APPLICATION OF

JACK A. COLE,
BANNON ENERGY INCORPORATED
BCO INCORPORATED,
AND DUGAN PRODUCTION CORPORATION

FOR THE DESIGNATION OF THE GALLUP
FORMATION IN THE LYBROOK AREA
AS A TIGHT FORMATION

CASE NO. 10273

18 APRIL 1991

Prepared by:

Neel L. Duncan, Petroleum Engineer
Mark E. Weidler, Petroleum Geologist

APPLICATION OF

JACK A. COLE,
BANNON ENERGY INCORPORATED,
BCO INCORPORATED,
AND DUGAN PRODUCTION CORPORATION

FOR DESIGNATION OF THE GALLUP
FORMATION IN THE LYBROOK AREA
AS A TIGHT FORMATION

CASE No. 10273 18 APRIL 1991

Prepared By:

Neel L. Duncan, Petroleum Engineer
Mark E. Weidler, Petroleum Geologist

TEXT

APPLICATION FOR TIGHT FORMATION DESIGNATION
Lybrook Tight Formation Area
Case #10273
18 April 1991

INTRODUCTION

Jack A. Cole, Bannon Energy Incorporated, BCO Incorporated, and Dugan Production Corporation, operators in the State of New Mexico seek designation of a certain continuous area of the Gallup horizon as a tight formation under NGPA Section 107. The area for which designation is sought meets all FERC and State guidelines set forth in that 1) Average in-situ gas permeability is 0.1 millidarcy or less, 2) Pre stimulation gas production rate does not exceed 163 MCFD for an average depth of 5377 feet, 3) Pre-stimulation oil production rate does not exceed 5.0 barrels per day, and 4) Fresh water zones can be adequately protected.

This report will define the area for which a tight sand designation is sought and provide geological and engineering evidence to show that the area meets the designation criteria.

DEFINITION OF TIGHT FORMATION AREA

Tight sand designation is sought for the Gallup formation, as defined by applicable pool rules, for the following area:

Township 23 North

Range 6 West: All Sections

Range 7 West: All Sections

Range 8 West: Section 1

Township 24 North

Range 6 West: Sections 18, 19, 29, 30, 31, 32

Range 7 West: Sections 6, 7, 8, 12, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22, 23, 24, 25, 26, 27, 28, 29, 30, 31, 32, 33, 34, 35, 36.

Range 8 West: Sections 5, 6, 7, 8, 12, 13, 16, 17, 18, 19, 20, 21, 22, 23, 24, 25, 26, 27, 28, 29, 30, 35, 36.

A map showing the area's location in relation to Santa Fe is presented as Exhibit 1 and a map outlining the area in detail is presented as Exhibit 2. The area, which will be referred to as the "Lybrook Tight Formation Area" or "Study Area" throughout this report contains 83,200 acres, more or less, and includes portions of the Counselors Gallup, Lybrook Gallup, Devil's Fork Gallup, Escrito Gallup, Dufer's Point Gallup and Alamito Gallup pools. The area also lies at the juncture of Rio Arriba, San Juan, and Sandavol County.

GEOLOGY

The Gallup formation in the subject area consists entirely of shales, sandstones, and siltstones which were deposited in a marine environment. Production has been established from four principle producing zones which are designated from top to bottom, respectively, the Skelly, Marye I, Marye II, and Marye III zones. These four zones are productive throughout much but not all of the area of interest. They occur within a stratigraphic interval spanning about 250 feet and are illustrated in Exhibit 3, a typical log in the area. Average depth to the top of the Gallup formation is 5377 feet.

Skelly Zone

This zone is present throughout much of the Lybrook Tight Formation Area but disappears as a reservoir in Township 24 North, Ranges 6 and 7 west. It consists of very fine to fine grained sandstone, well sorted, with abundant calcareous cement.

Matrix porosity, as measured by the density log varies from five percent to a maximum of ten percent. Porosity is six to eight percent over much of the area and overall pattern of deposition is northwest to southeast. "Pay" thickness varies from zero to a maximum of fourteen feet.

