APPLICATION OF

UNION OIL COMPANY OF CALIFORNIA d/b/a UNOCAL

FOR THE DESIGNATION OF THE

DAKOTA FORMATION
RINCON UNIT, RIO ARRIBA COUNTY, NEW MEXICO
AS A TIGHT FORMATION

CASE NO. 10420 19 DECEMBER, 1991

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APPLICATION FOR
TIGHT FORMATION DESIGNATION
DAKOTA FORMATION, RINCON UNIT

Case # 10420 **December 19, 1991**

I. INTRODUCTION

On behalf of the Working Interest Owners of the Rincon Unit, Union Oil Company of California d/b/a UNOCAL, as operator of the Unit, herein applies for designation of the Dakota Formation (herein known as the Dakota Producing Interval) within the Unit boundary as a tight formation under Section 107 of the Natural Gas Policy Act of 1978.

The Dakota Producing Interval within Rincon Unit demonstrates the qualities necessary as established by FERC and State guidelines for designation as a tight formation:

1. Average in-situ permeability is less than 0.1 md.
2. Pre-stimulation gas production rates are less than 290 MCF/D at an average depth to the formation top of 7347 feet.
3. Pre-stimulation oil production rates are less than 5 BBL/D.
4. Fresh water zones can be adequately protected.

The following geological and engineering evidence is submitted to support and quantify the tight formation characteristics of the Dakota Producing Interval within the Rincon Unit.

II. APPLICATION AREA

The Application Area for the tight formation designation is equivalent to the legal description for the Rincon Unit, a Federal unit, with the inclusion of the North half of Section 24, T27N, R7W, N.M.P.M. This half section is not in the Unit but is included within the Application Area as follows:

<u>Township 26 North, Range 6 West, N.M.P.M.</u>
Section 6: All

<u>Township 26 North, Range 7 West, N.M.P.M.</u>
Sections 1 and 2: All
Sections 11 and 12: All

<u>Township 27 North, Range 6 West, N.M.P.M.</u>
Sections 16 through 23: All
Sections 26 through 32: All

<u>Township 27 North, Range 7 West, N.M.P.M.</u>
Sections 13 and 14: All
Section 15: E/2
Section 22: E/2
Section 23 through 26: All
Section 27: NE/4, S/2
Section 28: S/2
Section 33 through 36: All

The Application Area (Rincon Unit) is shown in relation to populous areas of northwest New Mexico and the Dakota Formation outcrop in Exhibit 1a. The Rincon Unit is shown in relation to other tight formation designated areas (Dakota and various other intervals) in Exhibit 1b. The Application Area contains 20642.7 acres and is located entirely within Rio Arriba County. Exhibit 2 illustrates the Unit boundary and well lcoations for Townships 26 and 27, Ranges 6 and 7 West of the N.M.P.M.

Throughout the Unit the Dakota Producing Interval is designated as part of the Basin Dakota Pool.

III. GEOLOGY

Introduction

The Dakota Producing Interval beneath the Rincon Unit includes two Upper Cretaceous (Cenomanian) stratigraphic units: the Dakota Formation and the Graneros Formation, including all units correlatable with the interval from about 7360 to 7670 feet in the Rincon No. 130 well (type well, Exhibit 4a). The Lower Cretaceous Burro Canyon Formation unconformably underlies the Dakota Formation, whereas the Upper Cretaceous Greenhorn Formation (Bridge Creek Member) conformably overlies the Graneros Formation. The Burro Canyon Formation is nonproductive; the Greenhorn is composed of nonporous limestone and shale and is also nonproductive. Collectively, the Dakota and Graneros Formations average about 265 feet thick in the Rincon area and are composed of a variety of marine and nonmarine sandstones and mudrocks.

The Dakota and Graneros Formations were deposited in or near an ancient seaway that occupied much of the Rocky Mountain area during Late Cretaceous time, between 92 and 96 million years ago. In this large-scale context, the Dakota and Graneros Formations, are the result of sediment deposition in a variety of settings, including: river, floodplain, lake, swamp, bay, lagoon, distributary channel, delta front, beach, prodelta, inner shelf and open marine. These depositional interpretations come from geologic study of outcrops rimming the San Juan Basin (Exhibit 1a), plus evaluation of drill cores from within the basin. A number of geologic studies have been completed on the Dakota and Graneros Formations in the Four Corners area; a selected geological bibliography is included in the Appendix.

