ANALYSIS OF NEGATIVE REVISIONS TO NATURAL GAS RESERVES IN TEXAS

Final Report

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Prepared for
The Gas Research Institute
Contract No. 5083-800-0908

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Strategic Analysis and Energy Forecasting

June 1985

DISCLAIMER

50272-101

REPORT DOCUMENTATION PAGE	1. REPORT NO. GRI 85/1111	2.	3. Recipient's Accession No.

4. Title and Subtitle

Analysis of Negative Revisions to Natural Gas Reserves in Texas

5. Report Date (contract period) March 1984 - June 1985

6.

7. Author(s) Chester M. Garrett, Jr., Claude R. Hocott, Robert J. Finley, and William E. Galloway

8. Performing Organization Rept. No.

9. Performing Organization Name and Address

Bureau of Economic Geology
The University of Texas at Austin
University Station, Box X
Austin, Texas 78713

10. Project/Task/Work Unit No.

11. Contract(C) or Grant(G) No.

(C) 5083-800-0908 (Gas
(G) Research Institute)

12. Sponsoring Organization Name and Address

Gas Research Institute
1019 19th Street N.W.
Suite 615
Washington, D.C. 20036

Project Manager:
Dr. Thomas J. Woods

13. Type of Report & Period Covered

Research 1966 - 1979

14.

15. Supplementary Notes

Original research using industry and regulatory body data.

16. Abstract (Limit: 200 words)

The role of negative revisions in the large-scale decline in natural gas reserves in Texas during the late 1960's and through the 1970's was examined. Analysis of the factors that contributed to the negative revisions determined that no single element was responsible. However, (1) continued high levels of production, (2) original optimistic estimates of gas in place and recovery factors, (3) market-related factors that encouraged overestimation of reserves, and (4) unusually high reserves-to-production ratios (> 15) that obscured the underlying weakness in reserves combined in the Texas Gulf Coast to drastically reduce booked reserves of natural gas. Negative revisions totaling more than 20 Tcf during the period were found to have resulted mainly from ambiguities in the degree of reservoir heterogeneity, in calculation of water saturations, and in drive mechanism, along with the overestimation of reserves due to optimism encouraged by market-related incentives.

The much reduced reserves-to-production ratios that now exist, along with continued closer monitoring of technical, economic, and regulatory factors that affect gas reserves, indicate that a return of extensive negative revisions over the next 10 to 20 years is avoidable.

17. Document Analysis a. Descriptors

Natural gas depletion, natural gas reserves, oil and gas fields, reserves, reservoirs, Texas Gulf Coast.

b. Identifiers/Open-Ended Terms

Revisions of natural gas reserves, Texas Gulf Coast natural gas reserves.

c. COSATI Field/Group

18. Availability Statement:	19. Security Class (This Report)	21. No. of Pages
Release unlimited	unclassified	120
	20. Security Class (This Page) unclassified	**22. Price**

(See ANSI-Z39.18) See Instructions on Reverse

OPTIONAL FORM 272 (4-77)
(Formerly NTIS-35)
Department of Commerce

RESEARCH SUMMARY

Title	Analysis of Negative Revisions to Natural Gas Reserves in Texas
Contractor	Bureau of Economic Geology, The University of Texas at Austin GRI Contract No. 5083-800-0908
Principal Investigator	W. L. Fisher
Report Period	March 1984 - June 1985 Final Report
Objectives	To analyze the causes of the major negative revisions of natural gas reserves in Texas from 1966 through 1979, to determine leading indicators of any possible return of sustained negative revisions, and to assess the likelihood of additional sustained negative revisions to reserves within the United States.

Technical Perspective

Reserves of natural gas in Texas, which once appeared nearly inexhaustible, peaked in 1968 at 125 Tcf. Since then gas reserves have declined by 60 percent (1983). Reserves-to-production (R/P) ratios have been single-digit values since 1976, and additions to reserves failed to replace production from 1966 through 1980. Part of the decline in reserves arose from a series of negative revisions to reserves, principally from the Texas Gulf Coast districts that supplied the greater part of Texas natural gas production. The revisions were remarkable for their magnitude and duration. The reasons for extensive negative revisions to natural gas reserves have not previously been examined in detail; however, our analysis shows that a combination of technical, economic, and regulatory factors had a role in their occurrence, as follows: Very successful exploration and development in the gas-prone area of the Texas Gulf Coast through the 1930's, 1940's, and 1950's resulted in the discovery of large quantities of natural gas. As markets were not immediately available for these additional supplies, transmission companies developed a policy of prorating their gas purchases on the basis of operator-declared reserves; that is, those with the largest reserves would be the ones to supply larger volumes. Operators were thus encouraged to provide the most optimistic estimate of reserves that could be justified. As long as reserve additions appeared to easily replace production, no strong incentive existed to revise the optimistic early estimates of reserves. It was not until the late 1960's and into the 1970's, many years after the original declaration of reserves, that many of the early estimates were critically reviewed. Extensive negative revisions resulted from this long-delayed reassessment.

Several technical factors that affected negative revisions were examined. Recovery efficiencies, reservoir drive, and heterogeneity of reservoirs were factors that were deemed critical. Economic and regulatory environments were also reviewed and analyzed.

Results

Early problems in overestimating effective porosity in some deep Delaware Basin carbonate reservoirs in the Permian Basin in District 8 resulted in some noticeable negative revisions when these problems were finally resolved. However, the net negative volume of revisions for the Permian Basin (Districts 8, 8A, and parts of 7B and 7C) was nearly an order of magnitude less than that for the Gulf Coast Basin. The largest negative revisions of total natural gas reserves were concentrated in the Gulf Coast within Texas Railroad Commission Districts 2, 3, and 4. District 4, having the largest volume of negative revisions, accounted for 56 percent of all negative revisions in Texas from 1966 through 1979. The total for the three districts equaled that in the whole state for the same period. Negative revisions of nonassociated gas reserves in Districts 2, 3, and 4 accounted for more than two-thirds of negative revisions for total gas for the entire state from 1966 through 1979.

Large negative revisions were determined to be due to a combination of interrelated factors. Principal among these was an original overestimation of natural gas reserves, particularly in the Texas Gulf Coast, that resulted from optimism encouraged by market-related incentives. These estimates were not subjected to early critical review and reassessment because supplies greatly exceeded demand. Continued high reserves-to-production (R/P) ratios into the 1960's further delayed reassessment. Water saturation, degree of reservoir heterogeneity, and recovery factors were significant technical variables that were analyzed. Nontechnical variables included economic climate and regulatory controls.

There should be concern for the quality of reserve estimates declared in times of excess supply, as the stated reserves would not have been subjected to the test of extended maximum demand. However, there have been more frequent reviews of actual recoverable reserves over the last five years. Continued careful review of technical factors and awareness of the impacts of changes in economic and regulatory environment suggest that a return of extensive negative revisions over the next 10 to 20 years can be avoided.

Technical Approach

Substantiation of the major role of the Texas Railroad Commission Gulf Coast Districts 2, 3, and 4 was provided by the data used in the preparation of graphs and charts of revisions, additions, production, and remaining reserves of nonassociated, associated-dissolved, and total gas. The basic data for the charts and graphs were from American Petroleum Institute/American Gas Association annual reports from 1966 through 1979.

The still large but declining contribution to total production of the larger fields is documented in field data from the Gas Research Institute data file, supplemented by Texas Railroad Commission field production data assembled by Petroleum Information Corporation as well as surveillance field data from the Department of Energy/Energy Information Administration.

Serving as a most important contribution to the study, as well as a sounding board for our opinions and judgments, were interviews with experts representing operating companies, transmission companies, industry associations, and government regulatory bodies; these individuals shared information, opinions, and judgments about the natural gas industry that were invaluable.

Project Implications

This project has assessed the factors affecting the appearance of large-scale sustained negative revisions in Texas. No general technical or institutional explanations could be advanced to explain why large negative revisions occurred in Texas and nowhere else. In fact, no general explanations could be advanced to explain the concentration of the negative revisions in specific Texas Railroad Commission districts, other than the fact that these districts had reserve-to-production (RP) ratios well in excess of 15. Such high RP ratios, unless they are in tight formation dominated areas, tended to mask the extent to which reserves had been overestimated. It would appear that, with the current RP ratios of 10 or less, sustained negative revisions of the relative scale experienced from 1966 through 1979 would be unlikely.

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INTRODUCTION

Beginning in the late 1960's and continuing through much of the 1970's, substantial negative revisions to proven natural gas reserves occurred along the Gulf Coast of Texas. Although these negative revisions were a major contributing factor to concerns about the adequacy of natural gas supply during the 1970's, awareness of these concerns was late in developing within the petroleum industry.

Quite naturally, the focus of consumers is on deliverability of natural gas (appendix I), and only within the petroleum industry was attention directed to changes in reserve figures. Even within the industry, such attention was minimal in the early days of gas resource development. Although there were shortfalls in gas supplies locally during severe cold spells in the 1950's and 1960's, it was not until the widespread shortfall during the winter of 1973 that the situation became acute and forced a more careful and thorough appraisal of the availability of natural gas. Beginning at that time, the accurate assessment of gas reserves was given more attention.

The present study has as its objective an assessment of the distribution, nature, and causes of the significant negative revisions of natural gas reserves during the period 1966 through 1979. Based on this assessment, some indicators of possible future negative revisions were sought, and the likelihood of future negative revisions was evaluated.

HISTORICAL OVERVIEW

A brief look at the role of natural gas in the history of the petroleum industry is essential to understand the history of natural gas reserve statistics (appendix II). Early in its history, natural gas was seen as a necessary nuisance that accompanied oil production and an embarrassing by-product or co-product of oil exploration; natural gas was the stepchild of the industry. Gas dissolved in crude oil in the reservoir was separated at the surface as "casinghead" gas and was flared. In many fields having associated gas caps, the crude oil was produced with excessive gas/oil ratios as a result of the dissipation of the associated gas cap along with the crude oil. This gas, too, was flared in the field. Although Texas had a gas/oil ratio limitation for partial control of associated gas deposits and for their conservation, the limitation was difficult to monitor and, hence, was not rigidly enforced. Although this wasteful practice was widely recognized and deplored, the demand, and consequently the price, was so low that the capital investment and expense required to gather the gas for any purpose could seldom be justified.

In the meantime, nonassociated gas reservoirs were discovered in the course of oil exploration. These reservoirs were abandoned as noncommercial if they were small or of low producibility. The larger reservoirs were developed on a very wide well spacing, and local markets for the gas were sought. This gas was seldom transported any great distance, but reserves developed within the Panhandle of Texas are a notable exception. Consequently, a huge reserve of natural gas was developed over the years from the early 1930's to the mid-1940's, while industry sought in vain to develop widespread economic markets.

The Turnabout

It was not until the end of World War II that the markets for natural gas in large volume began to develop. This was made possible by the sudden availability of trunk pipelines formerly used for oil transport. As the war drew to a close, the threat of submarines to the coastal tanker fleet subsided, and the Big Inch and Little Inch pipelines built to transport crude oil from the Gulf Coast to the Eastern Seaboard were no longer needed for that purpose. These pipelines were sold by the government as surplus and immediately converted to natural gas service. Thus, for the first time, a huge supply of natural gas became available to eastern markets hungry for what was an abundant, cheap energy source.

In 1947, the Railroad Commission of Texas (TRRC) issued a "no-flare rule" that extinguished all oil well flares in the state. Thereafter, all gas produced with oil was to be gathered, sold, consumed on the lease, or returned to the reservoir. This meant that casinghead gas had first priority on the local markets, leaving a major surplus of gas in nonassociated gas reservoirs available for expanded markets. Diligent efforts were made to increase the use of this clean-burning, easily handled, and easily distributed energy source.

However, the surplus was of such dimensions that little concern was felt for an accurate measure of its magnitude. Early estimates of reserves had been determined by volumetric analyses based on sparse data from widely spaced wells, and depletion rates had been sufficiently low that material-balance data were probably not adequate in any case. Since reserves were well in excess of production and most production exhibited no depletion effects, there was little incentive for reserve reevaluations.

A Deterrent Arrives

About this time, however, another influence began to alter the gas market. In 1938 Congress passed the Natural Gas Act, which required the Federal Power Commission (FPC) to exercise utility price control over natural gas marketing. In 1949 the FPC proposed to extend the 1938 statute to the producer and to include control of the natural gas price at the wellhead. In 1954 the Supreme Court ruled that FPC jurisdiction did indeed extend to the wellhead. When the FPC set the price of gas too often below replacement cost, the development of gas reservoirs declined. Furthermore, because oil had to compete in price with an unrealistically low gas price, exploration for and development of new reserves of oil, as well as gas, declined. From a maximum number of wells drilled of more than 58,000, including about 16,000 exploratory wells, in 1956, activity declined to a total of about 26,000 wells, including somewhat more than 6,000 exploratory wells, in 1971 (DeGolyer and MacNaughton, 1981, their chart 34). No longer were discoveries replacing production. In fact, for gas, this probably had not been the case for some time, since many of the reserves being added during this period did not exist. Consequently, the surplus gas reserve was being dissipated, and depletion effects were beginning to appear.

Statistical Highlights

Beginning in the late 1960's and continuing through much of the 1970's, substantial negative revisions to proven reserves of natural gas were reported from Texas. They were of such severity that, in many of the years during this period, the negative revisions in Texas overwhelmed positive revisions elsewhere in the lower 48 states. These negative revisions posed serious concerns about the adequacy of the nation's natural gas supply, because Texas was such a major contributor to natural gas supplies for the nation. Table 1 includes highlights of our statistical review of negative revisions of natural gas reserves for 1966 through 1979. The years 1973, 1975, and 1978 were selected for tabulation because these were the only years in which total negative revisions exceeded additions (for example, extensions and discoveries).

Table 1 shows that, outside of Texas, net revisions to natural gas reserves were positive, averaging 1,900 Bcf per year. In Texas, on the other hand, revisions to gas reserves averaged a negative 1,200 Bcf per year. Similar observations can be made when only the 8 years in which negative revisions occurred in Texas are considered.

Table 1 also shows that the total of the combined negative revisions for TRRC Districts 2, 3, and 4 for the 3 years and for 1966 through 1979 are approximately equal to those for the state as a whole. In fact, the total negative revisions for Districts 2, 3, and 4 for the 3 main years were greater than the total of negative revisions for the U.S. for 1966 through 1979.

Estimation of Reserves

Estimation of reserves is a continuing process throughout the life of a reservoir or field. Each well drilled to a reservoir, if fully assessed, will indicate a need for reevaluation of gas in place, and careful observation of the pressure-production behavior of a reservoir will provide information for a running reestimation of reserves. No company will fully follow such a process, since the time and costs are not justified and the precision of estimation does not

Table 1. Negative revisions of total natural gas reserves.*

	Total U.S. (Bcf)	Total Texas (Bcf)	Texas districts 2 (Bcf)	3 (Bcf)	4 (Bcf)	2, 3, 4 (Bcf)
Net revisions, 1966-1979	(+9,339)	-17,227	-3,677	-3,155	-10,708	-17,540
Total, 1966-1979	-9,578	-22,446	-4,685	-5,854	-12,504	-23,043
Year						
1973	-3,474	-4,713	-643	-1,149	-3,605	-5,397
1975	(+383)	-3,083	-953	(+152)	-925	-1,878
1978	(+118)	-3,817	-1,409	-1,324	-1,212	-3,945
Total	-3,474	-11,613	-3,005	-2,473	-5,742	-11,220

*Source: American Petroleum Institute annual reports.

warrant it. It must be understood that the ultimate recovery from any given reservoir or field can never be known with complete accuracy until the last well is abandoned.

The earliest reserve estimates are made with minimal data. Geological and geophysical information, together with core and log data from the discovery well, provide the statistical parameters for an estimation of the original gas in place. Reserves are then estimated by applying an assumed recovery efficiency, based on experience, to this estimate of gas in place. Since early assumptions of reservoir conditions tend to be more simplified than the actual conditions, these estimates normally require adjustment as more detailed information becomes available.

Later reserve estimates can be made by material-balance calculations based on pressure-production history of a reservoir, assuming that adequate production data are available. The engineering technology based on such calculations is well established, and reserve calculations can be reasonably reliable, except in the case of the most complex reservoirs. When normal calculations are not adequate, the ultimate resort is made to decline-curve analysis. When fields have a sufficiently long record of production at full capacity, decline-curve estimates, although empirical, can be remarkably accurate.

Nature and Causes of Revisions

Revisions to reserve estimates are a continuing process for any given reservoir or field. These revisions can be negative or positive. Early estimates are mere approximations of technical, regulatory, and economic factors. Reestimation, or revisions, occurs when pressure-production behavior seriously departs from predicted behavior.

The most common physical or technical reasons for revisions reside in the inadequacy of basic data on the reservoir and its behavior. There are several sources of information over the life of a reservoir that provide this basic data for reestimation of reserves. The more important are included in the following discussion.

1. The geological and geophysical information on a given reservoir is sparse when original estimates of gas in place are made. Each new well drilled provides specific data on the stratigraphic thickness, quality, and continuity of pay zones that enable revisions to be made. Successful wildcat or step-out wells always add area and lead to reserve additions. Infill wells often call for adjustments, as updated isopachous contour maps of pay zones provide more definitive parameters for the detailed quantitative reservoir description. As development drilling nears completion, if the individual well data are correlated using a good understanding of the depositional regime, these volumetric estimates can prove to be quite accurate.

2. The quality of the reservoir rock is usually determined from the quantitative interpretation of well logs that have, in turn, been calibrated with laboratory data from study of a lesser number of key wells. It must be understood that, even if these determinations were precise, only a very small volume of reservoir rock has been sampled. Consequently, the quantitative description of the reservoir is estimated by interpretation of the heterogeneous rock character based on the best geological understanding available. If the depositional environment of the sediments is adequately known and can be used as a guide, these quantitative estimates are satisfactory for all reasonable decisions as to the development and exploitation of the reservoir.

3. The pressure-production history of a reservoir, given a sufficient time interval, can provide the necessary information for an accurate material-balance calculation of the volume of gas in place that is in pressure continuity with the producing wells. Reserves or ultimate recovery estimates based on this value are credible for any nonassociated reservoir producing by pressure depletion. The critical parameter is the pressure remaining in the reservoir at the economic limit of deliverability.

Associated gas reservoirs, or nonassociated reservoirs producing with an active aquifer, represent more complex situations. The material-balance calculations for these situations must account for reservoir fluids of different densities and compressibilities. Two-phase or three-phase relationships of these reservoir fluids require additional and more complex calculations.

Even in these cases, however, the technology is normally adequate for satisfactory estimates of reserves.

Some Common Difficulties

A common physical cause of revisions results from variation in treatment of the lower permeability strata contained in, or adjacent to, recognized pay zones. The porosity-permeability cutoff used in assessing volumetric gas in place may include or exclude strata whose contribution will be determined by the method of exploitation. If a reservoir is produced by pressure depletion, tight zones, which would contribute insignificantly to a well during the early production, may, over the long-term production history of the reservoir, transmit significant quantities of gas to the more permeable strata and subsequently to the wellbore. On the other hand, if such a reservoir is produced under pressure maintenance as an active water drive, these strata may be bypassed by the encroaching water. Revisions, then, may be either negative or positive depending on the production mechanism.

Another common cause for negative revisions is the recognition in recent years that the displacement efficiency of encroaching water in water-drive fields is less (sometimes much less) than was formerly presumed. A significantly lower ultimate recovery of the original gas in place therefore occurs. When the efficiency of the water drive in a field is not adequately recognized in early estimates of reserves, negative revisions can be even larger. In one case, a rapid advance of the water table in the reservoir indicated a much poorer displacement efficiency and hence a lower reserve. In this field, the residual gas saturation behind the water front was calculated to be 35 percent compared with an original assumption of 15 percent, resulting in a drastic negative revision of reserves. Several reservoirs in South Texas are known to have experienced this phenomenon. Some of these fields are now being dewatered to create a secondary gas cap for later pressure depletion and thus enhance their ultimate recovery. This is an expensive operation, and the extent to which it is practiced in the future depends on costs and gas price.

Another frequent reason for revisions resides in the inaccuracy of interstitial or connate water determinations. These are usually made using resistivity measurements from well logs. Ambiguities in these measurements were common in deeper wells and formations having high clay contents or abnormal pressures, or both. In the case of one large reservoir, the early determinations of connate water saturation indicated a value of 25 percent. Later, more detailed tests indicated that a significant segment of the pay zone had a water saturation of 35 percent, resulting in a negative revision of reserves of nearly 15 percent, or more than 150 Bcf, in that one field.

A Case History

A major gas field in Texas discovered in the late 1930's had its main reservoirs fully developed and under production by pressure maintenance through cycling over the next two decades or more. The produced gas was stripped of condensate and returned to the reservoir. Gas condensate reservoirs, which included several large blanket sand deposits, were successfully produced in this manner. Gas demand and price were low, and the cycling operation was profitable.

When the condensate yield began to fall, markets were sought, pipelines installed, and sale of gas initiated. There was a fair water drive in some of the reservoirs, and the field was produced partially under water drive and partially under pressure depletion. Additional wells were drilled at that time to provide the desired delivery rate within individual well efficiencies. In this drilling program, some new stringer sands were discovered at original pressure. Consequently, as the field was depleted, continuous drilling to maintain deliverability added sufficient reserves to replace depletion of the main blanket sands that had been produced by cycling of gas. Since reserves were never reported on a reservoir basis, there was no reduction in field reserve estimates until deliverability could no longer be maintained, at which time the negative revisions became marked.

Nontechnical Factors

In addition to the uncertainties among technical factors that led to overstated reserve estimates, other issues, such as economic development, market pressures, and regulatory practices, tended to encourage more optimistic estimates of reserves.

Many gas fields reached economic limits at higher reservoir pressures than had been assumed initially because of a long period of inflation when gas prices were arbitrarily held low. When lease and well expenses made wells uneconomic under such a situation, reserves had to be revised downward. These reserves, however, could be rebooked if the economics were to improve.

During the years of oversupply, available markets tended to be prorated or allocated on the basis of backup reserves. Long-term, favorable sales contracts often depended on the assurance of large reserves. Consequently, there was always pressure to state reserve estimates as optimistically as any rational basis would allow. Regulatory agencies further added to this pressure by insisting on minimum reserves to justify the pipelines, gathering facilities, and treatment plants necessary to market gas under contract.

Summary

There were numerous technical, regulatory, and economic reasons why revisions were made; however, the general conclusion of the 20 experts interviewed as part of this study was that the major reason for past extensive negative revisions of reserves was the optimistic nature of early estimates. Part of the reason that these revisions in Texas were so severe was the long delay and deferral in making them, owing to market conditions in the gas industry in the period before the late 1960's.

Reappraisals, resulting in negative revisions, followed the failure to supply market demand. This occurred when practically all wells and all fields were producing at capacity and yet were unable to meet demand. The serious shortfalls in deliverability and failure to supply urgent market needs, and the attendant negative revisions in reserve estimates, were the factors that generated the "gas crisis" alarm and contributed to widespread concern about the future of natural gas supplies in the United States.

OVERVIEW OF PROJECT

Introduction

The purpose of the study was an analysis of the phenomenon of extensive negative revisions of natural gas reserves that occurred from the late 1960's through the 1970's and that were a contributing factor to the gas crisis of the 1970's. The Texas Gulf Coast region provided the bulk of natural gas supplies for Texas, the nation's largest producer. This region experienced revisions of such a magnitude that they exceeded reserve additions from new field wildcats, new pools, and extensions in this region from 1969 through 1979 by almost 5 Tcf. Along with continued high rates of production, an alarming decline in remaining reserves occurred.

Methodology

The analysis of negative revisions in Texas was divided into four tasks that are discussed separately in this report.

Task 1. Locate (geologically and geographically) the source of the largest negative revisions.

Task 2. Determine possible reasons for the negative revisions.

Task 3. Identify the factors that might be useful as leading indicators of the likelihood of future sustained negative revisions.

Task 4. Assess the likelihood of future sustained negative revisions of U.S. natural gas reserves.

Defining the origin of the negative revisions (Task 1) proved to be simple yet elusive. It was readily ascertained that TRRC Districts 2, 3, and 4 (the Texas Gulf Coast) contributed an overwhelming proportion of the negative revisions reported for the state and for the nation. Overall net revisions for the three districts combined from 1966 through 1979 exceeded -17 Tcf of total gas, which equaled the total net revision for the entire state (table 1). However, more definitive efforts to assign volumes of negative revisions of reserves to particular reservoirs, productive plays, or geologic settings were unsuccessful. Reserve information is considered highly confidential by operating companies, and although those contacted willingly shared information about general conditions affecting negative revisions, they were understandably reluctant to specify examples from their files.

Revisions to natural gas reserves result from one or more of several possible sources. These sources include:

1. Discoveries from a previous year not recorded owing to delays in reporting discoveries indicated, but not confirmed, at year's end; or delays in reporting results of "tight holes" (wells drilled without releasing information that would affect nearby open acreage, etc.). These revisions would be positive and may be quite large.

2. Positive or negative corrections of numerical errors in original calculations of estimated reserves.

3. Miscellaneous corrections, particularly of estimations of production in previous years; adjustments could be positive or negative.

These three sources are considered adjustments and corrections by the Department of Energy/Energy Information Administration (DOE/EIA) and are reported as such (negative adjustments and corrections and positive adjustments and corrections) in their reports that replaced American Petroleum Institute/American Gas Association (API/AGA) published natural gas reserves and production data after 1979. However, the three sources are included by API/AGA under revisions, with the appropriate positive or negative indication.

4. Changes in production economics resulted in revised abandonment pressures (economic limits). Unfavorable economic conditions were a significant factor in the negative revisions to reserves, particularly interstate gas reserves. The low interstate prices and the rapidly increasing production costs that accompanied the escalation in the price of oil and intrastate gas after the Arab Oil Embargo of 1973, created pressures for negative revisions. Improved economic conditions, resulting from passage of the Natural Gas Policy Act (NGPA), led to positive revisions owing to lower abandonment pressures after 1978. Changes in economic conditions also affected reserves, as they allowed or disallowed the application of reservoir stimulation techniques that affect recovery efficiencies.

5. Development drilling and production experience may require positive or negative revision. Discontinuity of reservoir beds may be indicated from improved geological correlations or production-pressure information. Revision of original gas in place, or recoverable reserves, or both, often results from an advanced state of knowledge about heterogeneity of the reservoir.

6. Presence of an active water drive. Many early calculations and estimates of recoverable reserves assumed depletion drives and continuous reservoirs with subsequent recovery of a very high percentage of original gas in place. Revisions to account for the lower recovery factors of water-drive gas reservoirs (bypassing of gas trapped in lower permeability zones of a reservoir) may be quite substantial.

7. Ambiguities associated with early log determination of connate water saturations (too low) and gas-water contacts resulted in later substantial negative revisions of original gas in place.

Analysis of the reasons for the negative revisions (Task 2) benefited greatly from discussions with 20 individuals representing producers, pipeline companies, and regulatory agencies and including present and former API/AGA Reserves Committee members. In addition, earlier Bureau of Economic Geology studies of the geologic setting and the producing plays of the Texas Gulf Coast, such as Galloway and others (1982), provided background data on the nature of different reservoir units; articles in the Oil and Gas Journal and the Wall Street Journal, publications of the Railroad Commission of Texas, and other pertinent literature provided additional information on production and reserves of natural gas required for the analysis.

The assessment of those factors identified (Task 2) as possible leading indicators of sustained extensive negative revisions in the future (Task 3) entailed interpretations of geological and engineering data (technical factors), as well as regulatory conditions and economic influences (nontechnical factors). The events that occurred before the period of extensive negative revision in the Texas Gulf Coast and the extent to which such conditions might occur again, either in the Texas Gulf Coast or elsewhere, were investigated. The group of experts served as a sounding board for our ideas and as sources of information and were helpful in fulfilling the aims of the project.

An assessment of the likelihood of future sustained negative revisions to U.S. natural gas reserves was made (Task 4). This assessment is based on all data collected, including the comments of numerous panel members who offered us their personal insights.

Summary

After completing a historical overview, we examined in greater detail the distribution and causes of negative revisions to natural gas reserves. By focusing on specific TRRC districts in Texas where major negative revisions occurred, the causes of the overall negative revision can best be evaluated in a systematic manner. The chronology of gas reserve development, the geology of gas occurrences, and the regulatory and economic factors that may relate to the major negative revisions of gas reserves can all be closely examined for factors or trends that may be considered indicators of possible extensive negative revisions in the future.

TASK 1. IDENTIFY THE LOCATIONS OF SUSTAINED NEGATIVE REVISIONS TO PROVEN NATURAL GAS RESERVES IN TEXAS

Statistics of Revisions

Annual additions to natural gas reserves in known fields consist of extensions, new pool (reservoir) discoveries in older fields, and revisions to past reserve estimations. The volumes attributable to discoveries and extensions have been proportional to the level of drilling activity and rates of discovery and development. Revisions, on the other hand, have been most erratic and variable for the period from 1966 through 1979 and show no correlation with drilling activity.

With the exception of the state of Texas, revisions to natural gas reserves have been generally positive. Between 1966 and 1979, the revisions to gas reserves in the lower 48 states totaled 9.3 Tcf. However, during this period, net revisions to gas reserves in Texas totaled a negative 17.2 Tcf. Thus, outside of Texas, the revisions to gas reserves totaled 26.5 Tcf.

The negative revisions experienced in Texas have strongly affected the overall reserve picture in the state. Figure 1 presents a map of Texas divided into TRRC districts. The map summarizes reserves at the beginning of the period (1966) and at the end of the period (1979), along with cumulative production, exploratory reserve additions (that is, new fields, new pools, and extensions), and net revisions. In aggregate, Texas gas reserves declined 57 percent from 1966 to 1979 (appendix V). Almost 25 percent of this decline could be attributed to negative revisions.

Figure 1 shows that net negative revisions were rather common. Only three districts, 8A, 9, and 10, had net positive revisions over the period 1966 to 1979. The rest experienced net negative revisions. In Districts 2 and 4, negative revisions were so severe that they exceeded the total exploratory reserve additions.

