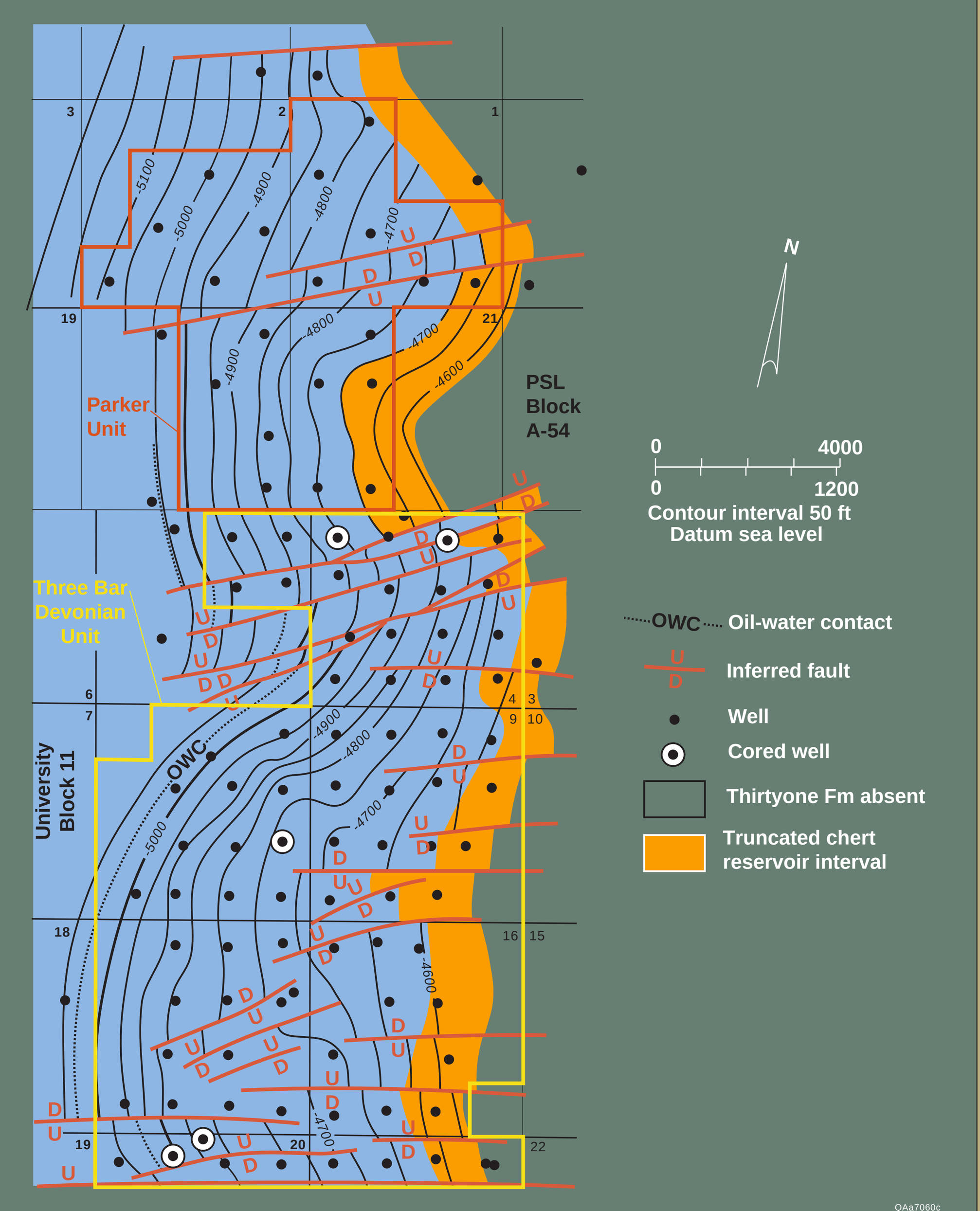
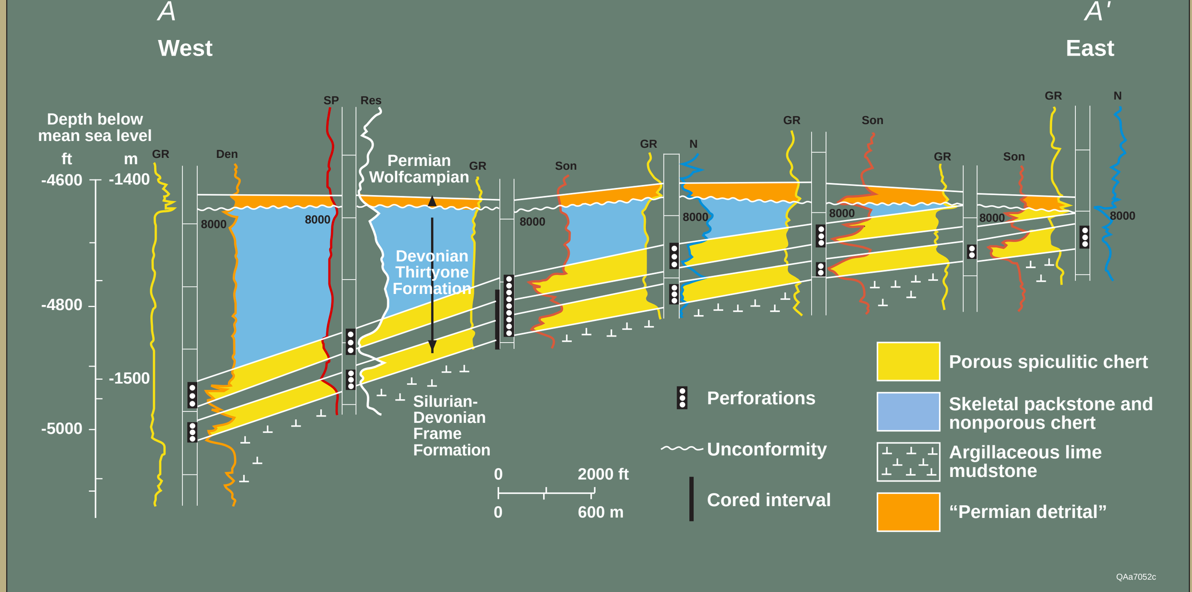
PROXIMAL CHERT RESERVOIRS
THREE BAR FIELD

