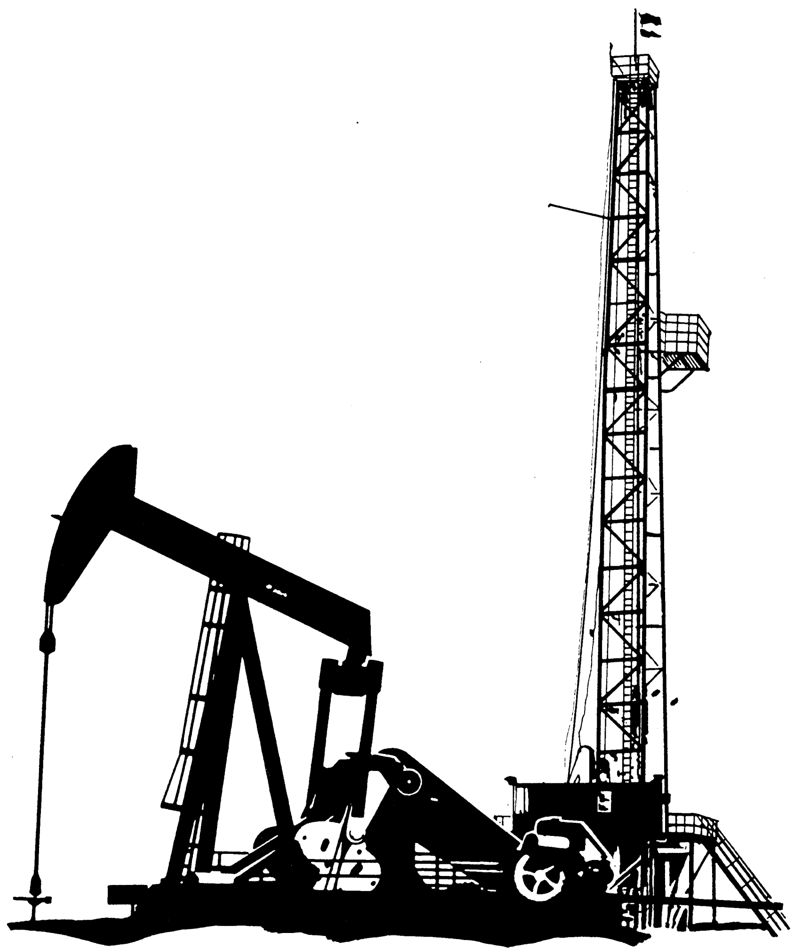
ENHANCED OIL RECOVERY INFORMATION

National Institute for Petroleum and Energy Research



EOR Dictionary

Oil Recovery Equations

Symbols

Conversion Factors

Process Drawings

NIPER

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CONTENTS

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NIPER'S *EOR DICTIONARY*

A

acid number — a measure of reactivity of crude oil with caustic solution, in terms of milligrams of potassium hydroxide that are neutralized by one gram of crude oil.

acidizing — a technique for improving the permeability of a reservoir by injecting acid.

acoustic log — *See* sonic log.

acre-foot — a measure of bulk rock volume where the area is one acre and the thickness is one foot.

adsorption — the physical/chemical phenomenon whereby a molecule or aggregate of molecules attaches itself to the rock surface.

after-flow — flow from the reservoir into the wellbore that continues for a period after the well has been shut in; after-flow can complicate the analysis of a pressure transient test.

air injection — an oil recovery technique using air to force oil from the reservoir into the wellbore.

alkaline — a material that causes high pH when dissolved in water; sodium hydroxide, sodium orthosilicate, and sodium carbonate are typical alkaline materials used in enhanced oil recovery.

alkaline flooding — *See* EOR process.

API — American Petroleum Institute.

API gravity — an index of specific gravity; units are degrees of API gravity (°API). (*See* p. 12).

apparent viscosity — the viscosity of a fluid, or several fluids flowing simultaneously, measured in a porous medium (rock), and subject to both viscosity and permeability effects; also called effective viscosity.

aquifer — a subsurface rock interval that will produce water; many oil reservoirs are underlaid by an aquifer.

areal sweep efficiency — the fraction of the flood pattern area that is effectively swept by the injected fluids.

asphaltenes — high molecular weight hydrocarbons.

B

bank — a concentration of oil (oil bank) or other fluid in a reservoir that moves cohesively through the reservoir.

barrel — a unit of volume used to measure petroleum equal to 42 U.S. gallons.

bbl — barrel(s).

biocides — any chemical capable of killing microorganisms.

biopolymer — a high molecular weight carbohydrate produced by bacteria. (*See* also xanthan.)

BTU — British Thermal Unit; a unit of energy approximately equal to the energy needed to raise the temperature of one pound of water one degree Fahrenheit.

Buckley-Leverett method — a theoretical method of determining frontal advance rates and saturations from a fractional flow curve.

C

capillary forces — interfacial forces between immiscible fluid phases, resulting in pressure differences between the two phases.

NOTE: The glossary from the National Petroleum Council's Enhanced Oil Recovery Study (1984) was used as a basis for this work.

capillary number — N_C, the ratio of viscous forces to capillary forces, and equal to viscosity times velocity divided by interfacial tension.

carbon/oxygen log — a pulsed neutron device giving information on the relative abundance of elements such as carbon, oxygen, silicon, and calcium in a formation.

caustic consumption — the amount of caustic lost from reacting chemically with the minerals in the rock, the oil, and the brine.

chemical flooding — *See* EOR process.

chromatographic separation — the separation of different species of compounds according to their size and interaction with the rock as they flow through a porous medium.

clastic — made up of pieces of pre-existing rocks.

CO_2 — carbon dioxide.

CO_2 augmented waterflooding — waterflooding by injection of a brine that is fully or nearly saturated with carbon dioxide; also called carbonated waterflooding.

CO_2 miscible flooding — *See* EOR process.

coalescence — the union of two or more droplets to form a larger droplet and, ultimately, a continuous phase.

COFCAW — combination of forward combustion and waterflooding.

cogeneration — an energy conversion method by which electrical energy is produced along with steam generated for EOR use.

combustion zone — the volume of reservoir rock wherein petroleum is undergoing combustion during enhanced oil recovery.

completion interval — that portion of the reservoir formation placed in fluid communication with the well by selectively perforating the wellbore casing.

condensate — a mixture of light hydrocarbon liquids obtained by condensation of hydrocarbon vapors: predominately butane, propane, and pentane with some heavier hydrocarbons and relatively little methane or ethane. (*See also* natural gas liquids.)

conductivity — a measure of the ease of flow through a fracture, perforation, or pipe.

conformance — the uniformity with which a volume of the reservoir is swept by injection fluids, both in the areal and vertical sense.

conventional recovery — primary and/or secondary recovery.

conversion cost — the cost of changing a producing well to an injection well, or some other change in the function of an oilfield installation.

corefloods — laboratory flow tests through small samples (cores) of porous rock.

cosurfactant — a chemical compound, typically an alcohol, that enhances the effectiveness of a surfactant.

cp — centipoise, a unit of viscosity. (*See* p. 13).

Craig-Geffen-Morse method — a popular technique for predicting waterflood oil recovery.

cross-linking — the combining of two or more polymer molecules into an aggregate of molecules by the use of a chemical that mutually reacts or bonds with a part of the chemical structure of the polymer molecules.

D

degradation — the loss of desirable physical properties of EOR fluids, e.g., the loss of viscosity by polymer solutions.

diagenetic — rock formed by conversion (as by pressure or chemical reaction) from another rock, e.g., sandstone is a diagenetic form of sand.

differential-strain analysis — measurement of isothermal stress relaxation in a recently cut core.

dispersion — a measure of the convective mixing of fluids due to flow in a reservoir.

displacement efficiency — ratio of the amount of oil moved from the zone swept by the recovery process to the amount of oil present in the swept zone prior to start of the process.

distribution coefficient — a coefficient that describes the distribution of a chemical substance in reservoir fluids, usually defined as the ratio of the equilibrium concentrations in the oil and aqueous phases.

divalent cation — an ion, such as calcium or magnesium, having two positive charges. (*See also* ions.)

downhole steam generator — a generator that is installed downhole in an oil well to which air or oxygen-rich air, fuel, and water are supplied for the purposes of generating steam for injection into the reservoir. Its major advantage over a surface steam generating facility is that heat losses to the wellbore and surrounding rock are eliminated between the surface and the oil zone.

Dykstra-Parsons coefficient — an index of reservoir heterogeneity arising from permeability variation and stratification. (*See* p. 12).

E

effective viscosity — *See* apparent viscosity.

emulsion — a dispersion of very small drops of one liquid in an immiscible liquid, such as oil in water.

enhanced oil recovery — petroleum recovery following recovery by conventional primary and secondary methods.

EOR — enhanced oil recovery.

EOR process — a known technique for recovering additional oil from a petroleum reservoir beyond that economically recoverable by conventional primary and secondary recovery methods. Methods are usually divided into three main categories.

chemical flooding: injection of water with added chemicals into a petroleum reservoir. The chemical processes include: surfactant flooding, polymer flooding, and alkaline flooding.

miscible flooding: injection into a petroleum reservoir of a material that is miscible, or can become miscible, with the oil in the reservoir. Carbon dioxide, hydrocarbons, and nitrogen are used.

thermal recovery: injection of steam into a petroleum reservoir, or propagation of a combustion zone through a reservoir by air or oxygen-enriched air injection. The thermal processes include: steam drive, cyclic steam injection, and in situ combustion.

ester — a compound formed by the reaction between an organic acid and an alcohol.

ethoxylated alcohols — alcohols having ethylene oxide functional groups attached to the alcohol molecule.

F

facies — one or more layers of rock that differs from other layers in composition, age or content.

FAST — Fracture Assisted Steamflood Technology, developed by Conoco, Inc.

field-scale — the application of EOR processes to a significant portion of a field.

fingering — the formation of finger-shaped irregularities at the leading edge of a displacing fluid in a porous medium which move out ahead of the main body of fluid.

first contact miscibility — *See* miscibility.

five-spot — an arrangement or pattern of wells with four injection wells at the corners of a square and a producing well in the center of the square.

flood, flooding — the process of displacing petroleum from a reservoir by the injection of fluids.

flue gases — the gaseous products of the combustion process, mostly comprised of carbon dioxide (CO_2), nitrogen (N_2), and water vapor (H_2O).

fluid — a gas or liquid.

fluidized bed combustion — a process used to burn low-quality solid fuels in a bed of small particles suspended by a gas stream (usually air) that will lift the particles but not blow them out of the vessel. Rapid burning removes some of the offensive by-products of combustion from the gases and vapors that result from the combustion process.

formation — an interval of rock with distinguishable geologic characteristics.

formation volume factor — the volume in barrels that one stocktank barrel occupies in the formation at reservoir temperature and with the solution gas that is held in the oil at reservoir pressure.

fractional flow — the ratio of the volumetric flow rate of one fluid phase to the total fluid volumetric flow rate within a volume of rock.

fractional flow curve — the relationship between the fractional flow of one fluid and its saturation during simultaneous flow of fluids through a rock.

fracture — a natural or man-made crack in a reservoir rock.

fracturing — the breaking apart of reservoir rock by applying very high fluid pressure at the rock face.

functional group — the portion of a molecule that is characteristic of a family of compounds and determines the properties of these compounds.

G

gas cap — a part of a hydrocarbon reservoir at the top that will produce only gas.

gas-oil sulfonate — sulfonate made from a specific refinery stream; the gas-oil stream.

gas-to-oil ratio — ratio of the number of cubic feet of gas measured at atmospheric (standard) conditions to barrels of produced oil measured at stocktank conditions.

gravity — *See* API gravity.

gravity drainage — the movement of oil in a reservoir that results from the force of gravity.

gravity segregation — partial separation of fluids in a reservoir caused by the gravity force acting on differences in density. (*See* also override.)

gravity-stable displacement — the displacement of oil from a reservoir by a fluid of a different density, where the density difference is utilized to prevent gravity segregation of the injected fluid.

H

H_2S — hydrogen sulfide.

hardness — the concentration of calcium and magnesium in brine.

HCPV — hydrocarbon pore volume.

Hearn method — a technique, used in reservoir simulation, for calculating a pseudo relative permeability curve that reflects reservoir stratification. J. Pet. Tech. July 1971, p.805.

heavy oil — thick sticky crude oil of low specific gravity and high viscosity. (Generally 10°-20° API and may be up to 10,000 cp).

heterogeneity — lack of uniformity in reservoir properties such as permeability.

Higgins-Leighton model — stream tube computer model used to simulate waterfloods.

huff-and-puff — a cyclic EOR technique whereby steam or gas is injected into a production well; after a short shut-in period, oil and the injected fluid are produced through the same well.

hydration — the association of molecules of water with a substance.

hydraulic fracturing — the opening of fractures in a reservoir by high-pressure, high-volume injection of liquids through an injection well.

hydrocarbons — organic compounds containing only hydrogen and carbon and occurring in fossil fuels.

hydrolysis — a chemical reaction in which water reacts with another substance to form one or more new substances.

