H. Technical Description

This study was done to determine geologic and hydrologic characteristics that identify compartmentalized reservoirs in oil and gas fields. This would improve our assessment of the hydrocarbon resource base and help increase recovery from such reservoirs. Such reservoir compartments are significant phenomena because they form major hydrocarbon reservoirs. The investigations focused on the Chocolate Bayou field in eastern Brazoria County on the upper Texas Gulf Coast (fig. 1). The methodology consisted of three main steps: (1) describing reservoir architecture using geologic data (structural and stratigraphic features, facies description), (2) describing hydrology (pressure distribution, reservoir depletion with production), and (3) determining produced and unproduced reserves and undrained sections.

The concept of compartmentalized reservoirs in sedimentary basins was introduced by Amoco Oil Company in the 1970's. These are hydrocarbon-bearing reservoirs, bounded by pressure seals, which are low-permeability envelopes enclosing the reservoirs. These can be visualized as "pressure chambers" with well-defined boundaries. The compartments usually exhibit abnormally high pressures. These compartments are characterized laterally by vertical seals separating the abnormally pressured compartments from adjacent normally pressured ones. Three types of seals can be envisioned: basal, lateral, and top. Basal seals define the bottom of abnormally pressured compartments and usually follow a stratigraphic horizon. Lateral seals are generally associated with faults. Top planar seals may parallel or cut across time-stratigraphic boundaries and may develop in any lithology. Sedimentological, mechanical, and chemical factors can cause compartmentalization.

Data Sources

The primary sources of data on field production, oil and gas well pressures, and completion depths were the Well History Control System (WHCS) data base maintained by Petroleum Information (PI) of Denver, Colorado, the gas well production data base maintained by Dwight's Energydata, Inc., of Richardson, Texas, and operators' filings at the Railroad Commission of Texas. Additionally, previous Bureau of Economic Geology publications, the Bureau well log library, and other scientific publications were used for compiling geologic and hydrologic information. Production and pressure data from nearly 200 wells were downloaded from Dwight's Energy data base and integrated with information available from other sources for compilation of potentiometric surfaces as well as for evaluation of depletion in the various producing fields.

Reservoir Hydrogeology

Geology

We examined the geology of seven major Frio gas reservoirs in the Chocolate Bayou field in the middle and lower parts of the Frio Formation; these include the Banfield, Schenck (upper and lower

Schenck locally differentiated), Upper Wieting, Lower Wieting, 12000 Sand, S Sand, and Andrau reservoirs. Geologic cross sections were made on the basis of well log information for the correlation of individual sand units and for the interpretation of structural features. Geologic structure has apparently been the greatest controlling factor in gas entrapment and recovery. The potential for compartmentalization of reservoirs is greatest along the growth fault zones, where sections of reservoirs are isolated from existing wells by individual fault plays. In these areas, reservoir sands are truncated by the faults and juxtaposed with impermeable shale seals on opposite sides. Natural pore cements that can lead to compartmentalization are absent or minor in reservoir quality sands. Normal compaction and early cementation have reduced porosity to less than 15% to a depth of about 9,000 ft (2,700 m). However, dissolution has increased porosity to approximately 30% between 8,000 and 11,000 ft (2,400 m and 3,350 m). Reservoirs deeper than 12,000 ft (3,650 m) show core permeabilities of hundreds of millidarcys (md).

Nearly all of the oil and gas wells producing from the deep Frio Formation in the Pleasant Bayou fault block vicinity are completed in sand units above the Frio C zone. Average porosities in these producing intervals are in the 15% to 30% range and permeabilities in the 200 to 1,500 md range. Productive sands are from 30 to 150 ft (9 to 46 m) thick.

