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PROJECT TITLE: Economic Implementation and Optimization of Secondary Oil Recovery Process: St. Mary West Field, Lafayette County, Arkansas

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ABSTRACT

The St Mary West Barker Sand Unit (SMWBSU or Unit) located in Lafayette County, Arkansas was unitized for secondary recovery operations in 2002 followed by installation of a pilot injection system in the fall of 2003 with initial water injection October 13, 2003. A second downdip water injection well was added to the pilot project and 250,000 barrels of saltwater has been injected into the reservoir sand. Daily injection rates have been improved over initial volumes by hydraulic fracture stimulation of the reservoir sand in the injection wells. The reservoir and wellbore injection performance data obtained during the pilot project will be important to the secondary recovery optimization study for which the DOE grant was awarded. The reservoir characterization portion of the modeling and simulation study is in progress by Strand Energy project staff under the guidance of University of Texas at Dallas Department of Geosciences professor Dr. Janok Bhattacharya and University of Texas at Austin Department of Petroleum and Geosystems Engineering professor Dr. Larry W. Lake. A geologic and petrophysical model of the reservoir is being constructed from geophysical data acquired from core, well log and production performance histories. Possible use of an outcrop analog to aid in three dimensional, geostatistical distribution of the flow unit model developed from the wellbore data will be investigated. The reservoir model will be used for full-field history matching and subsequent fluid flow simulation based on various injection schemes including patterned water flooding, addition of alkaline-surfactant-polymer (ASP) to the injected water, and high pressure air injection (HPAI) for in-situ low temperature oxidization (LTO) will be studied for optimization of the secondary recovery process.

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LIST OF GRAPHICAL MATERIALS & ATTACHMENTS

None, this report

EXECUTIVE SUMMARY

Project Scope

The purpose of this study is to investigate the economic impact of several secondary or enhanced oil recovery processes that are available to a small mature oil field located in southwest Arkansas. The secondary reservoir drive processes that can add oil reserves with acceptable levels of risked rate-of-return on investment criteria for a small independent operator are sought.

The secondary recovery optimization study and the implementation of the secondary recovery process in the field are being conducted in two phases. The DOE grant is funding the majority of the direct costs for the optimization study. The first phase of the study is to estimate possible oil recovery for each of the secondary processes that are reasonably available for the field location, reservoir rock and fluid parameters. This consists of a two part process of first creating a geologic model of the subsurface reservoir sand through reservoir characterization methods and then incorporating the petrophysical description of the reservoir created in the geologic model with reservoir formation fluid data in a computer based reservoir simulation model. The static reservoir model for estimating hydrocarbons-initially-in-place is then transitioned to a dynamic model for describing the expected movements of reservoir fluids by history matching past production and pressure performance data.

The reservoir model is constructed from existing subsurface data such as petrophysical measurements provided by reservoir cores, open hole well logs, well tests, produced fluid analyses and geologic mapping of reservoir units defined by rock type analyses of the reservoir data. The reservoir modeling process can be enhanced by dynamic rock-fluid interaction data acquired from core-flood tests conducted in the laboratory for the various secondary recovery processes under consideration and from reservoir, pilot fluid injection projects in the field.

The simulation or dynamic model is then used to estimate reserve volumes and reserve production projections for the various secondary recovery processes being considered for the SMWBSU which are: water injection, ASP assisted water-flooding, and HPAI with the accompanying LTO process in-situ to the reservoir sand. The second phase of the optimization study is to evaluate the economic merits of the various secondary oil reserve estimates. To do this an economic model of the reserve development and recovery process is built by coupling the reserve production forecast with the estimated costs to implement and operate each of the various enhanced flood methods being studied. The result of the optimization study is to identify the most economically efficient or cost effective secondary recovery reserve development and production process or processes for the SMWBSU.

EXPERIMENTAL

Reservoir core-flood tests for quantification of pore throat geometry complexity by capillary pressure measurement, oil-water relative permeability description, and estimation of displacement efficiency for the HPAI enhanced oil recovery process are expected to be completed in summer 2005 and will be reported on in the 2006 Technical Progress Report. The pilot injection project is in progress and is reported upon in the following section.

RESULTS AND DISCUSSION

Strand Energy geology and engineering staff with experience in the study and exploitation of petroleum reservoirs are developing the geologic modeling step of the reservoir characterization phase of the secondary recovery optimization study in-house under the guidance of Dr. Janok Bhattacharya of the Geoscience Department of the University of Texas at Dallas (UTD).

