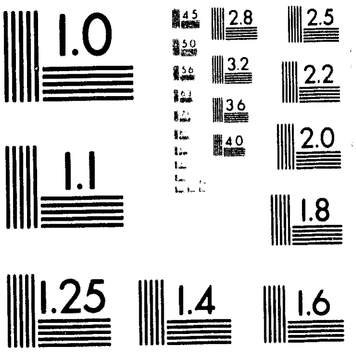
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DOE/MC/28130-3534
(DE94000060)
Distribution Category UC-132

Reserves in Western Basins
Part I: Greater Green River Basin

Topical Report

Work Performed Under Contract No.: DE-AC21-91MC28130

For
U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
P.O. Box 880
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October 1993

ABSTRACT

This study characterizes an extremely large gas resource located in low permeability, overpressured sandstone reservoirs located below 8,000 feet drill depth in the Greater Green River basin, Wyoming. Total in place resource is estimated at 1,968 Tcf. Via application of geologic, engineering and economic criteria, the portion of this resource potentially recoverable as reserves is estimated. Those volumes estimated include probable, possible and potential categories and total 33 Tcf as a mean estimate of recoverable gas for all plays considered in the basin.

Five plays (formations) were included in this study and each was separately analyzed in terms of its overpressured, tight gas resource, established productive characteristics and future reserves potential based on a constant $2/Mcf wellhead gas price scenario. A scheme has been developed to break the overall resource estimate down into components that can be considered as differing technical and economic challenges that must be overcome in order to exploit such resources: in other words, to convert those resources to economically recoverable reserves.

About 57% of the total evaluated resource is contained within sandstones that have extremely poor reservoir properties with permeabilities considered too low for commerciality using current frac technology. Cost reductions and technology improvements will be required to unlock portions of this enormous resource.

Approximately 12% of the total resource is contained within sandstone reservoirs which do not respond to massive hydraulic fracture treatments, probably due to their natural lenticular nature. Such depositional systems include various alluvial and non-marine facies. A detailed study of these systems and improvements or innovations in well completion and stimulation are required to exploit this resource.

Approximately 18% of the total resource is located in deeply buried settings below deepest established production. This resource is poorly defined due to sparse well control and the need for extrapolation of volumetric parameters from areas of better control. Additional deep drilling is required to characterize and better quantify this resource. This will require considerable price incentive, given the costs and risks involved.

Approximately 13% of the total resource is considered to represent overpressured, tight reservoirs that may be commercially exploited using today's hydraulic fracturing technology. From the viewpoint of current economics, drilling and completion cost, and risk, about 3% of the total resource has favorable risked expectations with the other 10% having unfavorable risked expectations. Reserves estimates consider both categories.

Total recoverable reserves estimates of 33 Tcf do not include the existing production from overpressured tight reservoirs in the basin. These have estimated ultimate recovery of approximately 1.6 Tcf, or a per well average recovery of 2.3 Bcf. Due to the fact that

considerable pay thicknesses can be present, wells can be economic despite limited drainage areas. It is typical for significant bypassed gas to be present at inter-well locations because drainage areas are commonly less than regulatory well spacing requirements.

ACKNOWLEDGEMENTS

Companies and individuals too numerous to list assisted in supplying data for use in this study and are acknowledged for their voluntary support. We would like to particularly acknowledge the assistance of Amoco, Celsius Energy, Core Lab, EG&G, Presidio, PG&E Resources, Snyder Oil, TerraTek, True Drilling, and UPRC for their cooperation. In addition, we would like to thank Petroleum Information Corporation for consenting to the use of digital well identification data from their WHCS database in the digital database that accompanies this report.

The Scotia project team consisted of Rob Caldwell (project manager), Mark Cocker (geology, petrophysics), Bill Cotton (computing, databases), Cliff Adams, Wayne Beninger, Dave Heather, and Pat Wagner (reservoir engineering), Simon Bidwell (engineering and petrophysics), Wendy Edmondson and Laurie Pasch (support), and Mary Ann Holubec (administration). Tom Carroll and Ken Ibsen provided consulting engineering and data support services. Al Jaffe acted as consulting business coordinator. These individuals are acknowledged for their diligent efforts.

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INTRODUCTION

Vast quantities of natural gas are entrapped within various tight formations in the Rocky Mountain area. This report seeks to quantify what proportion of that resource can be considered recoverable under today's technological and economic conditions and discusses factors controlling recovery. The ultimate goal of this project is to encourage development of tight gas reserves by industry through reducing the technical and economic risks of locating, drilling and completing commercial tight gas wells.

This report, the first of three, focuses on the Greater Green River basin (GGRB) located in southwestern Wyoming. Subsequent reports will focus on the Piceance and Uinta basins. The starting point for this study is a resource estimate completed by the U.S. Geological Survey (USGS) (Law et al, 1989). The USGS resource evaluation subdivided the geologic sequence into a series of plays occupying specific geographic and stratigraphic positions within the basin. Each play is characterized by a specific set of geological environments of deposition and by certain productive characteristics. The USGS resource assessment considers only resources located in tight reservoirs in overpressured portions of the basin, that is, in generally the deeper and more centrally located portions of the basin below 8,000 feet. Tight gas reservoirs are those that usually have an in-situ permeability of less than 0.1 md. The overpressured, tight reservoirs are referred to by the abbreviation OPT to distinguish them from other reservoirs in the basin that are not part of the USGS resource assessment.

The methodology utilized by the USGS in performing their resource assessment consisted of volumetric estimates based upon a grid of subsurface wireline log data cross-sections and correlations. This grid of cross-sections identified sequence boundaries and was the basis for counts of net sandstone utilizing a gamma ray cutoff. Volumetric estimates were completed via assumptions for average porosity and water saturation ranges and formation volume factor based upon temperature and pressure information. In place gas resource estimates were then computed on a volumetric and areal basis by play. The results of the USGS resource estimate are summarized in Table 1:

TABLE 1
USGS MEAN ESTIMATED RESOURCE BY PLAY
GREATER GREEN RIVER BASIN

PLAY	Tcf IN PLACE
Fort Union	96
Lance-Fox Hills	707
Lewis	610
Mesaverde	3,347
Cloverly Frontier	304
TOTAL	5,064

The magnitude of the resource estimate is staggering. Clearly, if only a small fraction of this resource was considered recoverable, then the GGRB would represent a significant contribution to the national gas supply picture. Addressing this issue is the subject of this report.

A twofold approach has been adopted involving firstly, a reexamination of the USGS resource estimate and adjustment of the parameters used, and hence deriving a revised resource estimate. Secondly, to address what proportion of that resource may be called "reserves," it should be clearly stated that the project brief is directed at the category classified as unproved reserves (that is, probable and possible) under standard Society of Petroleum Engineers (SPE) definitions. In the strict sense, such an analysis should be restricted only to volumes that have been discovered, with normal techniques for estimation being consideration of differing recovery factors or drainage radii around wells and allocating certain proportions to the probable and possible categories. Considering the immaturity of the OPT plays, such an approach would simply be a geometry exercise with little relevance to the larger aspect of OPT reserves potential and its future contribution to the national gas supply picture. As a result, "reserves" as used in this study, comprises volumes normally classified as probable and possible and also includes "potential reserves," that may qualify as commercial but remain undiscovered in the strictest sense. This definition and discussion of the distinction between "discovered" and "undiscovered" when dealing with unconventional resources is elaborated upon in the text.

This project seeks to not only document the performance and reserves from OPT gas wells in the GGRB, but also to explore the reasons behind differing recovery factors. Quantification of the reasons behind differing well performance is complex due to natural changes in reservoir properties and varying degrees of success of the massive hydraulic fracture treatment that is necessary to effect a commercial completion.

This report seeks to keep in focus the ultimate objective of encouraging further exploitation of the resource by industry. The process of successfully locating, drilling, completing, fracture treating, and producing an OPT gas well involves an interplay of complex geological, petrophysical and reservoir engineering components. As such, the text of this report has been organized so as to explain the basics involved in each contributing area by describing, in a qualitative fashion, the principles involved and relationships as currently understood. This approach is designed to introduce such topics to those who are not involved in such fields on a day to day basis and provide a working understanding of the tight gas problem. The report also seeks to provide factual and statistical background in the form of appendices describing in greater detail several of the more complex technical aspects involved in the study of tight gas reservoirs.

It should be noted that in working with OPT gas reservoirs, a greater degree of complexity and hence uncertainty is involved in comparison with conventional gas reservoirs. This uncertainty arises not only from the degree of heterogeneity normally exhibited by OPT gas reservoirs, but also due to the fact that conventional technical tools for measuring aspects such as reservoir properties (conventional logs, core analysis, DST data, etc.) were designed for use in conventional reservoirs. The data sources require special treatment and modification of approach, through to total data rejection in terms of supplying information which is useful in an analysis. Due to the low permeabilities and generally low porosities involved, most conventional measuring devices are at the lower end of their accuracy limit, introducing an additional base element of measurement error. All of these factors complicate the acquisition of base data, the reliability of such data, and its ultimate overall relevance to an evaluation. As a result, it is common for evaluation work to include an element of uncertainty, either via conducting analyses deterministically but providing ranges for input variables, or in fact taking such analyses to the next stage and working probabilistically. The original USGS resource estimate was performed probabilistically: that is, volumetric input data was estimated as ranges and combined into answers expressed as a distribution. The final results were presented as a numeric value with an associated probability level.

The USGS approach has been adopted in this study via expressing reserves results in the form of an estimated distribution. This system provides a quantitative and consistent methodology for expressing potential reserves data in evaluation situations typified by wide variation in individual well performance or, as otherwise expressed, in statistical type plays. The evaluation of reserves for OPT gas sands represents such a situation. It should be noted that in many cases it is not possible to accurately measure each of the factors controlling ultimate recovery or to determine which factors have the most impact.

SUMMARY OF RESULTS

1. Reevaluation of the base *in place* OPT gas resource by this study yields a mean estimate of 1,968 Tcf.

2. Of this base resource, 1,127 Tcf is contained within sandstones that are of extremely poor reservoir quality, having estimated in-situ permeabilities of less than 0.001 md. Such resources are termed *technologically nonviable* since they are contained in reservoirs and are considered too tight for commercial exploitation using today's hydraulic fracturing technology. Portions of this resource will only become accessible via future cost reduction and improvement in massive hydraulic fracturing technology.

3. The remaining 841 Tcf represents resources that are contained in reservoirs considered to have in-situ permeabilities greater than 0.001 md and are termed *technologically viable.* Of this resource, 233 Tcf (12% of the total) is termed *nondemonstrated* since it is contained in reservoirs that have not been shown to be commercially productive. *Nondemonstrated* resources commonly occur in particular facies such as alluvial and other nonmarine depositional systems that are characterized by a high degree of lenticularity. New developments in well completion and stimulation will be required to access these resources.

4. The remaining 608 Tcf represents *demonstrated* resources. These are in place volumes that are potentially available for conversion into reserves by application of an appropriate recovery factor. Of this volume, 68 Tcf (3% of the total) is considered to be *established* resource characterized by favorable expectations in terms of recovery and drilling risk. A further 191 Tcf (10% of the total) is considered *nonestablished* resource characterized by less favorable expectations in terms of recovery and a higher drilling risk and drilling cost. The differentiation of the *established* and *nonestablished* resource categories is based upon a drill depth criterion termed *economic basement*. *Economic basement* is a conceptual depth that depends upon drilling and completion costs, expected reserves, gas price, and success ratios. Changes in these parameters will cause dynamic movement of resources from one category to the other. The remaining 349 Tcf of *demonstrated* resources are considered *speculative. Speculative* resources are those occurring in deeply buried locations, characterized by poor well control and being deeper than any established commercial production. Such volumes are inferred by extrapolation of mapping into the deep basinal areas and are defined as being below the *deepest commercial production. Speculative* resources have a high degree of uncertainty associated with their quantification and are thus excluded from consideration from a reserves quantification perspective.

5. Table 2 summarizes the resource high-grading procedure:

TABLE 2
Breakdown of Revised Resource Estimate (Mean Values)

USGS Mean Resource Estimate		**5,064 Tcf**
Scotia Revised Mean Resource Estimate		**1,968 Tcf**
MINUS *Technologically Nonviable* Resources		**1,127 Tcf**
SUBTOTAL *Technologically Viable* Resources		**841 Tcf**
MINUS *Nondemonstrated* Resources		**233 Tcf**
SUBTOTAL *Demonstrated* Resources		**608 Tcf**
Subdivision:	***Speculative* Resources**	**349 Tcf**
	***Nonestablished* Resources**	**191 Tcf**
	***Established* Resources**	**68 Tcf**

Only *established* and *nonestablished* categories are considered for the purpose of estimating recoverable reserves.

6. Recoverable reserves, inclusive of probable, possible and potential categories, are estimated at 21 Tcf and 12 Tcf respectively for the *established* and *nonestablished* categories. These represent MAXIMUM recoverable volumes assuming a variable drilling pattern that leaves NO bypassed gas. The estimated ultimate recoveries (EUR) for existing OPT gas wells are not included in these figures.

7. Because OPT gas wells are characterized by significant variation in average drainage radius and due to large pay thicknesses, OPT gas wells may drain comparatively small areas. Development on a regulatory 640 or 320 acre spacing can result in significant bypassed gas. This gas remains in inter-drainage area locations at or near original reservoir pressure and is available for exploitation via infill drilling. It is common to have bypassed gas on the order of 50 to 90% of gas in place (GIP) on an initial 640 acre spaced development.

8. The Lewis play and Almond formation of the Mesaverde play contain the *established* resources and are the principal producing units in the basin with a combined EUR of 1,239 Bcf for existing OPT wells. *Nonestablished* resources are contained in the Frontier and Lewis plays, and in portions of the Almond and Ericson formations of the Mesaverde play. These units represent a combined EUR of 319 Bcf for existing OPT wells. The Lance-Fox Hills and Fort Union plays have no commercial production from the OPT section in the basin. Sub commercial production with an EUR of 0.9 Bcf is recorded from these two plays.

9. For all existing OPT gas wells in the GGRB, cumulative production to January 1, 1992 is 861 Bcf with an EUR of 1,559 Bcf. This represents proved developed producing (PDP) reserves developed mainly since 1975 in 667 producing wells. These EURs are log normally distributed with the average EUR for a GGRB OPT gas well being 2.3 Bcf and the median well being 0.5 Bcf.

10. The best producing areas have a distinct "sweet spot" character that involves favorable development of rock properties, diagenetic effects, sand body geometry, natural fracturing, and the optimal conditions for performing a successful hydraulic fracture treatment.

BACKGROUND/DISCUSSION

The USGS resource work has identified an extremely large potential resource in the GGRB. Recognition of the resource represents the first step in its exploitation. Gas developments in the GGRB have suffered from a combination of several "negatives." These include historically poor gas markets in terms of price and take, the requirement for the use of expensive and still developing technology particularly in the area of frac treatments, and a generally costly environment due to local logistics to name a few.

While the improving gas markets in the Rocky Mountain basins area and particularly in the GGRB are a positive factor, general industry skepticism of the resource itself and of the base economics compared to other opportunities in conventional oil and gas development are probably the main source of negative reaction towards the development of OPT gas.

Objectives and Purpose For Study

Encouraging commercial development of the OPT gas resource is the prime objective of this study. In comparison to conventional reservoirs, OPT reservoirs pose their own unique series of challenges. Since such challenges often involve the development and application of new technologies, and because such technologies can involve a significant cost component over those normally used in conventional reservoirs, a double negative is created by virtue of increased cost and increased risk (representing the very real possibility that such expenditures will be unsuccessful in providing an economic return).

As noted by Holditch (1992), despite the development and proof of concept of many of the technologies applied to tight gas development, such technologies have not been widely accepted for various reasons. Included amongst these is the inertia involved in technology transfer and demonstration that such technologies are indeed cost-effective. The approach taken herein has been to qualitatively describe the principles and mechanisms involved to generate an understanding rather than to approach the subject in the form of a critique, including mathematical development of each concept. The latter is incorporated by reference in that a large body of excellent technical material exists and key works are noted in the reference section of this report. In this way, it is hoped that the complexities involved in understanding the current state of the art as far as fracture treatments, permeability measurements, log interpretation, and other technical areas, will be presented with the objective of creating an understanding of the difficulties and processes involved.

It should be noted that the exploitation of OPT gas reserves involves physical measurements that can be at the lower limit of resolution of the various tools utilized in their measurement. Since such tools were designed and calibrated for conventional reservoirs, aspects of resolution and measurement error become of prime concern in tight gas. As such, taking certain measurements at face value without application of corrections or judgmental adjustments can often lead to faulty interpretations. These pitfall areas are identified and discussed.

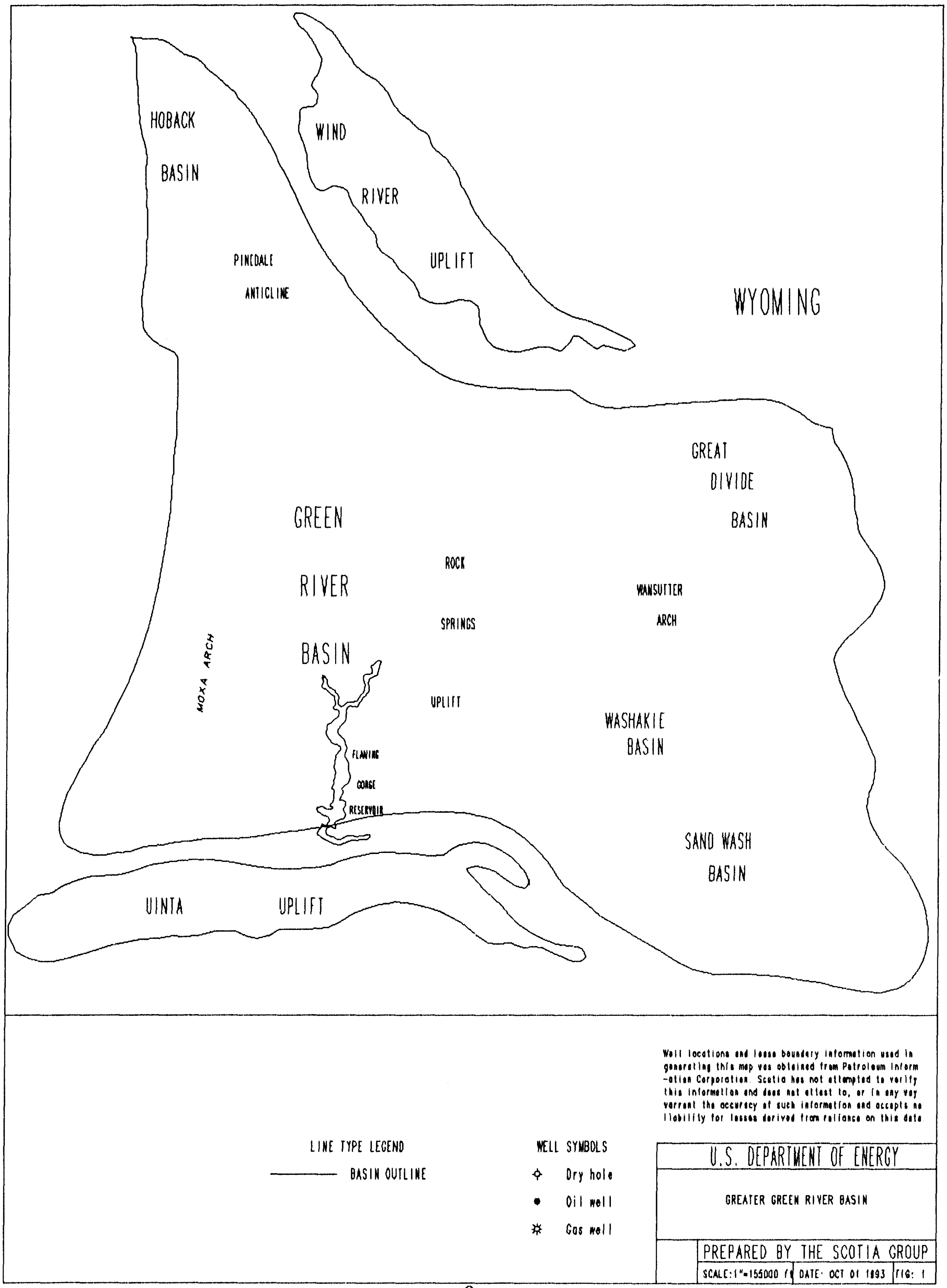
For companies or individuals who have not had long-standing experience in working with OPT gas reservoirs, climbing the necessary learning curve can represent a difficult task. Because many of the technologies have evolved and those close to them have experienced this evolution, it has been the experience of many that it is difficult to understand the current literature without a "from scratch" base in that technology. By example, the current state of the art as far as hydraulic fracture treatments are concerned, can involve a jargon totally foreign to engineers and geologists working in conventional reservoirs who have not followed the fracture technology development closely. Attached to this report as appendices are descriptions of certain of these technologies. These are intended to provide a basis for a "from scratch" understanding and to explain the evolution of the technologies with the objective of conquering those learning curves.

Finally, this report has been designed to provide not only our interpretations but to also share the base data so that others may complete their own analyses. These data are included in summarized form (both tabular and graphical) within the body of this report and are provided in digital form as a separate database.

Greater Green River Basin Setting

The GGRB is located in southwestern Wyoming and overlaps into northwestern Colorado and into Utah along its southern and western margins. The total basinal area is approximately 19,700 square miles. The major structural elements, and basinal and ridge designations are depicted in Figure 1.

The gas resources identified by the USGS are contained in low permeability, overpressured, Cretaceous and Tertiary sandstone reservoirs located in the deeper portions of the basin. These reservoirs usually have an in-situ permeability to gas of less than 0.1 md and require hydraulic fracturing to produce gas at commercial rates. The gas accumulation is a deep-basin or basin-centered type, similar to that originally described by Masters (1979). The reservoirs are usually below 8,000 feet drill depth, with the onset of gas saturation coinciding with the onset of overpressuring. The OPT reservoirs are apparently not structurally or stratigraphically trapped but rather are considered by the USGS to be of thermogenic origin and being the result of gas generation at a greater rate than gas loss. As such, the gas-bearing OPT reservoirs occupy the deeper parts of the basin downdip and underneath water-bearing normally pressured reservoirs. The top of overpressure cuts across structural and stratigraphical boundaries and grades vertically and updip through a transition zone into water bearing normally pressured reservoirs. As such, the OPT reservoirs do not usually have discrete gas/water contacts and, although water-bearing horizons are noted, most sandstone rock units within the overpressured section have some degree of gas saturation.

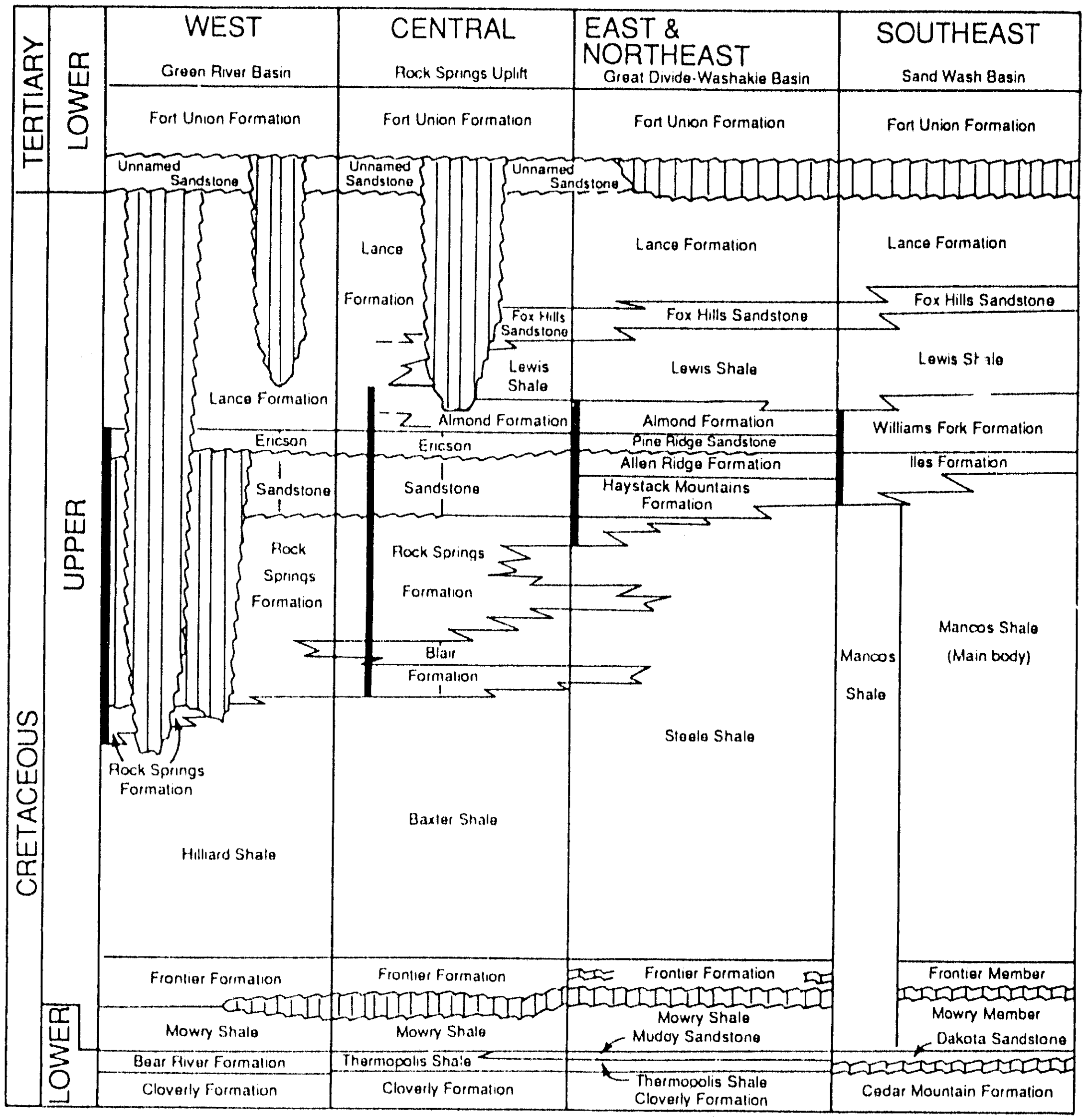


HOBACK
BASIN
WIND
RIVER
UPLIFT
PINEDALE
ANTICLINE
WYOMING
GREAT
DIVIDE
BASIN
GREEN
RIVER
BASIN
ROCK
SPRINGS
UPLIFT
WAMSUTTER
ARCH
MOXA ARCH
WASHAKIE
BASIN
FLAMING
GORGE
RESERVOIR
SAND WASH
BASIN
UINTA
UPLIFT
Well locations and lease boundary information used in generating this map was obtained from Petroleum Information Corporation. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.
LINE TYPE LEGEND
BASIN OUTLINE
WELL SYMBOLS
Dry hole
Oil well
Gas well
U.S. DEPARTMENT OF ENERGY
GREATER GREEN RIVER BASIN
PREPARED BY THE SCOTIA GROUP
SCALE:1"=155000 ft
DATE: OCT 01 1993
FIG: 1

The USGS has subdivided the gas-bearing interval into five stratigraphic plays for the purposes of conducting their resource estimate. In vertical sequence from bottom, up, these are as follows:

1. Cloverly Frontier
2. Mesaverde
3. Lewis
4. Lance-Fox Hills
5. Fort Union

FIGURE 2: GENERAL CORRELATION CHART OF THE CRETACEOUS & LOWER TERTIARY STRATIGRAPHIC LIMITS IN THE GGRB. BLACK BAR INDICATES LIMITS OF THE MESAVERDE GROUP (From Law et al)



These stratigraphic units contain a variety of sandstone reservoirs with geometry varying from lenticular through to blanket, and with environments of deposition varying from marine through marginal marine, to fluvial, paludal and alluvial. The blanket environments are mainly associated with the marine or marginal marine environments and have greater continuity and hence better response to hydraulic fracture treatment than the lenticular reservoirs, which due to their lateral heterogeneity, respond to hydraulic fracturing in a less predictable manner.

The tectonic history of the GGRB is complex, involving burial and uplift with considerable resulting sandstone diagenesis. Silica and carbonate cementation is significant and most of the present porosity is of a secondary nature caused by dissolution of rock fragments, cements and mineral grains. Many of the sediments have a high lithic component and subsequent diagenesis has resulted in the development of authigenic clays which have the additional effect of decreasing effective permeability to gas. Connection of the pore network is thought to be accomplished more by natural fracturing and microscopic sheet-like or ribbon-like capillaries as opposed to natural pore throats. These capillaries are less than 2 μm thick and often less than 1 μm thick. As a result, the best well completions are thought to occur where natural fracturing is best developed and where artificial stimulation can connect such natural fracturing to the wellbore.

While the GGRB contains a maximum of about 32,000 feet of Cambrian through Tertiary sediments, the primary focus is on the section from Lower Cretaceous through Lower Tertiary, the generalized stratigraphy of this section is depicted in Figure 2 from Law et al (1989):

A description of each rock unit, the plays and their local nomenclature, appears later in this report under the discussion of reserves evaluation of each play and also in Law et al (1989).

Production History

Production from the GGRB dates back to the 1940s. Estimates of total cumulative production through 1991 are approximately 750 MMbo and 9 Tcf. This study estimates that 861 Bcf has been produced from OPT reservoirs through the end of 1992 and projects ultimate recovery of over 1.5 Tcf from existing OPT gas wells. Production from the OPT section was first established in 1958 from the Mesaverde in the Wamsutter field. However, it was not until the mid to late 1970s that active development occurred. Most of the existing OPT production has been developed in the last 15 years.

It should be noted that much of the production in the basin is from conventional reservoirs as well as from low permeability reservoirs which are not overpressured. As an example, the USGS excluded the Moxa Arch and parts of LaBarge platform from their resource estimate despite Federal Energy Regulatory Commission (FERC) designation as tight, in that the areas appear to produce from a mixture of conventional and low permeability reservoirs which are apparently not overpressured and which are inter-mixed, creating difficulties in separating these on a regional basis.

The principal gas production from the OPT section is from the Mesaverde and Lewis in the Great Divide and Washakie basins. The Frontier production is less localized, being from several developments along the shallow edge of the play boundary. For the Lance-Fox Hills and Fort Union plays, no commercial production has as yet been established from the OPT sequence.

STUDY METHODS/APPROACH

Data Sources

This study was based entirely on public domain data and data volunteered by companies on the basis that it could be used as nonproprietary. Base data sources for this project consisted of the following:

1. Published Information: This consisted of reports and published literature on the basin and on various aspects of the technology utilized in exploiting low permeability gas reservoirs, not only in the Rocky Mountain area, but elsewhere.

2. Specific GGRB Reports: These consisted of reports directed specifically at the GGRB and were mainly of a research nature. These included reports in the USGS bibliography as well as reports generated by service contractors and companies in the area.

3. Public Domain Information: This consisted of various commercial data sources, particularly Petroleum Information Corporation's (PI) National Production System (NPS) and Well History Control System (WHCS) files. These consisted of reported historical production data for all wells in the basin as well as digital scout ticket information.

4. Reports to State Government Authorities: The State governments require oil and gas operators to file certain reports concerning oil and gas operations and these are part of the public record. These consist not only of forms required for drilling and completion of wells, but also include technical data such as drill stem test information, core analysis, and other useful information.

5. Special Technical Reports: These include submittals to State and regulatory authorities particularly in reference to obtaining tight gas sand designations for incentive pricing. Such reports are prepared by operators in support of their contention that certain areas should be designated as tight gas producing areas and hence qualify for incentive pricing. Most of such reports were made for the consideration of the FERC.

6. Proprietary Company Files: A significant effort was directed at persuading companies to volunteer information for the use in this study. Such information consisted of core and test data and certain proprietary data and reports. Such information was solicited from companies on a voluntary basis with the proviso that such information could be utilized as part of this report. We are grateful for the cooperation of many oil companies for taking the trouble to provide proprietary data and to release such data for the benefit of this study.

Data Handling Procedures

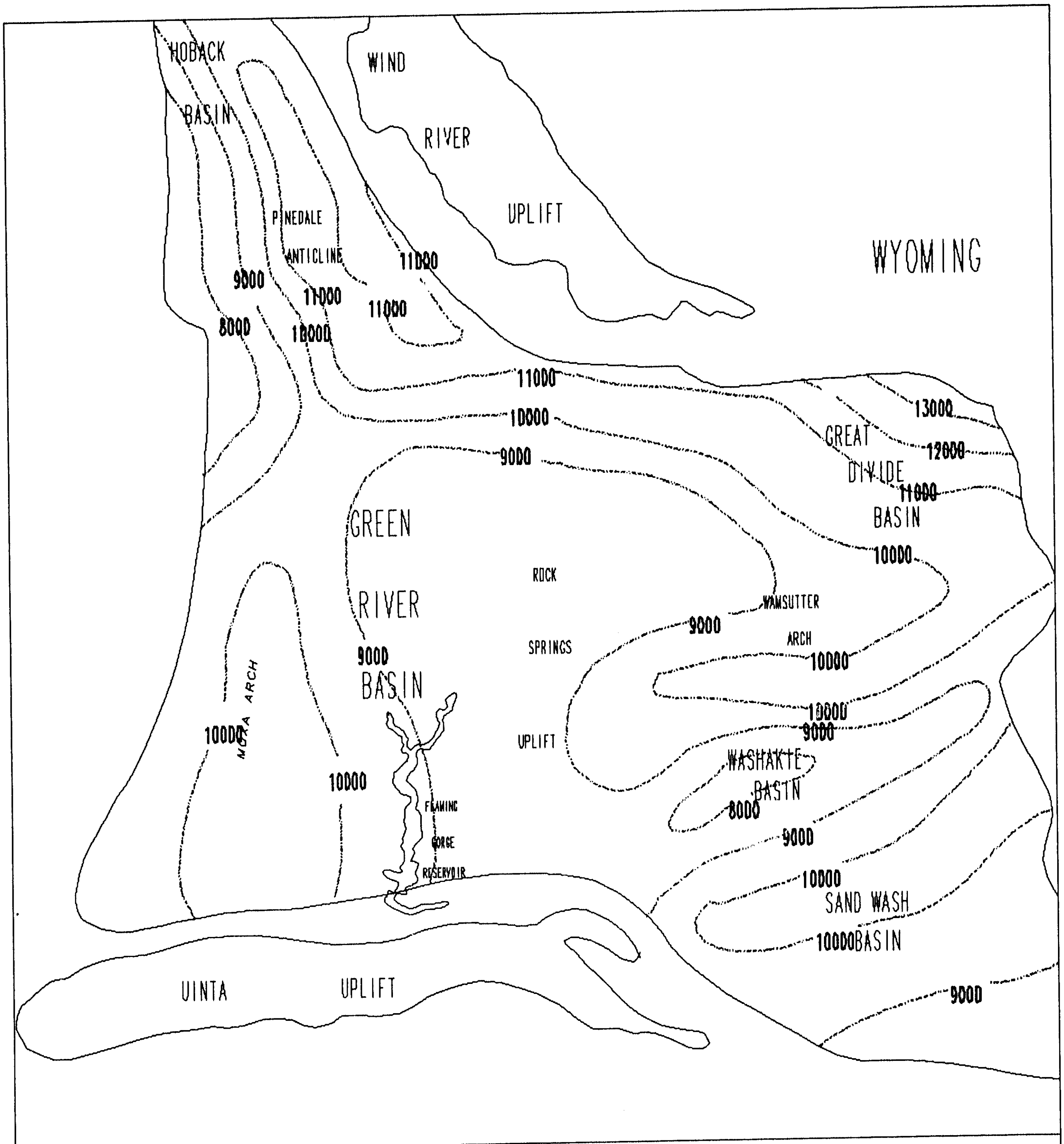
The approach to handling the large quantities of data relevant to this study was to firstly generate a relational database of information utilizing the Paradox database management system. This database was constructed by performing a load of culled well information from PI's WHCS. This created a well-level information system that was then cross-referenced by a variety of means to allow extraction of relevant information by horizon (play) to generate subsets that could be used for mapping and other forms of analysis. Mapping was achieved via utilizing the well coordinate latitude/longitude data and constructing latitude/longitude base maps for each horizon showing well penetrations, dry holes and completions.

The initial dataset obtained from PI consisted of the entire well population for the basin. A culling procedure was required to remove wells which were shallow completions and that did not penetrate the OPT section. This was accomplished by constructing a map that displayed the drill depth to top of overpressure (Figure 3). By excluding wells which failed to reach the top overpressure as displayed on the map and by virtue of each well's location, a first pass culling was achieved. Note that the top of overpressure is not an exact depth and some degree of interpretation is involved. As such, numerous wells were identified which had total depth that approximated top overpressure and thus were problematic. These were examined on an individual basis and judgmentally included or excluded.

The resulting culled dataset was then further subdivided by principal play and base maps generated along the following lines:

1. Penetration Map: This is a map of all wells which penetrated each given play (with penetration being defined as having a total depth below the top of the play but not necessarily entirely penetrating that sequence). The penetrations were further encoded as to whether part of the play interval was cored and again whether part of the play interval was drillstem tested. In addition, the USGS play boundary and FERC tight gas designated areas were also displayed. The penetration map afforded a graphic display of data availability, core information and shows as evidenced by drillstem tests (DSTs). Also posted for demonstration of control purpose was the grid of USGS cross-section control points.

2. Production Map: This map portrays all wells reported as completed in WHCS and also portrays dry holes to give a graphic display of the distribution of well completions for each play. The fact that such completions fall inside or outside of the USGS play boundary and FERC tight gas designated areas assisted in determining whether data culling procedures were adequate and allowed a second cull.



Well locations and lease boundary information used in generating this map was obtained from Petroleum Inform-ation Corporation. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

LINE TYPE LEGEND

- BASIN OUTLINE
- TOP OF OVERPRESSURE

WELL SYMBOLS

- Dry hole
- Oil well
- Gas well

U.S. DEPARTMENT OF ENERGY

GREATER GREEN RIVER BASIN

DRILL DEPTH TO

TOP OF OVERPRESSURE

PREPARED BY THE SCOTIA GROUP

SCALE:1"=145000 ft	DATE: OCT 08 1993	FIG: 3

3. EUR Map: WHCS well data was cross-referenced with NPS production data via API well number match. EURs performed by extrapolation of decline curves were displayed in the form of bubble maps (a circle representing each well was drawn with the area of the circle proportional to the EUR estimated for that well). This allowed a graphic display of not only the distribution of expected ultimate gas recoveries but also a visual of the relative magnitude from area to area within each play.

The base map displays allowed selection of control points for detailed analysis and rock property quantification for each play.

Production data was based upon PI's NPS file. This file was obtained for all relevant wells in the basin and was culled based upon API number matching to a culled WHCS well list. This afforded breakdown of production on a play by play basis and this data was loaded to Scotia's **MASTER** proprietary production data handling system which allowed the following:

1. The construction of a database of all production data for the basin.

2. Interfacing this database with interactive decline curve modelling software, allowing extrapolation of EURs.

3. Ability to analyze production data using Fetkovich type curve information for wells displaying a prolonged initial transient period.

4. Interface with volumetric calculations to determine recovery factors and drainage areas.

DST and well test information was collected in quantity and analyzed utilizing Scotia's **WELLTEST** software. It should be noted that with very few exceptions, most DST data was of inadequate quality for detailed formal analysis. This is principally due to the low permeability nature of the formations and the fact that DSTs were generally of insufficient duration to allow meaningful interpretation. Transient well test data was actively searched out and collected where possible and this information was analyzed using the **WELLTEST** software, principally to determine formation permeability.

Considerable effort was expended in assembling as much core data as possible both through obtaining core analysis data directly from State records and also soliciting additional data from local operators in the area. The core data in the form of porosity, permeability, water saturation, gas saturation, and grain density measurements (conventional core analysis) was databased, correlated with principal play, and analyzed utilizing Scotia's proprietary **COREPRO** system. This software allows the correction of properties measured at ambient conditions in the laboratory back to in-situ conditions via a variety of techniques. Since permeability is probably the most important unknown in analyzing low permeability gas reservoirs, a detailed discussion of permeability measurement and the process of performing corrections to in-situ conditions, together with the problems and their solutions, is provided in Appendix A of this report.

Basic rock property information was derived from openhole wireline log data. Wireline log data was obtained for a representative grid of wells covering each play. Wells were selected not only for their geographic position but also on the basis of available data, i.e., a representative suite of logs (minimum electric survey plus ideally three porosity tools, sonic, density and neutron), and the presence of core data to allow calibration of log responses, particularly for porosity determination and correlation with log derived permeability algorithms. Most logs were obtained in hard copy form and digitized in preparation for computerized log interpretation. A series of already digitized logs were obtained courtesy of EG&G, Morgantown who shared this information for the benefit of the study, and a small number of these wells were also incorporated. Log interpretation was run utilizing Scotia's proprietary SLOG system, specifically the tight gas module. A detailed description of this software and of the computations performed and problem areas appears as Appendix B.

Reserves Definitions

An objective of this project is to take the base USGS in place gas resource estimate and estimate what proportion may be potentially convertible to recoverable reserves. As defined for the purpose of this project, "reserves" refers to gas volumes that are classified within the unproved category according to SPE definitions, plus potential undiscovered volumes considered to be commercially recoverable. Since it is of prime importance that the results of this study be understood and accepted by industry, the techniques for reserves estimation must be similarly understood and accepted. To this end, it is worthwhile to clarify the aspect of differing reserves definitions utilized by industry and to place the requirements of this project within that perspective.

The reserves definitions most commonly used in the U.S. are those published by the Securities and Exchange Commission (SEC) and the SPE in conjunction with the Society of Petroleum Evaluation Engineers (SPEE). The most recent version published by the SPE, May 1987, is comprehensively described in SPEE Monograph I dated December 1988. Definitions are subdivided into proved, probable and possible categories with each category being subjected to a status modifier with four modifiers being recognized: producing, shut-in, behind pipe, and undeveloped. For any estimate, the assignment of category reflects the degree of certainty of the estimate since the definitions of proved, probable or possible are based upon applying a test of reasonable certainty. The status assignment provides an indirect confidence measure since the classifications in the higher confidence categories will benefit from hard production data, while those in the lower confidence area will rely on more inferential data and assumptions in order to derive an estimate. These definitions are strictly deterministic. That is, a single figure is estimated as to the future recovery of oil and gas from a well, lease, field or company as a whole or an area as a whole. The fact that such estimates are imprecise is acknowledged by all professional reserves evaluators.

The use of probabilistic reserves definitions in difficult reserves evaluation situations is discussed by Caldwell and Heather (1991). The case may be made that where reserves evaluation is required for certain technology sensitive, statistical or unconventional type plays, the probabilistic approach enhances traditional reserves determination methods. The evaluation of reserves in tight gas reservoirs represents such a situation. In this situation, a variety of factors control the ultimate performance of individual wells. In many cases it is not possible to accurately measure each of the controlling factors and indeed in many cases it is not possible to determine which factors are controlling.

For the purposes of conducting this study, Scotia felt that the assignment of a single recovery factor for a play, township, section or even individual well, would not do justice to the observed variation or document the range of outcomes that are experienced. For oil companies to make planning decisions for entry into a play, such as tight gas, the range of potential outcomes must be known and modelled in order that an economic decision weighing the reserves and reward versus the cost and risks can be made. Such expected value decisions invariably involve a range of reserves values (recovery factors) that can be anticipated and the strength of any analysis of a tight gas reserves picture must involve this distribution in order to have credibility.

These factors were recognized by the USGS in their resource estimation deliberation. The USGS report chose to express the resource estimates in probabilistic terms. That is, differing resource levels were associated with differing probabilities of occurrence. Scotia believes that this concept must be perpetuated into the reserves estimation procedure as outlined below.

The SPE definitions for unproved reserves are inclusive of the categories of probable and possible. In such cases, both categories are defined in accordance with a reasonableness test as to their likely existence. That is, probable and possible reserves are defined by individual reserves estimators based upon their personal judgment as to the likelihood of existence without quantification of that likelihood. It is worthy of note that whether deterministic or probabilistic reserves definitions are applied, the base methodology used to derive the figures is identical and that the base difference in approach between the two methodologies is the use of a consistent, nonarbitrary probability level to define probable and possible levels.

The approach taken for this report was to estimate the range of potential recoveries (recovery factors) and to express these as a distribution. These distributions are based upon actual measurements represented by the estimated ultimate recovery of completed OPT wells. It is felt that describing the outcome as a distribution with an associated range, standard deviation and mean, will provide a better understanding of the variability of each play rather than simply zeroing in on a single value arbitrarily defined.

It should be clearly understood that the term "reserves" as used in this report, includes volumes that extend beyond the SPE definitions of probable and possible. We have included "potential reserves" as described by Grace, Caldwell and Heather (1993). These represent volumes that are considered commercially recoverable but have not been "discovered."

The question of "discovered" in unconventional resources is a complicated question. In normal evaluations, the proportion of a reservoir considered discovered is based upon well control and the terms proved, probable and possible often equate to radii of confidence surrounding well data points. Water contacts and reservoir boundaries define the limits of the discovered volume.

For unconventional OPT resources, the reservoir is complex in its definition. Massive sections of gas-bearing rock exist with no defined fluid contact or obvious reservoir boundary. Producibility varies markedly from area to area and location to location based on a variety of factors, many of which are extremely difficult to measure or predict. This renders the radius method inoperable and poses the larger question of how to define "discovered." These considerations have prompted the broadening of the term "reserves" to encompass the proportion of the gas resource that may be potentially convertible to commercially productive reserves by adding the "potential reserves" category to the standard probable and possible definitions.

Rock Properties and Volumetrics: Gas In Place

The USGS resource estimate represents the starting point for this study. Because an examination of reserves or reserves potential in essence must commence with a GIP, it was felt that it was necessary to either accept the USGS estimates as a starting point or to perform modifications where it was expected that new estimates might differ to a significant degree.

The approach taken in this study to the volumetric calculation of GIP differed significantly from the methods used by the USGS in their resource estimate. The USGS used the Delphi approach whereby basic volumetric parameters were estimated by polling a group of experts. A more technical approach involving measurement of base volumetric parameters was chosen where possible. The differences in approach and methodology are described below on a parameter by parameter basis.

1. Net Reservoir Thickness Counts: The USGS counted all sands greater than ten feet thick from well logs and did not consider any porosity or water saturation discriminators since the geological model regards all sands within the OPT section to be gas-bearing. Utilizing data points from a regional grid of cross-sections, counts were totaled by play and isopached to derive a rock volume for each play. The USGS sand thicknesses could be reproduced for the most part, simply by applying a 50% V_{clay} cutoff to the gamma ray reading. Definition of reservoir quality rocks

(that portion of the sand thickness estimated to contribute to reserves) for use in this study was achieved by applying a suite of cutoffs including porosity, water saturation, V_{clay} and permeability developed for each play from a comprehensive evaluation of core, log and well test data, and published literature. The cutoffs, discussed in greater detail in Appendix B, ranged as follows:

Porosity %	> 4-9.7
Water Saturation %	< 65-80
V_{clay} %	< 35-40
Permeability, md	> 0.001-0.012

2. Porosity and Water Saturation: For the USGS estimate, porosity and water saturation were judgmentally estimated by a group of experts for each play. For modelling purposes, the water saturation was regarded as a dependent variable whereby porosity and hydrocarbon saturation were positively correlated. The values estimated by the USGS are tabulated below by play:

TABLE 3
USGS VOLUMETRIC PARAMETER SUMMARY

PLAY	POROSITY RANGE (%)	HYDROCARBON SATURATION RANGE (%)
Cloverly Frontier	3.0 - 6.0	40-50
Mesaverde	4.5 - 8.5	40-50
Lewis	6.0 - 10.0	45-60
Lance-Fox Hills	6.0 - 9.5	35-50
Fort Union	7.5 - 9.5	35-50

A formal digital tight gas log interpretation, calibrated to corrected core data where possible was used to calculate rock properties on a foot by foot basis. Appendix B details the methodology. This technique provided detailed porosity and water saturation data and more importantly, provided the distribution of these parameters and their interrelationship. Two sets of porosity and water saturation distributions were generated. The first corresponds to the larger sand count generated using a 50% V_{clay} cutoff, which approximates the thickness generated by the USGS; the second corresponds to the net reservoir rock thicknesses defined during this study. The following key differences to the USGS approach were found:

(a) Porosities were not normally distributed as assumed by the USGS, but rather were distinctly skewed such that lower porosities form the bulk of the distribution. These distributions are discussed by play later in this report.

(b) Calculated water saturations were generally higher than those assumed by the USGS. In addition, water saturations in the lower porosity rocks were very high, tending towards 100% as porosities reduce towards zero. Since the porosity is skewed in favor of the lower values, a significant portion of the rock volume has high water saturation.

(c) Application of the cutoffs resulted in significantly smaller reservoir rock thicknesses.

These factors resulted in significant reduction in calculated GIP in comparison to the USGS estimate.

3. Formation Volume Factor: The USGS used pressure and temperature data derived from regional gradients. Thus the formation volume factor varied with depth in accordance with the gradients chosen for each play.

   For this work, the formation volume factor calculation also took into account the following gas gravity data obtained from a variety of sources:

PLAY	GAS GRAVITY (Air = 1)
Cloverly Frontier	.67
Mesaverde	.67
Lewis	.63
Lance-Fox Hills	.65
Fort Union	.61

   While temperature gradients vary somewhat across the basin based on maximum recorded logging temperatures and temperatures recorded during DSTs, a gradient of 1.8°F/100 feet using a 40°F mean annual surface temperature represented a reasonable average. Analysis of available pressure and mud weight data indicated that a normal pressure gradient of about 0.45 psi/foot exists down to the top of the OPT zone. Below the top of the OPT zone, pressures increase at a gradient of 1.0 psi/foot. Thus, when measured from a surface datum, the pressure gradient increases with depth (see subsequent discussion of pressure data and gradients). This dual gradient model was used to calculate pressure versus depth within the OPT zone. Using this data and the Hall-Yarborough (1973) method for calculating gas deviation factor (Z), a formation volume factor versus depth relationship was derived for each play.

4. Calculation of GIP: The USGS utilized distributions for all parameters within the volumetric equation for the purpose of calculating GIP. This calculation was probabilistic and resulted in a distribution of in place gas calculations with associated

probabilities of occurrence. A program named FASP (Fast Appraisal System for Petroleum) was used to perform the computations (Crovelli and Balay (1986) and Crovelli (1987, 1988)).

During this study two estimates of resource in place were made. The first was a redetermination of the "total resource" using the sand thicknesses (50% V_{clay} cutoff) which approximate those used by the USGS, and the corresponding rock property distributions developed from log analysis during this study. The second was a determination of that portion of the total resource which would be expected to contribute to reserves. This was estimated using the net reservoir rock thicknesses (porosity, V_{clay}, water saturation and permeability cutoffs) and the corresponding rock property distributions developed during this study. The difference between these two figures represents that portion of the "total resource" which is not expected to contribute to reserves.

Two approaches were used to estimate resource in place in order to describe both the geographic (areal) and vertical distribution of GIP.

(a) <u>Volumetric Mapping.</u> Net reservoir rock thicknesses were contoured and planimetered to derive the net rock volume. At the same time, the USGS sand thickness maps were also planimetered to derive the rock volume for the total resource. A Monte Carlo simulator was then used along with the appropriate distributions of porosity, water saturation and formation volume factor, to derive the two estimates of resource in place.

(b) <u>Depth Slicing.</u> Both the USGS sand thickness and Scotia's net reservoir rock thickness maps were depth-gridded to segment them into 1,000 foot thick depth slices. Based upon well control, log derived rock properties within each 1,000 foot depth slice were compiled as distributions of porosity, water saturation and permeability. Utilizing the appropriate depth, formation volume factors were calculated as described above, and GIP for each 1,000 foot depth slice for both the USGS and Scotia maps was calculated deterministically.

The net result of applying these differing methodologies resulted in considerable departures from the USGS estimate as illustrated in Table 4.

TABLE 4
COMPARISON OF MEAN RESOURCE BY PLAY
(TCF IN PLACE)

PLAY	USGS ESTIMATE	SCOTIA ESTIMATE
Cloverly Frontier	304	279
Mesaverde	3,347	1,057
Lewis	510	229
Lance-Fox Hills	707	349
Fort Union	96	54
Total	5,064	1,968

The large magnitude of the figures derived through the USGS estimation procedure have been regarded with skepticism by some. Previous resource evaluations in the basin have derived smaller overall figures: 91 Tcf by Kuuskraa et al (1978), 136 Tcf by the National Petroleum Council (1980), and 240 Tcf by the Supply Technical Advisory Task Force (1973).

As argued by the USGS, the previous resource estimates were targeted at only evaluating selected reservoirs and areas and did not include the entire gas-bearing sequence. In contrast, the USGS estimate included the entire overpressured sequence. The USGS also argued that their figures may actually be conservative, since they do not include gas in sandstones thinner than 10 feet, gas in coals, nor gas in shales or siltstones. In addition, the assessment does not include gas within the normally pressured but tight portion of the basin or in so called "transition zones" that occur above and/or updip of the overpressured gas saturated intervals.

While the degree of revision due to changing the porosity distribution and magnitude as well as the correlation for water saturation result in a significant revision to the USGS figures, the revised figures are still substantial. However, as will be expanded upon in the next section, all of these resource volumes are not available for conversion into potential reserves. Significant resource volumes are resident in extremely tight rocks; rocks too tight for exploitation by current frac technology. Significant volumes are also present at great depth. Given anticipated recoveries, drilling to such depths does not represent an economic proposition.

The implication of recognizing that porosities are not normally distributed extends beyond a revision of GIP resources and through to the quantification of reserves. As noted by Masters (1979), in recognition of the "resource triangle," the lower quality resources are in significantly greater abundance than the higher quality (higher porosity) resources.

Evaluation Difficulties

Basic volumetric and recovery factor calculations are complicated by certain physical properties peculiar to OPT gas reservoirs. Recognition of these factors is important in attempting to predict the performance of OPT gas wells.

1. Study of core data indicated that in many cases porosity and permeability are poorly correlated, if correlated at all, particularly in the lower porosity ranges.

2. Distributions of log-derived and measured porosities tend to be heavily skewed towards the lower porosity ranges.

3. Because the bulk of porosity development is of secondary origin, much of such porosity is poorly connected in a conventional sense (i.e., via normal pore throats), but rather requires connection via an anastomosing network of natural fractures, microfractures and capillaries.

4. Due to the poor relationship shown in most plays between porosity and permeability, selection of the most porous zones for completion attempts may not necessarily encounter the greatest natural fracture permeability. However, since it has been shown that frac treatments in the basin achieve more significant height growth than has been previously modelled, it is likely that most fracs do not stay within the perforated zone and may in fact grow by up to several hundred feet above and/or below into adjacent horizons. This opens the possibility of accidentally fracing into the more naturally permeable sections. This would also explain some of the very high calculated recoveries observed occasionally in the basin whereby wells produce considerably more than can be attributed to the perforated zone. In such situations contributions from overlying and underlying reservoirs can be inferred.

5. Examination of frac, DST and production data within various areas and from play to play indicate that lateral continuity of the pay zone of interest is of extreme importance in controlling long-term well productivity. Where sands have a greater degree of lateral continuity, the ability to place a successful frac treatment is much enhanced. Where sands are lenticular or display lateral continuity only in given directions (e.g., channels), the ability to create a successful commercial completion is reduced. In such cases, directions of maximum in-situ stress and maximum direction of geological continuity must be fortuitously oriented to be able to exploit the natural directions of more favorable reservoirs. In a similar fashion where natural fracturing within the reservoir is not oriented favorably with respect to directions of maximum in-situ stress, frac results can be variable or disappointing. The subtleties of these geological and geomechanical properties are difficult to measure and predict and complicate the process of effecting a commercial completion. That is, even where log responses and log analysis indicate excellent pay potential in comparison to logs in wells which have been superior producers, the

inability to predict and quantify lateral variation may render completions as marginal or noncommercial.

Quantifying Recovery Factors

In considering conventional gas reservoirs, the subject of drainage and spacing is not so much at issue as when dealing with tight reservoirs. Well spacing can be decided upon without too much concern for areal reservoir continuity such that each well can be assumed to adequately drain the reserves within its no-flow boundaries. These boundaries surround the well at a position dependent upon the offtake rates of surrounding wells and the variability of reservoir characteristics between wells. In this scenario, recovery factor is independent of well spacing, whereas per well recoverable reserves and the rate of recovery for a given reservoir are very dependent on well spacing. Therefore, the concept of a reservoir-wide recovery factor has validity for conventional reservoirs.

In tight gas reservoirs, the ability of a well to drain a given area is dependent upon the amount and effectiveness of naturally occurring permeability (matrix and fracture), its ability to interconnect the porosity within the tight formation, and the effectiveness of a fracture treatment in connecting such natural permeability to the wellbore. Fracture treatments generate fractures which generally propagate in the direction of maximum horizontal stress, and result in circular to ellipsoidal shaped fractures oriented in a vertical or sub vertical plane. Effective drainage by the frac'd wellbore in plane view will tend towards an elongated ellipsoidal pattern as opposed to a circular drainage radius and the areas drained by individual wells will tend to be proportional to the dimensions of the effective artificial hydraulic fracture.

In expansion drive gas reservoirs, the recovery factor of GIP is proportional to the degree of pressure depletion that can be effected by the well down to its economic limit. The recovery factor will be the P/Z at original pressure, minus the P/Z at abandonment, divided by the P/Z at original pressure. In other words, if 85% of the P/Z value is achieved by the time a well has produced to its economic limit, then the recovery of accessed GIP will be 85%. The economic limit of course will depend upon that point at which revenues no longer exceed expenses and will be a function of prices, royalties, production taxes and operating expense. For any given well, the ability to produce is a direct function of surface versus bottomhole flowing pressures and it can be argued that with all else being equal, all gas wells will recover approximately the proportion of GIP (that is, will be produced to the same pressure depletion) and hence have approximately the same final recovery factors.

The issue at hand is not so much what the pressure at abandonment is, but rather what area is being accessed in terms of reservoir drainage down to this pressure. Since OPT gas wells may drain only a small area, the recovery factor of GIP within the regulatory spacing limit versus what proportion of that spacing limit is actually drained is the key issue. By example, if a gas well is drilled on a regulatory 320 acre spacing and effectively has a 75% recovery over a drainage area of 40 acres, then the recovery factor could be expressed as the effective recovery of GIP on the entire 320 acre unit (75% x 40/320), or 9.4% recovery of GIP.

The computation has greater significance than simply determining the recovery factor based upon a regulatory spacing. If in the above example the well was economically viable draining only 40 of the 320 acres, then an additional seven well locations would be available by downsizing the spacing unit to 40 acres, whereby similar recovered volumes could be anticipated. In other words, if the spacing unit was not reduced, 87.5% of the potentially recoverable gas would be bypassed by drilling on a 320 acre spacing. Many examples of bypassed reserves such as this occur in tight gas provinces. Cipolla (1992) reports virtually identical per well recoveries from wells drilled on an initial 640 acre program that was later down-spaced to 320 acres and then 160 acres. Resulting recovery on the 160 acre spacing averaged 61% of GIP and resulted in reserves growth of 190 Bcf.

The quantification of recovery factors thus becomes a function of well drainage area vis a vis the spacing unit area dictated by regulatory field rules. The area difference (spacing less drainage) is proportional to the undrained or bypassed gas that would be available to a reduced spacing (infill drilling) program.

Economic Basement Determination

Economic considerations play a role in the distinction between reserves and resources. For resources to qualify for potential conversion to reserves, such resources must be producible at rates and with ultimate volumes that will repay the cost of drilling and completion and provide a normal profit. For the purposes of this study, production which generates an operating income stream discounted at 10% (PV10) that is equal to drilling and completion costs represents the break over point for commerciality. The present value calculation assumes a royalty of 25%, severance and ad valorem taxes of 13%, operating costs of $2,000/month, and a $2.00/Mcf wellhead gas price. Drilling costs are a function of depth with separate relationships corresponding to dry hole cost and total completed well cost.

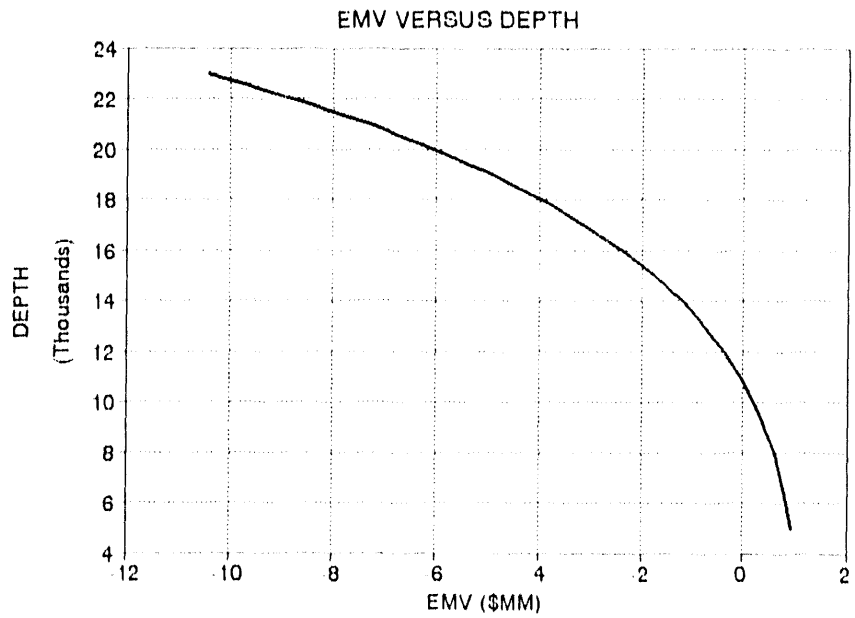
It should be clearly stated that the economic cutoff for qualification of reserves as used herein represents a payout of drilling costs plus a profit motivation. In practice, reserves are considered commercial if they produce sufficient income to cover operating costs without consideration of whether the capital expenditures incurred to drill and put wells on stream are ever paid out. That is, while operators do not intentionally drill wells that do not pay out, things do not always turn out as planned. Such situations are commonplace and are not predictable until after the wells have been put on stream. Exclusion of these nonpayout wells from the predictive model introduces a balancing effect to the more optimistic treatment of other variables. While numerically nonpayout wells may number 60% of the total producing well population, they contribute about 10% of the total EURs.

ECONOMIC BASEMENT DETERMINATION PLAY: LEWIS

FIGURE 4

BASE PARAMETERS:			
9779	DEPTH (FEET)	20.0%	PERCENT DRY
47	DRY HOLE $/FT	7000	P90 EUR (MMCF)
105	COMPLETED $/FT	1600	P70 EUR (MMCF)
464	DRY COST ($K)	550	P50 EUR (MMCF)
1026	COMPL COST ($K)	200	P30 EUR (MMCF)
0.78	AVG PV10, $/MCF	18	P10 EUR (MMCF)

EMV CALCULATIONS		PERCENT	UNRISKED	RISKED
	P90	16.0%	4434	709
	P70	16.0%	222	36
COMPLETIONS	P50	16.0%	-597	-95
	P30	16.0%	-870	-139
	P10	16.0%	-1012	-162
DRY HOLES		20.0%	-464	-93
EXPECTED MONETARY VALUE ($K)				256



To acknowledge the economic requirement for reserves qualification, the term *economic basement* is introduced. This term recognizes the fact that drilling costs increase with depth and hence the reserves that must be found to repay those costs must also increase with depth. *Economic basement* as a concept represents a depth where the curves cross. That is, where the risk weighted average reward equals the risk weighted average cost. Below this depth the probabilities are that expense will outweigh reward. Above this depth the reverse is true. *Established* resources are those located above *economic basement* and those located below are termed *nonestablished* resources.

Economic basement in the context of a resource/reserves evaluation represents a convenient break point for separation of the known from the unknown. In practicality, most of the productive horizons are situated in the shallower depth ranges, while resources are distributed variously with depth from play to play. In all cases, knowledge, development, performance, and control for the deeper zones is inferior to the shallower. As a result, the extrapolation of models developed for the better controlled shallow horizons into the deeper zones is not warranted unless an analogy can be developed that is justified by real data.

Determining *economic basement* depth for each play was approached as follows:

1. Determine Reward Expectation. In order to justify the expense of drilling, the target reserves must be of sufficient magnitude to provide a profit incentive. This magnitude must be sufficient to also outweigh the dry hole risk component. Since the OPT plays are new (generally less than 15 years old) and drilling density low, the distribution of existing EURs for each play was used as the model for future discovery expectation. Largely due to the immaturity of the plays, "sweet spots" tend to dominate development and hence dominate the distributions, if EURs are viewed on a per well basis. It is not known whether future results will have the same distribution or whether a "depleted" distribution would be more representative. This study used the existing per well EURs as the model for future expectation. This approach is more likely to err on the optimistic side.

   Sampling of the EUR distribution assumed a program (multi-well) approach. That is, rather than taking the median value which would be the expectation for a single well, the distribution was split into five units, each representing 20% of the EUR population and each unit was sampled at its midpoint leading to P10, P30, P50, P70, and P90 samples, each having an equal probability of occurrence. The reward is then calculated by cash flow construction and determining a PV10 for each sample, net of taxes, royalties, operating costs and drilling and completion costs.

2. Determine Dry Hole Risk. Historical drilling statistics were compiled to determine the historical dry hole frequency. This consisted of identifying all wells drilled in the OPT area for each play and subdividing those wells based upon the total depth (TD). Wells which TD'd in a play were regarded as having that play as their objective. Dry hole percentage was then determined. Note that a significant number of completions are made in OPT reservoirs that fail to produce commercially and are "worse than a dry hole" since the expense of a completion and frac was incurred. Such failed completions are accounted for in the EUR distribution and are handled as negative cash flow components. The argument may be made that discrimination should be made between well classes (exploration versus development) since success levels are

typically higher when considering development wells. Again, due to the immature nature of the OPT plays and the requirement for frac treatments to be successful (a significant element of mechanical risk), the distinction between an exploration (wildcat) and a development well becomes hazy. We have elected to simplify the model by selecting a success ratio based on historical drilling data that typifies the current status of the play under consideration. This will be weighted towards development drilling success levels in the more mature areas and towards exploration or wildcat success level in less known or less developed portions of the play.

3. Construct Expected Monetary Value (EMV) Analysis. The EMV analysis seeks to determine the *economic basement* depth as being that point where the EMV is zero. That is, above that depth, EMV is positive and risk weighted rewards are greater than risk weighted costs. Below that depth the cost of failure is greater than the risk weighted reward and EMV is negative. In summary, the EMV calculation takes into account the expected dry hole probability, the expected distribution of EURs that will be encountered, and the drilling cost environment versus depth. Figure 4 illustrates this calculation for a single depth and shows how the calculation varies as a function of depth. *Economic basement* represents that depth where the EMV equals zero.

In summary, the *economic basement* concept seeks to determine that depth at which the reward (profit) expectation no longer supports the risk (cost). This forms a logical dividing point for each play for performing reserves calculations. *Economic basement* is a dynamic depth. It is deepened by increasing gas prices, incentives, reduced drilling cost, higher success levels and larger finds. The reverse also applies. Since *economic basement* as a concept is dynamic, changing as its defining parameters change, the resources in the *established* and *nonestablished* categories will also be dynamic.

Reserves Calculations

Starting with the resource itself, the following steps were employed in estimating reserves:

1. Reevaluation of Basic Resource: This has previously been described, and consisted of applying a more sophisticated porosity, water saturation and formation volume factor model and depth slicing this data.

2. Identification of *a Technologically Viable* OPT Reservoir: Based on log analysis, pay quality zones were identified, isopached and GIP calculated by depth slice.

3. Removal of *Technologically Nonviable* Resources: By subtracting the pay quality GIP from the total resource GIP, the GIP in nonpay quality rocks was determined. This quantity is termed *technologically nonviable* since current frac technology has failed to yield a commercial completion in such OPT reservoirs. Such reservoirs will have in-situ permeabilities below 0.001 md in general. It is important to identify and

quantify this portion of the total resource since future technology improvements will move portions of it into the pay category.

4. Removal of *Nondemonstrated* Resources: A significant fraction of the *technologically viable* resources is located in geographic areas or stratigraphic units that have not established any commercial production or about which very little is known. That is, while sands may calculate as potentially productive based on log analysis, such sands have either not been tested or have been tested but with poor results and were thus included within the *nondemonstrated* category. Such resources are typically located in lenticular sands of various nonmarine/alluvial facies. Frac treatments are of limited benefit in this environment.

   Until such time as a technology is developed to successfully exploit the *nondemonstrated* category, such resources will be excluded from consideration from a reserves quantification viewpoint.

5. Removal of *Speculative* Resources. After removal of *nondemonstrated* and *technologically nonviable* resources, the remaining volume represents *demonstrated* resources. *Speculative* resources are that portion of *demonstrated* resources that lie in deep basinal areas below *deepest commercial production.* Their quantification depends upon extrapolation of geological mapping and has a significant degree of associated uncertainty. Because of this uncertainty, and lack of a production analog, *speculative* resources were excluded from consideration for reserves quantification purposes.

6. Subdivision Based on Economic Basement: The economic basement depth conveniently separates resources which on average represent economic targets from those which do not. This does not imply that all resources above *economic basement* are convertible to reserves via application of an appropriate recovery, nor does it imply that all resources below *economic basement* will contain no potential reserves. Rather, *economic basement* represents the break over point from one reserves and risk environment to another. The aspect of risk (drilling and reserves quantity) must be considered in order that the commerciality criterion to qualify as reserves is satisfied.

7. Derivation of Risk and Recovery Models: After all of the constraints described above have been applied, the remaining volumes represent *demonstrated* resources distributed in accordance with regional isopachs. It is recognized that the entire regional isopached volume will not all be uniformly productive. Dry holes exist within the mapped area as do productive wells, some of which are commercial (have reserves) and some of which are noncommercial (not qualifying as reserves).

   The recovery factor model thus requires not only a percent recovery of GIP factor, but must also take into account a factor representative of dry holes and noncommercial completions. This "nonreserves" factor represents that proportion of the *demonstrated* resources isopached volume that will not be commercially productive for a variety of reasons. Such reasons could include lateral discontinuity of reservoirs, unfavorable stress conditions for frac treatments, absence of natural fractures, etc.

The recovery factor model developed for this study was constructed as follows:

a. Determine Base Recovery Factor. For each well in the sample, a base recovery factor was derived from initial and final static bottomhole pressure. The latter was assumed to be 1,000 psi, which is probably optimistic and represents a minimum abandonment pressure for economical production. However, no actual abandonment pressure measurements are available. This assumed abandonment pressure resulted in base recovery factors varying from 70 to 80% and averaging 75%.

b. Determine Average Drainage Area. Based on a sampling of completed OPT gas wells, average drainage areas were calculated using the EUR from production performance analysis, the recovery factor and the volumetric parameters for the perforated interval based on log analysis. This result was checked against the average drainage area determined by Fetkovich type curve analysis on wells exhibiting a significant initial transient period with a reasonable match.

c. Determine Range of Drainage Area. Drainage area was plotted versus EUR and a log-log regression performed (Figure 5). The scatter on this plot is due to differences in petrophysical properties, mostly net pay thickness. By drawing lines that are parallel to the regression fit that effectively bracket all data points, an upper, most likely and lower relationship for EUR versus drainage area was determined.

   A minimum commercial volume was calculated representing the EUR that resulted in an operating income stream with a PV10 equal to drilling and completion costs at the representative depth for the play being considered. Using this EUR, the upper, most likely and lower drainage areas were determined graphically as shown in Figure 5. Note that the minimum economic drainage areas can be quite small due principally to significant perforated pay thickness. In this example, the following were derived for a minimum economic EUR of 1,300 MMcf.

