producing or shutting in the well for a specified period of time and measuring the pressure drawdown or buildup. In low-permeability reservoirs, however, this technique does not always produce useful results, especially during the short time periods feasible for shutting in the well.

Exploration Technologies

No new technologies have been developed specifically for exploration for unconventional resources, and they are not perceived to be a high priority need because considerable resources have been identified by past drilling efforts. Some existing state-of-the-art technologies used in conventional hydrocarbon exploration are applicable to the unconventional resources. These include aerial and satellite imagery and geophysical surveying.

In tight sands, mapping of surface features from aerial and satellite imagery has proved useful in determining dominant structural trends.[34] Such data may be useful in locating wells so that they make the best use of existing fracture systems.

In tight sands, there may be some potential for using seismic data to delineate the character of beds in a formation.[35,36] If clusters of sand-rich lenses and their orientation could be identified, these data in conjunction with data on regional stress patterns would determine the best location for a well. Three-dimensional, vertical, and cross borehole seismic surveys are being tested at the DOE multi-well site to delineate lenticular bodies and fracture zones in the lenticular formation.[37] Initial results have been disappointing; the data are not of sufficiently fine a scale to map the spatial relationship of the lenses. Detailed geophysical surveys are not likely to be used commercially in the near future due to high costs and complex time-consuming data reduction.

New Technologies and the Industry

It appears that both tight gas producers and well service companies are willing to experiment with new stimulation techniques. This may have contributed to the rapid development of sophisticated fracturing fluids and proppants.

In contrast, state-of-the-art diagnostic techniques both for reservoir characterization and for predicting and monitoring fracture behavior are not commonly in use among producers. The primary problem appears to be that these techniques are costly and time-consuming. For small and midsize producers in particular, with limited acreage, there is little cost benefit to developing information leading to improved stimulation if they will only be drilling and fracturing a few wells. Larger producers are more likely to make this investment.[38]

The diagnostic techniques may ultimately be the most important factor in making tight gas an economically viable resource. However, because of the limited interest, the rate of development of these technologies is likely to be slow, particularly in the transition from proven concept to commercial product. For these reasons, the industry may continue to be dependent for some time on external research efforts, such as those supported by the Department of Energy and the Gas Research Institute, to develop the tight gas resource.

34 J. A. Clark, "The Prediction of Hydraulic Fracture Azimuth Through Geological Core and Analytical Studies," *SPE/DOE Symposium on Low Permeability Gas Reservoirs,* SPE/DOE 11611 pp. 101-111.

35 T. L. Dobecki, "Application of Areal Seismics to Mapping Sandstone Channels," *Low Permeability Gas Reservoir Symposium,* SPE/DOE 9847, 1981, pp. 205-209.

36 C. A. Searls, M. W. Lee, J. J. Miller, J. W. Albright, J. Fried, and J. K. Applegate, "A Coordinated Seismic Study of the Multiwell Experiment Site," *SPE/DOE Symposium on Low Permeability Gas Reservoirs,* SPE/DOE 11613, pp. 115-117

37 Ibid.

38 J. W. Crafton, "Fracturing Technologies for Gas Recovery From Tight Sands," contractor report to OTA, September 1983.

THE RECOVERABLE RESOURCE BASE AND PRODUCTION POTENTIAL

Estimates of economically recoverable gas from tight gas formations are extremely sensitive to assumptions made about price, level of technology, and the volume of gas-in-place. Existing estimates range from a conservative 30 TCF to almost 600 TCF.

Some recoverable gas estimates include an assessment of the technically recoverable gas (also called maximum recoverable gas) in addition to the economically recoverable gas. Technically recoverable gas represents that gas recoverable from tight formations under optimistic assumptions of technological development, assuming price is relatively unconstrained. The economically recoverable gas, in contrast, is subject to both economic and technological constraints. It is usually calculated for several price and technology levels and reflects the sensitivity of recoverability to these parameters.

Detailed estimates of both technically and economically recoverable tight gas were made by Lewin Associates and by the National Petroleum Council in conjunction with their gas-in-place resource estimates. The Gas Research Institute (G RI) has also estimated the economically recoverable resource in tight formations. The NPC study is the most comprehensive of these analyses and is discussed here in the most detail. The other studies are included for comparison, particularly where different methodologies or assumptions are shown to substantially affect estimates. All these estimates assume two levels of technology. The "base case" uses technologies currently available or thought to be available in the near future. The "advanced case" represents technologies that might be developed given a concerted research effort.

Methodologies and Results

Lewin Estimate

The Lewin report calculated the technically recoverable gas using its "advanced case" technology criteria, which assume a maximum well spacing of six wells per section (107-acre spacing) and a maximum fracture length of 1,500 ft. They determined that 211 TCF, close to half of the total gas-in-place resource, was technically recoverable. The percent of gas-in-place estimated to be recoverable for the individual basins ranges from 10 to 80 percent, as shown in table 38.

Table 38.—Maximum Recoverable Tight Gas Resources, TCF

	Lewin			NPC		
Appraised basins	GIP[a]	Maximum recovery	Percent recovery	GIP[a]	Maximum recovery	Percent recovery
Northern Great Plains/Williston	74	35	47%	148	100	68 "/0
Greater Green River	91	36	40	136	87	61
Uinta	50	18	36	20	15	75
Piceance	36	12	33	49	33	67
Wind River	3		33	34	23	68
Big Horn	24	8	33			
Douglas Creek	3	0.3	10			
Denver	19	13	68	13	8	62
San Juan	15	12	80	3	2	67
Ozona				1	0.6	60
Sonora	24	16	67	4	2	50
Edwards Lime				14	9	64
Cotton Valley "sweet"	67	50	75	22	13	59
Cotton Valley "sour"	14	10	71			
Ouachita	5	1	20			
Total	423	212	500/0	444	292	66%
Extrapolated basins				480	315	66

aGIP = Gas-in-place.

Lewin determined that 70 to 108 TCF could be economically produced under **base case technology** conditions for well head prices ranging from $1.75 to $4.50/MCF (1977$) and $2.75 to $7/MCF (1983$), They determined that 150 to 188 TCF could be produced under **advanced case** technology conditions and the same price range, as shown in table 39. The different assumptions used for the base and advanced case estimates are given in table 40.

Table 39.- Economically Recoverable Gas at Two Technology Levels (TCF)

	Price per MCF		Base technology		Advanced technology	
	Study date dollars	1983 dollars				
Lewin (1977)	1.75	(2.75)	70		149	
	3.00	(4.70)	100		182	
	4.50	(7.00)	108		188	
GRI (1979).	3.12	(4.20)	30		100	
	4.50	(6.00)	45		120	
	6.00	(8.00)	60		150	
			Total	Appraised	Total	Appraised
NPC (1979)	2.50	(3.35)	192	97	331	142
	5.00	(6.70)	365	165	503	231
	9.00	(12.00)	404	189	575	271

Table 40.—Lewin & Associates Base v. Advanced Technology

Parameter	Base case	Advanced case
Fracture height , ...	4 times net pay (200' minimum, 600 maximum fracture height)	3 times net pay (150' minimum, 400 maximum fracture height)
Fracture length (one way)		
Shallow gas sands	200 '	500 '
Near-tight sands	500'	500 '
Tight gas sands.	1,000 '	1 ,500'
Fracture conductivity	Decreases with depth using current proppants and methods	(Using improved proppants and methods to maintain adequate conductivity)
Field development		
Lenticular	*320* acres per well (2 wells per section)	107 acres per well (6 wells per section)
Blanket	160 acres per well (4 wells per section)	160 acres per well (4 wells per section)
Net pay contacted		
Lenticular sands		
320 acres drainage	17%	—
107 acres drainage	—	800/0
Blanket sands	100%	100%
Dry hole rate:		
Lenticular ., ...	*300/0*	200/0
Blanket	*20%*	10%
Discount rate.	*26°/0 (20°/0* real)	16°/0 (10°/0 real)

SOURCE: V. A. Kuuskraa, et al., *Enhanced Recovery of Unconventional Gas: The Program- Volume II,* U.S. Department of Energy report HCP/T2705-02, October 1978.

The Lewin estimates were developed using reservoir simulation-based production curves for blanket and lenticular reservoirs to determine cumulative reserves from a well over a 30-year period. Input parameters included reservoir characteristics for the individual basins and pay quality intervals, fracture lengths, fracture conductivity, and drainage area of a well.