Geologic Data Sources

Data and information for the reservoir characterization of the Dakota Producing Interval in the Application Area and the immediate surrounding area (Exhibit 2) comes from two main sources: 1) subsurface drill cores; and 2) conventional wireline geophysical logs. Nine wells in the study area were cored. At the initiation of Unocal's operation of Rincon Unit in 1986 cores from only five of these wells could be located for study: Rincon Unit (RU) No. 127, RU No. 136, RU No. 159, San Juan Unit (SJU) 28-6 No. 98 and SJU 28-7 No. 109. The other four cores, RU Nos. 1, 31 and 57, and SJU 28-7 (Harvey) 3A, could not be located.

The five cores that were located consisted of small chips taken approximately one per foot; the remainder of the core had been discarded. Depth ranges for the core chips are as follows:

RU No. 127	7360 to 7619 feet
RU No. 136	7348 to 7632 feet
RU No. 159	7430 to 7714 feet
SJU 28-6 No. 98	7286 to 7490 feet
SJU 28-7 No. 109	7260 to 7448 feet

The total footage interval represented by the core chips is 1,219 feet.

Stratigraphic and structural relationships in the general Application Area were determined by analysis of 182 conventional wireline logs. Many logs contained a gamma-ray curve in combination with sonic, density and/or neutron curves. This latter set of logs was used to pick stratigraphic tops for various intervals in the Greenhorn, Graneros, Dakota and Burro Canyon Formations and to calculate gross and net thickness values.

Structural Framework

On a regional scale, the Application Area is located in the east-central San Juan Basin (Exhibit 1a). In the Application Area, the Dakota Producing Interval dips gently (monoclinal) to the northeast, as shown in Exhibit 3, which is a structure contour map utilizing the top of the Dakota Formation as the datum. The datum and formation tops are illustrated in Exhibit 4a, the type log. Depths are reported as subsea values. Exhibit 3 shows that the datum horizon ranges from negative 550 feet on the southwestern corner of Rincon Unit to negative 1000 feet on the northeast corner; thus, structural relief across the Unit is 450 feet. The average structural gradient is approximately 66 feet per mile.

The depth to the top of the Dakota Producing Interval within the Rincon Unit ranges from 7008 to 7586 feet and averages 7347 feet, as shown in Exhibit 5a.

Reservoir Stratigraphy

Details of the stratigraphic nomenclature pertinent to this Application are illustrated in Exhibits 4a and 4b. Exhibit 4b, describes lithology, stratigraphic subunits, depositional environments, and assessments of general reservoir quality. Data for Exhibit 4b came from study of drill-core samples, as previously described.

Within Rincon Unit the Dakota Formation is subdivided into five intervals, designated A through F. In Exhibit 4b, because of geological similarities, intervals B and C are combined, as are Intervals D and E. Also in Exhibit 4b, the Graneros Interval is subdivided into five subunits: the Shale Interval, A1 Interval, A2 Interval, X Marker and B Interval.

Gross Interval Thickness

Gross thickness values for the Dakota and Graneros Formations were determined from study of gamma-ray and resistivity logs for the Rincon Unit and surrounding area, as tabulated in Exhibit 5a. This includes the stratigraphic tops of the major stratigraphic units, and the "log-pick" values converted into thickness values. The gross thickness for the Dakota Producing Interval within the Rincon Unit ranges from 240 feet to 328 feet with an average of 265 feet.

Net Pay

The Dakota Producing Interval is composed of interbedded sandstones and shales. Sandstone intervals constitute the primary reservoir flow units, whereas the shales form flow barriers to gas migration. To quantify the reservoir capacity of the sandstone units, a "net-sand" map was constructed using standard geological procedures. Cutoff limits were applied to gamma-ray resistivity and/or porosity logs. The result is shown as Exhibit 5b, which is a net-sand isopach map for Dakota Producing Interval. In Exhibit 5b, net-sand values range from 60 to 110 feet and averages about 80 feet. The net-sand isopach values show a complex pattern, which is indicative of the stratigraphic variability of the component sandstone units. In a general sense, net-sand values increase from west to east across the study area.