Figures 2A, 2B, and 2C depict the relative shares of net negative revisions that occurred in each district for total gas reserves, nonassociated gas reserves, and associated dissolved gas

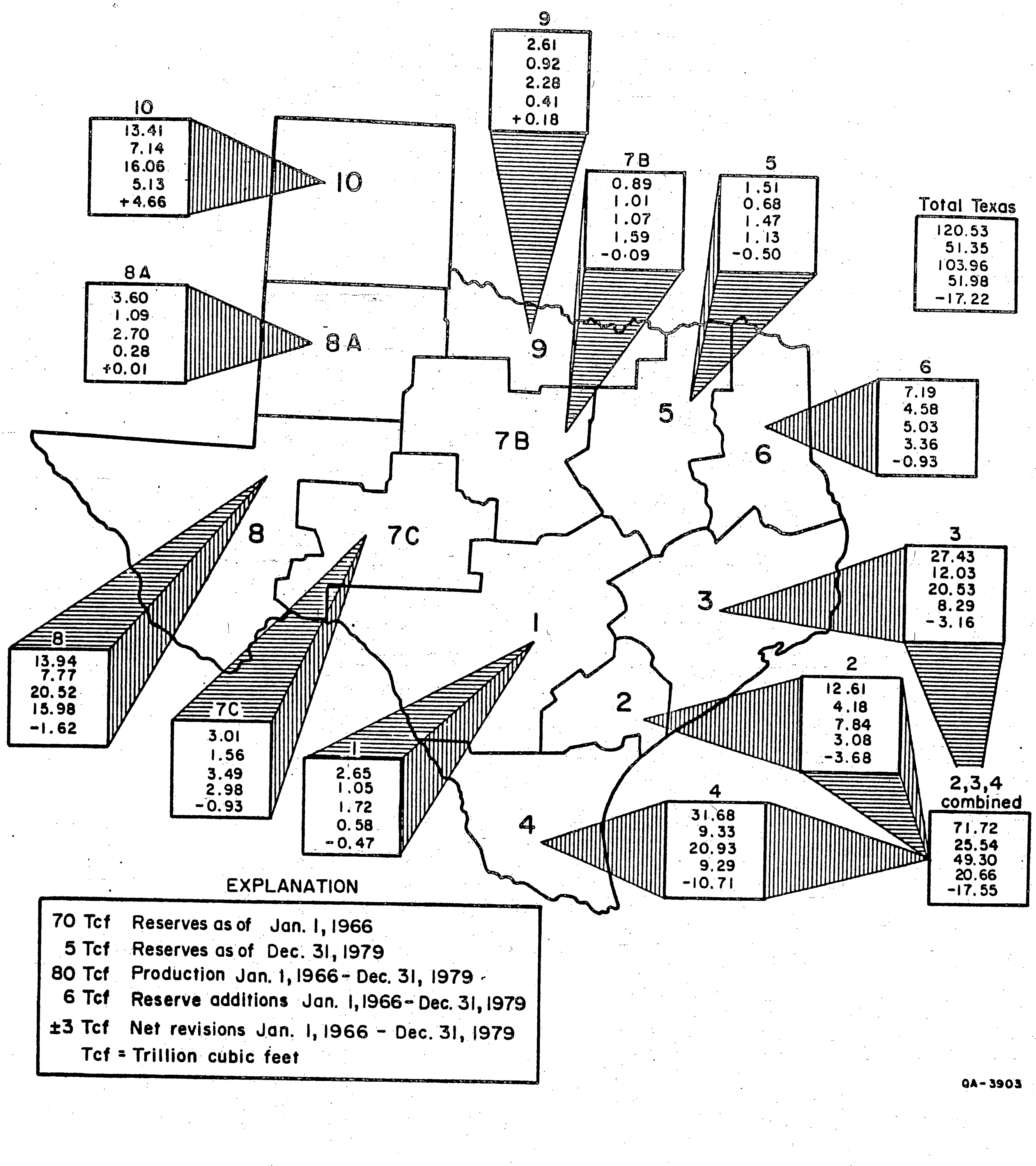

Figure 1. Map of Texas Railroad Commission districts showing district-by-district changes in total gas reserves for 1966 through 1979.

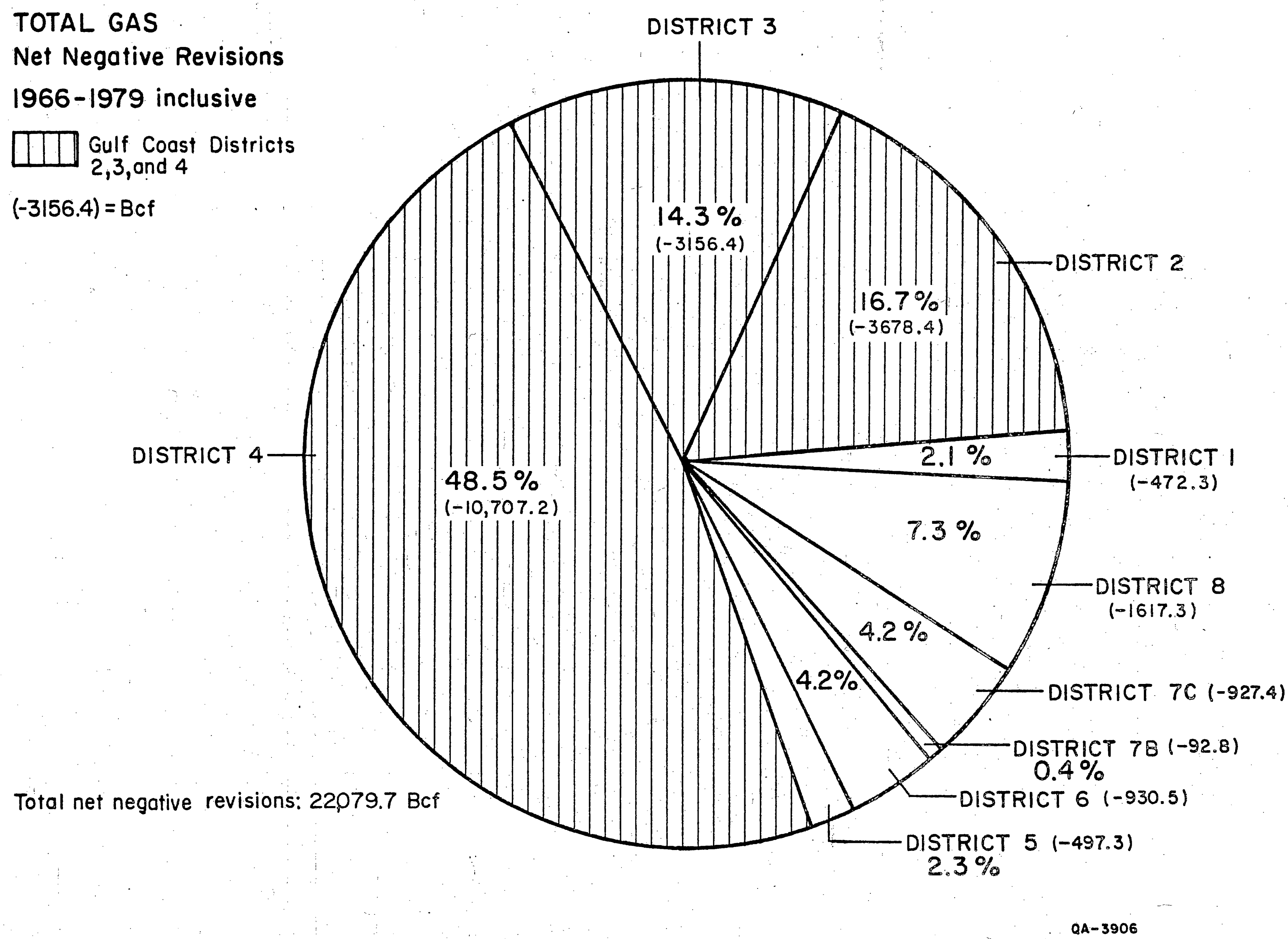

Figure 2A. Diagram illustrating the overwhelming predominance of the Gulf Coast districts in total Texas net negative revisions. Note that District 4 alone is responsible for nearly half of the state's total.

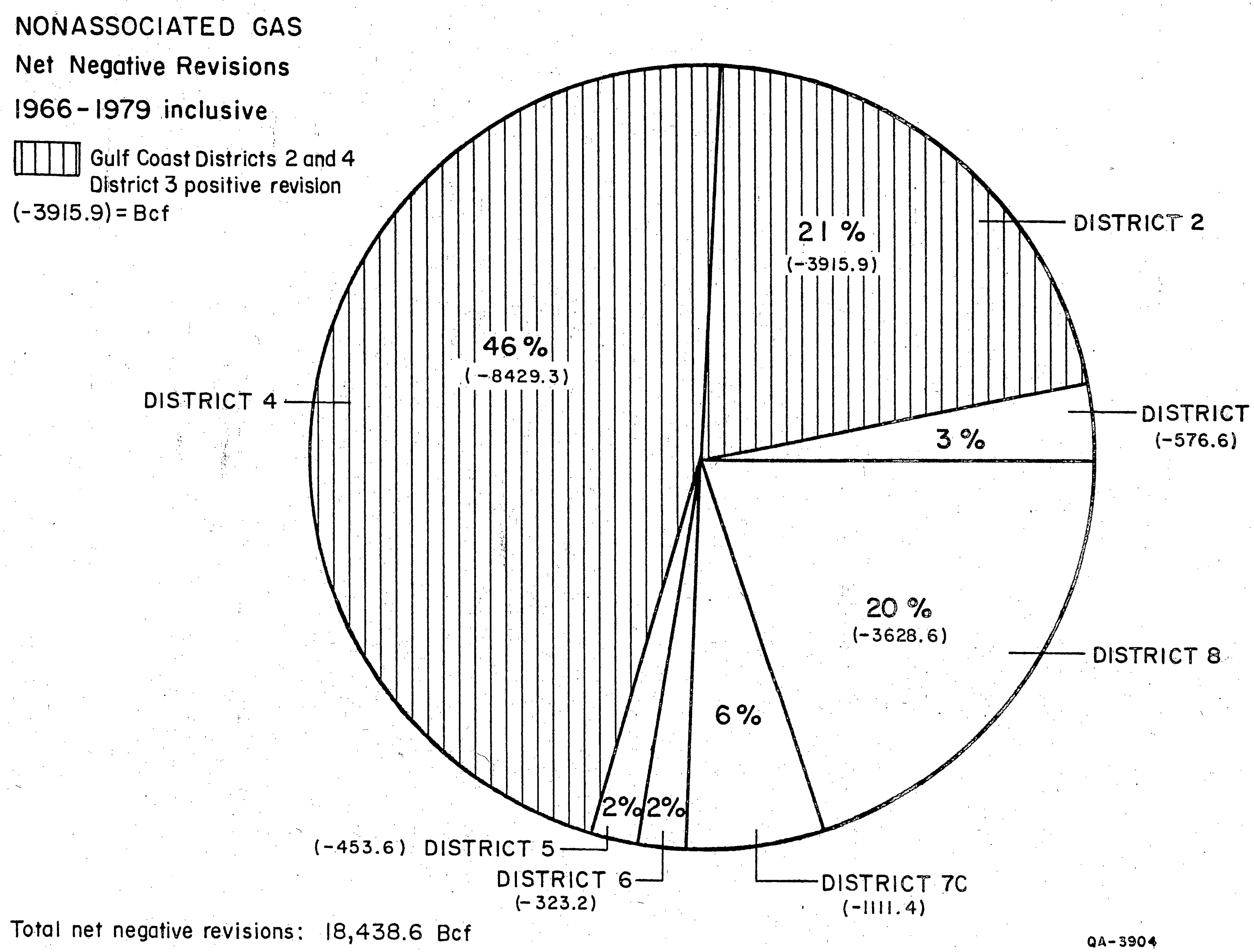

Figure 2B. Diagram showing that two of the Gulf Coast districts reported negative revisions for nonassociated gas reserves that accounted for two-thirds of the total for the state, with District 4 alone responsible for nearly one-half. The large revision for District 8 is not reflected in revisions for total gas, because positive revisions were recorded for associated gas in this district.

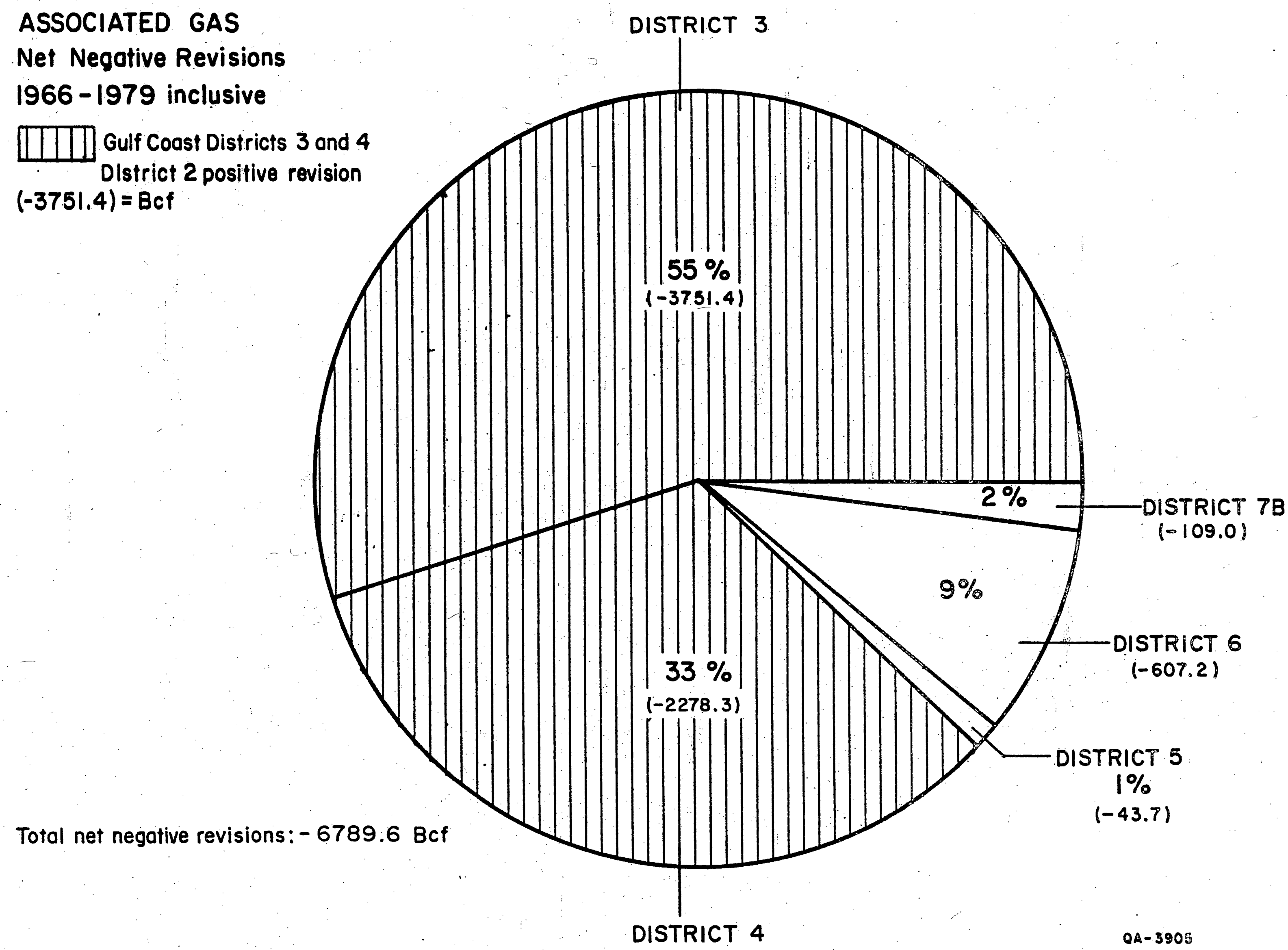

Figure 2C. Diagram highlighting the nearly 90-percent contribution from Gulf Coast Districts 3 and 4 to the net negative revisions for associated gas.

reserves. Figure 2A shows that almost 80 percent of the next negative revisions occurred in Texas Railroad Commission Districts 2, 3, and 4. Almost 50 percent of the net negative revisions occurred in District 4. On a nonassociated basis, the picture is less concentrated (fig. 2B). About 26 percent occurred in Districts 7C and 8, the Permian Basin, while 67 percent occurred on the Texas Gulf Coast. Associated gas revisions show the highest degree of concentration. Almost 90 pecent of the net negative revisions occurred in the Texas Gulf Coast.

Figures 2A, 2B, and 2C indicate that the reason the Gulf Coast districts dominate the net negative revisions is that, unlike the Permian Basin, which experienced some sizable net negative nonassociated revisions but had net positive associated revisions, the Gulf Coast districts had sizable net negative revisions in both categories. Because of the dominance of the Gulf Coast in the negative revisions picture during this period, the study will focus principally on Districts 2, 3, and 4 (tables 2A, 2B, and 2C).

Geologic Characterization of Gas Reserves

Production in the Gulf Coast region is almost exclusively from Tertiary sandstone deposits, with the Frio, Vicksburg, and Wilcox Formations providing the largest volume of recoverable gas reserves. In 1977, the last year in which AGA compiled these data, sandstone reservoirs accounted for 73 percent of the estimated ultimate recovery of total gas in the United States; for nonassociated gas the figure was 73 percent, and for associated gas 75 percent (table 3A). And, as a whole, the United States had net positive revisions.

In Texas in 1977, sandstone reservoirs are not as dominant, accounting for 59 percent of the ultimate recovery of total gas, 57 percent of nonassociated gas, and 63 percent of associated gas (table 3A). The Gulf Coast reservoirs, however, are almost all sandstone. Nearly four-fifths of Texas' ultimate recovery of natural gas from sandstone reservoirs is from fields located in Districts 2, 3, and 4 (table 3A), yet the fields in these three districts account for less than 1 percent of the ultimate recovery of total gas from carbonate reservoirs. District 2 records slightly more than 2 percent of its ultimate recovery of total gas from

Table 2A. Total gas for combined Districts 2, 3, and 4, 1966-1979.

Year	Revisions (Bcf)	Additions (Bcf)	Production (Bcf)	Remaining reserves (Bcf)
1966	925.4	2,886.7	3,611.4	71,925.6
1967	1,126.0	2,217.1	3,678.9	71,589.8
1968	-330.8	1,077.4	3,673.4	68,663.0
1969	-772.0	1,334.9	3,827.1	65,398.8
1970	-617.0	1,276.4	3,911.1	62,147.2
1971	-426.7	1,122.8	3,853.8	58,989.5
1972	-1,853.7	1,093.9	3,769.9	54,459.7
1973	-5,397.4	975.9	3,709.5	46,328.6
1974	-2,388.3	1,200.9	3,461.4	41,679.9
1975	-1,726.7	1,112.1	3,078.1	37,987.2
1976	-2,609.2	1,467.2	3,127.2	33,718.0
1977	1,175.8	1,872.9	3,148.1	33,618.6
1978	-3,945.3	1,423.1	3,064.7	28,031.4
1979	-702.1	1,604.4	3,388.0	25,545.5

Table 2B. Nonassociated gas for combined Districts 2, 3, and 4, 1966-1979.

Year	Revisions (Bcf)	Additions (Bcf)	Production (Bcf)	Remaining reserves (Bcf)
1966	950.9	2,777.4	2,831.8	50,996.2
1967	1,122.4	2,093.1	2,874.8	51,336.9
1968	1,776.2	1,023.4	2,896.3	51,240.1
1969	-547.5	1,258.7	3,018.2	48,933.2
1970	-699.4	1,224.9	2,994.4	46,464.4
1971	-83.6	1,059.2	2,902.4	44,537.6
1972	-2,038.3	1,045.4	2,854.7	40,689.9
1973	-6,330.8	936.0	2,743.3	32,551.9
1974	-2,068.6	1,152.0	2,661.7	28,973.5
1975	-1,195.5	1,036.4	2,245.6	26,568.8
1976	9.3	1,433.8	2,376.8	25,635.4
1977	774.9	1,808.5	2,343.5	25,875.1
1978	-2,961.7	1,349.4	2,296.8	21,965.8
1979	-458.4	1,540.1	2,731.8	20,315.9

Table 2C. Associated gas for combined Districts 2, 3, and 4, 1966-1979.

Year	Revisions (Bcf)	Additions (Bcf)	Production (Bcf)	Remaining reserves (Bcf)
1966	-25.6	109.3	779.6	20,929.5
1967	3.7	124.0	804.3	20,252.8
1968	-2,106.9	54.0	777.1	17,422.8
1969	-224.5	76.2	808.8	16,465.7
1970	82.5	51.7	916.8	15,682.9
1971	-343.2	63.8	951.5	14,452.0
1972	184.6	48.5	915.2	13,769.8
1973	933.4	39.9	966.3	13,776.7
1974	-319.8	49.1	799.7	12,706.4
1975	-531.2	75.6	832.5	11,418.3
1976	-2,618.7	33.3	750.6	8,082.7
1977	401.0	64.5	804.8	7,743.3
1978	-983.7	74.0	768.0	6,065.6
1979	-243.7	64.1	656.4	5,229.6

Table 3A. Estimated ultimate recovery of natural gas by reservoir lithology.

	Sandstone						Carbonate						Other	
	Nonassoc. (Bcf)	(%)	Assoc. (Bcf)	(%)	Total gas (Bcf)	(%)	Nonassoc. (Bcf)	(%)	Assoc. (Bcf)	(%)	Total gas (Bcf)	(%)	Total gas (Bcf)	(%)
1970 Total U.S.	331,864	73	164,372	77	496,236	73	124,389	27	48,868	23	173,257	26	9,807	1
Total Texas	110,431	59	51,918	66	162,349	61	76,061	41	26,716	34	102,777	39	367	~0
Percent of total U.S.		33		32		33		61		55		59		0
District 2	19,634	99	5,354	95	24,988	98	196	1	297	5	493	2	0	0
Percent of Gulf Coast districts		20		15		19		26		91		46		0
District 3	35,430	98	15,565	~100	50,995	99	542	2	29	0	570	1	0	0
Percent of Gulf Coast districts		37		44		39		72		9		53		0
District 4	40,915	~100	14,542	100	55,457	~100	18	~0	0	0	18	~0	0	0
Percent of Gulf Coast districts		43		41		42		2		0		<1		0
Districts 2 + 3 + 4	95,979	99	35,461	99	131,440	99	755	1	326	1	1,081	1	0	0
Percent of total Texas		87		68		81		1		1		1		0
District 8	683	4	3,808	23	4,491	14	15,321	96	12,499	77	27,820	86	313	~0
Percent of total Texas		1		7		3		20		47		27		~0
1977 Total U.S.	374,751	73	164,280	75	539,031	73	135,703	27	55,535	25	191,238	26	11,608	1
Total Texas	112,311	57	48,436	63	160,747	59	83,772	43	27,894	37	111,666	41	558	~0
Percent of total U.S.		30		29		30		62		50		58		5
District 2	18,975	99	5,723	93	24,698	98	119	1	406	7	525	2	0	0
Percent of Gulf Coast districts		20		18		19		21		94		52		0
District 3	39,526	99	13,200	~100	52,726	99	450	1	27	~0	477	1	0	0
Percent of Gulf Coast districts		42		41		42		79		6		47		0
District 4	35,982	100	13,397	100	49,379	100	4	~0	0	0	4	~0	0	0
Percent of Gulf Coast districts		38		41		39		<1		0		<1		0
Districts 2 + 3 + 4	94,483	99	32,320	99	126,803	99	573	1	433	1	1,006	1	0	0
Percent of total Texas		84		67		79		1		2		1		0
District 8	893	4	3,950	23	4,843	13	20,003	96	13,407	77	33,410	87	320	0
Percent of total Texas		1		8		3		24		48		30		57

1970 $\frac{\text{Districts 2 + 3 + 4}}{\text{Total Texas}}$ $\frac{\text{ult. recovery total gas all lithologies = 132,521 Bcf}}{\text{ult. recovery total gas all lithologies = 265,126 Bcf}} = 50\%$

1977 $\frac{\text{Districts 2 + 3 + 4}}{\text{Total Texas}}$ $\frac{\text{ult. recovery total gas all lithologies = 127,809 Bcf}}{\text{ult. recovery total gas all lithologies = 272,971 Bcf}} = 47\%$

% calculated for gas classification (nonassoc., assoc., or total) for lithology, by district
Example: Total Texas nonassoc. gas for reservoir lithology sandstone, 110,431 (59%) + carbonate, 76,061 (41%) = 186,492 (100%) (in 1970)

carbonates, whereas in Districts 3 and 4 less than 1 percent of the ultimate recovery for total gas is from carbonate reservoirs (table 3A). However, West Texas District 8, which also experienced noticeable negative revisions for nonassociated gas, contains 96 percent of its ultimate recovery of nonassociated gas from carbonate reservoirs (table 3B). It should be noted, however, that District 10, which had net positive revisions approaching 5 Tcf from 1966 through 1979, is also dominated by carbon reservoirs. The preceding discussion demonstrates that the nature of the deposit provides no a priori indication of the probability of negative revisions.

Large decreases in estimated ultimate recovery from 1970 to 1977 for nonassociated gas and total gas in sandstone reservoirs in District 4 reflect the results of large-scale negative revisions of reserves for these reservoirs (table 3A). Sandstone reservoirs in District 3, however, recorded an increase in nonassociated and total gas reserves, which may be the result of successful offshore exploration.

The three Gulf Coast districts show a clear dominance of structural traps (table 3B). In all three districts, less than 3 percent of the total ultimate recovery is assigned to stratigraphic traps. However, this simple trap classification does not reflect the major contribution of stratigraphically assisted trapping within the dominantly structural traps; this compartmentalization of reservoirs owing to depositional, or stratigraphic, heterogeneity is a major cause of difficulties in estimating reserves. In District 8, 12 percent of the ultimately recoverable nonassociated gas was located in stratigraphic traps in 1977 (table 3B).

Geopressured Reservoirs

A limited number of reservoirs in the deep Frio, Vicksburg, and Wilcox Formations exhibit abnormal fluid pressures. Normal overburden pressures can be approximated by a pressure gradient equal to that of a column of water, or 0.465 pounds per square inch (psi) per foot of depth in the Gulf Coast. Geopressured conditions result from abnormally thick deposits of sand and mud in areas of growth faults. These conditions also provide isolation of porous units, trapping fluids within the reservoirs so that, with further burial, the fluids support part of the

Table 3B. Estimated ultimate recovery of nonassociated gas by type of trap.

	Structural						Stratigraphic					
	Nonassoc. (Bcf)	(%)	Assoc. (Bcf)	(%)	Total gas (Bcf)	(%)	Nonassoc. (Bcf)	(%)	Assoc. (Bcf)	(%)	Total gas (Bcf)	(%)
1970 Total U.S.	289,335	62	157,814	73	447,149	66	174,783	38	57,367	27	232,150	34
Total Texas	120,379	64	53,657	68	174,037	66	66,147	36	25,309	32	91,456	34
Percent of total U.S		42		34		39		38		44		39
District 2	19,253	97	5,616	99	24,869	98	577	3	36	1	613	2
Percent of Gulf Coast districts		20		16		19		27		7		23
District 3	35,352	98	15,470	99	50,822	98	619	2	124	1	743	2
Percent of Gulf Coast districts		37		44		39		29		23		28
District 4	39,962	98	14,170	97	54,132	98	971	2	372	3	1,343	2
Percent of Gulf Coast districts		42		40		42		45		70		50
Districts 2 + 3 + 4	94,567	98	35,256	98	129,823	98	2,167	2	532	2	2,699	2
Percent of total Texas		79		66		75		3		2		3
District 8	14,036	88	10,967	66	25,003	77	1,968	12	5,653	34	7,622	23
Percent of total Texas		12		20		14		3		22		8
1977 Total U.S.	318,088	61	161,011	72	479,099	65	201,708	39	61,069	28	262,777	35
Total Texas	123,202	63	51,743	67	174,945	64	73,099	37	24,926	33	98,025	36
Percent of total U.S.		39		32		37		36		41		37
District 2	18,298	97	6,096	99	24,394	97	637	3	35	1	672	3
Percent of Gulf Coast districts		20		19		20		25		8		23
District 3	39,457	99	13,089	99	52,546	99	519	1	138	1	657	1
Percent of Gulf Coast districts		43		41		42		20		31		22
District 4	34,601	96	13,125	98	47,726	97	1,384	4	272	2	1,656	3
Percent of Gulf Coast districts		37		41		38		54		61		55
Districts 2 + 3 + 4	92,356	97	32,310	99	124,666	98	2,540	3	445	1	2,985	2
Percent of total Texas		75		62		71		3		2		3
District 8	18,468	88	11,717	66	30,185	78	2,428	12	5,960	44	8,388	22
Percent of total Texas		15		23		17		3		24		9

1970 $\frac{\text{Districts } 2+3+4}{\text{Total Texas}}$ $\frac{\text{ult. recovery total gas structural + stratigraphic traps}}{\text{ult. recovery total gas structural + stratigraphic traps}} = \frac{132{,}522 \text{ Bcf}}{265{,}493 \text{ Bcf}} = 50\%$

1977 $\frac{\text{Districts } 2+3+4}{\text{Total Texas}}$ $\frac{\text{ult. recovery total gas structural + stratigraphic traps}}{\text{ult. recovery total gas structural + stratigraphic traps}} = \frac{127{,}651 \text{ Bcf}}{272{,}970 \text{ Bcf}} = 47\%$

% calculated for gas classification (nonassoc., assoc., or total) for trap type, by district
Example: District 2 assoc. gas for trap types structural, 5,616 (99%) + stratigraphic, 36 (1%) = 5,651 (100%) (in 1970)

added overburden weight. Under these conditions pressure gradients of 0.75 psi per foot or higher have been noted.

Geopressured reservoirs require particular care. Drilling may prove difficult and may cause potentially dangerous blowouts; completions also require the utmost care in using equipment and in planning. Of particular interest for this study, geopressured reservoirs create special problems in estimating reserves. Given a simple situation of a thick sand surrounded by impermeable shale, drawdown calculations can readily account for reserves. However, under the typically complex conditions of multiple sands of varying degrees of reservoir quality, calculations become much more difficult. At higher pressures, the more permeable reservoirs deplete much more rapidly, leaving the bulk of the reserves to be produced over a longer period of time from the less permeable zones. Dependability of reserve estimations, therefore, varies with the stage of depletion of the reservoir.

Establishment of gas-water contacts and determination of water saturations, which are critical for reserve calculation, were especially difficult in geopressured reservoirs owing to inadequacies in earlier logging programs. Reserve determinations, therefore, were subject to substantial errors.

