3 CHOPS

3.1 CHOPS and Related Technologies

CHOPS comprises the deliberate initiation of sand influx during the completion procedure, maintenance of sand influx during the productive life of the well, separation of the sand from the oil, and finally the disposal of the sand. No sand exclusion devices (screens, liners, gravel packs…) are used in wellbores, and no filters, cyclones or high-pressure separators are used at the surface. The sand is produced along with oil, water and gas, and separated from the oil by settling before being cleaned and sent to a facility for upgrading to a synthetic crude.

To date, massive sand influx to increase production rate has been used only in unconsolidated sand reservoirs (UCSS, $\phi \approx 30\%$) containing viscous oil (μ of 500 to 15,000 cP), almost exclusively in the Canadian HOB (Fig. 1.1), and in shallow (<850 m), low-production wells (maximum of up to 100-125 m^3/d, with an average production of perhaps <20 m^3/d). Because of the startling economic success of CHOPS in these difficult conditions, the concepts behind sand influx management are, to a considerable degree, beginning to be implemented in other oil production processes, and are even affecting the industry's view of how to develop natural gas resources.[14]

The cavity completion approach developed for coal bed methane exploitation is a very similar process to CHOPS,[xv] carried out for very similar goals: to increase well productivity by enhancing fluid flow capacity in the region around the wellbore. With this technology, which will soon be used in development of methane from Canadian coal seams, deliberate production of 20-100 m^3 of coal from the formation during well completion creates a cavity and generates a surrounding zone in the coal where natural fractures are opened (Fig. 3.1). These wells immediately become good CH_4 producers, in contrast to wells completed with conventional methods that may produce water for months before economical CH_4 production begins. In "conventional" CH_4 production from coal, the natural fissures must de-water before gas can create a continuous flowing phase, and this also requires shrinkage of the coal as the methane in the near-wellbore environment is depleted of the gas. The large radius cavity and the surrounding perturbed zone give a "large well effect", and in general, the productivity of a large well, compared to a smaller diameter well, is approximately proportional to $ln(r_L/r_w)$, the natural logarithm of the radii ratio. Cavity completed methane wells in coal are generally better producers for their entire life, and also may have episodes of coal production during their life, usually for short periods. (In this sense, there is a further similarity to CHOPS wells.).

The concepts developed in CHOPS in Canada in the period 1988-1995 have begun to diffuse into conventional oil production from sandstones[xvi]. Traditionally, in conventional oil production from high rate oil and gas wells, exclusion of sand at the wellbore has been the norm. Sand exclusion methods, most of which have been tried at one time or another in the Canadian HOB with no success, may include:

- Selective perforation approaches, using small diameter deep-penetrating charges, careful perforation orientation, and avoidance of perforation in the most sensitive strata;
- Control of the flow rate of the well (exit velocity) so that sanding is not initiated;
- Various types of screens (slotted liners, expandable screens, wire-wrapped screens, special pre-packed filters);
- Gravel packing the well (internal placement of coarse-grained sand), or placement of gravel into the perforation channels outside the wellbore;
- Various types of hydraulic fracturing methods (often using resin-coated sand) such as ARCO-frac and "frac-and-pack" (high rate, high sand content fracturing with high pressures to pack sand into the wellbore region); and,
- Resin injection, where a special colloidal suspension of epoxy (or other approaches involving delayed chemical reactions or sodium silicate injection) is pumped into susceptible beds to generate cementation at the grain contacts to strengthen the sand.

Recent work[xvii,xviii,xix] has clearly demonstrated that conventional oil and gas wells, if properly managed and monitored to control risk, can episodically produce "bursts" of sand that clean up and unblock the near-wellbore region, without significantly increasing the chances of well

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[14] Apparently, allowing small amounts of sand into natural gas wells is beneficial to production rates. The erosion problem can be handled by various risk management methods such as wellhead redesign and regular monitoring of critical-area steel thickness.

impairment. In a five-year period in the North Sea (1995-2001, Norwegian Sector), over 200 wells have been converted to this approach. On average, such wells produce at ~35% higher rates, and because these are high-rate wells to begin with (1000 – 3000 m^3/d), the financial benefits are huge. The idea was generated in the early 1990s based on preliminary experience with CHOPS in Canada. Now, the concept is being tried elsewhere in the world, usually to the benefit of well production rates.

The "cross-fertilization" of ideas arising from CHOPS and other Canadian technologies has greatly benefited the world oil industry, more than is appreciated. This influence will continue, and some of the possibilities generated in Canada that are already feasible for "export" are listed here:

- Pressure pulsing technology[15] can be used with conventional oil to increase flow rates and to help stabilize waterfloods against excessive fingering.
- Inert gas injection, largely pioneered in Canada, can be used in conjunction with horizontal wells to revitalize old conventional oil reservoirs to increase total recovery.
- SAGD, VAPEX, and various combinations of these methods, can be applied to other heavy and intermediate oil deposits (up to 30°API ?).
- Heavy oil upgrading technologies being perfected in Canada can be implemented in other heavy oil beneficiation facilities around the world.
- New waste disposal practices such as slurry injection of produced sand[16] can provide better environmental protection.
- Sand management applications can be applied to in conventional oil and gas wells to increase production.[17]

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[15] Visit www.prismpt.com for more details.

[16] Visit www.terralog.com for sand injection.

[17] Visit www.geomec.com for information on sanding in conventional oil wells.

3.2 History of CHOPS Development

3.2.1 History of Sand Production in Canadian Heavy Oil

The first discoveries in the Canadian Heavy Oil Belt were made in the Lloydminster area in the late 1920's.[18] Heavy crude oil with a high asphaltenes content, an ideal feedstock for asphalt products, has been produced since that time. Typically, small diameter perforations, 10-12 mm, were used in these heavy oil wells to access the reservoir. However, the reciprocating pumps that were available were limited by slow rod fall velocity in the viscous oil in the tubing, and these wells achieved a maximum of 8-10 m^3/d of production, usually less. Many wells produced as little as 10-15 b/d toward the end of their productive phase, and reservoir extraction efficiency seldom exceeded 5-8% of OOIP.

Operators in the HOB soon discovered empirically that they had to cope with small amounts of sand entering the wellbores along with the oil (about 1% in the more viscous oils with the slow production rates and the small diameter perforations used before 1990). The small local operators learned that wells that continued to produce sand tended to be better oil producers, and that efforts to exclude sand with screens usually led to total loss of production. They learned to separate the sand and most of the water from the oil by gravity segregation in heated vertical stocktanks before shipping the oil by tanker truck to the small local upgrading facility in Lloydminster (actually mainly an asphalt production facility), or to refineries in Edmonton and Regina. The operators spread the waste sand on local gravel roads, and in some areas the roadbeds are now up to 1.5 m higher, courtesy of repeated applications of sand. These "micro-engineering" improvements advanced slowly for 50 years because the profit margins on heavy oil were always low and the demand was limited because most refineries would not accept even small amounts of the sulfur-rich, viscous feedstock.

The sharp oil price increases in the 1970's and 1980's led to great interest in the HOB resources (currently estimated as $>12\times10^9$ m^3 recoverable)[xx]; many international companies were attracted to the area. They introduced the latest screen and gravel pack technology, and even developed new technologies for screens, such as the Texaco steel-wool-packed screen. However, in all

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[18] Visiting websites such as www.bordercity.ca and searching on Lloydminster, Alberta will provide access to numerous sites with vignettes of history, lists of services suppliers, and other information on the HOB.

cases, sand exclusion resulted in greatly impaired productivity or total failure to bring the well on production. Hydraulic fracturing techniques of all types were tried, even injection of pea-sized gravel into the formations; all of these attempts failed. Wells were sometimes stimulated with a large slug of steam or super-heated hot water to increase near-wellbore mobility: after a few days of enhanced production, well productivity generally returned to very low rates. To this day, there are hundreds of inactive wells with expensive screens, gravel packs, and hydraulic fractured gravel placements that were carefully installed. (Incidentally, many of these wells can probably be rehabilitated at less than the cost of drilling a new well.)

