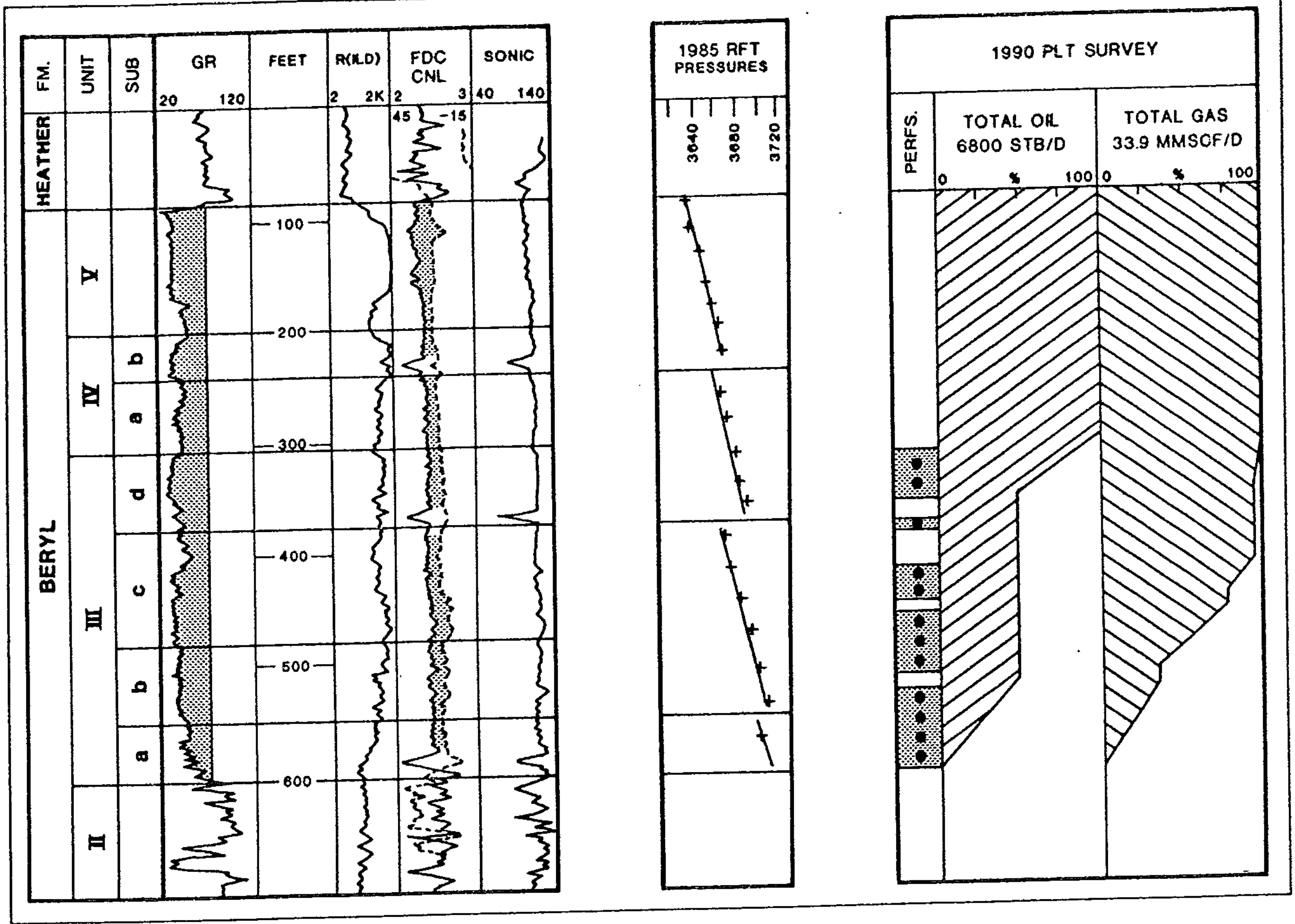


Fig. 5—Beryl formation type log and Well 9/13-A40 RFT pressures vs. depth and perforated intervals and flow profile vs. depth.