Depths to the top of geopressure vary greatly in the Gulf Coast region. In general, however, the top of geopressure is shallower in District 4 than in Districts 2 and 3. Thus, this factor would have more influence in District 4. However, as pointed out by several persons we interviewed, gas reserves in geopressured reservoirs are not large, and their reevaluation may not have been a major factor in the negative revisions.

Intrastate Versus Interstate Dedicated Reserves

The regulation of the price of natural gas sold to the interstate market had a significant effect on the capability of the interstate market to compete for supplies with the decontrolled intrastate market in Texas (appendix III). Economics has an effect on the level of revisions in a given gas field by affecting the point at which the field would be abandoned and the extent to which enhanced production techniques might be used. Table 4 presents the relative shares of gas production sold to interstate and intrastate pipelines in 1966 and 1979. Data are presented for each Texas Railroad Commission District and for Texas as a whole.

Table 4 shows that sales to intrastate pipelines accounted for a larger portion of Texas production in 1979 than in 1966. This is probably a reflection of the stronger competitive positive position of intrastate pipelines through 1978 (the passage of the NGPA). However, Table 4 also shows that the interstate/intrastate issue did not appear to significantly affect the issue of negative revisions. The most solidly interstate district, District 10, was the only district to have significant net positive revision from 1966 to 1979. The Texas Gulf Coast districts, which had the largest negative revisions, were either split between the two markets or more intrastate than interstate at the beginning of the period.

Size of Fields

Although there is no direct relationship between field size and volume of negative revisions, we believe that it deserves attention, since the larger fields represent high percentages of total reserves for different districts and, therefore, must have been involved in the large negative revisions. Using Petroleum Data Systems field data files from the Energy Resources Center, University of Oklahoma, augmented by cumulative production figures compiled by the TRRC and listed by Petroleum Information Corporation (1983), charts of cumulative gas production to December 1983 were prepared for each of the TRRC Gulf Coast districts. All gas fields that had produced more than 60 Bcf were included (appendix VI). This figure was selected as an approximate equivalent of the 10 million barrels of oil used as a reference point in a recent study of the characterization of major oil fields (Galloway and others, 1983). The 60 Bcf cutoff resulted in a list of 46 fields for District 2, 70 fields for District 3, and 92 fields for District 4.

The 92 large fields in District 4 contributed 61 percent of the total annual district production for 1983 (appendix VI). The same fields account for 77 percent of the cumulative

Table 4. Distribution of natural gas production in Texas between the intrastate and interstate markets, 1979.

District	Intrastate* (%)		Interstate (%)	
	1966	1979	1966	1979
1	55	73	45	27
2-Onshore	62	79	38	21
3-Onshore	70	87	30	13
4-Onshore	50	74	50	26
5	99	98	1	2
6	42	33	58	67
7B	93	99	7	1
7C	34	52	66	48
8	29	50	71	50
8A	70	72	30	28
9	71	68	29	32
10	22	26	78	74
State/Federal Offshore	N/A	23	N/A	77
Texas	50	57	50	43

*Intrastate share is derived by subtracting production reported by interstate pipelines on FPC Form 15 from total production in each district.

Source: Economics Planning, Inc. (1983)

production through 1983 (appendix VI). These data reflect the declining productivity of the older large fields, which, in turn, is partially a response to the negative revision of reserves that the large fields experienced during the 1970's.

Further confirmation of the declining productivity of these older major fields is seen in data reported by Rahman and Hicks (1982). The surveillance fields system was developed by the DOE/EIA in 1975 and included those gas fields that contributed 85 percent of nationwide gas-well gas production in 1970. The smallest of the surveillance fields produced 2,427 MMcf annually sometime between 1970 and 1975. Updated surveillance fields in Texas (1981) include those that had produced 2,427 MMcf in any one year from 1970 through 1981 and had at least one well with a back-pressure test in 1981. There were 606 surveillance fields in the 1981 study, representing 5.5 percent of the 10,971 gas fields in the state. The surveillance fields accounted for 3.12 Tcf, or 58 percent of the total gas-well gas in Texas in 1981. District 4, which produced more gas-well gas than any other district in 1981, had 173 surveillance fields out of 3,393, or 5.1 percent of the total (table 5). The production of 532 Bcf from these surveillance fields was 47 percent of the 1.14 Tcf gas-well gas produced in District 4 in 1981 (table 5), or a lesser contribution from the larger fields in District 4 than for the state as a whole. District 8 and District 10 reported much higher percentages of surveillance-field gas, producing 77 and 86 percent, respectively. Districts 2 and 3, the other major gas-well-gas-producing districts, had smaller percentages of production from the surveillance fields than District 4; the surveillance fields accounted for 43 percent of the total production for the three Gulf Coast districts combined (table 5).

Annual Production Rates and Decline Curves

Plots of annual production versus cumulative production for the 6 largest fields in District 2, 9 largest fields in District 3, and 14 largest fields in District 4 (appendix VII) were constructed to examine depletion patterns of fields in areas of large-scale negative reserve revisions. In District 4 the 14 largest fields had cumulative production of 12.98 Tcf through

Table 5. Surveillance gas fields production by Texas Railroad Commission district, 1981.

TRRC district	No. of surveillance fields / Total no. of gas fields		Surveillance fields / Total gas (MMcf)	
1	19 / 354	= 5.4%	70,202 / 109,418	= 64%
2	52 / 2,077	= 2.5%	127,231 / 376,694	= 34%
3	113 / 1,862	= 6.1%	397,787 / 944,396	= 42%
4	173 / 3,393	= 5.1%	532,138 / 1,136,164	= 47%
5	18 / 205	= 8.8%	75,024 / 151,156	= 50%
6	43 / 452	= 9.5%	240,166 / 398,910	= 60%
7B	7 / 991	= 0.1%	18,806 / 124,384	= 15%
7C	16 / 427	= 37.0%	173,368 / 255,641	= 68%
8	77 / 508	= 77.0%	740,350 / 958,122	= 77%
8A	4 / 36	= 11.1%	7,185 / 15,941	= 45%
9	4 / 362	= 1.1%	74,871 / 107,319	= 70%
10	80 / 354	= 22.6%	661,412 / 768,822	= 86%
State surveillance / Total Texas	606 / 10,971	= 5.5%	3,118,540 / 5,346,967	= 58%

1983 (table 6), which represents 38 percent of the district total. The volumetric significance of these fields suggests that they were at least partly responsible for revisions in reserves.

The largest gas fields in District 4 exhibited sharp declines in annual production rates, as shown in table 7 and appendix VIII. The reason for the decline may be related to revised reserve figures, since decided anomalies in the reserves-to-production (R/P) ratio would be produced if reserves were not decreased in a like manner. Prudent reservoir management requires a relationship between annual production rates and remaining reserves.

Allowables and ratable takes depend on operator-declared deliverability and pipeline (purchaser)-nominated takes (appendix IV), and they are assigned by the TRRC. Significant underproduction (decreases in rates of annual production) of these allowables indicates the inability of the reservoir to deliver assigned volumes of gas, and it may show the need for negative revision of reserves. Other factors, such as market interruptions, technical difficulties in production, etc., may be responsible for part of the decline in production; however, when wholesale concurrent negative revisions occur, the relationship of the decline in rates of production to the revision of remaining reserves must be considered.

Dates of Discovery

Tables of revisions in ultimate recovery by year of discovery for nonassociated, associated, and total gas were constructed to test possible discovery-date influence on revision. The years 1972 through 1979 were chosen because the data were readily available for those years, and they included the largest negative revisions of reserves. A problem with such plots is that of differing dates of discovery (reservoir rather than field?) for associated and nonassociated gas reserves in the same field and/or variations in dates between sources checked (International Oil Scouts Association; TRRC; Energy Information Administration [1983]). Because nonassociated gas in the Gulf Coast districts represents such a large part of the total gas, we concentrated our effort on nonassociated gas fields. However, the ambiguities in dates of discovery for different types of gas, and the fact that our list of larger fields still left room

Table 6. Cumulative production data for largest gas fields in Districts 2, 3, and 4, 1983.

District 2		District 3		District 4	
Field	Cum. prod. to 12/83 (Bcf)	Field	Cum. prod. to 12/83 (Bcf)	Field	Cum. prod. to 12/83 (Bcf)
Burnell	461	Chocolate Bayou	883	Alazan North	1,230
Heyser	542	College Port	325	Borregos	1,792
Lake Pasture	508	Fishers Reef	166	La Blanca	273
Provident City	411	Katy	6,382	La Gloria	1,379
Tom O'Connor	661	Magnet Withers	896	Laguna Larga	666
Tulsita Wilcox	457	Old Ocean	2,596	McAllen	375
		Pledger	1,472	McAllen Ranch	595
		Redfish Reef	266	Sarita	229
		Sheridan	1,330	Seeligson	1,391
				Stillman	186
				Stratton	1,512
				T.C.B.	469
				Thompsonville, NE	589
				Zone 21-B Trend	2,289
Total cum. prod. (6 fields)	3,040 (23%)		14,316 (48%)		12,975 (38%)
Total cum. prod. (district)	13,271		29,857		33,747

Cumulative production from TRRC data as listed by Petroleum Information Corporation (1983).

Table 7. Annual production declines for largest gas fields in District 4, 1968 to 1980.

Name of field	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
Alazan North	-41%*								*		*	*
Borregos						*				*		
La Gloria							*	*				
Laguna Larga							-28%*		*			
McAllen Ranch	*	-26%*				-22%*						
Sarita						*			-31%*			
Seeligson	*				*	-30%*						*
Stillman	*							-20%*				
TCB						-27%*	-33%*					
Thompsonville, NE			-20%*									
Zone 21-B Trend											*	*

* = Sharp break on decline curve plots.

-26% = Percentage decrease in annual production from preceding year.

for revisions that could not be accounted for, prevented the direct application of this approach. Some of the very large negative revisions, such as the 1975 decrease of 490 Bcf in estimated ultimate production for fields discovered in 1939 for District 4 nonassociated gas, may be related in part to revisions in reserves at La Gloria. This is indicated by abrupt changes in production rate (more than 20 percent annual decline) for this field in 1975 and 1976 (table 7). Grouping discoveries by decades resulted in a series of generalized graphs (appendix IX) that illustrate the variable nature of the very large negative revisions.

A look at reserves, production, and revisions suggests one reason for the difficulties encountered. Negative revisions for nonassociated gas reserves of 6.3 Tcf in 1973 were recorded, representing some 19 percent of the remaining reserves of nonassociated gas for the three Gulf Coast districts. Reserve additions during 1973 totaled only 0.94 Tcf (3 percent of remaining reserves) while production was 2.74 Tcf (8.3 percent of remaining reserves). Incremental negative revisions for individual fields would show a smaller percentage of total remaining reserves, so it would be difficult to document that all the revisions recorded necessarily came from these larger fields (60 Bcf cumulative production). Nonetheless, their size and importance suggest that they were important to the negative revisions process.

Task 1 Summary Statement

Revisions of reserves as reported by the American Petroleum Institute come from many sources. In the Texas Gulf Coast districts that dominated negative revisions in the state and provided a negative impact on national reserves, the negative revisions appear to be concentrated in nonassociated fields, many of which have been producing for more than 20 years. District 4, the source of more than two-thirds of the state's negative revisions, also has the highest ratio of nonassociated to total gas of any district in the state. Negative revisions of nonassociated gas fields in District 4 occurred throughout the period (1966-1979) but were concentrated in 1972, 1973, and 1974. Revisions in 1973 (-3.48 Tcf) were by far the largest, representing one-third of all the negative revisions of nonassociated gas reserves (1966-1979) for the district. Large decreases in production rates for the largest fields in the district are only somewhat coincident with the negative revisions of reserves; therefore, it is not possible to establish a direct volumetric relationship, though the larger fields must have been involved in the large-scale negative revisions of reserves.

TASK 2. ANALYZE THE CAUSES OF NEGATIVE REVISIONS

Causes and Nature of Reserve Revisions

Revisions of reserve estimates concurrent with efforts to extend specific reservoirs are a continuing part of a gas field's history, as is the discovery of additional reservoirs as new wells are drilled in and around a given field. Reserve revisions can be negative or positive, and the dominant direction depends to some degree on the optimism or pessimism applied to the original estimate. It must be understood, however, that the ultimate recovery from a given reservoir or field can never be known precisely until the last well is abandoned.

The earliest estimates of reserves are usually determined by applying a recovery factor to an estimate of the volume of original hydrocarbons in place in the reservoir. Hydrocarbons in place are in turn calculated by multiplying the reservoir volume by one minus the initial connate water saturation (1-Sw). Revisions are then made as new geologic and engineering data become available during development and production of the reservoir.

The most common physical reasons for revisions are related to the limited nature of initial data on the reservoir and its behavior. One common limitation is the accuracy of the determination of interstitial or connate water saturations from well logs. In one case, that of a large Gulf Coast gas reservoir, early determination of connate water saturation indicated a value of 25 percent. Later, more detailed tests indicated that a significant segment of the pay zone had connate water saturation as high as 35 percent, which resulted in a negative revision of nearly 15 percent, or more than 150 Bcf, in that one field. Many large Gulf Coast fields were subject to similar revisions as more accurate determinations of water saturation became available.

In another case, the displacement efficiency of the encroaching water in a strong water-drive field, as indicated by a rapid advance of the water table, was so much poorer than had been assumed that a reevaluation of reserves was required. In this field, the residual gas saturation behind the water front was calculated to be 35 percent compared with an original assumption of 15 percent; again, a drastic reduction of reserves occurred. Several reservoirs in southwest Texas have experienced this type of performance record; some of these fields are now being dewatered to create a secondary gas cap that will enhance ultimate gas recovery. However, the high cost of dewatering may limit the extent to which it is practiced.

Still another physical cause of revisions results from treatment of lower permeability lenses or strata contained in or adjacent to recognized pay zones. The porosity-permeability cutoff in assessing volumetric gas in place may include or exclude strata whose contribution will be determined by the method of exploitation. If a reservoir is produced by pressure depletion, tight zones, which would contribute little gas to the wellbore initially, will, over the productive life of the field, transmit gas to the more permeable strata for flow to the wellbore. On the other hand, if the reservoir is produced under pressure maintenance, these strata may be bypassed by the encroaching water, resulting in high residual gas saturation. Revisions, therefore, may be either negative or positive, depending on the reservoir management program.

Estimation of Reserves

Accurate estimation of reserves calls for continuous revision throughout the life of a field. Each well that is drilled in a reservoir, if fully assessed, will create a need for reevaluation of original oil in place or gas in place, and continuous observation of pressure-production history will provide information for continuous reestimation of reserves. Of course, no company will follow this process, because the time and cost are not warranted and the precision of estimation does not justify it. For fields discovered three or more decades ago, the market demand and, hence, production volume made such a procedure superfluous. Consequently, when market demand caught up with supply, the necessary revisions occurred over such a short time span that the impact was massive.

There are several sources of information that provide data for reserve estimation over the life of a reservoir. The more important are included in the following discussion.

1. The earliest estimates of reserves in a reservoir are made with limited geologic and engineering data. Geologic and geophysical information, together with core and log data from the discovery well, provide the statistical parameters for an estimation of original gas in place based on an assumption of stratigraphic homogeneity and continuity of pay zones. The actual characteristics of the reservoir will generally be less homogeneous and continuous than initially assumed. An optimistic recovery factor, when applied to this gas in place value, yields an overstated reserve volume.

2. Each new development well drilled into a reservoir provides additional information that may be used for revision of reserve estimates; these revisions may be either positive or negative. Successful field wildcats or step-out wells add area. Infill wells that provide information on stratigraphic continuity and heterogeneity frequently call for revisions as more precise isopachous contour maps of pay zones provide definitive parameters for detailed reservoir description and volumetric estimates.

3. The pressure-production history of a reservoir, given a sufficient time interval, can provide information for a material-balance estimate of the gas in the reservoir that is in pressure continuity with producing wells. For nonassociated gas reservoirs producing by pressure depletion, calculations for the determination of this estimate are simple and straightforward, following accepted reservoir engineering formulas, provided that the properties of the gas in the reservoir have been determined in the laboratory. Calculations for associated gas reservoirs, or reservoirs producing with an active aquifer, are more complex owing to the different phase relationships of the reservoir fluids. However, the engineering technology utilizing material-balance and unsteady-state calculations for such reservoirs is well

established, and estimation of reserves is reasonably reliable except for the most complex reservoirs, where adequate pressure-production histories are not available.

When normal calculations are not adequate, decline-curve analysis may be used. When fields have a sufficiently long performance record and are producing at capacity, a semilogarithmic plot of production rate versus cumulative production will extrapolate to an ultimate reserve value. This value is determined by projecting these data to an economic limit.

Optimistic Bias

It is likely that the earliest calculations by an operator of a new field would be biased toward an optimistic estimate of reserves. Explorationists responsible for the earliest estimates of discovered reserves are usually optimists by definition. Because early prorationing guidelines in the Gulf Coast favored those operators with highest reserve estimations, the more optimistic estimates were deemed appropriate, lacking data to the contrary. Daily contract quantity agreements for the purchase of gas provided 1 MMcf daily allowable for every 8 Bcf of reserves of nonassociated gas, or a 22-year supply at that rate.

No pressing reason existed for reappraisals as long as deliverable supply exceeded demand. However, as pressure declines were noted and deliverability was tested during periods of peak demand, more realistic reviews of reserves began to be made near the close of the 1960's and into the 1970's.

Technical Factors Affecting Revisions

Recovery Factors

Original volumetric estimates for a gas field depend on parameters established by wells that define the extent of the field. The recovery factor is an integral part of the recoverable reserve formula, and relates to the efficiency of producing the original gas in place (OGIP). The recovery factor $\left(\frac{\text{volume recoverable gas}}{\text{volume OGIP}}\right)$ must often be assumed because no accurate method exists to predict its value. Laboratory tests may supply useful information; however, duplication of actual field conditions is difficult, and large errors can occur. In a mature producing area, recovery factors, established by historical production data and/or material-balance calculations after stabilized maximum production has established a decline rate, are well known and generally quite accurate. However, in the development of many of the early Texas Gulf Coast gas fields, reliable recovery factors had not been determined. Since the gas surplus at the time did not allow a maximum production rate that would permit determination of decline rates, the initial estimated recovery factors were maintained until such time as production history indicated that the factors were not adequate. This began to occur in the late 1960's and extended through the 1970's.

Water-Drive Reservoirs

In many Gulf Coast gas fields, water influx can be a problem of some magnitude. In heterogeneous reservoirs, water can and often does bypass and thereby trap gas contained in less permeable parts of the reservoir, effectively reducing the producible reserves. The wide spacing of gas wells makes it more likely that trapped or bypassed gas is not properly considered in reserve estimates. When infill drilling programs began to supply more accurate reservoir data, or when water encroachment became a problem, operators began the process of revising reserve estimates in these fields. Actual recovery for water-drive gas reservoirs may be in the 55- to 65-percent range or even less, whereas for depletion drives, recovery might have been estimated at 85 to 90 percent or more. It can be seen, therefore, that the recognition of significant water-drive elements in Gulf Coast gas fields would necessitate large-scale negative revisions.

Heterogeneity of Reservoirs

The heterogeneity of a reservoir pertains to the degree of discontinuity of discrete permeable lenses within the reservoir and affects recovery factors as discussed above. Most of the early estimations of reserves in the Gulf Coast were based on assumptions that reservoirs penetrated in a well were homogeneous and continuous over the area of the field. With widely spaced gas wells and surplus supply conditions these assumptions were adequate. However, with infill drilling and increased demand, more sophisticated reservoir interpretations were possible and the degree of heterogeneity increased markedly (fig. 3). Significant negative revisions of reserves resulted from the improved understanding of reservoir conditions.

Compartmentalization (heterogeneity) exists when portions of a reservoir are not in fluid or pressure contact with the borehole or when the contact is limited or restricted for any reason. Sealing and nonsealing faults may be seen as special cases of compartmentalization that lead to changes in the heterogeneity of reservoirs in that compartments within the field would exist to a greater or lesser degree, depending on the nature of the bounding faults (fig. 4).

Fault zones, which do not allow passage of reservoir fluids, are a type of sealing fault (fig. 4A). Sealing may also occur when the fault zone does allow fluid passage if permeable reservoir beds are displaced opposite impermeable zones.

Nontechnical Factors Affecting Revisions

Regulatory Factor

Regulatory rulings can be a significant factor in determining reserves. This is true at both the national and state levels. The relatively low prices paid for gas in interstate commerce provided an incentive to operators to drill and produce gas for the intrastate market, where prices had risen rapidly in response to the increased demand and limited supply. As a result of greatly increased costs of operation along with constant gas prices (1973-1978), operators of interstate gas properties sometimes found that the new economic limit would shorten the life of a property. Bias would exist for the most pessimistic interpretation of interstate gas reserves owing to the changed economic conditions for the resource.

Optimistic Evaluations of Reserves

After the discovery of a new reservoir or field, several different valid interpretations can be made from the same data about the volume of recoverable reserves. Encouraged by market

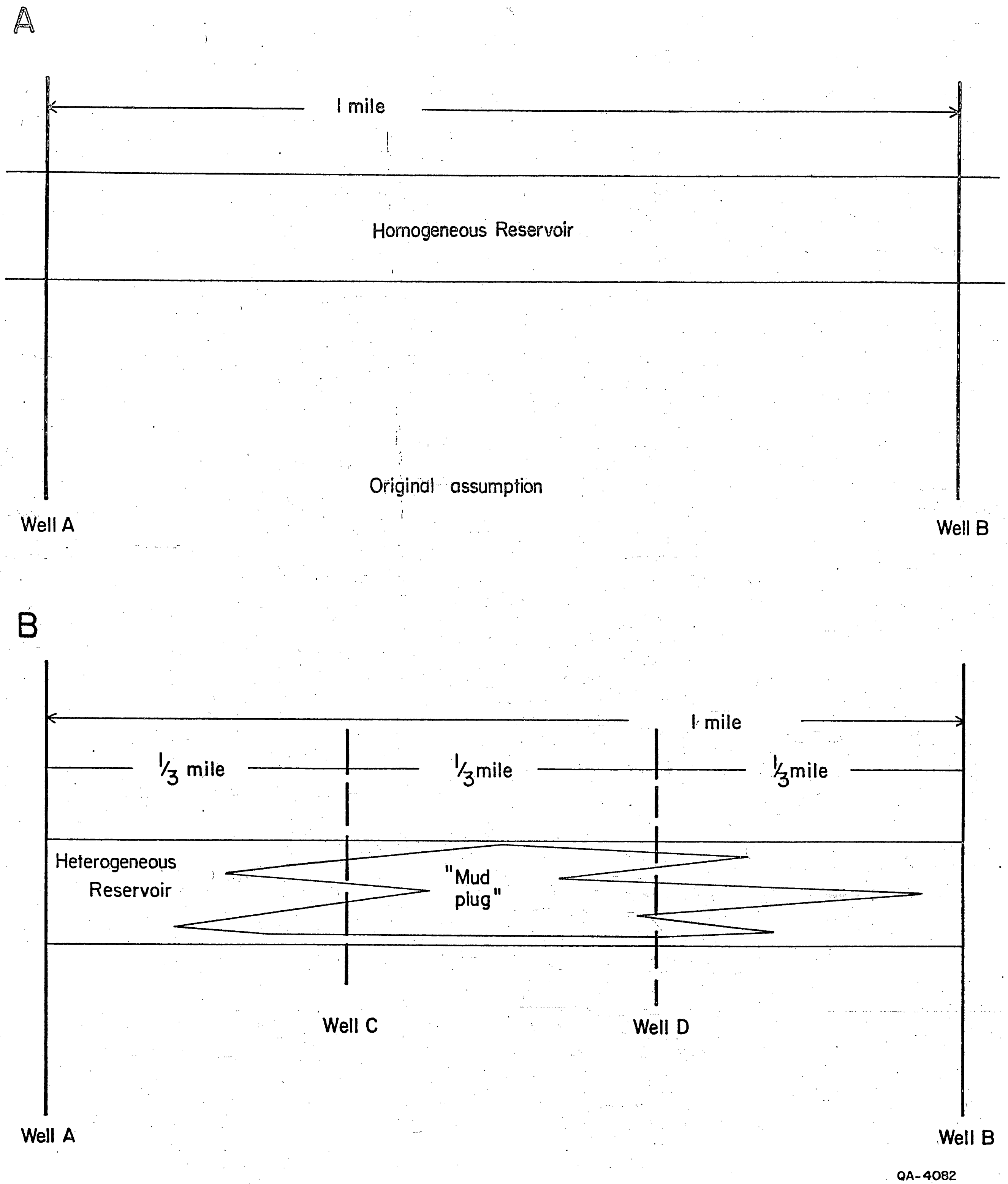

Figure 3. **Schematic drawing illustrating homogeneous (A) and heterogeneous (B) reservoirs. Interpretations before and after infill drilling.**

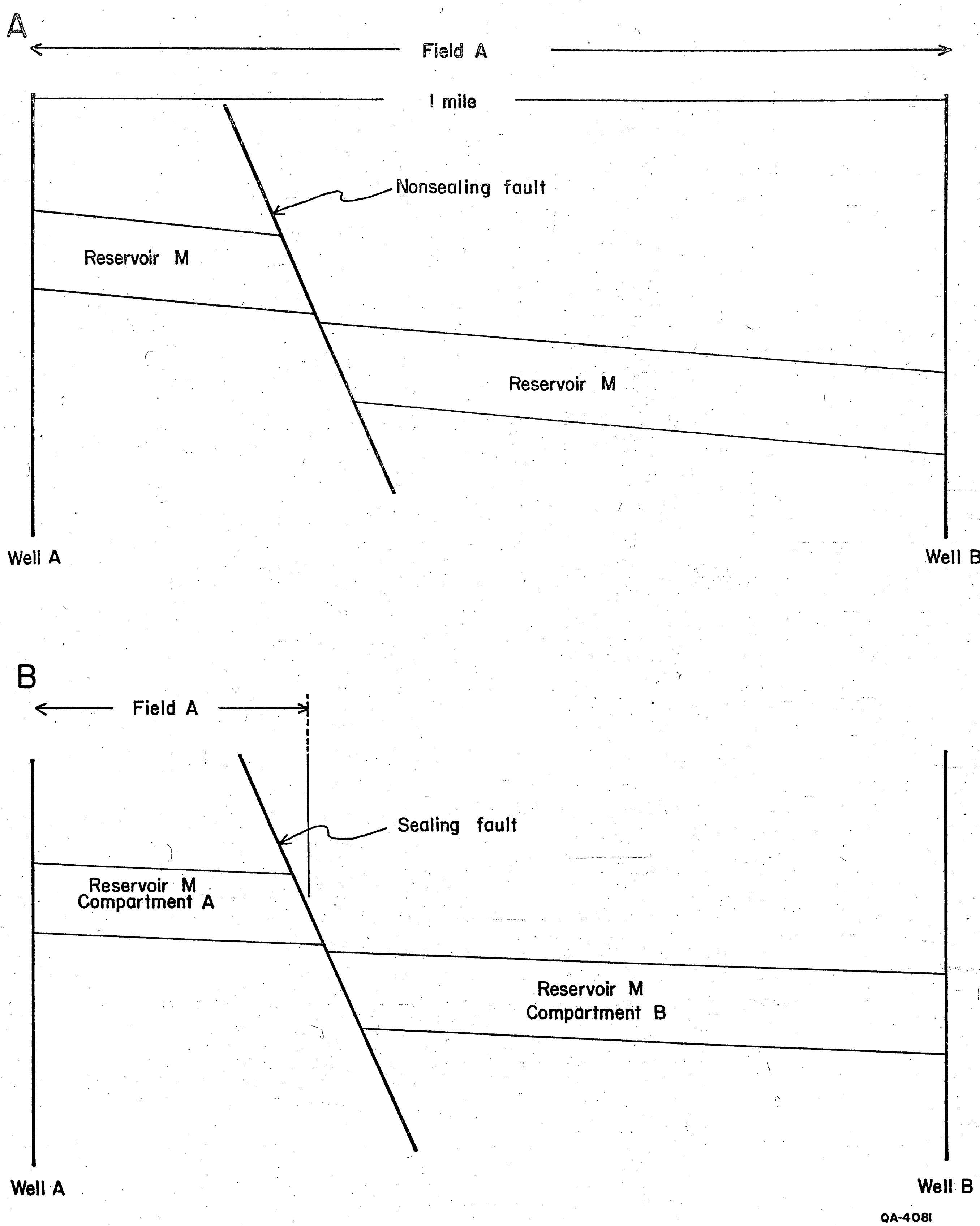

Figure 4. Schematic drawing showing different field sizes for situation in which fault associated with the field is nonsealing (A) or sealing (B).

conditions, excessive optimism as to reserve estimates was responsible for large negative revisions when decline occurred and realistic reappraisals were made.

Economic Factors

When price controls were applied to interstate markets, price failed to keep pace with rising costs of production. Exploratory drilling and even development drilling were eliminated if price was below replacement cost. In some cases, particularly in low-productivity reservoirs, the combination of the expense of repairs, maintenance, and general operations coupled with compression costs led to field abandonment at a higher final reservoir pressure than had been originally assumed. The ultimate recovery under these circumstances would be less than the initial reserves estimate and therefore would require negative revisions of reserves.

Interviews with API/AGA Reserves Committee Members and Other Experts

Causes for the downward revision in gas reserves were ascribed to both technical and non-technical factors. The original optimistic estimate of reserves can also be attributed to both factors. An optimistic attitude is obviously a nontechnical factor, yet the volumetric analysis that was used has a technical basis.

Widespread reevaluation of reserves occurred when deliverability peaked and all fields went into decline. However, because of the confidential nature of this type of information, it was not possible to identify revisions quantitatively on a field-by-field basis. On the other hand, frank discussions of the basis and nature of these negative revisions have allowed us to draw many of our conclusions.

Our interviews with individuals who have spent years estimating oil and gas reserves led to our findings that no one factor can be cited for the negative revisions in the Gulf Coast during the period of the investigation. Rather, there were a number of coincident events that caused sustained negative revision of reserves.

1. The consensus of opinion among 20 individuals representing producers, pipeline companies, and regulatory agencies was that an original optimistic bias in estimating original gas in place and in the assignment of recovery factors contributed to major negative revisions. There is a tendency to be optimistic about a new field in making estimates of the original volume of hydrocarbons in place. If there is the slightest possibility that good reservoirs will be continuous or that poor reservoirs will improve, such determinations will often be made by those responsible for the new field.