The higher oil prices that developed in the period 1973-1983, along with advent of progressing cavity (PC) pumps in the 1980s, changed the non-thermal primary heavy oil industry in Canada. The first PC pumps had a short lifespan and were not particularly cost-effective, but better quality control and continued advances led to longer life, fewer problems, and widespread acceptance in the 1990s. The rate limits of beam pumps were no longer a barrier, and operators in the period 1990-1995 changed their view of well management: sand began to be viewed as an asset because <u>more sand meant more oil</u>. Individual well productivity began to rise above the traditional 4-5 m^3/d average. The goal of completion and workover strategies gradually became more clear: do what is necessary to initiate and maintain sand influx. New workover methods, better pumps, and new completion methods meant that old inactive fields that had only produced 4-6% of OOIP could be profitably rehabilitated. These efforts are continuing at present, extracting more value from old fields than was thought possible even a few years ago.

Along with PC pumps and much higher sand rates (2-8% in most CHOPS fields), a new set of issues began to arise. Management of the sand and some other waste streams (emulsions) became paramount, and new micro-engineering developments have taken place to control costs and to minimize environmental impact. More highly integrated sand management methods have been developed and new methods of coping with sand separation and disposal implemented.

CHOPS is a new production technology that is still rapidly developing. New issues and better methods are being addressed, such as optimal workover strategies, different sand disposal practices, implementation of improved recovery methods (water flooding, pressure pulsing) along with CHOPS, and hybrids of several production technologies to increase recovery. Given the low operating costs that recently have been achieved (OPEX of CAN$5.00-8.00 appears typical), and given that thermal energy requirements are zero, interest in CHOPS as a primary production method is substantial. Also, it appears that the only serious limitation on the amount of oil in the Canadian HOB being produced by CHOPS in the year 2001 is the lack of upgrading capacity.

3.2.2 Current CHOPS status worldwide

To date CHOPS has achieved wide utilization only in Canada. However, anecdotal evidence suggests that heavy oil operators in California traditionally took no steps to exclude sand, realizing that screens and sand packs would simply become blocked (blinded by sand and clay particles) and production would cease. In the Duri Field (Chevron-Texaco, Sumatra, Indonesia), heavy oil is produced by thermal methods, and large amounts of sand accompany the oil. In China,[xxi] CHOPS has been tried with some success in the Nanyang Oilfield (Hebei Province) from 1997-2000, but was not permanently adopted. In the Liaohe Oilfield (Panjin City, Liaoning Province), trials were also conducted under challenging conditions, and continue to be attempted in reservoirs that are not as favorable as Canadian reservoirs (often partially depleted or steam treated at an earlier time). In 2001, Jilin Oilfield (Songyuan City, Jilin Province) initiated a CHOPS project in a heavy oil deposit in 300 m deep fine-grained sand in the northwestern part of the Province. Although rates are modest in comparison to Canadian production (2-6 m^3/d rather than >10 m^3/d), they are far greater than sand-free or thermal production rates.

Broad-ranging acceptance of sand influx as a valuable mechanism for enhancing production has not yet taken place in the industry, despite current production levels of over 70,000 m^3/d in Canada (estimated ~460,000 b/d). The reasons are the fear of sand influx in a producing asset that could impair production, the “non-traditional” nature of the production mechanisms, difficulty in production predictions when sanding takes place, complexity in properly implementing CHOPS, and the need for sand management strategies that can cope with large volumes of produced sand. Furthermore, CHOPS wells require repeated workovers and more effort to sustain economic production than conventional oil wells.

3.3 Typical Alberta Reservoirs

Heavy oil development using CHOPS in Alberta takes place largely in the HOB (Fig. 1.1), with a small amount of production generated in the region to the west and southwest of the Cold Lake

Deposit. With the exception of a few geologically older fields (Bakken Formation reservoirs found mainly in Saskatchewan), all the heavy oil UCSS reservoirs in Alberta are found in the Lower and Middle Mannville Group. The Mannville Group of formations is an undeformed and flat-lying Middle Cretaceous clastic sequence comprising sands, silts, shales, a few coal seams, and some thin (<0.5 m) concretionary beds. The depositional environment ranged from channel sands laid down in incised valleys carved several tens of meters into the underlying sediments, to estuarine accretion plains formed by lateral migration of river channels in a flat terrain, to deltaic, shallow marine, and offshore bar sands (hence the wide range of thicknesses and forms observed).

During the Middle Cretaceous period, what is now the HOB was low-lying land near the coast of a shallow inland sea. To the northeast lay the Canadian Shield, a low-relief terrain made up of granites, gneisses and metamorphic rocks, but few sediments. This area contributed some of the sediments in the Mannville Group, particularly to the lower reservoirs in the sequence, which are mainly alluvial sediments such as coalesced river channels. The seacoast gradually rose and moved from the northwest to the southeast, and fluctuations in the sea level also took place. The major sediment source shifted to the south and south west, where weathering and erosion of older sediments contributed finer-grained materials such as silts and clays. Volcanic activity in the southwest, where the Rockies currently sit (e.g. Crowsnest Pass area), contributed volcanic ash which turned into smectitic clays and eventually formed the high porosity swelling shales found throughout the Canadian west.

The sediments, on average, become finer grained higher in the sequence because the depth of water gradually increased during the Mannville Group sedimentation period. The lower and coarser-grained part of the Mannville Group, which contains almost all the heavy oil reservoirs in Canada, was eventually overlain by thick deposits of clays. This thick and regionally continuous shale sequence, called the Colorado Group, which can be traced all the way from Texas to Alberta and on north to the Mackenzie River valley.

After burial under a sedimentary cover that was about 500-700 m greater than at present, the region underwent slow uplift, and erosive processes have acted until the present time. The oil invaded the reservoirs from deeper in the Western Canadian Sedimentary Basin, and became viscous through two processes: the loss of lighter, volatile hydrocarbons and the increase of molecular weight because of bacterial action. This took place as the oil-bearing strata were exposed to more shallow waters, and the end product of the biodegradation was viscous oil with only CH_4 present as a light molecular weight phase. Glaciation in the last million years resulted in continued erosion and the deposition of a thin veneer of sediments. The present depth of burial of CHOPS reservoirs ranges from 350 to 900 m both in the HOB and in the heavy oil region west and southwest of the Cold Lake Deposit (Figure 1.1). The sediments have been buried much deeper than at present, so they are "over-compacted" with respect to present conditions.

The mineralogy of the sand bodies ranges from quartz arenites (>95% quartz grains) to litharenites and arkoses, with smaller amounts of quartz and more feldspar grains, shale grains, and volcanic glass shards. The more mature sands at the base of the Mannville Group tend to be more quartzose and coarse-grained with the major sediment source from the Canadian Shield, and the reservoirs higher up tend to be somewhat less quartzose and finer-grained, with many more feldspar grains and lithic fragments, but there are many exceptions to these generalizations. Some of the channel sands (including all of the McMurray/Dina Formation sands) were reworked many times during the long period of sedimentation, and any lithic fragments and feldspar grains were gradually destroyed.

In the more mature quartz sands at the base of the sequence, and in the thick channel sands higher up, the clay contents can be less than 1%, but they can be as high as 10% in fine-grained litharenites (sands that have many shale fragments). Thin clay seams (shale bands) less than 100 mm thick are common in many areas, and these clay seams are apparently largely produced in disaggregated form along with the sand in CHOPS wells, although large blocks are undoubtedly left behind around the well. Some reservoirs have large "shale" seams (> 1 m) within the producing zone, and the breaking apart of this shale during production can cause problems. (shale fragments can plug the well and stop CHOPS, and the more clay produced, the greater the amount of emulsion that is generated).

