UNCONSOLIDATED CONVENTIONAL CORE CASE HISTORY - GULF COAST SANDSTONE RESERVOIR

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ABSTRACT

A conventional core was taken in the subject unconsolidated Gulf Coast sandstone reservoir with the main objective being the collection of sufficient data to build a site-specific reservoir simulation model, with an emphasis on the determination of relative permeability relationships. The enclosed information includes a case study of the coring program, a discussion of the testing program design, results of the routine and special core analyses, and a commentary of the usefulness of the obtained information.

One hundred and twenty feet of whole core were cut from the subject unconsolidated Gulf Coast sandstone reservoir. Due to the expected unconsolidated nature of the core, each 30 foot section was immediately placed in freeze boxes at dry ice temperatures for 12 hours. The frozen core was chopped into 3 foot sections using a specially designed pneumatic chop saw, crated, and placed under dry ice in insulated metal shipping boxes. The core was shipped to the laboratory, core gamma was measured, and CT scanning performed for slabbing orientation and evaluation of potential shipping damage. Slabbing, plugging, core photography, and routine core analyses were performed to provide detailed information about the reservoir and facilitate sample selection for special core analyses testing.

Based on the routine core analyses data, representative samples were selected for permeability and porosity versus overburden, wettability, steady-state gas-oil and water-oil relative permeability, electrical properties and porous plate capillary pressure, acoustic velocity, and pore volume compressibility testing. The results of the testing program were used for reservoir description purposes in a simulation model. Use of the measured cementation exponent reduced the log calculated initial water saturation from 7-10 percent, and yielded log values comparable to the observed capillary pressure values.

As the observed wettability was slightly oil-wet, preserved-state samples were used for relative permeability testing. The steady-state water-oil relative permeability curves were very similar for all samples tested. The steady-state gas-oil testing, however, yielded extremely high residual oil saturations due to the low core flood rates utilized and corresponding significant end effects. Centrifuge and unsteady-state gas-oil relative permeability tests were performed for comparison. While the gas curves were very similar for all methods, significant variability was noted in the oil curves between the various methods. As the unsteady-state oil curves were very similar for all samples, and there was substantial variability in the steady-state ones, the unsteady state data was determined to be more reliable and were thus used in the model.

CORING PROGRAM OBJECTIVES

A conventional core was taken in the subject unconsolidated Gulf Coast sandstone reservoir with the main objective being the collection of sufficient data to build a site-specific reservoir simulation model, with an emphasis on the determination of relative permeability relationships. A special core analyses program was designed to acquire the specific data desired for input in the reservoir model including permeability to air versus porosity, vertical to horizontal permeability to air, and gas-oil and water-oil relative permeability characteristics. Additional testing was planned to improve log calibration, including grain density, pore volume compressibility, electrical properties, and acoustic velocity determinations.

Wellsite Core Handling

One hundred and twenty feet of whole core were cut from the subject unconsolidated Gulf Coast sandstone reservoir. Due to the expected unconsolidated nature of the core, each 30 foot section was immediately placed in freeze boxes at dry ice temperatures for 12 hours. The frozen core was chopped into

3 foot sections using a specially designed pneumatic chop saw, capped, crated, and placed under dry ice in insulated metal shipping boxes.

The core was shipped to the laboratory, core gamma was measured, and CT scanning performed for slabbing orientation and evaluation of potential shipping damage. The CT scans indicated that the core was undamaged during handling and that significant cross bedding was evident. Based on the CT scan information, the core was slabbed ¼ - ¾ using a band saw to expose the maximum dip. The slabs were cleaned and half scale white light and UV core photographs were taken for core description and documentation. In general, the core was observed to be an extremely uniform, clean sandstone throughout the entire interval.

Figure 1

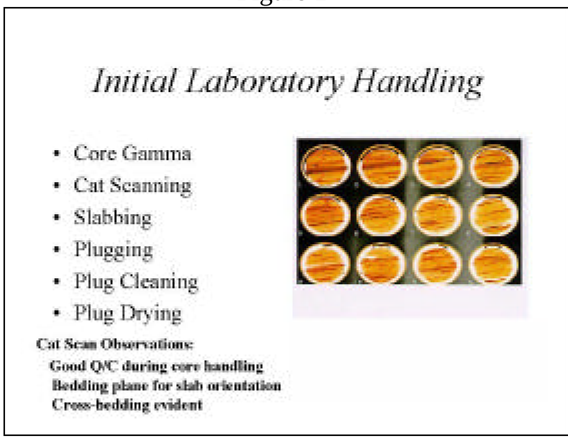
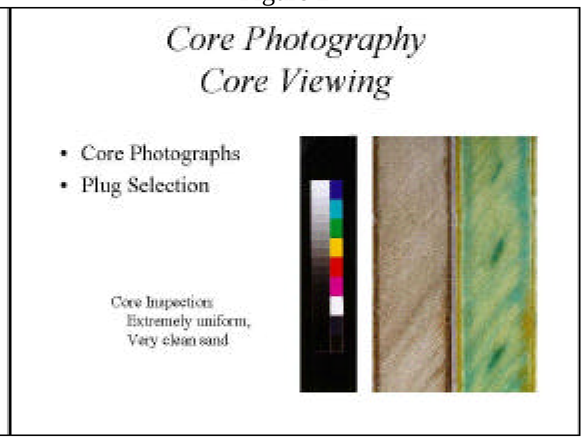


Figure 2



Routine Plug Preparation

After the slabbing was complete, 93 one inch diameter horizontally oriented plugs were drilled at approximately one foot spacing throughout the cored interval using liquid nitrogen as the bit lubricant and coolant. The frozen plugs were trimmed to right cylinders using a trim saw with liquid nitrogen as the coolant. The trimmed samples were mounted in nickel foil with 60 and 320 mesh screens on each end.

