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CHOPS Evolution – Creating CHOPS Contiguously from Toe to Heel in Horizontal Wells

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ABSTRACT

CHOPS – **C**old **H**eavy **O**il **P**roduction with **S**and. A recovery technique that benefits from the stimulation effect produced by inducing sand inflow in unconsolidated sandstone reservoirs.

Pre-CHOPS primary recovery was 5% to 8%. CHOPS recovery is 8% to 15%.

Primary recovery from Non-thermal heavy oil horizontal wells is similar to off-setting CHOPS wells. They are constructed to prevent sand production.

CHOPS and horizontal wells are leaving about 90% of reserves at the end of primary production. Inducing sand inflow contiguously from Toe to Heel in Horizontal wells would achieve 30% or greater primary recovery by:

1. Expanding the production drained area of a horizontal well up to two orders of magnitude.
2. Accessing the unexploited reservoir that occurs between vertical CHOPS wells.

Capital cost per recovered barrel can be shown to be competitive with vertical CHOPS well development, and, with conversion of depleted vertical CHOPS wells to secondary flood schemes.

The technique offers opportunities to reduce operating costs over the use of vertical wells in developing a field.

As a sequential exploitation strategy, parallel horizontal CHOPS wells create a post-CHOPS wellbore geometry with six orders of magnitude greater reservoir contact than vertical wells for flood schemes that would increase secondary recovery.

KEY WORDS

CHOPS, CHOPS Evolution, Horizontal well CHOPS, Limited Entry Perforating (**LEP**), sequential re-completions, cold heavy oil recovery, primary recovery, non-thermal heavy oil

INTRODUCTION

Cold heavy oil production from unconsolidated sandstone reservoirs in Western Canada began in the late 1930's. Evolution of methods to increase recovery has revolved around overcoming the impediments of oil viscosity and sand influx.

Introduction of the Progressing Cavity Pump (PCP) in the early 1980's overcame rod float allowing the wells to be produced at maximum drawdown. Producing sandcuts suggested complete destabilization of the near wellbore matrix. Total volumes of sand produced and the production profile of sand and fluid indicates that sand is also flowing from further out in the reservoir causing beneficial alterations in permeability. Fortunately the PCP could maintain continuous maximum drawdown at high sand concentrations until the sand inflow eventually diminished to trace amounts. Oil production rate remained high for several years until inflow abruptly ceased. Overall primary recovery has increased on average 7% as a result. In addition, reservoirs that could not be produced with reciprocating rod pumps became exploitable.

Horizontal wells with slotted liners were introduced for cold production about a decade later with the expectation of 2.5 to 3 times a vertical well recovery. Although they achieved profitable payouts they were theoretical and economic failures. Vertical CHOPS wells could be drilled and completed for half the cost and achieve a similar volume of oil recovery.

Combining the technologies of horizontal wells, CHOPS, sand control perforating, jet pumps, and sequential re-completion of horizontal wells from Toe to Heel, it can be shown cold primary heavy oil recovery can increase up to 30% or more.

Although developed while prospecting wells in the Lloydminster Heavy Oil Belt in Western Canada, the technique is based on the geomechanical behavior of unconsolidated sandstone during fluid extraction. It follows that any unconsolidated sandstone reservoir that contains mobile oil at reservoir conditions is a candidate. Exceptions would be oil pay in direct contact with active water aquifers or gas caps.

The Study Area

The prospected area, Township 32 Range 19 W3 to Township 55 Range 27 W3, covered 7,776 square miles (20,140 square kilometers) containing approximately 14,250 wells. Horizontal to vertical well ratio is 1:10. Eliminating thermal operations and wells in reservoirs where oil was in direct contact with an active water aquifer left 576 horizontal wells of interest.

Vertical wells are typically drilled on 40 acre spacing due to regulatory requirements based on a drainage radius derived using conventional oil theory calculations. Some approved down spacing has resulted in 20 acre spacing. In special pilot cases one quarter to one half of a section of land was drilled on 2 acre spacing.

Horizontal wellbores are 300 meters to 1,500 meters long at True Vertical Depths ranging from 400 meters to 800 meters. Wellbores were successfully placed in net pay from 1.5 meters to 20 meters thick. All wells have slotted liners and were drilled with medium radius build sections.

