DOE/FE/64202--T4-Add.

PROPERTY DESCRIPTION AND FACT-FINDING REPORT FOR

NOSR-1 & 3

GARFIELD COUNTY, COLORADO

ADDENDUM TO
STUDY OF ALTERNATIVES FOR
FUTURE OPERATIONS OF
THE NAVAL PETROLEUM AND
OIL SHALE RESERVES
NOSR-1 & 3

for

U.S. DEPARTMENT OF ENERGY
CONTRACT NO. DE-AC01-96FE64202

August 22, 1996

MASTER

GUSTAVSON ASSOCIATES
GEOLOGISTS • ENGINEERS

ADDENDUM:

PROPERTY DESCRIPTION AND FACT-FINDING REPORT FOR NAVAL OIL SHALE RESERVE NO. 1 & 3(NOSR-1 & 3) GARFIELD COUNTY, COLORADO

for the

U.S. DEPARTMENT OF ENERGY
Contract No. DE-AC01-96FE64202

Respectfully submitted on
August 22, 1996 by:

John B. Gustavson, President
Certified Minerals Appraiser

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PROPERTY DESCRIPTION

AND FACT-FINDING REPORT

FOR

NOSR 1&3

GARFIELD COUNTY, COLORADO

JUNE 30, 1996

FOR

U.S. DEPARTMENT OF ENERGY

Submitted by

GUSTAVSON ASSOCIATES, INC.
5757 Central Avenue, Suite D
Boulder, CO 80301

Respectfully submitted by

John B. Gustavson, President
Certified Minerals Appraiser

EXECUTIVE SUMMARY

The U.S. Department of Energy has asked Gustavson Associates, Inc. to serve as an Independent Petroleum Consultant under contract DE-AC01-96FE64202. This authorizes a study and recommendations regarding future development of Naval Oil Shale No. 1 and No. 3 (NOSR 1 and 3) in Garfield County, Colorado. The report that follows is the Phase I fact-finding and property description for that study.

The United States of America claims ownership of 100 percent of the minerals and 100 percent of the surface rights in 36,406-acre NOSR-1 and 20,171-acre at NOSR-3. Production has been established on NOSR-3 and currently the DOE owns interests in 53 gas wells that produce on or immediately adjacent to the acreage. NOSR-3 also contains undrilled locations that are classified as proved undeveloped or probable reserves. Recently, the Colorado Oil and Gas Commission (COGCC) approved an increased 40 acre drilling density for the Mesaverde formation that includes portions of NOSR-3.

All of NOSR-1 and the east side of NOSR-3 are located some distance from production and considered exploratory acreage at this time. The various reports which discuss full development scenarios for exploratory portions of NOSR-1 and 3 are considered optimistic due to the some of the underlying assumptions and risk factors used in projecting future income to the Government's interest.

The highest and best use of the mineral estate will include different uses since the oil and gas resources present range from producing to exploratory. This will include income from oil and gas production for the producing acreage to the generation of income from leasing or prospect evaluation on exploratory acreage.

There is an active market of recent leases, of nearby federal and private mineral rights as well as sales of mineral rights and producing properties. These data will be utilized in estimating the fair market value of the mineral rights at NOSR-1 and 3 under Phase II of this contract.

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INTRODUCTION

The U.S. Department of Energy has granted Gustavson Associates, Inc. a Contract DE-AC01-96FE64202. The work being performed under this Contract is aimed at determining the economic advantages which would accrue to the United States of America under each of the following scenarios:

1. Retention and operation of all or part of the Naval Petroleum and Oil Shale Reserves by the Secretary under Chapter 641 of Title 10, United States Code.

2. Transfer of all or part of the Naval Petroleum and Oil Shale Reserves to the jurisdiction of another Federal agency for administration under Chapter 641 of Title 10, United States Code.

3. Transfer of all or a part of the Naval Petroleum and Oil Shale Reserves to the Department of Interior for leasing in accordance with the Mineral Leasing Act (30 U.S.C. 181 et seq.) and surface management in accordance with the Federal Land Policy and Management Act (43 U.S.C. 1701 et seq.).

4. Sale of the interest of the United States of all or a part of the Naval Petroleum and Oil Shale Reserves.

Ultimately, the results of the work are to be provided in a Final Report as is specified in the Contract. However, in order to provide an early compilation of all available data about the individual properties, namely NPR-2, NPR-3, NOSR-1, NOSR-2 and NOSR-3, Gustavson Associates is herewith presenting the enclosed Report. While not a deliverable item under the Contract, this Report nevertheless will serve as a benchmark for review both by the DOE as well as by the employees of Gustavson Associates.

The DOE officials will have an opportunity at their own discretion to review the data and point to any omissions of data which inadvertently may not have been provided to Gustavson Associates, and possibly remedy the situation. Concurrently, Gustavson Associates will be able on basis of this report to enter into the evaluation and appraisal phase of the Contract and thereby assume the application of a uniform approach to the widely varying properties.

The Report is organized in three major sections, namely a Property Section which briefly discusses the nature of the property (with regard to the legal status of the mineral interests to be evaluated), surface conditions and access, the geology and geophysics of the property, any production history, any remaining reserves, and the preliminary economics which might govern the extraction thereof. This section is followed by with a description of any leasehold equipment on the property, any leads or prospects for future exploration and development, additional surface facilities, potential plugging and abandonment liabilities, as well as any environmental issues. This is concluded by a description of the effects of various taxes.

The second major section describes the current market and oil and gas activities in the surrounding area. Such a market could be expected both to influence the perception of future activities on the subject property as well as to provide guidance for the subsequent appraisal of the property. This section therefore consists of a description of the various types of recent mineral transactions which have taken place in the surrounding area within a reasonable time period of about three years.

Finally, the Report includes a section on the determination of the Highest and Best Use, a function which in accordance with the standards of the appraisal profession, is necessary to conduct *prior* to entering into the actual appraisal of property. On the basis of the Highest and Best Use an appraiser will select the most appropriate approach(es) to estimating the Fair Market Value.

In order to keep the body of the Report relatively brief, a substantial amount of the detail data has been relegated to appendices. We emphasize again that this is an informal report aimed primarily at gathering and communicating those facts about the property which typically would be considered by the DOE, by other agencies of the U.S. Government, or by potential private industry purchasers in preparation for the detailed valuation by these parties of the property prior to a potential transfer or purchase. It is the intent (a) to use this data during the immediately following valuation phase, (b) to make amendments or changes to the enclosed data if and when new facts become available, and finally (c) to include this entire Report, as amended, as an appendix to the Final Report to be submitted under this Contract.

1. PROPERTY

1.1 LEGAL STATUS OF PROPERTY

1.1.1 Location of Appraisal Tracts

Naval Oil Shale Reserve #1 & #3 are both located 8 miles west of the town of Rifle, in Garfield County, Colorado. The two NOSR sites are adjacent to one another and consist of approximately 36,406 for NOSR-1 and 20,171 acres for NOSR-3. Figure 1.1 shows that the properties are just north of the Interstate 70 which parallels the Colorado river. From a geologic and hydrocarbon potential standpoint, the properties are situated in the southeastern portion of the Piceance Basin where natural gas is produced from sedimentary formations in the subsurface.

1.1.2 Definition of Rights Being Appraised

The property being appraised consists of mineral interests owned by the United States of America in the NOSR-1 and NOSR-3 sites. It was beyond the scope of this assignment to appraise the value of any surface rights associated with these two properties.

1.1.3 Fee Simple

With the exception of 600 acres of private oil shale claims on Naval Oil Shale #1, the United States government owns 100 percent of the fee simple title interest for all lands and minerals in the subject properties. The location of the known private oil shale claims are shown on Figure 1.2 as part of the general overview map.

1.1.4 Leasehold

This Appraiser is not aware of any current mineral leasehold interests on the subject lands. All gas wells on the NOSR sites have been drilled and are operated by the DOE as part of the Gas

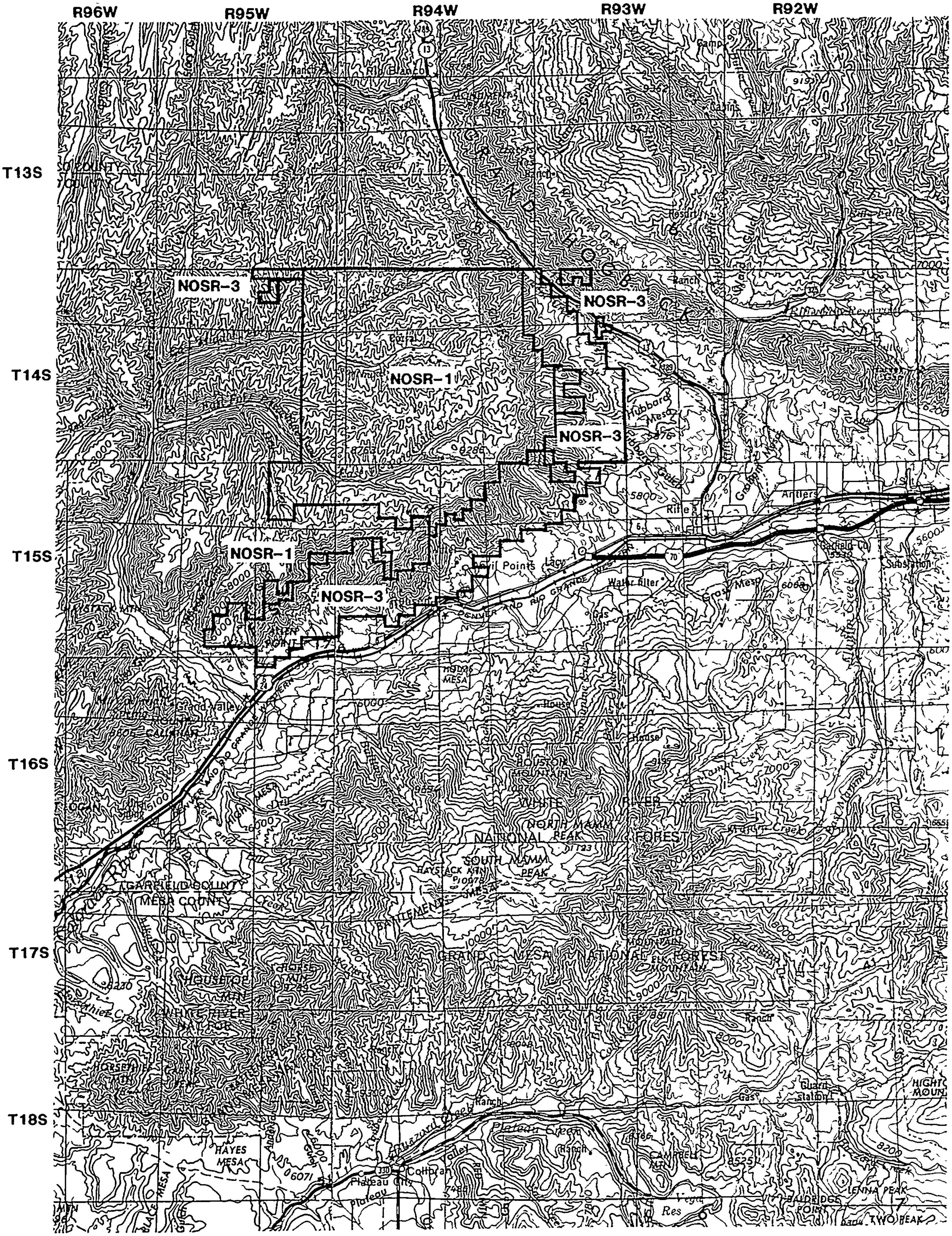
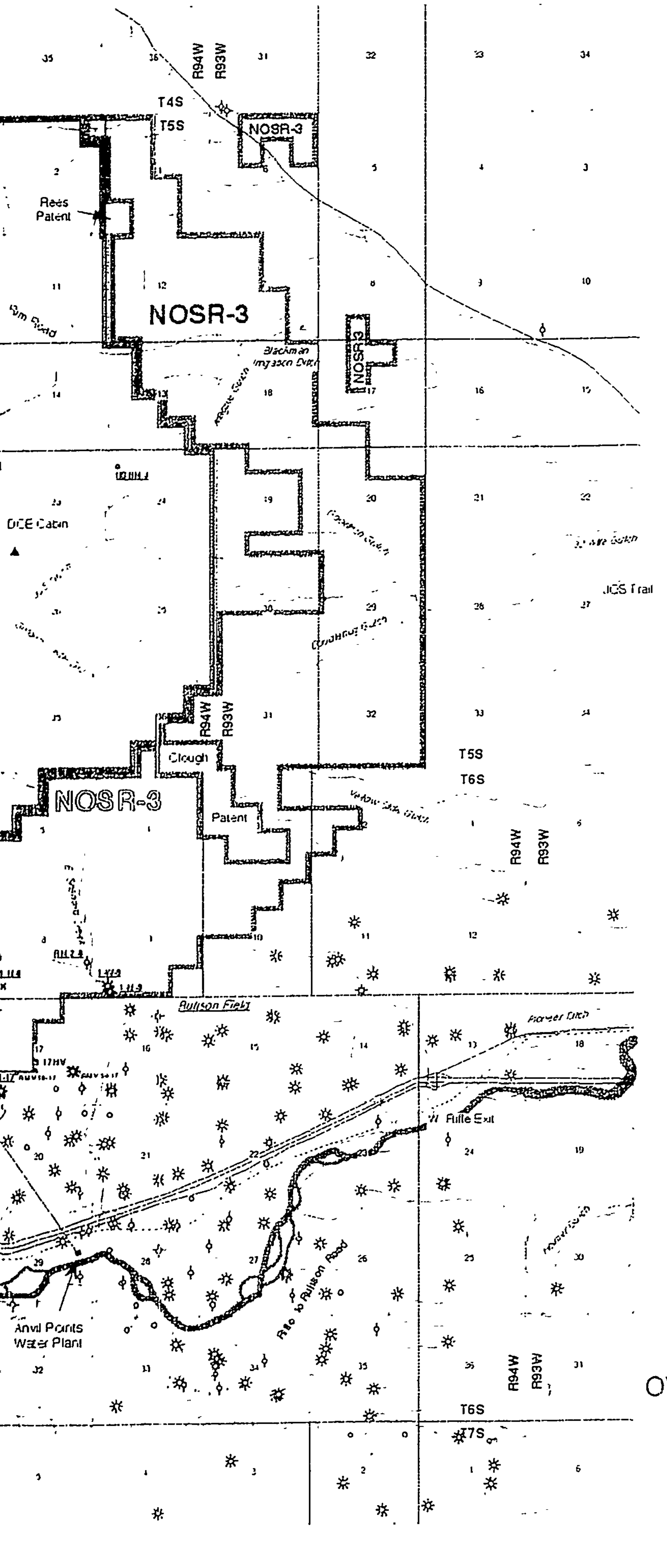


FIGURE 1.1-GENERAL LOCATION MAP FOR NOSR-1 & 3



NOSR-1 Boundary
NOSR-3 Boundary

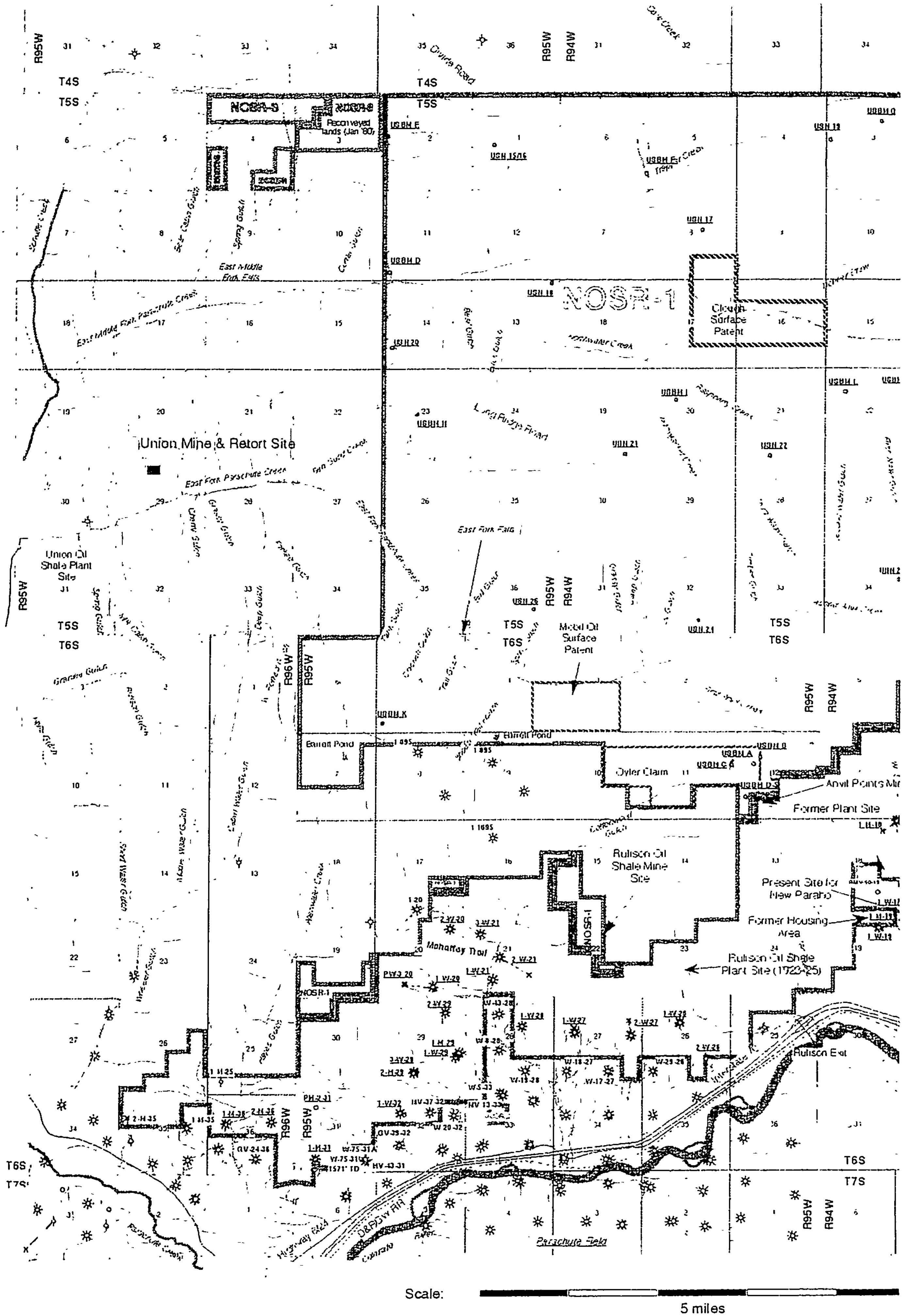
Proposed location, not drilled
Drilling, shut in, or temporarily abandoned
Producible gas well
Temporarily abandoned, show of gas
Plugged and abandoned, dry hole
Plugged and abandoned gas well
Plugged and abandoned, show of gas
Directionally drilled well
Non-DOE Communitized Wells
DOE Wells
Well Symbols

Roads:
Interstate highway
State highway
Dirt/Gravel road

FIGURE 1.2-GENERAL OVERVIEW MAP NOSR-1 & 3

Updated 8-23-95 Dan Newquist

FIGURE 1.2



T4S
T5S
T6S
T7S
R95W
R94W
R96W
NOSR-3
Reconveyed lands (Jan '80)
NOSR-1
Clough Surface Patent
Union Mine & Retort Site
East Fork Parachute Creek
Union Oil Shale Plant Site
East Fork Falls
Mobil Oil Surface Patent
Barrett Pond
Dyler Claim
Anvil Points Mine
Former Plant Site
Rulison Oil Shale Mine Site
Present Site for New Paraho
Former Housing Area
Rulison Oil Shale Plant Site (1923-25)
Rulison Exit
Mahaffey Trail
Long Ridge Road
Interstate 70
D&RGW RR
Colorado River
Parachute Creek
Parachute Field
Scale:
5 miles

Protection Drilling Program which was initiated in mid 1980s. In some cases, there are communitized areas for gas wells either on or near the boundary of the Naval Oil Shale Reserves.

1.2 COMMUNITIZATION ON NOSR-3

The Department of Energy has entered into communization agreement for approximately 26 wells on NOSR-3. Certain tracts were pooled under communitization agreements when they could not be developed independently in conformity with State well-spacing guidelines. Eighteen of these wells have been drilled and are operated by Barrett Resources. The remaining eight were drilled by the DOE and communitized with Barrett Resources and other partners. In this arrangement, each of the communitized wells are operated as a unit under the communitization agreement. Development costs and income from production are shared amongst the unit partners and the interest is based on a percentage of mineral ownership in the unit acreage.

1.3 SURFACE CONDITIONS AND ACCESS

1.3.1 NOSR-1

The subject properties are located in the rugged highland country of western Colorado (Figure 1.3). As shown on Figure 1.4, ground elevations at NOSR-3 are in the range of 6,000 feet above sea level. NOSR-1 is to the north of NOSR-3 and has a peak elevation in the range of 9,300 feet above sea level. The high mesa that characterizes NOSR-1 is underlain by the oil shale deposits of the Green River formation that were resistant to erosional processes over geologic time. This forms a spectacular escarpment which is known as the Roan Cliffs. Located along the eastern portion of the Naval Oil Shale Reserve, the Roan Cliffs generally marks the boundary between NOSR-1 and 3.

Surface use is managed by the Bureau of Land Management which includes grazing, road maintenance and other uses. For the most part, NOSR-3 is readily accessible by existing dirt roads and proximity to the interstate highway. In contrast, access to NOSR-1 is limited to two

FIGURE 1.3A-NOSR-1 SOUTH ACCESS ROAD

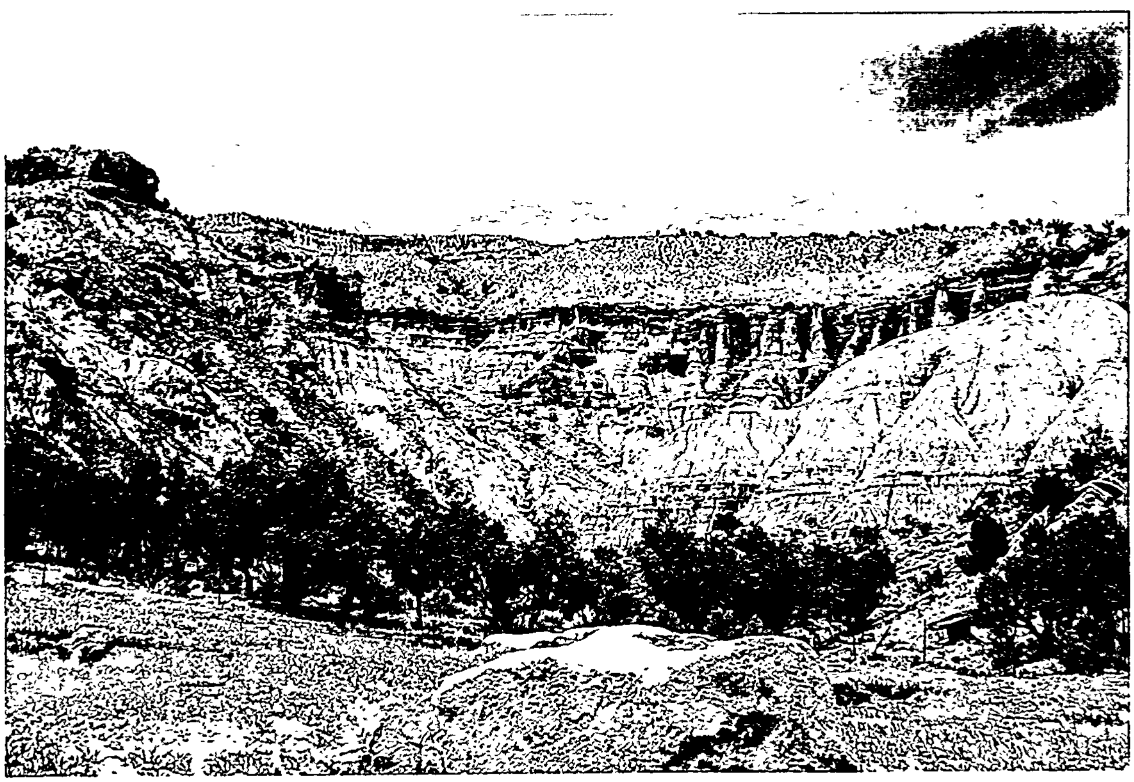


FIGURE 1.3B-NOSR-3 SURFACE AREA VIEW

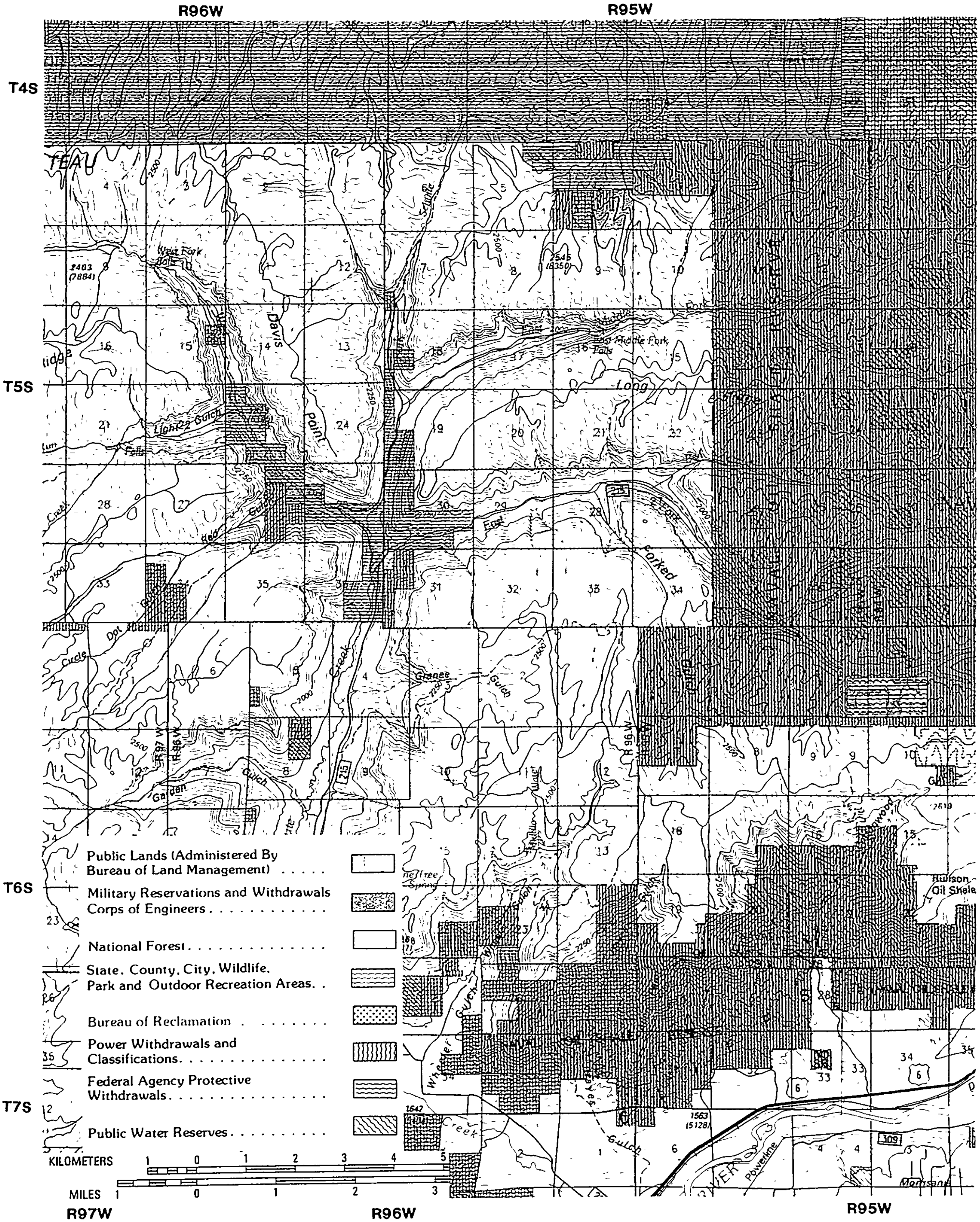
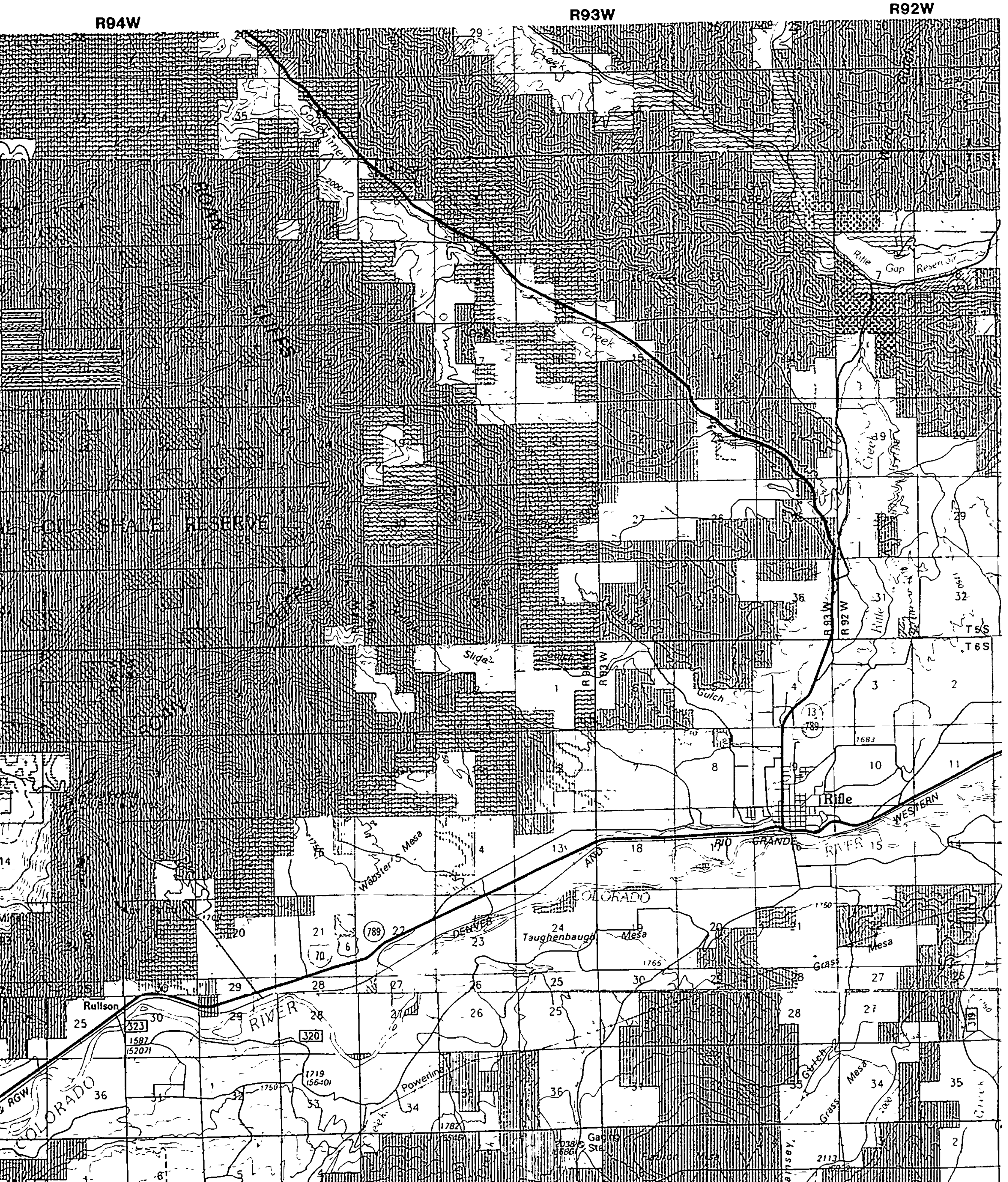


FIGURE 1.4–TOF
FOR SUBJEC



OGRAPHIC MAP
T PROPERTIES

FIGURE 1.

unpaved roads that traverse a series of switchbacks for more than fifteen miles. From October to April, NOSR-1 is virtually inaccessible by surface transportation given existing infrastructure. Underground springs frequently cause road washouts that require resurfacing and grading.

1.4 GEOLOGY AND GEOPHYSICS

1.4.1 Introduction and Methodology

The U.S. Naval Oil Shale Reserves 1 and 3 (NOSR-1 and NOSR-3) are located in the southeastern portion of the Piceance Basin in Garfield County, Colorado (Figure 1.5). The Reserves are underlain in turn by rich Lower Tertiary oil shale deposits and by the Lower Tertiary Wasatch Formation and Upper Cretaceous Mesaverde Group. In recent years the Wasatch and Mesaverde horizons have been the targets by industry operators for development of "tight gas" sands and coal bed methane reserves. This development has encroached on the NOSR properties from the south and has led to the drilling of more than two dozen drainage protection gas wells on NOSR-3 by both the U.S. Department of Energy and industry operators. In excess of 300 wells have been drilled for Wasatch and Mesaverde objectives in the vicinity of NOSRs 1 and 3. To date no drilling has been done on NOSR-1. Figure 1.5 shows the location of the NOSR properties in relation to the basin architecture and the developing gas fields. Figure 1.6, a map provided by the Department of Energy, shows historic and current gas development adjacent to and on NOSR-3, updated to March, 1996.

An extensive literature base exists describing both the regional and the petroleum geology of the Piceance Basin. This base includes a number of reports by the U.S. Geological Survey and by various DOE contractors as well as technical papers in industry publications. The intent of this geological and geophysical section is to review the current state of knowledge of the petroleum geology of the reserves and to assess its adequacy in characterizing the oil and gas potential of NOSRs 1 and 3 for the purposes of performing a fair market appraisal of the properties.

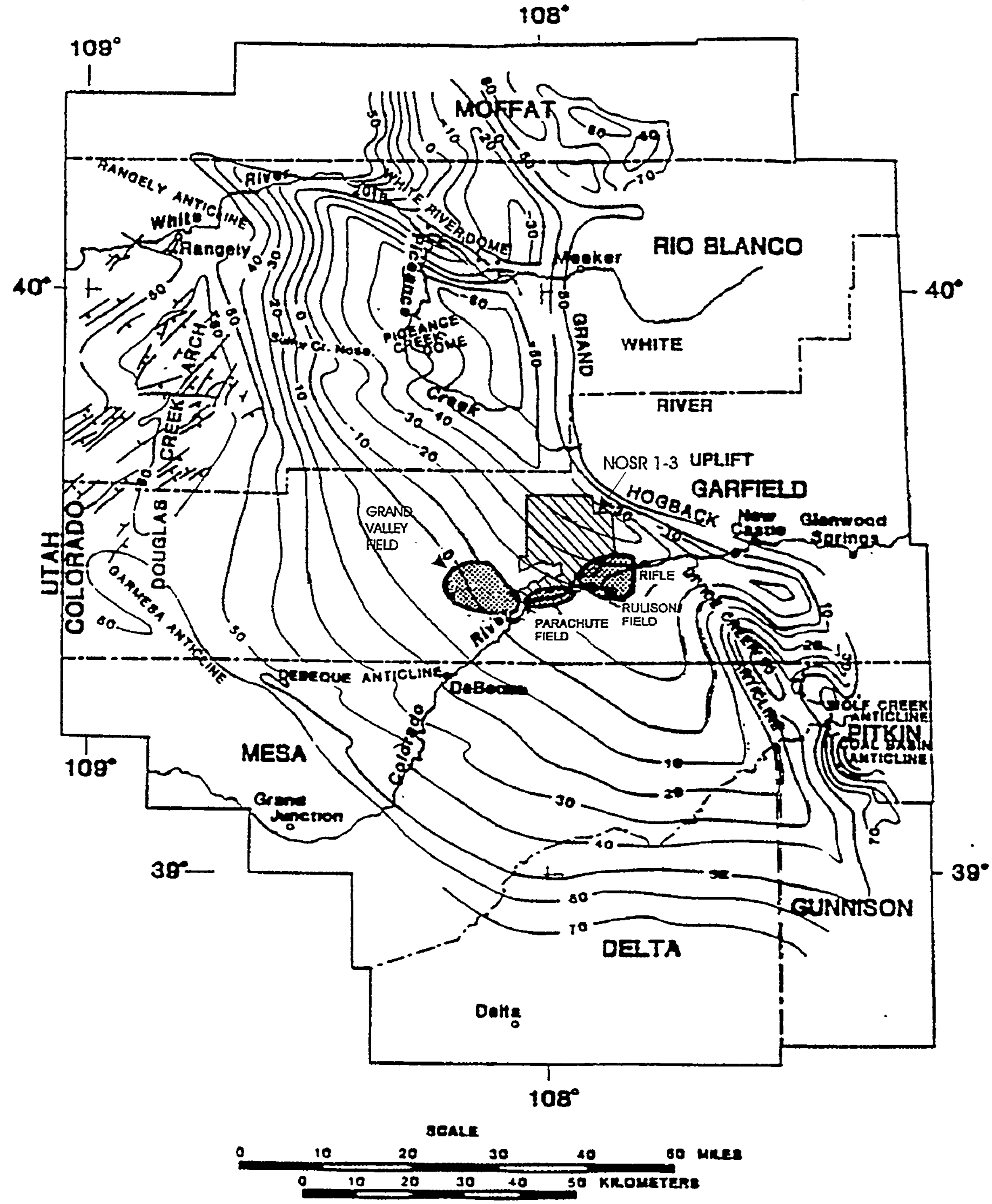
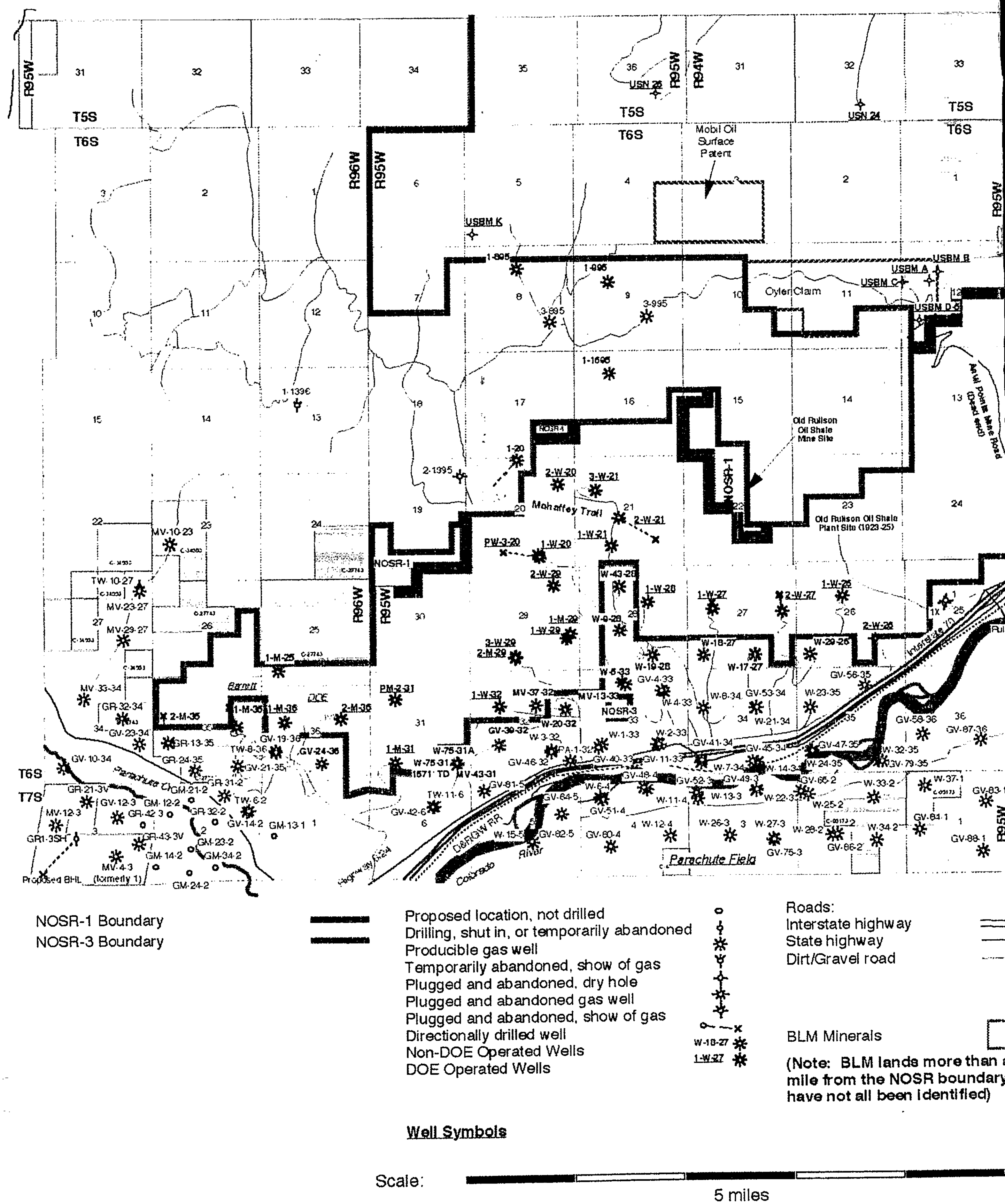
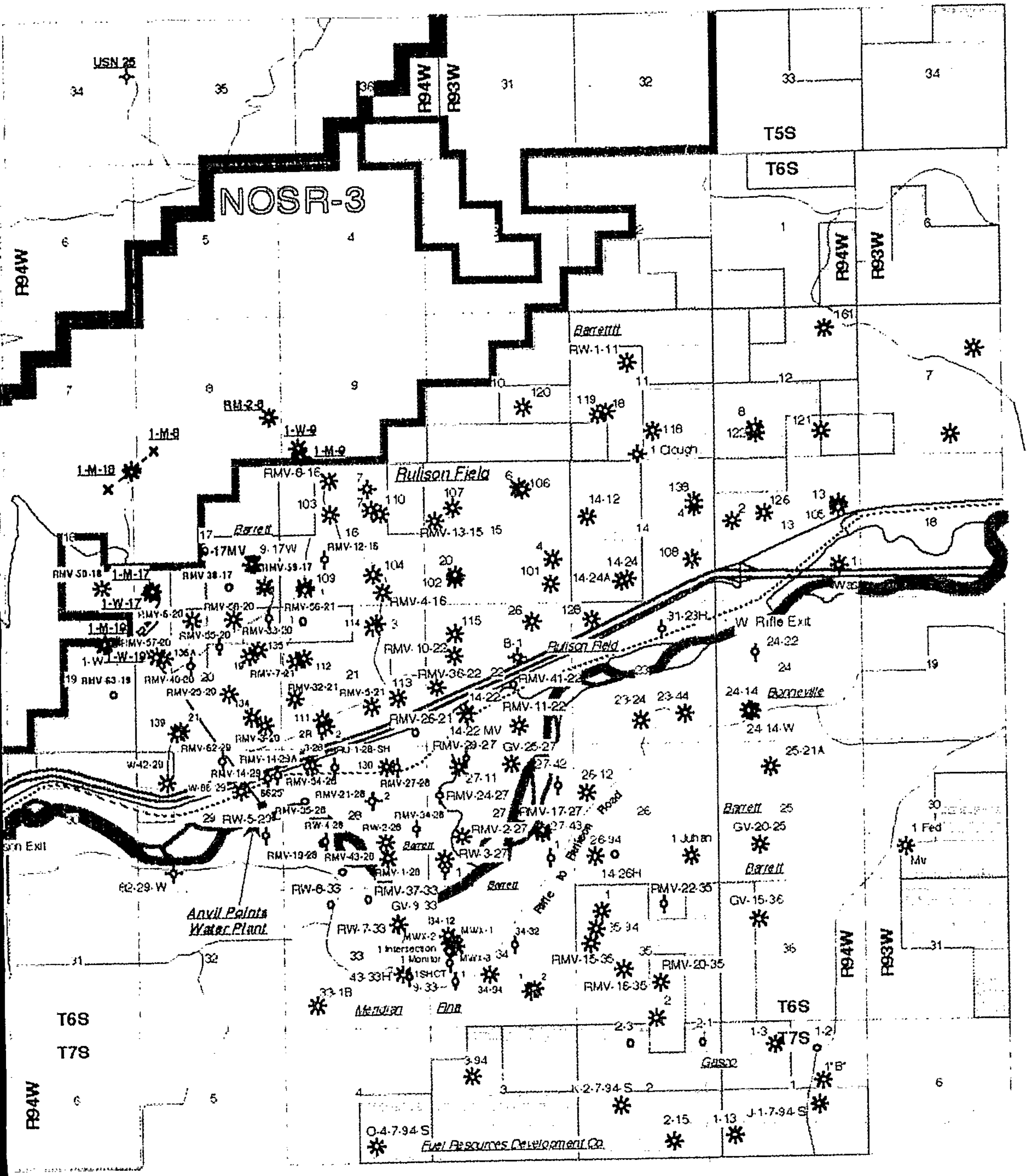


FIGURE 1.5 -**Map of Piceance basin, Colorado, showing location of Grand Valley, Parachute, and Rulison gas fields. Modified from Johnson and Rice (1990). Structure contours on top of the Rollins Sandstone or equivalent Trout Creek Sandstone Members of the Iles Formation. Contour interval 1,000 ft (305 m), numbers shown are in hundreds of feet.**
(modified after LaFreniere, 1994)



R95W
R96W
R94W
T5S
T6S
T7S
Mobil Oil Surface Patent
USBM K
USBM A
USBM B
USBM C
USBM D
USN 24
Cyler Claim
Old Rulison Oil Shale Mine Site
Old Rulison Oil Shale Plant Site (1923-25)
Anvil Points Mine Road (Dead end)
Mahaffey Trail
NOSR-1
NOSR-3
Interstate 70
D&RGW RR
Colorado River
Parachute Creek
Parachute Field
Barrett
DOE
Proposed BHL
MV-4-3 (formerly 1)
1571' TD
NOSR-1 Boundary
NOSR-3 Boundary
Proposed location, not drilled
Drilling, shut in, or temporarily abandoned
Producible gas well
Temporarily abandoned, show of gas
Plugged and abandoned, dry hole
Plugged and abandoned gas well
Plugged and abandoned, show of gas
Directionally drilled well
Non-DOE Operated Wells
DOE Operated Wells
W-18-27
1-W-27
Roads:
Interstate highway
State highway
Dirt/Gravel road
BLM Minerals
(Note: BLM lands more than a mile from the NOSR boundary have not all been identified)
Well Symbols
Scale:
5 miles



Oil and Gas Drilling Near NOSR-1 & 3

Updated 3-19-96 Dan Newquist

FIGURE 1.6

All documents provided to this Consultant by the Department of Energy have been reviewed and are utilized in this analysis. Particular attention has been placed on the U.S. Geological Survey Open-File Report 94-427 (Fouch et al., 1994) United States Geological Survey. Bulletin 1787 E and G (Johnson on 1989 and Pitman et al., 1989), and the various DOE Alternative Development Study reports (1994 and 1995), including Appendixes 2 and 3 on NOSR-3 which were prepared by Fluor-Daniel (LaFreniere, 1994 and Schulte, 1994).

In addition, Gustavson Associates staff have met with U.S. Geological Survey (USGS) technical staff and also with Colorado Oil and Gas Commission engineers in order to obtain pertinent information.

To the extent possible, geophysical data provided by the DOE and the USGS have been reviewed to determine adequacy for assessing the oil and gas potential of known deeper oil and gas producing horizons which underlie NOSRs 1 and 3 but which have not been penetrated by wells in the immediate vicinity.

Where data gaps were found in the reports, specifically regarding the analysis of wells drilled immediately northwest of NOSR-1, this consultant reviewed well logs, scout data, and Oil and Gas Commission files in order to aid in the assessment. The information gained in this additional evaluation is incorporated into this report.

1.4.2 Regional Geologic Setting

The Piceance Basin is a Mesozoic/Tertiary-age structural and topographic basin which trends northwest-southeast across portions of Delta, Garfield, Rio Blanco, and Moffat Counties, Colorado (Figure 1.5). It is filled with as much as 17,000 feet of Upper Cretaceous and Paleogene sedimentary rocks (Fouch et al., 1994). The total thickness of Phanerozoic rocks in the portion of the basin beneath NOSRs 1 and 3 is estimated to be in excess of 25,000 feet. The basin is strongly asymmetrical with a steeply dipping and thrust-faulted northeastern flank and a gently dipping southwestern limb. The basin axis lies at the toe of the steep eastern limb. In the vicinity of NOSRs 1 and 3 the eastern limb is expressed at the surface as the Grand Hogback which forms the western margin of the White River Uplift. This prominent uplift bounds the Piceance Basin on the east. The basin is bounded on the southwest by the Uncompahgre Uplift in the vicinity of Grand Junction, Colorado. It is separated from the Uinta Basin to the west by the north-south trending Douglas Creek Arch.

The U.S. Naval Oil Shale Reserves 1 and 3 straddle the Piceance basin axis and a portion of the gently dipping southwestern flank just north of the Colorado River drainage. The vast majority of NOSR-1 consists of a high plateau with average surface elevations of 8000 to 9000 feet, some 3000 feet higher than the adjacent Colorado River valley floor. Beneath a thin veneer of the Eocene Uinta Formation, the plateau is underlain by the Eocene Green River Formation which includes the rich oil shale deposits. Spectacular exposures of the Green River Formation and the underlying Paleocene/Eocene Wasatch Formation occur in the steep cliffs which form the edges of the plateau. NOSR-3 generally encompasses the lower portions of the cliffs and the valley floor on the north side of the Colorado River. Surface rock exposures on NOSR-3 are principally those of the Wasatch Formation.

1.4.3 Stratigraphy

Figure 1.7 is a generalized stratigraphic column for the NOSR 1 and 3 areas. Knowledge of the Paleozoic succession comes from outcrops in the adjacent White River Uplift in Glenwood Canyon east of Glenwood Springs, Colorado and from isolated deep test wells in the Piceance Basin. The closest Paleozoic control for the NOSR 1 and 3 areas is a 15,531' well drilled by Barrett Resources (#1-27 Arco Deep) approximately six miles to the west of NOSR-3 in Section 27, T6S-R97W. That well bottomed in what appears to be arkosic sandstone and conglomerate of Permian-Pennsylvanian age. No deeper Paleozoic horizons have been penetrated anywhere else in close proximity to the Reserves. Based on regional knowledge, the stratigraphic horizons described below can reasonably be expected to be encountered in future ultra-deep tests drilled on the NOSR acreage.

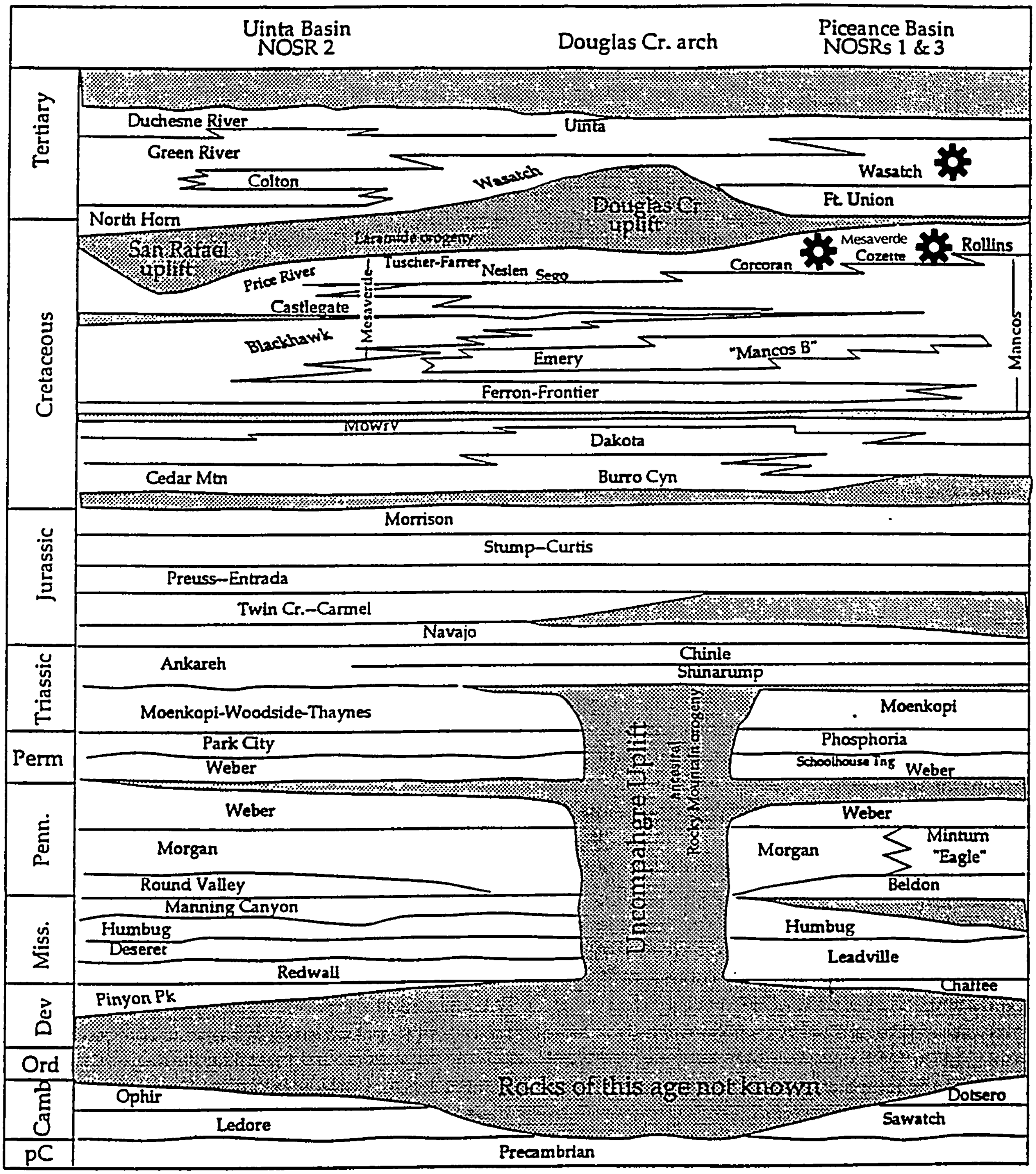


FIGURE 1.7– **Chronostratigraphic diagram extending from area of Naval Oil Shale Reserve (NOSR) 2, Uinta Basin, Utah to Naval Oil Shale Reserves 1 & 3, Piceance basin, Colorado. Stratigraphic names are those frequently applied by industry to the strata.** Main gas–producing zones at Grand Valley, Parachute, and Rullison fields are highlighted (after Fouch et al., 1994).

The basal sedimentary unit which rests unconformably on the Precambrian crystalline basement is the Upper Cambrian Sawatch Quartzite; this turn is overlain by carbonates of the Cambrian Dotsero Formation. Ordovician and Silurian rocks are not present in the nearest outcrop areas and are probably absent beneath the NOSR sites. Quartzites, shales, and carbonates of the Devonian Chaffee Group and limestone and dolomite of the Mississippian Leadville Formation are expected to overlie the Cambrian sequence. None of these Lower and Middle Paleozoic units produce oil and gas within or on the margins of the Piceance Basin and thus are not considered viable exploration targets within the NOSR reserves.

The overlying Permo-Pennsylvanian sequence is of more interest as potential hydrocarbon targets than the older Paleozoic rocks. The area occupied by the present-day Piceance Basin was part of the marine to marginal marine Central Colorado Trough during Pennsylvanian and Permian time. It was bounded on the northeast by the Ancestral Front Range Uplift and on the southwest by the Ancestral Uncompahgre Uplift. The basin was the site of restricted sedimentation and rapid facies changes from marginal alluvial and eolian clastics to basin-centered carbonates and evaporites. Paleogeographic maps presented in the USGS Open-File Report 94-427 (Fouch et al., 1994) suggest the presence of the following Permo-Pennsylvanian sequence in the vicinity of NOSRs 1 and 3 (Figure 1.7). Redbeds (paleokarst soils) of the Pennsylvanian Molas Formation are expected to rest on the Leadville Formation erosional surface with a great deal of variability in thickness. Overlying the Molas is a marine shale and carbonate sequence of the Belden Formation. This unit contains oil-stained algal mounds in wells along the northern flanks of the White River Uplift approximately 30 miles to the northeast of NOSRs 1 and 3. Similar algal mound reservoirs could exist in the subsurface beneath the NOSR acreage but subsurface confirmation is lacking and risks are high. The USGS report suggests that the Middle Pennsylvanian rocks in this area will consist of mixed shales and evaporites of the Eagle Valley Evaporite but could also contain mixed arkosic clastics and thin limestones of the laterally equivalent Minturn and Morgan Formations. The Barrett deep test mentioned above indicates that at least the upper portion of the Permo-Pennsylvanian contains arkosic conglomerates and sands with a few lenses of anhydrite. It should be noted that a lack of adequate deep well control increases the margin of error in the interpretation of the areal distribution of reservoir and non-reservoir rock types in this system of rapid and complex facies changes.

The most attractive Paleozoic target at the NOSR sites is the Permo-Pennsylvanian-aged Weber Formation; these strata consist of eolian to marginal marine sandstones of reservoir quality where they produce oil in large anticlinal structures on the northern and northeastern margins of the Piceance Basin (Figure 1.8). A tongue of the Weber sandstone is oil-stained in outcrops along the Grand Hogback to the east of the reserves. Regional facies changes from reservoir quality eolian sands of the Weber Formation to tight alluvial arkosic sandstones and red siltstones of the laterally equivalent Maroon Formation most likely occur across this area of the reserves and this increase the reservoir risk for the Weber.

The overlying Triassic and Jurassic section consists of shales and siltstones punctuated by a prominent eolian sand named the Jurassic Entrada Formation. It is a massive, highly porous, clean sandstone reservoir where it produces oil and gas at relatively shallow depths in the Wilson Creek Field which is situated in an anticlinal structure along the northeast margin of the Piceance Basin. It also produces at San Arroyo and Westwater Fields in eastern Utah (Figure 1.9).

The U.S. Geological Survey considers all of the pre-Cretaceous plays in NOSR 1 and 3 to be of extremely high risk due to a combination of factors including lack of close well control, depth of burial and the attendant loss of reservoir quality porosity, lack of close proximity to production, and high well costs. The Survey's assessment of the risks of these ultra-deep plays and the high probability of low economic return appears to be valid.

The Upper Jurassic Morrison Formation and the Lower Cretaceous Dakota Group constitute a sequence of sandstones, siltstones and shales deposited in a complex variety of coastal environments including coastal plain, fluvial, paludal, tidal flat, delta, beach and nearshore marine (LaFreniere, 1994). A large body of literature exists describing this group of rocks in great detail. Morrison/Dakota gas production is widespread on the Douglas Creek Arch to the west of the Piceance Basin (Figure 1.10). The closest such production to NOSRs 1 and 3 is at Shire Gulch Field approximately 20 miles to the southwest. In the immediate vicinity of the Naval Reserves only two wells have penetrated as deep as the Dakota. The Arco et al. #1 North Rifle Unit well immediately adjacent to the northeast boundary of NOSR-3 (Section 31,T4S-R94W) bottomed in the Dakota at a depth of 17,299 feet. The previously mentioned Barrett Arco #1-27

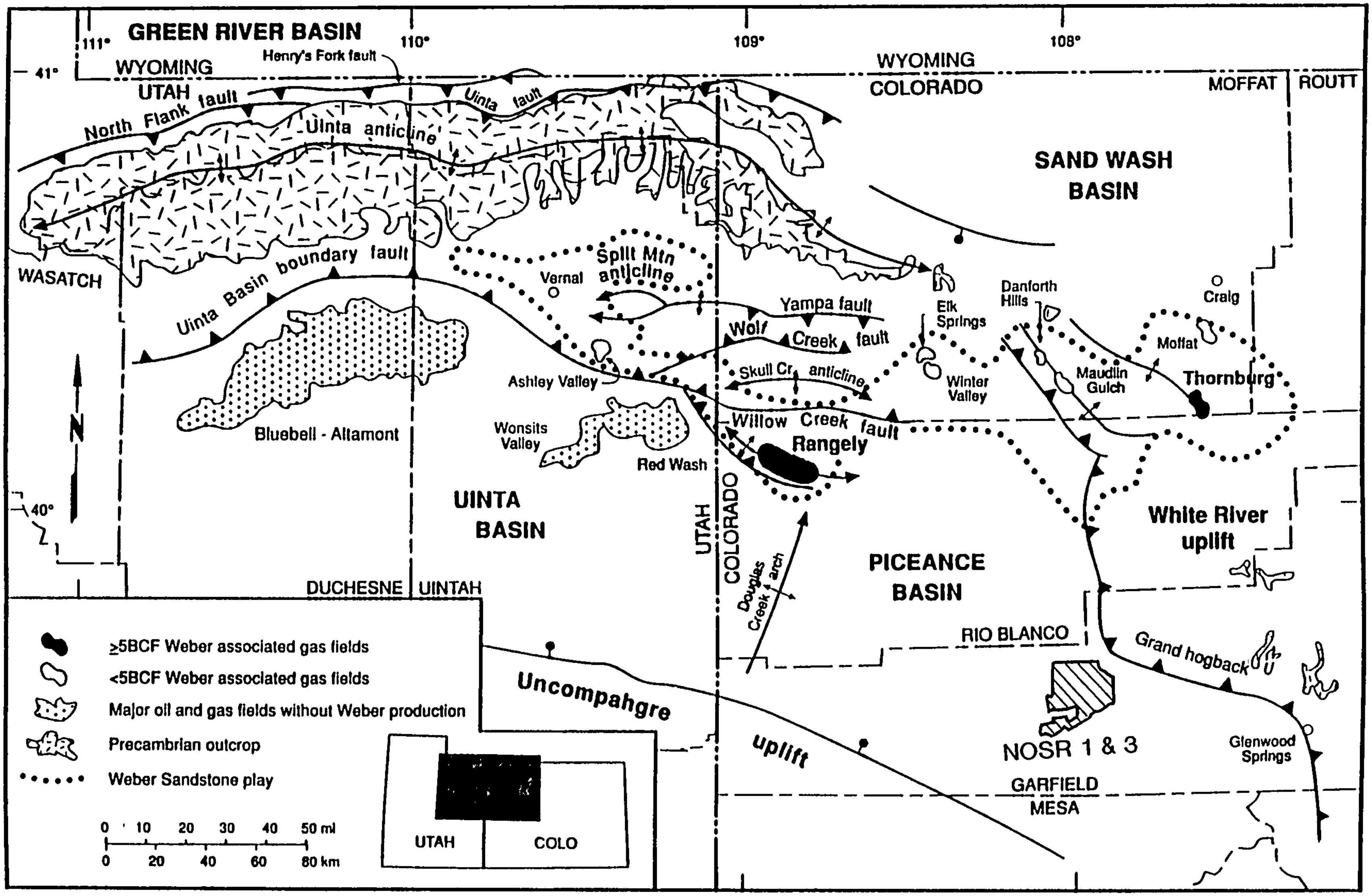


FIGURE 1.8 —The Uinta Mountain-White River structural block, major and minor Weber Sandstone reservoirs, and Weber Sandstone play outline. Modified from Bowker and Jackson, 1989. (after LaFreniere, 1994).

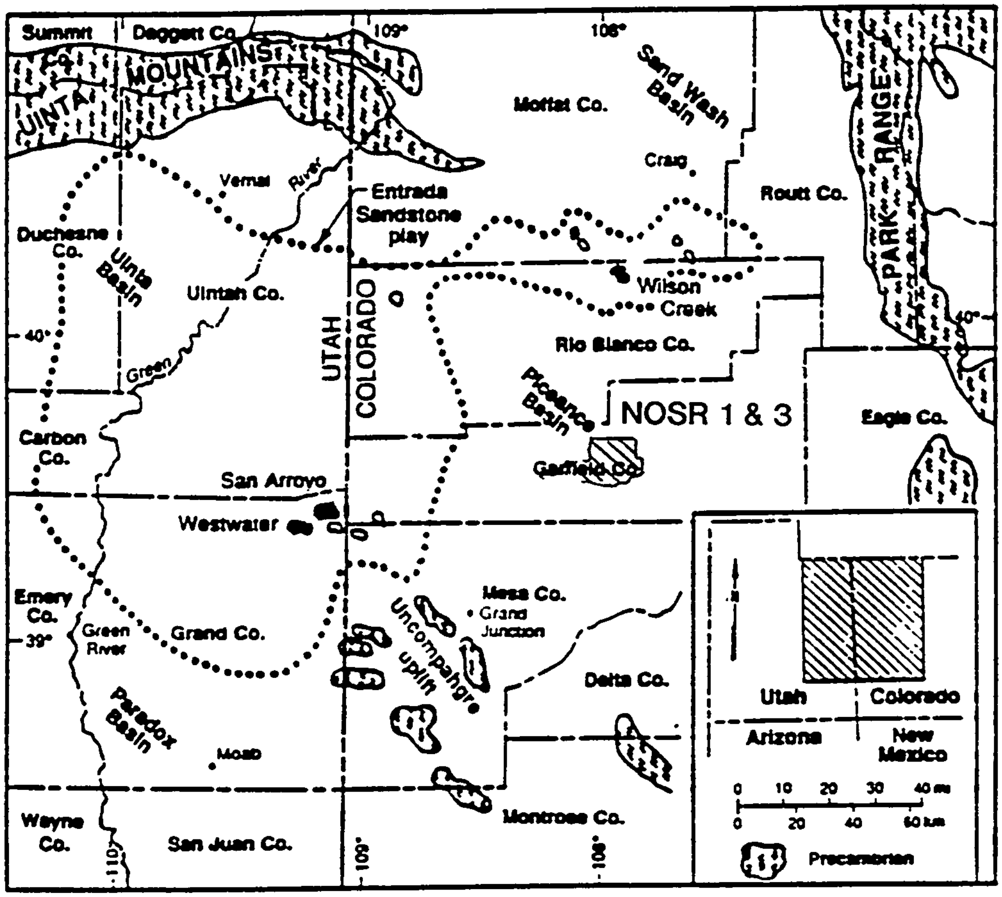


FIGURE 1.9 —Reservoirs and play outline in the Entrada Sandstone. Reservoirs that have produced more than 5 BCF of gas are solid. fields that have produced less than 5 BCF of gas are shown as open outlines.

(after LaFreniere, 1994)

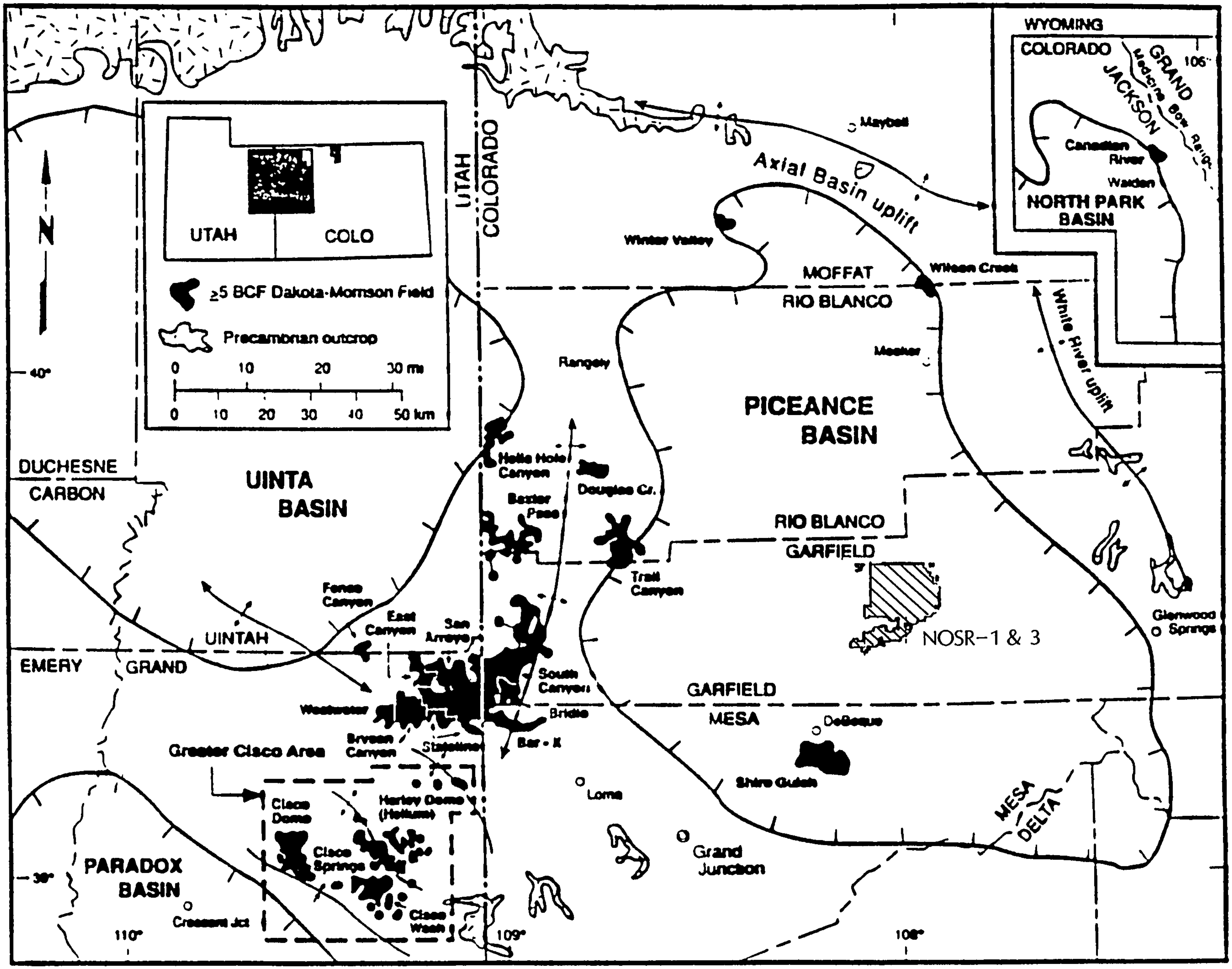


FIGURE 1.10– Fields that have produced at least 5 BCF gas from sandstone and conglomerate reservoirs in the Dakota–Cedar Mountain–Morrison play, Utah and Colorado (modified from Gurgel, 1983, Smith et al., 1991). (after LaFreniere, 1994)

well to the west of NOSR-3 topped the Dakota sand at 13,409 feet and reportedly encountered some gas shows; subsequent testing indicated that the Dakota was nonproductive. The U.S. Geological Survey assessment considers the Dakota Formation to have little economic significance at NOSR 1 and 3 due to the drilling depths involved and the disappointing results of the Barrett well. Their assessment appears to be reasonable, particularly in light of the current gas prices. This Consultant believes that the Dakota potential will have only minimal impact on the fair market value of the NOSR properties.

Overlying the Dakota Group is a thick sequence of dark grey to black marine shales and isolated sands assigned to the Upper Cretaceous Mancos Formation. Conformably overlying the Mancos Formation, and intertonguing with it, is the Upper Cretaceous Mesaverde Group. This sequence of sandstones, shales, and coals is one of the major gas-producing systems in the area nearby NOSR 1-3 and within NOSR-3 itself. Overlying the Mesaverde Group with regional angular unconformity is the Lower Tertiary (Paleocene/Eocene) Wasatch Formation. This is the other major gas-productive horizon both around NOSR 1 and 3 and within NOSR-3 itself. The detailed stratigraphy and petroleum geology of these two gas-bearing systems will be reviewed in the sections that follow; there is an abundant and detailed body of literature published on these horizons.

1.4.3.1 Mesaverde Stratigraphy

Figure 1.11 is a well log over the Mesaverde and Tertiary section from the Barrett #1-27 Arco Deep well just west of NOSR-3. It is representative of the pay section in and near the NOSR tracts. The basal formation of the Mesaverde Group is the Iles Formation consisting of the Corcoran, Cozzette and Rollins Sandstone Members in ascending order. These regressive shoreline/marine sandstones are separated by tongues of the Mancos shale. They are blanket-type sand bodies and should extend uniformly beneath NOSRs 1 and 3. The Iles is approximately 700 Figure 1.11 to 750 feet thick. Overlying the Iles Formation is the William Fork Formation which varies from about 2800 to 3700 feet in thickness. Although no formal members have been designated, the Williams formation has been divided into units on the basis of environments of

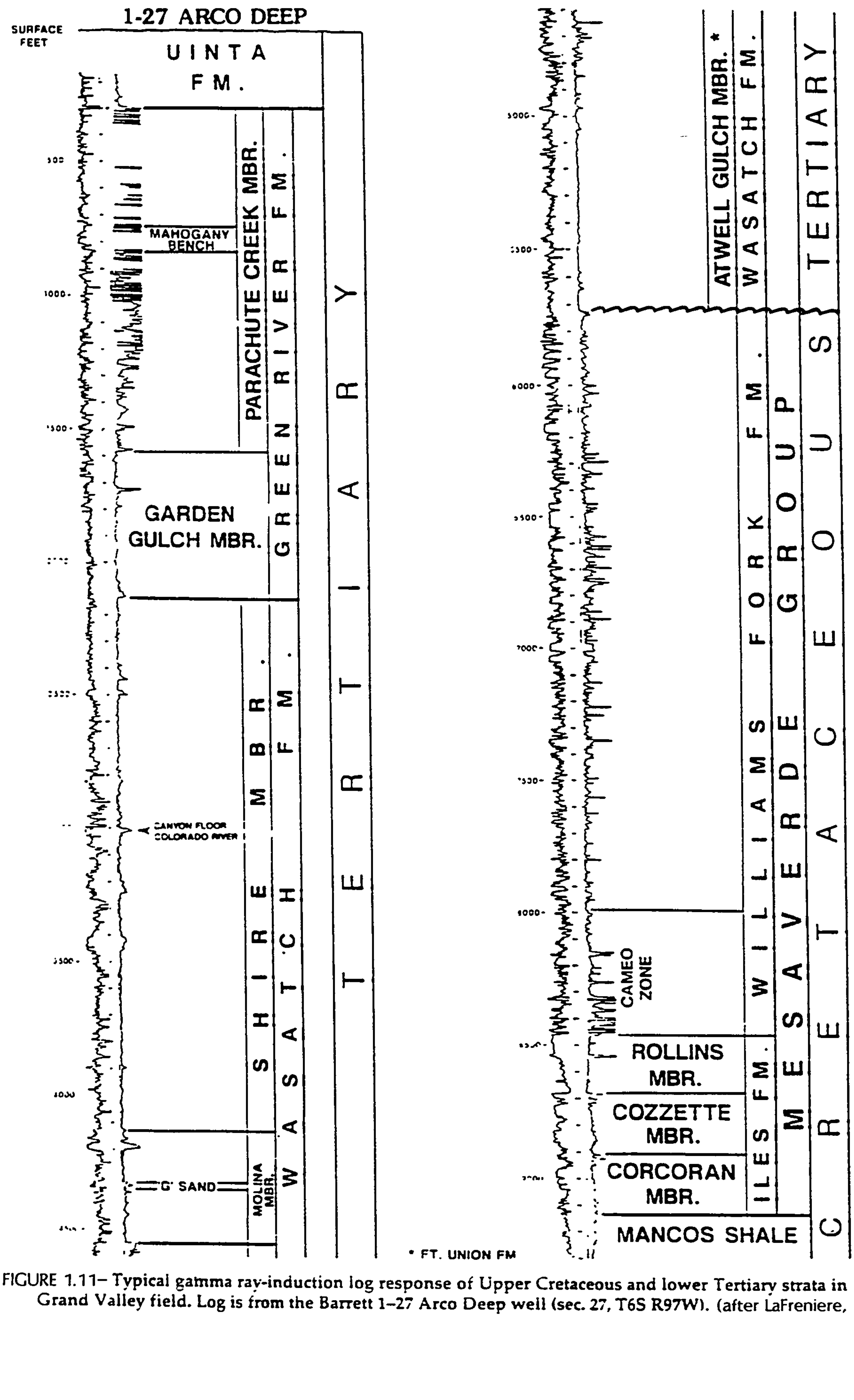


FIGURE 1.11– Typical gamma ray-induction log response of Upper Cretaceous and lower Tertiary strata in Grand Valley field. Log is from the Barrett 1-27 Arco Deep well (sec. 27, T6S R97W). (after LaFreniere, 1994)

deposition (Lorenz, 1982). Figure 1.12 is a generalized schematic section for the Mesaverde Group with Lorenz's environmental designations. His reports are based both on outcrop studies near Rifle, Colorado and on detailed core descriptions and correlations in the DOE Multi-Well Experiment wells drilled in Rulison Field.