I

immiscible — two or more fluids that do not have complete mutual solubility and co-exist as separate phases.

immiscible displacement — a displacement of oil by a fluid (gas or water) that is conducted under conditions so that interfaces exist between the driving fluid and the oil.

incremental ultimate recovery — the difference between the quantity of oil that can be economically recovered by EOR methods and the quantity of oil that can be economically recovered by conventional recovery methods. Synonym for enhanced oil recovery. (*See also* ultimate recovery.)

infill drilling — drilling additional wells within an established pattern.

injection profile — the vertical flow rate distribution of fluid flowing from the wellbore into a reservoir.

injection well — a well in an oil field used for injecting fluids into a reservoir.

injectivity — the relative ease with which a fluid is injected into a porous rock.

in situ — in its original place; in the reservoir.

in situ combustion — an EOR process consisting of injecting air or oxygen-enriched air into a reservoir under conditions that favor burning part of the in situ petroleum, advancing this burning zone, and recovering oil heated from a nearby producing well.

integrity — maintenance of a slug or bank at its preferred composition without too much dispersion or mixing.

interface — the thin surface area separating two immiscible fluids that are in contact with each other.

interfacial film — a thin layer of material at the interface between two fluids which differs in composition from the bulk fluids.

interfacial tension — the strength of the film separating two immiscible fluids, e.g., oil and water or microemulsion and oil; measured in dynes (force) per centimeter or millidynes per centimeter.

interfacial viscosity — the viscosity of the interfacial film between two immiscible liquids.

interference testing — a type of pressure transient test in which pressure is measured over time in a closed-in well while nearby wells are produced; flow and communication between wells can sometimes be deduced from an interference test.

interphase mass transfer — the net transfer of chemical compounds between two or more phases.

IOCC — Interstate Oil Compact Commission.

ion exchange — the exchange of two different ions on active sites on the surface of a mineral, e.g., replacement of calcium ions with sodium ions.

ion exchange capacity — a measure of the capacity of a mineral to exchange ions in amount of material per unit weight of solid. (*See* ion exchange.)

ions — chemical substances possessing positive or negative charges in solution.

isopach — a line on a map designating points of equal formation thickness.

K

kriging — a technique used in reservoir description for interpolation of reservoir parameters between wells based on random field theory.

L

lease — a part of a field belonging to one owner or owner group; an owner commonly "leases" the (mineral) rights to an operator who produces oil and gas and pays for the "lease" with part of the production (royalty).

light hydrocarbons — hydrocarbons with molecular weights less than that of heptane.

lithology — the geological characteristics of the reservoir rock.

Lorenz coefficient — a permeability heterogeneity factor.

lower-phase microemulsion — a microemulsion phase containing a high concentration of water that, when viewed in a test tube, resides near the bottom with oil phase on top. (*See also* microemulsion.)

LPG — liquified petroleum gas.

M

M — thousand.

Marx-Langenheim model — mathematical equations for calculating heat transfer in a hot water or steam flood. Trans. AIME (1959) 216, 312-315.

Mcf — unit of gas volume equal to 1,000 standard cubic feet.

md — millidarcy, a unit of permeability. (*See* p. 12.)

mechanical degradation — the loss of fluid properties of polymer solutions caused by permanent mechanical scission of the polymer molecule.

membrane technology — gas separation processes utilizing membranes that permit different components of a gas to diffuse through the membrane at significantly different rates.

methane (CH_4) — the simplest hydrocarbon molecule; normally the predominant chemical in natural gas.

MEOR — microbial enhanced oil recovery.

micellar fluid (surfactant slug) — an aqueous mixture of surfactants, cosurfactants, salts, and hydrocarbons. The term micellar is derived from the word micelle, which is a submicroscopic aggregate of surfactant molecules and associated fluid.

microemulsion — a stable, finely dispersed mixture of oil, water, and chemicals (surfactants and alcohols).

microorganisms — animals or plants of microscopic size, such as bacteria.

microscopic displacement efficiency — the efficiency with which an oil displacement process removes the oil from individual pores in the rock.

middle-phase microemulsion — a microemulsion phase containing a high concentration of both oil and water that, when viewed in a test tube, resides in the middle with the oil phase above it and the water phase below it. (*See also* microemulsion.)

minimum miscibility pressure (MMP) — *See* miscibility.

miscibility — an equilibrium condition, achieved after mixing two or more fluids, that is characterized by the absence of interfaces between the fluids.

first-contact miscibility: miscibility in the usual sense, whereby two fluids can be mixed in all proportions without any interfaces forming. Example: At room temperature and pressure, ethyl alcohol and water are first-contact miscible.

multiple-contact miscibility (dynamic miscibility): miscibility that is developed by repeated enrichment of one fluid phase with components from a second fluid phase with which it comes into contact.

minimum miscibility pressure: the minimum pressure above which two fluids become miscible at a given temperature, or can become miscible, by dynamic processes.

miscible flooding — *See* EOR process.

MM — million.

MMcf — unit of gas volume equal to a million standard cubic feet.

MMP — minimum miscibility pressure. (*See* miscibility.)

mobility — a measure of the ease with which a fluid moves through reservoir rock; the ratio of rock permeability to apparent fluid viscosity.

mobility buffer — the bank that protects a chemical slug from water invasion and dilution and assures mobility control.

mobility control — ensuring that the mobility of the displacing fluid or bank is equal to or less than that of the displaced fluid or bank.

mobility ratio — ratio of mobility of an injection fluid to mobility of fluid being displaced.

modified alkaline flooding — the addition of a cosurfactant and/or polymer to the alkaline flooding process.

monomer — small molecules that can be combined in large numbers to make polymers.

multiple-contact miscibility — *See* miscibility.

N

natural gas — hydrocarbons and other chemicals produced as a gas, usually predominantly methane.

natural gas liquids — the hydrocarbon liquids that condense during the processing of hydrocarbon gases that are produced from oil or gas reservoir.

NGL — natural gas liquid.

NIPER — National Institute for Petroleum and Energy Research — a research facility specializing in EOR operated by IIT Research Institute; formerly DOE's Bartlesville Energy Technology Center.

nonionic surfactant — a surfactant molecule containing no ionic charge.

non-Newtonian — a fluid that exhibits a change of viscosity with flow rate.

NPC — National Petroleum Council.

nuclear magnetic resonance spectroscopy — an analytical procedure that permits the identification of complex molecules based on the magnetic properties of the atoms they contain.

O

observation wells — wells that are completed and equipped to measure reservoir conditions and/or sample reservoir fluids, rather than to inject or produce reservoir fluids.

oil breakthrough (time) — the time at which the oil-water bank arrives at the producing well.

oil originally in place — the quantity of petroleum existing in a reservoir before oil recovery operations begin.

OOIP — oil originally in place.

optimum salinity — the salinity at which a middle-phase microemulsion containing equal concentrations of oil and water results from the mixture of a micellar fluid (surfactant slug) with oil.

override — the gravity-induced flow of a lighter fluid in a reservoir above another heavier fluid.

oxygen scavenger — a chemical which reacts with oxygen in injection water, used to prevent degradation of polymer.

P

particulates — finely divided material generally considered large enough to be filtered but small enough to be suspended in the air or in a liquid as contaminants. Particulates include soot, ash, and dust.

partitioning — the mass transfer of a chemical from one liquid phase to another liquid phase, resulting in concentration changes.

pattern — the areal pattern of injection and producing wells selected for a secondary or enhanced recovery project.

pattern life — the length of time a flood pattern participates in oil recovery.

permeability — a measure of the ability of reservoir rock to transmit fluid under the influence of a pressure gradient. (*See* p. 12.)

petroleum sulfonate — a surfactant used in chemical flooding prepared by sulfonating selected crude oil fractions.

pH — the negative logarithm of hydrogen ion concentration, which, is a measure of acidity and alkalinity. Acidity increases as pH decreases from 7 to 0; alkalinity increases as pH increases from 7 to 14.

phase — a separate fluid that co-exists with other fluids; gas, oil, water and other stable fluids such as microemulsions are all called phases in EOR research.

phase behavior — the tendency of a fluid system to form phases as a result of changing temperature, pressure, or the bulk composition of the fluids or of individual fluid phases.

phase diagram — a graph of phase behavior. In chemical flooding a graph showing the relative volume of oil, brine, and sometimes one or more microemulsion phases. In CO_2 flooding, conditions for formation of various liquid, vapor, and solid phases.

phase properties — types of fluids, compositions, densities, viscosities, and relative amounts of oil, microemulsion, or solvent, and water formed when a micellar fluid (surfactant slug) or miscible solvent (e.g., CO_2) is mixed with oil.

pilot-scale — a relative term that connotes the development of a relatively small portion of a field for the purpose of investigating, evaluation, or developing concepts, materials, equipment, or procedures that may later be used for fuller development of oil production from the same field or other fields. (*See also* field-scale.)

pilot test — an experimental test of an EOR process in a small part of a field.

polyacrylamide — very high molecular weight material used in polymer flooding.

polymer — in EOR, any very high molecular weight material that is added to water to increase viscosity for polymer flooding.

polymer stability — the ability of a polymer to resist degradation and maintain its original properties.

pore space — a small hole in reservoir rock that contains fluid or fluids. (A fist-sized volume of reservoir rock may contain millions of interconnected pore spaces.)

pore volume — total volume of all pores and fractures in a reservoir or part of a reservoir.

porosity — ratio of the pore volume and fracture volume to the total volume of reservoir rock, usually expressed as a fraction. (*See* p. 12).

porous medium — any solid that contains pore spaces.

power-law exponent — an exponent used to model the degree of viscosity change of some non-Newtonian liquids.

ppm — parts per million.

precipitates — chemical compounds that drop out of solution (i.e., precipitate) as a result of chemical reactions or changes in phase equilibrium.

preflush — a conditioning slug injected into a reservoir as the first step of an EOR process.

pressure cores — cores cut into a special coring barrel that maintains reservoir pressure when brought to the surface; this prevents the loss of reservoir fluids that usually accompanies the drop in pressure from reservoir to atmospheric conditions.

pressure gradient — rate of change of pressure with distance.

pressure maintenance — augmenting the pressure (and energy) in a reservoir by injecting gas or water through one or more wells.

pressure pulse test — a technique for determining reservoir characteristics by injecting a sharp pulse of pressure in one well and detecting it in surrounding wells.

pressure transient testing — measuring the effect of changes in pressure at one well on other wells in a field.

primary oil recovery — oil recovery utilizing only naturally occurring forces.

primary tracer — a chemical that, when injected into a test well, reacts with reservoir fluids to form a detectable chemical compound.

producibility — the rate at which oil or gas can be produced from a reservoir through a wellbore.

producing well — a well in an oil field used for removing fluids from a reservoir.

psi — pounds per square inch.

psia — pounds per square inch absolute.

psig — pounds per square inch gauge (above atmospheric).

pulse-echo ultrasonic borehole televiewer — a well-logging system wherein a pulsed, narrow acoustic beam scans the well as the tool is pulled up the borehole; the amplitude of the reflected beam is displayed on a cathode-ray tube, resulting in a pictorial representation of the wellbore.

R

relative permeability — the permeability of the rock to gas, oil, or water, when any two or more are present, expressed as a fraction of the single phase permeability of the rock.

reserves — recoverable oil; unless qualified, means economically recoverable oil with proved technology.

proved developed reserves: oil and gas reserves recoverable from existing wells with present operating methods and expense.

proved undeveloped reserves: oil and gas reserves recoverable from additional wells yet to be drilled, or major deepening of existing wells.

probable reserves: oil and gas reserves that are based on geologic evidence of producible oil or gas within the limits of a geologic feature or reservoir but located beyond the proved reserves.

possible reserves: oil and gas reserves characterized by less defined geologic control than probable reserves, based largely on subsurface geology utilizing seismic and electric logs and widespread evidence of oil and gas saturation.

reservoir — a rock formation below the earth's surface containing petroleum or natural gas.

reservoir simulation — analysis and prediction of reservoir performance with a computer model.

residual oil — petroleum remaining in situ after oil recovery.

residual oil saturation — *see* waterflood residual.

residual resistance factor — the reduction in permeability of rock to water caused by the adsorption of polymer.

resistance factor — a measure of resistance to flow of a polymer solution relative to the resistance to flow of water.

retention — the loss of chemical components due to adsorption onto the rock's surface, precipitation, or to trapping within the reservoir.

rock matrix — the granular structure of a rock or porous medium.