water and gas injection into the reservoir. Again, most production was from the central area, southern terrace, and southwest flank. To support high production rates, gas injection in the central area was increased and water injection begun on the southwest flank and in the central area. The reservoir pressures obtained in 1982 (Fig. 2) indicate that the pressure in the southwest flank was ≈4,100 psi (repressured at 50 psi), the central area ≈3,950 psi (repressured at 350 psi), and the southern terrace ≈3,800 psi (repressured at 250 psi). Finally, the southern crest, which was drilled during this period, was depleted to a pressure of 3,850 psi, which was slightly higher than the pressure of the southern terrace.

In Dec. 1981, the central area GOC was interpolated from measured data to be ≈10,400 ft subsea (Fig. 3). Gas breakthrough in the southern terrace suggested a similar GOC in that area. Uniform distribution of the secondary gas cap between the central and southern terrace areas was expected because the reservoir pressure in the southern terrace was lower than that of the central area. Gas distribution in the southern crest, however, was not as expected. The southern crest produced gas-free oil 650 ft above the GOC observed in the central and southern terrace areas.

Water production at the end of this period was still relatively minor. On the southwest flank, two wells were producing water, but no injection water had broken through. In the central area, injection water did break through to nearby producers and the injection program was terminated. Two wells drilled during this period, one each in the central area and the southwest flank, had flushed OWC's, indicating that formation water expansion was augmenting the water-injection support.

In summary, the pressure distribution described above indicates that gross fluid flow was toward the southern terrace and the largest differential was ≈300 psi (Figs. 2 and 4). Water movement was observed only locally, while gas movement was more significant. The secondary gas cap continued to expand to 10,400 ft subsea in the central area and the southern terrace. This gas did not move into the southern crest area, however, because of a combination of factors. First, gas did not move in from the central area because of a fault sealing to a pressure differential of at least 100 psi. The reservoir pressure in the southern crest was 100 psi lower than that of the central area and gas should have moved along this gradient. Because it did not, the fault is inferred. Second, gas did not move in from the southern terrace because of the pressure gradient. The southern crest was pressure depleted when it was drilled. Pressure depletion was through the southern terrace, the only area with a lower or equal pressure. The pressure gradient caused oil to move out of the southern crest, not gas to move in.

Pressure Divergence, 1982–91. This period is marked by pressure divergence and a shift in the direction of gross fluid flow. In the central area, water injection was terminated, but gas injection continued throughout the period. Water injection continued in the southwest flank until 1989, and began in the northern area in late 1987. Today, all areas are on production or have been produced except for the northern crest, which remains undrilled.

Irregular pressures in the southwest flank (Fig. 2) remain relatively high because of the water injection. Central-area pressures showed a gradual decline, with a pressure differential relative to the southwest flank of about −350 psi in 1982 and as much as −1,300 psi by Dec. 1990. Pressures in the northern area and the northwest flank followed those in the central area but were about 200 to 300 psi lower. Southern terrace pressures followed those in the central area but were about 100 to 200 psi higher because of water-injection support. A 100-psi pressure differential began to develop within the southern terrace in 1983. Pressures in the southern portion of the terrace continued to be slightly lower than those in the southern crest. Pressures in the northern portion became slightly higher.

"Within the Beryl reservoir, faults act as horizontal permeability restrictions and result in areas of bypassed oil. The effect. . .on fluid distribution can be studied by careful analyses of pressure and production histories and fluid monitoring."