Sand size ranges from very fine to fine (0.062mm to 0.125mm diameter). Experimentation to optimize slot size and density resulted in slot widths ranging from 0.010 inch to 0.250 inches and densities of 26 to 250 slots per meter. Insignificant volumes of sand cleaned from some depleted horizontal wells in various reservoirs suggest that all combinations of slot widths and densities have been successful at minimizing sand inflow.

Dead oil viscosities are 800 centipoises to 100,000 centipoises. Average oil rates are 30 barrels per well per day. At 30% solution gas by volume the highest viscosity oil has achieved rates of 375 bopd indicating that oil mobility is mostly a function of the expansion of the gas absorbed in the oil rather than the oil's viscosity. Reservoir temperature is 0.044 degree Celsius/meter. Original Reservoir Pressure is 9.8 kPa/meter.

Reservoirs are either relatively homogenous sands at a macro scale or are incised meandering channels. The homogenous sands contain 3m to 10m gross pay with 1.5m to 10m net pay. They can be contiguous over several square miles. Multiple pay zones are common in some areas with barriers between zones a few meters to tens of meters thick. Channels can be several kilometers long and up to 800m wide with 8m to 30m continuous net pay.

Means to Attaining 30% or more Recovery Using Horizontal Well CHOPS

Inducing Sand Inflow

3D seismic[1] over depleted CHOPS vertical wells shows production affected areas surrounding the wells. Larger areas correlate to greater oil recovery and total volumes of sand produced. Calculating areas of depletion using produced fluid and sand volumes closely match the areas depicted on the 3D seismic.

The calculated diameter of the production affected area surrounding a vertical CHOPS well is one to two orders of magnitude greater than the width of the calculated production affected area along a horizontal well. (Figure 1)

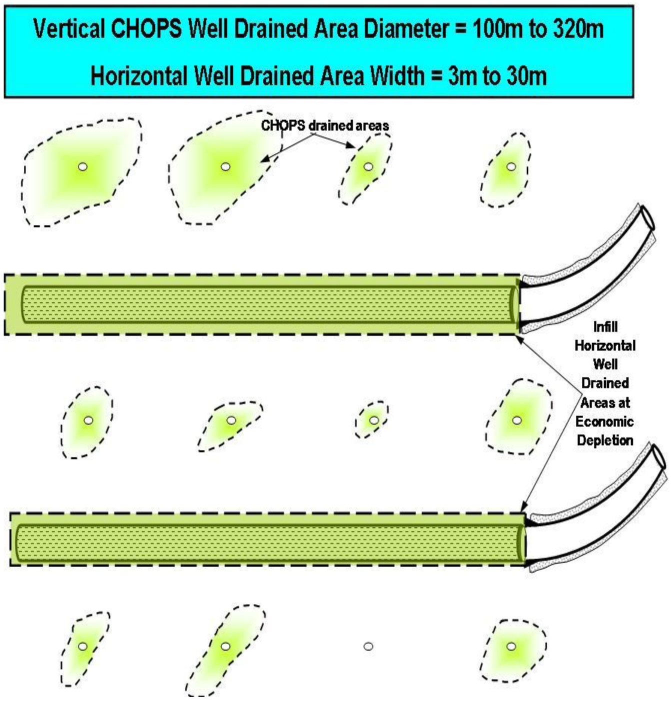

Figure 1. Illustrates drained areas surrounding vertical CHOPS wells identified by 3D seismic. Infill horizontal wells with pre-CHOPS drained areas are conceptual overlays.

CHOPS wells produce sand volumes 3% to 5% of total oil recovered while horizontal wells produce virtually no sand.

It follows that re-completing a horizontal well to induce sand inflow would achieve a wider production affected area thereby increasing recovery.

Sequential Recompletions

The second prominent feature identified by the 3D seismic is that production affected areas surrounding vertical CHOPS wells are insular and small in size relative to the surrounding unaffected reservoir. Infill drilling has proved pressure discontinuity between the production affected areas and the rest of the reservoir. In addition, terminal depletion occurs abruptly in vertical CHOPS wells. At depletion bottomhole pressure is less than 1% of Original Reservoir Pressure. This pressure will remain so for years further indicating pressure discontinuity with the remainder of the reservoir.

