Fossils were dolomitized at 250°C (482°F) in Ca/MgCl solutions for periods of time from 4.5 to 320 hours. Aragonitic corals, gastropods, and pelecypods formed stoichiometric, microcrystalline, xenotopic dolomite and low Mg-calcite (LMC). The dolomite was not pseudomorphic after the aragonite. The conversion of AR → LMC is more rapid than the AR → DOL in these experiments. For instance, gastropods run for 23 hours formed dolomite and LMC in a ratio of 1/10, at 170 hours the ratio was 1/4, and at 340 hours the ratio was 1/1.

HMC coralline algae, forams, and echinoderm fragments were dolomitized before and after conversion to LMC. The dolomite formed was cryptocrystalline and pseudomorphic after the forams and echinoderms regardless of the mineralogy. We attributed this to the cryptocrystalline nature of the substrate.

Oyster fragments composed of microcrystalline LMC formed non-stoichiometric, poorly ordered dolomite even after 320 hours. None of the other reactants were as resistant to dolomitization.

Our results indicate that grain size is more important than mineralogy in determining the fabric of dolomite replacement crystals. Both HMC and LMC can be pseudomorphically replaced. Pseudormophic replacement requires (1) abundant nucleation sites and (2) a regular crystallographic relationship between the calcite and dolomite. Argonite was not pseudomorphically replaced, probably because it was microcrystalline rather than cryptocrystalline. Also, most of the aragonite converted to LMC prior to dolomitization.

Selective replacement characteristics of many natural dolomites are readily explained as being an effect of the grain size of the material replaced. Freshwater diagenesis of a sediment prior to dolomitization may retard dolomitization if the grain size of the $CaCO_3$ is increased. However, conversion of LMC without appreciable increase in grain size may not retard dolomitization.

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Petroleum Exploration and Resource Potential of Offshore Newfoundland and Labrador

The continental margin of Newfoundland and Labrador, encompassing a total area of 714, 000 mi² (1,849,252 km²) has been the target of exploratory activity since the early 1960s.

Exploratory drilling began on the Grand Banks in 1966 and by 1974 a total of 40 dry wells had been drilled. This lack of success, accompanied by escalating drilling costs, resulted in the curtailment of exploratory activities. In 1979 wildcat drilling resumed on the Grand Banks and the Hibernia field was discovered with the drilling of the P-15 well. This well, with an estimated flow potential of more than 20,000 BOPD, was the first oil well drilled on the Atlantic shelf of North America capable of commercial production. Truly a "giant," the Hibernia structure has a resource potential of 1.85 billion bbl of oil and 2.0 tcf of gas at a probability level of 50%. Six significant oil discoveries have been made on the Grand Banks. Of these, the Hibernia, Nautilus, Hebron, and Ben Nevis discoveries are located in highly faulted hinge zones on the western and eastern flanks of the northward plunging Avalon basin graben. The South Tempest structure is located on a ridge complex to the east of the Avalon basin. The Adolphus well drilled a salt piercement structure in the basin depocenter. The reservoirs are fluvial-deltaic and shoreline sandstones of Jurassic and Cretaceous age.

Since 1971, 25 wells drilled on the Labrador Shelf resulted in one oil and five gas discoveries. The reservoirs are Paleozoic carbonates and Lower Cretaceous, Paleocene, and Eocene sandstones. All are capping or draping basement horst blocks.

By the end of 1982, total exploratory efforts had resulted in the drilling of 86 wells and the acquisition of approximately 240,000 line-mi of marine reflection seismic. Provincial land permits on the continental margin are held by ten permittees. This land position represents 54 million acres (22 million ha.) and 133 exploratory permits. A total resource potential of these structures has been estimated at 14.7 billion bbl of oil and 88.6 tcf of gas at a 50% probability level. A commercial discovery was long in coming but the recent high success rates confirm this margin as a major frontier of enormous potential.

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Regional Distribution of Hydrocarbon Fluid Inclusions in Carbonate Fracture Filling Cements: Geohistory Analysis and Timing of Oil Migration, Oman Foredeep

Fractured, reservoir limestones in Oman and the United Arab Emirates include the Shuaiba (lower Aptian) and Mauddud (upper Aptian-lower Cenomanian). Deposition of these bioturbated, argillaceous foraminiferal-peloidal wackestones and packstones ceased in the Early Cretaceous as the Oman foredeep subsided and filled with pelagic sediment. Petrography and geohistory analysis of four wells and one outcrop suite reveals five stages of diagenesis, fracturing, and fluid migration. (1) Shelf emergence: early cementation associated with regional unconformities overlying both limestones; (2) pre-orogenic shelf emergence, late Cenomanian to Turonian: fractures cutting Stage 1 cements are healed by very cloudy, cleaved, and twinned calcite containing microfractures with yellow-white fluorescent, hydrocarbon fluid inclusions; (3) initial foredeep downwarp of 0 to 800 m (0 to 2,624 ft), Coniacian to early Campanian: fractures crosscutting Stage 2 fractures are healed with cloudy, cleaved, and sometimes twinned calcite containing dull-blue fluorescent, hydrocarbon fluid inclusions; (4) rapid subsidence and filling with 600 to 3,400 m (1,970 to 11,155 ft) of flysch, exotic blocks, and thrust toes, Campanian to Maestrichtian: burial and tectonic stylolites crosscut Stage 2 and 3 fractures; and (5) uplift of the Oman Mountains after 3,900+ m (12,795+ ft) burial by early Tertiary: fractures crosscutting all diagenetic features are filled with clear untwinned and uncleaved calcite containing only nonfluorescent, aqueous fluid inclusions. If we can correlate earliest stylolite formation with a minimum burial load of ~800 m (~2,625 ft), then the hydrocarbon inclusions in Stage 2 fractures must predate all of Stage 4 and most of Stage 3. In the deepest portions of the foredeep, close to the Oman Mountain front, this limits the presence of oil in fracture porosity to late Turonian-early Campanian time. Farther to the west, in the shallower parts of the foredeep, this constraint relaxes, and oil migration occurred as late as early Tertiary.

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Illite/Smectite Diagenesis and Hydrocarbon Generation in Cretaceous Mowry and Skull Creek Shales of Northern Rocky Mountains-Great Plains Region

The Lower Cretaceous Mowry and Skull Creek Shales and their equivalents are among the major source rocks in the northern Rocky Mountains-Great Plains region. They are the major