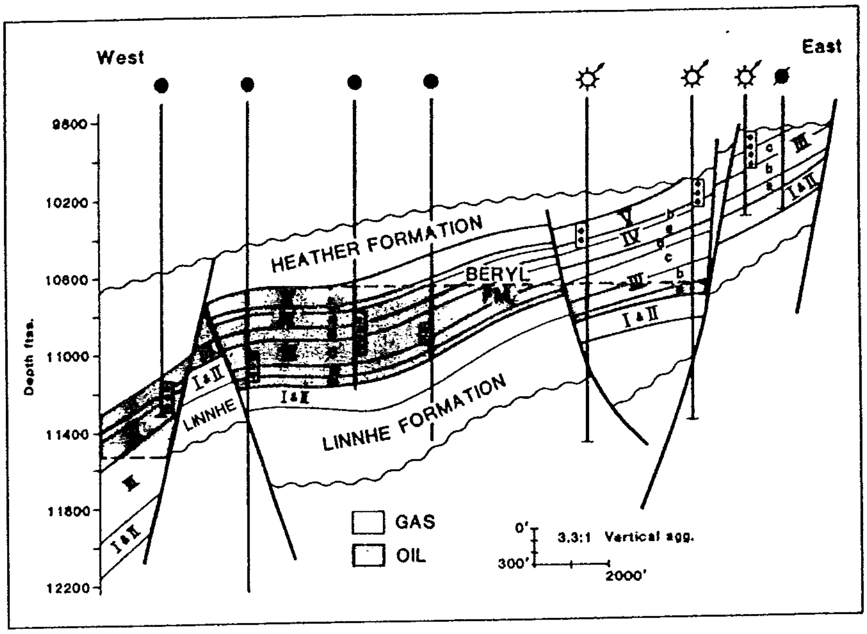


Fig. 6—Beryl formation cross section.

The pressure distribution determines the distribution of fluids in the reservoir. During this period, gas became even more unequally distributed (Fig. 4). The secondary gas cap in the central area continued to expand, and by 1990, was as low as 10,750 ft subsea (Fig. 3). Areas with pressures that diverged even slightly from those of the central area demonstrated independent gas caps. First, the northwest flank had low pressures and deep gas production. Small secondary gas caps formed because solution gas was prevented from migrating updip into the central area by faults that supported the observed 200-psi differential (Fig. 2). Second, and more critically, the expansion of the central area gas cap into the southern areas was prevented by the relatively high pressures in the south. The GOC in the southern terrace became fixed at about 10,400 ft subsea when the 50-to-100-psi differential and the direction of gas migration between the southern terrace and central area reversed in 1982 (Fig. 2). Third, a well drilled in 1990 in the southern crest indicated that gas from the southern terrace was still not moving updip. Two important inferences were made from this observation. First, because pressures in the northern portion of the southern terrace are now higher than those in the southern crest (Fig. 2), if gas is not migrating updip, then the southern crest must be communicating only with the lower-pressure, southern portion of the southern terrace. Second, because pressure in the southern terrace increased during 1987–90 but gas was not forced updip, the southern crest is still draining into the southern terrace and must be supported by a higher-pressure reservoir with no significant gas cap. The undeveloped northern crest will be appraised in 1991.

Water-production problems increased significantly during this period. Centered on the southwest flank, water injection caused high water production in many nearby wells. Produced water analyses indicate that the water produced was a mixture of injection and formation waters. No consistency exists among pressure communication to the water injector, spatial proximity to the water injector, and the amount of injection water produced. The water-injection pathway developed toward the low-pressure areas updip and bypassed some of the nearby downdip wells. The southern terrace became flushed with injection water, and recently, injection water reached the southernmost well in the central area. Water injection was terminated in the southwest flank in 1989 to minimize these problems.

Water production was also a problem in the southern area, which was first drilled during this period. Limited pressure information suggested a gently declining pressure profile (Fig. 2) similar to the southern terrace, but the pressures were relatively high and indicated outside support. Water-injection support from the southwest flank was nearby, but the pressure-decline profile and produced-water chemistry did not suggest water-injection support. With the information currently available, aquifer support from the south is inferred.

Horizontal Permeability Restrictions Summary

Four basic premises, stated at the outset, resolved the interpretation of fluid-movement history in the Beryl reservoir. Faults act as permeability barriers that set up pressure differentials related to the local voidage situation. The pressure distribution determines fluid movement, and careful analysis of the pressure histories explains the observed fluid distribution. In the Beryl reservoir, two fundamental concepts were especially critical to understanding the fluid distribution.