EXAMPLE MINIMUM ECONOMIC DRAINAGE AREA MODEL

Upper Area	**250 Acres**
Most Likely Area	**80 Acres**
Lower Area	**26 Acres**

Figure 5: Recovery Factor Model
Drainage Area versus EUR

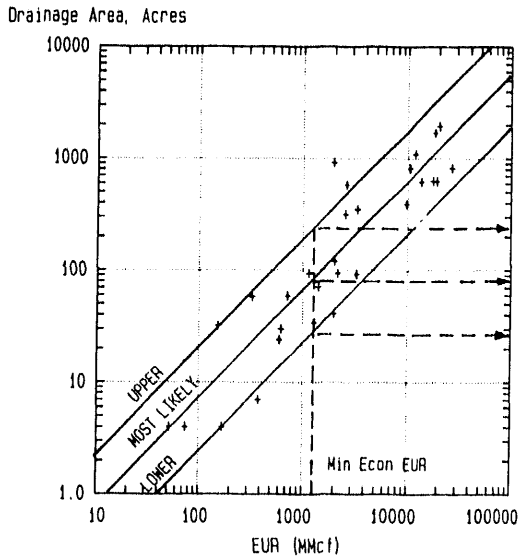
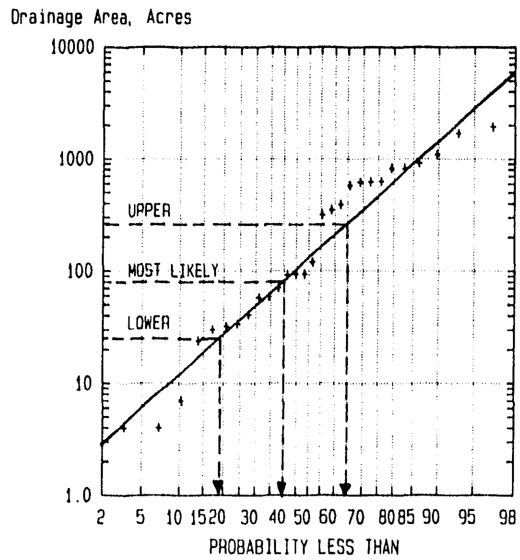


Figure 6: Drainage Area Probability Paper Plot
Non-Commercial Fraction Determination



d. Determine Noncommercial Fraction. The distribution for the fraction of wells expected to be noncommercial was determined by constructing a probability plot of drainage areas and using a smoothed correlation, reading off the percentage of drainage areas smaller than each of the areas representing the upper, most likely and low areas as shown on Figure 6.

EXAMPLE NONCOMMERCIAL FRACTION MODEL

Upper Area	**65%**
Most Likely Area	**40%**
Lower Area	**19%**

For example, for the most likely case, there is a 40% probability that a well will drain less than 80 acres and hence be noncommercial.

e. Determine Dry Hole Fraction. This represents the fraction of the resource volume condemned by dry holes. Historical drilling data from the WHCS was used to establish dry hole percentage to date. This data was used as a guide and was judgmentally rounded to reflect future dry hole expectation. For plays or portions of plays with an established drilling history, the dry hole statistics will tend to reflect development well drilling success ratios. Where less information is available and where commercial development has not been established, or is in its infancy, the statistics will reflect exploration well success ratios. The dry hole factor thus serves a dual role, reflecting not only historical success, but also maturity of the target in question.

f. Recovery factor (RF) was the net of dry hole fraction (DHF), noncommercial fraction (NF), and base recovery factor (BRF), combined as follows:

$$RF = (1\text{-}DHF)(1\text{-}NF)(BRF)$$

EXAMPLE RECOVERY FACTOR CALCULATIONS

	Dry Hole Fraction	**= 0.2**
	Base Recovery Factor	**= 0.75**
Maximum	**(1-0.2)x(1-0.19)x 0.75**	**= 0.49**
Most Likely	**(1-0.2)x(1-0.40)x 0.75**	**= 0.36**
Minimum	**(1-0.2)x(1-0.65) x 0.75**	**= 0.21**

The maximum, most likely and minimum RFs defined a triangular distribution which was applied along with distributions for porosity, water saturation (as a dependent variable to porosity), formation volume factor, and a single deterministic value for rock volume in a Monte Carlo simulation to derive a recoverable gas estimate expressed as a distribution.

Porosity and water saturation distributions that were used for each play are discussed and graphically displayed in the sections on each play.

8. Application of the Model. For model application, each play or sub play was segmented into two basic depth slices.

a) Top of play to *economic basement*.
b) *Economic basement* to deepest commercial production.

Each depth slice was characterized by its own dry hole fraction, noncommercial fraction and recovery factor distribution. As with any estimate of reserves, such estimates are subject to revision as ensuing developments provide additional data. This is the situation for the Fort Union and Lance-Fox Hills plays, both of which have no commercial production and, as a result, both have been assigned zero reserves.

BASIC TECHNICAL PARAMETERS

Log Interpretation

Statement of Problem: Comparison to Conventional

Use of conventional log interpretation techniques within OPT reservoirs meets with only limited success in accurately defining rock properties. This results from the fact that the normal logging tools are operating outside their optimal design range and the fact that OPT reservoirs have particular characteristics which differ significantly from conventional gas reservoirs. These include variable invasion profiles causing variable gas saturations within the invaded zone, considerable uncertainties in formation water resistivity, variable grain densities and the presence of clay minerals, both original and authigenic, distributed in various geometries. Special log interpretation techniques are required to account for these factors as detailed in Appendix B.

Some of the more successful methods for dealing with log interpretation problems in OPT reservoirs are those developed by Kukal (1981 and 1984). These methods are included within Scotia's proprietary log interpretation program, SLOG. The objective of the log interpretation exercise was to derive a set of rock properties including sand thickness, net gas pay, effective porosity, water saturation and a log derived permeability that could be used to map the distribution of gas and in volumetric calculations of GIP.

Formation Water Resistivity

Formation water salinity data available from a variety of sources indicate wide ranges of R_w, making the determination of a blanket R_w for a given play frustrating and problematic at best. The determination of R_w is complicated by the fact that OPT reservoirs produce little if any water, and that which is produced often contains condensation. R_w estimates from the spontaneous potential (SP) curves are generally unreliable due to poor development of the SP log in tight gas sands and the absence of a definitive wet clean reservoir for calibration purposes. This also limits the R_{wa} and Pickett plot techniques. Attempts to post and contour available R_w data showed no particular pattern and confounded any attempts to contour the exhibited variation.

The R_w used on a well by well basis was determined via Kukal's iterative method as described in Appendix B, and then compared against R_w values reported in the literature at reservoir temperature. In selecting a final R_w for use, generally the lower of these two values was used.

Porosity

Porosity determination in OPT sands must take into account several particular physical properties that influence not only the logging tools themselves but also the interpretation methods for deriving an effective porosity measurement. These effects include:

1. Variable gas saturation in the invaded zone or absence altogether of an invaded zone producing an inconsistent density and neutron log response to hydrocarbons.

2. Sonic log values are suspect in OPT sands since the sonic log will tend to record primary porosity and bypass secondary porosity. In many cases OPT sands have a predominant porosity network of a secondary origin that may be bypassed via sonic log readings.

3. The presence of clay minerals and abundant lithic fragments causes grain densities to vary and hence matrix values used to derive log porosities will also vary.

4. Due to the overpressured nature of the sediments and the normal practice of drilling wells balanced or under balanced as well as the generally fractured nature of the formation, can cause severe hole caving. This markedly affects the pad tools (density log) and can also affect other log measurements where boreholes are particularly rugose.

Porosities were derived from log data using the methods of Kukal developed specifically for tight gas sands. Kukal's equation which was derived from a combination of the neutron and density response equations, iteratively solves for S_{dn} (the saturation of the zone investigated by the neutron and density) to correct for porosity tool gas effects. Details of these calculations are included in Appendix B.

Water Saturation

Due to the presence of abundant authigenic clay minerals, a shaly sand approach was taken in evaluating water saturations involving use of the total shale (Simandoux) equation. While recent work in the basin has indicated that the use of a dual water or Waxman-Smits type of approach has been effective in obtaining reasonable results, the general lack of cation exchange capacity data except in extremely local areas limited the use of such techniques for the purposes of a project of this scale.

Archie exponents used in determining water saturation were investigated from a variety of sources and after considerable experimentation and consideration of net overburden effects, the following were selected as representative:

$$a = 1$$
$$m = n = 2.0$$

__Permeability From Log Data__

Attempts to derive permeability from log information are not usually highly successful. Correlations based on core to log relationships can be locally valid, however, extrapolating these into other areas or other formations often introduces the potential for considerable error. The presence of natural fracturing can also provide a separate and unquantifiable permeability overlay to the natural fabric of the OPT reservoirs.

The equations developed by Kukal based on his study of samples from the multiwell experiment (MWX) wells in the Piceance basin provided a reasonable permeability approximation. Two equations were used: the first required as input values of porosity, water saturation and clay volume; the second equation eliminates the saturation fraction which can have a fairly weak correlation with permeability in low permeability rocks. Log permeabilities derived from this study are displayed in the discussion of each individual play.

Permeability

The single most important factor and the single biggest unknown in dealing with OPT reservoirs is permeability. By definition, tight reservoirs are defined as having a natural in-situ permeability to gas of less than 0.1 md. The effective range for completion of OPT reservoirs, based principally on the current frac technology, is between 0.001 and 0.1 md. At permeabilities below this range, fracture treatment is commonly not successful and above this range is commonly not necessary.

Permeability in OPT reservoirs is not only low but complex in its source. Because the sediments are tightly compacted, cemented and contain abundant secondary mineralization and grain dissolution, the producing mechanism in the reservoir is quite different from that of a conventional reservoir. Rather than having discrete pores and pore throats, the porosity available within the OPT sand may be distributed in a nonuniform fashion and connected by an anastomosing network of microfractures and fine capillaries. As such, a standard core plug sampling of cores from OPT sands may not do justice to the range of parameters that may be expected from the gross sand itself and also may have permeabilities so low as to be not measurable utilizing standard core analysis techniques.

In addition, OPT sands are markedly influenced by the effects of unloading and require significant corrections to convert surface ambient measurements to in-situ conditions as discussed in Appendix A.

Scotia's proprietary COREPRO software was utilized to process a large database of core information collected for the GGRB. The COREPRO software performed the necessary corrections for overburden and the corrections for gas slippage (Klinkenberg) and brine saturation.

Corrections to In-Situ Conditions

Prior to the development of automated equipment able to measure porosity and permeability at net overburden (NOB), in use in many laboratories today, measurements were taken at ambient conditions. Essentially all the core data available for this study was measured at ambient conditions and consequently required the following corrections to represent in-situ conditions.

1. Overburden corrections to restore porosity and permeability to in-situ conditions. These were based upon the work of Jones and Owens (1980) and Luffel et al (1991).

2. Correction of air permeability for gas slippage. The Klinkenberg correction is large for tight gas sands. This correction increases with decreasing permeability and varies depending upon the gas used in the permeability measurement (usually air which is mainly nitrogen) and also the mean flowing pressure.

3. Correction to absolute liquid permeability. The application of the above corrections yields a NOB corrected dry Klinkenberg permeability which is often higher than a measured absolute liquid permeability. This is because the correction for gas slippage does not account for possible rock fluid interaction and alteration of pore geometry during the drying process (e.g., collapse of fibrous illite clay in high temperature ovens). Corrections were developed to convert dry Klinkenberg to absolute liquid permeabilities based upon work by Jones and Owens (1980) and are detailed in Appendix B.

4. Correction to effective gas permeability. Jones and Owens (1980) determined from their tight gas sand dataset that NOB corrected absolute liquid permeabilities approximate effective gas permeabilities measured at irreducible water saturation. Consequently, no further corrections were applied.

Correlation of Core, Log and Test Permeabilities

Based upon data collected in this study, considerable difficulty was found in correlating permeabilities derived from differing sources. Some of this difficulty is related to the way in which each parameter was measured and the effective volume of the reservoir that the measurement represents.

As noted, core and log correlations can be developed which are valid in localized areas but may provide poor correlations in other areas due to various nonquantifiable factors that necessitate a differing empirical relationship. Well test-derived permeabilities are representative of a much larger reservoir volume than those derived from log and core data and thus take into account a greater degree of heterogeneity. Suffice to state that due to the generally variable nature of OPT reservoirs, it is a rarity to have test derived and core/log derived permeabilities match with any high degree of consistency.

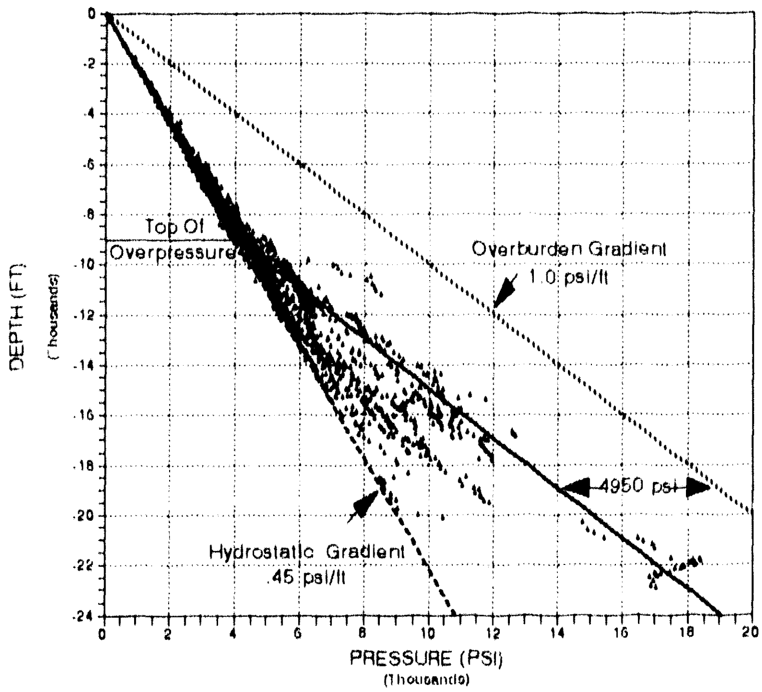
Reservoir Pressure

Volumetric GIP estimates require a knowledge of reservoir pressure in order to determine formation volume factors. Therefore it was necessary to develop a pressure versus depth relationship for the basin. Three types of data were employed: mud weights from mud logs, measured formation pressures from DSTs, and hydrostatic pressures from DSTs. Although the top of overpressuring varies as much as 2,000 feet across the basin, sufficient data was not available to develop geographical pressure versus depth correlations. Hence one correlation was developed for the entire basin.

Data from approximately 60 mud logs was entered into a database. Mud weights were converted to hydrostatic pressures and plotted versus depth (Figure 7). An increase in pressure gradient was observed at between 8,000 and 10,000 feet indicating the top of the overpressure. Since wells are typically drilled at balanced to under-balanced conditions, a basin wide average top of overpressure is estimated at a depth of 9,000 feet. Pressures appear to increase at a gradient of approximately 0.45 psi/ft to the top of the OPT section. From that point a gradient of 1 psi/ft is noted in line with a normal expectation of geopressuring without any aquathermal-pressuring effect (Magara, 1987).

DST hydrostatic data points and actual measured pressures were databased and also plotted versus depth. As in the mud log data, the top of the overpressure was seen between 8,000 and 10,000 feet. The correlation of pressure versus depth from the mud logs when superimposed on the hydrostatic data fell in the middle of the data and appeared to be reasonable. For actual measured formation pressures versus depth from DSTs, the superimposed mud data correlation fell at the upper limit of the data as might be expected. The majority of the DST pressure measurements were probably not of sufficient length to record the static reservoir pressure.

FIGURE 7: GGRB PRESSURE MODEL
MUD WEIGHT PRESSURES VS DEPTH



If an overburden pressure gradient of 1 psi/foot is assumed, the NOB pressure in the overpressured region is constant since the reservoir pressure gradient and the overburden gradient are equal. Since the reservoir fluids are supporting more of the overburden in the overpressured region, porosities and permeabilities are greater than they would be at any lower pressured conditions. Thus, this estimation of NOB pressure is conservative and corrections of porosity and permeability to in-situ conditions made on this basis will be optimistic.

Natural Fracturing

The OPT sandstone reservoirs of the GGRB have undergone burial and diagenesis that has been responsible for their present low porosity, low permeability character. The primary effects of burial were silica and carbonate cementation and the creation of authigenic clays within the pore spaces. Most of the present porosity is of a secondary nature, resulting from dissolution of rock fragments, mineral grains, and cements. As a result, most of the original primary permeability has been destroyed. The present pore spaces are connected by sheet-like capillaries less than two microns thick and often less than one micron thick (Spencer, 1983).

Natural fracturing in this low permeability situation is a very important factor in controlling well productivity. The best potential for well completions is in areas where natural fracturing is best developed and where the completion is successful in establishing communication between the natural fracture system and the wellbore via hydraulic frac treatments. Failure to place an appropriate frac treatment even in areas of well developed natural fracturing, will usually result in a noncommercial completion.

When hydraulic fracture treatments are designed to stimulate tight gas reservoirs, the predicted fracture growth direction will be in the direction of maximum in-situ stress. Because natural fractures are planes of low tensile strength, a misalignment of natural fracturing direction with direction of maximum stress can promote development of multiple fracture branches and abnormally high treating pressures as noted by Marin et al (1993).

Detection and identification of natural fractures is approached via several differing methodologies that are scale-dependent:

1. Macro Geological Methods: These include regional lineament mapping, such as through the use of aerial photograph or remote sensing data in combination with subsurface geological work, derivative mapping, etc. Such data, in conjunction with regional basin framework and identification of faulting, allows areas of maximum natural fracture likelihood to be inferred.

2. Visual Scale Measurements: These consist of identification of natural fractures at the visual scale via examination of cores or by various fracture identification logging tools such as the formation micro scanner (FMS) log. Fractures may also be inferred and properties quantified through the use of pressure transient well test analysis.

3. Microscopic Scale: This consists of the identification of fractures at the microscopic scale usually through the use of thin sections or other forms of microscopic examination of rock samples.

An investigation of natural fracturing as part of this regional scale report is inappropriate. However, it is mentioned here due to its importance and should be kept in mind as a key contributing factor to the variable performance of OPT gas wells.

Drilling

The OPT gas reservoirs of the GGRB are known to be sensitive to drilling and completion fluids. Such sensitivity is related to one or more of the following contributing factors:

1. Plugging: Because the pore structure is characterized by adjoinment involving thin ribbon-like micro fractures as opposed to discrete pore throats, entry of particulate matter can cause plugging and isolation of the wellbore from the main body of the formation.

2. Fluid Invasion: Most tight gas reservoirs are characterized by greater or lesser amounts of authigenic clay mineralization, some of which may be sensitive to fluids invading the formation as mud filtrate. This can cause swelling or dislodgment and migration to block permeable channels during subsequent production.

3. Drilling Induced Fracturing. Drilling induced fracturing has been noted and acts to impart localized near-wellbore areas of weakness that may cause increased tortuosity during subsequent frac treatment, thus reducing the effectiveness of such fracs.

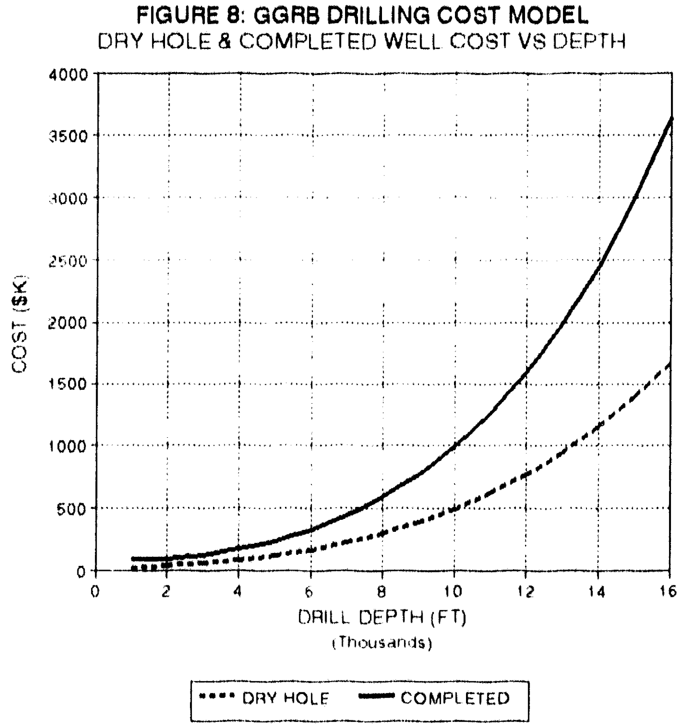
The above factors are exacerbated by the fact that the target reservoirs are overpressured causing increased gas readings while drilling, resulting in mud weight increases for safety purposes and hole stability. Such mud weight increases tend to compound the problems noted above, leading to an optimal situation of balanced or under-balanced drilling to attempt to minimize these problems.

GGRB drilling conditions are typified by Wamsutter Arch, Mesaverde gas completions. These wells are drilled to a TD of around 10,000 feet. Casing program consists of setting a surface 9-5/8 string to around 1,000 feet, drilling to TD, and then setting 5-1/2 inch casing. Drilling time to TD is normally in the range of 14 to 21 days. Low water loss mud systems are usually run to try and minimize mud filtrate fluid loss into the formation by drilling balanced or under-balanced. Mudding up usually occurs above the principal pay section and drilling of the pay section is attempted in a balanced fashion.

Development wells are usually logged with a minimum suite of induction electric log, sonic and density-neutron, while more elaborate logging programs may be run on exploration, step-out or "science" wells.

Completion intervals are selected via log analysis involving an evaluation of porosity and water saturation and keying off results of analogous wells in the vicinity. With the completion interval selected, frac design is based upon anticipated pay section and the optimal design is selected. Fracs are conducted via perforation of the pay interval and fracture treating. Usually only one or two zones will be completed and in certain cases wells are dually completed.

Other than water flows from shallow aquifers, drilling is comparatively problem free including deep drilling in the OPT section. Drilling costs increase with depth as illustrated in Figure 8. This is based on JAS survey data with slight modification as a result of a survey of operators and drilling contractors in the basin. Note that Moxa Arch drilling costs are generally less than those of Figure 8 which is more representative of the OPT section. Due to the tight nature of the reservoirs, elevated gas readings while drilling do not lead to significant well kicks or serious potential blowout situations that typify overpressured drilling in areas such as the Gulf Coast where reservoirs are not tight.



Completions

Successful placement of a hydraulic fracture treatment is necessary for commercial production of gas from OPT reservoirs within the GGRB. While the technology to successfully place the required hydraulic fracture treatment has evolved and advanced considerably over the past 20 or so years, the frequency with which adequate frac jobs are performed, in the eyes of the operator, is still open to considerable improvement. In a survey recently published by Holditch (1992) where operators were polled as to their levels of satisfaction with fracturing results, about half of the respondents indicated they were satisfied in over 75% of their wells and the other half responded that they were satisfied in less than 75% of their wells. This same survey also concluded that despite advances in fracturing technology and quality control, the majority of operators did not routinely employ such technology.

With respect to the GGRB, there have been several phases of popularity to differing fracture treatment types and methodologies. Historically, the evolution of thinking has progressed along the following lines based on an analysis of the WHCS database:

1. Pre-1975: Sand oil and sand water based fracs dominated the spectrum during this era with over 72% of the fracs being of these types. Average frac size was very low at 30,000 gallons and 31,000 pounds.

2. 1975 to 1985: Sand gel fracs dominated this decade at 30% of the fracs, with sand emulsion and water comprising 49%. Sand foam fracs started during this period with

experimental use of CO_2 and nitrogen fracs. The average size of the fracs increased dramatically to 110,000 gallons and 220,000 pounds.

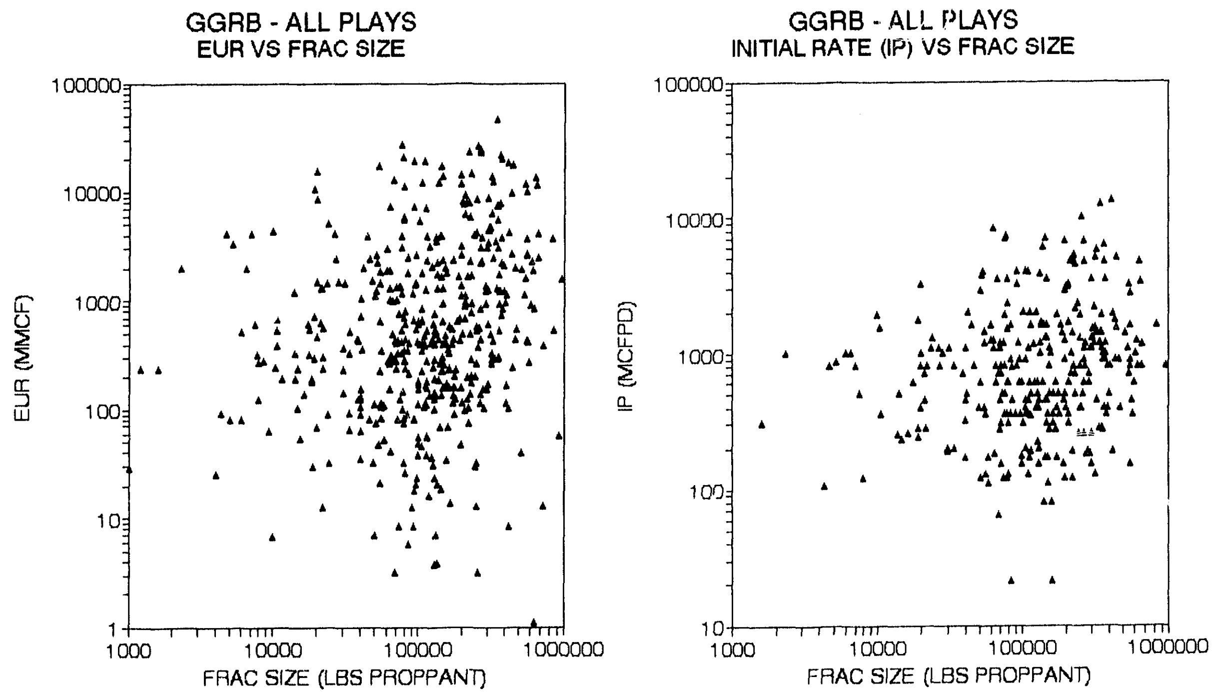
3. 1985 to 1991: Although overall numbers decreased dramatically from the previous decade, sand foam fracs increased to over 50% of the jobs, sand water fracs remained significant at 22%, and sand gel and emulsion fracs fell from a combined 55% to 6% during this period. Average frac sizes increased to 113,000 gallons and 285,000 pounds.

The most noticeable decrease in frac types occurred in two areas, sand emulsion and sand gels. During the 1975 to 1985 decade, these two types experienced dramatic increases from previous years, but during the period 1985 to 1991, fell off to a combined 6% of the total as stated previously. Historically the preferred sand proppant has been 20/40 mesh.

The latest data in the database is for 1991, however, based on an informal survey of various service companies and recent literature on the subject, the preferred frac type is moving toward the use of cross-linked gels.

Unfortunately the database has limited ability to distinguish between the differing types: foams, CO_2 and gel fracs. In fact, some of the reported foam fracs may even be a type of cross-linked gel frac.

FIGURE 9



The database also shows that the number of fracs per well went from 1.84 pre-1975 to 1.57 between 1975 and 1985, to 1.25 during the period 1985 to 1991. Thus, it seems operators are becoming more judgmental in terms of the number of fracs per well, given that the frac sizes and consequently dollars expended on these completions is increasing, but not in proportion to the return of value based on EUR.

Although the cross-plot of initial potential (IP) versus frac size (Figure 9) does not show a good correlation for the basin as a whole, there may be better relationships in more isolated field areas within each play. This has been observed by Scotia as well as others studying this phenomenon. There seems to be little if any correlation between EUR and frac size (on a basin or play level) based on cross-plots of each in the five plays. These digressions from a good correlation are affected by diversity of the formation properties in terms of rock quality, net pay thickness, stimulation type, job size, and various other factors.

Production Performance

Analysis of production performance data provided several key elements for this study:

1. All wells identified as being productive from the OPT section were projected utilizing rate versus time and rate versus cumulative techniques to derive an EUR. The estimates were based upon a calculated abandonment rate of 50 Mcfd assuming operating costs of $2,000/month as being average for the basin, an assumed 25% royalty, 13% combined severance and ad valorem tax, and a $2.00/Mcf wellhead gas price. The use of this gas price was a study requirement by the DOE. These EURs provide the base measure of ultimate well performance.

2. Initial Productivity and Decline Characteristics: These items governed the rate of gas recovery and provided the profile for recovery. It should be noted that while some wells exhibit the classic low permeability gas signature of a transient flush production that rapidly decreases from initial rates and then gradually stabilizes at a low rate of decline, many more tight gas completions exhibited erratic production behavior more connected with externally imposed producing and market conditions. For example, seasonal curtailment is noted at one time or another in most wells across the basin. In addition, many wells are produced in cyclic fashion, presumably in response to high local line pressures and low well productivity. Some previous researchers have discussed the initial linear flow period in these tight zones due to the massive hydraulic fracs placed on these wells. However, due to the curtailed nature of the production discussed above, no reasonable success was achieved through the use of linear flow analysis. Historic production from most wells, even the best wells in the basin, could be fit with a hyperbolic curve with an exponent of approximately 0.5. It also should be noted that even with curtailment and various shut-in periods, most wells exhibited fairly steady decline rates after the initial transient period and are thus fairly predictable in terms of production performance.

3. Transient Production Behavior: Many wells exhibited a transient phase of production that could last for several years. Analysis of this phase utilizing Fetkovich type curves provided valuable information on permeability and drainage area in conjunction with data from other sources.

   Fetkovich analysis was performed on wells containing enough backup petrophysical information, i.e., log analysis estimates of ϕ, S_W, and h, as well as enough production data to allow for a meaningful fit with the type curves. This analysis depends upon various factors such as: estimates of initial and final bottomhole pressures, bottomhole temperature, gas gravity, and wellbore radius, along with the items mentioned above. For this reason, only a sampling of wells was identified as having enough information to produce meaningful results.

   Although this procedure is very sensitive to subtle changes in the fit of production to the type curves, the final completed drainage radius value was checked against the drainage radius calculated using the same petrophysical parameters and a recovery factor of 75% of GIP. In general, drainage radius calculations from the Fetkovich analysis were slightly higher, but did serve as a check in terms of order of magnitude for the constant recovery factor model. In addition, since pressure data was extremely sparse, it was not possible to perform any reserves analyses based on P/Z data.

4. A break down of typical performance profiles for OPT wells by play is summarized in Table 5:

TABLE 5
TYPICAL PRODUCTION PERFORMANCE PARAMETERS BY PLAY

	Cloverly Frontier	Mesaverde	Lewis	Lance Fox-Hills	Fort Union
Average Initial Rate (Mcfd)	1,000	1,500	1,800	N/A	N/A
High Initial Rate Range (Mcfd)	120 to 4,100	100 to 6,600	190 to 2,400	N/A	N/A
Average Initial Decline	33%	27%	38%	N/A	N/A

Note: **Lance-Fox Hills and Fort Union plays contain insufficient OPT producing wells to provide meaningful data.**

Economic Considerations

Base economics are the driving force for development of any "technology" play such as the development of OPT gas reserves. It is fair to say that the GGRB has suffered over the years from gas prices and market takes that are below national averages. Recent introduction of the Kern River pipeline system, opening access to California markets, has considerably improved this situation and indeed prices in early 1993 for the area on the spot market averaged over $2.00 during several of the winter months.

The base premise for this study is to examine reserves development potential based upon an assumed gas price of $2.00/Mcf.

Base economic consideration can be broken down into the following elements:

1. Capital Costs: Consist of the cost to drill, complete and equip a gas well that is inclusive of front end costs such as leasehold, seismic and geological costs.

2. Operating Expenses: These consist of the monthly charges for direct and indirect expenses to operate the gas well.

3. Local Taxes: These consist of local State severance and ad valorem taxes. Jurisdiction varies in the GGRB involving freehold, State and Federal leases causing lease to lease variations.

4. Lease Royalty Expense: This represents the royalty burden that must be borne by the gas well and will be variable depending upon whether the leases represent freehold, State or Federal land.

5. Production Profile: This represents the rate of gas production over time and hence the likely distribution of derived revenues assuming a $2.00/Mcf constant gas price as required by the study specification.

A combination of the above parameters results in a projected cash flow profile for a given well. Several factors are worthy of note:

1. Wells Exhibiting a Typical Tight Gas Signature: That is, exhibiting an initial rate which declines rapidly in a hyperbolic fashion to stabilize at a low sustained level, the shape of the hyperbolic decline is extremely important. In situations where the rates drop to a break-even level with relative rapidity, the bulk of the cash flow from the well is derived early in its life.

2. Once the production has stabilized or the well has "turned the corner," base economics of further production depend upon the production rate and price versus

operating cost levels. Many tight gas wells are sensitive to small fluctuations in price and operating cost to determine their profitability.

3. A wide range in well performance is noted both on a regional basis and down to the well level within an individual field. This is apparently the norm for tight gas wells with the EURs being log normally distributed at most levels of aggregation.

Due to the fact that OPT wells must be frac'd in order to determine productivity characteristics, a significant proportion of completions do not ultimately pay out. That is, while such wells produce sufficient gas volumes to operate profitably by covering operating costs, the payout of drilling and completion costs is never achieved.

RESERVES EVALUATIONS BY PLAY

In examining resources and estimating what proportion of those resources is technically and economically recoverable and hence available for conversion to reserves, it is useful to diagrammatically express such concepts for the purposes of clarity. This concept was first proposed by the USGS as the McKelvey Box (Figure 10).

The McKelvey Box is an extremely useful tool for illustrating the relationships between reserves and resources. While this concept is embraced by industry, formal linkage of McKelvey's "measured," "indicated," and "inferred" categories with standard industry usage of proved, probable and possible has not occurred due to base concept and purpose differences.

The McKelvey Box was originally developed in 1972 when McKelvey was a director of the USGS. The box represents the total volume of unproduced mineral resources and classifies such volumes with reference to a horizontal axis representing the degree of geologic and engineering certainty, and a vertical axis representing the range of economic feasibility of recovery of such minerals.

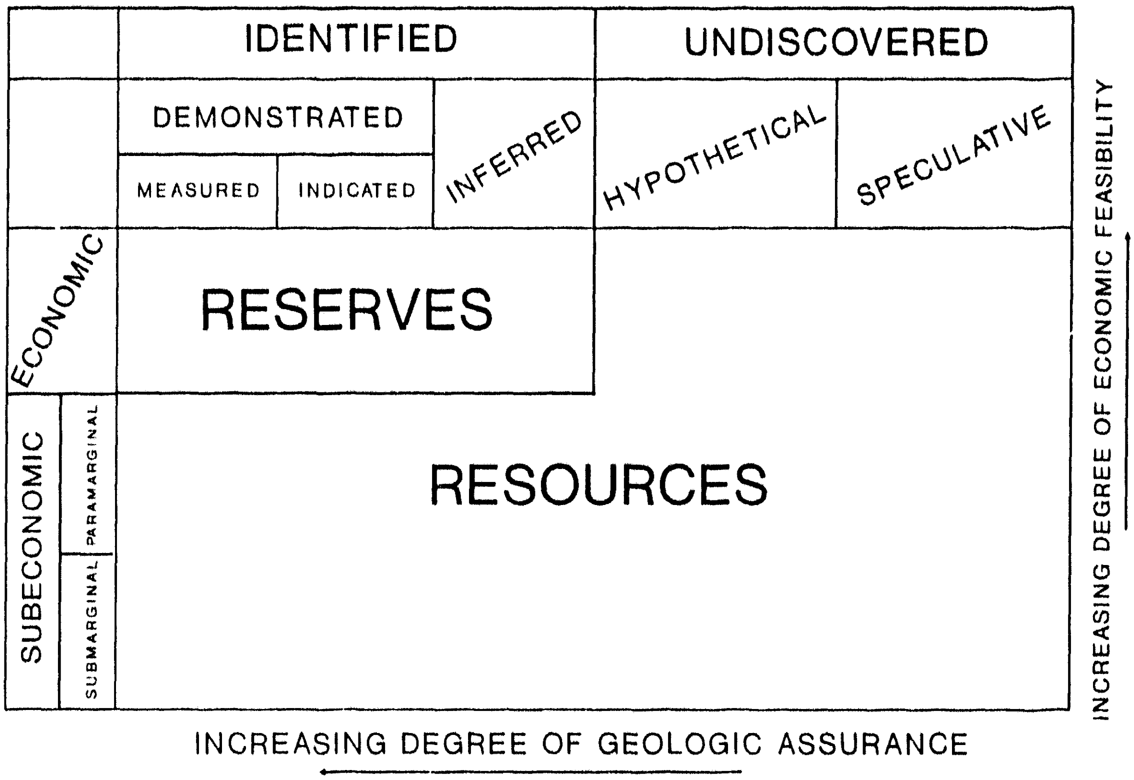
The economic and geologic axes each have two principal divisions. On the geologic axis, the logical division is between mineral deposits that have been discovered and those which are postulated with varying degrees of certainty but are still undiscovered. This line constantly moves to the right as more resources are discovered and converted to reserves. Likewise, as reserves are produced, they exit the upper left hand corner of the box to become cumulative production. On the economic axis, the division is between those volumes for which technical characteristics and the existing combination of costs and prices make them profitable to recover, and those that are not. This line moves down over time as technological advances make an increasing fraction of the resource base economically extractable. Cost and price changes will also cause vertical movements of this line.

The upper left hand sector of the McKelvey Box contains reserves. On the horizontal or geologic axis, these are the volumes of oil and gas about which there is the greatest confidence in their existence and characteristics. They have been discovered and characterized by information obtained through drilling. On the vertical or economic axis, reserves are restricted only to those volumes of discovered minerals for which there is the highest certainty about the feasibility of economic recovery.

The remainder of the McKelvey Box is filled by resources. These are minerals which remain to be discovered or have been discovered but for which economic recovery under present conditions is judged uncertain.

FIGURE 10

THE McKELVEY BOX



The normal subdivision of reserves, as represented by the standard SPE definitions, resides in the upper left hand corner of the McKelvey Box. To qualify as reserves, such volumes must pass an economic producibility test, a test of existence and a further test of level of certainty of existence. Where such reserves are thought to be reasonably certain, they are classified in the proved category. Reserves which are identified but do not pass the reasonable certainty test are classified in the unproved category with subdivisions noted as probable and possible.

For the purposes of expressing the results of this project, we have chosen to utilize the McKelvey Box concept in a modified form. This modification calibrates both X and Y axes in terms of the fundamental controlling technological and economic parameters.

Considering firstly the X or technology axis, this has been calibrated as a function of average reservoir permeability on a logarithmic scale. In addition, the axis has been reversed in comparison to the original McKelvey Box whereby permeability increases from left to right. The technology axis is subdivided based upon permeability ranges. The primary subdivision is between conventional reservoirs having permeabilities of greater than 0.1 md and unconventional reservoirs having permeabilities of less than 0.1 md. The second subdivision of the horizontal axis is based upon the current state of massive hydraulic fracturing technology. This technology is necessary to produce unconventional gas reservoirs at commercial rates and the current range of effective technology application is in the range of 0.001 to 0.1 md Holditch (1992). The lower limit of this range at 1 μd, essentially separates the technology axis into *technically nonviable* resources versus *technically viable* resources, a proportion of which become recoverable reserves based on the appropriate recovery factor. As improvements in fracturing technology are made, the boundary between *viable* and *nonviable* will move to the left and resources will move to the right.

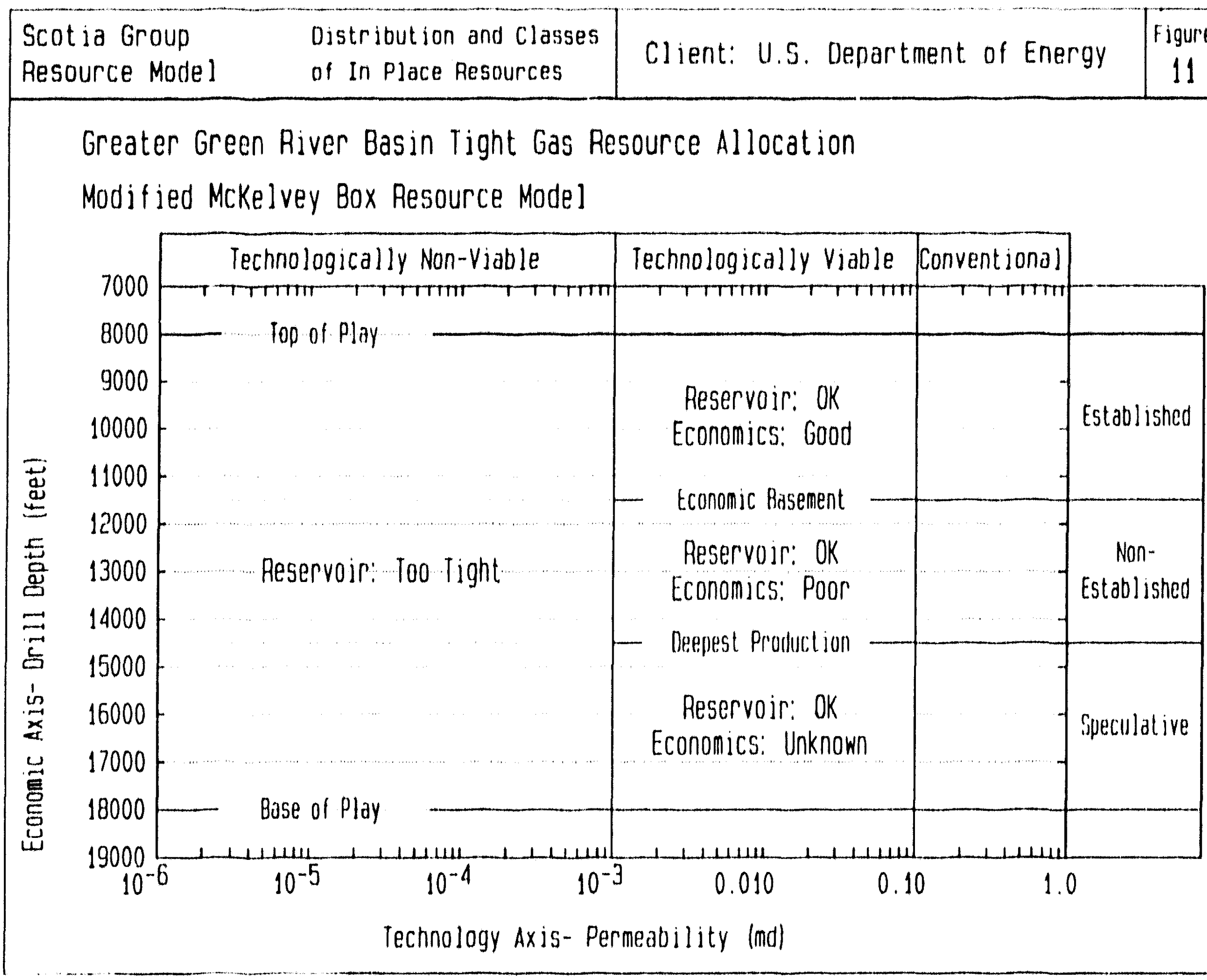
The vertical, or economic axis, is calibrated in units of drill depth and hence drilling cost. While the economics will be dependent upon a variety of factors including levels of royalties, taxes, gas prices and success ratio as well as cost to drill and complete, including frac cost, the primary consideration is the interplay of potential reserves volumes versus base drilling and completion costs. Because drilling and completion costs increase with depth, and potential reserves volumes per well tend to deteriorate with depth because of deteriorating porosity, the interplay of these two factors generates an *economic basement* that can be expressed as a function of drill depth, hence the choice of this parameter for the vertical axis. For a given play, the identified resource will occupy a given depth range between top and base of play with *economic basement* lying above, below or within that depth window depending upon the interplay of reserves and economics.

As economic conditions change, the *economic basement* line will move vertically. Increasing gas prices, decreasing royalties, taxes or increasing incentives or decreasing drilling cost will move this line down and resources will move up into the *established* category. The reverse also applies in that as costs increase or gas prices drop, the *economic basement* will move up and resources within the *established* category will move to nonestablished.

Figure 11 illustrates this subdivision. Only those resources in the upper right hand area being available as candidates for conversion into reserves by virtue of being potentially technically and economically recoverable. Thus only the fraction of that resource which is considered recoverable represents reserves. For resources below *economic basement*, reserves may still exist but their character will be higher risk and more costly, and thus they will represent a smaller fraction of the resource.

By breaking down the resource estimate into the four basic components based upon technical and economic feasibility of recovery, visualization of what components of that resource will be subject to changes in status in the future can be made. Such status changes will be the result of technological advances and economics by virtue of changes in prices, costs and the imposition of incentives. The diagram also allows the challenge that industry faces in attempting to exploit this resource to be examined in comparing one play to the next. This becomes obvious when comparing plays where the resource is located principally at depth versus those where a greater proportion is in the shallower depth ranges. For the deep resource to become economic, major changes in the cost and price environment must occur as opposed to the shallower resource. In addition, the relative proportion of the total evaluated resources occurring within each permeability range allows the benefits of technology improvements to be evaluated in terms of how much of the resource is available for the conversion to reserves by application of such technology.

Figure 11 illustrates this concept:



CLOVERLY FRONTIER PLAY

Description

The Cloverly Frontier play is the deepest stratigraphic unit considered by the USGS and includes all strata from the base of the Cloverly and equivalents to the top of the Frontier formation. This play covers the majority of the deeper portions of the GGRB. Principal reservoir units of interest are the Frontier formation itself, the Bear River formation, the Dakota sandstone, the Muddy sandstone, the Cloverly formation and the Cedar Mountain formation. Lithologies include sandstone, siltstone, shale and coal deposited in marine and nonmarine environments.

The area along the crest of the Moxa Arch and extending into the area of the LaBarge platform has been excluded from the USGS resource assessment. This area was excluded on the grounds that while being overpressured and gas-bearing, the reservoirs are a combination of both conventional and tight sandstones. Note that these areas are designated as tight by the FERC. It should be noted that the Moxa Arch and LaBarge platform area is one of the principal producing areas in the GGRB, particularly from the Frontier formation and also from the Dakota, which is a current exploration play of interest. After removal of this area, production from the Cloverly Frontier play is limited and indeed penetrations of the stratigraphic unit, particularly in the deeper portions of the basin, are few.

Control based upon the USGS cross-section grid is nonexistent as none of the wells making up the control for the cross-sections penetrated the Frontier formation in the deep overpressured area. Examining the Frontier penetrations (Figure 12), well control is generally limited to the shallow edge of the USGS defined play boundary with little or no control in the deeper basinal areas or at the basin margins.

The Frontier and Dakota are the principal producing formations within the play. Examination of available information on the Dakota formation, principally in the Moxa Arch area, indicates permeabilities well above 0.1 md on average. While the Dakota is apparently overpressured, permeabilities in the conventional reservoir range led us to exclude the Dakota formation from this evaluation.

Three areas within this play have been designated as tight by the FERC (Figure 13). The first area covers most of the central and northern parts of the Moxa Arch and edges of LaBarge platform and extends downdip off the eastern flank of the Moxa Arch and northward into the Pinedale anticline area. The second tight gas area is on the northern extension of the Rock Springs uplift and the third on the eastern flank of the Washakie basin. Production from the Cloverly Frontier play is restricted to within or just adjacent to these FERC designated tight gas sand areas with two exceptions (Figure 14). These are fields at either end of the Wamsutter Arch. Production from the third FERC tight gas area on the eastern flank of the Washakie basin as well as production along trend further to the north on the eastern end of the Wamsutter Arch occurs at or near the USGS boundary for this play and, from depth considerations, is probably near to or above the top overpressure and hence should be excluded from the evaluation despite having FERC tight designation.

The fields producing within the area considered by the USGS are summarized in Table 8. An average per well EUR of 1,173 MMcf is derived based on 123 wells in 20 designated fields. Of the 123 identified wells, 112 produce from the Frontier, nine from the Bear River and one each from the Mowry and Muddy. The play level production plot (Figure 15) shows a steady increase in activity (wells producing) and production, peaking in 1989. Total current producers number 75 wells averaging 330 Mcfd each.

Drilling statistics for the Cloverly Frontier play are dominated by activity in the Frontier formation on the Moxa Arch and LaBarge platform area. There is limited activity in other areas and virtually no activity in the areas where the Frontier formation exceeds 15,000 feet drill depth. Based principally on the Frontier formation in the Moxa Arch area, there is an historical 92% completion percentage. Eight percent of wells are dry holes. Since the OPT play is much less mature than the Moxa Arch/LaBarge activity, a success ratio of 50% has been assumed for reserves modelling. Examination of the distribution of EURs, after excluding the Moxa Arch and LaBarge platform areas, indicates approximately 28% of the wells represent commercial propositions, leading to a commercial success ratio of 14% (Figure 16). The commerciality percentage calculation is based on the proportion of EURs having a PV10 exceeding the cost to drill and complete a well to the average producing depth for the play or 9,585 feet.

Extrapolation of this risk model into deeper areas is not justified until additional deeper drilling occurs. Deterioration of reservoir properties downdip on the flanks of the Moxa Arch has been noted due to increases in carbonate cementation. Consequently, it is anticipated that the dry hole percentage will increase downdip should this be the case.

Stratigraphy and Rock Properties

The Cloverly Frontier sequence includes Lower and Upper Cretaceous rocks. The Lower Cretaceous sequence has limited subsurface control and is not as well understood as the Upper Cretaceous sequence. Lithologies consist of interbedded sandstones, siltstones, shales and coaly sediments, representative of a variety of marine and nonmarine depositional environments.

The Frontier formation is the main producing horizon and is up to 1,600 feet thick. The principal reservoirs within the Frontier are fluvial channel and marine shoreline deposits formed during periodic transgressions and regressions of the Western Interior Seaway. These reservoirs are variously termed the First through Fourth Frontier and are subdivided into several sandstone "benches." Sand thicknesses range from 10 to over 100 feet, depending on location.

Sandstone composition averages 65% quartz with the remainder being feldspar (4%) and rock fragments (31%) (Dutton and Hamlin 1991) with common detrital clay matrix. Authigenic cements are common including quartz, calcite, pyrite and a variety of clay minerals. The authigenic clays and particularly their monophology, are considered critical in their effect on permeability.

Porosities are comparatively favorable in the Frontier with modal values of 8% based on log analyses, but with porosities up to 16% being recorded even in deeply buried settings. The location of optimum reservoir conditions is controlled by original depositional setting at locations where matrix-free sandstones were deposited under high energy conditions and where subsequent burial diagenesis and cementation has had a minimal effect.

Figure 17 presents an example computer processed interpretation (CPI) log for the Frontier play. Well USA Amoco A-M #1 (S6 T27N R111W) was completed between 9,570 and 9,860 feet in 1984, with an IP of 1,696 Mcfd, 1 Bcpd, and 10 Bwpd. The well was stimulated between 9,570 and 9,648 feet with 19,000 gallons of acid with nitrogen additive. The well is situated at the edge of the USGS designated overpressured zone and is characterized by relatively high porosities. Note the bad hole flags in Track 1.

Core data for the Cloverly Frontier play consisted of a total of 710 samples. Routine core data was corrected to in-situ conditions and subdivided into three categories: Completed, Tested and Other samples. Figure 18 presents all Frontier core data combined. The porosity distribution is not bimodal as was observed for the Lewis and Mesaverde plays, rather, a wide relatively normal distribution was observed with porosities ranging between zero and 20% and averaging 9.7%. The correlation coefficient of the porosity permeability plot is poor, with a wide data scatter for all sample categories.

Reevaluation of Resource

The distribution of net pay within the OPT Frontier formation is restricted to the deeper parts of the basin (Figure 19). Of the measured gross rock volume, only 2% is above 10,000 feet, 28% is above 15,000, feet and 70% above 20,000 feet. With well log control being limited to 18,500 feet, almost 40% of the mapped rock volume lies below deepest analyzed penetration. For the purposes of resource computation, it was assumed that the rock properties in this deeper portion were similar to those of the deepest representative analyzed interval.

Examination of the distribution of log derived porosity within the play (Figure 20) shows a predominant skew towards the lower porosity units with corresponding high water saturations and calculated permeabilities below a microdarcy. Over half of the gross rock volume is below 17,000 feet. Despite low porosities and high calculated water saturations, this rock volume still represents a significant percentage of the total resource. The bulk of the calculated in place resource lies below 12,000 feet.

Examination of the distribution of EURs and variation of EUR with depth as well as porosity distributions indicates no particular trend with increasing depth (Figure 16). This pattern is poorly defined through lack of a significant number of producing wells within the deeper part of the section.

Economic basement calculations assume a 50% dry hole rate (the OPT area being less mature than the Moxa Arch which had 8% dry holes), and utilizes the existing OPT per well EUR distribution as the model of expectation for future discoveries. An EMV versus depth plot indicates *economic basement* at 7,100 feet, or above the top of the play. *Deepest commercial production* depth is estimated to be 12,500 feet.

The breakdown of resource and potential pay quality reservoirs is shown in Figure 21. Of the total resource of 279 Tcf, 33 Tcf or 12% occurs in low permeability rocks considered too tight to support commercial production. The remaining 246 Tcf, is below *economic basement* and the majority of this is below *deepest commercial production* and is based on minimal well control. A significant potential error could be associated with this volume.

Table 6 compares the USGS estimate for the Cloverly Frontier to the revised estimate derived herein and shows the breakdown:

TABLE 6
CLOVERLY FRONTIER RESOURCE ESTIMATE BREAKDOWN
(Tcf)

USGS Mean Resource Estimate	**304**
Scotia Revised Mean Resource Estimate	**279**
MINUS *Technologically Nonviable* Resources	**33**
SUBTOTAL *Technologically Viable Resources*	**246**
***MINUS Nondemonstrated* Resources**	**0**
SUBTOTAL *Demonstrated* Resources	**246**
Subdivision:	
***Speculative* Resources**	**223**
***Nonestablished* Resources**	**23**
***Established* Resources**	**0**

As evaluated, the bulk of the Cloverly Frontier play lies at great depth. Existing production is located at the shallow play edge and grades into conventional reservoirs laterally with decreasing depth. The majority of production is obtained from between 8,000 and 12,000 feet. The portion of the resource considered to represent a potentially economic target based upon current drilling costs, success ratios and anticipated reserves distribution, lies in the shallower areas. No reserves have been considered below 12,500 feet since no commercial production has been identified below that depth.

Reserves Evaluation

Table 7 summarizes the input parameters and results of the reserves calculations for the Cloverly Frontier play:

TABLE 7
RESERVES CALCULATION, CLOVERLY FRONTIER PLAY
Play Subdivision: *Nonestablished* Category

Parameters	Maximum	Most Likely	Minimum
Base Recovery Factor	0.75	0.75	0.75
Dry Hole Fraction	0.5	0.5	0.5
Minimum Economic Drainage Acres	16	71	195
Noncommercial Fraction	0.33	0.69	0.87
Recovery Factor	0.25	0.12	0.05
Rock Volume (M AcFt)		47,059	
Porosity	.160	.095	0.06
Water Saturation	.50	.62	.68
FVF (res cuft/scf)	.00335	.00383	.00450
Reserves Probability Distribution			
90% Probability of Exceeding (Tcf)		1.55	
70% Probability of Exceeding (Tcf)		2.22	
50% Probability of Exceeding (Tcf)		2.83	
30% Probability of Exceeding (Tcf)		3.58	
10% Probability of Exceeding (Tcf)		4.91	
Mean Value (Tcf)		3.07	
Proved Producing Reserves and Cumulative Production			
Cumulative Production (Bcf)		86	
Remaining PDP Reserves (Bcf)		58	
EUR of PDP Reserves (Bcf)		144	

The principal characteristic of the Cloverly Frontier play that is most notable is the fact that the bulk of the play rock volume lies at great depth. Based on extremely limited well control, porosities and water saturations are favorable, leading to a significant calculated in place gas resource. EURs are not outstanding. Recognition of this factor is probably the reason for lack of any deep drilling activity and the restriction of exploration to the shallower edge portions of the play. While no particular porosity versus depth relationship is evident, the Dakota formation is apparently characterized by conventional permeabilities. Deep Dakota exploration assisted in providing deep control in the Cloverly Frontier play and established the fact that producible reservoirs are present at depth.

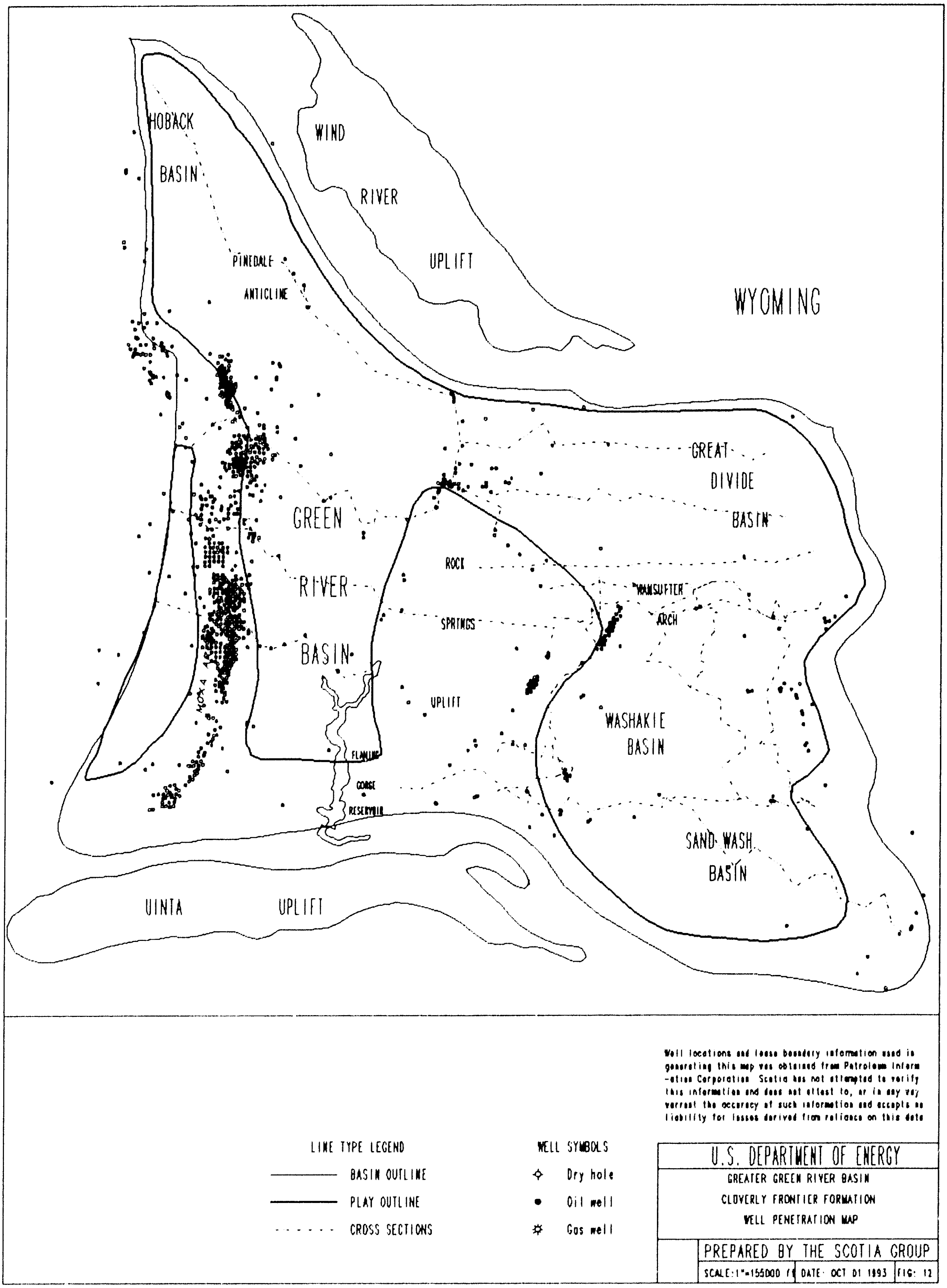
The low calculated drainage areas for most wells indicates the potential for infill drilling to down-space below the regulatory 320 acre spacing.

Since variation in reservoir properties will have a controlling factor on the ultimate productivity of Cloverly Frontier wells, and because of the inability to remotely measure such changes, the pace of development of this resource is likely to be sporadic.

In summary, reserves estimates for the Cloverly Frontier play are all in the *nonestablished* category, with a mean estimate of 3.1 Tcf overall, or 3.0 Tcf after subtraction of the EURs of existing Frontier OPT gas wells.

TABLE 8
CLOVERLY FRONTIER PLAY OPT FIELD LIST

Field Name	Avg Depth (Feet)	Cum MMcf	EUR MMcf	Number of Wells	Avg EUR MMcf/Well
Bird Canyon	11188	21736	30129	38	793
Blue Forest	11082	14	14	1	14
Browns Hill	7043	36	36	1	36
Buccaneer	17710	4	28	1	28
Cherokee Creek	7744	140	140	1	140
Deep Gulch	7953	1525	1525	2	763
Figure Four Canyon	8377	8611	12805	20	640
Four Mile Gulch	11131	717	2466	3	822
MacDonald Draw	8878	625	1000	2	500
Megas	16134	145	145	1	145
Mesa	10274	3997	15839	2	7920
Monument Butte	10790	4	4	2	2
Nitchie Gulch	8600	32141	50383	32	1574
Rim Rock	12277	455	977	1	977
Seven Mile Gulch	11422	448	505	1	505
Steamboat Mountain	11867	509	509	1	509
Swan	10764	13777	24709	7	3530
Table Rock	13956	44	62	1	62
Treasure	14001	611	611	2	306
Wilson Ranch	11612	770	2361	4	590
Totals		86309	144248	123	1173



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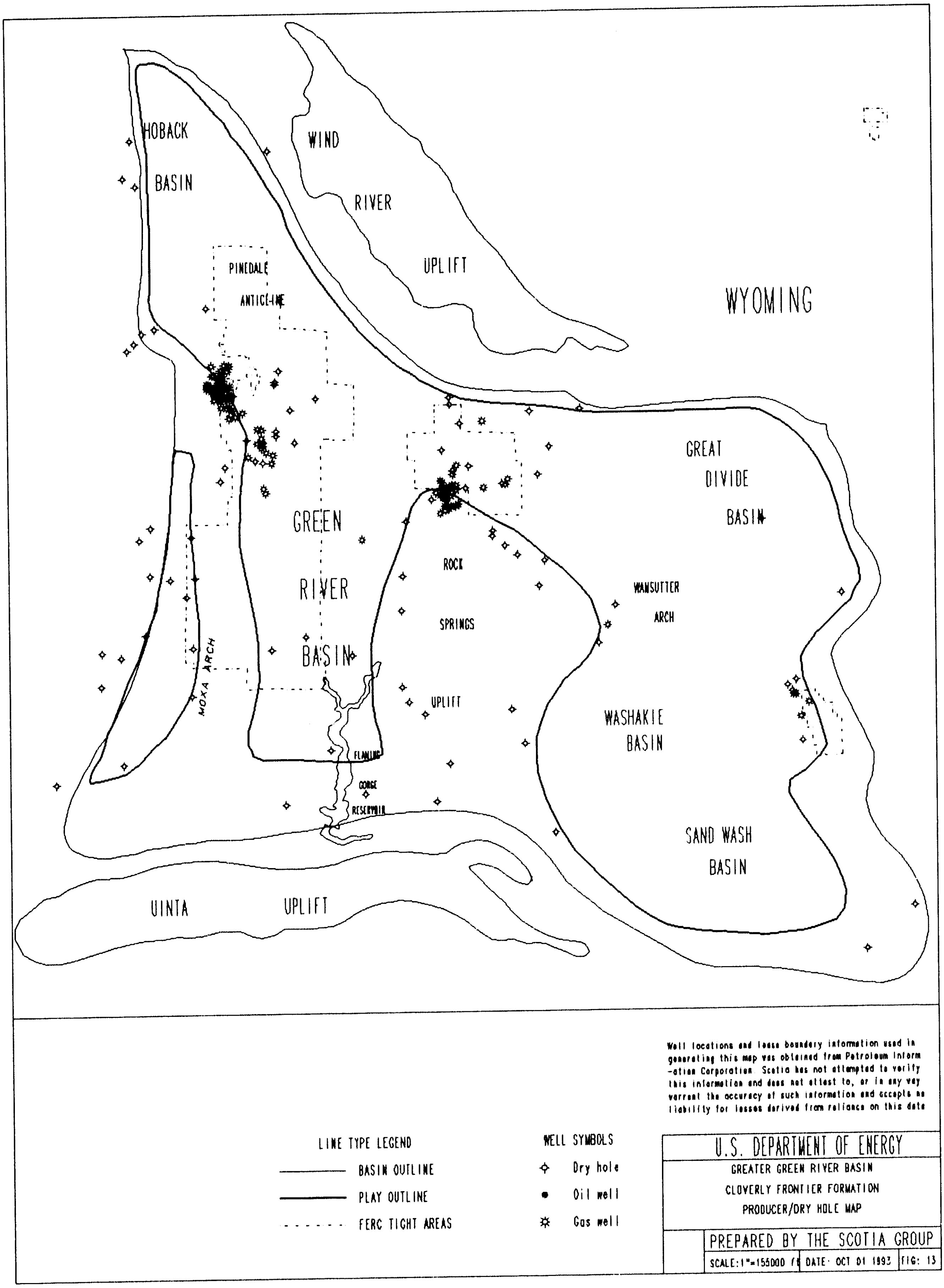
WAMSUTTER
ARCH
WASHAKIE
BASIN
SAND WASH
BASIN
MOXA ARCH
FLAMING
GORGE
RESERVOIR
UINTA
UPLIFT
Well locations and lease boundary information used in generating this map was obtained from Petroleum Information Corporation. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data
LINE TYPE LEGEND
BASIN OUTLINE
PLAY OUTLINE
CROSS SECTIONS
WELL SYMBOLS
Dry hole
Oil well
Gas well
U.S. DEPARTMENT OF ENERGY
GREATER GREEN RIVER BASIN
CLOVERLY FRONTIER FORMATION
WELL PENETRATION MAP
PREPARED BY THE SCOTIA GROUP
SCALE:1"=155000 ft
DATE: OCT 01 1993
FIG: 12



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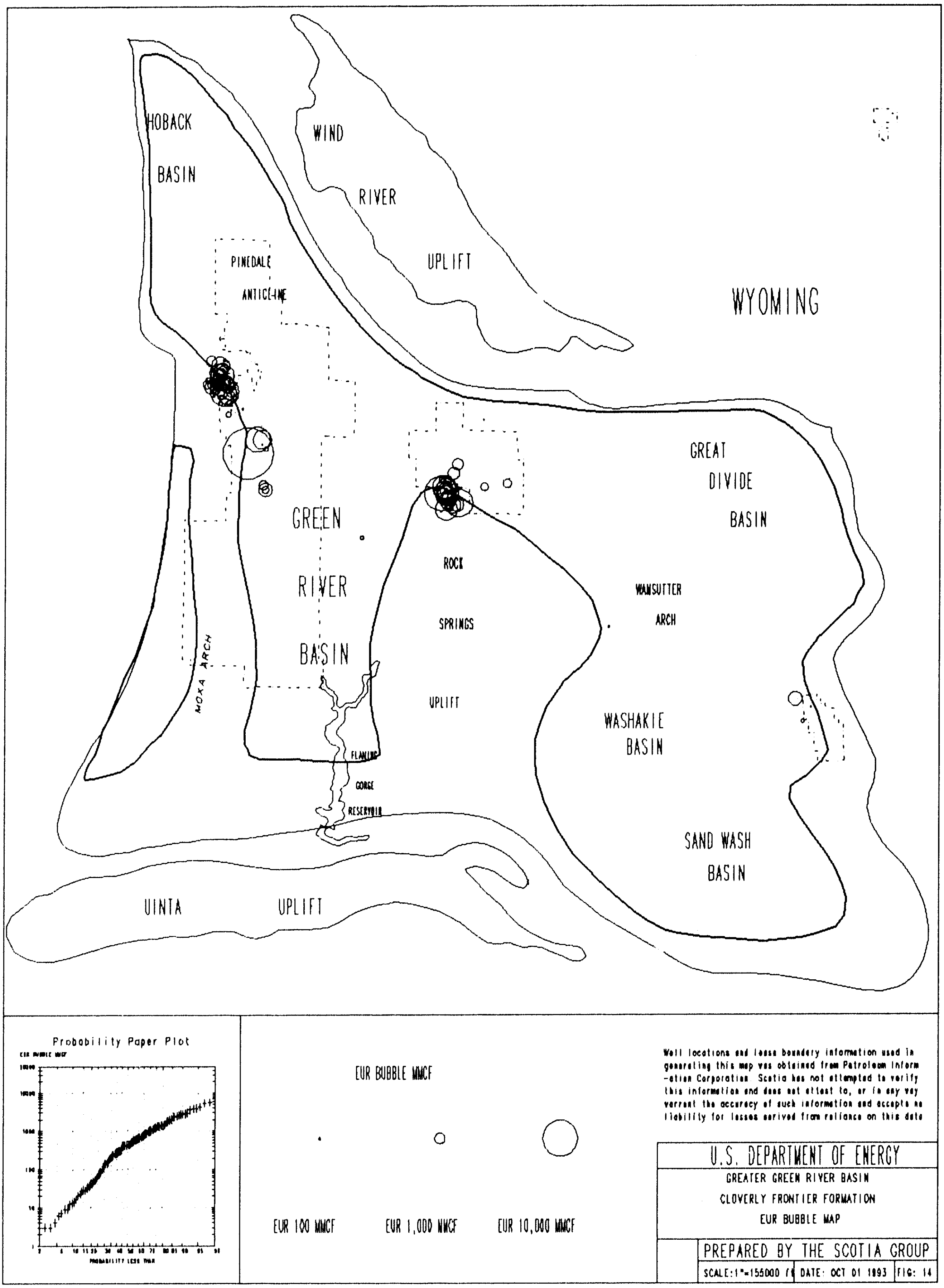
LINE TYPE LEGEND
BASIN OUTLINE
PLAY OUTLINE
FERC TIGHT AREAS
WELL SYMBOLS
Dry hole
Oil well
Gas well
U.S. DEPARTMENT OF ENERGY
GREATER GREEN RIVER BASIN
CLOVERLY FRONTIER FORMATION
PRODUCER/DRY HOLE MAP
PREPARED BY THE SCOTIA GROUP
SCALE:1"=155000 ft
DATE: OCT 01 1993
FIG: 13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Probability Paper Plot
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EUR 100 MMCF
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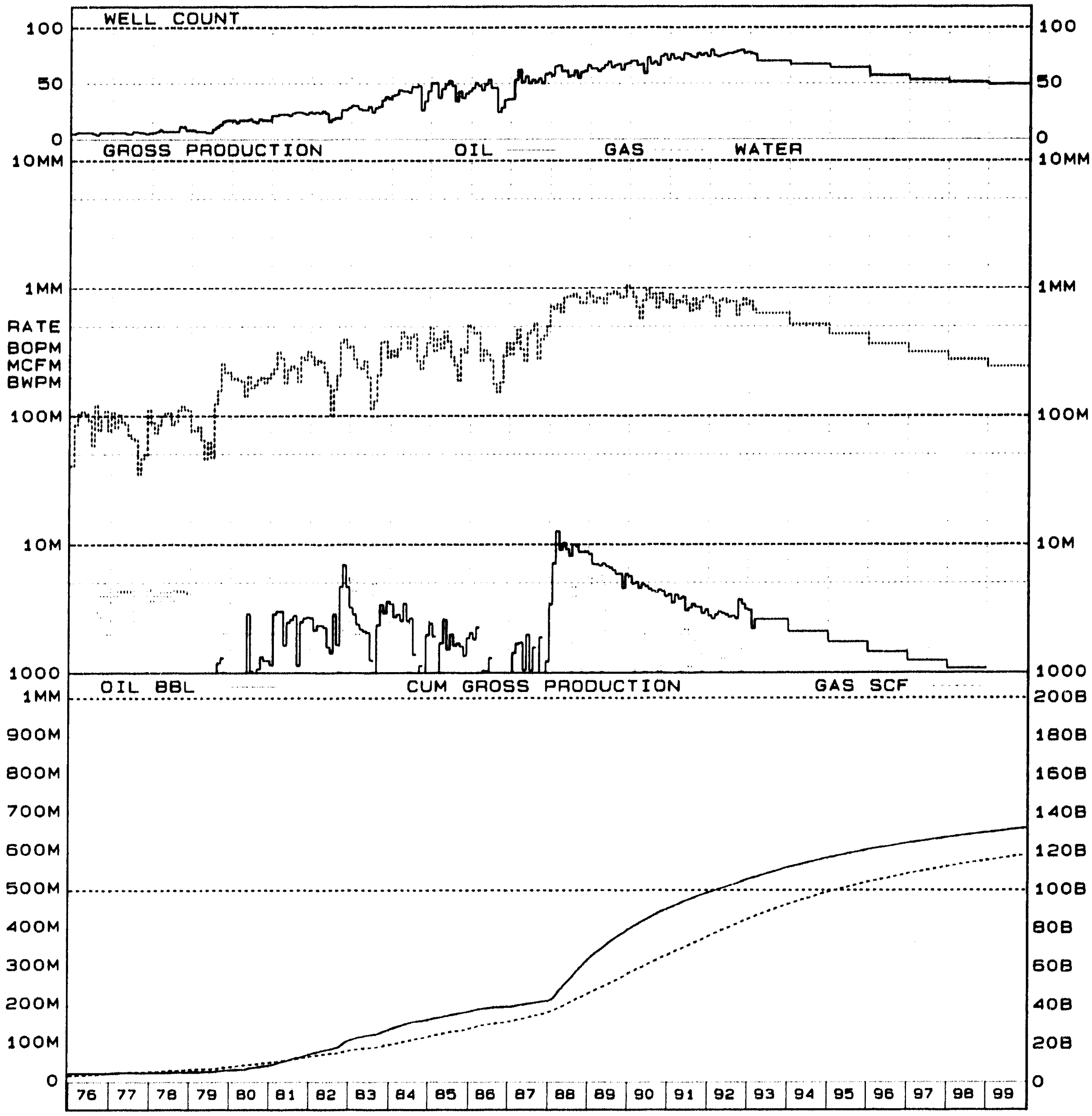
Well locations and lease boundary information used in generating this map was obtained from Petroleum Information Corporation. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data
U.S. DEPARTMENT OF ENERGY
GREATER GREEN RIVER BASIN
CLOVERLY FRONTIER FORMATION
EUR BUBBLE MAP
PREPARED BY THE SCOTIA GROUP
SCALE:1"=155000
DATE: OCT 01 1993
FIG: 14