Pressure Regimes and Hydrodynamics

A plot of formation pressures measured in wells versus depth (also called a pressure-depth profile) in Brazoria and Galveston Counties shows the existence of three hydrologic regimes: a shallow fresh to moderately saline water section in the upper 3,000 to 4,000 ft (915 to 1,220 m), an underlying 4,000- to 5,000-ft-thick (1,220- to 1,524-m), essentially saline hydrostatic section, and a deeper, geopressured section with moderate to high salinities (fig. 2). The 0.465-psi/ft (10.5-kPa/m) gradient line on this figure distinguishes the hydrostatic pressures from the geopressures. This gradient corresponds to a brine of approximately 100,000 ppm salinity. Geopressuring of fluids in sediments is controlled by two dominant processes: (1) compression caused by burial and compaction and (2) resistance to leakage (Dickinson, 1953). Compaction leads to a reduction of porosity and permeability. The state of equilibrium reached between the weight of the overburden and the load-bearing strength of the sediments under varying degrees of leakage ultimately determines the apparent fluid pressure gradient. The transition from a normally pressured to a geopressured hydrologic environment commonly is either abrupt where the sandstones are overlain by thick shale sections or gradual where sandstones and shales are interbedded. It is difficult to identify the nature of the transition in the Chocolate Bayou area because pressure data are generally available only for the reservoirs within each well. Pressures must be measured at increments throughout the entire stratigraphic interval containing the transition to accurately characterize the transition. Ewing and others (1983) provided the following description of pressure regimes in the Chocolate Bayou area: (1) an upper zone of normally pressured sandstones and shales, (2) an underlying zone of normally pressured sandstones and possibly overpressured shales, (3) a deeper zone of moderately overpressured sandstones and highly overpressured shales, and (4) a lower zone of highly overpressured sandstones and shales. The normally pressured sandstones of zones 1 and 2 exhibit high permeability and continuity across the growth faults, whereas the sandstones of zones 3 and 4 show generally lower porosity and permeability and greater lateral discontinuity.

Initial Reservoir Pressures

Formation pressures in wells completed in seven major gas-bearing sands in the middle and lower parts of the Frio Formation were examined; these include the Banfield, Schenck (upper and lower Schenck, locally differentiated), Upper Wieting, Lower Wieting, 12000 Sand, S Sand, and Andrau reservoirs. Initial reservoir pressures (at well completion) and initial production pressures (when well was first put on production) were plotted versus depth for the west, central, and south sections of the Chocolate Bayou (fig. 3). Also shown on the plot are the pressure-gradient lines of 0.465, 0.7, 0.85, and 1.0 psi/ft. The data illustrate that although the reservoirs in the west area range from overpressured to underpressured (either naturally or because of depletion), the reservoirs in the central and south areas are predominantly overpressured at equivalent depths. This indicates that the major faults in the west and east act as barriers to lateral fluid migration and have created compartmentalized reservoirs.

Production and Drive Mechanism

Geopressured reservoirs are considered in theory to be closed compartments having a fixed volume. Production of substantial quantities of fluids (oil, gas, condensate, and water) from these would result in large depletion of the reservoir pressure. Reliable estimates of the resource base are essential for efficient development and operation of the geopressured reservoir. Moreover, long-term recovery from the reservoir as a function of pressure and time will depend on the sources of energy and the drive mechanism. The source of reservoir energy controlling fluid production may be expansion of the overpressured fluids in the hydrocarbon-bearing sands or compaction of the aquifer rock, or both. The release of liquids from low-permeability zones because of reduced reservoir pressures may also contribute to fluid production. The primary source of energy in the Chocolate Bayou field is thought to be the expansion of the overpressured oil and gas and, in some cases, expansion of the underlying brine. No conclusive evidence of active water influx from contiguous aquifers is available.

Decline-curve analysis of available pressure-production data from wells in the Chocolate Bayou field was undertaken to estimate the original-gas-in-place volumes. These pressure-decline plots for p/z (reservoir pressure/compressibility factor) and trends in pressure and production rate with time are commonly used in the material-balance-analysis method for estimating initial gas reserves in place and for determinating the reservoir drive mechanisms. This type of analysis is complicated by the special hydrodynamics of geopressures and other factors, such as change in reservoir compressibility, which are not included in the traditional decline-curve analysis. Certain shortcomings in this procedure were evident: (1) the pressure data reported for the gas fields are not always reliable, either because of inadequate shut-in times for wells in low permeability reservoirs or because individual well pressures for multiwell fields are averaged, and (2) the fluid production reported for these fields does not always include accurate accountings of the water and condensate production, which are important in correlating cumulative production to pressure decline. Data from the fields reviewed for reserve estimation and pressure analysis were screened to identify the problems mentioned above. Of 132 gas wells drilled in 6 of the target reservoirs, 74 wells were selected for reserve evaluation. Table 1 summarizes the results of the pressure-decline data analysis for these wells. Of an estimated 1.71 trillion cubic feet (Tcf) of original gas in place in 6 target reservoirs (the S Sand was excluded from analysis because of scarce data), nearly 0.96 Tcf had been produced through the end of 1989, leaving an estimated 0.75 Tcf (or 44%) remaining within the drainage areas of these 74 wells. Some of the other 41 wells likely contain unrecovered gas resources. No reliable estimates of condensate reserves could be made because of the lack of condensate production data.

