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FLUID FLOW IN THE VICINITY OF A HORIZONTAL WELL DURING STEAM INJECTION

by

©

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Abstract

This research was directed towards the investigation of fluid flow around a horizontal well. Thirty-six experiments were carried out using a physical model. The main objectives of the steamflood experiments were to study the effect of the horizontal well length, diameter, and location on the steam injection process. Furthermore, the experiments investigated the suitability of the horizontal wells as producers or injectors and examined the effect of the oil viscosity and pressure differential on the oil production performance during the steam injection process.

The steamflood experiments were divided into three types based on the point where the steam was injected into the sand pack: radial steam injection from the top or bottom of the sand pack and steam injection using a horizontal injector.

Based on the experimental results, it was concluded that horizontal wells are more effectively used as producers than injectors and that long horizontal wells have higher cumulative oil recoveries than short wells. Moreover, the effect of horizontal well diameter is more significant in the case of horizontal producers than in the case for injectors. The vertical location of the horizontal well in the formation and the oil viscosity significantly affect the oil production performance during the steam injection process.

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Nomenclature

a	Scaling factor length, dimensionless
a_w	Fraction of peripheral area of the horizontal well open to inflow, dimensionless
A	Area between reservoir and overburden, associated with the reservoir volume, m^2
C	Specific heat, kJ/kg - °C
C_{ij}	Concentration of component j in phase i, mass fraction
g	Acceleration due to gravity, 9.80665 m/s^2
h_i	Enthalpy of phase i (i = oleic, aqueous, and vapour), kJ/kg
H	Thickness of reservoir, m
J	Mechanical equivalence of heat energy, dimensionless
k	Absolute permeability of porous media, m^2
S_i	Saturation of phase i, fraction
T	Temperature, °C
U	Internal energy, kJ/kg
U_i	Internal energy of phase i, kJ/kg
v	Velocity of fluids flowing inside the horizontal well, m/s
V_b	Bulk volume of the reservoir, m^3
W	Work energy done by the fluids flowing inside the well, kJ/s - kg
W_{ij}	Mass injection rate of component j in phase i, kg/s
r_w	Wellbore radius, m

Subscript:

g	Vapour phase
m	Mixture of oil and steam condensate
o	Oleic phase

p	Across the horizontal well
r	Reservoir
s	Steam additive
w	Horizontal well
ga	Concentration of steam additive in vapour phase
go	Capillary pressure between gas and oil
gw	Concentration of water component in vapour phase
oa	Concentration of steam additive in oleic phase
ob	Overburden
oo	Concentration of oil component in oleic phase
ow	Capillary pressure between oil and water
rg	Relative permeability for vapour phase
ro	Relative permeability for oil phase
rw	Relative permeability for aqueous phase
w, avg	Average wellbore radius
ww	Concentration of water component in aqueous phase
in	The inlet of the horizontal well
inj	injection
ou	the outlet of the horizontal well
prod	Production
D	Dimensionless
F	Field prototype
H	Horizontal well
M	Model
R	Reference quantity

Superscript:

sc	Standard conditions

Greek Symbol:

α	Thermal diffusivity ($\alpha = k_h/\rho C$), m^2/s
θ	Cylindrical coordinate, degree
μ_i	Viscosity of phase i, mPa.s
ρ	Density, kg/m^3
ρ_i	Density of phase i, kg/m^3
ϕ	Porosity, fraction
Φ	Potential, Pa

1. Introduction

The trade literature reflects the variety of ways in which horizontal wells are being used for solving several problems associated with the production of oil and gas. Even though horizontal wells have been used for secondary recovery (waterflooding) in a few instances, their main application is in thermal oil recovery, especially steamflooding, and for primary production, especially that of heavy oil. In thermal oil recovery, horizontal wells are used in preference to conventional vertical wells for a number of reasons. In the case of viscous oils, which are receiving a great deal of attention in Alberta and Saskatchewan, horizontal wells are used to improve the displacement efficiency and oil recovery efficiency. Horizontal injectors have a tendency to spread and distribute heat over a large area of the reservoir. The application of horizontal wells in the recovery of heavy oils and tar sands formations is more widespread than that of conventional wells. Due to their large reservoir contact area, horizontal wells increase initial injectivity when they are used as injectors. When horizontal wells are used as producers, their productivity indexes are higher than those of comparable vertical wells. As well as being effective in thermal recovery, horizontal wells are used to intersect as many fractures as possible in fractured reservoirs and to deplete low permeability tight formations.

Because of the lateral extension of horizontal wells into oil-bearing formations, they are most often used to recover oil from thin reservoirs, especially those with underlying communicating bottom water zones. Cold Lake and Lloydminster fields are two of the many examples where horizontal well applications have been successful in recovering oil from heavy oil formations.

Previously scaled model studies of flow in the vicinity of a horizontal well were carried out; however that, is not the focus of this study. This study is an attempt to contribute to the understanding of horizontal well applications in steamflooding. The study examines the suitability of a horizontal well as an injector or a producer, investigates the effect of the horizontal well length, diameter and location on oil production performance and examines the effect of oil viscosity and pressure differential on oil recovery during the steam injection process.

2. Literature Review

2.1 Thermal Recovery Methods

The known resources of heavy oil and bitumen are as large or larger than those of conventional crude oil, which makes their efficient and economic recovery an important and potentially profitable task. In most cases, the volumes of oil produced using conventional techniques such as primary and secondary recovery methods represent only one-third of the initial oil in place (IOIP).[1] This low recovery factor is a result of both unfavorable fluid and reservoir characteristics, such as high fluid viscosity and reservoir heterogeneity. These variations in fluids and reservoir properties are responsible for unswept areas and for poor displacement efficiency. Because of the great variety of reservoir conditions and the diversity of fluid behaviours, there is no single technique or method to enhance oil production; rather, there are a group of techniques aimed at enhancing oil recovery from different reservoir types. These techniques are referred to as Enhanced Oil Recovery (EOR) processes.

EOR consists of methods and techniques aimed at increasing the ultimate oil recovery by reducing the amount of oil remaining trapped after primary and secondary recovery methods have been used. To achieve this goal, the petroleum industry has adopted several techniques, such as chemical, microbial and thermal oil recovery methods. Thermal recovery can take the form of a hot waterflood, steam injection, in-situ combustion or any combination of the three processes. Steam injection is the most widely used technique among enhanced oil recovery processes. Seventy-two percent of the total enhanced oil recovery for the United States in 1988 resulted from steam injection in California.[1] Cyclic steam stimulation is one the most common injection methods used for heavy oil or oil sands reservoirs. It is common practice to steam stimulate prior to steamflooding or in-situ combustion to improve initial steam or gas injectivity. The use of cyclic steaming to reduce oil viscosity to aid flow from the reservoir to the production well has proven to be an effective technique. One advantage of cyclic steam stimulation is that it centres the heat around the wellbore, where the stream lines converge and the pressure gradients are highest. A major difference between cyclic steam stimulation and steamflooding is that, in cyclic steam stimulation, the oil being displaced remains hot as it flows to the production well, whereas in steamflooding, the oil must contact the cooler reservoir until the flood becomes mature.[2]

Steamflooding provides the energy necessary to sweep the oil from the injection site to the production wells. One of the most important properties of steam is its ability to transfer heat to reservoir fluids and its adequacy to form a bank upon condensation, creating a stable displacement front. Field experience[1] indicates that the residual oil saturation for steamflooding is far lower than that for waterflooding. One advantage of steam injection over hot water injection is that much energy can be injected into the formation and high oil recovery can be attained. Hot waterflooding is a relatively simple form of thermal recovery and is close to conventional waterflooding in terms of operation. Extraction of oil using hot water is accomplished by the reduction in residual oil saturation and oil viscosity at high temperature, thereby making the oil more mobile. Field applications of hot water drive have been complicated by channeling, severe viscous fingering and high water production. The Schoonebeek project in Holland[1,3] is one of many successful field tests where the oil viscosity at reservoir conditions is moderate (i.e., 180 mPa.s).

Another form of thermal recovery is in-situ combustion: a process where gas, normally oxygen or air, is injected into the formation to react with the oil. One advantage of in-situ combustion over steamflooding is that there are no heat losses from in-situ combustion until the oxygen from the injected gas reacts with the coke at the fire front transferring heat to the oil. With steamflooding, heat is lost at surface installations and pipes, tubing and casing, and to the over and underburden. In-situ combustion provides an economical and efficient method to recover oil from heavy oil reservoirs and oil sands. There is no need to supply an external energy source because combustion is sustained by the fuel provided by the residual oil.[2] Moss and White[4] described the in-situ combustion process as one of the best techniques among enhanced oil recovery methods, since it is a combination of several mechanisms: condensing steam drive, miscible drive and gas drive. However, one disadvantage they described is that most of the heat generated remained behind the front in the burned-out zone and did not affect oil production. Butler[2] suggested that even though it was necessary to provide energy to compress the gas, and, in the case of oxygen, to separate and compress the gas, the energy required was much less than that required for steam generation.

2.2 Mechanisms of Oil Displacement by Steam

2.2.1 Oil Viscosity Reduction

The main effect of steam on heavy oil is a steep reduction in viscosity. Because of the high enthalpy content of steam, it can reduce the viscosity of the oil from 1,000,000 to

8 mPa.s for a temperature increase of 25 to 200 °C.[2] The reduction in oil viscosity plays a major role in decreasing the flow resistance in the reservoir, thereby decreasing the mobility ratio and leading to high oil recovery. However, when steam contacts cold crude oil, the steam temperature drops, allowing steam to condense and to form a stable front to improve the displacement efficiency.

Hong[5] indicated that the change in oil viscosity is a reversible process, which means that, when the temperature decreases again, the oil viscosity reverts more or less to its original value. He also concluded that the high production rates and low water-oil ratios prior to or at the time of steam breakthrough at the production well was a result of the oil bank formed by the reversibility effect of the oil viscosity. In the reversible viscosity mechanism, steam increases reservoir temperature ahead of the front, thereby decreasing oil viscosity. Then oil is displaced from the high temperature region to an area of considerably lower temperature, causing the oil viscosity in the low temperature region to increase again, creating resistance to oil flow and forming an oil bank from the accumulation of oil.

2.2.2 Steam Distillation

Steam distillation is the main recovery mechanism in the steam zone behind the front, where it lowers the boiling point of the reservoir liquid. The effectiveness of steam distillation in increasing production is greater than the loss in production due to the distillate removed from the residual oil. As steam condenses and mixes with reservoir oil, it forms a solvent that reduces the viscosity of the oil beyond the steam zone. In a pioneering experimental laboratory study, Willman, Valleroy, Runberg, Cornelius and Powers[6] conducted a series of hot water and steamflooding experiments. They reasoned that the increase in the recovery of oil by steam is due to the ability of steam to remove additional material from the residual oil by steam distillation. They also pointed out that the incremental oil recovery by steam injection was a result of the solvent dilution caused by the condensation of the light ends in front of the steam zone. Hong[5] concluded that the recovery by steam distillation was higher for light oil than for heavy oil because steam preferentially distills the lighter fractions first. The lower the oil viscosity and the higher the steam quality, the higher the yield of distilled oil. The contribution of the steam distillation mechanism to overall steamflood recovery is low in the field compared to the results obtained in the laboratory studies. As much as 60 percent of some light oils can be collected as overhead products in laboratory steam distillation.

2.2.3 Changes in Relative Permeability

One phenomenon that plays a role in increasing the effectiveness of oil recovery by steam is that the relative permeabilities change with temperature. Laboratory studies[2] show that an increase in temperature changes the relative permeability curves. Steam introduces heat to reservoir rocks and fluids, altering the physical properties of the oil and reducing the oil residual saturation, thereby promoting some increase in the relative permeability to oil. However, the relative permeability to water seems to be lower under steamflooding conditions than under normal conditions (i.e., ambient temperature) due to the fact that some water is trapped in water-oil emulsions during the steam injection process. Butler[2] suggested that the reason behind a lower residual oil saturation is that steam has a tendency to distill the residual oil, forming a solvent that dilutes the oil and reduces its viscosity. The effect of steamflooding and temperature treatment on reservoir fluid relative permeabilities is complicated by other reservoir factors. However, it seems apparent that steam does have a positive effect on increasing oil relative permeability.

2.2.4 Oil Thermal Expansion

Thermal expansion is another important oil recovery mechanism, wherein steam supplies energy to the reservoir, heats the fluids, and increases the fluids tendency for thermal expansion. Depending on the type of crude oil, its initial saturation and the temperature of the heated zone, thermal oil expansion alone can recover 5 to 10 percent of the initial oil in place.[5] The amount of oil expansion depends on the type of reservoir and oil composition and characteristics. Since thermal expansion is higher for light oil than for heavy oil, this effect is more effective in increasing oil recovery from light oil reservoirs than from heavy oil deposits.

2.2.5 Compaction

Depending on the type of reservoir, sand characteristics and the depositional environment, compaction can be an effective mechanism in providing the energy to drive the oil to a production well during cyclic steam injection process. Consolidation of the reservoir sand and fine materials, along with a decrease in the average porosity as the pore pressure falls, can provide the necessary energy to transport oil to the wellbore. When the pore pressure is lowered, which reduces the pore volume, the rocks are compacted, squeezing the oil from the pore space and providing the pressure drive to transport the oil.

Butler[2] indicated that the compaction mechanism has been important in oil production from the Bolivar Coast of Lake Maracaibo in Venezuela.

In the early cycles of steam stimulation in the bitumen reservoir of Cold Lake, a compaction mechanism was observed following a reservoir expansion as a result of injecting steam at fracturing pressure. In heavy, low permeability reservoirs, injection at fracturing pressure is the only means to inject steam at practical rates. Steam injection at fracturing pressure causes an increase in pore volume. This increase is stored as potential energy, which is reflected by the rise in the ground surface elevation. As the pore pressure, or rather the well pressure, drops, oil is squeezed and pushed towards the production well by the stored potential energy provided by the strata as they subside.

2.2.6 Solution Gas Drive

Solution gas drive is not as effective as the drive mechanisms previously mentioned but still provides a driving force for heavy oil reservoirs containing fair amounts of dissolved gas. Most heavy oil reservoirs lack dissolved gases so the energy provided by gas coming out of solution is limited. However, in some cases carbon dioxide can be generated during a steamflood either from high temperature steam reacting with carbonate formations or from a reaction with the crude oil itself. As soon as carbon dioxide evolves, it provides a driving force by swelling the oil and reducing its viscosity, allowing for a more favourable mobility ratio and better sweep efficiency. Carbon dioxide injection is one of the most effective mechanisms in enhanced oil recovery, especially for heavy oil reservoirs, because of the ability of the carbon dioxide to swell the oil and reduce its viscosity.

2.3 Application of Horizontal Wells in Enhanced Oil Recovery

Horizontal drilling for primary oil recovery has become a routine operation, with more than 2,700 wells drilled around the world with an average horizontal extension of 456 to 1064 metres[7]. The vast majority of horizontal wells are drilled in reservoirs having a high vertical permeability or reservoirs having a substantial number of vertical fractures. Horizontal wells help reduce pressure drawdown, control coning problems and intersect many high conductivity fractures. The demand for crude oil and the difficulties and cost of discovering new reserves, as well as the rapid consumption of conventional oil reserves, have generated a special interest in the application of horizontal wells in enhanced oil recovery processes. In EOR applications, especially in thermal oil recovery, horizontal wells have been used extensively. A long horizontal well provides a larger reservoir contact area, increasing the injectivity and reducing the project life time. This is specially beneficial for heavy oil and oil sands where the initial injectivity is low. The application of horizontal wells to exploit heavy oil and oil sands reservoirs using thermal recovery methods has been studied extensively by several authors.[7-18]

2.3.1 Steam-Assisted Gravity Drainage

Thermal recovery of heavy oil from oil sands formations has received considerable attention for the past 35 years. Based on their viscosity, heavy oil reservoirs may be divided into two types: conventional heavy oil, which can be produced using conventional primary methods, and bitumen, which is immobile at in-situ conditions. Cold Lake, Peace River, Wabasca and Athabasca in Alberta are good examples of the latter reservoir type. Steam-assisted gravity drainage is an effective process to enhance the recovery of oil from such only low pressure Athabasca reservoirs.[8]

Many authors[9-17] have made experimental and theoretical efforts to investigate the effect of horizontal wells on the recovery of oil by gravity. Experimental work by Butler, McNab and Lo[8], using a visual model at atmospheric pressure, showed that a horizontal well placed at the base of a growing steam chamber provided continuous drainage for the oil and could be used for low pressure steam. Joshi[10] also investigated the gravity drainage process using a combination of horizontal and vertical wells. He used glass beads packed in a rectangular steel box with one transparent wall allowing flow visualization. His results indicated that the maximum oil recovery was obtained by a horizontal well pair. Yang and Butler[11] conducted experimental studies on the effect of reservoir hetrogeneities on the gravity drainage process. They used a two-dimensional reservoir model with thin shale layers and a reservoir containing layers with different permeabilities. Their results showed that production is not greatly affected by a short horizontal barrier. Faster production rates are observed when the higher permeability layer is on top, rather than if the conditions are reversed.

An effort was made by Sarkar and Deo[18] to compare three thermal EOR processes: Steam-Assisted Gravity Drainage (SAGD), Heated Annulus Steam Drive (HASD) and Cyclic Steam Stimulation (CSS). They used a three-dimensional simulator to investigate the effect of horizontal wells in combination with vertical wells on the performance of SAGD, HASD and CSS processes. When using SAGD, the movement of oil to the production well is caused by gravity forces. By using gravity as the main driving force to move the oil, it is possible to avoid the differential fingering that occurs when highly viscous oil is pushed by less viscous fluids.

2.3.2 Carbon Dioxide Flooding

All EOR methods should benefit by the use of horizontal wells because of the better sweep efficiencies and higher injectivities horizontal wells provide. Horizontal wells are used in carbon dioxide miscible flooding as a means to enhance oil recovery and increase sweep efficiency. Injection of carbon dioxide into an oil-bearing formation will initiate many recovery mechanisms that enhance the recovery of oil by carbon dioxide. One mechanism is swelling of crude oil, because carbon dioxide is more soluble in oil than in natural gas. As the concentration and pressure of carbon dioxide increases, its solubility increases leading to swelling of the crude oil. Viscosity reduction of the crude oil is a result of carbon dioxide solubility in the oil. This effect is more efficient and noticeable in heavy rather than light oils. When carbon dioxide is injected into a partially depleted reservoir at high pressure, oil is produced as a vapour along with the gas.[19] Surface tension, gravity reduction and other mechanisms also play a role in the recovery of oil by carbon dioxide.

A compositional equation-of-state simulator[20] has been developed to study the effect of different reservoir descriptions on carbon dioxide process performance using horizontal and vertical well combinations. Meszaros, Chakma, and Jha's[21] experimental work using a two-dimensional model suggested that close to 70 percent of the oil in place may be recovered by injecting gas from the top of 1000 and 4000 mPa.s viscosity reservoirs. Laboratory scale experiments[22] showed that oil recovery of carbon dioxide using horizontal wells is significantly higher than that of vertical wells.

2.3.3 Steamflooding

Steamflooding has been used for many years for enhanced oil recovery.[23] However, the use of a horizontal well as an injector or a producer is a relatively new application that can improve the process efficiency. Although horizontal well technology has recently been used in miscible and waterflood projects, the main EOR applications to date are in steam projects.[24-26] Reeves, Strickland and Crawford[7] developed an electric potentiometric model to evaluate areal sweep efficiency for various horizontal well patterns and compared it to the sweep efficiency obtained from conventional wells. They observed that areal sweep efficiencies for the base case of two vertical wells were higher than that for the case where a horizontal well pointed in the direction of the vertical production well. However, the highest areal sweep efficiency was obtained using two horizontal injection and production wells; the improved sweep efficiency approached 100 percent.

In their experimental study, Chang, Farouq Ali, and George[27] investigated the effect of bottom water formations on steamflooding performance using horizontal-vertical well combinations. Their results showed that the horizontal-horizontal combination recovered 68 percent of the oil in the presence of 10 percent thickness of high water saturation. They also found that a horizontal combination was only slightly better than vertical wells in the absence of bottom water. Field experience, as well as experimental and numerical modeling,[28,29] has shown that the productivity improvement of horizontal wells is a strong function of well length and reservoir lateral extent. The breakthrough time for horizontal wells is delayed as a result of a horizontal well maintaining a stable displacement front under gravity dominated flow.

Huang and Hight[30] developed a three-dimensional numerical steamflood simulator to investigate the effect of horizontal wells on steamflood conformance. Simulation results indicated that horizontal wells can be effective in reducing or preventing steam override. For a mature field, horizontal wells increased ultimate oil recovery from 63.2 to 74.7 percent of initial oil in place (IOIP). When steam is used at the start of the field life, a combination of horizontal and vertical wells resulted in a recovery of 72.2 percent of initial oil in place. Several authors[23,30-32] have indicated that horizontal wells in thermal projects can increase recovery performance due to better sweep efficiency, accelerate production which improves the oil steam ratio (OSR), boost project profitability and shorten project life.

2.4 Advantages of Horizontal Wells

2.4.1 Productivity Index Increase

Horizontal wells are usually drilled parallel to the reservoir extending 456 to 1064 metres along the horizontal section. They have been proven to be more effective in draining reservoirs, especially thin deposits (i.e., 10-20 metres), at lower drawdown pressures than comparable vertical wells. Because they penetrate long sections in the pay zone, horizontal wells provide a larger reservoir contact area as compared to conventional wells. Elf-Aquitaine[33] drilled three horizontal wells in Western Europe for research purposes. Their field experience, along with analytical derivations and numerical reservoir simulations, confirmed that the productivity of horizontal wells is five times more than that of vertical wells. They observed an increase in the ultimate oil recovery resulting from a reduction in water and gas coning or the possible intersection and linking of vertical fractures. Joshi[34] compared the productivity of horizontal and slant wells to that of vertical wells. He suggested that a horizontal well will always have a higher productivity index than a slant well in a 30-metre-thick reservoir, even when the ratio of vertical to horizontal permeability is low. This clearly indicates that drilling a horizontal well in thin reservoirs (i.e.,<30 metres) is to be preferred.

Recent field experience in the Safah field in Oman[35] confirmed that the average productivity index of horizontal wells is about 10 times more than that of vertical wells. Occidental of Oman has drilled seven horizontal wells with completion intervals ranging from 603 to 1434 metres. The performance of the wells indicates no direct correlation between the initial well productivity index and the length of the horizontal section. The long-term productivity index is a function of the gas oil-ratio of the well. Use of horizontal wells in the Safah field is expected to increase the overall recovery and shorten the production life of the field.

2.4.2 Low Pressure Drawdown

Horizontal wells are becoming an established method for the recovery of oil and gas, especially in heavy oil and oil sand reservoirs. In heavy oil reservoirs with low permeability and thin pay zones, horizontal wells provide a means to increase the initial injectivity for steam injection. Larger contact areas allow lower pressure drawdown, increase production rate, and reduce the potential of gas or water coning problems. These facts imply that a horizontal well should be as long as possible to recover the highest possible amount of oil. Because of advances in horizontal well technology, long horizontal wells are common industry practice. However, there is the disadvantage of pressure drop due to wellbore frictional losses as a result of greater horizontal well length. Most of the time, when performing pressure test analysis or reservoir simulations for horizontal wells, the wellbore pressure drop is assumed to be constant or negligible. In practice, some pressure drop between the production and injection end of the horizontal well is necessary to maintain fluid flow inside the well. Thus the pressure drop inside the horizontal well cannot be ignored, especially when two-phase flow, including compressible gas flow, is encountered in the wellbore.

Several experimental and theoretical studies have been reported; Novy[36] developed a single-phase model which incorporates well length, production rate, hole diameter, and roughness of the wellbore, to compute the length of a well that has a 10 percent loss of productivity caused by friction. Dikken[37] presented a simple analytical method that links single-phase turbulent well flow to the stabilized reservoir flow. He analyzed in detail the pressure gradient ignored in most treatments of horizontal wells. Folefac, Archer, Issa, and Arshad[38] developed a mathematical model to calculate the pressure drop and flow in a horizontal wellbore based on the drift flux. They applied a numerical procedure to solve the one-dimensional differential equation governing the wellbore flow. In their conclusions they pointed out that a high productivity index, a small well radius, a long perforated interval and two-phase flow can have a significant effect on the pressure drop inside a horizontal wellbore.

Ihara, Brill and Shoham[39] conducted experimental and theoretical investigations of the flow behaviour in and around the vicinity of horizontal wells. Their test facility consisted of a 2.54 centimetre inside diameter, 8 metre-long horizontal test section flowing into a 2.8 metre-high vertical section. The model used the inflow performance relationship (IPR) approach, a black oil model and mechanistic models for wellbore hydraulics. They performed a sensitivity analysis using the models for field operations and obtained good agreement between the experimental model and the preliminary experimental data. The effect of the accelerational pressure drop in a horizontal wellbore was also studied by Ihara and Shimizu[40] who improved an initial mechanistic model by including the accelerational pressure drop in the wellbore. From their comparison of the experimental data with the model, they found that the improved model described more rigorously the flow behaviour in a horizontal wellbore.

Plaxton[41] developed a scaled model to study, for the first time, the effect of influx into a two-phase system. He used a closed-loop pipe flow model to carry out experiments using turbulent oil-water flow and influx flow rates. He examined many pipe flow correlations and modified the Asheim, Kolnes and Oudeman model. Plaxton concluded that the pipe flow correlation method examined adequately predicts the oil-water flow pressure gradient and a constriction-disruption, or venturi-type, effect is the dominant factor determining the pressure drop across a single perforation in a horizontal wellbore.

2.4.3 Alleviating Water and Gas Coning

Production of water or gas from oil wells is not desirable in reservoirs having a gas-cap expansion or water drive mechanism. Inefficient use of water and gas-cap gas influences surface production facilities and subsurface recovery mechanisms. Undesirable water and gas production have a negative effect on the cost of oil production and the efficient depletion of the reservoir. Coning of water or gas into a producing well is caused by the pressure gradients around the wellbore established by the fluid flowing into the well. These pressure gradients are more influential in the vicinity of the wellbore and the perforations than anywhere else. Since fluid is being drawn into the wellbore by pressure drops, these pressure gradients tend to depress the gas-oil contact and elevate the water-oil contact in the immediate vicinity of the well. In horizontal wells, because of their larger reservoir contact area in comparison to vertical wells, the effect of gas or water coning is less severe.

Development of horizontal well technology offers a partial solution by providing a new approach to reducing the gas and water coning effect but not a complete elimination of the problem during oil production. Even though the effect of the water and gas coning problem is less deterimental for horizontal wells compared to their vertical counterparts, further improvement of the oil production rate of horizontal wells is still limited by the encroachment of the water or gas cone when bottom water or a gas-cap exists.

A number of authors[42-50] have addressed water and gas coning problems in vertical and horizontal wells with the objective of determining the critical rate which would allow water-free oil production. Guo and Lee[44] provided a theoretical and numerical analysis of water coning behaviour in horizontal wells. They analytically estimated the critical oil production rate and the location of the water crest under critical conditions. Guo and Lee built a numerical reservoir simulator to validate their analytical solution. Their numerical model confirmed the analytical solution and proved that the critical rate per unit length was proportional to the conductivity and thickness of the oil reservoir, the contrast between water and oil density and was related to the critical crest height and to the wellbore location.

Chaperon[43] studied the behaviour of cresting towards horizontal and vertical wells in anisotropic formations under steady-state and pseudo-steady state conditions. Her approach is similar to that used by Muskat,[48] except that she neglected the flow restriction caused by the immobile water in the cone. Her analysis gives an optimistic estimate of the critical rate. The outcome of her comparison between vertical and horizontal wells showed that horizontal wells allow a higher critical rate than vertical wells which decreases as the anisotropy increases. She also pointed out that critical cones are closer to horizontal wells than to vertical wells.

Yang and Wattenbarger[45] also analyzed water coning for vertical and horizontal wells and addressed the issue of water-oil ratio (WOR). Their studies aimed at developing a method to predict critical rate, breakthrough time and water-oil ratio after breakthrough in both vertical and horizontal wells. They used a numerical simulator to perform an extensive sensitivity analysis of water coning to develop an empirical coning correlation based on flow equations and regression analysis. Empirical correlations were also developed by Schols[46] from his laboratory experiments and by Høyland, Papatzacos and Skjaeveland[47] from their computer simulation runs. For onshore oil operations, the Abu-Dhabi Co.[51] developed a finite element model to predict the performance of horizontal wells and their effectiveness in reducing or eliminating water coning. Their results showed a reduction of water cuts from 40 to 1 percent and a significant increase in well productivity.

2.4.4 High Performance in Low Permeability and Fractured Reservoirs

The development of horizontal well technology provides an efficient means to recover oil and gas from naturally fractured and tight reservoirs. Due to their extended length, horizontal wells provide a high probability of intersecting many fractures. Horizontal wells also provide a viable approach for tapping a low permeability reservoir that may have been considered noncommercial due to low production rates.[52-54] Because of the importance of horizontal wells to the petroleum industry, many studies, research projects and field tests[52-55] have been conducted to investigate their performance and predict their production, as well as the financial risks and challenges.

Guo and Evans[55] developed analytical single and multiphase pseudo-steady state inflow performance equations to predict the future production performance for a horizontal wellbore intersecting a multiple hydraulic fracture system. In their development, Guo and Evans considered the effect of permeability variations, wellbore location eccentricity and fracture characteristics. They also accounted for non-Darcy flow phenomena in the inflow equation associated with flow of the gas phase. Steady-state and pseudo-steady state inflow performance equations for horizontal wells in nonfractured reservoirs have been derived by several authors.[56-59] Moreover, several authors[57,60,61] have analytically or numerically investigated the effect of natural and induced fractures on horizontal well productivity and performance. A computer program[62] was developed to perform the production forecasting and economical evaluation of a naturally fractured reservoir for any natural fracture characteristics, horizontal well configuration and reservoir fluid properties.

2.5 Previous Work Performed Using this Model

Doan[63] and Doan, Farouq Ali and George[64] studied the effects of wellbore geometry and completion (open well versus cased well) on steam recovery performance using a combination of horizontal and vertical wells. A scaled model was developed based on scaling criteria derived using basic flow equations, viz continuity, momentum and heat balance equations, along with the Darcy law. Scaling criteria governing pressure, gravity, viscous and capillary forces, along with the scaling criteria describing heat transfer, permeability, porosity and geometrical factors, were used to produce a 10.2-cm diameter and 61-cm long scaled cylindrical model. This scaled model, along with another partially scaled model, was used to study the flow behavior in and around a horizontal wellbore surrounded by a steam envelope.

In Doan's study, 22 experiments were carried out using both the partially scaled and the scaled model. Table 2.1 provides a summary of the 22 experiments conducted. Experiments carried out using the scaled model satisfy the scaling criteria more than the experiments conducted in the partially scaled model, especially for scaling groups involving permeability and porosity. This is due to the fact that the scaled model was equipped with a hydraulic compacting system which produced a tight sand pack that satisfied the scaling criteria more than the partially scaled model.

In all of the nine experiments carried out using the partially scaled model, the injector was a vertical well and the producer was a horizontal well, taking different completion forms, such as a constant diameter horizontal producer with no casing, a variable diameter horizontal producer with no casing, a constant diameter horizontal producer cased in a perforated casing, and a variable diameter horizontal producer cased in a perforated casing. The experiments were conducted at an injection pressure of 448 kPa (65 psig) and the production pressure was set at 241 kPa (35 psig). The primary motive for these experiments was to investigate the effects of horizontal producer geometry and completion on oil recovery performance.

Table 2.1: Summary of Previous Experiments Performed Using this Model

Run Type	Model Type	Injector	Producer	Porosity %	Absolute k Darcy	Water Sat. %PV	Steam Inj. Rate ml/s (CWE)	Pore Volume ml	Steam Vol. Inj. %PV (CWE)	Cum. Oil Rec. %IOIP
PS3	Part.-Scaled	Vertical	C-D Hor., NC	38.1	17.7	7.5	0.11	1060.0	40.6	23.8
PS4	Part.-Scaled	Vertical	C-D Hor., NC	35.4	8.5	5.7	0.09	985.0	55.2	21.4
PS5	Part.-Scaled	Vertical	V-D Hor., NC	36.2	15.0	10.2	0.09	1007.0	39.7	25.9
PS5A	Part.-Scaled	Vertical	V-D Hor., NC	35.6	15.8	3.2	0.11	991.0	58.0	27.8
PS6	Part.-Scaled	Vertical	V-D Hor., NC	34.2	9.6	6.0	0.08	951.0	42.1	31.2
PS7	Part.-Scaled	Vertical	C-D Hor., WC	40.6	16.3	17.8	0.10	1129.0	47.7	21.5
PS8	Part.-Scaled	Vertical	C-D Hor., WC	40.4	14.3	13.0	0.12	1123.0	60.1	26.9
PS9	Part.-Scaled	Vertical	V-D Hor., WC	37.0	16.3	31.1	0.10	1030.0	48.5	30.2
PS10	Part.-Scaled	Vertical	V-D Hor., WC	38.6	15.8	11.9	0.10	1073.0	51.3	32.1
FS1	Scaled	Vertical	Vertical	44.8	4.4	11.9	0.03	1908.0	10.7	0.9
FS1R	Scaled	Vertical	Vertical (IC)	44.5	5.1	9.0	0.30	1895.0	14.0	7.3
FS2R	Scaled	Vertical	C-D Hor., NC	43.9	5.0	7.3	0.14	1868.0	82.9	56.1
FS3H	Scaled	Vertical	C-D Hor., WC(1)	41.0	5.2	8.8	0.07	1744.0	41.0	20.8
FS3R	Scaled	Vertical	C-D Hor., WC(1)	44.8	6.1	9.0	0.14	1907.0	75.8	52.4
FS4A	Scaled	Vertical	C-D Hor., WC(2)	42.4	6.6	10.8	0.15	1804.0	86.6	65.0
FS5H	Scaled	Vertical	V-D Hor., NC	42.6	4.9	7.0	0.07	1811.0	34.2	28.0
FS5A	Scaled	Vertical	V-D Hor., NC	44.0	6.7	8.3	0.17	1871.0	88.4	64.6
FS5R	Scaled	Vertical	V-D Hor., NC	36.9	6.9	8.9	0.14	1570.0	105.7	71.8
FS6	Scaled	Vertical	V-D Hor., WC(1)	45.1	7.2	8.3	0.13	1920.0	71.6	55.1
FS7	Scaled	Vertical	V-D Hor., WC(2)	44.2	6.7	8.0	0.12	1881.0	66.5	43.8
FS8	Scaled	C-D Hor., NC	V-D Hor., NC	41.5	5.5	6.7	0.44	1767.0	45.2	27.2
FS9	Scaled	C-D Hor., NC	Vertical	41.5	4.6	9.6	0.01	1765.0	3.7	3.0

Legend: IC - Injector In Communication with Producer
NC - With No Casing (Open Well)
WC(1) - With Perforated Casing (Pattern #1)
WC(2) - With Perforated Casing (Pattern #2)
C - D Hor. - Constant Diameter Horizontal Well
V - D Hor. - Variable Diameter Horizontal Well

The remaining 13 experiments were conducted using the scaled model. They were also intended to investigate the effects of wellbore geomctry and completion and to study the effectiveness of a horizontal injector when used in combination with either a horizontal or a vertical producer. The steam injection pressure for scaled the model experiments was set at 207 kPa (30 psig) and the production pressure was varied between 0 - 103 kPa (0 - 15 psig). Doan, from his experimental results, observed that the scaled model sand pack porosity and permeability were lower than that of the partially scaled model. He suggested that the primary reason for a lower permeability and porosity in the scaled model was due to the incorporation of the hydraulic press in the design of the scaled model which provided highly compacted sand packs.

Doan investigated the recovery performance of a horizontal producer versus that of a horizontal injector in combination with a vertical well. He also studied the recovery performance of a vertical injector versus a vertical producer in combination with a horizontal well. He observed that the production performance of a horizontal well is much higher than that of a vertical well. Horizontal producers outperform vertical producers in all aspects: lower water-oil ratio, higher cumulative oil-steam ratio, fluid production rate and cumulative oil recovery. The effect of wellbore geometry was also investigated in this work using a variable diameter horizontal producer.

The results showed that a variable diameter horizontal well, with a narrow inlet end and a wider production end, could effectively reduce the axial well pressure gradient and affect the recovery performance of the steamflood process significantly, yielding a higher oil recovery and oil-steam ratio than a constant diameter well. The recovery performance obtained using an open hole completion was compared to that obtained using a cased hole completion. Perforated casing decreased the production performance of the cased horizontal well. In most cases, it had a lower cumulative oil recovery, production rate, oil-steam ratio and thermal efficiency, which led to an inefficient recovery performance compared to that of an open hole completion.

3. Objectives

Horizontal wells are increasingly being used in steamflood projects. In nearly all cases, horizontal wells in Cold Lake and LIoydminster have been used as producers. Only in a few cases were they used as injectors. This experimental research was directed towards an investigation of fluid flow in the vicinity of a horizontal producer or injector, to study mechanisms governing flow during the steam injection process. The main objectives for the steam injection experiments can be summarized as follows:

1. To modify an existing scaled model to be used in the steam injection experiments, equipped for a horizontal steam injector or producer.
2. To design and fabricate new horizontal wells.
3. To investigate the effect of the horizontal producer and injector length, diameter and location on oil production performance.
4. To examine the effect of pressure differential between the horizontal injector and producer on the effectiveness of the steam injection process.
5. To study the effect of oil viscosity on oil recovery performance during steamflooding.
6. To observe the temperature distribution profile around the horizontal producer and injector to study the shape and size of steam zone and their effect on steam zone growth.
7. To explore and analyze scaling criteria for flow around a horizontal well.

4. Experimental Apparatus and Procedure

4.1 Experimental Apparatus

4.1.1 Physical Model

The physical model used in this work consisted of a 61.0 cm (24 in) by 10.2 cm (4 in) diameter stainless steel cylinder with two end caps as shown in Figure 4.1. A sintered metal jacket was fitted into the inside wall of the cylinder to act as a distributing phase for radial steam injection. For the purpose of sensing the steam front and detecting steam zone growth sixteen thermocouples ports were drilled through the wall of the cylinder. Since the model was placed in the horizontal direction during steam injection experiments, eight thermocouples were installed 5.72 cm (2.25 in) apart at different depths at the top of the model and another eight were installed at the bottom of the model exactly opposite to the top thermocouples. Two openings having a 1.6 cm (5/8 in) diameter were drilled at the top of the model and another two were drilled at the bottom at offset positions from those on the top. These holes could be used as injection or production ports, to simulate injection from the top, bottom, middle, or from one side of the core. The two end caps shown in Figure 4.2 were used to seal the model and provide a saturation face (saturation cap) and a production end to accommodate a horizontal well and a pressure port for pressure drop measurement inside the horizontal well (production cap). The physical model was placed inside a hydraulic press frame, shown in Plate 4.1, in the vertical direction to produce a highly representative permeability of the prototype. The hydraulic press was used to apply a force on the saturation end cap of the model simulating overburden pressure.

4.1.2 Porous Media and Fluids

Ottawa sand with a US mesh size of 70-140 was used in all of the experiments. The sand pack porosity produced using this sand ranged between 34 percent and 37 percent and the average absolute permeability was 6.4×10^{-12} m^2 (6.5 darcies), close to the prototype porosity and permeability.

Three types of oil were used to investigate the effect of oil viscosity on steam performance. Faxam-100 having a viscosity of 290 mPa.s was used for all experiments except those experiments aimed at investigating the effect of oil viscosity on the steam process performance, in which Wainwright oils having viscosities of 975

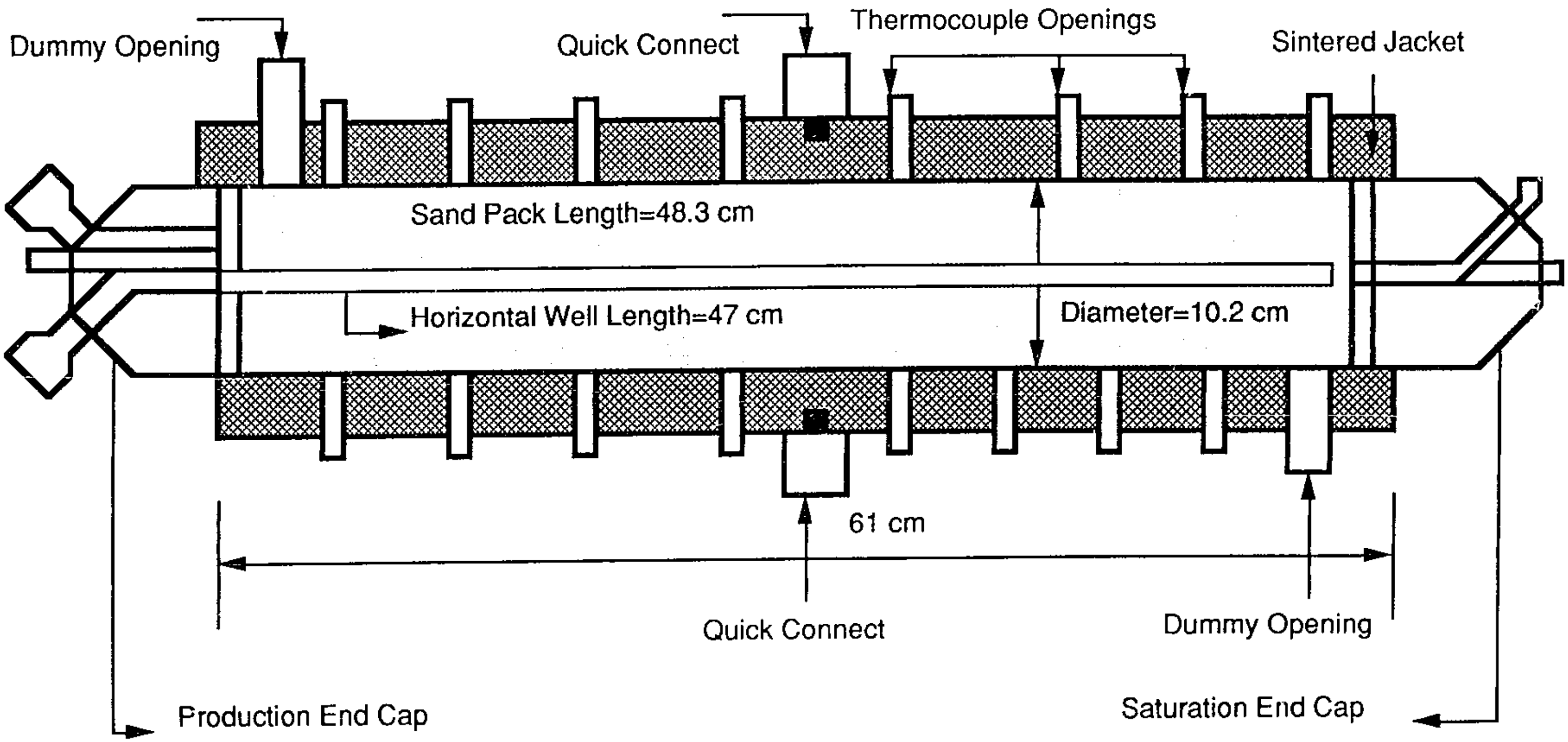


Figure 4.1: Cross-Sectional View of the Physical Model

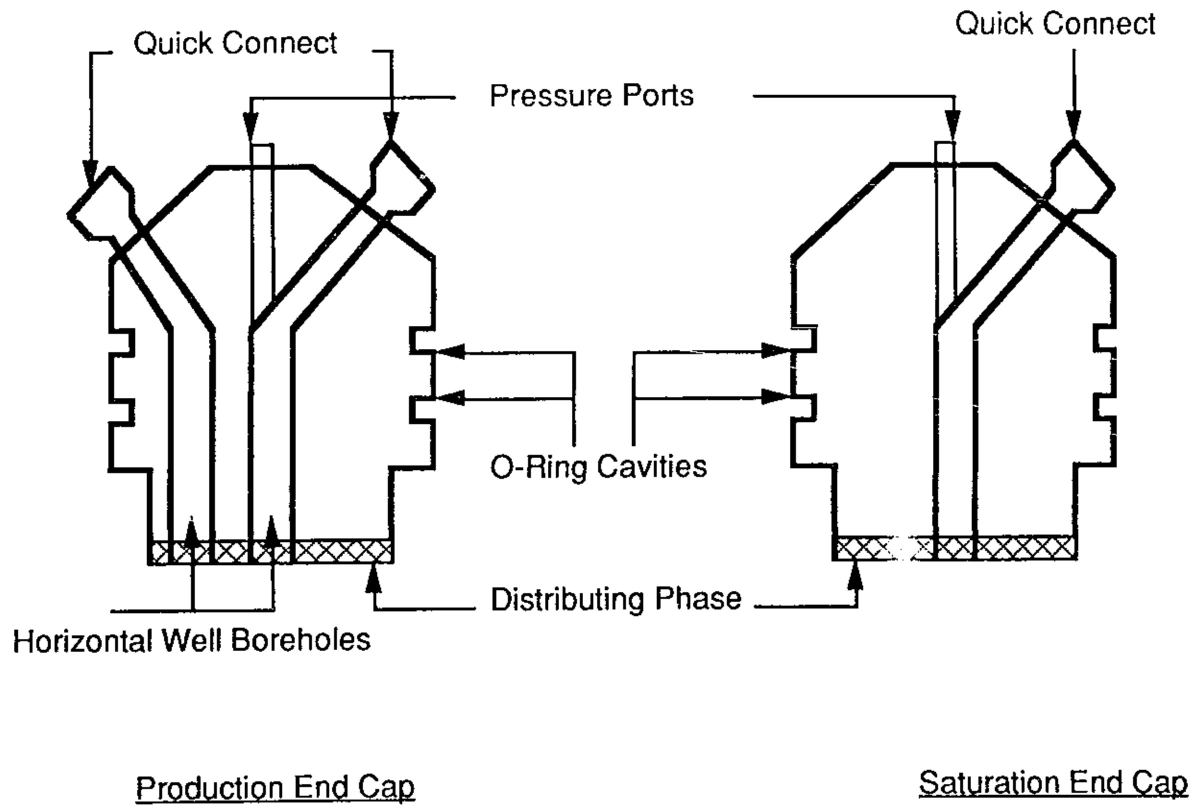


Figure 4.2: Cross-Sectional View of the Physical Model End Caps

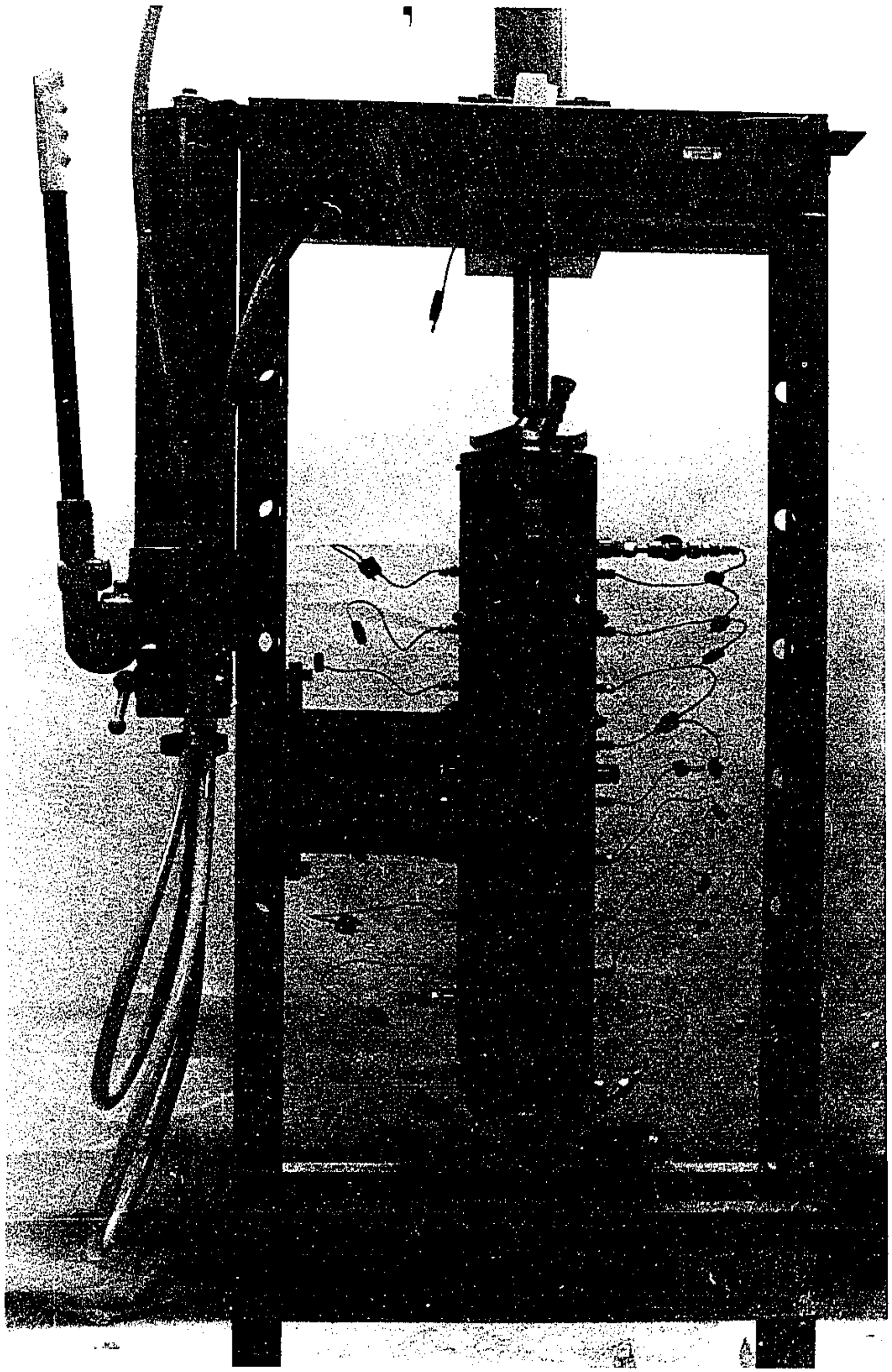


Plate 4.1 : The Model Inside a Hydraulic Press Frame

and 1800 mPa.s were used. Table 4.1 lists the API gravity, density and viscosity for the three types of oil used in this work.

Table 4.1: Properties of Oil Used

Oil Type	API @ 24 °C and 101.325 kPa	Viscosity @ 24 °C and 101.325 kPa	Density @ 24 °C and 101.325 kPa
Faxam-100	30	290 mPa.s	0.88 g/cc
Wainwright	18	975 mPa.s	0.95 g/cc
Wainwright	14	1800 mPa.s	0.97 g/cc

4.1.3 Horizontal Wells

One objective of this study was to investigate the effect of horizontal producer/injector length and diameter on steam process performance. Five wells were fabricated to simulate the horizontal producer/injector with different lengths and diameters. Wells having diameters of 0.32 cm (1/8 in), 0.64 cm (1/4 in) and 0.95 cm (3/8 in) were used to study the effect of the producer/injector diameter, and horizontal wells having lengths of 25, 50, 75 and 100% of the sand pack length were used to investigate the effect of producer/injector length on oil production performance during the steam injection process. Figure 4.3 shows a schematic representation of the horizontal wells used in this work.

4.1.4 Injection System

Good control of experimental conditions, i.e. injection pressure and temperature, is critical to any successful steam operation, whether it is in the laboratory or in the field. Injection temperature, to ensure that dry steam was injected, was maintained above the saturated steam temperature by means of a steam generator capable of producing steam up to a maximum temperature and pressure of 200 °C (392 °F) and 3.4 MPa (494 psi), respectively. A constant-rate Milroyal pump was used to pump water from the feedwater vessel into the steam generator and then steam from the steam generator into the injection tubing. The injection tubing was coupled with a thermocouple, a back pressure regulator, and a bypass valve to control injection temperature, pressure and direct steam overflow away from the sand pack.

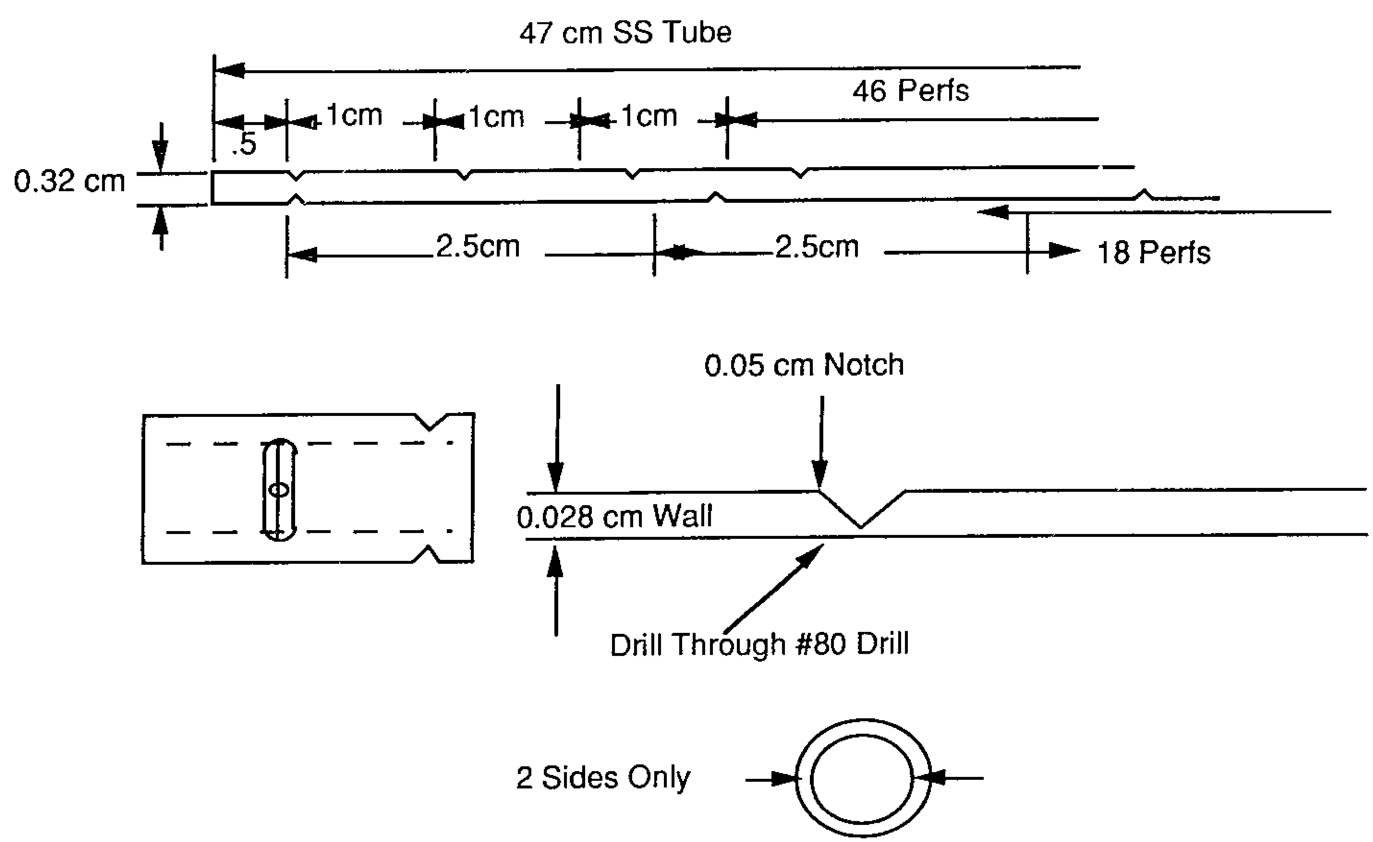


Figure 4.3: Schematic Representation of the Horizontal Wells (0.32, 0.64 and 0.95 cm Well Diameters were Used)

4.1.5 Production System

The collection system consisted of two cells made of temperature resistant glass. Each cell was capable of handling 250 cm^3 of produced fluid. The two cells were connected to a back pressure regulator regulated by nitrogen gas, to introduce a constant back pressure on the producer when needed. Another reason to have a pressurized production system was because produced fluids have high viscosity in the early stages of the experiment which reduces their flow out of the collection devices. Thus a back pressure was introduced to push the fluids out of the collection cells. However, towards the end of the experiment, produced fluid temperatures were very high (around steam saturation temperature), so a cooling system was installed to lower produced fluid temperatures and reduce the vapour lost through flashing.

4.1.6 Data Acquisition System

The data acquisition system used consisted of hardware and software systems. The hardware include 18 thermocouples connected into four EXP-16 boards and a pressure transducer connected into one 10-channel Validyne board. The temperature data were read using thermocouples and then transferred to the EXP-16 boards as electrical signals in millivolts. Unlike temperature, pressure data were read using pressure transducers, fed into the Validyne board, and then transferred to the EXP-16 boards in millivolts. The EXP-16 boards which were controlled by the Labtech Notebook software converted the pressure and temperature raw data from millivolts to values of pressure in Pascals and temperature in degrees Celsius, and then fed it into the IBM computer through a Das-8 card. The Labtech Notebook scanned each pressure and temperature channel every thirty seconds. Scanned temperature and pressure data were stored in an ASCII file format which allowed it to be analyzed in LOTUS 123 or Microsoft Excel.

4.2 Model Preparation

The type of experiment, experimental conditions (i.e. injection pressure and temperature), and experimental parameters to be investigated were determined before packing the model. Thermocouples and pressure transducers were calibrated and checked for any fault or unreliable readings. Also, quick connects, connections, tubing and production and saturation end caps were cleaned and tested for any blockage.

4.2.1 Packing Procedure

After a decision was made on the type of experiment to be carried out, the model, with its production cap and horizontal well installed, was positioned vertically in the core holder. The model was filled with water and then the saturation cap was installed. The volume of water inside the model, corrected for water volume inside the well, thermocouples, connections and quick connects, was the bulk volume. After the bulk volume was determined, the saturation end cap and some of the water was removed from the model and a mechanical vibrator was strapped onto the core. The vibrator was turned on to start vibrating the model while it was filled with Ottawa sand. The reason for vibrating and using water in the model while filling it with sand was to create a well sorted uniform packing. It was believed that using water and vibration helped sand particles settle and distribute evenly.

The model was vibrated for several hours, then the saturation end cap was installed and the model was positioned inside a hydraulic press designed to mechanically apply a 3500-lb force on the saturation end cap to create a tight sand pack. The sand pack was dried for 16 hours by passing high pressure (0.5 MPa/75 psig) air through the core. Then a vacuum was drawn for five hours to further remove any moisture remaining in the sand by means of evaporation and to prepare the core for a pore volume measurement. For a pore volume measurement, the core was positioned vertically, water was introduced into the bottom of the core and pulled upward towards the saturation end cap by means of a vacuum. The volume of water imbibed by the sand pack was the pore volume. Water was introduced at the bottom of the sand pack and sucked upward against gravity, to create a stable and uniform water saturation and accurate pore volume measurement.

Unlike the pore volume measurement, in the permeability measurement, the core was positioned horizontally and water was injected at the saturation phase and produced from the production end cap. A stream of water was injected into the sand pack at several pressure differentials, left to stabilize, and then a corresponding flow rate reading was taken for each pressure differential. The Darcy law for linear flow was rearranged and used to calculate absolute permeability for each pressure drop.

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

Given that

$L = 0.483$ m (Length of the sand pack)

$\mu = 1.0$ mPa.s (Water viscosity at 24°C and 101.325 kPa)

$A = 0.0082$ m^2 (Cross-sectional area of the sand pack)

$q = m^3/s$ (Water flow rate)

Δp = kPa (Pressure difference)

$k = m^2$ (Axial permeability)

then,

$$k = \frac{58.9204\ q}{\Delta p}$$

The absolute axial permeability of the sand pack for a particular run, was the arithmetic average of all permeability readings obtained for different pressure settings. A point to note is that the axial permeability of the sand pack is different from the radial permeability. The difference in permeabilities is a result of the 3500 lb compression force applied on the saturation end cap of the sand pack. Because the model was used for radial flow, it would be worth the effort to measure the radial permeability rather than the axial permeability.

In this work the permeability was measured only for the first nine runs. Since the same force, (3500 lb_f), was applied to each sand pack, it was thought that more or less the same permeability values would be obtained. For this reason an average permeability of the nine runs was used for the rest of the experiments.

4.2.2 Saturation Process

Special care was taken during the saturation of the sand pack with oil. The model was positioned in the vertical direction; the oil vessel and saturation lines were air free and full of oil, and the pump was turned on and oil circulated for at least 15 minutes to purge any gas trapped in the system. Then the saturation line was connected to the saturation face at the top of the sand pack, and water was drained from the bottom of the sand pack at atmospheric pressure. During the saturation process, oil was injected at a low rate at the top of the sand pack to displace water downward in a uniform and stable displacement achieving as high oil saturation as possible. The saturation process was terminated after oil breakthrough at the production end. The volume of oil injected into the sand pack at the end of the saturation process was the initial oil in place (IOIP). The initial water saturation was determined simply by dividing the volume of water which remained in the sand pack after it was flooded with oil by the pore volume. At the end of the saturation process the sand pack was at atmospheric pressure. However, to conduct an experiment, the sand pack had to be pressurized to the experimental pressure. Thus, the sand pack pressure was raised from zero to 345 kPa (50 psig) for experiments where a horizontal injector was used and to 276 kPa (40 psig) where a horizontal injector was used.

Water was used to pressurize the sand pack and minimize the effect of pressurizing the model on the initial sand pack oil and water saturations. In addition, a simple calculation (Appendix A) was made to determine the volume of water injected to pressurize the sand pack up to the experimental pressure. The compressibility of the water, sand and the cylinder is assumed to be negligible. To be on the conservative side, even though water was injected into the sand pack to raise the pressure, a compressibility of 3.626×10^{-6} kPa^{-1} for high gravity oil was used to calculate the volume of water injected to pressurize the system. From the calculation, the volume of water injected to increase the sand pack pressure was calculated to be 1.79 cm^3, which was even less than the amount of water in the end caps. From this simple calculation, it was proved that using water to pressurize the sand pack to the experimental pressure has a minimal effect on the initial oil and water saturations of the sand pack. The sand pack pressure was increased to experimental pressure for the run to commence.

4.3 Typical Run Procedure

After the sand pack bulk and pore volumes, initial oil and water saturations and permeability were determined and recorded, the model was positioned in the horizontal direction, as shown in Plate 4.2. The production system was connected to the sand pack, and the model was pressurized to experimental pressure and checked for leaks. At the injection end, the steam generator and the feedwater pump were turned on. The injection pressure was set to the desired injection pressure by means of a back pressure regulator and monitored by a pressure gauge. The injection temperature was set to the desired temperature and monitored, along with model temperatures, by the data acquisition system. The steam generator had to be turned on at least 60 minutes before

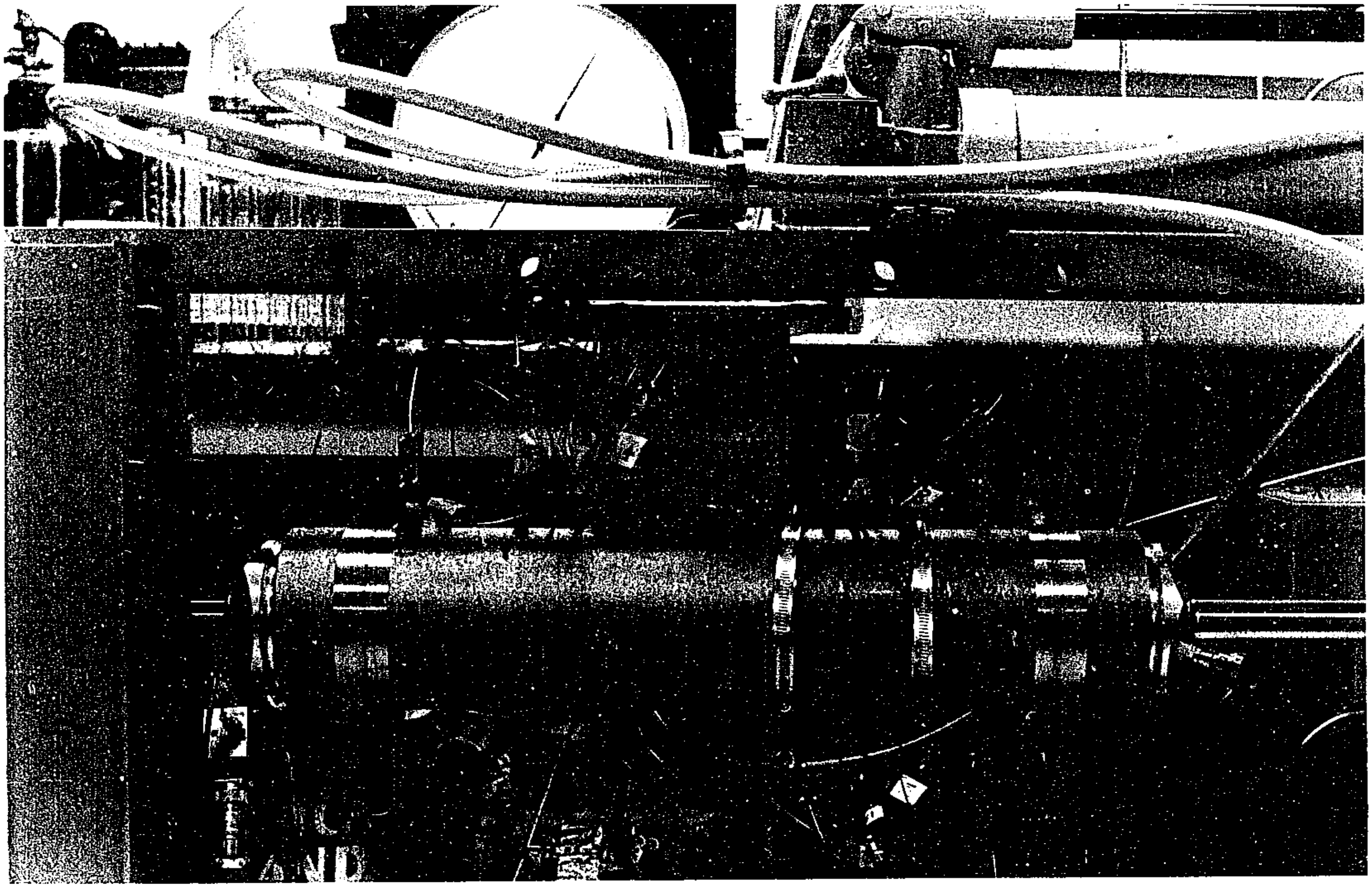


Plate 4.2 : The Model Set-up for an Experiment

starting the experiment to produce stable steam pressure and temperature. The feedwater vessel was filled, and the initial volume was recorded, the data acquisition system was restarted, the injection tubing was connected to the sand pack, and the production valve was opened marking the start of the experiment.

Depending on the type of experiment, either the injection pressure or the injection rate was maintained constant. Production pressure was always constant. The steam injection temperature is a function of the steam injection pressure. During constant pressure experiments, the injection pressure was regulated using a back pressure regulator and the injection temperature was almost constant. However during constant rate experiments, the injection pressure decreased as the experiment progressed. For experiments where a horizontal producer was used steam was radially injected either from the top or bottom of the sand pack and for those where a horizontal injector was used steam was injected via the horizontal well.

A typical time for an experiment was about 120 minutes, except for those experiments with high fluid viscosity which lasted for 180 minutes. Production fluids were collected at a predetermined volume (i.e. 200 cm^3) interval, and an emulsion breaker was added to speed separation of produced water from the oil. The experiment was terminated after injecting at least one pore volume of steam (CWE). The produced fluids were stored in 250 cm^3 cylinders and left over a 40 hour period for the water to settle and separate from the oil. A schematic overview of the experimental apparatus is shown in Figure 4.4.

4.3.1 Data Analysis

Upon completion of an experiment, the temperature data were stored in a binary file using a Labtech Notebook program, then processed using LOTUS 123 and Microsoft Excel. A commercial contouring package (SURFER) was used to produce the temperature distribution profile for steam inside the sand pack using temperature data gathered from different thermocouples at various locations and times to sense heat front movement through the sand pack.

Produced fluids were analyzed by recording the volume of oil and water produced, along with the elapsed time for each sample and the total volume of steam injected. Volume data were input on a spreadsheet and manipulated for graphical presentation. The following variables were then plotted as a function of the cumulative

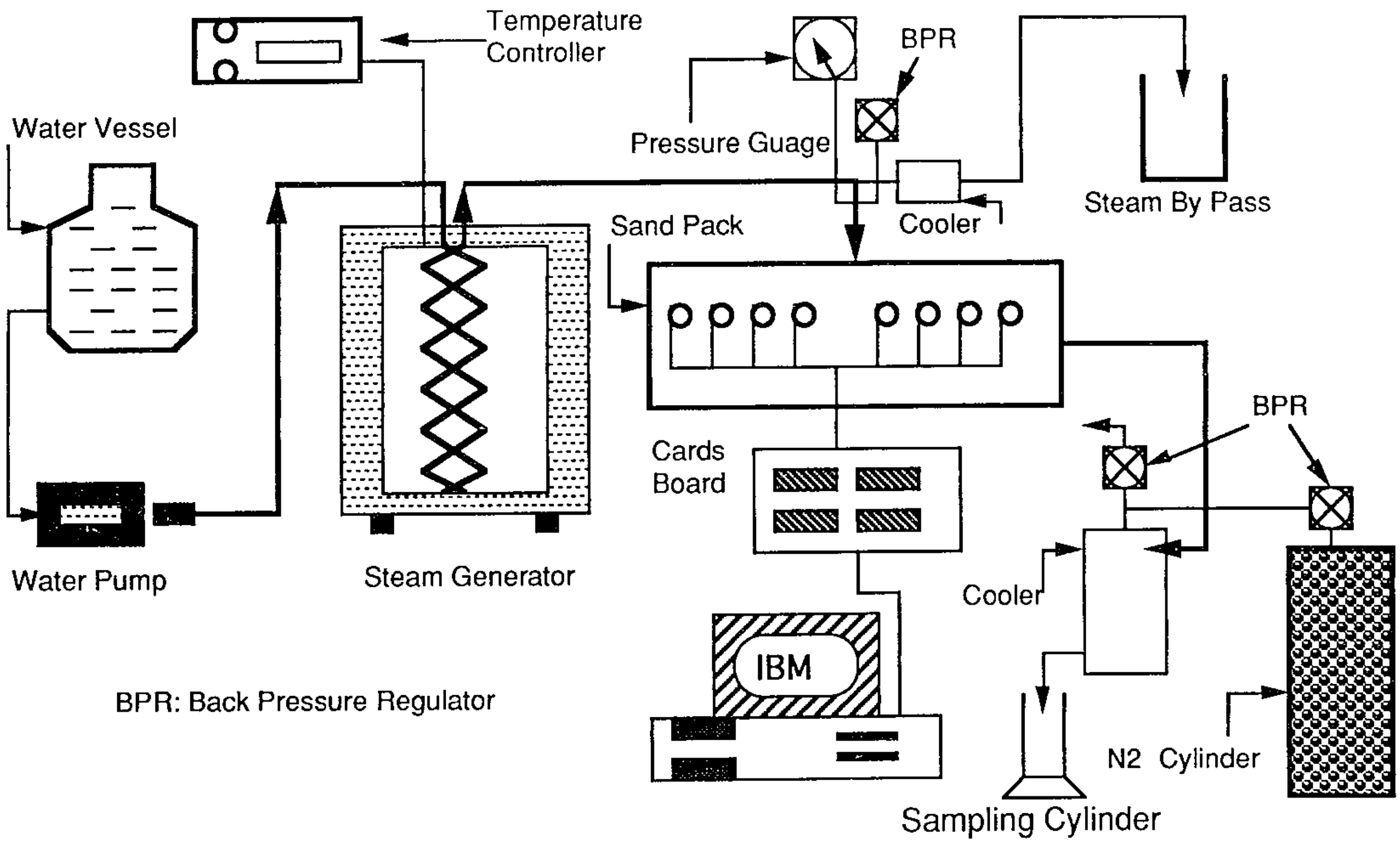


Figure 4.4: Schematic Overview of the Experimental Apparatus

steam volume injected (PV); the cumulative oil recovery, the cumulative oil-steam ratio (OSR), the water-oil ratio (WOR) and the oil rate.

4.3.2 Experimental Errors

Experimental errors are important factors in evaluating the reliability and accuracy of experimental data. Instrument accuracy and operational errors, depending on their magnitude, not only cause undesirable disturbances during the data gathering process, but may lead to an unexpected conclusion.

Most of the experimental errors in this study are a result of instrument accuracy range. Some errors are introduced to pore volume measurement, injection pressure and temperature, production pressure and temperature and permeability readings. A HEISE pressure gauge with ± 0.1% of full range accuracy was used to measure the injection pressure. Errors are introduced to pore volume measurement. It was difficult to accurately measure the amount of water stored in the model end caps, horizontal well and quick connects. J type thermocouples with ± 3 °C accuracy were installed at top and bottom of the sand pack to sense the steam front movement inside the sand pack.

Another source of error that may affect the properties of the sand pack is the thermocouples. Sand packing around thermocouples is looser and not like the rest of the pack. Uneven particle distribution may affect the sand pack porosity and permeability.

An effort was made to predict approximately steam breakthrough using production pressure and temperature. Due to production thermocouple accuracy, thirty second time gaps in scanning the data and most important the location of the thermocouple being out side the horizontal well, steam breakthrough prediction using pressure and temperature at the production end cap is not very reliable.

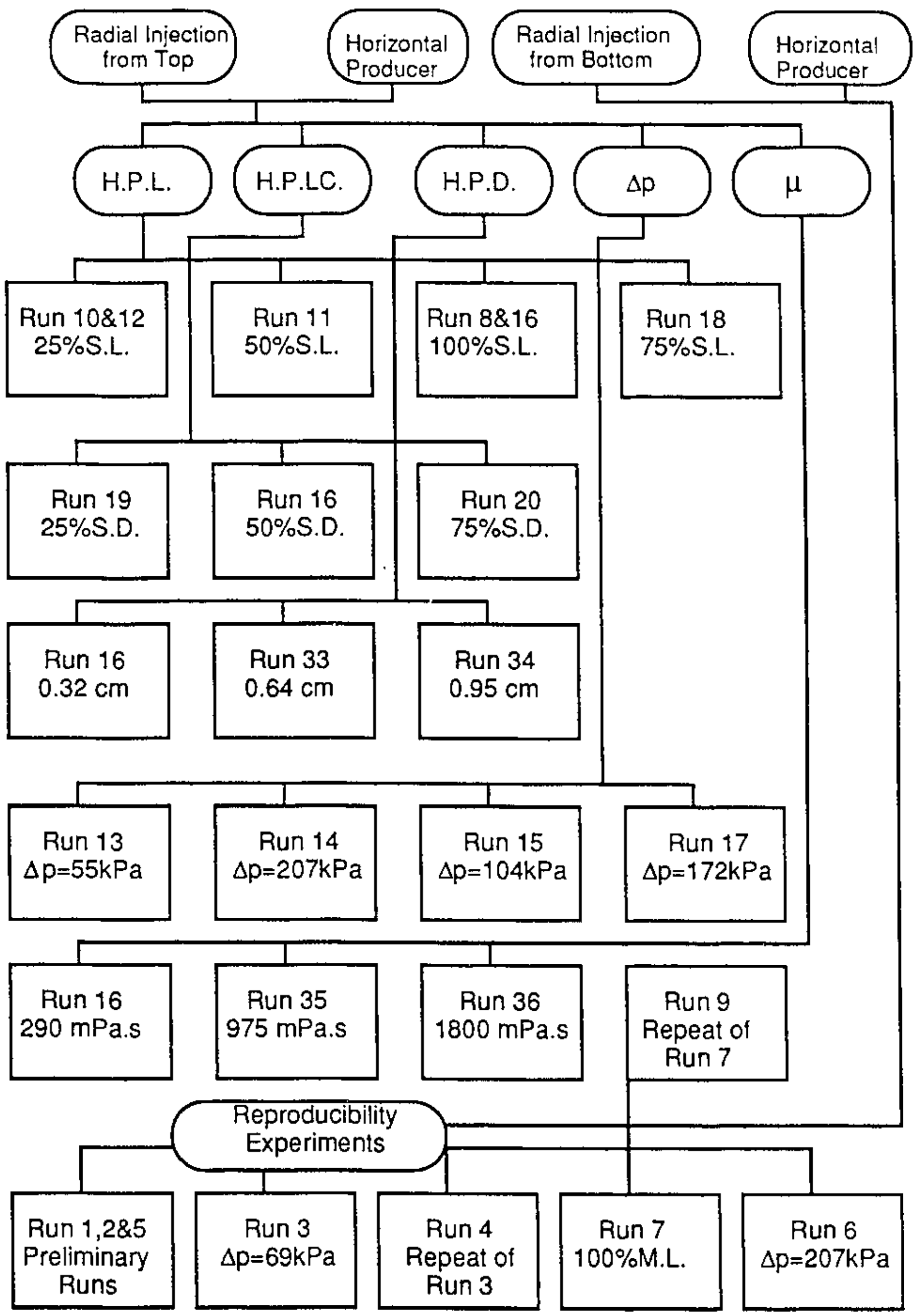
5. Discussion of Results

This study was directed towards an investigation of fluid flow in the vicinity of a horizontal injection or production well during steam injection. The study was divided into two phases: theoretical and experimental. The theoretical phase was aimed at the dimensionless group analysis which describes different mechanisms taking place during steam injection processes. The experimental phase of the study investigated the effect of horizontal producer or injector length, diameter, and vertical location in the sand pack on oil production performance. The effect of fluid properties such as oil viscosity along with the pressure drawdown on oil recovery process was also investigated in this phase.

5.1 Presentation of Results

Steam injection experiments for this research were conducted using a 61.0 by 10.2 cm diameter cylindrical model. The experiments were divided into three types based on the steam injection point. For experiments aimed at studying the effect of a horizontal producer on oil recovery performance, steam was injected radially from the top of the sand pack for top injection and from the bottom for bottom injection experiments; and oil was produced through the horizontal producer. For those experiments aimed at studying the effect of a horizontal injector, steam was injected using a horizontal injector, and oil was produced radially from the bottom of the sand pack. Thirty-six experiments were conducted using a volumetrically scaled model and horizontal wells.

Figures 5.1 and 5.2 schematically illustrate the steamflooding experiments performed in this research. Table 5.1 summarizes the oil recovery results and the pertinent sand pack initial properties, such as porosity and saturation for oil and water for the experiments conducted in this work. In all experiments, steam was injected into the sand pack for more than one pore volume, but data for only one pore volume was used in the analysis. The experimental results are discussed for each run by analyzing both the production data and the temperature profiles for the steam inside the sand pack. Production data for each experiment were compared with the results of a base case experiment to examine the effects of the recovery strategy under investigation. Temperature data were collected from different thermocouples during the steam injection experiment and used to generate a contour map of the temperature profile

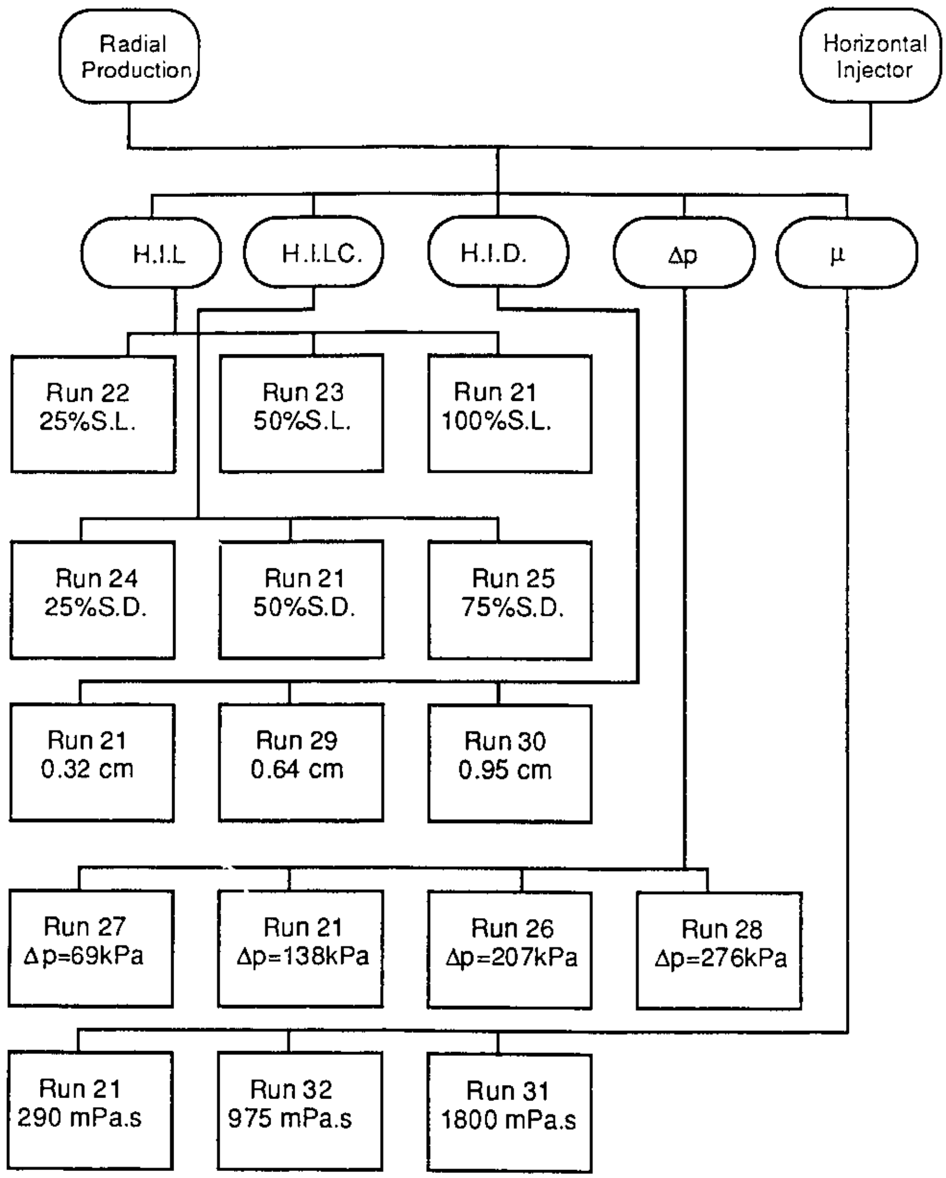


Legend:

H.P.L. - Horizontal Producer Length
H.P.LC. - Horizontal Producer Location
H.P.D. - Horizontal Producer Diameter
S.L. - Sand Pack Length
S.D. - Sand Pack Diameter

Δp: Pressure Differential Between Injector and Producer
μ - Oil of Viscosity 290 mPa.s was used for all runs Except in Runs 35 and 36 it was 975 and 1800 mPa.s, Respectively

Figure 5.1: Overview of Experiments Using a Horizontal Producer



Legend:

H.I.L. - Horizontal Injector Length
H.I.LC. - Horizontal Injector Location
H.I.D.: Horizontal Injector Diameter
S.L. - Sand Pack Length
S.D. - Sand Pack Diameterr

Δp - Pressure Drop Between Injector and Producer
μ - Oil of Viscosity 290 mPa.s was used for all runs Except Runs 31 and 32 it was 1800 and 975 mPa.s, Respectivelly

Figure 5.2: Overview of Experiments Using a Horizontal Injector

Table 5.1: Summary of Experiments Conducted in the Research

Run No.	Run Type	Ø %	Soi %PV	Swi %PV	Steam Injected (PV)	Oil Recovery %IOIP
1	Radial Injection from Bottom in Combination with a Horizontal Producer (Preliminary)	32.6	93.0	7.0	0.83	50.3
2	Radial Injection from Bottom and Δp of 138 kPa Using a Hor. Producer (Preliminary)	32.6	94.7	5.3	0.96	60.3
3	Radial Injection from Bottom and Δp of 69 kPa Using a Hor. Producer	33.0	92.3	7.7	0.99	56.2
4	Repeat of Run 3 for Reproducibility of Results	31.8	94.3	5.7	1.15	55.0
5	Radial Injection from Bottom in Combination with a Horizontal Producer (Preliminary)	32.8	91.4	8.6	0.76	67.0
6	Radial Injection from Bottom and Δp of 207 kPa Using a Hor. Producer	33.6	93.4	6.3	0.99	70.6
7	Radial Injection from Bottom and Hor. Prod. Penetrating 100% of the Sand Pack Length	33.1	92.4	7.6	1.04	67.1
8	Radial Injection from Top and Hor. Prod. Penetrating 100% of the Sand Pack Length (Bad Run)	34.5	91.2	8.8	1.20	74.1
9	Repeat of Run 7 for Reproducibility of Results	37.7	90.9	9.1	1.18	68.1
10	Radial Injection from Top and Hor. Prod. Penetrating 25% of the Sand Pack Length. (Bad Run)	37.7	90.9	9.1	1.04	54.3
11	Radial Injection from Top and Hor. Prod. Penetrating 50% of the Sand Pack Length	37.7	93.2	6.8	1.17	65.8
12	Radial Injection from Top and Hor. Prod. Penetrating 25% of the Sand Pack Length	37.6	89.9	10.1	1.15	76.5
13	Radial Injection from Top and Δp of 55 kPa Using a Hor. Producer	38.5	90.8	9.2	1.21	72.2
14	Radial Injection from Top and Δp of 207 kPa Using a Hor. Producer	39.9	89.9	10.1	1.12	73.9
15	Radial Injection from Top and Δp of 104 kPa Using a Hor. Producer	37.4	92.9	7.1	1.12	74.3
16	Radial Injection from Top and Hor. Prod. Penetrating 100% of the Sand Pack Length	35.4	95.9	4.1	1.07	81.0
17	Radial Injection from Top and Δp of 172 kPa Using a Hor. Producer	35.8	89.1	10.9	1.16	76.1
18	Radial Injection from Top and Hor. Prod. Penetrating 75% of the Sand Pack Length	38.1	91.8	8.2	1.33	75.0

Table 5.1 - Continued

19	Radial Injection from Top and Hor. Prod. Located 0.25D from the Sand Pack Upper Boundary	35.8	93.8	6.2	1.35	69.6
20	Radial Injection from Top and Hor. Prod. Located 0.75D from the Sand Pack Upper Boundary	38.1	90.1	9.9	1.19	61.1
21	Radial Production from Bottom and Hor. Inj. Penetrating 100% of the Sand Pack Length	35.6	89.7	10.3	1.24	66.3
22	Radial Production from Bottom and Hor. Inj. Penetrating 25% of the Sand Pack Length	35.8	90.7	9.3	1.23	55.1
23	Radial Production from Bottom and Hor. Inj. Penetrating 50% of the Sand Pack Length	35.0	89.9	10.2	1.28	61.0
24	Radial Production from Bottom and Hor. Inj. Located 0.75D from the Sand Pack Upper Boundary	35.0	90.4	9.6	1.36	56.3
25	Radial Production from Bottom and Hor. Inj. Located 0.25D from the Sand Pack Upper Boundary	34.5	90.3	9.7	1.29	60.1
26	Radial Production from Bottom and Δp of 207 kPa Using a Hor. Injector	35.8	89.4	10.6	1.14	67.2
27	Radial Production from Bottom and Δp of 69 kPa Using a Hor. Injector	34.5	91.6	8.4	1.26	68.1
28	Radial Production from Bottom and Δp of 276 kPa Using a Hor. Injector	34.6	89.4	10.6	1.23	58.2
29	Radial Production from Bottom and 0.64-cm Hor. Injector	35.0	91.1	8.9	1.22	65.3
30	Radial Production from Bottom and 0.95-cm Hor. Injector	35.3	89.5	10.5	1.19	75.9
31	Radial Production from Bottom and Oil of Viscosity 1800 mPa.s Using a Hor. Inj.	35.0	87.3	12.7	1.37	45.3
32	Radial Production from Bottom and Oil of Viscosity 975 mPa.s Using a Hor. Inj.	36.1	86.4	13.6	1.14	76.1
33	Radial Injection from Top and 0.64-cm Hor. Producer	36.1	94.4	5.6	1.09	63.3
34	Radial Injection from Top and 0.95-cm Hor. Producer	35.0	92.4	7.6	1.16	69.9
35	Radial Injection from Top and Oil of Viscosity 975 mPa.s Using a Hor. Prod.	34.8	97.1	2.9	1.29	74
36	Radial Injection from Top and Oil of Viscosity 1800 mPa.s Using a Hor. Prod.	36.0	92.9	7.1	1.26	47.8

Legend:

Hor. Prod. - Horizontal Producer   D - Diameter

Hor. Inj. - Horizontal Injector Δp - Pressure Differential inside the sand pack. The temperature distribution contours generated using a contouring software package (SURFER) enabled visual inspection of the steam zone growth and steam front advance during an experiment. The following sections will discuss in detail the objectives of each run.