The plugs were seated in the metal sleeves, then extracted of hydrocarbons and leached of salts with chloroform/methanol azeotrope and dried to a constant weight in a humidity controlled oven at 140°F and 45% relative humidity. Grain volume was measured on all samples, and grain density calculated.

ROUTINE CORE ANALYSES PROGRAM

Permeability and Porosity Versus Net Overburden Pressure

The first objective of this core study was to determine a net overburden correction to apply to the existing database of ambient condition permeability and porosity data. Permeability and porosity were measured at net confining stresses from 1000 psi to 10000 psi in 500 psi increments on three samples which were selected to represent the range of expected basic properties. These results (presented in Figures 3 and 4) indicate that 80-85% of the ambient permeability to air is retained at the reservoir net confining stress of 2100 psi and ambient porosities should be reduced by 2-3 porosity units. The information at pressures above 2100 psi was used to assess the potential for declining reservoir quality due to reservoir pressure depletion. Significant reductions in both permeability and porosity were observed as a function of overburden pressure suggesting that maintaining reservoir pressure as high as practical will result in maximum retention of reservoir permeability.

Figure 3

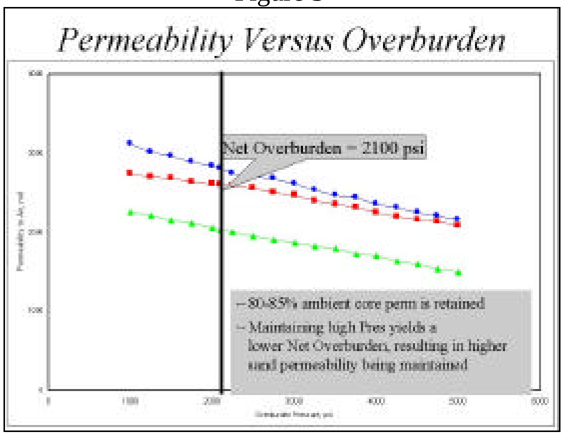
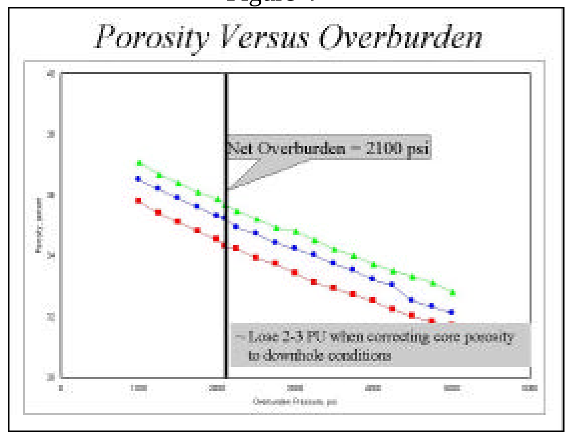


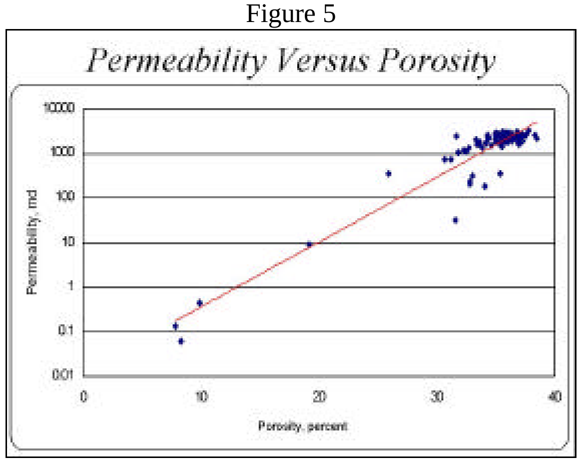
Figure 4



Permeability and Porosity at Net Overburden Pressure

Permeability and porosity were measured on the routine horizontal plug samples at the reservoir net confining stress of 2100 psi to provide detailed information about the reservoir and facilitate sample selection for special core analyses testing. The resulting data set, presented in Figure 5, shows a range of porosities from 7.9 to 38.5 percent, with an arithmetic average value of 34.2 percent. Permeability to air ranged from 0.06 to 3310 millidarcies, with an arithmetic average of 1980 md. Overall these data describe a high quality reservoir with significant production potential.