The primary reason for an optimistic or inflated early estimate can be attributed to market factors. In the first place, a minimum reserve of 8 Bcf per 1 MMcf of production was essential to justify a pipeline and related distribution facilities. Further, sales contracts usually called for a specific minimum backup reserve. Such commitments were not a great cause for concern in the industry, since extensions and new pool discoveries frequently made up for any deficiencies in deliverability from the main reservoirs for which the commitment was made. If these failed, it was always felt that exploration could find a new field to enable the company to meet its contracts and fulfill its obligations.

2. Many of the older large producing fields entered a period of natural decline following sustained high production, and this was felt to be a contributing factor to the timing of major negative revisions.

3. We have suggested problems in log interpretation of water saturations in deep geopressured formations; however, discussion with API/AGA Reserves Committee members indicated that this was not a highly significant factor in the total reserve picture. However, there was general agreement that early water-saturation determinations in the Gulf Coast had erred on the low side, and, in many cases, increased saturations were determined from later data, resulting in some large negative revisions of recoverable reserves.

Role of Optimism in the Oil and Gas Industry

Original, optimistic estimates of natural gas reserves in older fields were a major factor in the negative revisions that occurred during the 1970's. The fact that the negative revisions were so long delayed attests to the success of gas-finding efforts of the industry. In a way, this success can be attributed to the positive role of optimism in exploration and production activities. Without optimism as a guiding principle, many oil and gas prospects would never be drilled, and many prospects would be condemned by the first dry hole drilled. Optimism, therefore, can be seen as a positive and necessary force in the oil and gas industry; the original optimistic estimates of natural gas reserves should be seen as normal. However, earlier reassessments of the reserve estimates, as would be done today, would have eliminated much of the drastic effect of the later major reductions in reserves that resulted from the long-delayed critical review of reserve estimates.

Task 2 Summary Statement

Analysis of the factors responsible for the series of extensive negative revisions from non-associated gas fields of the Texas Gulf Coast allows us to draw several conclusions. The original overestimates resulted from optimism and lack of detailed information on reservoir continuity, the selection of higher recovery factors than could be later justified, and water-saturation determinations that failed to accurately indicate the amount of water and gas in the reservoirs. In each case, optimism played a role in the choices made.

Market conditions and reservoir management practices prevented normal assessment and review that should have accounted for much of the overestimates in a systematic, incremental way; however, economic incentives in the form of higher takes for greater declared reserves were a powerful encouragement for maintaining as favorable an estimate of reserves as could be justified. Coupled with the continued addition of reserves in excess of demand, the high R/P ratios obscured the underlying weakness in the older reserve figures until maximum demands could not be met without excessive pressure decline. A return to this scenario with current market conditions and prudent reservoir management practices would be most improbable. The extended period of large negative revisions, particularly in TRRC District 4, was a response to a unique set of circumstances that probably will not reoccur. Early optimistic estimates of reserves for many of the old large fields cannot be repeated for those producing fields and reservoirs in today's mature situation. Established recovery factors and detailed reservoir information provide the basis for greatly improved estimates of recoverable resources.

TASK 3. ASSESS FACTORS IDENTIFIED IN TASK 2 THAT MIGHT BE USEFUL AS LEADING INDICATORS OF FUTURE SUSTAINED NEGATIVE REVISIONS

Reserves Declared in Times of Surplus

During periods when reported deliverability exceeds demand, as has occurred in the past and is occurring at present (the "gas bubble"), some newly declared reserves have not been subjected to maximum production for a sufficient period of time to establish valid decline relationships. Rigorous long-duration testing so that decline rates may be accurately forecast is vital to proper evaluation of potential reserves, and lack of such data may be considered as being capable of producing inaccuracies in reserve figures that could result in negative revisions in the future. Possibly the greatest danger as far as this factor is concerned is that of complacency that may accompany the declaration of new reserves even though decline projections are not possible. The much-reduced reserves base and lower R/P ratios that resulted from the negative revisions of the past, however, do not provide the conditions that would obscure widespread weaknesses in reserves.

The Texas Gulf Coast gas reserves history of 1966 through 1979 suggests that the productive life of very large reservoirs must be considered, particularly those where R/P ratios are greater than 15/1. Fields that have produced large volumes of natural gas over a period of

25 to 30 years may be candidates for negative revisions if the reserves, declared in times of surplus, have not been subjected to critical review, especially if multiple reservoirs with differing trapping factors and drive mechanisms exist in the fields.

Widespread Application of Unproven Recovery Factors

The widespread use of unproven recovery factors in newly developed areas, which occurred in the Texas Gulf Coast in the 1930's, 1940's, and 1950's, is a factor that could be considered a leading indicator for future negative revisions.

Wide Spacing of Gas Wells

Lack of understanding of the heterogeneity of the reservoir and misunderstandings of the drainage capability of the wells occurred in many cases owing to the wide spacing of gas wells (often 320 or even 640 acres). Continued dependence on such widely spaced wells could be another leading indictor for a return of negative revisions.

Market Conditions

The continuing phenomenal increase in demand for natural gas, the rapid rise in prices that followed the Arab Oil Embargo, and the changes in intrastate and interstate markets that preceded and followed the adoption of NGPA occurred in the 1970's and disrupted market conditions drastically, contributing to negative revisions of reserves. Such occurrences would almost inevitably lead to revisions. However, the prediction of such events is beyond the scope of this paper.

TASK 4. LIKELIHOOD OF FUTURE SUSTAINED NEGATIVE REVISIONS TO U.S. NATURAL GAS RESERVES

Gas-well test forms (TRRC G-10), which deal with deliverability, have been revised, and now both operator and purchaser must sign the test form. The program of joint signing by producer and buyer was initiated shortly after the Texas Ratable Take Committee submitted its recommendations in July 1983 (Texas Railroad Commission, 1983a). Deliverability tests are now required by TRRC for most wells on a semiannual basis. These newly declared deliverabilities have not yet been tested by maximum-demand conditions to determine their validity.

The extreme winter of 1983-1984 provided an extended period of high demand, and significant volumes of supposedly deliverable gas supplies were not available. However, the lack of deliverability may reflect failure to conduct workovers, recompletions, and proper field maintenance, much of which might have been deferred during the "gas bubble."

Deliverability and reserves are not precise equivalents, yet the lack of deliverability may lead to doubts about reserves. It is also true that certain bottlenecks in transportation and problems with connections can prevent immediate access to some valid reserves. The fact remains, however, that during a period of high demand that extended for more than 3 weeks, the maximum volume available was less than 60 percent of that indicated by the deliverability tests on file with the TRRC (Texas Independent Producers and Royalty Owners, 1984). Concern certainly should be paid to the quality of these newly declared reserves that have not been subjected to the test of extended maximum demand. However, we should also point out that more sophisticated means of estimating reserves, greatly improved understanding of reservoir complexities, and better fluid-flow models continue to improve the capability of accurately measuring reserves.

The fact that more is known about the geology and engineering properties of gas reservoirs owing to the recent experience of the industry, such as the sustained negative revisions that occurred in the Texas Gulf Coast during the 1970's, would, in itself, suggest a lesser chance of such a situation recurring.

Heterogeneity of gas reservoirs, although not acknowledged to the extent that it is in oil reservoirs, does exist, and it provides new challenges to gas production and to calculation of reserves. More closely spaced gas wells (infill drilling), more precise material-balance calculations, better understood depositional models, and refined fluid-flow models have resolved many of these problems. The likelihood of negative revisions should therefore be less than in the past. Also, the smaller reserve base that resulted from the negative revisions would reduce the room for future revisions on the presumption that actual reserves are now more accurately represented.

DISCUSSION AND SUMMARY

An analysis of the extensive negative revision of natural gas reserves in the Texas Gulf Coast from 1966 through 1979 has led to the following findings:

It was not possible to determine the specific location of negative revisions as to pool and reservoir. However, some general information was assembled on the age of producing fields, size of fields, type of trap, lithology, depositional systems, and TRRC districts, which may help explain the conditions that led to the negative revisions.

Gulf Coast Districts 2, 3, and 4 dominated the negative revision listings for total gas, District 4 being the leader, followed by District 3, with District 2 a distant third. TRRC District 4, where nonassociated gas represented a high percentage of the total gas (table 6), had very large negative revisions of nonassociated gas reserves, particularly in 1973, 1974, 1975, and 1978. These principally affected those nonassociated gas fields discovered in the 1930's through the 1950's (appendix IX). Many large older fields suffered severe production declines during the years involved in the study. The production declines may, in part, be related to the revisions of reserves in this district, although other factors are present. The study concluded that negative revisions that occurred in the Texas Gulf Coast from 1966 through 1979 resulted from a combination of technical (geological and engineering) and nontechnical (market and regulatory) events. Mentioned in nearly all our interviews as a cause were early optimistic estimates of the recovery factors and volume of original gas in place. These estimates were not subjected to critical review because of market-related factors, including the existence of gas surpluses that resulted in pipeline-determined proration with the largest prorated gas takes from those fields with the largest declared reserves. As reservoir depletion effects began to be noticed, it became apparent that the very high reserves-to-production ratios that existed into the 1960's had obscured the fact that optimistic reserve estimates required critical reevaluations. In addition, low natural gas prices in the 1960's created situations where economic values of some nonassociated gas pools were improved by establishing production practices that maximized production of natural gas liquids early in the life of the reservoir (cycling).

From a technical standpoint, the assignment of lower recovery factors for a large number of at least partial water-drive reservoirs caused significant reductions in volume of potentially recoverable gas from these reservoirs. Reductions of 20 to 25 percent for particular fields could have been related specifically to this factor.

Ambiguities in resistivity measurements used in the initial establishment of gas-water contacts and water saturations led to later revisions of original gas in place estimates.

The degree of heterogeneity of many reservoirs was not understood, owing to the original widely spaced (often 640 acres or more) well control used to make estimates of original gas in place. As infill drilling provided closer control, revisions of original estimates were often necessary. Sizeable volumes of reserves were negatively affected by this factor.

Although there is some concern about the accuracy of reserves being developed in times of surplus capacity, as reflected by current deliverability concerns, the low reserves-to-production ratios that now exist indicate that overestimates that might be made would be significantly smaller. The Texas Gulf Coast experience of a period of extensive negative revision of reserves during the 1970's is a lesson in itself to the natural gas industry. Increased awareness of the necessity to constantly review reserve estimates, improved knowledge and understanding of reservoir heterogeneity, more advanced techniques of reserve estimation, and an improved price outlook encourage the judgment that a return of extensive negative revisions should not occur. Such a condition is avoidable provided that industry takes the proper steps and that the economic and regulatory climate is not drastically altered.

ACKNOWLEDGMENTS

This work was prepared for the Gas Research Institute under contract number 5083-800-0908, W. L. Fisher, Principal Investigator.

Appreciation is expressed to our informal panel of experts. Their counsel and advice were indispensable to the successful completion of the study.

The authors benefited greatly from discussions with and suggestions from Jim Morrow, Director of the Oil and Gas Division, Texas Railroad Commission; William J. Murray, Jr., Chairman, Texas Ratable Take Committee and former member of the Texas Railroad Commission; and W. L. Fisher, Director, Bureau of Economic Geology, The University of Texas at Austin.

Cristina Siqueira served as project research assistant, and additional assistance was provided by Michael D. Davis and Robert C. Murray.

The manuscript was prepared by Dorothy C. Johnson, Patricia H. Smolka, Lisa L. Poppleton, and Ginger Zeikus, under the direction of Lucille C. Harrell.

Original graphs and charts were prepared by Robert C. Murray, Michael D. Davis, and Cristina Siqueira. Drafting was by Kerza A. Prewitt and Jamie McClelland. Technical editorial review was by Jules R. DuBar and editing was by Diane Callis Hall.

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APPENDIX I. Definitions of terms.

Allowable is the volume of gas that is permitted to be produced from a well, reservoir, or field according to demand and deliverability schedules determined by regulatory authorities.

Associated-dissolved gas is the combined volume of natural gas that occurs in crude oil reservoirs, either as gas-cap gas or as gas in solution with the crude oil at reservoir conditions (dissolved). The latter is often referred to as casinghead gas.

Deliverability is the volume of gas that can be produced from a well, reservoir, or field during a given period of time against a certain wellhead back pressure under physical reservoir conditions, taking into account restrictions imposed by pipeline capacity, contract, or regulatory bodies.

Flow capacity is the volume of gas that can be produced from a well, reservoir, or field during a given period of time with no restriction other than wellhead back pressure and reservoir capability.

Natural gas is a mixture of hydrocarbon compounds existing in a gaseous phase or in solution with oil at reservoir conditions in natural underground reservoirs.

Nonassociated gas is defined as free natural gas not in contact with crude oil in the reservoir.

Reserves of natural gas, for the purpose of this study, are limited to proven reserves. They are the estimated volume of natural gas that geological and engineering data demonstrate to be recoverable from known oil and gas reservoirs under existing economic and operating conditions.

Revisions to reserves are changes in the estimates of the volume of natural gas that has been demonstrated to be recoverable from known oil and gas reservoirs in a particular field under current economic and operating conditions. There may be changes in the volume of original gas in place or changes in the volume of recoverable gas. Revisions may be positive or negative and are in order when the drilling of additional wells in a reservoir provides new or improved geological or engineering data that allow more precision in reserve estimation. In addition, productive performance may indicate the need to revise the volume of reserves.

Take is the volume of gas that is actually delivered to a pipeline.

Total gas is natural gas and includes nonassociated gas and associated-dissolved gas.

Ultimate recovery of natural gas is an estimate of the total quantity of gas that will ultimately be produced from a reservoir as determined by the interpretation of current geological and engineering information and under prevailing economic and operating conditions.

Volumes of natural gas are listed in:

1. Cubic feet (ft^3)
2. Thousands of cubic feet (Mcf)
3. Millions of cubic feet (MMcf)
4. Billions of cubic feet (Bcf)
5. Trillions of cubic feet (Tcf)

APPENDIX II. Texas Railroad Commission regulation of the natural gas industry.

A chronological listing of important historical events, legislative acts, judicial decisions, orders, and other relevant data regarding regulation by the Railroad Commission of Texas of the natural gas industry.

1. 1872 - First known gas production in Texas from well owned by the Graham brothers and located near Graham, Texas.

2. 1891 - Railroad Commission of Texas established by Texas Legislature, giving the commission jurisdiction over rates and operations of railroads, terminals, and express companies.

3. 1899 - Legislature declares that any gas well is to be shut in within 10 days after completion until such time as the gas produced is used for light, fuel, or power purposes.

4. 1917 - Legislature declares pipelines to be common carriers and gives Railroad Commission jurisdiction over them. First act to designate Railroad Commission as the agency to administer the conservation laws relating to oil and gas.

5. 1919 - Legislature enacts a statute requiring the conservation of oil and gas, forbidding waste, and giving the Railroad Commission jurisdiction.

6. 1919 - Railroad Commission adopts first statewide rule regulating the oil and gas industry, making Texas the first state to adopt a well spacing rule.

7. 1920 - Legislature declares the production and sale of natural gas to be a public utility and gives the Railroad Commission jurisdiction.

8. 1925 - Texas Court of Civil Appeals holds that casinghead gas is included within the term "oil."

9. 1928 - Railroad Commission issues its first proration order based on the conservation statutes pertaining to the Hendricks pool in Winkler County.

10. 1930 - Railroad Commission issues first statewide proration order to limit state production to 750,000 barrels per day. Reduced amount was based on market demand formula.

11. 1931 - Legislature amends 1899 statute covering allowable uses for gas to include any other purpose that the Railroad Commission finds to be practical and conducive to the public welfare. Act defines physical waste and forbids the Railroad Commission to consider market demand either directly or indirectly.

12. 1932 - Federal court sustains statute and subsequent order of Railroad Commission enjoining producer from stripping gas and flaring residue as wasteful.

13. 1932 - Special session of Legislature hurriedly enacts law removing prohibition against consideration of economic waste or limitation of production to market demand to conform to U.S. Supreme Court decision.

14. 1935 - Legislature enacts comprehensive gas regulation statute with detailed provisions for apportioning the reasonable market demand of gas throughout the state. Prohibits production of gas in such a way as to cause underground waste, prohibits blowing to the air before or after processing for gasoline content, and prohibits the use of sweet gas for the manufacture of carbon black but allows some gas to be used for such purpose.

15. 1945 - Texas Supreme Court holds that the Railroad Commission may prorate the production of gas for the protection of correlative rights even though no waste is involved.

16. 1947 - Railroad Commission issues the Seeligson Order restricting the production of gas and oil wells by prohibiting the production of oil and gas in the entire field until all of the casinghead gas produced with the oil is utilized for one of the beneficial uses set out in earlier statutes.

17. 1948 - Railroad Commission on the basis of the contested Seeligson case issues orders covering 16 fields, shutting down every oil well in those fields from which casinghead gas was being flared.

18. 1949 - Supreme Court of Texas upholds Railroad Commission order shutting down 16 fields from which casinghead gas was being flared (wells were shut down from December 1, 1948, to April 1949).

19. 1953 - Railroad Commission enters an order shutting down all wells in the giant Spraberry field until all casinghead gas produced in the field can be devoted to one of the beneficial uses prescribed by law.

20. 1953 - Texas Supreme Court holds that Spraberry shut-down order of March 25, 1953, was not a proper exercise of the Railroad Commission's authority.

21. 1953 - Railroad Commission alters order for Spraberry field by shutting in all wells in field for 20 days per month and fixing the field allowable in terms of market outlet for casinghead gas.

22. 1966 - Railroad Commission adopts statewide rule governing offshore allowable, allowing increases over onshore production to make offshore production equitable, considering unusual operating conditions for the offshore areas.

23. 1973 - Railroad Commission issues special order requiring every natural gas utility to file with the Railroad Commission its curtailment program for natural gas by February 12, 1973. Also provided for priority curtailment program for each gas utility until such time as the Railroad Commission had approved the curtailment program. (Early indication of lack of deliverable volume shown by forms filed with the Railroad Commission.)

24. 1975 - Supreme Court of Texas upholds a Railroad Commission order, holding Railroad Commission did not have jurisdiction to inquire into the effect on the public interest of contracts entered into by Lo-Vaca with specific customers at a time when it was unable to fulfill its contractual delivery obligations to two cities and a river authority. The Railroad Commission also could not require Lo-Vaca to apportion or share the gas in the Lo-Vaca system.

25. 1975 - The Railroad Commission issues a special order adopting rules and regulations pertaining to out-of-state sales of gas produced from publicly owned and leased minerals.

26. 1975 - The Railroad Commission issues a special order amending earlier rules and requiring annual well status reports on gas wells producing liquid hydrocarbons on modernized, machine-generated Form G-10. (Inflated G-10 forms still a problem, 1984.)

27. 1975 - Supreme Court of Texas upholds a Railroad Commission order establishing priorities for gas deliveries by gas utilities.

28. 1976 - Railroad Commission holds a statewide market demand hearing to review market demand regulation of natural gas production, recognizing the need for modernizing market demand determinations and allowables in order to provide a more realistic relationship of demand to allowables.

29. 1977 - Texas Legislature grants eminent domain powers for underground storage of gas and designates Railroad Commission as the agency that will determine, supervise, and classify all storage reservoirs to establish a better year-round supply for residential, commercial, and industrial gas customers.

30. 1977 - Legislature creates Texas Energy Advisory Council designed to articulate a state energy policy and facilitate extensive research and development in energy-related matters of particular importance to the Texas energy situation.

31. 1977 - U.S. Court of Appeals affirms Federal Power Commission (FPC) orders requiring all large producers of natural gas and their affiliates to submit detailed information concerning their exploration and development activities on an annual basis.

32. 1978 - U.S. Supreme Court affirms an FPC order requiring an application to abandon service once gas has begun to flow in interstate commerce from a field subject to a certificate of unlimited duration.

33. 1978 - Railroad Commission adopts rule prohibiting the escape of gas from a well into the air after 10 days from when the gas is first encountered, unless it is proven to be prudent and necessary.

34. 1978 - Federal court holds that there are two distinct and separate gas markets (interstate and intrastate) and sales of intrastate gas are irrelevant to a determination of the fair market value of gas irrevocably committed to interstate commerce.

35. 1978 - Railroad Commission adopts the gas market demand rule to allow determination of gas market demands and provide procedures for gas well allowable allocations and ratable take between gas wells and fields in Texas.

36. 1978 - Texas Court of Appeals rules that a proper method of determining the market value of gas produced during a period is to compute a weighted average market price for all gas sold by all producers in the area.

37. 1978 - Railroad Commission issues rules pursuant to the Natural Gas Policy Act (NGPA).

38. 1979 - Railroad Commission adopts statewide rule stating that no operator producing gas for sale from publicly owned or leased minerals may sell or contract to sell to any person, corporation, or other entity for ultimate use outside the State of Texas unless the Railroad Commission grants an exception.

39. 1979 - Senate bill grants Railroad Commission explicit authority to adopt rules necessary to implement federal programs such as energy determinations under NGPA and Underground Injection Control.

40. 1979 - Railroad Commission adopts revised and simplified NGPA determination procedures under authority that governs request for certain category determinations.

41. 1979 - Establishment of Texas Energy and Natural Resources Advisory Council (TENRAC) to adopt and assess Texas energy and natural resources policy, review existing and proposed federal action to determine its impact, recommend legislation, etc.

42. 1979 - Railroad Commission officially approves a long-negotiated settlement plan for Lo-Vaca and its approximately 400 Texas customers. Plan establishes new company, Valero Energy Corporation, and the undertaking of a massive $180 million to $230 million gas search program to supply Valero with gas at discounted prices. Includes dropping of more than $1.6 billion in law suits and other legal claims against Lo-Vaca by its customers for alleged breach of gas supply contracts dating back to the early 1970's.

43. 1980 - In an emergency rule, Railroad Commission adopts an amendment to the Curtailment Program for Natural Gas that directs intrastate gas companies to curtail all sales and deliveries to out-of-state markets under surplus sales clauses when the needs of their Texas customers are not met.

44. 1980 - Rule providing that NGPA applications may be reviewed and approved without a hearing, although hearings will be held when an examiner's recommendation is adverse to the applicant, when an intervention in protest is filed, when applicant makes a written request for a hearing, or when the staff determines a hearing is necessary.

APPENDIX III. Texas natural gas transmission industry during the 1970's.

This period is of particular interest because it covered market disruptions in both intrastate and interstate markets. Surpluses that had characterized the natural gas industry for 40 years disappeared. Interstate markets experienced years of severe curtailment during much of the period owing to the freezing of prices and subsequent loss of supply. Intrastate gas pipeline companies, faced with declining availability of gas in the Gulf Coast area, found relief by increasing their share of gas in the Permian Basin (Texas Railroad Commission Districts 8, 8A, and 7C).

The Texas Railroad Commission (TRRC) regulates the production, transmission, and disposition of oil and gas within Texas. Conservation of resources and protection of correlative rights, twin goals of the TRRC, have been sought through well spacing rules, production allowables, prohibition of gas flaring, and prorationing of gas production.

Although possessing appellate jurisdiction over local distribution companies and original jurisdiction over gathering and transmission companies, the TRRC has chosen not to intervene in most pipeline investment decisions and gas sales transactions, preferring to depend on competition in the industrial market to ensure efficient investment decisions and fair wellhead gas prices. The intrastate pipeline industry in Texas was dominated by a group of 11 companies that operated 69 percent of all intrastate pipelines. They purchased 56 percent of the intrastate wellhead gas and supplied 73 percent of the gas used by large industrial firms. Competition between these large pipeline companies performed relatively well in achieving the regulatory aims of the TRRC.

During the 1970's the principal concerns of the Texas gas pipeline industry were to secure additional gas supplies in a rapidly expanding market and to operate profitably at a time of rapidly rising gas costs. Difficulties are reflected in the varied performance of five of the largest companies during the decade.

Delhi is primarily a large gas gatherer that purchases gas at the wellhead and makes most of its sales to other pipelines. During the 1970's, Delhi increased the total length of its system by 700 percent. It was not one of the major transmission companies when the decade began, but it grew rapidly by taking advantage of the opening of new supply areas and the added deliverability in established areas that occurred as infill drilling campaigns were launched. Delhi was not bound by long-term fixed contracts, so in a period of rapidly rising prices and costs, the company was able to profitably obtain gas from different areas and sources.

Houston Pipe Line Company, a major company at the beginning of the 1970's in sales and in miles of pipe in service, profited from having most of its operations somewhat more geographically contained than the other major companies. Owing to the location of its market in the Houston area and to the fact that a large portion of its sales were to industrial users, it was relatively easy for the company to renegotiate contracts during the time of rapidly increasing prices and costs so that its profit margins did not suffer. Although the company bought most of its gas at the wellhead in 1970, by the end of the decade it was purchasing nearly 50 percent of its volume from other pipeline companies. Profit margins suffered during 1972-1973 when gas costs increased dramatically, but they recovered soon after.

Lone Star is both a gathering and transmission company and a residential distributor. It began the 1970's with 7,129 miles of pipe. In 1980 this had grown to slightly over 7,400 miles. It purchased 93 percent of its volume at the wellhead in 1970; by 1980, this had decreased only slightly to 89 percent. Because of its status as a major distributor, Lone Star was able to maintain its earnings margin at a time (1973-75) when many of its competitors could not.

United Texas Transmission Company began the decade purchasing 94 percent of its volume of gas at the wellhead; in 1980, 44 percent of its volume was supplied by other pipelines. The early part of the decade saw profit margins squeezed by rapidly rising gas costs. Unlike some other pipeline companies whose sales are principally to industrials, this company was unable to achieve acceptable profit margins until the latter part of the 1970's. It now enjoys a very healthy profit margin.

Valero Transmission Company, formerly named Lo-Vaca Gathering Company, along with Valero Energy Corporation was spun off from the Coastal Corporation in December 31, 1979. Circumstances leading up to this spinoff were primarily rooted in Lo-Vaca having signed long-term contracts in the 1960's to supply many Texas cities, including Austin, San Antonio, and Corpus Christi, at the flat rate of 20 cents per Mcf. When the price of purchased gas exceeded the sales price in 1973, it became apparent that Lo-Vaca could not long continue. Limited supplies were apparent when, during the peak demand period accompanying the severe winter conditions of 1972-73, deliveries were curtailed 13 times. Regulatory and court appearances and decisions allowed Lo-Vaca to establish a system of pass-through charges so that deliveries could be made to the different cities. The spinoff and name change occurred as a final settlement of the issue and the establishment of Valero Transmission Company as a viable, independent utility.

The negative revisions of gas reserves affected these companies to varying degrees, depending on their markets and supply bases. Those dealing principally with industrial users found it relatively easy to renegotiate contracts under the changed conditions that resulted from first oversupply, then undersupply, and finally oversupply. Since all these companies deal primarily with intrastate gas, the rapidly increasing cost of the resource was related directly to the reserves of the commodity. However, those companies like Lo-Vaca that found themselves short of reserves, owing in part to the negative revisions of their reserves, were forced to purchase more expensive gas, and they experienced considerable difficulties in passing through these extra costs to city-run utilities.

APPENDIX IV. Gas prorationing.

All natural gas fields in the state are included in the prorationing activities of the Texas Railroad Commission (TRRC). The aim is to allocate and adjust production so that each producing gas well in the state would be allowed to produce at a rate that would be an equal proportion of the state's total demand based on acreage and deliverability formulas. Determination of allowable is made by the TRRC.

Calculations for this determination are based on data supplied by two forms dealing with deliverability (G-10) and total pipeline nominations (T-3). Producer forecasts (G-10) are compared with the product of deliverability multiplied by the days of the month. The lesser of these two is the adjusted G-10.* Pipeline nominations are compared with the monthly limit that has been preset by the TRRC. The lesser of these is the adjusted T-3. Adjusted T-3 values are then divided by adjusted G-10 values. If the ratio is greater than 90 percent, the adjusted G-10 is taken as market demand; if it is less than 90 percent, the adjusted T-3 is the market demand.

Total field allowable* is then established for each field on the basis of the market demand plus or minus the third prior month's growth adjustments (subtracted if allowable exceeded production, added if allowable was less than production) plus or minus any changes in limited-status wells. A further adjustment for special conditions such as cold weather, etc., is allowed on the basis of a proration analyst's recommendation.

Individual well allowables within the field are based on deliverability tests (form G-10, which is required semiannually), acreage factors, or, not uncommonly, combinations of these. Some formulas are even based on bottom-hole pressures (BHP) or acres time BHP. Any of these parameters for an individual well is divided by the total field parameter, then multiplied by field demand, to give individual well allowable.

*Estimated production from special allowable wells, for example, increasingly higher water-cut, severely underproduced, and associated gas either as solution (casinghead) or gas cap (TRRC Rule 49B), is deducted from total field market demand before allowables are determined for the remaining wells.

