The American Association of Petroleum Geologists Bulletin
V. 64, No. 6 (June 1980), P. 960-963

ASSOCIATION ROUND TABLE

**1980 AAPG-SEPM-EMD ANNUAL MEETING
DENVER, COLORADO
June 8-11, 1980**

Additional Abstracts

CONLEY, CURTIS D., Kansas Geol. Survey, Lawrence, KS

Petrology of Arbuckle Group, Central Kansas

The Arbuckle Group (Late Cambrian and Early Ordovician) in Kansas is mostly crystalline dolomite with abundant chert in the upper part. The Arbuckle is entirely in the subsurface, and there are only scattered cores, mostly from the upper part. Depositional constituents and textures have been reported only from the chert. Study of thin sections from three cores from the Central Kansas uplift reveals abundant evidence of depositional components, as well as diagenetic features of dolomitization and porosity. Despite virtually complete dolomitization, it is often possible to identify primary grain types, fabrics, and textures, and by comparison with better preserved examples, to interpret less well-preserved features.

Identifiable grain types include oolites, pellets, intraclasts (of micrite, pellets, and oolites), and skeletal grains, including gastropods, echinoderms, and bivalves. Crenulate, laminated dolomite, interpreted as stromatolites, recurs. Depositional textures range from mudstone to packstone.

The dolomite is microcrystalline to coarsely crystalline, with porosity ranging erratically from 1 to 22%. Pore types are: (1) intercrystal (most common), supplemented and interconnected by (2) solution-enlarged fractures, (3) moldic, from solution of depositional grains, (4) fenestral, and (5) primary interparticle. Partly dissolved dolomite crystals have collapsed, compacted, and probably contributed to fracturing. Small, closely spaced fractures may be open or plugged by crystals mobilized from surrounding dolomite, thereby isolating bodies of dolomite with high intercrystal porosity. Laminae of low-porosity dolomite, presumably controlled by depositional texture, contribute also to porosity variability. Most large pores are reduced by dolomite cement. Other scarce cements are anhydrite and sparry calcite, which fills oomolds and fractures.

FEIR, J. DOUGLAS, Alsands Project Group

The Alsands Project—A Challenge in Petroleum and Mining Geology

A third mining operation in the Athabasca oil sands area of northern Alberta is planned by the Alsands Project Group, a consortium of nine petroleum companies.

The group is considering the use of large draglines to excavate oil sands from an open pit mine. This project contemplates separation of the bitumen and sand by a hot water process, followed by upgrading to synthetic crude oil. Production will begin in 1986; when design capacity of 140,000 b/d (22,250 m^3/d) is reached, this project will supply over 10% of Canada's forecast crude producibility.

The bitumen occurs in a 300 ft (90 m) sequence of unconsolidated sands and clays of the Lower Cretaceous McMurray Formation, at or near the surface. A thin veneer of Recent and Pleistocene aeolian and glacial deposits overlie the McMurray. Devonian carbonates and evaporites occur below the Cretaceous. McMurray deposition took place in a mesotidal, coastal environment. The lowermost sands are fluvial, upper delta plain, overlain by tidal channel and tidal flat sands and muds of the lower delta plain. Some marine barrier bars and beaches have been identified. The highest bitumen saturations occur in the fluvial and tidal channel sands. However, the lowermost sands are frequently water saturated under artesian conditions. The rugged paleotopography of the Devonian erosional surface has significantly influenced the depositional pattern of the overlying McMurray. This relief is, in part, due to the solution of Middle Devonian salt beds, with subsequent collapse of the overlying units.

This complex sequence of depositional patterns, varying lithologies, and fluid contents, combined with salt tectonics, has created the need for detailed geological and geotechnical studies to interface with mining engineering in developing a viable mine plan.

LENNOX, T. R., and M. M. LERAND, Alberta, Canada

Geology of In Situ Pilot Project, Wabasca Oil Sands Deposit, Alberta

The Wabasca oil sands deposit in north-central Alberta contains 24 billion bbl of bitumen in the Grand Rapids Formation (Albian, Lower Cretaceous). The 6 to 8° API bitumen has a viscosity at reservoir temperature (65°F) of 2 million cp. and a sulphur content of 4.6 wt. %. Since 1974 Gulf Canada has been experimenting with in-situ fireflood, cyclic-steam stimulation, steam flood and solvent processes in the uppermost "A" Member of the formation.

A gentle southwestward-dipping homocline in this area is locally complicated by differential compaction of Lower Cretaceous sediments over paleotopographic relief on the Paleozoic erosion surface. In the pilot area, low amplitude (10 ft), northwest oriented folds may represent compactional features or wrinkles produced by the down-dip creep and buckling of the unconsolidated sand.

The Grand Rapids "A" reservoir is entirely sand, 45 to 50 ft thick, and divisible into three members on the basis of grain size and sedimentary structures. Grain size increases upwards from very fine at the base of the Lower Member to fine sand in the Middle Member. In the Upper Member, grain size decreases upwards from granuliferous, coarse sand at the erosional base to fine sand at the top.

Oil saturation varies from 0 to 14 wt. % (average 8.5 wt. %), and is zero within: (1) calcite cemented beds, (2) a basal water zone varying from 4.5 to 11.5 ft thick, and (3) a thin water zone at the top of the reservoir.