S

salinity — the concentration of salt in water.

sandface — the cylindrical wall of the wellbore through which the fluids must flow to or from the reservoir.

saturation — the ratio of the volume of a single fluid in the pores to pore volume, expressed as a percent and applied to water, oil, or gas separately; sum of the saturations of each fluid in a pore volume is 100 percent.

screen factor — a simple measure of the viscoelastic properties of polymer solutions. Jennings, et. al., J. Pet. Tech. March 1971, pp. 391-401.

screening guide — a list of reservoir rock and fluid properties critical to an EOR process.

scrubber — a device that uses water and chemicals to clean air pollutants from combustion exhaust.

secondary recovery — oil recovery resulting from injection of water, or an immiscible gas at moderate pressure, into a petroleum reservoir after primary depletion.

secondary tracer — the product of the chemical reaction between reservoir fluids and an injected primary tracer.

sedimentary — formed by or from deposits of sediments, especially from sand grains or silts transported from their source and deposited in water, as sandstone and shale; or from calcareous remains of organisms, as limestone.

shear — mechanical deformation or distortion, or partial destruction of a polymer molecule as it flows at a high rate.

shear rate — a measure of the rate of deformation of a liquid under mechanical stress.

shear-thinning — the characteristic of a fluid whose viscosity decreases as the shear rate increases.

single well tracer — a technique for determining residual oil saturation by injecting an ester, allowing it to hydrolyze; following dissolution of some of the reaction product in residual oil the injected solution is produced back and analyzed.

slim tube testing — laboratory procedure for the determination of minimum miscibility pressure using long, small-diameter, sand-packed, oil-saturated, stainless steel tube.

slug — a quantity of fluid injected into a reservoir during enhanced oil recovery.

solvent gas — an injected gaseous fluid that becomes miscible with oil under reservoir conditions and improves oil displacement.

sonic log — a well log based on the time required for sound to travel through rock, useful in determining porosity.

specific gravity — the ratio of the density of oil (or other liquid) to the density of water.

steam drive — *see* EOR process.

steamflooding — *see* EOR process.

steam stimulation — injection of steam into a well and the subsequent production of oil from the same well.

Stiles method — a simple approximate method for calculating oil recovery by waterflood that assumes separate layers (stratified reservoirs) for the permeability distribution.

stocktank oil — oil under surface conditions of temperature and pressure.

stream tube model — a computer model that represents fluid flow through a reservoir by an array of individual flow paths or tubes.

stripper well — a well that produces (strips from the reservoir) less than 10 barrels of oil or 60 Mcf of gas per day

sulfated ethoxylated alcohols — obtained by sulfation of ethoxylated alcohol. (*See also* ethoxylated alcohols.)

sulfonate — a type of surfactant made up of a hydrocarbon with one or more SO_3 functional groups attached to it.

surface active material — a chemical compound, molecule, or aggregate of molecules with physical properties that cause it to adsorb at the interface between two immiscible liquids, resulting in a reduction of interfacial tension or the formation of a microemulsion.

surfactant — a type of chemical, characterized as one that reduces interfacial resistance to mixing between oil and water or changes the degree to which water wets reservoir rock.

sweep efficiency — the ratio of the pore volume of reservoir rock contacted by injected fluids to the total pore volume of reservoir rock in the project area. (*See also* areal sweep efficiency *and* vertical sweep efficiency.)

swelling — increase in the volume of crude oil caused by absorption of EOR fluids, especially carbon dioxide. Also increase in volume of clays when exposed to brine.

swept zone — the volume of rock that is effectively swept by injected fluids.

T

tar sand — a sandstone containing tar-like hydrocarbons that do not readily flow into a wellbore.

target oil — petroleum in situ at the start of an EOR process that remains in the reservoir after conventional recovery.

tapered slug — a technique where the concentration of EOR chemical (e.g., polymer) is lowered stepwise with injected volume.

Tcf — unit of gas volume equal to a trillion standard cubic feet.

TDS — total dissolved solids.

Tertiary Incentive Program (TIP) — government EOR program administered by the U.S. Department of Energy.

thermal recovery — *See* EOR process.

thief zone — any geologic stratum not intended to receive injected fluids in which significant amounts of injected fluids are lost; fluids may reach the thief zone due to an improper completion or a faulty cement job. Also, a zone in the oil bearing horizon that receives excessive amounts of injected fluids.

tiltmeter survey — a method of monitoring reservoir processes through analysis of near-surface ground deformation measured with very sensitive bubble level indicators (tiltmeters), which are placed in shallow boreholes around the area of interest.

time-lapse logging — the repeated use of calibrated well logs to quantitatively observe changes in measurable reservoir properties over time.

tracer test — a technique for determining fluid flow paths in a reservoir by adding small quantities of easily detected material (often radioactive) to the flowing fluid, and monitoring their appearance at production wells. Also used in cyclic injection to appraise oil saturation.

transmissibility (transmissivity) — an index of producibility of a reservoir or zone, the product of permeability and layer thickness.

triaxial borehole seismic survey — a technique for detecting the orientation of hydraulically induced fractures, wherein a tool holding three mutually seismic detectors is clamped in the borehole during fracturing; fracture orientation is deduced through analysis of the detected microseismic perpendicular events that are generated by the fracturing process.

type curves — graphical correlations among physical parameters that permit estimation of an unknown parameter from experimental data by the matching of curve shapes.

U

ultimate recovery — the cumulative quantity of oil that will be recovered when revenues from further production no longer justify the costs of the additional production. (*See also* incremental ultimate recovery.)

unconformity — a surface of erosion that separates younger strata from older rocks.

unitization — combination of adjacent oil leases for efficient operation in which the value of oil regardless of where the producing wells are located, is allocated among the properties according to some reasonable formula.

upper-phase microemulsion — a microemulsion phase containing a high concentration of oil that, when viewed in a test tube, resides on top of a water phase. (*See also* microemulsion.)

V

vector processor — an advanced computer capable of high-speed calculations.

vectorized codes — computer instruction sets (programs) that are written to take advantage of the parallel processing capabilities of vector processors to the fullest possible extent.

vertical sweep efficiency — the fraction of the layers or vertically distributed zones of a reservoir that are effectively contacted by displacing fluids.

viscosity — a fluid property that determines its resistance to flow through reservoir rock.

volumetric sweep — the fraction of the total reservoir volume within a flood pattern that is effectively contacted by injected fluids.

VSP — vertical seismic profiling, a method of conducting seismic surveys in the borehole for detailed subsurface information.

W

WAG process — injection of alternating slugs of water and gas into an injection well.

WAR — water air ratio used for in situ combustion.

waterflood residual — the waterflood residual oil saturation; the saturation of oil remaining after waterflooding in those regions of the reservoir that have been thoroughly contacted by water.

waterflooding — injection of water to displace oil from a reservoir (usually a secondary recovery process).

waterflood mobility ratio — mobility ratio of water displacing oil during waterflooding. (*See also* mobility ratio.)

wellbore — the hole in the earth comprising a well.

well completion — the complete outfitting of an oil well for either oil production or fluid injection; also the technique used to control fluid communication with the reservoir.

well conversion cost — the cost of changing a producing well to an injection well.

wellhead — that portion of an oil well above the surface of the ground.

wellhead price — value of the crude oil at the producing well.

wettability — the relative degree to which a fluid will spread on (or coat) a solid surface in the presence of other immiscible fluids.

wettability number — a measure of the degree to which a reservoir rock is water-wet or oil-wet, based on capillary pressure curves. Donaldson, E. C., R. D. Thomas and P. B. Lorenz, SPEJ, March 1969, 13-20.

wettability reversal — the reversal of the preferred fluid wettability of a rock, e.g., from water-wet to oil-wet, or vice versa.

WOR — ratio of the barrels of water produced to the barrels of oil produced at stock tank conditions.

WPT — Windfall Profit Tax.

X

xanthan — a polysaccharide (high molecular weight carbohydrate) produced during fermentation by the Xanthamonis bacteria, used in polymer flooding.

COMMON OIL RECOVERY EQUATIONS

Laboratory

$$k = \frac{q\mu L}{A_I \Delta P}$$

$$\phi = \frac{PV}{BV} = \frac{BV - SV}{BV}$$

$$\text{API gravity} = \frac{141.5}{\text{sp gr}} - 131.5$$

Field

$$OIP = 7758\, A_{II} h \phi S_o$$

Divide by B_o to obtain stock tank barrels

$$OR = OIP \times E_D \times E_{VS} \times E_{AS}$$

$$V = \frac{k50 - k84.1}{k50}$$

Symbols

k	permeability (darcies)
q	flow rate (cc/sec)
μ	viscosity (cp)
L	length (cm)
A_I	area (cm^2)
A_{II}	area (acres)
ΔP	pressure drop (atm)
ϕ	porosity (fraction)
BV	bulk volume
PV	pore volume
SV	solid volume
sp gr	specific gravity relative to water at 60°F
OIP	oil in place (bbl)
h	net pay (feet)
ϕ	porosity (fraction)
S_o	oil saturation (fraction)
B_o	oil formation volume factor (bbl/STB)
OR	oil recovery (bbl)
E_D	displacement efficiency
E_{VS}	vertical sweep efficiency
E_{AS}	areal sweep efficiency
V	Dykstra-Parsons permeability variation
k_{50}	permeability at norm or 50% point
k_{84}	permeability one standard deviation from norm or 84.1% point

CONVERSION FACTORS

1 acre = 43,560 sq ft

1 acre foot = 7758.0 bbl

1 atmosphere = 760 mm Hg = 14.696 psia = 29.91 in. Hg

1 atmosphere = 1.0133 bars = 33.899 ft. H_2O

1 barrel (oil) = 42 gal = 5.6146 cu ft

1 barrel (water) = 350 lb at 60°F

1 barrel per day = 1.84 cu cm per second

1 Btu = 778.26 ft-lb

1 centipoise × **2.42** = lb mass/(ft) (hr), viscosity

1 centipoise × **0.000672** = lb mass/(ft) (sec), viscosity

1 cubic foot = 28,317 cu cm = 7.4805 gal

Density of water at 60°F = 0.999 gram/cu cm = 62.367 lb/cu ft = 8.337 lb/gal

1 gallon = 231 cu in. = 3,785.4 cu cm = 0.13368 cu ft

1 horsepower-hour = 0.7457 kwhr = 2544.5 Btu

1 horsepower = 550 ft-lb/sec = 745.7 watts

1 inch = 2.54 cm

1 meter = 100 cm = 1,000 mm = 10^6 microns = 10^{10} angstroms (Å)

1 ounce = 28.35 grams

1 pound = 453.59 grams = 7,000 grains

1 square mile = 640 acres

SI Metric Conversion Factors

(E = exponent; i.e. E + 03 = 10^3)

acre-foot x 1.233482	**E + 03** = meters cubed
barrels x 1.589873	**E - 01** = meters cubed
centipoise x 1.000000	**E - 03** = pascal seconds
darcy x 9.869233	**E - 01** = micro meters squared
feet x 3.048000	**E - 01** = meters
pounds/acre-foot x 3.677332	**E - 04** = kilograms/meters cubed
pounds/square inch x 6.894757	**E + 00** = kilo pascals
dyne/cm x 1.000000	**E + 00** = mN/m
parts per million x 1.000000	**E + 00** = milligrams/kilograms

ENERGY PRODUCTION RESEARCH

NIPER's Energy Production Research engineers, geologists, chemists, and scientists are ready to provide total support in the following areas for your enhanced oil recovery projects.

Chemical Flooding
- Screening surfactants and mobility control agents
- Basic recovery mechanisms research
- Thermodynamics of adsorption and surfactant behavior
- Chemical consumption research
- Coreflood facility for chemical flooding
- Interfacial tension determinations
- Rheological measurements

Thermal Recovery
- Steamflood mechanism research
- Screening additives for steamflooding
- Light oil steamflooding
- In situ combustion research
- One- and two-dimensional steamflooding facilities

Gas Displacement Methods
- Gas-crude oil phase behavior
- Measurement of physical properties of mixtures of gases and crude oils
- Minimum miscibility pressure determination
- Coreflood facility for gas displacement

Microbial Oil Recovery Methods
- Screening microorganisms for oil recovery
- Coreflood facility for microbial oil recovery

Geosciences
- Reservoir characterization
- Routine core analysis
- Special core analysis

Stimulation Technology
- Damage due to hydraulic fracturing fluid
- Characterization and breaking of hydraulic fracturing fluid
- Measurement of flow conductivity in a propped hydraulic fracture

Simulation
- Black-oil Engineering and Simulation Tool (BEST)
- Chemical flooding models (NICHEM3)
- Hydraulic fracture model
- Thermal EOR simulators

Environmental
- EOR-associated environmental impacts
- Subsurface injection of wastes
- Injection water technology

TECHNICAL SERVICES

NIPER typically performs services in these areas on a contract basis.

Technical and Economic Feasibility of Primary, Secondary and EOR Projects

Environmental Aspects of EOR Projects

Special Core Analysis

Wettability
Relative Permeability
Capillary Pressures
Detailed Studies of Pore Surfaces
Petrographic Analyses
... and much more

Verifying Routine Core Analysis

Formulating and Evaluating EOR Fluids

Designing EOR Projects

Predicting Economic and Technical Results

Monitoring Progress of EOR Projects

Diagnostic Evaluation of Completed Projects

Reserve Evaluations

For more information contact:

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Bartlesville, Oklahoma 74005
918/337-4297

ENHANCED OIL RECOVERY METHODS

Enhanced oil recovery (EOR) is a term applied to methods used for recovering oil from a petroleum reservoir beyond that recoverable by primary and secondary methods. Primary recovery normally refers to production using the energy inherent in the reservoir from gas under pressure or a natural water drive. Secondary recovery usually refers to injection of water or waterflooding. Thus, enhanced oil recovery is often synonymous with tertiary recovery, although sometimes EOR methods can be used earlier in the sequence. In some older discussions, waterflooding was considered as enhanced oil recovery, but now EOR is generally thought to follow waterflooding.