Oil production is from a wide variety of reservoirs that may range from an extensive 3-5 m thick blanket sand (e.g. Lindbergh Field) to a 35 m thick channel sand (e.g. Bodo Field) with a sinuous trace no wider than a kilometer. In many areas up to three reservoirs may be intersected by vertical wells. These sand bodies are from 30 to 90 m apart, separated by intervening water-saturated silts and clay shales. They are all UCSS with porosities of ~28-32% and permeabilities of ~0.5-15 Darcy, depending on grain size. The highest permeability values reported are for gravel seams that are sometimes found in river channel deposits ("lag gravels"). Most CHOPS reservoirs have an average permeability of 1-4 Darcy.

It is impossible to obtain undisturbed specimens from the Alberta UCSS heavy oil reservoirs because gas exsolution leads irreversible core expansion (the high oil viscosity impedes gas escape[xxii] and this leads to internal pressure which causes "swelling"). Therefore, the porosities of the reservoirs are back-calculated from geophysical logs, and permeabilities are back-calculated from grain-size correlations and a limited number of well tests. *In situ* oil viscosities from 500 to >15,000 cP are found; in general the viscosities are higher toward the north in the HOB.[19]

A "typical" CHOPS stratum is a 5-12 m thick fine- to medium-grained unconsolidated sandstone (a "dense sand") buried at a depth of 500-650 m. The sand grains have an average grain size of 80 to 150 microns (1000 microns = 1 millimetre). The permeability of the sand is about 2 Darcy, which is a relatively high permeability for an oil reservoir. The saturation of the pore space[20] is about 87% viscous oil and 13% connate water that contains about 60,000 parts per million of dissolved salt (NaCl). There is no free gas in the pores of the sand. The initial (virgin) pressure in the reservoir (p_o) is about 4-6 MPa, and reservoirs are most often somewhat underpressured. This means that the pressure in the reservoir is somewhat less that the pressure that would be exerted by a continuous column of water to the surface. Taking $\bar{\gamma}_w$ as the mean unit weight of water ($\bar{\gamma}_w = \bar{\rho}_w g$), generally it is found that $p_o \sim 0.7 - 0.95\bar{\gamma}_w z$, where z is the depth (and g is the gravitational acceleration). The density of the water in the pores is on the order of 1.04 to 1.05 g/cm^3, being approximately twice as salty as seawater. In most cases *in situ*, the oil is >90% saturated with CH_4 dissolved into the liquid oil, the reservoir temperature is 20-25°C, and the viscosity of the oil is in the range 1000 – 12,000 cP (higher viscosities are seldom suitable for CHOPS production).

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[19] Unless otherwise stated, the *in situ* viscosities reported include methane gas in solution.

[20] $S_o \sim 87\%$, $S_w \sim 13\%$, and $S_g = 0$

3.4 Typical CHOPS Well Behavior Summary

CHOPS wells display great variation in their production histories, depending on a wide range of factors that will be discussed below. The major aspects of a "typical" CHOPS well are (Fig. 3.2):

- When a new well is completed, initial sand influx is large, typically as high as 10-40% of the volume of the (gas-free) produced liquids and solids.
- Over a period that can be as short as a few days or as long as several months, the high initial sand production rate gradually decays toward a steady-state influx rate of 0.5% to 10%, depending on the oil viscosity.
- The oil production rate increases toward a maximum several months or more after placing the well on production, and then slowly decays as the reservoir depletion effects begin to dominate and there is less reservoir energy available to the well.
- Continuous gas influx (generally not metered) characterizes all CHOPS production, giving a product at the surface that is charged with CH_4 and foams.
- Short-term sand and oil production rates appear to fluctuate chaotically about the mean long-term value, but time-averaged production rates follow the general pattern of Figure 3.2.
- A successful workover can partly re-establish oil and sand rate, but generally the workover does not raise production to levels as high as in the first cycle.

This liquid flux pattern is radically different than conventional well behavior. Because there is a peak in the oil rate curve, there must be at least two counteracting physical mechanisms with different characteristic effects (Fig. 3.3). The two dominant competing processes are considered to be the increasing well productivity because of the enhanced fluid conductivity (high porosity and high permeability) generated around the wellbore with continued sand production, and the diminishing well productivity because of the gradual depletion of reservoir energy. These two effects combine to give a peak production followed by a gradual decline as the depletion effects begin to dominate with time. This chapter will qualitatively explore the physics of this unusual behavior. Technical issues that arise in CHOPS implementation will be reserved for the next chapter.

It is important to emphasize that CHOPS in Canada is approaching the status of a mature technology: reasonable oil production rates can be achieved and most of the major technological problems appear to be solved. Nevertheless, continued micro-engineering advances that increase efficiency and reduce OPEX are still taking place. Because of the advent of CHOPS, primary heavy oil production in Alberta is no longer limited by technical production constraints. The writer is convinced that CHOPS production in Alberta alone could rise by 80,000 - 100,000 bbl/year for several years if stable demand and good returns to the producers are sustained. This undoubtedly would also require additional upgrading facilities.

3.5 CHOPS Production Behavior

The term CHOPS refers specifically to heavy oil production from unconsolidated sandstones with deliberate initiation and sustaining of sand influx into the wells. Not only are well completion and lifting practices different from those for conventional oil, but an entire array of novel materials handling practices have evolved to cope with sand influx and disposal. Production approaches remain based on practical considerations driven by field performance data because CHOPS does not yet rest on a theoretical base that allows *a priori* predictions of oil and sand rates from first principles (extant models must be calibrated to actual field behavior before they have genuine predictive capabilities). The role of experience is vital.

The experience in Canada resides in the “trade craft” and practical activities of thousands of engineers, technicians, and field operators in dozens of producing and service companies. Different views of “best-possible-practice” exist in different companies. The distillation and presentation of empirical and practical knowledge is far more difficult than the exposition of a theoretical model; any attempt to do so, as in this report, will be incomplete and in some cases incorrect in detail.

None of the large integrated multi-national oil companies currently have significant activity in the non-thermal Canadian heavy oil industry (Conoco-Phillips may be viewed as a recent exception as they are slowly moving into this domain). Rather, small companies with a simple horizontal command structure have generated the majority of the recent developments and experience base in new heavy oil technologies. Field personnel are usually encouraged to take the initiative in addressing practical sand management and production problems. It is clear that the day-to-day practical aspects of CHOPS have been conceived and perfected in the field, not in the laboratory or in front of a computer screen. Many of these practices, unfortunately, remain inadequately documented.

3.5.1 Production Profiles

A well production profile for three production cycles is shown in Figure 3.4. Its major features are the following:

- Immediately after initiation of oil and sand flow in a CHOPS well, the volume fraction of sand is extremely high, often as much as 30-45% of the total produced liquids and solids volume. This initial elevated sand rate is reservoir and viscosity dependent: low viscosity reservoirs may peak at 20% sand; high viscosity reservoirs with high gas contents may show peak sand rates exceeding 50% by volume of the total produced sand, oil and water.[21]
- The sand rate tends to drop over a period of weeks or months to a value of 1% to 8% of the total volume of liquids and solids, depending on the viscosity of the oil (Figure 3.5[22]).
- In the more viscous oils (>2000 cP), there is often a prolonged plateau for several months at rates of 10-20% before a decline to a "steady-state" rate of 2-6% that may be sustained for many months or even for several years.
- The oil rate starts at a level that is related to pumping practice, reservoir viscosity, and the amount of gas in solution in the oil. At the present time, this rate and its evolution are not predictable on theoretical grounds using mathematical models, physics-based equations, or scaled laboratory studies. Production initiation rates of 10-30 m^3/d are common, but in this phase oil rate may be controlled as well by torque limits on the PC pumps: low speeds are necessary because of high torque from the sand content, and this limits the production rate.

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[21] It seems impossible to pump a slurry of 50% sand through a vertical 3.5″ tubing 500-600 m long. In fact, because of evolution of gas in the formation and the wellbore outside of the pump, the slurry entering the well probably has >50% volume gas (depending on drawdown). This is compressed in the pump, but without total reversion to a liquid, as the gas goes back into solution extremely slowly.

