EXPERIMENTAL COMPARISON OF HOT WATER / PROPANE INJECTION TO STEAM / PROPANE INJECTION FOR RECOVERY OF HEAVY OIL

A Thesis

by

THOMAS NESSE

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

December 2004

Major Subject: Petroleum Engineering

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Approved as to style and content by:

Daulat D. Mamora
(Chair of Committee)

Richard Startzman
(Member)

Brian J. Willis
(Member)

Stephen Holditch
(Head of Department)

December 2004

Major Subject: Petroleum Engineering

ABSTRACT

Experimental Comparison of Hot Water / Propane Injection
to Steam / Propane Injection for Recovery of Heavy Oil. (December 2004)
Thomas Nesse, B.S., Stavanger University College, Norway
Chair of Advisory Committee: Dr. Daulat Mamora

Generating enough heat to convert water into steam is a major expense for projects that inject steam into reservoirs to enhance hydrocarbon recovery. If the temperature of the injected fluid is lowered this expense would be reduced. In the past, attempts have been made to inject hot water instead of steam. The results have all been rather poor, the major problem being low sweep efficiency. The hot water just doesn't enhance oil recovery enough.

Adding propane to the steam injected in the reservoir lowers the boiling point of the light to intermediate hydrocarbon fractions, upgrading the oil and reducing viscosity. The goal of this investigation is to see if the same effects could be achieved when adding propane to hot water – making it a lower cost option for an injection operation.

Results conclude that you need steam to achieve satisfactory recovery. These results reflect differences in heat injected by steam compared to that of hot water. Steam has a more penetrating effect, shooting into the reservoir where the hot water moves more slowly forward. The propane just doesn't seem to have the same accelerating effect when used with water as it does when used with steam.

ACKNOWLEDGEMENTS

First and foremost I would like to thank my advisor, Dr. Mamora, for being available and always taking the time to listen to my questions and concerns. Without his help this project would have been very difficult indeed. I am also grateful that Dr. Startzman and Dr. Willis agreed to serve on my committee.

Special thanks go to Jose Rivero who patiently explained the workings of the equipment in the Ramey Lab when I first started my experiments. This was time consuming work, and I really appreciate the effort. The hours spent in the lab would not have been so much fun if it wasn't for Jose's great mood and pleasant company.

I would also like to thank the Ramey Lab research group and all my friends here at Texas A&M for making these years so memorable. I really hope we get the chance to meet again in a few years. Hopefully by then we will all have huge expense accounts!

This research was made possible through the Ramey Laboratory Research Program. Sponsorship of the program by U.S. DOE, ChevronTexaco, Total S.A. and ConocoPhillips is gratefully appreciated

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CHAPTER I

INTRODUCTION

Hot water flooding of a reservoir has not been a very popular thermal recovery process. Only a few operations are described in the literature.[1-4] Water channeling with resulting high WOR's, indicating poor sweep efficiencies, characterize most of them. Instead, continuous steam injection (or steam flooding) has become the dominant method for recovering heavy oil. The most obvious benefits to this method are oil viscosity reduction and oil distillation.

When steam is injected into a reservoir, the resulting phase distribution defines five distinct zones at successfully greater distances from the injection well. The first zone, near the injector, is called the steam zone. It consists of water (in liquid and vapor phase) and residual oil. Light fractions of the oil are vaporized and condense ahead of the steam front, creating the solvent bank. The solvent bank comprising the second zone is miscible with the oil, thereby reducing its interfacial tension and viscosity. In the third zone, the hot water zone, steam and volatile oil condense upon contact with the cold matrix. As a result of oil viscosity reduction and displacement in the first three zones, an oil bank is formed in a fourth zone. Furthest away from the injector, the fifth zone is composed of original oil.

Since it was first implemented, the principles of steam flooding have remained basically unchanged. In order to improve the process, investigations have been made to determine the viability of injecting steam along with other additives. Carbon dioxide and light hydrocarbons are among those tested with a positive effect on recovery of heavy oils in the laboratory. However, the combined injection of steam and hydrocarbon additives (solvent) is often costly. There is a potential for significant reduction in

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expenses if hot water could be injected instead of steam, but it is unknown if the additives will have the same positive effect when used in conjunction with hot water as opposed to steam. Therefore, the need existed to better understand the oil recovery mechanisms associated with hot water-hydrocarbon injection.

A series of experimental studies[5-11] have been carried out in the Ramey Laboratory of the Petroleum Engineering Department at Texas A&M University. Encouraging results have been achieved while investigating effects of combined injection of steam and propane for heavy and intermediate oil recovery.

This work furthers that research by comparing the results of injecting hot water with propane to using steam-propane. Up until now, only superheated steam has been used in the laboratory experiments. If hot water or low-quality steam can be used with good results, then the cost of the injection can be significantly reduced in the field.

1.1 Research Objectives

This investigation compares the results of injecting hot water-propane to superheated steam and propane. A number of runs have been performed, using different temperatures while maintaining a fixed backpressure.

Final oil recovery and production rate were measured. Density and viscosity was determined from the collected samples. Produced gas was run through a gas chromatograph for compositional analysis. The total volume of produced gas was recorded every 30 seconds using a wet test meter. Injection and production pressures were measured using pressure transducers connected to an automated recording system that stored measurements in digital format. These pressure measurements helped identify differences in injectivity. Thermocouples inside the cell containing the sand/oil mixture defined a temperature profile showing the advance of the steam/hot water front. This formed a basis for comparison between the different runs.

Because the main reason for using hot water instead of steam is to reduce cost, this investigation compares the expenses associated with a steam injection to those of a hot water operation. An overview of expected propane costs is discussed.

CHAPTER II

LITTERATURE REVIEW

Thermal recovery methods have gone through an evolution from the mid 20th century electrical heaters to hot water injection, in-situ combustion and the more widely used steam injection.[12] Willman (1961) showed that hot water floods (as opposed to conventional waterfloods) have improved mobility ratio from reduction in viscosity, and reduction in residual oil from thermal expansion.[13]

Spillette and Nielsen (1968) compared calculations for hot water and cold water injection.[14] Hot water showed improved displacement efficiency and a more piston like displacement of the oil

Despite advantages compared to cold waterfloods, hot water flooding has not been as popular as steam injection. Several studies have been directed at further improving steam injection methods, especially the effects of injecting steam along with gaseous additives like carbon dioxide and propane.

Redford and McKay (1980) conducted tests using methane, propane, butane, pentane and a number of commercial hydrocarbon blends on a high viscosity oil from Alberta, Canada.[15] Contrary to earlier belief, these additives did not cause a reduction in reservoir permeability. Redford and McKay were also the first to show that such additives had the potential to improve recovery.

Redford (1982) continued to experiment with different additives,including carbon dioxide, ethane and/or naphtha in combination with steam.[16] He concluded that both the addition of carbon dioxide and ethane had a positive effect on recovery. The results got even better once naphtha was added.

Harding *et al.* (1983) presented both experimental and simulation results suggesting that the co-injection of carbon dioxide or flue gas with steam yielded higher recoveries as opposed to steam alone.[17] Stone and Malcolm (1985) conducted experiments with carbon dioxide, which for different reasons showed most promise of the additives.[18] They found the carbon dioxide to increase the production rate. Good agreement was found between the experimental results and numerical simulation also conducted in the study.

Hong (1985) studied the effects of doing post-steam waterflooding using both heated and cold water.[19] The results indicated that the lower the water temperature the higher the recovery. Heating it did not produce more oil.

Stone and Ivory (1987) carried out further investigations using the model from Stone and Malcolm.[20] This time, experiments with CO_2 presoak and CO_2 co-injection with a solvent were conducted. They found that under certain conditions, carbon dioxide pre-soaking increased recovery above the conventional CO_2-steam injection.

Nasr *et al.* (1987) conducted experiments to test the effects of injecting CO_2, N_2 and flue gas with steam.[21] Both continuous and cyclic injection was tested. The addition of gases also here increased bitumen recovery. The use of CO_2 resulted in higher recoveries than could be achieved with N_2 and flue gas.

Frauenfeld *et al.* (1988) presented results showing that for oils without an initial gas content, co-injection of CO_2 with steam was capable of improving oil recovery over that obtained with steam alone.[22] On the other hand, when an initial non-zero gas saturation was present, co-injection of CO_2 was not beneficial.

Metwally (1990) investigated the effects of carbon dioxide and methane on the performance of steam processes.[23] He conducted experiments to compare the performance of two different scenarios - simultaneous injection of steam and a gaseous additive versus injection of a gas slug prior to steam injection. The results showed that injecting a CO_2 slug prior to the steam improved injectivity. However, the presence of a non-condensable gas with steam did not improve steam drive recovery and resulted in higher residual oil saturation compared to that of steam injection alone.

Butler and Mokrys (1991) described a new recovery concept called VAPEX, based on steam-assisted gravity drainage (SAGD).[24] It was intended for use in thin reservoirs, where the application of SAGD alone was uneconomical due to heat losses. The process used a solvent, such as propane, to form a vapor-filled chamber within the reservoir. Vapor dissolves in the oil around the chamber and the resulting solution drains, driven by gravity, to a horizontal production well placed low in the formation. A horizontal well located at the top of the reservoir, is used to inject steam and the solvent. Additional work by Butler and Mokrys presented results of further investigations to the VAPEX process.[25,26,27] They indicated that the process could be applied economically for heavy oil recovery. Additional advantages derived from VAPEX are a partial in situ de-asphalting and a reduction of the content of heavy metals. The result can be higher quality, lighter oil that's better suited for direct refining.

Gumrah and Okandan (1992) performed linear and 3D displacement experiments to evaluate the performance of CO_2 addition to steam on the recovery of 24 ºAPI, 12 ºAPI and 10.6 ºAPI oils.[28] The 1D tests indicated that the recovery increased with increasing CO_2/steam ratios until an optimum value was reached. The addition of CO_2 did not produce a significant increase in the recovery of the lighter oil. However, for the heavier oils, the oil production rate was increased considerably.

Bagci and Gumrah (1998) performed experiments with both linear and 3D models to investigate the effects of injecting methane and carbon dioxide along with steam for a 12.4 ºAPI heavy oil.[29] The results showed that the use of CO_2 or CH_4 combined with steam yielded a higher incremental oil recovery than pure steam tests.

Goite (1999) conducted several experiments to determine the influence of injecting propane as a gaseous additive to steam.[5] Results showed that the optimal mass ratio of propane to steam appears to be somewhere in the region of 5 to100.

Ferguson (2000) continued Goite's experiments using a constant steam mass rate. Several tests were performed to determine the optimum propane concentration.[6] Oil production acceleration was found in the steam-propane runs when compared to those of pure steam. The optimum propane:steam mass ratio was found to be around 5:100. The acceleration in oil production was thought to be due to the dry distillation process in which the lighter oil fractions are vaporized and carried by propane. On contact with the colder part of the cell, the light fractions condense and are miscible with the oil, thus lowering the interfacial tension and decreasing the viscosity of the oil.

Tinns (2001) continued the experiments by Ferguson. Measurements of viscosity and density indicated an increase in API gravity and a reduction of viscosity in the produced oil.[7] A reduction in inlet-outlet pressure differential was also observed, and injectivity was improved.

Rivero (2002) found that in addition to production acceleration with steam-propane, significant increase in injectivity and oil upgrade was also achieved.[8] Plazas (2002) conducted a series of experiments of steam distillation and steam-propane distillation on light crude oil (34.2 ºAPI) and intermediate crude oil (25.1 ºAPI).[9] The results showed that the yield for steam-propane distillation is higher than steam distillation for the intermediate crude oil. On the other hand, propane seemed to have little effect on the light oil.

Hendroyono (2003) found acceleration in production with as little as 1.25:100 propane:steam mass ratio.[10] Up to 30% acceleration with optimum ratio (5% propane) was observed. Injectivity was reported to be three times higher than with steam alone.

Ramirez Garnica (2004) performed distillation experiments showing that propane effectively reduces the boiling point of hydrocarbons.[11] Thus, yields are higher with steam-propane, followed by that of pure steam injection, and lowest under dry distillation.

CHAPTER III

EXPERIMENTAL APPARATUS AND PROCEDURES

The experimental contains five main components: fluid injection, the cell, fluid production, gas measurement and analysis, and data recording. A schematic overview of the apparatus is shown in **Fig. 3.1**.

3.1 Fluid Injection

Two different fluids, water and propane, can be mixed and injected with the current setup. Distilled water is injected through a High Performance Liquid Chromatography (HPLC) pump at a set rate (**Fig. 3.2**). A backpressure valve with a gauge is mounted directly after the pump to maintain its minimum required operating pressure of 500 psig. The water is then directed through a flow meter, after which it is mixed with the propane flow.

The propane supply is of the same quality as common household barbeque gas. From the container it flows through a 1/16 inch pipe that is heated to about 40ºC by a band heater. This is to ensure all the propane is in its gas phase when it reaches the mass flow controller that defines injection rate. Between the propane container and the mass flow controller there is a backpressure valve set at 90 psig.

Propane and water are mixed by simply joining the flow at a T-connection. Through a series of valves the mix can then be either bypassed away from the rest of the system or directed to a steam generator. The steam generator (**Fig. 3.3**) heats up the mixed fluid to a set temperature, generating hot water or steam as desired. The heated fluid then goes through ¼ inch tubing before entering the cell. The tubing is installed with a band heater

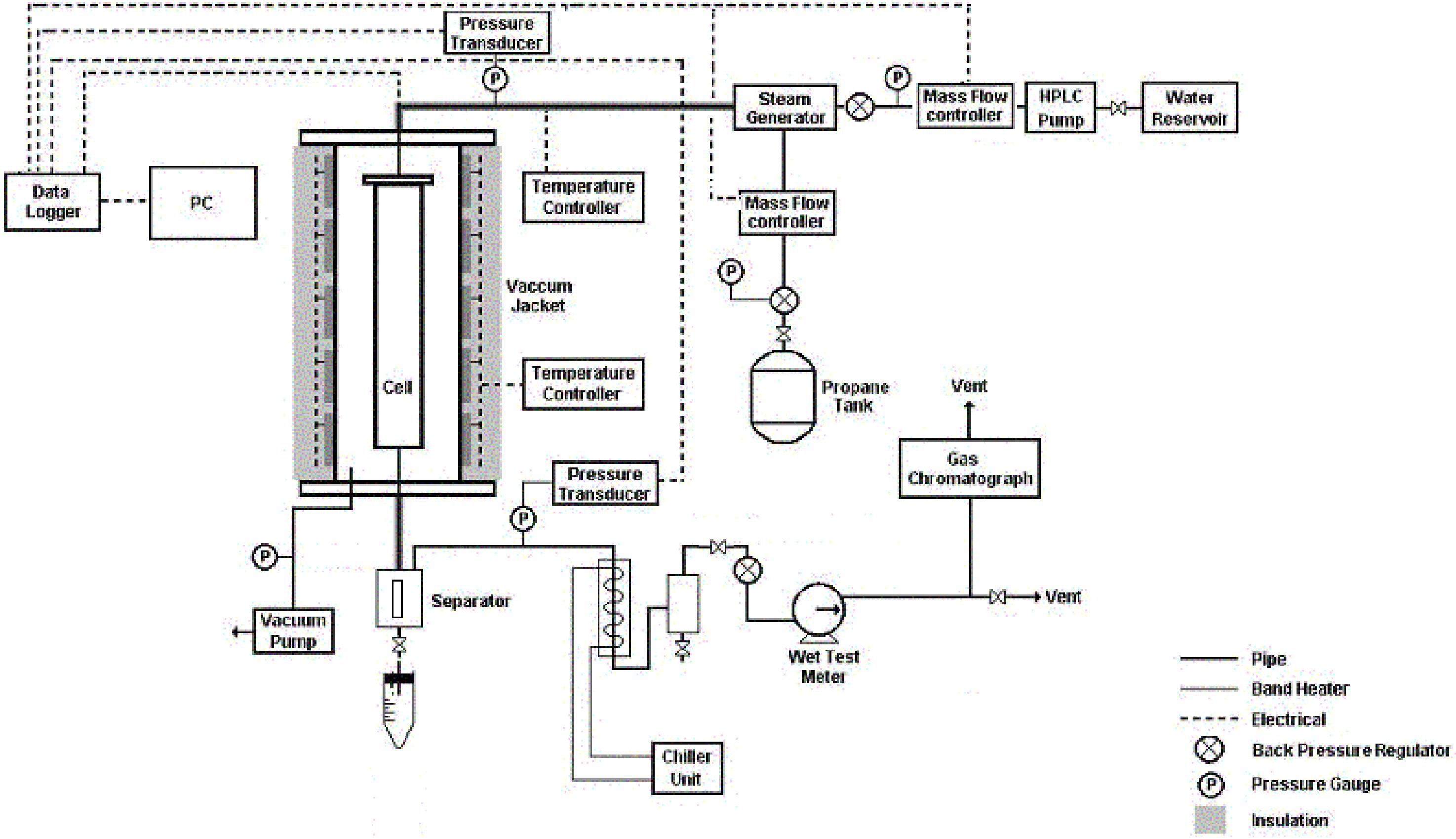

Fig. 3.1— Schematic diagram of experimental apparatus.

and also wrapped with insulating material. A temperature controller allows adjustment of a band heater to control the temperature of the injected fluid, effectively allowing the user to manipulate it all the way to the entry point of the cell.

Fig. 3.2— HPLC pump used for water injection.

3.2 Cell

The cell is a 27.13 inches long steel cylinder with a 2.913 inch inner diameter (**Fig. 3.4**). It holds a carefully weighed mixture of sand, water and oil. Placed inside the cell is a thermowell holding thermocouples. These thermocouples are spaced at different intervals to monitor temperature propagation through the experiment (**Fig. 3.5a and 3.5b**). At the bottom of the well there is a sand screen preventing sand particles from being produced with the fluid.

Fig. 3.3— Steam generator, insulated pipes and the thermocouples.

Fig. 3.4— The sand mix is contained within this cylindrical cell.

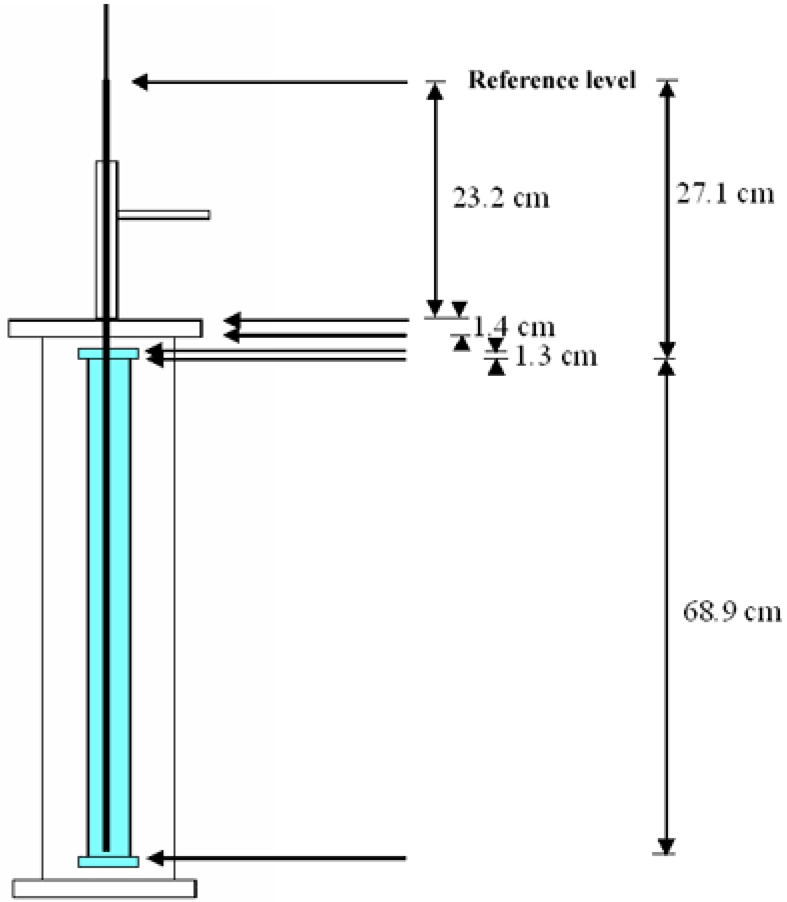

Fig. 3.5a— Position of the thermowell relative to the cell and heating jacket.

The cell is placed inside a larger diameter heating jacket, creating an annulus between the two (**Fig. 3.6**). During experimental runs a vacuum was pulled in this annulus using an external vacuum pump. This helped reduce heat loss. After the cell was placed inside the heating jacket the temperature is set at desired level with a temperature controller similar to the one used for the band heater in the injection system. To ensure uniform temperature throughout the cell, this heater is left on for about 12 hours to stabilize the system at “reservoir temperature”.

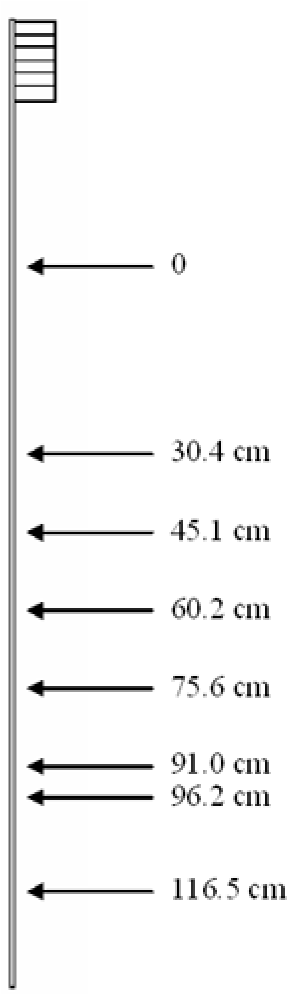

Fig. 3.5b— Position of the thermocouples relative to the top of the thermowell.

3.3 Fluid Production

The displaced fluid flows from the bottom of the cell to a gas-liquid separator unit (**Fig. 3.7**). Liquids are produced at the bottom of this unit and collected in 50cc sample bottles for later analysis. The separator is equipped with a see-through glass so the liquid level can be monitored, allowing continuous oil production without risk of escaping gas.

Fig. 3.6— The cell is placed inside a heating jacket.

Gases are produced at the top of the separator and then analyzed with equipment described in more detail later. Because that equipment is rather sensitive to liquids, a large condenser is installed between it and the separator. Any steam or liquids still flowing with the gas will condense here and return to the separator. A backpressure valve is installed after the condenser. Once the set pressure is exceeded it allows gas production.

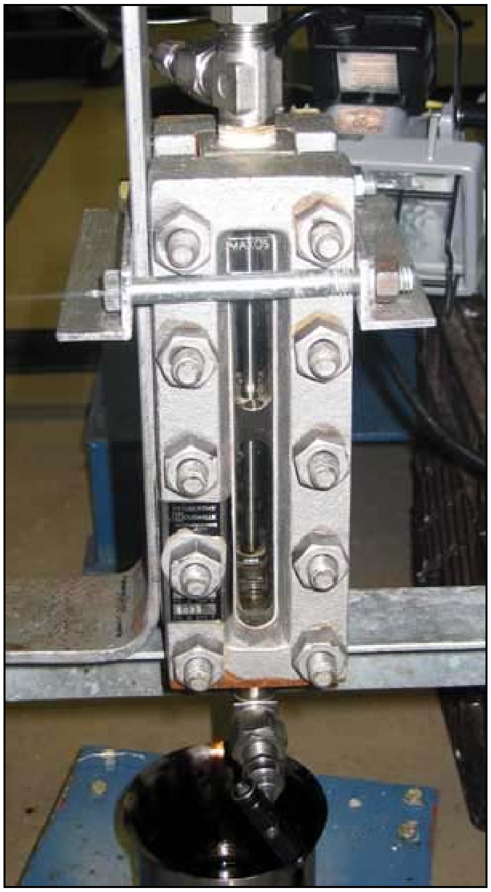

Fig. 3.7— The glass makes it easy to monitor the liquid level in the separator.

3.4 Gas Measurement and Analysis

A wet test meter measures the volume of gas produced (**Fig. 3.8**). After going through the wet test meter the gas is directed to a Gas Chromatograph (GC) (**Fig 3.9**). At regular intervals a sample of the gas is collected and run through the GC. A printer gives a visual representation of the results in form of a graph. Each peak on the graph represents a different compound. Before the first experiment a sample gas with known composition is run through the GC for calibration. Once the signature of each compound is known we can easily identify the gases later produced. The GC also provides an estimate of how much (relative volume) of each component is present in the gas.

Fig. 3.8— Wet test meter for measuring gas volume.

Fig. 3.9— A GC allows the produced gas composition to be measured.

3.5 Data Recording

Data is converted through data loggers so it can be recorded on a computer (**Fig. 3.10**). This includes input and output pressure, water and propane injection rates, steam injection temperature, cell temperature at 5 different points measured along the longitudinal center of the cell, and produced gas rate/volumes. The parameters are all recorded at 30 second intervals.

Fig. 3.10— Overview of temperature controllers, data loggers, computers and other electronic equipment used to monitor the experiments.

3.6 Summary of Equipment

A more detailed list of laboratory equipment can be found in **Table 3.1**:

TABLE 3.1— LIST OF MAIN COMPONENTS OF THE EXPERIMENTAL APPARATUS

Water reservoir	4-liter plastic container
HPLC pump	Alcott 760 HPLC
Steam generator	Custom-made by Texaco. Max. pressure: 2000 psig. Max. temperature: 1200 ºF
Injection cell	Stainless steel cylinder. Length: 27.126 in. I.D.: 2.913 in.
Temperature controller	Digi-Sense. Model 2186-10A, 20 Amp peak
Vacuum Pump	Welch director II, model 8811
Mass Flow Controller	Brooks. Model 5850E series. Max. flow 1000 cm^3/min
Wet test meter	GCA/Precision Scientific, capacity 0.1 ft^3 per revolution.
Gas chromatographs (GC)	Hewlett Packard 5890 Series II
Data logger	Hewlett Packard data acquisition unit. Model 3497A with 44422A T-couple acquisition assembly.
Rheometer	Brookfield. Model DV-III with cone and plate assembly.
Chiller unit	Hasskriss Co. Model R100
Tubing	¼-in., 1/8-in. and 1/16-in. stainless steel tubing with Swage lock and Autoclave connections.
Control valves	Autoclave Engineers ¼-in. Whithey ¼-in., 1/8-in.
Thermocouples	Omega JMQSS-020. Type J. Sheath diameter .020-in.
Gauges	HEISE CM-105620 and 3D instruments 0-100 psi test gauge
Centrifuge	IEC HN-II Benchtop centrifuge, 0-3000 RPM
Thermometer	Kessler. ASTM 40C
Industrial sand	100 mesh supplied by Baker Oil Tools
Oil	Circa 21 ºAPI.
Temperature bath	GCA/Precision Scientific
Pressure transducer	Validyne 0-50 psig
Backpressure valves	Testcom Corporation model 26-1727-24-043 rated 0-500 psi, and Matheson model 3590 rated 0-100 psi
Separator	Penberthy Houdaille, rated to 1440 psi at 100ºF

CHAPTER IV

EXPERIMENTAL RESULTS

4.1 Overview

Run 1 through 7 were made to get the experimental apparatus set up properly and are not included in this report. Run 8 through 15 are the actual experiments. To allow comparison between these runs, some parameters are kept constant for all experiments (**Table 4.1**). The sand mix properties are also kept as constant as possible (**Table 4.2**). The parameters that are changed are temperature, and in the first two runs also propane:steam mass ratio to establish a base case for comparison (**Table 4.3**).

TABLE 4.1— EXPERIMENTAL CONDITIONS FOR ALL RUNS

Steam injection rate, cm^3/min	3.5
Outlet pressure, psig	20
Vacuum jacket pressure, inches mercury	- 30
Initial cell temperature, ºC	40

TABLE 4.2— SAND MIX PROPERTIES FOR EACH RUN

Run	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
Porosity, %	43.4	43.1	42.8	42.7	43.5	42.9	43.6	43.9
Pore volume, cm^3	1,285	1,277	1,269	1,264	1,287	1,272	1,293	1,300
Water volume in cell, cm^3	195.5	196.4	197.4	198.0	195.2	197.1	194.6	193.8
Oil volume in cell (OOIP), cm^3	413.0	414.9	417.0	418.2	412.4	416.3	411.0	409.3
Initial water saturation, %	15.21	15.37	15.56	15.66	15.16	15.50	15.05	14.90
Initial oil saturation, %	29.82	30.14	30.50	30.70	29.72	30.37	29.49	29.21
Initial air saturation, %	54.97	54.49	53.94	53.64	55.11	54.13	55.46	55.89

TABLE 4.3— PROPANE CONCENTRATION AND INJECTION TEMPERATURE FOR EACH RUN

Run number	Propane:Steam ratio	Injection Temperature, ºC
8	0:100	157
9	0:100	157
10	5:100	157
11	5:100	125
12	5:100	135
13	5:100	130/145
14	5:100	120/140
15	5:100	157

The results for each run are described separately at first, and then a comparison is made. As a basis for the conclusions there are data of temperature profiles, pressure, injection rates, produced volumes, oil viscosity and oil density.

4.2 Run No. 8 (0:100 Propane:Steam Ratio, 157ºC)

The movement of the steam front can be followed in **Fig. 4.1**, which shows the temperature at each of 6 thermocouples as a function of time. The injection temperature is kept steady at 157ºC throughout the run, and little fluctuation is observed.

Cumulative oil and water production versus time is shown in **Fig. 4.2**. Ultimate recovery at the end of the 4 hour run is about 110 cm^3, or 27% of OOIP, as can be seen in **Fig. 4.3**.

Fig. 4.4 shows the oil and water production rates as a function of time. The first oil is produced after 89 minutes of injection, with a peak rate of about 7.7 cm^3/min after 99 minutes.

Fig. 4.5 shows how the temperature propagation at 20 minute intervals for the different thermocouples. It takes about 100 minutes for the whole cell to reach a more or less constant temperature of 127ºC.

The injection pressure, outlet pressure, and differential pressure are shown in **Fig. 4.6.** The outlet pressure is kept steady at 20 psig. As the oil bank is building up injection pressure increases, and as a result of that so does the differential pressure. From an initial differential pressure of close to zero it reaches highs of about 7 psi before oil production starts. Once that happens it drops back down to an average of about 3-4.5 psi.

Viscosity and density is plotted in **Fig. 4.7**. Cumulative gas production is shown in **Fig. 4.8**. It is plotted along with outlet pressure since gas is only produced once the outlet pressure exceeds the setting of the backpressure valve. In this run, where there is no propane, there is not much gas being produced. What little we do observe (slightly less than 2 liters) is all nitrogen as measured by the GC.

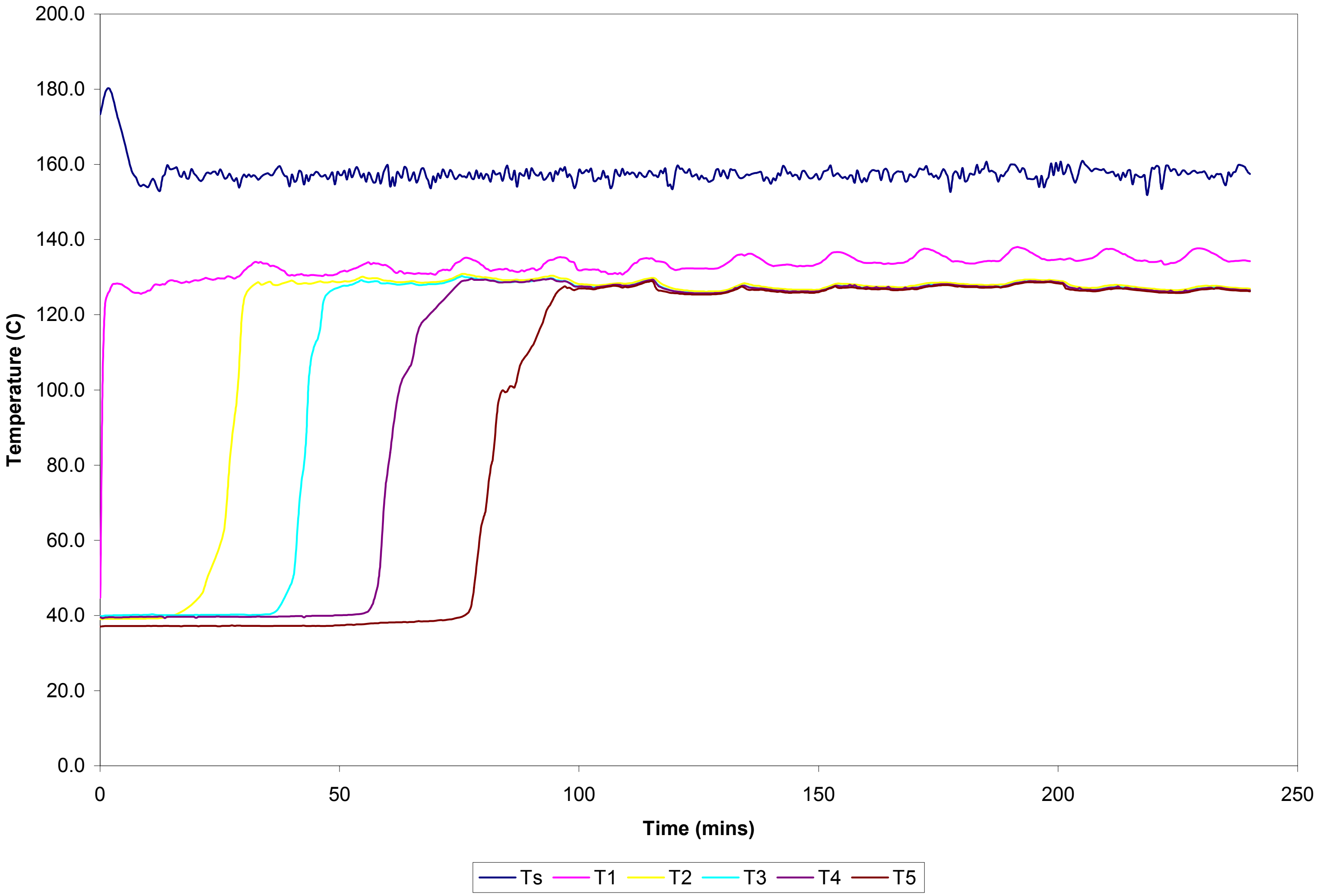

Fig. 4.1— Temperature profiles versus time for run no. 8.

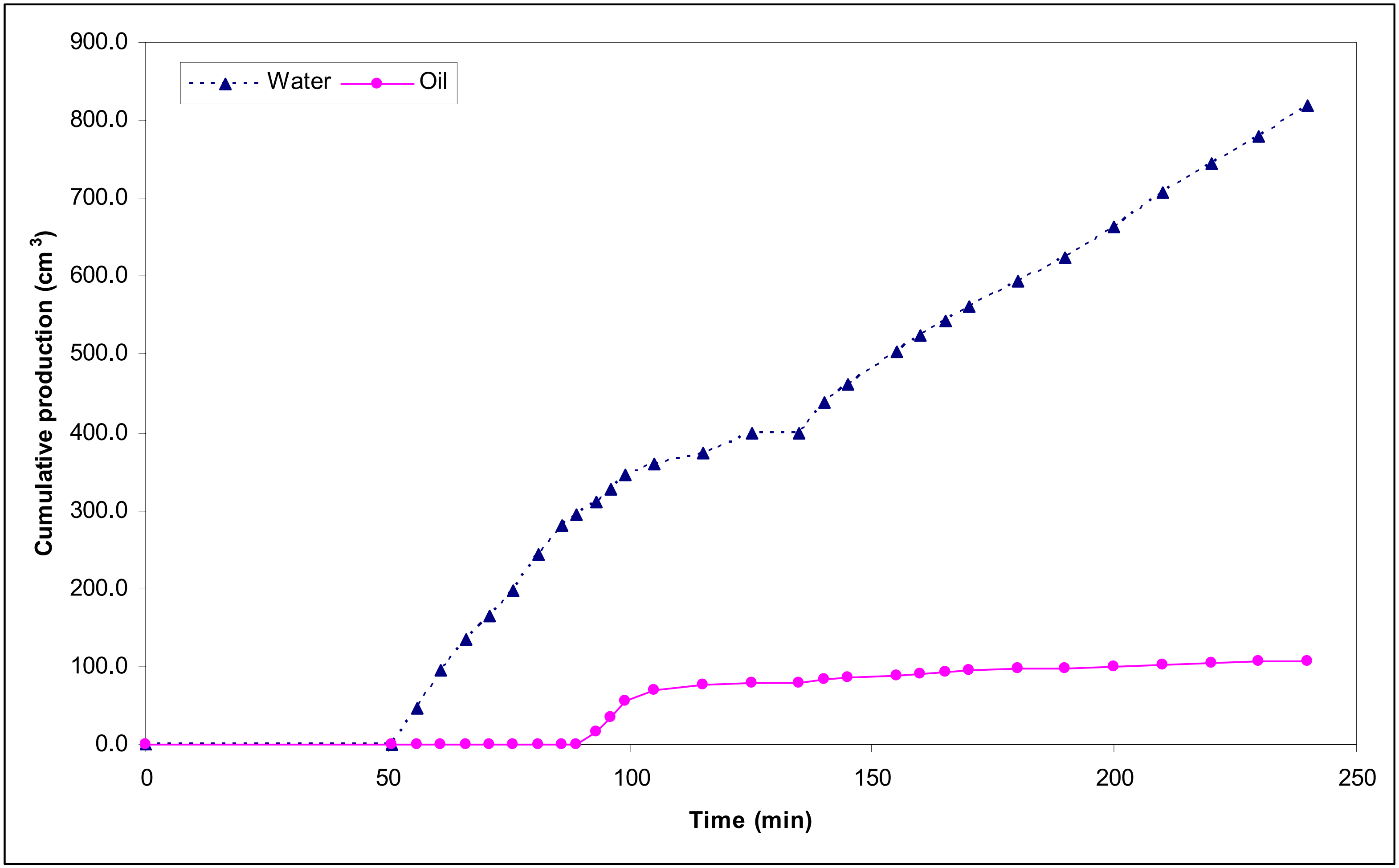

Fig. 4.2— Cumulative oil and water production versus time for run no. 8.