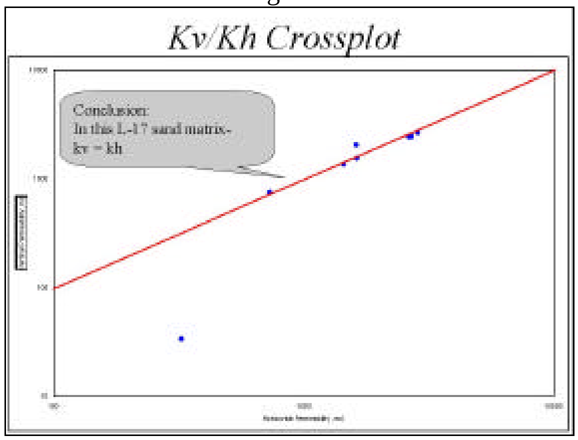
Figure 5



Vertical Permeability at Net Overburden Pressure

Vertically oriented plug samples were drilled from locations selected to provide a comparison of vertical to horizontal permeability for the main clean sand interval as well as potential barriers to flow observed on the core photographs. These plugs were mounted, seated, extracted, and dried as described previously and permeability to air measured on the routine horizontal plug samples at the reservoir net confining stress of 2100 psi. This information was crossplotted with the companion horizontal plug data as shown in Figure 6 and indicates that for the productive interval vertical and horizontal permeability are the same.

Figure 6



SPECIAL CORE ANALYSES PROGRAM

Based on the routine core analyses data and a detailed description of the core slabs, three intervals were selected for a complete suite of special core analyses tests including wettability, steady-state gas-oil and water-oil relative permeability, electrical properties with porous plate capillary pressure, acoustic velocity, and pore volume compressibility testing. One inch diameter plugs were drilled for each test from each of the three specified depths. The plugs were mounted and seated as mentioned above, then wrapped in Saran Wrap™ and aluminum foil, placed in sealed plastic bags, and kept in a freezer until tested.

Complete petrographic analyses, including thin section point counts (see Figures 7-9), scanning electron microscopy, and x-ray diffraction were performed on sample end trims from each of the selected intervals. Based on the petrographic evaluations, the samples are described as feldspathic litharenites and lithic arkoses with an average grain size ranging from 0.10 mm to 0.20 mm. The samples have a low overall clay matrix and are very poorly cemented.

Figure 7

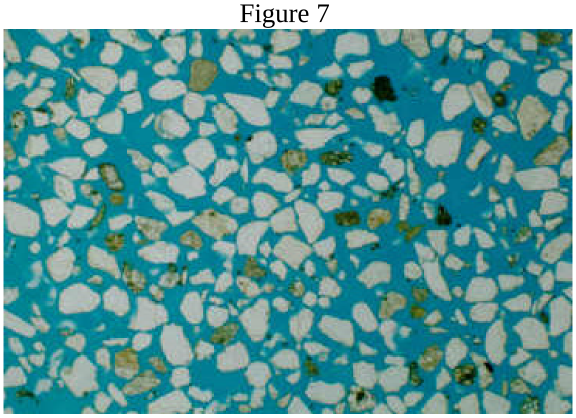


Figure 8

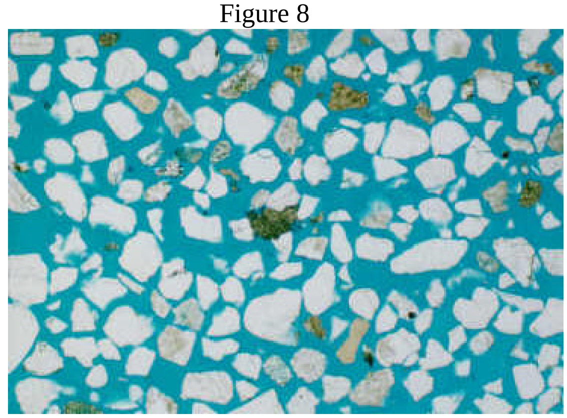
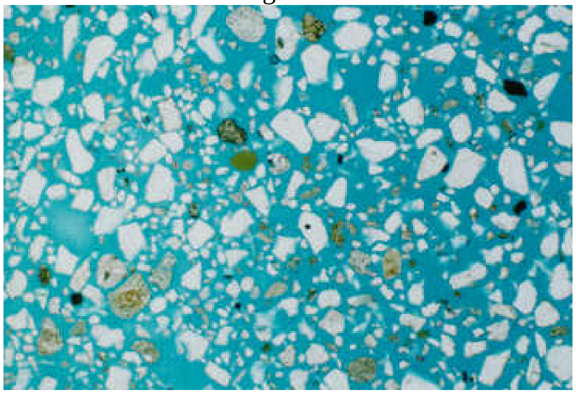


Figure 9



Synthetic formation brine was prepared based on a produced water analyses using reagent grade chemicals and deionized water. Test fluids were evacuated of air and prefiltered through a 0.45 micron Millipore™ filter prior to use. Laboratory oils of desired characteristics were supplied for use in two phase testing as described in the appropriate sections. Viscosities and densities of test fluids were measured using appropriately sized capillary viscometers and pycnometers. Resistivity of the brine (Rw) was measured at ambient temperature and corrected to 77°F using Arp's equation. Descriptions and results of each type of test follow in approximately chronological order.

Acoustic Velocity

Acoustic velocity measurements were done to determine compressional and shear velocities, calculate Poisson's ratio, Young's, Bulk, and Shear moduli, as well as provide information to calibrate sonic logs and evaluate bore hole stability.