Three groups of methods--thermal recovery, gas miscible recovery, and chemical flooding are well established, and a fourth, microbial flooding, is under developmental study. Eleven EOR methods are briefly described and illustrated in this booklet. The thermal recovery methods are cyclic steam stimulation, steamflooding, and in situ combustion. The gas miscible recovery methods are cyclic carbon dioxide stimulation, carbon dioxide flooding, and nitrogen flooding. The chemical flooding methods are polymer flooding, micellar-polymer flooding, and alkaline flooding. Microbial EOR methods include cyclic microbial recovery and microbial flooding. The illustration shows the effect of EOR on the 460 billion barrels of oil that has been discovered in the United States.

The illustrations and written descriptions of the various methods have been simplified for ready understanding, but where technical terms are used, the reader is referred to the glossary in this booklet.

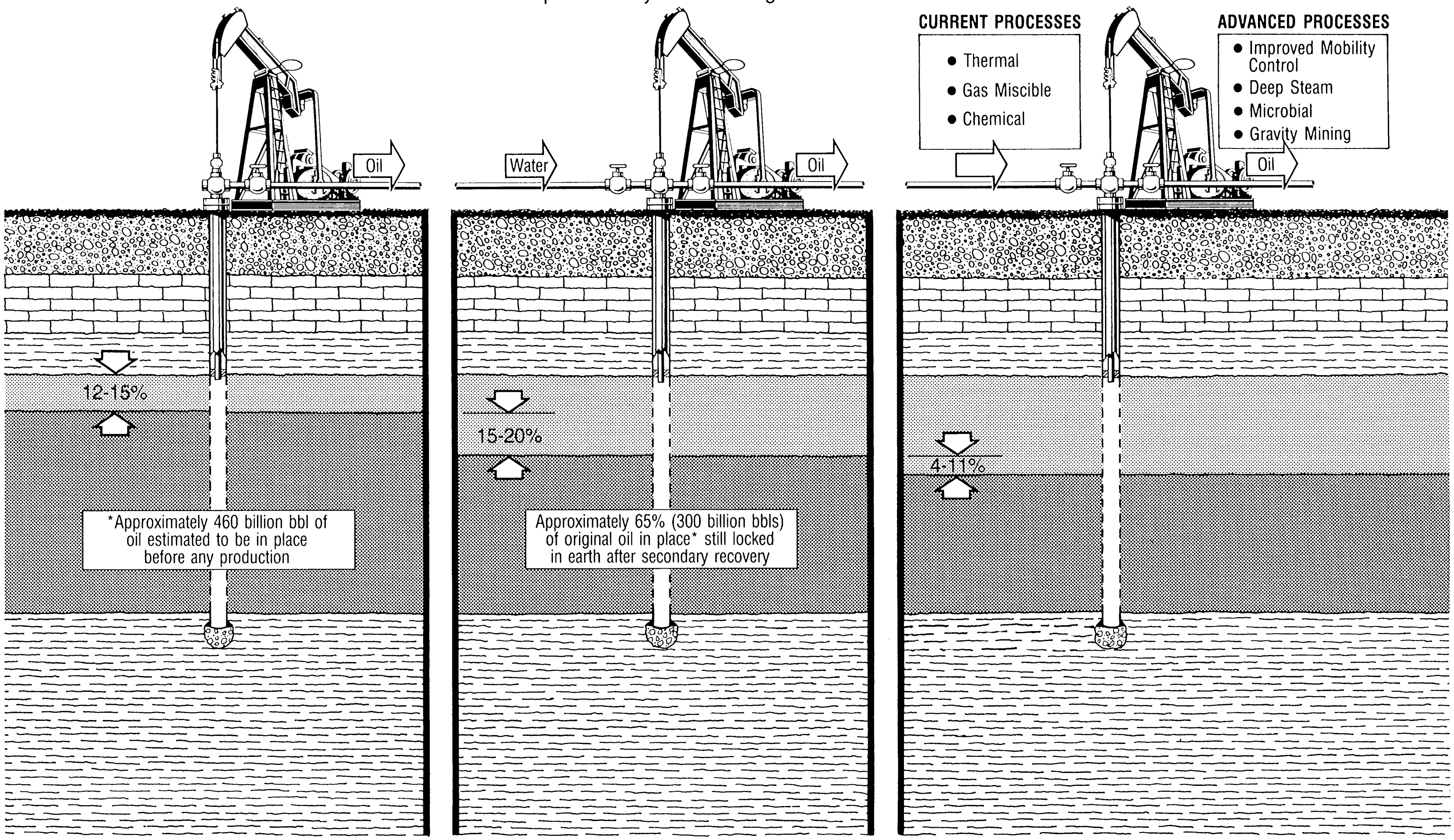
OIL PRODUCTION

Improved technology through research is enhancing oil recovery.

PRIMARY RECOVERY
Produces 12-15% of the original oil-in-place*

SECONDARY RECOVERY
Another 15-20% of the original oil-in-place* may be produced by waterflooding

ENHANCED OIL RECOVERY (EOR)
An additional 4-11% of the original oil-in-place* may be produced using current and advanced technology



CYCLIC STEAM STIMULATION
("Huff-and-Puff")
(A well-stimulation method)

This method is sometimes applied to heavy-oil reservoirs to boost recovery during the primary production phase. During this time it assists natural reservoir energy by thinning the oil so it will more easily move through the formation to the injection/production wells. It can also be used, however, as a single-well procedure.

To utilize this EOR method, a predetermined amount of steam is injected into wells that have been drilled or converted for injection purposes. These wells are then shut in to allow the steam to heat or "soak" the producing formation around the well. After a sufficient time has elapsed to allow adequate heating, the injection wells are placed back in production until the heat is dissipated with the produced fluids. This cycle of soak and produce, or "huff-and-puff", may be repeated until the response becomes marginal due to declining natural reservoir pressure and increased water production.

At this time a continuous steamflood is usually initiated for two reasons:

1. To continue the heating and thinning of the oil.
2. To replace declining reservoir pressure so that production may continue.

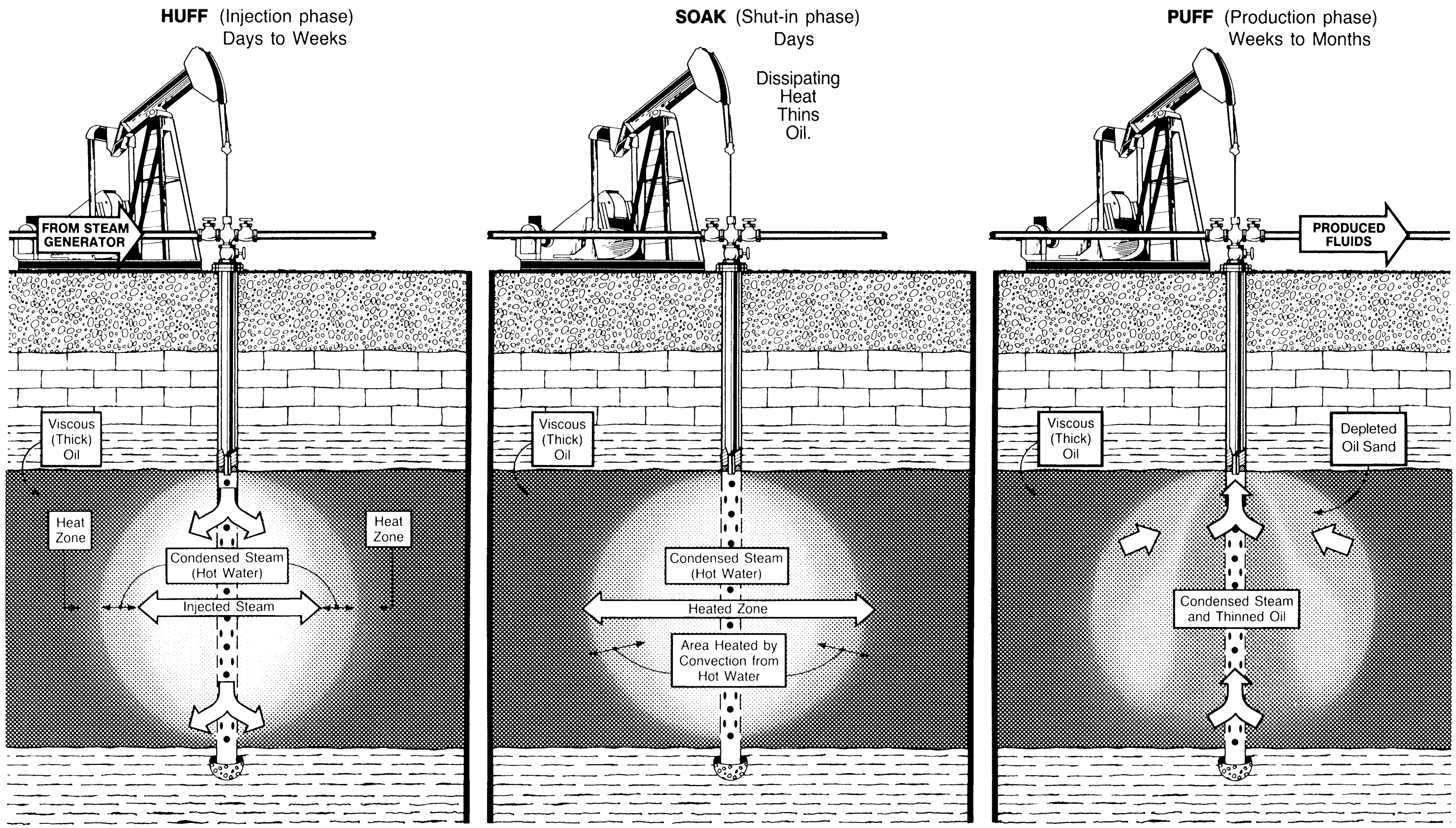
When steamflooding is started, some of the original injection wells will be converted to production wells. These wells, and others drilled or designated for that purpose, will be used for oil production. For details of the steamflooding process, see pages 20 and 21.

A visual representation of cyclic steam stimulation is shown on the following page.

CYCLIC STEAM STIMULATION

Steam, injected into a well in a heavy-oil reservoir introduces heat that, coupled with alternate "soak" periods, thins the oil allowing it to be produced through the same well. This process may be repeated until production falls below a profitable level.

Schematic portrays one well during the 3 phases of this process. Flow pattern is stylized for clarity.



STEAMFLOODING

As with cyclic steam stimulation, this enhanced recovery method usually is used in heavy-oil reservoirs containing oil whose viscosity is a limiting factor for achieving commercial oil producing rates. It has also been considered, however, as a method for recovering additional light oil.

High-temperature steam is generated on the surface then continuously introduced into a reservoir through injection wells. As the steam loses heat to the formation, it condenses into hot water, which, coupled with the continuous supply of steam behind it, provides the drive to move the oil to production wells.

As the formation is heated by the steam, oil recovery is increased because of the following effects:

1. The oil becomes less viscous, making it easier to move through the formation toward production wells.
2. Expansion or swelling of the oil aids in releasing it from the reservoir rock.
3. Lighter fractions of the oil tend to vaporize, and as they move ahead into the cooler formation ahead of the steam they condense and form a solvent or miscible bank.
4. Finally, the condensed steam cools as it moves through the reservoir and results in what amounts to an ordinary waterflood ahead of the heated zone.