The basal unit of the Williams Fork Formation is the Cameo or (paludal) zone which consists of interbedded sandstone, siltstone, shale and coals. These rocks were deposited in a variety of lower delta plain paludal environments including delta front, distributary channels, swamps and marshes. Sand body geometries vary from thin blanket deposits to laterally discontinuous lenticular channel sands.

The lower middle zone of the Williams Fork is referred to as the coastal zone and consists of lenticular upper delta plain distributary bodies. The upper middle portion of the Williams Fork is the fluvial zone; it consists of numerous composite sand bodies deposited in river meander belts as coalesced point bars. Approximately the uppermost 500 feet of the Williams Fork Formation in the vicinity of the Reserves is a paralic section with marine-influenced sedimentation in a coastal setting marking the beginning of the next transgressive cycle. The paralic section is generally water saturated and does not produce gas in the vicinity of NOSRs 1 and 3.

By their very nature, Mesaverde sand bodies are discontinuous, complex and rather erratic in size, shape and distribution. Lorenz (1982) demonstrates that individual point bar deposits of the upper Mesaverde are sand bodies on the order of 750 feet across and 2 to 13 feet thick. They are commonly stacked on top of each other in a random fashion; this produces composite meanderbelt sandstone reservoirs up to 20 to 60 feet in thickness and on the order of 1300 to 1700 feet in width.

Barrett Resources engineers have also recognized the heterogeneous nature of the Mesaverde section with respect to the correlatability of individual sands (Ely et al., 1995). They have coined the term "pseudohomogeneity" to describe this sequence of randomly oriented and stacked sandstone, siltstones and shale. By their use of this term they imply that statistically the sediment

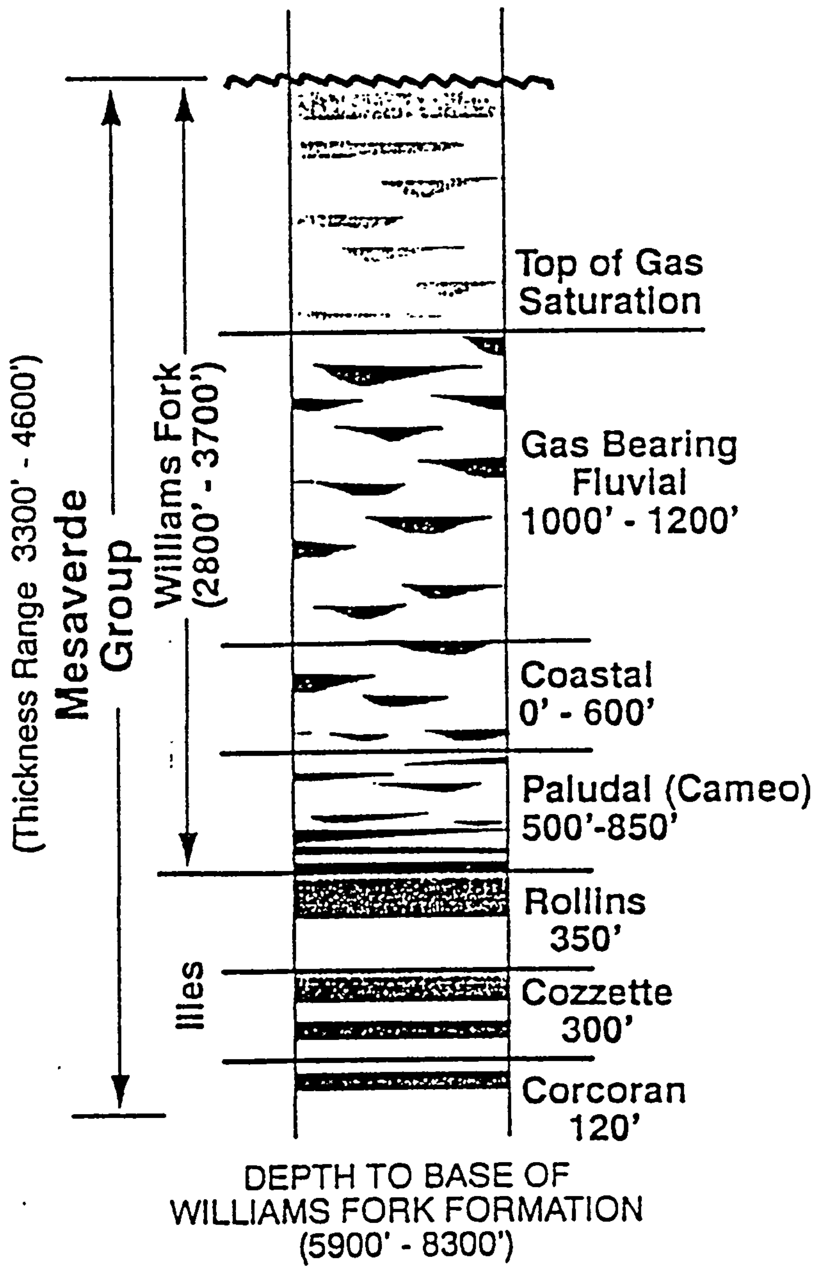


Figure 1.12
Generalized Mesaverde Section
Piceance Basin

(after Ely et al., 1995)

package appears to act like a homogeneous unit in that any well drilled within the area should encounter a similar sedimentary section; this is in spite of the fact that even individual sands are unlikely actually to correlate, even over very short distances (Figures 1.13 and 1.14). This well-documented concept is important for both evaluating play risks and for determining the appropriate well spacing to maximize drainage. Barrett Resources has used this geological concept to petition the Colorado Oil and Gas Commission for a higher drilling density of 40-acre well spacing for the Mesaverde; this represents a successive increased drilling density and down-spacing from the 80-acre designation and from the earlier 160-acre and 320 acre (original spacing) spacing orders. Figure 1.15 illustrates the type of compartmentalization that occurs in fluvial sands of the Mesaverde Group as a result of the random stacking of meander complexes with different orientations.

In addition to Lorenz's (1982) studies, the Mesaverde Group has been studied extensively by the U.S. Geological Survey (e.g., Johnson and Pitman et.al., 1989), 1787-G as well as by other workers (LaFreniere, 1993).

1.4.3.2 Wasatch Stratigraphy

The Paleocene/Eocene Wasatch Formation is the stratigraphically highest gas-producing zone in and around the NOSRs 1 and 3. It consists of a thick sequence of sandstones interbedded with varicolored shales, claystones and siltstones of continental origin. The varicolored claystones give the formation an overall pastel red appearance in outcrop. The sandstones are lenticular bodies which are laterally very discontinuous and randomly distributed throughout the section. They were deposited in river channels cut into alluvial shales and claystones. The sediments accumulated on broad sloping low-relief surfaces along the margins of the developing Uinta-Piceance Basin; the basin eventually became the site of Lake Uinta during Green River time. The overlying oil shales of the Green River Formation were deposited in the basin-centered lake.

Regionally, the upper Wasatch and Green River lithologies intertongued along the margins of the paleo-lake.

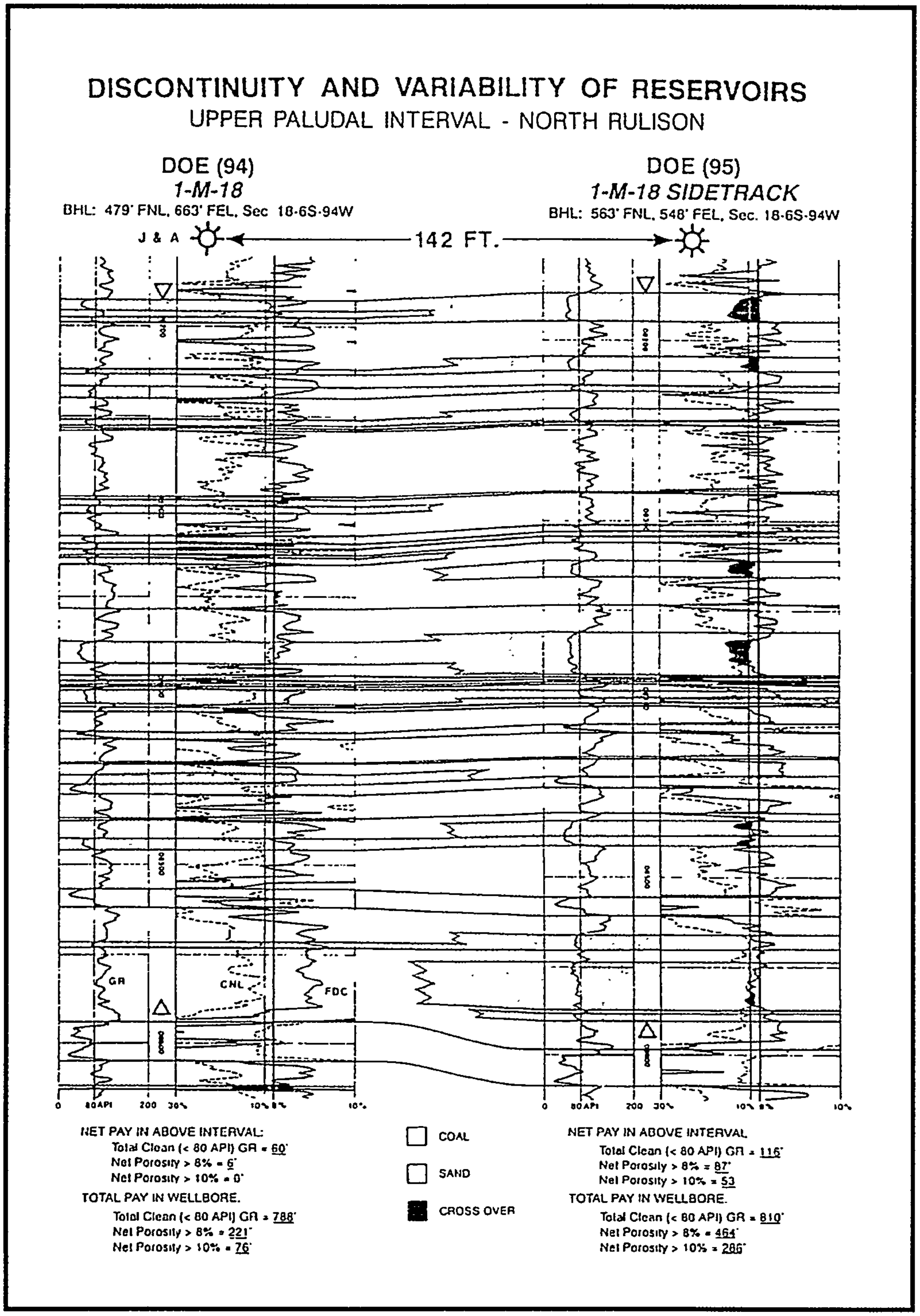
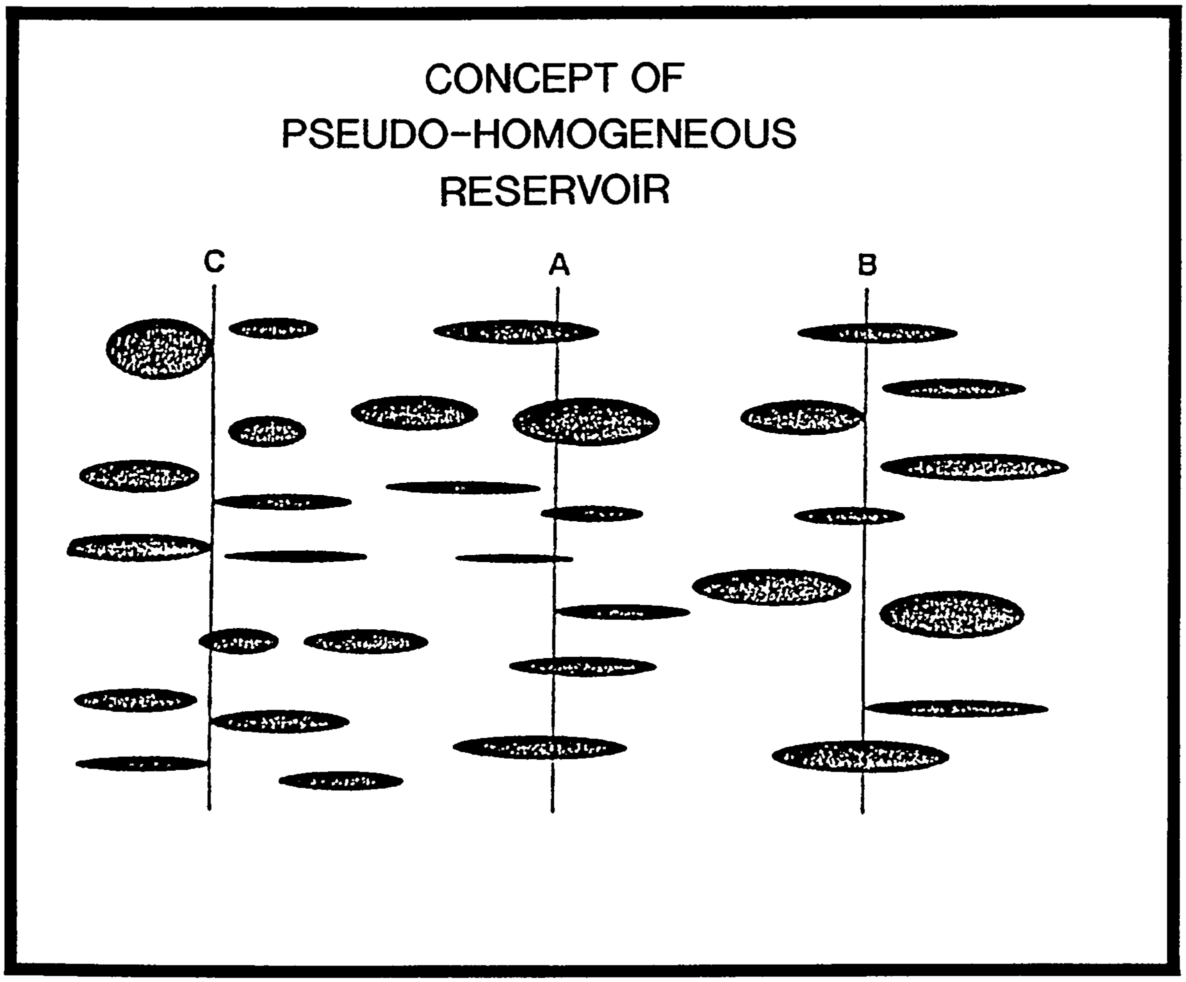
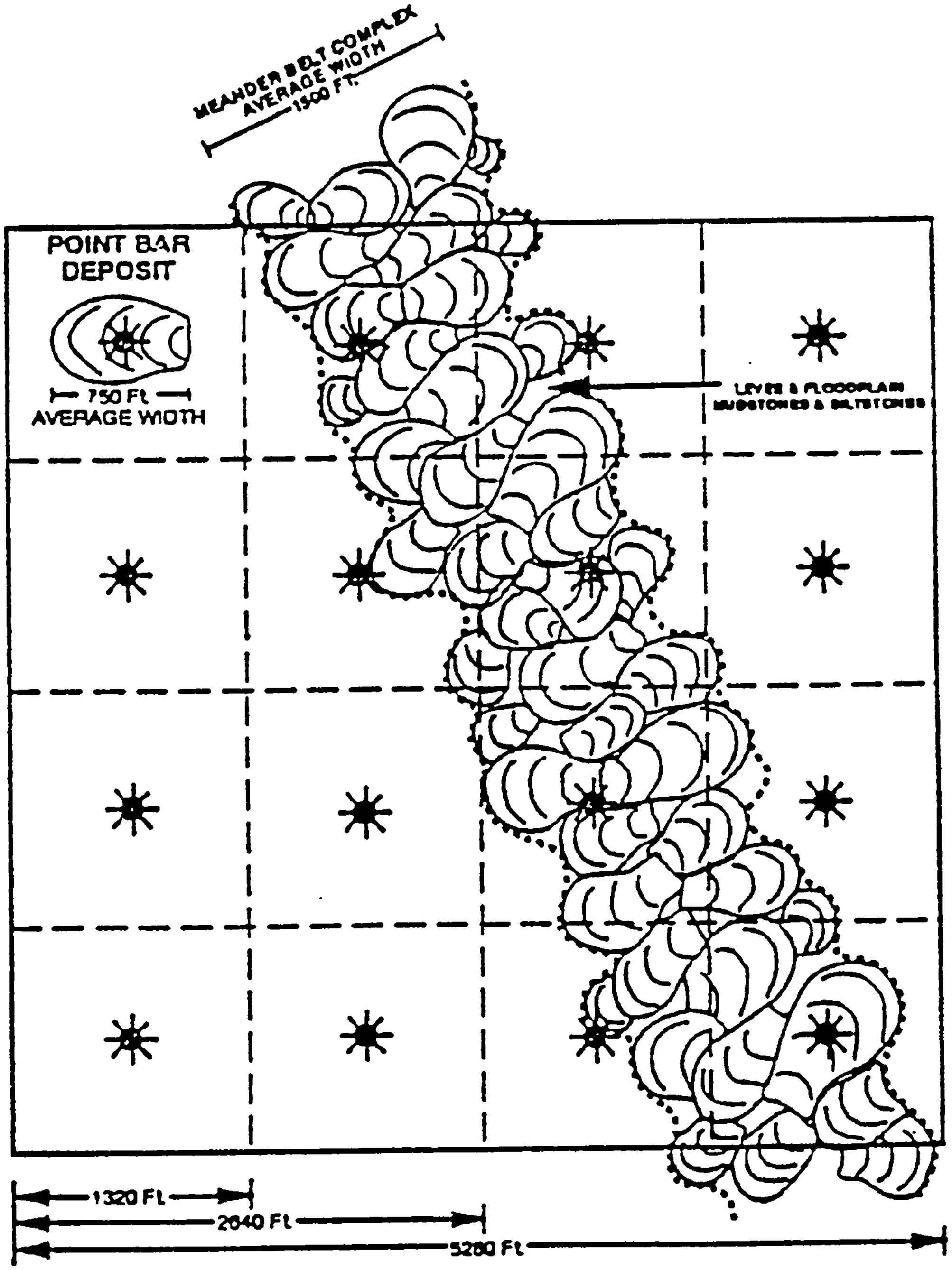


FIGURE 1.13 (after Ely et al., 1995).



(after Ely et al., 1995)

FIGURE 1.14



SECTION DRILLED ON 40 ACRE SPACING

Figure 1.15
Reservoir Compartmentalization
Standard Governmental Section

(after Ely et al., 1995)

The Wasatch in this portion of the Piceance Basin has been divided into three members (Figure 1.11). The lowest is the Atwell Gulch Member which rests on strata of the Mesaverde Group. This member is commonly referred to as the Fort Union Formation by industry operators as it is an age equivalent of the Ft. Union Formation of Wyoming. Overlying the Atwell Gulch is the Molina Member which contains the "G" sand, the main gas-producing zone in the fields surrounding NOSRs 1 and 3. This sand interval, unlike many of the others in the Wasatch, is more continuous and can be correlated over the several township area around the Naval Reserves. It can vary from less than 30 feet to over 100 feet in thickness (LaFreniere, 1994) changes abruptly both in quality and thickness. The uppermost Wasatch is comprised of the Shire member. This member is exposed in the Colorado River Valley and is considered of no economic significance.

Regionally the overall Wasatch Formation thickens eastward from the Douglas Creek Arch into the Piceance Basin. In the vicinity of the NOSR acreage, it varies from about 3500 to 5900 feet in thickness (including the Ft. Union-equivalent Atwell Gulch Member). Wells immediately northwest of NOSR-1 have Wasatch thicknesses ranging from 5500 to 5900 feet.

1.4.4 Structure

1.4.4.1 Shallow Structure (Wasatch and Mesaverde)

Figures 1.16 and 1.17 are structure maps on the Wasatch "G" Sand and the Rollins Sandstone Member of the Iles Formation (Mesaverde Group.), respectively. These are two of a series of structure and isopach maps constructed from well control on and around NOSR-3. They form a part of the geological study of NOSR-3 by LaFreniere (1994) for the DOE. At the Wasatch level the regional dip to the north and east is interrupted by a series of north to northwest plunging anticlines at Grand Valley, Parachute and Rulison Fields. At the Mesaverde level the structural formlines are less ameboid shaped and more uniform than those at the Wasatch level. In the western portion of the area, Mesaverde dip is still strongly to the northeast. A slight structural terrace is present between Grand Valley and Parachute Fields and a second flattening is present between Parachute and Rulison Fields. A prominent northwest-plunging anticline

STRUCTURE ON TOP OF WASATCH "G" SAND

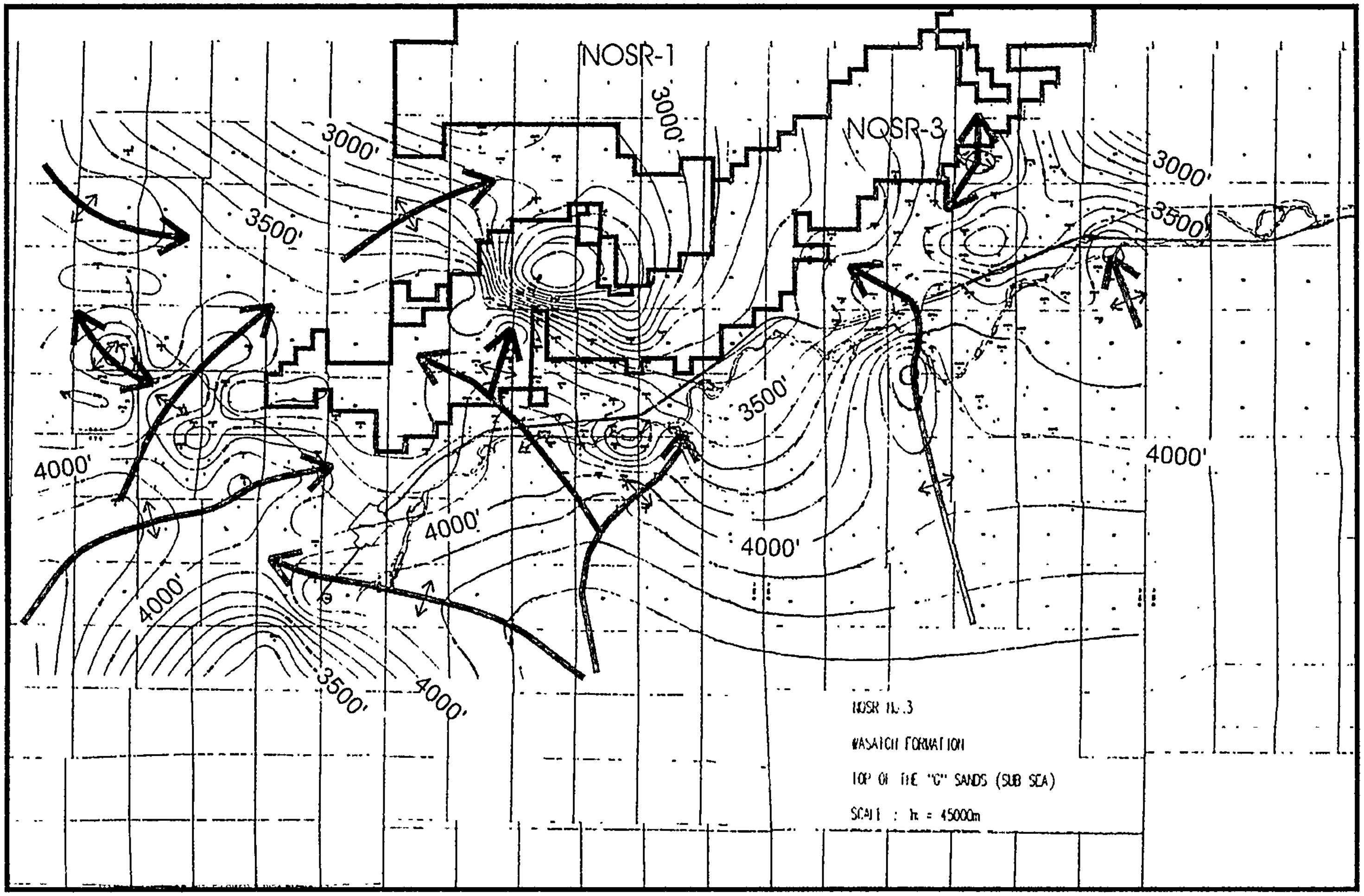


FIGURE 1.16 CONTOUR INTERVAL: 100' (after LaFreniere, 1994)

STRUCTURE ON TOP OF ROLLINS MEMBER-ILES FORMATION (MESAVERDE)

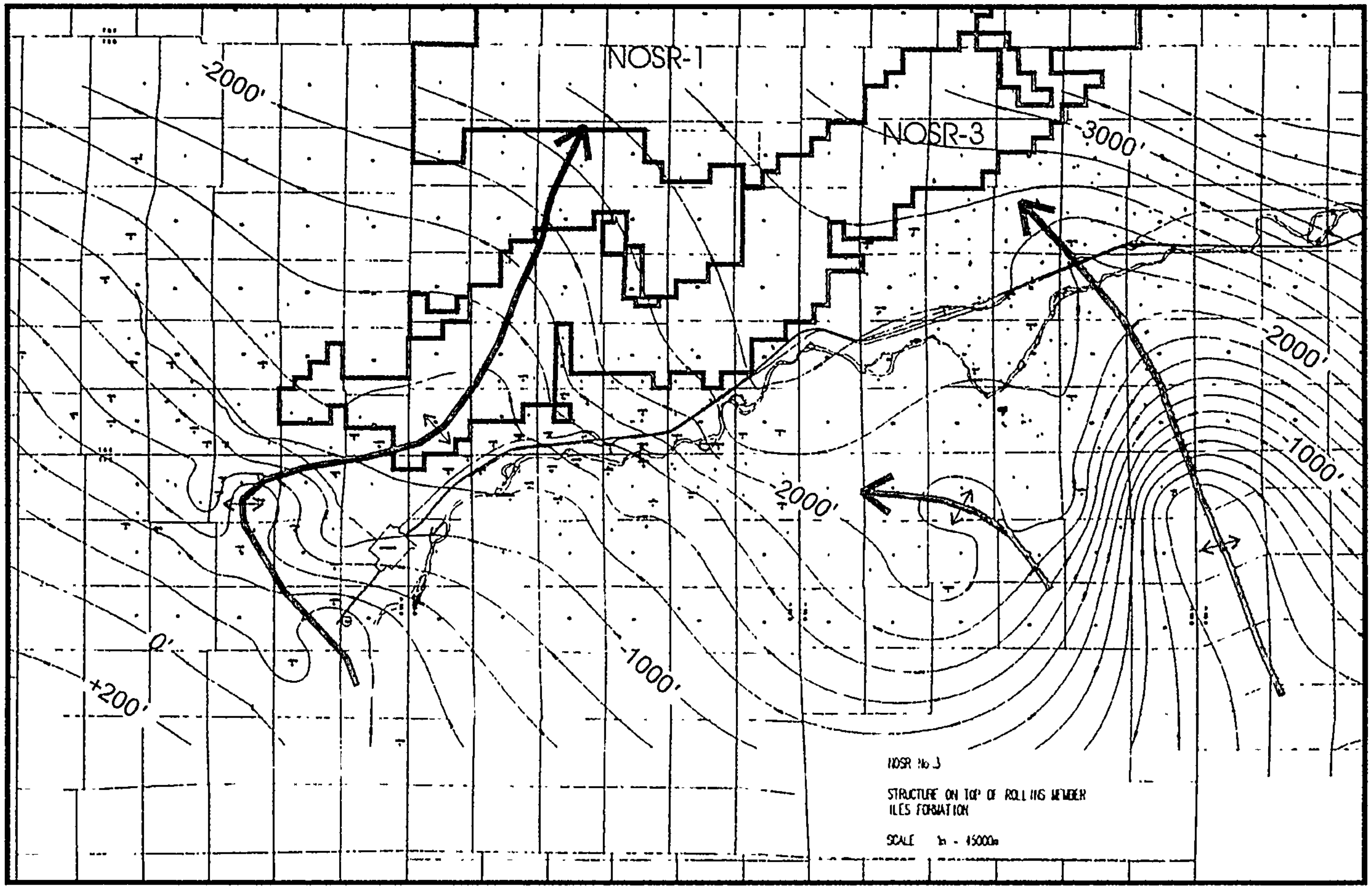


FIGURE 1.17 CONTOUR INTERVAL: 200' (after LaFreniere, 1994)

trends through the main part of Rulison Field in the eastern part of the mapped area. No closed structures are present at the Mesaverde level and only minor ones at the Wasatch. The localized highs and lows on the Wasatch map may be a function of stratigraphic variations in the thickness of the "G" sand superimposed on the first order structural dip seen at the Mesaverde level.

All of the maps by LaFreniere are computer generated. Where well control is dense south of NOSR-3, the maps appear to represent the true structure. Along the edges of the maps, and where well control is sparse, the computer-generated contours presumably are less accurate. Nevertheless, the overall "shallow" structural framework is depicted by these two maps. Trapping of gas is not controlled or limited to structural closures at either horizon.

1.4.4.2 Deep Structure and Seismic Evaluation

Two modern CDP seismic lines were shot across portions of NOSR 1 and 3. These 30-fold dynamite lines were acquired by Grant-Norpac, Inc. in 1988 as part of a much larger regional acquisition program. The locations of the CPB-1 and CPB-3 lines are shown in Figure 1.18 and Plate 1. The U.S. Geological Survey used these two lines in their analysis of the structure underlying NOSR 1 and 3. This Consultant has been granted permission by the DOE, and the current licensor, Seital Corporation, to review this confidential, non-exclusive seismic data in the course of our Phase 1 study of the Naval Oil Shale Reserves 1 and 3. A smaller-scale interpreted version of CPB-3 is included in the USGS Open File Report 94-427 (Fouch et al., 1994) and a similar version of CPB-1 is included in an internal USGS report (Fouch, 1993). The latter report is included here as Appendix A.

After reviewing copies of Lines CPB-1 and 3 as originally processed by Grant-Norpac, this Consultant has determined that they are of sufficient quality to allow for a reasonably good structural interpretation of the NOSR area. The seismic recording parameters represent those used for "state of the art" 2-D seismic acquisition at the time this data was acquired in 1988. The complete seismic adequacy report by this Consultant is included in this Phase 1 report as Appendix B. In addition to evaluating the adequacy of the data, a preliminary seismic interpretation was made in order to comment on the reported results of the USGS study. Also

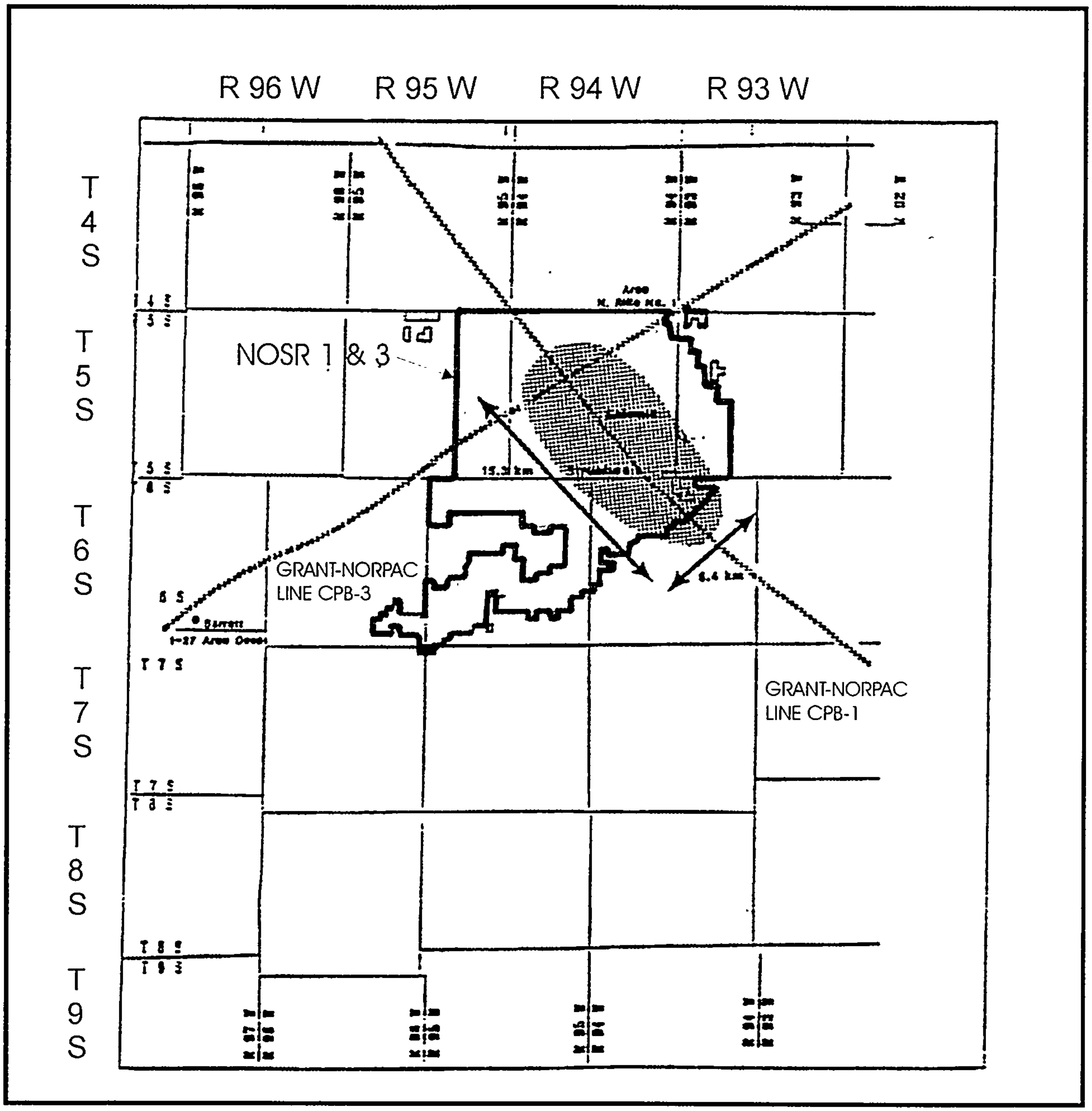


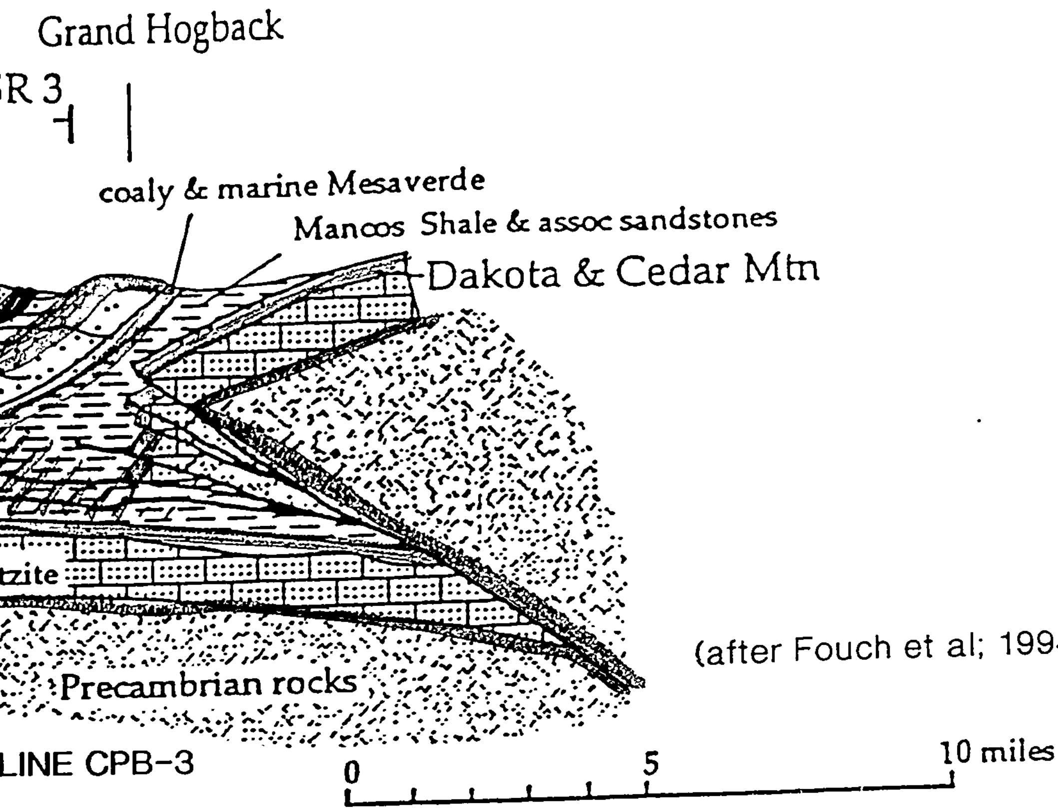
FIGURE 1.18 - Map of the NOSR 1 and 3 project area showing the extent of the structural high derived from seismic data as defined at the Cretaceous Dakota Fm. level (after Fouch et al., 1994).

included in the report in Appendix B are recommendations for further work which this Consultant believes would fill in some of the gaps in the previous studies mentioned above.

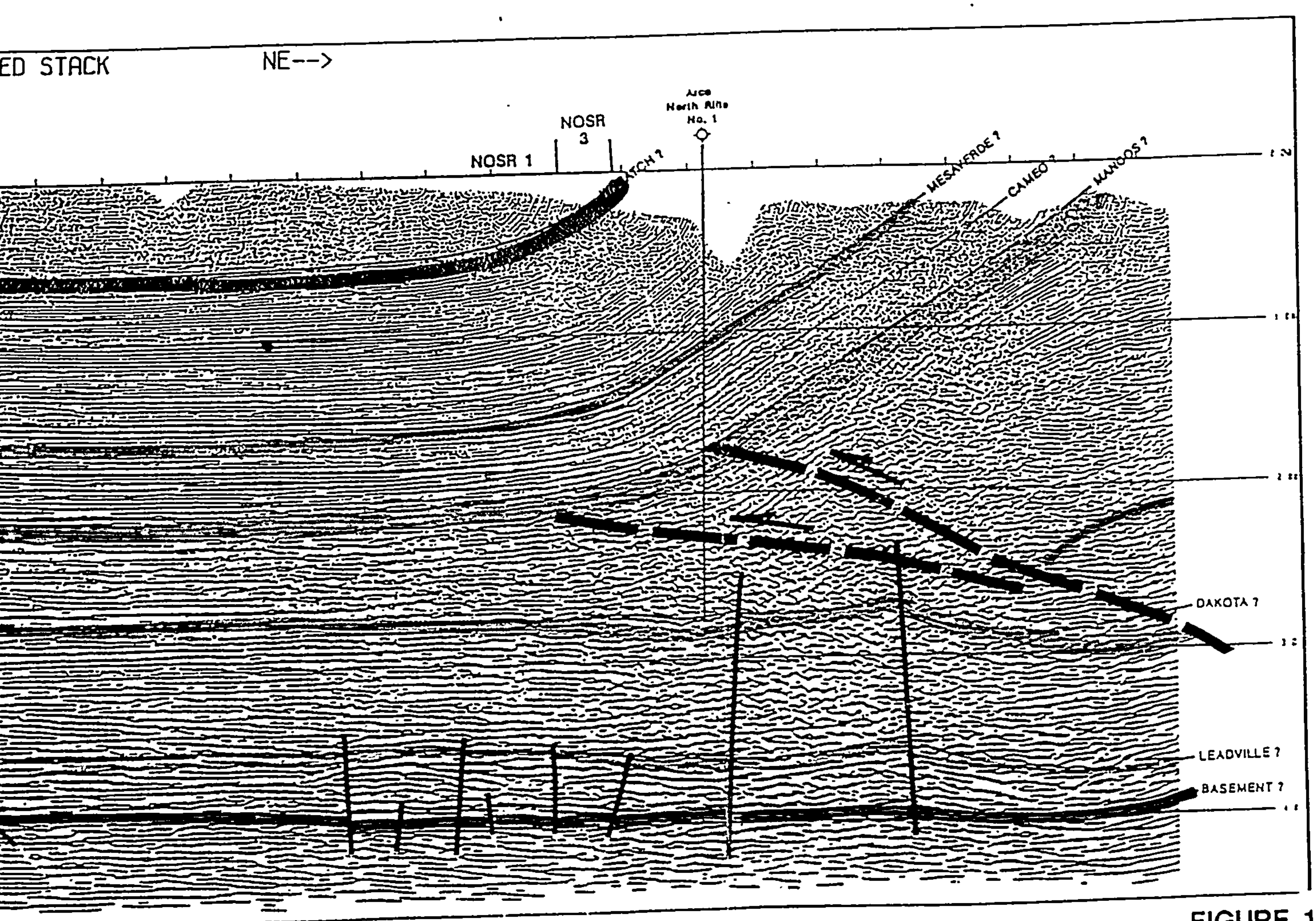
Figure 1.19a is an enlarged version of the NE-SW-oriented CPB-3 seismic line showing the USGS interpretation as presented in Fouch et al.(1994). It has been modified by this Consultant to reflect the position of the interpreted large thrust fault which probably underlies the Grand Hogback at the northeast end of the line. Figure 1.19b is a diagrammatic version of the structure displayed on the same seismic line below. Stratigraphic control for reflector identification comes from two deep wells which directly tie this line. The ARCO North Rifle #1 well (Section 31, T4S-R93W) is located just west of the Grand Hogback at the eastern end of the line and provides a tie to the Dakota level. The Barrett #1-27 Arco Deep well (not shown on the seismic line) near Parachute Creek provides a deeper tie to the Pennsylvanian top at the western end of the line.

Of particular importance to the evaluation of NOSR potential is the apparent low-relief time reversal (anticline) which underlies the east-central part of NOSR-1. This apparent seismic reversal is outlined on Plate 1. As interpreted by the U.S. Geological Survey, approximately 40 milliseconds of time reversal is present on this feature at the Dakota/Entrada level which translates into about 280 feet of two-way closure (Fouch, 1993). The USGS reprocessed the seismic data and converted the time section into a depth presentation. Based on the reprocessed version of CPB-3, they reported over 100 feet of two-way closure after depth conversion (Fouch et al., 1994). This line also suggests that the structure should have some surface expression, albeit extremely subtle.

Although the above structure is subtle on Line CPB-3, the cross line CPB-1 show a very prominent apparent reversal in the northwest-southeast direction with about 90 milliseconds of two-way reversal at the Dakota/Entrada level as interpreted by the U.S. Geological Survey (Fouch, 1993). They estimated that this could translate into about 740 feet of two-way structural closure at the Dakota level. The USGS interpreted a little over 40 milliseconds (about 200 feet) of reversal at the shallower Green River/Wasatch boundary. The same structure is present from



(after Fouch et al; 1994) ANTICLINE



LINE CPB-3

(after Fouch et al., 1994)

FIGURE 1.19a
FIGURE 1.19b

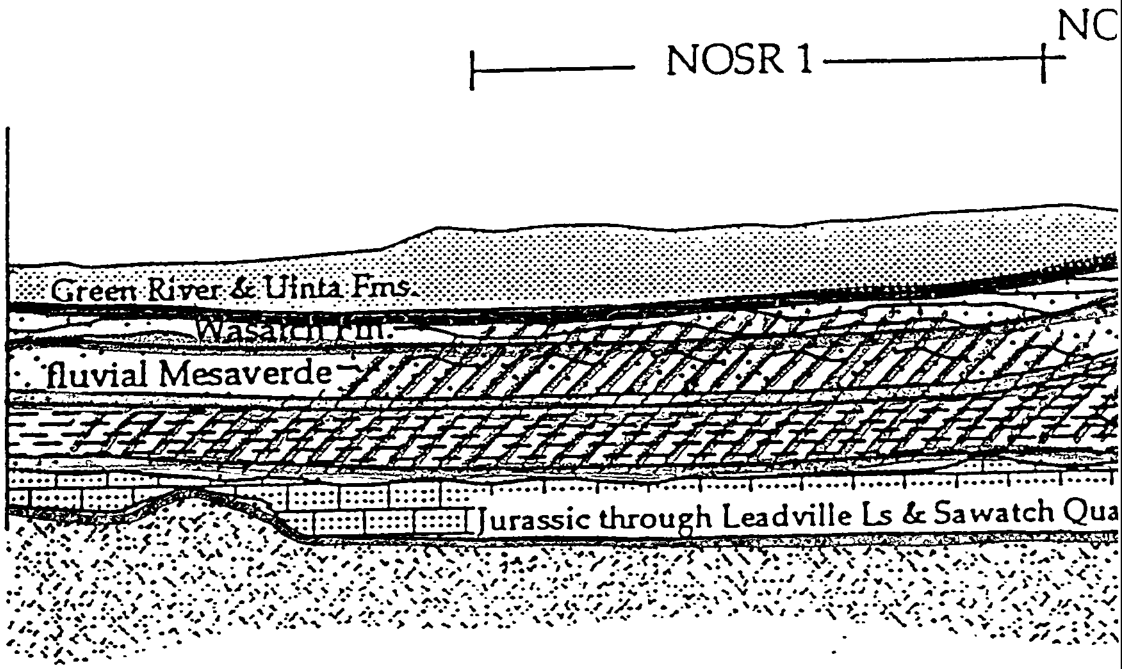


FIGURE 1.19b-STRUCTURAL CROSS SECTION ALONG SEISMIC

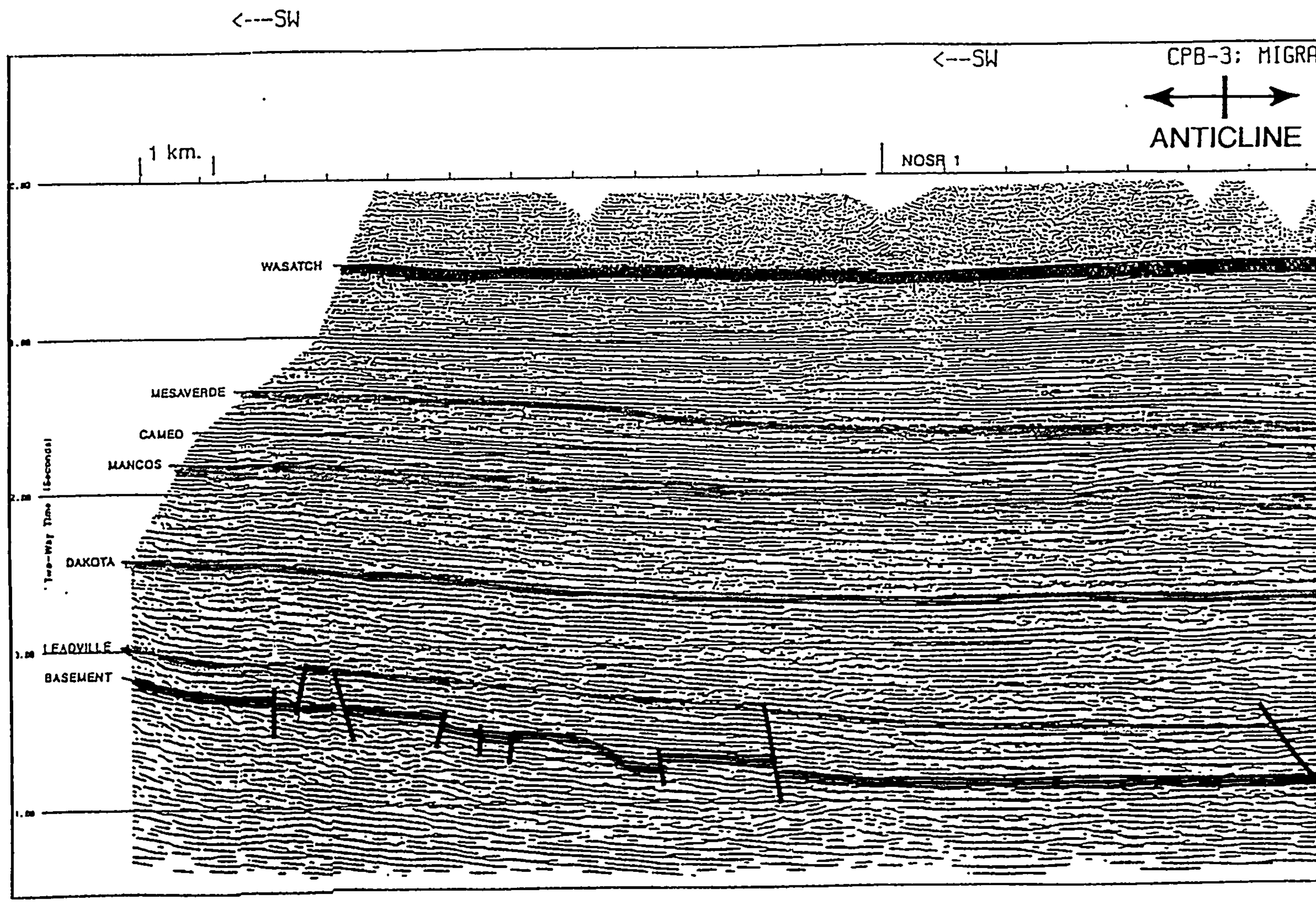


FIGURE 1.19a-INTERPRETED STRUCTURE-GRANT-NORPAC SEISMIC L

the surface all the way to acoustic basement and shows some evidence of fault control at depth according to their interpretation.

Location and areal extent of the above time high as interpreted by the USGS is shown on Figure 1.18 and Plate 1. The crest of this prominent feature is located in the southeastern portion of NOSR-1 near its boundary with NOSR-3. This apparent northwest-oriented seismic feature is on trend with the northwest-plunging anticline at Rulison Field as shown on the Mesaverde structure map in Figure 1.17. The most important aspect of this apparent closure may be its possible control of fracture enhanced permeability in the Wasatch and Mesaverde tight gas sands. The southeast portion of NOSR-1 may be highly prospective for better-quality Wasatch/Mesaverde production.

A number of interesting fault block structures as well as evidence of stratigraphic wedging are present on both lines in deeper horizons (Mississippian and below). Although these deeper seismic features are intriguing at first glance, it is important to keep in mind the extreme drilling depths to these features. At the crest of the prominent time high, drilling depths to the Dakota are estimated by this Consultant to be on the order of 18,000 to 20,000 feet (when adjusted for surface elevation relative to seismic datum). Estimated drilling depths to the Mississippian Leadville Formation are on the order of 23,000 to 26,000 feet. These extreme depths make the economic viability of such pre-Cretaceous targets highly questionable. Only large-scale reserve potential would justify the drilling of such deep expensive wells. Deep structures capable of containing large-scale Paleozoic reserves are not apparent on the two seismic lines.

To date, no attempt has been made to construct a Wasatch or Mesaverde structure map across NOSR-1 that would integrate the limited seismic data with the available well control (including the Barrett Schutte Creek wells immediately northwest of NOSR-1). Since structural closure is not necessary for Wasatch and Mesaverde gas accumulations, such a map is not absolutely critical to the assessment of NOSR-1 potential. However, it does represent a significant gap in the structural evaluation of the subject property.

After a preliminary review of the data (for more detail see Appendix B), this Consultant generally concurs with the above USGS findings. However, the additional work mentioned and described at length in Appendix B would be a necessary prerequisite for a more definitive assessment.

1.4.5 Petroleum Geology

1.4.5.1 General Setting of Basin-Center Gas Accumulation

The U.S. Geological Survey has characterized the Wasatch/Mesaverde gas accumulation in the vicinity of NOSRs 1 and 3 as a gas-saturated, basin center continuous-type accumulation. Similar accumulations have been identified in several of the deep basins in the Rocky Mountain, most notably in the San Juan Basin of New Mexico and Colorado, the Greater Green River Basin of Wyoming, and the Uinta Basin in Utah. The U.S. Geological Survey has studied this type of basin center "tight" gas sand accumulation in great detail.

In a continuous-type accumulation, the deep basin gas-saturation zone cuts across formation boundaries (Figure 1.20). Anywhere within the zone of saturation, essentially water-free gas production can be established wherever the permeability is sufficient to yield commercial gas flows. Structural closure or updip stratigraphic pinch-outs are not requirements for trapping gas in this type of accumulation. In general, sandstone reservoirs in these deep basin continuous accumulations are characterized by low porosities and extremely low permeabilities (usually <0.1 md). Artificial fracture enhancement of permeability is generally required for commercial gas production.

Updip from the continuously gas-saturated zone is a transition zone with reservoirs containing mixed gas and water in more traditional stratigraphic traps with downdip gas-water contacts. Near the basin margins and closer to outcrops the sandstone reservoirs are generally saturated with fresh water.

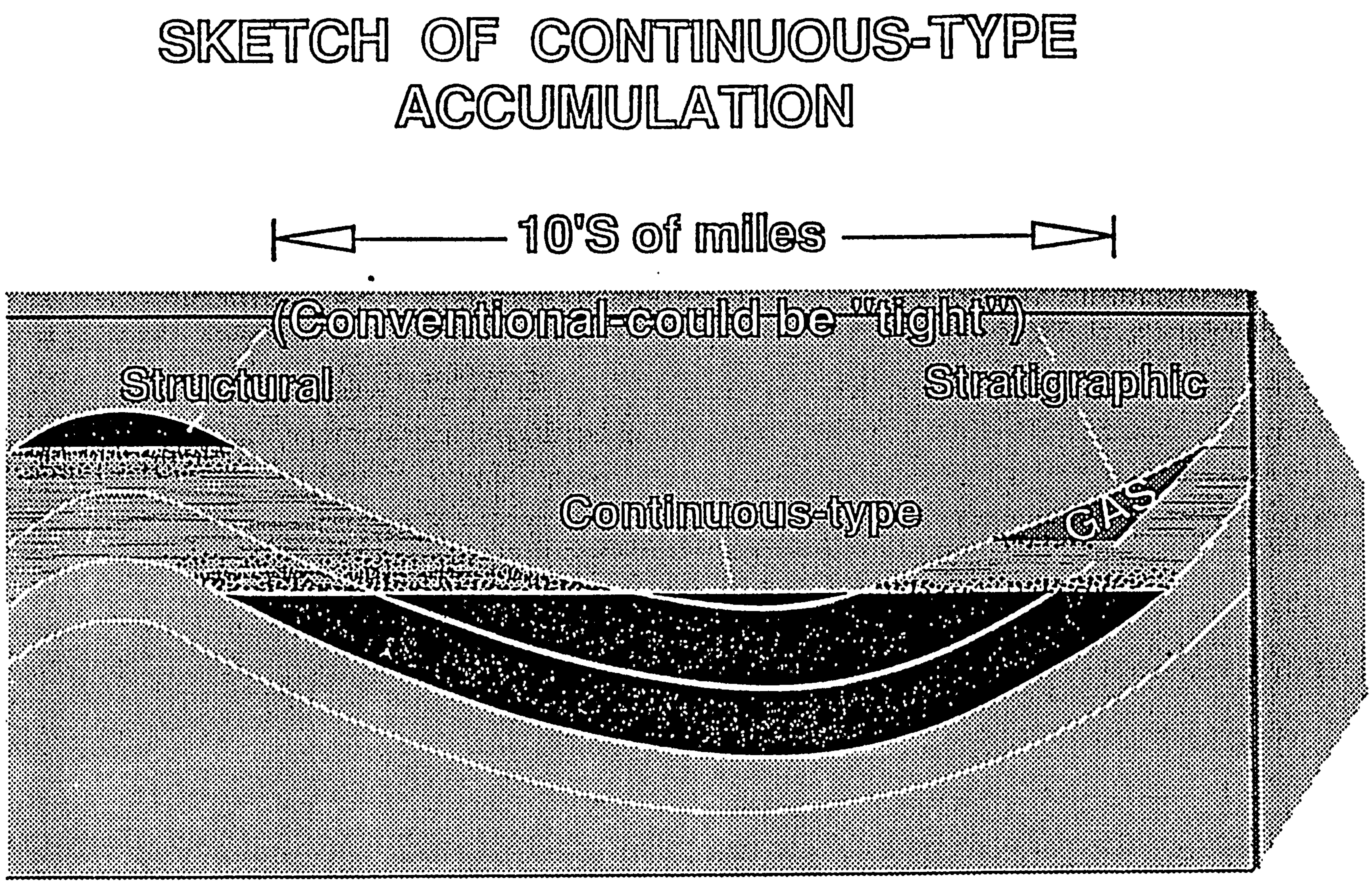


FIGURE 1.20–**Geologic setting of continuous-type gas or oil accumulations relative to discrete accumulations in structural or stratigraphic traps.** (after Fouch et al., 1994)

The Wasatch and Mesaverde reservoirs at the NOSR-3 (and by inference beneath the NOSR-1 site) site fits the classic model of a basin center continuous gas accumulation. Little or no water is produced with the gas and no significant structural closure is present. Sands with enough permeability will produce. Sands too tight to yield commercial gas still show indications of gas-saturation on density-neutron logs. No simple updip stratigraphic pinch-out describes the areal distribution of gas. This Consultant agrees with the U.S. Geological Survey's (Fouch et al., 1994) characterization of the fields offsetting the NOSR properties as being parts of a basin center continuous gas accumulation. As such, the real geological risk in field extension and establishing commercial production is permeability.

1.4.5.2 Gas Generation/Source Rocks

The Cameo zone coals of the lower Williams Fork Formation of the Mesaverde Group have been identified as the main source rocks for both the Wasatch and Mesaverde gas accumulations in the area of the reserves. The U.S. Geological Survey has done a massive amount of work in identifying the coals as the gas source and in characterizing the thermal maturity of this area. Vitrinite reflectance as a measure of thermal maturity and gas-generating potential of the coals has been the parameter that has been the focus of the USGS studies. Survey geologists have found that the boundary between continuous gas accumulations in the Cretaceous and Tertiary and those with gas-water contacts corresponds approximately to the R_o<1.10 percent vitrinite reflectance value at the base of the Mesaverde in the Piceance basin. Strata with R_o<1.10 percent at the base of the Mesaverde will have gas/water contacts and would be updip from the continuous accumulation-type of gas field. Figure 1.21 shows coal rank near the base of the Cameo coal zone. The NOSR tracts fall into an area of low-volatile bituminous coal rank which translates to a R_o in the range of 1.5 to 1.9 percent (Figure 1.22), well above the minimum value for gas generation required to source continuous accumulations. Isotopic studies of gases from the shallower Wasatch Formation have led USGS geologists to conclude that even the gas trapped in sands of that unit was derived from the Mesaverde coal source and that it migrated into the Wasatch along fault and/or fracture zones.

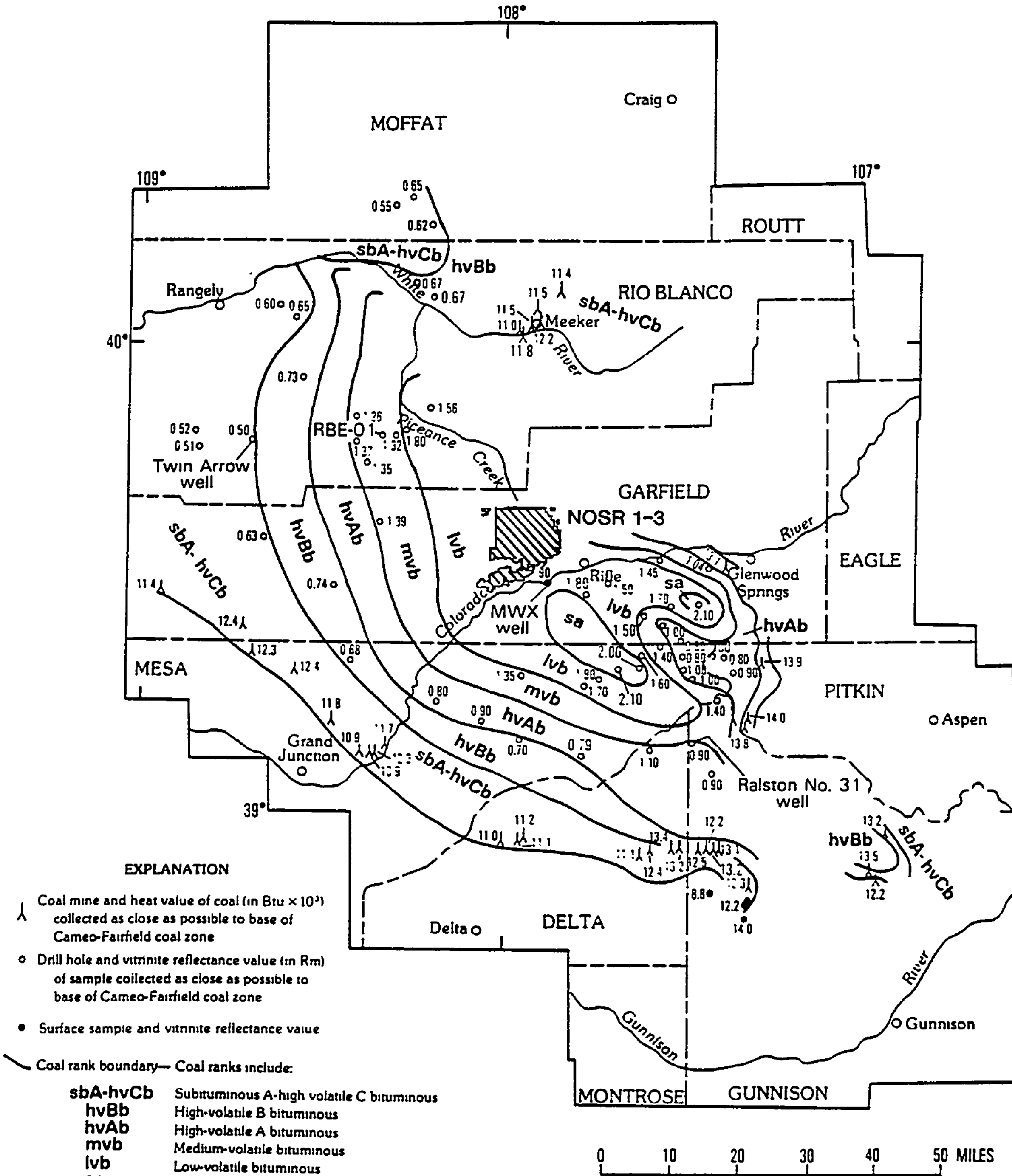


FIGURE 1.21 – Coal rank near base of Cameo-Fairfield coal zone. From Freeman (1979) and Nuccio and Johnson (1983).

(after Johnson, 1989)

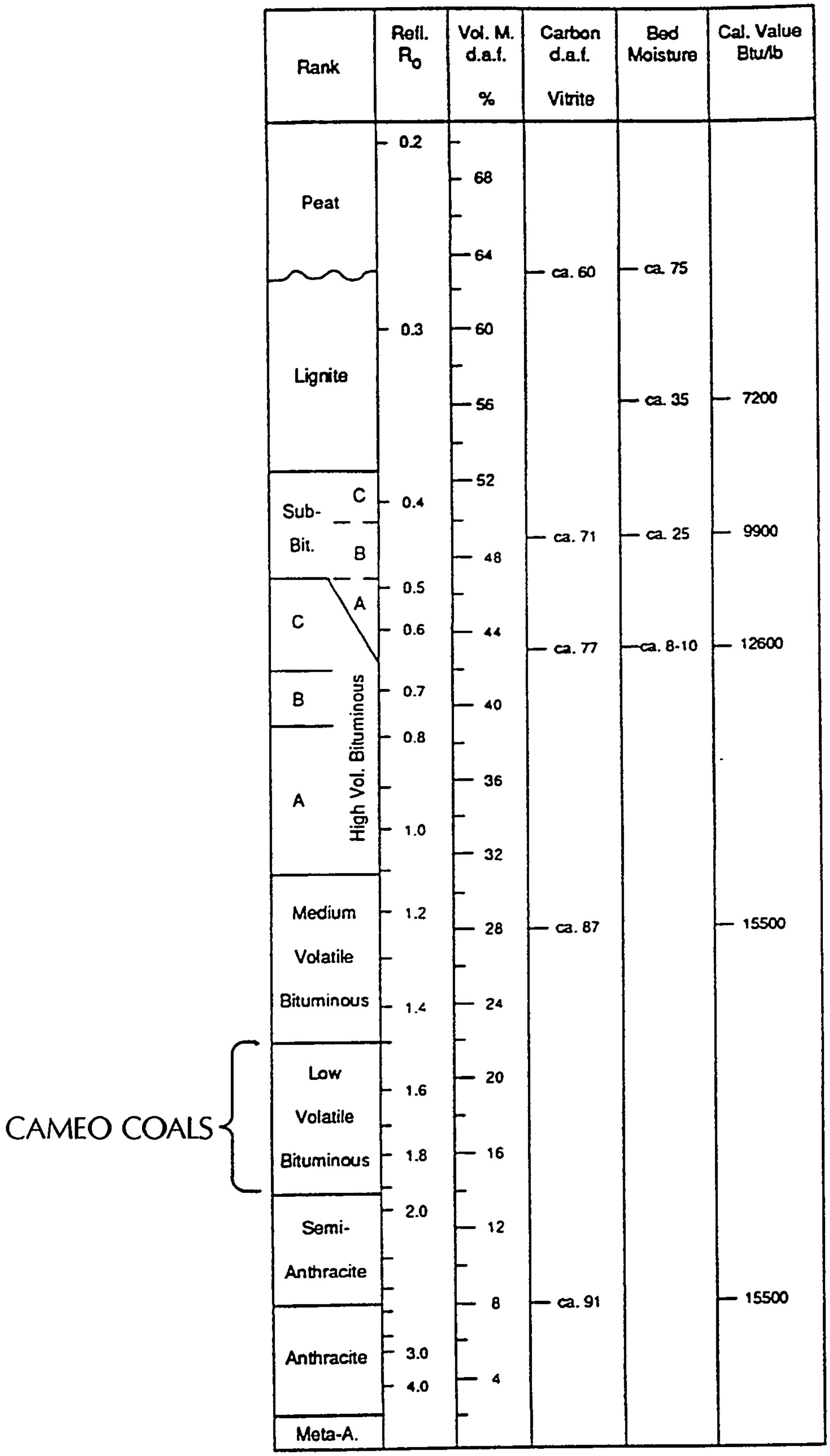


FIGURE 1.22– **Stages of coalification and common properties of measurement. Modified from Stach et al. (1982). D.a.f.= dry and ash free.** (after Rice, 1993)

Additional possible sources of thermogenic gas may be the marine shales of the Mancos Formation. Gases generated from this section may have migrated upwards and mixed with the coalbed gas or may even be trapped in fractures within the Mancos Formation itself. Few wells in the NOSR area went deep enough to evaluate this latter possibility.

1.4.5.3 Established Gas Reservoirs

Wasatch and Mesaverde gas production is widespread throughout the Piceance Basin both to the north and south of the NOSR properties (Figure 1.23). Tables 1.1A, B and C lists all of the major Tertiary and Upper Cretaceous gas fields along with their producing horizons and cumulative production. Rulison, Parachute and Grand Valley Fields have encroached into NOSR-3 from the south and southwest. Cumulative production figures for these three specific fields are listed in Table 1.2.

Fluor Daniel, under contract to DOE, has studied the Wasatch and Mesaverde reservoirs in detail in Rulison, Parachute, and Grand Valley Fields. Their study involved a detailed geological and reservoir engineering characterization of the accumulations. Fluor Daniel's analyses were a part of the DOE Alternative Development Study, and the results were published in the 1994 and 1995 NOSR-3 Alternative Development Reports and Appendices 2 and 3. They made no attempts to extend maps into NOSR-1. Their basic approach included isopach and structure mapping of all zones of interest from the Wasatch Formation down through the Corcoran Member of the Iles Formation. They also made maps of cumulative thickness of sands exhibiting density-neutron gas crossover as well as cumulative production and estimated ultimate recovery (EUR) maps. Their findings were used to determine an expected per well EUR in order to estimate Wasatch and Mesaverde resources on the undrilled portions of NOSR-3. In the 1995 Alternative Development Study Report, Fluor-Daniel incorporated the USGS concept of gas-saturated continuous accumulations into reserve and economic forecasts. Implications of the results and conclusions from Fluor Daniel's report will be discussed under the Reserves chapter of this NOSR 1 and 3 evaluation.

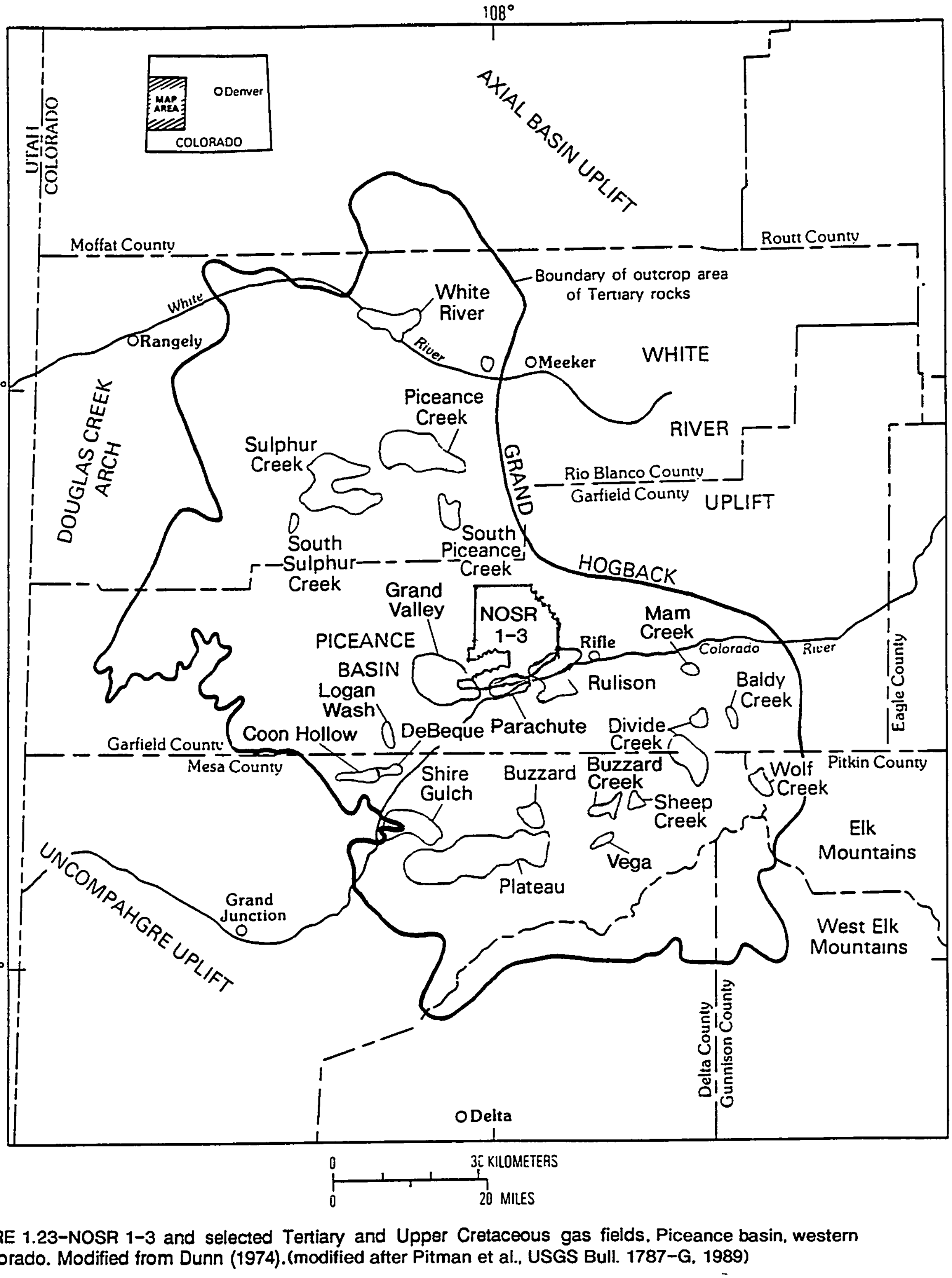


FIGURE 1.23–NOSR 1-3 and selected Tertiary and Upper Cretaceous gas fields, Piceance basin, western Colorado. Modified from Dunn (1974).(modified after Pitman et al., USGS Bull. 1787-G, 1989)

TABLE 1.1A

PRODUCTION SUMMARY

SELECTED TERTIARY AND UPPER CRETACEOUS GAS FIELDS, PICEANCE BASIN, COLORADO

(Through December, 1995)

Field (prod. horizons)	Disc.	Cum. Prod.	Current Prod. Wells	Status
Baldy Creek (Mesaverde)	1959	0 Bbls Oil 0.42 BCF 25,435 Bbls Wtr	0 0 0	No Production in 1995
Brush Creek (Mesaverde)	1985	0 Bbls Oil 0.73 BCF 11,948 Bbls Wtr	0 0 0	No Production December, 95
Buzzard (Mesaverde)	1958	0 Bbls Oil 2.38 BCF 6,957 Bbls Wtr	0 8 0	Producing
Buzzard Creek (Wasatch, Mesaverde)	1955	0 Bbls Oil 7.10 BCF 174 Bbls Wtr	0 0 0	No Production Last 4 Months of 1995
DeBeque (Mesaverde)	1902	112 Bbls Oil 0.82 BCF 4,622 Bbls Wtr	0 2 0	Producing
Divide Creek (Mesaverde)	1956	737 Bbls Oil 58.69 BCF 4,933,187 Bbls Wtr	0 7 0	Producing

TABLE 1.1B

Field (prod. horizons)	Disc.	Cum. Prod.	Current Prod. Wells	Status
Grand Valley (Wasatch, Mesaverde)		SEE TABLE 1.2		
Logan Wash (Mesaverde)	1982	179 Bbls Oil 1.63 BCF 11,861 Bbls Wtr	0 5 0	Producing
Mam Creek (Mesaverde)	1959	42,160 Bbls Oil 8.73 BCF 114,983 Bbls Wtr	0 36 0	Producing
Parachute (Wasatch, Mesaverde)		SEE TABLE 1.2		
Piceance Creek (Wasatch, Mesaverde)	1930	141,515 Bbls Oil 235.95 BCF 896,186 Bbls Wtr	0 41 0	Producing
Piceance Creek South (Wasatch)	1954	564 Bbls Oil 2.47 BCF 2,034 Bbls Wtr	0 0 0	No Production in December, 1995
Plateau (Mesaverde, Dakota)	1958	11,741 Bbls Oil 29.28 BCF 358,992 Bbls Wtr	0 75 0	Producing

TABLE 1.1C

Field (prod. horizon)	Disc.	Cum. Prod.	Current Prod Wells	Status
Rulison (Wasatch, Mesaverde)		SEE TABLE 1.2		
Sheep Creek (Mesaverde)	1985	0 Bbls Oil 0.29 BCF 8,033 Bbls Wtr	0 0 0	No Production in 1995
Shire Gulch (Mesaverde, Dakota)	1960	2,776 Bbls Oil 24.80 BCF 81,408 Bbls Wtr	0 67 0	Producing
Sulphur Creek (Wasatch, Mesaverde)	1955	7,583 Bbls Oil 8.25 BCF 3,231 Bbls Wtr	0 16 0	Producing
Sulphur Creek South (Mesaverde)	1957	6 Bbls Oil 0.43 BCF 0 Bbls Wtr	0 6 0	Producing
Vega (Mesaverde)	1977	227 Bbls Oil 0.21 BCF 2,057 Bbls Wtr	0 0 0	No Production in 1995
White River (Wasatch, Mesaverde)	1890	138,503 Bbls Oil 20.79 BCF 898,787 Bbls Wtr	0 28 0	Producing

Field (prod. horizon)	Disc.	Cum. Prod.	Current Prod Wells	Status
Wolf Creek (Mesaverde)	1960	0 Bbls Oil 2.68 BCF 0 Bbls Wtr	0 0 0	No Production in 1995

Source: Petroleum Information Corp.

