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A Geologic Assessment of Natural Gas From Tight Gas Sandstones in the San Juan Basin

Final Report
June 1989 - June 1991

M. R. Haas
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Work Performed Under Contract No.: DE-AC21-89MC26306

For
U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
Morgantown, West Virginia

By
ICF Resources Incorporated
Fairfax, Virginia

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Abstract

The authors conducted a detailed geologic appraisal, estimated gas in place and recoverable volumes, and evaluated the impact of technology improvements on potential Cretaceous (Pictured Cliffs, Chacra, Cliff House, Point Lookout and Dakota intervals) tight gas reserves of the San Juan Basin.

This report summarizes the results of a disaggregated appraisal of the undeveloped San Juan tight gas resource in the context of current and near-term technology, project economics and market potential. A geologic data base was constructed based on location reservoir properties, and typical well recoveries were modeled on a township-specific basis. Project costing and cash flow economics were analyzed to derive potential reserves for various technology specifications and wellhead prices. These data provide a foundation for operators and pipelines to more closely examine these tight formations for development in the near future.

Gas in place for the undeveloped tight portion of the five intervals studied was estimated at 17.2 Tcf, with the Dakota Formation accounting for two thirds of this volume. Using current technology, potential ultimate recovery for all intervals is 7.2 Tcf. Potential reserve additions are 1.1 Tcf at $1.50/Mcf, 2.3 Tcf at $2.00/Mcf, and 5.9 Tcf at $5.00/Mcf. The availability of the Nonconventional Fuels Tax Credit for eligible wells drilled in 1991 and 1992 could improve project economics by an after tax equivalent of $0.66/Mcf at the wellhead.

As part of this study, over 300 geophysical logs were evaluated to construct, depth, overburden and isopach maps and a location-specific resource database. The database was analyzed using TGAS-PC®, an integrated engineering and economics model for tight sands that has the capability to do rapid sensitivity analysis of geological, technology and economic assumptions. Although this study has identified the tight sands potential for various areas of the basin, more detailed geologic appraisal and reservoir engineering should be conducted before drilling.

Acknowledgements

This research was sponsored by the Morgantown Energy Technology Center under contract DE-AC21-89MC26306. ICF Resources acknowledges the efforts of the many San Juan Basin operators and service company personnel who contributed to this analysis. ICF Resources staff contributing to this analysis included Tracy Lombardi, Beth McGowan, Bruce Kelso, and Julie O'Brien. Mark Haas was the Project Manager.

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I. Executive Summary

After more than a decade, excess domestic natural gas deliverability seems to be decreasing. Given the structure of natural gas markets, especially with intensive competition brought about by wellhead price and pipeline deregulation, gas-on-gas competition has driven wellhead prices to historic lows. With the consequent decline in drilling and anticipated increases in natural gas demand, new concerns are being raised about the adequacy of domestic supplies. Increasing demand for natural gas will require reserve additions from areas with low extraction and transportation costs. For the rapidly growing California market and, possibly, West Texas, the San Juan Basin is an attractive supply region, assuming reserves can be added at sufficiently low cost and planned pipeline capacity expansion is completed. Technology effectiveness, development costs, and gas marketability are all important components in adding reserves from tight formations in the San Juan Basin.

The Upper Cretaceous sands of the San Juan Basin (Pictured Cliffs, Chacra, Cliff House, Point Lookout, and Dakota) still contain significant tight (less than or equal to 0.1 md in situ permeability) gas reserves. Drilling and production from the lower permeability parts of the Dakota and Mesaverde accelerated in the 1970's and 1980's due to extensive infill drilling programs, the availability of improved fracturing technology, and higher wellhead prices. This trend has slowed in the late 1980's due to excess deliverability and lower gas prices. The planned increase in transportation capacity, reinstatement of production tax credits for tight sands for wells drilled during 1991-1992 and continued technology improvements will increase the attractiveness of near-term development opportunities for operators in the tight sand formations in the San Juan Basin.

This study of the Upper Cretaceous sands of the San Juan Basin appraised the remaining potential of the principal tight formations: Pictured Cliffs, Chacra, Cliff House, Point Lookout and Dakota sands. The study found that the San Juan Basin contains 17.2 Tcf of tight gas in place, the majority (70%) of which is found in the Dakota. Assuming commercially available technology and sound engineering practices are used, potential tight reserves for remaining areas in all five intervals studied are estimated at 1.1 Tcf at \$1.50/Mcf, 2.3 Tcf at \$2.00/Mcf and 5.9 Tcf at \$5.00/Mcf (all in 1990 dollars).

In the past, the principal determinants of gas deliverability were reservoir properties and production technology. The increased competitiveness of gas markets, the low wellhead prices in recent years, and dramatic changes in pipeline operations render reservoir engineering only one of several aspects of getting gas from reservoir to market. Four issues are important to develop the remaining San Juan tight sands: pipeline capacity, competing supplies, tax incentives, and technology.

First, the San Juan Basin is served by El Paso, Northwest, Sunterra and Western pipelines, as well as several smaller gathering systems. San Juan tight gas could be produced to meet California's increasing demand, but it must compete with gas coming through the future Kern River line from Wyoming, Canadian gas through the Pacific Gas Transmission system, and Piceance Basin gas moving south through the future TransColorado system.

Second, the dominant competing supply in the San Juan Basin will be coalbed methane for the next several years. The development of technology to effectively stimulate, dewater, and produce coal seams has dramatically increased coalbed development in the past few years. An estimated 900 San Juan coalbed wells were producing at the end of 1990, spurred by availability of both technology and tax credits. While the rate of development activity is expected to decrease somewhat from 1990 levels, the two-year extension of the tax credit will maintain San Juan coalbed as a major play and keep coalbed gas extremely competitive. Already, in 1991, average price of gas delivered to pipelines is about $0.30/Mcf lower in San Juan than in the Permian Basin. The expected increase in per well gas production for all the recently drilled coalbed wells plus new wells stimulated by tax credits will produce tremendous volumes of gas in the next decade, thus keeping wellhead prices low.

Third, production tax credits have been reinstated for tight sands under Section 29 of the Internal Revenue Code. The Federal Energy Regulatory Commission (FERC), as part of the incentive pricing regulations it administers under the Natural Gas Policy Act (NGPA), has designated certain areas of the San Juan as tight gas sands. Wells drilled in these designated areas in 1991 and 1992 are eligible to receive a production tax credit of $0.52/Mcf on production through 2002. The regulations do not provide for any inflation adjustment for tight sands, thus coalbed methane will receive a credit of about $0.40/Mcf higher than tight sands. This will make marketing of tight sands gas more difficult relative to coalbed methane.

Finally, technology improvements are necessary to substantially increase reserve additions from the tight San Juan Cretaceous sands. Because most future San Juan tight sands reserves will be added through infill development, better reservoir engineering and stimulation design are keys to maximize reserves. Recompletion and refracturing old wells based on reinterpretation of original logs and correlation with offset wells show promise in appropriate circumstances. Horizontal wells, already used for coalbed methane development in the San Juan Basin and for tight gas formations in the Piceance and Appalachian Basins also show promise to dramatically increase recovery. Ultimate recovery and project economics were evaluated for alternative technology parameters, including an "advanced technology" scenario, assumed to be the result of full success of ongoing R&D, in formation evaluation and stimulation design and execution. Potential tight gas reserve additions for this advanced technology scenario were estimated at 1.9 Tcf at $1.50/Mcf, 3.3 Tcf at $2.00/Mcf and 7.1 Tcf at $5.00/Mcf.

The findings of this study indicate that substantial near-term potential exists for San Juan Basin tight sands. Most of this potential, however, will require tax credits or wellhead prices higher than May 1991 ($1.10-$1.20) levels.

II. Project Overview

A. Background

Development of the most geologically favorable portions of U.S. sedimentary basins is at a mature stage, requiring future emphasis on lower quality reservoirs to replace current reserves. Low permeability reservoirs, which could be sands, shales, carbonates, and coals, are currently the focus of a concerted research and development (R&D) effort by industry and government to improve reservoir understanding and extraction technology performance.

Current tight gas R&D aims to improve flow rates and reduce costs and risks by improving formation evaluation and stimulation technologies. These efforts by industry and government are directed at gaining a better understanding of the geological parameters, stimulation techniques, and production mechanisms affecting recovery. The development and commercialization of these advanced technologies will add reserves in low permeability settings that otherwise would be too costly to develop.

This report is a summary of the findings of a geological appraisal and analysis of the impact of technology on the recovery of gas from low permeability sands in the San Juan Basin in northwest New Mexico and Southern Colorado. The analysis was conducted to delineate the remaining tight formations in the basin and estimate potential recovery as a function of technology and economics.

This chapter discusses the context for technology R&D needed to maximize tight gas reserves and reduce costs of produced gas in the San Juan Basin. Subsequent chapters discuss the analytic approach, results of the analysis, and conclusions of the study.

1. The Domestic Natural Gas Resource Base

Since the early 1970's, changes in gas markets have made it hard to know whether or not gas supplies will be adequate to fulfill demand. By the late 1970's, the long term decline in booked reserves was predicted to leave the nation without adequate gas supplies within a decade. Then in the 1980s, changes in technology, economics, and market demand for gas created excess deliverability.

The market impact of this excess supply has been to drive down prices paid for supplies and emphasize cost minimization for producers. Decreasing prices paid for alternative fuels and the current structure of gas supply and demand markets created gas-on-gas competition that drove wellhead prices down further. Thus, near-term gas reserve additions must compete in a low cost environment.

Only recently has this excess deliverability begun to dissipate. In December of 1989, during colder than usual weather, gas demand in some areas exceeded deliverability. Once again facing potential regional shortages, industry is concerned about developing additional gas supplies over the near- to mid-term (5 to 15 years) to meet estimated increased demand. The extent and source of these new reserves is uncertain.

Despite uncertainty in supplies, demand is expected to increase. Concerns about air pollution and environmental impacts of tanker transport of oil have led to prospects for increased use of gas. Also, new technologies such as natural gas vehicles, cogeneration, and gas cooling may open up significant new markets for gas. Natural gas demand for electric utilities is expected to almost double in the next decade (an increase of 2.5 Tcf annually), making new, low-cost supplies even more critical.

Although the consensus of most analysts is that the natural gas resource base is large, others raise concerns about our ability to add the necessary reserves with prices at current levels and maintain deliverability. Large amounts of additional gas supplies are expected from frontier areas and unconventional resources, although a combination of improved technology and economics is required for reserve additions from these "higher cost" sources. Given today's highly competitive gas market and low alternative fuel prices, development of new gas resources will be highly sensitive to small increments in cost and technology effectiveness.

Several sources of natural gas are seen as providing the necessary reserve additions over the near- to mid-term. Two recent studies, conducted by the Department of Energy (DOE, 1988) and the National Academy of Sciences (NAS, 1990), estimated the potential gas resources of the U.S. (Table II-1). Other than the more intensive development of existing fields, these studies regarded gas from low permeability settings (tight sands, Devonian age shales, and coal seams) as the single largest increment to domestic gas supplies at near-term prices.

The potential recovery and economics of this resource, however, remain uncertain due to substantial geologic and technology uncertainties. Previous appraisals of domestic tight sands have estimated more than 500 Tcf of potential reserve additions, depending on technology and economic assumptions.

2. The Impact of Advanced Technology on Gas Reserve Additions

Estimation of potential reserves and future production of natural gas is rendered difficult by changing definitions of the resource base, extraction technologies and costs, and natural gas markets. Over the past 25 years, technologies have been developed to extract gas more efficiently from low permeability reservoirs, thus adding a potentially large volume of gas to the domestic resource base. The definition of how much tight gas exists in place and to what extent it can be economically produced under expected market conditions, however, remains highly uncertain in most basins. Most analyses of tight sands only address the portion of the resource associated with currently producing formations.

Reserve additions from low permeability reservoirs in the near term will be made from a resource base that is predominantly already delineated rather than from exploration and development of frontier areas. Improved technology for tight sands centers around two broad areas: formation evaluation and stimulation technology. Formation evaluation seeks to accurately define reservoir characteristics and geological parameters critical for effective stimulation treatments (e.g., higher resolution logging, stress measurement). Stimulation design aims to develop and implement a treatment that optimizes reservoir contact, and producibility (e.g., longer, limited height fractures).

Table II-1. DOE Natural Gas Resource Base Estimates

	Technically Recoverable Gas, Tcf[1]	Recoverable Gas by Price[2]	
		<$3/Mcf	$3-5/Mcf
Lower-48 (Conventional)			
Proved Reserves, 12/31/86, Onshore and Offshore	159	159	--
Inferred Reserves/Probable Resources, Onshore	85	85	--
Offshore Extended Reserve Growth in Nonassociated Fields, Onshore	23 119	23 56	-- 18
Gas Resources Associated with Oil Reserve Growth[3]	61	30	11
Undiscovered Onshore Resources	219	88	59
Undiscovered Offshore Resources[4]	134	54	28
Subtotal	800	495	116
Lower-48 (Unconventional)			
Gas in Low-Permeability Reservoirs	180	70	49
Coalbed Methane	48	8	4
Shale Gas	31	10	5
Subtotal	259	88	58
Alaska			
Proved: Reserves	33	7[5]	0
Proved Inferred Reserves (Cook Inlet Area)	3	3	0
Proved, Undiscovered, Onshore and Offshore	93	2[5]	2[5]
Subtotal	129	12	2
TOTAL	**1,188**	**595**	**176**

1. Volumes of gas judged recoverable with existing technology.
2. Volumes of gas (Tcf) judged recoverable with existing technology by Review Panel at wellhead prices shown (1987$).
3. Judged at oil prices of <$24/Bbl and $24-40/Bbl.
4. Outer Continental Shelf.
5. Component in southern Alaska.

Source: DOE (1988).

3. Prior Assessments Of Unconventional Gas Potential

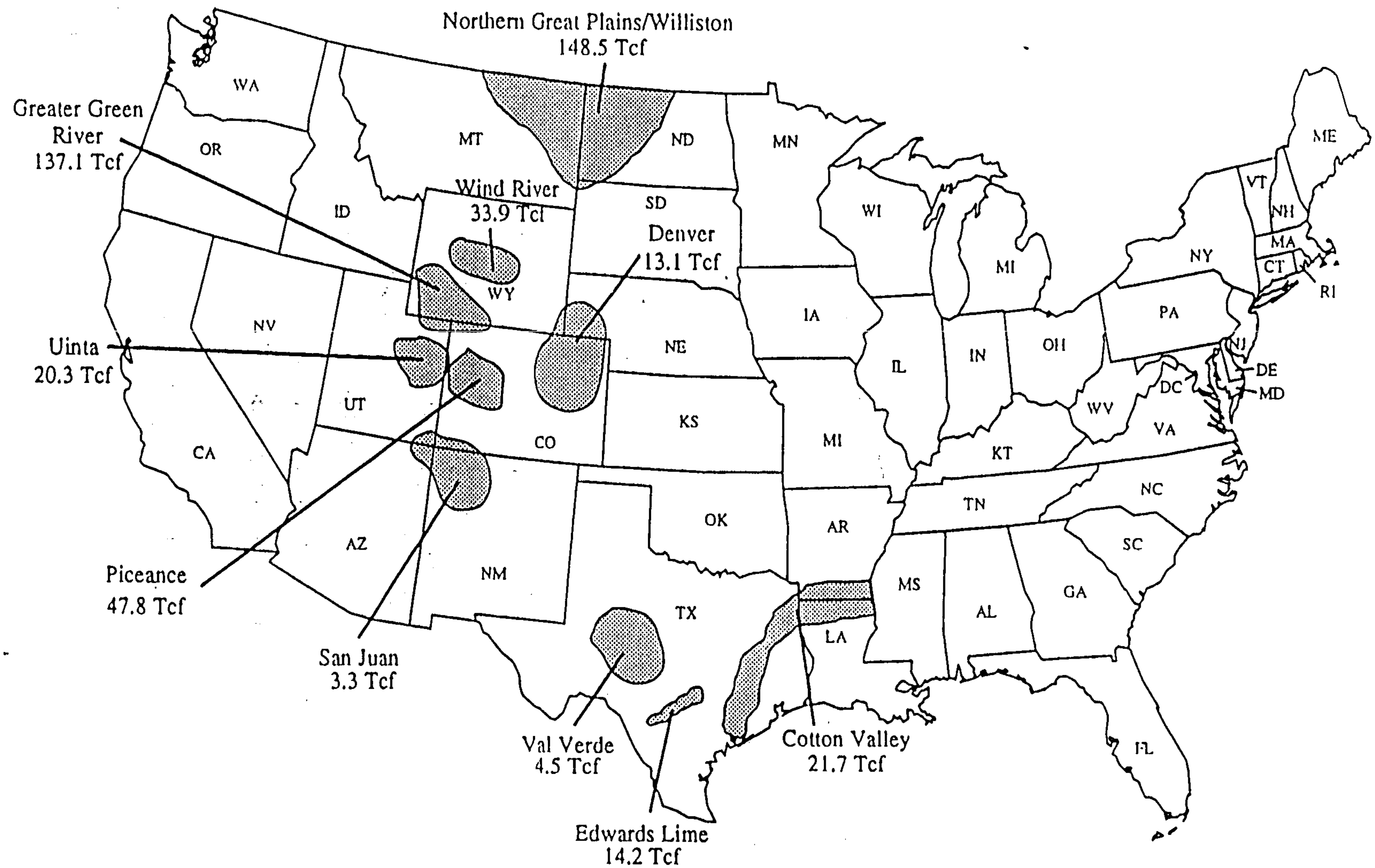
Tight sands are generally seen as having the largest resource base of the three principal unconventional gas resources. These sands are found extensively throughout the U.S. and the most favorable geological settings are already being developed. The long term potential, however, of the large portion of these sands is uncertain, since detailed studies of potential have not been conducted on all basins and formations.

In 1980, the National Petroleum Council (NPC, 1980) estimated that 946 Tcf of gas were contained in U.S. low permeability sands. This estimate was based on the detailed appraisal of 12 tight gas producing basins, using a combination of geologic and well data, to estimate 434 Tcf in place (Figure II-1). The NPC used these detailed appraisals as a basis for extrapolation to other U.S. tight formations to estimate an additional 512 Tcf of tight gas resource.

These NPC data have been used as the basis of almost every major assessment of tight gas potential since the study was completed. Both DOE and GRI (and derivatively, the American Gas Association, Potential Gas Committee, Stanford's Energy Modeling Forum and others) incorporated the NPC estimates of tight gas into total undiscovered gas estimates for the U.S. In addition, DOE and GRI assessments of the benefits of advanced technology and incremental gas recovery from tight sands are based on the NPC study. Thus, the credibility of nearly all current estimates of tight gas potential rests primarily on the accuracy and validity of the underlying NPC geologic appraisal.

The NPC study assessed the tight gas in place based on resource data available in 1979. The data the NPC generated however, have two limitations. First, they generally do not provide the regional distribution of tight gas resource within the geological framework of a given basin. Each formation was represented by groups of "typical wells" without reference to location. This distribution is critical to understand the geologic controls on tight gas production, especially to operators who need to target geologic settings amenable to specific tight gas recovery technologies. Also, the ability to predict the potential of advanced completion or stimulation techniques (e.g., multiple completions, slant holes) in specific areas is limited by the NPC data because they do not reflect the inherent distribution of reservoir and flow properties that control tight gas production. The NPC effort was substantial and represented the most appropriate appraisal methodology for the extent of tight sands

Figure II-1. NPC Estimates of Tight Gas Resource In Place (Appraised Basins)



Source: NPC 1980.

development at the time. Development in the past decade (over 42,000 tight sands wells were drilled between 1979 and 1986, the latest year for which detailed data are published), however, has provided enough new data to allow more detailed geologic appraisals of some basins.

Second, the NPC data represent only the highest quality portion of the low permeability settings (potentially productive areas based on 1978-79 assumptions concerning technology and market conditions). Recent exploration, as well as advances in formation evaluation, stimulation, and production practices, have resulted in significant additions to the prospective U.S. tight gas resource. For example, the Dakota Formation constituted the entire NPC tight gas resource for the San Juan Basin, while current development indicates remaining potential from several other formations. The Wilcox and Vicksburg in South Texas and the Clinton-Medina and Berea in Appalachia are other examples of major current tight gas plays that were excluded from the NPC explicit basin appraisal (although they may be implicit in the NPC extrapolated resource base). Finally, recent estimates of tight gas in place by the U.S. Geological Survey for the Piceance and Green River Basins are substantially higher than those of the NPC. The large differences between the NPC and USGS approaches of these basins raise questions about the ability to accurately estimate potential reserves.

B. Research Objectives

The first significant U.S. production of tight gas occurred in the San Juan Basin from the Dakota sands to supply the growing California market in the 1950's. Since that time, multiple tight horizons have been produced, principally the Dakota, Pictured Cliffs, Sanostee member of the Mancos shale, Cliff House and Point Lookout sands of the Mesaverde. Since the NPC appraised only a small portion of the total undeveloped area of the Dakota (only areas at the basin margin outside the boundaries of producing fields), many analysts contend the 3 Tcf of undeveloped tight resource estimated for the San Juan Basin is too low. As shown later in this report, the validity of the NPC's appraisal was confirmed for those areas it appraised. This study updates and extends the appraisals for all currently undeveloped tight portions of the basin.

Accurate estimation of the San Juan tight gas resource is important for two reasons. First, the demand for gas from the region is large. It is estimated that gas demand from the Southern Rocky Mountain area (which includes the San Juan Basin) will increase substantially during the 1990

- 2010 period. The recently approved Mojave pipeline will provide an outlet for additional San Juan Basin gas supplies to the cogeneration and EOR markets in California. Although originally planned to bring gas from the Piceance Basin, backhauling San Juan gas through the planned TransColorado line provides another possible outlet. Also, demand in West Texas will increase over the same period, and some San Juan gas production may move east.

Tight sands can play a major role in meeting the demand for increased San Juan gas reserves, yet no clear characterization of tight sands existed in terms of resource in place, productive potential or technology needs. An effective formation evaluation and stimulation R&D program cannot be designed without knowing the near term technical constraints to increased production. This study provides the analytical basis to improve the effectiveness of tight sands R&D.

Past estimates of tight gas potential in the San Juan Basin have ignored large areas of currently producing tight formations on the assumption that the reserves they contain are mostly proved. This overlooks the potential impact that advanced technology could have on recovery from undeveloped acreage in the near term. Only a complete appraisal, which includes both undeveloped prospects in producing plays and undeveloped plays can evaluate the potential of such advanced technologies to add tight gas reserves in the San Juan Basin.

The purpose of this study was to compile and interpret the discrete geological and technological data needed to estimate potential reserve additions under alternative technology scenarios (i.e., current operator practices and implementation of advanced technologies). The overall study had three principal analytic objectives:

- Estimate the Remaining Tight Gas Resource In Place. Conduct a detailed analysis of the geologic and reservoir properties of the five low-permeability sandstone intervals in the San Juan Basin, to estimate the gas in place and its geologic/regional distribution.

- Estimate Technical Recovery and Reserves. Estimate tight gas production under current stimulation and operating practices. Establish the economics of predicted gas production using explicit costing of required technologies and standard industry financial analyses.

- Determine the Impact of Implementing Advanced Technologies. Estimate aggregate incremental production and economic benefits resulting from the use of newly developed technologies on currently undeveloped San Juan tight gas prospects.

All three of these analytical objectives were met and the results are reported in Chapter IV.

C. Scope of Work

This analysis incorporated available public data on geology and production of the San Juan Basin. We analyzed the data to estimate remaining reserves using log interpretation, reservoir simulation and economic modeling. No additional field work or well testing was proposed or conducted. The scope of this work was limited to a comprehensive survey of currently available data for the San Juan Basin, geological analyses and mapping, and reservoir and economic analyses. The analysis was built on data previously collected by ICF Resources, state geological surveys, regional geological associations, and published analyses and records for the various formations in the San Juan Basin. Where necessary, production and well records were obtained from commercial data services (Petroleum Information and Dwights Energydata) and operators.

D. Application of Results

A principal value to industry of this analysis is the transfer of these research findings within a regional geologic, technical and economic framework. The San Juan is a mature basin, with future development potential likely to be in decreasing quality reservoir settings. As it is developed further, a better understanding of those geological and technical parameters that limit recovery is needed to maximize recovery from these lower quality settings.

III. Summary of Analytic Approach

The core of the analytic approach was the selection and study of representative producing wells in the most active low permeability San Juan Basin reservoirs. We estimated potential recovery from these typical wells for both current and improved technology to determine the benefits of successful R&D. These benefits and increased potential were then extrapolated to the remaining undeveloped areas to estimate maximum benefits of applying improved technology for tight gas in the San Juan Basin. The analytic approach consisted of ten tasks:

Task 1 - Characterize Geological Setting
Task 2 - Delineate Tight Portions of Target Stratigraphic Intervals
Task 3 - Develop Historical Production/Reservoir Properties Database
Task 4 - Map Reservoir Engineering Characteristics
Task 5 - Complete Geological Analysis and Develop TGAS-PC® Database
Task 6 - Validate Recovery Models and Define Current Production Practices
Task 7 - Conduct Case Studies
Task 8 - Estimate Gas in Place and Technically Recoverable Gas
Task 9 - Estimate Potential Tight Gas Reserves
Task 10 - Conduct Technology Sensitivities

A. Task 1 - Characterize Geological Setting

We conducted a literature review to identify and compile geologic and reservoir data specific to the five San Juan Basin intervals evaluated in this appraisal. Data were used to better understand reservoir geometry, formation lateral extent and geologic characteristics. Key data collected include geologic cross-sections, reservoir properties, and fracture trends. A bibliography of literature is included in this report as Appendix A.

Geological data were reviewed and operator contacts established to support geological and reservoir engineering analyses in subsequent tasks. Regional cross-sections were identified and an index map constructed to better understand correlations previously established for the target formations. As part of the geological appraisal we constructed a limited number of cross-sections for specific areas and/or formations lacking in cross-section coverage, although these were not published.

B. Task 2 - Delineate Tight Portions of Target Stratigraphic Intervals

Most gas productive formations in the basin contain a mixture of tight and non-tight reservoirs. This task delineated the tight portions of the formations. The structural setting of the basin, deposition and diagenesis were reviewed to determine which geological characteristics make some portions of these reservoirs tight.

The unit of analysis for this study is the stratigraphic interval within a township. There are 222 townships within the area of the basin bounded by the outcrop of the Pictured Cliffs. Although deeper formations extend areally beyond this limit, these portions are either high permeability, water infiltrated, or not gas bearing. The five stratigraphic intervals selected for this analysis are (in descending stratigraphic order):

1. Pictured Cliffs
2. Chacra
3. Cliff House
4. Point Lookout
5. Dakota

Thus, there are potentially 1,110 analytic units (= 5 intervals X 222 townships).

Geological analyses were conducted to estimate reservoir properties for each unit of analysis, and a typical well was selected as the basis for reservoir engineering and economic analysis. Over 300 geophysical logs were interpreted and correlated with prior studies. Data sheets were completed for selected wells as control points for the geologic analysis and included the following information: well identification and location, well status, formation depths and thicknesses, perforation intervals, completion intervals, temperature, pressure, permeability, porosity, water saturation, and fracture information. In producing areas, reservoir properties were based on averages for current wells in respective analytic units.

C. Task 3 - Develop Historical Production/Reservoir Properties Database

Geological data were compiled for the selected formations from public sources, commercial data services and from operators. From wells evaluated to be typical of each unit of analysis (township/interval combinations), geophysical logs were used to derive the depth and thickness of target formations. Although rarely available, interpreted logs with calculated values of kh based on known cutoffs and water saturation data were used. These were supplemented and validated by contacts with state geological survey personnel and operators currently active in the basin. Historical production data were collected for use in history matching.

D. Task 4 - Map Reservoir Engineering Characteristics

Based on accepted geological appraisal practices, cross sections correlating the target formations within the designated low permeability regions were constructed, with stratigraphic markers and regional depositional trends used as guides. These were supplemented by overburden, structure, and net sand isopach maps for each target sand based on data from previous tasks. Since permeability varies widely even within a single township (the unit of analysis for this study), a permeability map was deemed inappropriate.

Since a credible geological appraisal requires delineation of contours across a formation of the key reservoir properties defining gas content, we also developed porosity, water saturation and initial pressure contour maps from known data in each target formation. In areas lacking well control, reservoir properties were assigned based on regional correlations. Due to the maturity of the San Juan Basin and extensive well control, this step was necessary for less than 10% of analytic units.

E. Task 5 - Complete Geological Analysis and Develop TGAS-PC® Database

A TGAS-PC® database was created for typical wells in the target San Juan formations. The database contained location, reservoir properties, and undeveloped area represented by each typical well. Reservoir properties were derived from field data, operator reports and history matching of production data for one well in each township. Data were checked against default values and all anomalous values were verified or additional data were obtained to support revisions. Where no wells or data on such wells existed for a township, properties were extrapolated from the closest and most geologically similar township. Production estimates using these reservoir data and alternative technology assumptions were the basis for quantifying the benefits of improved technology.

The TGAS-PC® data record for a typical well in each unit of analysis contains the following information:

- Location (township and range)
- Producing Interval
- Depth
- Pressure
- Temperature
- NGL Yield
- In Situ Permeability
- Porosity
- Water Saturation
- Net Pay
- Drainage Area
- Decline Constant

The results of analyses on each of these typical wells was scaled up to the unit of analysis based on remaining undeveloped areas. The results of technology and economic analyses on each unit were aggregated to define an overall impact of alternative technologies on tight gas recovery and reserves in the San Juan Basin.

F. Task 6 - Validate Recovery Models and Define Current Production Practices

Two computer models (MIDA® and TGAS-PC®) were used in the analysis, each of which was validated against benchmarks in the literature. First, history matching of production data to derive and/or confirm reservoir properties using advanced decline curve analysis. Second, estimation of production as a function of alternative technology scenarios and estimation of reserves was accomplished with a type curve model. The type curves are one component of TGAS-PC®, an integrated tight gas production and economics model developed under partial sponsorship of METC. Type curve production estimates were validated by a 2D, finite difference reservoir simulator.