Production per year per well for the assumed wells, multiplied by the assumed gas price, gives the positive cash flow for the economic model. Offsetting costs include the initial investment in exploration, drilling, and stimulation, plus operating and maintenance costs, royalties, and taxes. A required rate of return of 20 percent (real) was used for the base case estimates, dropping to 10 percent in the advanced case to reflect lower risks associated with the greater predictive capabilities and higher efficiencies associated with advanced technology,

National Petroleum Council

In contrast to the Lewin method of calculating the technically recoverable gas using its advanced technology criteria, the NPC determined the maximum recoverable gas directly from the gas-in-place estimates. The maximum recoverable gas is defined as the total amount of gas that can be produced from a reservoir before the gas pressure in the reservoir reaches the "well bore drawdown pressure."[39] This quantity is further modified by a "recovery adjustment factor" meant to take into account the existence of very low permeability areas within a field that are unlikely to be productive, Recovery adjustment factors range from 50 percent for blanket reservoirs with average permeabilities of 0.00001 md, to 95 percent for blanket reservoirs with average permeabilities of 0.3 md.[40] Lenticular reservoirs use more conservative adjustment factors. The NPC study determined the technically recoverable gas for a set of appraised and extrapolated basins to be 292 and 315 TCF respectively. Its results are also shown in table 38.

The NPC estimates of economically recoverable gas range from 192 TCF at $2.50/MCF (1979$) with **base case** technology to 575 TCF at $9/MCF with **advanced technology,** as shown in table 39. The base case is represented as "current fracturing technology and well spacing regulations, " but apparently allows for some evolution and improvement of the technologies over time as operators gain experience. The advanced case incorporates new technologies developed by a concerted R&D program. The methodology used by the NPC to determine the economically recoverable gas is similar to the Lewin methodology. Cumulative production per well was determined from type curves[41] for base and advanced technologies. This gives the number of wells per section required to produce all of the recoverable gas in a given permeability level in a formation. The base and advanced technology criteria are shown in table 41. In the economic model, costs of drilling and fracturing and operating costs are subtracted from income from production at various prices, and a marginal rate of return is calculated. All formations with a rate of return less than a prescribed value (10, 15, or 20 percent) are considered unprofitable.

It has been suggested that the NPC method of using type curves designed for 640-acre (one well per section) spacing to determine cumulative production levels from blanket formations at 160-acre (four wells per section) and smaller spacings could result in a substantial overestimate of the recoverable resource. The expected cause of this overestimate is the inability of the (640-acre) type curve to account for the greater interference between wells that would occur at 160-acre spacing (interference reduces the production per

[39] The production of gas depends on a pressure gradient existing between the wellbore and the rest of the reservoir. As the pressure in a formation is reduced through production, the reservoir pressure and the wellbore pressure approach equilibrium. Eventually no further gas will flow naturally, The NPC assumed that the reservoir pressure at this point would be approximately 10 percent of the original formation pressure. Any gas remaining in the reservoir cannot be produced except by expending energy to induce an artificial pressure gradient.

[40] NPC Report, vol. V, part 1, table 15.

[41] Type curves are normalized representations of cumulative production over time generated from reservoir simulation models. Because the data are generated in terms of dimensionless values, they are applicable over a wide range in the reservoir parameters (permeabilities, porosities, net pay, pressure, temperature, gas composition, and fracture conductivity). Different type curves, however, are required for different well spacing rules. They are an efficient technique for obtaining estimates of cumulative recovery and producing rates for a large number of reservoirs.

Table 41.-NPC Base v. Advanced Technology

	Blanket formations		Lenticular formations	
1. Fracture height	4 times net pay	3 times net pay	6 times net pay	4 times net pay
Range (ft)	200-600	150-400	300-1,000	200-600
2. Fracture conductivity (md-ft)	500	1,000	500	1,000
3. Fracture length, wellbore to tip (ft), permeability >=0.1 md				
Effectively achieved	1,000[a]	2,000[a]	1,000[a]	4,000[a]
Hydraulic design required . .	1,700[a]	2,500[a]	1,700[a]	5,000[a]
4. Field development, wells per section (maximum)	4	12	4	12
Acres per well (minimum) . .	160	53	160	53
5. Lenses remote from the wellbore may be contacted by fractures?	NA	NA	Yes	Yes

[a]Product of fracture permeability and fracture width.

SOURCE: National Petroleum Council, Unconventional Gas Sources, vol. V, part 1, December 1980.

well).[42] The overestimate of production per well would be greatest at the higher permeability levels where more of the economically producible gas is found. This problem is not as serious as it might appear, however, because of the way the type curve data were used in the NPC report. If the NPC had computed total production from wells drilled to determine gas recovery, assuming a standard "four wells per productive section, " then they would have overestimated the maximum recoverable resource. Instead, as noted previously, NPC determined the maximum recoverable gas independently of the type curves, applying recovery factors to the gas-in-place. The cumulative 30-year production of a well, derived from the type curves, was used only to determine the number of wells per section required to produce the maximum recoverable gas.

At the higher permeability levels, all of the recoverable gas can be produced by less than the four wells per section base case constraint. Thus, although the NPC may have *underestimated the number of wells* required to produce these permeability levels, unless the actual number of wells required exceeds the four wells per section constraint, *it has not overestimated the amount of gas* that can be produced.

At lower permeabilities (0.3 md and lower), where more than four wells per section are required to produce all the gas in the formation, the NPC technique may overestimate the economically recoverable gas for the base case. Nevertheless, the amount of gas involved is not large. For example, a sensitivity analysis of the NPC estimates shows that a shift to 160-acre type curves would not have changed the estimate of recoverable reserves for the blanket formations by more than 10 percent.[43] A similar problem does not exist for the advanced case because all of the gas at all permeability levels can be produced from less than the allowed 12 wells per section.

Gas Research Institute

The most recent estimate of the gas recoverable at different price and technology levels has been made by the Gas Research Institute and is also shown in table 39. These estimates are considerably lower than both the Lewin and the NPC estimates, ranging from 30 TCF at $3/MCF (1 979$) and base technology, to 150 TCF at $6/MCF and advanced technology. GRI derived its estimate by making judgmental adjustments to existing estimates. It concentrated on those basins where

[42]Gruy petroleum Technology Inc. report to EIA, "Correlations for Projecting Production From Tight Gas Reservoirs. "

[43]J P. Brashear, et al., "Tight Gas Resource and Technology Appraisal: Sensitivity Analysis of the National Petroleum Council Estimates, 1984 *SPE/DOE/GRI Unconventional Gas Recovery Symposium,* SPE/DOE/GRI 12862, Pittsburgh, PA, May 13-15, 1984.

the tight sands resource was best understood and, in addition, attempted to eliminate tight gas that might conceivably be considered conventional. Its conservative approach was specifically designed to provide an estimate of that portion of the tight gas resource which had a high probability of occurrence.

Comparison of Estimates and Discussion of Uncertainties

One of the major differences between the recoverable resource estimates is the difference in the total areas assessed, since the amount of gas estimated to be recoverable is intimately tied to the proportion of the gas-in-place actually included in the study and evaluated for recoverability. The NPC, Lewin, and GRI recoverable resource estimates each are based, implicitly or explicitly, on a different gas-in-place resource base. The NPC, by including both the appraised and extrapolated basins, begins with the largest gas-in-place resource base. Lewin restricts its estimate to those basins for which considerable information is available. GRI also restricts its estimate on this basis, but apparently further limits the resource base it evaluates by excluding all potential areas of overlap with conventional resource estimates. Where the areas assessed by NPC, Lewin, and GRI overlap, however, there are still substantial differences in the estimates of recoverable gas. These differences result from the underlying assumptions used in the estimating process.

In the sections that follow, we first compare recovery estimates for a comparable area—the appraised resource—to show how different assumptions affect the estimates of technical y and economically recoverable gas. Next, we briefly discuss a portion of the resource base evaluated by broad geologic analogy rather than direct appraisal—the extrapolated resource. Finally, we discuss briefly the geological/geographical boundaries used in the resource estimates. Included in each section is a discussion of the major uncertainties underlying the estimates and how these uncertainties affect the amount of gas recoverable. it is important to remember that many of the uncertainties in calculating the gas-in-place are propagated through to the calculations of the technically and economically recoverable resource.