TABLE 1.2

PRODUCTION SUMMARY

WASATCH/MESAVERDE GAS FIELDS ADJACENT TO NOSR-3

INCLUDES WELLS WITHIN NOSR-3 ITSELF

(Through December, 1995)

Field	Disc.	Cum. Prod.	Current Prod. Wells	Status
Grand Valley	1986	15,084 Bbls Oil	0	Producing
		36.14 BCF	6	
		200,520 Bbls Water	0	
Parachute	1985	3,863 Bbls Oil	0	Producing
		37.92 BCF	19	
		47,394 Bbls Water	0	
Rulison	1956	98,347 Bbls Oil	0	Producing
		46.00 BCF	55	
		435,520 Bbls Water		

Source: Petroleum Information Corporation

Wasatch Formation

The main producing Wasatch reservoir is the "G" sand of the Molina Member (Figure 1.11). In the NOSR 1 and 3 area it is the most consistently developed sand in the Wasatch. Other stray sands are present but cannot be mapped with any degree of confidence. Table 1.3 (Fouch et al., 1994) summarizes the reservoir properties for the various gas reservoirs at fields adjacent to NOSR 1 and 3. As noted earlier, the "G" sand can vary from less than 30 feet to more than 100 feet in thickness but averages about 70 feet (LaFreniere, 1994). In general, the "G" sand log-

TABLE 1.1A

PRODUCTION SUMMARY

SELECTED TERTIARY AND UPPER CRETACEOUS GAS FIELDS,

PICEANCE BASIN, COLORADO

(Through December, 1995)

Field (prod. horizons)	Disc.	Cum. Prod.	Current Prod. Wells	Status
Baldy Creek (Mesaverde)	1959	0 Bbls Oil 0.42 BCF 25,435 Bbls Wtr	0 0 0	No Production in 1995
Brush Creek (Mesaverde)	1985	0 Bbls Oil 0.73 BCF 11,948 Bbls Wtr	0 0 0	No Production December, 95
Buzzard (Mesaverde)	1958	0 Bbls Oil 2.38 BCF 6,957 Bbls Wtr	0 8 0	Producing
Buzzard Creek (Wasatch, Mesaverde)	1955	0 Bbls Oil 7.10 BCF 174 Bbls Wtr	0 0 0	No Production Last 4 Months of 1995
DeBeque (Mesaverde)	1902	112 Bbls Oil 0.82 BCF 4,622 Bbls Wtr	0 2 0	Producing
Divide Creek (Mesaverde)	1956	737 Bbls Oil 58.69 BCF 4,933,187 Bbls Wtr	0 7 0	Producing

TABLE 1.1B

Field (prod. horizons)	Disc.	Cum. Prod.	Current Prod. Wells	Status
Grand Valley (Wasatch, Mesaverde)		SEE TABLE 1.2		
Logan Wash (Mesaverde)	1982	179 Bbls Oil 1.63 BCF 11,861 Bbls Wtr	0 5 0	Producing
Mam Creek (Mesaverde)	1959	42,160 Bbls Oil 8.73 BCF 114,983 Bbls Wtr	0 36 0	Producing
Parachute (Wasatch, Mesaverde)		SEE TABLE 1.2		
Piceance Creek (Wasatch, Mesaverde)	1930	141,515 Bbls Oil 235.95 BCF 896,186 Bbls Wtr	0 41 0	Producing
Piceance Creek South (Wasatch)	1954	564 Bbls Oil 2.47 BCF 2,034 Bbls Wtr	0 0 0	No Production in December, 1995
Plateau (Mesaverde, Dakota)	1958	11,741 Bbls Oil 29.28 BCF 358,992 Bbls Wtr	0 75 0	Producing

TABLE 1.1C

Field (prod. horizon)	Disc.	Cum. Prod.	Current Prod Wells	Status
Rulison (Wasatch, Mesaverde)		SEE TABLE 1.2		
Sheep Creek (Mesaverde)	1985	0 Bbls Oil 0.29 BCF 8,033 Bbls Wtr	0 0 0	No Production in 1995
Shire Gulch (Mesaverde, Dakota)	1960	2,776 Bbls Oil 24.80 BCF 81,408 Bbls Wtr	0 67 0	Producing
Sulphur Creek (Wasatch, Mesaverde)	1955	7,583 Bbls Oil 8.25 BCF 3,231 Bbls Wtr	0 16 0	Producing
Sulphur Creek South (Mesaverde)	1957	6 Bbls Oil 0.43 BCF 0 Bbls Wtr	0 6 0	Producing
Vega (Mesaverde)	1977	227 Bbls Oil 0.21 BCF 2,057 Bbls Wtr	0 0 0	No Production in 1995
White River (Wasatch, Mesaverde)	1890	138,503 Bbls Oil 20.79 BCF 898,787 Bbls Wtr	0 28 0	Producing

Field (prod. horizon)	Disc.	Cum. Prod.	Current Prod Wells	Status
Wolf Creek (Mesaverde)	1960	0 Bbls Oil 2.68 BCF 0 Bbls Wtr	0 0 0	No Production in 1995

Source: Petroleum Information Corp.

TABLE 1.2

PRODUCTION SUMMARY

WASATCH/MESAVERDE GAS FIELDS ADJACENT TO NOSR-3

INCLUDES WELLS WITHIN NOSR-3 ITSELF

(Through December, 1995)

Field	Disc.	Cum. Prod.	Current Prod. Wells	Status
Grand Valley	1986	15,084 Bbls Oil	0	Producing
		36.14 BCF	6	
		200,520 Bbls Water	0	
Parachute	1985	3,863 Bbls Oil	0	Producing
		37.92 BCF	19	
		47,394 Bbls Water	0	
Rulison	1956	98,347 Bbls Oil	0	Producing
		46.00 BCF	55	
		435,520 Bbls Water		

Source: Petroleum Information Corporation

Wasatch Formation

The main producing Wasatch reservoir is the "G" sand of the Molina Member (Figure 1.11). In the NOSR 1 and 3 area it is the most consistently developed sand in the Wasatch. Other stray sands are present but cannot be mapped with any degree of confidence. Table 1.3 (Fouch et al., 1994) summarizes the reservoir properties for the various gas reservoirs at fields adjacent to NOSR 1 and 3. As noted earlier, the "G" sand can vary from less than 30 feet to more than 100 feet in thickness but averages about 70 feet (LaFreniere, 1994). In general, the "G" sand log-

TABLE 1.3

Reservoir data for fields adjacent to NOSR 1–3

Field/Reservoirs	Location	Prod.	Net Pay	Porosity	Perm	Sw	Spacing	Pressure (drilling-mud density)	Reference
			ft	%	md	%	acres		
NOSR 1 - 3									
Grand Valley	T. 6-7 S. R. 94-96 W.	gas				40 av	160-210		Reinecke et al., 1991
Wasatch ("G" sand)		gas	<75 31 av	9-18 (log) av 14	——	——	——	normal	
Mesaverde		gas	260	10-12 log 7-9 core	<0.1	——	——	over	
Cameo Coals		gas	50-70	——	0.02-0.2	——	——	over	
Dakota		gas	30	6-20 (log)	——	——	——	normal	
Rulison	T. 6-7 S. R 93-94 W.						320/640		Martinez and Duey, 1982
Wasatch		gas	70 av	6.5 (core)	<0.1-.2	28-70	——	normal	
Mesaverde		gas	400 av	8-16 (log)	<0.1	30-100	——	over	CER, 1984; Finley, 1984; Kukal, 1987, 1989, 1990

(after Fouch et al., 1994)

derived porosity averages about 14 percent but can be as high as 18 percent (USGS). Core-derived porosities at Rulison Field average 6.5 percent (LaFreniere, 1994). Permeabilities are generally less than 1.0 millidarcy. For example, at Rulison Field the permeability ranges from 0.06 to 0.25 millidarcies (LaFreniere, 1994), and from a permeability standpoint these are therefore "tight" gas sands. Figure 1.24 is a net (>10 percent porosity) sand isopach map for the "G" sand. From this map it is apparent that there is a great deal of variability in thickness, and changes can occur abruptly between offset wells. The same is true for isopach maps of density-neutron gas crossover (Figure 1.25) and estimated ultimate gas recovery (EUR; Figure 1.26). It is apparent from this set of three maps that care must be taken in choosing a single value for "average" net pay or "average" EUR for projecting resources under large undrilled areas such as NOSR-1.

NOSR-1 is a very large area with no well control for directly evaluating the Wasatch potential. It is therefore extremely important to analyze wells that have been drilled close to its perimeters. Barrett Resources drilled four wells in the Schutte Creek and Redpoint areas within three miles of the northwestern corner and western boundary of NOSR-1 (Plate 1). All of these wells were drilled to a sufficient depth to penetrate the Wasatch "G" interval but none were drilled deep enough to reach the potential middle and lower Mesaverde reservoirs.

Stratigraphic cross section A-A' documents the presence of thick "G" sands to the northwest of NOSR-1 and correlates them with the producing sands at Parachute Field in the NOSR-3 area. "G" sandstones can reasonably be anticipated beneath NOSR-1 lands. However, as indicated earlier, permeability is difficult to predict with any degree of certainty in the undrilled areas. Neither the Schutte Creek wells nor the Redpoint well were successfully completed as gas producers even though they generally show good sand development with log characteristics similar to producing wells to the south. None of them display significant gas crossover similar to the Barrett Arco Tosco #14-34 well, an exceptionally good Wasatch producer in the Parachute Field. However, they do demonstrate gas effect similar to the Barrett Allen Point #1-8-95 and #3-8-95 wells which range from poor to average producers.

WASATCH FORMATION-ISOPACH NET 8% POROSITY "G" SANDS (PERFORATED INTERVAL)

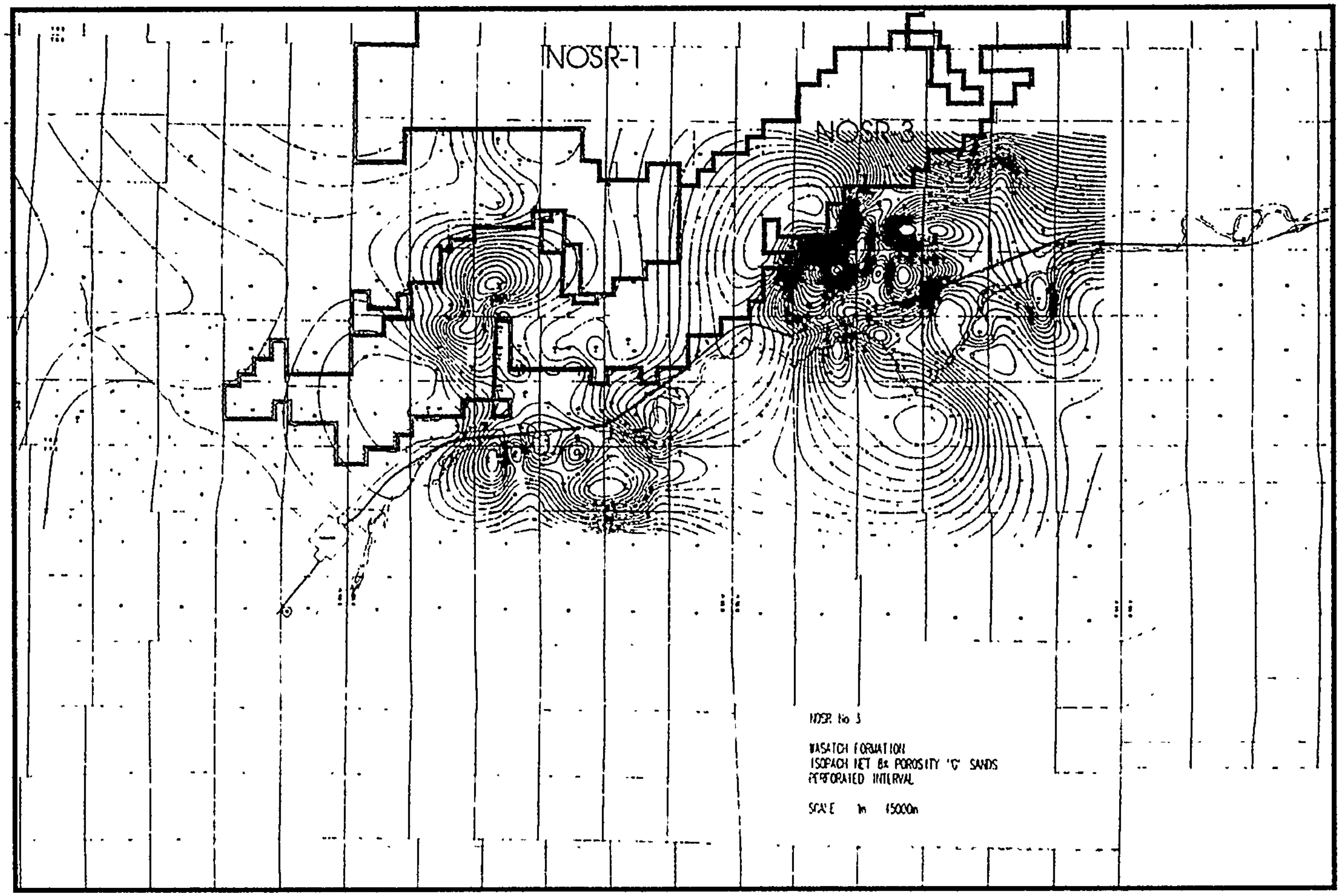
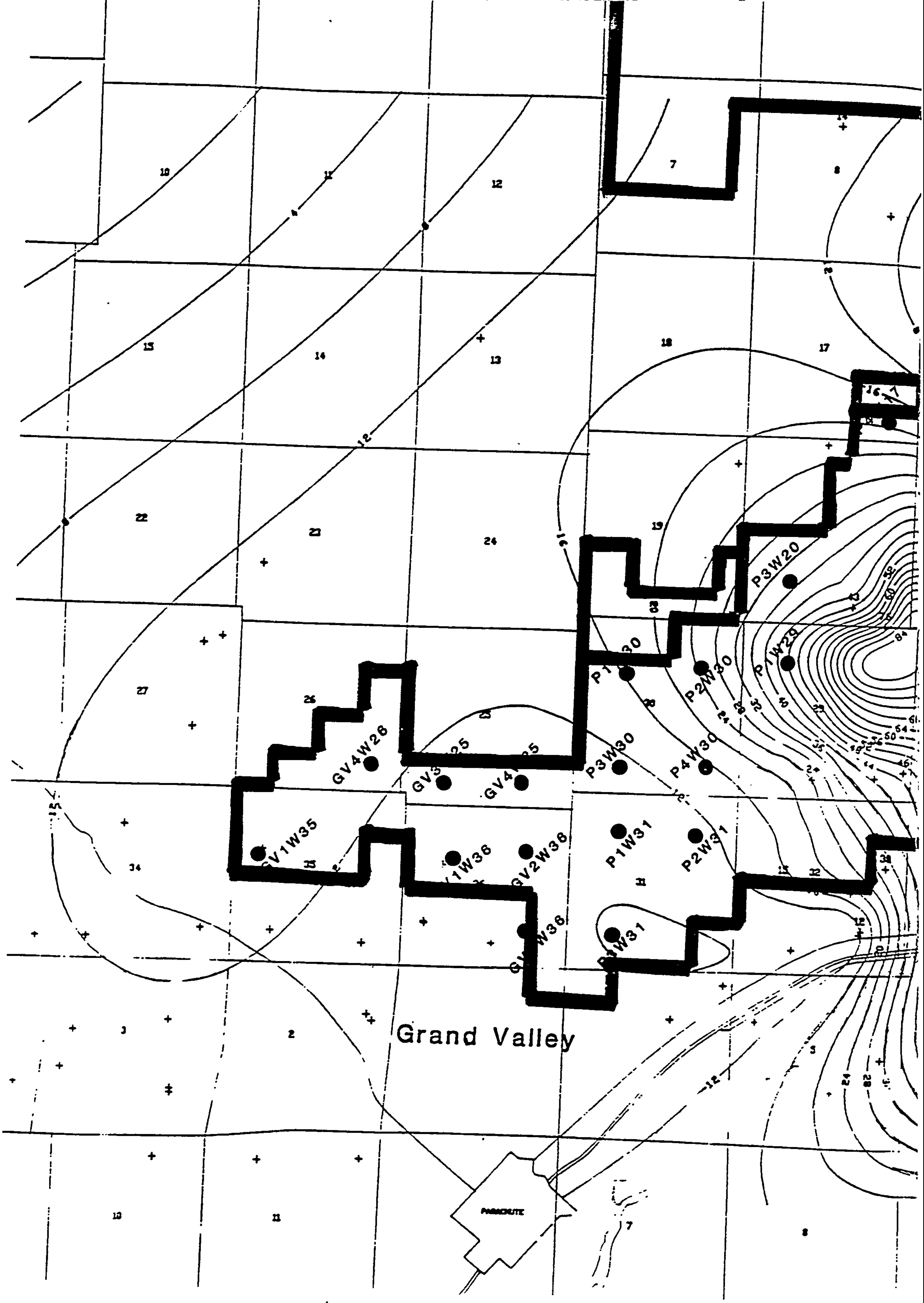


FIGURE 1.24

(after LaFreniere, 1994)



GV4W26
GV1W35
GV2W36
P3W30
P4W30
P2W30
P3W20
P1W31
P2W31
Grand Valley
PARACHUTE

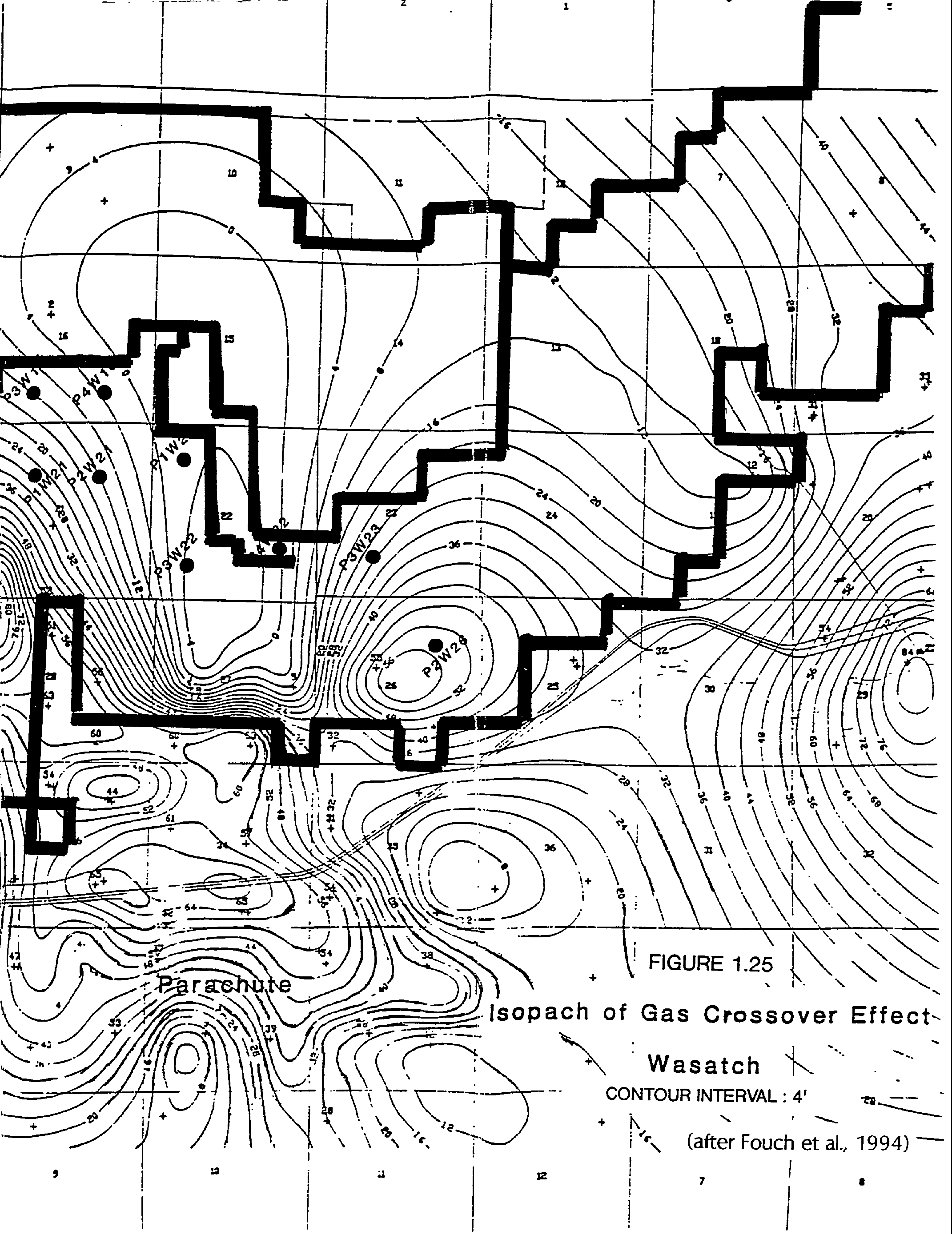


FIGURE 1.25

Isopach of Gas Crossover Effect

Wasatch

CONTOUR INTERVAL : 4'

(after Fouch et al., 1994)

WASATCH FORMATION-ESTIMATED ULTIMATE RECOVERY-MCF

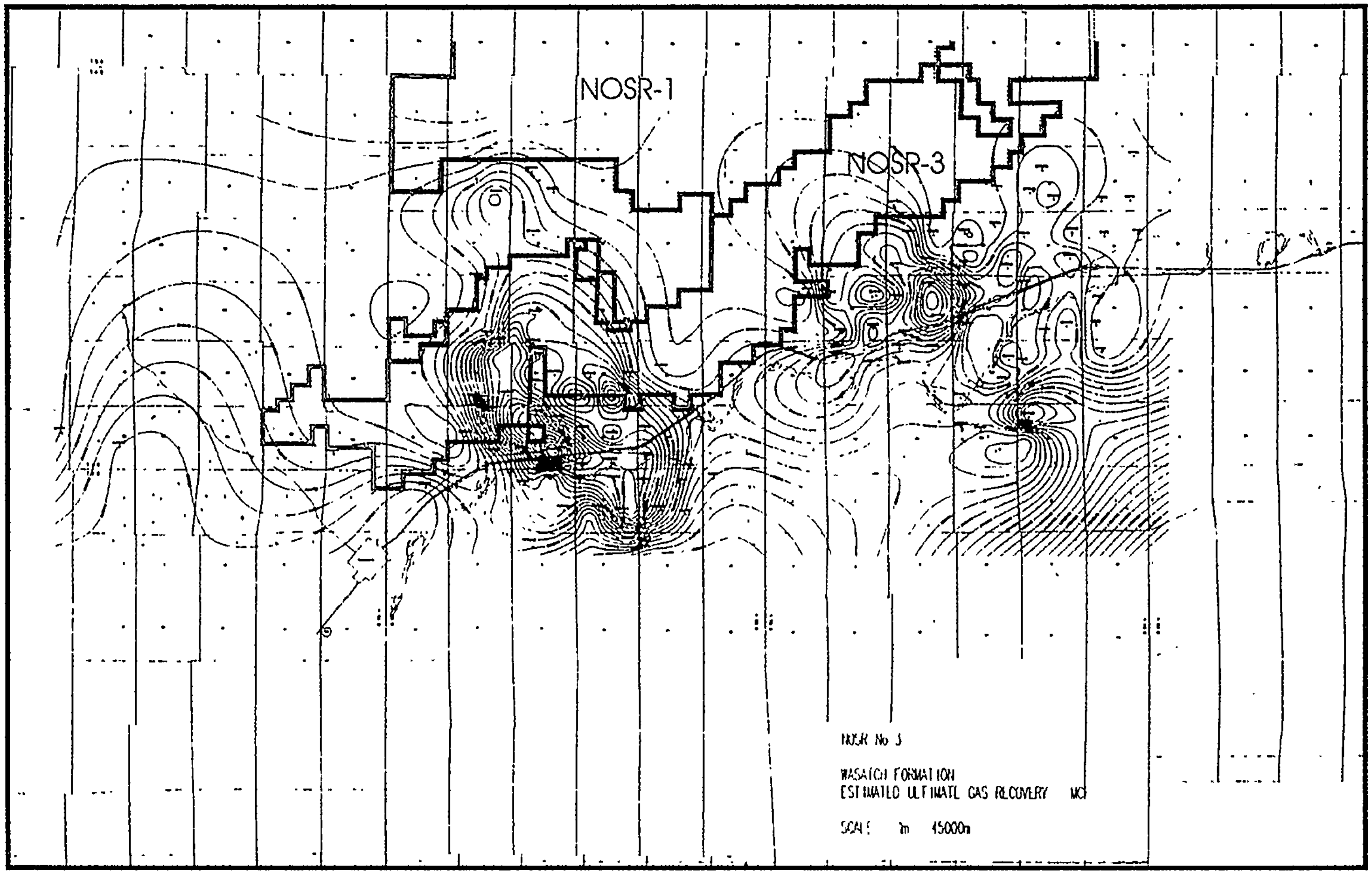


FIGURE 1.26

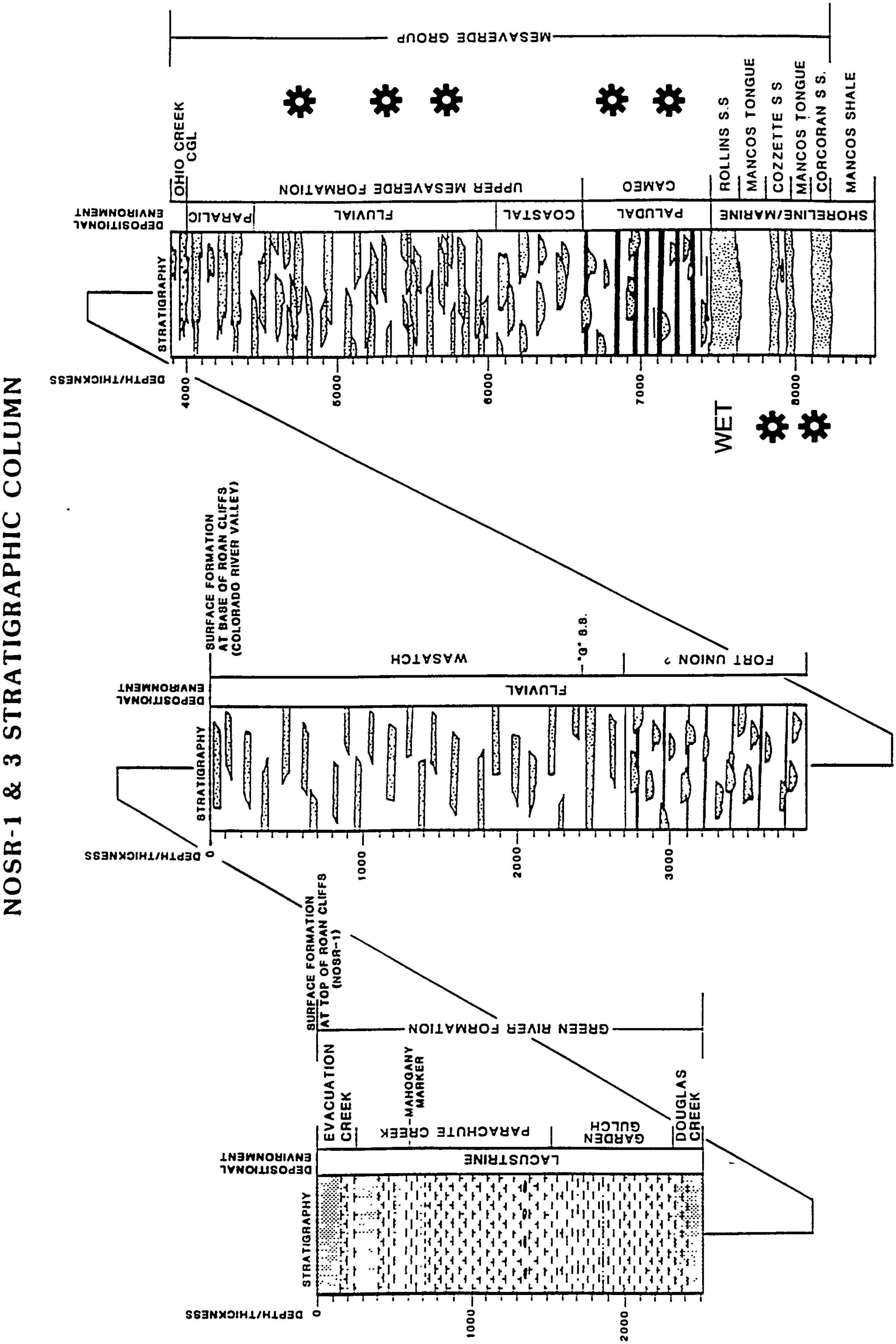
(after LaFreniere, 1994)

Industry scout information indicates that the Schutte Creek #1-32 well was given a hydraulic fracture treatment of similar magnitude to commercial producers at Parachute Field. Discussions with Barrett Resources revealed that noncommercial gas flows were gauged on some of the Schutte Creek wells. These wells are in a remote location with respect to pipelines. Barrett indicated that both the remoteness and low gas prices were factors in the decision to abandon the wells. Noncommercial water-free gas flows from the underlying Ft. Union equivalent (Atwell Gulch Member of Wasatch) supports the validity of a gas-saturated condition at Schutte Creek, and by inference, under NOSR-1.

Assuming that there is a good possibility for the occurrence of gas-saturated "G" sand beneath NOSR-1, then permeability enhancement by natural fracturing may be necessary for realizing commercial Wasatch production on NOSR-1. Based on this criteria, the best area for exploring the Wasatch on NOSR-1 would be over the seismically-defined closure in the eastern part of the Reserve (Plate 1). This structural feature is the best target or prospect for continued exploration of "tight" gas sand accumulations within NOSR-1.

Mesaverde Group

Gas reservoirs in the Mesaverde Group occur throughout the gas-saturated portion of the section. Gas-saturated rock encompasses all but the upper few hundred feet of the Williams Fork Formation and most of the underlying Iles Formation. In the Williams Fork Formation isolated and stacked channel sands form reservoirs in the middle fluvial and coastal portions of the formation (Figure 1.27). LaFreniere (1994) reports that there appears to be a direct relationship between thickening in these zones and higher gas production. In the lower paludal Cameo coal zone, gas reservoirs consist of both interlayered channel sands and the coalbeds themselves. During the period of time of tax credits for coalbed methane (CBM) development, wells were deliberately drilled and completed in the coals. According to the Colorado Oil and Gas Commission, most Mesaverde zones are commingled so that the distinction between CBM wells and tight sand completions within the Cameo zone is disappearing.



NOSR-1 & 3 STRATIGRAPHIC COLUMN
MESAVERDE GROUP
DEPTH/THICKNESS
STRATIGRAPHY
DEPOSITIONAL ENVIRONMENT
PARALIC
FLUVIAL
COASTAL
PALUDAL
SHORELINE/MARINE
OHIO CREEK CGL
UPPER MESAVERDE FORMATION
CAMEO
ROLLINS S.S
MANCOS TONGUE
COZZETTE S S
MANCOS TONGUE
CORCORAN S S.
MANCOS SHALE
4000
5000
6000
7000
8000
WET
SURFACE FORMATION AT BASE OF ROAN CLIFFS (COLORADO RIVER VALLEY)
WASATCH
'G' S.S.
FORT UNION ?
FLUVIAL
0
1000
2000
3000
SURFACE FORMATION AT TOP OF ROAN CLIFFS (NOSR-1)
GREEN RIVER FORMATION
EVACUATION CREEK
MAHOGANY MARKER
PARACHUTE CREEK
GARDEN GULCH
DOUGLAS CREEK
LACUSTRINE
0
1000
2000

FIGURE 1.27

Like the Wasatch, the Mesaverde is highly variable. As indicated earlier, it is common for sand reservoirs in one well to not be in pressure communication with sands in a 40-acre offset well. This is due to rapid stratigraphic changes and has resulted in approval for a downspacing for Williams Fork wells to 40-acre spacing. Unlike the Wasatch "G" sand, individual sands cannot be mapped with any degree of certainty. Therefore, in the previous work conducted by Fluor Daniel, all of the sands in a given well were combined in order to generate cumulative net sand isopachs and isopachs of cumulative feet of density-neutron gas cross-over. These values were then used for estimating net feet of gas pay. In addition, cumulative production and EUR maps were constructed to aid in evaluating field extensions for NOSR-3. Figures 1.28 and 1.29 demonstrate the variability in reservoir quality which in turn affects the estimated recovery of gas. As with the Wasatch, care must be taken when trying to estimate ultimate gas recovery for an "average" well in the area. Uncertainties are compounded by the fact that NOSR-1 is basically undrilled and there is no well control immediately to the north which penetrates the Mesaverde Formation.

Most of the Mesaverde production to date has been from the Williams Fork Formation. The underlying blanket sands of the marine Iles Formation (Figure 1.30) have also been the targets of a limited number of wells in the vicinity of NOSR-3 which resulted in at least two gas wells. Regionally, the Iles Formation produces gas at a number of fields in the Piceance Basin (Figure 1.31 and Table 1.4). In Rulison Field, the Clough #21 well IP'd for 600 MCFGD from the Corcoran and was dually completed with overlying Williams Fork zones. In Parachute Field the GV 46-32 Exxon well flowed 215 MCFGD and was also dual completed with Williams Fork. At least two horizontal wells have been drilled in the Cozzette Sand with mixed results including some water influx in one of the wells. This water was not encountered in the vertical producers. In general, the uppermost Iles member, the Rollins Sandstone, is wet possibly due to better porosity and permeability and the influx of water from updip. However, LaFreniere (1994) reports the completion of one Rollins gas well on NOSR-3. The marine Mesaverde (Iles) sands have reasonably good porosity (Corcoran 4 to 17 percent, Cozzette 2.6 to 18 percent; (LaFreniere, 1993). Permeabilities, however, are extremely low (0.002 to 0.08 millidarcies). The Cozzette and Corcoran sands may be good future horizontal targets for operators looking to improve

WILLIAMS FORK FORMATION (MESAVERDE)-ISOPACH NET 10% POROSITY (PERF'D AND NON-PERF'D INTERVALS)

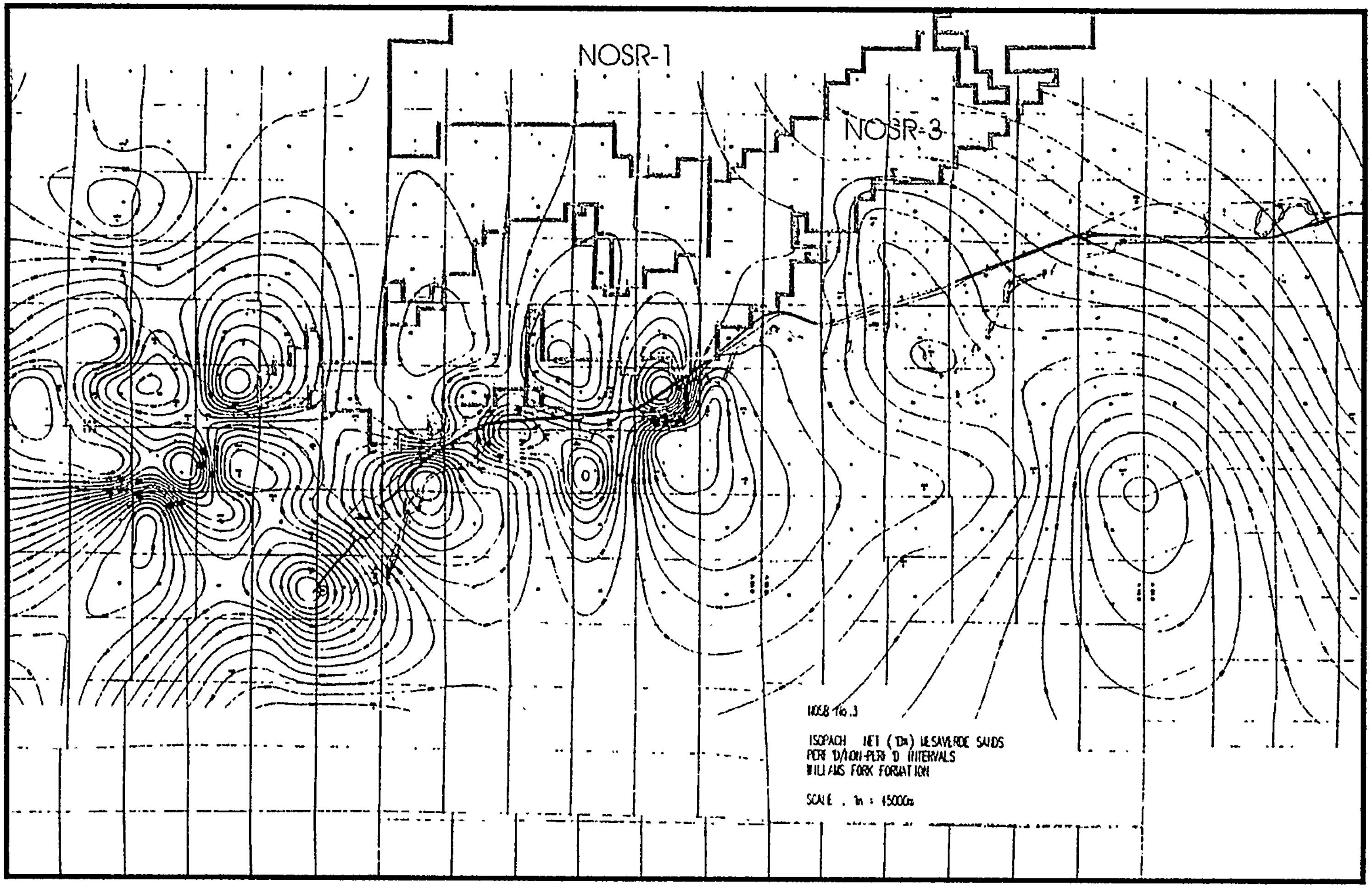
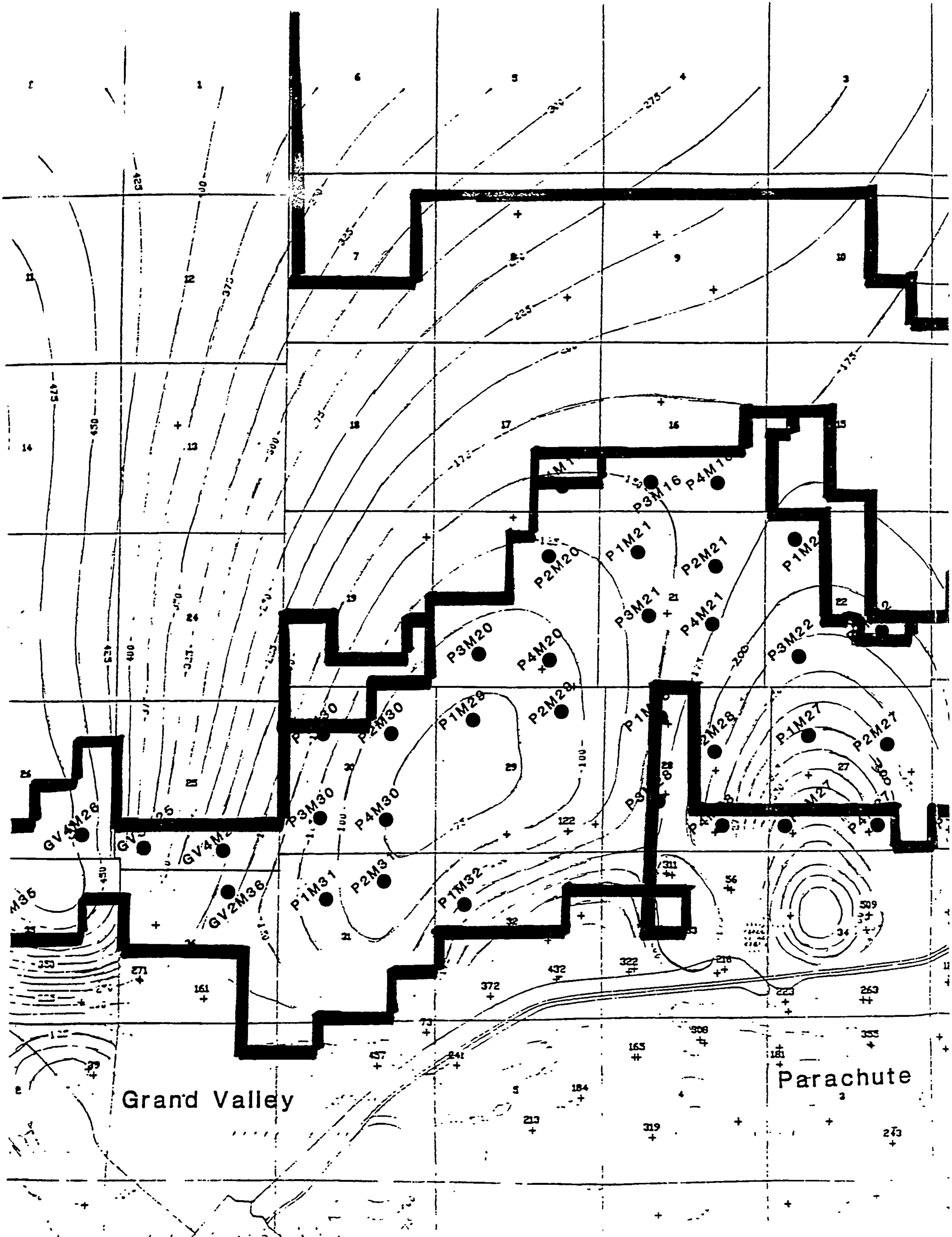


FIGURE 1.28

(after LaFreniere, 1994)



Grand Valley
Parachute
P3M16
P4M16
P1M21
P2M21
P2M20
P3M21
P4M21
P3M20
P4M20
P3M22
P1M27
P2M27
P1M29
P2M29
P2M30
P3M30
P4M30
P1M31
P2M31
P1M32
GV4M26
GV2M36

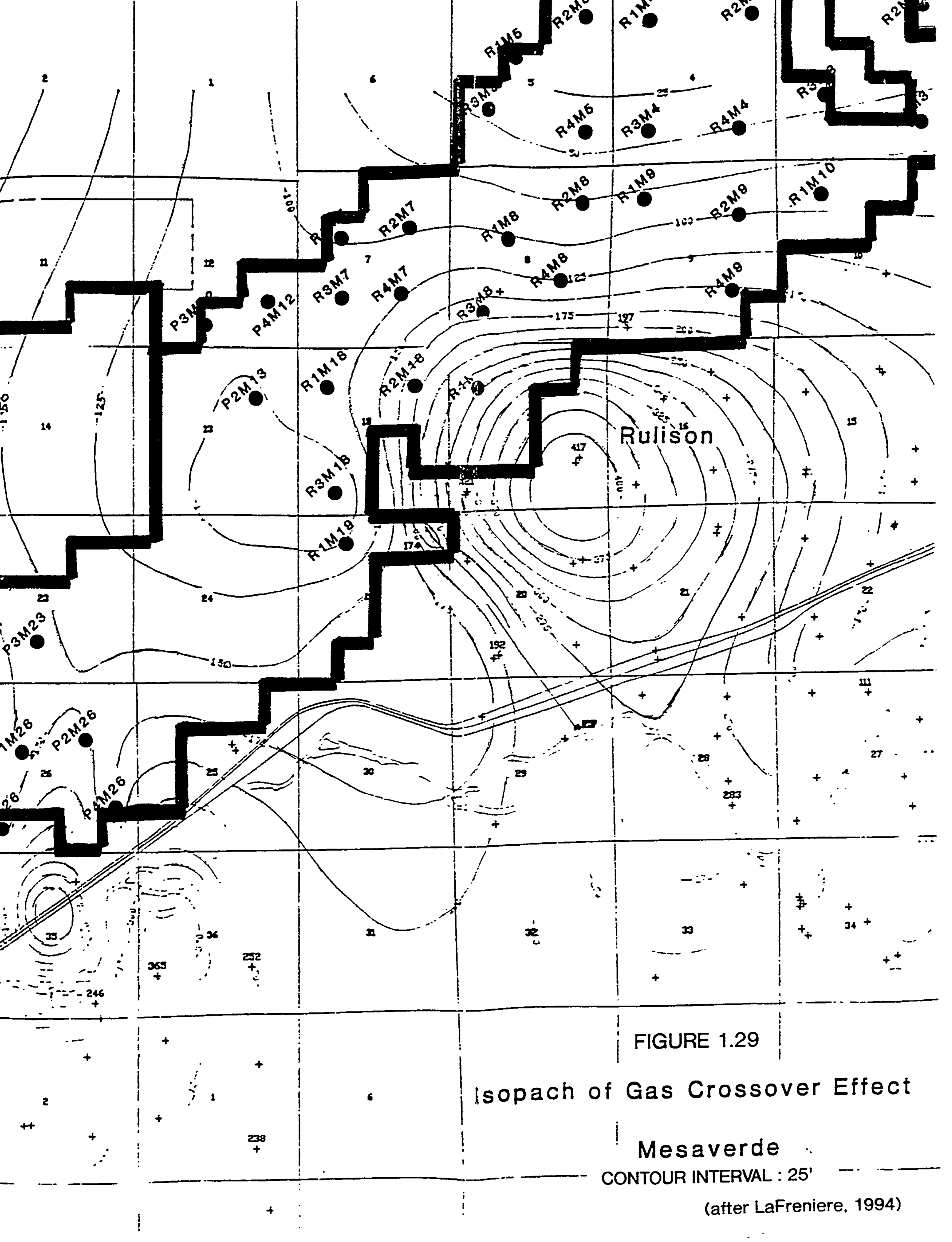


FIGURE 1.29

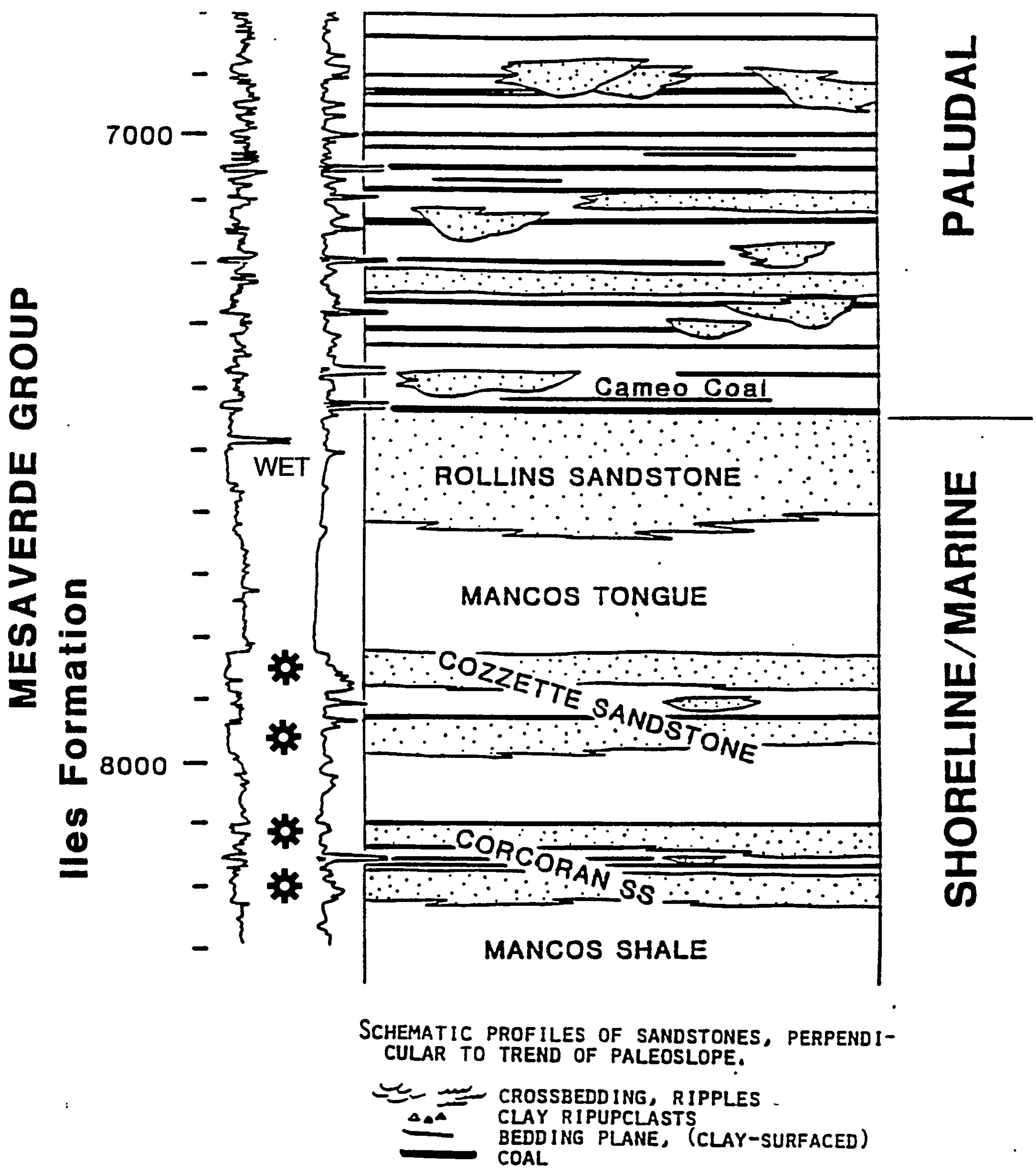
Isopach of Gas Crossover Effect

Mesaverde

CONTOUR INTERVAL : 25'

(after LaFreniere, 1994)

ILES FORMATION NOMENCLATURE AND DEPOSITIONAL ENVIRONMENTS



(after LaFreniere, 1993)

FIGURE 1.30

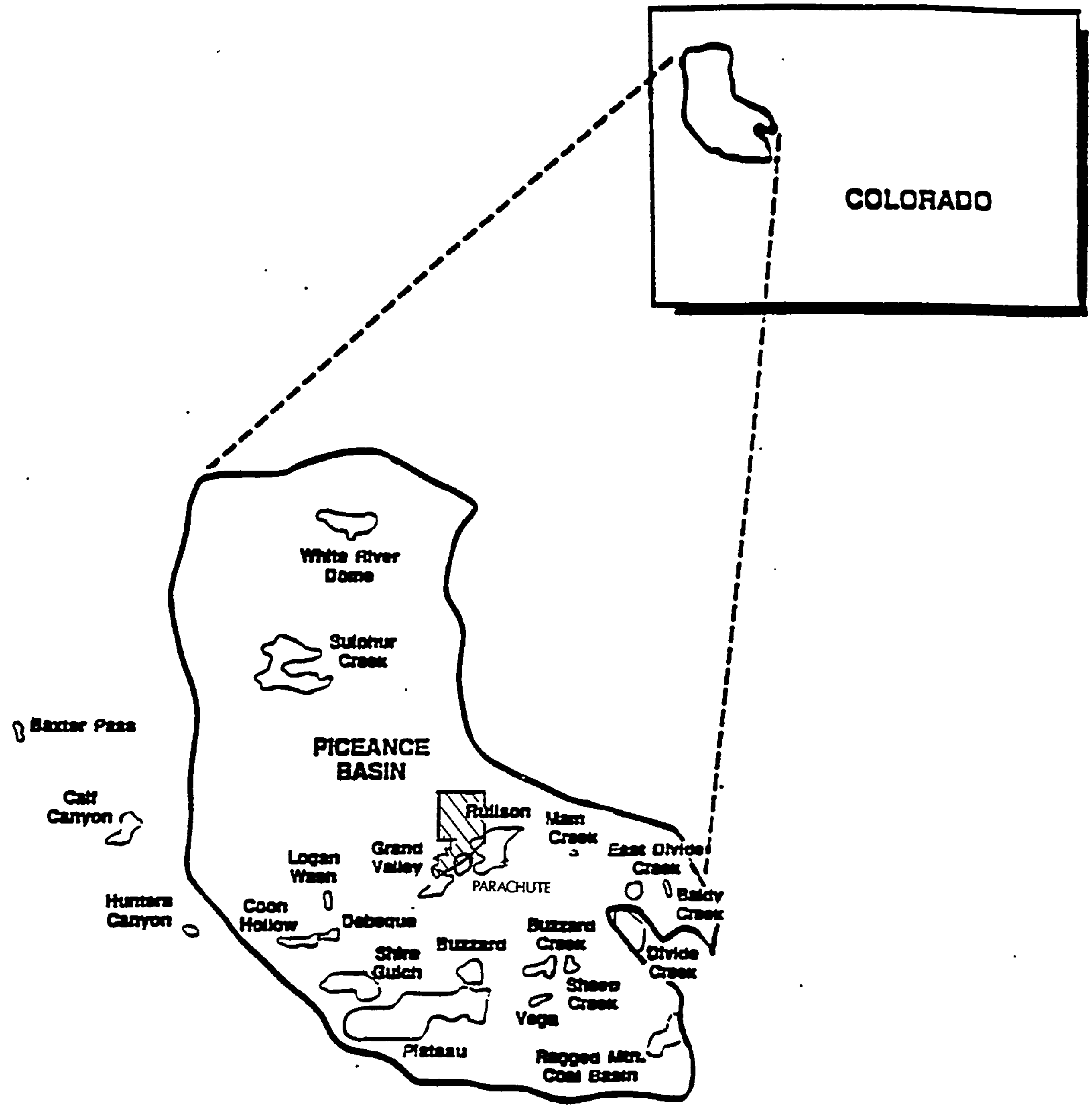


FIGURE 1.31– Piceance Basin of Colorado Showing Mesaverde Gas Fields and NOSR 1–3 Location. Fields with Iles production are highlighted (after LaFreniere, 1993).

TABLE 1.4A

PRODUCTION SUMMARY

FIELDS PRODUCING FROM ILES FORMATION-

ROLLINS, COZZETTE AND CORCORAN MEMBERS

(Through December, 1995)

Field	Disc.	Cum. Prod.	Current Prod Wells	Status
Baldy Creek CZ/CR Southeast	1959	0 Bbls Oil .42 BCF 25,435 Bbls Water	0 0 0	No Production in 1995
Brush Creek MV/CZ/CAM/CR Southwest	1985	0 Bbls Oil .73 BCF 11,948 Bbls Water	0 0 0	No Production in 1995
Buzzard MVRD/CR/CZ Southwest	1958	0 Bbls Oil 2.38 BCF 6,957 Bbls Water	0 8 0	Producing
Buzzard Creek MV/CR/CZ/WSTC Central	1955	0 Bbls Oil 7.1 BCF 174 Bbls Water	0 0 0	No Prod Last Four Mths. in 95
DeBeque MVRD/CR/CZ/R	1902	112 Bbls Oil .82 BCF 4,622 Bbls Water	0 2 0	Producing
Divide Creek MVRD/CAM/CR/CZ/ Southeast	1956	737 Bbls Oil 58.9 BCF 4,933,187 Bbls Water	0 7 0	Producing

TABLE 1.4B

Field	Disc.	Cum. Prod.	Current Prod Wells	Status
Logan Wash CZ/CR/MV/R Undefined	1982	179 Bbls Oil 1.63 BCF 11,861 Bbls Water	0 5 0	Producing
Mam Creek CAM/RL/CR/MV Central	1959	42,160 Bbls Oil 8.3 BCF 114,983 Bbls Water	0 36 0	Producing
Plateau CR/CZ/R/MV/DKTA Southwest	1958	11,741 Bbls Oil 29.3 BCF 358,992 Bbls Water	0 75 0	Producing
Shire Gulch CR/MVRD/CZ/FR/DKTA/R Southwest	1960	2,776 Bbls Oil 24.8 BCF 81,408 Bbls Water	0 67 0	Producing
Vega MV/CZ Central	1977	227 Bbls Oil .21 BCF 2,057 Bbls Water	0 0 0	No Prod. in 1995
Wolf Creek Undefined	1960	0 Bbls Oil 12.7 BCF 0 Bbls Water	0 0 0	No Prod. in 1995

Source: Petroleum Information Corp. (modified and updated from LaFrenier, 1994) permeability by encountering vertical fractures. However, this is not considered economically feasible nor technically viable due to current gas prices, horizontal well costs, and anticipated completion problems.

1.4.5.4 Published Reserves and Resources (Wasatch and Mesaverde)

A detailed evaluation and estimation of total estimated gas reserves and resources by category will be discussed in the Reserves section of the report. In this section, only a summary of the basic methodology and summary reserve numbers will be reviewed. Two separate approaches were used by the U.S. Geological Survey (Fouch et al., 1994) and Fluor Daniel (LaFreniere, 1994) in estimating reserves on the NOSR 1 and 3 sites. The U.S. Geological Survey used a rather comprehensive probabilistic approach using an in-house computer program that was developed for evaluating resources on a "play" basis. Their probabilistic resource analysis was initially tied to analog production performance (decline curve projections) of existing wells which met certain criteria and were then assumed to be representative of play resources. A probability distribution of an EUR per well was projected and used as one variable in their statistical analysis. Other probability distributions used to define the geologic model included number of "cells" (i.e., well spacings) in a given play, number of untested cells, number of untested productive cells, and probabilities of play success. A detailed description of the methodology is found in Fouch et al., (1994). In this report, the results were listed for various confidence levels in the probabilistic approach. It is important to keep in mind that this approach does not use basic reservoir engineering volumetric data such as porosity, thickness, and gas-saturation. The USGS comments that, where available, detailed engineering-derived EUR's should be used to more precisely estimate resources.

The USGS evaluated five plays for NOSR 1 and 3. Four assumed the continuous gas-saturated condition (Wasatch, Mesaverde, Mancos, and Dakota/Morrison) and the fifth evaluated the deep Paleozoic play. Their analysis predicted that only the gas-saturated Wasatch and Mesaverde plays would be economic for exploration and development. The summary of their probabilistic modeling is shown in Table 1.5. Average EUR per well numbers were the basis for the listed

TABLE 1.5

Resources (potential additions to reserves) of Nonassociated Gas In Naval Oil Shale Reserves.

Mean	Std Dev	F95	F75	F50	F25	F05	EUR/well (mean)	Comment
				Naval Oil Shale Reserve 1, Colorado				
Play 2007 Mesaverde								
Gas in billions of cubic feet								
670	203	393	524	641	783	1044	1.88	80 acre spacing
321	119	167	236	301	383	542	1.88	160 acre spacing
Play 2008 Wasatch Formation			**Revised 4/20/94**					
Gas in billions of cubic feet								
144.8	44.5	84.4	113	138.4	169.6	227	0.7	
Play 2005P Paleozoic Strata Gas								
Gas in billions of cubic feet]								
0.48	0.472	0	0.19	0.37	0.64	1.35	0.2	
Play 2011P Dakota & Morrison Gas saturated								
Gas in billions of cubic feet								
47.46	18.33	23.98	34.43	44.28	56.94	81.76	0.28	
Play 2021P Mancos & Assoc. Gas Saturated								
Gas in billions of cubic feet								
3.4	1.68	1.4	2.22	3.04	4.18	6.6	0.2	
				Naval Oil Shale Reserve 3, Colorado				
Play 2007 Mesaverde Gas Saturated								
Gas in billions of cubic feet								
315	97	184	246	302	369	493	1.88	80 acre spacing
198	123	66	114	168	247	430	1.88	160 acre spacing
Play 2008 Wasatch Formation								
Gas in billions of cubic feet								
63.1	24.3	31.96	45.84	58.9	75.67	108.5	0.7	
Play 2005P Paleozoic Strata Gas								
Gas in billions of cubic feet								
0.23	0.31	0	0	0.15	0.33	0.8	0.2	
Play 2011P Dakota & Morrison Gas saturated								
Gas in billions of cubic feet								
22.76	9.23	11.1	16.21	21.09	27.44	40.08	0.2	
Play 2021P Mancos & Assoc. Gas Saturated								
Gas in billions of cubic feet								
1.63	0.98	0.55	0.96	1.39	2.04	3.5	0.2	

(after Fouch et al., 1994)

"mean" projected resources across undrilled portions of NOSR 1 and 3. The projected resources were then used in the economic analysis of Alternative Development Options for NOSR 1 and 2 (DOE, 1994).

The USGS used a mean EUR per well of 0.7 BCF for a 160-acre spaced Wasatch well; this value was derived from reserve reports prepared by Fluor-Daniel. Their "mean" Wasatch gas resources for NOSR 1&3 are 144.8 BCF and 63.1 BCF, respectively. For the Mesaverde, their mean EUR/well was 1.88 BCF. The USGS concluded in their report that Mesaverde wells may only be draining 80 acres rather than the original 160 acres. They listed results for both spacings (cell sizes), assigning the same EUR per well for both spacings. The USGS predicted that "mean" Mesaverde resources for NOSR-1 are 670 BCF (80-acre spacing) and 321 BCF (160-acre). Analogous Mesaverde resource figures for NOSR-3 are 315 BCF (80-acre) and 198 BCF (160-acre).

More recently, technical information presented at the Colorado Oil and Gas Commission hearings supports the possibility that Mesaverde gas wells may only be draining 40 acres in the vicinity of Parachute and Rulison Fields. The technical information further indicates that the EUR per well is 1.88 BCF for a 40 acre spacing. This would again increase estimated Mesaverde resources by a factor of two. No findings were presented for a 40-acre case.

Fluor Daniel used a more traditional engineering approach in their 1994 NOSR-3 Reserve Report. The methodology they used involved detailed well-by-well decline curve analysis and further statistical analysis of the data to arrive at an expected EUR per well. They related the EUR projections from decline curve analysis to the amount of prospective gas pay which was actually perforated and producing in the wellbore. Net gas pay was picked from density-neutron cross-over on petrophysical well logs. Based on statistical analysis of production data, a value for "mean" gas resource per foot of density-neutron cross-over was derived.

Based on this methodology, Fluor Daniel projected a recovery factor to 19 MMCFG/foot for the Wasatch "G" sand. This factor was then multiplied by an average of 38 feet of net gas pay for the Expected Wasatch EUR 0.722 BCF per well. For each undrilled location on NOSR-3, Fluor

Daniel calculated a *separate* Wasatch EUR based on the isopach map of density-neutron cross-over effect and the 19 MMCFG per foot recovery factor. The results for NOSR-3 (minus the northeast extension) are an estimated total resource of 13.766 BCF of Wasatch gas.

Fluor Daniel undertook a similar analysis for the Mesaverde Formation. The problem of non-perforated or behind-pipe pay in the Mesaverde is more severe here than in the Wasatch. Fluor Daniel assumed that only a limited amount of the potential gas pay (cross-over) was perforated in a given well. Therefore, decline curve-derived EUR's for this formation had to be normalized to 100 percent the expected EUR for 100 percent perforation of all potential pay. This method resulted in a Mesaverde per well recoverable reserve of 7 MMCFG per foot of gas crossover. For the "average" Mesaverde well with 252 feet of fully perforated pay, the expected EUR would be 1.764 BCF per well. This is somewhat less than the USGS estimate (1.88 BCF per well) but the difference is only seven percent. Fluor Daniel's estimated Mesaverde resource (using same methodology as for the Wasatch) for NOSR-3 is 84.168 BCF, including 10.738 BCF of behind-pipe reserves. A comparison of the USGS and Fluor Daniel resource estimates for NOSR-3 is shown in Table 1.6. No comparison can be made for NOSR-1 since Fluor Daniel did not evaluate those lands.

In their 1995 Addendum Report on NOSR-3, Fluor Daniel incorporated the USGS spacing of 80 acres for Mesaverde and 160 acres for Wasatch wells. They also added resources to the northeast extension of NOSR-3 using the USGS figures of 0.7 BCF (Wasatch) and 1.88 BCF (Mesaverde) for all locations greater than 1/2 mile from and existing well. For locations within 1/2 mile of existing production, Fluor Daniel used their earlier described method of calculating separate and variable per well reserves on the basis of recovery factor and the gas cross-over isopach map. Based on this blended methodology, they estimated NOSR-3 unrisked reserves as to ranging from 444 BCF to 467 BCF and risked reserves between 162 BCF and 353 BCF, depending on the particular case analyzed. Figure 1.32 is a reserve summary for the five cases they evaluated.

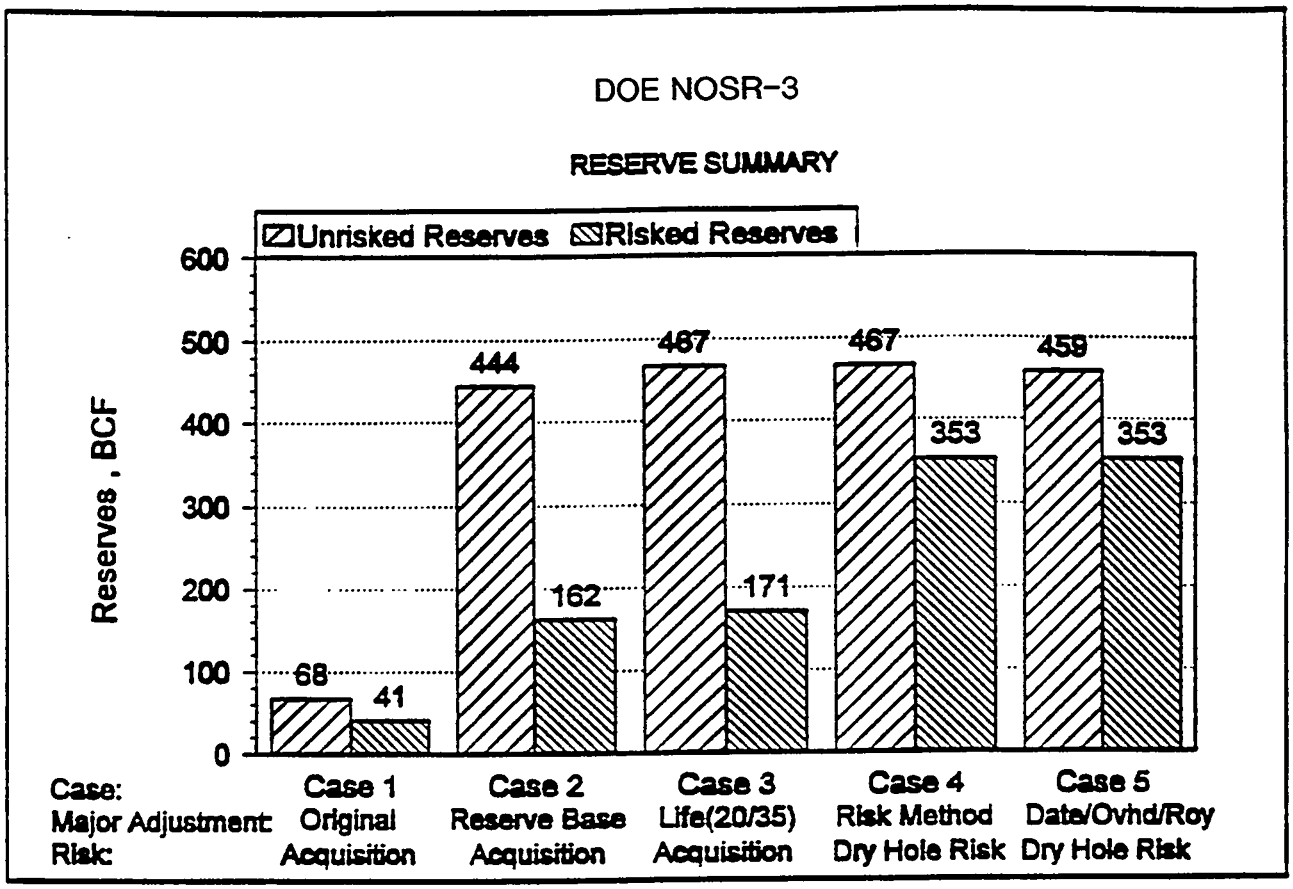


FIGURE 1.32-

Case 1 - The original NOSR-3 Alternative Development Study dated January 1994.

Case 2 - Adjustment for added development drilling as a result of the new reserve base and revised spacing.

Case 3 - Revise Case 2 from a 20 year project and well life to a 35 year project life and a 30 year Mesaverde well life.

Case 4 - Changes the method of risk assessment to utilize the probabilities of success determined by the USGS. Case 4 includes the changes of Cases 2 and 3 and in the focal point case of this study.

Case 5 - An informational case designed to be more consistent with the NOSR-1 and 2 Development Options Study. Case 5 revises the effective date forward to FY 1996 and makes other changes to enhance the marketability of non-DOE development options to private industry.

TABLE 1.6

COMPARISON OF RESOURCE (POTENTIAL ADDITIONS TO RESERVES) ESTIMATES FOR NOSR-3 (IN BCF)

Play	Fluor Daniel 1994 Report	USGS 1994 Open-File Report	Fluor Daniel Estimates as Percentage of USGS Estimates
Gas-Saturated Wasatch	13.8* (160 acre spacing)	63.1 (160 acre spacing)	21.9%
Gas-Saturated Mesaverde	84.2* (160 acre spacing)	198 (160 acre spacing)	42.5% (160 acre spacing for both)
		315 (80 acre spacing)	26.7% (160 acre spacing for FD versus 80 acre spacing for USGS)

* Fluor Daniel only considered resources (potential reserve additions) in productive southern and southeastern parts of NOSR-3. They assigned no resources (potential reserve additions) to the portions of NOSR-3 in Township 5S.

A further discussion of the adequacy and validity of these published EUR and total resource numbers -- and the conclusions of this Consultant as to the appropriate numbers to use for a fair market value appraisal -- are contained in the Reserves portion of this report.

1.4.5.5 Geologic Risking of Resources

It is common and prudent industry practice to geologically risk exploration and development prospects and plays in order to evaluate the economic feasibility of projects and to compare one project with another. Depending on company philosophy, geological risk can be evaluated using a variety of approaches ranging from highly quantitative methods to more qualitative ones Correctly-applied geological risking takes into account all of the geological variables including presence of source rock, reservoir, trap, seal, and timing of hydrocarbon migration relative to trap development. It also should reflect the probability of finding the "low", "high", and "expected" quantities of hydrocarbons projected for the prospect or play. The geological risk number or "chance of success" is one factor used in the typical exploration and/or development economic analysis in order to arrive at an estimate of Return on Investment and Rate of Return for specific drilling projects.

For typical exploration prospects and plays the geological chance of success usually ranges from five percent for high-risk projects to 30 percent for lower risk ventures. When looking at development projects, oil companies generally utilize a chance of success for probable reserves on the order of 50 to 80 percent. When acquiring or valuing probable reserves, oil companies will use a much lower chance of success in the range of 30 to 50 percent. Substantially higher than that for exploration projects. It is also common practice in industry to run preliminary Play Economics to determine if a given play meets certain economic criteria and then to run separate Prospect Economics for specific drilling prospects within the larger play framework.

The U.S. Geological Survey methodology for evaluating geologic risk consists of two variables: a) the Play Probability, and b) the Success Ratio. Play Probability (0-1.0) is a measure of the overall geologic risk that untested cells in a play are not capable of producing at least the minimum threshold of hydrocarbon reserves (one million barrels of oil or six billion cubic feet of gas). Lower probability equates to a greater geologic risk. All of the continuous-type plays evaluated by the USGS for NOSR 1 and 3, were assigned Play Probabilities of 1.0, indicating that it was a virtual certainty that the minimum reserve levels would be encountered. It is clear from the USGS report (Fouch et al., 1994) that the survey considers all the plays from the Dakota/Morrison to the Wasatch to be of the continuous gas-saturation type. It is less clear how they regard the Paleozoic. However, this Consultant does not believe that possible Dakota and Paleozoic accumulations would be of the continuous type.

Success Ratio, according to the USGS definition, is the fraction (0-1.0) of untested cells in a play which are expected to be productive. The product of Success Ratio and the number of untested cells in a play yields the number of productive untested cells in a play. The Survey's Success Ratio definition compares most directly with private industry's from the risking of well success rates.

The U.S. Geological Survey used a variety of geologic risking in the probabilistic model for assessing the oil and gas resources for the five exploration plays considered present at NOSRs 1 and 3. The deep Paleozoic play was assigned a success ratio of one percent due to its high geologic risk. This is not considered unreasonable but may be somewhat low due to the presence of Weber production within the basin. In this regard, a five percent success ratio may be justifiable. This possible increase is insignificant however when considering the cost and uncertainty associated with this received uneconomic play.

