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Increasing Reserves Through Optimized Waterflooding: The Long Beach Unit, Wilmington Field, California

The Long Beach Unit is part of the giant Wilmington Oil Field and is located about 35 miles south of Los Angeles, California (**Figure 1**). The Unit originally contained more than 3 billion barrels of oil-in-place and has been producing under waterflood since the start of production in 1965. In 1992, ARCO reached an agreement with the City of Long Beach and the State of California to provide technology and capital for field redevelopment in exchange for a share of the incremental profits. The resulting optimized waterflood program added 135 million barrels of proven reserves with the potential to recover an additional 90 million barrels. This total target of 225 MMBO represents a 25% increase over the expected ultimate recovery prior to beginning the optimized waterflood.

To date, more than 875 million barrels of oil have been produced from the Long Beach Unit by drilling over 1400 wells (**Figure 2**). Well spacing is variable, ranging from about 10 acres in some of the shallow reservoirs to 40 acres in the deeper horizons. The Unit currently produces about 37,000 barrels of oil per day at an average water cut of 95%. Because of the potential for reservoir compaction and resulting subsidence, about 1.05 barrels of water must be injected for every barrel of fluid removed from the reservoirs.

The Long Beach Unit is part of a large, doubly-plunging anticline with a structural relief of about 1600 feet (**Figure 3**). Historically, this structure was interpreted to be an en-echelon anticline between the Newport-Inglewood and Palos-Verdes strike-slip fault zones. A re-interpretation based on a 1995 seismic survey indicates that this anticline is being carried southwestward on the back of a large blind thrust fault (THUMS-Huntington Beach Fault). The anticline is cut by several large normal faults, many of which also show strike-slip displacement. These faults have dips of 40-80 degrees and throws of 50-450 feet, effectively compartmentalizing the Long Beach Unit reservoirs.

Wells in the Long Beach Unit are primarily drilled from four artificial islands constructed in Long Beach Harbor. A cross-section beneath one of these islands shows that the stratigraphic column has been divided into five zones: the Tar, Ranger, Terminal, UP/Ford, and 237 Shale (**Figure 4**). The deepest zone is a naturally-fractured shale which has been penetrated by about a dozen wells. The other four zones are composed of semi-consolidated turbidite sandstones of Miocene and Pliocene age. The division of these sandstones into four zones was necessary because the total reservoir thickness is about 3300 feet, which is much too thick to produce from a single completion.

Core descriptions and log interpretations indicate that the Long Beach Unit reservoirs are part of a progradational submarine fan complex containing discrete lobes that are up to 200 feet thick in their mid-fan area and 2-6 square miles in size. The lobes exhibit a strong compensating relationship whereby the thickest portion of the underlying lobe is overlain by the thinnest portion of the next lobe (**Figure 5**). Laterally-extensive shales up to 30 feet thick separate these lobes (**Figure 6**). Internally, the lobes exhibit strong off-lapping behavior (shingling) at multiple scales, creating additional baffles and barriers to fluid movement. For example, some of the lobes can be subdivided into smaller lobate sandbodies that are 20-40 feet thick, 0.25-1 square mile in area, and separated by shales that are 2-5 feet thick. Mid-fan lobes in the Unit are primarily confined to the Tar and Ranger Zones. The deeper Terminal and UP/Ford Zones are dominated by thinner, finer-grained, outer fan sandstones. The net-to-gross ratios, permeabilities and oil saturations of these sandstones are all lower than in the mid-fan lobes.

Figure 7 summarizes the Long Beach Unit reservoir properties. A key aspect is that permeabilities extend over several orders of magnitude and the oil gravity is relatively heavy. This results in the viscous fingering of injected water, leading to early water breakthrough and the development of thief zones. These problems were exacerbated by early completions which consisted of gravel-packed slotted liners and very long completion intervals that sometimes exceeded 1000 feet. Water broke through quickly, and it was difficult to pump-off the wells, resulting in little production from the deeper sands in each completion. This problem was addressed in the early 1980's by drilling over 450 wells targeted into the lower portions of these initial completions. This subzoning program added 160 million barrels of oil reserves and increased the field rate by 30,000 BOPD.