FIGURE 15



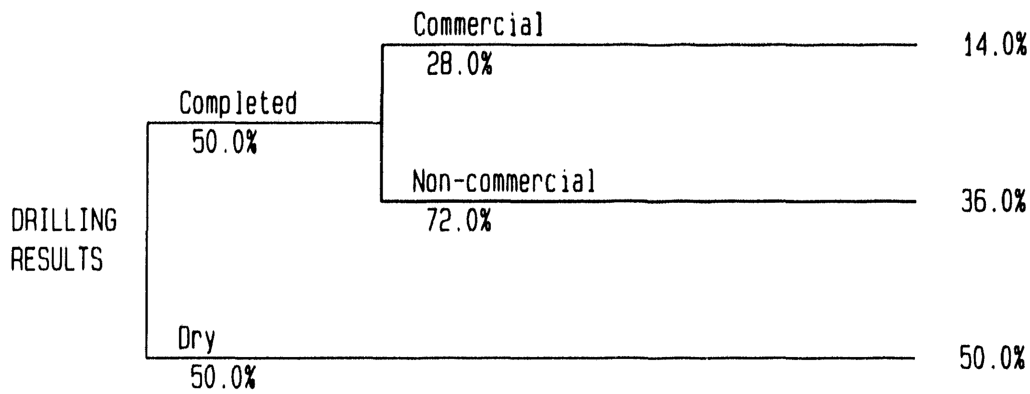
FRONTIER TOTAL PRODUCTION PROFILE
Projections are averages for each year commencing at the effective date of the evaluation. Results are subject to the qualifications and limitations stated in the attached document

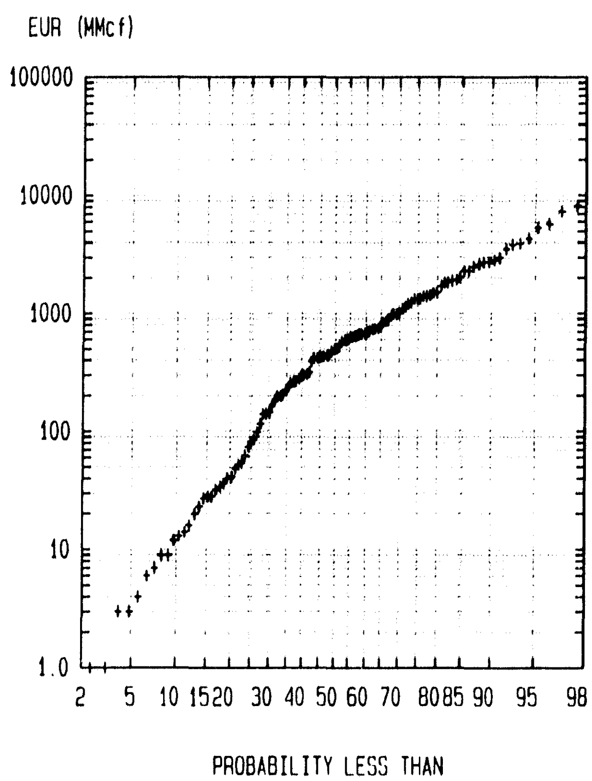
PREPARED BY THE SCOTIA GROUP, INC. *S.S.L. FRI OCT 01 1993 16:19:19*

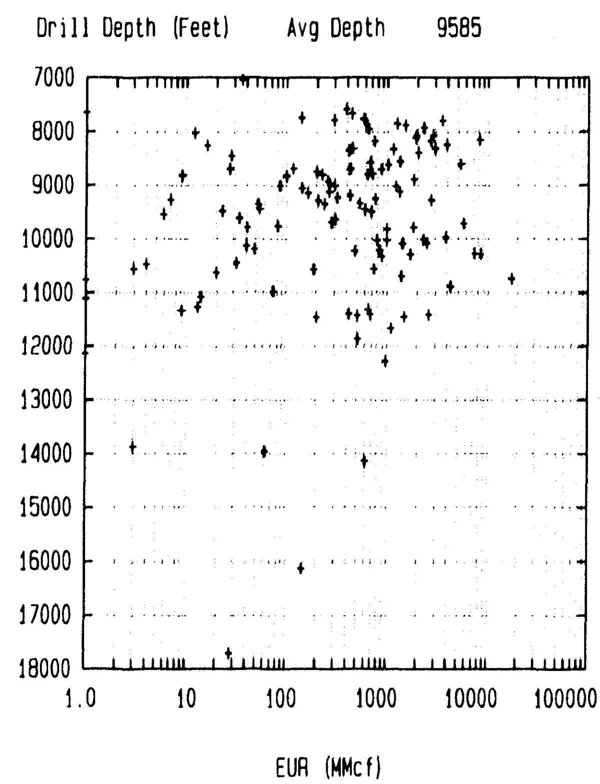
Scotia Group Resource Model	Distribution of EURs and Risk Model	Client: U.S. DEPARTMENT OF ENERGY	Figure 16

CLOVERLY FRONTIER PLAY

Technical Success 50.0%
Commercial Success 14.0%







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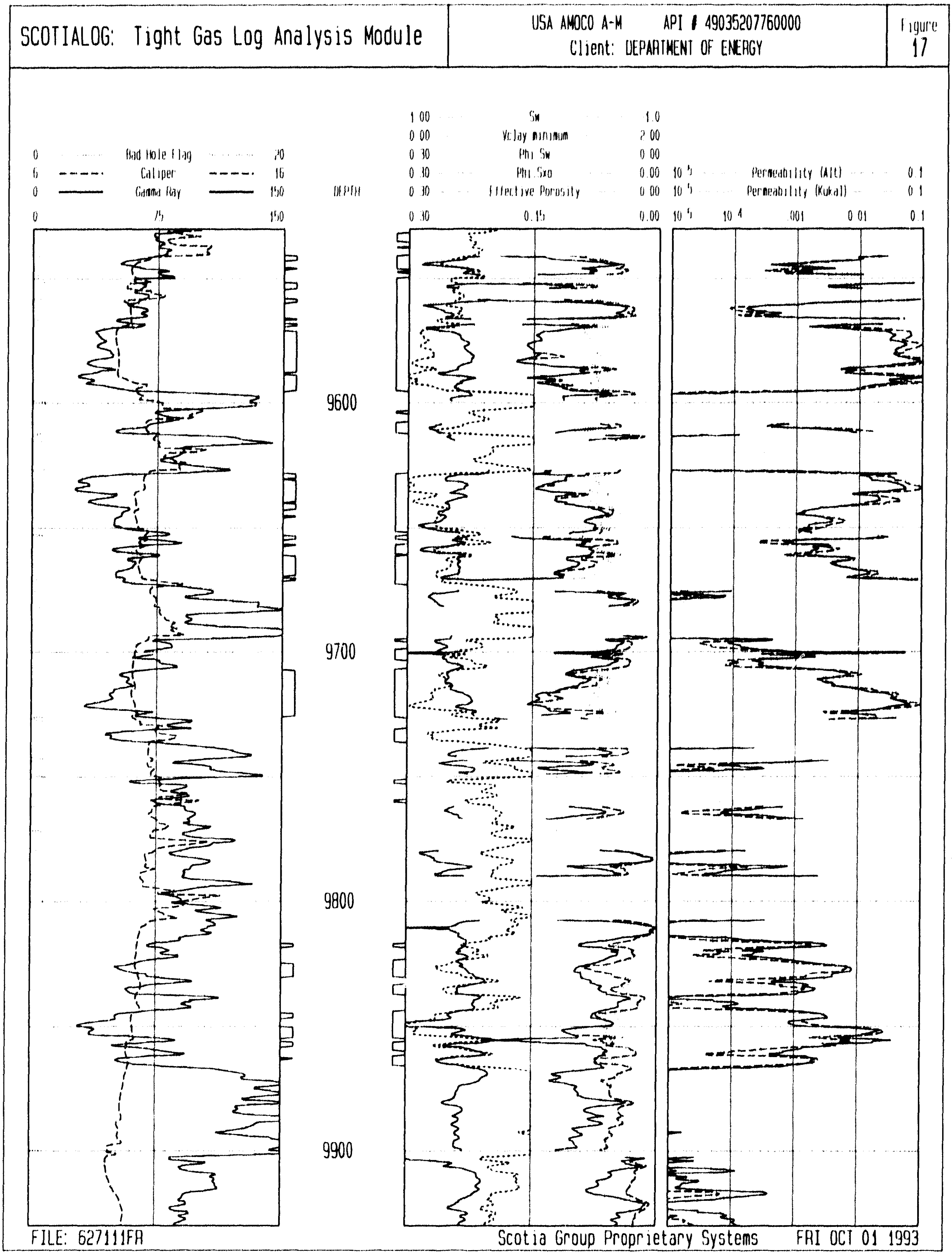

SCOTIALOG: Tight Gas Log Analysis Module
USA AMOCO A-M API # 49035207760000
Client: DEPARTMENT OF ENERGY
Figure 17
0 Bad Hole Flag 20
6 Caliper 16
0 Gamma Ray 150
0 75 150
DEPTH
1.00 Sw 1.0
0.00 Vclay minimum 2.00
0.30 Phi Sw 0.00
0.30 Phi Sxo 0.00
0.30 Effective Porosity 0.00
0.30 0.15 0.00
10^{-5} Permeability (Alt) 0.1
10^{-5} Permeability (Kukal) 0.1
10^{-5} 10^{-4} .001 0.01 0.1
9600
9700
9800
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FILE: 627111FA
Scotia Group Proprietary Systems
FRI OCT 01 1993

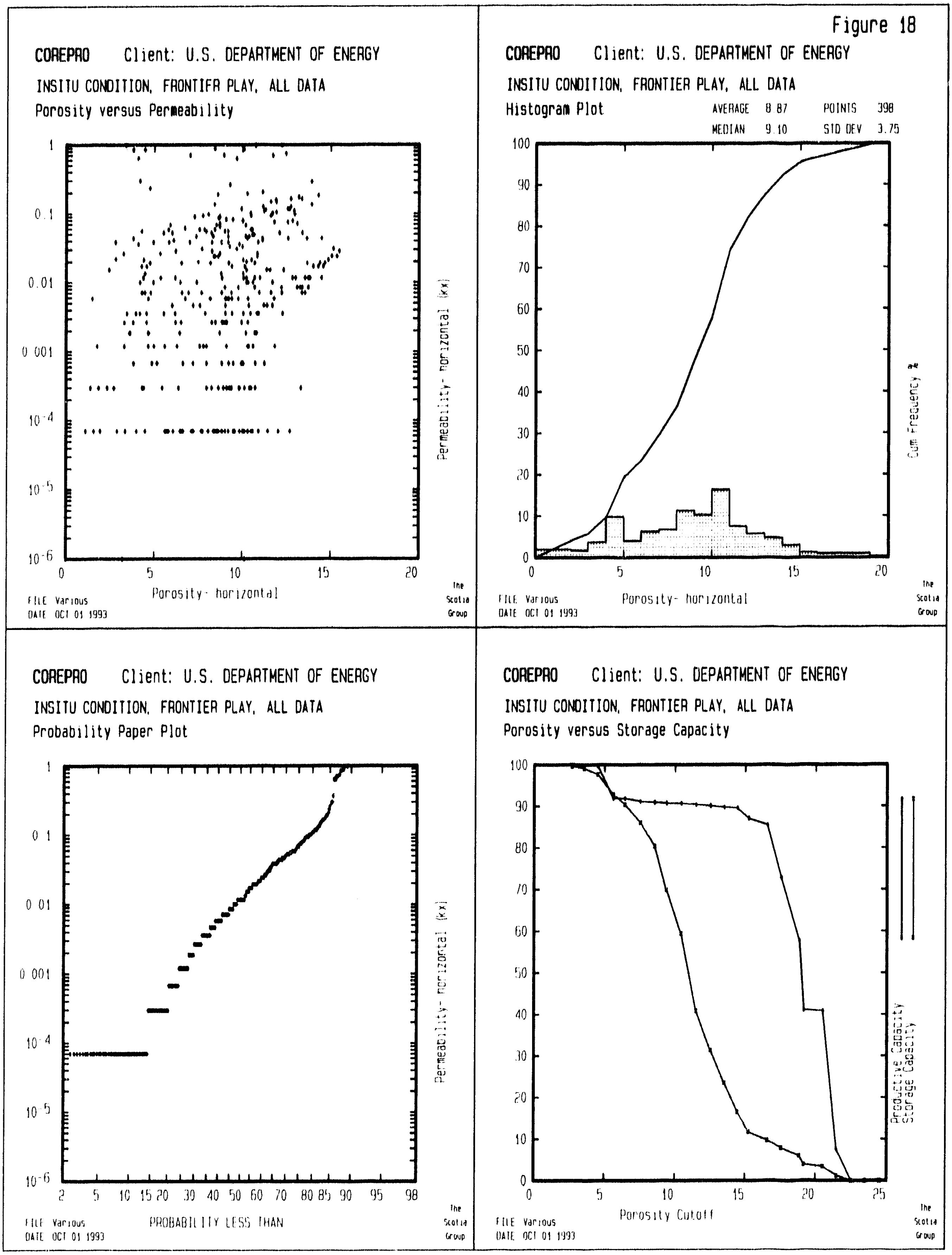
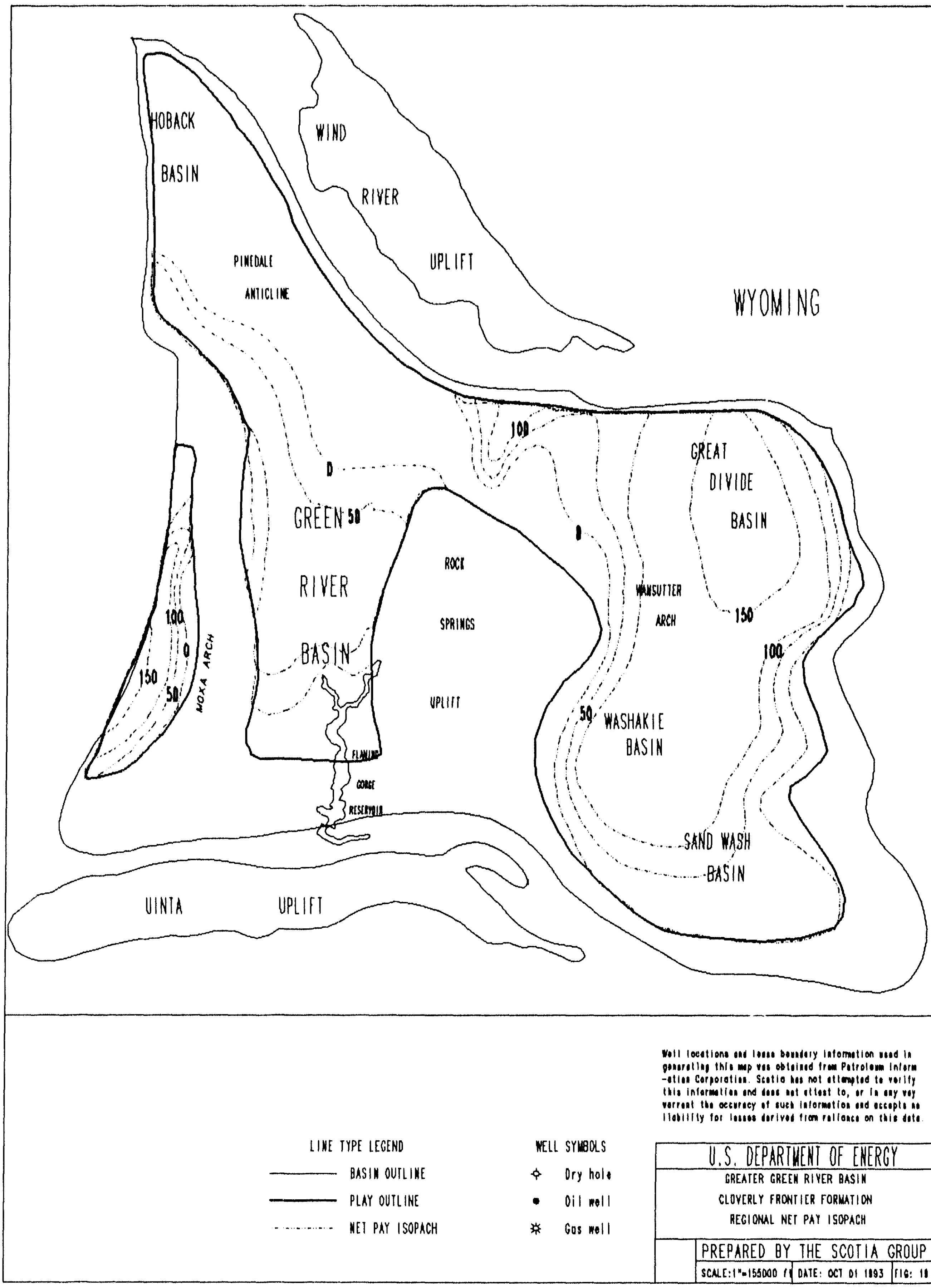


Figure 18
COREPRO Client: U.S. DEPARTMENT OF ENERGY
INSITU CONDITION, FRONTIFR PLAY, ALL DATA
Porosity versus Permeability
Permeability- horizontal (kx)
Porosity- horizontal
FILE Various
DATE OCT 01 1993
The Scotia Group
COREPRO Client: U.S. DEPARTMENT OF ENERGY
INSITU CONDITION, FRONTIER PLAY, ALL DATA
Histogram Plot
AVERAGE 8.87
MEDIAN 9.10
POINTS 398
STD DEV 3.75
Cum Frequency %
Porosity- horizontal
FILE Various
DATE OCT 01 1993
The Scotia Group
COREPRO Client: U.S. DEPARTMENT OF ENERGY
INSITU CONDITION, FRONTIER PLAY, ALL DATA
Probability Paper Plot
Permeability- horizontal (kx)
PROBABILITY LESS THAN
FILE Various
DATE OCT 01 1993
The Scotia Group
COREPRO Client: U.S. DEPARTMENT OF ENERGY
INSITU CONDITION, FRONTIER PLAY, ALL DATA
Porosity versus Storage Capacity
Productive Capacity
Storage Capacity
Porosity Cutoff
FILE Various
DATE OCT 01 1993
The Scotia Group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WASHAKIE
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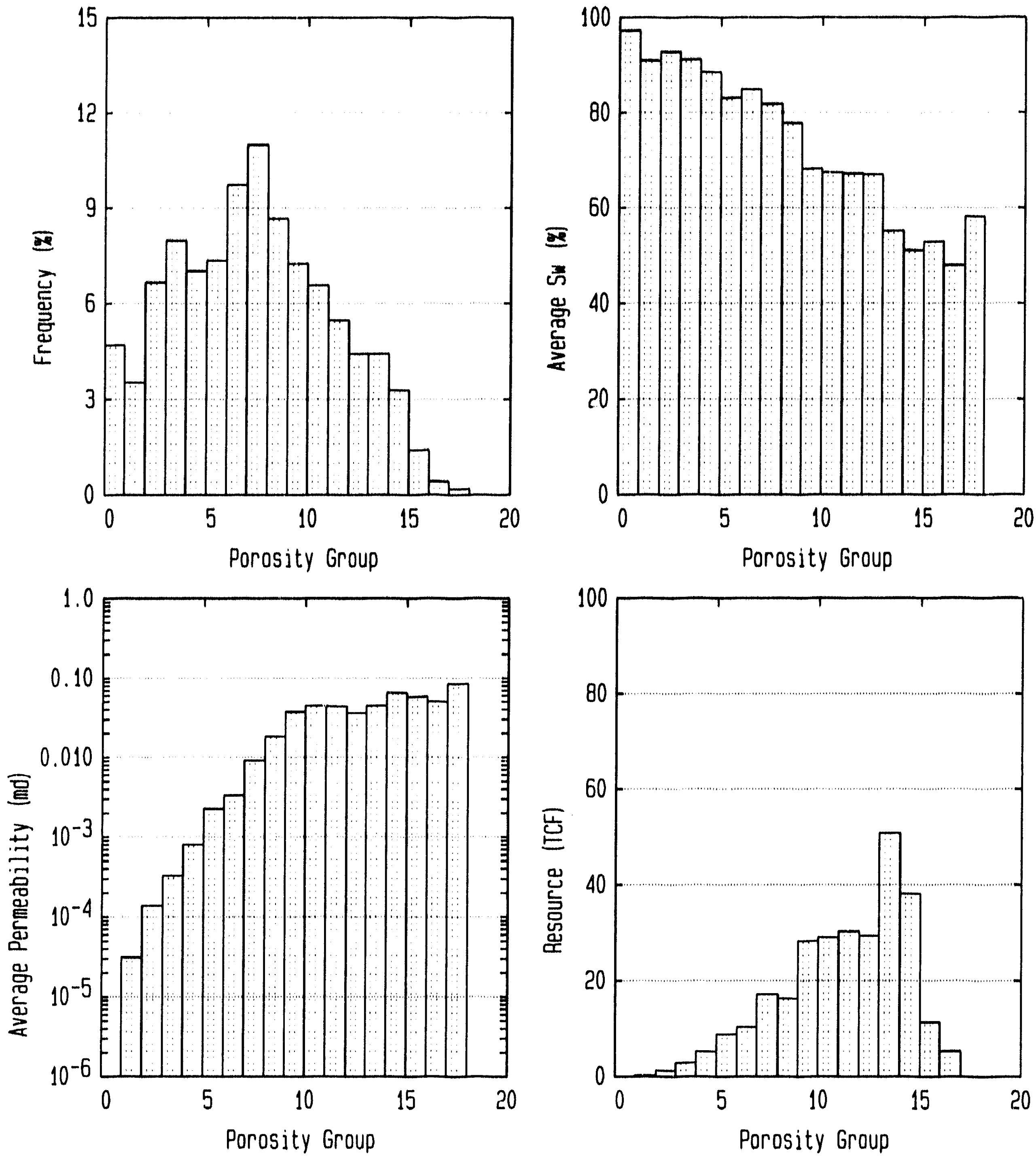
Well locations and lease boundary information used in generating this map was obtained from Petroleum Information Corporation. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.
LINE TYPE LEGEND
BASIN OUTLINE
PLAY OUTLINE
NET PAY ISOPACH
WELL SYMBOLS
Dry hole
Oil well
Gas well
U.S. DEPARTMENT OF ENERGY
GREATER GREEN RIVER BASIN
CLOVERLY FRONTIER FORMATION
REGIONAL NET PAY ISOPACH
PREPARED BY THE SCOTIA GROUP
SCALE:1"=155000 ft
DATE: OCT 01 1993
FIG: 18

Scotia Group Resource Model	Rock Property and In-Place Resource Distributions	Client: U.S. DEPARTMENT OF ENERGY	Figure 20

Greater Green River Basin: Rock Property Distributions

CLOVERLY FRONTIER PLAY



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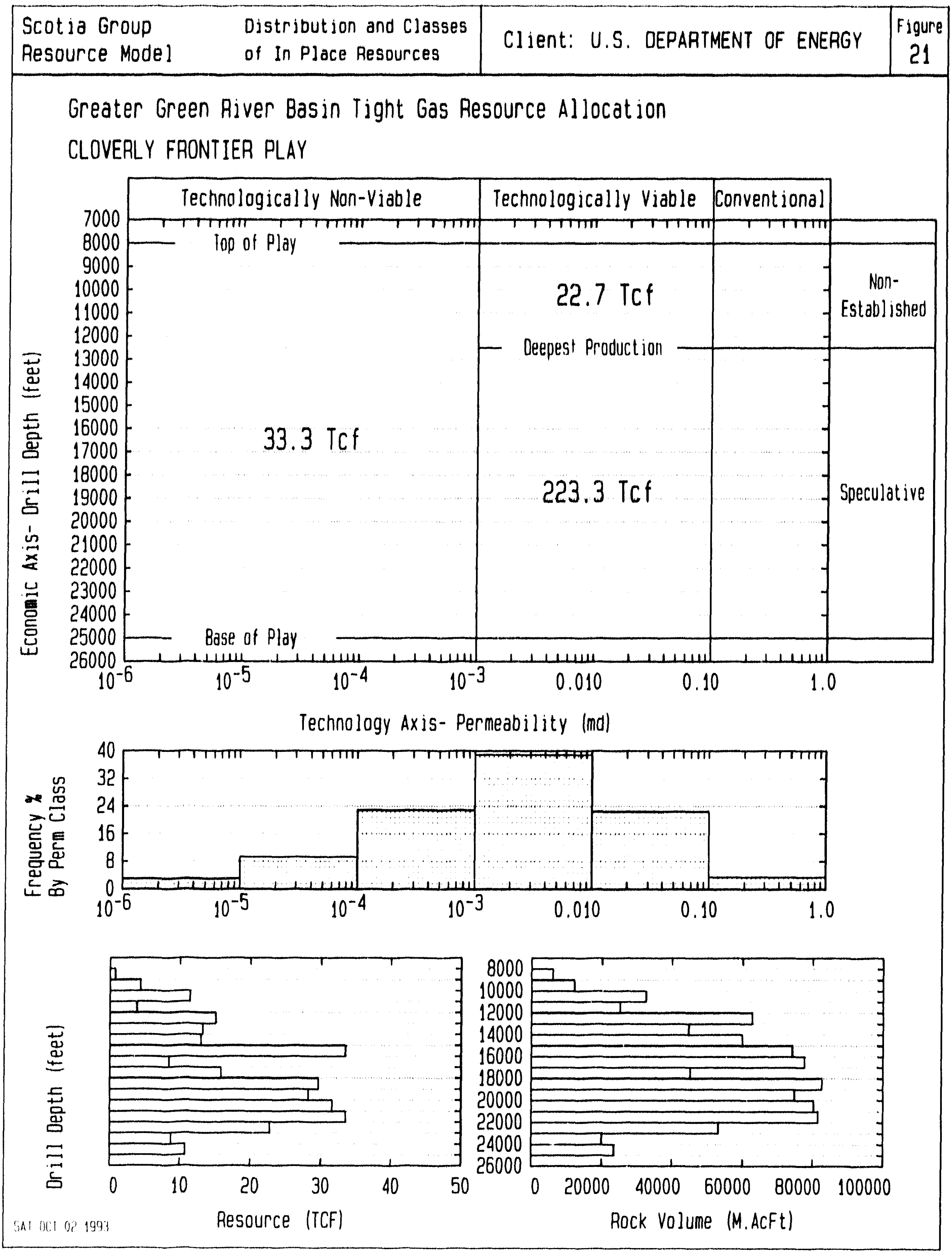


Scotia Group
Resource Model
Distribution and Classes
of In Place Resources
Client: U.S. DEPARTMENT OF ENERGY
Figure
21
Greater Green River Basin Tight Gas Resource Allocation
CLOVERLY FRONTIER PLAY
Technologically Non-Viable
Technologically Viable
Conventional
Top of Play
Base of Play
Deepest Production
22.7 Tcf
33.3 Tcf
223.3 Tcf
Non-
Established
Speculative
Economic Axis- Drill Depth (feet)
Technology Axis- Permeability (md)
Frequency %
By Perm Class
Drill Depth (feet)
Resource (TCF)
Rock Volume (M.AcFt)
SAT OCT 02 1993

MESAVERDE PLAY

Description

The Mesaverde play represents the thickest and most prolific OPT play in the GGRB. In terms of nomenclature, the Mesaverde group includes various formations; the Ericson, Almond, Rock Springs, Blair and the Mesaverde undifferentiated being the principal units. The base of the Mesaverde group is marked by a major shale unit that has various nomenclature and stratigraphic relationships with the reservoir units. In western and central parts of the basin this is termed the Hilliard or Baxter shale, while in the eastern areas the Steele shale or Mancos shale. The upper limit of the Mesaverde group is marked by the Lewis shale in central and eastern parts of the basin and the Lance formation in western areas.

The OPT area as defined by the USGS for the Mesaverde play occupies the eastern portion of the GGRB including the Sand Wash, Washakie, Wamsutter Arch and Great Divide basin areas. The play extends across the northern nose of the Rock Springs anticline and up into the Pinedale anticline and Hoback basin area. The Moxa Arch and LaBarge platform as well as the Rock Springs uplift are excluded in that while the Mesaverde group is present across much of this area, it exists at depths shallower than the top overpressure for the most part.

Total play area encompasses approximately 8,125 square miles with gross sandstone thicknesses generally between 750 and 2,000 feet. Well control in the eastern portion of the play is generally good, this area being the location of all Mesaverde production (Figures 22 and 23). Within the western portions of the play from the northern nose of the Rock Springs anticline through the Hoback basin, control is limited to isolated well penetrations. Production from the Mesaverde is restricted to the Great Divide and Washakie basins and the Wamsutter Arch. These areas are all included within the FERC designated tight gas production area for the Mesaverde group. It should be noted that the Mesaverde production within the tight gas designated area includes both overpressured and normally pressured reservoirs within the Mesaverde group. For the purposes of this evaluation, the reservoirs considered to be normally pressured have been excluded from the analysis.

The Almond and Ericson sandstones are the principal producing zones with the main producing area being the Wamsutter Arch (Figure 24). Due to the significant thickness of the total Mesaverde section, its diversity and variations in productive characteristics, the play has been broken down into segments for the purpose of analysis. This breakdown is both stratigraphic and areal, and attempts to group areas that share common aspects in terms of depositional environment and reservoir performance.

Table 11 summarizes the Mesaverde play OPT producing fields. Subdivision of the production and allocation to specific sub units in the Mesaverde is not a simple task since a significant number of wells are simply designated as Mesaverde. On detailed inspection, the majority of such "undesignated" wells are considered to represent the Almond. An additional complicating factor is commingled Almond-Ericson production. The Ericson production dataset includes some commingled Almond production and since the Almond is generally the superior zone, the distribution of EURs for the Ericson may err on the optimistic side.

A total of 444 OPT Mesaverde wells have been identified in 54 fields. The field count is based on reported designation and does not necessarily represent discrete, bounded reservoirs. These fields consolidate with additional development. Average Mesaverde EURs are 2.8 Bcf/well with a significant component of superior gas producers. Several of the best Mesaverde wells have already produced over 15 Bcf and have projected EURs over 25 Bcf based on an established, steady decline curve.

Figure 25, a composite production profile for the Mesaverde play, shows about 300 wells currently producing at an average rate of 440 Mcfd/well.

Drilling statistics for the Mesaverde play are dominated by activity in the eastern portions of the GGRB. The risk model for the Mesaverde play indicates that 85% of wells drilled targeting the Mesaverde are completed with 15% being dry holes. A 20% dry hole factor was used to develop the Mesaverde risk model.

Extrapolation of this risk model to areas of lesser control in the north-central and western portions of the play is not justified. Drilling results in this area have been disappointing. Although reservoir quality rocks are identified via log interpretation including porous sections with gas response on neutron-density logs, DST results have not been encouraging and are indicative of lack of lateral reservoir continuity. This is related to the transition to marginal marine, nonmarine and alluvial sedimentary environments in this area. As such, the base resource is subdivided into the eastern area versus the central and western areas based on control and productive characteristics.

Stratigraphy and Rock Properties

Petrophysical properties can vary significantly with changes in depositional environment (Lohrenz et al 1989, Spencer 1983) and consequently it was necessary to attempt to relate reservoir performance (EURs) not only to the mapped pay thicknesses and rock properties, but also to the various environments of deposition defined for the OPT formations of the GGRB.

Spencer (1983) identified four tight gas reservoir types, two of which, marginal-marine blanket and lenticular, apply to the study area. Marginal-marine blanket reservoirs have reasonable lateral continuity compared to lenticular reservoirs and should be expected to have greater drainage potential. They respond more predictably to hydraulic fracturing. Examples are the upper Almond and Frontier formations. Lenticular reservoirs are predominantly fluvial, discontinuous and exhibit significant permeability anistropy. Response to hydraulic fracturing is erratic because of the lack of sand continuity. Examples are the fluvial sandstones of the Mesaverde group. Both reservoir types exhibit the same "Variety 2" poor porosity permeability relationship (Spencer 1983) owing to the small pore and pore throat sizes, and significant post-depositional dissolution creating secondary porosity.

Lohrenz et al (1989) studied the petrophysical properties of MWX core and identified four different depositional environments in the Mesaverde group: marine, paludal, coastal and fluvial. Petrophysically, sorting and roundness is highest in marine core samples with destruction of less stable grains by high energy wave action. Maximum petrologic heterogeneity was found in the fluvial samples with only moderate sorting. Porosities and permeabilities are highest in the paludal zone, though irregularly distributed. For a given permeability, paludal samples have higher porosities than fluvial samples. The highest degree of variability in permeability was observed in fluvial core samples and is more sensitive to changes in stress than permeabilities of the other zones. Overall, the marine and coal bearing paludal intervals exhibit different characteristics from the other zones due to a higher degree of winnowing and sorting, and also because of differences in the local geochemical environment and diagenesis due to the presence of coals.

For the purpose of this study, the Mesaverde group has been subdivided into five formations which, from youngest to oldest, are listed below (along with lateral equivalents):

Almond formation (+ upper Williams Fork formation)
Ericson formation (+ Allen Ridge and Iles formation)
Rock Springs formation (Steele and Mancos shales)
Blair formation (Steele and Mancos shales)
Undifferentiated

The undifferentiated category includes stratigraphic section identified as belonging to the Mesaverde group but which has not been attributed to a specific formation within the Mesaverde. The stratigraphy of the formations are summarized below. Much of this information has been drawn from Roehler (1990).

The Mesaverde sediments are Late Cretaceous Campanian to Maestrichtian in age. The Mesaverde group constitutes a landward to seaward progression (west to east) of alluvial plain, flood plain, coastal plain, barrier plain, tidal flat, delta plain, marine shorelines, and marine shelves and slopes. Most sediments were sourced from the Sevier orogenic belt which extended along the west side of the present North American continent, and were transported eastward by river systems into a large interior Cretaceous seaway, which also extended the length of the North American continent and which the GGRB was a part. Sediment distribution is complicated by a series of marine transgressions, regressions and stillstands of varying intensity. Shorelines generally trended northeast and migrated extensively across the Great Divide, Washakie and Sand Wash basins. Sediments of the GGRB to the west are predominantly continental delta plain, barrier plain, tidal flat, coastal plain, and alluvial in origin. Sediments of the southern Sand Wash basin are predominantly deep water marine shales. Those basins in between contain complexly inter-tonguing sediments from the eight depositional environments recognized by Roehler (1990).

Blair Formation

The Campanian Blair formation is marine in origin, represented by submarine fan deposits at its base (basal Blair sandstone), pro-delta and shelf sediments above. It is restricted to a relatively narrow depositional band 12-30 miles wide striking northeast from immediately northwest of the Wyoming-Utah-Colorado boundary. To the west, the Blair formation is replaced by the laterally equivalent lower Rock Springs formation deposited on coastal plains, arcuate deltas, and marine shorelines, while to the east the formation grades into the deeper water marine Cody, Steele and Mancos shales. Blair sand thicknesses, where differentiated on the USGS cross-sections, range from less than 100 feet to more than 400 feet.

Sand thickness mapping control for the Blair formation is limited to the northern part of the Rock Springs uplift (Figure 26). Only one well evaluated during this study penetrated the differentiated Blair section, and encountered no pay section. Rather than eliminate the Blair based on this one well, the average ratio of net pay to sand thickness derived from the undifferentiated Mesaverde section was applied to the Blair sand thickness distribution map to derive a net pay map. However, production identified from the Blair comprised only two wells, both of which produced small, noncommercial volumes of gas. Since commercial production has not been established, no reserves are assigned to the Blair formation.

Rock Springs Formation

The Rock Springs formation ranges in age from early to Middle Campanian. At its lower part, the Rock Springs inter-tongues with and is replaced laterally by the marine Blair formation to the east. Higher in the section the formation is replaced by the deeper water Steele and Mancos shales. The lower Rock Springs is represented by coastal plain, delta and shoreline marine sandstones. Thick persistent shoreline and shelf sandstones and marine shales covering the full Rock Springs section make up (from oldest to youngest) the Chimney Rock, Black Butte, Brooks, Coulson, McCourt, and Gottsche tongues deposited during a series of stillstands, regression and transgressions. The laterally extensive Chimney Rock tongue initially trended approximately northeast 45°, though it became arcuate during the delta build-out at its northeast and southwestern extremities. Development of these deltas persisted, becoming lobate and, in the case of the delta to the northeast, extended more than 60 miles southeast across the Rawlins platform, a marine shelf located across the east part of the present day Wamsutter Arch. Across this platform was deposited the Haystack Mountains formation and associated Hatfield sandstone member, eastward lying lateral equivalents of the upper part of the Rock Springs formation. The Black Butte tongue extended into the Black Butte embayment in response to progradation into the southwest Washakie basin. The Rawlins delta migrated toward the southwest across and to the south of the present day Wamsutter Arch during upper Rock Springs time, and filled much of the Washakie and northern Sand Wash basins.

The Rock Springs net pay, Figure 27, ranges in thickness from zero feet at the northern part of the Rock Springs uplift, to over 100 feet across the Wamsutter Arch. The pay thins in a southerly direction across the Washakie basin and is interpreted to disappear in the Sand Wash basin where the Rock Springs is replaced by the laterally equivalent Mancos Shale. Thinning of the pay is also interpreted in the eastern Great Divide basin where the laterally equivalent Cody shale replaces the Lower Rock Springs. Two tongues of pay thickening may be associated with the progradation of the Rawlins delta across the Rawlins platform and later westerly migration toward the center of the Washakie basin. The ratio of pay to total sand thickness does not exceed 30% across the GGRB and diminishes to zero across the northern Rock Springs uplift, even though sand thickness exceeds 1,000 feet.

Examination of historical production data yielded only two Rock Springs wells, both of which produced small, noncommercial volumes. Since commercial production has not been established from the Rock Springs in the OPT area, no reserves have been assigned.

Ericson Formation

The Ericson is represented by three main units from oldest to youngest: Trail member, Rusty zone and Canyon Creek member. The Trail member extends over the Green River basin, Rock Springs uplift and western parts of the Great Divide and Washakie basins and attains a maximum thickness of 600 feet. It is represented by alluvial plain sediments deposited in response to the uplift and denudation of the Moxa Arch to the west at the end of Rock Springs deposition. The Trail member grades laterally into flood plain, delta plain and marine shoreline deposits of the Allen Ridge formation in the east Washakie basin and west Sand Wash basin, and the Iles formation in east Sand Wash basin. Following deposition of the Trail member and peneplanation of the Moxa Arch, sediments from the Sevier orogenic belt were laid down over much of the study area as flood plain deposits representing both the Rusty zone and Allen Ridge formation to the east. These deposits extended across the Green River, Great Divide and Washakie basins, while delta plain and early marine shoreline deposits were limited to the Sand Wash and far east Great Divide basins. The Rusty zone is separated from the overlying Canyon Creek member and Pine Ridge sandstone by the Moxa erosion surface over most of the GGRB. Both these members are represented by alluvial plain deposits which grade laterally into the marine Williams Fork formation in the southern Sand Wash basin.

The Ericson net pay, Figure 28, ranges in thickness from zero feet in the north part of the Great Divide basin (Allen Ridge/Pine Ridge equivalents) and west of the Rock Springs uplift, to over 400 feet across the Wamsutter Arch and in the Washakie basin. The net pay distribution reflects that of the Ericson sand isolith map derived from the USGS sandstone reservoir isopach of the Mesaverde, though the ratio of pay to total sand never exceeds 50% and in the north diminishes to zero. The pay thins toward the south end of the Washakie basin, but thickens again in the Sand Wash basin, probably as a result of a higher incidence of marine sands from the Tow Creek, Trout Creek and Twenty Mile sandstone members. Rock properties for the Ericson appear as Figure 29.

Historical production data indicates that commercial production has been established from the Ericson sandstone, although no large scale developments are present. Due to its thickness, the Ericson has an extremely large in place gas resource.

Almond Formation

The Late Campanian-Early Maestrichtian Almond formation is represented from oldest to youngest by fresh water coastal plain deposits, brackish-water barrier-plain deposits, and marine shoreline (mostly barrier island) deposits. These deposits inter-tongue and grade laterally into the Lewis shale deposited in the Hallville embayment to the south and east. The Lewis shale represents a marine transgressive phase which at the start of Almond deposition was generally limited to the east Washakie and Sand Wash basins, but which progressed northward covering the Rawlins platform. By the end of the Almond deposition, sedimentation had reached as far as the Rock Springs uplift. Throughout most of the Almond coastal plain, deposition the laterally equivalent Williams Fork delta plain deposits were accumulating during a stillstand along the southwest margin of the Sand Wash and Washakie basins.

The Almond net pay (Figure 30) varies in thickness from less than 20 feet in the northern Great Divide basin and flanks of the Washakie and Sand Wash basins, to approximately 140 feet between the present day Wamsutter Arch and Washakie basin center. The location of maximum thickening is immediately south of the most distal extent of Roehler's (1990) average strandline position for the early Almond (Baculites eliasi). Thickening is thought to correspond to the location of maximum stacking of higher energy marine shoreline tongues. Thinning to the south and southeast reflects the decreasing frequency of lateral extension of these tongues during local regressive/transgressive events. Maximum pay development should then correspond with the more continuous marine "blanket" type reservoirs of Spencer, though stratigraphic work by Roehler (1990) indicates that sediments consist of coastal plain and barrier plain as well as marine shoreline deposits. North of the distal position of the average strandline, the net pay thins and is expected to be represented by mostly lower energy coastal and barrier plain deposits and therefore of lower reservoir quality. Figure 31 illustrates the rock property distributions for the Almond.

A review of the Mesaverde EUR bubble map (Figure 24) reveals apparent north-south trends of producing wells with a NNE-SSW band of high EUR wells located across the east flank of the Wamsutter Arch (T14-20, R 92-94). This band of wells lies to the east of the maximum mapped net pay thickness. A second band of lower EUR wells is centrally located across the Wamsutter Arch and crosses the area of maximum mapped net pay thickness and extends to the north where pay thins to less than 40 feet.

Almond producers are sparse in the west part of the area of maximum net pay thickness and this may represent a region of future development potential. It is speculated, however, that natural fracturing associated with the development of the Wamsutter Arch may not be as prevalent across this west area.

Figure 32 is an example of a CPI log for the Mesaverde play. The top of the Almond and Ericson formations are at 10,584 feet and 10,918 feet respectively. Well Siberia Ridge Unit #5 (S3 T21N R94W) located on the Wamsutter Arch, was completed in the Almond between 10,586-10,606 feet with an IP following stimulation of 990 Mcfd and 1 Bcpd. The well reached total depth at 12,580 feet, but was plugged back to 10,770 feet. No record of the Ericson tests were found. The well was cored extensively in the Almond and Ericson between 10,580-11,698 feet with a recovery of 1,087 feet.

The majority of sand thickness (right side pay flag) and net pay thickness (left side pay flag) were identified in the Ericson formation. A total of 861 feet of sand thickness was estimated (148 feet Almond, 713 feet Ericson) within the Mesaverde gross of 1,908 feet. Of this, 382 feet (64 feet Almond, 318 feet Ericson) is considered as net pay. Note the bad hole flag in Track 1.

Figure 33 presents a comparison of log and core derived porosities and permeabilities. The match is considered to be very good. Core porosities and permeabilities were corrected to in-situ conditions. The high core permeability spikes at 12,858 and 12,861 feet are probably the result of fractures in the core plugs.

A total of 4,946 samples of Mesaverde core data were corrected to in-situ conditions and subdivided into three categories: Completed, Tested and Other samples (Figure 34a and 34b). Note how the porosity histograms change from strongly negatively skewed to strongly positively skewed, with a mode shift from around 10% to 3% between the Completed and Other categories. The porosity-permeability plot of all data shows a significant degree of scatter. This is a function of the changes in porosity-permeability relationships related to the various depositional environments encountered across the basin, plus the destructive effect of diagenesis on the original pore structure.

The Completed category displays a moderately good relationship between porosity and permeability, with only a few samples displaying high permeabilities in the lower porosity mode. As with the Lewis play, the intermode trough occurs between 5% and 7% porosity, which brackets an equivalent in-situ permeability of 1 μd for a "best fit" transform through the Completed category dataset.

Reevaluation of Resource

Dealing firstly with the eastern portion of the play, the best quality reservoirs occur in the Ericson and Almond at the top of the Mesaverde group interval. Additional reservoirs exist deeper within the unit in the Rock Springs and Blair, albeit of a generally lower quality. The bulk of the Mesaverde rock volume and hence resource lies within the 9,000 to 12,000 feet.

In the central and western portions of the play, the Mesaverde dips towards the northeastern basin margin and is interpreted to also thicken in that direction, as such, a greater proportion of the resource occurs below 13,000 feet. Reservoir quality is thought to be much poorer in this area than in the eastern portion of the basin with generally low porosities, high water saturations and high lenticularity due to the prevailing alluvial and fluvial dominated depositional environment.

Examining the pattern of EUR versus depth shows no marked correlation. While the bulk of the production is in the 8,000 to 11,000 foot depth range, additional production from below 12,000 feet is also characterized by a significant proportion of excellent EURs. Taking the EUR distribution as a whole, approximately 10% of the wells have EURs in excess of 10 Bcf with about 40% of the wells having an EUR of 1 Bcf or greater. The average EUR within the Mesaverde play is 2.8 Bcf/well. The Almond formation is the dominant producer, accounting for about 93% of the Mesaverde producing wells. The Ericson accounts for 6% and the Rock Springs and Blair 1%. Figures 35 and 36 display the Almond and Ericson EUR distribution and associated risk models.

Reserves Evaluation

As noted above, the Mesaverde play has been subdivided into the eastern area versus the central and western areas. For the eastern area, existing production data for the Almond and Ericson provides ample information for examining recoveries and construction of a recovery factor model. For the undifferentiated Mesaverde in the central and western area, and for the Rock Springs and Blair in the eastern area, no commercial production has been established and these units have been eliminated from consideration for calculation of reserves.

The Mesaverde play is characterized by significant thicknesses of gas-bearing OPT sediments. However, productivity is strongly correlated to certain facies types: particularly marine shoreline deposits of the Almond formation which account for the vast majority of Mesaverde current production. Alluvial-type facies, despite having pay quality reservoir rock based on core and log data, do not tend to respond to frac treatments, probably due mainly to the lenticular, limited nature of sand development. As a result, no commercial production exists in these rock types.

Focusing on the Almond and Ericson production characteristics, both show well defined log normal distributions of EUR and both show no consistent trend of EUR versus depth. *Economic basement* has been calculated at about 12,100 feet for the Almond and, for the Ericson of a depth above the top of the play. *Deepest commercial production* depth is estimated at 14,000 feet for the Almond and 11,000 feet for the Ericson.

Limitation of commercial production to certain rock units within the overall Mesaverde Group, removes the great majority of in place resource from consideration for reserves calculation purposes. Table 9 illustrates this fact, as do Figures 37 through 41.

TABLE 9
MESAVERDE PLAY, RESOURCE BREAKDOWN BY UNIT
(Tcf)

	Almond	Ericson	Rock Springs	Blair	Undiff	TOTAL
USGS Mean Resource Estimate	----	----	------	-----	----	3347
Scotia Revised Mean Resource Estimate	228	636	102	7	83	1057
MINUS *Technologically Nonviable* Resources	157	405	44	2	57	666
SUBTOTAL *Technologically Viable* Resources	71	231	58	5	26	391
MINUS *Nondemonstrated* Resources	0	0	58	5	26	89
SUBTOTAL *Demonstrated* Resources	71	231	0	0	0	302
Subdivision:						
Speculative Resources	17	105	0	0	0	122
Nonestablished Resources	14	126	0	0	0	140
Established Resources	40	0	0	0	0	40

Table 10 details the reserves calculations and parameters.

TABLE 10
RESERVES CALCULATION, MESAVERDE PLAY

	Almond Formation *Established* Category			Almond Formation *Nonestablished* Category			Ericson Formation *Nonestablished* Category		
	Max	Most Likely	Min	Max	Most Likely	Min	Max	Most Likely	Min
Base Recovery Factor	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
Dry Hole Fraction	0.20	0.20	0.20	0.50	0.50	0.50	0.90	0.90	0.90
Min Econ Drainage (Ac)	26	80	250	50	160	490	15	50	93
Noncommercial Fraction	0.19	0.40	0.65	0.31	0.55	0.77	0.28	0.55	0.68
Recovery Factor	0.49	0.36	0.21	0.26	0.17	0.09	0.04	0.03	0.02
Rock Volume (M AcFt)		87,541			21,811			233,520	
Porosity	0.12	0.085	0.05	0.12	0.075	0.04	0.13	0.085	0.04
Water Saturation	0.48	0.52	0.55	0.38	0.45	0.05	0.42	0.47	0.52
FVF (res cuft/scf	0.00450	0.00381	0.00333	0.00333	0.00320	0.00309	0.00429	0.00383	0.00354
Reserves Probability Distribution									
90% Probability of Exceeding (Tcf)		9.4			1.3			2.2	
70% Probability of Exceeding (Tcf)		11.8			1.7			2.9	
50% Probability of Exceeding (Tcf)		13.9			2.1			3.4	
30% Probability of Exceeding (Tcf)		16.0			2.5			4.0	
10% Probability of Exceeding (Tcf)		19.3			3.2			4.9	
Mean Value (Tcf)		14.2			2.2			3.5	
PDP Reserves & Cum Production									
Cumulative Production (Bcf)		601			35			26	
Remaining PDP Reserves (Bcf)		476			82			18	
EUR of PDP Reserves (Bcf)		1,077			117			44	

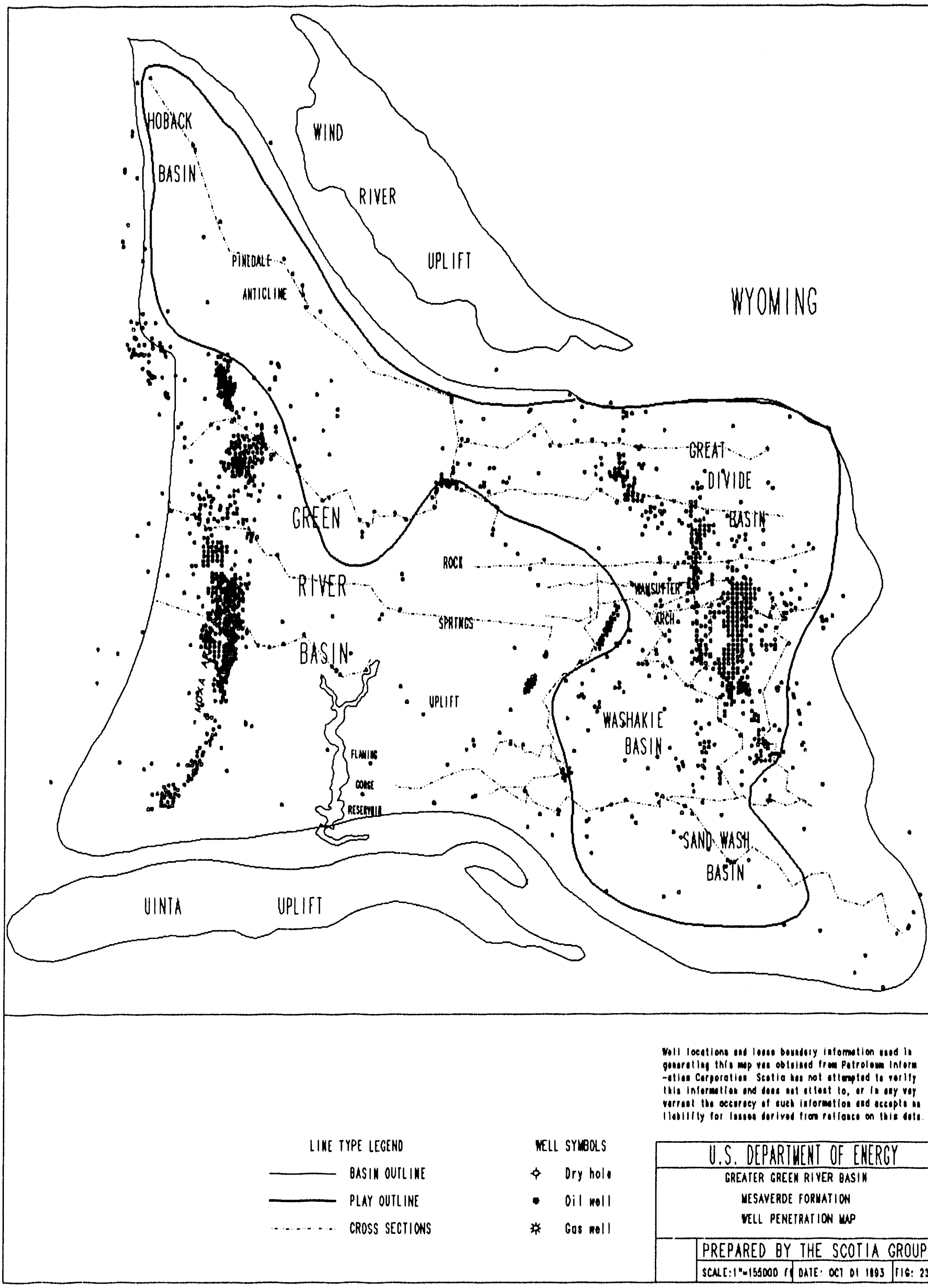
Since the Almond is the shallowest unit of the Mesaverde group and the principal target, penetrations and hence understanding of the underlying units decreases with increasing depth. In addition, the excellent results obtained in the Almond have overshadowed investigation of the potential in the deeper units. Although the Ericson produces commercially at several locations, results for this unit have been inconsistent and not localized in a significant development or sweet spot.

Given the significant resource in the Ericson and Rock Springs, efforts to locate the most favorable area and apply the optimum completion technology creates the potential to unlock significant reward. The most remarkable aspect of Almond production is the quality of a significant proportion of the producers. About 10% of the wells have EURs over 10 Bcf and 40% of wells have EURs in excess of 1 Bcf. In calculating drainage areas for many of the superior wells based on the interval perforated, it is obvious that sands outside the main pay zone are contributing. It is likely that frac height growth has connected significant additional gas-bearing sands to the main pay zone that contribute via well developed internal fracture systems.

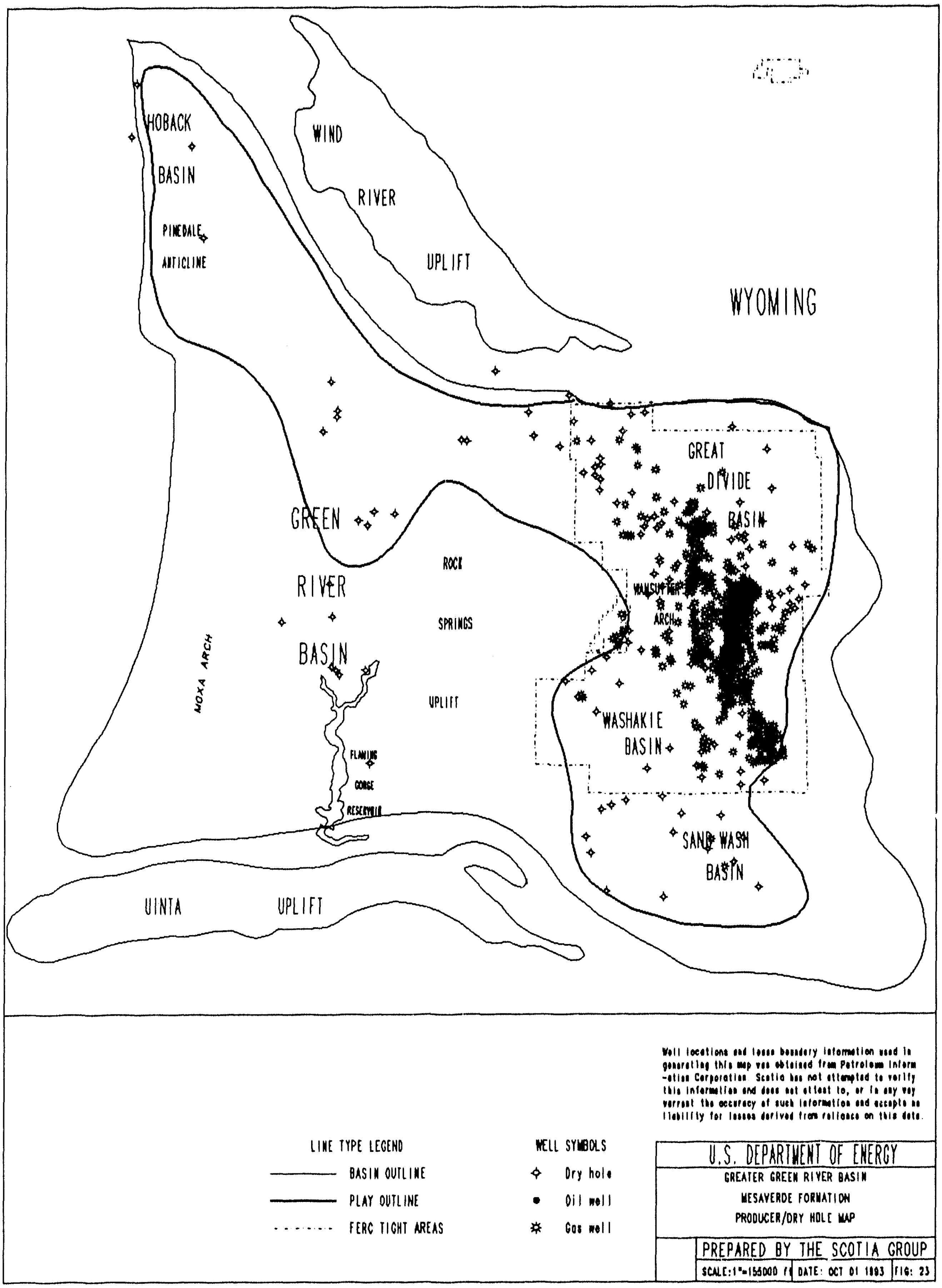
In summary, reserves are recognized in both the *established* and *nonestablished* categories in the Mesaverde. The Almond is the principal producing zone and contains all of the *established* reserves, with a mean estimate of 14.2 Tcf overall, or 13.1 Tcf after subtraction of the EURs of existing Almond OPT gas wells. *Nonestablished* reserves are recognized in both the Almond and Ericson with a mean estimate of 5.7 Tcf overall, or 5.6 Tcf after subtracting the EURs of existing OPT wells in those zones.