APPENDIX V. History of Texas natural gas--production and reserves.*

Year	Gas-Well Gas Produced (Mcf)**	Percent of Total Gas	Casinghead Gas Produced** (Mcf)	Percent of Total Gas	Total Gas Produced** (Mcf)	Natural Gas Reserves as of Jan. 1 (MMcf)**	Reserves Total U.S. "Lower 48" (MMcf)**,***	Reserves Texas Percent of U.S. Total
1936	575,275,000	67	269,463,000	33	844,738,000			
1937	658,713,000	66	335,175,000	34	993,888,000			
1938	705,908,000	64	393,367,000	36	1,099,275,000			
1939	872,286,000	66	442,773,000	34	1,315,059,000			
1940	1,087,089,000	71	452,238,000	29	1,539,327,000			
1941	1,382,830,000	76	427,462,000**	24	1,810,292,000			
1942	1,508,794,000	79	402,328,000**	21	1,911,122,000			
1943	1,683,920,809	79	438,647,209	21	2,122,568,018			
1944	1,907,704,332	78	527,013,593	22	2,434,717,925			
1945	2,065,266,423	78	599,911,322	22	2,665,177,745			
1946	2,098,867,220	76	664,545,023	24	2,763,412,243	78,306,676		
1947	2,231,430,080	76	706,070,607	24	2,937,500,687	86,363,459		
1948	2,540,917,386	78	707,303,721	22	3,248,221,107	90,025,566		
1949	2,739,790,600	78	770,732,048	22	3,510,522,648	95,708,553		
1950	3,099,606,096	77	924,570,897	23	4,024,176,993	99,170,403		
1951	3,518,486,197	75	1,155,049,259	25	4,673,535,456	102,404,077		
1952	3,779,106,990	74	1,310,269,791	26	5,089,376,781	105,653,229		
1953	3,835,635,847	72	1,479,135,184	28	5,314,771,031	105,732,763		
1954	3,955,492,811	72	1,555,169,157	28	5,510,661,968	106,529,626		
1955	4,061,169,733	71	1,679,288,713	29	5,740,458,446	105,129,062**		

APPENDIX V (continued)

Year	Gas-Well Gas Produced (Mcf)**	Percent of Total Gas	Casinghead Gas Produced** (Mcf)	Percent of Total Gas	Total Gas Produced** (Mcf)	Natural Gas Reserves as of Jan. 1 (MMcf)**	Reserves Total U.S. "Lower 48" (MMcf)**,***	Reserves Texas Percent of U.S. Total
1956	4,196,274,738	70	1,808,459,532	30	6,004,734,270	108,287,548		
1957	4,209,022,841	70	1,827,840,669	30	6,036,863,510	112,728,750		
1958	4,383,259,164	72	1,666,868,115**	28	6,050,127,279	113,084,518		
1959	4,707,673,353	73	1,714,236,548	27	6,421,909,901	115,045,743		
1960	5,017,874,190	75	1,657,295,605**	25	6,675,169,795	120,475,783		
1961	5,126,897,899	75	1,667,118,864	25	6,794,016,763	119,489,393**		
1962	5,258,336,700	76	1,647,302,820**	24	6,905,639,520	119,838,711		
1963	5,530,700,927	77	1,682,973,822	23	7,213,674,749	119,503,798**		
1964	5,846,879,988	77	1,707,287,547	23	7,554,167,535	117,809,376**		
1965	6,132,764,258	78	1,721,780,862	22	7,854,545,120	118,855,055	252,376	47
1966	6,258,199,039	77	1,839,765,501	23	8,097,964,540	120,616,760	252,068**	48
1967	6,314,445,633	76	2,022,348,049	24	8,336,793,682	123,609,326	251,034**	49
1968	6,512,818,553	76	2,100,053,643	24	8,612,872,196	125,415,064	242,103**	52
1969	6,838,026,114	76	2,125,458,089	24	8,963,484,203	119,001,106**	230,344**	52
1970	7,204,522,710	76	2,245,335,308	24	9,449,858,018	112,392,622**	217,191**	52
1971	7,367,204,617	77	2,203,426,957**	23	9,570,631,574	106,352,993**	204,168**	52
1972	7,450,363,616	78	2,152,266,013**	22	9,602,629,629	101,472,108**	190,919**	53
1973	7,322,579,995**	78	2,018,102,992**	22	9,340,682,987**		95,042,043**	177,006**
1974	7,068,268,065**	79	1,839,160,750**	21	8,907,428,815**		84,936,502**	165,531**
1975	6,491,849,189**	81	1,560,262,733**	19	8,052,111,922**		78,540,717**	154,176**
1976	6,247,330,373**	81	1,460,988,470**	19	7,708,318,843**		71,036,854**	142,555**

APPENDIX V (continued)

Year	Gas-Well Gas Produced (Mcf)**	Percent of Total Gas	Casinghead Gas Produced** (Mcf)	Percent of Total Gas	Total Gas Produced** (Mcf)	Natural Gas Reserves as of Jan. 1 (MMcf)**	Reserves Total U.S. "Lower 48" (MMcf)**,***	Reserves Texas Percent of U.S. Total
1977	6,150,029,884**	81	1,414,605,290**	19	7,564,635,174**	64,651,410**	134,590**	48
1978	5,690,601,922**	80	1,386,498,376**	20	7,077,100,298**	62,157,836**	127,915**	49
1979	5,775,570,824	81	1,340,247,339**	19	7,115,818,163	54,600,235**	123,143**	44
1980	5,675,595,010**	81	1,322,296,207**	19	6,997,891,217**	51,610,771**	165,639†	(31)
1981	5,376,163,312**	80	1,356,878,719	20	6,733,042,031**	50,287,000**	176,385†	(29)
1982	4,721,572,710**	77	1,392,277,794	23	6,113,850,504**	50,469,000		
1983	4,227,636,672**	75	1,415,546,191	25	5,643,182,863**	49,757,000**		

* From Texas Railroad Commission (1983b)

** Declined from previous year

*** From American Gas Association

† From Department of Energy/Energy Information Administration

APPENDIX VI. Largest gas fields in Texas--Districts 2, 3, and 4.

District 2

County	Name of field	Year disc.	1968-1980 (Bcf)	Cum. gas-well gas 1983 (MMcf)	Formation	1983 prod. gas-well gas (MMcf)	Depth
Calhoun/Jackson	Appling	1935	27	348,698	Frio	982	6,000-9,300
De Witt	Arneckeville	1950	30	75,209	Wilcox/ Yegua	670	8,000-9,000 5,000
Refugio/Bee	Blanconia	1943	12	61,598	Frio	354	2,000-5,000
Lavaca	Borchers	1953	79	86,706	Frio	1,415	1,500-4,700
Bee/Karnes	Burnell	1944	204	461,227	Wilcox	1,869	6,000-7,500
Live Oak	Clayton	1944	54	221,103	Wilcox	1,454	8,000
Victoria	Cologne	1939	DNA*	76,294	Miocene/ Frio	568	500-4,500
De Witt	Cook, S	1963	46	79,202	Lower Wilcox		1,063
Live Oak	Elms	1957	30	64,054	Wilcox	347	6,900-7,900
Refugio	Fagan	1940	49	83,211	Frio	857	2,000-5,500
Jackson	Francitas	1938	DNA	146,222	Frio	356	7,300-8,600
Jackson	Ganado	1937	DNA	126,783	Miocene/ Frio	347	3,600-4,100 5,700-7,700
Live Oak	George West, W	1953	21	61,102	Wilcox	14,559	7,300-7,600
Refugio	Greta	1933	DNA	778,317	Miocene	2,641	1,500-5,000
Live Oak	Harris	1947	DNA	112,570	Wilcox	806	7,300-8,600
Bee	Heard Ranch	1939	145	235,532	Frio	2,512	4,700-8,000
De Witt/Victoria	Helen Gohlke	1950	75	122,145	Wilcox	1,009	1,300-8,200
Victoria	Helen Gohlke, SW	1953	32	63,864	Wilcox	313	8,500-8,600

APPENDIX VI

District 2 (continued)

County	Name of field	Year disc.	1968-1980 (Bcf)	Cum. gas-well gas 1983 (MMcf)	Formation	1983 prod. gas-well gas (MMcf)	Depth
Calhoun/Victoria	Heyser	1936	208	541,833	Frio/Greta	12,308	4,300-8,200
Refugio/Victoria	Huff	1951	DNA	143,546	Miocene/ Frio	1,475	3,400-5,200
Goliad	Karon	1957	75	126,681	Wilcox	6,039	7,000-7,500
Live Oak	Katz-Slick	1959	DNA	67,720	Wilcox	140	10,500
Jackson	La Ward, N	1941	DNA	108,180	Upper Frio	132	4,600
Refugio	Lake Pasture	1939	293	507,985	Frio	19,374	4,500-5,100
Calhoun	Magnolia Beach - Kellers Bay	1952	103	233,972	Frio	1,278	7,600-8,800
Calhoun	Matagorda Bay	1947	31	75,517	Miocene	419	4,300-4,500
Calhoun/Jackson	Maude B. Traylor, N	1957	38	87,450	Frio	341	8,800-9,300
Jackson	Mayo	1942	DNA	74,685	Frio	499	3,300-5,300
Refugio/Victoria	McFaddin	1930	155	261,249	Miocene	1,432	1,800-2,700
Victoria	McFaddin, N	1962	29	83,821	Miocene/ Frio	237	3,700-5,300
Jackson/Lavaca	Morales, N	1953	DNA	83,064	Frio/ Wilcox	581	3,600-10,000
Bee	Normanna	1930	82	177,496	Wilcox	1,236	8,800-9,600
Live Oak	Oakville-Wilcox	1946	DNA	68,774	Wilcox	144	6,800-7,500
Victoria	Placedo	1935	DNA	86,040	Frio	138	4,000-6,000
Lavaca	Provident City	1941	188	411,325	Yegua/ Wilcox	8,617	8,400-13,500

APPENDIX VI

District 2 (continued)

County	Name of field	Year disc.	1968-1980 (Bcf)	Cum. gas-well gas 1983 (MMcf)	Formation	1983 prod. gas-well gas (MMcf)	Depth
Bee	Ray-Wilcox	1943	DNA	69,231	Wilcox	338	7,700-8,200
Goliad	Sarco Creek	1938	37	70,074	Frio	1,549	2,800-4,700
Lavaca	Speaks, SW	1949	DNA	91,289	Wilcox	1,515	8,000-9,900
Jackson	Texana	1939	DNA	75,190	Frio	271	5,300-6,600
Live Oak	Tom Lune	1948	DNA	61,729	Queen	418	6,000±
Refugio	Tom O'Connor	1934	262	660,643	Frio	6,795	2,500-6,500
Bee	Tuleta, W	1937	31	74,696	Wilcox	835	7,500-9,500
Goliad/Karnes	Tulsita-Wilcox	1945	208	456,872	Wilcox	1,914	6,600-7,100
Jackson	West Ranch	1938	118	216,815	Miocene/ Upper Frio	5,572	3,500-6,000
Lavaca	Word, N	1944	47	97,692	Wilcox/ Edwards	21,168	7,000-14,000
De Witt	Yorktown	1942	71	82,131	Wilcox	609	9,900-11,500
	46 fields			8,299,537		127,496	
	Total District 2			13,271,025		333,942	
				62.5%		38.2%	

*DNA: data not available

From field data sheets (Petroleum Data Systems)
Fields with less than 60 Bcf cum. prod. (as of 12/83)
Prod. total 1983 = 88,073 MMcf 1983 = 26.4% of
District 2 annual prod. 1983 = 333,942 MMcf

Fields with more than 60 Bcf cum. prod. (as of 12/83)
Prod. total 1983 = 117,127 MMcf = 35.1% of
District 2 annual prod. 1983 = 333,942 MMcf

APPENDIX VI

District 3

County	Name of field	Year disc.	1968-1980 (Bcf)	Cum. gas-well gas 1983 (MMcf)	Formation	1983 prod. gas-well gas (MMcf)	Depth
Galveston	Alta Loma, W	1956	DNA*	63,845	Frio	212	12,000±
Brazoria	Alvin, S	1956	DNA	96,784	Frio	826	9,400-11,000
Chambers	Anahuac	1935	118	193,935	Frio/ Miocene	3,288	1,600-8,800
Harris	Bammel	1938	DNA	151,568	Cockfield	11	6,200-7,000
Matagorda	Bay City, E	1936	DNA	419,697	Frio	1,159	8,500-10,000
Wharton	Bernard, W	1947	DNA	94,855	Frio/ Yegua	748	2,700-7,600
Jefferson	Big Hill	1949	DNA	212,241	Miocene/ Frio	1,250	8,500-10,000
Jefferson	Big Hill, W	1952	DNA	83,010	Marginulina	432	7,600-8,100
Matagorda	Blessing	1940	37	126,055	Frio	441	8,250-10,500
Offshore State	Brazos Blk 386-S	1972	52	65,163	Miocene	2,564	7,700-10,500
Offshore State	Brazos Blk 405-B	1966	DNA	158,346	Miocene	1,736	7,800-10,800
Offshore State	Brazos Blk 440	1966	DNA	153,074	Miocene	1,868	6,700-8,500
Offshore State	Brazos Blk 446	1966	DNA	81,970	Miocene	1,476	7,000-9,400
Matagorda	Cavallo	1980	43	94,642	Marginulina	3,697	8,000-12,000
Colorado	Chesterville	1945	DNA	106,569	Wilcox	1,024	6,000-9,700
Brazoria	Chocolate Bayou	1941	123	883,165	Frio	1,770	9,500-11,500
Brazoria	Chocolate Bayou, S	1960	DNA	75,600	Frio	1,130	11,700-13,600
Brazoria	Clemens, N	1963	91	82,662	Frio	950	9,800-11,600

APPENDIX VI

District 3 (continued)

County	Name of field	Year disc.	1968-1980 (Bcf)	Cum. gas-well gas 1983 (MMcf)	Formation	1983 prod. gas-well gas (MMcf)	Depth
Matagorda	College Port	1939	159	325,399	Miocene	5,455	2,200-5,600
Colorado	Columbus	1944	DNA	240,166	Wilcox	2,373	7,300-9,700
Montgomery	Conroe	1931	DNA	133,311	Cockfield	276	4,600-5,000
Offshore State	Cove	1967	DNA	128,234	Miocene	916	7,600-8,600
Matagorda	El Gordo	1976	82	126,769	Miocene	11,308	11,900-13,000
Chambers	Fishers Reef	1940	118	165,994	Frio	3,300	8,000-8,700
Madison	Fort Trinidad	1970	140	173,906	Glen Rose	2,214	10,200-11,000
Galveston	Franks	1953	DNA	79,258	Frio	953	10,500-11,500
Galveston	Galveston Island	1949	62	78,347	Miocene	2,975	7,700-8,800
Lee	Giddings	1960	24	101,494	Austin Chalk	19,919	7,000-10,000
Galveston	Gillock, S	1948	DNA	106,470	Frio	5,444	7,500-9,000
Hardin	Hampton, S	1952	DNA	100,082	Yegua	109	7,600-8,100
Jefferson	Hamshire, W	1950	DNA	67,362	Frio	390	11,300-12,800
Offshore State	High Isl. Blk 14-L	1971	125	148,096	Miocene	6,238	9,300-10,400
Offshore State	High Isl. Blk 24-L	1969	478	288,686	Miocene	5,994	7,400-12,800
Offshore Federal	High Isl. Blk 160	1966	309	308,684	Miocene	0	DNA
Galveston	Hitchcock, NE	1957	DNA	85,955	Frio	738	7,000-9,000
Fort Bend/ Harris/Waller	Katy	1935	4,219	6,381,834	Wilcox	165,757	5,500-10,500
Galveston	Lafittes Gold	1971	52	61,881	Miocene	3,452	8,000-10,000
Colorado/Wharton	Lissie	1954	DNA	64,572	Wilcox	538	9,400-9,700

APPENDIX VI

District 3 (continued)

County	Name of field	Year disc.	1968-1980 (Bcf)	Cum. gas-well gas 1983 (MMcf)	Formation	1983 prod. gas-well gas (MMcf)	Depth
Brazoria	Lochridge	1936	DNA	62,959	Miocene	175	4,700-6,200
Wharton	Louise, N	1943	DNA	76,254	Miocene/ Frio	396	2,200-4,600
Jefferson	Lovells Lake	1938	135	179,802	Frio	555	7,600-7,800
Grimes/Madison	Madisonville	1946	DNA	139,120	Clarksville	1,679	8,200-9,300
Matagorda/Wharton	Magnet Withers	1936	487	895,784	Miocene/ Upper Frio	6,435	3,000-6,600
Brazoria	Manor Lake	1955	DNA	120,661	Frio	107	9,800-10,000
Matagorda	Markham, N Bay City, N	1938	DNA	363,719	Frio	454	8,500-8,600
Jefferson	Marrs McLean	1954	DNA	281,070	Frio	852	9,800-11,200
Harris	Milton, N	1963	DNA	139,381	Wilcox	3,482	9,800-13,100
Brazoria	Old Ocean	1934	1,472	2,595,675	Frio	51,268	9,300-10,800
Matagorda	Palacios	1937	DNA	215,438	Frio	962	7,800-8,900
Matagorda	Pheasant	1956	DNA	108,077	Frio	185	8,700-9,100
Matagorda	Pheasant, SW	1959	DNA	81,011	Frio	1,044	11,200-11,700
Brazoria	Pledger	1925	892	1,472,044	Miocene/ Frio	4,462	4,600-7,700
Galveston	Point Bolivar, N	1966	281	341,744	Frio	8,648	12,200-13,000
Jefferson	Port Acres	1957	DNA	290,522	Frio	109	9,200-10,600
Jefferson	Port Arthur	1958	DNA	74,191	Frio	0	12,000
Jefferson/Orange	Port Neches, N	1946	67	344,733	Frio/ Hackberry	887	7,900-8,500

APPENDIX VI

District 3 (continued)

County	Name of field	Year disc.	1968-1980 (Bcf)	Cum. gas-well gas 1983 (MMcf)	Formation	1983 prod. gas-well gas (MMcf)	Depth
Liberty	Raywood	1953	DNA	107,215	Yegua	1,009	10,600-11,700
Chambers	Redfish Reef	1940	209	266,158	Frio/ Miocene	5,742	3,000-11,000
Chambers	Redfish Reef, SW	1951	DNA	106,027	Frio	704	10,000-11,100
Austin	Sealy	1942	DNA	60,686	Wilcox	568	8,600-10,700
Colorado	Sheridan	1940	745	1,330,171	Wilcox	12,104	8,000-10,800
Galveston	Shipwreck	1976	125	143,458	Frio	2,316	8,000-12,500
Hardin	Silsbee	1936	DNA	74,672	Yegua	249	7,000-8,000
Matagorda	Sugar Valley	1946	DNA	68,782	Frio	641	8,700-10,200
Brazoria	Sweeney	1958	DNA	64,880	Frio	414	11,600-11,700
Galveston	Texas City Dike	1975	59	67,938	Frio	1,093	10,100-10,500
Harris	Tomball	1954	130	207,095	Miocene/ Vicksburg	5,243	3,300-5,500
Chambers	Trinity Bay	1950	87	145,336	Frio	947	7,000-8,300
Matagorda	Wadsworth	1951	DNA	108,364	Frio	749	9,600
Chambers	Willow Slough	1937	DNA	169,262	Frio	726	8,100-8,400
	70 fields			23,011,910		377,136	
	Total District 3			29,857,288		697,113	
				77%		54%	

*DNA: data not available

From field data sheets (Petroleum Data Systems)
Fields with less than 60 Bcf cum. prod. (as of 12/83)
Prod. total 1983 = 44,045 MMcf = 6.3% of
District 3 annual prod. 1983 = 697,112 MMcf

Fields with more than 60 Bcf cum. prod. (as of 12/83)
Prod. total 1983 = 339,022 MMcf = 48.6% of
District 3 annual prod. 1983 = 697,112 MMcf

APPENDIX VI

District 4

County	Name of field	Year disc.	1968-1980 (Bcf)	Cum. gas-well gas 1983 (MMcf)	Formation	1983 prod. gas-well gas (MMcf)	Depth
Nueces	Agua Dulce	1928	DNA*	957,097	Frio	11,270	4,500-8,900
Kleberg	Alazan, N	1958	897	1,230,397	Frio	8,439	6,400-9,800
Nueces	Arnold-David	1960	56	74,989	Frio	2,990	9,200-10,600
Kleberg	Borregos	1945	1,401	1,791,840	Frio/ Vicksburg	35,725	1,800-8,400
Nueces	Brayton	1944	DNA	99,839	Frio	508	6,600-7,000
Brooks	Cage Ranch	1946	DNA	68,095	Frio/ Vicksburg	881	6,900-8,000
Kenedy	Calandria	1952	39	104,761	Frio	20,973	4,000-9,200
Kenedy	Candelaria	1954	DNA	74,401	Frio	3,327	8,600
Nueces	Chapman Ranch	1941	DNA	84,646	Catahoula/ Upper Frio	476	3,000-4,200
Kleberg	Chevron	1954	DNA	205,863	Miocene/ Frio	250	6,400-7,200 7,500-9,500
Aransas	Copano Bay, S	1962	DNA	73,850	Frio	336	7,000-9,000
Nueces	Corpus Channel, NW	1956	DNA	68,089	Frio	248	8,800-11,100
Nueces	Corpus Christi, E	1953	DNA	70,075	Frio	86	6,200-6,300
Hidalgo	Donna	1949	DNA	164,034	Frio	3,047	5,200-8,100
Kenedy	El Paistle, Deep	1964	87	98,230	Frio	2,595	13,600-14,450
Nueces	Encinal Channel	1965	126	146,078	Frio	1,593	8,800-11,000
Brooks	Encinitas	1940	64	80,509	Vicksburg	1,442	8,200-8,500

APPENDIX VI

District 4 (continued)

County	Name of field	Year disc.	1968-1980 (Bcf)	Cum. gas-well gas 1983 (MMcf)	Formation	1983 prod. gas-well gas (MMcf)	Depth
Nueces	Flour Bluff	1936	331	199,723	Frio	1,521	6,000-7,000
Nueces	Flour Bluff, Deep, E	1940	DNA	171,483	Frio	1,220	9,300-9,900
Nueces	Flour Bluff, E	1940	DNA	138,112	Frio	709	6,600-9,300
Aransas	Fulton Beach	1947	DNA	151,648	Frio	330	6,900-7,100
Aransas	Fulton Beach, W	1951	DNA	106,232	Frio	321	6,100-6,500
(Nueces) Offshore State	GOM State-904	1957	DNA	90,331	Frio	4	7,700-8,900
Duval	Government Wells, N	1928	DNA	74,927+	Frio/Yegua/ Jackson/ Wilcox	578	7,600-8,200
Duval	Hagist Ranch	1932	108	254,059	Frio/ Wilcox	5,030	Shallow:750-2,100 > 7,000-10,000
Hidalgo	Hidalgo	1951	DNA	220,258	Frio	1,826	6,000-7,000
Cameron	Holly Beach	1960	69	108,414	Miocene	400	7,100-7,800
Zapata	J.C. Martin	1974	186	262,338	Lower Wilcox/ Lobo	21,992	6,700-9,800 most 8,000-9,000
Hidalgo	Jeffress	1960	149	176,864	Vicksburg	9,216	8,100-12,700
Brooks/Jim Hogg	Kelsey	1938	DNA	125,273	Frio	797	4,600-5,000
Starr/ Brooks/Jim Hogg	Kelsey, Deep	1944	141	172,344	Frio/Vicksburg/ Jackson	3,830	5,000-7,800
Starr/ Brooks/Jim Hogg	Kelsey, S	1938	262	128,172	Frio/ Vicksburg	1,848	5,300-7,200
Hidalgo	La Blanca	1936	151	273,177	Frio	2,726	6,500-9,500
Starr	La Copita	1948	52	106,446	Vicksburg	5,067	7,400-9,400

APPENDIX VI

District 4 (continued)

County	Name of field	Year disc.	1968-1980 (Bcf)	Cum. gas-well gas 1983 (MMcf)	Formation	1983 prod. gas-well gas (MMcf)	Depth
Nueces	Flour Bluff	1936	331	199,723	Frio	1,521	6,000-7,000
Nueces	Flour Bluff, Deep, E	1940	DNA	171,483	Frio	1,220	9,300-9,900
Nueces	Flour Bluff, E	1940	DNA	138,112	Frio	709	6,600-9,300
Aransas	Fulton Beach	1947	DNA	151,648	Frio	330	6,900-7,100
Aransas	Fulton Beach, W	1951	DNA	106,232	Frio	321	6,100-6,500
(Nueces) Offshore State	GOM State-904	1957	DNA	90,331	Frio	4	7,700-8,900
Duval	Government Wells, N	1928	DNA	74,927+	Frio/Yegua/ Jackson/ Wilcox	578	7,600-8,200
Duval	Hagist Ranch	1932	108	254,059	Frio/ Wilcox	5,030	Shallow:750-2,100 > 7,000-10,000
Hidalgo	Hidalgo	1951	DNA	220,258	Frio	1,826	6,000-7,000
Cameron	Holly Beach	1960	69	108,414	Miocene	400	7,100-7,800
Zapata	J.C. Martin	1974	186	262,338	Lower Wilcox/ Lobo	21,992	6,700-9,800 most 8,000-9,000
Hidalgo	Jeffress	1960	149	176,864	Vicksburg	9,216	8,100-12,700
Brooks/Jim Hogg	Kelsey	1938	DNA	125,273	Frio	797	4,600-5,000
Starr/ Brooks/Jim Hogg	Kelsey, Deep	1944	141	172,344	Frio/Vicksburg/ Jackson	3,830	5,000-7,800
Starr/ Brooks/Jim Hogg	Kelsey, S	1938	262	128,172	Frio/ Vicksburg	1,848	5,300-7,200
Hidalgo	La Blanca	1936	151	273,177	Frio	2,726	6,500-9,500
Starr	La Copita	1948	52	106,446	Vicksburg	5,067	7,400-9,400

APPENDIX VI

District 4 (continued)

County	Name of field	Year disc.	1968-1980 (Bcf)	Cum. gas-well gas 1983 (MMcf)	Formation	1983 prod. gas-well gas (MMcf)	Depth
Brooks/Jim Wells	La Gloria	1939	672	1,378,697	Frio/ Vicksburg	6,861	5,700-6,200
Kleberg/Nueces	Laguna Larga	1949	539	666,425	Frio	31,714	6,000-9,000
Zapata	La Perla Ranch	1958	15	73,768	Wilcox/ Queen	18,205	2,400-9,700
Hidalgo/Starr	La Reforma	1938	DNA	68,920	Frio/ Vicksburg	612	5,500-8,500
Webb	Laredo	1973	243	363,242	Lower Wilcox/ Lobo	32,959	5,200-9,200
Willacy	La Sal Vieja	1945	DNA	72,829	Frio	2,005	8,600-11,500
Brooks	Loma Blanca	1962	77	118,374	Frio/ Vicksburg	1,002	8,900-9,200
Zapata	Lopeno	1934	DNA	117,504	Queen/ Wilcox	1,581	2,000-10,300
Nueces	Luby	1937	DNA	275,788	Catahoula/ Frio	1,673	3,800-9,000
Duval/Webb	Lundell	1937	DNA	129,001	Queen/ Wilcox	2,647	1,500-8,100
Kleberg	Madero	1963	61	73,984	Frio	4,057	9,500
Kleberg	Madero, E	1968	85	91,894	Frio	947	9,100-9,500
Brooks	Mariposa	1945	DNA	69,159	Frio/ Vicksburg	498	8,900
Kleberg	May	1955	57	151,875	Frio	313	8,000-9,400
Hidalgo	McAllen	1938	129	374,653	Frio/ Vicksburg	2,104	5,700-10,400

APPENDIX VI

District 4 (continued)

County	Name of field	Year disc.	1968-1980 (Bcf)	Cum. gas-well gas 1983 (MMcf)	Formation	1983 prod. gas-well gas (MMcf)	Depth
Hidalgo	McAllen Ranch	1960	413	595,271	Vicksburg	22,228	9,300-14,200
Hidalgo	McCook, E	1970	55	73,646	Vicksburg	4,459	12,000-14,000
Hidalgo	Mercedes	1935	DNA	108,384	Frio	1,654	6,700-10,200
San Patricio	Midway, E	1960	127	84,906	Frio	5,840	9,200-13,000
Nueces	Mobil-David	1965	129	170,777	Frio	736	9,200-13,000
Hidalgo	Monte Christo	1953	62	168,248	Frio	18,159	7,400-9,500
Kenedy	Murdock Pass	1952	101	193,947	Marginulina/ Frio	669	7,200-7,300
Nueces	Mustang Island	1949	DNA	131,394	Frio	1,092	7,000-7,500
Aransas	Nine Mile Point	1965	DNA	62,762	Frio	2,123	10,900-11,900
San Patricio	Odem	1939	DNA	108,535	Miocene/ Frio	4,908	2,100-7,000
Nueces	Petronilla	1941	DNA	78,675	Frio	295	7,500-8,000
Hidalgo	Pharr	1949	DNA	167,430	Frio	701	9,700-10,600
Duval	Piedre Lumbre	1935	DNA	84,139	Jackson/ Wilcox	478	6,900-7,400
Brooks	Pita	1946	DNA	92,429	Frio	170	8,000-8,300
Brooks	Pita, NW	1975	68	79,504	Upper Frio/ Miocene	2,219	5,500-7,800
San Patricio	Plymouth	1935	DNA	61,891	Frio	494	1,400-5,600
Nueces	Redfish Bay - Mustang Island	1949	98	393,843	Frio	1,836	6,800-7,200
Starr	Rincon	1938	DNA	81,000	Frio	1,356	3,300-4,200

APPENDIX VI

District 4 (continued)

County	Name of field	Year disc.	1968-1980 (Bcf)	Cum. gas-well gas 1983 (MMcf)	Formation	1983 prod. gas-well gas (MMcf)	Depth
Starr	Rincon, N	1940	125	274,769	Frio/ Vicksburg	3,841	2,900-8,300
Kenedy	Rita	1949	112	128,180	Miocene/ Frio	4,408	3,400-9,300
Kleberg	Samedan	1979	DNA	86,890	Frio	22,726	5,000-8,900 10,300-12,100
Hidalgo	San Carlos	1953	DNA	235,046	Frio	1,121	7,100-7,800
Brooks/Hidalgo	San Salvador	1935	DNA	256,529	Frio	2,914	6,100-9,000
Brooks	Santa Fe, E	1959	DNA	94,505	Frio	2,578	7,900-8,400
Hidalgo	Santellana, S	1957	DNA	66,753	Frio/ Vicksburg	353	7,900-8,500
Kenedy/Kleberg	Sarita	1948	187	228,785	Miocene/ Frio	4,686	1,900-8,300
Kenedy	Sarita, E	1967	DNA	74,269	Frio	1,439	1,200-1,500
Nueces	Saxet	1923	DNA	117,943	Miocene/ Frio	936	1,600-4,000
Jim Wells/Kleberg	Seeligson	1938	976	1,391,384	Frio/ Vicksburg	24,897	4,300-7,400
Duval	Sejita	1942	113	253,545	Yegua/ Jackson	3,833	5,200-7,300
Duval	Seven Sisters, E	1961	DNA	127,366	Wilcox	38,929	9,400-10,100
Kenedy	Stillman	1961	124	186,102	Frio	6,474	5,600-12,500
Jim Wells/ Kleberg/Nueces	Stratton	1937	1,244	1,512,301	Frio/ Vicksburg	21,757	4,000-8,300
Starr	Sun	1938	DNA	109,724	Frio	2,259	3,800-5,100

APPENDIX VI

District 4 (continued)