A survey of seven active operators was conducted to determine current practices and potential future practices. Practices included formation evaluation, drilling and completion, production equipment, and stimulation. The dominant operator in each major producing field and/or the operator of each typical well was contacted. These survey results and additional analyses of wells were used to develop "Current" and "Advanced" technology scenarios. Current technology represents the practices generally in use across the basin. Advanced technology represents the practices and technologies applied by the most sophisticated operators in the best geological settings. The specific technology parameters used to evaluate current and advanced cases are shown in Table IV-4 of this report. With sufficient R&D to demonstrate widely the effectiveness of these technologies and to reduce costs, these technologies could be more uniformly implemented in the basin.

G. Task 7 - Conduct Case Studies

Four small-scale (a few townships each) studies were conducted to confirm reservoir properties and validate recovery projections (Pictured Cliffs, Chacra, Mesaverde, and Dakota). Monthly production data for gas, water and condensate, as well as flowing pressures and days on line were collected where available and analyzed for these areas. Additional data collected for these small-scale studies included well test, stimulation and completion data. These data were combined with production data to evaluate reservoir properties. Data sources consisted of PI cards and completion reports, obtained from Petroleum Information, state agencies, field hearing files, and operators. The study for the Pictured Cliffs is discussed in detail in Chapter IV.

H. Task 8 - Estimate Gas in Place and Technically Recoverable Gas

Gas in place and ultimate recovery were calculated for typical wells within each unit of analysis. The appropriate reservoir parameters for each township were derived from the geologic and reservoir engineering data developed in prior tasks. The typical well reservoir properties (derived in Task 5) were not adjusted or weighted in any way. Type curve analysis was used to estimate typical well recoveries. The base case (current practice) technology assumptions (e.g., fracture length, conductivity, and height) were explicitly modeled. For selected units of analysis, both reservoir simulation and advanced decline curve analysis were used to confirm the results of type curve modeling. The decline curve technique, developed by Fetkovich and based on fluid flow equations and real gas laws, provides more valid estimates of resources than the more commonly used graphical decline curve methods.

I. Task 9 - Estimate Potential Tight Gas Reserves

Investment and operating costs of wells were incorporated into the analysis to determine economically recoverable gas as a function of technology. The analysis used industry standard financial calculations to determine the minimum levelized constant wellhead price required to make a 10% return on investment. Other financial performance indicators, such as payback, ROR and NPV were also calculated. Results were aggregated into price supply curves for each formation. The areas with the lowest required prices were then checked with the operators to confirm that estimated low cost reserves are generally in the same areas as current development.

J. Task 10 - Conduct Technology Sensitivities

Incremental reserve additions at a given wellhead price for alternative technology scenarios were used as the measure of how effective advanced technologies could be. Improved technology usually increases recovery at a somewhat higher investment cost. Whether increased revenues offset increased costs is a function of the effectiveness of the improved technology relative to the formation characteristics of the area in which it is applied. The minimum required price for advanced technology is compared to the price estimated for current technology to determine which technology can be most cost-efficiently used to add reserves. Formation-specific price-supply curves were constructed to show the economic reserves at each market gas price and the aggregate benefit of R&D to add reserves.

IV. Results of Analysis

A. Characterization of Geologic Setting

This research builds on the efforts of others as well as ICF Resources. We used to the extent possible all publicly available analyses in San Juan Cretaceous reservoir characterization, geologic appraisals, resource maps, well tests, and production data. The description of San Juan Basin geology in this chapter includes summaries of prior studies, results of a literature search, cross section mapping, and an overview of structure and stratigraphic characteristics of the basin.

1. Prior Studies

Several prior studies were reviewed to determine a context for this research and to avoid duplication. The most relevant sources of information were: FERC tight gas designations, the 1980 NPC Unconventional Gas Resources study, the biennial report of the Potential Gas Committee, the University of Texas Bureau of Economic Geology, the petroleum literature, American Gas Association, and other public information on specific San Juan formations. Only some of these studies specifically evaluated tight sands; others include only portions of it.

Federal Energy Regulatory Commission

The Natural Gas Policy Act of 1978 (NGPA) provided for a category (Section 107 (c) (5)) of regulated gas deemed "high cost" and eligible for incentive pricing. Regulations implementing the NGPA, administered by the Federal Energy Regulation Commission (FERC), provided for the designation of formations within specified geographic areas as "tight." To encourage development of the tight resource, such designations allowed for a regulated wellhead ceiling price twice that of new gas from non-tight sources.

The process to designate these areas required explicit documentation from operators (i.e., engineering data supporting an in situ permeability of 0.1 md or less, adherence to guidelines for depth-specific unstimulated flow rates, and elimination of areas with wells that produce more than 5 barrels per day of liquids). The FERC tight gas designations are viewed as one of the most relevant indications of near-term interest in tight sands. These designations must go through a rigorous certification process at the state level and it is in the best economic interest of industry to designate them as tight. Much of this data from the San Juan Basin designations is still on file at the New Mexico and Colorado state agencies.

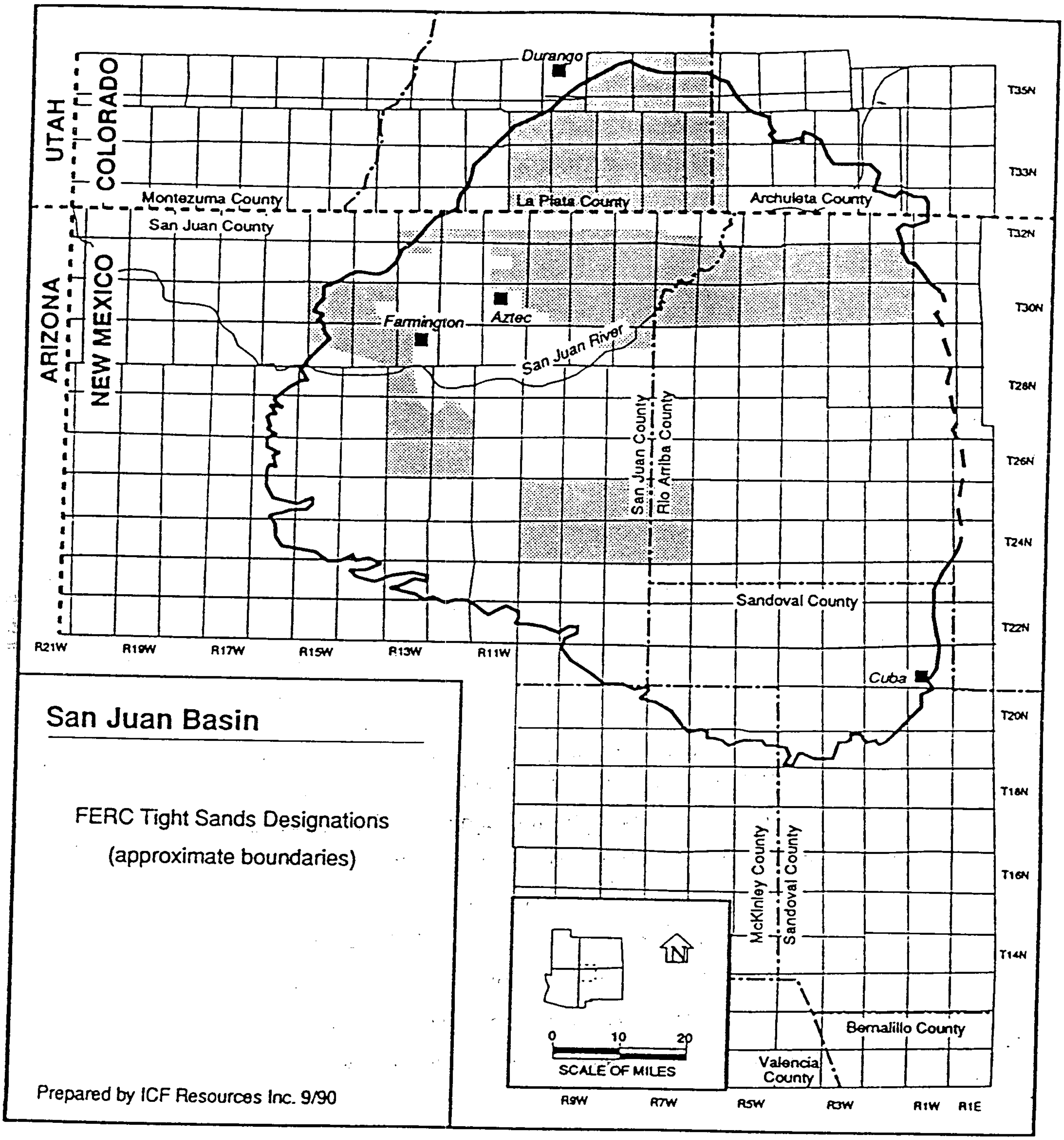
FERC has approved 19 separate tight formation designations in the San Juan Basin that total over 2,000 square miles. Actual surface area is less than the sum of designated areas since many designations overlay or underlay others. These range in size from a Mesaverde designation covering 7 sections, to a Dakota designation covering 528 sections. Table IV-1 shows the formations designated, indicating the extent of near-term tight formation potential seen by operators. Their general location within the basin is shown in Figure IV-1.

Table IV-1. FERC Tight Gas Designations in the San Juan Basin

Formation	# Designations	Total Area (square miles)
Fruitland	1	47
Pictured Cliffs	2	75
Chacra	3	158
Mesaverde	3	546
Sanostee	1	106
Dakota	9	2,015

Note: Areas are not additive since many of the designations overlap.
Source: Haas (1985).

Figure IV-1. FERC Tight Sands Designations for San Juan Basin



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The National Petroleum Council (NPC)

The NPC's 1980 assessment of unconventional gas included the Dakota as the only formation considered as having significant remaining potential for tight gas in the San Juan Basin. The NPC geologists felt that the major producing horizons were all Upper Cretaceous in age. Since the tight portions of the Blanco Mesaverde field were mostly developed and the Pictured Cliffs sands were of limited extent, they felt only the Dakota remained as a development target. The limits of the remaining tight portions of the Dakota, as defined by the NPC, were outside current producing field limits and within the occurrence of updip water. The NPC considered most of the basin center to be proved reserves and only estimated approximately 3 Tcf in place as the potential Dakota tight gas resource.

University of Texas Bureau of Economic Geology (BEG)

The BEG compiled and published data on several formations in the San Juan and other basins in 1984. These summaries were derived principally from the data supplied by operators for FERC designations and the published literature. The compilation of data on reservoir properties, geologic features, development activity, and economic parameters provides a good overview of each formation. No independent estimates of gas in place, technical recovery, or potential reserves were reported.

Potential Gas Committee (PGC)

The PGC conducts a biennial analysis of remaining recoverable gas resources in the U.S. They provide probability-weighted, aggregate (all formations combined) estimates by basin of natural gas in the probable, possible and speculative categories. The PGC considers only those resources producible with current technology and economics, thus most of these estimates represent the conventional and higher quality tight reservoirs. PGC's "most likely" estimates for the San Juan Basin are 1.5 Tcf in the probably category, 0.5 Tcf as possible. Due to the extensive development of the basin, the PGC estimates no speculative resource. These amounts seem low when the large number of as yet undesignated infill and extension locations in currently producing reservoirs are considered.

American Gas Association (AGA)

AGA compiles data for booked reserves for the largest fields in the San Juan Basin. Data for New Mexico are only published aggregated at the formation level, and include tight as well as conventional permeability portions of the identified reservoirs. Cumulative production and proved reserves by formation are useful benchmarks of current activity (Table IV-2). These data can be compared to tight gas potential estimated by this study to provide a context for incremented reserve additions.

Table IV-2. 1989 Production and Reserves of the San Juan Basin

Formation	Cumulative Production (Bcf)	Proved Reserves (Bcf)
Fruitland Sands	63	74
Pictured Cliffs	3,282	1,467
Chacra	177	181
Mesaverde	7,302	6,088
Dakota	4,646	3,671

Note: Production and reserves data are from the New Mexico portion of the basin only. AGA reports various formations in the Ignacio-Blanco field in Colorado as containing approximately 0.9 Bcf of remaining reserves.

Source: AGA (1990).

2. Literature Search

We conducted a literature search for studies and data for the five target formations using data bases at the U.S. Geological Survey Library, Denver Earth Resources Center, Colorado School of Mines, and the American Geological Institute (GeoRef). Identified sources includes San Juan Basin topical reports, company well and field reports, state regulatory body reports and hearing testimony, professional society publications, theses and textbooks.

We compiled data on formation descriptions (i.e., including depositional environments, lithology, lateral extent, maps, cross-sections), and reservoir data (i.e., core analyses, well tests, porosity, permeability and water saturation, fracture analyses, and stimulation treatments). Many of the references applicable to the study were found in publications already held by either the Denver or the Fairfax ICF Resources libraries. Literature not found in-house was purchased or photocopied and is on file in the Denver ICF office. A bibliography of the literature containing 130 references is attached as Appendix A.

3. Cross-Section Index

ICFR collected regional cross-sections and posted their locations on an index map (Figure IV-2). Eighteen published cross-sections were collected as broad representation of the Pictured Cliffs, Chacra, Cliff House, Point Lookout, and Dakota Sandstones. These cross-sections provided a basis for determining formation trends and continuity. Correlations from one cross-section to another were not, however, always effective in determining continuity, since they were based on varying factors such as log quality, criteria for picking sand interval tops, bottoms and thickness, and personal judgement. The correlations do, however, represent the best publicly available data.

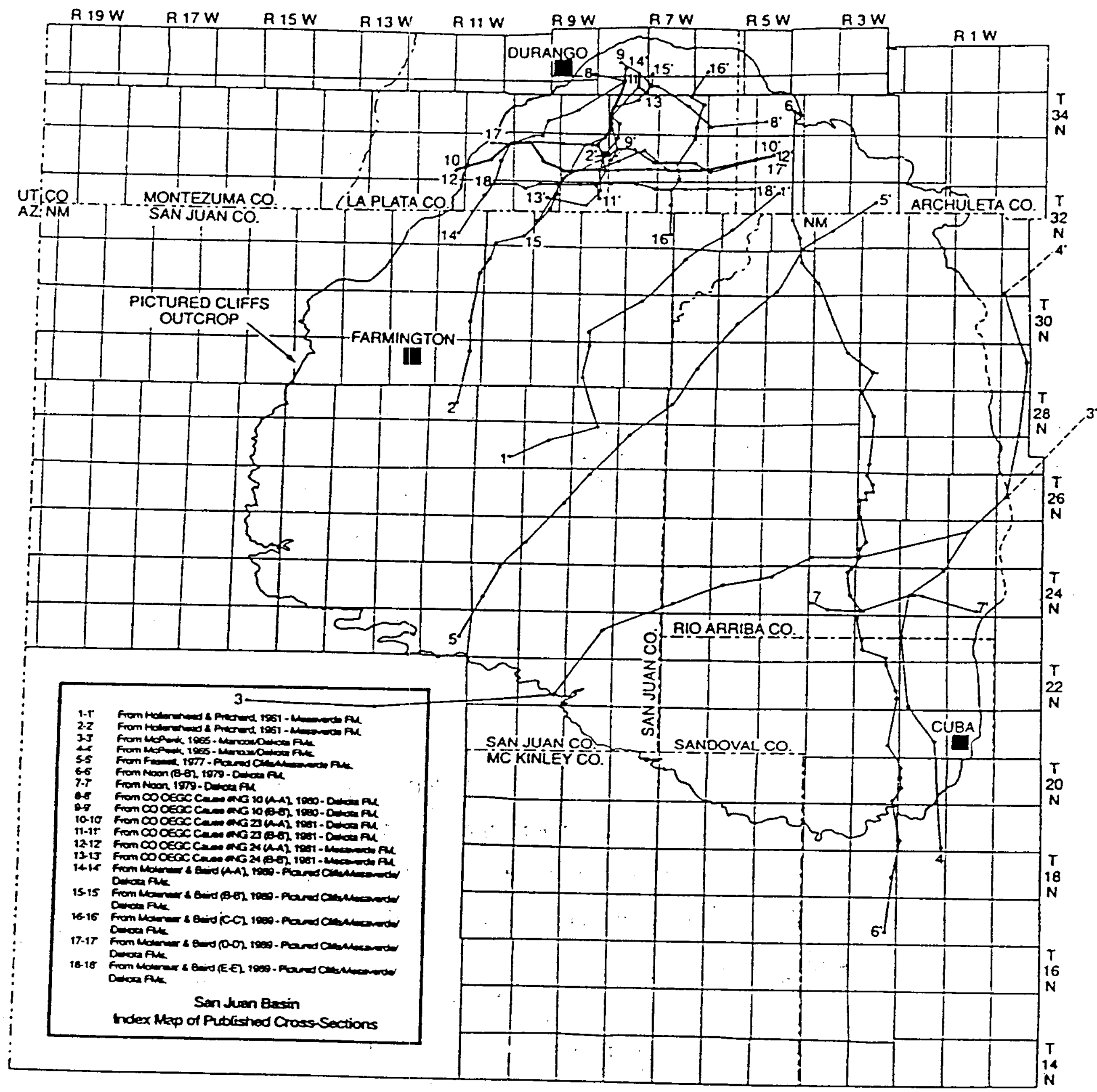
4. Geologic Setting

The San Juan Basin, located in southwest Colorado and northwest New Mexico and is roughly circular in shape. The basin extends approximately 100 miles, north to south, and 90 miles, east to west. The basin contains about 25,000 cubic miles of sediment. For this investigation, the study area is stratigraphically defined by the outcrop of the top of the Pictured Cliffs Sandstone. The study area encompasses an area of approximately 7,500 square miles, and includes portions of six counties: La Plata and Archuleta counties Colorado, and San Juan, Rio Arriba, Sandoval, and McKinley counties, New Mexico.

5. Structural Setting

The San Juan Basin is defined structurally by numerous monoclines and uplifts that were formed during the late Cretaceous and early Tertiary time (Figure IV-3). The northern boundary of

Figure IV-2. Regional Cross Section Index



Source: ICF Resources Incorporated

the basin is formed by the Hogback Monocline. Structural relief is over 7,800 feet and strata dip basinward at angles up to 60 degrees. The south eastern boundary is formed by the Nacimiento Uplift and the Ignacio Monocline. To the south the sediments rise gently on the Chaco Slope and are bounded by the Zuni Uplift. Along the western portion of the basin the strata again begins to rise sharply, pushed up by the Defiance Monocline and the southern end of the Hogback Monocline.

Radial folds and normal faults occur around the basin perimeter and are the result of the uplift of monoclines and subsidence of the basin. Anticlines and synclines are found on a localized scale, but in general the rocks are flat or gently dipping (Kelley, 1957, 1960, and Condon, 1988). Figure IV-4 shows the tectonic features of the basin.

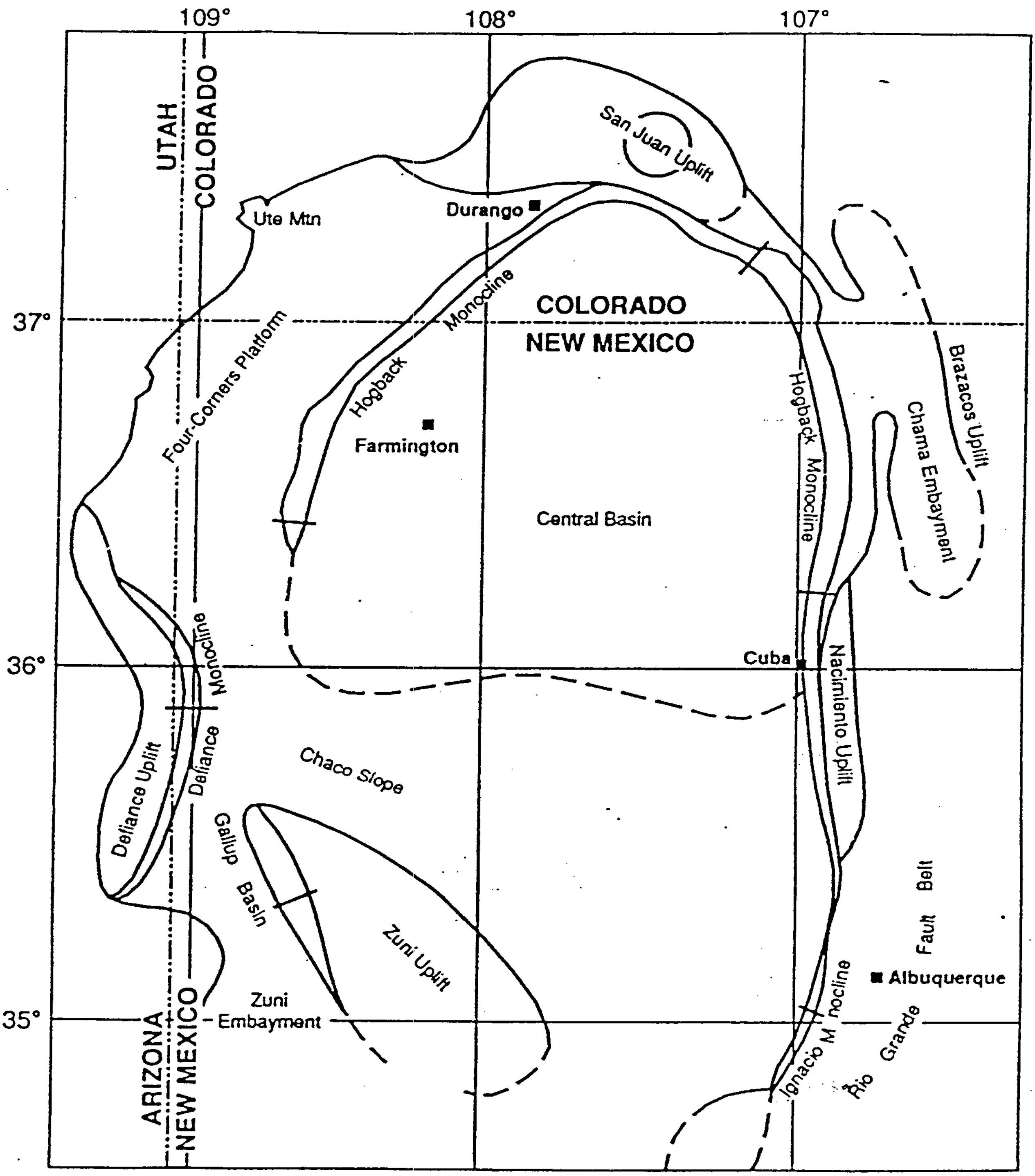
6. Cretaceous Stratigraphy

The Cretaceous formations of the San Juan Basin owe their existence to an epirogenic sea that transgressed and regressed from north to south through the region approximately 100 million years ago. The Cretaceous formations in ascending order are the Dakota Formation, Mancos Shale, Gallup Sandstone, Point Lookout Sandstone, Menefee Formation, Cliff House Sandstone, Lewis Shale, Chacra Sandstone, Pictured Cliffs Sandstone, Fruitland Formation and the Kirtland Shale (Figure IV-5). Many of the references in Appendix A discuss Cretaceous stratigraphy.

The *Dakota Formation* ranges from 175 to 275 feet in thickness and is generally divided into three zones. The lowest zone is a fluvial, coarse conglomerate generally water-bearing and nonproductive in the center of the basin. The middle zone is a paludal, carbonaceous shale and coal sequence with localized sandstones. The upper zone is a fined-grained, marginal marine sandstone. The Upper two zones are more continuous and generally gas bearing. The NPC estimated historically productive areas to have producing intervals averaging 50 to 70 feet, porosity of 8% and water saturation ranging from 30 to 50%.

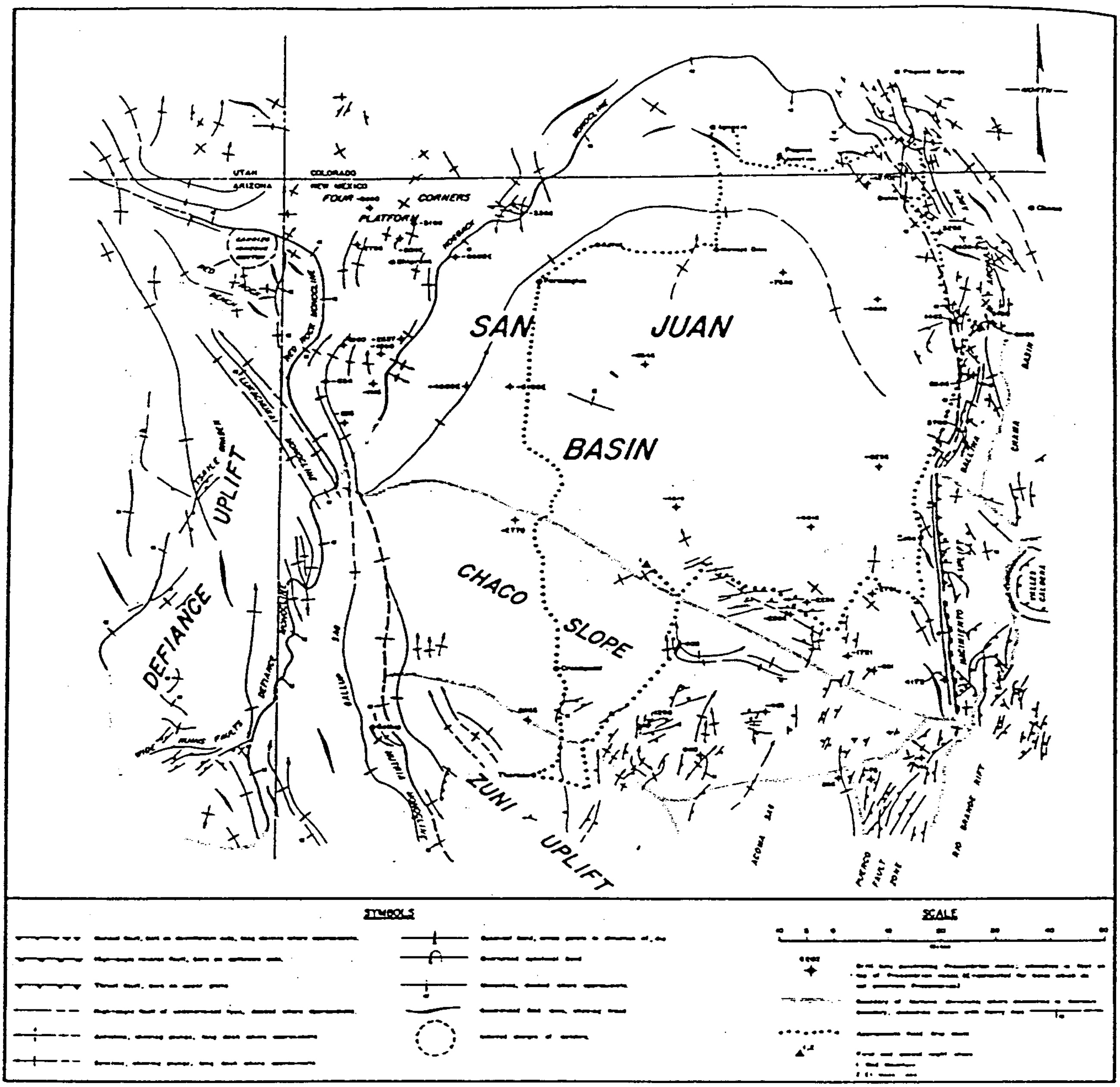
The *Mancos Shale* was deposited seaward of the Dakota in a deep water, low energy environment and ranges in thickness from 400 to 2,000 feet. Within the Mancos Shale is the *Gallup Sandstone*, a regressive sand found in the southern part of the basin that was deposited as a near shore beach sand, and ranges from 10 to over 100 feet in thickness. The Gallup is generally

Figure IV-3. Structure Map of the San Juan Basin



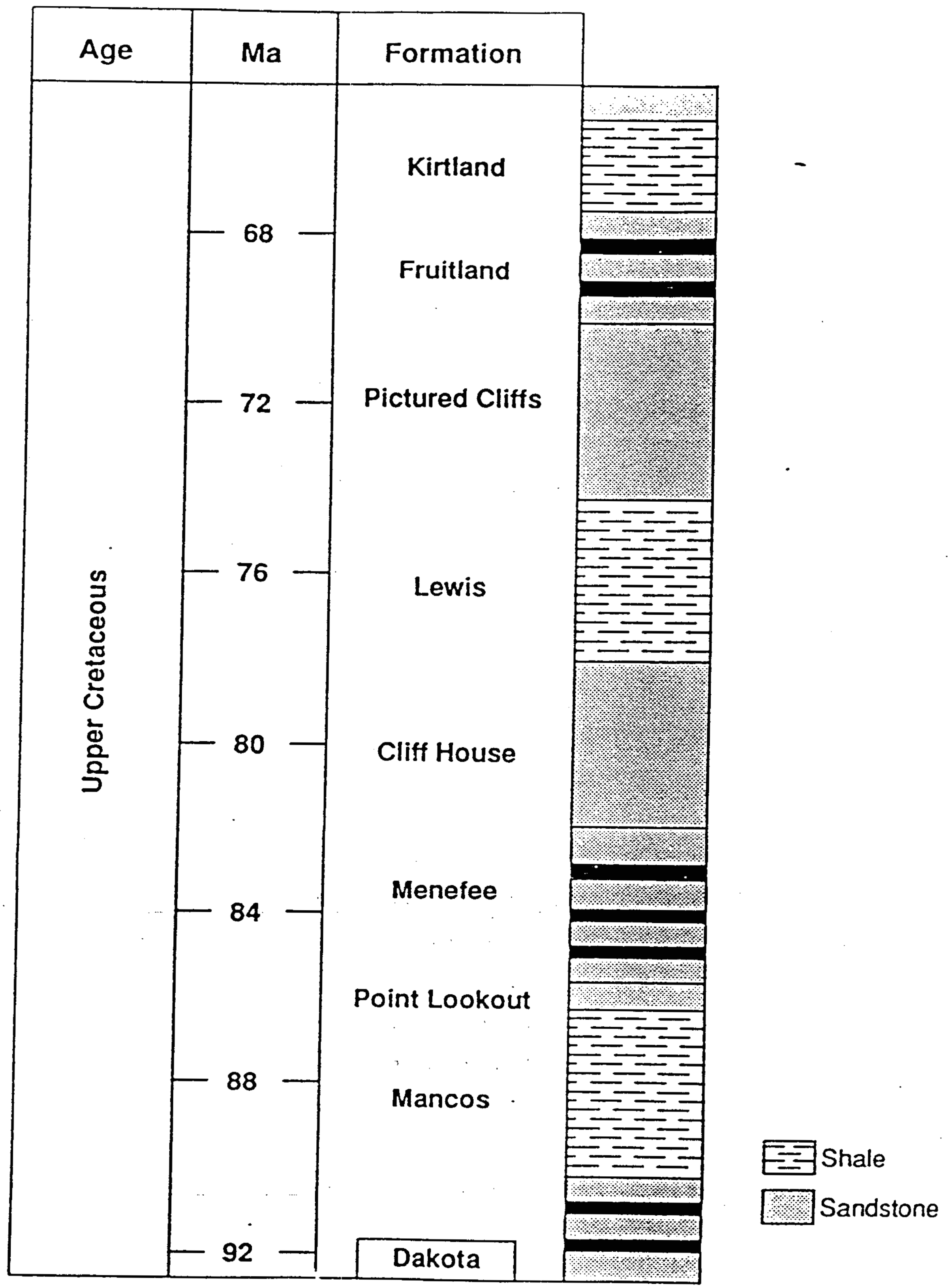
Source: A. Kelley (1951, p. 125)

Figure IV-4. Tectonic Features of the San Juan Basin



Source: Woodward and Collender, 1977; Courtesy New Mexico Geological Society

Figure IV-5. Stratigraphic Cross-Section of the San Juan Basin



Modified from: Kelso and Rushworth, 1982

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productive of oil with associated gas. No extensive tight zones have been reported in the backup.