TABLE 11
MESAVERDE PLAY OPT FIELD LIST

Field Name	Avg Depth (Feet)	Cum MMcf	EUR MMcf	Number of Wells	Avg EUR MMcf/Well
Baldy Butte	8208	664	953	4	238
Barrell Springs	9512	33558	53671	47	1142
Battle Springs	12640	135	135	1	135
Big Hole	13219	177	177	1	177
Big Ridge	10846	2	2	1	2
Bitter Creek	11193	469	469	2	235
Blue Gap	8796	14195	17098	33	518
Bush Lake	13334	1718	1718	3	573
Cedar Breaks	12918	1239	2068	2	1034
Coal Gulch	8847	41314	75525	11	6866
Continental Divide	12259	142	142	1	142
Creston	8826	5489	6527	11	593
Delaney Rim	8198	829	848	5	170
Desert Flat	9772	54	54	1	54
Dripping Rock	12319	27375	88806	10	8881
Echo Spring	9591	172554	314074	59	5323
Emigrant Trail	11053	432	432	3	144
Fillmore	9332	113	113	2	57
Figure Four Canyon	9066	192	192	1	192
Five Mile Gulch	10664	2656	3104	3	1035
Forbes	12929	18	18	1	18
Frewen	9909	143	243	2	122
Gale	11136	288	288	1	288
Hansen Draw	11806	104	104	2	52
Lost Creek	9760	121	121	1	121
Lost Creek Basin	10816	111	111	1	111
Lost Valley	12360	5	5	1	5
Mahoney Draw	13083	450	450	2	225
McPherson Springs	12307	81	81	1	81
Monument Lake	11764	401	401	2	201
Mulligan Draw	12852	2261	11536	3	3845
Nickey	12383	299	299	1	299
Red	10873	126	126	2	63
Red Desert	9948	238	238	1	238
Red Lakes	10031	2257	2472	7	353
Robbers Gulch	8694	8967	13431	25	537
Salazar	12566	412	412	2	206
Sentinal Ridge	11919	809	809	5	162
Sheep Camp	8408	604	841	4	210
Shell Creek	9394	522	522	1	522
Siberia Ridge	10938	17506	26130	32	817
Standard Draw	8983	182730	349579	38	9199
Stock Pond	11146	747	1289	2	645
Stratton Draw	14520	3	3	1	3
Table Rock	8071	240	297	3	99
Tierney	9836	6753	9706	10	971
Two Rim	9697	180	250	1	250
Unnamed	10017	605	8918	6	1486
Wamsutter	9723	37074	59590	30	1986
Wells Bluff	11426	326	326	2	163
Wild Rose	10015	93597	176836	48	3684
Willow Reservoir	12926	96	5519	1	5519
Windmill Draw	11280	616	696	3	232
Windy Hill	11822	32	32	1	32
Totals		662029	1237787	444	2788



HOBACK
BASIN
WIND
RIVER
UPLIFT
PINEDALE
ANTICLINE
WYOMING
GREAT
DIVIDE
BASIN
GREEN
RIVER
BASIN
ROCK
SPRINGS
UPLIFT
WAMSUTTER
ARCH
WASHAKIE
BASIN
FLAMING
GORGE
RESERVOIR
SAND WASH
BASIN
UINTA
UPLIFT
Well locations and lease boundary information used in generating this map was obtained from Petroleum Inform-ation Corporation. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.
LINE TYPE LEGEND
BASIN OUTLINE
PLAY OUTLINE
CROSS SECTIONS
WELL SYMBOLS
Dry hole
Oil well
Gas well
U.S. DEPARTMENT OF ENERGY
GREATER GREEN RIVER BASIN
MESAVERDE FORMATION
WELL PENETRATION MAP
PREPARED BY THE SCOTIA GROUP
SCALE:1"=155000 ft
DATE: OCT 01 1993
FIG: 22


HOBACK
BASIN
PINEDALE
ANTICLINE
WIND
RIVER
UPLIFT
WYOMING
GREAT
DIVIDE
BASIN
GREEN
RIVER
BASIN
ROCK
SPRINGS
UPLIFT
MOXA ARCH
WAMSUTTER
ARCH
WASHAKIE
BASIN
FLAMING
GORGE
RESERVOIR
SAND WASH
BASIN
UINTA
UPLIFT
Well locations and lease boundary information used in generating this map was obtained from Petroleum Information Corporation. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.
LINE TYPE LEGEND
BASIN OUTLINE
PLAY OUTLINE
FERC TIGHT AREAS
WELL SYMBOLS
Dry hole
Oil well
Gas well
U.S. DEPARTMENT OF ENERGY
GREATER GREEN RIVER BASIN
MESAVERDE FORMATION
PRODUCER/DRY HOLE MAP
PREPARED BY THE SCOTIA GROUP
SCALE:1"=155000 ft
DATE: OCT 01 1993
FIG: 23

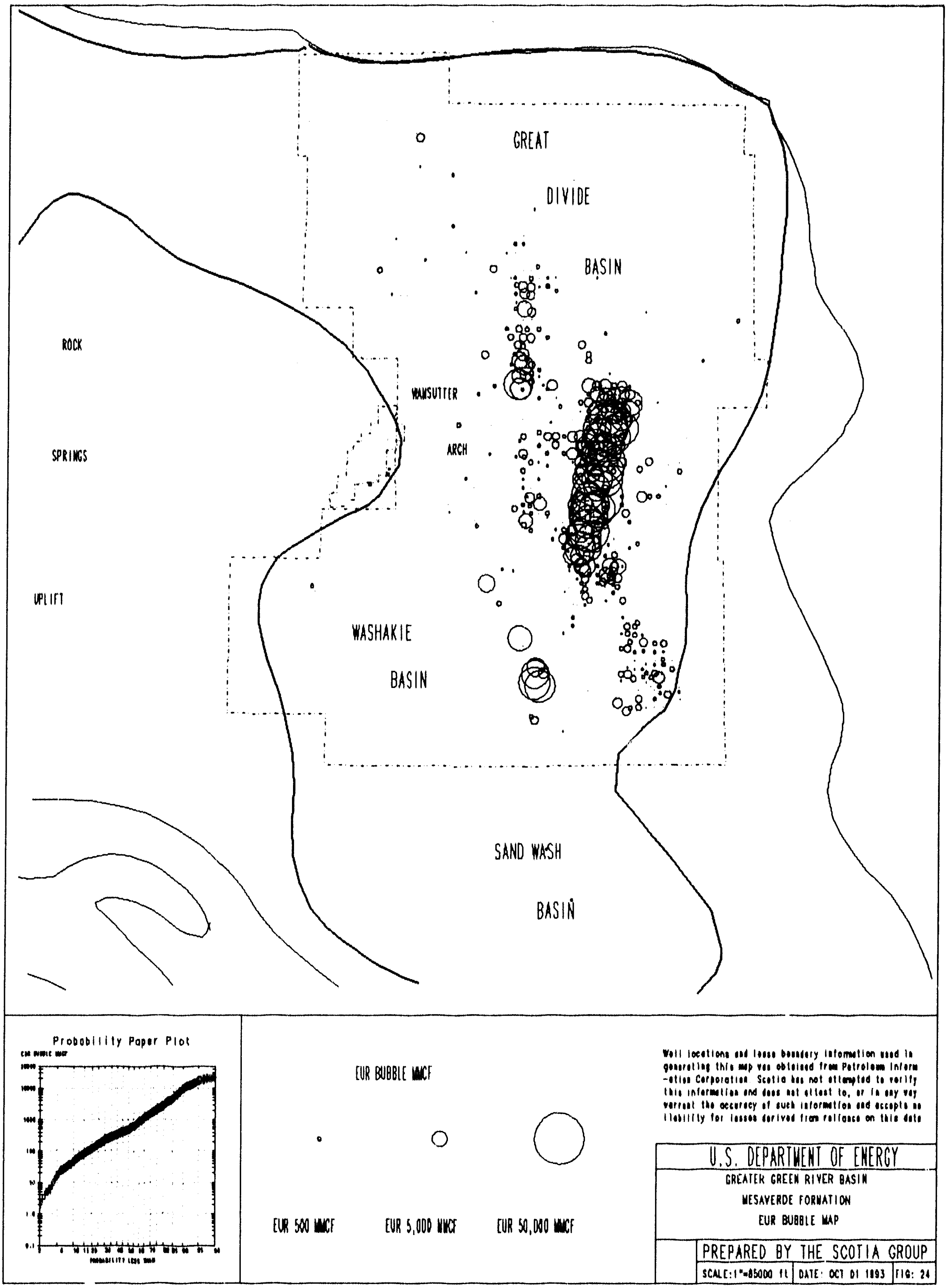
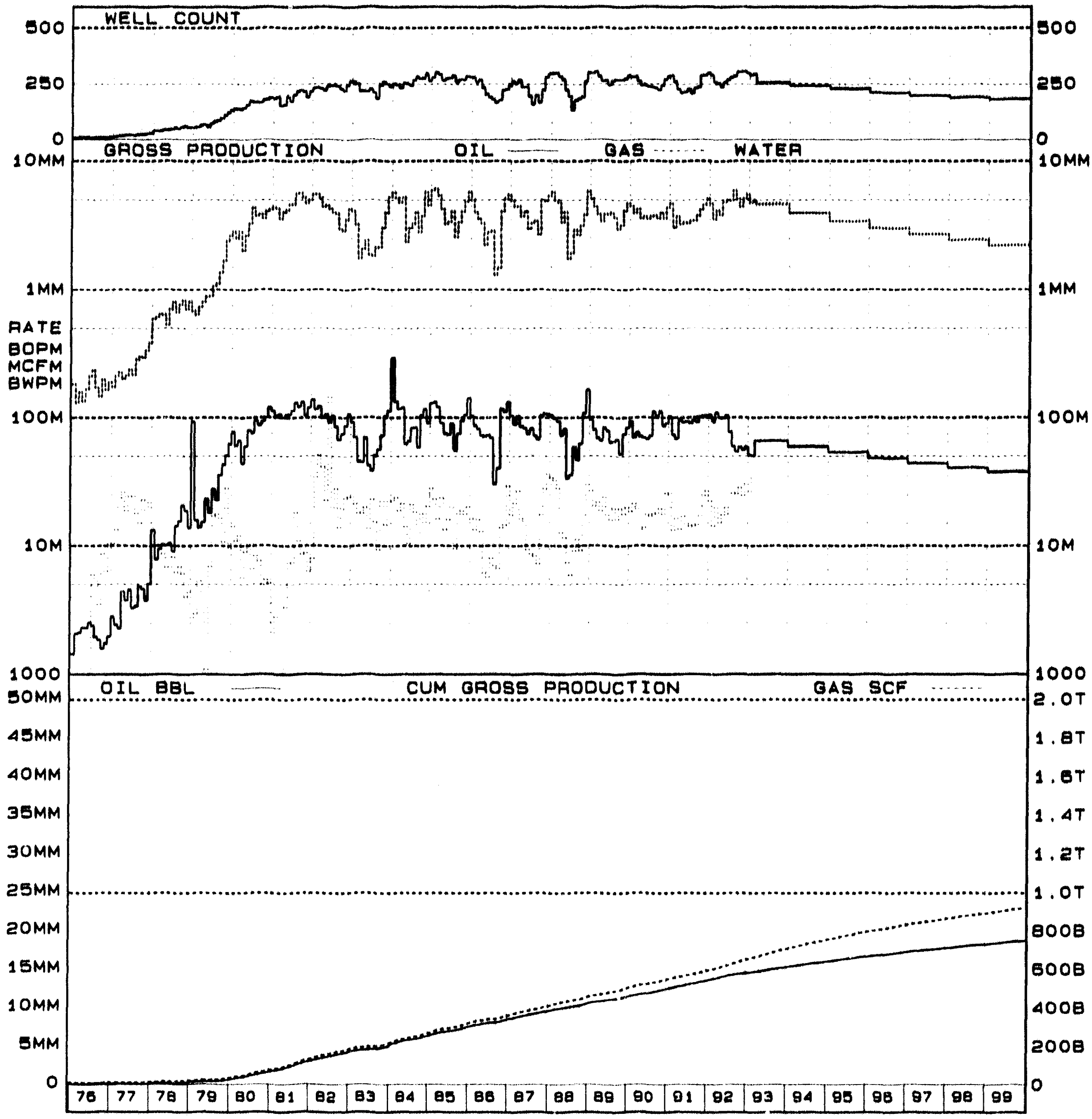

GREAT
DIVIDE
BASIN
ROCK
SPRINGS
UPLIFT
WAMSUTTER
ARCH
WASHAKIE
BASIN
SAND WASH
BASIN
Probability Paper Plot
EUR BUBBLE MMCF
EUR 500 MMCF
EUR 5,000 MMCF
EUR 50,000 MMCF
Well locations and lease boundary information used in generating this map was obtained from Petroleum Inform-ation Corporation. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data
U.S. DEPARTMENT OF ENERGY
GREATER GREEN RIVER BASIN
MESAVERDE FORMATION
EUR BUBBLE MAP
PREPARED BY THE SCOTIA GROUP
SCALE:1"=85000 ft
DATE: OCT 01 1893
FIG: 24

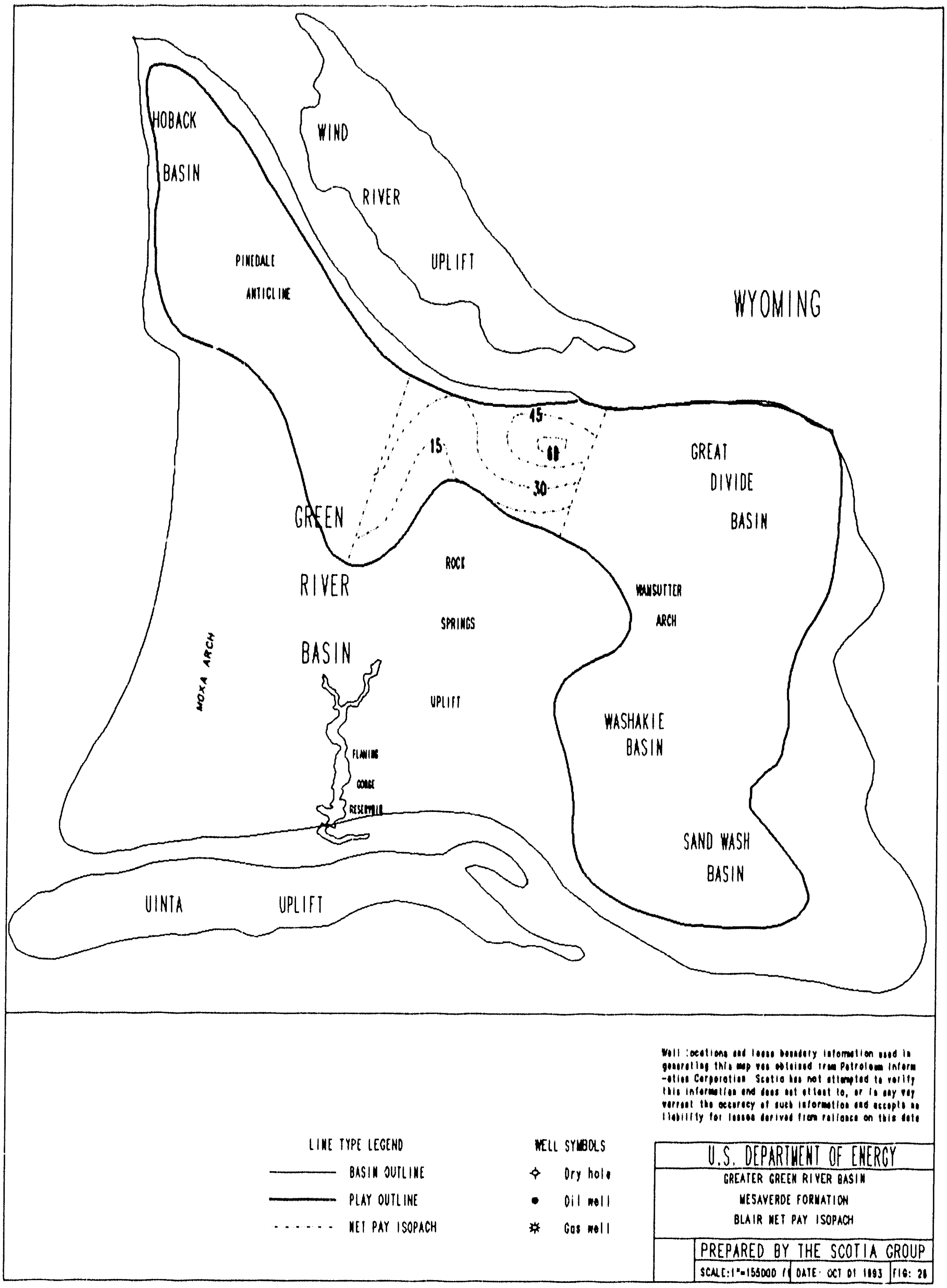
FIGURE 25



MESAVERDE TOTAL PRODUCTION PROFILE

Projections are averages for each year commencing at the effective date of the evaluation. Results are subject to the qualifications and limitations stated in the attached document

PREPARED BY THE SCOTIA GROUP, INC. *S.S.L. FRI OCT 01 1993 16:08:30*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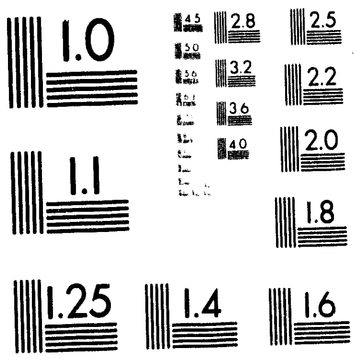
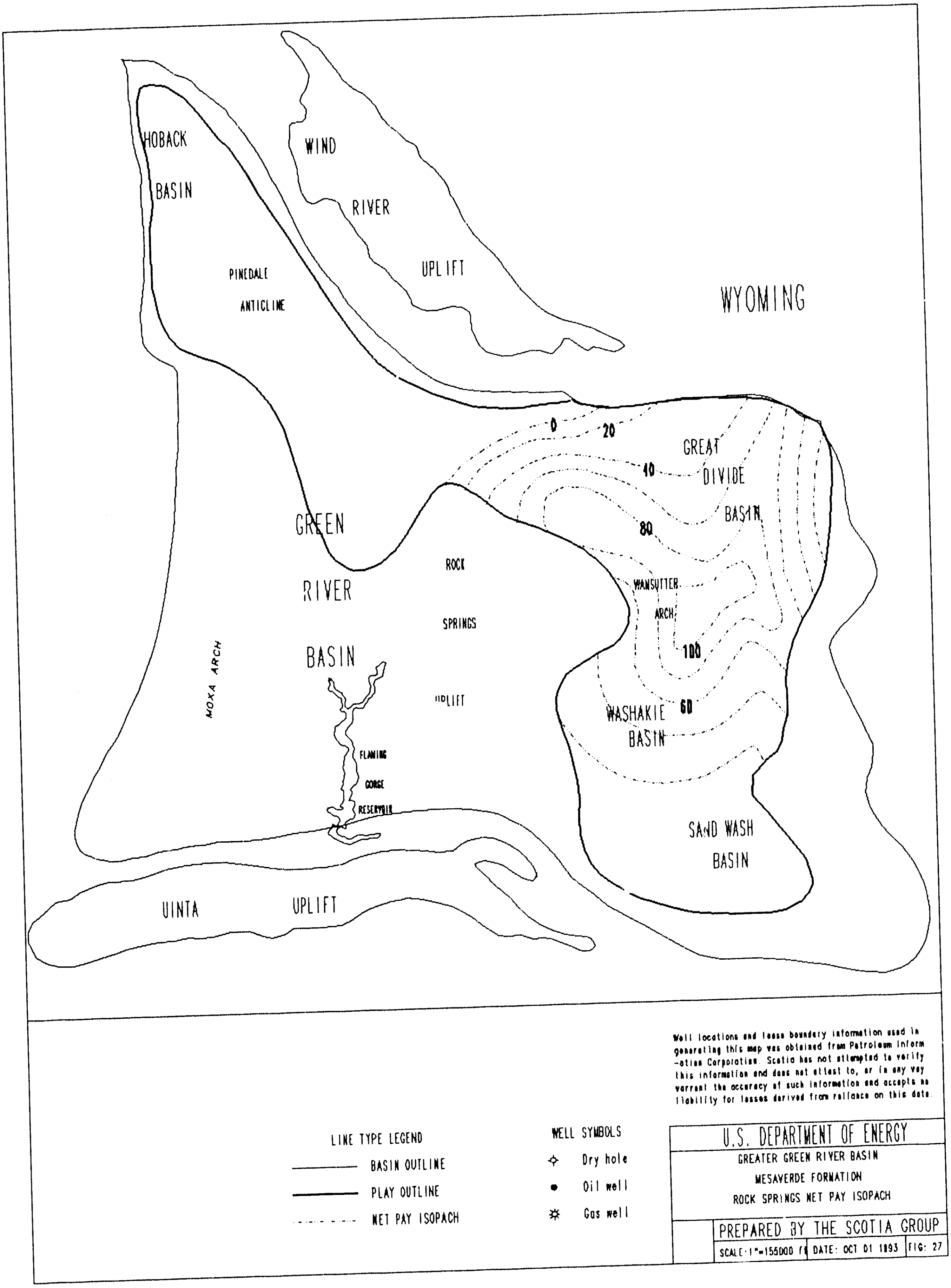
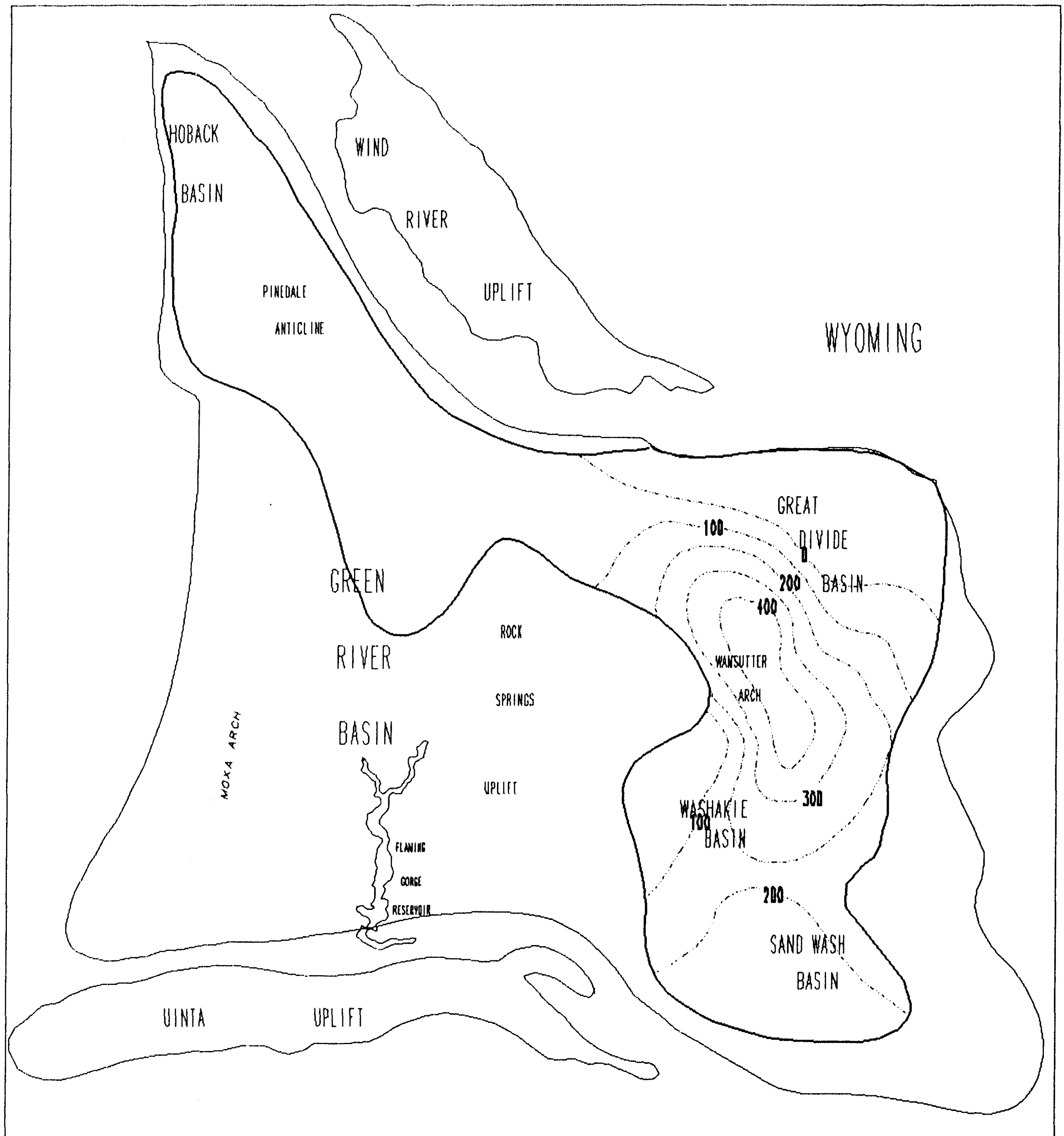
WIND
RIVER
UPLIFT
PINEDALE
ANTICLINE
WYOMING
45
60
15
30
GREAT
DIVIDE
BASIN
GREEN
RIVER
BASIN
ROCK
SPRINGS
UPLIFT
WAMSUTTER
ARCH
MOXA ARCH
FLAMING
GORGE
RESERVOIR
WASHAKIE
BASIN
SAND WASH
BASIN
UINTA
UPLIFT
Well locations and lease boundary information used in generating this map was obtained from Petroleum Inform-ation Corporation. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data
LINE TYPE LEGEND
BASIN OUTLINE
PLAY OUTLINE
NET PAY ISOPACH
WELL SYMBOLS
Dry hole
Oil well
Gas well
U.S. DEPARTMENT OF ENERGY
GREATER GREEN RIVER BASIN
MESAVERDE FORMATION
BLAIR NET PAY ISOPACH
PREPARED BY THE SCOTIA GROUP
SCALE:1"=155000 f
DATE: OCT 01 1993
FIG: 28


1.0
2.8
2.5
3.2
2.2
3.6
4.0
2.0
1.1
1.8
1.25
1.4
1.6


HOBACK
BASIN
WIND
RIVER
UPLIFT
PINEDALE
ANTICLINE
WYOMING
0
20
40
GREAT
DIVIDE
BASIN
80
GREEN
RIVER
BASIN
ROCK
SPRINGS
UPLIFT
WAMSUTTER
ARCH
100
MOXA ARCH
60
WASHAKIE
BASIN
FLAMING
GORGE
RESERVOIR
SAND WASH
BASIN
UINTA
UPLIFT
Well locations and lease boundary information used in generating this map was obtained from Petroleum Information Corporation. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.
LINE TYPE LEGEND
BASIN OUTLINE
PLAY OUTLINE
NET PAY ISOPACH
WELL SYMBOLS
Dry hole
Oil well
Gas well
U.S. DEPARTMENT OF ENERGY
GREATER GREEN RIVER BASIN
MESAVERDE FORMATION
ROCK SPRINGS NET PAY ISOPACH
PREPARED BY THE SCOTIA GROUP
SCALE: 1"=155000 ft
DATE: OCT 01 1993
FIG: 27



Well locations and lease boundary information used in generating this map was obtained from Petroleum Information Corporation. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

LINE TYPE LEGEND
- BASIN OUTLINE
- PLAY OUTLINE
- NET PAY ISOPACH

WELL SYMBOLS
- Dry hole
- Oil well
- Gas well

U.S. DEPARTMENT OF ENERGY

GREATER GREEN RIVER BASIN
MESAVERDE FORMATION
ERICSON NET PAY ISOPACH

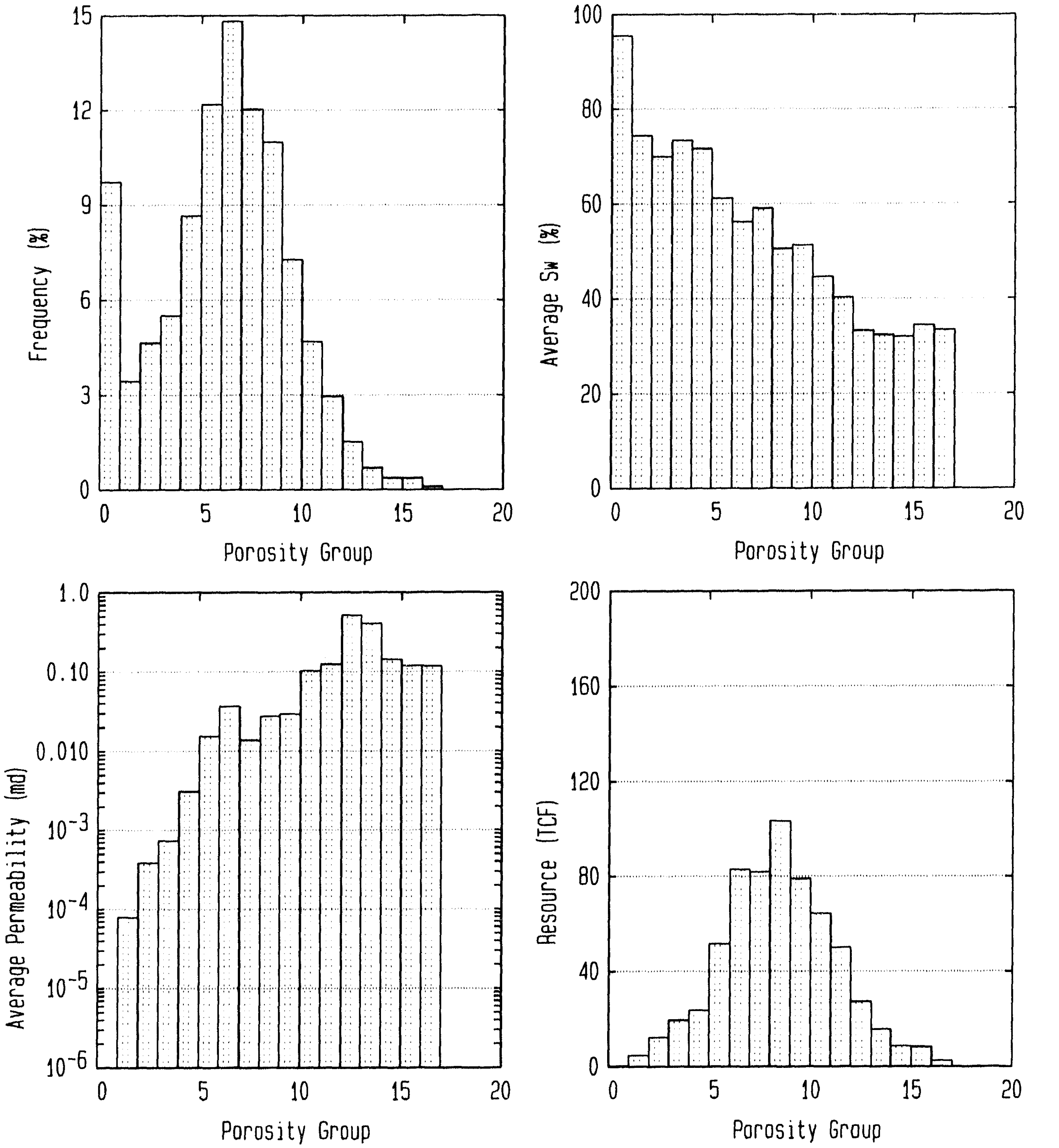
PREPARED BY THE SCOTIA GROUP

SCALE: 1"=155000 ft | DATE: OCT 01 1993 | FIG: 28

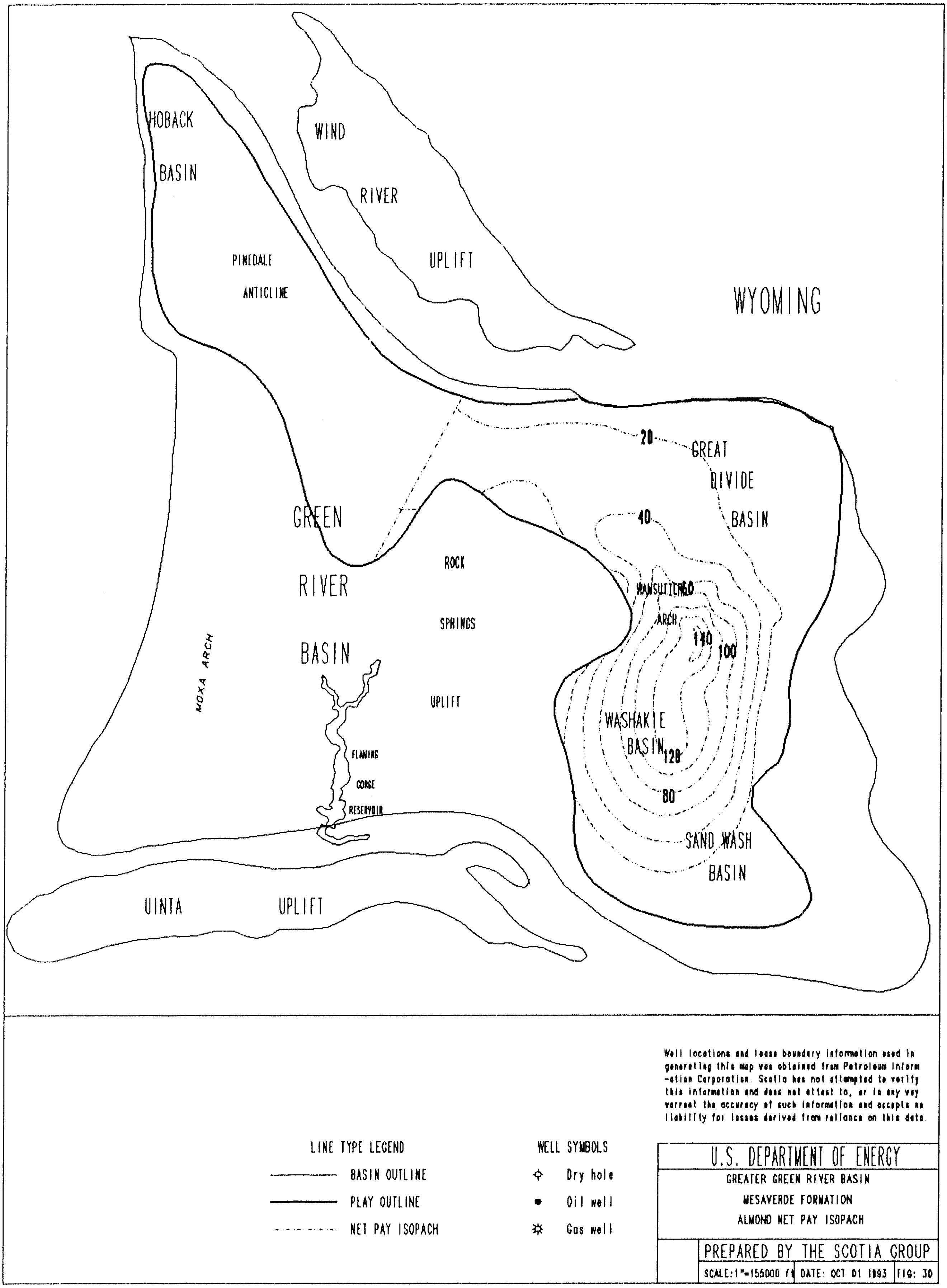
Scotia Group Resource Model	Rock Property and In-Place Resource Distributions	Client: U.S. DEPARTMENT OF ENERGY	Figure 29

Greater Green River Basin: Rock Property Distributions

ERICSON FORMATION



SAT OCT 02 1993

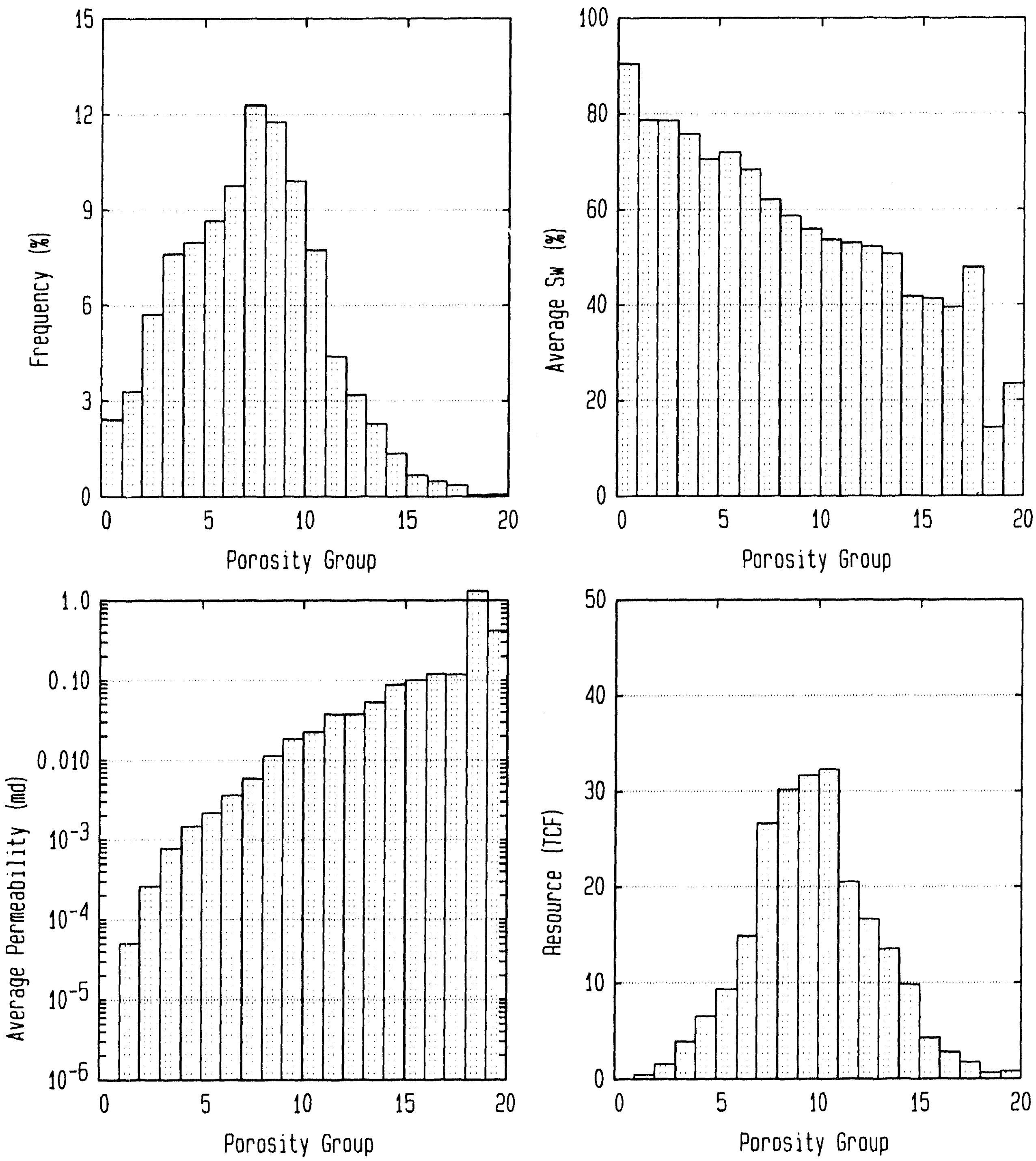


HOBACK
BASIN
WIND
RIVER
UPLIFT
PINEDALE
ANTICLINE
WYOMING
20
GREAT
DIVIDE
BASIN
GREEN
RIVER
BASIN
40
ROCK
SPRINGS
UPLIFT
WAMSUTTER
ARCH
60
140
100
MOXA ARCH
WASHAKIE
BASIN
120
80
FLAMING
GORGE
RESERVOIR
SAND WASH
BASIN
UINTA
UPLIFT
Well locations and lease boundary information used in generating this map was obtained from Petroleum Information Corporation. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.
LINE TYPE LEGEND
BASIN OUTLINE
PLAY OUTLINE
NET PAY ISOPACH
WELL SYMBOLS
Dry hole
Oil well
Gas well
U.S. DEPARTMENT OF ENERGY
GREATER GREEN RIVER BASIN
MESAVERDE FORMATION
ALMOND NET PAY ISOPACH
PREPARED BY THE SCOTIA GROUP
SCALE:1"=155000
DATE: OCT 01 1993
FIG: 30

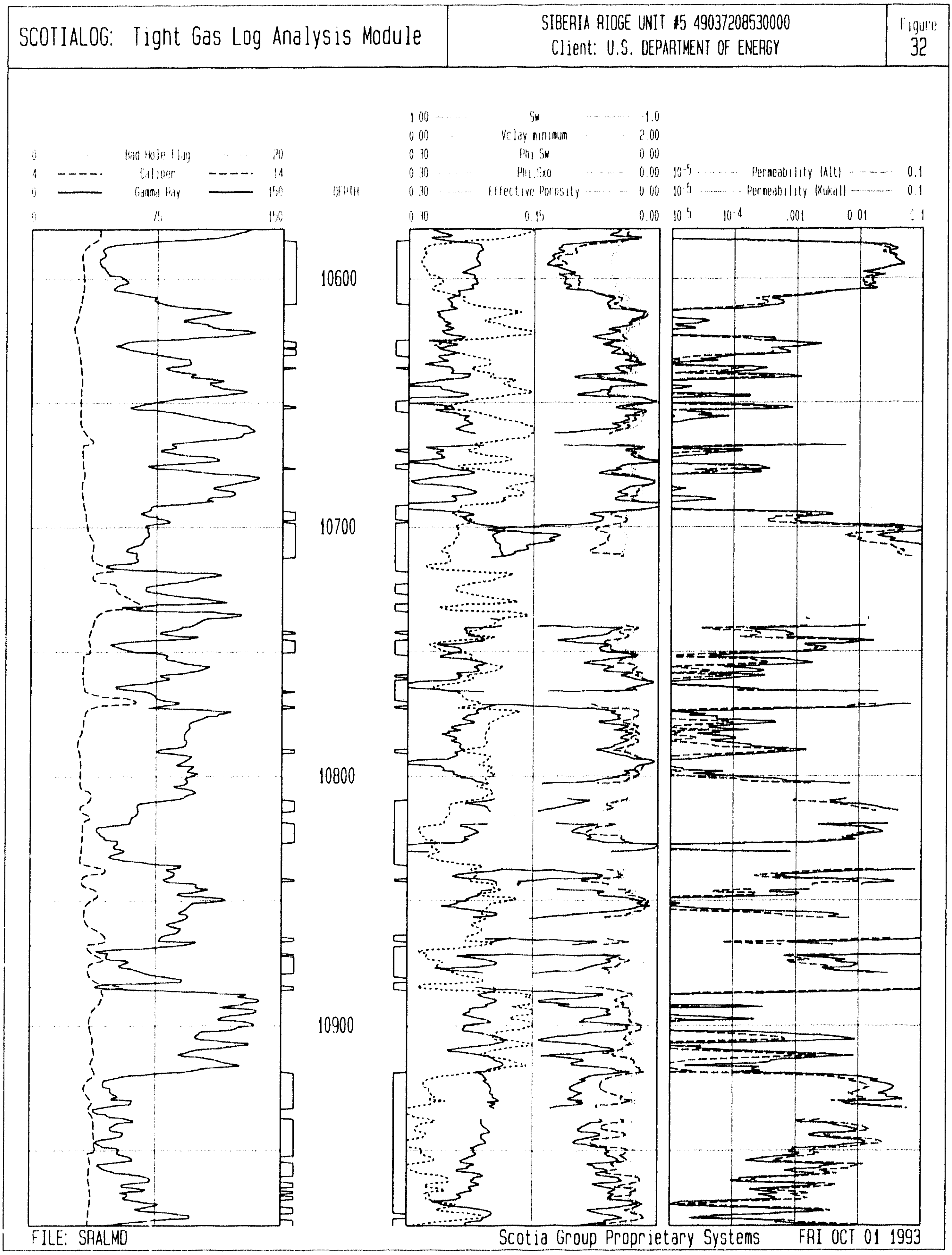
Scotia Group Resource Model	Rock Property and In-Place Resource Distributions	Client: U.S. DEPARTMENT OF ENERGY	Figure 31

Greater Green River Basin: Rock Property Distributions

ALMOND FORMATION



SAI OCT 02 1993


SCOTIALOG: Tight Gas Log Analysis Module
SIBERIA RIDGE UNIT #5 49037208530000
Client: U.S. DEPARTMENT OF ENERGY
Figure 32
Bad Hole Flag
Caliper
Gamma Ray
DEPTH
Sw
Vclay minimum
Phi Sw
Phi Sxo
Effective Porosity
Permeability (Alt)
Permeability (Kukal)
10600
10700
10800
10900
FILE: SRALMD
Scotia Group Proprietary Systems
FRI OCT 01 1993

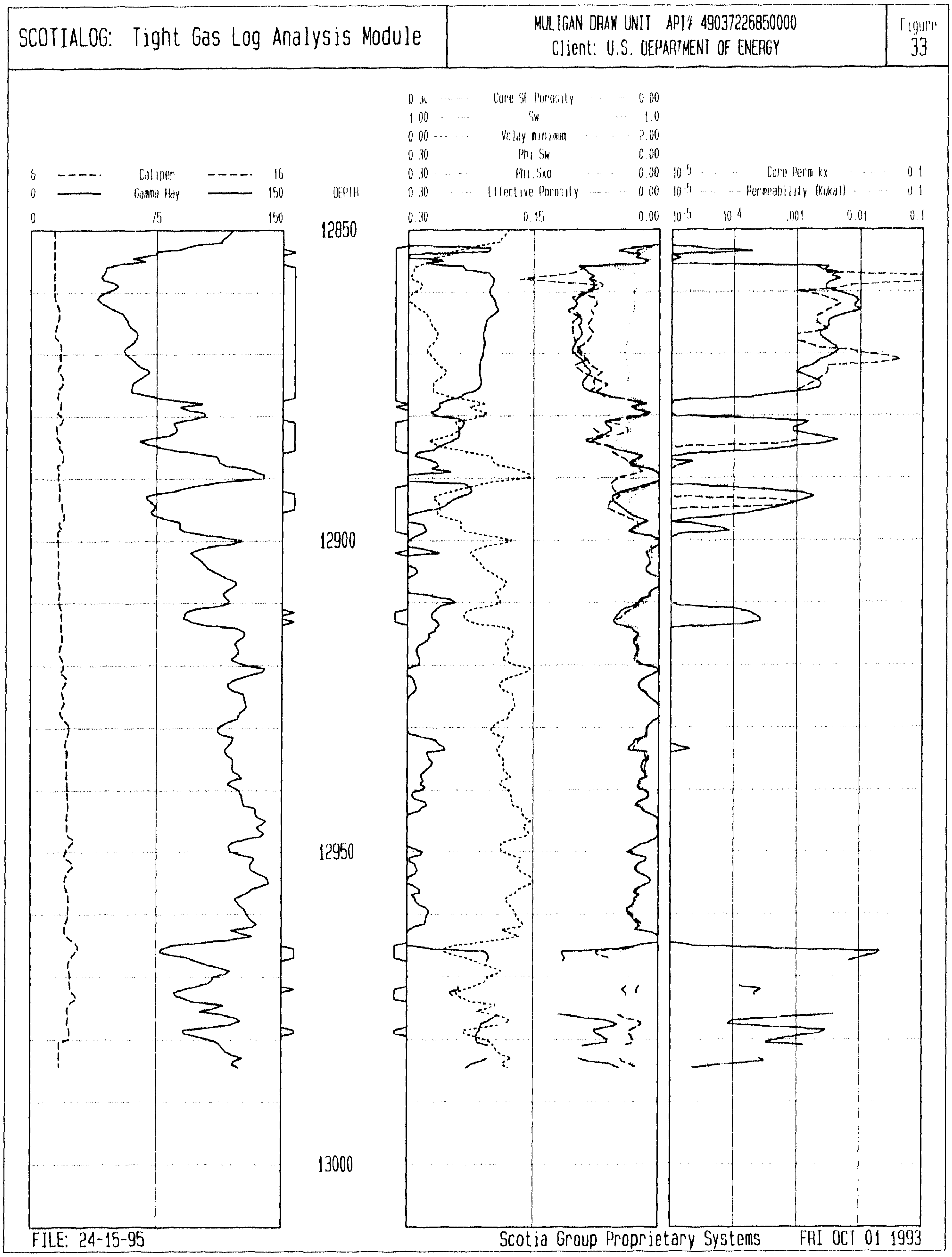
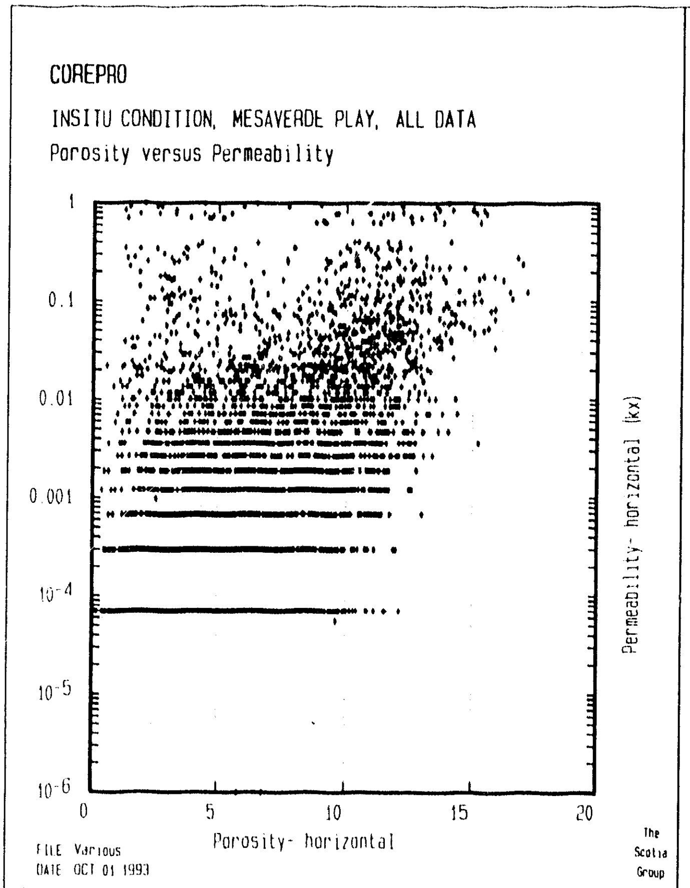
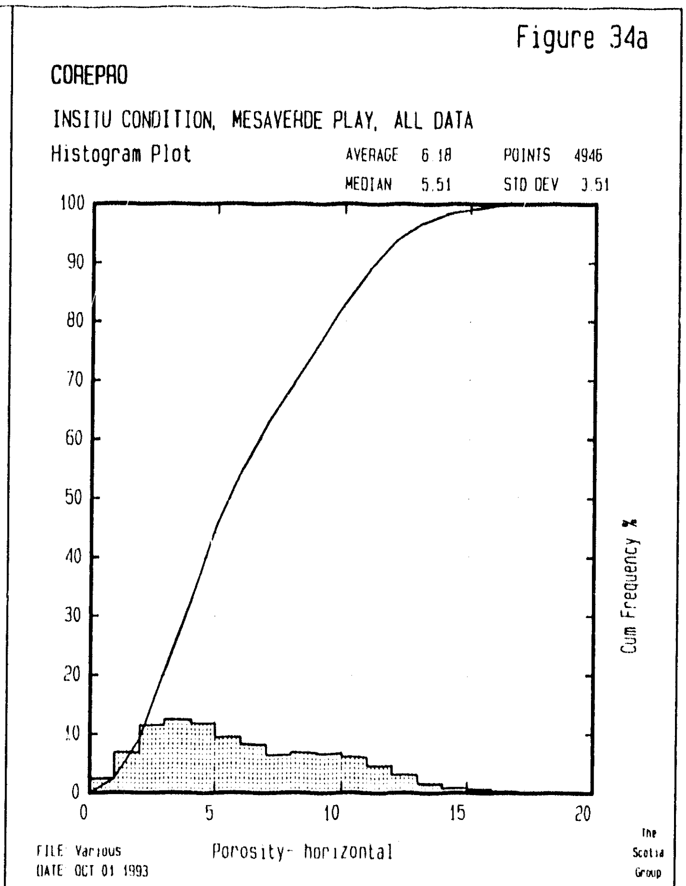
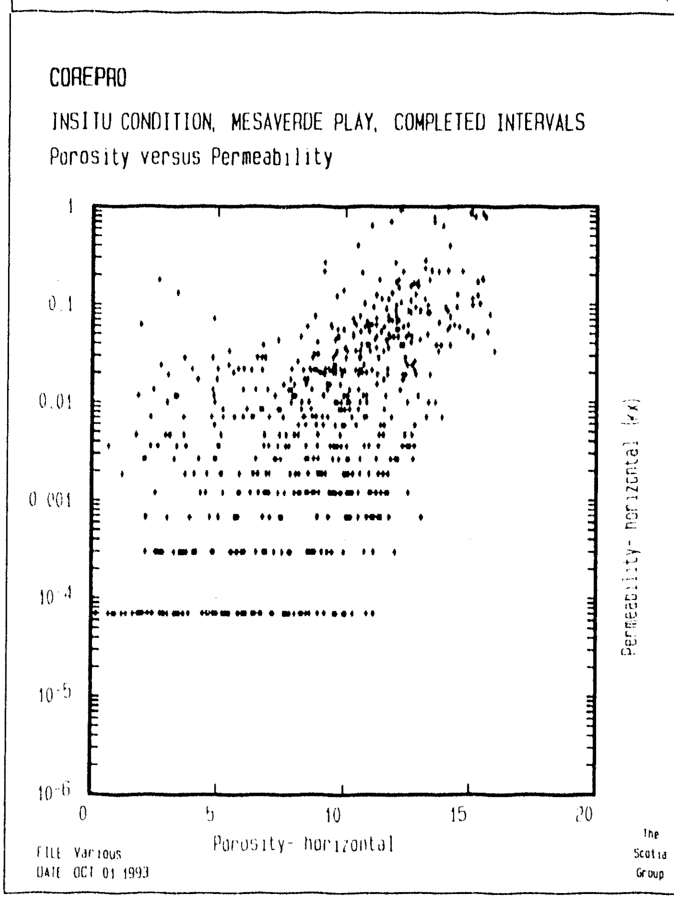

SCOTIALOG: Tight Gas Log Analysis Module
MULIGAN DRAW UNIT API# 49037226850000
Client: U.S. DEPARTMENT OF ENERGY
Figure 33
Core SF Porosity
Sw
Vclay minimum
Phi Sw
Phi Sxo
Effective Porosity
Caliper
Gamma Ray
DEPTH
Core Perm kx
Permeability (Kukal)
12850
12900
12950
13000
FILE: 24-15-95
Scotia Group Proprietary Systems
FRI OCT 01 1993

Figure 34a


COREPRO
INSITU CONDITION, MESAVERDE PLAY, ALL DATA
Porosity versus Permeability
Permeability- horizontal (kx)
Porosity- horizontal
FILE Various
DATE OCT 01 1993
The Scotia Group


COREPRO
INSITU CONDITION, MESAVERDE PLAY, ALL DATA
Histogram Plot
AVERAGE 6.18
POINTS 4946
MEDIAN 5.51
STD DEV 3.51
Cum Frequency %
Porosity- horizontal
FILE Various
DATE OCT 01 1993
The Scotia Group


COREPRO
INSITU CONDITION, MESAVERDE PLAY, COMPLETED INTERVALS
Porosity versus Permeability
Permeability- horizontal (kx)
Porosity- horizontal
FILE Various
DATE OCT 01 1993
The Scotia Group

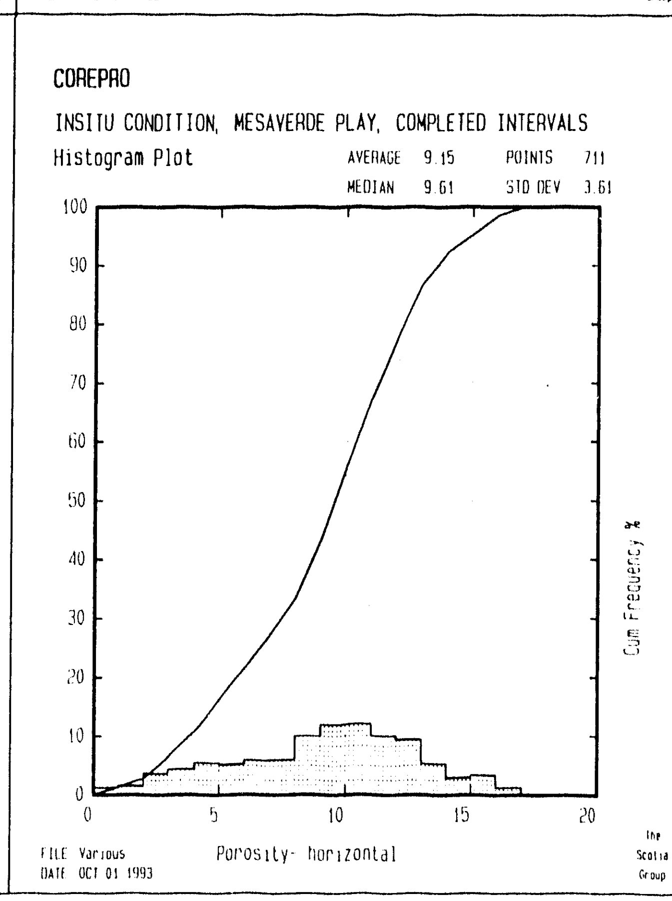
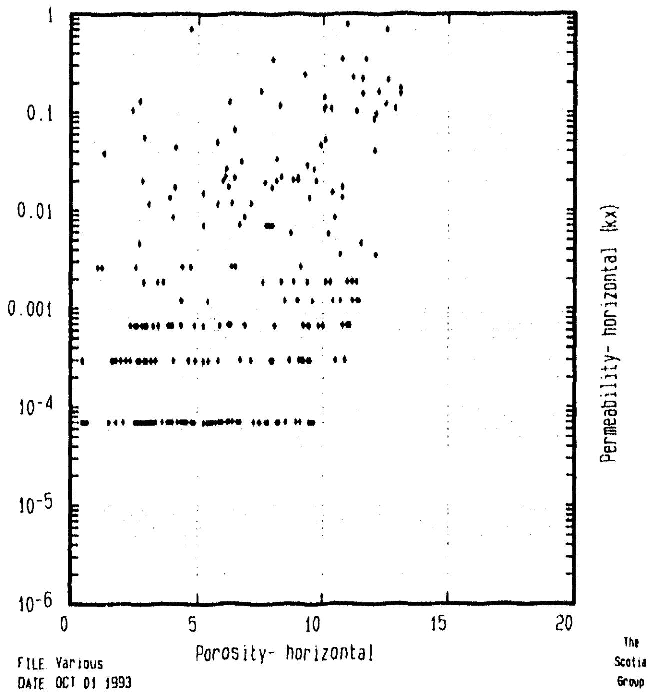

COREPRO
INSITU CONDITION, MESAVERDE PLAY, COMPLETED INTERVALS
Histogram Plot
AVERAGE 9.15
POINTS 711
MEDIAN 9.61
STD DEV 3.61
Cum Frequency %
Porosity- horizontal
FILE Various
DATE OCT 01 1993
The Scotia Group

Figure 34b

COREPRO

INSITU CONDITION, MESAVERDE PLAY, TESTED INTERVALS

Porosity versus Permeability

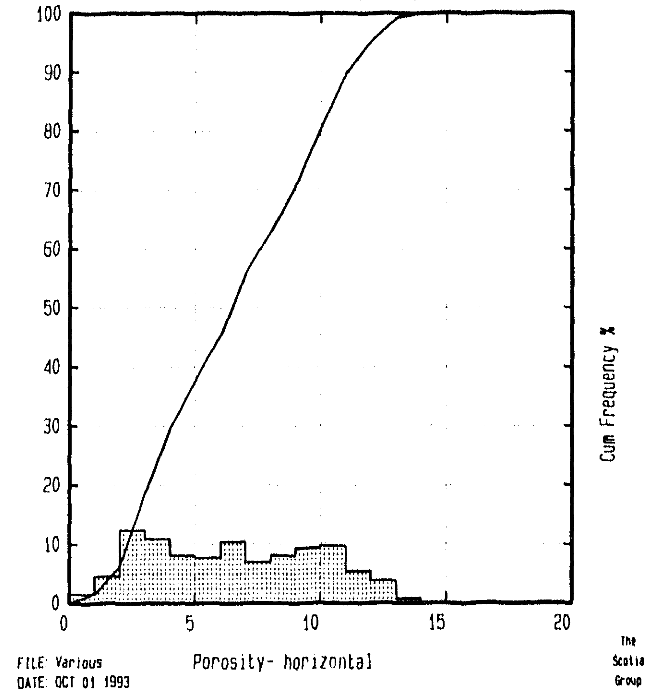


COREPRO

INSITU CONDITION, MESAVERDE PLAY, TESTED INTERVALS

Histogram Plot

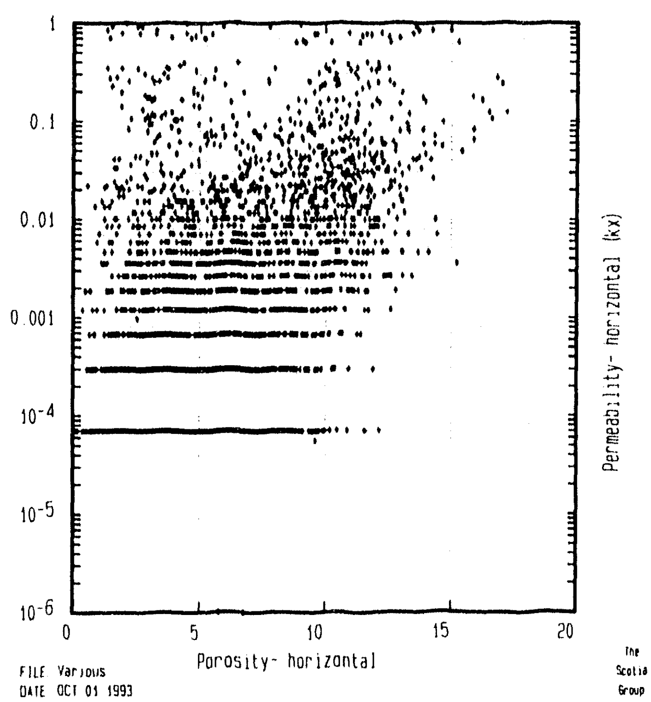
AVERAGE 6.57 POINTS 258
MEDIAN 6.29 STD DEV 3.28



COREPRO

INSITU CONDITION, MESAVERDE PLAY, OTHER DATA

Porosity versus Permeability

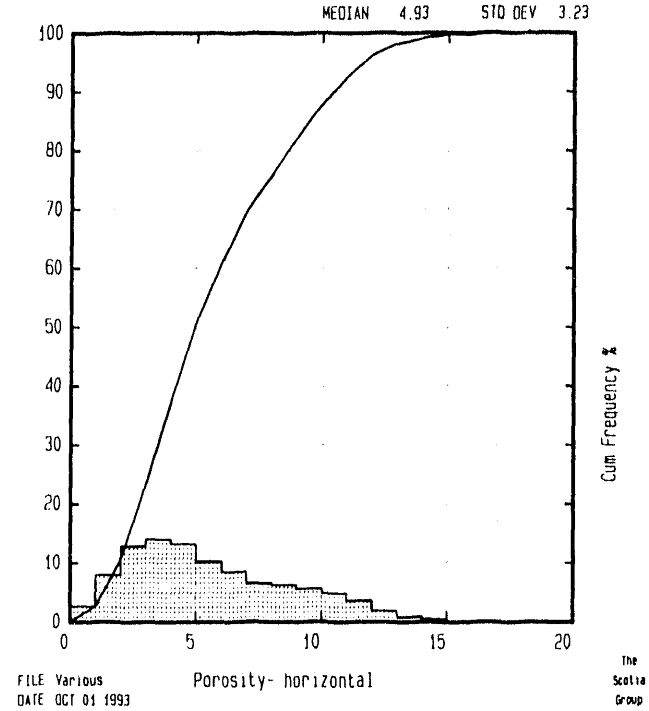


COREPRO

INSITU CONDITION, MESAVERDE PLAY, OTHER DATA

Histogram Plot

AVERAGE 5.63 POINTS 3977
MEDIAN 4.93 STD DEV 3.23

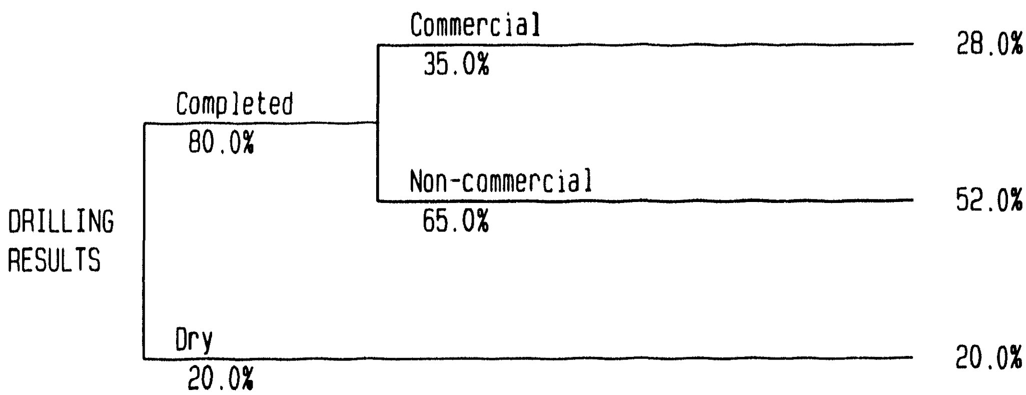


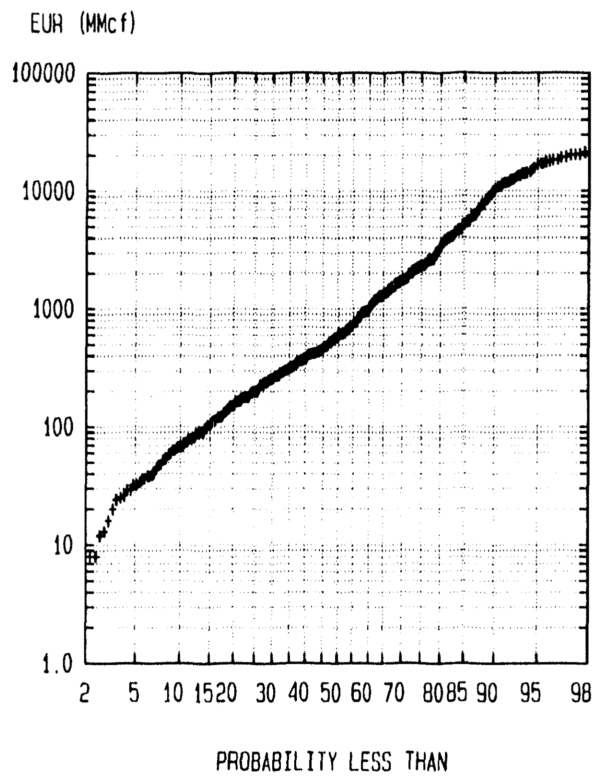
Scotia Group Resource Model	Distribution of EURs and Risk Model	Client: U.S. DEPARTMENT OF ENERGY	Figure 35

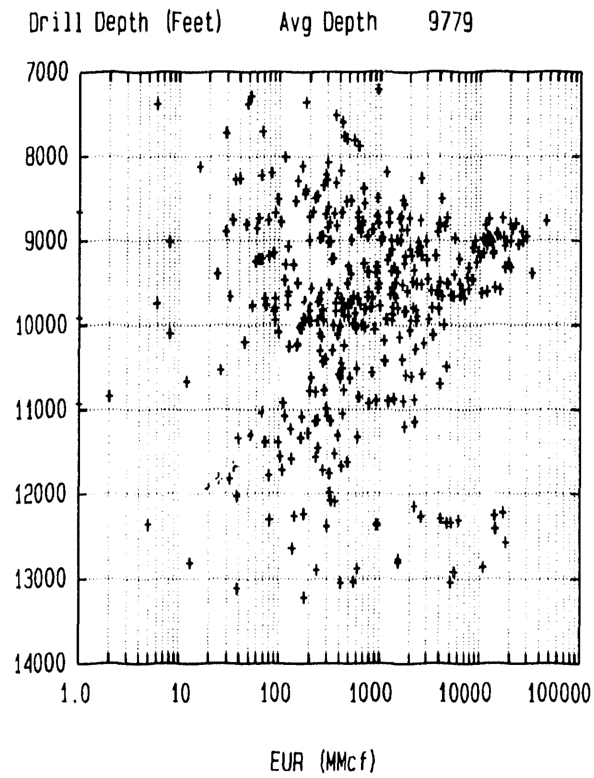
Greater Green River Basin: Rock Property Distributions

ALMOND FORMATION

Technical Success 80.0%
Commercial Success 28.0%







SAT OCT 02 1993

Scotia Group Resource Model	Distribution of EURs and Risk Model	Client: U.S. DEPARTMENT OF ENERGY	Figure 36

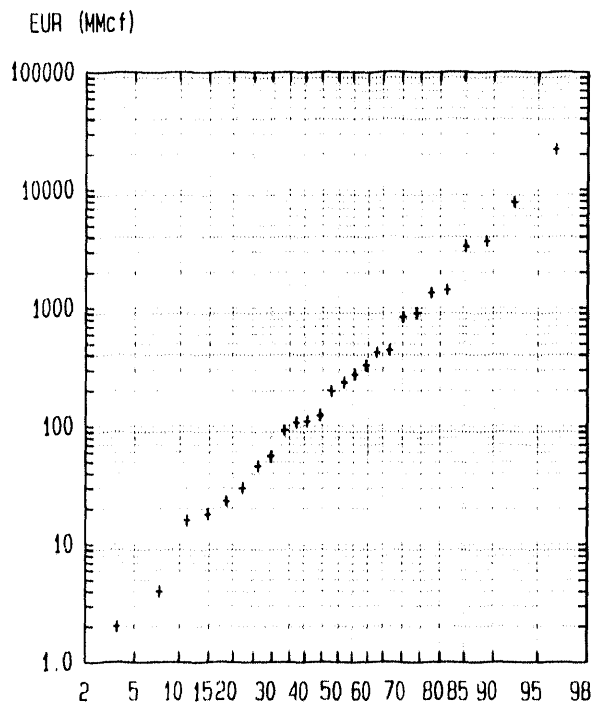
Greater Green River Basin: Rock Property Distributions

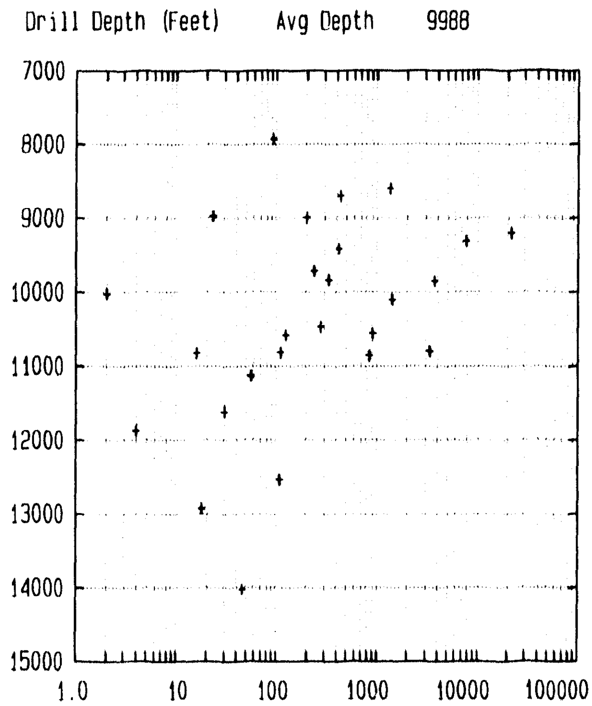
ERICSON FORMATION

Technical Success	10.0%
Commercial Success	2.5%

DRILLING RESULTS

- Completed 10.0%
  - Commercial 25.0% — 2.5%
  - Non-commercial 75.0% — 7.5%
- Dry 90.0% — 90.0%



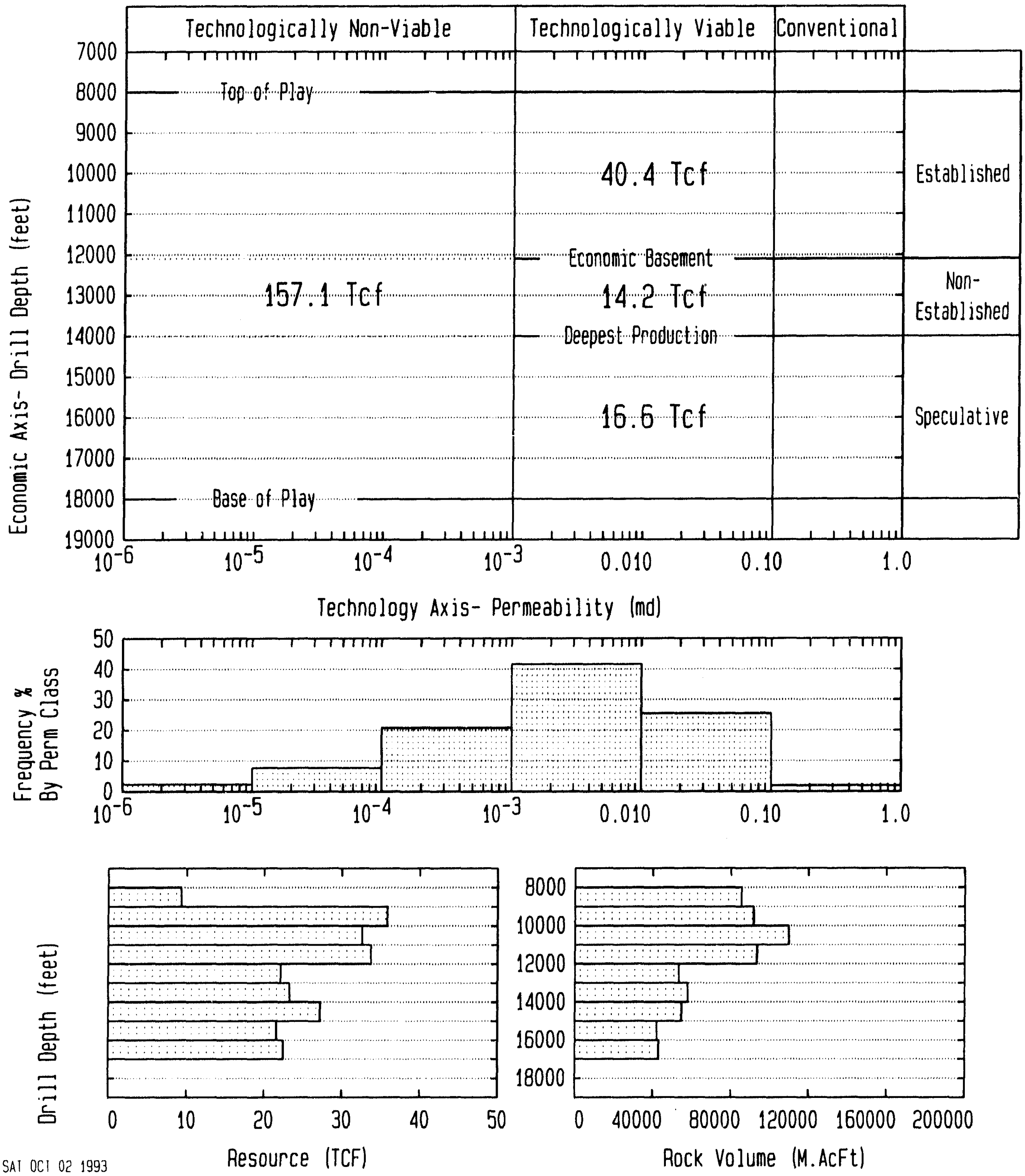


SAT OCT 02 1993

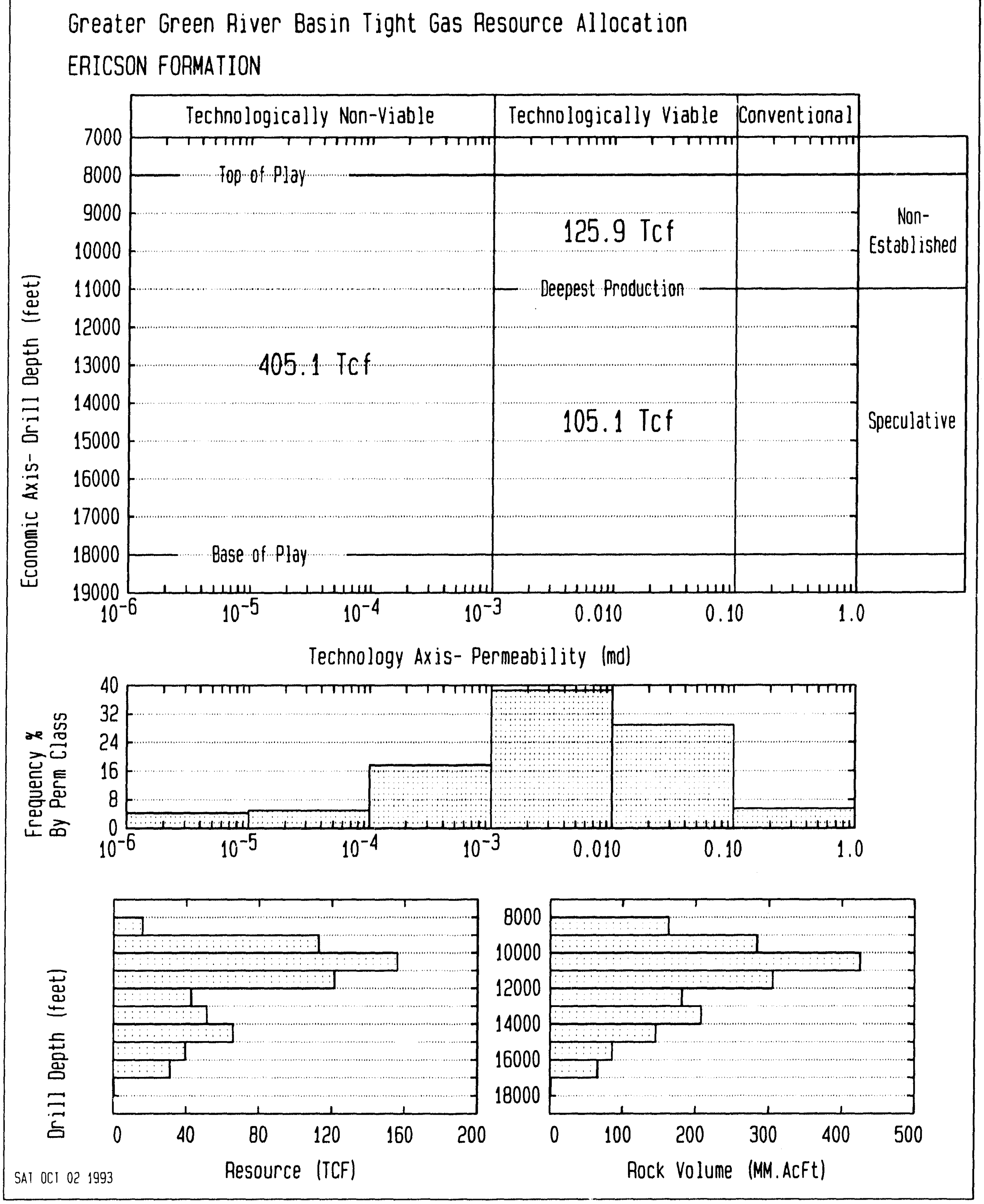
Scotia Group Resource Model	Distribution and Classes of In Place Resources	Client: U.S. DEPARTMENT OF ENERGY	Figure 37

Greater Green River Basin Tight Gas Resource Allocation

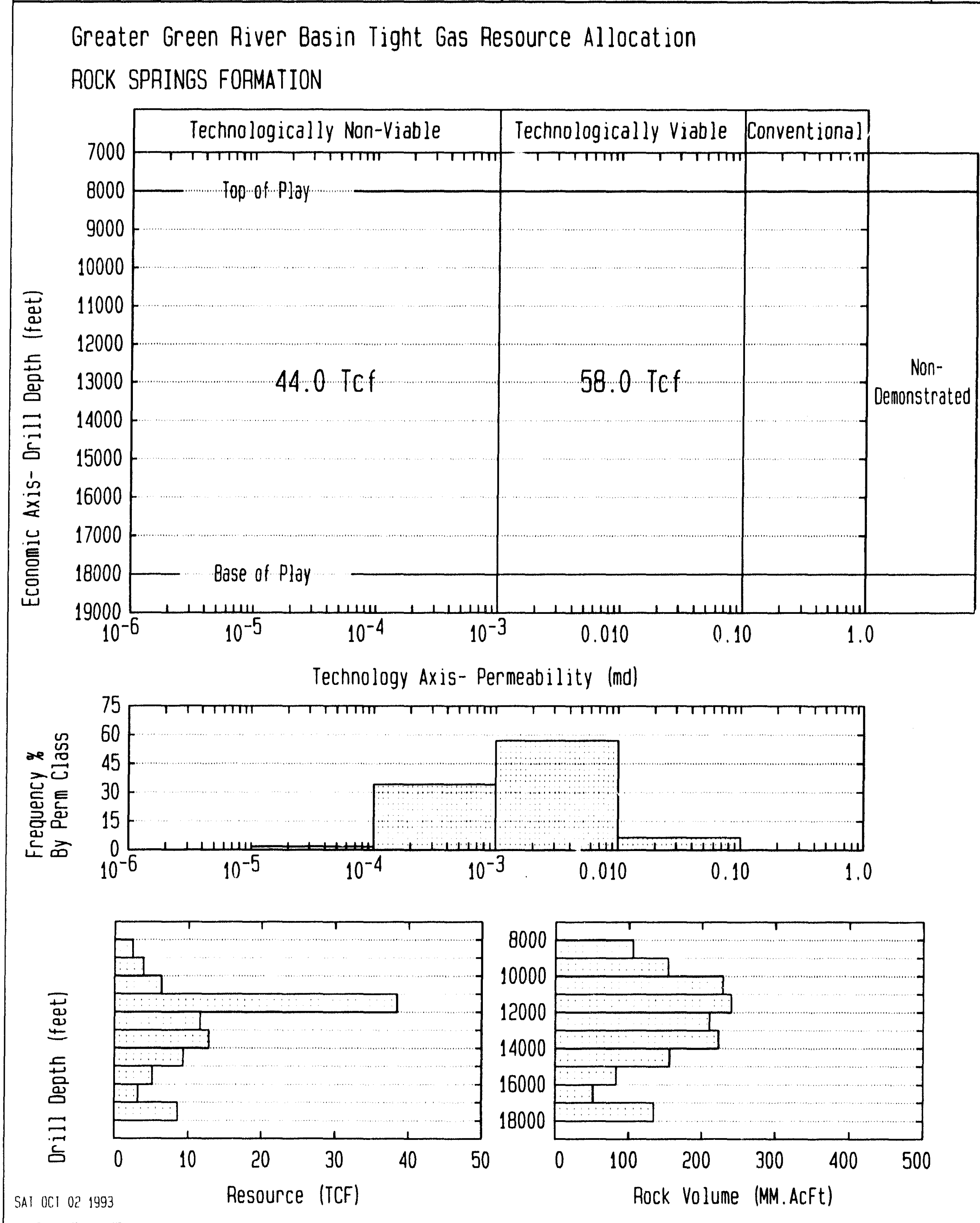
ALMOND FORMATION



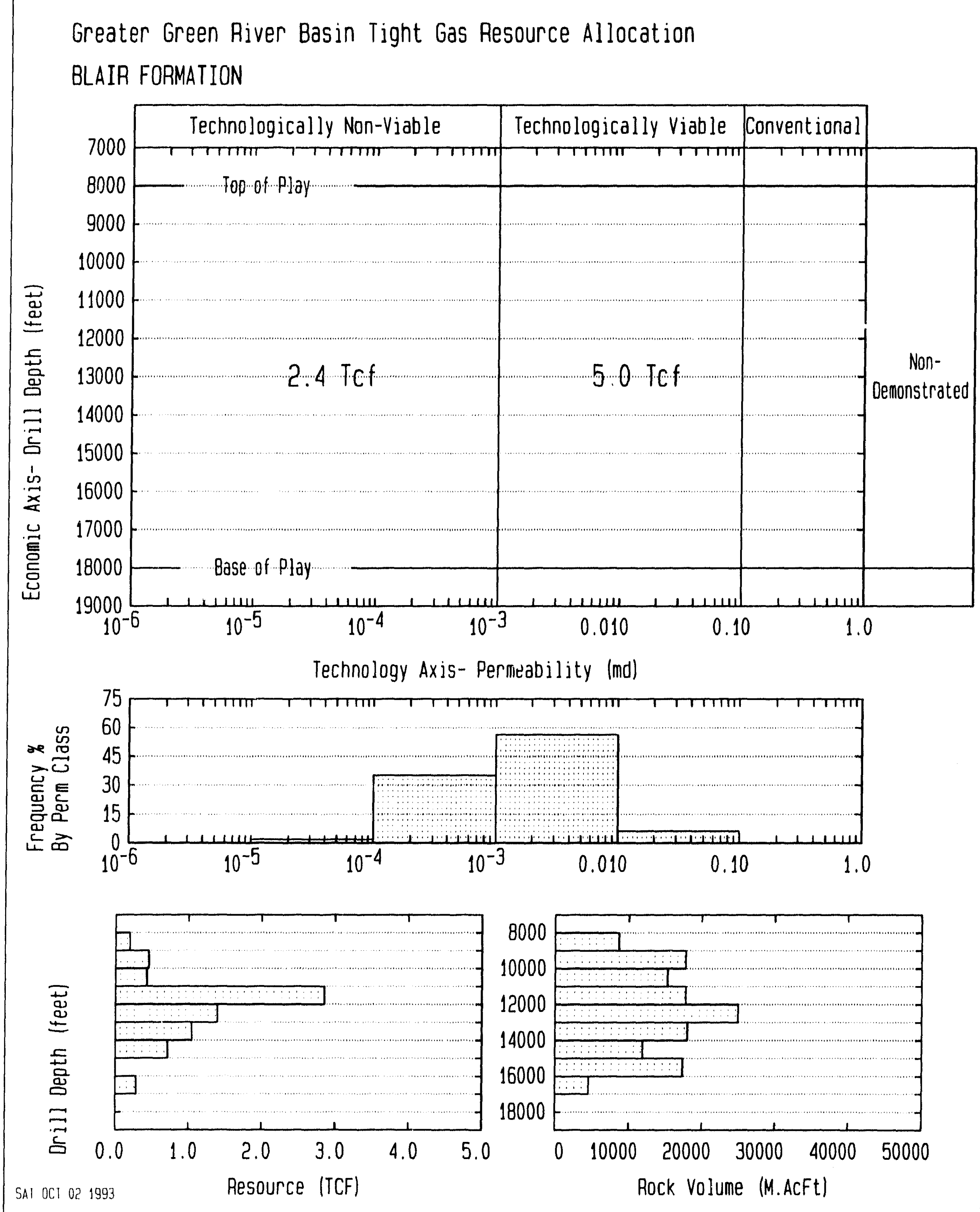
Scotia Group Resource Model	Distribution and Classes of In Place Resources	Client: U.S. DEPARTMENT OF ENERGY	Figure 38



Scotia Group Resource Model	Distribution and Classes of In Place Resources	Client: U.S. DEPARTMENT OF ENERGY	Figure 39



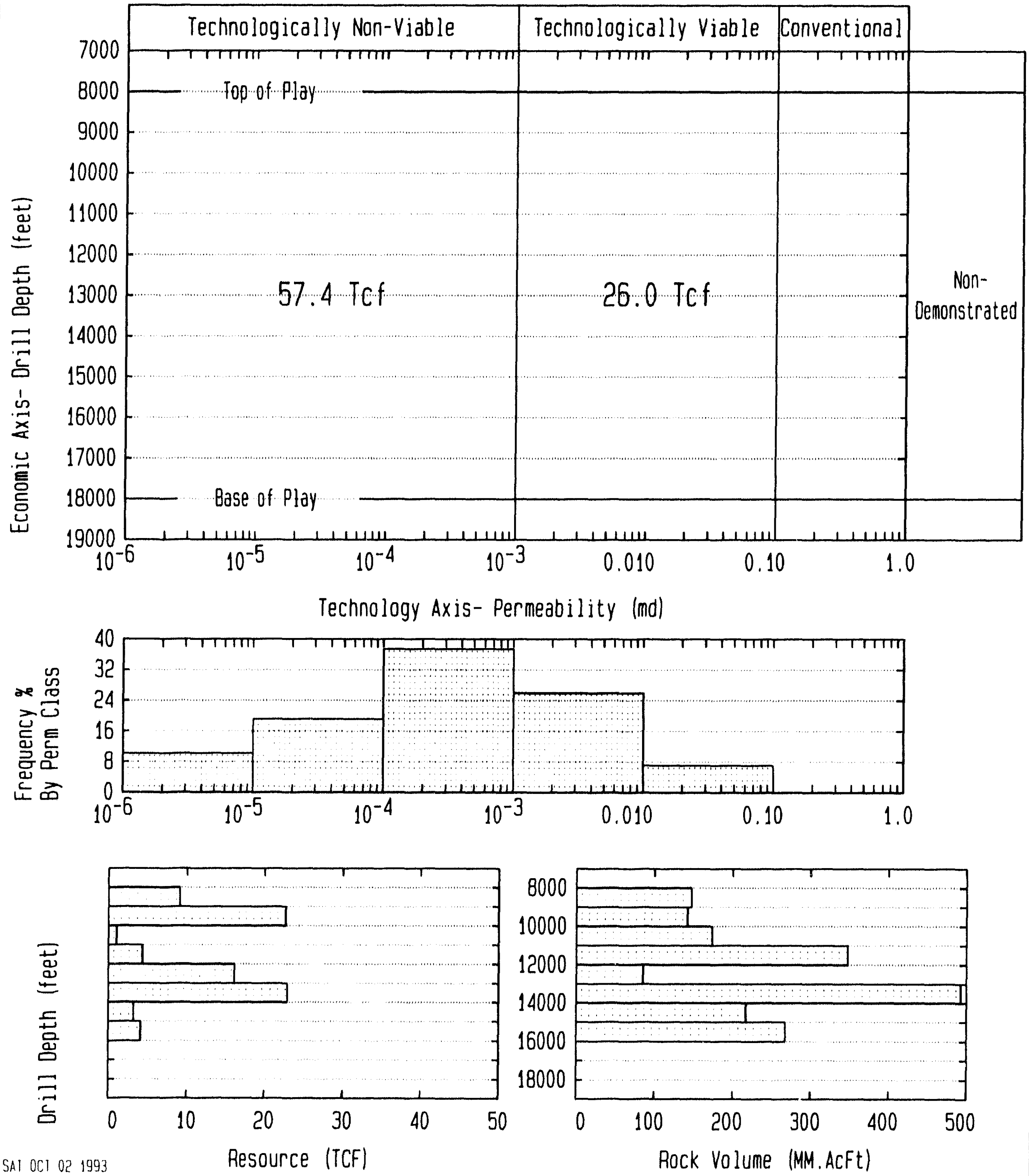
Scotia Group Resource Model	Distribution and Classes of In Place Resources	Client: U.S. DEPARTMENT OF ENERGY	Figure 40



Scotia Group Resource Model	Distribution and Classes of In Place Resources	Client: U.S. DEPARTMENT OF ENERGY	Figure 41

Greater Green River Basin Tight Gas Resource Allocation

MESAVERDE UNDIVIDED



SAI OCT 02 1993

LEWIS PLAY

Description

The Lewis play lies immediately above the Mesaverde (Ericson and Almond formations) on the eastern side of the GGRB being restricted to the Great Divide, Washakie and Sand Wash basins and the Wamsutter Arch. The western limit of the play coincides with the western edge of the Lewis shale transgression. Targeted reservoirs consist of sandstone bodies of net thickness up to 200 feet occur within the overall Lewis shale section. Total area of the play is approximately 3,900 square miles.

