The November edition of the Crisman Institute Newsletter contains summaries on two new programs and updates on-going work

1. Environmentally Friendly Drilling Systems
2. Viscosities of Natural Gases at HPHT
3. Mixing Rules in Cyclic Steam Simulation of Extra-Heavy Oil
4. Novel Method to Enhance Oil Production During Cyclic Steam Injection

David Burnett introduces his new program Environmentally Friendly Drilling Systems program and discusses the joint venture created to test new technology in field applications.

Bill McCain and Catalin Theodoriu give updated information on the experimental testing equipment to measure the viscosity of natural gases at high temperatures and high pressures.

Maria Barrufet and her student Alonso Mago have written a SPE paper on the importance of choosing the correct mixing rules for components when simulating extra heavy oil recovery by huff and puff operations.

Daulat Mamora presents a new type of thermal oil recovery stimulation through the uses of top injection – bottom production of cyclic steam injection.

Also included is a summary for the “Fracture Fluid Damage and Cleanup” meeting held September 6, 2006.

Reminder: Upcoming semi-annual Crisman Institute meetings are scheduled for November 7, 8, and 9th in College Station. Agendas are posted at the Department of Petroleum Engineering’s main web page under the topic header of News and Upcoming Events.
Environmentally Friendly Drilling Systems (EFD)

In 2003 Anadarko Petroleum Corporation installed and operated a reusable, modular platform to search for gas hydrate deposits on Alaska’s North Slope. The platform drilling concept was chosen to decrease the footprint and environmental effect of drilling operations in an ecologically sensitive area. That drilling project was a success. Figure 1 is a photograph of the platform deployed on the North Slope. Since then Anadarko has donated four modules from the platform to A&M to use in additional testing and demonstrations. The EFD Project is incorporating the platform into a system to achieve a minimal footprint and eliminate impact on the surrounding ecosystem (See Fig.1 on pg. 3). Faculty from Civil Engineering are adapting the platform drilling technology initially to desert ecosystems then later to wetlands environments.

Almost 6,000 acres of land are available to test the new systems in West Texas near Pecos, Texas. The new facility, once a test track for Firestone Tire Company is operated by the Texas Transportation Institute (TTI) with the assistance from the Joint Venture. TTI will be part of the Joint Venture and will be working with EFD to test low impact access to well sites.

Two of the modules are en route to Pecos. They will be stored temporarily in Monahans Texas at the Halliburton Baroid Drilling Services yard.

In addition to desert ecosystems, A&M plans EFD operations in the coastal margin of the Gulf Coast. A potential site for EFD in a coastal margin is on the Rio Vista Bluff Ranch in Goliad County. Ranch Manager David Moore is working with the scientists managing the venture and if a prototype of an environmentally friendly drilling system can be developed, it will be tested in the flood plain along the San Antonio River at its mouth. Ranch owner Jan Wheelis is excited about the potential for the project but has made it clear to A&M’s scientists and engineers that they will be watched closely as the project develops.

Why Now?
The U.S. economy runs on fossil energy. The biggest “target” for additional production is thought to be existing fields and properties. As oil and gas become harder to find, these resources become more valuable. At the same time, it is becoming more expensive to drill for and produce oil and gas and one of the major expenses is the cost to protect the environment and perform remediation in the impacted area.

This project is also a GPR project and receives substantial funding from the U.S. DOE NETL.
EFD Systems--Continued
Pad-Free Platform Drilling

Figure 1 - Anadarko’s platform deployed on the North Slope (Kadaster and Milheim). Field application of the new platform clearly demonstrated the ability to dramatically decrease the footprint and environmental effects of drilling operations in ecologically sensitive areas. This project also showed that a system could be installed “road less” without any adverse impact on the tundra, and that a zero-discharge facility could be operated safely.
Viscosities of Natural Gases at High Pressures and High Temperatures (HPHT)

**Approach**

The VISCOpvt has been successfully calibrated for use with gases. Both nitrogen and methane were used for calibration check. Very good accuracy has been achieved in terms of measured viscosity against published results from National Institute for Science and Technology (NIST) for the calibration temperature. Temperature calibration needs to be performed for the near future, since the machine has no temperature compensation unit.

Shown below is the viscosity versus pressure for Methane from one of our tests. The graph shows the measured viscosity at 116 °F and various pressures against the reference viscosities at these conditions.

We are working through problems we have encountered with VISCOpvt viscometer. First, the viscometer loses resolution at around 0.02 cP. Hence no verifiable measurements can be made below 0.02 cP. Second, the instrument requires that the starting viscosity be known beforehand, i.e. the viscosity at around 4000 psi. This problem can however be solved by using the secondary viscometer available in the laboratory, the RUSKA rolling ball viscometer.
The RUSKA rolling ball viscometer is an intermediate pressure viscometer. It has been found that it works very well for gases, especially at its higher range (8000-10000 psi). Thus the viscosity measured from the rolling ball viscometer can be used as the starting point for measurements on the VISCOpvt.

Future Work
1. A new calibration plan will be started to better understand the temperature dependence of the VISCOpvt measurements.

2. The RUSKA viscometer will be recalibrated for low viscosity measurements.

3. We are now making progress and expect to generate data in the coming months and 2007 that can be used to improve PVT correlations of natural gas at HPHT conditions.
Improved Accuracy Mixing Rules for Cyclic Steam Simulation of Heavy Oil Recovery Processes

Heavy oil is a major source of energy in this century with a worldwide base reserve exceeding 2.5 trillion barrels. Management decisions and production strategies from thermal oil recovery processes are frequently based on reservoir simulation. A proper description of the physical properties, particularly oil viscosity, is essential in performing reliable modeling studies of fluid flow in the reservoir.