Marye I Zone

This interval was deposited in a pattern consistently trending northwest to southeast. The sandstones involved are very heterogeneous, being composed of very fine to very coarse sand, consisting of quartz sand and rock clasts, which are very poorly sorted and containing abundant calcareous cement. These are referred to by some in our industry as "strike valley" sands which appear to have been deposited in subtle depressions developed on the sea floor, above a sub-marine unconformity.

Porosity, as measured by density logs varies from six to fourteen percent, with the most common values being six to twelve percent.

The poor sorting and calcareous cement make the zone distinctly variable in reservoir characteristics and significantly reduces permeability. "Pay" thickness varies from a minimum of five feet to a maximum of 22 feet in our area of interest.

Marye II and III Zones

These are the lower-most Gallup producing zones in the area. They consist of very fine to fine-grained sandstones and siltstones which are fairly well sorted but have significant calcareous cement which reduces porosity and permeability. Both of these zones were deposited in a distal deltaic, marine environment, prograding from southwest to northeast.

The Marye II zone varies from zero to fifteen feet in thickness. Porosity varies from five to fourteen percent (average eight percent) with the best development in the southern part of the study area (Township 23 North, Ranges 6 and 7 West) The zone pinches out in the southern part of T 23N R 6 and 7W.

The Marye III zone varies from zero to a maximum of eighteen feet of pay. Porosity varies from five to thirteen percent and averages about nine percent. The zone progrades from southwest to northeast and pinches out in the mid part of Township 24 north, Ranges 6 and 7 west.

The structural configuration of the Gallup zones in the area is fairly uniform northeastward, homoclinical dip averaging 75 feet per mile. (Exhibit 2.) There is no structural closure mappable in the area and all production is accounted for by stratigraphic entrapment.

Exhibits 4a and 4b are cross section presented to illustrate the continuous nature of these zones. The cross sections are constructed from northwest to southeast and southwest to northeast in the area of interest and show that the entire study area is a single reservoir.

PERMEABILITY

Average in-situ gas permeability for the Lybrook Tight Formation Area is less than 0.1 millidarcy and this is evidenced with core data, well performance analysis, and pressure build-up data.

Core data is the primary permeability evidence source for this application. All samples from the sixteen wells which were cored in the Study Area have been analyzed. Since the core data is well distributed it is believed to provide an accurate representation of reservoir permeability.

To close gaps between cored wells and assign confidence to the core data, well performance matching techniques are also used to determine permeability. Methods include 1) a production histry match performed by Stephen A. Holditch and Associates at Texas A&M University and 2) use of the Darcy flow equation to back-calculate permeability.

Finally, a one-month pressure build-up test was performed on Jack A. Cole's Rincon No. 21 to determine permeability.

Exhibit 5 is a map which shows permeability and method of derivation for each well studied.

CORE PERMEABILITY

Core data was obtained from 16 wells in the study area which are depicted with orange dots on Exhibit 5. For the 16 wells studied, in-situ permeability in gross pay averages .0170 millidarcys and in net pay (greater than 6% porosity) averages .0243 millidarcys. Gross and net pay averages may be as low as .0065 and .0098 millidarcys, respectively, depending upon the severity of the correction required for overburden stress and water saturation. (This will be discussed later.)

As evidenced in the exhibit, the core data provides excellent coverage of the study area and is therefore believed to provide an accurate representation of the reservoir. Permeability averages for net pay in individual wells range from a minimum of .0017 millidarcys (South Blanco Navajo No. 25-1) to a maximum of .0531 millidarcys (McBee No. 1). No relationship appears to exist between well location and permeability.

In-situ permeability was obtained by correcting laboratory measurements on dry, unstressed core samples for the effects of overburden pressure and fluid saturations which are present at reservoir conditions. The method used was developed by Amoco in 1979.

Amoco's method, presented in its entirety as Exhibit 6, provides a means of correcting laboratory measured permeabilities to account for the mechanisms which cause reduced permeability at reservoir conditions.