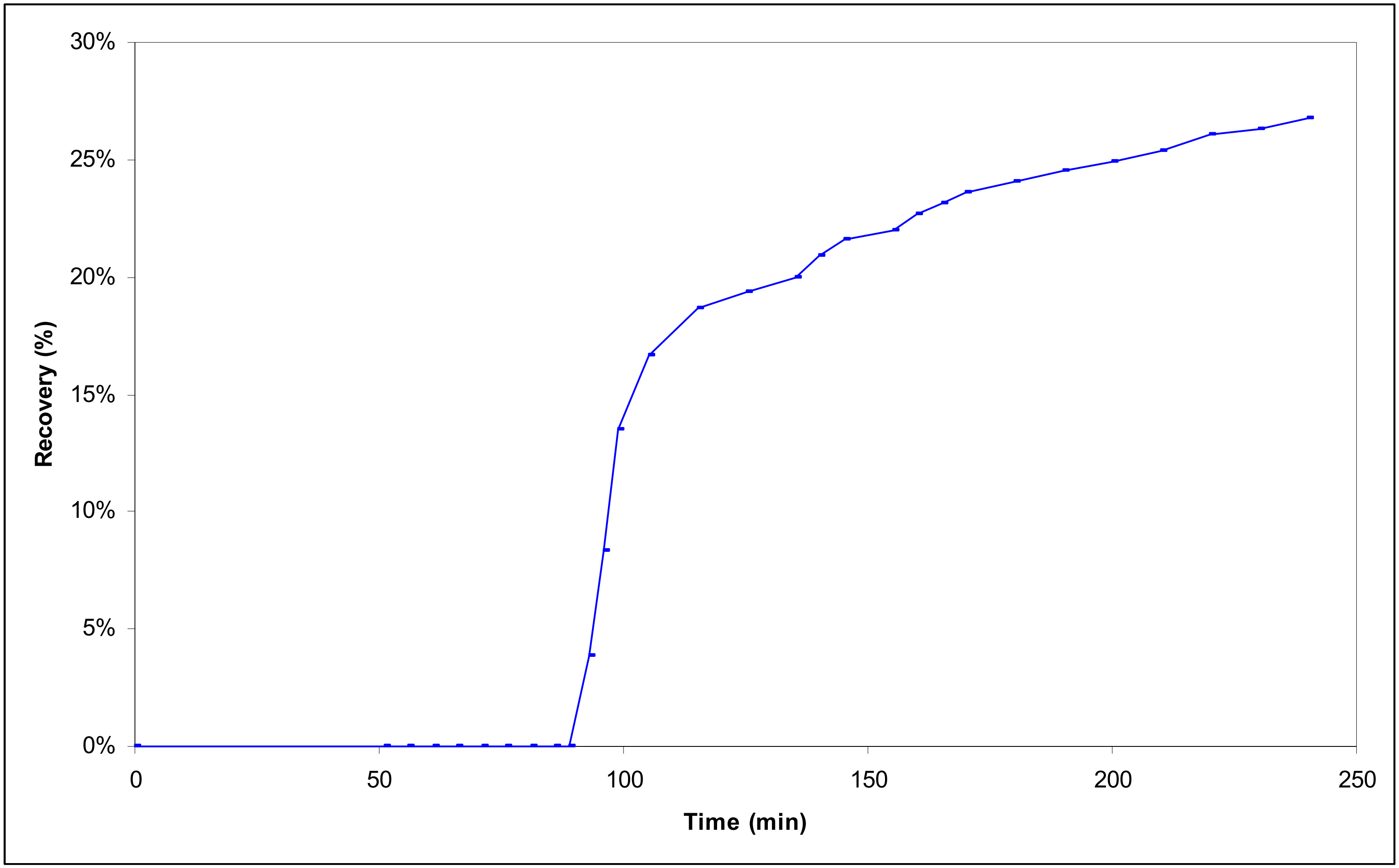

Fig. 4.3— Oil recovery versus time for run no. 8.

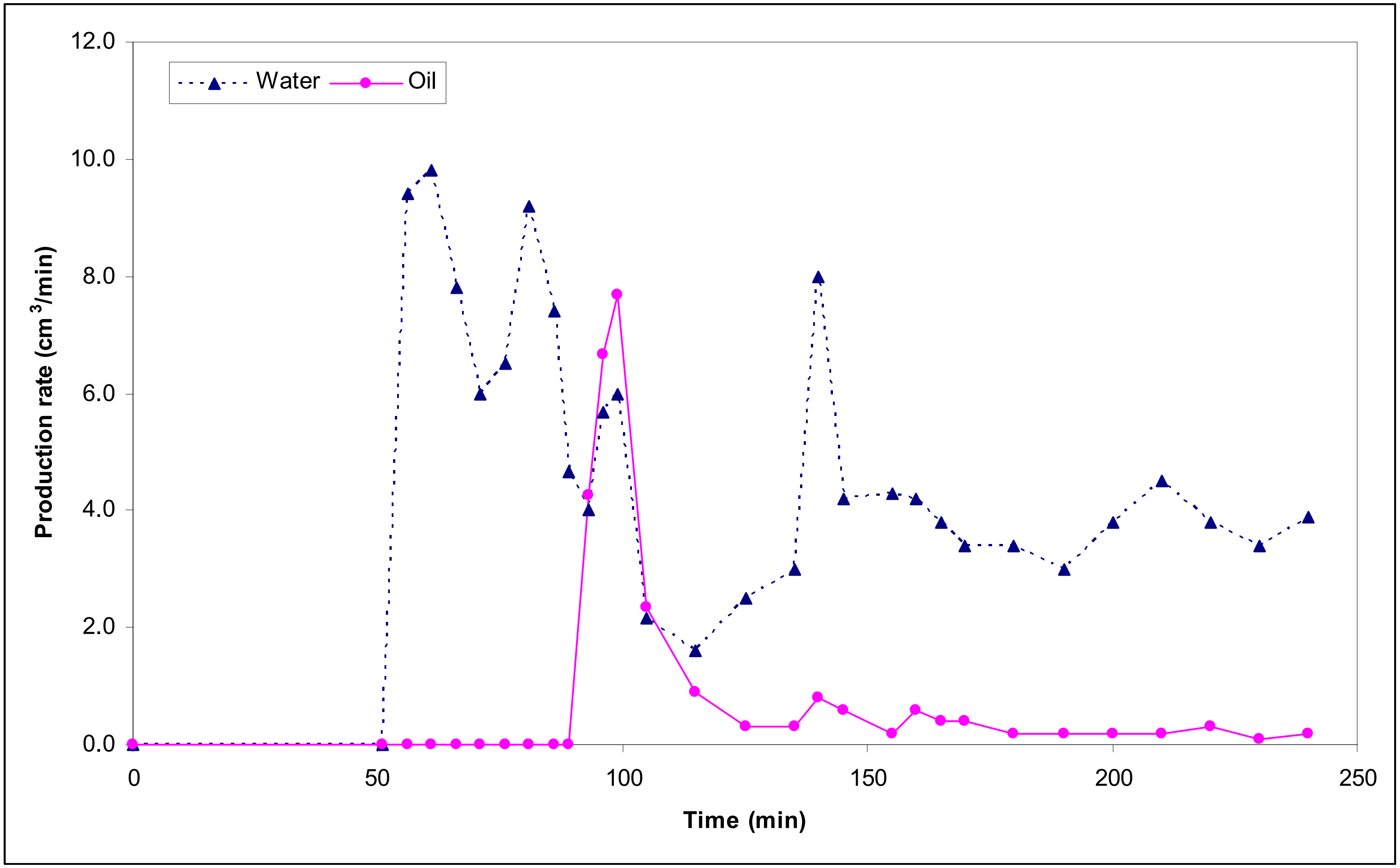

Fig. 4.4— Oil and water production rates versus time for run no. 8.

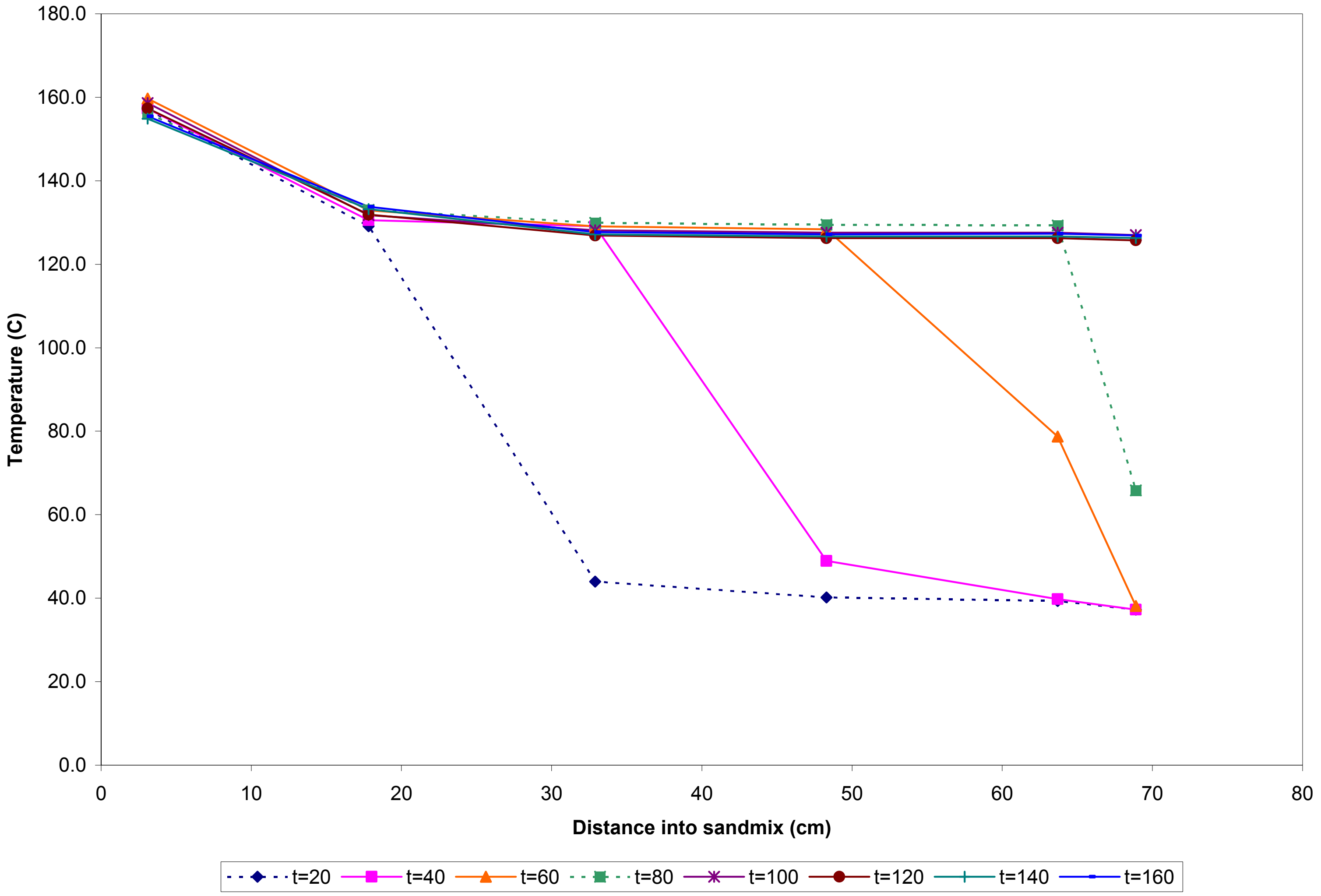

Fig. 4.5— Propagation of temperature in the sand mix for run no. 8.

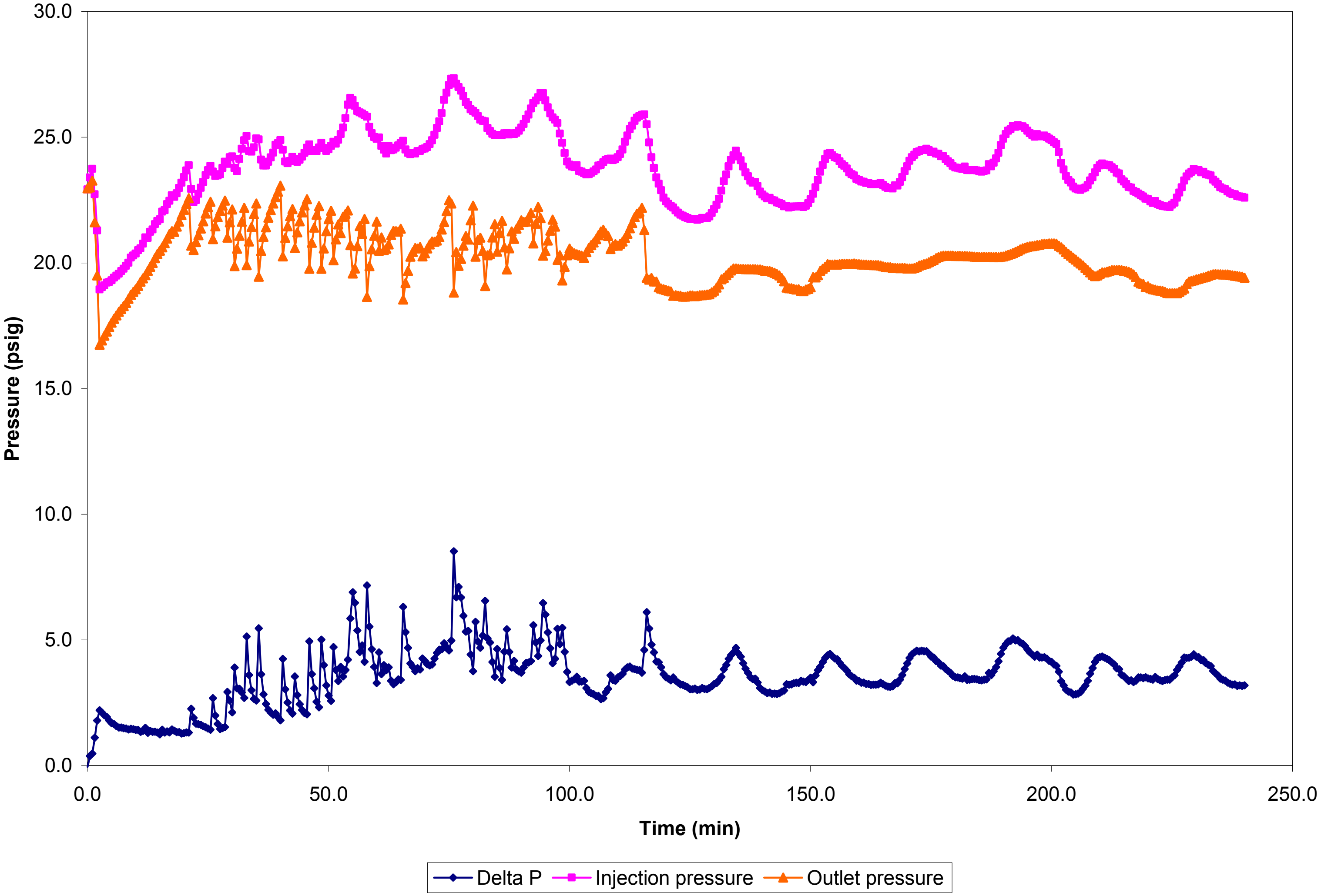

Fig. 4.6— Cell pressures versus time for run no. 8.

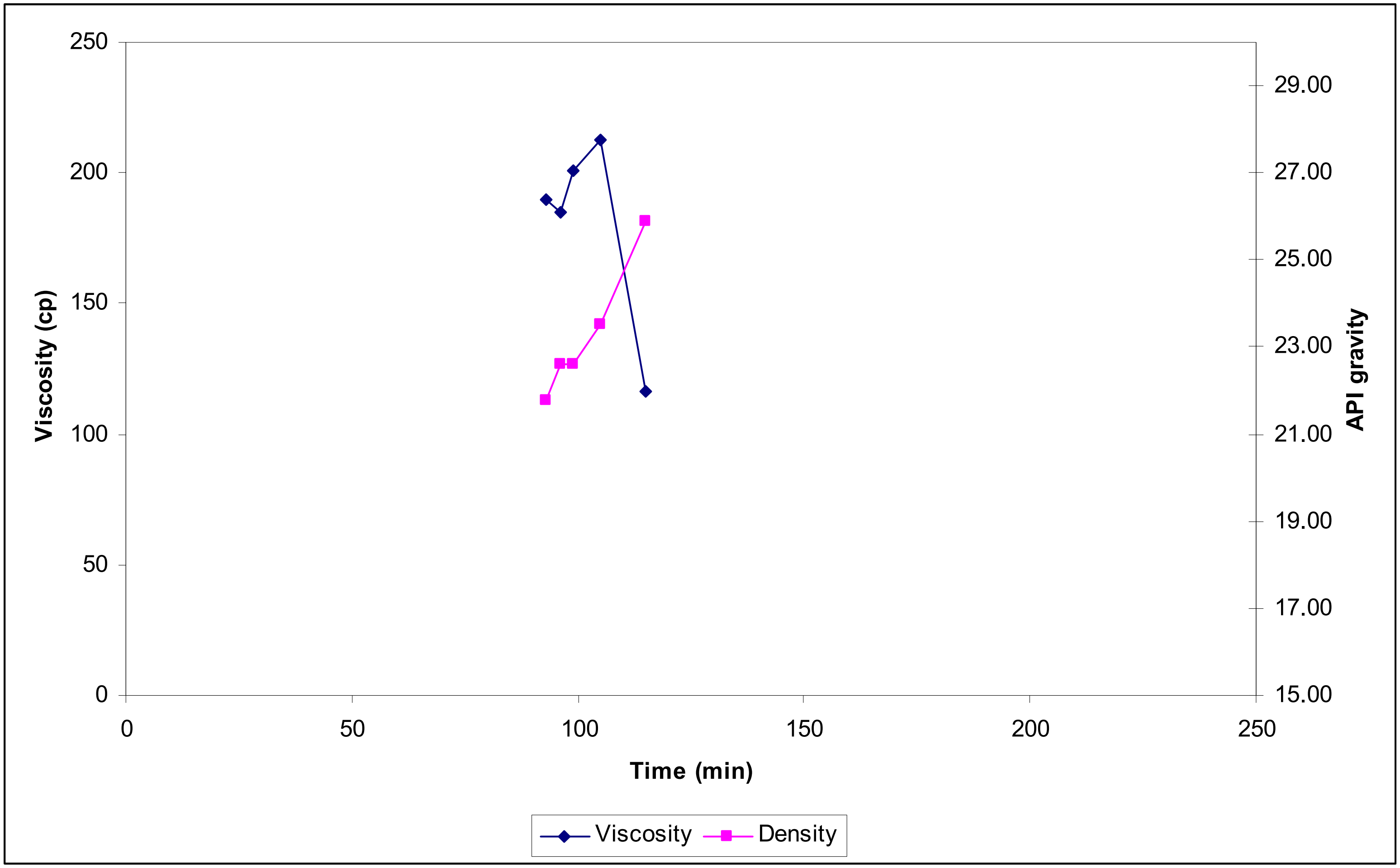

Fig. 4.7— Viscosity and density from the collected samples of run no. 8.

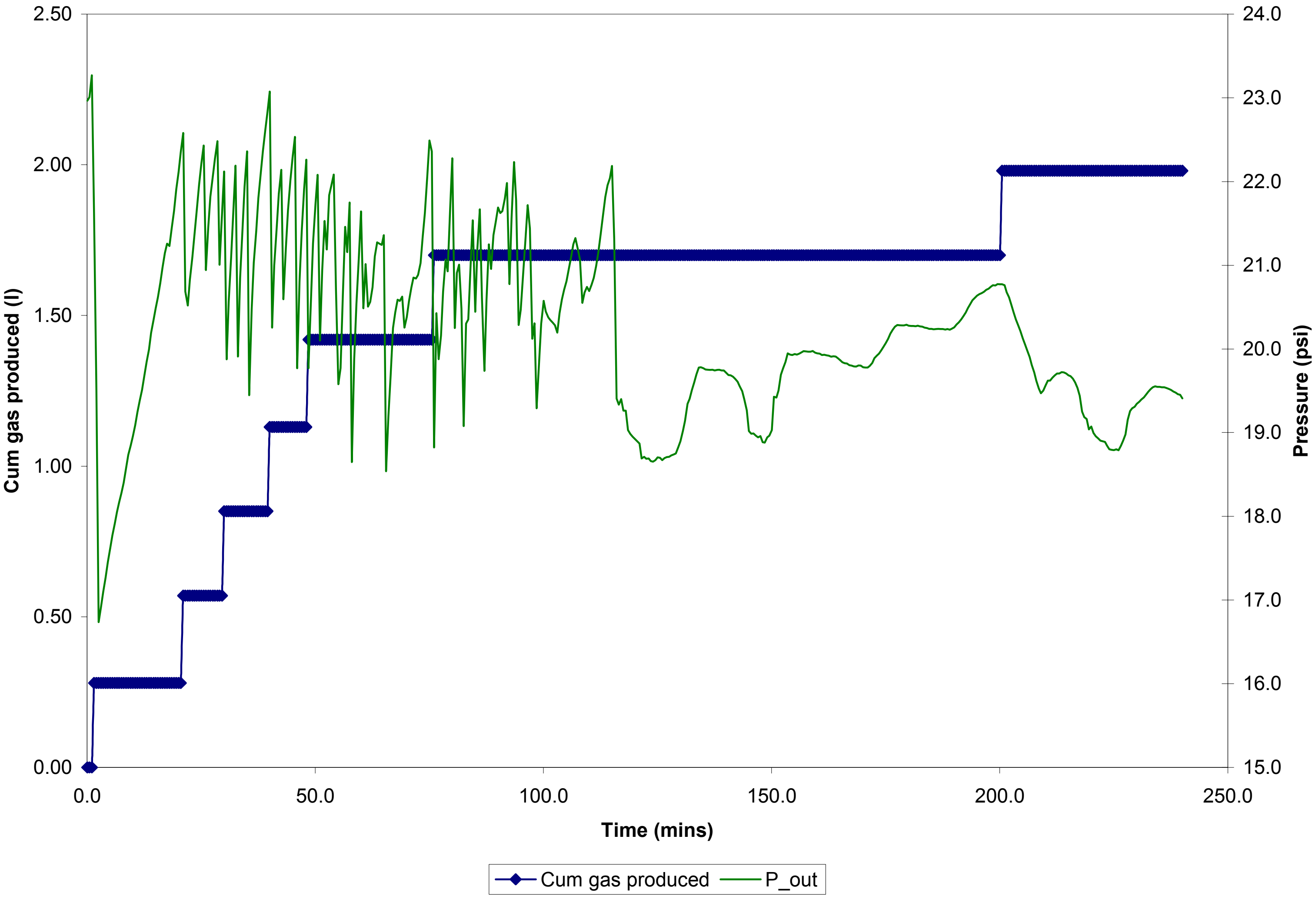

Fig. 4.8— Cumulative gas production and outlet pressure versus time for run no. 8.

4.3 Run No. 9 (0:100 Propane:Steam Ratio, 157ºC)

This is a repeat run with the same conditions as run no. 8. The movement of the steam front can be followed in **Fig. 4.9**. The injection temperature is kept steady at 157ºC throughout the run, and little fluctuation is observed.

Cumulative oil and water production versus time is shown in **Fig. 4.10**. Ultimate recovery at the end of the 4 hour run is about 111 cm^3, or 27% of OOIP, as can be seen in **Fig. 4.11**. **Fig. 4.12** shows the oil and water production rates as a function of time. The first oil is produced after 87 minutes of injection, with a peak rate of about 5.4 cm^3/min after 100 minutes.

Fig. 4.13 shows how the temperature propagation at 20 minute intervals for the different thermocouples. It takes about 100 minutes for the whole cell to reach a more or less constant temperature of 127ºC.

The injection pressure, outlet pressure, and differential pressure are shown in **Fig. 4.14.** The outlet pressure is kept steady at 20 psig. As the oil bank is building up injection pressure increases, and as a result of that so does the differential pressure. From an initial differential pressure of close to zero it reaches highs of about 7-8 psi before oil production starts. Once that happens it drops down slightly, to an average of about 4-5 psi.

Viscosity and density is plotted in **Fig. 4.15**. Cumulative gas production is shown in **Fig. 4.16**. It is plotted along with outlet pressure since gas is only produced once the outlet pressure exceeds the setting of the backpressure valve. In this run, where there is no propane, there is not much gas being produced. What little we do observe (about 1.7 liters in total) is all nitrogen as measured by the GC.

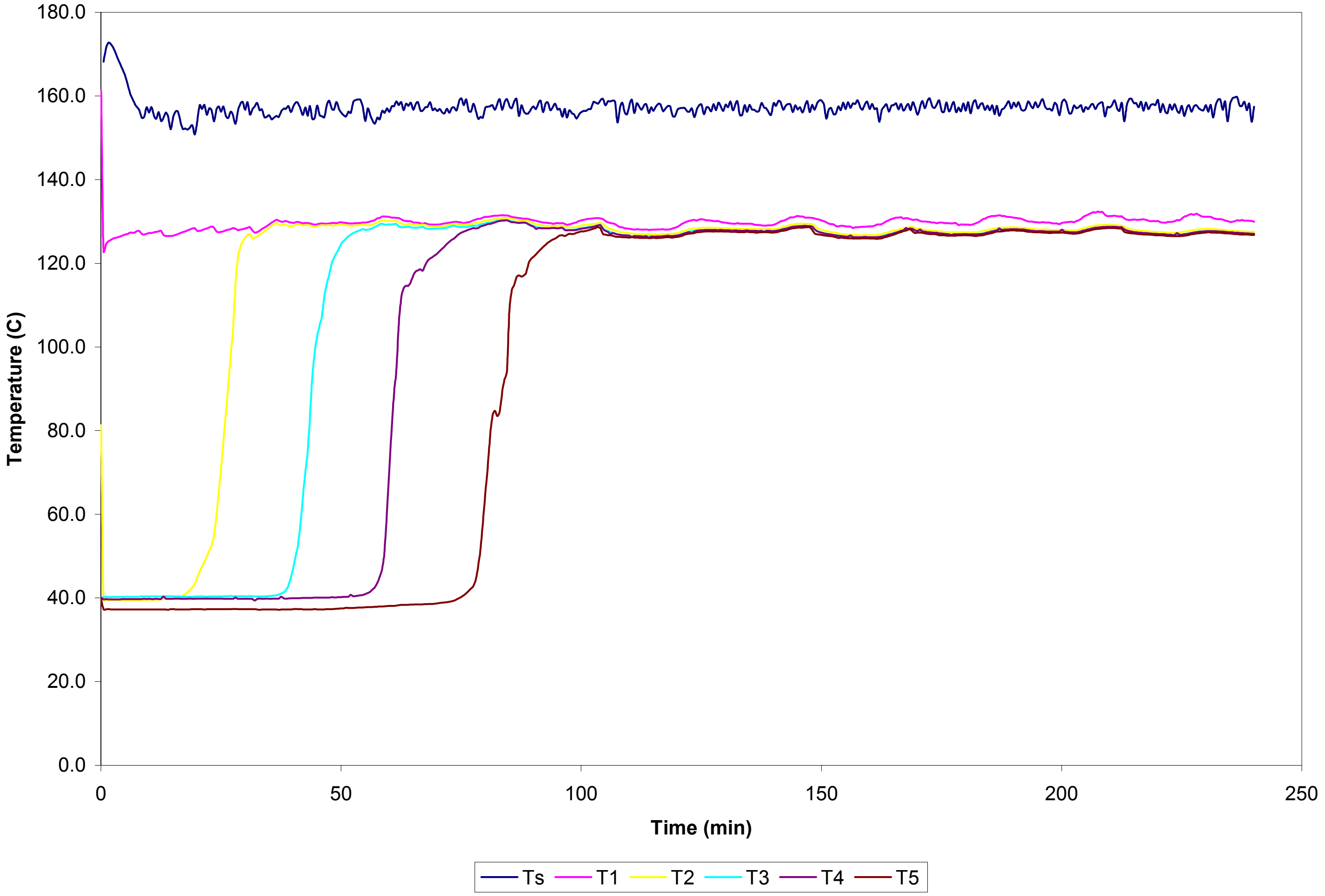

Fig. 4.9— Temperature profiles versus time for run no. 9.

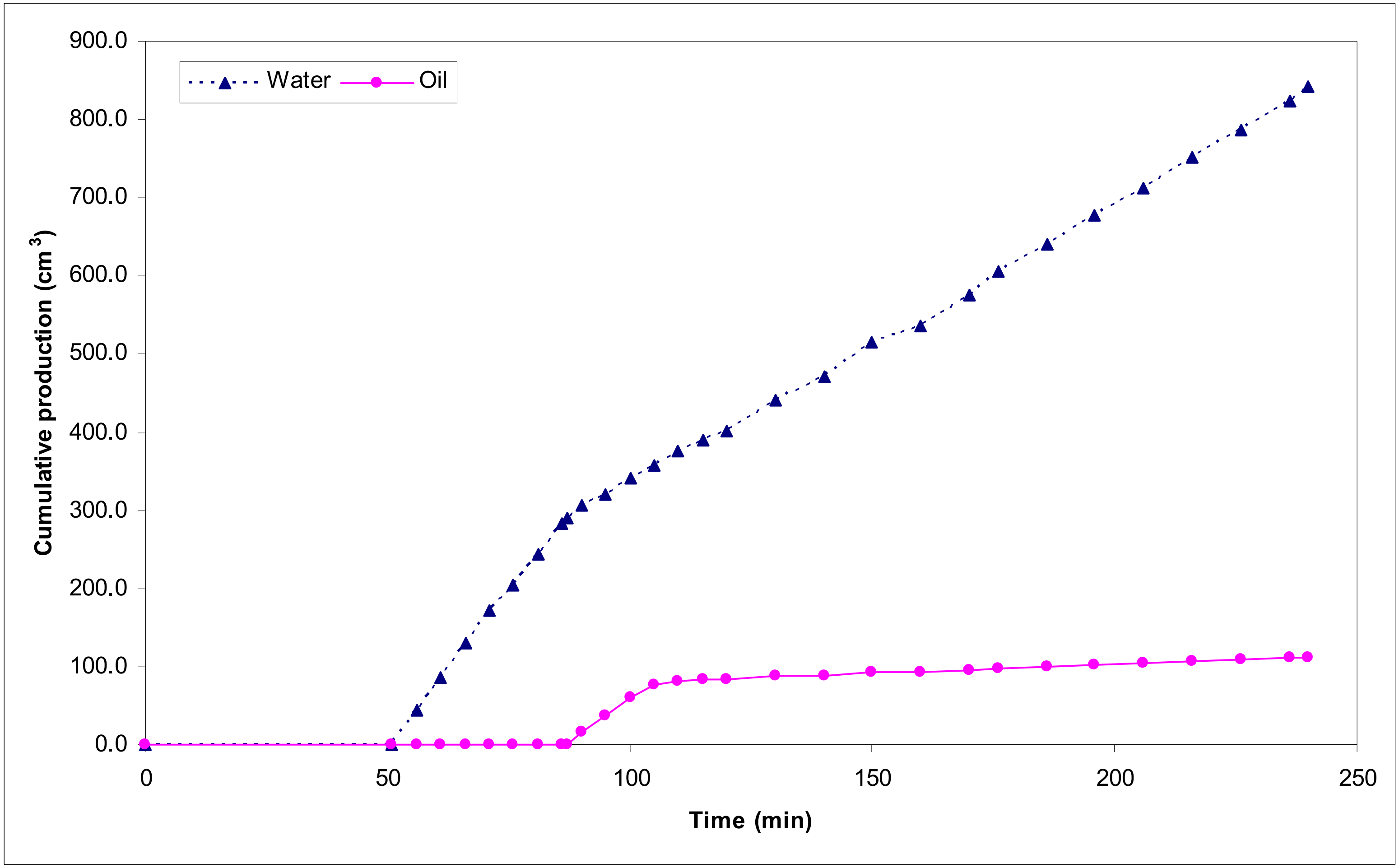

Fig. 4.10— Cumulative oil and water production versus time for run no. 9.

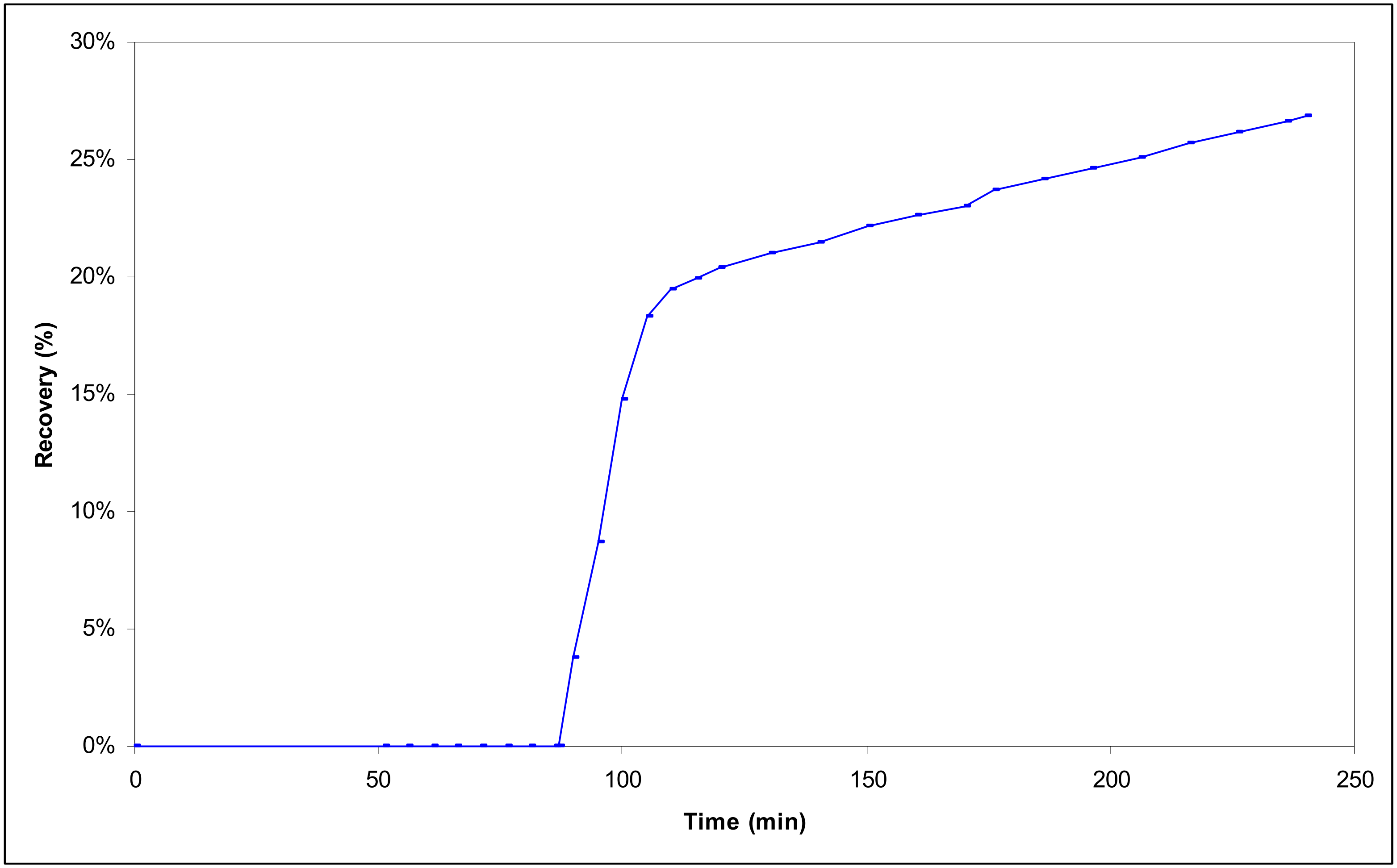

Fig. 4.11— Oil recovery versus time for run no. 9.

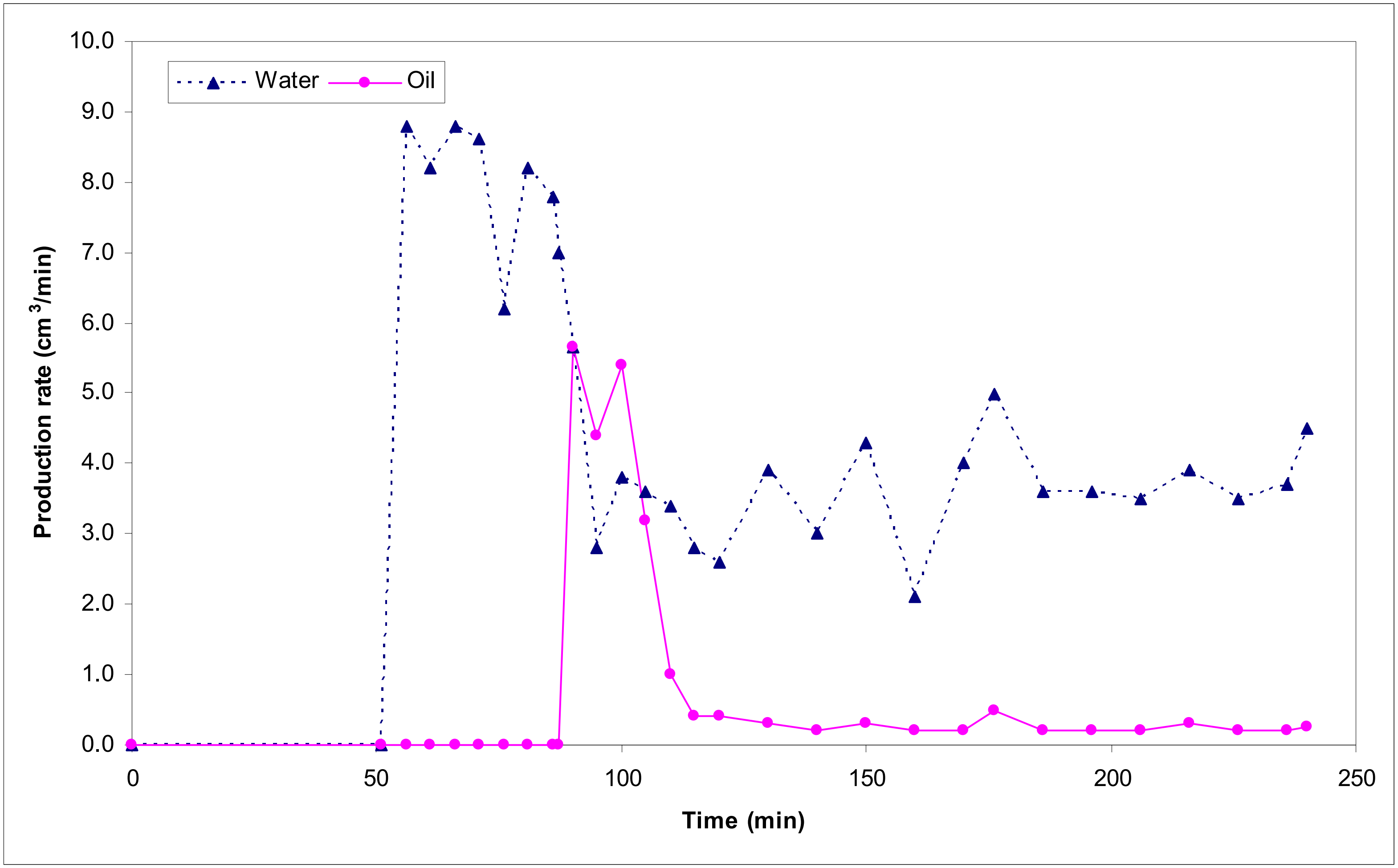

Fig. 4.12— Oil and water production rates versus time for run no. 9.