By the late 1980's, decreasing oil prices made it difficult to continue the subzoning program, and the Unit looked elsewhere for capital and technology. To help fill this role, ARCO became a partner in the Unit in 1992, agreeing to spend at least $100 million on redevelopment. Initial work focused on integrating core and log data from hundreds of wells to refine the reservoir zonation. This was accompanied by a detailed material balance study to identify areas of the Unit that were underinjected or were experiencing water cycling. Many of these areas were located along the north flank of the Unit, where much of the water injected in the past had been lost to the aquifer instead of sweeping oil to producers (**Figure 8**).

Once these underinjected areas were identified, infill wells were drilled to change the well streamlines and create different pattern flood geometries. For example, in the northwest corner of the Unit (Block 1) the Ranger Zone was converted from a 3:1 staggered line drive to a series of 12 seven-spot patterns by drilling 15 new producers and 10 new injectors (**Figure 9**). The injectors were selectively perforated in underpressured sandstones with high remaining oil saturations to increase throughput. Producers were completed with slotted liners or as cased-hole completions to increase withdrawals. As a result of this work, water injection and produced oil rates doubled, with the oil rate reaching a peak of 6000 BOPD (**Figure 10**). A key element in this work was the control of waterflood conformance at the injectors, by shutting-off injection in those reservoirs producing above an economic water cut (97%) and redirecting this water into reservoirs containing moveable oil.

Horizontal producers have played a critical role in optimizing recovery from the Unit. More than 40 of these wells have been drilled and completed to date, with horizontal well lengths ranging from 800 to more than 1800 feet. The average initial production of one of these wells is about 250 BOPD at a 45% water cut, which is 2.5 times that of an average vertical well. The horizontal wells typically target 20-50 foot thick sands containing oil that has been banked against faults by water injection, or containing attic oil that has been left behind in the tops of large sandbodies**.** An example is shown in **Figure 11** where injected water has effectively swept sandbodies 3a and 3b, but sandbody 3c at the top is separated from these by a thin, off-lapping shale. A pass-through log shows the existence of an oil accumulation in this sandbody, which can then be tapped by a horizontal well.

Hydraulic fracture stimulation has been another critical technique used to increase oil rates and recoveries. The Long Beach Unit sands are semi-consolidated with relatively high permeabilities, requiring short, fat, high conductivity fractures to increase production. Because the stress contrast is high (shales are stronger than the sandstones), fracture stimulations are conducted in multiple stages. Cross-linked gels are used to transport the proppant which is typically a resin-coated sand that helps inhibit the production of formation sand and reduce sand embedment. Fractured wells typically produce 2-3 times as much oil as unstimulated wells. The target of most fracture stimulations has been the UP/Ford Zone, which contains thinner, lower permeability sands. About 50 wells were fracture stimulated in this zone over a two year period with the incremental oil rate reaching a peak of 5000 BOPD in early 1998 (**Figure 12**).

In order to improve the structural interpretation of the Long Beach Unit, locate missed pay, and identify deeper or step-out opportunities, a 3D seismic survey was conducted in early 1995. Within one year of its acquisition, the survey was being used to optimize well planning. For example, in 1997-98, the seismic survey was used to adjust the trajectory, bottomhole location or completion interval of 33 new wells. The survey was also used to explain well performance anomalies through the reinterpretation of faults (**Figure 13**). Several in-field prospects were imaged including amplitude anomalies and compartments along strike-slip faults (**Figure 14**).

A key finding was that the Long Beach Unit is contained in the hanging wall of the THUMS-Huntington Beach Fault (**Figure 15**). Beneath this fault, high impedance contrasts indicate the possibility of structural and combined structural-stratigraphic traps. These traps are in Miocene and lower Pliocene turbidite sandstones equivalent to producing horizons in the Long Beach Unit. In addition, the possibility exists for production from Monterey-type fractured chert reservoirs atop Miocene paleo-highs. To test this subthrust potential would require drilling a well 14,000 feet deep at a cost of about $2.5 million dollars. Because of the relatively high geologic risk associated with such a well, a new, high-resolution seismic survey is being considered to quantify these deeper prospects. In addition, lessons learned in acquiring the first survey should improve its resolution, allowing the internal architecture of the producing LBU reservoirs to be better imaged.