5.2 Horizontal Producer and Radial Injection from Top

In this set of experiments, steam was injected radially from the top of the sand pack into the sintered metal jacket used as a distributor for the injected steam to enter the sand pack radially, and oil was produced through the horizontal well. The main objective of these experiments was to study the horizontal producer length, diameter and vertical location effect on steam drive performance. Moreover, some experiments were directed to investigate the effect of pressure drop between the injector and producer and to examine the oil viscosity effect on the oil recovery process using a horizontal producer.

5.2.1 Production History of a Typical Run

The main objective of this set of experiments was to study oil production performance using a horizontal producer during steam injection. Twelve experiments were carried out to investigate the effect of the horizontal producer length, diameter and location on steam injection performance. Run 16 was the base case for all steamflood experiments in which the horizontal producer was used; thus, it will be discussed and analyzed in detail. The experiment was conducted using a horizontal producer positioned at the center and penetrating 100% of the sand pack length. It was carried out in a homogenous and anisotropic sand pack with an average axial permeability of 6.4×10^{-12} m^2 (6.5 darcies), a measured porosity of 35.4% and an initial oil saturation of 95.9% . Steam was injected radially from the top of the sand pack at a constant rate of 0.34 cc/s of steam (CWE) and the injection pressure and temperature were 276 kPa (40 psig) and 142 °C (288 °F), respectively. Since most of the sand pack was at steam saturation temperature after the injection of approximately one PV of steam (CWE), this experiment, as with most other experiments, was terminated at that point. Moreover, at this point, the water cut was becoming very high, and the production data did not show any significant changes to warrant continuation.

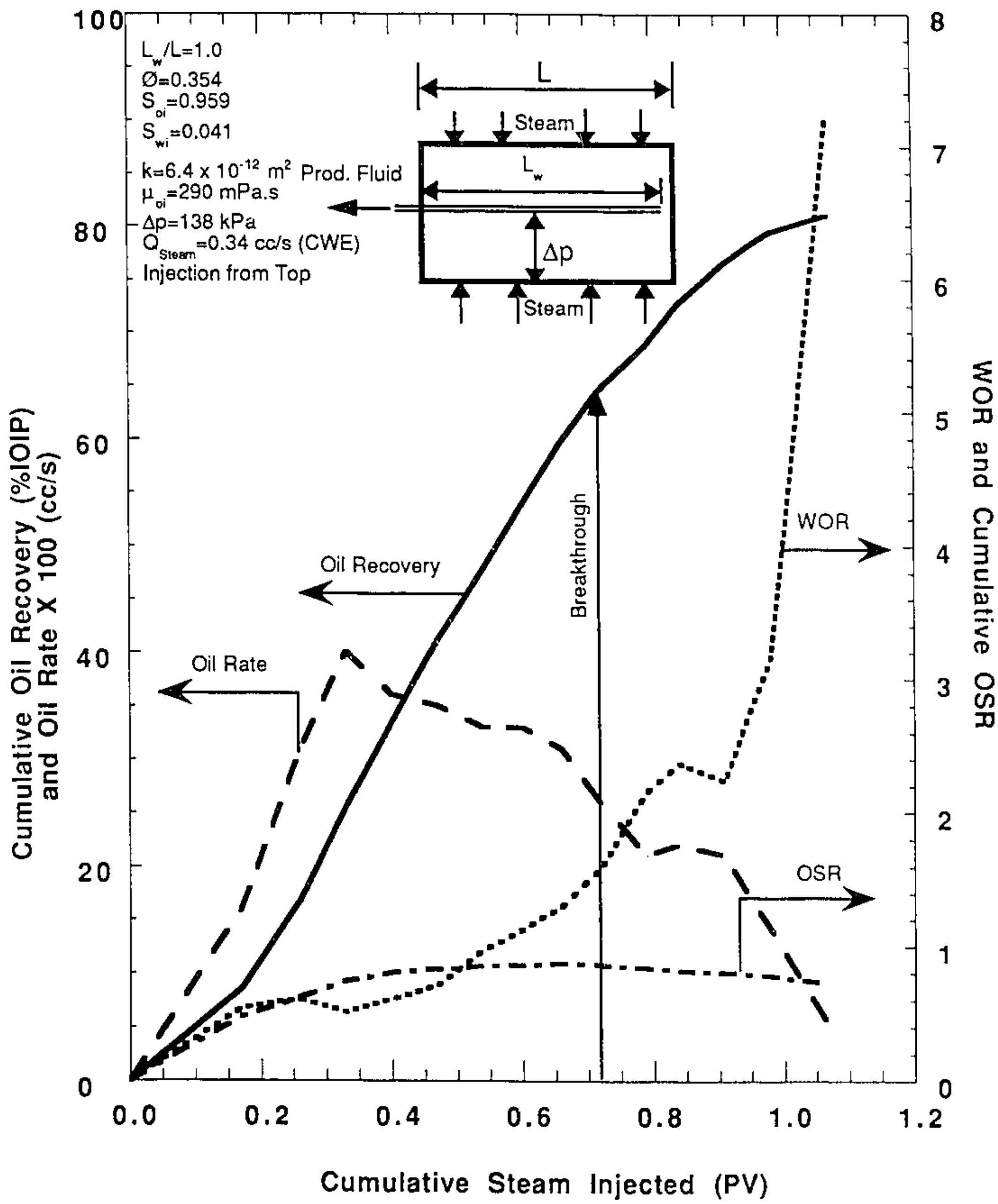
Table 5.2 presents the experimental and production data used to draw Figure 5.3, which graphically illustrates the production history of Run 16. In this

Table 5.2 - Run 16: Horizontal Producer Penetrating 100% of the Sand Pack Length

Bulk Volume:	4492 cc	Initial Oil Saturation:	95.9 %PV
Pore Volume:	1592 cc	Initial Water Saturation :	4.1 %PV
HC Pore Volume:	1527 cc	Type of Oil Used:	Faxam-100
Porosity:	35.4%	Oil Viscosity @ 24 °C and101 kPa:	290 mPa . s
Average Absolute Permeability :	6.4 x 10^-12 m^2 (6.5 darcies)	API Gravity @ 24 °C and101 kPa:	30 °API
Average Steam Injection Rate:	0.34 cc/s (CWE)	Production Pressure:	138 kPa
Net Oil Recovery:	**81.0%**	**Total Steam Injected:**	**1703 cc**

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	13.27	271	0.17	200	130	130	8.5	0.16	0.54	0.48
2	6.87	411	0.26	202	126	256	16.8	0.31	0.60	0.62
3	5.55	524	0.33	201	133	389	25.5	0.40	0.51	0.74
4	5.70	640	0.40	198	123	512	33.5	0.36	0.61	0.80
5	5.57	754	0.47	198	116	628	41.1	0.35	0.71	0.83
6	5.12	858	0.54	199	101	729	47.7	0.33	0.97	0.85
7	4.77	955	0.60	200	94	823	53.9	0.33	1.13	0.86
8	4.78	1053	0.66	202	88	911	59.7	0.31	1.30	0.87
9	4.93	1154	0.72	196	76	987	64.6	0.26	1.58	0.86
10	4.85	1253	0.79	196	62	1049	68.7	0.21	2.16	0.84
11	4.53	1345	0.84	199	59	1108	72.6	0.22	2.37	0.82
12	4.77	1442	0.91	191	59	1167	76.4	0.21	2.24	0.81
13	5.48	1554	0.98	192	46	1213	79.4	0.14	3.17	0.78
14	7.28	1703	1.07	198	24	1237	81.0	0.05	7.25	0.73

Figure 5.3 - Production History of Run 16: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected Using a Horizontal Producer Penetrating 100% of the Sand Pack Length



figure, cumulative oil recovery (%IOIP), cumulative oil-steam ratio (OSR), oil rate and water-oil ratio (WOR) were plotted against cumulative steam injected (PV) (CWE). There was no production the instant the injection started. That was because steam is a condensable fluid and it took some time to heat and mobilize the oil. Furthermore, at the beginning of the experiment, most of the steam energy was dissipated in heating the sand pack and oil around the injection port and only a small portion of the steam was used to push the oil toward the producer. A close examination of the water-oil ratio curve shows that water was produced shortly after the start of the experiment.

In some experiments, the water-oil ratio was high at the beginning of the experiment, then next decreased and remained constant as the experiment progressed, and then increased after steam breakthrough. This behaviour in the water-oil ratio curve was caused by the oil saturation process during preparation of the sand pack. When the sand pack was saturated with oil, it was positioned vertically, oil was injected at the upper end of the sand pack, and water was drawn at atmospheric pressure from the bottom end (production end). However, water was not completely swept out of the sand pack by the end of the oil saturation process, so that the remaining water concentrated near the production end, and, as the experiment started, a high volume of water was produced initially. Since most of the unswept water left from the saturation process concentrated around the production end, it was produced before the oil, giving a high initial water-oil ratio which decreased and stabilized as the experiment progressed until it reached the breakthrough point, at which time the water-oil ratio increased sharply due to the incursion of steam condensate. The oil rate curve followed an expected trend, starting with a positive slope and decreasing shortly after steam breakthrough.

One observation is that, when the oil rate started decreasing, the water-oil ratio started increasing to a point at which the water-oil ratio was high, indicating a high production of water. The oil-steam ratio was always less than one; it reached a maximum at about 0.66 PV. At the beginning of the experiment, most of the steam was consumed in generating the steam zone and heating the oil ahead of the steam front, and only a minute amount was spent mobilizing and producing the oil. That was one reason the oil-steam ratio was low at the start of the experiment. However, as the experiment progressed, the steam zone started growing, transporting the heat that mobilized and produced the oil.

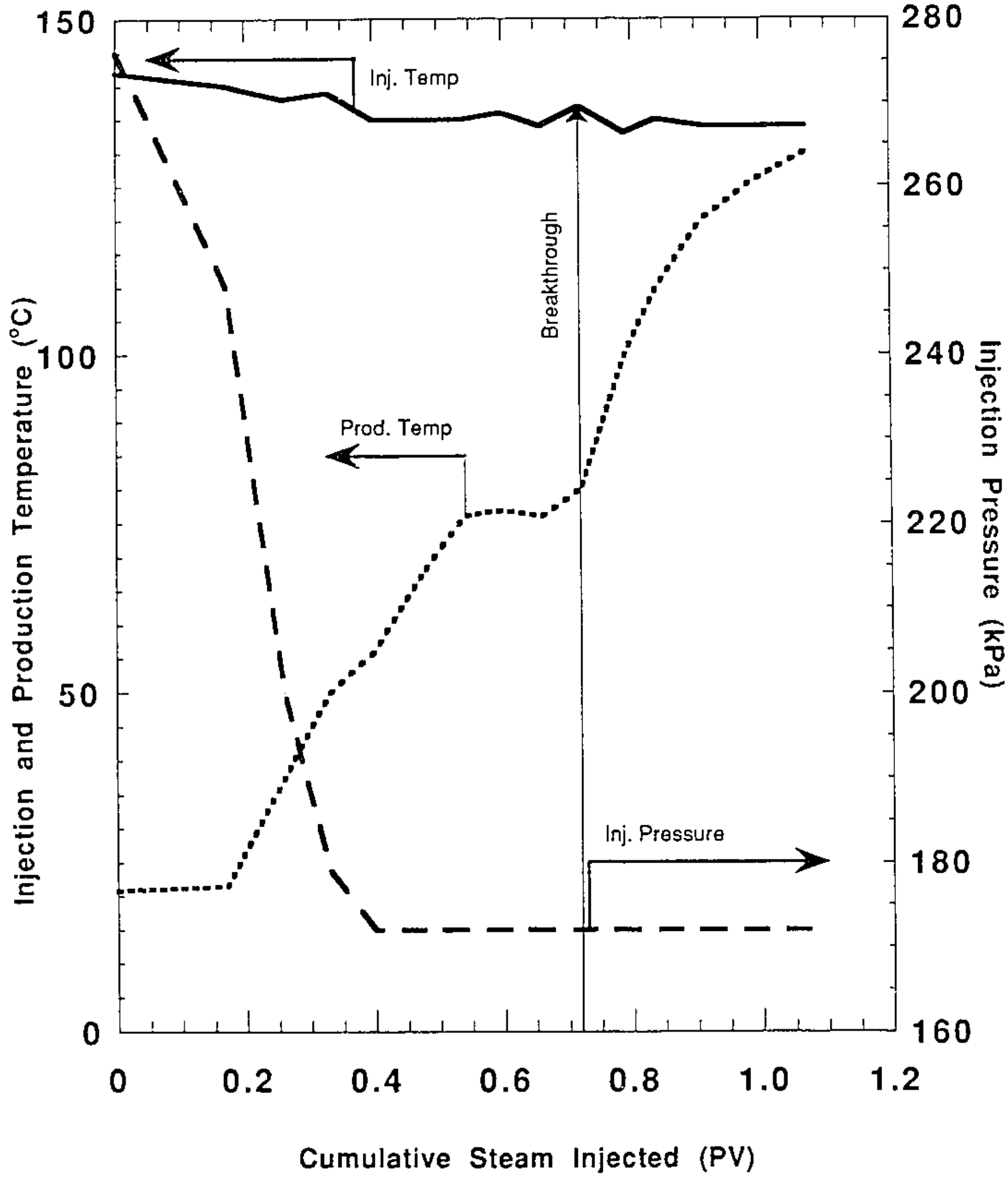
Figure 5.4 shows the injection/production temperature and pressure profiles of Run 16. The experiment was conducted at a constant production pressure in which a back pressure regulator was used to maintain a constant pressure of 138 kPa (20 psig) at the production end. The injection pressure was set at 276 kPa (40 psig) at the beginning of the experiment. However, during the injection of the first 0.4 PV, the injection pressure declined steeply to 173 kPa (25 psig) and stabilized at this level during the experiment. The sharp decline in the injection pressure was caused by the fact that steam was injected radially through the sintered metal jacket surrounding the sand pack and by steam channeling into the sand pack. The injection and production temperature were also plotted on Figure 5.4. The injection temperature was always maintained above steam saturation temperature to ensure that steam and not hot water was injected. The injection temperature fluctuated as injection pressure increased or decreased but always remained around the steam saturation temperature.

For the injection of the first 0.18 PV, the production temperature increases slightly until the steam front moved toward the horizontal producer, allowing the steam zone to grow and heat the oil, reducing its viscosity. After 0.18 PV of steam CWE was injected into the sand pack, the production temperature started to increase steadily because hot fluid arrived at the horizontal producer. At steam breakthrough, a sharp jump in production temperature occurred, indicating that the stable interface separating the cold fluid ahead of the front from the hot fluid behind the front was ruptured and steam propagated straight through to the horizontal producer. By the time one PV was injected, the sand pack temperature was almost at steam saturation temperature and steam was already being produced at the production well marking experiment termination.

For the purpose of sensing the steam front and steam zone growth, 16 thermocouples were installed in the model at different locations. These thermocouples were installed at different depths in the sand pack to sense steam front movement. In addition, two thermocouples were also installed at the injection and production ports to monitor and trace the steam path from the injector to the horizontal producer. Temperature data were collected through the experiment using thermocouples and were plotted on a contour map using the SURFER program.

Figure 5.5 shows a cross-sectional views of the temperature distribution profile inside the sand pack for Run 16 after the injection of A) 0.25, B) 0.50, C) 0.75 and D)

Fig 5.4 - Production History of Run 16: Injection/Production Temperature and Injection Pressure vs. Cumulative Steam Injected Using a Horizontal Producer Penetrating 100% of the Sand Pack length, Injection from Top



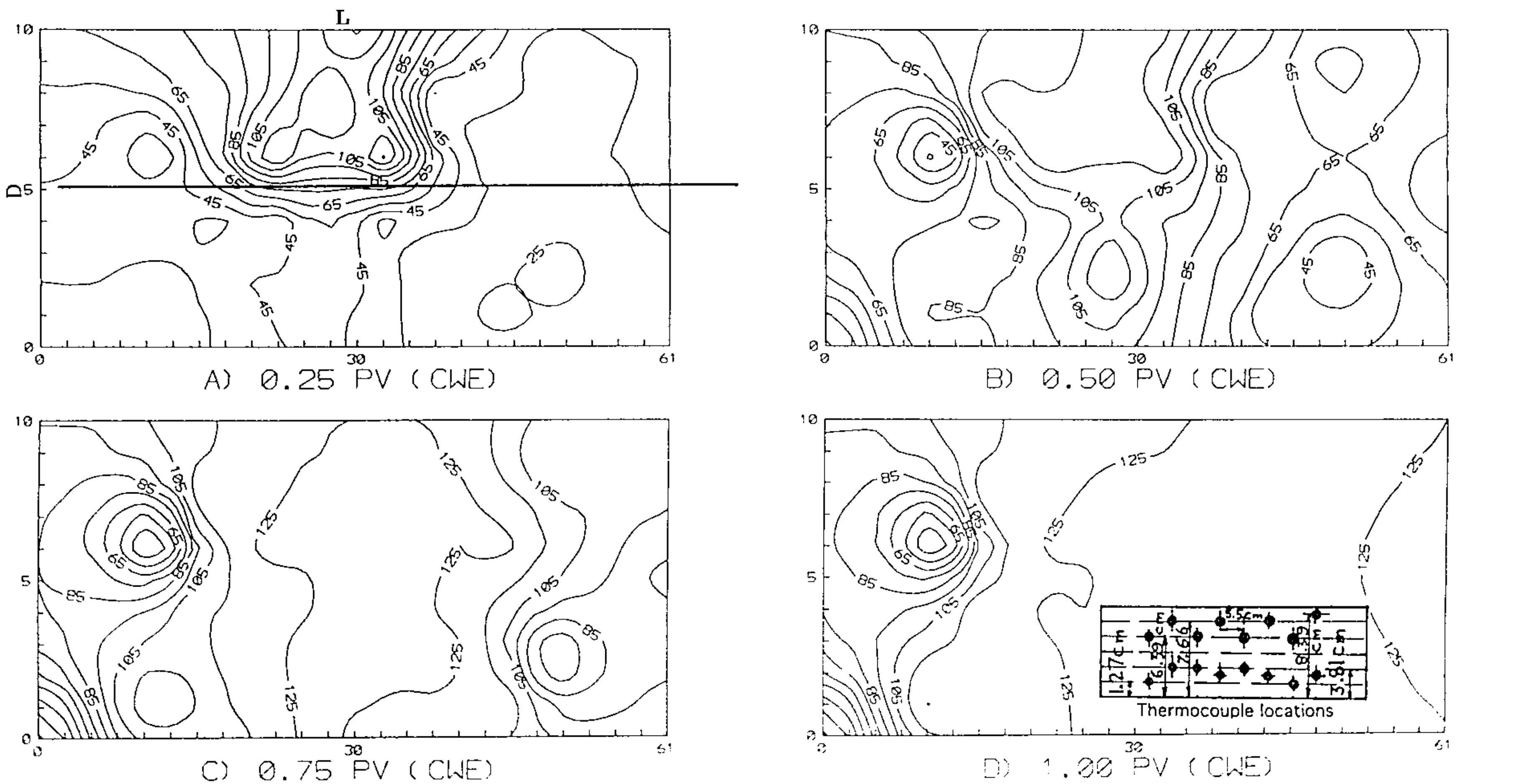
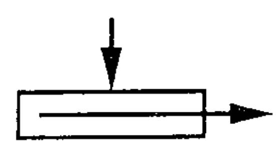


Figure 5.5: Cross-Sectional Views of the Temperature Distribution Inside the Sand Pack after the Injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV (CWE) of Steam for Run 16 Using a Horizontal Producer Penetrating 100% of the Sand Pack Length



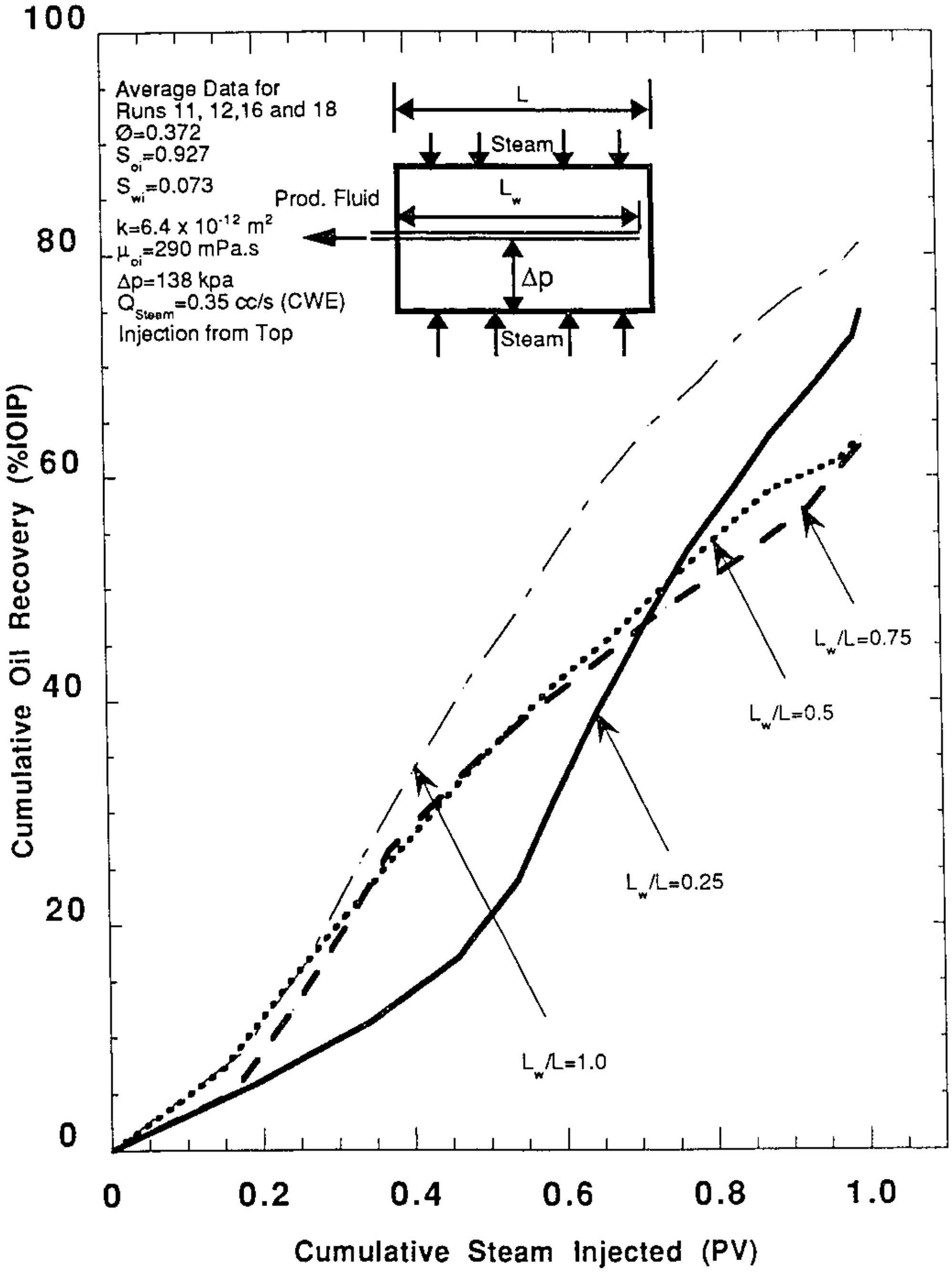
1.00 PV CWE. The letters D and L in the figure refers to the sand pack diameter and length, respectively. Steam was radially injected at the mid-point of the top of the sand pack, and oil was produced through the horizontal producer situated at the center of the sand pack. Even though steam was injected radially around the sand pack, it did not enter the sand pack in a symmetrical fashion. However, most of the steam was coming from the upper half of the sand pack, sweeping the oil down towards the horizontal producer. After steam injection was started, steam was at the upper boundary forcing the steam zone to expand and grow laterally. As injection continued, the steam front moved in both the vertical and the horizontal directions efficiently sweeping the oil. By the time 0.75 PV was injected into the sand pack, the steam front had already reached the producer, leaving the area away from the produced fluid path unswept. The unswept region left behind the steam front resulted because the steam was directed towards the production end by pressure drawdown, which accelerated steam movement towards that end.

The experiment was terminated after the injection of 1.07 PV of steam, and it can be seen from the 1.00 PV CWE temperature distribution profile that the sand pack temperature was already at 125 °C, and that steam was produced at the production end making the continuation of the steam injection process unattractive. This experiment was the base experiment for horizontal producer experiments. It gave the highest cumulative oil recovery and oil-steam ratio of 81% IOIP and 0.87 respectively at 1.07 PV.

5.2.2 Effect of Horizontal Producer Length

Four well lengths were used to investigate the horizontal producer length effect on oil production performance. The four lengths of the horizontal producer used represented 25, 50, 75 and 100% of the sand pack length. Steam was radially injected from the top of the sand pack, and oil was produced through the horizontal producer located at the center of the cylindrical sand pack. Figure 5.6 compares cumulative oil recovery obtained using horizontal producer lengths of 25, 50, 75 and 100% of the sand pack length. The longest horizontal producer penetrated the entire length of the sand pack and had the highest cumulative oil recovery of 81% IOIP. The 75% and 50% of the sand pack length producers did not show an appreciable difference between them; the cumulative oil recoveries were 61 and 62% IOIP, respectively, which were less than those obtained from the 100% length producer.

Figure 5.6 - Runs 11, 12, 16 and 18: Effect of Horizontal Well Length on Oil Recovery for L_w/L Ratio of 1.0, 0.75, 0.5 and 0.25 Using a Horizontal Producer



The cumulative oil recovery curve for the 25% producer started with a low cumulative oil recovery up to 0.75 PV injected, then crossed over the 50 and 75% producer recovery curves to obtain a cumulative oil recovery of 77% IOIP. The reason that the 25% producer had an initially low cumulative oil recovery was because most of the steam was consumed in heating the large sand pack volume between the injection point and the 25% producer. The highest cumulative oil recovery was obtained using a horizontal producer penetrating the full length of the sand pack because, in this case, the entire sand pack length was open to flow. The sand pack contact area provided by the 100% producer was larger than that of the area provided by the 25, 50 and 75% producers. In the case of the 25% producer, recovery started slowly because steam had to travel a longer distance and heat a larger volume than those of the 50, 75 and 100% producers. Since most of the steam was initially consumed in heating the large volume between the injector and producer and mobilizing the oil ahead of the steam front, the 25% producer recovery was initially much less than that of the 50, 75 and 100% producers.

Figures 5.7 and 5.8 show the oil-steam ratio and water-oil ratio vs. cumulative steam injected. The 25% producer had the lowest cumulative oil-steam ratio and the lowest water-oil ratio, while the 100% producer had the highest cumulative oil-steam ratio and lowest water-oil ratio and the 50 and 75% producers had values in between. As already explained, the highest cumulative oil steam ratio was obtained using the 100% producer as a result of the large sand pack contact area provided by the full length horizontal producer. Water-oil ratio curves for the 25 and 75% producers started at high values because of the production of the remaining unswept water left after saturation of the sand pack with oil. The remaining water from the saturation process was concentrated around the production end and was produced as soon as the steam injection process started.

Cross sectional views of the temperature distribution profile inside the sand pack after the injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV CWE of steam are shown in Figures 5.5, 5.9 and 5.10 for the 100, 50 and 25% horizontal producers. A close examination of the temperature of the steam front for the 25 and 100% producers shows that the steam front reached the 100% producer before it reached the 25% producer. Since the distance the steam had to travel to reach the producer was longer in the 25% producer than in the 100% producer, early steam breakthrough in the 100% horizontal producer was expected. However, at this time most of the oil was produced

Figure 5.7 - Run 11, 12, 16 and 18: Effect of Horizontal Well Length on Oil-Steam Ratio for L_w/L Ratio of 1.0, 0.75, 0.5 and 0.25 Using a Horizontal Producer

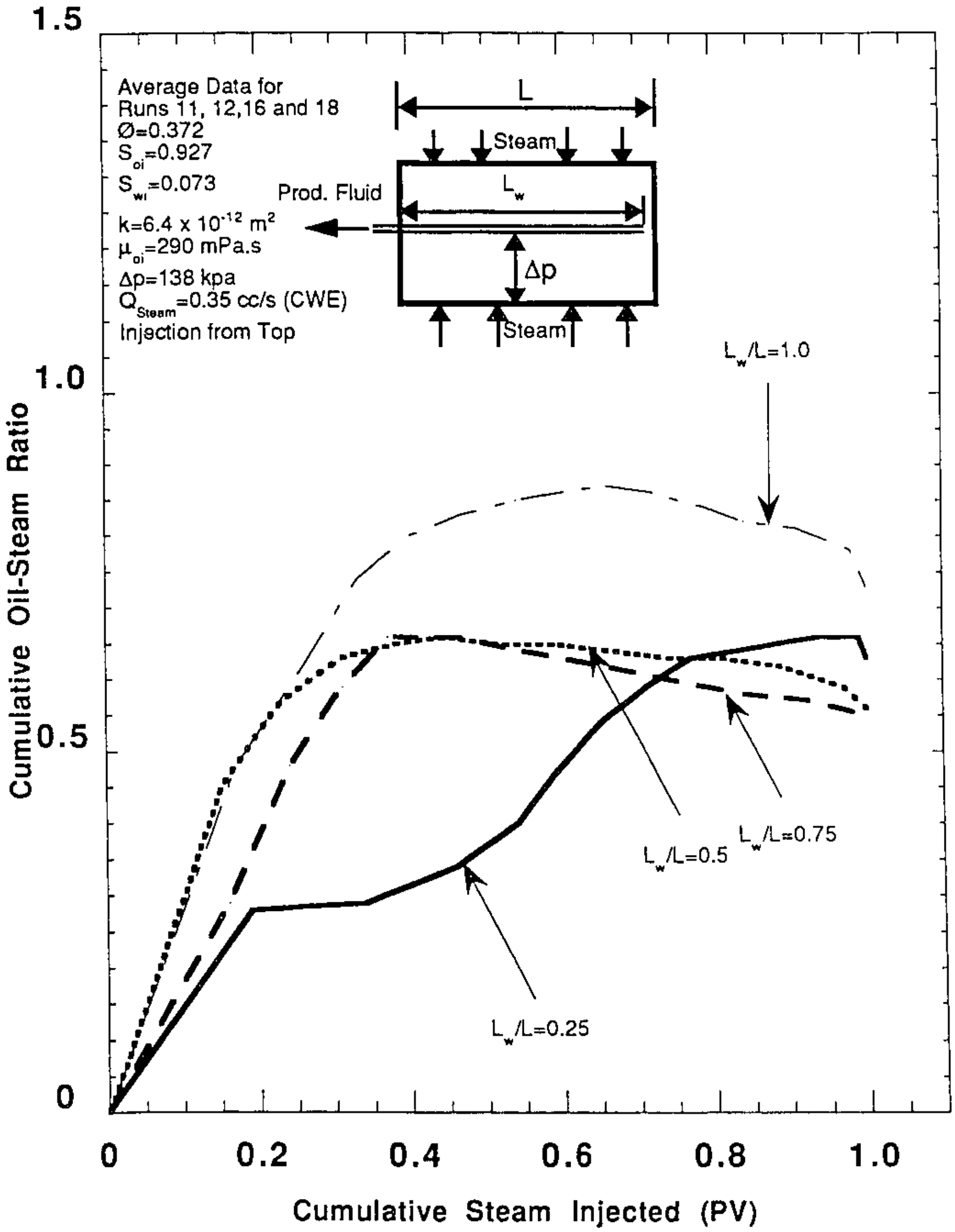
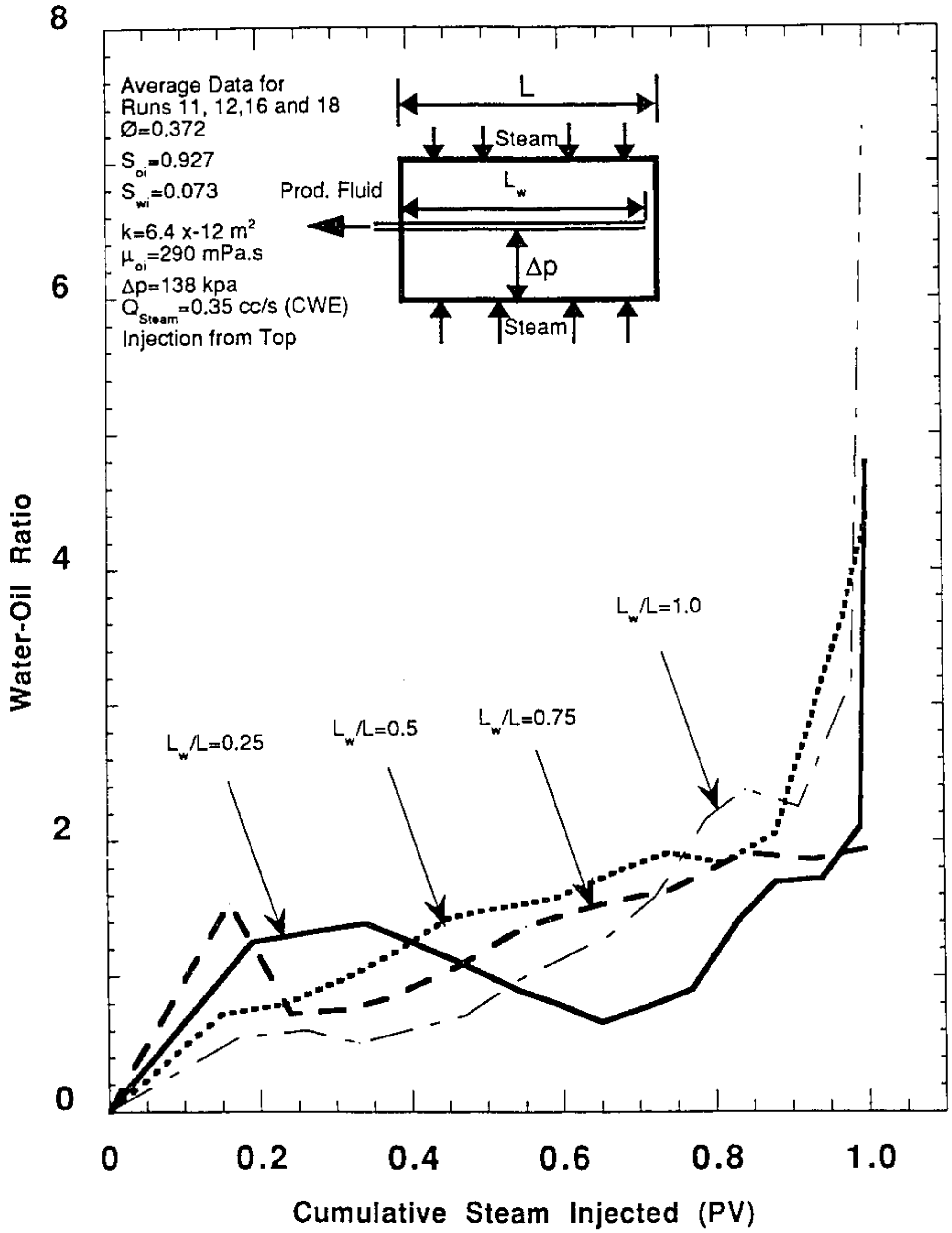
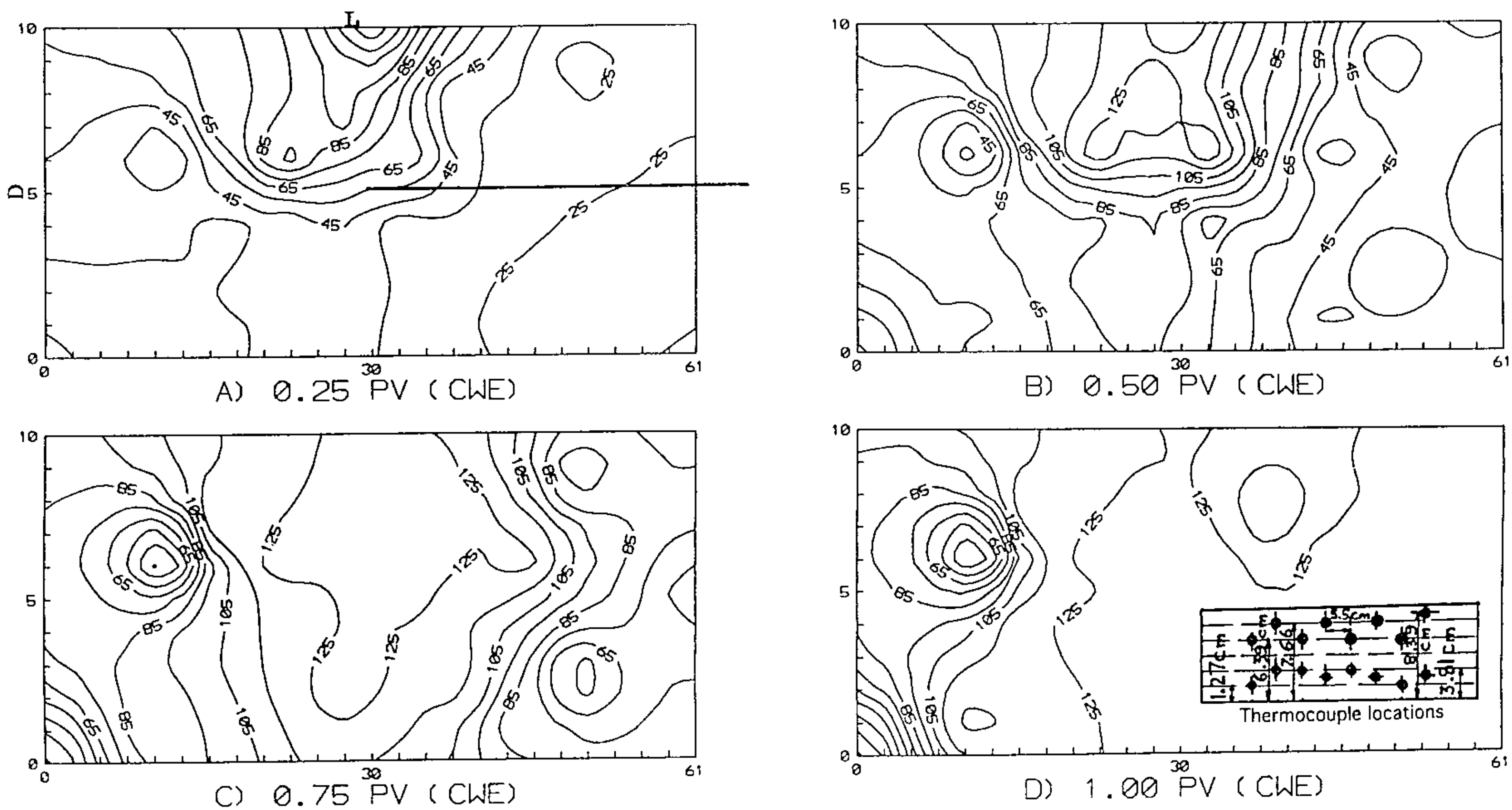


Figure 5.8 - Runs 11, 12, 16 and 18: Effect of Horizontal Well Length on Water-Oil Ratio for L_w/L Ratio of 1.0, 0.75, 0.5 and 0.25 Using a Horizontal Producer





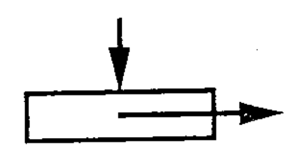
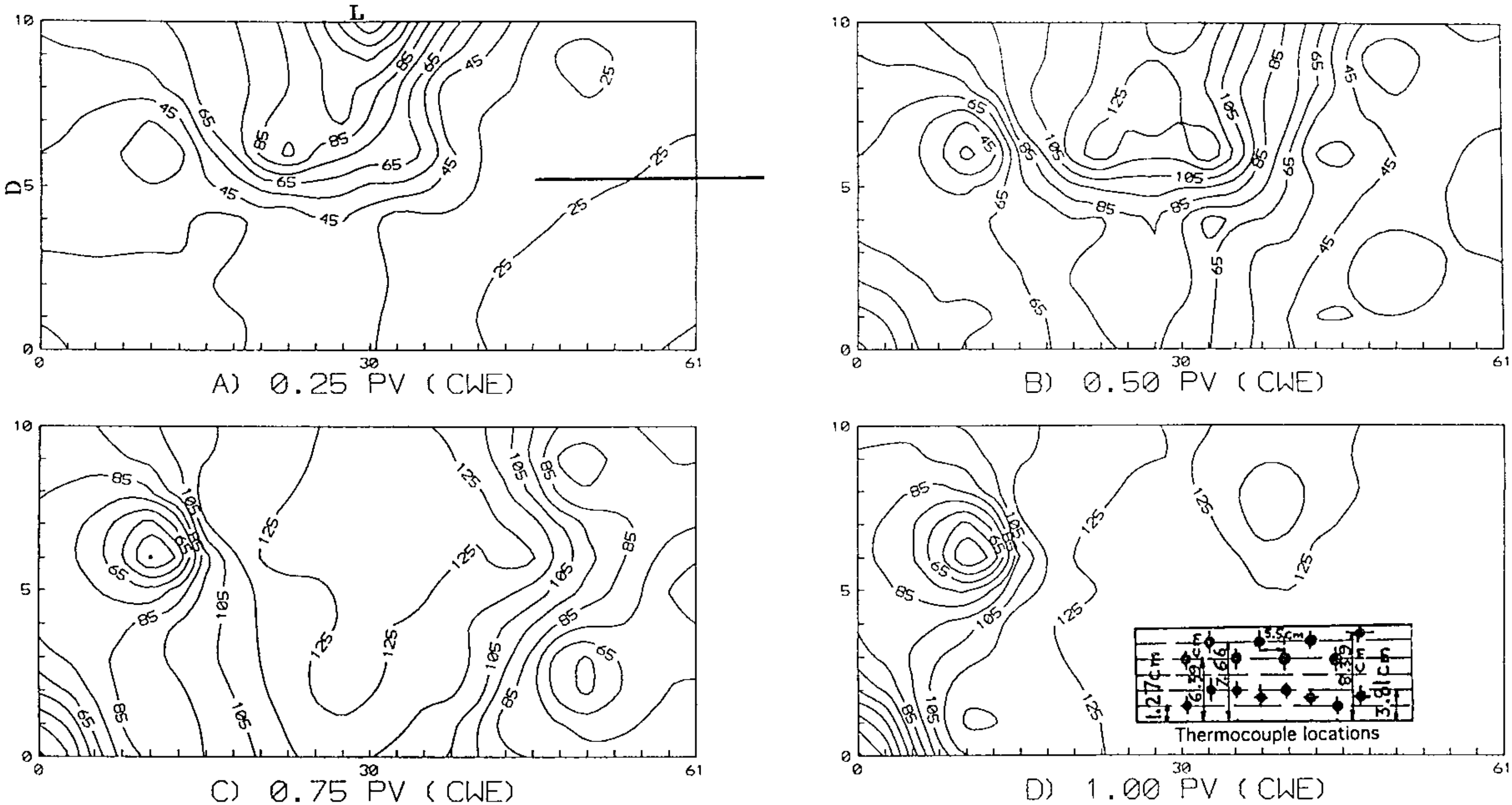


Figure 5.9: Cross-Sectional Views of the Temperature Distribution Inside the Sand Pack after the Injection of: A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV (CWE) of Steam for Run 11 Using a Horizontal Producer Penetrating 50% of the Sand Pack Length



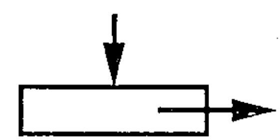


Figure 5.10: Cross-Sectional Views of the Temperature Distribution Inside the Sand Pack after the Injection of: A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV (CWE) of Steam for Run 12 Using a Horizontal Producer Penetrating 25% of the Sand Pack Length

from the sand pack. Moreover, in almost all cases when steam was injected from the top of the sand pack, the steam zone grew laterally and vertically toward the horizontal producer as shown by the temperature contours in Figures 5.5, 5.9 and 5.10.

The moment steam injection was started, steam was at the upper boundary of the sand pack and spread in the horizontal direction to the right and left of the injection port. The lateral spread created a more or less stable horizontal front pushing the oil down towards the producer and efficiently sweeping the sand pack portion located closer to the production end. As previously mentioned, because the drawdown caused steam to flow towards the production end, the sand pack located between the injection and production ends was more efficiently swept than the sand pack located away from the production end.

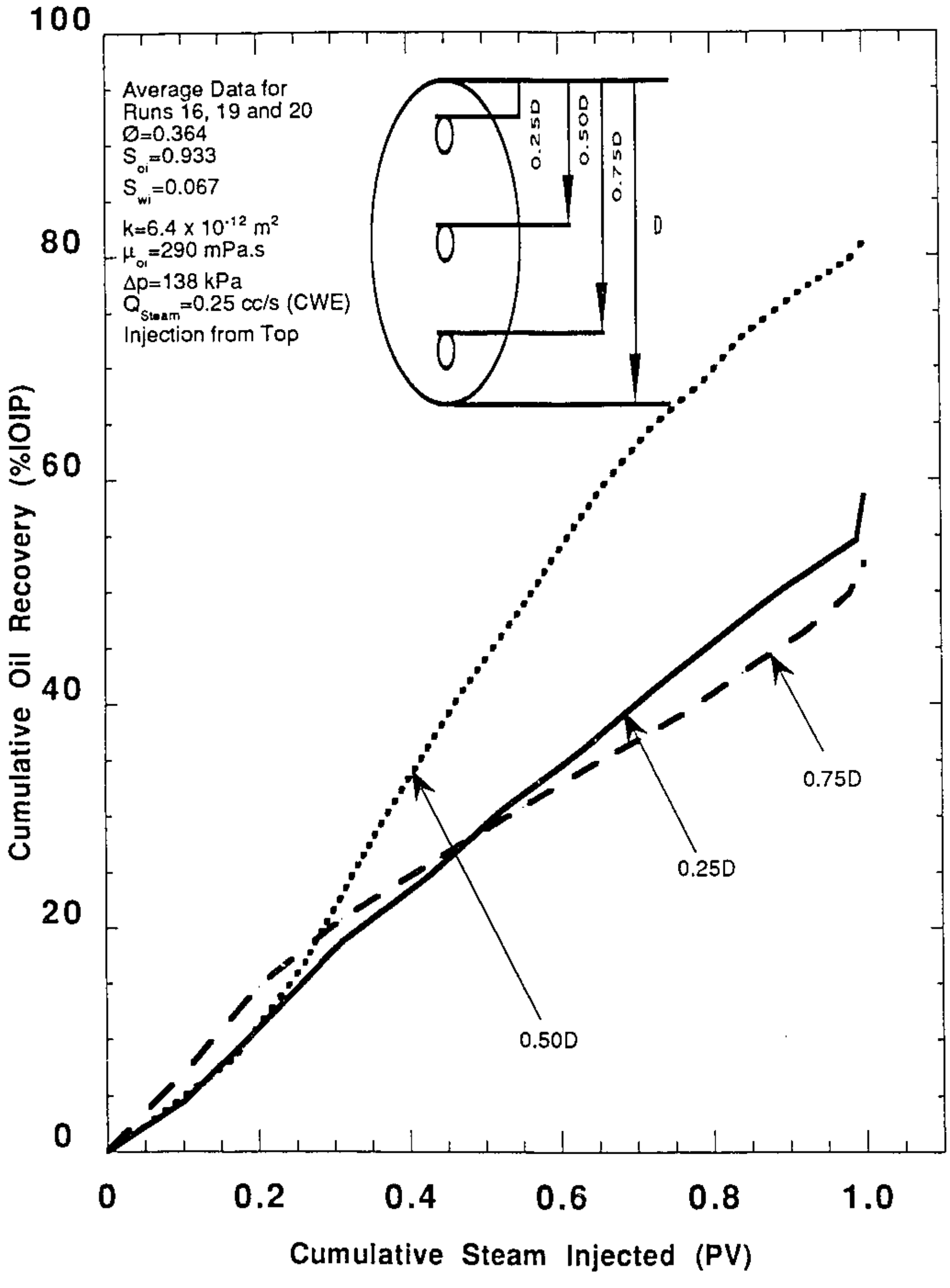
This set of experiments provided insight into the horizontal producer length effect on oil production performance during steamflooding. A longer horizontal producer, because of its large reservoir contact area, accelerates oil recovery and produces higher cumulative oil recovery than a shorter horizontal producer. However, due to the extent of the length, early steam breakthrough was often associated with oil production using longer horizontal producers in this research.

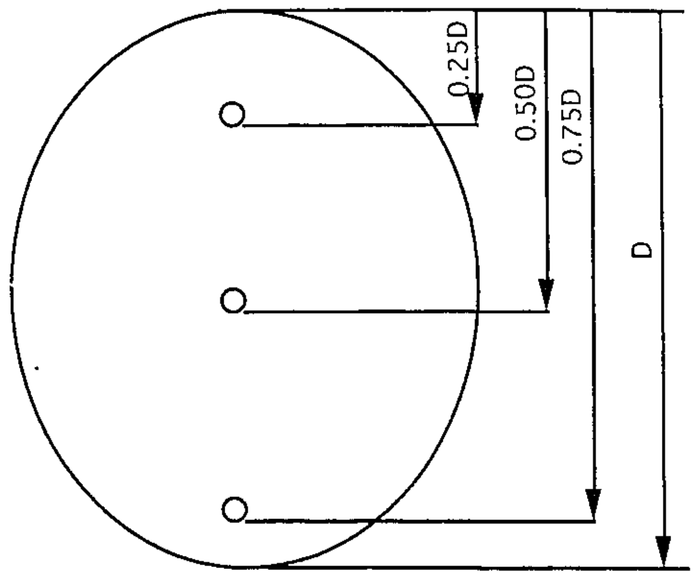
5.2.3 Effect of Horizontal Producer Vertical Location

Three experiments were conducted to investigate the effect of horizontal producer vertical location on steam recovery performance. The horizontal producer penetrating the full length of the sand pack was placed at different positions along the diameter of the cylindrical sand pack to study the well location effect on oil production performance.

Experiments 16, 19, and 20 were carried out with horizontal producers located at 25, 50, and 75% along the sand pack diameter taking the upper boundary of the sand pack to be the datum. Steam was injected from the top of the sand pack at a constant rate, and oil was produced through the horizontal producer. The 50%-diameter producer had a higher steam injection rate than the 25 and 75% -diameter producers. Cumulative oil recovery curves for the 25, 50 and 75%-diameter horizontal producers are shown in Figure 5.11. The highest cumulative oil recovery was obtained when the horizontal producer was positioned at the center of the sand pack. Cumulative oil recoveries ranged from 81% IOIP for the 50%-diameter producer to 52% for the 75%-

Figure 5.11 - Runs 16, 19 and 20: Effect of Horizontal Well Location on Oil Recovery for 0.25D, 0.50D and 0.75D Using a Horizontal Producer





diameter producer and 59% for the 25%-diameter producer. When the horizontal producer was placed at 25%-diameter from the sand pack upper boundary or the injection port, the production process was complicated by an early steam breakthrough.

Figures 5.12, 5.13 and 5.14 show temperature distribution profiles inside the sand pack after the injection of A) 0.25, B) 0.50, C) 0.75, and D) 1.00 PV CWE for horizontal producers located 50, 25, and 75%-diameter from the sand pack upper boundary. The temperature distribution profiles for the three experiments indicate that the 25%-diameter producer had the earliest steam breakthrough, the 75%-diameter producer had the latest and the 50%-diameter producer had a breakthrough time in between. Since oil production performance using the 25%-diameter producer was complicated by early steam breakthrough, oil was not efficiently swept by the time one PV of steam (CWE) was injected.

Figure 5.12 shows a low temperature region in the upper left corner of the 0.50, 0.75 and 1.00 PV profiles. This is because the horizontal producer is perforated through its entire length. Another reason that the steam is drawn towards the production end leaving the oil in the left side of the core unswept resulting in low temperature readings.

The 1.0 PV CWE temperature profile in Figure 5.13 shows how steam channeled and propagated straight through to the producer, leaving unproduced oil behind on both sides of the sand pack. In the case of the 75%-diameter producer, the

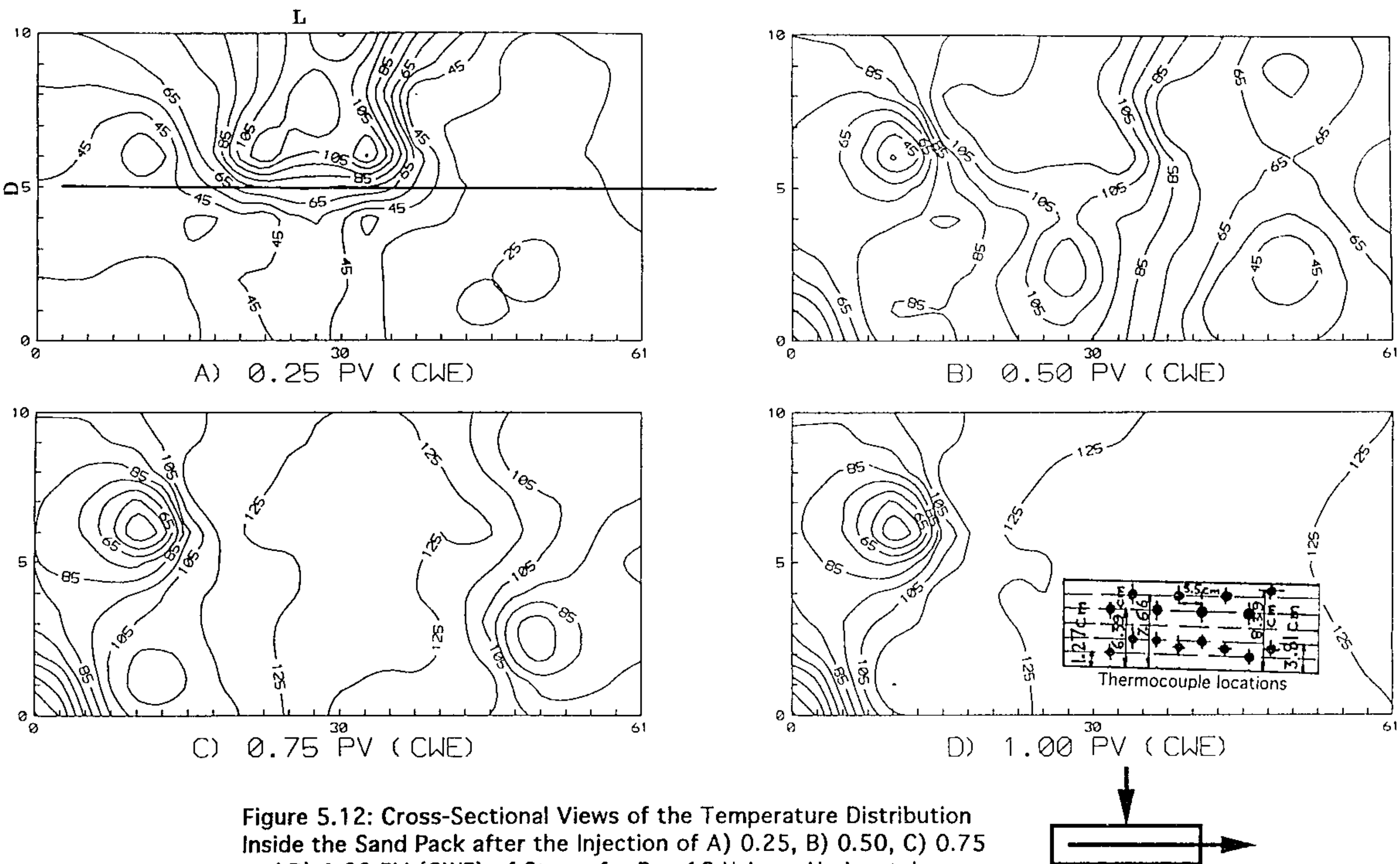


Figure 5.12: Cross-Sectional Views of the Temperature Distribution Inside the Sand Pack after the Injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV (CWE) of Steam for Run 16 Using a Horizontal Producer Located 0.50D from the Sand Pack Upper Boundary

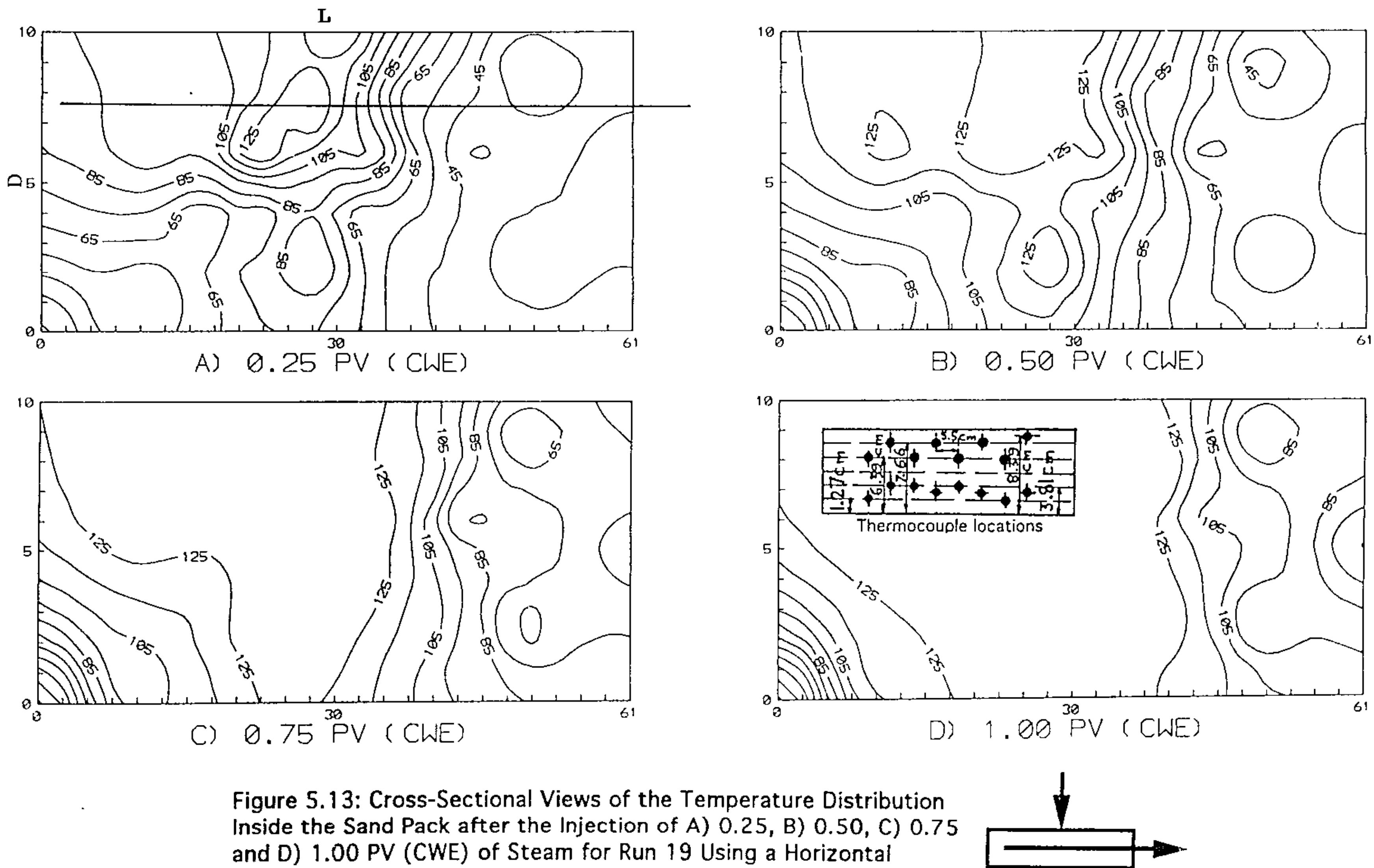


Figure 5.13: Cross-Sectional Views of the Temperature Distribution Inside the Sand Pack after the Injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV (CWE) of Steam for Run 19 Using a Horizontal Producer Located 0.25D from the Sand Pack Upper Boundary

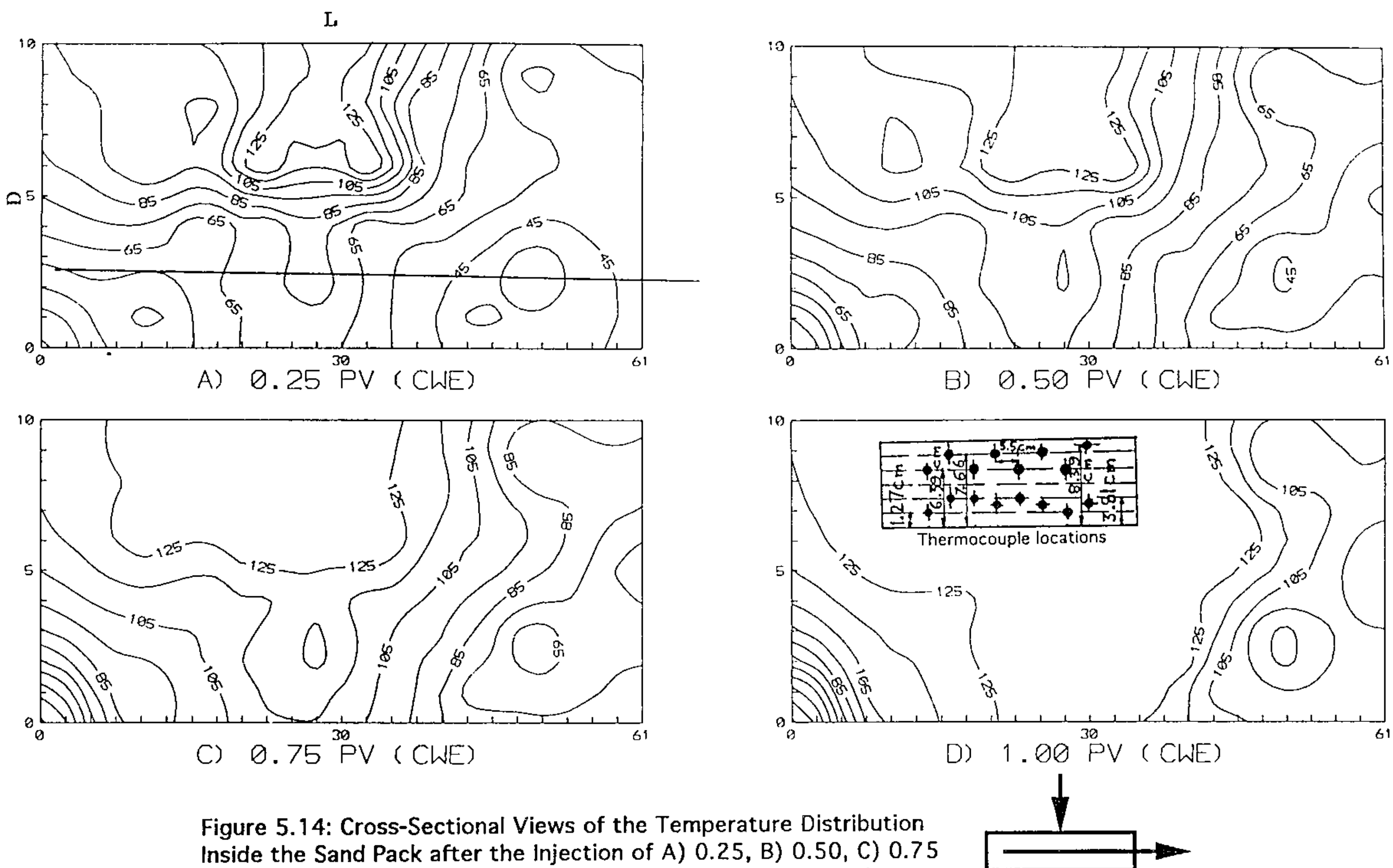


Figure 5.14: Cross-Sectional Views of the Temperature Distribution Inside the Sand Pack after the Injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV (CWE) of Steam for Run 20 Using a Horizontal Producer Located 0.75D from the Sand Pack Upper Boundary

cumulative oil recovery was less than that for the 50%-diameter producer because the 75%-diameter producer performance suspected to be complicated by the non uniform water saturation resulted from not injecting sufficient amount of oil to ensure a uniform irreducible water saturation. Figure 5.15 compares water-oil ratios for the three producer locations; the 75%-diameter producer had the highest water-oil ratio, and the 50%-diameter producer had the lowest which indeed supports the fact that the 75%-diameter producer was placed too close to the water zone and the steam injection process was not as efficient in sweeping the oil due to high water production.

Moreover, placing the horizontal producer 75%-diameter from the sand pack upper boundary increased the volume that steam had to heat, which delayed establishing an early communication between the injector and producer which, in turn, produced a low oil recovery by the time one PV of steam (CWE) was injected. However, the 50%-diameter producer, because it was positioned at an optimum location, at the center of the sand pack, gave the highest cumulative oil recovery. Its production performance was not significantly affected by early steam or water breakthrough, as can be seen in Figures 5.15 and 5.16.

Based on the results obtained from the three experiments carried out to investigate the effect of the horizontal producer vertical location on the steam injection process, the oil production performance of the 25%-diameter producer was complicated by early steam breakthrough and that of the 75%-diameter producer was affected by a high production of water. Furthermore, the highest oil recovery was obtained using a horizontal producer placed at the center of the cylindrical sand pack.

5.2.4 Effect of Horizontal Producer Diameter

This set of experiments investigated the horizontal producer diameter effect on pressure drop inside a horizontal well and studied steam production performance using different horizontal producer diameters. The measurement of pressure drop inside the horizontal producer was complicated by several mechanical problems.

Since the pressure drop inside the horizontal producer was extremely small (less than 1.0 psig), a very sensitive transducer was used. The use of so sensitive a transducer was problematic in terms of both calibration and operation. A calibration device that would accurately calibrate a one psi pressure plate was not available. Operationally, the use of the transducer was affected by the temperature changes across

Figure 5.15 - Runs 16, 19 and 20: Effect of Horizontal Well Location on Water-Oil Ratio for 0.25D, 0.50D and 0.75D Using a Horizontal Producer

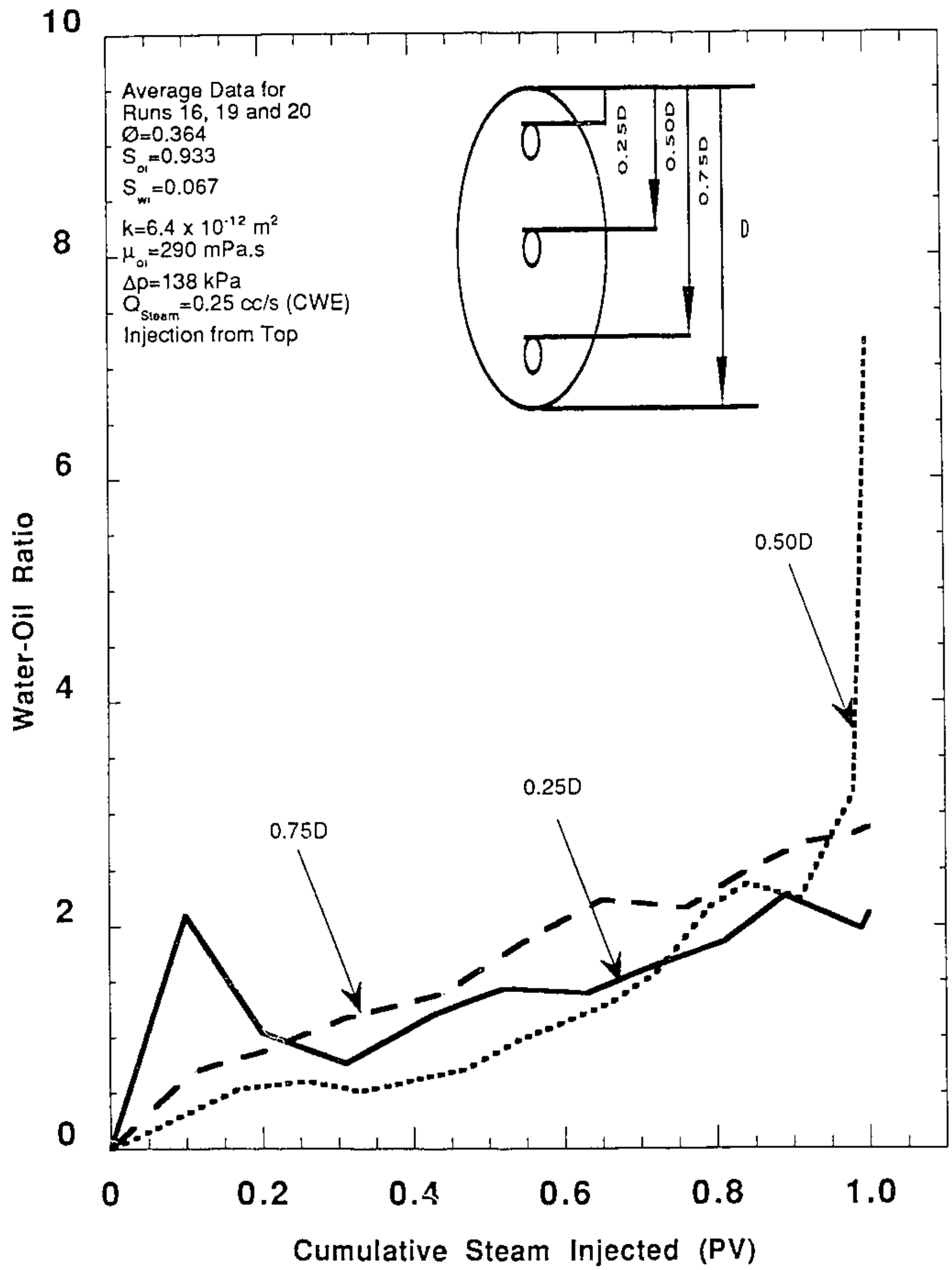
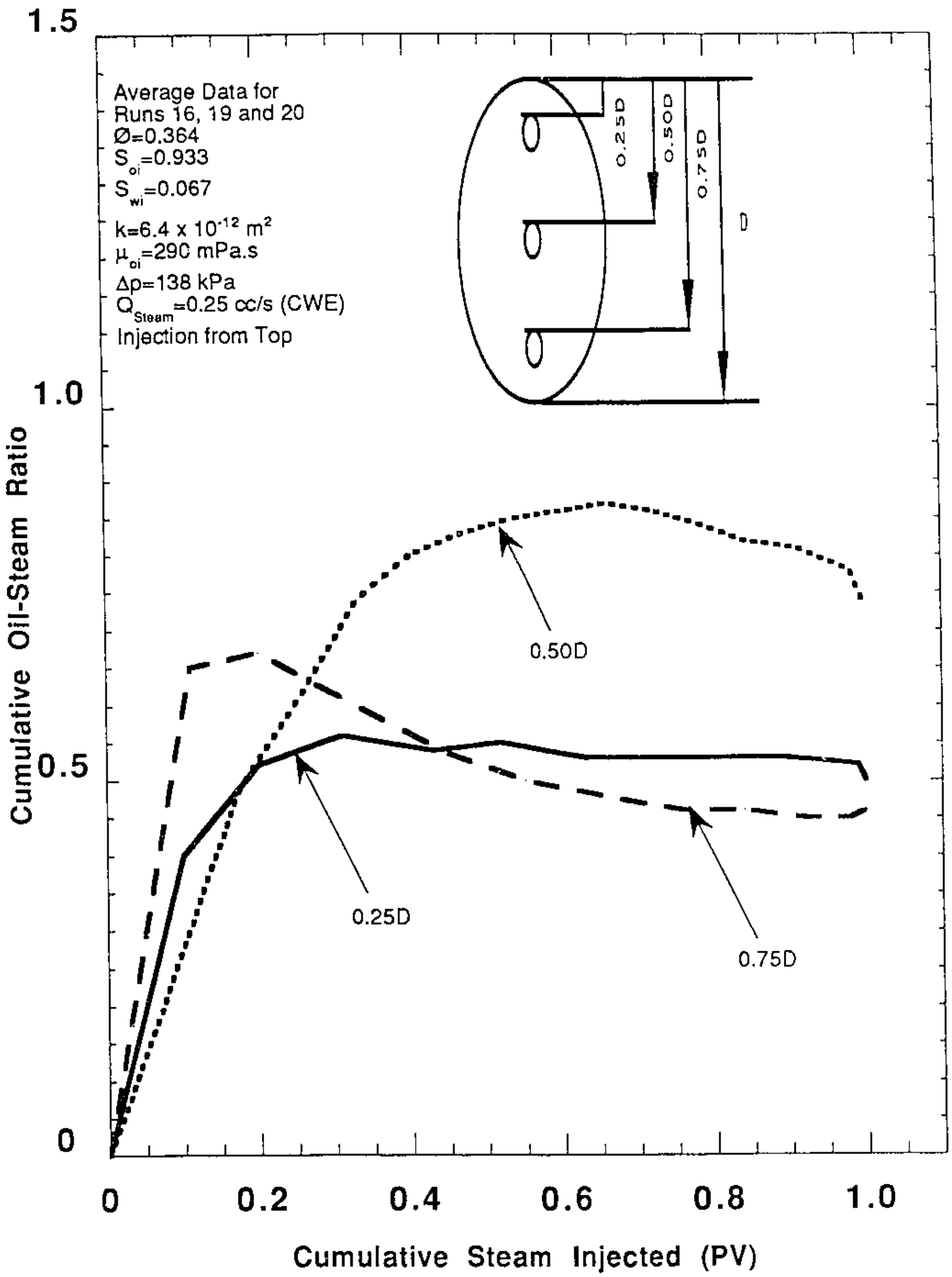


Figure 5.16 - Runs 16, 19 and 20: Effect of Horizontal Well Location on Oil-Steam Ratio for 0.25D, 0.50D and 0.75D Using a Horizontal Producer



the transducer and by the entrapment of gas inside the small tube connected to the transducer outlets. Despite many attempts to measure the pressure drop inside the horizontal producer, no reliable results were obtained. After several unsuccessful measurements of the pressure drop inside the producer, the study was directed to investigate the effect of the producer diameter on oil production performance.

Three well diameters (0.32 cm (1/8 in), 0.64 cm (1/4 in) and 0.95 cm (3/8 in)) were used to study the horizontal producer diameter effect on the behaviour of the steam injection process. Runs 33 and 34 were carried out using horizontal producer diameters of 0.64 cm and 0.95 cm, respectively, and were compared with the base experiment, Run 16, in which a 0.32-cm diameter well was used.

Figures 5.17 and 5.18 show the cumulative oil recovery and the cumulative oil-steam ratio vs. cumulative steam injected for the 0.32, 0.64 and 0.95-cm producers, respectively. The highest cumulative oil recovery of 81% IOIP was obtained using the 0.32-cm horizontal producer, while the 0.64-cm and the 0.95-cm producers both gave lower cumulative oil recoveries than the 0.32-cm producer. The cumulative oil recovery for the 0.64-cm producer was 63% and that for the 0.95-cm producer was 58% IOIP by the time one PV of steam (CWE) was injected. Even though the 0.64-cm and 0.95-cm producers had about the same oil recovery by the time one PV was injected, they showed some differences in cumulative oil recovery at the beginning of the experiment. Up to 0.2 PV injected, the 0.95-cm producer had the same recovery as that of 0.32-cm producer. However, after 0.2 PV injected, the cumulative oil recovery curve for the 0.95-cm producer declined and stabilized at a level even lower than that of the 0.64-cm producer.

The same was observed from the cumulative oil-steam ratio curves for the three producer diameters in Figure 5.18. The highest cumulative oil-steam ratio was obtained using the 0.32-cm producer, while the 0.64-cm and 0.95-cm producers had the lowest cumulative oil-steam ratios. Because the 0.32-cm producer diameter is smaller, its steam production performance was not complicated by water production compared to that for the 0.64-cm and 0.95-cm producers. Both the 0.64-cm and the 0.95-cm producers had higher water-oil ratios than that of the 0.32-cm producer during the experiment as can be seen from Figure 5.19 which shows water-oil ratio vs. cumulative steam injected for the three producer diameters.

Figure 5.17 - Runs 16, 33 and 34: Effect of Horizontal Well Diamter on Oil Recovery for Well Diameter of 0.32, 0.64 and 0.95 cm Using a Horizontal Producer

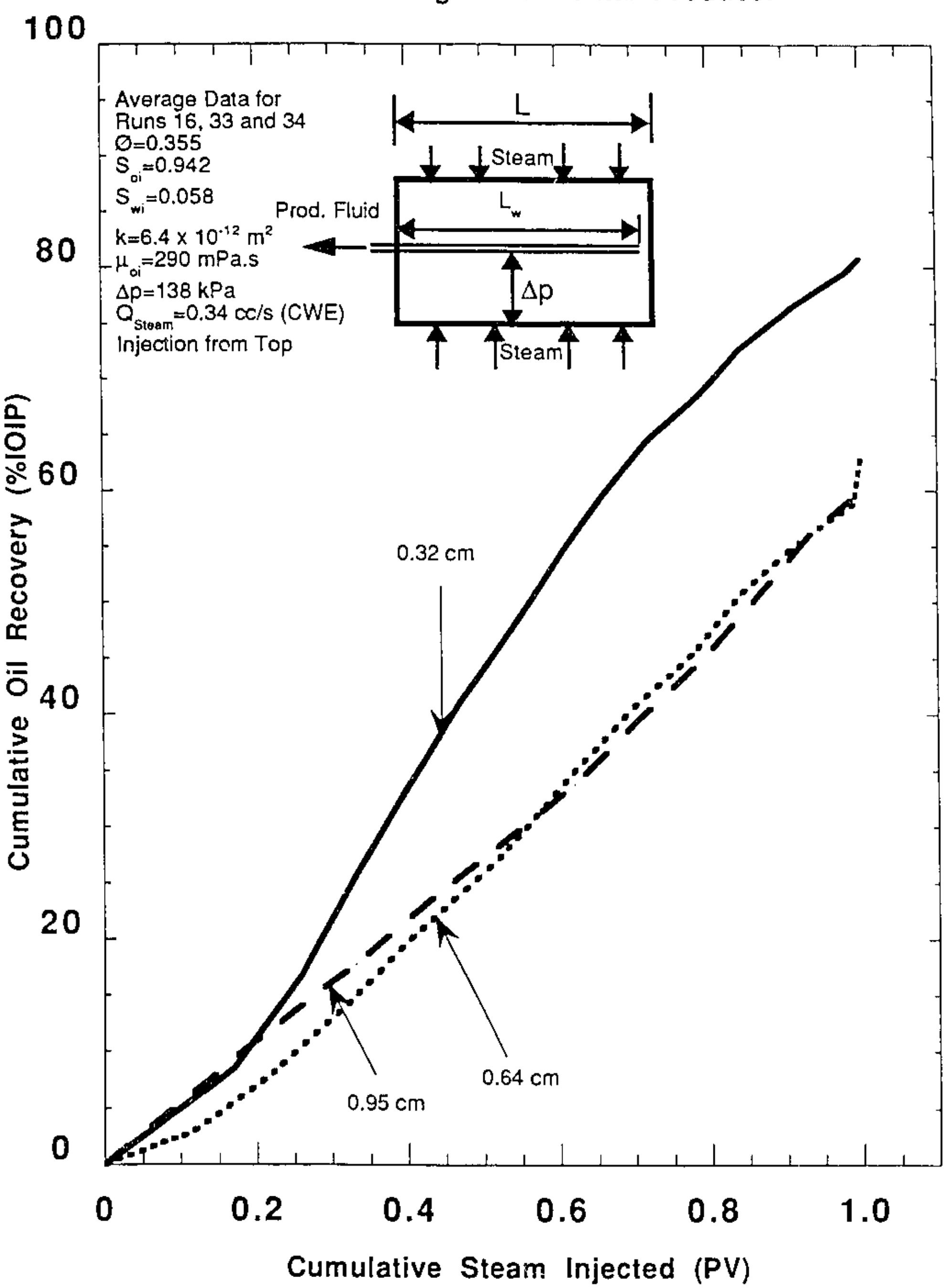


Figure 5.18 - Runs 16, 33 and 34: Effect of Well Diameter on Oil-Steam Ratio for Well Diameter of 0.32, 0.64 and 0.95 cm Using a Horizontal Producer

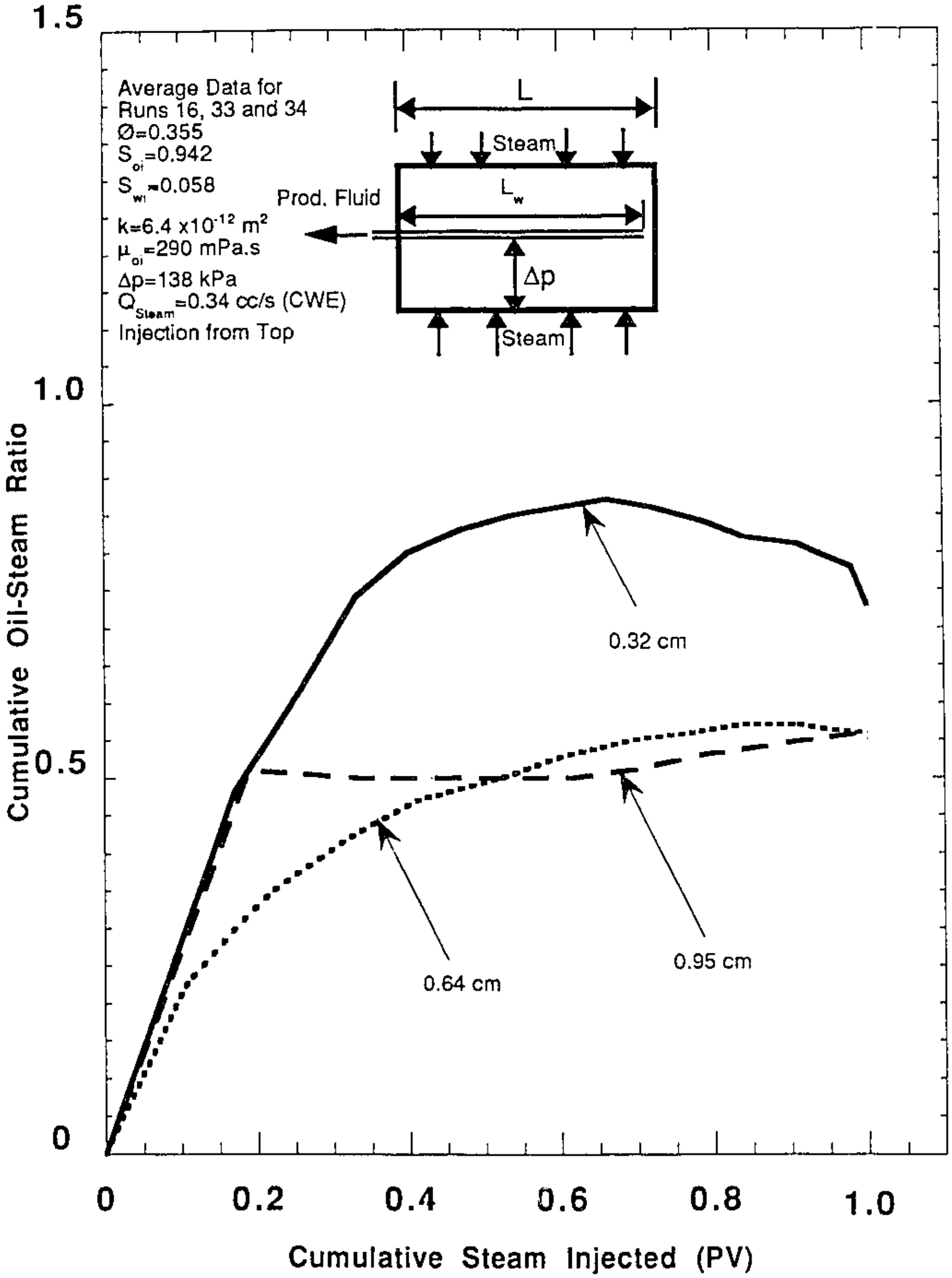
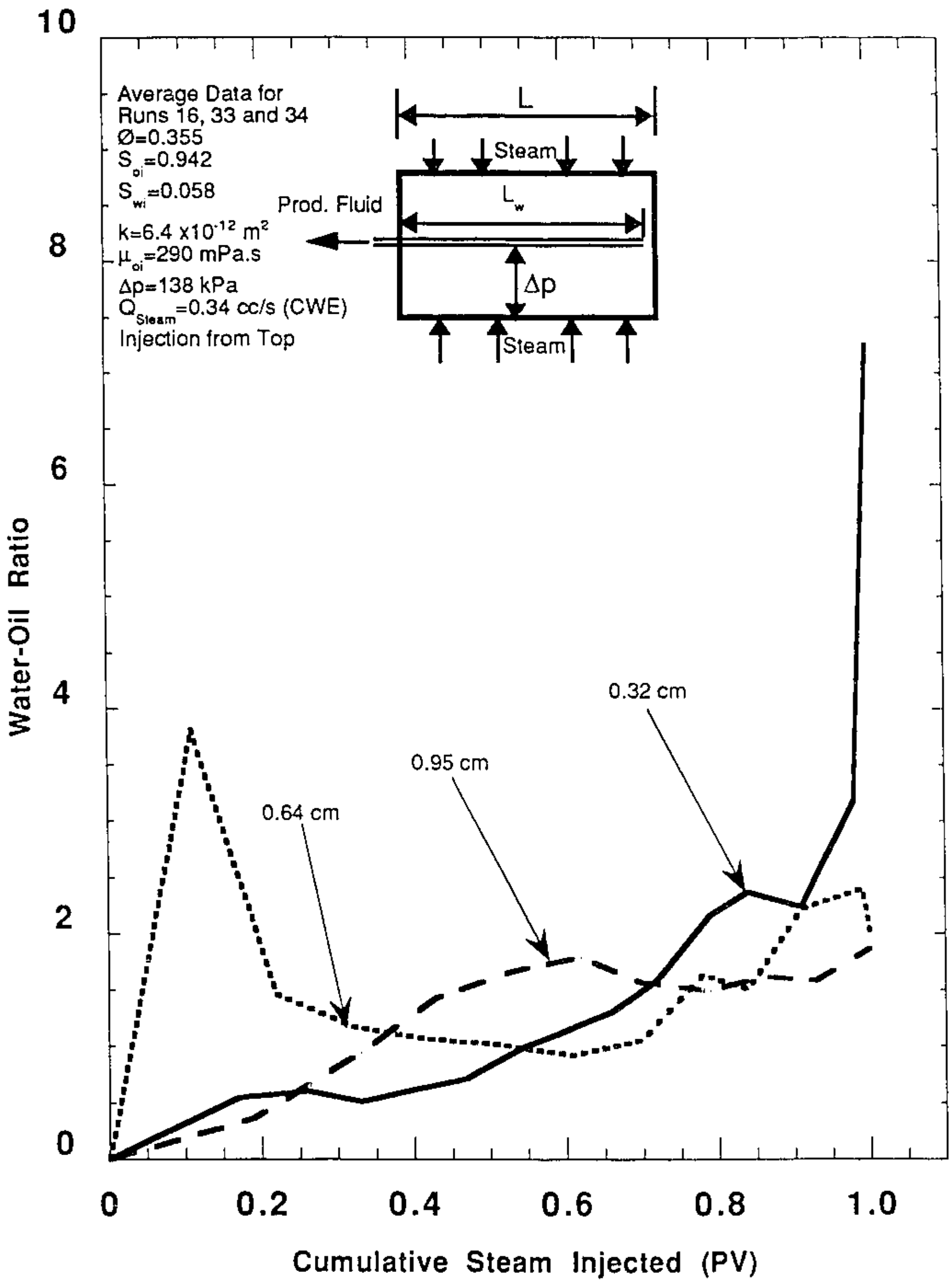


Figure 5.19 - Runs 16, 33 and 34: Effect Well Diameter on Water-Oil Ratio for Well Diameter of 0.32, 0.64 and 0.95 cm Using a Horizontal Producer



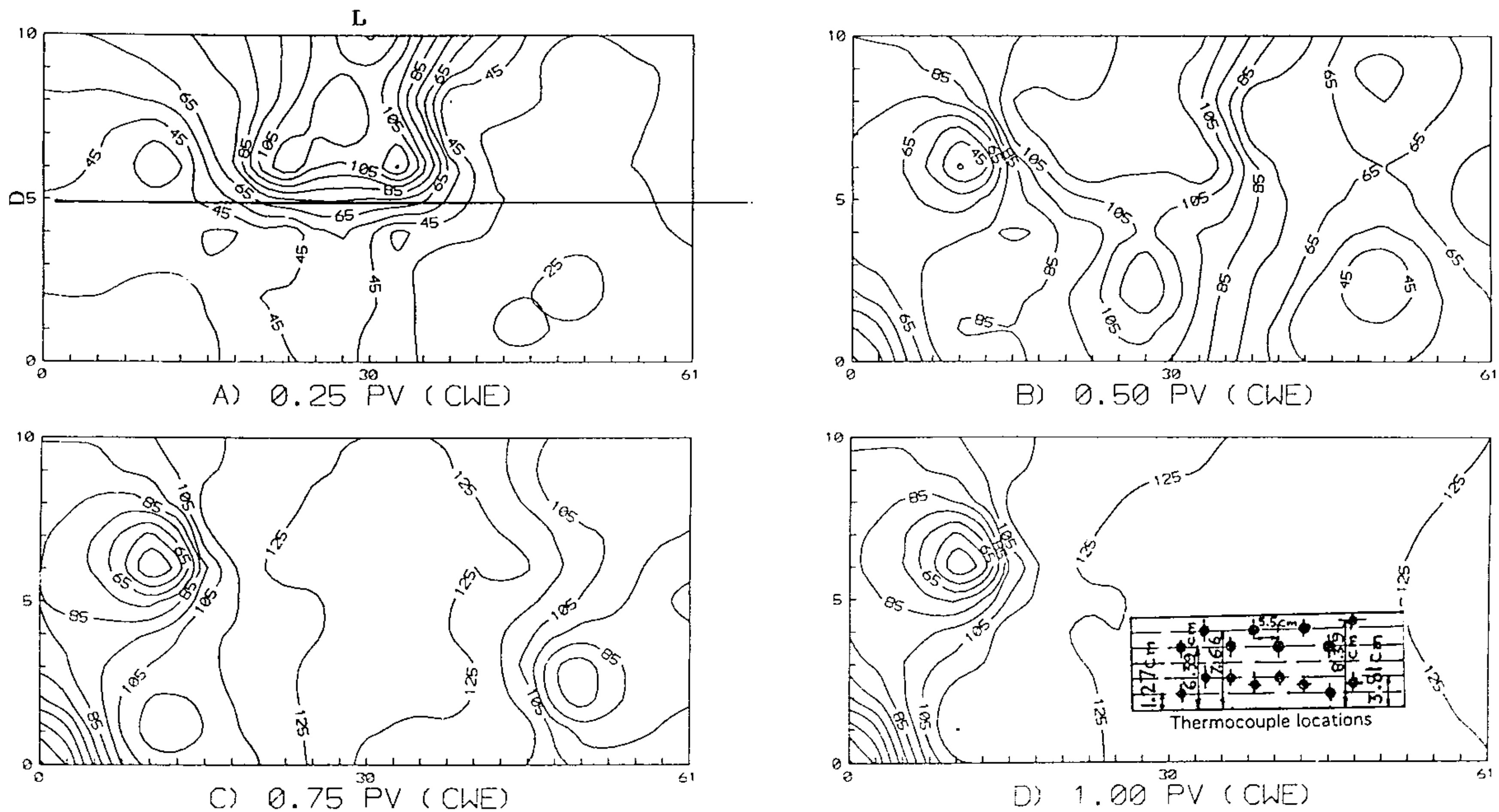
Temperature distribution profiles inside the sand pack after the injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV CWE for 0.32-cm, 0.64-cm and 0.95-cm horizontal producers are presented in Figures 5.20, 5.21 and 5.22, respectively. Temperature distribution profiles for the 0.32 cm producer show that early steam breakthrough occurred. However, the steam breakthrough for the 0.64-cm and 0.95-cm producers did not occur until later in the experiment, indicating that, by the time one PV was injected, some parts of the sand pack were left unheated and oil was not efficiently swept throughout the sand pack. The abrupt increase in WOR in the case of the 0.32-cm well, Figure 5.19, indicates that the steam zone was well-defined and preceded by a condensate zone. Higher oil recovery, in this case (Figure 5.17), supports this view.