This work demonstrates the importance of more appropriate simulations and mixing rules for fluids. Results should alert reservoir engineers to the significance of using different options that companies built in their platforms to describe the viscosity of heavy oils. Log linear and power mixing rules do not provide enough flexibility to describe the viscosity of extra heavy oil with temperature.

Our modeling studies simulated cyclic steam injections on the highly viscous Hamaca oil, with a viscosity of over 10,000 cp at ambient temperature. The production was drastically impacted by up to an order of magnitude when using improper mixing rules to describe the oil viscosity. A recently implemented mixing rule in a commercial simulator has been studied providing satisfactory results. However, the methodology requires substantial interventions, and cannot be automatically updated. We provide guidelines to improve it and suggest more flexible mixing rules that could easily be implemented in commercial simulators.

We also provide a methodology to determine the adequate time for each one of the periods in cyclic steam injection: injection, soaking and production. There is a lot of speculation in this matter and one of the objectives of this study is to better understand and provide guidelines to optimize oil production using proper lengths in each one of these periods. We have found that the production and injection periods should be similar in time length. Nevertheless, the production period should not be less than the injection period. On the other hand, the soaking period should be as short as possible because it is unproductive time in terms of field oil production for the well and therefore it translates into a negative cash flow for a company.
Cell Description in Reservoir

Description of the Hamaca oil viscosity versus temperature simulated with PVTSim
We have developed a novel method to enhance oil production during cyclic steam injection. In the Top-Injection and Bottom-Production (TINBOP) method, the well contains two strings: the short string (SS) is completed in the top quarter of the reservoir, while the long string (LS) is completed in the bottom quarter of the reservoir (Figure 1). The method requires an initial warm-up stage where steam is injected into both strings for 21 days; then the LS is opened to production while the SS continues to inject steam for 14 days. After the initial warm-up, the following schedule is repeated: the LS closed and steam is injected in the SS for 21 days; then steam injection is stopped and the LS is opened to production for 180 days. There is no soak period.

We have simulated and compared the performance of the TINBOP method against that of a conventional cyclic steam injector (perforated across the whole reservoir). Three reservoir types were simulated using 2-D 20x1x20 radial, 10-acre black oil models run on CMG: SPE fourth comparative solution project (14°API), Hamaca (9°API), and San Ardo (12°API).

Simulation results (See Figure 2 on pg. 8 and Figures 3-4 on pg. 9) indicate oil recovery after 10 years are 5.7-27% OIIP with TINBOP, i.e. 57-93% higher than conventional cyclic steam injection (3.3-14% OIIP). Steam-oil ratios are also decreased with TINBOP (0.8-3.1) compared to conventional (1.2-5.3), resulting from the improved reservoir heating efficiency.

![Figure 1 - Schematic diagram of TINBOP.](image1)

![Figure 2 - Cyclic steam injection: conventional versus TINBOP (SPE case).](image2)

**Project Information**

**Crisman Project**: 1.3.11

**Project Title (modified)**: Top-Injection and Bottom-Production (TINBOP) Cyclic Steam Injection Method Enhances Oil Recovery.

**Related Publications**


**Contacts**

Daulat Mamora  
979.845.2962  
daulat.mamora@pe.tamu.edu

Eric Matus
Figure 3 – Cyclic steam injection: conventional versus TINBOP (Hamaca).

Figure 4 – Cyclic steam injection: conventional versus TINBOP (San Ardo).
Fracture Fluid Damage Meeting Summary
September 6, 2006

A Crisman Institute meeting on Fracture Fluid Damage was held in College Station on September 6. Attending were Drs. Hill, Holditch, and Zhu from Texas A&M Petroleum Engineering Department and 8 industry representatives from 6 different Crisman sponsors. The purpose of the meeting was to review with the industry representatives our plans for the DOE-sponsored project “Advanced Hydraulic Fracturing Technology for Unconventional Tight Gas Reservoirs,” and to receive their feedback on these plans.

Drs. Hill and Zhu first presented an overview of the DOE project. This project began in April 2006, and in the first year has two major parts – an assessment of current field practices in the U. S. for hydraulically fracturing tight gas wells, and the development of an experimental apparatus and methodology to conduct fracture fluid damage studies in a way that is representative of actual fracturing conditions.

Dr. Holditch reviewed the work that has been done to date to statistically assess the current tight gas hydraulic fracturing practices. Dr. Holditch’s students have collected hundreds of papers from the SPE literature and other sources, and are inputting data about the fracturing treatments described in these papers into a searchable database.

Dr. Hill then reviewed the planned dynamic fracture conductivity experiments. These tests will consist of the following steps:

1. Injection of frac fluid carrying proppant into a modified fracture conductivity cell at an injection rate and temperature representative of actual field conditions.
2. Simulated fracture closure by applying a load from a load frame on the conductivity cell, while leakoff is occurring through the rock samples.
3. Simulated fracture cleanup by flowing gas (nitrogen) through the fracture and through the rock samples.

There was extensive discussion of these difficult experiments, with a number of helpful suggestions offered by the industry representatives. Based on this feedback, we are modifying some of the planned apparatus to address concerns about slurry mixing and transport to the cell. Also, the discussion of the planned experiments resulted in new approaches to simulating the gel cleanup than we had not envisioned before this meeting. This phase of the meeting concluded with a tour of the existing acid fracture conductivity laboratories.

The final topic of the meeting was modeling fracture fluid cleanup. Professor Holditch described our plans for modifying an existing three-phase reservoir simulator to model fracture fluid cleanup. Instead of oil-water-gas flow, the simulator will model gas, water, and frac fluid gel as the 3 phases. The fracture fluid will be modeled as behaving as a Bingham-type fluid with a yield stress. Again, the industry representatives offered a number of suggestions to guide this work, particularly concerning previous work on relative permeability relationships for such modeling.