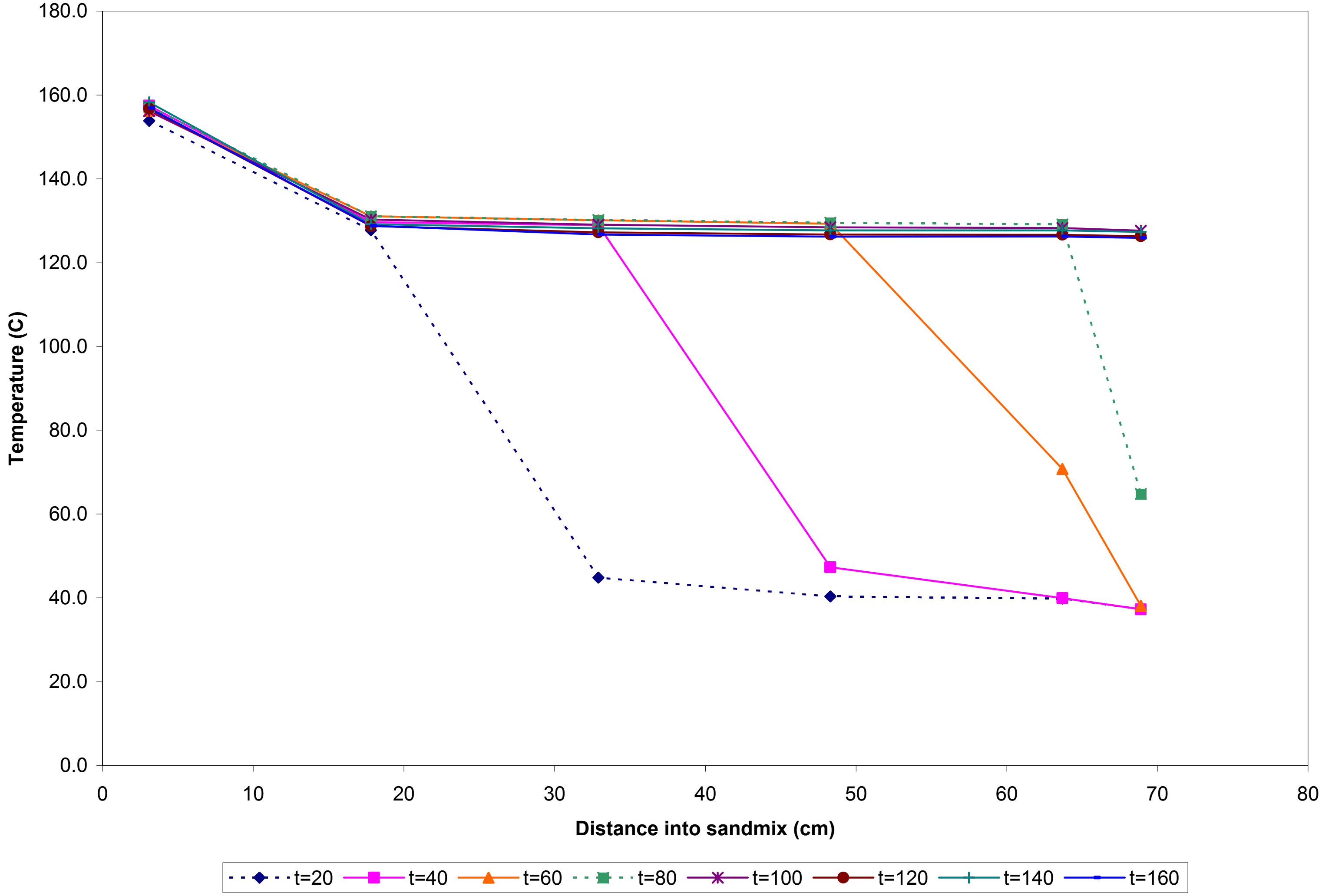

Fig. 4.13— Propagation of temperature in the sand mix for run no. 9.

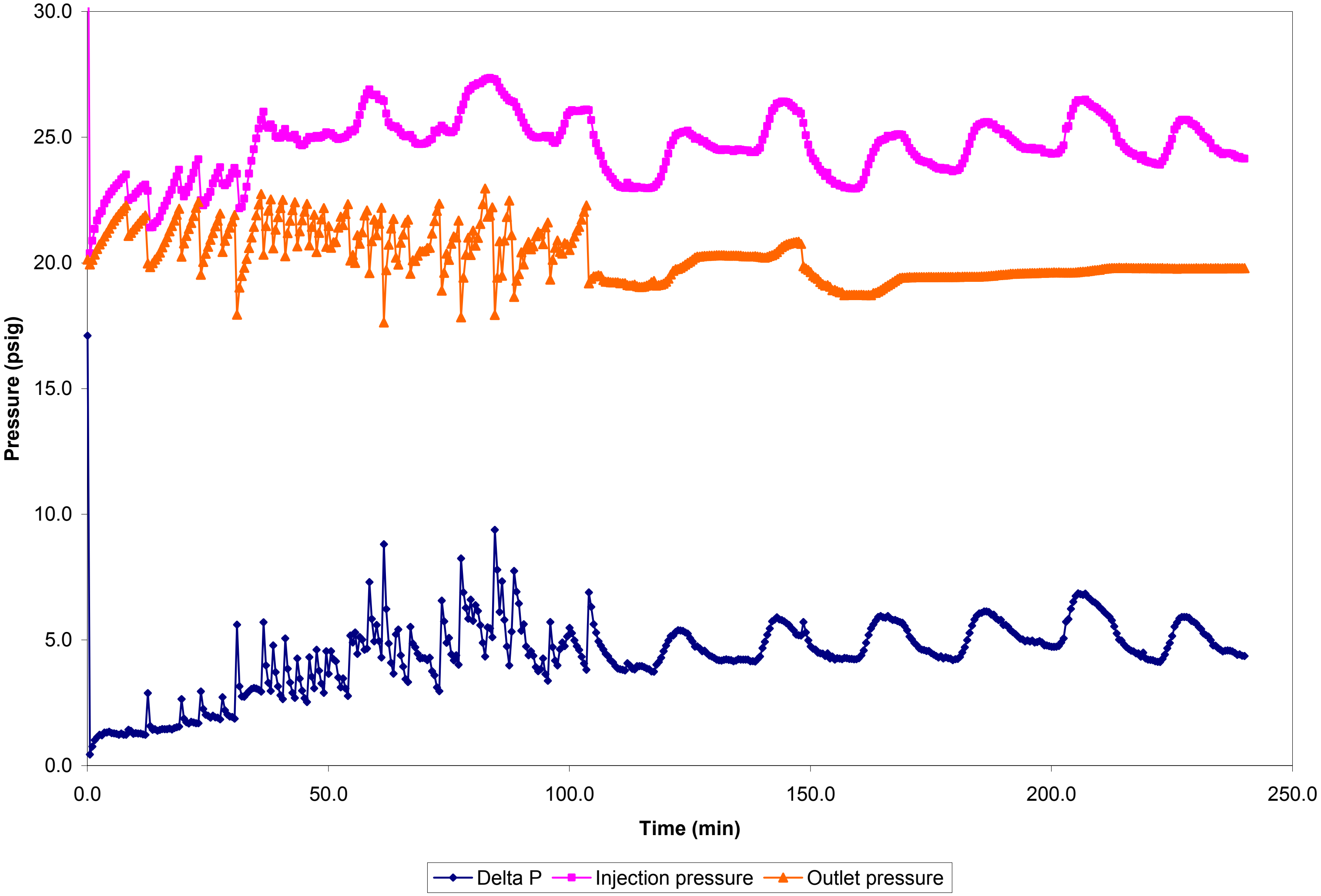

Fig. 4.14— Cell pressures versus time for run no. 9.

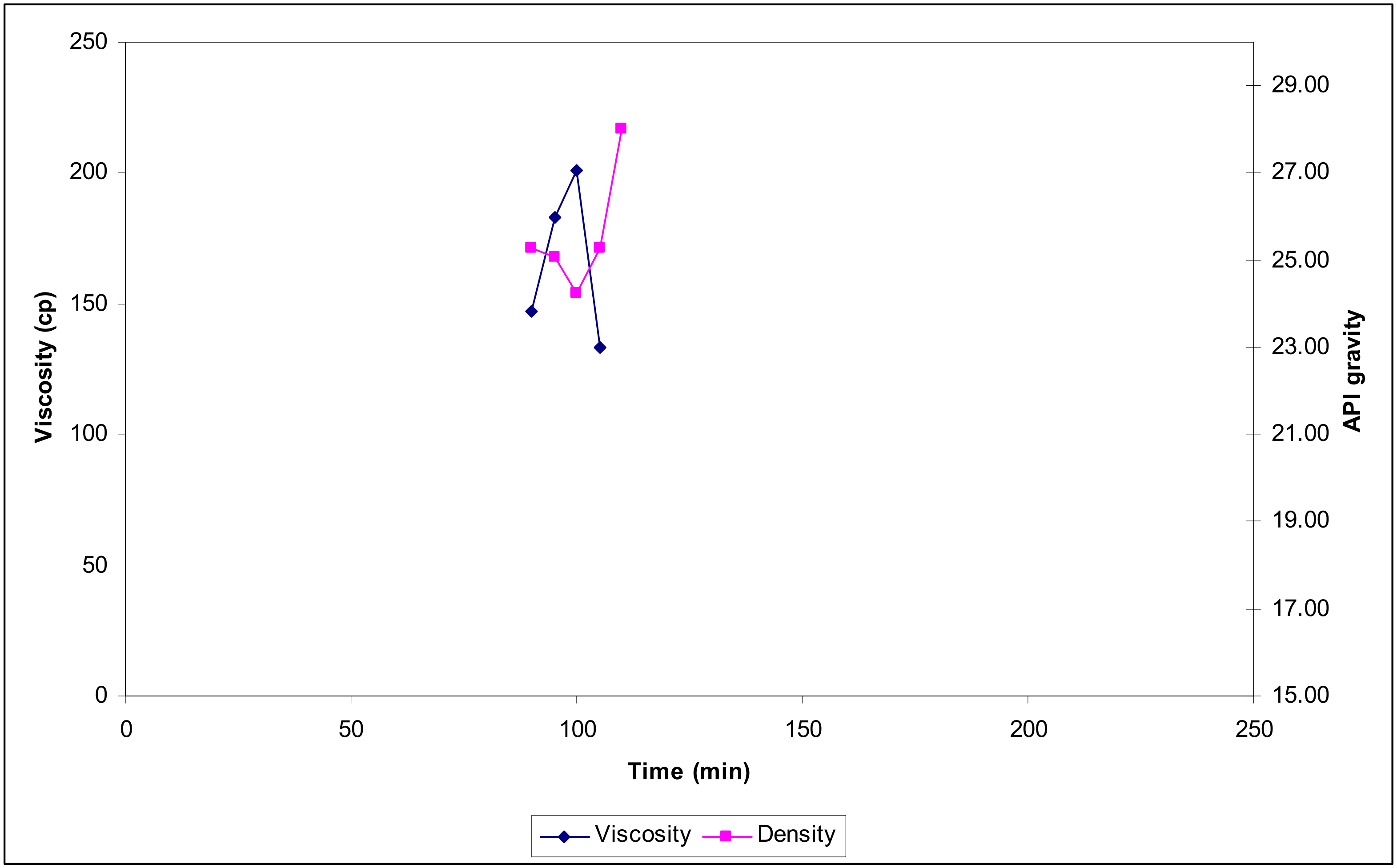

Fig. 4.15— Viscosity and density from the collected samples of run no. 9.

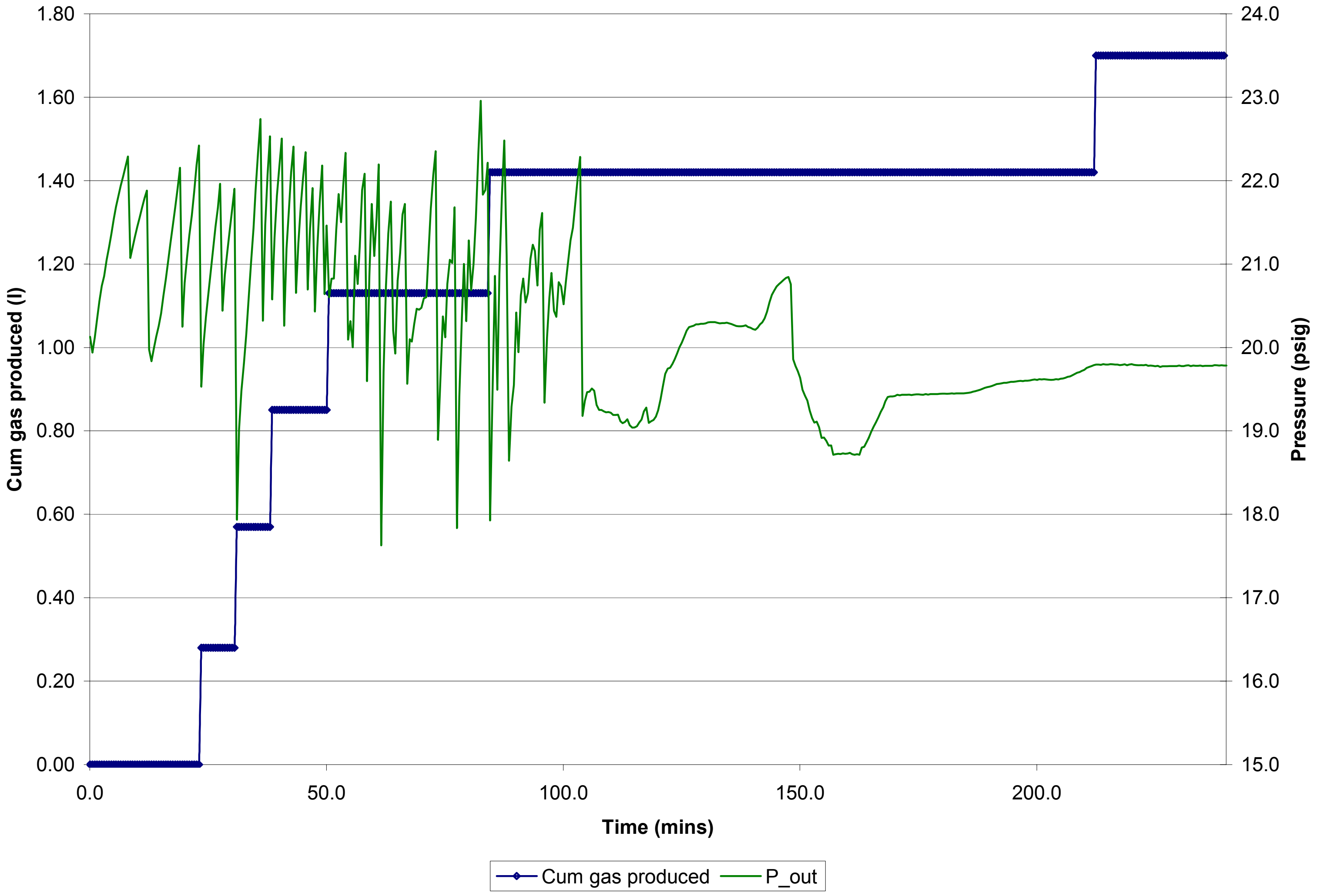

Fig. 4.16— Cumulative gas production and outlet pressure versus time for run no. 9.

4.4 Run No. 10 (5:100 Propane:Steam Ratio, 157ºC)

This run is identical to the previous ones except now we are adding 5% mass ratio propane to the injected fluid, which translates to 0.175 g/min. The movement of the steam front can be followed in **Fig. 4.17**. The injection temperature is kept steady at 157ºC throughout the run, and little fluctuation is observed.

Cumulative oil and water production versus time is shown in **Fig. 4.18**. Ultimate recovery at the end of the 4 hour run is about 133 cm^3, or 32% of OOIP, as can be seen in **Fig. 4.19**. **Fig. 4.20** shows the oil and water production rates as a function of time. The first oil is produced after 81 minutes of injection, with a peak rate of about 7.3 cm^3/min after 89 minutes.

Fig. 4.21 shows how the temperature propagation at 20 minute intervals for the different thermocouples. It takes about 100 minutes for the whole cell to reach a more or less constant temperature of 127ºC.

The injection pressure, outlet pressure, and differential pressure are shown in **Fig. 4.22.** The outlet pressure is kept steady at 20 psig, a task which is easier now that we produce gas. As the oil bank is building up injection pressure increases, and as a result of that so does the differential pressure. From an initial differential pressure of close to zero it reaches highs of about 8 psi before oil production starts. Once that happens it quickly drops down to an average of about 2-4 psi.

Viscosity and density is plotted in **Fig. 4.23**. Cumulative gas production is shown in **Fig. 4.24**. It is plotted along with outlet pressure since gas is only produced once the outlet pressure exceeds the setting of the backpressure valve. The production is fairly smooth instead of the step-wise increase we observed in the first two runs. After about 100 minutes of injection it takes on an almost linear shape, producing gas at a fairly constant rate. About 16 liters of gas is produced.

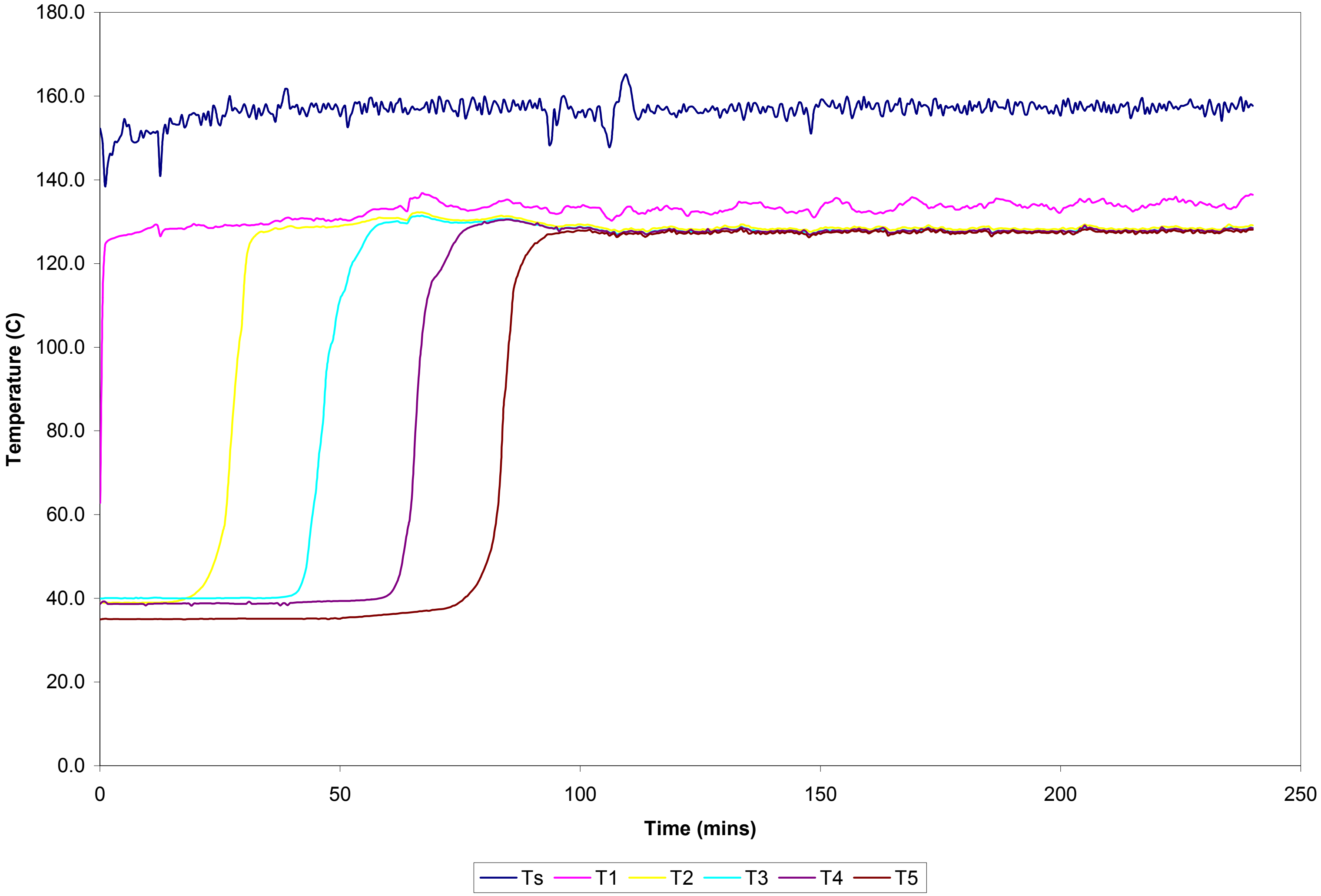

Fig. 4.17— Temperature profiles versus time for run no. 10.

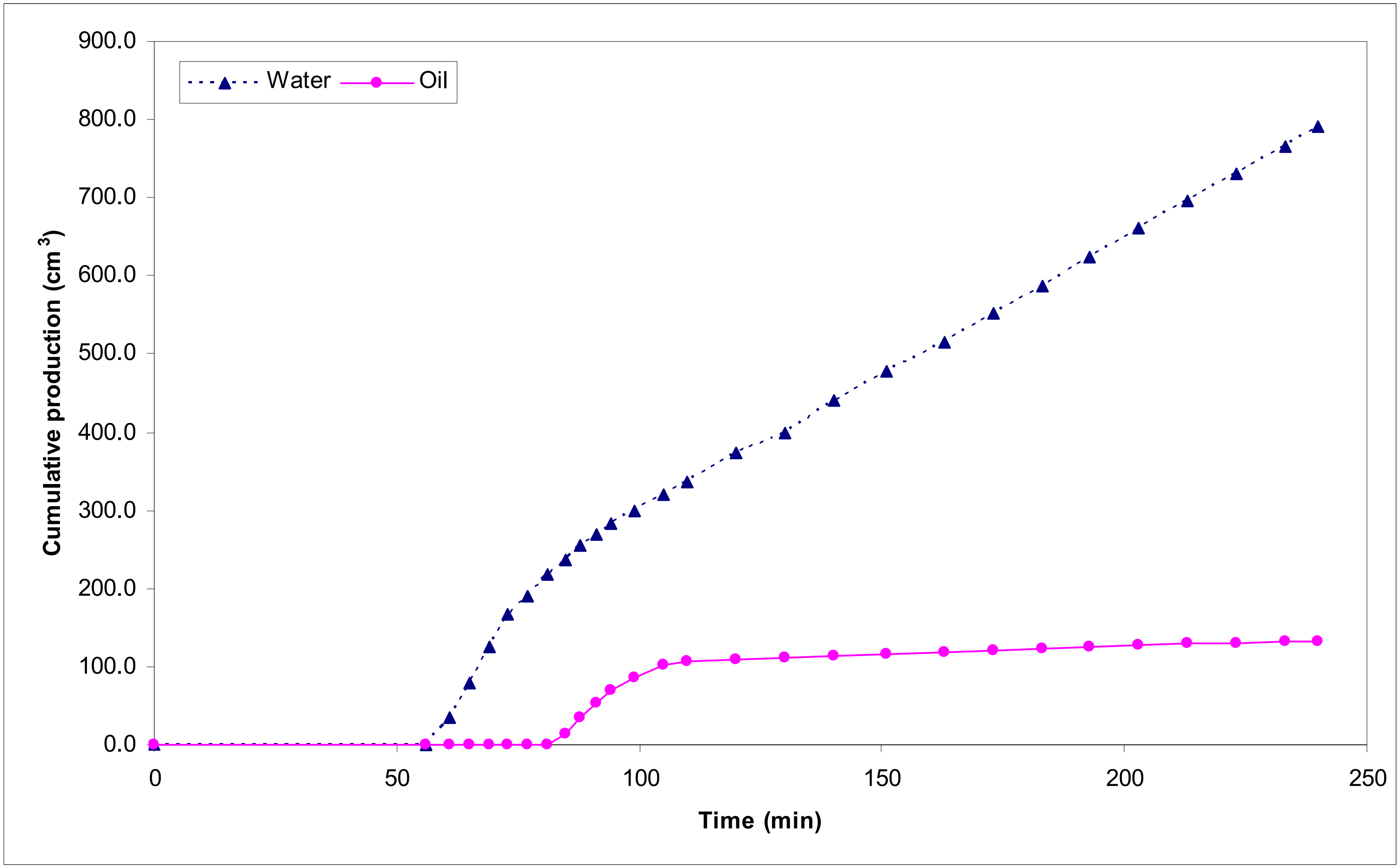

Fig. 4.18— Cumulative oil and water production versus time for run no. 10.

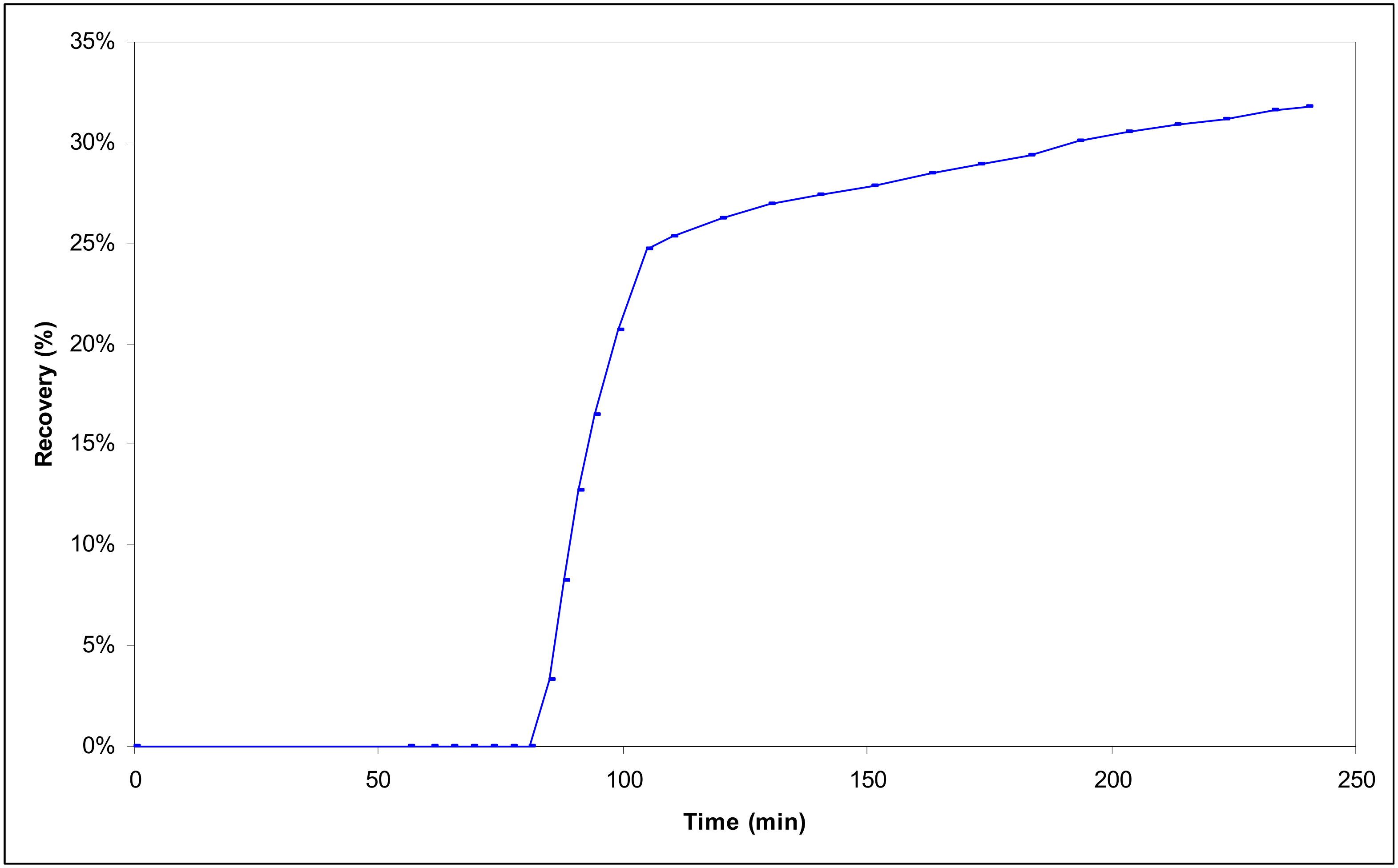

Fig. 4.19— Oil recovery versus time for run no. 10.

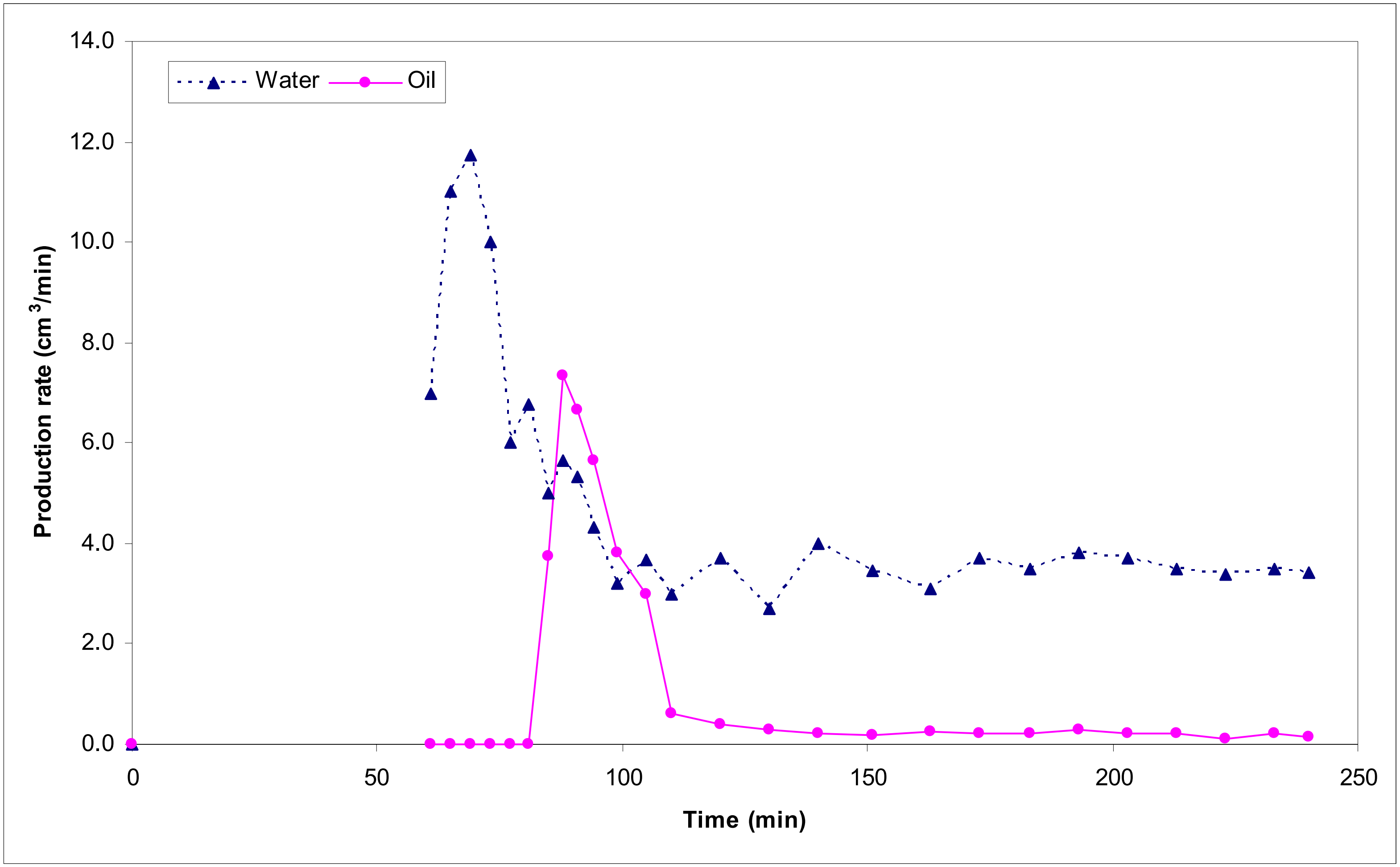

Fig. 4.20— Oil and water production rates versus time for run no. 10.

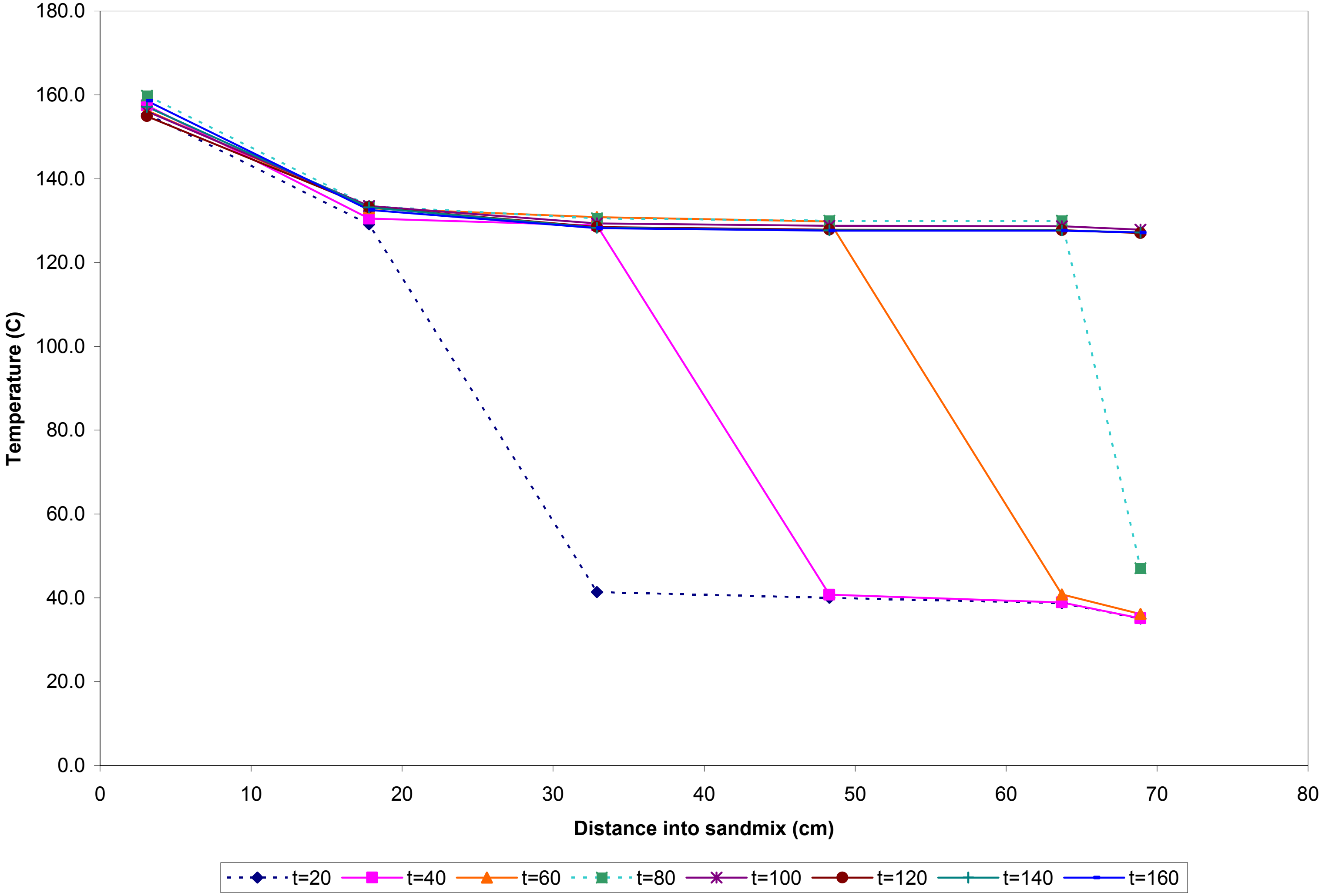

Fig. 4.21— Propagation of temperature in the sand mix for run no. 10.