Hydrologic Continuity

Hydrocarbon production and pressure data from other fields proximal to the Chocolate Bayou field were also reviewed to evaluate hydrologic continuity within the Pleasant Bayou fault block and across its boundaries. Data concerning pressure changes were compared and correlated to determine whether these other fields affected depletion in the Chocolate Bayou field. Reservoir pressures in individual wells were converted to equivalent brine hydraulic heads and used to draw potentiometric surfaces (contour maps of head values) for individual reservoirs. These were used to determine hydrologic continuity and areal trends in reservoir depletion. The potentiometric surfaces contain several localized highs and lows (bull's-eyes) resulting from nonuniform depletion in the productive reservoirs. Results of depletion in Chocolate Bayou field are most pronounced in the center and northwest sections of the fault block.

Results

These investigations provided geologic and hydrologic evidence supporting the existence of compartmentalized hydrocarbon-bearing reservoirs in the Tertiary Frio Formation of the Texas Gulf Coast. In the Chocolate Bayou area, this phenomenon is primarily controlled by geologic factors, where productive sands are confined vertically and horizontally by impermeable barriers. An evaluation of pressures, production data, and original gas in place suggests that gas recovery in the main reservoir areas has been limited to about 56%, mainly because of the large well spacing (currently 160 to 320 acres). Infill drilling at reduced well spacings would allow more efficient recovery from the reservoirs.

Potential for additional recovery exists in sections incompletely drained by existing wells and by previously plugged and abandoned wells.

ACKNOWLEDGMENTS

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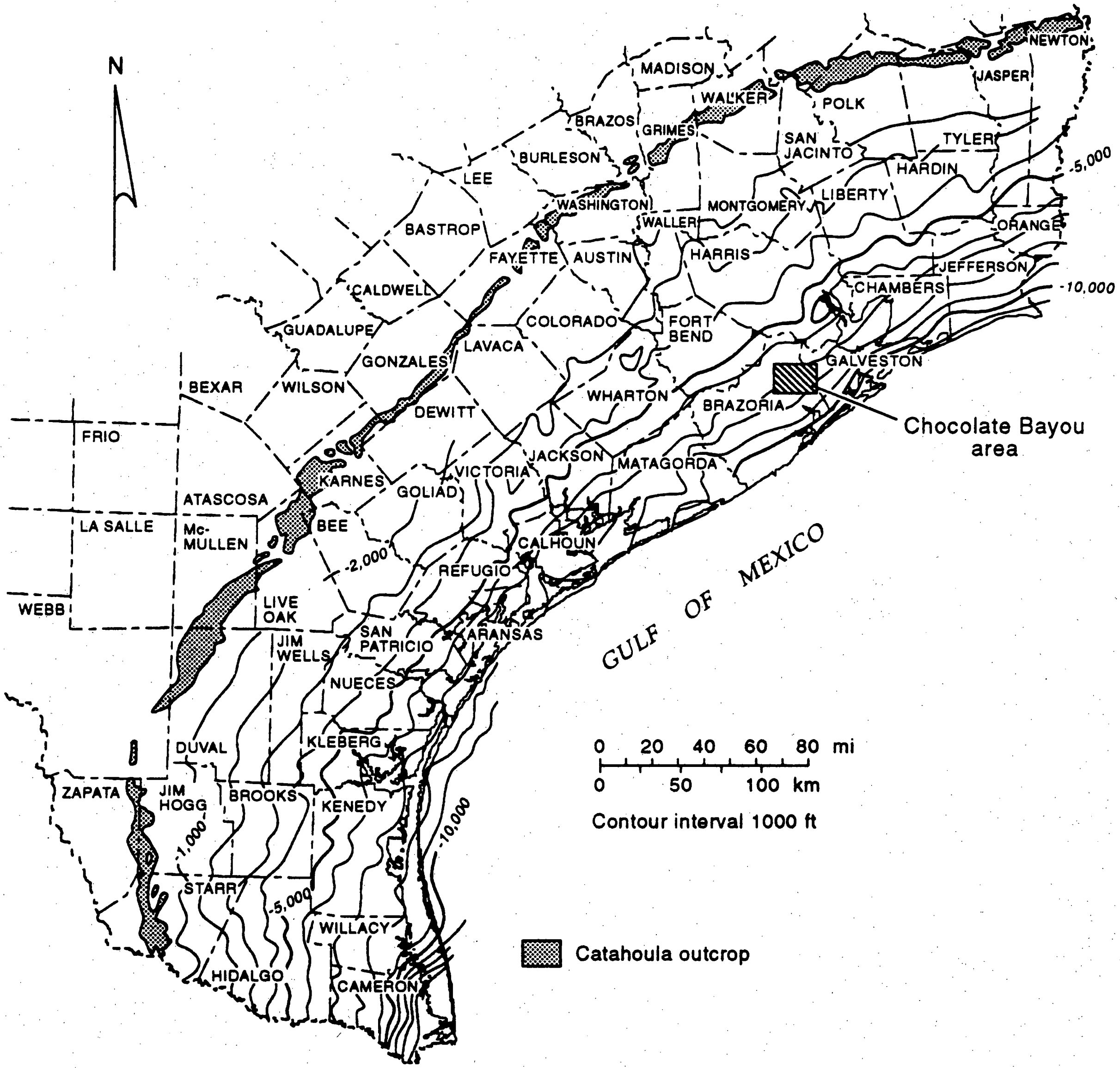