During the optimized waterflood program, effective cost management has been a huge contributor to financial success. Increases in pump run times, construction of a waste injection facility on one of the islands, and improvements in rig scheduling efficiency are just a few of the ways in which costs have been reduced. This is absolutely critical as water cuts continue to rise and oil production decreases. Operating costs are about $8 per barrel of oil with the potential to reduce this further in the future. Development costs are a little over $2 per barrel as shown in **Figure 16**. In addition to the remaining potential within and beneath the Long Beach Unit, there are other possible opportunities outside the current leaseline. For example, **Figure 17** shows that extended reach wells could be drilled eastward to access oil in the State PRC 186 lease which was abandoned in the early 1990's with several million barrels of remaining oil reserves.

Figure 18 summarizes the history of the optimized waterflood. The initial work emphasized redirecting injected water into those intervals with remaining oil. This was followed by production increases from horizontal wells and fracture stimulation. The graph clearly shows that the optimized waterflood significantly exceeded the 1991 Unit forecast (base case).

Figure 1: Long Beach Unit Regional Setting

Figure 2: Reservoir Performance

- Oil Rate = 37,000 barrels per day
- Water Rate = 660,000 barrels per day
- Water Injection Rate = 760,000 barrels per day

- Number of Active Producers = 670
- Number of Active Injectors = 370
- Well Spacing = 10 to 40 acres

- Total Oil Production = 875 million barrels
- Total Gas Production = 230 billion cubic feet
- Total Water Production = 4.7 billion barrels

Figure 3: Structure of the Long Beach Unit

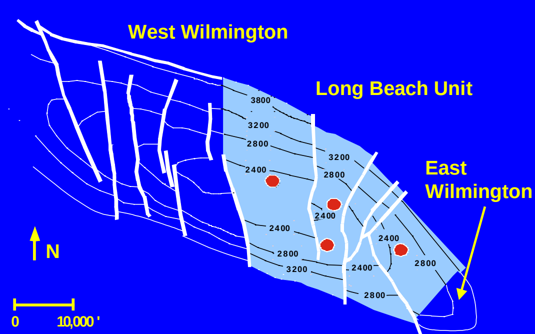


Figure 4: Cross-Section Through Drilling Island

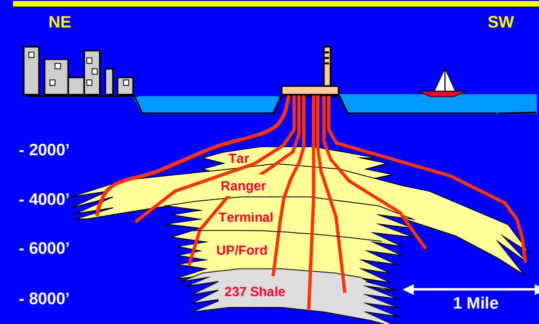
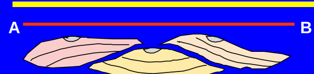


Figure 5: Long Beach Unit Depositional Setting



- Submarine fan deposits
- Shallower zones composed of thick mid-fan lobes
- Deeper zones composed of thinner outer fan sandstones
- Sandbodies exhibit strong off-lapping behavior at multiple scales

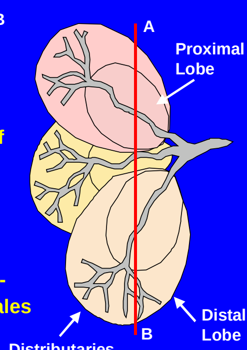


Figure 6: Sandbody Geometries & Shales

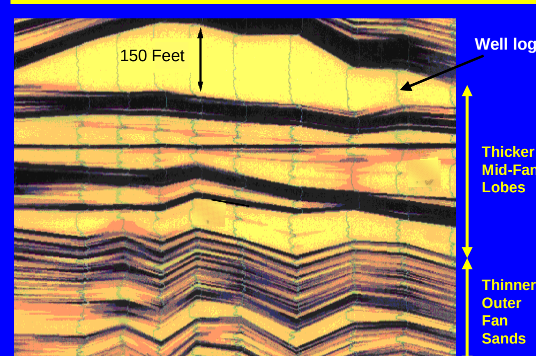


Figure 7: Reservoir Properties

- **Porosity = 22 to 27%**
- **Permeability = 1 to 1,000 md**
- **Initial Water Saturation = 25 to 40%**