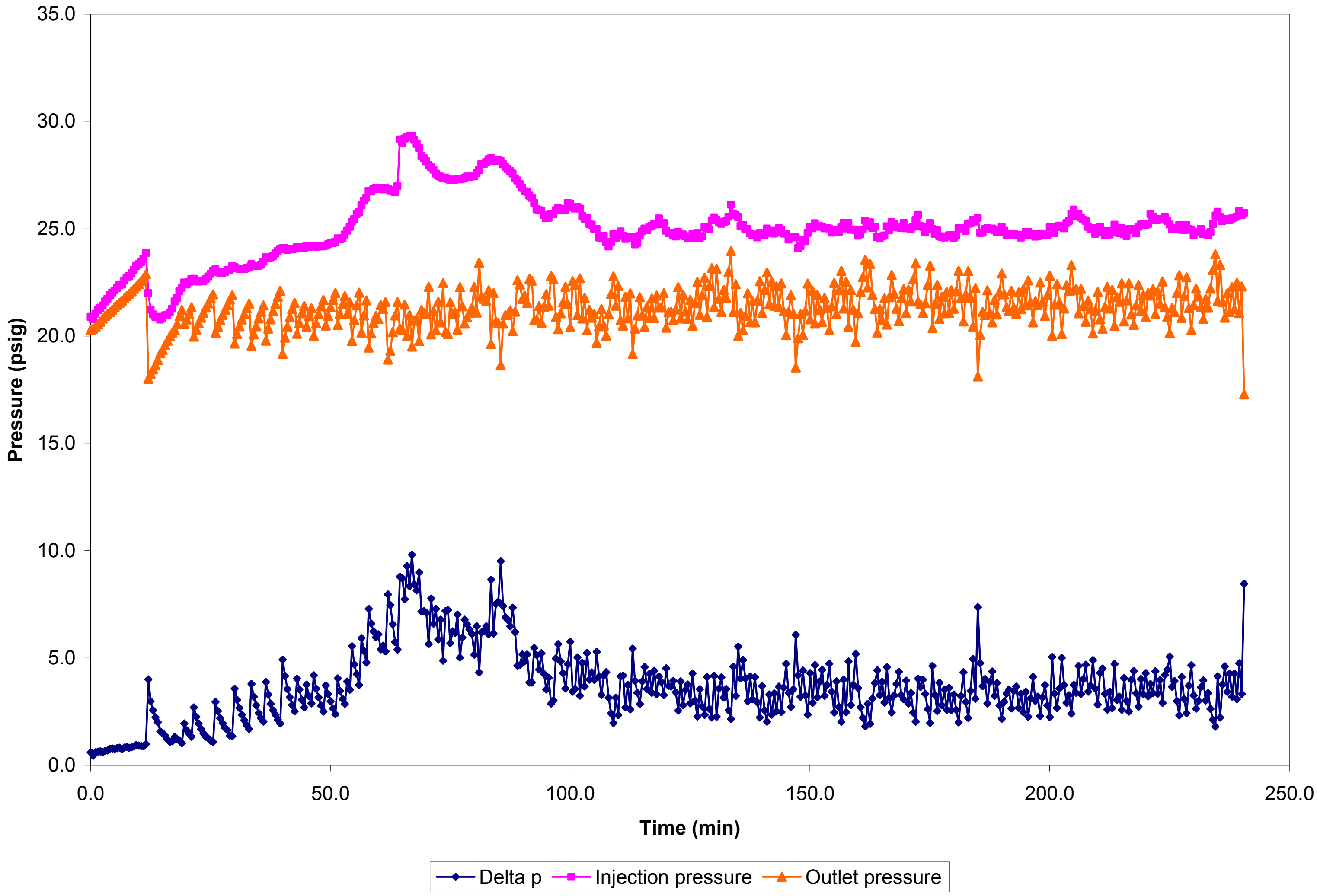

Fig. 4.22— Cell pressures versus time for run no. 10.

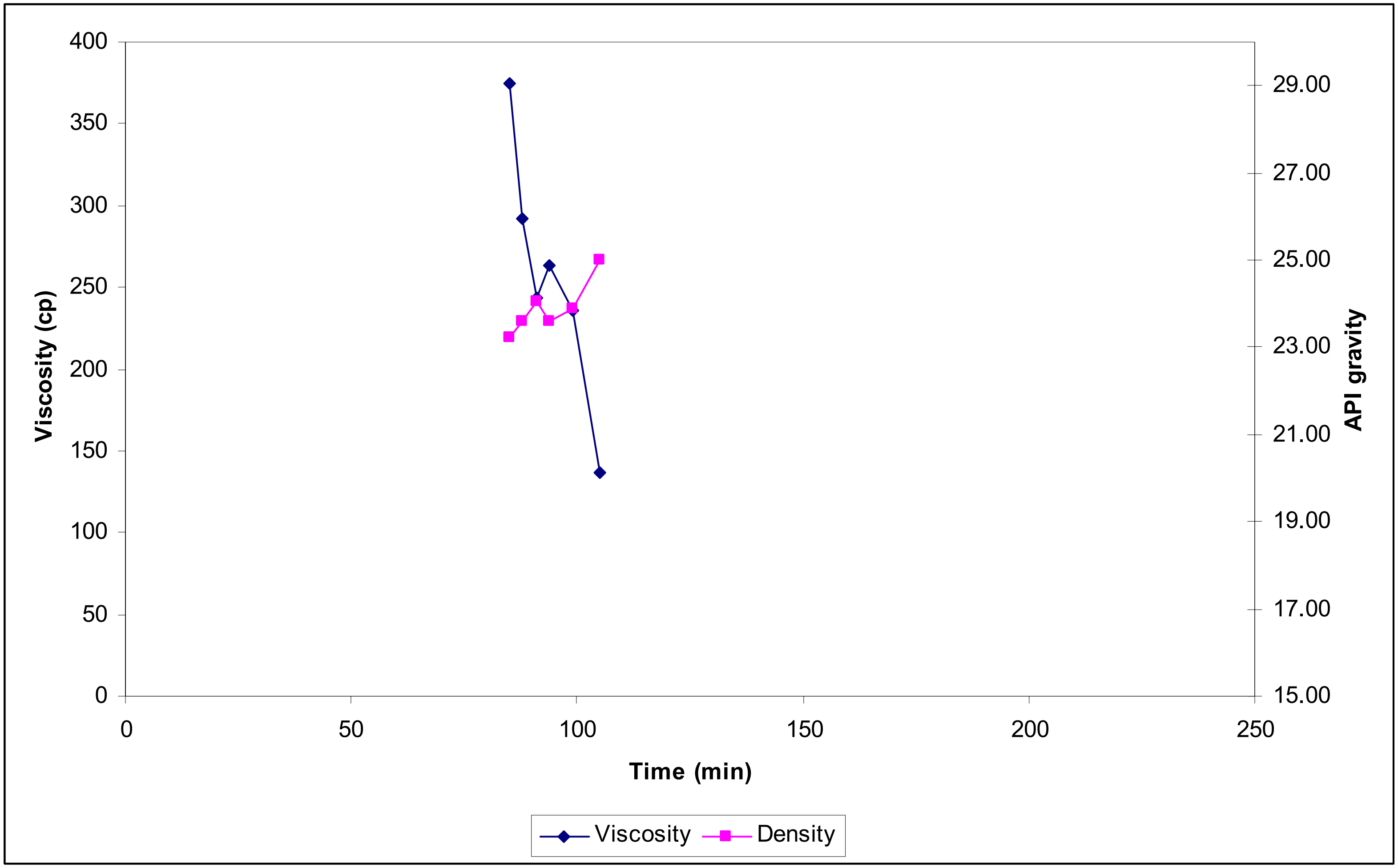

Fig. 4.23— Viscosity and density from the collected samples of run no. 10.

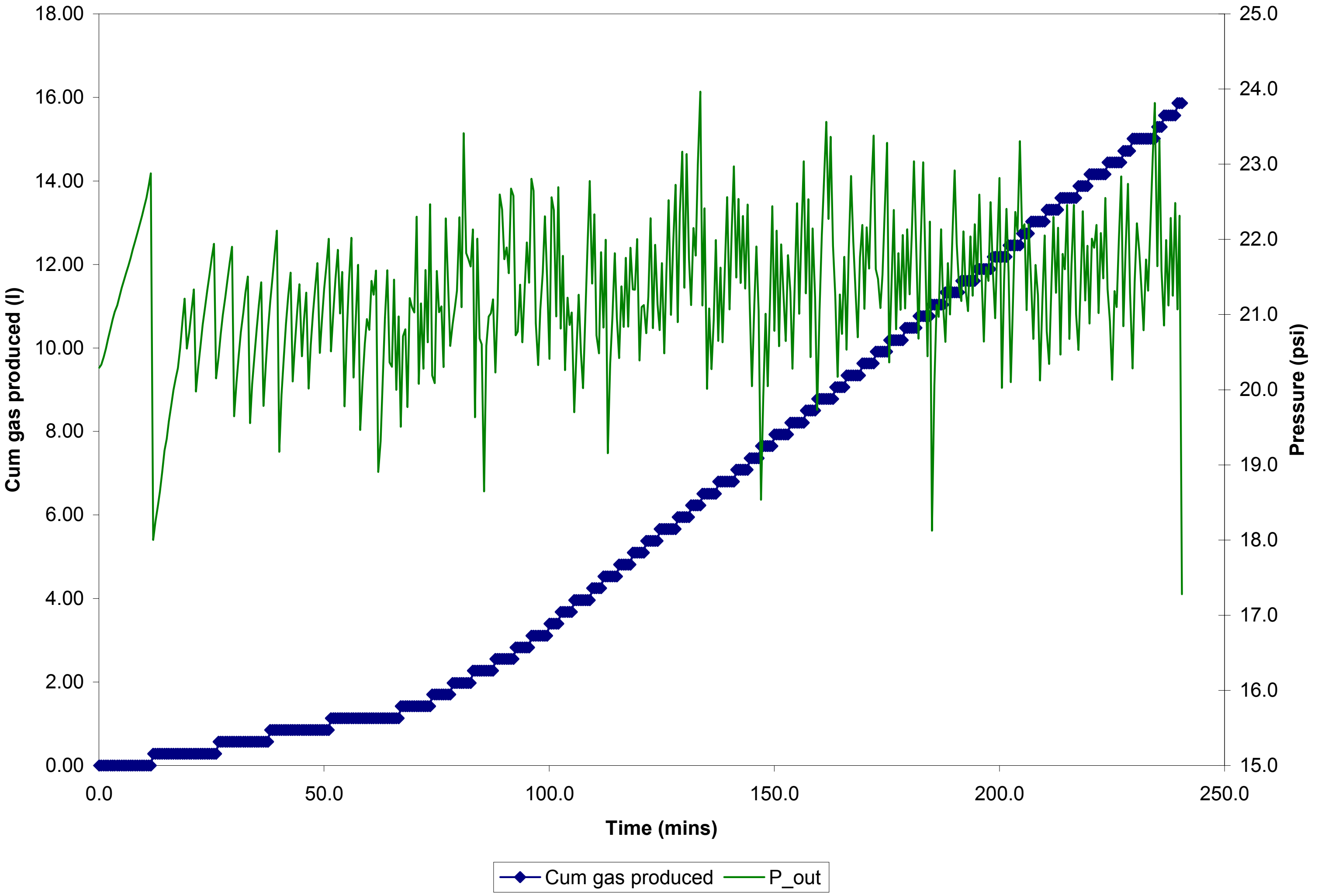

Fig. 4.24— Cumulative gas production and outlet pressure versus time for run no. 10.

4.5 Run No. 11 (5:100 Propane:Steam Ratio, 125ºC)

For this run the injection temperature is lowered just below the saturation point so we are injecting hot water instead of steam. The movement of the front can be followed in **Fig. 4.25**, which shows the temperature profile for all the thermocouples. The injection temperature is kept steady at 125ºC throughout the run, and little fluctuation is observed.

Cumulative oil and water production versus time is shown in **Fig. 4.26**. Ultimate recovery at the end of the 7 hour run is about 84 cm^3, or 20% of OOIP, as can be seen in **Fig. 4.27**. **Fig. 4.28** shows the oil and water production rates as a function of time. The first oil is produced after 80 minutes of injection, but at low rates. The oil bank appears to be produced after about 300 minutes, at which point the peak rate is a meager 0.7 cm^3/min.

Fig. 4.29 shows how the temperature propagation at 20 minute intervals for the different thermocouples. Only T_1 actually stabilize at 125ºC, the rest of the cell never reaches constant temperature. .

The injection pressure, outlet pressure, and differential pressure are shown in **Fig. 4.30.** The outlet pressure is kept steady at 20 psig. A differential pressure builds up very slowly until the oil bank is produced after 300 minutes of injection, reaching highs of up to 5-6 psi. After this point it seems to slowly drop to an average of about 4 psi before the run is aborted.

Viscosity and density is plotted in **Fig. 4. 31**. Cumulative gas production is shown in **Fig. 4.32**. It is plotted along with outlet pressure since gas is only produced once the outlet pressure exceeds the setting of the backpressure valve. The production is also here smooth and linear. Close to 35 liters of propane is produced during the run.

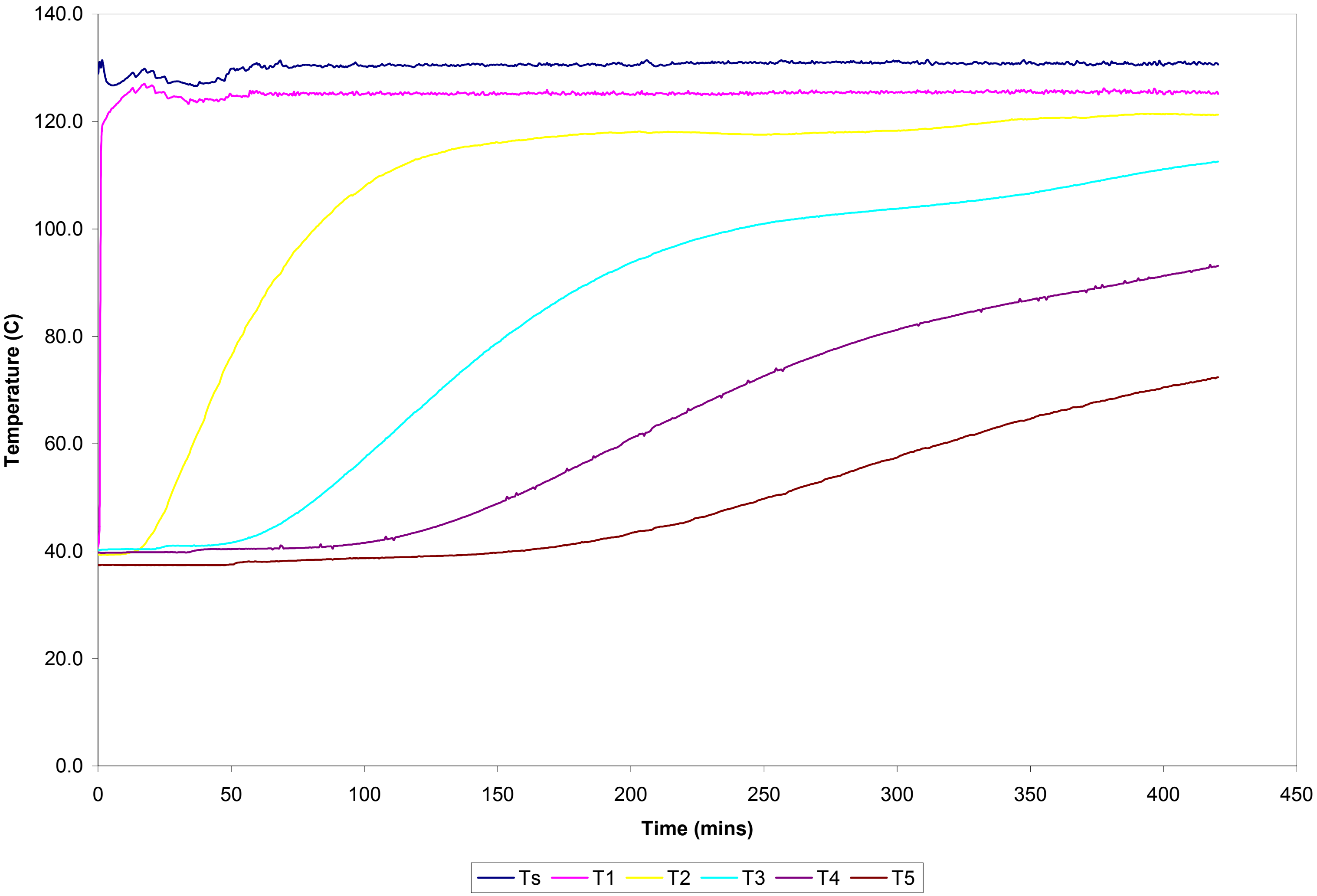

Fig. 4.25— Temperature profiles versus time for run no. 11.

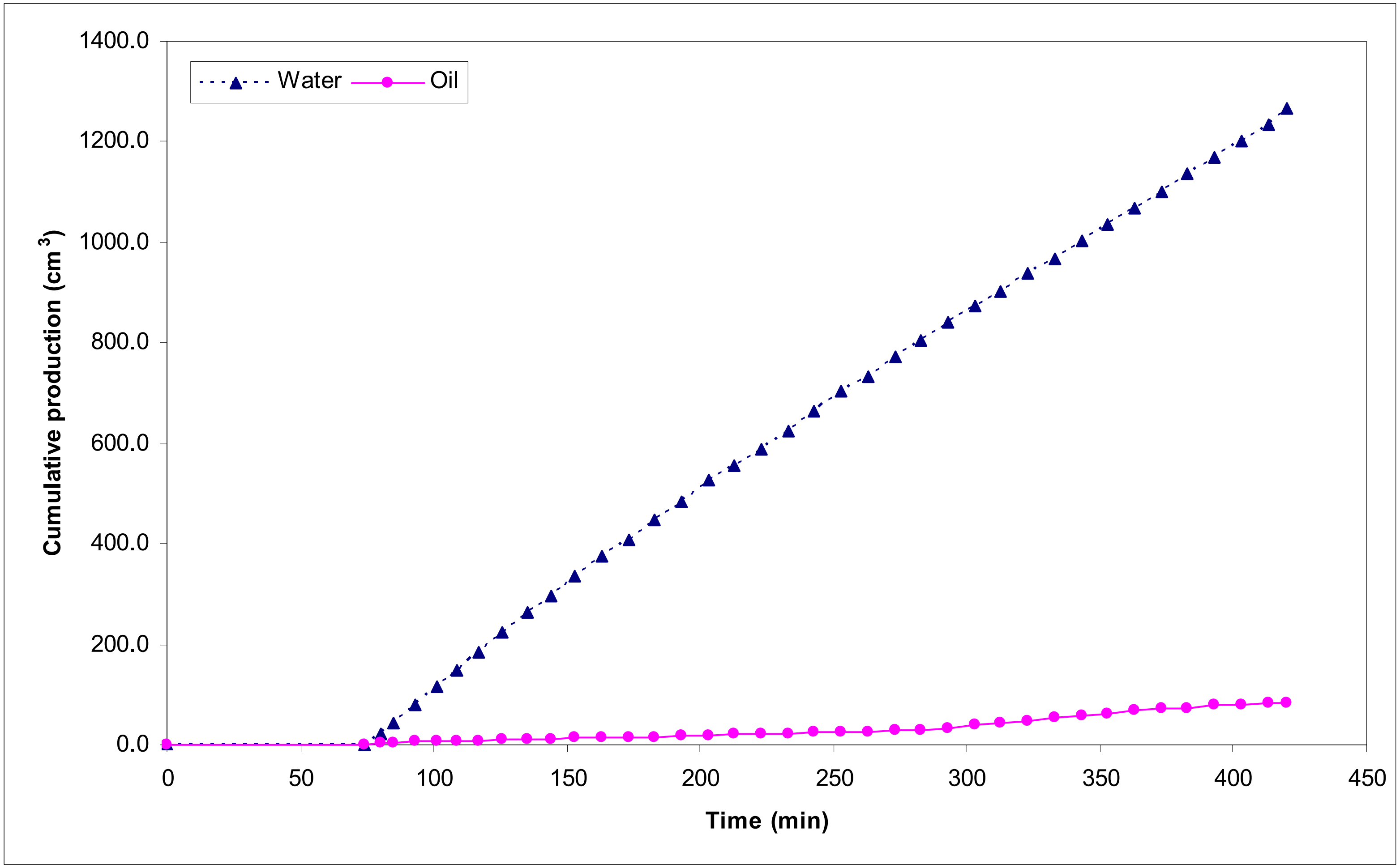

Fig. 4.26— Cumulative oil and water production versus time for run no. 11.

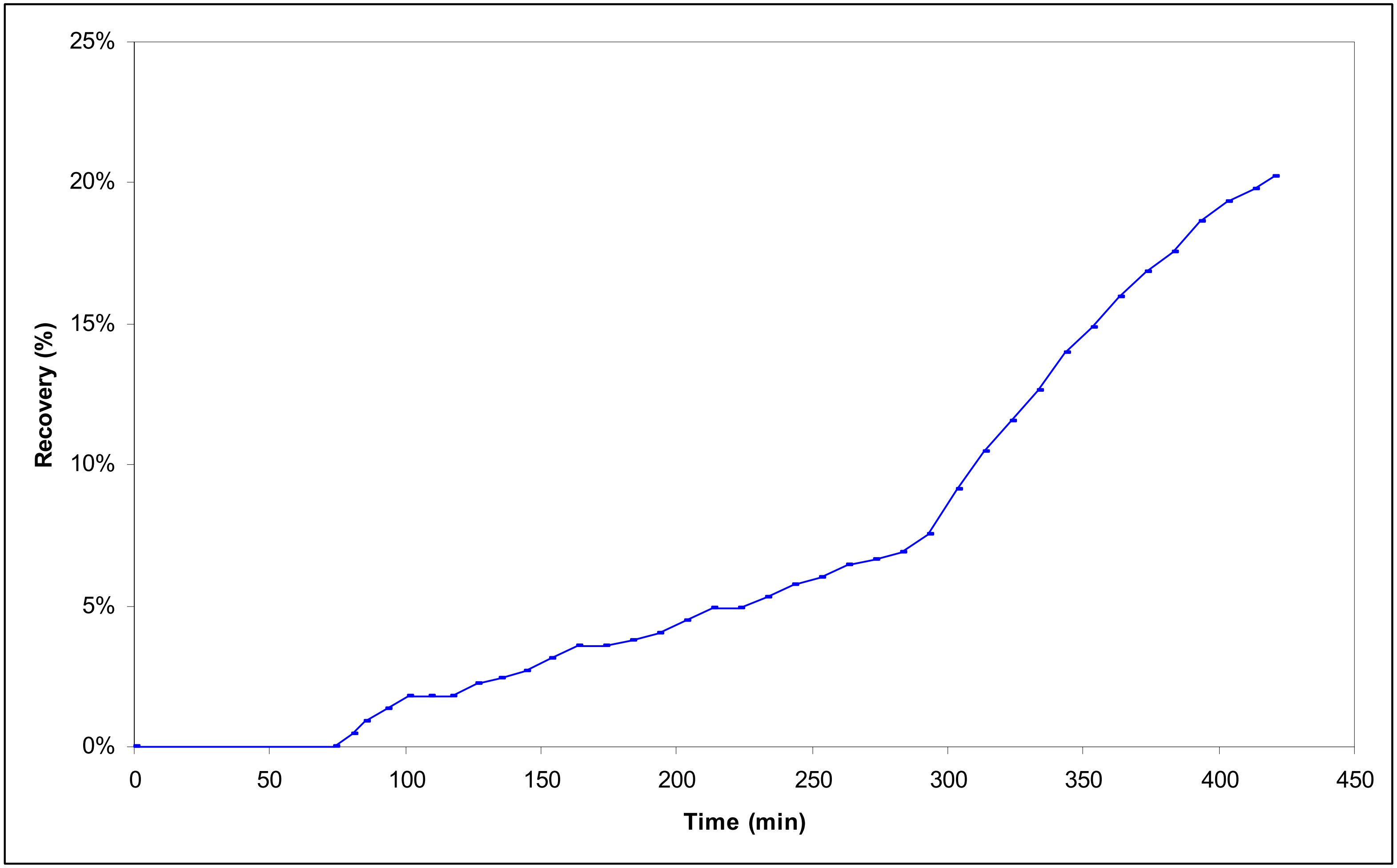

Fig. 4.27— Oil recovery versus time for run no. 11.

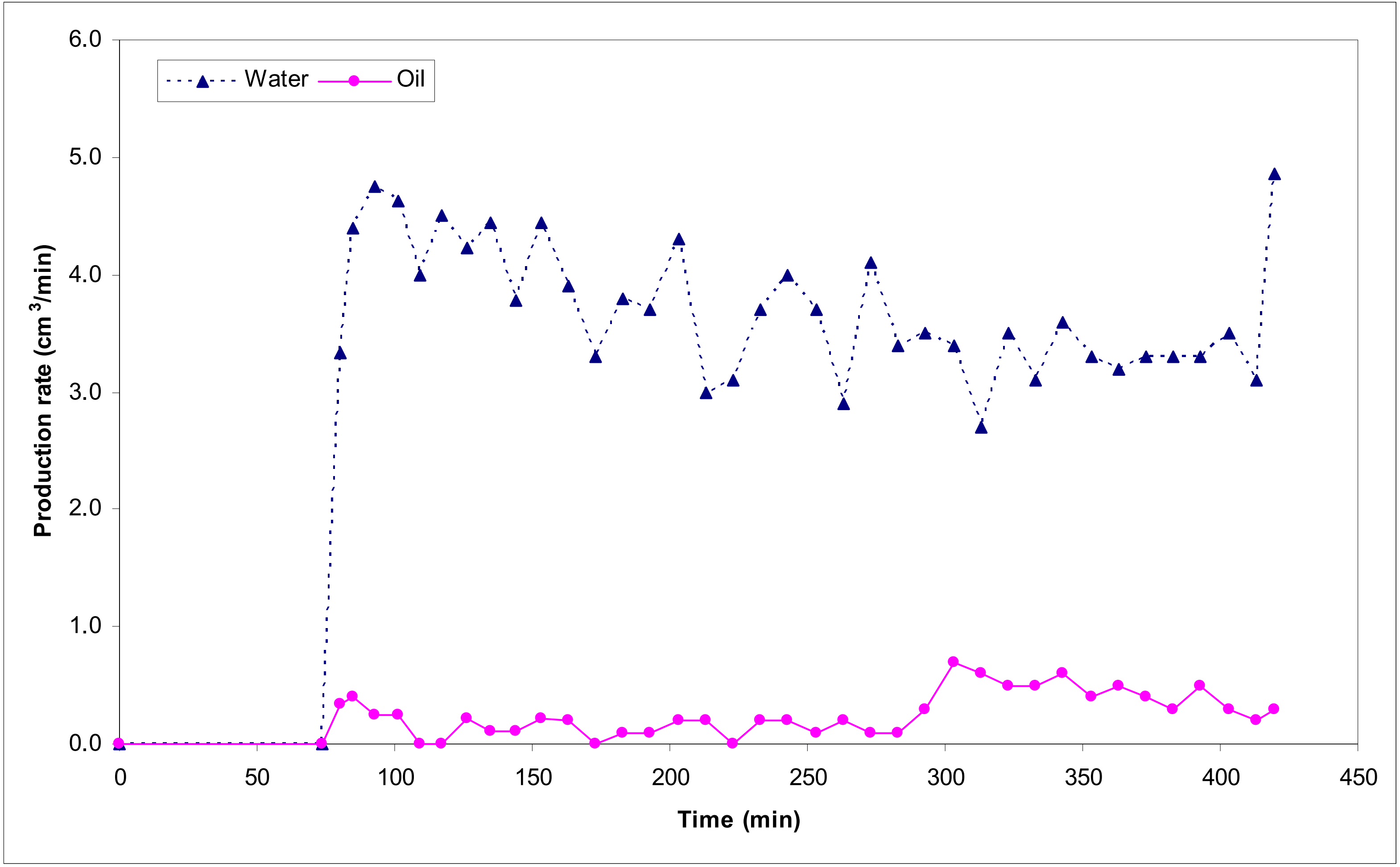

Fig. 4.28— Oil and water production rates versus time for run no. 11.

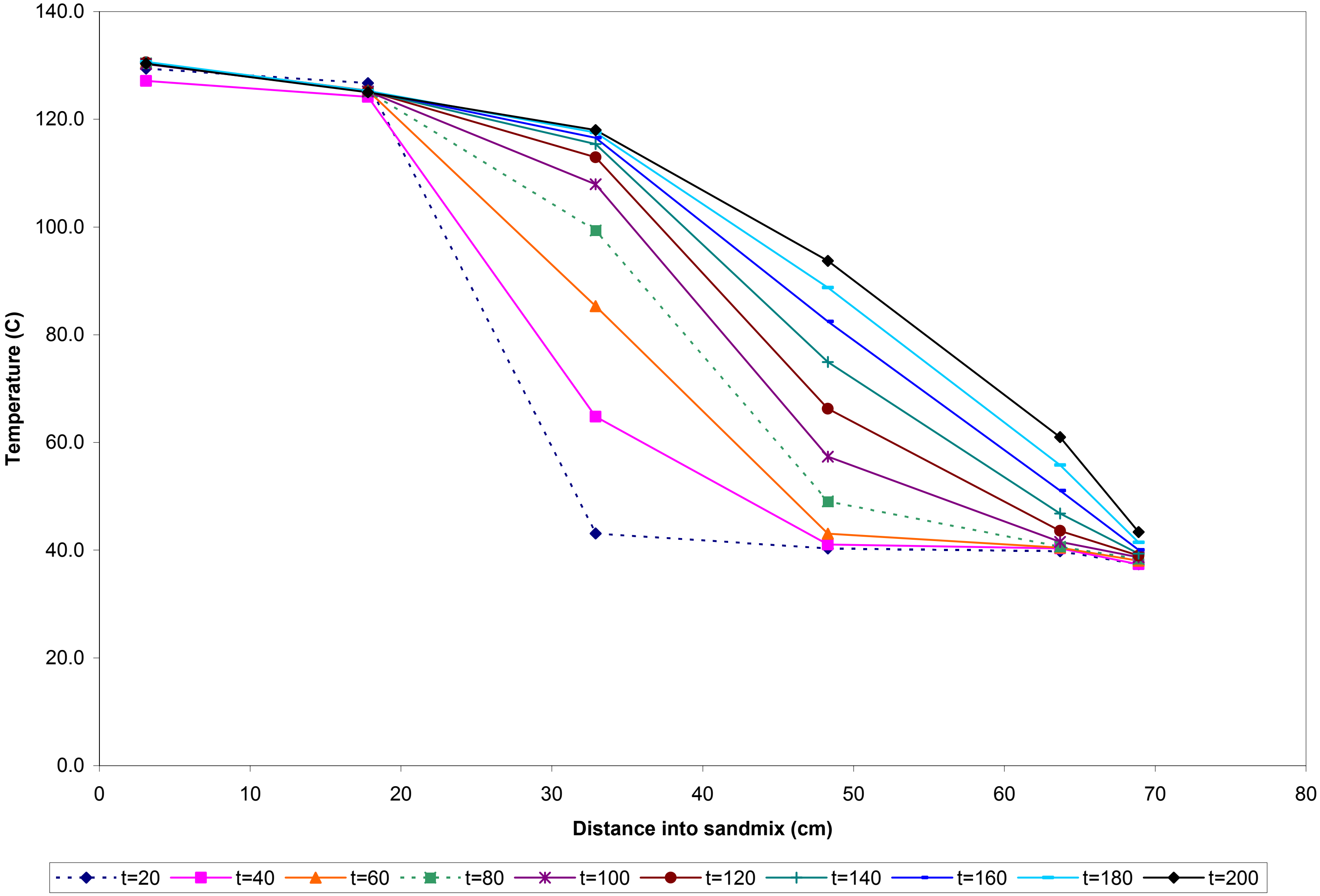

Fig. 4.29— Propagation of temperature in the sand mix for run no. 11.

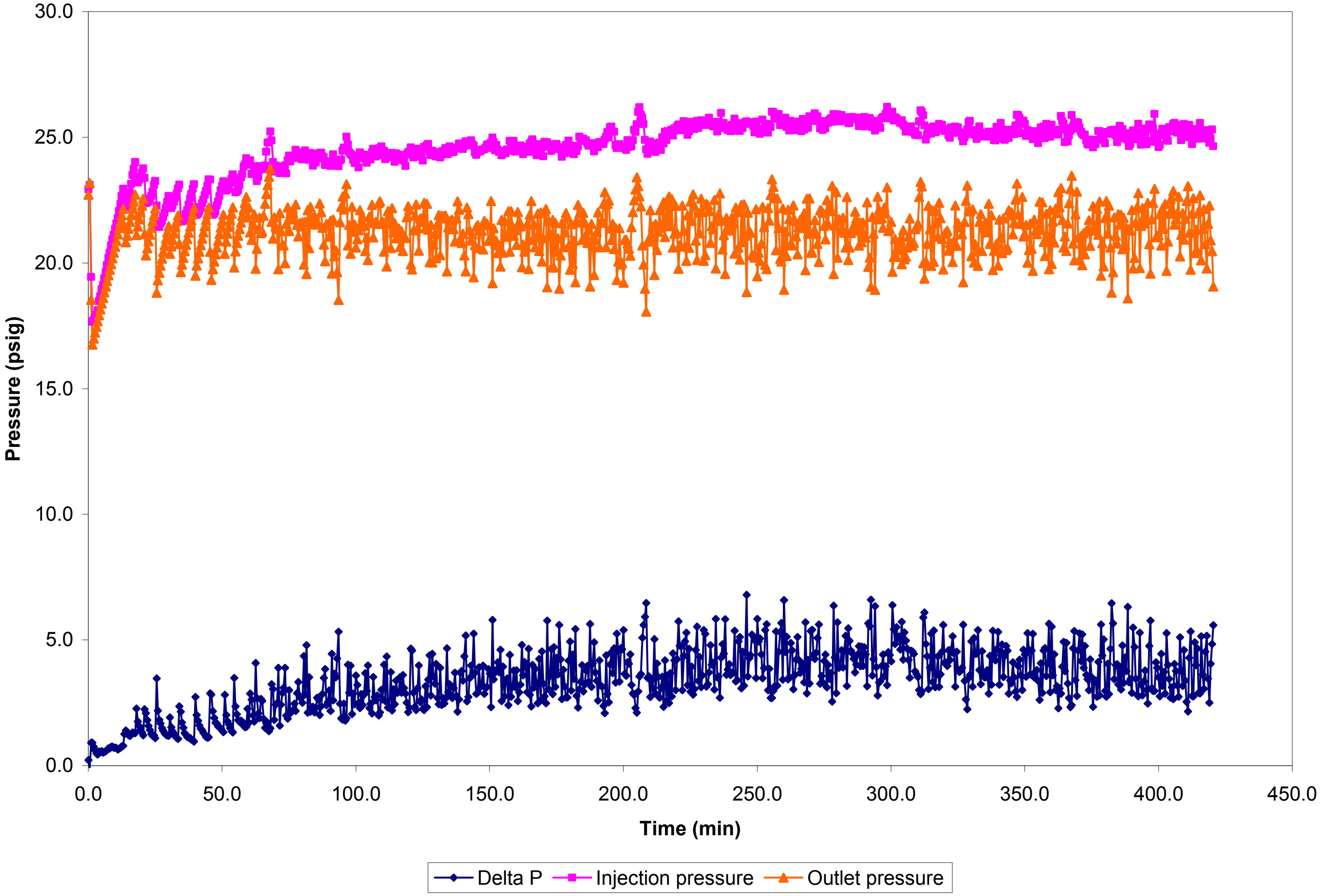

Fig. 4.30— Cell pressures versus time for run no. 11.

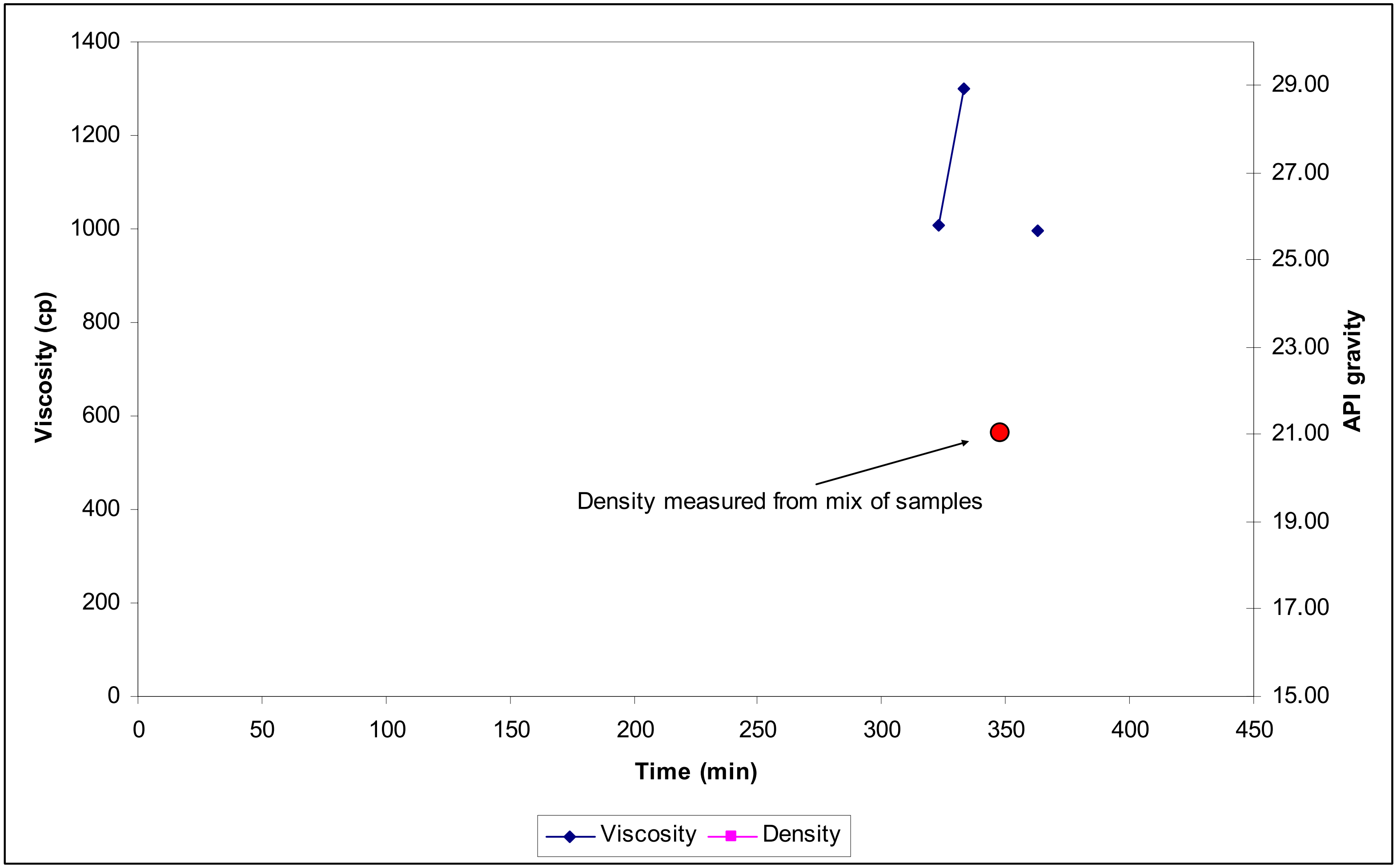

Fig. 4.31— Viscosity and density from the collected samples of run no. 11.