In summary, several unsuccessful attempts were made to measure pressure drop inside the horizontal producer. Due to calibration difficulties and operational problems in using too sensitive a pressure transducer, the experiments were directed to study the effect of producer diameters on oil production performance during steam injection. Three well diameters were used, and the highest cumulative oil recovery was obtained using the smallest diameter.

5.2.5 Effect of Oil Viscosity Using a Horizontal Producer

The effect of oil viscosity on steam production performance was investigated using three oil viscosities. Run 16 was carried out using Faxam-100 oil with a viscosity of 290 mPa.s at 101.325 kPa and 24 °C, while Runs 35 and 36 were conducted using Wainwright oils with viscosities of 975 and 1800 mPa.s, respectively. Runs 35 and 36 had lower injection rates than that for Run 16; for this reason the experimental times for Runs 35 and 36 were longer than that for Run 16. Both Runs 35 and 36 were complicated by the production of cold oil. Due to fluctuations in the injection pressure when a high viscosity oil was used, sluggish production dominated the production mechanism in Runs 35 and 36, affecting the cumulative oil recoveries. The cumulative oil recoveries for Runs 16, 35 and 36 are plotted in Figure 5.23.

The cumulative oil recovery for Run 16, obtained using an oil viscosity of 290 mPa.s, was higher than the cumulative oil recovery for Runs 35 and 36, conducted using oil viscosities of 975 and 1800 mPa.s, respectively. The highest cumulative oil recovery obtained using 290 mPa.s viscosity oil was due to the fact that the steam



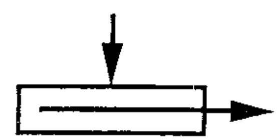


Figure 5.20: Cross-Sectional Views of the Temperature Distribution Inside the Sand Pack after the Injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV (CWE) of Steam for Run 16 Using 0.32-cm Diameter Horizontal Producer

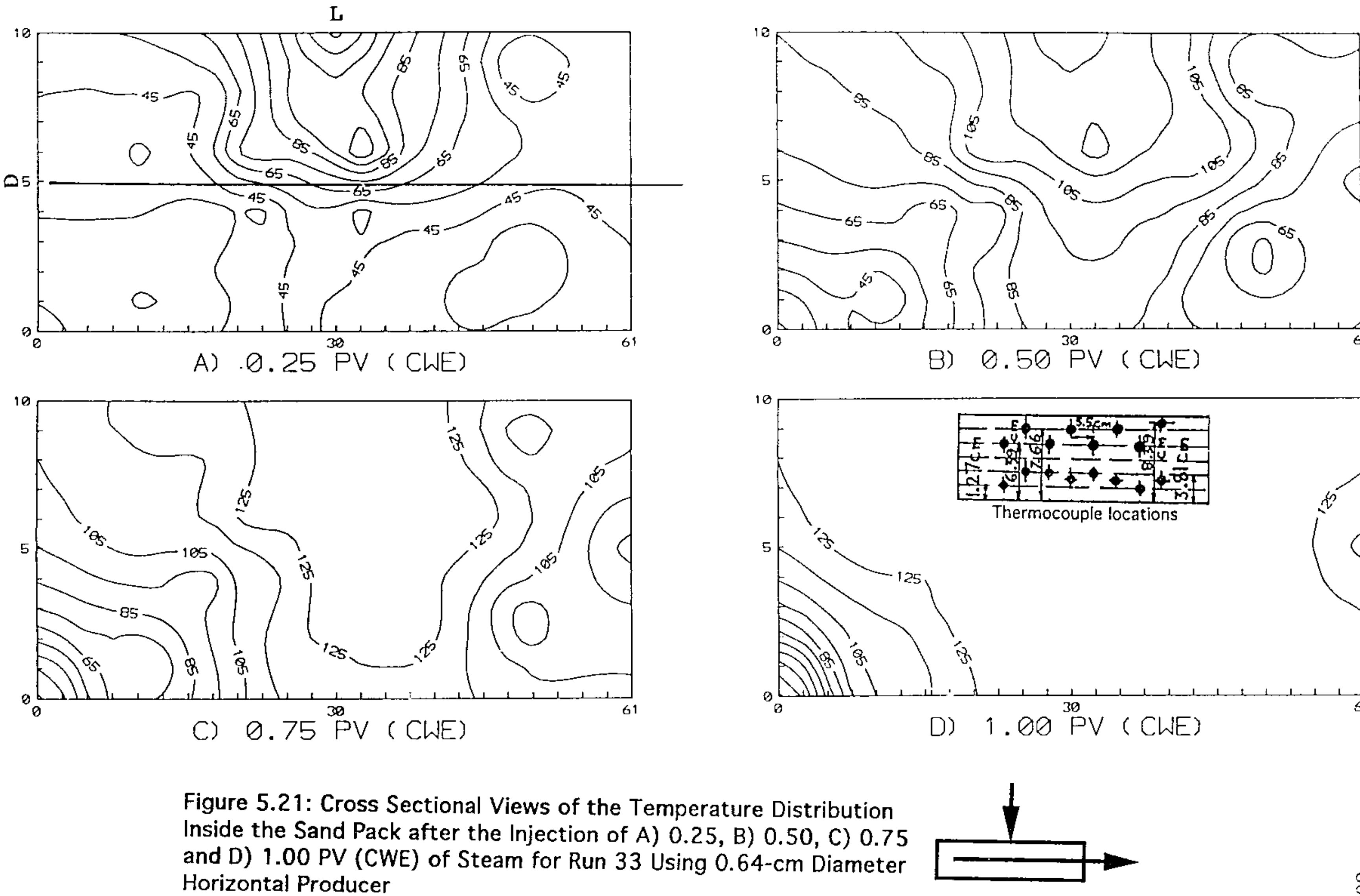
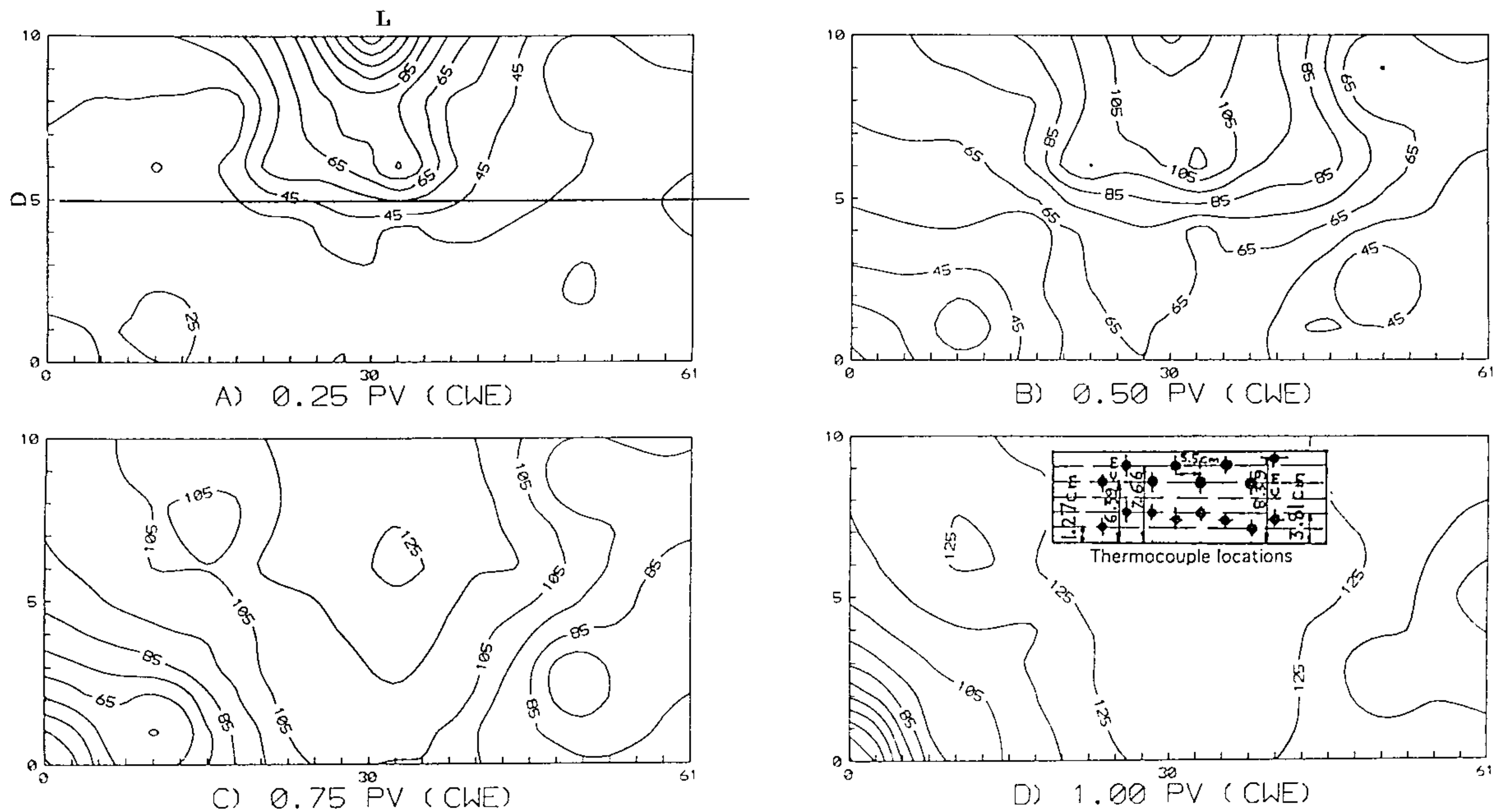


Figure 5.21: Cross Sectional Views of the Temperature Distribution Inside the Sand Pack after the Injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV (CWE) of Steam for Run 33 Using 0.64-cm Diameter Horizontal Producer



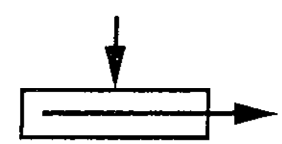
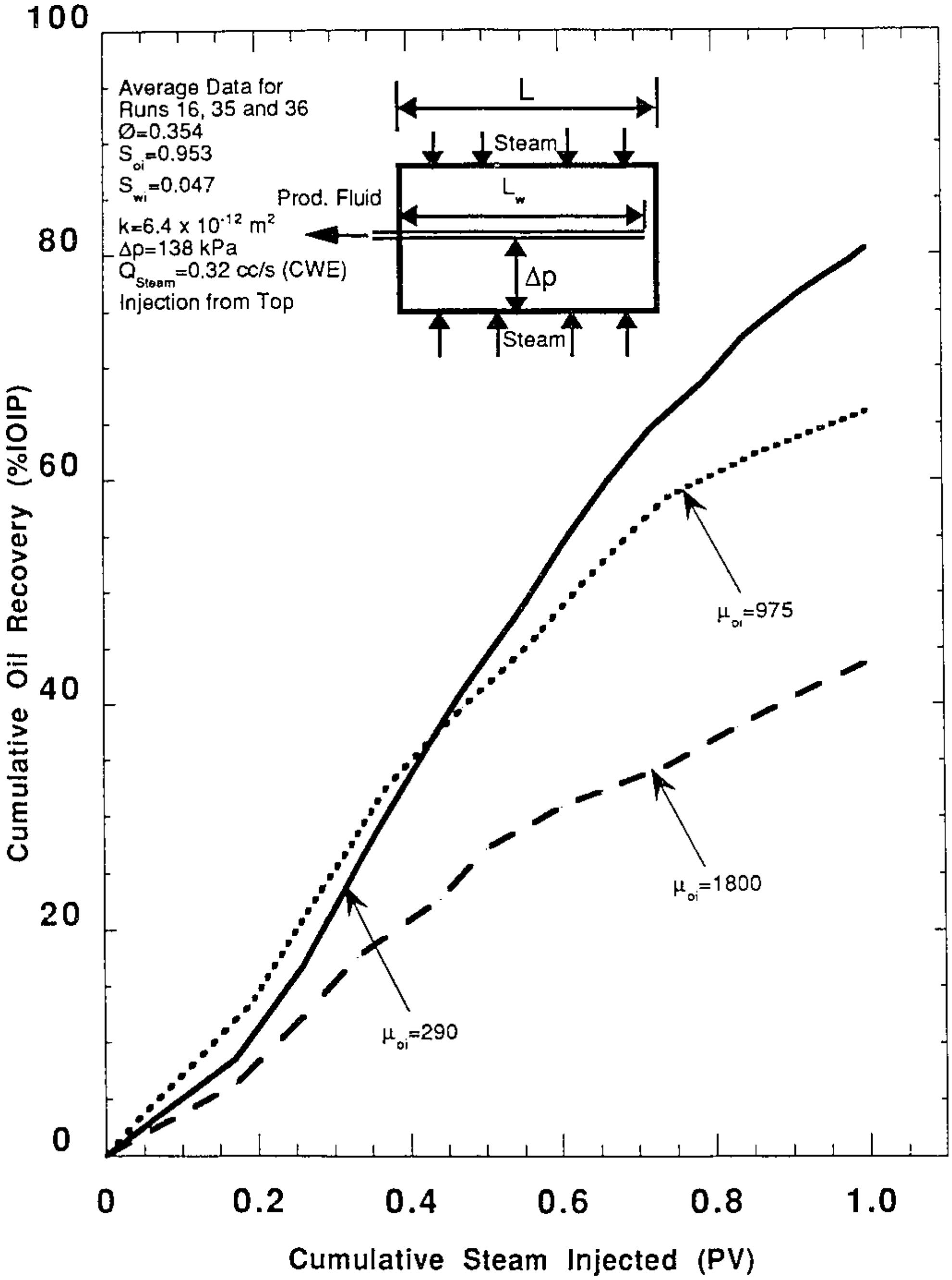


Figure 5.22: Cross-Sectional Views of the Temperature Distribution Inside the Sand Pack after the Injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV (CWE) of Steam for Run 34 Using 0.95-cm Diameter Horizontal Producer

Figure 5.23 - Runs 16, 35 and 36: Effect of Oil Viscosity on Oil Recovery for Oil of Viscosity 290, 975 and 1800 mPa.s Using a Horizontal Producer



injection process was more stable and effective in sweeping the lighter 290 mPa.s viscosity oil than in sweeping the high viscosity 1800 mPa.s oil. Furthermore, when high viscosity oil was used in Runs 35 and 36, as can be seen from the temperature distribution profiles in Figure 5.24 and 5.25, steam was slowly spreading and moving down towards the horizontal producer. Runs 35 and 36 oil production performance was complicated by steam channeling through the high viscosity oil, while that of Run 16 was more or less stable and uniform.

Figure 5.26 depicts the temperature distribution profile inside the sand pack for Run 16; it can be seen that at the end of one PV injection, oil was efficiently and uniformly swept and the sand pack was at the injection temperature. However, after the injection of one PV when high viscosity oil was used, steam fingered through the oil and was produced at the production end without uniformly sweeping the oil, as can be seen from Figures 5.24 and 5.25. Run 36 produced the lowest cumulative oil recovery of the three runs due to the high viscosity oil used and the high water production from the start of the experiment.

Figures 5.27 and 5.28 show the water-oil ratio and the cumulative oil-steam ratio vs. cumulative steam injected for the three runs. Both the water oil-ratio and the cumulative oil-steam ratio figures show that, when the high viscosity oil, (1800 mPa.s), was used, a high volume of water was produced almost as soon as the experiment started. The oil-steam ratios obtained using the 290 and 975 mPa.s viscosity oils, Runs 16 and 35, were higher than that obtained using the 1800 mPa.s viscosity oil in Run 36.

The main objective of Runs 16, 35 and 36 was to study the effect of oil viscosity on the oil production performance using different viscosity oils. Run 16 was conducted using Faxam-100 oil with a viscosity of 290 mPa.s and had a cumulative oil recovery of 81% IOIP, while experiments 35 and 36 conducted using Wainwright oils with viscosities of 975 and 1800 mPa.s, respectively, had cumulative oil recoveries of 66 and 44% IOIP, respectively. Due to the viscosity contrast and its effect on mobility ratio, oil recovery efficiency decreased as oil viscosity increased. When a heavy oil was used, steam tended to finger and channel through the oil, producing an unstable displacement and low sweep efficiency which resulted in a low cumulative oil recovery.

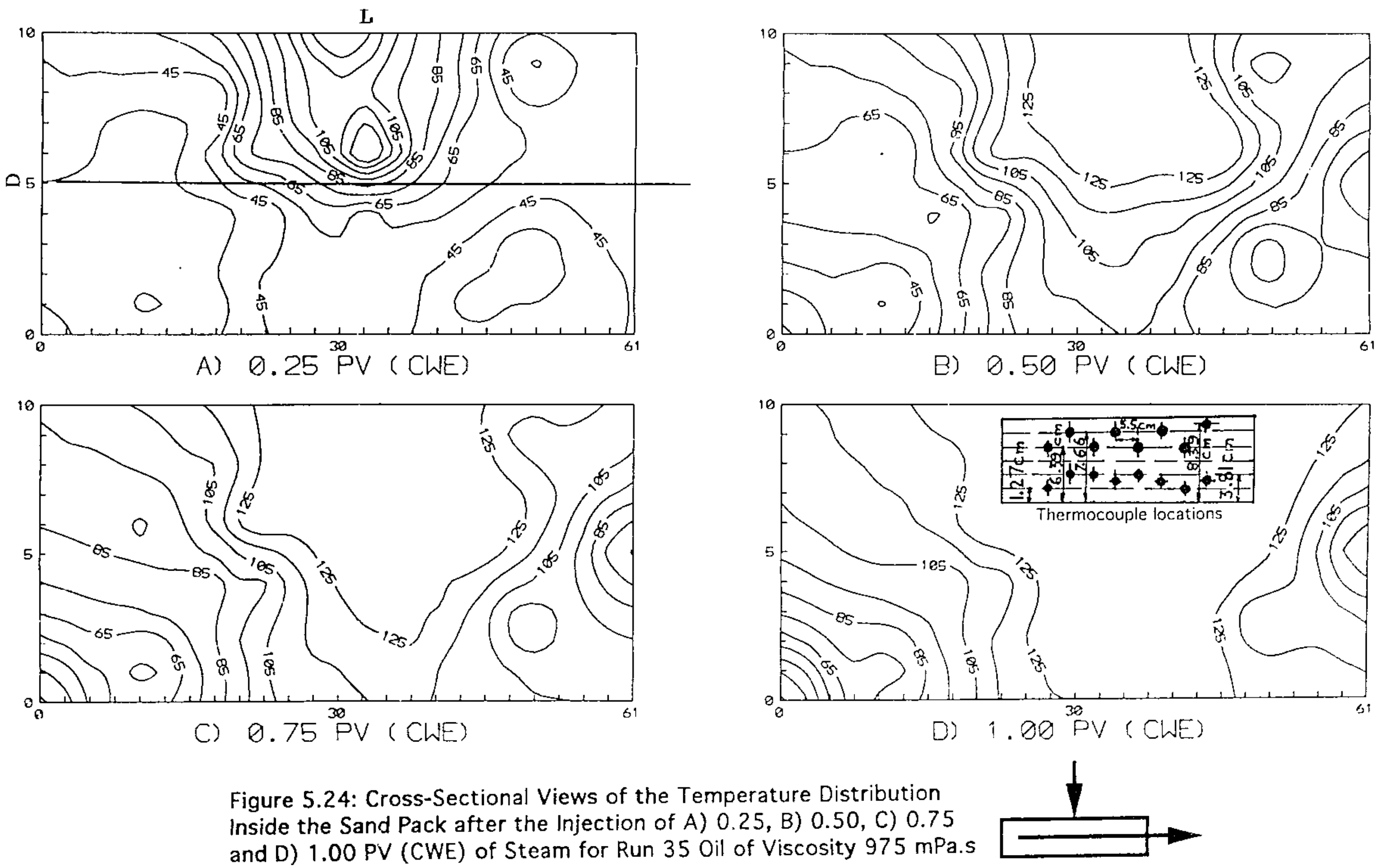
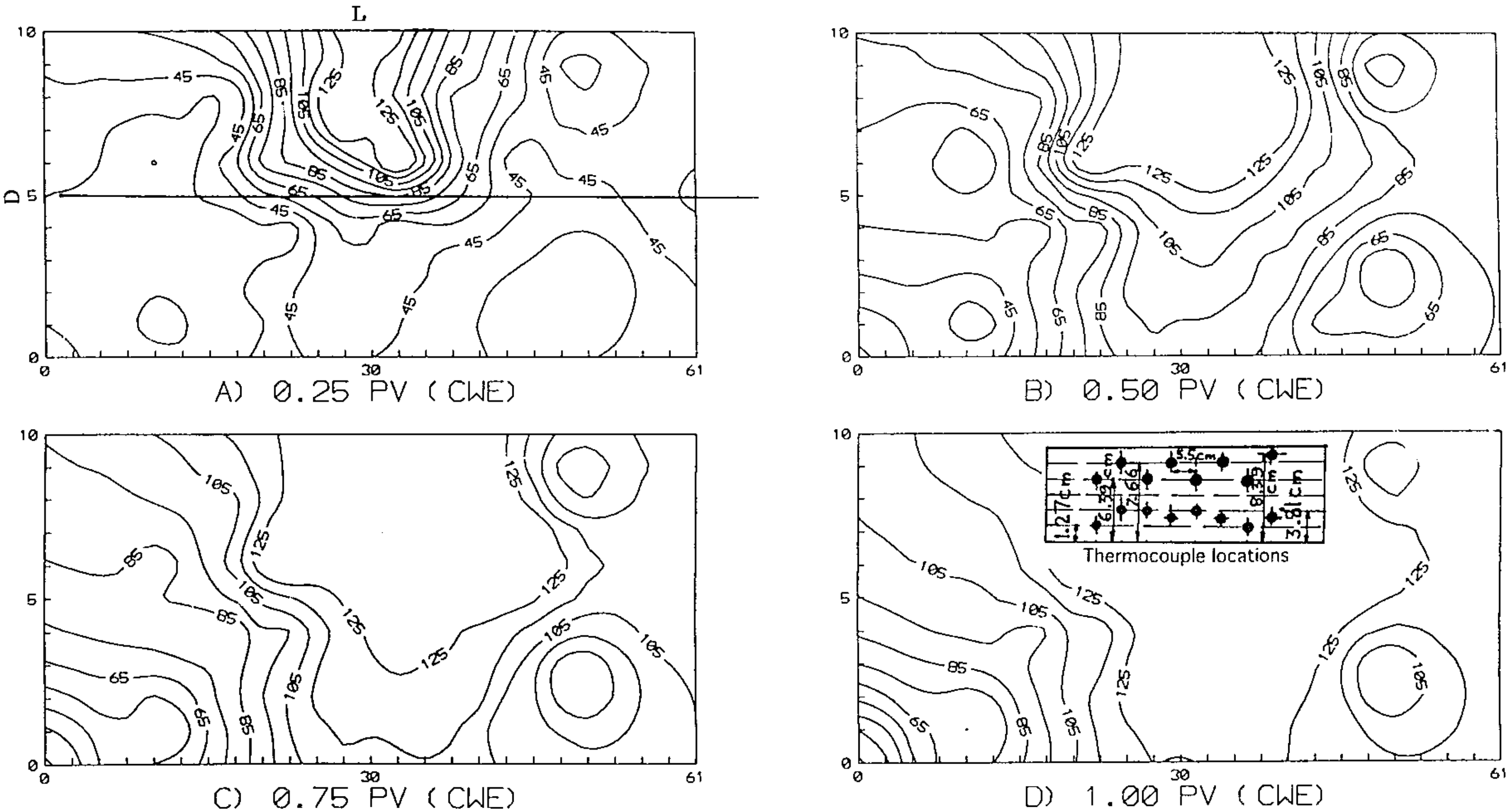


Figure 5.24: Cross-Sectional Views of the Temperature Distribution Inside the Sand Pack after the Injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV (CWE) of Steam for Run 35 Oil of Viscosity 975 mPa.s Using a Horizontal Producer



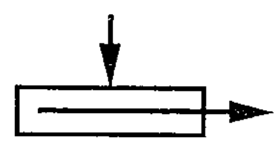


Figure 5.25: Cross-Sectional Views of the Temperature Distribution Inside the Sand Pack after the Injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV (CWE) of Steam for Run 36 Oil of Viscosity 1800 mPa.s Using a Horizontal Producer

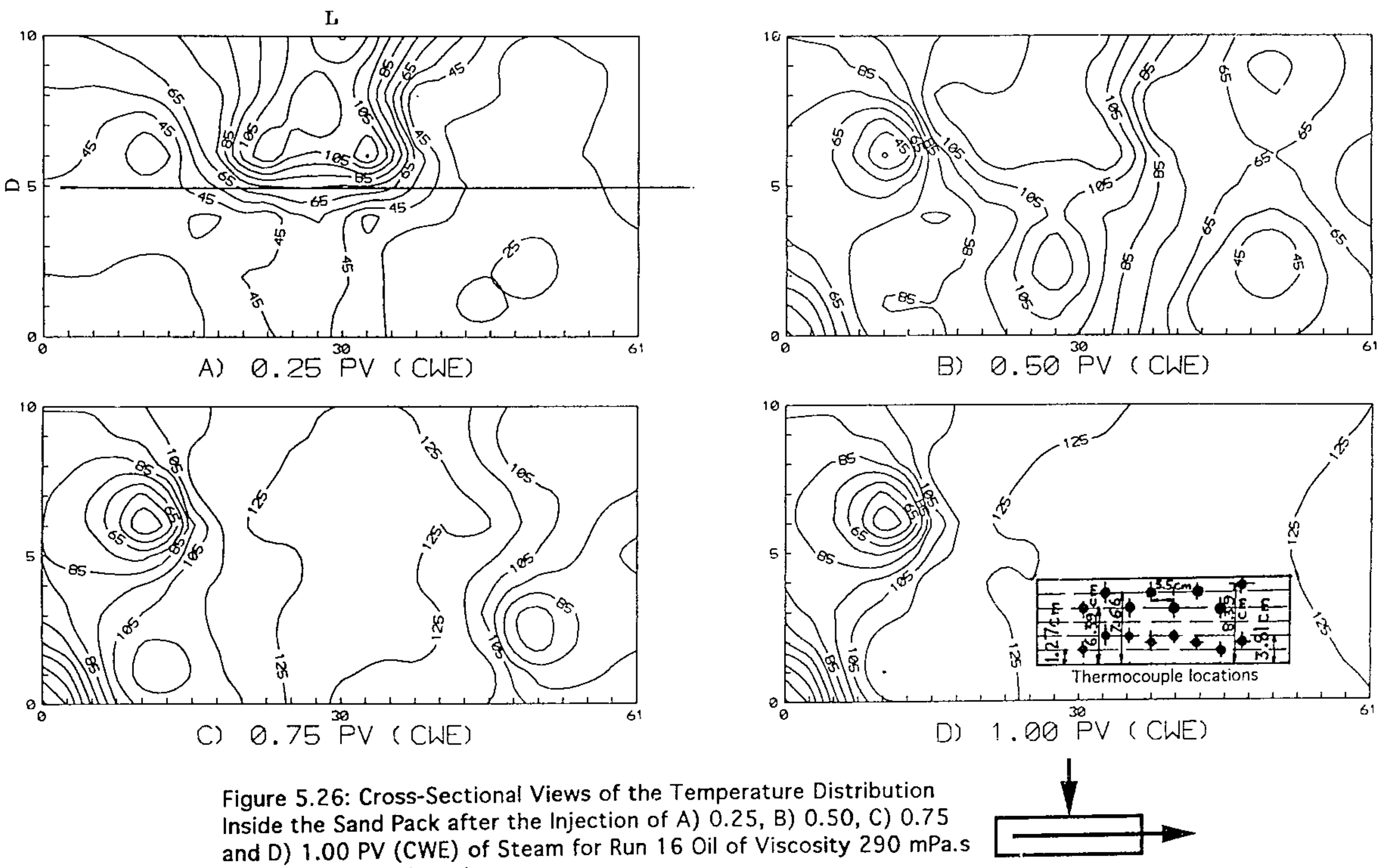


Figure 5.26: Cross-Sectional Views of the Temperature Distribution Inside the Sand Pack after the Injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV (CWE) of Steam for Run 16 Oil of Viscosity 290 mPa.s Using a Horizontal Producer

Figure 5.27 - Runs 16, 35 and 36: Effect of Oil Viscosity on Water-Oil Ratio for Oil of Viscosity 290, 975 and 1800 mPa.s Using a Horizontal Producer

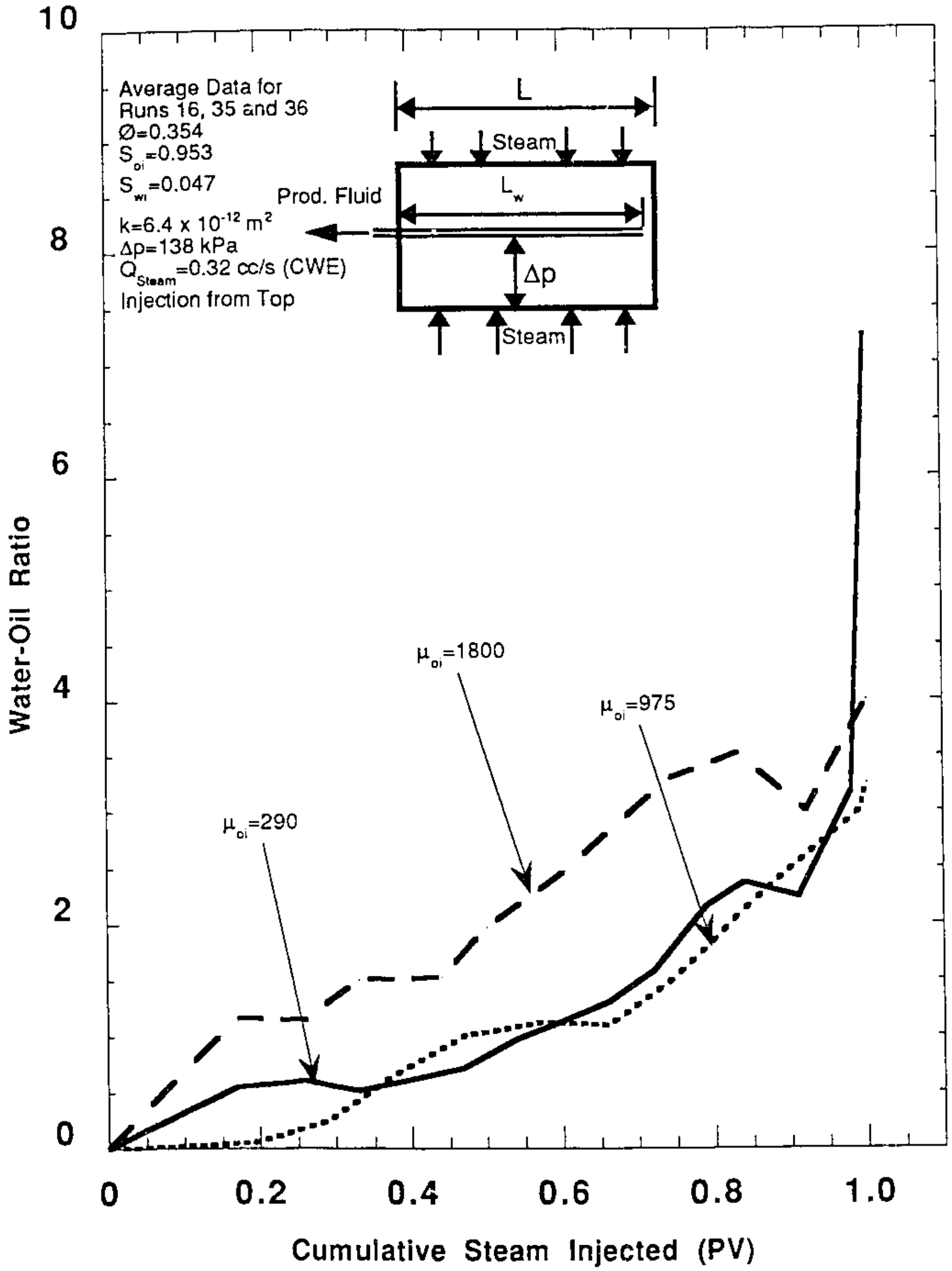
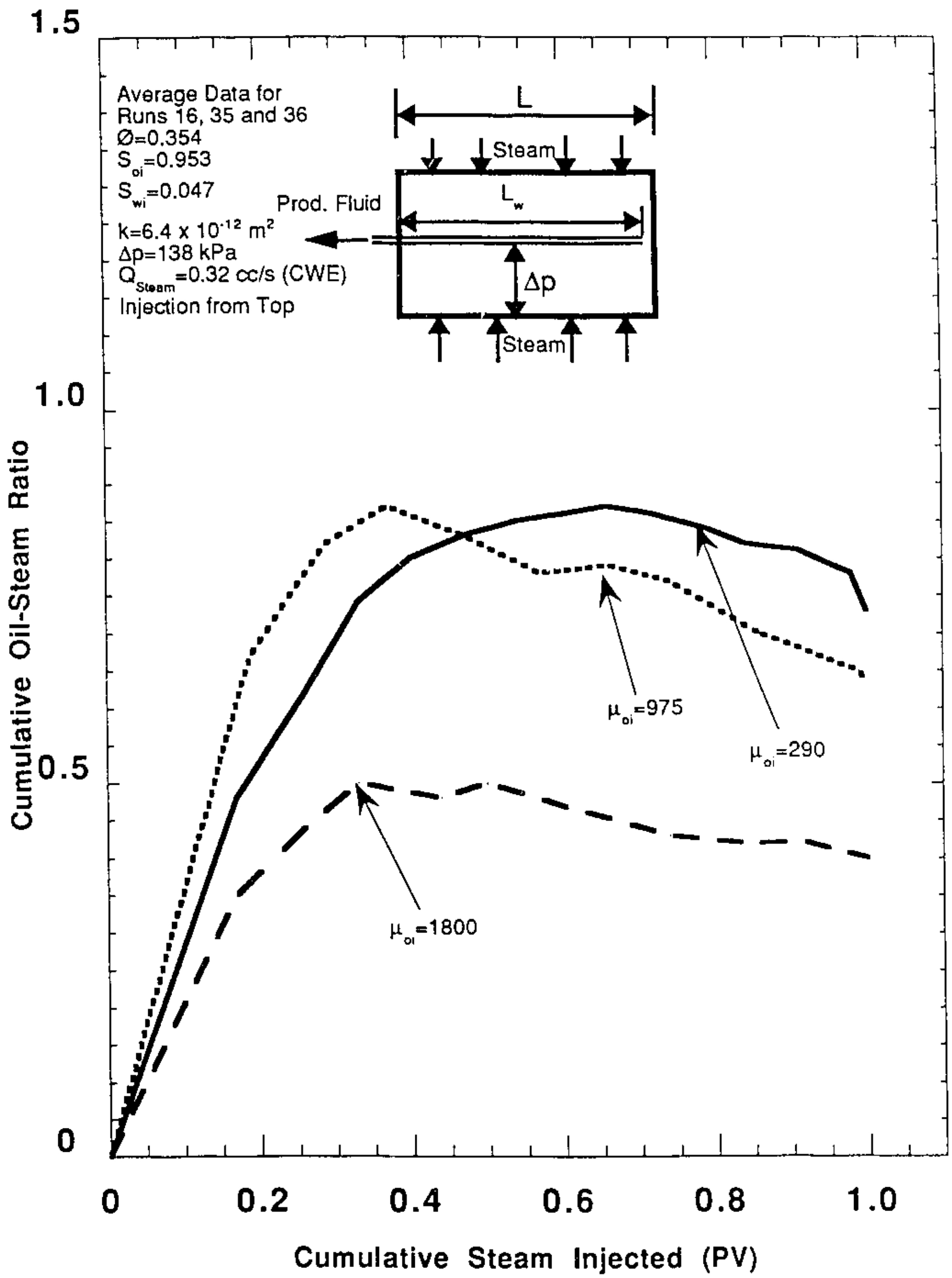


Figure 5.28 - Runs 16, 35 and 36: Effect of Oil Viscosity on Oil-Steam Ratio for Oil of Viscosity 290, 975 and 1800 mPa.s Using a Horizontal Producer



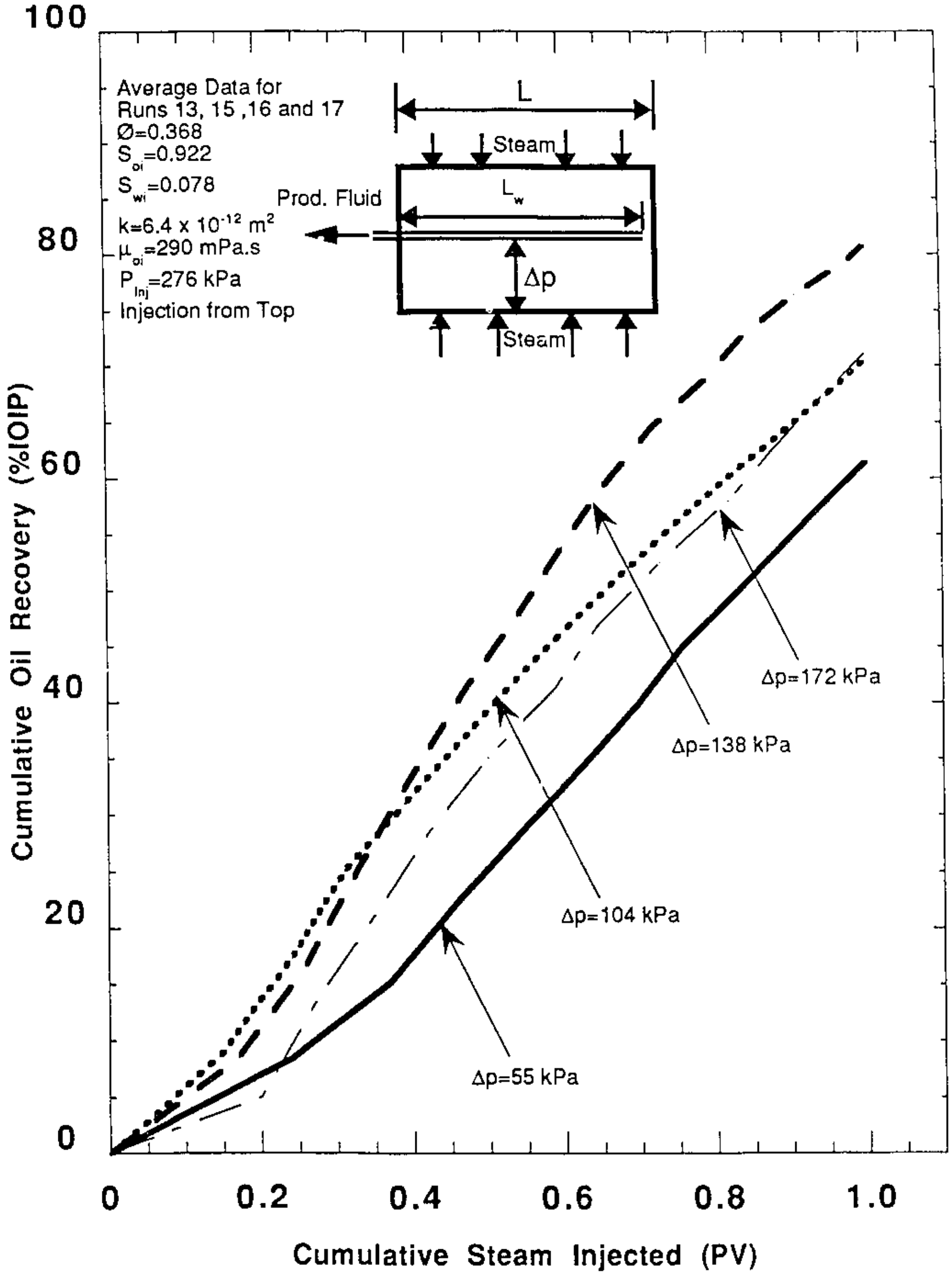
5.2.6 Effect of Pressure Differential Using a Horizontal Producer

The main objective of this set of experiments was to study the effect of pressure differential between the injector and horizontal producer on oil production performance during the steam injection process. Runs 13, 15, 16 and 17 were carried out at pressure differentials of 55 kPa (8 psig), 104 kPa (15 psig), 138 kPa (20 psig) and 172 kPa (25 psig), respectively, to investigate the pressure differential effect on the oil recovery process. Since the pressure drops inside the horizontal producer and the production line were very small, they were not included in the overall pressure differential. Thus, when the term "pressure differential" is used, it means the pressure differential between the injection point and the point of entry to the horizontal producer.

One difficulty encountered in conducting this set of experiments was keeping the injection pressure constant. To overcome this problem, a back pressure regulator monitored the steam injection pressure; that is, to increase or decrease the injection pressure accordingly. Moreover, a pressure reading was taken for each sample, and the steam injection pressure was taken to be the arithmetic average of all readings during the course of the experiment. Since the steam injection rate was fluctuating to sustain a constant injection pressure, an average injection rate was also estimated (Appendix B). Overall, the steam injection rate for the four experiments increased as the pressure drop between the injector and the producer increased. The pressure differential of 138 kPa (20 psig) gave the highest cumulative oil recovery of 81% IOIP, and the pressure differential of 55 kPa (8 psig) gave the lowest cumulative oil recovery of 62% IOIP.

Figure 5.29 shows the cumulative oil recoveries as a functions of cumulative steam injected for 55, 104, 138 and 172 kPa (gauge) pressure differentials. The figure clearly shows that cumulative oil recovery increased as the pressure drop increased to an optimum pressure differential. From the pressure drop of 55 to 138 kPa, the cumulative oil recovery increased; however, when the highest pressure differential was used, (172 kPa), the cumulative oil recovery decreased to a level even below that obtained using the 104 and 138 kPa pressure differentials. One reason that the lowest and highest pressure differentials gave low recoveries was because when the low pressure differential of 55 kPa was used, the steam injection rate was very low. A low steam injection rate in the case of a low pressure differential prolonged the experimental

Figure 5.29 - Runs 13, 15, 16 and 17: Effect of Pressure Differential on Oil Recovery for 55, 104, 138 and 172 kPa Pressure Differential Using a Horizontal Producer

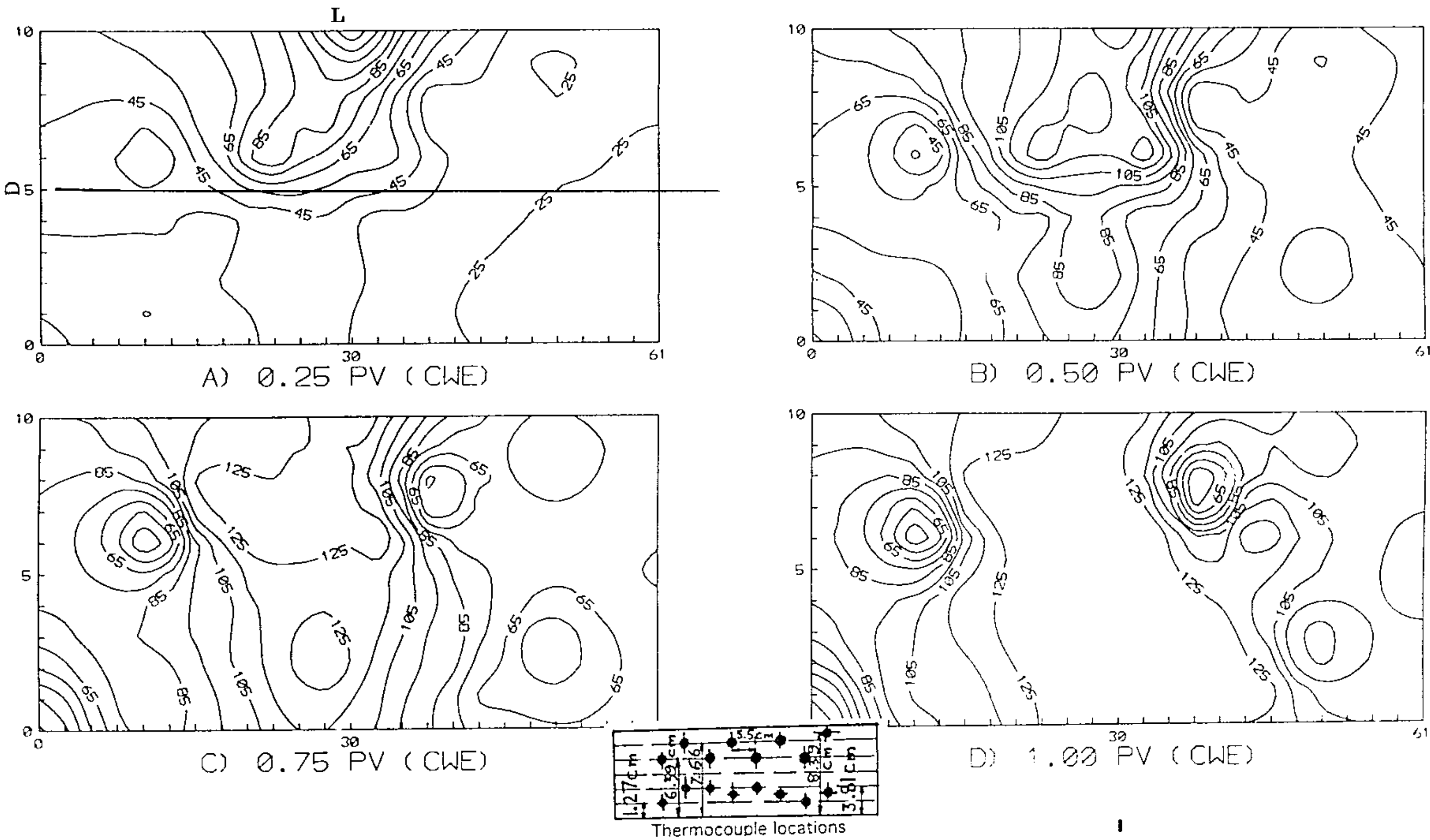


time for that particular run and resulted in high amount of heat loss (A heat loss calculation is shown Appendix A).

Figure 5.30 shows the temperature distribution profile inside the sand pack for the 55 kPa pressure differential case and it clearly demonstrates how slowly steam was moving inside the sand pack. After the injection of 0.5 PV in the case of the 55 kPa pressure differential the temperature in the sand pack parts around the horizontal producer was 90 °C when that for the 172 kPa case was 115 °C. By the time one PV was injected, the sand pack was still not at steam injection temperature, and steam did not efficiently sweep the oil throughout the entire sand pack. However, when the high pressure differential of 172 kPa was used, a high steam injection rate was obtained which resulted in a shorter experimental time than that obtained using a low pressure differential.

Furthermore, the oil production performance for the 172 kPa pressure differential case was complicated by early steam breakthrough as shown in Figure 5.31, which shows the temperature profile inside the sand pack. Run 16 was the base case conducted at a 138 kPa (20 psig) pressure differential. This experiment produced the most stable displacement and the highest sweep efficiency of the four runs, which in turn gave the highest cumulative oil recovery and cumulative oil-steam ratio. Figures 5.32 and 5.33 present the cumulative oil-steam ratios and water-oil ratios vs. steam injected into the sand pack for the four pressure differentials. There was no variation in the water-oil ratio curves between the different pressure differentials, but the cumulative oil steam ratio curves show some differences, especially between the base case and the low and high pressure differential cases.

In this set of experiments, the effect of pressure differential on steam production performance was investigated. Both high 172 kPa (25 psig) and low 55 kPa (8 psig) pressure differentials resulted in a lower cumulative oil recovery than that obtained using a pressure differential of 138 kPa (20 psig). The oil production performance for the 172 kPa pressure differential case was adversely affected by early steam breakthrough, and that for the 55 kPa pressure differential case was complicated by high heat loss, while the pressure differential of 138 kPa produced the highest cumulative oil recovery of 81% IOIP.



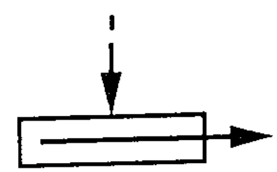


Figure 5.30: Cross-Sectional Views of the Temperature Distribution Inside the Sand Pack after the Injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV (CWE) of Steam for Run 13 Pressure Differential of 55 kPa Using a Horizontal Producer

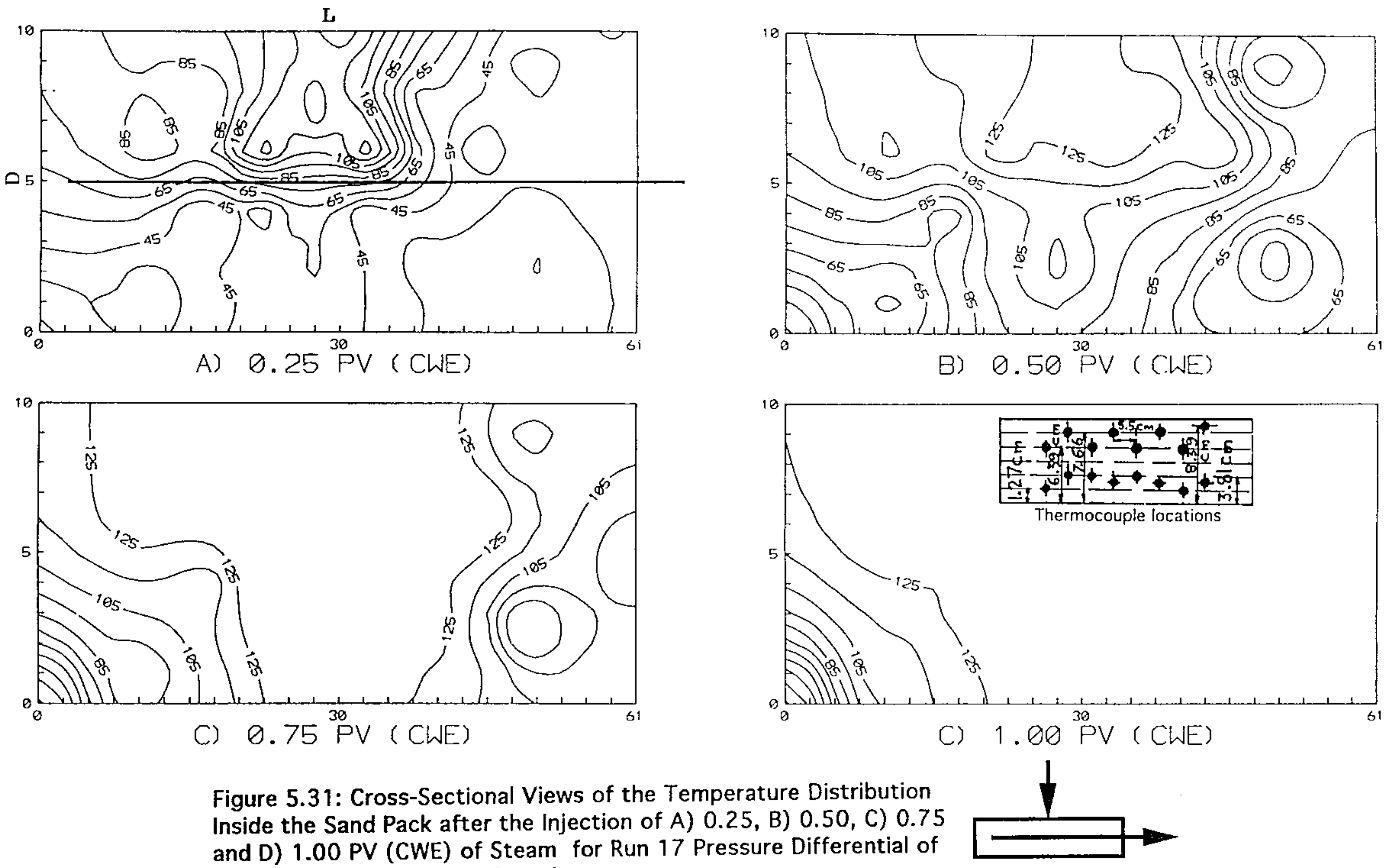


Figure 5.31: Cross-Sectional Views of the Temperature Distribution Inside the Sand Pack after the Injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV (CWE) of Steam for Run 17 Pressure Differential of 172 kPa Using a Horizontal Producer

Figure 5.32 - Runs 13, 15, 16 and 17: Effect of Pressure Differential on Oil-Steam Ratio for 55, 104, 138 and 172 kPa Pressure Differential Using a Horizontal Producer

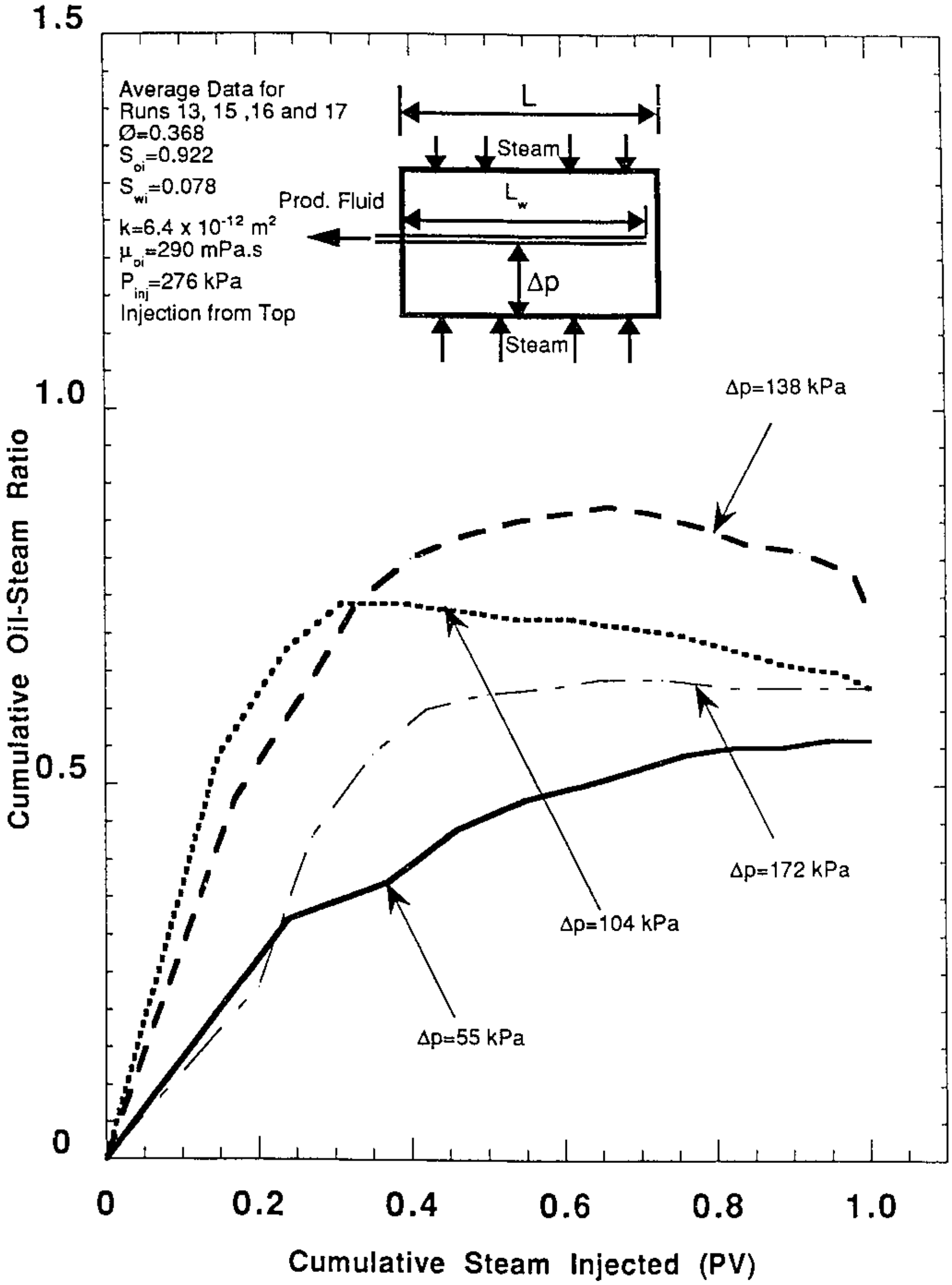
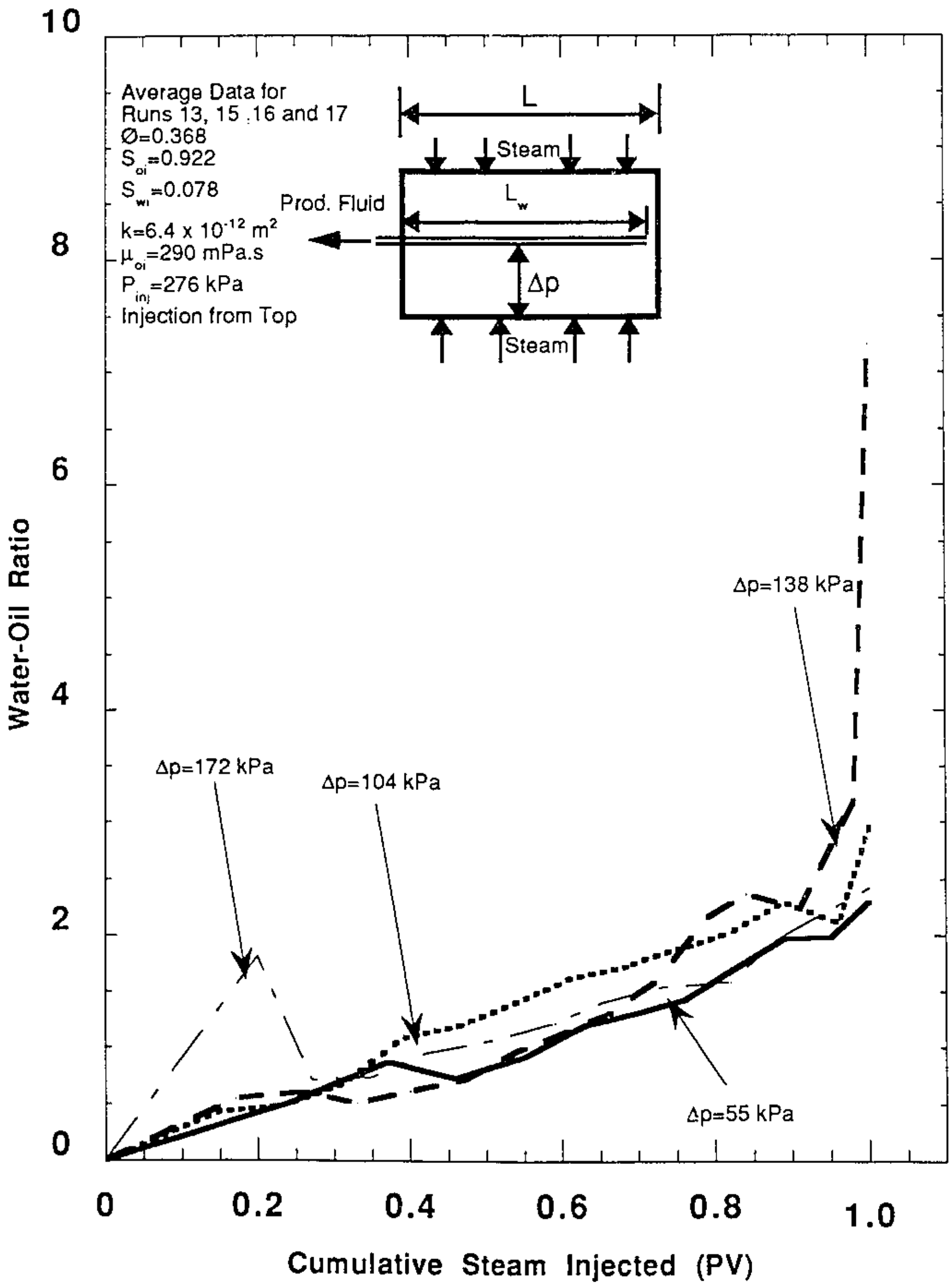


Figure 5.33 - Runs 13, 15, 16 and 17: Effect of Pressure Differential on Water-Oil Ratio for 55, 104, 138 and 172 kPa Pressure Differential Using a Horizontal Producer



5.3 Horizontal Producer and Radial Injection from Bottom

This set of experiments was directed towards the investigation of the oil production performance using a horizontal producer in combination with radial steam injection from the bottom of the cylindrical sand pack. In addition, some experiments, such as Runs 7 and 3, were repeated to evaluate the reproducibility of the results. In this set of experiments, steam was injected from the bottom of the sand pack, and oil was produced using a horizontal well located at the center of the sand pack. Since this set was carried out at the beginning of the research, Runs 1, 2 and 5 were preliminary runs conducted for the researcher to get used to different experimental apparatus and their components. The following sections discuss the results obtained from eight experiments conducted using a horizontal producer in combination with radial steam injection from the bottom of the sand pack.

5.3.1 Production History of a Typical Run

Run 7 had the highest cumulative oil recovery and the fewest experimental and operational problems; thus, it was taken as the base run for the bottom injection experiments and will be discussed in detail. The experiment was performed using a horizontal producer penetrating the full length of a homogenous cylindrical sand pack. The sand pack was anisotropic with an average permeability of 6.4×10^{-12} m^2 (6.5 darcies) and measured porosity and initial oil saturation of 33.1 and 92.4%, respectively. Steam was injected from the bottom of the sand pack with an average injection rate of 0.18 cc/s (CWE). Table 5.3 lists the experimental and production data used to construct Figure 5.34 which shows cumulative oil recovery, cumulative oil-steam ratio, water-oil ratio and oil rate vs. cumulative steam injected for Run 7.

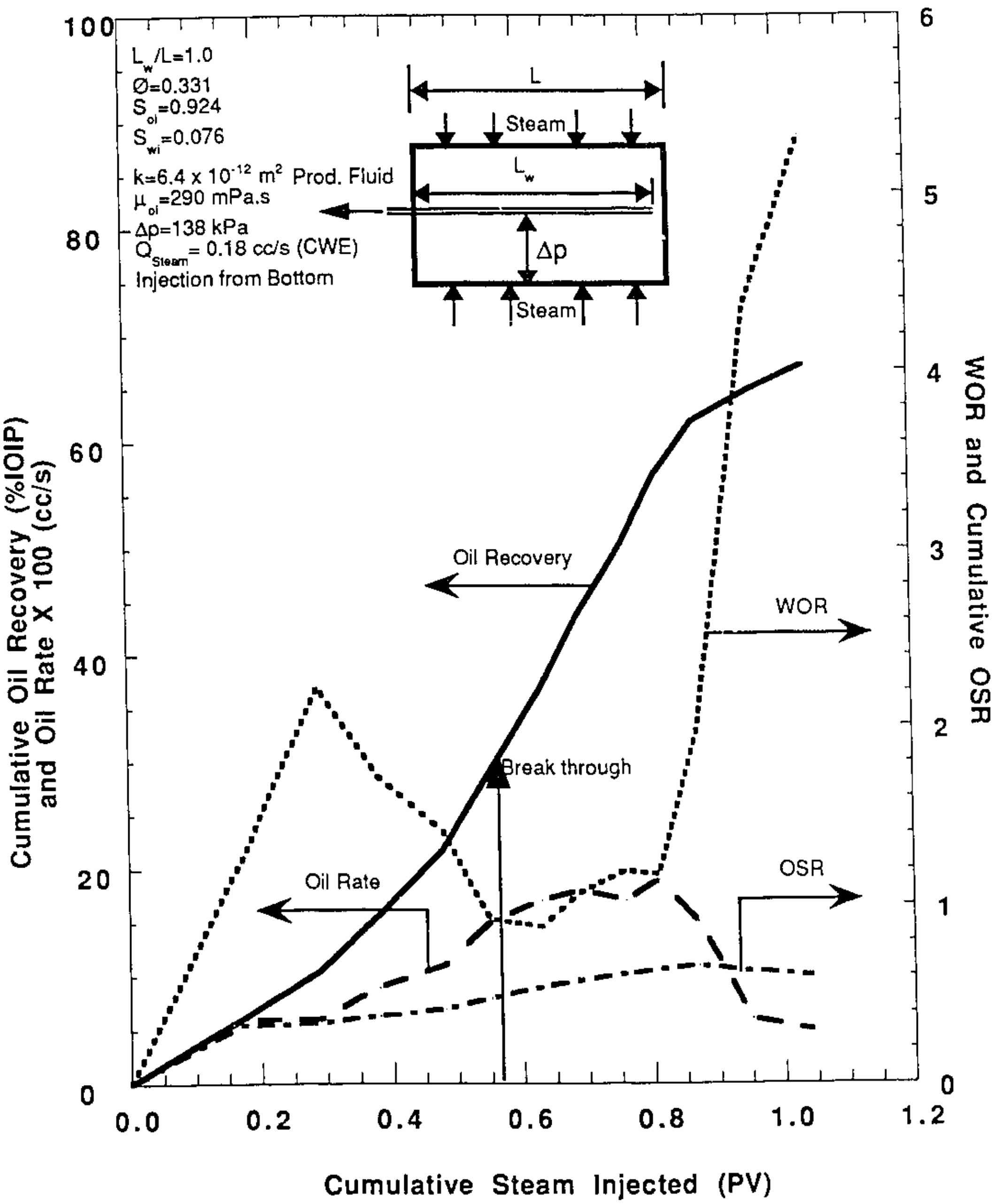
A cumulative oil recovery of 67% was obtained by the time 1.04 PV of steam (CWE) was injected into the sand pack. The water-oil ratio curve shows rather unusual behaviour; it started with a high water-oil ratio, decreased and stabilized, and then increased after breakthrough. The high water-oil ratio at the start was caused by the production of unswept water left behind during the saturation process of the sand pack with oil. The oil-steam ratio curve shows rather a typical behaviour for a steamflood experiment in this research. In this experiment, as in other experiments, the temperature data were collected throughout the experiment using thermocouples located at different points along the length and diameter of the sand pack. To detect and track

Table 5.3 - Run 7: Radial Injection from Bottom in Combination with a Horizontal Producer

Bulk Volume:	4492 cc	Initial Oil Saturation:	92.4 %PV
Pore Volume:	1635 cc	Initial Water Saturation :	7.6 %PV
HC Pore Volume:	1510 cc	Type of Oil Used:	Faxam-100
Porosity:	33.1%	Oil Viscosity @ 24 °C and101 kPa:	290 mPa . s
Average Absolute Permeability :	4.6 x 10^-12 m^2 (6.5 darcies)	API Gravity @ 24 °C and101 kPa:	30 °API
Average Steam Injection Rate:	0.18 mL/s (CWE)	Production Pressure:	138 kPa
Net Oil Recovery:	**67.1%**	**Total Steam Injected:**	**1694 cc**

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	25.27	273	0.17	202	90	90	6.0	0.06	1.24	0.33
2	17.90	466	0.29	222	69	159	10.5	0.06	2.22	0.34
3	14.58	624	0.38	212	78	237	15.7	0.09	1.72	0.38
4	14.33	779	0.48	222	92	329	21.8	0.11	1.41	0.42
5	11.45	903	0.55	204	106	435	28.8	0.15	0.92	0.48
6	11.15	1023	0.63	220	117	552	36.6	0.17	0.88	0.54
7	10.10	1132	0.69	224	108	660	43.7	0.18	1.07	0.58
8	10.02	1240	0.76	223	102	762	50.5	0.17	1.19	0.61
9	8.47	1331	0.81	208	96	858	56.8	0.19	1.17	0.64
10	8.28	1420	0.87	222	75	933	61.8	0.15	1.96	0.66
11	12.12	1551	0.95	225	42	975	64.6	0.06	4.36	0.63
12	13.23	1694	1.04	240	38	1013	67.1	0.05	5.32	0.60

Figure 5.34 - Production History of Run 7: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected Using a Horizontal Producer and Bottom Steam Injection



steam zone growth and the steam front, temperature data were plotted on a contour map using the SURFER program.

Figure 5.35 presents the temperature distribution profiles inside the sand pack after the injection of A) 0.25, B) 0.50 C) 0.75 and D) 1.00 PV CWE for Run 7. After the injection of one PV of steam (CWE) into the sand pack, the temperature profile shows that steam had not yet advanced through the entire sand pack, and, as a result, some parts of the sand pack, especially at the top half, were not completely swept. Since steam was injected from the bottom of the sand pack, there was a tendency for it to channel through the oil, producing an unstable displacement and low sweep efficiency. Run 7 was carried out at a constant injection rate using a constant rate pump. The injection temperature was always maintained above the steam saturation temperature. The production pressure was kept constant throughout the experiment by means of a back pressure regulator. Figure 5.36 shows the injection and production temperatures and the injection pressure vs. cumulative steam injected for the run. The sudden decline in the injection pressure at the start of the experiment was caused by the steam channeling inside the sand pack. This experiment, as the case with other experiments, was terminated after one pore volume of steam (CWE) was injected into the sand pack.

5.3.2 Top versus Bottom Radial Injection Using a Horizontal Producer

Steam injection from the top or bottom of the sand pack affects oil production performance during the steam injection process. Two experiments, Run 16 (injection from the top) and Run 7 (injection from the bottom) were conducted using horizontal producers penetrating the full length and located at the center of the sand pack to investigate top and bottom steam injection on the oil production performance. Both experiments were carried out in a homogeneous and anisotropic sand pack with an average permeability of 6.4×10^{-12} m^2 (6.5 darcies), and average porosity and initial oil saturation of 34 and 94%, respectively. Run 16 had a higher steam injection rate of 0.34 cc/s (CWE) than that of 0.18 cc/s (CWE) for Run 7. Moreover, the cumulative oil recovery obtained when steam was injected from the top was higher than that obtained when steam was injected from the bottom of the sand pack, as can be seen from Figure 5.37.

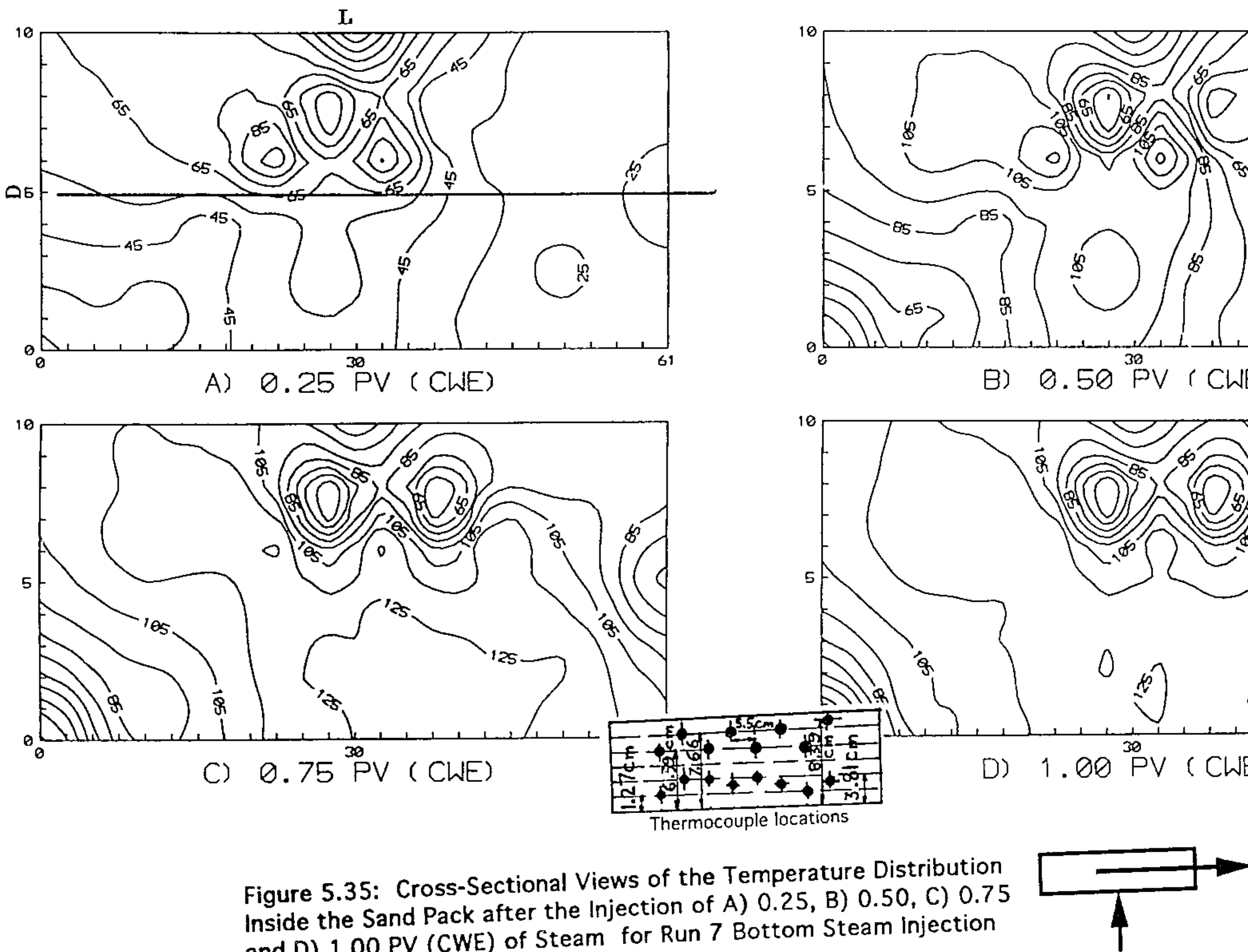


Figure 5.35: Cross-Sectional Views of the Temperature Distribution Inside the Sand Pack after the Injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV (CWE) of Steam for Run 7 Bottom Steam Injection Using a Horizontal Producer

Fig 5.36 - Production History of Run 7: Injection/Production Temperature and Injection Pressure vs. Cumulative Steam Injected Using a Horizontal Producer and Injection from Bottom

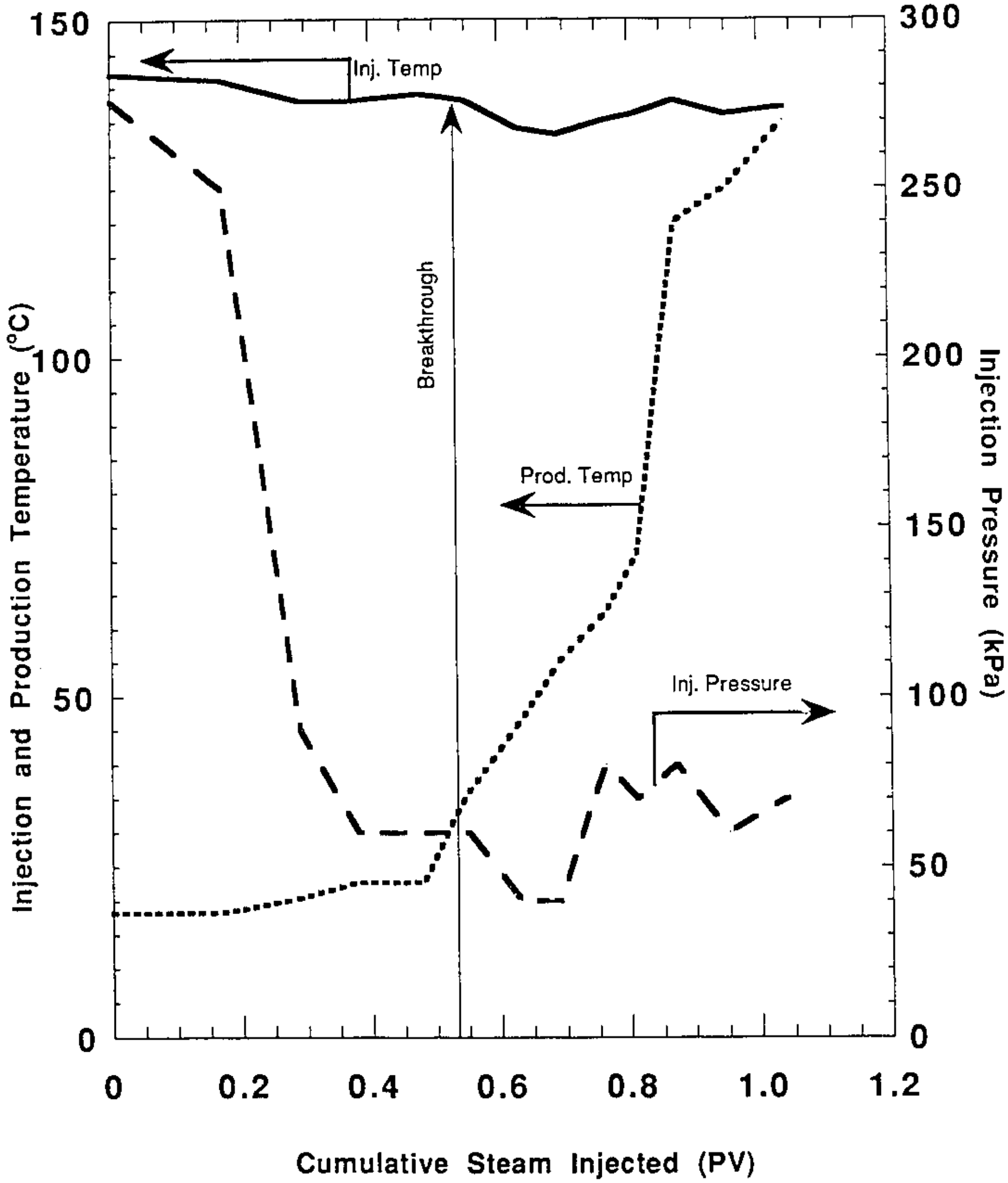


Figure 5.37 - Runs 7 and 16: Effect of Steam Injection from Top or Bottom of the Sand Pack on Oil Recovery Using a Horizontal Producer

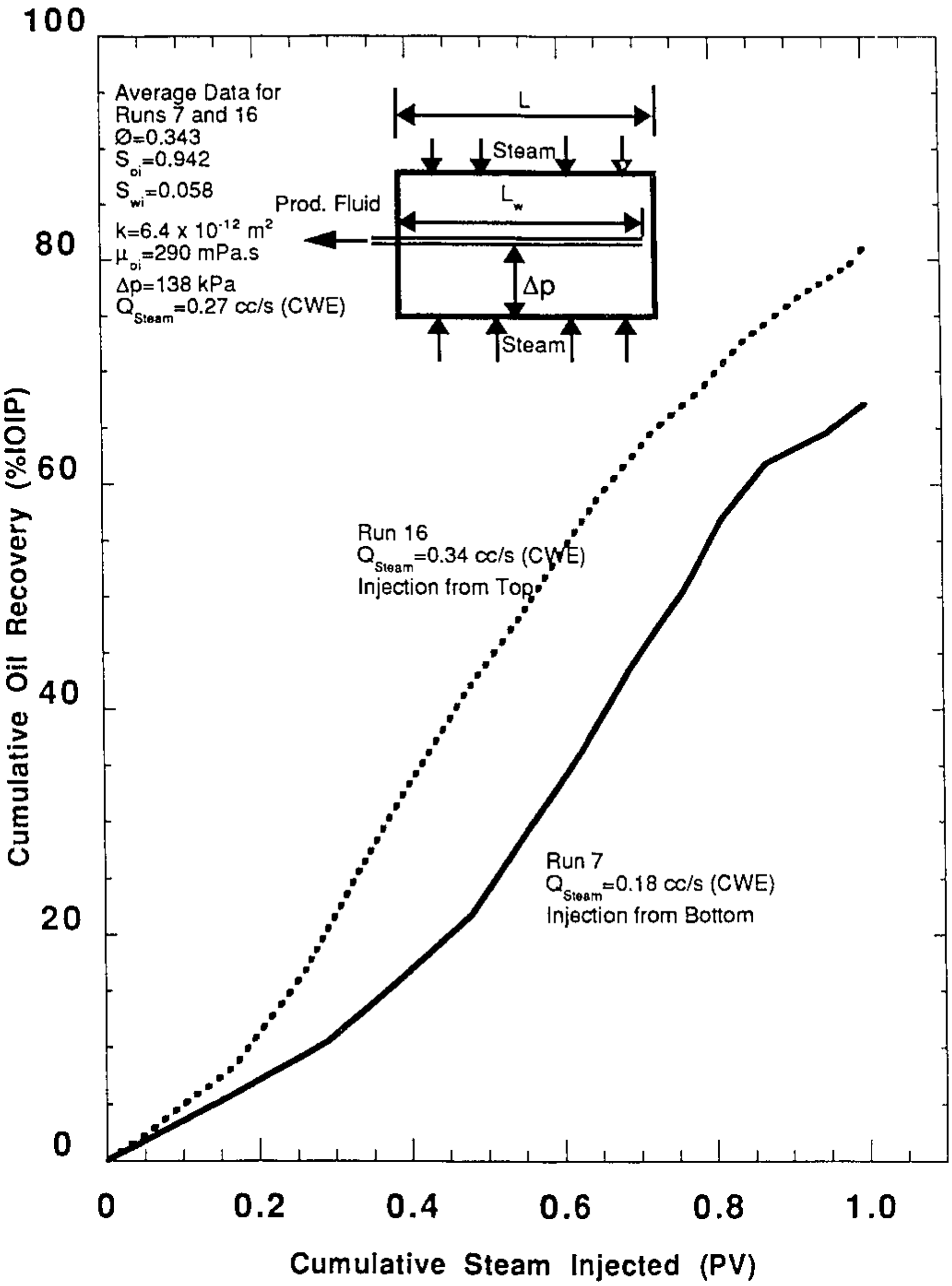


Figure 5.37 shows that after one PV of steam (CWE) was injected in the sand pack, cumulative oil recovery was 81% IOIP for top injection and 66% for bottom injection. One reason injection from the top produced higher recovery than bottom steam injection was steam gravity override. The gravity effect was more pronounced during bottom steam injection than during top injection. This effect may be observed in Figures 5.5 and 5.35, which show temperature distribution profiles inside the sand pack for both top and bottom steam injection. When steam was injected from the top of the sand pack, the steam displacement was stable and efficient in displacing the oil. After the injection of one PV, the entire sand pack was at injection temperature and most of the oil was efficiently produced.

However, when steam was injected from the bottom of the sand pack, the steam injection process was complicated by steam gravity override, fingering and early breakthrough. Because of the tendency for steam to rise, before the injection of one PV, steam quickly fingered and propagated to the horizontal producer leaving unswept oil particularly in the upper half of the sand pack. Gravity override and viscous fingering complicated the steam production process, making steam injection, in this case from the bottom of the sand pack, an unattractive alternative. In addition to gravity override, steam injection from the bottom of the sand pack was also complicated by high production of water at the start of the experiment, as shown in Figure 5.38. The oil-steam ratios for top and bottom steam injection were plotted in Figure 5.39, and, again, the highest cumulative oil-steam ratio was obtained during steam injection from the top of the sand pack. The major reason that steam injection from the bottom of the sand pack produced lower cumulative oil recovery than steam injection from the top, is the high heat loss resulting from the low injection rate when steam was injected from bottom.

Based on the experimental results obtained from Run 16 (top injection) and Run 7 (bottom injection), it can be concluded that the steam injection process was more stable and efficient when steam was injected from the top of the sand pack. For bottom injection, the steam injection process was complicated by steam gravity override and viscous fingering, which made oil displacement by steam an unstable process and unattractive alternative to produce oil. Higher injection rate was obtained when steam was injected from the top than from the bottom of the sand pack resulting in a high cumulative oil recovery.

