13 TECHNOLOGY AND THE CANADIAN HEAVY OIL INDUSTRY

13.1 The Old Technologies

Interest in developing heavy oil is as old as the oil industry itself, and in Canada, dates from the first discoveries in the Lloydminster area in 1926. Because all approaches to oil production were based on pressure driven flow to wells, a process dominated by the permeability of the sand and the viscosity of the oil, thermal methods to reduce viscosity and high differential pressures to promote flow were the obvious choices. This led to a generation of attempts to perfect the "old" technologies, all of them involving high differential pressures between wells. Billions of dollars have been spent on these technologies, and to this day, significant successes have been rare.

13.1.1 Problems with Older Technologies

The huge heavy oil resources in Canada have been a magnet for companies which recognized that development of efficient extraction technologies would permanently alter the North American oil supply picture (perhaps this is happening at present). Various technologies were tried in pilot project at many scales (a few wells to projects involving 50-80 wells). These have for the most part been economic failures. Imperial Oil Cold Lake, Shell Peace River, and Husky Pike's Peak in Saskatchewan are the only major exceptions. A discussion of the types of problems encountered in these processes helps to explain why CHOPS has become the dominant technology for recovery of 11-20°API heavy oil.

13.1.2 Cyclic Steam Stimulation (CSS)

CSS involves injecting steam into a single well, usually for many weeks, allowing the steam to "soak" for several weeks, then producing the hot fluids. CSS has been tried by many large to intermediate sized companies in the HOB deposits. The reasons for general technical failure (ignoring the cost of generating steam) include a number of reasons related to geological complexity, geomechanics processes, and thermodynamic inefficiencies (high steam-oil ratios).

Reservoir problems arise with CSS steam injection:

- To inject enough steam fast enough to heat reservoirs requires injection pressures above the overburden stress, at least on the first few cycles. In thinner zones, this causes hydraulic fracturing out of the zone (Figure 13.1), perhaps intersection with “thief” zones and consequent loss of heat, poor conformance, loss of process control, and possibly the opening of pathways for the ingress of formation waters from overlying strata during the low-pressure production phases.

- Steam rises rapidly in the reservoir because it is far lighter than the rock and fluids. Such “steam override” leads to high heat losses, inability to access the resources in the interwell regions near the bottom of the deposits, and incomplete coverage because the thermal zone is never symmetric or complete in its coverage.
- High pressures in injection cycles, combined with poor mobility ratios and high permeability streaks, leads to massive viscous fingering and channelling. This bypasses oil and disconnects oil zones because it creates capillary barriers (pinch-off of oil zones).
- Drawdown to low pressures during production cycles leads to water coning into the production region, giving excessive water production and high heat losses
- Well problems and surface problems that arise because of cyclic high-pressure steam injection and low-pressures during the drawdown phase may include:
- Accelerated corrosion of steel goods, leading to breaching of the casing, occurs relatively commonly. Apparently, there are particular strata in the overburden that have chemically aggressive formation waters, and as these are heated, steel goods in the wellbore are more rapidly corroded.
- Because of differential thermal expansion of the convectively-heated target reservoir, compared with the overlying shales that transmit heat slowly by conduction, casing shearing at the interface with the overlying strata (Figures 13.2, 13.3) is extremely common.[lix]
- In thinner zones, less than ~20-25 m, the heat losses are substantial simply because as the thermal zone grows in size, conductive and convective heat losses become greater.
- Heating of the shale and cemented zone around the casings leads to dehydration and shrinkage, so that even with excellent cementing and intact casing, substantial upward leakage can occur.

- Well blowouts because of casing impairment (sheared or corroded casing, threaded joint failure) lead to the impairment of shallow groundwaters. Apparently, this has occurred a number of times in the Ft McMurray area and the Cold Lake area.
- Removing dissolved species (CO_3^{--} minerals) in make-up water and for treating back-produced water for reinjection entails substantial costs, and the water treatment sludges remaining in open ponds is an irritating environmental issue.

These potential difficulties must also be combined with the high cost of generating heat, the cost of project capital expenditures, and other factors. These all combine to make the economic viability of such projects problematic. It appears impossible, even in the best of the reservoirs (i.e. Imperial Oil Cold Lake), to achieve steam-oil ratios less than 3.5. High CH_4 prices in 2000 raised operating costs temporarily well above CAN$15.00 per barrel of oil produced in thermal CSS projects.

Even though several high Δp projects have been economically viable, it is worth noting that these are taking place in intermediate viscosity reservoirs (<100,000 cP). No thermal successes have been recorded in the Athabasca deposit, which is much more viscous (>500,000 cP). CSS is probably impossible in zones that have active bottom water legs because water influx during the production phase would be catastrophic. Of course, this is also a constraint for CHOPS technology applications and for any process that uses a large pressure drawdown during production.

Except for the continuation of existing projects, it is not likely that CSS will be used in the future, even given recent developments such as alternating (or combined) CO_2 and steam in the heating cycles. The best recovery ratios that can be expected in CSS are limited to about 15% in most reservoirs, perhaps 25% in the exceptional reservoirs being exploited by Imperial Oil Limited in Cold Lake.

13.1.3 Steam-Drive Methods

These methods possess all of the same problems listed above for CSS methods, except for the coning and premature water breakthrough that happen in the low-pressure production phase of CSS. Depending on the specific geometry of the drive process (line drive being the worst), casing shear can be much more serious than in CSS because of the high shear stresses generated in a “2-D” in line drive (In CSS, which is process that develops radially around a well, the shear stresses drop off with distance from the heated zone leading edge. For example, in steam drive exploitation in field in California (Lost Hills), 40-60 wells are sheared off each year.

Steam drive, in theory and in practice, is shown in Figure 13.4. It is rare, even in good deposits, to achieve more than 20% recovery. There are no known long-term economic successes for steam drive in Canada, nor are any experimental projects active at present. In the writer’s opinion, it is unlikely that this technology will ever again be tried in Canadian <20°API crude oils. Even new developments in steam drive are unlikely to be competitive with SAGD methods.

A variant of steam drive is steam circulation through a bottom water zone (Figure 13.5), using additives to help emulsify the oil and entrain it in the circulating steam and hot water. Shell Canada used a variant of this in some of their operations in the Peace River area, apparently with economic success. Like conventional steam drive, this variant is also unlikely to be employed in Alberta again. Currently (2001), the Peace River Project is being revitalized through the use of multi-lateral short-radius horizontal wells using a steam soak process.

13.1.4 In Situ Combustion Methods

In situ combustion involves burning part of the oil in place (preferably the carbon-rich fraction deposited as coke) to provide heat and pressures, using only air or O_2 injection to sustain the combustion. The concept of the “*in situ* reactor” is clearly appealing for the following reasons:

- The produced oil contains much less sulphur (although various SO_x gases are produced).
- Heavy metals are largely left behind, precipitated on the mineral substrates.
- Molecular weight is reduced, with a concomitant increase in API gravity (from 11-12°API to 17-20°API reported in the laboratory).
- Less coking and H_2 are required at surface to upgrade the material into a synthetic crude oil.
- No additional fuel is needed to sustain the process.
- However, the following disadvantages have almost always overcome the apparent promise:

- The long flow path cools the products, the crude is left behind, and the combustion gases (CO_2, SO_x…) and inert gases (N_2, with air injection) usually channel rapidly to the production well, leading to early breakthrough of the heat, and loss of the production well.
- Gravity override and poor conformance are serious problems.
- The oil is a chemically active product (a "live" oil) very different from conventional oil or heavy oil, and new refining technologies are needed to handle this difficult material.

Although THAI™, a process using a long horizontal well to short-circuit the flow path (See Section 1.3.2),[90] may eventually overcome most of these difficulties, live oil would still be produced, with attendant treatment and transportation problems

There are no active firefloods in Canada at this time, nor are any planned for the future.

13.2 Producers of Alberta Primary Heavy Oil

13.2.1 History of Major Oil Companies in CHOPS

The only integrated international oil companies remaining active in the Heavy Oil Belt are Chevron-Texaco Canada and Imperial Oil Resources Canada (EXXON-Mobil), both subsidiaries of larger international corporations. (Shell Oil remains active in the Peace River bitumen deposit where API gravity < 10°). Their operations in CHOPS in the HOB have been minor compared to the other players. A brief history is helpful in understanding the heavy oil industry of Alberta and Saskatchewan.

Large oil companies came into the HOB after the first sudden oil price rise in the 1970's, and especially after the second "shock" in the early 1980's. They brought their well-developed technologies, such as sand screening, gravel packs, and so on. Solutions to sand influx into wells were sought through implementation of these expensive approaches because sand was viewed as a problem to be avoided through exclusion. .

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[90] THAI stands for Toe-to-Heel Air Injection, and although it has been tried in the laboratory with great success, no field trials have been attempted in Canada.

The large companies also brought with them strong vertically organized structures; decisions were made by engineering groups or by research teams in head office facilities, far from the field sites.[91] This was not conducive to development of better operating and production technologies in these different and difficult materials.

The large integrated international oil companies focused most of their energies on thermal approaches, and many pilot projects were tried in the HOB. Throughout the area thermal project sites can be found, dismantled completely, or “temporarily” abandoned, with the facilities and wells left in place without plugging and abandonment perhaps to serve as future assets. The companies had little interest in the low-rate wells throughout the region producing small quantities of heavy oil and small amounts of sand, and this attitude persists to this day. Large integrated international oil companies appear to be ill-equipped to work in heavy oil, where margins are slim and there are no “elephants” to find through exotic exploration methods.

Large companies are best equipped to handle large projects, and CHOPS development is not of this nature. Imperial Oil’s project in Cold Lake, however, fits this definition more closely. Renewed interest by large companies is still focused on large projects, such as new mines in the Athabasca deposit (Shell Oil, CNRL), new synthetic oil plants near Edmonton, a number of SAGD projects, and so on.

Intermediate-Size Canadian Producers

The major intermediates in the HOB are Husky Energy, Canadian Natural Resources (CNRL), Petrovera Energy (owned jointly by PanCanadian and Conoco), PanCanadian Petroleum, Nexen Inc. (Wascana Division) and Anderson Exploration Ltd., recently purchased by Devon Energy (2001). They are listed in approximate order of their production in the HOB. Only Husky has its own upgrading capability. Many of these companies have grown through the acquisition of other, smaller companies, particularly during the 1997-2000 period (e.g. CNRL which absorbed Ranger, Elan and others; PanCanadian which absorbed CS Resources; and Husky which

[91] This structure, common in the 1970s and 1980s, became less pronounced in the late 1980s and 1990s. Most large international companies have reorganised toward an “asset-based structure” rather than a vertical hierarchy, which has helped push down decision-making to a level commensurate with the impact of the decisions, helping corporate profitability and flexibility.

absorbed Renaissance as well as several other smaller companies). All of these companies have their (Canadian) head offices in Calgary.

Of these companies, PanCanadian and Petrovera deserve special mention as they have consistently tried to be innovative in CHOPS technology development, experimenting with different production configurations, new pumps, new completions approaches and so on. Small Canadian Heavy Oil Producers

There are over 350 oil and gas producing companies listed in corporate directories. Many of these have very small heavy oil operations, a few wells in a limited area. Among these small producers one may note, in no particular order, Barcomp Petroleum, Beau Canada Exploration Ltd., Anadarko, Exxon-Mobil Canada (Celtic and Iron River in Saskatchewan), Koch Exploration (part of Koch Industries), Murphy Oil Company Ltd. and Baytex.

Of these, Koch Industries must be singled out because they have large upgrading capacity located in the United States in Kansas and Minnesota. Koch Exploration has followed a successful corporate policy of buying land when prices were low, selling when prices were high, and sustaining as large a differential price as possible in order to maximize their financial returns in their facilities in the United States. This is relevant because a high differential means that Canadian producers are getting less for their heavy crude, and at the same time the profitability of the upgrading companies, mostly in the United States but also in Canada, are increasing the profit margins.

13.2.2 Other Companies

Corlac, Grithog, Can-Viro, E-Vac, Enviro-Vault, Weatherford, Kudu, Jet Perforating, PRISM Production Technologies, and many other companies are active in providing services. These companies are largely Canadian owned (or were originally started as Canadian companies), and along with the oil companies, provide an economic backbone to eastern Alberta and western Saskatchewan

The best way to get a list of service and product companies is to consult the websites of Canadian Small Business, the City of Lloydminster, other towns, and the Canadian Petroleum Directory. A large effort would be needed to evaluate the large positive impact of CHOPS technologies on Alberta industry through the generation of small and intermediate companies that employ local people. This is a regional economic study that should be carried out.