1. The movement of gas is dictated by pressure, not by structure, in a dynamic situation. Gas will not migrate updip if the area updip has a higher pressure owing to a more positive voidage replacement situation (e.g., only minor gas finds exist in the southern crest, which is 600 ft above the southern terrace GOC).

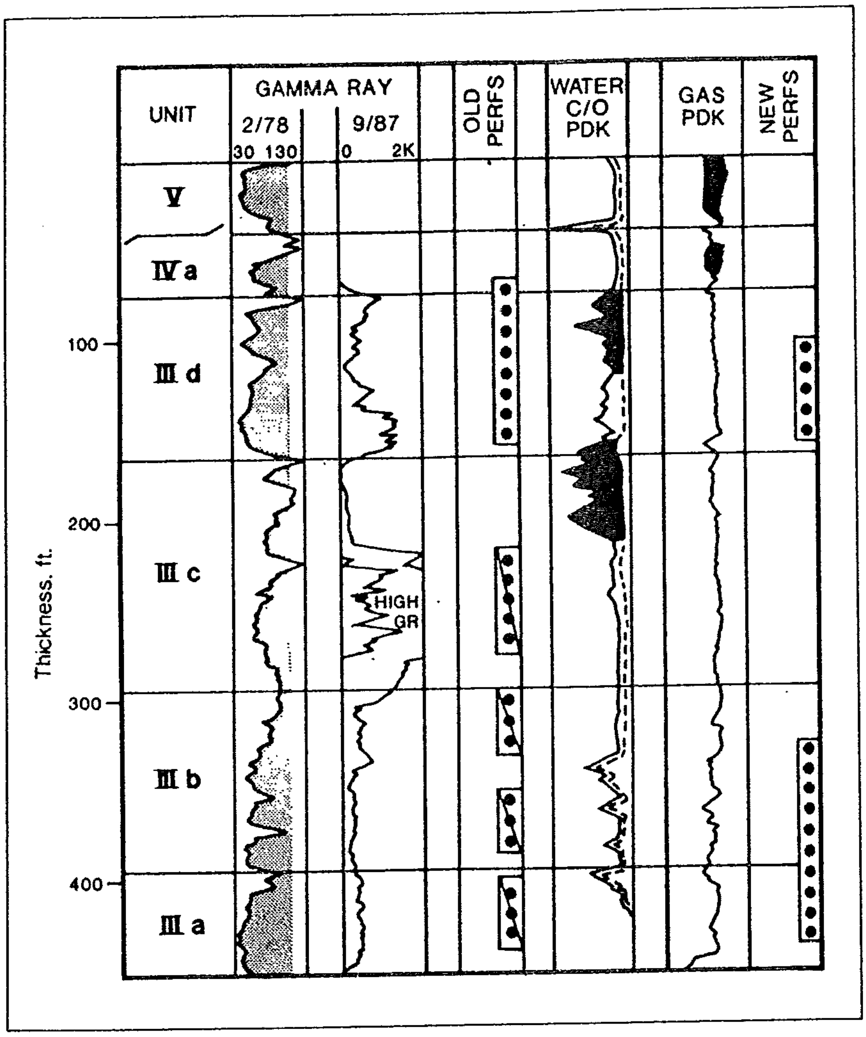
2. Two areas can have a similar pressure history but a very different fluid history if the pressure differential separating them reverses (e.g., there is close pressure communication between the central area and southern terrace but a 350-ft difference in GOC's).

The reservoir model described in this section has already affected reservoir management. An understanding of oil preservation in the southern crest has allowed the area to be produced and managed efficiently. Also, the recognition that the southern crest must be supported by a relatively undepleted oil area generated an attractive drilling program during 1990–91 to appraise an estimated 10×10^6 to 15×10^6 bbl of unswept oil reserves. In addition, the reservoir model was used as the starting point for a simulation exercise designed to maximize recovery after the 1992 initiation of gas sales. An attempt to maximize recovery by returning to a more balanced pressure regime has resulted in termination of water injection in the southwest and an effort to increase production elsewhere in the south.