THIRTYONE FORMATION STRUCTURE

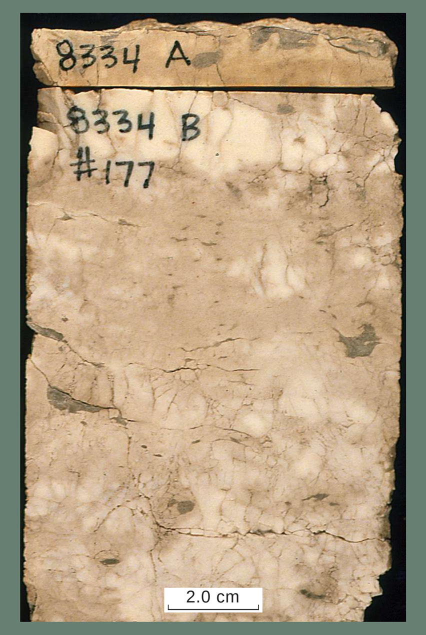


Three Bar field is developed along the western margin of a breached Pennsylvanian anticline. The reservoir is truncated to the east by erosion. Top seal is formed by Lower Permian shales.

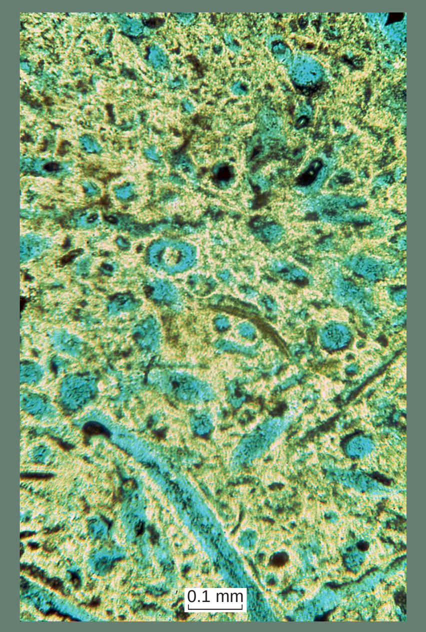
STRUCTURAL SETTING



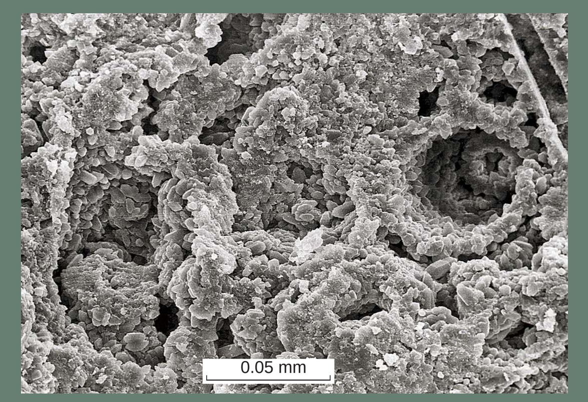
BURROWED POROUS SPICULITIC CHERT



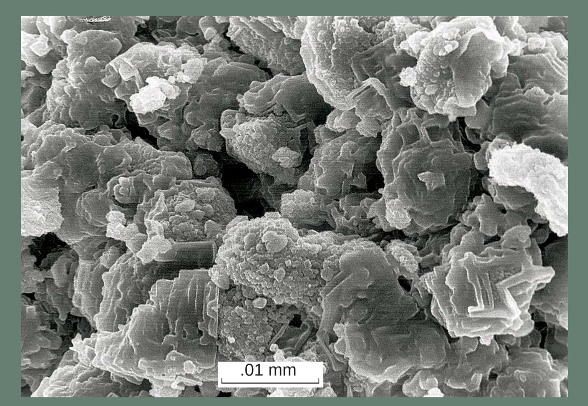
Core slab of typical productive chert reservoir facies at Three Bar field. Small fractures are common throughout; larger fractures are more abundant near apparent fault zones.



Photomicrograph of Thirtyone reservoir chert showing abundance of monaxon sponge spicules.