Overlying the Mancos is the Mesaverde Group which ranges in thickness from 200 to 2,500 feet. It is divided into three members: the Point Lookout Sandstone, the Menefee Formation and the Cliff House Sandstone. The lowest member, the *Point Lookout*, is a regressive barrier beach sandstone, deposited as the sea withdrew from the region from south to north with a shoreline trend generally west to southeast. The *Menefee Formation* was deposited in floodplain, swamp and lagoonal environments, shoreward of the Point Lookout and overlying Cliff House Sandstones. It consists of mudstone, carbonaceous shale, siltstone, coal, floodplain sandstone and fluvial sandstone. The Menefee ranges in thickness from 50 feet in the extreme northeast to more than 2,000 feet in the southwest. Overlying the Menefee Formation is the *Cliff House Sandstone*, deposited as a beach sand when the sea transgressed from north to south. In general the shoreline parallels the shoreline trend of the Point Lookout.

The *Chacra Sandstone* and an upper unnamed tongue of the La Ventana Sandstone of the Cliff House Sandstone intertongue with the Lewis Shale. The Chacra lies unconformably above the Mesaverde and the gas productive areas are generally found in the northern and central parts of the basin.

The *Lewis Shale* is a marine shale, ranging from 100 to 2,500 feet in thickness. It contains sandy intervals (intertonguing from the La Ventana Sandstone of the Cliff House Sandstone), calcareous concretions and numerous bentonite beds. The Huerfanito Bentonite bed is frequently used as a correlation tool within the basin. Located in the upper portion of the Lewis shale, the Huerfanito can be identified on resistivity, conductivity and transit-time geophysical logs, and has been correlated across the entire basin (Fassett and Hinds, 1971).

Overlying the Lewis shale is the *Pictured Cliffs Sandstone*, a regressive, coastal-barrier sandstone. The depositional environment and geometry of the Pictured Cliffs is similar to that of the Point Lookout.

The *Fruitland Formation* was deposited over the Pictured Cliffs and is similar to the Menefee Formation. It is a coastal plain deposit of paludal carbonaceous shales, siltstone, sandstones and coals deposited shoreward of the Pictured Cliffs. The formation ranges from less than 100 feet in the southeast to greater than 600 feet in the northwest.

The uppermost Cretaceous formation in the basin is the *Kirtland Formation*. It is 1,000 to 2,000 feet thick, deposited in back coastal areas and floodplains. It is divided in to a lower shale member, gray to brown in color, and an upper shale member, the Farmington Shale, which consists of shale and sandstones.

7. Hydrocarbon Occurrence

Hydrocarbon occurrence of the Cretaceous Rocks of the San Juan Basin generally can be separated into two settings. Around the perimeter of the basin reservoirs are stratigraphically higher than their counterparts in the central portion of the basin. In these perimeter areas, oil and associated gas are produced, and in the center of the basin, nonassociated gas is produced with very little oil or condensate. The type of hydrocarbon found in a given location is affected by numerous mechanisms which are, as a whole, not fully understood. These mechanisms include chemical composition of the hydrocarbon, structure, water saturation, water contact and thermal history. More detailed discussions of hydrocarbon occurrence can be found in the literature.

B. Delineation of Tight Portions of Target Intervals

Our geological analysis was based primarily onlog evaluation and geologic information from published literature, maps and cross-sections. These were used to estimate reservoir properties and to delineate the lateral extent and continuity of the target sands.

Because there is a lack of published cross-sections representing the entire mid-basin trending north-south and east-west, three cross sections were constructed to depict the correlation made in this study. These in-house cross-sections assisted in determining formation tops, pinch-outs and thickening in the sandstones studied.

As a result, some correlative interpretations vary form those found in literature, mainly due to differences in the criteria used for determining depth and thickness.

Geologic mapping was performed using a statistical mapping package and conventional mapping methods. Depth, structure, and net pay isopach maps were constructed based on information obtained from the data sheets. There was good well control to provide a foundation for constructing geologic maps of the Pictured Cliffs, Chacra, Cliff House, Point Lookout, and to a lesser extent the Dakota formations. Many logs did not fully penetrate the Dakota, thus limiting the degree of well control for this stratigraphically deeper formation. The results of the geologic analysis (overburden, structure and isopach maps) are presented below.

The definition used for picking the tops of the target tight sands are as follows (see Figure IV-5 for Cretaceous stratigraphy):

Pictured Cliffs: the first regressive marine sand after the last Fruitland coal;

Chacra: the bar sand(s) occurring 350 to 550 feet below the Huerfanito Bentonite, below the Unnamed Tongue of the Cliff House Sandstone if present, and above the La Ventana Tongue of the Cliff House Sandstone;

Cliff House: the transgressive marine basal sand occurring above the first Menefee coal and below the Lewis Shale, and/or after the La Ventana Tongue Sandstone;

Point Lookout: the first regressive marine sand occurring below the last Menefee coal;

Dakota: the first regressive marine sand occurring below the Greenhorn Limestone and Graneros Shale, and including all fluvial sands to the top of the Morrison Formation.

The bases of the Chacra and fluvial Dakota could not be consistently determined because of the abrupt change in facies between the bar sands and the underlying shale. Likewise, the Cliff House base could be fixed due to the facies change between sand and coal. The Pictured Cliffs, Point Lookout, and marine Dakota all grade upward into coarser sands, making it difficult to determine a consistent basal contact with shale. Picking the base for these sands was achieved by a specific GR cutoff (80 API units or less), rather than determining that point where sand had completely graded into shale.

C. Historical Production and Reservoir Properties

Development of the San Juan Basin began in the 1920's and proceeded slowly, with significant production coming only recently from the five target intervals. The New Mexico portion of the basin currently has about 13,300 producing wells and 2,000 abandoned wells. Cumulative gas production as of 1989 was 15.2 Tcf.

In general, drilling in the basin has closely followed trends in wellhead prices. Recent drilling and production peaked with prices in 1985, then declined with prices during 1986-1988, finally recovering to former levels with firming prices in 1989. Table IV-3 shows New Mexico San Juan gas well drilling and production. By the end of 1990, extensive production of coalbed methane, stimulated by tax credits, has again depressed wellhead prices in the basin.

Table IV-3. San Juan (NM) Gas Well Drilling and Production

Year	Gas Wells Drilled	Total Gas Production (Bcf)
1985	539	431
1986	236	308
1987	100	309
1988	176	367
1989	351	420
Source: State of New Mexico (1990).		

1. Overview of Development History

Early Dakota activity was located on anticlinal structures around the Four Corners Platform. The central basin Dakota discovery well was drilled in 1947, although significant development still had not occurred by the mid-1950's. The Dakota basin field was discovered in 1961 and by 1976 contained 2,400 producing wells with cumulative production of over 2.7 Tcf (Huffman 1987).

Cumulative New Mexico Dakota production as of 1989 is 4.2 Tcf. As of 1989, there were about 3,550 producing wells and 660 abandoned wells.

Initial Mesaverde activity occurred in 1927, with the discovery of the Blanco Mesaverde field. The Ignacio Blanco Mesaverde field was discovered in 1952 and, with the Blanco Mesaverde field, encompasses much of the central basin. Almost 7 Tcf of gas has been produced from the New Mexico Mesaverde reservoirs as of 1989. There are currently about 3,600 producing and 480 abandoned wells in the New Mexico Mesaverde.

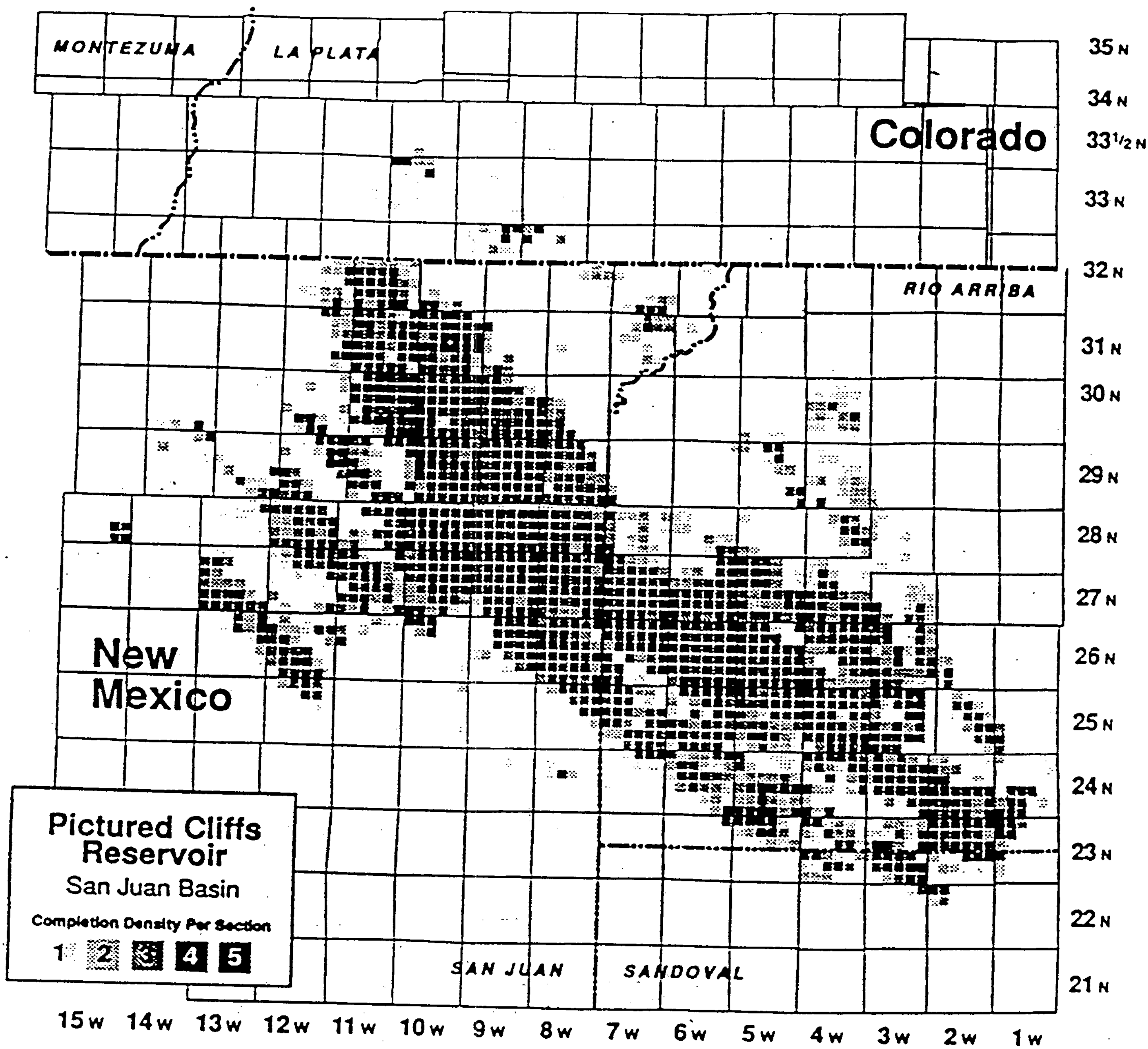
Pictured Cliffs gas was discovered in 1927 and most of the fields were discovered by the 1950's. Much of the more recent discoveries have been relatively small fields. The tight portion of the formation is generally to the north of the current producing areas. As of 1989, there were nearly 1,500 producing wells with a cumulative production of 1.2 Tcf.

2. Historical Production Patterns

Development of the five target formations is concentrated in the central part of the basin. Data from commercial sources were used to generate maps of total and producing wells, and upper and lower perforations data aided in determining development patterns and producing depths. The maps correlate closely with the formation depths derived from the log analysis. Figures IV-6 through IV-8 show the distribution of wells for the Pictured Cliffs, Mesaverde, and Dakota, respectively.

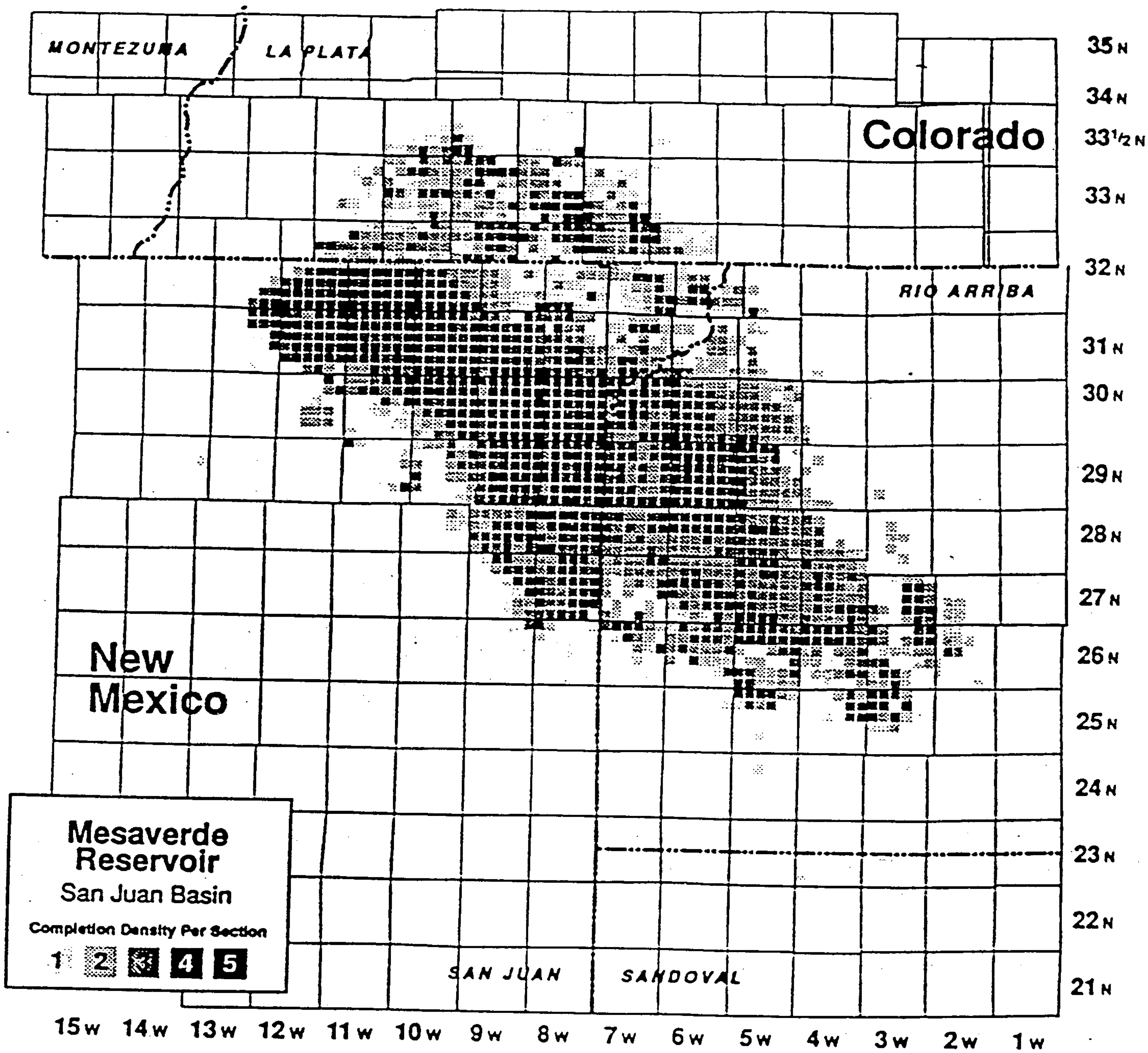
Over 300 geophysical logs were analyzed as part of the data collection and reservoir description phase of the study. Logs were selected on the basis of geographic dispersion and penetration of the maximum number of zones. Figure IV-9 shows the locations of wells used in the log analysis. Following log analysis, data sheets were completed listing all information derived from logs as well as other data sources. The data sheets represent the basic data repository supporting the TGAS-PC® database creation in Task 6.

Figure IV-6. Distribution of Wells - Pictured Cliffs



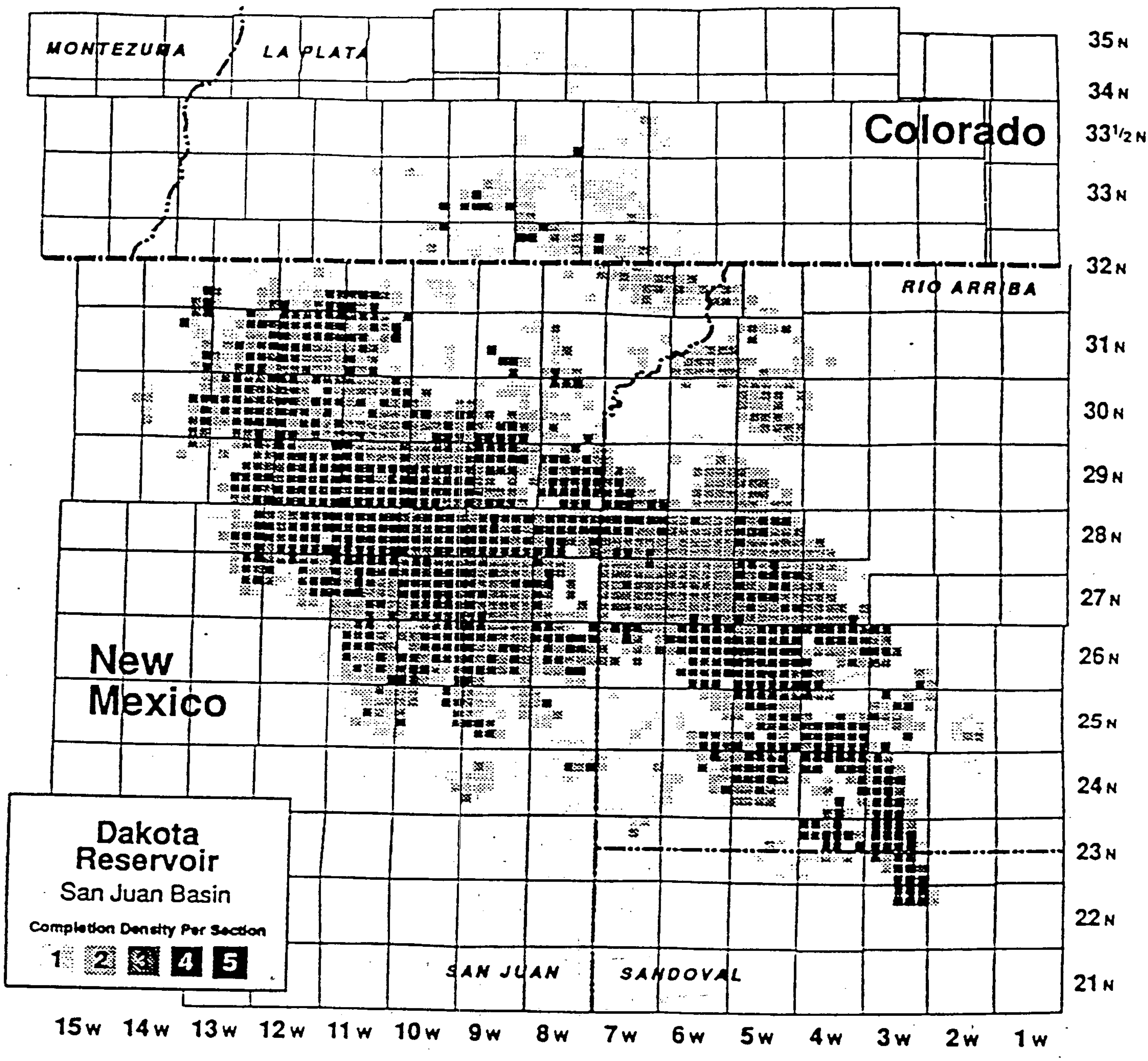
Source: Gas Research Institute (1989)

Figure IV-7. Distribution of Wells - Mesaverde



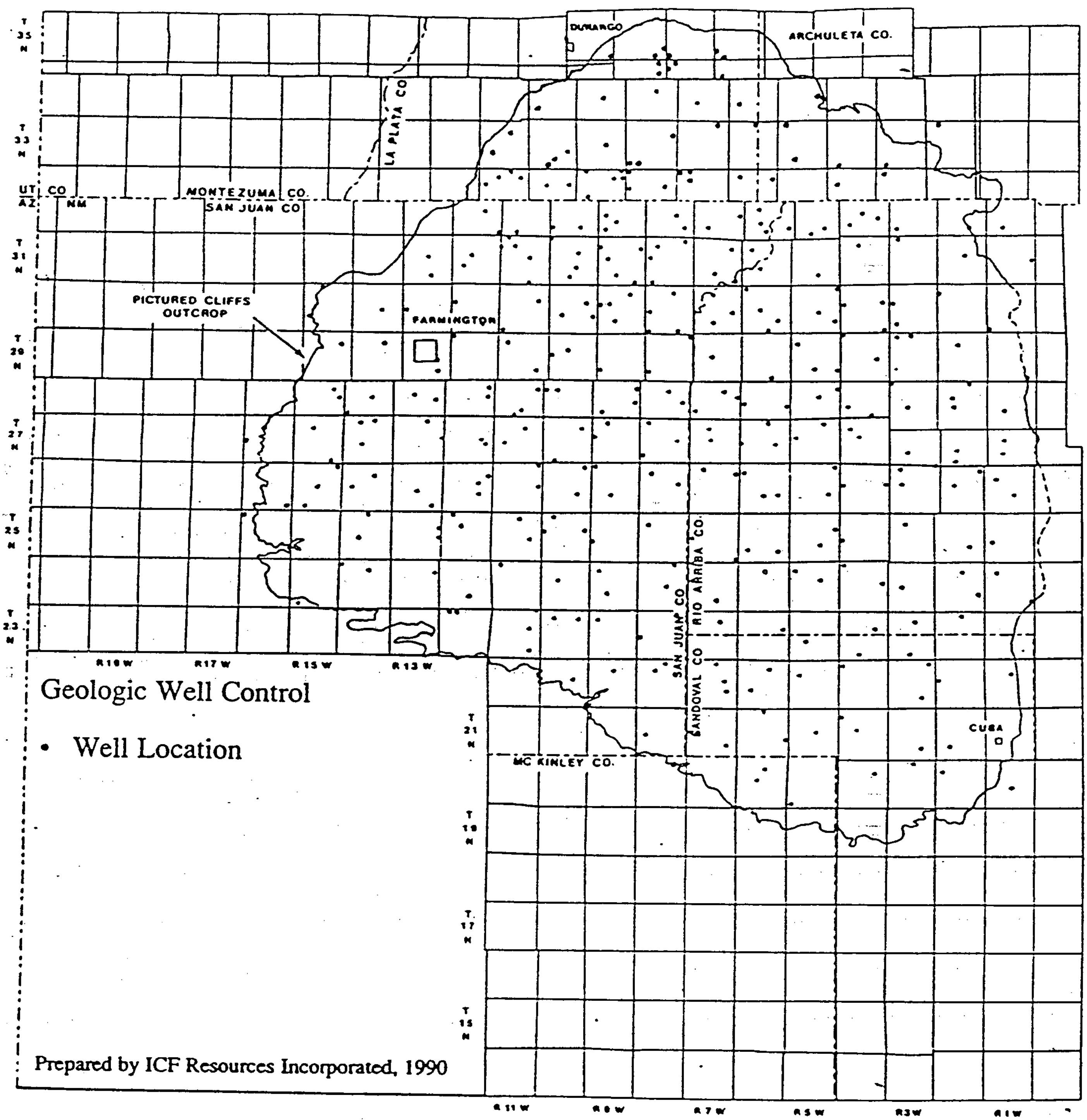
Source: Gas Research Institute (1989)

Figure IV-8. Distribution of Wells - Dakota



Source: Gas Research Institute (1989)

Figure IV-9. Location of Wells Used in Geologic Analysis



3. Log Analysis

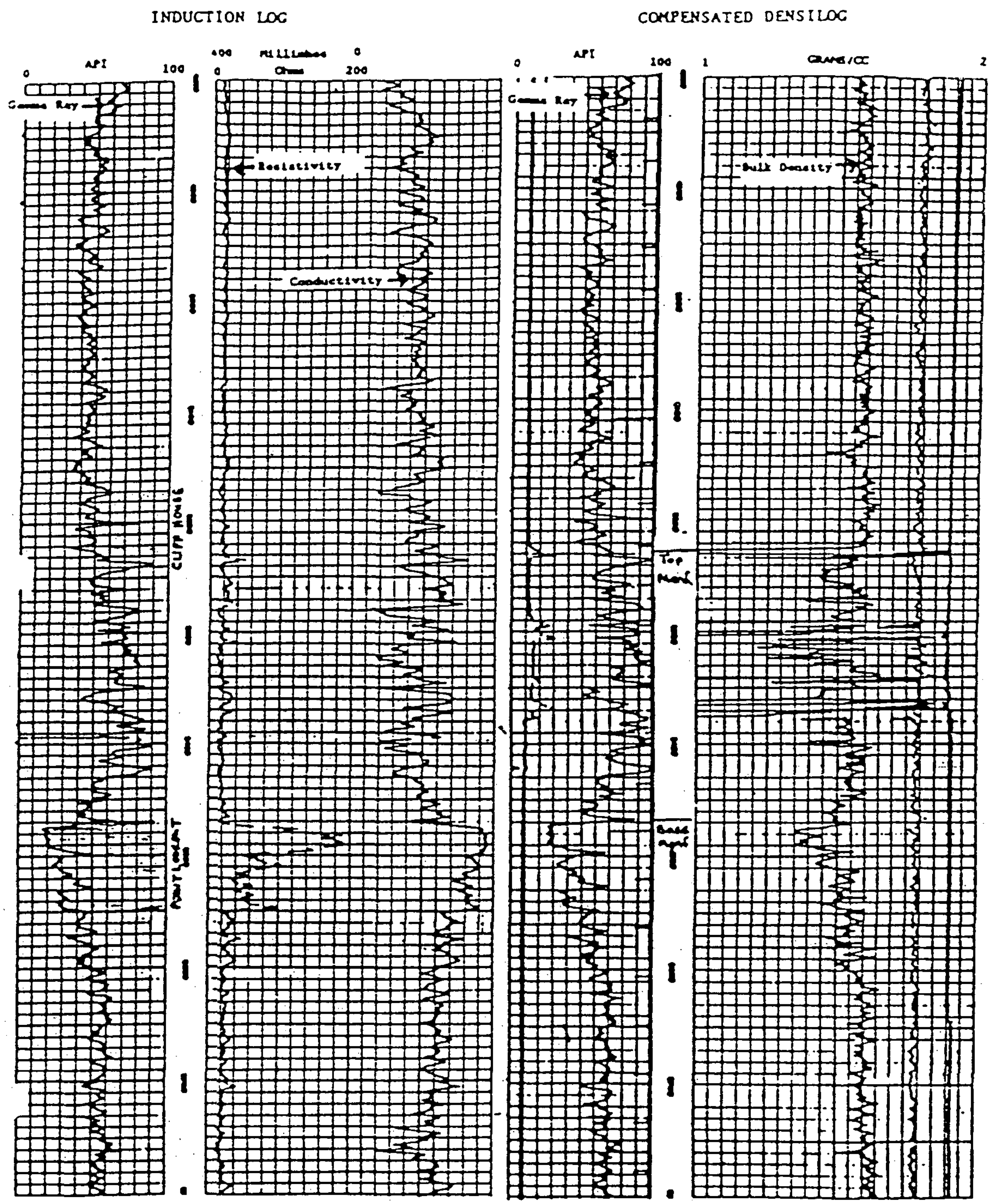
Log data were acquired from Petroleum Information's (PI) Library. Log evaluation provided data on formation depths and thicknesses. The log suites used for determining formation depths and thicknesses were Resistivity (R), Conductivity (C), Spontaneous Potential (SP), Compensated Density (CD), Bulk Density (BD), and Compensated Neutron (CN). Figure IV-10 is an example of a logging suite of the Mesaverde.

Resistivity and Conductivity (R/C) curves measure a rock's capacity to conduct or resist a flow of electric current. A clean sand will slow down the flow of current, thus producing a curve deflection to the right in both the resistivity and conductivity curves. Coal and limestone produce a similar response. Generally, hydrocarbon bearing zones and fresh water hinder the current flow, creating a good resistive response, while salt water and metals produce high induction, causing resistivity to be poor. Shales do not impede the flow of current and typically will exhibit a flat curve response and low ohms and millimhos readings. These various responses aid in the identification of sands, and help to differentiate between beds.