Figure 5.38 - Runs 7 and 16: Effect of Steam Injection from Top or Bottom of the Sand Pack on Water-Oil Ratio Using a Horizontal Producer

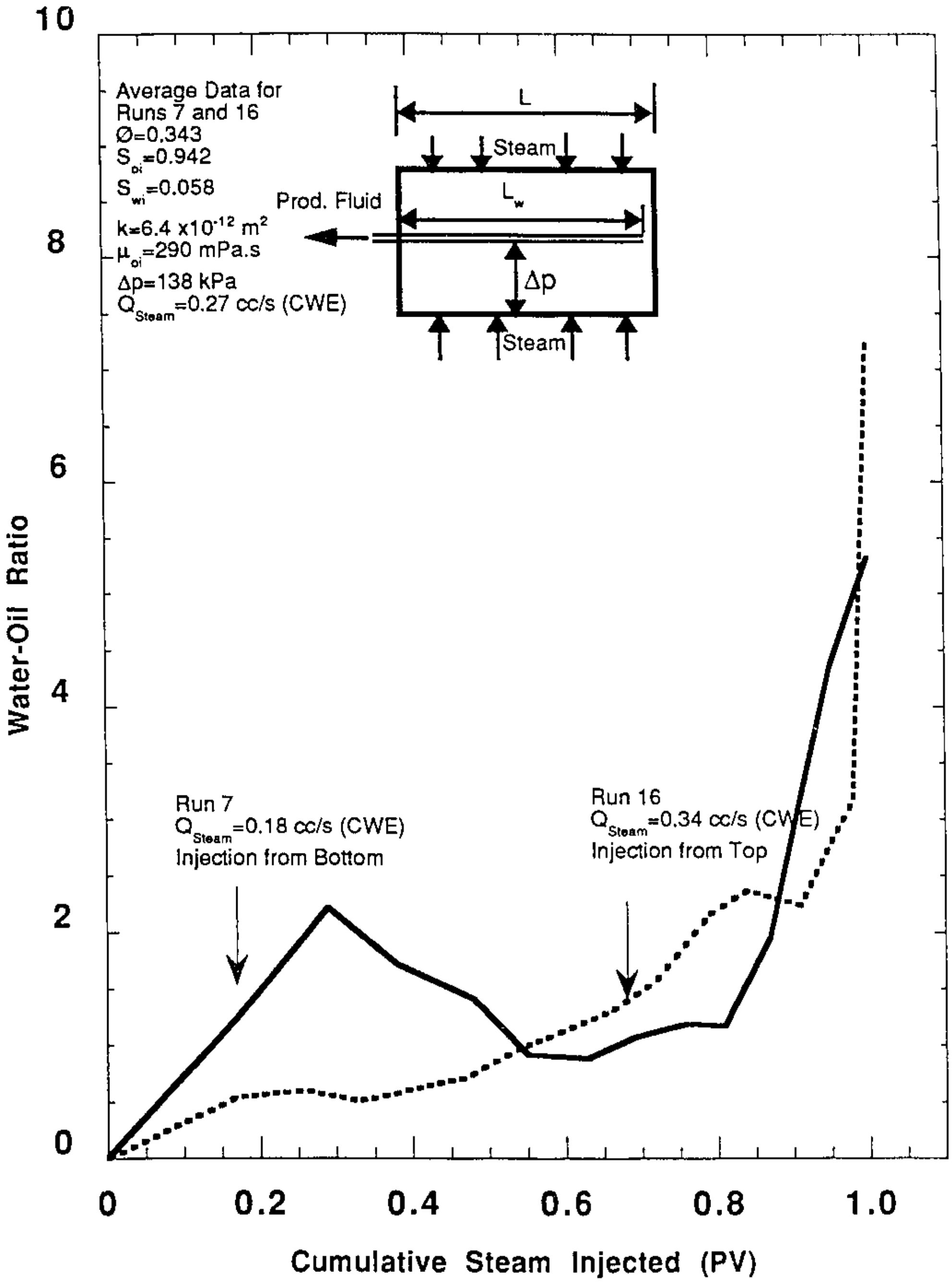
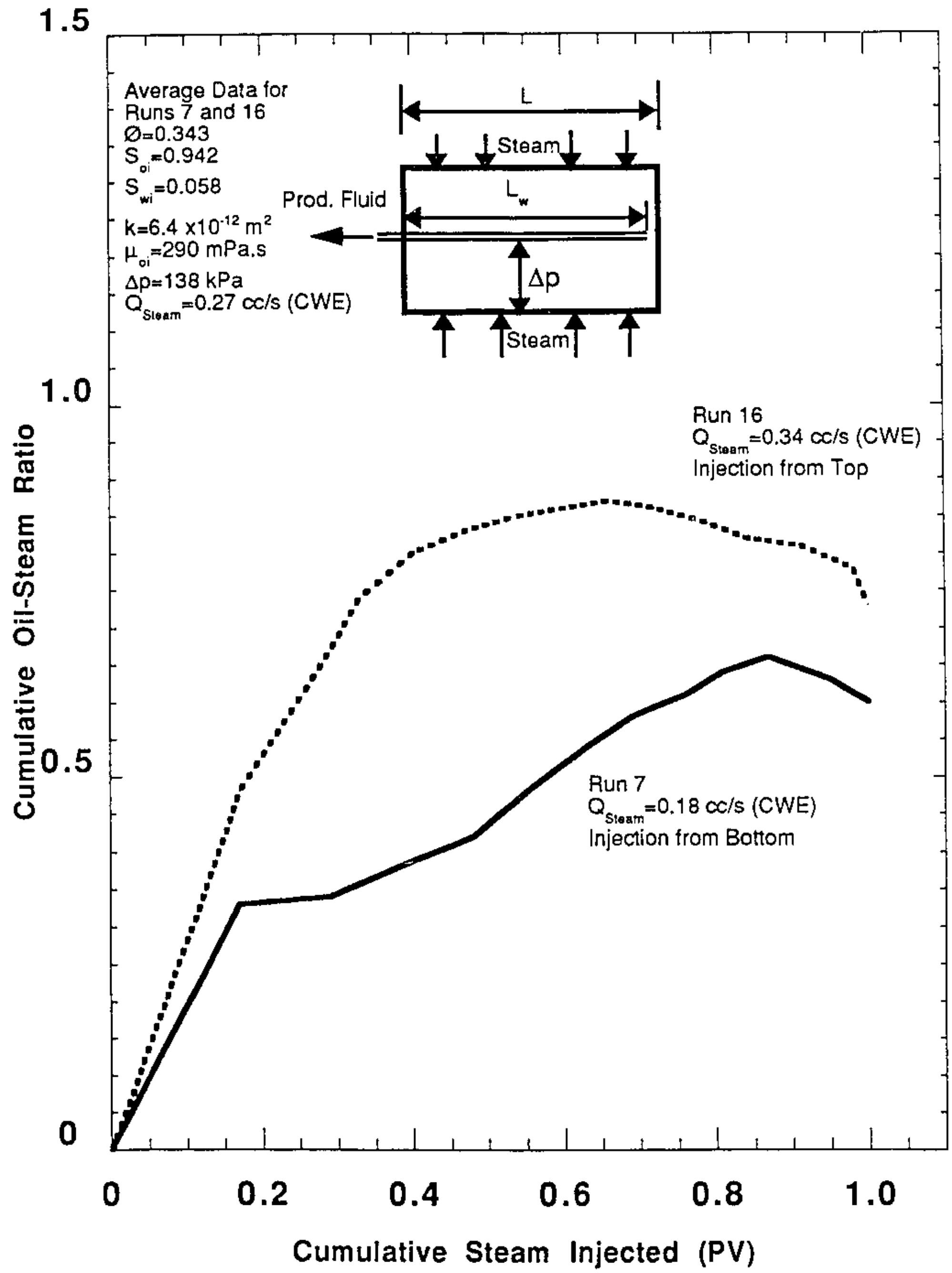


Figure 5.39 - Runs 7 and 16: Effect of Steam Injection from Top or Bottom of the Sand Pack on Oil-Steam Ratio Using a Horizontal Producer



5.3.3 Reproducibility of Experimental Results

Repeatability of experiments and reproducibility of results are some of the important elements in evaluating experimental data reliability and accuracy. Reproducibility of experimental results was checked at the beginning of this research to ensure reliable and accurate experimental results. Four experiments-Run 4 which was a repeat of Run 3 and Run 9 which was a repeat of Run 7-were carried out to investigate experimental results reproducibility. In this section, Runs 7 and 9 will be compared and discussed to show the similarities and differences, if any. The results for Runs 3 and 4 are given in Appendices B and C.

Both Runs 7 and 9 were conducted using a homogeneous sand pack with an average permeability of 6.4×10^{-12} m^2 (6.5 darcies) and a measured porosity of 33.1% for Run 7 and 37.7% for Run 9. Steam was injected from the bottom, and oil was produced using a horizontal producer penetrating the full length of the sand pack. The initial oil saturations for Runs 7 and 9 were 92.4 % and 90.9%, respectively, using Faxam-100 oil with a viscosity of 290 mPa.s. The two runs had the same experimental settings, i.e. the same injection pressure of 276 kPa (40 psig), temperature of 142 °C (288 °F) and the same back pressure of 138 kPa (20 psig) at the production end. After the injection of one PV of steam (CWE), as shown in Figure 5.40, the absolute difference in cumulative oil recovery between the two runs was approximately 3 percent. The water-oil ratio and cumulative oil-steam ratio for Runs 9 and 7 are plotted in Figures 5.41 and 5.42 and have very similar trends.

Moreover, a close agreement was observed in the temperature distribution profiles of the steam inside the sand pack for Runs 7 and 9, as shown in Figures 5.35 and 5.43. Cumulative oil recoveries, cumulative oil-steam ratios, water-oil ratios, and temperature distribution profiles for both runs were in a close agreement with a modest absolute difference of 3 percentage points. It was felt that a 3% difference or less in the experimental data should be considered as experimental discrepancy. Overall, results reproducibility was satisfactory.

5.4 Horizontal Injector and Radial Production from Bottom

Earlier in this chapter, steam injection performance using a horizontal producer was discussed. In the following sections, steam injection performance using a horizontal injector will be discussed. Sixteen experiments were conducted in which

Figure 5.40: Reproducibility of Experimental Results, Cumulative Oil Recovery vs. Cumulative Steam Injected Using a Horizontal Producer (Run 9 Repeat of Run 7)

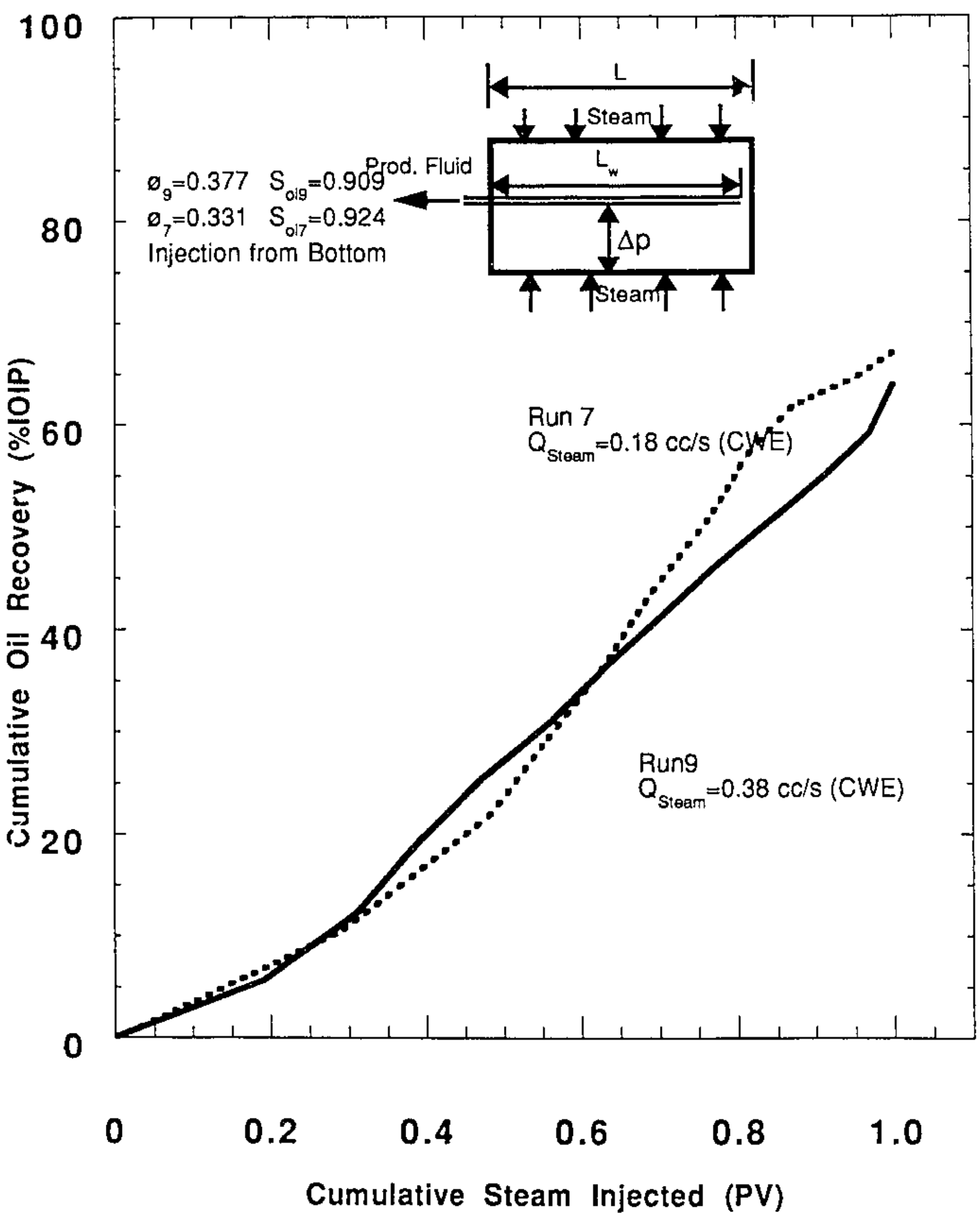


Figure 5.41: Reproducibility of Experimental Results, Water-Oil Ratio vs. Cumulative Steam Injected Using a Horizontal Producer (Run 9 Repeat of Run 7)

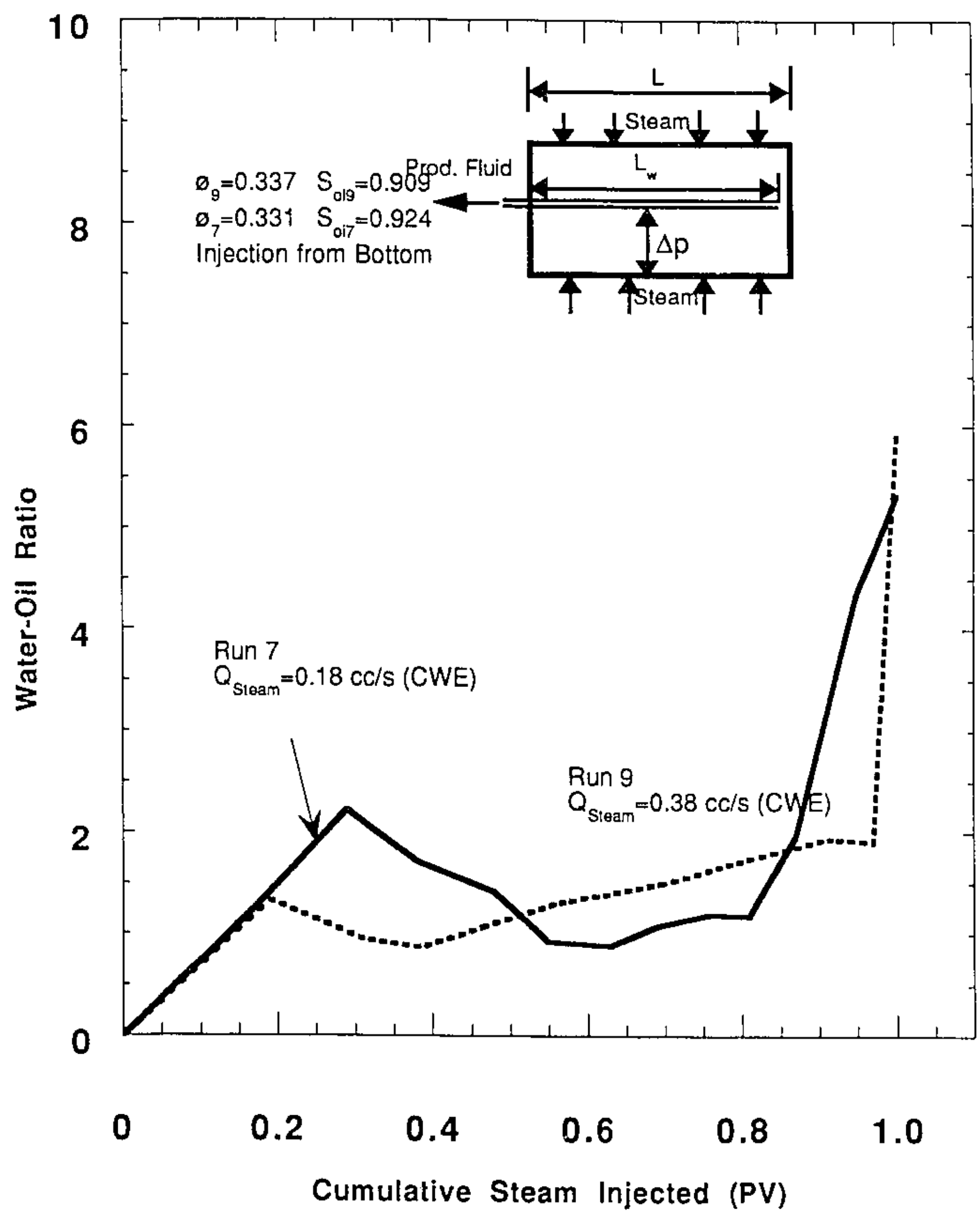
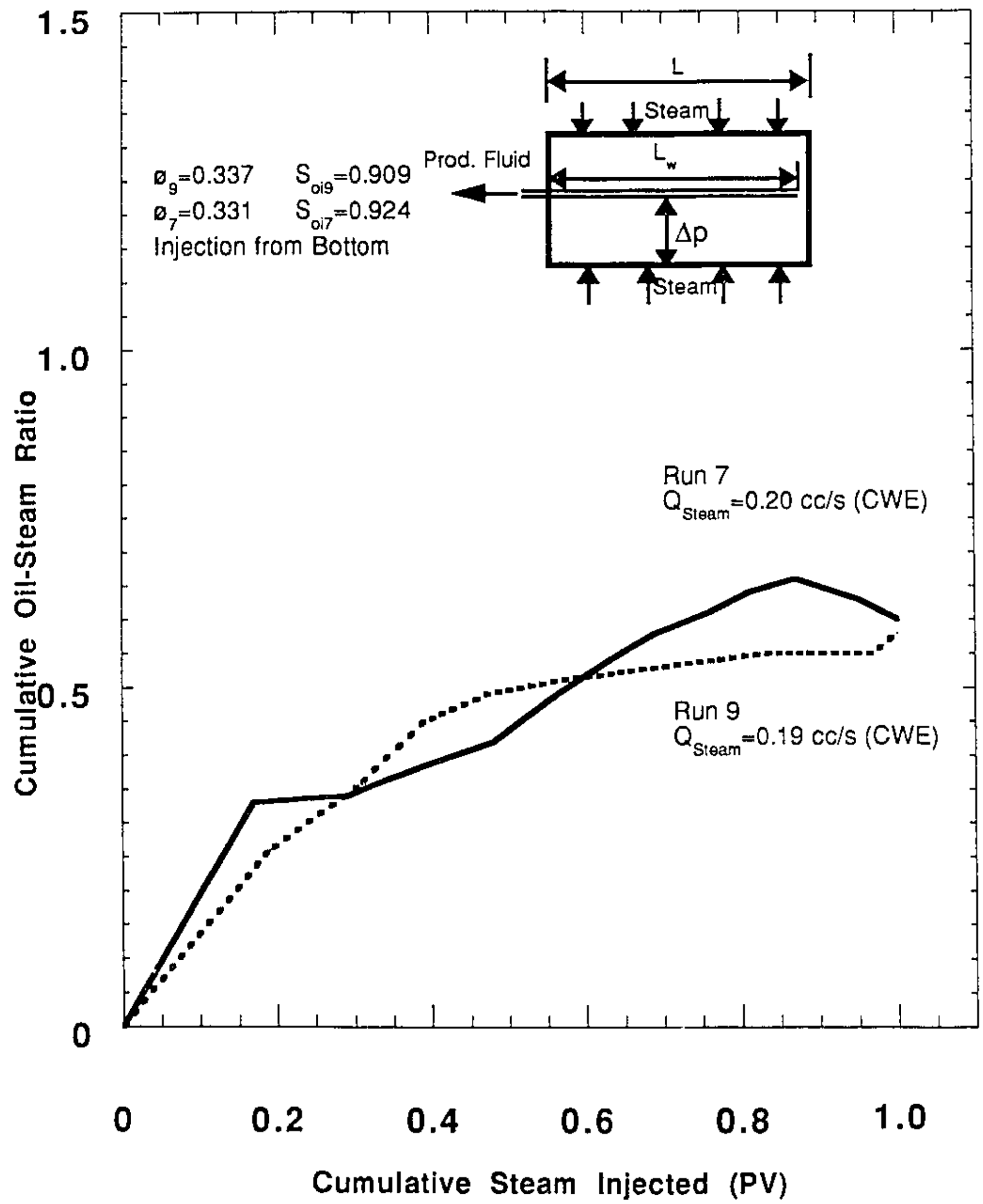


Figure 5.42: Reproducibility of Experimental Results, Cumulative Oil-Steam Ratio vs. Cumulative Steam Injected Using a Horizontal Producer (Run 7 Repeat of Run 9)



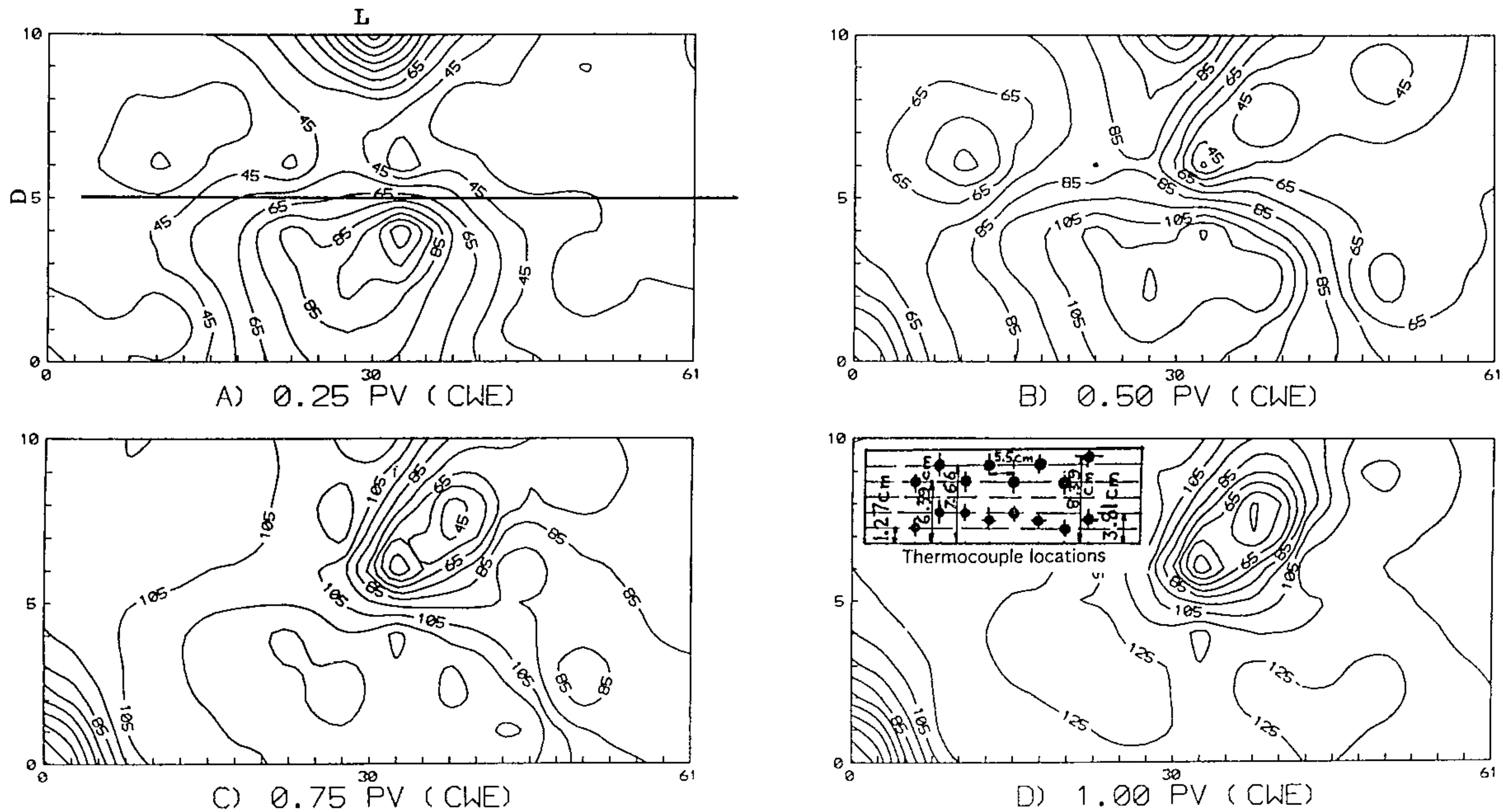
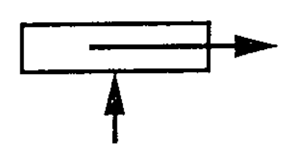


Figure 5.43: Cross-Sectional Views of the Temperature Distribution Inside the Sand Pack after the Injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV (CWE) of Steam for Run 9 Bottom Steam Injection Using a Horizontal Producer



steam was injected using a horizontal injector and in which oil was radially produced from the bottom of the sand pack. The main objective of these experiments was to investigate horizontal injector length, diameter and vertical location on the oil production performance during the steam injection process. In addition, the effect of oil viscosity and pressure differential between the injector and producer on oil production performance were studied.

5.4.1 Production History of a Typical Run

Run 21 was chosen to be the base case for the horizontal injector experiments. It was conducted using a horizontal injector penetrating the full length of the sand pack. The sand pack was assumed to be homogeneous and anisotropic with a measured porosity of 35.6% and an average permeability of 6.4 x 10^{-12} m^2 (6.5 darcies). Steam was injected at a rate of 0.40 cc/s (CWE) using a horizontal injector located at the center of the sand pack in which the initial oil and water saturations were 89.7% and 10.3%, respectively. The production data, along with the sand pack properties, are given in Table 5.4. Usually steam was injected for more than one pore volume. In this particular experiment, 1.24 PV of steam (CWE) was injected into the sand pack. However, data for only one pore volume were used for the analysis

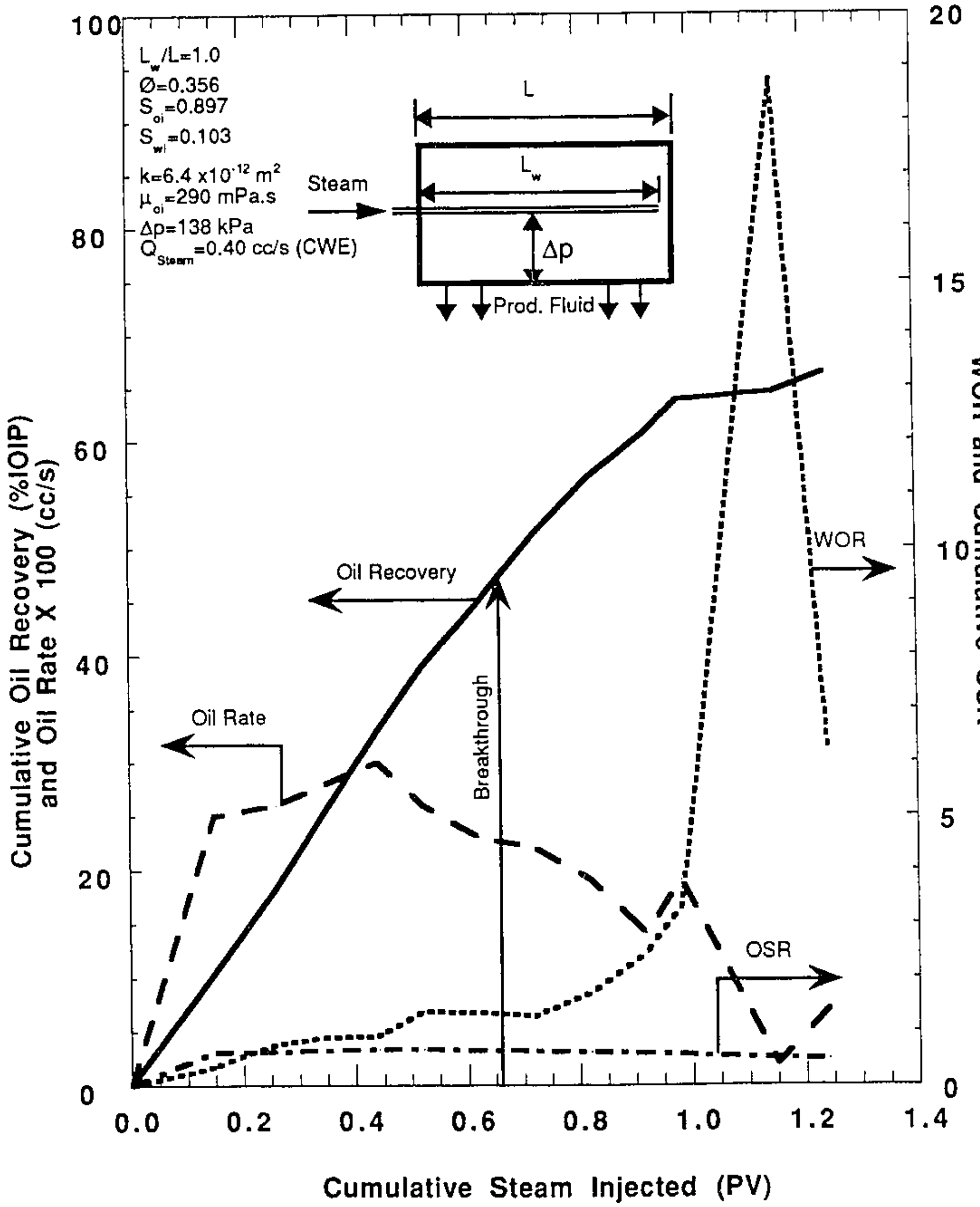
Figure 5.44 shows the cumulative oil recovery, cumulative oil-steam ratio, water-oil ratio and oil rate vs. cumulative steam injected for Run 21. The cumulative oil recovery obtained in this experiment was 64% IOIP, which was one of the highest cumulative oil recoveries obtained in the experiments conducted using the horizontal injector. The water-oil ratio and cumulative oil-steam ratio curves exhibit a typical behaviour; the cumulative oil-steam ratio, as usual, was less than 1.0 and was maximal at about 0.5 PV, while the water-oil ratio started with a low value, steadily increased and then increased drastically around 0.95 PV due to steam condensate breakthrough to the producer. The oil rate started with a low value, increased as the experiment progressed, and reached its maximum at about 0.43 PV. The injection and production pressures for this experiment were set at 345 kPa (50 psig) and 207 kPa (30 psig), respectively, and regulated using two back pressure regulators. The injection temperature was maintained above steam saturation temperature and monitored using thermocouples to ensure that steam and not hot water was injected into the sand pack,

Table 5.4 - Run 21: Horizontal Injector Penetrating 100% of the Sand Pack Length

Bulk Volume:	4492 cc	Initial Oil Saturation:	89.7 %PV
Pore Volume:	1600 cc	Initial Water Saturation :	10.3 %PV
HC Pore Volume:	1435 cc	Type of Oil Used:	Faxam-100
Porosity:	35.6%	Oil Viscosity @ 24 °C and101 kPa:	290 mPa . s
Average Absolute Permeability :	6.4 x 10^-12 m^2 (6.5 darcies)	API Gravity @ 24 °C and101 kPa:	30 °API
Average Steam Injection Rate:	0.40 cc/s (CWE)	Production Pressure:	207 kPa
Net Oil Recovery:	**66.3%**	**Total Steam Injected:**	**1985 cc**

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	10.13	243	0.15	202	150	150	10.5	0.25	0.35	0.62
2	7.30	418	0.26	197	112	262	18.3	0.26	0.76	0.63
3	6.20	567	0.35	200	106	368	25.6	0.28	0.89	0.65
4	5.75	705	0.44	200	104	472	32.9	0.30	0.92	0.67
5	5.52	837	0.52	204	86	558	38.9	0.26	1.37	0.67
6	6.13	984	0.62	200	85	643	44.8	0.23	1.35	0.65
7	6.92	1150	0.72	211	92	735	51.2	0.22	1.29	0.64
8	6.70	1311	0.82	206	76	811	56.5	0.19	1.71	0.62
9	6.75	1473	0.92	200	58	869	60.6	0.14	2.45	0.59
10	4.13	1572	0.98	198	46	915	63.8	0.19	3.30	0.58
11	10.90	1834	1.15	198	10	925	64.5	0.02	18.80	0.50
12	6.30	1985	1.24	197	27	952	66.3	0.07	6.30	0.48

Figure 5.44 - Production History of Run 21: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected Using a Horizontal Injector Penetrating 100% of the Sand Pack Length



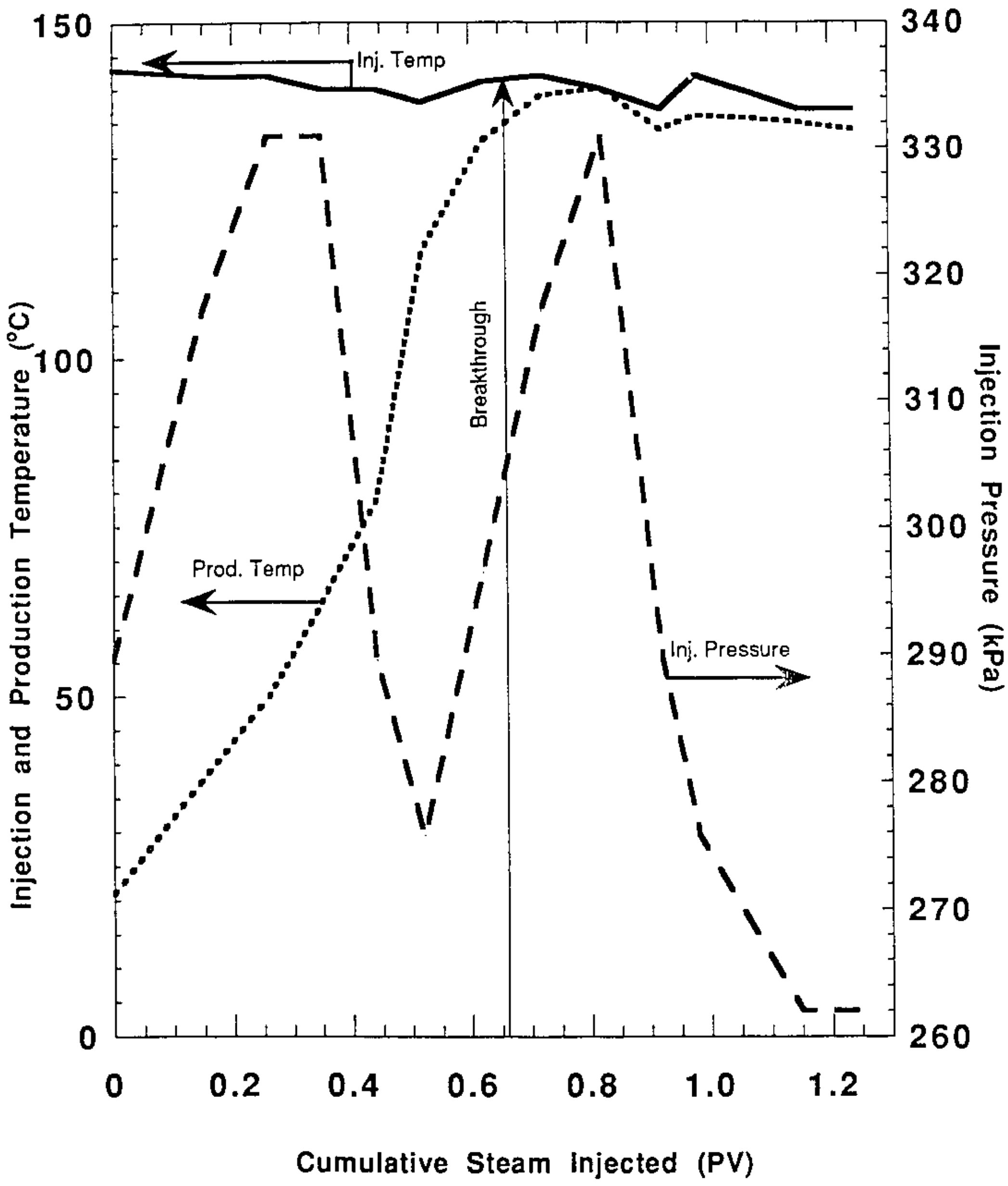
Injection and production temperatures, along with the injection pressures are plotted in Figure 5.45. As can be seen in Figure 5.45, despite the fluctuations in the injection pressure, injection temperature was stable and remained around the steam saturation temperature. Moreover, the production temperature steadily increased, indicating that the steam zone was growing and that the steam front was advancing towards the producer. After 0.75 PV of steam (CWE) was injected into the sand pack, most of the oil was produced, and the sand pack temperature was almost at steam injection temperature. Temperature distribution profiles of the steam inside the sand pack after the injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV CWE are shown in Figure 5.46. The 0.25 PV CWE temperature profile shows that steam was coming from the right top corner of the sand pack rather than from the center through the horizontal injector. This was because as soon as steam injection was started, steam segregated to the top, heating the oil in the upper half faster than that in the lower half of the sand pack.

By the time 0.75 PV was injected, oil was already heated and most of the sand pack was at the injection temperature as can be seen in the 0.75 PV CWE temperature profile. Despite the minimal gain in cumulative oil recovery after the injection of 0.75 of steam (CWE) PV CWE, the experiment was continued until 1.24 PV of steam (CWE) was injected into the sand pack simply to sweep any oil left behind. At this point, steam had already broken through at the production end and a large volume of water was produced. The experiment was terminated after the injection of 1.24 PV, and production and temperature data were recorded and prepared for analysis.

5.4.2 Effect of Horizontal Injector Length

This set of experiments was directed towards an investigation of the horizontal injector length on the steam production performance. Steam was injected at the centre of the sand pack using horizontal injectors penetrating 25, 50, and 100% of the sand pack length, and oil was radially produced from the bottom of the sand pack. Horizontal injector lengths of 25, 50, and 100% of the sand pack length were, respectively, used in Runs 21, 22, and 23 to study the effect of horizontal injector length on steam production performance. Cumulative oil recoveries obtained using 25, 50, and 100%- horizontal injectors are plotted in Figure 5.47. The highest cumulative oil recovery was obtained using a horizontal injector penetrating 100% of the sand pack

Figure 5.45 - Production History of Run 21: Injection/Productio Temperature and Injection Pressure vs. Cumulative Steam Injected Using a Horizontal Injector Penetrating 100% of the Sand Pack length



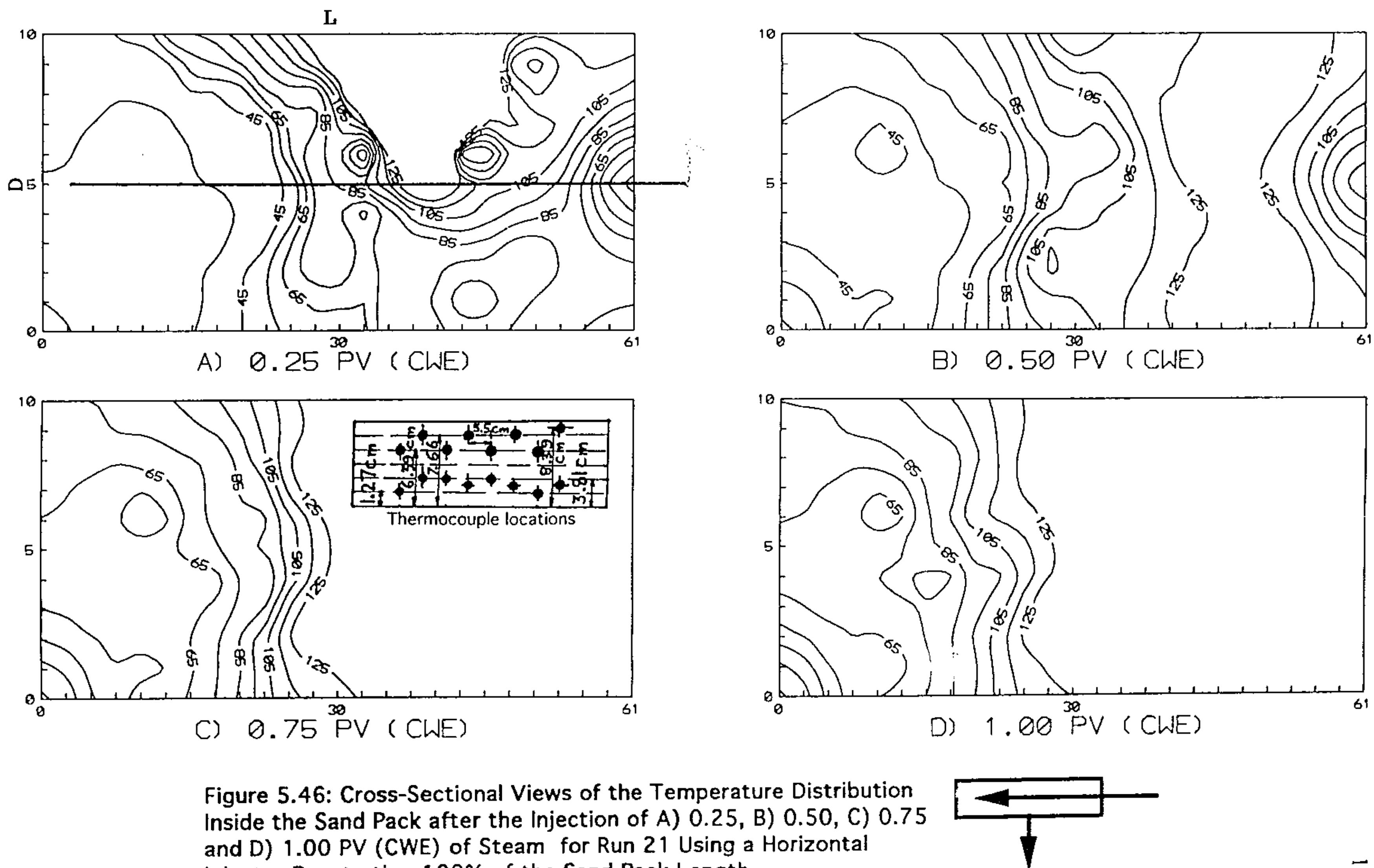
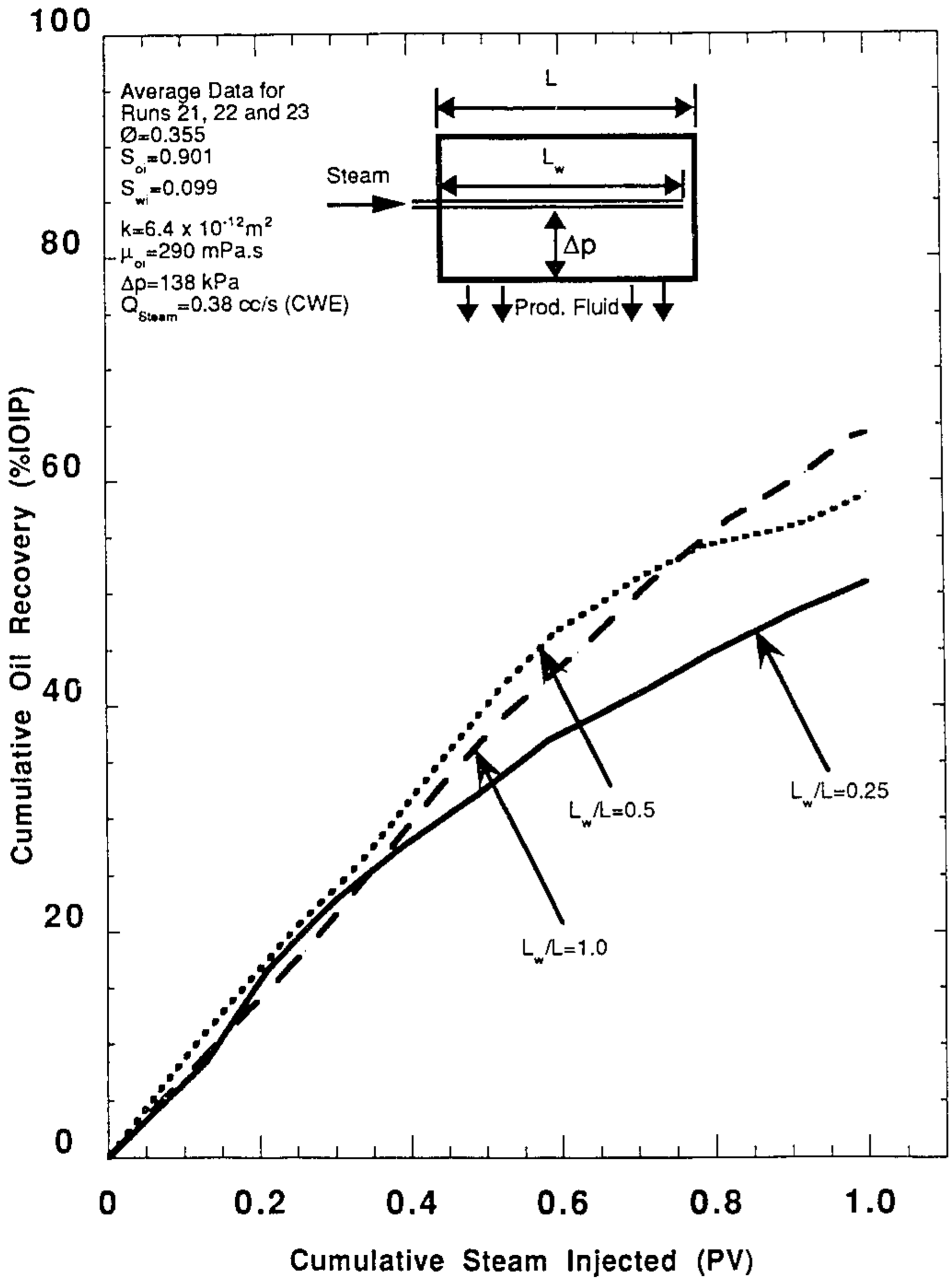


Figure 5.46: Cross-Sectional Views of the Temperature Distribution Inside the Sand Pack after the Injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV (CWE) of Steam for Run 21 Using a Horizontal Injector Penetrating 100% of the Sand Pack Length

Figure 5.47 - Runs 21, 22, and 23: Effect of Horizontal Well Length on Oil Recovery for L_w/L Ratio of 1.0, 0.5 and 0.25 Using a Horizontal Injector



length, while the lowest cumulative oil recovery was obtained using an injector penetrating 25% of the sand pack length.

When a 50%-horizontal injector was used, as expected, it gave a higher recovery than that obtained using the 25%-injector and moderately lower than that obtained using the 100%-injector. One reason the 100%-injector gave the highest cumulative oil recovery was due to its large sand pack contact area. Another reason was the early communication between the injector and the producer. The 100%-injector provided a large sand pack contact area for the steam zone to grow laterally and evenly, heating the entire sand pack oil. The 25%-injector sand pack contacted area was one fourth of the 100%-injector and the 25%-injector steam production performance was complicated by early steam breakthrough and high water production. Relatively high water production was encountered when the 25%-injector was used compared to water production when the 50% and 100%-injectors were used, as shown in Figure 5.48 which shows the water-oil ratio curves for the three injectors.

Oil-steam ratios for the 50% and 100%-injectors, plotted in Figure 5.49, have a similar trend, while those for the 25% injector have low values simply due to an inefficient steam injection process when the 25%-horizontal injector was used. For visual inspection of steam zone growth and steam front movement, temperature data were gathered throughout the experiments using thermocouples located at different positions along the length and diameter of the cylindrical sand pack. Temperature distribution profiles for steam inside the sand pack for the 25% and 100%-injectors are shown in Figures 5.50 and 5.46. By the time 1.00 PV was injected, the area swept by the steam was greater for the 100%-injector than for the 25%-injector, as may clearly be seen in the 1.0 PV CWE temperature profile.

Runs 21, 22, and 23 were carried out to investigate the effect of horizontal injector length on oil production performance. Steam was injected at the center of the sand pack using 25, 50, and 100% of the sand pack length horizontal injectors. The longest horizontal injector (100%) gave the highest cumulative oil recovery of 64% IOIP, while the shortest (25%) injector gave the lowest cumulative oil recovery of 52% IOIP. Furthermore, the oil production performance of the longest horizontal injector was more stable and efficient in displacing the oil than that of the shortest injector, in which steam performance was complicated by high water production and early steam

Figure 5.48 - Runs 21, 22, and 23: Effect of Horizontal Well Length on Water-Oil Ratio for L_w/L Ratio of 1.0, 0.5 and 0.25 Using a Horizontal Injector

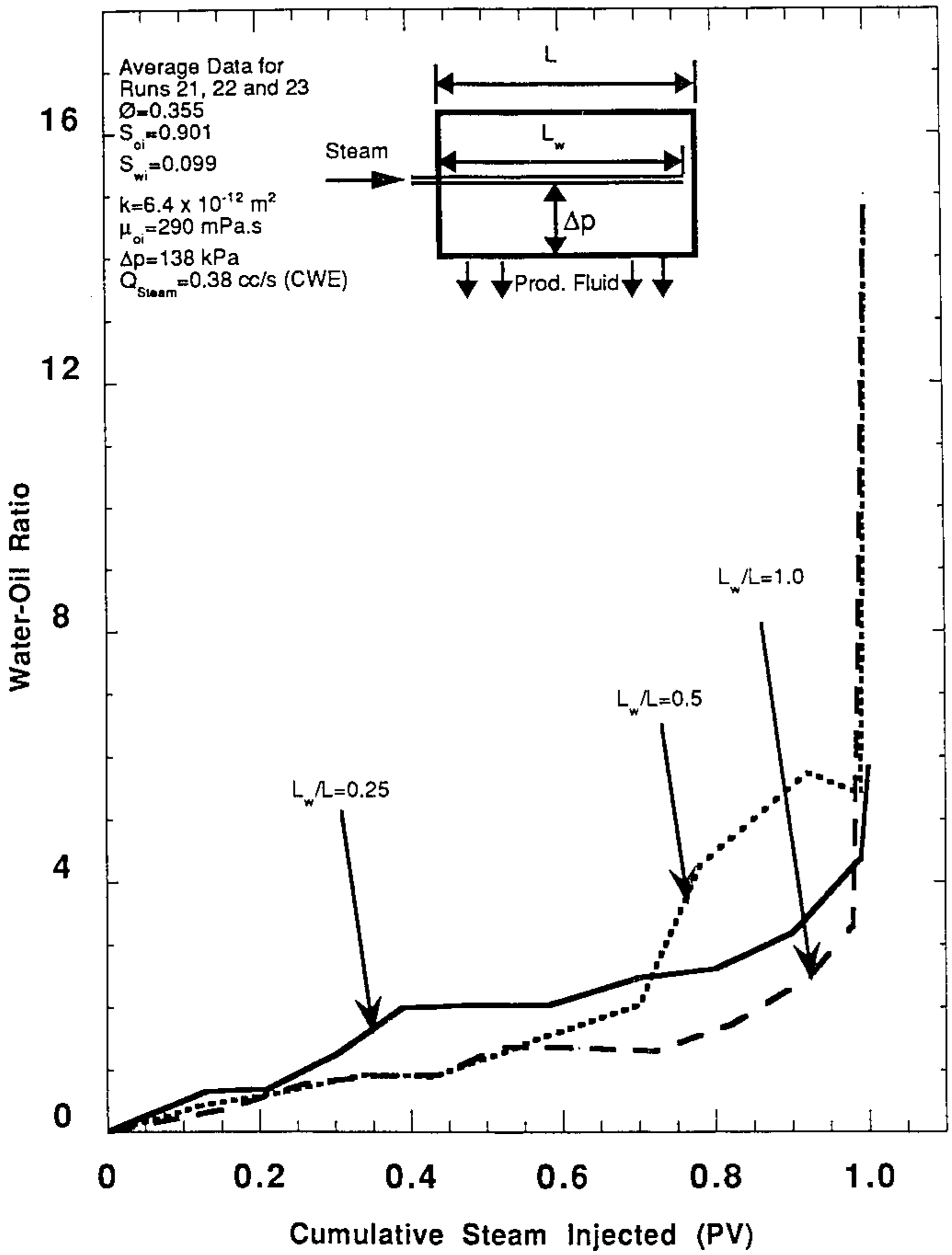
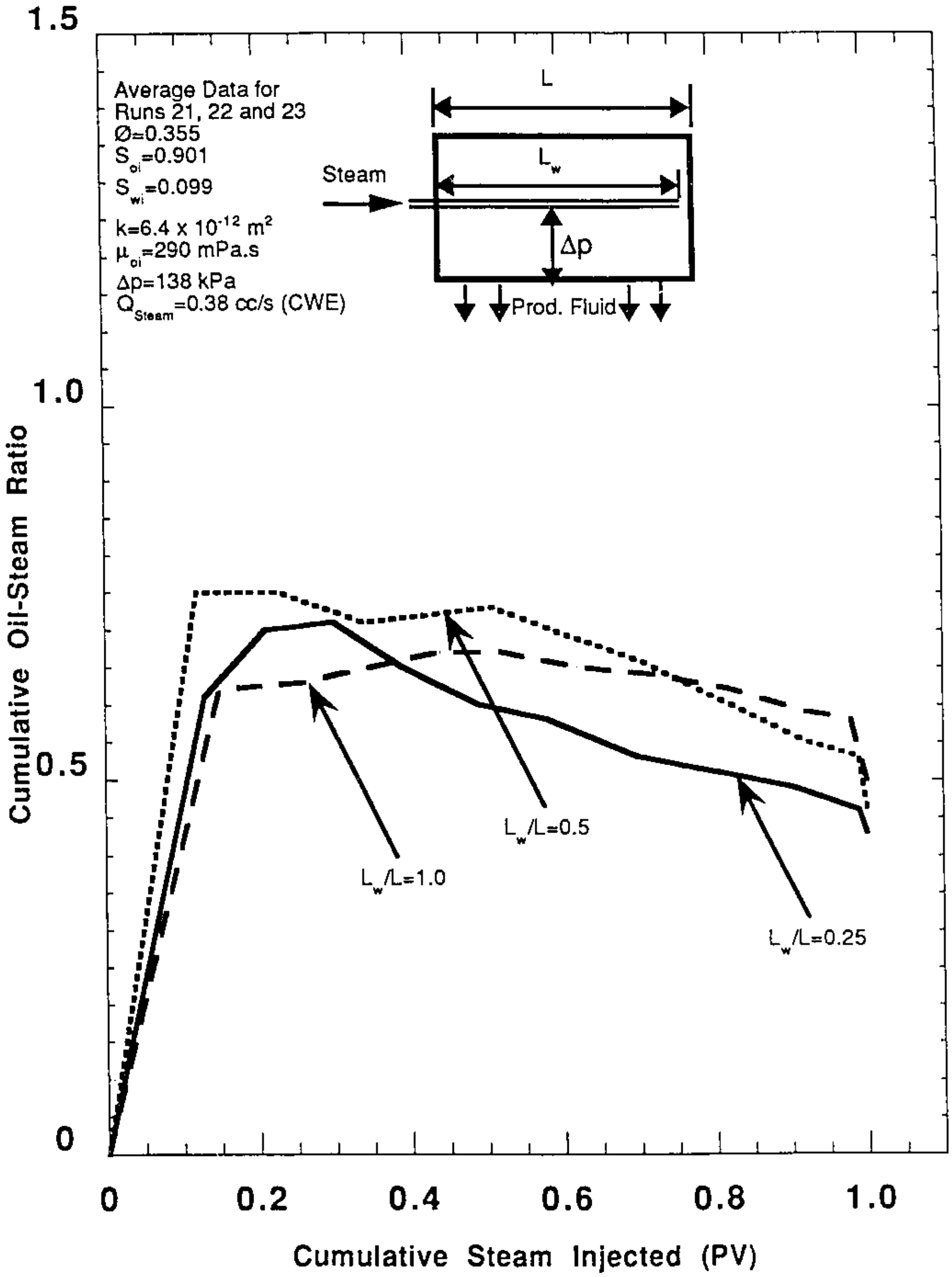


Figure 5.49 - Runs 21, 22, and 23: Effect of Horizontal Well Length on Oil-Steam Ratio for L_w/L Ratio of 1.0, 0.5 and 0.25 Using a Horizontal Injector



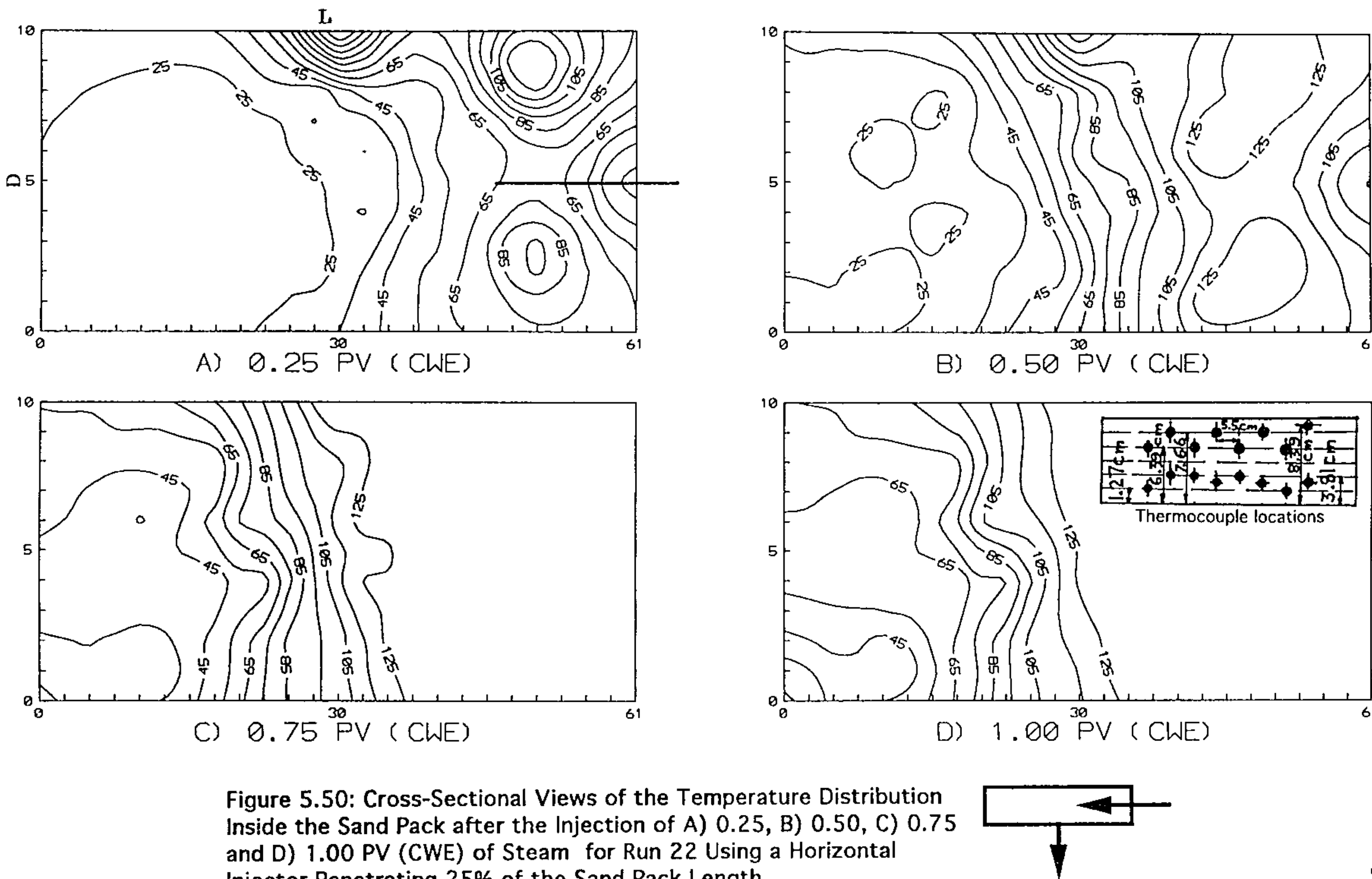
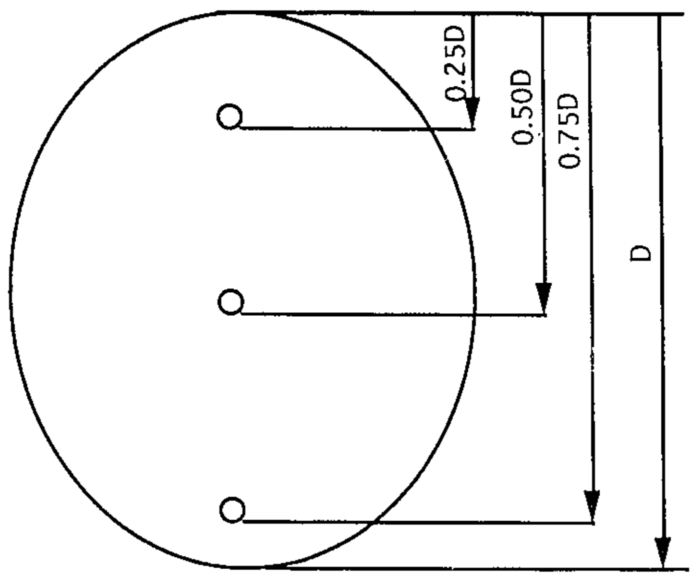


Figure 5.50: Cross-Sectional Views of the Temperature Distribution Inside the Sand Pack after the Injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV (CWE) of Steam for Run 22 Using a Horizontal Injector Penetrating 25% of the Sand Pack Length

breakthrough. Due to their large sand pack contact area longer horizontal injectors are more attractive than shorter injectors during steam injection.

5.4.3 Effect of Horizontal Injector Vertical Location

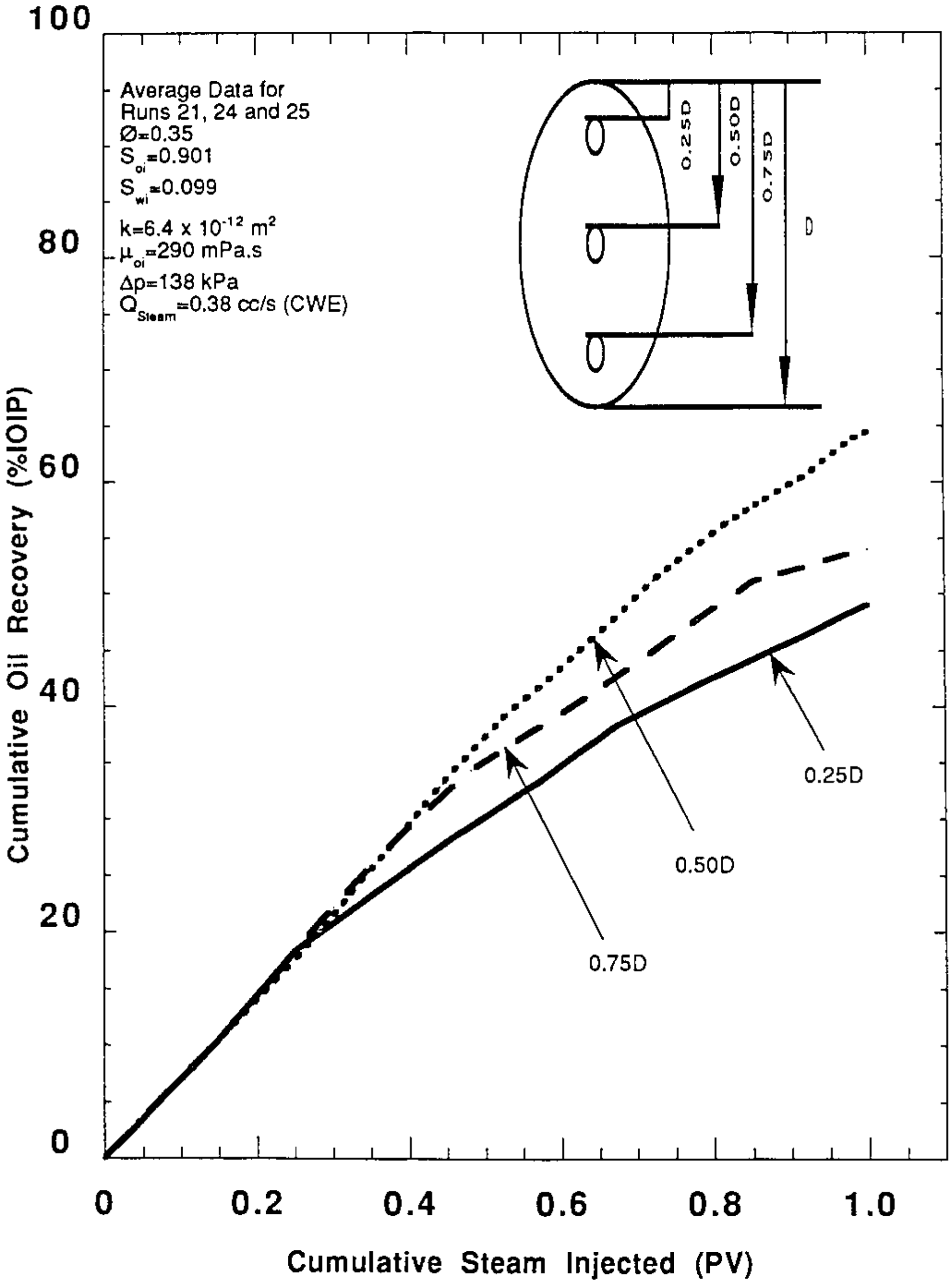
This set of experiments investigated the horizontal injector vertical location effect on oil production performance. The horizontal injector vertical location was varied along the diameter of the sand pack taking the upper boundary to be the datum.



Three experiments, 21, 24 and 25, were conducted using a horizontal injector penetrating the full length and located at 25, 50 and 75% diameter from the sand pack upper boundary. Steam was injected using a horizontal injector at an average steam injection rate of 0.38 cc/s (CWE), and oil was radially produced through the sintered metal jacket from the bottom of the sand pack. The sand pack was assumed to be homogeneous and anisotropic with 35% porosity and 6.4 x 10^{-12} m^2 (6.5 darcies) permeability. The sand pack reservoir was initially saturated with 90.1% Faxam-100 oil and 9.9% water.

The 25, 50 and 75%-diameter horizontal injector experiments were conducted with injection and production pressures of 345 kPa (50 psig) and 207 kPa (30 psig), respectively. Cumulative oil recoveries for 25, 50 and 75%-diameter horizontal injectors are shown in Figure 5.51. The highest cumulative oil recovery of 64% IOIP was obtained using a horizontal injector situated at the center of the sand pack, and the

Figure 5.51 - Runs 21, 24 and 25: Effect of Horizontal Well Location on Oil Recovery for 0.25D, 0.50D and 0.75D Using a Horizontal Injector



lowest cumulative oil recovery of 46% IOIP was obtained using an injector located 25%-diameter from the sand pack upper boundary. However, the horizontal injector located 75%-diameter from the sand pack upper boundary gave a 49% IOIP cumulative oil recovery. The reason the 25%-diameter and 75%-diameter injector cumulative oil recoveries were lower than that of the 50%-diameter injector was that the 25%-diameter oil production performance was complicated by high water production and that of the 75%-diameter injector was affected by early steam breakthrough.

Figures 5.52, 5.53 and 5.54 show temperature distribution profiles for steam inside the sand pack after the injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV CWE for the three injectors. When steam was injected using a horizontal injector located close to the bottom boundary of the sand pack, (the 75%-diameter injector Figure 5.53), steam advanced towards the upper sand pack boundary, heating the oil in the thick sand pack portion above the injector. Heated oil and condensed steam were drained by gravity and radially produced through the sintered metal jacket. However, when steam was injected using a horizontal injector located close to the sand pack upper boundary, (the 25%-diameter injector Figure 5.54), due to the short distance and thin sand pack between injector and the metal jacket, the steam immediately rose out of the sand pack into the hollow metal jacket surrounding it. After rising into the sintered metal jacket, the steam condensed and was produced at the bottom through the metal jacket surrounding the sand pack.

Steam used in the 25%-diameter injector followed a shortcut to the producer through the sintered jacket production and for this reason performance of the 25%-diameter injector, as shown in Figure 5.55, was complicated by high water production. Another reason the 25%-diameter injector had low cumulative oil recovery was because the lateral separation between the injector and producer was too large for the steam to establish early communication with the producer. Since the 50%-diameter injector was located at the center of the sand pack, its oil production performance was neither complicated by early steam breakthrough nor was it affected by high water production. Figure 5.56, which shows cumulative oil-steam ratio vs. cumulative steam injected into the sand pack for 25, 50, and 75%-diameter horizontal injectors, shows that the 50% injector had the highest cumulative oil-steam ratio.

It can be concluded that the oil production performance of a horizontal injector located too close to the producer may be complicated by an early steam breakthrough

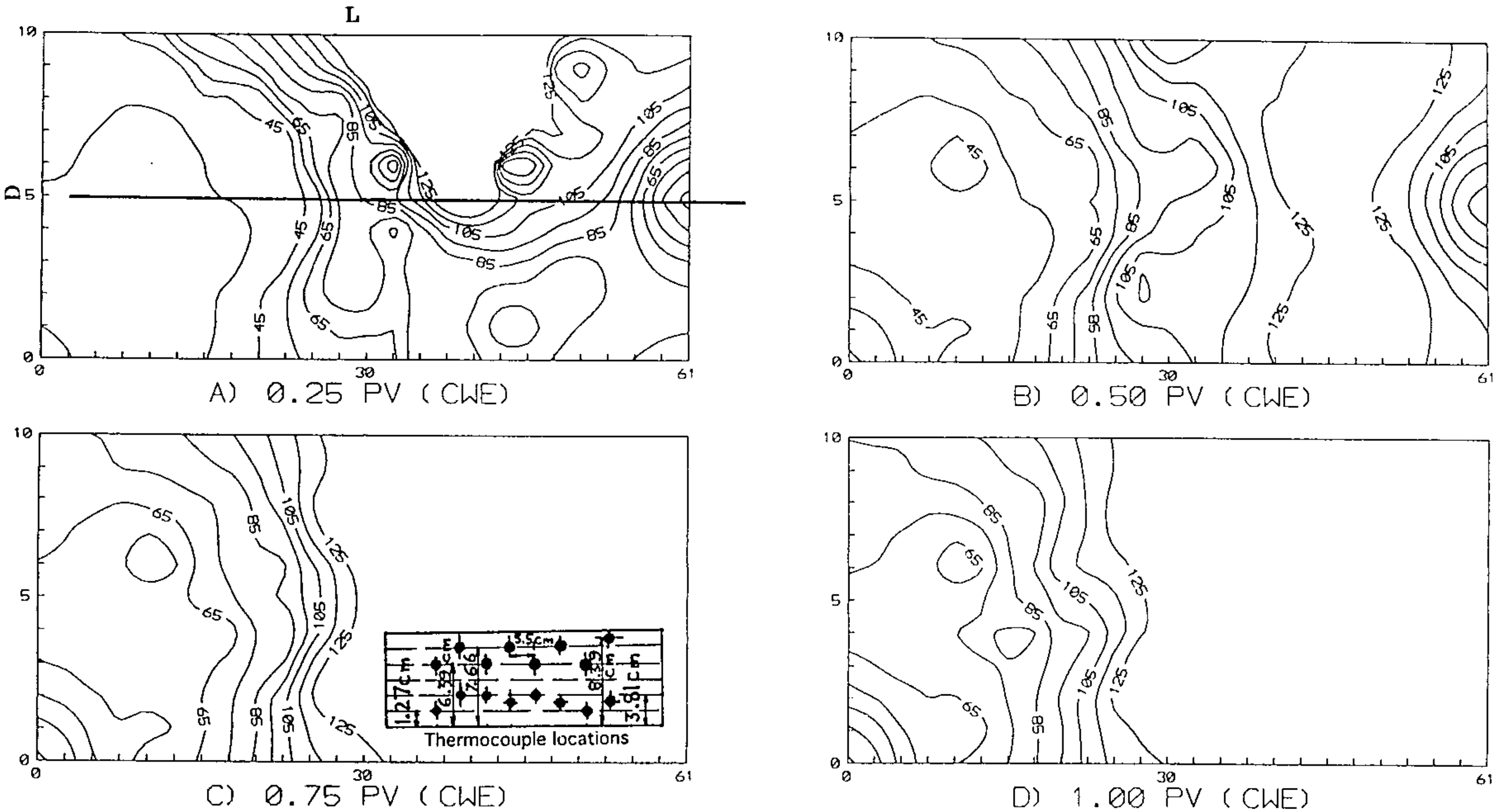


Figure 5.52: Cross-Sectional Views of the Temperature Distribution Inside the Sand Pack after the Injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV (CWE) of Steam for Run 21 Using a Horizontal Injector Located 0.50D from the Sand Pack Upper Boundary

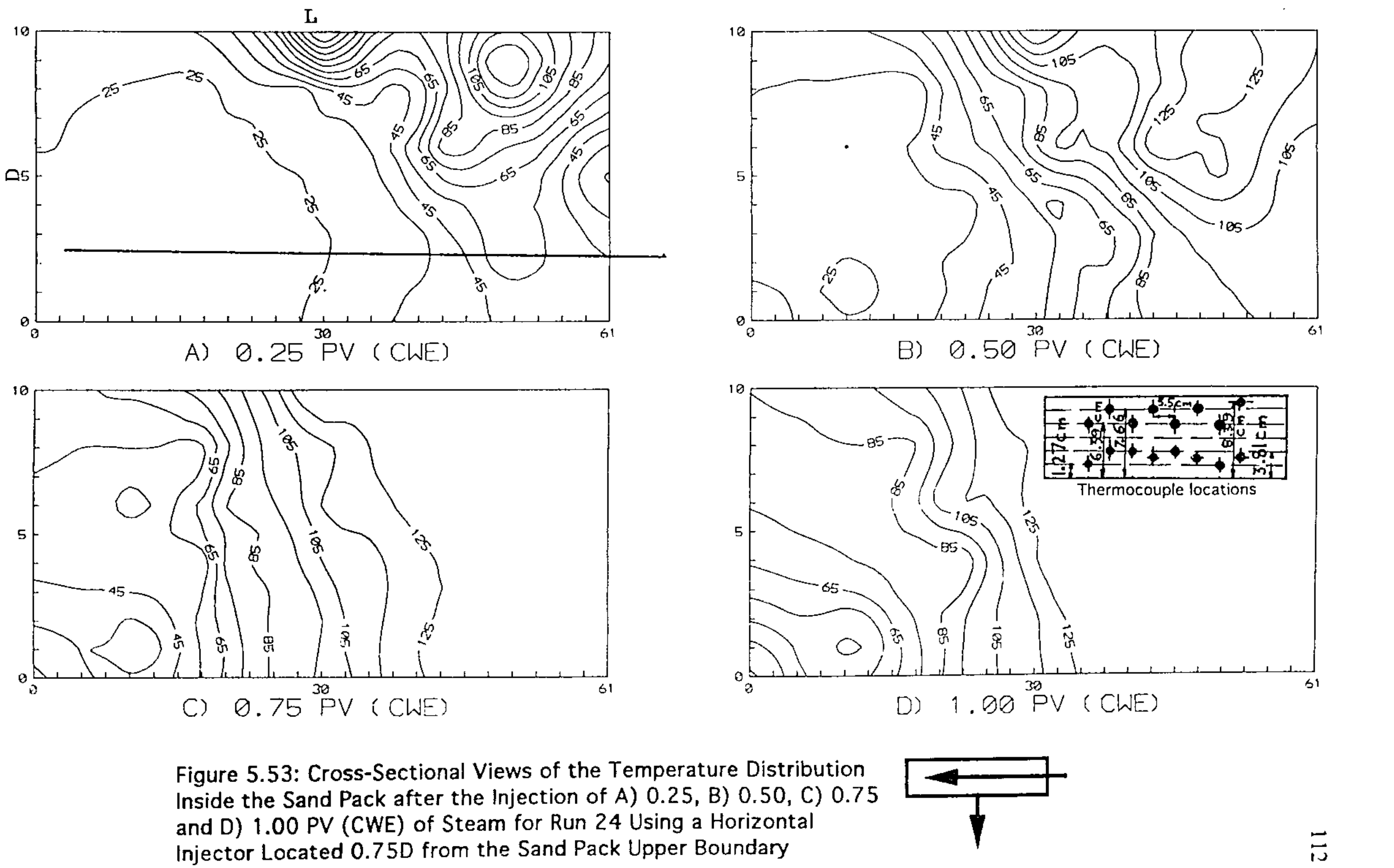


Figure 5.53: Cross-Sectional Views of the Temperature Distribution Inside the Sand Pack after the Injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV (CWE) of Steam for Run 24 Using a Horizontal Injector Located 0.75D from the Sand Pack Upper Boundary

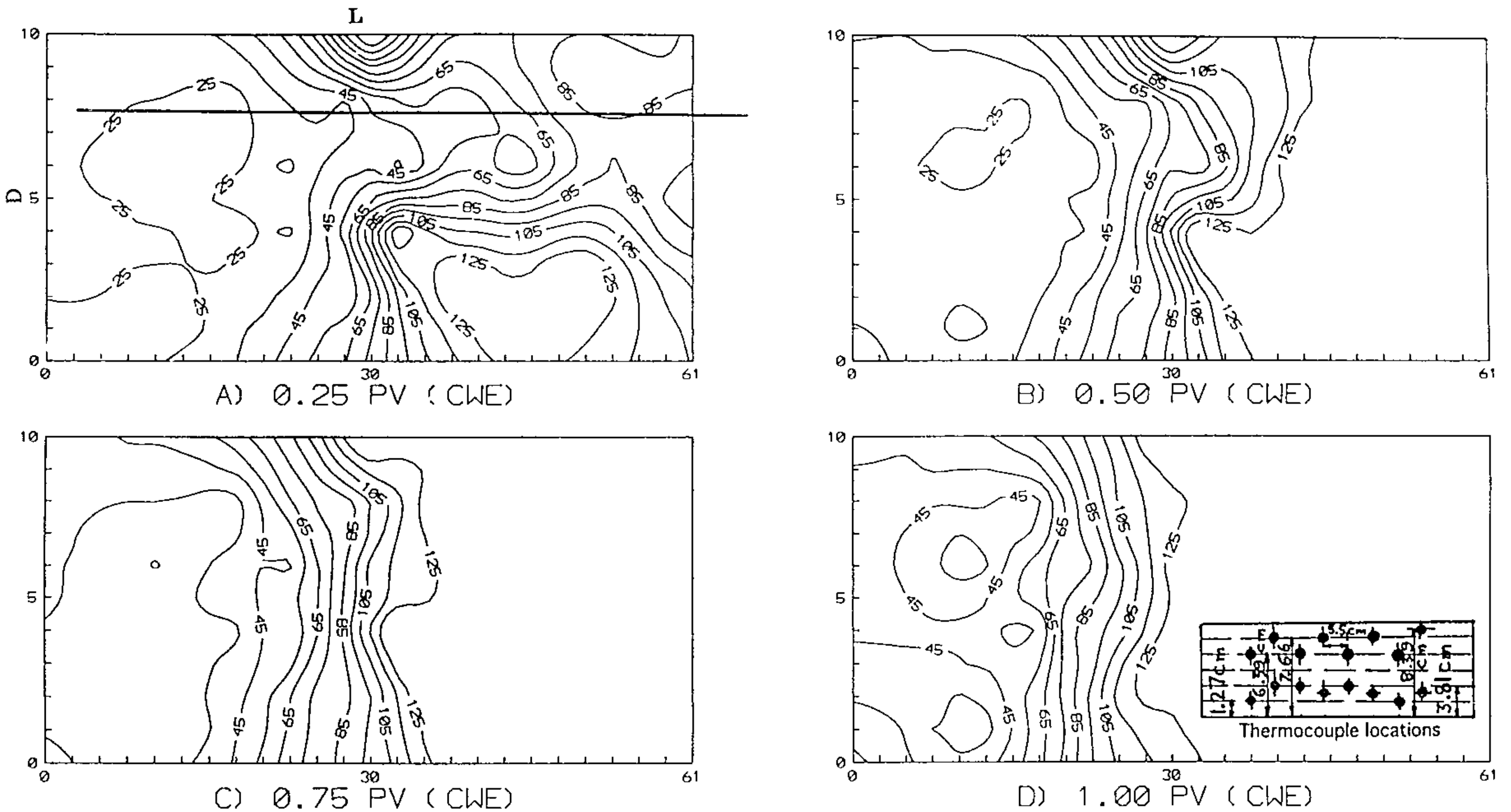


Figure 5.54: Cross-Sectional Views of the Temperature Distribution Inside the Sand Pack after the Injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV (CWE) of Steam for Run 25 Using a Horizontal Injector Located 0.25D from the Sand Pack Upper Boundary

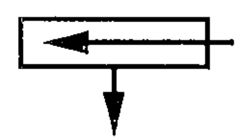


Figure 5.55 - Runs 21, 24 and 25: Effect of Horizontal Well Location on Water-Oil Ratio for 0.25D, 0.50D and 0.75D Using a Horizontal Injector

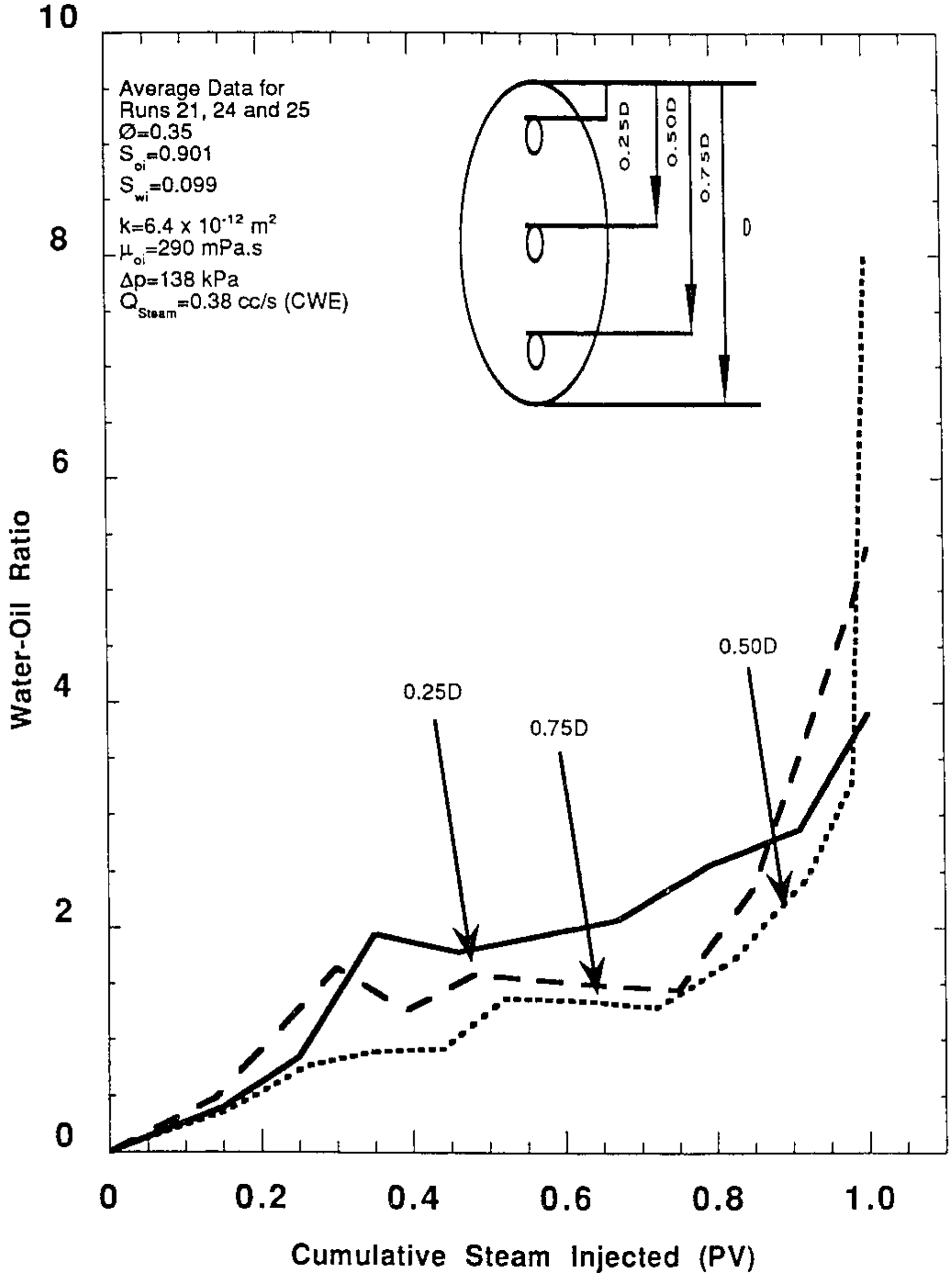
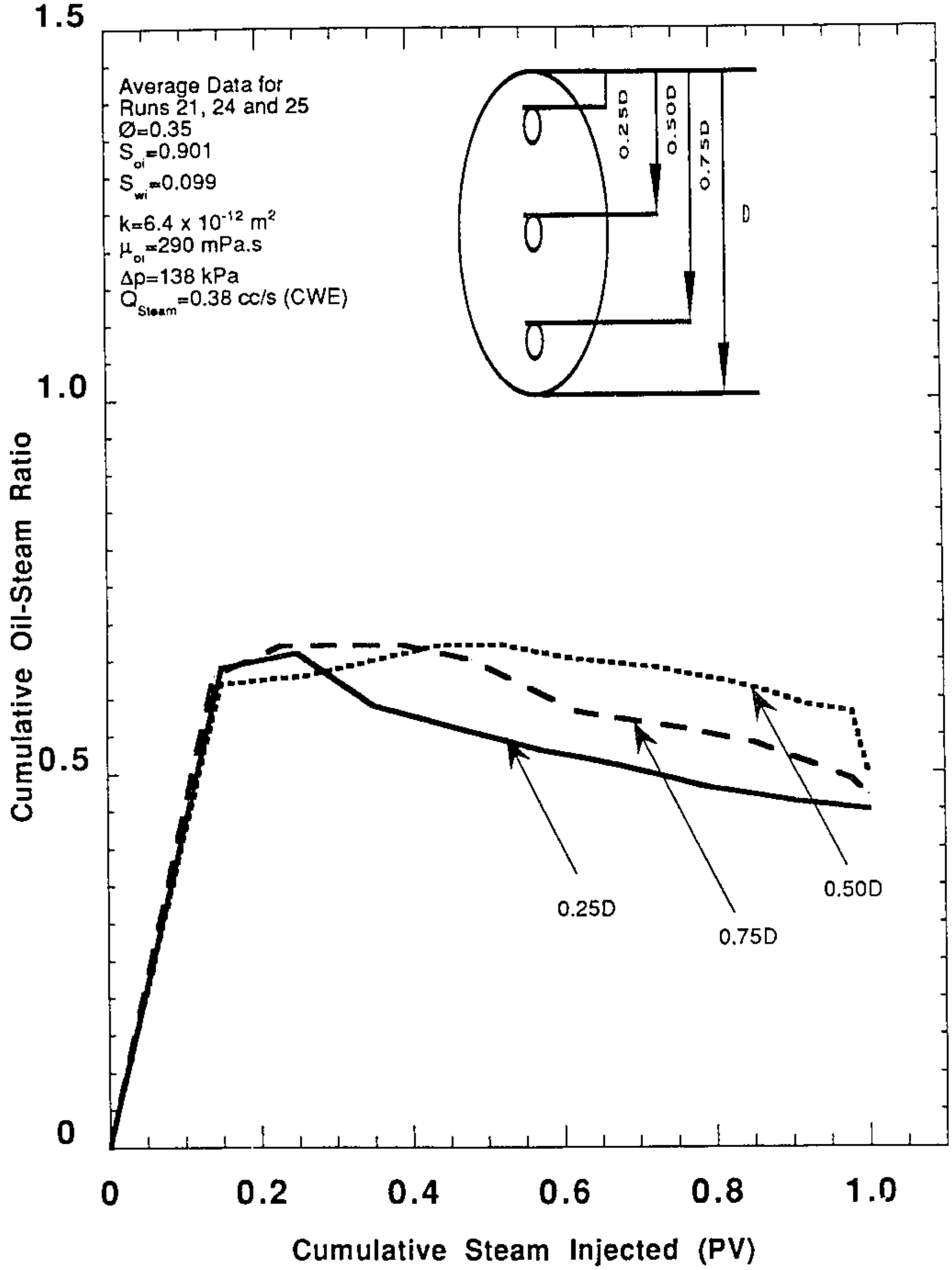


Figure 5.56 - Runs 21, 24 and 25: Effect of Horizontal Well Location on Oil-Steam Ratio for 0.25D, 0.50D and 0.75D Using a Horizontal Injector



and high water production while that of an injector located far from the producer may be affected by delay in steam communication. When the horizontal injector was located close to the upper boundary of the sand pack, steam was produced through the sintered metal jacket surrounding the sand pack. However, when the horizontal injector was at the center of the sand pack, its production performance was not complicated by early steam breakthrough or high water production.