13.2.3 Public Research Agencies

The following agencies in Canada have had or currently have active research programs relating to CHOPS in one way or another: Petroleum Recovery Institute (now part of the Alberta Research Council), Alberta Research Council, Canadian Centre for Frontier Engineering Research (now part of the Alberta Research Council), Saskatchewan Research Council, Regina Petroleum Research Institute established at the University of Regina by the Saskatchewan Government, and the Porous Media Research Institute (University of Waterloo). To varying degrees, all Alberta and Saskatchewan Universities have been active in research activity relating to heavy oil development.

13.3 Science and Technology Development in Heavy Oil

An understanding of the major events in the development of the science and technology associated with CHOPS and other heavy oil production technologies can help understand to some degree the evolution of the Alberta heavy oil industry.

13.3.1 AOSTRA: Alberta Oil Sands Technology and Research Authority

AOSTRA played an important part in the history of heavy oil in Alberta. The Alberta Oil Sands Technology and Research Authority (AOSTRA) was in existence for 25 years from 1970 to 1995).[92] It funded pilot projects by industry, supported researchers in several universities, and also undertook projects entirely on its own. AOSTRA established scholarships and professorships, and to this day, in the heavy oil industry, these people that were funded in their studies and research continue to play a major role. The great majority of the field projects that AOSTRA funded (generally in 50% funded participation with industrial consortia) have not produced startling advances in technology. Many of the projects ended up giving “negative” results, which are often as vital as “positive” results in the advance of technology. Various

[92] The Universities Research Program of the Alberta Department of Energy is the successor to AOSTRA, albeit with a restricted budget and far less funding, and continues to support Alberta university-based research in heavy oil areas.

projects such as tailings disposal for oil sand mines, biological extraction processes, foam blockage of channeled zones, and so on, helped delineate the physics of processes, the difficulties in coping with real reservoir conditions, and even helped to demonstrate that some technologies were unlikely to ever achieve practical and economic success.

AOSTRA's major achievement in production technology development is undoubtedly the current status of SAGD. In the middle 1980's AOSTRA decided to pursue SAGD thorough implementation of an underground mine access scheme northwest of Fort McMurray. The technology of horizontal well placement at that time did not allow surface drilling (little geosteering capability was available). They formulated a project (the Mackay River UTF, or Underground Test Facility) involving three parallel SAGD well pairs 500 m long with 75 metres horizontal spacing. Industry was approached, and all companies declined to participate with the exception of Chevron, which was not particularly interested in SAGD, but wanted to field test the company's patented HasDrive™ system. At that time, all companies and many engineers and scientists considered the AOSTRA scheme to be silly: sarcastic comments about government boondoggles were wide-spread.

In the first Underground Test Facility phase plan, 10 simulation groups (academic, industry, and consultant groups) made predictions of the process progress and recovery efficacy in the lithostratigraphic conditions at the MacKay River site (very shallow, < 200 m and very viscous, > 500,000 cP). Only one of the groups predicted a recovery ratio over 25%, and the scientific basis of this prediction was questionable. Furthermore, none predicted any recovery from the upper section that was separated from the lower, richer reservoir by a 2 to 3 m silty shale band of very low permeability, a classic Darcy flow barrier. These groups used "state-of-the-art" models that were thought to be complete in terms of first-order thermodynamics and physical processes, and few experts questioned the results obtained through use of these models.

Of course, the UTF First Phase achieved astounding success, vindicating the project entirely (the Second Phase of the UTF was even oversubscribed by industry). By some estimates, over 90% OOIP recovery was achieved for the central well pair. The "flow barrier" in the upper central part of the formation was bypassed easily, likely through thermally induced shrinkage followed by fracture growth upward to give fluid flow access. The recovery rate was faster than expected, and the flow regime stability, driven by density differences rather than pressure differences, was remarkable

It is useful to remember this example when considering basing economic decisions on numerical (mathematical) simulation modeling of complex processes *in situ* under conditions of massive heterogeneity and uncertainty. Modeling has a spotty history of success in true *a priori* predictions. Of course, it is highly successful in "predicting" (history matching) well-characterized case histories, but these successes do not prove that a simulator contains all the relevant physics: there are many unknown or ill-defined parameters that are "chosen" by the operator or otherwise determined during the simulation process. It is not unusual during a simulation exercise to set aside known parameter values and use different values to achieve a better "fit" to the history.

More than any single other agency, company or institution, AOSTRA is responsible for the current massive interest in SAGD and the initiation of large projects in 2001 that are expected to be fully commercial by the year 2003.

The UTF also contributed to the development of new instrumentation technologies and the establishment of new Canadian companies (e.g. PROMORE, now owned by Core Labs, and PRISM Production Technologies, established in 2000 by the original founders of PROMORE). Other advances aided by the UTF project included the development of gravity SAGD mathematical simulation models.

AOSTRA support was often implicated in new technology developments in other institutions, often indirectly through funding positions at the Alberta Universities, often directly through the funding of specific small projects in academia, often by funding research projects of private individuals or government research establishments (Alberta Research Council and the Alberta Geological Survey were major beneficiaries). Pressure pulsing had its origins in the University of Alberta Physics Department theoretical developments. CHOPS was studied academically at the University of Waterloo (PMRI) and with C-FER in Edmonton long before it became fashionable in the late 1990s. Slurry injection of wastes, mineralogy, geology, geochemistry, geophysics, hydraulic fracturing behavior, *in situ* combustion, medium to high temperature aqueous geochemistry reactions, biological methods, shale behavior, and many other topics were funded. These have massively expanded the range of knowledge and technology in heavy oil in

Canada, and if Canada is clearly the world leader in this area, AOSTRA funding appears to have been the most seminal factor.

The example of AOSTRA should be studied by politicians who are looking for ways to promote technology advance and industrial activity. It is an example of building on strengths, promoting local initiatives, and taking the lead in idea development rather than being dictated to by industry.

13.3.2 Technology Emergence

In science, novel ideas are often rejected initially in a hostile manner by those who have strong psychological and financial interest in the accepted paradigm. This has clearly been the case in the heavy oil industry in Canada:[93]

- In 1980, it was well known in the industry that horizontal wells would never be practical (too expensive , little control of placement).
- In the middle 1980s, the industry believed that large-scale thermal gravity methods (i.e. SAGD) were a waste of time. On the other hand, at the time, the same people usually believed that combustion had a bright, perhaps even a hot future.
- In the late 1980s, suggestions that one might be able to dispose in excess of 10,000 m^3 of sand into a single disposal well were met by the comment: "You sure don't understand fracturing and tip screen-out, do you?"
- In the late 1980s and early 1990s, even though data developed in Alberta proved it, many oil industry experts didn't believe that it was possible to pump wells for months with 20% sand (and even, in some cases, 45% sand for short periods). Pockets of disbelief remain, although no longer in Canada.
- In the period 1998-2001, the concept of pressure pulsing the liquid phase *in situ*[94] to accelerate fluid flow and enhance production through increasing conformance of flooding was regarded with amusement.

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[93] A number of these are direct personal experiences of the writer. Apologies are tendered to those whose favorite examples have been omitted. This section should be cleansed of such comments

The point made by these examples is that technological progress continues, often by conceptual leaps. Generally, new concepts have had to be proven under difficult conditions because in field trials, companies often allow a new concept to be tried only on poor quality assets. This means that initial trials may take place in much less than optimum conditions.

Attempts by agencies and key people to "guide" research in science and technology by choosing in advance the potential winners from a set of possible candidates is thus likely to be a conservative approach that slows progress. The same may be said of efforts by industry to advise government on directions to support. This advice lacks originality, and is usually self-serving.

13.4 Emerging Technologies

In addition to pressure pulsing, which has had small commercial successes, several new concepts that are emerging are VAPEX and THAI™: Vapor-Assisted Petroleum Extraction, and Toe-to-Heel Air Injection. Not only can these technologies be used as "stand alone" methods in the right reservoirs, but they may also be combined, used as adjuncts to other technologies, or used in some sequenced form. This section will discuss the major elements of the emerging technologies, as they each may impact CHOPS evolution through hybrid projects and sequential use.

13.4.1 VAPEX

VAPEX is essentially the same physical process as SAGD: vertical, density-driven fluid segregation through pore-scale to larger scale countercurrent flow. The reduction of viscosity is achieved by diffusion of gaseous and light liquid phases into the heavy oil, rather than by heating. As with SAGD, the generation of a three-phase zone *in situ* (water wetting the grains, gas in the pores, oil as a continuous film between the two) allows the process to maintain contact with oil zones, rather than pinching them off and isolating them, and this allows the oil to drain

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[94] It is also worth mentioning that this development came from the work of T. Spanos and his colleagues at the University of Alberta, Physics Department, and the mathematical basis for it was developed by the 1980s. The theory has repeatedly, in experimental, analysis and field modes, been shown to be a more profound and complete statement of the dynamic behavior of multiphase porous media over the entire range of excitation frequencies from diffusion (very low ω, Darcy flow) to wave propagation (very high ω, the incomplete Biot Gassmann formalism).

(Figure 13.6a, 13.6b & 13.7) until local saturations become low because the oil has been replaced by the VAPEX gases.

As with SAGD and Inert Gas Injection, another gravity dominated process, the principle of voidage replacement is critical: for each cubic metre produced, a cubic metre of volume must be introduced into the reservoir. Overproduction will lead to water coning, over-injection will lead to the gases short-circuiting to the production wells and failure to maintain a liquid saturated bank above the horizontal production well. This need for careful control under the complex conditions of dissolution, diffusion, and fluid flow is perhaps too complicated to calculate with sufficient precision, and it is believed that the VAPEX process (as well as SAGD) will be controlled by precision pressure measurements that allow the voidage balance to be controlled empirically, through pressure measurements within the producing zone.

The VAPEX concept will be tried in the field soon, and may be the next technology of note in intermediate viscosity oil. Major applications are likely to be in reservoirs with lighter oils (>20°API) if used cold, but it can be used in combination with SAGD (warm VAPEX), or as an alternating approach with SAGD. In the latter conception, pure steam is used to heat and generate a chamber, then the steam is replaced cyclically with a changing mix of appropriate CO_2 and C_nH_{2n+2} gases, tailored to the temperature in the chamber so that maximum dilution efficacy and diffusion speed can be attained.

In addition to permeability (particularly k_v), VAPEX efficacy is governed by the diffusion rate of the gaseous and liquid phases into the viscous oil. Because this process is slow, a large reactive flow area is required, so VAPEX production will likely be slow for a long period until the chamber achieves a sufficient size. Of course, as the size becomes very large, the flow path for the vapors and returning product is long, and this eventually slows down production rate until the process is shut down. After termination, the pressure in the chamber is dropped to recover the valuable gases and light HC liquids, but in many cases where there is lateral active water or bottom water, this will be a more difficult process because of coning and rapid invasion by the low viscosity fluids. It may be possible to "reverse" gravity drainage: the incoming water is denser than the light fluids in the VAPEX chamber, and therefore should displace the light fluids

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Opposition, which remains quite general at the time of writing, will gradually die out under the weight of new from the bottom up with a density-stabilized interface (bottom water drive). Because the VAPEX zone is now largely free of heavy oil, it has a high permeability, and the bottom water displacement can be carried out at the right rate to achieve an excellent recovery ratio for the VAPEX fluids, which can then be recycled to other VAPEX wells.

VAPEX is impeded by the presence of barriers to vertical flow (the same may be said of all gravity processes). It is unlikely to work well in cases where there are many thin shale streaks that are continuous at the well influence zone scale. In such cases, it would be necessary to place propped vertical fractures to serve as conduits to the gases and returning fluids, allowing access to higher zones. However, in the shallower oil sands (<400 m depth), fractures are generally not vertical, so VAPEX enhancement through fracturing may be problematic. Also, because of the cost of the horizontal wells and the gradual reduction in lateral migration of the heavy oil dissolution front, it is unlikely that VAPEX will find economical applications in reservoirs that are thinner than 15 metres.

VAPEX will likely be most effective in achieving high recovery ratios in oils of $\sim 18°$ to 32°API gravity, where the diffusion rate is fast enough to allow economic production rates. In cold VAPEX, there are no thermal losses and no continuous fracturing (as in CSS), therefore VAPEX will not be economically limited by the increase in conductive heat losses as the chamber grows, nor will it be limited by large VAPEX fluid losses through the overburden seal. Because no high pressures are used, fracturing does not take place and advective instabilities such as viscous fingering can be controlled.