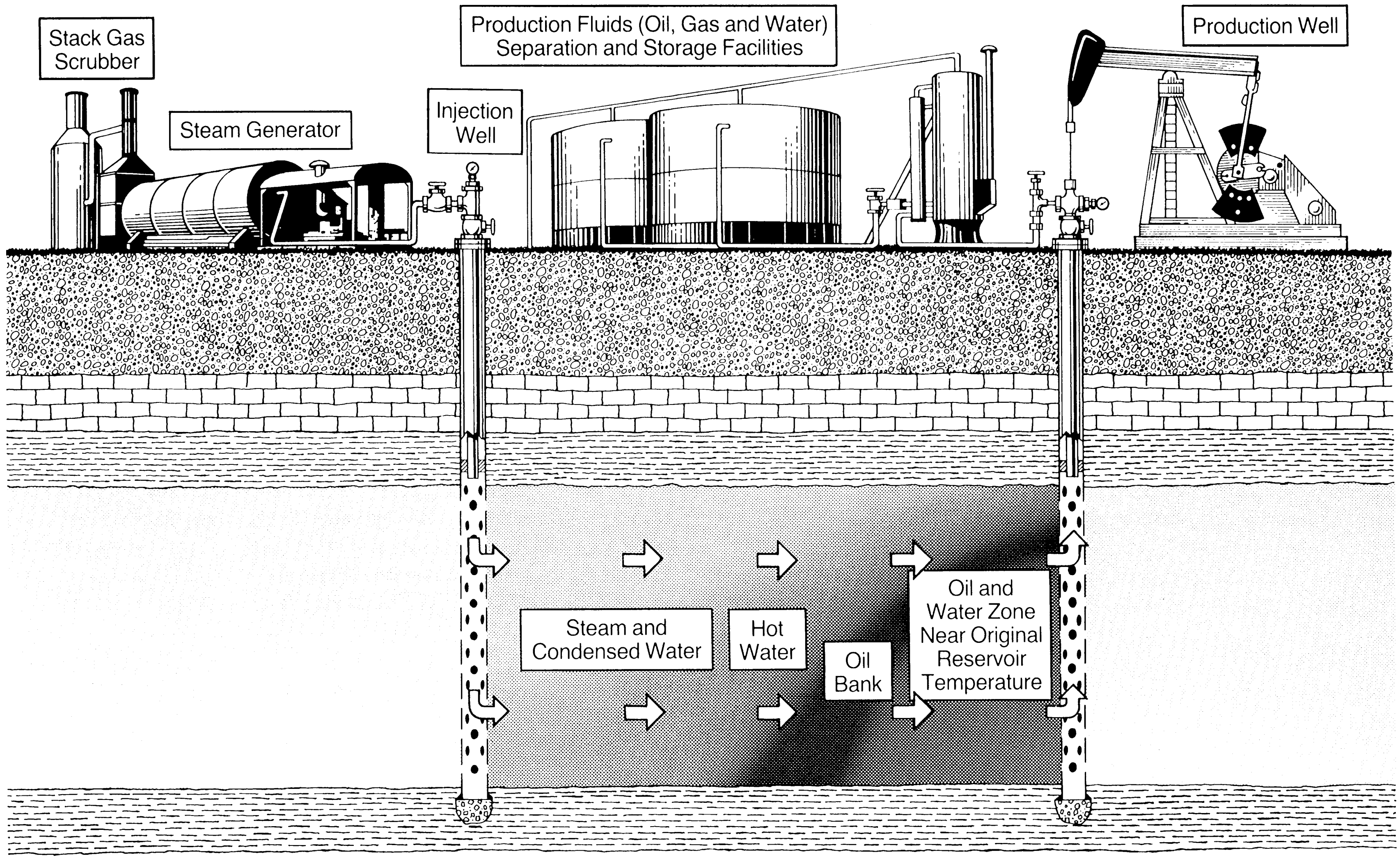
An added bonus from the use of steam in both cyclic steam stimulation and steamflooding is the flushing of liners and casing perforations, as well as the reduction of deposits that may build up in the wells. Possible flow restrictions to oil production through the wells are thus reduced.

Steamflooding is illustrated on the following page.

STEAMFLOODING

Heat, from steam injected into a heavy-oil reservoir, thins the oil making it easier for the steam to push the oil through the formation toward production wells.

Heat reduces viscosity of oil and increases its mobility.



IN SITU COMBUSTION
or "Fireflooding"

This method is sometimes applied to reservoirs containing oil too viscous or "heavy" to be produced by conventional means. By burning some of the oil in situ (in place), a combustion zone is created that moves through the formation toward production wells. A steam drive, together with an intense gas drive is thus provided for the recovery of oil.

This process is sometimes started by lowering a heater or ignitor into an injection well. Air is then injected down the well, and the heater is operated until ignition is accomplished. After heating the surrounding rock, the heater is withdrawn, but air injection is continued to maintain the advancing combustion front. Water is sometimes injected simultaneously or alternately with air, creating steam which contributes to better heat utilization and reduced air requirements.

Many interactions occur in this process, but the drawing on the following page shows the essential elements. The numbered statements below correspond to numbers on the drawing.

1. This zone is burned out as the combustion front advances.
2. Any water formed or injected will turn to steam in this zone due to residual heat. This steam flows on into the unburned area of the formation, helping to heat it.
3. This shows the combustion zone which advances through the formation.
4. High temperature just ahead of the combustion zone causes lighter fractions of the oil to vaporize, leaving a heavy residual coke or carbon deposit as fuel for the advancing combustion front.
5. A vaporizing zone that contains combustion products, vaporized light hydrocarbons, and steam.
6. In this zone, owing to its distance from the combustion front, cooling causes light hydrocarbons to condense and steam to revert back to hot water. This action displaces oil miscibly, condensed steam thins the oil, and combustion gases aid in driving the oil to production wells.
7. In this zone, an oil bank (an accumulation of displaced oil) is formed. It contains oil, water, and combustion gases.
8. The oil bank will grow cooler as it moves toward production wells, and temperatures will drop to that near initial reservoir temperature.

When the oil bank reaches the production wells, the oil, water, and gases will be brought to the surface and separated--the oil to be sold and the water and gases sometimes reinjected.

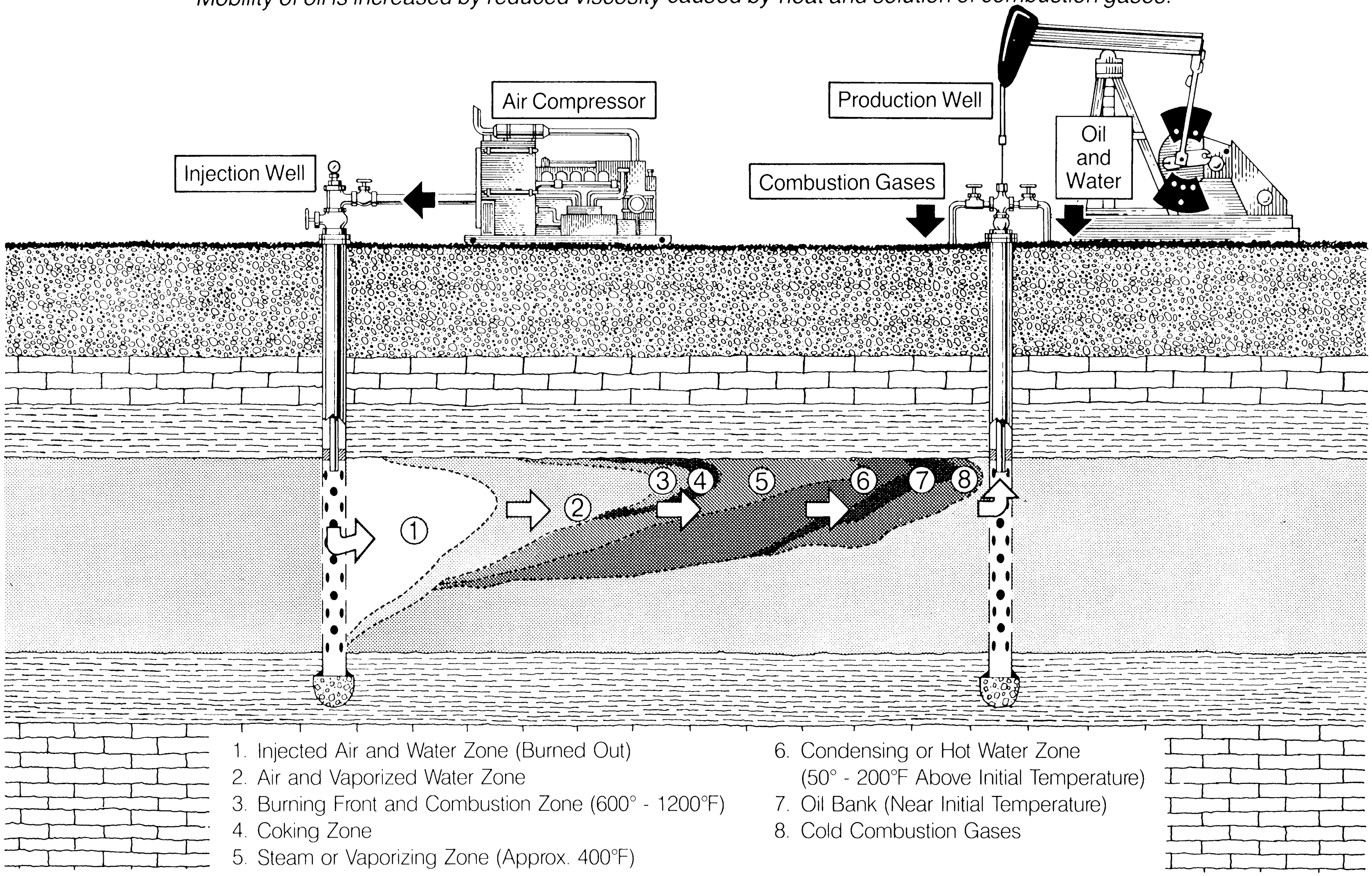
The process will be terminated by stopping air injection when predesignated areas are burned out or the burning front reaches production wells.

Notice in the accompanying illustration that the lighter steam vapors and combustion gases tend to rise into the upper portion of the producing zone, lessening the effectiveness of this method. Injection of water alternately or simultaneously with air can lessen the detrimental overriding effect.

IN SITU COMBUSTION

Heat is used to thin the oil and permit it to flow more easily toward production wells. In a fireflood, the formation is ignited, and by continued injection of air, a fire front is advanced through the reservoir.

Mobility of oil is increased by reduced viscosity caused by heat and solution of combustion gases.



CYCLIC CARBON DIOXIDE STIMULATION
(A well-stimulation method)

Cyclic CO_2 stimulation is a single well operation, which is developing as a method of rapidly producing heavy oil.

Cyclic CO_2 stimulation is similar in operation to the conventional cyclic or "huff-and-puff" steam injection process. In other words, CO_2 is injected into a well drilled into an oil reservoir, the well is then shut in for a time providing for a "soak period", then is opened allowing the oil and fluids to be produced.

In this process the production of additional oil produced is accomplished by some or all of the following mechanisms:

1. CO_2 dissolves in the oil, reducing its viscosity and allowing the oil to flow more easily toward the well.
2. Increased oil-phase saturation due to CO_2 dissolving in the oil and causing it to swell.
3. Solution-gas drive achieved by the evolution of CO_2 and natural gas from the oil phase at the lower pressures occurring during production.
4. Hydrocarbon extraction by the supercritical CO_2 gas.

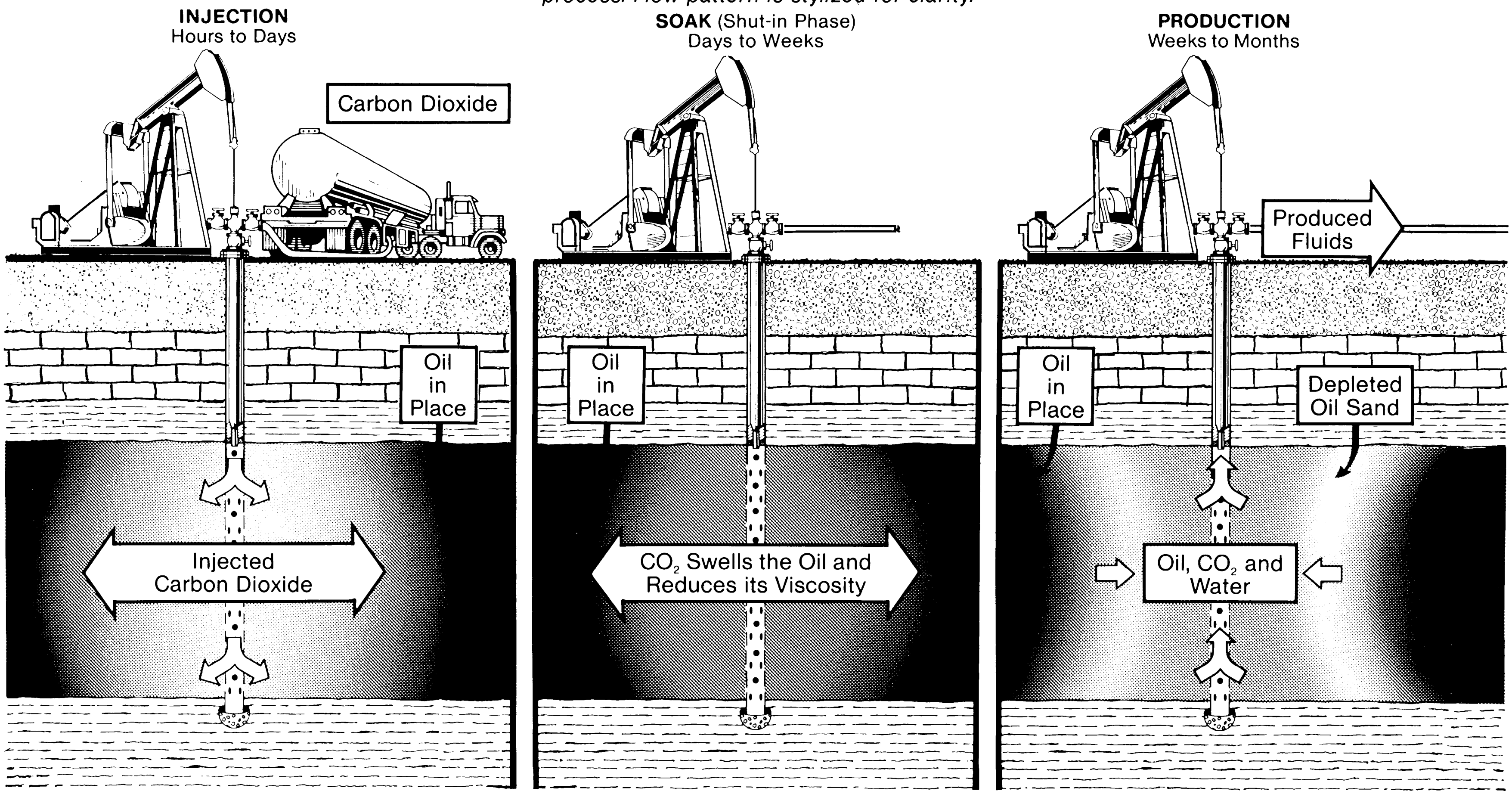
This process is most applicable to viscous (heavy) oil reservoirs that have a high oil saturation and temperatures or pressures that preclude miscibility between oil and CO_2. The most important operating parameters are volume of CO_2 injected per cycle, number of cycles, and degree of back pressure during production.