5.4.4 Effect of Horizontal Injector Diameter

One study objective was to investigate horizontal producer or injector diameter on steam production performance. This section discusses the effect of a horizontal injector on the oil recovery process during steamflooding. Three horizontal injectors sized 0.32 cm (1/8 in), 0.64 cm (1/4-in), and 0.95 cm (3/8 in) were used to investigate the injector diameter effect on steam production performance. Runs 21, 29, and 30 were carried out using 0.32-cm, 0.64-cm, and 0.95-cm horizontal injectors located at the center of the sand pack in which the initial oil and water saturations were 90.1% and 9.9%, respectively.

A homogeneous and anisotropic sand pack with a measured porosity of 35.3% and an average permeability of 6.4 x 10^{-12} m^2 (6.5 darcies) was used to carry out Runs 21, 29, and 30. Steam was injected into the sand pack through the horizontal injector at an average injection rate of 0.39 cc/s (CWE), and oil was produced from the bottom of the sand pack through the sintered metal jacket surrounding the sand pack. Injection and production pressures for the three experiments were maintained at 345 kPa (50 psig) and 207 kPa (30 psig), respectively, using back pressure regulators. The cumulative oil recovery, cumulative oil-steam ratio and water-oil ratio curves are presented in Figures 5.57, 5.58 and 5.59. Unlike the horizontal producer diameter, the horizontal injector diameter has almost no effect on the steam production performance. Cumulative oil recoveries of 64, 63, and 67%, respectively, were obtained using 0.32-cm, 0.64-cm, and 0.95-cm horizontal injectors. The water-oil ratio and oil-steam ratio curves have the same trends for the three injectors.

However, the steam temperature profiles in Figures 5.60, 5.61 and 5.62 are different for each run for early times (0.25 and 0.50 PV). The same volume of steam was introduced into the sand pack using the 0.32-cm, 0.64-cm, and 0.95-cm injectors. However, due to its larger diameter, the 0.95-cm injector provided a larger sand pack

Figure 5.57 - Runs 21, 29 and 30: Effect of Horizontal Well Diameter on Oil Recovery for Well Diameter of 0.32, 0.64 and 0.95 cm Using a Horizontal Injector

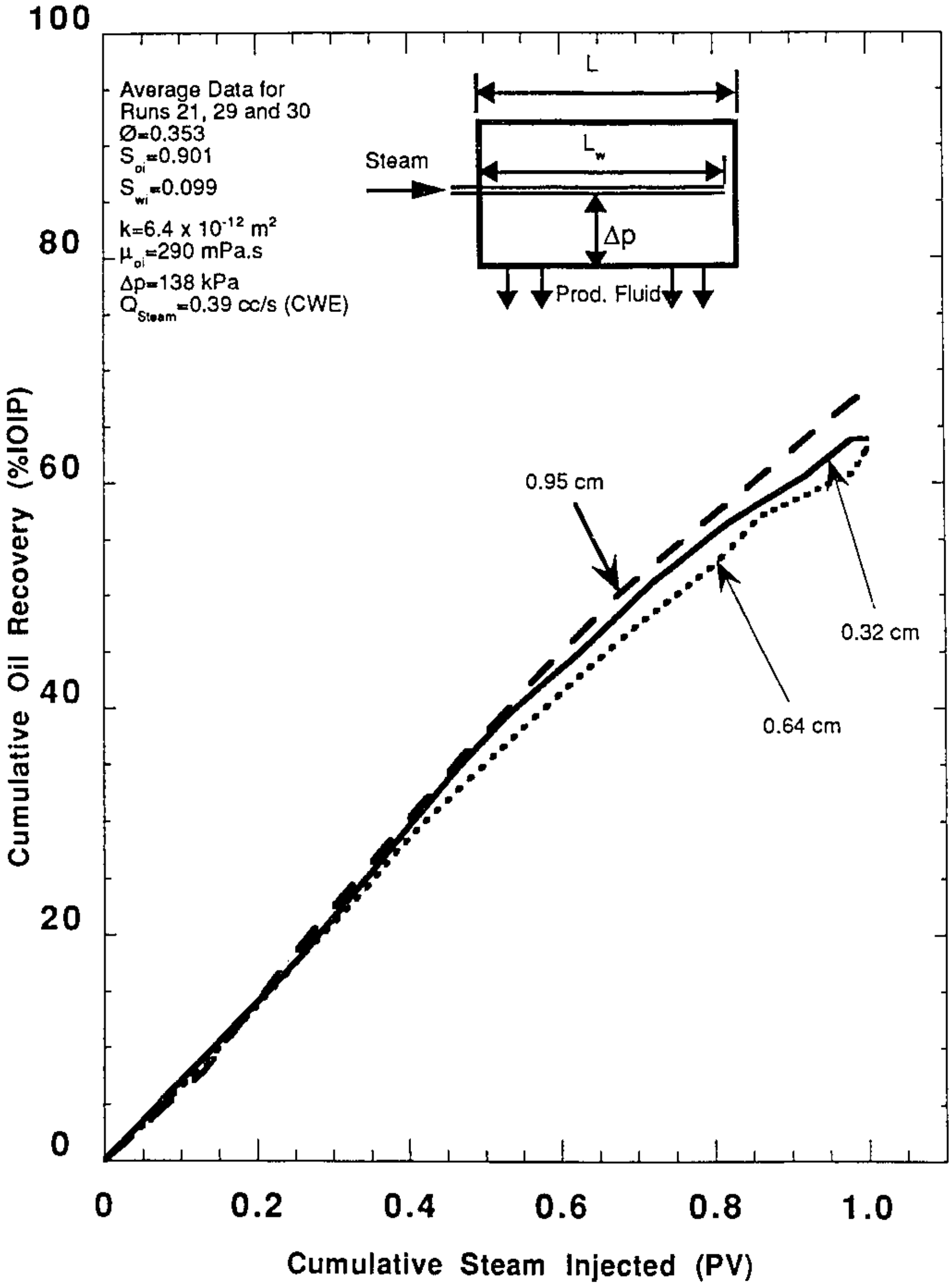


Figure 5.58 - Runs 21, 29 and 30: Effect of Horizontal Well Diameter on Oil-Steam Ratio for Well Diameter of 0.32, 0.64 and 0.95 cm Using a Horizontal Injector

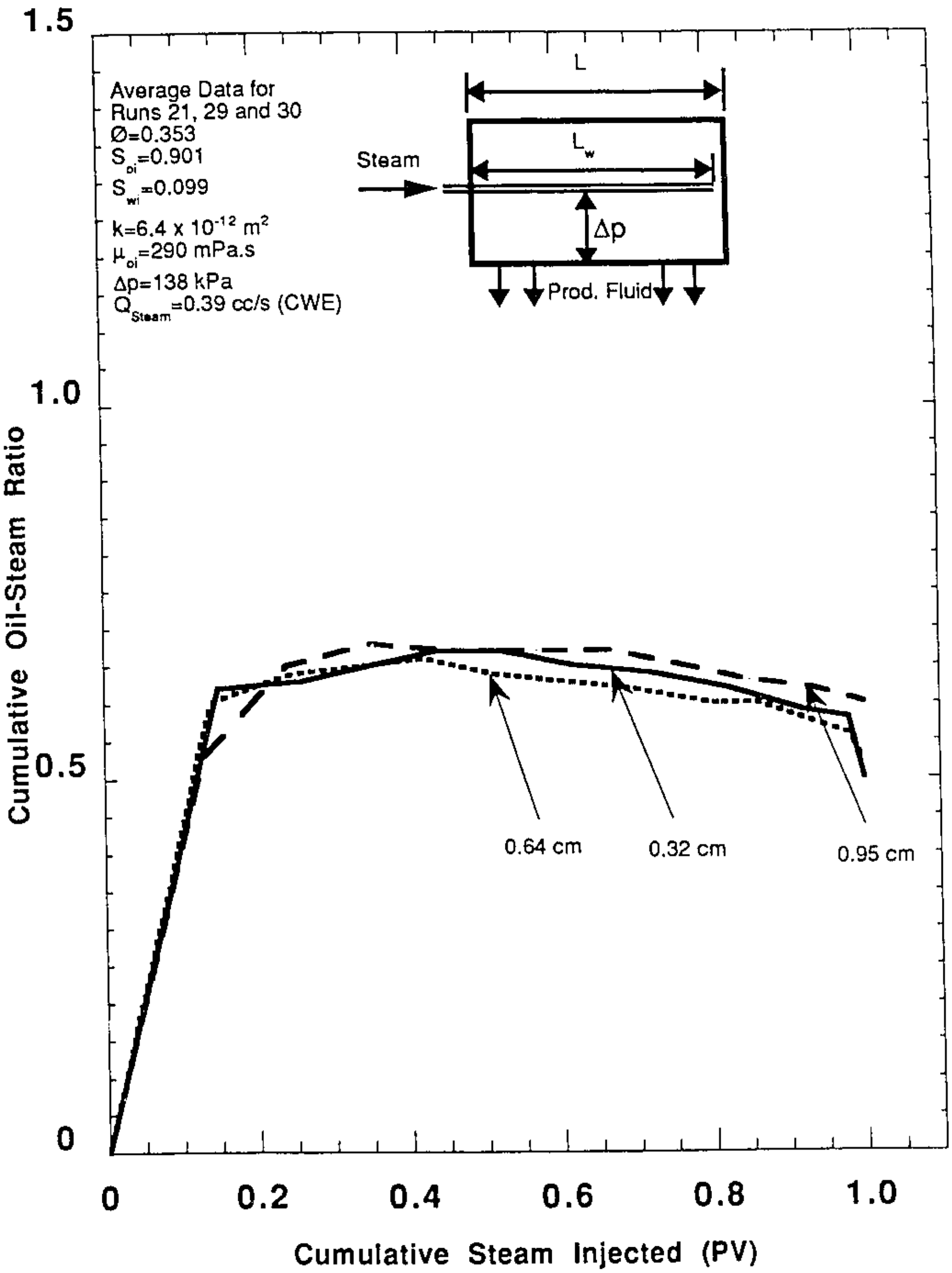
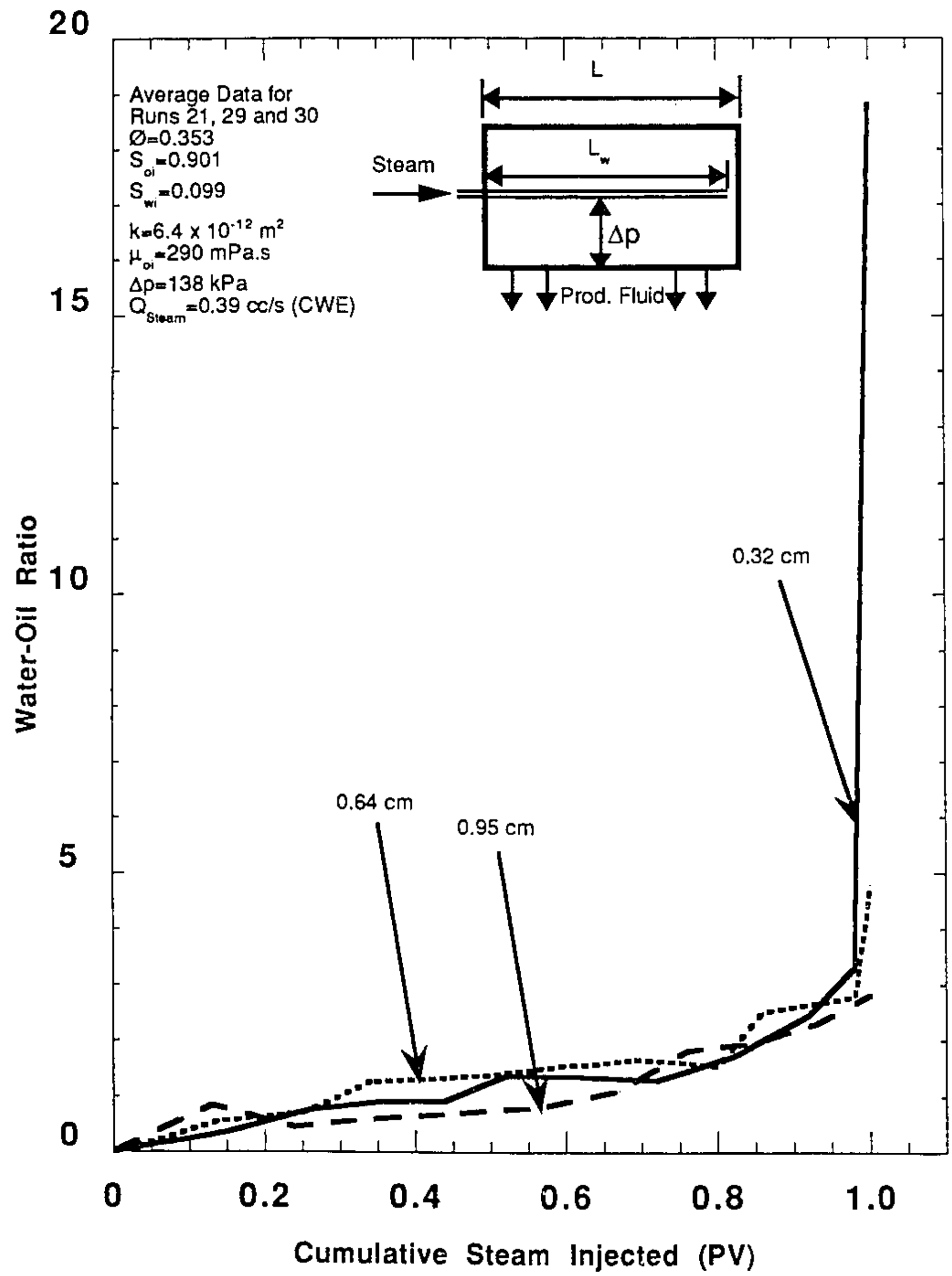
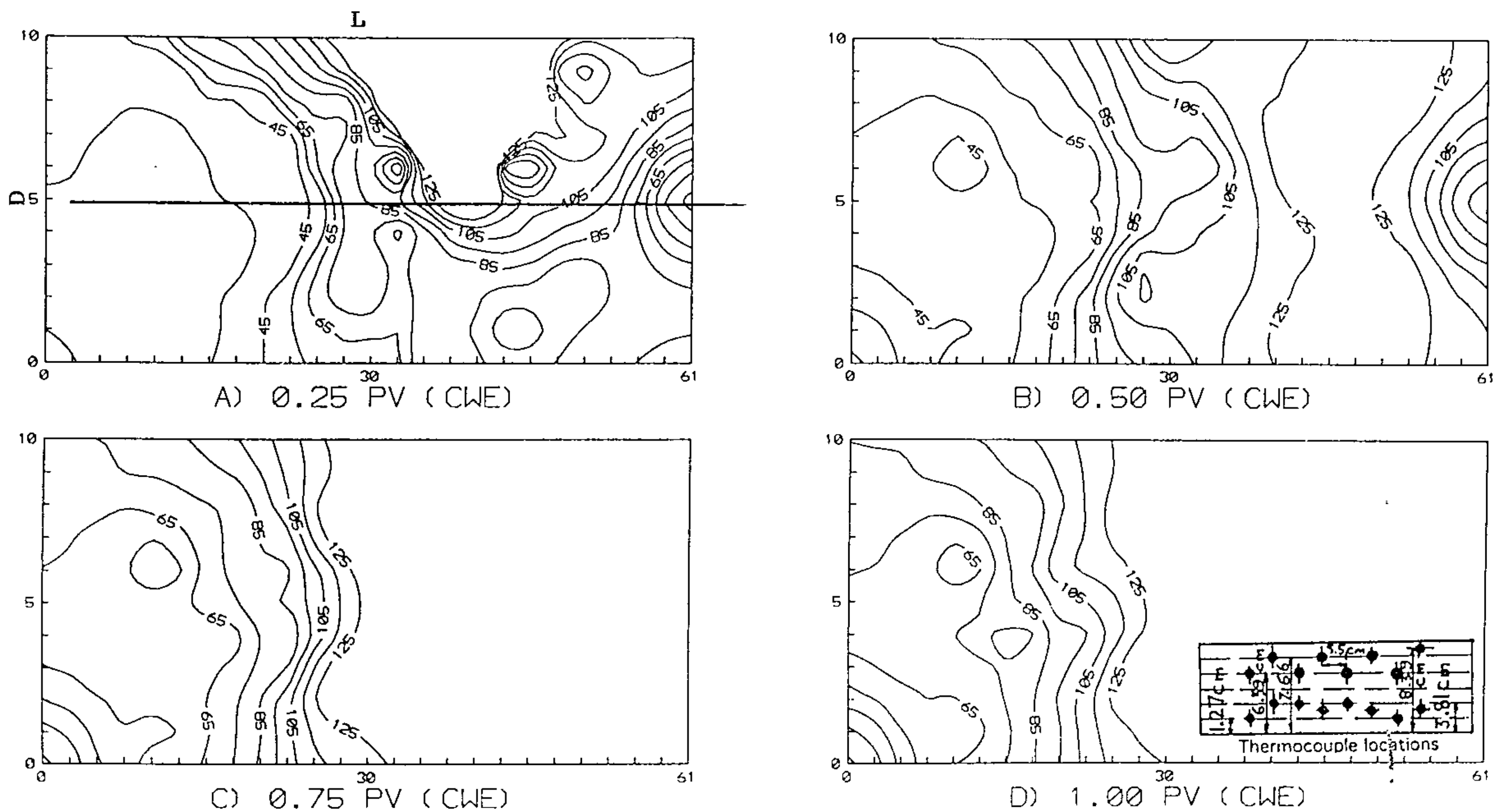


Figure 5.59 - Runs 21, 29 and 30: Effect of Horizontal Well Diameter on Water-Oil Ratio for Well Diameter of 0.32, 0.64 and 0.95 cm Using a Horizontal Injector





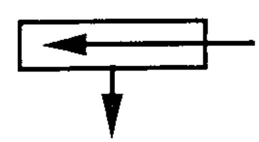


Figure 5.60: Cross-Sectional Views of the Temperature Distribution Inside the Sand Pack after the Injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV (CWE) of Steam for Run 21 Using 0.32-cm Diameter Horizontal Injector

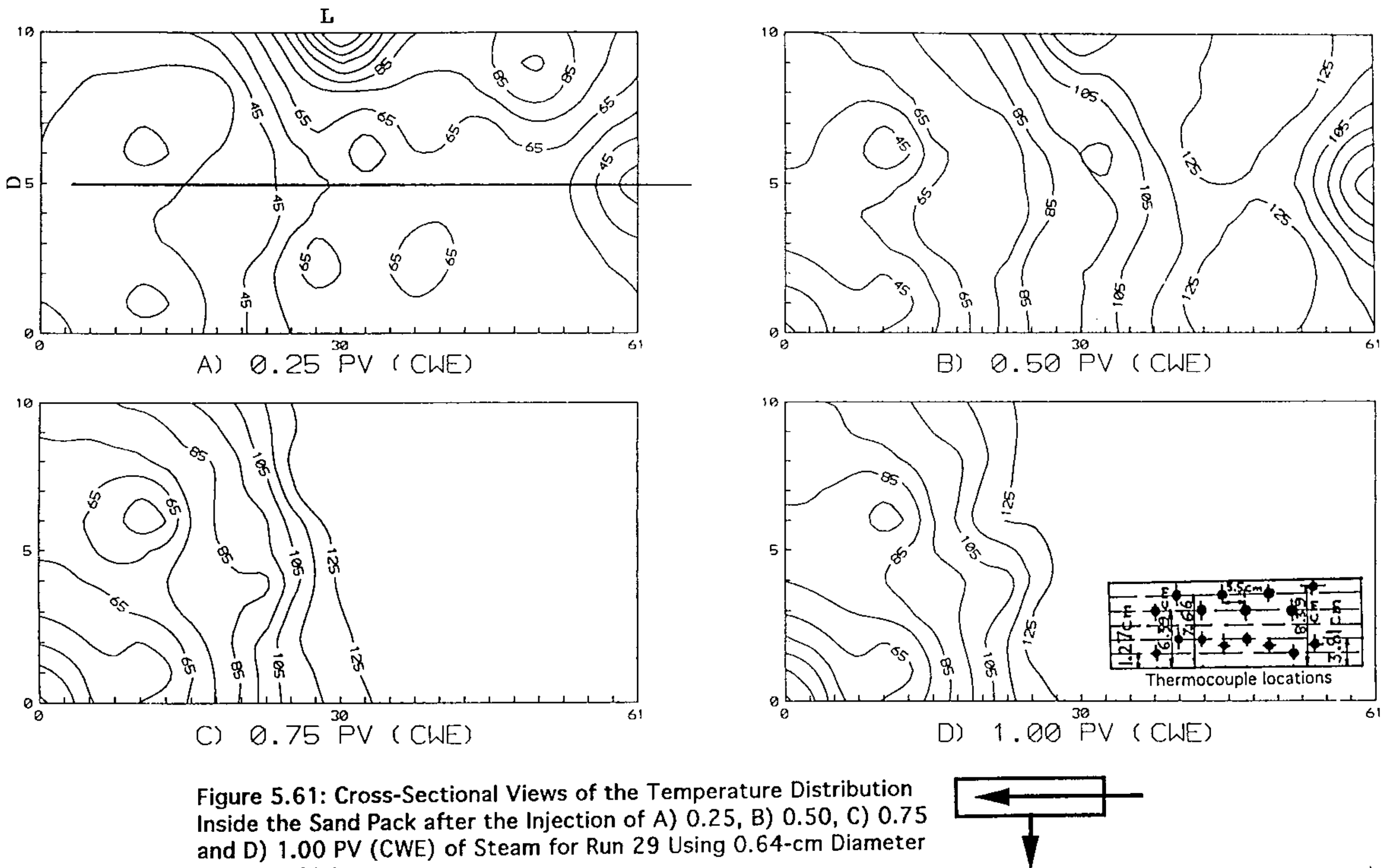


Figure 5.61: Cross-Sectional Views of the Temperature Distribution Inside the Sand Pack after the Injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV (CWE) of Steam for Run 29 Using 0.64-cm Diameter Horizontal Injector

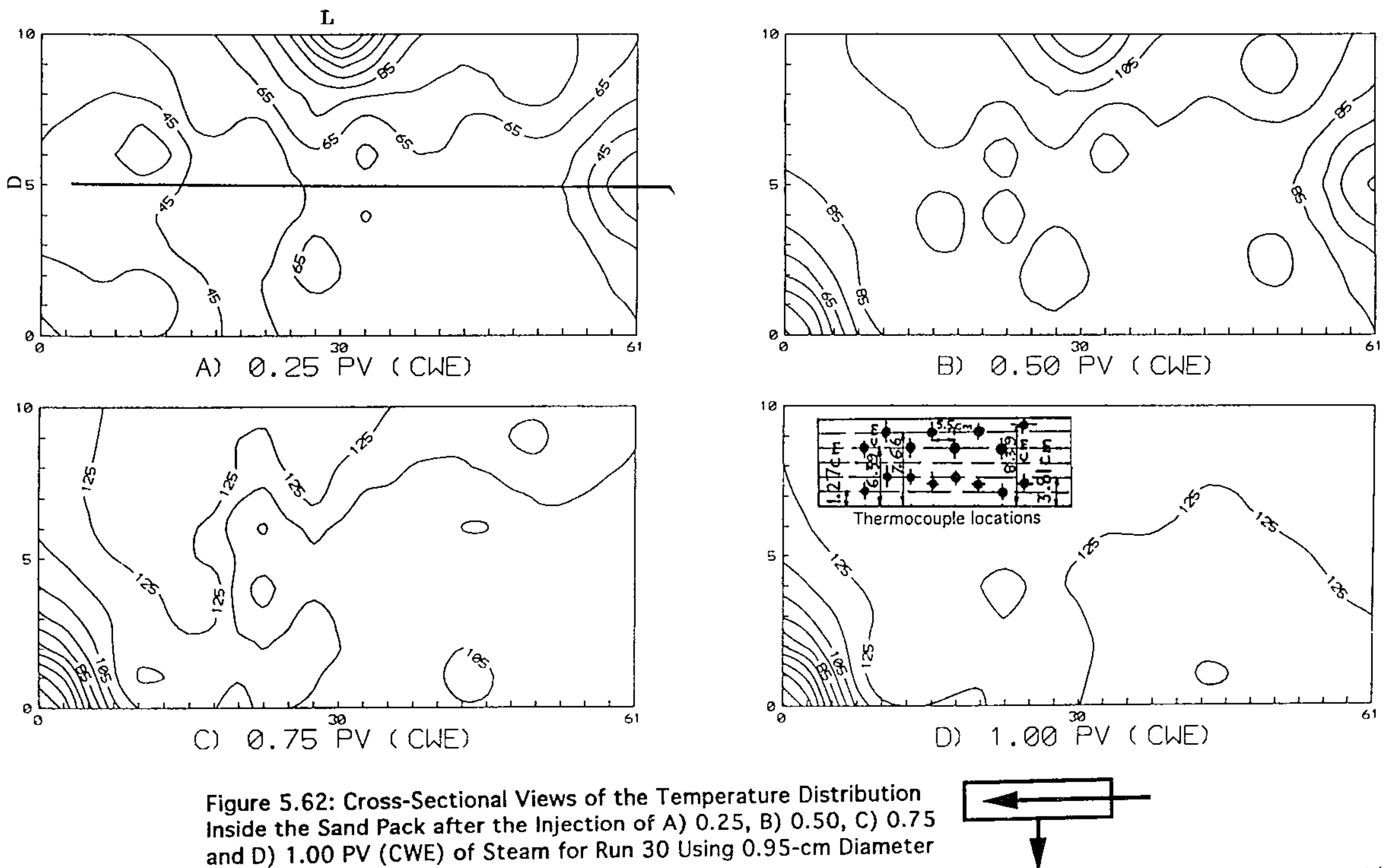


Figure 5.62: Cross-Sectional Views of the Temperature Distribution Inside the Sand Pack after the Injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV (CWE) of Steam for Run 30 Using 0.95-cm Diameter Horizontal Injector

contact area. The volume of steam introduced using the 0.95-cm injector extended over the entire area of the sand pack, heating the oil and producing a higher cumulative oil recovery than the 0.32-cm and 0.64-cm injectors. By the time one PV was injected using the 0.95-cm injector, as shown in the 1.0 PV CWE temperature profile, the entire sand pack was at injection temperature and possibly most of the recoverable oil was already produced.

Based on the experimental results obtained from Runs 21, 29, and 30, it may be said that the effect of the horizontal injector diameter on steam production performance is not as pronounced as that for the diameter of the horizontal producer.

5.4.5 Effect of Oil Viscosity Using a Horizontal Injector

One research objective was to investigate the oil viscosity effect on the oil production performance during the steam injection process using a horizontal injector. Runs 21, 31, and 32 were carried out in a homogeneous and anisotropic sand pack with average initial oil and water saturations of 87.8% and 12.2%, respectively, and an absolute permeability of 6.4×10^{-12} m^2 (6.5 darcies). Runs 21, 31 and 32 were conducted using Faxam-100 oil with a viscosity of 290 mPa.s and Wainwright oils with viscosities of 975 and 1800 mPa.s, respectively, at 24°C and 101.325 kPa. Steam was injected at a constant rate of 0.35 cc/s (CWE) through a horizontal injector located at the center of the sand pack, and oil was produced radially from the bottom. During Run 32, which used a high viscosity oil of 1800 mPa.s, the injection pressure was not as stable as when a low viscosity oil of 290 mPa.s was used.

The cumulative oil recoveries and oil-steam ratios for 290, 975 and 1800 mPa.s viscosity oils are plotted in Figures 5.63 and 5.64. The 290 and 975 mPa.s oils have very similar trends and gave higher cumulative oil recoveries than the 1800 oil. The lowest cumulative oil recovery was obtained using the 1800 mPa.s viscosity oil because, the steam injection process was not stable and was complicated by high water production in the experiment, as shown in Figures 5.65 and 5.66 in which the temperature distribution profiles for the steam inside the sand pack and a plot of water-oil ratio vs. steam injected are shown. After 0.5 PV of steam (CWE) had been injected, the steam zone growth was more noticeable in the sand pack with the lighter oil, (290 mPa.s), than in the sand pack with the heavier oil, (1800 mPa.s, viscosity). Furthermore, during the experiment in which the 1800 oil was used, the fluid

Figure 5.63 - Runs 21, 31 and 32: Effect of Oil Viscosity on Oil Recovery for Oil of Viscosity 290, 975 and 1800 mPa.s Using a Horizontal Injector

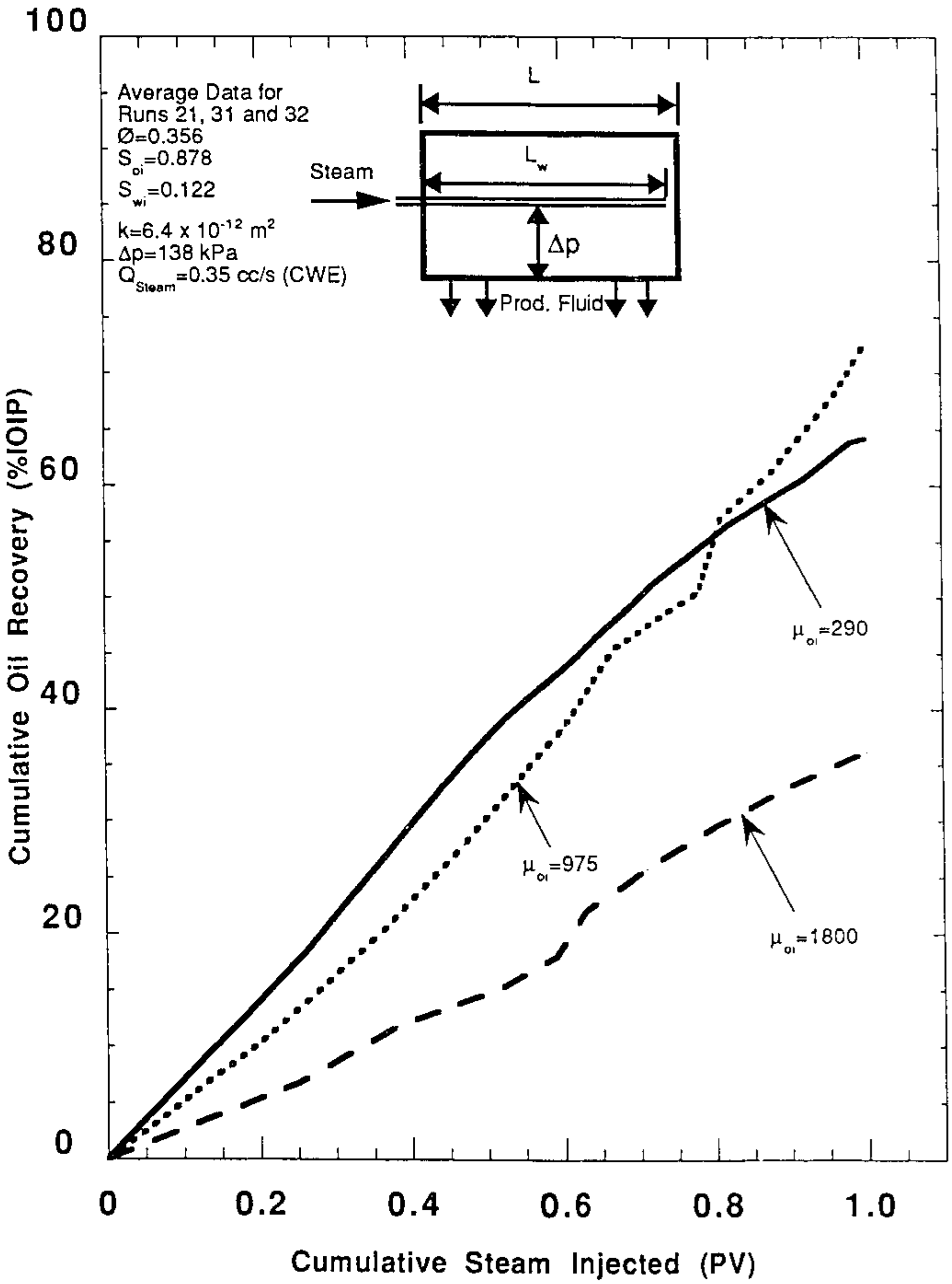
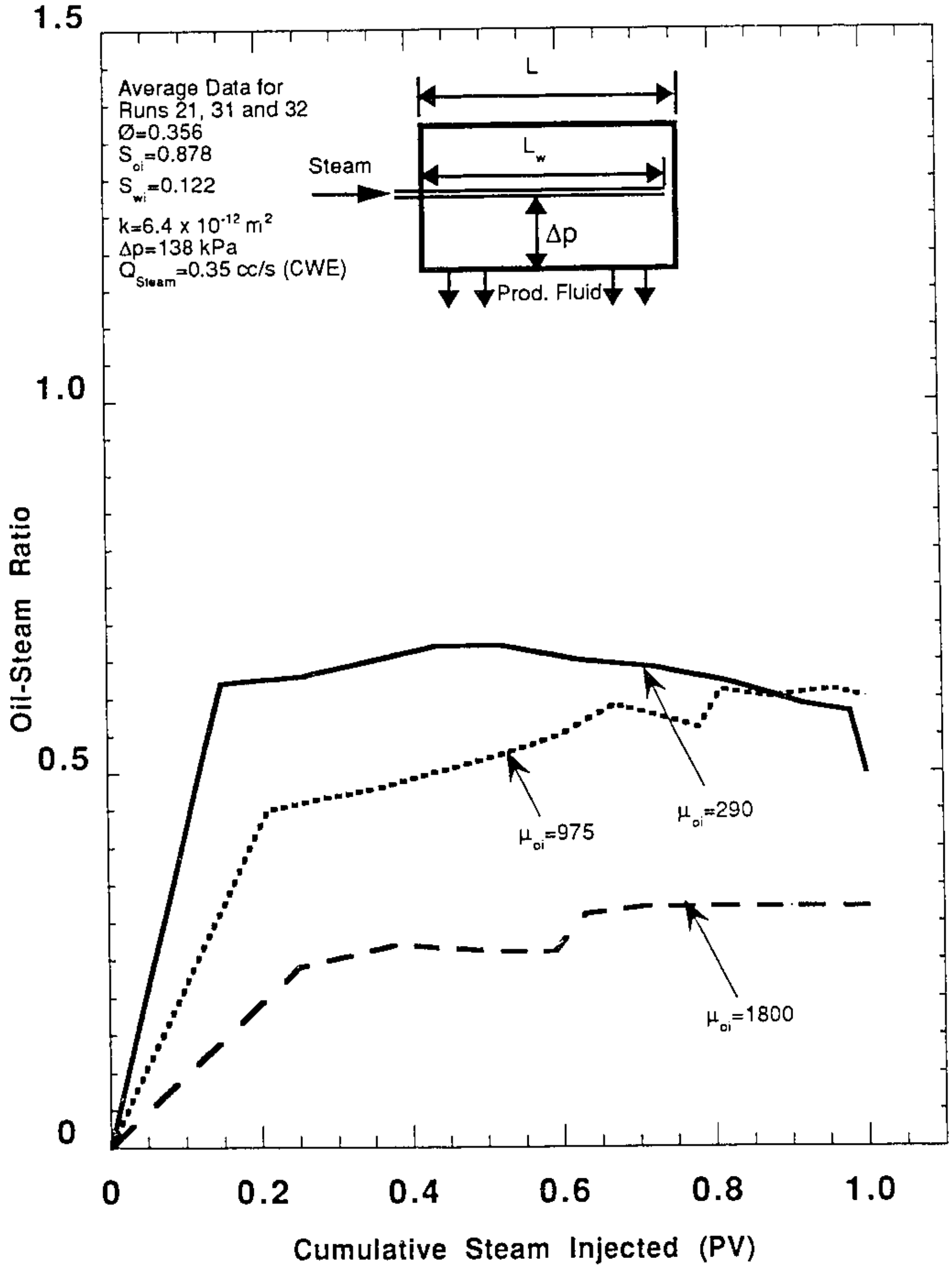


Figure 5.64 - Runs 21, 31 and 32: Effect of Oil Viscosity on Oil-Steam Ratio for Oil of Viscosity 290, 975 and 1800 mPa.s Using a Horizontal Injector



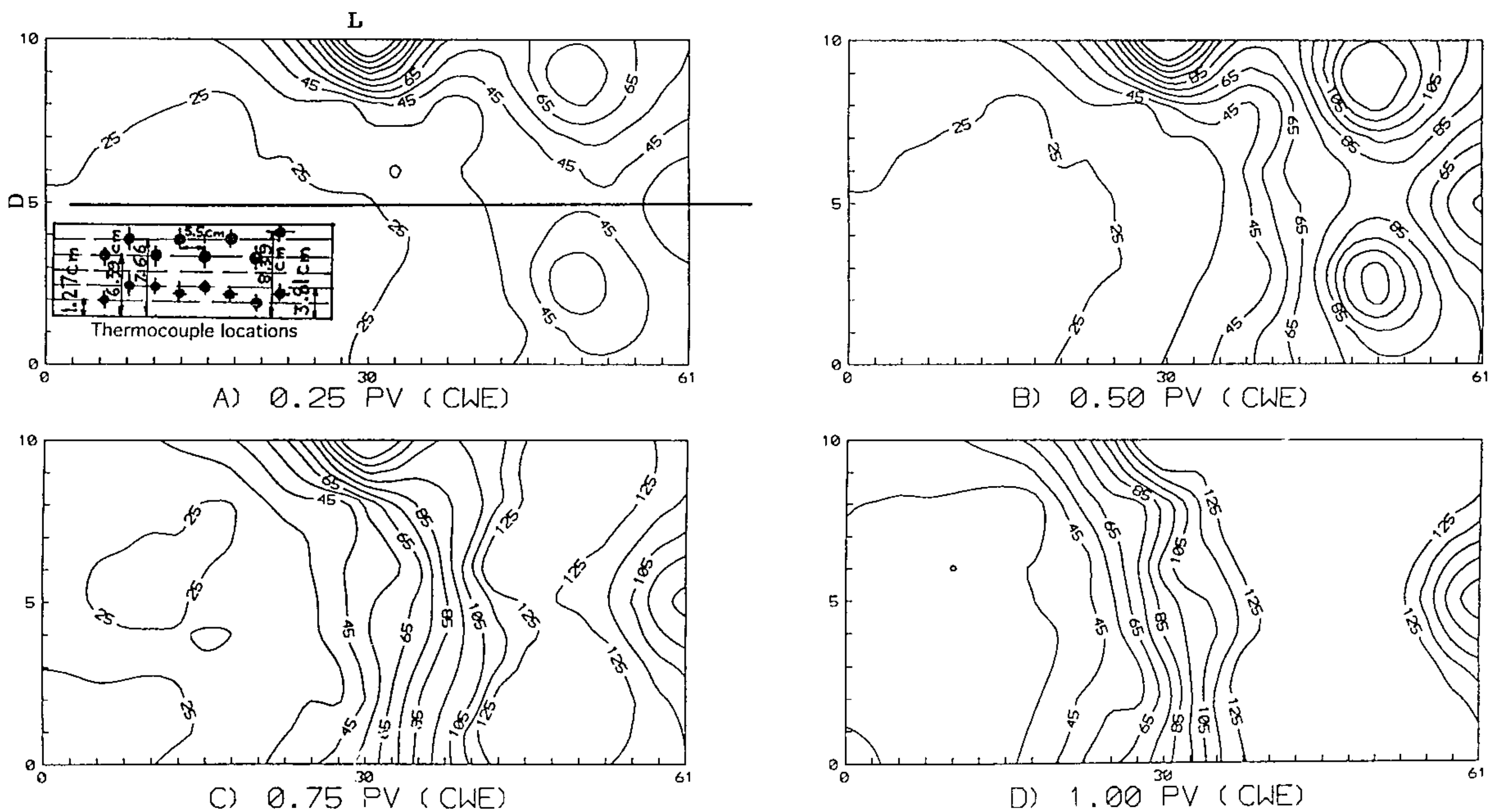
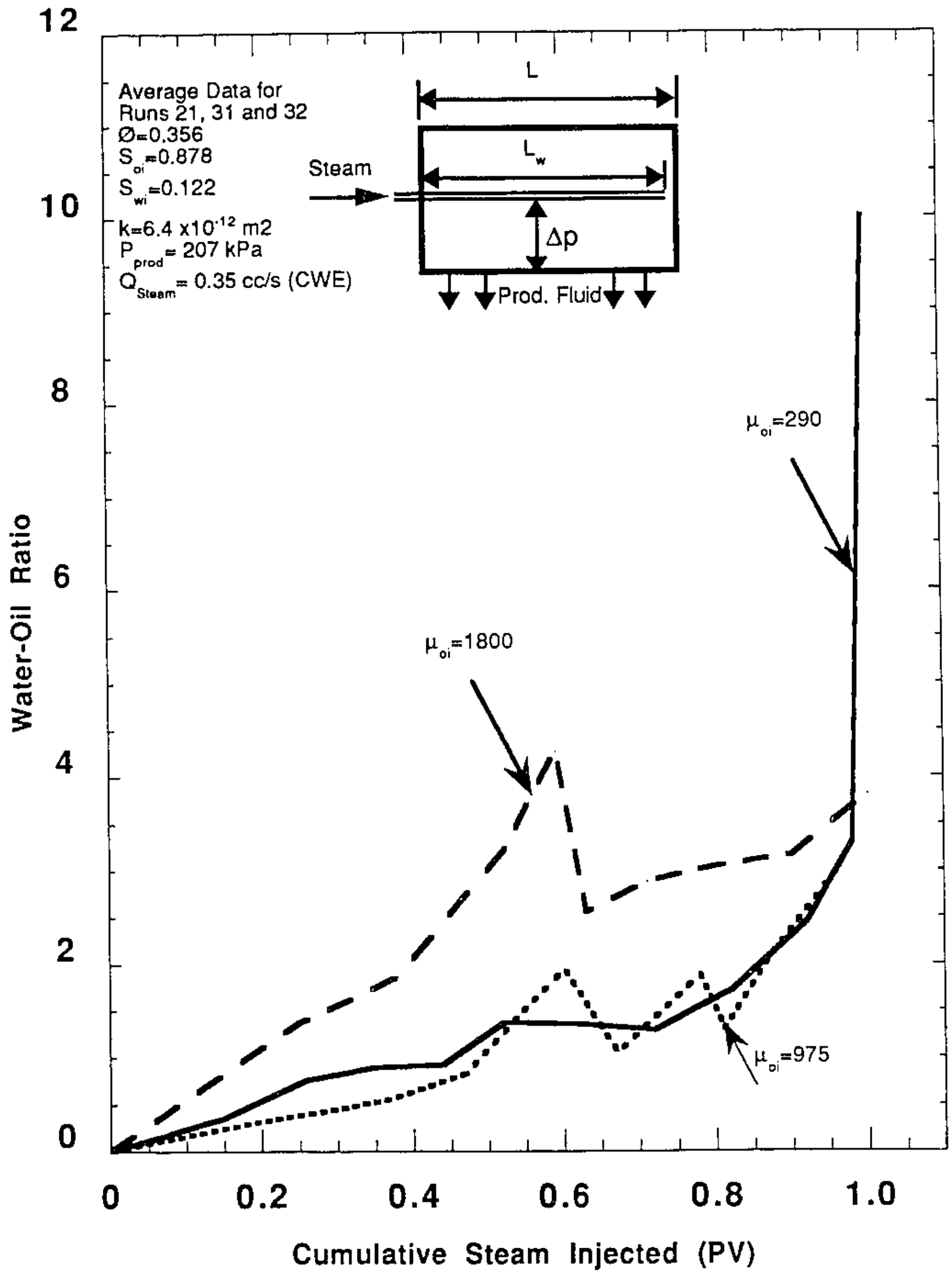


Figure 5.65: Cross-Sectional Views of the Temperature Distribution Inside the Sand Pack after the Injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV (CWE) of Steam for Run 31 Oil of Viscosity 1800 mPa.s Using a Horizontal Injector

Figure 5.66 - Runs 21, 31 and 32: Effect of Oil Viscosity on Water-Oil Ratio for Oil of Viscosity 290, 975 and 1800 mPa.s Using a Horizontal Injector



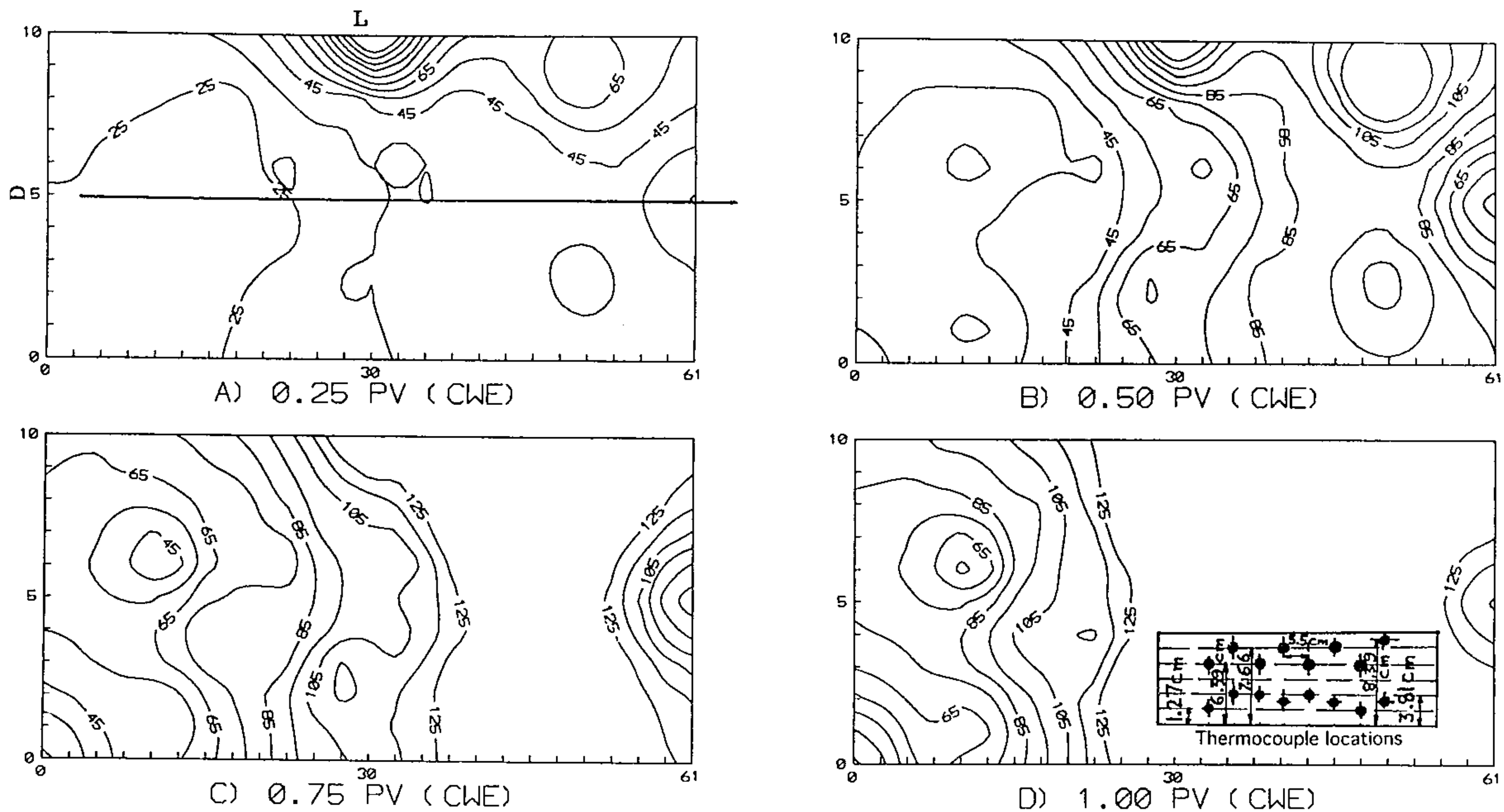
production was associated with high pressure surges and sluggish production. This was due to the relatively cold high viscosity oil swept by steam from different parts of the sand pack.

Figures 5.67 and 5.68 show temperature distribution profiles for steam inside the sand pack after the injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV CWE for 975 mPa.s and 290 mPa.s viscosity oils. Initially the cumulative oil recovery for the 290 mPa.s viscosity oil was higher than that of the 975 mPa.s oil, as shown in Figure 5.63. However, by the time approximately 0.8 PV of steam (CWE) had been injected, the 975 mPa.s oil cumulative oil recovery became higher than that of the 290 mPa.s oil because the heat at the start of the steam injection process was consumed heating the sand pack and mobilizing the oil around the injector. However, towards the end of the steam injection process, the 975 mPa.s oil was heated and its viscosity was decreased. This decrease improved the mobility ratio promoting a better and stable sweep efficiency.

Three experiments were conducted using 290, 975, and 1800 mPa.s viscosity oils to investigate the oil viscosity effect on oil production performance. The steam recovery performance for the 1800 mPa.s oil was adversely affected by high water production and unstable steam displacement which, as a consequence, produced 36.6% IOIP cumulative oil recovery. The 290 and 975 mPa.s oils showed the same behaviour in production performance and recovered 64% and 74% of the initial oil in place, respectively.

5.4.6 Effect of Pressure Differential Using a Horizontal Injector

Experiments 21, 26, 27 and 28 investigated the effect of pressure differential between the injector and the producer on oil recovery during the steam injection process. Steam was injected at the center using a horizontal injector penetrating the full length of a homogeneous sand pack. The sand pack initial oil and water saturations were 90% and 10%, respectively, and the average permeability was 6.4×10^{-12} m^2 (6.5 darcies). Runs 21, 26, 27 and 28 were conducted at 138 kPa (20 psig), 207 kPa (30 psig), 69 kPa (10 psig) and 276 kPa (40 psig) pressure differentials, respectively, to investigate the effect of pressure differential on oil recovery performance. Due to mechanical and operational problems encountered using too sensitive pressure transducers, the pressure drop inside the horizontal injector was ignored, and the



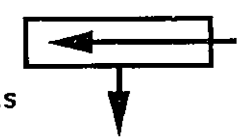


Figure 5.67: Cross-Sectional Views of the Temperature Distribution Inside the Sand Pack after the Injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV (CWE) of Steam for Run 32 Oil of Viscosity 975 mPa.s Using a Horizontal Injector

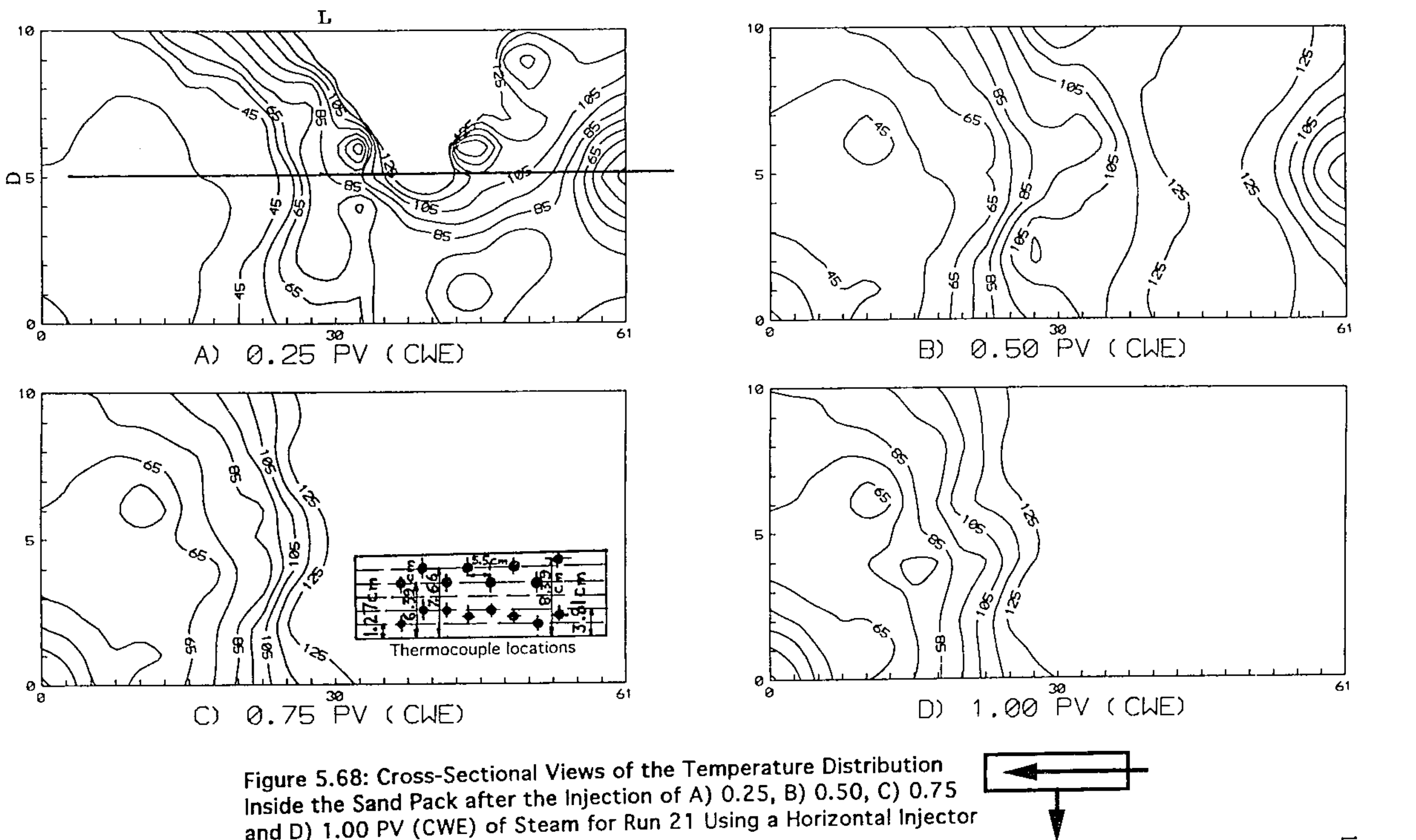


Figure 5.68: Cross-Sectional Views of the Temperature Distribution Inside the Sand Pack after the Injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV (CWE) of Steam for Run 21 Using a Horizontal Injector and Oil of Viscosity 290 mPa.s

overall pressure differential was taken to be the pressure differential inside the sand pack only.

The production pressure was varied for each run by a back pressure regulator to create different pressure differentials between the injector and producer. However, to ensure that these experiments were conducted at the same experimental conditions, the injection pressure was kept constant at 345 kPa (50 psig) in the entire set of experiments. The injection pressure in these experiments was kept constant using a back pressure regulator which was adjusted to maintain the desired injection pressure throughout each particular run. Both production and temperature data for pressure differentials of 69, 207 and 276 kPa were analyzed and compared with that of the base pressure differential of 138 kPa. Figures 5.69 and 5.70, which show cumulative oil recoveries and cumulative oil-steam ratios vs. cumulative steam injected for 69, 138, 207, and 276 kPa pressure differentials, clearly show that the cumulative oil recovery and oil-steam ratios increased as the pressure differential increased, reaching the highest cumulative oil recovery at 207 kPa pressure differential and then decreased to reach the lowest value at 276 kPa.

The highest, (276 kPa), and lowest, (69 kPa), pressure differentials produced the lowest cumulative oil recoveries and cumulative oil-steam ratios. This was because for the 69 kPa pressure differential steam production performance was complicated by high heat loss and for the 276 kPa pressure differential performance was complicated by early steam breakthrough and high water production. For visual inspection of the steam zone growth and steam front movement, temperature profiles of the steam inside the sand pack after the injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV CWE for 69, 138 and 276 kPa pressure differentials are shown in Figures 5.71, 5.72 and 5.73. When the lowest, (69 kPa), pressure differential was used, the steam injection process was very slow, and the oil production performance was complicated by the highest heat loss encountered in this set of experiments.

The heat loss for Run 27, (69 kPa differential pressure), was 135 W and that for Run 28, (276 kPa differential pressure), was 95 W. Heat balance calculations are given in Appendix A. However, an unstable steam process and early steam breakthrough complicated the steam production performance when the 276 kPa pressure differential was used. The steam production performance for the 276 kPa

Figure 5.69 - Runs 21, 26, 27 and 28: Effect of Pressure Differential on Oil Recovery for 69, 138, 207 and 276 kPa Pressure Differential Using a Horizontal Injector

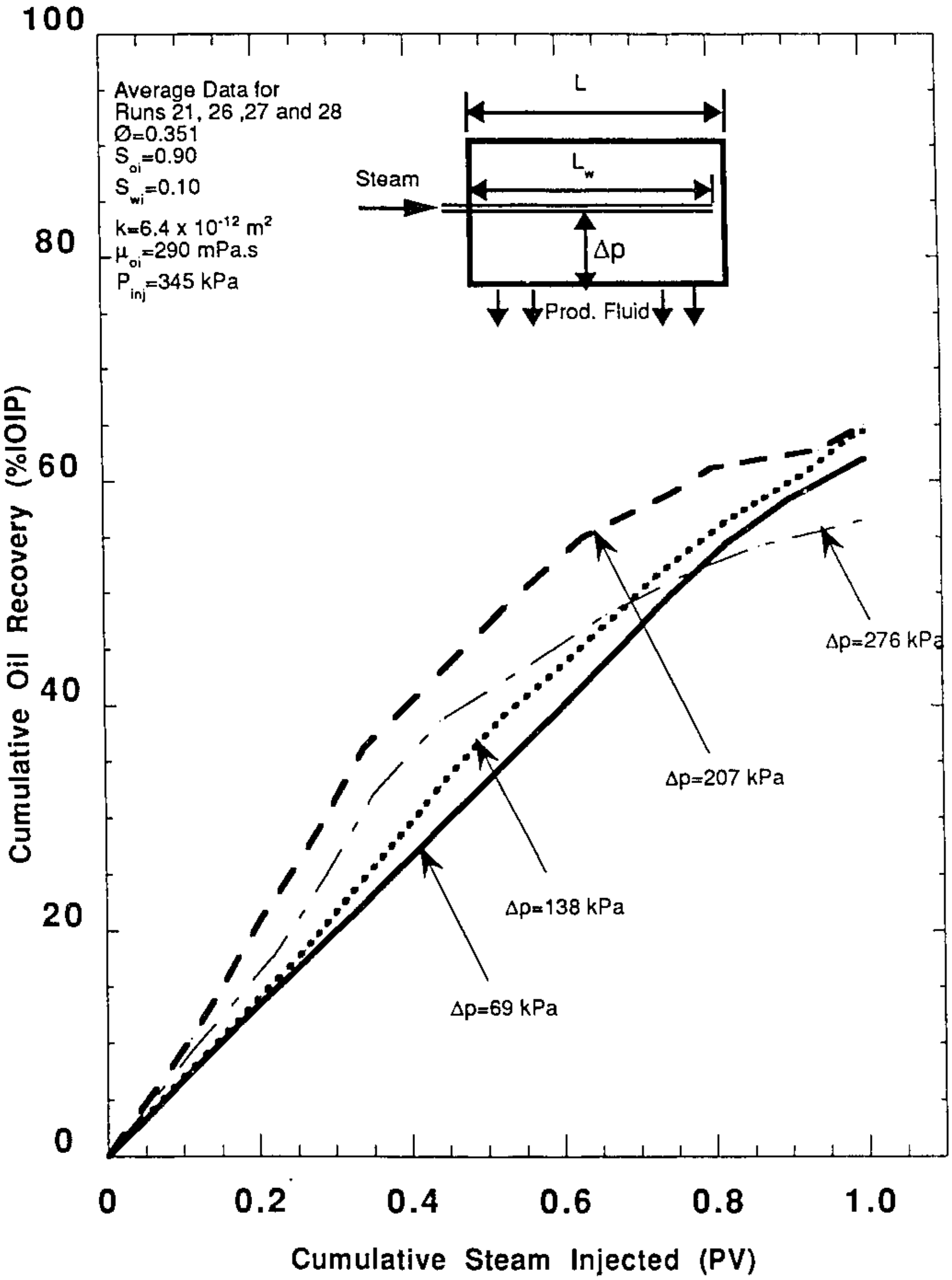
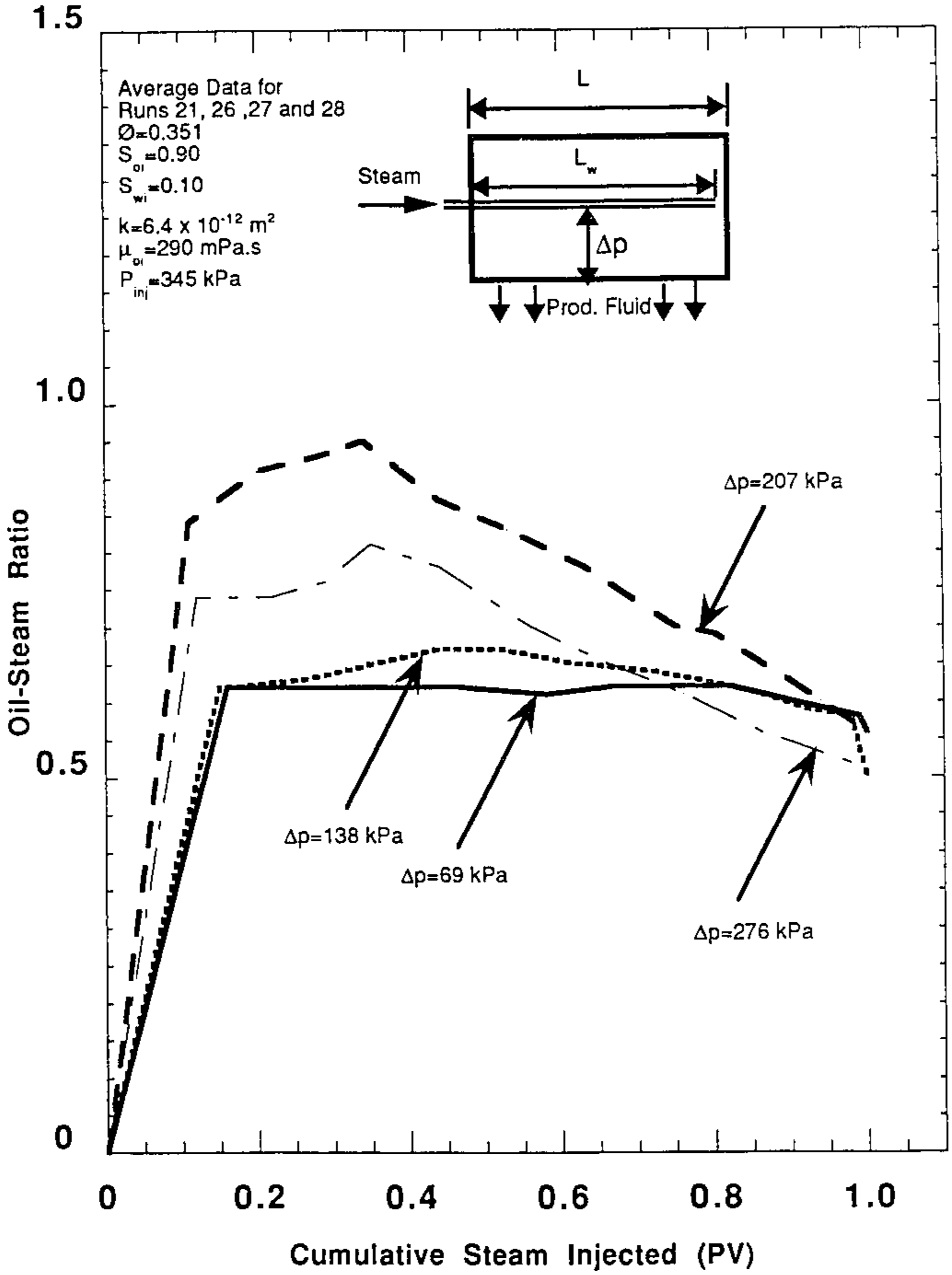


Figure 5.70 - Runs 21, 26, 27 and 28: Effect of Pressure Differential on Oil-Steam Ratio for 69, 138, 207 and 276 kPa Pressure Differential Using a Horizontal Injector



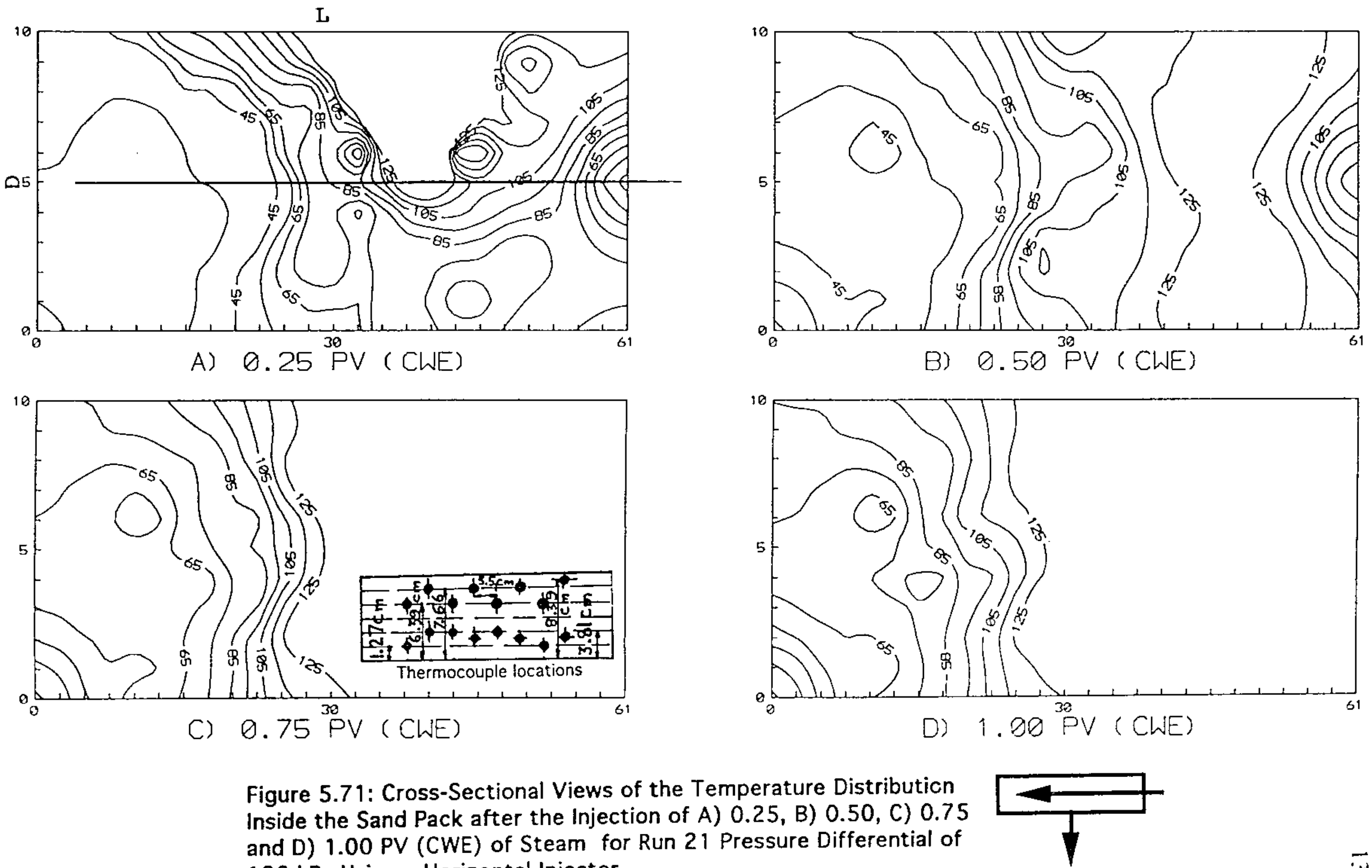
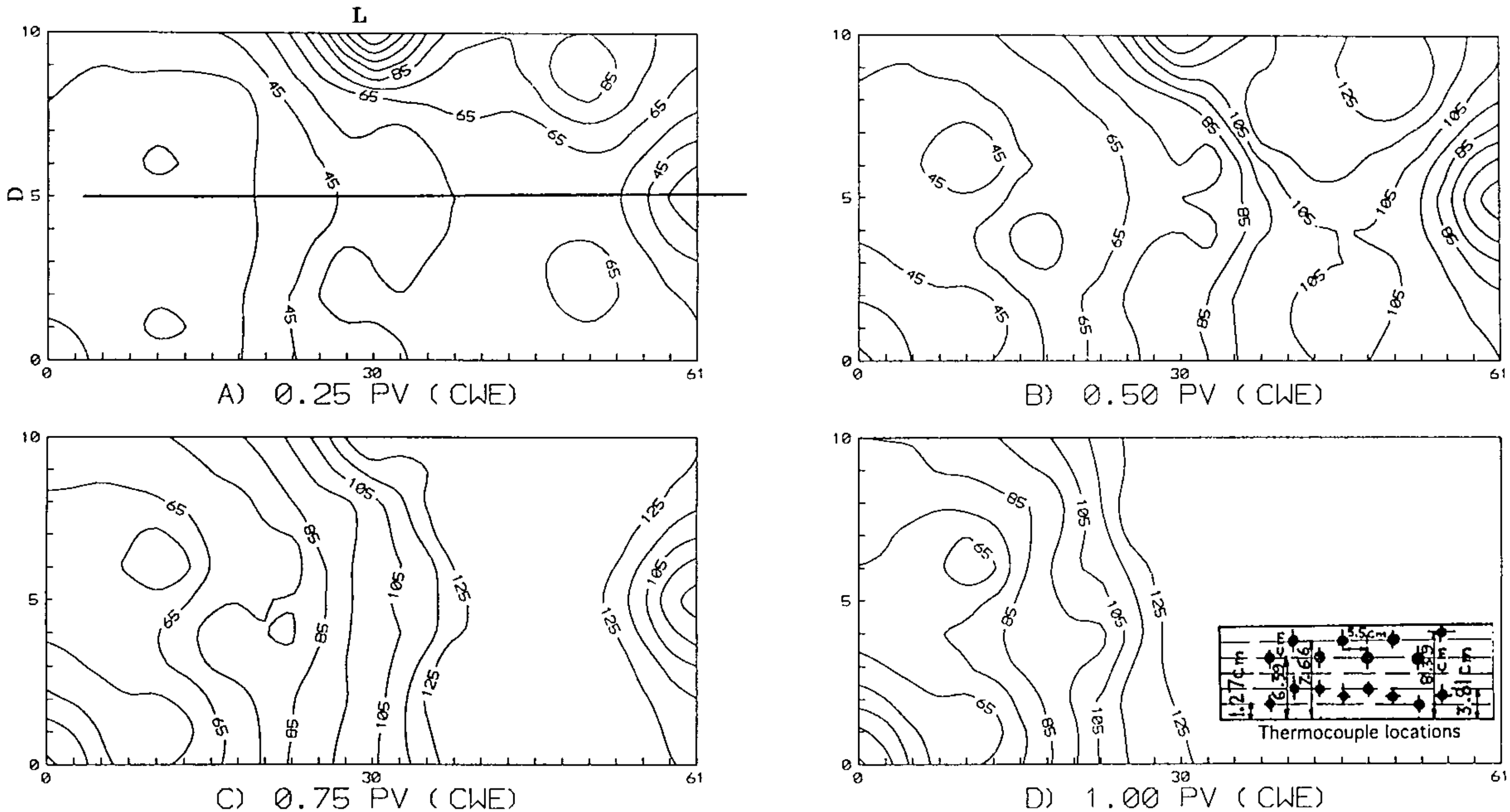


Figure 5.71: Cross-Sectional Views of the Temperature Distribution Inside the Sand Pack after the Injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV (CWE) of Steam for Run 21 Pressure Differential of 138 kPa Using a Horizontal Injector



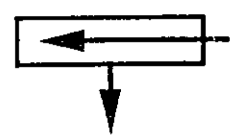
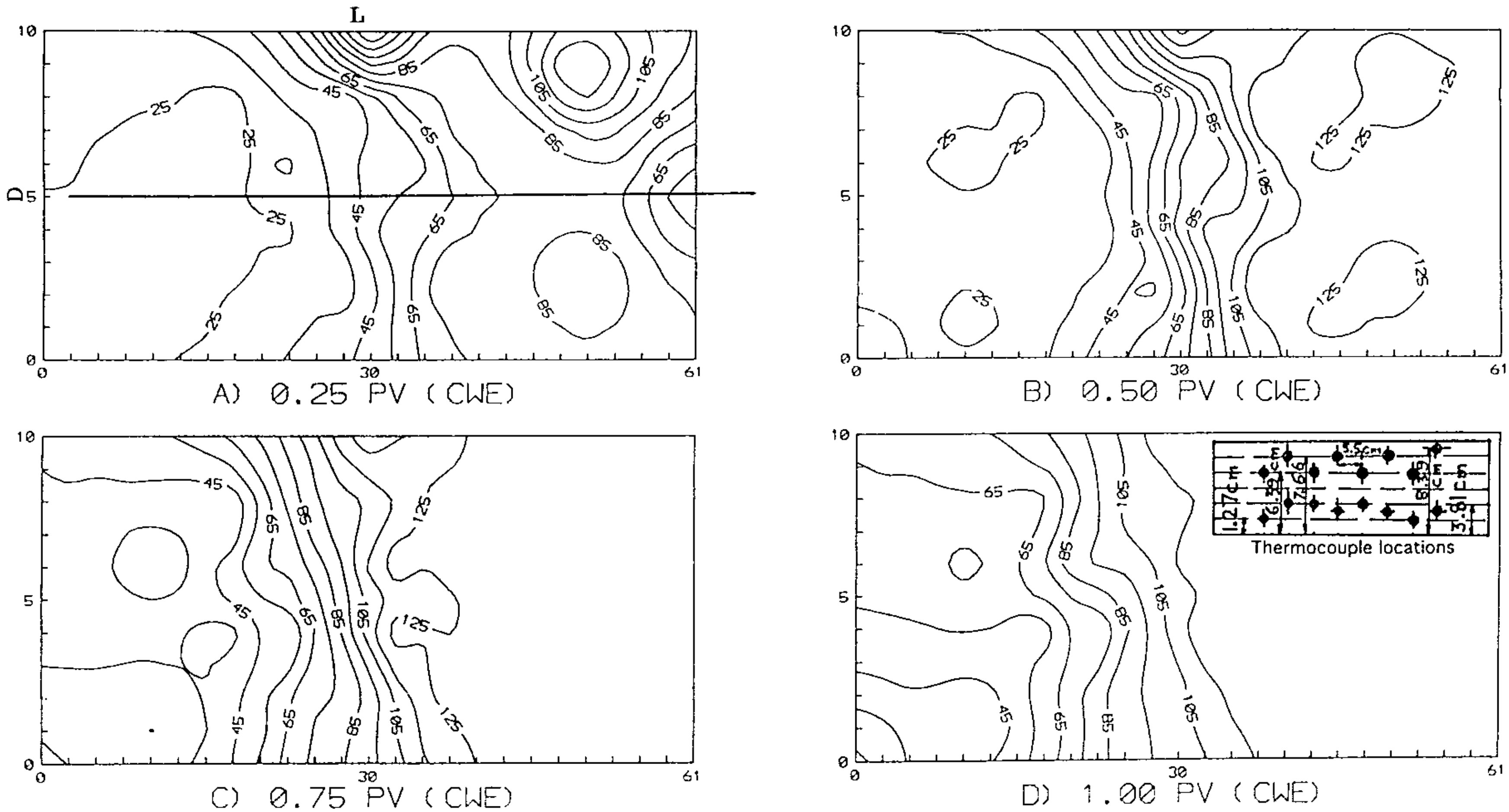


Figure 5.72: Cross-Sectional Views of the Temperature Distribution Inside the Sand Pack after the Injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV (CWE) of Steam for Run 27 Pressure Differential of 69 kPa Using a Horizontal Injector



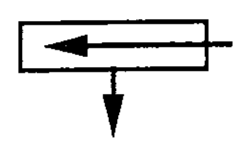


Figure 5.73: Cross-Sectional Views of the Temperature Distribution Inside the Sand Pack after the Injection of A) 0.25, B) 0.50, C) 0.75 and D) 1.00 PV (CWE) of Steam for Run 28 Pressure Differential of 276 kPa Using a Horizontal Injector

pressure differential was also complicated, as shown in Figure 5.74, by high water production almost from the start of the experiment.

In summary, Runs 21, 26, 27, and 28 were carried out at 69, 138, 207 and 276 kPa pressure differentials to study the effect of pressure differential between the horizontal injector and the producer on oil production performance. Cumulative oil recovery increased as the pressure differential increased to an optimum 207 kPa pressure differential for which the highest, (65% IOIP), cumulative oil recovery was obtained.

Moreover, oil production performance of the lowest 69 kPa (10 psig) pressure differential was complicated by high heat loss and that of the highest 276 kPa (40 psig) pressure differential was complicated by unstable steam displacement and early steam breakthrough. Unstable steam displacement and early steam breakthrough produced low cumulative oil recoveries and made the steam injection process unattractive at both the low, (69 kPa), and the high, (276 kPa), pressure differentials.

5.5 Horizontal Well Performance as Injector or Producer

In this work, the effect of horizontal well type, i.e. producer vs. injector, on oil displacement by steam was investigated. When oil was produced using a horizontal producer, steam was radially injected into the sand pack through the sintered metal jacket which acted as a distributor for the injected steam. However, when a horizontal injector was used, steam was injected into the sand pack via the horizontal injector, and oil was radially produced through the sintered metal jacket and collected at the bottom of the sand pack. Thirty six experiments were conducted during this work to study the effects of horizontal well injector or producer length, diameter and vertical location on steam recovery performance. Moreover, the effects of oil viscosity and pressure differential between the injector and the producer on the steam injection process were also investigated using a horizontal well as injector or producer.