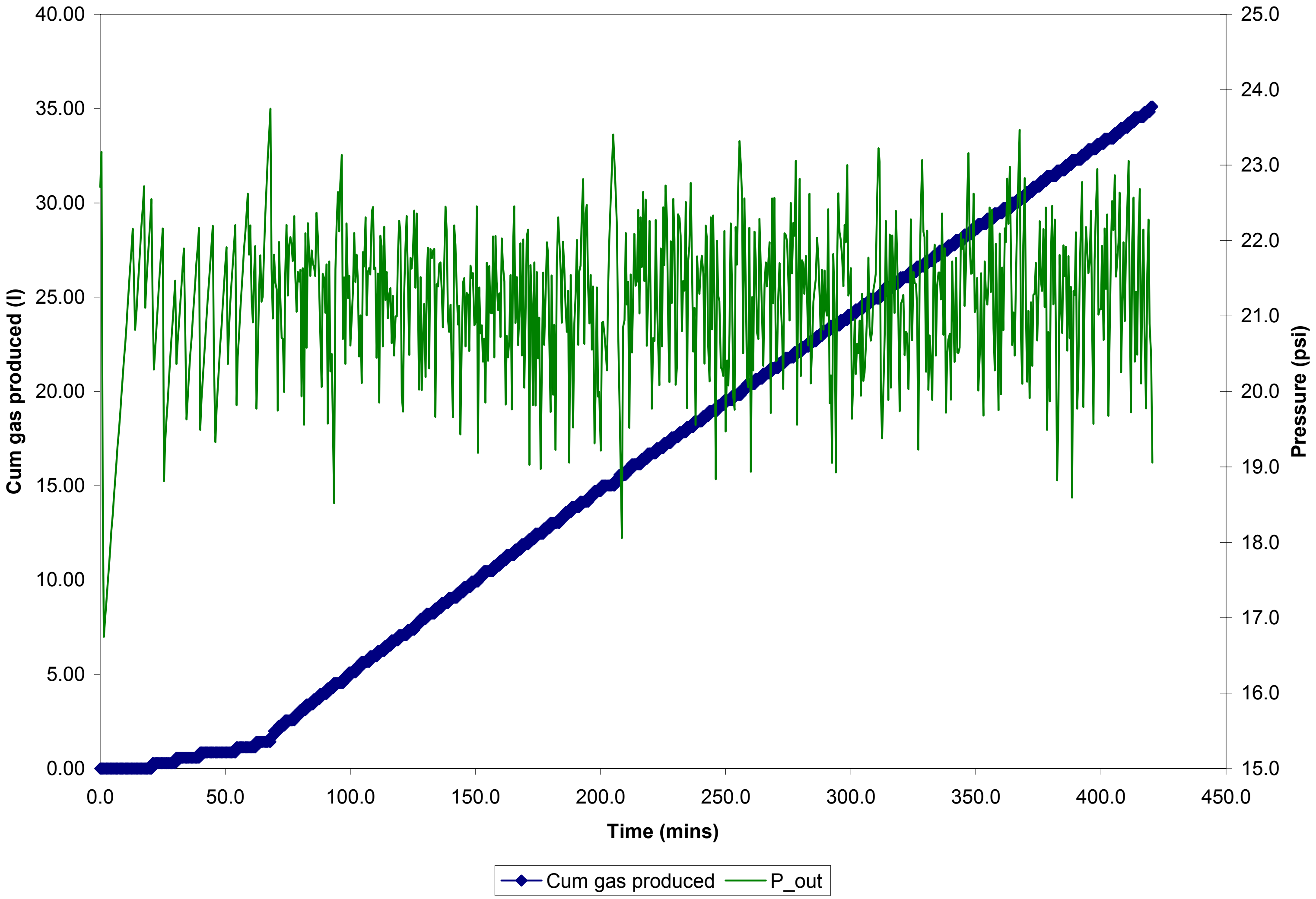

Fig. 4.32— Cumulative gas production and outlet pressure versus time for run no. 11.

4.6 Run No. 12 (5:100 Propane:Steam Ratio, 135ºC)

For this run the injection temperature is set at 135ºC, which is the expected saturation temperature. The movement of the steam front can be followed in **Fig. 4.33**, which shows the temperature profile for all the thermocouples. The injection temperature is kept steady throughout the run, and little fluctuation is observed.

Cumulative oil and water production versus time is shown in **Fig. 4.34**. Ultimate recovery at the end of the 4 hour run is about 105.8 cm^3, or 26% of OOIP, as can be seen in **Fig. 4.35**. **Fig. 4.36** shows the oil and water production rates as a function of time. The first oil is produced after 100 minutes of injection. This is also when the highest production rates are observed, 3 cm^3/min.

Fig. 4.37 shows how the temperature propagation at 20 minute intervals for the different thermocouples. It takes about 140 minutes for the whole cell to reach a more or less constant temperature of 126ºC.

The injection pressure, outlet pressure, and differential pressure are shown in **Fig. 4.38.** The outlet pressure is kept steady at 20 psig. A differential pressure builds up very slowly and never seems to start going back down, ending at about 8 psi.

Viscosity and density is plotted in **Fig. 4.39**. Cumulative gas production is shown in **Fig. 4.40**. It is plotted along with outlet pressure since gas is only produced once the outlet pressure exceeds the setting of the backpressure valve. Close to 21 liters of propane is produced during the run.

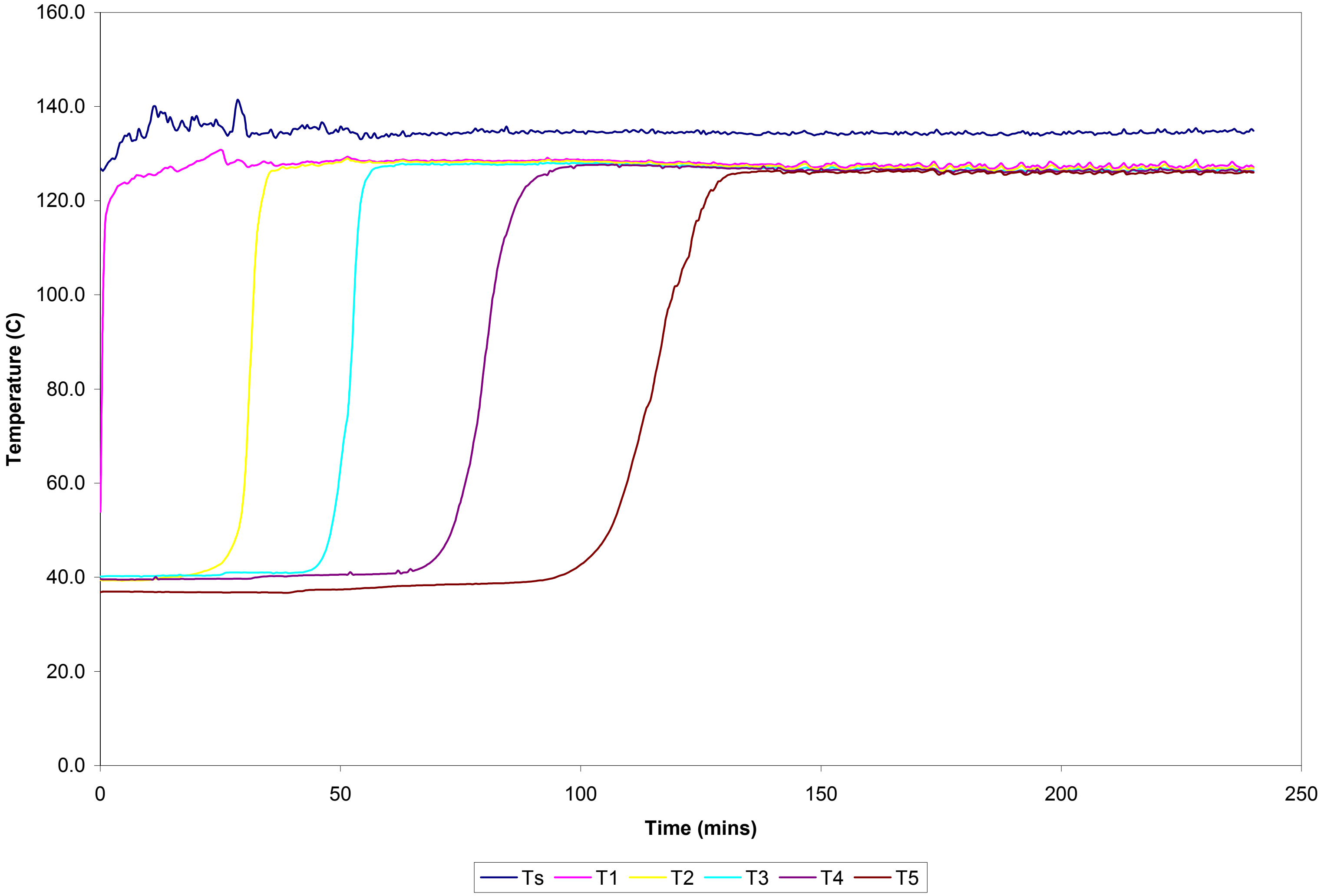

Fig. 4.33— Temperature profiles versus time for run no. 12.

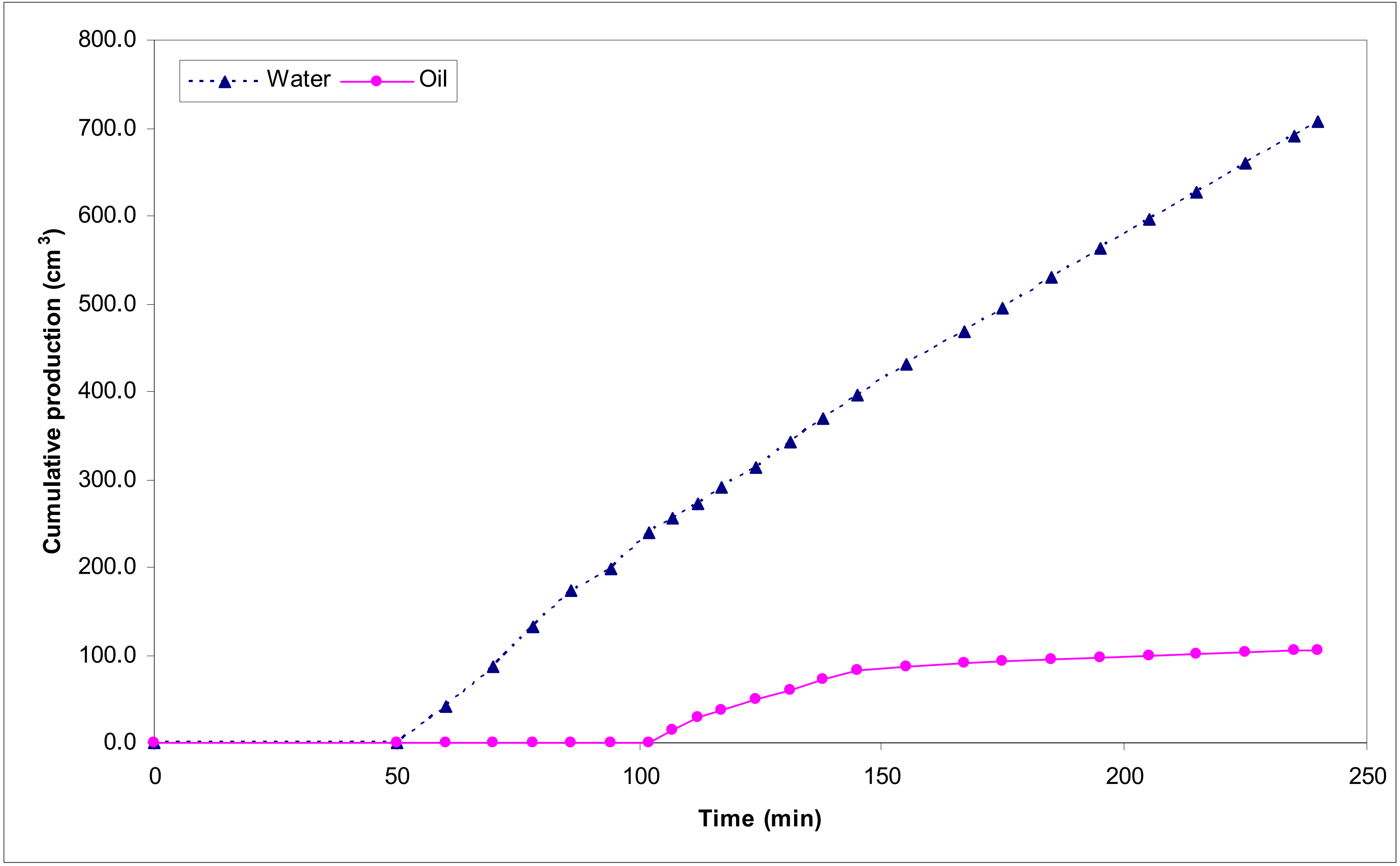

Fig. 4.34— Cumulative oil and water production versus time for run no. 12.

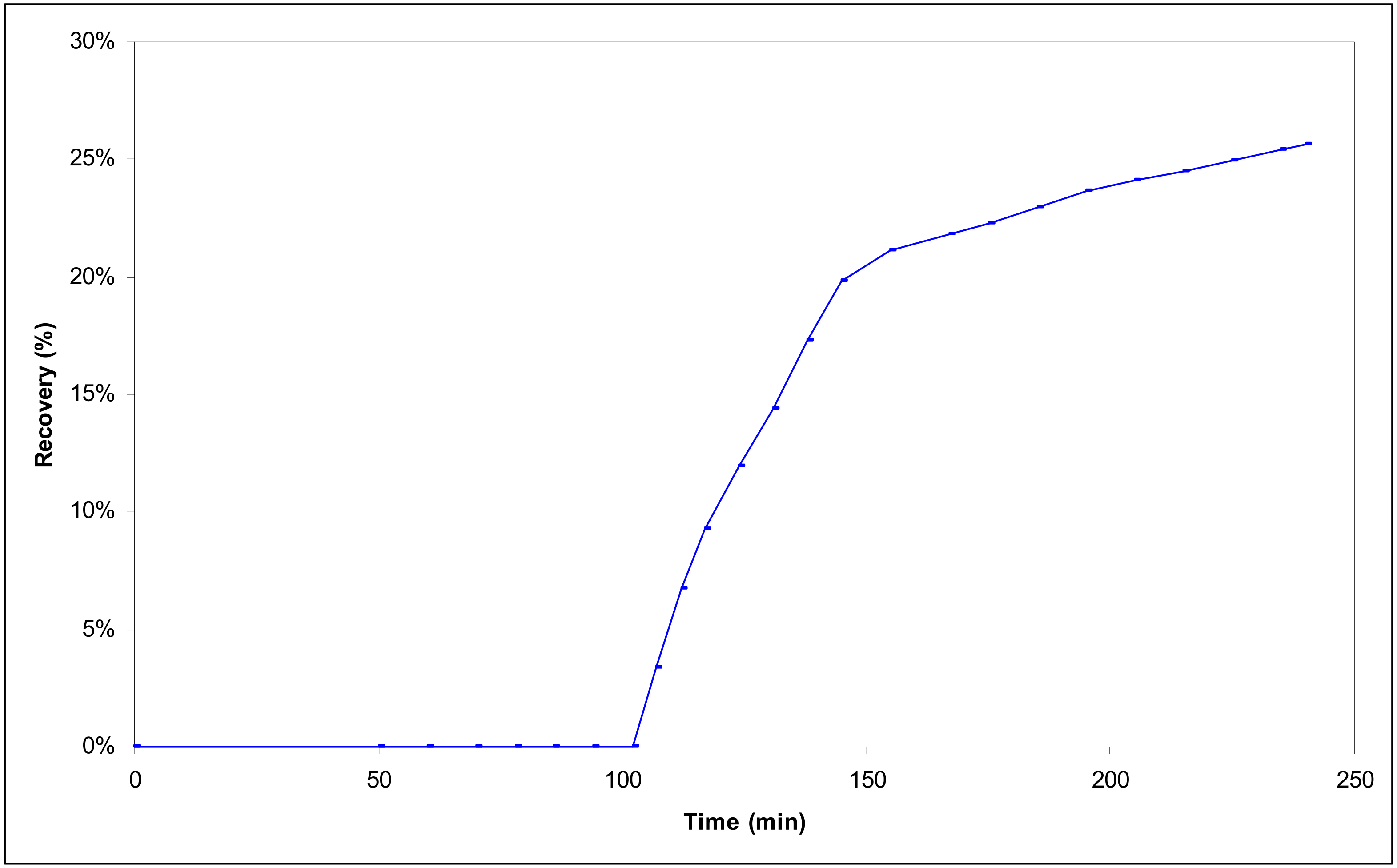

Fig. 4.35— Oil recovery versus time for run no. 12.

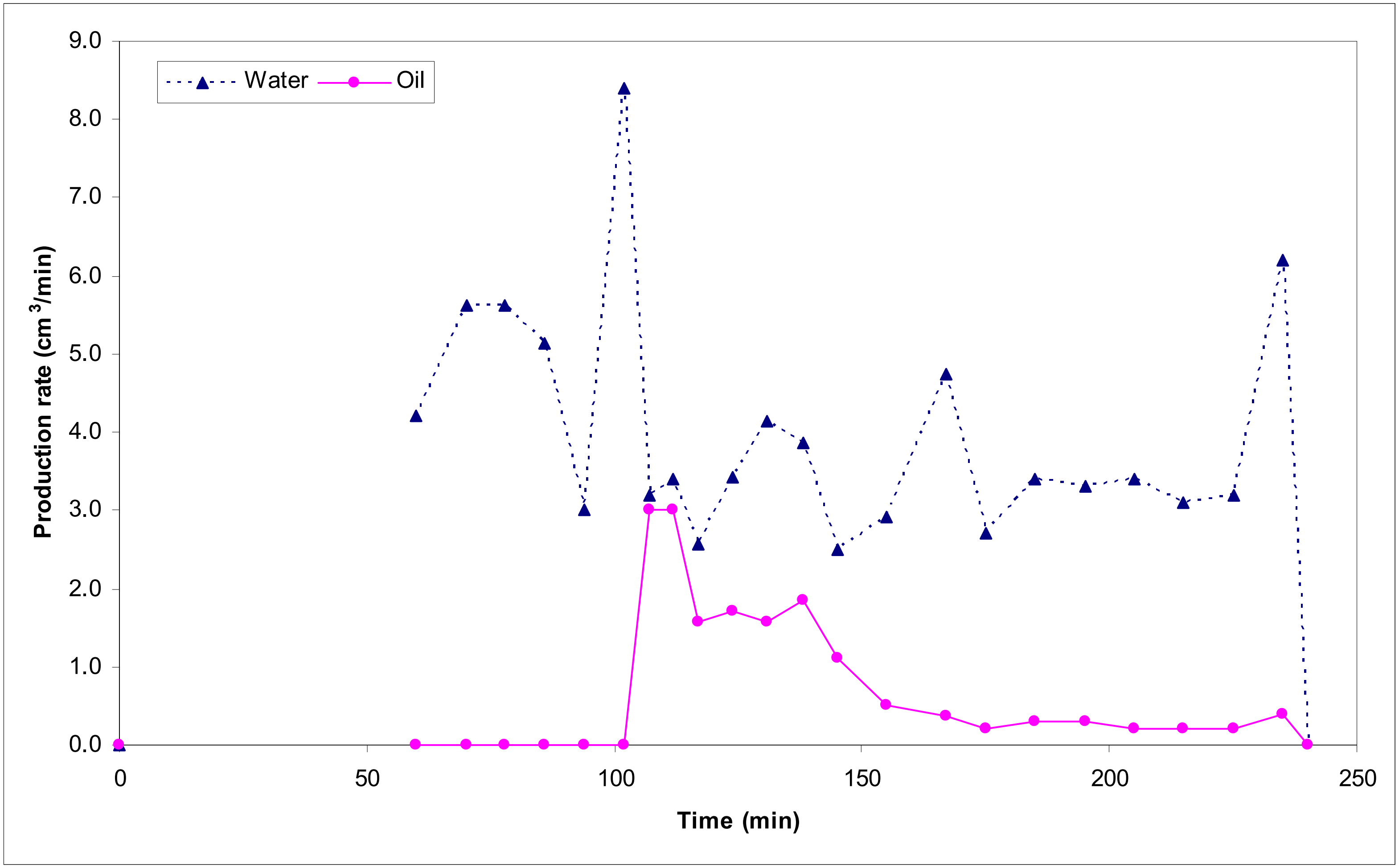

Fig. 4.36— Oil and water production rates versus time for run no. 12.

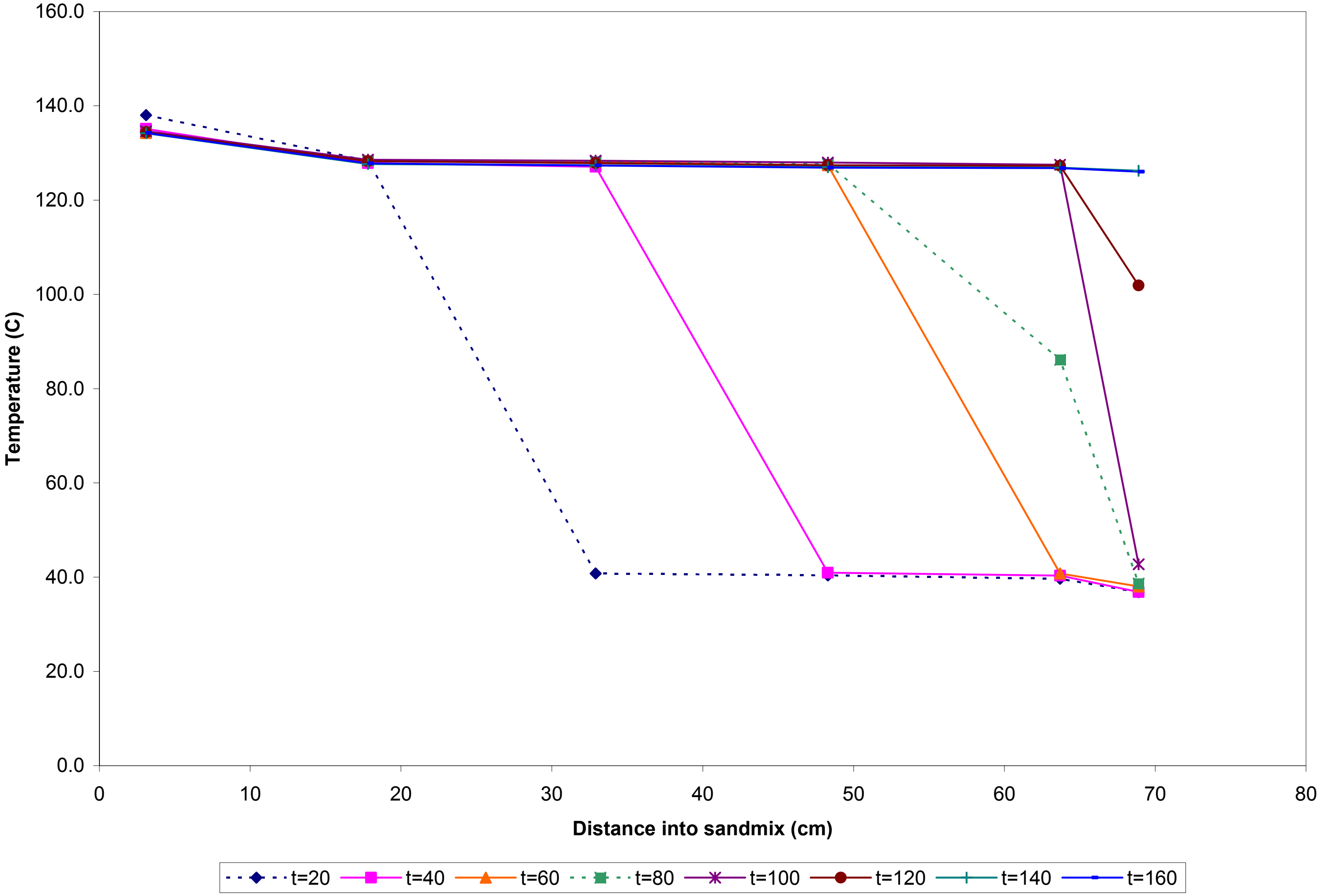

Fig. 4.37— Propagation of temperature in the sand mix for run no. 12.

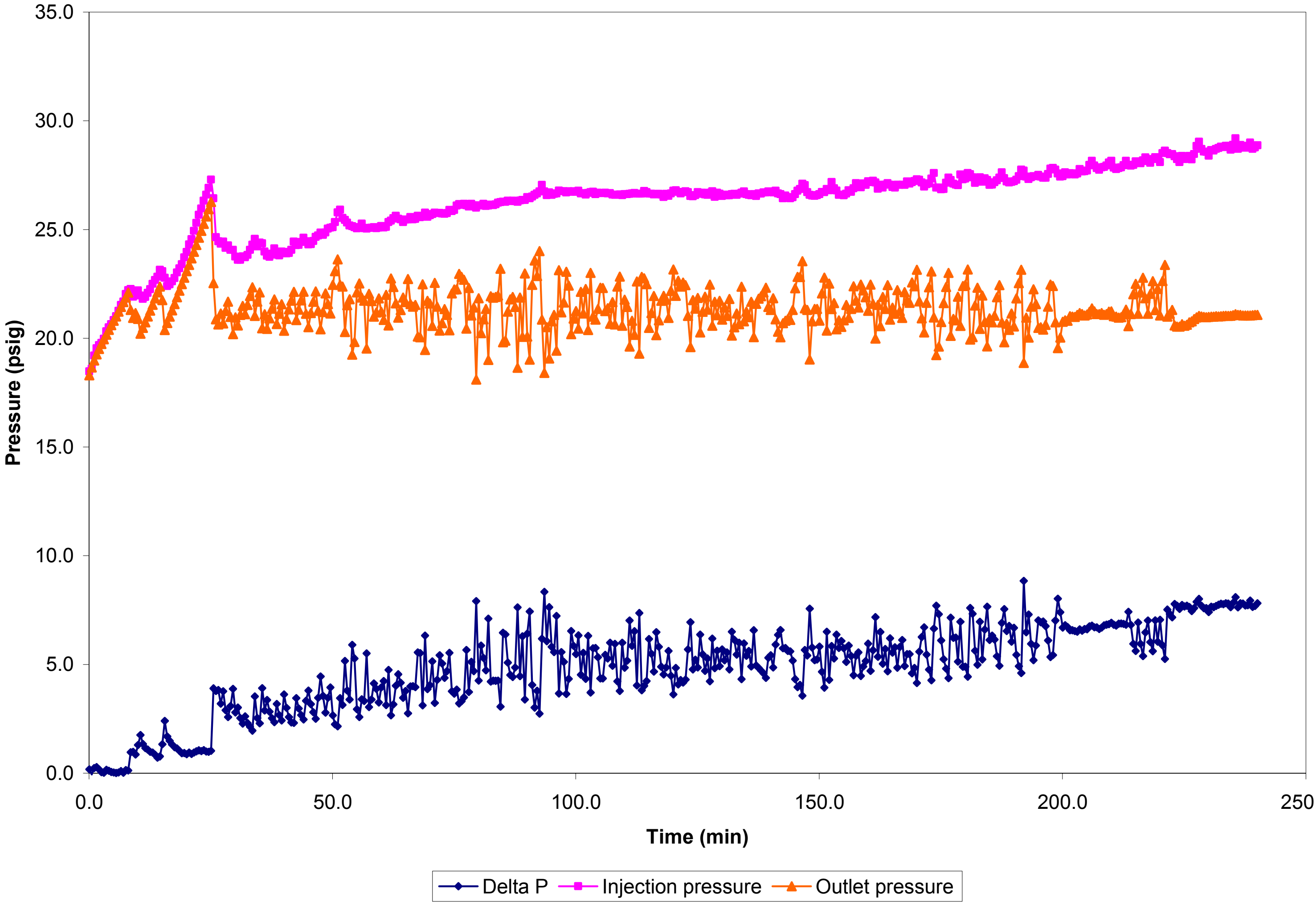

Fig. 4.38— Cell pressures versus time for run no. 12.

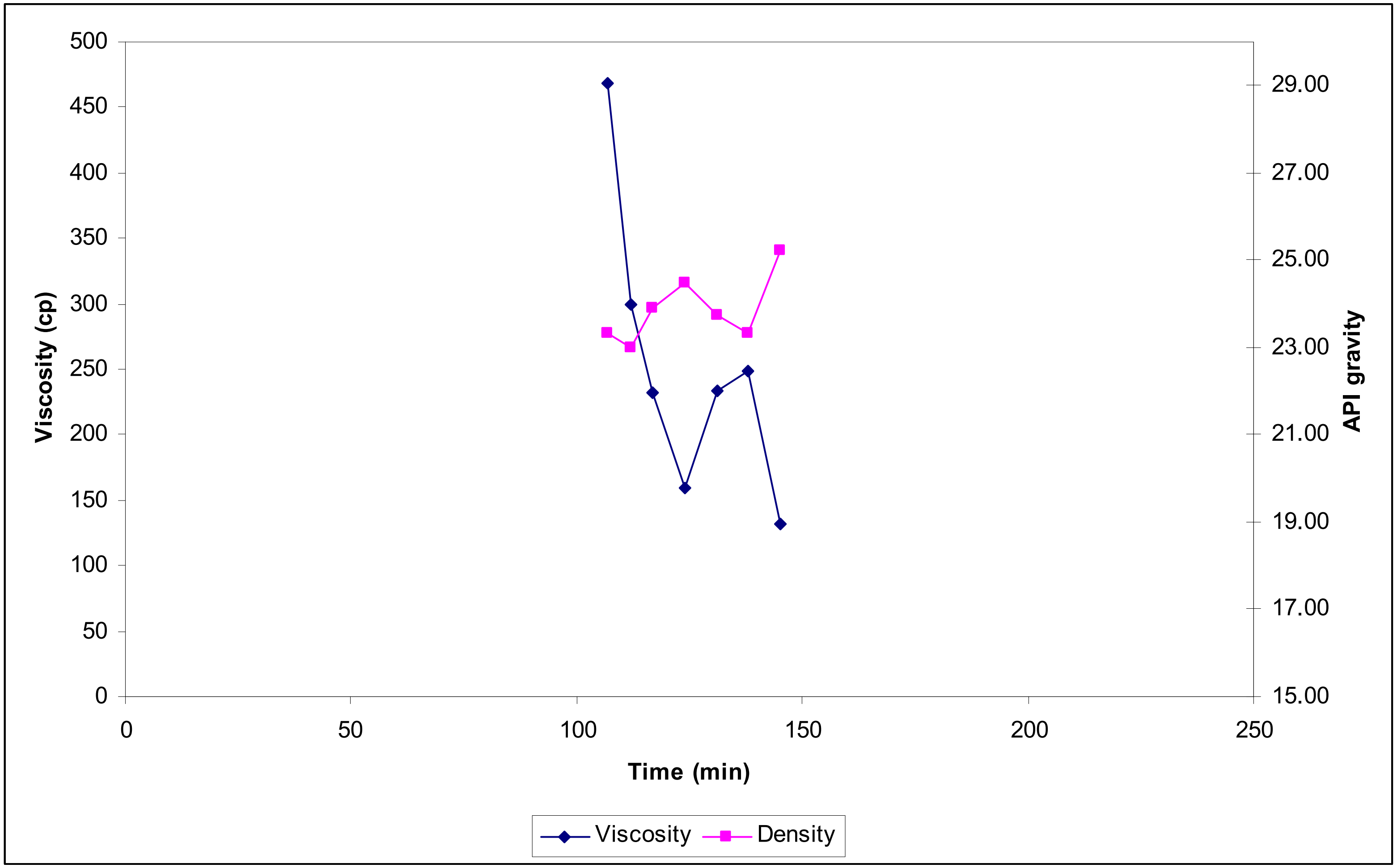

Fig. 4.39— Viscosity and density from the collected samples of run no. 12.

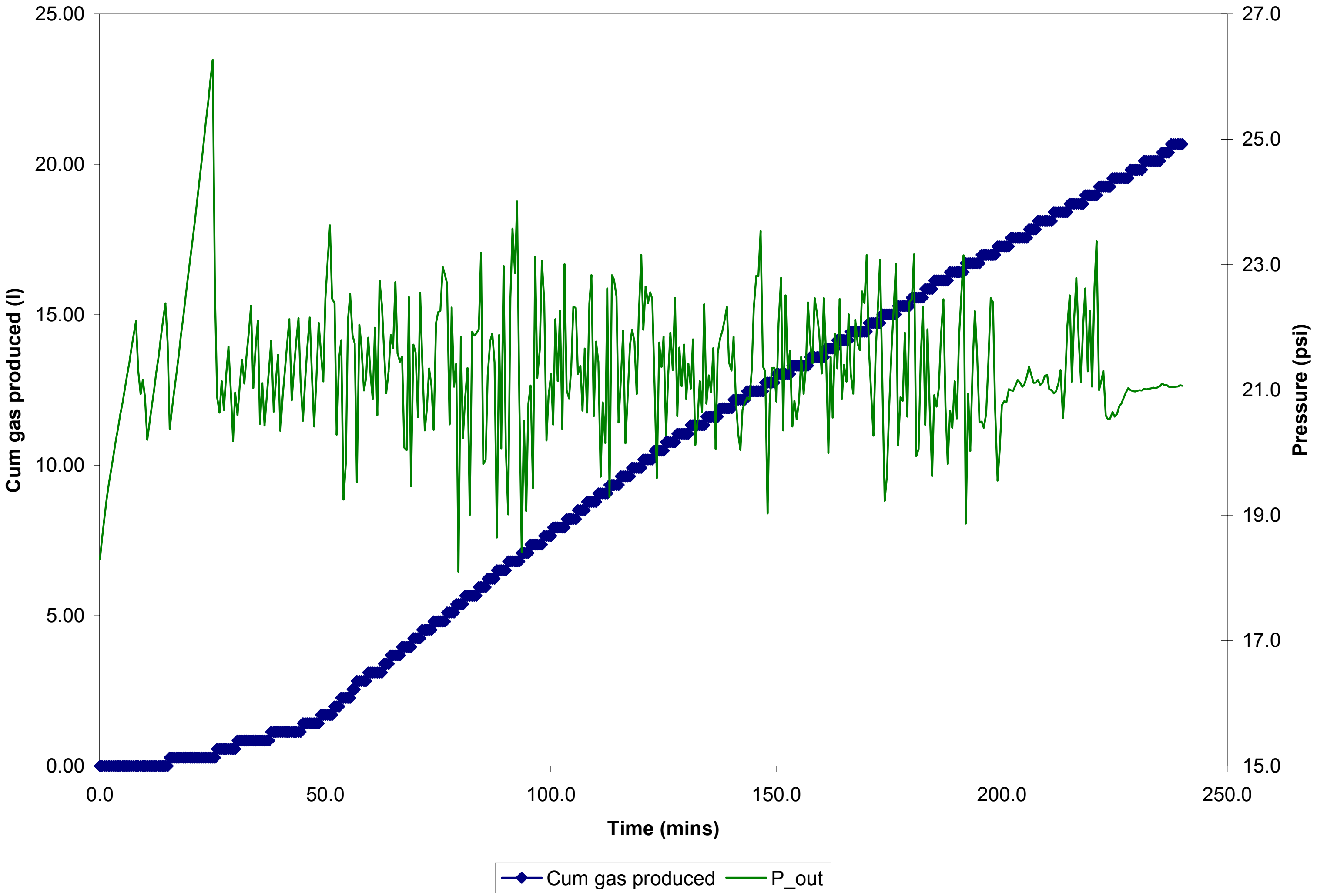

Fig. 4.40— Cumulative gas production and outlet pressure versus time for run no. 12.

4.7 Run No. 13 (5:100 Propane:Steam Ratio, 130ºC and 145ºC)

In run 12 it turned out almost impossible to know if we were in fact above or below the saturation temperature. From comparing results with run 8 through 11 we probably stayed above most of the run, and then below for short periods. A different theory would be that we are below saturation temperature for larger parts of the run, but just those few bursts of steam when we are above have enough of a positive effect to allow efficient recovery. To test this theory another run was designed where we injected steam in cycles. First steam for 9 minutes at 145ºC, then hot water for 21 minutes at 130ºC. This should equal an average steam quality of about 70% (**Appendix B**). The movement of the steam front can be followed in **Fig. 4.41**, which shows the temperature profile for all the thermocouples. Note the 30 minute injection temperature cycles.

Cumulative oil and water production versus time is shown in **Fig. 4.42**. Ultimate recovery at the end of the 4 hour run is about 77.9 cm^3, or 19% of OOIP, as can be seen in **Fig. 4.43**. **Fig. 4.44** shows the oil and water production rates as a function of time. The first oil is produced after 94 minutes of injection, with a peak rate of about 3.2 cm^3/min after105 minutes. **Fig. 4.45** shows how the temperature propagation at 20 minute intervals for the different thermocouples. It takes about 105 minutes for the whole cell to reach a more or less constant temperature of 126ºC. The injection pressure, outlet pressure, and differential pressure are shown in **Fig. 4.46.** The outlet pressure is kept steady at 20 psig. As the oil bank is building up injection pressure increases, although maybe not as notably as in other experiments. From an initial differential pressure of close to zero it reaches highs of about 5-6 psi before oil production starts.

Viscosity and density is plotted in **Fig. 4.47**. Cumulative gas production is shown in **Fig. 4.48**. It is plotted along with outlet pressure since gas is only produced once the outlet pressure exceeds the setting of the backpressure valve. The production is fairly smooth. After about 100 minutes of injection it takes on an almost linear shape, producing gas at a fairly constant rate. A total of about 22 liters is produced.