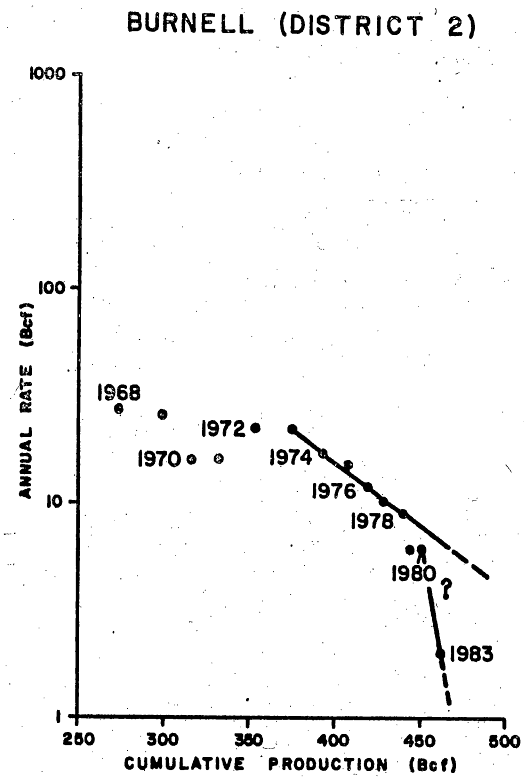
County	Name of field	Year disc.	1968-1980 (Bcf)	Cum. gas-well gas 1983 (MMcf)	Formation	1983 prod. gas-well gas (MMcf)	Depth
Starr	Sun, N	1941	DNA	111,164	Frio/ Vicksburg	5,658	3,900-5,500
Hidalgo	Tabasco	1952	148	153,861	Frio	5,167	5,800-8,600
Jim Hogg/ Webb	Thompsonville, NE	1959	357	589,026	Wilcox	4,608	7,400-12,700
Jim Wells/Kleberg	Tijerina-Canales-Blucher (T.C.B.)	1942	347	469,150	Frio/ Vicksburg	12,366	6,800-11,200
Brooks	Viboras	1949	DNA	1,837,236	Frio	46,181	6,300-7,500 8,000-8,800
Nueces/San Patricio	White Point, E	1938	83	242,639	Miocene/Frio/ Vicksburg	4,397	2,500-12,400
Willacy	Willamar, W	1941	DNA	102,234	Miocene	410	4,900-6,300
Kleberg	Yeary	1953	82	173,254	Frio	1,373	8,300-10,700
Jim Wells/Kleberg	Zone 21-B Trend	1974 (created)	969	2,288,620	Frio/ Vicksburg	48,687	6,300-7,300
	92 fields			26,029,763		600,194	
	Total District 4:			33,747,030		981,353	
				77.1%		61.2%	

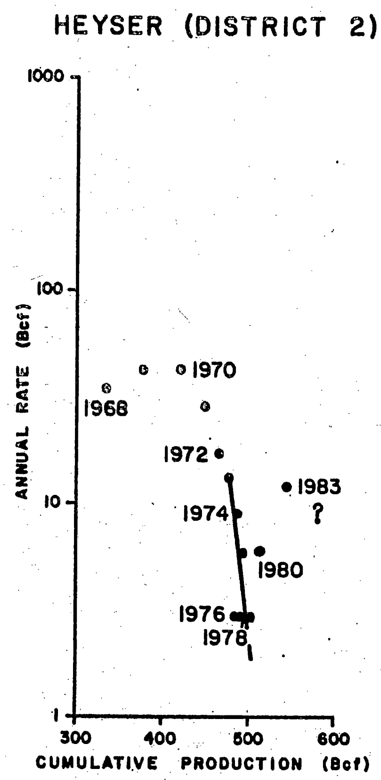
*DNA: data not available

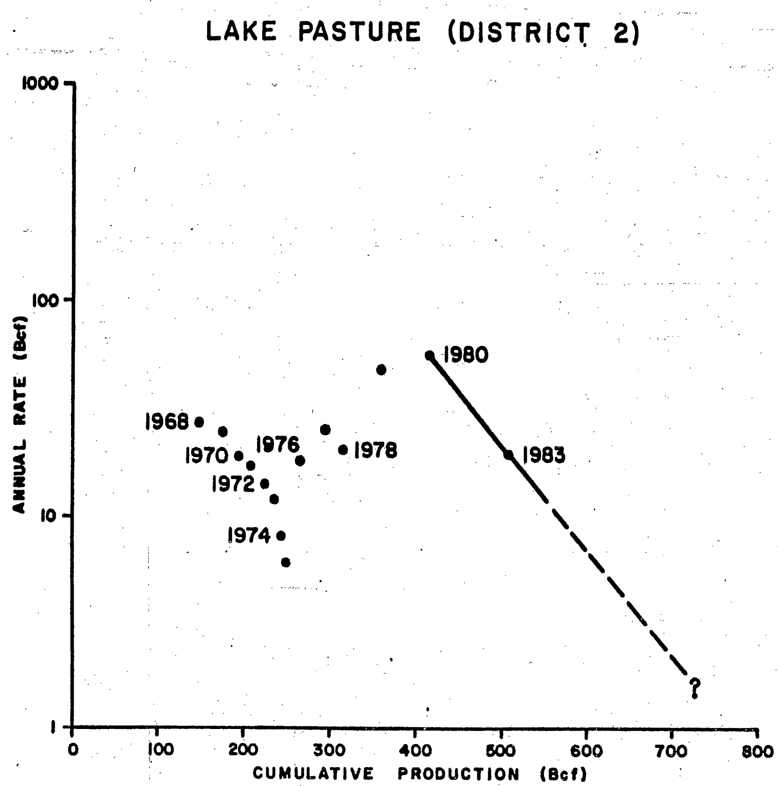
From field data sheets (Petroleum Data Systems)
Fields with less than 60 Bcf cum. prod. (as of 12/83)
Prod. total 1983 = 53,289 MMcf = 5.4% of
District 4 annual prod. 1983 = 981,353 MMcf

Fields with more than 60 Bcf cum. prod. (as of 12/83)
Prod. total 1983 = 425,789 MMcf = 43.4% of
District 4 annual prod. 1983 = 981,353 MMcf

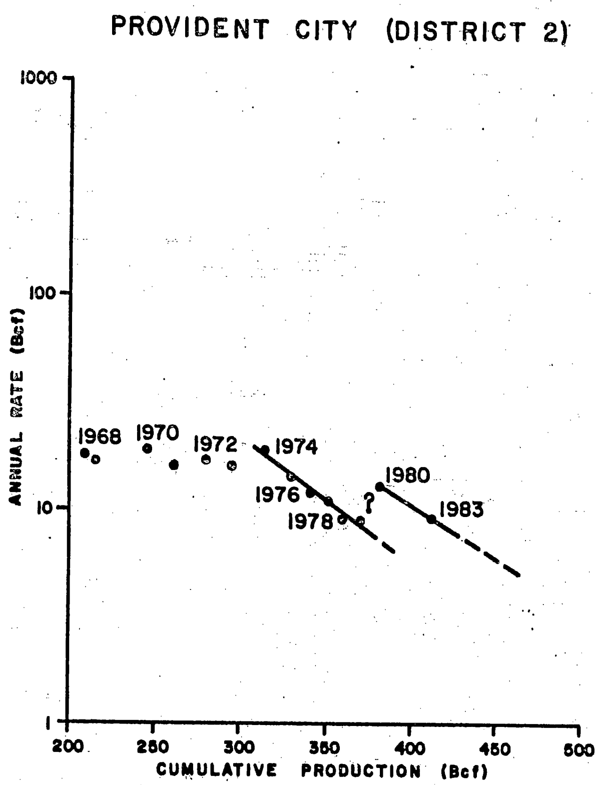
APPENDIX VII. Decline curve plots for largest fields--Districts 2, 3, and 4.

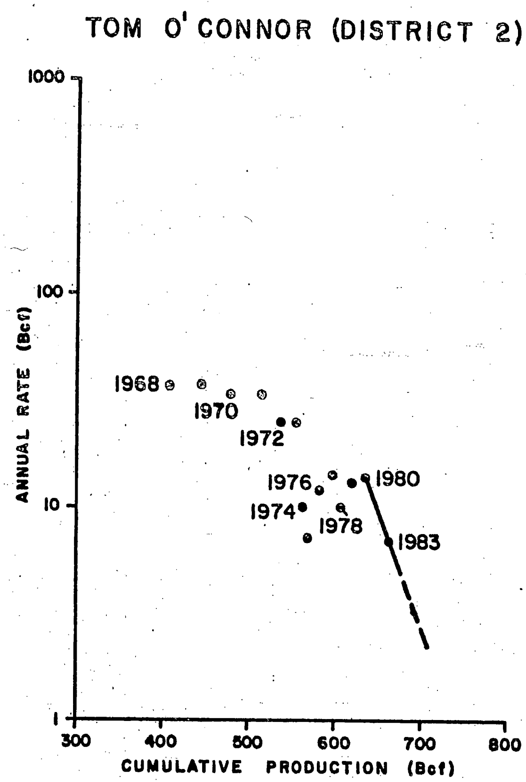


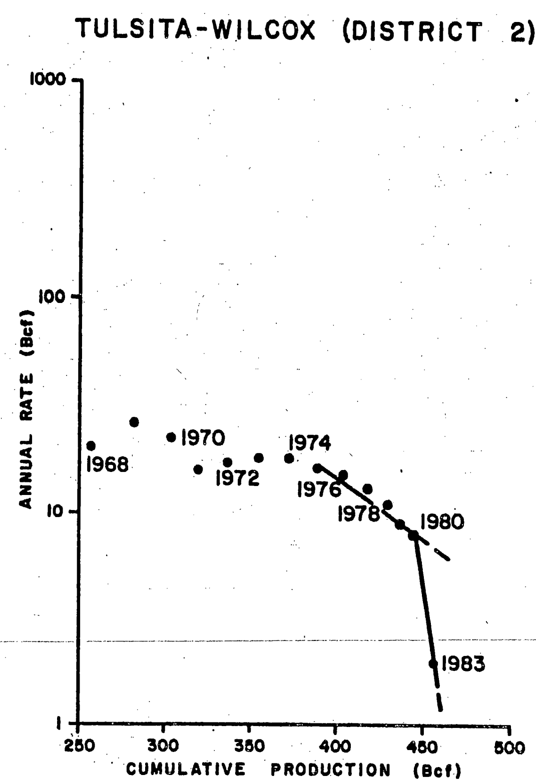




QA4067

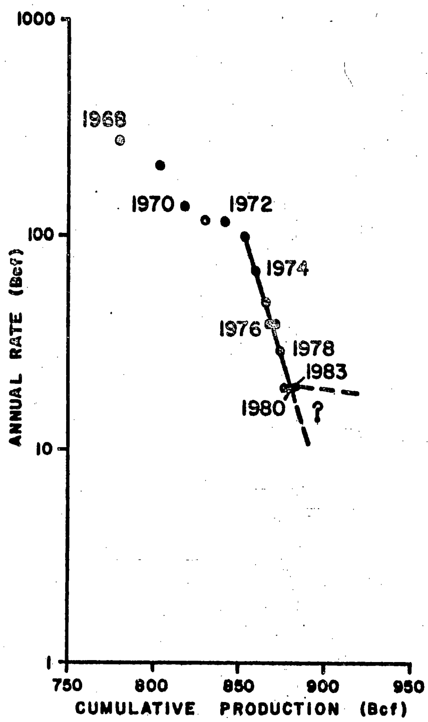

PROVIDENT CITY (DISTRICT 2)
ANNUAL RATE (Bcf)
1000
100
10
1
1968
1970
1972
1974
1976
1978
1980
1983
?
200
250
300
350
400
450
500
CUMULATIVE PRODUCTION (Bcf)


TOM O'CONNOR (DISTRICT 2)
ANNUAL RATE (Bcf)
1000
100
10
1
1968
1970
1972
1974
1976
1978
1980
1983
300
400
500
600
700
800
CUMULATIVE PRODUCTION (Bcf)

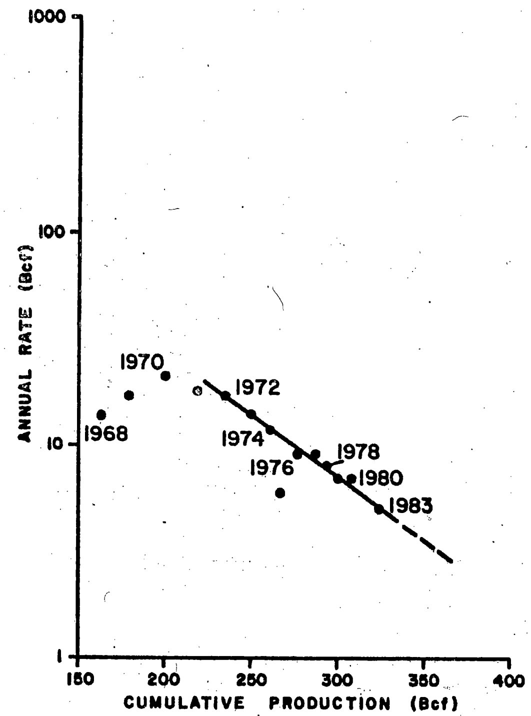

TULSITA-WILCOX (DISTRICT 2)
ANNUAL RATE (Bcf)
1000
100
10
1
1968
1970
1972
1974
1976
1978
1980
1983
250
300
350
400
450
500
CUMULATIVE PRODUCTION (Bcf)

QA4068

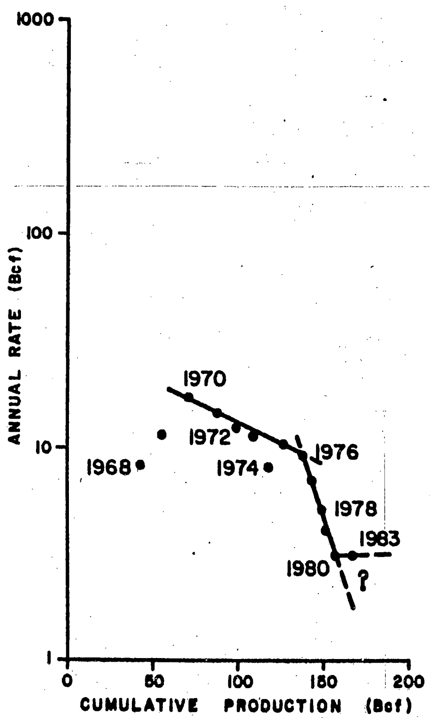
CHOCOLATE BAYOU (DISTRICT 3)



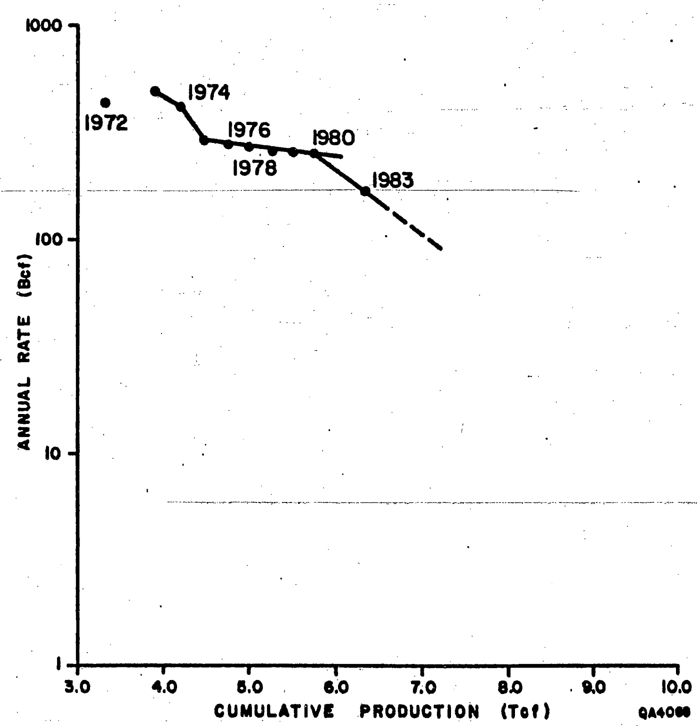
COLLEGE PORT (DISTRICT 3)

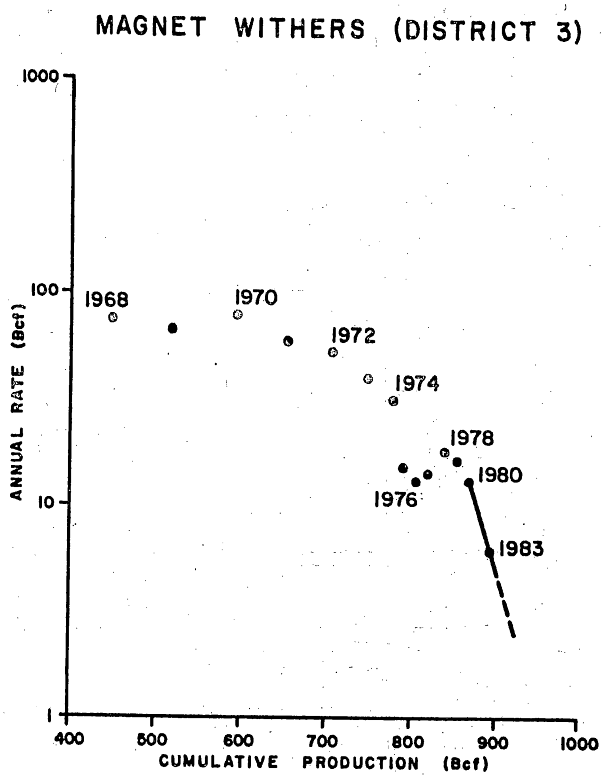


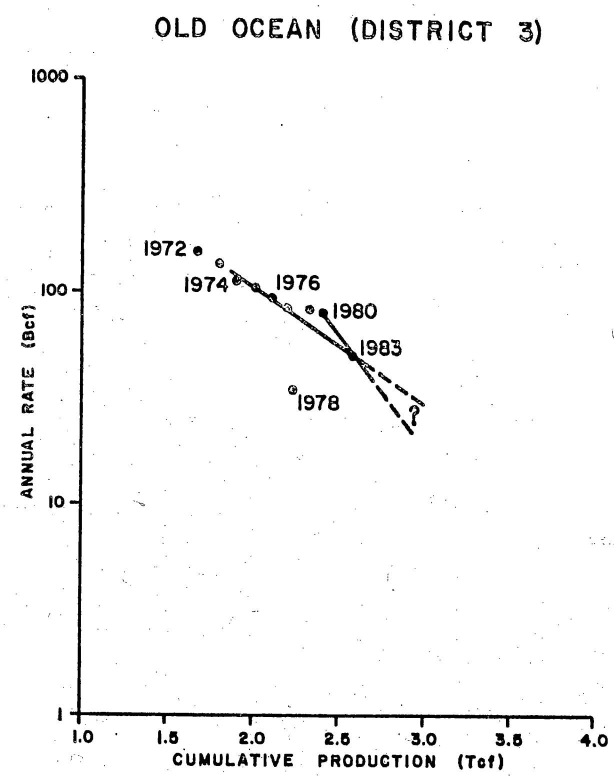
FISHERS REEF (DISTRICT 3)

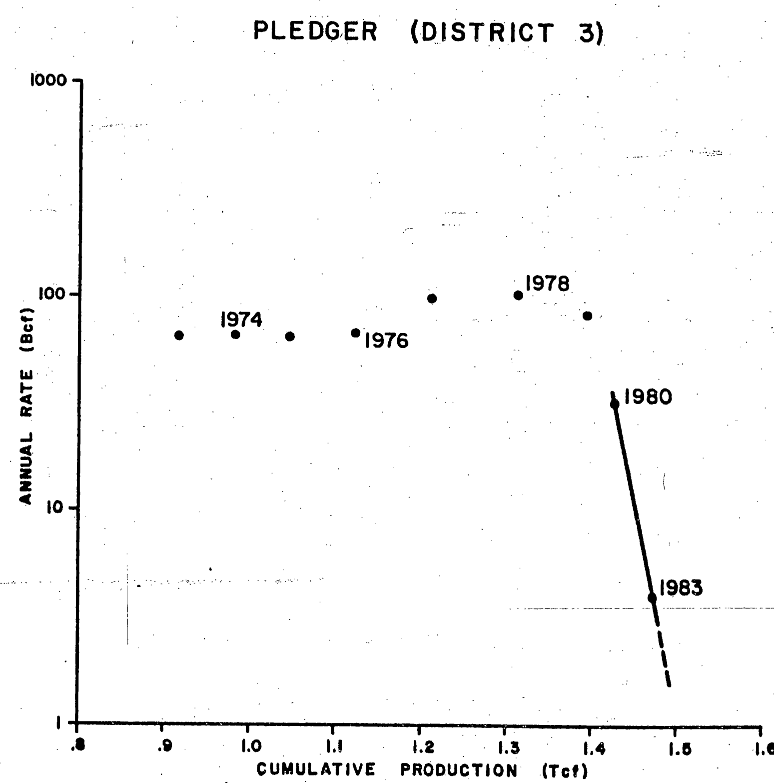


KATY (DISTRICT 3)



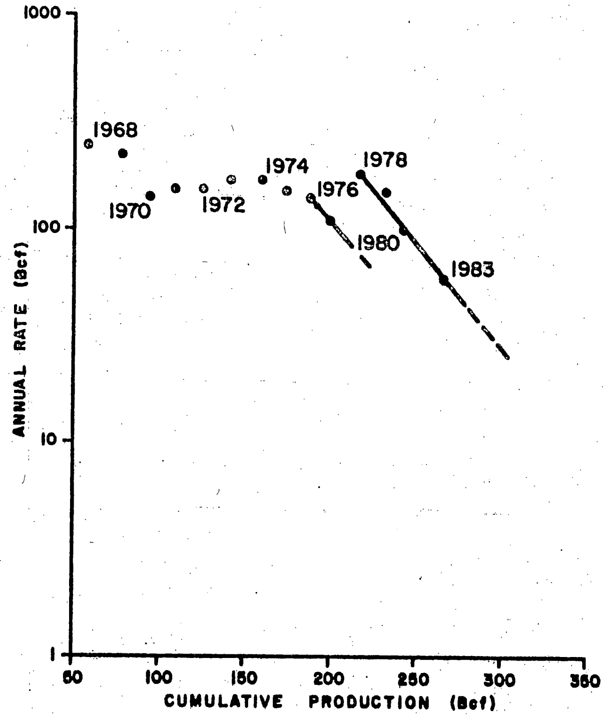

MAGNET WITHERS (DISTRICT 3)
1000
100
10
1
ANNUAL RATE (Bcf)
1968
1970
1972
1974
1976
1978
1980
1983
400
500
600
700
800
900
1000
CUMULATIVE PRODUCTION (Bcf)


OLD OCEAN (DISTRICT 3)
1000
100
10
1
ANNUAL RATE (Bcf)
1972
1974
1976
1980
1983
1978
?
1.0
1.5
2.0
2.5
3.0
3.5
4.0
CUMULATIVE PRODUCTION (Tcf)

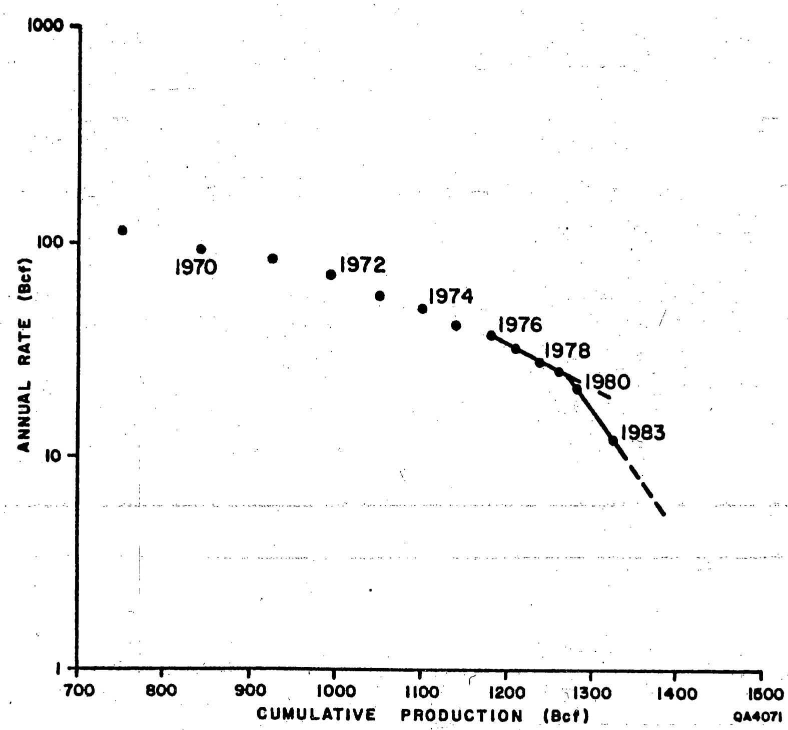

PLEDGER (DISTRICT 3)
1000
100
10
1
ANNUAL RATE (Bcf)
1974
1976
1978
1980
1983
.8
.9
1.0
1.1
1.2
1.3
1.4
1.5
1.6
CUMULATIVE PRODUCTION (Tcf)

QA4070

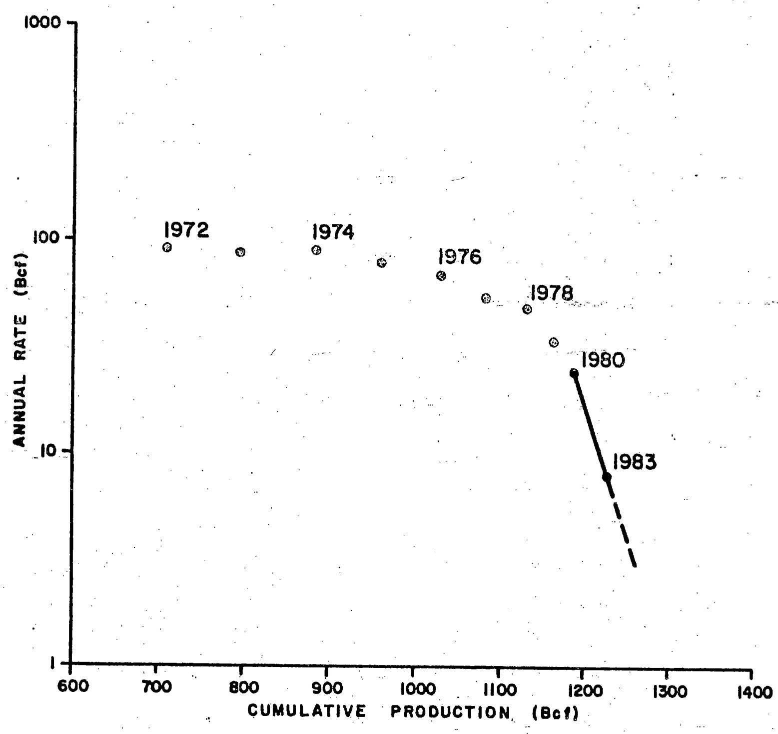
REDFISH REEF (DISTRICT 3)



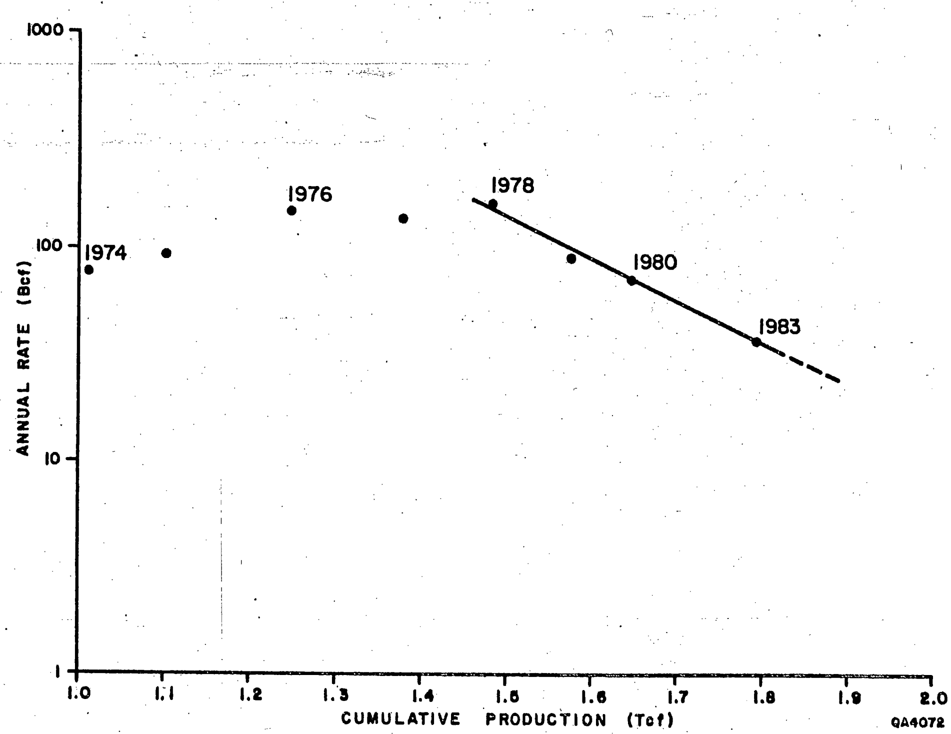
SHERIDAN (DISTRICT 3)