Well control within the play area is generally good, comprising Lewis wells plus penetrations through the Lewis with Mesaverde objectives (Figure 42). In fact, many of the Lewis producers TD in the Mesaverde, presumably with the objective of data acquisition and choice of the best potential reservoir for completion. The deeper portions of the play, particularly in the Great Divide and Washakie basins, are sparsely drilled, providing only limited control. Similarly, the Sand Wash basin area has only sparse control. The bulk of the Lewis play has been FERC designated as tight with the exception of the Sand Wash basin and Cherokee Ridge area (Figure 43). Two areas within this designated area have been excluded, these bracketing specific sections in the Hay reservoir area of the Great Divide basin. These excluded areas represent areas of improved permeability within the Lewis to levels no longer considered tight for the purposes of FERC tight gas designation.

Examination of the Lewis field list (Table 14) shows a cumulative production of 112 Bcf from 91 wells. The EURs of these wells is 176 Bcf or an average of 1.9 Bcf/well. The Hay reservoir accounting for over a third of the wells and over half the production, dominates Lewis producing statistics. Other Lewis production is scattered along the Hay pinchout trend in the Great Divide basin and again scattered diagonally across the Washakie basin (Figure 44). Significant recoveries exist at Lost Creek and Wamsutter fields and also at Triton, a relatively deep Washakie basin field. Examining the play level production plot (Figure 45), approximately 50 wells are currently producing with average per well rates of 500 Mcfd. The production plot also suggests considerable curtailment during the mid 1980s, however, curtailment is no longer evident.

Analysis of drilling statistics relevant to the Lewis are somewhat complicated by the fact that the majority of Lewis completions are deepened to TD in the top of the Mesaverde. However, examining just the wells with Lewis TDs as being representative of a Lewis objective, 83% were completed and 17% were dry holes. The Lewis risk model assumes 20% dry holes. This risk model is based upon drilling activity and production concentrated principally in the Hay area of the Great Divide basin and Wamsutter Arch areas. There is little information on deeper areas, particularly in the central portions of the Washakie basin and the deep areas of the northeastern portion of the Great Divide basin, or on the Sand Wash basin.

Stratigraphy and Rock Properties

Prospective OPT gas reservoirs in the Lewis consist of a series of sandstone bodies encased within the overall Lewis shale interval. Total sandstone thicknesses vary up to 600 feet. The sandstones are associated with the Lewis marine transgression and are variously stacked and positioned parallel to the western limit of deposition. Figure 46 is the regional net pay isopach for the Lewis and Figure 47 displays the rock property distribution.

Figure 48 is an example of a CPI log from the Lewis play. The Davis Oil Picket Lake #5 well is located in the northern Great Divide basin at S13 T26N R97W. The well tested 527 Mcfd and 22 Bcpd following acid stimulation between 13,545 and 13,613 feet. The top Lewis was encountered at 13,016 feet and the well reached total depth in the Lewis at 13,725 feet and was plugged back to 13,660 feet.

A total of 673 samples of Lewis core data were available and these were corrected to in-situ conditions and subdivided into three categories: Completed, Tested and Other samples, Figure 49a and 49b. Immediately apparent is the change from excess negative skewness (Completed) to excess positive skewness (Other) displayed by the porosity histograms. Note that when all samples are plotted together, a bi-modal porosity distribution is evident with intermodal trough lying between 5 and 7% porosity.

The average permeability decreases from the Completed through to Other categories, but more apparent is the increase in width of the corridor of scatter on the porosity permeability plots. Considering that the Completed porosity-permeability distribution is derived from many wells, the relationship is relatively tight. The large scatter of data for the lower porosity range of the Other category may be attributed in part to fractures in the samples and also to a strong diagenetic overprint destroying much of the original porosity. As discussed in Appendix A, the better reservoir quality rocks (Completed) are speculated to retain much of their original fabric and pore structure, hence the higher correlation coefficient, while the poorer quality rocks (Other) have undergone significant diagenetic alteration.

Note that the lines of data points on the porosity-permeability plot at .07 μd, .3 μd and .7 μd are "not measured" samples at ambient conditions and become the graphed values after correction to in-situ conditions.

Reevaluation of Resource

The bulk of the rock volume comprising the Lewis play lies between 9,000 and 13,000 feet with the base of the play extending down to a depth of 18,000 feet at the deepest extremities of the basin. Approximately 80% of the rock volume lies above 14,000 feet which is the main interval of interest. This depth corresponds to the deepest evaluated well control with rock volumes below this depth being assigned the same properties as the deepest evaluated interval.

The porosity distributions tend to be skewed towards the lower porosity values with calculated water saturations increasing rapidly at below 5% porosity. Porosities over 15% tend to evaluate as conventional reservoirs from a calculated permeability standpoint which is in line with the observed behavior within the Hay reservoir. When examining the Lewis section in individual wells or via core data, it is common to note a bi-modal distribution of porosity with the lower values representing nonreservoir quality tight rocks and the higher distribution representing pay.

The existing production from the Lewis is dominated by the Hay reservoir which exhibits superior EURs in comparison to most of the rest of Lewis production in the basin. For constructing a distribution of expected recoveries for *economic basement* calculations, all Lewis wells were included. This gives the resulting distribution a definite "sweet spot" character such that the EMV analysis and the *economic basement* that results are considered to err on the optimistic side. This model in calculated the *economic basement* at approximately 10,800 feet. *Deepest commercial production* places a floor for consideration of reserves at 14,000 feet. Figure 50 illustrates the EUR distributions and the Lewis risk model.

Of the total resource of 229 Tcf evaluated for the Lewis, 169 Tcf or 74% occurs in low permeability rocks considered to be too tight to support commercial production. Of the remaining 60 Tcf, 34 Tcf lies below an *economic basement* of 10,800 feet, leaving an *established* resource of 28 Tcf which will be the main contributor to reserves.

Table 12 compares the USGS estimate for the Lewis play to the revised estimate derived herein. Figure 51 graphically illustrates this breakdown.

TABLE 12
LEWIS PLAY RESOURCE ESTIMATE BREAKDOWN
(Tcf)

USGS Mean Resource Estimate	**610**
Scotia Revised Mean Resource Estimate	**229**
MINUS *Technologically Nonviable* Resources	**169**
SUBTOTAL *Technologically Viable* Resources	**60**
MINUS *Nondemonstrated* Resources	**0**
SUBTOTAL *Demonstrated* Resources	**60**
Subdivision:	
***Speculative* Resources**	**4**
***Nonestablished* Resources**	**28**
***Established* Resources**	**28**

Reserves Evaluation

The Lewis play reserves evaluation is subdivided into *Established* and *Nonestablished* divisions, involving the following parameters:

TABLE 13
RESERVES CALCULATION, LEWIS PLAY

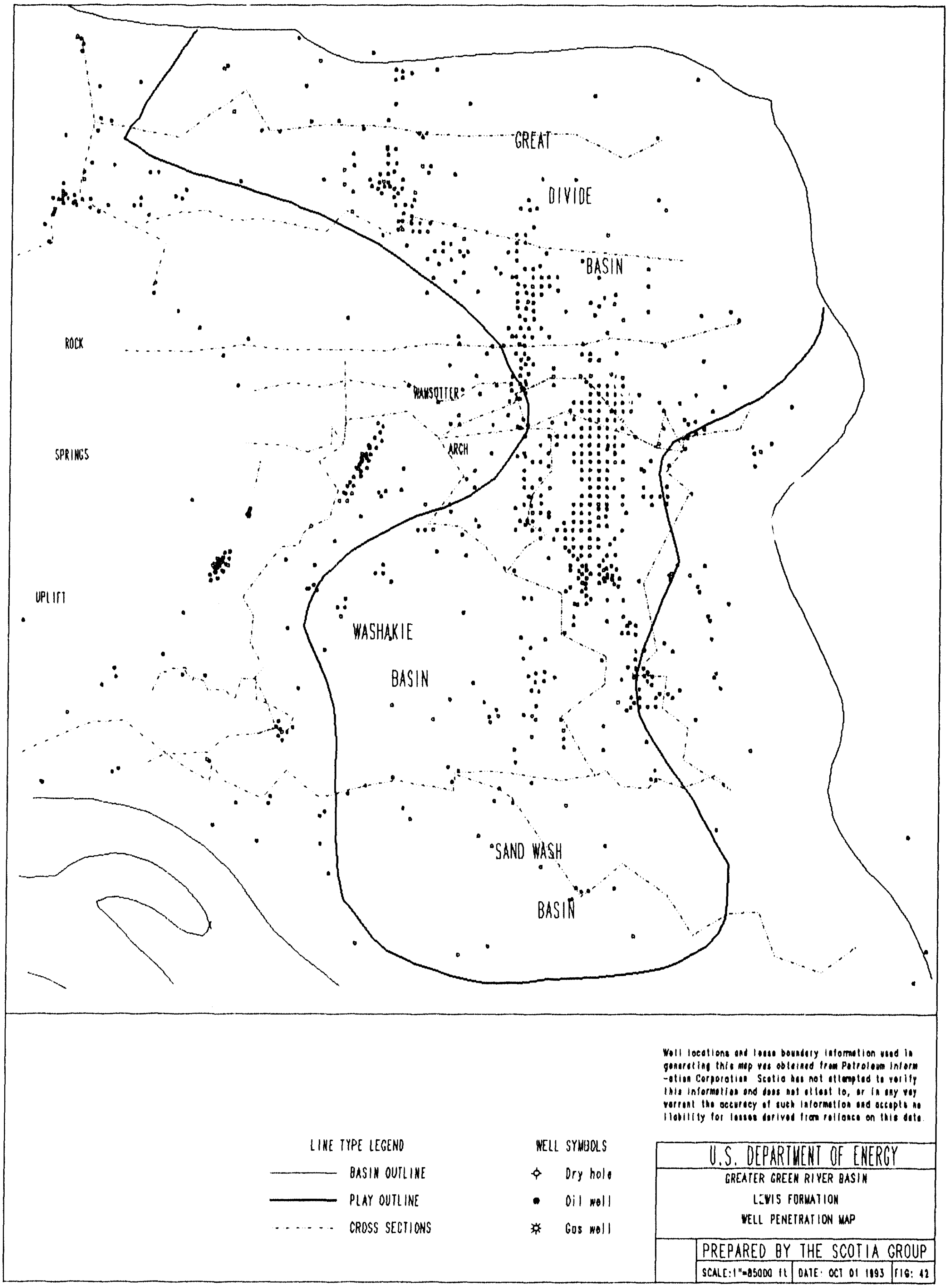
	Established Category			*Nonestablished* Category		
Parameters	Max	Most Likely	Min	Max	Most Likely	Min
Base Recovery Factor	0.75	0.75	0.75	0.75	0.75	0.75
Dry Hole Fraction	0.20	0.20	0.20	0.50	0.50	0.50
Minimum Economic Drainage Acres	24	89	200	44	160	570
Noncommercial Fraction	0.29	0.57	0.74	0.42	0.70	0.89
Recovery Factor	0.43	0.26	0.16	0.22	0.11	0.04
Rock Volume (M AcFt)		60,983			49,156	
Porosity	0.14	0.095	0.06	0.13	0.075	0.06
Water Saturation	0.48	0.53	0.57	0.41	0.50	0.52
FVF (res cuft/scf)	0.00458	0.00412	0.00361	0.00361	0.00328	0.00308
Reserves Probability Distribution						
90% Probability of Exceeding (Tcf)		5.4			2.0	
70% Probability of Exceeding (Tcf)		6.9			2.7	
50% Probability of Exceeding (Tcf)		8.1			3.4	
30% Probability of Exceeding (Tcf)		9.5			4.2	
10% Probability of Exceeding (Tcf)		11.8			5.5	
Mean Value (Tcf)		8.4			3.6	
PDP Reserves & Cum Production						
Cumulative Production (Bcf)		102			10	
Remaining PDP Reserves (Bcf)		60			4	
EUR of PDP Reserves (Bcf)		162			14	

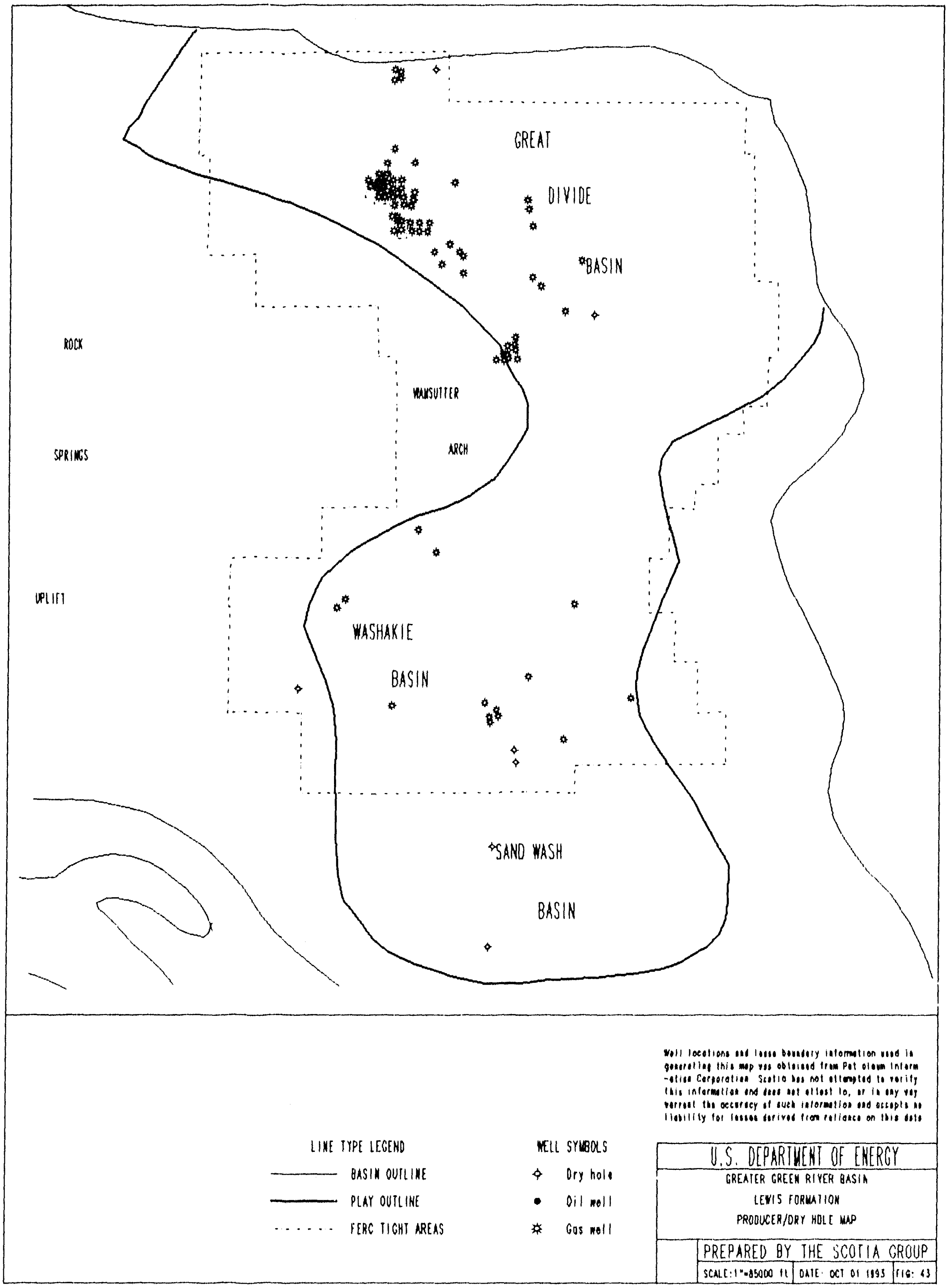
The most notable aspect of the Lewis play is the concentration of activity in the area of the Hay reservoir. Attractive pay sections in the Lewis are noted behind pipe in Mesaverde wells along the Wamsutter Arch and deep production in the Washakie basin at Triton field indicates that the Lewis may be prospective in a variety of settings.

In summary, reserves are recognized in both the *established* and *nonestablished* categories in the Lewis. The mean estimate for *established* reserves is 8.4 Tcf overall, or 8.2 Tcf after subtraction of the EURs of existing Lewis OPT wells. *Nonestablished* reserves are recognized with a mean estimate of 3.6 Tcf overall and after subtraction of the negligible EURs of existing OPT wells in this category.

TABLE 14
LEWIS PLAY OPT FIELD LIST

Field Name	Avg Depth (Feet)	Cum MMcf	EUR MMcf	Number of Wells	Avg EUR MMcf/Well
Alkaline Creek	11615	542	542	2	271
Barrell Springs	8620	27	55	1	55
Bastard Butte	10930	4	4	1	4
Battle Springs	12080	1118	1328	2	664
Bush Lake	11191	182	182	1	182
Cepo	12577	82	106	1	106
Continental Divide	11390	157	157	1	157
Dripping Rock	11197	139	139	1	139
Emigrant Trail	12435	30	30	1	30
Five Mile Gulch	9563	8	8	1	8
Gale	9904	2	2	1	2
Great Divide	9721	3367	4775	7	682
Hay Reservoir	9973	67476	105971	36	2944
Laney Wash	9915	132	132	1	132
Lost Creek	9181	5037	9555	2	4778
Lost Creek Basin	9927	157	157	2	79
McPherson Springs	10615	102	102	1	102
Nickey	11390	325	499	1	499
Picket Lake	13464	2348	2348	4	587
Red Desert	9711	158	158	2	79
Rim Unit	12989	34	34	1	34
Robbers Gulch	8795	91	91	1	91
Sentinal Ridge	11977	222	222	1	222
Siberia Ridge	10634	1593	2096	5	419
Triton	12890	3456	6469	4	1617
Twin Fork	17195	367	367	1	367
Wamsutter	8364	25017	40370	9	4486
Play Totals		112173	175899	91	1933


GREAT
DIVIDE
BASIN
ROCK
SPRINGS
UPLIFT
WAMSUTTER
ARCH
WASHAKIE
BASIN
SAND WASH
BASIN
Well locations and lease boundary information used in generating this map was obtained from Petroleum Inform-ation Corporation. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.
LINE TYPE LEGEND
BASIN OUTLINE
PLAY OUTLINE
CROSS SECTIONS
WELL SYMBOLS
Dry hole
Oil well
Gas well
U.S. DEPARTMENT OF ENERGY
GREATER GREEN RIVER BASIN
LEWIS FORMATION
WELL PENETRATION MAP
PREPARED BY THE SCOTIA GROUP
SCALE:1"=85000 ft
DATE: OCT 01 1993
FIG: 42



GREAT
DIVIDE
BASIN
ROCK
SPRINGS
UPLIFT
WAMSUTTER
ARCH
WASHAKIE
BASIN
SAND WASH
BASIN
Well locations and lease boundary information used in generating this map was obtained from Petroleum Information Corporation. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data
LINE TYPE LEGEND
BASIN OUTLINE
PLAY OUTLINE
FERC TIGHT AREAS
WELL SYMBOLS
Dry hole
Oil well
Gas well
U.S. DEPARTMENT OF ENERGY
GREATER GREEN RIVER BASIN
LEWIS FORMATION
PRODUCER/DRY HOLE MAP
PREPARED BY THE SCOTIA GROUP
SCALE:1"=85000 ft
DATE: OCT 01 1993
FIG: 43

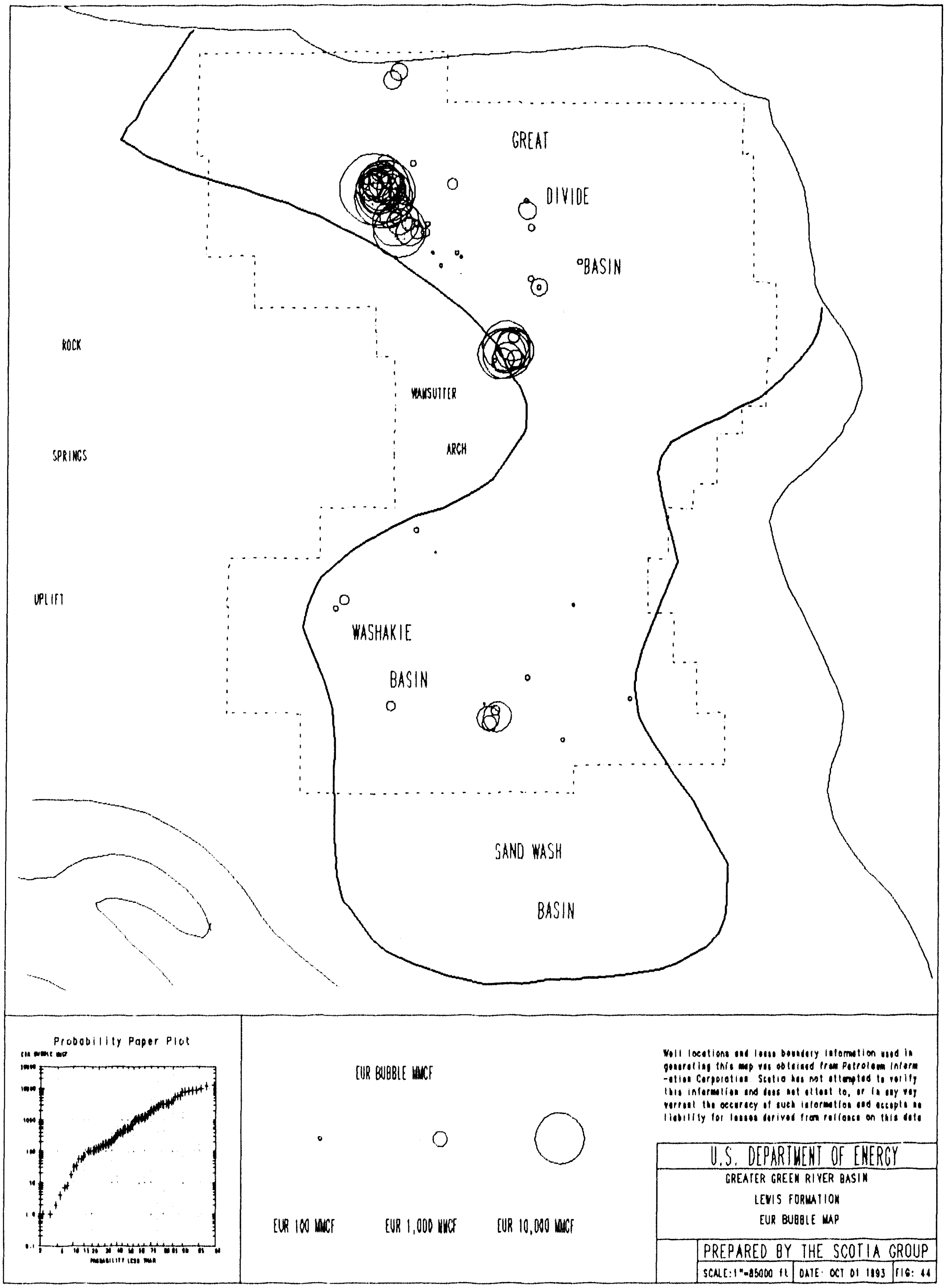
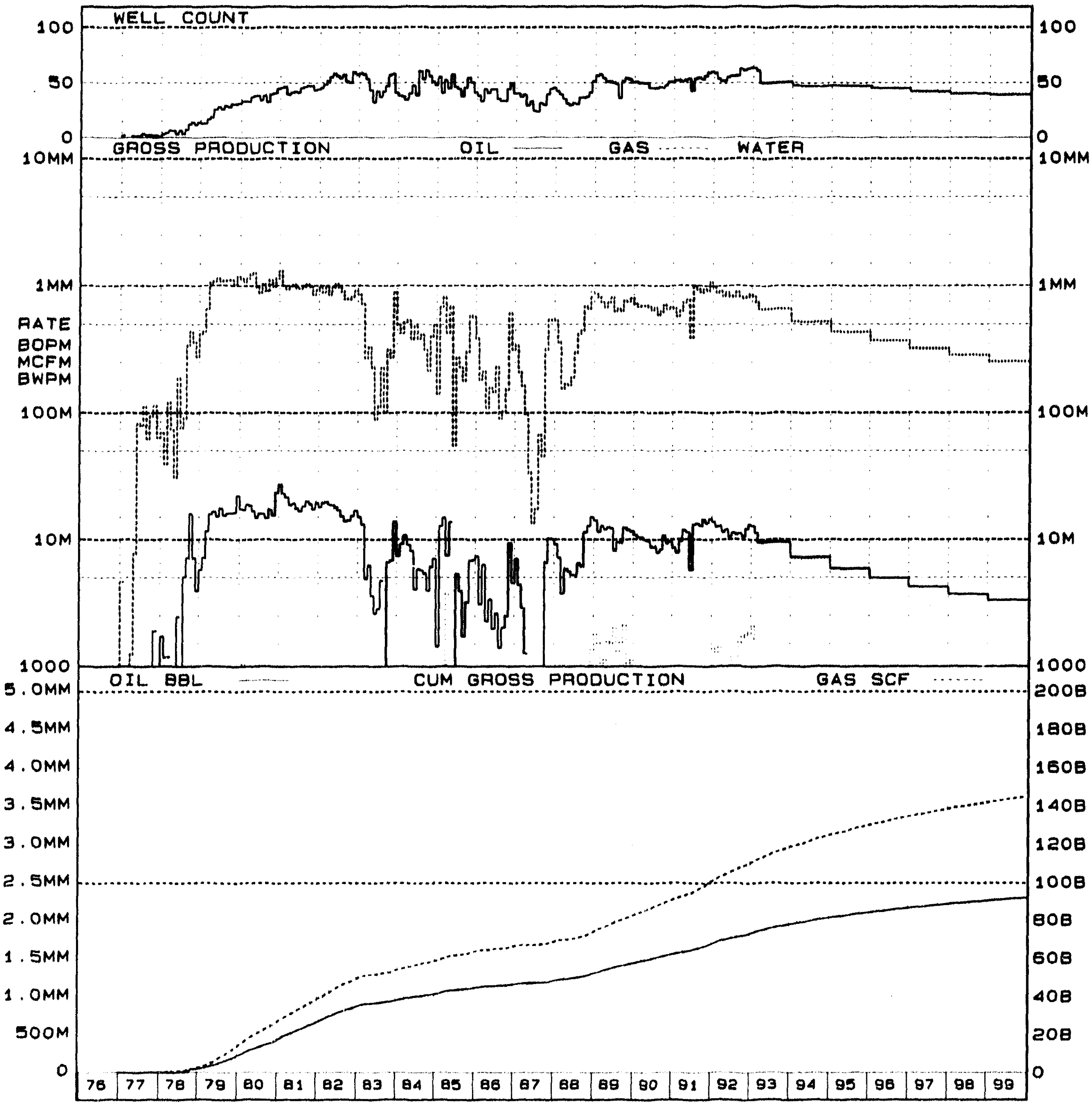

GREAT
DIVIDE
BASIN
ROCK
SPRINGS
UPLIFT
WAMSUTTER
ARCH
WASHAKIE
BASIN
SAND WASH
BASIN
Probability Paper Plot
EUR BUBBLE MMCF
EUR 100 MMCF
EUR 1,000 MMCF
EUR 10,000 MMCF
Well locations and lease boundary information used in generating this map was obtained from Petroleum Inform-ation Corporation. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data
U.S. DEPARTMENT OF ENERGY
GREATER GREEN RIVER BASIN
LEWIS FORMATION
EUR BUBBLE MAP
PREPARED BY THE SCOTIA GROUP
SCALE:1"=85000 ft
DATE: OCT 01 1893
FIG: 44

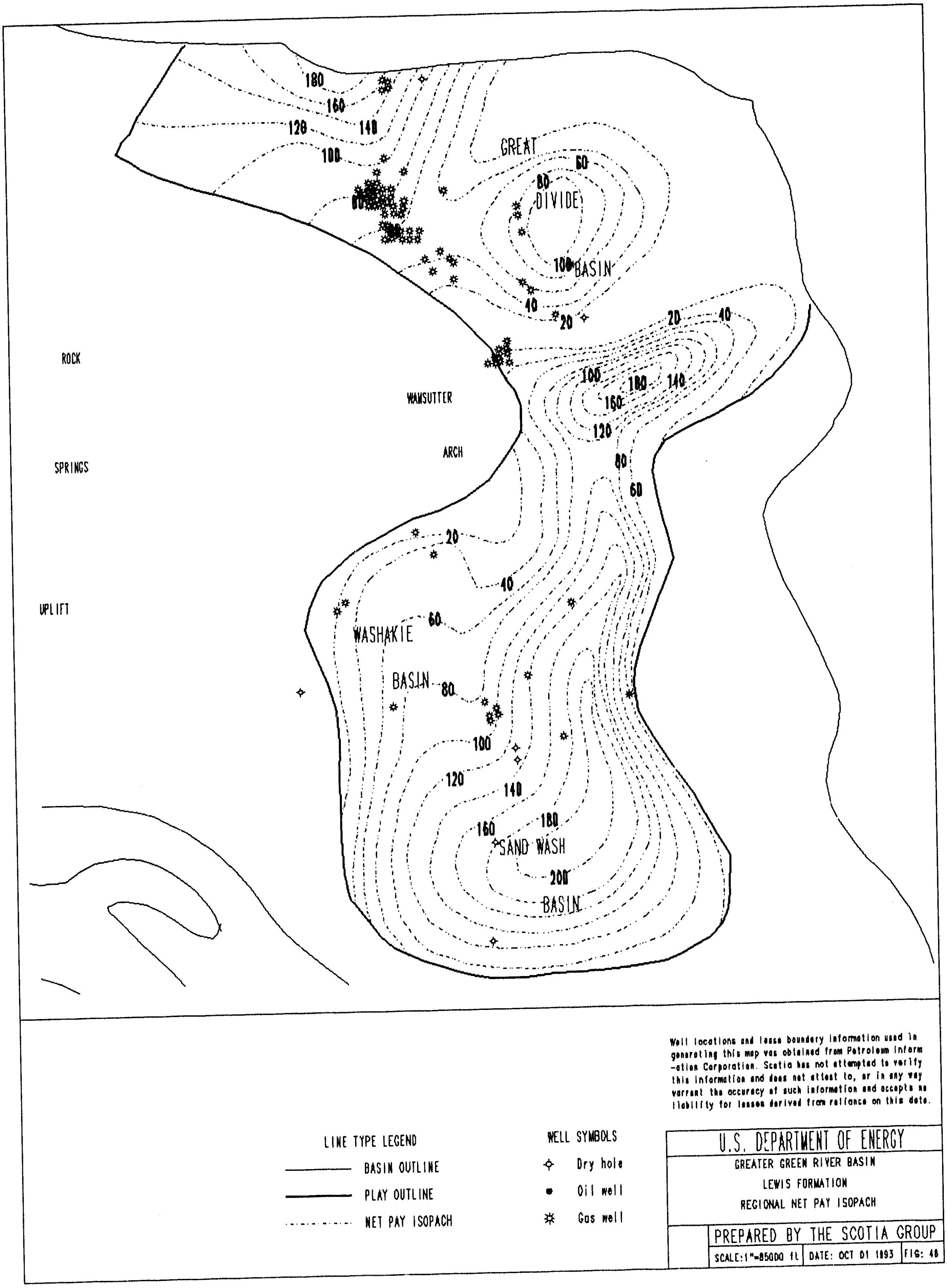
FIGURE 45



LEWIS TOTAL PRODUCTION PROFILE

Projections are averages for each year commencing at the effective date of the evaluation. Results are subject to the qualifications and limitations stated in the attached document

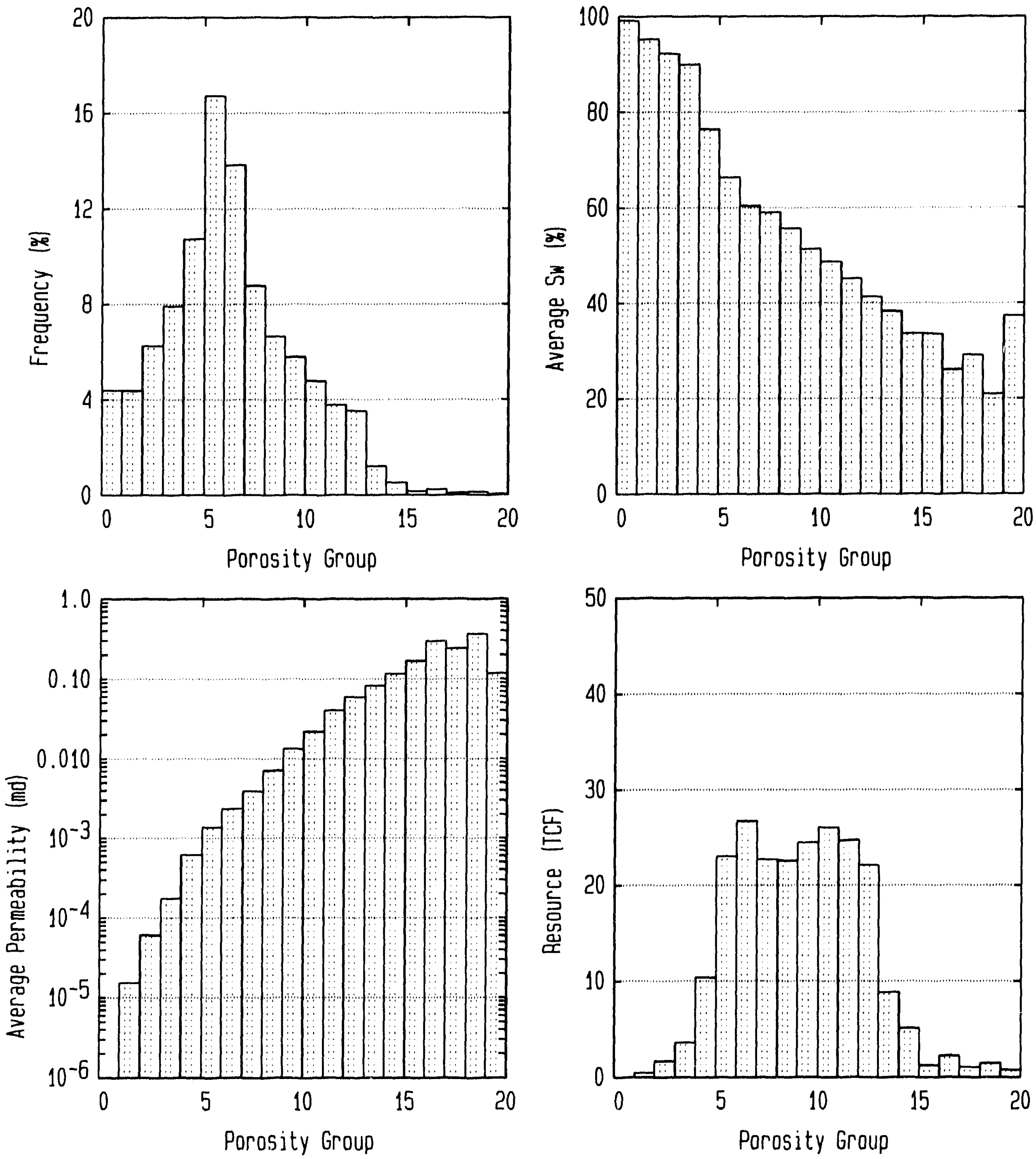
PREPARED BY THE SCOTIA GROUP, INC. *S.S.L. FRI OCT 01 1993 15:50:01*


GREAT DIVIDE BASIN
ROCK SPRINGS UPLIFT
WAMSUTTER ARCH
WASHAKIE BASIN
SAND WASH BASIN
180
160
140
120
100
80
60
40
20
200
Well locations and lease boundary information used in generating this map was obtained from Petroleum Information Corporation. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.
LINE TYPE LEGEND
BASIN OUTLINE
PLAY OUTLINE
NET PAY ISOPACH
WELL SYMBOLS
Dry hole
Oil well
Gas well
U.S. DEPARTMENT OF ENERGY
GREATER GREEN RIVER BASIN
LEWIS FORMATION
REGIONAL NET PAY ISOPACH
PREPARED BY THE SCOTIA GROUP
SCALE:1"=85000 ft
DATE: OCT 01 1993
FIG: 48

Scotia Group Resource Model	Rock Property and In-Place Resource Distributions	Client: U.S. DEPARTMENT OF ENERGY	Figure 47

Greater Green River Basin: Rock Property Distributions

LEWIS PLAY

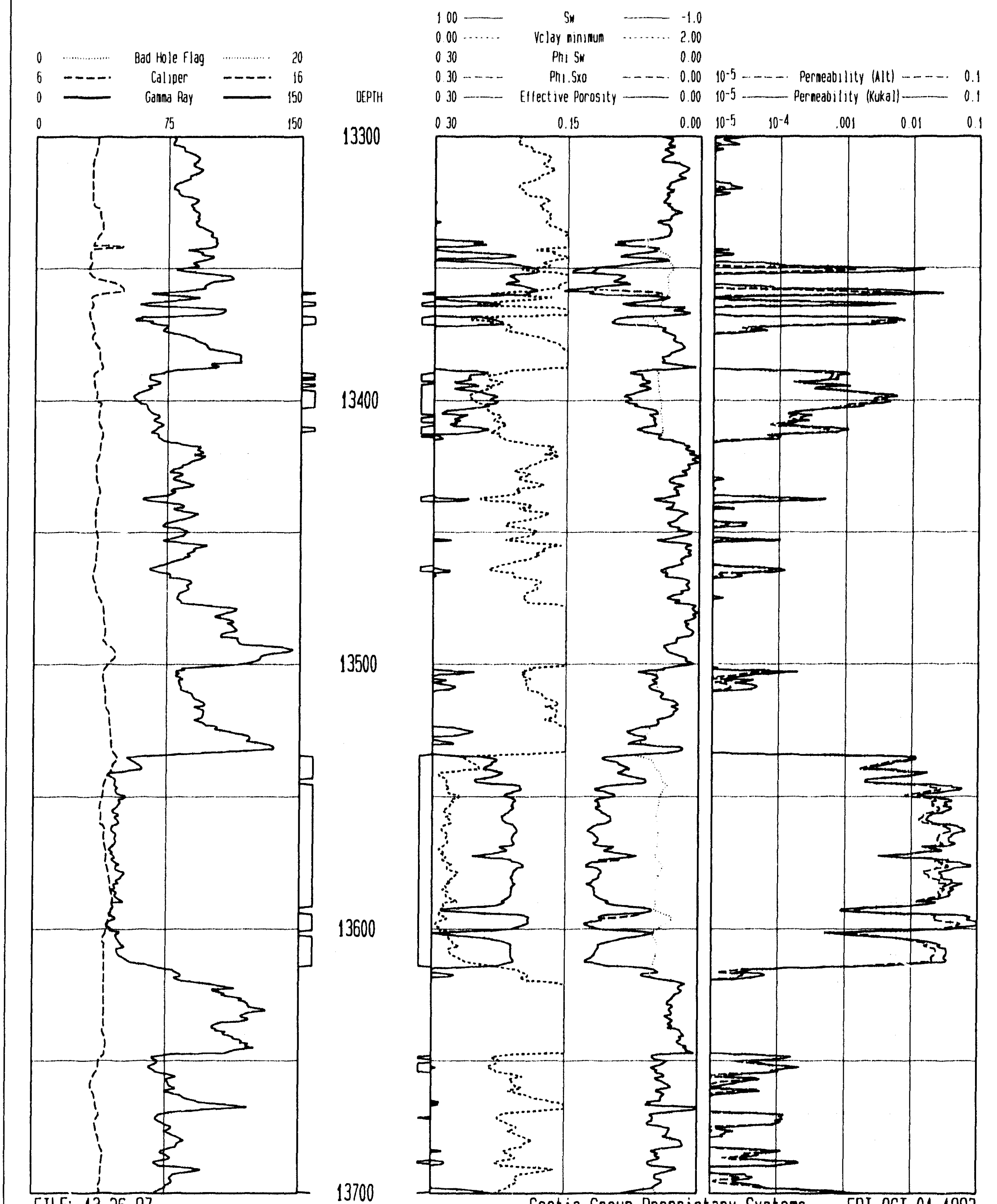


SAT OCT 02 1993

SCOTIALOG: Tight Gas Log Analysis Module

DAVIS OIL PICKET LAKE #5 API #49037214970000
Client: U.S. DEPARTMENT OF ENERGY

Figure 48



FILE: 13-26-97

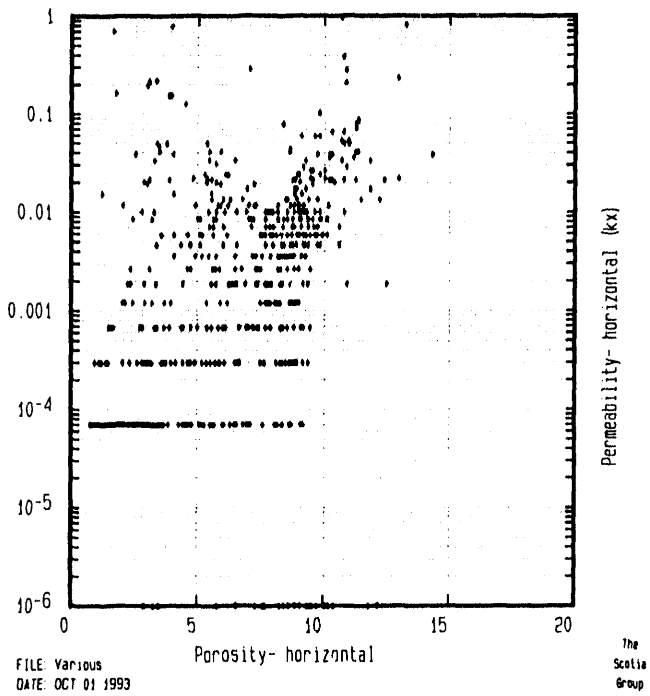
Scotia Group Proprietary Systems FRI OCT 01 1993

Figure 49a

COREPRO Client: U.S. DEPARTMENT OF ENERGY

INSITU CONDITION, LEWIS PLAY, ALL DATA

Porosity versus Permeability

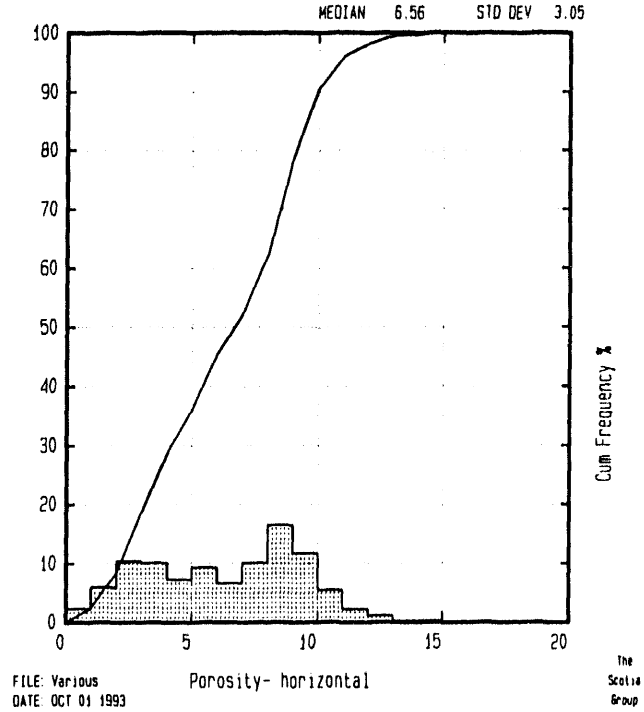


COREPRO Client: U.S. DEPARTMENT OF ENERGY

INSITU CONDITION, LEWIS PLAY, ALL DATA

Histogram Plot

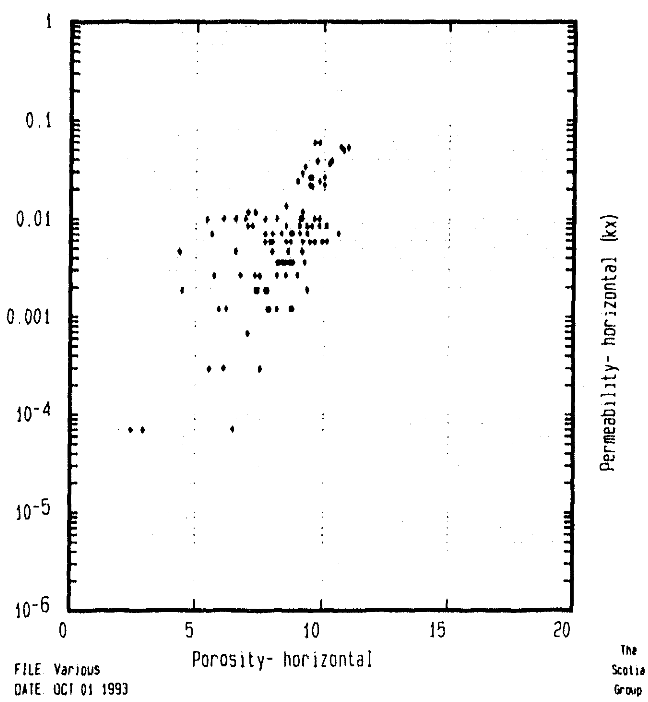
AVERAGE	6.32	POINTS	673
MEDIAN	6.56	STD DEV	3.05



COREPRO Client: U.S. DEPARTMENT OF ENERGY

INSITU CONDITION, LEWIS PLAY, COMPLETED INTERVALS

Porosity versus Permeability



COREPRO Client: U.S. DEPARTMENT OF ENERGY

INSITU CONDITION, LEWIS PLAY, COMPLETED INTERVALS

Histogram Plot

AVERAGE	8.28	POINTS	104
MEDIAN	8.53	STD DEV	1.59

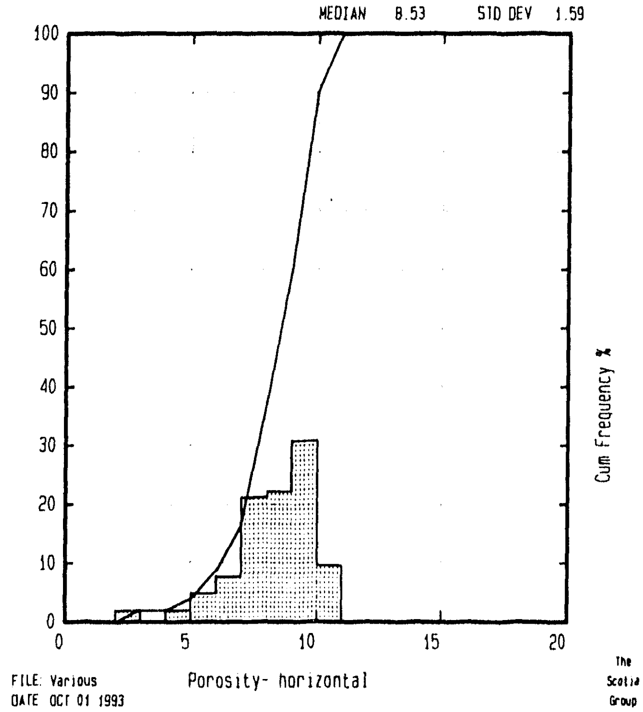
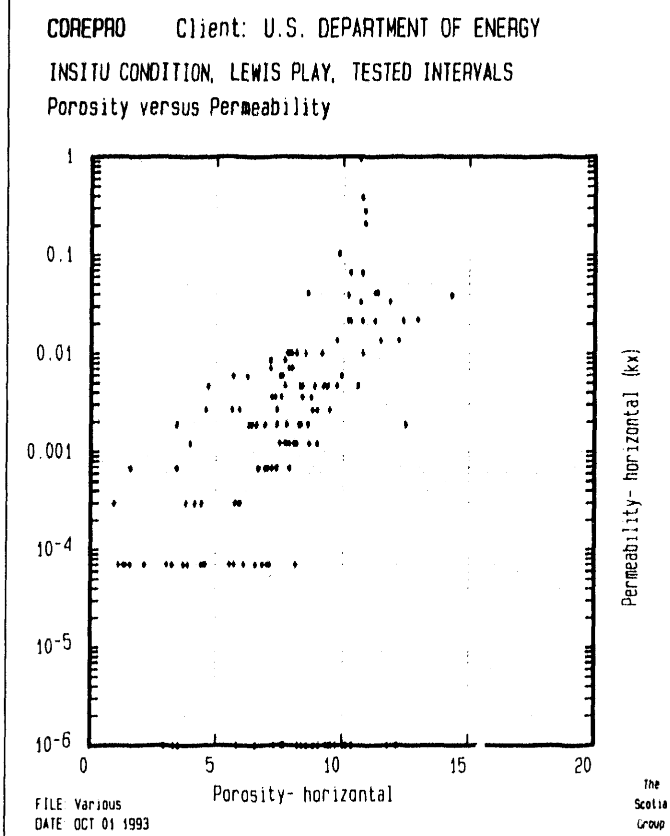
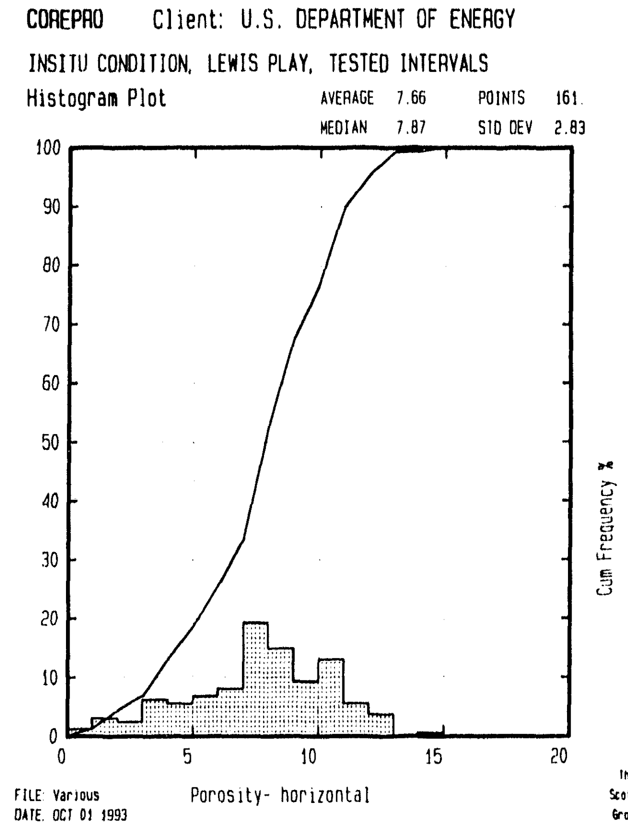
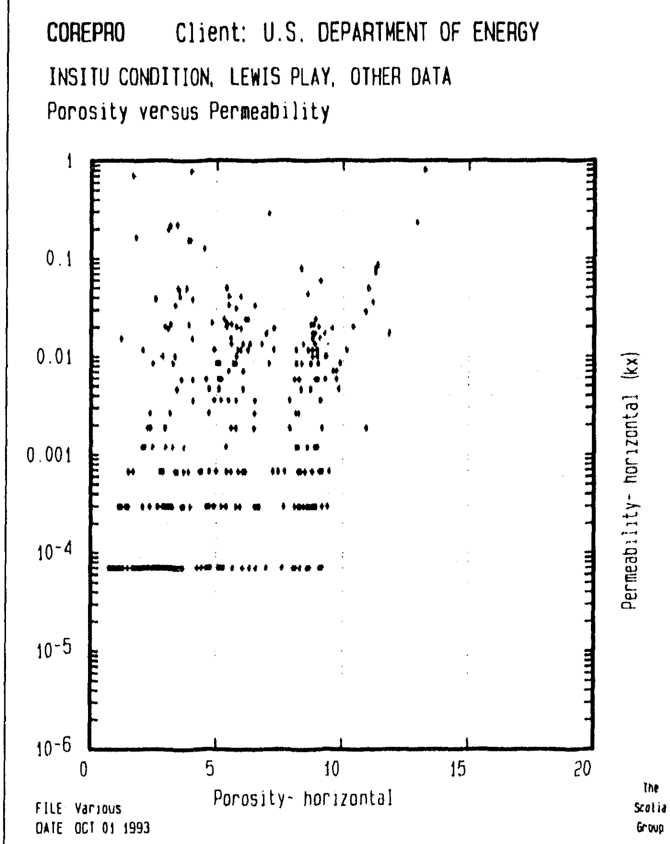
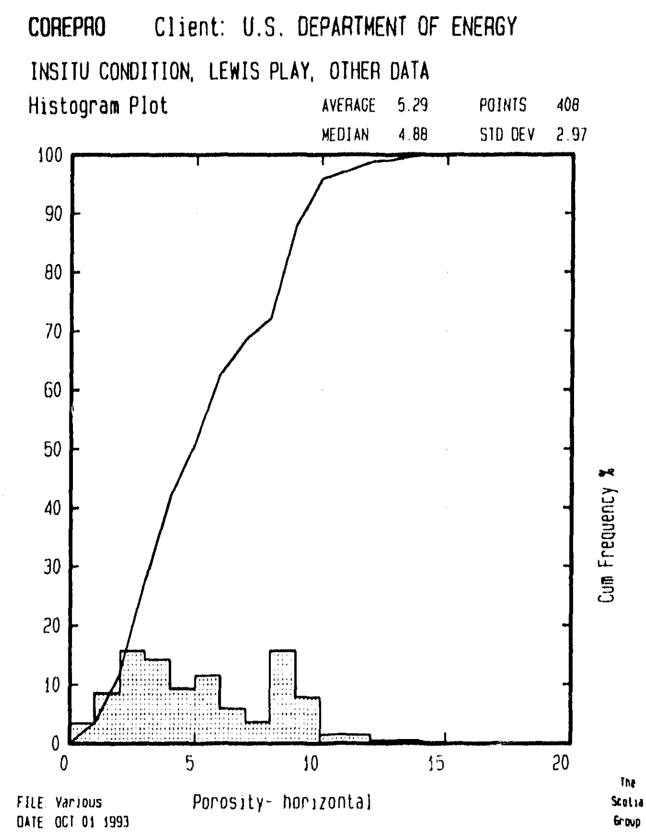


Figure 49b


COREPRO Client: U.S. DEPARTMENT OF ENERGY
INSITU CONDITION, LEWIS PLAY, TESTED INTERVALS
Porosity versus Permeability
1
0.1
0.01
0.001
10^{-4}
10^{-5}
10^{-6}
0
5
10
15
20
Porosity- horizontal
Permeability- horizontal (kx)
FILE Various
DATE OCT 01 1993
The Scotia Group


COREPRO Client: U.S. DEPARTMENT OF ENERGY
INSITU CONDITION, LEWIS PLAY, TESTED INTERVALS
Histogram Plot
AVERAGE 7.66
POINTS 161
MEDIAN 7.87
STD DEV 2.83
100
90
80
70
60
50
40
30
20
10
0
0
5
10
15
20
Porosity- horizontal
Cum Frequency %
FILE Various
DATE OCT 01 1993
The Scotia Group


COREPRO Client: U.S. DEPARTMENT OF ENERGY
INSITU CONDITION, LEWIS PLAY, OTHER DATA
Porosity versus Permeability
1
0.1
0.01
0.001
10^{-4}
10^{-5}
10^{-6}
0
5
10
15
20
Porosity- horizontal
Permeability- horizontal (kx)
FILE Various
DATE OCT 01 1993
The Scotia Group

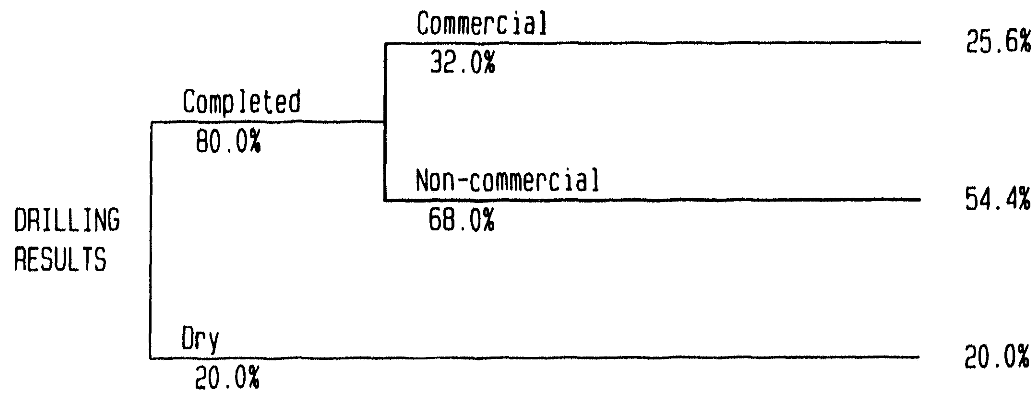

COREPRO Client: U.S. DEPARTMENT OF ENERGY
INSITU CONDITION, LEWIS PLAY, OTHER DATA
Histogram Plot
AVERAGE 5.29
POINTS 408
MEDIAN 4.88
STD DEV 2.97
100
90
80
70
60
50
40
30
20
10
0
0
5
10
15
20
Porosity- horizontal
Cum Frequency %
FILE Various
DATE OCT 01 1993
The Scotia Group

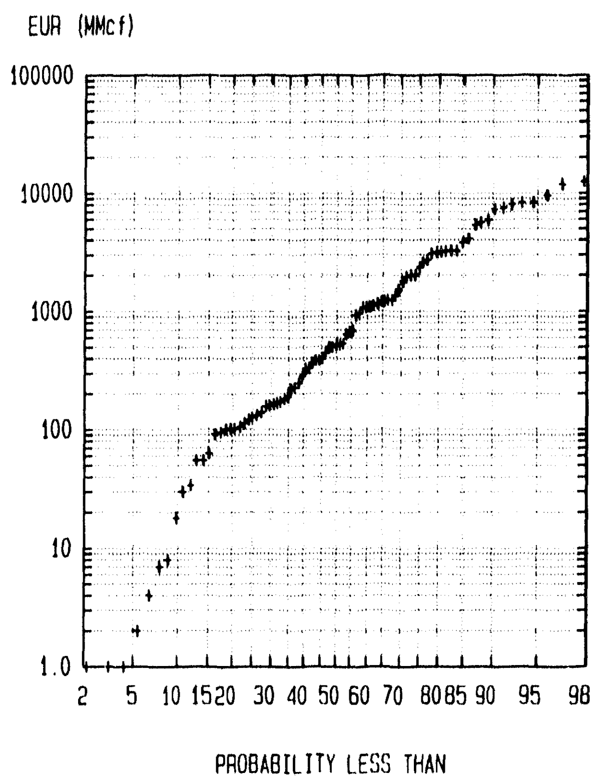
Scotia Group Resource Model	Distribution of EURs and Risk Model	Client: U.S. DEPARTMENT OF ENERGY	Figure 50

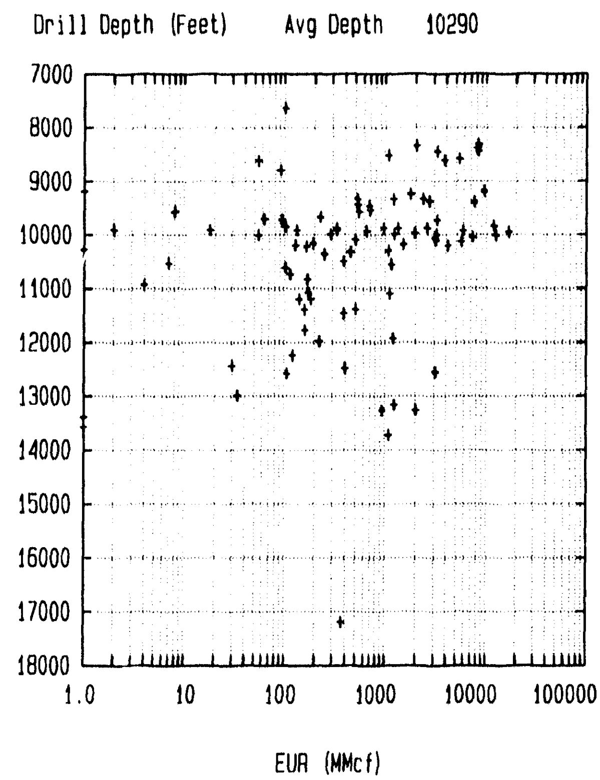
Greater Green River Basin: Rock Property Distributions

LEWIS PLAY

Technical Success	80.0%
Commercial Success	25.6%





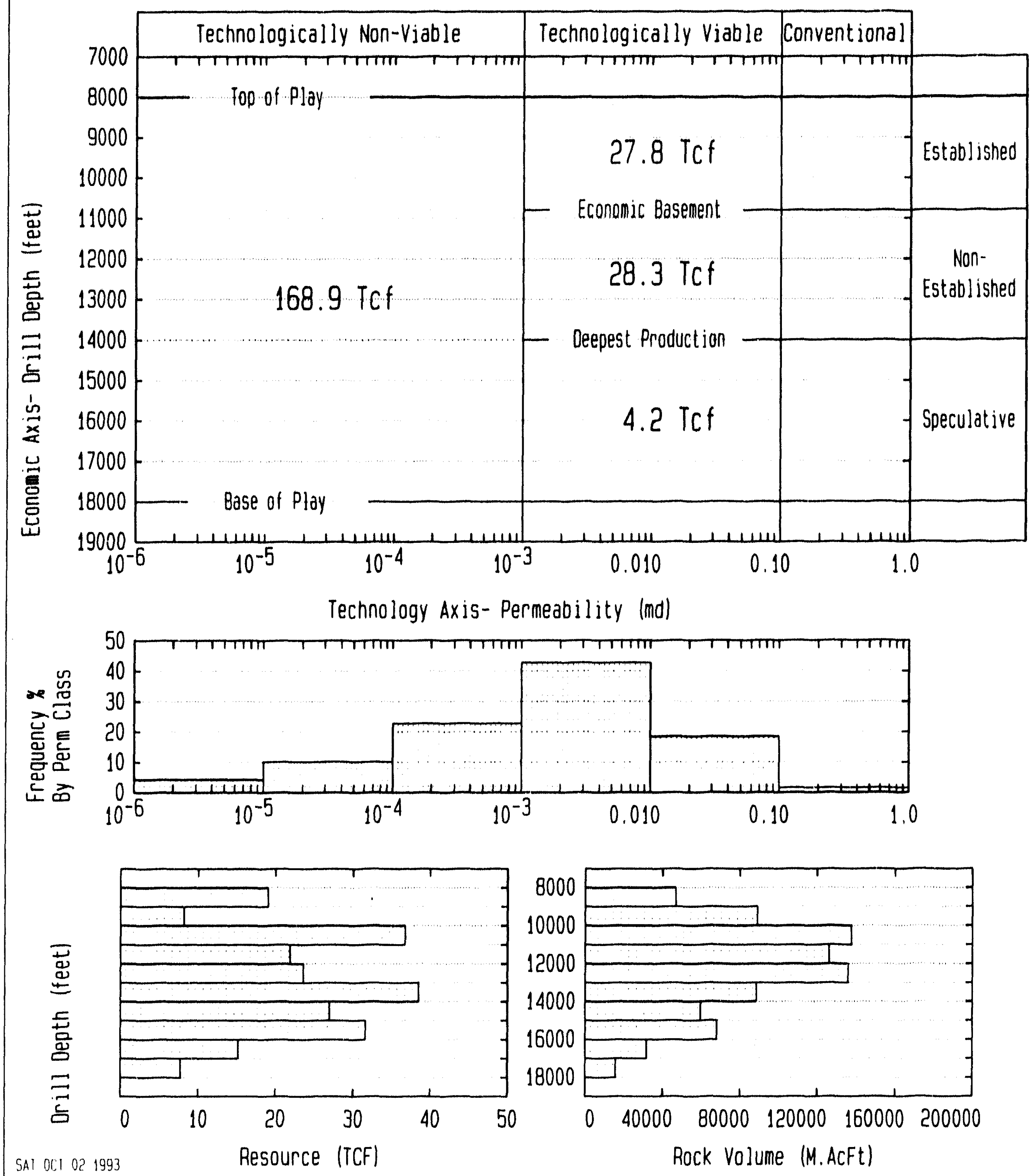


SAT OCT 02 1993

Scotia Group Resource Model	Distribution and Classes of In Place Resources	Client: U.S. DEPARTMENT OF ENERGY	Figure 51

Greater Green River Basin Tight Gas Resource Allocation

LEWIS PLAY



LANCE-FOX HILLS PLAY

Description

The Lance-Fox Hills play lies immediately above the Lewis formation in eastern and central parts of the GGRB and over the Mesaverde in western areas where the Lewis is absent. The Fox Hills sandstone is generally limited to the central and eastern portions of the basin and lies immediately beneath the Lance formation.