The gas-saturated plays in the Cretaceous and Tertiary formations have the highest chances of success with the shallow Wasatch assigned a success ratio of 83 percent and the Mesaverde a success ratio of 71 percent, essentially development-type risks. The deeper Dakota/Morrison play was also considered a gas-saturated play and was assigned a success ratio of 70 percent. The Wasatch and Mesaverde values are probably reasonable for those portions of NOSR-3 which are close to existing production. While the gas-saturated model is accepted as reasonable, this Consultant believes that the high success ratios are too optimistic for NOSR-1 due to the lack of geologic control for the Mesaverde on and immediately north of these lands. This lack of geologic control provides a low confidence level for predicting (with any certainty) the sand quality, reservoir permeability and average estimated ultimate recovery for Mesaverde reservoirs in the undrilled areas of NOSR-1. In addition, the disappointing results for the Wasatch in the Schutte Creek area just northwest of the tract cast doubt on whether the Wasatch is economically feasible for gas development on NOSR-1.

In the area of the apparent seismic structure in the eastern portion of NOSR-1 (Plate 1), success ratios for Wasatch/Mesaverde wells might be higher. This would be a consequence of assumed fracture enhancement of permeability associated with the broad fold. In any case, NOSR-1 lands should be considered exploratory with regard to Wasatch/Mesaverde or deeper horizons.

The deep Dakota probably does not warrant a development-type risk factor of 70 percent (as assigned by the USGS). It is the opinion of this Consultant that the gas-saturation model cannot automatically be assumed to prevail in this interval. Throughout the Rockies and in areas surrounding the deep Piceance, Dakota reservoirs often have water contacts associated with their hydrocarbon accumulations. The Dakota is too far removed stratigraphically from the Mesaverde for Mesaverde generated gas to have migrated down into the Dakota. Furthermore, it is unclear if associated Dakota coaly source beds would generate the volumes of gas necessary to saturate the Dakota reservoir. Even in light of the possible presence of a significant closed structure on NOSR-1, the Dakota play is still exploratory in nature and would be considered as a rank wildcat prospect.

1.4.5.6 Oil Shale Resources

Much has been written on the oil shale richness and the potential oil shale resource on NOSR-1. All of the present oil-pricing and development cost scenarios indicate that these resources cannot be exploited economically at the present time nor in the foreseeable future. Most studies indicate that within NOSR-1 somewhere between 6 and 9 billion barrels of oil are present in oil shales capable of yielding greater than 25 gallons-per-ton. This makes NOSR-1 by far the richest of the Naval Oil Shale Reserves. Nevertheless, extraction of oil from oil shale is not economically feasible at this time. NOSR-3 has essentially no oil shale resources within its boundaries. It was acquired to provide transportation and water access to future oil shale operations.

1.4.6 Summary of Findings and Opinion of Adequacy

This Consultant has reviewed the reports furnished by the DOE regarding the oil and gas resources on the NOSR 1 and 3 sites. From a geologic and geophysical perspective, these reports are considered to be adequate for overall resource characterization. However, we have found some shortcomings which require additional effort. Some of these shortcomings have already been remedied by work carried out during Phase 1 and incorporated into this report.

For example, the Wasatch wells drilled by Barrett in the Schutte Creek area had to be incorporated into a stratigraphic cross section in order to compare them with known producing wells. This was not done in any of the previous studies and was considered an essential prerequisite to evaluating the Wasatch potential.

However, additional work is still required to more thoroughly characterize the resources of the study area. This additional work involves a more complete interpretation of the seismic data across NOSR 1 and 3. The U.S. Geological Survey presented a good seismic interpretation of one of the lines in Open-File Report #94-427 (Fouch et al., 1994) and discussed the potential structural closure on NOSR-1. However, no integrated seismic map tied to well control was generated in order to map the potential size of the deep seismic feature. Such a map is necessary for making a proper geological assessment of the NOSR 1 and 3 sites.

A summary of the significant geologic findings is presented below and these will be incorporated as part of Phase 2 of this project:

1. Gas-saturated Wasatch and Mesaverde sands form a continuous-type gas accumulation in the vicinity of NOSR 1 and 3. However, it is not known whether the gas would be economically recoverable in undrilled areas located some distance from production.

2. In such continuous-type gas accumulations, water legs are absent and any sand with adequate permeability (matrix and/or fracture) will be productive. Rulison, Parachute and Grand Valley Fields are actually all parts of the same continuous gas accumulation in the Wasatch and Mesaverde.

3. Wasatch "G" and Mesaverde sands are present beneath the main part of NOSR-3 and probably are present both beneath the northeast part of NOSR-3 and all of NOSR-1.

9. The deep Dakota could be a target in the above portions of NOSR-1 if the structure is confirmed. Fracture enhancement could again increase reservoir permeability in this deep potential reservoir. Estimated depth to the Dakota is 18,000 to 20,000 feet on this feature.

10. Paleozoic reservoirs are extremely deep throughout NOSR 1 and 3(estimated depth to Mississippian Leadville is 23,000 to 26,000 feet) and are considered to be rank wildcat exploration targets.

11. Because of the variability of reserve recovery exhibited in the Wasatch and Mesaverde sands at Parachute, Grand Valley and Rulison Fields, it is very difficult to project (with any degree of certainty) average ultimate recoveries for the area encompassing all of NOSR-1 and the northeastern portion of NOSR-3.

1.5 RESERVES AND ECONOMICS

1.5.1 Scope of Work and Opinion of Adequacy

This Consultant was directed by the DOE to review reports which assessed oil and gas resources present in the Naval Oil Shale Reserve No. 1 and 3. Several reports with reserve estimates have been prepared by the Department of Energy (DOE) and Fluor Daniel (FD) with input from various other sources, including the United States Geological Survey (USGS). This section of the fact finding report discusses our review of these reports along with this Consultant's opinion of these evaluations. Upon review of these reports, this Consultant found a broad range of projected oil and gas resources for the NOSR 1 and 3 sites. The projections ranged from 30 BCF for proved producing reserves on NOSR-3 to 800 BCF for a full gas development scenario across the entire area.

Because of this broad range, it was necessary to evaluate oil and gas resources (both proved and otherwise) in accordance with the guidelines established by Society of Petroleum Engineers (SPE) and Society of Petroleum Evaluation Engineers (SPEE). Based on our findings in the Geology and Geophysics section, this review was also conducted with the knowledge that a basin centered gas accumulation is most likely present across the area of study. It is understood by this Consultant that these types of accumulations are not formed by trapping mechanisms found in conventional types of oil and gas accumulations. It was in this manner that we systematically reviewed reserve estimates for existing production established on and adjacent to NOSR-3 followed by an evaluation of projected rates of recovery for oil and gas resources in the undrilled areas of NOSR 1 and 3. As part of our methodology, we examined whether the reserve estimates are reasonable and that these reports were in conformity with petroleum engineering principles.

The following reports contained resource estimates, and were reviewed as part of the fact finding portion of this project :

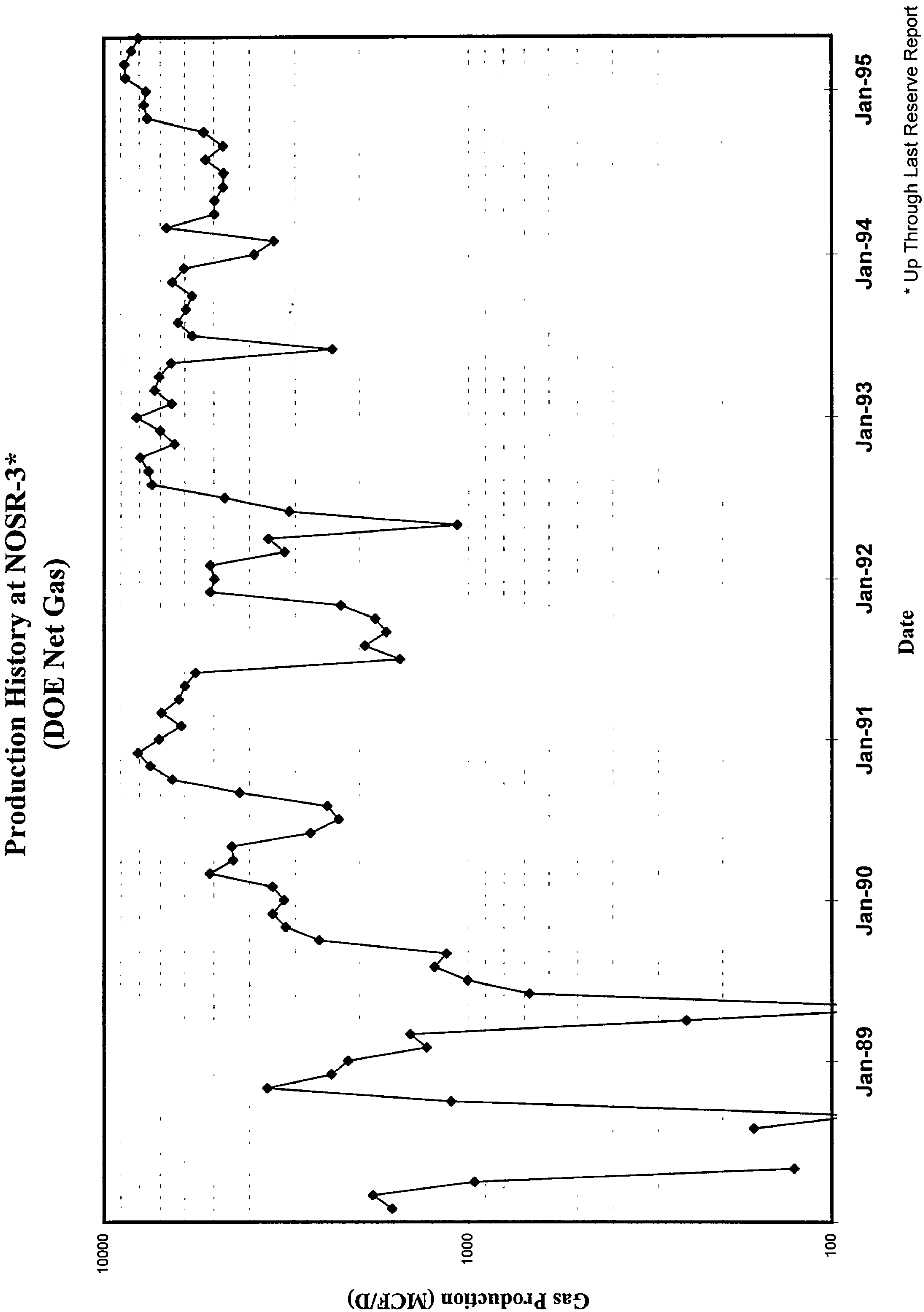
1. FY 1995 Oil and Gas Reserves Evaluation Prepared By Fluor Daniel (September 1995).
2. Study of Alternate Development Options for the Naval Oil Shale Reserves Nos. 1&2 Prepared By USDOE (June 1994).
3. NOSR Full Development Study -- Naval Oil Shale Reserve No.3 Prepared By Lorraine M. LaFreniere, Ph.D. (February, 1994).
4. Alternate Development Study Naval Oil Shale Reserves No.3 Prepared By Fluor Daniel (January 1994).
5. Alternate Development Study Naval Oil Shale Reserves No.3 Addendum Report Prepared By USDOE and Fluor Daniel (January, 16 1995).

The 1995 Fluor Daniel reserve report for NOSR-3 is considered reasonable and honors all available engineering data. The remaining reports prepared by DOE are detailed full development scenarios for the undrilled acreage on NOSR 1 and 3. Although most of the underlying assumptions in these reports are reasonable, the future income projections to the Government's interest associated with a full development scenario have a low degree of certainty. Certain critical assumptions were just too optimistic and relate primarily to the economic variables and success rates for drilling the exploratory areas of NOSR 1 and 3.

1.5.2 General Background

Hydrocarbon production at the NOSR sites is from gas bearing sands in the Piceance Basin. The majority of production comes from 2 gas bearing sands, the Wasatch and Mesaverde formations. Currently, only the NOSR-3 property has existing production, with wells being drilled by the DOE as part of the Natural Gas Protection Program. As of the date of this report, the Department of Energy (DOE) has ownership interests in 53 producing gas wells at NOSR-3. Twenty-nine of these wells are operated by DOE along with 24 communitized wells presently operated by Barrett Resources. Net gas production for the 53 wells are presented in Figure 1.33. As described previously, gas production in the vicinity of NOSR-3 is from three distinct fields, Rulison Gas, Parachute and Grand Valley. Gas production operations are conventional for industry and a typical wellhead configuration from NOSR-3 is presented as Figure 1.34.

The Wasatch formation is Eocene to Paleocene in age and comprised of multiple sandstone lenses interbedded with shales and siltstones. The sands were deposited as channels with restricted porosity development further impeded by clay content in the pore space. Wasatch wells must be drilled and completed without fresh water based fluids because fresh water will cause swelling of the clays and thereby reduce permeability in the reservoir matrix. Most of the Wasatch wells in the region are drilled with air for this reason. The Wasatch sands are "tight" sandstone reservoirs with permeabilities typically under 1 millidarcy. Therefore, economic gas production rates and recoveries are highly dependant on natural and induced fracture systems within the producing horizon. The Wasatch wells in the offsetting fields are drilled on 160 acre spacing. The best Wasatch producers on the NOSR 3 property are estimated to produce 1 BCF of ultimate recoverable gas reserves with very little produced water. The most prolific sand unit in the Wasatch formation at NOSR-3 is the “G sand,” and this sand member accounts for the majority of the Wasatch production in the NOSR-3 region.



Production History at NOSR-3*
(DOE Net Gas)
Gas Production (MCF/D)
10000
1000
100
Jan-89
Jan-90
Jan-91
Jan-92
Jan-93
Jan-94
Jan-95
Date
* Up Through Last Reserve Report

FIGURE 1.33

FIGURE 1.34A- NOSR-3
Well
Configuration

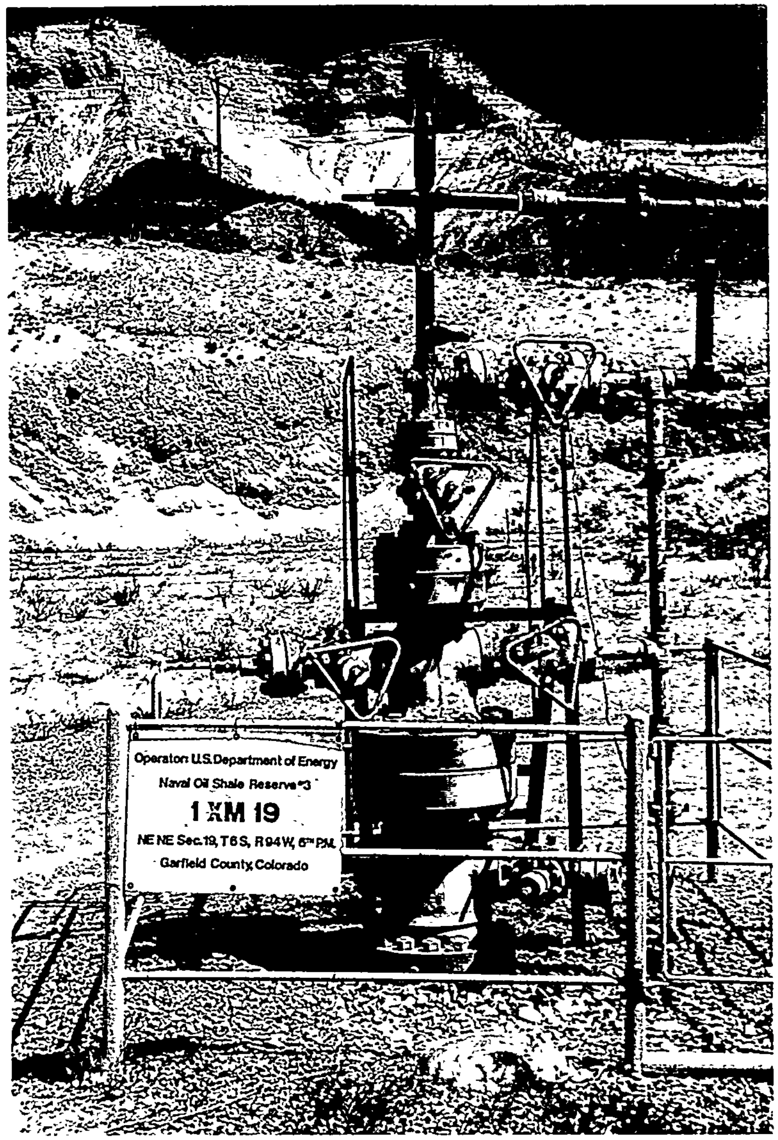


FIGURE 1.34B

The Mesaverde group produces from lenticular, fluvial, shoreline-marine sandstones and coals. The Mesaverde includes the cameo coal sequence of the lower Williams Fork formation, as well as the shoreline-marine sandstones of the Rollins, Cozzette, and Corcoran members of the Lower Mesaverde Iles Formation. Recorded Mesaverde production in the typically includes all of these formations since many area wells are commingled within the Mesaverde. As expected, Mesaverde EURs vary greatly depending on the location of the well, the members of the formation completed, and the effectiveness of the fracture stimulation. Typically, only a portion of the interval can be completed at one time, and therefore EUR estimates often include behind pipe reserve estimates. Recently drilling density in the Mesaverde increased to 40 acres for an area that includes a significant portion of NOSR-3.

1.5.3 Proved Reserves at NOSR-3

1.5.3.1 Guidelines for Reporting Oil and Gas Reserves

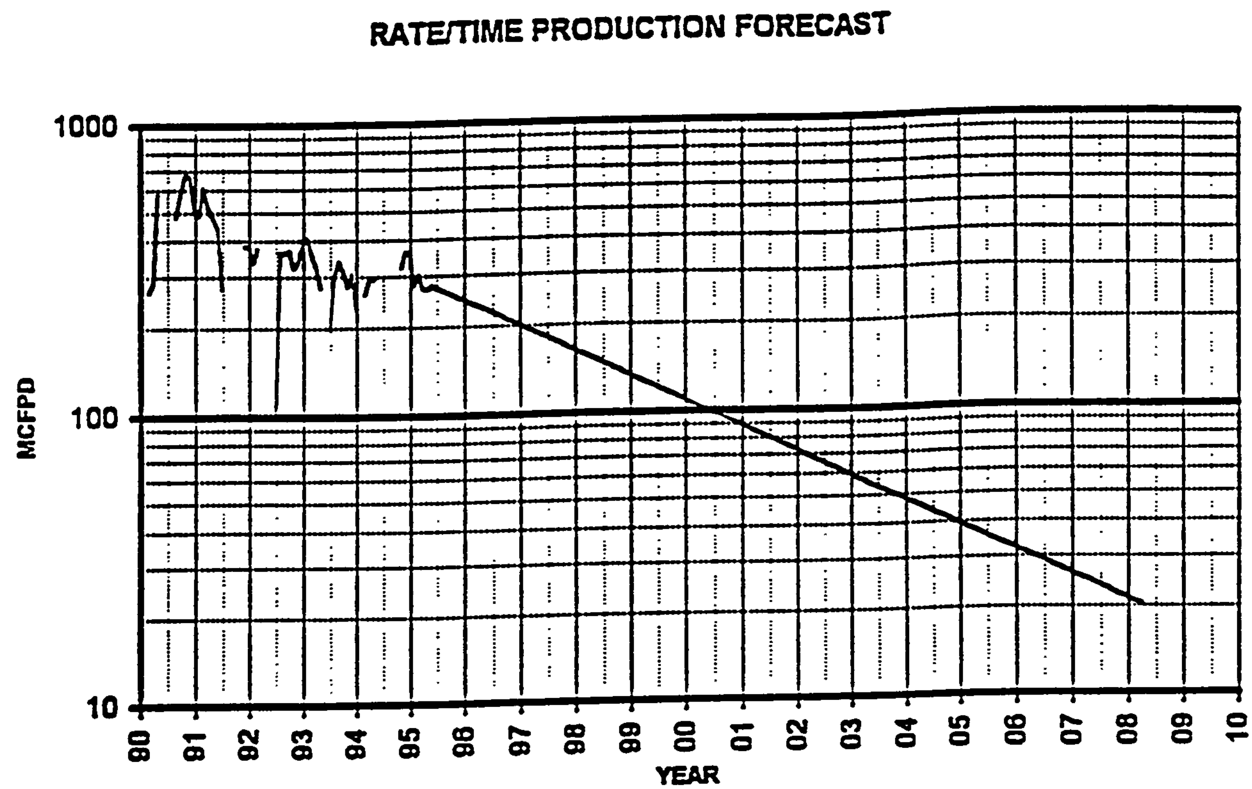
Reserves are defined as volumes of oil, condensate, natural gas, natural gas liquids, and associated substances which are expected to be commercially recoverable from known hydrocarbon accumulations. The Society of Petroleum Engineers categorize reserves as shown in Figure 1.35. A detailed description of these reserve categories is shown in Appendix C. Reserve estimates are based on interpretation of geologic and engineering data available at the time of the evaluation. Proved reserves are estimated with reasonable certainty to be recoverable under current economic conditions. Reserves are generally considered proved when commercial producibility of the reservoir is supported by actual production or formation tests. Proved reserves generally fall into several major categories. Proved developed producing (PDP) reserves are reserves that are expected to be recovered from existing wellbores and completion intervals open and producing at the time of the estimate. Proved developed nonproducing (PDNP) reserves are also expected to be recovered from existing wellbores, but include production shut-in or behind pipe at the time of the estimate. The 1995 FD Reserve Report includes an evaluation of all PDP and PDNP reserves at NOSR-3.

FIGURE 1.35

Example of Fluor Daniel Decline Curve Analysis

1-W-27
SWNW 27-T6S-R95W
GARFIELD CO., COLORADO

OPERATOR: DOE
FORMATION: WASATCH
PERFS: 2512-2585



DOE WI / RI %: 100

FORECAST DATE 6/1/95

PRODUCTION FORECAST SUMMARY * :

	MMCF	Cal. Day MCFD	Cond.** MBBL
1994 Production	46.988	128.8	
1995 Production	44.895	246.1	
Cum Production	434.050		NA
Remaining Production	465.950		NA
Est. Ultimate Recovery	900.000		NA

* Includes "proven producing" reserves only!

1.5.3.2 Proved Developed Reserves

Fluor Daniel presents proved developed reserves on a well by well basis utilizing 3 readily available reservoir engineering methods for evaluating reserves. Pressure data on wells that had been shut in for relatively long periods of time was used to generate P/Z plots and evaluate recoverable reserves based on gas material balance. The recoverables were then used in conjunction with the production history for a given well to perform a decline curve analysis.

Both methods were utilized in order to check the reasonableness of the reserve estimates. In addition, a detailed volumetric analysis was utilized to estimate proved developed reserves behind pipe. This Consultant has conducted a reserve audit on each well's estimated ultimate recovery. The audit resulted with some minor differences in methodology, but none significant enough to justify a complete re-evaluation of developed reserves at NOSR-3. Therefore, the bulk of reserve revisions will be associated with cumulative production, and new wells drilled since the FD report was prepared. The FD report is discussed below.

This Consultant found that Fluor Daniel improperly plotted gas material balance (P/Z) data because they used surface wellhead pressures instead of bottom hole pressures. In order to correct for this, this Consultant generated a new P/Z plot for each well utilizing the extrapolated bottom hole pressure and compressibility factor. This P/Z plot was evaluated down to a reasonable reservoir abandonment pressure in order to check ultimate recoverable gas reserves. Given the dry gas fluid columns in the wells, there were very few changes in the slopes of the P/Z plots, and therefore no differences between our analysis and Fluor Daniel. This exercise was also warranted given the low permeabilities in the Wasatch and Mesaverde formations. Pressure data taken without a reasonable shut in time should not be weighted equally with the pressure data taken over a long shut in time. Low permeability reservoirs often require a significant length of time to obtain an accurate estimate of reservoir pressure. Fluor Daniel accurately accounted for this by ignoring poor or unreliable data.

Another issue pertains to Fluor Daniel's reserve projections through time. Although the majority of Fluor Daniel's decline curve estimates were reasonable and defendable given past production histories, it is important to note that tight sand formations such as the Wasatch and Mesaverde typically exhibit a hyperbolic decline. Nearly all of Fluor Daniel's production rate projections were declined exponentially with time (Figure 1.35).

Many of the production histories support an exponential decline, probably associated with increased effective permeabilities from a successful fracture stimulation. However, several wells justified a second look utilizing a hyperbolic decline. Reserve projection differences were insignificant and did not warrant a new projection. It is our opinion that a hyperbolic forecast should be used for all new wells recently drilled and for projecting proved undeveloped locations.

Cash flows were not generated in the FD report, so other PDP reserve variables such as pricing, and operating costs were not evaluated by Fluor Daniel. However, all of the decline curves were taken to an economic limit of 20 MCFD. This seems reasonable given this Consultant's current estimates for wellhead gas price, and operating costs for Mesaverde and Wasatch wells.

Additional reserve estimates were based on the pore volume estimates behind pipe in existing wellbores at NOSR 3. By Fluor Daniel's own admission, the pore volume estimates have some notable inaccuracies. The first inaccuracy was centered around the analytical algorithms developed to determine porosity from the density log. The algorithms did not include a correction for gas as the reservoir fluid.

Second, the pore volume reserves were only booked on wells with a detailed log analysis evaluation. There were not any Wasatch wells in this group. Although it is likely that stray producible Wasatch sands exist, the majority of potential being pipe reserves would likely be in the Mesaverde where most of the recompletions to open more pay have been conducted. In addition, the porosity algorithm error noted above would not likely have more than a plus or minus 15 percent effect on pore volume reserves. An example pore volume analysis from the 1995 Fluor Daniel report is included in this report as Table 1.7.

TABLE 1.7

Example of Fluor Daniel Pore Volume Assessment

NOSR-CUW — WELL LOG ANALYSIS — 8/21/95

Pore Volume Determination

Well Name: DOE 1-M-31
Operator: Dept. of Energy
Field Name: Parachute
Location: SWSW SEC 31-T6S-R95W

	Pay Interval Top	Btm	Avg. Por %	Avg. SwA	Avg. SwS	Ft Pay at 5 %	HCPV	OGIP* BCF	Ft Pay at 8 %	HCPV	OGIP* BCF	Ft Pay Special	HCPV	OGIP* BCF
	3831.5	3838.0	14.6	42.0	34.7	6.5	0.632	0.039	6.0	0.625	0.039	5.0	0.569	0.035
	3843.5	3850.0	15.2	41.6	35.5	6.5	0.659	0.041	6.0	0.644	0.040	4.5	0.475	0.030
	3851.0	3868.0	18.1	32.8	29.4	15.0	1.949	0.121	15.0	1.949	0.121	13.0	1.825	0.114
	3918.5	3933.0	12.7	61.9	53.1	14.5	0.866	0.055	14.5	0.866	0.055			
	3936.0	3941.0	11.5	65.8	55.8	5.0	0.256	0.016	5.0	0.256	0.016			
	3949.0	3958.0	17.4	37.9	34.2	9.0	1.046	0.067	9.0	1.046	0.067	8.0	0.975	0.062
	3968.5	3973.5	13.4	46.7	40.1	5.0	0.397	0.025	5.0	0.397	0.025	3.0	0.259	0.017
	3998.5	4005.0	21.6	37.9	35.0	6.5	0.911	0.059	6.5	0.911	0.059	6.5	0.841	0.054
	4020.5	4030.0	10.2	58.3	50.8	9.5	0.482	0.031	9.5	0.482	0.031	1.0	0.084	0.005
	4032.5	4036.5	13.8	47.0	41.1	4.0	0.328	0.021	3.5	0.319	0.021	3.5	0.252	0.016
	4056.5	4062.0	14.9	43.4	39.3	5.5	0.509	0.033	5.5	0.509	0.033	4.0	0.430	0.028
	4087.0	4091.5	11.3	51.0	44.5	4.5	0.284	0.019	4.5	0.284	0.019			
	4193.5	4198.5	17.2	38.7	35.7	5.0	0.570	0.038	5.0	0.570	0.038	3.5	0.399	0.027
	4253.0	4257.5	20.6	36.2	33.2	4.5	0.622	0.042	4.5	0.622	0.042	4.0	0.580	0.039
	4291.5	4296.0	12.7	46.4	42.2	4.5	0.349	0.024	4.0	0.337	0.023	3.0	0.290	0.020
	4307.5	4316.0	15.0	37.7	34.8	8.5	0.847	0.058	8.5	0.847	0.058	8.0	0.830	0.057
	4394.0	4398.5	11.7	62.1	57.3	4.5	0.223	0.016	4.5	0.223	0.016			
	4403.0	4408.5	10.6	56.1	51.4	5.5	0.281	0.020	5.5	0.281	0.020			
	4475.0	4480.5	16.8	44.7	41.7	5.5	0.540	0.038	5.5	0.540	0.038	5.5	0.468	0.033
	4505.0	4514.5	11.4	56.3	51.0	9.5	0.530	0.038	9.5	0.530	0.038	2.0	0.141	0.010
	4547.0	4555.5	14.5	38.0	34.6	8.5	0.827	0.059	8.5	0.827	0.059	7.5	0.707	0.051
	4607.5	4618.5	15.1	58.5	52.6	11.0	0.786	0.057	11.0	0.786	0.057			
	4738.0	4753.5	17.7	39.7	36.1	15.5	1.761	0.130	15.5	1.761	0.130	15.5	1.710	0.126
	4767.0	4771.0	13.3	53.5	47.5	4.0	0.282	0.021	4.0	0.282	0.021	2.0	0.163	0.012
	4773.0	4778.0	16.3	50.2	45.7	5.0	0.446	0.033	5.0	0.446	0.033	4.0	0.382	0.028
	4861.0	4867.5	14.8	46.9	42.2	6.5	0.558	0.042	6.5	0.558	0.042	5.0	0.467	0.035
	4924.0	4929.5	10.7	62.5	57.5	5.5	0.248	0.019	5.5	0.248	0.019			
	4932.0	4946.5	13.1	52.7	48.9	14.5	0.978	0.074	14.5	0.978	0.074	4.5	0.284	0.022
	4966.0	4978.0	12.0	51.0	45.7	12.0	0.810	0.062	11.5	0.791	0.060	4.0	0.403	0.031
	4980.5	4988.5	14.5	45.8	42.2	8.0	0.694	0.053	8.0	0.694	0.053	5.0	0.534	0.041
	4995.5	5001.5	15.5	37.1	34.4	6.0	0.624	0.048	6.0	0.624	0.048	5.5	0.527	0.040
	5101.5	5108.5	11.1	56.7	51.9	7.0	0.368	0.029	7.0	0.368	0.029			
	5183.0	5189.5	10.9	59.7	55.0	6.5	0.317	0.025	6.5	0.317	0.025			
	5194.5	5198.5	16.3	38.1	35.6	4.0	0.433	0.034	4.0	0.433	0.034	4.0	0.271	0.021
	5241.0	5252.0	10.6	59.8	54.9	11.0	0.531	0.042	11.0	0.531	0.042			
	5253.5	5257.5	13.5	48.5	45.0	4.0	0.302	0.024	4.0	0.302	0.024	1.5	0.093	0.007
	5259.0	5266.0	17.0	37.3	34.9	7.0	0.798	0.064	7.0	0.798	0.064	6.0	0.736	0.059
	5266.5	5292.5	13.2	49.9	46.2	26.0	1.903	0.152	26.0	1.903	0.152	9.0	0.811	0.065
	5497.0	5501.5	9.9	56.5	51.2	4.5	0.214	0.018	4.5	0.214	0.018			
	5783.0	5796.5	12.0	55.8	51.8	13.5	0.781	0.066	13.5	0.781	0.066	1.0	0.072	0.006
	5846.0	5863.5	13.4	51.6	48.0	17.5	1.251	0.107	17.5	1.251	0.107	5.5	0.492	0.042
	6059.5	6065.5	11.9	55.8	52.0	6.0	0.339	0.030	6.0	0.339	0.030			
ST	3931.5	6065.5				342.5	27.532	1.990	340.0	27.470	1.986	154.5	16.070	1.133
Reserves at 60% Recovery Factor								1.194			1.192			0.680
P	6187.0	6193.5	12.4	56.6	52.9	6.5	0.378	0.034	6.5	0.378	0.034			
P	6259.5	6277.5	14.4	50.4	47.2	18.0	1.380	0.123	18.0	1.380	0.123	9.5	0.775	0.069
P	6300.0	6310.0	14.2	46.7	43.6	10.0	0.803	0.072	10.0	0.803	0.072	8.0	0.679	0.061
P	6403.5	6407.5	12.7	53.1	49.1	4.0	0.253	0.023	4.0	0.253	0.023			
P	6420.0	6431.5	13.9	48.9	45.7	11.5	0.870	0.079	11.5	0.870	0.079	7.5	0.543	0.049
P	6469.5	6484.0	13.1	60.0	56.0	14.5	0.838	0.076	14.5	0.838	0.076			
ST	6187.0	6484.0				64.5	4.522	0.407	64.5	4.522	0.407	25.0	2.000	0.180
Reserves at 60% Recovery Factor								0.244			0.244			0.110
Reserves at 60% Recovery Factor and 20 acred drainage								0.488			0.488			0.210
O	6709.5	6718.5	10.4	53.0	47.9	9.0	0.483	0.045	9.0	0.483	0.045	2.0	0.126	0.012
TOTAL WELL						416.0	32.537	2.442	413.5	32.475	2.438	181.5	18.193	1.324
Reserves at 60% Recovery Factor								1.465			1.463			0.794

*OGIP calculated for 10 acre drainage. Larger drainage can be indexed from the 10 acre values.

Legend: P=perforated interval, O=non perforated, AB=abandoned, I= included in reserves, ST=Sub Total

Despite the inaccuracies, the methodology behind the evaluations is consistent with industry practice for technical evaluation of oil and gas reserves. All pore volume estimates were based on a 20 acre drainage area, which is much smaller than the regulatory spacing requirements for Wasatch and Mesaverde wells. In addition, 60 percent recoveries were assumed for all behind-pipe gas reserves, which is relatively conservative from a reservoir engineering standpoint. The reserve evaluation was also reasonable with respect to how the reserves were categorized. Reserves were categorized from proved non producing (PDNP) to possible, as opposed to listing them all as proved. The Fluor Daniel pore volume estimates are considered reasonable by this Consultant.

In conclusion, the methodology used and estimates provided by the Fluor Daniel in the 1995 Reserve Report is considered reasonable and can be utilized as part of the Phase 2 evaluation.

1.5.3.3 Proved Undeveloped Reserves

Generally, proved undeveloped reserves are assigned to undrilled locations that are direct offsets to wells with established production, given reasonable certainty that the location is within that known proved productive limits of the subject formation. Proved undeveloped (PUD) reserves were not assigned in the 1995 FD report. However, in accordance with SPE definitions (Appendix C), sufficient geologic and engineering data exist to evaluate proved undeveloped reserves at NOSR-3. A cursory review of current developed locations, EUR maps, and proposed well locations identified in the NOSR-3 Full Development Study indicates that proved undeveloped locations could be assigned for a significant portion of the southern part of NOSR-3. Other areas and the east side of NOSR-3 would most likely be classified as probable reserves.

In February 1995, the Colorado Oil and Gas Conservation Commission approved increased drilling density to 40 acres for Mesaverde which includes a portion of NOSR-3. This change in density will result in an increased drilling adjacent to and on the NOSR-3 site. Barrett Resources Corporation was the main advocate for the increased density, and has since drilled approximately 6 Mesaverde infill wells on 40 acre spacing. Barrett's data suggested that 80 acres well spacing would not effectively drain the Mesaverde.

The data presented at the commission included a 40 acre spacing test area (MWX site), where two offset 40 acre wells were monitored as they were produced. There was no evidence of any pressure communication within the major channels of the Mesaverde formation. Additional evidence to support Mesaverde well spacing at 40 acres or lower can be found in the extremely low gas recoveries observed given an 80 acre drainage area. Fluor Daniel's pore volume estimates for perforated Mesaverde zones over 80 acres in conjunction with the anticipated EUR's indicate gas recoveries below 25 percent. Recoveries this low cannot be supported by reservoir engineering principles as shown in many of the P/Z plots for the Mesaverde wells.

In the January 1995 Alternative Development Study Addendum Report, the DOE proposed additional development across the most of the remaining area of NOSR-3. This report was prepared in response to new information and events that was considered to have an impact on the development options. This consisted of the findings of the USGS study, rulings by the Colorado Oil and Gas Commission (COGCC) regarding spacing and to reevaluate the method for assessing risk.

As discussed in the previous section on Geology and Geophysics, the USGS considered the Wasatch and Mesaverde as a continuous play and assigned high success rates because of these conditions. It was stated on page 7 in the Addendum report that by "using the USGS definition, which assumes that gas is present throughout the play area, the entire NOSR-3 area would be designated as proved", including the east side.

The addendum report explores various scenarios (Cases 1 through 5) which project future income to the Government's interest. Cases 1 through 3 use the acquisition method for risking the reserves associated with future development. Cases 4 and 5, the dry hole method is applied and utilizes success ratios established by the USGS probabilistic model.

The acquisition method makes use of risk factors assigned to designated reserve categories where unproved reserve categories have the highest possible risk. The acquisition method is typically used by the financial community and industry when purchasing or borrowing against reserves.

The dry hole method simulates success rates based on a probabilistic model for a given area. It is typically used by industry for internal planning of exploration programs.

Higher success rates were used for Cases 4 and 5 when projecting full development across NOSR-3 and this added considerable reserves to the resource base. These success rates are considered too high when projecting future income to the Government's interest. In addition, the gas price forecast is very aggressive when compared with historical prices received. As discussed in later sections of this report, there is potential for gas price improvement but this is subject to negotiations with pipeline companies, gas market and infrastructure improvements.

Again, this Consultant agrees with the concept of a basin centered gas accumulation and is of the opinion that the Mesaverde and Wasatch formations are most likely gas saturated across substantial portion of the study area. However, it is untenable to assign proved reserves to the unexplored areas of NOSR-3. Consequently, Case 4 and 5 are considered too optimistic for projecting future income to the Government's interest.

1.5.4 Probable and Possible Reserves Associated With Full Gas Development Scenario

Unproved or probable and possible reserves are supported by available geologic and engineering data suggesting recoverable in place hydrocarbons. However, uncertainties related to technical, contractual, economic, or regulatory conditions prevent assignment in the proved category. Probable and possible reserves are estimated based on a set of assumptions related to future economic conditions, or incomplete technical data. As a result, these types of reserves have a higher risk factor and a much lower confidence level when trying to project income from production. In the case of possible reserves, the income approach is considered not applicable when estimating the fair market value.

The NOSR 1 and 3 sites contain large areas of what this Consultant considers to be probable and possible reserves. The remaining speculative areas of NOSR-3 and all of NOSR-1 fall into these categories. These highly speculative potential resources are only considered possible due to the strong geologic evidence that supports a continuous accumulation across the NOSR 1&3 sites. This geologic data is discussed in previous sections of this report, and fully supports the premise that a continuous accumulation exists for both the Wasatch and Mesaverde formations. Possible reserves are even more speculative that probable, and should never be valued utilizing a net income cash flow approach. However, as part of the fact finding effort, various estimates of the full development for NOSR-1 were reviewed as presented in the Study of Alternate Development Options for NOSRs 1 and 2.

The Study of Alternate Development Options for NOSRs 1 and 2 prepared by the DOE (June 1994) outlines the full development of the NOSR-1 property with 432 BCF developed over a 35 year period. This development includes drilling 249 Wasatch wells and 241 Mesaverde wells for a total capital cost of $585 million dollars. An evaluation of the parameters used in these projections is discussed in the following sections of this report.

The report projects reserves as per the probabilistic model developed by the USGS. According to the USGS model, all Wasatch wells were assigned EURs of 700 MMCF of gas, while Mesaverde wells were assigned EURs of 1.88 BCF for the entire NOSR 1 area. These reserves are based on statistical production data from the Rulison, Parachute and Grand Valley fields in the vicinity of the study area. The probabilistic model is a reasonable approach when estimating upside potential for an exploration program. However, the reserves for the full development scenario are considered to be too high and not appropriately risked given the exploratory nature of the acreage.

The risk factor associated with the full development scenario has the most significant impact on the projection of future income. The risk factor was derived from the USGS resource characterization of NOSR-1 and it was projected that there was an 83 percent chance of success for Wasatch wells, and an 71 percent chance of success for Mesaverde wells. Unsuccessful wells incurred dry hole costs associated with drilling the well. Risk factors in this range are usually considered when valuing reserves in the proved undeveloped category. Given the lack of geologic control, problems with surface access and exploratory nature, the success rates projected for drilling and development on NOSR-1 are much too high for probable and possible reserves. Success rates less than 50 percent are considered more realistic.

Gas prices used in the full development scenario were started at $1.50/mcf and then escalated 5 percent to life. Historically, the DOE well at NOSR-3 received a gas price in the range of $0.70 to $0.75 per mcf. A new gathering system and pipeline expansion in the area may improve gas prices to the DOE wells in the near future. This work is currently in progress and scheduled to be completed by the fall of this year. The impact of these improvements on gas pricing is presently being investigated by this Consultant. In addition, the escalated gas price is not capped in the future, and increased to over $10.00 /mcf as part of the future cash flow. This is considered too optimistic and should be modified to a reasonable cap price.

The DOE's estimates of operating costs in the report seem low at approximately $1,100 per well per month. Barrett Resources indicated that monthly operating costs for their production on top of the mesa were approximately $900 per well higher than for wells 3,000 feet below in the valley. DOE's own estimate of 1995 operating costs for NOSR-3 were at $254 per well per month for Wasatch wells, and $1,150 per well per month for Mesaverde wells and these appear to be understated in the full development scenario for NOSR-1. NOSR-1 is much less accessible to pumpers and operating equipment needed to keep the wells operational. In addition, snowfall limits or precludes access 4 to 5 months out of a given year. These operational cost increases would likely be more significant in the initial stages of development where the costs could only be allocated between a few wells. If economic gas resources can be established by exploratory wells on NOSR-1, then economies of scale may improve operating costs in this difficult environment. Operating costs were escalated at 4.3 percent per year which may be slightly low when comparing with inflation.

Drilling costs estimated by the DOE were $556,500 to drill and complete a Wasatch well, and $1,417,500 to drill and complete a Mesaverde well. Dry hole costs estimated were $260,400 and $483,000 respectively. Discussions with operators in the area indicate that some of the initial wells drilled on top of the mesa to the Wasatch cost approximately $1,500,000. These costs were high because of fluid loss problems, directional drilling requirements, altered casing string designs, and the additional drilling depths associated with an additional 3,000 feet of overlying sediments. The higher drilling costs reported by the operators appear reasonable when this Consultant's visited the NOSR-1 site and observed the inherent access difficulties associated with drilling. Currently, only one road can be used to transport a drilling rig to NOSR-1 on top of the mesa. In addition, roughly one-third of the topography at NOSR-1 would justify some type of directional drilling requirement in order to drill the locations as per the current regulatory spacing units. Maybe too low during the initial stages of development This information would indicate that drilling costs may be too low during the initial stages of development. However, it is important to note the difficult nature of quantifying these costs given that only a few wells have been drilled on the mesa. The efficiency of drilling on the mesa will increase as more wells are drilled, and drilling problems are curtailed. In this regard, drilling cost will require further investigation when conducting Phase 2 of this study. In conclusion, NOSR-1 and the east side of NOSR-3 are considered exploratory acreage where average reserves and high success rates (established by the USGS) are too optimistic for projecting (with reasonable certainty) to the Government's interest. In addition, some of the economic variables such as pricing, operating and capital cost may require some additional scrutiny.

1.5.5 Gas Pipeline and Transportation Agreements

Transportation and gathering agreements are not expected to adversely impact the value of the properties. Recent efforts by DOE are expected to enhance the value of the properties by reducing gathering costs, developing new markets along the front range of Colorado, and entering into the Midwest markets thereby increasing wellhead prices.

DOE does not have any long term commitments on NOSR-3 gas. The gas is normally sold using annual contracts. However, for the period April 1 through September 30, 1996, a six month contract was let in an attempt to maximize summer revenues and coordinated sales with the planned installation of a new gathering system at NOSR-3. Until October 1, 1996, Pan Energy has a contract to purchase all of the gas produced on NOSR-3. DOE has a long term goal to sell 100 percent of the gas 100 percent of the time and they have been successful in accomplishing this goal.

The Pan Energy contract is for 7400 mmbtu/d at "Index" price and 3000 mmbtu/d at a fixed price of $0.72/mmbtu at the wellhead. The index price is the average of Questar and Northwest Pipeline Rocky Mountain monthly gas prices less gathering costs. The gas purchaser pays the gathering on DOE gas and in this case, Pan Energy is paying $0.34/mmbtu. Based upon NPOSR-CUW AOP Status Report for September 1995, gas prices have seasonal fluctuations and wellhead prices have ranged from $1.26 to $0.51/mmbtu over fiscal year 1995. The average price was $0.79/mmbtu.

Recent developments will reduce the gathering costs thereby increasing the wellhead price DOE receives for the gas. Under an existing contract, DOE and Williams Field Service gathers the gas off DOE leases. This gas then passes through Williams to Questar's system at a charge of $0.34 per mmbtu. The DOE has a contract with Piceance Natural Gas (PNG) to gather all DOE gas and deliver it to Questar's transmission system beginning October 1, 1996. DOE will pay up to $0.28/mmbtu for volumes at 6,000 mmbtu/D or less. At the current production rates of over 10,000 mmbtu per day, using PNG will result in a $0.16/mmbtu savings on gathering charges. The net effect to DOE will be an expected average wellhead price of $0.95/mmbtu for an annual savings of approximately $500,000.

Colorado Interstate Gas (CIG) is in the process of installing a transmission system into the NOSR-3 area which will provide the DOE with an alternative to Questar for selling its gas. According to discussion with PNG, the CIG system will allow access to the front range of Colorado and Midwestern markets. Potential increases in wellhead price of $0.50 to $0.70 per mmbtu could be realized. On annual sales of 3.4 BCF this could amount to an additional $2.38 million per year in gross revenues. After the new gathering system is installed the DOE plans to sell gas on whatever schedule will allow them to maximize revenue. Furthermore, other contract terms are favorable to maintaining revenue in a fluctuating market.

In a similar positive move, DOE held discussion with Colorado Interstate Gas (CIG) concerning moving NOSR gas into other markets. The elusive Midwest market -- at today's prices -- could double revenue to the Federal Government at current production rates. This based upon increasing the current well head price of $0.72/mmbtu to $1.49/mmbtu by using the current $2.02/mmbtu Gage, Nebraska index price less $0.52/mmbtu gathering and transportation cost using CIG to transport the gas.

Selling gas to military bases along the front range of the Rocky Mountains may provide an advantage to the DOE for marketing gas from the NOSR sites. Under authorization by the Natural Gas Transfer Agreement between the Department of Energy and the Department of Defense, the two departments are exploring ways to utilize NOSR gas for mutual benefit. DOE estimates that wellhead prices could be increased to $1.22/mmbtu (69 percent increase) while reducing costs to the bases by up to 36 percent over their past year's expenditures. Any price projections that may be realized from selling gas to the Midwest or to Front Range markets requires firm transportation agreements in order to guarantee sales to end users. DOE estimated transportation costs based upon preliminary discussions with CIG. At the current time, DOE has not entered into a transportation or sales agreement that would realize these benefits.

1.6 LEASEHOLD EQUIPMENT

This Appraiser is not aware of any leasehold equipment that is present on the subject properties that may impact this study.

1.7 PROSPECTS

1.7.1 Exploratory

As described previously, the NOSR-1 site is considered prospective for additional hydrocarbon exploration. The presence of an apparent structure defined by seismic data is a potential drilling target for possible enhanced natural fracturing of the Wasatch and Mesaverde formations and for possible structural entrapment of hydrocarbons in deeper Cretaceous and Paleozoic sediments.

1.7.2 Oil Shale

The Green River formation which underlies much of the surface at NOSR-1 is estimated to contain more than 18 billion barrels of shale oil in place, with approximately 2.5 billion barrels of recoverable reserves of oil. Currently, there are no plans to develop these resources because the cost for extraction from oil shale is not competitive with the production of conventional crude oil. The economic feasibility of developing this resource relies mainly on the future price of crude oil which has not yet seen any drastic increases since the late 1970s and early 1980s. Until then, oil shale prospects can be held in inventory, bartered or sold for whatever the market might pay for such a resource.

1.7.3 Other Minerals

This Consultant is not aware of any other types of minerals such as coal, uranium, or gypsum that might be prospective on the subject properties or have a material impact on the value of mineral estate.

1.8 ADDITIONAL SURFACE FACILITIES

1.8.1 Production Equipment

The production equipment that currently exists for the 53 gas wells drilled on NOSR-3 consist of wellheads, tank batteries, separators and dehydration units necessary for conventional production of natural gas. This equipment is an integral part of producing the reserves and would not be sold off separately unless the reserves were depleted. At the plugging and abandonment stage, the equipment can bring a salvage value that will offset costs associated with plugging and abandonment of depleted wellbores. These issues are discussed later in the report in the Plugging and Abandonment Liabilities section.

1.8.2 Cabin on NOSR-1

Surface facilities on NOSR-1 include a cabin for housing government personnel while doing field investigation work. The cabin was not valued as part of this fact finding report because it is not an integral part of the mineral estate.

1.8.3 Dismantled Oil Shale Retort Facility

The majority of the buildings from the oil shale retort facility were dismantled and demolished during the mid 1980s and no longer exists on the property. One building remains and consists of a water pump house facility that was used to pump water out of the Colorado River in support of operations. This facility could be viewed as an asset when considered as a source of water or as a liability if it requires demolition.

1.9 PLUGGING AND ABANDONMENT LIABILITIES

1.9.1 Summary

An updated inventory list (Appendix G) indicates that there are currently 53 wells at NOSR-3 that will require plugging and abandonment (P&A) in accordance with requirements set by the State of Colorado. The total P&A liability to the DOE is estimated to be $1.21 million. The cost to plug and abandon all 53 wells is summarized on Table 1.8. This cost includes an estimation of $1.62 million to perform the P&A work and also credits $410,000 in salvageable well equipment such as tubing, casing and dehydration equipment against the overall cost to all 53 P&A wells (Figure 1.36).

1.9.2 Colorado Requirements for Plug and Abandonment

The Colorado Oil and Gas Conservation Commission has a set of basic procedures for plugging wells in order to protect all fresh water aquifers and to seal off any oil and gas bearing formations. These procedures are summarized as follows:

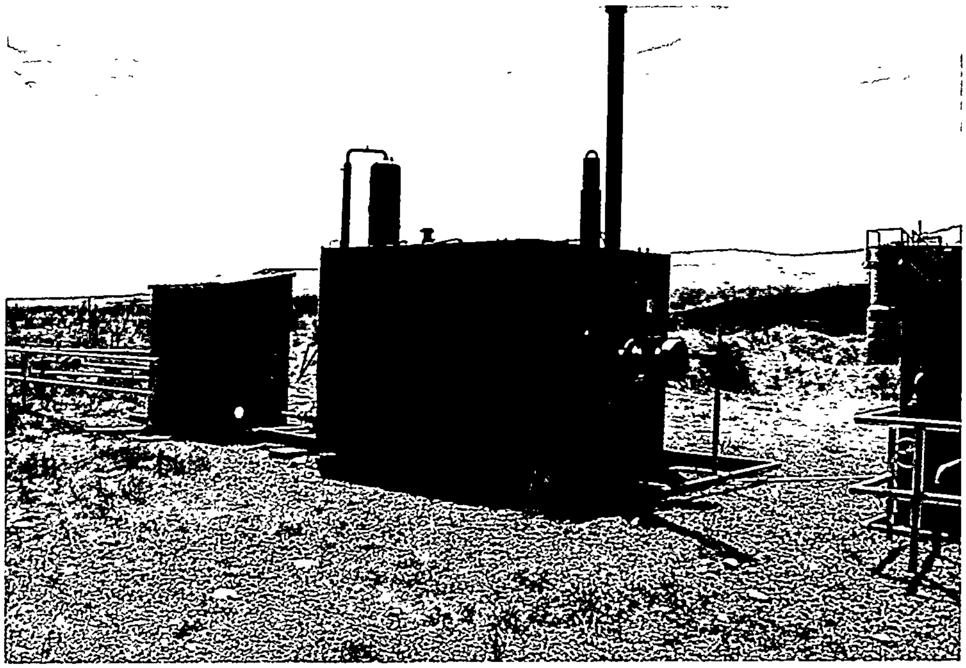


FIGURE 1.36A– TYPICAL WELL LOCATION EQUIPMENT ON NOSR-3

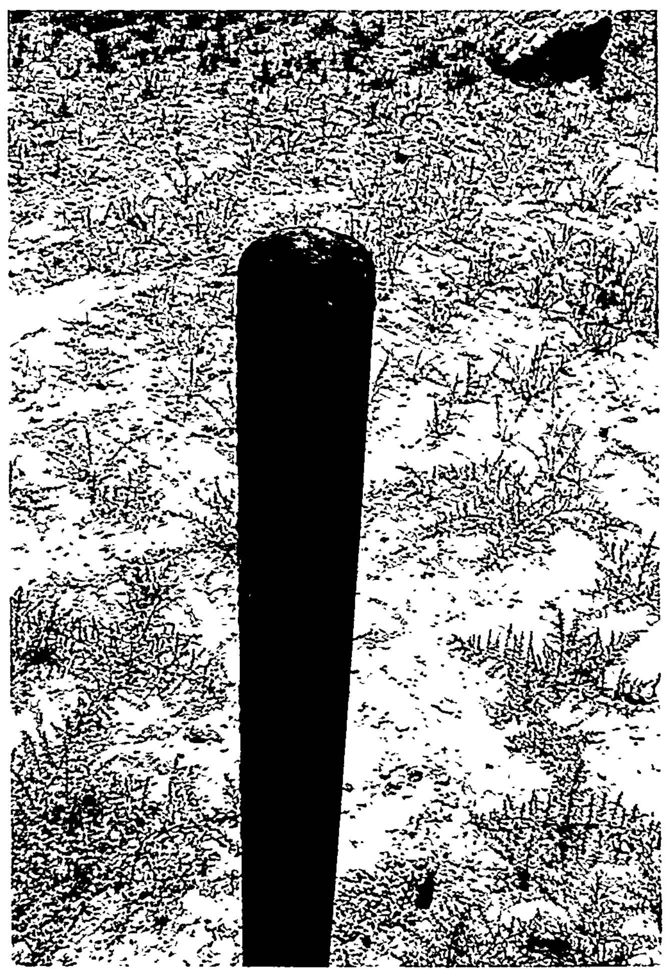


FIGURE 1.36B
NOSR-3 P&A'D WELL

Table 1.8

NOSR-3 PLUG & ABANDONMENT COST ESTIMATES

PRODUCING ZONE	PBTD	AVERAGE WORKING INTEREST DOE	PLUGGING COST PER WELL	RECLAIM COST PER WELL	NUMBER OF WELLS (as of 5/29/96)	NET P&A COST FOR ALL WELLS IN THIS ZONE	SALVAGE FOR TUBING AND CASING	SALVAGE FOR SURFACE EQUIPMENT
Wasatch (operated)	3,000	0.9534	$19,800	$1,000	17	$337,122	$32,349	$42,140
Wasatch (non-operated)	2,000	0.4754	$22,000	$1,000	11	$120,276	$18,120	$13,596
Mesaverde (operated)	6,000	0.9762	$63,000	$1,000	12	$749,722	$135,582	$55,058
Mesaverde (non-operated)	6,000	0.5318	$58,000	$1,000	13	$407,891	$80,016	$32,493
TOTALS					53	$1,615,011	$266,067	$143,287

TOTAL P&A LIABILITY $1,205,656

ASSUMPTIONS
Reclamation cost includes grating location and road and reseeding ($700 for location $300 for road)
Assume tubing is 100' off bottom and salvage rate for tubing and casing is 75% (60% for 1 1/2")
Tubing salvage=tubing length x $.60/ft
The 1 1/2" tubing in the MV wells is worth $.30/ft
Casing is recovered in all but 14 DOE-op'd Wasatch wells
4 1/2" casing - $1.74/ft
5 1/2" casing - $2.33/ft
Surface equipment is valued at $2000; Wasatch wellheads-$600; MV wellheads-$2700

1. A minimum cement plug length of 50' must be set across or above and below any zone that contains oil, gas or water. The material used in plugging (cement, mechanical plug or other method) must be approved in writing by the Director. The plugging material must be placed in a manner to permanently prevent migration of oil, gas water or other substance from the formation in which it originally occurred.

2. The method of placement can be (a) dump bailer, (b) pumping through tubing, (c) pump and plug or (d) an equivalent method approved by the Director. All wells shall have water or some approved fluid between plugs.

3. All abandoned wells shall have a plug or seal placed at the surface of the ground or the bottom of the cellar in such a manner as not to interfere with soil cultivation or other surface use.

4. Upon abandonment, all pits, rat holes and cellars shall be backfilled, debris and equipment removed and the location graded. All reclamation work shall be completed within six months of plugging the well.

1.9.3 Methodology for Cost Estimation

This Consultant did not estimate P&A costs for each individual well in the field. There are four categories of wells for estimating purposes. The Wasatch Wells were divided between operated and non-operated (Barrett) not only because the working interests are different, but the DOE plans to P&A all of their Wasatch Wells in one program and should realize some savings.

In contrast, the Mesaverde Wells will be individually plugged and abandoned as they become uneconomic in the future. As a result, the DOE does not enjoy the cost savings and the cost to P&A those wells are slightly higher than the non-operated wells. The working interests between operated and non-operated Mesaverde Wells are also significantly different. Therefore, the

Mesaverde wells are divided between operated and non-operated wells for cost estimation purposes also.

The rig cost, cement cost and mud cost are components of the P&A expense and included under plugging cost in Table 1.8. The reclamation cost is the other P&A cost component and is summarized in Table 1.8 as a separate category.

Plugging and abandonment expenses (including reclamation costs) for the four well categories described previously were multiplied by the total number of wells in the respective average working interest. Based on this analysis, the total net P&A cost is $1.62 million to the DOE's interest.

1.9.4 Plugging Costs

There is no representative P&A history to draw upon in this field. The cost to plug and abandon is based on similar well operations in other areas. The costs summarized in Table 1.8 account for 5 to 7 days of rig time to perform the following well operations:

1. kill the well
2. pull the tubing and packer
3. pull the casing
4. set the cement plugs and place the mud

In addition to the actual well costs, there is an estimated $1000 per well to reclaim the location (see BLM requirements-next section).

1.9.5 BLM Requirements for Abandonment

In addition to plugging costs, the well locations must be reclaimed and remediated. On federal land such as NPR-3, the BLM has established requirements for returning the well locations to original condition. Mr. Bob Anderson, a former BLM employee, informed us that this is a requirement for all wells drilled since 1978. All of the wells have been drilled since then, so the remediation costs include returning all well locations and roads to the wells to "pristine condition". Those cost estimates are included in Table 1.8 in the reclamation cost.

1.9.6 Salvage

In addition to these P&A costs are salvage value estimates for equipment associated with the production of a particular well. All wells have tubing that can be salvaged, and it is assumed that the casing from all but some of the Wasatch wells will also be recovered.

The wellheads will also have some salvage value. These wellheads have not been exposed to extreme conditions and appear to be in good condition. The Mesaverde wellheads will bring $2700 each and the Wasatch wellheads will bring $600 each.

Nearly all of the wells have certain surface equipment associated with that individual well's production. Typically each well had a meter run, a dehydration skid and a small separator tank (Figure 1.36). This equipment is relatively new and in good condition. Discussion with equipment brokers supports a market estimate of 20 percent of acquisition cost. With an average of $50,000 in surface equipment for each well, an allocation of $10,000 for salvage value of the surface equipment for each well is considered reasonable. The total salvage value of $410,000 has been credited directly against the P&A cost for estimating a net cost of $1.2 million for the plugging and abandonment of 53 wells on NOSR-3 (Table 1.8)

1.10 ENVIRONMENTAL LIABILITIES

1.10.1 Introduction

This Consultant was directed by the DOE to estimate costs associated with environmental liability (including plug and abandonment of natural gas wells - reference Section 1.9) in order to comply with Federal, State, and Local laws for NOSR-3. In order to accomplish this task, available information was reviewed to determine the nature and type of environmental remediation that is required for these sites. Identification of current and potential environmental liabilities are included in this Fact-Finding Report.

The DOE Reports reviewed by this Consultant for the Phase I Fact-Finding study includes a Sitewide Environmental Assessment (EA) conducted in 1991 for National Environmental Policy Act (NEPA) compliance for the proposed development of gas on NOSR 1 and 3 and an Environmental, Safety, and Health (ES&H) Management Plan for NPOSR to assess environmental liability costs. Additionally, this Consultant made a site visit in mid June, 1996 and met with David Miles, the Environmental Manager for NPOSR. This visit was important in evaluating mitigation, remediation, compliance, and reclamation measures at NOSR 1 and 3.

1.10.2 Summary of NOSR-3 Environmental Issues

NOSR-3 environmental issues are grouped into three primary categories: DOE operated gas wells; the burnt shale pile; and potential liabilities involving proposed future development of natural gas on the Reserve. Within each of these categories, comparisons are made between the DOE costs (operating and capital) versus private sector costs. The costs are different due to varied management styles between the public and private sectors. The items that tend to encumber the DOE with higher operating costs involve more rigorous environmental compliance standards than private industry and the use of subcontractors.

If a transfer to the BLM occurs, environmental mitigation costs subsequent to drilling operations will be comparable to DOE mitigation costs. This is due to re-seeding and erosion control requirements for federal agencies versus less stringent private industry requirements. Some expenses listed in the ES&H Management Plan have already accrued because the projects have been or will be completed prior to the "as of" date of this appraisal. For example, the ES&H Management plan has a cost associated with a biological assessment and a cultural resources study for NOSR-3. This Consultant has been informed by David Miles that these projects will be completed by FY 1996 and will no longer be a liability to the NOSR-3 site in FY 1997.

1.10.2.1 DOE Operated Gas Wells

As a result of DOE's monitoring activities, it was determined in 1983 that mineral exploration and development activity on private lands adjacent to the NOSR sites had the potential to drain hydrocarbons and possibly affect correlative mineral rights on NOSR-3. Under the Gas Protection Act, the DOE commenced drilling activity and currently has 29 operational gas wells on the NOSR-3 site. There are 26 communitized wells on the lease boundary and are included in plug and abandonment liability. The operating liability issues are routine monitoring and mitigation programs as required by Federal environmental regulations and staff requirements (Figure 1.37).

Environmental compliance for DOE operated gas wells includes:

1) Routine well monitoring for environmental regulations compliance with the Resource Conservation and Recovery Act (RCRA) concerning hazardous waste characterization and disposal.
2) Environmental mitigation programs for reseeding and reclamation of drill sites according to guidelines promulgated by the Environmental Assessment under the National Environmental Policy Act.
3) Ground and surface water monitoring as required by the Clean Water Act (CWA).
4) Air quality management program for detection of wind speed, direction, velocity and temperature.
5) Staff costs including subcontractors who perform environmental and safety oversight and administrative support.

Total annual environmental compliance costs for the DOE at NOSR-3 is $87,300 (Table 1.9).

Private industry would also have to comply with RCRA and Clean Water Act regulations. The private sector would comply with the minimum environmental restrictions and allocate fewer

Table 1.9

Department of Energy Environmental Operating Costs

	Annual Cost
Hazardous Waste Disposal Characterize and dispose, as necessary, hazardous waste; equipment maintenance, Underground Storage Tank and soil testing.	**$3,000**
Environmental Mitigation Reseeding and reclamation of drill sites as needed.	**10,800**
Routine environmental monitoring Annual groundwater and surface water testing of shale pile	**2,500**
Air Quality Management Program Purchase and installation of NET/Air Quality Monitoring Stations and associated operation procedures.	**2,000**
Environmental, Safety, and Health Staff	
Environmental Manager	23,500
Safety & Health Manager	18,500
Travel costs for oversight and monitoring	5,000
ES&H Clerk (subcontracted 25%)	7,000
Total	**$54,000**
TOTAL ANNUAL DOE OPERATING COSTS:	**$72,300**

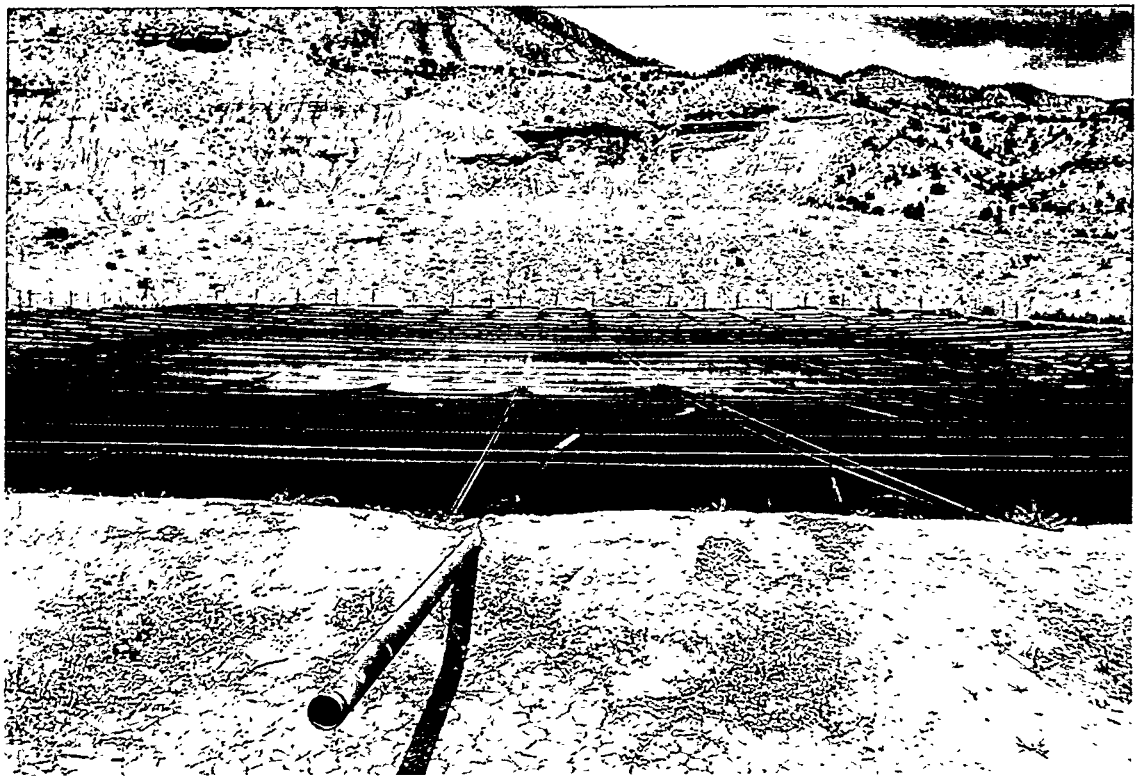


FIGURE 1.37A- NOSR-3 Netted water disposal pit

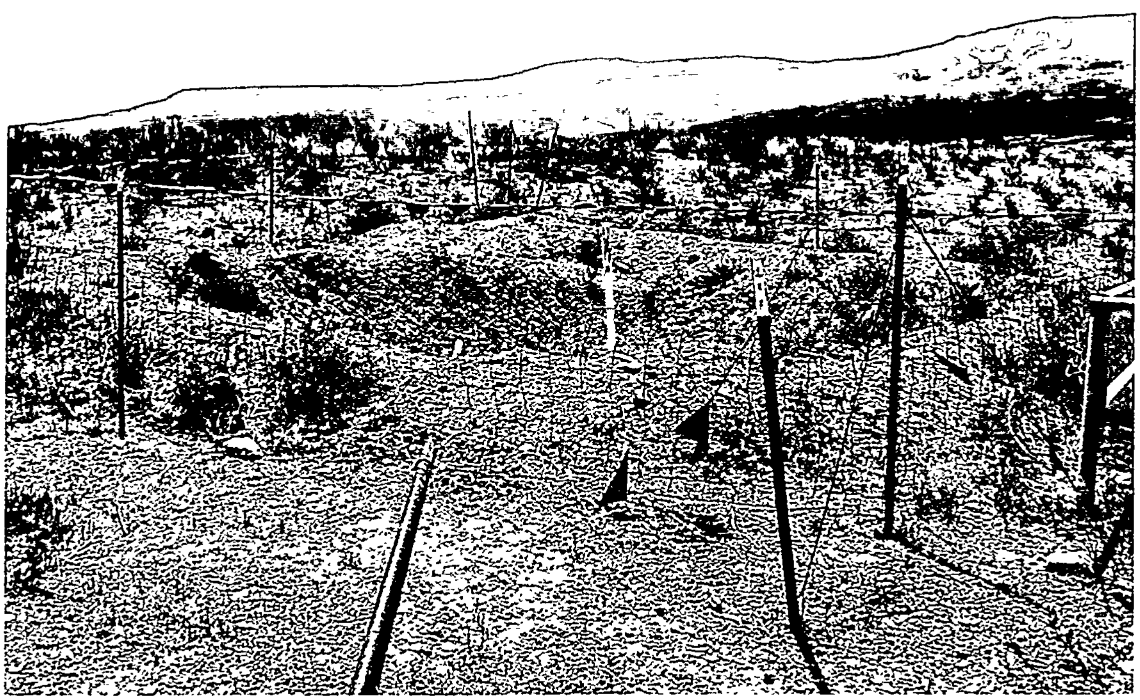


FIGURE 1.37B- NOSR-3 Gas well Blowdown pits

employees for monitoring and oversight. Total annual private sector environmental compliance costs are estimated to be $45,500 if they assumed operation of NOSR-3 (Table 1.10).

1.10.2.2 Shale Pile

An experimental oil shale mining project was conducted by Paraho Corporation between 1946 and 1982 under a DOE subcontract. Using a Shale Oil Modified Asphalt (SOMAT) process, stockpiled shale from past DOE shale mining activities was processed for oil production. The most significant environmental issue at NOSR-3 is a 300,000 ton (178,000 cubic yards) burnt shale pile left from the SOMAT process (Figure 1.38A). The shale pile rests approximately 50 yards from the West Sharrard Bank, a drainage into the Colorado River. There is an annual monitoring program in place at a cost of $2,500 annually (Figure 1.38B). Currently, the shale pile appears to be static. However, if the shale pile's residual hydrocarbons begin to migrate into the drainage area, stabilization will be necessary for Clean Water Act and CERCLA compliance. It may be difficult to transfer this liability to a potential purchaser. In this regard, DOE may choose retain responsibility for mitigating the shale pile. The total cost for stabilizing the shale pile is estimated at $12,000,000.

1.10.2.3 Potential NOSR-3 Environmental Liability

The 1991 Environmental Assessment described a proposed development plan that included drilling 82 additional wells for continued development on NOSR 1 and 3. There will be environmental compliance and remediation costs associated Figure 1.38 with each new well. Currently, annual operating costs for environmental compliance at NOSR-3 is estimated to be $3,000 per well.

NOSR-3 Environmental Liability

FIGURE 1.38A-NOSR-3
300,000 ton Burnt shale pile.

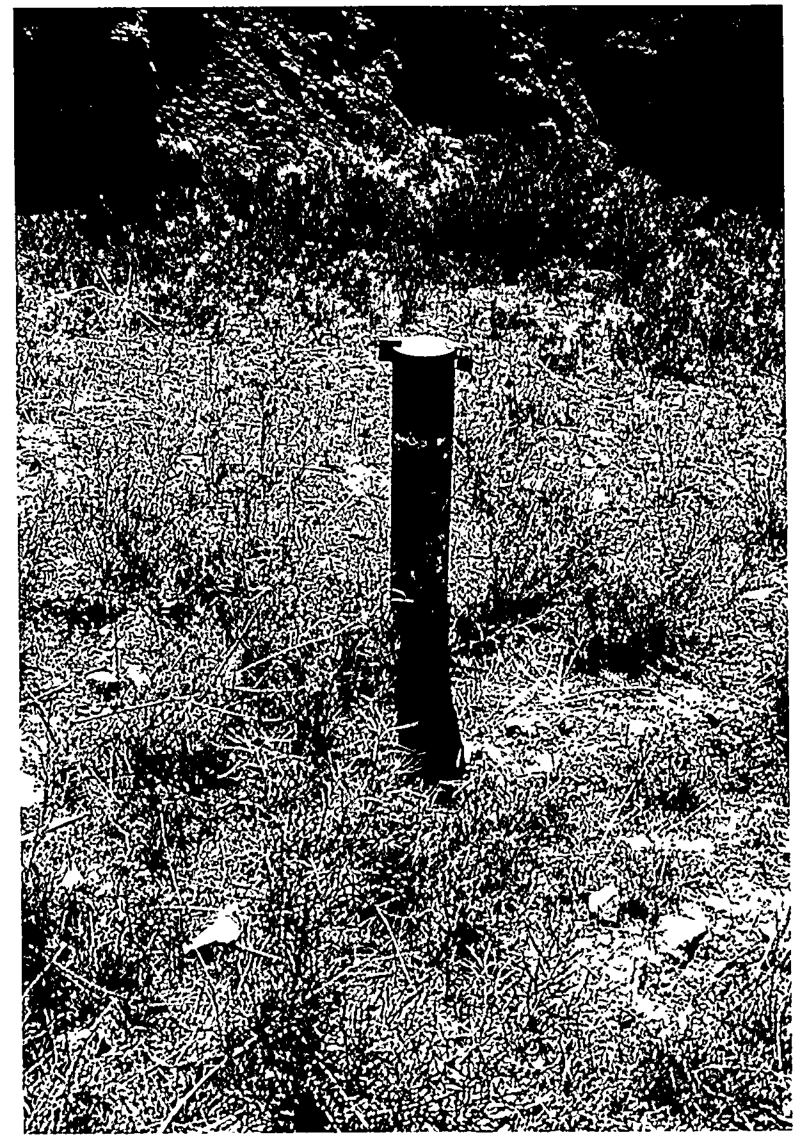


FIGURE 1.38B-NOSR-3 Shale pile
groundwater monitoring well

Table 1.10

Private Sector
Environmental Operating Expenses

	Annual Cost
Hazardous Waste Disposal	**$3,000**
Characterize and dispose, as necessary, hazardous waste; equipment maintenance, Underground Storage Tank and soil testing.	
Routine environmental monitoring	**$2,500**
Annual groundwater and surface water testing of shale pile	
Environmental, Safety, and Health Staff	
33% of one employee for Environmental, Safety, & Health oversight and management	$23,500
Travel costs for oversight and monitoring	$ 5,000
	$28,500
Compliance and Monitoring Equipment	**$11,500**
ES&H materials such as containers, test kits and general supplies for operation of compliance and monitoring programs.	
TOTAL PRIVATE INDUSTRY ANNUAL OPERATING COSTS:	**$45,500**

1.10.2.4 Potential NOSR-1 Environmental Liability

NOSR-1 has remained undeveloped, therefore, environmental impacts have been confined to present-day cattle and sheep grazing, hunting and camping. NOSR-1 contains critical habitat for Table 1.10 endangered species (Figure 1.39A and B) and would require an environmental impact statement prior to full scale oil and gas drilling. Potential environmental liabilities for proposed oil and gas drilling on NOSR-1 include: An Environmental Impact Statement (EIS) - National Environmental Policy Act (NEPA), waste water storage - Clean Water Act (CWA), hazardous waste disposal - Resource Conservation and Recovery Act (RCRA), and ground and surface water monitoring - Clean Water Act (CWA), and site reclamation - Colorado Oil and Gas Commission. An EIS takes between 12 and 18 months to conduct prior to development and costs and estimated $2,000,000. Based on annual compliance costs for existing wells on NOSR-3 there will be an additional $3,000 per year for each new well drilled on NOSR-1. Mud pit reclamation capital costs associated with drilling activities will add approximately a $3,000 one-time cost per well.