13.4.2 THAI™: Toe-to-Heel Air Injection

The potential attractions and disadvantages of conventional *in situ* combustion processes were outlined in Section 12.1.4. THAI™ and its sister concept, CAPRI™ (Catalyst-Assisted), which uses a catalyst placed around the producing well to reduce the chemical activity of the produced fluids, may help address the advective (Δp) instabilities and cooling effects that have always been characteristic of conventional high pressure combustion processes.

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practical resultsdoes this need to be said again?.

In the basic concept of THAI and CAPRI (Figures 13.8 a and b, but several other geometrical configurations are possible), air or oxygen is injected into cheap, vertical injection wells and combustion is initiated. In the horizontal wells, a burning zone is created initially at the toe of the well and propagated out some distance before the flow of air is reversed, and the air injection wells are activated. Continued "toe-to-heel" combustion is then allowed to develop, and the production and injection rates are controlled to allow the combustion zone to develop as a relatively narrow front, and also to grow vertically and laterally to give better reservoir sweep.

The hot gases and fluids generated during combustion, instead of flowing through many metres of cold formation under high gradients, are withdrawn at the base of the combustion zone by the horizontal well. When compared with the injection rate, withdrawal that is too rapid will reduce lateral spreading, withdrawal that is too slow will cause instabilities and loss of control of the location of the fire front. Just in advance of the combustion zone, where all the fluids are extremely hot, the denser liquids segregate somewhat by gravity effects, but the major driving process is the Δp from the combustion zone to the horizontal well intake point. THAI™ is therefore not a gravitationally stabilized process; it is stabilized by the maintenance of a short flow path to reduce cooling and channeling effects.

Successful THAI™ in horizontal wells requires several conditions. First, the section of the horizontal well beyond the combustion front must somehow be isolated so that the injection gases do not short-circuit to the open toe, bringing unconsumed oxygen into the well.   Such short-circuiting will slow and stop the combustion zone propagation and also burn out the well. Probably some form of a sleeve that has to be periodically reinstalled will be necessary, although it may be possible to find a material to pack around the well that melts and seals the well at the right temperature, still allowing flow through it at cooler temperatures closer to the heel.

Undoubtedly, a second requirement for THAI™ success in the field will be careful tracking of the combustion zone. There are three possible approaches (not counting multiple monitoring wells that would be excessively expensive): thermocouples along the horizontal well to locate the front along its axis; microseismic monitoring to locate the front progression through the spatio-temporally evolving acoustic emission field; and, three-dimensional electrical resistivity monitoring[lx,lxi] to track the zone of extremely high resistivity generated by the combustion process. (The hot zone with water will be highly conductive, the zone that has never been heated will have a low conductivity, and the cooled combusted zone will be even lower in conductivity.) Microseismic monitoring, combined with thermocouples that can withstand the temperatures in the production well, afford the best possibility for process control. Also, continuous gas analysis at the surface of the produced gases will be necessary to detect any free oxygen influx and changes in composition that could be diagnostic of the progress of the combustion process.

As with other combustion processes, THAI™ can be used with air, oxygen, or enriched air, and either dry or with the addition of small amounts of water to the injected materials to allow the combustion to proceed at lower temperatures.

13.4.3 Pressure Pulsing Technologies

Conventional recovery ratios in many reservoirs are as low as 20-40% of the original oil in place (OOIP). Improved recovery technologies may increase these numbers by as much as 10-15% (i.e. to 30-50% of the OOIP). Only exceptionally is more than 60-65% of the OOIP recovered from a single conventional oil reservoir. Various physical processes (linked to Darcy flow, capillarity, viscosity, permeability, heterogeneity, and pressure gradients) dictate the amount of oil recovered by conventional methods.

- Capillary blockage leads to isolation of bodies of oil because the capillary entry pressure cannot be overcome under static flow conditions.
- In cases of unfavorable mobility ratio (where the viscosity ratio of displacing to displaced fluids is far less than 1), the less viscous phase channels through the more viscous phase, even if the permeability is perfectly homogeneous. This is called viscous fingering, and is endemic in gas or water flooding of more viscous oils.
- Water coning and gas coning to oil wells under production are forms of viscous fingering, and they lead to sudden declines in oil production.
- The presence of channels of different permeability leads to flow channeling, where most or all the displacing fluids flow to the producing well through the most permeable zone, leaving other zones undeveloped or underdeveloped.

For example, residual oil saturation, a concept related to Darcian fluid flow through porous media, is the result of bypassing of oil during a water displacement test, and this value is typically between 10% and 50% of the original oil in place.

The basic physical process behind oil and gas exploitation is fluid flow. It has long been supposed that the physics of Darcy flow dictates recovery ratios that can be attained in multiphase systems. However, along with gravity drainage methods, pressure impulse flow enhancement has recently been found to be effective. This is achieved through the input of dynamic energy.

13.4.3.1 Darcy Theory and Biot Theory

There is a broad range of possible frequencies of mechanical excitation of the liquid phase or the solid phase of a liquid-saturated porous medium (Figure 13.10). Conventionally, there have been two theoretical formalisms for this broad range of excitation frequencies: for high frequencies: Biot-Gassmann wave mechanics theory forms the foundation of analysis; and for low frequencies ("zero frequency"), Darcy diffusion theory is the basis of analysis.

Biot theory was largely laid out in the period 1945-1965.[lxii] It is a wave mechanics theory that is considered valid for excitation frequencies greater than 10 Hz. In Biot formalism, there are several assumptions that are inherent to the formulation that restrict its broader suitability:

Biot assumed that for a representative elementary volume (REV) in a multiphasic porous medium, a single energy functional could be stipulated to define the energy state. More recently, it has been shown that this is a restrictive assumption; for N continuous contiguous phases, N energy functionals are needed to fully generalize behavior. (Simultaneous countercurrent flow of two immiscible liquids in a horizontal laboratory specimen is evidence that at least two separate energy functionals are needed.)

Biot assumed that porosity (ϕ) was a scalar physical parameter. However, recent work has shown that for porous media, ϕ is a thermodynamic variable, similar to pressure and temperature. For a complete description of the energy state of a porous medium, the porosity must be stipulated. Without this, all the developments described below would remain on a purely empirical basis.

Biot approached wave attenuation (not spatial spreading) empirically, rather than quantifying it in a fundamental thermodynamics framework (e.g. adiabatic compression and rarefaction, etc.). Recently, it has been shown that a more thermodynamically rigorous approach can quantify the attenuation component due to phase compression cycles.

An implicit assumption is that liquids deform by straining, and that no discrete flow takes place during dynamic excitation. For years, attempts have been made to overcome this shortcoming of Biot theory through introduction of "squirt flow" concepts.

Wave theory predicts the existence of many of the known strain waves in porous media, but fails to predict the existence of a slow displacement wave ($v \sim 150$ m/s) that is often observed in earthquake coda (not to be confused with the Biot "slow wave"). This displacement wave arrives well after all the known strain waves, and is characterized by a low vibration frequency spectrum.

At the low end of the excitation frequency spectrum, Darcy formalism deals with flow through porous media subject to a number of assumptions: including the following:

- The liquids are incompressible and the strains are small (this is not the same as saying that the solid skeleton is incompressible). This restriction has been modified in order to analyze gas flow to wells, for example.
- There are no dynamic (inertial) effects, therefore all motion is described by a set of diffusion equations, which is equivalent to saying that Darcy diffusion theory is a static theory, or more correctly, a "quasi-static" theory.

It is widely accepted that Darcy theory is acceptable to describe the behavior of porous systems subjected to excitation frequencies of less than $\sim 10^{-4} - 10^{-5}$ Hz. The pore liquids do in fact behave incompressibly in this dynamic range, leading to a pure displacement process through the pores.

Thus, slow excitation can be described by a diffusion equation ($\partial \mathbf{u}/\partial t$ terms) where the liquid behaves incompressibly, whereas rapid excitation can be described by a wave equation ($\partial^2 \mathbf{u}/\partial t^2$ terms) where the liquid undergoes strain but does not displace. This discussion, expressed diagrammatically in Figure 13.9, leads to an inescapable conclusion: there must be a range of three orders of magnitude of excitation frequency between these limits where both diffusion and dynamic aspects are of primary importance in porous media mechanics. Furthermore, there must be a transition zone where the liquid phase undergoes a transition from compressible to incompressible behavior.

13.4.3.2 The Porosity Dilation (PD) Wave

The shortcomings of Biot and Darcy formalisms have been largely overcome by the development of a set of coupled diffusion-dynamic differential equations.[lxiii],[lxiv] This was achieved in the conventional manner, satisfying all the laws of conservation including the law of conservation of momentum transfer (often ignored). Porosity is introduced as an explicit thermodynamic variable, so that $\partial\phi/\partial t$ and $\partial^2\phi/\partial t^2$ terms are found in the equations. The equations are mixed hyperbolic and parabolic, highly non-linear, not amenable to easy numerical model development, and are not known to lead to any simple closed-form solutions at this time. Nevertheless, if they are solved subject to the assumption of the incompressibility of a liquid saturant, the existence of a slow displacement wave is predicted. This wave, which is called the porosity dilation (PD) wave, is not a strain wave: it is a coupled liquid-solid displacement wave, and it has some remarkable properties.

- The PD wave is a body wave of small elastic porosity dilation that propagates through a liquid-saturated porous medium.
- The wave cannot exist without liquid-solid coupling, and it is preferentially generated through excitation that is dominated by moderate frequency energy (0.1 – 1 Hz), in the range where the liquid evidences a transition to incompressible behavior.
- With regard to conventional strain waves such as compressional and shear waves, the PD wave is analogous to the relationship between a tsunami (a liquid displacement wave) and a liquid-transmitted compressional wave (the “P” liquid strain wave). In fact, the velocity ratios are similar (roughly 1/20th).

The theoretical, laboratory and field demonstration of the existence of the PD wave helps explain several physical phenomena that to date have escaped rigorous analysis. For example, post-earthquake flow rate enhancements in oil wells can be explained by the micromechanical effects associated with the PD wave. The groundwater table response after a large earthquake at a distance is well documented; e.g. in Alberta in 1964 many hours after the huge Alaska earthquake. The unusual delay in the response, which occurs long after all strain waves and surface waves have transited, can now be linked to the low velocity of the PD wave. Similarly, delayed triggering of sympathetic earthquakes, groundwater response to low-frequency vibrations (such as storm-wave induced inland flow in porous sediments), and other phenomena can perhaps be better understood by PD wave mechanics.[lxv]

In practice, excitation is achieved through high impulse downhole pressure pulsing devices.[lxvi]

13.4.3.3 Benefits to Flow Processes

Pressure pulsing creates the PD wave, which transits through the system, and results in the acceleration ($\bar{a}$) of a small amount of the fluid mass (m) into and out of the pore throats. This gives rise to a force, $\mathbf{F} = m\bar{a}$, and if the force is divided by the area (A) of the pore throat that is blocking the flow, it is clear that a dynamic pressure $\Delta p = \mathbf{F}/A$ is generated at the throat. If $m\bar{a}/A > \gamma_{ow}/2r$, the dynamic Δp can overcome the capillary barrier, and cause phase breakthrough. Once breakthrough has been achieved, fluid can flow through the pore easily, and oil production can continue with fewer sources of impedance. If capillary barriers are overcome, there will be less bypassed oil in situations such as bottom-water drive: excitation in the bottom-water zone will help generate a more planar front. This process will increase the ultimate oil recovery factor in such cases.

The diagram in Figure 13.11a represents a case of viscous fingering around a wellbore. These cases typically arise when a low viscosity liquid is injected into a porous medium containing a higher viscosity liquid; examples are water floods or chemical treatments in heavy oil reservoirs where the viscosity differences are so large that viscous fingering completely dominates the process, leading to early low-viscosity phase breakthrough, poor chemical contact with the reservoir, and so on. With pulsing, there is high dynamic energy near the wellbore to help overcome the barriers to flow that generate viscous fingering, but far from the well, the pulsing energy is diminished by geometric spreading. Thus, viscous fingering and channeling effects near the wellbore tend to be overcome, and this increases sweep efficiency (Figure 13.11b).