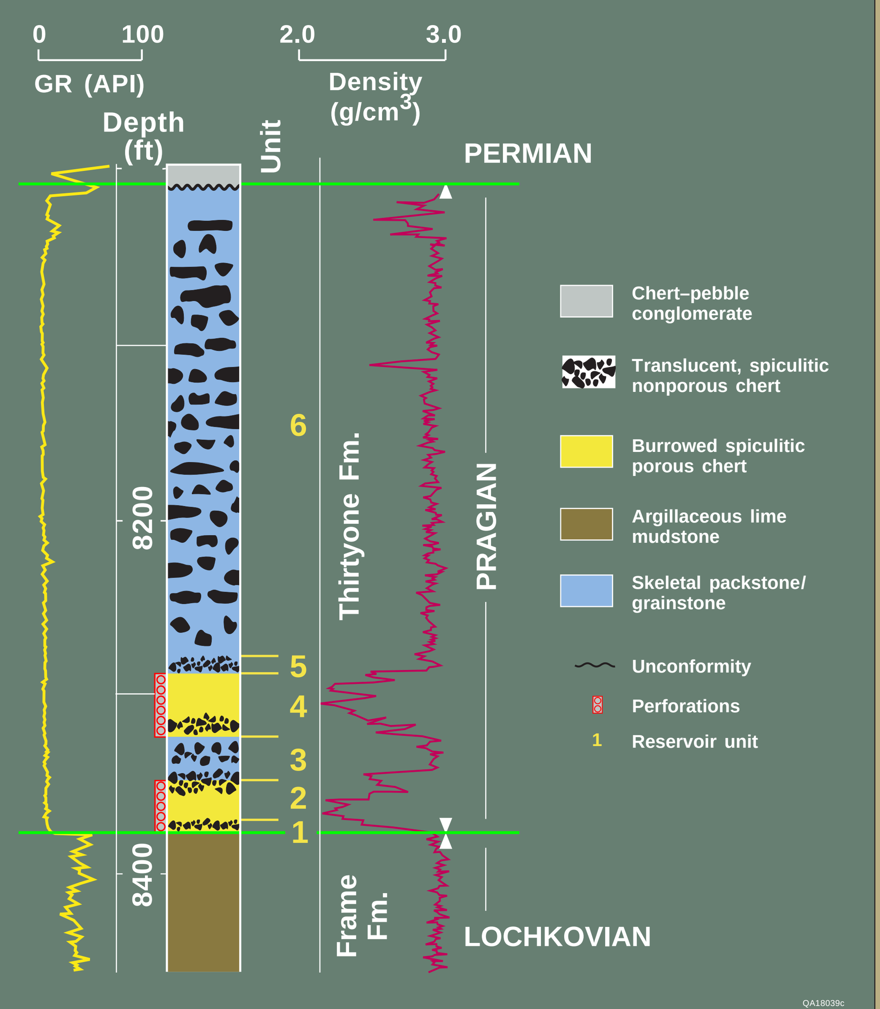


SEM photomicrograph showing spicule-moldic and microcrystalline pores in Thirtyone chert at Three Bar field.



SEM photomicrograph showing microporosity developed between aggregates of 1-μm ellipsoids.

RESERVOIR FACIES

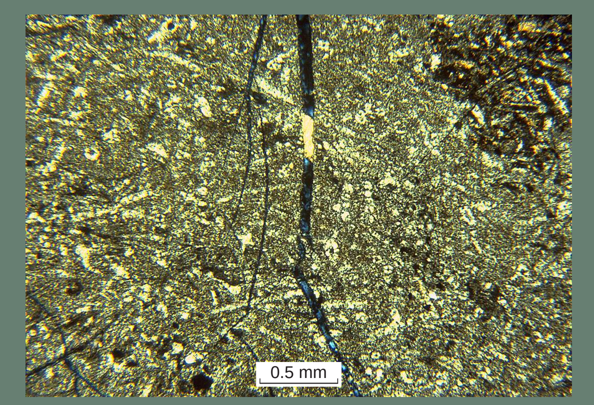


Proximal Thirtyone reservoirs are characterized by a basal chert reservoir section and an overlying carbonate section that is commonly much less productive.