1.11 SPECIAL ASSETS/LIABILITIES

This Appraiser is not aware of any special assets or liabilities other than those mentioned in the previous section of this Report.

1.12 EFFECT OF TAXES

Taxes are levied by federal, state and local authorities. DOE, as a part of the U. S. Government, is not required to pay taxes to any of these authorities. However, if a portion or all of the mineral (i.e., oil and gas) interests and surface rights are transferred to private ownership; then taxes reduce the income to the owner and thereby impact the value.

NOSR-1 Critical Habitat for Endangered Species

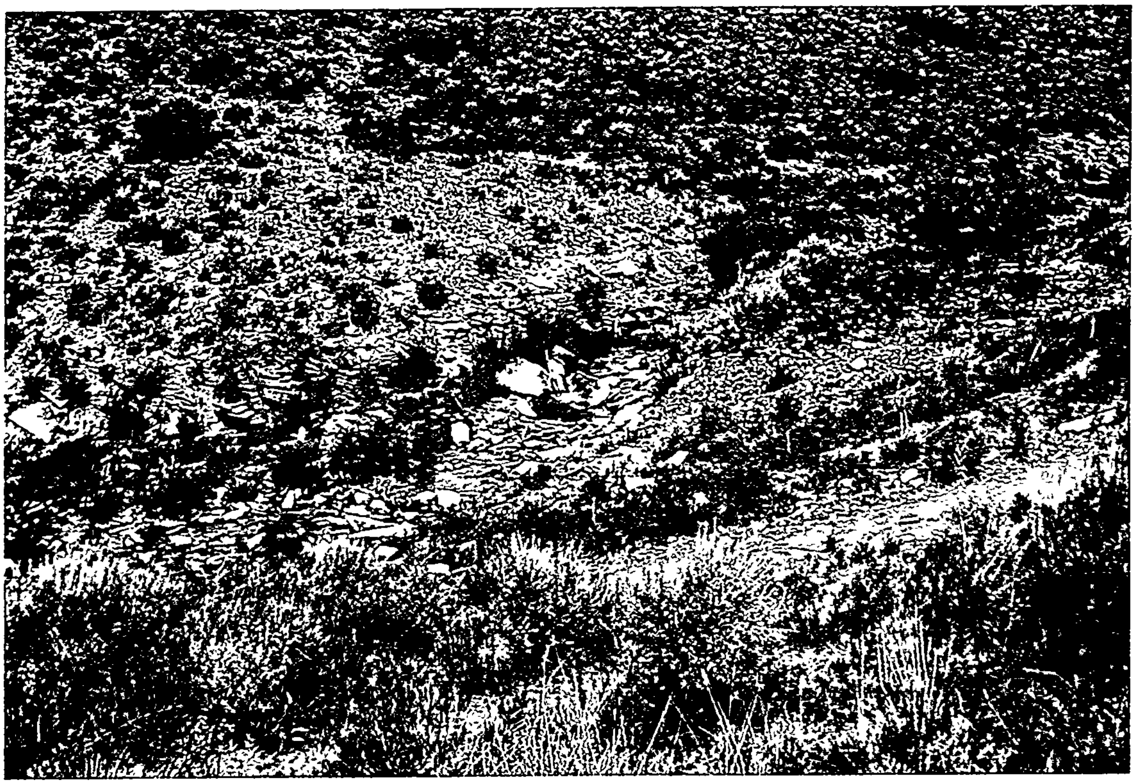


FIGURE 1.39A-NOSR-1
Colorado
Cutthroat trout
Habitat
(State listed)

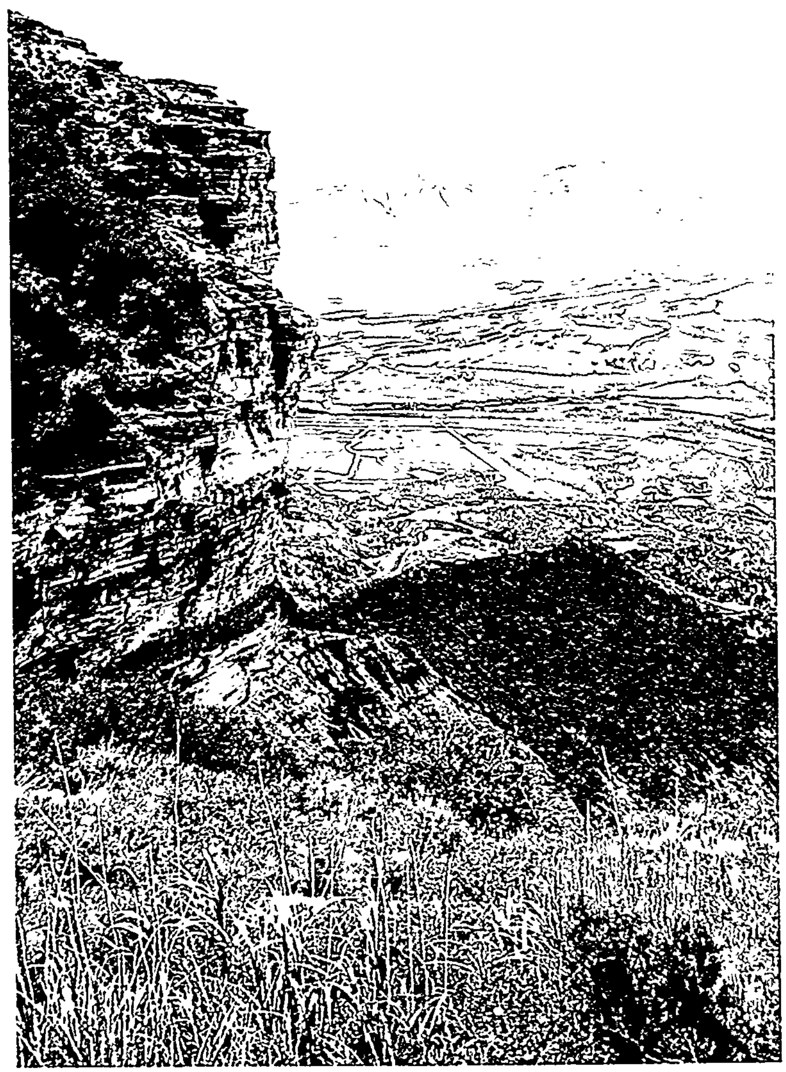


FIGURE 1.39B- NOSR-1
Peregrine
Falcon Habitat
(Federally listed)

1.12.1 Federal Income Taxes

The private ownership of mineral interests are taxable to the extent that taxable income is generated from the sale of those minerals. Currently, NOSR-1 does not generate any income and NOSR-3 generates income that is not taxable because all revenue goes to the Treasury Department. Transfer within the Federal Government is not expected to change the flow of revenue to the Treasury Department. If Department of Interior (DOI) leases the properties, the lease transfers a portion of the mineral ownership to the individuals and companies. These parties are expected to continue gas production from NOSR-3 and begin production from NOSR-1. As a result of production, taxable income may be generated by the lessees. The transfer of fee interest in the properties is expected to produce taxable income in a similar fashion.

Federal income tax liability impacts the value of the mineral interest that is transferred to private individuals or companies. Estimating the new owner's tax liability is a rigorous process based upon ever changing IRS regulations. There are tax differences, such as tax rates, between individuals and corporations. Similarly, there are tax differences due to variations between corporations.

1.12.2 Colorado Income Taxes

Similar to the impact of federal income taxes, the transfer of ownership of the properties in ownership will impact the value of NOSR 1 and 3. Currently, corporate state income tax in Colorado is five percent.

1.12.3 Ad Valorem Taxes

Local taxing authorities levy taxes against property owners when the property is located within the authority's taxing district. Based upon the value of the NOSR 1 and 3 properties, as determined by the county tax assessor, the new owner would be liable for ad valorem taxes. These taxes are estimated to be 5.25 percent of the previous year's well head revenue, that is, revenue after transportation charges but before operating expenses.

1.12.4 Severance Taxes

Colorado also levies taxes based upon the well head value of produced oil and gas. Like ad valorem taxes, severance taxes are independent of the profitability of the owner. If sold or lease, the new owner would be liable for severance taxes for their portion of the production. Severance taxes are estimated to be two percent of the well head revenue paid quarterly in arrears. Colorado allows the owner to take a tax credit against their severance taxes equal to 87.5 percent of the ad valorem taxes. Since Garfield County ad valorem taxes are 5.25 percent, 87.5 percent of ad valorem taxes exceed severance tax liability. As a result, no severance taxes would be due on either NOSR 1 or 3.

The following table shows the impact on each taxing authority under the different cases:

Taxing Authority		*Retention by Federal Government*	*Transfer to DOE*	*Sale*
Federal	Income tax and royalties	No taxes	Income from lease bonus, 50% of royalties, and income taxes	Income from sale and income taxes
State	Income, severance, and sales taxes and royalty	Not an eligible taxing authority	Income from income taxes, sales tax, and 50% of royalty	Income from income and sales taxes
Local	Ad valorem and sales taxes	Not an eligible taxing authority	Income from ad valorem and local sales taxes	Income from ad valorem and local sales taxes

If the properties are retained by the Federal Government without further develop these resources. Without further development and at steady prices, the federal treasury revenue would decline and the properties would not generate any income for state or local economies. New legislation is required to move the custody of the properties to another federal agency. Assuming the legislation also provides money and gives authority for exploration and development, there is a possibility that gas reserves could be further developed. The addition sale gas would generate additional revenue for the Federal Government. Neither the state or local government would be direct beneficiaries of the success of the government's exploration and production. However, there would be a secondary benefit to the state and local government in terms of increased employment, personal income taxes and sales taxes. However, as opposed to private development and production, the state would not receive severance and income taxes. Similarly, local governments would not receive ad valorem taxes.

Another option is for DOI to lease the properties. Income to the Federal Government would be generated from the lease bonus, delayed rentals, royalties, and annual income taxes from taxable income. The lease bonus is received quickly. Delayed rentals are received before production begins. The royalties would be received as production came on and only if oil and gas were discovered and developed. Federal and state income taxes attributed to this property may be delayed several years until the firm recovers their investments through depletion, depreciation, and a write-off of the expenses. The state would receive some benefits as soon as production began from their share of royalties and later from income taxes. Local governments would receive ad valorem taxes immediately. These ad valorem taxes can be expected to increase while more reserves are proven.

Income to the Federal Government can be generated from a one-time fee interest sale and from annual income taxes. Like the lease bonus, the sale price is received quickly. No delayed rental would be received in this case. Federal and state income taxes attributed to this property would be delayed several years until the firm recovers their investments through depletion, depreciation, and a write-off of the expenses. The local governments would receive some benefits as soon as production began from ad valorem taxes.

2. MARKET

2.1 CURRENT LEASING ACTIVITIES

2.1.1 Methodology

Market data was obtained from the Lakewood office of the Bureau of Land Management for recent competitive oil and gas lease sales on federal lands in western Colorado. Research was also conducted in certain county courthouses in western Colorado in order to obtain information on lease transactions for fee lands. There were no lease sales on lands owned by the State of Colorado that could be used in this market assessment.

2.1.2 Area of Investigation

Research for the leasing activity described above was conducted in Garfield, Mesa, and Rio Blanco Counties, Colorado. Oil and gas activity in these counties is considered comparable to the conditions present on the NOSR-1 and 3 sites. Incorporating these areas of the western slope as part of the study area allowed for a good statistical sampling of market data.

2.1.3 Assessment of Current Lease Rates for Rank Wildcat Properties

The results of Colorado federal and fee leasehold transactions are presented in Appendices D and E. Lease transactions on federal lands report all pertinent information regarding the transaction including bonus amount, royalty rate, rental and term. Fee lease transactions typically only report royalty rate and term on the lease document. Acreage rentals and bonus amounts usually are not reported and must be obtained from the parties involved.

Leasing activity in the area of investigation was moderately active over the past three years. A considerable amount of acreage was leased to the south, southwest and northwest of NOSR 1 and 3 (Plate III). For the federal lease transactions, bonus amounts range from a low of $2.00 per acre to a high of $600 per acre (Figure 2.1). Bonus amounts in the $2.00 per acre range were for those lands that were undeveloped and located some distance from production. The data is presented statistically on Table 2.1. Higher bonus amounts are paid for those lands closer to production and/or considered prospective by the oil and gas operator. Two separate tracts located in close proximity to Rulison field were leased for bonus amounts of $36.00 and $85.00 per acre respectively. Federal acreage located southwest and northwest of the subject properties were in the range of $2.00 to $20.00 per acre.

Based on the market data obtained, royalty rates for both fee and federal acreage are almost always 1/8 or 12.5 percent (Figure 2.2). Some private landowners granted leases for a 1/6 royalty in western Garfield County. One lease transaction involved a 25 percent royalty. Acreage rentals do not vary much and the lessor typically receive one to two dollars per acre over the term of the lease.

The lease term for federal acreage is ten years. On fee leases, the lease term is typically three to five years with options to renew for an additional two years (Figure 2.3).

2.1.4 Standard Terms for BLM Leases Under the Federal Onshore Oil and Gas Leasing System

The Mineral Leasing Act of 1920, as amended, and the Mineral Leasing Act for Acquired Lands of 1947, as amended, give the Bureau of Land Management (BLM) responsibility for oil and gas leasing on about 570 million acres of BLM, national forest lands, as well as private lands where mineral rights have been retained by the Federal Government.

Regulations that govern the BLM's oil and gas leasing program are found in Title 43, Groups 3000 and 3100, of the Code of Federal Regulations.

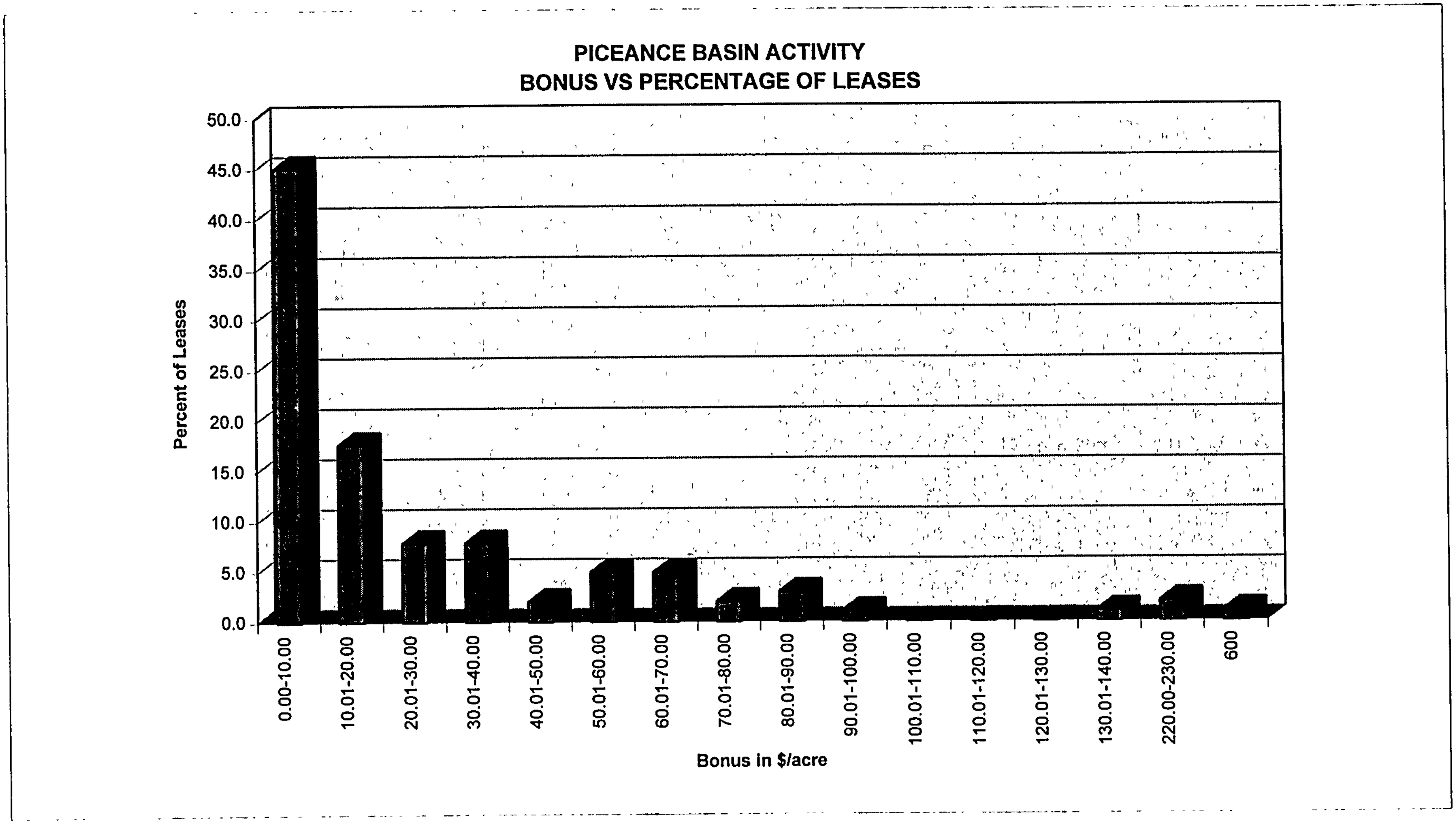


Figure 2.1 Federal oil and gas lease bonus data.

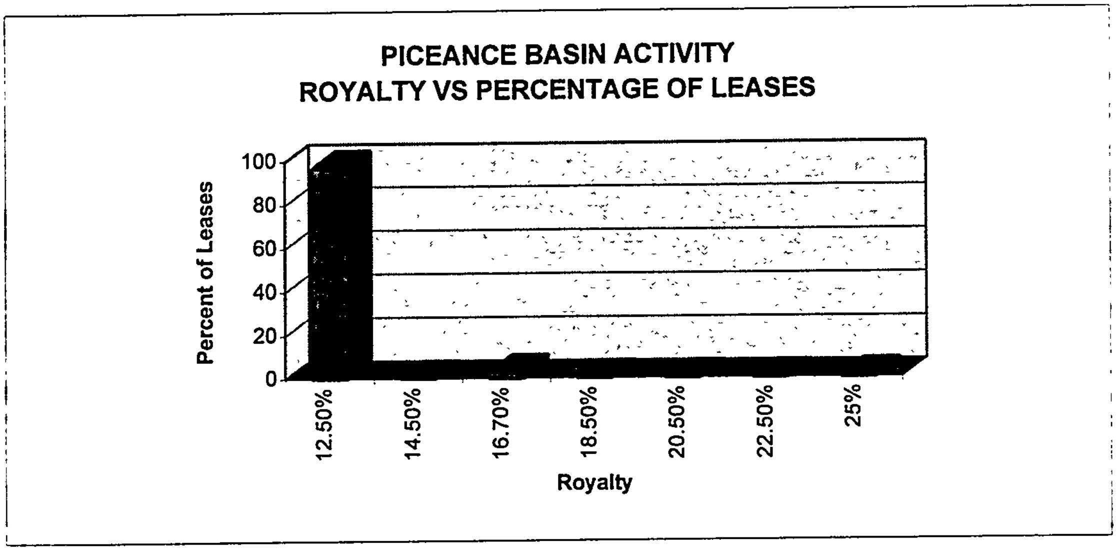


Figure 2.2: Federal and Fee oil and gas lease royalty rates.

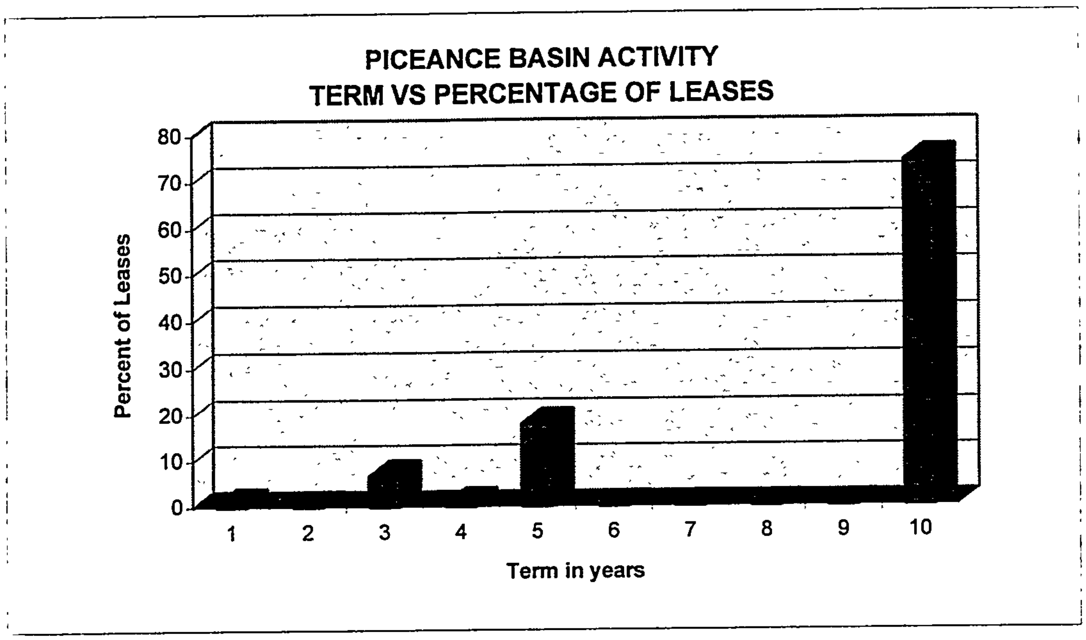


Figure 2.3: Federal and Fee oil and gas lease terms.

Table 2.1
Statistical Data for Piceance Basin Oil and Gas Lease Sales

		Bonus $/acre	Royalty %	Term years
Federal	**Mean**	$ 32.29	12.50	10
	Median	$ 2.50	12.50	10
	Mode	$ 2.00	12.50	10
Fee	**Mean**	*	16.70	5.4
	Median	*	12.50	5
	Mode	*	12.50	5
Total	**Mean**	$ 32.29	12.7	8.5
	Median	$ 2.50	12.5	10
	Mode	$ 2.00	12.5	10

* Currently under investigation

2.1.4.1 Lands Available for Leasing

Public lands are available for oil and gas leasing only after they have been evaluated through the BLM's multiple-use planning process. In areas where development of oil and gas resources would conflict with the protection or management of other resources or public land uses, mitigating measures are identified and may appear on leases as either stipulations to uses or as restriction on surface occupancy.

2.1.4.2 Lessee Qualifications and Limitations

Federal oil and gas leases may be obtained and held by any adult citizen of the United States. No lease may be acquired by a minor, but a lease may be issued to a legal guardian or trustee on behalf of a minor. Associations of citizens and corporations organized under the laws of the United States or of any State also qualify.

Aliens may hold interests in leases only by stock ownership in U.S. corporations holding leases and only if the laws of their country do not deny similar privileges to citizens of the United States. They may not hold a lease interest through units in a publicly traded limited partnership.

2.1.4.3 Types of Oil and Gas Leases

The BLM issues two types of leases for oil and gas exploration and development on lands owned or controlled by the Federal Government - competitive and noncompetitive.

The Congress passed the Federal Onshore Oil and Gas Leasing Reform Act of 1987 to require that all public lands that are available for oil and gas leasing be offered first by competitive leasing. Noncompetitive oil and gas leases may be issued only after the lands have been offered competitively at an oral auction and not received a bid.

The maximum competitive lease size is 2,560 acres in the lower 48 States and 5,760 acres in Alaska. The maximum noncompetitive lease size in all States is 10,240 acres.

Since passage of the Energy Policy Act of 1992, both competitive and noncompetitive leases are issued for a 10 year period. Both types of leases continue for as long thereafter as oil or gas is produced in paying quantities.

2.1.4.4 Competitive Leasing Process

Oral auctions of all oil and gas leases are conducted by BLM State Offices not less than quarterly when parcels are available. A Notice of Competitive Lease Sale, which lists lease parcels to be offered at the auction, are published by each BLM State Office at least 45 days before the auction is held. Lease stipulations applicable to each parcel are specified in the Sale Notice.

Lands included in the Sale Notice come from three sources:

1) Existing leases that have expired, terminated, or been canceled or relinquished;
2) Parcels identified by informal expressions of interest from the public or by the BLM for management reasons;
3) Lands included in offers filed for noncompetitive leases.

Each Sale Notice may be obtained for a nominal fee from the appropriate BLM State Office having jurisdiction over the lands.

All auctions are conducted with oral bidding. Bidders must attend the auction to obtain a competitive lease or provide for someone to represent them. No sealed or mailed bids are accepted.

On the day of the auction, the successful bidder must submit a properly executed lease bid form, which constitutes a legally binding lease offer, and pay a share of the sale costs ($75 per lease); the first year's advance rental ($1.50 per acre or fraction thereof); and not less than the $2.00 per acre minimum bonus bid. The balance of the bonus bid must be received within 10 working days of the auction. Those bidders who fail to submit the balance of the bonus on time will forfeit their entire deposit.

2.1.4.5 Noncompetitive Leasing Process

The lands in expired, terminated, relinquished, or canceled leases will not be available for noncompetitive leasing until they have been offered competitively in a Sale Notice for an auction and failed to receive a bid. A noncompetitive presale offer may be filed on such lands if the prior lease expired or terminated or was relinquished or canceled at least 1 year before the presale offer is submitted to the proper BLM State Office.

Following an auction, all the lands that were offered competitively but received no bids will be available for noncompetitive lease issuance for 2 years, beginning the first business day following the last day of the auction, as specified in the Sale Notice.

For noncompetitive leasing, each offer must be submitted on a separate lease offer form. From the first business day following the auction through the last day of the same month, lands must be identified only by the parcel identification number as specified in the Sale Notice. Thereafter, and until the end of the 2 years of noncompetitive availability, offers must use legal land descriptions and are not limited to the parcel configurations offered at the auction.

Offers must be made on a BLM - approved form. They must include payment of a $75 non-refundable filing fee and the first year's advance rental of $1.50 per acre.

All noncompetitive lease offers filed on the first business day following the auction will be considered as having been filed simultaneously. The priority among any multiple offers received on this day for the same parcel will be determined by drawings open to the public. Offers received on subsequent days will receive priority according to the time of filing; for example, an offer filed at 10:15 a.m. will have priority over an offer filed at 10:16 a.m.

2.1.4.6 Lease Terms and Conditions

The lease grants the lessee the right to explore and drill for, extract, remove, and dispose of oil and gas deposits, except helium, that may be found in the leased lands.

Subject to special restrictions as noted above, the leases are granted on the condition that the lessee will have to obtain BLM approval before conducting any surface-disturbing activities. The oil and gas lease conveys the right to develop those resources on the leased land. The lessee or his/her operator cannot build a house on the land, cultivate the land, or remove any minerals other than oil and gas from the leased land.

2.1.4.7 Bonding

Before any surface-disturbing activities related to drilling can begin, the lessee or his/her operator must furnish a bond in the amount of at least $10,000 to ensure compliance with all the lease terms, including protection of the environment. With the consent of the surety and principal, the operator may use the bond of another party such as the lessee. Each time there is a new operator, that operator must notify the BLM that he/she is the responsible operator, giving the particulars of the bond under which he/she will operate. Acceptable instruments of bonding are surety bonds, or personal bonds accompanied by negotiable Treasure securities, cashier's check, certified check, certificate of deposit, or irrevocable letter of credit.

The BLM may require an increase in the bond amount any time conditions warrant such an increase.

2.1.4.8 Rentals

Annual rental rates for both competitive and noncompetitive lease are $1.50 per acre (or fraction thereof) in the first 5 years and $2.00 per acre each year thereafter. After the lease is issued, rentals must be received at the Department of the Interior's Minerals Management Service (MMS) on or before the lease anniversary date to prevent statutorily required automatic termination of the lease. this requires mailing of the annual rental at least a week or 10 days in advance of the lease anniversary date to ensure timely receipt by the MMS.

2.1.4.9 Royalties

Royalty on production is 12.5 percent for both competitive and noncompetitive leases.

2.1.4.10 Assigning A Lease

Some people who acquire an oil and gas lease will assign the lease to another party. The value of oil and gas leases varies greatly. None of the parcels offered has been evaluated by the BLM for oil and gas potential prior to the competitive auction or to being made available for noncompetitive leasing. All of the lands included in noncompetitive lease have been offered at auction and received no bids.

Leases may be transferred by assignment or sublease. The transfer must be submitted to the BLM for approval within 90 days from the date of execution by the transferor. The rights of any transferee will not be recognized by the Government, and the transferor will remain responsible for the lease, until the transfer has been approved by the BLM. Leases may be transferred by assignment of record title or transfer of operating rights (sublease) as to all or part of the acreage in the lease or as to either a divided or undivided interest therein. An assignment of record title to either a separate zone or deposit or of part of a legal subdivision will not be approved, although a transfer of operating rights (sublease) as to a separate zone or deposit may be approved by the BLM, and the sublessee will be responsible for all obligations with respect to the lease rights transferred to the lessee.

2.1.4.11 How a Lease Expires or Terminates

Oil and gas leases expire at the end of their primary term -- the 10th year -- unless diligent drilling operations are in progress on or for the benefit of the lease; the lease contains a well capable of producing oil or gas in paying quantities; or the lease is receiving or is entitled to receive an allocation of production under the terms of an approved communitization agreement or unit agreement.

Leases without a producible well automatically terminate if the lessee fails to make full and timely payment of the annual rental. The rental must be received by the proper Federal office on or before the anniversary date of the lease. The automatic termination is specifically prescribed by law, is not the result of BLM action, and cannot be waived.

The owner of a lease may also surrender the lease in whole or in part by filing a written relinquishment with the proper BLM State Office having jurisdiction over the lands. A relinquishment takes effect on the date it is filed. However, the lessee must plug any abandoned well, perform other work as may be required by the BLM to place the leasehold in proper condition for abandonment, and bring his account into good standing. If the lessee fails to perform the necessary work, the lessee's bond will be used to do so, and the lessee will be prohibited from leasing any additional Federal lands.

A nonproducing lease may be canceled for failure to comply with lease terms.

2.2 RECENT MINERAL SALES

2.2.1 Methodology

An assessment of the current market was conducted in order to find transactions of mineral properties recently sold in the area of study. Market data was gathered for all types of oil and gas properties since the NOSR-1 and 3 sites included producing wells, offset locations and exploratory acreage.

Research was conducted at the Colorado Oil and Gas Commission in order to identify recent operator transfers of producing properties in the Piceance Basin. These transfers often indicate a sale and the legal instruments associated with this transaction were then obtained from the county courthouse records.

The market for undeveloped and exploratory acreage is best evaluated using mineral conveyances in the area. In this regard, this Consultant searched and obtained information on mineral deeds and conveyances that were recorded in the county courthouse.

2.2.2 Area of Investigation

Research for the transactions described above was conducted in Garfield, Mesa and Rio Blanco Counties, Colorado. Oil and gas activity in these counties is considered comparable to the conditions present on the NOSR-1 and 3 sites. Incorporating these areas of the western slope allowed for a good statistical sampling of market data as part of the study area.

2.2.3 Assessment of Current Market

2.2.3.1 Producing Gas Properties

A courthouse search was conducted to obtain mineral deed, lease, and royalty sales, assignments and/or transfer data for the region surrounding NOSR-1 and NOSR-3 in Garfield, Mesa, and Rio Blanco Counties, Colorado. This search included lands surrounding NOSR-1 and NOSR-3 for a radius of approximately 50 miles. Over 90 records of such sales, transfers and assignments were recovered for a two year period dating back to mid-1994. A cursory analysis of these records was performed to determine the type of transaction that occurred, the parties that were involved, the status of the property which was conveyed or transferred and the geologic and geographic relationship to NOSR-1 and NOSR-3.

Records and documents retrieved include mineral deeds, assignment of interests or royalties, bills of sale, leases and subleases. The majority of the transactions involved leases of federal and fee acreage. There were only a handful of state lease transactions. Transactions involved very small amounts of acreage (a few gross acres) to very large areas of up to 20,000 gross acres. Most of the transactions involved a few hundred to approximately 1,000 gross acres. Where working interests were conveyed and amounts were recorded, they varied from a few percent to up to 100 percent working interest.

Transactions were eliminated from the overall list if they did not appear to be 'arms-length' in nature, or were not subject to normal market conditions. Such transactions included those where companies or individuals were assigned royalties or rights to related or affiliated companies or individuals. For example, estate transfers involving trusts and/or wills. This eliminated approximately six of the transactions. Another ten transactions were temporarily eliminated because they were over 50 miles from NOSR-1 and NOSR-3.

The remaining records were further analyzed for properties which consisted of primarily producing vs. nonproducing acreage. The majority of the transactions (55 percent) involved primarily nonproducing acreage. The remainder (33 transactions) involved producing acreage. Most of the transactions found involving producing acreage are geologically comparable since they are all situated within 30 miles of NOSR-1 and NOSR-3. The geologic setting and producing horizons of the surrounding fields are similar in nature, therefore these nearby transactions are considered to be highly comparable. Further analysis should reveal the true nature of the transaction, the actual area and amount of interest transferred and the price per net mineral acre paid or received.

Transactions involving producing acreage were retrieved for areas within several nearby fields, including the adjacent Grand Valley-Parachute-Rulison area, Mam Creek, Gibson Gulch, Debeque, Coon Hollow, Roberts Canyon, Shire Gulch, Plateau, Whiskey Gulch, Buzzard, Sheep Creek and Divide Creek. These fields produce primarily from the Mesa Verde and Wasatch formations common to NOSR-1 and NOSR-3.

Within a ten mile radius of NOSR-1 and NOSR-3 there were 12 transactions involving producing acreage during the past two years. The remainder of the transactions are within a 30 mile radius of NOSR-1 and NOSR-3.

2.2.3.2 Mineral Deeds

Research in the county records over the past three years found twelve transactions involving mineral conveyances or mineral deeds where fee mineral interest was sold between two parties (Appendix G). A cursory glance indicates that some of these transactions may have involved lands with production established while others appear to be undeveloped. Most of the transactions are in the vicinity of subject properties. The terms of the deal and an accurate description of the mineral interest purchased is currently being researched by this Consultant as part of Phase 2.

2.3 FACILITY AND EQUIPMENT MARKET

2.3.1 Market for Used Tubular and Production Equipment

Essentially all wellbore tubulars and production equipment at NOSR-3 are presently utilized to maintain production operations. The equipment consists primarily of meter runs, and glycol dehydration units for each of the producing wells. This equipment is an integral part of gas reserve recovery, and therefore could not be sold at the present time. As previously stated in this report, equipment salvage values are much lower than the associated abandonment operations after production operations are completed and the associated reserves have been produced.

2.3.2 Market Value of Surface Assets

As discussed previously in this report, there is very little equipment that is not dedicated to the daily production from each well. The remaining surface assets at the NOSR sites is not expected to exceed $100,000 in value. Although these assets are not dedicated to a particular well, they are utilized as part of production operations at NOSR, and it is assumed that this equipment could only be salvaged at the end of field life. It is important to note that it may take some time and effort to realize the maximum market value for all of this equipment.

3. HIGHEST AND BEST USE DETERMINATION

3.1 INTRODUCTION

In conformance with standard appraisal techniques the property to be appraised must first be examined for its *Highest and Best Use*. This Appraiser is using the following definition for *Highest and Best Use*:

> "Either some existing use on the date of the transaction, or one which the evidence shows was so reasonably likely in the near future that the use would have affected its market price on the date of the transaction and would have been taken into account by a purchaser under fair market conditions" (emphasis added).

This definition has been adopted from the *Uniform Appraisal Standards for Federal Land Acquisitions*, 1992.

With this in mind, it becomes clear that an oil or gas property will have substantially different *Highest and Best Uses,* depending on its stage of development. Clearly, the *Highest and Best Use* of a producing oil or gas property is to produce income from the sale of production. Likewise, on the other end of the development spectrum, the *Highest and Best Use* of rank wildcat acreage, is the present value of the future bonuses and rentals that the property will bring to the landowner. Between these two extremes, properties may be nonproducing, although the reserve may be proven, or the property may be a prospect defined by seismic, by subsurface control, or by other means.

The *Highest and Best Use* of a nonproducing property may occasionally be related to the ability to produce income, if such income is shown to be reasonably close in the future. On the other hand, a prospect cannot be considered to be anywhere near the stage of income from oil production, partially because there may be a very substantial question with regard to actual discovery of reserves, and partially because the timing of drilling may be impossible to determine.

The acreage in NOSR 1 and 3 presents oil and gas properties with practically every type of *Highest and Best Use*. The types of uses are known in the oil and gas industry, in simplistic terms, as:

1. producing properties
2. undrilled development sites offsetting producing wells
3. exploratory prospects (drilling prospects)
4. seismic anomalies, also called seismic leads, and
5. land positions with no seismic or other geological leads.

Properties with each of these uses are represented by market transactions with unit values on a per-acre or per-MCF (or barrel-of-oil-equivalent) basis increasing in value from the nonprospective acreage on the low end of the spectrum to the producing wells on the high end. Figure 3.1 shows typical unit values as well as the apportionment thereof between the owners of various parts of the mineral estate.

Apportionment is an appraisal of the portion of the overall Fair Market Value accruing to each of <u>dissimilar</u> types of interests, such as leasehold versus executory versus non-participatory royalty interests and others. This is in contrast to Division, which is a clerical division of a Fair Market Value within a group of <u>similar</u> rights owners, such as leasehold interests, overriding royalty interests, unitized land owners' interests, etc.

3.2 PRODUCING PROPERTIES

The producing wells in NOSR-3, in Rulison, Grand Valley and Parachute fields represent a *Highest and Best Use* being the generation of income from gas (and related liquids) production.

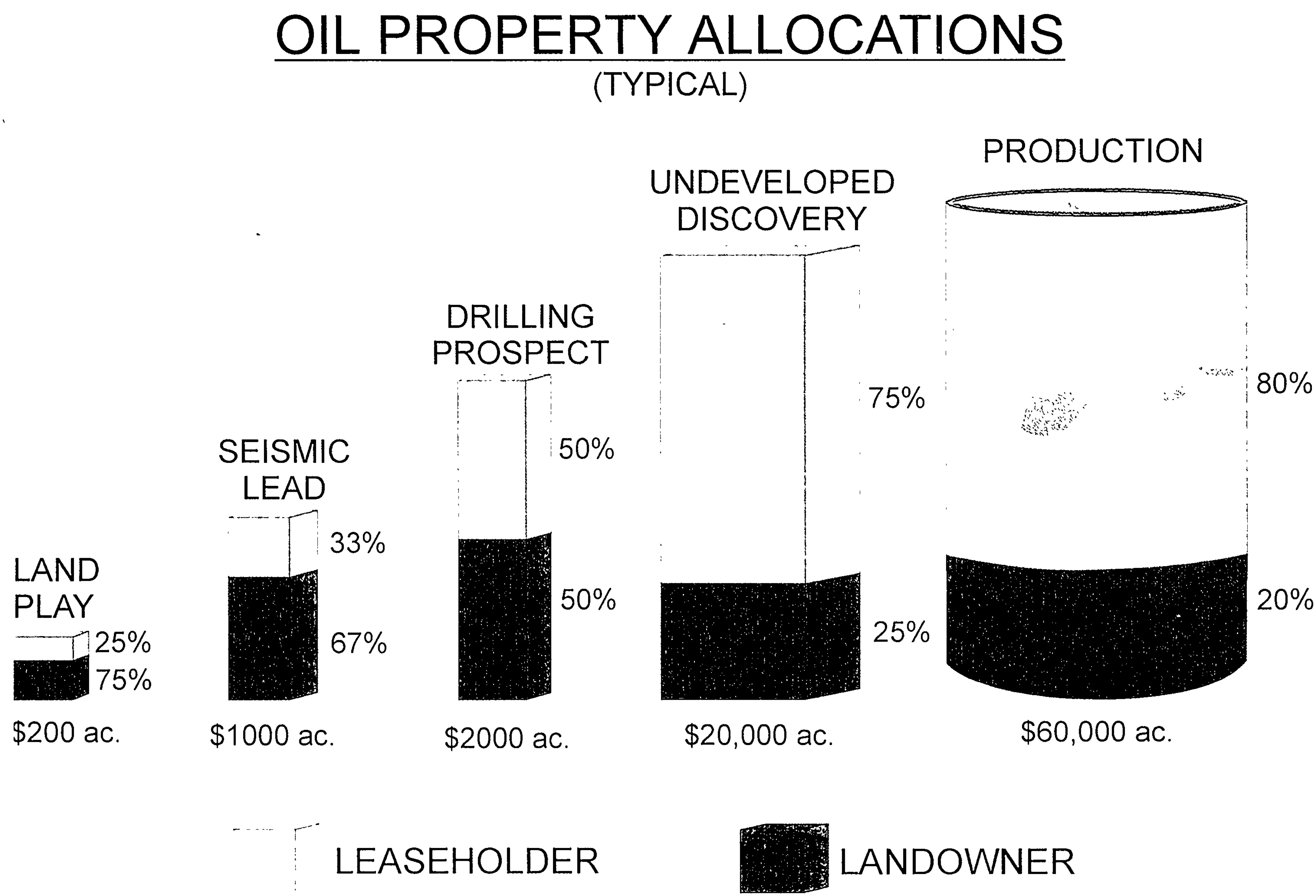

OIL PROPERTY ALLOCATIONS
(TYPICAL)
LAND PLAY
25%
75%
$200 ac.
SEISMIC LEAD
33%
67%
$1000 ac.
DRILLING PROSPECT
50%
50%
$2000 ac.
UNDEVELOPED DISCOVERY
75%
25%
$20,000 ac.
PRODUCTION
80%
20%
$60,000 ac.
LEASEHOLDER
LANDOWNER

FIGURE 3.1

As described in Section 1 and Appendix G, the DOE owns interest in 53 wells that produce gas from the Wasatch and Mesaverde formations. The *highest and best use* to this interest is the future income from production that will accrue to this ownership.

3.3 UNDRILLED DEVELOPMENT LOCATIONS

There are also likely many Wasatch and Mesaverde developmental locations immediately offsetting some of the producing wells which, until they are drilled, would represent the second category of *Highest and Best Use* of undrilled development sites. The exact number depends on spacing, gas pricing, and economic variables. The identification and assignment of these undrilled development sites is part of the additional effort in Phase 2.

3.4 EXPLORATORY DRILLING PROSPECTS

The third category, namely exploratory drilling prospects, is represented by seismic data acquired in the late 1980s and by possible extension or stepouts of existing fields. The nature of seismic data and its interpretation are such that an interpretation does not prove the existence of oil and gas or even a structure, but rather shows the possibility of a lead or prospect, subject to the skill and subjective opinion of a geophysicist.

If the data are good, and if the geophysicist is correct in his interpretation, and if an exploratory well is drilled, and if it penetrates the reservoir, and if the reservoir contains pore space and if the pore space contains oil or gas instead of water, and if the oil or gas can be produced economically and brought to market in a pipeline, then, and only then can income be derived from such production. Therefore, the *Highest and Best Use* of the exploratory drilling prospects at NOSR 1 and 3 are removed, both in distance and in timing, from income generation from oil and gas production. Instead, any drilling prospect has in own *Highest and Best Use* long before possible production because there is a brisk trade in such drilling prospects.

3.5 SEISMIC ANOMALIES OR LEADS

Frequently, the seismic data which is acquired in an exploratory area such as the east side of NOSR-1 may be inconclusive with regard to the possibility of oil or gas accumulations. Frequently, all that can be derived from the first seismic data acquired in an area may be an anomaly, or in other words something that looks unusual as compared to its surroundings. These anomalies may be leads which must be further analyzed. Generally this can only happen by acquisition of additional seismic data in the detail area of the anomaly. Consequently, the oil industry has developed the concept of buying seismic options in such areas of anomalies. The option concept is indicative that there is great uncertainty and therefore risk with regard to the possibility of drilling in the area, not to mention making discoveries of any oil or gas.

Typically, one oil company will option out its rights, or parts thereof to another capital-strong oil company in return for a binding agreement by the latter to finance the next stage of expenditures, that is the acquisition of additional seismic data. The conventional industry trade in this regard is for the new party (the buyer) to pledge to pay the entire cost of the next seismic acquisition in return for receiving 50 percent ownership in the property from the original oil company (the seller). The consideration is therefore not paid from one oil company to the other but rather "put into the ground" in form of a performance obligation.

Immediately after having signed the binding contractual agreement, the value of the seismic option is therefore equal to that of a performance commitment. The parties perceive that once the seismic work has been accomplished, then the value of the property has *theoretically* doubled (the cost expended divided by 50 percent). However, it is clear that it rarely will have exactly this value because the results of the seismic would either show that there now is a greater opportunity for finding a drillable structure (and consequently it would have a much greater value than before), while at other times the acquisition of the seismic and the interpretation may have shown that the opposite is the case (and consequently the value has been reduced). In short, the outcome is speculative and a new appraisal must be made once the results (good or bad) have been interpreted.

In the case of NOSR-1, various geologists and geophysicists have interpreted the existing seismic data. They sometimes differ in opinion with regard to both quality and location of the various lead areas. These leads represent areas where additional seismic data might be acquired either by the oil company itself or through option to another party. These properties represent a higher risk and consequently have a lower value than a drillable prospect.

3.6 EXPLORATORY

Portions of NOSR 1 and the east side of 3 also includes acreage which would fall into the exploratory acreage designation. This is acreage over which seismic data may or may not have been acquired, but where the interpretation has shown no specific promise of any prospects. It is also acreage where no data are available or which is some distance from production that it must be considered exploratory acreage. Still, oil companies will be willing to lease such acreage from time to time to conduct exploration. The present value of the future income from bonuses and rentals represents the overall value of the property, while the oil company's actual cost for such leases comprises its share of the overall value. This will be quantified in Phase II.

3.7 HIGHEST AND BEST USE OF THE PROPERTY INTERESTS APPRAISED

The *Highest and Best Use* of the property interest appraised herein is therefore the following:

1. For generation of income from producing properties: Those parts of the NOSR-3 acreage that has established production from producing wells. Specifically, the 53 wells that the DOE owns an interest which includes 26 communitized wells.

2. For evaluation of undrilled development locations offsetting producing wells: This includes the southern part of NOSR-3 which is adjacent to and in the vicinity of established production in the Parachute, Rulison and Grand Valley Fields.

3. For evaluation of exploratory drilling prospects: Those areas of NOSR 1 and 3 that include both seismic anomalies and possible regional extensions of the continuous gas accumulation given that such accumulations can be exploited economically.

4. For leasing: all those remaining tracts that do not contain seismic anomalies.

3.7.1 Comparison with Appraisal Institute Standards

An alternate approach is recommended by the Appraisal Institute (1992), who defines *Highest and Best Use* as: "The reasonable probable and legal use of vacant land or improved property, which is physically possible, appropriately supported, financially feasible, and that results in the highest value." Each of these criteria must be met sequentially.

For oil and mineral properties the comparable definition can be applied by testing the candidate uses sequentially against each of five criteria:

1. Physically possible. The property must possess adequate size, dimension, shape, quality of reservoir and resource, and geotechnical quality to support the proposed use. As an example, an oil reservoir consisting of many, very thin interfingering sands and shales may not be physically possible to produce.

2. Legally permissible. The proposed use of the property must conform to all local, state and federal zoning and use restrictions for the property. A negative example is an otherwise well-tested stone quarry, ready to develop except for the lack of a mining permit.

3. Financially feasible. The proposed use must be capable of providing a net return to the property owner or leaseholder. Here, the uncertainty of, for example, the amount and category of gas reserves could reduce an undeveloped location to an exploratory drilling prospect.

4. Maximally productive. Of those physically possible, legally permissible, and financially feasible uses, the *Highest and Best Use* for a property is that use that results in the highest value; that is, the use that provides the greatest net return to the property owner and leaseholder in combination, and as of the date of the evaluation or firmly planned for the immediate future.

5. Economically fitting. This fifth criterion adds: the proposed use must fit with the constraints with regard to oil and mineral development of relevant firms, institutions, governments, and markets. For example, impending environmental or surface access regulations on the area as a whole may make the proposed use of a mineral property problematic.

3.7.2 Application to NOSR 1 and 3

Depending on the location with regard to the results of the geological and geophysical interpretation, this Appraiser searched for candidate uses ranging from leasing to oil companies to generation of income from oil and gas production. In this section we will apply the Appraisal Institute criteria for *Highest and Best Use* to double check our prior selection. Note that once a criterion is not met, the sequential test is suspended for that possible use, and another use must be tested.

It is seen from Table 3.1 that NOSR 1 and 3 fulfills all sequential criteria for the current use as producing wells, development locations, drilling prospects, seismic leads and exploratory acreage.

3.7.3 Conclusions with Regard to Highest and Best Use

The Fair Market Value is to be estimated with reference to the property's *Highest and Best Use* -- that is, the highest and most profitable use for which the property is suited and needed or likely to be adapted to which in the near future without speculation.

TABLE 3.1
SEQUENTIAL TEST FOR HIGHEST AND BEST USE

Candidate Use	CRITERIA MET				
	1 Physically Possible	2 Legally Permissible	3 Financially Feasible	4 Maximally Productive	5 Economically Fitting
Producing Wells	Yes	Yes	Yes	Yes	Yes
Development Locations	Yes	Yes	Yes	Yes	Yes
Drilling Prospects	Yes	Yes	Yes	Yes	Yes
Seismic Leads	Yes	Yes	Yes	Yes	Yes
Exploratory Acreage	Yes	Yes	Yes	Yes	Yes

Specifically, this Appraiser has carefully studied the geology and production history of the property. We have fairly shown that producing wells and development locations offsetting the wells exist. Also, exploratory drilling for oil and gas is reasonably likely and might be conducted in the near future for certain tracts. The *Highest and Best Use* of certain other portions of the NOSR 1 and 3 is as seismic anomalies that would require additional seismic evaluation. The remainder of the appraisal property does not even contain seismic leads, so its *Highest and Best Use* is for the generation of income to the mineral rights owner by leasing of oil and gas exploration rights to oil companies. These considerations would be brought forward and given substantial weight in a bargaining over the property between willing and knowledgeable buyers and sellers.

APPENDIX A

USGS UNPUBLISHED REPORT ON PETROLEUM GEOLOGY OF PICEANCE BASIN

Petroleum Geology Of Piceance Basin,
Context For
Naval Oil Shale Reserve 3, Colorado,

Geologic Framework

U.S. Naval Oil Shale Reserve 3 is located near the southeast margin of the Piceance basin, Colorado. The Reserve is underlain by petroliferous rocks of several ages that have yielded oil and/or gas in nearby fields.

The combined Uinta-Piceance (UP) basin is a structural and topographic basin that trends east-southeast in northeastern Utah and northwestern Colorado and roughly parallels the Uinta Mountains to the north. It is an asymmetrical structural trough filled by as much as 5,000 m (17,000 ft) of Cretaceous Maastrichtian and Paleogene sedimentary rocks. The sedimentary-rock section reaches a thickness of greater than 30,000 ft over much of the area with Cretaceous and Tertiary strata locally comprising more than 2/3 of that thickness.

Oil & Gas Plays

Oil and gas accumulations in the UP basin can be grouped into *plays*, that is, hydrocarbon accumulations with common characteristics. The play has as its essence the notion that variance in stratal or rock properties, generally factors involving petroleum source, reservoir, and trapping units, has served to isolate accumulations to restricted areas. If conditions are favorable for discovery and exploitation, the accumulations may become fields. In other words, groups of fields and undiscovered hypothesized accumulations with similar geologic and engineering (production) characteristics constitute a play. These common characteristics or factors establish a basis for understanding such that their presence can be predicted in undrilled and otherwise unexplored areas, and so that the amount of oil and gas resources in the undrilled areas can be estimated.

At least three major plays can be identified in the NOSR 3 area . The three are 1: the Pennsylvanian-Permian play; 2: the Cretaceous play; and 3: The Tertiary Wasatch Formation play. These plays can in turn be subdivided (i.e.. Cameo, Corcoran, Cozzette, Mt. Garfield, Dakota, Sego, Castlegate, Morrison, Weber, Mancos B, etc.).

Reserve 3 yields a great quantity of gas in reservoir whose values of matrix permeability, exclusive of fracture permeability, are commonly below 0.1 md *in situ* to gas. Gas in these reservoirs is commonly included in the estimates of unconventional gas. For the most part, successful production of unconventional natural gas in the Piceance basin is most successful where the strata are fractured naturally and where the rocks have fluid-pressure gradients more than 0.5 psi/ft.

Play 1: The Pennsylvanian and Permian play involves a regionally extensive complex of reservoir quality eolian and associated sandstone that is bounded on the west and north by nonreservoir marine rocks, and on the east and southeast by the nonreservoir redbed lithologies . Over much of the region, reservoir rocks in Play 1 contain oil in the subsurface and are stained on surface exposures. For purposes of this study, structures associated with salt in the Paleozoic section are grouped with this play as are Mississippian age potential carbonate reservoir rocks.

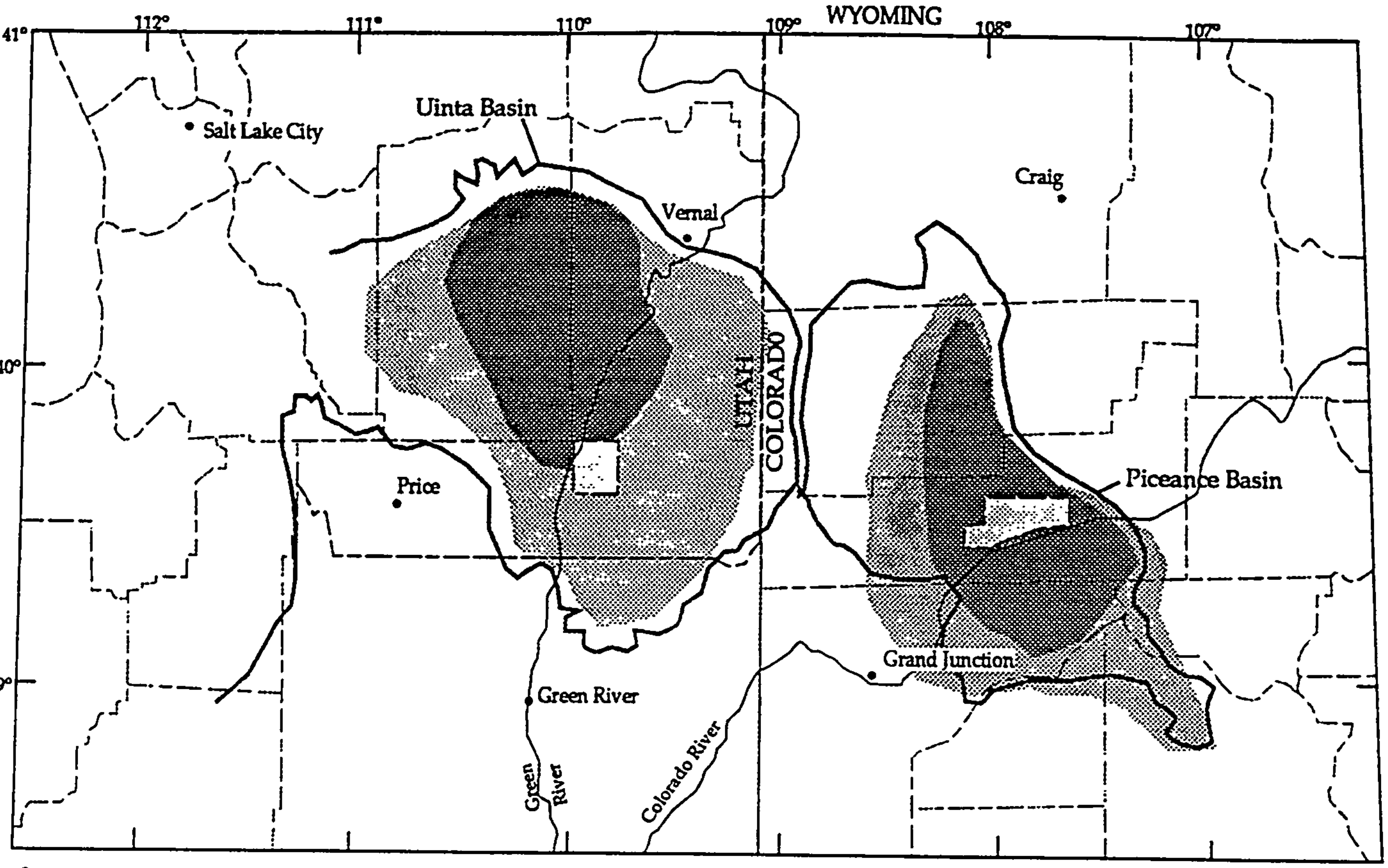
Existing fields in the play involve stratigraphic traps draped across structures in the Paleozoic rocks. The play includes the largest oil field in the Rocky Mountain region, Rangely field, and stratigraphically and temporally equivalent beds contain several billion barrels of oil in place at the Tar Sand Triangle in the northern part of the Paradox basin of eastern Utah .

The largest known accumulations in the play are of oil, but vitrinite reflectance values (Ro > 1.1) for strata of this play in the area, and the anticipated deep drilling depths required to reach the play under the NOSR 3, suggest that the stable hydrocarbon species will be gas.

Play 2: The Cretaceous play consists of mixed stratigraphic and structural accumulations, of both conventional and unconventional gas, in sandstone reservoirs of the Upper Cretaceous Mesaverde Group, the Mancos B (Emery Sandstone part? equivalent), Frontier and Ferron Sandstones, Lower and Upper Cretaceous Dakota Group and associated units, and in various members of the Jurassic Morrison Formation.

Reconstructions of the burial history of the strata and measures of vitrinite reflectance (Ro), indicate that gas is currently being generated from source rocks within the section and as a result, fluid-pressure gradients exceed 0.5 psi/ft in existing wells and can be expected to as high or higher in unexplored units. Porosity for units below 10,000 ft is commonly below 10%. Many of these reservoirs will be characterized by values of matrix permeability below 0.1 md *in situ* to gas.

The composition of source rock (Type III organic matter--high oxygen to hydrogen ratio) units is such that most hydrocarbons generated from them are gas. In addition, the gas generating section appears to be continuously saturated and relatively free of water/gas contacts. These relations suggest that the regional extent of the gas-saturated zone will be much larger than that established by current drilling, and that it will underlie most of Reserves 3 and 1. In addition, seismic data from the NOSR and regional stratigraphic data indicate the play should yield gas on the Reserves.



0 50 100 KILOMETERS

20 40 60 MILES

Figure 3

Play 2: Cretaceous Mesaverde gas play: darker pattern indicates area where porosity values for most Kmv reservoirs will be 10 % or below, but is area of significant gas generation; fluid-pressure gradients are likely to be 0.5 psi/ft or higher; and gas/water contacts are rare to absent. Includes all Cretaceous and Jurassic rocks. Many current gas wells yield 1 BCF ± recoverable. Light play area features reservoirs of higher porosity & permeability and water/gas contacts are common.

Play 3: The Tertiary Wasatch Formation play consists of structural and stratigraphic accumulations of gas trapped in Paleocene and Eocene sandstone reservoirs of the Wasatch Formation. Most of the gas in the play has migrated vertically from source Type III (woody-herbaceous) rocks in the underlying Cretaceous section or possibly from local sources in the Green River Formation.

Gas/water contacts are rare to absent, and reservoirs yield gas, some condensate and a little water. The play can be expected to be productive over much of the Colorado Reserves. In southern parts of the play in the Piceance basin, reservoirs yield gas on structures but yield water in structural lows. Thus, the structure of the Tertiary strata is locally especially important to the evaluation of resources and reserves in regions near the play margin.

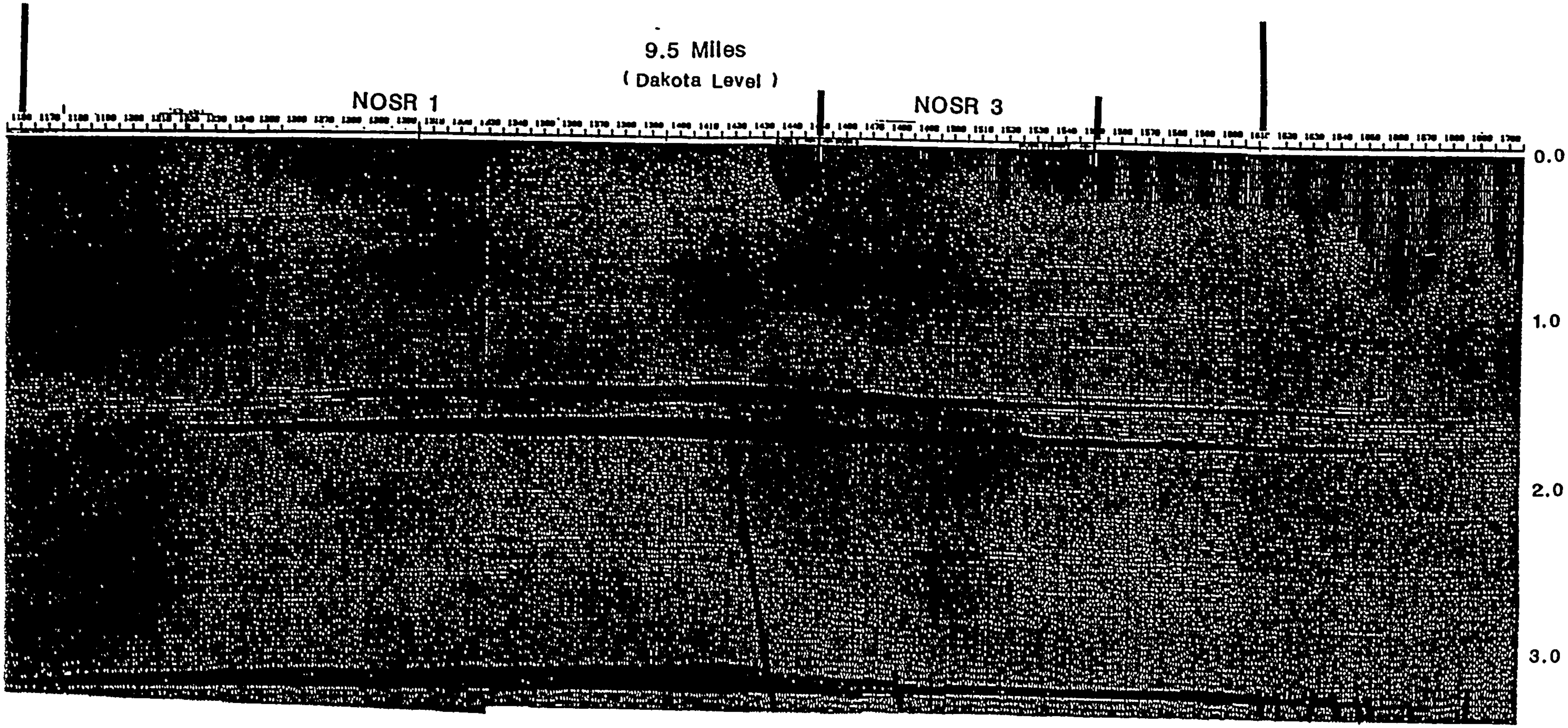
Key Data Gaps

For the most part, the petroleum geology of the Naval Oil Shale Reserves is known only through estimation of the natures of the rocks that underlie the Reserves using data from nearby areas, seismic data, and comparison of the estimates to known oil and gas-bearing rocks in the region. Existing seismic data remotely sense rocks under the reserve but the amount and distribution of these data are limited and its scarceness restricts quantitative measures of such key factors such as size and configuration of deeply buried faults and folds, the distribution of trapping elements and the precise distribution and thickness of reservoir beds. In addition, few data exist that permit 1) the direct measure of the species and composition of hydrocarbons, or 2) the distinction between *insitu* coaly rocks or gases in unexplored strata (seismic bright spot studies).

Seismic Data Indicate a Structure on NOSR 1

Using the data from two wells on either end of seismic line CPB-3 which runs from the southwest to the northeast across NOSR 1, We have been able to make some preliminary interpretations of the Upper Cretaceous Cameo, Rollins, Cozzette, and Corcoran formations of the Mesaverde Group, Mancos Shale , and the Lower Cretaceous Dakota/Upper Jurassic Entrada "events". No drill holes on this line penetrate strata below the fluvial Jurassic Shinarump Conglomerate. We have made an inferred pick on the Mississippian-age Leadville event, but this identification is highly speculative. Using the picks on seismic line CPB-3, we have extrapolated them to the cross tie line CPB-1. The interpreted reflectors match well between the lines.

There appears to be a very broad structural high on both lines CPB-1 and CPB-3 which has its crest in the NOSR 1 area. The high seems to be related to a Precambrian basement horst block, and the structure strongly deforms strata as young as Lower Cretaceous Dakota/Upper Jurassic Entrada beds. From this


9.5 Miles
(Dakota Level)
NOSR 1
NOSR 3
0.0
1.0
2.0
3.0
Two-Way Travel Time

CPB-1

stratigraphic level up through the overlying members of the Cretaceous section, the closure dies out (flattens) as you move up section until it is only a flattening of the regional dip. There may be some very minor closure in the Cameo/Corcoran (basal Mesaverde) sequence.

It is unclear if this closure is tested to the south on NOSR 3. If it is present there, we do not know if it is important to the production of gas in that field. Because much of the Upper Cretaceous and lowermost Tertiary section in the NOSR 1 and 3 region is characterized by a pod of continuous gas saturation, production from these strata may not be limited to structural highs. However, gas from underlying strata may be limited to structural closures. In addition, fractured strata may be preferentially developed over the uplifted basement blocks thereby increasing formation permeability in those regions. This increased formation permeability maybe essential for production of gas from the otherwise "tight" deeply buried rocks.

The amount of closure at the Dakota/Entrada level is about 35 milliseconds. Using a interval velocity of about 16,500 '/sec, as derived from analysis of the Barrett 1-27 Arco Deep well, 35 milliseconds of two-way travel time equals about 280 ft of closure. The horizontal extent of the closure on seismic line CPB-3 at the Dakota/Entrada level is about 3.8 miles. This is a large and potentially significant structure.

The same structure is visible on seismic line CPB-1 and exhibits more closure and a wider horizontal extent. The maximum closure at the Dakota/Entrada level is about 90 milliseconds which equals roughly 740 ft. The horizontal extent of the structure on seismic line CPB-1 at the Dakota/Entrada level is almost 9.25 miles. The structure is again related to a high in the basement. Closure up section seems to be consistent with over 40 milliseconds (about 200 ft) of closure at the suspected Green River/Wasatch Formation interface. Spotting the ends of the closures on both seismic lines reveals an elongate structure with a southeast/northwest axis, the crest of which sits about 0.6 miles northwest of the Roan Cliffs on NOSR 1.

Presently, we do not think that the structure is caused by a statics problem which may not have been properly handled in the processing of the data. Without the raw data on magnetic tape we have no way of re-processing to confirm if the structure is caused by a statics problem or not. Our immediate feeling is that this structure is real.

APPENDIX B

INITIAL ASSESSMENT OF GRANT NORPAC SEISMIC DATA (ORIGINAL DATA)

APPENDIX B: NOSR-1 and NOSR-3

Preliminary Evaluation of
Seismic Line CPB-1 (Northwest-Southeast) and
Seismic Line CPB-3 (Northeast-Southwest)

INTRODUCTION

Two modern CDP seismic lines have been acquired across the NOSR-1 and NOSR-3 areas. These data were originally acquired in 1988 as part of a speculative seismic survey by Grant Norpac, and were licensed to the Department of Energy from Grant Tensor in 1993. This Consultant has been provided permission by the DOE, and the current licensor, Seitel Corporation, to review these confidential, non-exclusive seismic data in the course of this study (ref: DOE letter of 6/14/96, Ser. No. WBS/034.142).

SEISMIC RECORDING PARAMETERS

Seismic recording parameters for the two seismic lines across the NOSR area were as follows:

SEISMIC RECORDING PARAMETERS

Location:	Garfield Co., Colo., T 2-8 S, R 92-97 W
Acquisition Date:	August 1988
Crew:	Grant Norpac Crew # 115
Recording Instruments:	Texas Instruments DFS-V-2
Recording Channels:	Total 240 - 2x120 Master/Slave config.
Source:	Dynamite
Source Size/Depth:	50 lbs @ 60 feet
Sample Rate:	2 milliseconds
Record Length:	6.0 seconds
Shotpoint Interval:	440 feet
Group Interval:	110 feet
Fold:	30 fold
Near Offset:	165 feet
Far Offset:	13,255 feet
Geophones:	10 Hz Mark L-10A
Recording Filter:	12/18 - 72-128 Hz

These parameters represent those used for "state of the art" 2-D seismic acquisition at the time this data was acquired in 1988.

SEISMIC PROCESSING PARAMETERS

The original seismic processing of Lines CPB-1 and CPB-3 was conducted by Grant Norpac in 1989 in their Houston processing center. The seismic processing flow utilized for the original processing effort is as follows:

PROCESSING SEQUENCE

DEMULTIPLEX
- 32 BIT FLOATING POINT
- 4 MS. SAMPLE RATE

TRACE EDIT

AMPLITUDE DECAY CORRECTION

DECONVOLUTION
- SPIKING. SURFACE CONSISTENT
- 240 MS OPERATOR LENGTH

REFRACTION STATICS
- DATUM 7000 FEET
- V0=5000 FT./SEC.
- VR=9350 FT./SEC.

COMMON DEPTH POINT GATHER
- 30 FOLD

VELOCITY ANALYSIS (CVS)
- ONE/MILE

PRELIM NORMAL MOVEOUT

AUTO STATICS
- SURFACE CONSISTENT
- 4 ITERATIONS 20HZ. TO 53HZ.
- PILOT SMASH 17-7
- MAX SHIFT 32 MS.

VELOCITY ANALYSIS (CVS)
- ONE/MILE

FINAL NORMAL MOVEOUT
- ANNOTATE EVERY OTHER FOR DISPLAY

AUTO STATICS
- CDP TRIM
- PILOT SMASH 5

TRACE MUTE
- FIRST BREAK SUPPESSION

COMMON DEPTH POINT STACK

TIME VARIANT FILTER

0.3 SEC.	17-80 HZ.
2.2 SEC.	17-60 HZ.
2.6 SEC.	15-60 HZ.
3.5 SEC.	15-40 HZ.
4.6 SEC.	15-30 HZ.

TRACE BALANCE

WAVE EQUATION MIGRATION

The original processing sequence appears to be a simple, straightforward sequence which was commonly utilized on non-exclusive speculative seismic data sets during the late 1980's. A subsequent seismic reprocessing effort on Lines CPB-1 and CPB-3 was apparently conducted by the USGS in 1993 to 1994. Seismic data from this seismic reprocessing effort was discussed in USGS Open File Report 94-427.

Reprocessed versions of Lines CPB-1 and CPB-3 have not been provided to this Consultant, and any improvements in data quality as a result of the reprocessing program are not directly known to us. However, it is likely that some improvement in structural and stratigraphic definition was derived from this reprocessing effort, particularly if some of the following modern processing steps were applied:

- DMO (Dip Move Out) application
- F-K and Tau P filtering for noise removal
- Refraction statics applications
- Spectral balancing for improved frequency resolution
- Improved velocity picking and analysis
- Pre-stack migration
- Beam steering techniques to remove out-of-plane reflections

PRELIMıNARY ANALYSIS OF SEISMIC DATA

Overall Assessment of Data Quality

General

The 2-D seismic lines which were reviewed over the NOSR-1 and NOSR-3 areas were the original processed versions of line CPB-1 and CPB-3 which were acquired from Grant-Norpac. These lines appear to be of adequate quality to allow for a reasonably good structural interpretation of the NOSR area. Dominant seismic frequencies at the Mancos level are 33 to 35 Hz, and decrease to 28 to 32 Hz at the Dakota level. With the high interval velocities present in the geological section, the seismic wavelet at Mancos level is calculated to be between 425 and 450 feet in length. The seismic wavelet at the Dakota level is computed to be between 470 and 535 feet in length. The relatively low frequency of the seismic data, coupled with extremely high acoustic velocities yields a theoretical geological bed resolution limit (one-quarter wavelength minimum thickness) of between 105 to 135 feet. Higher frequencies would provide the means to define thinner geological strata.

Line CPB-1

Line CPB-1 strikes northwest-southeast across the NOSR study area. This line crosses the NOSR-1 area between shotpoints 1075 to 1450, and the NOSR-3 area between shotpoints 1450 to 1550. A number of missed shots, or data 'skips', are evident on the southeast end of this line. Data gaps cut into the Wasatch and Upper Mesaverde seismic interval, but do not appear to materially affect overall seismic structural definition. Seismic data quality on this line is generally good, but deteriorates to fair quality on the southeastern end of the line due to the presence of noise throughout the record section.

A gentle structural reversal at Mancos level (1.400 seconds) is evident on this 2-D line between shotpoints 1200 to 1550. The structural crest is positioned approximately at shotpoint 1420. Nearly 100 milliseconds of reversal is noted at the Mancos horizon. Based on high RMS seismic velocities derived in seismic processing, this corresponds to approximately 600 feet of possible reversal on this structure.

Line CPB-3

Line CPB-3 strikes northeast-southwest across the NOSR study area. This line crosses the NOSR-1 area between shotpoints 500 to 900, and traverses a small portion of NOSR-3 between shotpoints 475 to 500. A number of missed shots, or data 'skips', are evident on the southwest end of this line. The resulting loss of seismic fold and offsets create data gaps which cut into the Fort Union interval, and in at least two cases, deeper into the top of the Mancos Shale reflection.

A pronounced structural reversal is evident on the northeast end of this line between shotpoints 101 to 450. Seismic data quality deteriorates significantly over this structural feature, with only fair to poor reflection energy present. Numerous discontinuous reflections and probable out-of-plane diffractions are noted at this end of the line. Significant basement deformation and faulting appears to be present in the core of this feature. Reflection quality improves southwest of the structure, and good quality seismic events at the Top of Cretaceous, Mancos Shale, Dakota Sandstone, and Top of Paleozoic are present.

A low-relief anticlinal reversal appears to be present between shotpoints 500 to 900 at the Mancos level (1.600 - 1.700 seconds), as well as at the overlying Mesaverde level (approximately 1.400 seconds). Up to 35 milliseconds of apparent reversal is noted at the Mancos level. Based on seismically derived velocities, the magnitude of this reversal is calculated to be (+/-) 250 feet. This same structure is seen at the Dakota level (2.500 seconds), and underlying block faulting in the basement (3.200 seconds) is evident.