Sequential re-completions, with each sequence produced to depletion before moving uphole, and spaced the diameter of the production affected area of an off-setting vertical CHOPS well, would generate multiples of vertical well recovery from a single horizontal well. (Figure 2)

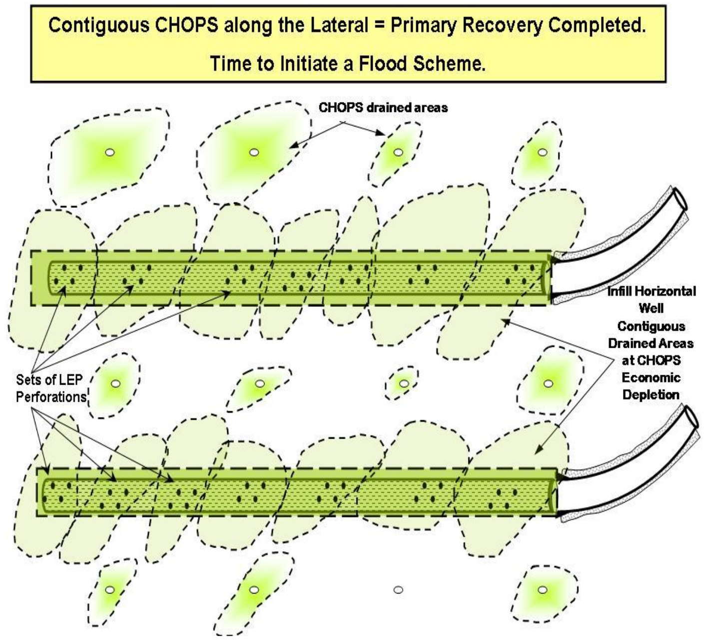

Figure 2. The expanded drained areas along the horizontal well created by sequential Limited Entry Perforating (**LEP**) are conceptual overlays.

Two other methods that could be used to determine re-completion spacing are cased hole neutron density logging to identify changes in porosity along the wellbore, or 4D seismic.

The Physics of CHOPS

Geomechanical behavior of unconsolidated sandstone coupled with foamy oil flow is more successful in explaining observed CHOPS production behaviour[2].

The simplest description of the geomechanical stress condition is: Fluid Pressure + Horizontal Stresses = Vertical Stresses.

Removing fluid puts the system into imbalance. Uncemented sand grains re-organize in reaction to the stress imbalance resulting in dynamic alteration of porosity and permeability from the near wellbore to further into the reservoir.

Risnes and Bratli's[3] experiment with unconsolidated sand under triaxial stress demonstrated fluid flow rate to be the primary factor affecting the production of sand:

1. At very low flow rates virtually no sand was produced.
2. Discrete intermediate production rate ranges produced sand free. At the upper end of each discrete

rate range sand production occurred in small amounts temporarily.

3. At very high rates the sand matrix totally destabilized resulting in massive sand production.

Tremblay et al[4,5] used CAT Scans to observe the growth of tunnels while flowing live oil through unconsolidated sand. Backpressure and rate were held constant. Pressure was measured along the length of the sample vessel. Sand production occurred from the tip of the tunnel until geomechanical forces re-established matrix stability at a particular rate and backpressure within the tunnel. When the tunnel stopped growing in length it remained stable. Complete sudden removal of the backpressure caused total collapse of the tunnel and massive re-organization of the remaining sand in the vessel resulting in an overall increase in porosity.

Geomechanics offers a plausible explanation for the phenomena creating pressure discontinuity between depleted wells and the remainder of the reservoir. As fluid and matrix material near the wellbore are removed the vertical force of the overburden is redistributed to the parts of the reservoir containing higher sand concentration causing compaction arches to form. The final result is a compacted sand dome-like structure which cuts off further fluid flow and isolates the depleted area from the remainder of the reservoir.

Field Observations Match Experimental Results

Pre-CHOPS wells were completed 90% to 95% underbalanced to encourage the well to unload sand and drilling fluid damage from the near wellbore. A service rig mechanically removed sand laden fluid until sand inflow stopped, then installed a reciprocating rod pump sized to match fluid inflow rate. The well would produce below 1% sand cut. If there was a means of increasing the pump speed, an influx of sand would occur. The service rig would return to remove sand laden fluid from the well. When sand inflow stopped the pump could be installed and produced below 1% sand cut at the new higher rate.

Converting a rod pumped well to a PCP allowing for maximum drawdown that resulted in sandcuts increasing to 60% and 70% for a brief period before diminishing eventually to below 1%. In a reservoir with 30% porosity, this high sand cut suggests total disintegration of the near wellbore sand matrix. Cased hole gamma-ray and neutron density logging after depletion has shown changes in the gamma-ray and an increase in porosity that supports the speculation of near wellbore matrix disintegration.