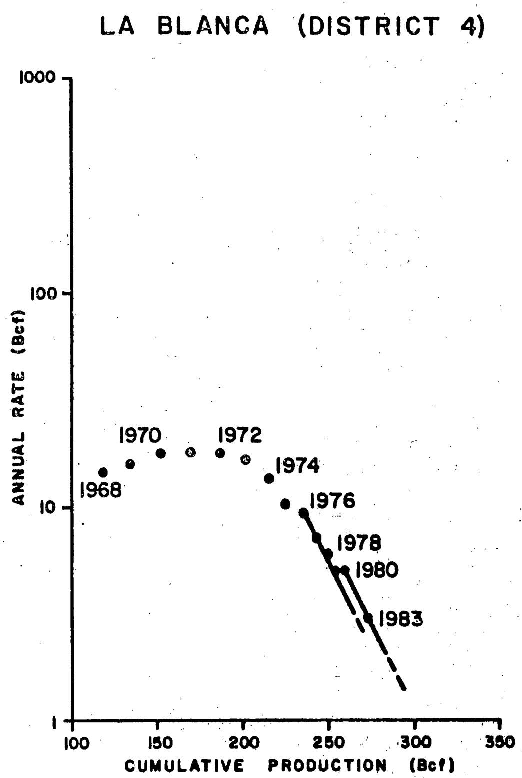


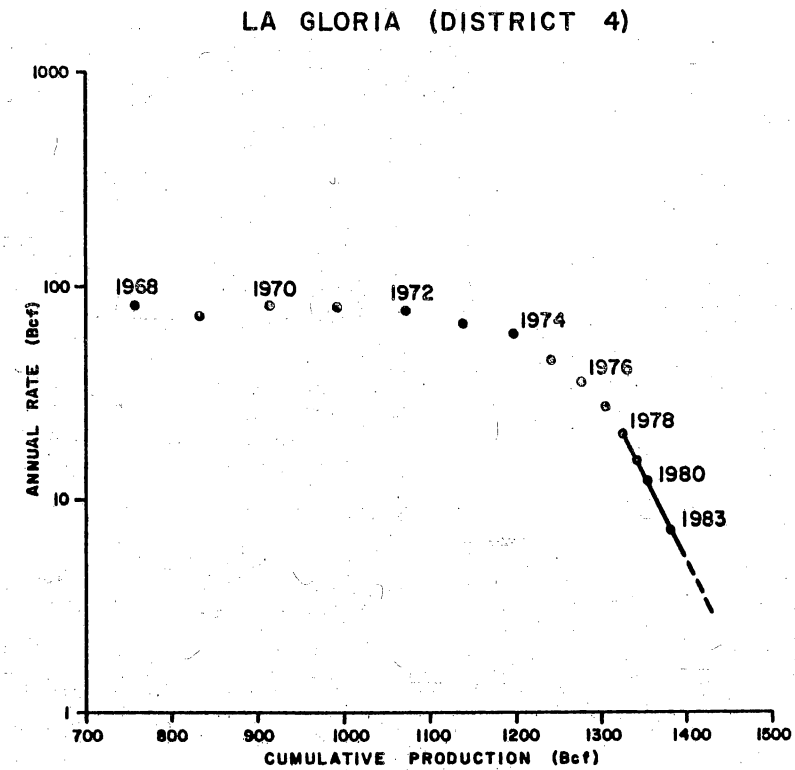
ALAZAN, N (DISTRICT 4)

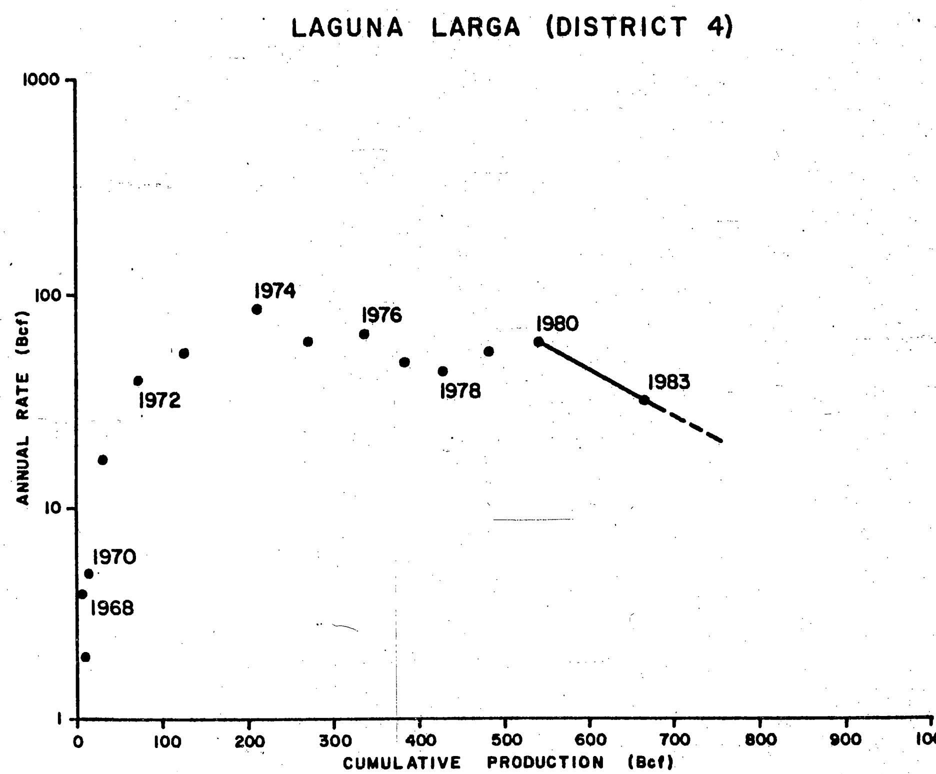


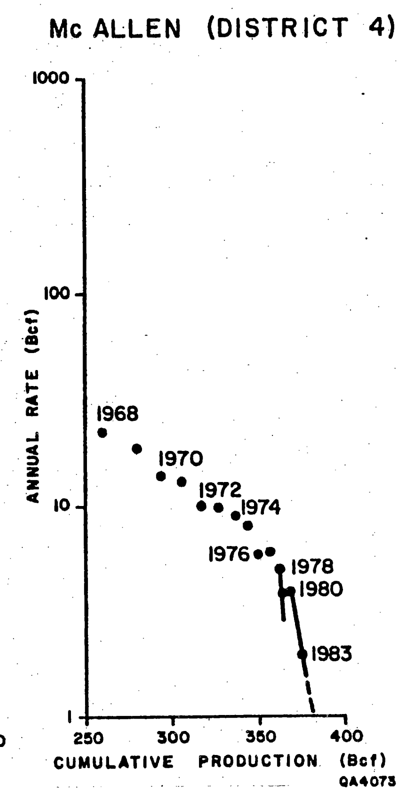
BORREGOS (DISTRICT 4)



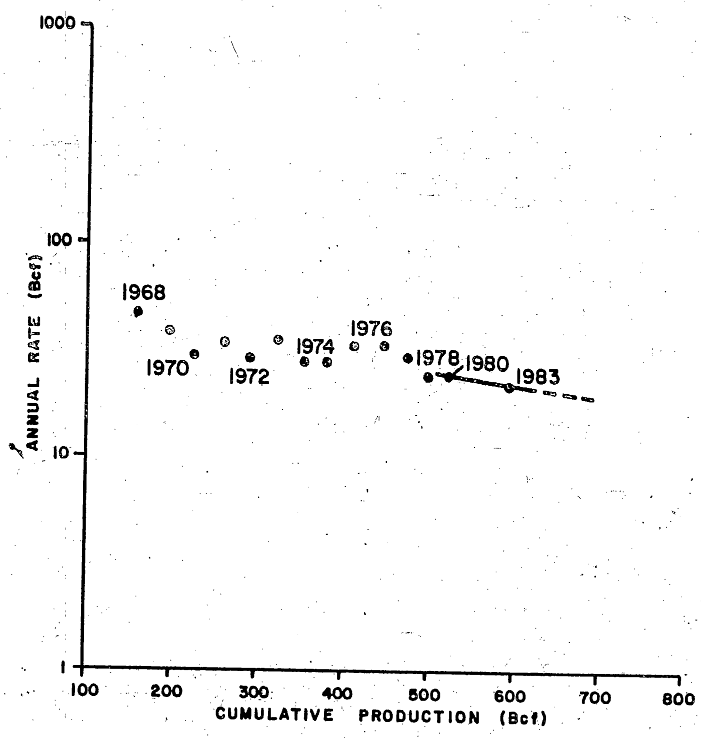

LA BLANCA (DISTRICT 4)
ANNUAL RATE (Bcf)
CUMULATIVE PRODUCTION (Bcf)
1968
1970
1972
1974
1976
1978
1980
1983


LA GLORIA (DISTRICT 4)
ANNUAL RATE (Bcf)
CUMULATIVE PRODUCTION (Bcf)
1968
1970
1972
1974
1976
1978
1980
1983

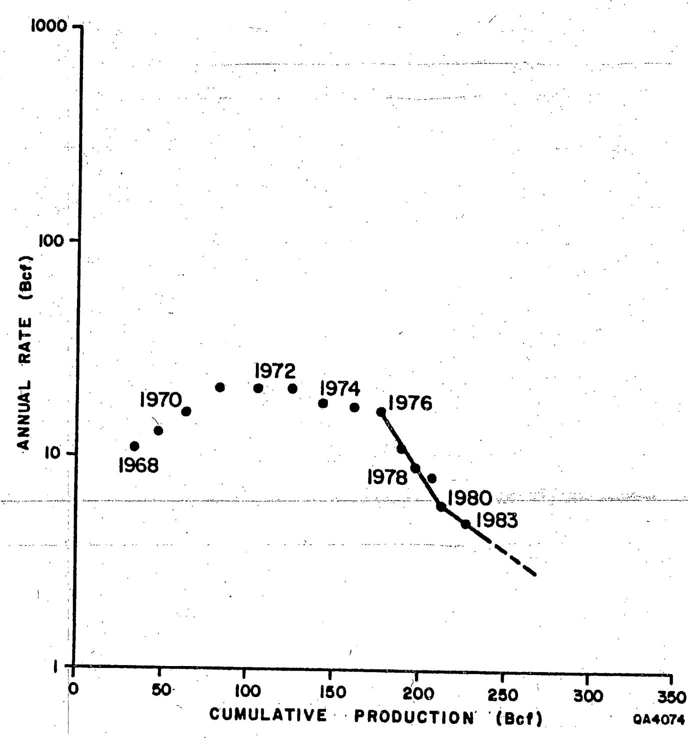

LAGUNA LARGA (DISTRICT 4)
ANNUAL RATE (Bcf)
CUMULATIVE PRODUCTION (Bcf)
1968
1970
1972
1974
1976
1978
1980
1983


Mc ALLEN (DISTRICT 4)
ANNUAL RATE (Bcf)
CUMULATIVE PRODUCTION (Bcf)
1968
1970
1972
1974
1976
1978
1980
1983
QA4073

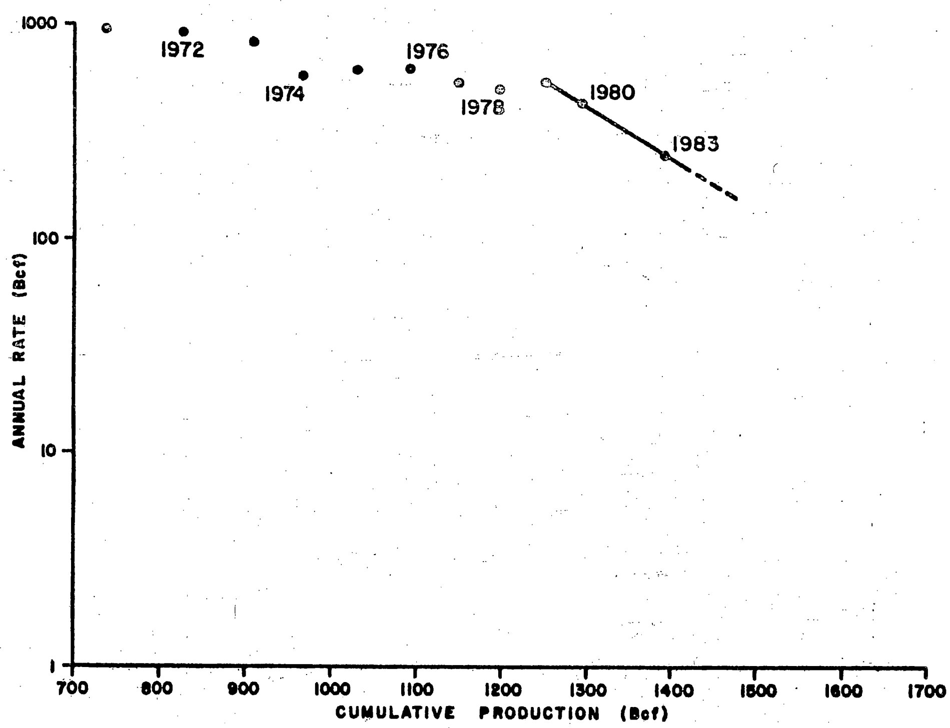
MCALLEN RANCH (DISTRICT 4)



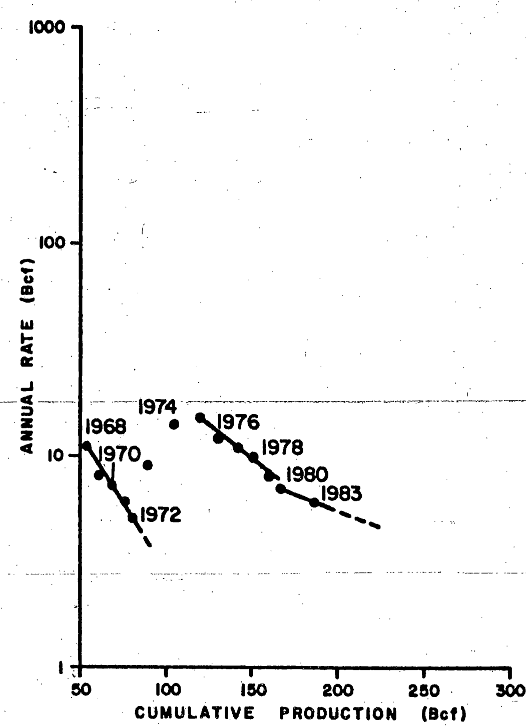
SARITA (DISTRICT 4)



SEELIGSON (DISTRICT 4)

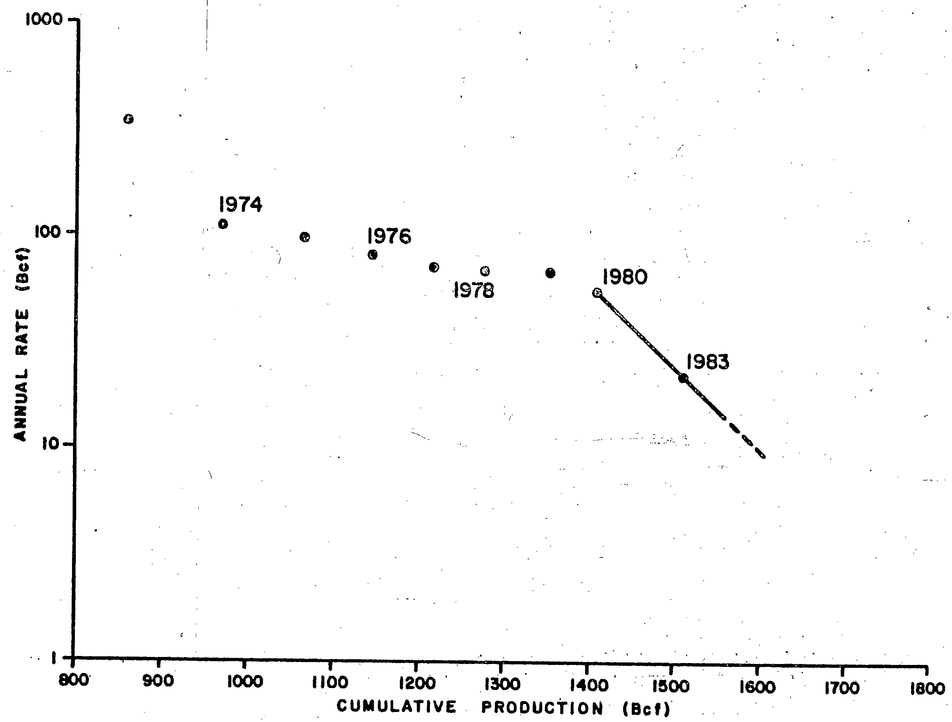


STILLMAN (DISTRICT 4)

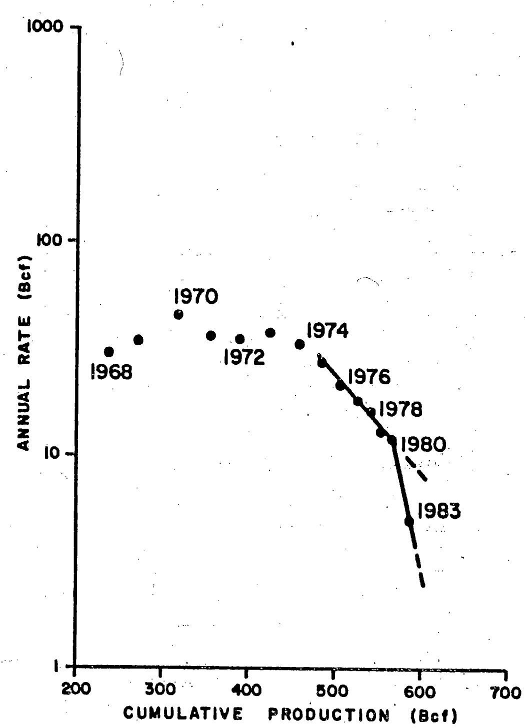


QA4078

STRATTON (DISTRICT 4)

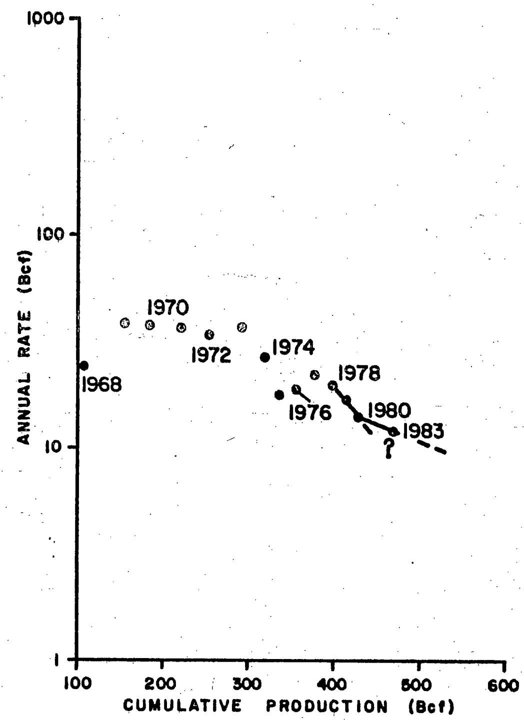


THOMPSONVILLE, NE (DISTRICT 4)

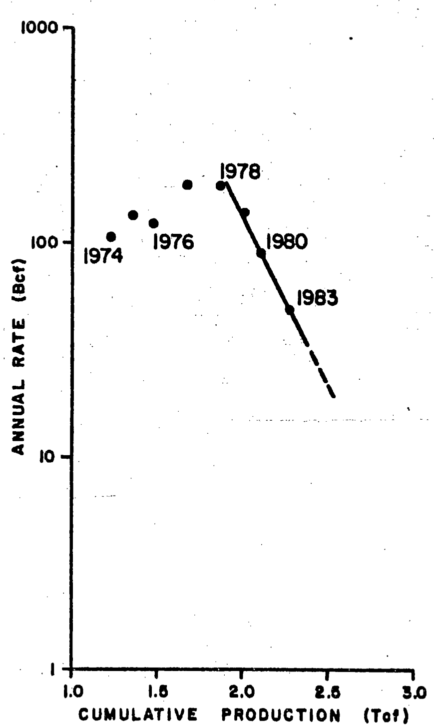


QA4076

TIJERINA-CANALES-BLUCHER (T.C.B.) (DISTRICT 4)



ZONE 21-B TREND (DISTRICT 4)



QA4077

APPENDIX VIII. Annual production and cumulative production for largest fields--Districts 2, 3, and 4

District 2

YEAR	Calhoun/Victoria Counties HEYSER Frio ± 5,000' Bcf ANNUAL RATE	Bcf CUM. PROD.	Refugio County LAKE PASTURE Frio 2,000'-6,000' Bcf ANNUAL RATE	Bcf CUM. PROD.	Refugio County TOM O'CONNOR Frio 3,000'-6,000' Bcf ANNUAL RATE	Bcf CUM. PROD.
1968	34	338	27	150	37	408
1969	41	379	24	174	37	445
1970	42	421	19*	193	34	479
1971	28*	449	17	210	34	513
1972	17*	466	14	224	25*	538
1973	13*	479	12	236	15*	553
1974	9*	488	8*	244	10*	563
1975	6*	494	6*	250	7*	570
1976	3*	497	18	268	12	582
1977	3	500	25	293	14	596
1978	3	503	20*	313	10	606
1979	3	506	47	360	13	619
1980	6	512	54	414	14	633
1981**						
1982**						
1983	12	542	19	508	7	661

*Abrupt decrease in annual productive rate (20% or more) may indicate negative revision of reserves.
**Data not available.

APPENDIX VIII

District 2 (continued)

	Bee/Karnes Counties BURNELL Wilcox 6,000'-7,500'		Lavaca County PROVIDENT CITY Wilcox 8,000'-14,000'		Goliad/Karnes Counties TULSITA WILCOX Wilcox 6,800'-8,900'	
YEAR	Bcf ANNUAL RATE	Bcf CUM. PROD.	Bcf ANNUAL RATE	Bcf CUM. PROD.	Bcf ANNUAL RATE	Bcf CUM. PROD.
1968	27	274	18	210	20	257
1969	26	300	17	227	26	283
1970	16*	316	19	246	22	305
1971	16	332	16	262	16*	321
1972	22	354	17	279	17	338
1973	22	376	16	295	18	356
1974	17*	393	19	314	18	374
1975	15	408	14*	328	16	390
1976	12	420	12	340	15	405
1977	10	430	11	351	13	418
1978	9	439	9	360	11	429
1979	6*	445	9	369	9	438
1980	6	451	13	382	8	446
1981**						
1982**						
1983	2	461	9	411	2	457

*Abrupt decrease in annual productive rate (20% or more) may indicate negative revision of reserves.
**Data not available.

APPENDIX VIII

District 3

YEAR	Brazoria County CHOCOLATE BAYOU Frio 9,500'-11,500' Bcf ANNUAL RATE	Bcf CUM. PROD.	Fort Bend/Harris/Waller Cos. KATY Cockfield/Wilcox 5,500'-10,500' Bcf ANNUAL RATE	Bcf CUM. PROD.	Matagorda/Wharton Cos. MAGNET WITHERS Miocene 3,000'-6,600' Bcf ANNUAL RATE	Bcf CUM. PROD.
1968	28	782	265	1,848	74	458
1969	21*	803	324	2,172	67	525
1970	14*	817	364	2,536	77	602
1971	12	829	389	2,925	59*	661
1972	12	841	420	3,345	52	713
1973	10	851	476	3,821	39*	752
1974	7	858	404	4,225	31	783
1975	5	863	282*	4,507	15*	798
1976	4	867	276	4,783	13	811
1977	4	871	269	5,052	14	825
1978	3	874	250	5,302	18	843
1979	2	876	252	5,554	16	859
1980	2	878	248	5,802	13	872
1981**						
1982**						
1983	2	883	166	6,382	6	896

*Abrupt decrease in annual productive rate (20% or more) may indicate negative revision of reserves.

**Data not available.

APPENDIX VIII

District 3 (continued)

	Brazoria County OLD OCEAN Frio 9,300'-10,800'		Brazoria County PLEDGER Miocene/Frio 4,600'-7,700'		Colorado County SHERIDAN Wilcox 8,000'-10,800'	
YEAR	Bcf ANNUAL RATE	Bcf CUM. PROD.	Bcf ANNUAL RATE	Bcf CUM. PROD.	Bcf ANNUAL RATE	Bcf CUM. PROD.
1968	118	1,061	63	603	100	640
1969	161	1,222	65	668	113	753
1970	157	1,379	67	735	92	845
1971	152	1,531	61	796	84	929
1972	154	1,685	59	855	70	999
1973	137	1,822	64	919	56*	1,055
1974	113	1,935	66	985	50	1,105
1975	104	2,039	64	1,049	41	1,146
1976	95	2,134	67	1,116	37	1,183
1977	84	2,218	98	1,214	32	1,215
1978	34*	2,252	102	1,316	28	1,243
1979	83	2,335	83*	1,398	25	1,268
1980	79	2,414	32*	1,430	21	1,289
1981**						
1982**						
1983	51	2,596	4	1,472	12	1,330

*Abrupt decrease in annual productive rate (20% or more) may indicate negative revision of reserves.
**Data not available.

APPENDIX VIII

District 3 (continued)

YEAR	Matagorda County COLLEGE PORT Miocene 2,200'-5,600' Bcf ANNUAL RATE	Bcf CUM. PROD.	Chambers County FISHERS REEF Frio 8,000'-8,700' Bcf ANNUAL RATE	Bcf CUM. PROD.	Chambers County REDFISH REEF Miocene/Frio 3,000'-11,000' Bcf ANNUAL RATE	Bcf CUM. PROD.
1968	14	163	8	44	24	59
1969	17	180	11	55	22	81
1970	21	201	17	72	14*	95
1971	18*	219	14	86	15	110
1972	17	236	12	98	15	125
1973	14	250	11	109	17	142
1974	12	262	8	117	17	159
1975	6*	268	10	127	15	174
1976	9	277	9	136	14	188
1977	9	286	7*	143	11*	199
1978	8	294	5*	148	18	217
1979	7	301	4	152	15	232
1980	7	308	3	155	10	242
1981**						
1982**						
1983	5	325	3	166	6	266

*Abrupt decrease in annual productive rate (20% or more) may indicate negative revision of reserves.
**Data not available.

APPENDIX VIII

District 4

YEAR	Hidalgo County LA BLANCA Frio 6,500'-9,400' Bcf ANNUAL RATE	Bcf CUM. PROD.	Hidalgo County McALLEN Frio (Vicksburg) 5,800'-10,400' Bcf ANNUAL RATE	Bcf CUM. PROD.	Kenedy/Kleberg Counties SARITA Miocene/Frio 1,900'-8,300' Bcf ANNUAL RATE	Bcf CUM. PROD.
1968	14	122	23	261	11	37
1969	15	137	19	280	13	50
1970	17	154	14*	294	16	66
1971	17	171	13	307	21	87
1972	17	188	10*	317	21	108
1973	16	204	10	327	21	129
1974	13	217	9	336	18	147
1975	10*	227	8	344	17	164
1976	9	236	6*	350	16	180
1977	7*	243	6	356	11*	191
1978	6	249	5	361	9	200
1979	5	254	4	365	8	208
1980	5	259	4	369	6	214
1981**						
1982**						
1983	3	273	2	375	5	229

*Abrupt decrease in annual productive rate (20% or more) may indicate negative revision of reserves.
**Data not available.

APPENDIX VIII

District 4 (continued)

YEAR	Kenedy County STILLMAN Frio 5,600'-12,400' Bcf ANNUAL RATE	Bcf CUM. PROD.	Kleberg County ALAZAN NORTH Deep Frio 6,400'-11,400' Bcf ANNUAL RATE	Bcf CUM. PROD.	Kleberg County BORREGOS Frio 5,000'-7,000' Vicksburg 7,500'-8,200' Bcf ANNUAL RATE	Bcf CUM. PROD.
1968	11	54	117	410	103	350
1969	8*	62	69*	479	97	447
1970	7	69	63	542	103	550
1971	6	75	78	620	108	658
1972	5	80	90	710	124	782
1973	9	89	87	797	157	939
1974	14	103	87	884	76*	1,015
1975	15	118	79	963	92	1,107
1976	12*	130	68	1,031	144	1,251
1977	11	141	53*	1,084	131	1,382
1978	10	151	48	1,132	106	1,488
1979	8*	159	34	1,166	89	1,577
1980	7	166	24*	1,190	71*	1,648
1981**						
1982**						
1983	6	186	8	1,230	36	1,792

*Abrupt decrease in annual productive rate (20% or more) may indicate negative revision of reserves.
**Data not available.

APPENDIX VIII

District 4 (continued)

YEAR	Brooks/Jim Wells Counties LA GLORIA Frio 5,200'-8,200' Bcf ANNUAL RATE	Bcf CUM. PROD.	Kleberg/Nueces Counties LAGUNA LARGA Frio 6,000'-6,500' Bcf ANNUAL RATE	Bcf CUM. PROD.	Hidalgo County McALLEN RANCH Vicksburg 9,300'-14,000' Bcf ANNUAL RATE	Bcf CUM. PROD.
1968	81	762	4	7	46	160
1969	73	835	2	9	38*	198
1970	82	917	5	14	30*	228
1971	80	997	17	31	34	262
1972	76	1,073	40	71	29	291
1973	67	1,140	54	125	36	327
1974	60	1,200	84	209	28*	355
1975	45*	1,245	60	269	28	383
1976	35*	1,280	65	334	33	416
1977	27*	1,307	48*	382	33	449
1978	20*	1,327	44	426	29	478
1979	15*	1,342	54	480	24	502
1980	12*	1,354	60	540	24	526
1981**						
1982**						
1983	7	1,379	32	666	22	595

*Abrupt decrease in annual productive rate (20% or more) may indicate negative revision of reserves.
**Data not available.

APPENDIX VIII

District 4 (continued)

YEAR	Jim Wells/Kleberg Cos. SEELIGSON Frio 4,200'-7,500'		Jim Wells/Kleberg/Nueces Cos. STRATTON Wardner/Frio 4,000'-9,000'		Jim Hogg/Webb Cos. THOMPSONVILLE, NE Wilcox 9,400'-12,600'	
	Bcf ANNUAL RATE	Bcf CUM. PROD.	Bcf ANNUAL RATE	Bcf CUM. PROD.	Bcf ANNUAL RATE	Bcf CUM. PROD.
1968	125	447	93	262	30	240
1969	98*	545	108	370	34	274
1970	90	635	110	480	45	319
1971	97	732	119	599	36*	355
1972	94	826	127	726	35	390
1973	84	910	134	860	37	427
1974	59*	969	111	971	33	460
1975	62	1,031	97	1,068	27	487
1976	63	1,094	80	1,148	21*	508
1977	55	1,149	71	1,219	18	526
1978	51	1,200	69	1,288	16	542
1979	55	1,255	67	1,355	13	555
1980	43*	1,298	55	1,410	12	567
1981**						
1982**						
1983	25	1,391	22	1,512	5	589

*Abrupt decrease in annual productive rate (20% or more) may indicate negative revision of reserves.
**Data not available.