Calibration of reflections on this seismic line was originally accomplished with a synthetic seismogram from the Arco North Rifle #1 well, drilled in section 31, T 4 S, R 93 W. This well is situated very close to Line CPB-3 approximately at shotpoint 445. The synthetic seismogram for this well was provided to this Consultant by DOE with seismic correlations already made. Review of this data indicates that the previously-made synthetic-to-seismic line calibrations appear to be reasonably correct, although seismic data quality is only fair at the point of the synthetic tie.

RECOMMENDATIONS FOR ADDITIONAL EFFORT

Seismic Workstation Interpretation

The two seismic lines which were presented to this Consultant by DOE were provided with an existing interpretation depicted on the lines. It appears that alternative seismic event correlations, structural picks, stratigraphic interpretation, etc., could be derived from this data. It is suggested that a digital copy of these two lines be provided to this Consultant to load on a seismic workstation for a more accurate structural and stratigraphic interpretation.

The data quality from the original Grant-Norpac processing appears to generally be adequate for a meaningful reinterpretation of this data set. However, it is recommended that data from the reprocessing effort be provided to this Consultant for workstation analysis in order to benefit from the application of modern seismic processing algorithms. The workstation analysis will provide the means to analyze subtle changes in seismic amplitudes, frequencies, and phase, and character, which might be important in defining additional potential in the NOSR study area. Additionally, better seismic structural correlation can be obtained by utilizing various horizon flattening and scaling methodologies on the workstation.

Examination of Additional Seismic Data

Since only two seismic lines were available for review over the NOSR study area, a comprehensive picture of the subsurface structure in this area is not possible. It is suggested that an attempt be made to determine whether any additional seismic data may exist in the NOSR area. Efforts should be made to review any such additional data, and a recommendation made to DOE to acquire access to this data through purchase and/or licensing. Supplemental seismic data would provide better insight into the structural and stratigraphic nature of this area.

APPENDIX C

SPE/SPEE RESERVE DEFINITIONS

Definitions for Oil and Gas Reserves[1]

Reserves

Reserves are estimated volumes of crude oil, condensate, natural gas, natural gas liquids, and associated substances anticipated to be commercially recoverable from known accumulations from a given date forward, under existing economic conditions, by established operating practices, and under current government regulations. Reserves estimates are based on interpretation of geologic and/or engineering data available at the time of the estimate.

Reserves estimates generally will be revised as reservoirs are produced, as additional geologic and/or engineering data become available, or as economic conditions change.

Reserves do not include volumes of crude oil, condensate, natural gas, or natural gas liquids being held in inventory. If required for financial reporting or other special purposes, reserves may be reduced for on-site usage and/or processing losses.

The ownership status of reserves may change due to the expiration of a production license or contract; when relevant to reserves assignment such changes should be identified for each reserves classification.

Reserves may be attributed to either natural reservoir energy, or improved recovery methods. Improved recovery includes all methods for supplementing natural reservoir energy to increase ultimate recovery from a reservoir. Such methods include (1) pressure maintenance, (2) cycling, (3) waterflooding, (4) thermal methods, (5) chemical flooding, and (6) the use of miscible and immiscible displacement fluids.

All reserves estimates involve some degree of uncertainty, depending chiefly on the amount and reliability of geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves in one of two classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be subclassified as probable or possible to denote progressively increasing uncertainty.

Proved Reserves

Proved reserves can be estimated with reasonable certainty to be recoverable under current economic conditions. Current economic conditions include prices and costs prevailing at the time of the estimate. Proved reserves may be developed or undeveloped.

In general, reserves are considered proved if commercial producibility of the reservoir is supported by actual production or formation tests. The term proved refers to the estimated volume of reserves and not just to the productivity of the well or reservoir. In certain instances, proved reserves may be assigned on the basis of electrical and other type logs and/or core analysis that indicate subject reservoir is hydrocarbon bearing and is analogous to reservoirs in the same area that are producing, or have demonstrated the ability to produce on a formation test.

The area of a reservoir considered proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) the undrilled areas that can be reasonably judged as commercially productive on the basis of available geologic and engineering data. In the absence of data on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the proved limit unless otherwise indicated by definitive engineering or performance data.

Proved reserves must have facilities to process and transport those reserves to market that are operational at the time of the estimate, or there is a commitment or reasonable expectation to install such facilities in the future.

In general, proved undeveloped reserves are assigned to undrilled locations that satisfy the following conditions: (1) the locations are direct offsets to wells that have indicated commercial production in the objective formation, (2) it is reasonably certain that the locations are within the known proved productive limits of the objective formation, (3) the locations conform to existing well spacing regulations, if any, and (4) it is reasonably certain that the locations will be developed. Reserves for other undrilled locations are classified as proved undeveloped only in those cases where interpretations of data from wells indicate that the objective formation is laterally continuous and contains commercially recoverable hydrocarbons at locations beyond direct offsets. .

Reserves that can be produced through the application of established improved recovery methods are included in the proved classification when (1) successful testing by a pilot project or favorable production or pressure response of an installed program in that reservoir, or one in the immediate area with similar rock and fluid properties, provides support for the engineering analysis on which the project or program is based, and (2) it is reasonably certain the project will proceed.

Reserves to be recovered by improved recovery methods that have yet to be established through repeated commercially successful applications are included in the proved classification only (1) after a favorable production response from subject reservoir from either (a) a representative pilot or (b) an installed program, where the response provides support for the engineering analysis on which the project is based, and (2) it is reasonably certain the project will proceed.

Unproved Reserves

Unproved reserves are based on geologic and/or engineering data similar to that used in estimates of proved reserves; but technical, contractual, economic, or regulatory uncertainties preclude such reserves being classified as proved. They may be estimated assuming future economic conditions different from those prevailing at the time of the estimate.

Estimates of unproved reserves may be made for internal planning or special evaluations, but are not routinely compiled.

Unproved reserves are not to be added to proved reserves because of different levels of uncertainty.

Unproved reserves may be divided into two subclassifications: **probable** and **possible.**

Probable Reserves

Probable reserves are less certain than proved reserves and can be estimated with a degree of certainty sufficient to indicate they are more likely to be recovered than not.

In general, probable reserves may include (1) reserves anticipated to be proved by normal stepout drilling where subsurface control is inadequate to classify these reserves as proved; (2) reserves in formations that appear to be productive based on log characteristics but that lack core data or definitive tests and which are not analogous to producing or proved reservoirs in the area; (3) incremental reserves attributable to infill drilling that otherwise could be classified as proved but closer statutory spacing had not been approved at the time of the estimate; (4) reserves attributable to an improved recovery method that has been established by repeated commercially successful applications when a project or pilot is planned but not in operation and rock, fluid, and reservoir characteristics appear favorable for commercial application; (5) reserves in an area of a formation that has been proved productive in other areas of the field but subject area appears to be separated from the proved area by faulting and the geologic interpretation indicates subject area is structurally higher than the proved area; (6) reserves attributable to a successful workover, treatment, retreatment, change of equipment, or other mechanical procedure, where such procedure has not been proved successful in wells exhibiting similar behavior in analogous reservoirs; and (7) incremental reserves in a proved producing reservoir where an alternate interpretation of performance or volumetric data indicates significantly more reserves than can be classified as proved.

Possible Reserves

Possible reserves are less certain than probable reserves and can be estimated with a low degree of certainty, insufficient to indicate whether they are more likely to be recovered than not.

In general, possible reserves may include (1) reserves suggested by structural and/or stratigraphic extrapolation beyond areas classified as probable, based on geologic and/or geophysical interpretation; (2) reserves in formations that appear to be hydrocarbon bearing based on logs or cores but that may not be productive at commercial rates; (3) incremental reserves attributable to infill drilling that are subject to technical uncertainty; (4) reserves attributable to an improved recovery method when a project or pilot is planned but not in operation and rock, fluid, and reservoir characteristics are such that a reasonable doubt exists that the project will be commercial; and (5) reserves in an area of a formation that has been proved productive in other areas of the field but subject area appears to be separated from the proved area by faulting and geologic interpretation indicates subject area is structurally lower than the proved area.

Reserve Status Categories

Reserve status categories define the development and producing status of wells and/or reservoirs.

Developed

Developed reserves are expected to be recovered from existing wells (including reserves behind pipe). Improved recovery reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Developed reserves may be subcategorized as producing or nonproducing.

Producing

Producing reserves are expected to be recovered from completion intervals open at the time of the estimate and producing. Improved recovery reserves are considered to be producing only after an improved recovery project is in operation.

Nonproducing

Nonproducing reserves include shut-in and behind-pipe reserves. Shut-in reserves are expected to be recovered from completion intervals open at the time of the estimate, but which had not started producing, or were shut in for market conditions or pipeline connection, or were not capable of production for mechanical reasons, and the time when sales will start is uncertain.

Behind-pipe reserves are expected to be recovered from zones behind casing in existing wells, which will require additional completion work or a future recompletion prior to the start of production.

Undeveloped

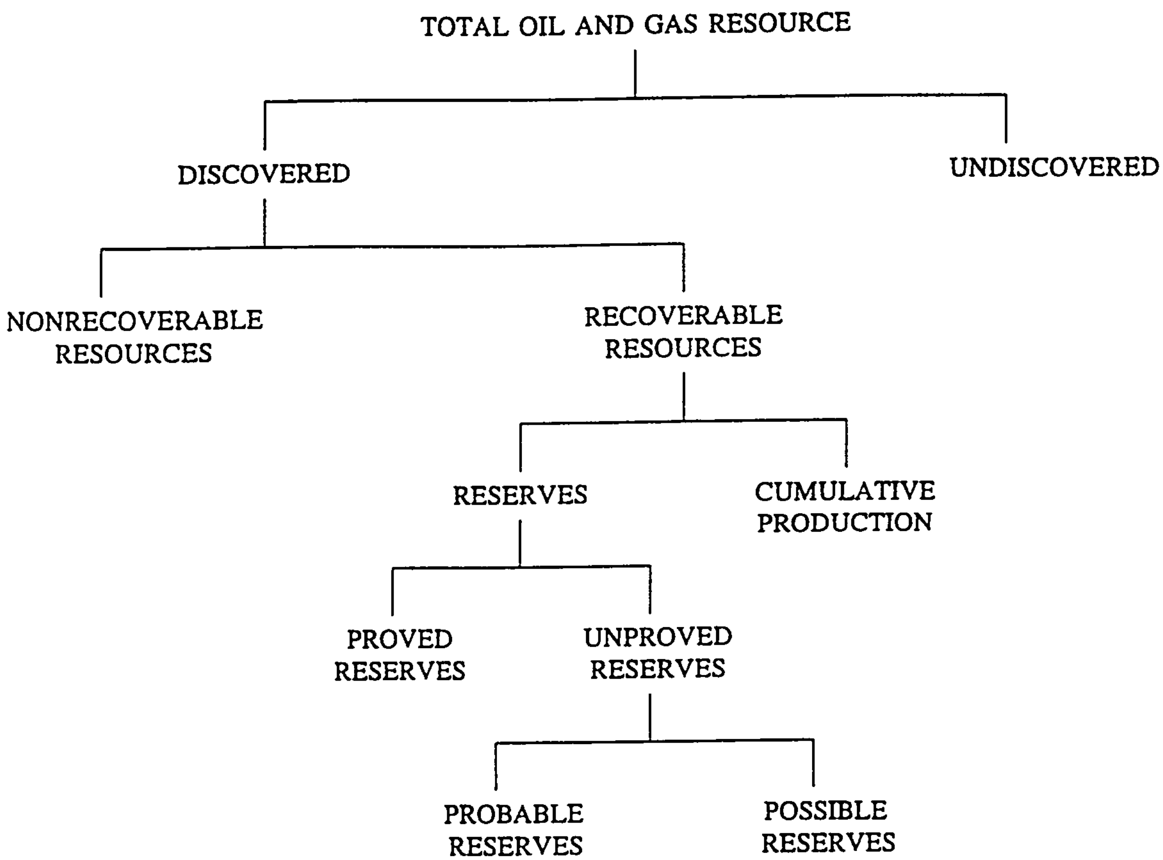
Undeveloped reserves are expected to be recovered: (1) from new wells on undrilled acreage, (2) from deepening existing wells to a different reservoir, or (3) where a relatively large expenditure is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

[1]Approved by the Board of Directors, Society of Petroleum Engineers (SPE), Inc. Feb. 27, 1987.

RESERVE TERMINOLOGY

The following table illustrates generally accepted terminology for classification of oil and gas resources and reserves. The portion covered by these guidelines encompasses those classifications included under the category "Recoverable Resources."

OIL AND GAS RESOURCE—RESERVE TERMINOLOGY



SOURCE: Chapman Cronquist's SPE 1987 Distinguished Lecture Tour, Speaker's Notes.

APPENDIX D

LIST OF FEDERAL LEASE SALES IN WESTERN COLORADO

LIST OF FEDERAL LEASE SALES IN WESTERN COLORADO

County	Lease #	Lessors	Lessee	File Date	Bonus $/Acre	Acres	Total Bonus $	Rlty	Rental $/Acre	Term Yrs	Location
Garfield	56027	U.S.A.	Western Minerals Partnership	2/10/94	$131.00	533.22	$ 69,954.00	12.5%	$ 1.50	10	T6S R92W SEC 1 LOTS 3,4, SEC 16 SWSE, SEC 28 SW, SEC 29 E2SE, SEC 33 SW
Garfield	56028	U.S.A.	Western Minerals Partnership	2/10/94	$ 55.00	103.59	$ 5,720.00	12.5%	$ 1.50	10	T7S R92W SEC 1 LOT 2, SEC 2 LOTS 1,2, SEC 3 LOT 1 SEC 4 LOTS 1,2, SEC 11 SENE
Garfield Mesa	56029	U.S.A.	Northwestern Land and Oil Properties	2/10/94	$ 12.00	240.00	$ 2,880.00	12.5%	$ 1.50	10	T8S R92W SEC 12 SESE SEC 13 SWNE, SE
Garfield	56035	U.S.A.	Northwestern Land and Oil Properties	2/10/94	$ 56.00	360.00	$ 20,160.00	12.5%	$ 1.50	10	T6S R 93W SEC 21 S2NW, SEC 24 NESW, S2SW, W2SE, SEC 25 NWNE, SEC 28 NENW
Rio Blanco	56036	U.S.A.	Douglas P. Cullen	2/10/94	$ 2.00	747.16	$ 1,496.00	12.5%	$ 1.50	10	T2S R94W SEC 5 NWSW, SWSE, SEC 6 LOTS 1-7, 9-12, W2 LOT 8, SESW, W2SE
Rio Blanco	56037	U.S.A.	Douglas P. Cullen	2/10/94	$ 2.00	835.76	$ 1,672.00	12.5%	$ 1.50	10	T2S R94W SEC 7 LOTS 1-4 E2, E2W2, SEC 8 NENW, W2W2
Rio Blanco	56038	U.S.A.	Douglas P. Cullen	2/10/94	$ 2.00	400.00	$ 800.00	12.5%	$ 1.50	10	T2S R94W SEC 17 W2W2 SEC 20 W2NW, SEC 29 SWNW, NWSW, SEC 32 SWSW
Garfield	56039	U.S.A.	Northwestern Land and Oil Properties	2/10/94	$ 36.00	241.39	$ 8,640.00	12.5%	$ 1.50	10	T6S R94W SEC 1 S2SW, SEC 2 N2SE, SESE, SEC 12 LOT 3, SEC 23, LOT 10
Garfield	56040	U.S.A.	Huntington T. Walker	2/10/94	$ 85.00	363.31	$ 30,940.00	12.5%	$ 1.50	10	T7S R94W SEC 9 LOT 7, SEC 11 LOTS 1,2, S2NE, SE
Mesa	56041	U.S.A.	Brad J Okerlund	2/10/94	$ 12.00	803.03	$ 9,648.00	12.5%	$ 1.50	10	T10S R94W SEC 20 N2SW, SWSW, SEC 28 LOTS 1-10, SEC 29 LOTS 1-6
Rio Blanco	56042	U.S.A.	Douglas P. Cullen	2/10/94	$ 2.00	640.80	$ 1,282.00	12.5%	$ 1.50	10	T3S R95W SEC 2 LOTS 1-4, S2N2, S2
Rio Blanco	56043	U.S.A.	Anadarko Petroleum Corporation	2/10/94	$ 4.00	684.40	$ 2,740.00	12.5%	$ 1.50	10	T2S R98W SEC 15 LOTS 4,5, SEC 16 E2, E2W2, SWNW, W2SW
Rio Blanco	56044	U.S.A.	Anadarko Petroleum Corporation	2/10/94	$ 12.00	800.00	$ 9,600.00	12.5%	$ 1.50	10	T2S R98W SEC 17 SE, SEC 20 N2, SEC 21, N2
Rio Blanco	56045	U.S.A.	Western Mineral Search, Inc.	2/10/94	$ 5.00	1177.16	$ 5,890.00	12.5%	$ 1.50	10	T2S R98W SEC 22 NESE, SEC 23 N2SW SEC 27 NWNE, NW, W2SW, SEC 31 LOTS 7-10, 12-20, SEC 32 LOTS 1-4, NE
Rio Blanco	56046	U.S.A.	Robert D. St. John	2/10/94	$ 2.00	707.32	$ 1,416.00	12.5%	$ 1.50	10	T1S R99W SEC 20 LOTS 1-11, SEC 34 W2NE, NW
Rio Blanco	56047	U.S.A.	Anadarko Petroleum Corporation	2/10/94	$ 21.00	960.00	$ 20,160.00	12.5%	$ 1.50	10	T2S R99W SEC 23 N2, SEC 24 ALL

LIST OF FEDERAL LEASE SALES IN WESTERN COLORADO

Rio Blanco	56048	U.S.A.	Western Mineral Search, Inc.	2/10/94	$ 4.00	718.38	$	2,876.00	12.5%	$ 1.50	10	T2S R99W SEC 29 S2NW, SEC 30 LOTS 1-4, E2, E2W2
Rio Blanco	56049	U.S.A.	Western Mineral Search, Inc.	2/10/94	$ 4.00	637.77	$	2,552.00	12.5%	$ 1.50	10	T2S R99W SEC 31 LOTS 1-4, E2, E2W2
Rio Blanco	56050	U.S.A.	Western Mineral Search, Inc.	2/10/94	$ 8.00	640.00	$	5,120.00	12.5%	$ 1.50	10	T2S R99W SEC 36 ALL
Rio Blanco	56051	U.S.A.	Douglas P. Cullen	2/10/94	$ 2.00	80.00	$	160.00	12.5%	$ 1.50	10	T1S R100W SEC 11 N2SW
Rio Blanco	56052	U.S.A.	Western Mineral Search, Inc.	2/10/94	$ 6.00	640.00	$	3,840.00	12.5%	$ 1.50	10	T1S R100W SEC 27 ALL
Rio Blanco	56053	U.S.A.	Western Mineral Search, Inc.	2/10/94	$ 2.00	1141.76	$	2,284.00	12.5%	$ 1.50	10	T1S R100W SEC 28 NW, S2, SEC 33 LOTS 2-6, N2, N2S2
Rio Blanco	56054	U.S.A.	Western Mineral Search, Inc.	2/10/94	$ 6.00	654.80	$	3,930.00	12.5%	$ 1.50	10	T1S R100W SEC 34 LOTS 1-4, N2S2, N2
Garfield	56298	U.S.A.	Robert L. Schuh	5/12/94	$ 2.00	320.00	$	640.00	12.5%	$ 1.50	10	T7S R93W SEC 24 NENW, SEC 34 TR 67
Garfield	56299	U.S.A.	Huntington T. Walker	5/12/94	$ 4.00	42.53	$	172.00	12.5%	$ 1.50	10	T5S R95W SEC 7 LOT 10, SEC 18 LOT 4
Garfield	56300	U.S.A.	OXY USA Inc.	5/12/94	$ 55.00	160.00	$	8,800.00	12.5%	$ 1.50	10	T6S R97W SEC 15 SW
Garfield	56827	U.S.A.	Huntington T. Walker	8/11/94	$ 32.00	262.80	$	8,416.00	12.5%	$ 1.50	10	T7S R96W SEC 7 SW, SEC 31 LOT 2, SESW, SWSE
Garfield	56828	U.S.A.	OXY USA Inc.	8/11/94	$ 35.00	2212.11	$	77,455.00	12.5%	$ 1.50	10	T5S R97W SEC 5 S2, SEC 6 LOTS 8-14, S2NE, SENW, E2SW, SE, SEC 7 LOTS 5-8, E2, E2W2, SEC 8 ALL
Garfield	56829	U.S.A.	OXY USA Inc.	8/11/94	$ 37.00	942.78	$	34,891.00	12.5%	$ 1.50	10	T5S R97W SEC 18 LOTS 5-8, E2, E2W2, SEC 19 LOTS 5,6, NE, E2NW
Garfield	56830	U.S.A.	OXY USA Inc.	8/11/94	$ 79.00	283.93	$	22,436.00	12.5%	$ 1.50	10	T6S R97W SEC 3 LOTS 7, 8, SEC 4 LOTS 5-8
Garfield	56831	U.S.A.	OXY USA Inc.	8/11/94	$ 13.00	488.91	$	6,357.00	12.5%	$ 1.50	10	T7S R97W SEC 4 TR 77B, 77C, TR 79E, 79F, 79G, SEC 5 LOTS 5-10, SEC 8 LOTS 1-8, SEC 9 LOTS 1,2, TR 94C, 94D, 94E
Mesa	56832	U.S.A.	Celcius Energy Company	8/11/94	$ 55.00	959.58	$	52,800.00	12.5%	$ 1.50	10	T9S R97W SEC 1 LOTS 1-4, S2N2, S2, SEC 2 S2
Rio Blanco	56833	U.S.A.	Anadarko Petroleum Corporation	8/11/94	$ 65.00	1180.87	$	55,900.00	12.5%	$ 1.50	10	T2S R98W SEC 9 N2SW, SEC 19 E2, SEC 28 LOTS 1-8, SW, N2SE, SWSE T2S R99W SEC 13 NE, NESE
Rio Blanco	56834	U.S.A.	Western Mineral Search Inc.	8/11/94	$ 13.00	2248.37	$	29,237.00	12.5%	$ 1.50	10	T4S R98W SEC 6 LOTS 1-7, S2NE, SENW, E2SW, SE, SEC7 LOTS 1,2, NE, E2NW, SEC 8 ALL SEC 9 ALL

LIST OF FEDERAL LEASE SALES IN WESTERN COLORADO

Rio Blanco	56835	U.S.A.	Western Mineral Search Inc.	8/11/94	$ 13.00	1360.00	$	17,680.00	12.5%	$ 1.50	10	T4S R98W SEC 11 NE, SW, SEC 15 N2, N2SW, NWSE, SEC 16 N2, N2S2, S2SW, SWSE
Garfield	56836	U.S.A.	Western Mineral Search Inc.	8/11/94	$ 29.00	1083.81	$	31,436.00	12.5%	$ 1.50	10	T5S R98W SEC 11 ALL, SEC 13 LOTS 3,4, SEC 14 LOTS 1-4, N2
Rio Blanco	56837	U.S.A.	Western Mineral Search Inc.	8/11/94	$ 5.00	640.44	$	3,205.00	12.5%	$ 1.50	10	T3S R99W SEC 19 LOTS 3,4, E2SW, SEC 20 E2, SEC 21 SW
Garfield	56838	U.S.A.	Glenwood Resources, Inc.	8/11/94	$ 6.00	40.00	$	240.00	12.5%	$ 1.50	10	T6S R99W SEC 13 NWSW
Rio Blanco	56839	U.S.A.	Western Mineral Search Inc.	8/11/94	$ 45.00	1795.80	$	80,820.00	12.5%	$ 1.50	10	T2S R100W SEC 3 LOTS 6-10, S2N2, S2, SEC 4 LOTS 5-7, 9, 10, S2N2, S2, SEC 9 N2, SE
Rio Blanco	56840	U.S.A.	Western Mineral Search Inc.	8/11/94	$ 45.00	1600.00	$	72,000.00	12.5%	$ 1.50	10	T2S R100W SEC 10, ALL SEC 11 ALL, SEC 13 W2
Rio Blanco	56841	U.S.A.	Western Mineral Search Inc.	8/11/94	$ 13.00	1652.09	$	21,489.00	12.5%	$ 1.50	10	T3S R100W SEC 24 LOTS 7-12, W2, SEC 25 LOTS 1,4,17,18, SEC 26 W2NE, SENE, NW, SEC 35 ALL, SEC 36 SW
Rio Blanco	56842	U.S.A.	Western Mineral Search Inc.	8/11/94	$ 7.00	1585.60	$	11,102.00	12.5%	$ 1.50	10	T4S R100W SEC 10 ALL, SEC 11 NWNE, S2NE, W2, SE, SEC 12 LOTS 7-12, SW
Rio Blanco	56843	U.S.A.	Snyder Oil Corp.	8/11/94	$ 22.00	1983.47	$	43,648.00	12.5%	$ 1.50	10	T4S R100W SEC 13 LOTS 1-12, W2, SEC 14 ALL, SEC 15 ALL
Rio Blanco	56844	U.S.A.	Snyder Oil Corp.	8/11/94	$ 22.00	1431.44	$	31,504.00	12.5%	$ 1.50	10	T4S R100W SEC 24 LOTS 1-12, W2, SEC 25 LOTS 1-12, W2
Mesa	57284	U.S.A.	James W. Hunt	11/10/94	$ 26.00	238.84	$	6,214.00	12.5%	$ 1.50	10	T10S R94W SEC 19 LOTS 3,4, SEC 30 LOTS 1-4
Rio Blanco	57285	U.S.A.	Great Northern Gas Company	11/10/94	$ 32.00	714.27	$	22,880.00	12.5%	$ 1.50	10	T2S R97W SEC 7 LOTS 5-20, SEC 18 N2NE
Rio Blanco	57286	U.S.A.	Western Mineral Search Inc	11/10/94	$ 25.00	1197.58	$	29,950.00	12.5%	$ 1.50	10	T2S R97W SEC 8 LOTS 1-16, SEC 16 SWSW, SEC 17 N2, N2SE, SEC 21, N2NW, SWNW
Mesa	57287	U.S.A.	James W. Hunt	11/10/94	$ 40.00	40.00	$	1,600.00	12.5%	$ 1.50	10	T9S R97W SEC 5 SWSW
Rio Blanco	57288	U.S.A.	LLANO Royalty Corporation	11/10/94	$ 40.00	124.98	$	5,000.00	12.5%	$ 1.50	10	T2S R98W SEC 1 LOTS 21,28,29,36
Rio Blanco	57289	U.S.A.	LLANO Royalty Corporation	11/10/94	$ 85.00	574.82	$	48,875.00	12.5%	$ 1.50	10	T2S R98W SEC 15 LOTS 1-3, 6-8, S2
Rio Blanco	57290	U.S.A.	LLANO Royalty Corporation	11/10/94	$ 67.00	1281.43	$	85,894.00	12.5%	$ 1.50	10	T3S R98W SEC 3 LOTS 1-4, S2N2, S2, SEC 4 LOTS 1-4, S2N2, S2
Rio Blanco	57291	U.S.A.	LLANO Royalty Corporation	11/10/94	$ 71.00	1437.55	$	102,098.00	12.5%	$ 1.50	10	T3S R98W SEC 21 E2W2, NWNW, SEC 28 LOTS 1-8, SEC 29 LOTS 1-10, NENE, S2NE, W2SE, SESE, SEC 32 SW, SEC 33 NW

LIST OF FEDERAL LEASE SALES IN WESTERN COLORADO

Rio Blanco	57292	U.S.A.	Great Northern Gas Company	11/10/94	$ 60.00	1720.00	$	103,200.00	12.5%	$ 1.50	10	T3S R98W SEC 23 SWNW, SE, SEC 24 S2, SEC 25 N2NE, SWNE, NW, SEC 26 NE, SEC 35 SW, SEC 36 N2, SW, N2SE, SWSE
Rio Blanco	57293	U.S.A.	David M. Munson Inc.	11/10/94	$ 95.00	1086.98	$	103,265.00	12.5%	$ 1.50	10	T1S R99W SEC 18 LOTS 5-19, SESE, SEC 27 SWNW,SW, SEC 28 NE, SEC 29 LOT 7
Rio Blanco	57294	U.S.A.	David M. Munson Inc.	11/10/94	$ 85.00	40.00	$	3,400.00	12.5%	$ 1.50	10	T1S R99W SEC 35 SWSW
Rio Blanco	57295	U.S.A.	David M. Munson Inc.	11/10/94	$230.00	639.53	$	147,200.00	12.5%	$ 1.50	10	T2S R99W SEC 4 LOTS 1-4, S2N2, S2
Rio Blanco	57296	U.S.A.	David M. Munson Inc.	11/10/94	$220.00	1160.00	$	255,200.00	12.5%	$ 1.50	10	T2S R99W SEC 9 ALL, SEC 10 W2E2, W2, SESE
Rio Blanco	57297	U.S.A.	Western Mineral Search Inc	11/10/94	$ 65.00	1359.80	$	88,400.00	12.5%	$ 1.50	10	T3S R99W SEC 1 S2, SEC 2 LOTS 1-4, S2NW, SW, W2SE, SEC 3 LOTS 1-4, S2N2, SW, W2SE
Rio Blanco	57298	U.S.A.	Western Mineral Search Inc	11/10/94	$ 65.00	1920.00	$	124,800.00	12.5%	$ 1.50	10	T3S R99W SEC 9 ALL, SEC 10 ALL, SEC 11 ALL.
Rio Blanco	57299	U.S.A.	Western Mineral Search Inc	11/10/94	$ 65.00	1280.00	$	83,200.00	12.5%	$ 1.50	10	T3S R99W SEC 12 W2E2, W2, SEC 13 SE, SEC 24 ALL
Garfield	57300	U.S.A.	Glenwodd Resources Inc.	11/10/94	$600.00	80.00	$	48,000.00	12.5%	$ 1.50	10	T6S R99W SEC 11 NWSE, SEC 12 E2NENE, E2NESE
Garfield	57301	U.S.A.	Western Mineral Search Inc	11/10/94	$ 40.00	40.00	$	1,600.00	12.5%	$ 1.50	10	T7S R99W SEC 3 S2S2S2SW, SEC 4 S2S2S2SE
Rio Blanco	57302	U.S.A.	Western Mineral Search Inc	11/10/94	$ 25.00	40.00	$	1,000.00	12.5%	$ 1.50	10	T1S R100W SEC 2 SENW
Rio Blanco	57303	U.S.A.	Western Mineral Search Inc	11/10/94	$ 25.00	72.59	$	1,825.00	12.5%	$ 1.50	10	T1S R100W SEC 13 LOT 1 SEC 24 LOT 2
Rio Blanco	57304	U.S.A.	Western Mineral Search Inc	11/10/94	$ 8.00	640.00	$	5,120.00	12.5%	$ 1.50	10	T2S R100W SEC 12 ALL
Rio Blanco	57683	U.S.A.	Lonetree Energy Inc.	2/9/95	$ 2.00	2361.33	$	4,644.00	12.5%	$ 1.50	10	T4S R96W SEC 5 LOTS 1-4, S2N2, S2, SEC 6 LOTS 1-7, S2NE, E2SW, SE, SEC 7 LOTS 1-4 E2, E2W2, SEC 8 ALL
Rio Blanco	57684	U.S.A.	Lonetree Energy Inc.	2/9/95	$ 2.00	1929.53	$	3,780.00	12.5%	$ 1.50	10	T4S R96W SEC 13 LOTS 1-4, S2N2, S2, SEC 14 ALL, SEC 15 LOTS 1-3, SWNE, W2, SE
Garfield	57685	U.S.A.	Lonetree Energy Inc.	2/9/95	$ 2.00	1788.85	$	3,578.00	12.5%	$ 1.50	10	T4S R96W SEC 19 LOTS 1-4, E2, E2W2, SEC 20 ALL, SEC 29 N2, SEC 30 LOTS 3,4, NE, E2NW
Rio Blanco	57687	U.S.A.	Lonetree Energy Inc.	2/9/95	$ 2.00	1281.28	$	2,564.00	12.5%	$ 1.50	10	T4S R97W SEC 3 LOTS 1-4, S2N2, S2, SEC 4 LOTS 2-4, S2NW, SW, NESE, S2SE, SEC 6 LOTS 6, 7, E2SW

LIST OF FEDERAL LEASE SALES IN WESTERN COLORADO

Garfield	57688	U.S.A.	Western Mineral Search Inc.	2/9/95	$ 3.00	1446.21	$	4,341.00	12.5%	$ 1.50	10	T7S R99W SEC 7 LOTS 6, 7, E2SW, W2SE, SESE, TR 38, SEC 8 S2, SEC 9 E2, S2NW, SW, SEC 10 NENW, S2NW, SW
Garfield	57689	U.S.A.	Western Mineral Search Inc.	2/9/95	$ 4.00	1376.20	$	5,508.00	12.5%	$ 1.50	10	T7S R99W SEC 16 S2S2, SEC 17 ALL, SEC 18 LOTS 5-8, NE, E2W2, W2SE, SESE
Mesa	57691	U.S.A.	Western Mineral Search Inc.	2/9/95	$ 6.00	10.39	$	66.00	12.5%	$ 1.50	10	T6S R100W SEC 32 LOTS 2, 3, 6, 7,
Garfield	57692	U.S.A.	Western Mineral Search Inc.	2/9/95	$ 4.00	813.46	$	3,256.00	12.5%	$ 1.50	10	T7S R100W SEC 3 LOTS 9, 10, SEC 4 LOTS 5-8, SEC 5 LOTS 5,6, SEC 8 E2NW, SEC 10 SENW, SEC 11 S2NE, SENW, S2S2, SEC 12 S2N2, S2S2
Garfield	57693	U.S.A.	Western Mineral Search Inc.	2/9/95	$ 8.00	1360.00	$	10,880.00	12.5%	$ 1.50	10	T7S R 100W SEC 9 N2, S2SW, SE, SEC 10 W2NW, S2, SEC 15 N2, N2SW
Garfield	58668	U.S.A.	Vessels Oil & Gas Company	11/9/95	$ 2.00	1040.00	$	2,080.00	12.5%	$ 1.50	10	T6S R91W SEC 35 N2NE, W2, W2SE, SEC 36 NENE, S2NE, W2NW, SENW, N2SW, SESW, SE T7S R91W SEC 12 NENW
Garfield	58670	U.S.A.	Tab Mcginley	11/9/95	$ 12.00	1085.47	$	13,032.00	12.5%	$ 1.50	10	T8S R95W SEC 5 LOTS 6, 7, 8, 10, SEC 8 W2E2NE, W2NE, W2, W2NESE, NWSE, N2SWSE, SWSWSE, NWSESE, SEC 16 TR 45, 46, SEC 17 TR 45, 46, SEC 20 TR 46, SEC 21 TR 46
Garfield	58671	U.S.A.	Lonetree Energy Inc.	11/9/95	$ 2.00	485.13	$	972.00	12.5%	$ 1.50	10	T4S R96W SEC 36 LOTS 1-6, S2N2, N2SW
Garfield	58672	U.S.A.	Tab Mcginley	11/9/95	$ 16.00	160.00	$	2,560.00	12.5%	$ 1.50	10	T5S R96W SEC 26 SWNE, N2SE, SWSE
Garfield	58673	U.S.A.	Tab Mcginley	11/9/95	$ 20.00	1308.11	$	26,180.00	12.5%	$ 1.50	10	T7S R96W SEC 22 NWNW, LOTS 3-5, SEC 28 NWNE, N2NW, N2S2, SWSW, LOTS 1-5, SEC 29 W2NE, NW, N2SW, NWSE, LOTS 1-7
Garfield	58674	U.S.A.	Western Mineral Search Inc.	11/9/95	$ 19.00	2439.99	$	46,360.00	12.5%	$ 1.50	10	T8S R96W SEC 1 SENE, NESE, LOT 1, SEC 9 S2S2NE, S2S2NW, S2, N2NE, N2S2NE, N2S2NW, SEC 10 NWNW, N2SWNW, S2SWNE, SW, W2SE, SEC 13 E2NE, SWNE, SEC 14 SWNW, NWSW, SESW, SEC 15 W2E2, SENE, W2, NESE, SEC 16 ALL

LIST OF FEDERAL LEASE SALES IN WESTERN COLORADO

Mesa	58675	U.S.A.	Western Mineral Search Inc.	11/9/95	$ 19.00	1461.80	$	27,778.00	12.5%	$ 1.50	10	T8S R96W SEC 8 SWNE, SE, SEC 17 ALL, SEC 18 SENE, SENW, E2SW, NESE, S2SE, SEC 19 NE, E2NW, LOTS 1, 2, SEC 21 SWSW
Mesa	58676	U.S.A.	Western Mineral Search Inc.	11/9/95	$ 2.00	1440.00	$	2,880.00	12.5%	$ 1.50	10	T8S R96W SEC 13 SW SEC 28 ALL, SEC 29 ALL
Mesa	58677	U.S.A.	Western Mineral Search Inc.	11/9/95	$ 2.00	58677.00	$	1,120.00	12.5%	$ 1.50	10	T8S R96W SEC 22 W2NE, NW, S2
Mesa	58678	U.S.A.	Western Mineral Search Inc.	11/9/95	$ 2.00	58678.00	$	1,564.00	12.5%	$ 1.50	10	T8S R96W SEC 30 LOTS 1-4, NE,E2NW, E2SE, SEC 31 E2, SEC 32 SWSW
Garfield	58680	U.S.A.	Western Mineral Search Inc.	11/9/95	$ 19.00	1480.00	$	22,800.00	12.5%	$ 1.50	10	T8S R97W SEC 11 ALL, SEC 12 S2N2, S2, SEC 13 NE, NWNW, S2NW, SEC 17 NENE, SEC 18 SWSE
Mesa	58681	U.S.A.	Western Mineral Search Inc.	11/9/95	$ 2.00	320.00	$	640.00	#####	$ 1.50	10	T8S R97W SEC 24 SE, S2SW, SEC 25 NWNE, NENW
Mesa	58682	U.S.A.	Mary C. Sellers	11/9/95	$ 8.00	640.00	$	5,120.00	12.5%	$ 1.50	10	T9S R97W SEC 14 S2NE, SW, N2SE, SWSE, SEC 24, NENW, S2NW, N2SW
Rio Blanco	58683	U.S.A.	Lonetree Energy Inc.	11/9/95	$ 2.00	2440.19	$	4,882.00	12.5%	$ 1.50	10	T4S R98W SEC 1, SWNE, SW, W2SE, LOT 2, SEC 2 LOTS 1-4, S2N2, S2, SEC 4 LOT 4, SEC 11 NW,SE, SEC 12 N2NE, SENE, NW, N2SW, SWSW, SE, SEC 14 N2, S2SW, SE
Rio Blanco	58684	U.S.A.	Lonetree Energy Inc.	11/9/95	$ 2.00	2280.00	$	4,560.00	12.5%	$ 1.50	10	T4S R98W SEC 17 ALL, SEC 20 ALL, SEC 21 W2NE, NW, S2, SEC 22, S2N2, N2SW, SESW, SE
Garfield	58685	U.S.A.	Lonetree Energy Inc.	11/9/95	$ 13.00	2560.00	$	33,280.00	12.5%	$ 1.50	10	T4S R98W SEC 24 , 25, 26, 27, ALL
Garfield	58686	U.S.A.	Lonetree Energy Inc.	11/9/95	$ 12.00	1360.00	$	16,320.00	12.5%	$ 1.50	10	T4S R98W SEC 34, E2E2E2, SEC 35 ALL, 36 ALL
Garfield	58687	U.S.A.	Tab Mcginley	11/9/95	$ 16.00	2098.64	$	33,584.00	12.5%	$ 1.50	10	T5S R98W SEC 1 S2N2, S2, LOTS 5-8, SEC 2 LOTS 5-8, S2N2, S2, SEC 12 ALL, SEC 13 N2N2
Garfield	58688	U.S.A.	Tab Mcginley	11/9/95	$ 16.00	1212.98	$	19,408.00	12.5%	$ 1.50	10	T5S R98W SEC 3 LOTS 5-8, S2NE, SENW, E2SWNW, NWSWNW, N2SWSWNW, N2S2SWSWNW, E2SW, E2W2SW, SE, SEC 4 LOTS 5,6,9, SENE, NESWNE, N2SESWNE, N2S2SESWNE, SEC 10 LOTS 4, 5, SE, SEC 15 NE, LOTS 1-5
Mesa	58689	U.S.A.	Maralex Resources, Inc.	11/9/95	$ 6.00	1270.00	$	7,626.00	12.5%	$ 1.50	10	T9S R98W SEC 5 LOTS 1-4, S2, S2N2, SEC 6 LOTS 1-7, S2NE, SENW, E2SW, SE

LIST OF FEDERAL LEASE SALES IN WESTERN COLORADO

Mesa	58690	U.S.A.	Maralex Resources, Inc.	11/9/95	$ 18.00	1271.96	$ 22,896.00	12.5%	$ 1.50	10	T9S R98W SEC 7 LOTS 1-4, E2W2, E2, SEC 8 ALL
Garfield	59132	U.S.A.	Western Mineral Search Inc.	5/9/96	$ 2.00	43.37	$ 88.00	12.5%	$ 1.50	10	T7S R93W SEC18 LOT 5
Rio Blanco	59135	U.S.A.	Strachan Exploration Co.	5/9/96	$ 2.00	1843.36	$ 3,688.00	12.5%	$ 1.50	10	T3S R95W SEC 19 LOTS 2, 3, 4, E2, SENW, E2SW, SEC 30 LOTS 1, 2, E2NW, NE T3S R96W SEC 24 ALL SEC 25 N2
Garfield	59136	U.S.A.	Huntington T. Walker	5/9/96	$ 2.00	480.00	$ 2,880.00	12.5%	$ 1.50	10	T7S R95W SEC 32 S2 N2, S2
Garfield	59137	U.S.A.	Huntington T. Walker	5/9/96	$ 2.00	80.00	$ 240.00	12.5%	$ 1.50	10	T7S R96W SEC 26 E2NE
Rio Blanco	59138	U.S.A.	Lonetree Energy Inc.	5/9/96	$ 2.00	40.00	$ 80.00	12.5%	$ 1.50	10	T3S R97W SEC 14 NWSW
Rio Blanco	59140	U.S.A.	High Plains Associates Inc.	5/9/96	$ 2.00	1920.00	$ 3,840.00	12.5%	$ 1.50	10	T4S R100W SEC 4,5,6. ALL
Rio Blanco	59141	U.S.A.	High Plains Associates Inc.	5/9/96	$ 2.00	1600.00	$ 3,200.00	12.5%	$ 1.50	10	T4W R100W SEC 7 ALL, SEC 8 S2, SEC 9 ALL

APPENDIX E

LIST OF FEE LEASE TRANSACTIONS

LIST OF FEE LEASE TRANSACTIONS

County	Book Page	Lessors	Lessee	Date of Instrmt	Record Date	Bonus $/Acre	Acres	Total Bonus $	Rlty	Rental $/Acre	Term Yrs	Location
Garfield	823-712	David E. Clarke	Barrett Resources Corp.	2/14/92	4/24/91		120.00		1/8		10	T6S R95W SEC 28 SESE, 32 SENE, 33 SWNW
Mesa	1837-72	Frances J. Lansing	Dove Energy Corp.	11/28/90	5/14/91		210.00		1/8		10	T10S R95W SEC 2 NWSE, SWNE T10S R94W SEC 29 SWSW, SEC 30 E2SE, SENE
Mesa	1837-76	Audrey McKelvie	Dove Energy Corp.	11/20/90	5/14/91		320.00		1/8	$1.00	10	T10S R95W SEC 13 W2NE, SE, SEC 24 N2NE
Mesa	1837-81	W. Russell James	Dove Energy Corp.	1/7/91	5/14/91		1,968.26		1/8		10	T10S R95W SEC 21, 22 ,27, 28, 29, 33
Mesa	1842-31	Albert M. Coury	Dove Energy Corp.	4/1/91	6/17/91		440.00		1/8	$1.00	10	T10S R95W SEC 13 E2, SEC 24 N2NE T10S R94W SEC 16 NWSE
Mesa	1842-79	Thomas E. Lewis, Steven E. Lewis, Sandra E. Kretschman, Daniel E. Lewis	Dove Energy Corp.	3//23/91	6/17/91		240.00		1/8	$1.00	10	T10S R95W SEC 26 NWSE, S2SE, SEC 35 N2NE, SENE
Mesa	1842-83	John R. Jones	Dove Energy Corp.	2/12/91	6/17/91		555.69		1/8	$1.00	10	T 9S R94W SEC 34 SWSE, SESW, T10S R94W SEC 3 N2SW, SWNW, SEC 4
Mesa	1842-89	Beryle Tomlinson	Dove Energy Corp.	3/13/91	6/17/91		187.00		1/8		10	T9S R94W SEC 15 SWSE, W2SESE, SEC 22 W2NE, SENW
Mesa	1870-640	Desmond D. Bertholt	Dove Energy Corp.	1/7//91	12/16/91		1,968.26		1/8		10	T10S R95W SEC 21, 22, 27, 28, 29, 33
Garfield	0891-216	Joe Ann Nichols	Barrett Resources Corp.	1/12/94	1/31/94		120.72		1/8		5	T6S R93W SEC 19 T6S R94W SEC 13, 24
Garfield	933-642	Karla Gayle Keller	Snyder Oil Corporation	11/8/94	3/6/94		168.00		1/8		5	T6S R92W SEC 27 NWSW
Garfield	0903-132	Ruth L. Pittenger	Barrett Resources Corp.	4/5/94	5/20/94		187.00		1/8	$1.00	5	T6S R93W SEC 18 T6S R94W SEC 13
Garfield	908-993	Amoco Production Co.	AA Production Inc.	6/23/94	7/18/94		2,833.35		1/4		1	T6S R98-99W
Garfield	095-353	Wendell G. Swanson	Snyder Oil Corporation	6/8/94	9/9/94		471.00		1/8		5	T6S R92W SEC 21 SWSW, SEC 28 NWNW, SEC 29 NW, N2NE, SWNE
Garfield	0928-379	Harry A. Dutton, Jr,	Barrett Resources Corp.	1/11/95	9/26/94		78.00		1/8		3	T7S R95W SEC 9 SENW, SEC 19 SENE

LIST OF FEE LEASE TRANSACTIONS

Garfield	0928-360	McLeed Hittson	Barrett Resources Corp.	5/16/94	1/11/95		312.40		1/6		3	T7S R95W SEC 9,10
Garfield	0928-375	Sarah E. Farris	Barrett Resources Corp.	5/16/94	1/11/95		100.00		1/8		3	T7S R95W SEC 8 SESE, NESE, SEC 9 SWSW, NWSW
Garfield	933-602	The Bishop of Pueblo	Snyder Oil Corporation	11/19/94	3/6/95		315.00		1/8		5	T6S R92W SEC 8 LOT 8,9, S2SE, SEC 16 NWNW, SEC 17 N2NE
Garfield	933-604	Elmer Blackmore	Snyder Oil Corporation	12/15/94	3/6/95		127.00		1/8		5	T6S R92W SEC 9 LOT3, W2SW, NWNESW
Garfield	933-630	Mabelle C. Darrow	Snyder Oil Corporation	11/8/94	3/6/95		160.00		1/8		5	T6S R93W SEC 26 W2SE, SEC 35 N2NE
Garfield	933-632	Dene A. Hangs	Snyder Oil Corporation	11/19/94	3/6/95		200.00		1/8		5	T6S R92W SEC 16 SWNW, N2SW, SESW, SEC 17 SENE
Garfield	937-434	Elois Bryant St. John	Snyder Oil Corporation	12/8/94	4/14/95		200.00		1/8		5	T6S R92W SEC 34 SE, SEC 35 SWSW
Garfield	938-430	Paul M. Searle, Catherine Shiner	Wells Petrolem Inc.	2/17/95	4/26/95		160.00		1/6		5	T5S R103W SEC 7 E2E2
Garfield	938-432	Karl Wallace	Wells Petrolem Inc.	2/17/95	4/26/95		160.00		1/6		5	T5S R103W SEC 7 E2E2
Garfield	938-481	William L George	Barrett Resources Corp.	3/20/95	4/26/95		278.73		1/8		5	T5S R92-93W
Garfield	943-991	Margurite M. Colton	Wells Petrolem Inc.	1/31/95	6/15/95		160.00		1/6		5	T5S R103W SEC 7 E2E2
Garfield	945-779	Darrell L. & Lynne J. Lowdermilk	Carmack Consulting	4/17/94	7/7/95		10.00		1/8		4	T5S R92W SEC 33 SENWSE
Garfield	946-78	Marcia Gardener	Stewart Petroleum Corporation	6/26/95	7/7/95		480.00		1/8		5	T7S R95W SEC 16 SWSW, SEC 17 N2NESW, E2SWSE, E2SE, NWSE, SEC 20 E2SE, SWSE, S2NE, NENE, SEC 21 NWSW
Garfield	946-83 946-86	Bobby L. McPherson Milton W. McPherson	Vessels Oil & Gas Co.	3/29/95	7/7/95		1,260.00		1/8		3	T6S R92W SEC 14 N2, NESE, W2SE, SW, SEC 15 E2NW, SEC 16 SENE, SEC 23 NWNE, NENW
Garfield	946-872	Wendell G Swanson	Snyder Oil Corporation	12/16/94	7/17/95		56.75		1/8		5	T6S R92W SEC 8 SWNWNW
Garfield	946-880	Rifle Land & Cattle	Snyder Oil Corporation	12/22/94	7/17/95		66.61		1/8		5	T6S R92W SEC 34 N2SE

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Garfield	946-885	Donald J. Hangs	Snyder Oil Corporation	12/7/94	7/17/95		144.50		1/8		5	T6S R92W SEC 9 LOT 4, SESW, S2NESW, NENESW
Garfield	952-320	Harry W. Hoag	Barrett Resources Corp.	4/28/95	9/8/95		47.05		1/8		5	T7S R95W SEC 10 part of N2
Garfield	952-536	Lawence V. Brunken	Barrett Resources Corp.	4/28/95	9/8/95		56.83		1/8		5	T7S R95W SEC 10 S2SWSE, NWSWSE, SWNWSE
Garfield	956-392	Katherine E. Ziegler	Barrett Resources Corp.	9/11/95	10/23/95		502.29		1/8		5	T7S R95W SEC 10 SEC 11 E2SW
Garfield	956-774	Carl O. Wittwer	Maguire Oil Company	8/2/95	10/25/95		145.00		1/8	$1.00	3	T5S 92W SEC 30
Garfield	965-838	Farm Credit Bank of Wichita	Barrett Resources Corp.	12/7/94	2/1/96		80.00		1/8		5	T6S R92W SEC 30 E2SE
Garfield	965-840	Farm Credit Bank of Wichita	Barrett Resources Corp.	12/7/94	2/1/96		40.00		1/8		5	T7S R92W SEC 4 SWSW
Garfield	966-726	Waren H. Buxton, Charles K. Buxton, Edith E. Sarver	Barrett Resources Corp.	12/30/95	2/9/96		70.69		1/8		5	T6S R94W SEC 30
Garfield	966-733	Verda Holder	Barrett Resources Corp.	12/29/95	2/9/96		90.00		1/8		5	T7S R95W SEC 17 SENW, S2SWNE, N2SENE, SWSENE
Garfield	966-735	Eugene and Juliana Fairfax	Barrett Resources Corp.	12/29/95	2/9/96		75.00		1/8		5	T7S R95W SEC 18 N2SE less the E2SENESE
Garfield	969-479	Wenonah Mackey	Maguire Oil Company	1/20/96	3/6/96		120.00		1/8		3	T5S R92W SEC 35 W2NW, W2E2N2
Garfield	969-482	M.R. Clemmer	Maguire Oil Company	2/23/96	3/6/96		240.64		1/8	$1.00	3	T5S R91W SEC17 NWSW, SEC 18 LOTS 2, 3, NESW
Garfield	976-567	Teresa A. Potter	Maguire Oil Company	2/29/96	5/2/96		1,520.00		1/8		3	T5S R93W
Garfield	976-860	Vivian F. Stark	Vessels Oll & Gas Co.	3/21/96	5/6/96		35.74		1/8		3	T6S R92W SEC 27 SESW, NESW
Garfield	976-866	William B. Jackson	Vessels Oll & Gas Co.	2/27/96	5/6/96		168.00		1/8		5	T6S R92W SEC 27 NWSW SEC 28 SE
Garfield	976-868	Robert E. & Barbara J. Stone	Vessels Oll & Gas Co.	3/5/96	5/6/96		19.22		1/8		5	T6S R92W SEC 34 NE
Garfield	976-870	Rose C. Anderson	Vessels Oll & Gas Co.	3/18/96	5/6/96		400.00		1/8		3	T6S R92W SEC 21 SESW, SWSE, SEC 28 NE, S2NW, NENW, SEC 29 SENE

APPENDIX F

LIST OF ASSIGNMENTS AND BILLS OF SALE

LIST OF ASSIGNMENTS AND BILLS OF SALE ON PRODUCING PROPERTIES IN WESTERN COLORADO

GARFIELD COUNTY																
Book Page	Lease Number	Assignor	Assignee	Eff. Date	Rec. Date	Type of Instrument	Location Descp.	Well Name	Working Interest Conv.	Gross Acres	Net Acres	ORRI Res. Prev. Res.	NRI	Amount Paid	Field Name	Relative to NOSR 1 & 3
0875-507	Multiple	Piute Acquisition Corporation	Tamarack Energy	11/1/92	9/15/93	Assignment, Bill of Sale and Conveyance	T7S R90, 91W			5,938	3926			$ 10.00		20mi SE
0878-846	Multiple	Fina Oil and Chemical Co.	Barrett Resources Corp.	9/29/93	10/18/93	Assignment and Bill of Sale	T5S R94W, T6S R93, 94W							$ 10.00	Rulison	6mi E.
879-613	Multiple	ORYX Energy Co.	Snyder Oil Corp.		10/25/93	Assignment of Leases	Very Large area	Multiple	100.00%							16mi SE of NOSR 3
882-905	Multiple	Mobil Oil Corp.	Snyder Oil Corp.	11/1/93	11/22/93	Partial Assignment of Leases	Very Large area	Multiple	100.00%							8mi SE of NOSR 3
887-589		Liedtke Development Corp.	Energy Investments Inc.	4/1/93	12/27/93	Assignment, Bill of Sale	T6S R93W	R.H. Ranch #1	60%GWI 46.5% NWI	160				$ 100.00	Mam Creek	9mi SE of NOSR 3
887-593		Energy Investments	Snyder Oil Corp.	4/1/93	12/27/93	Assignment, Bill of Sale	T6S R93W	R.H. Ranch #2	60%GWI 46.5% NWI	160				$ 100.00	Mam Creek	9mi SE of NOSR 4
892-578		Pioneer Oil and Gas	Riata Energy Inc.		2/14/94	Assignment, Bill of Sale	T7S R95W							$ 10.00		4mi S. of Nosr 3
913-236		Timberline Energy Inc.	Vessels Oil and Gas Co.	8/15/94	8/22/94	Assignment of Leases	T6S R91W, T7S R91W		100.00%					$ 100.00		20mi E. of NOSR 3
929-141		LoneTree Energy.	Chevron USA Prod.		1/17/95	Assignment of Leases	T7S R93W		100.00%	480					Mam Creek	10mi SE of NOSR 3
930-875	CO-50470	Benson Mineral Gp	Pawnee Management Corp. Et al.		2/6/95	Assignment of Leases	T7S R94W		100.00%					$ 10.00	Rulison	5mi SE of NOSR 3
932-707	COC- 50268	Strachan Exploration, Inc.	Texakoma Oil & Gas Co.	11/1/89	2/27/95	Assignment of Record Title Interest in a Lease	T4S R97W		75.00%	1,281		7.50%			Whiskey Gulch	20mi NW of NOSR 3
933-634	Multiple	Mobil Oil Corp.	Snyder Oil Corp.		3/6/95	Assignment of Leases	T7S R91W, T8S R91W, T9S R90-91W,								Divide Creek	30mi SE of NOSR 3
938-427	CO-35787 CO-35793	Gyrodyne Petroleum	Meridian Oil Inc.		4/26/95	Assignment of Leases	T6S R94W		100.00%					$ 10.00	Rulison	4mi E of NOSR 3
946-906		Gyrodyne Petroleum	Barret Resources Corp.	4/31/95	7/17/95	Assignment and Bill of Sale	T6S R94W, T7S R94-95W,	Multiple	100.00%					$ 10.00	Rulison	2mi S.
947-595		Barrett Resources	Barrett Resources Et. al.		7/24/95	Assignment and Bill of Sale	T6S R95W, T7S R94-95W		100.00%	104				$ 1.00		2mi S.

LIST OF ASSIGNMENTS AND BILLS OF SALE ON PRODUCING PROPERTIES IN WESTERN COLORADO

GARFIELD COUNTY (continued)																
949-993		Barrett Resources	Barrett Resources Et. al.	12/1/94	8/10/95	Assignment and Bill of Sale	T6S R94W		100.00%					$ 10.00	Rulison	2mi SE.
952-71	Multiple	Conquest, Arata, & Rimco	SG Interests		9/5/95	Assignment and Bill of Sale	T8S R98W			6,680					Coon Hollow	18mi SW of NOSR 3
953-82		Piute Acquisition Corporation	Tamarack Energy	11/1/92	9/15/95	Assignment, Bill of Sale and Conveyance	T7S R92W		100.00%	480	290			$ 10.00		22mi S. of NOSR 1
953-85		Piute Acquisition Corporation	Tamarack Energy	11/1/92	9/15/95	Assignment, Bill of Sale and Conveyance	T10S R95W		100.00%	240	240			$ 10.00	Plateau	20mi S.
955-838	COC-12736	Conquest, Rimco	SG Interests	1/1/95	10/16/95	Transfer of Operating Rights in a Lease	T8S R98W	S. Shale Ridge Unit 9-17, 3-20	60.00%	1,320		8.00%			Coon Hollow	20mi SW of NOSR 1
956-729	Multiple	Timberline Energy Inc.	Vessels Oil & Gas Co.	10/1/95	10/25/95	Assignment of ORRI	T6S R92W	1 Well						$ 100.00		15mi E. of NOSR 3
960-690	CO-50136-14 CO-50917-4	Fina Oil and Chemical Co.	Barrett Resources Corp.	9/29/93	12/11/95	Assignment and Conveyance	T6S R94W		100.00%	120				$ 10.00	Rulison	3 mi E. of NOSR 3
968-982		Timberline Energy Inc.	Vessels Oil and Gas Co.	1/1/96	3/1/96	Assignment and Bill of Sale	T6S R91-92W, T7S R91W	Multiple	100.00%					$ 10.00	Gibson Gulch	18mi E of NOSR #
973-661	Multiple	Darwin W. Brown Et al.	Vessels Oil & Gas Co.	1/1/96	4/11/96	Assignment and Bill of Sale	T6S R91, 92W, T7S R91W	Multiple	100.00%	49,920				$ 10.00	Gibson Gulch	18mi S.

LIST OF ASSIGNMENTS AND BILLS OF SALE ON PRODUCING PROPERTIES IN WESTERN COLORADO

MESA COUNTY

Book Page	Lease Number	Assignor	Assignee	Eff. Date	Rec. Date	Type of Instrument	Description	Well Name	Working Interest Conv.	Gross Acres	Net Acres	ORRI Res. Prev. Res.	NRI	Amount Paid	Field Name	Relative to NOSR 1 & 3
2039-960		John F. Sheridan	Lamar Roemer	11/1/93	1/7/94	Assignment and Bill of Sale	T10S R95W SEC 3 SESE	Hill 3x-3	1.87%	40			1.64%		Plateau	18mi S.
2043-308	Fee & USA Multiple	Phoenix Hydrocarbons Inc. Et al.	Snyder Oil Corp	1/1/94	1/21/94	Assignment, Bill of Sale and Conveyance	T9S R97W	Dolley 1, Fed 22-1, 23-1, 32-1, 32-5, 32-2	100.00%	1,685				$ 10.00	Shire Gulch, Roberts Canyon	20mi S.
2046-318		John F. Sheridan	Lamar Roemer	11/1/93	2/3/94	Assignment and Bill of Sale	T10S R95W SEC 3 SESE		9.38%	40			8.20%		Plateau	18mi S.
2105-580	USA & CO Multiple	K N Production, Inc. Gasco, Inc.	Genesis Gas and Oil L.L.C.	2/1/94	10/19/94	Assignment, Bill of Sale and Conveyance	T9S R94, 95, 97, 98W, T10S R94-95W, T11S R96W	Multiple	50.00%					$ 10.00	Buzzard, Plateau	15-20 mi S.
2169-931	COC-18445 COC-18820 COC-18820	Maroja, Inc.	James P. Garman Et al.		9/5/95	Assignment of ORRI	T8S R104W, T9S R97W							$ 10.00	Roberts Canyon	22mi SW.
2186-893	USA & CO Multiple	KN Production Co.	Maralex Resources, Inc.	8/1/95	11/16/95	Assignment, Bill of Sale and Conveyance	T9S R98, 100W, T10S R96W		100.00%					$ 10.00	Craig, Plateau	25mi S. 20mi S.
2188-9712	CO 000641 CO 000642 CO 000643	Viola Production Inc.	KN Production Co.	12/1/94	11/27/95	Assignment, Bill of Sale and Conveyance	T9S R92W		100.00%					$ 10.00	Sheep Creek	22mi SE
2201-432	USA Multiple	Maralex Resources	Coalseam Developent, L.L.C.	8/1/95	1/22/96	Assignment, Bill of Sale and Conveyance	T8S R99W, T9S R99-100W, T10S R95-98W, T11S R95W	Multiple	50.00%			0.00%		$ 10.00	Roberts Canyon, Shire Gulch	15mi SW
2228-56		Forcenergy Gas Expl., Inc.	Chemco Inc.	5/1/96	5/1/96	Assignment, Bill of Sale and Conveyance	T10S R94, 95W		100.00%	3,205				$ 100.00	Plateau	20mi S.

APPENDIX G

LIST OF MINERAL CONVEYANCES

LIST OF MINERAL CONVEYANCES

County	Book Page	Grantor	Grantee	Inst. Date	Rec. Date	Type of Instument	Gross Acres	Net Acres	Mineral Interest Conv.	Location
Mesa	823-804	Saul Braverman, Lynn Robinson	Chaparral Royalty Company (1/3) F.H. Mills, JR,. Trustee (1/3) Ed Phillips & Associates Inc. (1/3)	1/28/92	2/18/92	Mineral Deed			100.00%	T7S R95W
Mesa	859-485	Mearl E. Kiper	Joe Bob Neal	4/12/93	4/13/93	Mineral Deed	850.00		3.13%	T6S R95W SEC 28 E2W2, S2SE, SEC 32 SENE, SEC 33 NE, SWNW, NENW, SEC 34 NW, SWNWNE
Garfield	890-206	Marjorie Fern Peables	Darla sue Bolin	12/27/92	1/19/94	Correction Mineral Deed	137.07		100.00%	T6S R95W SEC 36 SENE T6S R94W SEC 31 W2SESW T7S R94W SEC 6 LOT 3
Garfield	892-828	Richard E. Barr	William H. Spires	1/25/94	2/16/94	Mineral Deed	280.00		100.00%	T6S R92W SEC 35 SWNW, N2SW, SWNE, W2SE, SESW
Garfield	912-782	Pamela Morris Cooper	Henry H. Gordon	7/26/94	8/18/94	Mineral Deed	897.35	367.29	50.00%	T8S R102, 96,97W
Garfield	912-783	Pamela Morris Cooper	Henry H. Gordon	7/26/94	8/18/94	Mineral Deed	2723.37	330.44	50.00%	T8S R96W, T6S R97W, T7S R96W
Garfield	915-093	Western Minerals Partnership	Timberline Energy Et al.	8/29/94	9/7/94	Mineral Deed	1000s		100.00%	T6S R92W, T7S R92W, T8S R92W,
Garfield	930-076	Karen E. Haese	Strider Resources Co.	1/24/95	1/30/95	Quitclaim Deed			100.00%	T6S R92W, T7S R92W, T8S R91W, T8S R92W, T9S R91W, T7S R90W
Garfield	930-078	Strider Resources Co.	George G. Vaught, Jr. (1/3) Steven G. Shaddock (1/3) McCulliss Resources Co., Inc. (1/3)	1/26/95	1/30/95	Quitclaim Mineral Deed			33%	T6S R92W, T7S R92W, T8S R91W, T8S R92W, T9S R91W, T7S R90W
Garfield	939-67	Maxwell Petroleum Inc.	May Kwok-Keating	4/1/95	5/1/95	Mineral Deed			100.00%	T6S R92W, T7S R92W, T8S R92W,
Garfield	939-871	Shear Inc.	Sunnyside Production Co.	5/1/95	5/5/95	Mineral Deed	1220.1		100.00%	T6S R94W SEC 23 T7S R93W SEC 7 T7S R94W SEC 12
Garfield	954-900	Timberline Energy	Bay Minerals, LLC, Et al.	9/19/95	10/4/95	Mineral Deed			100% of 20% right	T6S R92W, T7S R92W, T8S R92W

APPENDIX H

INVENTORY OF DOE WELLS ON NOSR-3

INVENTORY OF DOE WELLS ON NOSR-3

Field	Operator	Lease/well name	S	T	R	Well #	Stat	Oil Cum	Gas Cum	Last Month Oil	Last Month Gas	Last Prod Date	1st Prod Date	Upper Perf	Lower Perf	Total Depth
Grand Valley (CC)	Barrett Resources	DOE 1-M-35	36	6S	96W		ACT	143	325338	0	9517	Nov-95	Aug-94	5388	7109	7405
Grand Valley (CC)	Barrett Resources	GV 24-36	36	6S	96W		ACT	0	272638	0	3316	Nov-95	Feb-90			
Grand Valley (CC)	Barrett Resources	MV-13-33	33	6S	95W		ACT	0	50459	0	780	Nov-95	Aug-92			
Grand Valley (CC)	Barrett Resources	MV-43-31	31	6S	95W		ACT	0	163491	0	2112	Nov-95	May-92			
Grand Valley (CC)								143	811926	0	15725					
Grand Valley (MV)	Barrett Resources	GV 24-36	36	6S	96W		ACT	0	153515	0	1354	Nov-95	Feb-90			6900
Grand Valley (MV)	Barrett Resources	GV 24-36	36	6S	96W		ACT	0	153515	0	1354	Nov-95	Feb-90			6900
Grand Valley (MV)	Barrett Resources	MV-13-33	33	6S	95W		ACT	0	126218	0	2583	Nov-95	Aug-92			
Grand Valley (MV)	Barrett Resources	MV-43-31	31	6S	95W		ACT	0	332309	0	5567	Nov-95	Aug-92			
Grand Valley (MV)	US Dept. of Energy	DOE 1-M-36	36	6S	96W		ACT	293	315131	33	16317	Dec-95	Nov-93			
Grand Valley (MV)	US Dept. of Energy	NOSR #3 DOE 2-M 36	36	6S	96W		ACT	102	132831	0	8700	Dec-95	Feb-95			
Grand Valley (MV)								395	1213519	33	35875					
Parachute (CC)	Barrett Resources	GV 39-32	32	6S	95W		ACT	0	157099	0	2218	Nov-95	Oct-90			6750
Parachute (CC)	Barrett Resources	MV-37-32	32	6S	95W		ACT	0	53218	0	1288	Nov-95	Sep-92			
Parachute (CC)	US Dept. of Energy	NOSR #3 DOE 1-M 31	31	6S	95W		ACT	0	231058	0	15681	Dec-95	Feb-95			
Parachute (CC)	US Dept. of Energy	NOSR #3 DOE 2-M 29	29	6S	95W		ACT	293	127882	10	4629	Dec-95	Feb-95			
Parachute (CC)								293	569257	10	23816					
Parachute (MV)	Barrett Resources	GV 39-32	32	6S	95W	39	ACT	0	441783	0	4938	Nov-95	Oct-90			6750
Parachute (MV)	Barrett Resources	MV-37-32	32	6S	95W		ACT	0	151146	0	4646	Nov-95	Aug-92			
Parachute (MV)	US Dept. of Energy	DOE 1-M-29	20	6S	95W		ACT	713	222899	83	18856	Dec-95	Nov-93			
Parachute (MV)								713	815828	83	28440					

INVENTORY OF DOE WELLS ON NOSR-3

Field	Operator	Lease/well name	S	T	R	Well #	Stat	Oil Cum	Gas Cum	Last Month Oil	Last Month Gas	Last Prod Date	1st Prod Date	Upper Perf	Lower Perf	Total Depth
Parachute (W)	Barrett Resources	ALLEN POINT 1-895	8	6S	95W		ACT	0	67280	0	908	Jul-95	Nov-90			
Parachute (W)	Barrett Resources	ALLEN POINT 1-995	9	6S	95W	1-995	ACT	0	106948	0	1002	Jul-95	Nov-90			
Parachute (W)	Barrett Resources	ALLEN POINT 1-1695	16	6S	95W	1-1695	ACT	0	219999	0	1391	Jul-95	Nov-90			
Parachute (W)	Barrett Resources	ALLEN POINT 1-2095	20	6S	95W	35084	ACT	0	136961	0	2313	Nov-95	Jan-91	3267	3527	3880
Parachute (W)	Barrett Resources	ALLEN POINT 3-895	8	6S	95W	3-895	ACT	0	244369	0	1625	Jul-95	Nov-90			
Parachute (W)	Barrett Resources	W- 5-33 MOBIL	33	6S	95W		ACT	0	1083279	0	7580	Nov-95	Nov-87	1772	1849	3191
Parachute (W)	Barrett Resources	W- 9-28 MOBIL	28	6S	95W		ACT	0	665733	0	4162	Nov-95	Nov-87	1996	2067	3400
Parachute (W)	Barrett Resources	W-17-27 MOBIL	27	6S	95W		ACT	0	796029	0	5638	Nov-95	Nov-87	1984	2046	3100
Parachute (W)	Barrett Resources	W-18-27 MOBIL (BPO)	27	6S	95W		ACT	0	500990	0	3636	Nov-95	Oct-87	1908	1974	3250
Parachute (W)	Barrett Resources	W-19-28 MOBIL	28	6S	95W	19-28	ACT	0	695944	0	4608	Nov-95	Nov-87			
Parachute (W)	Barrett Resources	W-20-32	32	6S	95W		ACT	0	700176	0	6544	Nov-95	Oct-87	1422	1457	2900
Parachute (W)	Barrett Resources	W-29-26 (BPO)	26	6S	95W	29-26	ACT	0	459672	0	3725	Nov-95	Dec-87			
Parachute (W)	Barrett Resources	W-43-28 (APO)	28	6S	95W	43-28	ACT	0	716766	0	5850	Nov-95	Nov-87			
Parachute (W)	US Dept. of Energy	DOE 2-W-20	20	6S	95W		ACT	0	145906	0	5636	Dec-95	Nov-93			
Parachute (W)	US Dept. of Energy	NOSR #3 DOE 1-W-20	20	6S	95W		ACT	0	296843	0	8275	Dec-95	Aug-92			
Parachute (W)	US Dept. of Energy	NOSR #3 DOE 1-W-21	21	6S	95W	1-W-21	ACT	0	371496	0	4484	Dec-95	Mar-90			3750
Parachute (W)	US Dept. of Energy	NOSR #3 DOE 1-W-26	26	6S	95W	1-W-26	ACT	0	139698	0	1480	Dec-95	Mar-90			3901
Parachute (W)	US Dept. of Energy	NOSR #3 DOE 1-W-27	27	6S	95W	1-W-27	ACT	0	479239	0	6048	Dec-95	Mar-90			3650
Parachute (W)	US Dept. of Energy	NOSR #3 DOE 1-W-28	28	6S	95W	1-W-28	ACT	0	513664	0	5865	Dec-95	Mar-90			3400
Parachute (W)	US Dept. of Energy	NOSR #3 DOE 1-W-29	29	6S	95W	1-W-29	ACT	0	701714	0	7148	Dec-95	Mar-90			3300

INVENTORY OF DOE WELLS ON NOSR-3

Field	Operator	Lease/well name	S	T	R	Well #	Stat	Oil Cum	Gas Cum	Last Month Oil	Last Month Gas	Last Prod Date	1st Prod Date	Upper Perf	Lower Perf	Total Depth
Parachute (W)	US Dept. of Energy	NOSR #3 DOE 1-W-32	32	6S	95W	1-W-32	ACT	0	144407	0	1647	Dec-95	Mar-90			2747
Parachute (W)	US Dept. of Energy	NOSR #3 DOE 2-W-21	21	6S	95W	2 W 21	ACT	0	420996	0	7558	Dec-95	Apr-92	3442	3556	3780
Parachute (W)	US Dept. of Energy	NOSR #3 DOE 2-W-27	27	6S	95W	2-W-27	ACT	0	301966	0	3928	Dec-95	Mar-90			3900
Parachute (W)	US Dept. of Energy	NOSR #3 DOE 2-W-29	29	6S	95W	2-W-29	ACT	0	442685	0	4893	Dec-95	Mar-90			3452
Parachute (W)	US Dept. of Energy	NOSR #3 DOE 3-W-21	21	6S	95W		ACT	0	137993	0	7638	Dec-95	Jan-95			
Parachute (W)	US Dept. of Energy	NOSR #3 DOE 3-W-29	29	6S	95W		ACT	0	298287	0	5493	Dec-95	Jul-92			
Parachute (W)								0	10789040		119075					
Rulison (CC)	Barrett Resources	DOE FEDERAL 9-17 MV	17	6S	94W	9 17MV	ACT	483	196126	0	585	Sep-95	Oct-91	7939	7939	8120
Rulison (CC)	Barrett Resources	DOE FEDERAL 9-17 MV	17	6S	94W		ACT	1602	351538	165	33088	Nov-95	Dec-94			
Rulison (CC)	US Dept. of Energy	NAVAL OIL SHALE DOE	18	6S	94W		ACT	489	99623	38	11171	Dec-95	Mar-95			
Rulison (CC)	US Dept. of Energy	NOSR #3 DOE 1-M 17	17	6S	94W	1 M 17	ACT	14	300684	14	11225	May-95	Feb-92	7315	8280	8459
Rulison (CC)								2588	947971	217	56069					
Rulison (MV)	US Dept. of Energy	NOSR #3 DOE1-M-17	17	6S	94W	1 M 17	ACT	4214	727940	49	15630	Dec-95	Feb-92	6688	7269	8459
Rulison (MV)	US Dept. of Energy	NOSR #3-DOE 1-M 19	19	6S	94W	1XM-19	ACT	1662	458184	9	4129	Dec-95	Oct-89			7692
Rulison (MV)	US Dept. of Energy	NOSR #3-DOE 1-M 9	9	6S	94W	1XM-9	ACT	5589	983649	41	12855	Dec-95	Oct-89			7893

INVENTORY OF DOE WELLS ON NOSR-3

Field	Operator	Lease/well name	S	T	R	Well #	Stat	Oil Cum	Gas Cum	Last Month Oil	Last Month Gas	Last Prod Date	1st Prod Date	Upper Perf	Lower Perf	Total Depth
Rulison (MV)								1465	2169773	99	32614					
Rulison (W)	US Dept. of Energy	NOSR DOE 1-W-17	17	6S	94W		ACT	0	288844	0	4082	Dec-95	Nov-90	2318	2372	3496
Rulison (W)	US Dept. of Energy	NOSR DOE 1-W-19	19	6S	94W		ACT	0	70139	0	1529	Dec-95	Nov-90	2318	2331	3303
Rulison (W)	US Dept. of Energy	NOSR DOE 1-W-9	9	6S	94W		ACT	0	194814	0	3056	Dec-95	Nov-90			
Rulison (W)								0	553797	0	8667					
Rulison (WM)	US Dept. of Energy	NAVAL OIL DOE 1-M-18	18	6S	94W		ACT	191	135742	31	22286	Dec-95	Mar-95			
CC= Cameo Coals																
MV= Mesaverde																
W = Wasatch																
WM= Williams																

APPENDIX I

BIBLIOGRAPHY

BIBLIOGRAPHY

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APPENDIX J

SEISMIC DATA INTEGRATION

APPENDIX J

SEISMIC MAPPING PROJECT
U.S. NAVAL OIL SHALE RESERVES 1 AND 3
GARFIELD COUNTY, COLORADO

OBJECTIVE OF THE GEOPHYSICAL WORK

The major objective of the geophysical work at the NOSR-1 and NOSR-3 areas was to calibrate and integrate the existing subsurface control with two seismic lines which cross the study area. Deep well control consisted of the Arco North Rifle Unit #1 and Barrett #1-27 Arco Deep, both of which closely tied a northeast-southwest seismic line. Seismic structure and isochron maps were constructed on key horizons and intervals in the study area, and an attempt made to assess the prospective nature of the productive Wasatch "G" interval.