Log porosity of saturated sand ranges up to 36%; permeability reaches 25 md and several darcys after extraction. The reservoir contains seven thin (0.5 to 1.5 ft), tightly calcite cemented beds that form permeability barriers. Permeability is highly directional and correlative with grain fabric. Oil saturation is controlled by grain size, fines, sorting, roundness and authigenic clay.

Current pilot experiments have been inconclusive. Difficulties have occurred with injection into oil-saturated sand and confinement therein. Laboratory simulation experiments have resulted in marked chemical and physical reservoir changes.

NELSON, C. HANS, and AUDREY A. WRIGHT, U. S. Geol. Survey, Menlo Park, CA

Variation in Turbidite Sand Facies and Application to Petroleum Geology

Turbidite sand in canyon, slope base, fan valley, and depositional lobe deposits interbedded with hemipelagic mud provides an ideal environment for petroleum accumulation. The geometry of sand facies, composition of source mud, and petroleum potential vary with basin size and setting.

In the smallest restricted basins (i.e., carbonate platform troughs <10 km diameter) with multiple sources of extremely coarse-grained material, channelized turbidite facies do not develop. Thick, coarse-grained sediment gravity flows accumulate in slope valleys and base-of-slope settings associated with potentially organic-rich slope mud. At greater distances from the slope base, turbidite sand beds become fewer, thinner, and more widely dispersed in basin mud.

Restricted basin fans of intermediate size (i.e., California borderland basins <100 km) fed by canyons intercepting littoral drift cells have excellent petroleum reservoir potential. Low-matrix turbidite sand is channeled to mid-fan lobes and may be interbedded with organic-rich hemipelagic mud. Sandstone continuity extends laterally from inner fan channels to suprafan lobes and vertically within lobe sequences. Tectonic overprint in restricted basin settings commonly permits preservation of turbidite reservoir beds and enhances thermal maturation of organic-rich mud.

Turbidite sand of large, open basin fans fed from major river sources is: (1) finer grained and contains more matrix and (2) channeled to more distal depositional sites than those of restricted basin fans. The organic content of interbedded pelagic or hemipelagic mud is low because of oxidation and infaunal activity. Continuity is poor laterally between lower fan depositional lobes and upper to middle fan channel sand or vertically within mud-rich depositional lobe sand beds. Subduction of deep-sea floor fan complexes may destroy turbidite sand bodies as reservoir sites, just as it may tectonize linear turbidite sand bodies of trench fill and deep-sea channel systems. Similar sand bodies of submarine canyons however may have good petroleum potential where they are enclosed by organic-rich slope mud.

PARSON, ELMER S., GORDON W. HENDERSON, and LOUIS J. CONTI, Casper, WY

Red Wing Creek Field—Cosmic Impact Structure

Red Wing Creek field is located near the center of the Williston basin in McKenzie County, North Dakota. The discovery well was drilled by True Oil Co. in August 1972. The primary trapping mechanism is structural. Seismic and subsurface data indicate that Triassic, Permian, and Pennsylvanian formations are missing over the center of the structure. Replacing these are rocks of Mississippian age which have undergone intensive deformation in an uplifted structural cone approximately 3,000 ft (914 m) high and 3 mi (4.8 km) in diameter at its base. Formations above and below the structure show very little tectonic disturbance.

Mission Canyon Limestone of Mississippian age is the primary producing horizon. The discovery well has over 1,600 ft (438 m) of net pay which is the best well in the field. Porosities range as high as 25% but most of the reservoir has porosities in the range of 6 to 10%. Oil-water contact is placed at a subsea depth of 7,600 ft (2,316 m). Reservoir studies indicate approximately 100, 000,000 bbl of oil in place.

To date the field has 11 wells capable of production. There are eight dry holes. Two wells have been drilled to the Red River Formation of Ordovician age. At present there has been no commercial production above or below the Mississippian.

Present data have indicated that the field is producing from the central peak of an astrobleme, or meteorite impact structure of Jurassic age. Proof of this origin is based on geometry and shock deformation features, which include monolithologic breccia, shatter cones, and shock deformed quartz. The feature has been modified by subsequent salt collapse and differential compaction.

AAPG SEALS FOR HYDROCARBONS RESEARCH CONFERENCE, SEPTEMBER 14-17, 1980 KEYSTONE LODGE KEYSTONE, COLORADO

The Seals for Hydrocarbons Research Conference is being convened by T. T. SCHOWALTER and M. W. DOWNEY to focus attention on a fundamental, but relatively neglected area of petroleum geology. Recent advances in organic geochemistry and the study of migration have added to the understanding of the significance of hydrocarbon seals. The program is divided into discussions of the "micro" view (seal capacity, permeability, hydrodynamics, and prediction from core data), and the "mega" view (worldwide review of types, controls in faulted structures, trap leakage detected by acoustical devices, evaporites as seals, etc) and a general session on the direction of future research. Besides the two conveners, speakers will be R. R. BERG, Texas A&M; D. S. STONE, Independent; B. ROBERTS, Gulf R&D; H. GRUNAU, Petroconsultants; R. J.