New Production Technologies

Maurice B. Dusseault
University of Waterloo
Waterloo Ontario Canada
SPE DISTINGUISHED LECTURER SERIES

is funded principally through a grant of the SPE FOUNDATION

The Society gratefully acknowledges those companies that support the program by allowing their professionals to participate as Lecturers.

And special thanks to The American Institute of Mining, Metallurgical, and Petroleum Engineers (AIME) for their contribution to the program.
New Production Technologies

- **CHOPS** (Cold Heavy Oil Prod. w. Sand)
- **PPT** (Pressure Pulsing Techniques)
- **GAD** (Gravity Assisted Drainage)
  - IGI (Inert Gas Injection)
  - SAGD (Steam-Assisted Gravity Drainage)
  - VAPEX (Vapor-Assisted Petr. EXtraction)
- **Hybrids** of these will be used
- Projects will use them in “phases”
The Coming Revolution Will:

- Allow much higher oil recovery from all types of oil reservoirs
- Allow us to re-enter old fields and recover much of the oil left behind
- Permit economic recovery of more viscous oils ($\mu > 100$ cP in situ)
- Extend recoverable reserves of world oil dramatically
**World Reserves**

- Currently, 90% of production is from conventional oil
- Heavy oil and bitumen are growing rapidly
- Canada and Venezuela together have >35% of the non-conventional oil reserves in sands

**World Oil in Place**

- Conventional: <100 cP
- Heavy Oil: 100 – 10000 cP
- Bitumen: >10,000 cP

New Production Technologies
Future of Conventional Oil

- 2001 predictions:
  - Demand +1.5%/yr
  - Less replacement
  - World production peaks in ~2006-2008
  - Middle East now at 30%, 50% by 2011

Conventional Oil Prediction in Red
Total Need Prediction in Blue Dots

Campbell and Laherrère
March 1998 Scientific American, p. 78 ff

New Production Technologies
Only CSS was commercially viable, and only in the very best reservoirs (> 25 m, uniform, homogenous)
New Production Technologies

Commercial technologies have emerged in all categories

Modified after Isaacs, 1998
Technology Drivers

- Better understanding of the physics
- Better equipment
  - Progressing cavity pumps
  - Coiled tubing drilling and workovers
- Horizontal wells
- Improved monitoring technologies
- Better waste handling and disposal
- Canadian heavy oil and tar sands work
- etc...

New Production Technologies
Alberta Bitumen Production

2.2 MB/day

0.75 MB/day

Actual → Forecast

In situ
Surface mining

Courtesy: Alberta EUB
Horizontal Wells (Cold)

- Large numbers of horizontal wells have been drilled in Canada since 1990
- Applications in many technologies
  - Direct “cold production” of oil (high $\Delta p$)
  - Inert Gas Injection (no $\Delta p$)
  - Thermal processes (SAGD, drive, ...)
  - WAG, various IOR configurations
- Essential for *gravity assisted drainage*
- Large applications in Venezuela
The “Old” Technologies

New Production Technologies
The “Old” Technologies

- Cyclic steam stimulation
- Steam drive (many variations)
- Pressure-driven (Δp) processes
  - High p water floods, solvents...
- Pressure-driven combustion processes
  - Wet or dry, forward or reverse, air or O₂
- All these processes suffer from
  - Advective instability (Δp & µ instabilities)
  - Poor recovery, heat cost, well problems
Steam Drive Processes

- Gravity override
- Bypassed oil
- Poor recovery
- High heat losses
- Sheared wells
CHOPS

- **C** - **Cold**
- **H** - **Heavy**
- **O** - **Oil**
- **P** - **Production with Sand**

- Produces ~650,000 bbl/day of <20° API oil in Canada (25% of total!)
- >20% oil recovery in good reservoirs
- Applicable worldwide? (I think so)
A CHOPS Case History

- Luseland Field, Saskatchewan
- Shows well improvement with CHOPS
  - Average 5- to 6-fold increase
- Shows the physical reasons for +Q
- Shows that horizontals are not as successful in these sands
- The field selected has many similarities to other unconsolidated sandstones around the world
Luseland Field History