Cenozoic – Texas Gulf coast

AGE	SERIES	GROUP/ FORMATION
Quaternary	Recent	Undifferentiated
	Pleistocene	Houston
Tertiary	Pliocene	Goliad
	Miocene	Fleming
		Anahuac
	—?—?—	
	Oligocene	Frio
		Vicksburg
	Eocene	Jackson
		Claiborne
		Wilcox
		Midway

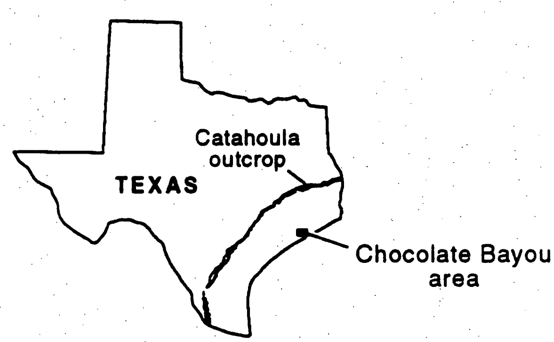

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Figure 1. Location of Chocolate Bayou area and position of Frio Formation within Texas Gulf Coast stratigraphic section. Contours indicate depth to top of the Frio Formation; outcrop of updip equivalent Catahoula Formation is also shown. Modified from Bebout and others (1976, 1978).