The USGS resource assessment identified OPT Lance-Fox Hills in two areas within the GGRB. The first is in the central deeper portions of the Washakie basin and the second area along the northern margins of the basin comprising parts of the Great Divide basin through to the Hoback basin. Total play area approximates 4,000 square miles with reservoirs ranging in thickness from 250 to 1,500 feet.

Control based upon the USGS grid of cross-sections essentially surrounds the Washakie basin evaluated area with no control in the central portions (Figure 52). For the northern area, cross-section control runs the length of the evaluated area.

The FERC has designated a tight gas area within the Lance-Fox Hills play on the northern edge of the Washakie basin (Figure 53). The FERC area straddles the boundary of the first USGS area with about half lying within and half outside of the USGS area. The second USGS area does not contain any FERC designated tight gas areas for the Lance-Fox Hills play section.

Examination of the Lance-Fox Hills field list (Table 16) shows cumulative production of 788 MMcf from seven wells and an average EUR of 113 MMcf/well. All of this production is from the Washakie basin area (Figure 54). The northern portion of the play has no producing wells, although two completions were unsuccessfully attempted at Jonah field in the Pinedale anticline area. Note that for Laney Wash and Shallow Creek fields, wells are still producing but at sub-commercial rates, hence no production projection has been made and the cumulatives equal the EURs. Examining the play level production plot (Figure 55), it appears that Lance-Fox Hills wells have not exhibited stabilized production profiles, but rather exhibit cycles of production, rapid decline and shut-in. Using Shallow Creek field as an example, wells produce at initial high rates of 1 to 3 MMcfd but decline rapidly over a few months to noncommercial rates and are shut-in through summer. This cycle is repeated with a summer shut-in and production during subsequent winter months. While the reservoir section looks attractive, based on log analysis, lateral continuity is lacking due to basic geologic factors and/or failure of the frac treatment to connect sufficient pay to the wellbore. Although a decline is noted with each producing cycle, the fact that repressuring does occur over the summer provides encouragement that given a favorable geologic setting and frac treatment, the large resource in this play may have future commercial potential.

In consideration of the drilling cost and exhibited productive characteristics and EURs, no commercial production has as yet been demonstrated for the Lance-Fox Hills play. Based upon the limited number of wells in the Lance-Fox Hills play which are considered to target this play by virtue of their TD, 56% are dry holes and 44% of the wells were completed. Of those completions, none are considered to be commercial propositions, making the commercial success ratio for the play zero.

Stratigraphy and Rock Properties

The Lance-Fox Hills play is represented by a thick sequence of clastic sediments comprising mainly sands and shales. While a variety of depositional environments are represented, sand bodies in the main appear to be lenticular and of limited connectivity, leading to poor production performance despite attractive appearance on logs. Figure 56 is a regional net pay isopach and Figure 57 displays rock property distributions.

Figure 58 presents an example of a CPI log for the Lance-Fox Hills play. The Emigrant Trail Unit #2 (S32 T17N R96W) was drilled in 1982 and completed in the Lance between 10,965-10,982 feet and 11,170-11,198 feet with an IP of 413 Mcfd and 12 Bcpd. The well was tested extensively in the Lance between 10,965-10,982 feet (80 Mcfd, 1 Bwpd), 11,170-11,179 feet (608 Mcfd, 3 Bcpd, 14 Bwpd), and 11,382-11,402 feet (194 Mcfd, 4 Bcpd, 8 Bwpd) and in the Fox Hills 11,560-11,572 feet (629 Mcfd, 2 Bcpd, 10 Bwpd). Acid fracture treatments were performed across each of these intervals and ranged between 1,200-17,600 gallons of acid and 18,400 pounds of sand at between 5,000 and 7,400 psi. The log displays significant porosity development with a net pay count of 151 feet across a gross interval of 1,146 feet. Note the net sand flags to the right of the depth column and net pay flags to the left. Note also the bad hole flag in Track 1. The well was cored between 11,180-11,410 feet with a recovery of 172 feet.

Only 159 samples of Lance-Fox Hills core data were available (Figure 59). The sampling is not sufficient to develop meaningful trends from subdivision into Completed, Tested and Other categories. Immediately apparent is the bi-modal porosity distribution shown on the histogram (inter-modal trough between 5 and 7%), and significant scatter of points on the porosity permeability plot. The majority of permeabilities from 0 to 5% porosity mode are below 1 μd and are considered to represent poor reservoir rock. Note that the line of data points at 0.007 μd should be ignored. These are samples reported as 0.1 md at ambient conditions and input as 0.1 md.

Reevaluation of Resource

Structurally, the Lance-Fox Hills play occupies basinal positions both in the Washakie basin and in the Hoback and Great Divide basins. The unit top reaches depths of 13,000 feet in the Hoback basin and also in the center of the Washakie basin. In the northern area along the northern nose of the Rock Springs uplift and adjacent to the LaBarge platform, the Lance-Fox Hills occurs at drill depths of less than 7,000 feet. These areas lie within the

USGS designated area but have been eliminated from this analysis on the grounds that such areas are probably too shallow to still be overpressured. The majority of the evaluated rock volume lies between 9,000 and 14,000 feet.

Porosity distribution within the play is extremely variable both overall and with depth. Porosities in the overall sense are skewed towards the lower porosity distributions and tend to exhibit relatively high water saturations.

The lack of commercial production in the play places the entire *technologically viable* resource in the *nondemonstrated* category at this time. As such, the only subdivision of the total estimated resource of 349 Tcf is 224 Tcf (64%) in the *technologically nonviable* category (low permeability rocks considered too tight to support commercial production) and 125 Tcf (36%) in the *technologically viable* category (occurs in rocks with more favorable reservoir properties).

Table 15 compares the USGS estimate for the Lance-Fox Hills to the revised estimate derived herein and Figure 60 displays this information graphically.

TABLE 15
LANCE-FOX HILLS PLAY RESOURCE ESTIMATE BREAKDOWN
(Tcf)

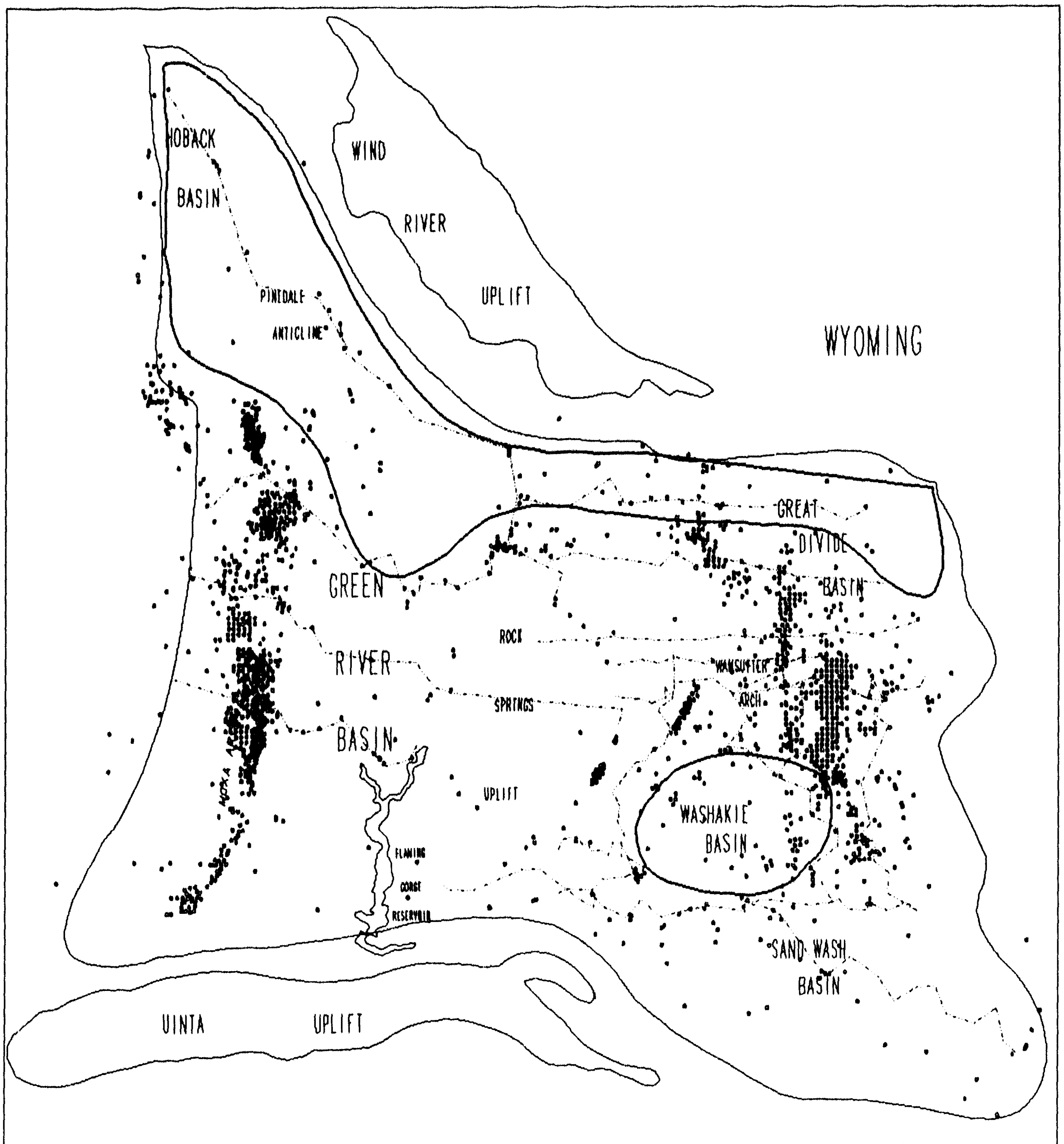
USGS Mean Resource Estimate	707
Scotia Revised Mean Resource Estimate	349
MINUS *Technologically Nonviable* Resources	224
SUBTOTAL *Technologically Viable* Resources	125
MINUS *Nondemonstrated* Resources	125
SUBTOTAL *Demonstrated* Resources	0
Subdivision:	
Speculative Resources	0
Nonestablished Resources	0
Established Resources	0

Reserves Evaluation

The lack of commercial production from the Lance-Fox Hills play is the most notable aspect of this play. While evaluation of well log information indicates the presence of reservoirs which calculate as gas productive, actual completion attempts have had disappointing results to date. As such, there is no basis for constructing a model which would include the resulting volumes within the economic category and hence being termed reserves.

TABLE 16
LANCE FOX HILLS PLAY OPT FIELD LIST

Field Name	Avg Depth (Feet)	Cum MMcf	EUR MMcf	Number of Wells	Avg EUR MMcf/Well
Cedar Breaks	10388	97	97	1	97
Gap Road	12530	21	21	1	21
Iron pipe	10178	262	262	1	262
Laney Wash	9776	114	114	1	114
Shallow Creek	9111	281	281	2	141
Twin Fork	12980	13	13	1	13
Play Totals		788	788	7	113



Well locations and lease boundary information used in generating this map was obtained from Petroleum Inform-ation Corporation. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.

LINE TYPE LEGEND

BASIN OUTLINE

PLAY OUTLINE

CROSS SECTIONS

WELL SYMBOLS

Dry hole

Oil well

Gas well

U.S. DEPARTMENT OF ENERGY

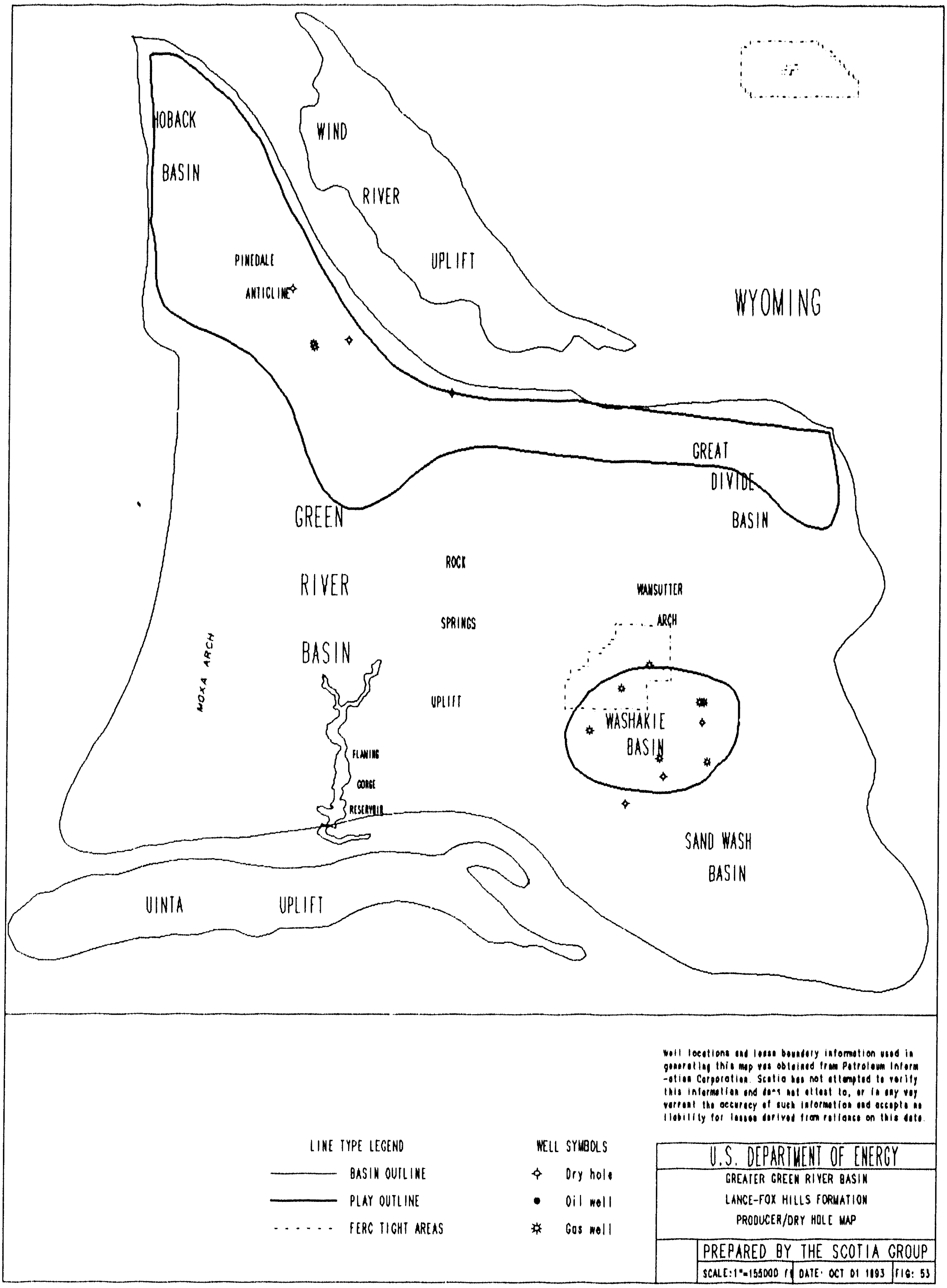
GREATER GREEN RIVER BASIN

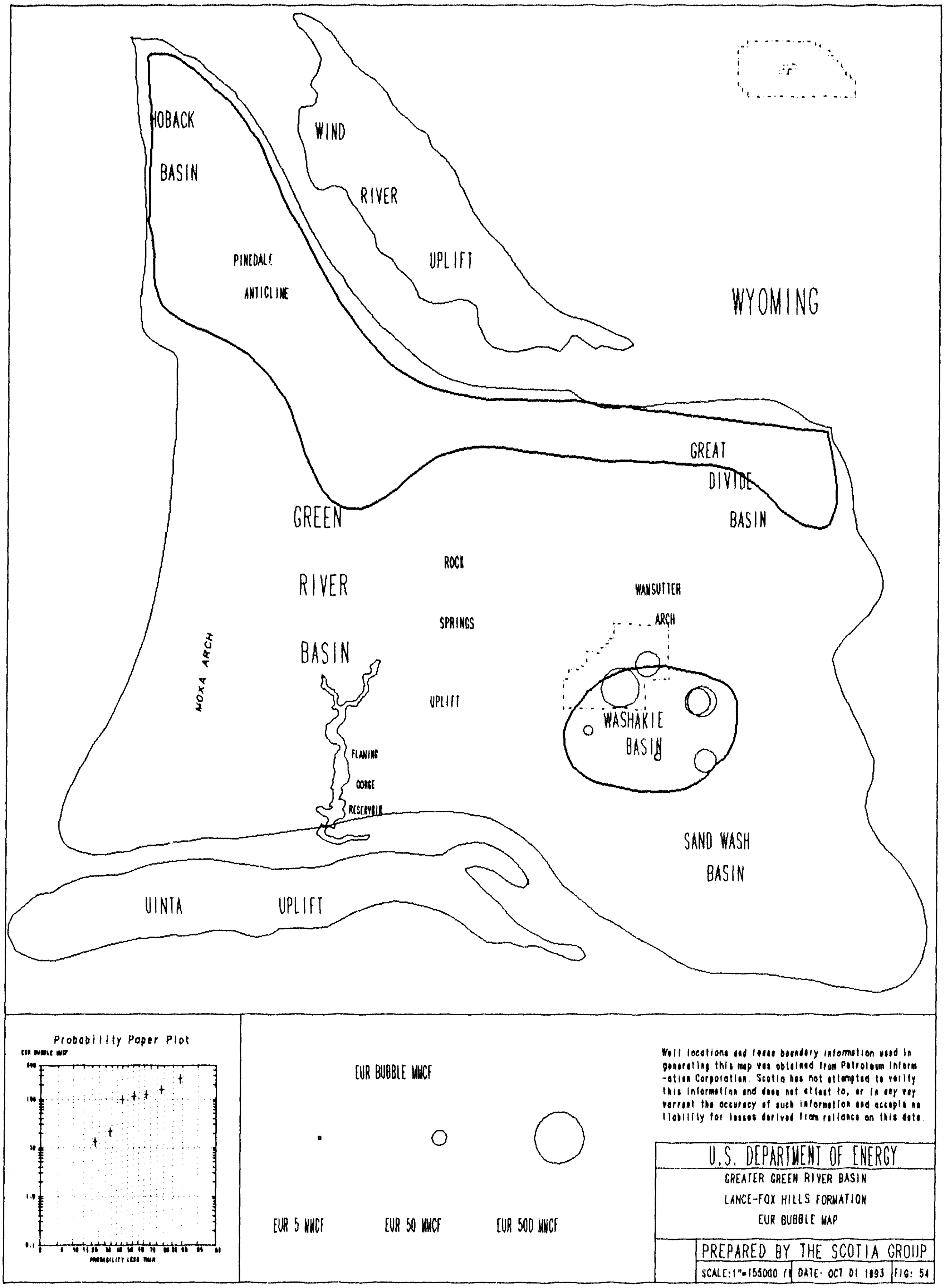
LANCE-FOX HILLS FORMATION

WELL PENETRATION MAP

PREPARED BY THE SCOTIA GROUP

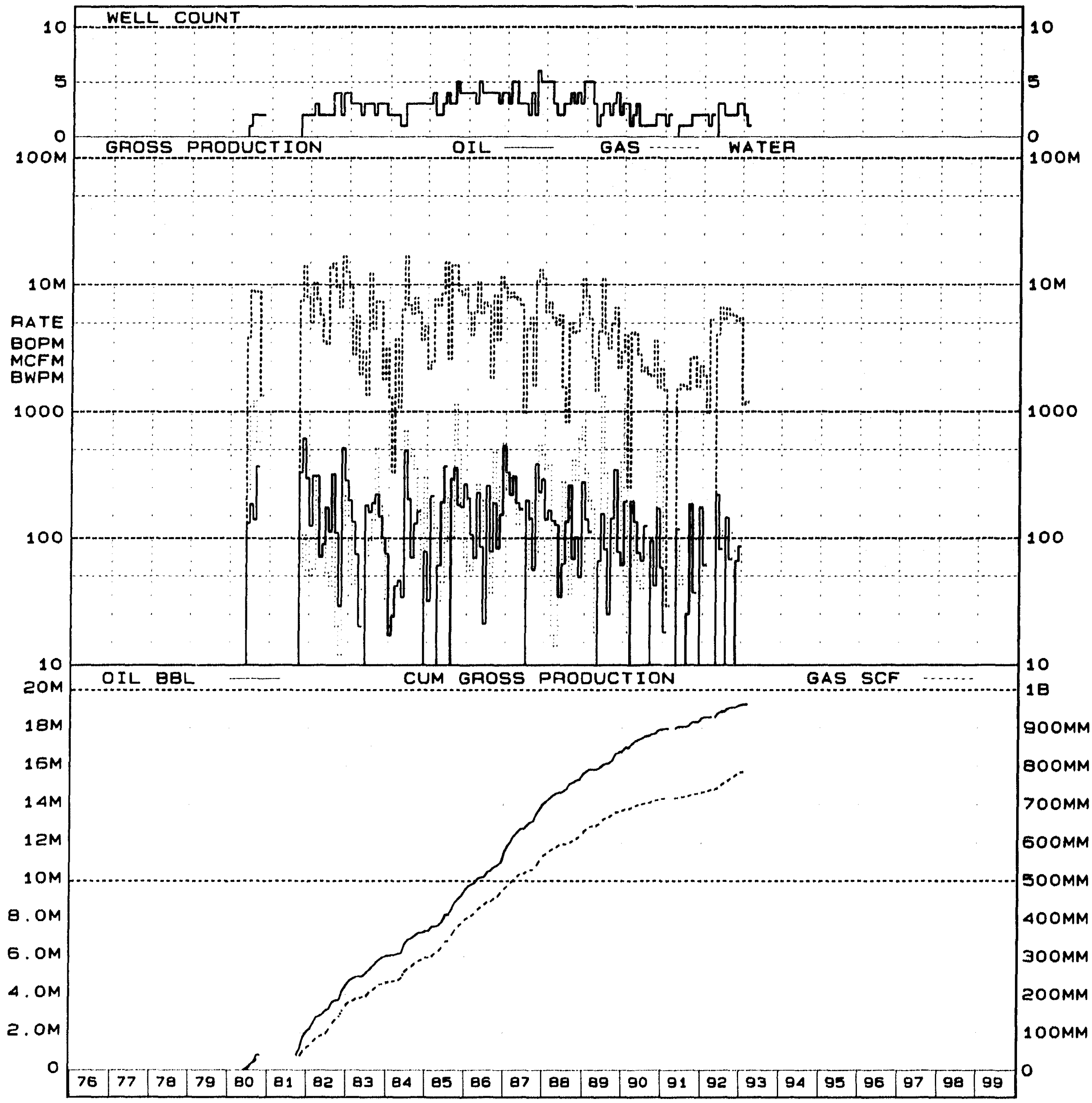
SCALE:1"=155000 ft | DATE: OCT 01 1993 | FIG: 52


HOBACK
BASIN
WIND
RIVER
UPLIFT
PINEDALE
ANTICLINE
WYOMING
GREAT
DIVIDE
BASIN
GREEN
RIVER
BASIN
ROCK
SPRINGS
UPLIFT
WAMSUTTER
ARCH
MOXA ARCH
WASHAKIE
BASIN
FLAMING
GORGE
RESERVOIR
SAND WASH
BASIN
UINTA
UPLIFT
Well locations and lease boundary information used in generating this map was obtained from Petroleum Inform-ation Corporation. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.
LINE TYPE LEGEND
BASIN OUTLINE
PLAY OUTLINE
FERC TIGHT AREAS
WELL SYMBOLS
Dry hole
Oil well
Gas well
U.S. DEPARTMENT OF ENERGY
GREATER GREEN RIVER BASIN
LANCE-FOX HILLS FORMATION
PRODUCER/DRY HOLE MAP
PREPARED BY THE SCOTIA GROUP
SCALE:1"=155000 ft
DATE: OCT 01 1993
FIG: 53



HOBACK
BASIN
WIND
RIVER
UPLIFT
PINEDALE
ANTICLINE
WYOMING
GREAT
DIVIDE
BASIN
GREEN
RIVER
BASIN
ROCK
SPRINGS
UPLIFT
WAMSUTTER
ARCH
MOXA ARCH
WASHAKIE
BASIN
FLAMING
GORGE
RESERVOIR
SAND WASH
BASIN
UINTA
UPLIFT
Probability Paper Plot
EUR BUBBLE MMCF
EUR 5 MMCF
EUR 50 MMCF
EUR 500 MMCF
Well locations and lease boundary information used in generating this map was obtained from Petroleum Information Corporation. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.
U.S. DEPARTMENT OF ENERGY
GREATER GREEN RIVER BASIN
LANCE-FOX HILLS FORMATION
EUR BUBBLE MAP
PREPARED BY THE SCOTIA GROUP
SCALE:1"=155000 (
DATE: OCT 01 1993
FIG: 54

FIGURE 55



LANCE-FOX HILLS TOTAL PRODUCTION PROFILE

Projections are averages for each year commencing at the effective date of the evaluation. Results are subject to the qualifications and limitations stated in the attached document

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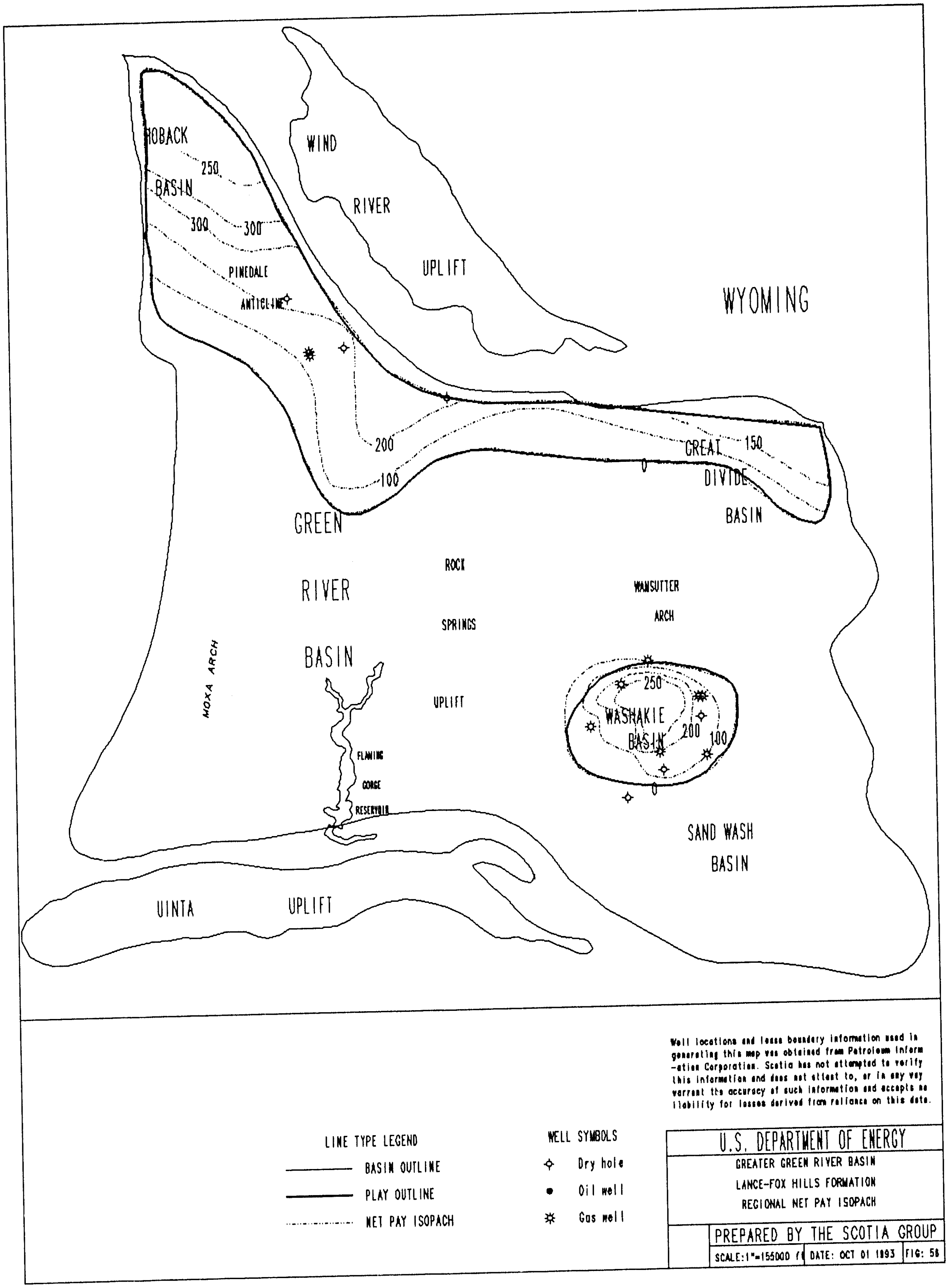
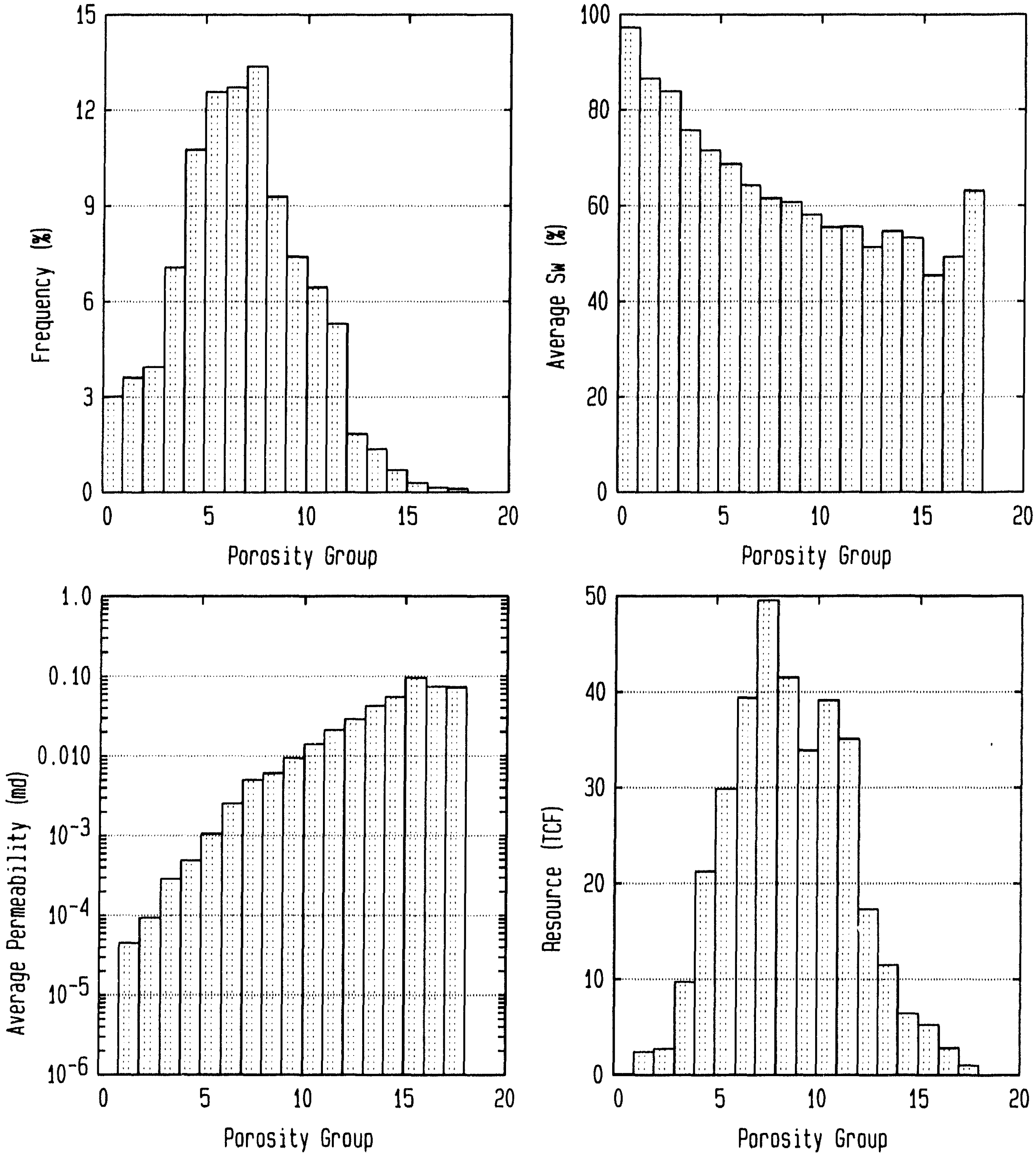

HOBACK
BASIN
250
300
300
PINEDALE
ANTICLINE
WIND
RIVER
UPLIFT
WYOMING
200
100
0
150
GREAT
DIVIDE
BASIN
GREEN
RIVER
BASIN
ROCK
SPRINGS
UPLIFT
WAMSUTTER
ARCH
MOXA ARCH
FLAMING
GORGE
RESERVOIR
250
WASHAKIE
BASIN
200
100
0
SAND WASH
BASIN
UINTA
UPLIFT
Well locations and lease boundary information used in generating this map was obtained from Petroleum Inform-ation Corporation. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.
LINE TYPE LEGEND
BASIN OUTLINE
PLAY OUTLINE
NET PAY ISOPACH
WELL SYMBOLS
Dry hole
Oil well
Gas well
U.S. DEPARTMENT OF ENERGY
GREATER GREEN RIVER BASIN
LANCE-FOX HILLS FORMATION
REGIONAL NET PAY ISOPACH
PREPARED BY THE SCOTIA GROUP
SCALE:1"=155000 ft
DATE: OCT 01 1993
FIG: 58

Scotia Group Resource Model	Rock Property and In-Place Resource Distributions	Client: U.S. DEPARTMENT OF ENERGY	Figure 57

Greater Green River Basin: Rock Property Distributions

LANCE FOX HILLS PLAY



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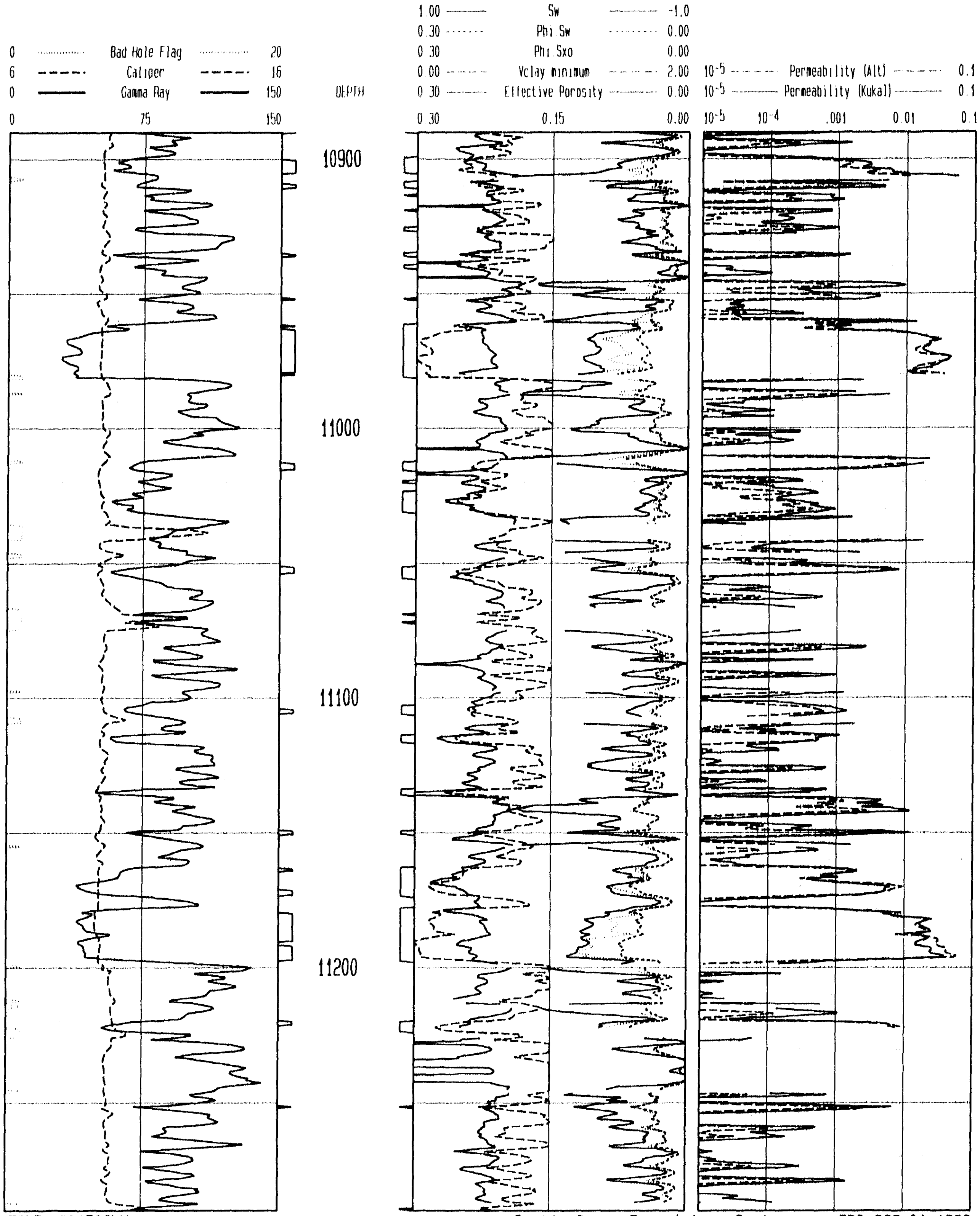
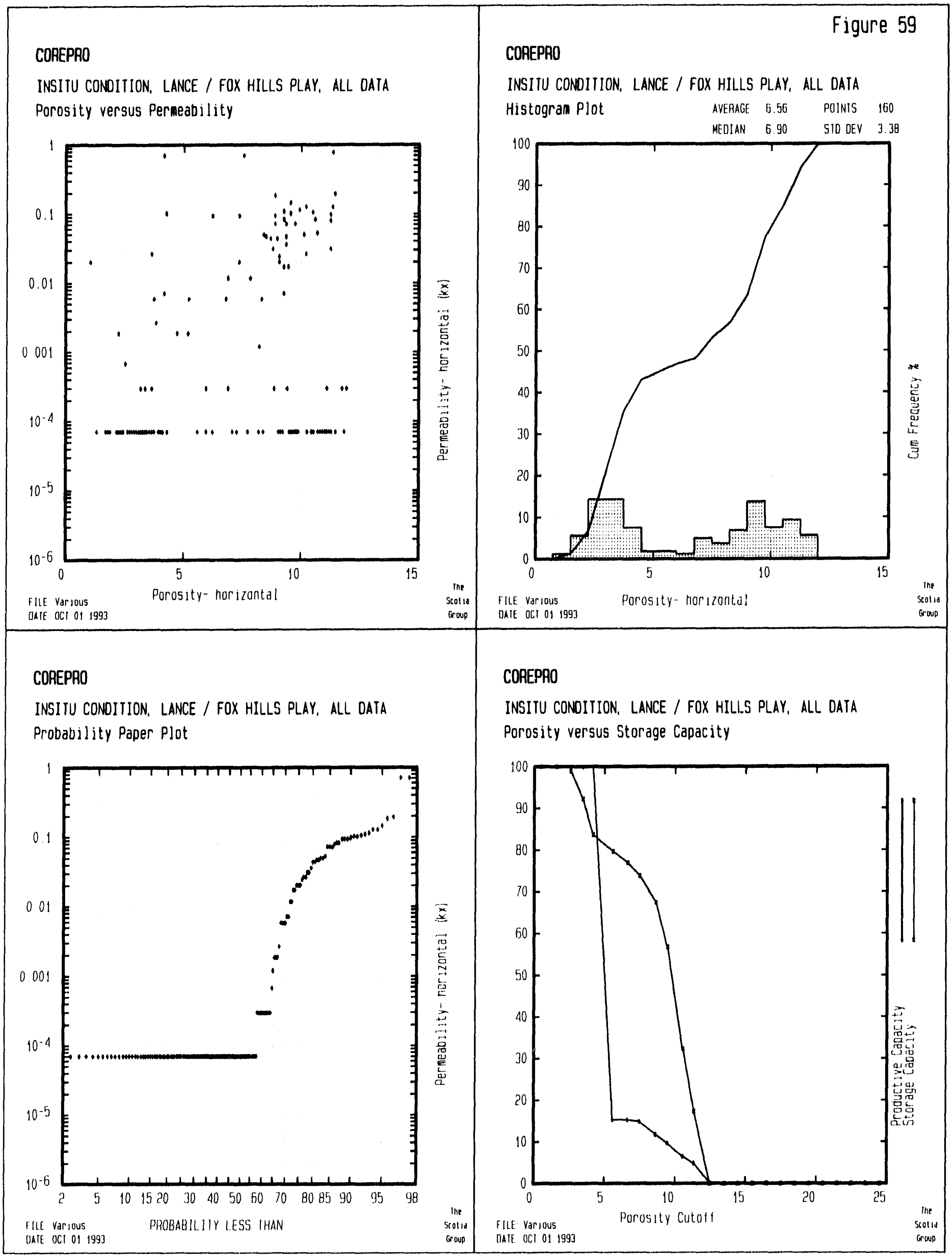
SCOTIALOG: Tight Gas Log Analysis Module	EMIGRANT TRAIL UNIT 2 API # 49037216860000 Client: DEPARTMENT OF ENERGY	Figure 58



FILE: 321796LN Scotia Group Proprietary Systems FRI OCT 01 1993

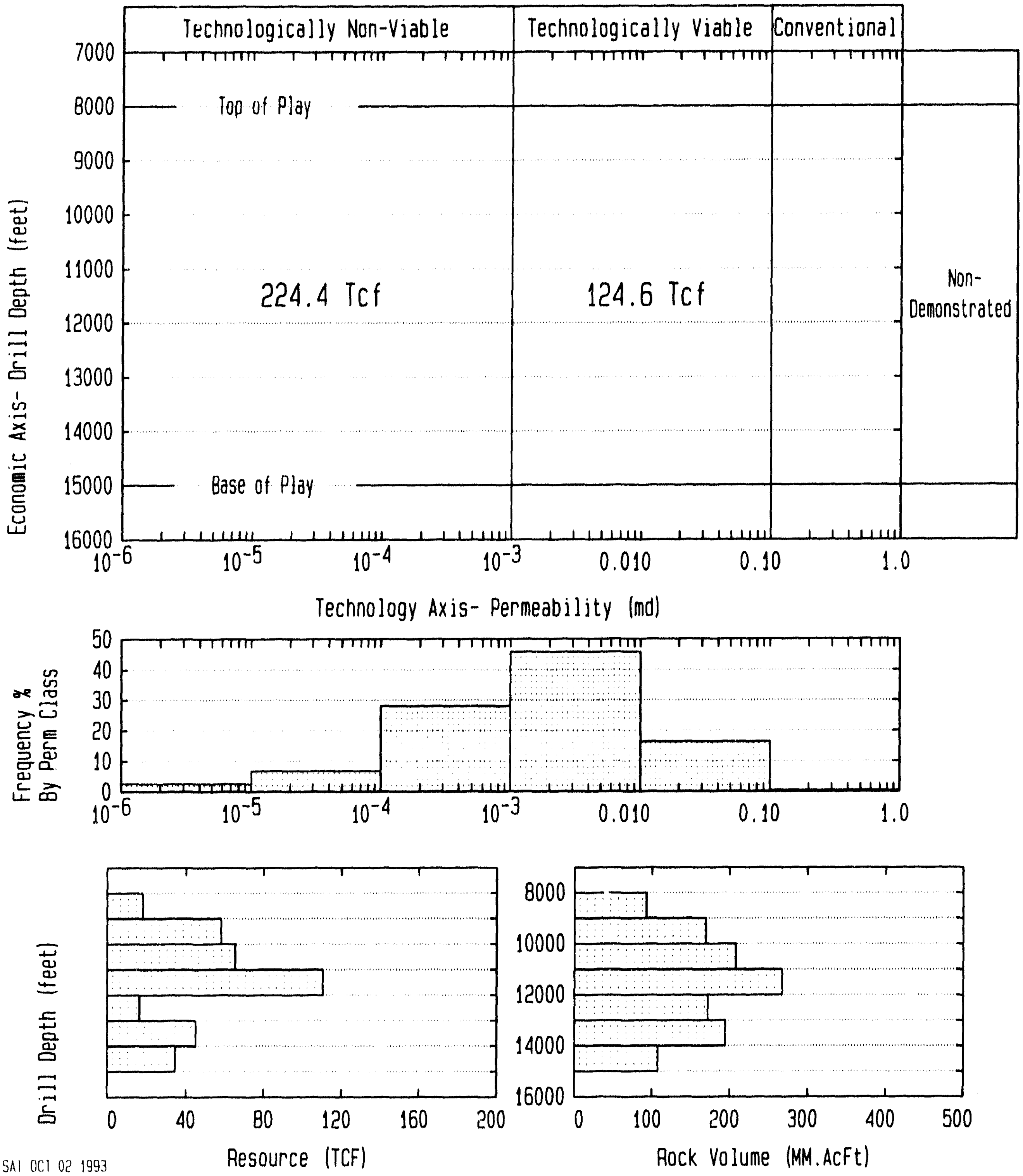
Figure 59


COREPRO
INSITU CONDITION, LANCE / FOX HILLS PLAY, ALL DATA
Porosity versus Permeability
Permeability- horizontal (kx)
Porosity- horizontal
FILE Various
DATE OCT 01 1993
The Scotia Group
COREPRO
INSITU CONDITION, LANCE / FOX HILLS PLAY, ALL DATA
Histogram Plot
AVERAGE 6.56
POINTS 160
MEDIAN 6.90
STD DEV 3.38
Cum Frequency %
Porosity- horizontal
FILE Various
DATE OCT 01 1993
The Scotia Group
COREPRO
INSITU CONDITION, LANCE / FOX HILLS PLAY, ALL DATA
Probability Paper Plot
Permeability- horizontal (kx)
PROBABILITY LESS THAN
FILE Various
DATE OCT 01 1993
The Scotia Group
COREPRO
INSITU CONDITION, LANCE / FOX HILLS PLAY, ALL DATA
Porosity versus Storage Capacity
Productive Capacity
Storage Capacity
Porosity Cutoff
FILE Various
DATE OCT 01 1993
The Scotia Group

Scotia Group Resource Model	Distribution and Classes of In Place Resources	Client: U.S. DEPARTMENT OF ENERGY	Figure 60

Greater Green River Basin Tight Gas Resource Allocation

LANCE FOX HILLS PLAY



SAI OCT 02 1993

FORT UNION PLAY

Description

The Tertiary Fort Union play is the shallowest stratigraphic unit considered by the USGS and unconformably overlies the Cretaceous Lance formation. The general designation for this play includes the Fort Union and other locally younger Tertiary rocks. The play as evaluated is restricted to the central portions of the Washakie basin and covers and area of approximately 500 square miles with sandstone thicknesses varying up to 1,500 feet.

Well control based upon the USGS cross-section grid basically surrounds the evaluated area with no central well control (Figure 61).

The only area designated as tight by the FERC within the Fort Union play is the Pinedale anticline area (Figure 62). The USGS did not allocate any OPT gas resources to this area, so it has not been considered as part of this study.

Production from the Fort Union play within the Washakie basin area is limited to two fields which are both single well entities and both of which produced uneconomic volumes of gas (Figure 63 and Table 18). For comparative purposes, Fort Union production from the Pinedale area has been included in the field list and also as part of the EUR distributions.

Drilling statistics are not meaningful for the Washakie basin area, being limited in number, but imply a 50% completion percentage with 50% of the attempts being dry holes. Since no commercial production has been achieved, all attempts are regarded as unsuccessful and commercial success ratios are zero.

Stratigraphy and Rock Properties

The Fort Union is a thick sequence of sands and shales that is not only tight but also exhibits a high degree of lenticularity and hence has shown poor productive characteristics in the few tests within the OPT area. Figure 65 is a regional net pay isopach and Figure 66 illustrates the rock property distribution.

Figure 67 is an example of a CPI log from the Fort Union play. Well Adobe Town Unit #1 (S20 T15N R97W) was completed both in the Fort Union between 13,152-13,241 feet (IP = 95 Mcfd) and Lance formation between 14,049-14,067 feet (IP = 352 Mcfd, 24 Bwpd). The well was acidized in the Fort Union with 4,000 gallons 7.5% HCl and stimulated in the Lance with 114,300 gallons 7.5% acid and 82,500 pounds of sand. The log shows significant sand development (1,843 feet) over a gross interval of 3,560 feet. Net pay is estimated to be 178 feet. Sands contain a significant quantity of clay in the upper 2,700 feet. The bulk of the reservoir quality rock occurs within the bottom 860 feet of the formation.

Reevaluation of Resource

The evaluated rock volume for the Fort Union play occurs between 8,000 and 14,000 feet in the central portions of the Washakie basin. Porosity distributions based upon log analysis show a fairly uniform trend of decrease with depth causing the evaluated resource to occur mainly in the shallower depth ranges.

Since commercial production has not been established, all resources are allocated as *nondemonstrated* under current conditions. Based upon the inferred distribution of porosities and permeabilities, the total resource of 54 Tcf is subdivided as being 34 Tcf or 63% occurring in low permeability rocks considered too tight to support commercial production and the remaining 20 Tcf or 37% of the total in place resource being considered of reservoir quality but is not considered commercial at this time.

Table 17 compares the USGS estimate for the Fort Union to the revised estimate derived herein and illustrated graphically in Figure 68.

TABLE 17
FORT UNION PLAY RESOURCE ESTIMATE BREAKDOWN
(Tcf)

USGS Mean Resource Estimate	96
Scotia Revised Mean Resource Estimate	54
MINUS *Technologically Nonviable* Resources	34
SUBTOTAL *Technologically Viable* Resources	20
MINUS *Nondemonstrated* Resources	20
SUBTOTAL *Demonstrated* Resources	0
Subdivision:	
Speculative Resources	0
Nonestablished Resources	0
Established Resources	0

Reserves Evaluation

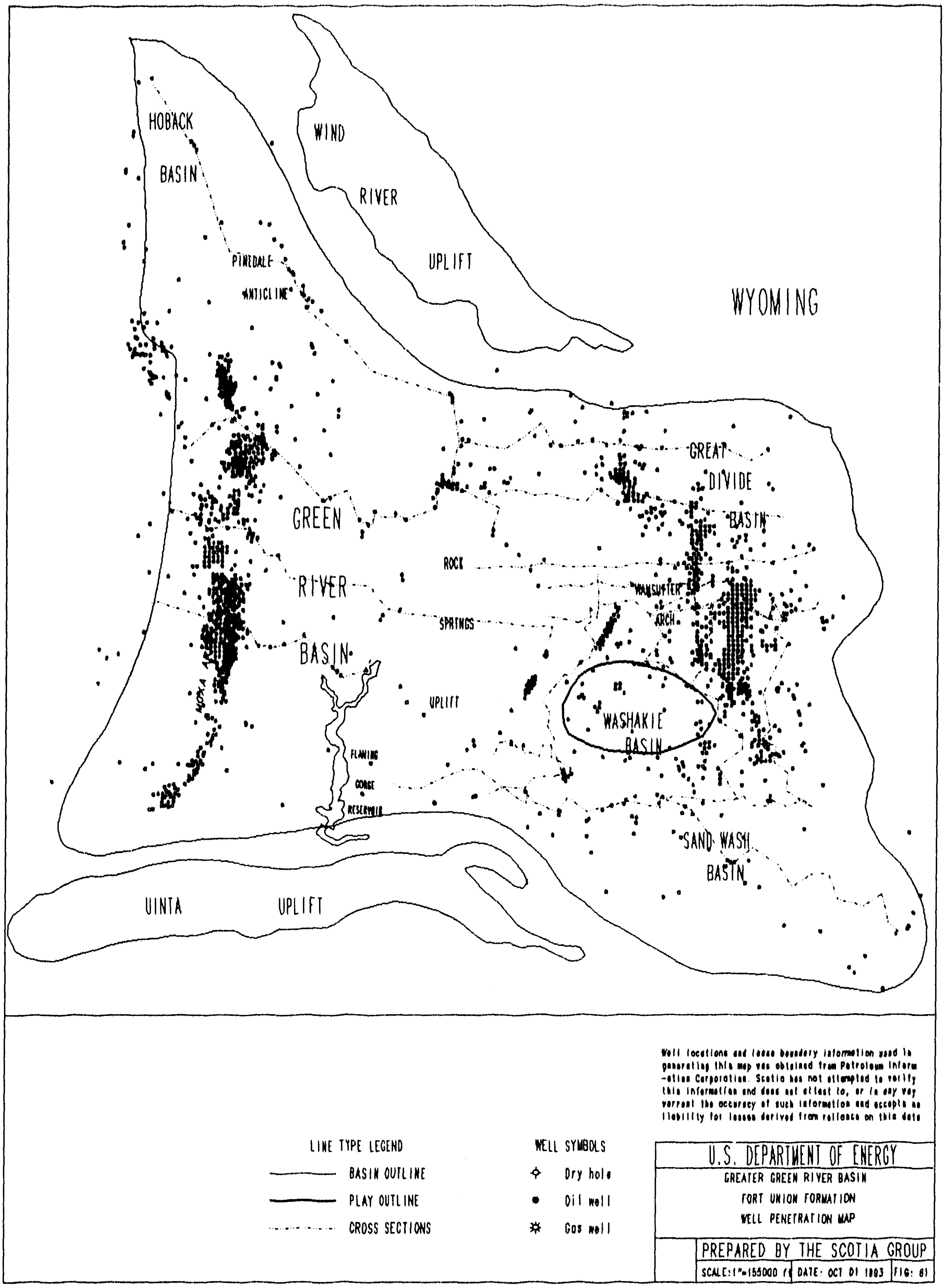
As noted above, the absence of commercial production within the OPT area in the central Washakie basin precludes assignment of reserves on the grounds of economics. However, Fort Union production in the Pinedale anticline area, while marginal, does provide encouragement that given further scrutiny of the play, commerciality can be established. The Powder Wash field in the south flank of the Washakie basin, while outside the OPT area, contains four wells that have already produced between 12 and 25 Bcf each, showing the potential of the Fort Union given the appropriate conditions.

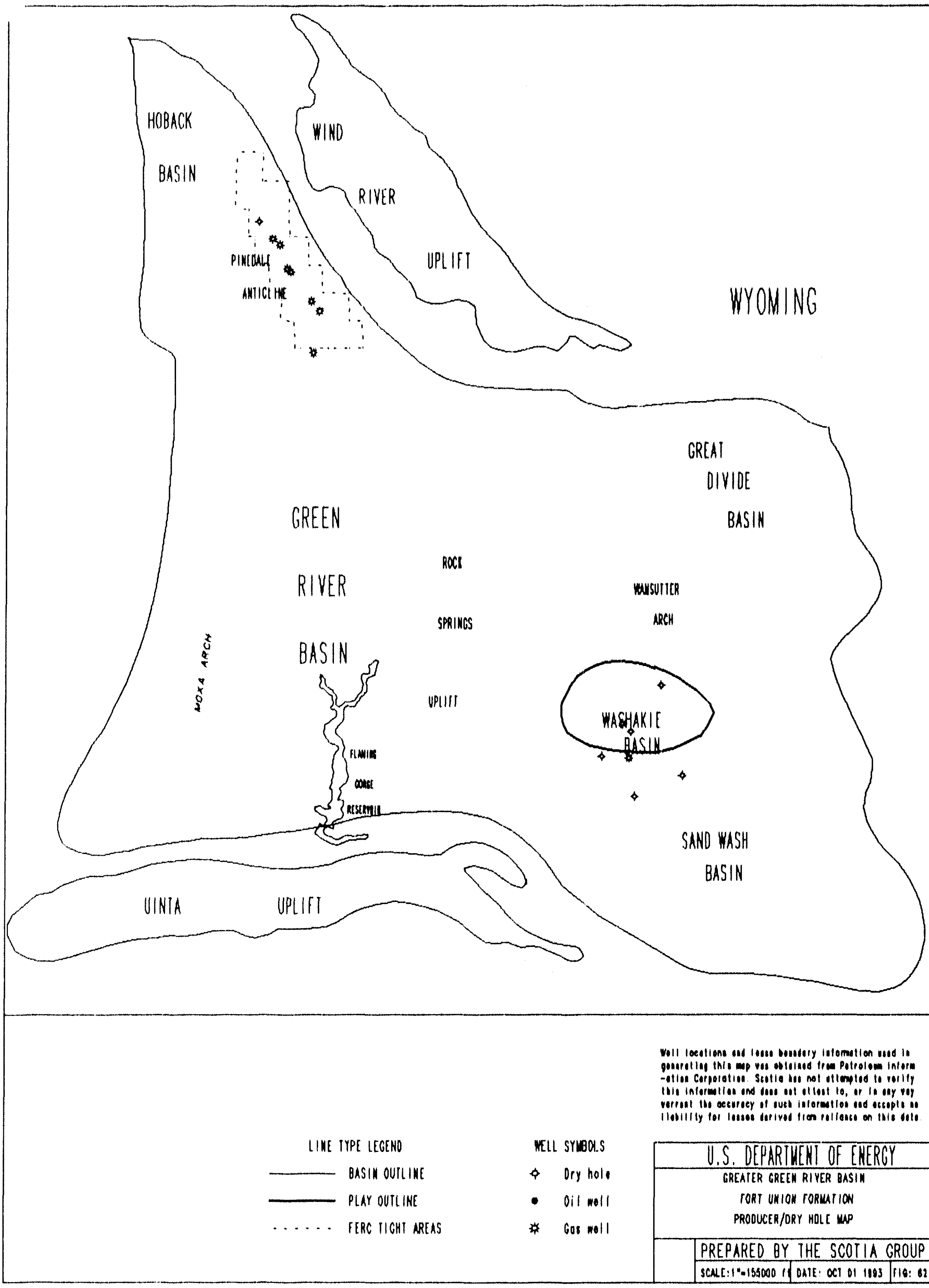
TABLE 18
FORT UNION PLAY OPT FIELD LIST

Field Name	Avg Depth (Feet)	Cum MMcf	EUR MMcf	Number of Wells	Avg EUR MMcf/Well
Adobe Town	13197	21	21	1	21
Twin Fork	11514	86	86	1	86
Play Totals		107	107	2	54

PINEDALE AREA FORT UNION FIELDS

Field Name	Avg Depth (Feet)	Cum MMcf	EUR MMcf	Number of Wells	Avg EUR MMcf/Well
Jonah	11118	21	21	1	21
Mesa Unit	11154	713	713	2	357
Pinedale	9602	2779	3138	4	785
Play Totals		3513	3872	7	553


HOBACK
BASIN
PINEDALE
ANTICLINE
WIND
RIVER
UPLIFT
WYOMING
GREAT
DIVIDE
BASIN
GREEN
RIVER
BASIN
ROCK
SPRINGS
UPLIFT
WAMSUTTER
ARCH
WASHAKIE
BASIN
FLAMING
GORGE
RESERVOIR
SAND WASH
BASIN
UINTA
UPLIFT
Well locations and lease boundary information used in generating this map was obtained from Petroleum Information Corporation. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data
LINE TYPE LEGEND
BASIN OUTLINE
PLAY OUTLINE
CROSS SECTIONS
WELL SYMBOLS
Dry hole
Oil well
Gas well
U.S. DEPARTMENT OF ENERGY
GREATER GREEN RIVER BASIN
FORT UNION FORMATION
WELL PENETRATION MAP
PREPARED BY THE SCOTIA GROUP
SCALE:1"=155000 ft
DATE: OCT 01 1993
FIG: 61



HOBACK
BASIN
WIND
RIVER
UPLIFT
PINEDALE
ANTICLINE
WYOMING
GREAT
DIVIDE
BASIN
GREEN
RIVER
BASIN
ROCK
SPRINGS
UPLIFT
WAMSUTTER
ARCH
MOXA ARCH
WASHAKIE
BASIN
FLAMING
GORGE
RESERVOIR
SAND WASH
BASIN
UINTA
UPLIFT
Well locations and lease boundary information used in generating this map was obtained from Petroleum Information Corporation. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.
LINE TYPE LEGEND
BASIN OUTLINE
PLAY OUTLINE
FERC TIGHT AREAS
WELL SYMBOLS
Dry hole
Oil well
Gas well
U.S. DEPARTMENT OF ENERGY
GREATER GREEN RIVER BASIN
FORT UNION FORMATION
PRODUCER/DRY HOLE MAP
PREPARED BY THE SCOTIA GROUP
SCALE:1"=155000 ft
DATE: OCT 01 1993
FIG: 62

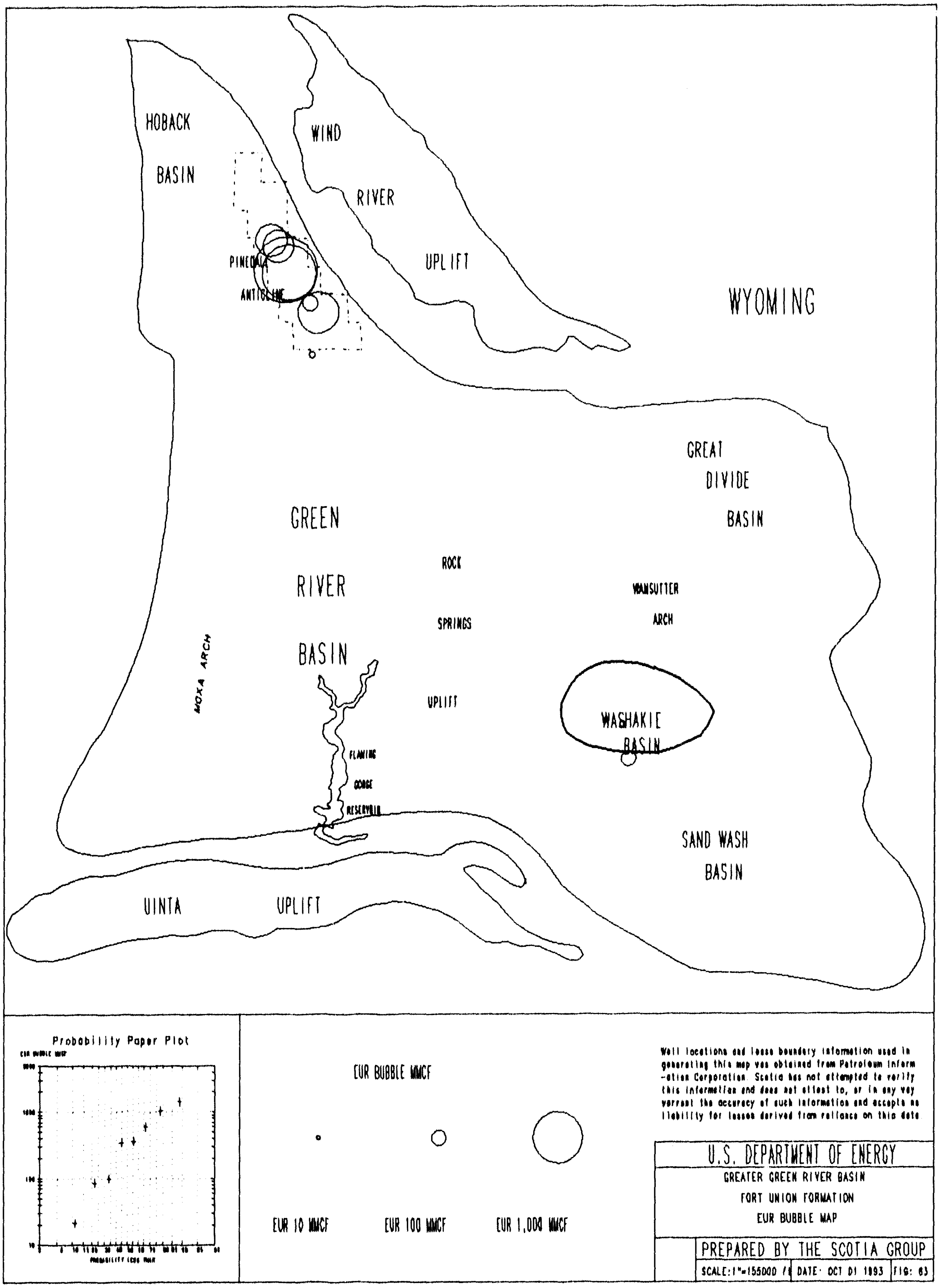
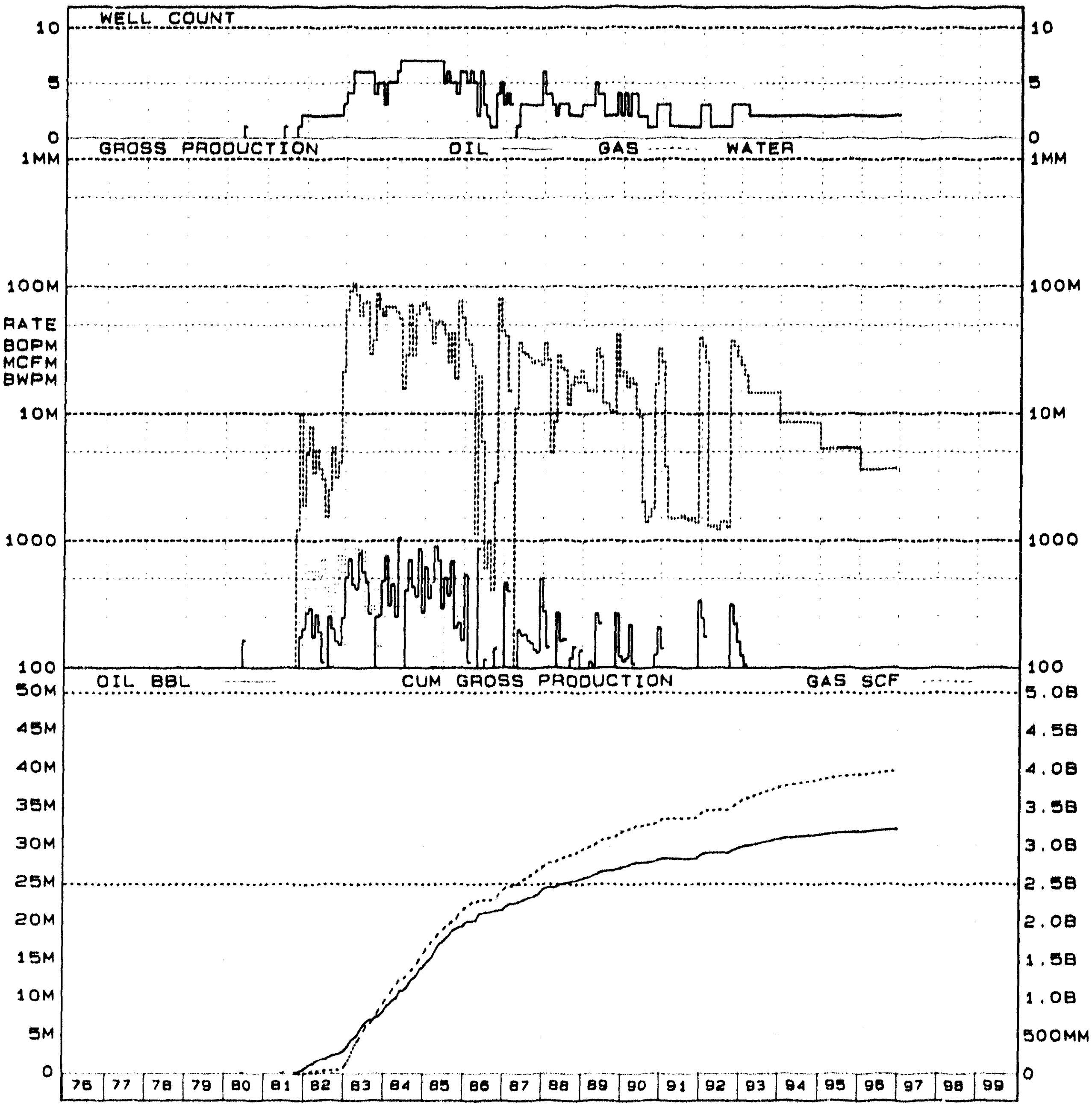