Spontaneous Potential (SP) is a measure of change in fluids, based on current flows from fluid contact. When the filtrate is fresher than the formation water, the SP curve deflects to the left, or negative. When the formation water is fresher than the filtrate, the SP curve deflects to the right, or positive. The SP aides in distinguishing impermeable, electrically conductive beds such as shale, from the permeable, resistive beds such as sand. Shales exhibit a flat curve, ideally, at 0 millivolts, and is referred to as the shale line. Coals create a curve that dips slightly to the right. Limestones produce a curve that has a poor deflection to the left. Sands cause a good deflection to the left of shale line.

The Gamma-Ray curve (GR) is a measure of radioactivity. Shale and mud contain radioactive elements and usually produce curves of 100 API units or higher. Sand and limestone containing little silt are clean and non-radioactive, thus have curve deflections of less than 100 API units. Coals and carbonaceous zones exhibit a low GR deflection also. They can be distinguished from sands by the Bulk Density log (coal has a density of less than 2.0 grams/cubic centimeter, while sand has a density averaging around 2.5 grams/cubic centimeter). The GR curve is used to

Figure IV-10. Example of Logging Suites Used in Analysis



differentiate rock types and provide a good estimate of thickness. For this geological evaluation, sandstone thickness was determined using the GR curve. In general, thickness was counted when the GR curve exhibited a deflection of 80 API units or less. When necessary, the thickness read from the SP curve had a deflection of approximately -20 millivolts from the shale line.

We used a more qualitative approach to estimate depth and thickness because of discrepancies in available log data. There is a general inconsistency in the log suites of individual wells, especially since not all operators ran GR, SP, or porosity logs. Log data were interpreted subjectively due to variation in tool response from well to well, log quality, and varying characteristics of individual sands due to depositional environment and formation geometry.

The tops, bottoms, and net clean sand, along with making correlations could not always be determined with the same logging tool from well to well. The combination of the mechanical variations and the characteristic variations makes evaluation using a specified response value impossible. Consequently, a variety of tools were used, and measurements were adjusted based on the quality of the log response.

4. Compilation of Reservoir Properties

Geological data sheets were completed for each of the 482 typical wells for which log data or history matches were analyzed. Reservoir properties from all sources that could be verified were included on the sheet. To complete sections regarding formation reservoir characteristics, we gathered completion cards, well completion reports and test information from PI and the OGC. Additional information includes FERC field and formation descriptions, which occasionally included geologic evaluations and reservoir analysis.

Very few wells in the San Juan Basin have had drill stem tests or core analysis performed. In light of this, detailed information pertaining to permeability, porosity, water saturation, pressure, and natural fracture data were generally not available through the public domain. Data that were obtained were supplied by operators in the basin for specific wells or reservoirs. Operators contacted for additional reservoir information indicated that such detailed data were never collected.

When possible, certain reservoir properties were derived from log analysis. The CD and CN suite provided an estimate of porosity, however accuracy is questioned since tight sands cause density readings to be too high and neutron readings to be too low (Kukal, G.C., et al, 1983). The results indicate porosities derived from the CD/CN log are too high.

The Geologic Data Sheets provide information on individual wells. Information included are well identification, location, surface elevation, kelly bushing, type of logs used, well status and producing interval, bottom hole temperature, formations, formation depths, perforated interval, net thickness and porosity, as well as notes pertaining to formation tests and log quality (Figure IV-11).

D. Reservoir Properties Mapping

Based on the log analysis and evaluation of additional data, we generated maps of depth, structure and net clean sand for the five target intervals. Each of the target intervals is reviewed below.

1. Pictured Cliffs

The Pictured Cliffs is a regressive sandstone deposited as a shoreface sand when the interior sea withdrew from the basin from the southwest to the northeast for the final time. Intertonguing of the overlying Fruitland Formation and the Pictured Cliffs occurs at the base of the Fruitland in portions of the basin, however the top of the Pictured Cliffs is picked at the base of the last Fruitland coal seam. The Pictured Cliffs is composed of siltstone and sandstone that is well sorted, fine-grained, and composed primarily of quartz and feldspar. The Pictured Cliffs produces nonassociated gas with very little condensate (Rice, 1984). The low permeability of the Pictured Cliffs is believed to be caused by the effects of digenetic clays (Cumella, 1981).

The Pictured Cliffs outcrops around the basin perimeter, encompassing an area of approximately 7,500 square miles. Stratigraphically it rises to the northeast in a series of steps, or benches, which show a definite northwest-southeast trend. A structure map was prepared on the top of the Pictured Cliffs Sandstone (Figure IV-12). The structure of the Pictured Cliffs is asymmetrical

Figure IV-11. Sample Geologic Data Sheet

Hole I.D.: 30-045-25008	Southland Royalty Co. - DAYSTATE #2E	Dakota Basin, San Juan

Location	32-32N-11W	Type of Data	IND/CD	Production Data	
Surface Elevation	6289/6277	Source of Data	PI	Year of First Production	
Total Depth	7640'	Confidence Level		Current Status	

ZONE ID	Depth to Top (feet)	Depth to Bottom (feet)	Perforated Interval (feet)	Productive Zone (Y/N)	Net Thickness (feet)	Matrix Permeability (md)	Matrix Porosity (%)	Water Saturation (%)	Initial Pressure (psi)	Current Pressure (psi)	Initial Temperature (°F)	Fracture Orientation (degrees)	Fracture Spacing (feet)
Pictured Cliffs	2960	3140			No GR						109 °		
Chacra	4070	4190			80/0'								
Cliff House	4695	4790			80/87'								
Point Lookout	5220	5570			80/60'								
Dakota M-1	7415	7490	7418, 22, 49, 54	Y	80/46'		8-13*						
Dakota F	7495	TD	7500 - 7546		80/40+						184 ° BHT		

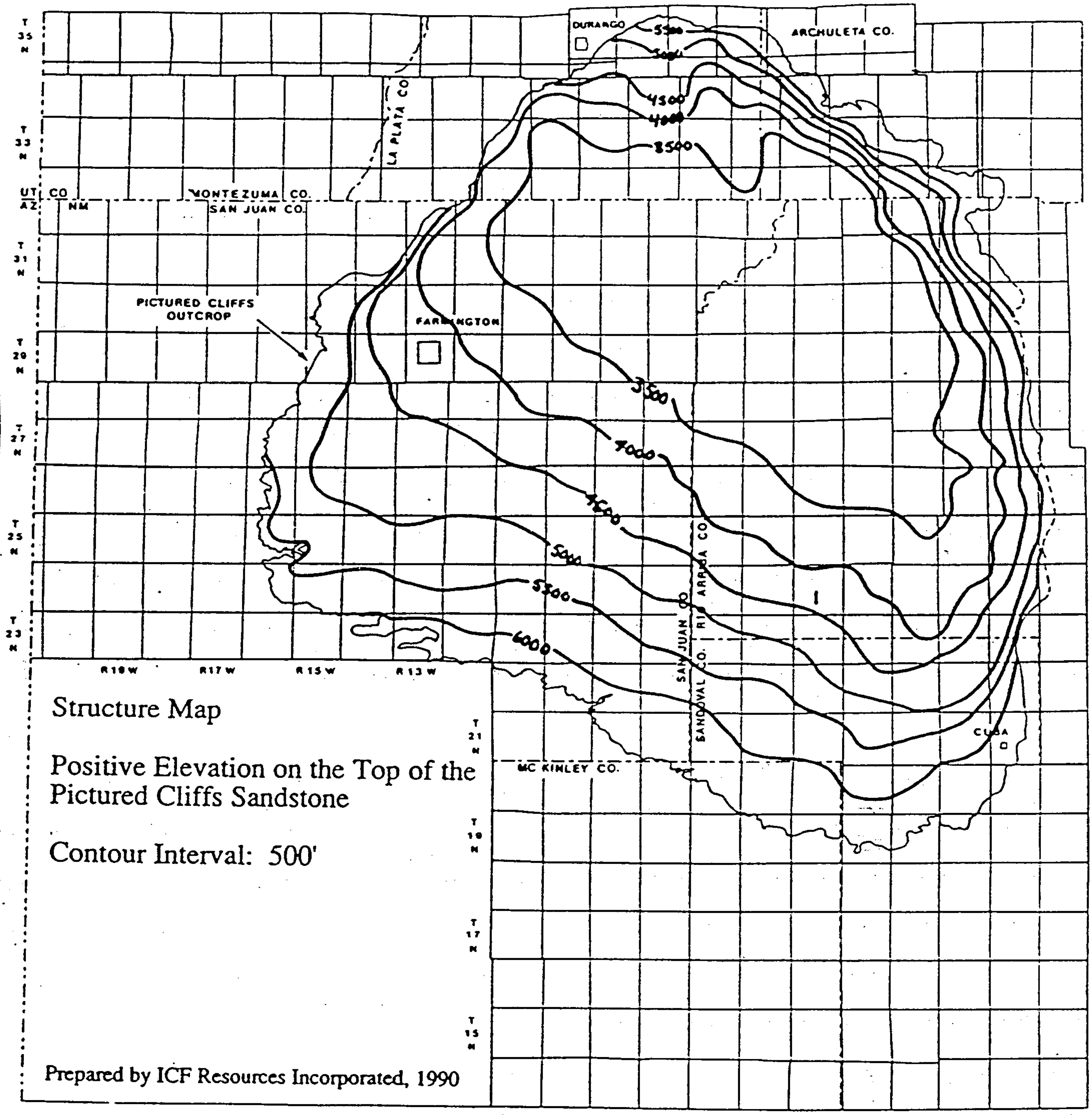
NOTES:

* From CDCN Log Analysis

BHT = 3009' - 109°F/7640' - 184°F

Analyst Initials BM

Figure IV-12. Structure Map of Pictured Cliffs Sandstone



as a result of tectonic activity (uplift contemporaneous to and post deposition), a structural profile that is exhibited by all Cretaceous rocks in the San Juan Basin. In the central portion of the basin the structural elevation averages between 3,000 and 3,500 feet.

An overburden map was prepared on the top of the Pictured Cliffs (Figure IV-13). Overburden of the Pictured Cliffs is greatest in the northern-central and along the eastern-central portions of the basin, coinciding with the basin axis. Here depth ranges from 3,000 to over 4,000 feet. To the south, as the formation rises structurally, overburden decrease at a rate of approximately 500 feet per 15 miles.

An isopach map of the upper clean portion of the Pictured Cliffs Sandstone is presented in Figure IV-14. Thickness trends appear in elongated areas parallel to the paleoshoreline. Net clean sand ranges from zero to over 200 feet. Regionally the trends in thickness depicted in this map are similar to trends established by other authors, however as this is a map of the clean sand portion of the Pictured Cliffs, rather than the gross sand, thickness values are generally less. Several well developed thick benches appear on this map, one along the southern margin, one north of the town of Farmington, and one in the central portion of the basin, bisecting the Colorado-New Mexico state line. Additional discussion of the Pictured Cliffs can be found in the literature (Fassett and Hinds, 1971, Molenaar, 1977, Brown, 1977, and Huffman, 1987).

2. Chacra

The Chacra Sandstone has been defined by the New Mexico Oil and Gas Conservation Commission (NMOGCC) as an interval in the Lewis Shale that extends 750 feet downward from the Huerfanito Bentonite. This interval includes several sands that are extensions of the La Ventana Tongue of the Cliff House Sandstone. This definition, while providing nomenclature to a number of unnamed sands, causes numerous problems as these sands may be similar in depositional environment, but are not necessarily similar in lateral extent, lithological composition or reservoir properties, and are not stratigraphically equivalent.

Gas is produced from several "sand bodies" in this interval, and FERC has designated one area of the Chacra in the south central portion of the basin as tight. It has not been determined at

Figure IV-13. Overburden Map of Pictured Cliffs Sandstone

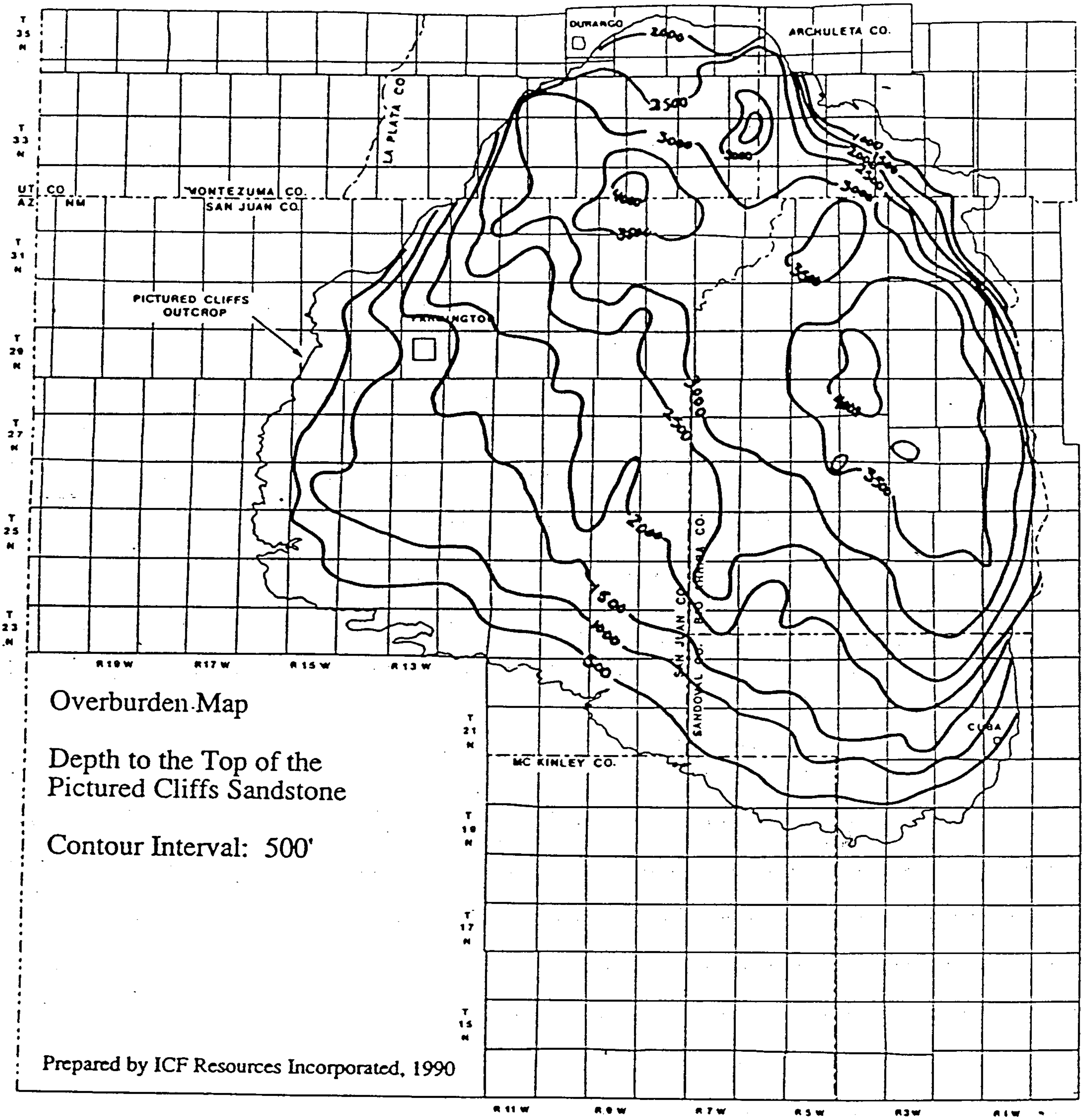


Figure IV-14. Isopach Map of Pictured Cliffs Sandstone

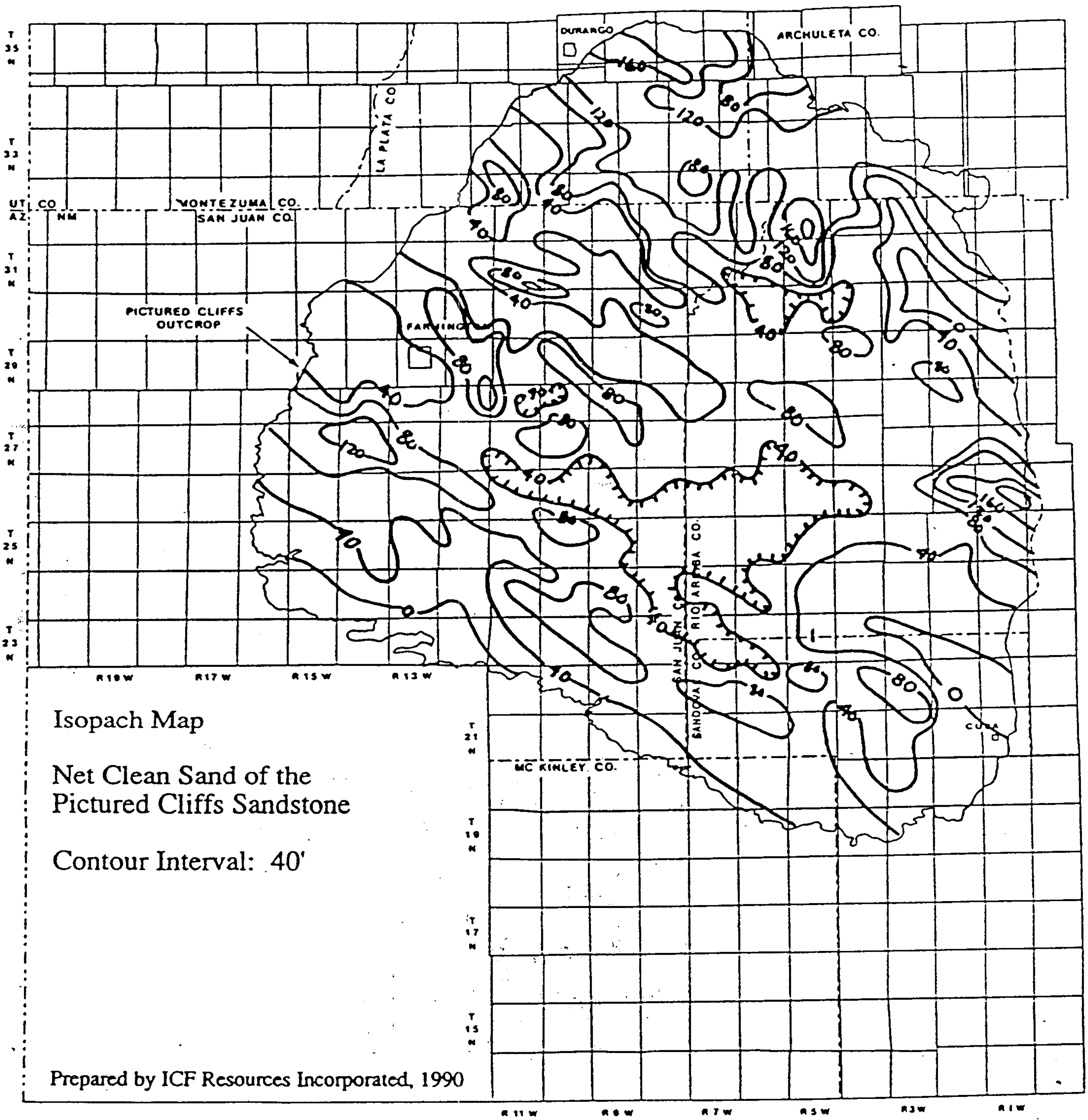
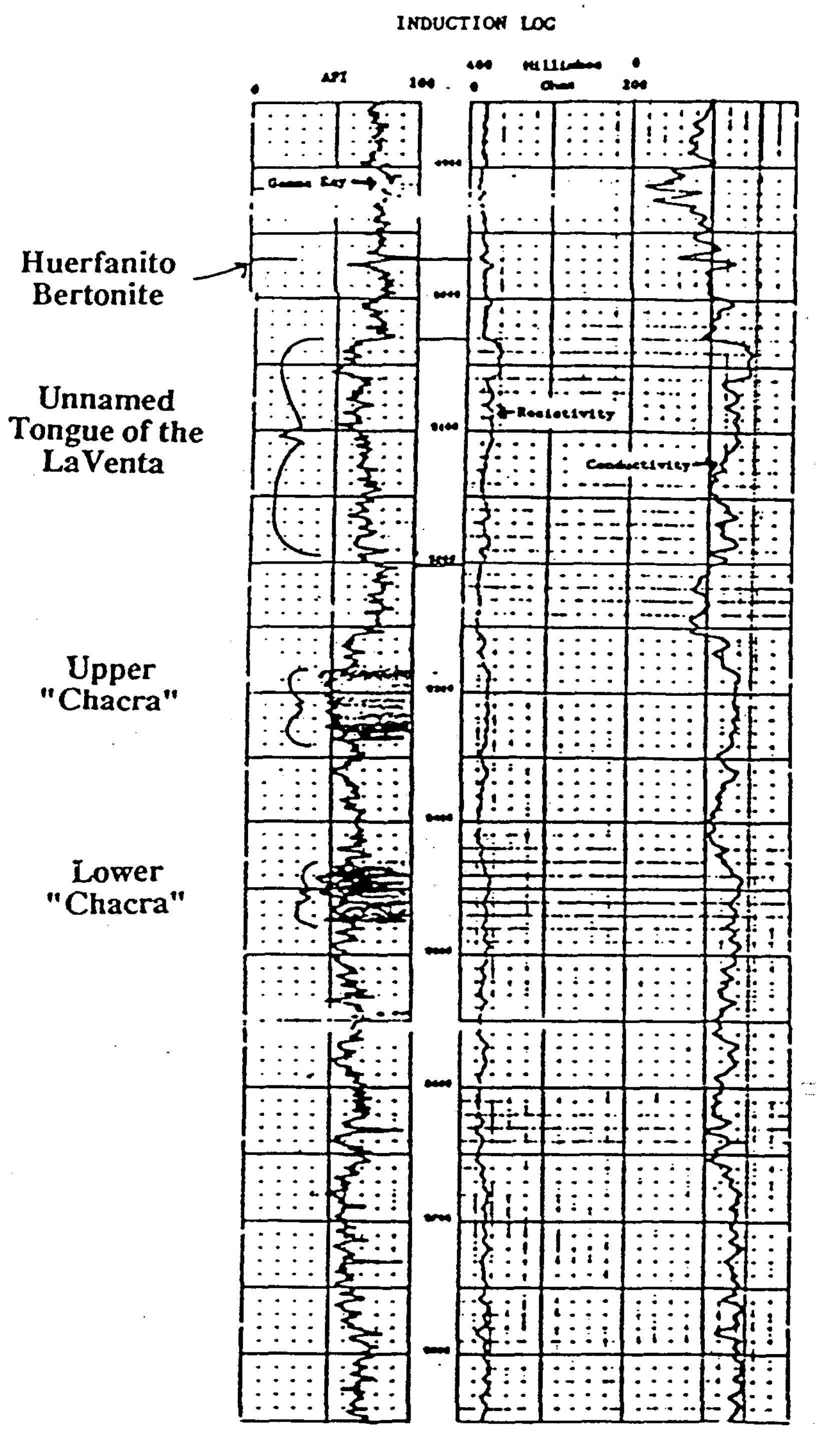


Figure IV-15. Designation of Upper and Lower Chacra Sands



this time which sand/sands are producing in this area and whether the tight status applies to all sands in the interval as defined by the NMOGCC. For simplicity sake, Figure IV-15 depicts the sands designated as upper and lower Chacra, although this name application is probably incorrect (Fassett 1977). Regionally these sands are found approximately 450 feet below the Huerfanito Bentonite, and occur in a band that trends southeast to northwest across the central portion of the basin. They were deposited as off-shore bar sands in a marginal marine environment parallel to the shoreface, or as thin beach sands during a minor regressive episode.

3. **Cliff House**

The Cliff House Sandstone is the upper member of the Mesaverde Group. It consists of a clean beach sand deposited in a near shore environment, overlying the continental deposits of the Menefee formation. The contact of the Cliff House and the Menefee is well defined. In the northern portion of the basin the Cliff House is thin and poorly developed. Progressing southward, it rises through a series of steps to the southwest, generally becoming thicker and better developed, however in some locations it is missing completely. The thickest bench of the Cliff House Sandstone is referred to as the La Ventana Tongue and is located along the southern margin of the basin. The La Ventana is a complex assortment of deltaic and beach sands resting on the basal, clean beach sand of which is the Cliff House Sandstone. The contact between this basal sand and the La Ventana is difficult to determine, but has been picked based on a correlatable shaly zone which separates them. The La Ventana produces gas, however is not considered a tight sand, and was not included in the analysis of the Cliff House.

Figure IV-16 is a structure map on the top of the Cliff House Sandstone. The Cliff House structure is similar to that of the Pictured Cliffs. It exhibits a broad regional dip from the southwest across most of the basin. In the northeast part of the basin is large scale closure. In the extreme northeast portion of the basin is a steep, asymmetric monocline dipping to the southwest.

The overburden map on the top of the Cliff House Sandstone is shown in Figure IV-17. Depth to the top of the Cliff House Sandstone ranges from 1,000 feet in the south to over 5,500 feet in the northwest part of the basin. Wells producing from the Cliff House generally are less than 2,500 feet above sea level, or more than 4,000 feet below the surface. The Cliff House overburden

Figure IV-16. Structure Map of Cliff House Sandstones

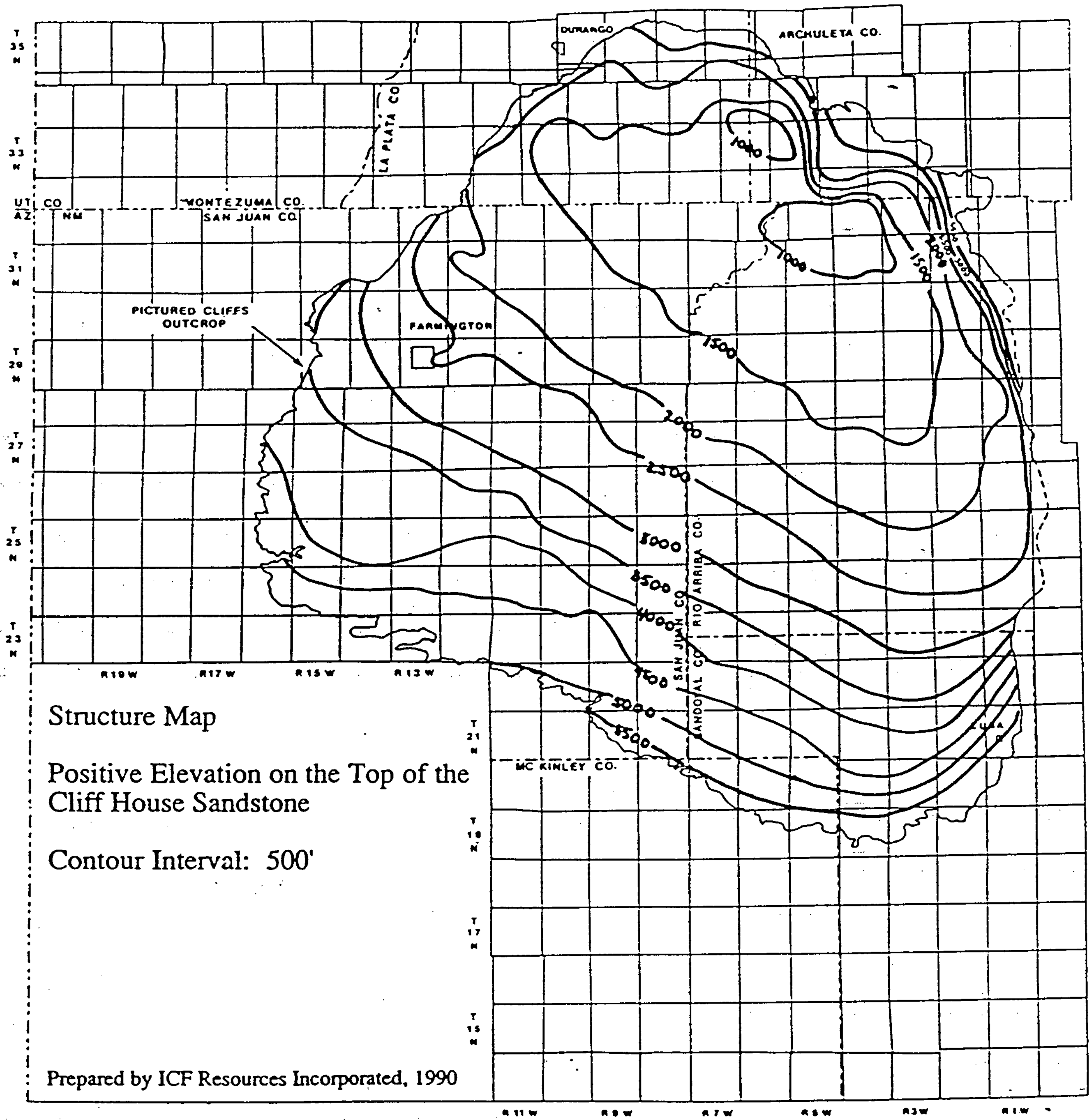
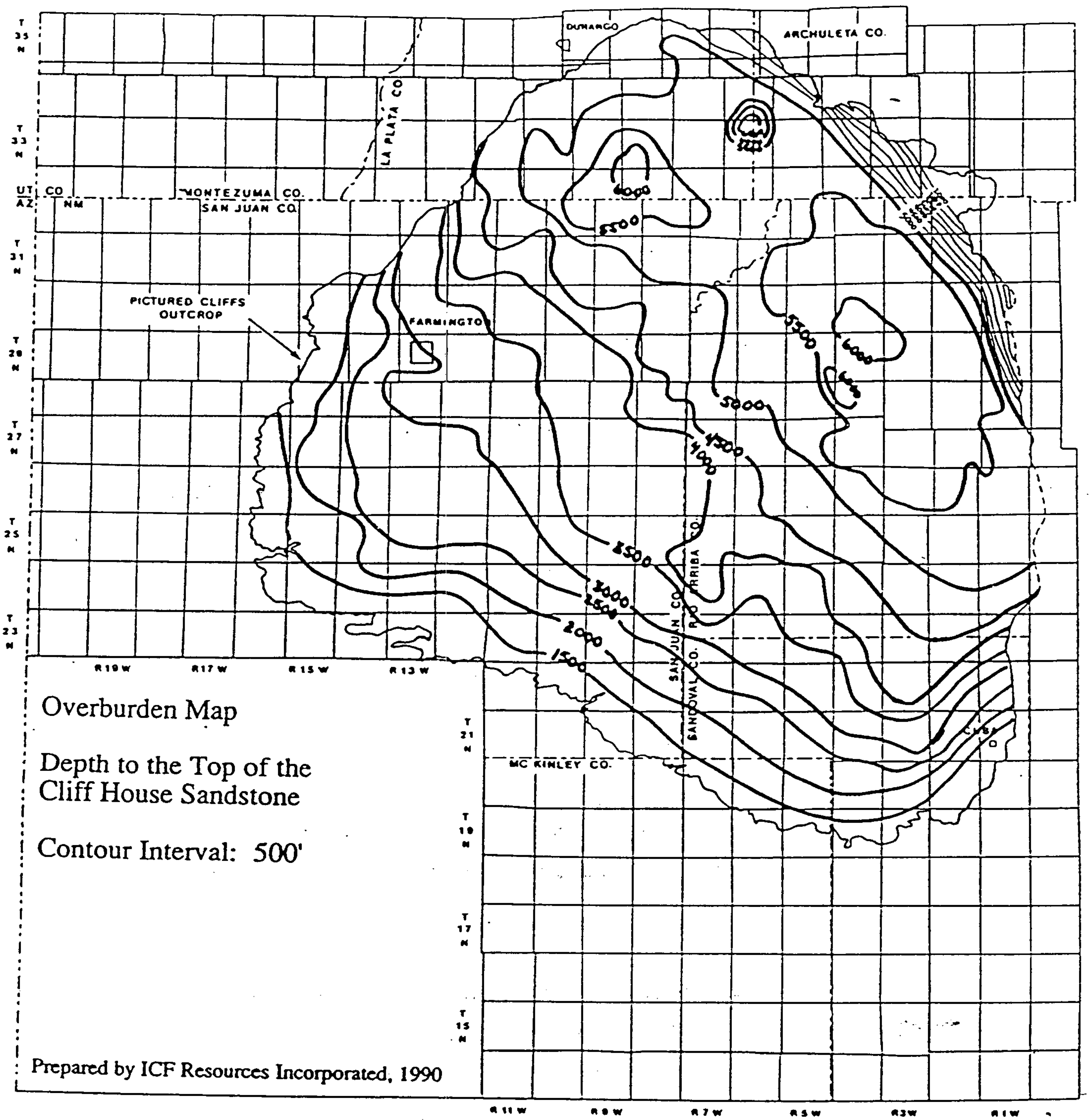


Figure IV-17. Overburden Map of Cliff House Sandstone



map reflects some smaller scale closures in the northeast, that trend northwest to southeast. Determining the top of the Cliff House is difficult due to the gradational contact with the overlying Lewis Shale, however, a top can be selected using the SP and Gamma ray log.