The three selected samples were extracted, dried, and basic properties measured at 2100 psi net overburden pressure, as described above. The plugs were saturated with synthetic formation brine and compressional and shear wave acoustic velocity measurements performed on the 100% saturated samples at 2100 psi hydrostatic confining pressure. The test samples were desaturated to irreducible water saturation at 200 psi capillary pressure, and acoustic velocities at Swi measured as before.

The observed velocity data were used to calculate bulk modulus, Young's modulus, shear modulus, and Poisson's ratio for each sample at each saturation condition. The core determined values, presented in Figure 10, are currently being compared to earlier estimates, for modifications in sand control design, as well as for logging and geophysical calibrations.

Figure 10

Acoustic Velocity

Velocity				Bulk	Young's	Shear	
Compressional,		Shear,		Modulus,	Modulus,	Modulus,	Poisson's
ft/sec	dt, µs/ft	ft/sec	dt, µs/ft	1e+06psi	1e+06psi	1e+06psi	Ratio
9508	105.18	4616	216.62	1.847	1.710	0.635	0.346
7969	125.49	3705	269.84	1.481	1.209	0.444	0.362
Core determined values are currently being compared to earlier estimates, for modifications in sand control design, as well as for logging and geophysical calibrations.							
8431	118.61	3738	267.50	1.424	1.046	0.380	0.378
8217	121.70	3698	256.90	1.342	1.165	0.430	0.365

Pore Volume Compressibility

Pore volume compressibility testing was performed to determine reduction in porosity due to reservoir pressure depletion in presence of water saturation, provide a comparison to the previous dry porosity versus overburden results, and allow for the calculation of pore volume compressibility factor.

The selected plugs were cleaned and dried as described above, and basic properties were measured at 400 psi net overburden pressure. The samples were then saturated with synthetic formation brine and installed in hydrostatic coreholders at 400 psi net confining pressure. Twenty pore volumes of additional brine were injected against backpressure to completely saturate the samples. The backpressure was removed and the samples allowed to equilibrate for 24 hours. The overburden pressure was then increased incrementally to 10000 psi, while monitoring produced fluid volumes at each pressure.

Porosity versus overburden data were calculated from the observed test results. Based on this information shown Figure 11, ambient porosity values should be reduced by 2-4 porosity units when correcting to reservoir net confining pressure. These data are in good agreement with the change in porosity observed in the dry sample measurements described previously. Pore volume compressibility factors (for the interval 400-2100 psi) were calculated from the measured results and are presented in Figure 12. These values ranged from 36*10-6 to 66*10-6 .

The information at pressures above 2100 psi was used to assess the potential for declining reservoir quality due to reservoir pressure depletion. As observed in the helium measurements, significant reductions in porosity were observed as a function of overburden pressure suggesting that maintaining reservoir pressure as high as practical will result in maximum retention of reservoir quality.

Figure 11

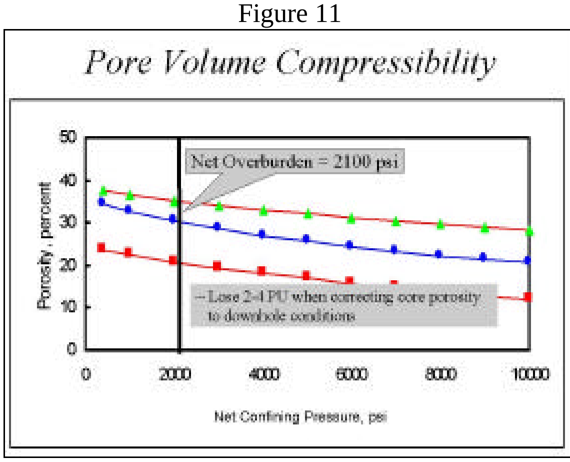
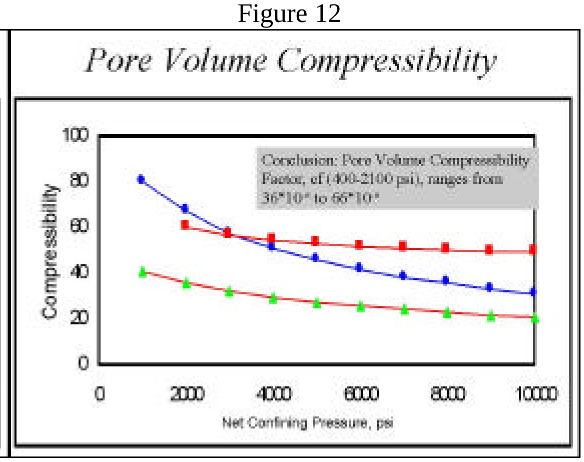


Figure 12



Electrical Properties and Air-Brine Capillary Pressure

Electrical properties testing was performed using the 2 terminal method and porous plate desaturation, to determine the Archie equation parameters, a, m, and n, for calibrating log determined water saturations and to measure air-brine capillary pressure relationships and irreducible water saturation. The samples were extracted, dried, and basic properties measured at 2100 psi in the same manner as the routine plugs. The test samples were then partially saturated with synthetic formation brine, wrapped in Saran Wrap™ and aluminum foil, placed in sealed plastic bags, and kept in a freezer overnight.