Figures 5.75, 5.76 and 5.77 show cumulative oil recoveries for horizontal injectors and producers penetrating 25% and 100%, located 0.50 and 0.75 diameter from the sand pack upper boundary and having 0.32-cm and 0.95-cm diameters. Figures 5.78 and 5.79 show the cumulative oil recoveries obtained using horizontal wells with oil viscosities of 290 and 1800 mPa.s and a pressure differential of 138 kPa. The cumulative oil recoveries obtained using a horizontal well as the producer were

Figure 5.74 - Runs 21, 26, 27 and 28: Effect of Pressure Differential on Water-Oil Ratio for 69, 138, 207 and 276 kPa Pressure Differential Using a Horizontal Injector

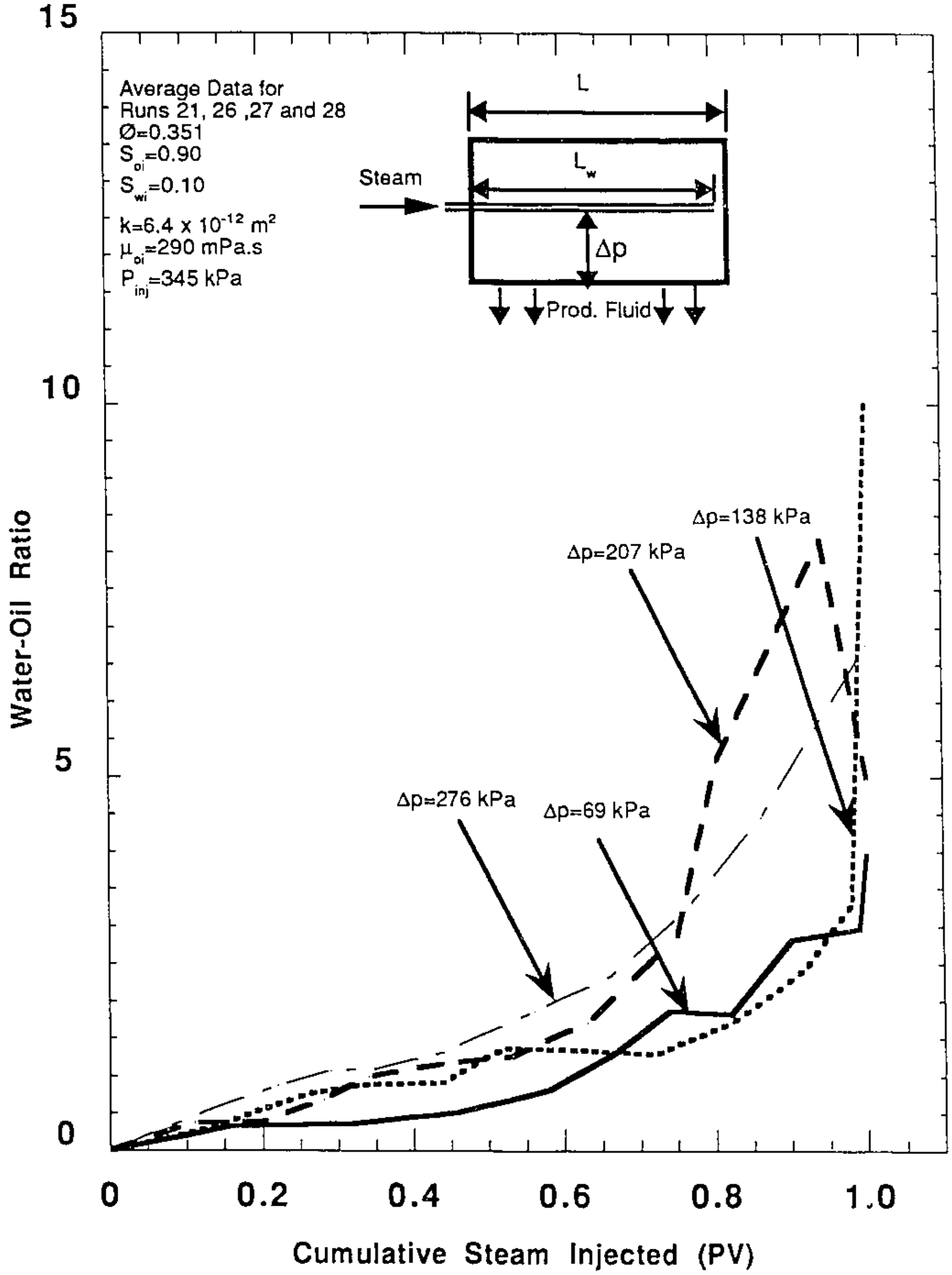


Figure 5.75 - Runs 12, 16, 21 and 22: Effect of Horizontal Well Type (Producer vs. Injector) and Length on Oil Production Performance Using a Horizontal Well Penetrating 25% and 100% of Sand Pack Length

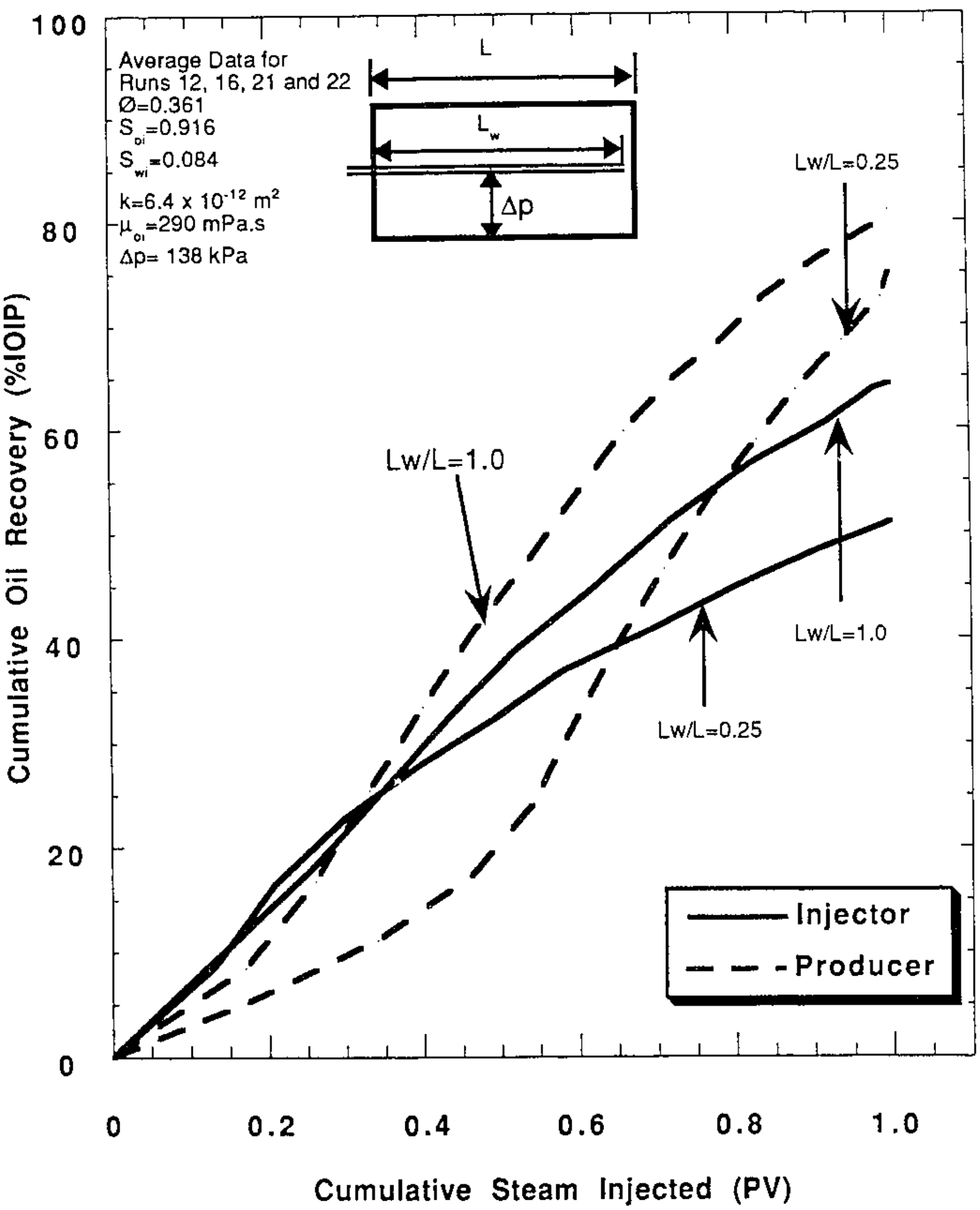


Figure 5.76 - Runs 16, 20, 21 and 24: Effect of Horizontal Well Type (Producer vs. Injector) and Location on Oil Production Performance Using a Horizontal Well Located 0.50D and 0.75D from the Sand Pack Upper Boundary

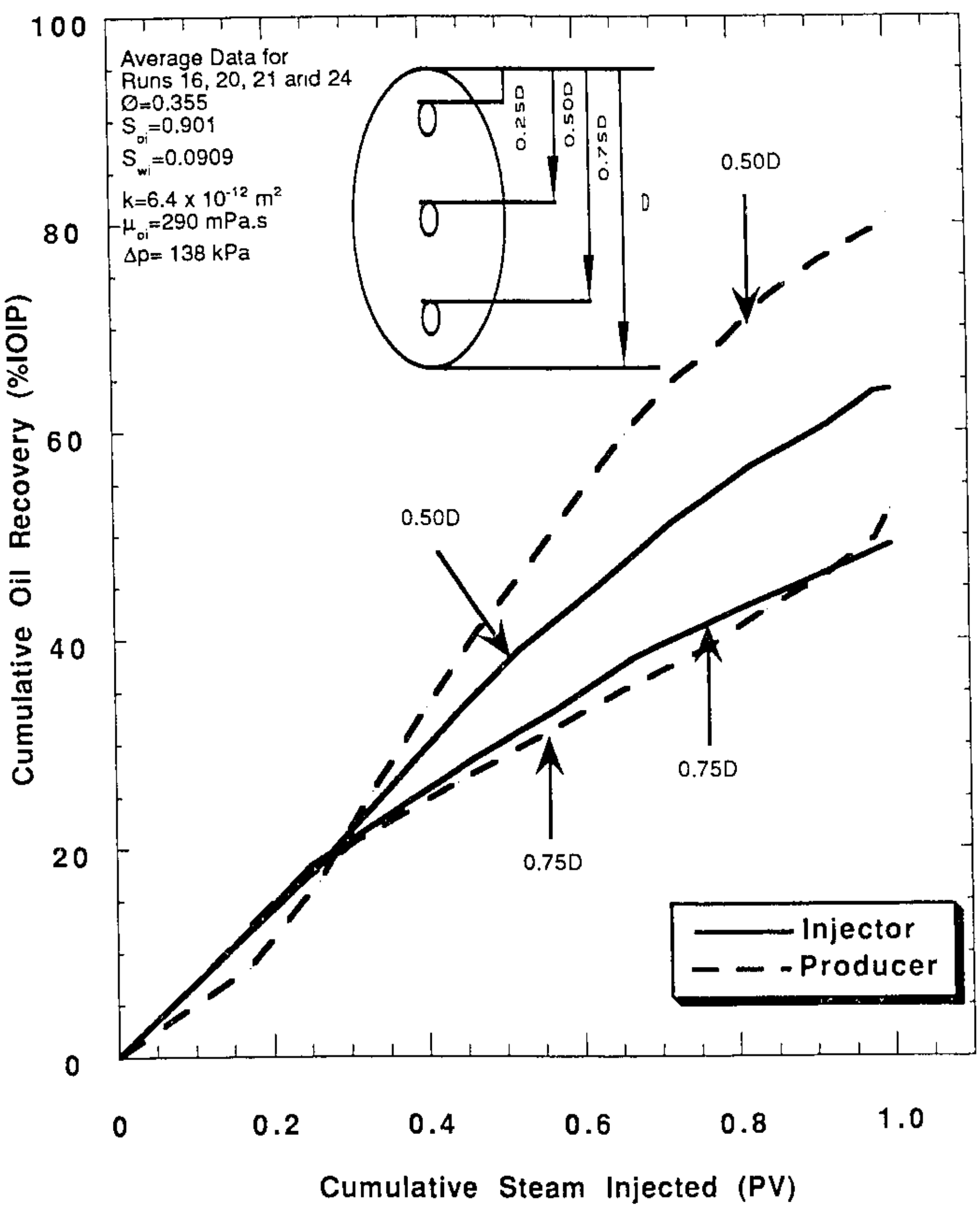


Figure 5.77 - Runs 16, 21, 30 and 34: Effect of Horizontal Well Type (Producer vs. Injector) and Diameter on Oil Production Performance Using 0.32 and 0.95-cm Diameter Horizontal Well

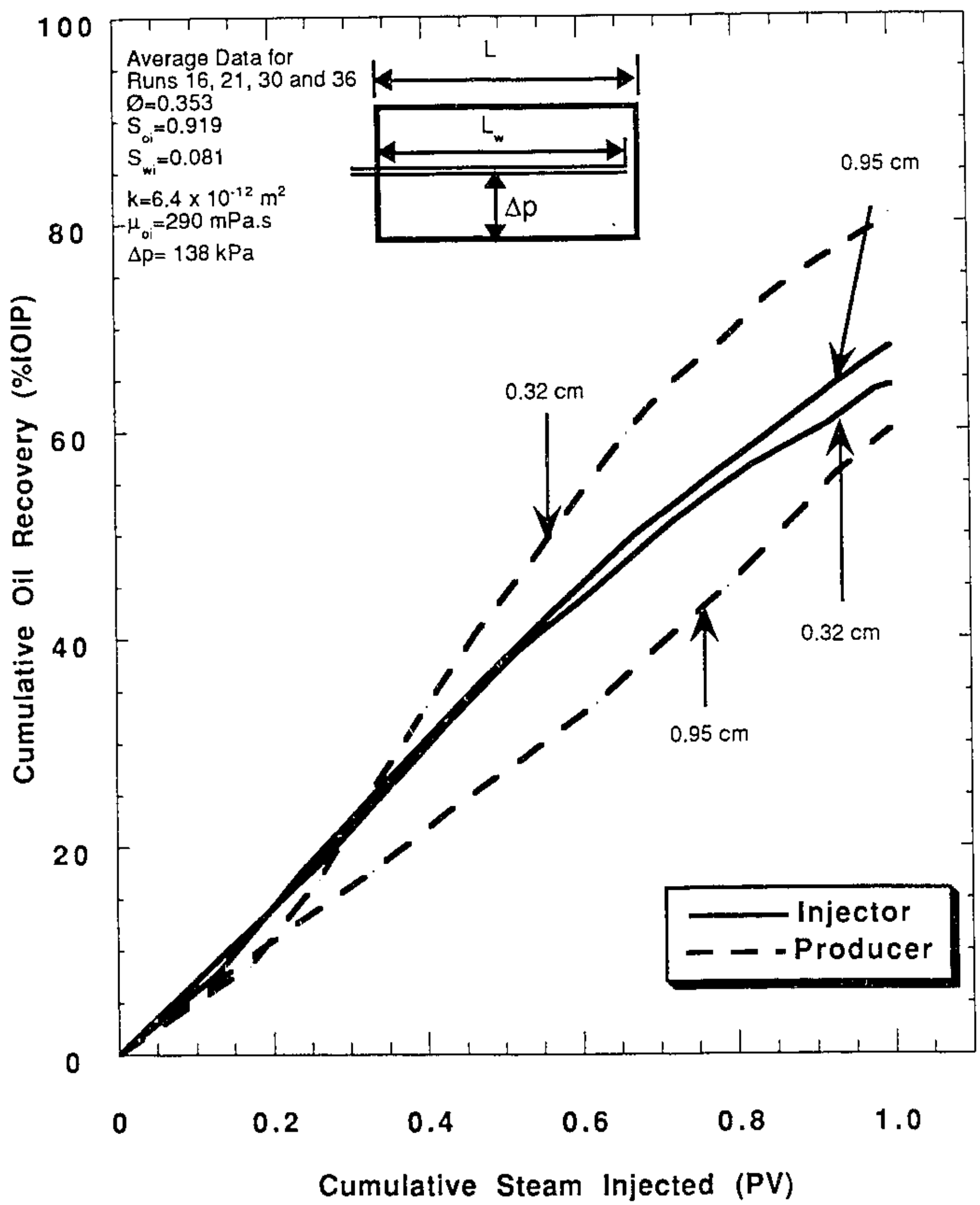


Figure 5.78 - Runs 16, 21, 31 and 36: Effect of Horizontal Well Type (Producer vs. Injector) and Oil Viscosity on Oil Production Performance Using Oil of Viscosity 290 and 1800 mPa.s

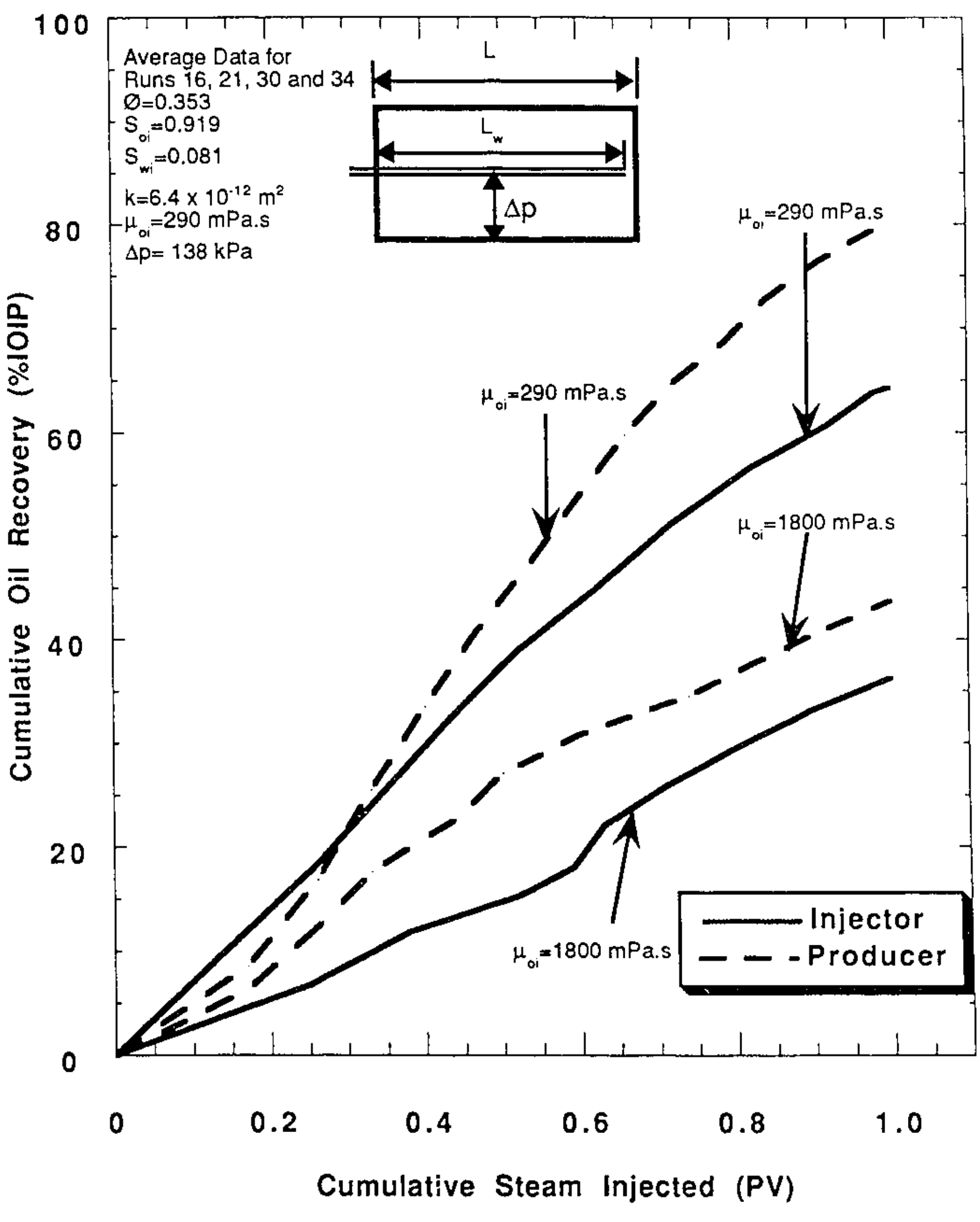
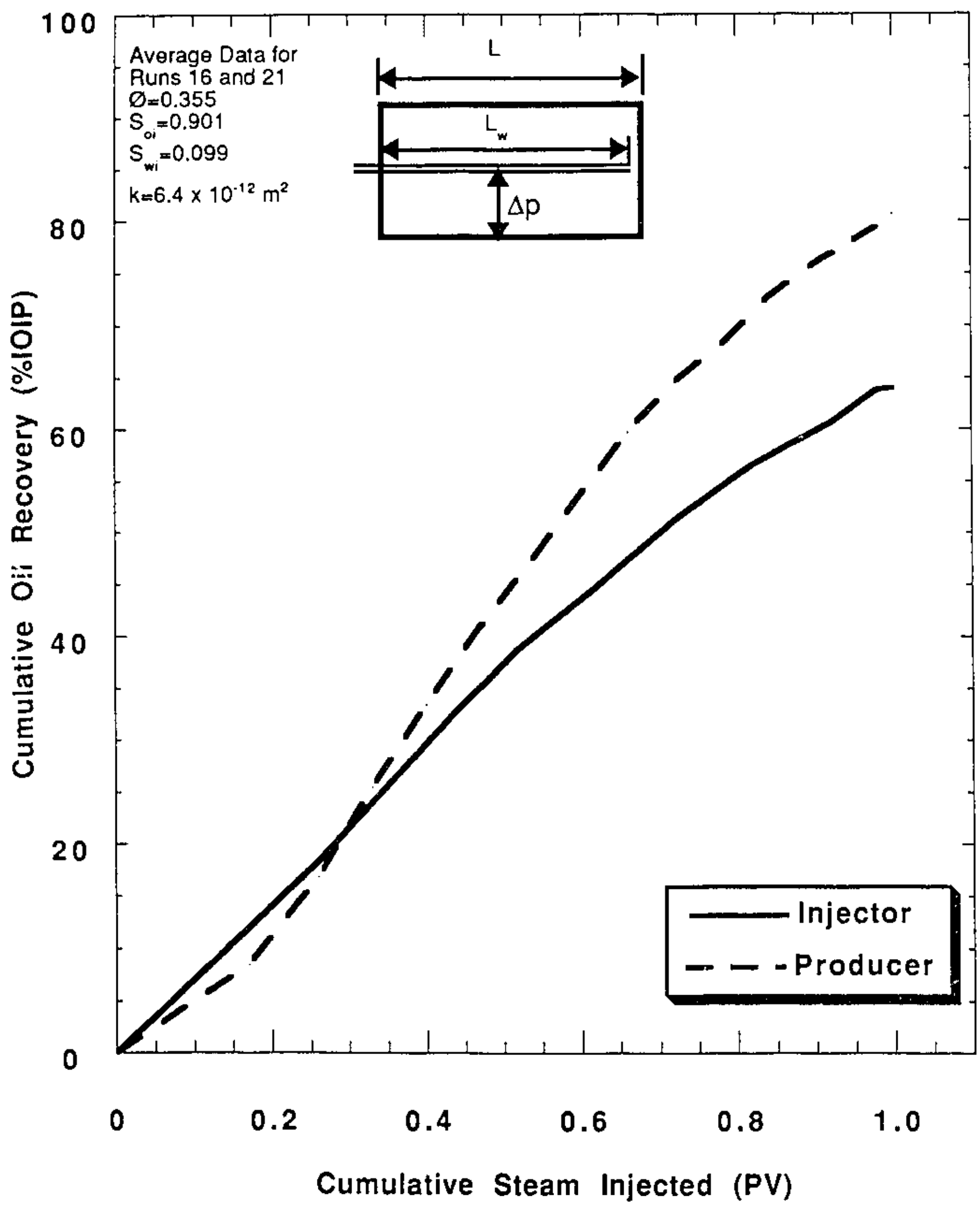


Figure 5.79 - Runs 16, and 21: Effect of Horizontal Well Type (Producer vs. Injector) on Oil Production Performance for Pressure Differential of 138 kPa



more than those obtained using a horizontal well as the injector. Furthermore, when the horizontal injector diameter was increased from 0.32 cm to 0.95 cm, there was hardly any effect on the cumulative oil recovery.

However, when the producer diameter was increased from 0.32 cm to 0.95 cm, the cumulative oil recovery decreased from 81% to 58% IOIP. The high cumulative oil recovery obtained in the case of the horizontal producer was because the steam was radially injected and distributed around the sand pack via the sintered metal jacket which covered the entire surface area of the sand pack. However, when a horizontal well was used as the injector, steam was injected via the horizontal well and the sand pack contact area was much less than when steam was radially injected into the sand pack. When a horizontal well was used as a producer in combination with radial injection, the horizontal well attained a higher cumulative oil recovery than when it was used as an injector in combination with radial oil production. Actually if we were to compare the oil recoveries at different pore volumes injected the difference would be large at small pore volumes injected and not that large at higher pore volumes injected.

In conclusion, based on the experimental results obtained from using a horizontal well as injector or producer, use of a horizontal well as a producer rather than an injector is more effective. Radial steam injection provides a larger steam contact area and higher cumulative oil recovery than steam injection using a horizontal injector.

5.6 Marx and Langenheim Model[65]

Marx and Langenheim's model is useful for highlighting some features of reservoir heating. In their development, Marx and Langenheim suggested that the steam injected must heat the newly invaded formation as well as make up for the heat loss to adjacent formations. They assumed that steam was injected at a constant rate and constant temperature. Even though they recognized a radial temperature transition zone, they treated the temperature inside the steam zone to be a constant temperature equivalent to the sand face injection temperature, and the temperature outside of the steam zone to be equivalent to the initial reservoir temperature. In their analysis, Marx and Langenheim neglected the effect of gravity and assumed no vertical or horizontal temperature variations within the heated zone. To match Marx and Langenheim's results, their assumption of increasing heat loss with time, as the steam zone grows, was modified for a constant heat loss. An overall heat balance on the sand pack gives

$$q_{in} = q_{acum} + q_{loss}$$

where

q_{in} = Heat input = 682 W (Calculations are give in Appendix A)

q_{loss} = Heat loss = 145 W (Calculations are give in Appendix A)

q_{acum} = The amount of heat required to bring the sand pack to 142 °C above the initial temperature of 19 °C = 537 W (Calculations are give in Appendix A)

Heat accumulated in the sand pack is given by

$$q_{acum} = M_{res}\,\Delta T\,\frac{dV}{dt} \text{ ----------------------------(1)}$$

where

M_{res} = Reservoir volumetric heat capacity
= 2.55 J/cm^3 °C

ΔT = Steam Injection Temperature - Initial Sand Pack Temperature
= $T_{inj} - T_{res}$ = 142 - 19 = 123 °C

dV/dt = Steam zone volume growth, cm^3/s

The rate of steam volume growth can be determined using Equation (1)

$$\frac{dV}{dt} = \frac{q_{acum}}{M_{res}\,\Delta T} = \frac{537}{(2.55)(123)} = 1.71 \text{ cm}^3\text{/s}$$

Total (water and oil) production rate is given by

$$Q_t = \frac{dV}{dt}\,\phi\,(1 - S_{sorst} - S_{wr})$$

where

ϕ = Porosity = 0.354

S_{wr} = Irreducible water saturation (assumed to be equal to the sand pack initial water saturation, S_{wi}) = 0.041

S_{sorst} = Residual steam oil saturation (assumed to be equal to the sand pack final oil saturation, S_{of})

$$S_{of} = S_{oi}(1 - RF) = 0.959\ (1 - 0.81) = 0.18$$

RF = Recovery factor = 0.81

S_{oi} = Initial sand pack oil saturation = 0.959

$$Q_t = (1.73)\ (0.354)\ (1 - 0.18 - 0.041) = 0.48\ cm^3/s$$

This can be compared with the experimental value Q_{exp}

From Table 5.2 average production rate is

$$Q_{exp} = \frac{\text{cumulative fluid produced}}{\text{cumulative time}} = \frac{2772\ cm^3}{(83.47\ x\ 60)\ s} = 0.55\ cm^3/s$$

In the above calculations the Marx and Langenheim Model was modified for constant heat loss. A heat balance approach similar to that of Marx and Langenheim was used to estimate approximately the experimental rate. The experimental rate of 0.55 cm^3/s is higher than the 0.48 cm^3/s predicted using Marx and Langenheim Model. The reason that the experimental and predicted rates do not match is because the Marx and Langenheim Model assumes that the steam zone is growing and the heat loss is increasing as the steam zone area increases where in the present model the steam zone growth and heat loss is assumed to be constant.

6. Summary and Conclusions

The primary objective of this study was to examine flow in the vicinity of a horizontal production well, or steam injection well, and study the impact of selected variables on oil recovery. An experimental model was designed for examining the steam/oil-water flow in the vicinity of and inside a horizontal well. The following conclusions were based on the experimental results obtained in this work:

1. The oil recovery performance strongly depends on whether a horizontal well is used as an injector or as a producer. The latter gave higher oil recovery (i.e., 81% in Run 16 vs. 64% in Run 21).
2. Steam override plays an important role in the process, as judged from the temperature distributions at various times. The extent of this effect depends on the location of the horizontal well in the vertical plane.
3. Oil viscosity is important, with oil recovery decreasing with an increase in oil viscosity. The effect was more pronounced when the horizontal well was used as a producer.
4. The length, diameter and vertical location of a horizontal well are important variables.

   (i) In the case of a horizontal producer, a smaller diameter, a greater length and a location near the centre of the porous pack were most effective.

   (ii) In the case of a horizontal injector, the recovery was insensitive to well diameter; a greater length and a location near the centre were most effective.
5. Even for the complex experiments conducted, a Marx-Langenheim calculation gave results close to the experimentally observed values.

7. Recommendations

The following recommendations are offered to extend the scope of the research and improve the experimental techniques.

1. Investigate the effect of gravity vs. pressure drawdown on oil production performance during steamflooding by plugging the bottom perforations of the horizontal producer.

2. Study the effect of steam blow-down on the incremental oil recovery.

3. Incorporate pressure transducers to measure the magnitude of the pressure drop inside the horizontal well and to examine the effect of the horizontal well diameter and length on the pressure drop inside the horizontal well.

4. Add more thermocouples to the existing model to better map the steam zone growth inside the sand pack.

5. Examine the perforated interval location along the horizontal well (i.e., perforated interval location at the heel, toe, or the middle of the horizontal well).

6. Investigate the effect of pre-injection vs. co-injection of solvents or steam additives on the steam process efficiency.

7. Compare oil production performance using a steam-slug process vs. continuous steam injection.

8. Study the effect of heating and cooling of the sand pack on absolute permeability.

9. Investigate the effect of oil viscosity and steam quality on the steam residual oil saturation.

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Appendix A: Sample Calculations

1. Effect of Pressurizing the Sand Pack on Initial Oil and Water Saturations

Thirty-six experiments were conducted in this research, in each of which a new sand pack was used. The model was packed with Ottawa sand, and then the sand pack pore volume and the initial oil and water saturations were determined at atmospheric pressure. However, the steam injection pressure was 276 kPa (40 psig) for those experiments in which a horizontal producer was used, and was 345 kPa (50 psig) for those in which a horizontal injector was used. In order to have an equally pressurized system, the sand pack was pressurized to the steam injection pressure by means of injecting water prior to steam injection process. The reason water was used to pressurize the sand pack was because of its compressibility was lower than that of the Faxam-100 oil used to saturate the sand pack with oil. The following sample calculations were performed to determine the volume of water which had to be injected to pressurize the sand pack to 345 kPa, and the effect of that volume on the sand pack initial oil and water saturations.

Assumptions:

1) Isothermal oil compressibility.
2) Incompressible sand pack with a constant pore volume.
3) Faxam-100 being the most compressible fluid in the system.
4) Negligible water and cylinder compressibility.
5) Isothermal compressibility equation is valid

then, $c = \frac{1}{v}\left(\frac{\partial v}{\partial p}\right)_T$ [66] ---------------------------------- A-1

To describe the volume reduction it is more convenient to express it in the form

$$dV_o = c_o V_{oi}\,\Delta p \quad \text{------------------------------------ A-2}$$

where,

c_o	Oil compressibility, $3.626 \times 10^{-6}\ kPa^{-1}$
V_{oi}	Initial oil volume in the sand pack, cm^3
Δp	Pressure difference, kPa

Sample Calculation:

Using Equation A-2 and data from Run 21 (Highest injection pressure)

V_{oi} = 1435 cm^3

Δp = 345 - 0 = 345 kPa (gauge),

we have $dV_o = 1.79\ cm^3$

$$\%\ \text{Error} = \left(\frac{S_{oiold} - S_{oinew}}{S_{oiold}}\right) \times 100$$

$$\text{Error} = \left(\frac{89.7 - 89.6}{89.7}\right) \times 100 = 0.11\%$$

In the above calculations, a higher compressibility than that of the water and Faxam-100 was used to produce a conservative estimate of fluid volume reduction induced by pressurizing the sand pack to the injection pressure i.e., 345 kPa (50 psig). Although, a conservative estimate was made to calculate the volume of water introduced into the sand pack, the volume of water injected was calculated to be 1.79 cm^3 which introduced a minimal change to initial oil saturation.

2. Heat Balance

Some experiments in this research investigated the effect of the pressure drop between the injector and producer on oil production performance during the steam injection process. The experimental results obtained indicated that cumulative oil recovery increased as the pressure differential increased to an optimum value, and then decreases thereafter. One of the reasons for low cumulative oil recovery at low pressure differential was due to high heat loss. The following is an example of the heat balance calculation for Run 16.

Assumptions:

1) The film temperature was used for the boundary temperatures; this takes into account the fact that fluid properties vary with temperature across the boundary layer.

$$T_{film} = \frac{T_{surf} + T_{amb}}{2} \qquad \text{A-3}$$

T_{surf} and T_{amb} are surface and ambient temperatures

2) Surface temperature of the sand pack was taken to be

$$T_{surf} = \frac{T_{inj}+T_{prod}}{2} \quad \text{------------------------------------ A-4}$$

T_{inj} and T_{prod} are injection and production temperatures

Equations for free convections on a horizontal cylinder[67]

$$\text{Rayleigh number} = \text{Ra} = \frac{g\,\beta\,(T_{surf} - T_{amb})\,L^3}{\nu\,\alpha} \quad \text{------------------- A-5}$$

where,

- g Gravitational acceleration, m/s^2
- β Volumetric thermal expansion coefficient, K^{-1}
- L Model length, m
- ν Kinematic viscosity, m^2/s
- α Thermal diffusivity, m^2/s

Values for β, ν and α are evaluated at the film temperature

$$\text{Nusselt number} = \text{Nu} = \left\{0.60 + \frac{0.387\ (\text{Ra})^{0.1667}}{\left[1 + \left(\frac{0.599}{\text{Pr}}\right)^{0.5625}\right]^{0.2963}}\right\}^2 \quad \text{--- A-6}$$

Pr Prandtl number

Equation A-6 is valid for $10^{-5} < \text{Ra} < 10^{12}$; all values for Ra in each run were within this range

$$\text{Convection coefficient} = h = \frac{\text{Nu}\,k_{air}}{L} \quad \text{-------------------------------- A-7}$$

k_{air} is the thermal conductivity of air evaluated at the film temperature

Convective coefficient can also be determined from the relation given in Perry's Chemical Engineering Handbook[68] (pg. 10-13) Equation 10-54

$$h = b\,(\Delta T)^m\,L^{3m-1} \quad \text{--------------------------------- (A-8)}$$

where values for b and m are given in Table 10-1

Percent difference between using Equations A-7 and A-8 was 7%. This difference was a result of using b and m values which were experimentally determined, where as for Equation A-5 values only relevant to the runs were used .

Heat Balance for Run 16

Steam injection rate = 0.34 cc/s (CWE)
Injection temperature = 142 °C
Production temperature = 138 °C
Ambient temperature = 24 °C
Using Equations A-3 and A-4
Film temperature = 82 °C ≈ 355 K
Surface temperature = 140 °C ≈ 413 K

Air properties interpolated at film temperature

$\beta = 2.82 \times 10^{-3}\ K^{-1}$
$L = 0.61$ m
$\nu = 2.15 \times 10^{-5}\ m^2/s$
$\alpha = 3.1 \times 10^{-5}\ m^2/s$
$k = 3.38 \times 10^{-2}$ W/m K
$Pr = 0.7$

Water properties interpolated at surface temperature

ρ_w = Water density = 941 kg/m^3
h_v = Latent heat of vaporization = 2132 kJ/kg

Using Equations A-5, A-6 and A-7;

$$Ra = \frac{9.81 \times 0.00282 \times 116 \times 0.61^3}{2.15\ E\text{-}5 \times 3.1\ E\text{-}5} = 1.1 \times 10^9$$

$$Nu = \left\{ 0.60 + \frac{0.387\ (1.1\ E9)^{0.1667}}{\left[1 + \left(\frac{0.599}{0.7}\right)^{0.5625}\right]^{0.2963}} \right\}^2 = 118$$

$$h = \frac{118 \times 0.0338}{0.61} = 6.54\ \ W/m^2\,K$$

$$q_{loss} = h\ A\ (T_{surf} - T_{amb}) \text{ ---------------------------- A-9}$$

$$q_{loss} = 6.54 \times \pi \times 0.1 \times 0.61\ (140 - 24) = 145\ W$$

$$q_{in} = m_w \times h_v \text{ --- A-10}$$

where m_w is mas flow rate input to the system, kg/s

$m_w = Q_{inj} \times \rho_w$

$m_w = 3.4 \times 10^{-7} \times 941 = 3.2 \times 10^{-4}$ kg/s

Using Equations A-8

$$q_{in} = 3.2 \times 10^{-4} \times 2132 = 682 \text{ W}$$

Heat Loss for other Runs (W)

Run No	Heat loss	Run No	Heat loss
1	N/A	21	130
2	N/A	22	128
3	108	23	123
4	91	24	135
5	N/A	25	123
6	120	26	119
7	95	27	135
8	102	28	95
9	108	29	131
10	112	30	128
11	110	31	101
12	116	32	116
13	95	33	112
14	98	34	98
15	115	35	99
16	110	36	127
17	122		
18	89		
19	81		
20	110		

3. Steam Performance Prediction Using Marx and Langenheim Model[65,69,70]

In the following calculations the Marx and Langenheim Model was used to predict the steam performance for Run 16. The assumptions Marx and Langenheim used in developing their model are not applicable to the model used in this work; the predicted theoretical results did not match the experimental results.

Steam Zone Volume

For time equivalent to 1.00 PV = 1.3 hr

$$V_{st} = \left(\frac{H^2 M_{res} Q_{st}}{4\, k_{hob}\, M_{ob} (T_{inj} - T_{res})}\right) F_1 \text{----------------(A-11)}$$

where,

V_{st} = Steam zone volume, ft^3

H = Sand pack thickness = 1.58 ft

M_{ob} = Overburden volumetric heat capacity, BTU/ ft^3 °F

M_{ob} = ρ_{steel} x cp_{steel} = 488 x 0.12 = 58.56 BTU/ ft^3 °F

k_{hob} = Overburden thermal conductivity = 8.73 BTU/ hr ft °F

T_{inj} = Steam injection temperature = 288 °F

T_{res} = Sand pack temperature = 66 °F

Q_{st} = Steam injection rate, BTU/hr

$$Q_{st} = \left(\frac{350}{24}\right) q_{st} \{(h_{inj} - h_{res}) + f_{st} L_v \} \text{------------(A-12)}$$

q_{st} = steam injection rate = 2.54 lb_m/hr

f_{st} = Steam quality = 0.90

L_v = Latent heat of vaporization evaluated at 288 °F = 919 BTU/lb_m

h_{inj} = Water enthalpy evaluated at 288 °F = 257 BTU/lb_m

h_{res} = Water enthalpy evaluated at reservoir temperature 66 °F = 34 BTU/lb_m

$$Q_{st} = \left(\frac{350}{24}\right) 2.54 \{(257-34) + 0.9 \times 919\} = 31500$$

BTU/hr

M_{res} = Reservoir volumetric heat capacity, BTU/ ft^3 °F

$$M_{res} = \phi s_{oi} \rho_o c_{po} + \phi s_w \rho_w c_{pw} + (1 - \phi) \rho_{sand} c_{psand} \text{--------------(A-13)}$$

where,

ϕ = 0.354

S_{oi} = 0.959

S_w = 0.041

ρ_{o1} = Oil density 54.8 lb_m/ft^3 evaluated at 60 °F

ρ_o = Oil density 44.9 lb_m/ft^3 evaluated at 177 °F

c_{po} = Oil heat capacity estimated as the arithmetic average heat capacities

$$c_{po} = \frac{0.388 + 0.00045\left(\left(\frac{T_{res} + T_{inj}}{2}\right)\right)}{\sqrt{\gamma_o}} \quad \text{-----------------------------(A-14)}$$

$$c_{po} = \frac{0.388 + 0.00045\left(\left(\frac{66 + 288}{2}\right)\right)}{\sqrt{0.878}} = 0.499 \text{ , BTU/ ft}^3 \text{ °F}$$

ρ_w = Water density = 60.8 lb_m/ft^3 evaluated at 177 °F

c_{pw} = Water heat capacity over the temperature range

$$c_{pw} = \frac{h_{winj} - h_{wres}}{T_{inj} - T_{res}} = \frac{257 - 34}{288 - 66} = 1.0045\text{, BTU/ ft}^3 \text{ °F}$$

using Equation (A-13)

$$M_{res} = (0.354 \times 0.959 \times 44.9 \times 0.499) + (0.354 \times 0.041 \times 60.8 \times 1.0045) + (1 - 0.354)34 = 38.1$$

$$F_1 = \frac{t_D}{1 + 0.85\sqrt{t_D}} \quad \text{---------------------------------(A-15)}$$

$$t_D = \frac{4 M_{ob} k_{hob} t}{M^2{}_s H^2}$$

$$t_D = \frac{4(58.56)(8.73)(1.3)}{(38.1)^2 (1.58)^2} = 0.7336$$

using Equation (A-15)

$$F_1 = \frac{0.7336}{1 + 0.85\sqrt{0.7336}} = 0.4245$$

using Equation (A-11)

$$V_{st} = \left(\frac{(1.58)^2 (38.1)(31500)}{4\,(8.73)(58.56)(288 - 66)}\right) 0.4245 = 2.80 \text{ ft}^3$$

$$V_{st} = 0.0793 \text{ m}^3$$

Performance Prediction

$$N_p = \frac{V_{st}\,\phi\,\alpha \left(\frac{h_{oil}}{H}\right)\left(s_{oi} - s_{orst}\right)}{5.615}$$

where,

α = Capture efficiency assumed to be 0.81

(h_{oil}/H) = Ratio of oil thickness to sand pack thickness = 1.0

S_{ort} = Steam residual oil saturation (assumed to be equal to the sand pack final oil saturation S_{of}) = s_{oi} (1-RF) = 0.18

thus,

$$N_P = \frac{(2.8)(0.354)(0.81)(\,0.959 - 0.18)}{5.615} = 0.11, \text{ ft}^3$$

$$V_{st} = 0.00311 \text{ m}^3$$

In the above calculation an effort was made to predict the steam performance and steam zone volume. The Marx and Langenheim Model was used without any modification. The steam zone volume predicted using Marx and Langenheim Model is rather high compared to the experimental steam zone size. However, since the model assumes an increasing steam zone growth and variable heat loss, such results are expected.

4. Final oil Saturation

The sand pack final oil saturation was calculated at the end of all the steam injection experiments. The calculated final oil saturation was compared with the steam residual oil saturation (S_{orst}) obtained from the literature[71]. The sand pack final oil saturations listed below were calculated using Equation (A-16),

$$S_f = S_{oi}\,(1 - RF)$$

where,

RF = Recovery factor
S_{oi} = Initial sand pack oil saturation

Run No	S_{of}	Run No	S_{of}
1	0.47	21	0.30
2	0.38	22	0.41
3	0.40	23	0.35
4	0.42	24	0.40
5	0.30	25	0.36
6	0.27	26	0.29
7	0.30	27	0.29
8	0.24	28	0.37
9	0.29	29	0.32
10	0.42	30	0.22
11	0.32	31	0.48
12	0.21	32	0.21
13	0.25	33	0.35
14	0.23	34	0.28
15	0.24	35	0.25
16	0.18	36	0.48
17	0.21		
18	0.23		
19	0.29		
20	0.35		

Appendix B: Tables of Experimental Results

Table B1 - Run 1: Radial Injection from Bottom in Combination with a Horizontal Producer

Bulk Volume:	4492 cc	Initial Oil Saturation:	93 %PV
Pore Volume:	1612 cc	Initial Water Saturation :	7 %PV
HC Pore Volume:	1500 cc	Type of Oil Used:	Faxam-100
Porosity:	32.6%	Oil Viscosity @ 24 °C and101 kPa:	290 mPa . s
Average Absolute Permeability :	8.2 x^-12 m^2 (6.5 darcies)	API Gravity @ 24 °C and101 kPa:	30 °API
Average Steam Injection Rate:	0.39 cc/s (CWE)	Production Pressure:	138 kPa
Net Oil Recovery:	**50.3%**	**Total Steam Injected:**	**1341 cc**

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	3.55	83	0.05	204	74	74	4.9	0.35	1.76	0.89
2	8.38	279	0.17	210	97	171	11.4	0.19	1.16	0.61
3	7.83	462	0.29	208	92	263	17.5	0.20	1.26	0.57
4	7.50	638	0.40	210	91	354	23.6	0.20	1.31	0.55
5	3.82	727	0.45	198	90	444	29.6	0.39	1.20	0.61
6	5.32	851	0.53	208	96	540	36.0	0.30	1.17	0.63
7	6.33	999	0.62	202	85	625	41.7	0.22	1.38	0.63
8	6.63	1154	0.72	202	72	697	46.5	0.18	1.81	0.60
9	8.00	1341	0.83	206	58	755	50.3	0.12	2.55	0.56

Table B2 - Run 2: Radial Injection from Bottom and Pressure Differential of 138 kPa (20 psig) Using a Horizontal Producer

Bulk Volume: 4492 cc
Pore Volume: 1610 cc
HC Pore Volume: 1525 cc
Porosity: 32.6%
Average Absolute Permeability : 5.9 x^-12 m^2 (6.5 darcies)
Average Steam Injection Rate: 0.33 cc/s (CWE)

Net Oil Recovery: 60.3%

Initial Oil Saturation: 94.7 %PV
Initial Water Saturation : 5.3 %PV
Type of Oil Used: Faxam-100
Oil Viscosity @ 24 °C and101 kPa: 290 mPa . s
API Gravity @ 24 °C and101 kPa: 30 °API
Production Pressure: 138 kPa

Total Steam Injected: 1551 cc

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	14.50	287	0.18	206	118	118	7.7	0.14	0.75	0.41
2	10.02	485	0.30	223	127	245	16.1	0.21	0.76	0.51
3	7.02	624	0.39	205	112	357	23.4	0.27	0.83	0.57
4	7.65	775	0.48	212	117	474	31.1	0.25	0.81	0.61
5	6.25	899	0.56	205	105	579	38.0	0.28	0.95	0.64
6	6.33	1024	0.64	209	89	668	43.8	0.23	1.35	0.65
7	5.33	1130	0.70	202	78	746	48.9	0.24	1.59	0.66
8	6.00	1249	0.78	208	72	818	53.6	0.20	1.89	0.65
9	7.25	1393	0.87	204	62	880	57.7	0.14	2.29	0.63
10	8.00	1551	0.96	206	40	920	60.3	0.08	4.15	0.59

Table B3 - Run 3: Radial Injection from Bottom and Pressure Differential of 55 kPa (8 Psig) Using a Horizontal Producer

Bulk Volume:	4492 cc	Initial Oil Saturation:	92.3 %PV
Pore Volume:	1630 cc	Initial Water Saturation :	7.7 %PV
HC Pore Volume:	1505 cc	Type of Oil Used:	Faxam-100
Porosity:	33.0%	Oil Viscosity @ 24 °C and101 kPa:	290 mPa . s
Average Absolute Permeability :	5.9 x^-12 m^2 (6.5 darcies)	API Gravity @ 24 °C and101 kPa:	30 °API
Average Steam Injection Rate:	0.20 cc/s (CWE)	Production Pressure:	207 kPa

Net Oil Recovery: **56.2%**

Total Steam Injected: **1614 cc**

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	26.42	317	0.19	207	109	109	7.2	0.07	0.90	
2	14.35	489	0.30	212	120	229	15.2	0.14	0.77	0.34
3	11.85	631	0.39	208	116	345	22.9	0.16	0.79	0.47
4	11.33	767	0.47	215	113	458	30.4	0.17	0.90	0.55
5	11.47	905	0.56	208	92	550	36.5	0.13	1.26	0.60
6	11.00	1037	0.64	213	75	625	41.5	0.11	1.84	0.61
7	11.62	1176	0.72	206	69	694	46.1	0.10	1.99	0.60
8	11.73	1317	0.81	210	60	754	50.1	0.09	2.50	0.59
9	11.47	1455	0.89	208	52	806	53.6	0.08	3.00	0.57
10	13.25	1614	0.99	222	40	846	56.2	0.05	4.55	0.55

Table B4 - Run 4: Radial Injection from Bottom and Pressure Differential of 55 kPa (8 psig) Using a Horizontal Producer

Bulk Volume: 4492 cc
Pore Volume: 1570 cc
HC Pore Volume: 1480 cc
Porosity: 31.8%
Average Absolute Permeability : 6.3 x^-12 m^2 (6.5 darcies)
Average Steam Injection Rate: 0.19 cc/s (CWE)

Net Oil Recovery: 55.0%

Initial Oil Saturation: 94.3 %PV
Initial Water Saturation : 5.7 %PV
Type of Oil Used: Faxam-100
Oil Viscosity @ 24 °C and101 kPa: 290 mPa . s
API Gravity @ 24 °C and101 kPa: 30 °API
Production Pressure: 207 kPa

Total Steam Injected: 1806 cc

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	29.38	335	0.21	224	104	104	7.0	0.06	1.15	0.31
2	32.77	709	0.45	209	115	219	14.8	0.06	0.82	0.31
3	29.50	1045	0.67	225	93	312	21.1	0.05	1.42	0.30
4	15.25	1219	0.78	237	90	402	27.2	0.10	1.63	0.33
5	10.25	1336	0.85	223	92	494	33.4	0.15	1.42	0.37
6	8.62	1434	0.91	205	80	574	38.8	0.15	1.56	0.40
7	9.17	1539	0.98	220	74	648	43.8	0.13	1.97	0.42
8	6.78	1616	1.03	203	56	704	47.6	0.14	2.63	0.44
9	9.68	1726	1.10	222	62	766	51.8	0.11	2.58	0.44
10	7.05	1806	1.15	208	48	814	55.0	0.11	3.33	0.45

Table B5 - Run 5: Radial Injection from Bottom in Combination with a Horizontal Producer

Bulk Volume:	4492 cc	Initial Oil Saturation:	91.4 %PV
Pore Volume:	1620 cc	Initial Water Saturation :	8.6 %PV
HC Pore Volume:	1480 cc	Type of Oil Used:	Faxam-100
Porosity:	32.8%	Oil Viscosity @ 24 °C and101 kPa:	290 mPa . s
Average Absolute Permeability :	5.8 x^-12 m^2 (6.5 darcies)	API Gravity @ 24 °C and101 kPa:	30 °API
Average Steam Injection Rate:	0.27 cc/s (CWE)	Production Pressure:	138 kPa
Net Oil Recovery:	**67.0%**	**Total Steam Injected:**	**1227 cc**

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	12.05	195	0.12	226	128	128	8.6	0.18		0.66
2	9.10	342	0.21	201	116	244	16.5	0.21	0.77	0.71
3	8.28	476	0.29	230	130	374	25.3	0.26	0.73	0.79
4	6.07	574	0.35	210	114	488	33.0	0.31	0.77	0.85
5	8.23	707	0.44	220	105	593	40.1	0.21	0.84	0.84
6	5.98	804	0.50	203	87	680	45.9	0.24	1.10	0.85
7	6.27	906	0.55	220	88	768	51.9	0.23	1.33	0.85
8	5.52	995	0.61	206	80	848	57.3	0.24	1.50	0.85
9	7.12	1110	0.69	222	82	930	62.8	0.19	1.58	0.84
10	7.25	1227	0.76	212	61	991	67.0	0.14	1.71	0.81

Table B6 - Run 6: Radial Injection from Bottom and Pressure Differential of 207 kPa (30 psig) Using a Horizontal Producer

Bulk Volume:	4492 cc	Initial Oil Saturation:	93.4 %PV
Pore Volume:	1660 cc	Initial Water Saturation :	6.3 %PV
HC Pore Volume:	1555 cc	Type of Oil Used:	Faxam-100
Porosity:	33.6%	Oil Viscosity @ 24 °C and101 kPa:	290 mPa . s
Average Absolute Permeability :	6.5 X^-12 m^2 (6.5 darcies)	API Gravity @ 24 °C and101 kPa:	30 °API
Average Steam Injection Rate:	0.27 cc/s (CWE)	Production Pressure:	138 kPa
Net Oil Recovery:	**70.6%**	**Total Steam Injected:**	**1642 cc**

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	12.17	197	0.12	206	114	114	7.3	0.16	0.81	0.58
2	9.55	352	0.21	222	114	228	14.7	0.20	0.95	0.65
3	8.12	484	0.29	204	112	340	21.9	0.23	0.82	0.70
4	9.33	636	0.38	222	111	451	29.0	0.20	1.00	0.71
5	8.23	769	0.46	204	98	549	35.3	0.20	1.08	0.71
6	7.83	896	0.54	219	97	646	41.5	0.21	1.26	0.72
7	6.35	999	0.60	198	84	730	46.9	0.22	1.36	0.73
8	9.57	1154	0.70	225	87	817	52.5	0.15	1.59	0.71
9	5.85	1249	0.75	208	72	889	57.2	0.21	1.89	0.71
10	8.00	1379	0.83	226	81	970	62.4	0.17	1.79	0.70
11	7.23	1496	0.90	205	72	1042	67.0	0.17	1.85	0.70
12	9.03	1642	0.99	226	56	1098	70.6	0.10	3.04	0.67

Table B7 - Run 7: Radial Injection from Bottom in Combination with a Horizontal Producer

Bulk Volume:	4492 cc	Initial Oil Saturation:	92.4 %PV
Pore Volume:	1635 cc	Initial Water Saturation :	7.6 %PV
HC Pore Volume:	1510 cc	Type of Oil Used:	Faxam-100
Porosity:	33.1%	Oil Viscosity @ 24 °C and101 kPa:	290 mPa . s
Average Absolute Permeability :	4.6 x^-12 m^2 (6.5 darcies)	API Gravity @ 24 °C and101 kPa:	30 °API
Average Steam Injection Rate:	0.18 cc/s (CWE)	Production Pressure:	138 kPa
Net Oil Recovery:	**67.1%**	**Total Steam Injected:**	**1694 cc**

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	25.27	273	0.17	202	90	90	6.0	0.06	1.24	0.33
2	17.90	466	0.29	222	69	159	10.5	0.06	2.22	0.34
3	14.58	624	0.38	212	78	237	15.7	0.09	1.72	0.38
4	14.33	779	0.48	222	92	329	21.8	0.11	1.41	0.42
5	11.45	903	0.55	204	106	435	28.8	0.15	0.92	0.48
6	11.15	1023	0.63	220	117	552	36.6	0.17	0.88	0.54
7	10.10	1132	0.69	224	108	660	43.7	0.18	1.07	0.58
8	10.02	1240	0.76	223	102	762	50.5	0.17	1.19	0.61
9	8.47	1331	0.81	208	96	858	56.8	0.19	1.17	0.64
10	8.28	1420	0.87	222	75	933	61.8	0.15	1.96	0.66
11	12.12	1551	0.95	225	42	975	64.6	0.06	4.36	0.63
12	13.23	1694	1.04	240	38	1013	67.1	0.05	5.32	0.60

Table B8 - Run 8: Horizontal Producer Penetrating 100% of the Sand Pack Length (Bad run)

Bulk Volume:	4492 cc	Initial Oil Saturation:	91.2 %PV
Pore Volume:	1590 cc	Initial Water Saturation :	8.8 %PV
HC Pore Volume:	1450 cc	Type of Oil Used:	Faxam-100
Porosity:	34.5%	Oil Viscosity @ 24 °C and101 kPa:	290 mPa . s
Average Absolute Permeability :	6.7 x^-12 m^2 (6.5 darcies)	API Gravity @ 24 °C and101 kPa:	30 °API
Average Steam Injection Rate:	0.32 cc/s (CWE)	Production Pressure:	138 kPa
Net Oil Recovery:	**74.1%**	**Total Steam Injected:**	**1901 cc**

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	16.25	312	0.20	224	114	114	7.9	0.12	0.96	0.37
2	7.77	461	0.29	209	105	219	15.1	0.23	0.99	0.47
3	7.33	602	0.38	226	106	325	22.4	0.24	1.13	0.54
4	6.17	720	0.45	208	93	418	28.8	0.25	1.24	0.58
5	6.26	841	0.53	229	97	515	35.5	0.26	1.36	0.61
6	5.18	940	0.59	195	97	612	42.2	0.31	1.01	0.65
7	5.87	1053	0.66	221	87	699	48.2	0.25	1.54	0.66
8	5.17	1152	0.72	207	83	782	53.9	0.27	1.49	0.68
9	5.50	1258	0.79	219	81	863	59.5	0.25	1.70	0.69
10	4.85	1351	0.85	200	72	935	64.5	0.25	1.78	0.69
11	6.40	1474	0.93	200	57	992	68.4	0.15	2.51	0.67
12	7.03	1609	1.01	224	29	1021	70.4	0.07	6.72	0.63
13	8.00	1762	1.11	201	28	1049	72.3	0.06	6.18	0.60
14	7.23	1901	1.20	210	26	1075	74.1	0.06	7.08	0.57

Table 9 - Run 9: Radial Injection from Bottom in Combination with a Horizontal Producer

Bulk Volume:	4492 cc	Initial Oil Saturation:	90.9 %PV
Pore Volume:	1695 cc	Initial Water Saturation :	9.1 %PV
HC Pore Volume:	1540 cc	Type of Oil Used:	Faxam-100
Porosity:	37.7%	Oil Viscosity @ 24 °C and101 kPa:	290 mPa . s
Average Absolute Permeability :	7.7 x^-12 m^2 (6.5 darcies)	API Gravity @ 24 °C and101 kPa:	30 °API
Average Steam Injection Rate:	0.38 cc/s (CWE)	Production Pressure:	138 kPa
Net Oil Recovery:	**68.1%**	**Total Steam Injected:**	**1993 cc**

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	14.37	328	0.19	200	86	86	5.6	0.10	1.33	0.26
2	8.53	523	0.31	199	102	188	12.2	0.20	0.95	0.36
3	6.03	660	0.39	200	107	295	19.2	0.30	0.87	0.45
4	6.25	803	0.47	200	96	391	25.4	0.26	1.08	0.49
5	6.07	941	0.56	198	86	477	31.0	0.24	1.30	0.51
6	5.75	1072	0.63	196	82	559	36.3	0.24	1.39	0.52
7	5.25	1192	0.70	190	76	635	41.2	0.24	1.50	0.53
8	5.27	1312	0.77	194	73	708	46.0	0.23	1.66	0.54
9	5.05	1427	0.84	196	70	778	50.5	0.23	1.80	0.55
10	4.85	1538	0.91	197	67	845	54.9	0.23	1.94	0.55
11	4.70	1645	0.97	192	66	911	59.2	0.23	1.91	0.55
12	4.18	1740	1.03	193	66	977	63.4	0.26	1.92	0.56
13	5.28	1860	1.10	204	44	1021	66.3	0.14	3.64	0.55
14	5.83	1993	1.18	194	28	1049	68.1	0.08	5.93	0.53

Table B10 - Run 10: Horizontal Producer Penetrating 25% of the Sand Pack Length (Bad run)

Bulk Volume:	4492 cc	Initial Oil Saturation:	90.9 %PV
Pore Volume:	1695 cc	Initial Water Saturation :	9.1 %PV
HC Pore Volume:	1540 cc	Type of Oil Used:	Faxam-100
Porosity:	37.7%	Oil Viscosity @ 24 °C and101 kPa:	290 mPa . s
Average Absolute Permeability :	6.4 x^-12 m^2 (6.5 darcies)	API Gravity @ 24 °C and101 kPa:	30 °API
Average Steam Injection Rate:	0.30 cc/s (CWE)	Production Pressure:	138 kPa
Net Oil Recovery:	**54.3%**	**Total Steam Injected:**	**1770 cc**

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	20.35	366	0.22	198	96	96	6.2	0.08	1.06	0.26
2	14.72	631	0.37	195	95	191	12.4	0.11	1.05	0.30
3	9.18	796	0.47	206	110	301	19.5	0.20	0.87	0.38
4	6.00	904	0.53	197	105	406	26.4	0.29	0.88	0.45
5	5.92	1011	0.60	204	97	503	32.7	0.27	1.10	0.50
6	5.18	1104	0.65	198	88	591	38.4	0.28	1.25	0.54
7	4.87	1192	0.70	195	77	668	43.4	0.26	1.53	0.56
8	3.90	1262	0.74	196	72	740	48.1	0.31	1.72	0.59
9	5.68	1364	0.80	200	40	780	50.6	0.12	4.00	0.57
10	7.13	1492	0.88	188	20	800	51.9	0.05	8.40	0.54
11	7.78	1631	0.96	192	20	820	53.2	0.04	8.60	0.50
12	7.73	1770	1.04	192	16	836	54.3	0.03	11.00	0.47

Table B 11 - Run 11: Horizontal Producer Penetrating 50% of the Sand Pack Length

Bulk Volume:	4492 cc	Initial Oil Saturation:	93.2 %PV
Pore Volume:	1695 cc	Initial Water Saturation :	6.8 %PV
HC Pore Volume:	1580 cc	Type of Oil Used:	Faxam-100
Porosity:	37.7%	Oil Viscosity @ 24 °C and101 kPa:	290 mPa . s
Average Absolute Permeability :	6.4 x^-12 m^2 (6.5 darcies)	API Gravity @ 24 °C and101 kPa:	30 °API
Average Steam Injection Rate:	0.38 cc/s (CWE)	Production Pressure:	138 kPa
Net Oil Recovery:	**65.8%**	**Total Steam Injected:**	**1983 cc**

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	11.40	260	0.15	200	116	116	7.3	0.17	0.72	0.45
2	5.93	395	0.23	199	111	227	14.4	0.31	0.79	0.57
3	5.40	518	0.31	198	100	327	20.7	0.31	0.98	0.63
4	5.33	640	0.38	196	90	417	26.4	0.28	1.18	0.65
5	5.30	761	0.45	199	82	499	31.6	0.26	1.43	0.66
6	5.48	886	0.52	198	79	578	36.6	0.24	1.51	0.65
7	5.37	1008	0.59	196	76	654	41.4	0.24	1.58	0.65
8	5.37	1130	0.67	197	71	725	45.9	0.22	1.77	0.64
9	5.47	1255	0.74	201	69	794	50.3	0.21	1.91	0.63
10	5.15	1372	0.81	198	70	864	54.7	0.23	1.83	0.63
11	5.37	1494	0.88	198	65	929	58.8	0.20	2.05	0.62
12	5.65	1646	0.97	191	41	970	61.4	0.12	3.66	0.59
13	7.30	1812	1.07	194	36	1006	63.7	0.08	4.39	0.56
14	7.50	1983	1.17	199	33	1039	65.8	0.07	5.03	0.52

Table B12 - Run 12: Horizontal Producer Penetrating 25% of the Sand Pack Length

Bulk Volume:	4492 cc	Initial Oil Saturation:	89.9%PV
Pore Volume:	1690 cc	Initial Water Saturation :	10.1%PV
HC Pore Volume:	1520 cc	Type of Oil Used:	Faxam-100
Porosity:	37.6%	Oil Viscosity @ 24 °C and101 kPa:	290 mPa . s
Average Absolute Permeability :	6.4 x^-12 m^2 (6.5 darcies)	API Gravity @ 24 °C and101 kPa:	30 °API
Average Steam Injection Rate:	0.33 cc/s (CWE)	Production Pressure:	138 kPa
Net Oil Recovery:	**76.5%**	**Total Steam Injected:**	**1947 cc**

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	15.12	315	0.19	198	88	88	5.8	0.10	1.25	0.28
2	13.33	579	0.34	196	82	170	11.2	0.10	1.39	0.29
3	9.78	773	0.46	190	90	260	17.1	0.15	1.11	0.34
4	7.13	914	0.54	200	105	365	24.0	0.25	0.90	0.40
5	4.57	1004	0.59	198	110	475	31.3	0.40	0.80	0.47
6	4.72	1097	0.65	202	122	597	39.3	0.43	0.66	0.54
7	4.90	1194	0.71	197	111	708	46.6	0.38	0.77	0.59
8	5.18	1297	0.77	198	104	812	53.4	0.33	0.90	0.63
9	5.03	1397	0.83	198	82	894	58.8	0.27	1.41	0.64
10	4.82	1492	0.88	199	74	968	63.7	0.26	1.69	0.65
11	4.62	1583	0.94	196	72	1040	68.4	0.26	1.72	0.66
12	4.58	1674	0.99	195	63	1103	72.6	0.23	2.10	0.66
13	6.37	1800	1.07	208	36	1139	74.9	0.09	4.78	0.63
14	7.42	1947	1.15	200	24	1163	76.5	0.05	7.33	0.60

Table B13 - Run 13 : 55 kPa (8 psig) Pressure Differential Using a Horizontal Producer

Bulk Volume: 4492 cc
Pore Volume: 1730 cc
HC Pore Volume: 1570 cc
Porosity: 38.5%
Average Absolute Permeability : 6.4 x^-12 m^2 (6.5 darcies)
Average Injection Rate: 0.31 cc/s (CWE)

Net Oil Recovery: 72.2%

Initial Oil Saturation: 90.8 %PV
Initial Water Saturation : 9.2 %PV
Type of Oil Used: Faxam-100
Oil Viscosity @ 24 °C and101 kPa: 290 mPa . s
API Gravity @ 24 °C and101 kPa: 30 °API
Production Pressure: 221 kPa

Total Steam Injected: 2097 cc

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	22.22	413	0.24	198	132	132	8.4	0.10	0.50	0.32
2	12.33	642	0.37	198	106	238	15.2	0.14	0.87	0.37
3	8.67	803	0.46	195	113	351	22.4	0.22	0.73	0.44
4	7.95	951	0.55	196	102	453	28.9	0.21	0.92	0.48
5	7.50	1091	0.63	198	90	543	34.6	0.20	1.20	0.50
6	6.22	1207	0.70	194	84	627	39.9	0.23	1.31	0.52
7	6.12	1321	0.76	197	81	708	45.1	0.22	1.43	0.54
8	5.88	1430	0.83	196	72	780	49.7	0.20	1.72	0.55
9	5.52	1533	0.89	196	66	846	53.9	0.20	1.97	0.55
10	5.87	1642	0.95	197	66	912	58.1	0.19	1.98	0.56
11	5.78	1750	1.01	198	60	972	61.9	0.17	2.30	0.56
12	5.87	1859	1.07	194	58	1030	65.6	0.16	2.34	0.55
13	5.28	1976	1.14	199	54	1084	69.0	0.17	2.69	0.55
14	6.52	2097	1.21	197	49	1133	72.2	0.13	3.02	0.54

Table B14 - Run 14: 207 kPa (30 psig) Pressure Differential Using a Horizontal Producer

Bulk Volume:	4492 cc	Initial Oil Saturation:	89.9 %PV
Pore Volume:	1792 cc	Initial Water Saturation :	10.1 %PV
HC Pore Volume:	1610 cc	Type of Oil Used:	Faxam-100
Porosity:	39.9%	Oil Viscosity @ 24 °C and101 kPa:	290 mPa . s
Average Absolute Permeability :	6.4 x10^-12 m^2 (6.5 darcies)	API Gravity @ 24 °C and101 kPa:	30 °API
Average Injection Rate:	0.43 cc/s (CWE)	Production Pressure:	69 kPa
Net Oil Recovery:	**73.9%**	**Total Steam Injected:**	**2003 cc**

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	6.88	178	0.10	199	139	139	8.6	0.34	0.43	0.78
2	3.90	279	0.16	194	142	281	17.5	0.61	0.37	1.01
3	4.50	395	0.22	198	126	407	25.3	0.47	0.57	1.03
4	5.02	525	0.29	196	104	511	31.7	0.35	0.88	0.97
5	4.72	647	0.36	200	94	605	37.6	0.33	1.13	0.94
6	4.92	774	0.43	195	87	692	43.0	0.29	1.24	0.89
7	5.02	904	0.50	196	79	771	47.9	0.26	1.48	0.85
8	4.93	1031	0.58	199	79	850	52.8	0.27	1.52	0.82
9	4.67	1151	0.64	194	79	929	57.7	0.28	1.46	0.81
10	5.25	1286	0.72	188	77	1006	62.5	0.24	1.44	0.78
11	5.23	1421	0.79	197	71	1077	66.9	0.23	1.77	0.76
12	6.73	1596	0.89	192	56	1133	70.4	0.14	2.43	0.71
13	7.75	1796	1.00	190	30	1163	72.2	0.06	5.33	0.65
14	8.03	2003	1.12	213	27	1190	73.9	0.06	6.89	0.59

Table B15 - Run 15: 104 kPa (15 psig) Pressure Differential Using a Horizontal Producer

Bulk Volume:	4492 cc	Initial Oil Saturation:	92.9 %PV
Pore Volume:	1680 cc	Initial Water Saturation :	7.1 %PV
HC. Pore Volume:	1560 cc	Type of Oil Used:	Faxam-100
Porosity:	37.4%	Oil Viscosity @ 24 °C and101 kPa:	290 mPa . s
Average Absolute Permeability :	6.4 x10^-12 m^2 (6.5 darcies)	API Gravity @ 24 °C and101 kPa:	30 °API
Average Injection Rate:	0.38 cc/s (CWE)	Production Pressure:	172 kPa
Net Oil Recovery:	**74.3%**	**Total Steam Injected:**	**1886 cc**

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	11.30	258	0.15	200	140	140	9.0	0.21	0.43	0.54
2	6.03	395	0.24	194	130	270	17.3	0.36	0.49	0.68
3	5.82	528	0.31	200	120	390	25.0	0.34	0.67	0.74
4	5.62	656	0.39	193	93	483	31.0	0.28	1.08	0.74
5	5.75	787	0.47	208	94	577	37.0	0.27	1.21	0.73
6	5.48	912	0.54	198	82	659	42.2	0.25	1.41	0.72
7	4.92	1024	0.61	194	74	733	47.0	0.25	1.62	0.72
8	4.88	1135	0.68	196	72	805	51.6	0.25	1.72	0.71
9	5.20	1254	0.75	196	68	873	56.0	0.22	1.88	0.70
10	5.33	1376	0.82	196	65	938	60.1	0.20	2.02	0.68
11	5.58	1503	0.89	198	60	998	64.0	0.18	2.30	0.66
12	2.17	1621	0.96	196	63	1061	68.0	0.48	2.11	0.65
13	5.78	1753	1.04	198	50	1111	71.2	0.14	2.96	0.63
14	5.82	1886	1.12	202	48	1159	74.3	0.14	3.21	0.61

Table B16 - Run 16: Horizontal Producer Penetrating 100% of the Sand Pack Length

Bulk Volume: 4492 cc
Pore Volume: 1592 cc
HC Pore Volume: 1527 cc
Porosity: 35.4%
Average Absolute Permeability : 6.4 x10^-12 m^2 (6.5 darcies)
Average Steam Injection Rate: 0.34 cc/s (CWE)

Net Oil Recovery: 81.0%

Initial Oil Saturation: 95.9 %PV
Initial Water Saturation : 4.1 %PV
Type of Oil Used: Faxam-100
Oil Viscosity @ 24 °C and101 kPa: 290 mPa . s
API Gravity @ 24 °C and101 kPa: 30 °API
Production Pressure: 138 kPa

Total Steam Injected: 1703 cc

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	13.27	271	0.17	200	130	130	8.5	0.16	0.54	0.48
2	6.87	411	0.26	202	126	256	16.8	0.31	0.60	0.62
3	5.55	524	0.33	201	133	389	25.5	0.40	0.51	0.74
4	5.70	640	0.40	198	123	512	33.5	0.36	0.61	0.80
5	5.57	754	0.47	198	116	628	41.1	0.35	0.71	0.83
6	5.12	858	0.54	199	101	729	47.7	0.33	0.97	0.85
7	4.77	955	0.60	200	94	823	53.9	0.33	1.13	0.86
8	4.78	1053	0.66	202	88	911	59.7	0.31	1.30	0.87
9	4.93	1154	0.72	196	76	987	64.6	0.26	1.58	0.86
10	4.85	1253	0.79	196	62	1049	68.7	0.21	2.16	0.84
11	4.53	1345	0.84	199	59	1108	72.6	0.22	2.37	0.82
12	4.77	1442	0.91	191	59	1167	76.4	0.21	2.24	0.81
13	5.48	1554	0.98	192	46	1213	79.4	0.14	3.17	0.78
14	7.28	1703	1.07	198	24	1237	81.0	0.05	7.25	0.73

Table B17 - Run 17: 172 kPa (25 psig) Pressure Differential Using a Horizontal Producer

Bulk Volume:	4492 cc	Initial Oil Saturation:	89.1 %PV
Pore Volume:	1610 cc	Initial Water Saturation :	10.9 %PV
HC Pore Volume:	1435 cc	Type of Oil Used:	Faxam-100
Porosity:	35.8%	Oil Viscosity @ 24 °C and101 kPa:	290 mPa . s
Average Absolute Permeability :	6.4 x10^-12 m^2 (6.5 darcies)	API Gravity @ 24 °C and101 kPa:	30 °API
Average Injection Pressure:	276 kPa	Production Pressure:	103 kPa
Net Oil Recovery:	**76.1%**	**Total Steam Injected:**	**1862 cc**

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	14.55	314	0.20	202	72	72	5.0	0.08	1.81	0.23
2	5.85	440	0.27	200	117	189	13.2	0.33	0.71	0.43
3	5.53	559	0.35	200	115	304	21.2	0.35	0.74	0.54
4	5.62	680	0.42	201	103	407	28.4	0.31	0.95	0.60
5	5.88	807	0.50	198	96	503	35.1	0.27	1.06	0.62
6	6.40	945	0.59	200	90	593	41.3	0.23	1.22	0.63
7	5.03	1054	0.65	199	83	676	47.1	0.28	1.40	0.64
8	5.88	1181	0.73	198	78	754	52.5	0.22	1.54	0.64
9	6.18	1314	0.82	202	78	832	58.0	0.21	1.59	0.63
10	5.08	1424	0.88	198	67	899	62.6	0.22	1.96	0.63
11	4.20	1515	0.94	198	62	961	67.0	0.25	2.19	0.63
12	4.72	1617	1.00	202	59	1020	71.1	0.21	2.42	0.63
13	4.33	1711	1.06	198	46	1066	74.3	0.18	3.30	0.62
14	7.00	1862	1.16	194	26	1092	76.1	0.06	6.46	0.59

Table B18 - Run 18: Horizontal Producer Penetrating 75% of the Sand Pack Length

Bulk Volume: 4492 cc
Pore Volume: 1710 cc
HC Pore Volume: 1570 cc
Porosity: 38.1%
Average Absolute Permeability : 6.4 x^-12 m^2 (6.5 darcies)
Average Steam Injection Rate: 0.23 cc/s (CWE)

Net Oil Recovery: 75.0%

Initial Oil Saturation: 91.8 %PV
Initial Water Saturation : 8.2 %PV
Type of Oil Used: Faxam-100
Oil Viscosity @ 24 °C and101 kPa: 290 mPa . s
API Gravity @ 24 °C and101 kPa: 30 °API
Production Pressure: 138 kPa

Total Steam Injected: 2276 cc

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	19.28	266	0.16	198	78	78	5.0	0.07	1.54	0.29
2	10.27	408	0.24	200	116	194	12.4	0.19	0.72	0.48
3	8.52	526	0.31	201	115	309	19.7	0.22	0.75	0.59
4	8.12	638	0.37	202	110	419	26.7	0.23	0.84	0.66
5	10.52	783	0.46	203	98	517	32.9	0.16	1.07	0.66
6	11.68	944	0.55	204	86	603	38.4	0.12	1.37	0.64
7	11.93	1109	0.65	202	80	683	43.5	0.11	1.53	0.62
8	11.85	1273	0.74	200	76	759	48.3	0.11	1.63	0.60
9	11.75	1435	0.84	201	69	828	52.7	0.10	1.91	0.58
10	11.02	1587	0.93	200	70	898	57.2	0.11	1.86	0.57
11	11.60	1747	1.02	200	68	966	61.5	0.10	1.94	0.55
12	10.25	1888	1.10	205	59	1025	65.3	0.10	2.47	0.54
13	9.65	2021	1.18	200	54	1079	68.7	0.09	2.70	0.53
14	8.75	2142	1.25	190	45	1124	71.6	0.09	3.22	0.52
15	9.73	2276	1.33	210	54	1178	75.0	0.09	2.89	0.52

Table B19 - Run 19: Horizontal Producer Located 0.25D from the Sand Pack Upper Boundary

Bulk Volume:	4492 cc	Initial Oil Saturation:	93.8 %PV
Pore Volume:	1610 cc	Initial Water Saturation :	6.2 %PV
HC Pore Volume:	1510 cc	Type of Oil Used:	Faxam-100
Porosity:	35.8%	Oil Viscosity @ 24 °C and101 kPa:	290 mPa . s
Average Absolute Permeability :	6.4 x^-12 m^2 (6.5 darcies)	API Gravity @ 24 °C and101 kPa:	30 °API
Average Steam Injection Rate:	0.20 cc/s (CWE)	Production Pressure:	138 kPa

Net Oil Recovery: **69.6%**

Total Steam Injected: **2170 cc**

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	13.87	166	0.10	204	66	66	4.4	0.08	2.09	0.40
2	12.73	319	0.20	204	100	166	11.0	0.13	1.04	0.52
3	15.40	504	0.31	204	116	282	18.7	0.13	0.76	0.56
4	13.63	692	0.43	208	94	376	24.9	0.11	1.21	0.54
5	12.52	842	0.52	202	83	459	30.4	0.11	1.43	0.55
6	14.68	1018	0.63	203	85	544	36.0	0.10	1.39	0.53
7	11.67	1165	0.72	203	77	621	41.1	0.11	1.64	0.53
8	11.12	1298	0.81	205	72	693	45.9	0.11	1.85	0.53
9	11.07	1431	0.89	202	62	755	50.0	0.09	2.26	0.53
10	13.55	1594	0.99	202	68	823	54.5	0.08	1.97	0.52
11	14.85	1772	1.10	202	65	888	58.8	0.07	2.11	0.50
12	11.95	1915	1.19	202	55	943	62.5	0.08	2.67	0.49
13	10.67	2043	1.27	205	55	998	66.1	0.09	2.73	0.49
14	10.58	2170	1.35	204	53	1051	69.6	0.08	2.85	0.48

Table B20 - Run 20: Horizontal Producer Located 0.75D from the Sand Pack Upper Boundary

Bulk Volume:	4492 cc	Initial Oil Saturation:	90.1 %PV
Pore Volume:	1710 cc	Initial Water Saturation :	9.9 %PV
HC Pore Volume:	1540 cc	Type of Oil Used:	Faxam-100
Porosity:	38.1%	Oil Viscosity @ 24 °C and101 kPa:	290 mPa . s
Average Absolute Permeability :	6.4 x^-12 m^2 (6.5 darcies)	API Gravity @ 24 °C and101 kPa:	30 °API
Average Steam Injection Rate:	0.21 cc/s (CWE)	Production Pressure:	138 kPa
Net Oil Recovery:	**61.1%**	**Total Steam Injected:**	**2033 cc**

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	14.43	182	0.11	200	118	118	7.7	0.14	0.69	0.65
2	12.38	338	0.20	202	108	226	14.7	0.15	0.87	0.67
3	14.58	522	0.31	204	94	320	20.8	0.11	1.17	0.61
4	17.87	747	0.44	203	85	405	26.3	0.08	1.39	0.54
5	16.07	949	0.55	201	70	475	30.8	0.07	1.87	0.50
6	13.35	1117	0.65	200	62	537	34.9	0.08	2.23	0.48
7	14.17	1296	0.76	202	64	601	39.0	0.08	2.16	0.46
8	11.77	1444	0.84	202	58	659	42.8	0.08	2.48	0.46
9	9.97	1570	0.92	202	54	713	46.3	0.09	2.74	0.45
10	9.02	1684	0.98	198	52	765	49.7	0.10	2.81	0.45
11	8.72	1794	1.05	205	53	818	53.1	0.10	2.87	0.46
12	8.90	1906	1.11	202	61	879	57.1	0.11	2.31	0.46
13	10.05	2033	1.19	202	62	941	61.1	0.10	2.26	0.46

Table B21 - Run 21: Horizontal Injector Penetrating 100% of the Sand Pack Length

Bulk Volume:	4492 cc	Initial Oil Saturation:	89.7 %PV
Pore Volume:	1600 cc	Initial Water Saturation :	10.3 %PV
HC Pore Volume:	1435 cc	Type of Oil Used:	Faxam-100
Porosity:	35.6%	Oil Viscosity @ 24 °C and101 kPa:	290 mPa . s
Average Absolute Permeability :	6.4 x10^-12 m^2 (6.5 darcies)	API Gravity @ 24 °C and101 kPa:	30 °API
Average Steam Injection Rate:	0.40 cc/s (CWE)	Production Pressure:	207 kPa

Net Oil Recovery: **66.3%**

Total Steam Injected: **1985 cc**

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	10.13	243	0.15	202	150	150	10.5	0.25	0.35	0.62
2	7.30	418	0.26	197	112	262	18.3	0.26	0.76	0.63
3	6.20	567	0.35	200	106	368	25.6	0.28	0.89	0.65
4	5.75	705	0.44	200	104	472	32.9	0.30	0.92	0.67
5	5.52	837	0.52	204	86	558	38.9	0.26	1.37	0.67
6	6.13	984	0.62	200	85	643	44.8	0.23	1.35	0.65
7	6.92	1150	0.72	211	92	735	51.2	0.22	1.29	0.64
8	6.70	1311	0.82	206	76	811	56.5	0.19	1.71	0.62
9	6.75	1473	0.92	200	58	869	60.6	0.14	2.45	0.59
10	4.13	1572	0.98	198	46	915	63.8	0.19	3.30	0.58
11	10.90	1834	1.15	198	10	925	64.5	0.02	18.80	0.50
12	6.30	1985	1.24	197	27	952	66.3	0.07	6.30	0.48

Table B22 - Run 22: Horizontal Injector Penetrating 25% of the Sand Pack Length

Bulk Volume:	4492 cc	Initial Oil Saturation:	90.7 %PV
Pore Volume:	1610 cc	Initial Water Saturation :	9.3 %PV
HC Pore Volume:	1460 cc	Type of Oil Used:	Faxam-100
Porosity:	35.8%	Oil Viscosity @ 24 °C and101 kPa:	290 mPa . s
Average Absolute Permeability :	6.4 x^-12 m^2 (6.5 darcies)	API Gravity @ 24 °C and101 kPa:	30 °API
Average Steam Injection Rate:	0.38 cc/s (CWE)	Production Pressure:	207 kPa

Net Oil Recovery: **55.1%**

Total Steam Injected: **1980 cc**

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	8.95	204	0.13	203	124	124	8.5	0.23	0.64	0.61
2	6.15	344	0.21	198	118	242	16.6	0.32	0.68	0.70
3	5.75	475	0.30	206	93	335	22.9	0.27	1.22	0.71
4	6.50	623	0.39	203	68	403	27.6	0.17	1.99	0.65
5	7.00	783	0.49	204	67	470	32.2	0.16	2.04	0.60
6	6.70	936	0.58	209	69	539	36.9	0.17	2.03	0.58
7	8.30	1125	0.70	205	59	598	41.0	0.12	2.47	0.53
8	7.03	1285	0.80	202	56	654	44.8	0.13	2.61	0.51
9	7.12	1447	0.90	200	48	702	48.1	0.11	3.17	0.49
10	6.67	1599	0.99	204	38	740	50.7	0.09	4.37	0.46
11	8.30	1788	1.11	205	30	770	52.7	0.06	5.83	0.43
12	8.43	1980	1.23	226	34	804	55.1	0.07	5.65	0.41

Table B23 - Run 23: Horizontal Injector Penetrating 50% of the Sand Pack Length

Bulk Volume: 4492 cc
Pore Volume: 1570 cc
HC Pore Volume: 1410 cc
Porosity: 35.0%
Average Absolute Permeability : 6.4 x10^-12 m^2 (6.5 darcies)
Average Steam Injection Rate: 0.37 cc/s (CWE)

Initial Oil Saturation: 89.8 %PV
Initial Water Saturation : 10.2 %PV
Type of Oil Used: Faxam-100
Oil Viscosity @ 24°C and101 kPa: 290 mPa . s
API Gravity @ 24°C and101 kPa: 30 °API
Production Pressure: 207 kPa

Net Oil Recovery: **61.0%**

Total Steam Injected: **2003 cc**

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	8.75	194	0.12	206	146	146	10.4	0.28	0.41	0.75
2	7.50	361	0.23	202	124	270	19.1	0.28	0.63	0.75
3	7.60	530	0.34	204	106	376	26.7	0.23	0.92	0.71
4	6.53	675	0.43	202	107	483	34.3	0.27	0.89	0.72
5	5.37	794	0.51	206	93	576	40.9	0.29	1.22	0.73
6	6.25	933	0.59	205	79	655	46.5	0.21	1.59	0.70
7	7.45	1098	0.70	206	68	723	51.3	0.15	2.03	0.66
8	5.88	1229	0.78	205	39	762	54.0	0.11	4.26	0.62
9	9.77	1446	0.92	202	30	792	56.2	0.05	5.73	0.55
10	5.23	1562	0.99	205	32	824	58.4	0.10	5.41	0.53
11	11.15	1810	1.15	218	14	838	59.4	0.02	14.57	0.46
12	8.68	2003	1.28	216	22	860	61.0	0.04	8.82	0.43

Table B24 - Run 24: Horizontal Injector Located 0.25D from the Sand Pack Upper Boundary

Bulk Volume:	4492 cc	Initial Oil Saturation:	90.4 %PV
Pore Volume:	1570 cc	Initial Water Saturation :	9.6 %PV
HC Pore Volume:	1420 cc	Type of Oil Used:	Faxam-100
Porosity:	35.0%	Oil Viscosity @ 24 °C and101 kPa:	290 mPa . s
Average Absolute Permeability :	6.4 x^-12 m^2 (6.5 darcies)	API Gravity @ 24 °C and101 kPa:	30 °API
Average Steam Injection Rate:	0.39 cc/s (CWE)	Production Pressure:	207 kPa
Net Oil Recovery:	**56.3%**	**Total Steam Injected:**	**2129 cc**

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	10.00	234	0.15	207	149	149	10.5	0.25	0.39	0.64
2	6.80	393	0.25	204	111	260	18.3	0.27	0.84	0.66
3	6.95	556	0.35	206	70	330	23.2	0.17	1.94	0.59
4	7.12	723	0.46	206	74	404	28.5	0.17	1.78	0.56
5	7.50	899	0.57	202	69	473	33.3	0.15	1.93	0.53
6	6.77	1057	0.67	212	69	542	38.2	0.17	2.07	0.51
7	7.77	1239	0.79	206	58	600	42.3	0.12	2.55	0.48
8	7.80	1422	0.91	213	55	655	46.1	0.12	2.87	0.46
9	6.08	1564	1.00	206	42	697	49.1	0.12	3 90	0.45
10	8.02	1752	1.12	206	44	741	52.2	0.09	3.68	0.42
11	8.62	1954	1.24	203	25	766	53.9	0.05	7.12	0.39
12	7.47	2129	1.36	206	33	799	56.3	0.07	5.24	0.38

Table B25 - Run 25: Horizontal Injector Located 0.75D from the Sand Pack Upper Boundary

Bulk Volume:	4492 cc	Initial Oil Saturation:	90.3 %PV
Pore Volume:	1550 cc	Initial Water Saturation :	9.7 %PV
HC Pore Volume:	1400 cc	Type of Oil Used:	Faxam-100
Porosity:	34.5%	Oil Viscosity @ 24 °C and101 kPa:	290 mPa . s
Average Absolute Permeability :	6.4 x^-12 m^2 (6.5 darcies)	API Gravity @ 24 °C and101 kPa:	30 °API
Average Steam Injection Rate:	0.34 cc/s (CWE)	Production Pressure:	207 kPa
Net Oil Recovery:	**60.1%**	**Total Steam Injected:**	**2003 cc**

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	10.78	220	0.14	205	139	139	9.9	0.21	0.47	0.63
2	6.38	350	0.23	202	95	234	16.7	0.25	1.13	0.67
3	5.47	462	0.30	203	77	311	22.2	0.23	1.64	0.67
4	6.83	601	0.39	206	91	402	28.7	0.22	1.26	0.67
5	6.92	742	0.48	206	80	482	34.4	0.19	1.58	0.65
6	11.03	967	0.62	205	82	564	40.3	0.12	1.50	0.58
7	9.30	1157	0.75	206	84	648	46.3	0.15	1.45	0.56
8	8.23	1325	0.85	229	68	716	51.1	0.14	2.37	0.54
9	9.55	1520	0.98	205	35	751	53.6	0.06	4.86	0.49
10	7.30	1669	1.08	204	32	783	55.9	0.07	5.38	0.47
11	5.98	1791	1.16	207	32	815	58.2	0.09	5.47	0.46
12	10.38	2003	1.29	216	27	842	60.1	0.04	7.00	0.42

Table B26 - Run 26: 207 kPa (30 psig) Pressure Differential Using a Horizontal Injector

Bulk Volume:	4492 cc	Initial Oil Saturation:	89.4 %PV
Pore Volume:	1610 cc	Initial Water Saturation :	10.6 %PV
HC Pore Volume:	1440 cc	Type of Oil Used:	Faxam-100
Porosity:	35.8%	Oil Viscosity @ 24 °C and101 kPa:	290 mPa . s
Average Absolute Permeability :	6.4 x^-12 m^2 (6.5 darcies)	API Gravity @ 24 °C and101 kPa:	30 °API
Average Injection Rate:	0.36 cc/s (CWE)	Production Pressure:	138 kPa
Net Oil Recovery:	**67.2%**	**Total Steam Injected:**	**1836 cc**

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	8.25	178	0.11	206	150	150	10.4	0.30	0.37	0.84
2	6.95	328	0.20	204	148	298	20.7	0.35	0.38	0.91
3	5.70	451	0.28	204	121	419	29.1	0.35	0.69	0.93
4	4.63	551	0.34	208	104	523	36.3	0.37	1.00	0.95
5	7.25	708	0.44	205	95	618	42.9	0.22	1.16	0.87
6	6.73	853	0.53	197	87	705	49.0	0.22	1.26	0.83
7	7.80	1021	0.63	236	87	792	55.0	0.19	1.71	0.78
8	8.85	1212	0.75	222	57	849	59.0	0.11	2.89	0.70
9	3.18	1281	0.80	198	32	881	61.2	0.17	5.19	0.69
10	10.55	1509	0.94	211	23	904	62.8	0.04	8.17	0.60
11	7.80	1677	1.04	210	35	939	65.2	0.07	5.00	0.56
12	7.38	1836	1.14	208	33	972	67.5	0.07	5.30	0.53

Table B27 - Run 27: 69 kPa (10 psig) Pressure Differential Using a Horizontal Injector

Bulk Volume:	4492 cc	Initial Oil Saturation:	91.6 %PV
Pore Volume:	1550 cc	Initial Water Saturation :	8.4 %PV
HC Pore Volume:	1420 cc	Type of Oil Used:	Faxam-100
Porosity:	34.5%	Oil Viscosity @ 24 °C and101 kPa:	290 mPa . s
Average Absolute Permeability	6.4 x^-12 m^2 (6.5 darcies)	API Gravity @ 24 °C and101 kPa:	30 °API
Average Injection Rate:	0.31 cc/s (CWE)	Production Pressure:	276 kPa
Net Oil Recovery:	**68.1%**	**Total Steam Injected:**	**1950 cc**

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	13.55	252	0.16	205	155	155	10.8	0.19	0.32	0.62
2	12.92	492	0.32	204	150	305	21.2	0.19	0.36	0.62
3	11.88	713	0.46	206	136	441	30.6	0.19	0.51	0.62
4	10.27	904	0.58	204	113	554	38.5	0.18	0.81	0.61
5	7.18	1038	0.67	205	88	642	44.6	0.20	1.33	0.62
6	5.97	1149	0.74	204	71	713	49.5	0.20	1.87	0.62
7	6.58	1271	0.82	203	72	785	54.5	0.18	1.82	0.62
8	6.82	1398	0.90	206	54	839	58.3	0.13	2.81	0.60
9	6.93	1527	0.99	206	52	891	61.9	0.13	2.96	0.58
10	6.92	1656	1.07	203	41	932	64.7	0.10	3.95	0.56
11	7.52	1796	1.16	206	26	958	66.5	0.06	6.92	0.53
12	8.28	1950	1.26	206	22	980	68.1	0.04	8.36	0.50

Table B28 - Run 28: 276 kPa (40 psig) Pressure Differential Using a Horizontal Injector

Bulk Volume:	4492 cc	Initial Oil Saturation:	89.4 %PV
Pore Volume:	1555 cc	Initial Water Saturation :	10.6 %PV
HC Pore Volume:	1390 cc	Type of Oil Used:	Faxam-100
Porosity:	34.6%	Oil Viscosity @ 24 °C and101 kPa:	290 mPa . s
Average Absolute Permeability :	6.4 x^-12 m^2 (6.5 darcies)	API Gravity @ 24 °C and101 kPa:	30 °API
Average Injection Rate:	0.39 cc/s (CWE)	Production Pressure:	69 kPa
Net Oil Recovery:	**58.2%**	**Total Steam Injected:**	**1917 cc**

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	8.00	187	0.12	208	139	139	10.0	0.29	0.50	0.74
2	6.37	336	0.22	204	109	248	17.8	0.29	0.87	0.74
3	5.17	457	0.29	205	99	347	25.0	0.32	1.07	0.76
4	4.00	551	0.35	205	98	445	32.0	0.41	1.09	0.81
5	5.90	689	0.44	210	91	536	38.6	0.26	1.31	0.78
6	7.47	864	0.56	203	71	607	43.7	0.16	1.86	0.70
7	6.70	1021	0.66	203	61	668	48.1	0.15	2.33	0.65
8	6.63	1176	0.76	202	48	716	51.5	0.12	3.21	0.61
9	6.72	1333	0.86	202	37	753	54.2	0.09	4.46	0.56
10	8.68	1536	0.99	202	26	779	56.0	0.05	6.77	0.51
11	7.97	1722	1.11	204	30	809	58.2	0.06	5.80	0.47
12	8.32	1917	1.23	212	27	836	60.1	0.05	6.85	0.44

Table B29 - Run 29: Using 0.64-cm (1/4-in) Diameter Horizontal Injector

Bulk Volume: 4492 cc
Pore Volume: 1570 cc
HC Pore Volume: 1430 cc
Porosity: 35.0%
Average Absolute Permeability : 6.4 x^-12 m2 (6.5 darcies)
Average Steam Injection Rate: 0.39 cc/s (CWE)

Net Oil Recovery: 65.3%

Initial Oil Saturation: 91.1 %PV
Initial Water Saturation : 8.9 %PV
Type of Oil Used: Faxam-100
Oil Viscosity @ 24 °C and101 kPa: 290 mPa . s
API Gravity @ 24 °C and101 kPa: 30 °API
Production Pressure: 207 kPa

Total Steam Injected: 1912 cc

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	9.42	220	0.14	205	132	132	9.2	0.23	0.55	0.60
2	7.32	391	0.25	202	119	251	17.6	0.27	0.70	0.64
3	5.78	526	0.34	207	91	342	23.9	0.26	1.27	0.65
4	5.40	652	0.42	204	88	430	30.1	0.27	1.32	0.66
5	6.55	805	0.51	202	84	514	35.9	0.21	1.40	0.64
6	6.02	946	0.60	204	80	594	41.5	0.22	1.55	0.63
7	6.00	1086	0.69	204	77	671	46.9	0.21	1.65	0.62
8	7.03	1251	0.80	208	82	753	52.7	0.19	1.54	0.60
9	4.17	1349	0.86	218	62	815	57.0	0.25	2.52	0.60
10	8.20	1541	0.98	204	54	869	60.8	0.11	2.78	0.56
11	8.12	1731	1.10	208	36	905	63.3	0.07	4.78	0.52
12	7.73	1912	1.22	211	29	934	65.3	0.06	6.28	0.49

Table B30 - Run 30: Using 0.95-cm (3/8-in) Diameter Horizontal Injector

Bulk Volume: 4492 cc
Pore Volume: 1587 cc
HC Pore Volume: 1420 cc
Porosity: 35.3%
Average Absolute Permeability : 6.4 x^-12 m^2 (6.5 darcies)
Average Steam Injection Rate: 0.39 cc/s (CWE)

Net Oil Recovery: 75.9%

Initial Oil Saturation: 89.5 %PV
Initial Water Saturation : 10.5 %PV
Type of Oil Used: Faxam-100
Oil Viscosity @ 24 °C and101 kPa: 290 mPa . s
API Gravity @ 24 °C and101 kPa: 30 °API
Production Pressure: 207 kPa