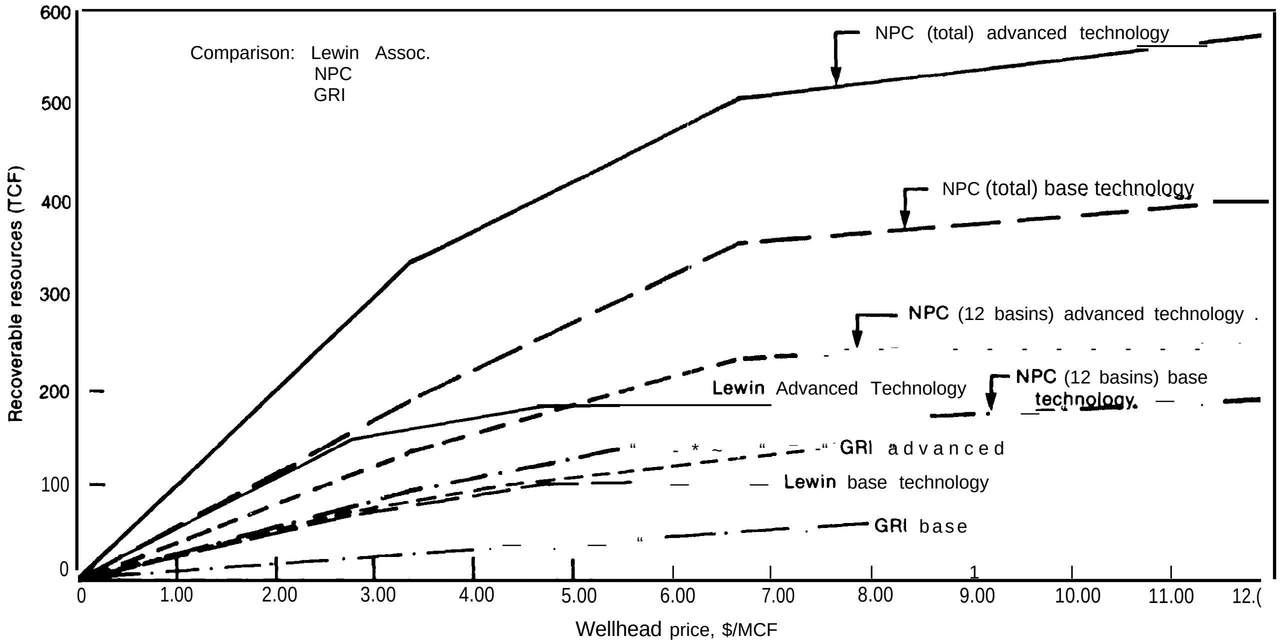
The Appraised Basins

The appraised basins of the Lewin and NPC studies have comparable total volumes of gas-in-place, as discussed in the previous chapter. Despite this agreement, their estimates for potential recovery of tight gas are significantly different (the technically recoverable gas is two-thirds of the gas-in-place in the NPC study compared to half of the gas-in-place in the Lewin study). Differences in percent of gas-in-place recoverable are particularly apparent on an individual basin level, as seen in table 38, and can be attributed to the different assumptions used by the estimators to calculate both technically and economically recoverable gas.

The NPC approach to estimating **maximum recoverable gas is independent of any technology assumptions and effectively assumes that virtually all gas in a formation** will ultimately be in contact with a well bore. In contrast, the Lewin estimate is constrained by a set of advanced technology criteria that do not allow the entire gas-bearing portion of a formation to be contacted, even under the most favorable conditions. The Lewin estimate is more conservative than the NPC estimate in its assumed fracture lengths and, for lenticular resources, in its assumptions about the probability of producing from lenses not in direct contact with the wellbore.

Differences between the Lewin and NPC estimates of **economically recoverable** gas in the appraised basins are caused primarily by differences in their assumptions about base and advanced case technology conditions (tables 40 and 41). For the base technology case, the Lewin estimates of economically recoverable gas are only two-thirds of the NPC estimates (see fig. 31). The effects of shorter assumed fracture lengths in some areas, especially the Northern Great Plains, a constraint of two wells per section in lenticular formations, and the constraint that only lenses in direct contact with the wellbore could be produced probably account for the lower estimates of recoverable gas in the Lewin estimate.

Figure 31.—Comparison of Recoverable Estimates (for gas price in 1983$)



Under advanced technology criteria, there is little difference between the NPC and Lewin estimates at the lower prices despite the NPC technical potential for much higher levels of production using 2,000- to 4,000-ft fractures and up to 12 wells per section. The increased "per section" production potential in the NPC analysis is probably offset by increased costs of longer fractures, which would make many of the lower permeability prospects unprofitable at lower prices. The lower marginal rate of return in the Lewin advanced case allows it to bring a number of its previously unprofitable wells on line, increasing the percent of the technically recoverable gas that can be economically produced. In this case, tradeoffs between costs, rates of return, and recovery per well allow two entirely different sets of assumptions to result in approximately the same amount of gas produced. At higher prices, however, the higher fracturing costs of the NPC estimate become less of a factor in determining profitability of a well and the NPC estimate of recoverable gas is again higher than the Lewin estimate.

The above comparison of the Lewin and NPC appraised basin estimates points out how different assumptions of price, rate of return, and state of tech no logic development affect the estimates of technically and economically recoverable gas. The inherent uncertainty in some of these assumptions is the major factor in whether the estimates can be considered an accurate representation of the recoverable resource.

The primary uncertainty lies in the technology assumptions for the different tight gas formations. The NPC assumptions are considerably more optimistic than those used by Lewin. Assumptions made by the NPC that are most likely to be challenged include:

1. fractures in lenticular formations will contact (and allow production from) lenses distant from the wellbore;
2. currently available technology will allow propped 1,000-ft fractures in all producing situations, advanced technology will allow 4,000-ft fractures with fracture heights less

than currently achieved with 1,000-ft fractures; and

3. every stimulation will be successful in achieving its design criteria (length, orientation, and direction).

OTA considers these assumptions to be optimistic, especially for the base case, but also for the advanced case as well. As noted in the technology discussion, not all of the base case conditions have been met at the present time. Although evolution and improvement of existing technology during normal operations[44] will occur, the base case criteria still appear optimistic. Some of the base case and advanced case criteria do appear likely to be met over the long term under a strong R&D program; others may deserve to be substantially modified.

1. **Contacting Remote Lenses.** A major assumption of the NPC study is that massive hydraulic fractures in lenticular formations can contact lenses distant from the wellbore, in both the base and advanced technology cases. This assumption underlies the inclusion of vast areas of lenticular formations into the tight gas recoverable resource base. The NPC estimates that 126 TCF is recoverable from lenticular formations in 4 of the 12 appraised basins—43 percent of the total recoverable resource in all appraised basins. To date, **no** evidence exists that remote lenses can be contacted, despite a number of fractures completed in lenticular formations. In recent analyses of tight gas resources, GRI has assumed zero contact of remote lenses for its "present technology" case.[45] The DOE Multiwell Experiment is designed to answer this remote lens question; if the results of this experiment prove disappointing, estimates of the amount of gas that can be recovered from tight lenticular formations may need to be substantially reduced.

A recent sensitivity analysis of the ability to contact remote lenses has been performed using a computer simulation of the NPC study.[46] This analysis determined that the technically recoverable gas from appraised lenticular formations would be reduced by about half if remote lenses could not be contacted. For example, for an allowable 12 wells per section, recovery per well would drop from 100 to 48 BCF. This effect is magnified for the **economically** recoverable gas, especially at moderate prices, because some lenticular formations cannot be developed at all unless remote lenses can be produced. For example, **at gas** prices of $2.50/MCF in 1979$ ($3.35 in 1983$) and a rate of return of 15 percent, assuming advanced case technology, the NPC-estimated economically recoverable gas from the appraised lenticular basins is 37 TCF if remote lenses can be produced and only 10 TCF if they cannot be. Without production from remote lenses, the lenticular tight formations may not play a significant role in future U.S. gas production.

2. **Achievable fracture characteristics.** As noted earlier, there is considerable disagreement about the extent to which the NPC-defined fracture characteristics realistically reflect both current technology and achievable future technology.

For the NPC "base" or current technology, OTA is particularly skeptical of the assumption of 1,000-ft achievable fractures for the lenticular resource (see the *Technology* section). Recent Gas Research Institute analyses have used propped fracture lengths of 600 ft and fracture conductivities[47] of 400 md-ft (v. NPC's 500 md-ft) to represent "present" technology.[48,49] As with changes in assumptions about contacting remote lenses, the effect of these changes in fracture characteristics is to substantially reduce the recoverable gas at all price levels. Figure 32 shows the combined effect on recoverable resources of the "no contact of remote lenses" assumption and the changes in fracture characteristics. For example, recoverable gas at $9/MCF (1982$) is reduced by about 25 percent, from roughly 400 to 300 TCF.

[44] As noted previously, such evolution and improvement is considered to be included in the base case technology conditions.

[45] Briefing document for the Tight Gas Analysis System, Lewin & Associates, Inc., 1984.