An isopach map of the net clean sand portion of the Cliff House Sandstone was prepared and is presented in Figure IV-18. Net clean sand varies from a few feet to about 200 feet in thickness. Thicker accumulations trend northwest to southeast, and to some degree, reflect the Cretaceous sea shoreline. Thick deposits are also found along the perimeter to the east, south, southwest and west. The variation in thickness can be attributed to fluctuations in the shoreline, and the subsequent "bench" deposits that represent different shoreline stages.

Cliff House production is not as widespread as the other Mesaverde members and occurs in the central and northern portions of the basin. Cliff House production is mainly concentrated in areas where thickness ranges from 4 to 104 feet. For further discussion the reader is referred to Palmer, 1984, and Fassett, 1977.

4. Point Lookout

The Point Lookout Sandstone is the lower member of the Mesaverde Group. It is generally gray to brown in color and is fine to medium-grained. This formation represents a regressive sandstone that was deposited as the Cretaceous sea retreated to the northeast, and is very similar in geometry to the Pictured Cliffs. It was deposited parallel to the northwest-southeast trending paleoshoreline. The thickness and lithology of the Point Lookout vary as a result of the regressive environment. In areas where the shoreline remained relatively stationary, thick, clean sandstone benches accumulated, where as when the location and rate of shift of the shoreline changed, thin silty sands were deposited.

Figure IV-19 is a map of structure on the top of the Point Lookout Sandstone. The Point Lookout structure trends northwest to southeast and regionally dips to the northeast. An asymmetric monocline in the northeast dips sharply to the southwest. There is large structural closure in the northeast portion of the basin. The high structural points are over 4,500 feet above sea level and the lowest is under 500 feet above sea level.

Figure IV-18. Isopach Map of Cliff House Sandstone

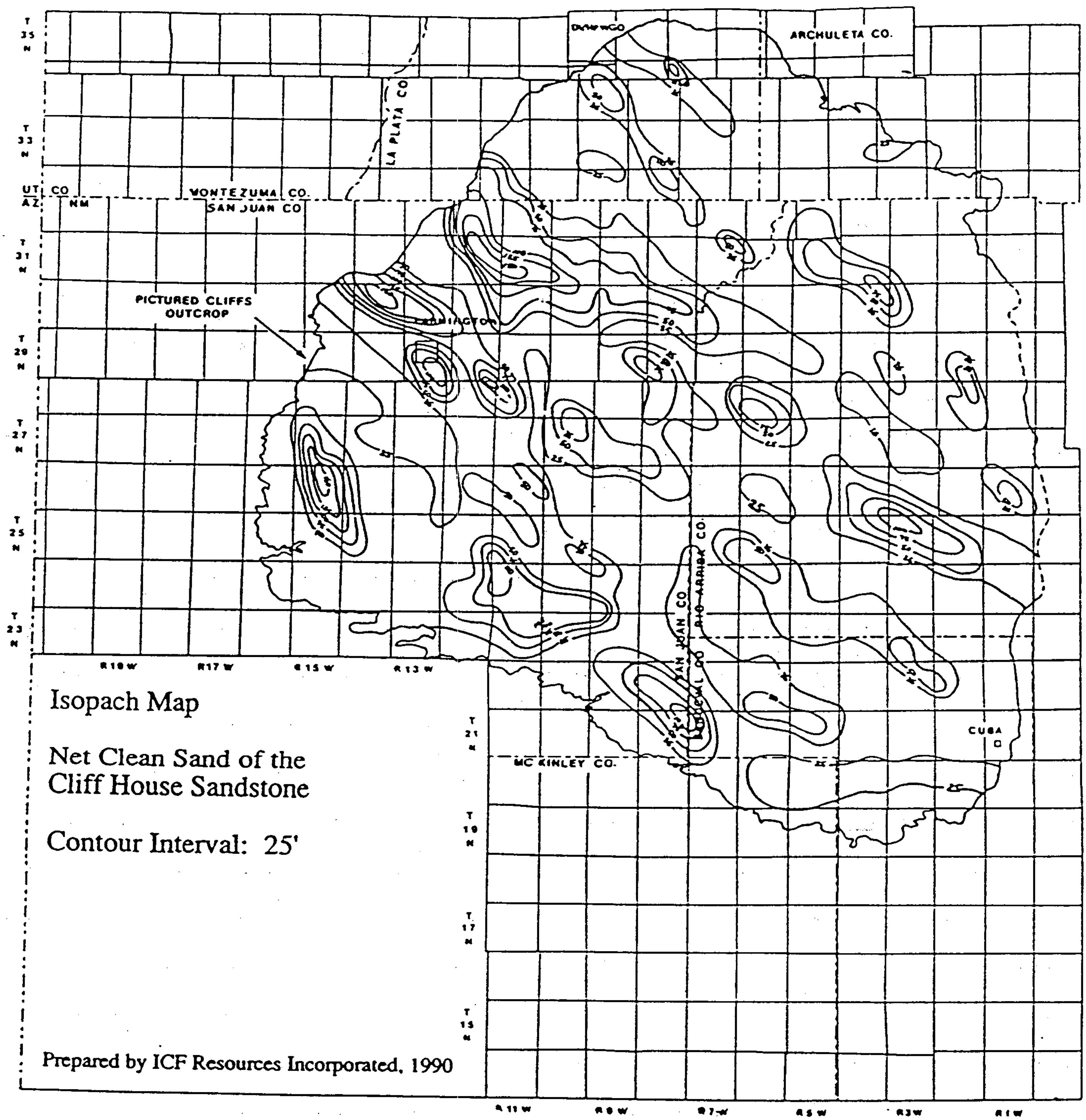


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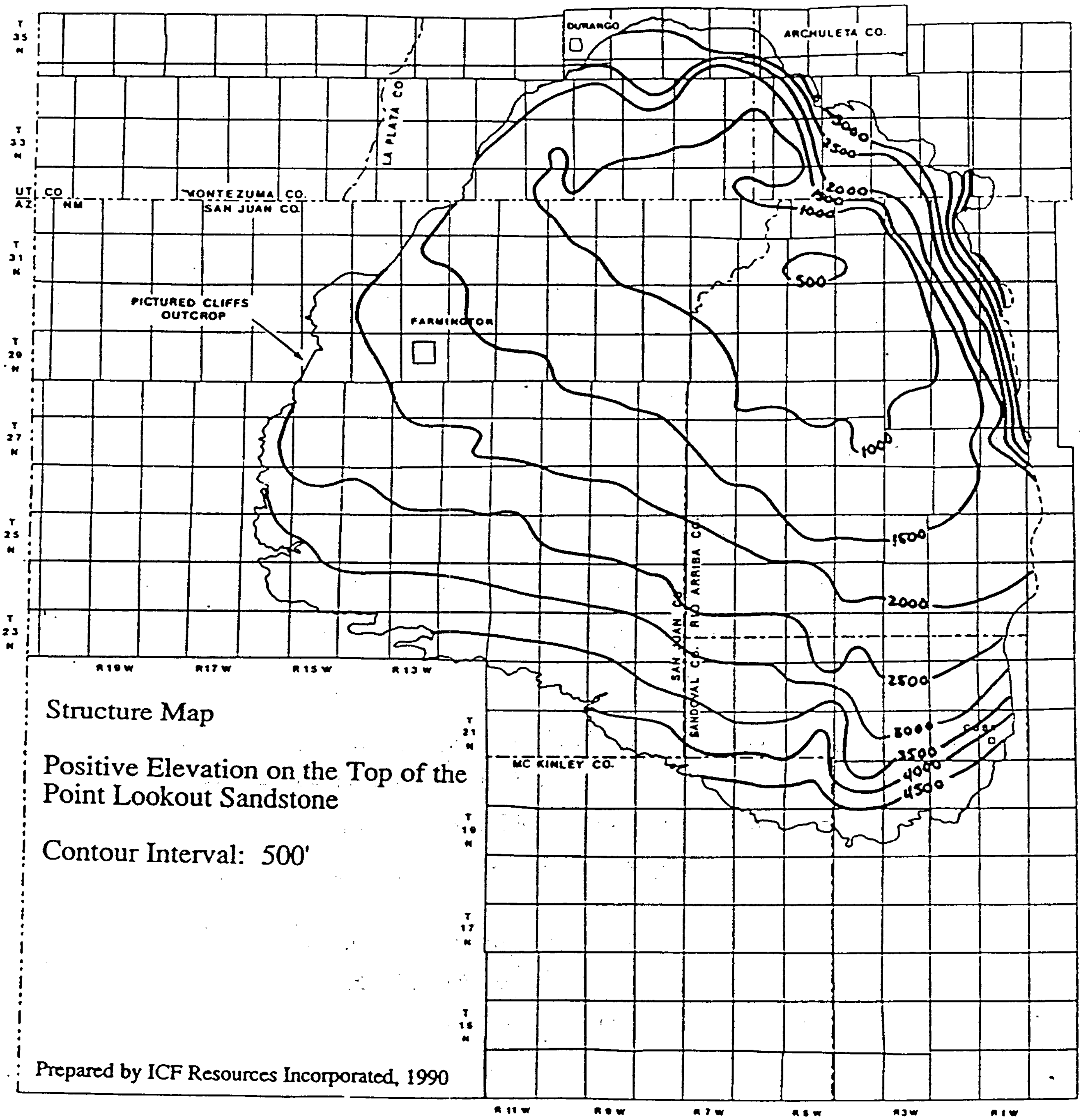
Figure IV-19. Structure Map of Point Lookout



The Point Lookout fields are located where structure is less than 2,500 feet above sea level. Figure IV-20 is a Point Lookout overburden map. The formation tops vary from less than 2,500 feet in depth in the south to more than 6,500 feet in depth to the northeast.

The net pay isopach map of the Point Lookout reveals benches of thick sandstone deposited in over two thirds of the basin (Figure IV-21). However, in the remaining portion of the basin to the northeast, the thickened sections of Point Lookout sand occur in more isolated pods or bars that follow the same northwest-southeast trend, suggesting deposition in a near to offshore environment rather than along the shoreline.

The Mesaverde Group produces nonassociated gas and condensate. The Ignacio Blanco and Blanco Mesaverde field combined produce nearly half of the total nonassociated gas and condensate from the San Juan Basin. For further discussion see Huffman, 1987, Fassett, 1977, 1978, and Hollenshead and Pritchard 1961.

5. Dakota

The Dakota Formation is a complex assemblage of continental fluvial sandstones, shale and coals, and transgressive marine sandstones, which were deposited as the interior seaway made its initial transgression through the San Juan Basin region. It is defined by the NMOGCC as extending 400 feet below the Greenhorn Limestone. This includes the overlying Graneros Shale and underlying rocks of Jurassic and Triassic age, on which the Dakota rests unconformably. The depositional direction of the Dakota is not entirely understood. In the northern portion of the basin, the Dakota is primarily fluvial with only one or two marine sandstones present. In the southern portion of the basin, the Dakota is primarily marine, consisting of up two five marine sands. Owen (1973) has defined four depositional environments for the Dakota.

Dakota production occurs from fluvial and marine sands. Initial evaluation indicates that the marine sands are tight, while permeability is higher in the fluvial sands. The evaluation of the Dakota digenesis and productive regions is on-going.

Figure IV-20. Overburden Map of Point Lookout Sandstone

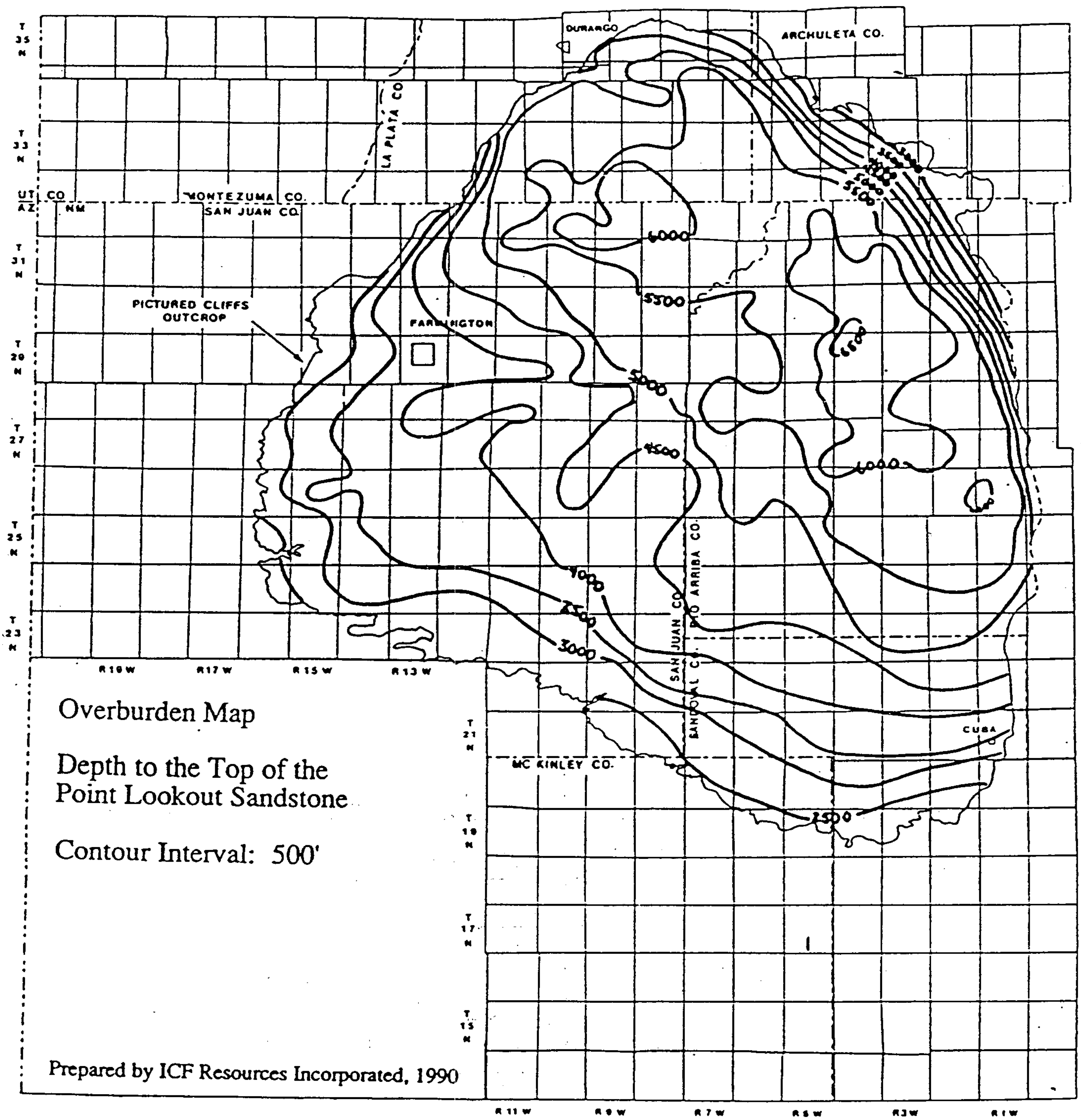


Figure IV-21. Isopach Map of Point Lookout Sandstone

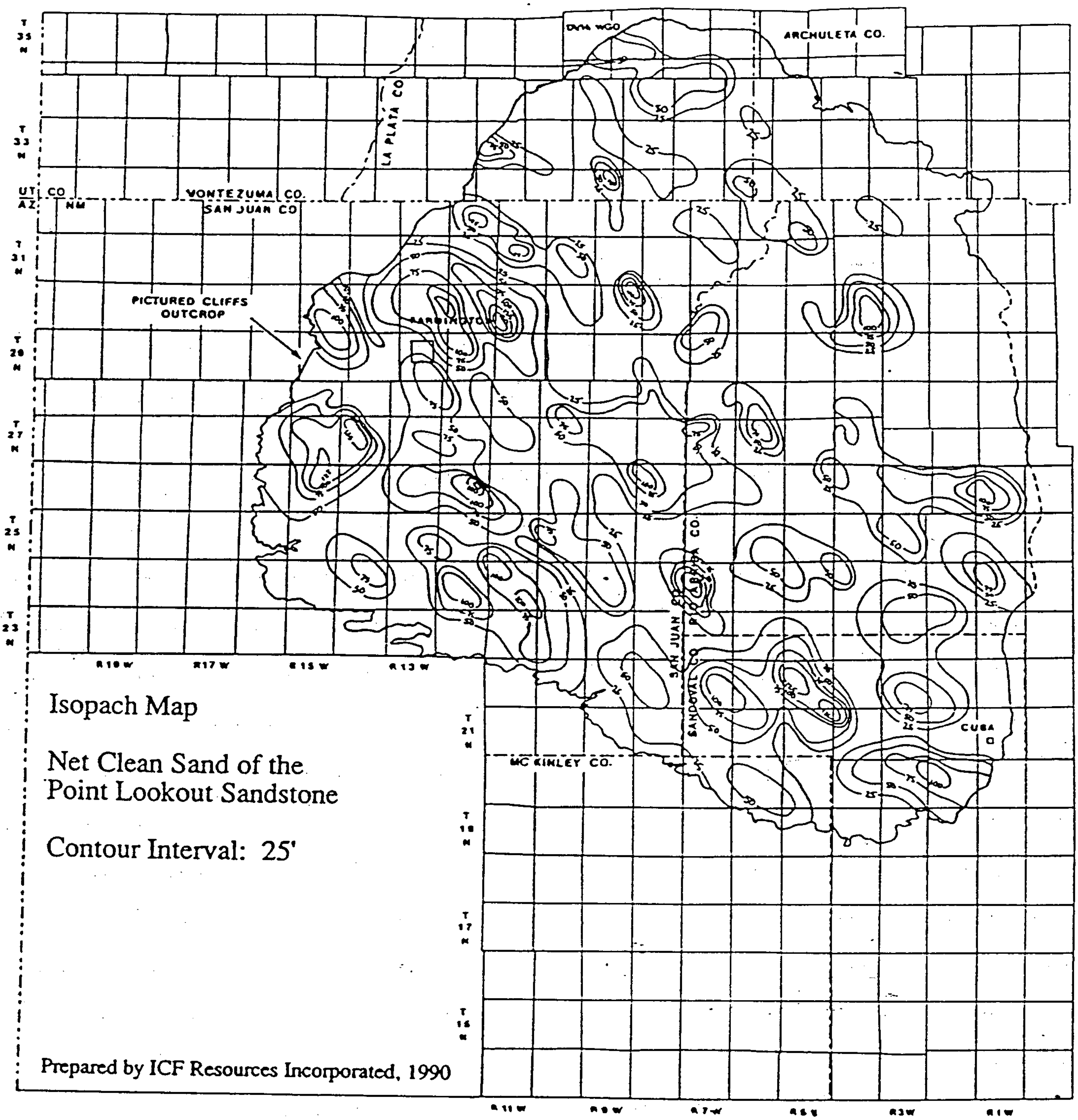


Figure IV-22 depicts the structure of the top of the first marine sandstone. The structure of the Dakotas is highly asymmetrical. In the northeast, the Dakota outcrops at elevations exceeding 3,000 feet. It plunges at high angles toward the central portion of the basin where structure ranges from 1,000 to 1,500 feet below sea level.

Figure IV-23 is an overburden map on the top of the Dakota. Overburden within the study area ranges from 4,500 to over 9,000 feet, following trends previously discussed in other formations.

An isopach map of net thickness for the marine sands of the Dakota is shown in Figure IV-24. A majority of the wells used in this study either reached total depth in the Dakota fluvial sandstone or were drilled to shallower depths, therefore only the marine portion was evaluated. Thick sandstone deposits are concentrated in the east and southeast portion of the basin. The overall depositional trend is parallel to what was a northeast-southwest shoreline, and is consistent with a dynamic, transgressive depositional environment. As exhibited on the map, the northern portion of the basin has thinner deposits of sand reflecting the lack of marine influence.

Net sand of 80 API units or less ranges from under 25 feet and up to 180 feet in thickness in the southern portion of the basin, while to the north, thickness varies from 0 feet to about 100 feet.

E. Resulting Geological Analysis and TGAS-PC® Dataset Description

The purpose of the geological analysis is to characterize the target formation reservoirs in terms that can be used to estimate technical and economic recovery. The principal challenge was to define undeveloped areas in consistent terms, despite different criteria used in the individual data sources (e.g., different porosity cutoffs for estimates of pay made by various analysts). Where well control in a particular formation was minimal, reservoir properties from geologically similar reservoirs were extrapolated. The basin was divided into five general plays, based on tectonic and producing characteristics. This division and geologic assumptions used in the remainder of the analysis are described below.