- 30 verticals drilled in 1982-85
- Produced using beam pumps, low sand content in oil (<0.5%)
- Horizontals tried in 1992-1993 (6×600 m), not successful (all abandoned by 1998)
- Aggressive CHOPS w. PC pumps started in 1994
- Now, about 4% sand cut in liquids
Luseland Field Parameters

- Bakken Fmn. (unconsolidated)
- $Z = 800 \text{ m, } \phi = 28 - 30\%, k = 2-4 \text{ D}$
- $\text{API} = 11.5-13^\circ, \mu = 1400 \text{ cP (live oil in situ, gas in solution)}$
- $S_o = 0.72, S_w = 0.28 \text{ (high!), } S_g = 0$
- Stratum thickness: $5 - 15 \text{ m in centre}$
- Initial pressure: $p_o \sim 6-7 \text{ MPa, } T \sim 30^\circ C$
- Gas bubble point: $p_b \approx p_o$
"Typical" Horizontal Well

Luseland Field, 600 m long well

Production rate - bbl/d

Oil rate

Water rate

New Production Technologies
Luseland Field, Monthly Oil and Water Rates

- **Oil rate**:
  - Feb-82: 16000 m³/mo
  - Feb-86: 12000 m³/mo
  - Feb-90: 8000 m³/mo
  - Feb-94: 4000 m³/mo
  - Feb-98: 20,000 m³/mo

- **Water rate**: Beam pumps, small amounts of sand

- **Start aggressive CHOPS**

**New Production Technologies**
Well 14-8 Performance

Luseland Field

Central Well 14-8

Production rate (bbl/d)

0 50 100 150 200 250

Jan-81 Jan-85 Jan-89 Jan-93 Jan-97 Jan-01

Oil rate

Start CHOPS

Water rate

New Production Technologies
Comparison of total oil and water production to Dec 98, all Luseland vertical wells

**Luseland Field**

- **Mean oil production:** 161,947 bbl/oil/well
- **Mean water production:** 58,750 bbl/H₂O/well

**New Production Technologies**

- Mainly recent high risk wells
Why More Oil??

- If sand flows, resistance to liquid flow is reduced
- “Foamy oil” behavior accelerates flow and destabilizes the sand
- A growing high permeability zone around the well is created
- Any mechanical skin (asphaltenes, clay) is continuously removed
Well Behavior in CHOPS

After Wong & Ogrodnick

New Production Technologies
For Successful CHOPS

- Foamy oil mechanism must be active (sufficient gas in solution)
- Continuous sand failure must occur (unconsolidated sands)
- No free water zones in the reservoir
- PC pumps (or similar) are necessary
- Integrated sand handling system
  - Sound sand disposal technology
Progressing Cavity Pump

- Belt drive with torque control
- Electric motor (or hydraulic)
- Well casing (usually 175 mm)
- Production tubing (usually 72 or 88 mm)
- Polished rod
- Production flow line
- Well-head assembly
- Sucker or co-rods in production tubing
- Chromed rotor in fixed stator
New Idea?

“Other things being equal, the maximum recovery of oil from an unconsolidated sand is directly dependent upon the maximum recovery of the sand itself. ... The higher the viscosity and the lower the gas pressure within the oil reservoir the greater becomes the importance of creating and maintaining a movement of sand toward a producing well.”

CHOPS Summary

- More profitable than thermal methods
- Very low CAPEX (cheap verticals)
- OPEX has been reduced to ~$4.00/bbl
- Pumping issues are now solved (PC & other pumps can handle large sand %)
- Sand disposal has been solved
- Production is currently limited only by:
  - Upgrading capacity
New Production Technologies

- P - Pressure
- P - Pulsing
- T - Techniques
- Sharp pressure pulses applied to the liquid in wells
- Reduces advective instabilities
- Reduces capillary blockage effects
- Reduces pore throat blockage
Pressure Pulsing Laboratory Setup
New Production Technologies

**Oil-Wet - Waterflood**

- **No pulsing**
  - Time = 139.2 s
  - 35 cP light oil
  - Water flood
  - 0.5 m static pressure head
  - Identical tests