The metal sleeves and screens were removed from the frozen plugs, which were placed in rubber sleeves with a previously saturated porous plate placed on the downstream end and saturated silver membranes on each end of the assembly. The sleeve assemblies were placed in an oil bath cell and 2100 psi net confining stress was applied. Synthetic formation brine was injected against a back pressure of 200 psi while measuring resistivity approximately every four hours, until less that 1 percent change in resistivity was observed over a 48 hour period of time.

The resistivity measurements (Ro) were corrected to 77°F using Arp's equation and formation factor (Ro/Rw) was calculated for each sample. Formation factor was plotted against porosity on a log-log scale and cementation exponent, m, determined from a straight line power function fit to be 1.41 as shown in Figure 13. Using this value in log calibration, the calculated irreducible water saturation was decreased from 7-10 percent.

The samples were then desaturated by injecting gas to displace the water at a series of increasing pressures while monitoring the produced fluid volumes and sample resistivity (Rt). The resistivity data were corrected to 77°F using Arp's equation and presented versus water saturation in a log-log format, which appears as Figure 14. Saturation exponent, n, was determined from a straight line power function fit to be 2.02.

Figure 13

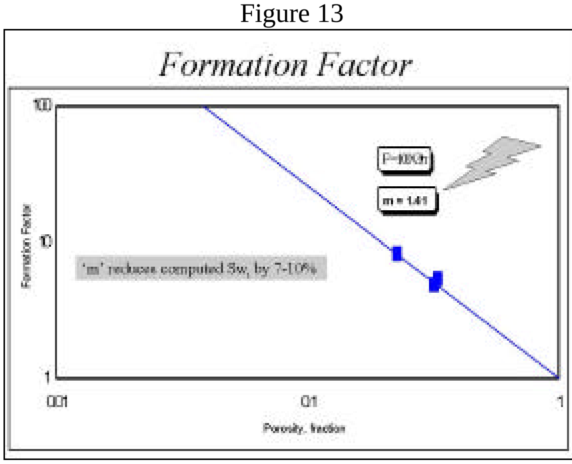
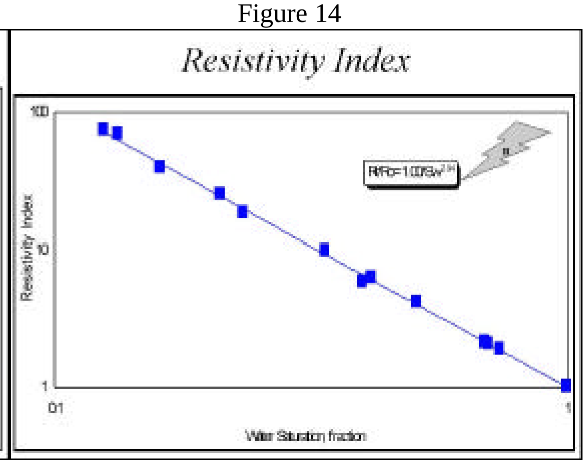


Figure 14



Gas-water capillary pressure relationships were determined from the observed production data and Leverett J-function and equivalent height above free water calculated as shown in Figures 15 and 16. The connate water saturation for the three samples ranged from 12.5 to 16.1 percent pore space at 35 psi capillary pressure with a transition zone of approximately 20 feet.

Figure 15

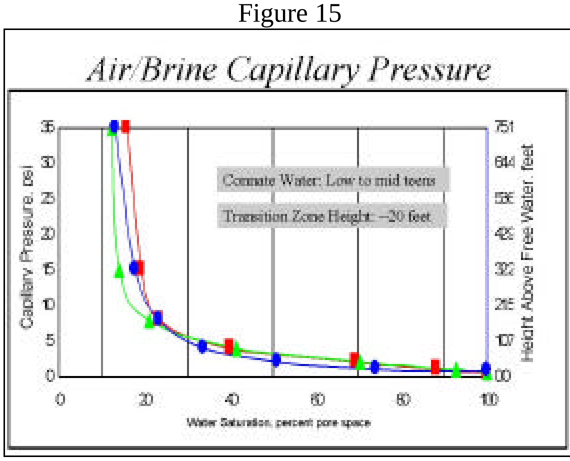
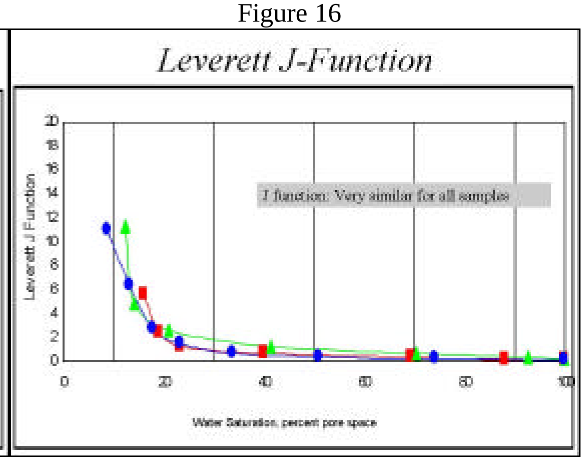


Figure 16



Relative Permeability Program Design

One of the primary objectives of the coring program was to obtain representative gas-oil and water-oil relative permeability curves for use in reservoir simulation. As the core was taken with a low invasion oil-based mud system, the inner portion of the core was expected to be uninvaded by drilling fluids. An examination of the core photographs and CT scans appears to confirm low invasion of the center of the core.