Vertical Permeability Restrictions

The Beryl reservoir subdivisions are based on gross variations in reservoir behavior. Within these eight subdivisions are local variations resulting from vertical permeability restrictions. The vertical permeability markers affect reservoir management primarily in the northern areas. In the southern areas, the markers are less continuous and have irregular, but nevertheless locally significant, effects.

Units 3 through 5 of the Beryl reservoir consist of a massive deltaic/marine sandstone 500 to 600 ft thick and typically 90%



"The key to understanding fluid distribution within the Beryl reservoir is to recognize that... pressure differentials and flow directions between areas have locally reversed. This observation...is critical to explain how adjacent areas can have similar pressure histories but different fluid histories."

Fig. 7—Well 9/13-A01 water and gas accumulations vs. depth.

to 95% shale-free. The initial expectation of this apparently homogeneous reservoir was that it would behave like a tank. An efficient gravity-segregated gasdrive was also expected because of the high dip and relief of the reservoir structure. During the first 10 years of production, the reservoir management practice was to partially perforate the thick reservoir section and to assume efficient drainage of the entire section. Early production performance supported this reservoir model.[2] In June 1985, however, RFT pressures from Well 9/13-A40, drilled downdip in the central area, indicated that differential pressures (Fig. 5) had developed within the apparently homogeneous reservoir section.

The observation of differential depletion indicated that the Beryl reservoir was not depleting like a homogeneous tank. The lateral extent of the inferred vertical permeability restrictions was not known, but if a zonation within the Beryl did exist, it had to be considered to optimize reservoir management. Vertical permeability restrictions would disrupt the efficiency of gravity drainage and the existing completion strategy. To examine the possibility of a vertical zonation, the main reservoir area (i.e., central, north, and northwest flank areas) was studied in detail with open- and cased-hole logs, RFT data, pressure-transient tests, and reservoir performance histories.

Openhole Logging. The first step in the investigation was a detailed correlation within the Beryl formation of all wells in the main reservoir area. In addition to the general division of Beryl Units 3 through 5, six subtle lithologic markers (Fig. 5) were correlated from well to well to divide Unit 3 into four subunits (3a through 3d) and Unit 4 into two subunits (4a and 4b). Markers 3d and 4b were generally coals, whereas Markers 3b, 3c, 4a, and 5 were associated with siltstones or shales. Although openhole logs did not indicate whether these geologic markers were permeability restrictions, the correlations provided a framework within which engineering data could address the question. As the west-east cross section (Fig. 6) shows, if any of the markers were permeability restrictions, the existing perforation strategy was inefficient and oil was being bypassed.

The openhole logs were also used qualitatively to describe the development and distribution of the geologic markers. The degree of development of the markers was judged from the logs' lithologic signature and then described in map view as well, whether moderately or poorly developed. Clearly, if a marker was to have a significant affect on reservoir depletion, it would be in the area where it was well-developed and continuous.

The core coverage in the Beryl reservoir, unfortunately, does not allow detailed examination of these lithologic markers. Cores from three wells indicate that the markers are related to facies with reduced permeability. The general sedimentary environment is interpreted to be an estuarine/deltaic system prograding northeasterly and interacting with shallow marine and tidal processes. The good-quality reservoir rocks have permeabilities ranging from 50 to 2,000 md and are typically interpreted as mouth bars, channel sands, or upper/middle shoreface sands. The poorer-quality reservoir rocks have permeabilities ranging from 0.1 to 50 md and are interpreted as either more-distal facies or proximal abandonment facies. The more-distal facies are finer-grained lower-shoreface sands, commonly bioturbated. The abandonment facies are lagoonal or interchannel mudstones commonly rich in carbonaceous detritus. Interestingly, some of the most significant permeability contrasts observed in the cores were not associated with pressure differentials. This demonstrates that the effect of permeability restrictions on the reservoir is a function of lateral continuity and relative contrast.