[22] The sand rate vs. viscosity relationship in the figure is to be viewed as semi-quantitative because sand rates also depend on pumping practices and other factors. Furthermore, operators are learning how to sustain and cope with higher sand cuts in order to produce oil more rapidly, therefore the relationship is in a state of flux.

- The oil rate generally climbs over a period of several months, reaching a peak production rate that may be 30-60% higher than the initial rate, exceeding 50 m^3/d in the best wells, but more commonly in the range 20-40 m^3/d.
- After the peak oil rate is passed, wells usually display a gradual decline in production, but this also depends in part on pumping strategy. If a pre-decided value of oil production rate is used, it is often feasible to sustain well productivity at this level for many months or even years, although well annulus fluid level and pump speed will have to be adjusted as the reservoir conditions change.
- After a period of production that may last from a year to several years, the well gradually approaches a production rate that is no longer acceptable to the operator. At this point (usually in the range of 2-3 m^3/d) a workover is initiated to attempt to re-establish a high production rate.
- The post-workover behavior in successful cases is similar to the first cycle of production, but the well rarely achieves the peak sand rates and production rates of the first cycle. Exceptions to this occur if the well is perforated during the workover with large-diameter and more closely spaced ports, a common practice for the redevelopment of old fields from the pre-CHOPS era.

About 85% of wells follow this production history. However, there are many exceptions, including:

- Cases where sand initiation is not possible (perhaps 5-6% of wells, usually in the more marginal reservoirs with high shale contents).
- Cases where water influx is early and massive. This appears to be highly dependent on the field and the well position with respect to water-saturated zones; the closer the well is to active bottom water, the greater the risk of early water influx.
- Cases where early destabilisation of the shale overburden causes loss of the well. This occurs mostly in the more viscous reservoirs when extremely aggressive production is attempted.

- Cases where the oil production rate declines rather than increases during the initial heavy sand production phase, a response that is usually accompanied by gradually increasing water production.
- Cases where the production profiles are anomalous for unknown causes such as premature perforation blocking, lightly cemented sand that is hard to destabilise, too much lost-circulation material forced into the reservoir during drilling, or overuse of cement during casing cementation.

For various reasons, a CHOPS well may experience mechanical failure or a productivity drop, and a workover is then required to re-establish an economical level of oil production. Many workover choices are possible, which is used depends on the operator assessing the reason for well productivity loss.

A CHOPS well may experience a number of workovers during its life, and each workover usually results in a surge of oil and sand production, though diminishing in magnitude with each cycle. Some wells produce for years without a need for a workover except to change the PC pump (15-20 months average life); other wells require repeated workovers to sustain economic production rates. Figure 3.6 is an attempt to show this behavior over the life of wells that have encountered different production difficulties. Sand and oil production rates in CHOPS wells fluctuate substantially on a short term basis, and for production rate evaluation, it is necessary to take a series of samples or to take a long term average.[23]

Water ingress is a common factor in the decline of well productivity, and one of the criteria for the selection of reservoirs that are suitable for CHOPS is the absence of a mobile water zone. Lateral invasion of water from considerable distances (lateral coning of "flank" water) has been a problem in some reservoirs (Figure 3.7), even if no active bottom water was detected in individual wells during the geophysical logging evaluation. There remains debate as to whether more moderate production practices in CHOPS wells would increase the oil recovery factor by delaying lateral coning, or reduce profitability by unnecessary delay of production. The two options are: implementing a less aggressive draw down during the early phases as production is

[23] The Energy Utilities Board requires monthly reporting, and these monthly rates are calculated based on tanker truck tickets for individual wells in most cases; therefore they represent long-term averages.

gradually ramped up; or, capping the production rate deliberately at a value below the maximum short-term rate that the well can sustain.

Water ingress can be rapid, with the well going from a few percent to 100% water production in several months, or slow, with a gradual increase in water cut over several years. In spite of CHOPS being a high Δp process (usually high Δp conditions are conducive to water coning), some CHOPS reservoirs are characterized by producing wells that have operated for over a decade without significant water cut increase. In these cases, it is supposed that active water is totally absent, or that any active water is so far away that the pressure decline in the producing well never affects it.

As yet, it is not possible to make rigorous scientific or empirical predictions of well behavior with respect to water ingress behavior; it is necessary to do careful geological studies, and even then there is a great deal of uncertainty. Comprehensive analysis of the large public domain databases for dozens of reservoirs and thousands of wells could generate considerable insight into this question, but no company or agency has yet undertaken this task.[24] Furthermore, since many older wells have been modified in the period since 1992 to take advantage of CHOPS methods (re-perforating, new pumps, new workover methods based on pressure pulsing, etc.), it is difficult to carry out such an evaluation based on the public production records alone. Corporations do not record all relevant production factors, nor do they record sand cuts or gas-oil ratios (GOR) in a standardized manner for the public domain.

Old fields that were abandoned with the wells left intact can be converted to CHOPS if the company finds it feasible and if the old wells are in reasonable condition. Other fields remain on slow production with beam pumps because the company does not need the additional production capacity that comes with CHOPS, or does not want to incur the capital cost of conversion.

Conversion engenders a cost of approximately CAN$65,000.00, including service charges, a PC pump and perhaps formation stimulation. Conversion of a number of old fields in the Provost area and to the south of Lloydminster took place in the period 1991-2001 and slowly continues at this time. New fields, such as Elk Point, Lindbergh and Bear Trap (all north of Township 53) have never experienced a slow phase followed by a conversion to CHOPS, and have been on

[24] This is a recommendation for the future.

stable production at economic rates for up to 10 years. Many operators are currently planning or carrying out drilling programs to place new wells in old fields (infill drilling), dropping the well spacing to 10 acres from 20 acres, and even, in some cases where individual well production is good and there is a thick oil zone, down to 5 acre spacing. There are also continued activities to develop previously non-developed fields, and to redevelop old wells through novel workover approaches and better pumping methods.

Some field operators claim that "…each field is different". Whereas this statement is obviously correct, it can also lead to a counterproductive attitude: if all fields are different, why bother seeking generalizations and doing science? There are substantial differences among fields, but there are also major commonalities, particularly in terms of the lithostratigraphic and reservoir conditions and the physics of the CHOPS process. Operators who understand the physics of the CHOPS process tend to be the most successful.

3.5.2 Well Productivity and Evolution

Before 1990, CHOPS wells typically produced 2-12 m^3/d, the upper limit being set by pump rate limitations, and sand was co-produced only out of sheer necessity rather than being regarded as a production enhancement factor. Currently, much higher production rates are typical, ranging from 3 to 45 m^3/d. The lower oil rate limit for CHOPS wells varies among companies, depending on their assessment of the lowest production rate at which OPEX can still be met. At high heavy oil prices, wells may be kept on production even though oil rates drop to below 1.5-2 m^3/d. When heavy oil prices are low (as in 1997-1998), a producing company will execute a ranking of all their CHOPS wells in terms of productivity and OPEX, and eliminate those with both low production rates and high maintenance costs. Once a CHOPS well has been shut it, it costs on average CAN$35,000 (exclusive of the PC pump) to bring that well back to a reasonable level of production. This may be achieved through a workover program, such as a re-completion with larger diameter perforations, or through implementation of a different approach such as pressure pulsing to help sustain reservoir drive processes. Furthermore, after a CHOPS well has been shut-in for many months or years, there is at least a 10% chance that workovers will fail to bring it back into production, and the well will have to be suspended or abandoned.