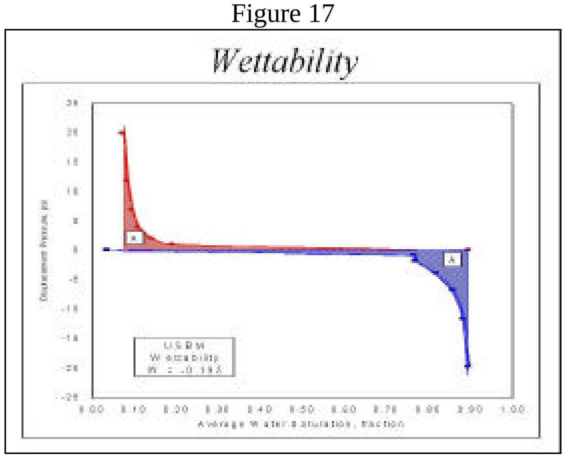
USBM wettability testing was performed on samples from each interval to determine the wetting preference of the preserved-state core and to evaluate whether any alteration in wettability had occurred. The samples were installed in specially designed centrifuge coreholders at 2100 psi net confining stress and configured for an oil displacing water displacement.

The samples were centrifuged under treated kerosene to irreducible water saturation in preparation for testing, then configured for water displacing oil. The samples were centrifuged under water at several increasing water-oil capillary pressures while monitoring produced oil volumes. The coreholders were then reconfigured for oil displacing water, and the process repeated at equivalent oil-water capillary pressures.

At the conclusion of testing, the samples were subjected to Dean Stark and soxhlet toluene extraction to determine residual fluid saturations, leached of salts with methanol, and dried to a constant weight in a humidity controlled oven at 140°F and 45% relative humidity. Permeability to air and Boyle's law helium porosity measured at 2100 psi net confining stress and fluid saturations at each point in the displacement process determined by material balance.

Applied capillary pressure was plotted as a function of water saturation for each displacement and the area under each curve determined by integration. The USBM wettability index was calculated from this data and ranged from 0.100 to –0.229 for the four tested samples. These values indicate a range of wetting preferences from slightly water-wet to slightly oil wet suggesting minimal drilling fluid invasion. Based on these results and the visual evidence of low invasion described above, it was decided to use preserved-state samples for the relative permeability test program.

Figure 17



The x-ray attenuation steady-state method was selected for the gas-oil and water-oil relative permeability tests. An oil blend, containing 12.5 % iododecane, which is opaque to the x-rays used to determine fluid saturations, was prepared for the testing program.

The samples were installed in specially designed centrifuge coreholders at 2100 psi net confining stress and configured for an oil displacing water displacement. The samples were centrifuged under the oil blend to irreducible water saturation in preparation for testing.

Steady-State Gas-Oil and Water-Oil Relative Permeability

Each sample was installed in the specially designed x-ray coreholder, 2100 psi net confining stress was applied, and a backpressure of 200 psi established. The x-ray oil blend was injected at a constant rate until an equilibrium differential pressure was observed, and effective permeability to oil at initial water saturation was measured while scanning the sample.

A steady-state gas-oil relative permeability test was performed by coinjecting humidified nitrogen and the x-ray oil blend at several increasing gas-oil ratios (using a total injected flow rate of 1 ml/min at each point) to allow the gas saturation of the sample to increase. Differential pressure was monitored continuously and x-ray scans recorded periodically until a stable differential pressure and saturation profile was observed at each ratio. Lastly, humidified nitrogen alone was injected at the constant rate of 1 ml/min until an equilibrium differential pressure was observed, and effective permeability to gas at residual oil saturation was measured while scanning the sample.

The plug was resaturated with oil blend, and additional oil blend injected until an equilibrium differential pressure was observed. Effective permeability to oil at initial water saturation was measured while scanning the sample. As these values were in good agreement with the previous values, testing was continued.

A steady-state water-oil relative permeability test was performed by coinjecting synthetic formation brine and the x-ray oil blend at several increasing water-oil ratios (using a total injected flow rate of 3 ml/min at each point) to allow the water saturation of the sample to increase. Differential pressure was monitored continuously and x-ray scans recorded periodically until a stable differential pressure and saturation profile was observed at each ratio.

Lastly, brine alone was injected at the constant rate of 3 ml/min until an equilibrium differential pressure was observed, and effective permeability to water at residual oil saturation was measured while scanning the sample.

At the conclusion of testing, the samples were subjected to Dean Stark and soxhlet toluene extraction to confirm final fluid saturations, leached of salts with methanol, and dried to a constant weight in a humidity controlled oven at 140°F and 45% relative humidity. Permeability to air and Boyle's law helium porosity were measured at 2100 psi net confining stress.

To determine the base scans for saturation calculation, each plug was saturated with oil blend, installed in the x-ray coreholder at test conditions and specific permeability to oil measured while scanning the sample. Toluene was injected to remove the oil blend, followed by methanol to replace the toluene. Synthetic formation brine was then injected until an equilibrium differential pressure was observed, and specific permeability to water was measured while scanning the sample. The sample was unloaded, leached of salts and redried as described previously. The dry plug was installed in the x-ray coreholder at test conditions and specific permeability to gas measured while scanning the sample.