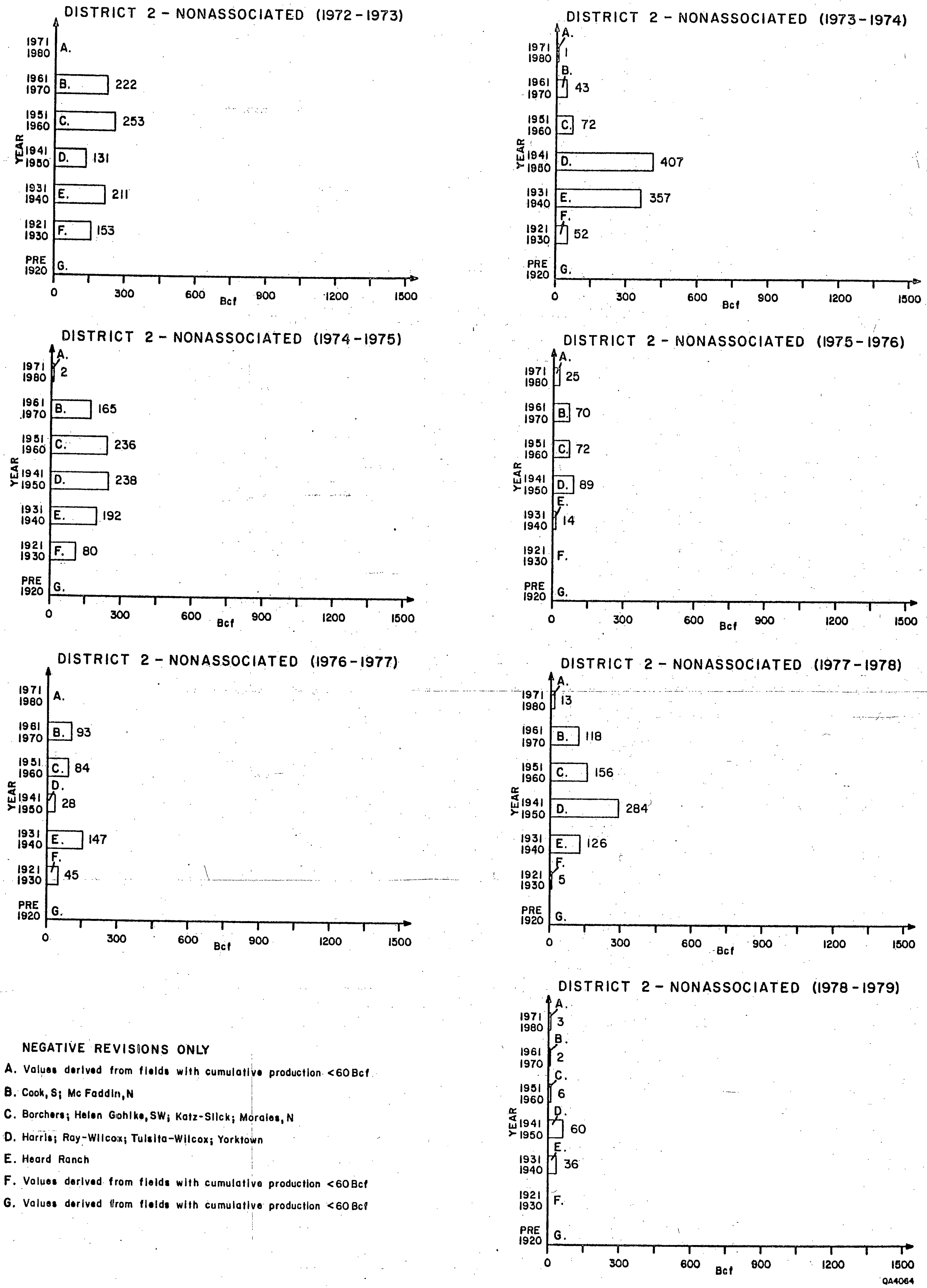
APPENDIX VIII

District 4 (continued)

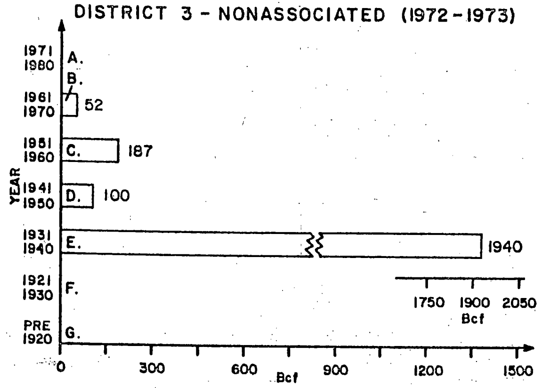
YEAR	Jim Wells/Kleberg Counties TIJERINA-CANALES-BLUCHER (T.C.B.) Frio 6,700'-11,400' Bcf ANNUAL RATE	Bcf CUM. PROD.	Jim Wells/Kleberg Counties ZONE 21-B TREND Frio 6,500'-7,200' Bcf ANNUAL RATE	Bcf CUM. PROD.
1968	24	108	0	
1969	39	147	0	
1970	38	185	0	
1971	37	222	0	
1972	34	256	0	
1973	37	293	0	
1974	27*	320	107	1,239
1975	18*	338	132	1,371
1976	19	357	126	1,497
1977	22	379	188	1,685
1978	20	399	188	1,873
1979	17	416	139*	2,012
1980	14	430	90*	2,102
1981**				
1982**				
1983	12	469	49	2,289

*Abrupt decrease in annual productive rate (20% or more) may indicate negative revision of reserves.
**Data not available.

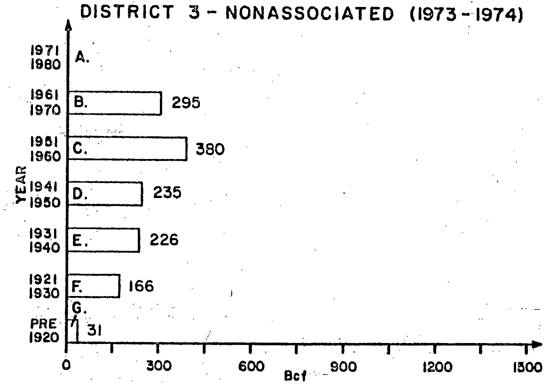
APPENDIX IX. Negative revisions in estimated ultimate production by decade of discovery for nonassociated gas fields, 1972-1979--Districts 2, 3, and 4.



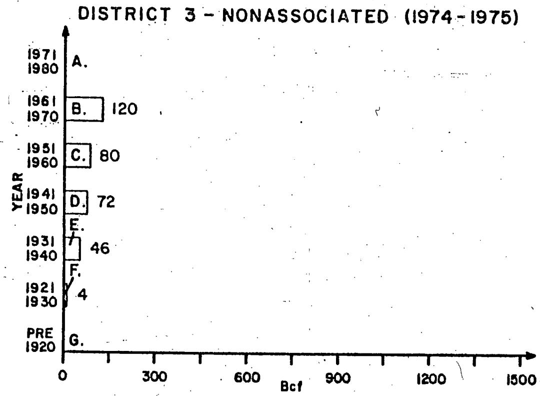
DISTRICT 3 - NONASSOCIATED (1972-1973)



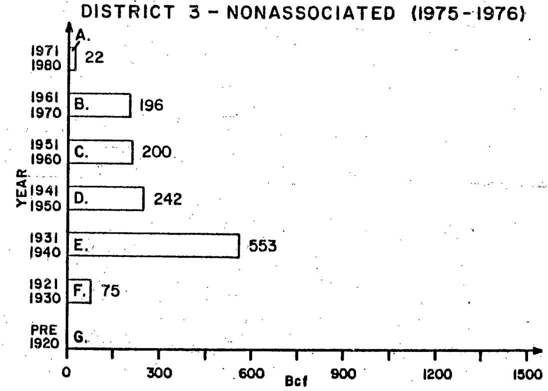
DISTRICT 3 - NONASSOCIATED (1973-1974)



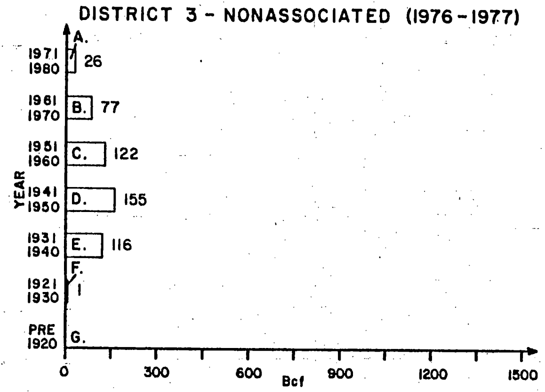
DISTRICT 3 - NONASSOCIATED (1974-1975)



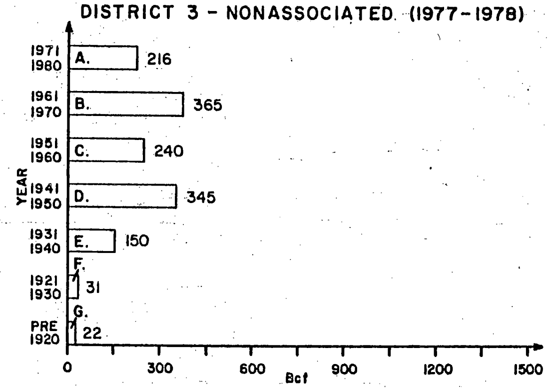
DISTRICT 3 - NONASSOCIATED (1975-1976)



DISTRICT 3 - NONASSOCIATED (1976-1977)



DISTRICT 3 - NONASSOCIATED (1977-1978)



NEGATIVE REVISIONS ONLY

A. Brazos Blk 386-S; Cavallo; El Gordo; High Island Blk 14-L; Shipwreck; Texas City Dike

B. Cove; High Island Blk 160; Milton, N; Point Bolivar, N

C. Chocolate Bayou, S; Clemens, N; Hitchcock, NE; Lissie; Manor Lake; Port Arthur; Sweeney

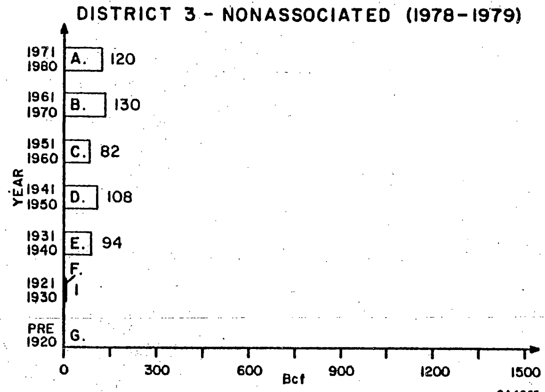
D. Bernard, W; Chesterville; Galveston Island; Hamshire, W; Port Neches, N

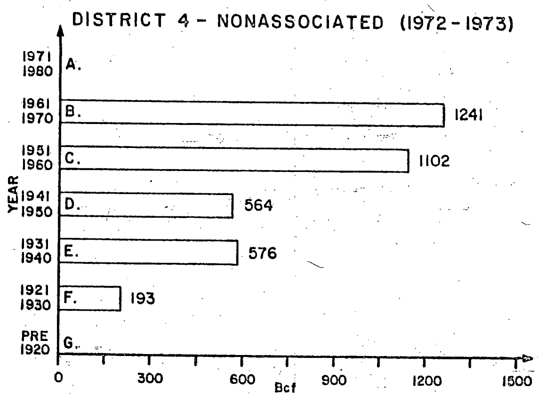
E. Katy; Magnet Withers

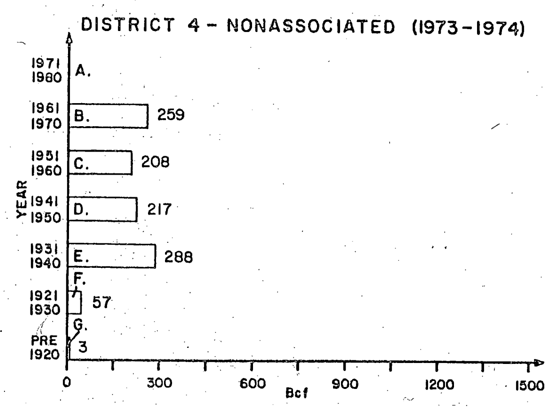
F. Values derived from fields with cumulative production <60 Bcf

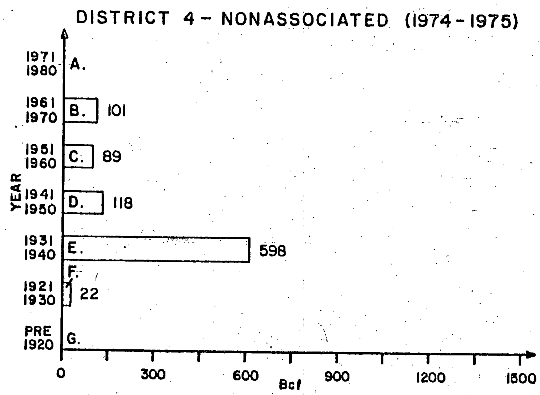
G. Values derived from fields with cumulative production <60 Bcf

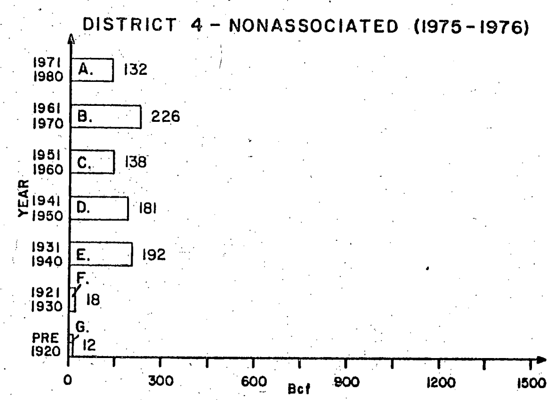
DISTRICT 3 - NONASSOCIATED (1978-1979)

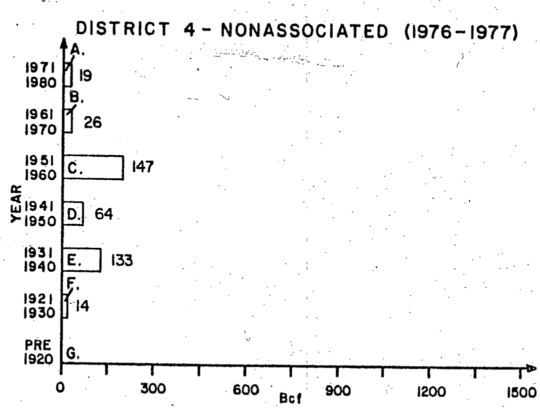


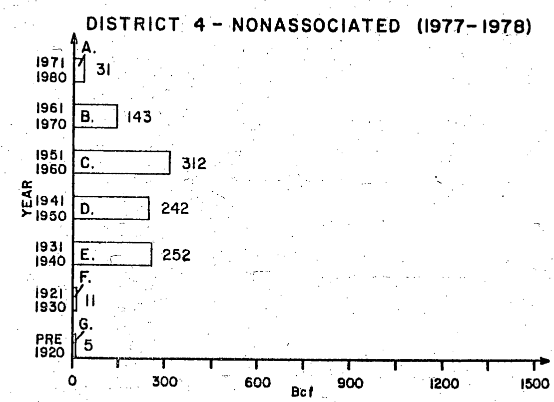












NEGATIVE REVISIONS ONLY

A. Laredo; J.C. Martin; Pita, NW; Samedan

B. El Paistle, Deep; Encinal Channel; Loma Blanca; Madero, E; Mc Cook, E; Nine Mile Point; Sarita, E; Seven Sisters, E; Stillman

C. Calandria; Corpus Christi, E; GOM State-904; Hidalgo; Holly Beach; Jeffress; La Perla Ranch; Mc Allen Ranch; Monte Christo; Murdock Pass; San Carlos; Sante Fe, E; Santellana, S; Thompsonville, NE; Yeary

D. Laguna Larga; La Sal Vieja; Pharr; Redfish Bay-Mustang Island

E. Kelsey, S; La Blanca; La Reforma; Lundell; Mc Allen; Mercedes; Piedre Lumbre; San Salvador

F. Values derived from fields with cumulative production <60 Bcf

G. Values derived from fields with cumulative production <60 Bcf

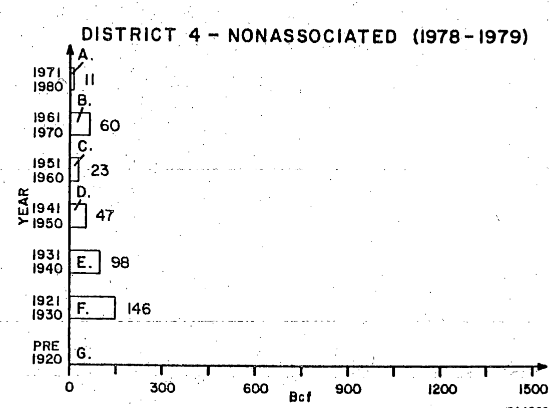


Figure Captions

Figure 1. Map of Texas Railroad Commission districts showing district-by-district changes in total gas reserves for 1966 through 1979.

Figure 2A. Diagram illustrating the overwhelming predominance of the Gulf Coast districts in total Texas net negative revisions. Note that District 4 alone is responsible for nearly half of the state's total.

Figure 2B. Diagram showing that two of the Gulf Coast districts reported negative revisions for nonassociated gas reserves that accounted for two-thirds of the total for the state, with District 4 alone responsible for nearly one-half. The large revision for District 8 is not reflected in revisions for total gas, because positive revisions were recorded for associated gas in this district.

Figure 2C. Diagram highlighting the nearly 90-percent contribution from Gulf Coast Districts 3 and 4 to the net negative revisions for associated gas.

Figure 3. Schematic drawing illustrating homogeneous (A) and heterogeneous (B) reservoirs. Interpretations before and after infill drilling.

Figure 4. Schematic drawing showing different field sizes for situation in which fault associated with the field is nonsealing (A) or sealing (B).

APPENDIX VII. Decline curve plots for largest fields--Districts 2, 3, and 4.

APPENDIX VII (continued)

APPENDIX VII (continued)

APPENDIX VII (continued)

APPENDIX VII (continued)

APPENDIX VII (continued)

APPENDIX VII (continued)

APPENDIX VII (continued)

APPENDIX VII (continued)

APPENDIX VII (continued)

APPENDIX VII (continued)

APPENDIX IX. Negative revisions in estimated ultimate production by decade of discovery for nonassociated gas fields, 1972-1979--Districts 2, 3, and 4.

APPENDIX IX (continued)

APPENDIX IX (continued)

Table 5. Volumes and corresponding percentages for interstate and intrastate gas production, 1976 to 1984.*

Year	Interstate** (Bcf)	Interstate** (Percentage)	Intrastate (Bcf)	Intrastate (Percentage)	Total
1976	2,408.5	32	5,115.7	68	7,524.2
1977	2,260.8	31	5,082.8	69	7,343.6
1978	2,029.0	29	4,875.6	71	6,904.6
1979	2,269.8	32	4,888.1	68	7,157.9
1980	2,318.5	34	4,573.3	66	6,891.8
1981	2,278.2	34	4,403.1	66	6,681.3
1982	2,198.0	37	3,697.6	63	5,895.6
1983	1,853.5	34	3,558.0	66	5,411.5
1984+	1,067.2	38	1,770.7	62	2,837.9

*Data from State Comptroller's Office.

**Texas gas exported is from pipeline reports to TRRC and is considered as interstate.

+One-half year.

Note the effect of the Natural Gas Policy Act (1978) in changing trends as to percentages.

APPENDIX VIII. Annual production and cumulative production for largest fields--Districts 2, 3, and 4

District 2

	Calhoun/Victoria Counties HEYSER Frio ± 5,000'		Refugio County LAKE PASTURE Frio 2,000'-6,000'		Refugio County TOM O'CONNOR Frio 3,000'-6,000'	
YEAR	Bcf ANNUAL RATE	Bcf CUM. PROD.	Bcf ANNUAL RATE	Bcf CUM. PROD.	Bcf ANNUAL RATE	Bcf CUM. PROD.
1968	34	338	27	150	37	408
1969	41	379	24	174	37	445
1970	42	421	19*	193	34	479
1971	28*	449	17	210	34	513
1972	17*	466	14	224	25*	538
1973	13*	479	12	236	15*	553
1974	9*	488	8*	244	10*	563
1975	6*	494	6*	250	7*	570
1976	3*	497	18	268	12	582
1977	3	500	25	293	14	596
1978	3	503	20*	313	10	606
1979	3	506	47	360	13	619
1980	6	512	54	414	14	633
1981**						
1982**						
1983	12	542	19	508	7	661

*Abrupt decrease in annual productive rate (20% or more) may indicate negative revision of reserves.
**Data not available.

APPENDIX VIII

District 2 (continued)

YEAR	Bee/Karnes Counties BURNELL Wilcox 6,000'-7,500' Bcf ANNUAL RATE	Bcf CUM. PROD.	Lavaca County PROVIDENT CITY Wilcox 8,000'-14,000' Bcf ANNUAL RATE	Bcf CUM. PROD.	Goliad/Karnes Counties TULSITA WILCOX Wilcox 6,800'-8,900' Bcf ANNUAL RATE	Bcf CUM. PROD.
1968	27	274	18	210	20	257
1969	26	300	17	227	26	283
1970	16*	316	19	246	22	305
1971	16	332	16	262	16*	321
1972	22	354	17	279	17	338
1973	22	376	16	295	18	356
1974	17*	393	19	314	18	374
1975	15	408	14*	328	16	390
1976	12	420	12	340	15	405
1977	10	430	11	351	13	418
1978	9	439	9	360	11	429
1979	6*	445	9	369	9	438
1980	6	451	13	382	8	446
1981**						
1982**						
1983	2	461	9	411	2	457

*Abrupt decrease in annual productive rate (20% or more) may indicate negative revision of reserves.
**Data not available.

APPENDIX VIII

District 3

YEAR	Brazoria County CHOCOLATE BAYOU Frio 9,500'-11,500' Bcf ANNUAL RATE	Bcf CUM. PROD.	Fort Bend/Harris/Waller Cos. KATY Cockfield/Wilcox 5,500'-10,500' Bcf ANNUAL RATE	Bcf CUM. PROD.	Matagorda/Wharton Cos. MAGNET WITHERS Miocene 3,000'-6,600' Bcf ANNUAL RATE	Bcf CUM. PROD.
1968	28	782	265	1,848	74	458
1969	21*	803	324	2,172	67	525
1970	14*	817	364	2,536	77	602
1971	12	829	389	2,925	59*	661
1972	12	841	420	3,345	52	713
1973	10	851	476	3,821	39*	752
1974	7	858	404	4,225	31	783
1975	5	863	282*	4,507	15*	798
1976	4	867	276	4,783	13	811
1977	4	871	269	5,052	14	825
1978	3	874	250	5,302	18	843
1979	2	876	252	5,554	16	859
1980	2	878	248	5,802	13	872
1981**						
1982**						
1983	2	883	166	6,382	6	896

*Abrupt decrease in annual productive rate (20% or more) may indicate negative revision of reserves.
**Data not available.

APPENDIX VIII

District 3 (continued)

YEAR	Matagorda County COLLEGE PORT Miocene 2,200'-5,600' Bcf ANNUAL RATE	Bcf CUM. PROD.	Chambers County FISHERS REEF Frio 8,000'-8,700' Bcf ANNUAL RATE	Bcf CUM. PROD.	Chambers County REDFISH REEF Miocene/Frio 3,000'-11,000' Bcf ANNUAL RATE	Bcf CUM. PROD.
1968	14	163	8	44	24	59
1969	17	180	11	55	22	81
1970	21	201	17	72	14*	95
1971	18*	219	14	86	15	110
1972	17	236	12	98	15	125
1973	14	250	11	109	17	142
1974	12	262	8	117	17	159
1975	6*	268	10	127	15	174
1976	9	277	9	136	14	188
1977	9	286	7*	143	11*	199
1978	8	294	5*	148	18	217
1979	7	301	4	152	15	232
1980	7	308	3	155	10	242
1981**						
1982**						
1983	5	325	3	166	6	266

*Abrupt decrease in annual productive rate (20% or more) may indicate negative revision of reserves.
**Data not available.

APPENDIX VIII

District 3 (continued)

	Brazoria County OLD OCEAN Frio 9,300'-10,800'		Brazoria County PLEDGER Miocene/Frio 4,600'-7,700'		Colorado County SHERIDAN Wilcox 8,000'-10,800'	
YEAR	Bcf ANNUAL RATE	Bcf CUM. PROD.	Bcf ANNUAL RATE	Bcf CUM. PROD.	Bcf ANNUAL RATE	Bcf CUM. PROD.
1968	118	1,061	63	603	100	640
1969	161	1,222	65	668	113	753
1970	157	1,379	67	735	92	845
1971	152	1,531	61	796	84	929
1972	154	1,685	59	855	70	999
1973	137	1,822	64	919	56*	1,055
1974	113	1,935	66	985	50	1,105
1975	104	2,039	64	1,049	41	1,146
1976	95	2,134	67	1,116	37	1,183
1977	84	2,218	98	1,214	32	1,215
1978	34*	2,252	102	1,316	28	1,243
1979	83	2,335	83*	1,398	25	1,268
1980	79	2,414	32*	1,430	21	1,289
1981**						
1982**						
1983	51	2,596	4	1,472	12	1,330

*Abrupt decrease in annual productive rate (20% or more) may indicate negative revision of reserves.

**Data not available.

APPENDIX VIII

District 4

YEAR	Hidalgo County LA BLANCA Frio 6,500'-9,400' Bcf ANNUAL RATE	Bcf CUM. PROD.	Hidalgo County McALLEN Frio (Vicksburg) 5,800'-10,400' Bcf ANNUAL RATE	Bcf CUM. PROD.	Kenedy/Kleberg Counties SARITA Miocene/Frio 1,900'-8,300' Bcf ANNUAL RATE	Bcf CUM. PROD.
1968	14	122	23	261	11	37
1969	15	137	19	280	13	50
1970	17	154	14*	294	16	66
1971	17	171	13	307	21	87
1972	17	188	10*	317	21	108
1973	16	204	10	327	21	129
1974	13	217	9	336	18	147
1975	10*	227	8	344	17	164
1976	9	236	6*	350	16	180
1977	7*	243	6	356	11*	191
1978	6	249	5	361	9	200
1979	5	254	4	365	8	208
1980	5	259	4	369	6	214
1981**						
1982**						
1983	3	273	2	375	5	229

*Abrupt decrease in annual productive rate (20% or more) may indicate negative revision of reserves.
**Data not available.

APPENDIX VIII

District 4 (continued)

YEAR	Kenedy County STILLMAN Frio 5,600'-12,400' Bcf ANNUAL RATE	Bcf CUM. PROD.	Kleberg County ALAZAN NORTH Deep Frio 6,400'-11,400' Bcf ANNUAL RATE	Bcf CUM. PROD.	Kleberg County BORREGOS Frio 5,000'-7,000' Vicksburg 7,500'-8,200' Bcf ANNUAL RATE	Bcf CUM. PROD.
1968	11	54	117	410	103	350
1969	8*	62	69*	479	97	447
1970	7	69	63	542	103	550
1971	6	75	78	620	108	658
1972	5	80	90	710	124	782
1973	9	89	87	797	157	939
1974	14	103	87	884	76*	1,015
1975	15	118	79	963	92	1,107
1976	12*	130	68	1,031	144	1,251
1977	11	141	53*	1,084	131	1,382
1978	10	151	48	1,132	106	1,488
1979	8*	159	34	1,166	89	1,577
1980	7	166	24*	1,190	71*	1,648
1981**						
1982**						
1983	6	186	8	1,230	36	1,792

*Abrupt decrease in annual productive rate (20% or more) may indicate negative revision of reserves.
**Data not available.

APPENDIX VIII

District 4 (continued)

YEAR	Brooks/Jim Wells Counties LA GLORIA Frio 5,200'-8,200' Bcf ANNUAL RATE	Bcf CUM. PROD.	Kleberg/Nueces Counties LAGUNA LARGA Frio 6,000'-6,500' Bcf ANNUAL RATE	Bcf CUM. PROD.	Hidalgo County McALLEN RANCH Vicksburg 9,300'-14,000' Bcf ANNUAL RATE	Bcf CUM. PROD.
1968	81	762	4	7	46	160
1969	73	835	2	9	38*	198
1970	82	917	5	14	30*	228
1971	80	997	17	31	34	262
1972	76	1,073	40	71	29	291
1973	67	1,140	54	125	36	327
1974	60	1,200	84	209	28*	355
1975	45*	1,245	60	269	28	383
1976	35*	1,280	65	334	33	416
1977	27*	1,307	48*	382	33	449
1978	20*	1,327	44	426	29	478
1979	15*	1,342	54	480	24	502
1980	12*	1,354	60	540	24	526
1981**						
1982**						
1983	7	1,379	32	666	22	595

*Abrupt decrease in annual productive rate (20% or more) may indicate negative revision of reserves.
**Data not available.

APPENDIX VIII

District 4 (continued)

YEAR	Jim Wells/Kleberg Counties TIJERINA-CANALES-BLUCHER (T.C.B.) Frio 6,700'-11,400' Bcf ANNUAL RATE	Bcf CUM. PROD.	Jim Wells/Kleberg Counties ZONE 21-B TREND Frio 6,500'-7,200' Bcf ANNUAL RATE	Bcf CUM. PROD.
1968	24	108	0	
1969	39	147	0	
1970	38	185	0	
1971	37	222	0	
1972	34	256	0	
1973	37	293	0	
1974	27*	320	107	1,239
1975	18*	338	132	1,371
1976	19	357	126	1,497
1977	22	379	188	1,685
1978	20	399	188	1,873
1979	17	416	139*	2,012
1980	14	430	90*	2,102
1981**				
1982**				
1983	12	469	49	2,289

*Abrupt decrease in annual productive rate (20% or more) may indicate negative revision of reserves.
**Data not available.

APPENDIX VIII

District 4 (continued)

YEAR	Jim Wells/Kleberg Cos. SEELIGSON Frio 4,200'-7,500' Bcf ANNUAL RATE	Bcf CUM. PROD.	Jim Wells/Kleberg/Nueces Cos. STRATTON Wardner/Frio 4,000'-9,000' Bcf ANNUAL RATE	Bcf CUM. PROD.	Jim Hogg/Webb Cos. THOMPSONVILLE, NE Wilcox 9,400'-12,600' Bcf ANNUAL RATE	Bcf CUM. PROD.
1968	125	447	93	262	30	240
1969	98*	545	108	370	34	274
1970	90	635	110	480	45	319
1971	97	732	119	599	36*	355
1972	94	826	127	726	35	390
1973	84	910	134	860	37	427
1974	59*	969	111	971	33	460
1975	62	1,031	97	1,068	27	487
1976	63	1,094	80	1,148	21*	508
1977	55	1,149	71	1,219	18	526
1978	51	1,200	69	1,288	16	542
1979	55	1,255	67	1,355	13	555
1980	43*	1,298	55	1,410	12	567
1981**						
1982**						
1983	25	1,391	22	1,512	5	589

*Abrupt decrease in annual productive rate (20% or more) may indicate negative revision of reserves.
**Data not available.