Total Steam Injected: 1893 cc

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	9.05	212	0.13	206	112	112	7.9	0.21	0.84	0.53
2	7.47	387	0.24	202	139	251	17.7	0.31	0.45	0.65
3	7.32	558	0.35	202	126	377	26.5	0.29	0.60	0.68
4	7.63	737	0.46	204	120	497	35.0	0.26	0.70	0.67
5	7.35	909	0.57	206	114	611	43.0	0.26	0.81	0.67
6	6.40	1059	0.67	204	97	708	49.9	0.25	1.10	0.67
7	6.22	1205	0.76	206	73	781	55.0	0.20	1.82	0.65
8	5.95	1344	0.85	207	70	851	59.9	0.20	1.96	0.63
9	5.42	1471	0.93	207	63	914	64.4	0.19	2.29	0.62
10	5.87	1608	1.01	206	54	968	68.2	0.15	2.81	0.60
11	5.45	1736	1.09	210	52	1020	71.8	0.16	3.04	0.59
12	6.70	1893	1.19	205	58	1078	75.9	0.14	2.53	0.57

Table B31 - Run 31: Oil of Viscosity 1800 mPa.s Using a Horizontal Injector

Bulk Volume:	4492 cc	Initial Oil Saturation:	87.3 %PV
Pore Volume:	1570 cc	Initial Water Saturation :	12.7 %PV
HC Pore Volume:	1370 cc	Type of Oil Used:	Wainwright
Porosity:	35.0%	Oil Viscosity @ 24 °C and101 kPa:	1800 mPa . s
Average Absolute Permeability :	6.4 x^-12 m^2 (6.5 darcies)	API Gravity @ 24 °C and101 kPa:	14 °API
Average Steam Injection Rate:	0.33 cc/s (CWE)	Production Pressure:	207 kPa
Net Oil Recovery:	**45.3%**	**Total Steam Injected:**	**2146 cc**

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	19.42	385	0.25	218	92	92	6.7	0.08	1.37	0.24
2	10.65	596	0.38	201	70	162	11.8	0.11	1.87	0.27
3	10.83	810	0.52	198	47	209	15.3	0.07	3.21	0.26
4	6.05	930	0.59	195	37	246	18.0	0.10	4.27	0.26
5	2.75	984	0.63	195	55	301	22.0	0.33	2.55	0.31
6	6.38	1110	0.71	202	52	353	25.8	0.14	2.88	0.32
7	7.70	1262	0.80	206	51	404	29.5	0.11	3.04	0.32
8	7.25	1406	0.90	204	49	453	33.1	0.11	3.16	0.32
9	8.17	1568	1.00	207	43	496	36.2	0.09	3.81	0.32
10	8.67	1740	1.11	242	64	560	40.9	0.12	2.78	0.32
11	9.85	1935	1.23	199	29	589	43.0	0.05	5.86	0.30
12	10.67	2146	1.37	236	32	621	45.3	0.05	6.38	0.29

Table B32 - Run 32: Oil of Viscosity 975 mPa.s Using a Horizontal Injector

Bulk Volume:	4492 cc	Initial Oil Saturation:	86.4 %PV
Pore Volume:	1620 cc	Initial Water Saturation :	13.6 %PV
HC Pore Volume:	1400 cc	Type of Oil Used:	Wainwright
Porosity:	36.1%	Oil Viscosity @ 24 °C and101 kPa:	975 mPa . s
Average Absolute Permeability :	6.4 x^-12 m^2 (6.5 darcies)	API Gravity @ 24 °C and101 kPa:	18 °API
Average Steam Injection Rate:	0.31 cc/s (CWE)	Production Pressure:	207 kPa
Net Oil Recovery:	**76.1%**	**Total Steam Injected:**	**1847 cc**

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	18.13	337	0.21	202	152	152	10.9	0.14	0.33	0.45
2	13.53	589	0.36	200	130	282	20.1	0.16	0.54	0.48
3	9.27	761	0.47	198	108	390	27.9	0.19	0.83	0.51
4	6.26	877	0.54	193	79	469	33.5	0.21	1.44	0.53
5	5.05	971	0.60	197	67	536	38.3	0.22	1.94	0.55
6	6.08	1084	0.67	211	103	639	45.6	0.28	1.05	0.59
7	9.45	1260	0.78	196	68	707	50.5	0.12	1.88	0.56
8	2.40	1307	0.81	212	92	799	57.1	0.64	1.30	0.61
9	6.63	1430	0.88	190	60	859	61.4	0.15	2.17	0.60
10	6.93	1559	0.96	220	95	954	68.1	0.23	1.32	0.61
11	6.83	1686	1.04	221	65	1019	72.8	0.16	2.40	0.60
12	8.63	1847	1.14	220	46	1065	76.1	0.09	3.78	0.58

Table 33 - Run 33: Using 0.64-cm (1/4-in) Diameter Horizontal Producer

Bulk Volume:	4492 cc	Initial Oil Saturation:	94.4 %PV
Pore Volume:	1620 cc	Initial Water Saturation :	5.6 %PV
HC Pore Volume:	1530 cc	Type of Oil Used:	Faxam-100
Porosity:	36.1%	Oil Viscosity @ 24 °C and101 kPa:	290 mPa . s
Average Absolute Permeability :	6.4 x^-12 m^2 (6.5 darcies)	API Gravity @ 24 °C and101 kPa:	30 °API
Average Steam Injection Rate:	0.33 cc/s (CWE)	Production Pressure:	138 kPa
Net Oil Recovery:	**63.3%**	**Total Steam Injected:**	**1769 cc**

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	9.32	185	0.11	202	42	42	2.7	0.08	3.81	0.23
2	8.63	356	0.22	202	82	124	8.1	0.16	1.46	0.35
3	8.55	525	0.32	204	94	218	14.2	0.18	1.17	0.42
4	7.30	670	0.41	199	96	314	20.5	0.22	1.07	0.47
5	8.52	839	0.52	204	102	416	27.2	0.20	1.00	0.50
6	7.87	995	0.61	207	108	524	34.2	0.23	0.92	0.53
7	6.97	1133	0.70	201	98	622	40.7	0.23	1.05	0.55
8	6.23	1256	0.78	200	76	698	45.6	0.20	1.63	0.56
9	5.35	1362	0.84	196	78	776	50.7	0.24	1.51	0.57
10	5.52	1471	0.91	206	64	840	54.9	0.19	2.22	0.57
11	6.88	1607	0.99	204	60	900	58.8	0.15	2.40	0.56
12	8.18	1769	1.09	206	68	968	63.3	0.14	2.03	0.55

Table B34 - Run 34: Using 0.95-cm (3/8-in) Diameter Horizontal Producer

Bulk Volume:	4492 cc	Initial Oil Saturation:	92.4 %PV
Pore Volume:	1570 cc	Initial Water Saturation :	7.6 %PV
HC Pore Volume:	1450 cc	Type of Oil Used:	Faxam-100
Porosity:	35.0%	Oil Viscosity @ 24 °C and101 kPa:	290 mPa . s
Average Absolute Permeability :	6.4 x^-12 m^2 (6.5 darcies)	API Gravity @ 24 °C and101 kPa:	30 °API
Average Steam Injection Rate:	0.36 cc/s (CWE)	Production Pressure:	138 kPa
Net Oil Recovery:	**69.9%**	**Total Steam Injected:**	**1819 cc**

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	13.68	295	0.19	205	151	151	10.4	0.18	0.36	0.51
2	10.30	517	0.33	206	106	257	17.7	0.17	0.94	0.50
3	7.62	682	0.43	204	84	341	23.5	0.18	1.43	0.50
4	7.28	839	0.53	202	76	417	28.8	0.17	1.66	0.50
5	6.52	980	0.62	204	73	490	33.8	0.19	1.79	0.50
6	5.85	1106	0.70	202	79	569	39.2	0.23	1.56	0.51
7	6.10	1238	0.79	204	82	651	44.9	0.22	1.49	0.53
8	4.97	1345	0.86	204	78	729	50.3	0.26	1.62	0.54
9	5.67	1467	0.93	206	80	809	55.8	0.24	1.58	0.55
10	5.42	1584	1.01	204	71	880	60.7	0.22	1.87	0.56
11	5.68	1707	1.09	206	71	951	65.6	0.21	1.90	0.56
12	5.20	1819	1.16	205	63	1014	69.9	0.20	2.25	0.56

Table B35 - Run 35: Oil of Viscosity 975 mPa.s Using a Horizontal Producer

Bulk Volume:	4492 cc	Initial Oil Saturation:	97.1 %PV
Pore Volume:	1565 cc	Initial Water Saturation :	2.9 %PV
HC Pore Volume:	1520 cc	Type of Oil Used:	Wainwright
Porosity:	34.8%	Oil Viscosity @ 24 °C and101 kPa:	975 mPa . s
Average Absolute Permeability :	6.4 x10^-12 m^2 (6.5 darcies)	API Gravity @ 24 °C and101 kPa:	18 °API
Average Steam Injection Rate:	0.28 cc/s (CWE)	Production Pressure:	138 kPa
Net Oil Recovery:	**74.0%**	**Total Steam Injected:**	**2018 cc**

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	18.02	303	0.19	212	202	202	13.3	0.19	0.05	0.67
2	8.73	450	0.29	205	165	367	24.1	0.32	0.24	0.82
3	7.33	573	0.37	209	129	496	32.6	0.29	0.62	0.87
4	9.47	732	0.47	216	108	604	39.7	0.19	1.00	0.83
5	9.76	896	0.57	208	98	702	46.2	0.17	1.12	0.78
6	7.74	1026	0.66	218	104	806	53.0	0.22	1.10	0.79
7	7.74	1156	0.74	201	81	887	58.4	0.17	1.48	0.77
8	11.67	1352	0.86	202	62	949	62.4	0.09	2.26	0.70
9	11.45	1544	0.99	200	50	999	65.7	0.07	3.00	0.65
10	7.60	1672	1.07	204	48	1047	68.9	0.11	3.25	0.63
11	9.87	1838	1.17	202	50	1097	72.2	0.08	3.04	0.60
12	10.70	2018	1.29	198	28	1125	74.0	0.04	6.07	0.56

Table B36 - Run 36: Oil of Viscosity 1800 mPa.s Using a Horizontal Producer

Bulk Volume:	4492 cc
Pore Volume:	1615 cc
HC Pore Volume:	1500 cc
Porosity:	36.0%
Average Absolute Permeability :	6.4 x10^-12 m^2 (6.5 darcies)
Average Steam Injection Rate:	0.34 cc/s (CWE)
Net Oil Recovery:	**47.8%**

Initial Oil Saturation:	92.9 %PV
Initial Water Saturation :	7.1 %PV
Type of Oil Used:	Wainwright
Oil Viscosity @ 24 °C and101 kPa:	1800 mPa . s
API Gravity @ 24 °C and101 kPa:	14 °API
Production Pressure:	138 kPa
Total Steam Injected:	**2042 cc**

Sample No.	Time Minutes	Cum.Steam Inj. cc (CWE)	Cum.Steam Inj. PV (CWE)	Fluid Produced cc/Sample	Oil Produced cc/Sample	Cum.Oil Produced (cc)	Cum.Oil Rec. %IOIP	Oil Rate cc/s	Produced WOR	Cum. OSR (CWE)
1	13.23	270	0.17	205	95	95	6.3	0.12	1.16	0.35
2	7.15	416	0.26	191	89	184	12.3	0.21	1.15	0.44
3	5.62	531	0.33	200	80	264	17.6	0.24	1.50	0.50
4	8.53	705	0.44	192	76	340	22.7	0.15	1.53	0.48
5	4.83	804	0.50	196	66	406	27.1	0.23	1.97	0.50
6	8.33	974	0.60	194	56	462	30.8	0.11	2.46	0.47
7	10.82	1195	0.74	240	56	518	34.5	0.09	3.29	0.43
8	7.00	1338	0.83	226	50	568	37.9	0.12	3.52	0.42
9	7.00	1481	0.92	192	48	616	41.1	0.11	3.00	0.42
10	6.93	1622	1.00	195	39	655	43.7	0.09	4.00	0.40
11	6.93	1763	1.09	200	25	680	45.3	0.06	7.00	0.39
12	13.68	2042	1.26	227	37	717	47.8	0.05	5.14	0.35

Appendix C: Production History of Experiments Conducted

Figure C1 - Production History of Run 1: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected Bottom Steam Injection Using a Horizontal Producer

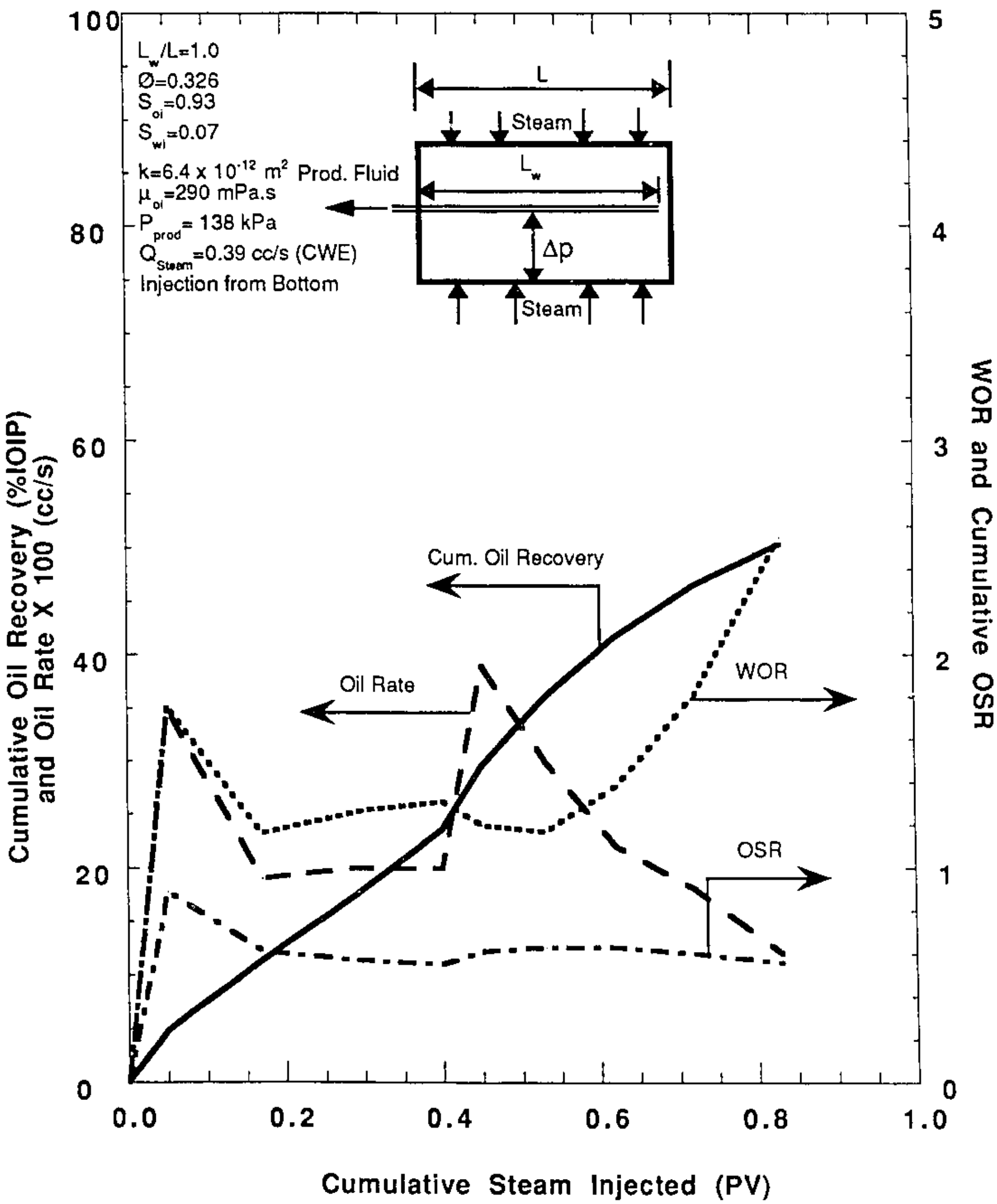


Figure C2 - Production History of Run 2: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected Bottom Steam Injection and Δp of138 kPa Using a Horizontal Producer

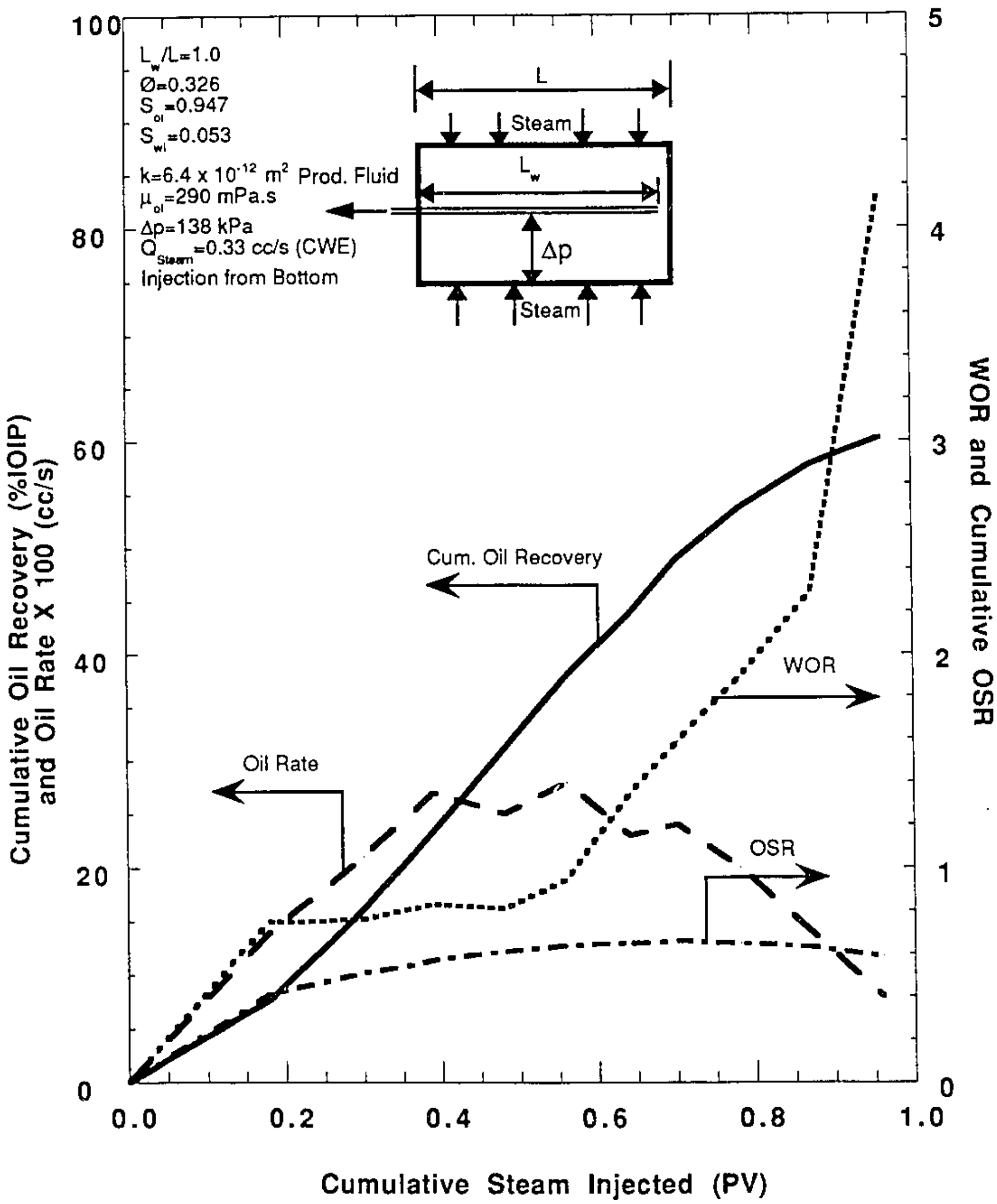


Figure C3 - Production History of Run 3: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected Bottom Steam Injection and Δp of 69 kPa Using a Horizontal Producer

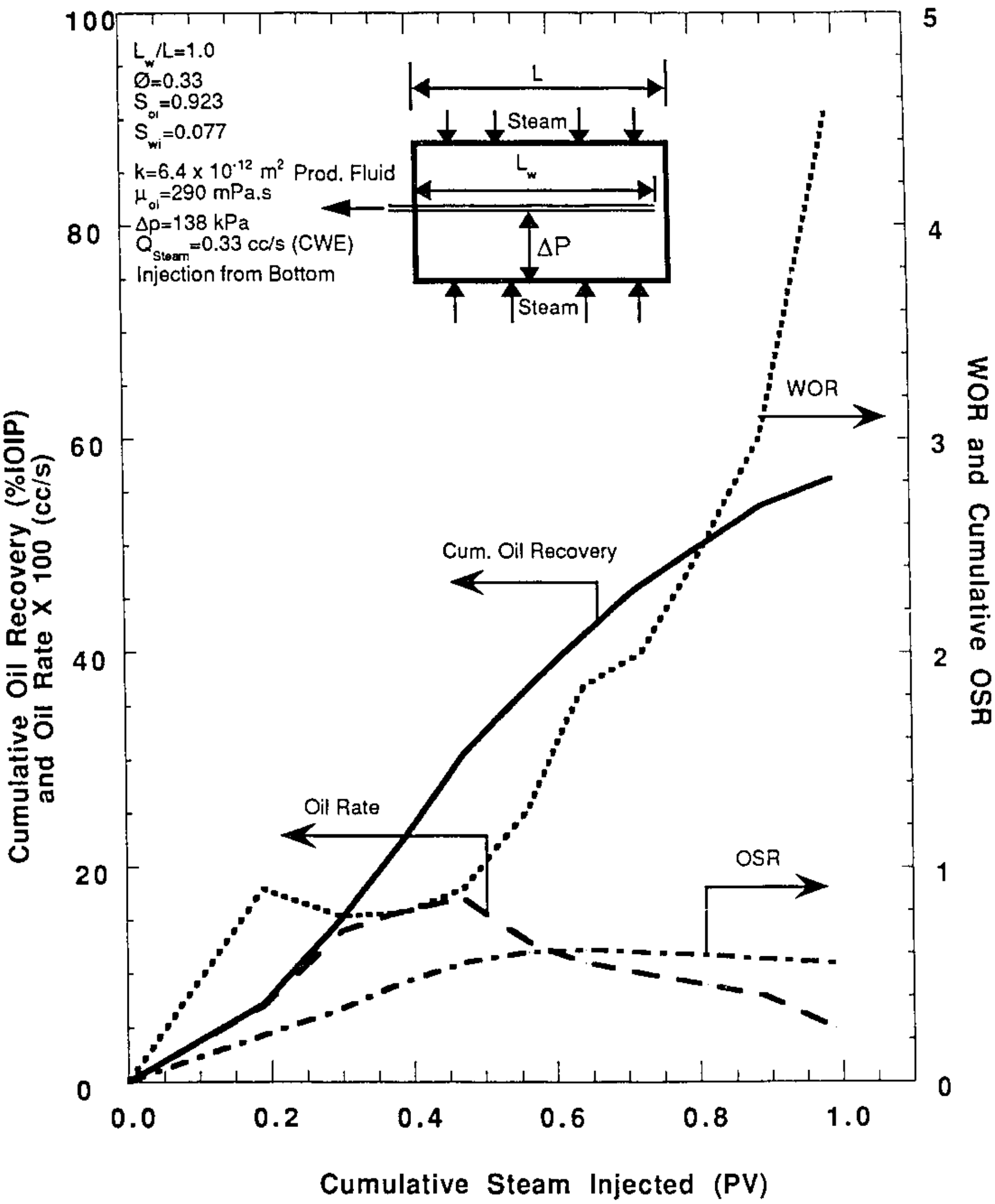


Figure C4 - Production History of Run 4: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected (Repeat of Run 3 for Results Reproducibility)

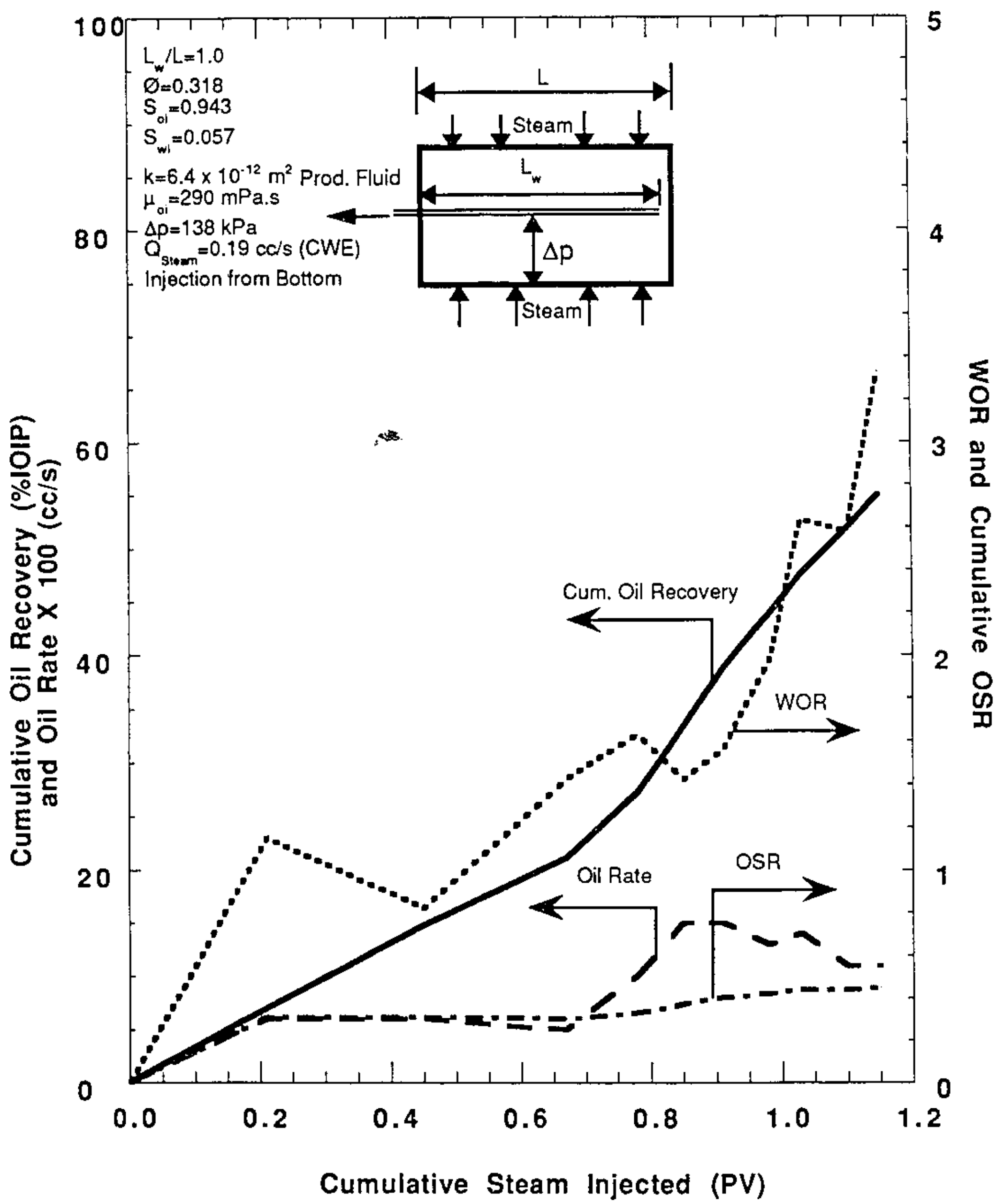


Figure C5 - Production History of Run 5: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected Bottom Steam Injection Using a Horizontal Producer

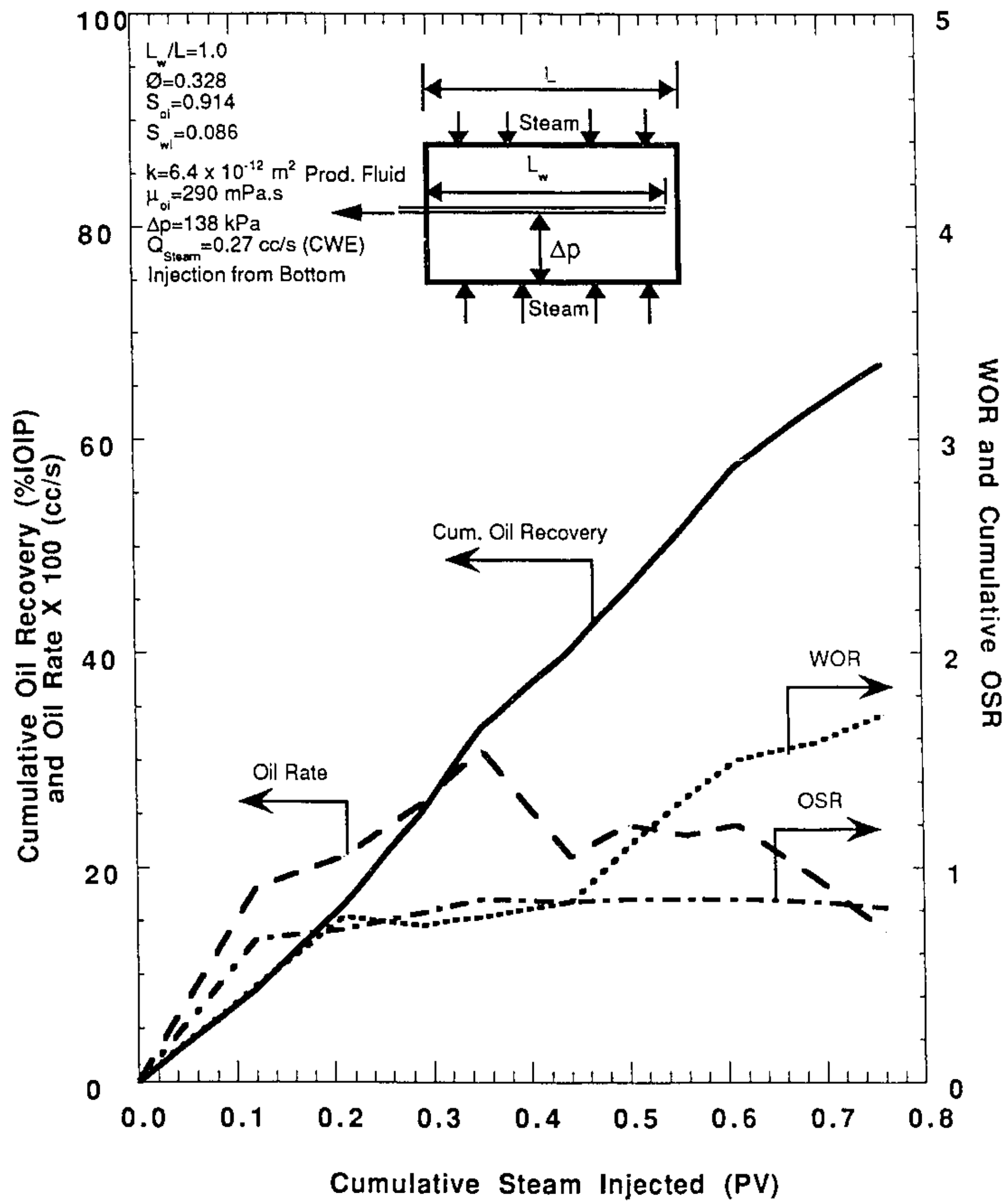


Figure C6 - Production History of Run 6: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected Bottom Steam Injection and Δp of 207 kPa Using a Horizontal Producer

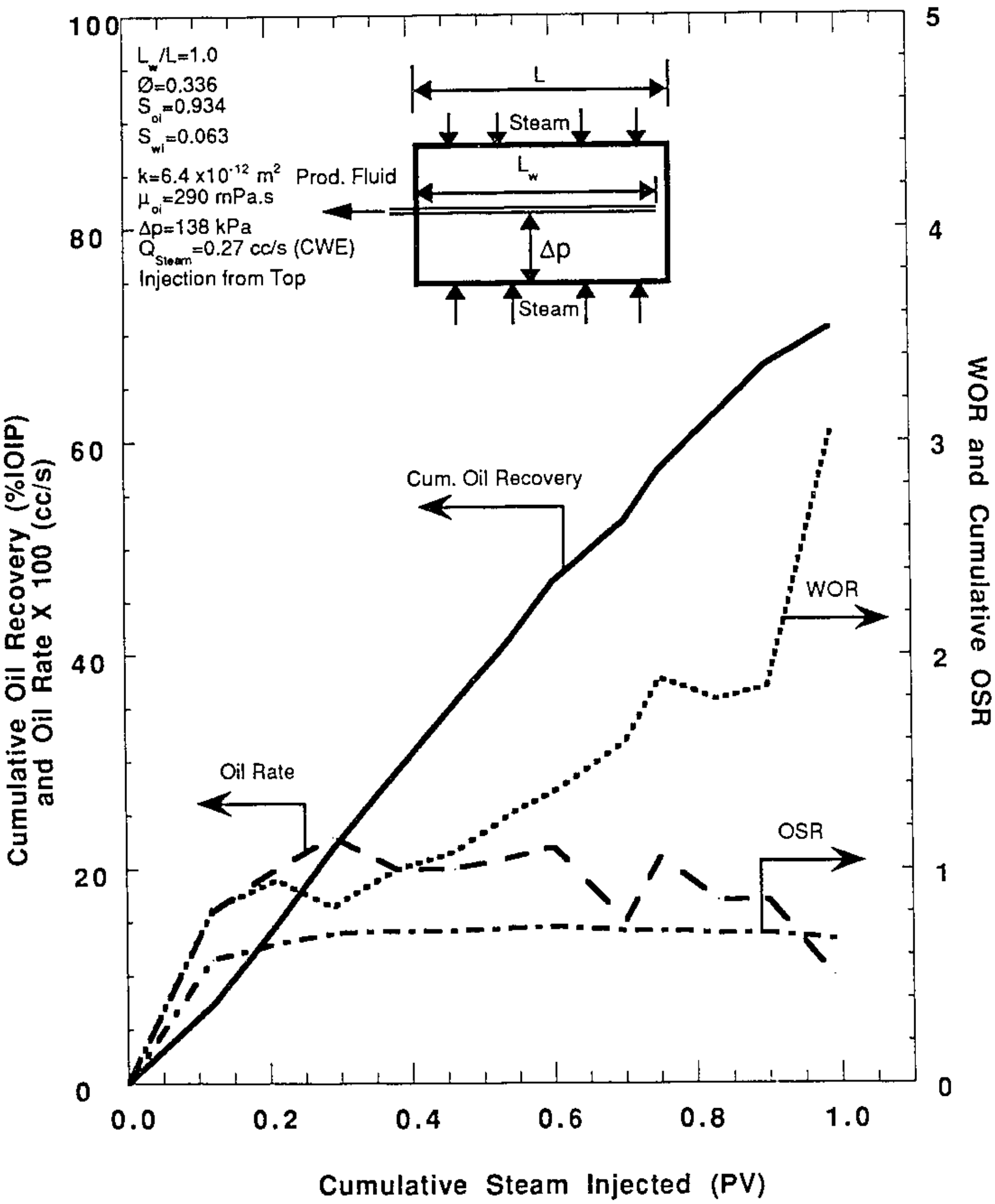


Figure C7 - Production History of Run 7: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected Bottom Steam Injection Using a Horizontal Producer

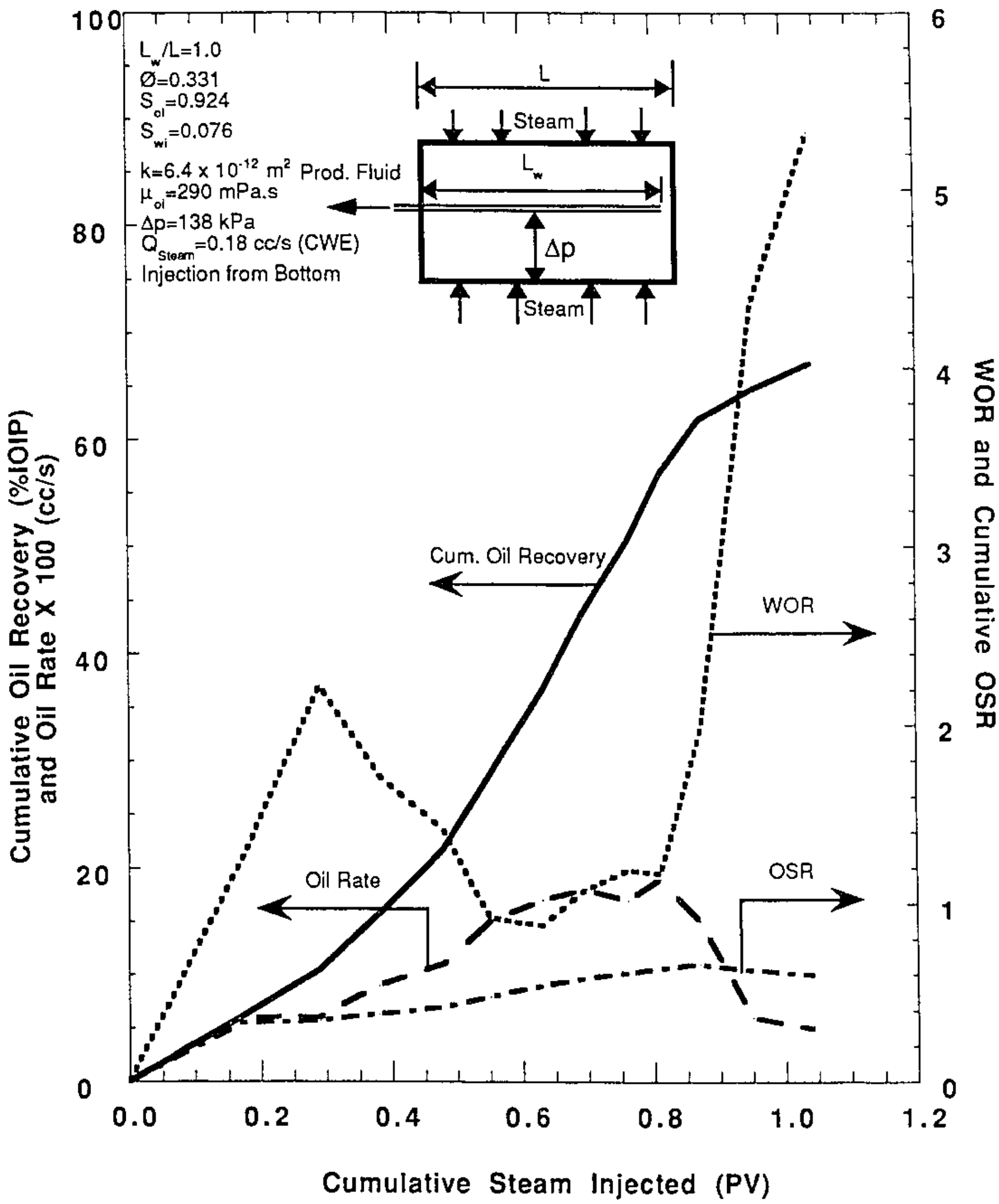


Figure C8 - Production History of Run 8: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected Using a Horizontal Producer Penetrating 100% of the Sand Pack Length

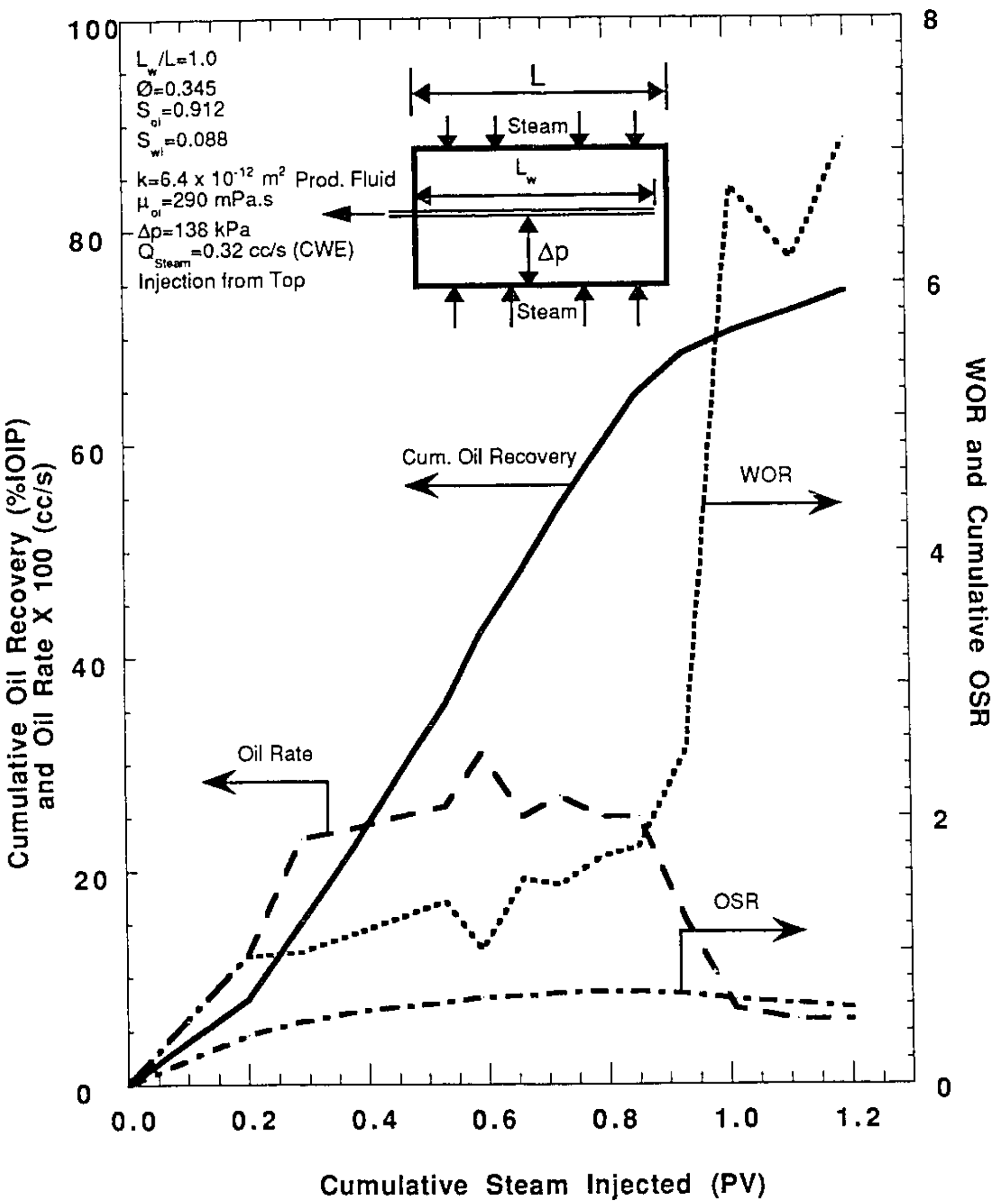


Figure C9 -Production History of Run 9: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected (Repeat of Run 7 for Reproducibility Results)

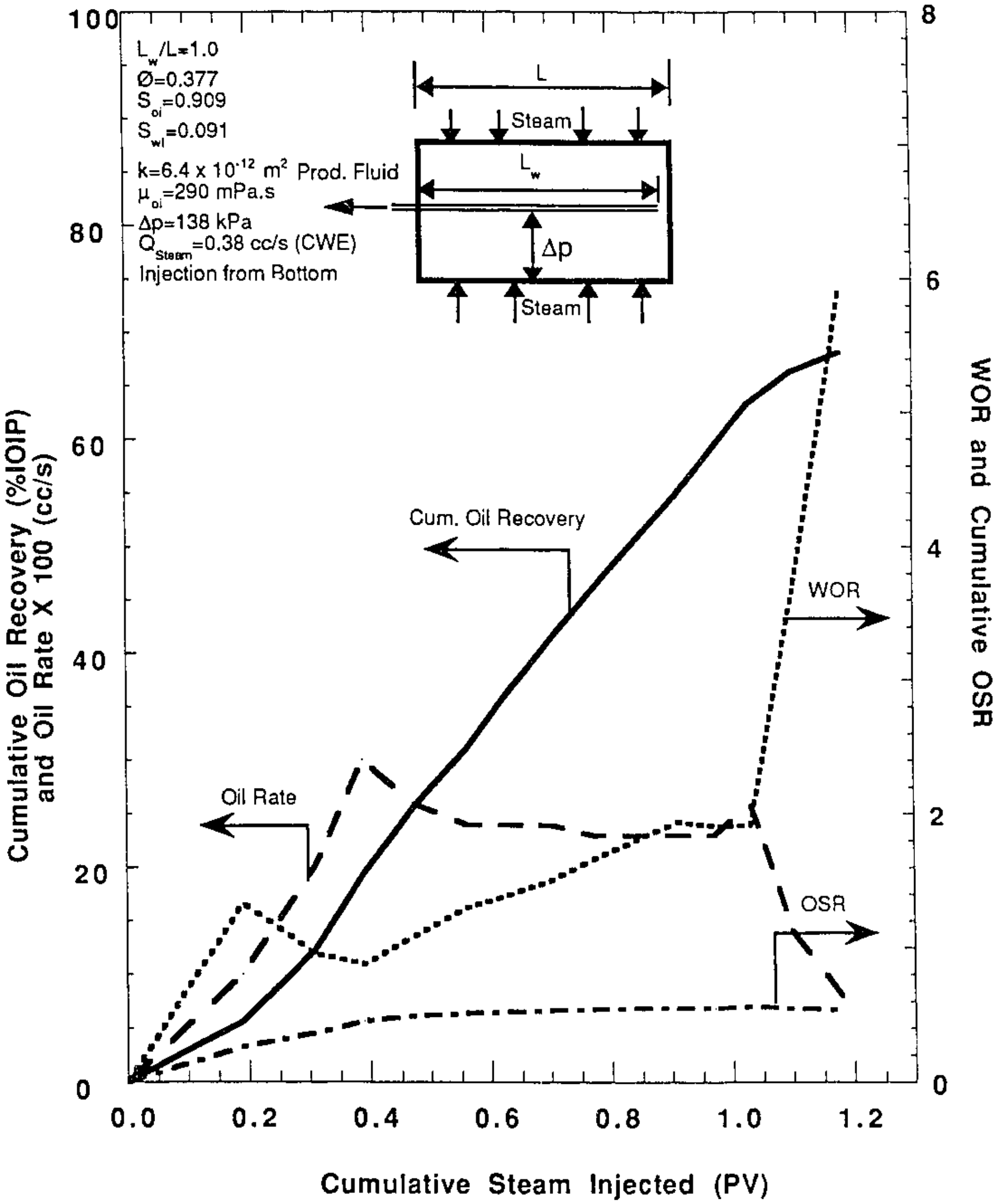


Figure C10 - Production History of Run 10: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected Using a Horizontal Producer Penetrating 25% of the Sand Pack Length

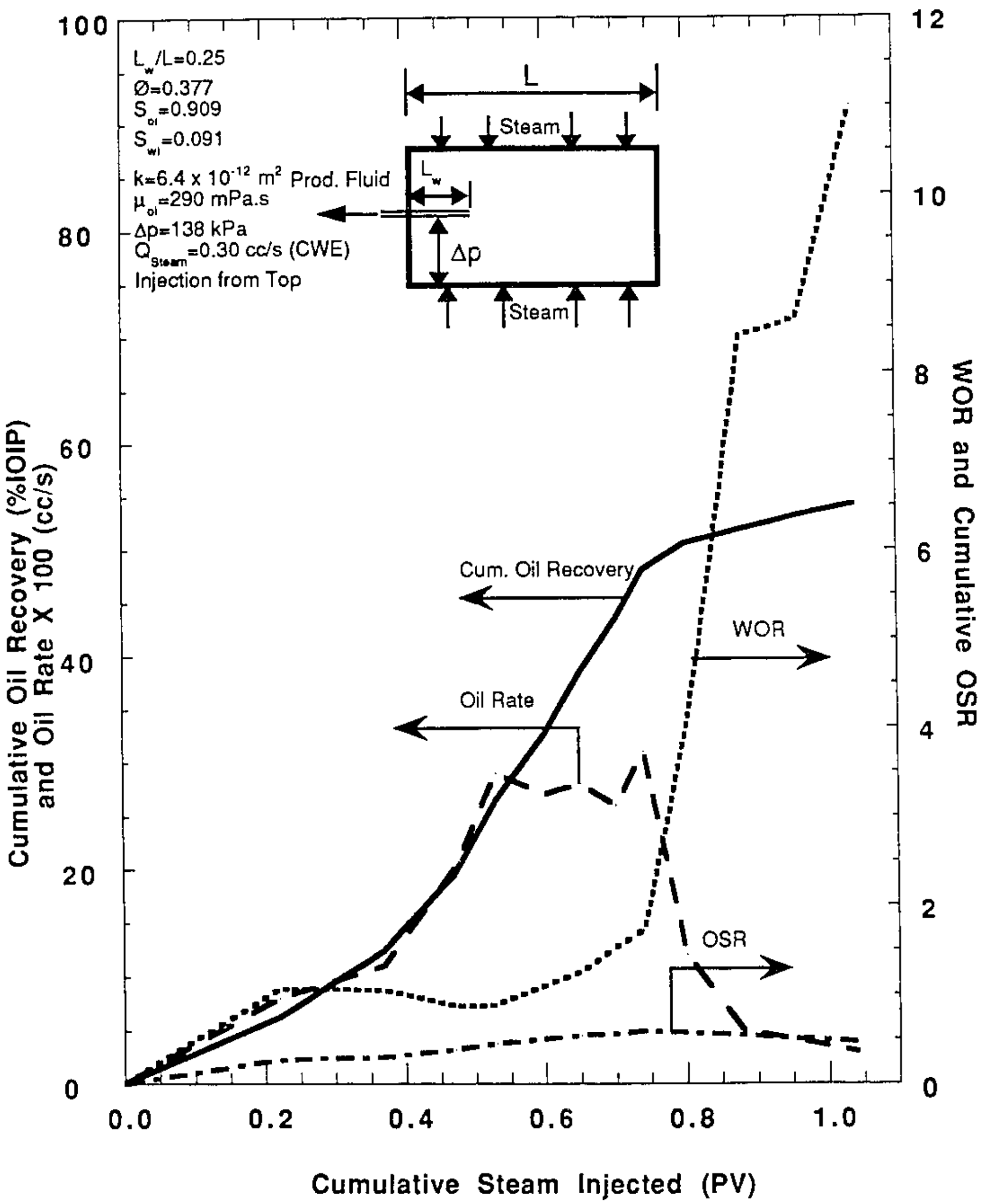


Figure C11 - Production History of Run 11: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected Using a Horizontal Producer Penetrating 50% of the Sand Pack Length

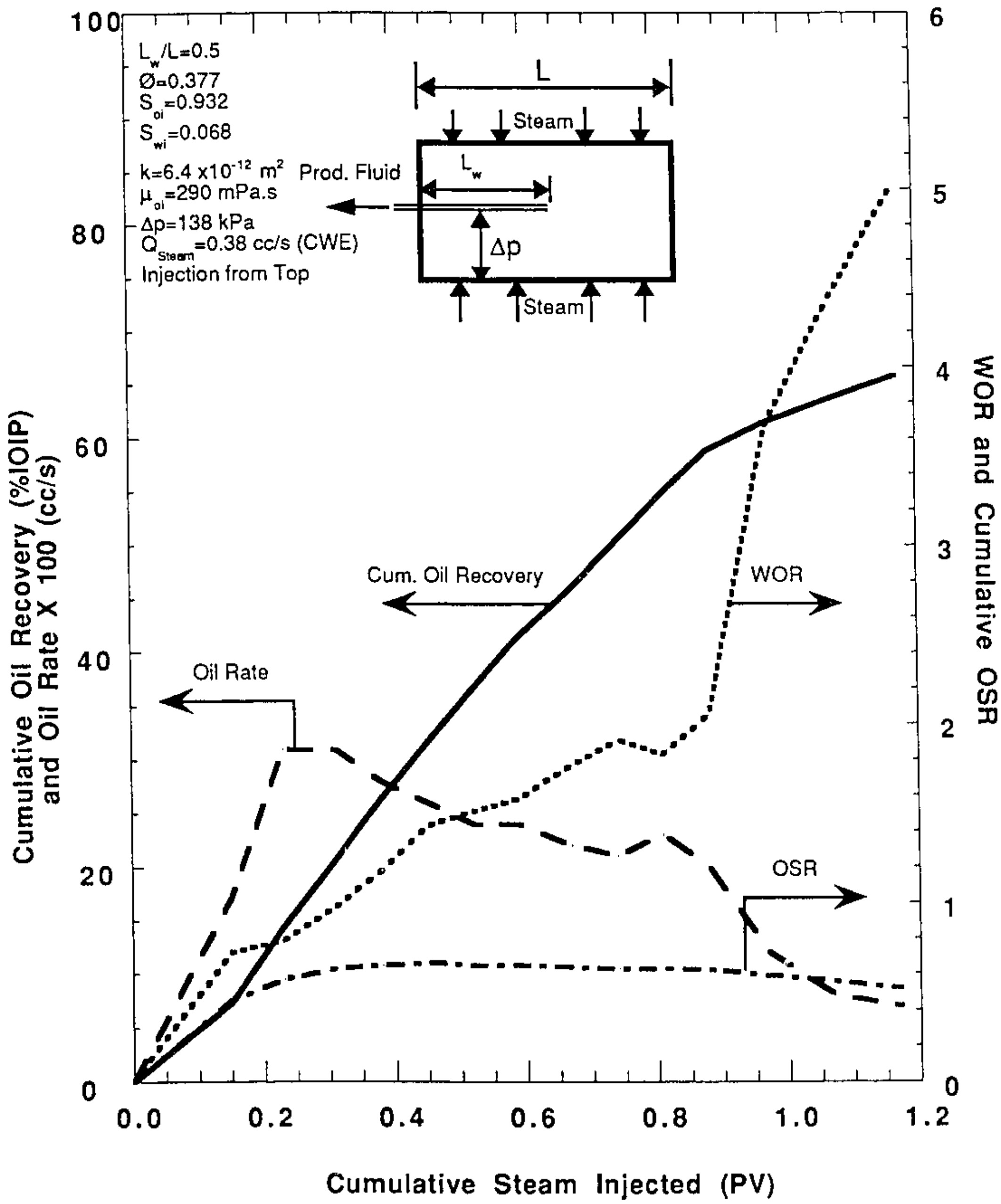


Figure C12 - Production History of Run 12: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected Using a Horizontal Producer Penetrating 25% of the Sand Pack Length

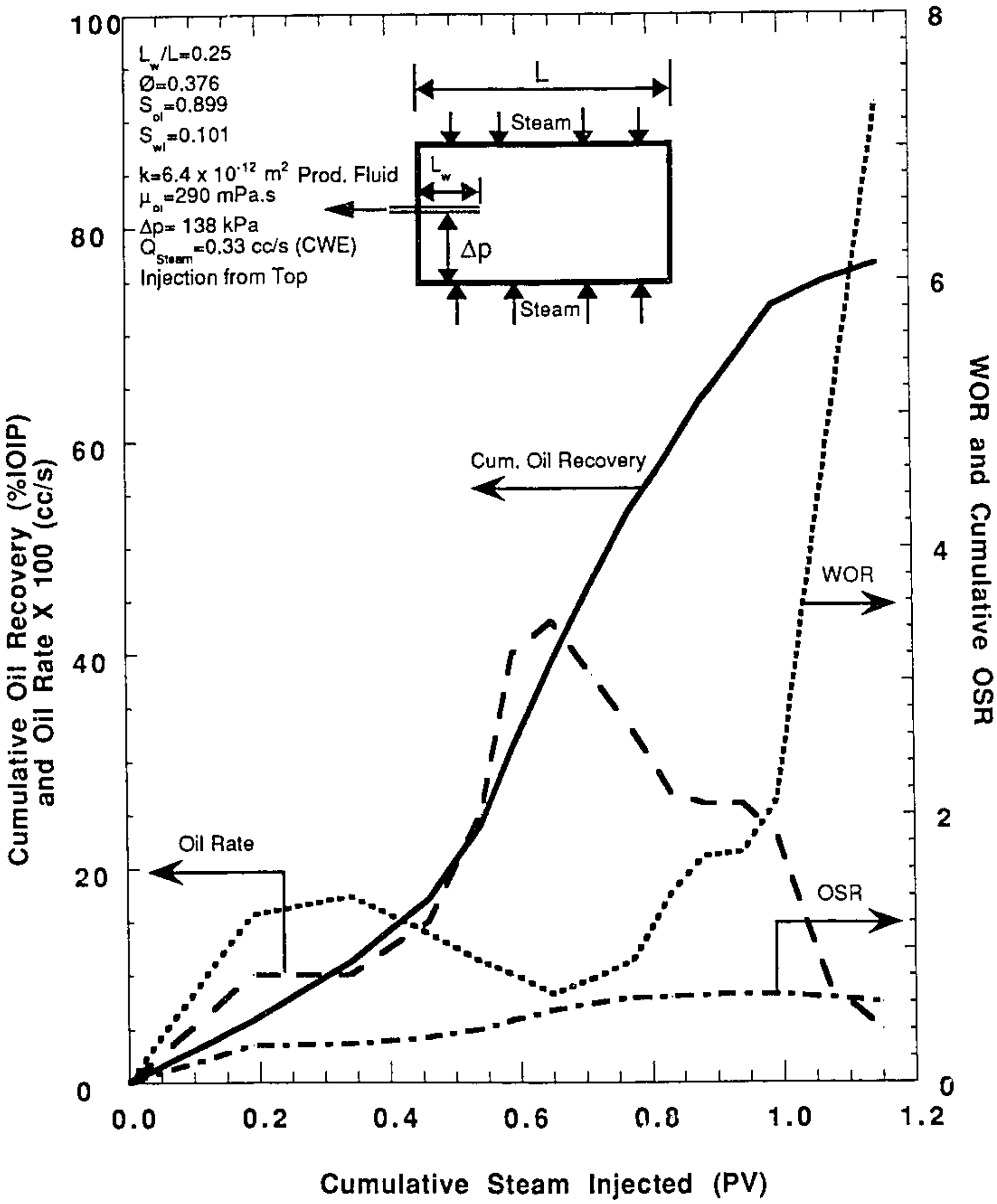


Figure C13 - Production History of Run 13: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected for Pressure Differential of 55 kPa Using a Horizontal Producer

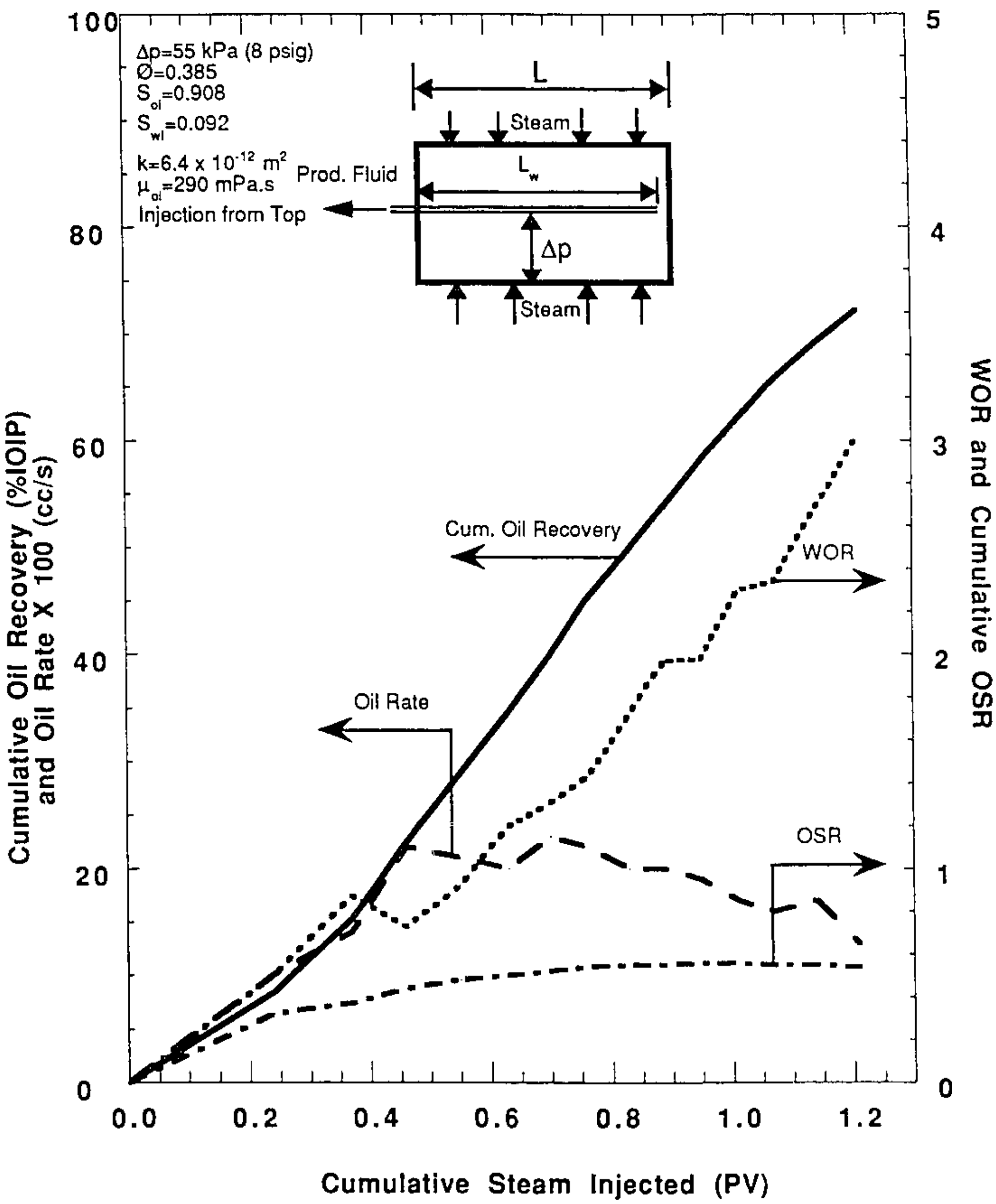


Figure C14 - Production History of Run 14: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected for 207 kPa Pressure Differential Using a Horizontal Producer

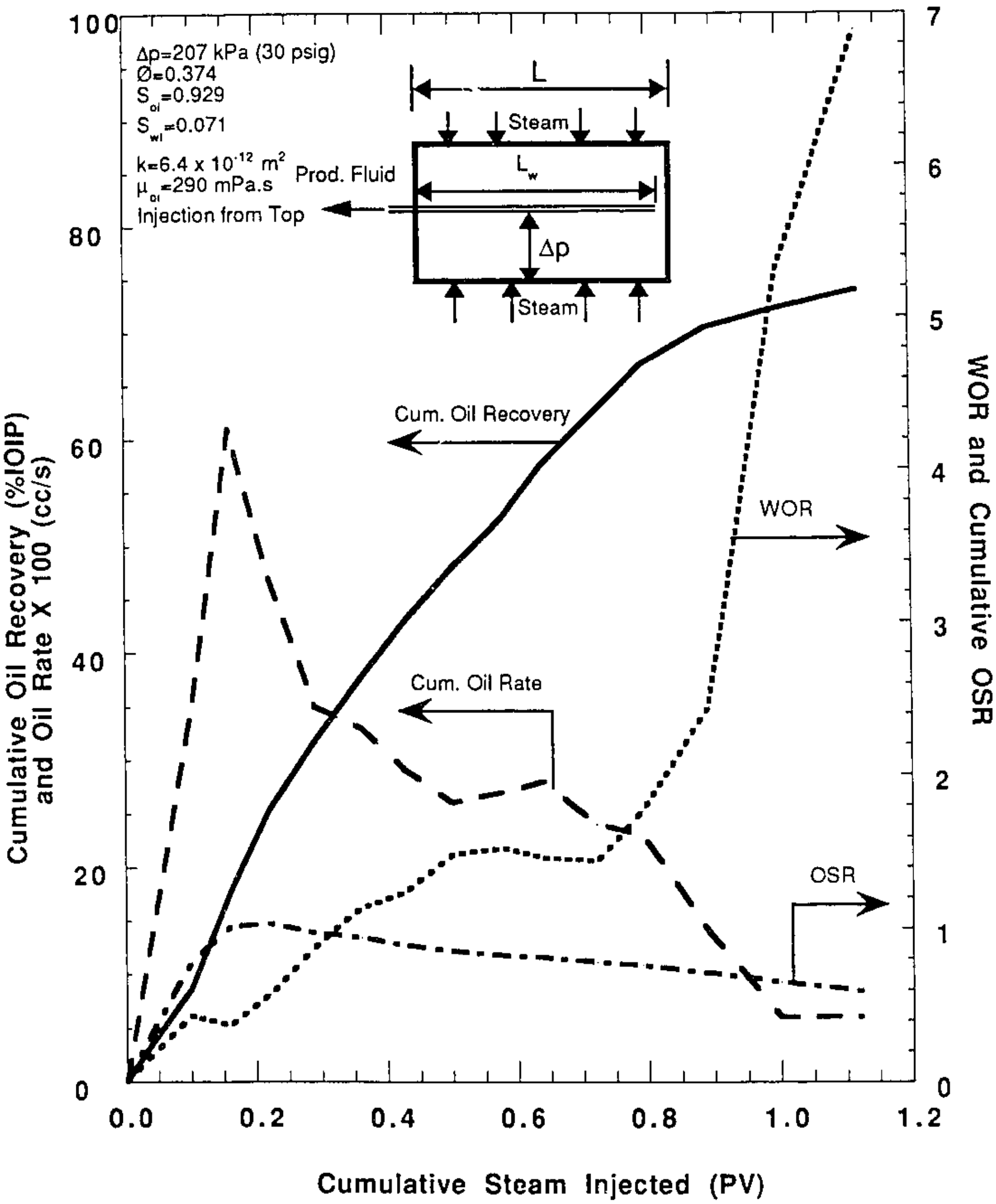


Figure C15 - Production History of Run 15: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected for104 kPa Pressure Differential Using a Horizontal Producer

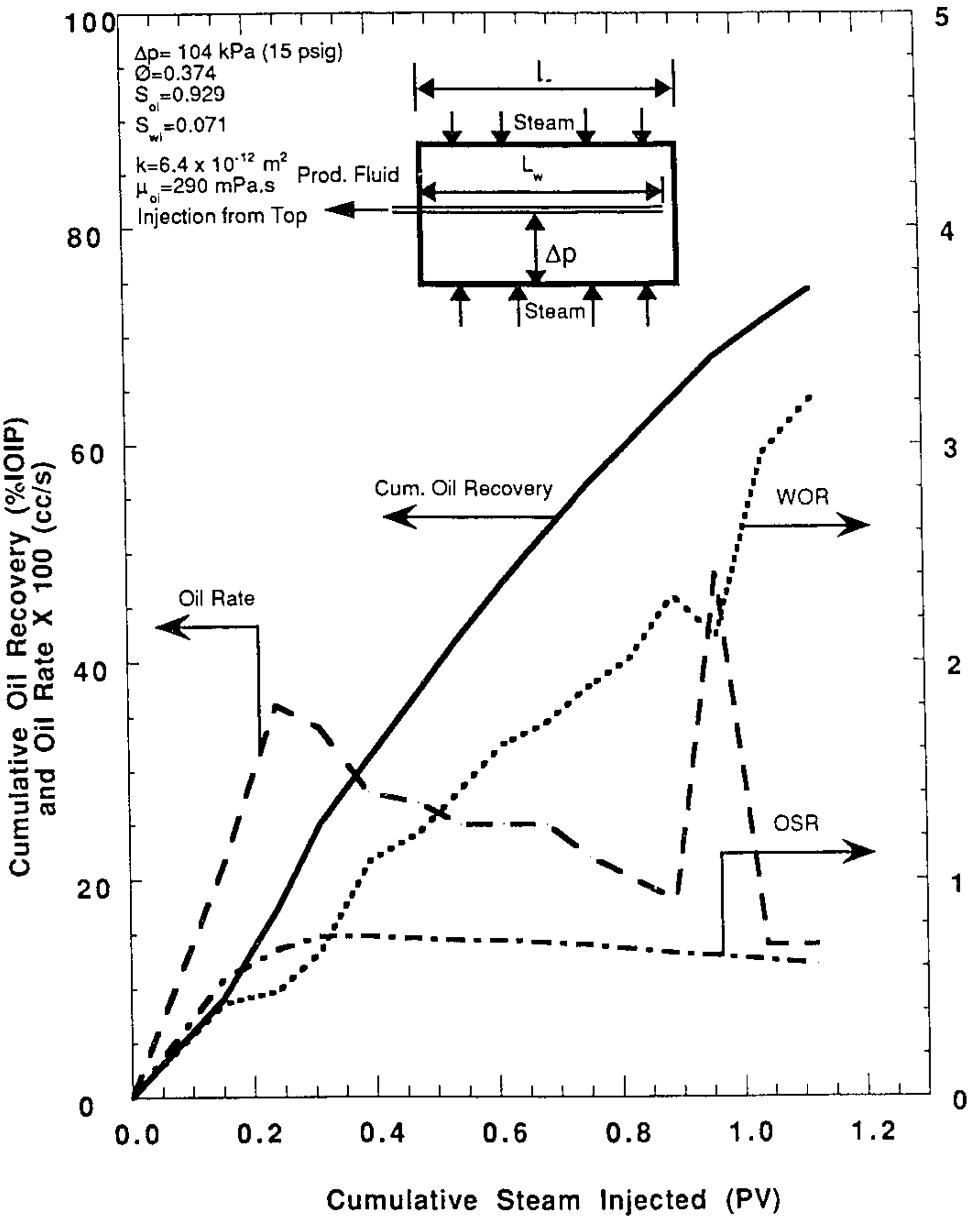


Figure C16 - Production History of Run 16: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected Using a Horizontal Producer Penetrating 100% of the Sand Pack Length

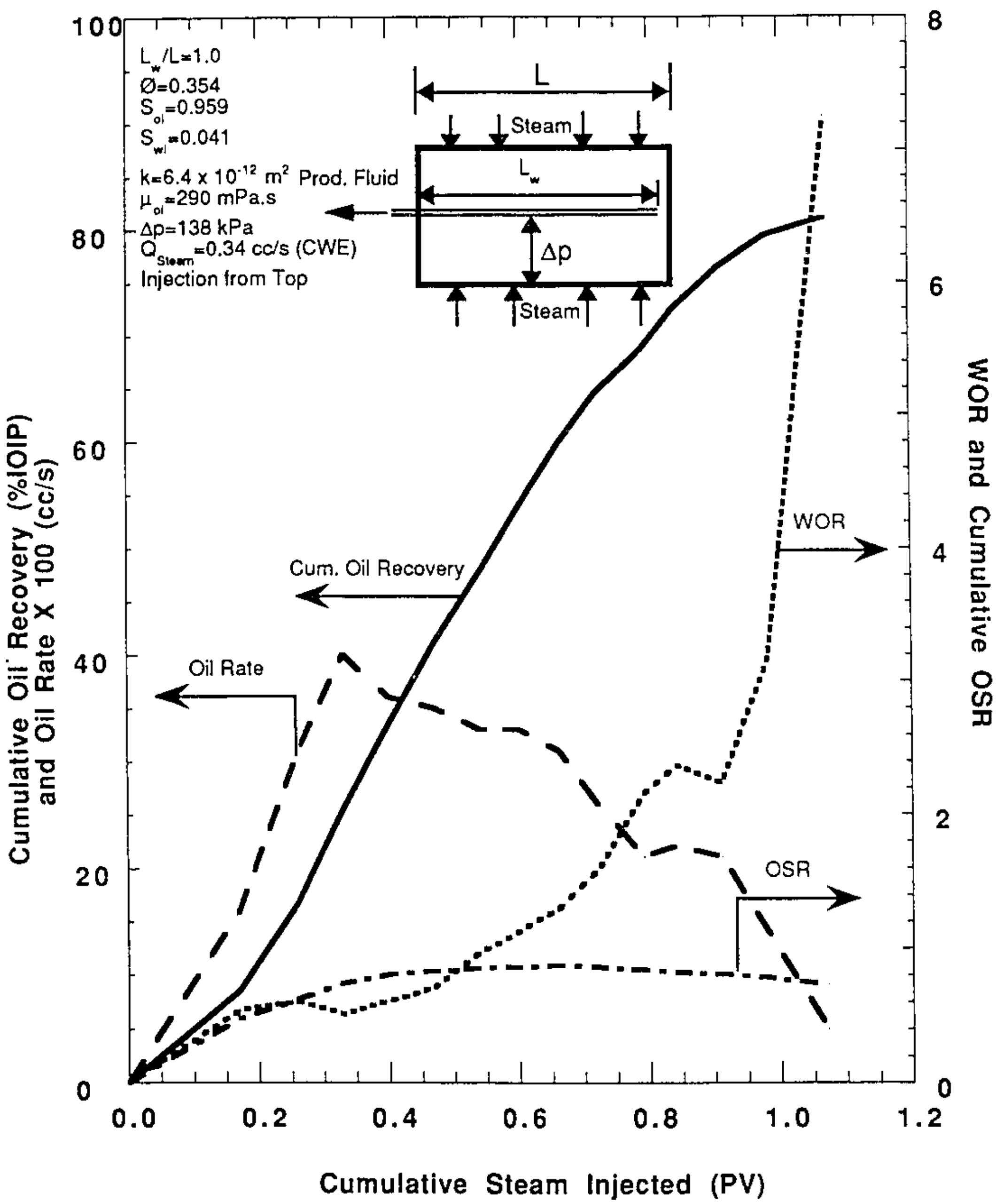


Figure C17 - Production History of Run 17: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected for 172 kPa Pressure Differential Using a Horizontal Producer

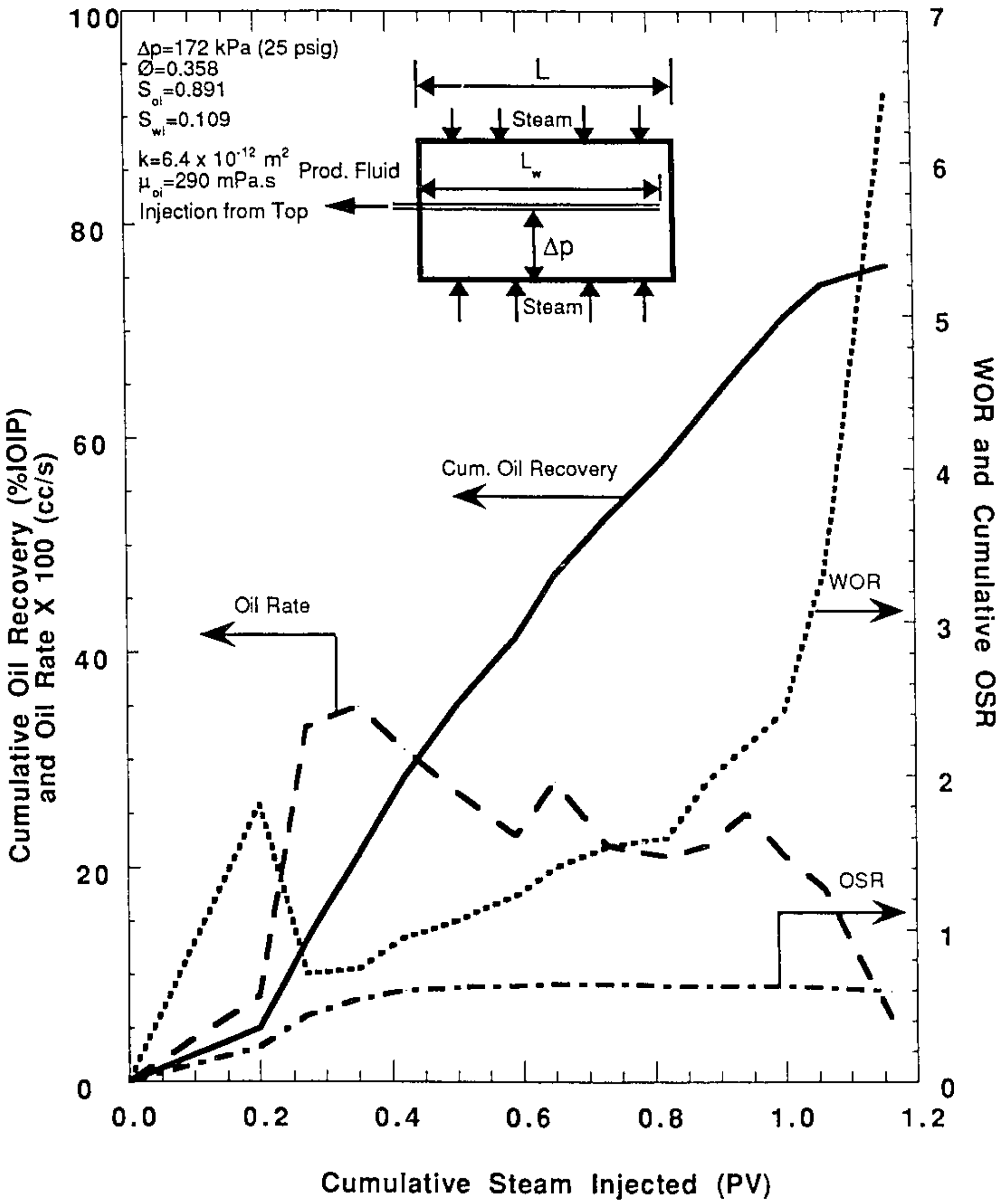


Figure C18 - Production History of Run 18: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected Using a Horizontal Producer Penetrating 75% of the Sand Pack Length

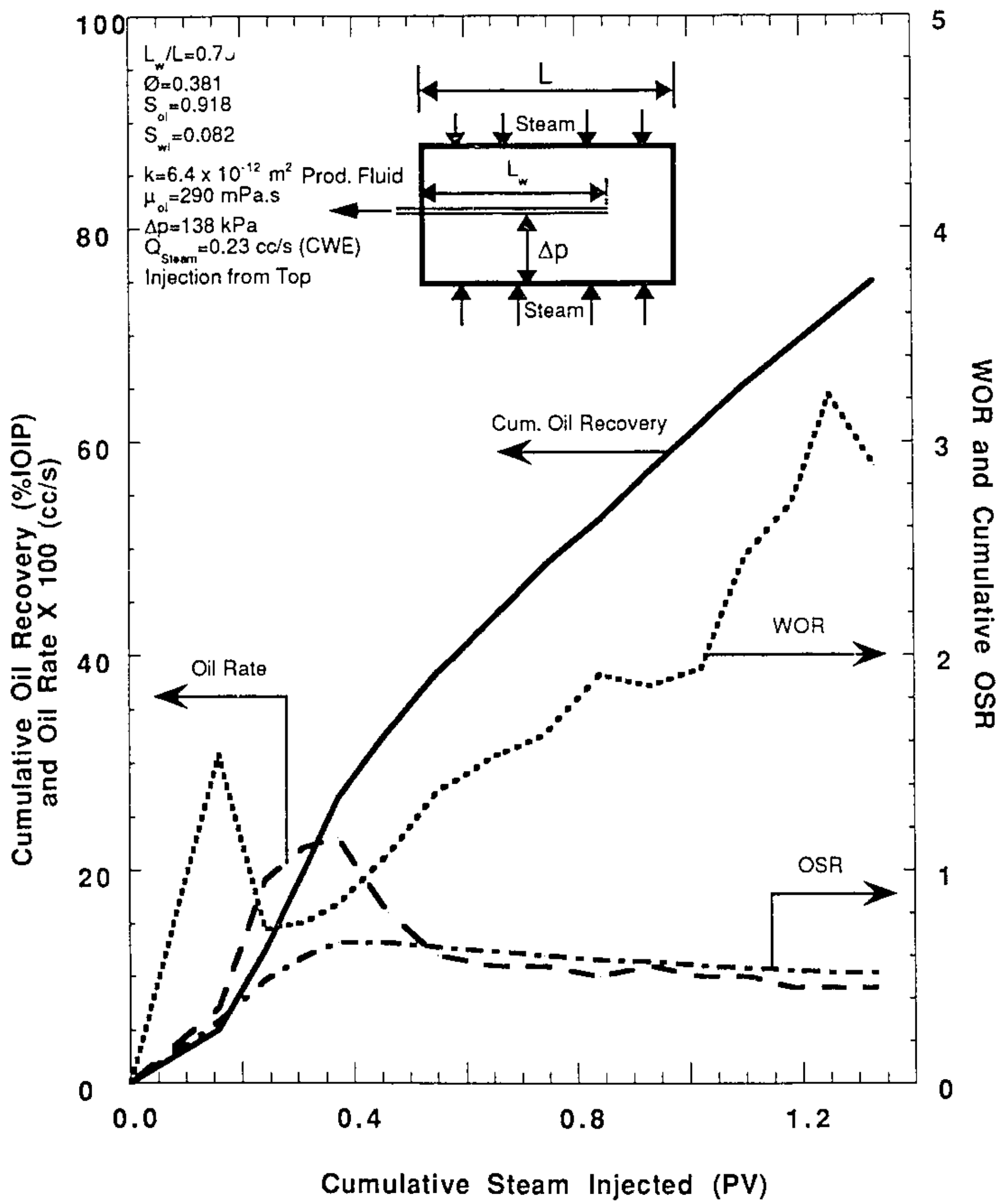


Figure C19 - Production History of Run 19: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected Using a Horizontal Producer 0.25D from the Sand Pack Upper Boundary

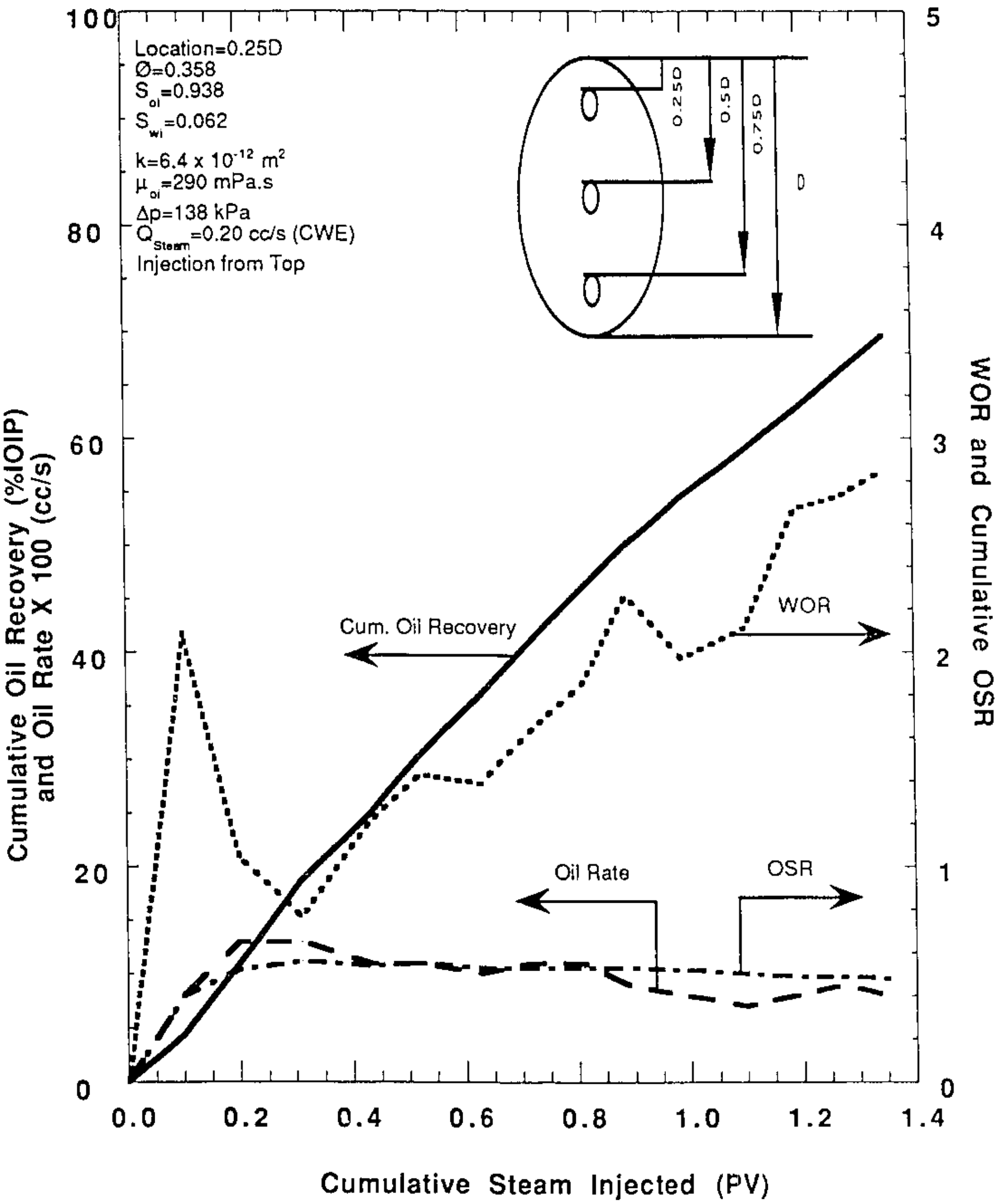


Figure C20 - Production History of Run 20: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected Using a Horizontal Producer 0.75D from the Sand Pack Upper Boundary

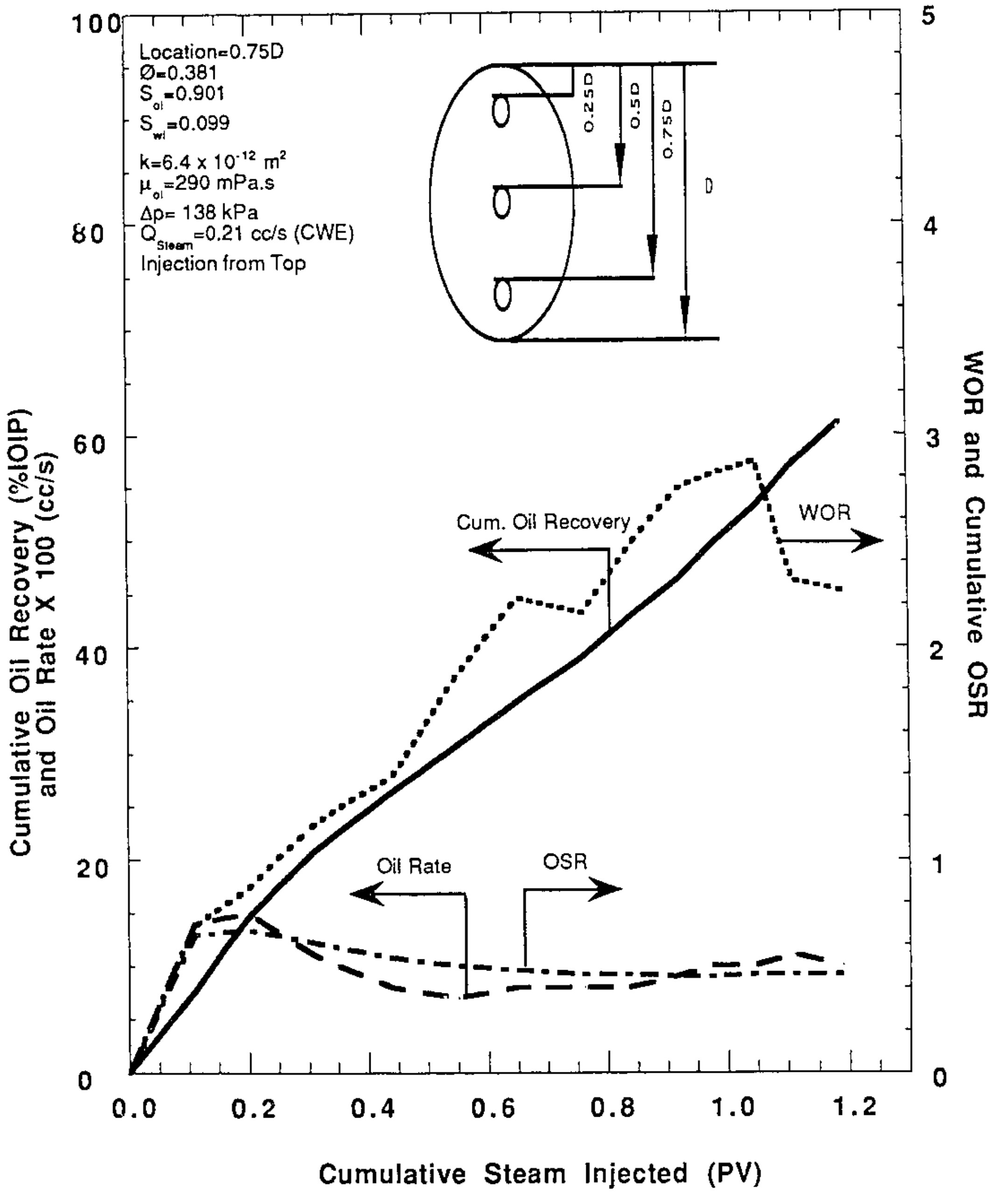


Figure C21 - Production History of Run 21: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected Using a Horizontal Injector Penetrating 100% of the Sand Pack Length