To further define the stratigraphic characteristics of the various reservoir units in the Dakota and Graneros Formations, two stratigraphic cross sections (A-A', B-B') are offered as Exhibits 6a and 6b, respectively. Several of the cored wells are included on these displays. Cross-section A-A' traverses the Rincon Unit from southwest to northeast, whereas cross-section B-B' is oriented northwest-southeast. On each cross section the stratigraphic boundaries shown in Exhibit 4b are shown. The two main reservoir flow units are the Graneros A1 Interval and the Dakota A Interval. The datum horizon for both cross sections is the base of the "X" marker, which is located in the lower third of the Graneros Formation (Exhibits 4a and 4b).

Exhibits 6a and 6b document the stratigraphic continuity of the major Dakota and Graneros subunits across the Rincon Unit. The Dakota A Interval is the most persistent subunit and shows only minor thickness variations. The Graneros A1 Interval also shows good persistence; however its thickness varies considerably. The Graneros A1 Interval is thickest in the central part of Rincon Unit, but thins on the eastern and western edges.

IV. PERMEABILITY

Permeability is the measure of fluid flow through a porous media. Several methods are used to determine the permeability to the reservoir fluid in-situ. The most reliable and direct is laboratory measurement of core. A correction is applied to these results to adjust the laboratory air permeability data to in-situ values.

Well performance analyses and pressure build-up analyses both back-out permeability values utilizing fluid flow equations with measured performance parameters, volumes, pressures, etc. These methods are indirect and have many assumptions; however, they serve as a check to confirm the validity of the core data. The application of these methods confirms the average in-situ gas permeability for the Dakota Producing Interval in the Application Area is less than 0.1 md.

Exhibit 7 provides an index to the various wells and permeability derivation methods utilized.

Petrophysical Core Data

Core-plug petrophysical data provide the most direct method for the determination of permeability. In the Rincon area, standard petrophysical data (horizontal porosity and permeability) are available for all cores. The original core data is presented in Exhibit 8. The petrophysical values were entered into a computer to facilitate the interpretation. In this database, the stratigraphic interval from which each core plug was taken was also entered. Exhibit 9 provides a tabular listing of this information.

Statistical summaries of the data by well and stratigraphic interval for both "gross" and "net" cases are given in Exhibit 10a and 10c. For the gross case, all porosity and permeability values are included, whereas for the net case, only those analyses from producing intervals are utilized. Statistical summaries for each stratigraphic unit (all cores combined together) are given in Exhibit 10b (gross interval) and Exhibit 10d (net pay). In all statistical calculations, permeability values listed as zero or <0.01 md by the contractor were treated as 0.01 md.

The average permeabilities calculated on a net-pay basis are half those of the gross calculation. This appears reverse of expectations; however, this is the result of removing non-pay, shaley samples with higher permeability measurements due to fracturing (during unstressing). Regardless, the overall permeability measurements were very low for all stratigraphic units. (see following table).

Also presented in Exhibits 10b and 10d are the corrected permeability data. The correction is applied separately to the average permeability values for the gross and net intervals from each stratigraphic unit.

The correction is based on an industry accepted methodology defined by Jones and Owens (see Appendix iv) which relates laboratory measured air permeability of dry, unstressed core samples to reservoir conditions. The effect can be a reduction of the measured permeability by ten to one thousand times, depending on the reservoir conditions and lithology. The equation accounts for the combined effects of overburden stress, water saturation and gas slippage (Klinkenberg) effects:

$$k_g = ak^b$$

with: k_g = effective gas permeability
k = laboratory permeability
a,b = coefficients correcting for the effects of stress and water

Coefficient "a" typically varies from 1/5 to 1/20 and "b" from 1.5 to 2.7 as the effect of stress and water increases. However, the pressure build-up analyses (discussed later) indicate the minimum suggested correction coefficients are too high. A calibration of the coefficients was done honoring the Flow and Build-up data and analyses. The resulting coefficients of "a" = 1 and "b" = 1.2 were determined to be sufficient for correction of the Dakota and Graneros core data.