- **Pulsing**
  - Time = 138.7 s

---

*Society of Petroleum Engineers*
Effects of Pulsing

- Increases the basic flow rate
- Increases OOIP recovery
- Reduces coning, viscous fingering
- Reduces plugging by fines and asphaltenes
- Helps overcome capillary barriers at throats
- Emerging technology, much remains to be optimized

New Production Technologies
Pulsing Sustains Oil Production

New Production Technologies

Pre Pulsing — 180 bbl/d
Pulsing — 160 bbl/d
Post Pulsing — 140 bbl/d

Lindburgh Field, water flood; 9,800 cP oil + sand


Oil Prod - 7 Offset Wells (bbl/d)
E.g.: Incremental Heavy Oil

Reservoir:
Near end of CHOPS life
10,600 cP, $\phi = 30\%$
Waterflood in 1 pulse well

Before pulsing
Pulsing started
Pulsing stopped
Incremental oil

Oil rate – m³/day – 6 offset wells

New Production Technologies
PPT and Horizontal Wells

PPT wells (cheap vertical wells)

Flow enhancement

Horizontal multi-lateral

New Production Technologies
New Production Technologies

GAD

- **G** - Gravity
- **A** - Assisted
- **D** - Drainage methods

- Horizontal wells are essential
- Flow is driven by density differences
- Most effective with a gas phase
- Wells produce slowly, but recovery ratios can be very high, >90%
Inert Gas Injection (Cold)

Gas is injected high in the reservoir to move the oil interface downward.

Generally, it is a top down displacement process, gravitationally assisted and density stabilized.

**Note**: in a water-wet reservoir, a continuous 3-D oil film exists, providing that $\gamma_{wg} > \gamma_{og} + \gamma_{wo}$.

Recovery % can be high.
IGI, With Structure

- Horizontal wells parallel to structure
- Inert gas injection
- Oil bank, two-phase zone
- Water-wet sand
- Water, one phase

Gas rates are controlled to avoid gas (or water) coning

Mainly gas

Three-phase zone

Keep Δp to a minimum

Voidage balance necessary!

New Production Technologies
If there are Shale Streaks?

- Horizontal wells parallel to water
- Water, one phase
- Oil bank, two-phase zone, water-wet sand
- Three-phase zone
- Inert gas injection
- Gas rates are controlled to avoid gas (or water) coning

Voidage balance necessary!

New Production Technologies
IGI in Flat-Lying Strata

\[
\frac{\Delta V}{\Delta t}\text{oil + water} = \frac{\Delta V}{\Delta t}\text{gas}
\]

(voidage filled)

\[
\Delta p \approx 0
\]

N₂ or CH₄

3-phase region

2-phase region

water

no \( \Delta p \), no H₂O coning

no \( \Delta p \), no gas coning

hydraulic fractures

horizontal wells

Voidage balance necessary!

New Production Technologies
Gravity Drainage of Reefs

Oil bank is “squeezed” into the horizontal well by proper pressure control so that density controls flow.

new horizontal well trajectory

gas cap

gas inj.

bottom water drive (some wells are converted to water injection)

old production wells now used to balance voidage, control coning

low Δp

New Production Technologies
IGI Summary

- Method commercialized in Canada
- Not for heavy oils (low $\mu$ required)
- Good $k_v$ is required (if no structure)
- Ideal approach for converting old conventional fields to a GD process
- Operating expenses are quite low
- Should be considered for new fields, and for renewing old fields
Foster Creek, Alberta

Production wells at base of oil zone

Glacial Gravel and Till

Colorado Group

Mannville

Clearwater A & B

McMurray Oil Sands

Paleozoic Limestone

130m

300m

395m

450m

525m

Production

Injection

Ground

Courtesy Neil Edmunds, EnCana
SAGD (or VAPEX) Schematic

SAGD Facility

Steam Chamber

Steam Injector

Oil Producer

Oil Sand Formation

Steam Chamber

Slots

Steam Flow

Oil Flow

Courtesy Neil Edmunds, EnCana
SAGD Physics

Keep $\Delta p$ small to maximize stability

overburden

“insulated” region

CH$_4$ + oil

countercurrent flow

steam + oil + water + CH$_4$

countercurrent flow

liquid level

lateral steam chamber extension

$\theta$

oil and water

water leg

cool bitumen plug

New Production Technologies
Countercurrent flow in the pores and throats lead to a stable 3-phase system.