In the period 1990-2001, production rates increased because of new pumps and different completion and production practices. Today, new CHOPS wells may be targeted for a rate of 20-35 m^3/d, and a pump of 50 m^3/d/100 rpm capacity will be installed. The CHOPS well may be operated either at a chosen rate that is profitable, or the well flow rate may be optimized using measurements to achieve the maximum oil rate possible while still leaving 10-20 m of fluid level in the annulus above the perforations. In other words, CHOPS wells may be produced aggressively or gently. The general consensus in the period 1990-2001 has evolved toward a relatively aggressive drawdown to maximize early oil production and target rapid payback on each well. Nevertheless, for various reasons (such as a risk of overburden shale destabilization) some field operators will cap their production rates at a value they believe will give good profits with lower risk of excessive workover requirements or overburden destabilization. Typically, these field operators will target production rates of 8-15 m^3/d, operating the well below its capacity in the belief that the well life will be extended so that more total oil will be produced at lower OPEX. There is no public database or analysis that statistically supports one approach over another.[25]

At a heavy oil price of CAN$18.00, after the price differential between light and heavy oil has been applied, companies expect to achieve full CAPEX payback (plus OPEX) during a period of less than 15 months for a typical CHOPS well. Part of the reason for the quick payback potential is that drilling and completing shallow CHOPS wells has become more economical. Approximately CAN$300,000 will pay for:

- A cased, cemented perforated well 600 m deep, on a lease with gravel road access.
- 600 m strings of 3½″ or 4½″ tubing and 7/8″ sucker rods, a well head assembly, and so on.
- A 30-50 m^3/d/100 rpm PC pump with a variable speed surface electrical drive.
- A 1000 bbl heated stocktank on site to hold the oil, water and sand.

[25] It is recommended that this question be addressed by an industry study.

The best of CHOPS wells, perhaps the top 5%, can achieve a production level of more than 100,000 m^3 over their lifetime, although the mean for all CHOPS wells (including those that never were successfully placed on production) is in the range 25,000-40,000 m^3.

Good wells produce less water than poor wells (see case history, Chapter 5), but there are exceptional cases where a well can sustain economic oil production for many years while also producing water cuts in excess of 25-40%. Recently, companies that have to cope with water influx have been experimenting with water injection (i.e. water flooding as a secondary recovery process), despite a remarkably unfavorable mobility ratio that would seem to eliminate water flooding as an option. This has had generally beneficial effects, but at a small scale, extending the life of a group of wells by a few months or a year, for example, rather than giving long-term sustained improved oil production. In the lighter heavy oils in southwest Saskatchewan, aggressive production as water cuts rise has resulted in several fields continuing to be profitable even as water cuts rose above 95% of produced liquids (i.e. only 5% oil).

To analyze well performance for all CHOPS wells in Canada, individual well time series of oil production, water production, and gas-oil ratios[26] are available through the conservation authorities of the provinces. If a company is seriously considering CHOPS for a major heavy oil operation, analysis of the time series production data available publicly can be quite useful.

3.6 Typical Sanding Rates in Canadian Wells and Fields

A CHOPS well produces its highest amount of sand in absolute terms (m^3/d) and in relative terms (as a percentage of gross fluids) during the days and weeks after it is brought into production on the first production cycle. Therefore, younger fields produce more sand than older fields. An exception to this arises in older fields where new PC pump technology is implemented after some years on reciprocating pump exploitation, or where re-perforation of wells and more aggressive production practices are instituted to deliberately promote sand influx.

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[26] Gas-oil ratios are available for some wells, but the quality of the data is in question because of sampling difficulties.

The maximum amount of sand generated in any single year in Canada was approximately 330,000 m^3 in 1997[27], but this will likely be exceeded in 2001 because of aggressive drilling programs for new wells undertaken in 2001 by the industry. Likely, more than 400,000 m^3 of sand will be produced in Alberta and Saskatchewan in 2001, or an aggregate volume of approximately 2% of the total heavy oil produced by CHOPS methods (estimated to be 460,000 b/d in 2000-2001).

Because of wide differences in water production, well productivity, and methods of reporting sand rates, it is recommended that sand rates also be recorded as volume of sand per volume of oil, although most operators record sand only as a percent of gross fluids produced. The sand-cleaning truck operators measure the volume of sand in stocktanks when they clean them, and the amount of produced oil is calculated from truck tickets for the wells, or on the basis of test separator trials on individual wells. (Note that in the reservoir, the porosity may be assumed to be about 30% everywhere in the HOB, and when the sand has been produced and has sedimented in the stocktank, the porosity is about 40-42%.)

Given that more viscous oils will produce more sand, sand production as a percentage of oil production is not consistent over the HOB. In the southern part of the HOB the average viscosity is often below 1000 cP, and the amount of sand produced is ~0.5-1.0%, perhaps less in some cases. For the long horizontal wells (not truly CHOPS wells) used in the Pelican and Amber Fields to the west of Cold Lake (generally the Wabasca Formation oil sands), fine-grained sand enters through the production screen (open-hole slotted liners are used) at volume rates of ~0.25% or even lower. The oil viscosity is only 200-1000 cP in these fields, and therefore both CHOPS and non-thermal horizontal wells are economical.

In the viscous oils of the large Lindbergh and Elk Point Fields and other fields to the north of Lloydminster, where the viscosity generally exceeds 5000 cP, oil production rates from CHOPS wells are lower than in the low viscosity areas, but the sand percentage approaches 4-6% in productive wells, and 2-4% in less productive wells. In CHOPS trials in highly viscous oils

[27] Because oil companies do not have to report sand production rates or sand volumes treated, all industry-wide estimates are subject to substantial uncertainty (±20%), and estimated values for specific cases will have a somewhat larger uncertainty.

between 15,000 cP and 40,000 cP (Frog Lake, North Primrose), 6-10% sand at steady-state oil production is not uncommon.

Thus, a single CHOPS well producing 30-35 m^3/d of oil of viscosity 1400 cP will produce approximately 0.5 – 1.5 m^3/d (2-4% by volume) of stocktank sand per day. A CHOPS well north of Lloydminster in 10,600 cP oil producing at the high rate of 15 m^3 per day will produce about the same amount of sand, about 1 m^3/d (7%). In the aggregate, given that there are many CHOPS wells that produce only a few cubic metres of heavy oil per day, the industry average amount of sand per well will be approximately 0.3-0.5 m^3/well/day (lower in the south, higher in the north).

An operator of a field with 200 wells producing on average 12 m^3/day of 2000 cP oil must cope with 18-30 m^3/day of sand, or from 6,000 to 10,000 m^3/yr. In the high viscosity oils of the Lindbergh Field (8000-10,800 cP), where average well production rates are perhaps 6-7 m^3/d, 500 active wells will produce ~ 40,000-50,000 m^3/yr of sand.

3.7 What Constitutes a CHOPS Project?

CHOPS is a single-well technology. It is not necessary to have a pattern of wells, such as in steam injection processes.[28] Apparently, no significant benefit accrues to an individual CHOPS well because there are other similar wells surrounding it. Because each well has its own stocktank that is emptied by truck, there are no economies of scale to be achieved in manifolding many wells into a single large facility (unless EUB regulations change). Therefore, in the limit, a CHOPS "project" could even be defined as a single well.

However, in practice, more and more CHOPS fields are being developed using pad development with from three to ten wells drilled from the same 1-3 acre site so that the number of roads and length of services corridors can be optimized. Furthermore, consideration is always given to the capacity of local facilities such as batteries to clean the oil. If a company has a battery with a capacity of 20,000 b/d (~3000 m^3/d), then the company will target sustaining approximately 300 wells, each producing on average 70 b/d (10-11 m^3/d).

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[28] To achieve economies of scale and reduce heat losses, commercial scale thermal processes need a central steam generating facility sufficient to feed on the order of 30-100 wells (depending on the technology used). In pilot projects, as few as 15-20 wells will be used to test ideas and develop process understanding.

Small local operators must deliver their oil to batteries that can accept it, and battery capacity in the industry is limited to what can be shipped to local upgraders or similar facilities in the United States. There are local operators in the Lloydminster who operate only 10-20 wells, although the great majority of projects in specific fields by one operator involve larger numbers of wells, up to 400-500 wells in the Lindbergh and Elk Point fields.

Thus, there is no minimum size for a CHOPS project, and the maximum size is usually controlled by the capacities of the batteries and local facilities.