A similar effect happens in the case of permeability inhomogeneities. Once water breakthrough to the production well occurs, flow becomes constrained to the high-k zone because of the high water saturation of the swept zone. This causes bypassing of oil-containing zones, and the oil phase, which was once continuous, is pinched off so that large isolated ganglia are generated, with attendant capillary barriers isolating them from the flow regime. If the water flood is carried out with pulsing, it helps to advance the water displacement front in the lower permeability zones near the excitation source, achieving more uniform water displacement and better oil recovery.

PD waves and dynamic excitation also have the effect of maintaining a higher liquid pressure near the dynamic excitation well because the energy put into the system helps liquid flow through the pore throats. This occurs through several mechanisms, depending on the nature of the liquids, and it occurs even in single-phase porous media, indicating that it is not exclusively linked to capillarity effects. The high accelerations that take place at the pore throats help overcome the retardation effect of Darcian parabolic flow, leading to more efficient plug flow cross-sections through the pore throats, and also reducing the restrictive effect of electrostatically adsorbed water on the mineral surfaces adjacent to the pore throats. The continuous pore flexing with PD wave excitation helps to maintain a higher flow rate near the excitation well, this leads to a higher pressure, compared to the more distant production well. Laboratory measurements indicate that even though the external pressure head on a test remains fixed, the internal pressure distribution changes substantially, resulting in an increase in flow rate, despite no permeability or viscosity changes. However, the system permeability still controls the flow rate; pressure pulsing can increase the flow rate dynamically, but it cannot overcome this physical fact.

Pore throats accumulate fine-grained fluid-transported minerals as well as precipitates such as asphaltenes or minerals coming out of solution because of geochemical or pressure changes. The presence of these solids leads to the development of massive restrictions around producing wellbores. Many chemical treatments and technologies exist to attempt to dissolve or dislodge this material so that the well can be become a good producer again. Pressure pulsing helps loosen existing pore blockages and reduces the creation of future blockages because of the acceleration of the fluids into and out of the pores. This appears to be the same mechanism that causes groundwater wells to turn murky with colloidal substances some time after a distant earthquake has occurred.

13.4.3.4 Field Successes for Pressure Pulsing

Pressure pulsing has been tried in three fields, using only a small excitation tool in a well., The goal in one case was simply to dynamically excite the reservoir, and in two other cases the goal was to stabilize a waterflood.

One case was the Morgan Field, a CHOPS field 30 km northwest of Lloydminster with 10,600 cP heavy oil. Here, 10.5 weeks of excitation resulted in the reversal of production declines in most of a group of 11 offset wells, and the excitation well changed from a non-producer to a reasonable producer (>8 m^3/d). Although severely depressed prices and a corporate reorganization caused project termination, the stimulation clearly increased oil rates and more than paid for itself.

In a field north of Township 53 in Alberta, pressure pulsing helped waterflooding significantly reduce the rate of depletion of a field, leading over a six-month period to average additional net profits of CAN$58,000.00/month. Also, when the excitation well was placed back on production, it went from zero production before excitation (it had been shut-in) to rates that peaked at about 9 m^3/d, generating an additional CAN$150,000.00 for the oil company at the prices in 2000.

In a field south of Township 53 in Alberta, in 6000 cP oil, the company Murphy Oil produced additional oil at enhanced rates that were more profitable than before pulsing, using a waterflooding concept as well.

Pressure pulse workovers have had high success ratios in re-establishing well production, in helping initiate sanding in wells where other approaches proved ineffective in initiating sand influx, and in chemical placement processes.[lxvii]

13.5 After CHOPS?

CHOPS will produce perhaps 15-25% of the oil in place from appropriate reservoirs. It can also be used as a possible new completion approach in more conventional wells, in a manner similar to the cavity completion in coal-bed methane exploitation.

Nevertheless, although CHOPS alone is useful for heavy oil recovery in reservoirs that are unsuitable for other technologies such as cold horizontal well production, VAPEX or SAGD, combinations of CHOPS and other technologies may enhance recovery ratios in future operations. This section discusses some of the possible combinations.

13.5.1 PPT With CHOPS

Pressure pulsing technology (PPT) will soon become a valuable adjunct to CHOPS technology. To date, it has been tried only in extremely poor conditions. The writer believes that early application in a CHOPS reservoir will raise overall recovery ratios appreciably, perhaps by as much as 50% more than CHOPS alone. The laboratory successes with PPT[lxviii] suggest that using it from the beginning in slow waterflooding in a central well surrounded by CHOPS wells (Figure 13.12) will be more successful than dynamic excitation alone. After the primary oil phase production in currently exploited CHOPS reservoirs, PPT may help in waterflooding to achieve a few percent more oil recovery. However, the massive changes in stresses and porous medium structure in the reservoir after CHOPS would make this less successful compared to implementing PPT with CHOPS from the beginning.

13.5.2 SAGD With CHOPS?

CHOPS generates a zone of massively enhanced permeability because of the remolding and plastic deformation that takes place. It may be possible to combine CHOPS with SAGD in a hybrid scheme to take advantage of the enhanced permeability to increase SAGD speed and reservoir access. Currently, SAGD well pair spacing is ~ 3 to 3.5 times the reservoir height, and SAGD is used only in thick reservoirs (>15 m). If rapid lateral spreading into CHOPS disturbed zones occurs when the steam zone intersects the CHOPS zone, it may be possible to double this spacing, reducing costs.

To implement simultaneous SAGD with CHOPS, double horizontal drains 1000-1500 m in length would be drilled near the bottom of the reservoir, one or two metres above any active water leg, between rows of vertical CHOPS wells (Figure 13.13). Horizontal well drilling programs must be carried out before substantial sand production has occurred to avoid lost circulation during drilling because of the low horizontal stresses that develop during CHOPS. Also, early and slow thermal stimulation is needed to ensure that the SAGD process achieves a stable geometry. As mentioned above, reservoirs with active water zones are less favorable for CHOPS, but gravity-dominated processes can proceed even in the presence of mobile water.

Pressure pulsing wells can be installed in this configuration to help sustain the flow rate to the CHOPS wells. Also, the horizontal wells that are installed can be used for a period of cold production if there is no active bottom water. This phase of production in the horizontal wells will also be enhanced by the use of pressure pulsing wells, which will help sustain well productivity for a longer time. However, if there is an active water leg, it will not be possible to use the horizontal wells in "cold mode", and SAGD may have to be started immediately (or some time after the start of the CHOPS wells, depending on the assessment of the spreading time of the two processes).

The SAGD process would be implemented at the same time that the CHOPS wells commence production, and the horizontal drains would continue producing for the life of the project in the SAGD mode. In the long-term, CHOPS production should give good early time oil rates, and the presence of the CHOPS wells is likely to be a distinct advantage for process control later in the process.

CHOPS processes are driven by a combination of overburden stresses and fluid hydrodynamic forces for sand destabilization, as well as by reservoir solution gas pressure that is responsible for the foamy fluid flow aspects. CHOPS processes will terminate naturally when pressure depletes, when water breaks through, or when sand becomes stable and ceases to flow toward the well with the foamy fluid.

When a successful CHOPS process terminates for an individual well, a reservoir-scale yielded and channeled zone exists with an absolute permeability several times greater than the virgin rock. This zone still has substantial amounts of free gas present, largely as a discrete bubble phase, and only locally as a continuous gas phase. Although data are limited, the writer believes that the CHOPS zones tend to be in the upper part of the reservoir, ideal for fluid injection to aid gravity drainage.

It seems reasonable to convert the CHOPS wells to fluid injection or drainage to aid and control the SAGD process. Although other uses are possible for these wells (water injection, thermal fluids injection, slurry fracture injection wells, monitoring wells), this discussion focuses on miscible or inert gas use for pressure control, perhaps with hot water addition to replenish voidage. The amount of fluid and pressure used and the strategy of gas injection or withdrawal depend on the nature and maturity of the SAGD process; analysis, and the continued interpretation of monitoring data are necessary to make these decisions.

If injection is mandated to raise pressures and increase the thickness of the upper gas cap that is now growing and helping to displace the oil downward, many possibilities exist: partially miscible but non-condensing gases (CH_4, C_2H_6…), immiscible non-condensing gases (CO_2 or N_2), condensable hydrocarbons (C_3H_8 to C_5H_{12}), or even naphtha (C_6H_{14} to C_8H_{18}). There are many combinations of these materials, and the converted CHOPS wells can be operated in many modes (cyclical, slow but continuous, etc.). In the case of slow injection of gas mixtures, a project now starts to take on the characteristics of a mixed SAGD-VAPEX process.

The goal in such a gravity-driven process should be to stabilize the gravity-dominated process once the CHOPS wells are converted, and this requires re-establishing uniform reservoir pressures. Thus, once sufficient injection has taken place to stabilize the process, voidage balance in the reservoir ($V_{in} = V_{out}$) must be maintained. Doing this with a complex mixture of gases and fluids is challenging; pressure monitoring data are essential to achieve the required pressure conditions.

At this time, it is not clear if there are advantages to using gas that is highly soluble in oil or not; conclusions on this will come from analysis and experience. However, injecting hot water combined with inert gas is attractive for several reasons:

- Because fluids produced from SAGD wells are quite hot, surface heat exchangers can cool the fluids and provide thermal energy to the water being injected into the old CHOPS wells without expensive water treatment. It may be possible to separate the water directly from the oil and return it down wells in a hot state.
- Water injection will generate a substantial mobile water phase in the yielded region, which will accelerate the mobility of oil in the SAGD process when the steam front contacts the mobile water zone.
- Hot water use permits recycling of formation waters, unlike steam, which must be produced from pure water only.
- Vertical wells do not have to be completed as expensively as thermal steam wells if only hot water is injected.

If operational optimization shows that cyclic injection or production of various gas-water ratios at various times is beneficial, the system can accommodate these changes.

Whatever fluids are injected, the process should proceed slowly so as not to over-drive the system and force it into the domain of high Δp-driven flow, where instabilities can soon dominate the reservoir, to the detriment of production. This means that the bottom-hole injection well pressure should never substantially exceed the SAGD production well fluid pressure, in order to avoid coning of gas or water, generation of massive frontal instabilities, or other negative effects (such as hydraulic fracture generation). If negative injection-related effects occur, the wells can be throttled back or shut down to allow the SAGD process to restabilize gravitationally through phase segregation. The tendency for gravity-dominated processes to restabilize is one of their great strengths. On the other hand, a weakness of SAGD is that oil production rates cannot easily be increased, as instability occurs if higher injection pressures or excessive fluid withdrawal takes place.

If it is necessary to withdraw gas that has accumulated at the top of the reservoir during SAGD, the CHOPS wells that have been re-perforated near the top of the interval can be used for a short time as production wells for gas, allowing excess gases to bleed off. This is done if too much gas accumulation is excessively insulating the heat flow and heat transfer process, not allowing steam or condensable gas to be distributed most efficiently, given the geometry and thickness of the particular reservoir. Also, pressure control to remain in the gravity-dominated regime may require withdrawal of gas to prevent gas coning if a substantial Δp is generated by thermal gas exsolution.

At various times in the process of SAGD, the CHOPS wells may be used for a number of purposes in process control and to promote reservoir sweep efficiency. If they are not used for injection or withdrawal, they may be converted to p-T monitoring wells. Some wells can also be used to achieve microseismic front tracking of the SAGD process: if monitoring data indicate poor behavior or irregular sweep, the process conformance can then be altered and confirmed directly through the microseismic measurements.

The proposed CHOPS-SAGD technology in this section was presented in some detail to demonstrate that there are a large number of technical improvements that can be brought into practice in the HOB. These improvements mean that the ultimate oil production from the HOB is likely to be at least twice as much as predictions made by various agencies (e.g. National Energy Board, AEUB). The radical improvements in extraction technology that have been implemented (CHOPS), the new technologies that are emerging (SAGD, PPT), the new ideas that remain to be field tested (VAPEX, THAI™), and hybrids of these approaches (warm VAPEX, SAGD + CHOPS, CHOPS + PPT, etc.) have not been accounted for in production predictions for the HOB.