In-situ permeability is generally ten to one thousand times less than that which is observed using routine laboratory methods due to the combined effects of overburden stress, connate water saturation, and reduced gas slippage. The presence of clays in the rock makes these effects even more dramatic.

By measuring permeabilities of over 100 core samples under simulated reservoir conditions in a special cell, Amoco developed an equation and a set of constants to convert routine permeabilities to in-situ permeabilities. The constants used in the equations vary with the severity of the effect of overburden stress and connate water on permeability. The equation and the constants are as follows:

<u>Equation</u>	<u>Constants</u>
$k_g = ak^b$	Minimum: a= 1/5 b= 1.5 Moderate: a= 1/7.5 b= 1.9 Great: a= 1/12 b= 2.3 Very Great: a= 1/20 b= 2.7

The study examined reservoir rocks which varied in clay content from clean to relatively shaly over an overburden stress range from 2000 to 6000 psi. Core permeabilities requiring the most correction were shaly (high clay content) sands at high overburden pressures.

Since the Gallup formation in the Study Area is a shaly sand with net overburden stress ranging from 4100 to 5000 psi, the constants ranging from "moderate" to "very great" apply.

A well-by-well summary of the corrected core data is presented in Exhibit 7a. Presented for each well is the average laboratory measured permeability and corrected permeability values for the gross and net pay intervals in the Gallup. K_{MOD} is permeability corrected for moderate severity of overburden stress and saturation effect and K_{VG} is permeability corrected using the "very great" severity constants. Actual permealility should fall somewhere between the two.

A foot-by-foot permeability detail for each well is presented in Exhibits 7b through 7q. There are a few cases in which an individual permeability measurement for a test sample exceeds 0.1 millidarcys but these are very isolated, show no correlative pattern, and have little effect on average in-situ permeability. Further, these anomalies are probably the result of fractures created while drilling the samples out of the whole core. There is no core evidence to support the existence of an organized fracture system and production characteristics also fail to support the existence of natural fractures or zones of high permeability.

To ensure completeness of the evidence presented, the raw (unprocessed) core data is presented as Exhibit 8.

PERMEABILITY FROM WELL PERFORMANCE ANALYSIS

Two well performance analysis techniques were used as a second method to determine permeability and ascertain the validity of the core data. A discussion of each of these methods follows.

HOLDITCH MODEL

A computer program developed by Stephen A. Holditch and Associates of Texas A&M University uses an iterative procedure to match known reservoir parameters and production history with an unknown reservoir parameter, which in this case is permeability. The computer loops through calculations until it finds a permeability which will produce a production performance curve similar to the well's actual performance history.

Stephen A. Holditch and Associates performed a history match on Dunn Nos. 10 and 11, operated by BCO, Inc, in Section 3 of T23N R7W. A coefficient of fit of 1.000 (indicating a perfect match) was achieved for permeabilities of .0181 md and .0256 md for the respective wells.

These permeabilities are relatively close to the core derived permeabilities so they are believed to be representative. As with the case of the core permeabilities, the values obtained from the Holditch model are almost a full order of magnitude below the maximum average in-situ gas permeability of 0.1 millidarcy specified in 18 CFR 271.703.

The computer input and output data for the Holdich model is provided in Exhibit 9 and the locations of the wells are shown with yellow dots in Exhibit 5.

DARCY CALCULATION METHOD

A simple, yet valid approach for estimating permeability from well performance data is to use Darcy's radial flow equation corrected for the negative skin caused by a vertical fracture. In its original form, the equation is written as follows:

$$Q_{gas} = \frac{.703\ kh\ (P_{avg}^2 - P_{wf}^2)}{uTz\ (8+s)}$$

Where: Q_{gas} = gas flow rate, SCF/day
k = gas permeability, millidarcys
h = net pay height, feet
P_{avg} = average drainage area pressure, psia
P_{wf} = producing bottom hole pressure, psia
u = gas viscosity, centipoise