The oil flow is aided by a “thin-film” surface tension effect which helps to draw down the oil very efficiently.

To maintain a gravity-dominated flow system, it is essential to create the fully interconnected phases, and to not try and overdrive using high pressures.
Shale Barriers and SAGD

Shales are impermeable to steam, and behave differently than sands.

SAGD passes through shales because of $\Delta V/\Delta T$ & $t$ effects.

New Production Technologies
Thermal GAD Processes

- Best for heavy oils (<20°API?)
- Good heat efficiency & flow stability
- High recovery ratios possible (>60% ?)
- May be used with other approaches (CHOPS or SAGD + cyclic steam)
- Not the solution to all heavy oil cases!!
- Heat costs are an issue (t > 15-20 m)
- Careful optimization needed
Recovery Ratios in GAD

- > 75-95% OOIP in lab.  WHY?
- Three-phase continuity → no oil is isolated from the $\rho$-flow system (no pinch off)
- Even the oil in low-k zones will slowly drain, aided by T or miscible gases
- No $\Delta p = $ no fingering: sweep efficiency is remarkably high, fronts are stable
Ganglia Reconnection in GAD

Generation of a 3-phase interconnected system from two 2-phase regions

isolated ganglia (immobile)

gravity forces at upper tip of a gas channel are at the pore-scale only

no oil film initially

rapid oil spreading (disjoining film)

\[ \gamma_{wg} > \gamma_{og} + \gamma_{wo} \]

New Production Technologies
GAD Summary

- Must keep $\Delta p$ low for stability
- Three-phases, oil-water-gas, is best
- Wells are at base of the reservoir
- Reservoirs must be relatively thick
- Countercurrent density flow occurs
- Helped by gas, steam, condensable fluid injection & good pressure control
Time Moves On...

- Horizontal wells are uneconomical (1980)
  - Now, they are widely used
- SAGD will never be practical (1984)
  - Over 200 pairs to be installed in 2001-2003
- Producing 20% sand is not feasible (1988)
  - Over 650,000 b/d from CHOPS in 2003
- VAPEX can’t ever be economical (1995)
  - First field trials are now starting
- Pulse flow enhancement not possible (1999)
  - 3 small-scale successes to date
- Don’t write off new ideas lightly!

New Production Technologies
# The New Technologies

<table>
<thead>
<tr>
<th>Method</th>
<th>Years</th>
<th>Status (2002)</th>
<th>Suitability</th>
</tr>
</thead>
<tbody>
<tr>
<td>CHOPS</td>
<td>&gt;10</td>
<td>$$$ - fully commercial</td>
<td>Best for 5-20 m zones, no mobile water or water legs</td>
</tr>
<tr>
<td>SAGD</td>
<td>~6-8</td>
<td>$ profitable</td>
<td>Probably limited to thicker zones, &gt; 15-20 m</td>
</tr>
<tr>
<td>PPT</td>
<td>2</td>
<td>$$ early days</td>
<td>Useful along with other methods (cold flow, CHOPS)</td>
</tr>
<tr>
<td>VAPEX</td>
<td>0</td>
<td>? no field trials yet</td>
<td>Best in &gt;20° API cases, or along with SAGD</td>
</tr>
<tr>
<td>IGI</td>
<td>&gt;10</td>
<td>$$$</td>
<td>Good $k_v$ &amp; low $\mu$ needed</td>
</tr>
</tbody>
</table>
Conclusions

- Conventional oil will peak (4-6 years?)
- Good for heavy oil, IOR, profits
- Remarkable technology advances recently (mainly in Canada)
- **We must try to consolidate & perfect them**
- The future for heavy oil & IOR looks genuinely promising at present
Acknowledgements

- Gracias para su invitación, y gracias también a...
- Society of Petroleum Engineers
- Local Sections of the SPE who are hosting me
- Donna Neukum, SPE – the Organizer
- Cheryl Stark, SPE, - the Editor
- Colleagues and companies