METHODOLOGY

Digital tape copies of seismic Lines CPB-1 and CPB-3 were obtained on behalf of DOE from Seitel Data Corporation. The Final Migrated Stack data set was provided to this Consultant by Seitel for analysis on a Geoquest workstation. A reprocessed version of line CPB-3 was also obtained by this Consultant from the USGS Denver office. It was discovered after loading the data tape on the Geoquest workstation that only a small segment of the reprocessed line from the USGS had been provided in digital form. Since the reprocessed version of this line was incomplete, it was not utilized in the geophysical analysis.

The NOSR-1 and NOSR-3 geophysical project was conducted at the workstation facilities of Gustavson Associates. This work was performed on a Geoquest IESX workstation running on Silicon Graphics hardware. A digital township and range grid of the NOSR area was loaded into the project, and shotpoints from Lines CPB-1 and CPB-3 digitized from a small scale seismic base map provided by DOE.

SYNTHETIC SEISMOGRAM CONSTRUCTION

Well logs from the Arco North Rifle Unit #1 and Barrett #1-27 Arco Deep wells were digitized to create synthetic seismograms to establish an accurate calibration of seismic horizons to geological formation tops. A complete sonic curve was not available for the Barrett #1-27 well. Consequently, a 'pseudo-sonic' curve was created by digitizing the density log curve for this well, and converting to a sonic curve utilizing Gardner's equation.

Well tops were picked independently by this Consultant, and input into the Geoquest Synview synthetic seismogram package. A seismic wavelet was extracted from Line CPB-3 near the location of the Arco North Rifle well. Additionally, other seismic wavelets were created utilizing deterministic frequency analysis methods. Synthetic seismograms were constructed on both the Arco North Rifle Unit #1 and Barrett #1-27 Arco Deep wells (Plates 4 and 5, Addenda). These synthetics were tied to seismic Line CPB-3 (Figure 1), and seismic horizon calibrations made on significant reflectors.

Based on synthetic seismogram calibration, mappable events were identified at the Wasatch "G" horizon, Top Mesaverde, Top Mancos Shale, Top Niobrara, Frontier/Dakota, Mississippian Leadville, and Basement. Line CPB-3 was utilized as the baseline, and seismic correlations carried to Line CPB-1 (Figure 2) at the intersection of these two lines.

Immediately northeast of NOSR 1 and 3, Line CPB-3 crosses the Grand Hogback which marks the structural boundary between the Piceance Basin on the west and the White River Uplift to the east. It is a relatively narrow, structurally complex zone consisting of intense folding and thrust-faulting. All of the mapped seismic horizons progressively outcrop at the surface over a very short distance. Surface geology (Figure 3) was used to constrain the seismic interpretation along this northeasternmost portion of Line CPB-3.

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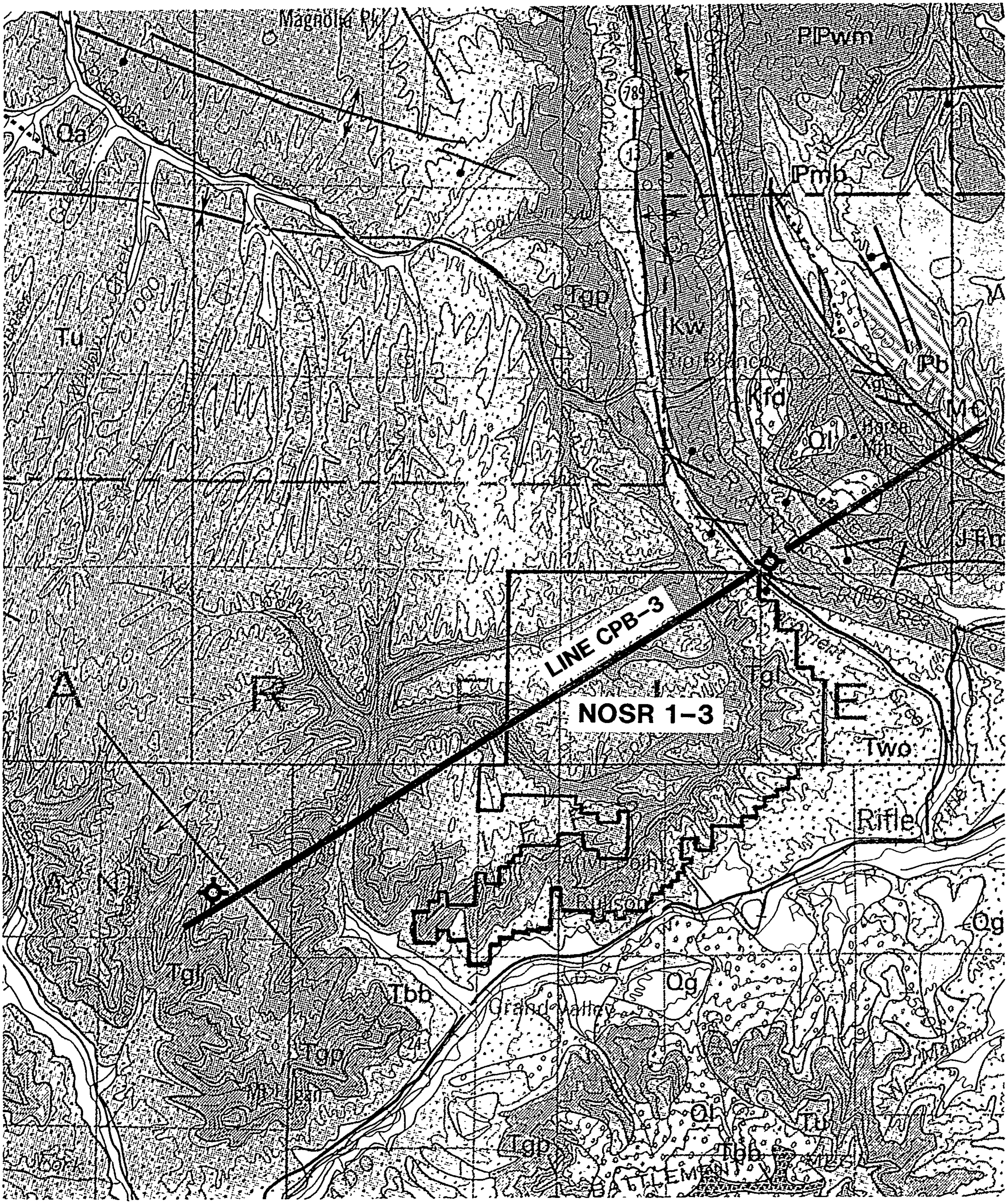

FIGURE 3 –Surface geology map showing locations of seismic line CPB–3 and NOSR 1–3 (from Geologic Map of the State of Colorado, published by U.S. Geological Survey, 1979).

SEISMIC STRUCTURE AND ISOCHRON MAPS

Contoured seismic time structure maps were created on the Wasatch "G", Mesaverde, Frontier/Dakota, and Basement horizons (Plates 6 through 9, Addenda). In addition, isochron interval maps were constructed on the Wasatch "G" to Mesaverde interval, and the Frontier/Dakota to Basement interval (Plates 10 and 11, Addenda). All maps have the same contour interval (20 milliseconds), and are plotted at a scale of 1" = 4000'.

The reader is referred to the original Gustavson Property Description and Fact-Finding Report for NOSR 1 and 3, dated June 30, 1996, for a general discussion of the structural setting of these properties. In addition, the set of computer-generated seismic maps and interpretted seismic sections are included with this report as noted above and provide the basis for the following discussion.

The analysis confirms the presence of a prominent time-structural high in the southeastern portion of NOSR-1, centered on Sections 26 and 35, T5S - R94W. The feature also extends onto the adjoining portions of NOSR-3. At the Wasatch "G" and Mesaverde horizons, this feature is a broad southwest-plunging anticlinal nose with approximately 35 milliseconds of two-way time reversal on Line CPB-1 between shotpoints 1330 and 1510. A small amount of four-way time closure is shown on the maps of these horizons; however, additional seismic coverage would be required to confirm the presence and extent of a potentially closed structure. Perhaps of more significance is the potential for fracture enhancement of reservoir permeability which might be expected on this structural feature.

The time structure is also present at the deeper horizons with the potential for 50 milliseconds of four-way closure at the Dakota level. At a minimum, one more seismic line oriented parallel to CPB-3 and centered over the feature would be required to verify the presence of actual four-way closure. As with the shallower horizons, fracture enhancement of Dakota reservoir permeability may be possible on this structure independent of the presence of actual four-way domal closure. Deeper Jurassic and Paleozoic horizons could be potential targets on this feature if four-way closure can be confirmed. However, the current economic viabilty of exploring the potential of such deeper targets is not feasible due to the extreme drilling depths required.

The structure as mapped in this study is of much smaller areal extent than that inferred by the U.S. Geological Survey in Open-File Report 94-427 (Fouch et al., 1994). That report suggested that the feature could cover nearly two-thirds of NOSR-1 and over half of the NOSR-3 lands lying in T6S - R94W. The present interpretation indicates that the structure is confined to about a nine-section area--in itself, a sizeable prospect. Depth conversion which would require significantly more analysis and investigation and was not done as part of this study. However, this Consultant believes that the time-structural interpretations presented provide the basis for assessing the prospectivity for oil and gas potential on portions of NOSR 1 and 3.

SEISMIC ATTRIBUTE ANALYSIS - WASATCH "G" ZONE

A seismic attribute was extracted from a time interval window surrounding the Wasatch 'G' horizon. This zone is productive to the south of the NOSR area from the Rulison, Parachute, and Grand Valley Fields. The attribute of "Average Magnitude of Amplitude" was selected within a window 100 milliseconds above, and below the Wasatch "G" seismic pick. This attribute measures the strength of reflection coefficients within a particular seismic interval, and can be useful in delineating areas of possible sand presence, improved porosities in reservoirs, and hydrocarbon 'bright spots'. A multiple-color display showing the variation in the extracted Wasatch amplitude is superimposed on the Wasatch "G" Time Structure Map (Plate 6, Addenda).

Based on analysis of Estimated Ultimate Recoveries (EUR) for the Wasatch "G" zone at the Parachute and Rulison Fields (as mapped by LaFreniere, 1994), it appears that there may be a good correlation between the amount of production and the magnitude of extracted seismic amplitudes. At Parachute Field the higher calculated EUR's appear to be distributed in a linear, narrowly defined, northwest-southeast trend (see EUR overlay to the accompanying Wasatch "G" Time Structure with Amplitude Map). It is possible to extrapolate this production trend northwestward to a point where it might intersect Line CPB-3. An extracted seismic amplitude anomaly appears to be present over the Wasatch "G" window between shotpoints 910 and 1120 on this line.

A similar narrow, northwest-southeast oriented trend of high Wasatch EUR's is present at Rulison Field to the east of Parachute Field. This narrow zone can be regionally projected to the northwest into an areally-more restricted but equally high amplitude anomaly located between shotpoints 710 and 770 on Line CPB-3. The confidence level of this projection is much lower due to the greater distance of extrapolation. A third area of higher extrapolated amplitudes appears to be present between shotpoints 580 and 650 on the same seismic line.

Also of interest is the relative lack of amplitude anomalies along the southeastern portions of the northwest-southeast oriented seismic Line CPB-1 where it traverses Wasatch production at Rulison Field. The Wasatch "G" EUR overlay shows that the better Wasatch production lies parallel to and 1 1/2 to 2 miles to the southwest of Line CPB-1. Predicted Wasatch EUR's for locations beneath CPB-1 are significantly lower.

In contrast to the southeastern portions of Line CPB-1, the northwestern segment exhibits Wasatch "G" high amplitude anomalies between shotpoints 1010-1070 and 1110-1140, suggesting possible Wasatch gas potential in the northern half of NOSR-1. A more subtle extracted amplitude anomaly between shotpoints 1390 and 1500 appears to be coincident with the time high discussed earlier. If elevated values of extracted seismic amplitude are correlative with increased porosity (perhaps a function of increased fracturing), then it would not be unreasonable to see such an amplitude anomaly associated with an anticlinal structure. This suggests the possibility that Wasatch ""G" sands may be prospective on this feature.

Since no wells are actually drilled or productive from the Wasatch "G" zone within the area of these seismic amplitude anomalies, the extrapolation of productive trends into these areas must be considered as conjectural. However, such productive trends which are defined with this seismic methodology do exist in productive analogs throughout the world, and the trends identified from the sparse seismic control across the NOSR area should be given some credibility.

In this regard, similar analyses for the various Mesaverde Group horizons (i.e., Williams Fork, Cameo Coal, and Rollins Sandstone) could be done and might provide some additional insights into these stratigraphically deeper established gas zones. This additional work is beyond the current scope of this project.

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NOTICE

APPENDIX K

NOSR-3 Reserves - Including Proved Undeveloped Infill/Offset Potential

Introduction

Fluor Daniel prepared detailed estimates of developed reserves at NOSR-3 on a well by well basis. As previously discussed, these estimations are considered reasonable for use in Phase II of the NOSR-1&3 property evaluation. The FY 1995 reserves have been adjusted to reflect cumulative production since the last report, and to reflect the new wells drilled and recompleted since the Fluor Daniel FY 1995 reserve report was prepared. In addition, Gustavson Associates has estimated proved undeveloped reserve potential at NOSR-3 as discussed in this section of the report.

Proved Developed Producing Reserves

The Proved Developed Producing Reserves have been updated through the 1st quarter of 1996, and therefore reflect new wells and recompletions up through that time period. Since the FY 1995 reserve report was prepared, the following wells have been drilled: PM 2-31, 2-M-35R, RMV 59-17, RMV 50-18, RM 2-8, PW 3-20. Projected reserves associated with these wells were included as part of the total NOSR-3 PDP volumes. The PDP reserve projections were calculated as net to DOE and added on a well by well basis. The resulting net DOE PDP forecast is shown as Figure K-1. The associated net PDP reserves are 11.3 BCF and 12.9 thousand barrels of condensate.

Behind Pipe Reserves

Proved developed non-producing reserves and probable behind pipe reserves were also supplied by Fluor Daniel in the FY 1995 reserve report. These reserves were only assigned to Mesaverde wells, and were based on a detailed pore volume analysis. The reserves were forecast by this Consultant based on several assumptions. The PDNP reserves for a given well were only forecast after the existing production from the well became uneconomic. The remaining probable reserves

TABLE K-1

NOSR-3 Behind Pipe Reserves
[DOE Net]

Proved Developed Non-Producing

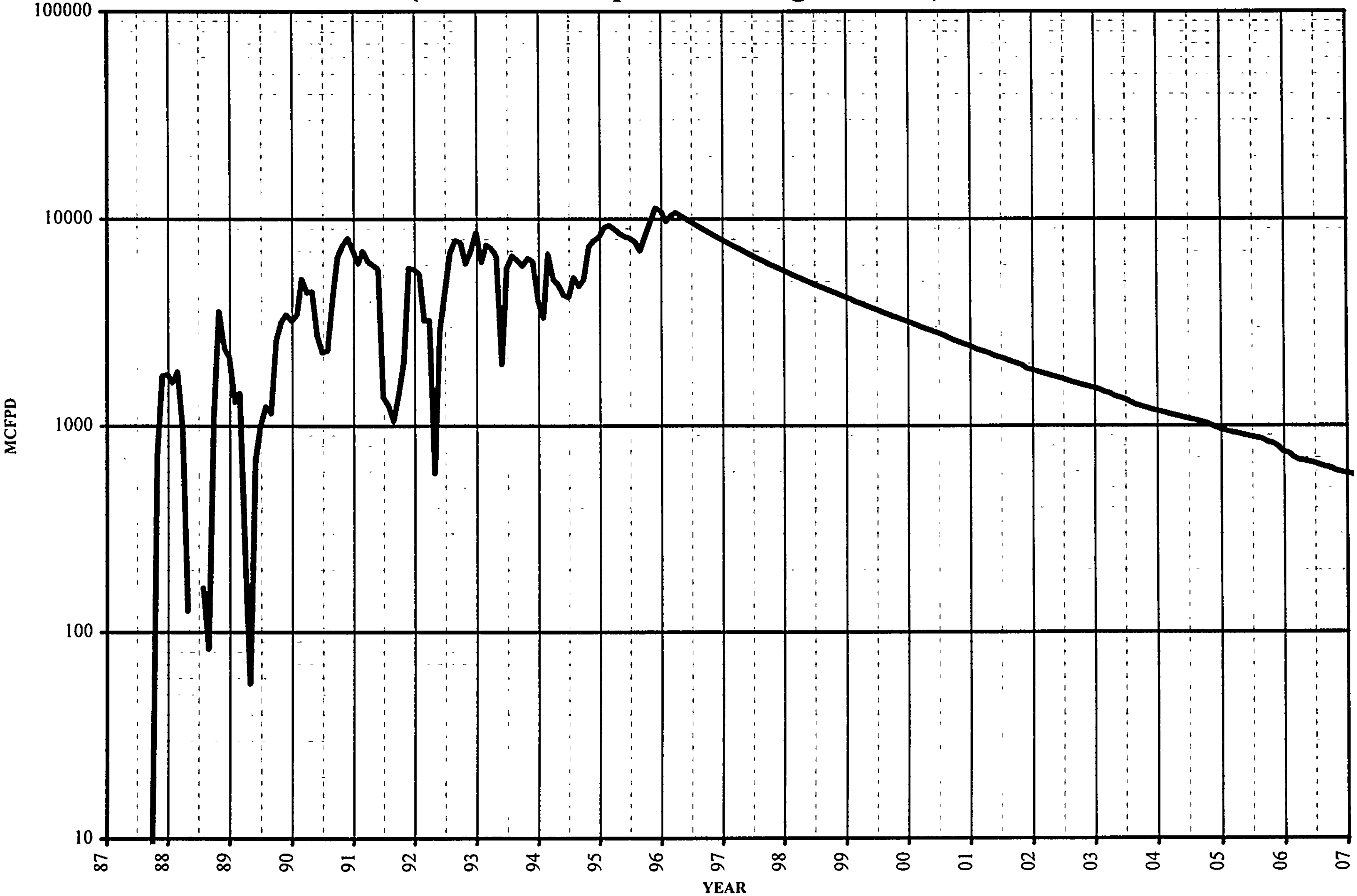
Date	PDNP Wells	PDNP Capital	PDNP Op.Cost	PDNP Gas (MCF)	PDNP Cond.
	0				
2000	3	$ 376,692	$ 30,109.08	37,708	45
2001	4	$ 129,419	$ 41,365.87	64,522	77
2002	7	$ 400,176	$ 74,590.93	195,033	234
2003	7	$ -	$ 76,858.49	184,768	222
2004	7	$ -	$ 79,194.99	262,488	315
2005	10	$ 438,176	$ 116,575.03	437,829	525
2006	12	$ 301,085	$ 144,142.69	495,228	594
2007	12	$ -	$ 148,524.63	465,062	558
2008	12	$ -	$ 153,039.78	434,896	522
2009	12	$ -	$ 157,692.19	404,730	486
2010	13	$ 169,898	$ 176,026.53	405,777	487
2011	13	$ -	$ 181,377.74	427,564	513
2012	12		$ 172,515.35	361,994	434
2013	12	$ -	$ 177,759.81	329,314	395
2014	12	$ -	$ 183,163.71	296,634	356
2015	10		$ 157,276.57	219,962	264
2016	10	$ -	$ 162,057.78	192,728	231
2017	10	$ -	$ 166,984.34	165,495	199
2018	10	$ -	$ 172,060.66	138,262	166
2019	10	$ -	$ 177,291.30	111,028	133
2020	8		$ 146,144.77	67,036	80
2021	7		$ 131,764.12	43,992	53
2022	7	$ -	$ 135,769.75	30,795	37
2023	7	$ -	$ 139,897.15	21,996	26
2024	7	$ -	$ 144,150.03	13,198	16
2025	4		$ 84,875.54	5,028	6
2026	2		$ 43,727.88	2,095	3
2027	2	$ -	$ 45,057.20	1,676	2
2028	2	$ -	$ 46,426.94	1,257	2
2029	2	$ -	$ 47,838.32	838	1
2030	1		$ 24,646.30	209	0
2031	1	$ -	$ 25,395.55	-	0
2032	1	$ -	$ 26,167.58	-	0
2033	1	$ -	$ 26,963.07	-	0
2034	1	$ -	$ 27,782.75	-	0
2035	0		$ -	-	0
2036		$ -	$ -		0
2037		$ -	$ -		0
2038		$ -	$ -		0
2039		$ -	$ -		0
2040		$ -	$ -		0
2041		$ -	$ -		0
2042		$ -	$ -		0
2043		$ -	$ -		0
2044		$ -	$ -		0
2045		$ -	$ -		0
2046		$ -	$ -		0
2047		$ -	$ -		0
2048		$ -	$ -		0
2049		$ -	$ -		0
2050		$ -	$ -		0

Probable

Date	Prob.BP Wells	Prob.BP Capital	Prob.BP Op.Cost	Prob.BP Gas (MCF)	Prob.BP Cond.
2000	0	$ -	$ -		0
2001	0	$ -	$ -		0
2002	0	$ -	$ -		0
2003	0	$ -	$ -		0
2004	0	$ -	$ -		0
2005	0	$ -	$ -		0
2006	0	$ -	$ -		0
2007	0	$ -	$ -		0
2008	0	$ -	$ -		0
2009	0	$ -	$ -		0
2010	1	$ 169,898	$ 13,540.50	3,183	4
2011	1	$ -	$ 13,952.13	3,024	4
2012	2	$ 180,490	$ 28,752.56	12,094	15
2013	2	$ -	$ 29,626.64	11,458	14
2014	2	$ -	$ 30,527.29	10,821	13
2015	4	$ 395,257	$ 62,910.63	45,830	55
2016	4	$ -	$ 64,823.11	43,284	52
2017	4	$ -	$ 66,793.73	40,738	49
2018	4	$ -	$ 68,824.26	38,192	46
2019	4	$ -	$ 70,916.52	35,646	43
2020	6	$ 459,770	$ 109,608.58	87,841	105
2021	7	$ 236,943	$ 131,764.12	118,077	142
2022	7	$ -	$ 135,769.75	110,279	132
2023	7	$ -	$ 139,897.15	102,482	123
2024	7	$ -	$ 144,150.03	94,684	114
2025	10	$ 802,220	$ 212,188.84	219,603	264
2026	12	$ 551,232	$ 262,367.26	320,812	385
2027	12	$ -	$ 270,343.22	297,897	357
2028	12	$ -	$ 278,561.65	274,982	330
2029	12	$ -	$ 287,029.93	252,066	302
2030	13	$ 311,053	$ 320,401.94	289,622	348
2031	13	$ -	$ 330,142.16	264,797	318
2032	13	$ -	$ 340,178.48	239,972	288
2033	13	$ -	$ 350,519.91	217,216	261
2034	13	$ -	$ 361,175.71	194,460	233
2035	14	$ 361,822	$ 400,782.80	229,470	275
2036	13	$ -	$ 383,468.98	192,392	231
2037	13	$ -	$ 395,126.44	171,704	206
2038	12	$ -	$ 375,819.95	139,400	167
2039	12	$ -	$ 387,244.88	120,304	144
2040	12	$ -	$ 399,017.12	101,208	121
2041	10	$ -	$ 342,622.70	71,610	86
2042	10	$ -	$ 353,038.43	60,470	73
2043	10	$ -	$ 363,770.80	49,331	59
2044	10	$ -	$ 374,829.43	38,192	46
2045	10	$ -	$ 386,224.25	27,053	32
2046	8	$ -	$ 318,372.37	16,550	20
2047	7	$ -	$ 287,044.53	12,253	15
2048	7	$ -	$ 295,770.68	10,025	12
2049	7	$ -	$ 304,762.11	7,798	9
2050	7	$ -	$ 314,026.88	5,570	7

FIGURE K-1

Doe Net Gas Production Forecast NOSR-3
(Proved Developed Producing Reserves)



were forecast only after the PDNP reserves were recovered in a given wellbore. A $150,000 capital expense (gross) was assigned to each of the required recompletions associated with recovering behind pipe reserves. Reserve projections of PDNP and Probable BP are shown in Table K-1. These projections will be used in Phase II of the NOSR-1&3 evaluation.

Proved Undeveloped Reserve Potential

Definition and Background

Generally, proved undeveloped reserves are assigned to undrilled locations that are direct offsets to wells with established production, given reasonable certainty that the location is within the known proved productive limits of the subject formation. Proved undeveloped (PUD) reserves were not assigned in the 1995 FD report. However, in accordance with SPE definitions (Appendix C), sufficient geologic and engineering data exist to evaluate proved undeveloped reserves at NOSR-3. A significant portion of these locations would result from the recent increase in Mesaverde well density to 40 acres spacing in portions of NOSR-3.

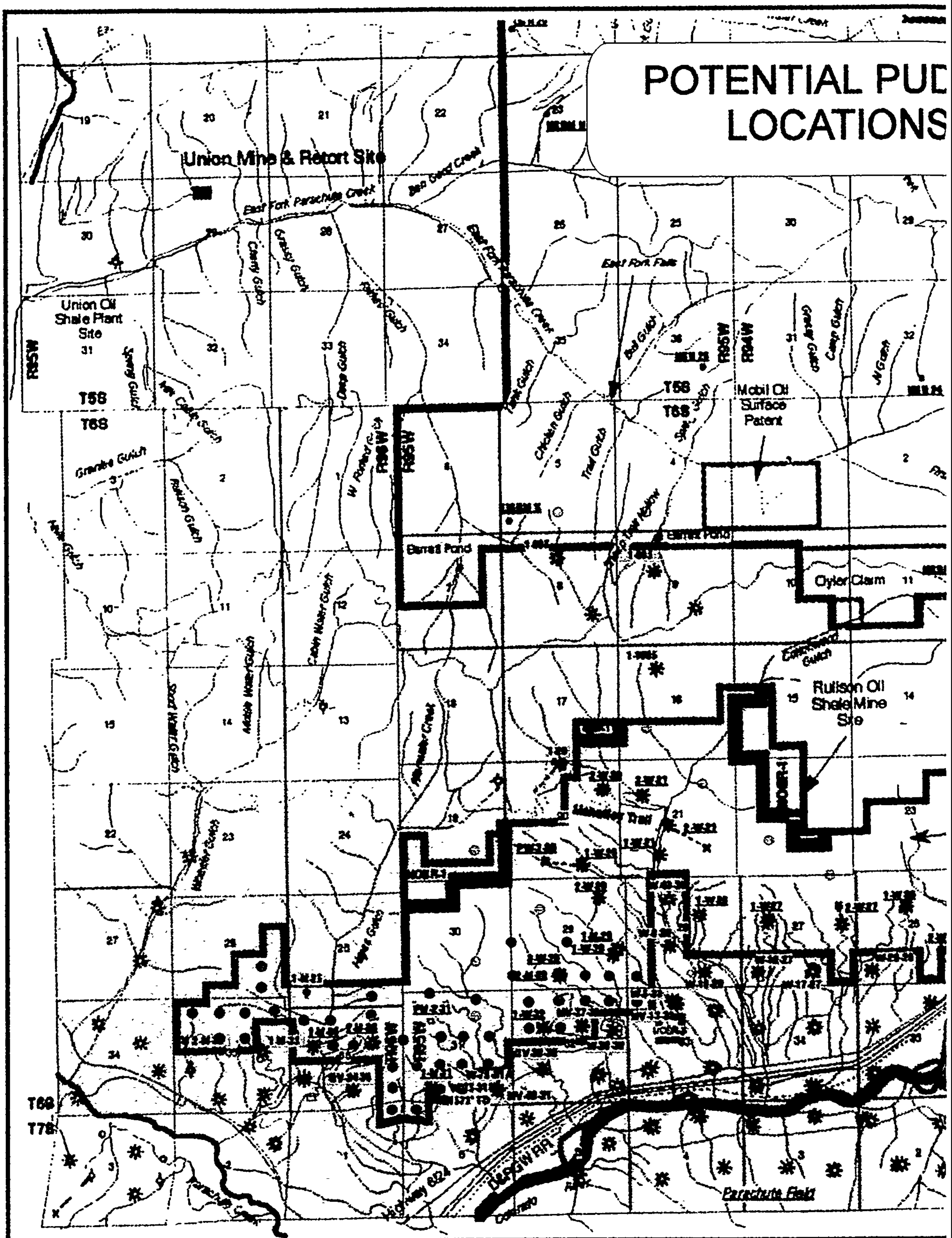
As noted above, in February 1995, the Colorado Oil and Gas Conservation Commission approved 40 acre spacing in the Mesaverde for an area which includes a portion of NOSR-3. This change in spacing will result in an increase in drilling density adjacent to and on the NOSR-3 site. Barrett Resources Corporation was the main advocate for the down spacing, and has since drilled approximately 6 Mesaverde infill wells on 40 acre spacing. Barrett's data suggested that 80 acre spacing would not effectively drain the Mesaverde.

This Consultant suggests assigning PUD locations only in areas of the field proven commercial by other wells, and only 1 offset from an existing well. This conservative methodology reflects the extremely heterogeneous nature of the formations with areas of very low permeability and porosity. This methodology is reasonable for NOSR-3, and is further supported by the practices of the largest operator in the region, Barrett Resources. Reserves should be assigned based on regional EURs, with offset EURs given the most consideration. Production forecasts should follow a hyperbolic decline. Assigning EURs based on a regional average (as seen in the various full development studies) is reasonable only when offset data is not available, and this precludes categorizing the reserves as proved.

Potential PUD assignment methodology

Proved undeveloped reserve potential exists at infill and offset Mesaverde and Wasatch locations at NOSR-3. These locations are identified in Figure K-2. The methodology for PUD assignments was based on the Society of Petroleum Engineer's reserve categorization guidelines. These reserve estimates were warranted by the recent well spacing change to 40 acres for Mesaverde wells in the region, and the fact that PUD reserves were not included in any existing reserve reports. The initial PUD locations shown in Figure K-2 were based on 40 acre Mesaverde well spacing and 80 acre Wasatch well spacing. Infill locations were assigned in accordance with the well spacing where control existed between at least two existing producers in the same formation. Offset locations were assigned based on existing producers as long as there was not any direct control indicating that the offset might not be commercial. An example of an offset area that was not assigned PUD locations is seen just to the West of the Rulison field where several dry holes have been drilled in a structural low indicating that there would not likely be commercial production in the area. Viable offset locations were assigned on 160 acre spacing for the Wasatch and 80 acre spacing for the Mesaverde. The Mesaverde PUD assignments are justified since most of the offset area is still within an area still spaced at 80 acres for the Mesaverde. Although the Colorado Oil and Gas Conservation Commission has indicated that approval of 40 acre Mesaverde spacing would be a very simple process for the NOSR-3 offset areas, current regulatory spacing dictates these assignments. 61 Mesaverde and 13 Wasatch locations identified in Table K-2 were considered as potential PUD reserve assignments.

Reserves were assigned based on existing reports and EUR maps provided by the DOE. Many of the locations were identified in the Full Development Study of NOSR-3.



POTENTIAL MESAVERDE PUD INFILL/OFFSET LOCATION

POTENTIAL WASATCH PUD INFILL/OFFSET LOCATION

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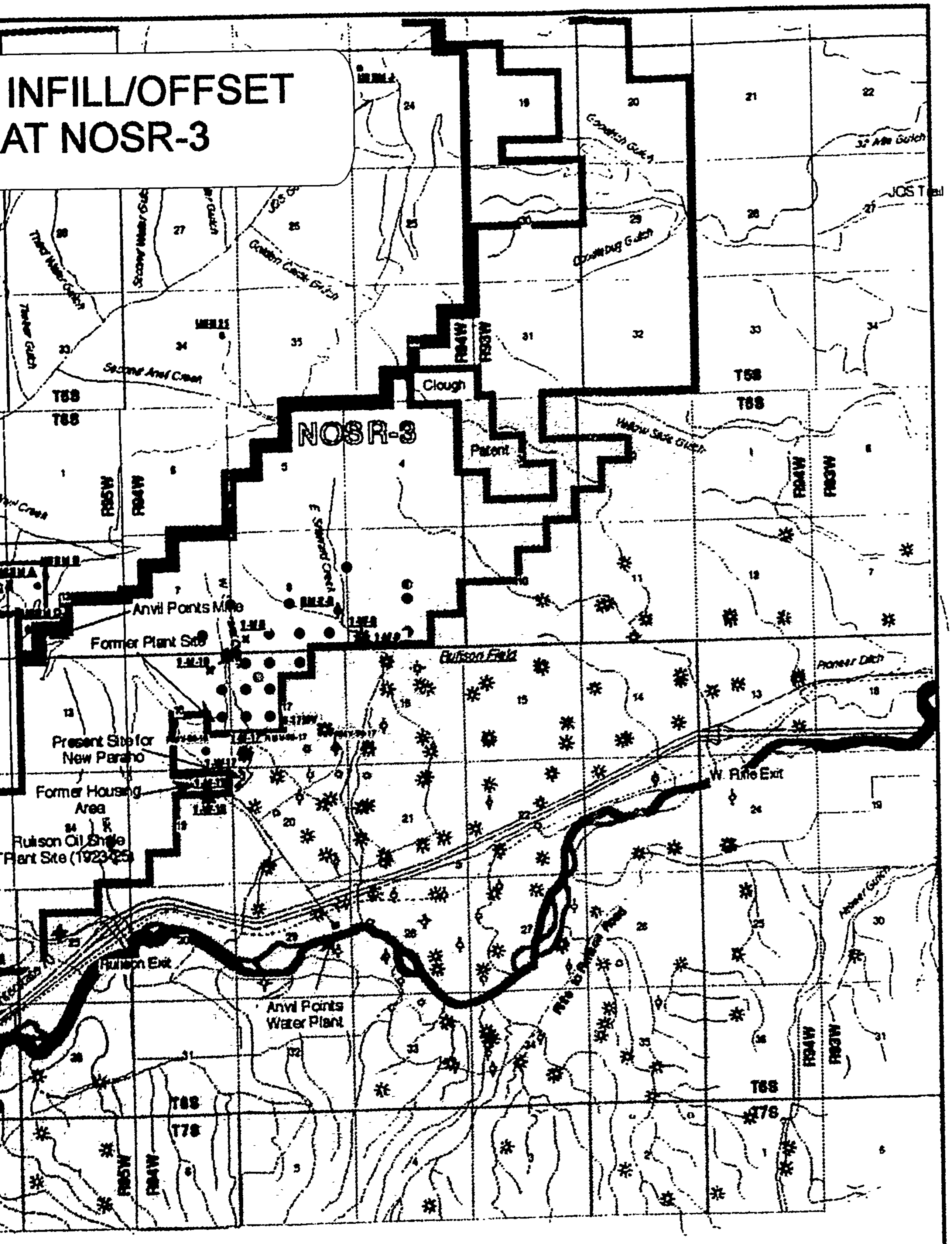


DOE OPERATED WELLS

NON-DOE OPERATED WELLS

AREA APPROVED BY COGCC FOR
40 ACRE MESAVERDE WELL SPACING

TABLE K-2

Parameters for Potential PUD Assignments
NOSR-3

Wasatch

	Location	Estimated DOE Int.	Direct. Drill?	Estimated D&C Costs	Estimated EUR	Estimated Proved	Estimated Probable	Estimated Possible	Comments on Drilling Requirements
PUD#1	SE 19-T6S-R95W	50%	DIR	$ 400,000	0	0	0	0	Very difficult locations, with some locations on the mesa
PUD#2	SE 30-T6S-R95W	100%	DIR	$ 400,000	100	100	0	0	Difficult topography, new locations, mostly directional
PUD#3	NE 31-T6S-R95W	100%	DIR	$ 400,000	0	0	0	0	Difficult topography, new locations, mostly directional
PUD#4	NW 29-T6S-R95W	100%	DIR	$ 400,000	600	600	0	0	Difficult topography, new locations, mostly directional
PUD#5	SE 17-T6S-R95W	50%	DIR	$ 400,000	400	400	0	0	Very difficult locations, with some locations on the mesa
PUD#6	S 5-T6S-R95W	100%	VERT	$ 600,000	90	90	0	0	Top of the mesa
PUD#7	SW 4-T6S-R95W	100%	VERT	$ 600,000	90	90	0	0	Top of the mesa
PUD#8	SW 16-T6S-R95W	75%	VERT	$ 300,000	510	510	0	0	Difficult topography, new locations, mostly directional
PUD#9	NE 21-T6S-R95W	100%	DIR	$ 400,000	800	800	0	0	Mostly directional well using existing well pads
PUD#10	SW 22-T6S-R95W	100%	DIR	$ 400,000	820	820	0	0	Mostly directional well using existing well pads
PUD#11	NE 27-T6S-R95W	100%	DIR	$ 400,000	450	450	0	0	Mostly directional well using existing well pads
PUD#12	NW 17-T6S-R94W	100%	VERT	$ 300,000	570	570	0	0	Vertical wells with directional from difficult locations
PUD#13	9-T6S-R94W	100%	DIR	$ 400,000	100	100	0	0	Mostly directional wells

MesaVerde

	Location	Estimated DOE Int.	Direct. Drill?	Estimated D&C Costs	Estimated EUR	Estimated Proved 1	Estimated Proved 2	Estimated Probable	Estimated Possible	Comments on Drilling Requirements
PUD#1	NW-NW 35-T6S-R96W	100%	DIR	$ 975,000	2905	1086	680	532	607	Difficult topography with new access, mostly directional wells
PUD#2	SE-NW 35-T6S-R96W	100%	DIR	$ 975,000	2905	1086	680	532	607	Difficult topography with new access, mostly directional wells
PUD#3	NE-NW 35-T6S-R96W	100%	DIR	$ 975,000	2905	1086	680	532	607	Difficult topography with new access, mostly directional wells
PUD#5	N-SE 26-T6S-R96W	100%	DIR	$ 975,000	1470	550	344	269	307	Difficult topography with new access, mostly directional wells
PUD#6	S-SE 26-T6S-R96W	100%	DIR	$ 975,000	1470	550	344	269	307	Difficult topography with new access, mostly directional wells
PUD#7	NW-NE 35-T6S-R96W	100%	DIR	$ 975,000	2905	1086	680	532	607	Difficult topography with new access, mostly directional wells
PUD#8	SW-NE 35-T6S-R96W	100%	DIR	$ 975,000	2905	1086	680	532	607	Difficult topography with new access, mostly directional wells
PUD#9	NE-NE 35-T6S-R96W	100%	DIR	$ 975,000	2905	1086	680	532	607	Difficult topography with new access, mostly directional wells
PUD#12	NW-NW 36-T6S-R96W	100%	DIR	$ 975,000	1260	471	295	231	263	Difficult topography with new access, mostly directional wells
PUD#13	NE-NW 36-T6S-R96W	100%	DIR	$ 975,000	1260	471	295	231	263	Difficult topography with new access, mostly directional wells
PUD#14	SE-NW 36-T6S-R96W	100%	VERT	$ 850,000	1260	471	295	231	263	Straight holes, many locations on existing pads
PUD#15	SW-NE 36-T6S-R96W	100%	VERT	$ 850,000	1260	471	295	231	263	Straight holes, many locations on existing pads
PUD#16	N-NE 36-T6S-R96W	100%	DIR	$ 975,000	1260	471	295	231	263	Difficult topography with new access, mostly directional wells
PUD#17	S-SE 25-T6S-R96W	100%	DIR	$ 975,000	3325	1244	778	608	695	Difficult topography with new access, mostly directional wells
PUD#18	NE-SE 36-T6S-R96W	100%	VERT	$ 850,000	1260	471	295	231	263	Straight holes, many locations on existing pads
PUD#19	SE-SE 36-T6S-R96W	100%	VERT	$ 850,000	1260	471	295	231	263	Straight holes, many locations on existing pads
PUD#20	NE-NE 1-T7S-R96W	100%	VERT	$ 850,000	1260	471	295	231	263	Straight holes, many locations on existing pads
PUD#21	NW-NW 6-T7S-R95W	100%	VERT	$ 850,000	1260	471	295	231	263	Straight holes, many locations on existing pads
PUD#22	NW-SW 31-T6S-R95W	100%	VERT	$ 850,000	1085	406	254	199	227	Straight holes, many locations on existing pads
PUD#23	•SW-NW 31-T6S-R95	100%	VERT	$ 850,000	770	288	180	141	161	Straight holes, many locations on existing pads
PUD#24	•S-SW 30-T6S-R95W	100%	DIR	$ 975,000	525	196	123	96	110	Difficult topography with new access, mostly directional wells
PUD#25	SE-NW 31-T6S-R95W	100%	DIR	$ 975,000	770	288	180	141	161	Difficult topography with new access, mostly directional wells
PUD#26	NE-SW 31-T6S-R95W	100%	VERT	$ 850,000	1085	406	254	199	227	Straight holes, many locations on existing pads
PUD#27	SE-SW 31-T6S-R95W	100%	VERT	$ 850,000	1085	406	254	199	227	Straight holes, many locations on existing pads
PUD#28	SW-SE 31-T6S-R95W	100%	VERT	$ 850,000	750	281	176	137	157	Straight holes, many locations on existing pads
PUD#29	NW-SE 31-T6S-R95W	100%	VERT	$ 850,000	750	281	176	137	157	Straight holes, many locations on existing pads
PUD#30	SW-NE 31-T6S-R95W	100%	VERT	$ 850,000	595	223	139	109	124	Straight holes, many locations on existing pads
PUD#31	N-NE 31-T6S-R95W	100%	VERT	$ 850,000	595	223	139	109	124	Straight holes, many locations on existing pads
PUD#32	SE-NE 31-T6S-R95W	100%	VERT	$ 850,000	595	223	139	109	124	Straight holes, many locations on existing pads
PUD#33	NE-SE 31-T6S-R95W	100%	VERT	$ 850,000	750	281	176	137	157	Straight holes, many locations on existing pads
PUD#34	•S-SW 29-T6S-R95W	100%	DIR	$ 975,000	525	196	123	96	110	Difficult topography with new access, mostly directional wells
PUD#35	•N-SW 29-T6S-R95W	100%	DIR	$ 975,000	525	196	123	96	110	Difficult topography with new access, mostly directional wells
PUD#36	NW-NW 32-T6S-R95W	100%	VERT	$ 850,000	1120	419	262	205	234	Straight holes, many locations on existing pads
PUD#37	SW-NW 32-T6S-R95W	100%	VERT	$ 850,000	1120	419	262	205	234	Straight holes, many locations on existing pads.
PUD#38	NE-NW 32-T6S-R95W	100%	VERT	$ 850,000	1120	419	262	205	234	Straight holes, many locations on existing pads
PUD#39	SE-NW 32-T6S-R95W	100%	VERT	$ 850,000	1120	419	262	205	234	Straight holes, many locations on existing pads.
PUD#40	NW-NE 32-T6S-R95W	100%	VERT	$ 850,000	1120	419	262	205	234	Straight holes, many locations on existing pads
PUD#41	SW-SE 29-T6S-R95W	100%	VERT	$ 850,000	1260	471	295	231	263	Straight holes, many locations on existing pads
PUD#42	•NE-SW 29-T6S-R95W	100%	VERT	$ 850,000	1120	419	262	205	234	Straight holes, many locations on existing pads
PUD#43	SE-SE 29-T6S-R95W	100%	VERT	$ 850,000	1260	471	295	231	263	Straight holes, many locations on existing pads
PUD#44	NE-NE 32-T6S-R95W	100%	VERT	$ 850,000	1260	471	295	231	263	Straight holes, many locations on existing pads
PUD#45	NW-NW 33-T6S-R95W	100%	VERT	$ 850,000	1260	471	295	231	263	Straight holes, many locations on existing pads
PUD#46	SW-SW 28-T6S-R95W	100%	VERT	$ 850,000	1260	471	295	231	263	Straight holes, many locations on existing pads
PUD#47	NE-SE 18-T6S-R94W	100%	DIR	$ 950,000	1295	484	303	237	271	Difficult locations, combination vertical-directional from pads
PUD#48	SE-NE 18-T6S-R94W	100%	DIR	$ 950,000	1295	484	303	237	271	Difficult locations, combination vertical-directional from pads
PUD#49	S-SE 7-T6S-R94W	100%	DIR	$ 950,000	840	314	197	154	176	Difficult locations, combination vertical-directional from pads
PUD#50	•NE-SE 7-T6S-R94W	100%	DIR	$ 950,000	840	314	197	154	176	Difficult locations, combination vertical-directional from pads
PUD#51	NW-NW 17-T6S-R94W	100%	DIR	$ 950,000	1855	694	434	339	388	Difficult locations, combination vertical-directional from pads
PUD#52	SW-NW 17-T6S-R94W	100%	DIR	$ 950,000	1855	694	434	339	388	Difficult locations, combination vertical-directional from pads
PUD#53	NW-SW 17-T6S-R94W	100%	DIR	$ 950,000	1855	694	434	339	388	Difficult locations, combination vertical-directional from pads
PUD#54	NE-SW 17-T6S-R94W	100%	DIR	$ 950,000	1855	694	434	339	388	Difficult locations, combination vertical-directional from pads
PUD#55	SE-NW 17-T6S-R94W	100%	DIR	$ 950,000	1855	694	434	339	388	Difficult locations, combination vertical-directional from pads
PUD#56	NE-NW 17-T6S-R94W	100%	DIR	$ 950,000	1855	694	434	339	388	Difficult locations, combination vertical-directional from pads.
PUD#57	SE-SW 8-T6S-R94W	100%	DIR	$ 950,000	1190	445	278	218	249	Difficult locations, combination vertical-directional from pads
PUD#58	•N-S 8-T6S-R94W	100%	DIR	$ 950,000	1190	445	278	218	249	Difficult locations, combination vertical-directional from pads
PUD#59	SW-SE 8-T6S-R94W	100%	DIR	$ 950,000	875	327	205	160	183	Difficult locations, combination vertical-directional from pads
PUD#60	NW-NE 17-T6S-R94W	100%	DIR	$ 950,000	1855	694	434	339	388	Difficult locations, combination vertical-directional from pads
PUD#61	SE-SE 8-T6S-R94W	100%	DIR	$ 950,000	875	327	205	160	183	Difficult locations, combination vertical-directional from pads
PUD#62	•SE-NE 8-T6S-R94W	100%	DIR	$ 950,000	525	196	123	96	110	Difficult locations, combination vertical-directional from pads
PUD#63	•N-S 9-T6S-R94W	100%	VERT	$ 800,000	1050	393	246	192	219	Less difficult locations, mostly vertical wells
PUD#64	•S-S 9-T6S-R94W	100%	VERT	$ 800,000	1050	393	246	192	219	Less difficult locations, mostly vertical wells.

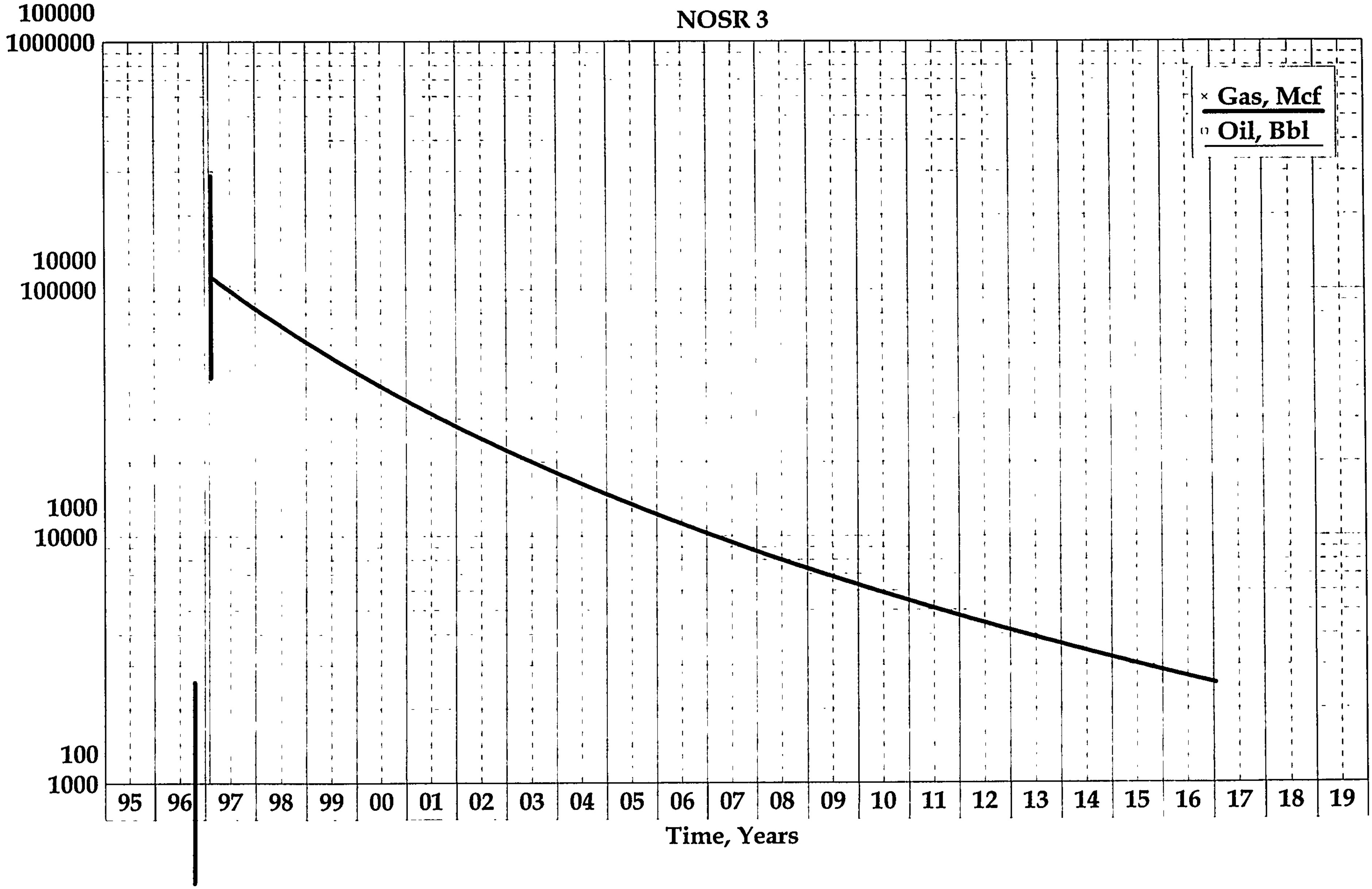
Wasatch Production Type Curve

Wasatch gas production was modelled after typical production declines exhibited by the many Wasatch wells in the region. The majority of these production declines were very close to exponential, with production histories that were relatively flat hyperbolic declines. The average type curve was hyperbolic with an exponent of 0.3 and an initial decline rate of 30 percent per year. Only gas production was modeled since Wasatch condensate production is very insignificant. Initial rates were back calculated given the type curve, the estimated ultimate recovery, and a well life near 20 years. As expected, the calculated initial rates were reasonable for a typical Wasatch wells in the area. Production histories were extended to the economic limit for a given well, with 20 years being the target expected well life. All of the most recent pricing and cost data was used to determine when a given well would reach its economic limit. A typical Wasatch production decline forecast is shown as Figure K-3.

Mesaverde Production Type Curve

Mesaverde gas production was modeled after typical production declines exhibited by the many Mesaverde wells in the region. The majority of these production declines were very close to harmonic with a hyperbolic exponent of 1.0 and an initial decline of 90 percent per year. An average condensate to gas ratio (CGR) of .0012 BC/MCF was used based on typical Mesaverde production in the region. As previously stated, the EURs assigned were based on existing reports supplied by the DOE. These EURs were based on a petrophysical analysis of existing wells in the area. Typical Mesaverde EURs include too many sand lenses that have sufficient depth differences to allow them to be completed and produced at once. Therefore, it would be incorrect to model them as part of a single production decline. The Mesaverde type curve was set up to play out the assigned reserves in a reasonable manner. Since the Mesaverde PUD locations are infill and offset locations to the existing DOE wells at NOSR-3, these well's production characteristics and reserve assignments were used to setup the type curve. This type

FIGURE K-3
EXAMPLE WASATCH
TYPE CURVE
NOSR 3



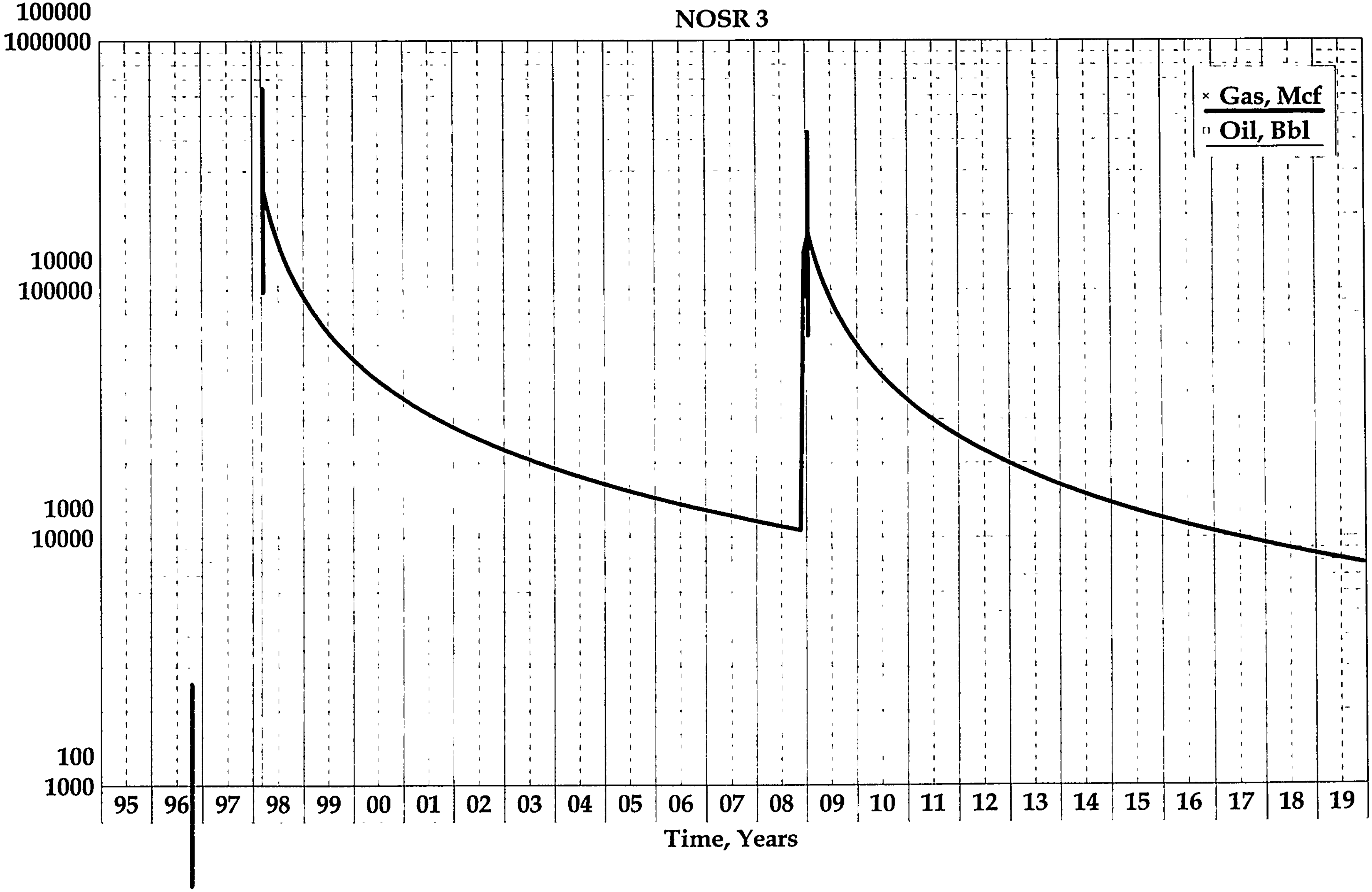
curve incorporates a recompletion as part of the reserve recovery. The reserves produced before and after the recompletion were determined by the average reserve ratios assigned in the FY 1995 Fluor Daniel reserve report for the Mesaverde wells at NOSR-3. Initial rates were back calculated given the type curve, the estimated ultimate recovery, and a total well life near 35 years. As expected, the calculated initial rates were reasonable for typical Mesaverde wells in the area. The recompletion is taken when the well becomes uneconomic. Recompletion costs were estimated at $150,000 based on the well work and fracture jobs required to change zones in the Mesaverde. All of the most recent pricing and cost data was used to determine when a given well would reach its economic limit. A typical Mesaverde production decline forecast is shown below as Figure K-4.

Operating Costs

Accurate operating cost estimations are very important for marginal fields and prospects such as those seen at NOSR-3. This is especially true given the relatively flat declines seen at the end of a typical Wasatch or Mesaverde well's production history. Wasatch and Mesaverde wells must be examined independently because they exhibit different production characteristics, and therefore, different operating costs. The deeper Mesaverde wells tend to produce more condensate and water than a typical Wasatch gas well. Therefore, most Mesaverde wells are more expensive to operate. This Consultant's operating cost estimates are based on a report prepared by the Department of Energy under Job Order 541101 dated February 6th, 1996. The report is a comparison of direct operating costs at and around NOSR-3 for DOE operated wells as compared to Barrett Resources operated wells. This report reviewed all of the DOE wells at NOSR-3 for the fiscal year 1995. From this report, average direct operating costs of $470 per well per month for Wasatch and $1,000 per well per month for Mesaverde was derived as explained below. Operating costs for the non-DOE options were reduced by 5% due to industry knowledge and efficiency.

FIGURE K-4

EXAMPLE MESAVERDE
TYPE CURVE
NOSR 3



There were 16 DOE operated Wasatch wells used in the comparison. The total adjusted operating cost for these wells was $254/well/month. However, compression costs for the 11 Parachute wells had been taken out. This was done in order to compare with the Barrett Wasatch wells which did not have a direct compression cost since they owned a compressor. Determination of actual direct operating costs should include the compression costs allocated to each of the subject wells. Other 1 time costs had been correctly removed from the operating cost estimations by the DOE. This Consultant's estimate was $470/well/mo after the adjustment. The Wasatch well operating costs estimates are shown in Table K-3.

The Mesaverde costs are much more difficult to compare due to the very different operating conditions for wells in the Rulison, Parachute, and Grand Valley Fields. For example, the deeper Rulison Field wells tend to produce more water than the other Mesaverde wells. The DOE's estimate for all Mesaverde wells was $1,150/well/month. However, it is important to note that a significant portion of these costs come from a few wells. Many of the newer wells are still producing water associated with lost completion fluids. Removing the 4 wells with the highest water production results in an average Mesaverde operating cost of $661/well/month. In addition, since only 10 DOE operated wells are part of the average, all of the daily gauging, draining, and sales transportation is allocated only between those wells. Additional Mesaverde wells would likely bring the average per well cost down as seen with Barrett's larger infrastructure. Therefore, this Consultant has selected an average Mesaverde operating cost of $1,000/well/month. The Mesaverde direct operating cost estimates are shown in Table K-3.

The operating costs used for the DOE study were taken during fiscal year 1995 as supplied by the DOE finance department. Average $/well/month values were normalized by grossing up the values to reflect a 100% working interest. Intermittent production periods were also normalized to reflect operating costs for a producing well on a per month basis. Operating costs utilized in income estimates as part of Phase II of this project are based on $470 per well per month for Wasatch wells, and $1,000 per well per month for Mesaverde wells. Operating costs for non-

DOE options were reduced by 5% due to industry knowledge and efficiency.

Table III Operating Cost Table (SGH-OGRE)

PUD Schedule

The proved undeveloped reserves assigned at NOSR-3 are utilized in net income estimates as part of Phase II of this report. Since these reserve forecasts are hypothetical, there were a number of assumptions made to come up with the estimates. All of these estimates were based on data and trends seen in this particular oil and gas region. The assumptions are outlined in this section of the report.

The Wasatch PUDs were drilled starting in October of 1996, with the first PUD being completed in November of 1996. The PUDs were drilled in an order based on their profitability. Wasatch wells were drilled in 1 week with and additional week to fracture and complete the wells. The 2 week drilling and completion time yields 2 wells per month assuming that there would be 1 drilling rig designated to the Wasatch PUDs. The NOSR-3 Full Development reports were utilized to outline a given PUD's drilling access problems and directional drilling requirements. There were 3 types of wells included in the Wasatch PUDs. Vertical wells with difficult access were drilled and completed for $300,000. Directional wells were drilled and completed for $400,000, and locations on top of the mesa were drilled for $600,000. All of these assumptions are based on actual operator data in the area. Table K-4 shows the order and schedule for drilling the Wasatch PUDs.

The Mesaverde PUDs were also drilled starting in October of 1996, with the first PUD being completed in November of 1996. As with the Wasatch PUDs, it was assumed the best PUDs would be drilled first. The remaining PUDs were drilled in an order based on their profitability. Mesaverde wells were drilled in 3 weeks with and additional 3 weeks to fracture and complete the wells. The 6 week drilling and completion time yields 1 well per month assuming that there

TABLE K-3

NOSR-3 Operating Cost Data
As Compiled by the Department of Energy
(FY 1995 DATA)

Wasatch Wells

Field	Well	Gross Direct Costs ($/yr)	Total Cost ($/month)	
Parachute	1-W-21	$ 6,533.00	$ 544.42	
	2-W-21	$ 6,714.00	$ 559.50	
	3-W-21	$ 10,386.00	$ 865.50	
	1-W-26	$ 6,445.00	$ 537.08	
	1-W-27	$ 6,694.00	$ 557.83	
	2-W-27	$ 6,485.00	$ 540.42	
	1-W-28	$ 6,891.00	$ 574.25	
	1-W-29	$ 6,619.00	$ 551.58	
	2-W-29	$ 6,605.00	$ 550.42	
	3-W-29	$ 7,170.00	$ 597.50	
	1-W-32	$ 6,748.00	$ 562.33	**Average**
	TOTAL	$ 77,290.00	$ 6,440.83	$ 585.53
Rulison	1-W-9	$ 2,530.00	$ 210.83	
	1-W-17	$ 1,757.00	$ 146.42	
	1-W-19	$ 2,885.00	$ 240.42	**Average**
	TOTAL	$ 7,172.00	$ 597.67	$ 199.22
Allen Point	1-W-20	$ 2,647.00	$ 220.58	
	2-W-20	$ 3,480.00	$ 290.00	**Average**
	TOTAL	$ 6,127.00	$ 510.58	$ 255.29
TOTAL WASATCH AVERAGE:			**$ 470**	

Mesaverde Wells

Field	Well	Gross Direct Costs ($/yr)	Total Cost ($/month)	
Rulison	1-M-19	$ 5,786.00	$ 482.17	
	1-M-9	$ 9,793.00	$ 816.08	
	1-M-17	$ 10,869.00	$ 905.75	
	1-M-8	$ 12,436.00	$ 1,036.33	
	1-M-18	$ 62,129.00	$ 5,177.42	**Average**
	TOTAL	$ 101,013.00	$ 8,417.75	$1,683.55
Parachute	1-M-29	$ 7,066.00	$ 588.83	
	1-M-31	$ 7,066.00	$ 588.83	
	2-M-29	$ 8,378.00	$ 698.17	**Average**
	TOTAL	$ 22,510.00	$ 1,875.83	$ 625.28
Grand Valley	1-M-36	$ 5,889.00	$ 490.75	
	2-M-36	$ 8,590.00	$ 715.83	**Average**
	TOTAL	$ 14,479.00	$ 1,206.58	$ 603.29
TOTAL MESAVERDE AVERAGE:			**$ 1,150**	

TABLE K-4

Estimated Drilling Schedule
NOSR-3 Potential PUDs

MESAVERDE

Completion Date	PUD	Completion Date	PUD
Nov-96	PUD#17	Jul-99	PUD#36
Dec-96	PUD#2	Aug-99	PUD#37
Jan-97	PUD#3	Sep-99	PUD#38
Feb-97	PUD#1	Oct-99	PUD#39
Mar-97	PUD#7	Nov-99	PUD#40
Apr-97	PUD#8	Dec-99	PUD#42
May-97	PUD#9	Jan-00	PUD#12
Jun-97	PUD#51	Feb-00	PUD#13
Jul-97	PUD#52	Mar-00	PUD#16
Aug-97	PUD#53	Apr-00	PUD#57
Sep-97	PUD#54	May-00	PUD#58
Oct-97	PUD#55	Jun-00	PUD#47
Nov-97	PUD#56	Jul-00	PUD#48
Dec-97	PUD#60	Aug-00	PUD#23
Jan-98	PUD#5	Sep-00	PUD#28
Feb-98	PUD#6	Oct-00	PUD#29
Mar-98	PUD#14	Nov-00	PUD#33
Apr-98	PUD#15	Dec-00	PUD#30
May-98	PUD#18	Jan-01	PUD#31
Jun-98	PUD#19	Feb-01	PUD#32
Jul-98	PUD#20	Mar-01	PUD#49
Aug-98	PUD#21	Apr-01	PUD#50
Sep-98	PUD#41	May-01	PUD#59
Oct-98	PUD#43	Jun-01	PUD#61
Nov-98	PUD#44	Jul-01	PUD#25
Dec-98	PUD#45	Aug-01	PUD#62
Jan-99	PUD#46	Sep-01	PUD#24
Feb-99	PUD#63	Oct-01	PUD#34
Mar-99	PUD#64	Nov-01	PUD#35
Apr-99	PUD#22		
May-99	PUD#26		
Jun-99	PUD#27		

WASATCH

Completion Date	PUD
Nov-96	PUD#10
Nov-96	PUD#9
Dec-96	PUD#12
Dec-96	PUD#4
Jan-97	PUD#8
Jan-97	PUD#5
Feb-97	PUD#11
Feb-97	PUD#1
Mar-97	PUD#3
Mar-97	PUD#13
Apr-97	PUD#2
Apr-97	PUD#6
May-97	PUD#7

Notes: 1) Assuming that PUDs would be drilled in order based on profitability.
2) Assuming 2 mesaverde drilling rigs and 1 wasatch drilling rig running 75% of the year.

would be 1-2 drilling rigs designated to the Mesaverde PUDs. The NOSR-3 Full Development reports were utilized to outline a given PUD's drilling access problems and directional drilling requirements. There were 4 types of wells included in the Mesaverde PUDs. Vertical wells with relatively easy access were drilled and completed for $800,000, while vertical wells with access problems were drilled and completed for $850,00. Directional wells with relatively easy access were drilled and completed for $950,000, and directional wells with difficult access were drilled and completed for $975,000. There were not any potential Mesaverde PUDs on top of the Mesa. All of these assumptions are based on actual operator data in the area. Drilling costs for the non-DOE options were reduced by 5% due to industry knowledge and efficiency. Table K-5 outlines the drilling schedule for all of the Mesaverde PUDs.

All of the assumptions regarding PUD reserve projections are based on actual data in the region. Barrett Resources, the largest operator in the region, has verified that each of these assumptions is reasonable for a typical Wasatch or Mesaverde drilling prospect.

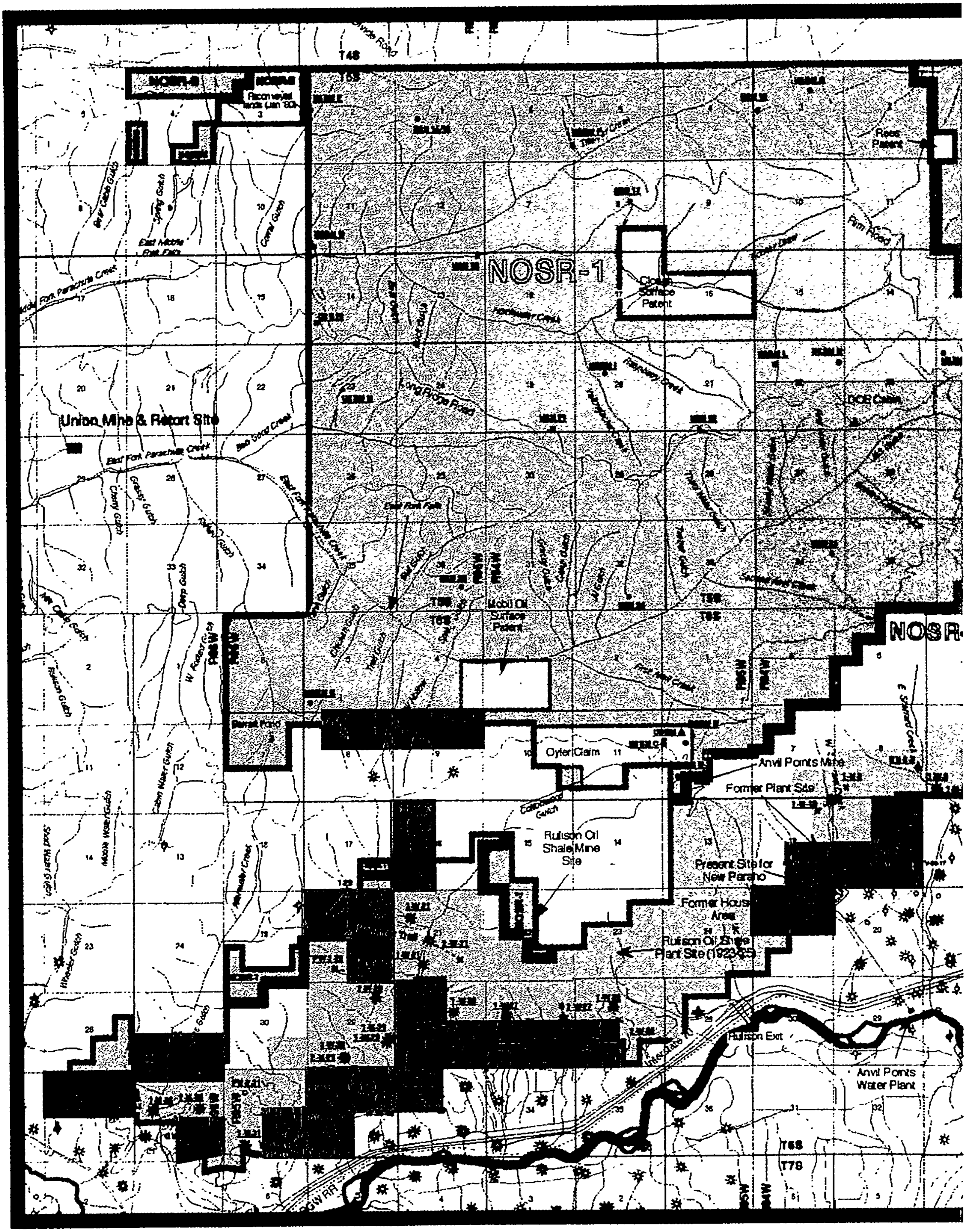
Commercial PUDs given Current DOE Wellhead Gas Price

Proved undeveloped reserves must be considered commercial by industry standards to be categorized as proved. As discussed in the NOSR-1&3 report, the average DOE wellhead gas price at NOSR-3 is currently $1.00 per MCF. Given this gas price, in conjunction with the assumptions outlined above for PUD prospects, only 4 of the 74 locations can be considered commercial at a discount rate of 13.5%. Net income from these PUDs was used in the evaluation phase of this project. If the net income from PUD reserves was negative after risking, then it was assumed the PUDs would not be drilled by a prudent operator. However, they were included in the DOE retention scenario regardless of net income, since the DOE continues to drill protection wells regardless of profitability. PUD reserves that are non-commercial at current oil and gas prices are considered possible reserves in accordance with the SPE reserve standards. Therefore, the bulk of the infill/offset prospects at NOSR-3 are currently categorized as possible reserves, and consequently have no effect on net income estimates for the property. As expected, the profitability of the prospects at the current gas price was highly dependent on drilling costs. Therefore, the most profitable locations tended to be Wasatch locations down in the valley on the southern side of NOSR-3.

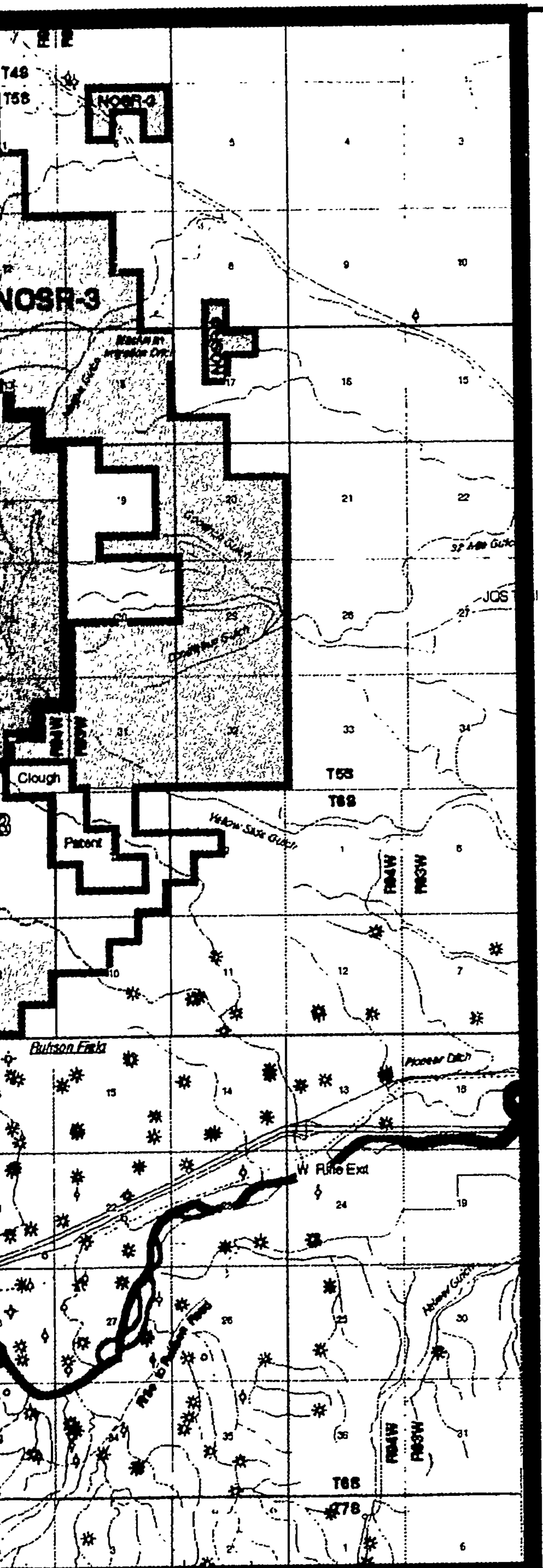
Summary of Total NOSR-3 Reserves

A summary of all NOSR-3 reserves used in the net income forecasts for NOSR-1&3 in the evaluation phase of this project is shown below. All of the reserve projections are as of 10/01/1996. A more detailed discussion on the assumptions and limiting conditions associated with the income from reserves projections can be found in the Phase II report.