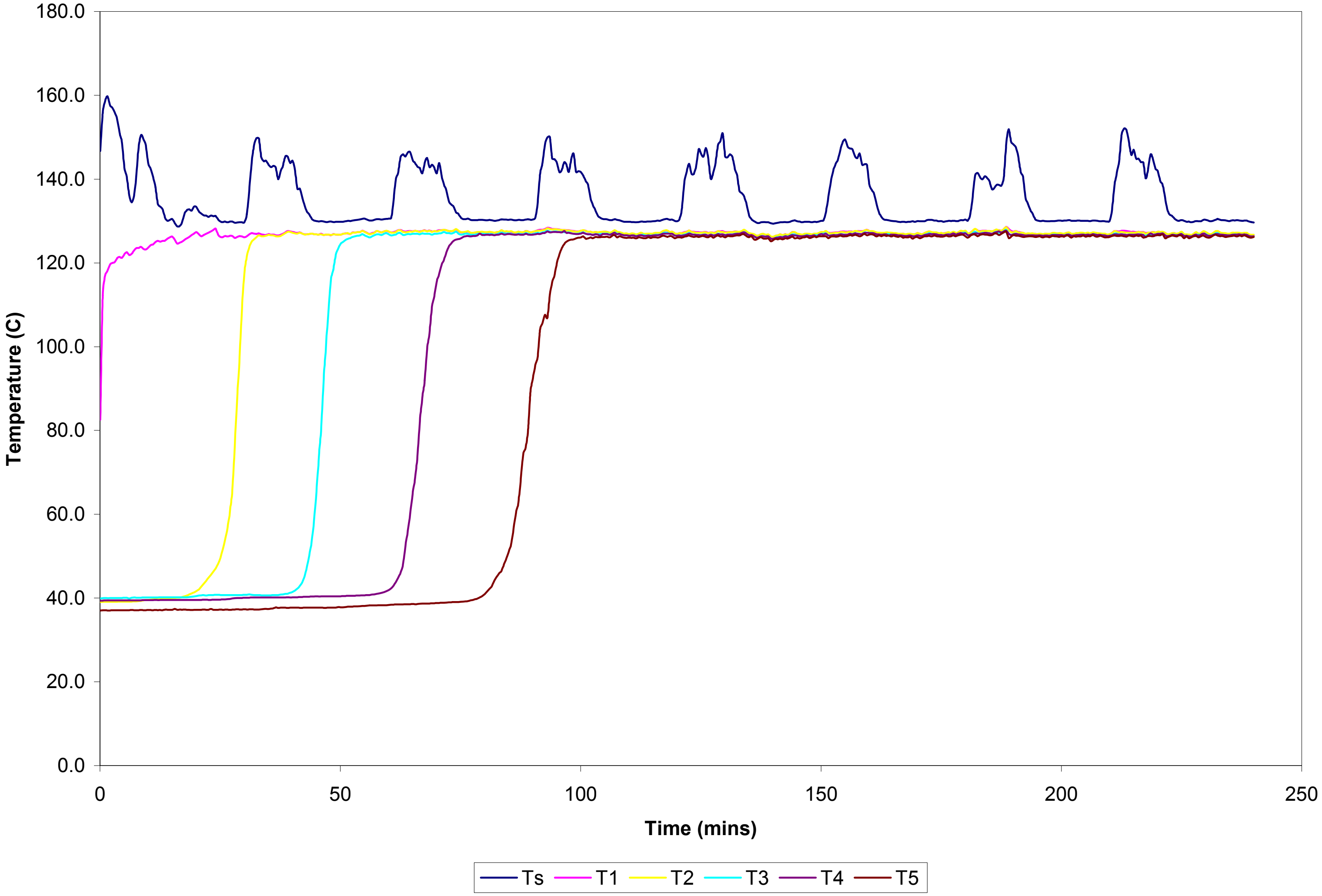

Fig. 4.41— Temperature profiles versus time for run no. 13.

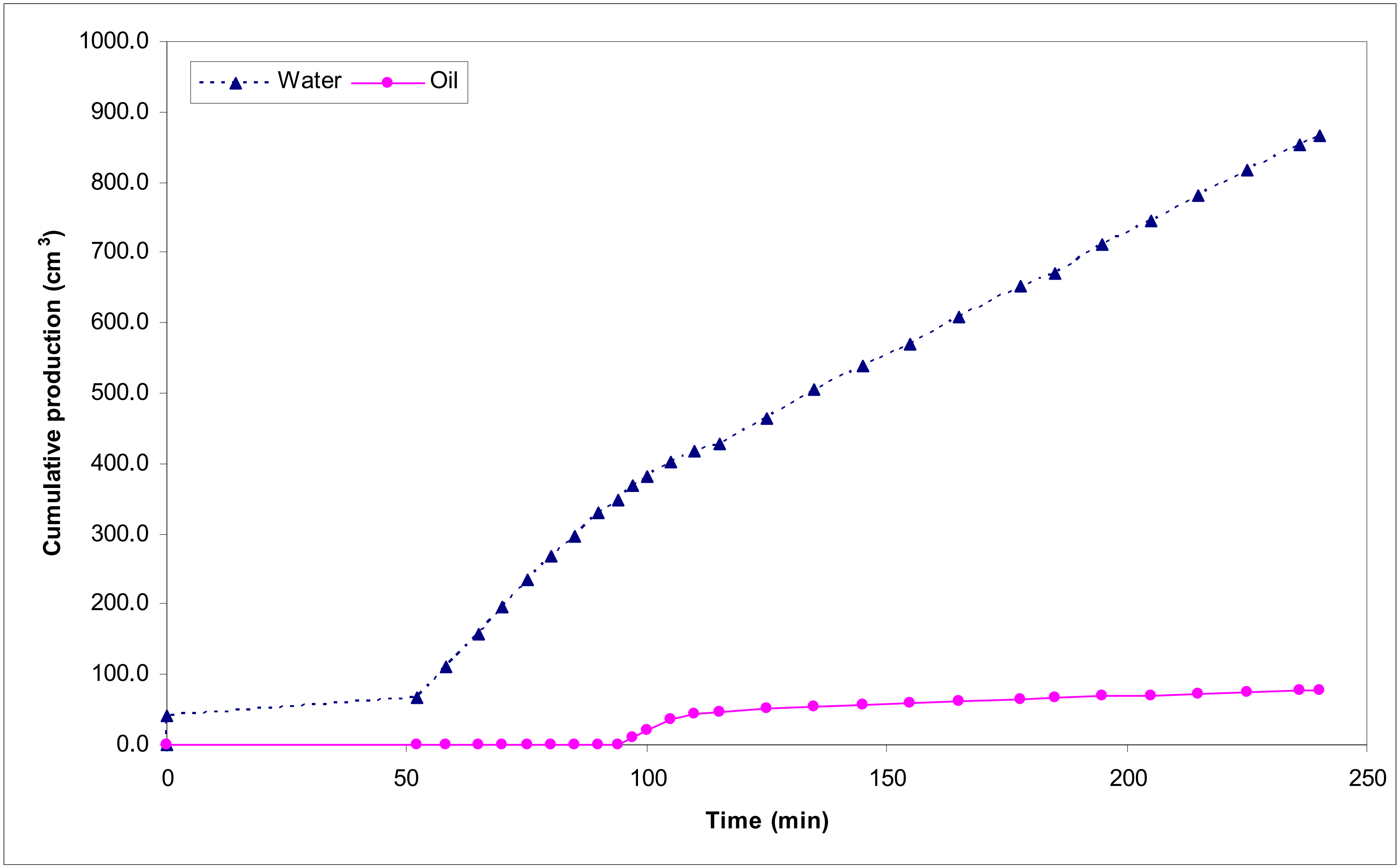

Fig. 4.42— Cumulative oil and water production versus time for run no. 13.

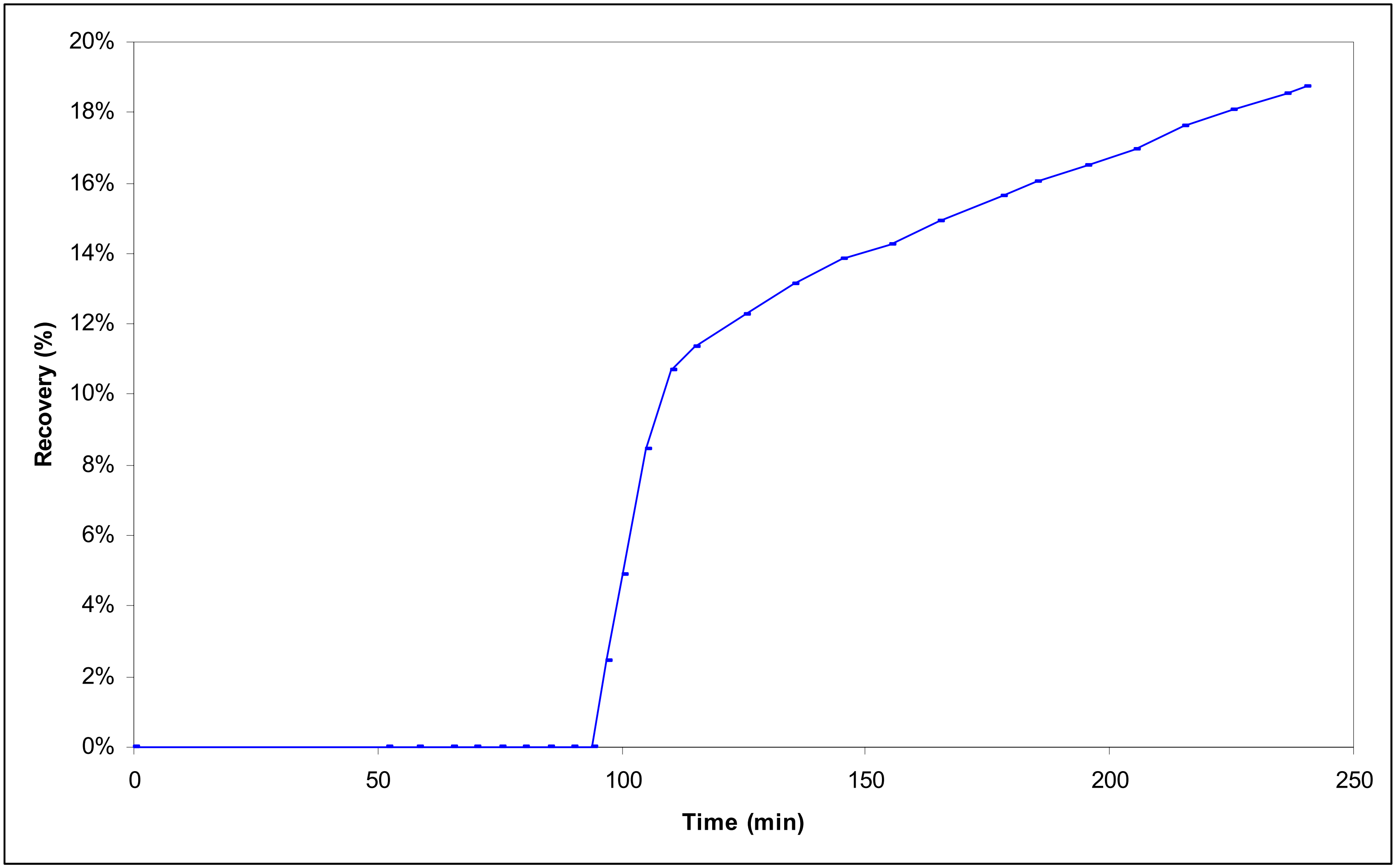

Fig. 4.43— Oil recovery versus time for run no. 13.

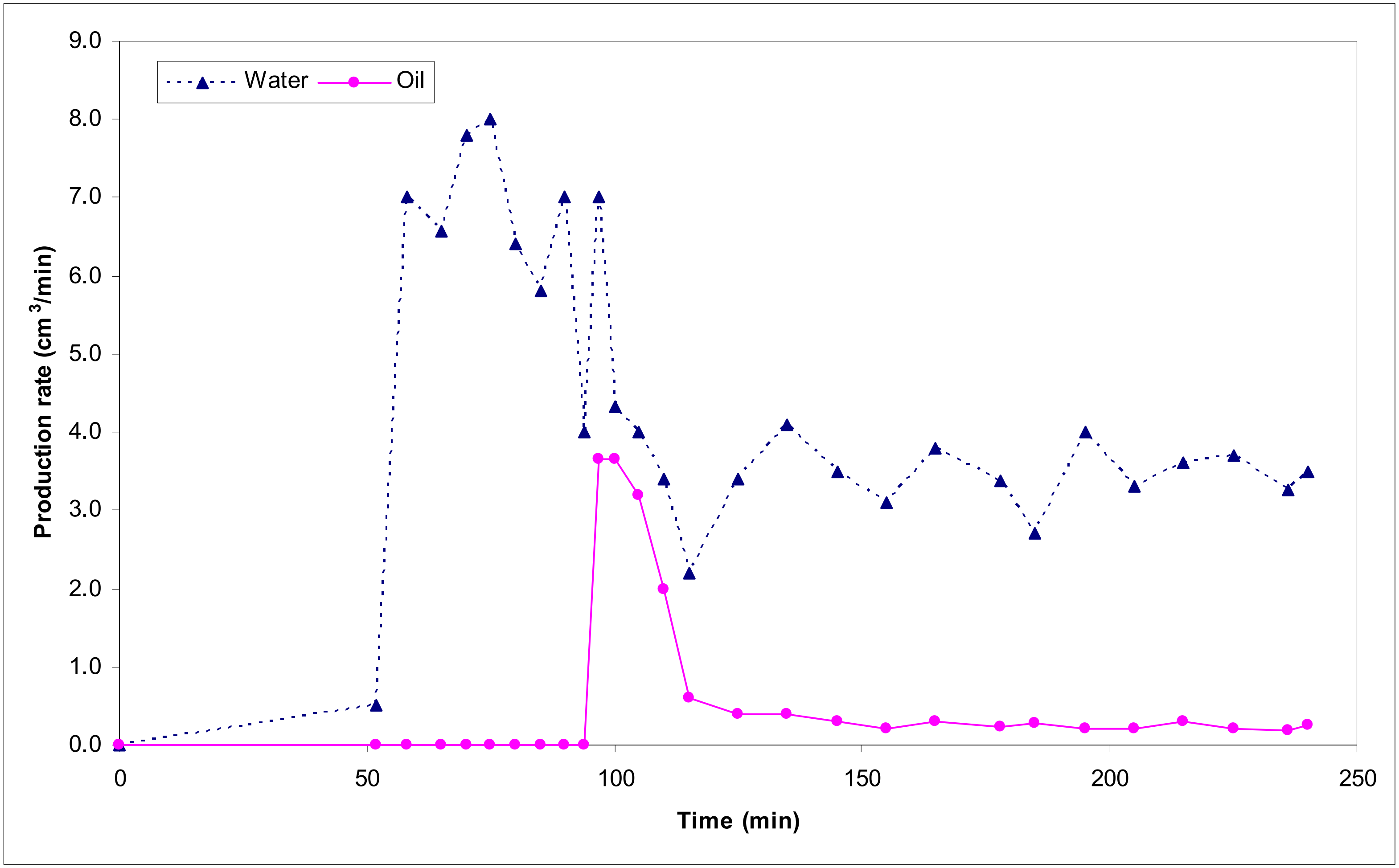

Fig. 4.44— Oil and water production rates versus time for run no. 13.

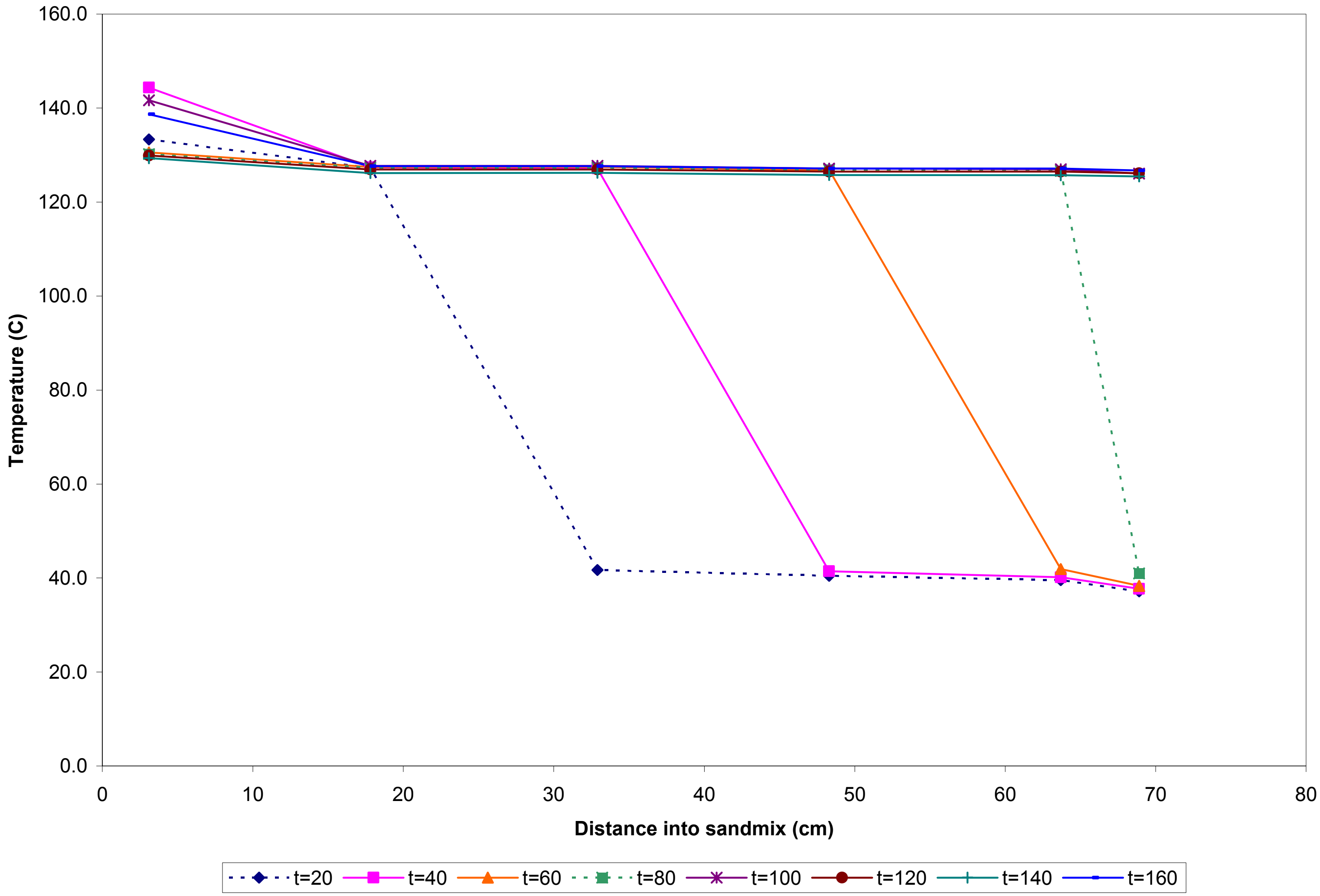

Fig. 4.45— Propagation of temperature in the sand mix for run no. 13.

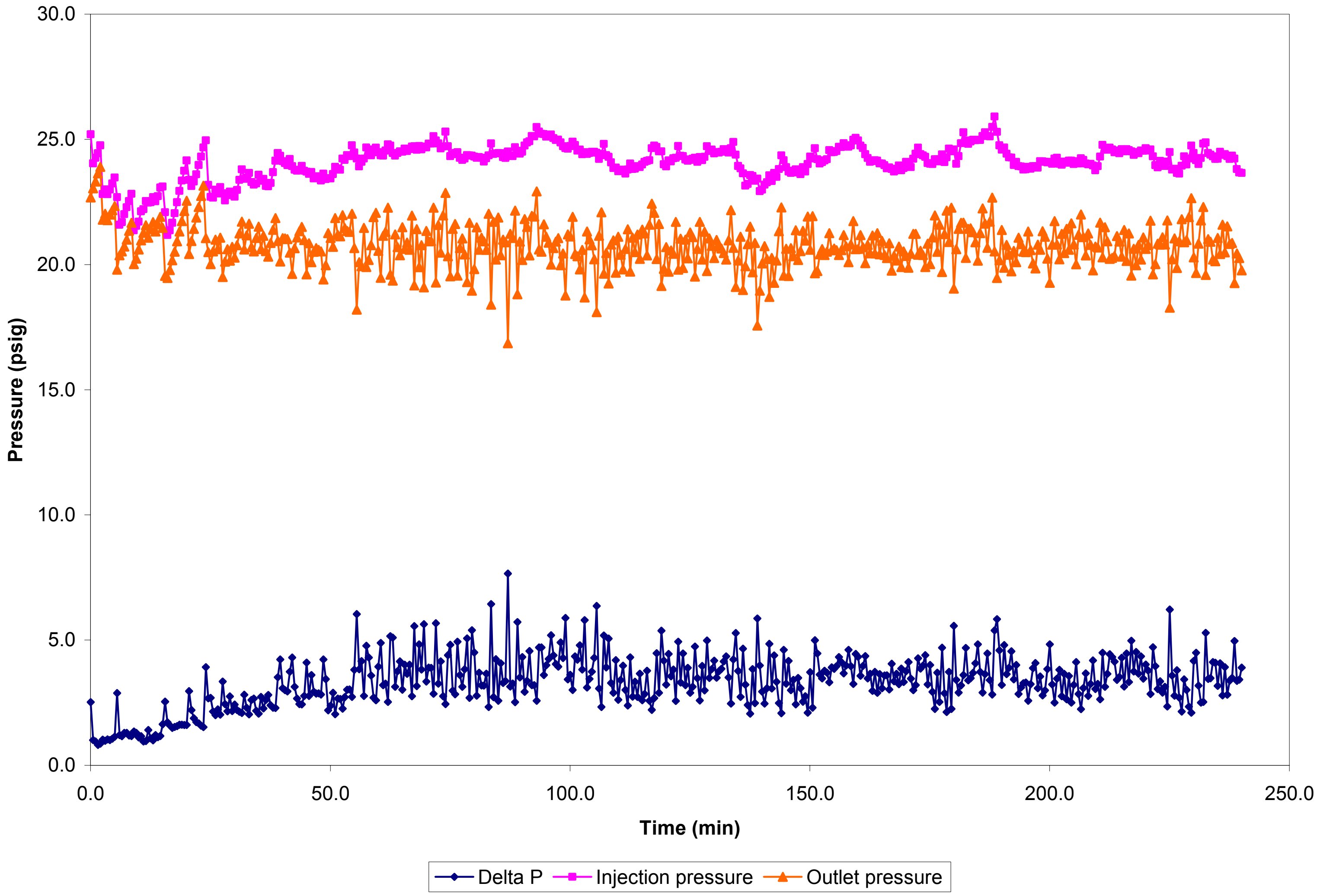

Fig. 4.46— Cell pressures versus time for run no. 13.

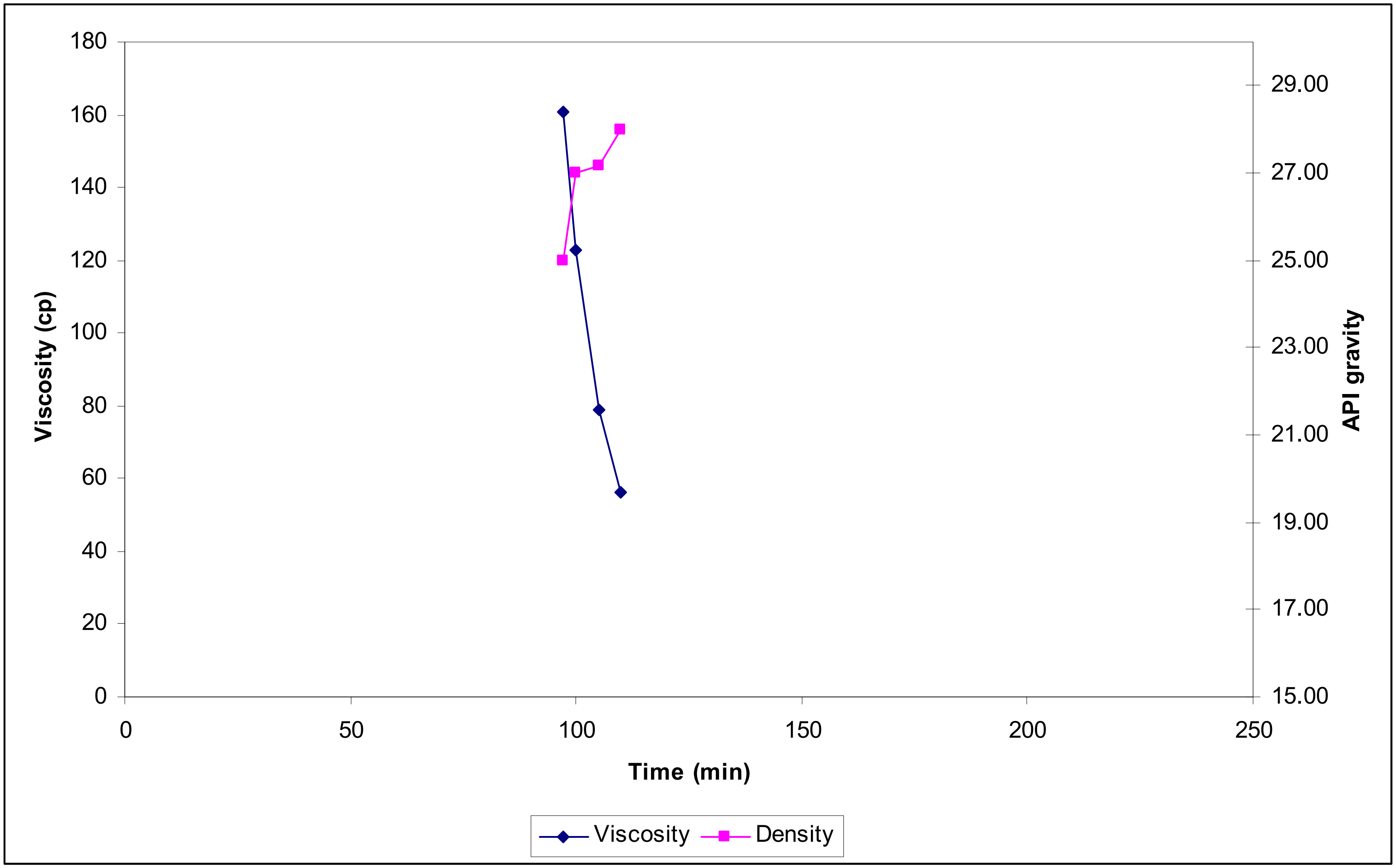

Fig. 4.47— Viscosity and density from the collected samples of run no. 13.

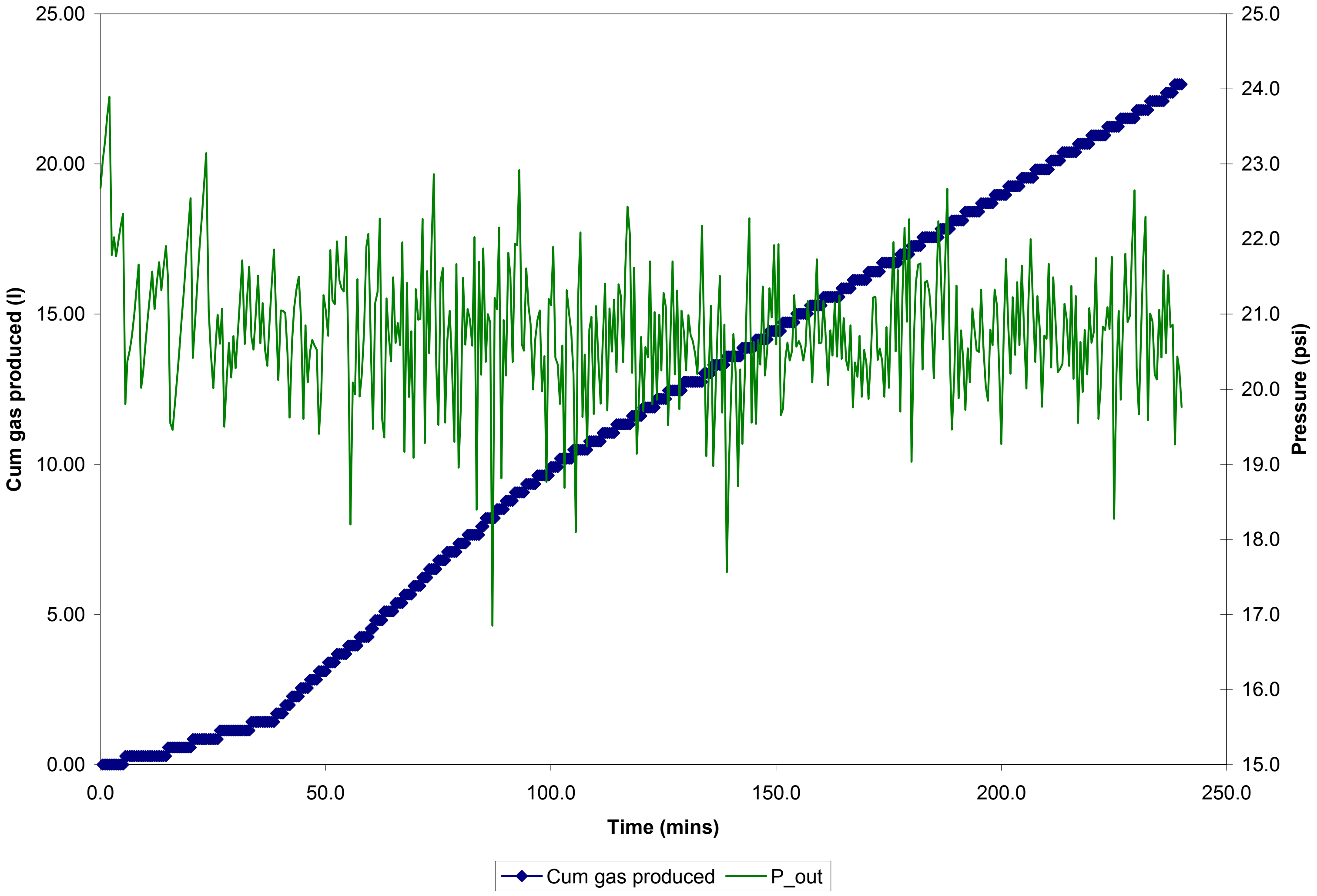

Fig. 4.48— Cumulative gas production and outlet pressure versus time for run no. 13.

4.8 Run No. 14 (5:100 Propane:Steam Ratio, 120ºC and 140ºC)

In certain parts of run 13 it was difficult to tell if we were above or below saturation temperature as the injection pressure changed with Ts more than expected. To mitigate this, a new run was designed with more hot water and superheated steam temperatures further removed from the expected saturation values.

In run 14 steam is injected for 9 minutes at 140ºC, then for 21 minutes as hot water at 120ºC. This should equal an average steam quality of about 70%. The movement of the steam front can be followed in **Fig. 4.49**, which shows the temperature profile for all the thermocouples. The cycles are reflected not only in Ts, but into the cell as well.

Cumulative oil and water production versus time is shown in **Fig. 4.50**. No oil is produced, resulting in 0% recovery (**Fig. 4.51)**. **Fig. 4.52** shows the water (oil and) production rates as a function of time.

Fig. 4.53 shows how the temperature propagation at 20 minute intervals for the different thermocouples. The cell never reaches uniform temperature.

The injection pressure, outlet pressure, and differential pressure are shown in **Fig. 4.54.** The outlet pressure is kept steady at 20 psig. There are huge fluctuations as the increasing temperature forces the pressure up. This trend gets more and more pronounced throughout the run, with the differential pressure approaching 14-15 psi towards the end of the 6 hour run.

No viscosity or density plots were included as there was no oil produced. Cumulative gas production is shown in **Fig. 4.55**. It is plotted along with outlet pressure since gas is only produced once the outlet pressure exceeds the setting of the backpressure valve. The production is fairly smooth, as with the other runs. A total of 33 liters of propane is produced.

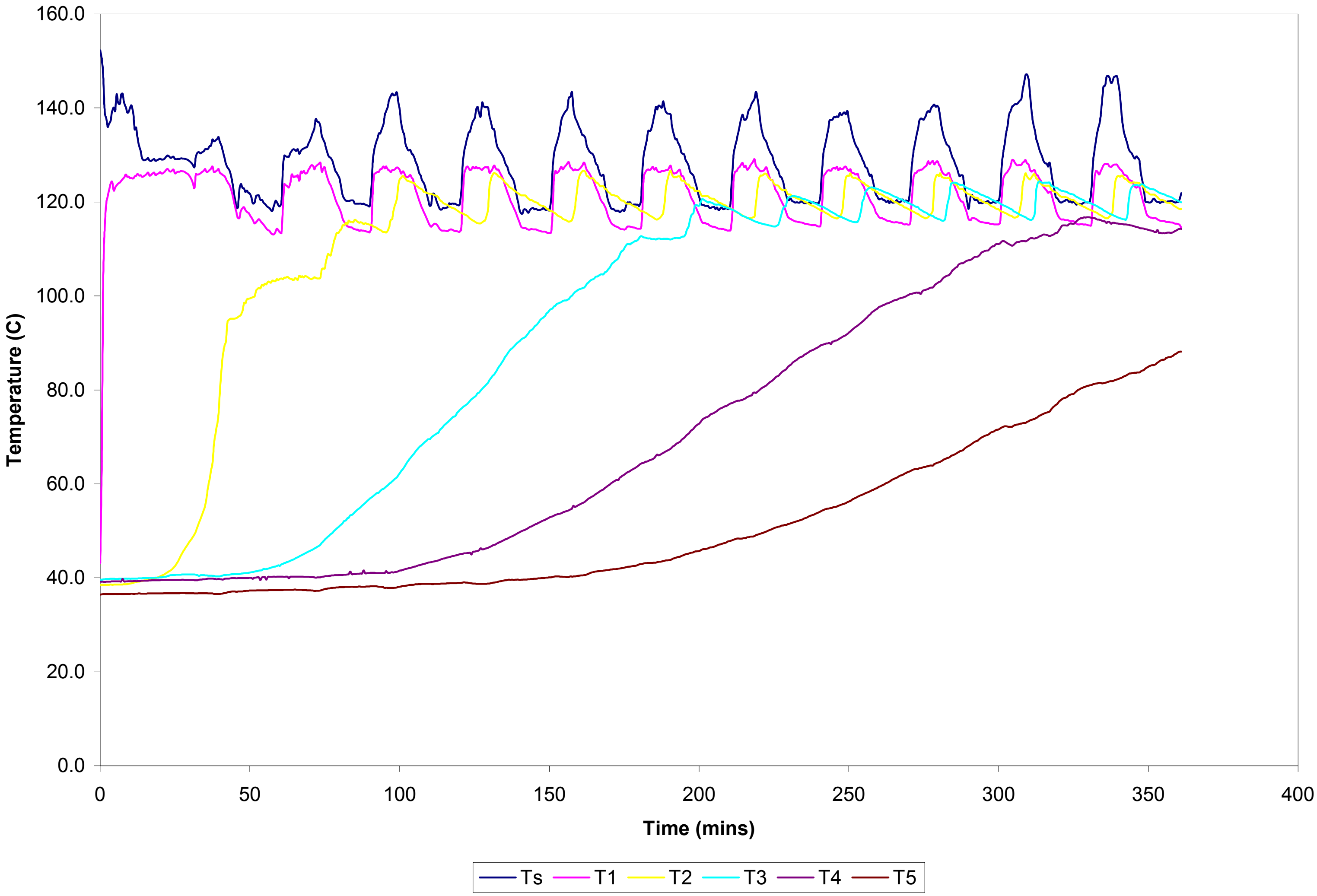

Fig. 4.49— Temperature profiles versus time for run no. 14.

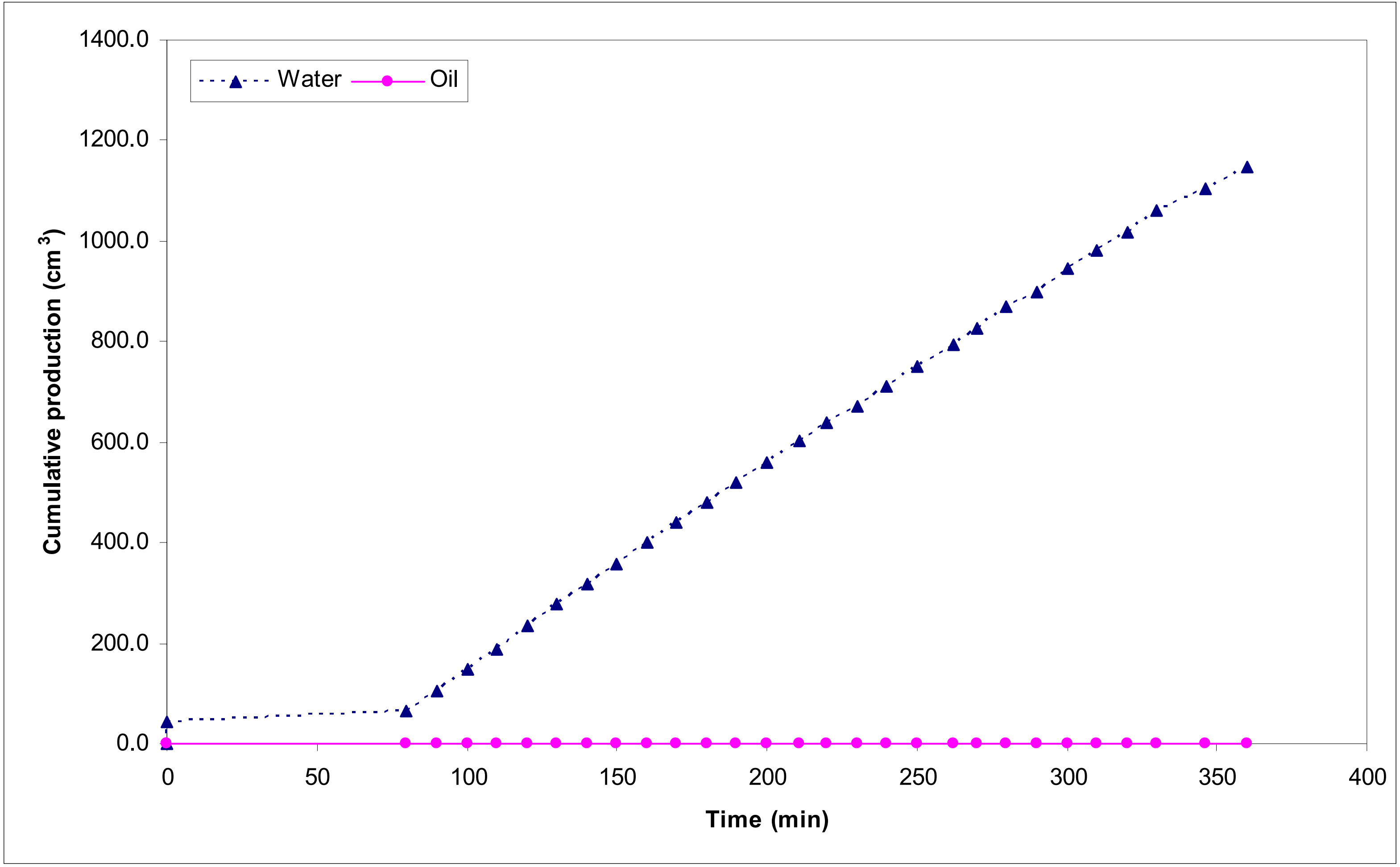

Fig. 4.50— Cumulative oil and water production versus time for run no. 14.