RFT Pressures. Review of RFT pressures was the best quantitative tool for measuring the effect of a geological marker as a permeability restriction. The RFT pressures from Well 9/13-A40 indicated that three markers were associated with pressure differentials in 1985 when the well was drilled. The pressure differentials were small (8 psi across Marker 3b, 39 psi across Marker 3d, and 20 psi across Marker 4b, Fig. 5) but were clues that the reservoir was not draining like a tank. Review of RFT data from many wells indicated that typical pressure differentials are 15 to 40 psi. As an area becomes depleted, however, these small differentials can increase significantly. As an example, a 430-psi differential was observed across Marker 4a in Well 9/13-A44, which was drilled into a maturely developed area in 1989.

The review of RFT data clearly indicated the value of abundant pressure information early in the reservoir's life. In early wells, unfortunately, few RFT pressures were obtained because of the early assessment that the Beryl reservoir would behave like a tank. For some of these wells, the density of RFT measurements was inadequate to identify differential depletion confidently. In addition, RFT technology in the early years of Beryl development was relatively primitive, so when RFT data did suggest pressure differentials, measurement inaccuracies were generally assumed. A greater abundance of early RFT data would have allowed recognition of differential depletion sooner and better resolution of the vertical zonation. Well 9/13-A40, drilled 9 years after the start of production, was the first well to recognize differential depletion because it was the first well with an abundance of RFT measurements. Careful review of RFT data from wells drilled before Well 9/13-A40 indicated that the onset of differential pressures depended on the area voidage situation, and not simply on the timing of the well. For example, RFT data from Well 9/13-A09, drilled in 1977, only 1 year after production began, suggest several permeability restrictions with differential pressures of 10 to 40 psi. Well 9/13-A09 was drilled adjacent to a well producing >20,000 BOPD. Conversely, Well 9/13-A32, drilled in 1981 into an area with lower production rates, demonstrated no pressure differentials across markers that later proved to be permeability restrictions. This is discussed further later.

Cased-Hole Logs. Cased-hole logs were also re-examined. In general, several anomalous distributions of gas, oil, and water saturations were found. For example, the Oct. 1990 production log from Well 9/13-A40 (PLT in Fig. 5) indicated that 75% of the gas was coming from the bottom two perforation sets, while 50% of the oil and only 5% of the gas were coming from the top perforation set. The flow profile observed in Well 9/13-A40 is not possible without a vertical permeability restriction inhibiting the upward migration of gas. The permeability restriction is inferred at Marker 3d, where an RFT pressure differential of 40 psi was observed in 1985.

In a second example, Well 9/13-A01 was worked over in Oct. 1987 to alleviate high gas production. A pulse and decay (PDK) log was run to identify zones of high gas saturation. A carbon/oxygen (C/O) log was run to identify zones of high water saturation that were expected to be related to low-salinity (40 to 50 ppm) injection water. A gamma ray (GR) log was run in conjunction with the C/O log to identify zones of scale buildup caused by high water production. When the logs were interpreted in combination, they indicated high oil saturations in Units 3a and 3b, high water saturations in Units 3c and 3d, and high gas saturations in Units 4 and 5 (Fig. 7). A permeability restriction separating the high water saturations from underlying oil at Marker 3c was inferred. No corresponding RFT pressure differential was observed at this marker because the well was drilled very early in the development history. Recompletion of the well to Units 3a and 3b, however, recovered an additional 900×10^3 bbl of oil.