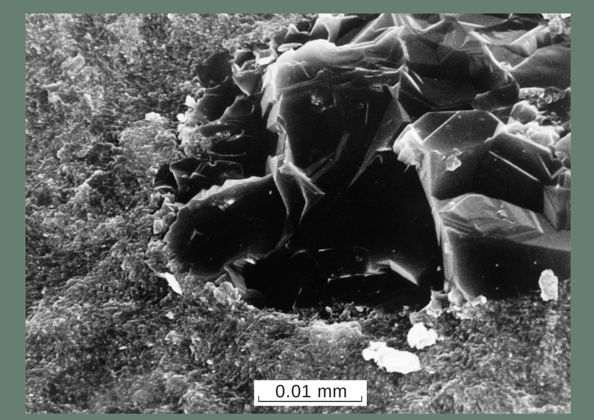
RESERVOIR CHARACTERISTICS AND VOLUMETRICS

Discovery date:	March 6, 1945
Average depth:	8,100 ft (2,470 m)
Area:	3,640 acres (1,470 hectares)
Well spacing:	40 acres (16 hectares)
Top seal:	Pennsylvanian/Permian "detrital"
Bottom seal:	Frame Formation (Silurian Wristen Group)
Trap:	Updip pinchout
Hydrocarbon source:	Woodford Formation
Producing unit:	Thirtyone Formation (Lower Devonian)
Lithology:	Chert
Oil-water contact:	-5,050 ft (1,540 m) subsea elevation
Average gross pay:	90 ft (27 m)
Average net pay:	70 ft (21 m)
Average porosity:	15%
Average permeability:	5 md
Water saturation:	0.37
Residual oil saturation (S_{or}):	0.14 (measured from mercury injection)
Oil gravity:	41.5°API @ 60°F
Original bottom-hole pressure:	3,200 psia
Temperature:	121°F (50°C)
Formation volume factor:	1.595 (at original bottom-hole pressure)
Oil viscosity:	2.38 centipoise (at original bottom-hole pressure)
Water salinity:	92,548 ppm NaCl
Water saturation (S_w):	0.37 (measured from mercury injection)
Original oil in place:	131.1 Mbbl
Cumulative production:	36.1 Mbbl (1989)
Recovery efficiency:	27%

Core slab of nonporous chert facies at Three Bar field. Fractures are more abundant in nonporous cherts and indicative of more brittle deformation.



Photomicrograph of nonporous chert showing spicules replaced by chalcedony or microquartz or filled with quartz.



SEM Photomicrograph of nonporous chert showing absence of microcrystalline pore space.