Effective permeabilities at each saturation were calculated from the observed differential pressure and flow rate information using Darcy's law. Fluid saturations at each point in the displacement process determined by the x-ray attenuation method using the observed x-ray scans and the base scans at 100% saturations determined above.

The steady-state water-oil relative permeability curves were very similar for all samples tested with an average oil recovery of 61.7 percent pore space yielding an average residual oil saturation of 30.2 percent pore space. No anomalies from expected behavior were observed. This information is presented in Figures 18 and 19.

Figure 18

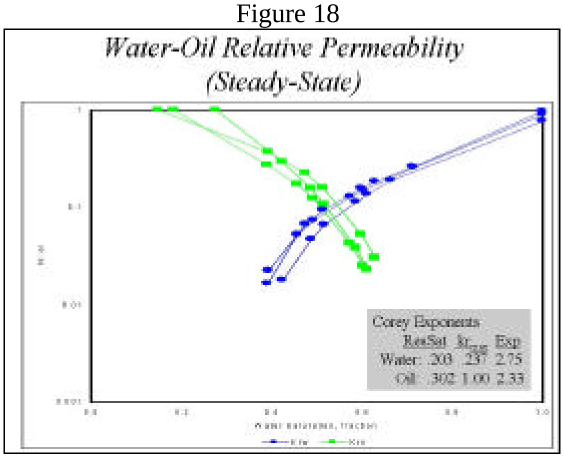
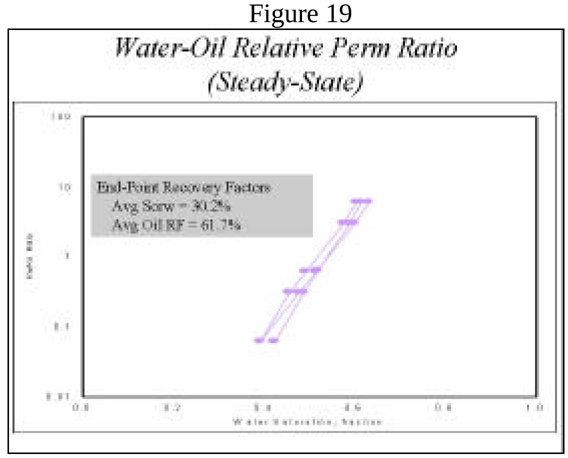


Figure 19



The steady-state gas-oil testing, however, yielded unexpectedly high residual oil saturations, averaging 51.7 percent, due to the low core flood rates utilized and corresponding significant end effects as seen in Figures 21, 22, and 23. The terminal differential pressures observed in these floods ranged from 0.01 to 0.06 psi.

Figure 21

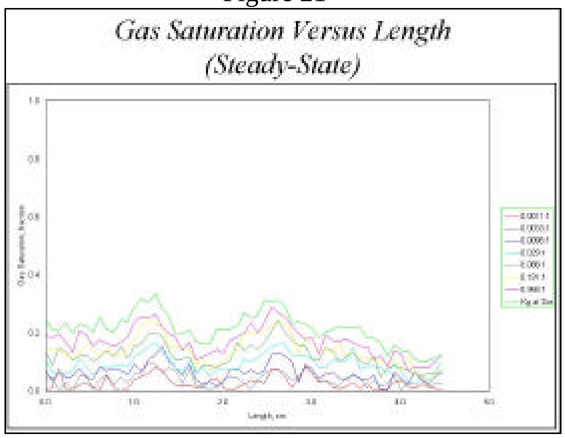


Figure 22

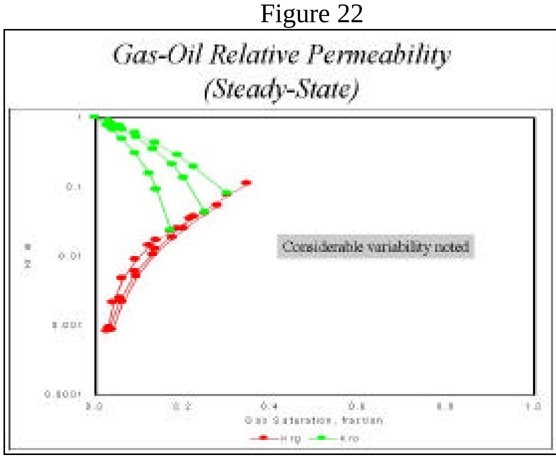
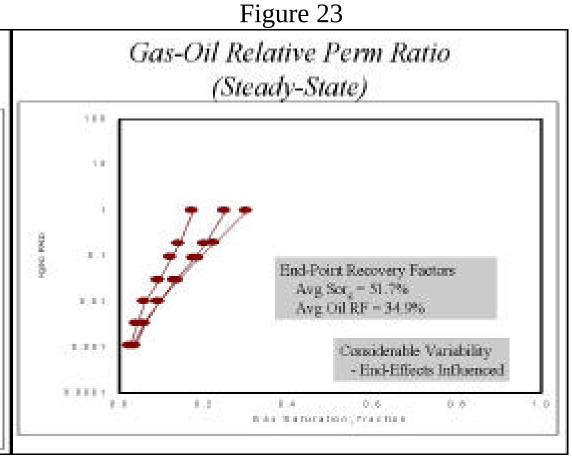


Figure 23



In an effort to confirm these conclusions, and obtain more representative relative permeability curves, centrifuge and unsteady-state gas-oil relative permeability tests were performed on a set of companion samples.