Implementation of the optimum secondary recovery project in the field is also a two step process. Strand Energy completed the first phase with the installation of a pilot water injection system in the SMWBSU in the fall of 2003. First injection was on October 13, 2003. Construction of the pilot injection system consisted of converting a shallow saltwater disposal well to a water supply well, installation of a water filter, header and meter surface facility, laying water flow lines, and converting one former production well to an injection well. A second injection well was recently added to the pilot water injection project and the reservoir sand in both injection wells was hydraulic fracture stimulated to increase injectivity. All wellbore work expenditures, equipment fabrication and acquisition costs, and facility construction and installation costs were provided by Strand Energy and its project Partners.

Cumulative water injected exceeded 250,000 barrels in June 2005 and daily water injection into the initial pilot injection well, the SMWBSU #701, averaged 550 BWPD during the first six months of waterflood operations. SMWBSU #701 injectivity steadily decreased to less than 200 BWPD at the first of this year. The well was hydraulic fracture treated and sand proppant was pumped into the artificially induced reservoir fracture in March 2005. Water injection increased to an average of 780 BWPD for the following month and is currently averaging 500 BWPD.

The original estimate of injection rate for the SMWBSU #701 well, which has the thickest reservoir sand penetration at 24 ft of all wells in the field, was 2,000 BWPD and unfortunately this daily rate was never observed. In order to increase water injection rates into the reservoir sand in the area of the pilot flood, a shut-in well located 750 ft from the initial injector and slightly structurally lower to the SMBSU #701, was converted to water injection in May 2005. The SMWBSU #801 was hydraulic fracture stimulated before starting water injection. Initial injectivity of the SMWBSU #801 is also less than predicted averaging only 170 BWPD for the first month of operations.

A production performance study completed in early 2004 by Strand Energy engineering staff revealed that all oil producers in the St Mary West field had periodically experienced abnormal decreases in fluid deliverability from the reservoir. It was noted that to return production rates to the normal decline curve small "formation break-down" stimulation treatments of the sandface in the wellbores was necessary. Small volumes of acid would be pumped into the reservoir sand at pressures exceeding the hydraulic fracture gradient of the rock and oil production would then recover to expected daily rates. Only one well in the field was hydraulic fracture stimulated with sand proppant pumped into the induced fracture, during the previous 20 years of field production. Strand Energy pumped a sand proppant fracture stimulation treatment into a shut-in producer, the SMWBSU #201, in January 2005. The well was returned to production and is currently averaging 18 BOPD versus 5 BOPD the well use to produce prior to being shut-in due to mechanical problems several years past. The two continuously active producers, the SMWBSU #301 and SMWBSU #601, are scheduled to be fracture stimulated in July 2005. If increased oil production rates are achieved in all three active producers net revenue cash flow for the SMWBSU will be greatly improved and this will accelerate expansion of the enhanced oil recovery, flood project.

Strand Energy is planning to acquire capillary pressure measurements and HPAI core-flood tests this summer. These data are important ingredients for the rock type identification step of the reservoir characterization study and for fluid behavior prediction in the simulation study of the HPAI flood process. These tests will be performed by third party laboratories using existing reservoir sand cores and the results will be discussed in the 2006 Technical Progress Report.

CONCLUSION

The design and installation of a pilot injection system was completed in the SMWBSU in October 2003.
The water injection system consisting of the water supply well, the filtering vessels and the injection header distribution and metering equipment are performing as designed and monthly operating expense savings are being realized by fueling the WSW pumping unit engine with casing head gas from the active oil wells. Corrosion of water handling equipment is being inhibited by the construction materials used and chemical inhibitors injected at the WSW.

The SMWBSU #701 and #801 injection wells are currently taking 700 BWPD and a cumulative injection volume of 250,000 barrels of water has been exceeded. The two injection wells have been fracture stimulated to increase daily injectivity. Strand Energy engineering staff are currently evaluating possible conversion to injection of additional idle wellbores in a down-dip structural position in the reservoir to increase water injection rates.

Bottom-hole pressure data gathered from four wellbores during the last round of field work measured pressures that were 1,000 psig higher than originally expected for the mature reservoir. The prospect of significant pressure drive remaining in the reservoir prompted Strand Energy to experiment with a sand propped hydraulic fracture stimulation an idle production well. A four fold increase in daily production rate for this well was the result of this reservoir treatment and additional fracture treatments of the other producers are scheduled. Current total daily oil production for the SMWBSU is 32 BOPD.

Several reservoir rock type data sets such as capillary pressure curves for pore throat geometry quantification, relative permeability curves for fractional flow prediction of reservoir fluids and HPAI core-flood tests for measurement of LTO process recovery efficiencies will be acquired by third party laboratories this summer. These data sets are important components of the final reservoir simulation model being constructed for the secondary recovery processes optimization evaluation.

The geologic model of the reservoir characterization portion of the secondary recovery optimization study for which the DOE grant was awarded, is expected to be completed by year end, following which the full-field reservoir simulation model will be constructed.