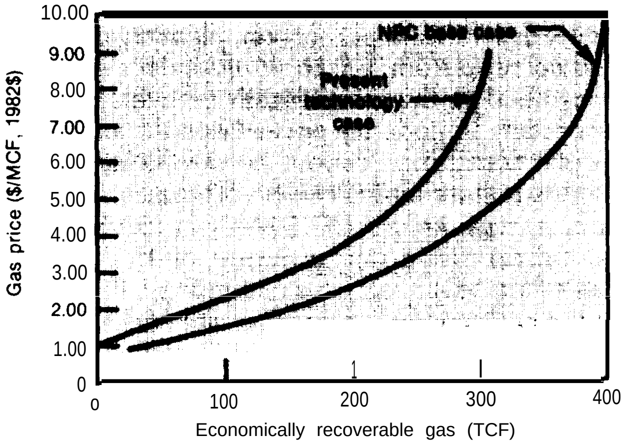
[46] The simulation is called the TGAS Simulator, described in Brashear, et al., op. cit.

[47] Fracture conductivity: the product of fracture permeability and width, a measure of how well gas can flow along the fracture.

[48] Briefing document for the Tight Gas Analysis System, *op. cit.*

[49] GRI's "present technology" and NPC's base case may not describe precisely the same technology level, however, because NPC's base case includes the evolutionary effects of future operations. On the other hand, the GRI criteria were defined several years after the NPC's were.

Figure 32.–Comparison of NPC Study Results With GRI Present Case—Tight Gas Sands Recoverable Gas



SOURCE: S. Ban and D. Dreyfus, "Adequacy of Gas Supply: The Role of Technology," Natural Gas in Texas Conference, Austin, TX, May 10, 1984. Available from Gas Research Institute.

GRI has also chosen to use more modest fracture characteristics than NPC for its "R&D Success" case, which includes improved geological and geophysical techniques, improved fracture design and diagnostics, and real-time fracture diagnosis and control:[50] fracture length and conductivity are assumed to be 2,000 ft and 800 md-ft, respectively, v. NPC's 4,000 ft and 1,000 md-ft. Although OTA agrees that these NPC "advanced case" fracture characteristics appear to be quite optimistic, our major concern lies with the NPC assumptions for fracture height. GRI has accepted the NPC's fracture height criteria for both the current and advanced cases.[51] According to these criteria, the 4,000-ft fractures will have shorter fracture heights than the 1,000-ft fractures (e.g., for blanket sands, fracture height is six times net pay for the 1,000-ft fracture and four times net pay for the 4,000-ft fracture).

Because of the shorter fracture height, the longer fractures will be cheaper per unit length than the base case fractures, which in turn adds substantially to the estimated recoverable resource in the "advanced technology" case. The fracture height assumption reflects NPC's belief that careful control of fracture placement and fracturing fluid pressure will serve to maintain small fracture heights. This is the opposite of current experience, where longer fractures generally are associated with increased fracture height and higher (per unit length) costs. On the other hand, current fracturing technology does not include reservoir and fracture-propagation modeling capabilities that provide "real time" (during the actual fracturing process) control of well treatmerits.[52] GRI is sponsoring research to develop this capability and clearly hopes that successful development will allow longer fractures to be produced without increasing fracture height. Future improvement in fracture control clearly is a certainty. Nevertheless, assuming a reduction in fracture height in conjunction with a fourfold increase in fracture length appears to be optimistic.

In addition, the NPC's specification of fracture height as a constant multiple of net pay thickness serves to automatically favor thin, higher permeability intervals over thicker, low-permeability intervals, This is because fracturing costs area function of the volume of fracture fluid required, which in turn is a function of fracture height. Consequently, using NPC's assumptions, thin, rich, high-permeability pay intervals will tend to appear very attractive to develop even though in actual experience it may be difficult to achieve very long fractures in such intervals without exceeding the "four or six times net pay" fracture height constraint. As a result, the NPC's fracture height assumptions may yield estimates of more gas at lower prices than maybe realistically producible. However, this effect may be counter balanced somewhat by the empirical relationship between net pay thickness and permeability assumed by NPC. Because the NPC believed that most of the tight gas resource lies in the lower permeability rocks, they assumed that the higher permeability gas-bearing zones would be thin and the lower permeability zones would be thick. Because the initial productivity, and thus the economic viability, of a well depends on the product of thickness and permeability, the assumption that higher permeability zones would essentially always be thin is pessimistic. An alternative

[50] The latter improvement allows problems encountered in fracturing to be diagnosed and fixed in "real time, " i.e., as the fracture is being made.

[51] Briefing document, Op. cit.

[52] Gas Research Institute, Status *Report: GRI's Unconventional Natural* Gas *Subprogram,* December 1983,

assumption, albeit an optimistic one, that all pay zones are the same thickness would yield a 46-percent increase in the recoverable resource at $2.50 gas in 1979$ ($3.35 in 1983$) with the base technology. The relative effect decreases at higher gas prices and improved recovery technology.[53]

Finally, whether or not the NPC's fracturing criteria are **generally** realistic, OTA is concerned that they were universally applied to all formations regardless of geologic character, except for the separation of blanket and Ienticular formations. For example, using these fracturing criteria, the Northern Great Plains becomes one of the dominant sources of recoverable gas from blanket formations. Apart from the question of how much gas exists in the Northern Great Plains, geologic characteristics of these shallow, low-pressure reservoirs can also restrict the amount of recoverable gas. For example, the presence of water-sensitive clays makes these reservoirs sensitive to formation damage.[54] Also, experience has shown that fractures in shallow formations may propagate horizontally rather than vertically, reducing the net pay drained by each well, and significantly reducing the recovery efficiency, Thus, the appropriateness of assuming 4,000- or even 1,000-ft fractures in assessing recovery from these reservoirs, and thus counting on up to **70** to 90 percent recovery of the gas-in-place, is questionable. The Lewin study assumed that short fractures (200 to 500 ft) would be used in these reservoirs, and assumed that fractures in the shallower formations would propagate horizontally.[55] Its ultimate recovery efficiency in the Northern Great Plains is only 47 percent of the gas-in-place (table 38). More accurate assessment of the recoverability of gas from these formations, using more site-specific technologies, is needed. For example, the use of air-drilled open hole wells at close spacings may be a preferred method of production considering the low drilling and completion costs for these depths and the avoidance of formation damage.[56] Ultimate recovery from this region appears more likely to be on the order of so percent (or less) of the gas-in-place rather than the NPC's estimated **70** to 90 percent.[57]

3. **Success Rate of Fracture Treatments.** Further, the NPC study assumes that each fracture treatment is successful in achieving design criteria. Fractures are assumed to never grow vertically out of the pay zone at the expense of fracture length. They are never offset against existing natural fractures or intersect one another at close well spacings. Formation damage is minimal. The NPC approach assumes that technologic development will be able to overcome all of these problems. In fact, however, some of these problems appear to be inherent to the formations. With better reservoir characterization, producers may be able to better predict where fractures will grow out of the pay zone or what the probability is that they may intersect, but they may never be able to control many of these occurrences; other occurrences may be controllable but only at added cost. OTA feels that 100 percent fracture success is an overly optimistic assumption.

[n addition to uncertainties associated with the fracturing technology criteria, an important uncertainty in the appraised recoverable resource is associated with the geology of the Northern Great Plains:

The Northern 'Great Plains

If gas does not exist in large quantities in the Northern Great Plains, the estimated recoverable resource will have to be substantially reduced regardless of the success of advanced technologies. The NPC estimates that 100 TCF, one-third of the technically recoverable gas in the appraised basin estimate, can be produced from this region.

According to the NPC criteria, much of this gas ought to be relatively inexpensive to produce. Approximately 54 TCF is estimated to be recoverable at $2.50/MCF (1 979$) using base technologies. Even the more conservative Lewin estimates predict that 21 TCF will be recoverable at $1.75 (1977$) under base case conditions. Despite this apparent incentive, however, there appears to be little current interest in developing

[53] J. P. Brashear, et al., op. cit.

[54] R. L. Gautier and D. D. Rice, "Conventional and Low Permeability Reservoirs of Shallow Gas in the Northern Great Plains," *Journal of Petroleum Technology,* July 1982.

[55] Lewin, vol. II, pp. 3-57.

[56] Gautier and Rice, Op. cit.

[57] Dudley Rice, U.S. Geological Survey, Denver, CO, personal communication.

tight gas in the Northern Great Plains. No FERC filings for tight gas designations in the Northern Great Plains have been made to date. Reasons for the lack of interest may include external constraints, such as an absence of pipelines and market problems due to the existing surplus. However, there are other tight gas basins with similar transportation/market problems—e.g., the Uinta and Piceance basins—that have sustained at least moderate development efforts, so these problems do not fully explain the lack of activity in the Northern Great Plains.