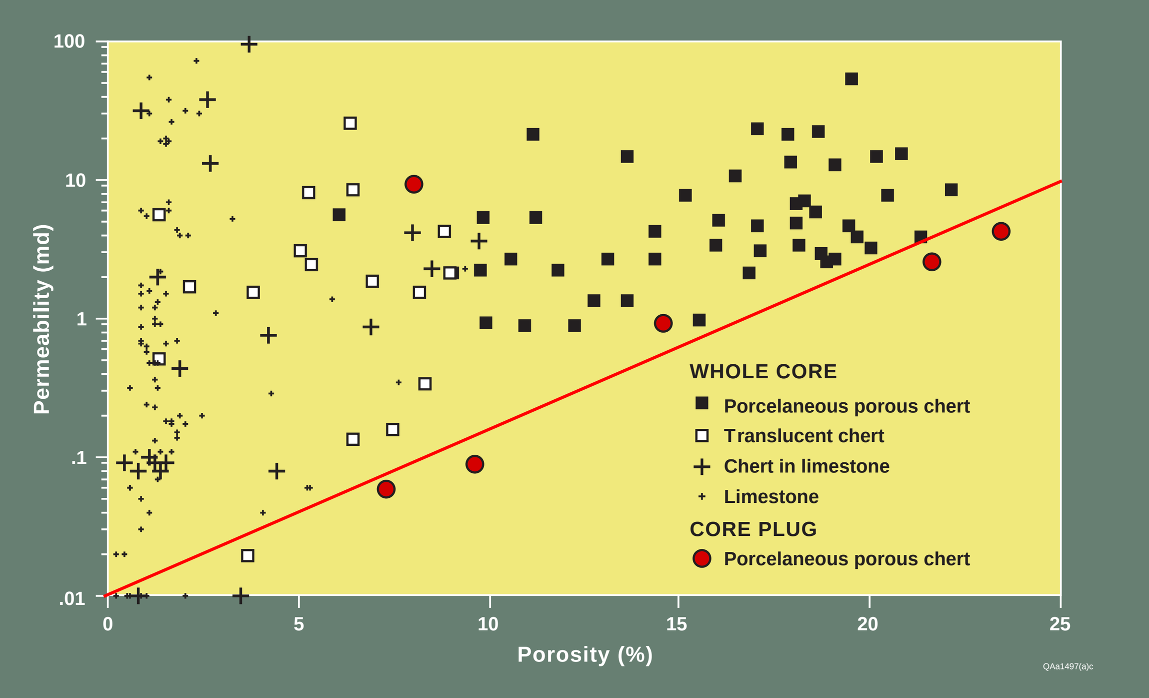
SUMMARY OF HETEROGENEITY IN PROXIMAL THIRTYONE RESERVOIRS

The Thirtyone chert section in proximal reservoirs is remarkably continuous, being traceable throughout more than 250 mi^2 display. Despite this continuity, there are significant causes of internal heterogeneity that affect fluid flow and recovery in these reservoirs. Primary causes of heterogeneity and incomplete drainage and sweep of remaining mobile oil at Three Bar are (1) faulting and fracturing, (2) carbonate dissolution, and (3) small-scale facies architecture. Faults and fractures appear to variably facilitate or inhibit fluid movement. In some parts of the field, zones of abundant faults and fractures are associated with areas of high productivity, whereas in other areas faults separate distinct reservoir compartments.

Leaching and dissolution of carbonate was caused by fluids that entered the top of the Thirtyone section and along the truncated and exposed updip margin of