Figure IV-22. Structure Map of Dakota Sandstone

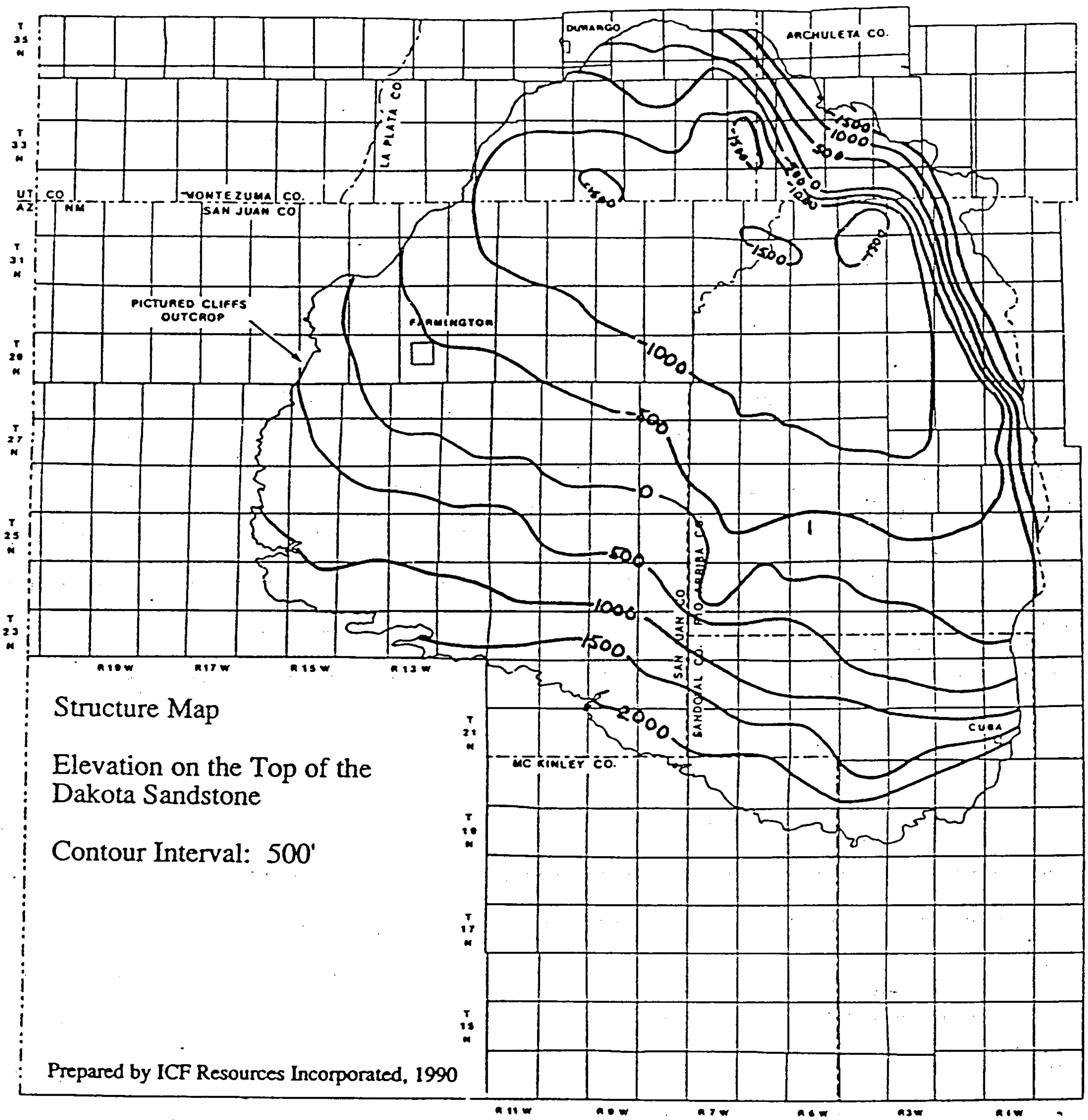


Figure IV-23. Overburden Map of Dakota Sandstone

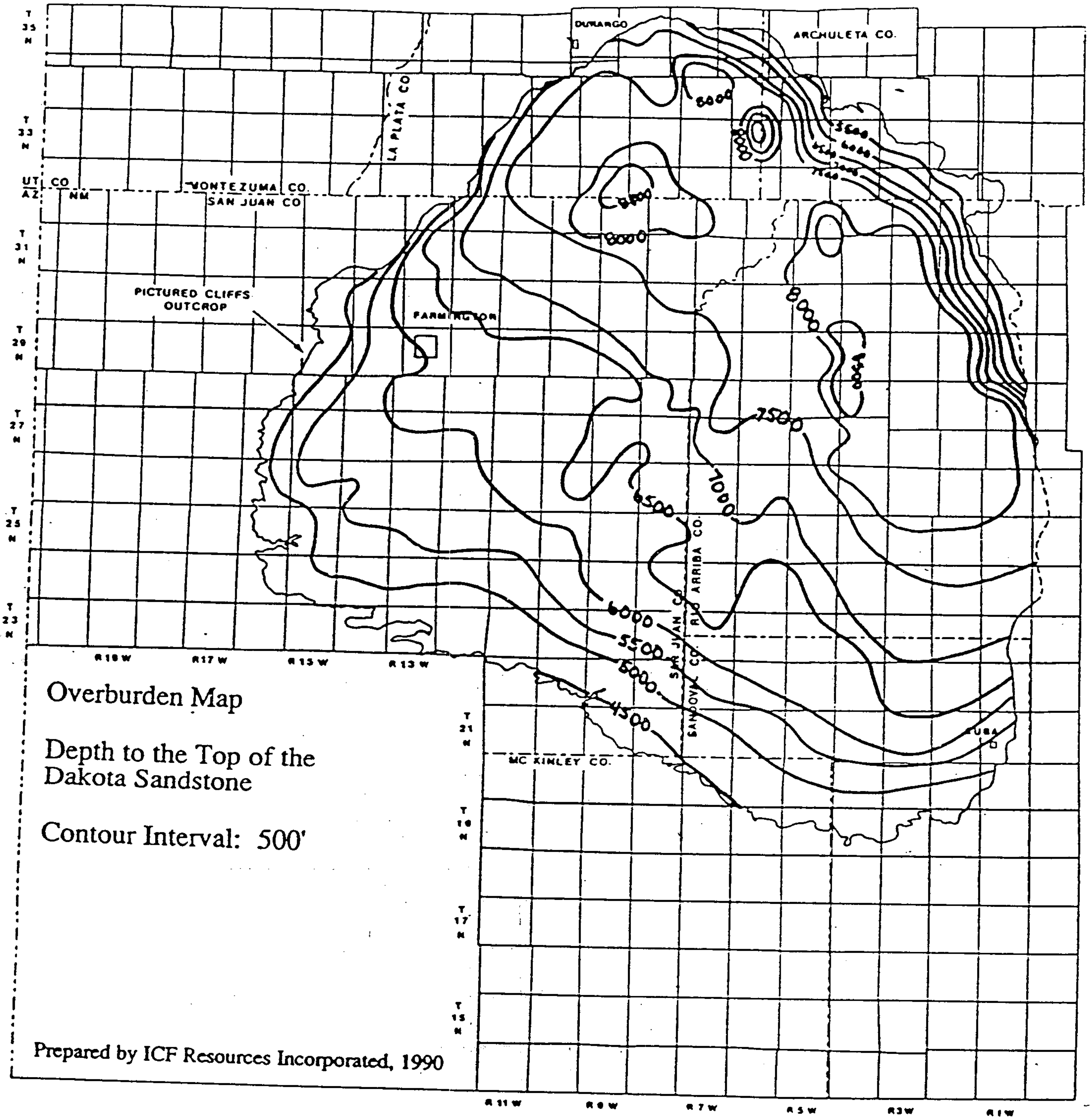
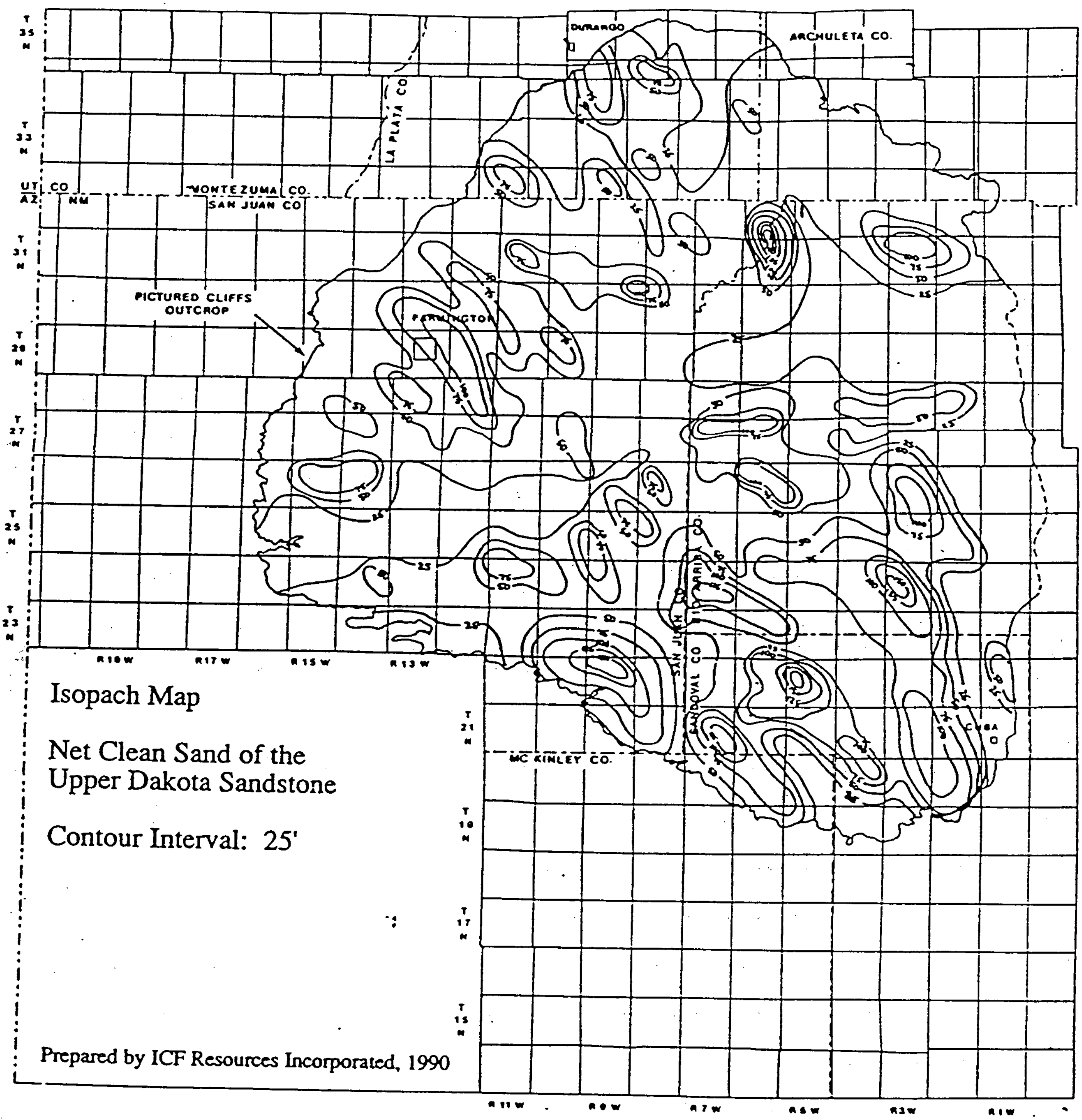


Figure IV-24. Isopach Map of Dakota Sandstone



1. Delineation of Basin Into Plays

Based on data collected for this study and prior geological appraisals, ICF Resources divided the basin into five plays (Figure IV-25). The plays are described as follows:

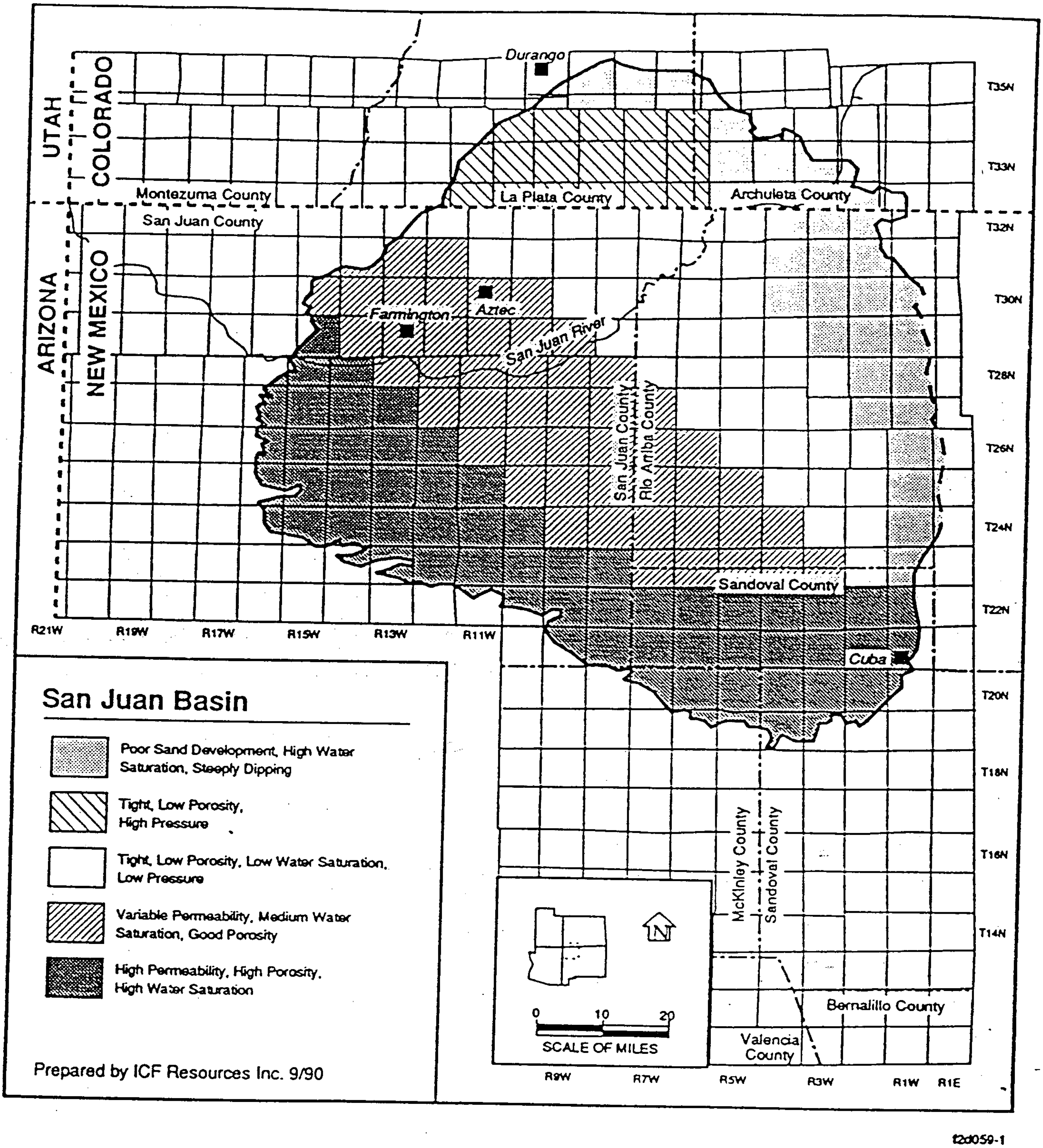
- Play 1 - Located in the Colorado portion of the basin, this play is generally tight, with low water saturation, low porosity, and generally higher pressure.
- Play 2 - Located on the northeastern flank adjacent to the Hogback Monocline, this play has generally poor sand development, steeply dipping structure, variable permeability and high water saturation.
- Play 3 - Located in the central part of the basin trending northwest-southeast, this play is generally tight, with low water saturation, moderate porosity, and lower pressures due to depletion.
- Play 4 - Located in the south central portion of the basin, this play has variable, generally higher permeability, good porosity development, and moderate water saturation.
- Play 5 - Located on the southern flank (Chaco slope and Zuni Uplift), this play has high permeability, good porosity and is generally water saturated.

These plays were used to extrapolate reservoir properties from townships with known properties to those with no well control. Township data were estimated based on the closest township with well data within the play. If no empirical data were available from a township within two townships (the one immediately adjacent and the next township beyond that) of the one being characterized, the play average was used. This assumption was required in less than 10% of cases.

2. Geological Assumptions

Two issues had to be addressed before the resource data collected could be put into a database for analysis: adjustment of clean sand to net pay and validation of reservoir property distributions. First, the net clean sand derived from log analysis had to be corrected to derive effective net pay. Because of the relatively few good porosity logs available in many areas, a formation-wide correction factor was developed to adjust clean sand to net pay. These correction factors were based on comparisons of estimated net pay in the literature or gathered from operators, and the clean sand maps developed for this analysis.

Figure IV-25. San Juan Basin Plays



Although depositional and diagenetic differences across a formation suggest several net sand-net pay scaling factors, insufficient data existed to estimate several scaling factors within each formation. Given the net sand maps provided in this report and additional estimates of pay for more areas of the basin, this detailed scaling might be done in future analyses. For all formations, the net pay was estimated at 70% clean sand.

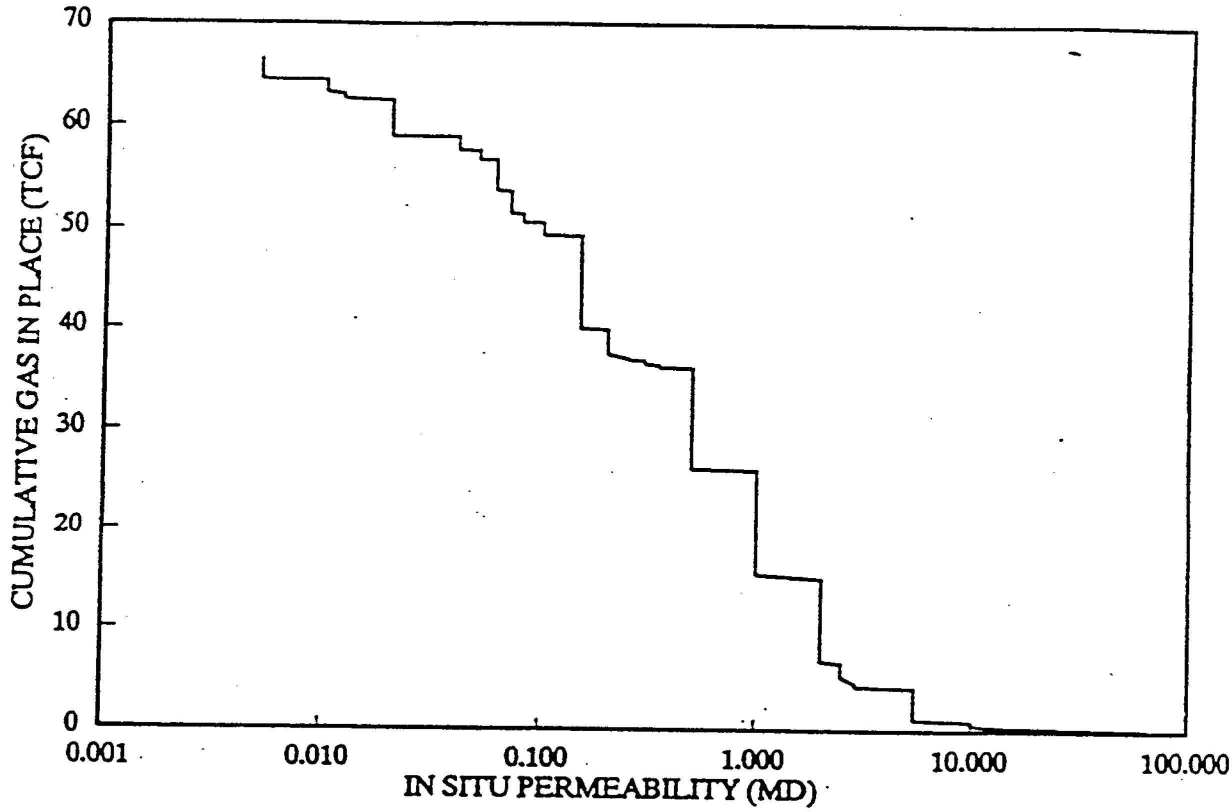
Second, regardless of the method used to estimate reservoir properties for the undeveloped areas of the basin, some uniform distribution of reservoir properties should be expected. Permeability generally is distributed log normally, and porosity and water saturation are generally normally distributed. Frequency distributions of reservoir properties were used to check the plausibility of the many independently derived estimates of permeability, porosity, and net pay. Figure IV-26 shows the distribution of cumulative gas in place by permeability, which conforms very closely to the theoretical log normal distribution observed for other gas resources.

4. TGAS Model Overview

The Tight Gas Analysis System (TGAS), was developed as an automation and validation of the NPC data and analysis methods for tight sands. The original TGAS was developed by ICF Resources in 1984 under joint DOE/METC and GRI sponsorship. It successfully validated the analysis of the NPC and provided a means to conduct sensitivity analyses of geologic, technology, and economic assumptions used by the NPC. It was developed also to analyze formations and basins not examined by the NPC as geologic data became available. This San Juan analysis is exactly the type of appraisal for which TGAS was developed.

Although TGAS was used by DOE, GRI, AGA, National Academy of Science and the Stanford Energy Modeling Forum as the sole basis of estimates of tight gas potential, there were requests for a more accessible capability than the mainframe TGAS. In 1988, ICF Resources developed a microcomputer version (TGAS-PC®) with expanded analytic capabilities. TGAS-PC® is now available for use in basin and play analyses such as this, either with the original NPC data or using resource data generated by independent geological appraisal.

Figure IV-26. San Juan Gas Reservoir Property Correlations



The structure and capabilities of TGAS-PC® are described in the model documentation, available from ICF Resources. It consists an operating system, file handling and database management routines, analytical modules, a report writer, and routines to provide graphical and tabular summaries. The four main analytical modules are:

Geology - Calculates gas in place and maximum recoverable gas (gas in place less gas remaining at abandonment and gas uncontacted due to reservoir heterogeneities).

Production - Calculates annual and cumulative per-well production streams based on reservoir properties and technology assumptions (e.g., drainage area, fracture length and conductivity).

Costing - Estimates per well costs for predevelopment, drilling and completion, stimulation, lease equipment, and operations.

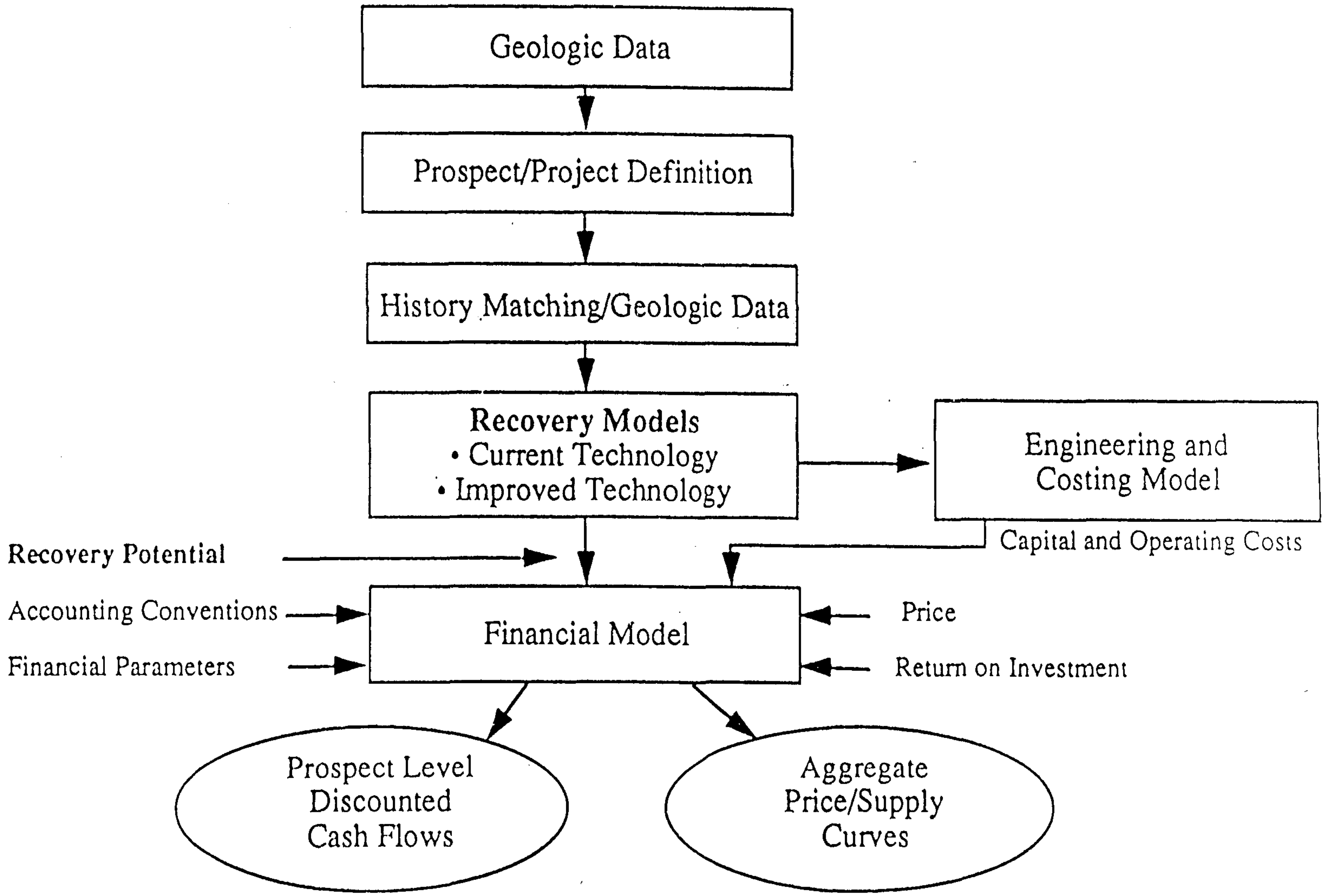
Economics - Conducts discounted cash flow analysis of project economics to provide ROR, NPV and minimum required price, and aggregate results into price-supply curves.

The logic flow of this resource economic methodology is shown in Figure IV-27. A complete analysis (including geological and technology sensitivities) was conducted for the San Juan Basin using this methodology. The results are reported in parts H, I, and J of this section.

5. Dataset Content and Format

The TGAS-PC® dataset constructed for this analysis consists of a data record for each township-formation unit of analysis. Data were compiled and verified for each of the 482 potentially productive analytic units (153 of which are predominantly tight), distributed among the target intervals as follows:

Figure IV-27. Summary of Tight Gas Resource Economics Methodology



Townships With Undeveloped Potential

	Total	Tight
Pictured Cliffs	148	45
Chacra	46	5
Cliff House	76	16
Point Lookout	71	14
Dakota	141	73
TOTAL	482	153

The database consists of the following data for each unit of analysis:

- State
- Basin/Subbasin
- Township/Range
- Formation
- Depth
- Initial Pressure
- Bottomhole Temperature
- Condensate Yield
- Undeveloped Area (within township)
- Average In Situ Permeability
- Porosity
- Water Saturation
- Net Pay
- Drainage Area
- Decline Constant

F. Validation of Recovery Models and Definition of Current Production Practices

It is inappropriate to estimate potential production based solely on reservoir properties derived from geological analyses without some form of calibration. Reservoir properties derived from geological and petrophysical analyses should be validated and modified as needed before being used in reservoir simulation to calculate production profiles. Various production practices (e.g., differences in backpressure, stimulation design, or curtailment) for geologically similar wells can cause them to vary substantially in their production profiles. Therefore, reservoir properties derived from history matching of actual field production data are not necessarily equivalent to those values derived directly from geological analyses.

This study derived reservoir properties from published and proprietary sources and then modified them as required to be consistent with the production mechanism and profiles of the typical wells. Most typical wells were analyzed and reservoir properties calibrated by history matching the average production profile of wells in the representative reservoir. Each typical well's properties then were validated against other wells in the reservoir as a function of current technology parameters. The final reservoir properties defined for a typical well, therefore, reflected the average properties of a well in the unit of analysis using current technology.

1. Overview of Validation Method

Decline curves have been used extensively in the analysis of petroleum reservoirs as a means of predicting future recovery. The application involves transforming production time series into a linear trend for extrapolation to some abandonment rate. While this method has some validity in idealized reservoirs, it gives little insight into the production mechanisms or combinations of reservoir properties influencing production rate or ultimate recovery. Since trend extrapolation of production still in transient flow can lead to significant errors in estimating remaining reserves, and since low permeability reservoirs can take years to reach the depletion stage, analysis of tight reservoirs requires more sophisticated means.

The use of type curves increases the engineer's ability to define the parameters that most influence rates and recovery and more accurately characterize reservoir properties. A type curve is usually a log-log plot of flow rate, pressure or cumulative flow against time or other parameter related to the plotted data. Matching field data against these idealized curves provides insights into the flow regime and reservoir properties of the analyzed well. The procedure can be time consuming and rarely gives a unique match.

The "advanced" decline curve analysis method developed by Fetkovich was used for this analysis. Unlike graphical decline curve methods and numerical curve fitting commonly used to predict recoveries, the advanced decline curve method has a strong theoretical basis and is grounded in fundamental engineering flow equations. It combines the constant terminal pressure solutions for the diffusivity equation with empirical depletion equations. By combining both of these equations into a family of log-log dimensionless curves, both transient and depletion flow can be matched, significantly increasing the accuracy of reserve estimates (Figure IV-28).

Because these curves are based on fluid flow equations and accepted engineering principles, they can be used to estimate or verify reservoir properties and production parameters such as permeability, drainage area, and fracture length. This is a powerful analytic tool, since it is possible to match production even if technology (e.g., fracture length) or producing practices (e.g., days producing or flowing pressure) are different between wells. Also, since curtailment of individual wells makes long term production forecasting difficult for a single well, and since in this study only area wide average producing characteristics are desired, the method provides for analysis of composite production from a field or area.

2. Sample Validation

The Carthage Gas Unit 24-3 well in Panola County was selected as a sample for the advanced decline curve analysis. This well was completed in 1977 in the thick (378 feet of net pay), layered, and prolific Cotton Valley Sand. It produced 5.4 Bcf in its first 12 years and currently produces over 250 MMcf per year. It was selected for analysis because Union Pacific Resources has done extensive flowmeter testing and 3D reservoir simulation to estimate reservoir properties, ultimate recovery and drainage area. No such detailed evaluation on a San Juan tight gas well is known to the authors.

Figure IV-29 is the production profile of CGU 24-3. Production decline is typical for a tight gas well, with rapid decline for three years then a lower decline rate since that time. Based on flowmeter and well test results, UPR estimated that the reservoir was best represented by a four layer system with unique properties in 13 separate zones (Figure IV-30).

The advanced decline curve analysis technique incorporated UPR's estimates of net pay, saturations, and porosity from log analysis. Production data were normalized (adjusted to correspond to a constant bottomhole pressure) and transformed into dimensionless production decline and time. Data were then smoothed (three month moving average), plotted and matched (Figure IV-31).