Figure 3.1 Cavity Completion in a Coal Seam

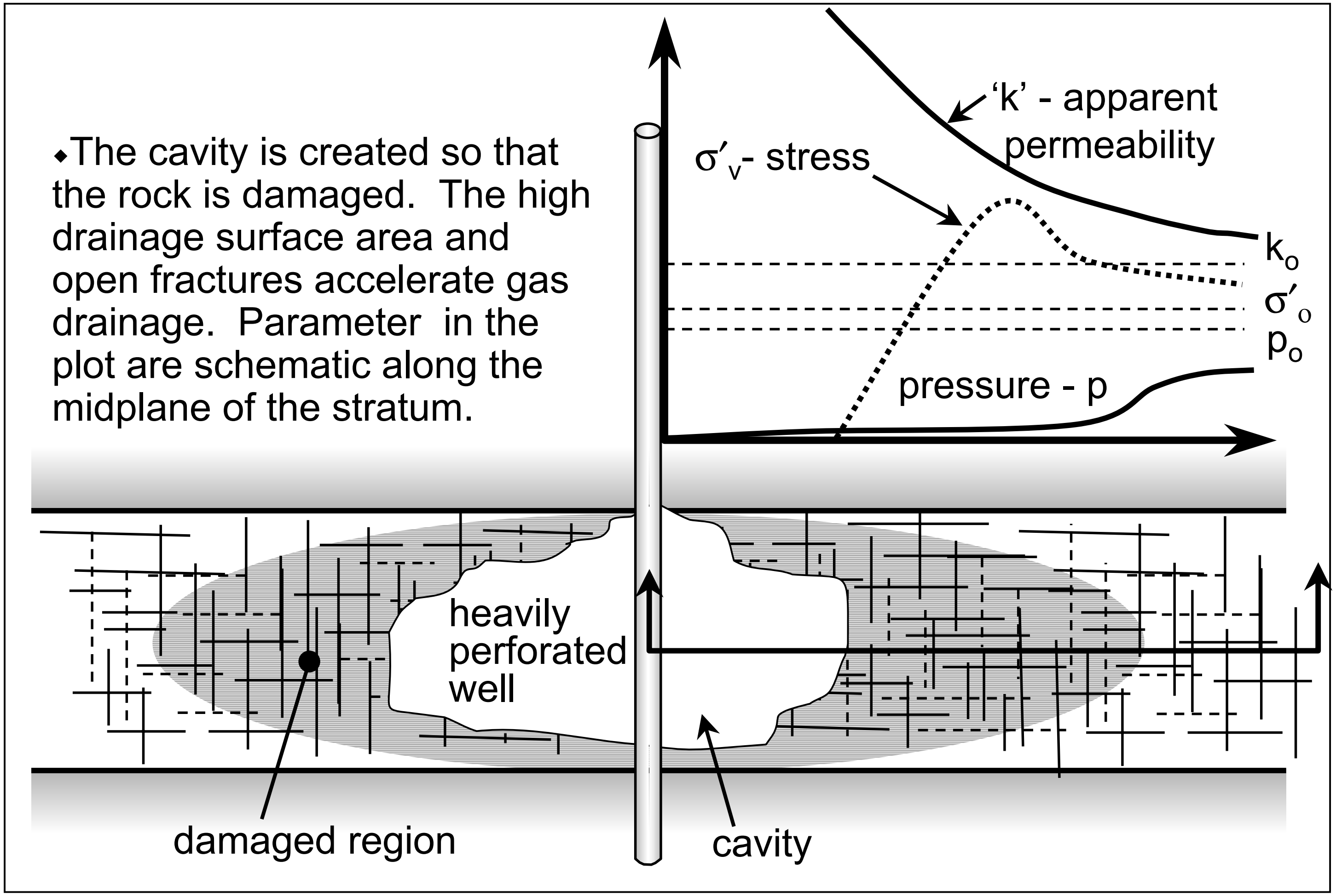

Figure 3.2: Oil and Sand Production Profiles for a "Typical" CHOP Well (*Actual data are "noisy"; curves are smoothed)

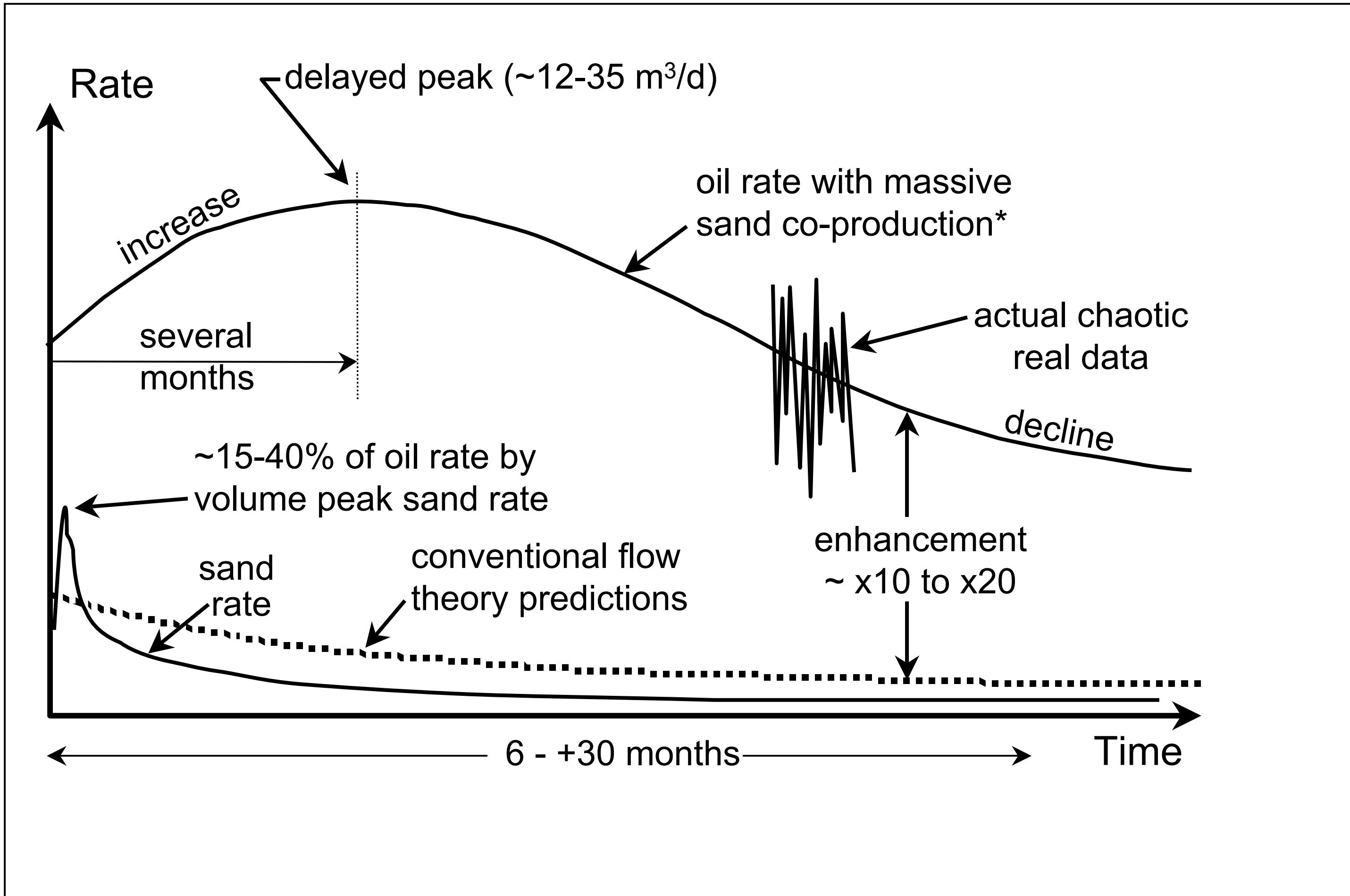

Figure 3.3: A Delayed Peak Indicates at Least Two Co-Existing Physically Different Mechanisms Act in CHOPS Wells