the field during the Pennsylvanian. Evidence of carbonate dissolution is apparent especially in areas with greater fault densities, suggesting that faults have acted as flow pathways for diagenetic fluids. In updip parts of the field, vertical communication has been enhanced and productivity increased by this diagenesis.

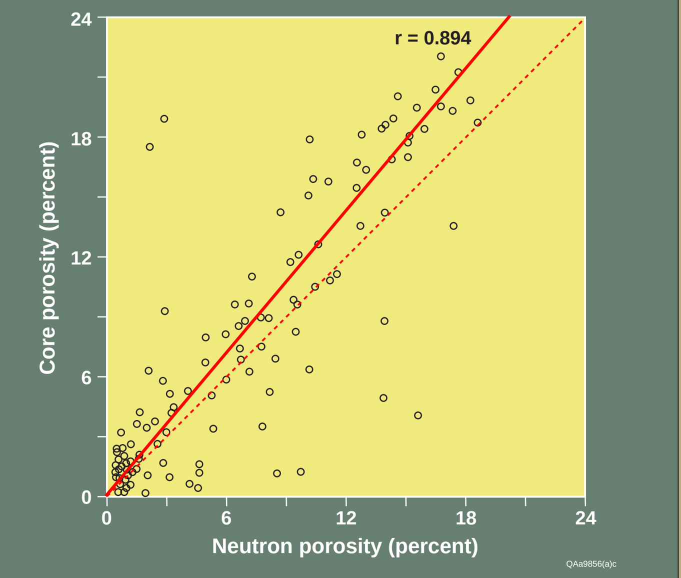
Complex chert/carbonate interbedding in chert section has created poor lateral and vertical communication between high-matrix-porosity chert beds within the reservoir section. These facies variations, which are the result of combined original depositional facies patterns and subsequent diagenesis, may contribute to significant mesoscale reservoir compartmentalization.

PETROPHYSICAL RELATIONSHIPS



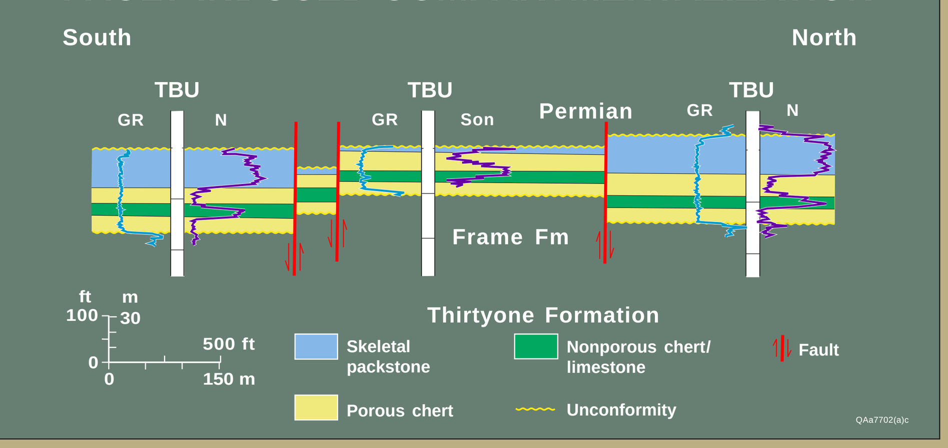
Core analysis permeability values commonly reflect the presence of fractures in the Thirtyone. Selected fracture-free samples (circles) define the matrix porosity/permeability transform.