Horizontal well liner slot widths choke the viscous foamy oil inflow generating a very high backpressure against the reservoir. Oil seeps at a creeping rate from the reservoir at this high back pressure without dislodging sand grains. Fluid removal allows the vertical and horizontal stresses to push the sand grains closer together causing compaction which impedes inflow. If the fluid is carrying fines, they can lodge in the compacted pore throats further inhibiting inflow. Eventually inflow becomes uneconomic. Evidence of this compaction occurred when a slotted liner was accidentally pulled from a well during an attempted clean-out of the liner intended to restore production. After cleaning and inspecting the liner it was re-installed without issue. Because of the ease of extraction and re-installation, the same workover was conducted on five near-by wells without issue. None of the workovers restored inflow.

Case Study: Results from Two Sequential Re-completions of an Economically Depleted Horizontal Well (Figure 3)

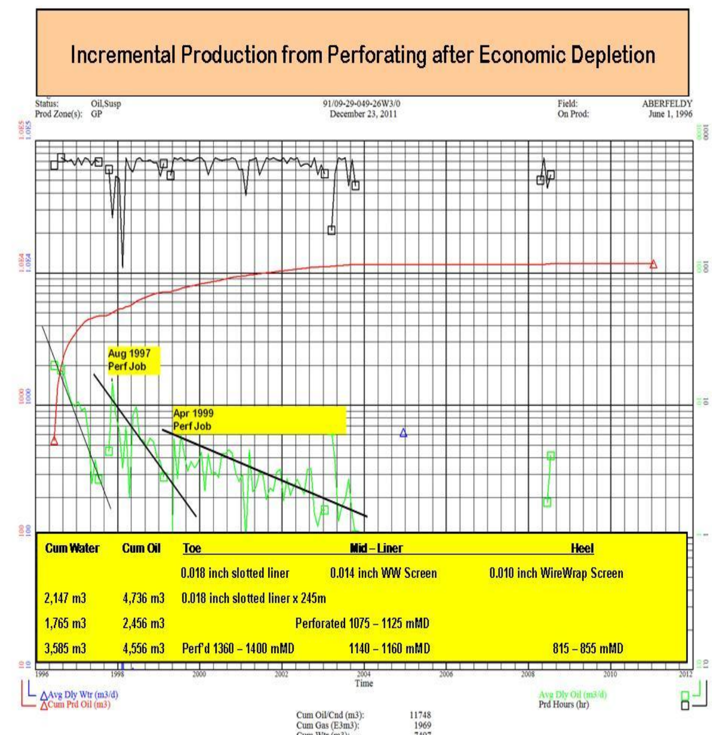

Figure 3. Description of the Horizontal well slotted liner segments, sequential perforation intervals, and production associated with each.

Two vertical wells in 4 meter thick pay were produced to depletion as a first step to exploit a large contiguous asset. Average recovery per vertical well was 3,541 m3 at 18% watercut.

An 855m horizontal wellbore was drilled adjacent to the vertical wells to evaluate horizontal well recovery capability. Analysis of sand sampled from the vertical wells was unable to generate conclusive results for liner slot width selection. The solution chosen was to test three slot widths: 0.018 inch in the Toe, 0.014 inch in Mid-Liner, and 0.010 inch in the Heel. Each set of slot sizes were segregated using two blank joints of liner with inflatable external casing packers at each end to retard flow in the annular space outside the liner. The lengths of slotted liner were 245m, 191m, and 335m, respectively.

The Toe of the well was produced first. The slot area open to flow was 1,208 square inches compared to 80 square inches of perf area in the vertical wells. A PCP was landed at the top of the build section to avoid rapid wear failure of the rods and tubing. Six hundred meters of tailpipe with a packer on the end were landed in the blank liner uphole of the Toe slots to isolate production from the uphole liner. Production rate was similar to the off-setting vertical wells. Sand cut was a trace. Ultimate recovery was 29% greater than the vertical wells.

At economic depletion of the Toe, the tailpipe and packer were removed. The well was produced for two months. Production rate did not change indicating there was no inflow from the other two sections of slotted liner.