DOE Net PDP	DOE Net PDNP	DOE Net PUD	DOE Net Probable Behind Pipe
11.3 BCF	5.8 BCF	2.7 BCF	4.6 BCF



T4S
T5S
Reconveyed lands (Jan '80)
NOSR-1
Clough Surface Patent
Rim Road
East Middle Fork Parachute Creek
Union Mine & Retort Site
East Fork Parachute Creek
Long Ridge Road
DOE Cabin
East Fork Falls
T6S
Mobil Oil Surface Patent
NOSR-
Oyler Claim
Anvil Points Mine
Former Plant Site
Rulison Oil Shale Mine Site
Present Site for New Paraho
Former Housing Area
Rulison Oil Shale Plant Site (1923-25)
Rulison Exit
Interstate
Anvil Points Water Plant
T7S



ACREAGE CLOSE TO EXISTING PRODUCTION

TREND ACREAGE

STRUCTURAL LOW AREAS

COMMUNITIZED ACREAGE

SEISMIC STRUCTURE ACREAGE

AMPLITUDE ANOMALY ACREAGE

EXPLORATORY

APPENDIX L

SURFACE APPRAISAL

LIMITED APPRAISAL

Of Government Property Known As

NAVAL OIL SHALE RESERVES NO. 1 & 3

Property Located In

GARFIELD COUNTY, COLORADO

Professional Agri Service

555 Breeze Street, Suite 120, Craig, Colorado 81625, (970) 824-4461

Pro Ag

LIMITED APPRAISAL

Of Government Property Known As

NAVAL OIL SHALE RESERVES NO. 1 & 3

Property Located In

GARFIELD COUNTY, COLORADO

PREPARED AT THE REQUEST OF

EDWIN C. MORITZ
Gustavson Associates, Inc.
5757 Central Avenue, Suite D
Boulder, Colorado 80301

Date of Value: August 9, 1996

PREPARED BY

LARRY C. WHITEMAN, A.R.A.
Certified General Appraiser
Colorado No. CG 01314159
Wyoming Permit No. 84

dba

PROFESSIONAL AGRI SERVICE
555 BREEZE STREET
SUITE 120
CRAIG, COLORADO
81625

Professional Agri Service

LARRY C. WHITEMAN, A.R.A.
Appraiser, Broker

555 Breeze Street, Suite 120 Craig, Colorado 81625 (970) 824-4461

August 9, 1996

Gustavson Associates, Inc.
Attn: Edwin C. Moritz
5757 Central Avenue, Suite D
Boulder, Colorado 80301

Dear Mr. Moritz:

As per your request, I have completed a Limited Appraisal and am submitting to you a Restricted Report on the government property known as the U.S. Naval Oil Shale Reserves No. 1 and 3, located west of Rifle and State Highway 13-789, north of Interstate Highway 70 and east of Parachute Creek, Garfield County, Colorado. Based on information furnished by you, the NOSR No. 1 contains 36,406.21 acres more or less, NOSR No. 2 contains 20,170.94 acres more or less for a total acreage of 56,577.15 acres more or less.

This restricted report of the limited appraisal assignment invokes the departure provisions of the Uniform Standards of Professional Appraisal Practice (USPAP). The departure provision allows limited exceptions to specific guidelines of USPAP provided the exceptions, in the judgment of the appraiser, will not confuse or mislead the client. Use of this appraisal is restricted to the client or property managers who are familiar with the property, the neighborhood, area and market conditions. The value estimate contained herein is reported in a relatively narrow range that I feel would be typical and applicable to each parcel of the subject property.

In the process of preparing this appraisal, the work completed has gone beyond the typical definition of a limited appraisal and would approach a complete appraisal, limited by the fact that only the market approach was used and some of the sales data was furnished by others. The limited report may also go beyond the definition and approach a summary report due to the amount of information contained herein.

I understand and agree that this report is of a confidential nature, for your specific purpose, and I agree to not divulge any information contained herein to any person, unless duly authorized by you, except as stated in the assumptions and limiting conditions.

The range of value estimated in this appraisal is based on a marketing period of less than 12 months, under normal market conditions and the property in "as is" condition.

Having considered all the conditions affecting the value of the property, it is my opinion that a typical and supportable range of value for the subject property by parcels would be:

NOSR No. 1 - 36,406.21 Acres - $ 55.00 to $ 60.00 per acre

NOSR No. 3 - 20,170.94 Acres - $ 25.00 to $ 30.00 per acre

The value as stated above is subject to the conditions and statements appearing on the following pages of this report. There are 28 numbered pages in this report including maps and photos in the addenda.

Respectfully Submitted,

Larry C. Whiteman

Larry C. Whiteman A.R.A.
Certified General Appraiser
Colorado No. CG 01314150
Wyoming Permit No. 84

Table of Contents

SUMMARY - SALIENT FACTS AND CONCLUSIONS

Authorization - Inspection; A Limited Appraisal of the U.S. Naval Oil Shale Reserves No. 1 & 3 was requested and authorized by Edwin C. Moritz, with Gustavson Associates, by letter dated July 30, 1996. Copy included in the addenda.

An aerial inspection was made by Larry C. Whiteman on August 1, 1996 and a ground inspection from Highway 13-789 and I-70 of the east and south borders was made on August 2, 1996.

Effective date of Valuation; August 9, 1996

Identification and Brief Description of Property; The property appraised in this report consists of the U.S. Naval Oil Shale Reserves No. 1 & 3. Based on information furnished by the client, NOSR No. 1 contains 36,406.21 acres more or less, NOSR No. 2 contains 20,170.94 acres more or less for a total acreage of 56,577.15 acres more or less. The two parcels are contiguous for the most part with a couple of small tracts being severed a short distance.

NOSR No. 1 is basically on top and to the north and west of the Roan Cliffs with a very small part extending over onto the steep part of the cliffs on the east and southeast. There are three small parcels severed, but contiguous with NOSR 3 located to the south. Terrain is typified by large gently rolling mesa to canyons that are gentle rolling on the east end of the parcel to very deep and steep sides as they traverse the property to the west. Numerous small streams are located in the bottom of the canyons which include East Fork of Parachute Creek, Northwater Creek and Trapper Creek. Other small creeks are tributary to the ones mentioned above via smaller canyons and draws. Some of the streams have intermittent flows and some have a minimal continuous flow. Many springs with adjudicated water rights are located on the parcel as well as several ponds. Vegetation consists of native grasses and sagebrush on the open mesas of the parcel with aspen, spruce and fir tree cover on some parts of the parcel. Elevation ranges from about 6,500 feet in the bottom of the canyons to over 9,300 feet on the high points. There are some small private land inholdings within the boundaries of this parcel. Access to the parcel is from Highway 13-789 on a very steep and winding road and from Parachute Creek via similar roads.

NOSR 3 covers primarily the steep face of the Roan Cliffs on the east and south of NOSR 1. There are two severed parcels near the northeast part of this parcel and some small severed parcels on the northwest which are contiguous to NOSR 1. Terrain is moderately steep on the lower end of the Roan Cliffs to extremely steep higher up on the cliffs. There is little or no level ground on this parcel. There are several small drainages, tributary to Government Creek and the Colorado River, which originate on this parcel.

SUMMARY (Con't)

Property Identification and Description (Con't)

There is an adjudicated water right for 1.04 cfs out of Sharrard Creek and 0.3 cfs from another source in Section 18, T6S, R94W. There is also a conditional right out of the Colorado River for 100 cfs. Vegetation consists of native grasses, sagebrush, pinyon, juniper, scrub oak, with aspen pockets and some spruce and fir on the higher parts of the parcel. Elevation ranges from about 5,700 feet to over 8,200 feet. There is also some small private land inholding in this parcel. Access to this parcel is via the same road leading to NOSR 1 from Highway 13-789 and other roads leading off of a frontage road along I-70.

The BLM administers livestock grazing privileges on both parcels of this property through several different grazing allotments. On NOSR 1 there are permits for 8,295 animal unit months (aum's) which is about 4.4 acres per aum. NOSR 3, due to the steep terrain and barren hills, has much less carrying capacity and has permits for only 1,248 aum's or about 16 acres per aum. An aum is defined as the amount of forage required to maintain one animal unit for one month.

Some recreational amenities are present on the parcels in the form of big game hunting during the fall months. NOSR 1 would be accessable and offer good hunting opportunities while NOSR 3 would have limited access due to the steep terrain and would not offer the same opportunities.

Legal Description - Water Rights; No legal description was furnished for the property and for purpose of this appraisal, the maps contained in the addenda are referenced to serve as the legal description. One map, furnished by the client, identifies each parcel and the other, from a BLM map, outlines the boundary of the entire property.

A summary of the water rights associated with the property, furnished by the client, is included in the addenda.

Taxes; No information is available concerning taxes as this is a tax exempt government property..

Ownership; United States of America.

Zoning; The zoning is Agriculture, with no restrictions for the present use of the property.

Highest and Best Use; The highest and best use for the surface estate is agriculture, forage for livestock. There is some potential for recreational use on a seasonal basis for big game hunting.

SUMMARY (Con't)

Property Rights Appraised; Surface estate only, excluding any prior reservations, encumbrances, liens or other restrictions upon the ownership.

Purpose of Appraisal; The purpose of this appraisal to estimate a reasonable and supportable range of value for the property as of August 9, 1996. The value estimates are based on an estimated marketing period of 12 months or less in "as is" condition.

Function of Appraisal; The function of this appraisal is for the specific use of Gustavson Associates in preparing an overall value estimate, including minerals, for the property.

Valuation Estimate;

NOSR No. 1 - 36,406.21 acres - $ 55.00 to $ 60.00 per acre

NOSR No. 3 - 20,170.94 acres - $ 25.00 to $ 30.00 per acre

Scope of Appraisal; In preparing this appraisal of the subject property I have completed the following:

- inspected the property from a small aircraft and made a limited ground inspection from the Highways;
- analyzed the data on the subject property furnished by the client:
- analyzed the highest and best use of the property;
- talked with BLM range managers to obtain permitted livestock grazing use on the property:
- obtained the market data used in this report from information furnished by Mr. Moritz, my own research within the county and surrounding area, contact with other appraisers realtors, lenders and others familiar with the market;
- analyzed the data and allocated values to the various land classes to develop the market approach to value:
- I have invoked the departure provisions of USPAP SR-1 in that I have omitted the cost and income approaches. Only the market approach is considered and a range of value is estimated.
- I have invoked the departure provisions of USPAP SR-2 by making this a restricted report. Only a summary of the area and neighborhood analysis, site data, highest and best use, and market data is included in the report; this information as well as my analysis of the information is retained in my files;

The information is then reconciled into a final estimated range of values for the Subject Property. Limited descriptive and factual data and the results of my study and analysis are presented in a restricted narrative report.

SUMMARY (Con't)

Competency Provision; I hereby certify that I, Larry C. Whiteman A.R.A., have the knowledge and experience necessary to complete this appraisal assignment. I have previously appraised numerous other livestock ranches, farms and vacant land parcels, many with scenic and recreational amenities, in the western and central parts of the States of Colorado and Wyoming. I have also completed the continuing education requirements, as necessary, for the American Society of Farm Managers and Rural Appraisers, as well as for licensing in Colorado and Wyoming. My qualification sheet, which will furnish additional information is included in the addenda of this report.

Area Data; Garfield County is located in west central Colorado and extends from the Utah state line on the west approximately 100 miles east into the mountains. The Grand Mesa lays to the south and the Roan Plateau and the Flat Tops Mountains to the north. The area has traditionally been agriculture oriented, however, in recent years, national attention was focused on oil shale development in the western part of the county. This development ceased in the early 1980's and it is not known if or when it might be continued. Recreation is has become a major economic factor in the eastern part of the county. Glenwood Springs has the famous hot springs and swimming pool and the Glenwood Canyon is well known for its scenic beauty. Glenwood Springs is also the gateway to the world famous Aspen Snowmass recreation centers.

The Colorado River, Interstate Highway 70 and the Southern Pacific Railroad all pass through the county. Glenwood Springs is the county seat of Garfield County and has an estimated population of about 8,000. Glenwood Springs and Rifle are the main trade centers in the county and furnish adequate shopping facilities, hospitals, churches, schools and other services. Other small towns in the county include Carbondale to the south of Glenwood, Newcastle and Silt between Glenwood and Rifle, Parachute and Battlement Mesa to the west of Rifle. Grand Junction, the largest city in western Colorado, is located about 65 miles southwest of Rifle in Mesa County.

The immediate neighborhood of the subject is west of Highway 13-789, northwest of Rifle, north of the Colorado River and Interstate Highway 70 and east of Parachute and Parachute Creek. The NOSR Lands constitute a large portion of the neighborhood with the remaining land between the Roan Cliffs and the River and or Highway being mostly private fee owned land. There has been a large amount of drilling for oil and gas on the surrounding land and many wells are in evidence. The neighborhood had a major part of the oil shale exploration during the 1970's and early 1980's. There are some livestock ranching operations and rural residential homesites within the neighborhood.

ASSUMPTIONS AND LIMITING CONDITIONS

This appraisal report, the letter of transmittal and the certification of value are made expressly subject to the following assumptions and limiting conditions and any special limiting conditions contained in the report which are incorporated herein by reference.

1. The legal description and acreage furnished is assumed to be correct. No responsibility is assumed for matters legal in character, nor is any opinion rendered as to title which is assumed to be good. All existing liens and encumbrances, if any, have been disregarded and the property is appraised as though free and clear, under responsible ownership and competent management.

2. The sketches and maps contained in this report are included to help the reader in visualizing the property, and the appraiser assumes no responsibility for their accuracy. No formal survey of the subject property was made, and no responsibility is assumed in connection with such matters.

3. Information or opinions furnished to the appraiser and contained in this report were obtained from sources considered reliable and believed to be true and correct. No responsibility for accuracy of such items furnished can be assumed.

4. The appraiser shall not divulge the material (evaluation) contents of the report, analytical findings or conclusions, or give a copy of the report to anyone other than the client or his designee as specified in writing except as may be required by the American Society of Farm Managers and Rural Appraisers or the State Appraisal Commission as they may request in confidence for ethics enforcement or appraisal review; or by court of law or body with the power of subpoena.

5. No liability for legal matters is assumed and no right to testimony is included. Prior arrangements for court testimony are required.

6. The distribution of the total valuation in this report between the land and improvements applies only under the existing program of utilization. The separate valuations for land and improvements must not be used in conjunction with any other appraisal and are invalid if so used.

7. The land and particularly the soil of the area under appraisement appears firm and solid. The appraiser does not warrant against conditions which may occur and would be detrimental.

ASSUMPTIONS AND LIMITING CONDITIONS (Con't)

8. All furnishings and equipment, except those specifically indicated and typically considered as part of real estate have been disregarded by the appraiser. Only the real estate has been considered.

9. The comparable sales data relied upon in this appraisal is believed to be from reliable sources, however, it was not possible to inspect the comparables completely and it was necessary to rely on some information furnished by others as to said data; therefore, the value conclusions are subject to the correctness and verification of said data.

10. The appraiser has made a limited inspection by observation the land and the improvements thereon; however it was not possible to personally observe conditions beneath the soil or hidden structural components within the improvements. Therefore, no representations are made herein as to these matters, and unless specifically considered in this report the value estimate is subject to any such conditions that could cause a loss in value. Condition of heating, cooling ventilating, electrical, and pumping equipment,if any, is considered to be commensurate with the condition of the balance of the improvements unless otherwise stated.

11. Neither all nor part of the contents of this report shall be conveyed to the public through advertising, public relations, news, sales, or other media, without the written consent and approval of the author, particularly as to the value conclusions, the identity of the appraiser or firm with which he is connected, or any reference to any professional organizations or any professional designations.

12. The value estimate as contained in this report is valid only under normal market conditions. Any duress or abnormal conditions which may affect the market would make this value estimate invalid.

13. The appraiser is not qualified to detect the existence of potentially hazardous material which may or may not be present on or near the property. The existence of such substances may have an effect on the value of the property No consideration has been given in my analysis to any potential diminution in value should such hazardous material be found.

14. Acceptance of, and/or use of, this appraisal report by Client or any Third Party constitutes acceptance of the above conditions.

MARKET VALUE DEFINED

"Market Value" is the most probable price which a property should bring in a competitive and open market under all conditions requisite to a fair sale, the buyer and seller each acting prudently and knowledgeably, and assuming the price is not affected by undue stimulus. Implicit in this definition is the consummation of a sale as of a specific date and the passing of title from seller to buyer under conditions whereby:

1. Buyer and seller are typically motivated;
2. Both parties are well informed or well advised, and acting in what they consider their own best interest;
3. A reasonable time is allowed for exposure in the open market;
4. Payment is make in terms of cash in U.S. dollars or in terms or financial arrangements comparable thereto; and
5. The price represents the normal consideration for the property sold, unaffected by special or creative financing or sales concessions granted by anyone associated with the sale.

From the OCC's Final Rule, 12 CFR Part 34, Subpart C-Appraisals, Section 34.42(f), effective August 24, 1990.

The Appraisal Process:

The appraisal process is an orderly procedure of gathering information from the market which will lead to an estimate of value. This information is obtained from many sources, but the best source is through recent sales of similar type property. All sales used are examined and confirmed by either the buyer, seller, or a party knowledgeable to the transaction. All pertinent facts from the sales are analyzed, classified and interpreted for use in the valuation process. There are three approaches to value which should be considered when arriving at an estimate of value for real estate.

(1) The Cost Approach
(2) The Income (Earnings) Approach
(3) The Market Data (Sales Comparison) Approach

In the Cost Approach, the value of the various classes of land is estimated from market data. The replacement cost of the buildings is estimated, accrued depreciation (physical, functional and external) is estimated and subtracted from the replacement cost estimate, for an indication of the contributing value of the buildings. The estimated value of land, added to the contributing value of the buildings results in an estimate of value by the Cost Approach.

In the Income Approach, the appraiser measures the present value of the future benefits of property ownership, and like the cost and market approaches, requires extensive market research. The appraiser investigates areas such as the property's gross income expectancy, the expected loss in gross income from lack of full use, the expected operating expense, the pattern and duration of the income stream, and the anticipated resale value. When accurate income and expense estimates are established, the net income is converted into present value by the process of capitalization. The rates or factors used for capitalization are derived by investigation into acceptable rates of return for similar properties.

The Market Data Approach is most viable when an adequate number of properties of similar type have been sold. The application of this approach produces a value indication for a property through comparison with like properties, called comparable sales. The sale prices of properties judged to be most comparable tend to set a range within which the value indication for the subject property falls. The comparison results in specific dollar adjustments to the sale price of the comparable property. Positive adjustments are made for deficiencies in the sale property relative to the subject and negative adjustments are made for superior characteristics of the sale relative to the subject. Through this procedure, the appraiser derives a logical estimate of the probable price for which the subject property could be sold on the date of the appraisal.

DATA ANALYSIS AND CONCLUSIONS

Sale 7	Sale 8	Sale 9	Sale 10	Sale 11	Sale 12	Sale 13	Sale 14
O'Neil & Shadid	Adams Wes & Donald	Adams Wes	Quarter Circle Bar	Miller Land Co	Amwest Savings	Bogle Farms	Met Life Ins Co
Anderson Agri-Bus	Farney David	K Ranch LLC	Booth Land&Lvst	Quarter Circle Bar	Walker Ag Grp	Cross Mtn Ranch LLC	Cook
10/27/94	4/27/94	8/12/94	12/14/93	11/06/92	7/06/92	2/12/92	8/06/90
B467 P721 Albany Wyoming	B900 P284 Garfield Mesa Colorado	R355 661 Moffat Uinta CO - UT	B452 P838 Albany Carbon Wyoming	B434 P748 Albany Carbon Wyoming	B2603P217 Las Animas Pueblo Colorado	B648 P342 670 1391 RC MC RBC Colorado	B407 P363 Albany Wyoming
T25-26N R76-77W Var Sects	T5-7&9S R102-104W Var Sects	T3-5N R101-104W Var Sects	T16-17N R76-77W Var Sects	T16-17N, R76-77W Var Sects	SE of Pueblo Var T & R	Numerous Twp & Rgs Var Sects	North of Laramie Var T & R
$ 469,000	1,475,000	1,500,000	3,200,000	5,500,000	2,600,000	4,960,000	2,100,000
11,120 A	9,984 A	11,400 A	53,107 A	76,584 A	68,509 A	58,318 A	52,495 A
$ 42.18	$ 147.74	$ 132.00	$ 60.00	$ 72.00	$ 38.00	$ 85.00	$ 40.00
Cash	Cash	Cash	Cash	Cash Equi Seller	Cash	Cash to Assumpt'n	Cash
Livestock	Irrig and Livestock	Irrig and Livestock	Irrig and Livestock	Irrig and Livestock	Livestock	Irrig and Livestock	Irrig and Livestock
None	$ 120,000 $ 12.00	$ 142,250 $ 12.48	$ 75,000 $ 1.41	$251,500 $ 3.28	$ 115,330 $ 1.68	$ 150,000 $ 2.57	$ 75,000 $ 1.43
None	193 A $1,400/A	80 A $ 680/A	700 A $ 400/A	1,240 A $ 450/A	None	995 A $ 350/A	1,200 A $ 300/A
None	None	None	10,390 A $ 150/A	12,835 A $ 200/A	None	823 A $ 200/A	850 A $ 150/A
None	* 430 A *$ 400/A	6,320 A $ 145/A	None	None	None	16,960 A $ 120/A	None
None	None	None	None	None	68,509 A $ 35/A	#2,670 A #$ 150/A	None
None	9,361 A $ 65/A	5,000 A $ 57/A	None	None	None	10,000 A $ 60/A	None
11,120 A $ 41/A	None	None	42,017 A $ 28/A	62,509 A $ 31/A	None	26,870 A $ 29/A	50,455 A $ 29/A
BLM State $ 8,560 $ 0.77	BLM $300,480 $ 30.10	BLM State $103,850 $ 9.11	BLM State $ 91,425 $ 1.72	BLM State $163,215 $ 2.13	BLM State $ 86,855 $ 1.27	BLM For St $483,180 $ 8.29	BLM State $ 83,350 $ 1.59

Notes:

* Sale 8 - Land listed as mountain pasture is grazing land associated with farm in Mesa County.

\# Sale 13 - Land listed as E Plains pasture is non irrigated cropland that has been seeded to grass.

SUMMARY OF MARKET DATA

	Sale 1	Sale 2	Sale 3	Sale 4	Sale 5	Sale 6
Grantor	Dikeou, Wachsmann	Tuttle Inv. Co.	Douglas Pass Ltd	Union Oil	Haas Ranch	Sun Land & Cattle
Grantee	Goodman	Anschutz Philip	Hutchens	Kimbal Mt Outfitter	Biber	Faddis
Date of Sale	5/07/96	1/31/96	2/27/96	10/17/95	9/22/95	2/15/95
Recorded		B926 P114	B523 P598 B969 P259	B956 P282		B916 P243
County State	Carbon Wyoming	Carbon Wyoming	RB & Gar Colorado	Garfield Colorado	Las Animas Colorado	Carbon Wyoming
Legal Desc	T21N,R91W E² of Twp	T17-21N, R83-90W Var Sects	T2-5S, R100&101W Var Sects	T6 & 7S, R100W Var Sects	NE of Trinidad	T22-23N R89-90W Var Sects
Sale Price	$ 338,475	7,500,000	3,355,000	$ 325,000	2,700,000	$ 489,547
Size	11,475 A	139,585 A	13,200 A	4,270 A	36,721 A	17,484 A
Price Per Acre	$ 29.50	$ 54.00	$ 269.00	$ 76.00	$ 74.00	$ 28.00
Terms	Cash	Cash	Cash Equi Seller	Casn	Cash	Cash
Water Rights	Livestock	Irrig and Livestock	Irrig and Livestock	Livestock	Irrig and Livestock	Livestock
Imp Value Per Acre	None	$ 600,000 $ 4.30	$ 350,000 $ 26.50	None	$ 200,000 $ 5.45	None
Irrig Meadow	None	2,800 A $ 500/A	585 A $ 700/A	None	2,250 A $ 300/A	None
Sub Irr Pasture	None	1,620 A $ 200/A	None	None	None	None
Mountain Pasture	None	None	12,615 A $ 200/A	None	None	None
E Plains Pasture	None	None	None	None	34,471 A $ 53/A	None
Foothill Pasture	None	45,165 A $ 50/A	None	4,270 A $ 76/A	None	None
Desert Pasture	11,475 A $ 27/A	90,000 A $ 28/A	None	None	None	17,484 A $ 25/A
Leases $ Value Cont/Ac	BLM State $ 25,640 $ 2.50/A	BLM/St/RR $387,900 $ 2.78/A	BLM $274,750 $ 20.72	None	State $ 14,400 $ 0.40	BLM State $ 53,600 $ 3.07

Discussion of Sales:

There were fourteen sales selected for this appraisal that were considered to be somewhat comparable to the subject property. Five of the sales are located in northwest Colorado, two in eastern Colorado and seven in south central Wyoming. There are three 1996 sales, three 1995 sales, three in 1994, one in 1993, three in 1992 and one in 1990. They range in size from 4,270 acres to 139,585 acres. Each of the sales has some comparable aspect to the subject, size, proximity to subject, or similar land classes. I have allocated the sale price to the various land classes found on the properties as well as to the per acre contribution of improvements and leases.

Sale 1; One of the smaller Wyoming sales that is all high desert grazing land. This is the most recent sale but has one of the lower indicated values for the grazing land.

Sale 2; This sale is an extremely large ranch located on the North Platte River near Saratoga. It can be utilized for a year around operation or may be used as a winter grazing and hay unit. The deeded land is mostly checkerboard pattern with alternating sections being deeded, BLM and railroad lease. This ranch has numerous recreational amenities in the form of fishing and big game hunting.

Sale 3; This sale is located near the Cathedral Bluffs some distance west of the subject. It is one of the larger sales for the area and is indicating a considerable higher value than any of the other sales. This property sold in 1993 for 1,400,000 in what was reported to be a distress situation. Mountain land would be considered superior to subject.

Sale 4; This is the smallest of the sales but is closest proximity to the subject. This was a property without any grazing permits and no minerals were included. The buyer had a perpetual grazing agreement with the seller prior to the sale. This sale is in one contiguous parcel with good recreational amenities in the form of hunting. Land considered comparable to NOSR 1.

Sale 5; This is a sale of a large southeastern Colorado ranch that was used as a year around operation. Carrying capacity on grazing land would be comparable to NOSR 1 of the subject. Sale would not have the scenic or recreational amenities but would have better access and ease of operation.

Sale 6; Another of the smaller Wyoming sales of high desert grazing land. Carrying capacity comparable to NOSR 2. Does not have the recreational and scenic amenities of the subject.

Sale 7; Another small Wyoming sale located west of Laramie. Typical high desert grazing land.

Discussion of Sales (Con't)

Sale 8; This sale is a relatively small ranch in western Mesa and Garfield counties. Includes a small farm in the valley west of Grand Junction. These farms are in great demand and will bring a high price. Grazing land is non contiguous parcels extending north to Baxter Pass. BLM permits allow contiguous access and movement of livestock. Property sold in 1992 for $865,000.00 reportedly under a distress condition.

Sale 9; Another relatively small ranch sale in northwest Colorado and eastern Utah. Mountain land is superior to subject and foothill land would be considered comparable to land on NOSR 1. Ranch sold in 1991 for $1,100,000.00.

Sale 10; Sale of a large ranch property west of Laramie, Wyoming. This property was purchased as part of sale 11 and it is interesting to note that the sale price was lower than the allocated values on the original sale. I was unable to find any explanation for this. Typical high desert grazing land superior to NOSR 3 but inferior to NOSR 1.

Sale 11; A large Wyoming sale that included sale 10. Same land and comments as in sale 10.

Sale 12; A very large eastern Colorado sale located southeast of Pueblo. All plains grazing land with comparable carrying capacity to NOSR 1. Does not have the scenic and recreational amenities of subject.

Sale 13; This is a sale of one of the larger ranches in western Colorado. Ranch was on the market for an extended period of time prior to sale. Land is situated in large blocks but is not all contiguous. Winter country is about 80 miles west of the summer country. Foothill land would be comparable to NOSR 1 and Desert pasture is somewhat superior to NOSR 3.

Sale 14; This is the oldest sale in this appraisal and is a large Wyoming ranch northwest of Laramie. Although this is an older sale the value allocation on the land classes is in line with the more recent sales.

Summary; In general I feel that it was fortunate to find as many large sales as are reported here. Not all of the sales are good overall comparisons but have some comparable aspects. I feel that these sales are the most representative of the market and provide a reliable indicator for a reasonable value range estimate on the subject property.

DATA ANALYSIS AND CONCLUSIONS (CON'T)

Valuation - Market Approach

In preparing this limited appraisal of the surface estate only, I have considered only the market or comparison approach to value. I have considered the highest and best use to be agriculture with a compatible recreational secondary use. Most of the sales used for comparison have similar utility to NOSR 1 but superior to NOSR 3 due to steep terrain and barren cliffs. This property is all vacant land and is much larger than the typical property on the market in the area.

Much of the agricultural property, especially mountain land in this area, generally is selling for more than actual value if a reasonable return is expected from agricultural production. The typical operational rancher cannot afford the prices in todays market unless he has other land free and clear or another source of income. Much of this inflated price is due to socio-economic factors that has little to do with the producing value of the land itself. Some of these factors include the rapid rise and increasing affluence of the population of the western United States, which results in much of the ranch land being converted to non ranching uses, ranch land being purchased as a hedge against inflation, for tax advantages, depreciation purposes, recreation, speculation, or for the sheer desire of owning land. The immediate neighborhood of the subject does not have the scenic and recreational amenities of the higher mountain areas of Colorado.

Very large parcels, such as the subject property, present a difficult marketing situation because of the total dollars necessary to consummate a purchase. The market is very limited as to buyers with the necessary resources. The prices are influenced by many factors including size, location, scenic amenities, recreational amenities, proximity to National Forest land, and physical features such as trees, streams and topography. Income that can be realized from this type property is generally low compared to value and results in a very low indicated capitalization rate on the comparable sales.

Within the area there have been certain wealthy buyers that have acquired ranch holdings at a premium price. These, for the most part, are smaller units with good year around access, scenic and recreational amenities not found on the subject and other potential uses. The sales of larger properties revealed in the market are from a wide area and represent prices that appear to be similar over this large area. Most are strictly agricultural properties with little or no potential for other uses.

Valuation - Market Approach (Con't)

In appraising the subject property, I have considered NOSR 1 and 3 separately due to differences in access, terrain, livestock carrying capacity and overall utility. Comparisons are made with the sales to arrive at an estimated range of value for the subject property. Very few of the sales are truly representative of the type property represented by the subject however, they are representative of values for properties with similar utility. In my opinion the foothill pasture classification is most comparable to NOSR 1 which is considered foothill or high mesa land. The large high desert type property is comparable in utility to the NOSR 3 parcel which is also considered foothill property but with lower utility, due to the steep and inaccessible terrain, than NOSR 1.

In the sales analysis on the preceding pages of the report, we have five sales with the foothill pasture classification with a range in value from $ 50.00 to $ 76.00 per acre with the higher values found on sales considerable smaller in total acreage than the subject. The low sale is no. 2, a much larger parcel in total acreage.

Based on the above sales, with most consideration given to sales no. 9 and 13, it my opinion that a range of value of $55.00 to $ 60.00 per acre would be reasonable and supportable for the NOSR No. 1 Lands.

In the sales analysis on the preceding pages of the report, we find a range in indicated values for the desert pasture classification from $ 25.00 to $ 41.00 per acre with seven of the eight sales within a range of $ 25.00 to $ 31.00 per acre.

Based on the sales above it is my opinion that a range of value of $ 25.00 to $ 30.00 per acre would be reasonable and supportable for the NOSR No. 3 Lands.

<u>FINAL ESTIMATE OF VALUE</u>

NOSR No. 1 - 36,406.21 Acres - $ 55.00 to $ 60.00 per acre

NOSR No. 3 - 20,170.94 Acres - $ 25.00 to $ 30.00 per acre

APPRAISERS CERTIFICATION

I certify that, to the best of my knowledge and belief:

1. The statements of fact contained in this report are true and correct.

2. The reported analyses, opinions and conclusions are limited only by the reported assumptions and limiting conditions and are my personal, unbiased professional analyses, opinions and conclusions.

3. I have no present or prospective interest in the property that is the subject of this report and I have no personal interest or bias with respect to the parties involved.

4. My compensation is not contingent upon the reporting of a predetermined value or direction in value that favors the cause of the client, the amount of the value estimate, the attainment of a stipulated result or the occurrence of a subsequent event.

5. My analyses, opinions and conclusions were developed, and this report has been prepared, invoking the departure provisions, in conformity with the Uniform Standards of Professional Appraisal Practice.

6. I have made a personal inspection by small aircraft and a limited ground inspection of the property that is the subject of this report.

7. Edwin Moritz, with Gustavson Associates, the client, furnished some basic information, maps, etc, for the property as well as some market data obtained by him.

8. The appraisal assignment was not based on a requested minimum or maximum valuation, or a specific valuation.

Based on the information outlined herein, together with the appraiser's knowledge of the area, it is the considered judgement of the appraiser that the property that is the subject of this report has a supportable range of Value as of August 9, 1996 of:

NOSR No. 1 - 36,406.21 Acres - $ 55.00 to $ 60.00 per acre

NOSR No. 3 - 20,170.94 Acres - $ 25.00 to $ 30.00 per acre

Larry C. Whiteman

Larry C. Whiteman A.R.A.
Certified General Appraiser
Colorado No. CG01214159
Wyoming Permit No. 84

Dated: August 9, 1996

ADDENDA

QUALIFICATIONS OF THE APPRAISER

Larry C. Whiteman A.R.A.

Education:

High School Graduate, Hayden, Colorado 1954
Colorado State University Graduate, 1958 B.S. Degree Agric

Completed numerous appraisal courses and seminars offered by American Society of Farm Managers and Rural Appraisers.

Completed numerous real estate courses offered by Colorado University, Division of Continuing Education, Colorado Real Estate Commission, Wyoming Real Estate Commission and Colorado Northwest Community College.

The American Society of Farm Managers and Rural Appraisers conducts a mandatory program of continuing education. I have met the requirements of the program through 12/31/96.

Experience

Extensive background in agriculture with emphasis in all phases of livestock production and marketing.

Fee appraiser since January 1973, specializing in Colorado and Wyoming mountain ranches and farms.

Owner and Manager of Professional Agri Service, established in July 1988, offering complete Appraisal, Real Estate Brokerage and Consulting Services.

Have completed many appraisals on farm and ranch property, recreation property, residential and commercial real estate and also livestock and other personal property.

Qualified as an expert witness in numerous courts.

Real Estate Broker, Licensed in Colorado and Wyoming. Experience in real estate sales dating back to 1973.

Professional Memberships

American Society of Farm Managers and Rural Appraisers.

Colorado Chapter ASFMRA

Local, State and National Association of Realtors.

Colorado Cattlemen's Association and National Cattlemen Association.

Professional Designation

Accredited Rural Appraiser (A.R.A.) awarded by American Society of Farm Managers and Rural Appraisers.

Certification

Colorado Certified General Appraiser Number CG01314159
Wyoming Certified General Appraiser, Permit Number 84

GUSTAVSON ASSOCIATES
GEOLOGISTS • ENGINEERS

July 30. 1996

Mr. Larry Whiteman
Professional Agri Service
555 Breeze Street. #120
Craig, CO. 81625

Re: Appraisal Request

Dear Mr. Whiteman:

Per our conversation of July 29. 1996. I have outlined below our request for engaging your services in order to furnish Gustavson Associates with a range of value for the surface rights of approximately 55.000 acres of land located approximately eight miles west of Rifle. Garfield County, Colorado.

Client:	Gustavson Associates, Inc. 5757 Central Avenue, Suite D Boulder. Colorado 80301
Appraiser:	Larry Whiteman. ARA
Assignment:	The assignment is to arrive at a supportable and defensible range of the market value for the surface rights of the subject property.
Legal Description of the Property to be Appraised:	The property to be appraised is the U.S. Naval Oil Shale Reserves # 1 & 3. The client is to furnish the appraiser with a complete legal description of the subject property.
Appraisal Request:	The appraiser is requested to perform a Limited Appraisal-Restricted Report Format as allowed by the Departure Provisions of the Uniform Standards of Professional Appraisal Practice (U.S.P.A.P.).

Rights to be Appraised: The fee simple interest of the subject land. excluding any mineral rights. or equipment in place for the production of minerals. oil. or natural gas.

Definition of Market Value: The most probable price which a property should bring in a competitive and open market under all conditions requisite to a fair sale. the buyer and seller, each acting prudently, knowledgeably, and assuming the price is not affected by undue stimulus.

Implicit in this definition is the consummation of a sale as of a specified date and the passing of title or bill of sale from seller to buyer under all condition whereby:

1. Buyer and seller are typically motivated;
2. Both parties are well informed or well advised and each acting in what he considers his own best interest;
3. A reasonable time is allowed for exposure in the open market:
4. Payment is made in terms of cash in U.S. dollars or in terms of financial arrangements comparable thereto: and
5. The price represents the normal consideration for the property sold unaffected by special or creative financing or sales concessions granted by anyone associated with the sale.

Purpose of the Appraisal: The purpose of this appraisal is to assist the client. Gustavson and Associates in their efforts of appraising the total subject property including any minerals. oil. and gas located on the subject property.

Access to Subject Property: The client is to arrange permission for the appraiser to inspect the subject property.

Appraisal Fee: Not to exceed $4,000.00 - $1,000 Retainer.

Due Date: The report is expected to be delivered to the client by August 14. 1996.

Standards of Appraisal: A. Provide. as appropriate. the highest and best use analysis for the Subject Property.

Mr. Larry Whiteman
July 30. 1996
Page 3

B. Conform to the Uniform Standards of Professional Appraisal Practice (U.S.P.A.) as adopted by the Appraisal Standards Board of the Appraisal Foundation:

C. Be written and presented in a format that satisfies the requirements of the engagement:

D. Indicate the current owner and the ownership of the Subject Property for the three (3) previous years for commercial property and one year (1) for residential 1-4 unit properties. Analyze and report in reasonable detail. any prior sales of the commercial property being appraised that occurred within three (3) years. one year for a residential property, preceding the effective date of the Appraisal:

E. Include in the Certification required by U.S.P.A.P. an additional statement. as required by F.I.R.R.E.A. that the appraisal assignment was not based on a requested minimum valuation. a specific valuation. or the approval of a loan;

F. Contain sufficient supporting documentation. with all pertinent information reported. so that the Appraiser's logic, reasoning, judgement. and analysis in arriving at a conclusion indicates the reasonableness of the value reported to the reader;

G. Include a legal description of the real estate being appraised. in addition to the description required by U.S.P.A.P.

CLIENT	APPRAISER
John B. Gustavson, President	Larry Whiteman. President
GUSTAVSON ASSOCIATES	PROFESSIONAL AGRI SERVICES
5757 Central Avenue. Suite D	555 Breeze St.. #120
Boulder. Colorado 80301	Craig, Colorado 81625

Sincerely.
GUSTAVSON ASSOCIATES. INC.

Edwin C. Moritz
Minerals Appraiser

DOE Surface Water Rights - NOSRs 1 and 3

NOSR-1 comprises 45,440 acres withdrawn for the exclusive use of oil shale development by the United States Navy in 1916. In 1919, certain portions of this land were restored back to the public domain. Claimed reserved water rights of 49,000 acre feet (af) exist for NOSR-1 and 3 with priority dates of December 6, 1916 and September 27, 1924. These rights would be fulfilled respectively from direct flow, storage and groundwater. The Executive Order reserved 10,000 af from the East Fork of Parachute Creek and the remaining balance of 39,000 af would be diverted from the Colorado River and from groundwater under the NOSRs for the primary purpose of development and production of 200,000 barrels per day of fuel oil from oil shale. The United States made no claim to surface water on the NOSR-3 acreage.

Appropriated water for the surface of NOSR-1 is .38 cubic feet per second (cfs). This water originates from 38 springs at .01 cfs per spring. The use is exclusively for livestock and wildlife. See the NOSR-1 water right table for more detailed information.

The DOE currently has water rights on NOSR-3 for 1.04 cubic feet per second (cfs) on Sharrard Creek, a wet weather tributary to the Colorado River located on Section 9, Township 6 south, Range 94 west and for .3 cfs in Section 18, Township 6 south, Range 94 west. The total adjudicated water right for NOSR-3 is 1.34 cfs. A "conditional water right" for a 100 cubic feet per second (cfs) diversion rate from the Colorado River exists on NOSR-3. The right will remain conditional until the water is appropriated with reasonable diligence and the user reapplies for a final or "adjudicated" water right. All of the water (adjudicated and conditional) on NOSR-3 is appropriated for oil and gas development.

Ground Water Rights

Colorado divides groundwater into two categories - designated groundwater and groundwater tributary to a stream. Each has their own institutional arrangements and rules. Designated groundwater is any groundwater within a designated groundwater basin. other than groundwater tributary to a stream. The Colorado Groundwater Commission exercises primary control and regulation over such groundwater. Groundwater tributary to a stream is essentially administered as if it were surface water. One difference does exist between the structure for administering surface water and groundwater tributary to a stream. Before commencing a well to appropriate groundwater, a person must obtain a permit from the State Engineer.[2]

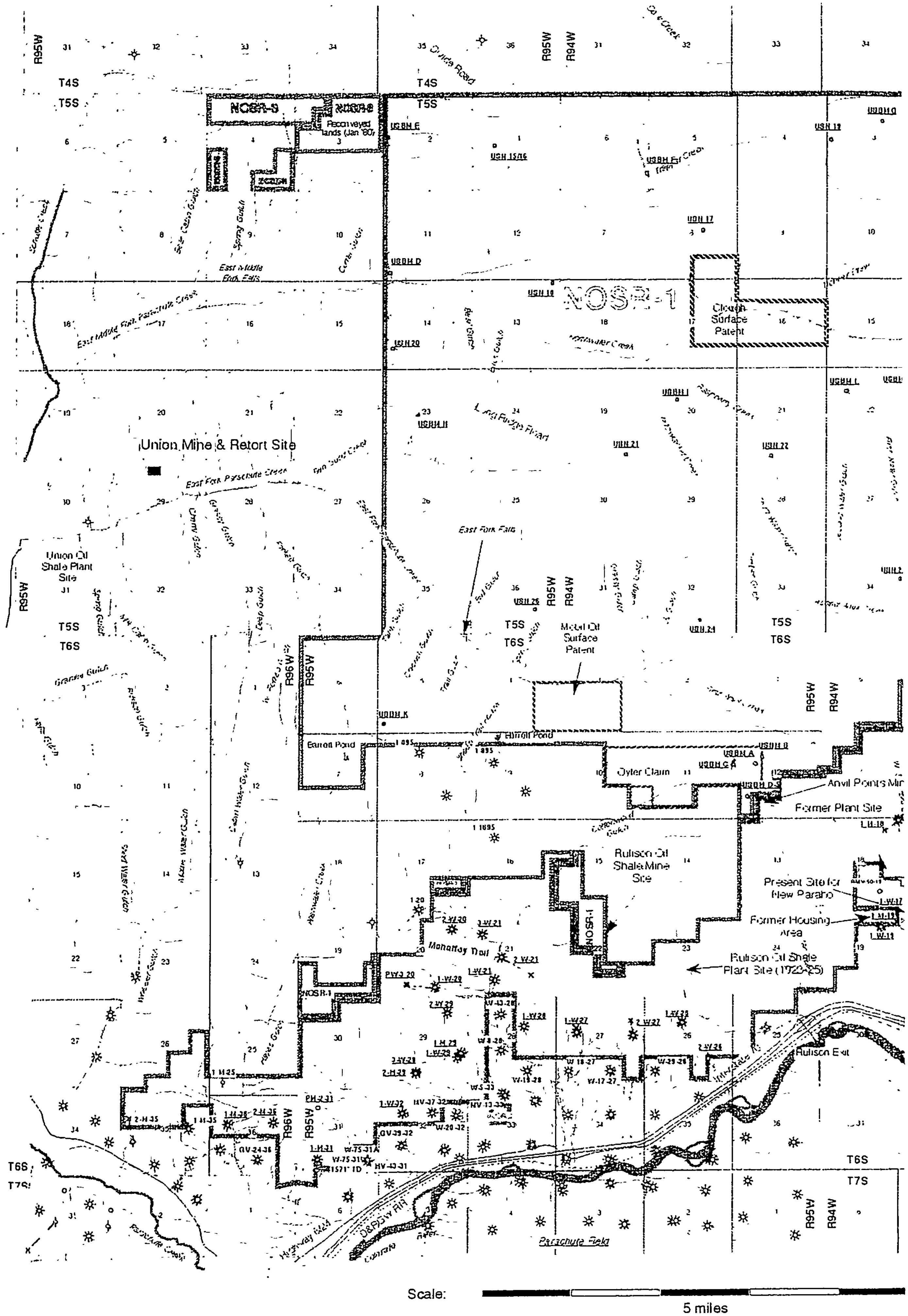
DOE Groundwater rights - NOSRs 1 and 3

The reserved water right for "recoverable groundwater" for oil shale development is 2,650 af/year on NOSR-1 and 100 af/year on NOSR-3. Water in the mainstem of the Colorado River alluvium is excluded from this reserved groundwater right. Before constructing any well the water right owner/developer must notify the State Engineer and provide him/her the location and depth of the well. maximum pumping rate. estimated annual pumpage, specific uses of the water to be withdrawn and the place or places of use for the well.

[2] State Water Law in the West. Los Alamos Scientific Laboratory.

NOSR-2 WATER RIGHTS

Applicant	Amount	Units	Start Date	Use	Source	Location
Bown Livestock Co.	2.82	cfs	7/30/25	Irrigation	Hill Creek	T12S, R19E Sec. 13 SW; N 1800, E 1340
Bown Livestock Co.	1.43	cfs	4/4/21	Irrigation	Hill Creek	T12S, R19E Sec. 13 SW N 1800, E 1340
State of Utah Board of Water Resources	250000	ac-ft	5/19/65	Domestic mining power	White River & Tributaries	T12S, R19E Sec. 24 NE; S 1673, W 3542
State of Utah Board of Water Resources	105000	ac-ft	5/19/65	Domestic power	White River & Tributaries	T12S, R19E Sec. 24 NE; S 1673, W 3542
BLM	0.25	ac-ft	1861	Stockwatering	Lower Grey Knolls Reservoir	T12S, R19E Sec. 21 E4; S 700, W 200
Bown Livestock Co.	2.82	cfs	7/30/25	Irrigation	Hill Creek	T12S, R19E Sec. 24 SE; N 560, W 3060
Bown Livestock Co.	1.43	cfs	4/4/21	Irrigation	Hill Creek	T12S, R19E Sec. 24 SE; N 560, W 3060
Bown Livestock Co.	2.82	cfs	7/30/25	Irrigation	Hill Creek	T12S, R19E Sec. 24 SE; N 119, W 1655
BLM	0.25	ac-ft	1861	Stockwatering	Tabyago Canyon Reservoir	T12S, R19E Sec. 30 W4; N 900, E 700
BLM	1.4	ac-ft	1861	Stockwatering	Upper Benion Bench Reservoir	T12S, R19E Sec. 29 SW; N 1000, E 500
BLM	0.5	ac-ft	1861	Stockwatering	Middle Benion Bench Reservoir	T12S, R19E Sec. 32 NW; S 1000, E 1000
BLM	3.3	ac-ft	1861	Stockwatering	Dog Knoll Reservoir	T12S, R19E Sec. 33 E4; S 800, W 1000
BLM	0.25	ac-ft	1861	Stockwatering	Lower Benion Bench Reservoir	T12S, R19E Sec. 32 SW; N 300, E 1300
BLM	0.015	cfs	1861	Stockwatering	Dog Knoll Spring	T13S, R19E Sec. 4 NW; S 800, E 50
BLM	0.015	cfs	1861	Stockwatering	Cat Canyon Spring	T13S, R19E Sec. 8 NE; S 700, W 100
BLM	0.25	ac-ft	1861	Stockwatering	Lower Tabyago Basin Reservoir	T13S, R19E Sec. 7 N4; S 1000, W 1000
BLM	0.25	ac-ft	1861	Stockwatering	Upper Tabyago Basin Reservoir	T13S, R19E Sec. 7 W4; N 600, E 1000
BLM	0.25	ac-ft	1861	Stockwatering	Mustanger Reservoir	T13S, R19E Sec. 16 E4; S 400, W 2000
BLM	0.015	cfs	1861	Stockwatering	Mustanger Spring	T13S, R19E Sec. 16 W4; S 1000, E 1000
BLM	1.4	ac-ft	1861	Stockwatering	Chimney Canyon Reservoir	T13S, R19E Sec. 19 S4; N 1500, W 500
Norman A. Taylor	1.91	cfs	3/25/16	Irrigation	Hill Creek	T13S, R19E Sec. 24 SE; N 660, W 1300
Norman A. Taylor	0.71	cfs	2/18/14	Irrigation	Hill Creek	T13S, R19E Sec. 25 SE; N 650, W 45
Total	14.09	cfs				
and	355014	ac-ft				


R95W
R94W
R96W
T4S
T5S
T6S
T7S
NOSR-3
Reconveyed lands (Jan '80)
NOSR-1
Clough Surface Patent
Union Mine & Retort Site
East Fork Parachute Creek
East Middle Fork Parachute Creek
Long Ridge Road
East Fork Falls
Union Oil Shale Plant Site
Mobil Oil Surface Patent
Barron Pond
Oyler Claim
Anvil Points Mine
Former Plant Site
Rulison Oil Shale Mine Site
Present Site for New Paraho
Former Housing Area
Rulison Oil Shale Plant Site (1923-25)
Rulison Exit
Mahaffey Trail
D&RGW RR
Parachute Field
Scale:
5 miles

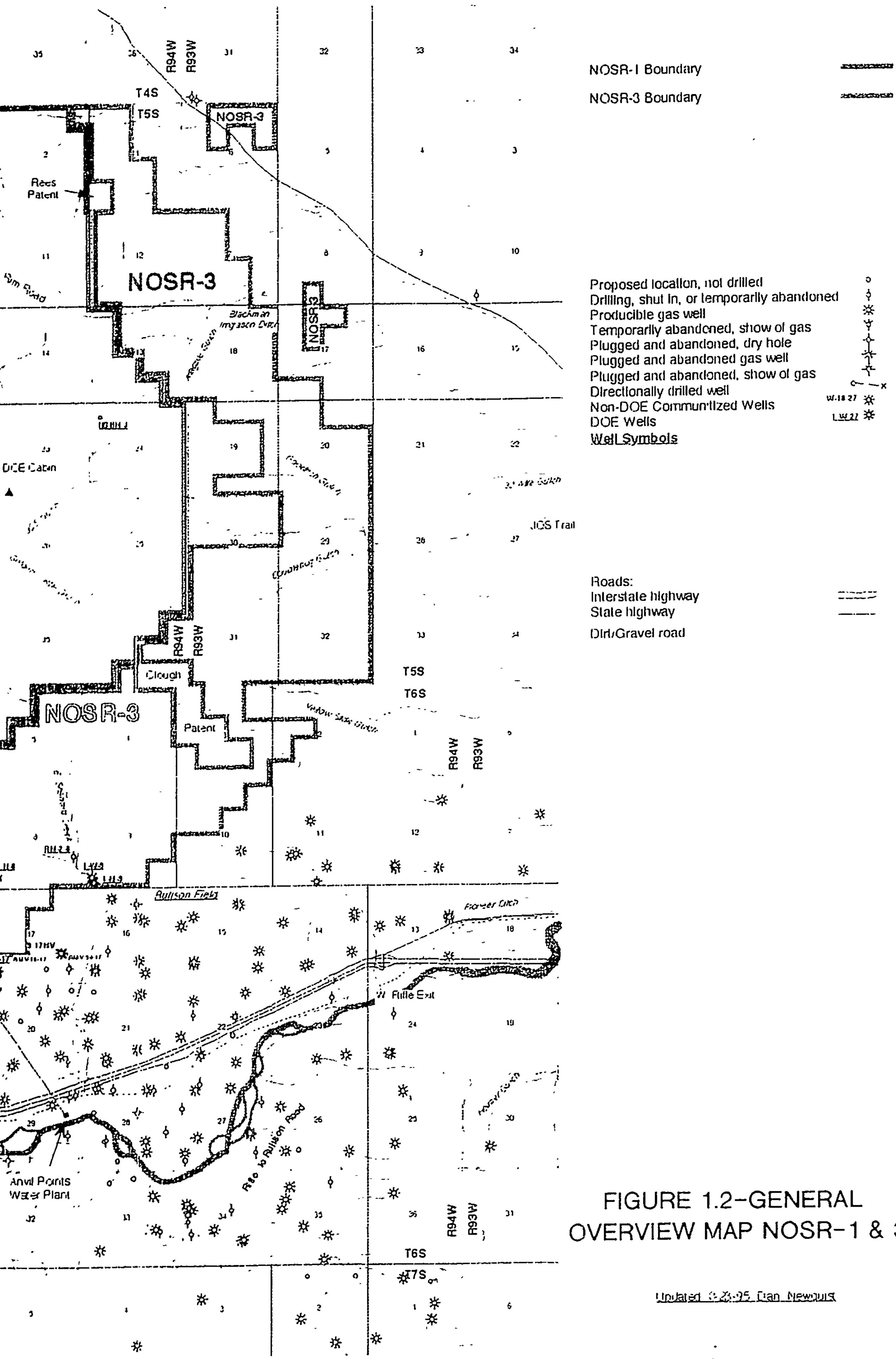
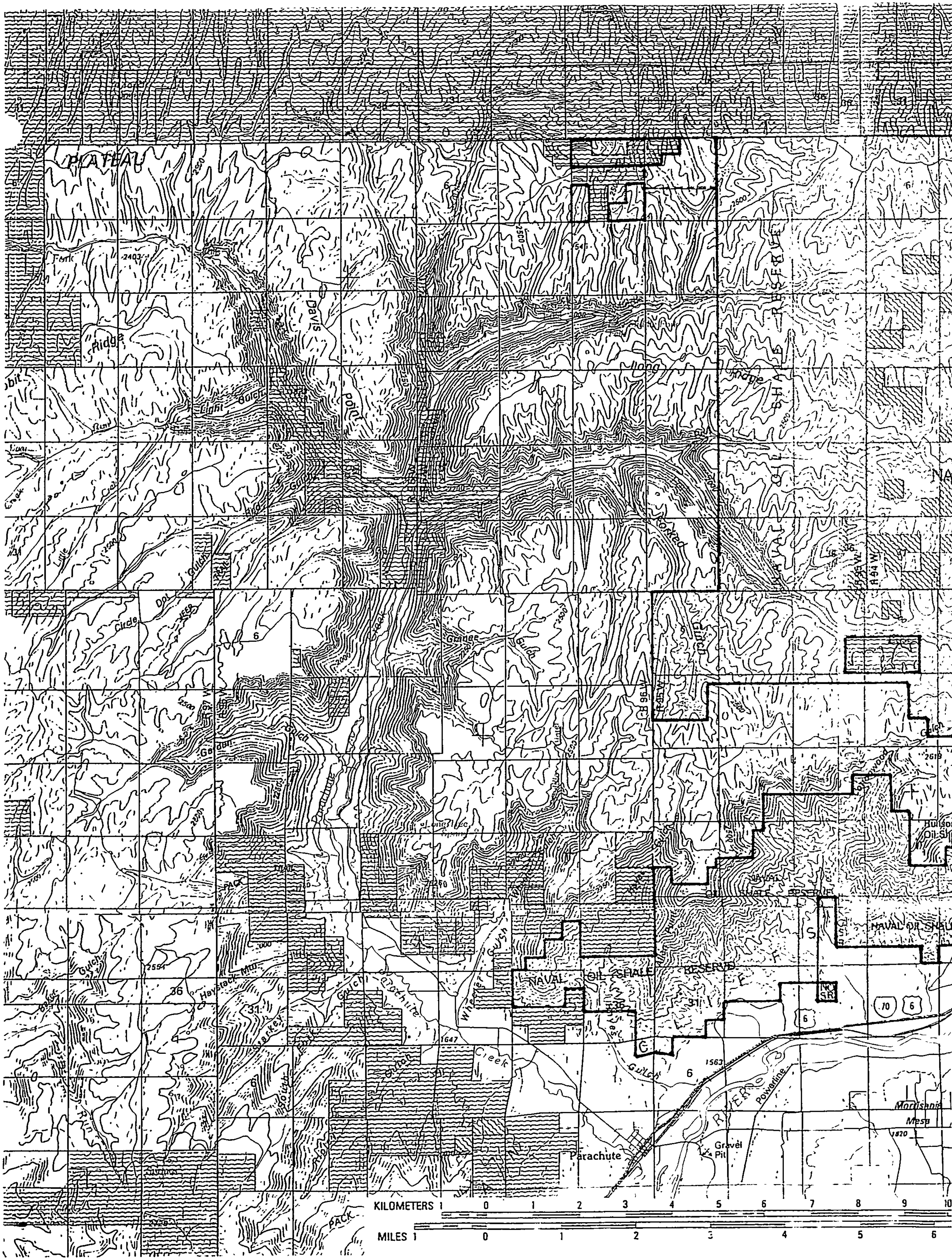


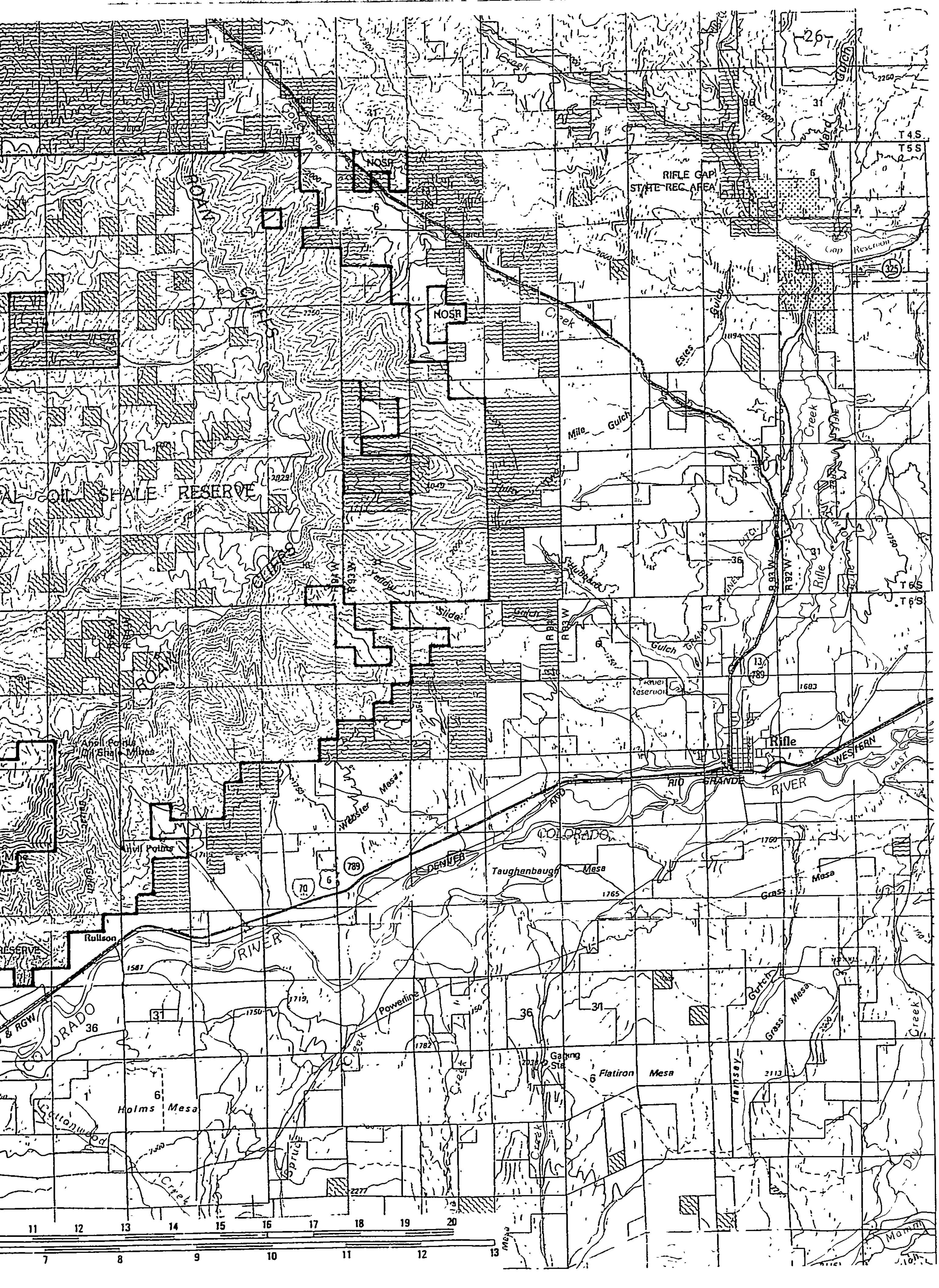
FIGURE 1.2-GENERAL OVERVIEW MAP NOSR-1 & 3

Updated 2-23-95 Dan Newquist

FIGURE 1.2

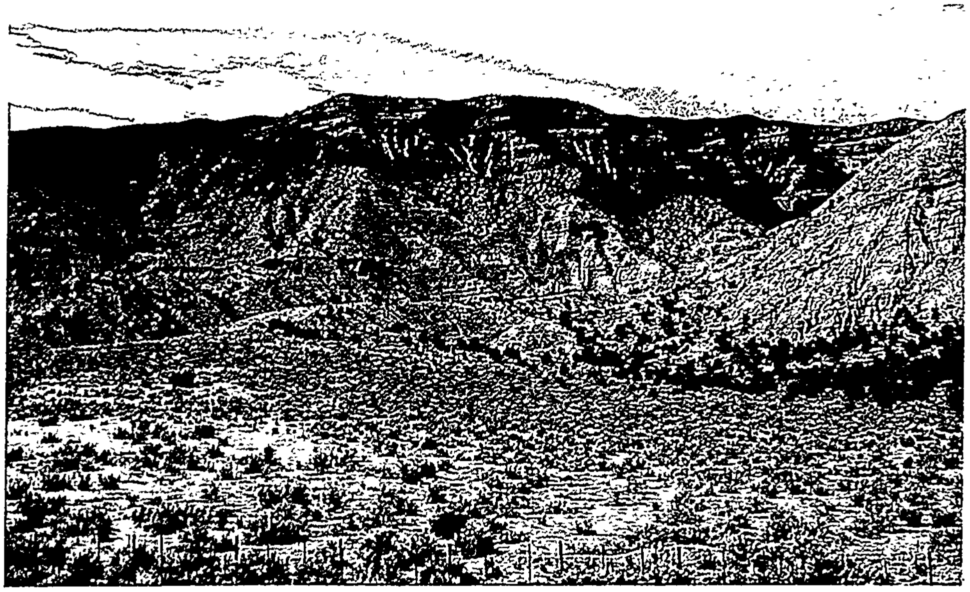


PLATEAU
Ridge
Davis Point
Light Gulch
Long Ridge
Forked
Circle Dot JEEP
Grange Gulch
Garden Gulch
R 95 W.
R 96 W.
R 97 W.
R 94 W.
NAVAL OIL SHALE RESERVE
Haystack Mtn
Starkey
Parachute
Wheeler Gulch
Creek
Gulch
Powerline
Parachute
Gravel Pit
Mesa
PACK
1647
1563
1820
2619
2554
KILOMETERS 1 0 1 2 3 4 5 6 7 8 9 10
MILES 1 0 1 2 3 4 5 6



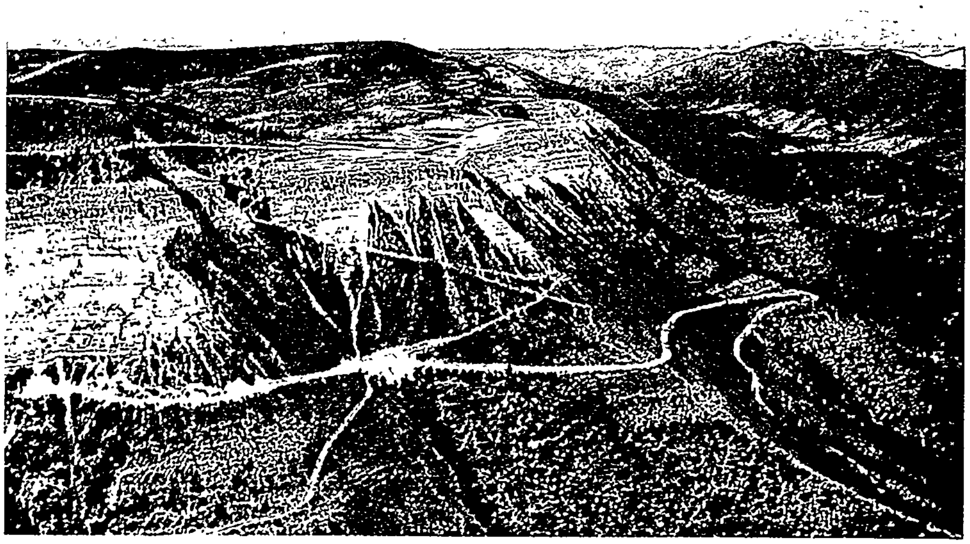
RIFLE GAP STATE REC AREA
Rifle Gap Reservoir
NOSR
ROAN CLIFFS
OIL SHALE RESERVE
T 4 S
T 5 S
T 6 S
R 93 W
R 92 W
Estes Gulch
Mile Gulch
Hubbard
Yellow Slide Gulch
Rifle Creek
Rifle
Rifle Reservoir
RIO GRANDE
WESTERN
DENVER
COLORADO RIVER
Webster Mesa
Taughenbaugh Mesa
Grass Mesa
Anvil Points
Anvil Points Oil Shale Mines
Rulison
Powerline
Gaging Sta
Flatiron Mesa
Holms Mesa
Cottonwood
Spruce
Ramsey Gulch
Dry
Mamm
& RGW
70
6
13
789
325

PHOTOGRAPHS

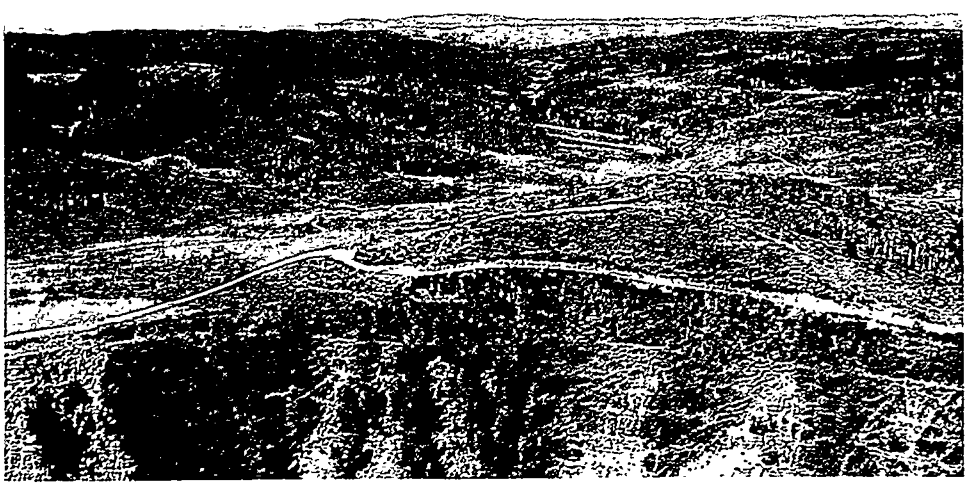


Photos taken Aug 8-9, 1996

Typical terrain south facing ng cliffs NOSR 3 from I-70 at Rulison exit



Typical terrain east facing cliffs NOSR 3; access road from east; NOSR 1 on top



Typical terrain NOSR 1; looking west; cliffs & rim road in foreground

PHOTOGRAPHS

Photos taken
Aug 8-9, 1996

Typical terrain NOSR 1; looking west across top of mesa

Typical terrain NOSR 1; one of several canyons

Typical terrain NOSR 1; deep canyon looking east from approximate west boundary

APPENDIX M

ADDITIONAL FACT FINDING INFORMATION
AUGUST 22, 1996 THROUGH DECEMBER 15, 1996

ADDITIONAL FACT FINDING INFORMATION
AUGUST 22, 1996 THROUGH DECEMBER 15, 1996

DIVESTITURE COSTS

The Department of Energy has supplied Gustavson Associates with cost estimates associated with the sale of the NPOSR properties. These Government costs are associated with all aspects of the sale of the property to industry. These costs include severance packages for Government employees, and all consulting and/or legal fees associated with the sale of the property to industry. Divestiture cost estimates have been provided by the Department Energy and were only used for the sale scenario for each of the NPOSR properties.

We have assumed divestiture costs of $200,000 for NOSR-1, and $1,300,000 for NOSR-3. This is based on information provided by the Department of Energy related to the sale of the NOSR properties. Total divestiture costs for all of the NOSR properties were estimated at $1,700,000. These total divestiture costs were partitioned at $1,300,000 for NOSR-3 and $200,000 for each of the undeveloped properties (NOSR-1 and NOSR-2). The divestiture cost fractions for the NOSR properties are based on the assumption that the majority of costs would be associated with the producing properties that require the most DOE personnel. For the NOSR properties, $1,300,000 for NOSR-3 represents roughly 75 percent of the total NOSR divestiture costs.

ENVIRONMENTAL COSTS

The Department of Energy has advised Gustavson Associates that transfer or sale of NOSR-1&3 would constitute a major federal action. According to the Department of Energy, an Environmental Impact Statement would be required at a cost of approximately $600,000 per property. Gustavson Associates has utilized the services of an Environmental Consultant to independently review the Department of Energy's cost estimate for an Environmental Impact Statement. E.I.S. estimates varied from $50,000 to $2,000,000 depending on the property being reviewed and the scope of the environmental review. Based on this information, and from information provided by several sources within the Bureau of Land Management, the $600,000 estimate was used for each of the NOSR properties. Under the retention scenario DOE is planning to share in the costs associated with the preparation of a regional EIS that includes the NOSR-1&3 properties. The total cost of the EIS is expected to be $1.0 million, and the DOE Casper office reports that the DOE's share is estimated at $300,000 for FY98. Other contributors include the BLM and area operators such as Barrett Energy, Snyder Oil, Vessels Oil and Gas and Chandler Associates.

BONUS AND RENTAL REVENUE SHARING WITH THE STATE

Under the transfer to the Department of Interior (Bureau of Land Management) option, royalties retained by the Federal Government were split with the State Government for a given property. However, this Appraiser has learned that all future bonus and rental income from the property would also be split with the State Government under the transfer option. This includes a split of the bonus paid for existing production. This split of all royalty, bonus, and rental income from the property with the State Government will significantly reduce the value of the transfer option for each of the NPOSR properties.

SURFACE AND LEASING INCOME DISCOUNT RATE UNDER SALE SCENARIO

Surface and leasing income under the sale scenario has previously been discounted at 10.3 percent. This was derived based on a 10.2 percent cost of capital plus 3 percent for "pricing" risk less 2.9 percent for inflation. However, this Appraiser has reviewed this methodology and found it to be slightly inconsistent with the other discount rates under the sale option. The 2.9 percent for inflation should not be subtracted from the total discount rate for surface and leasing income under the sale scenario. The correct discount rate as described in Appendix E to the final report would be 13.2 percent. This is derived by using the cost of capital (10.2 percent) and adding the "pricing" risk of 3 percent. The net effect of this change is relatively small as seen in the December 1996 final report. The value of the property to the Federal Government under the sale scenario is reduced slightly by the higher discount rate.

SHALE PILE MONITORING COSTS

Potential environmental liabilities associated with the shale pile have been identified in previous Gustavson Associates reports. However, recently the Department of Energy has advised Gustavson Associates that this cost would be approximately $2,000 per year. These costs were considered under the sale option for NOSR-3 as a condition for the sale of the property. However, an annual expense this low, discounted into the future is relatively insignificant and did not affect the rounded total value to the Federal Government under sale. In addition, this Consultant had no tangible evidence to support the assumption that the property could only be sold to industry if the DOE was willing to continue to monitor the shale pile.

PUD SCHEDULING UNDER RETENTION

Previous Gustavson Associates reports have outlined all of the Proven Undeveloped reserve potential at NOSR-3 given current DOE field development, economic conditions on the "as of" date, and recent regulatory well spacing changes that affect the property. Based on past DOE operations, it was assumed that DOE would drill 4 more undeveloped locations as part of the drainage protection mandate. The only 4 PUD locations that were economic, unrisked, were Wasatch PUDs. Therefore, it was assumed DOE would drill the most profitable PUDs available over the course of the next fiscal year. However, DOE has informed us that they only have plans to drill 1 Mesaverde PUD in the foreseeable future. This Appraiser has replaced the 4 Wasatch PUDs with the most profitable Mesaverde PUD location available at NOSR-3.

RECENT MARKET CHANGES

Since the value of the NOSR-3 property is highly sensitive to market changes such as the wellhead price received for produced gas, recent market changes were reviewed for the time period between August 22, 1996 and October 1, 1996. This Consultant found that the DOE gas price at NOSR-3 had changed less than $0.05 per MCF as of October 1, 1996. Therefore, there were not any notable changes to the recommendations associated with market fluctuations between the time the reports were submitted and the "as of" date.

Although it does not affect the recommendations in the Gustavson report, it is important to note recent price fluctuations (+200 to +400 percent) in the months following the "as of" date of October 1, 1996.

NOTICE