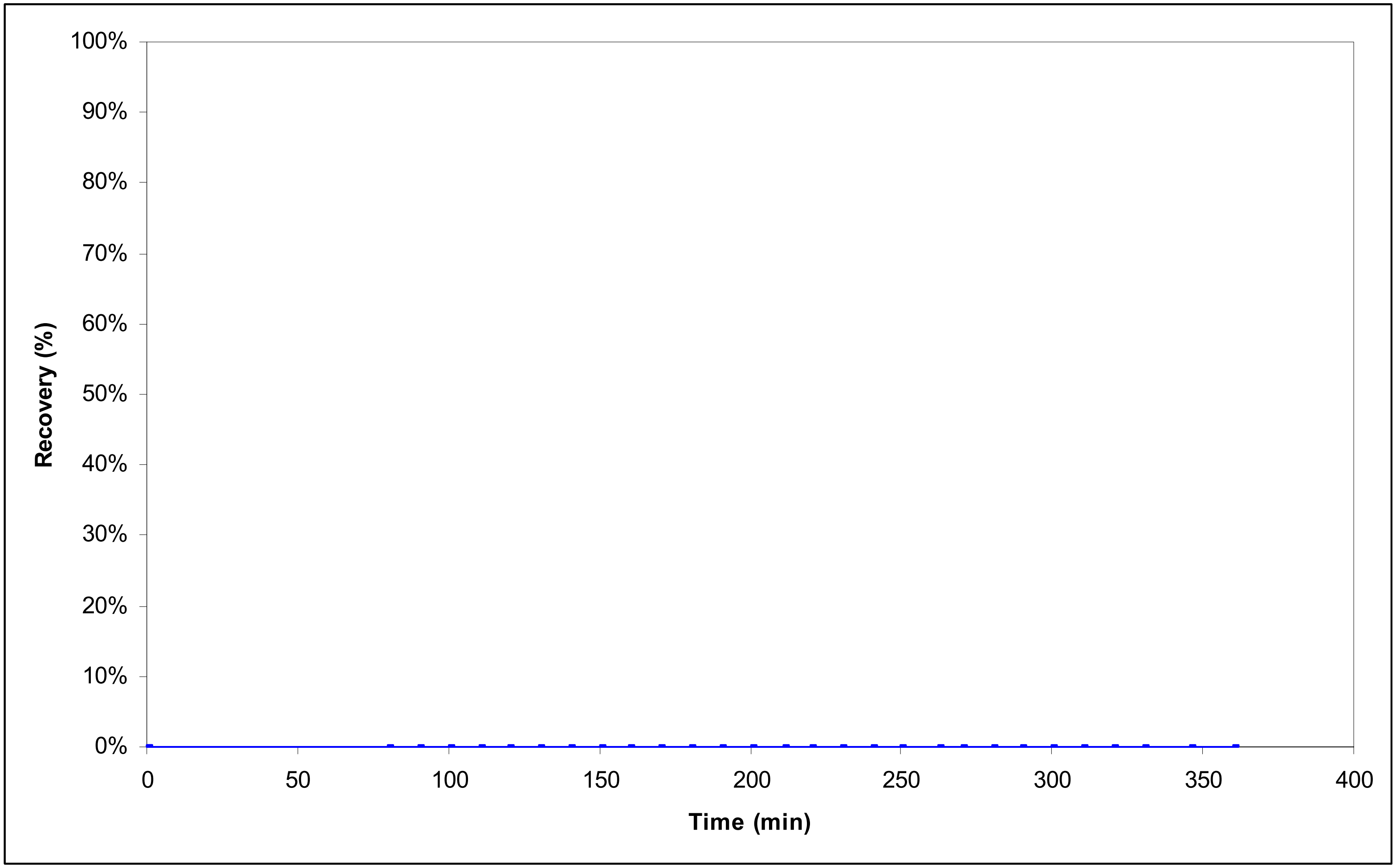

Fig. 4.51— Oil recovery versus time for run no. 14 is zero.

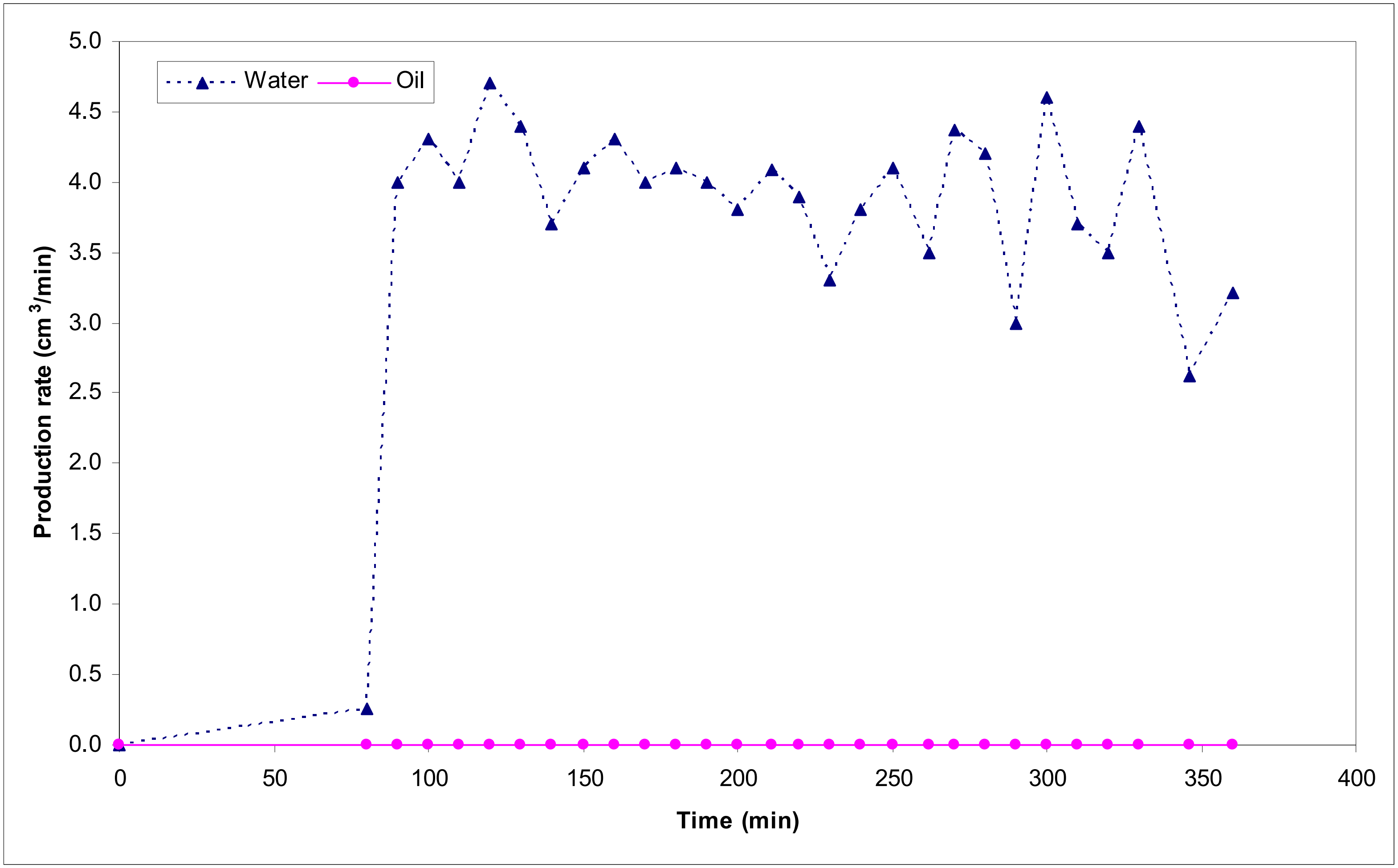

Fig. 4.52— Oil and water production rates versus time for run no. 14.

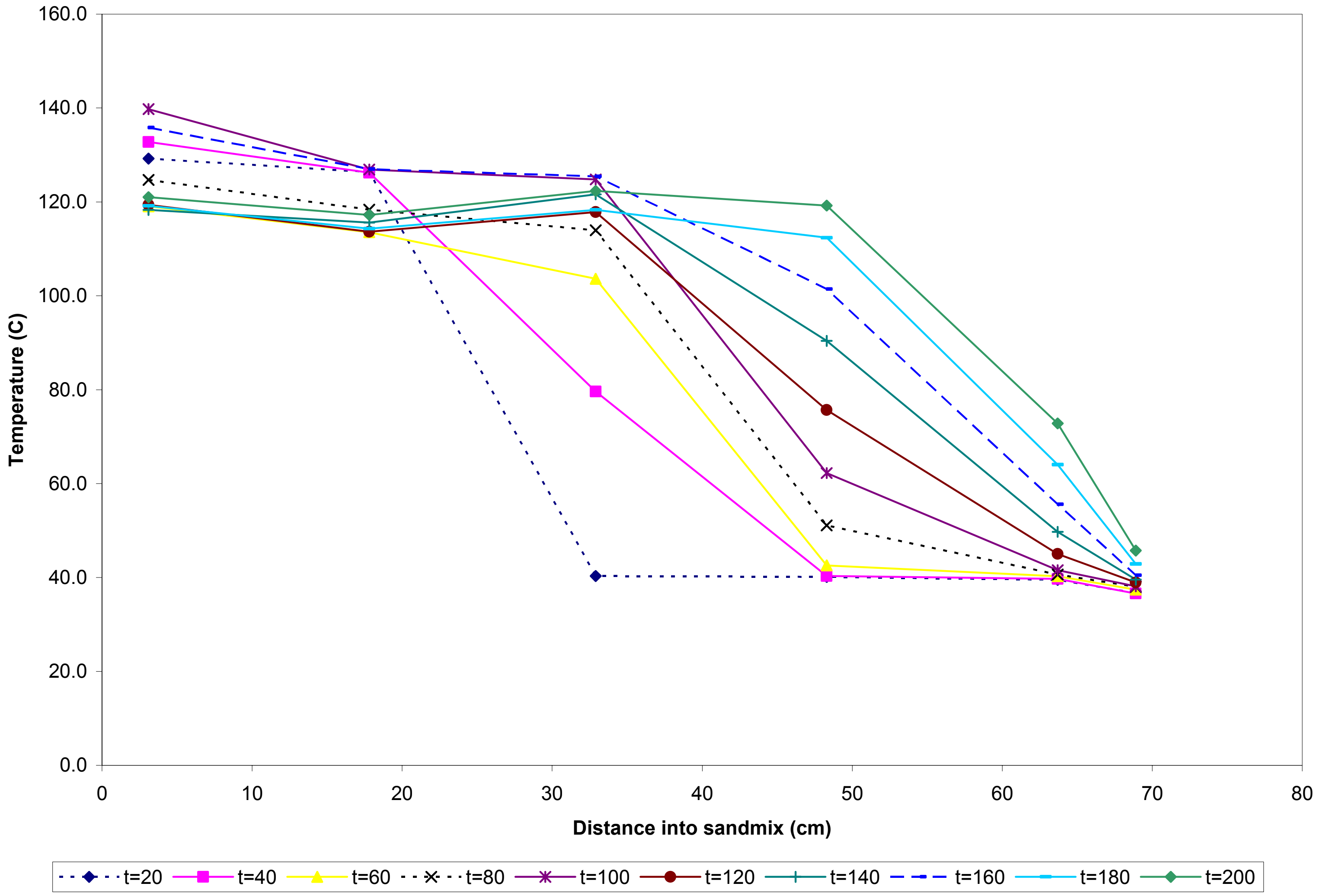

Fig. 4.53— Propagation of temperature in the sand mix for run no. 14.

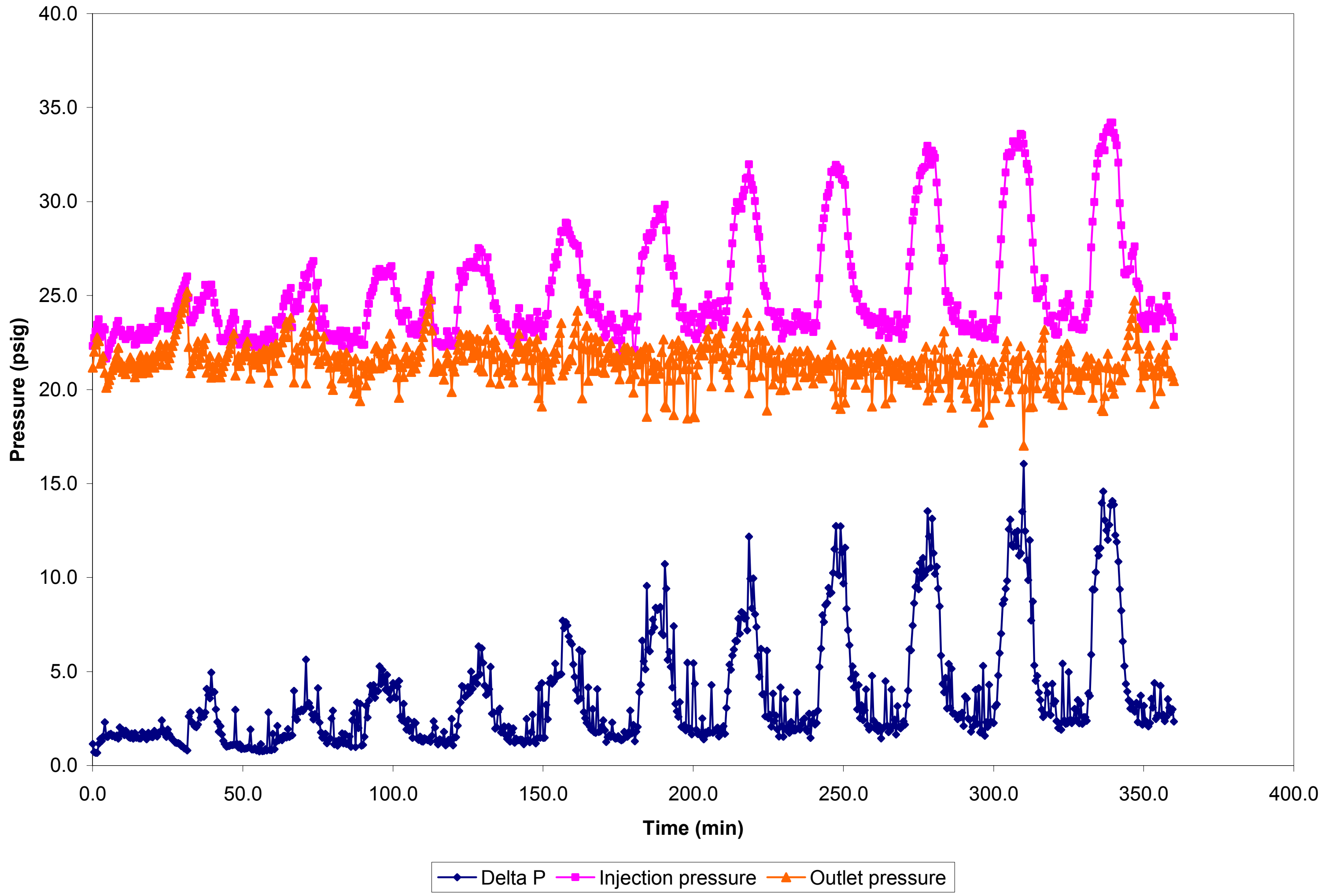

Fig. 4.54— Cell pressures versus time for run no. 14.

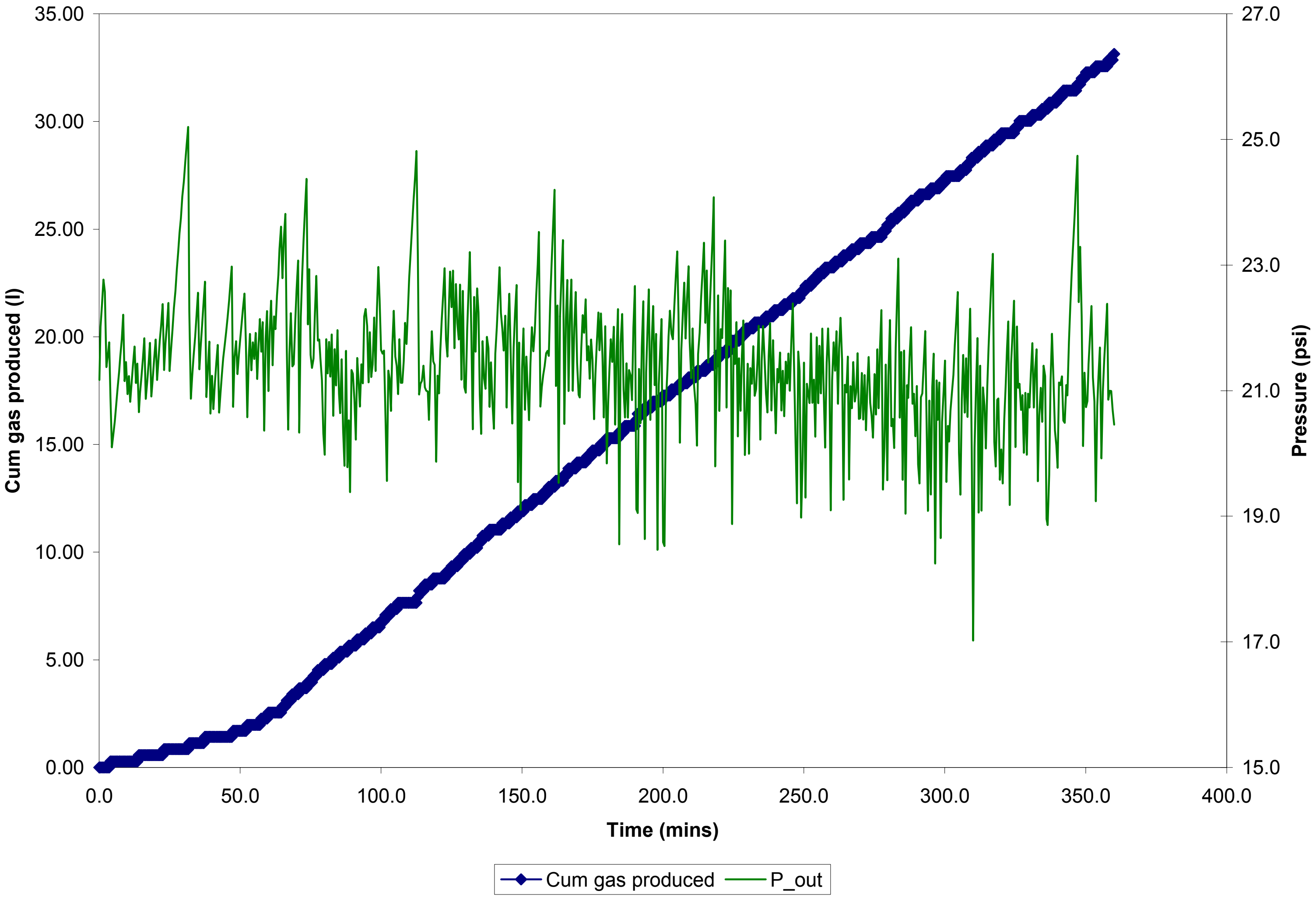

Fig. 4.55— Cumulative gas production and outlet pressure versus time for run no. 14.

4.9 Run No. 15 (5:100 Propane:Steam Ratio, 157ºC)

This run is a repeat of run no.10. The movement of the steam front can be followed in **Fig. 4.56**, which shows the temperature profile for all the thermocouples. The injection temperature is kept steady at 157ºC throughout the run.

Cumulative oil and water production versus time is shown in **Fig. 4.57**. Ultimate recovery at the end of the 4 hour run is about 132 cm^3, or 32% of OOIP, as can be seen in **Fig. 4.58**. **Fig. 4.59** shows the oil and water production rates as a function of time. The first oil is produced after 81 minutes of injection, with a peak rate of about 6.7 cm^3/min after 87 minutes.

Fig. 4.60 shows how the temperature propagation at 20 minute intervals for the different thermocouples. It takes about 96 minutes for the whole cell to reach a more or less constant temperature of 126ºC.

The injection pressure, outlet pressure, and differential pressure are shown in **Fig. 4.61.** The outlet pressure is kept steady at 20 psig. As the oil bank is building up injection pressure increases, and as a result of that so does the differential pressure. From an initial differential pressure of close to zero it reaches highs of about 8 psi before oil production starts. Once that happens it quickly drops down to an average of about 3-4 psi.

Viscosity and density is plotted in **Fig. 4.62**. Cumulative gas production is shown in **Fig. 4.63**. It is plotted along with outlet pressure since gas is only produced once the outlet pressure exceeds the setting of the backpressure valve. The production is fairly smooth instead of the step-wise increase we observed in the first two runs. After about 100 minutes of injection it takes on an almost linear shape, producing gas at a fairly constant rate. A total of 23 liters propane is produced.

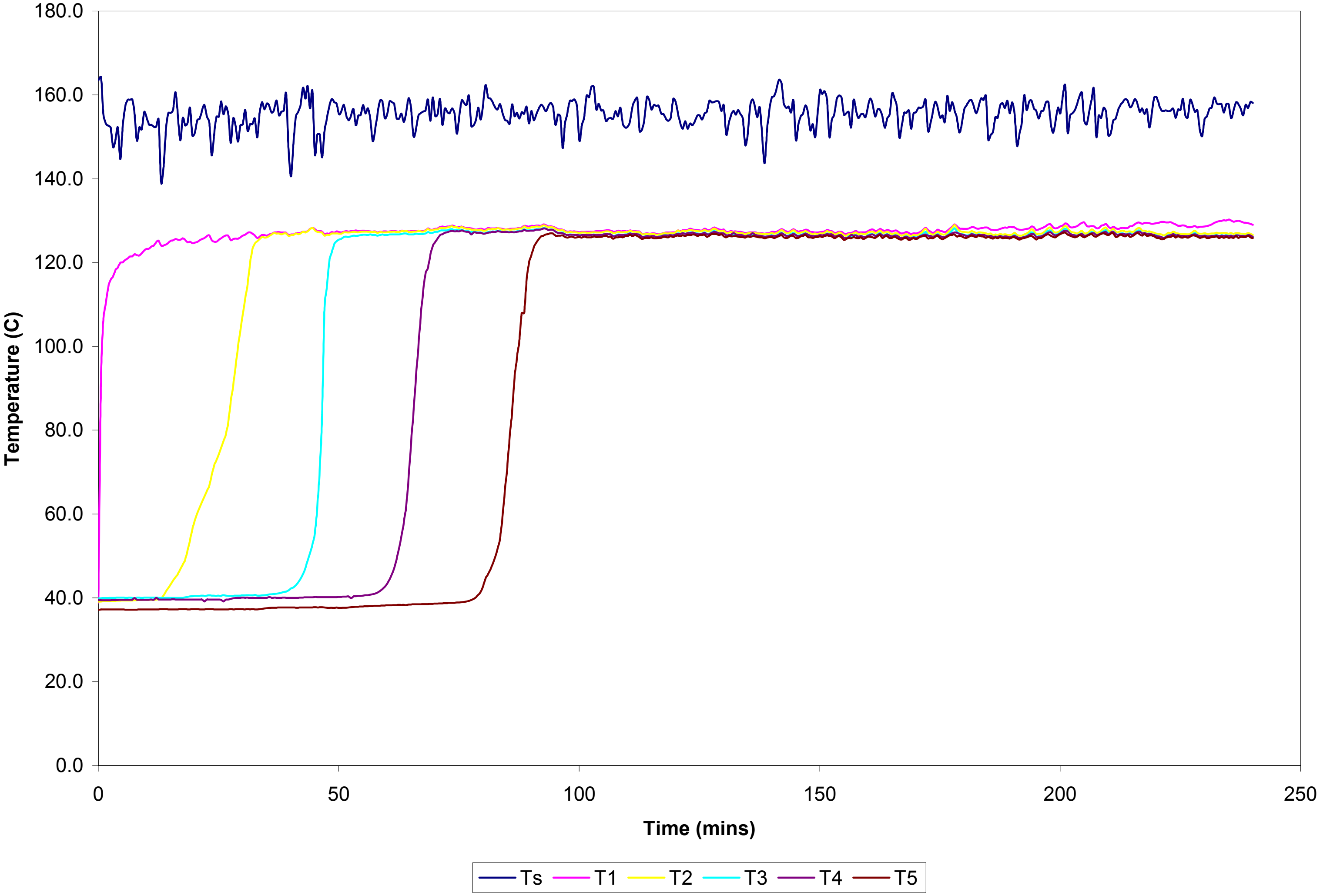

Fig. 4.56— Temperature profiles versus time for run no. 15.

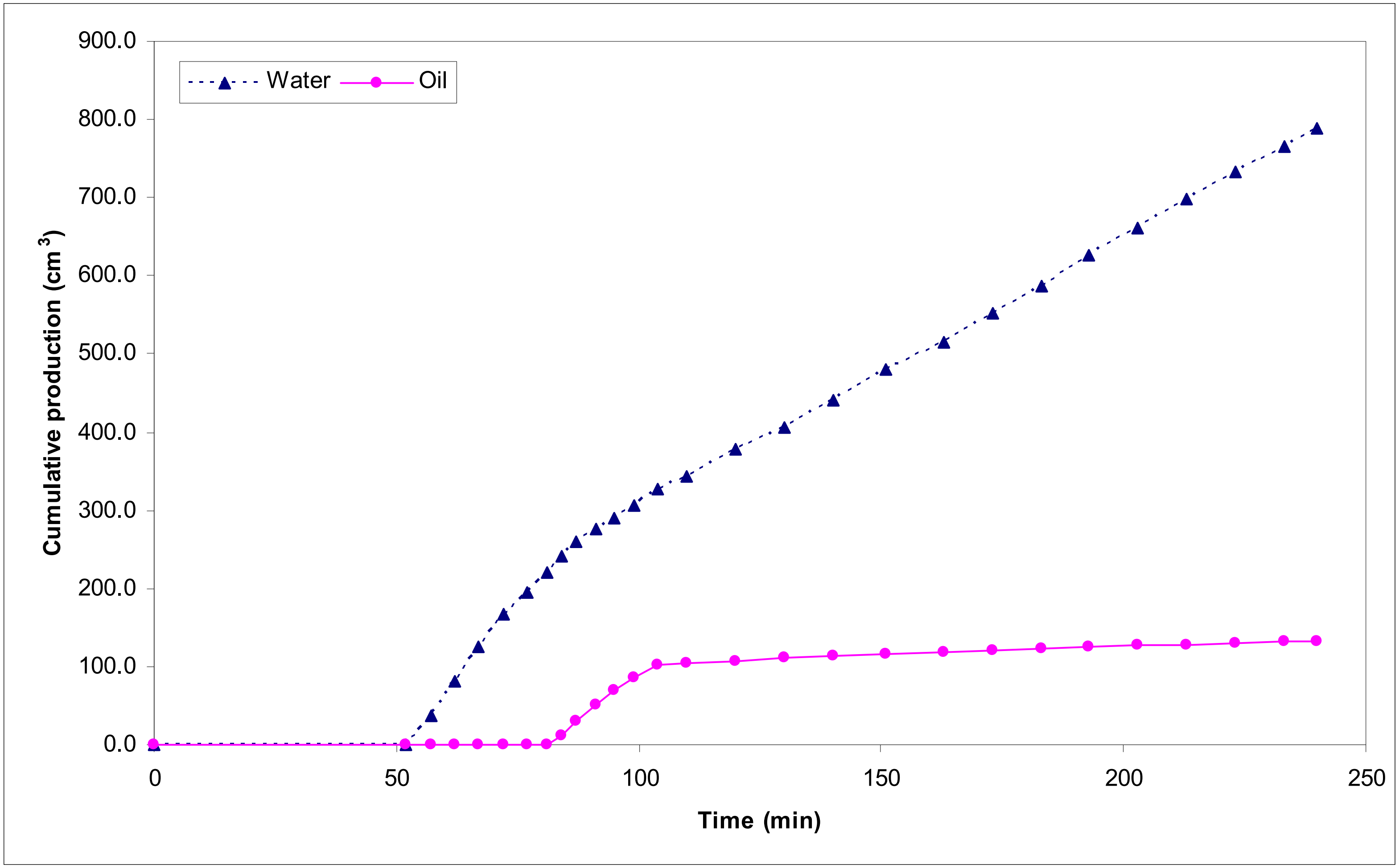

Fig. 4.57— Cumulative oil and water production versus time for run no. 15.

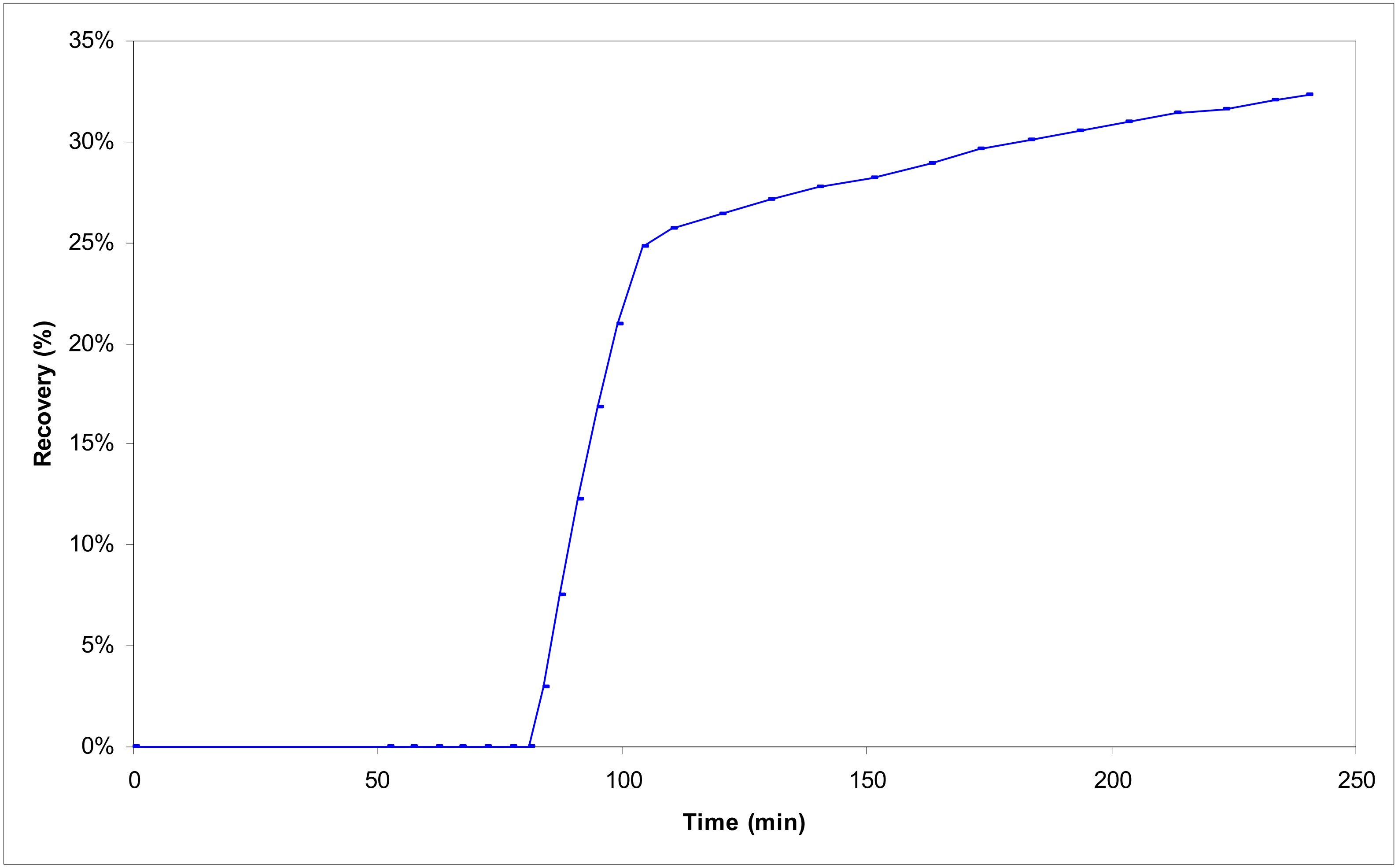

Fig. 4.58— Oil recovery versus time for run no. 15.

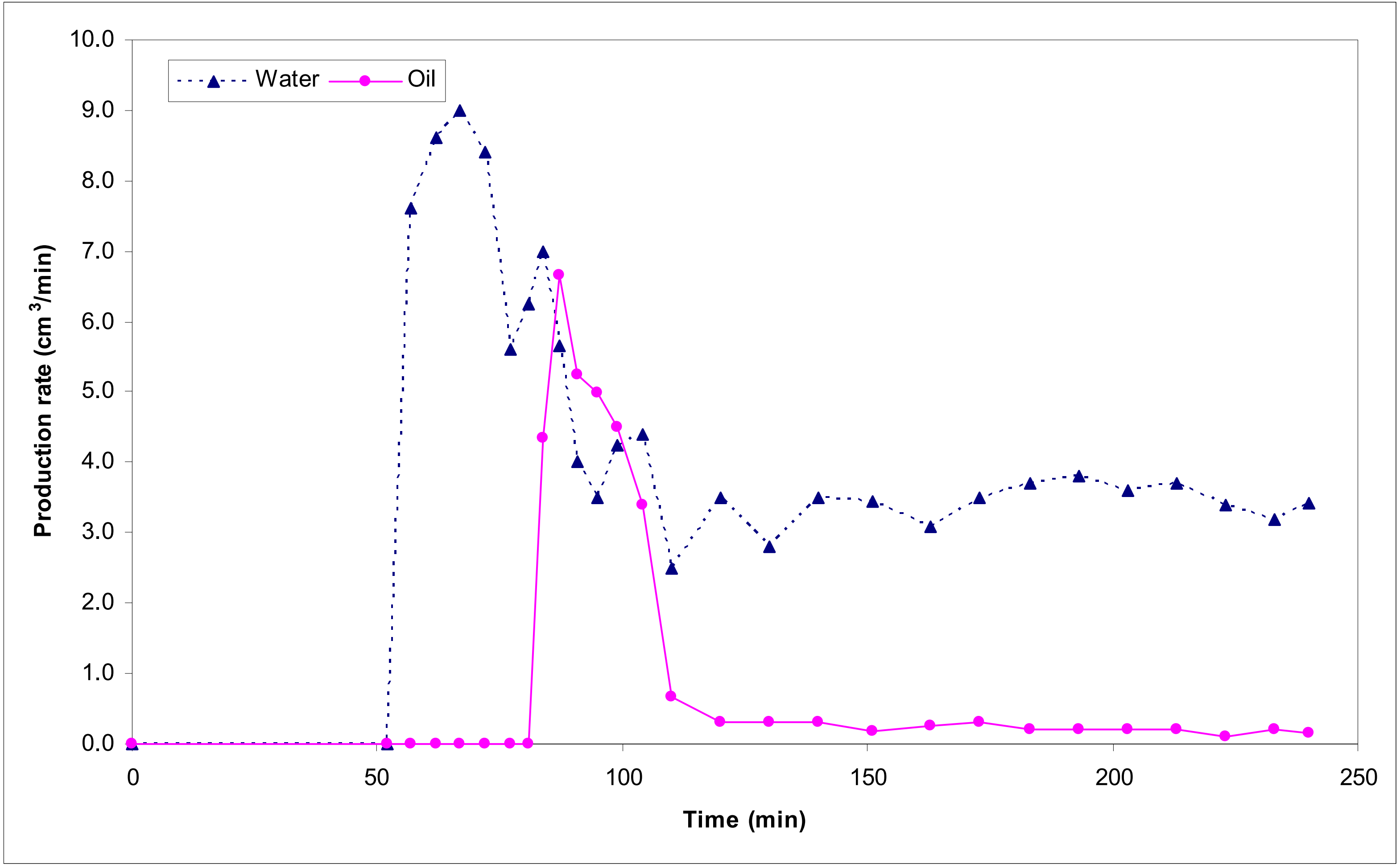

Fig. 4.59— Oil and water production rates versus time for run no. 15.

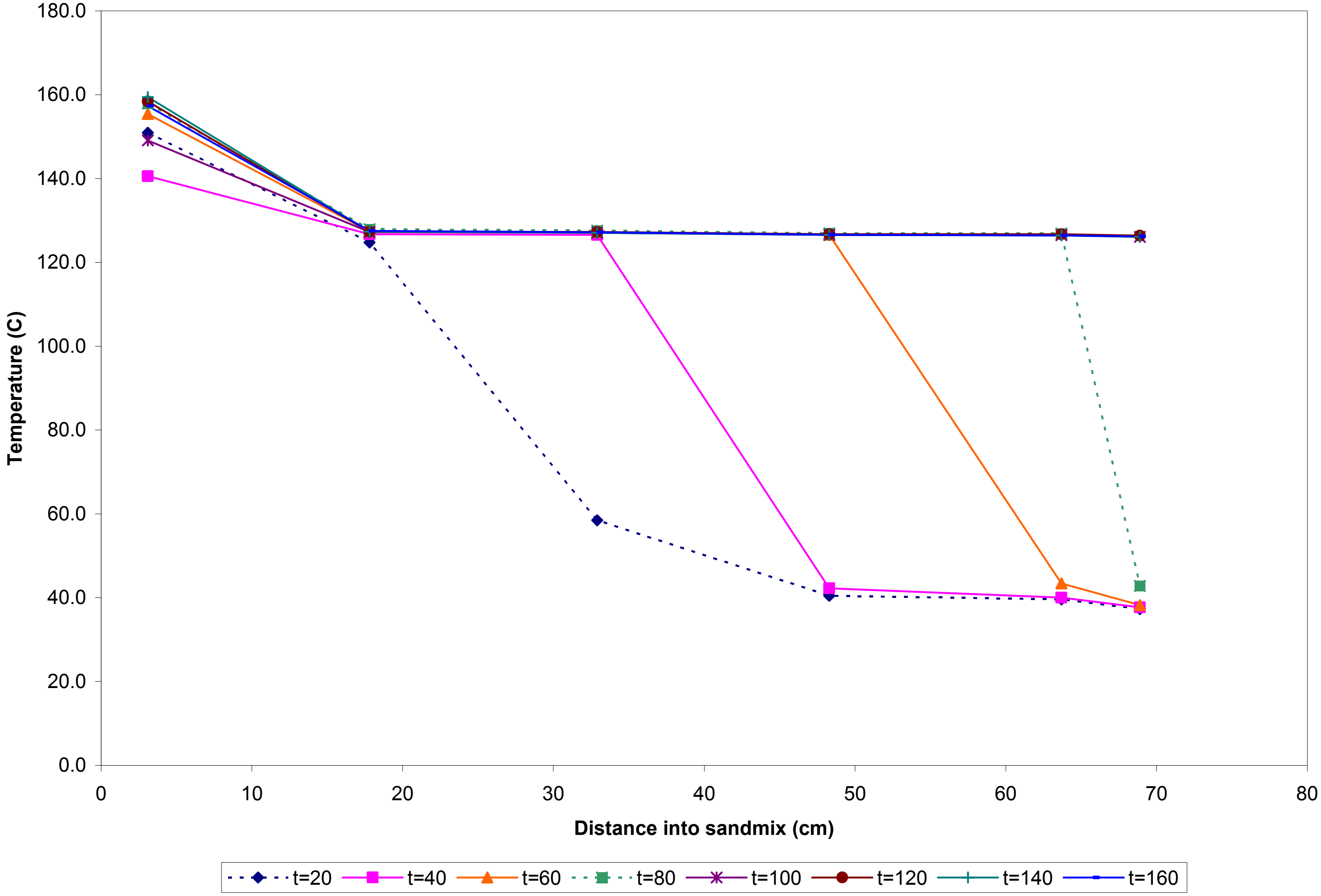

Fig. 4.60— Propagation of temperature in the sand mix for run no. 15.