Figure IV-28. Composite of Analytical and Empirical Decline Curves

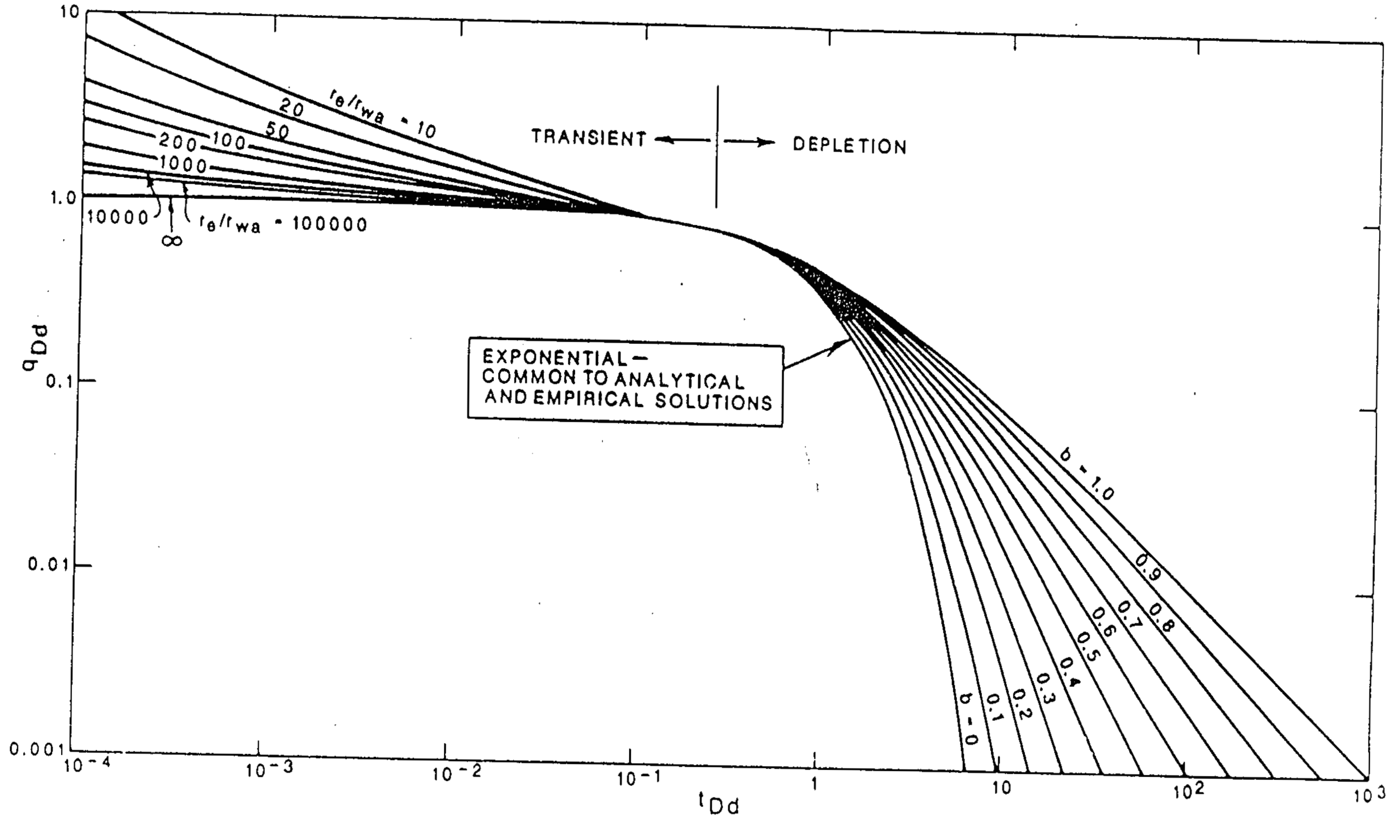


Figure IV-29. CGU 24-3 Cotton Valley Historical Production

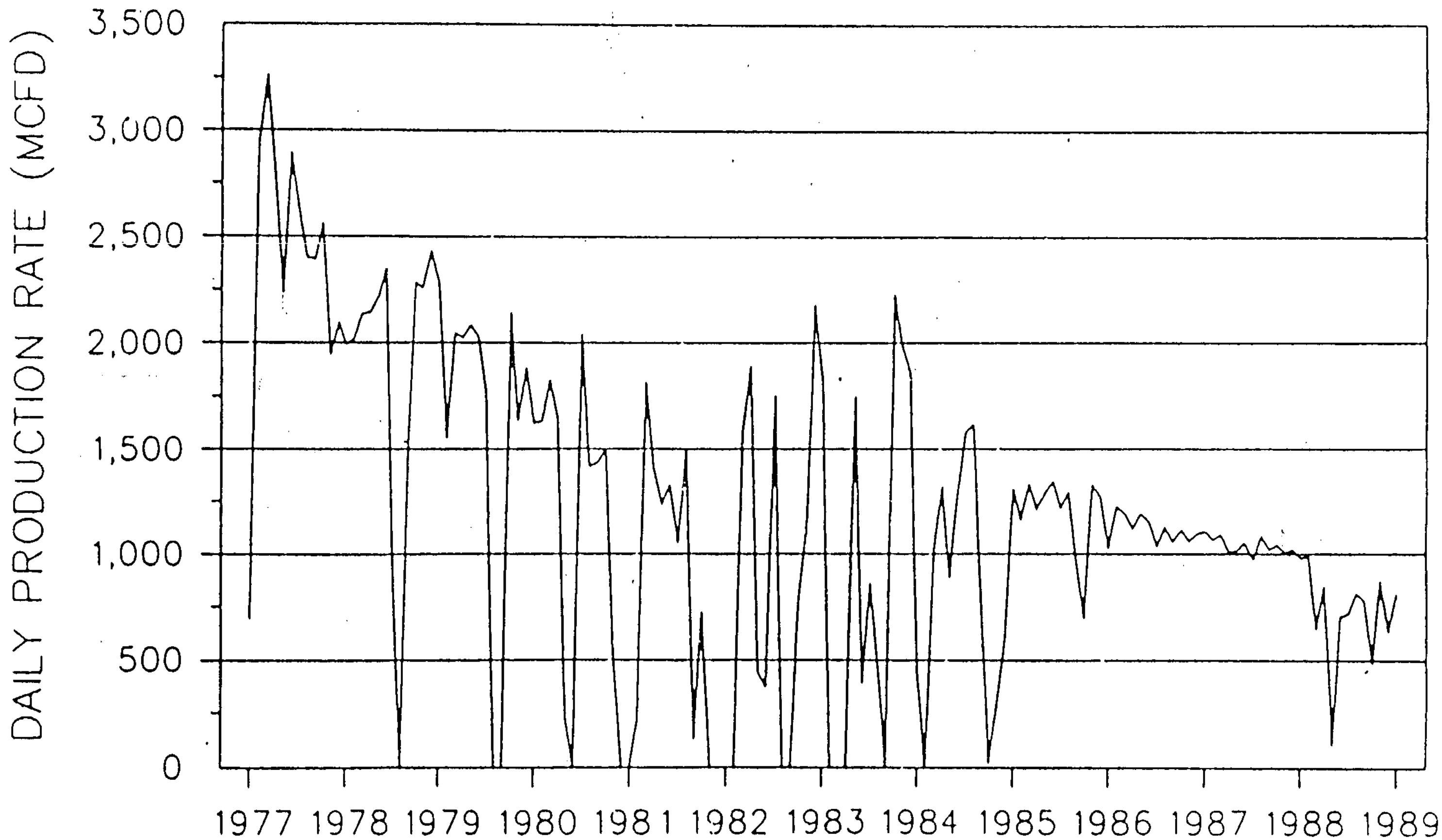
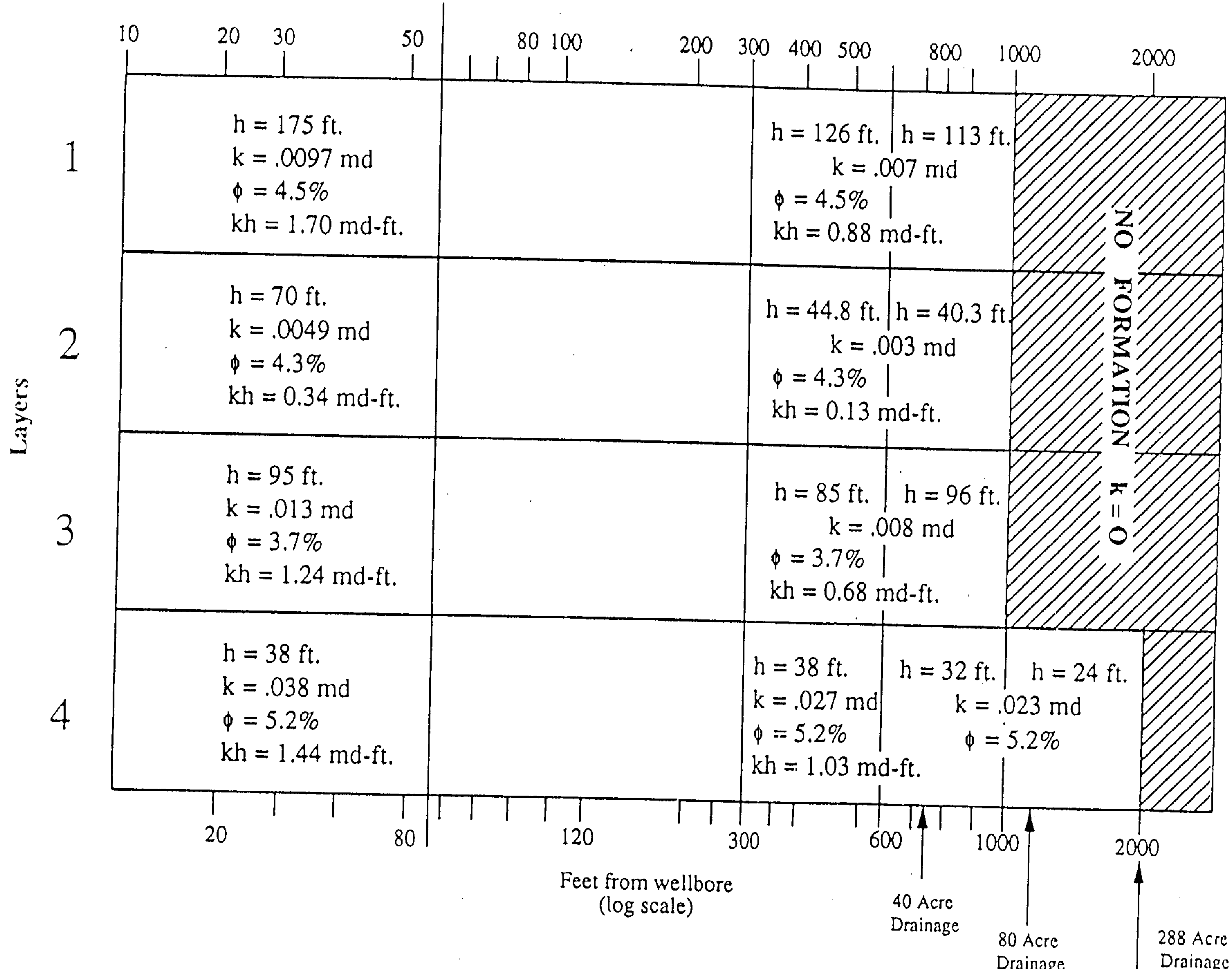


Figure IV-30. CGU 24-3 Formation Cross Section (Hypothesized)



3. Estimation of Target Gas In Place and Gas Recovery for a Typical Well

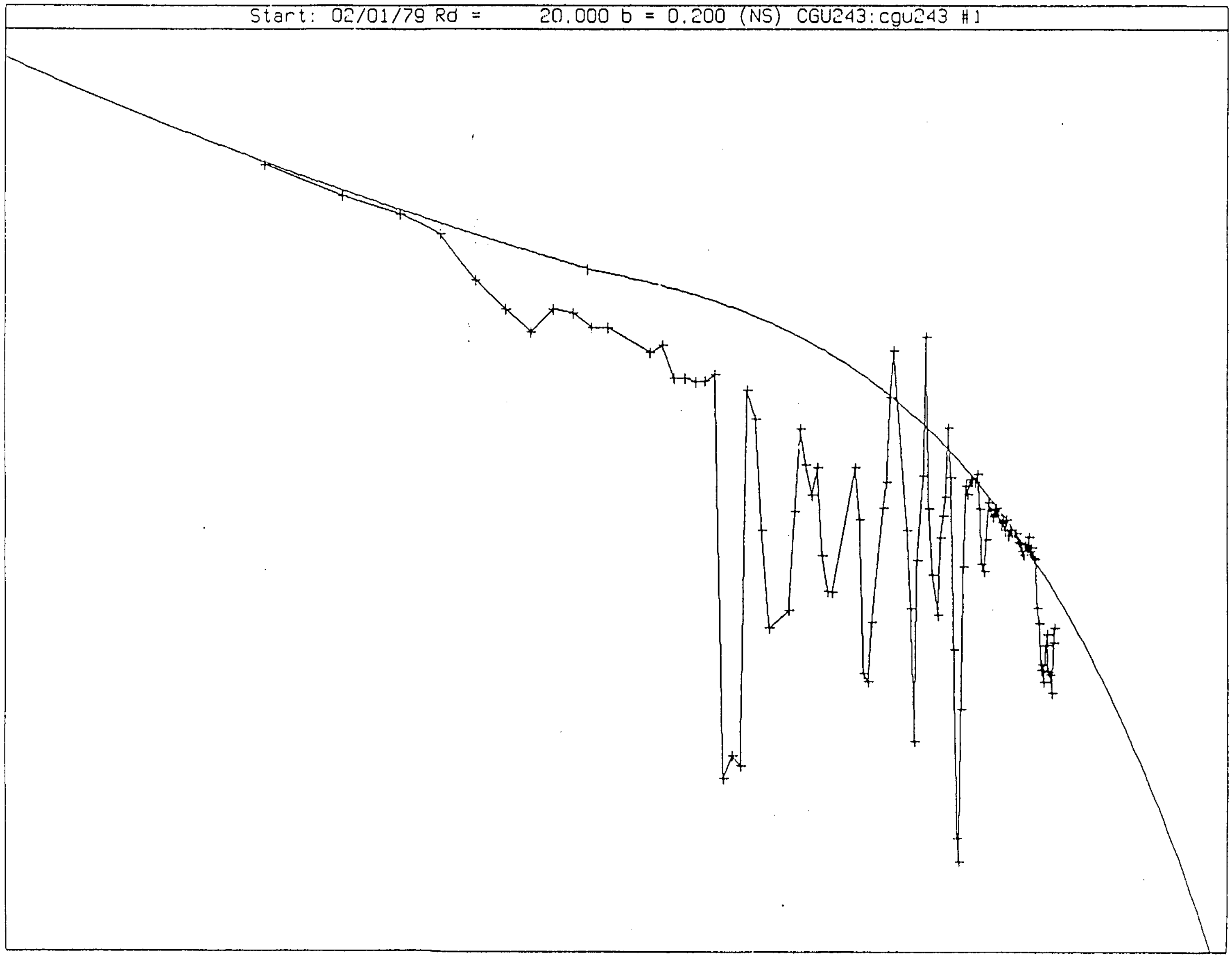
UPR's detailed reservoir modeling indicated that CGU 24-3 had drainage areas of one layer of 288 acres and three layers of about 72 acres. Gas in place was estimated at 11.5 Bcf, ultimate recovery at 7.5 Bcf and permeability at 0.0125 md.

The match of actual production to dimensionless decline curves, shown in Figure IV-31, yielded an equivalent single layer drainage area of 69 acres, for a gas in place of 11.3 Bcf. The match also indicates a permeability of 0.011 md, quite close to the more detailed model results of 0.0125 md. Ultimate recovery estimated by UPR was 7.5 Bcf. Extrapolation of production using a matched hyperbolic decline constant (b) of 0.2 yielded estimated recovery of 8.5, or 13% higher than estimated UPR. Most of this difference is because the well actually produced below its full potential early in its producing life due to curtailment, only partially recovered during flush production after the periodic curtailments.

This is indicative of the quality of matches possible with this method. For any analytic history matching method, erratic production can compromise the expected accuracy of results. For San Juan cases where erratic production data or uncertain porosity, saturation or net pay values existed, additional wells were analyzed. In a given reservoir, all wells exhibit the same decline behavior, although skin and fracture lengths could be different. Therefore, analyses of grouped wells were occasionally used for areas whose wells were subject to severe curtailment or otherwise exhibited erratic production histories. This approach is theoretically consistent with the Fetkovich method.

Finally, derived reservoir properties were input into TGAS-PC® to determine whether these properties could replicate average production profiles. This was a critical step since the core of the analysis was to determine the response of typical wells to alternative technologies. Type curve-generated production profiles generally estimated recoveries 5-20% higher than estimated ultimate recoveries from actual wells. Given the frequent curtailment of actual wells, the validity of this method and the results of analyses were accepted.

Figure IV-31. Advanced Decline Curve Analysis Match of CGU 24-3



4. Current Practices

Active operators in the San Juan Basin were contacted to determine current drilling, stimulation and production practices. Each of these operators was asked about current practices and reservoir engineering practices for their own wells, including completion practices, stimulation design and effective achieved lengths, fracture conductivity, drainage areas, and recoveries.

Decline curve analysis provided an empirical basis for these parameters for each typical well, which were provided to the operator for review. Although conventional practices vary considerably with the characteristics of each well, a general consensus emerged as to the average effective fracture length and conductivity, containment, well spacing, and dry hole rate. Using the reservoir parameters required to match production from current wells, Table IV-4 defines the parameters for the current and full advanced technology cases.

Operators frequently cited fracture design lengths of over 600 feet and achieved finite conductivity lengths of 300 feet or more. More recently, however, many are beginning to doubt that equivalent infinite conductivity lengths are any more than 300 feet. Note that the values shown here reflect the parameter inputs required to duplicate current production from typical wells and are meant to represent fully propped fractures over the entire net pay specified in the resource data. In practice, those 200 foot, 200 md-ft conductivity fractures are likely to be predicted as 300-500 foot finite conductivity fractures. These parameters are best viewed in relative terms and are indicative of the magnitude of improvement due to R&D. Based on the most optimistic estimate of stimulation performance of the most technically sophisticated operators in the basin, a "Full Advanced" case set of technology parameters was specified. A comparison of reserves and production using these advanced case parameters with estimates for current technology provides a basis for quantifying the impact of R&D. The maximum impact is achieved when the techniques used by the most advanced operators become widely commercialized.

Table IV-4. San Juan Tight Gas Study Technology Parameters

Parameter	Current Technology Case	Full Advanced Technology Case
Effective Fracture Length (feet)[1]	200	600
Fracture Conductivity wk_f (md-ft)[2]	200	Infinite
Well Spacing (acres)[3]	160	160
Frac Containment (maximum h_f feet)[4]	300	420
Leakoff Control (1-fluid loss)[5]	60%	80%
Dry Hole Rates[6]	20%	10%

Notes

1. Effective fracture half-length for fully propped treatment.
2. Dimensionless fracture conductivity, wk_f/kx_f for current technology ranges from 10 (at Kg = 0.1 md) to infinite (at Kg<0.02 md).
3. Well spacing is a function of reservoir properties (drainage area) and field rules. For the San Juan, well density is limited to 4 wells per section for both Current and Advanced cases.
4. Fracture height is a function of amount of net pay to be stimulated. Maximum height for the Current Case is 300 feet, equal to a maximum height to length ratio of 75%. The Full Advanced Case provided for more effective containment, thus requiring a smaller amount of fluid, so that the maximum height to length ratio is 35%. Due to the limited pay intervals in these formations, neither of these limits is reached. This factor influences costs and net fracture performance in the model.
5. Indicates effectiveness of controlling fluid leakoff. Treatment designs with better leakoff have no impact on well performance in this analysis but reduce volume and cost of fluid required.
6. Dryhole costs are allocated to successful wells. Dryhole costs include drilling and completion (less recovered casing), plus stimulation and testing costs equal to 50% of a normal stimulation cost.

G. Small Scale Field Studies

These regional geologic and technological assessments were validated by several small scale field studies. The purpose of this analysis was to confirm the estimated reservoir properties and the estimates of production from typical wells upon which they were based.

The method used for this validation was advanced decline curve analysis, developed by Fetkovich to history match well production using dimensionless decline curves. Production volume, pressure and producing time data were analyzed to check that the empirically derived reservoir properties were consistent with the flow regime assumed for the selected wells. The validated reservoir properties could then be used in type curves to estimate recovery under alternative technologies. The theory and application of this method will be discussed below.

One township was selected for each of the target intervals for detailed analysis. All producing wells in the selected township were reviewed to select those most likely to represent wells to be drilled in the future. Average wells were selected based on estimated ultimate recoveries and producing rate decline, corrected for amount of pay completed and stimulation size. The townships selected (and the fields in which they reside) are as follows:

- Pictured Cliffs (Choza Mesa) - 28N 4W
- Chacra (Rusty) - 22N 6W
- Mesaverde (Blanco) - 32N 9W
- Dakota (Basin) 29N 14W

Additional well completion information was collected along with any published reservoir data, mostly from applications to the states and FERC, for designation as a tight gas formation. The results of the field study for the Choza Mesa field are discussed in this section.

The Choza Mesa field was selected as a small, currently producing field with near-tight permeability for previously drilled wells and low permeability expected for future wells. An analysis was conducted on 7 wells with sufficient quality producing data for advanced decline curve analysis. The analysis methodology was consistent for all four field studies, so it will be described in detail only for the Pictured Cliffs.

The Choza Mesa field covers parts of townships 28-29N and ranges 3-4W in Rio Arriba county, New Mexico. The discovery well was the EPNG No. 2 San Juan 29-4, drilled in 1953. As of 1989, there were 58 wells, of which 52 were active. Average production for 1988 was 12.3 MMcf per year, although many wells were curtailed part of the year.

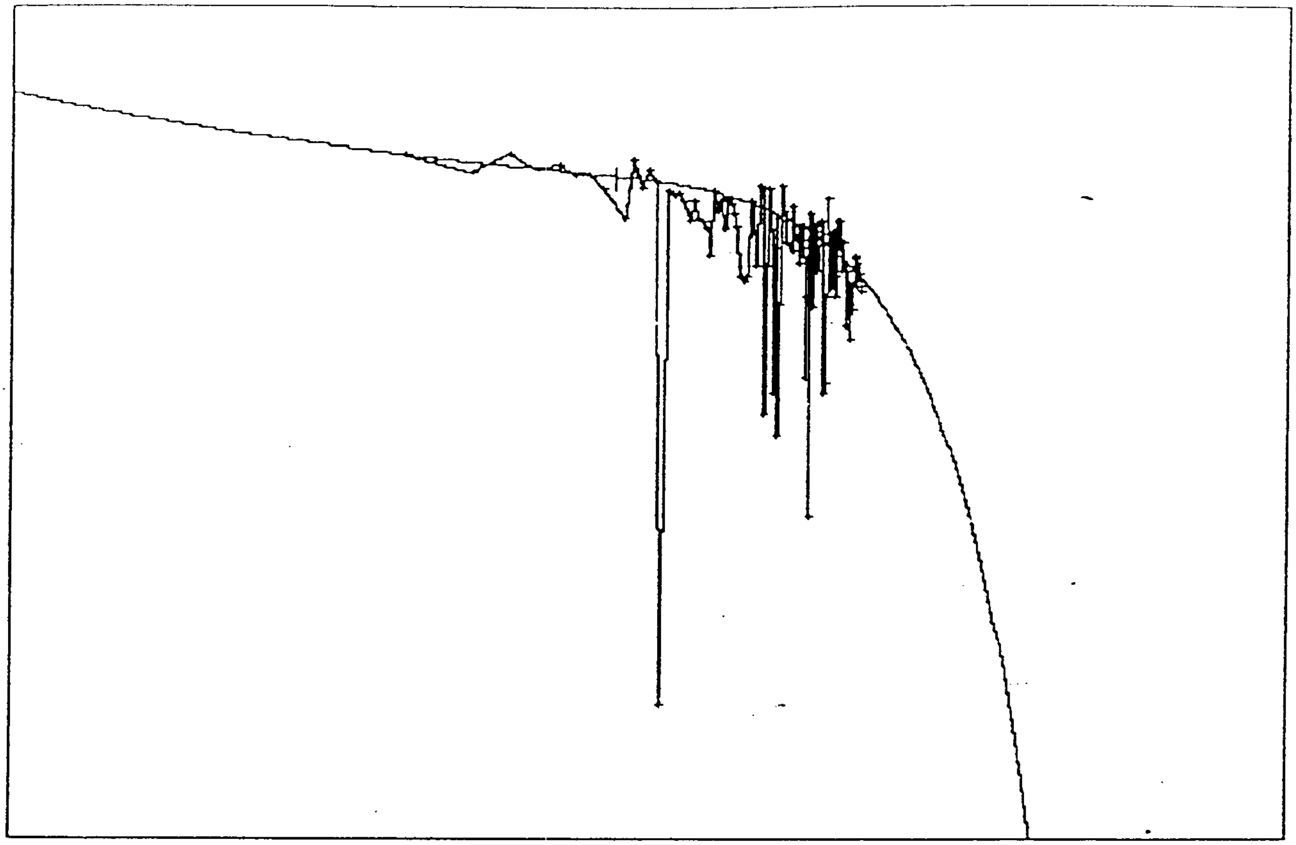
Although the discovery well was not stimulated, a review of completion reports for all wells in the field show increasing size and sophistication of treatments over time. In the 1950's, treatments were about 20,000 to 30,000 pounds of sand carried in water or oil. By the mid-1970's, job sizes had increased to over 150,000 pounds of sand at 1 pound per gallon of water. Some nitrogen fracs were placed in the late 1970's, and dual completions were successful within the Pictured Cliffs. The largest treatment at that time (1978) was the Amoco 25 Valencia Canyon Unit. Its two zones were faced with 63,000 gallons of emulsion with 124,000 pounds of sand, and 112,000 gallons of emulsion with 224,000 pounds of sand.

Reservoir properties reported in published sources vary widely between wells. Averages or ranges are net pay of 130 feet, porosity of 0 to 16 percent, permeability of 0 to 0.84 millidarcies (average 0.15 md, indicating that production may be greatly enhanced by fracture permeability), water saturation of 0 to 98 percent, gas gravity of 0.664, and depth of current wells from 3,300 to 4,800 feet.

All Choza Mesa Pictured Cliffs wells were evaluated as to their suitability for analysis and representativeness. Seven wells met the criteria for evaluation: at least one year in depletion, average 3-year cumulative recoveries (in the mid 50% of all wells), and relatively uniform production (indicative of constant pressure decline with limited effects of curtailment). Monthly production data from these wells were combined, normalized to the first month of production and analyzed. Thus, the analysis started with expected average reservoir properties and actual composite production data. The history matching with decline curves would derive a consistent set of reservoir properties and producing characteristics appropriate to estimate recovery from a typical well in the Choza Mesa Pictured Cliffs area.

The matching procedure, shown in Figure IV-32, indicated that the typical well is in transient flow for about 2 years before declining exponentially. Note the first period of apparent curtailment is the result of coincidental curtailments in the three highest volume wells early in their lives. Many

Figure IV-32. Choza Mesa Sample Well Decline Curve Match



San Juan wells over the past decade have been curtailed in the summer, making this composite history matching particularly useful, since accurately history matching a severely curtailed individual well is extremely difficult without flowing pressure data.

Reservoir properties matched for this set of composite wells was as follows:

Reservoir Property	Source	Value
• Net pay	field data	130 feet
• Porosity	FERC designation	10 percent
• Water Saturation	FERC designation	60 percent
• Permeability	derived	0.15 md
• Drainage Area	current spacing	140 acres
• Effective Fracture Length	derived	116 feet
• Decline Constant	derived	0.0

Reservoir properties are consistent with an average gas in place per 160 acre well spacing unit of 4.6 Bcf. Estimated ultimate recovery of 2.8 Bcf indicates a 61% recovery efficiency. Fracture lengths are consistent with the volumes pumped in these wells. Assuming a 60,000 pounds average treatment over a 130 foot gross interval, and 1.5 - 2.0 pounds of proppant per square foot of fracture face, a propped fracture length of 116 feet is plausible. Based on these empirically derived parameters, production from future typical wells was estimated for alternative stimulation designs.

H. Estimated In Place and Technically Recoverable Tight Gas

The geological appraisal comprised the majority of effort in this study. Once the extent of potentially productive area and typical well reservoir properties were derived, gas in place and per well ultimate recovery could be calculated.

1. Reservoir Engineering Assumptious

For this study, gas in place was based on gas properties derived using industry standard correlations. Coefficient of isothermal compressibility and formation volume factor used the z-factor algorithm of Dranchuk, Purvis and Robinson. Viscosity was estimated by Lee's method. These properties were derived on a township specific basis and used in all recovery modeling.

Initial reservoir pressure was estimated as an average for undeveloped areas, extrapolated from initial pressures of the latest wells in each township. Densely developed areas with higher permeability or those that have been produced for some time may have been partially depleted. This possible effect was not addressed in this study for two reasons. First, analysis of long-term pressure profiles of original and infill wells (first and second wells in 320 acre units) in the Mesaverde and Dakota show no interference (Maldarzdo, et. al., 1983). Second, since the major purpose of the study was a comparison between reservoirs for alternative technology scenarios, the impact of small differences in initial pressure would have little effect on estimates of comparative technical recovery. Average pressure gradient for the remaining tight prospects was 0.43 psi/ft.

Undeveloped area was delineated, on a township average basis, as the area where a formation had not encountered updip water and where porosity and permeability had not graded into silt or shale. Total undeveloped area in each township was then reduced by undrillable area (e.g., cities, restricted areas) and already developed area (wells drained 160 or 320 acres per well, averaging 165 acres). Remaining undeveloped areas cover a total of 10,571 sections, of which 3,427 sections represent tight reservoirs.

Reservoir properties used for gas in place calculations were based on estimated average properties for current wells in a township. For densely developed areas, the properties of the most recently drilled wells were used, where available. For areas with little well control, properties were estimated based on playwide correlations.

2. Estimated Tight Gas In Place

Remaining gas in place for the five target formations is estimated to be 66.5 Tcf. These estimates are based on the calculation of gas in place for each of the 482 (153 tight) typical wells, each draining 160 acres, multiplied by the undeveloped area in each township. Gas in place per section averages 6.3 Bcf per section for all reservoirs and 5.0 Bcf per section for tight reservoirs. Volumes and distributions of tight gas in place are shown in Table IV-5.

3. Type Curve Analysis of Technical Recovery

Recoveries from typical wells were estimated using type curves. Type curves are pre-plotted solutions of the constant terminal pressure solutions of the diffusivity equation. They are presented in the dimensionless form as the log-log plot of dimensionless cumulative pressure drop against dimensionless time. Given reservoir properties and producing characteristics for a typical well, cumulative recovery can be derived from the transformed cumulative time on the plots. This is accomplished in TGAS-PC® through the use of digitized type curves.

Table IV-5. Estimated Remaining Gas in Place for San Juan Cretaceous Formations

Formation	Tight Gas in Place		Potentially Productive Right Area (Sections)
	Tcf	Bcf/Sect	
Pictured Cliffs	2.5	3.0	823
Chacra	0.1	0.8	168
Cliff House	1.0	2.9	345
Point Lookout	1.2	4.4	280
Dakota	12.4	6.8	1,811
Total/Average	17.2	5.0	3,427

Several assumptions are required to make the type curve prediction method valid, and are generally accepted in the literature:

- Homogeneous, isotropic reservoir of constant volume
- Closed boundary reservoir
- Horizontal reservoir with negligible gravity effects
- Uniform distribution of initial reservoir pressure
- Constant fluid viscosity
- Small and constant reservoir compressibility
- Gas expansion mechanism with single phase flow
- Hydraulic fractures have uniform conductivity and shape

Since all reservoirs depart from this idealized picture, a finite difference reservoir simulator is often used for detailed reservoir modeling. For purposes of this regional analysis, however, these assumptions are largely satisfied.

Typical wells were analyzed to derive effective permeability to gas, drainage radius, and to confirm achieved fracture length. These derived properties were used as inputs to type curves to estimate production. Additional detail on the theory and application of the method are described in detail by Fetkovich (1980).

The data were input into the type curve model to estimate production streams and ultimate recovery of tight gas for each typical well. Inputs are as follows:

- Initial pressure (P_i).
- Bottomhole temperature (BHT)
- Porosity (Ø).
- Net pay (h).
- Water saturation (S_w).
- Drainage area (Ad).
- In-situ gas permeability (k_g).
- Decline constant (b, if layered reservoir effect is significant, as determined from advanced decline curve analysis).
- Productive area represented by the typical well (A).

Where data were not available, defaults were generated using established engineering algorithms or regional correlations. In general, data sources and defaults were as follows:

Data Element	**Preferred Data Source**	**Default Method**
Temperature	geophysical log	gradient from local wells
Pressure	log or well test	gradient from local wells
Porosity	sonic log or core	field average from literature
Net pay	geophysical log	well test derived (kh), decline curve
Water saturation	log, core analysis	field study average
Drainage area	operator	decline curve analysis
Permeability	well test, core	decline curve analysis
Decline constant	decline curve analysis	b=0
Productive area	Field maps	isopach maps
Depth	drillers log	formation structure map
Condensate yield	producing well avg	N/A

I. Estimates of Tight Gas Reserves

Estimated potential reserves were calculated for each of the 153 typical wells, based on current San Juan engineering costing and cash flow analyses. A minimum required levelized wellhead price was estimated that could cover all capital and operating costs and return the cost of capital to the operator. Estimated potential reserves for the basin at specific wellhead prices were calculated by multiplying the number of remaining drilling prospects in each township by estimated typical well reserve additions at that price. The methods of costing and economic analysis are discussed below.

1. Costing Overview

The engineering costing model provides estimates of site-specific capital and operating costs for low permeability natural gas exploration, development, and production. The model includes:

- Pre-Development Costs for lease acquisition, geological and geophysical and other pre-development activities.
- Development Costs for site preparation, drilling, completing and stimulating wells, for installing lease equipment, and for installing field facilities.
- Operating and Maintenance Costs for producing natural gas and for maintaining wells and lease equipment.

The cost data and algorithms are based on widely used, publicly available sources and include well cost data from the Joint Association Survey (1989) and the U.S. Department of Energy, (1989) as well as data from operators. All published costs are updated to 1990 dollars based upon the Producers Price Index (PPI) published by the Bureau of Labor Statistics. Drilling is assumed to be straight hole with no directional drilling. Costs are specific to tight gas resources, recovery processes and the San Juan Basin and account for variable well depths and gas production rates.

2. Costing Algorithms

The factors of estimation for the San Juan Basin are detailed below.

- **Predevelopment Costs.** There are two components to the predevelopment costs: geology and geophysics (G&G) and the lease bonus. The G&G costs are based upon both fixed and footage costs. Lease bonus includes a fixed cost for filing and administrative fees and a per acre charge based on well spacing.

- **Drilling and Completion Cost.** Drilling and completion costs refer to the costs involved from site preparation through setting pipe and perforating including casing costs. The cost also includes geophysical logging but not drill stem tests, or coring or stimulation. In addition, casing costs are calculated separately as shown in the third cost component. Completion equipment referred to by the values determined here assume naturally flowing wells (i.e., no pumping units). In addition, flowlines, gathering systems, or any surface facilities are not included in the drilling and completion costs.

- **Casing Costs.** The cost of casing includes labor, rentals, and pipe, and assumes that pipe will be set to the total depth. No allowance is given for liners.