On the other hand, a recent GRI analysis[58] claims that the current lack of activity and high estimated recoverable resource can be reconciled by comparing the profitability of **individual prospects** in the Northern Great Plains with prospects in other tight gas basins. The Northern Great Plains is described as "having a very geologically diffuse resource, which would require large numbers of shallow, low-pressure wells spread over great distances."[59] While the Northern Great Plains contains more total economically recoverable gas than competing basins at any price level, several basins in the Rockies and Southwest were found to contain a number of individual formations offering greater profitability **per thousand cubic feet of gas extracted.** These prospects are characterized as offering larger field sizes and greater well productivity and recoverable gas per section than prospects in the Northern Great Plains. Because developers make investment decisions on the basis of individual prospects and not entire basins, development of the Northern Great Plains might not be expected to occur until the more attractive prospects elsewhere were exploited. GRI also speculated that the intermingling of tight formations with established gasfields in the Rockies and Texas would also provide an important incentive for developing these basins first, because developers tend to want to drill in areas where they have had previous successful experience.

The questions concerning gas-in-place, producibility, and current activity levels call for an independent assessment of the Northern Great Plains production potential. Such an assessment should include a reevaluation of the gas-in-place, the engineering characteristics of the reservoirs, and the costs and technologic requirements of producing from these reservoirs. An analysis of the external constraints and their temporal significance is also needed.

The Extrapolated Resource

The NPC approximately doubles the volume of its gas-in-place estimate by including 101 additional basins in the resource base. Because it assumes that the formations in the extrapolated basins have similar producing characteristics to analog formations in the appraised basins, it also approximately doubles the estimated technically recoverable resource as well as the economically recoverable resource.

It is generally agreed that the extrapolated basins represent the most speculative part of the NPC resource estimate. In addition to the uncertainty as to the quantity of gas existing in these basins, there are further uncertainties in the extrapolation of engineering characteristics for gas-producing formations and the consequent estimates of production. There is sufficient information in these areas to say that some gas is there, and that some of it may be economically produceable, so the extrapolated resource certainly cannot be entirely disregarded. If FERC filings can be considered indicative of productive areas (if not of actual volumes of gas), then the large number of filings for the Eastern and Southwestern United States may bean encouraging sign for the production potential from extrapolated basins.

Recent studies have been undertaken to better characterize the extrapolated basins,[60] but data sufficient to revise the NPC estimates are not yet available. Because the potential contribution of the extrapolated basins to the recoverable resource has been estimated to be so large, more detailed assessments remain a high-priority area for future research.

[58] J. 1. Rosenberg, "The Economics of Tight Sands Gas Extraction as Affected by R& D," *Gas Research Insights* series, Gas Research Institute, August 1983.

[59] Ibid.

[60] R. J. Finley and P.A. O'Shea, "Geologic and Engineering Analysis of Blanket-Geometry Tight Gas Sandstones, " *1983 SPE/DOE Joint Symposium on Low Permeability Gas Reservoirs,* SPE/DOE 11607.

Many who use the NPC figures in their analysis of gas supply consider only the recoverable gas in the appraised basins because of the speculative nature of the extrapolated resource. OTA suggests that it is overly conservative to disregard the extrapolated resource altogether, especially since FERC filings indicate that development is going forward in some of the extrapolated basins; however, until better estimates are available, it may be more useful to consider the extrapolated recoverable resource estimates in a category separate from the more precise estimates of the appraised basins.

Effect of Boundary Conditions

Double Counting.–The separate estimation of the conventional and unconventional natural gas resource base by different groups, coupled with poorly stated "boundary conditions" for each estimate, can lead to some resources being counted in both conventional and unconventional estimates (e.g., "double counting"). This would lead to an overestimate of the total natural gas resource.

Tight gas has the highest level of current production of all the unconventional resources. Because of the existing production, there is some controversy over how much of the tight gas resource has already been included in conventional resource estimates, and thus in estimates of future conventional gas production. To the extent that it is so included, it cannot be considered as a potential **supplemental** source of supply.

Most conventional resource assessments are not well documented; and comparison of conventional with unconventional estimates is not straightforward. Recently, the Potential Gas Committee (PGC) has attempted to determine what percent of its total conventional undiscovered **recoverable** resource[61] occurs in tight formations. It concludes that 172 TCF, or 20 percent of its total potential recoverable resource, is tight gas.[62]

[61] Including resources made avai [able by the growth of already-discovered fields because of enhanced recovery, discovery of new reservoirs, etc.

[62] The PGC tight gas estimate included both tight sands and Devonian shales. However, conversations with the people responsible for determining tight gas in the eastern region have indicated that the Devonian shale contribution to the tight gas estimate is very small.

A considerable portion of this gas does not overlap with the NPC tight gas resource, however, because it is below 15,000 ft (the NPC depth limit), in areas already undergoing development (and thus not unconventional according to the NPC definition), or simply in locations not considered by the NPC study to be prospective.

There is no unequivocal data set that will allow an accurate estimate of the overlap between conventional and unconventional natural gas resources. Estimates range up to 100 TCF,[63] and the PGC has recently suggested that as much as half of the tight gas in its estimate may represent an overlap with the NPC resource[64] An OTA analysis of the overlap, presented in appendix C, indicates that the total overlap between the PGC-estimated 172 TCF of tight gas and the N PC-estimated 606 TCF of recoverable tight gas may be as low as 30 TCF. Even the low side of the overlap, however, though relatively small compared to the total size and large uncertainties in the tight gas resource estimates, **is still important in assessing the unconventional tight gas contribution to near- and mid-term production** because the 30 TCF are in the most accessible, least expensive portion of the tight gas resource. The main areas of overlap occur in the blanket formations of the Rocky Mountain Basins and the Cotton Valley Trend in Texas and Louisiana. These areas currently are the major producers of gas from tight formations, and the NPC report has predicted these areas to be the main contributors to "unconventional" supply in the next 20 years.

Deep Tight Gas.–Another problem arising from inadequately defined boundary conditions is that certain potential resources may be overlooked entirely, resulting in an **underestimate** of the total resource base. For example, the PGC estimated that its conventional gas resource base includes some 89 TCF of gas in tight formations at depths greater than 15,000 ft. The NPC report acknowledges that large volumes of gas probably occur at depths greater than 15,000 ft, but they assumed this gas to be too speculative a resource to in-

[63] Vello Kuuskraa, Lewin & Associates, Inc., personal communication, 1984.

[64] H. C. Kent, Director, Potential Gas Agency, testimony before the Subcommittee on Energy Regulation, Senate Committee on Energy and Natural Resources, Apr. 26, 1984.

elude in its tight gas assessment.[65] Other experts have concurred that large volumes of gas exist in deep tight formations, in the Rocky Mountain Basins as well as the Anadarko and Arkoma Basins in Oklahoma and Arkansas. Many of the deeper Rocky Mountain formations are Ienticular.

Apart from the PGC estimate, which is widely viewed as an estimate of the **conventional** resource, there are no quantitative estimates of recoverable resources in deep tight formations. Deep tight formations, other than those already included in the PGC estimates, probably should be included in future estimates of the unconventional tight sands resource at least for the estimates of gas-in-place. They represent no more speculative a source of gas supply than the unfractured portions of the Devonian shales or the deep coal seams, both of which generally are included in gas-in-place estimates of unconventional resources.

Conclusions About Recoverable Gas

To summarize, OTA considers the NPC estimates of recoverable tight gas resources to be optimistic. The major reasons for this appraisal are:

1. **The Northern Great Plains.** OTA considers it quite plausible that the recoverable resources in the Northern Great Plains are considerably lower than the 100 TCF maximum recoverable gas projected by the NPC.
2. **Gas-in-Place.** Aside from the Northern Great Plains, OTA believes the NPC's gas-in-place estimates to be reasonable, in the context of "most likely" values. The margin for error is large, however, especially for the extrapolated resource; the estimate for the extrapolated resource should be considered as speculative.
3. **Technology.** OTA considers some important aspects of NPC's appraisal of current technology and projection of advanced technology to be over-optimistic. Of particular concern is the assumption that fractures will be able to penetrate and drain lenses remote from the wellbore. Another important concern is that very long fractures (up to 4,000 ft) can be achieved with a net decrease in fracture height.

OTA also believes that **all** available estimates of recoverable tight gas are highly uncertain because of poorly defined reservoir characteristics and technologic uncertainties. However, there seems little doubt that large quantities—at least a few hundred TCF—of tight gas will be recoverable even under relatively pessimistic technologic circumstances, provided gas prices reach moderately high levels in the future (e.g., $5 to $7/MCF in 1984$).

Annual Production Estimates

Any forecasting of actual production from the tight gas resource requires making a number of assumptions over and above those made to estimate the recoverable resource, and similarly uncertain. Projections must be made of the price of gas and the state of technology development over the time interval of the forecast. These are the critical uncertainties. The amount of "high potential" land immediately available for drilling must be estimated. Finally, an estimate must be made of the number of wells that can be drilled within a single year and the rate of increase in following years. The comparison of different forecasts requires an understanding of these underlying assumptions.