- **Depth = 2,500 to 7,000 feet**
- **Gross Thickness = 3300 feet**
- **Pay Thickness = 900 feet**

- **Oil Gravity = 13 to 25 degrees API**
- **Oil Viscosity = 0.3 to 450 centipoise**
- **Temperature = 100 to 175 degrees F.**

Figure 8: Ranger Zone Redevelopment Focus

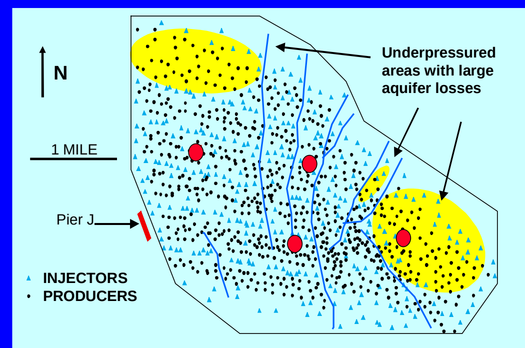


Figure 9: Ranger Block 1 Optimized Waterflood

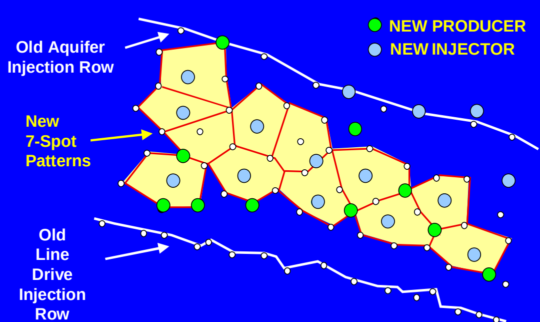


Figure 10: Ranger Block 1 Waterflood Response

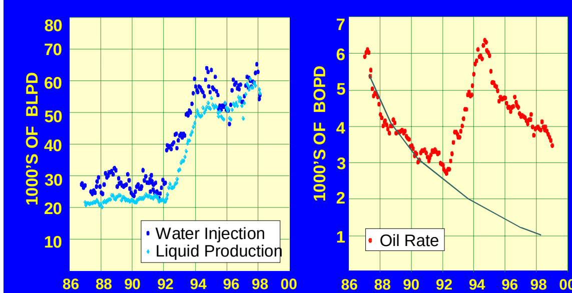


Figure 11: Capturing Attic Oil with Horiz. Wells

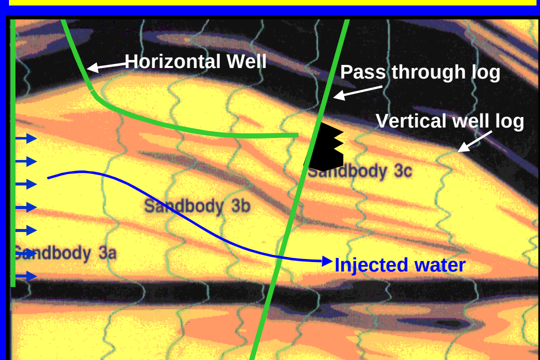
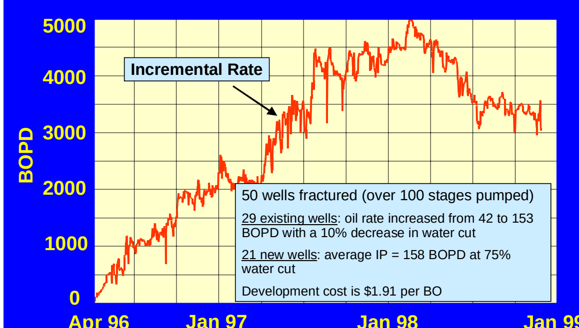