50m of the Mid-liner were perforated at 13 shots per meter using alternating Big Hole and Deep Penetrating charges. Perforation diameters were 0.8 inches and 0.6 inches respectively. Perforating created 261 square inches of liner open to flow. Initial rates were similar to the production from the Toe. Sand cuts at surface were a trace. Overall recovery was 52% of the recovery from the Toe.

Following economic depletion of the perforations in the Mid-liner, plans were made to perforate in the Heel, Mid-Liner, and Toe. A workstring encountered fill inside the liner at the beginning of the perforations in Mid-Liner. It was flushed back into the formation by pumping lighter crude down the annulus and workstring simultaneously while moving the workstring downhole. The same perforation charges and shot density were used to perforate 40m in the Toe, 20m in Mid-Liner 15m downhole of the original perforations, and 40m in the Heel. Initial production rate was 60% of the previous rates. Sand cut was a trace. Overall recovery was similar to the original Toe recovery.

Total recovery from the horizontal well was 11,748 m3 at 39% watercut. This was the only cold production horizontal well in this prospected area to have recovered multiples of the off-setting vertical wells. It was the only economically depleted horizontal well to have been perforated.

Calculated width of the area affected by production in the vertical wells was 70m. Production volume from the Toe slots generated a calculated width of 31m. Production from the 50m and 100m of perforation generated calculated widths of 94m and 91m, respectively.

Case Study Observations:

1. Perforating economically depleted horizontal well slotted liner can restore profitable inflow.

2. Multiple perforation events in different sections of the liner each generated profitable production.

3. The width of the production affected area of the slotted liner is less than the diameter of the area affected by production of off-setting vertical CHOPS wells.

4. Perforated areas of the liner created production affected widths greater than the slotted area.

5. Landing the pump hundreds of meters from the perforations impaired its ability to remove sand inflow possibly leading to premature cessation of economic production.

CAPEX and OPEX (in Canadian Dollars)

Capital Cost Estimate per Recovered Barrel (CAPEX)

The zone used to derive an estimate of capital cost is ubiquitous over a very large area. Thousands of vertical wells have been drilled into this zone making it well known and predictable. It has the least prolific production rates and overall recovery of the several zones in the region. It also has the thinnest commercial net pay at 1.5m to 2m. Demonstrating economic viability in this zone would be incentive to infill drill with horizontal wells in this and other zones throughout the Lloydminster Heavy Oil Belt.

Another attraction is the operator of the sample section had drilled 14 parallel horizontal wells 100m apart and 1,500m long amongst off-setting depleted vertical wells which are on 40 acre spacing. Horizontal well production came on at 7 to 15 times vertical well rates further supporting the premise that horizontal wells can access untapped oil outside the depleted area of the vertical wells.

The 16 vertical wells had been produced to depletion 20 years earlier. They provided the average volume per CHOPS well used in the capital cost estimate. The average diameter of drained area from these 16 wells was 90m. Using 100m between sequenced re-completions of the horizontal wells reduces the number of re-completions thus adding a factor of conservatism to the overall recovery and cost estimate.

Reservoir heterogeneity and planar unevenness affected the amount of horizontal wellbore in effective pay. Length of wellbore in effective pay impacts the recovery volume of a re-completion sequence. 16 re-completion sequences represent 100% of wellbore in effective pay. Costs based on 80% and 50% of wellbore in effective pay were generated to provide a range of costs from ideal to worst case expected.

Sequentially re-completing an existing economically depleted horizontal well from Toe to Heel is estimated to cost $4 to $6 per recovered barrel.

As a development strategy, drilling and sequentially re-completing 14 parallel wellbores 1,500m in length from pads is estimated to cost $7.26 to $11.43 per recovered barrel. (Figure 4)

Estimated Capital Cost per Recovered Barrel for Sequenced CHOPS in 1.5m of Net Pay based on 3,394m3 recovery per **LEP** Sequence

Well Length to TD meters	Meters of Lateral in Effective Pay	Number of 100m Drained Area Sequences	Total Oil per Well m3	Drill Cost per Well with **Slotted Liner**	Initial Completion Cost	1st Sequence **LEP** Recompletion Cost	Total Cost for Subsequent Sequence Recompletions	**Total Capital Cost per Barrel**
2200	1500	16	54,304	$1,100,000	$260,000	$130,000	$990,000	**$7.26**
2200	1200	13	44,122	$1,100,000	$260,000	$130,000	$792,000	**$8.22**
2200	750	8	27,152	$1,100,000	$260,000	$130,000	$462,000	**$11.43**
1500	800	9	30,546	$1,000,000	$260,000	$95,000	$528,000	**$9.80**
1500	400	5	16,970	$1,000,000	$260,000	$95,000	$264,000	**$15.17**