The Lewin study used two different development schedules, described in table 42, to determine potential production under base and advanced technology conditions. The schedules represent a rapid early development of the resource. For the base case, tight sands production is 3 TCF in 1990 and rises to nearly 4 TCF in 2000, at $3/MCF (1 977$). The advanced case contributes 4 TCF by 1985 and nearly 8 TCF in 1990 but declines to less than 7 TCF by the year 2000. In contrast, the NPC standard scenario at $5/MCF (1979$) will contribute only 2 TCF by 1990 but up to 9 TCF in the year 2000.

The NPC approach was to assume that there are few external constraints on most of the factors affecting production. Rather than a forecast of the "most probable" production, its supply

[65] According to Ovid Baker, Chairman of the NPC Tight Gas Task Group, deep tight gas below 15,000 ft would cost more than $12/MCF to produce, and the NPC upper limit on price was $9/MCF (Ovid Baker, personal communication, 1984).

Table 42.-Projections of Annual Tight Gas Production, TCF

Assumptions	1990				2000		
Lewin:							
All drilling begins in 1978 and is completed by 2003							
Base case: drill probable acreage immediately, lag drilling of possible acreage 9 years; 20 percent DCF ROR	Price[a] ($/MCF)		Base	Advanced	Base		Advanced
Advanced case: lag drilling of probable acreage 3 years, lag drilling of possible acreage 9 years but complete in 15 years; 10 percent DCF ROR	**3.00 (4.70)**		**3.2**	**7,7**	**4.0**		**6.8**
NPC:							
Standard scenario, phase in advanced technology, 5 percent by 1983, 100 percent by 1989 in blanket sands; 2 years lag in lenticular sands; 40 percent of most profitable prospects (> 50% DCF ROR) drilled in first 20 years; 4 years from first drilling to initial production.	Price ($/MCF) 15% ROR	1/2 std	Standard	2 X std	1/2 std	Standard	2 X std
2 *times standard:* faster technology development and drilling schedule,	2,50 (3.35)		1.1			5.8	
1/2 *standard:* slower technology development and drilling schedule	3.50 (4.65)		1.3			7.0	
	5,00 (6.70)	0.9	1.8	2,2	4.1	8,3	15.5
	9.00 (12.00)		2.5			10,5	
GRI:							
Assume average production decline curves, increase in numbers of wells drilled by 200 per year.	Price[a] ($/MCF)		Base	Advanced	Base		Advanced
Base case: begin with 100 wells in 1984 to 800 in 1988 and 10 percent to 15 percent growth beyond 1988	3.12 (4.20)		0.48	0.93	1.99		3.44
Advanced case. begin with 200 wells in 1984; increase to 800 in 1987 with 10 percent to 15 percent growth beyond 1987.	4.50 (6,00)		0.53	1.02	2.51		5,21
	6.00 (8.00)		0.57	1,12	3.31		6.04
AGA:							
Price and rate of return not defined; average production decline curve similar to GRI; lower drilling rates than NPC; slower implementation of advanced technology			Conservative	High	Conservative		High
Conservative case: lower initial average production rates to account for areas where massive hydraulic fracturing cannot be used	Calculated		1.1	1.2	4.3		6.2
Consensus case: modified to account for slow technologic development and overlapping conventional and tight definitions.	Consensus		—			1.2-3[b]	

aPrice in dollars at the time of the study(1983$)
bRange includes Devonian shale

scenarios are quite deliberately structured to represent a maximum—the amount of gas that could be produced given a concerted effort to develop the required technology and no market restrictions[66] on field development.

The NPC study combines the resource base and economic model to develop several scenarios for production of the tight gas resource. The scenarios incorporate a development schedule in which a certain percentage of the more profitable prospects in all basins are drilled first. Certain constraints were incorporated in the development schedule to reflect the fact that not all the leases on the most profitable prospects will be immediately available for drilling. Development in some areas, such as the Northern Great Plains, is delayed due to lack of pipelines. Advanced technology is phased in according to specific schedules. Annual production rates and cumulative additions to reserves for each scenario

[66]That is, producers can sell all the gas they can produce and transport to potential markets, at the assumed wellhead price plus transportation costs.

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were **calculated for various prices and rates of return. Results of the different scenarios are shown** in table 42.

Figure 33 compares several of the NPC scenarios with the Lewin base and advanced case. The primary difference between the two sets of estimates is the rapidity with which profitable prospects are developed in the Lewin study, and also in the period of time between discovery and actual production from a prospect. In the NPC study, it takes 4 years to place a well under production after drilling; in the Lewin study, production begins the year after discovery.

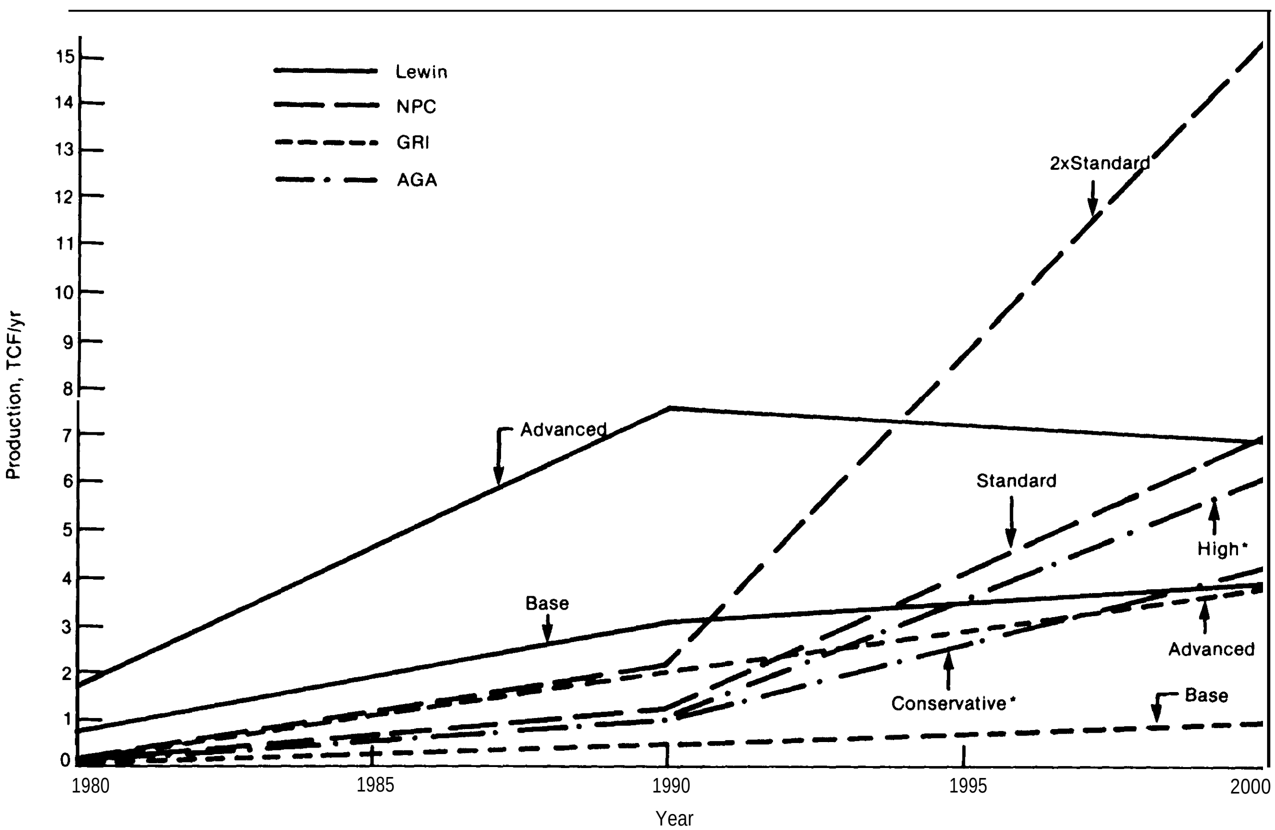
GRI took a slightly different approach to forecasting annual production from tight sands in the earlier (1980) of its two analyses.[67] It determined a production decline curve representative of an "average" well with a production life of 30 years and specified a rate of increase in the number of wells drilled per year. Initial production rates and rate of drilling varied for the base and advanced case scenarios. Details are given in table 42, Its production estimates for base and advanced technology cases range from 0.48 to 1.12 TCF in 1990 and 1.99 to 6 TCF in the year 2000.

A more recent GRI production analysis[68] is based on the TGAS model of the NPC study

[67] J. C. Sharer and J. J. Rasmussen, "Position Paper: Unconventional Natural Gas," *Gas Research Institute*, May, 1981.