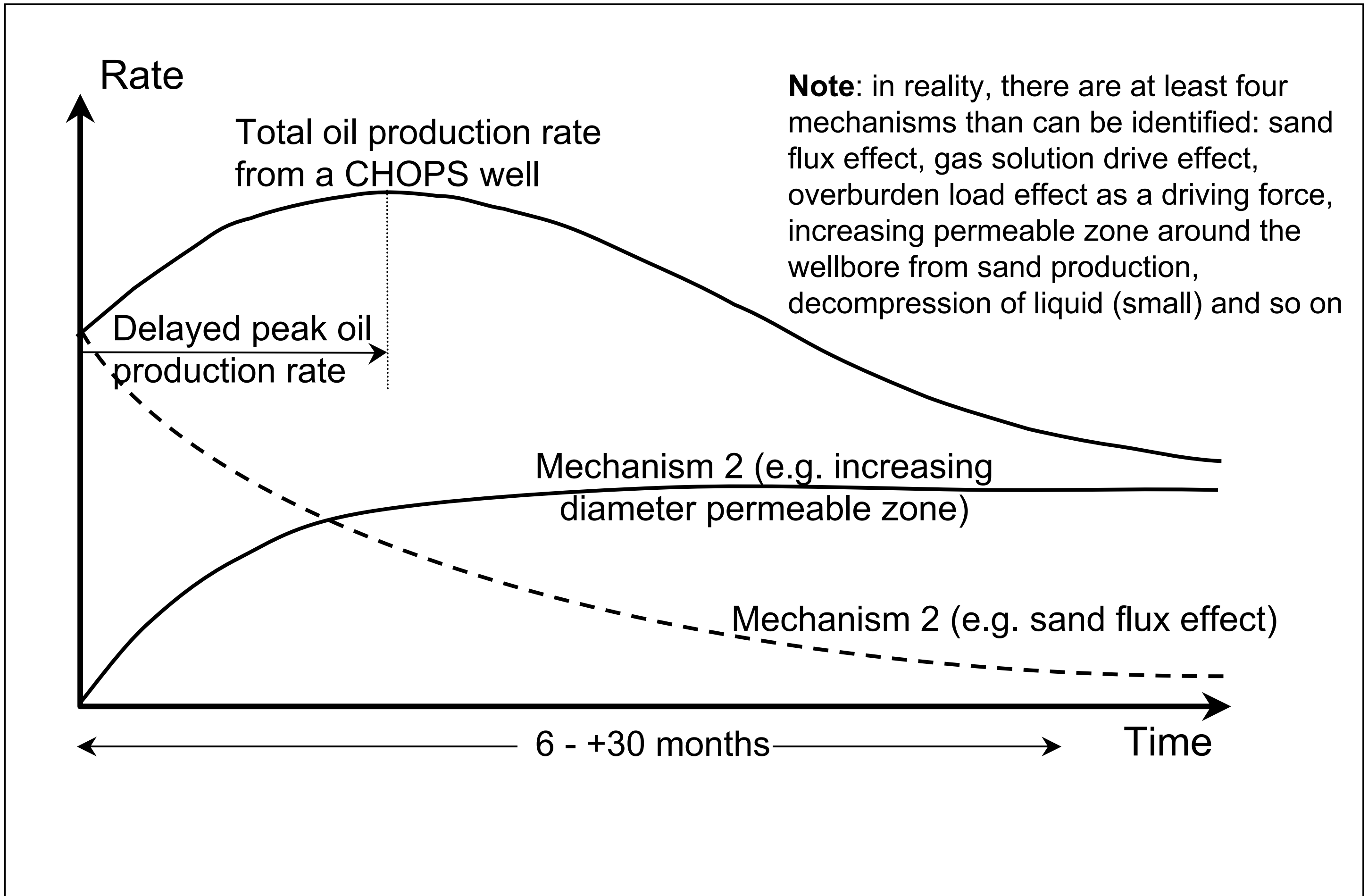

Figure 3.4: A CHOPS Well Behavior Over Three "Production Cycles" Separated by Workovers to Maintain Sand Influx

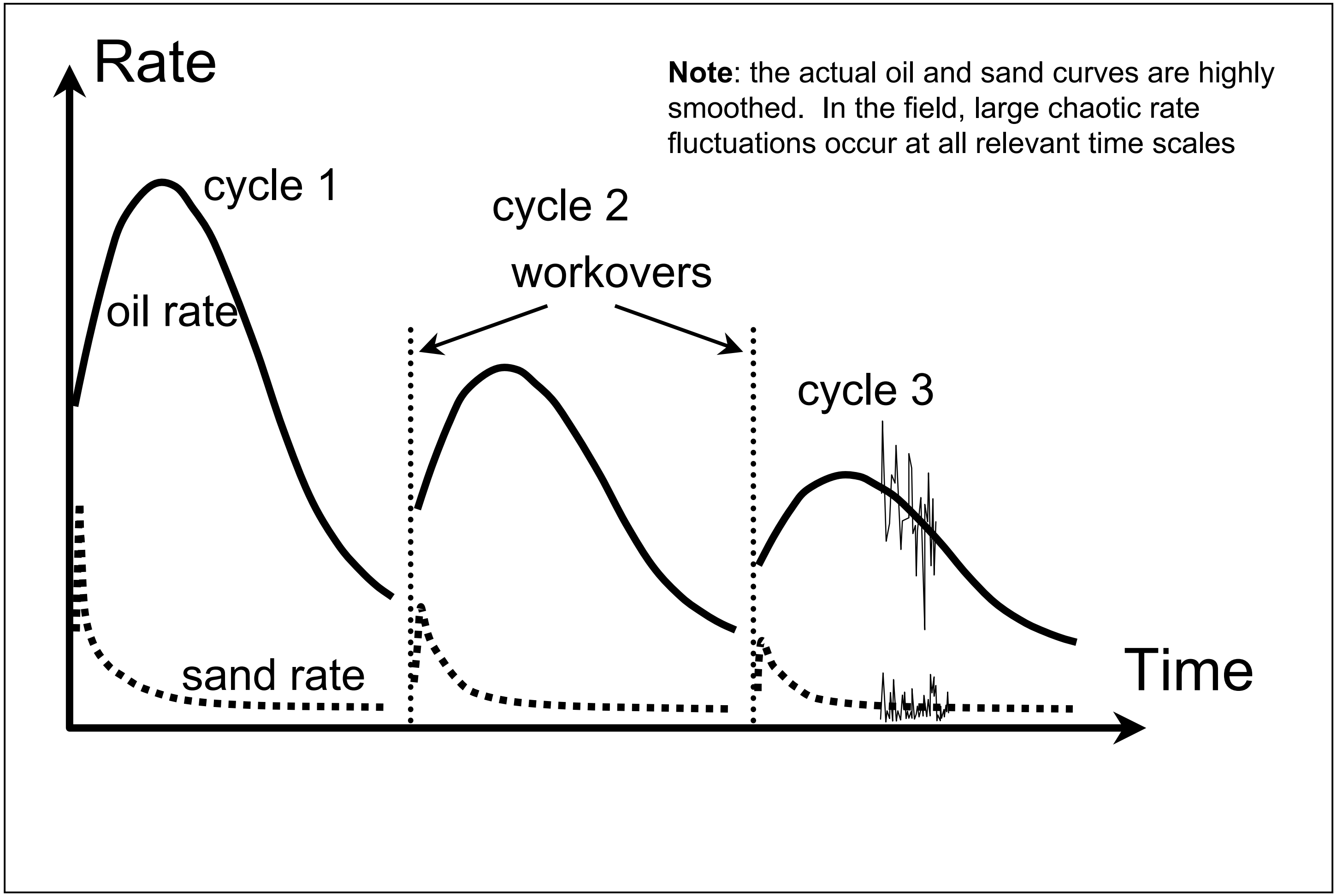

Fig 3.5: "Steady-State" Sand Rates as a Function of Heavy Oil Viscosity: More Viscous Oils Produce Higher Sand Rates