COMPARISON OF LOG AND CORE POROSITY



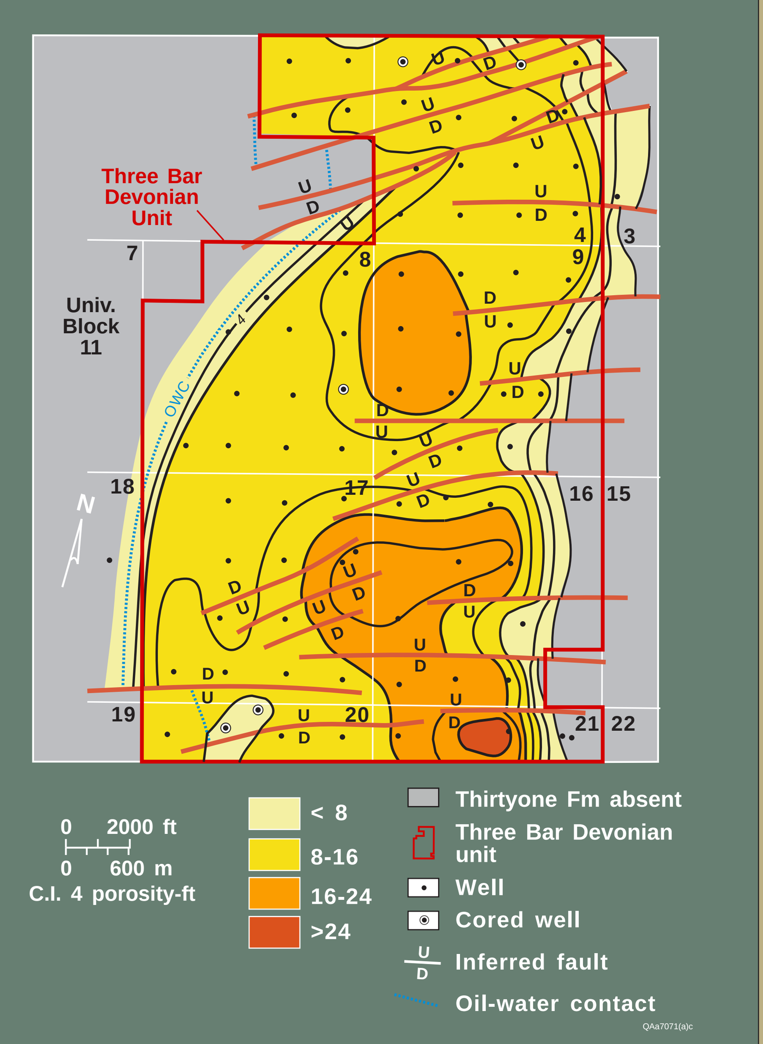
Although there is a good relationship between true matrix porosity and wireline log values, neutron logs typically underestimate porosity.

FAULT-INDUCED COMPARTMENTALIZATION



Apparent faults defined from structural mapping suggest the possibility of partial reservoir compartmentalization due to flow unit offset.

RESERVOIR PHI•H



Mapped phi*h values conform to net chert thickness maps. Primary production patterns closely match phi*h trends documenting the dominance of matrix permeability on recovery.

PRIMARY RECOVERY