This process can be repeated several times, but efficiency decreases with the number of cycles. Cyclic CO_2 stimulation can be useful in recovering heavy oil in cases where thermal methods are not feasible.

CYCLIC CARBON DIOXIDE STIMULATION

Carbon dioxide is introduced into an oil reservoir during injection. The injection well is then shut in for a "soak period" during which the carbon dioxide swells the oil and reduces its viscosity. The well is then opened and the carbon dioxide provides a solution gas drive, allowing the oil and fluids resulting from the soak period to be produced. This process is repeated.

Schematic portrays one well during the 3 phases of this process. Flow pattern is stylized for clarity.



CARBON DIOXIDE FLOODING

Carbon dioxide (CO_2) is a common material normally used in the form of a gas and can sometimes be used to enhance the displacement of oil from a reservoir. It occurs naturally in some reservoirs either with natural gas, or as a nearly pure compound. It can also be obtained as a by-product from chemical and fertilizer plants, or it can be manufactured or separated from power plant stack gas.

When pressure in a candidate reservoir has been depleted through primary production and possibly waterflooding, it must be restored before CO_2 injection can begin. To do this, water is pumped into the reservoir through injection wells until pressure reaches a desired level, then CO_2 is introduced into the reservoir through these same injection wells.

Even though CO_2 is not miscible with oil on first contact, when it is forced into a reservoir a miscible front is generated by a gradual transfer of smaller, lighter hydrocarbon molecules from the oil to the CO_2. This miscible front is in essence a bank of enriched gas consisting of CO_2 and light hydrocarbons. Under favorable conditions of pressure and temperature, this front will be soluble with the oil making it easier to move toward production wells.

This initial CO_2 slug is followed by alternate water and CO_2 injection--the water serving to improve sweep efficiency and to minimize the amount of CO_2 required for the flood.

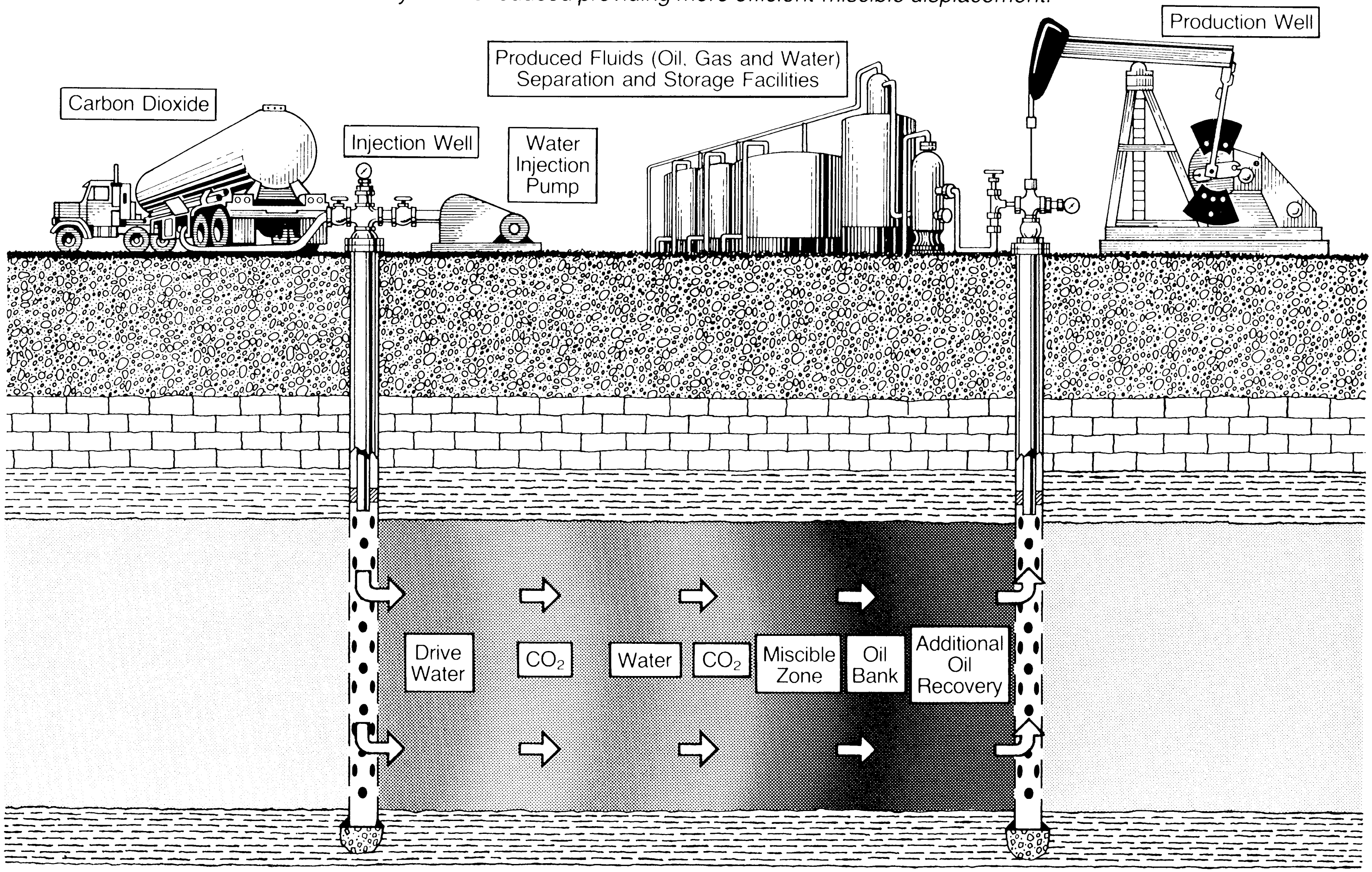
Production will be from an oil bank that forms ahead of the miscible front. As reservoir fluids are produced through production wells, the CO_2 reverts to a gaseous state and provides a "gas lift" similar to that of original reservoir natural gas pressure. On the surface, the CO_2 can be separated from the produced fluids and may be reinjected helping to reduce the amount of new CO_2 required for the project; thus, the CO_2 can be recycled.

This procedure may be repeated until oil production drops below a profitable level.

CARBON DIOXIDE FLOODING

This method is a miscible displacement process applicable to many reservoirs. A CO_2 slug followed by alternate water and CO_2 injections (WAG) is usually the most feasible method.

Viscosity of oil is reduced providing more efficient miscible displacement.



NITROGEN FLOODING

Nitrogen flooding can be a viable EOR method if certain conditions exist in the candidate reservoir. These conditions are as follows:

1. The reservoir oil must be rich in ethane through hexane (C_2-C_6) or lighter hydrocarbons. These crudes are characterized as "light oils" having an API gravity higher than 35 degrees.
2. The oil should have a high formation volume factor, or the capability of absorbing added gas under reservoir conditions.
3. The oil should be undersaturated or low in methane (C_1).
4. The reservoir should be at least 5,000 feet deep to withstand the high injection pressure (in excess of 5,000 psi) necessary for the oil to attain miscibility with nitrogen without fracturing the producing formation.

Gaseous nitrogen (N_2) is attractive for flooding this type of reservoir because it can be manufactured on site at less cost than other alternatives. Since it can be extracted from air by cryogenic separation, there is an unlimited source, and being completely inert it is non-corrosive.

In general, when nitrogen is injected into a reservoir, it forms a miscible front by vaporizing some of the lighter components from the oil. This gas, now enriched to some extent, continues to move away from the injection wells, contacting new oil and vaporizing more components, thereby enriching itself still further. As this action continues, the leading edge of this gas front becomes so enriched that it goes into solution, or becomes miscible, with the reservoir oil. At this time, the interface between the oil and gas disappears, and the fluids blend as one.

Continued injection of nitrogen pushes the miscible front (which continually renews itself) through the reservoir, moving a bank of displaced oil toward production wells. Water slugs are injected alternately with the nitrogen to increase the sweep efficiency and oil recovery.

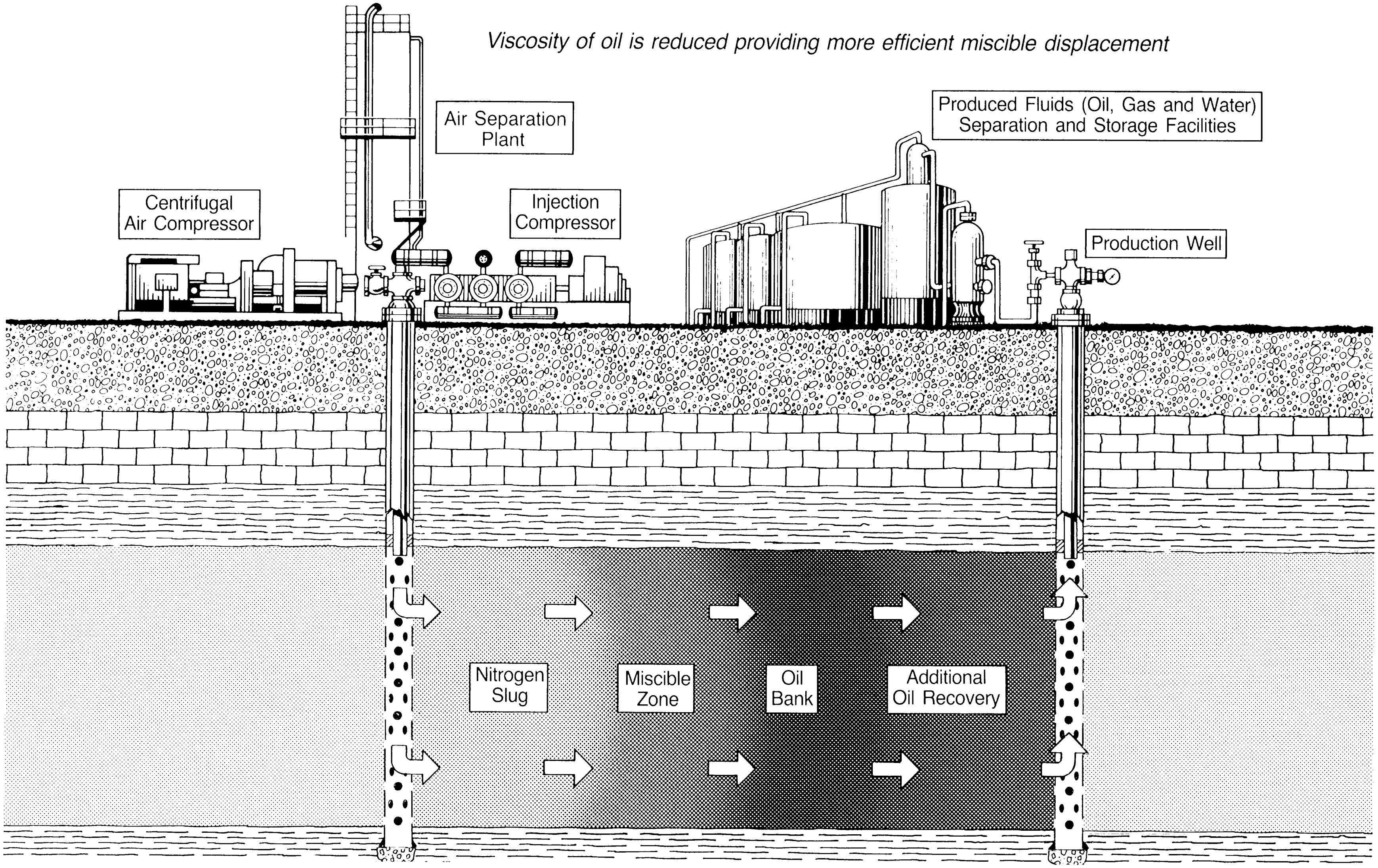
At the surface, the produced reservoir fluids may be separated, not only for the oil but also for natural gas liquids and injected nitrogen.

A representation of this process is illustrated on the following page.

NITROGEN FLOODING

This method can be used as a substitute for CO_2 in deep reservoirs with high API gravity oil. When injected at high pressure, nitrogen can form a miscible slug which aids in freeing the oil from the reservoir rock.