Centrifuge and Unsteady-State Gas-Oil Relative Permeability

The samples were installed in specially designed centrifuge coreholders at 2100 psi net confining stress and configured for an oil displacing water displacement. The coreholder assemblies were centrifuged under the oil blend to irreducible water saturation in preparation for testing.

A backpressure of 200 psi was established and the x-ray oil blend was injected at a constant rate until an equilibrium differential pressure was observed. Effective permeability to oil at initial water saturation was measured. The coreholder assemblies were configured for a gas-oil displacement.

A centrifuge gas-oil relative permeability test was performed as follows. The samples were centrifuged at a constant rotational speed, selected to represent the maximum expected capillary pressure of approximately 16 psi, while monitoring produced fluid volumes until less than 1 percent pore space oil was recovered over a four hour period. The coreholders were removed from the centrifuge, and humidified nitrogen alone injected at a suitable constant rate until an equilibrium differential pressure was observed. Effective permeability to gas at residual oil saturation was measured.

The samples were resaturated with the oil blend and a backpressure of 200 psi established. The x-ray oil blend was injected at a constant rate until an equilibrium differential pressure was observed. Effective permeability to oil at initial water saturation was measured. Humidified nitrogen was injected at a constant pressure of approximately 1 psi while collecting produced gas and oil volumes and monitoring elapsed time until a gas-oil ratio of approximately 30 was achieved. Effective permeability to gas at residual oil saturation was measured.

At the conclusion of testing, the samples were subjected to Dean Stark and soxhlet toluene extraction to determine final fluid saturations, leached of salts with methanol, and dried to a constant weight in a humidity controlled oven at 140°F and 45% relative humidity. Permeability to air and Boyle's law helium porosity measured at 2100 psi net confining stress.

End-point effective permeabilities were calculated from the observed differential pressure and flow rate information using Darcy's law. Centrifuge gas-oil relative permeability data were computed using the method of Kyte, and unsteady-state gas-oil relative permeability relationships were calculated using Jones-Rozelle.

While the gas curves were very similar for all methods, significant variability was noted in the oil curves between the various methods as shown in Figure 11. The differences in the oil curves are a result of the methodologies, largely due to the applied differential pressure in each technique. The centrifuge data were felt to be too optimistic for use in the simulation. As the unsteady-state oil curves were very similar for all samples, and there was substantial variability in the steady-state ones, the unsteady state data in Figures 24 and 25 were determined to be more reliable and were thus used in the model. Average oil recovery was 57.3 percent pore space yielding an average residual oil saturation of 34.0 percent.

Figure 24

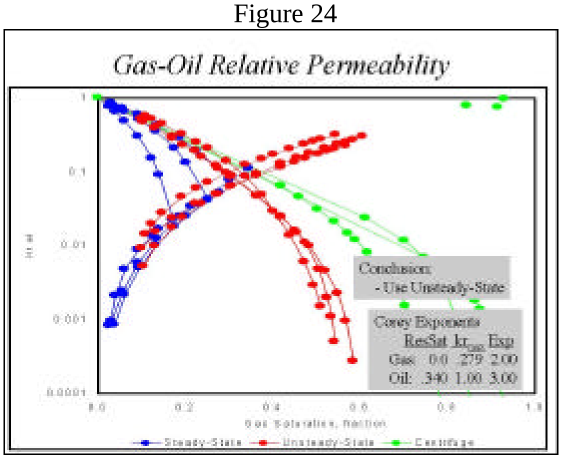
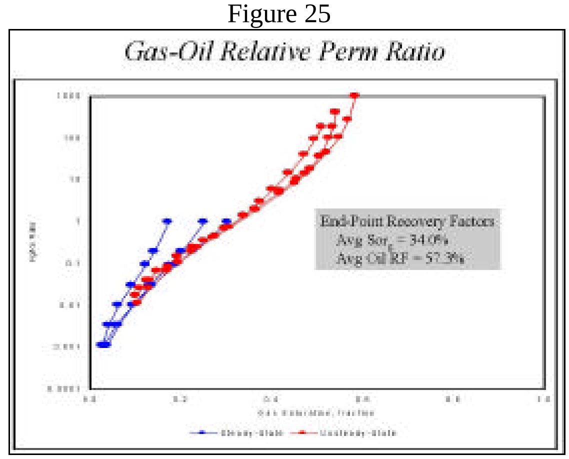


Figure 25



Summary

The objectives of the coring program were met. Permeability to air versus porosity, vertical to horizontal permeability to air, and gas-oil and water-oil relative permeability characteristics were determined for use in the reservoir model. Additional testing was performed to improve log calibration, including grain density, pore volume compressibility, electrical properties, and acoustic velocity determinations. Data from this comprehensive coring program are the key building components for the site-specific reservoir simulation model currently under construction.

Acknowledgement

We would like to thank Coastal Oil and Gas Corporation for granting permission to publish this paper.