T = formation temperature, degrees Rankine
z = gas compressibility factor
s = skin factor
$8 = \ln .61(re/rw)$

Skin factor for a fracture stimulation can be estimated with the following equation:

$$s = -\ln \frac{L_f}{2\ r_w}$$

where: L_f = length of one wing of the vertical fracture, feet
r_w = well radius, feet

Solving for permeability:

$$k = \frac{Q_{gas}\ uTz\ [8 - \ln(L_f/2r_w)]}{.703\ h\ (P_{avg}^2 - P_{wf}^2)}$$

Knowing the production rate, one can calculate in-situ gas permeability. The results of the Darcy calculations are presented as Exhibit 10. Average permeability for the twenty one wells modeled in this manner is .00743 millidarcys. The highest calculated permeability is .01882 md which is well below the 0.1 millidarcy cut-off for a tight sand designation.

It may also be noted that the Darcy average permeability of .0074 millidarcys is very close to the average core permeability of .0098 millidarcys when the high severity correction constants are used. (Refer again to Exhibit 7a.)

Data used in calculating the Darcy permeabilities includes net pay height, fracture height, fracture half length, and average reservoir pressure.

Net pay for each well was determined using compensated density logs. A porosity cut-off value of six percent was used to define net pay as this is the cut-off value normally used for perforating.

Fracture height was also estimated using density logs. Hydraulic fracture height propagation is assumed to extend ten feet above and below each perforated interval unless bound by a dense shale interval. The ten-foot rule is based on radioactive tagging experiments performed in the Lybrook area during 1989.

Fracture length was estimated using Halliburton's fracture treatment design simulator and pressure build-up data. Fracture lengths were calculated for various job sizes then corrected using using an actual to theoretical length ratio developed from pressure build-up data on State "J" #1, operated by BCO, Incorporated. In the build-up test, actual hydraulic fracture length was determined to be 74 percent of the simulated fracture length. Fracture length versus specific job size (pounds of proppant per foot of fracture height) is presented as Exhibit 11.

Reservoir pressure was estimated using observed pressures during the completion of wells in 1989 and 1990. Reservoir pressure varies from 700 psig in the extreme northeastern portion of the Study Area to 1400 psig in portions of Township 23 North, Ranges 6 and 7 West.

Admittedly there are many variables involved and significant percentage errors may be present in the Darcy calculations as a result of the many assumptions. However, since the permeability values derived from this technique are one to three **orders of magnitude** below 0.1 millidarcys, the approach is reasonable. Errors of several thousand percent would be required to invalidate this approach as a method of proving that permeability is below the maximum allowed in 18 CFR 271.703. Further, the favorable comparison with core data also adds faith to the analysis.

PRESSURE BUILD-UP ANALYSIS

A widely accepted method for determining formation permeability is pressure build-up analysis and this was performed on the Rincon No. 21 well operated by Jack A. Cole. The test revealed an average drainage area permeability of .003 millidarcys which is well below the tight formation cut-off value of .1 millidarcy.

The test was performed by producing the well for nine months then shutting the well in for one month and monitoring the build-up of bottom hole pressure. Formation permeability was determined by matching the actual pressure data with a dimensionless pressure versus time type curve for a vertically fractured well using Halliburton's interactive graphics program.

The raw pressure data, match plot, and computer output are presented as Exhibit 12. The well's location is shown with a red dot in Exhibit 5.

STABILIZED UNSTIMULATED PRODUCTION RATE

Obtaining stabilized unstimulated gas or oil production rate for Gallup formation wells is not a standard practice for operators in the Study Area. Experience has shown that the Gallup is not commercially productive without stimulation and therefore wells are stimulated prior to being tested.

However, the limited pre-stimulation test data which is available does ascertain that the unstimulated gas production rate for wells in the Study Area does not exceed 163 MCF per day and unstimulated oil production rate does not exceed five barrels per day.

Exhibit 13 details the natural production tests available for Study Area wells. In all tests, a "no flow" situation was observed when swabbing a well to atmosphere prior to hydraulic fracture stimulation.