Figure 13.1: Upward Fracturing and Pressures in a Cyclic Steam Process

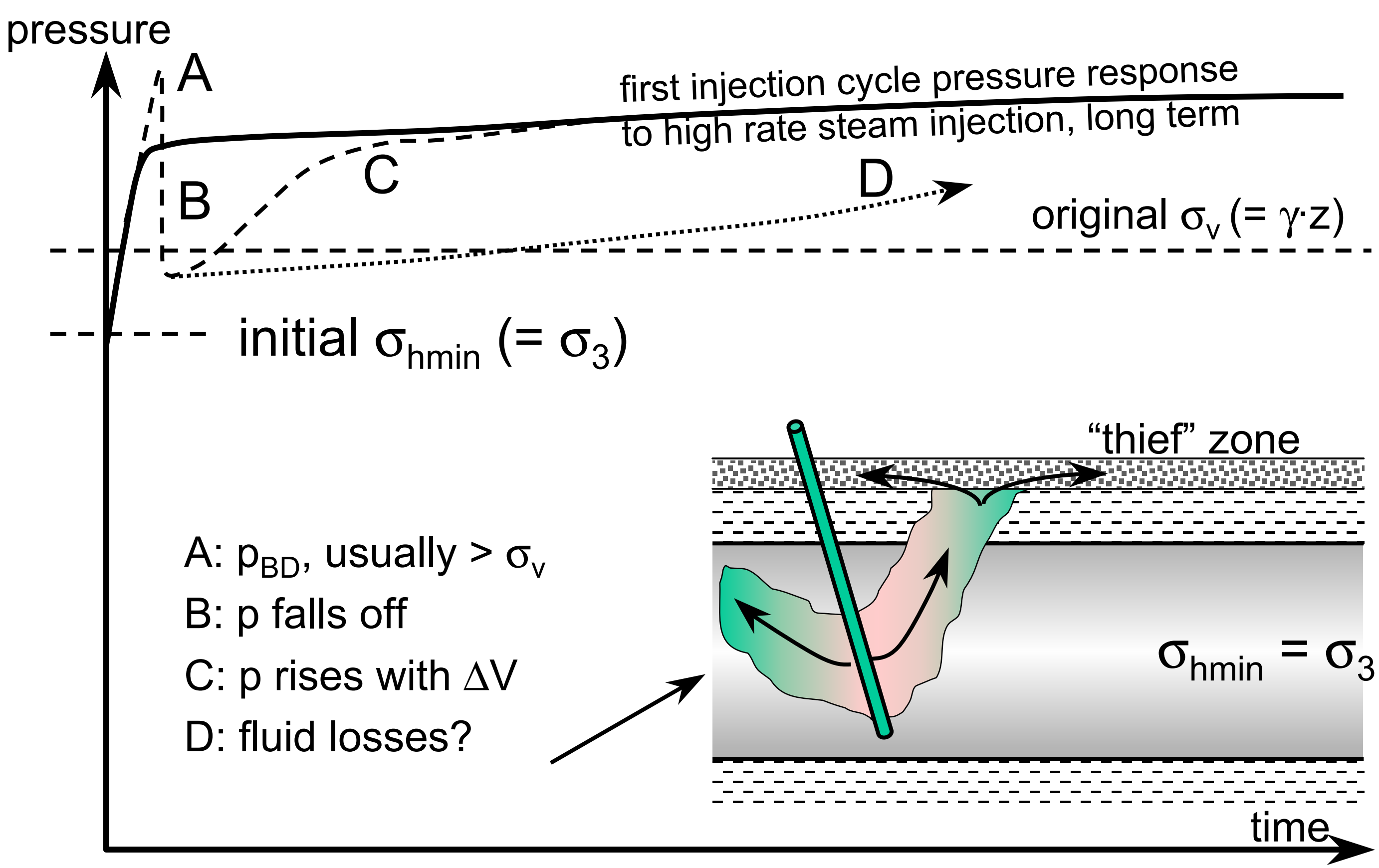


Figure 13.2: Thermal Expansion of a Zone can Lead to Casing Shearing

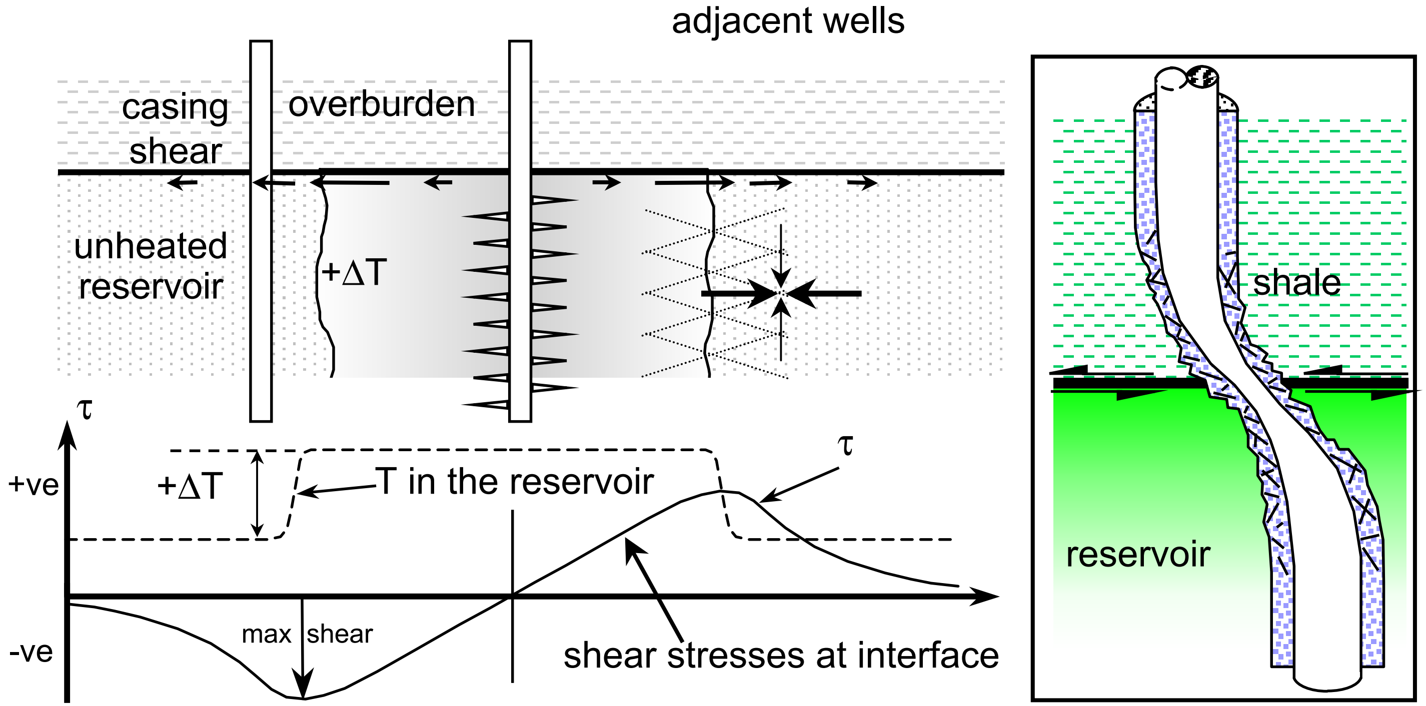


Figure 13.3: Casing Shear Locations in the Context of Alberta Lithostratigraphy