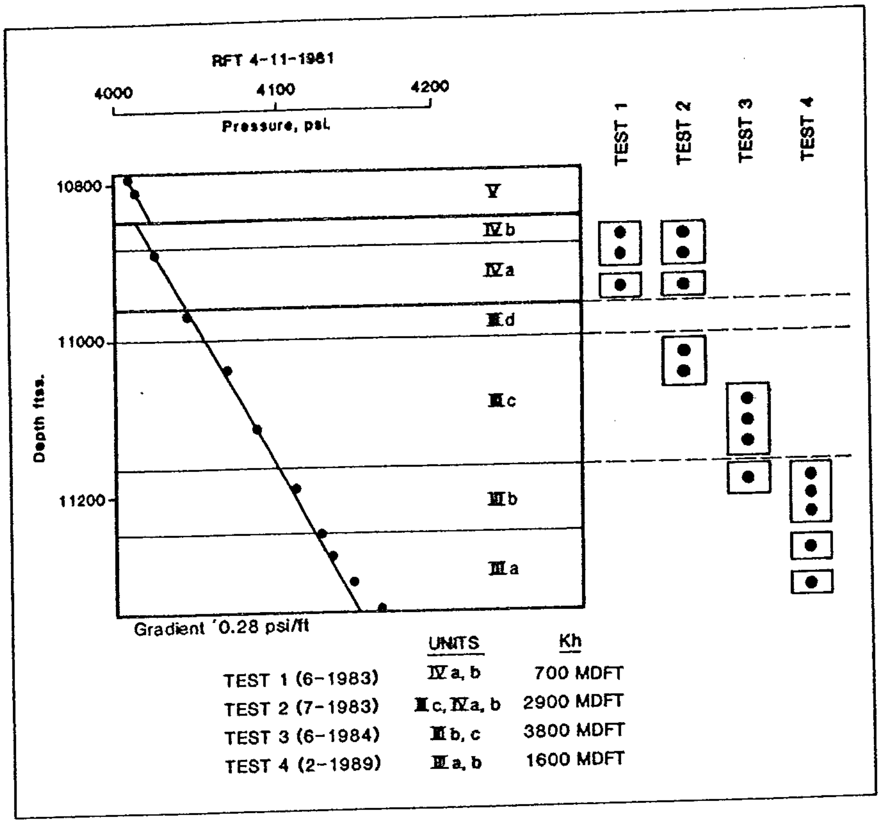


Fig. 8—Well 9/13-A32 RFT pressures vs. depth, perforated intervals, and pressure-transient test results.

Pressure-Transient Tests. Past pressure-transient tests were reviewed as an indirect method of identifying permeability restrictions. Routine pressure-transient tests were conducted in Beryl A as part of prudent reservoir management to calculate the permeability-thickness, *kh*, of the reservoir section in a given well. Theoretically, in a reservoir with no vertical permeability barriers, the calculated *kh* should not change when a well workover changes the perforated interval. Well 9/13-A32 was worked over four times to reduce gas production (Fig. 8), and the calculated *kh* changed after each workover. Permeability restrictions at two of the geologic markers are suspected to have caused the differences in calculated *kh* by limiting the effective reservoir thickness contributing to each perforation set. Interestingly, no RFT pressure differentials were observed when the well was drilled, indicating that the area was being depleted uniformly until the well was completed.

The difference in calculated *kh* (Fig. 8) between Tests 1 and 2 (700 and 2,900 md-ft, respectively) indicates that a permeability restriction exists either at Marker 4a or 3d and that the *kh* of the reservoir interval below these markers is 2,200 md-ft, assuming no interlayer crossflow. The difference in calculated *kh* between Tests 2 and 3 (2,900 and 3,800 md-ft, respectively) indicates that another permeability restriction exists at Marker 3c and that the zones below this marker contribute 1,600 md-ft to the perforated interval. Finally, the difference in calculated *kh* between Tests 3 and 4 (3,800 and 1,600 md-ft, respectively) indicates that Marker 3b is not a permeability restriction and verifies that the *kh* for the reservoir below Marker 3c is 1,600 md-ft, as calculated from Tests 2 and 3.