Figure 12: UP/Ford Fracture Stimulation Results



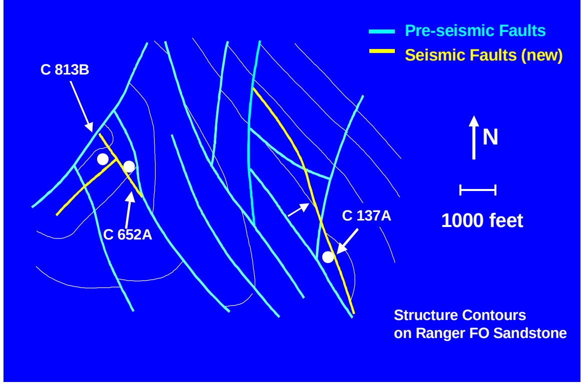


Figure 13: Reinterpretations of Faults from Seismic

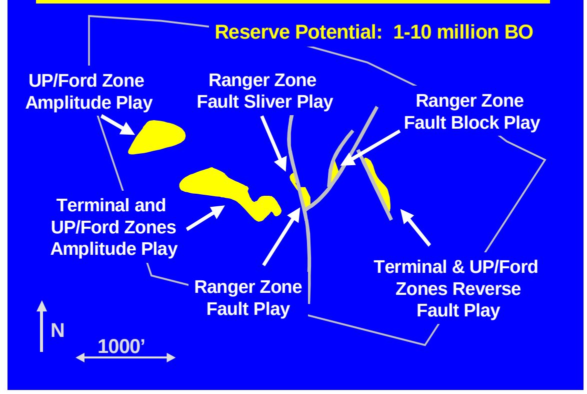


Figure 14: Producing Zone Seismic Targets

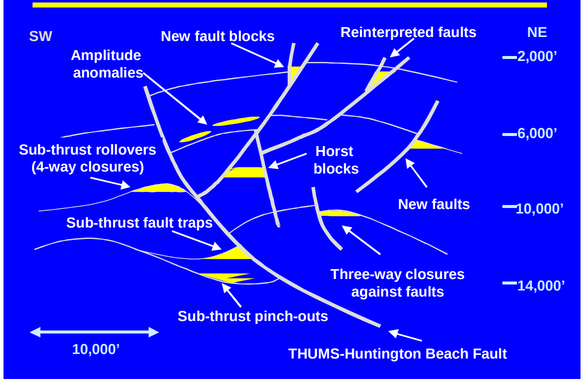


Figure 15: 3-D Seismic Opportunities

Figure 16: Development Costs: 1/97 to 6/99

Project Type	Number of Projects	Cost $ Million	Inc. Reserves Million BO	Dev. Cost $ / BO
Drilling	65	47	17	$2.76
Investment Wellwork	133	24	16	$1.50
Total	198	71	33	$2.15

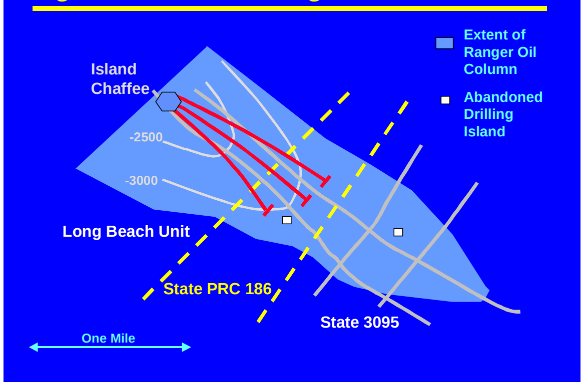


Figure 17: East Wilmington Potential

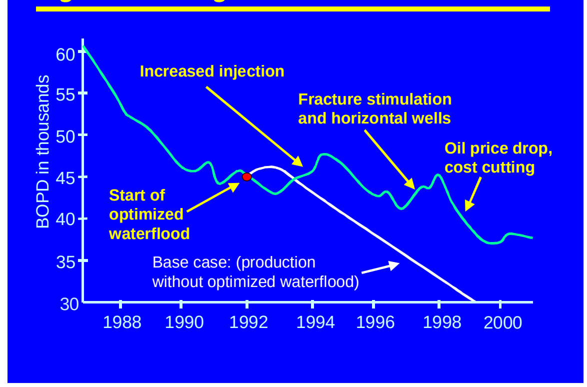


Figure 18: Long Beach Unit Oil Rate