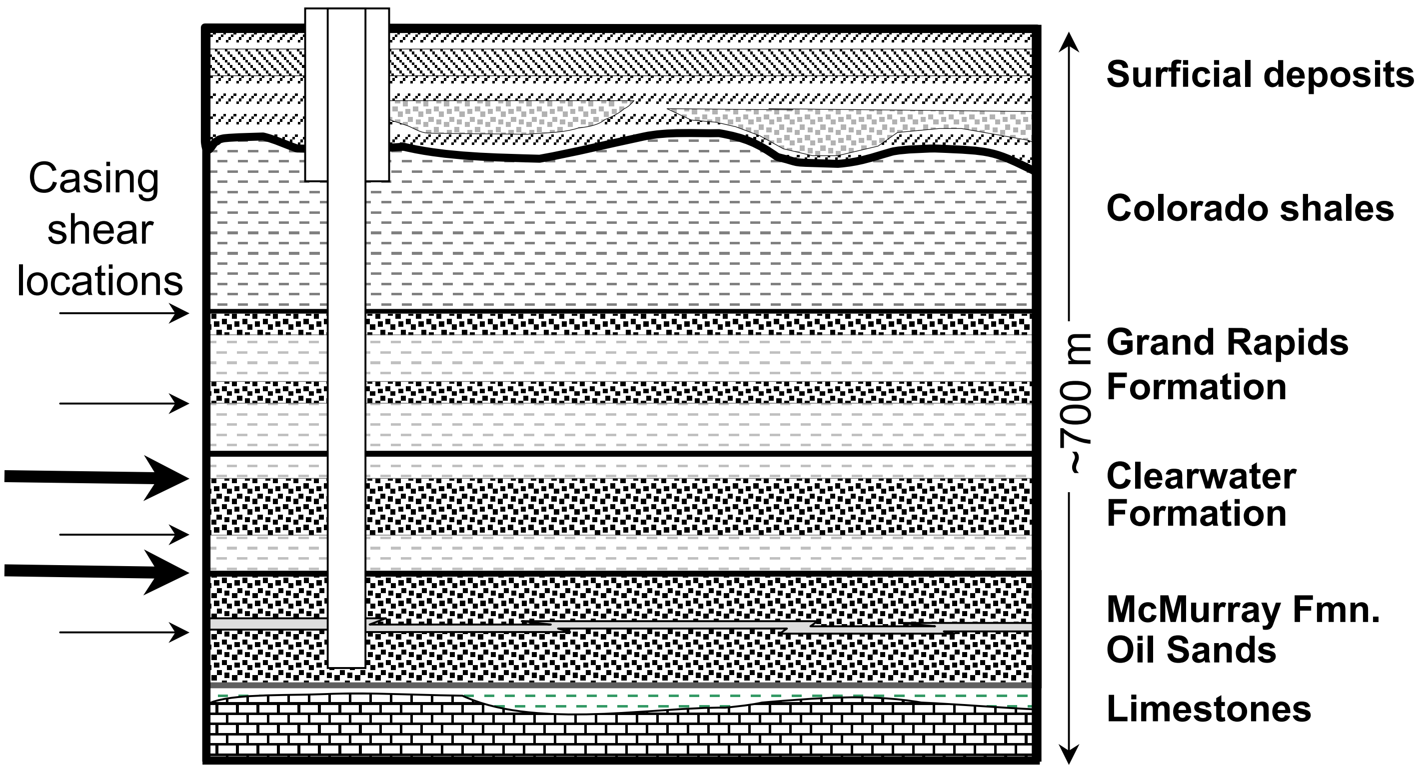


Figure 13.4: Typical Steam Drive Instabilities; Theory and Practice

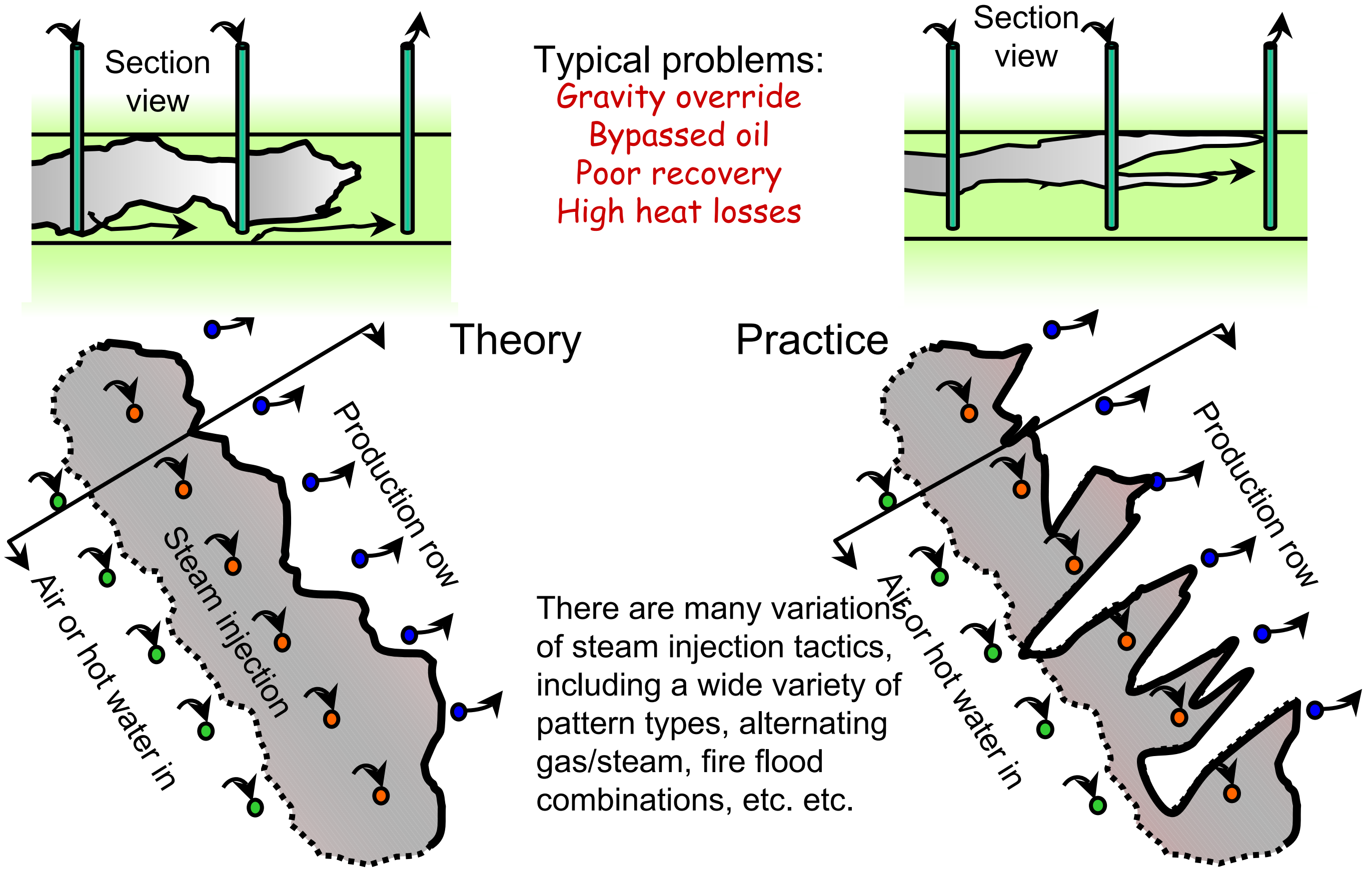


Figure 13.5: Steam (or Hot Fluids) Circulation Principles

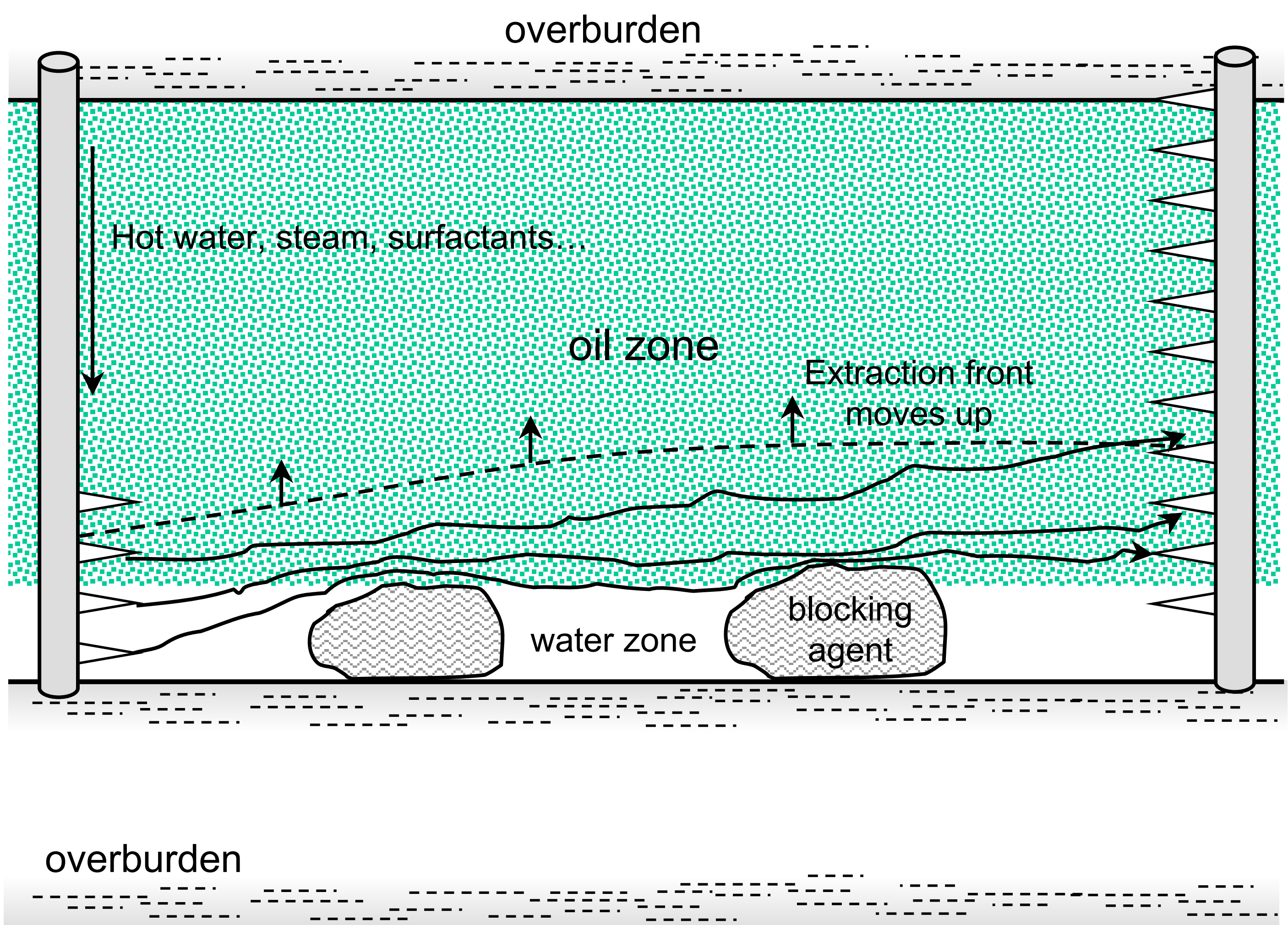
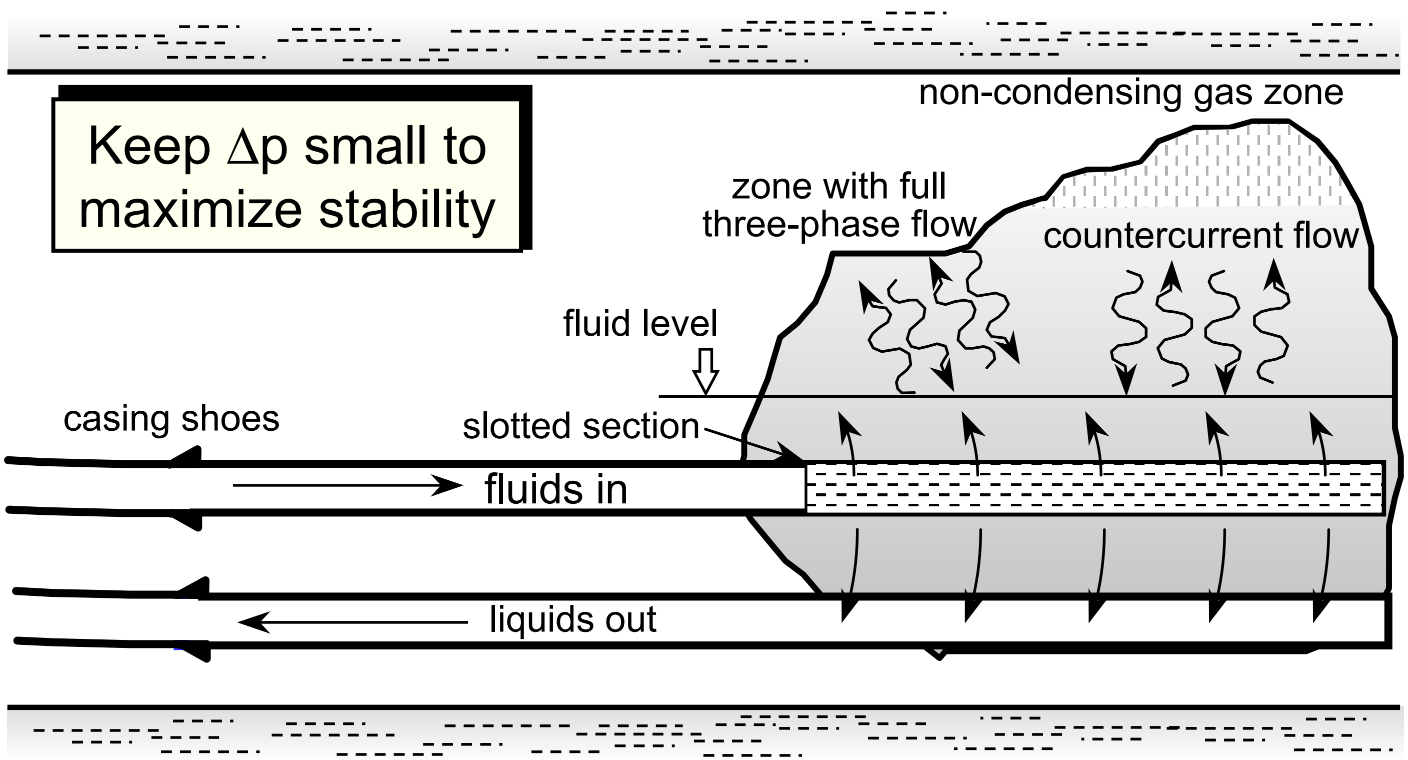