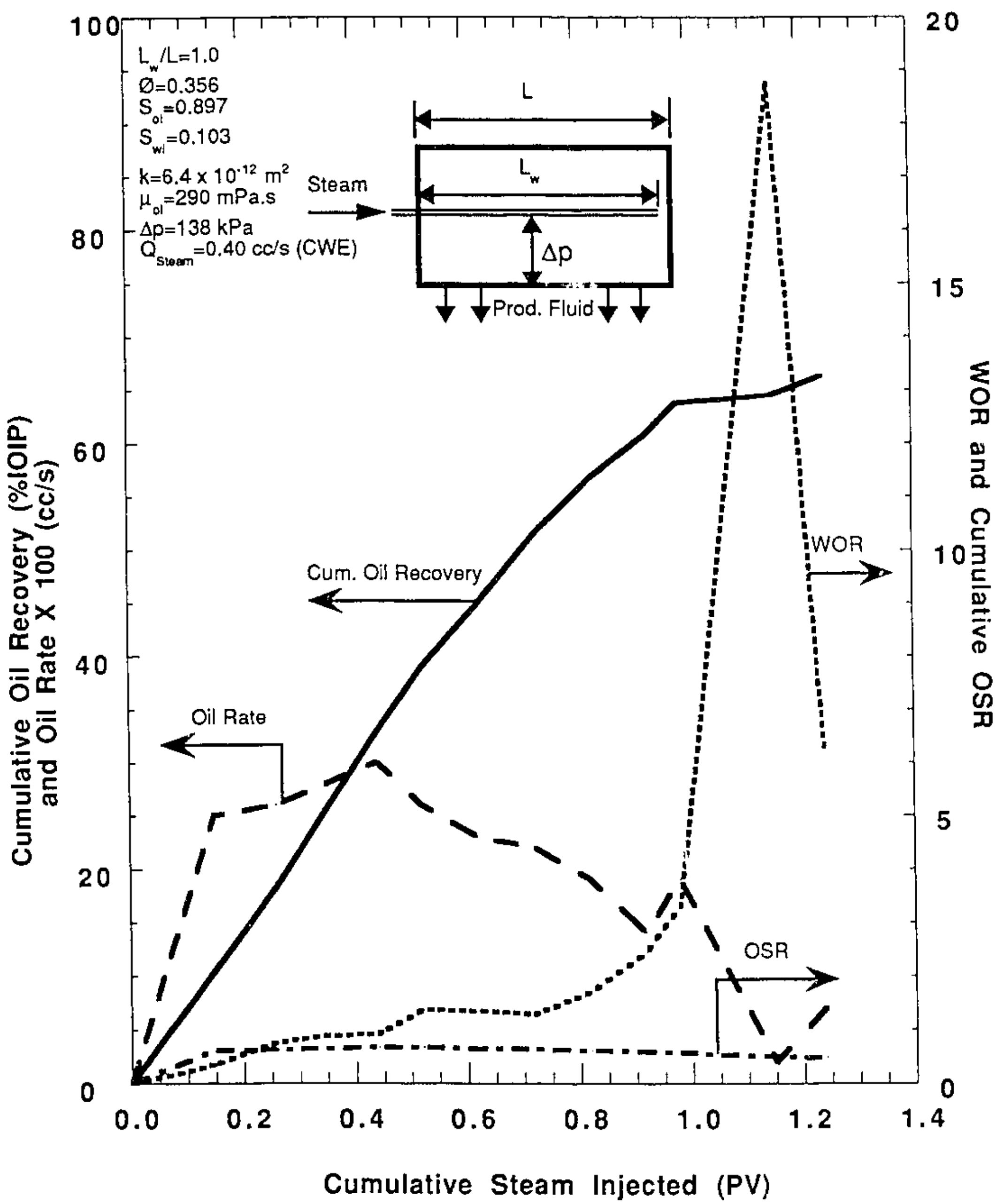


Figure C22 - Production History of Run 22: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected Using a Horizontal Injector Penetrating 25% of the Sand Pack Length

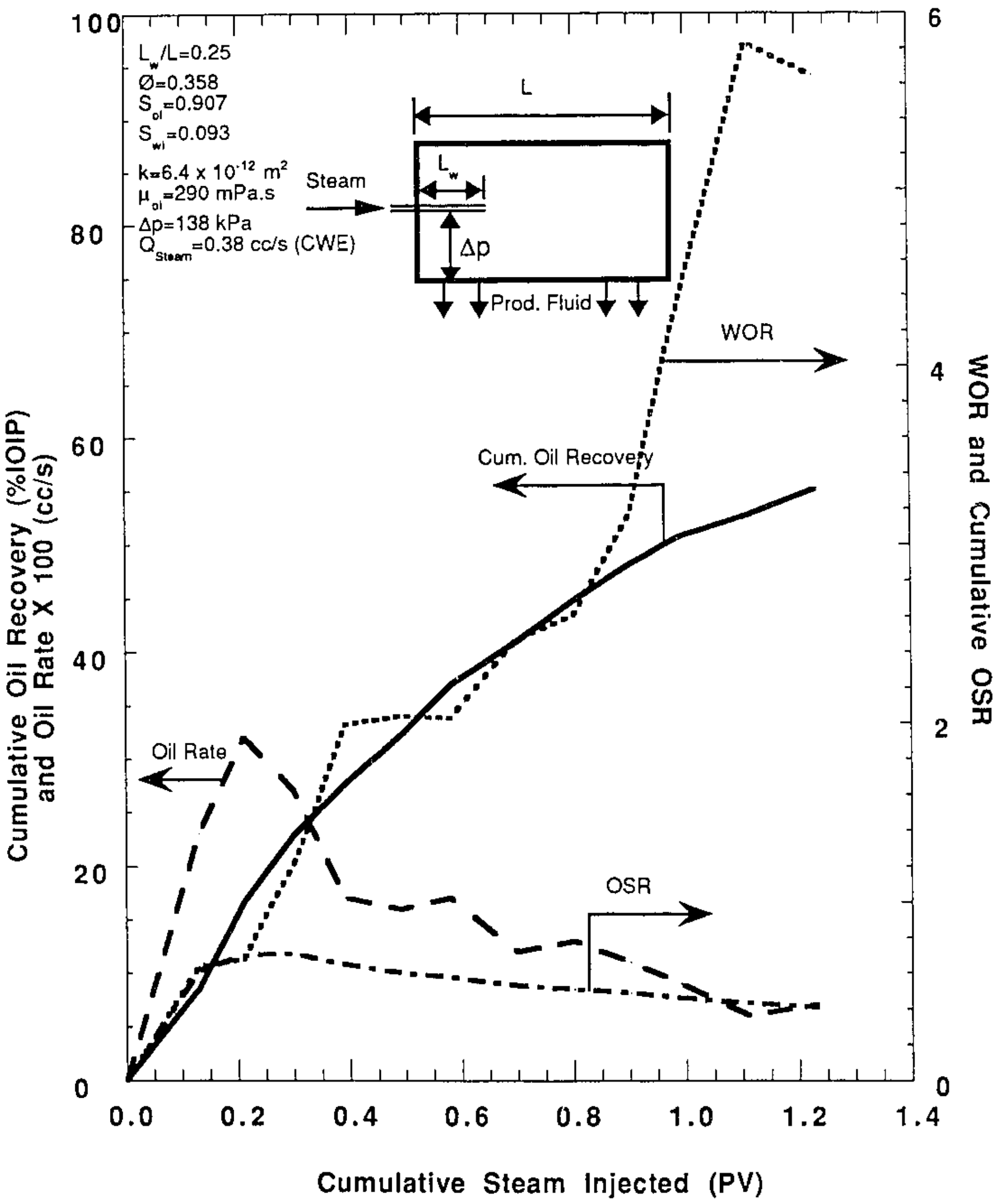


Figure C23 - Production History of Run 23: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected Using a Horizontal Injector Penetrating 50% of the Sand Pack Length

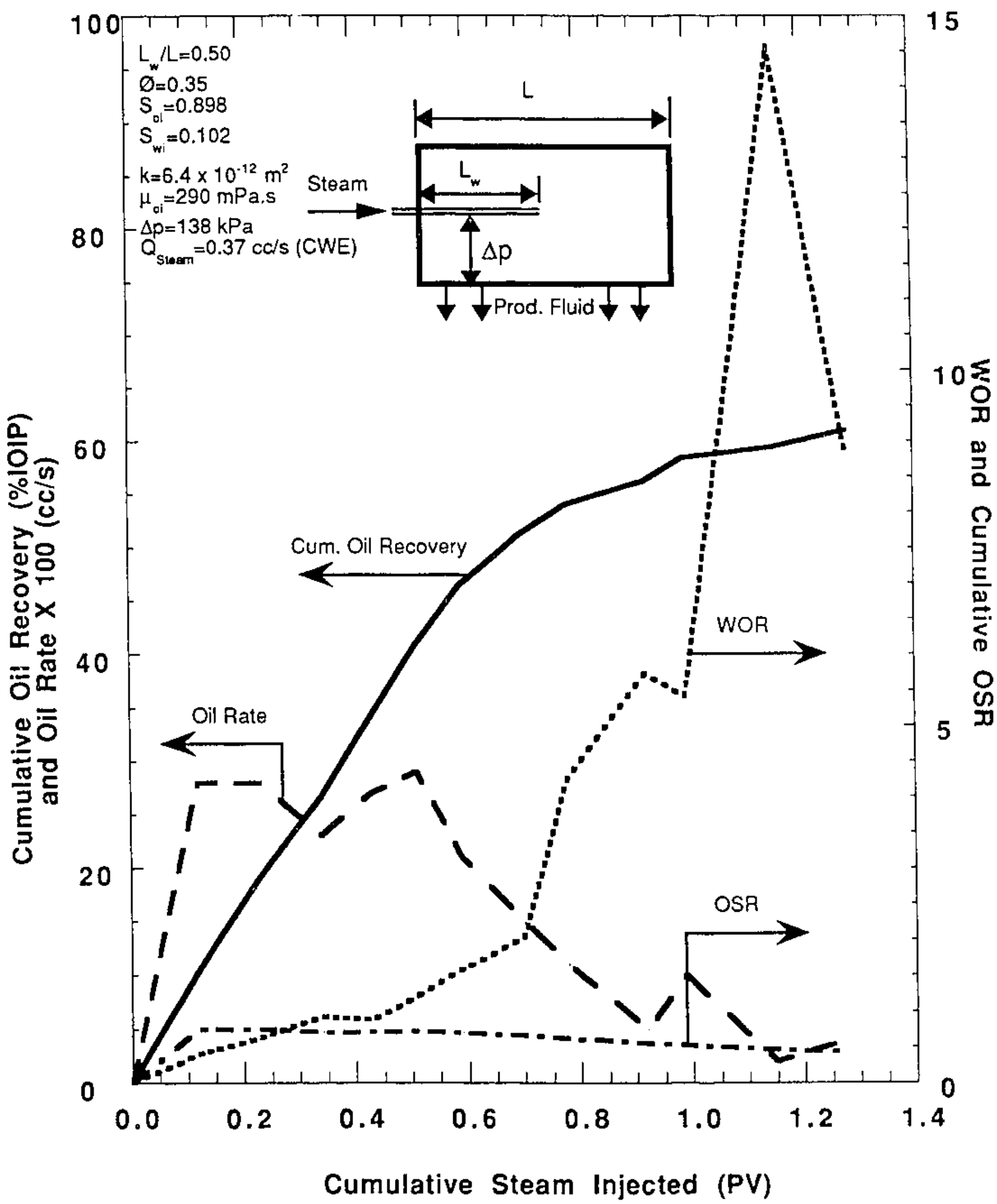


Figure C24 - Production History of Run 24: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected Using a Horizontal Injector 0.25D from the Sand Pack Upper Boundary

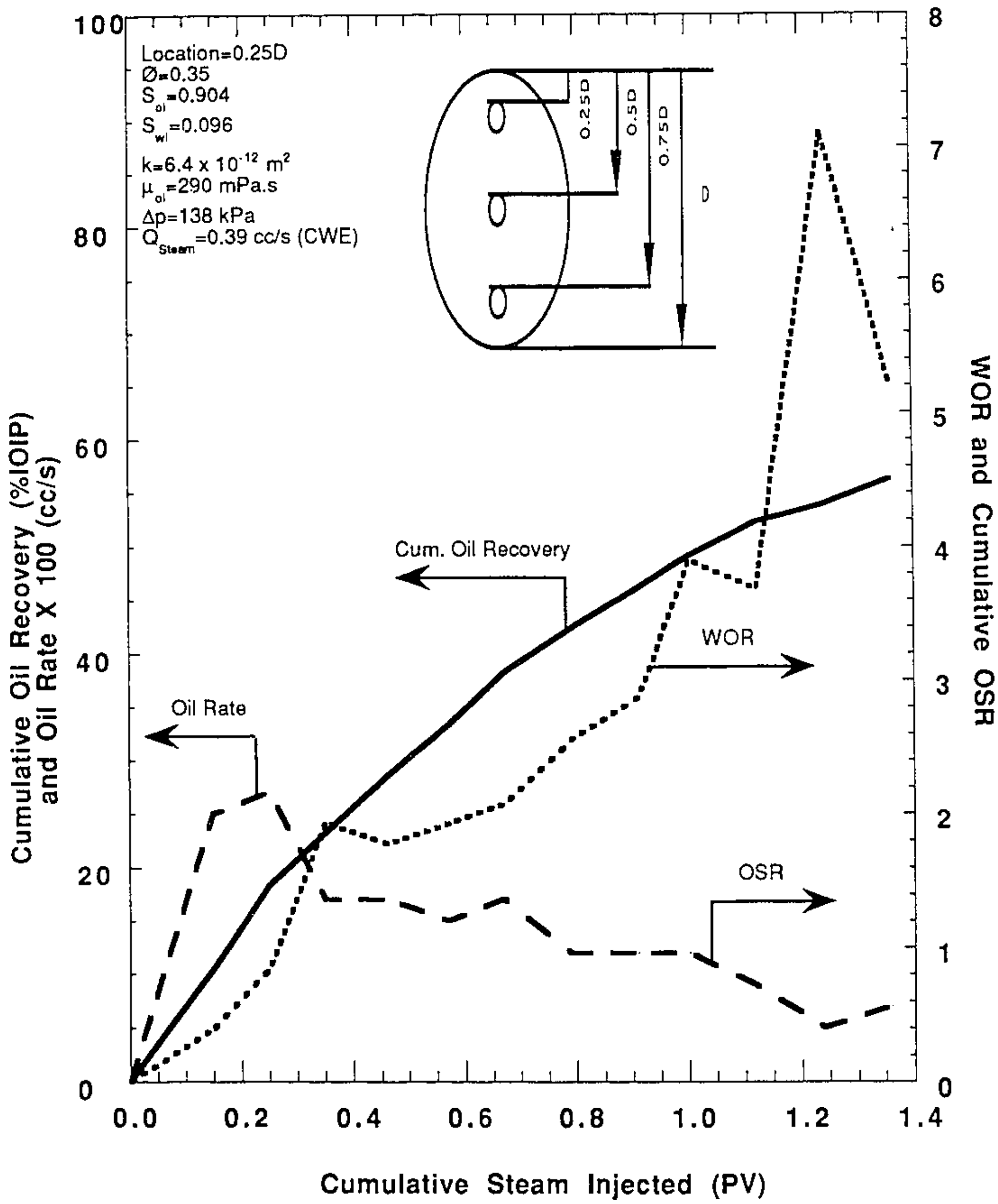


Figure C25 - Production History of Run 25: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected Using a Horizontal Injector 0.75D from the Sand Pack Upper Boundary

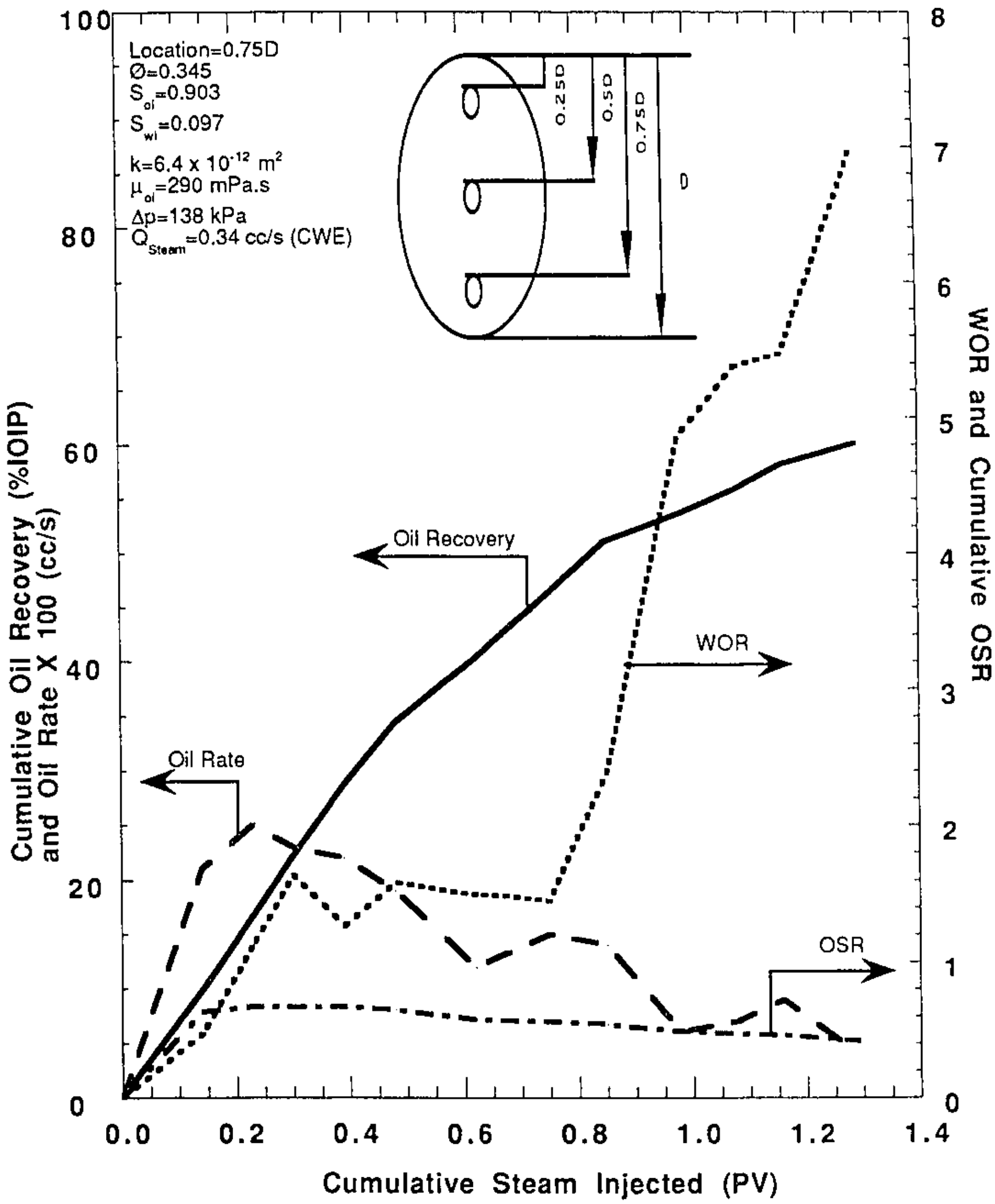


Figure C26 - Production History of Run 26: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected for 207 kPa Pressure Differential Using a Horizontal Injector

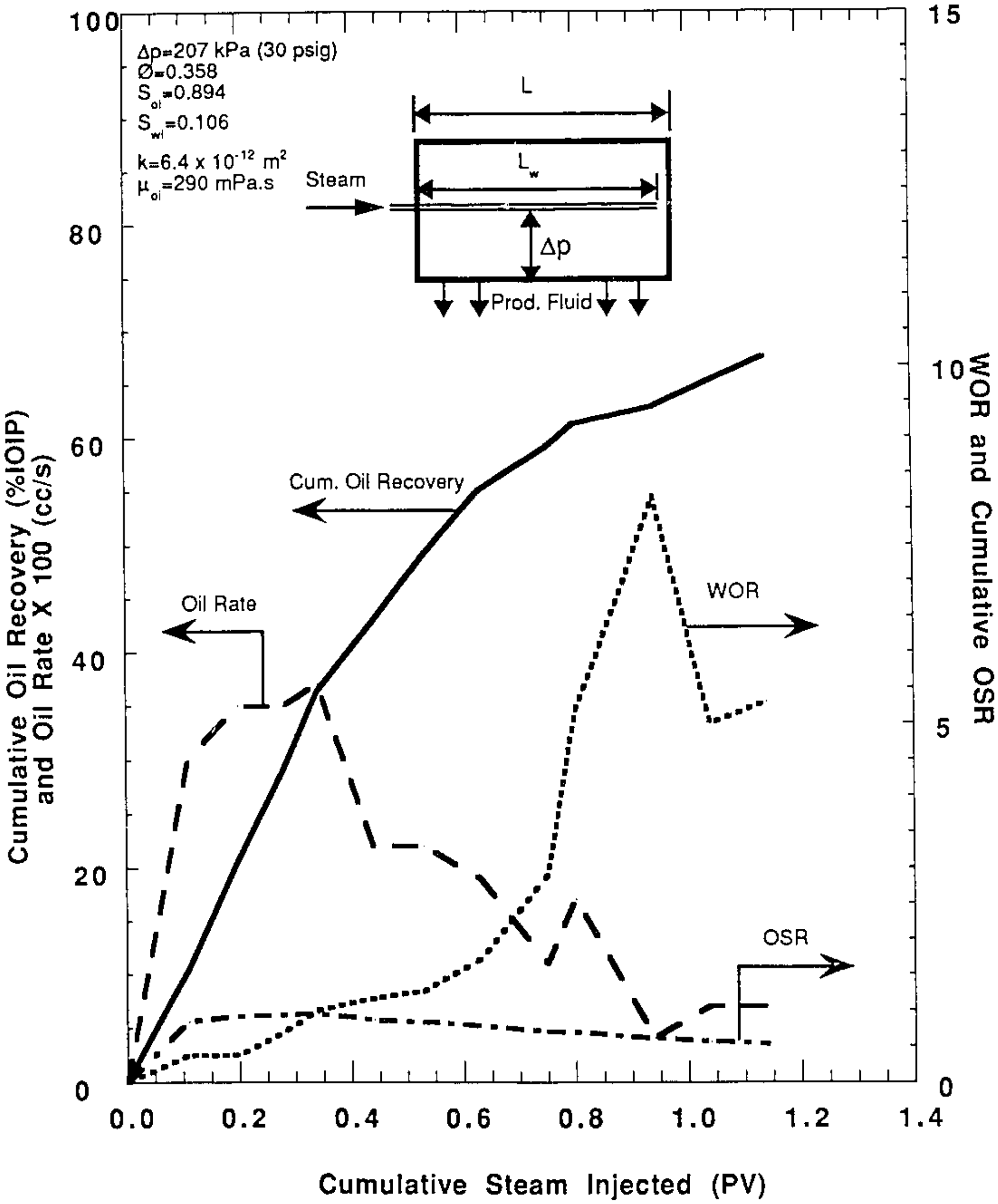


Figure C27 - Production History of Run 27: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected for 69 kPa Pressure Differential Using a Horizontal Injector

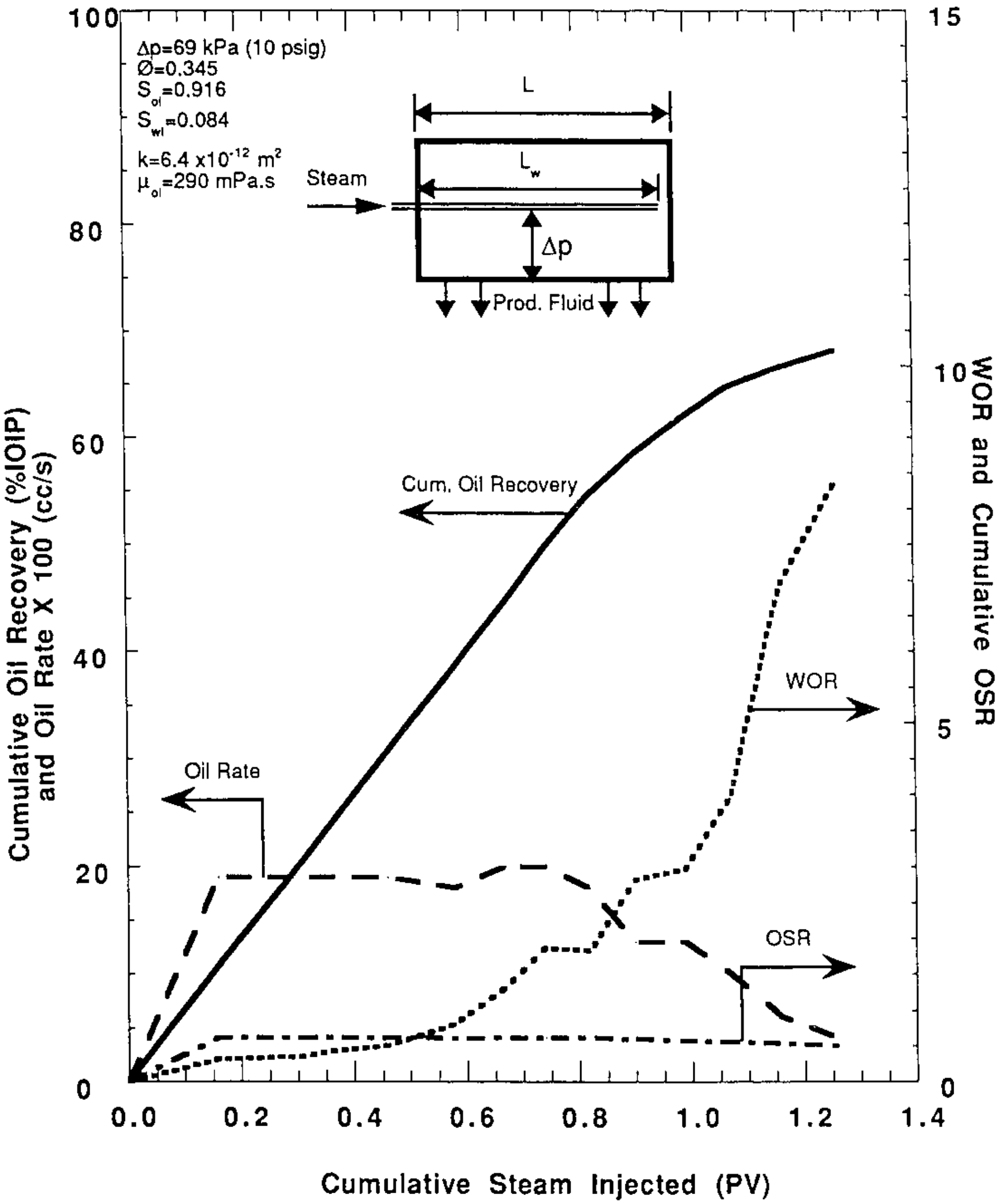


Figure C28 - Production History of Run 28: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected for 276 kPa Pressure Differential Using a Horizontal Injector

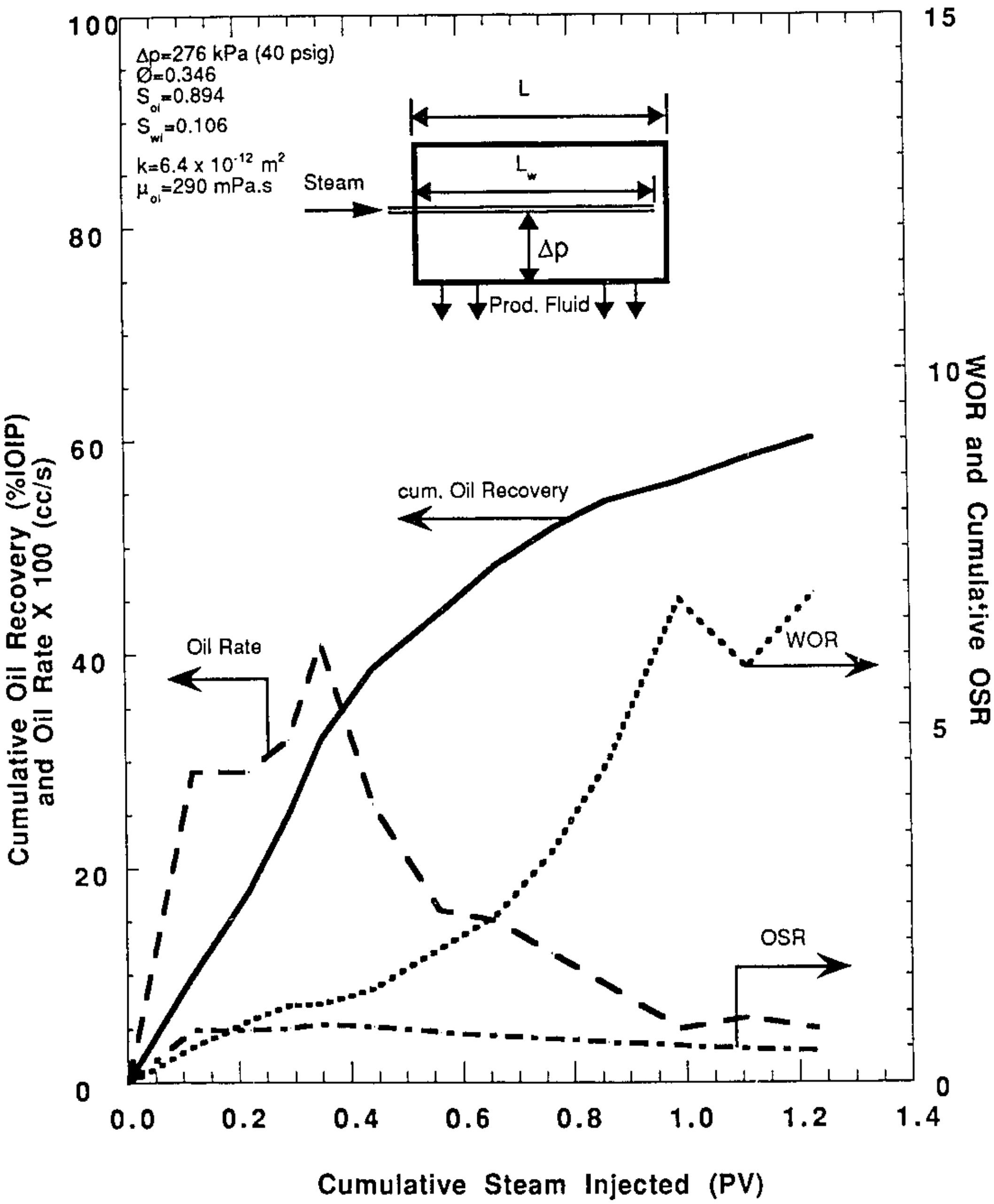


Figure C29 - Production History of Run 29: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected Using 0.64-cm Diameter Horizontal Injector

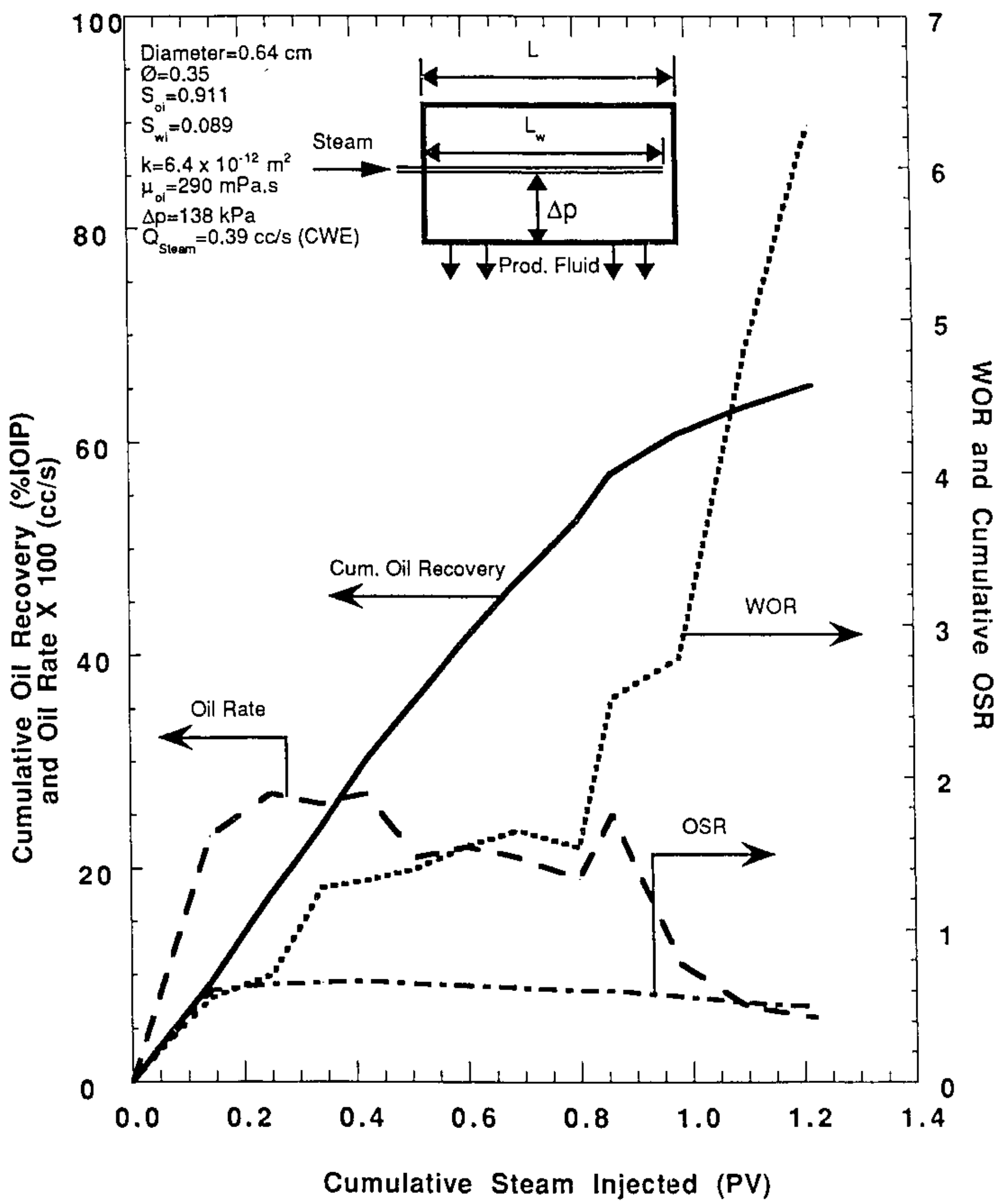


Figure C30 - Production History of Run 30: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected Using 0.95-cm Diameter Horizontal Injector

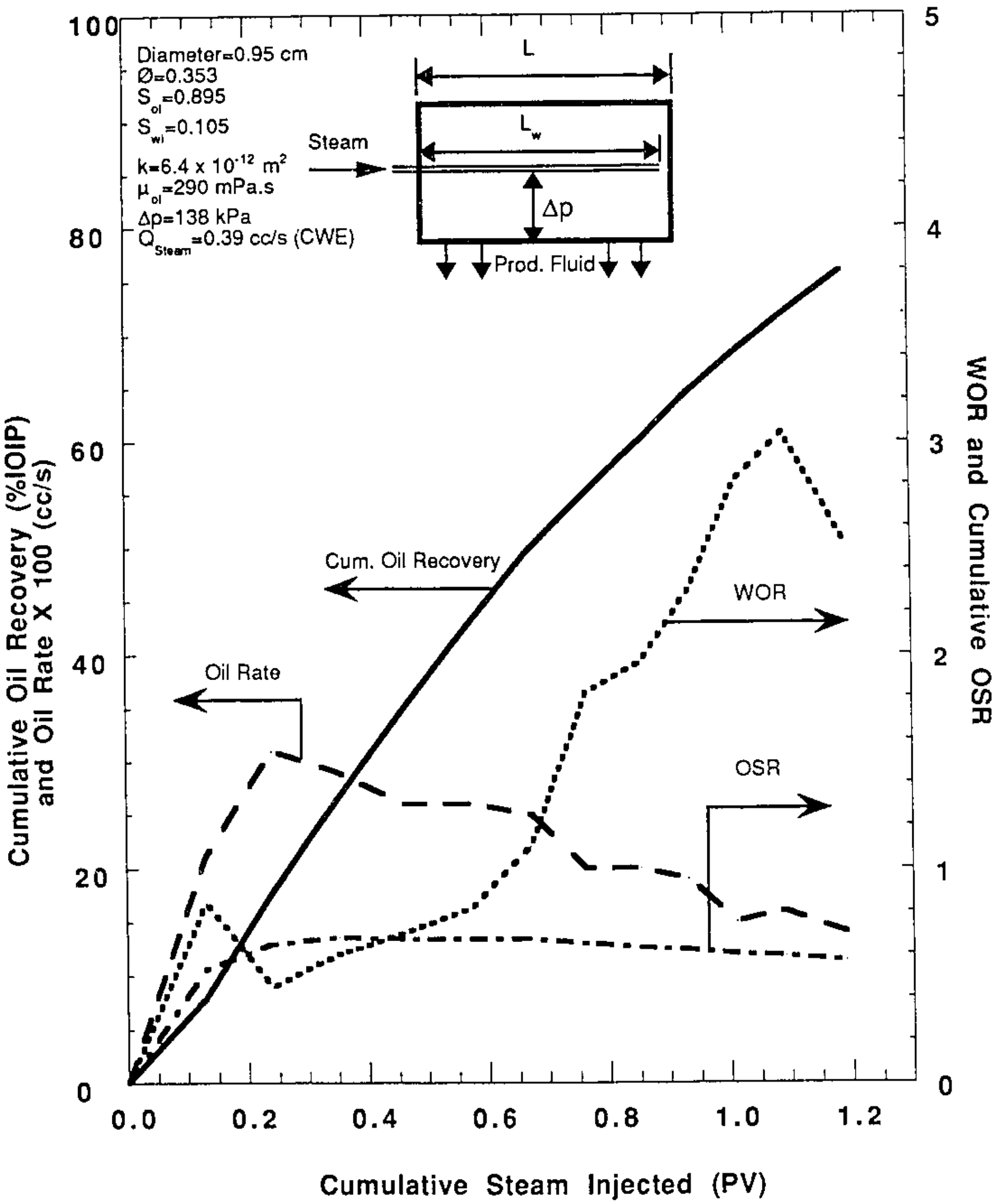


Figure C31 - Production History of Run 31: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected for Oil of Viscosity 1800 mPa.s Using a Horizontal Injector

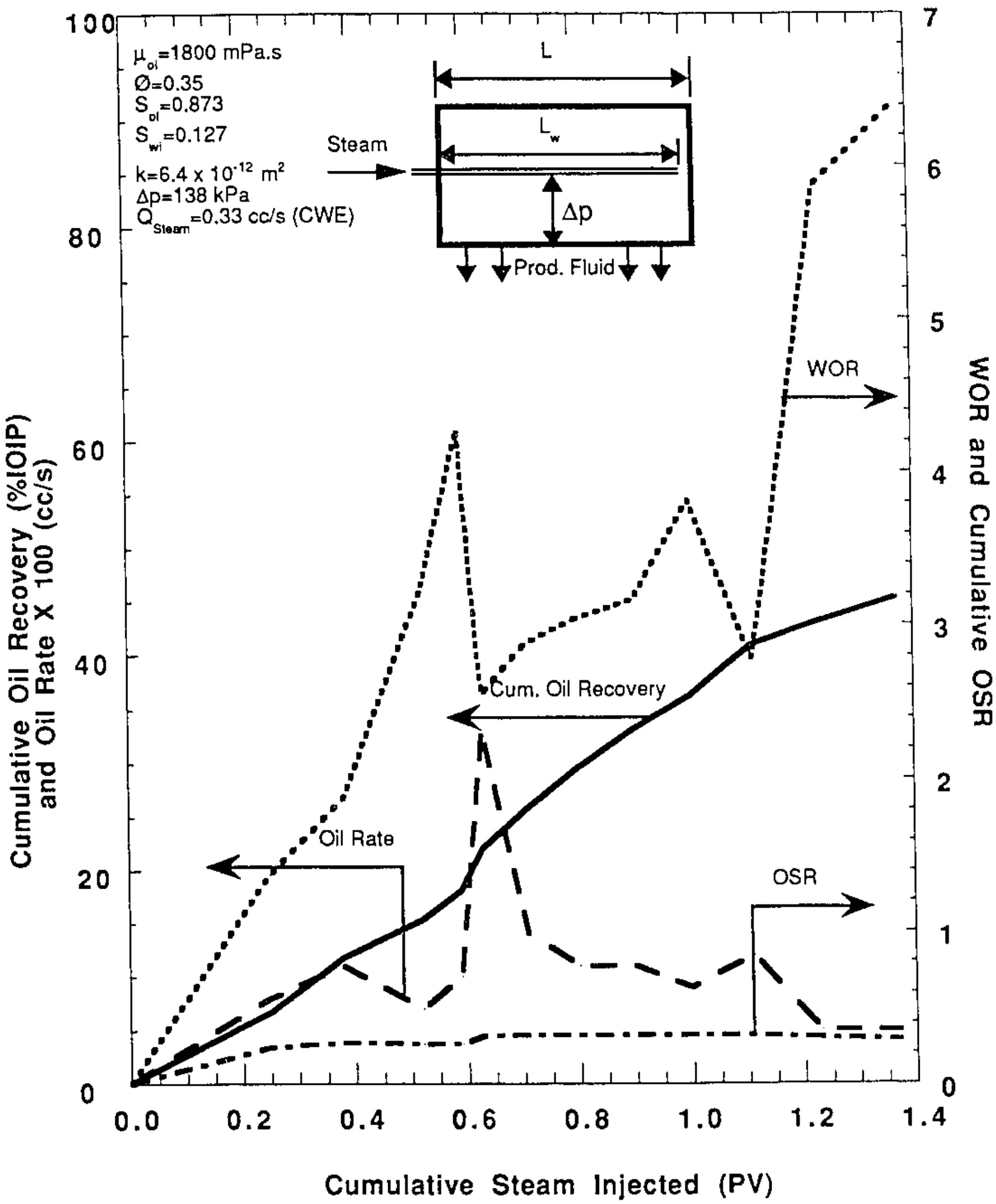


Figure C32 - Production History of Run 32: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected for Oil of Viscosity 975 mPa.s Using a Horizontal Injector

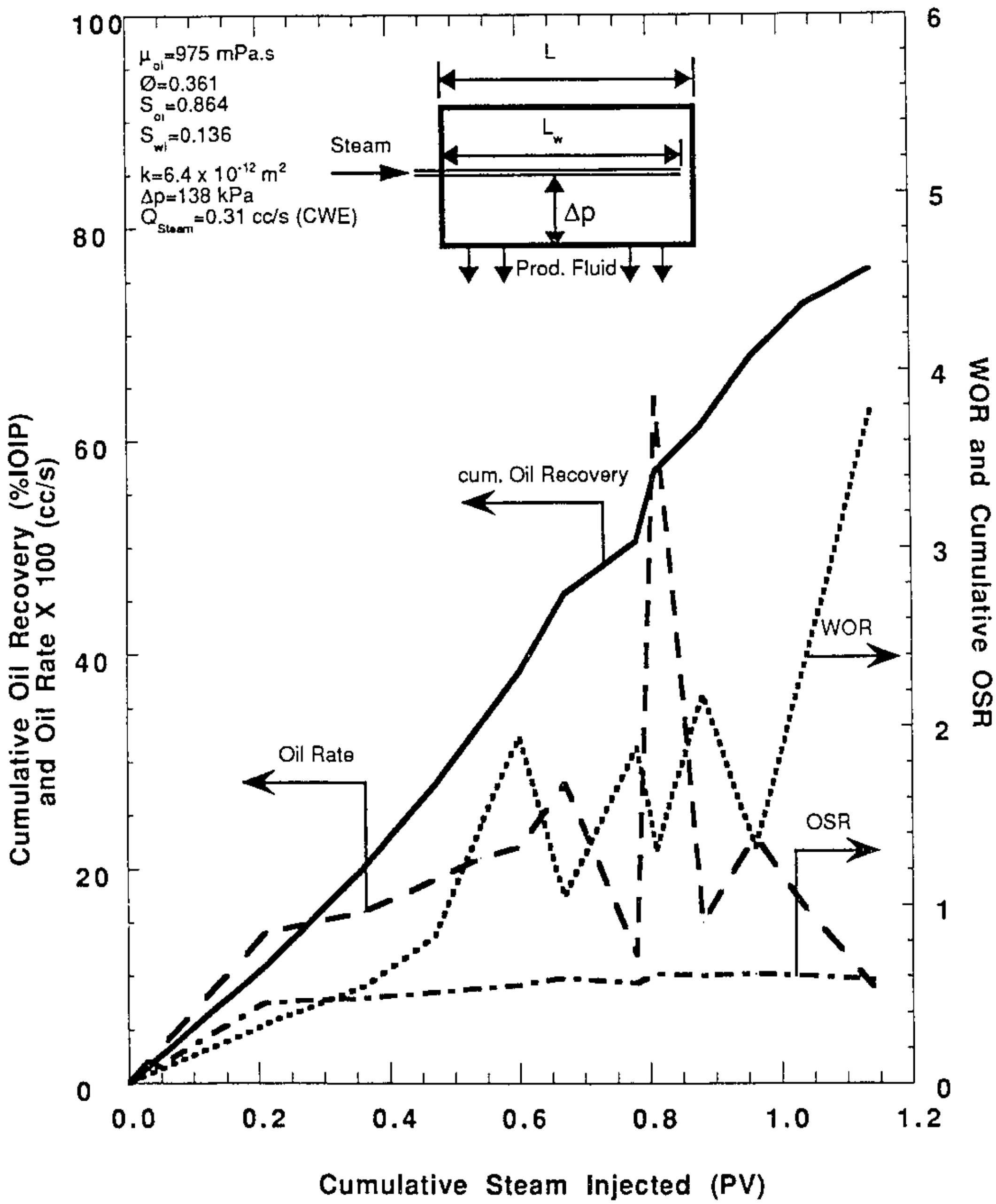


Figure C33 - Production History of Run 33: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected Using 0.64-cm Diameter Horizontal Producer

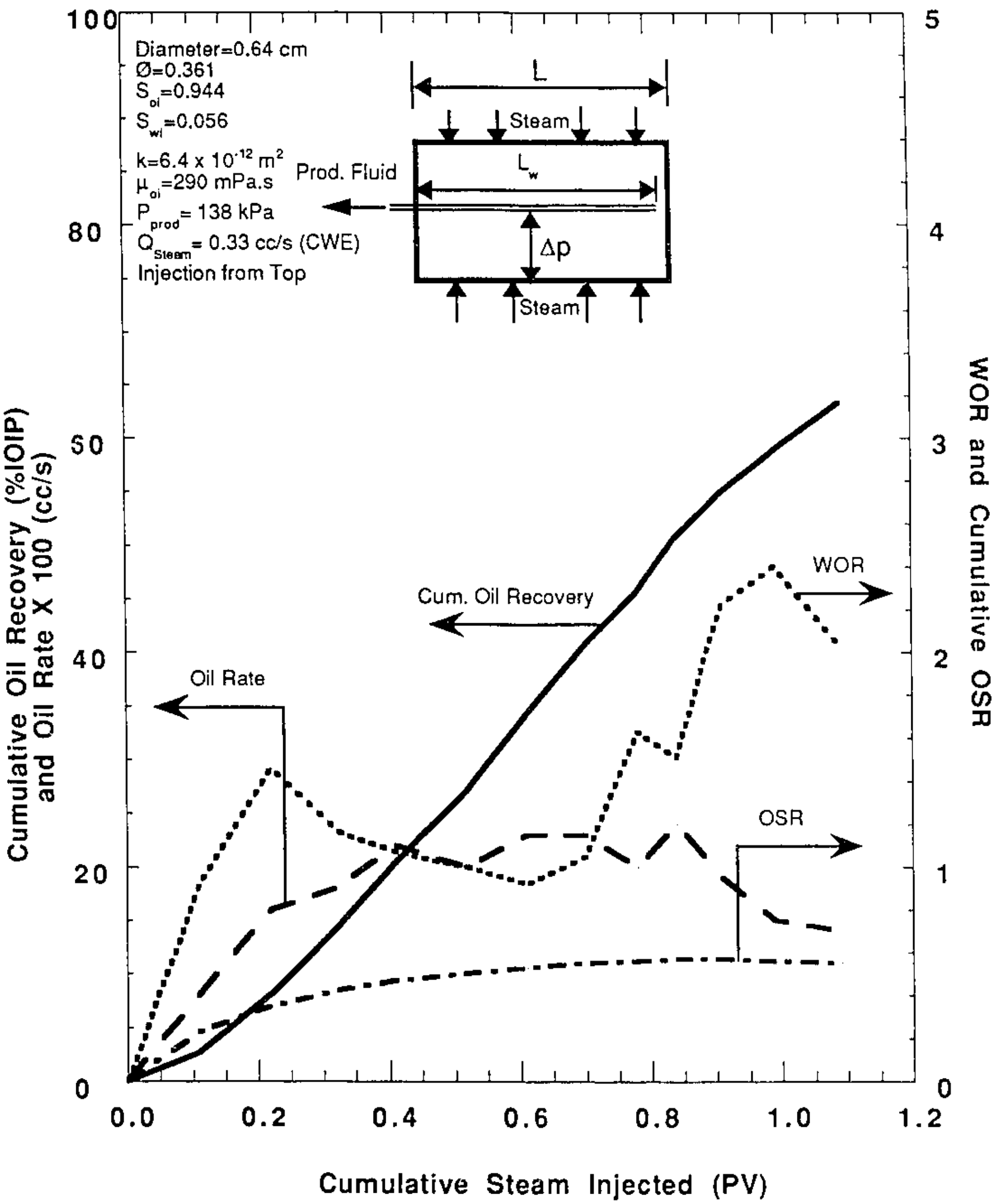


Figure C34 - Production History of Run 34: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected Using 0.95-cm Diameter Horizontal Producer

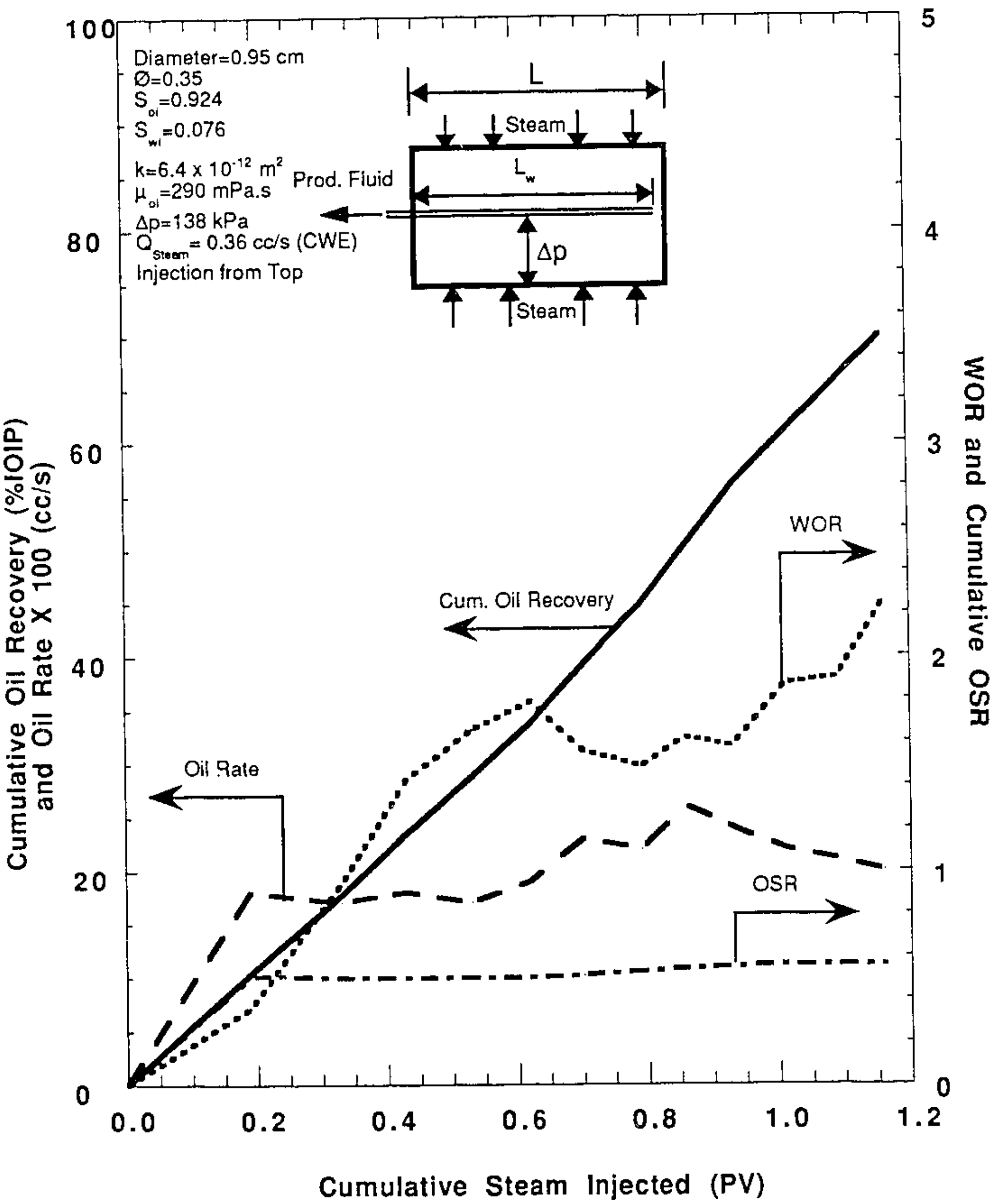


Figure C35 - Production History of Run 35: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected for Oil of Viscosity 975 mPa.s Using a Horizontal Producer

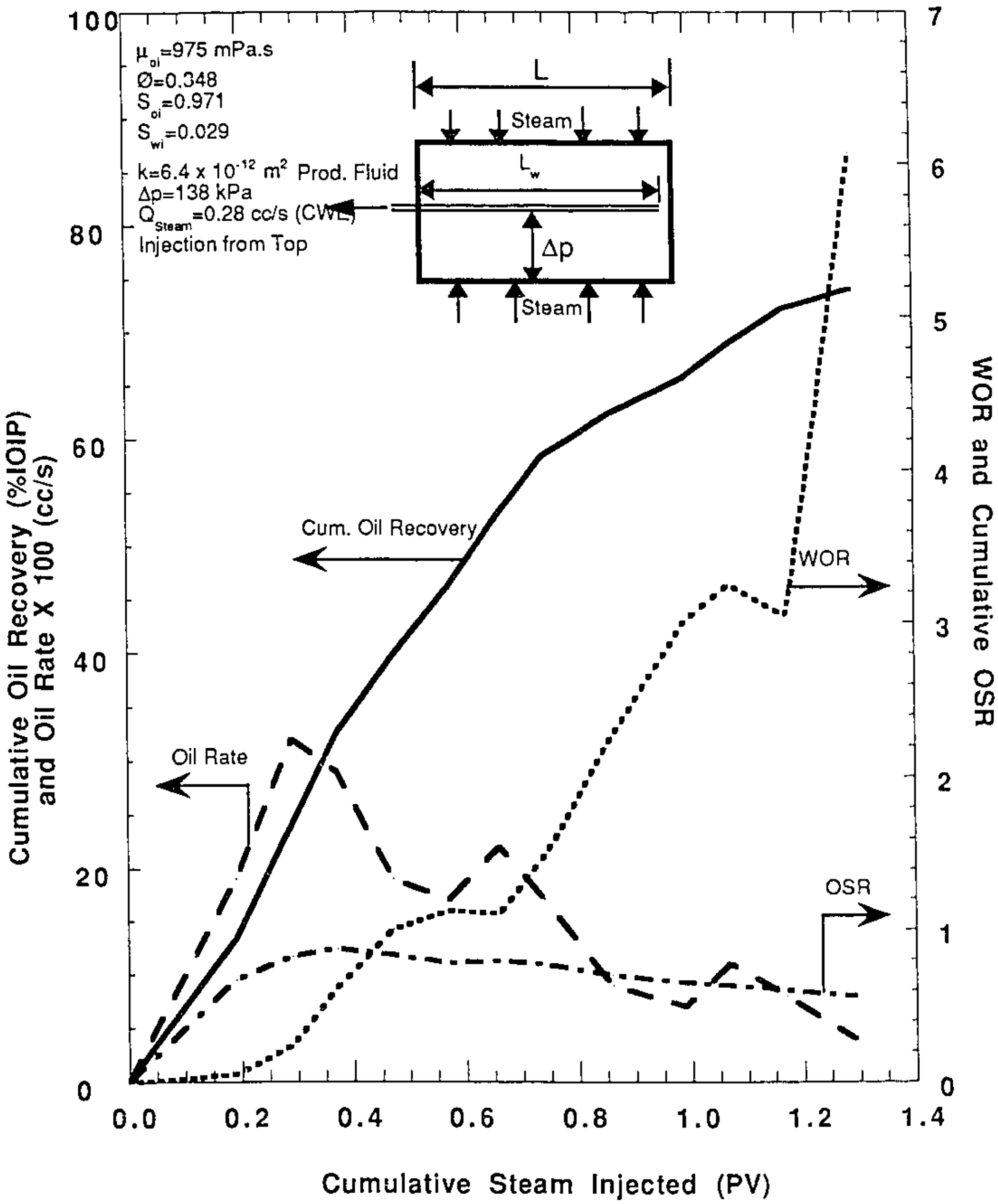
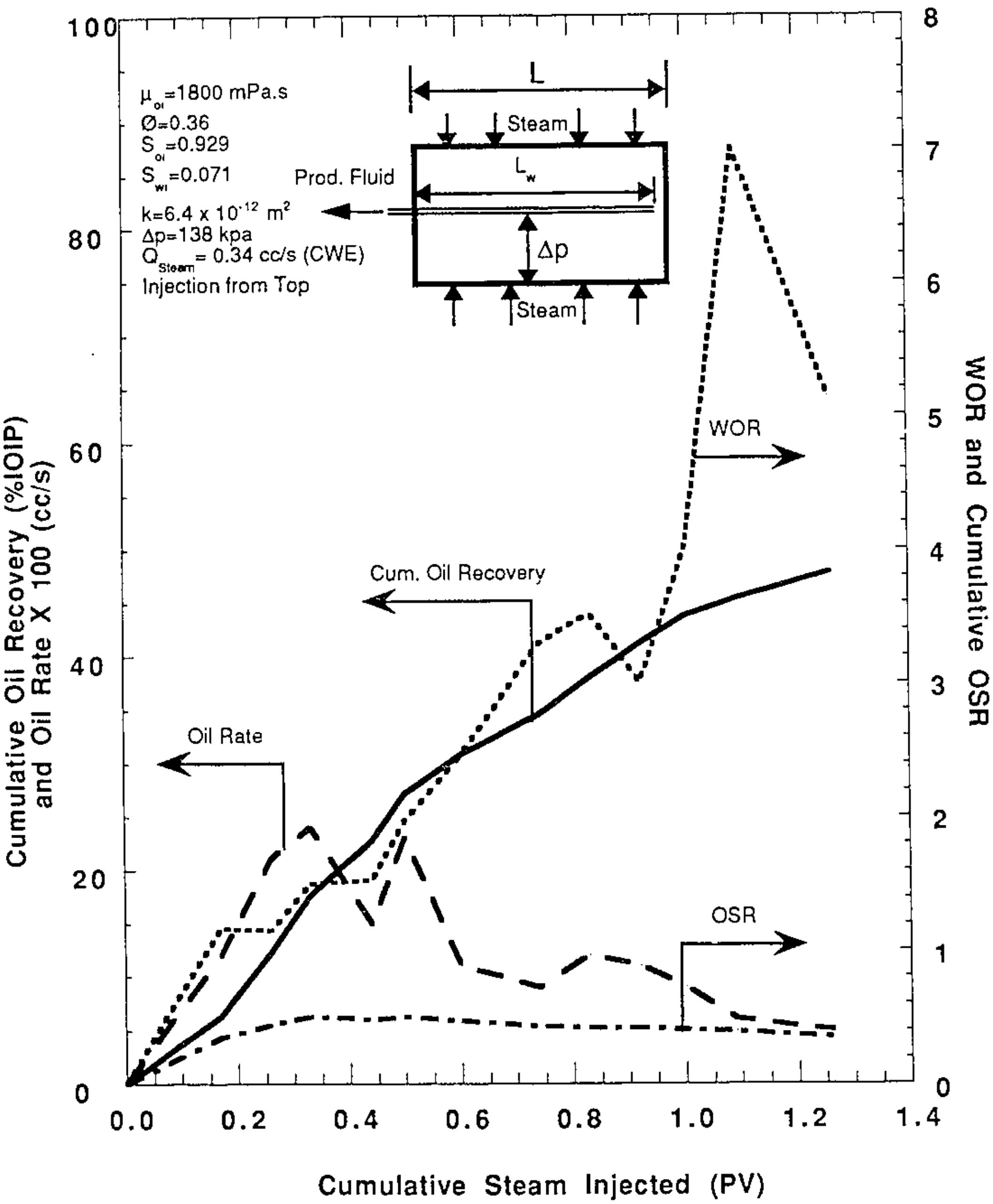


Figure C36 - Production History of Run 36: Cumulative Oil Recovery, Cumulative Oil-Steam Ratio, Water-Oil Ratio and Oil Rate vs. Cumulative Steam Injected for Oil of Viscosity 1800 mPa.s Using a Horizontal Producer



Appendix D: Scaling Parameters and Calculations

The experiments and work outlined in this research are not scaled. However, an existing scaled model was used to carry out the experiments. Some modifications, such as installing new horizontal wells and choosing a suitable geometrical factor, were introduced into the model. This chapter provides information on the original design and purpose for which the model was constructed.

1 Scaling Techniques

1.1 Dimensional and Inspectional Analyses

Laboratory displacement experiments are used widely to investigate, directly or indirectly, the production behaviour of petroleum reservoirs. Such experiments are representative of the reservoir behaviour only if carried out with properly scaled models. The performance of a specific reservoir is governed by the value of a number of variables, which can be mathematically combined and manipulated into different sets of dimensionless groups.

Two general methods, inspectional analysis and dimensional analysis, are available for derivation of dimensionless groups. Inspectional and dimensional analyses[72] are techniques for expressing the behavior of a physical system, in this case petroleum reservoirs, in terms of the minimum number of independent variables, arranged in the form of dimensionless groups, of the physical quantity defining the system. In dimensional analysis, the combination of variables is done using Buckingham's Pi-Theorem. Its successful application requires a complete knowledge of the variables in a particular process. It produces a large number of similarity criteria if many variables are considered.

Inspectional analysis, attributed to Stokes,[73] is applied to the differential equations defining the physical process involved. However, in inspectional analysis, the derivation of dimensionless groups is accomplished by normalizing the differential equations, i.e. making the independent variables dimensionless and carrying out a judicious inspectional analysis of the variables. This leads to a dimensionless differential equation, with the variables appearing as groups, which can be identified with, or modified to be identified with, well-known dimensionless groups.

A characteristic feature of this method is the existence of a mathematically expressible concept of the phenomenon. This entails introduction of any approximation to enhance and stabilize the analytical or numerical solution to the equation if one is sought. Moreover, dimensionless groups derived by inspectional analysis have a more apparent meaning than that of the groups derived by dimensional analysis. Inspectional analysis is a desirable procedure for obtaining scaling groups for constructing a physical model or a mathematical expression for an analytical or numerical model. Details of this procedure are given in Reference 74.

2 Scaling Procedures

Scaled models of the steam process have contributed significantly to the design and implementation of field projects. Scaling groups used to scale petroleum reservoirs are derived from the equations describing flow phenomena in porous media using dimensional or inspectional analysis. Equations describing flow phenomena in porous media can be classified as follows: those describing conservation of mass, momentum and heat; those describing properties of the components, such as density (equation of state) and viscosity; and those describing the mutual interaction of the components, such as diffusion of two miscible liquids into each other, capillary phenomena at the interface between phases and relative permeabilities. Furthermore, some similarity states such as geometrical, kinematics, dynamic, thermal and chemical similarity may have to be satisfied by models to simulate a petroleum reservoir process.

2.1 Physical Model

The first step in modeling the steam process is the development of scaling groups or scaling criteria. The scaling groups for the physical model, horizontal wells, steam drive process, and steam assisted gravity process presented in this work were obtained by putting the governing equations into dimensionless form, determining similarity parameters by inspectional analysis, and then combining and modifying these similarity parameters using engineering judgment to obtain a set of scaling groups which can generally be matched between the scaled model and the field prototype. Flow processes simulated in this work did not account for dispersion and diffusion of steam-additives in the oil, water or vapour.

Additional assumptions were needed to simplify the complex nature of the steam process, including that the porous medium was homogenous and isotropic; rock compressibility and thermal expansion were negligible; mass transfer took place solely due to convection; water condensed out of or vaporized into the steam; the system was always in local thermodynamic equilibrium; kinetic, potential and viscous energies were negligible compared to thermal energy; and dispersive and diffusive heat losses were small compared to conductive heat flux. In addition, Darcy and Fourier's laws were assumed to be valid, that the fluids under consideration behaved according to Newton's model for a viscous fluid and their properties were functions of pressure, temperature and concentration. Scaling groups for flow in the reservoir are given in Table D1. These scaling groups were used to construct a physical model in an effort to simulate steam processes in the prototype field whose properties are given in Table D2.

Table D1: Physical Meaning of the Scaling Criteria for Flow in the Reservoir (after Doan, 1991)[63]

ϕ_R	Porosity factor
$\frac{H}{2L}$	Geometrical factor
$\frac{\rho_{oR}\sin\theta_R H g_R}{2p_{oR}}$	Ratio of gravitational forces to pressure drawdown
$\frac{q_{oR}^{sc} H^2 \mu_{oR}}{4\rho_{oR} k k_{roR} p_{oR}}$	Ratio of viscous force to pressure drawdown
$\frac{\rho_{wR}}{\rho_{oR}}$	Ratio of aqueous and oleic phase densities
$\frac{\rho_{gR}}{\rho_{oR}}$	Ratio of vapour and oleic phase densities
$\frac{p_{oR}}{p_{wR}}$	Ratio of oleic and aqueous phase pressures
$\frac{p_{oR}}{p_{gR}}$	Ratio of oleic and vapour phase pressures
$\frac{S_{gR}}{S_{oR}}$	Ratio of vapour and oleic phase saturation

Table D1- Continued

$\frac{C_{gaR}^{sc} q_{gR}^{sc}}{C_{oaR}^{sc} q_{oR}^{sc}}$	Ratio of produced steam-additive in vapour and oleic phases
$\frac{k_{rhR} T_R \mu_{oR}}{\rho_{oR} k k_{roR} h_{oR} p_{oR}}$	Ratio of conductive heat to oleic phase convective heat
$\frac{\phi_R S_{oR} H^2 \mu_{oR}}{4 k k_{roR} p_{oR} t_R}$	Time scale factor
$\frac{h_{wR}}{h_{oR}}$	Ratio of aqueous and oleic phase enthalpies
$\frac{h_{gR}}{h_{oR}}$	Ratio of vapour and oleic phase enthalpies
$\frac{q_{hR}^{sc}}{q_{oR}^{sc} h_{oR}}$	Ratio of rate of heat injected/produced to oleic phase enthalpy
$\frac{q_{hR}^{sc}}{q_{lR}^{sc}}$	Ratio of rate of heat injected/produced to rate of heat loss
$\frac{\rho_{rR} U_{rR}}{\rho_{oR} h_{oR}}$	Ratio of reservoir rock energy to oleic phase enthalpy
$\frac{U_{oR}}{h_{oR}}$	Ratio of aqueous phase internal energy and its enthalpy
$\frac{U_{wR}}{h_{oR}}$	Ratio of aqueous phase internal energy to oleic phase enthalpy
$\frac{U_{gR}}{h_{oR}}$	Ratio of vapour phase internal energy to oleic phase enthalpy
$\frac{p_{cgoR}}{p_{oR}}$	Ratio of gas-oil capillary pressure to oleic phase pressure
$\frac{p_{cowR}}{p_{oR}}$	Ratio of water-oil capillary pressure to oleic phase pressure
$\frac{S_{oiR}}{S_{oR}}$	Ratio of initial and instantaneous oleic phase saturation

Table D1- Continued

$\frac{T_{iR}}{T_R}$	Ratio of initial and instantaneous temperatures
$\frac{p_{oiR}}{p_{oR}}$	Ratio of initial and instantaneous oleic phase pressures
$\frac{p_{oR} k k_{roR}}{\phi_R S_{oR} \mu_{oR} \alpha_{obR}}$	Ratio of oleic phase produced and thermal diffusion to overburden
$\frac{q_{lR}^{sc} H^2}{4 k_{hobR} T_{obR}}$	Ratio of heat loss and overburden thermal capacity
$\frac{q_{oR}^{sc}}{q_{wR}^{sc}}$	Ratio of oleic and vapour phase production rates
$\frac{A_R^{sc} k_{hobR} T_{obR}}{V_{bR} L q_{lR}^{sc}}$	Ratio of overburden thermal conductivity to heat loss rate
$\frac{h_{winjR}^{sc} q_{winjR}^{sc}}{q_{hinjR}^{sc}}$	Ratio of production aqueous phase enthalpy to heat injected
$\frac{h_{sinjR}^{sc}}{h_{winjR}^{sc}}$	Ratio of injected steam-additive enthalpy to injected aqueous enthalpy
$\frac{q_{oprodR}^{sc}}{C_{gwprodR}^{sc} q_{gprodR}^{sc}}$	Ratio of produced oleic phase and produced steam-additive in vapour
$\frac{k_{roR} \mu_{wR}}{k_{rwR} \mu_{oR}}$	Mobility ratio between oleic and aqueous phases
$\frac{k_{roR} \mu_{gR}}{k_{rgR} \mu_{oR}}$	Mobility ratio between oleic and vapour phases
$\frac{k_{rwR} \mu_{gR}}{k_{rgR} \mu_{wR}}$	Mobility ratio between aqueous and vapour phases
$\frac{W_{gwR} h_{gwinjR}}{W_{wR} h_{winjR}}$	Ratio of injected water enthalpy to injected aqueous enthalpy
$\frac{W_{wR} \mu_{wR}}{\rho_{wR} k k_{rwR} H p_{wR}}$	Ratio of aqueous injection rate to reservoir storage capacity

Table D2: Prototype Reservoir Data (after Doan, 1991)[63]

Pattern spacing	5.0 ha
Pattern type	Isolated
Pay thickness	18 m
Porosity	0.325
Permeability	3.95×10^{-12} m^2 (4.0 darcies)
Initial reservoir temperature	19 °C
Initial reservoir pressure	4.2 MPa
Steam injection pressure	7.0 MPa
Steam injection rate	200 m^3/d
Steam quality @ sand face (assumed)	1.0
Oil viscosity @ 19 °C	4400 mPa.s
API gravity @ 19 °C	13 °API
Wells	
Two vertical steam injectors	
One horizontal producer	
Length	404 m
Diameter	17.78 cm
Completion	Slotted Liner

An element of symmetry was selected to represent the prototype reservoir shown in Figure D1. Using a geometrical factor a of 430 and the smallest elemental length of 202 m, the horizontal well length was determined to be 47 cm.

a = Length of element of symmetry/Length of the model

The sand pack length was chosen to be 48.3 cm long to account for the prototype end effect. Furthermore, the total length of the model was selected to be 61 cm to make room for the end caps to seal off the model. Since the prototype was rectangular in shape, to produce a linear and cylindrically shaped model, the prototype and the model bulk volumes were used to calculate the diameter of the model.

$$a^3 = \frac{V_{bF}}{V_{bM}}$$

or

$$V_{bM} = \frac{(202 \text{ m} \times 124 \text{ m} \times 18 \text{ m})}{430^3} = 0.00567 \text{ m}^3$$

Gives

$$r_{wM} = \left[\frac{V_{bM}}{\pi L_M}\right]^{0.5} = \left[\frac{0.00567}{\pi \times 0.61}\right]^{0.5} = 5.4 \text{ cm}$$

where V_{bF} and V_{bM} are the field and model pore volume, respectively.

Thus, the linear, high pressure physical model is a cylinder with a diameter of 10.2 cm (4 in) and a total length of 61 cm (24 in). The reason that a 10.2-cm (4-in) instead of a 10.8-cm (4.3-in) diameter model size was used is that pipes come in standard sizes. For the purpose of radial steam injection, the inside wall of the cylinder was lined with a rolled sheet of sintered metal to act as a distributing boundary for the injected steam.

2.2 Horizontal Wells

It was assumed that incompressible and immiscible heated bitumen and condensate are the only fluids flowing inside the horizontal well. To further simplify

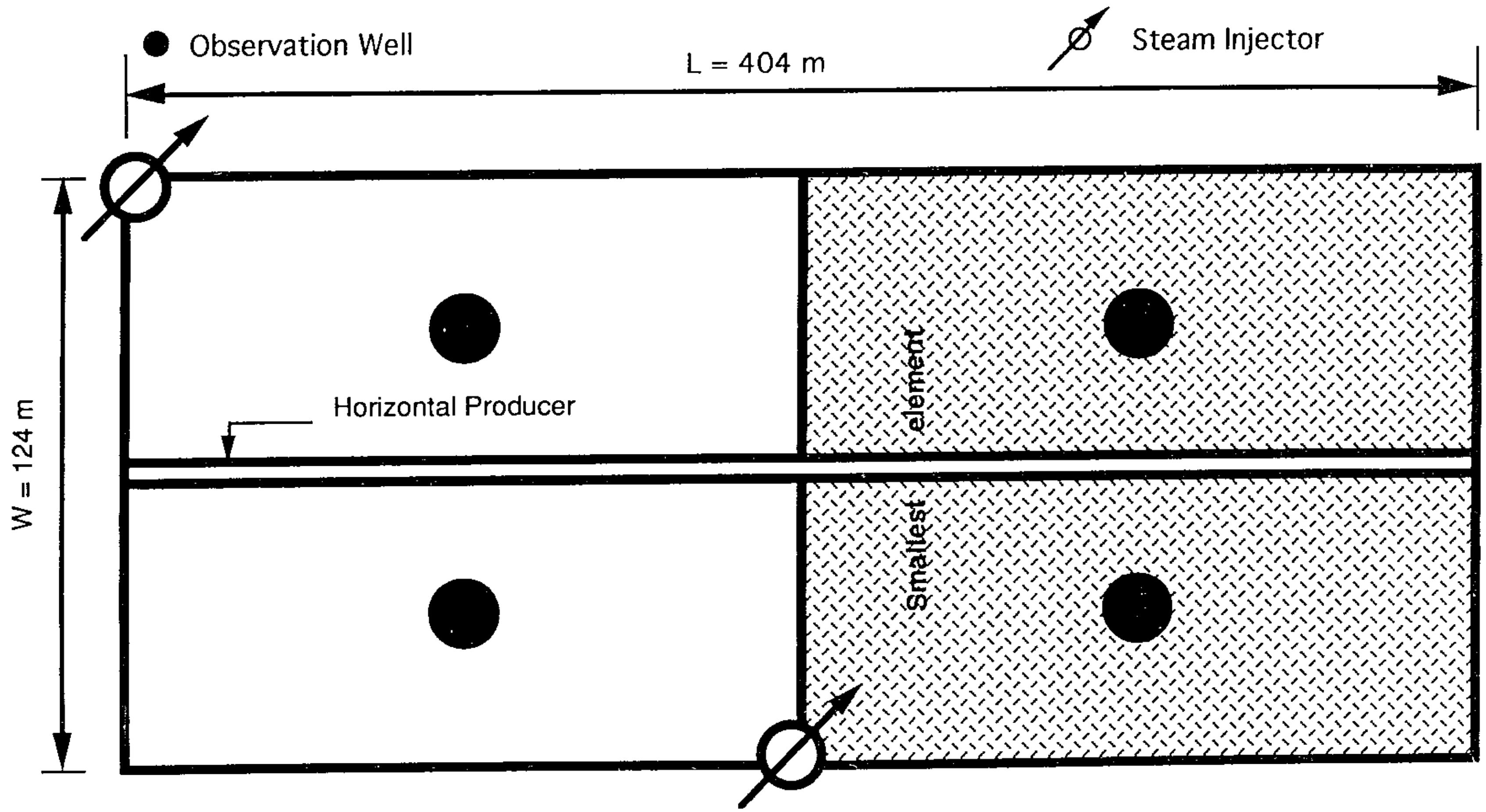


Figure D1: Plan View of the Prototype Reservoir (after Doan,1991) the derivation of the scaling criteria, the flow was considered to be single-phase steady-state flow and the volume of inflow into the horizontal well was a function of the potential gradient between the reservoir and the horizontal well. Table D3 lists the scaling criteria for flow inside the horizontal well; for a detailed derivation, see Reference 63. The length of the horizontal well was scaled down by a factor of 430; however, some problems were encountered in satisfying the scaling criteria to scale down the diameter of the horizontal well. Using the pressure drawdown scaling group shown below;

$$r_{w,M} = \left[\frac{r_{w,F}^2 (p_{mR} k k_{rmR})_M}{a \, (p_{mR} k k_{rmR})_F} \right]^{0.5}$$

Given,

$(kk_{rmR})_M = 6.4 \times 10^{-12}$ m^2 (Single-phase flow assumption)

$(kk_{rmR})_F = 3.95 \times 10^{-12}$ m^2 (Single-phase flow assumption)

$(p_{mR})_M = 0.138$ MPa (Experimental pressure drawdown)

$(p_{mR})_F = 2.8$ MPa (Field pressure drawdown)

$r_{w,F} = 0.1778$ m (Horizontal well radius in the field)

Gives $r_{w,M} = 0.24$ cm

In practice, it was difficult to satisfy the group for horizontal well scaling criteria, simply because the scaled horizontal well diameter was too small (0.24 cm (0.094 in)). For these and other reasons, five horizontal wells (three having 0.32 cm (1/8 in) diameter and the other two having 0.64 cm (1/4 in) and 0.95 cm (3/8 in) diameters) were fabricated.

Table D3: Physical Meaning of the Scaling Criteria for Flow inside the Horizontal Well (after Doan, 1991)[63]

$\frac{r_{w,inlet}}{r_{w,outlet}}$	Geometrical factor for horizontal well
$\frac{L}{r_{w,outlet}}$	Geometrical factor for horizontal well
$\frac{\rho_{mR} H g_R \sin \theta_R}{2 p_{mR}}$	Ratio of gravitational force to pressure drawdown
$\frac{2 v_{outR} U_{outR}}{W_R J_R L}$	Ratio of total energy at outlet to total work done
$\frac{W_R t_R}{C_{HR} T_R}$	Ratio of work done to the energy of the fluid inside the well
$\frac{J_R U_{mR} \Delta p_R}{\rho_{mR} U_R v_R^2}$	Ratio of energy loss to energy of fluid stream
$\frac{r_{w,outlet}^2 \Delta p_R}{L \mu_{mR} v_R}$	Ratio of pressure drop across the well to fluid flow velocity
$\frac{3 \mu_{mR} r_{w,inlet}^2 v_R U_R}{8 \pi k k_{rmR} p_{mR} J_R L U_{mR}}$	Ratio of energy of inside-well flow to energy of inflow

2.3 Steam Drive Process

For the steam drive process, the effect of gravity in providing the driving force necessary to move the steam zone and mobilized oil bank forward toward the producer was assumed to be negligible compared to the force provided by the pressure drop between the injector and producer. Thus, to better represent the effect of pressure drop between the injector and producer, some modifications included removing the gravity terms contributing to the flow in the porous medium and the flow inside the horizontal well. Table D4 shows a list of the reservoir flow scaling criteria modified for the steam drive process.

Table D4: Scaling Criteria for Steam Drive Process (after Doan, 1991)[63]

1) Flow in the Reservoir:

$$\frac{H}{2L},\ \frac{q_{oR}^{sc}H^2\mu_{oR}}{4\rho_{oR}kk_{roR}p_{oR}},\frac{\rho_{wR}}{\rho_{oR}},\ \frac{\rho_{gR}}{\rho_{oR}},\ \frac{p_{oR}}{p_{wR}},\ \frac{p_{oR}}{p_{gR}},\ \frac{W_{wR}\mu_{wR}}{\rho_{wR}kk_{rwR}Hp_{wR}},\ \frac{S_{wR}}{S_{oR}},\ \frac{S_{gR}}{S_{oR}},$$

$$\frac{C_{gaR}^{sc}q_{gR}^{sc}}{C_{oaR}^{sc}q_{oR}^{sc}},\ \frac{k_{hrR}T_R\mu_{oR}}{\rho_{oR}h_{oR}p_{oR}kk_{roR}},\ \frac{\phi_R S_{oR}H^2\mu_{oR}}{4kk_{roR}p_{oR}t_R},\ \frac{h_{wR}}{h_{oR}},\ \frac{h_{gR}}{h_{oR}},\ \frac{q_{hR}^{sc}}{q_{oR}^{sc}\,h_{oR}},\ \frac{q_{hR}^{sc}}{q_{lR}^{sc}},\ \phi_R,$$

$$\frac{\rho_{rR}U_{rR}}{\rho_{oR}h_{oR}},\ \frac{U_{oR}}{h_{oR}},\ \frac{U_{wR}}{h_{oR}},\ \frac{U_{gR}}{h_{oR}},\ \frac{p_{cgoR}}{p_{oR}},\ \frac{p_{cowR}}{p_{oR}},\ \frac{S_{oiR}}{S_{oR}},\ \frac{p_{oiR}}{p_{oR}},\ \frac{T_{iR}}{T_R},\ \frac{p_{oR}kk_{roR}}{\phi_R S_{oR}\mu_{oR}\alpha_{obR}},$$

$$\frac{q_{lR}^{sc}H^2}{4k_{hobR}T_{obR}},\ \frac{q_{oR}^{sc}}{q_{wR}^{sc}},\ \frac{h_{winjR}^{sc}q_{winjR}^{sc}}{q_{hinjR}^{sc}},\ \frac{A_R^{sc}k_{hobR}T_{obR}}{V_{bR}Lq_{lR}^{sc}},\ \frac{h_{sinjR}^{sc}}{h_{winjR}^{sc}},\ \frac{q_{oprodR}^{sc}}{C_{gwprodR}^{sc}q_{gprodR}^{sc}},$$

$$\frac{k_{roR}\mu_{wR}}{k_{rwR}\,\mu_{oR}},\ \frac{k_{roR}\mu_{gR}}{k_{rgR}\,\mu_{oR}},\ \frac{k_{rwR}\mu_{gR}}{k_{rgR}\,\mu_{wR}},\ \frac{W_{gwR}h_{gwinjR}}{W_{wR}\,h_{winjR}}$$

2) Flow inside the Horizontal Well:

$$\frac{L}{r_{w,outlet}},\ \frac{2v_{outR}U_{outR}}{W_RJ_RL},\ \frac{J_RU_{mR}\Delta p_R}{\rho_{mR}U_Rv_R^2},\ \frac{W_Rt_R}{C_{HR}T_R},\ \frac{r_{w,outlet}^2\Delta p_R}{L\mu_{mR}v_R},\ \frac{3\mu_{mR}r_{w,inlet}^2v_RU_R}{8\pi kk_{rmR}p_{mR}J_RLU_{mR}}$$

2.4 Steam Assisted Gravity Drainage Process

In the case of the steam assisted gravity drainage process, the effect of the pressure drop between the injector and producer in providing the driving force to drive the steam zone and mobilize the oil bank is assumed to be negligible compared to the driving force provided by gravity. So, the modification in this case was to dismiss all the pressure drop terms contributing to flow in the porous medium as well as inside the horizontal well. The modified reservoir and horizontal well flow scaling criteria are listed in Table D5.

Table D5: Scaling Criteria for Thermal-Aided Gravity Drainage Process
(after Doan, 1991)[63]

1) Flow in the Reservoir:

$$\frac{H p_{oR}}{2L^2 \rho_R g_R \sin\theta_R},\ \frac{q_{oR}^{sc} H^2 \mu_{oR}}{2\rho_{oR}^{sc} k k_{roR} g_R \sin\theta_R},\ \frac{\rho_{wR}}{\rho_{oR}},\ \frac{\rho_{gR}}{\rho_{oR}},\ \frac{C_{gaR}^{sc} q_{gR}^{sc}}{C_{oaR}^{sc} q_{oR}^{sc}},\ \frac{S_{wR}}{S_{oR}},\ \frac{S_{gR}}{S_{oR}},\ \frac{h_{wR}}{h_{oR}},$$

$$\frac{h_{gR}}{h_{oR}},\ \frac{k_{hrR} T_R \mu_{oR}}{\rho_{oR}^2 k k_{roR} h_{oR} g_R \sin\theta_R},\ \frac{\phi_R S_{oR} H^2 \mu_{oR}}{2\rho_{oR} k k_{roR} g_R \sin\theta_R t_R},\ \frac{q_{hR}^{sc}}{q_{oR}^{sc}\, h_{oR}},\ \frac{q_{hR}^{sc}}{q_{IR}^{sc}},\ \phi_R\ \frac{\rho_{rR} U_{rR}}{\rho_{oR} h_{oR}},$$

$$\frac{U_{oR}}{h_{oR}},\ \frac{U_{wR}}{h_{oR}},\ \frac{U_{gR}}{h_{oR}},\ \frac{p_{cgoR}}{p_{oR}},\ \frac{p_{cowR}}{p_{oR}},\ \frac{S_{oiR}}{S_{oR}},\ \frac{p_{oiR}}{p_{oR}},\ \frac{T_{iR}}{T_R},\ \frac{p_{oR} k k_{roR}}{\phi_R S_{oR} \mu_{oR} \alpha_{obR}},\ \frac{q_{IR}^{sc} H^2}{4 k_{hobR} T_{obR}},$$

$$\frac{q_{oR}^{sc}}{q_{wR}^{sc}},\ \frac{h_{winjR}^{sc} q_{winjR}^{sc}}{q_{hinjR}^{sc}},\ \frac{A_R^{sc} k_{hobR} T_{obR}}{V_{bR} L q_{IR}^{sc}},\ \frac{h_{sinjR}^{sc}}{h_{winjR}^{sc}},\ \frac{q_{oprodR}^{sc}}{C_{gwprodR}^{sc} q_{gprodR}^{sc}},\ \frac{k_{roR}\mu_{gR}}{k_{rgR}\,\mu_{oR}},\ \frac{k_{rwR}\mu_{gR}}{k_{rgR}\,\mu_{wR}},$$

$$\frac{k_{roR}\mu_{wR}}{k_{rwR}\,\mu_{oR}},\ \frac{W_{gwR} h_{gwinjR}}{W_{wR}\, h_{winjR}},\ \frac{W_{wR}\mu_{wR}}{\rho_{wR} k k_{rwR} H p_{wR}}$$

2) Flow inside the Horizontal Well:

$$\frac{L}{r_{w,outlet}},\ \frac{2 v_{outR} U_{outR}}{W_R J_R L},\ \frac{W_R t_R}{C_{HR} T_R},\ \frac{r_{w,outlet}^2 \Delta p_R}{L \mu_{mR} v_R},\ \frac{3\mu_{mR} r_{w,inlet}^2 v_R U_R}{8\pi k k_{rwR} \rho_{mR} H g_R J_R \sin\theta_R},$$

$$\frac{J_R U_{mR} \Delta p_R}{\rho_{mR} U_R v_R^2}$$