HOBACK
BASIN
WIND
RIVER
UPLIFT
PINEDALE
ANTICLINE
WYOMING
GREAT
DIVIDE
BASIN
GREEN
RIVER
BASIN
ROCK
SPRINGS
UPLIFT
WAMSUTTER
ARCH
MOXA ARCH
WASHAKIE
BASIN
FLAMING
GORGE
RESERVOIR
SAND WASH
BASIN
UINTA
UPLIFT
Probability Paper Plot
EUR BUBBLE MMCF
EUR 10 MMCF
EUR 100 MMCF
EUR 1,000 MMCF
Well locations and lease boundary information used in generating this map was obtained from Petroleum Information Corporation. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data.
U.S. DEPARTMENT OF ENERGY
GREATER GREEN RIVER BASIN
FORT UNION FORMATION
EUR BUBBLE MAP
PREPARED BY THE SCOTIA GROUP
SCALE:1"=155000 ft
DATE: OCT 01 1993
FIG: 63

FIGURE 64



FORT UNION TOTAL PRODUCTION PROFILE

Projections are averages for each year commencing at the effective date of the evaluation. Results are subject to the qualifications and limitations stated in the attached document

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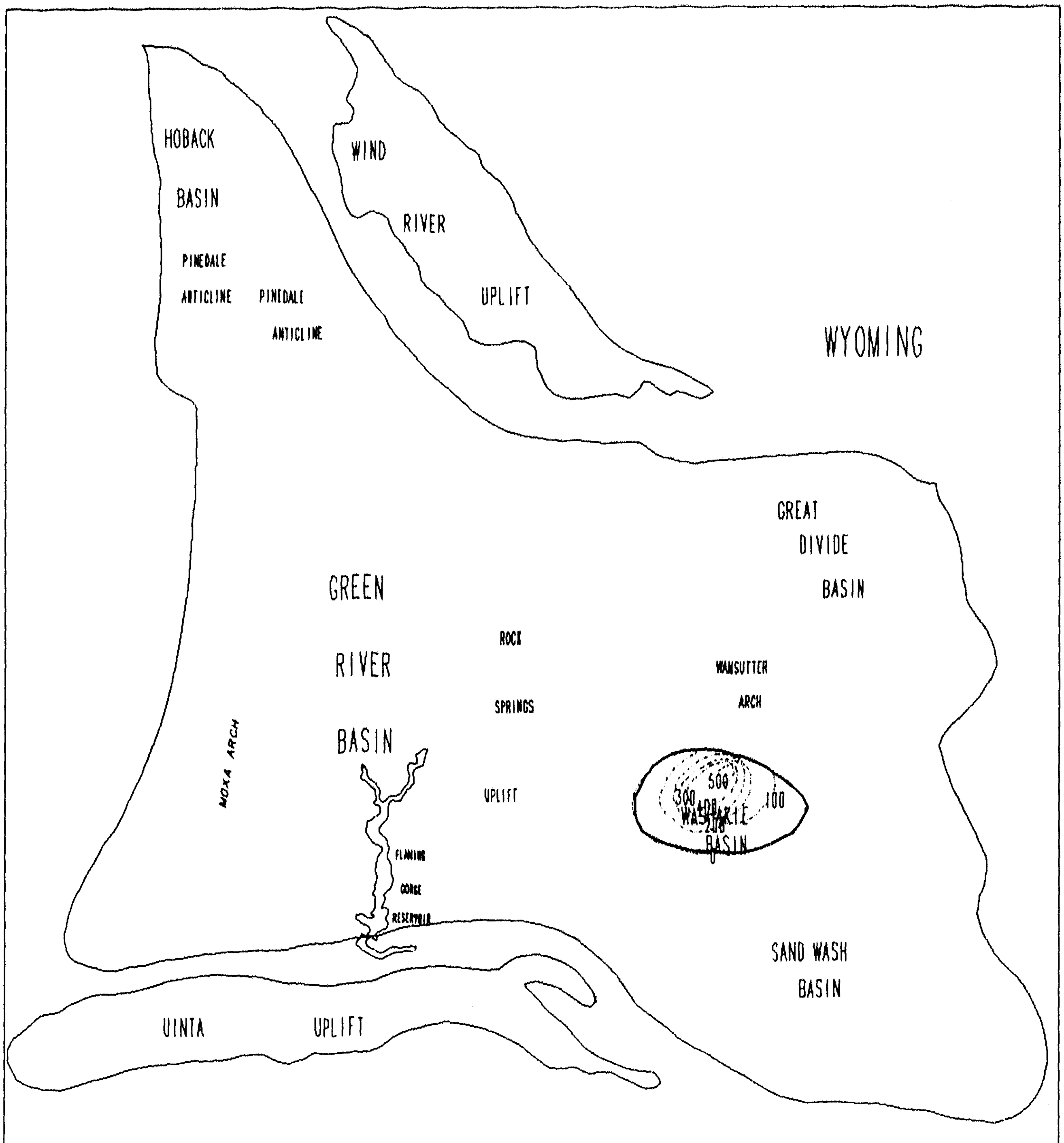


Well locations and lease boundary information used in generating this map was obtained from Petroleum Information Corporation. Scotia has not attempted to verify this information and does not attest to, or in any way warrant the accuracy of such information and accepts no liability for losses derived from reliance on this data

LINE TYPE LEGEND	
————	BASIN OUTLINE
━━━━	PLAY OUTLINE
- - - - - -	NET PAY ISOPACH

WELL SYMBOLS	
⌖	Dry hole
●	Oil well
☼	Gas well

U.S. DEPARTMENT OF ENERGY

GREATER GREEN RIVER BASIN

FORT UNION FORMATION

REGIONAL NET PAY ISOPACH

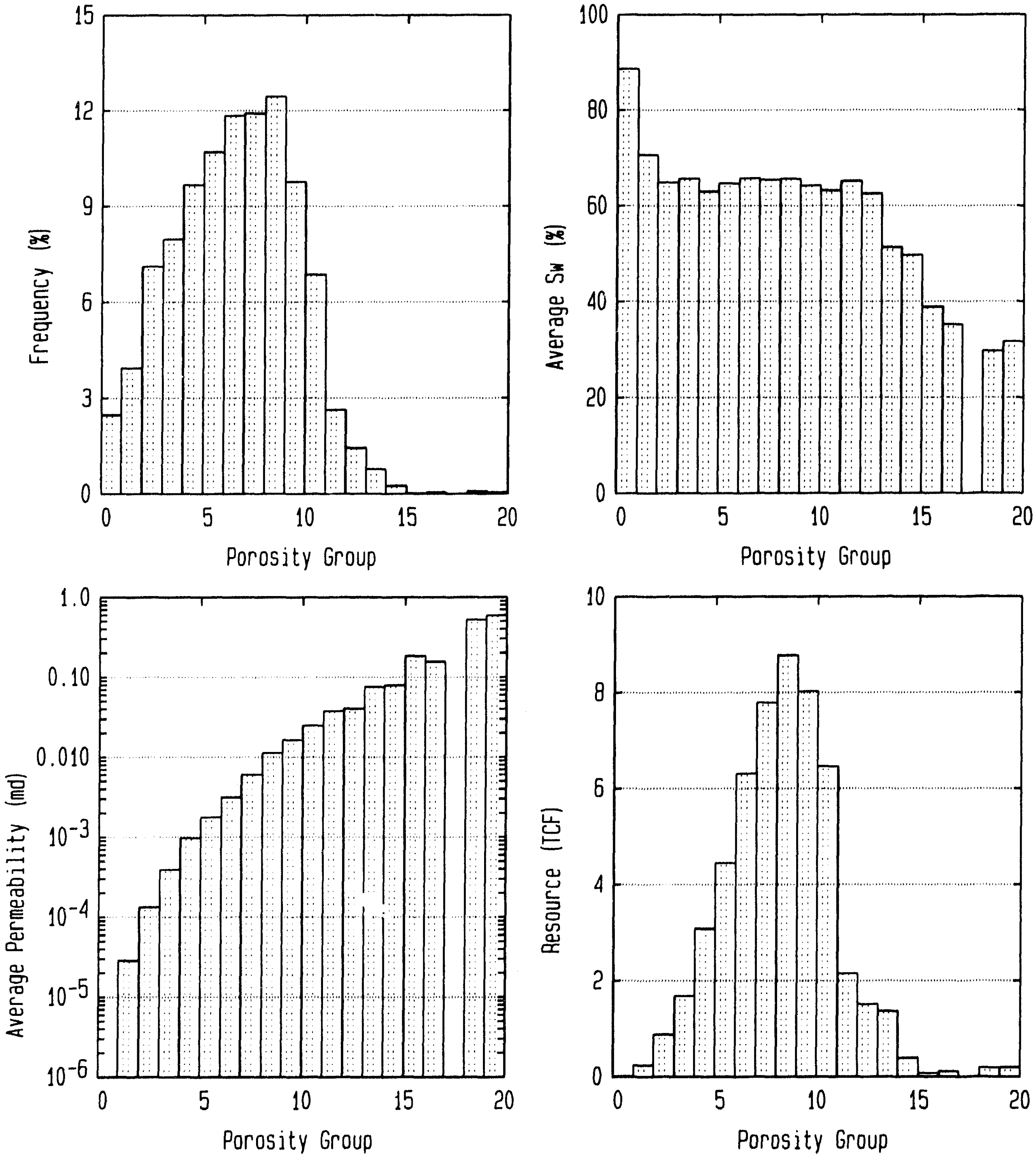
PREPARED BY THE SCOTIA GROUP

SCALE:1"=155000 ft	DATE: OCT 01 1993	FIG: 65

Scotia Group Resource Model	Rock Property and In-Place Resource Distributions	Client: U.S. DEPARTMENT OF ENERGY	Figure 66

Greater Green River Basin: Rock Property Distributions

FORT UNION PLAY

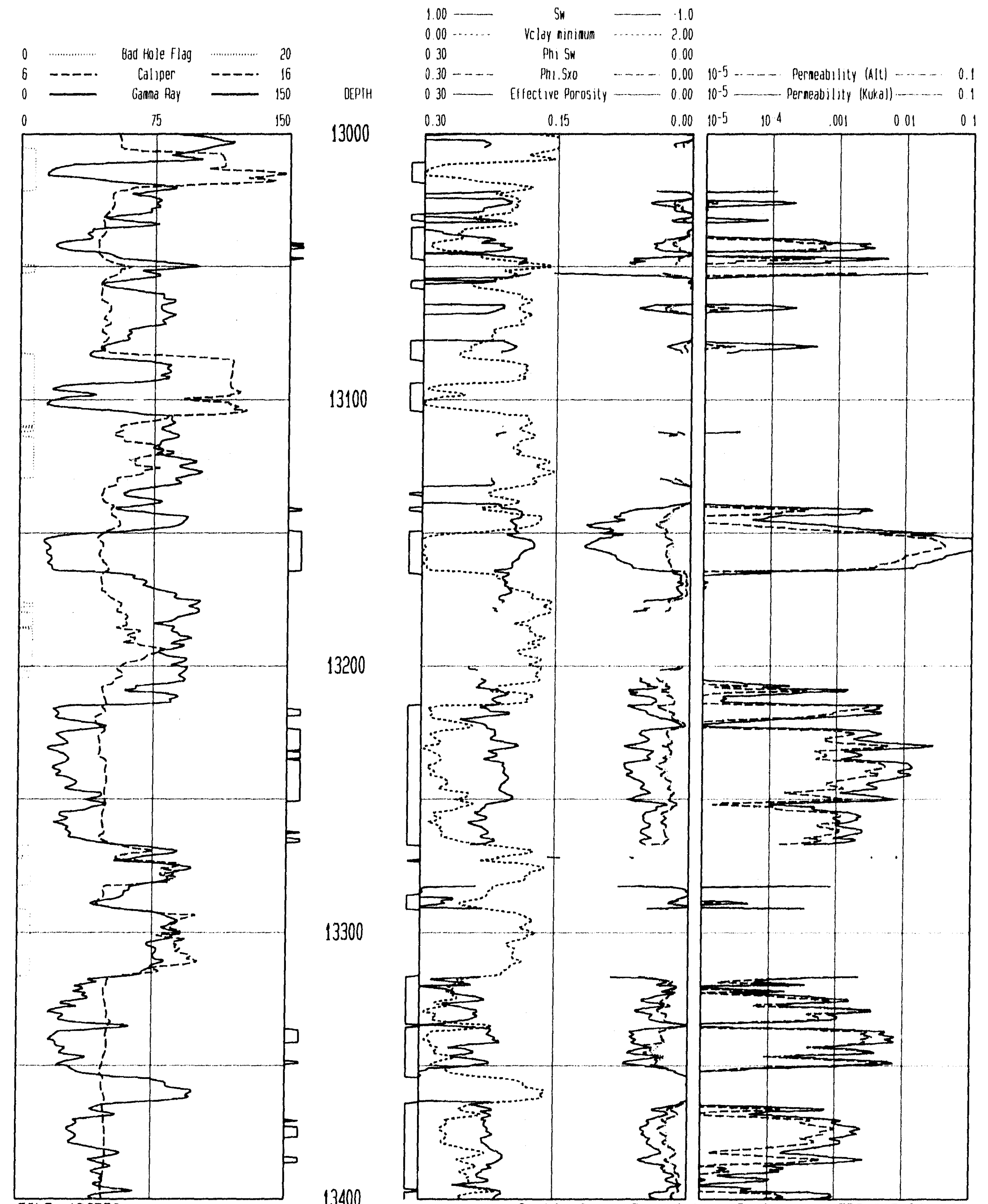


SAI OCT 02 1993

SCOTIALOG: Tight Gas Log Analysis Module

ADOBE TOWN UNIT #1 API # 49037212460000
Client: DEPARTMENT OF ENERGY

Figure 67



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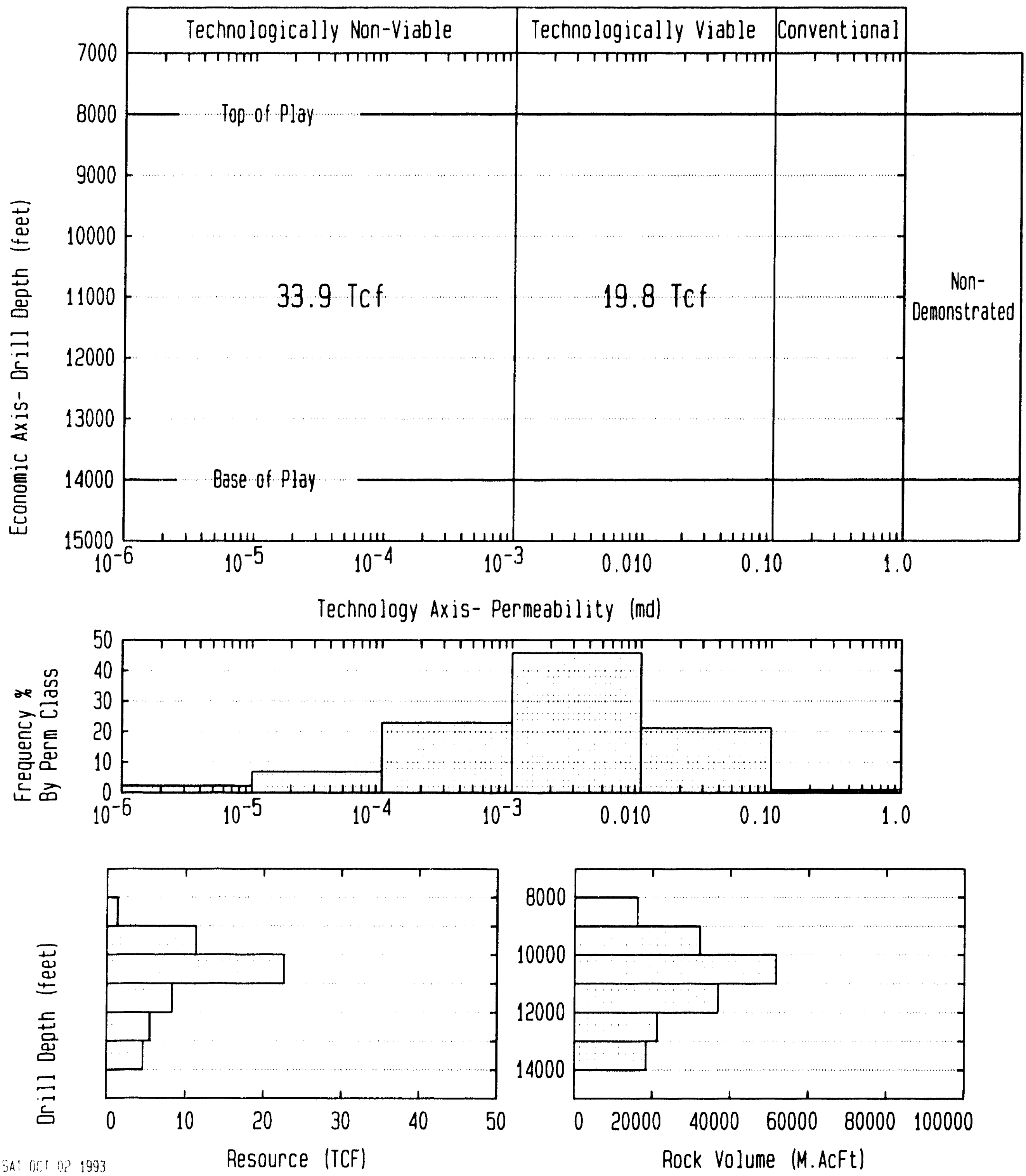
Scotia Group Proprietary Systems FRI OCT 01 1993

Scotia Group Resource Model	Distribution and Classes of In Place Resources	Client: U.S. DEPARTMENT OF ENERGY	Figure 68

Greater Green River Basin Tight Gas Resource Allocation

FORT UNION PLAY



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GLOSSARY OF ABBREVIATIONS

API	American Petroleum Institute
Bcf	Billion Cubic Feet
Bcpd	Barrels of Crude Per Day
Bwpd	Barrels of Water Per Day
CPI	Computer Processed Interpretation
DST	Drillstem Test
EMV	Expected Monetary Value
EUR	Estimated Ultimate Recovery
FERC	Federal Energy Regulatory Commission
GGRB	Greater Green River Basin
GIP	Gas In Place
IP	Initial Potential
Mbo	Thousand Barrels of Oil
MWX	Multiwell Experiment
NOB	Net Overburden
NPS	National Production System
OPT	Overpressured Tight
PDP	Proved Developed Producing
PI	Petroleum Information Corporation
Scf	Standard Cubic Feet
SEC	Securities and Exchange Commission
SP	Spontaneous Potential
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
Tcf	Trillion Cubic Feet
TD	Total Depth
USGS	U.S. Geological Survey
WHCS	Well History Control System

APPENDIX A

DISCUSSION OF ROUTINE CORE DATA PROCESSING AND INTERPRETATION

INTRODUCTION

This appendix is designed to provide a basic understanding of the techniques used to process and interpret routine core data in tight gas sands. It is not intended to be an extensive treatise on the theory and derivation of suitable equations since significant research has been conducted and published by other workers. Rather, the methods are summarized to provide the reader with a basic understanding of the problems inherent with tight gas sand petrophysical analysis.

The objective of the core and log interpretation was to derive a set of representative rock properties by well, including sand thickness, net gas thickness, effective porosity, water saturation, and permeability, which could be used to map the distribution of gas and estimate volumetrically gas in place for each play in the GGRB.

Routine Core Data

Significant effort was expended during this study to compile porosity and permeability values by well for each play from measured data and from calculations. Measured values were derived from a substantial database of routine core data compiled for this study and are summarized below:

PLAY	# OF CORE SAMPLES
Fort Union	0
Lance-Fox Hills	159
Lewis	556
Mesaverde	4946
Cloverly Frontier	384
TOTAL	6045

Routine (predominantly plug type) core data was compiled from a total of 113 wells in the GGRB. Data typically consisted of Boyles Law helium porosity, less frequently, summation of fluids porosity, horizontal permeability measured with gas (normally air, but occasionally nitrogen and rarely helium), few vertical permeabilities, and residual fluid saturations and grain densities. Brief visual descriptions of the core samples were also available for most wells. Core data ranged in age from 1971 to 1990. Core analysis laboratories included Core Laboratories, TerraTek Core Service, and Chemical and

Geological Laboratories. All numerical core data were keyed into a data base by well for each play. Descriptive information was not entered.

Almost all of the routine analyses were performed at laboratory ambient conditions. To facilitate comparison of the core permeabilities with those derived from well tests and open hole logs, a series of corrections were applied to convert the core data to in-situ conditions. Since laboratory studies were outside the scope of work, the adjustment of core to reservoir conditions was accomplished using relationships derived from published literature. COREPRO, Scotia's statistical grouping and averaging program was used to process the core data and to correct porosity and permeability for the effects of overburden stress (net confining pressure or net effective overburden), and to correct permeability for gas slippage (Klinkenberg correction) and brine saturation. Each correction is discussed below:

Net Effective Overburden

NOB is the difference between gross overburden pressure and reservoir fluid pressure:

$$NOB = GOB - P_r$$

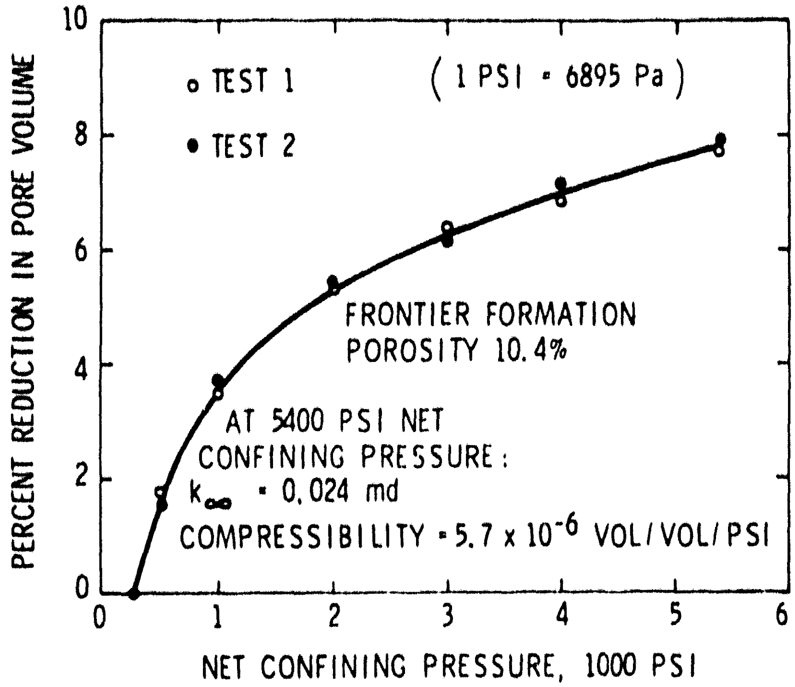
NOB	=	Net effective overburden
GOB	=	Gross overburden, 1 psi/ft x depth
P_r	=	Reservoir pressure

Reservoir pressure gradients across the GGRB were derived from an analysis of mud weight pressures and DST results. Pressures resulting in gradients less than 0.45 psi/foot were eliminated from the dataset, since the study is limited to overpressured areas. NOB was found to be a constant 4,950 psi over the depth range 9,000 to 23,000 feet (see Reservoir Pressure discussion on page 38).

NOB Correction to Porosity

The effect of confining pressure (NOB) on porosity of tight gas sands is not substantial and has been found to be similar to the behavior of conventional sands. Pore volumes typically diminish to 95 - 90% of porosity at ambient conditions with little variation in percentage reduction due to rock type. A plot of confining pressure percentage reduction in porosity for the Frontier formation presented by Jones and Owens (1980), Figure A-1, was digitized and the equation below derived to correct porosity to NOB conditions using.

Figure A-1
(from Jones and Owens, 1980)



$$\Delta Por = -.196+.872\ NOB-4.14\ NOB^2+.102\ NOB^3-.12\ NOB^4+.520\ NOB^5$$

Where:

ΔPor = % reduction in porosity
NOB = Net effect overburden (confining) pressure x 100 psi

The average pore volume reduction using this relationship is 7.4%. Corrections were limited so as not to exceed 10% pore volume reduction. No other corrections were applied to core porosity.

Work conducted by Luffel et al (1991) on Travis Peak porosity relationships at reservoir stress produced roughly the same values of corrected porosity as those obtained using the equation presented above.

Gas Slippage Correction Permeability

Since routine core permeabilities are determined by measuring gas flow rates through core plugs at pressures close to atmospheric, corrections must be made for slippage which occurs between the gas molecules and the walls of each pore. The correction for gas slippage (Klinkenberg correction) varies with permeability and is large for tight gas sands (Jones and Owens, 1980). COREPRO uses the Klinkenberg equation presented below:

$K\infty = K_{air} - b\ 1/P_m$ Where:

$K\infty$ = Dry Klinkenberg permeability equivalent to equivalent liquid permeability, assuming no rock fluid reaction.

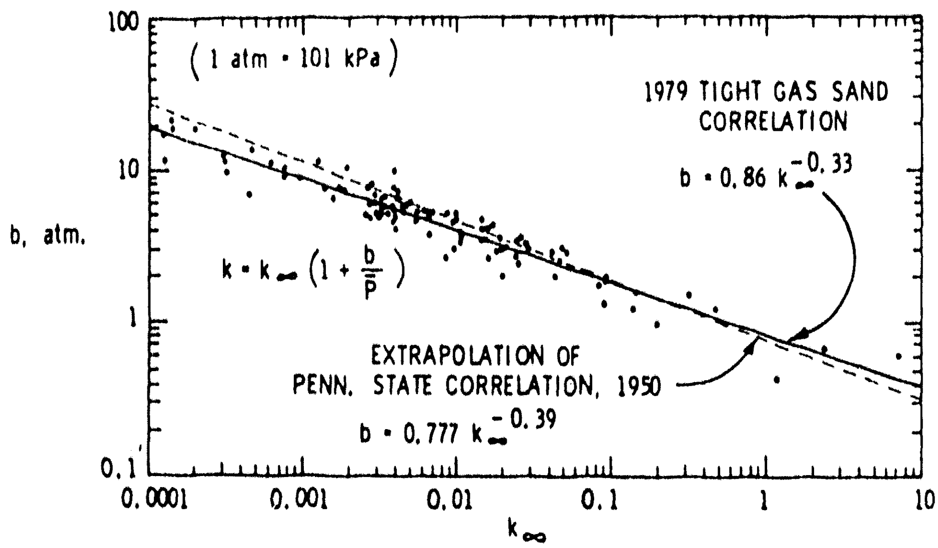
b = Klinkenberg constant for a given gas in a given medium.

P_m = Mean flowing pressure.

Work conducted by Jones and Owens (1980) on more than 100 tight gas sand samples (Figure A-2) derived a best fit equation for b:

$b = .86\ (K_\infty)^{.33}$ for air

Figure A-2
(from Jones and Owens, 1980)



This equation represents the slope of a line plotted from a graph of reciprocal mean pressure ($1/P_m$) versus permeability and is affected by the gas used in the measurement of permeability. Gas types used by commercial laboratories have included air, nitrogen and helium. Air has been by far the most frequently used gas, with nitrogen used interchangeably (air = 71% nitrogen). Helium is now used in automated permeability measuring equipment used by many commercial laboratories. Since helium has a lower molecular weight, the slope "b" is steeper but can be corrected to an equivalent air slope using the approximation:

$b_{air} = b_{hel} \times .35$

The Klinkenberg equation is also affected by the mean flowing pressure. Most commercial equipment prior to modern automated apparatus could attain a maximum inlet pressure of 32 psig and for tight gas samples this highest pressure would be the most likely inlet pressure. It is possible that inlet pressures on tight gas sand measurements may have been as low as 16 psi. Other commercial laboratories may have had equipment capable of 50 psig maximum inlet pressure (Core Laboratories personal communication).

COREPRO uses the Jones and Owens (1980) relationship for "b," described above. It is necessary to iteratively solve for dry Klinkenberg permeability and a second relationship was derived by Jones and Owens (1980) to avoid iteration:

$K\infty = 10^{EXP}$ Where:

$EXP = -.0398 \log K_{air}^2 + 1.067 \log K_{air} -.0825$

The relationship assumes that K_{air} is measured at 100 psig upstream pressure.

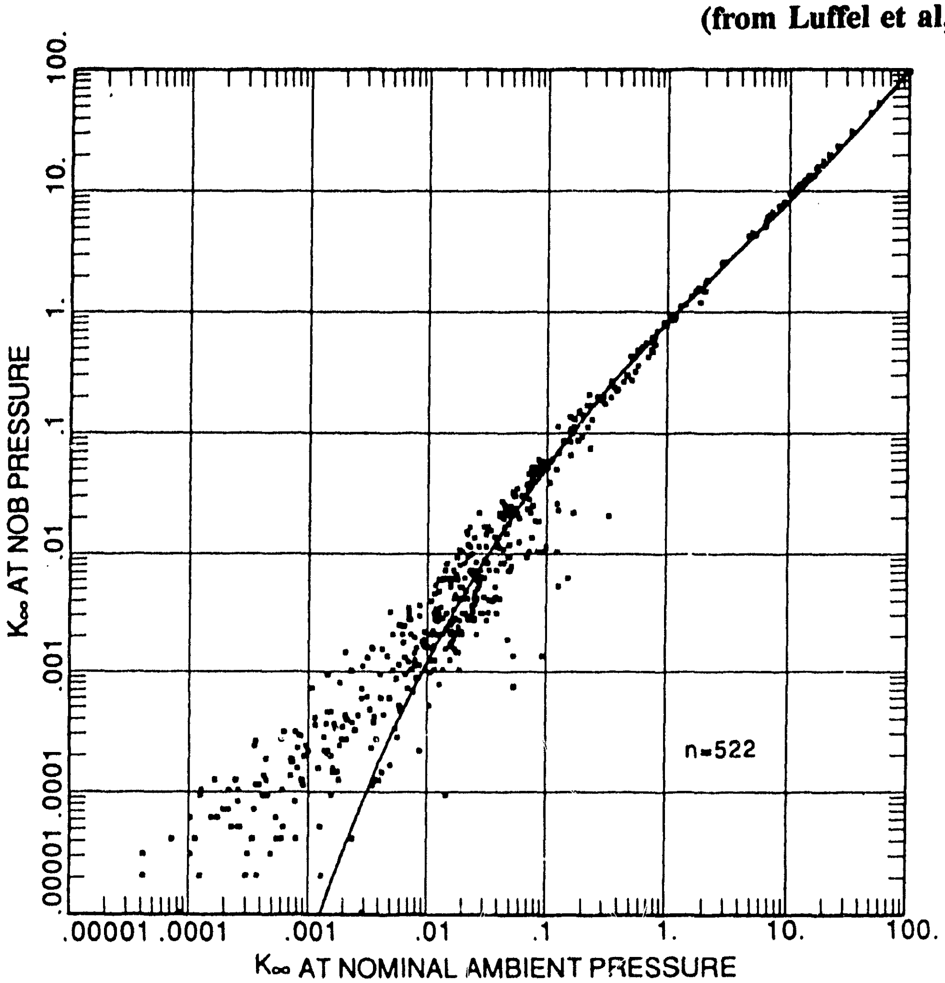
The two relationships agree closely over the K_{air} range of 0.0001 to 1 md. Where permeabilities exceed 1 md, the more conventional Penn State correction (Heid et al, 1950) for the Klinkenberg effect is used by COREPRO.

NOB Correction To Permeability

Application of confining pressure (NOB pressure) causes a reduction of tight gas sand permeabilities (Jones and Owens, 1980, Thomas and Ward 1972). Confining pressure has greater effects on tight gas sands than on more permeable sands. Increasing confining pressure causes a further nonlinear reduction in permeability. Jones and Owens (1980) quote reductions from less than threefold to more than twentyfold for confining pressures of 5,000 to 6,000 psi. This implies the need for a permeability correction which varies as a function of NOB pressure. It has been observed during this study and from literature (Spencer, 1987) that pressure gradients in OPT gas sands of the GGRB increase with depth. Plots of mud weight pressure versus depth (see discussion on pressures) result in pressure gradients which range from normal (.45 psi/foot from surface to around 8,000 to 9,000 feet) to overpressured values as high as .8 psi/foot at around 23,000 feet. The increasing pressure gradient causes the NOB pressure (overburden pressure at 1 psi/ft less the reservoir pressure using the increasing gradient) to be a constant 4,950 psi, Figure A-3.

The correction of permeability for confining pressure as reported by Jones and Owens (1980) is not readily applicable to the dataset used in this study since it requires permeability values to be normalized on the basis of permeability measured at 1,000 psi NOB to allow direct comparison of the influence of confining pressure independent of permeability level. A relationship of gas permeability at NOB versus ambient pressure is presented by Luffel et al (1991) from core samples from six wells in the Travis Peak formation whose NOBs ranged from 3,303 to 5,572 psi and averaged 4,650 psi.

Figure A-3
(from Luffel et al, 1991)



Since the estimated NOB pressure in the overpressured region of the GGRB approximates that reported by Luffel, this relationship was considered as a basis for correcting permeabilities in this study. It should be noted that the slope of the transform increases with decreasing permeability such that below 0.01 md, the correction for NOB becomes very severe. In deriving his transform, Luffel considered samples from only two out of six wells cored (samples from the two wells were analyzed using automated equipment) and as a consequence discarded data points below 0.01 md ambient permeability. Comparison of permeabilities corrected for gas slippage (Jones and Owens, 1980) overburden (Luffel et al 1991) and liquid permeability (described below) with the same samples corrected using Jones and Owens (1980) "Stadium" equation (described below), led to the development of a less severe 'best fit' overburden correction curve using the data from all six wells (excluding fractured plugs). The equations for this new transform, subdivided into three straight line segments are presented below:

For > 1.0 md	$K\infty_{NOB}$	=	$0.8\ K\infty_A^{1.02113}$
For 0.1 - 1.0 md	$K\infty_{NOB}$	=	$0.8\ K\infty_A^{1.9435}$
For < 0.1 md	$K\infty_{NOB}$	=	$0.9\ K\infty_A^{1.19082}$

Where:

$K\infty_{NOB}$ = Dry Klinkenberg permeability at net effective overburden pressure
$K\infty_A$ = Dry Klinkenberg permeability at ambient conditions

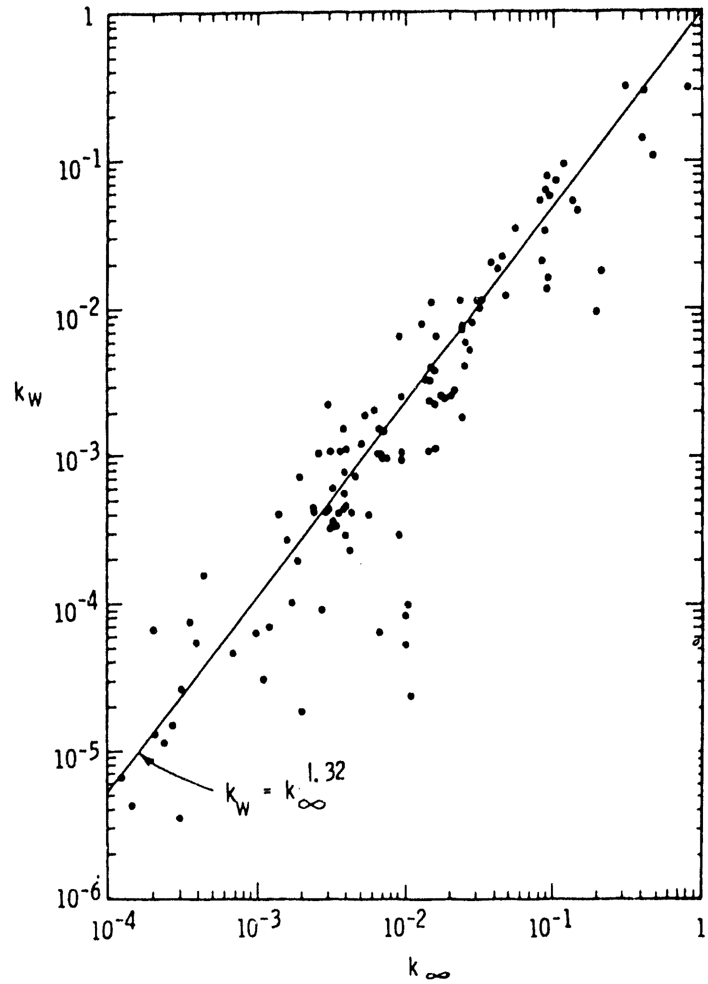
Specific Water Permeability Correction

Correction of tight gas sand permeabilities in the GGRB for gas slippage results in a "dry Klinkenberg" permeability which is normally higher than measured absolute liquid permeability. The difference in dry Klinkenberg and specific water permeability values is often attributed to the sample drying process, clay mineralogy (Luffel et al, 1991b; Luffel et al, 1990; Kukal 1981a) and ordering of water molecules against high energy grain surfaces sufficient to reduce effective pore diameters (Jones and Owens, 1980). Fibrous illite, often present in GGRB sands, collapses during drying in normal humidity ovens, causing dry core air permeabilities to be optimistic. Restoration of the sample with brine causes the illite to rebound, resulting in a lower but more realistic specific water permeability. Sample drying in high humidity ovens can significantly reduce the difference between dry Klinkenberg and specific water permeabilities. Tangential illite, even in larger quantities than fibrous illite, will not reduce reservoir gas permeability much compared to that measured on dry cores (Luffel et al, 1991b). Routine core analysis or log analysis alone are not satisfactory for predicting the presence of fibrous versus tangential illite.

The clay mineralogy and distribution and sample preparation conditions of almost all the core data collected is unknown. The error associated with using a single specific water permeability correction factor therefore could be significant in some wells.

Jones and Owens (1980) present a relationship developed from more than 100 samples taken from the Lewis, Mesaverde, Frontier and Spirit River formations of the GGRB to correct dry Klinkenberg permeabilities (NOB corrected) to specific water permeability (Figure A-4):

Figure A-4
(from Jones and Owens, 1980)



$K_w = K\infty^{1.32}$ for $K < 1$ md @ NOB

This relationship is used in COREPRO. Actually, data scatter on the Jones and Owens (1980) plot of dry Klinkenberg permeability versus specific water permeability indicate that the exponent 1.32 could range between 1.3 and 1.51. A correction to absolute liquid permeability developed from Travis Peak core (Luffel et al, 1991a), $K_w = .52\ K\infty^{1.13}$, results in corrections which fall within the range of those using the two extremes above. Similarly, corrections using the Chowdiah (1987) equation, $K_w = K\infty^{1.42}$, fall within this range.

Effective Gas Permeability Correction

Gas drive experiments conducted by Jones and Owens (1980) on 22 core samples showed that effective gas permeabilities were within a factor of two of the specific permeability to formation water. Since specific water permeabilities at in-situ conditions approximate effective gas permeability under conditions of reservoir stress, gas slippage and partial water saturation, no further corrections were applied.

Stadium Equation

For comparative purposes, the "Stadium" equation of Jones and Owens (1980) combines corrections for overburden, slippage and connate water into one relationship:

$K_g = ak^c$ for .02 md $< k <$ .55 md

Where:

K_g	=	Effective gas permeability
K	=	Routine permeability
a,c	=	Stress and water variables

SEVERITY	a	c	EXAMPLE
Minimum	1/5	1.5	Clean Mesaverde
Moderate	1/7.5	1.9	Cleaner Frontier
Great	1/12	2.3	Most Frontier
Very Great	1/20	3.2	Shaley Frontier

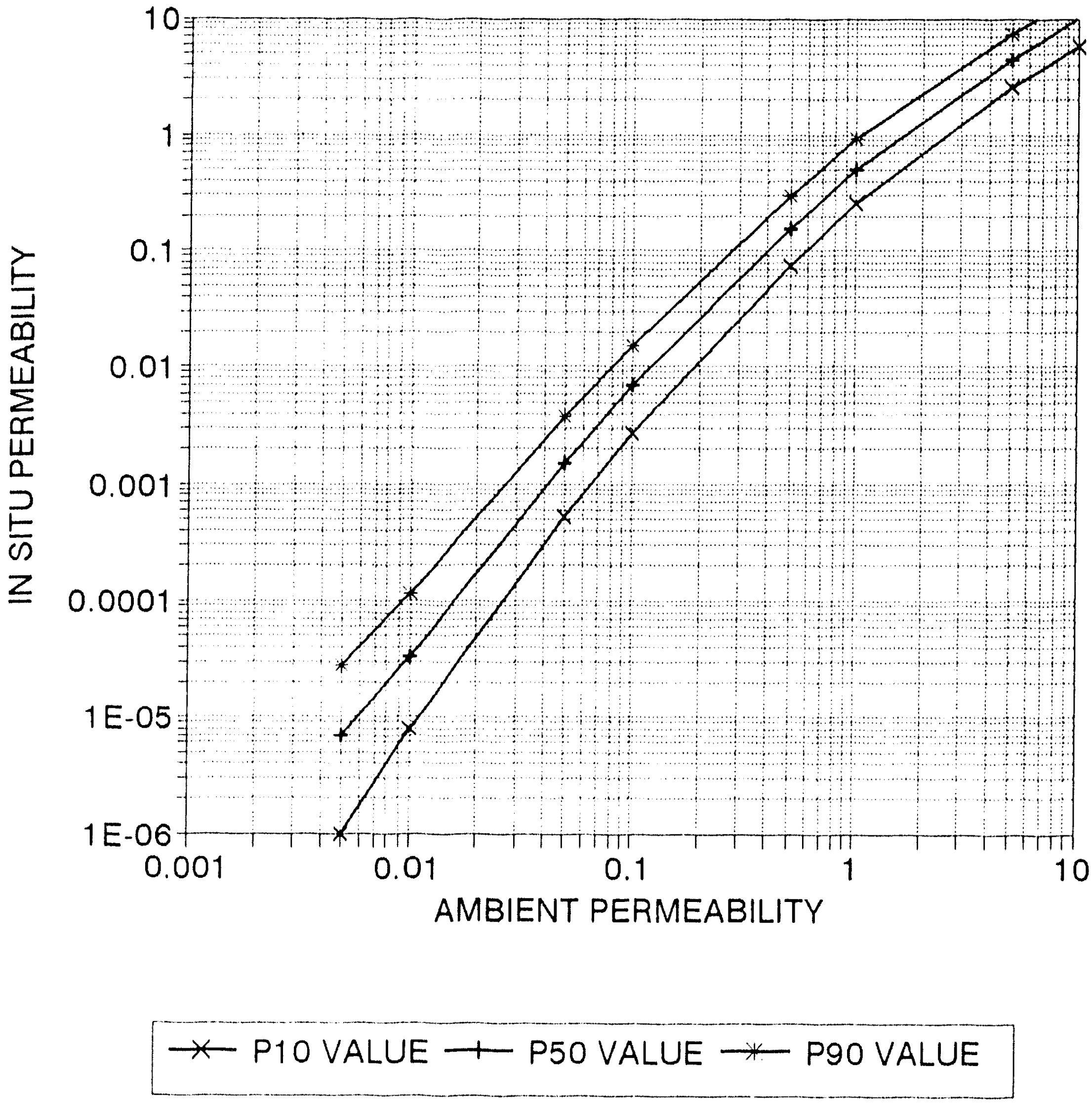
Estimate of Error in Performing Correction to In-Situ Conditions

The process of correcting ambient measurements to in-situ conditions as described herein is extremely important in the study of OPT gas reservoirs. Because a degree of error is involved in many of the measurements themselves, and because several of the steps involve empirical relationships that may or may not be representative, it is important to consider the degree of error that may result in the final permeability corrected to in-situ conditions.

An estimate of the error was made by performing a Monte Carlo simulation involving the correction formulae using expected error ranges for each input parameter. The result is a single relationship that relates ambient to in-situ permeabilities. This relationship (see below) displays three transforms representing the P90, P50 and P10 situations. That is, the net correction will be less than the P90 correlation 90% of the time and less than the P10 correlation 10% of the time. The P50 correlation represents the median value where the net correction will be more 50% of the time and less 50% of the time. These correlation lines generate an error window.

This representation is very useful in visualizing the magnitude of the correction as well as the potential degrees of error.

FIGURE A5: CORRECTION OF CORE ANALYSES AMBIENT TO IN SITU CONDITIONS



APPENDIX B

DISCUSSION OF OPEN HOLE LOG PROCESSING AND INTERPRETATION

INTRODUCTION

Conventional methods of log interpretation have limited success in defining the rock properties of tight gas sands. The main concerns include variable invasion profiles causing variable gas saturations, uncertainty in formation water resistivities, formation clay content, and water saturation (Kukal et al, 1983a). In low porosity tight gas sands invasion can increase from zero to deep, depending on reservoir permeability, circulation time and differential pressure (Kukal, 1983b).

A comprehensive approach to the evaluation of open hole logs was adopted using published techniques developed specifically for low permeability gas sands. Scotia's proprietary interpretation program, SLOG, was used to computer process a variety of log suites using the tight gas interpretation methods of Kukal (1981 and 1984). The complex lithology methods of Poupon, Hoyle and Schmidt (1971) were also incorporated into SLOG.

The objective of the log interpretation was to derive a set of rock properties by well including net gas, effective porosity, water saturation and permeability which could be used in the volumetric determination of GIP for each play in the GGRB.

Log Data

Full computerized log interpretation was run on open hole logs from 75 wells in the GGRB. A partial interpretation was run on an additional 101 wells. Log suites were of various vintages (1968 to 1990) and types available for individual wells ranged from a single GRN log to suites comprising CNL-FDC, BHC, and DIL-MSFL, along with GR, SP and caliper. Schlumberger, Dresser Atlas, Gearhart, and Electric Log Services logs were available, with Schlumberger being dominant. Reproduction quality of the logs was variable, with depth scales ranging from 5 inches = 100 feet to 2.5 inches = 100 feet.

Open hole log curves were digitized on a 0.5 foot increment. Digitized data was plotted against depth and checked against the original logs. Curves were depth shifted where necessary. Drilling fluid data and temperatures reported on the log headers were keyed into the constants file along with Archie constants, tool lithology responses and formation water resistivity data.

Previously digitized (one sample per foot) open hole logs from approximately 50 wells were provided by EG&G, Morgantown, West Virginia in digitized tape form. Only six of these wells were located within the USGS designated overpressured area. Selected intervals from only the Mesaverde section had been digitized, and no log header information was available.

Clay Volume

Clay volumes were calculated from the density-neutron porosity combination $(V_{Cl})_{dn}$ using the methods of Kukal (1984b) and from the GR curve $(V_{Cl})_{GR}$. The $(V_{Cl})_{GR}$ method uses a linear interpolation equation which incorporates a factor to correct for non-clay minerals within the shale (Kukal, 1984b).

$$(V_{Cl})_{GR} = (GR-GR_{MIN})/(GR_{clay})-GR_{MIN})$$

Where:

GR_{clay}	=	$(GR_{MAX}-(1-V_{clk} \times GR_{MIN})/V_{clk}$
V_{clk}	=	Fraction of clay present in shale, constant
$(V_{Cl})_{GR}$	=	Gamma ray clay volume

The Kukal equation for calculating clay volume from the density and neutron curves is derived from the combination of the density and neutron response equations.

$$(V_{Cl})_{dn} = [\phi n+(\Delta\phi n)_{ex}-\frac{(\rho b-\rho ma)\ (S_{dn}\ (\phi n)_{fl}+(1-S_{dn})\ (\phi n)_h)}{S_{dn}\ \rho fl+(1-S_{dn})\ \rho h-\rho ma}]/(\phi n)_{Cl}$$

Where:

ϕ	=	Neutron porosity corrected for lithology (sandstone porosity), variable
$(\Delta\phi n)_{ex}$	=	Neutron excavation effect, iterative
ρb	=	Bulk density, variable
ρma	=	Matrix density, constant or variable
S_{dn}	=	Saturation of zone investigated by neutron and density tools, constant (set to 1.0 initially and varied)
$(\phi n)_{fl}$	=	Neutron response to water in investigated zone, constant
$(\phi n)_h$	=	Neutron response to hydrocarbons, constant
ρfl	=	Density response to water in investigated zone, constant
ρh	=	Density response to hydrocarbons, constant
$(\phi n)_{Cl}$	=	Neutron response to clay, constant

The equation contains an S_{dn} term which is initially set to 1.0 (representing totally flushed) and varied until similarity with the $(V_{Cl})_{GR}$ is achieved. By reducing the S_{xo} term the equation compensates for the gas effect on the density and neutron curves. The minimum, $(V_{Cl})_{MIN}$, of $(V_{Cl})_{GR}$ and $(V_{Cl})_{dn}$ was then used to correct porosity for the effects of clay and in the calculation of water saturation and permeability.

Porosity

Two approaches were used to calculate porosity for wells having neutron-density porosity combinations.

a. Neutron-density cross-plot porosity, corrected for clay and hydrocarbon effects according to the methods of Poupon, Hoyle and Schmidt (1971). This method first corrects the log readings for the effects of clay, then obtains an initial cross-plot porosity, which is used to calculate the invaded zone saturation (S_{xo}). The invaded zone saturation is required for the computation of the gas correction factors for the density and neutron curves. The curves are then corrected for gas effects and a new gas-corrected cross-plot porosity is calculated. This porosity is used to recalculate S_{xo} and the process is repeated until the change in the porosity correction becomes minimal. Between one and four iterations are usually required.

b. Neutron-density porosity, corrected for clay and hydrocarbon effects according to the methods of Kukal (1981, 1983, 1984). This approach uses the Kukal equation, derived from the combination of the neutron and density response equations and developed specifically for tight gas sands from a detailed study of the Mesaverde formation in the MWX wells, Piceance basin, Colorado.

$$\frac{\rho b-\rho ma}{(S_{xo})dx\rho fl+[1-(S_{xo})d]x\rho h-\rho ma}=\frac{\o n-V_{Cl}(\o n)_{Cl}+(\Delta \o n)_{ex}}{(S_{xo})nx(\o n)fl+[1-(S_{xo})n]x(\o n)h}$$

Where:

$(S_{xo})d$ = Water saturation of zone investigated by density tool
$(S_{xo})n$ = Water saturation of zone investigated by neutron tool
V_{Cl} = Clay volume

It too requires the iterative calculation of porosity and invaded zone saturation (S_{dn} - saturation of the zone investigated by the density and neutron curves).

In wells having only a density-sonic porosity combination, plus a resistivity suite, porosities were generally evaluated in SLOG using the sonic because of the difficulty of correcting the density curve alone for gas effects. Wells having porosity logs and no resistivity curves were evaluated by hand to estimate net pay and porosity. Again, the sonic log was favored for the reason discussed.

In-Situ corrected core porosities were loaded into SLOG, depth shifted where necessary and compared against log derived porosities. Log porosity calculations were repeated until acceptable matches were achieved and the models developed to achieve the matches were then applied to uncored intervals.

Formation Water Resistivity

Formation water resistivities used in the determination of water saturation were derived from a variety of sources including:

Wyoming Geological Symposium, 1979/1992. Wyoming Oil and Gas Fields.
Rocky Mountain Formation Water Resistivities - publisher and date unknown.
Direct communication with operators.

An inordinately wide range of resistivities is reported for each play. In the Mesaverde group for example, resistivities range from 0.1 to 8.9 ohm-m at 68°F through the majority of samples are less than 1 ohm-m. The variation in reported resistivities may be a function of one or more factors including:

1. Condensation of water from the produced gas, diluting the water samples collected at the surface.

2. In the paludal (coaly, swampy) intervals, generation of fresher water as a result of the coalification process, diluting the connate water (Kukal, 1984).

3. Drilling fluids contamination.

Determination of R_w in the tight gas sands in the GGRB is frustrating and problematic at best. R_w estimates derived from SP curves are generally unreliable because of the poor development of the SP in tight sands. Determination of R_{wa} using Archie's equation in clean, wet sands is usually not possible since water bearing sands are generally not encountered in the overpressured gas-bearing sections of interest. For the same reason, Pickett plots are generally of little use. Reported R_w values were posted to a base map for each play formation and the distribution of values were studied. A first approximation S_w was determined using the lower values of R_w reported for the geographic area in which the well being studied was located. R_ws were then upgraded according to a modification of the approach taken by Kukal (1984) and discussed below.

A value of water saturation in the zone investigated by the neutron and density tools, S_{dn}, can be derived from a combination of the equations for these two curves, which is independent of the resistivity tool. Depending on the degree of invasion, the saturation, S_{dn}, may range between S_w and S_{xo}. If $S_{dn} = S_w$, no invasion exists. If $S_{dn} = S_{xo}$ and $S_{xo} \neq S_w$, then the saturation represents that of the invaded zone.

Kukal was able to derive water resistivities using the Archie and Total Shale water saturation equations, and the independently calculated S_{dn}. The water resistivity obviously varies between R_{mf} and R_w, depending on the depth of invasion. When $S_{dn} = S_w$ then no invasion is interpreted and the derived water resistivity represents R_w. The concern with this approach is that the answer to the problem must be known before the problem can be solved. That is, a value of R_w must be known to calculate S_w before a comparison of S_w and S_{dn} can be made to determine if the derived water resistivity represents R_w. Theoretically, when $S_{dn} = S_w$, the derived R_w and the R_w used initially to calculate S_w should be the same, but not necessarily correct. A high initial R_w would produce a high Sw. This would reduce the difference between S_{dn} and S_w (Δ_{sw}) indicating less invasion and lower permeability rock, but no conclusion regarding true R_w could be reached. Again, using a low initial R_w, a lower S_w would be calculated, creating a higher Δ_{sw}, indicating greater invasion and higher permeability, but no conclusion about true R_w could be reached.

Rather than comparing S_{dn} with S_w (for which the R_w is not known), the approach taken in this study was to compare S_{dn} with S_{xo}, for which R_{mf} is known. Now, both S_{xo} and S_{dn} are affected by the depth of invasion and S_{xo} calculated using an R_{xo} curve is often unreliable in tight gas sands because of the varied invasion profile. If $S_{dn} = S_{xo}$ and $S_{xo} \neq S_{wo}$, invasion exists to a greater or lesser extent and a water resistivity derived from S_{dn} may represent R_{mf} or a mixture of R_{mf} and R_w. If, however, $S_{dn} < S_{xo}$, at the point of maximum departure the derived water resistivity should be least like R_{mf} and approach R_w. The maximum separation of the two curves should also represent shallow invasion. A best fit line drawn through points on the R_w line corresponding to the maximum separation of S_{xo} and S_{dn} (in clean porous sands) should define a maximum possible R_w, assuming R_{mf} is normally greater than R_w. This in turn, would result in a maximum water saturation.

This value of R_w was then compared against R_ws reported in the literature at reservoir temperature. Generally the lower of the two values was used to calculate water saturations.

Water Saturation

Water saturation is probably the most difficult petrophysical parameter to determine in tight gas sands. This is of great concern since water saturation has the greatest influence on effective gas permeability and the ability of the rock to produce. The difficulty in estimating water saturations from logs is generally related to the uncertainty in the parameters used in its derivation, specifically formation water resistivity and Archie exponents m and n. Errors caused by uncertainty in these parameters outweigh those created by using an inappropriate water saturation equation, for example, V_{clay}-based versus clay conductivity (CEC) methods. In this study, invaded zone (S_{xo}) and uninvaded zone (S_w) water saturations were calculated using the Total Shale (Simandoux) equation. This equation as with other shaly sand equations, reverts to the classic Archie equation when the clay volume is zero.

$$\frac{1}{R_t} = \frac{V_{clay}\ S_w}{R_{Cl}} + \frac{\varnothing^m\ S_w^{\ n}}{a\ R_w}$$

R_t	=	True formation resistivity
S_w	=	Water saturation
R_{Cl}	=	Clay resistivity
ϕ	=	Effective porosity
m	=	Cementation exponent
n	=	Saturation exponent
a	=	Tortuosity factor
R_w	=	Formation water resistivity

In addition, to account for variable invasion profiles experienced in tight gas sands, the Kukal equation was used to calculate the average water saturation (S_{dn}) of the zone investigated by the density and neutron tools:

$$S_{dn} = \frac{(\varnothing n)h(\rho b - \rho ma) - (\rho h - \rho ma)[\varnothing n - V_{Cl}(\varnothing n)_{Cl} + (\Delta\varnothing n)_{ex}]}{(\rho fl - \rho h)[\varnothing n - V_{Cl}(\varnothing n)_{Cl} + (\Delta\varnothing n)_{ex}] - [(\varnothing n)_{fl} - (\varnothing n)_h](\rho b - \rho ma)}$$

Archie Exponents

Limited laboratory measured Archie exponents were available. Cementation exponents (m) and saturation exponents (n) from formation factor and resistivity index measurements made on Mesaverde core samples from the MWX wells in northwestern Colorado (Sattler 1983, 1991) are reported below.

Effective Overburden Pressure, PSI	Cementation m	Exponent m*	Saturation n	Exponent n*
0	1.72-1.82	1.92-2.03	1.08-1.85	1.47-2.55
200	1.79-1.92	1.98-2.12		
3000-3600	1.88-1.95	2.08-2.17		

* Shaly sand values obtained from core CEC values

Cementation exponents vary only slightly considering their measurement from cores cut in different depositional environments (paludal, coastal and fluvial). Saturation exponents display a wider range of values and measurements were not taken at in-situ stress conditions. Sattler (1983) reports the appropriate saturation exponent from the above data to be 1.85 at room conditions. In-Situ corrections for saturation exponents were not found in the literature. Increasing effective overburden pressure from zero to around 3,200 psi causes the average cementation factor (m) to increase from 1.74 to 1.88, an increase of 8% (Sattler 1991). A linear extrapolation of the increase in m to an average NOB of 4950 psi results in an m value of 1.96 which may indicate an appropriate in-situ value.

Laboratory derived Archie exponents m and n were measured on Lewis core samples recovered from Well Hay #5 (S27 T24N R97W, Sweetwater County, Wyoming). The averaged values are 1.79 and 1.41 for m and n respectively. No record of these measurements having been made at NOB conditions exists and it is likely the tests were performed at ambient conditions. Archie exponents used in this study were generally as follows:

$a = 1.0$
$m = n = 2.0$

Permeability

Log permeabilities were calculated using relationships established by Kukal (1981a) from a study of a low permeability database of 261 core samples taken from the MWX wells in western Colorado. Two permeability values were calculated. The first requires as input log derived values of porosity, water saturation and clay volume:

$$K_{KUK} = \frac{3.6[\phi e\ (1-V_{Cl})]^{2.8}}{S_{wi}^{\ 2}}$$

Where:

K_{KUK} = Kukal permeability
ϕe = Effective porosity
S_{wi} = Irreducible water saturation
V_{Cl} = Clay volume

The generalized form of the equation was developed by Timur (1968). Core permeability data used to establish Kukal's relationship was dried in a humidity controlled oven to help prevent the collapse of individual clay crystals, and was corrected for gas slippage and NOB pressure. Studies by Soeder (1984) have shown that humidity controlled drying avoids much of the change in pore structure which often occurs during conventional oven drying and that measured permeabilities were 33% lower on average than for vacuum dried samples Kukal (1981a). Jones and Owens (1980) and Luffel et al (1991) applied a further correction to dry Klinkenberg permeabilities to account for the pore structure changes during drying, particularly the collapse of fibrous illite, and the rock-saturating fluid interaction, to derive the equivalent of 100% brine saturated liquid permeabilities. The Kukal equation should produce permeabilities which approximate those from vacuum dried core, corrected for gas slippage, net effective overburden and liquid permeabilities equivalent to 100% brine saturation.

A second permeability, the Alternative Kukal permeability, was calculated using the equation below:

$K_{alt} = 171.4[\phi e(1-V_{cl})]^{3.86}$ Where:

K_{alt} = Alternative Kukal permeability

This equation was derived from the same 261 core sample database and eliminates the saturation function which can have a fairly weak correlation with permeability in low permeability reservoirs.

In-Situ corrected core permeabilities were loaded into SLOG, depth shifted where necessary and compared against log derived permeabilities. In many instances log derived permeabilities were in reasonable to excellent agreement with the core values. In several wells the exponents of the Kukal permeability equation were adjusted to achieve more acceptable matches. In other cored wells, transforms were developed from in-situ corrected porosity-permeability data which was then used along with the log porosities to generate log derived permeability. Neither the transforms developed from core data nor the modifications to the Kukal equation exponents were sufficiently consistent from well to well to be applied to uncored wells across the GGRB. For uncored wells, the Kukal equation was generally used for calculating log derived permeabilities.

Bad Hole

Out-of-gauge hole was experienced frequently in many wells, particularly across the Mesaverde section. Logic used in SLOG to account for this problem was relatively simple. Curve reconstruction techniques were not adopted. Rather, bad hole was flagged using constraints applied to the caliper, density and sonic curves with an option to use any combination of these. An option was available to automatically substitute sonic porosity for density-neutron or density porosity if the density was out-of-gauge and assuming the sonic was within the selected bad hole constraints. Selection of sandstone thickness and net pay across bad hole is discussed below.

Pay Identification Criteria, Cutoffs

Identification of reservoir and nonreservoir quality rocks in tight gas sands is a significant problem since the ability of these sands to produce is as much a function of the success of the stimulation program (fracturing) as it is the natural rock properties of the reservoir.

Several approaches were used to distinguish between reservoir and nonreservoir quality rock. In-Situ corrected routine core data was sorted and placed into three categories as follows:

Category A: Completed intervals
Category B: Tested but not completed intervals
Category C: Nontested Other intervals

Frequency distributions, probability plots, porosity-permeability plots and cumulative storage (ϕh) and flow (Kh) capacities versus porosity cutoffs were studied in detail to define the typical ranges and average rock properties for each category. Tight gas sand log analysis was performed as discussed previously and various frequency histograms and cross-plots of porosity, log derived permeability, clay volume and water saturation were generated for each category to define the rock property ranges and averages. Published literature was also researched to locate criteria for defining pay.

Initially pay cutoffs were adjusted by trial and error to reproduce thicknesses used in the USGS sandstone reservoir thickness isopachs. Using a cutoff of 50% on the Vclay curve of the processed well logs, it was possible to approximate the mapped sand thicknesses. As discussed by Law et al (1989), the thickness of reservoirs in each play was determined during the USGS study by examining well logs and summarizing the thickness of sandstone greater than 10 feet thick. Indeed, it was possible to reproduce the mapped thicknesses from a manual estimation of sand versus shale on the gamma ray and SP curves of wells included in a set of 19 stratigraphic cross-sections covering much of the GGRB prepared by the USGS between 1978 and 1983. Additionally, logs from cross-sections prepared by Roehler (1990) were also evaluated.

A review of the log derived rock properties indicated that much of the retained section was of very poor reservoir quality with porosities of less than 5% and water saturations at or near 100%. A more rigorous examination of the processed well logs and core data was conducted to eliminate obviously poor reservoir quality sandstones as described below. Figure B-1 is a combination plot of all Mesaverde core samples corrected to in-situ stress conditions. The bulk of porosity is distributed between 0 and 15% and though not readily apparent from the frequency histogram, two populations of samples are indicated on the porosity permeability plot, a first population, 0-5% porosity having permeabilities from less than 1μd to greater than 1 md, and a second population, 5 to 15%+ porosity which poorly defines a more typical relationship of increasing porosity with increasing permeability.

Figures B-2, B-3, and B-4 present "combination" plots of Mesaverde core data at in-situ conditions for the three categories. The porosity frequency histogram for Category A is slightly negatively skewed with an excess left tail below about 5-6%. The frequency of samples 6% and below increases in Category B and in Category C, the porosity is strongly positively skewed with an excess right tail between 6 and 15%. The average porosity decreases from 9% to 7.8% to 5.6% for categories A through C respectively.