Figure 13.6a: SAGD and VAPEX View, Vertical Cross Section Along Wells



CH_4, CO_2, N_2, C_2H_6 etc can be added to maximize spreading and drainage

Figure 13.6b: Sectional View of SAGD and VAPEX Physics Across Well Axes

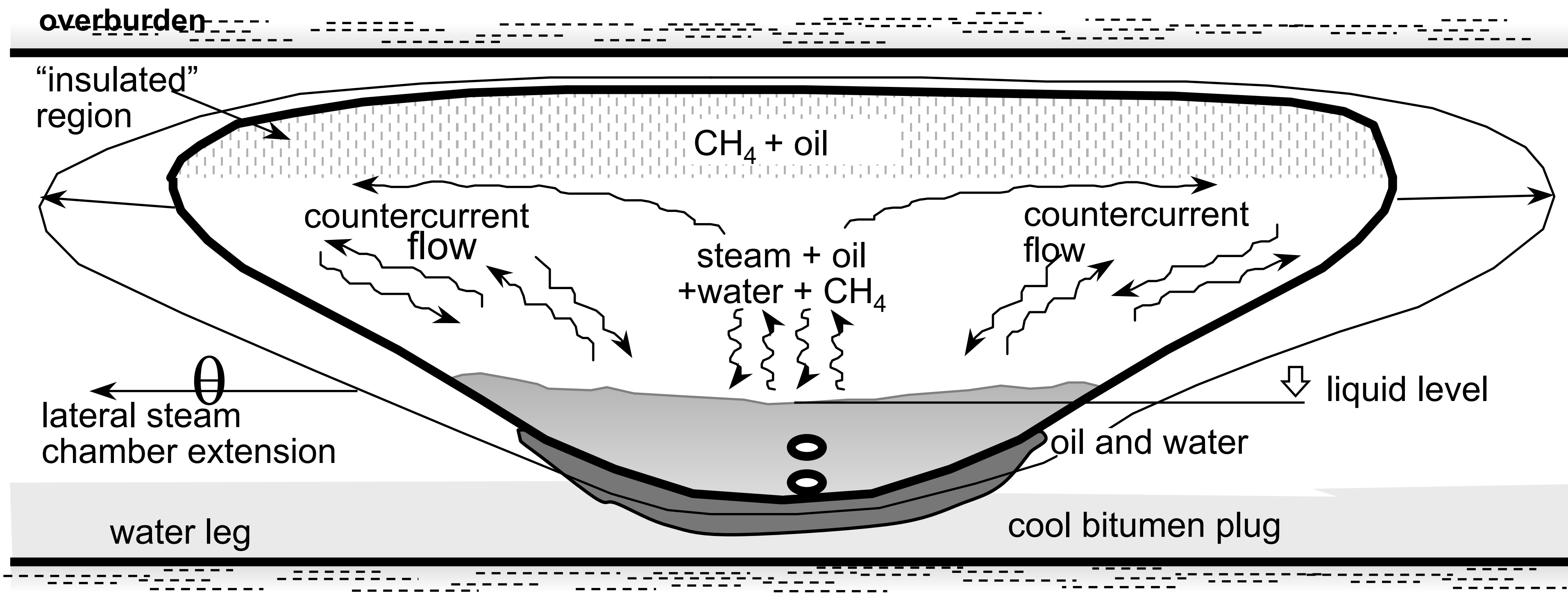
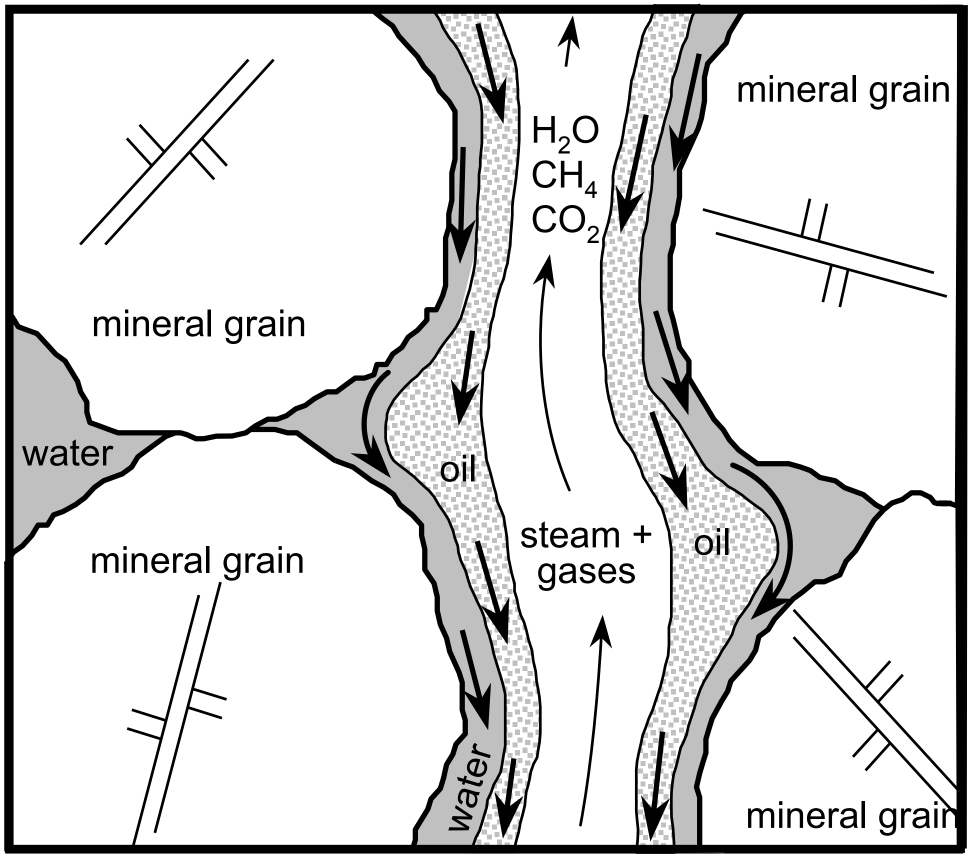


Figure 13.7: Continuity of the Oil Film in a Three-Phase, Water-Wet System



Countercurrent flow in the pores and throats leads 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.

Figure 13.8a: The THAI™ Concept for *In Situ* Combustion, "3-D" Layout

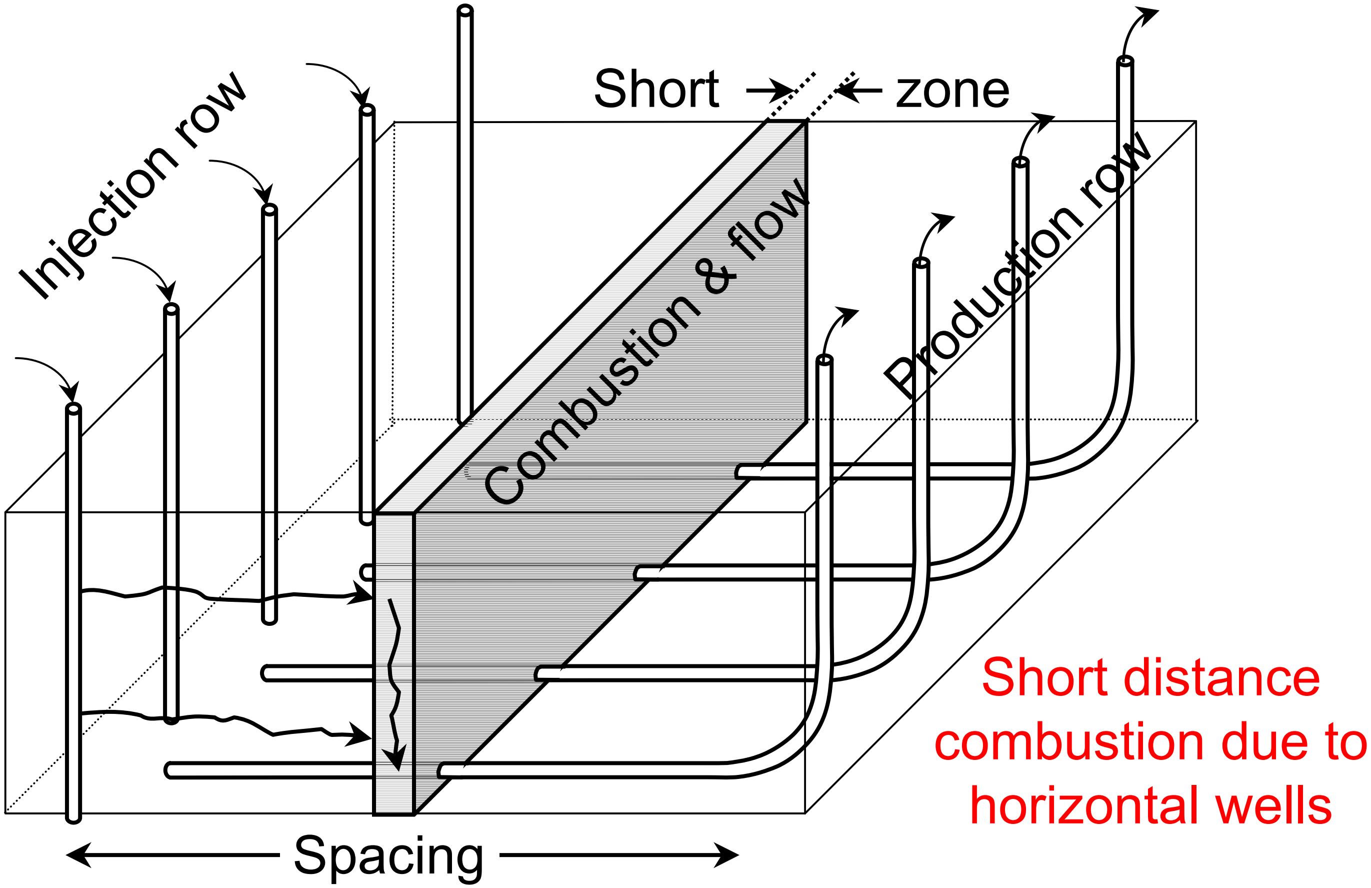


Figure 13.8b: The THAI™ Concept for *In Situ* Combustion, Cross Section

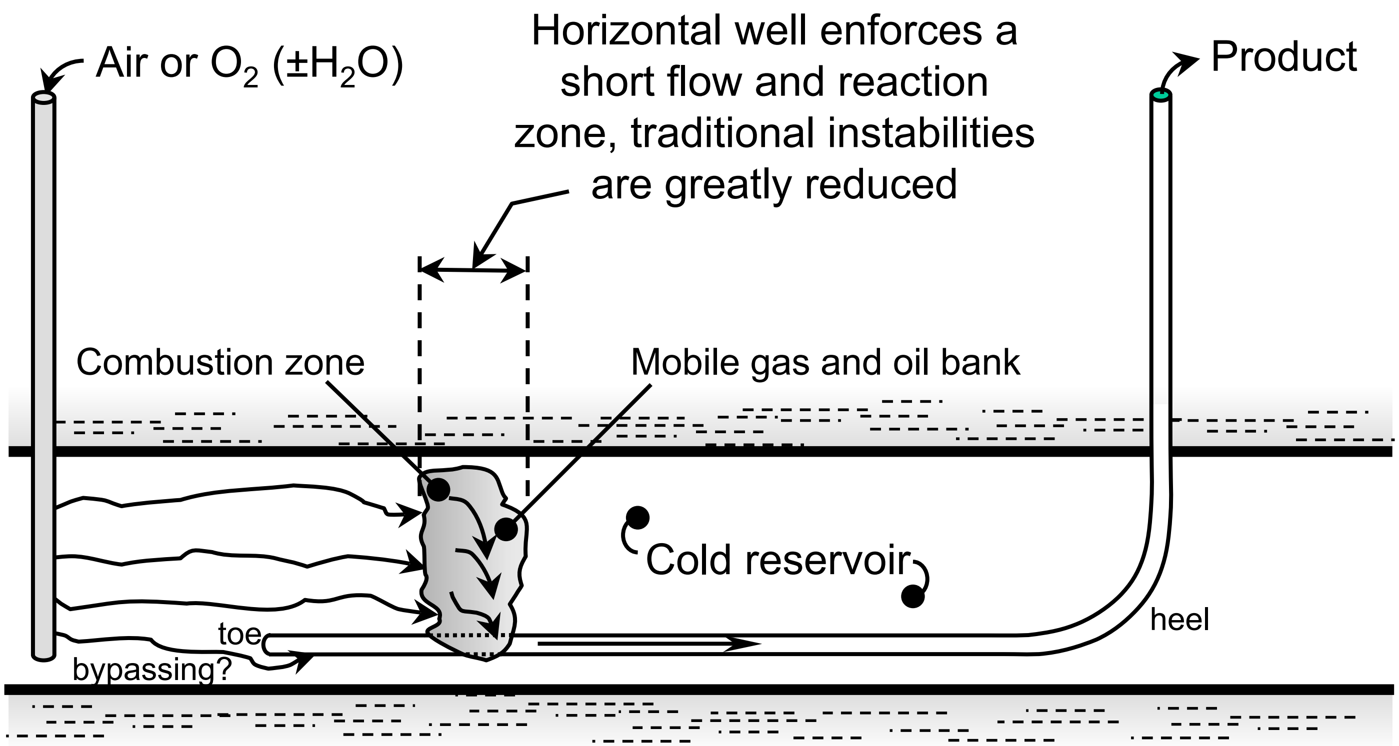
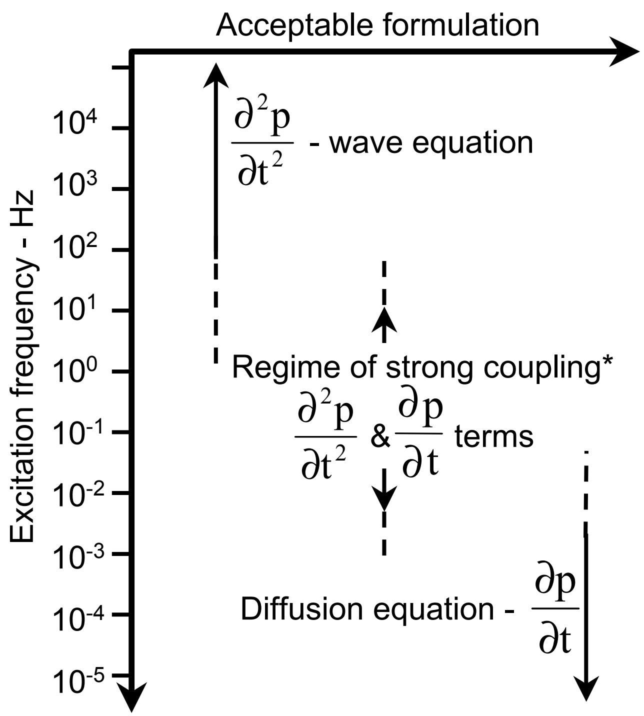


Figure 13.9: The Range of Frequencies for Dynamic Excitation



*Specific values depend on viscosity and compressibility of the phases

Correct analysis of porous media response over the total range of frequencies of excitation required a coupled theory that includes diffusion and inertial terms. Simpler theories include Biot-Gassmann formalism, with inertial terms only, and Darcy formalism, which is a quasi-static diffusion theory with no inertial terms.

The correct approach to porous media analysis is to formulate a fully coupled theory with minimal simplifications, treat porosity as a time variant thermodynamic quantity (porosity diffusion), and scale the problem correctly. Spanos – de la Cruz formalism does these correctly.