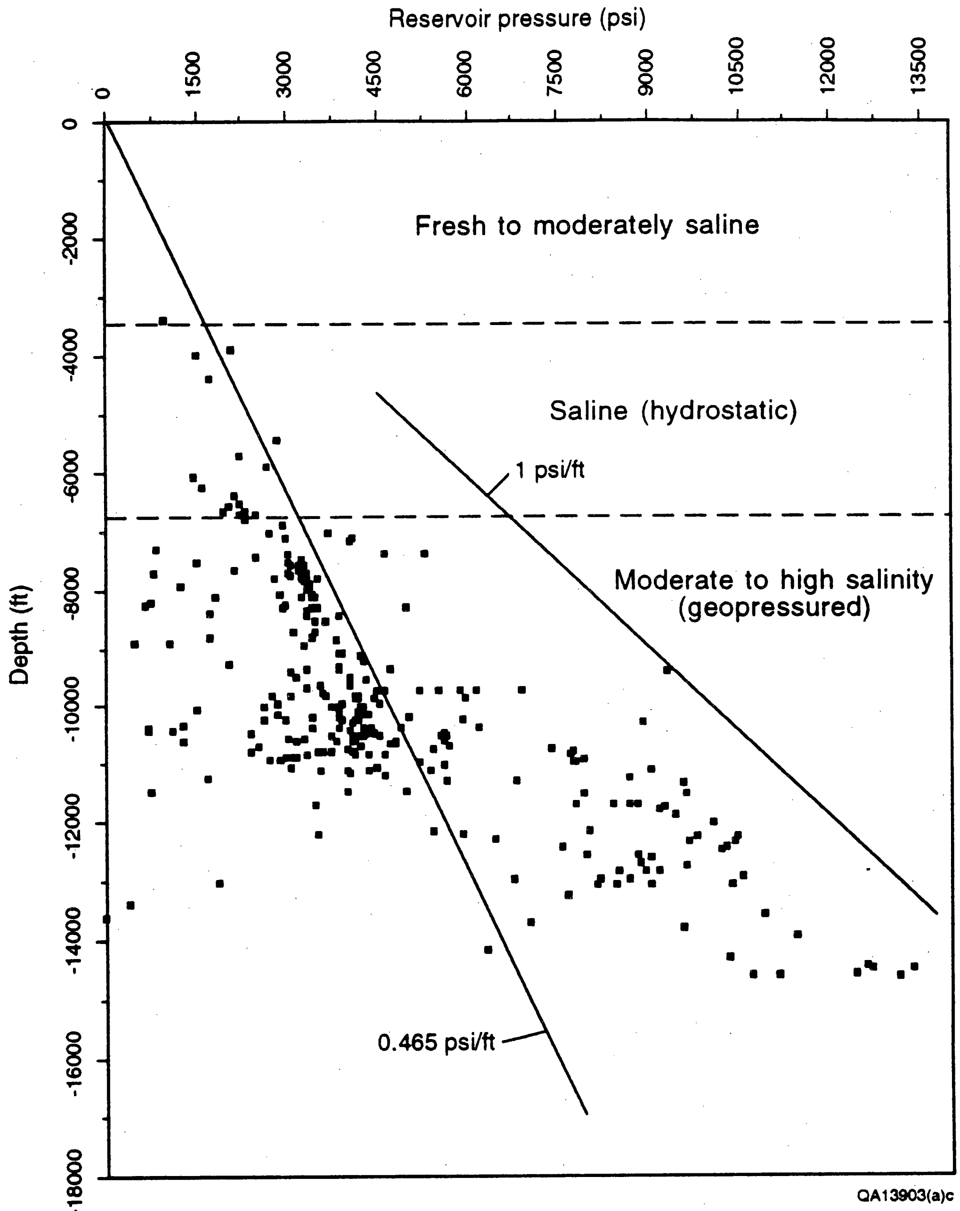
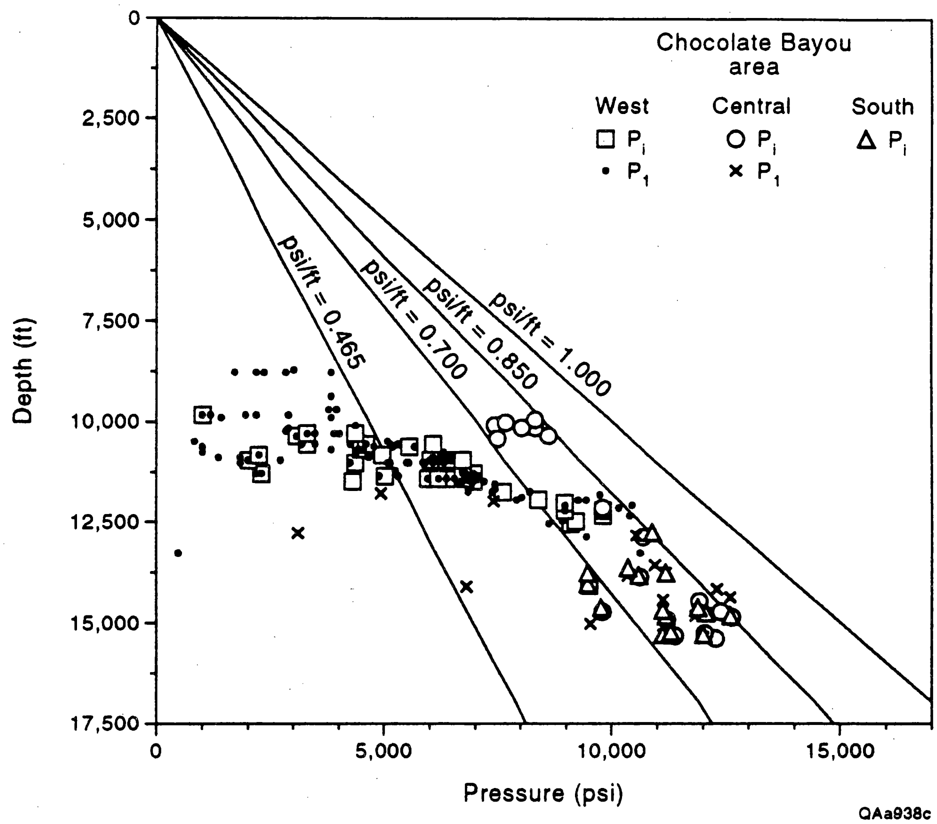