[68] J. 1. Rosenberg, F. Morra, Jr., and M. Marchlik, "Future Gas Contributions From Tight Sand Reservoirs, " *1984 International Gas Research Conference,* Sept. 10-13, 1984, Washington, DC.

Figure 33.-Annual Tight Gas Production Estimates
(wellhead gas price = $4.70/MCF, 1983$)



*No gas price specified.

methodology, but adopts a series of advanced technology assumptions that are more modest than the NPC's. The production projections are based on a price **path** rather than a constant real price, with gas prices assumed to reach $6.20/MCF in 2000 and $7.80/MCF in 2010 (all prices in 1982$), and assuming a 15 percent discount rate. The model is deliberately calibrated to produce a year 2000 base production level at around the average of current projections by AGA and DOE, so the value of the analysis lies in the sensitivity analyses around the base production level (described later), and not the level itself.

The production estimates for the base and advanced technology cases range from 1,9 to 2.7 TCF in 2000 and 2.9 to 5.6 TCF in 2010. An additional set of estimates was made for a case where no limits were set on gas demand, capital and drill rig availability, or level of investment. As might be expected, the production estimates for this case are very high, 8 to 11 TCF in 2000 and 8 to 14 TCF in 2010. The investment and drilling implications of this latter case appear unrealistic, but the estimates give some idea about what might be possible with an emergency development program.

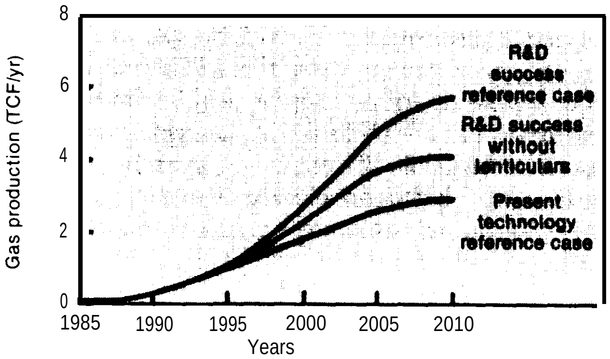
An additional estimate of future production rates is given by the American Gas Association (AGA),[69] AGA used the NPC's analysis as a starting point and superimposed its own assumptions. Its initial estimate projected annual production of 1.2 TCF in 1990 and 6.2 TCF in the year 2000. AGA attributes these lower estimates (relative to the NPC forecasts) to lower drilling rates and a slower implementation of advanced technology. A more conservative estimate, based on lower initial production rates per well, projects 1.1 TCF in 1990 and 4.3 TCF in 2000. No price levels are indicated. AGA suggests that even lower annual production (from 1.2 to 3 TCF from both tight sands and Devonian shales) is likely due to definitional overlap between conventional and tight reservoirs (i. e., some of the production formerly considered to be unconventional more properly belongs in the conventional category) and a less optimistic outlook for the potential of advanced technologies. This lower production range probably is not directly comparable to the NPC's, however, because the AGA definition of unconventional gas appears to exclude gas resources not yet under development that are economically recoverable at today's price and technology—resources that are included in the NPC's tight gas resource base. Such resources, which are in a "grey area" between clearly conventional and unconventional resources, probably make up at least 100 TCF of the NPC's recoverable resource and play a major role in NPC's projected production during the first few decades of tight gas development.

The time frame and extent of technological development is a major factor contributing to the uncertainty of actual production from the tight gas reservoirs. The production of most of the resource contained in the lower permeability formations and the Ienticular formations is strongly dependent on advanced technology development. A slower rate of technology development may severely limit the potential contribution of the tight sands resource to U.S. supply in the next 20 years. For example, NPC made its scenario projections based on immediate utilization of base technology, and implementation of advanced technology in all blanket formations by the year 1989 and in all Ienticular formations by 1991. Events of the last few years have indicated that this rate of development is too optimistic. As discussed previously, the base case technology criteria have not yet been met, especially not in Ienticular reservoirs.

Aside from the **rate** at which new technology will be developed, the advanced technology characteristics assumed by the NPC appear to be quite optimistic, and GRI has used more modest assumptions. However, in reality the specification of future technologies has always been a risky undertaking, and past efforts in other technological areas have not tended to be wildly successful. As shown by figure 34 and by an examination of the "base" and "advanced technology" production projections in each of the studies, the adequacy of exploration and production technology is critical to the economics of tight gas development, and errors in projecting the future state of technology may be translated into sub-

[69] American Gas Association, *The Gas Energy Supply Outlook: 1983-2000*, October 1983.

Figure 34.—incremental Tight Gas Sands Production Rates As a Function of R&D Advances



SOURCE: Lewin & Associates, Gas Research Institute.

stantial errors in projecting future production levels at a particular gas price.

Figure 34 shows GRI's projected production levels at current technology, advanced technology, and a modified advanced technology case where the ability to produce lenticular reservoirs not in direct contact with the well bore has never been achieved. Because of the time delay involved in developing and implementing new technologies, the three cases do not diverge until the mid-1990s, but by 2000 the advanced technology case produces about 50 percent more than the current technology case. By 2010, the advanced case produces 100 percent more—5.6 TCF/yr v. 2.9 TCF/yr About half of the additional production would be lost, however, if remote lenses cannot be produced.

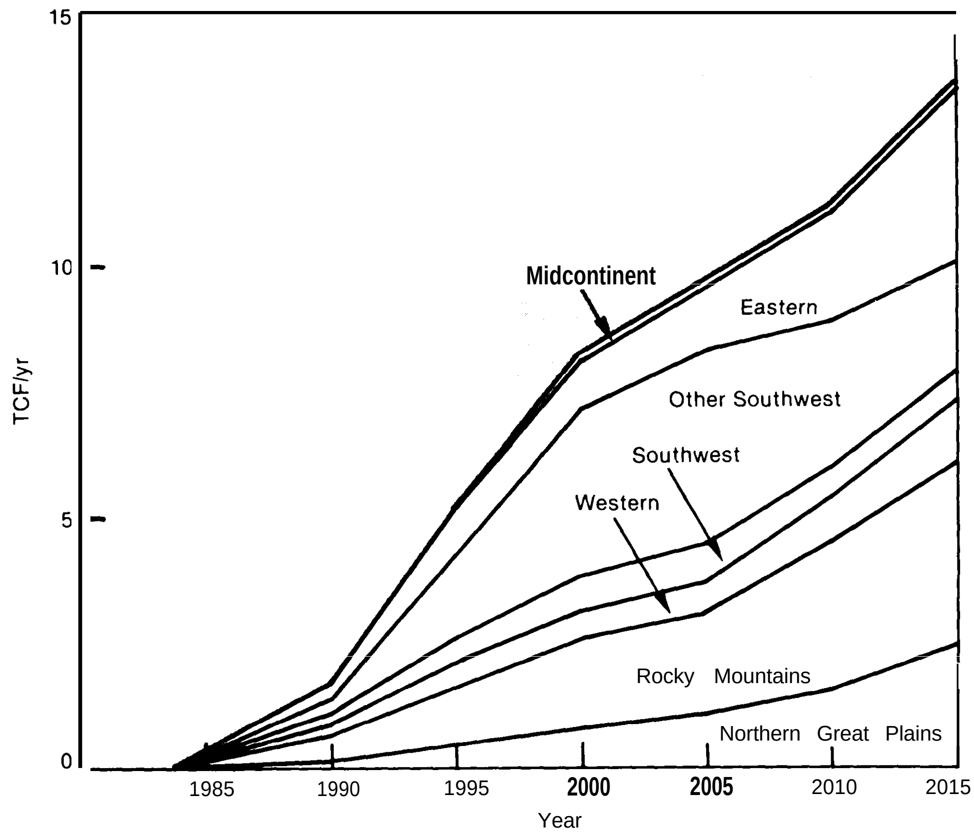
Another important area of uncertainty is the potential for errors in resource assessment. A number of the resource estimates for individual basins have been questioned. Figure 35 breaks out the NPC standard development scenario into the contributions by each basin. In this way, the effect of delaying or otherwise constraining development of certain basins can be more easily visualized. Significant errors in the resource assessments for these basins might be reflected in errors in the production estimates. However, because operators will shift from one target to another if the first does not meet their expectations, the effect on national production of an overestimate of resources in a single basin may include both an overestimate of production **from that area** and a partially offsetting underestimate of production from adjoining areas.

A significant contributor to annual production is the group of Eastern basins. These fall in the extrapolated portion of the resource assessment; recoverable resource estimates for these basins are subject to considerably greater uncertainties than those for the appraised basins.