The total Dakota Producing Interval core analysis is summarized as follows:

	Permeability (md)	Porosity (%)
Gross Interval (Exhibit 10b)		
Minimum	<0.0100	0.6
Maximum	6.3500	13.5
Average (lab)	0.0832	4.9
Corrected	0.0506	-
Net Interval (Exhibit 10d)		
Minimum	<0.0100	0.5
Maximum	6.3500	13.5
Avg (lab)	0.0543	5.1
Corrected	0.0303	-

The average measured core permeability and corrected permeability on a gross or net basis are all less than the required 0.1 md cut-off for designation as a tight formation. In addition, the permeability appears to be randomly distributed (no relationship to location), with no natural fractures of significance.

Well Performance

As described previously, in-situ gas permeability can be calculated from well performance data. A version of Darcy's Law, the radial flow equation, modified for unsteady state gas flow (as per Aronofsky and Jenkins) with a vertical fracture correction can be stated as:

$$Q_g = \frac{.703 k_g h (Pavg^2 - Pwf^2)}{\mu T z \, (\ln .472(re/rw) - \ln (Xf/2rw))}$$

with:
- Q_g - gas rate SCF/D
- k_g - permeability to gas
- h - net pay
- Pavg - average gas pressure in drainage radius
- Pwf - bottom hole flowing pressure
- μ - viscosity of the gas
- T - reservoir temperature
- z - gas compressibility factor
- re - drainage area radius
- rw - wellbore radius
- Xf - fracture half length

This equation utilizes performance data to back-out an average in-situ permeability. The results are indicated on Exhibit 7. The average value of 0.0435 md of the 8 wells modeled by this method agrees with the core results and is well below the 0.1 md cut off for tight gas designation.

The input parameters utilized in Darcy's Law include net pay, reservoir pressure, flowing pressure, and fracture half length. Net pay was calculated as previously discussed and is presented in map form in Exhibit 5b. Flow rates and flowing pressures were based on biannual deliverability tests and/or flow and pressure build-up tests. A start-up production report is presented in Exhibit 11. Reservoir pressure was based on recent observed pressures from drilling and pressure build-up analyses. A Unit wide shut-in in 1987 for an extended period also serves as a pressure reference. Reservoir pressures range from 500 psi to 2200 psi.

The Dakota Producing Interval has been stimulated by varying methods in the past. At times the two zones were treated in isolation with an average of 40,000 lbs of 20/40 sand per zone. Alternatively, the interval was treated whole, with jobs averaging 75,000 lbs. As a result, fracture half lengths are estimated to range between 100 to 350 feet depending on the success and size of the stimulation. This has been confirmed in-house utilizing STIMPLAN, a fracture simulation model (by NSI Technologies of Tulsa).

Pressure Build-Up Analyses

Two pressure build-ups were conducted (as noted on Exhibit 7) and analyzed utilizing a Finite Conductivity Type Curve Analysis method. The results from Rincon 184 and Rincon 137 indicate average drainage area permeabilities to gas of 0.043 md and 0.046 md, respectively. Both values agree with the core and Darcy calculations and fall below the 0.1 md tight formation cut-off.

The methodology has been well documented (Gringarten, et al; Cinco-Ley; Agarwal, etc.,) and utilizes dimensionless pressure versus dimensionless time finite conductivity vertical fracture type curves applicable to low permeability gas wells stimulated by induced hydraulic fractures.

The pressure data and results are presented in Exhibits 12a through 12d.

V. PRE-STIMULATION FLOW DATA

Within the Rincon area, flow tests were generally not conducted prior to stimulation. Experience dictated the Dakota would not produce sufficient volumes necessary for meaningful analysis. However, some of the early wells were drill stem tested and other gas drilled wells were rudimentarily flow gauged while drilling. The summary of some of the available data is presented in Exhibit 13. Many other gauge reports were TSTM (to small to measure).

Of the limited pre-stimulation data available, none exceeds the designated 290 MCF/D limit. No oil production was reported during any of the tests.