Reservoir Performance Histories. For further indirect evidence of permeability restrictions, the reservoir performance history was reviewed in relation to the geologic zonation. For example, the GOR in Well 9/13-A09 began to increase in 1982 in response to growth of the secondary gas cap. A workover was performed in 1983 in which all perforations above Marker 3d were plugged. The workover was unusually successful and reduced gas production for more than 2 years. Thus, a permeability restriction that inhibited the downward migration of gas was inferred at Marker 3d. No evidence is available to support this inference because Well 9/13-A09 was an early development well with only a few RFT points.

In another example, Marker 4a in Well 9/13-A37 was suspected to be a vertical permeability restriction. Review of the RFT data indicated a 25-psi pressure differential across the marker when the well was drilled. In addition, the well was perforated only above Marker 4a, and pressure-transient tests indicated a low *kh*. On the basis of these data, a 50-ft perforation interval was added below Marker 4a. In strong validation of a permeability restriction, the oil rate increased from 3,000 to 8,500 BOPD, while the GOR decreased from 4,500 to 1,800 ft^3/bbl.

Vertical Permeability Restrictions Summary

The reviews of RFT data, cased-hole logs, pressure-transient tests, and reservoir performance histories indicated that of the six geologic markers identified and correlated, four (Markers 3b, 3c, 3d, and 4b) are significant permeability restrictions causing differential depletion in parts of the central, north, and northwest flank areas. With this knowledge, workovers were performed and wells were drilled deeper to improve well productivity. For example, Well 9/13-A32 was worked over in 1988 to reduce high GOR production. At that time, the well was perforated in Zones 3b and 3c (Fig. 8, Test 3) and producing at 1,700 BOPD with a GOR of 5,500 ft^3/bbl. Pressure-transient Tests 1 through 3 in 1983 and 1984 (Fig. 8) indicated that Marker 3c was a permeability restriction. The well was drilled deeper and perforated below Marker 3c. The GOR decreased to 1,500 ft^3/bbl and the oil rate increased to 4,000 BOPD. By Dec. 1990, an incremental 1.3×10^6 bbl oil had been produced.

In a second example, Well 9/13-S35 was drilled into a southern area with known oil reserves but high water production. The well was designed to drill only 150 ft into the reservoir, but logging indicated that this interval was swept with water. Acknowledgment of the concepts of vertical zonation and differential depletion led to the well's being drilled deeper to find an oil zone. Confidence in these concepts was rewarded when a 70-ft oil zone was penetrated 300 ft into the formation. The vertical permeability restriction separating the oil zone from the overlying water was subtle, but the well was able to produce 1 million bbl oil nearly water-free at rates of 2,500 to 3,000 BOPD before being shut in for mechanical reasons.

Workovers designed to utilize the vertical zonation of the Beryl reservoir significantly affected overall production. In the central and northwest flank areas, successful workovers contributed an estimated 5 million bbl of incremental oil to production during 1987–90. Reduced gas production, resulting from the workovers, is an added benefit because oil production from the platform is sometimes constrained by the gas-compression facilities.

Conclusions

The Beryl reservoir, with its abundance of data through a long reservoir history, allows insight into the complexities of reservoir behavior and fluid movement. Even in this apparently massive sandstone reservoir, problems of horizontal and vertical permeability restrictions must be addressed. The reward for careful development of a reservoir model is a significant increase in recovery and well productivity in the field's mature years. Within the Beryl reservoir, faults act as horizontal permeability restrictions and result in areas of bypassed oil. The effect of these restrictions on fluid distribution can be studied by careful analyses of pressure and production histories and fluid monitoring.

In addition, thin lithologic breaks act as vertical permeability restrictions. The effect of these lithologic breaks can be studied by establishing a geologic zonation and carefully reviewing RFT data, pressure-transient tests, cased-hole logs, and reservoir performance histories. Horizontal and vertical permeability restrictions that originally seem insignificant may greatly affect the reservoir as it becomes more depleted.

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SI Metric Conversion Factors

bbl	× 1.589 873	E−01	=	m^3
ft	× 3.048*	E−01	=	m
ft^3	× 2.831 685	E−02	=	m^3
psi	× 6.894 757	E+00	=	kPa

*Conversion factor is exact.

Provenance

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