These results can be expected considering the low in-situ permeability of the reservoir and Darcy's Law can be used to illustrate this point. For the well of highest known core permeability (.0531 md) the following maximum production rates would be expected at maximum anticipated reservoir pressure:

$$Q_{oil} = \frac{.00708\ kh\ (P_i - P_{wf})}{uB_o\ (8 + s)}$$

$$= \frac{.00708\ (.0531)(40')(1400-0)}{.600(1.42\ RB/STB)\ (8 + 0)}$$

$$Q_{oil} = 3.08\ BOPD;\ < 5\ BOPD$$

And for gas:

$$Q_{gas} = \frac{.703\ kh\ (P_{avg}{}^2 - P_{wf}{}^2)}{uTz\ (8+s)}$$

$$= \frac{.703(.0531)(40)(1400^2 - 0^2)}{(.0154cp)(600\ R)(.83)(8+0)}$$

$$= 47{,}701\ SCF/day\ or\ 48\ MCFD;\ < 163\ MCFD$$

Although the calculation for oil appears to be very close to the maximum allowed it must be remembered that these calculations provide extremely generous estimates of natural flow rates because they assume zero skin effect. In practice this will never occur because near wellbore formation damage is induced by the drilling and cementing process due to fluid invasion and the building of wall cakes. Additional damage is caused by rock crushing during the perforating process. Hydraulic hydraure stimulation is required to provide a flow path through this damaged zone.

Skin factors caused by these damaging mechanisms can range from 10.0 to infinity (creating "no-flow" as seen in the pre-frac test data). If we assume a minimum natural completion skin of 10.0, the flow rates calculated above are further reduced to 1.37 BOPD and 21 MCFD. Additionally the producing bottom hole pressure used in the calculations is zero and in practice this will usually be between 100 and 200 psig, even when a well is flowing to atmosphere. The added sandface pressure will further reduce the pre-stimulation flow rates.

Another way to estimate pre-stimulation production rate is by examining early post-stimulation production data and correcting it for the effects of stimulation.

Stimulation ratio, or the ratio of post-stimulation producing rate to pre-stimulation producing rate, is a function of both fracture length and production time. Stimulation ratio increases with increasing fracture length because of increased reservoir system transmissibility and decreases with productin time, because of accelerated drainage.

Exhibit 14 shows the relationship between stimulation ratio, fracture length, and time. Note that after one month, a well with a modest fracture wing length of 250 feet will produce 30 times its natural (radial) flow rate. After 60 months (5 years) the well will be producing seven times the rate it would have been had it produced naturally for the same period of time.

Using this relationship, we can estimate natural (unstimulated) production rate from post stimulation data. If we assume a fracture length of 150 feet (worst case) we can divide a well's first month stabilized producing rate by 22.5 to obtain the natural flow rate.

Exhibit 15 details the results of this approach. First month stabilized production rates for the best wells in the Study Area were divided by 22.5 (regardless of whether or not they were stimulated with larger frac jobs) and none of the calculated natural production rates exceed 5 barrels of oil or 163 MCF of gas per day.

PROTECTION OF FRESH WATER HORIZONS

Existing State and Federal regulations will assure that continued development of the Gallup formation will not adversely affect or impair any fresh water acquifers. Regulations require that casing programs be designed to seal off potential water bearing formations from oil and gas producing formations.

Fresh water zones exist from the surface to the Ojo Alamo formation, the base of which averages 1500 feet from surface.

Gallup wells in the Study Area are drilled with a water based mud that will not contaminate fresh water zones. Casing programs normally consist of 8-5/8" surface set at 250 feet and 4-1/2" casing set from surface to total depth.

Both the surface casing string and production casing string are cemented from total depth to surface. Applicants ensure that the cement top reaches the surface by pumping sufficient excess to obtain cement returns at the surface before the cementing job is complete.

To further ensure that the Ojo Alamo acuqifer is protected, applicants comply fully with NTL-FRA-90-1 which requires the use of casing centralizers and turbulators in fresh water zones.