Figure 2. Pressure-depth profile for Frio Formation in Brazoria and Galveston Counties showing approximate boundaries between hydrologic regimes. Pressure data from drill-stem tests and bottomhole measurements and estimates from shut-in wellhead pressures. Lines mark pressure gradients caused by weight of overlying rocks (lithostatic pressure gradient is 1 psi/ft) and of unconfined brine of 100,000 ppm salinity (brine hydrostatic pressure gradient is 0.465 psi/ft).



Figures 3. Pressure-depth profile for west, central, and south Chocolate Bayou field, P_i initial reservoir pressure; P_1 is initial production pressure. Profile shows that reservoirs in the west area range from overpressured to underpressured, whereas reservoirs in central and south areas are overpressured.

Table 1. Chocolate Bayou target reservoir production performance.

	Well Type	% OGIP Produced*	No. of Wells	OGIP BCF*	Production BCF*	Pressure Depletion Min.	Pressure Depletion Max.	Pressure Depletion Avg.
				All Chocolate Bayou Reservoirs				
	Active	54%	22	297.63	160.63	0.04	0.97	0.46
	S/I	59%	28	403.58	236.89	0.02	0.84	0.39
	P&A	68%	82	1249.29	692.22	0.09	1.00	0.45
	Subtotal	55.9%	132	1950.49	1089.74			
				Target Reservoirs				
Banfield	Active	95%	3	75.90	71.81	0.11	0.66	0.34
	S/I	61%	6	161.48	98.90	0.10	0.77	0.27
	P&A	79%	4	151.26	118.97	0.10	0.77	0.27
	Subtotal	74.5%	13	388.64	289.69			
Schenck	Active	96%	1	1.69	1.62	0.04	0.04	0.04
	S/I	69%	2	33.05	22.66	0.14	0.40	0.27
	P&A	53%	12	137.64	73.49	0.14	0.93	0.48
	Subtotal	56.7%	15	172.38	97.78			
Upper Wieting	Active	81%	5	52.40	42.40	0.04	0.46	0.28
	S/I	71%	6	72.06	51.28	0.07	0.68	0.29
	P&A	69%	9	114.55	79.49	0.18	0.76	0.35
	Subtotal	72.4%	20	239.02	173.16			
Lower Wieting	Active	0%	0	0.00	0.00	-	-	-
	S/I	92%	2	13.34	12.26	0.11	0.11	0.11
	P&A	30%	4	67.88	20.39	0.40	0.98	0.62
	Subtotal	40.2%	6	81.22	32.65			
12000 Sand	Active	42%	2	21.60	9.12	0.53	0.72	0.63
	S/I	58%	1	58.20	28.08	0.62	0.62	0.62
	P&A	89%	3	88.91	55.26	0.50	0.57	0.54
	Subtotal	54.8%	6	168.71	92.46			
Andrau	Active	7%	2	83.56	6.08	0.95	0.97	0.96
	S/I	?%	1	n.a.	n.a.	n.a.	n.a.	n.a.
	P&A	46%	11	572.15	263.54	0.10	0.77	0.27
	Subtotal	41.1%	14	655.71	269.62			
Target reservoir subtotal		56.0%	74	1705.68	955.36			

* Abbreviations: OGIP - original-gas-in-place; BCF - billion cubic feet; n.a. - not available