Modification of Reservoir Porosity by Hydrothermal Fluids: Recognition and Setting

Robert H. Goldstein and students

STATUS: Long-term project in progress
TIMING: Significant results to be reported – Results currently available to membership
FUNDING: Partial

Purpose
It is now well known that warm fluids injected into cooler rocks have an effect on thermal maturation and porosity distribution. In some cases, such hydrothermal systems enhance porosity and in others they reduce it. The goal of this long-term project is to develop techniques for recognition of hydrothermal systems, and evaluate how geologic setting controls porosity modification to begin to form predictive conceptual models useful in the oil and gas industry.

Project Description
Carbonate specialists are just now identifying the hallmarks of hydrothermal processes (e.g., Smith and Davies, 2006) and recognizing that many pore systems thought to have formed by meteoric waters were likely to have formed from hydrothermal fluids (Esteban and Taberner, 2007). Some of the largest oil (e.g., Ghawar) and gas (e.g., North) fields have been affected by hydrothermal alteration. Hydrothermal processes in reservoirs are known to lead to moldic porosity (e.g., Newell et al., 2003), cavernous pores (Carlson, 1995), vugs (Hiemstra and Goldstein, 2005) and solution enlargement of fractures. Ultimately, the explanation for hydrothermal porosity enhancement may simply be the cooling of hydrothermal fluids, which leads to undersaturation with respect to carbonate minerals (Rossi et al., 2002), but mixing and other processes are possible (Mazzullo and Harris, 1991; Salas et al., 2007).

To understand many hydrothermally enhanced reservoirs, it appears necessary to understand early as well as late paragenesis. For example, using data from the Indian Basin Field, New Mexico, Hiemstra and Goldstein (2005) showed that the distribution of hydrothermal dolomite and secondary porosity were controlled by depositional setting, preferentially forming where facies were deposited deep enough to escape early meteoric diagenesis, as well as proximity to fault and fracture systems in the presence of a fluid drive (Figure 1). This complex group of controls led to the best reservoirs forming only in downdip positions, and would not have been predictable without understanding the earlier paragenesis.

This project will systematically study reservoir carbonates and use fluid inclusion and other geothermometers to develop methodologies for the identification of ancient hydrothermal systems. Models for fluid flow will be developed for implementation of predictive models based on geologic setting.

Deliverables
Hydrothermal alteration is clearly important in the localization of sandstone and carbonate oil and gas reservoirs as well as MVT ore deposits (e.g. Leach and Sangster, 1993; Wojcik

Kansas Interdisciplinary Carbonates Consortium Proposal – June 2013
et al., 1997; Rossi et al., 2002; Cantrell et al., 2004; Smith and Davies, 2006; Davies and Smith, 2006). Fluid inclusions and other geothermometers are essential in recognizing ancient hydrothermal fluid flow. Geothermometers, such as fluid inclusions, are useful in identifying when and where the normal burial system has been perturbed by hydrothermal fluid flow and flow of cool waters into warmer rocks.

New results show that hydrothermal systems typically require a mechanism to move fluids upward from deeper parts of the basin, a setting in which warmer fluids exist and are capable of being transmitted into cooler rocks, and conduits such as fractures or permeable horizons that provide a focus for rapid fluid flow.

There has been much discussion of the criteria necessary to identify ancient hydrothermal heating (e.g., Machel and Lonnee, 2002; Esteban and Taberner, 2003; Davies and Smith, 2006). It has been suggested that measured paleotemperature higher than predicted from burial history modeling is an appropriate indication. On the other hand, it must be pointed out that the many assumptions of such modeling and the nature of the thermal maturity data typically available (i.e., vitrinite reflectance, pyrolysis data from Rockeaval) normally make it impossible to unequivocally distinguish between a hydrothermal system, higher heat flow than modeled, or deeper burial than interpreted.

New models, developed in this research, for identification of hydrothermal systems include evidence for: (1) fluctuating paleotemperature; (2) geothermometers higher than possible from burial history models; (3) gradients and pressure data inconsistent with normal thermal regime; (4) variation in paleotemperature at same depth; and (5) higher paleotemperatures in conduits (Figure 2).

Detailed case histories of hydrothermal alteration will be used to constrain geologic models of localization of porosity enhancement and reduction.

References


Figure 1. Core images from the Indian Basin field, studied by Erik Hiemstra. Hydrothermal processes have both enhanced and reduced porosity.

Figure 2. A. Carbon and Oxygen stable isotope data from Indian Basin field of New Mexico. Data come from dolomite cement, correlated with cement stratigraphy and shown to be approximately time equivalent throughout the area. Circled data are from fault zones and other data come from the same dolomite phase away from fault zones. The more negative oxygen isotopic data indicate that the dolomite from the fault zones formed from warmer fluids than the dolomite outside of the fault zones. This character confirms a hydrothermal origin in which the fault zones were preferred conduits for fluid flow (Hiemstra and Goldstein, 2005) B. Stratigraphic variation in vitrinite reflectance values from Pennsylvanian strata of southeastern Kansas. Locally, anomalously high vitrinite values are located in close stratigraphic proximity to the sub-Pennsylvanian unconformity. The diagram shows schematically that the sub-Pennsylvanian unconformity is a regional paleokarst, and that it acts as a regional stratigraphic conduit for hydrothermal fluid flow. The Pennsylvanian section, however, acts as a leaky confining unit. This pattern confirms hydrothermal fluid flow for the system. Data from Barker et al. (1992). Modified from Walton et al. (1995).