Viscosity of oil is reduced providing more efficient miscible displacement



POLYMER FLOODING

Reservoir conditions sometimes exist that cause a lowering of the efficiency of a regular waterflood. Natural fractures or high-permeability regions in the reservoir rock sometimes will cause the injected water to channel or flow around much of the oil in place by taking the path of least resistance. The heavier or more viscous oils will also cause problems for a waterflood operation because of their resistance to the more mobile or free-flowing water.

To help prevent injected water from bypassing oil, the water can be made more viscous or thickened by the addition of a water-soluble polymer. This, in effect, allows the water to move through more of the reservoir rock, resulting in a larger percentage of oil recovery.

Fresh water is usually injected behind the polymer solution to prevent it from being contaminated by the final drive water which may be produced brine.

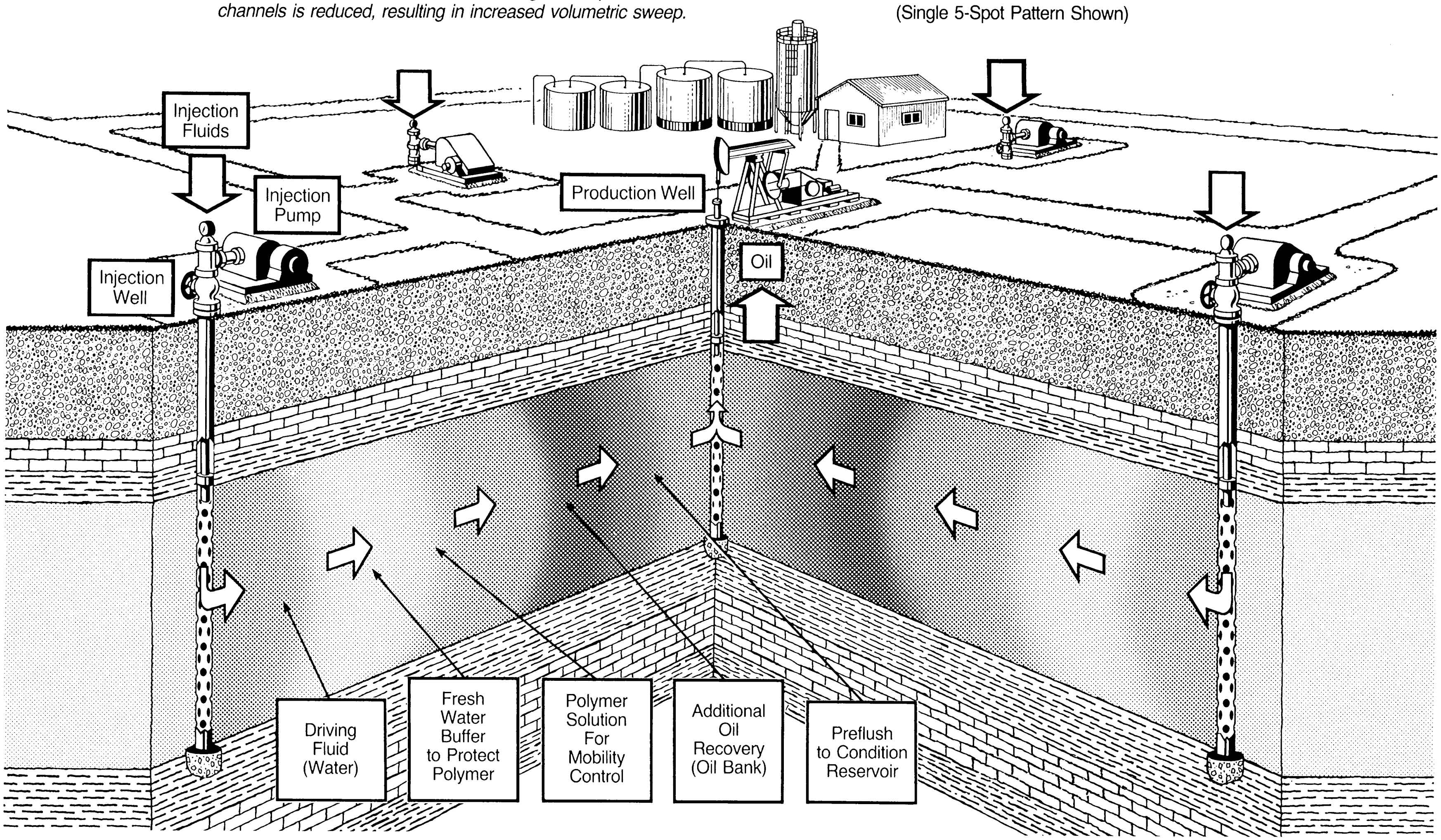
The following illustration shows in a schematic fashion the mechanisms of this process.

POLYMER FLOODING

The method shown requires a preflush to condition the reservoir, the injection of a polymer solution for mobility control to minimize channeling, and a driving fluid (water) to move the polymer solution and resulting oil bank to production wells.

Mobility ratio is improved and flow through more permeable channels is reduced, resulting in increased volumetric sweep.

(Single 5-Spot Pattern Shown)



MICELLAR-POLYMER FLOODING

This is an EOR method which uses the injection of a micellar slug into a reservoir. This slug is a solution containing a mixture of a surfactant, alcohol, brine, and oil and acts to release oil from the pores of the reservoir rock much as a dishwashing detergent releases grease from dishes so that it can be flushed away by flowing water.

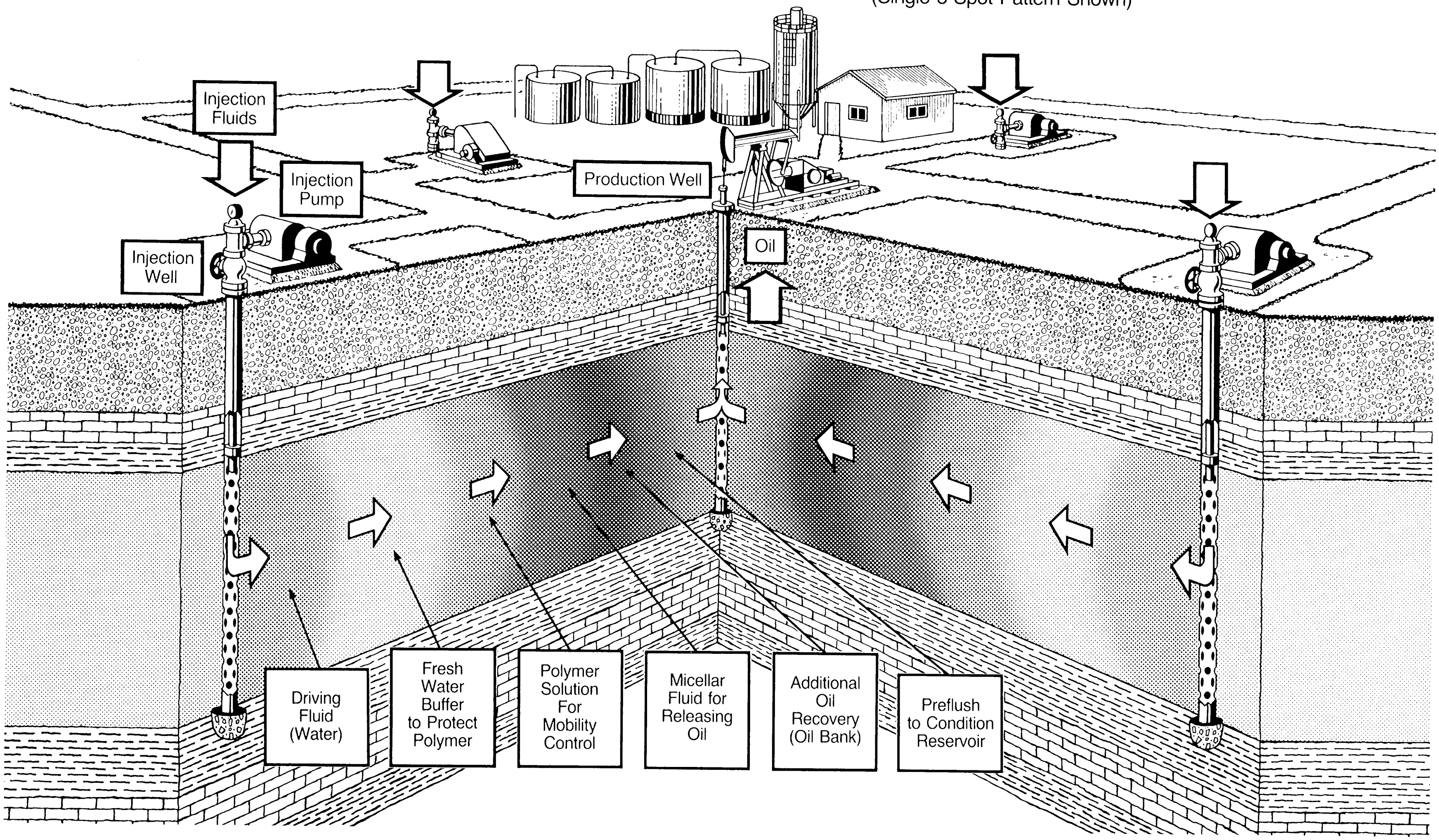
As the micellar solution moves through the oil-bearing formation in the reservoir, it releases much of the oil trapped in the rock. To further enhance production, polymer-thickened water for mobility control (as described in the polymer flooding process) is injected behind the micellar slug. Here again, a buffer of fresh water is injected following the polymer and ahead of the drive water to prevent contamination of the chemical solutions.

See the following illustration for a visual representation of this EOR method.

MICELLAR-POLYMER FLOODING

The method shown requires a preflush to condition the reservoir, the injection of a micellar fluid for releasing oil, followed by a polymer solution for mobility control to minimize channeling, and a driving fluid (water) to move the chemicals and resulting oil bank to production wells.

(Single 5-Spot Pattern Shown)



ALKALINE FLOODING

This method of EOR requires the injection of alkaline chemicals (lye or caustic solutions) into a reservoir. The reaction of these chemicals with petroleum acids in the reservoir rock results in the in situ formation of surfactants. The surfactants help release the oil from the rock by one or more of the following mechanisms: reduction of interfacial tension, spontaneous emulsification, and wettability changes. The oil can then be more easily moved through the reservoir to production wells.

As in the two preceding methods, a polymer-thickened water solution is introduced after the chemicals are injected to aid in obtaining a more uniform movement or "sweep" through the reservoir. Fresh water is then injected behind the polymer solution to prevent contamination from the final drive water which may be salty or otherwise incompatible with the chemicals.

Alkaline flooding is usually more efficient if the acid content of the reservoir oil is relatively high.

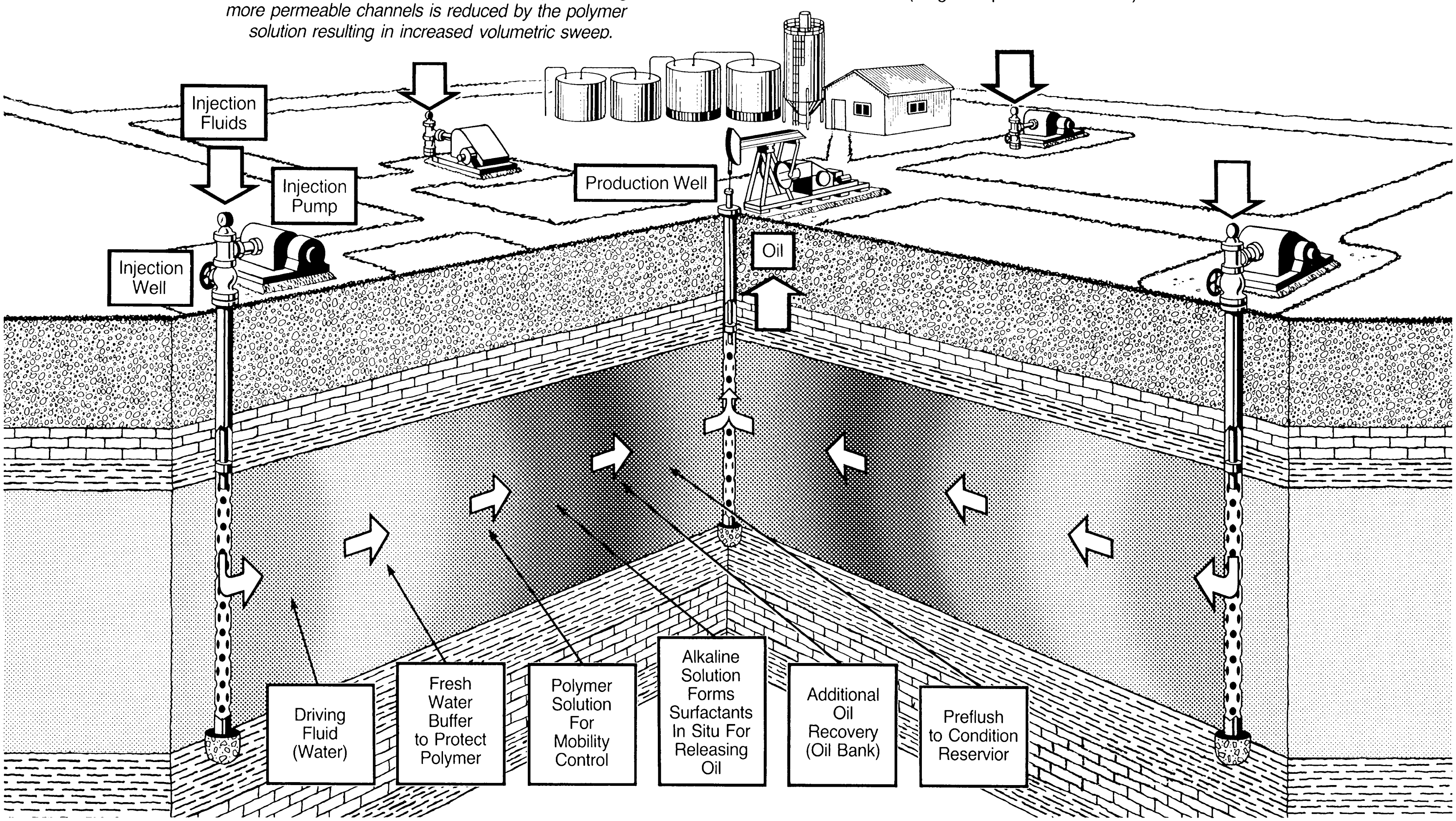
See the following illustration for a visual representation of this process.