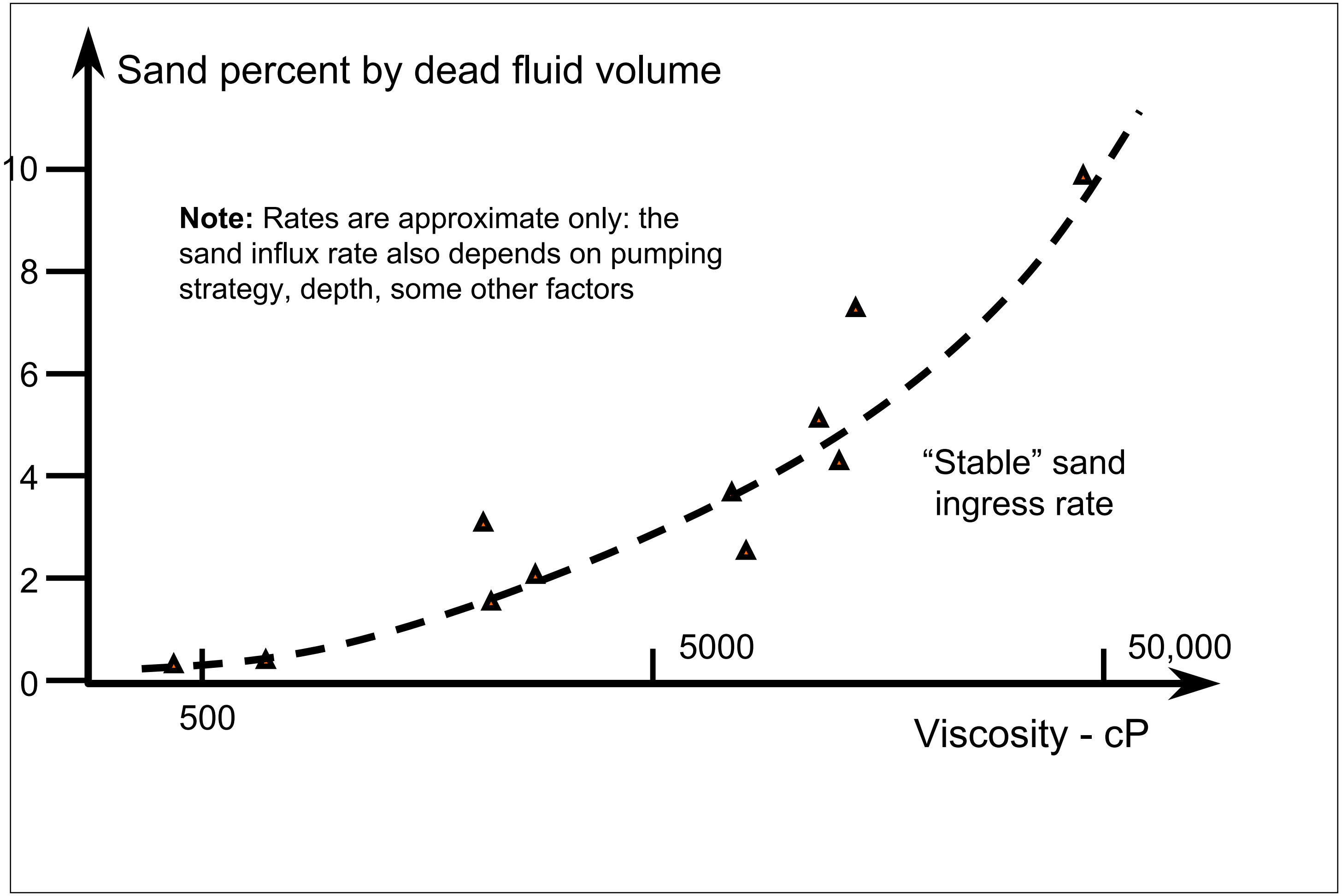

Figure 3.6: CHOPS Well Histories can be Widely Variable, Depending on Several Reservoir Mechanisms

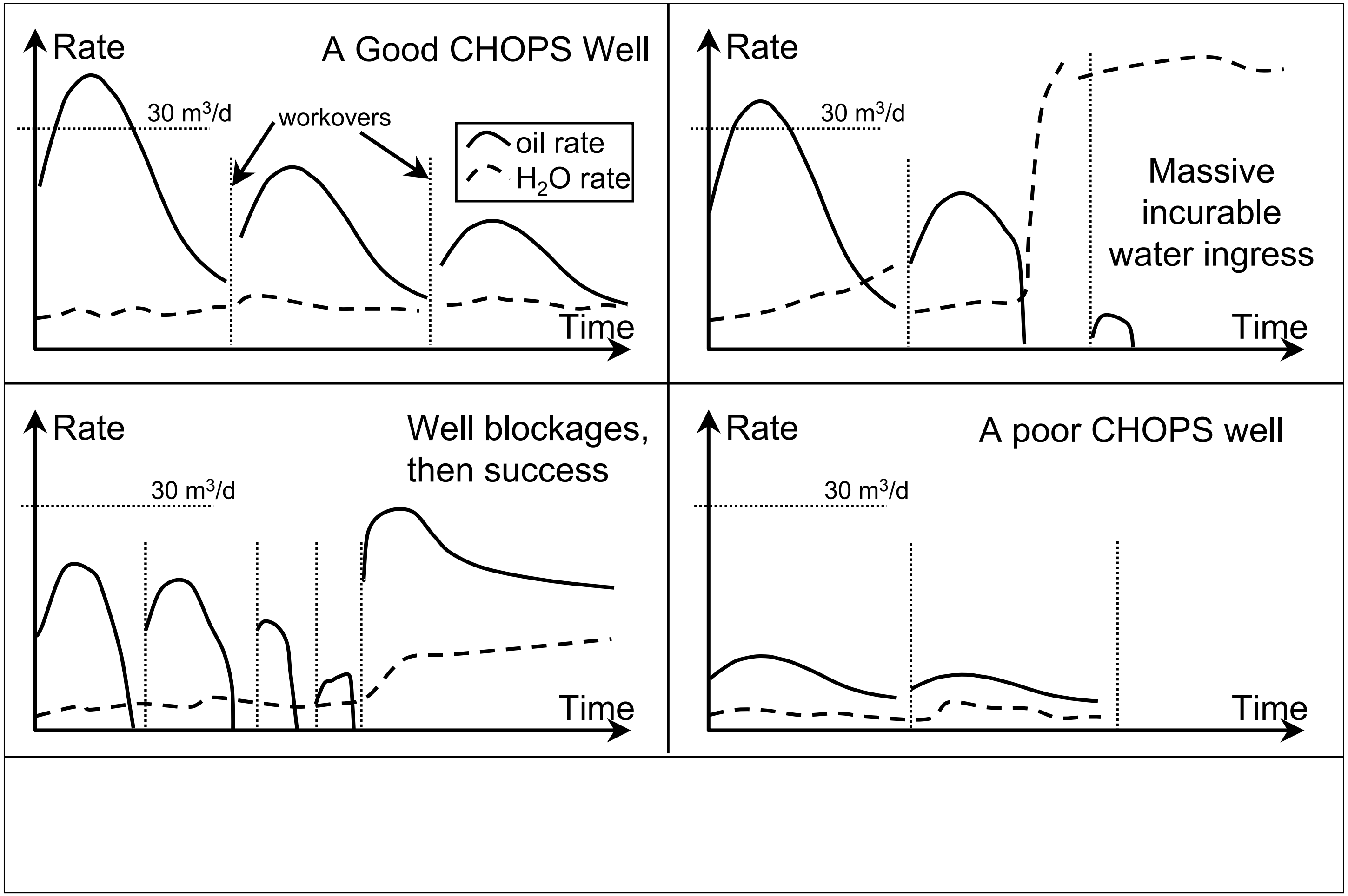

Fig 3.7: Water Ingress can Prematurely Ruin CHOPS Oil Production