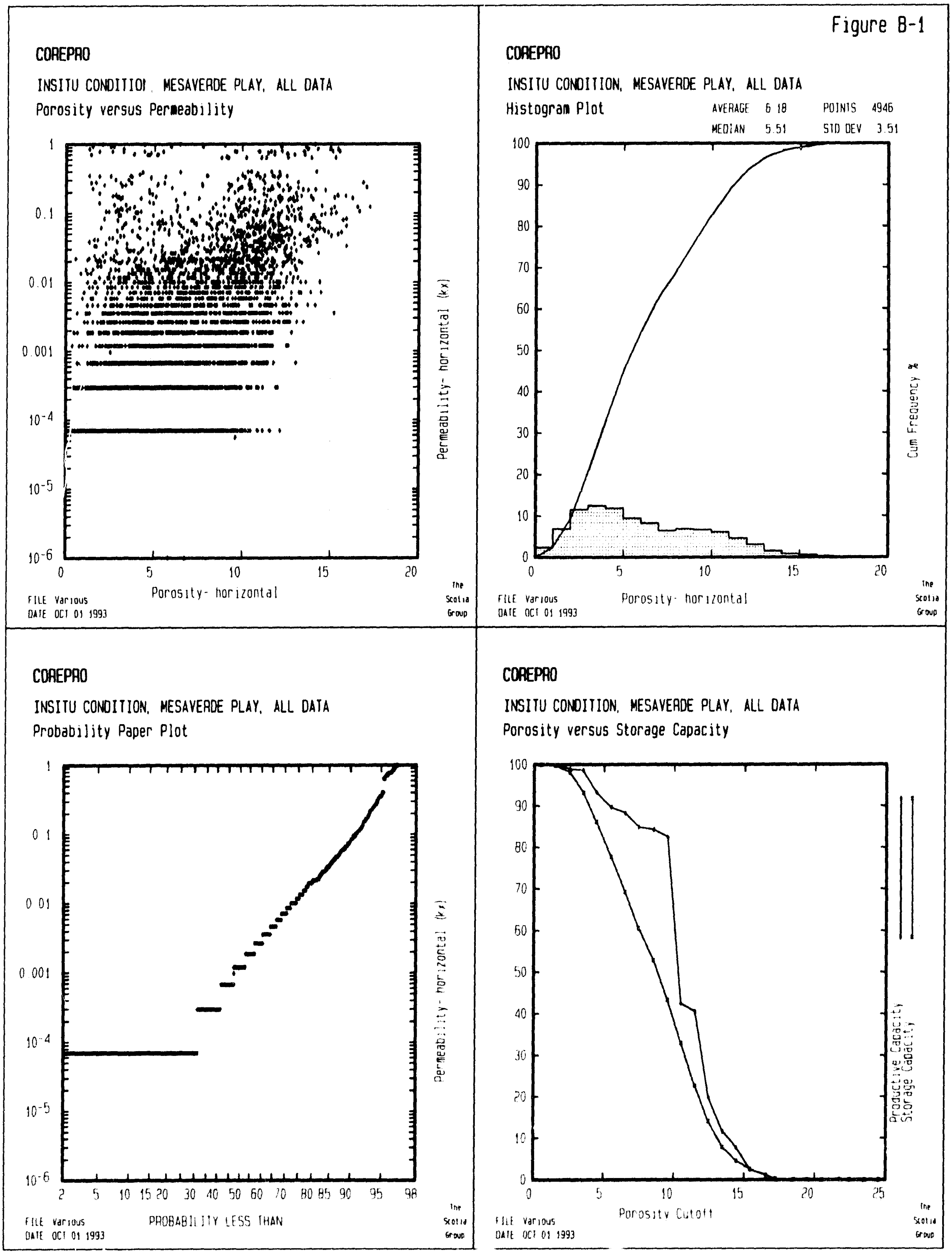


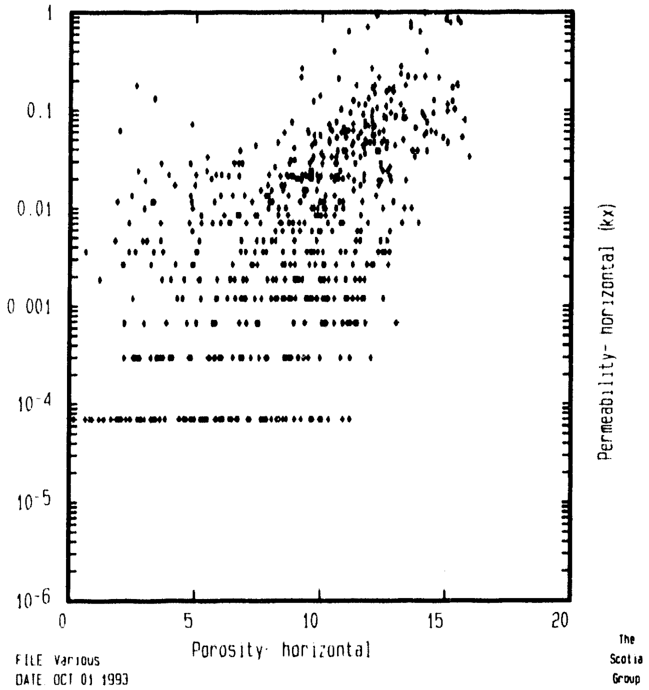
Figure B-1
COREPRO
INSITU CONDITIOI , MESAVERDE PLAY, ALL DATA
Porosity versus Permeability
Permeability- horizontal (kx)
Porosity- horizontal
FILE Various
DATE OCT 01 1993
The Scotia Group
COREPRO
INSITU CONDITION, MESAVERDE PLAY, ALL DATA
Histogram Plot
AVERAGE 6.18
POINTS 4946
MEDIAN 5.51
STD DEV 3.51
Cum Frequency %
Porosity- horizontal
FILE Various
DATE OCT 01 1993
The Scotia Group
COREPRO
INSITU CONDITION, MESAVERDE PLAY, ALL DATA
Probability Paper Plot
Permeability- horizontal (kx)
PROBABILITY LESS THAN
FILE Various
DATE OCT 01 1993
The Scotia Group
COREPRO
INSITU CONDITION, MESAVERDE PLAY, ALL DATA
Porosity versus Storage Capacity
Productive Capacity
Storage Capacity
Porosity Cutoff
FILE Various
DATE OCT 01 1993
The Scotia Group

Figure B-2

COREPRO

INSITU CONDITION, MESAVERDE PLAY, COMPLETED INTERVALS

Porosity versus Permeability



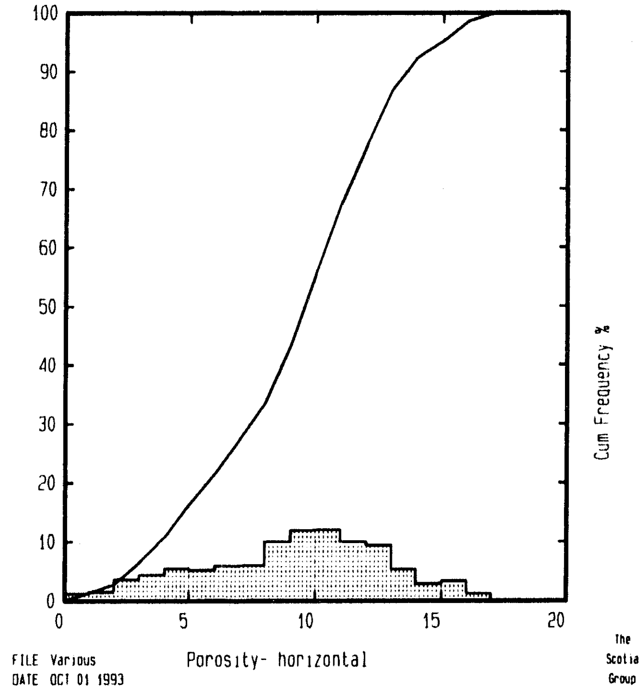
COREPRO

INSITU CONDITION, MESAVERDE PLAY, COMPLETED INTERVALS

Histogram Plot

AVERAGE 9.15 POINTS 711

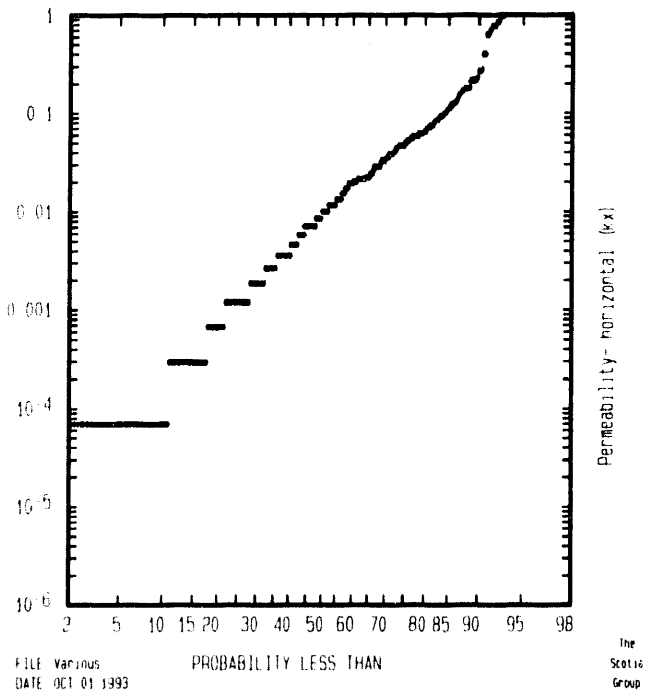
MEDIAN 9.61 STD DEV 3.61



COREPRO

INSITU CONDITION, MESAVERDE PLAY, COMPLETED INTERVALS

Probability Paper Plot



COREPRO

INSITU CONDITION, MESAVERDE PLAY, COMPLETED INTERVALS

Porosity versus Storage Capacity

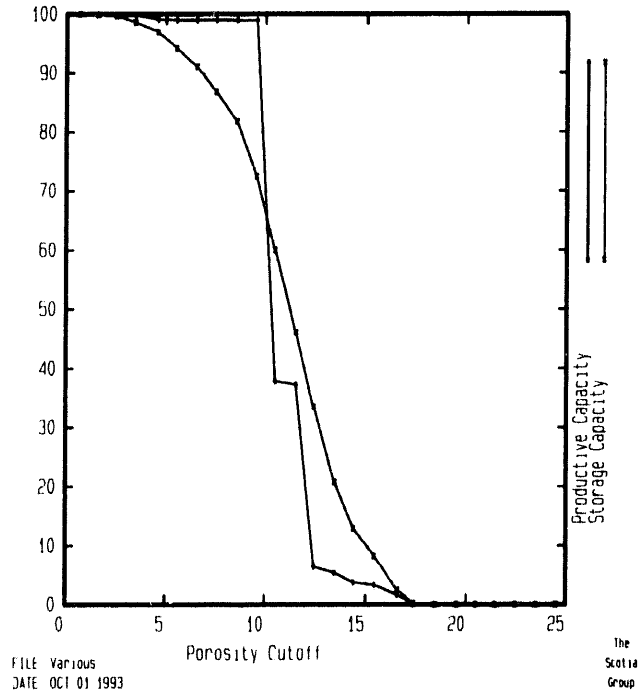
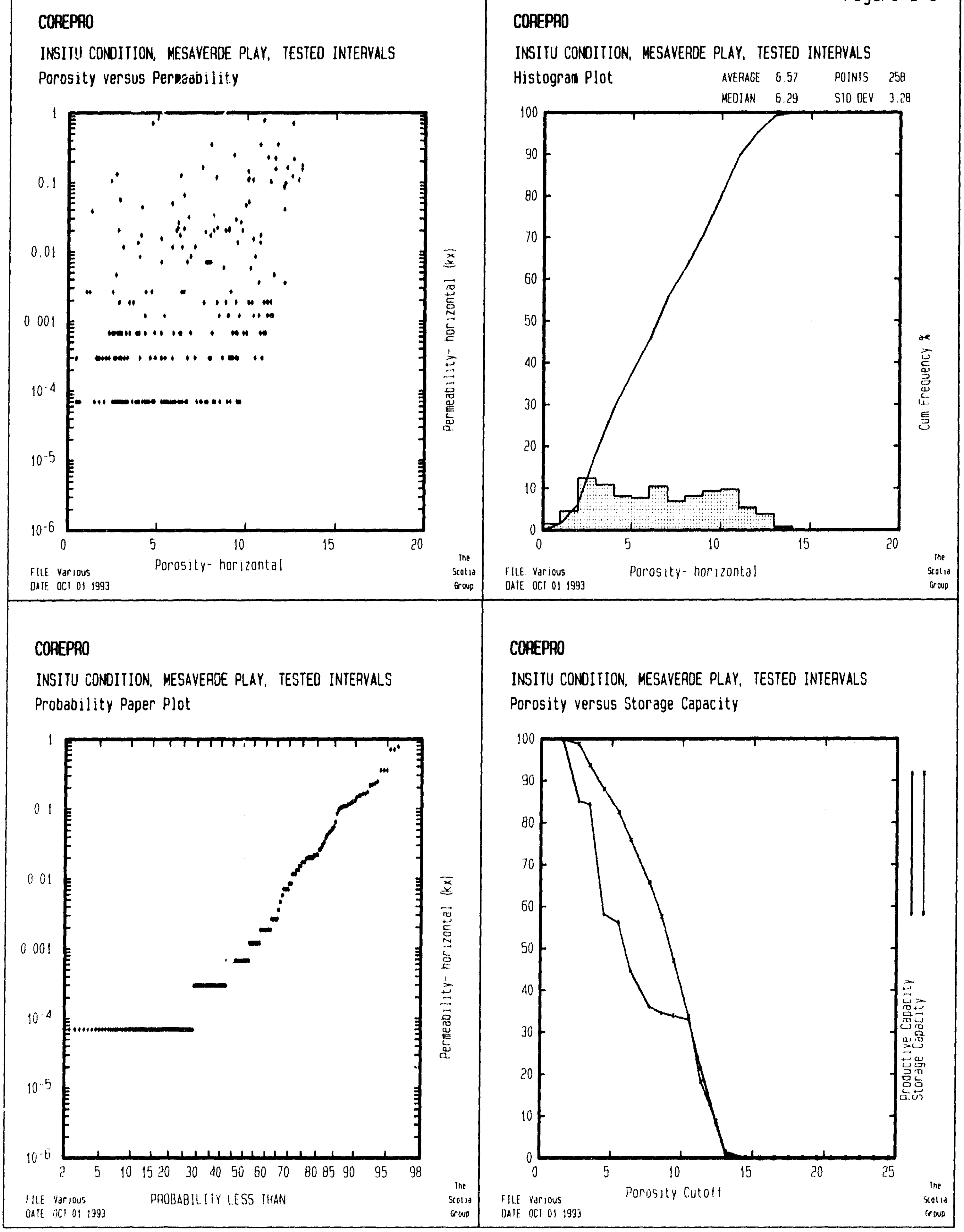


Figure B-3


COREPRO
INSITU CONDITION, MESAVERDE PLAY, TESTED INTERVALS
Porosity versus Permeability
Porosity- horizontal
Permeability- horizontal (kx)
FILE Various
DATE OCT 01 1993
The Scotia Group
COREPRO
INSITU CONDITION, MESAVERDE PLAY, TESTED INTERVALS
Histogram Plot
AVERAGE 6.57
POINTS 258
MEDIAN 6.29
STD DEV 3.28
Porosity- horizontal
Cum Frequency %
FILE Various
DATE OCT 01 1993
The Scotia Group
COREPRO
INSITU CONDITION, MESAVERDE PLAY, TESTED INTERVALS
Probability Paper Plot
PROBABILITY LESS THAN
Permeability- horizontal (kx)
FILE Various
DATE OCT 01 1993
The Scotia Group
COREPRO
INSITU CONDITION, MESAVERDE PLAY, TESTED INTERVALS
Porosity versus Storage Capacity
Porosity Cutoff
Productive Capacity
Storage Capacity
FILE Various
DATE OCT 01 1993
The Scotia Group

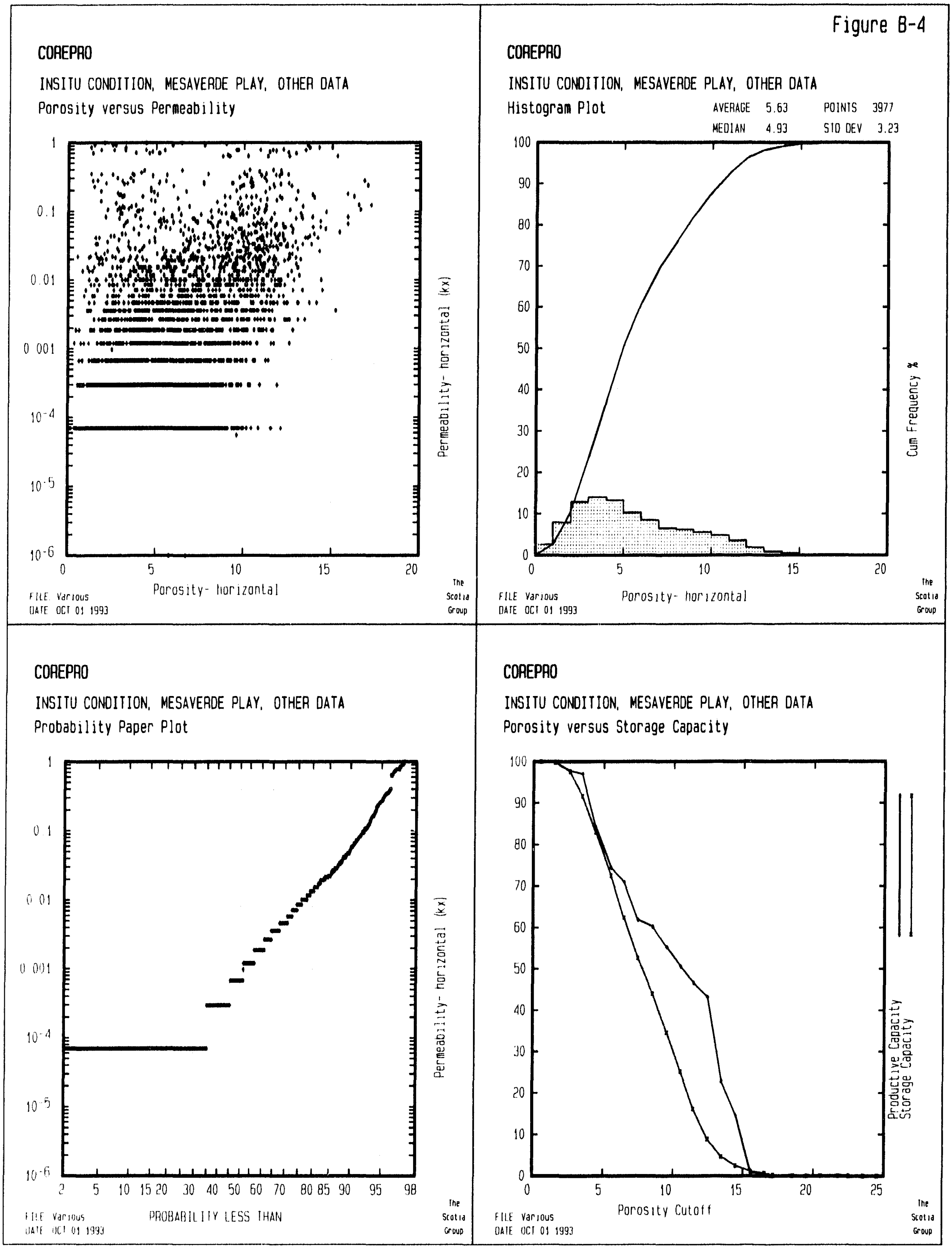

COREPRO
INSITU CONDITION, MESAVERDE PLAY, OTHER DATA
Porosity versus Permeability
Permeability- horizontal (kx)
Porosity- horizontal
FILE Various
DATE OCT 01 1993
The Scotia Group
COREPRO
INSITU CONDITION, MESAVERDE PLAY, OTHER DATA
Histogram Plot
AVERAGE 5.63
POINTS 3977
MEDIAN 4.93
STD DEV 3.23
Cum Frequency %
Porosity- horizontal
FILE Various
DATE OCT 01 1993
The Scotia Group
COREPRO
INSITU CONDITION, MESAVERDE PLAY, OTHER DATA
Probability Paper Plot
Permeability- horizontal (kx)
PROBABILITY LESS THAN
FILE Various
DATE OCT 01 1993
The Scotia Group
COREPRO
INSITU CONDITION, MESAVERDE PLAY, OTHER DATA
Porosity versus Storage Capacity
Productive Capacity
Storage Capacity
Porosity Cutoff
FILE Various
DATE OCT 01 1993
The Scotia Group

Figure B-4

A relatively tight envelope of data exists (considering that sampling is basin wide) for the porosity permeability plot for Category A. By ignoring the mode of samples from 0-6% (more apparent in Category C) which may be related to fracturing, a "best fit" transform may be drawn such that 5-6% porosity corresponds to about 1μd. Work conducted by Holditch et al (1992) has shown that successful completions occur mostly in sections with pre-stimulation permeabilities greater than 1 μd. Poor relationships between porosity and permeability have been observed in tight gas sands by previous workers (Spencer 1983). However, the relatively good fit of porosity permeability data in Category A which improves still further when subdividing the samples by formation and by well, suggests that the original pore structure of the rock may still be dominant. This would seem to suggest that the better quality sands have undergone the least diagenetic changes. That is, the pore structure is controlled more by the original grain size, geometry and sorting, rather than by a diagenetic overprint. Note that these interpretations are based only on a review of routine core data without the benefit of thin section or scanning electron microscopy (SEM) observations of porosity.

The distribution of samples in Categories B and C indicate a higher percentage of Spencer's (1983) Variety 2 reservoir rock. Variety 2 reservoirs have low porosity (< 12%) with pores created by post-depositional dissolution of mineral grains, rock fragments and matrix cements, and secondary cementation of matrix cement and clays. The pores are connected by ribbon-like tortuous capillaries 1 to 2 μm thick which restrict gas flow and consequently high capillary pressure. Variety 2 reservoirs typically have a poor porosity permeability relationship.

Figures B-5, B-6 and B-7 present examples of porosity and permeability versus water saturation, and porosity versus permeability calculated from logs. A porosity cutoff of 7% eliminates most water saturations greater than 70%. Porosity cutoffs typically range between 5 and 8%, which in this example, correspond to between 90 and 65% water saturation. The 7% porosity cutoff eliminates permeabilities less than 2 μd. A Vclay cutoff was also applied which discriminates between sandstone and shale. In out-of-gauge hole where bad hole logic fails to correct anomalous porosity readings, the Vclay cutoff eliminates apparent pay not excluded by the porosity cutoff.

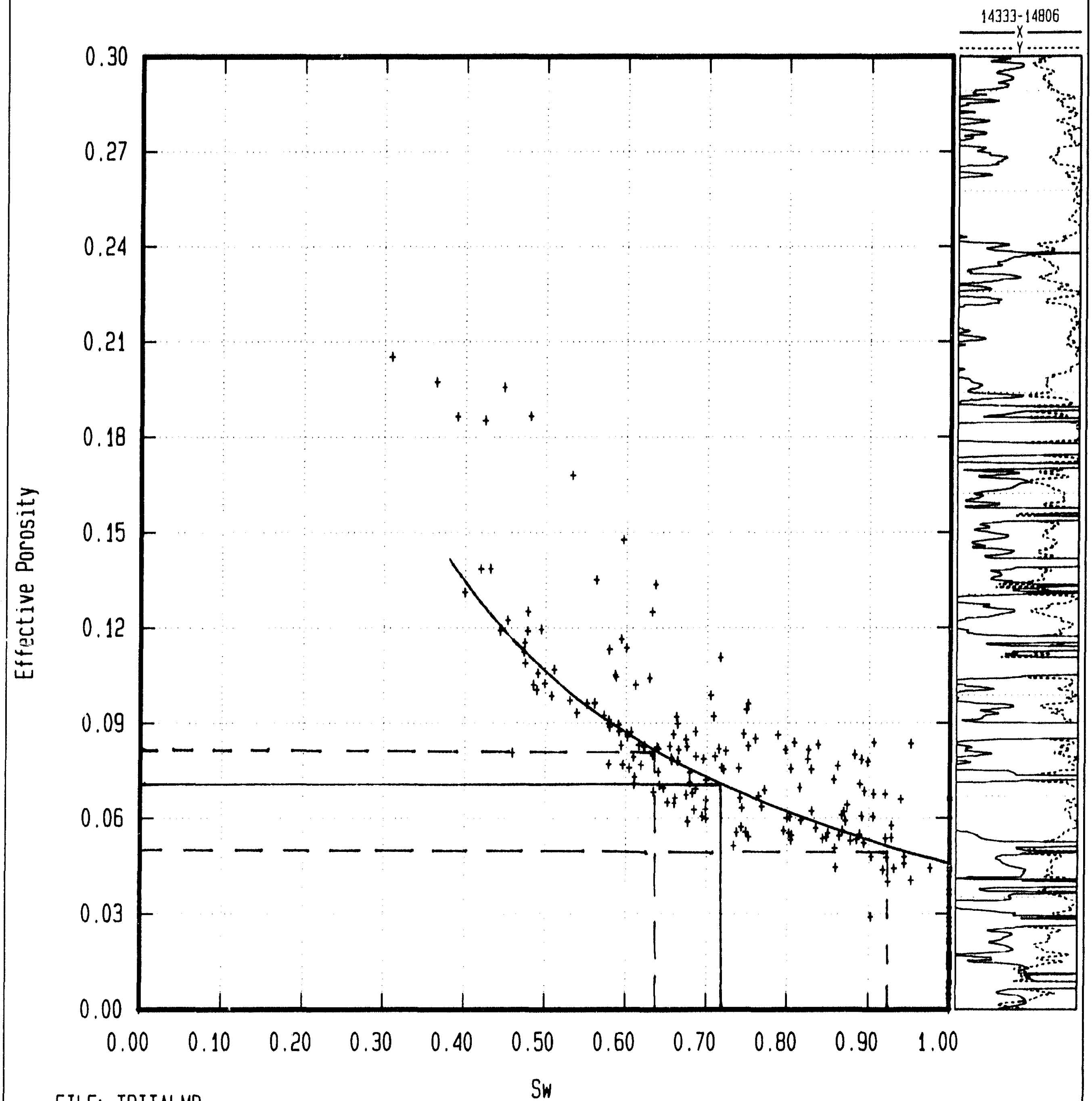
The water saturation cutoff was used to eliminate excessively high saturations included as pay in spite of the Vclay, porosity and permeability cutoffs. Generally, the OPT gas sands below about 9,000 feet exhibit high capillary pressures and are generally at irreducible saturation. The main concern then is the effect of irreducible water saturation on effective gas permeability. A water saturation will exist, above which the effective gas permeability drops drastically and gas will no longer flow; the result of water blocking pore throats and creating a discontinuous gas phase. Defining this saturation is very difficult.

SCOTIALOG Tight Gas Log Analysis Module	Client: DEPARTMENT OF ENERGY	Figure B-5

TRITON UNIT #10 API # 49037209750000

Sw versus Effective Porosity

Constraint: Net Reservoir Points Only



FILE: TRITALMD
DATE: OCT 08 1993

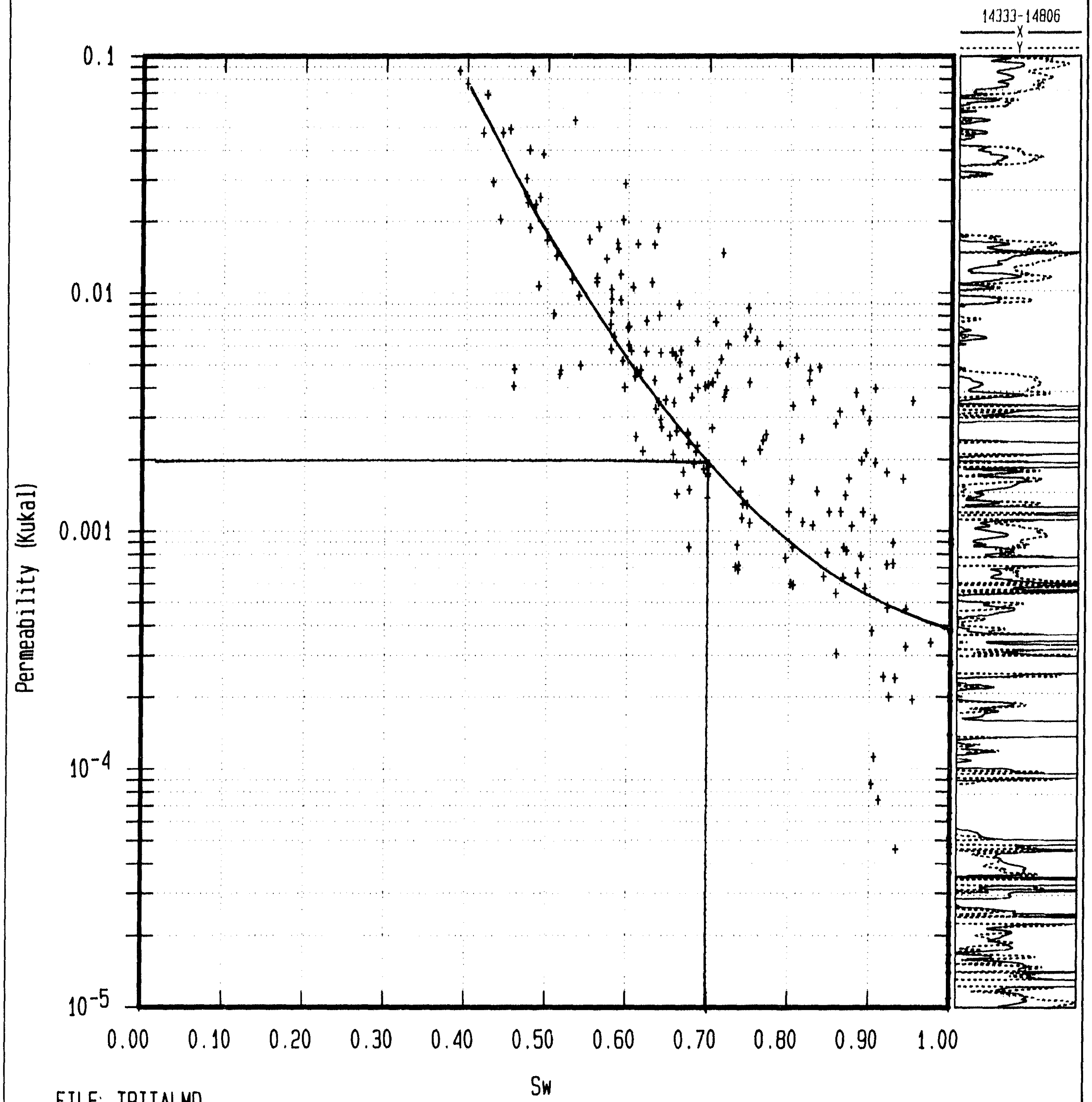
Scotia Group Proprietary Systems

SCOTIALOG Tight Gas Log Analysis Module	Client: DEPARTMENT OF ENERGY	Figure B-6

TRITON UNIT #10 API # 49037209750000

Sw versus Permeability (Kukal)

Constraint: Net Reservoir Points Only



FILE: TRITALMD
DATE: OCT 08 1993

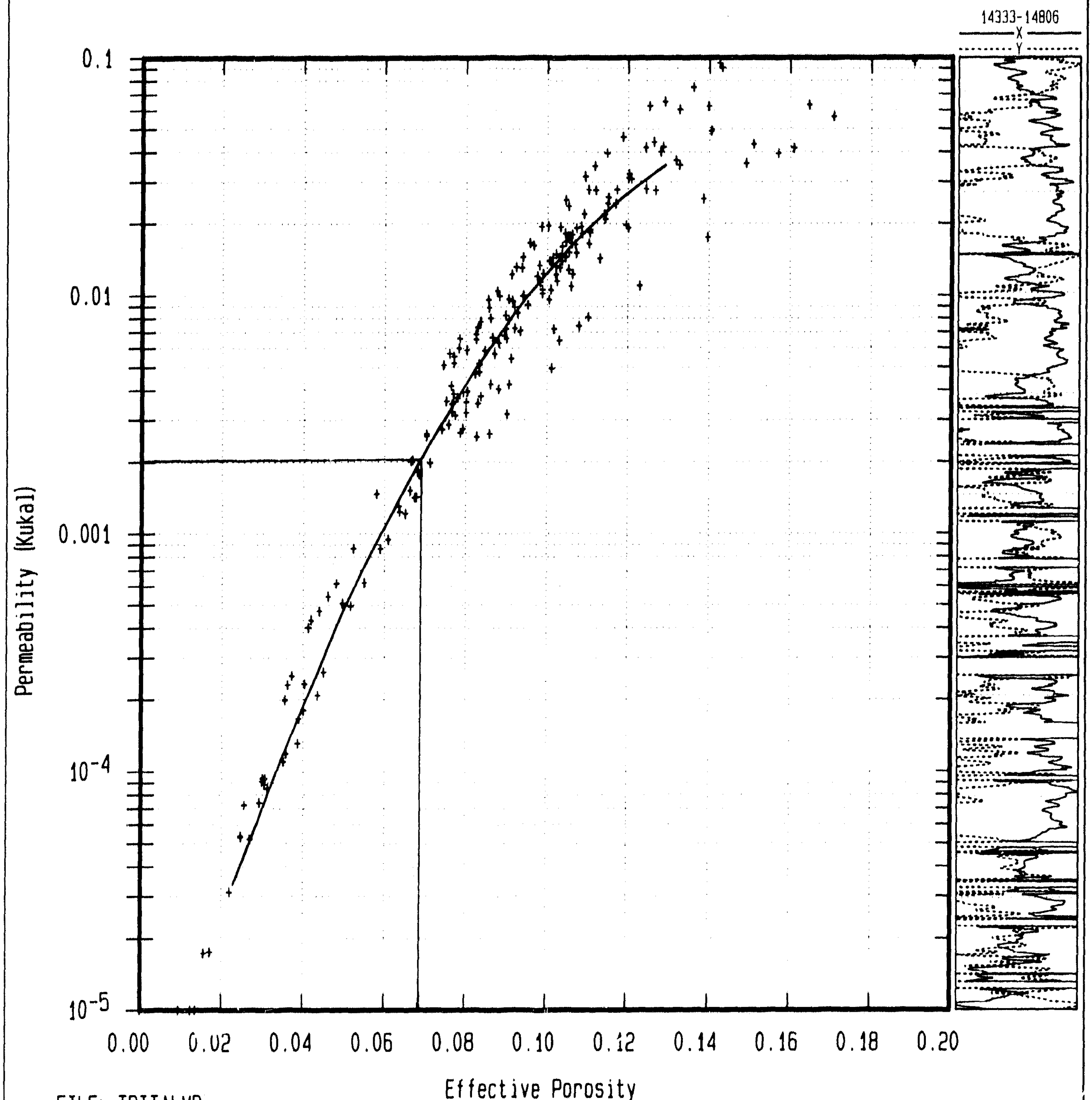
Scotia Group Proprietary Systems

SCOTIALOG Tight Gas Log Analysis Module	Client: DEPARTMENT OF ENERGY	Figure B-7

TRITON UNIT #10 API # 49037209750000

Effective Porosity versus Permeability (Kukal)

Constraint: Net Reservoir Points Only

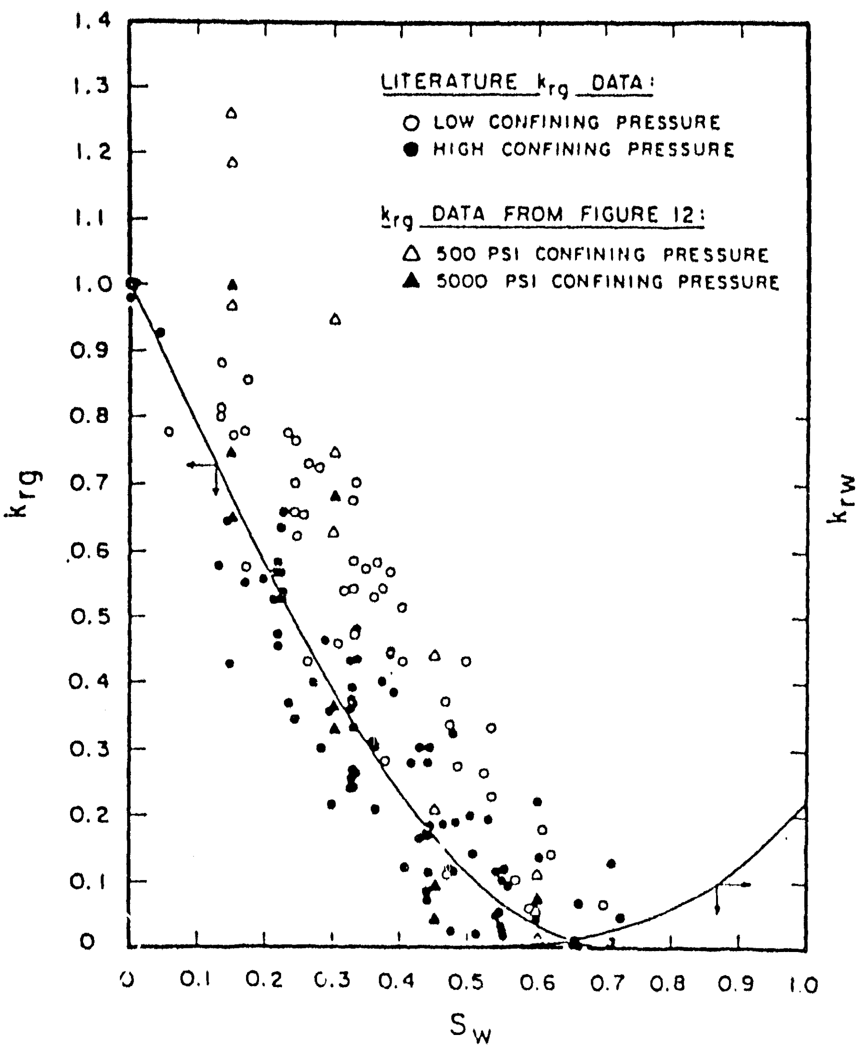


FILE: TRITALMD
DATE: OCT 08 1993

Scotia Group Proprietary Systems

Ward and Morrow (1987) compiled tight gas sandstone relative permeability data from a variety of literature sources, including Byrnes, Sampath and Randolph (1979), Thomas and Ward (1972), Walls, Nur and Bourbie (1982), Sampath and Keighin (1982), and Walls (1982), for comparison with data generated during their own studies. Overall results for high confining pressures fall within a fairly well defined band and an end point residual gas saturation of 30% (S_w 70%) can be derived from a hand drawn, best fit curve. The curve provides a reasonable representation of the effect of water on gas permeability at formation conditions. Water saturation cutoffs of between 65 and 80% were used in this study.

Figure B-8
(from Ward and Morrow, 1987)



The range of cutoffs used to define pay are summarized below for each play:

		NET			PAY			CUTOFFS		
		ϕ Decimal Fraction			S_w Decimal Fraction			K md		
Play	Vclay %	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max
Fort Union	.4	0.040	0.053	0.070	0.680	0.693	0.700	0.0014	0.0025	0.0050
Lance-Fox Hills	.4	0.060	0.066	0.080	0.650	0.700	0.800	0.0008	0.0045	0.0120
Lewis	.4	0.065	0.065	0.065	0.750	0.790	0.800	0.0010	0.0010	0.0010
Mesaverde	.35	0.40	0.059	0.097	0.700	0.776	0.800	0.0010	0.0017	0.0100
Cloverly Frontier	.35	0.050	0.057	0.070	0.650	0.746	0.800	0.0010	0.0018	0.0050

Sandstone thicknesses and net pay summaries were generated automatically by well for each play according to the cutoffs applied. Sandstone thicknesses were determined for both in-gauge and out-of-gauge hole since it was usually possible to generate a Vclay curve throughout the section of interest using the gamma ray curve which is less sensitive to hole wash out. Net pay thicknesses were estimated in out-of-gauge hole by applying the ratio of net pay and sandstone thickness determined for the in-gauge hole to the sandstone thickness in the washed out sections.

APPENDIX C

DISCUSSION AND OVERVIEW OF HYDRAULIC FRACTURING

INTRODUCTION

This Appendix is designed to provide a base understanding of hydraulic fracturing. It is not intended to provide a detailed technical critique or treatise on the subject since an extensive body of literature has been developed and key references are cited. Rather, a more qualitative approach is adopted describing physical processes and relationships and the direction of current and future development of this technology.

In 1983, Veatch estimated that more than 800,000 frac treatments had been performed since the introduction of the technology in 1949, and that about 35-40% of all currently drilled wells in the U.S. are hydraulically fractured. Veatch (1983) estimates that about 25-30% of total U.S. oil reserves have been made economically producible by this process and that it has increased America's oil reserves by an additional 8 Bbo

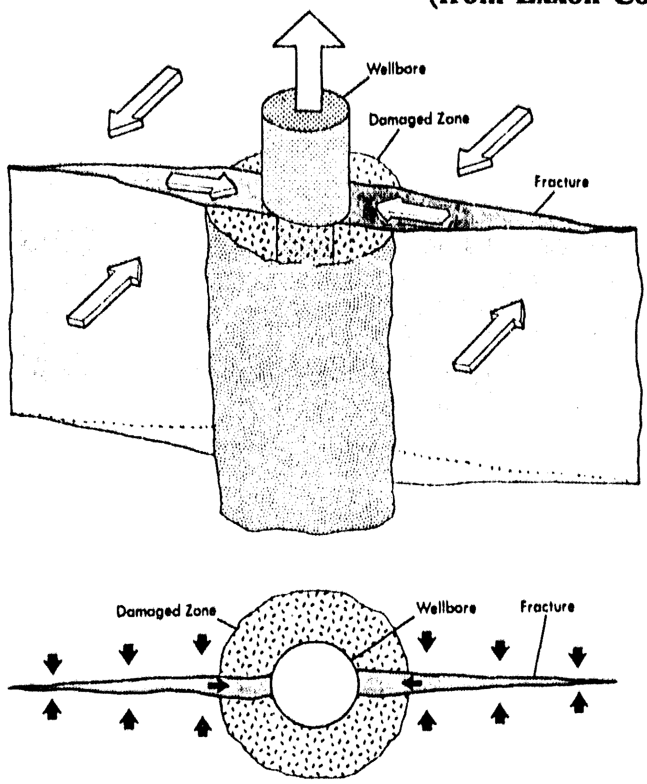
PURPOSE

Hydraulic fracturing is a commonly used industry technique to counteract several of the causes of low well production rates. In the context of low permeability formations, the prime purpose of conducting a hydraulic fracturing treatment is to impart the ability to produce a formation at commercial rates. The hydraulic fracture process itself does not change the reservoir permeability but rather imposes a high permeability structure within the reservoir that allows communication of the natural formation permeability to the wellbore.

An alternate form of stimulation, acidizing, invades the near wellbore rock matrix. It helps preserve the radial flow characteristics of the produced fluids. Acidizing in sandstone typically involves the use of mud acid to remove damaged clays from the rock matrix. Hydrochloric acid is used to dissolve near-wellbore formation material in limestone and dolomite formations.

In a fracture, the pressure drop that the fluid would undergo in a radial flow pattern is substantially reduced. This is done by creating linear flow patterns. While the permeability throughout the reservoir remains fundamentally unchanged, the fluids flow into the wellbore once they have reached the fracture with a minimized pressure drop (Figure C-1). Even so, native permeability of the reservoir has a high degree of influence on the production rate of the well.

Figure C-1
(from Exxon Company U.S.A., 1985)



As an enhancement on matrix acidizing, mini-fracs are designed to circumvent the region of immediate near-wellbore damage. In this case, the flow characteristic remains predominately radial.

For tight formations as in the GGRB, where sandstone formations predominate, successful hydraulic fracture treatments consist of placing a propped fracture. The performance of the well then becomes a function of the conductivity contrast between the fracture and surrounding reservoir and the geometry of the fracture itself within the reservoir horizon. In these lower permeability formations there can be the requirement to place a deeply penetrating propped fracture requiring massive hydraulic fracturing (MHF) treatments in excess of 1,000,000 gallons of fracturing fluid and 3,000,000 pounds of propping agents. Despite extensive experience and research, the ability to accurately place the frac as designed and to predict its performance still leaves considerable room for advancement. Even with significant advances in the use of 3D models, in-situ stress profiles and fracture treatment quality controls, as described by Holditch (1993), and a new understanding of the role played by tortuosity (Cleary et al 1993), a significant number of frac treatments are conducted with less than optimal results. This may be attributed to not only the failure to adopt new technologies, but also the inability to model and hence account for reservoir heterogeneity.

ROCK MECHANICS

Some of the factors identified as playing an important role in the propagation of fractures are as follows:

1. Differences in the mechanical rock properties including ductility, toughness, elastic modulus and Poisson's ratio.
2. Pore pressure variation between zones.
3. Pressure gradient within the fracture.
4. Variation of stresses between adjoining zones and differences of the stresses in 3-dimensions within each zone.

Fracture orientation (vertical versus horizontal) is dominated by variations in stress between adjacent zones. Differences in stress fields within a zone dominates the compass direction (azimuth) in the case of a vertical fracture (Figure C-2). Fractures usually propagate in a direction parallel to maximum principal stress (Figure C-3).

Figure C-2
(from SPE Monograph 12, 1989)

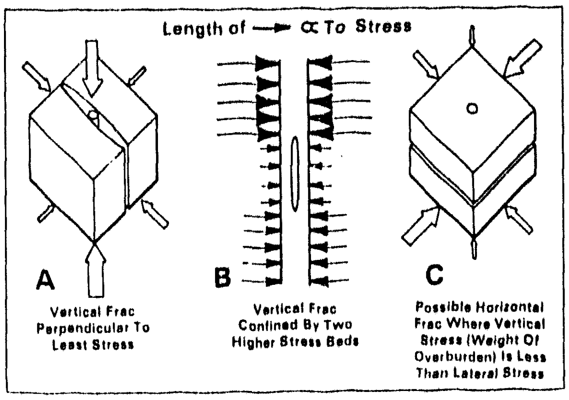
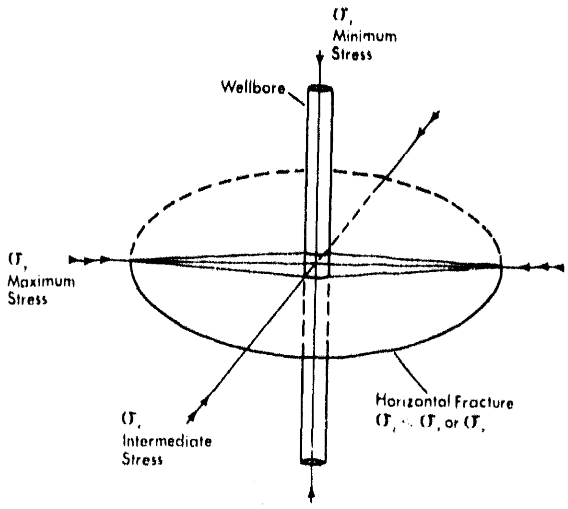
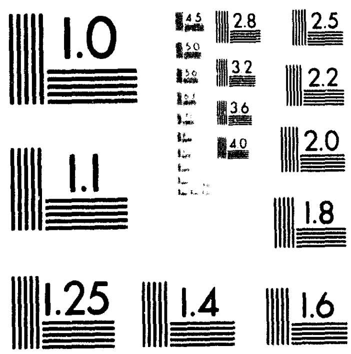


Figure C-3
(from Exxon Company U.S.A., 1985)



Owing to the vertical stresses caused by the overburden, horizontal fractures are not usually encountered below approximately 1,000 to 2,000 feet. At these depths, fractures are usually oriented vertically or subvertically and their vertical growth is usually terminated by zones above and below with higher lateral stresses (Figure C-2).


1.0
1.1
1.25
1.4
1.6
1.8
2.0
2.2
2.5
2.8
3.2
3.6
4.0

3 of 3

In-Situ stresses necessary for the determination of the size and direction of an induced fracture can be obtained by measurement of oriented cores or more reliably from pump-in methods. A multitude of pump-in methods have been proposed (Veatch et al, 1986 and Perkins et al, 1961) with various strengths and weaknesses in the results.

Because in-situ stress data is a primary criterion for a reliably designed fracture treatment, it is important to have methods to determine them with certainty. Efforts to estimate the stresses using acoustical wave train measurements on cores under various levels of stress have met with some success. Long spaced digital sonic logs also appear to show good correlation with pump-in stress tests. Figure C-4 shows a good comparison between these two measurements in several tight gas plays. However, Figure C-5 shows this same comparison for the Colorado Mesaverde group with very poor agreement.

Figure C-4
(from SPE Monograph 12, 1989)

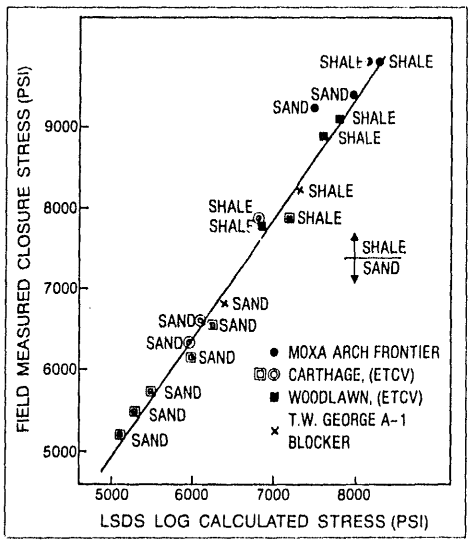
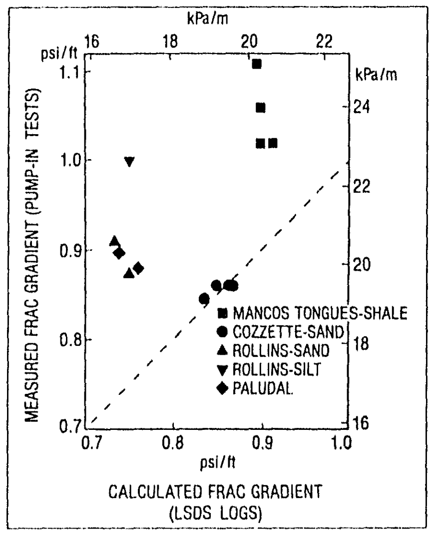


Figure C-5
(from SPE Monograph 12, 1989)

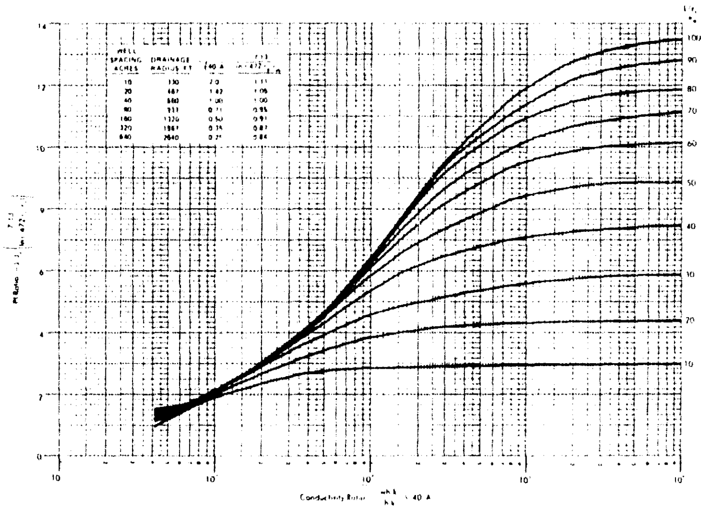


FRACTURE GEOMETRY

When the rock fails fracturing fluid enters the fracture and serves as a wedge propagating the fracture in height, length and width. Typical fracture heights are in the range of 50 to 250 feet. A very small fracture height would fall into the range of about 25 to 50 feet, while a very large fracture height would be a height greater than 350 feet.

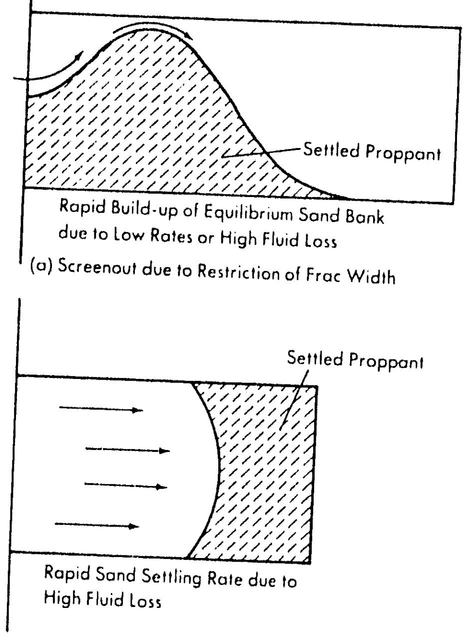
Fracture length is the distance from the wellbore to the tip of a fracture wing. A fracture will propagate along the direction of the maximum axial stress in the formation. Generally it is assumed that two fracture wings will be created and these wings will be symmetrical, 180° apart. In order to increase fracture length, a corresponding increase in treatment size is necessary. A set of curves has been developed (McGuire-Sikora, Figure C-6) indicating that increases in the stimulation ratio are a function of fracture length. Typically the limits on design lengths are placed by cost and well spacing considerations. Fracture lengths below 100 feet are considered relatively short, while those greater 1,000 feet are considered relatively long. Typical sandstone treatments result in a range of 200 to 800 feet. In limestone or dolomite, typical fracture lengths range from 30 to 100 feet. Short acid fractures have lengths less than 10 feet, while long fractures have lengths in excess of 100 feet.

Figure C-6
(from Exxon Company U.S.A., 1985)



In general there are two fracture widths. Dynamic Width is the width of the fracture during pumping operations while Final Propped Width is the propped fracture width after pumping operations have ceased and the fracture has closed on the proppant. The Dynamic Width must be large enough to allow proppant through the fracture without the proppant stacking up (screen-out). This occurs when the width is too narrow to allow the proppant to be transported away from the perforations to the tip of the fracture (Figure C-7). When the proppant accumulates, the fracture is closed off. At that point, injection pressure will rapidly rise to the pressure limit of the equipment in use. Break down in fluid viscosity, low injection rates, high rate of sand settling and high fluid loss can also cause screen-out. The final propped width is an important factor in the conductivity in the fracture. Conductivity is the product of the width of the fracture times the permeability of the proppant. Typical dynamic fracture widths range from 0.2 to 0.5 inches and typical propped fracture widths range from 0.1 to 0.2 inches.

Figure C-7
(from Exxon Company U.S.A., 1985)



(a) Screenout due to Restriction of Frac Width

(b) Tip Screenout

FRACTURE MODELING

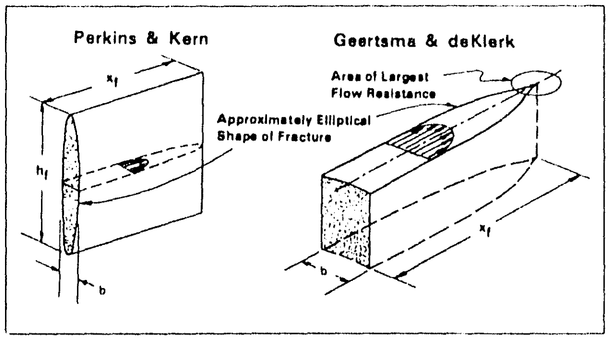
Currently both 2D and 3D fracture models are in use. Of the 2D models, one presented by Perkins and Kern (1961) and modified by Nordgren (PKN), and the other by Geertsma and de Klerk (1969) (GDK), seem to be most commonly used.

The PKN model assumes that the cross-section of the fracture in the vertical plane, perpendicular to the long axis of the fracture, generally maintains an elliptical configuration (Figure C-8). It begins with fracture width expressed in terms of fracture height as shown in Equation 1.

$$w \sim \frac{h_f P}{E} \qquad (1)$$

w	=	fracture width
P	=	fracture pressure
E	=	Young's modulus
h_f	=	fracture height

Figure C-8
(from SPE Monograph 12, 1989)



The GDK model assumes a rectangular shape in the vertical plane and an approximately elliptical configuration in the horizontal plane. The model's development is based on fracture width expressed in terms of fracture length as shown in Equation 2:

$$w \sim \frac{x_f P}{E} \qquad \text{.......... (2)}$$

x_f = fracture length

In general, fracture theory states that the injection pressure and the rate at which the fluid is injected will govern both the height and length of the fractures. However, for constant injection rate, the PKN model predicts increasing injection pressures proportional with fracture length raised to the 1/4 power (Equation 3) while the GDK predicts decreasing injection pressures under the same circumstances proportional to fracture length raised to the 1/2 power (Equation 4). Widths calculated from the PKN model are generally smaller than those based on the GDK model. This relationship predicts a significantly longer fracture with the PKN model, all other factors being equal.

$$P \sim \frac{(E^3 \mu q_i x_f)^{\frac{1}{4}}}{h_f} \qquad \text{.......... (3)}$$

$$P \sim \frac{(E^3 \mu q_i)^{\frac{1}{4}}}{h_f^{\frac{1}{4}} x_f^{\frac{1}{2}}} \qquad \text{.............................}(4)$$

μ = viscosity of the injected fluid
q_i = injection rate

Table C-1 shows a comparison or fracture design calculations for the different fracturing models performed by Geertsma and Haafkens (1979).

Table C-1
(from SPE Monograph 12, 1989)

	Geertsma and de Klerk	Daneshy	Perkins and Kern	Nordgren
Pad volume, bbl	750	320	1,350	1,650
Proppant-laden fluid volume, bbl	1,250	1,680	650	350
Average sand concentration, lbm/gal	3	2.5	2.5	3.5
Total amount of sand, lbm	157,500	176,000	68,000	51,000
Viscosity after pad, cp	36	36	36	36
Created fracture length, ft	698	670	804	845
Effective fracture length, ft	486	453	240	185
Created fracture width, in.	0.22	0.43	0.17	0.16
Effective fracture width, in.	0.20	0.31	0.16	0.16
Effective fracture height, ft	98	97	94	85
Average fracture conductivity, darcy-ft	7.1	9.8	6.5	6.5

*Results calculated on the basis of different theories for predicting fracture dimensions.

3D hydraulic fracturing models presented in the literature include:

1. Lumped-parameter models.
2. Pseudo 3D (P3D) models.
3. General 3D fracture models.

A description of the main features of these models can be found in Mendelsohn (1984a and 1984b). In general, a majority of the models assume that fracture propagation is planar. Narendran and Cleary (1993) have presented a model with a curved fracture in the sense of 2D elasticity.

3D fracturing models break the problem down into the three areas of:

1. Crack opening.
2. Fluid flow.
3. Crack propagation.

When a numerical solution is attempted, a fracture propagation algorithm is necessary. The algorithm combines the crack opening and fluid flow interaction in a manner that satisfies the requirements for crack propagation prediction. In general, the algorithms are iterative.

Griffith (1920, 1948) proposed a critical stress-intensity factor K_c (formation fracture toughness) that could be used to estimate the critical width (critical crack opening) at a given distance behind the crack front. This critical width should not be exceeded for a crack to be stable. Equation 5 shows the relationship between this critical width and the fractured toughness proposed by Griffith.

$$w_c = 4(1-\nu)(K_c/G)(r/2\pi)^{\frac{1}{2}} \qquad (5)$$

r	=	specific distance behind the crack front
G	=	shear modulus
ν	=	Poisson's ratio of the medium
w_c	=	critical crack opening
K_c	=	fracture toughness

3D simulators are valuable for many aspects of hydraulic fracturing analysis and design. They can be used to:

1. Determine fracture shape under various stress and treatment conditions.

2. Predict fracture width and dimension changes with time to allow for an estimate of proppant size, pad volume and total treatment volume.

3. Predict the occurrence of width pinching (narrow crack at perfs caused by the frac propagating assymetrically above or below the perfs) associated with the location of the perforations relative to the target zone.

4. Diagnose closure stresses by history matching the results of actual recorded fracture pressures with simulation pressures.

An actual field case study presented by Abou-Sayed (1984) compares the fracture shape evolution with time under two somewhat different stress profile assumptions (Figure C-9). The perforations are below the target Zone T because the zone exhibits severe solids production problems according to field experience. By treating Zone U the operator has the added benefit of stimulating Zone U while communicating with Zone T. The effect of assuming significantly lower closure stresses in Zone T is a fairly drastic asymmetrical fracture growth. Figure C-10 shows a penny shaped fracture profile and Figure C-11 shows fairly uniform width dimensions approximately symmetrical around the perforations. Case B is illustrated in Figure C-12 which indicated a much greater fracture length in Zone T caused by the assumption of much lower closure stresses. Figure C-13 shows that Case B also suffers from width pinching at the perforations which could result in an undesirable screen-out early in the treatment.

Figure C-9
(from SPE Monograph 12, 1989)

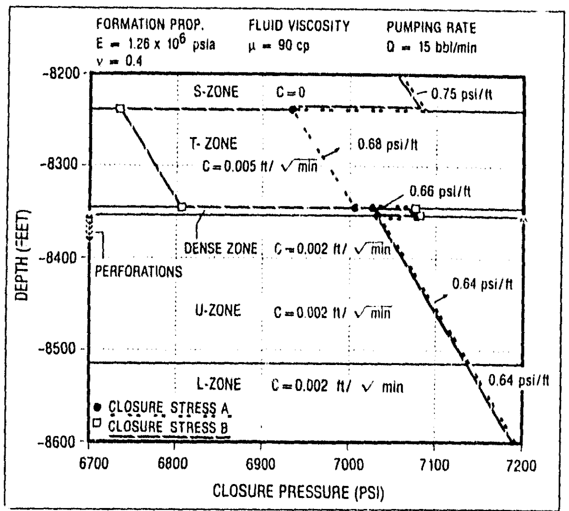


Figure C-10
(from SPE Monograph 12, 1989)

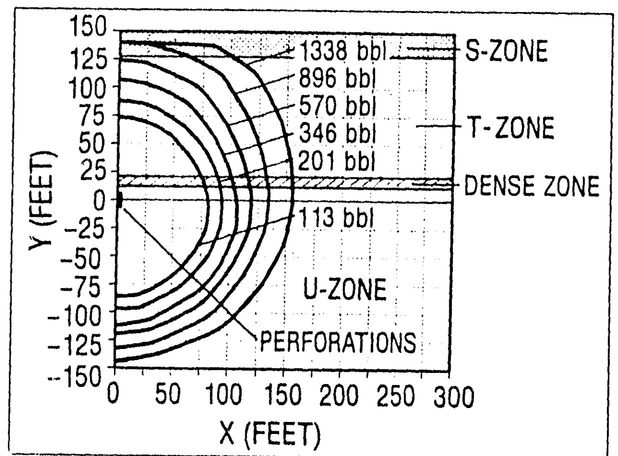


Figure C-11
(from SPE Monograph 12, 1989)

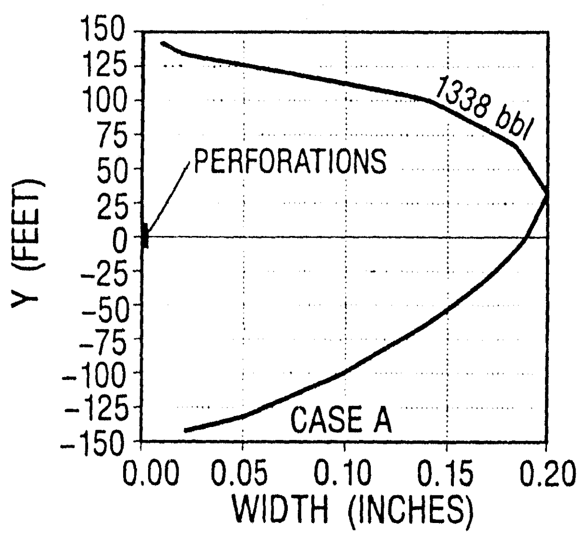


Figure C-12
(from SPE Monograph 12, 1989)

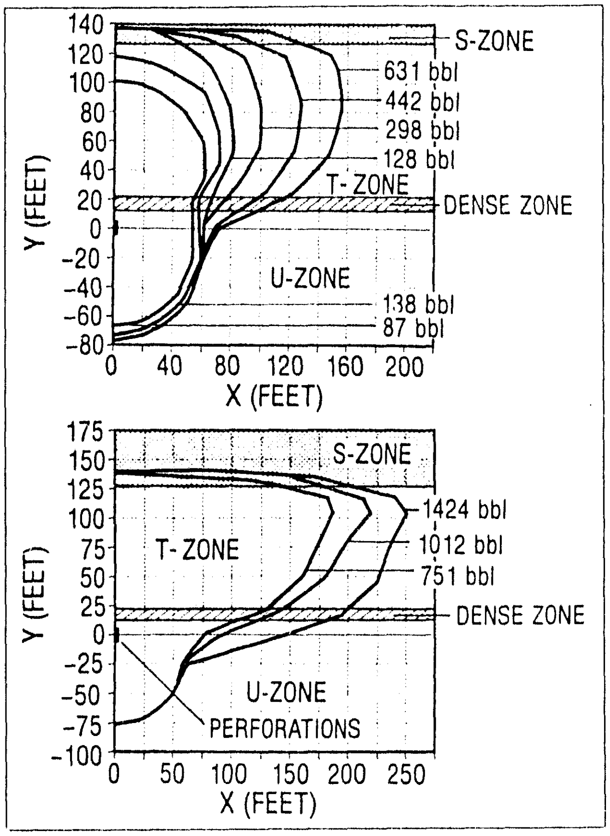
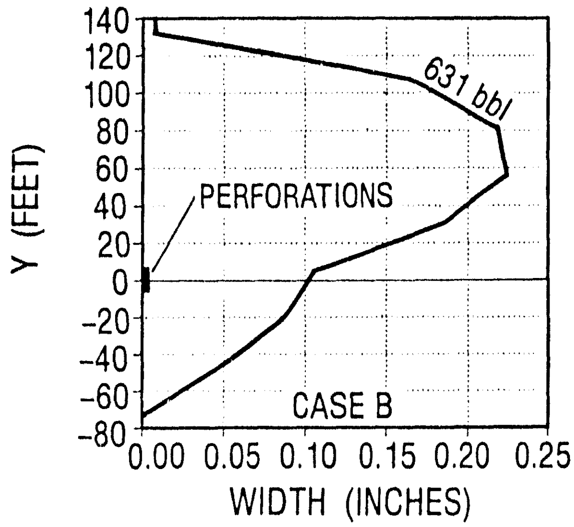


Figure C-13
(from SPE Monograph 12, 1989)



Data, such as that shown in Figures C-10 through C-13 can be used to determine required pad volumes, proppant concentrations and proppant size.

PROPPING AGENTS FOR HYDRAULIC FRACTURING

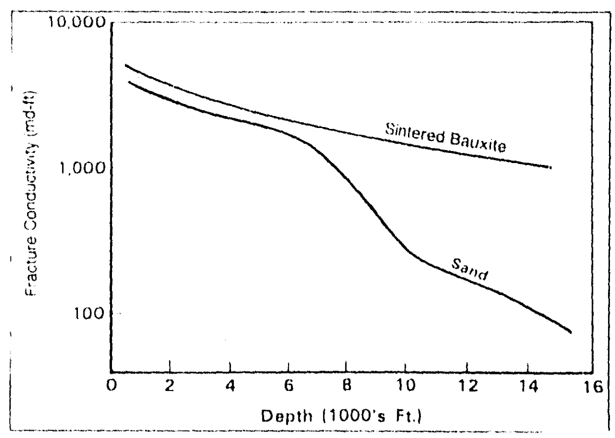
Early experimental work in shallow wells demonstrated that a hydraulically formed fracture tends to heal unless the fracture is held open. This function is performed by propping agents (proppants) and allows fluids to flow from the extremity through the fracture to the wellbore through a very high permeability proppant pack.

Proppants are graded on their size distribution, sphericity and roundness, solubility in acid and crush resistance. Silica sand is the most common proppant material in the U.S. Aluminum oxide (sintered Bauxite) is often used in place of sand when high fracture closure stresses will be encountered that tend to severely crush sand. Table C-2 shows the typical size designations established by the API. Figure C-14 shows a comparison of fracture conductivity versus depth indicating the relative improvements expected from the higher strength Bauxite. However, Bauxite has a specific gravity between 3.5 and 3.7 as compared to 2.65 for sand. As a result, special fracturing fluids are required to transport Bauxite at desireable proppant concentrations.

Table C-2
(from SPE Monograph 12, 1989)

Mesh Range Designation	Range (μm)
Primary Sizes	
12/20	850 to 1,700
20/40	425 to 850
40/70	212 to 425
Alternate Sizes	
6/12	1,700 to 3,350
8/16	1,180 to 2,360
16/30	600 to 1,180
30/50	300 to 600
70/140	106 to 212

Figure C-14
(from SPE Monograph 12, 1989)



Many other materials including carbides and ceramics have been introduced as proppants. There are also resin coated proppants (typically sand) that have been intended to relieve the high stresses caused by grain-to-grain contact and thus to improve the load carrying capacity of the proppant pack before crushing becomes a factor. Other resins are intended to consolidate the proppant pack by causing the individual particles to adhere to one another.

Fracture conductivity in the presence of proppants is an important factor in the success of hydraulic fracturing. To estimate the fracture conductivity, the following factors must be considered:

1. Type of proppant.

2. Proppant size distribution.

3. Proppant concentration in the fracture.

4. The stress load of the proppant pack (usually related to depth and reservoir pore pressure).

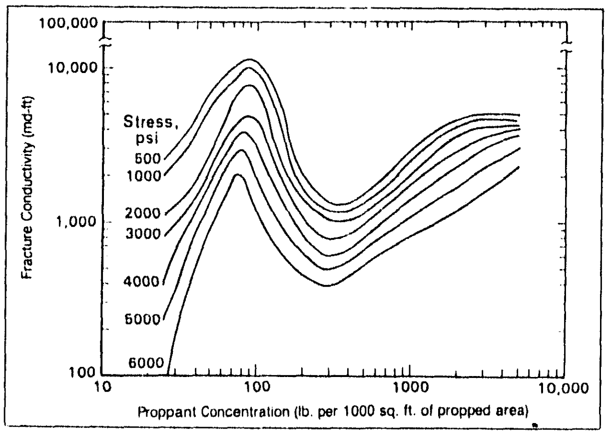
5. Formation and bed characteristics.

6. Potential plugging from fracturing fluid residue.

7. Long-term degradation under the in-situ environment.

Figure C-15 shows fracture conductivity testing for 20/40 proppant under a wide variety of closure stresses and sand concentrations. Conductivity is highest at concentrations around 100 pounds per 1,000 square feet of propped area. This represents what is called a partial monolayer of proppant. The decrease in conductivity between 200 and 400 pounds per 1,000 square feet is the result of changing the packed geometry to a fully packed monolayer. The increase above 500 pounds per 1,000 square feet results from multiple proppant layers and wider fractures. Generally it is desirable to achieve concentrations of at least 1,000 pounds per 1,000 square feet. Although monolayers appear to be more attractive, it is virtually impossible to achieve in a vertical fracture where proppants can fall to the lower part of the crack. Further monolayers are severely effected by imbedment of the proppant in the formation.

Figure C-15
(from SPE Monograph 12, 1989)



FRACTURING FLUIDS

The role of a fracturing fluid is to:

1. Initially open and propagate a fracture hydraulically.

2. Provide a medium for transportation and distribution along the fracture of the proppant.

Fluids that leak off rapidly into the formation have a low efficiency in hydraulically wedging and extending a fracture. This can result in an undesirable concentration of residue in the fracture. In the designing of a carrier fluid, the following considerations should be included:

1. Formation temperature and fluid temperature profile while the fluid is in the fracture.

2. Proposed treatment volume and pumping rates.

3. Type of formation (sandstone or limestone).

4. Potential fluid loss control requirements.

5. Formation sensitivity to fluids.

6. Pressure.

7. Depth.

8. Type of proppant to be pumped.

9. Fluid breaking requirements.

Table C-3 shows a list of commonly used fracturing systems and Table C-4 shows additives used to enhance the characteristics of the basic systems.

Table C-3
(from SPE Monograph 12, 1989)

Water-based polymer solutions
Natural guar gum (guar)*
HPG*
HEC
Carboxymethyl HEC*
Polymer water-in-oil emulsions
⅔ hydrocarbon** + ⅓ water-based polymer solution†
Gelled hydrocarbons
Petroleum distillate, diesel, kerosene, crude oil
Gelled alcohol (methanol)
Gelled CO_2
Gelled acid (HCl)
Aqueous foams
Water phase—guar, HPG solutions
Gas phase—nitrogen, CO_2

*Can be crosslinked to increase viscosity.
**Petroleum distillate, diesel, kerosene, crude oil.
†Usually guar or HPG.

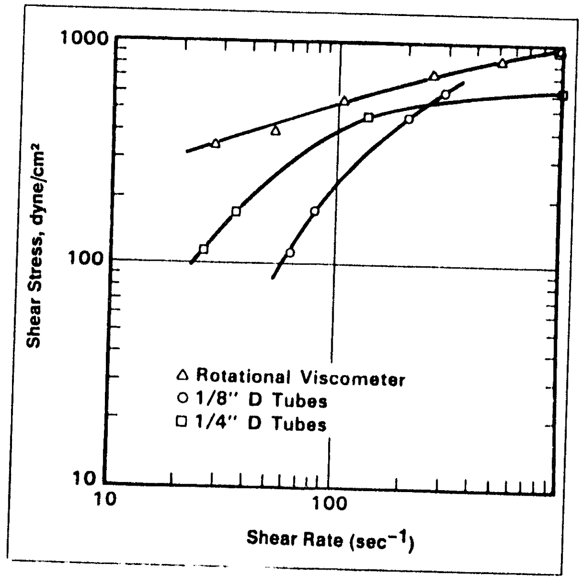
Table C-4
(from SPE Monograph 12, 1989)

Antifoaming agents
Bacteria-control agents
Breakers for reducing viscosity
Buffers
Clay-stabilizing agents
Crosslinking or chelating agents (activators)
Defoamers
Demulsifying agents
Dispersing agents
Emulsifying agents
Flow-diverting or flow-blocking agents
Fluid-loss-control agents
Foaming agents
Friction-reducing agents
Gypsum inhibitors
pH-control agents
Scale inhibitors
Sequestering agents
Sludge inhibitors
Surfactants
Temperature-stabilizing agents
Water-blockage-control agents

Water based polymers are relatively low cost and constitute the majority of applications. Some of the polymers are cross-linked for added viscosity and increased range of temperature applications. Polymer emulsions provide somewhat better fluid loss behavior but cannot be used at temperatures in excess of 250°F. Water sensitive formations typically are frac'd with gelled hydrocarbons or alcohols. Gelled acids have proved to be very effective for stimulating carbonate reservoirs. One major drawback of these gelled systems is their greater cost.

Although high in cost, cross-linked fluids are popular in low permeability fracturing because of their proppant carrying ability and temperature stability performance. However, prediction of cross-linked fluid behavior is difficult. Work by Rogers et al (1984) (Figure C-16) shows comparative viscometer data on "identical" cross-linked fluids. Attempts were made to test the fluids under identical conditions yet the data was not repeatable. This of course reduces confidence in the fluids ability to perform as expected.

Figure C-16
(from SPE Monograph 12, 1989)



FRACTURE DESIGN

Existing methods to accurately quantify essential fracturing parameters such as length, width, conductivity, height, azimuth, shape, symmetry about the wellbore, etc., are still experimental. Items of primary importance to the design are often heavily influenced by the local characteristics of the reservoir. Although extensive, the attached list of information requirements for design should therefore not be considered comprehensive:

1. Well drainage area and drainage configuration.

2. Vertical distribution of formation net pay.

3. Formation permeability, porosity and hydrocarbon saturation and the vertical distribution profile of these parameters.

4. Formation fluid properties including viscosity and formation volume factors.

5. Static reservoir pressures.

6. Formation temperature.

7. Thermal conductivities of formations penetrated by the fracture as well as in the vicinity of the fracture.

8. Fracture height or vertical growth extent that will occur during treatment.

9. Fracture extension and/or closure stress profiles.

10. Critical net fracturing pressure.

11. Formation effective modulus, Poisson's ratio and density profiles.

12. Fracturing fluid apparent viscosity.

13. Fracturing fluid friction data for the pipe and perforations.

14. Fracturing fluid spurt loss including temperature dependance.

15. Fracturing fluid combined leak off coefficient.

16. Vertical extent of the net leak off height.

17. Fluid thermal properties.

18. Proppant size distribution.

19. Proppant density.

20. Proppant fracture conductivity as a function of closure stress, proppant type, proppant size distribution, proppant concentration in the fracture and imbedment into the formation.

21. Formation imbedment pressure.

22. Perforation configuration (intervals, shots per foot and size of holes).

23. Tubular goods and wellhead configurations, sizes and pressure ratings.

Reservoir Conditions as Criteria for Candidate Selection

The possibility of fracture stimulation can be severely limited by the following:

1. High GORs or WORs.

2. Wellbore geometry of offset wells.

3. Geological containment barriers for causes of low productivity.

If the fracture stimulation increases GOR or WOR, the change is likely irreversible. In these cases the fracture extended into an overlying gas cap or an underlying water zone.

The risk of causing these increases can be quantified and must be balanced against the economic potential of the well.

The depth of penetration of the fracture may interfere with the production radius of another well. Interference can be with the wellbore itself or the fracture of another well. Accurate prediction of expected fracture Azimuth would be helpful in avoiding such difficulties. The results can be particularly damaging in the presence of nearby water injection wells.

In order to cause effective length propagation of a fracture there must be adequate geological containment barriers to contain the vertical height. Laboratory and field tests have demonstrated that a fracture will preferentially propagate in a sandstone rather than a shale. Until recently, prevalent rock mechanics theory held that shales could contain vertical fracture height growth solely due to their rock properties. Current theory holds that fracture height is controlled by two factors:

1. The vertical stress profile controls the height independent of rock type. If high stress contrast is present, the height will be confined. If no stress differential is present, the fracture height will not be confined.

2. Rock property differences themselves influence height growth to a small extent. However, property differences contribute to stress differences.

Tectonic stresses tend to be added equally to all nearby layers thereby preserving the overburden induced differences between sands and shales.

Data in a specific area or formation is necessary to estimate a particular shale's ability to contain a fracture. In some areas, at least 25 to 35 feet or more of a clean shale is required to contain a fracture while in other areas as little as 10 or as much 100 feet is required. Local experience with fracture growth is important.

Increase in injection will lead to increases in fracture height. Data from other fracs in the area should be used to limit the fluid injection rate to a level of which will avoid penetrating the fracture boundaries. Although rate dependence has a secondary effect on height growth, the vertical stress profile of the formation primarily controls the height growth.

In general, low productivity due to near-wellbore formation damage is generally the result of damage induced during drilling, completion, workover or production operations. Low productivity problems due to native formation characteristics such as low permeability are the result of the original properties of the formation or formation damage extending beyond the near-wellbore region. In general, fracturing is used if the damage is too deep to be removed by matrix treatments or if the natural reservoir permeability is very low (less than 1 md for a dry gas well and less than 10 md for an oil well). Pressure transient testing to determine reservoir permeability and the state of damage (skin) are necessary to successfully design a fracture. Often natural permeability is found to be sufficient but low productivity is caused by near-wellbore damage. If matrix acidizing is ineffective or undesirable, a mini-frac procedure might be attempted to frac the reservoir deep enough to completely penetrate and bypass the damage. Mini-fracs typically are in the range of 5,000 to 20,000 pounds of proppant.

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