Figure 13.10: Pressure Pulsing can Overcome Capillary Barriers to Flow

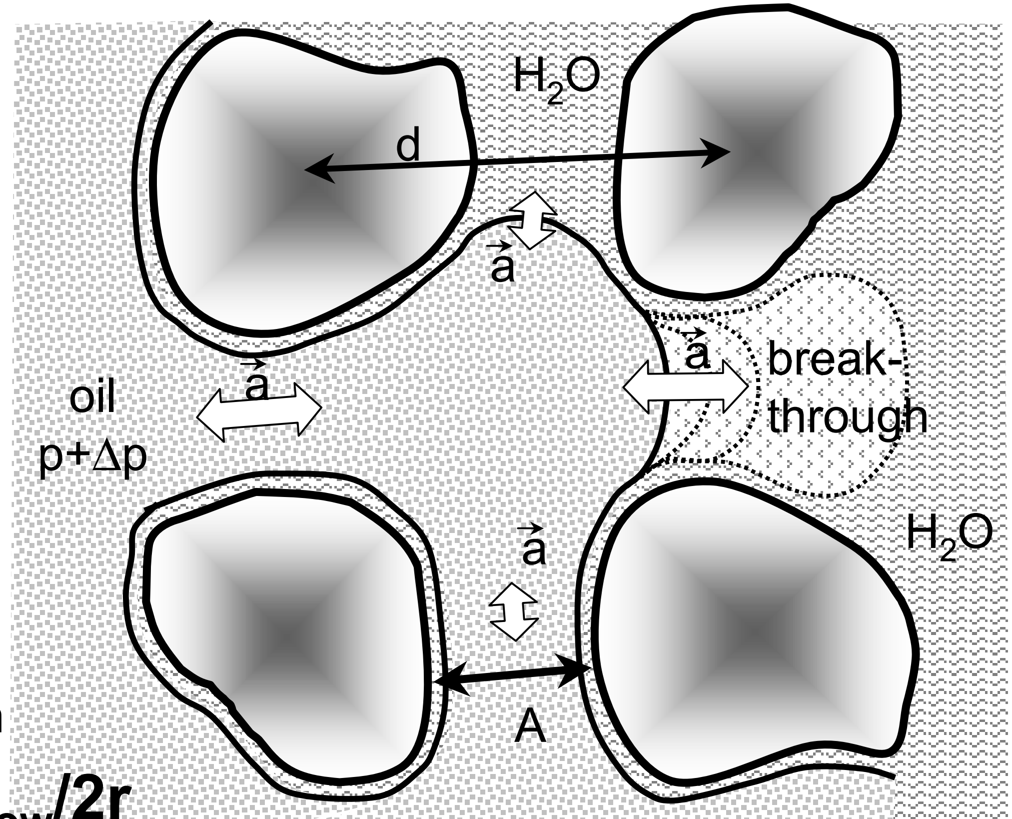
$$d \cdot \frac{\partial p}{\partial l} = \Delta p_S$$

static force

$$\frac{\vec{F}}{A} = \frac{m\vec{a}}{A} = \Delta p_D$$

dynamic force

A = throat area
F = new force
m = fluid mass
a = acceleration



$$\mathbf{\Delta p_S + \Delta p_D > \gamma_{ow}/2r}$$

Figure 13.11a: Pressure Pulsing can Reduce Viscous Fingering

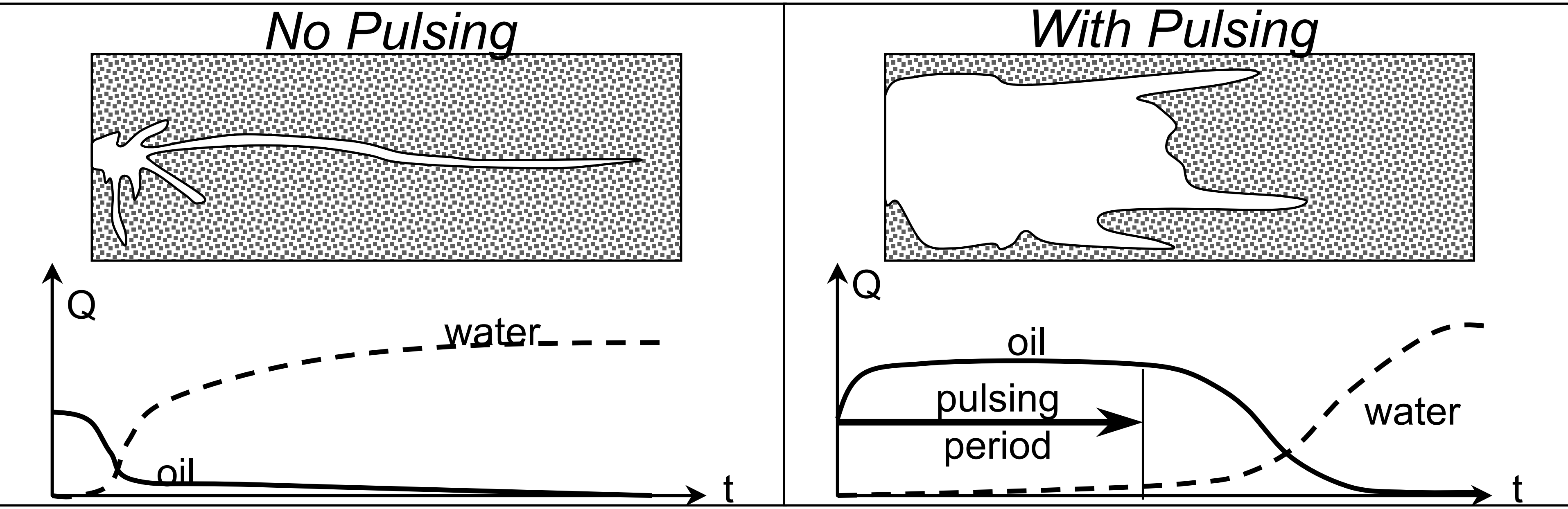


Figure 13.11b: Pressure Pulsing can Reduce Viscous Fingering

- $E = f(1/r)$ (in 2-D)
- Close to the well: more acceleration
- Far from the well, less acceleration
- Pulsing overcomes capillary barriers
- Thus, oil closer to well is mobilized
- Less farther away
- Thus, fingering is suppressed

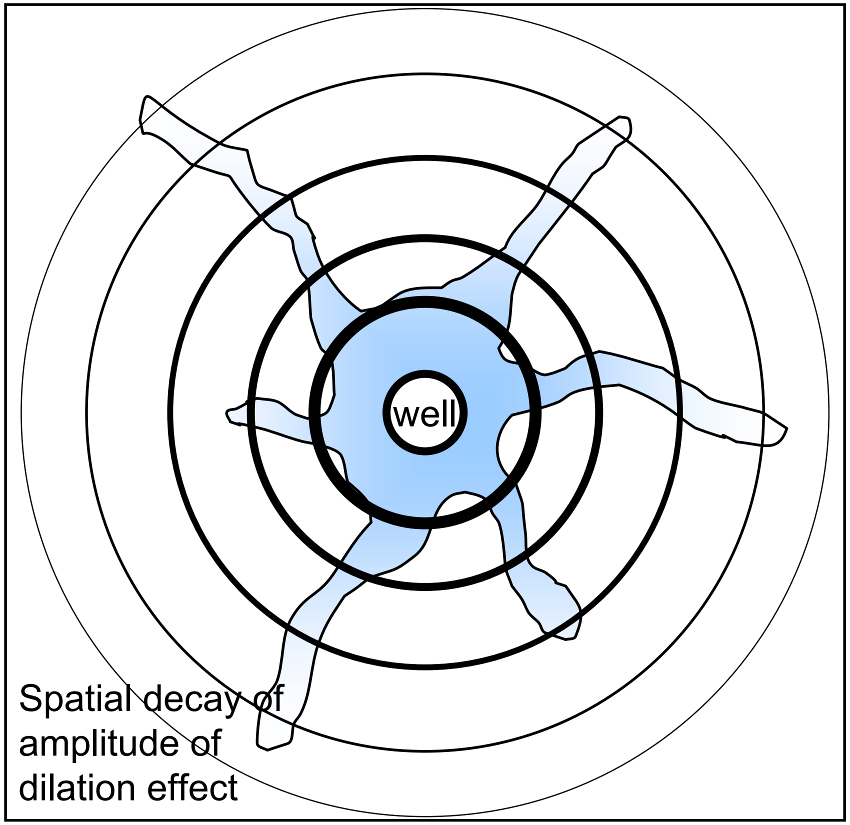


Figure 13:12: Pressure Pulsing a CHOPS Field With Simultaneous Waterflooding

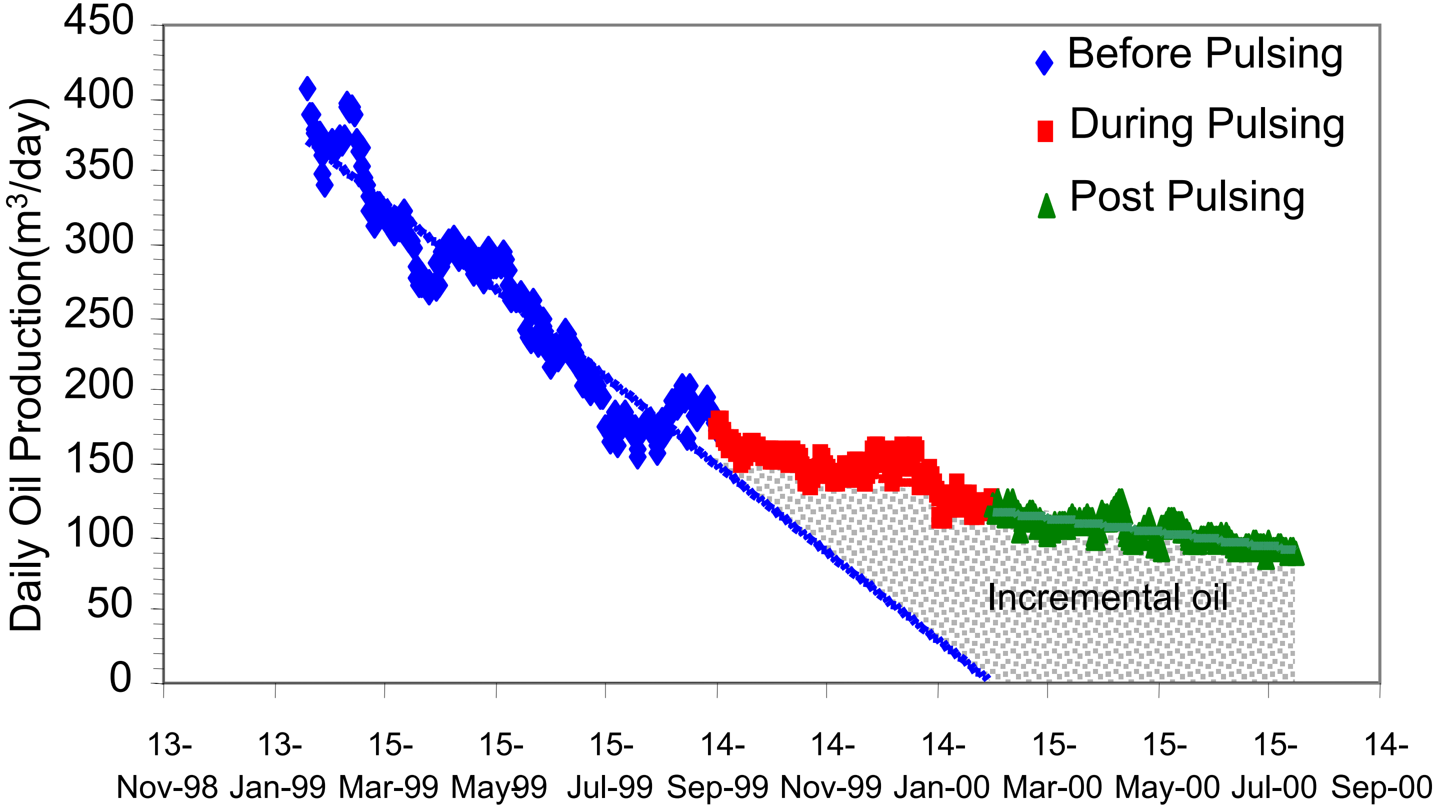


Figure 13:13: A Possible CHOPS-SAGD Simultaneous Approach