ALKALINE FLOODING

The method shown requires a preflush to condition the reservoir and injection of an alkaline or alkaline/polymer solution that forms surfactants in situ for releasing oil. This is followed by a polymer solution for mobility control and a driving fluid (water) to move the chemicals and resulting oil bank to production wells.

Mobility ratio is improved, and the flow of liquids through more permeable channels is reduced by the polymer solution resulting in increased volumetric sweep.

(Single 5-Spot Pattern Shown)



CYCLIC MICROBIAL RECOVERY
(A well-stimulation method)

This is one of the newest EOR methods and requires the injection of a solution of microorganisms and nutrients down a well into an oil reservoir. This injection can usually be performed in a matter of hours, depending on the depth and permeability of the oil-bearing formation. Once injection is accomplished, the injection well is shut in for days to weeks. During this time, known as an incubation or soak period, the microorganisms feed on the nutrients provided and multiply in number. These microorganisms produce products metabolically that affect the oil in place in ways that make it easier to produce. Depending on the microorganisms used, these products may be acids, surfactants, and certain gases, most notably hydrogen and carbon dioxide.

At the end of this period, the well is opened, and the oil and products resulting from this process are produced.

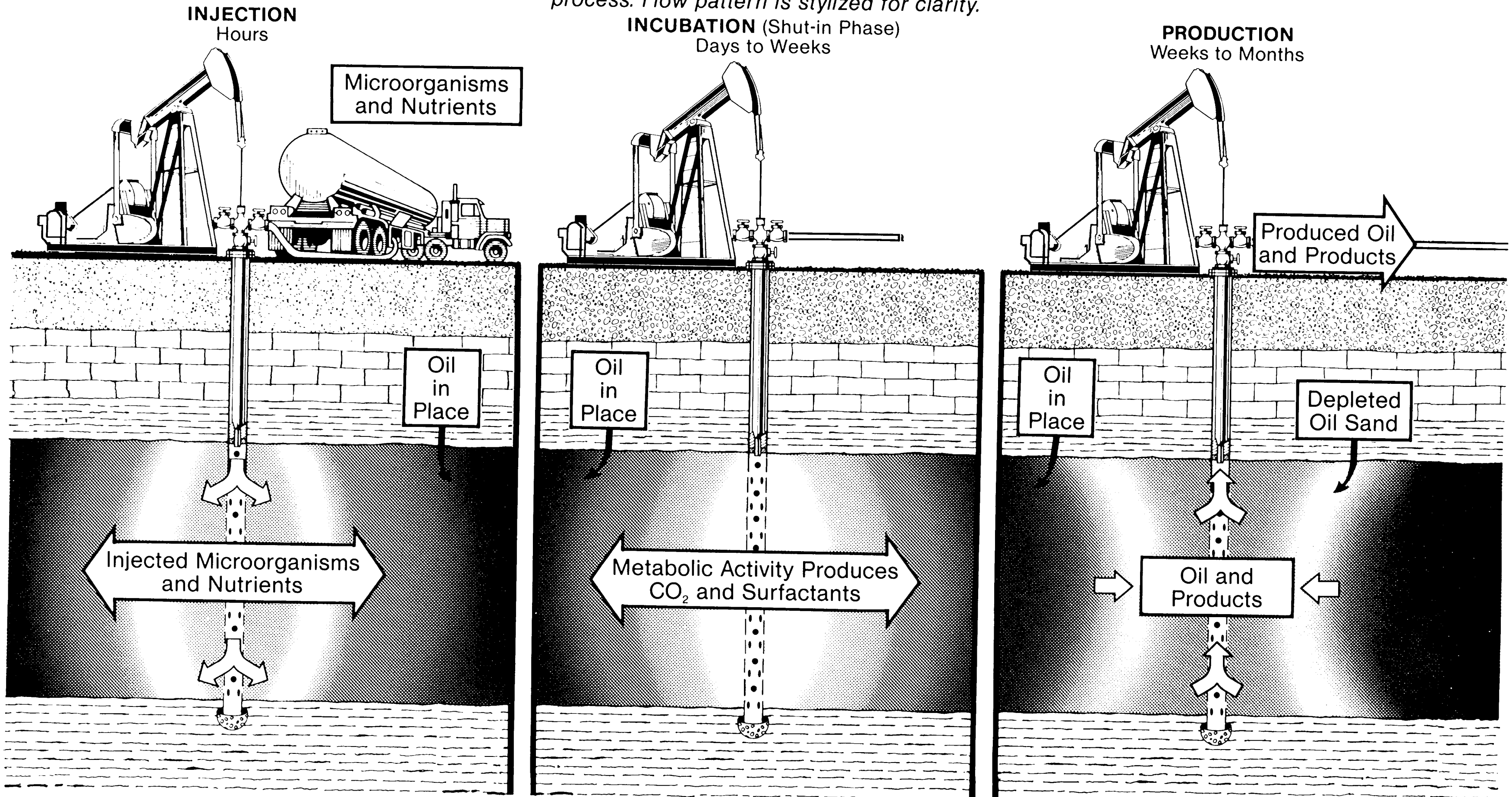
This method eliminates the need for continual injection, but after the production phase is completed a new supply of microorganisms and nutrients must be injected if the process is to be repeated.

This method is illustrated on the following page.

CYCLIC MICROBIAL RECOVERY

A solution of microorganisms and nutrients is introduced into an oil reservoir during injection. The injection well is then shut in for an incubation period allowing the microorganisms to produce carbon dioxide gas and surfactants that help to mobilize the oil. The well is then opened and oil and products resulting from the treatment are produced. This process may be repeated.

Schematic portrays one well during the 3 phases of this process. Flow pattern is stylized for clarity.



MICROBIAL FLOODING

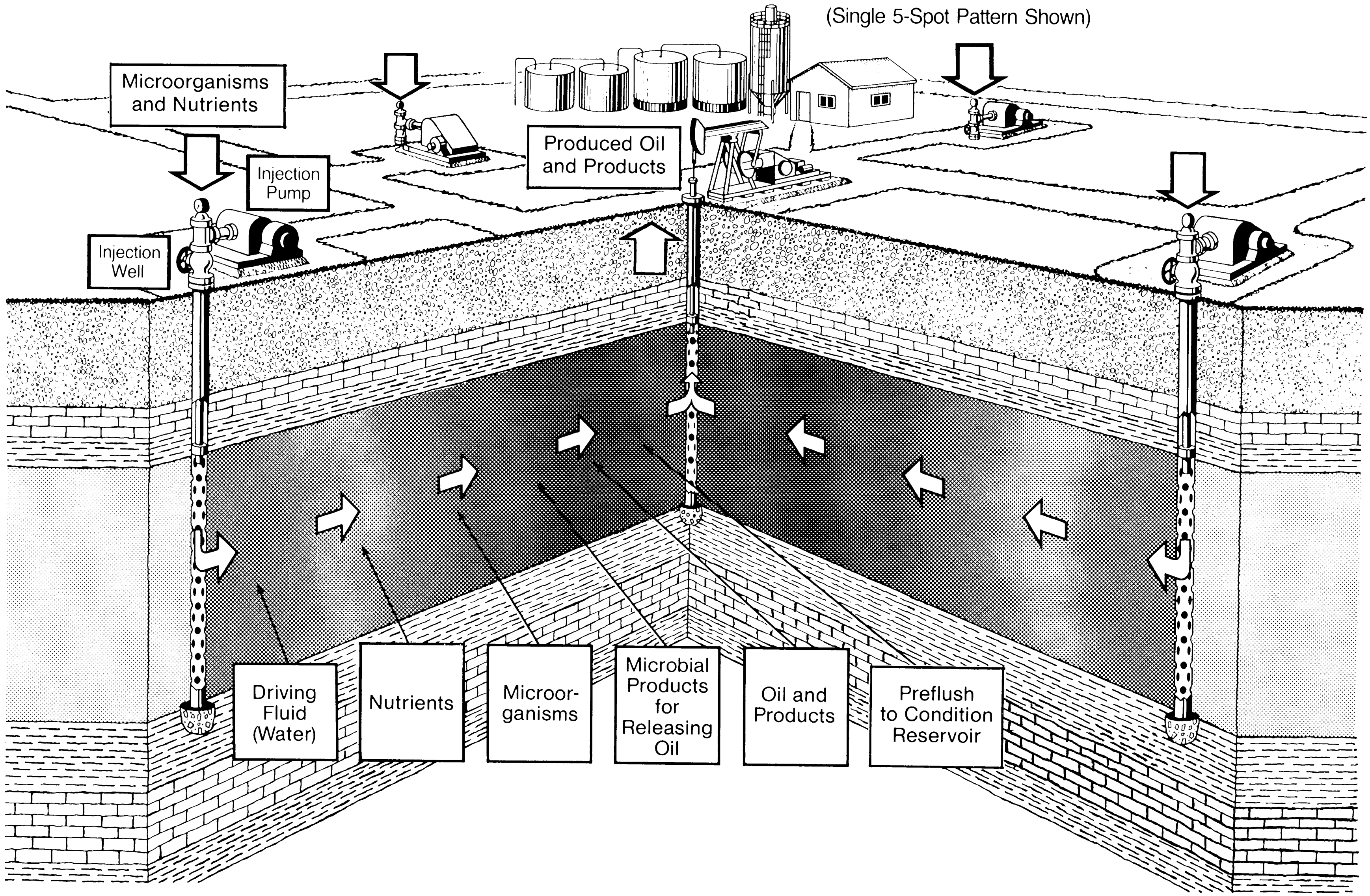
Microbial flooding is performed by injecting a solution of microorganisms and a nutrient such as industrial molasses down injection wells drilled into an oil-bearing reservoir. As the microorganisms feed on the nutrient, they metabolically produce products ranging from acids and surfactants to certain gases such as hydrogen and carbon dioxide. These products act upon the oil in place in a variety of ways, making it easier to move the oil through the reservoir to production wells.

The microbial and nutrient solution and the resulting bank of oil and products are moved through the reservoir by means of drive water injected behind them, as illustrated in the accompanying drawing.

MICROBIAL FLOODING

Recovery by this method utilizes the effect of microbial solutions on a reservoir. The reservoir is usually conditioned by a water preflush, then a solution of microorganisms and nutrients is injected. As this solution is pushed through the reservoir by drive water, it forms gases and surfactants that help to mobilize the oil. The resulting oil and product solution is then pumped out through production wells.

(Single 5-Spot Pattern Shown)



BACKGROUND

National Institute for Petroleum and Energy Research

- Founded as a government petroleum research laboratory in 1918
- Pioneered in research to advance scientific knowledge about petroleum production, processing, and use
- Operated by IITRI since Oct. 1, 1983
- 260-member staff, including 170 technical personnel
- Performs long-term, high-risk, basic research for the Department of Energy under a cooperative agreement
- Performs contract research and specialized technical services for industrial clients
- Specializes in:

  Geoscience

  Recovery processes research

  Reservoir engineering, recovery and projections

  Processing and thermodynamics research

  Fuel chemistry research

  Fuels/engines research

IIT Research Institute

- Not-for-profit research institute founded in 1936
- Headquartered in Chicago with technical operations in Chicago; Bartlesville; Annapolis, Md; and Rome, N. Y.
- 1,700-member staff, including 1,375 technical personnel
- Solves problems for industrial and government clients on a contract basis to meet the changing demands of technology
- Specializes in:

  Chemistry and chemical engineering

  Computer systems and application

  Electromagnetics

  Explosion science and application

  Life science

  Materials and processing technology

  Microwave and electro-optics

  Software engineering and information sciences

  Petroleum technology

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