Fracture stimulation of Gallup wells also poses no threat to fresh water sands. The vertical distance between the highest Gallup interval stimulated and the deepest fresh water sand is 3,500 feet or greater. This distance is more than adequate to assure that the fracture created will not propagate into an acquifer.

SUMMARY

Geological and engineering data on the Lybrook Tight Formation Area provides conclusive evidence that the criteria for a tight formation designation under NGPA section 107 are met in that:

i) The average in-situ gas permeability throughout the Gallup is 0.1 millidarcy or less.

ii) For an average Gallup well depth of 5377 feet, the stabilized gas production rate at atmospheric pressure without stimulation is not expected to exceed 163 MCFD.

iii) No well drilled in the Gallup formation is expected to produce, without stimulation, more than 5 barrels of oil per day.

iv) Fresh water zones will be adequately protected with continued development of the Gallup formation.

REFERENCES

Jones, Lloyd G. "Well Deliverability Calculations" Mobil Research and Development Corporation, 1987.

Lee, W. John, Well Testing, Society of Petroleum Engineers Press, Dallas, Texas 1982.

Jones, F. O. and Owens, W. W. "A Laboratory Study of Low Permeability Gas Sands", Society of Petroleum Engineers #7551. 1979.

Craft, B. C. and Hawkins, M. F. Applied Petroleum Reservoir Engineering. Prentice-Hall, Inc. 1959.

LIST OF EXHIBITS

LIST OF EXHIBITS
Application for Tight Formation Designation
Jack A. Cole et.al.
Case No. 10273

EXHIBIT No.	TITLE(s)	PURPOSE OF EXHIBIT
1	Locator Map	Show location of area relative to Santa Fe.
2	Structure Map	Show with contours the top of the Gallup Formation. Map also shows outline of area for which tight formation designation is sought and pool boundaries.
3	Type Log	Shows major Gallup producing intervals in the proposed Tight Sand area. Source of log is the State 16-2 well operated by Bannon Energy.
4a,b	Cross Sections A-A' and B-B'	Show that reservoir is correlative throughout the area for which tight designation is sought.
5	Permeability Map	Show formation permeability and method used to obtain same.
6	Technical Paper	SPE #7551 "A Laboratory Study of Low Permeability Sands"; F.O. Jones and W. W. Owens Amoco Production Co. Purpose: Details core permeability correction method.
7a-q	Corrected Core Data Summary and Detail List	Summarize core analysis data. Also shows corrected core permeabilities for 16 wells on a foot-by-foot basis.
8	Raw Core Data	Provide copies of original core data from the sixteen wells studied.
9	Holditch Model Input/Output	Provide back-up data for permeability determinations made by S.A. Holditch and Associates using a production history match.
10	Darcy Permeability	Summarize permeability estimates made by using current production rates and known reservoir parameters with the Darcy equation.

LIST OF EXHIBITS (page 2)

Application for Tight Formation Designation
Jack A. Cole et.al.
Case No. 10273

EXHIBIT No.	TITLE(s)	PURPOSE OF EXHIBIT
11	Fracture Length versus Job Size	Show how hydraulic fracture length for input into Darcy equations was estimated based on frac job size.
12	Pressure Build-up Test Report	Provide raw pressure data and analysis report for pressure build-up test on Rincon No. 21.
13	Natural Production Tests	Show that flow could not be established from Study Area wells without stimulation.
14	Stimulation Ratio vs. Frac Length	Compares stimulated well production to radial flow rate ratio versus fracture length for various flow times.
15	Calculated Radial Flow Rates	Shows calculated unstimulated production rate for best wells in the Study Area based on initial stabilized production and stimulation ratio.
16	Producton Data	Shows current production rate, cumulative production, IP, and completion date for wells inside and outside of the study area. Data is sorted by Pool, Year Completed, and Operator.
17	Formation Tops	Shows reported top of Gallup formation for wells in the Study Area.