Another area that deserves particular attention is the Northern Great Plains, which has been the subject of considerable argument concerning the magnitude of its recoverable resource. As illustrated by figure 35, the Northern Great Plains (NGP) plays only a moderate supply role in the NPC standard scenario. One cause of this moderate role may be that the NPC assumed that lack of pipeline availability would significantly delay development in this region. However, the relative development costs of the NGP's shallow gas resource are projected to be quite low, and a supply analysis that assumed fewer supply restrictions would project a more extensive role for NGP gas. Figure 36 illustrates GRI's TGAS projection of tight gas production with and without the NGP, with current and advanced technology. The projection assumes a gradually rising gas price rather than the NPC's constant real price. For both the present and advanced technology cases, removal of the NGP drastically curtails total tight gas production, especially in the short term. For the present technology case, production only "recovers" to about half the reference case by the year 2010. The effect of "losing" the NGP in the advanced technology case is less severe, with production in 2010 about two-thirds of the reference production.

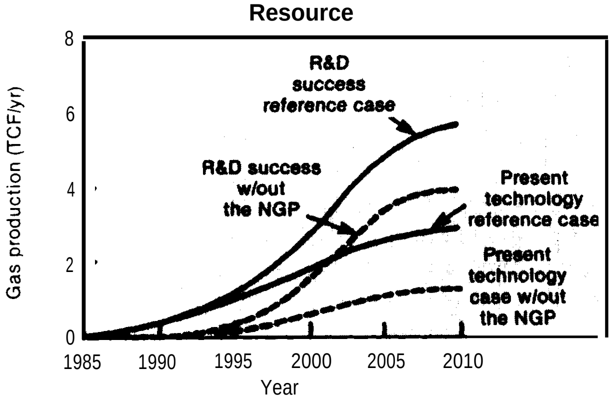
Another potential supply constraint, the total size of the resource, probably will not significantly affect production rates over the next 20 years. in fact, if development of the tight gas resource continues to be as slow as in the last few years, this boundary constraint is not likely to be felt until well into the next century. it may, however, have an impact on the long-term contribution to supply. Comparison of the NPC and Lewin scenarios demonstrates the effect of a smaller total resource on production. Supply from the Lewin appraised resource will begin to decline near the

Figure 35.—Annual Production by Basin—NPC, $5.00/MCF (1979$), 15°/0 DCF ROR, Standard Scenario



SOURCE National Petroleum Council.

Figure 36.—Incremental Tight Sands Gas Production Rates With and Without the Northern Great Plains Resource



SOURCE Lewln & Associates, Gas Research Institute.

year 2000, apparently due to the boundary constraints imposed by the size of the resource. In contrast, production from the total U.S. resource appraised by the NPC continues to increase well into the next century and remains as a significant source of supply until at least 2040 (NPC report, fig. **27).**

The absence of pipelines in many potential tight sands production regions further constrains near- and mid-term development of the tight sands resource. Development of new regions has always been something of a problem for gas development: pipeline companies cannot get approval to build new lines without evidence of proved reserves, whereas producers are reluctant to drill and prove reserves without the presence of a nearby line. For tight gas fields, pipelines may require evidence of larger reserves than are presently required for conventional fields, because the tighter reservoirs produce more slowly.

In the short term, pipeline constraints will affect the pattern of development. Fields near existing pipelines will be developed first. Already much of the new production from tight sands fields is coming from the Southwest, which has excess pipeline capacity. In other areas without pipelines, despite potentially large volumes of gas and low estimated costs of extraction, development is likely to be delayed for several years due to lack of pipeline capacity.

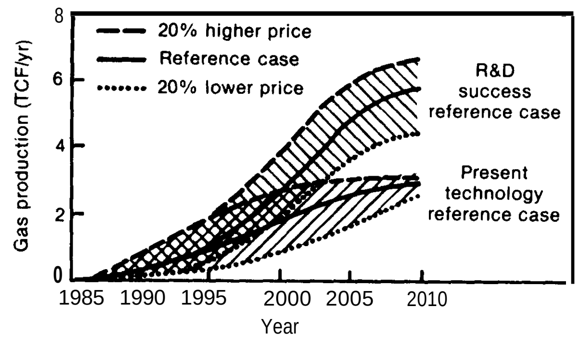
Aside from technical considerations, future tight gas production will be dependent on future gas prices and investment discount rates. For example, figure 37 illustrates how production will change if prices are 20 percent higher or lower than the projected values in GRI's analysis. The price variation produces a production variation in the present technology case of about 1 to 3 TCF in the year 2000, a major difference in production for a relatively modest range of gas prices. Similarly, the range of year 2000 production projections for the advanced case will be about 2 to 4 TCF. Because future gas prices are likely to be closely tied to unpredictable oil prices, the chance of estimating year 2000 gas prices to within better than +/- 20 percent—and thus, estimating **production** to better than about +/- 1 TCF—seems remote.

Figure 38 shows the effect of changes in discount rate on production. Discount rate is essentially a proxy for the perceived risk associated with an investment. The range of discount rates—10 to 20 percent–displayed in the figure seems a reasonable measure of uncertainty for the present technology case because the profile of the potential developers, the development climate, and the physical uncertainty associated with development expenditures are not well understood at this time.

As illustrated by the figure, discount rate is a crucial variable over the entire course of development and for both base and advanced technology. For example, in the year 2000, the 10 point spread in discount rate introduces an uncertainty of about +/- 50 percent in the expected production for the present technology case and + 100 percent, –5o percent for the advanced technology case.

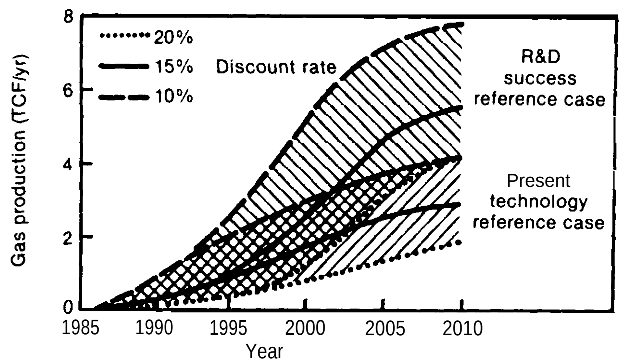
In the NPC and Lewin reports, and possibly in the GRI and AGA reports as well, little or no consideration was given to the possibility that market problems might constrain the future production of tight gas. in the past few years, however, declines in gas usage and the widely perceived optimistic prospects for conventional gas supply and price stability have altered even the enthusiasts' perception of the near-term future of tight gas and other forms of unconventional gas, It is generally considered improbable that massive financial resources will be channeled into development of very low permeability formations if ample prospects of conventional gas are avail-

Figure 37.—incremental Tight Sands Gas Production Rates as a Function of Gas Price



SOURCE: Lewin & Associates, Gas Research Institute.

Figure 38.—incremental Tight Sands Gas Production Rates As a Function of Discount Rate



SOURCE: Lewin & Associates, Gas Research Institute.

able. Consequently, many supporters of the NPC study, while remaining convinced of the accuracy of the gas-in-place and recoverable resource estimates, no longer consider the high production projections to be very likely. To a certain extent, more pessimistic projections of future tight gas production can be self-fulfilling because their acceptance is likely to discourage the research necessary for a major expansion of tight gas production. on the other hand, at least a moderate rate of improvement in tight gas exploration and production expertise and technology will continue regardless of markets, because of continued research on oil production from tight formations and the momentum of existing research programs and tight gas development.

OTA believes that future tight gas development will be closely linked to the availability of conventional gas resources. As discussed in Part I of this report, we do not believe that the year 2000 supply of conventional gas can be projected without a large error band. Consequently, we are skeptical of our ability to reliably project tight gas production to the year 2000 except on a "what if . . ." basis.

On an optimistic basis, we do believe that the year 2000 incremental production of tight gas[70] can reach 3 or 4 TCF/yr, or perhaps even somewhat higher, **if** the present gas bubble ends within a year or two, markets for gas remain firm and real prices increase steadily for the remainder of the century, and the industry is confident of the long-term marketability of tight gas and thus is willing to make the necessary investments in R&D. Such a future is consistent with the pessimistic end of OTA's projected range of 9 to 19 TCF/yr for year **2000** production of conventional gas.

On the other hand, there are plausible circumstances that could stifle future tight gas production, including high conventional gas production and stable or declining real prices, low future demand for gas, or the loss of industry confidence in future gas marketability. A pessimistic scenario might involve year **2000** incremental production of 1 to 2 TCF/yr. Beyond 2000, the size of the recoverable resource, as affected particularly by production technology and the availability of gas in the lenticular basins and the Northern Great Plains, will play a critical role in determining the magnitude of production. In addition, the production rate will always be extremely sensitive to the introduction of any new technological advances affecting production costs and recovery efficiency.

[70] That is, over and above the 1 TCF/yr or so of tight gas produced today that is generally included in "conventional" production figures.