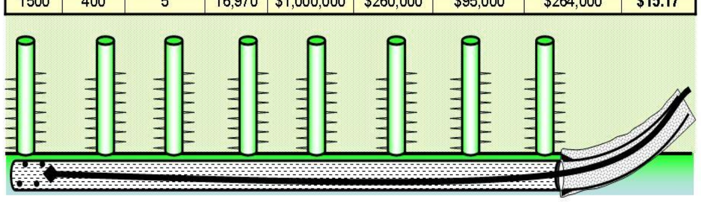

Figure 4. On a new well the cost estimate follows the sequence: 1. Produce the entire slotted liner to economic depletion using a jet pump landed at the first slots below the Heel. 2. First re-completion follows at the Toe. 3 Subsequent re-completions move uphole to the Heel.

224 vertical wells at $600,000 per well to drill & complete would have to be drilled to directly access the same amount of reservoir in this case. CAPEX would average $28 per recovered barrel.

Representatives of various companies report costs of $12 to $17 per recovered barrel for the conversion of sixteen depleted vertical wells to waterflood or polymer/ASP floods for an incremental 8% to 12% recovery.

<u>Operating Costs (OPEX)</u>

During the past 20 years two service companies have demonstrated that jet pumps deployed on coil tubing are effective for removing sand laden fluids from horizontal well liners. The jet pump surface equipment and its installation are similar in cost to PCP hydraulic skids with natural gas engines. With no moving parts, proven treatment processes to mitigate abrasion/erosion, the ability to riglessly access the downhole components for replacement, and a higher tolerance before failure when pumped off, the jet pump would experience lower well service and intervention costs than a PCP in this application.

Individual well life will increase from an average 5 years to 20+ years affording opportunities to create further efficiencies in sand handling and disposal practices.

Pad drilling reduces the amount of surface land disturbed for drilling and production operations by 60% while accessing six orders of magnitude more reservoir than vertical wells. The concentration of wellheads on pads supports cost reducing and production enhancing infrastructure such as central facilities, flowlines, sales oil pipeline connections, solution gas gathering for lease fuel, and electrification.

Post-Horizontal CHOPS Flood Schemes

Radial dispersion models inaccurately describe what is observed when injecting into depleted unconsolidated sandstone reservoirs. It was known prior to CHOPS that channeling occurred in heavy oil waterfloods. Channels form between injectors and producers six to eighteen months after injection begins. Field work in 1993 and 2012 demonstrated the existence of channels ranging from 3mm to 7mm in width.[6,7]. Up to 80% of flood recovery occurs before breakthrough. The remaining recovery occurs over decades of injecting fluids at higher and higher rates as watercut increases to 95%+. Overall recovery ranges between 8% and 12%.[8]

Channeling will also occur in post-horizontal CHOPS flood schemes. The advantage of post-horizontal CHOPS wells as injectors is that placement of injected fluids can be distributed over the length of reservoir accessed by the horizontal wellbore using Injection Control Devices. Pulsed Fluid Injection[9] appears to spread injected fluid through more of the reservoir lengthening the time to breakthrough. Combining these technologies with the post-horizontal CHOPS well will increase secondary recovery over vertical well flood schemes.

Conclusion

Although it has been demonstrated that perforating an economically depleted horizontal well generates profitable incremental oil recovery, the full potential for cold primary oil recovery from horizontal wells has yet to be realized.

Sequentially creating CHOPS production affected area the length of the wellbore is the next step. Re-completing economically depleted horizontal wells with Limited Entry Perforating and a jet pump is the means to demonstrate this.

When the veracity of the technique has been established it can be utilized

1. In any unconsolidated sandstone reservoir with mobile oil at reservoir conditions. Exceptions would be zones where oil pay is in direct contact with active water aquifers or a gas cap.
2. To infill fields with depleted vertical wells.
3. To infill in flood schemes that have reached their limit of profitability.
4. To exploit less prolific assets which are marginal or unprofitable using vertical wells.
5. To replace the use of vertical wells as the means of new field development.

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