EXHIBIT 1
LOCATOR MAP

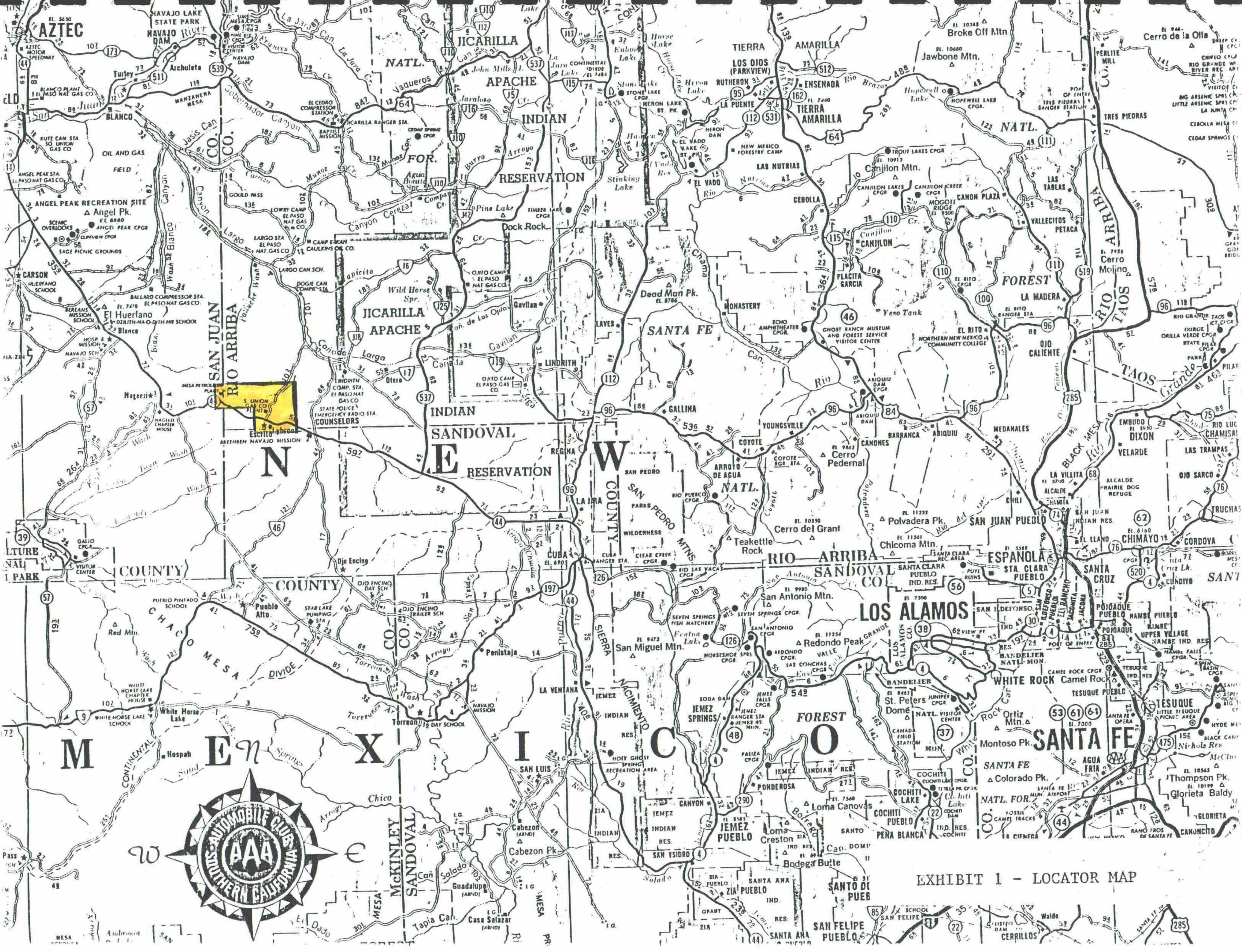

EXHIBIT 1 - LOCATOR MAP

EXHIBIT 2
STRUCTURE MAP

change to zone -6

copy Kenai River portion
& [illegible] portion

OGJ NOV 25 '91 p36