The low pre-stimulation flow rates can be expected considering the tight characteristics of the reservoir. Applying Darcy's Law, utilizing the average corrected core permeability, maximum observed reservoir pressure from the recent drilling, other field average parameters, and assuming a zero skin (S), the maximum unstimulated rate (AOF) calculates as follows:

$$Q_g = \frac{.703k_gh(Pavg^2 - Pwf^2)}{\mu Tz\ (\ln .472(re/rw)+S)}$$

$$Q_g = \frac{.703(.0303)(80)(1850^2-0)}{(0.014)(650)(.865)(8+0)}$$

$$Q_g = 130 \text{ MCF/D (which is less than 290 MCF/D)}$$

The condensate (oil) ratio, based on the historic maximum observed ratio of 16.5 BBL/MMCF, would equate to 2.1 BBL/D, which is less than the 5 BBL/D maximum allowed for tight formation designation.

VI. PROTECTION OF FRESH WATER FORMATIONS

The deepest known fresh water zone in the Rincon area is the Ojo Alamo which averages approximately 2500 ft below surface.

Drilling methods and casing and cement designs have varied with era and operator. El Paso Natural Gas Co. operated and drilled most of the existing wells. Typically, 10 3/4 inch surface casing is set from 250 to 500 feet and 7 or 5 inch production casing run to total depth.

Since Unocal received operatorship in 1986 only one Dakota well has been drilled. To ensure adequate protection of fresh water zones the casing design consisted of 13 3/8 inch surface casing set at 500 feet, 9 5/8 inch intermediate casing set at 4300 feet and 7 inch to total depth. The cement job for the intermediate string was staged with a diverting tool at 2260 feet and cemented to surface.

With regard to the stimulation design (previously discussed) it would not be possible to fracture up to the Ojo Alamo, as there is some 4500 feet of rock between the Dakota and Ojo Alamo.

Unocal will continue to take a pro-active stance with regard to meeting Federal and State regulations and ensure the protection of fresh water zones.

VII. ECONOMICS

Two economic models have been built and are presented in Exhibits 14a and 14b. Both models are typical wells based on current estimated drilling and completion costs of $805,000, field average (per well) operating expenses, and forecasted production stream from the production module of the STIMPLAN simulator. Gas prices utilized are based on those realized through current sales at Rincon. The forecast netback for 1992 is $1.18/MCF escalating by an average of 4% (real) thereafter.

Case 1 includes no tax credits, whereas Case 2 illustrates a $.50/MMBTU tax credit. It is evident from this analysis, infill development is a marginal opportunity without the tax credit. With the tax credit the ROR reaches an acceptable level given the relatively low risk. It is safe to say Unocal will not pursue further infill drilling, under current market conditions, if the tax incentive is not available.

VIII. SUMMARY

It is evident based on the preceding data that the Dakota Producing Interval within the Rincon Unit meets the tight formation criteria as established by the FERC and State guidelines, as follows:

1. The average in-situ gas permeability is less than 0.1 md.
2. Pre-stimulation gas production rates are less than 290 MCF/D at an average depth to the formation top of 7347 feet.
3. Pre-stimulation oil production rates are less than 5 BBL/D.
4. Fresh water zones can be adequately protected.

In addition, economic analyses indicates this potential natural resource will not be developed without incentives beyond the current market conditions.

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Addendum to Text, Section VII, Economics

Within the Unit the Dakota has not been developed to its optimum extent. The majority of the drilling in the Unit was performed by the former operator (EPNG) during the 1950's and 60's. Of the sixty Dakota wells only seven were drilled in the 70's and one well in the 80's. Subsequent to the approval of Order No. R-1670-V, in 04/1979 returning the drilling spacing to the original 160 acres/well, only one well has been drilled. This was the Rincon 192E drilled by UNOCAL in midyear 1991. The 192E was a pilot well to determine the economic viability of further development drilling. The results have been mixed, but do confirm the marginal economics previously discussed. As a result UNOCAL has not pursued further development drilling. Historically then, it is apparent that development of the Dakota has not been pursued due to the marginal economics under the prevailing market conditions.

1952 - 160 acre spacing