- **Dry Hole Rate.** Dry hole costs are inherent in development programs. To account for this expense, 10 percent of the dry hole cost is added to each well. This assumed a 90 percent success ratio, slightly lower than historical averages, due to the expectation that drilling outside current producing area entails more risk. These numbers are based upon values reported in the AAPG Bulletin of October 1988.

- **Dry Hole Cost.** Due to the fact that we are dealing with a tight gas reservoir, most wells are fraced before their potential is determined. Given improvements in prefracture stimulation analysis of permeability and potential productivity, we assume that only 50% of eventual dry holes are fractured. That is, half of dry holes can be determined to be productive without stimulation. If the well is still unproductive after fracture treatment, some costs can be recovered by pulling the casing (drilling and completion and any stimulation costs are already incurred).

- **Stimulation Cost.** Although stimulations vary across the San Juan Basin in type and size, an average stimulation was estimated for this analysis. Stimulation is modeled as a sand/gel treatment, averaging 80,000 pounds of 40/60 sand and uses a 40 pound guar gel. Treatment designs vary tremendously, and are more commonly designed by the operators than in the past. Common rules of thumb are 4,000 pounds per foot of pay for proppant volume and about 1.2 barrels per minute per perforation for pumping rates. No additional costs are included for larger than normal acid stimulation or exotic fluids or proppants. The well stimulation cost is the sum of a fixed site cost, plus the cost of sand and fluid uses for fracturing, plus the cost of generating the required pressure to pump material into well.

- **Equipment cost.** The surface equipment cost is the sum of the cost for flow lines and connectors, production, condensate recovery systems, compressor costs, and costs for fuels, chemicals, and disposal. There are no allowances for water production. Costs are based on depth and flow rates. A compressor will be needed if gas pressure at the well head becomes insufficient for the gas transportation pipelines. If the production model indicates that this situation exist, the production year of occurrence is calculated. Compressor costs are calculated as for years when average bottomhole pressure falls below 500 psi (average of high and low pressure gathering systems in the basin).

- **Operations and Maintenance Costs.** The operating cost is the sum of direct labor costs, surface maintenance costs, subsurface maintenance costs, and compressor maintenance costs. Costs are based on depth and flow rates.

Costs were estimated for each of the 153 typical wells and checked against operator quotes for recent wells. Assumptions used for well costing are shown in Table IV-6. The results of the costing analysis for a sample Dakota well are shown in Table IV-7.

Table IV-6. San Juan Costing Algorithms

Parameter	Algorithm
Geological and Geophysical	$5,000 + $4/ft
Lease Acquisition	$1,000 + $20/acre
Drilling and Completion (based on 1989 JAS)	2,500 ft $254,000 5,000 ft $354,000 7,500 ft $534,000 10,000 ft $832,000
Stimulation Fixed Cost Proppant Fluid HHP (100% reserve) Frac volume	 $30,000 $0.08/lb $0.21/bbl $4* pressure f(length, height, leakoff)
Production & Lease Equipment Flowlines and Connectors Production Package Condensate Recovery System Compressor	 f(depth, average daily rate) f(depth, average daily rate) $10,700 $190/Mcf average daily rate
Operations Normal O&M (Direct Labor) Normal O&M (Surface Maintenance) Normal O&M (Subsurface Maintenance) Compressor Operations	 $3,000 + $0.20/ft f(depth, average daily rate) $0.39/ft $0.05/Mcf
Dry Hole Cost Allocation (DHCA)* Drilling and Completion Less Recovered Casing Plus Stimulation/Testing Dry Holes	 Same as above $10,000 + (depth-2,500)*10 50% of frac cost
*Each successful well bears allocated dry hole costs equal to the above DHCA value times the ratio = success rate/(1-success rate)	

Table IV-7. Costs for a Typical San Juan Tight Gas Wells

Capital Costs Data	
Geological and Geophysical Costs per well	$2,800
Lease Acquisition Costs	$4,700
Drilling and Completion Costs per Well (6,236 ft)	$443,000
Production and Lease Equipment Costs per Well General Lease Equipment Condensate Recovery System Water System Compressor (not required)	 $23,500 $ 0 $ 0 $ 0
Stimulation Costs per Well ($91,000 per zone and 333 ft design)	$91,000
Allocated Dryhole Cost (ratio to succ. wells = 0.11) Drilling ($396,000) Stimulation ($45,000*)	$49,000 $44,000 $ 5,000
G&A on Investments (10%)	$61,500
Total Capital Investment	$675,500
Annual Expenditure Data	
Average Annual Operating Costs Per Well	$14,000
G&A on Operations (20%)	$2,800
Tangible Costs Include: 88.9% 100.0% 25.0% 100.0%	 G&G Lease Acquisition Drilling and Completion Of Production and Lease Equipment
Intangible Costs Include: 11.1.% 75.0% 100.0% 100.0%	 G&G Of Drilling and Completion Of Stimulation Costs Of Dry Hole Costs
*Only 50% of ultimately dry holes are stimulated before being condemned as dry.	

2. Economic Assumptions

The financial analysis model integrates the engineering costs, royalties, severance taxes and income taxes, and the capital charge to establish the minimum required price for tight gas recovery. The key features of the financial model are:

- Timing of investment and operating costs (particularly the effect of front-end dry hole and other capital outlays) to establish before-tax cash flows and operating net revenues.
- Accounting conventions (e.g., tax credits and depreciation) to establish taxable income and tax obligations, using the current federal/state tax code.
- Standard internal rate of return, net present value, payback and minimum required selling price financial algorithms.

The final product of the resource economics methodology described above is a set of price/supply curves of potential tight gas reserves.

Explicit assumptions about project economics are as follows, with parameter values shown in Table IV-8:

- Lease costs are constant basinwide.
- Drilling costs for vertical wells are based on depth.
- All successful wells require a hydraulic fracture; only a portion of dry wells incur fracture costs.
- Wells are drilled on 160 acre spacing.
- There is a market outlet for all gas at the estimated minimum required price.
- No gathering costs are included in the calculated wellhead price.
- Discount rate is assumed to be 10% to comply with standard SEC guidelines for petroleum and gas reserves (even though anecdotal evidence suggests current returns are lower than 10%).
- All economics are evaluated in current (1990) dollars and aggregated into time-independent price supply curves.
- Cost escalation is excluded, assuming parity between real well costs and average wellhead prices over time.
- The Non Conventional Fuels Tax Credit is <u>excluded</u> from the analysis.

Results of the cash flow analysis for the sample wells are shown in Table IV-9.

Table IV-8. Economic Parameters Used for San Juan Tight Gas Analysis

Economic Parameter	Parameter Value
Royalty Rate	0.125
Severance Tax Rate (avg. CO/NM)	0.0778
State Income Tax Rate (avg. CO/NM)	0.072
Federal Income Tax Rate	0.34
Minimum Economic Gas Rate (Mcfd)	25
Development Drilling Success Rate	0.90
Portion of D&C as IDC	0.28
Portion of IDC to Expense	0.70
G&A - Operations	0.20
G&A - Investment	0.10
Depreciation Rate	1986 Tax Act

3. Results of Economic Analysis

Potential reserves were estimated for each unit of analysis by multiplying typical well reserves by the number of drilling prospects in the respective townships. These estimates were then aggregated into a time-independent price supply curve to indicate potential reserves at alternative wellhead prices. San Juan tight gas potential using current technology is estimated at 1.1 Tcf at wellhead prices of $1.50/Mcf. If wellhead prices increase to $2.00/Mcf, enough additional prospects become economic to increase potential reserves to 2.3 Tcf. At $4.00/Mcf, prices estimated by DOE's Energy Information Administration within 15 years, 5.4 Tcf are potentially economic (DOE/EIA, 1990).

The Dakota Formation contains the majority of remaining tight gas resources in the basin. The remainder of the Cretaceous sands are either higher than 0.1 md on average or have low productivity. The Mesaverde sands tend to have high permeability and high water saturation. The Chacra tends to have thin pays.

Table IV-9. Cash Flow Analysis for a Typical San Juan Tight Gas Well

Category	Total Cost ($M)	$/MMBtu
Total Revenues	1,792.8	2.18
Total Investment	**675.5**	**0.82**
G&G, Lease Acquisition and Dry Holes	56.6	0.07
Normal Drilling and Completion	443.0	0.54
Equipment Costs	23.5	0.03
Normal Equipment	23.5	0.03
Other Equipment	0.0	0.00
Stimulation Costs	91.0	0.11
Horizontal Well Costs	0.0	0.00
G&A/Overhead on Investment	61.4	0.47
Total Operating Costs Plus Overhead	**369.6**	**0.45**
Operating Costs	308.8	0.37
Normal O&M Costs	308.8	0.37
Other Operating Costs	0.00	0.00
G&A On Operations	61.6	0.07
Financial Costs	**499.0**	**0.61**
Royalties	224.1	0.27
Severance Taxes	117.3	0.14
Federal and State Taxes Minus Credit	157.6	0.19
After Tax Cash Flow (Return on Investment)	**248.8**	**0.30**
Total Hydrocarbon Production (McfE)	822.4	
Total Gas Production (Mcf)	822.4	

The Dakota contains the bulk (70%) of the remaining recoverable tight gas. Figure IV-33 shows the potential tight gas reserves by formation for the five intervals analyzed. In Table IV-10, the estimated potential tight gas reserves are shown for several ranges of required wellhead prices. Also shown are capital and operating costs per MMBtu for each price range. Note that these results are consistent with the rule of thumb that wellhead prices must be about 2½ times the finding ("capital") cost to be economic.

The impact on near-term reserve potential of the Section 29 production tax credit for tight sands cannot be overlooked. Although only about half the highest potential remaining area is currently eligible to receive the credit, potentially all of the remaining tight areas appraised in this

Figure IV-33. Price Supply Data for Selected San Juan Tight Formations

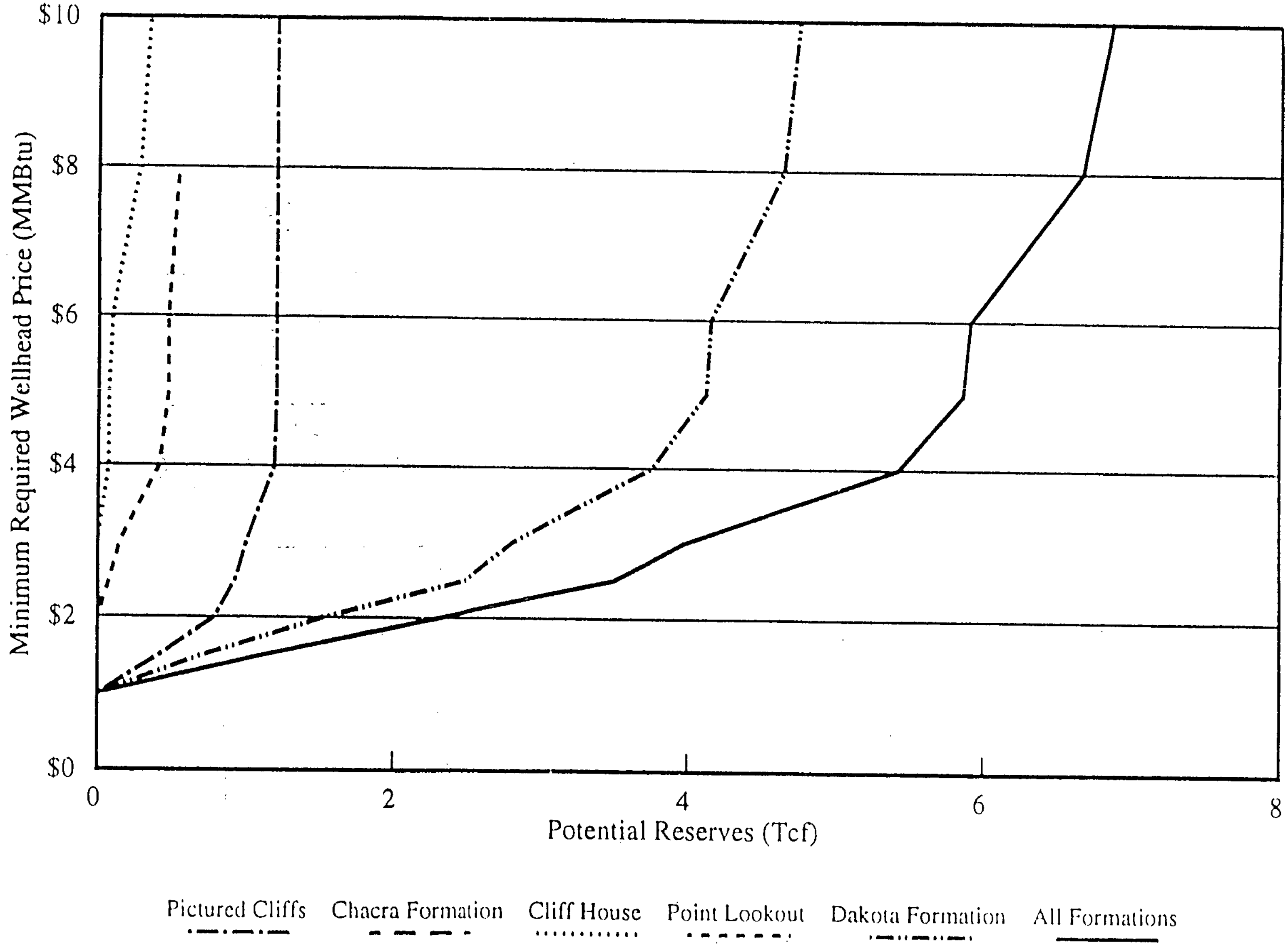


Table IV-10. Potential Reserves of San Juan Cretaceous Tight Gas

Min Req. Price 1990 $/MMBtu	Incremental Recovery (Tcf)	Cumulative Recovery (Tcf)	Capital Costs $/MMBtu	Operating Costs $/MMBtu	Cum GIP Check (Tcf)
Total San Juan					
$0.00 - 0.50	0.00	0.00	$ 0.00	$ 0.00	0.00
$0.50 - 1.00	0.00	0.00	$ 0.00	$ 0.00	0.00
$1.00 - 1.50	1.10	1.10	$ 0.47	$ 0.28	2.24
$1.50 - 2.00	1.21	2.31	$ 0.64	$ 0.32	4.76
$2.00 - 2.50	1.20	3.51	$ 0.88	$ 0.39	7.33
$2.50 - 3.00	0.46	3.97	$ 0.87	$ 0.54	8.53
$3.00 - 4.00	1.45	5.42	$ 1.35	$ 0.61	11.72
$4.00 - 5.00	0.44	5.86	$ 1.92	$ 0.77	12.60
$5.00 - 6.00	0.05	5.91	$ 1.93	$ 1.17	12.71
$6.00 - 8.00	0.74	6.66	$ 2.05	$ 1.21	15.16
$8.00 - 10.00	0.20	6.86	$ 2.67	$ 1.56	15.83
> $10.00	0.36	7.22	$ 4.16	$ 2.12	17.24
Pictured Cliffs					
$0.00 - 0.50	0.00	0.00	$ 0.00	$ 0.00	0.00
$0.50 - 1.00	0.00	0.00	$ 0.00	$ 0.00	0.00
$1.00 - 1.50	0.41	0.41	$ 0.35	$ 0.35	0.90
$1.50 - 2.00	0.38	0.79	$ 0.53	$ 0.38	1.69
$2.00 - 2.50	0.14	0.93	$ 1.06	$ 0.43	1.93
$2.50 - 3.00	0.07	1.00	$ 0.89	$ 0.58	2.09
$3.00 - 4.00	0.19	1.19	$ 1.57	$ 0.61	2.42
$4.00 - 5.00	0.01	1.20	$ 2.17	$ 0.92	2.44
$5.00 - 6.00	0.00	1.20	$ 2.10	$ 1.08	2.44
$6.00 - 8.00	0.00	1.20	$ 0.00	$ 0.00	2.44
$8.00 - 10.00	0.00	1.20	$ 4.11	$ 1.97	2.44
> $10.00	0.01	1.21	$ 8.10	$ 3.13	2.51
Chacra					
$0.00 - 0.50	0.00	0.00	$ 0.00	$ 0.00	0.00
$0.50 - 1.00	0.00	0.00	$ 0.00	$ 0.00	0.00
$1.00 - 1.50	0.00	0.00	$ 0.00	$ 0.00	0.00
$1.50 - 2.00	0.00	0.00	$ 0.00	$ 0.00	0.00
$2.00 - 2.50	0.00	0.00	$ 0.00	$ 0.00	0.00
$2.50 - 3.00	0.00	0.00	$ 0.00	$ 0.00	0.00
$3.00 - 4.00	0.00	0.00	$ 0.00	$ 0.00	0.00
$4.00 - 5.00	0.00	0.00	$ 0.00	$ 0.00	0.00
$5.00 - 6.00	0.00	0.00	$ 0.00	$ 0.00	0.00
$6.00 - 8.00	0.00	0.00	$ 0.00	$ 0.00	0.00
$8.00 - 10.00	0.00	0.00	$ 0.00	$ 0.00	0.00
> $10.00	0.04	0.04	$ 8.73	$ 3.70	0.14

Table IV-10. Potential Reserves of San Juan Cretaceous Tight Gas (Continued)

Min Req. Price 1990 $/MMBtu	Incremental Recovery (Tcf)	Cumulative Recovery (Tcf)	Capital Costs $/MMBtu	Operating Costs $/MMBtu	Cum GIP Check (Tcf)
Cliff House					
$0.00 - 0.50	0.00	0.00	$ 0.00	$ 0.00	0.00
$0.50 - 1.00	0.00	0.00	$ 0.00	$ 0.00	0.00
$1.00 - 1.50	0.00	0.00	$ 0.00	$ 0.00	0.00
$1.50 - 2.00	0.00	0.00	$ 0.00	$ 0.00	0.00
$2.00 - 2.50	0.00	0.00	$ 0.00	$ 0.00	0.00
$2.50 - 3.00	0.00	0.00	$ 0.00	$ 0.00	0.00
$3.00 - 4.00	0.07	0.07	$ 1.00	$ 0.68	0.17
$4.00 - 5.00	0.00	0.07	$ 0.00	$ 0.00	0.17
$5.00 - 6.00	0.03	0.09	$ 1.85	$ 1.19	0.24
$6.00 - 8.00	0.19	0.28	$ 2.05	$ 1.36	0.71
$8.00 - 10.00	0.06	0.34	$ 2.67	$ 1.82	0.85
> $10.00	0.06	0.40	$ 3.84	$ 2.63	1.00
Point Lookout					
$0.00 - 0.50	0.00	0.00	$ 0.00	$ 0.00	0.00
$0.50 - 1.00	0.00	0.00	$ 0.00	$ 0.00	0.00
$1.00 - 1.50	0.00	0.00	$ 0.00	$ 0.00	0.00
$1.50 - 2.00	0.00	0.00	$ 0.00	$ 0.00	0.00
$2.00 - 2.50	0.08	0.08	$ 0.67	$ 0.54	0.17
$2.50 - 3.00	0.07	0.15	$ 0.81	$ 0.60	0.33
$3.00 - 4.00	0.26	0.41	$ 1.23	$ 0.80	0.88
$4.00 - 5.00	0.06	0.47	$ 1.50	$ 0.97	1.02
$5.00 - 6.00	0.00	0.47	$ 0.00	$ 0.00	1.02
$6.00 - 8.00	0.00	0.54	$ 2.15	$ 1.42	1.17
Dakota					
$0.00 - 0.50	0.00	0.00	$ 0.00	$ 0.00	0.00
$0.50 - 1.00	0.00	0.00	$ 0.00	$ 0.00	0.00
$1.00 - 1.50	0.70	0.70	$ 0.54	$ 0.23	1.33
$1.50 - 2.00	0.83	1.53	$ 0.69	$ 0.30	3.07
$2.00 - 2.50	0.98	2.51	$ 0.87	$ 0.37	5.22
$2.50 - 3.00	0.31	2.82	$ 0.87	$ 0.51	6.12
$3.00 - 4.00	0.93	3.76	$ 1.37	$ 0.56	8.24
$4.00 - 5.00	0.37	4.12	$ 1.99	$ 0.74	8.96
$5.00 - 6.00	0.02	4.15	$ 2.03	$ 1.15	9.01
$6.00 - 8.00	0.49	4.64	$ 2.04	$ 1.13	10.84
$8.00 - 10.00	0.11	4.75	$ 2.60	$ 1.34	11.30
> $10.00	0.24	4.99	$ 3.20	$ 1.65	12.35

study could be designated by FERC. The credit mechanism provides a $0.52/Mcf credit on federal income taxes to the operator on gas produced through 2002 from wells spudded through 1992 in designated areas. Unlike the other unconventional gas resources, this credit is not adjusted for inflation. Table IV-11 shows the maximum impact on potential resources of the credit; since not all these resources will be developed by 1992, the total impact will be somewhat less. At $1.50/Mcf, the availability of the tax credit increases potential resources by 2.1 Tcf, from 1.1 Tcf to 3.2 Tcf.

Table IV-11. Impact of Section 29 Tax Credits on San Juan Basin Tight Gas Potential (Current Technology)

Minimum Required Wellhead Price (1990$)	Cumulative Reserves Without Tax Credit (Tcf)	Cumulative Reserves With Tax Credit (Tcf)
$0.00 - 0.50	0.00	0.36
$0.50 - 1.00	0.00	1.74
$1.00 - 1.50	1.10	3.19
$1.50 - 2.00	2.28	3.75
$2.00 - 2.50	3.47	4.38
$2.50 - 3.00	3.97	5.15
$3.00 - 4.00	5.46	5.78
$4.00 - 5.00	5.86	5.88
$5.00 - 6.00	5.91	6.25
$6.00 - 8.00	6.66	6.71
$8.00 - 10.00	6.86	7.01
>$10.00	7.22	7.22

J. Technology Sensitivities

Alternative assumptions of reservoir properties or technologies would affect these estimates of potential reserves. Reservoir properties are based on recent published field information and history matching of wells where good production data were available. They can be revised only as development takes place and more accurate estimates from well testing and logging become available.

Technology assumptions, however, could vary substantially based on individual operator preferences and economics.

The impact on estimated resources of a group of improved technologies is shown in Table IV-12 as "Advanced Technology." It represents more efficient stimulations (through better leakoff control, better height containment, and more accurate prestimulation well tests to determine optimum design), and improved development and operating practices. These advances result in effective half-lengths of 600 feet. The comparison of potential shows that reserves are cost effectively added at every price level by the use of advanced technology.

Table IV-12. Potential Tight Gas Reserves Under Alternative Technology Scenarios

Minimum Required Wellhead Price ($/MMBtu)	Cumulative Technology Potential Reserves (Tcf)	Advanced Technology Potential Reserves (Tcf)
$0.00 - 0.50	0.00	0.00
$0.50 - 1.00	0.00	0.00
$1.00 - 1.50	1.10	1.87
$1.50 - 2.00	2.31	3.33
$2.00 - 2.50	3.51	4.41
$2.50 - 3.00	3.97	4.98
$3.00 - 4.00	5.42	6.19
$4.00 - 5.00	5.86	7.08
$5.00 - 6.00	5.91	7.53
$6.00 - 8.00	6.66	8.05
$8.00 - 10.00	6.86	8.13
>$10.00	7.22	8.24

The application of advanced technology, however, may not be appropriate for all wells. Although more gas may be recovered for a given well, added recovery may not offset the added costs.

To estimate the effect of this factor, we conducted sensitivity analyses of the most important technology parameters. Per well recovery and minimum required price are most sensitive to effective fracture length.

Since effective fracture lengths are usually much shorter than design lengths, operators try to increase achieved fracture length by improving fracture efficiency than just by increasing design length. Advanced technology cases assume R&D results in improved efficiency and reduced costs for new technology. If the Full Advanced technology (described in Table IV-4) were not achieved, then potential reserves would be less than indicated. These technology sensitivities also show the effects of partial R&D success. Since effective fracture length is a suitable proxy for stimulation effectiveness, we estimated recoveries, costs, and potential reserves for 100 foot increments of effective fracture length between 100 and 600 feet.

Each sensitivity assumed that the fracture treatment design that added reserves at the lowest cost is the optimum (i.e., as opposed to maximizing recovery without regard for cost). In each of the five fracture length sensitivities (e.g., 100, 300, 400, 500, 600 feet) we estimate reserves for all lengths up to and including the specified length for optimization. For example, the 400 foot case assumes that the maximum achievable effective length is 400 feet and optimizes on minimum required price for lengths up to and including 400 feet.

Since increased recovery occasionally fails to offset the cost of longer fractures, the optimum length is a function of both wellhead price and reservoir properties. Generally, higher prices and longer available lengths allow for more potential reserves. Table IV-13 shows the impact of alternative fracture length between the 100 and 600 foot cases. Using the optimum fracture length, potential recovery at $1.50/Mcf increases from 1.1 Tcf (under the uniform 200 foot case) to 1.6 Tcf. This is because some wells that optimally would be stimulated with a 100 foot achieved length were over designed, thus rendered higher cost by a 200 foot length fracture.

At $1.50/Mcf, there is a significant increase in potential recovery for each increment of available fracture length. R&D that increase the available effective length from 200 to 300 feet will increase potential reserves by 12% (from 1.6 Tcf to 1.8 Tcf). At the same wellhead price, R&D that allows up to 600 foot fractures increases potential reserves to 2.1 Tcf.

Table IV-13. Potential San Juan Tight Gas Reserves (Tcf) for Optimized Fracture Length

	x_f = 100	x_f = 200	x_f = 300	x_f = 400	x_f = 500	x_f = 600
$ 0.50	0.00	0.00	0.00	0.00	0.00	0.00
$ 1.00	0.00	0.00	0.11	0.57	0.72	0.55
$ 1.50	0.09	1.62	1.82	2.23	2.16	2.08
$ 2.00	0.90	2.68	2.80	2.94	2.95	2.84
$ 2.50	1.25	3.33	3.48	3.84	3.67	3.53
$ 3.00	1.90	4.18	4.14	4.35	4.25	4.07
$ 4.00	2.59	5.28	4.93	4.77	4.55	4.39
$ 5.00	3.35	5.64	4.99	4.90	4.78	4.55
$ 6.00	3.60	5.82	5.28	5.23	4.99	4.79
$ 8.00	3.90	6.39	5.65	5.49	5.21	5.00
$10.00	4.35	6.66	5.79	5.57	5.29	5.08

V. Summary and Conclusions

Historically one of the major gas producing basins in the Rocky Mountain region, the San Juan Basin, remains a significant potential source of new tight gas reserves. A location-specific resource database was constructed and typical well recoveries were modeled on a township-specific basis for five known tight formations: the Pictured Cliffs, Chacra, Cliff House, Point Lookout, and Dakota. Project costing and cash flow economics were analyzed to derive potential reserves for various technology specifications and wellhead prices. These data provide a foundation for operators and pipelines to more closely examine San Juan tight sands for development in the near future.

The tight portion of the resource analyzed in this study contains 17.2 Tcf of gas in place of which 7.2 Tcf is recoverable using technologies and practices generally applied in the basin today. Potential tight reserves as \$1.50/Mcf (not considering tax credits) are 1.1 Tcf and at \$3.00/Mcf are 3.5 Tcf. The Dakota comprises three-fourths of this potential.

In the past, the principal determinants of gas deliverability were reservoir properties and production technology. The increased competitiveness of gas markets, the low wellhead prices paid in recent years, and dramatic changes in pipeline operations render reservoir engineering only one of several aspects of getting gas from the ground to market.

Four issues are important to develop the remaining San Juan tight sands: pipeline capacity, competing supplies, tax incentives, and technology. Currently, the San Juan Basin is served by El Paso, Northwest, Sunterra and Western pipelines, as well as several smaller gathering systems. Posner (1988) summarizes the current operations, capacities and charges of each of theses systems. San Juan tight gas could be produced to meet California's increasing demand, but it must compete with gas coming through the Kern River line from Wyoming, Canadian gas through the Northwest system, and Piceance Basin supplies moving south through the TransColorado system.

Second, the dominant competing supply in the San Juan Basin will be coalbed methane for the next several years. The development of technology to effectively stimulate, dewater, and produce coal seams has dramatically increased coalbed development in the past few years. An estimated 900 coalbed wells were drilled in 1990, spurred by availability of both technology and tax credits. While development activity is expected to decrease somewhat in 1991, the two-year extension of the tax credit will maintain the rapid development pace and keep coalbed gas extremely competitive.

Third, production tax credits are once again available for tight sands under Section 29 of the Internal Revenue Code. The Federal Energy Regulatory Commission (FERC), as part of the incentive pricing regulations it administers under the Natural Gas Policy Act (NGPA), has designated certain areas of the Dakota as tight gas sands. These designations cover over 2,000 square miles in the north-central portion of the basin. Wells drilled in these designated areas through December 31, 1992 are eligible to receive a production tax credit of \$0.52/Mcf on production through 2002. Operators may designate additional tight areas during the next two years. Because the credit is not adjusted for inflation and is only available until 2002, it provides the equivalent after-tax revenue effect of a \$0.66/Mcf increase in wellhead price over the life of the project. In other words, at current tax rates, an operator would be indifferent between a tax credit of \$0.52/Mcf at current wellhead prices or an increase in wellhead price of \$0.66/Mcf alone.

Finally, improved technology can increase recovery and lower costs of San Juan tight gas. Since a majority of potential tight sands is infill development, better reservoir engineering and stimulation design holds the promise for maximizing reserves. Recompletion and refracturing old wells based on reinterpretation of original logs and correlation with offset wells both show promise in appropriate circumstances. Horizontal wells, already used for coalbed methane development in the San Juan Basin and for tight formations in the Piceance and Appalachian Basins also show promise to dramatically increase recovery.

Technology improvements are necessary to substantially increase reserve additions from tight formations. Improved formation evaluation techniques, cost reductions in drilling and stimulation, and longer effective fracture lengths (where appropriate) can increase potential reserve additions at \$1.50/Mcf to 1.9 Tcf. Potential reserve additions at \$3.00/Mcf, prices expected within 15 years, could be increased by 25% from 4.0 Tcf to 5.0 Tcf if the full advanced technology case specified were implemented.

Appendix A

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