Fig. 4.61— Cell pressures versus time for run no. 15.

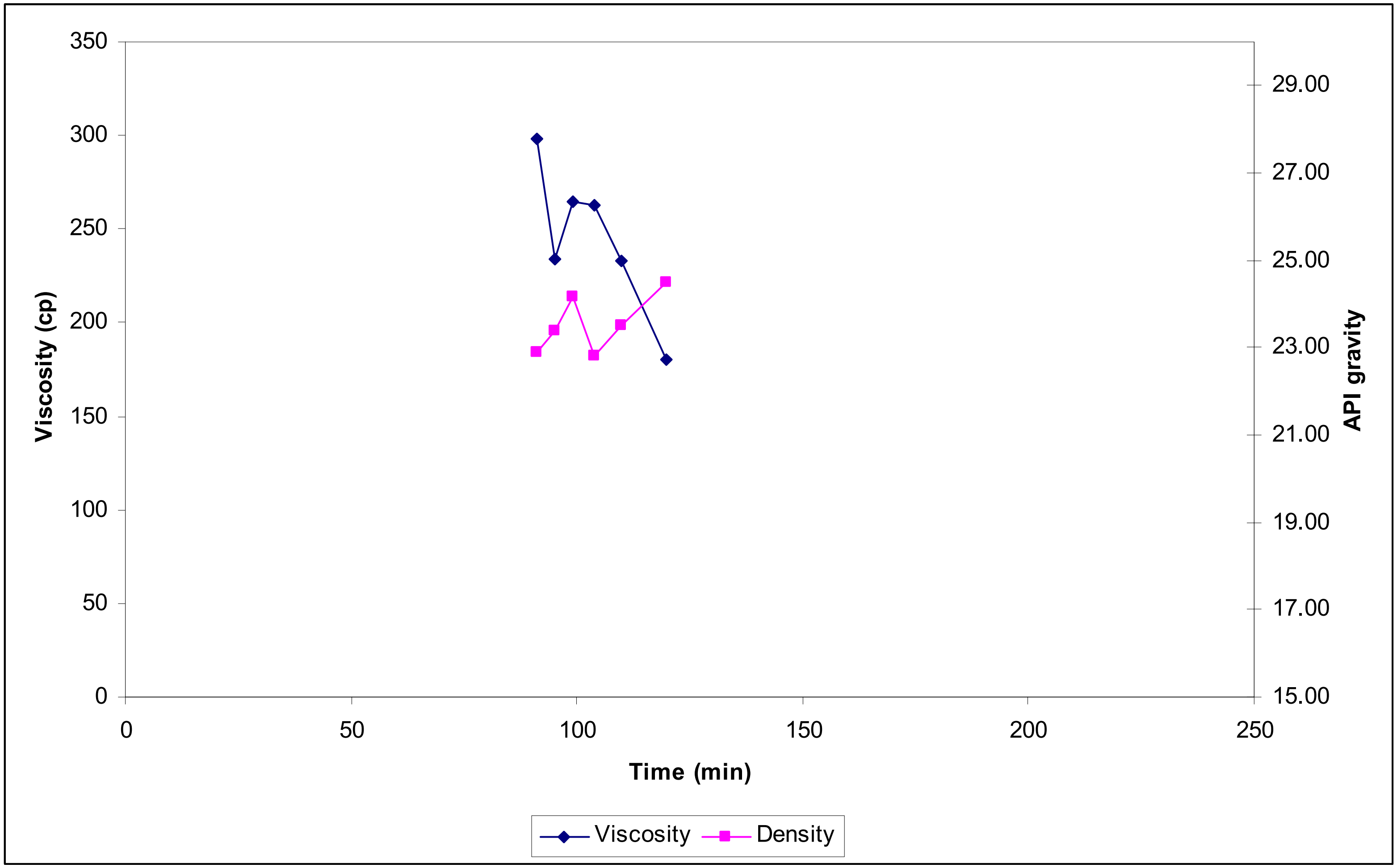

Fig. 4.62— Viscosity and density from the collected samples of run no. 15.

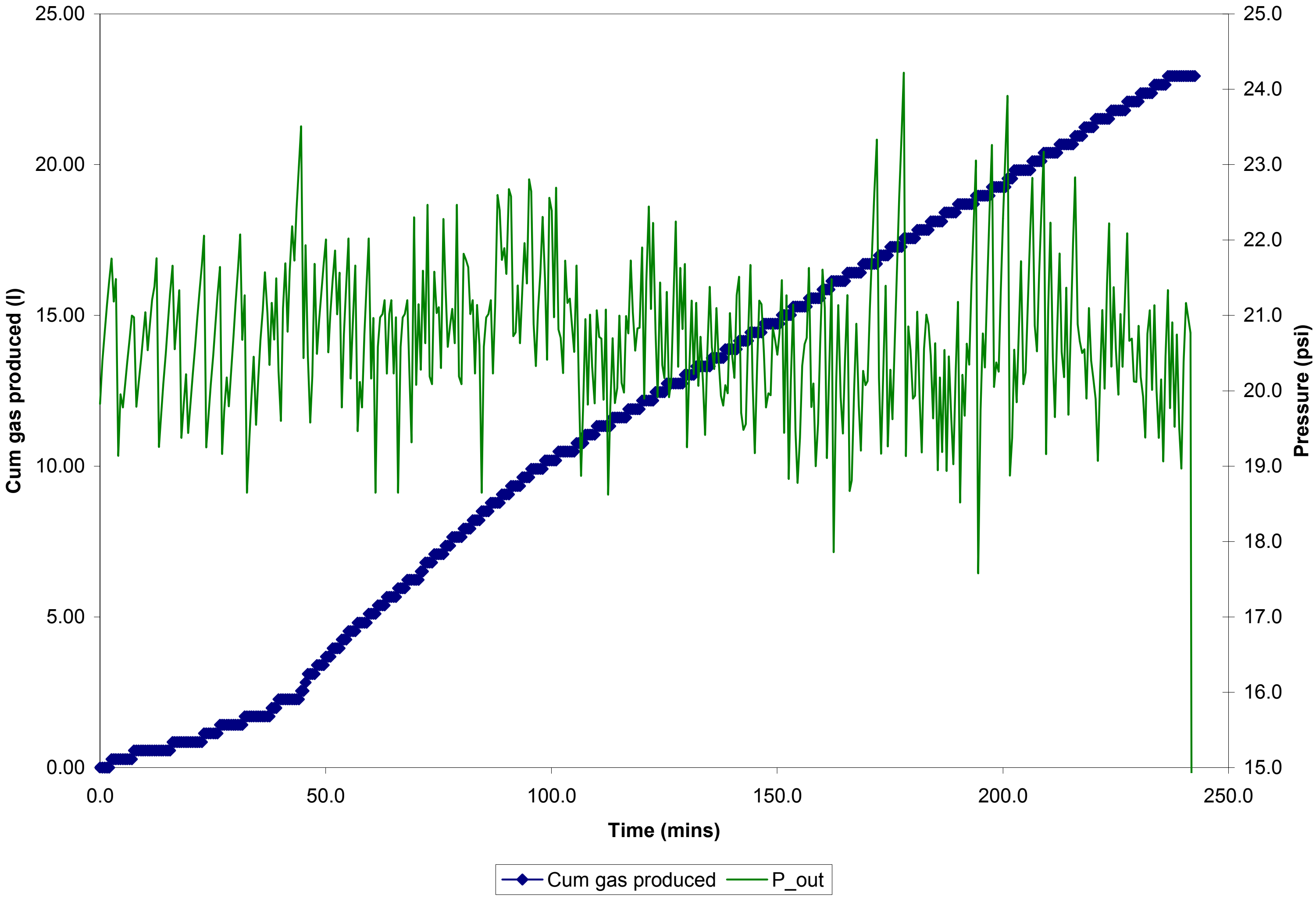

Fig. 4.63— Cumulative gas production and outlet pressure versus time for run no. 15.

4.10 Discussion of Experimental Results

Some of the following graphs have been cut off at 250 minutes to achieve less overlap between results, and more readable graphs. Run 11 and 14 lasted longer. If more information is wanted on those two runs the reader is referred to sections 4.5 and 4.8 respectively.

Oil production rates versus time for all runs are plotted in **Fig. 4.64**. Run 10 and 15 (superheated steam with propane) have accelerated production compared to run 8 and 9 (superheated steam but no propane). Run 11, which is a hot water/propane run, never reaches anywhere close to the production rates we see when steam is introduced. Run 12 (close to saturation temperature) has late oil production. It is able to maintain a plateau production rate for a longer time than the others though. Run 13 (roughly 70% steam quality) achieves a much later peak in production than the pure steam runs.

Water production as a function of time can be seen in **Fig. 4.65**. It starts after about 50 minutes for all runs except 11 and 14, which are the runs with little or no steam injection. When hot water is injected it appears to fill more of the voids containing gas (nitrogen), whereas steam will travel further into the mix while pushing liquids ahead of it. This makes the hot-water front move forward slower than if you inject steam.

Fig. 4.66 shows the cumulative oil production versus time. It clearly illustrates that more production is achieved from the steam/propane runs than with steam alone. However, the 100% steam runs with no propane still produce more than the case with 70% steam quality using propane. The hot water runs have the lowest cumulative production. This can be quantified better when looking at **Fig. 4.67**, which shows the cumulative recovery as a function of time. By the time we stop most experiments, run 14 has only produced about 5% of OOIP. That can be compared to 32% for steam/propane and 27% for pure steam and 19% for the 70% steam quality.

In **Fig. 4.68** the differential pressure between the 4 runs using superheated steam can be compared. It appears it might be slightly higher for a short period when the oil bank is building up for run 10 and 15, but after about 100 minutes or so it seems to drop down and stabilize at slightly lower differential pressure than run 8 and 9. In **Fig. 4.69** we can see how only the superheated runs that are building up a significant oil bank get the increase in differential pressure around 60-90 minutes. The other runs however all have slow buildups in differential pressure as they approach their breakthrough time.

Fig. 4.70 and **Fig. 4.71** show how viscosity and density of the produced oil changes with time. There seems to be a trend towards oil upgrading, with API gravity increasing and viscosity decreasing. This trend can be observed for runs using propane as well as those without.

Figure 4.72 shows the cumulative heat injected to the cell for each run in BTU's. Around the saturation temperature however, the calculations of energy become very sensitive to pressure differences. So sensitive that the calibration of the pressure measuring equipment might not be good enough for these purposes. Just one or two psi off can change the curve completely. Run 11 is one example of this, where it appears we are injecting a lot of heat into the reservoir according to Fig. 4.72. However, if the injection pressure is changed just a little we generate curve 11b. This is further explained by the calculations in Appendix B. What can be seen though is that injecting with temperatures above saturation temperature does not make much difference to the total amount of heat you get in the reservoir.

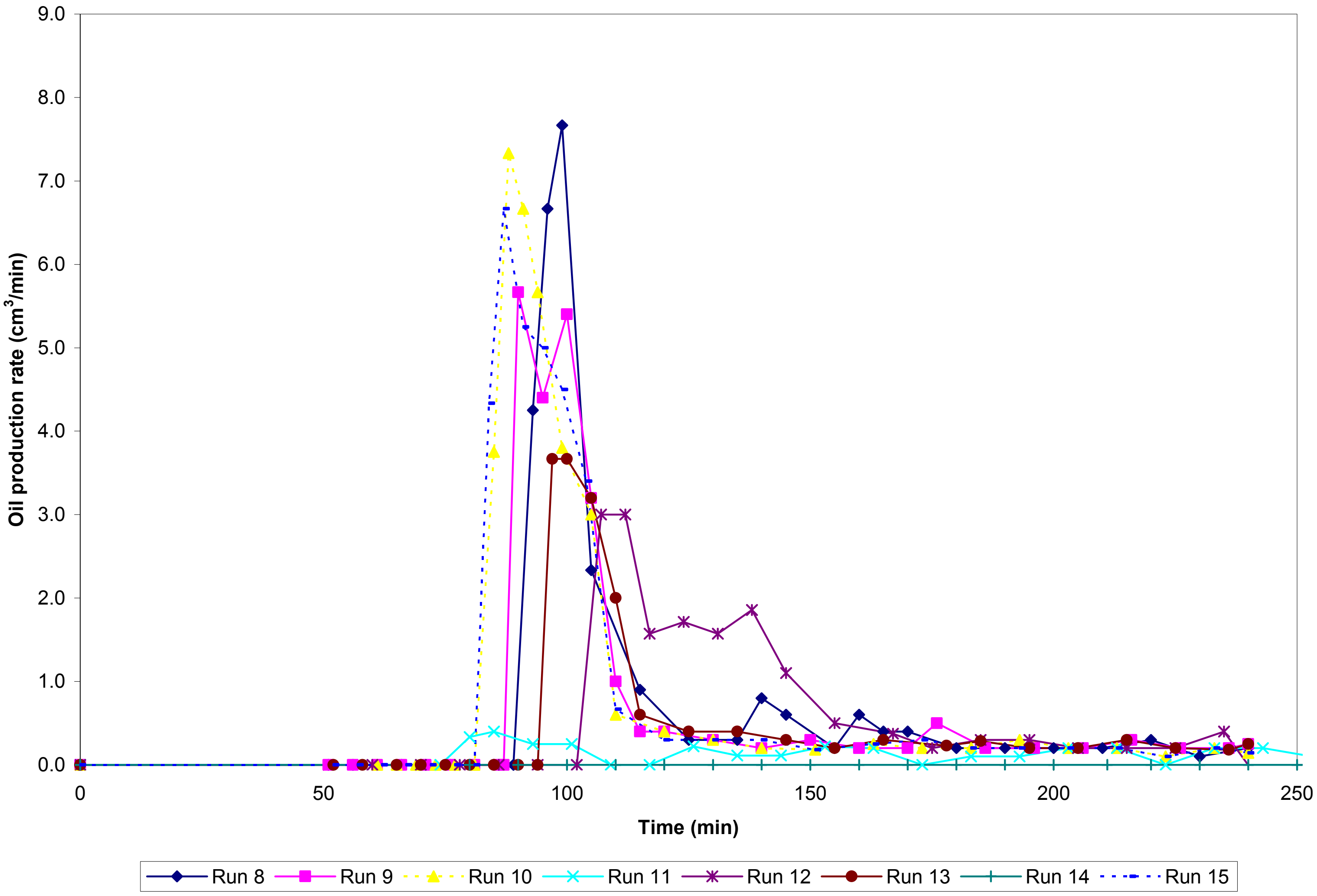

Fig. 4.64— Oil production rates versus time for all runs.

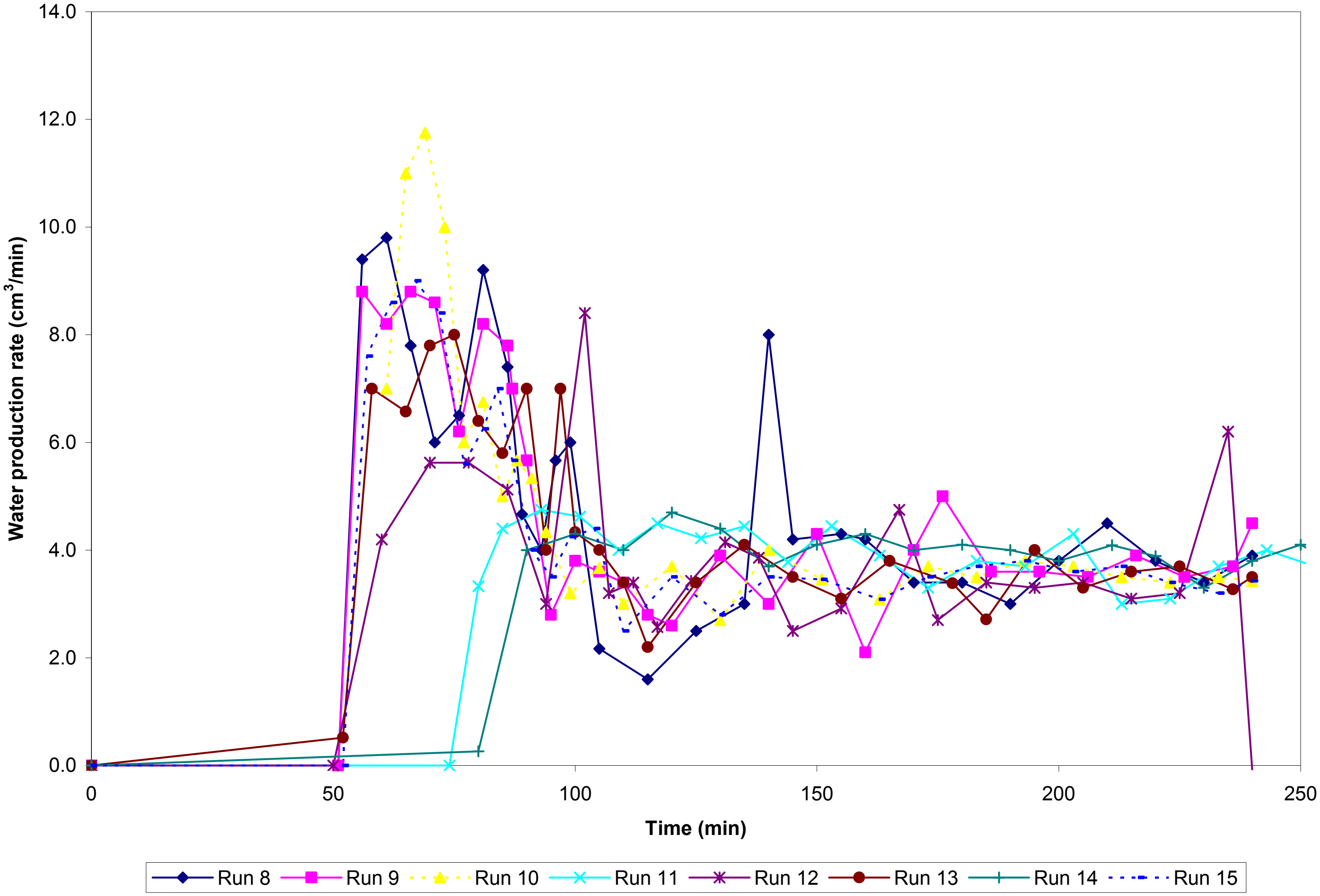

Fig. 4.65— Water production rates versus time for all runs.

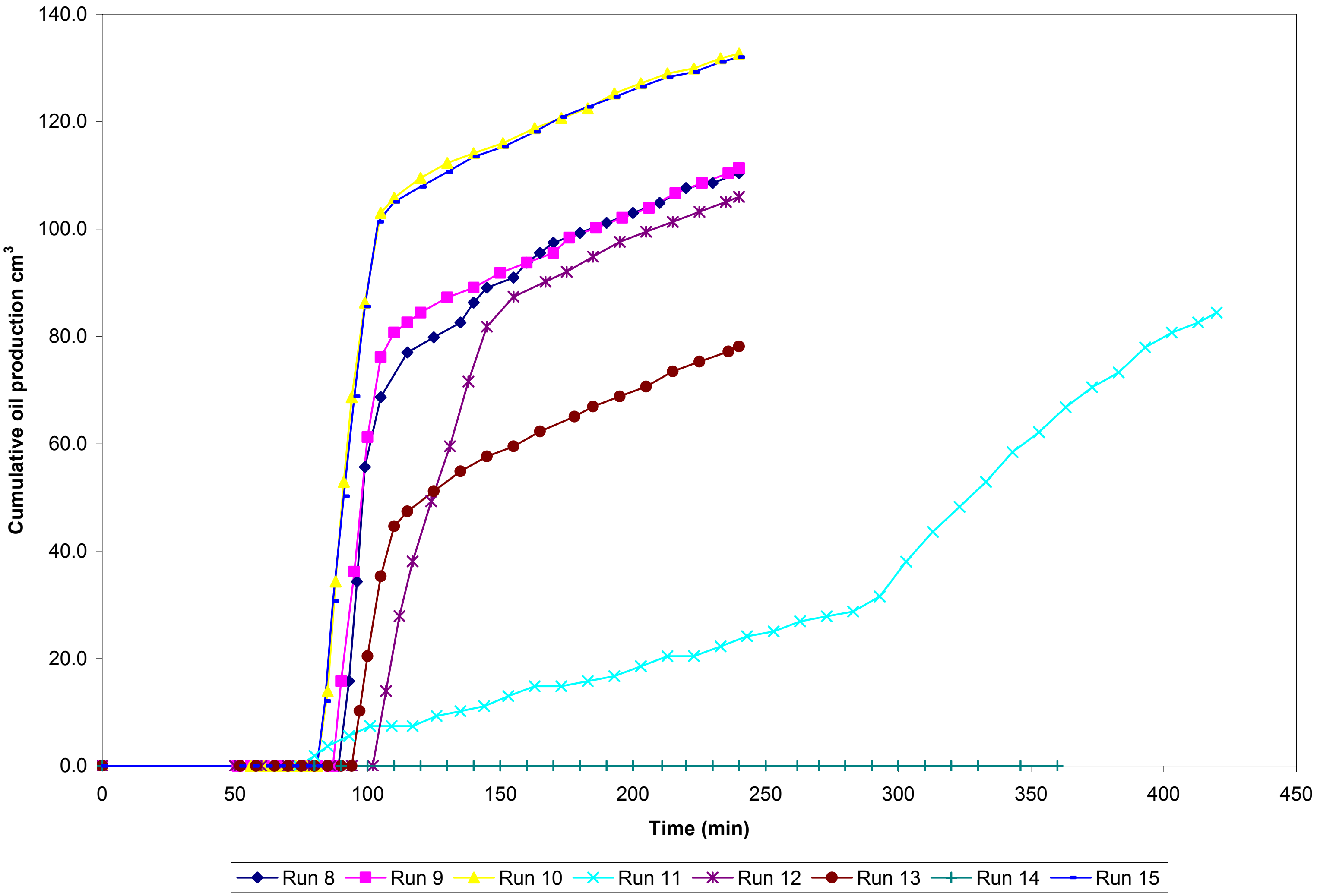

Fig. 4.66— Cumulative oil production versus time for all runs.

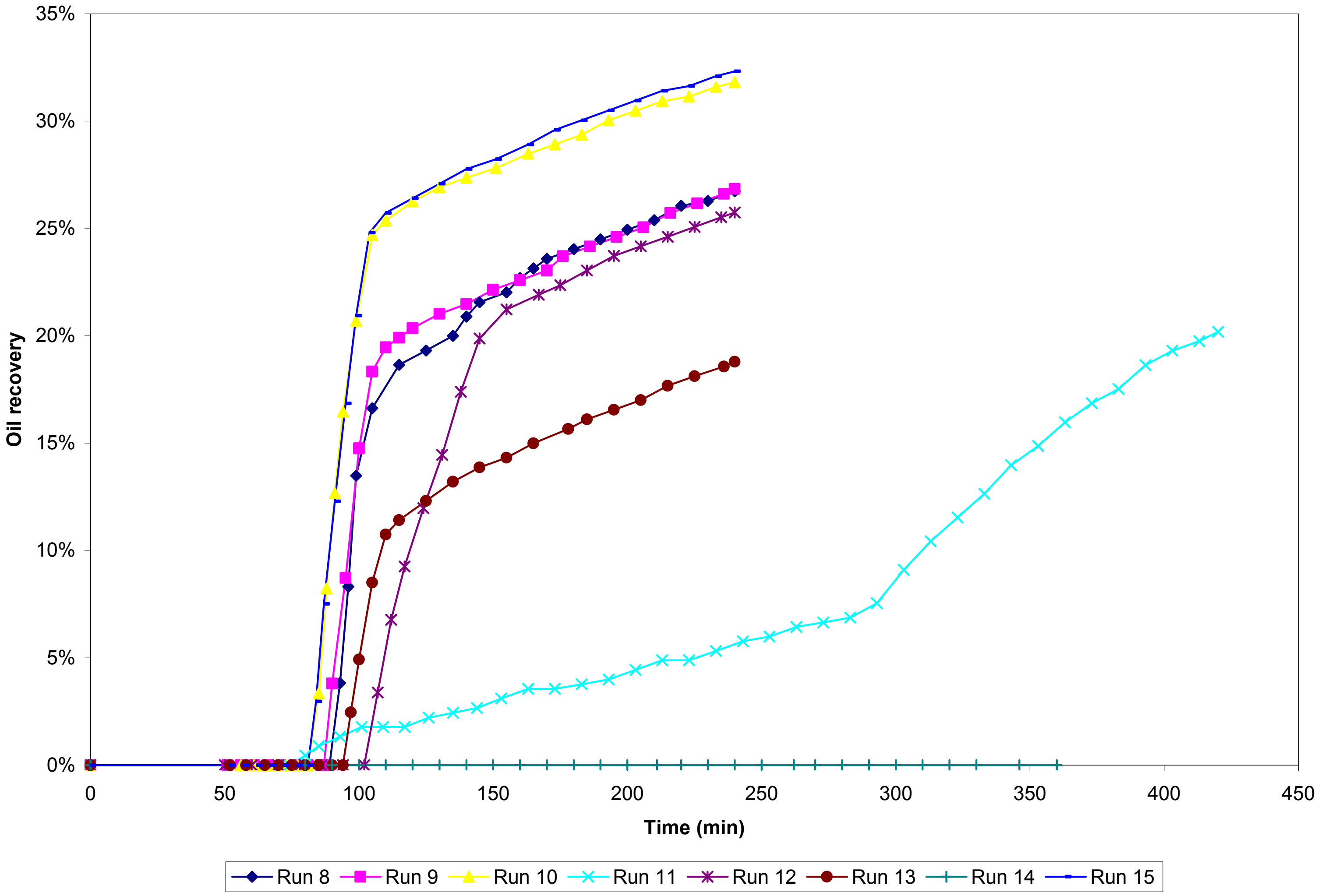

Fig. 4.67— Total recovery versus time for all runs.

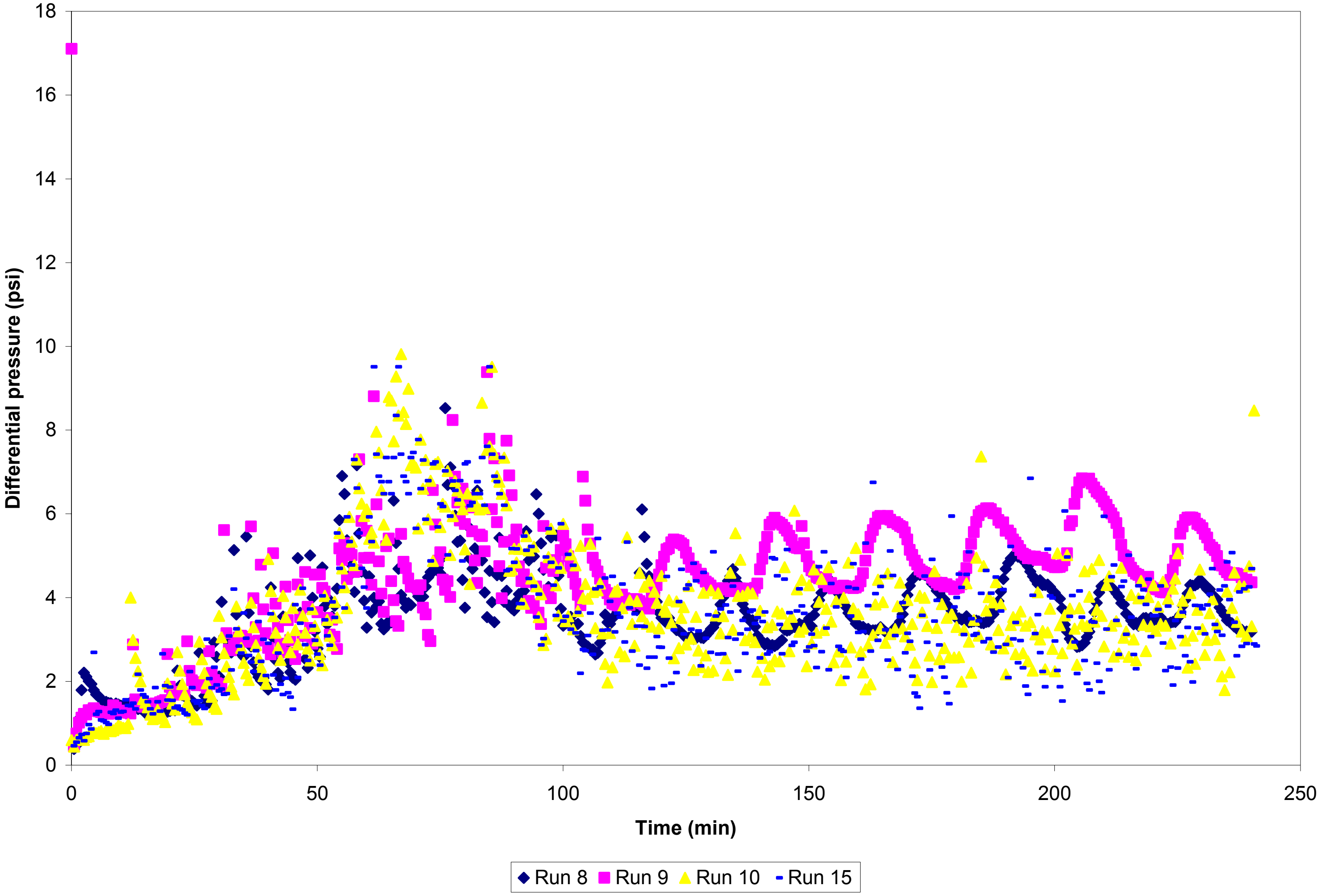

Fig. 4.68— Comparison of differential pressure for the superheated steam runs.

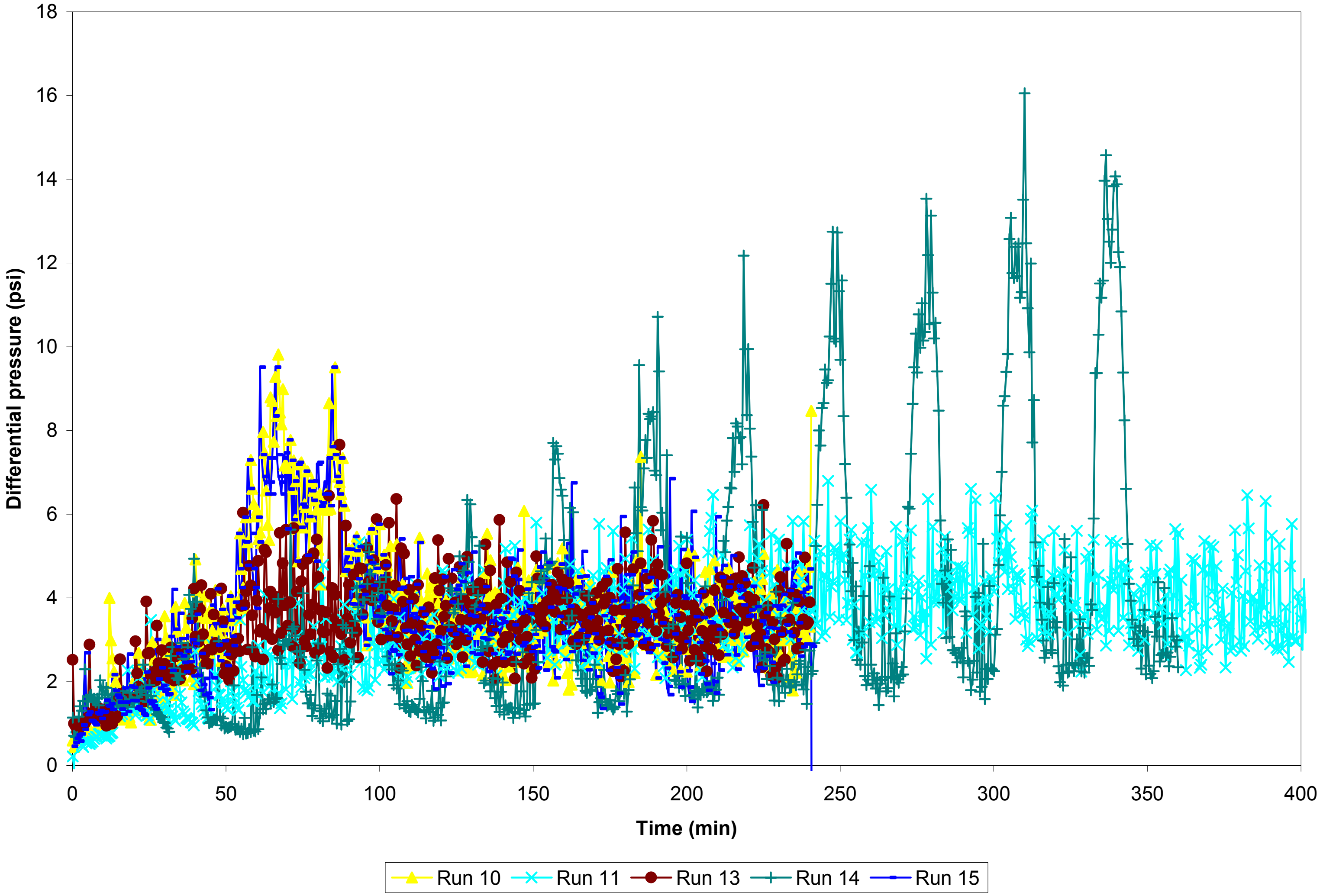

Fig. 4.69— Comparison of differential pressure for the propane runs.

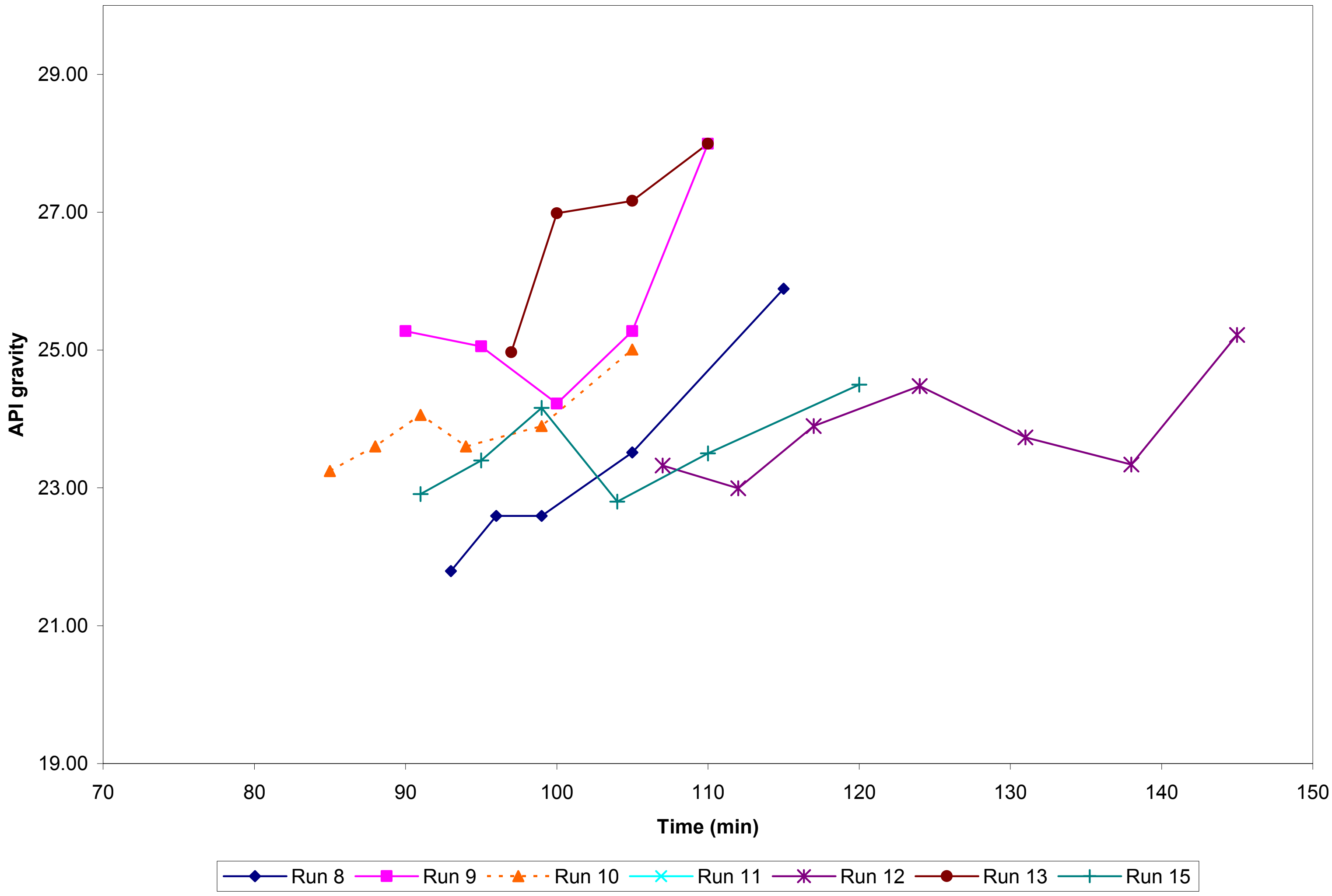

Fig. 4.70— Oil density versus time for all runs.

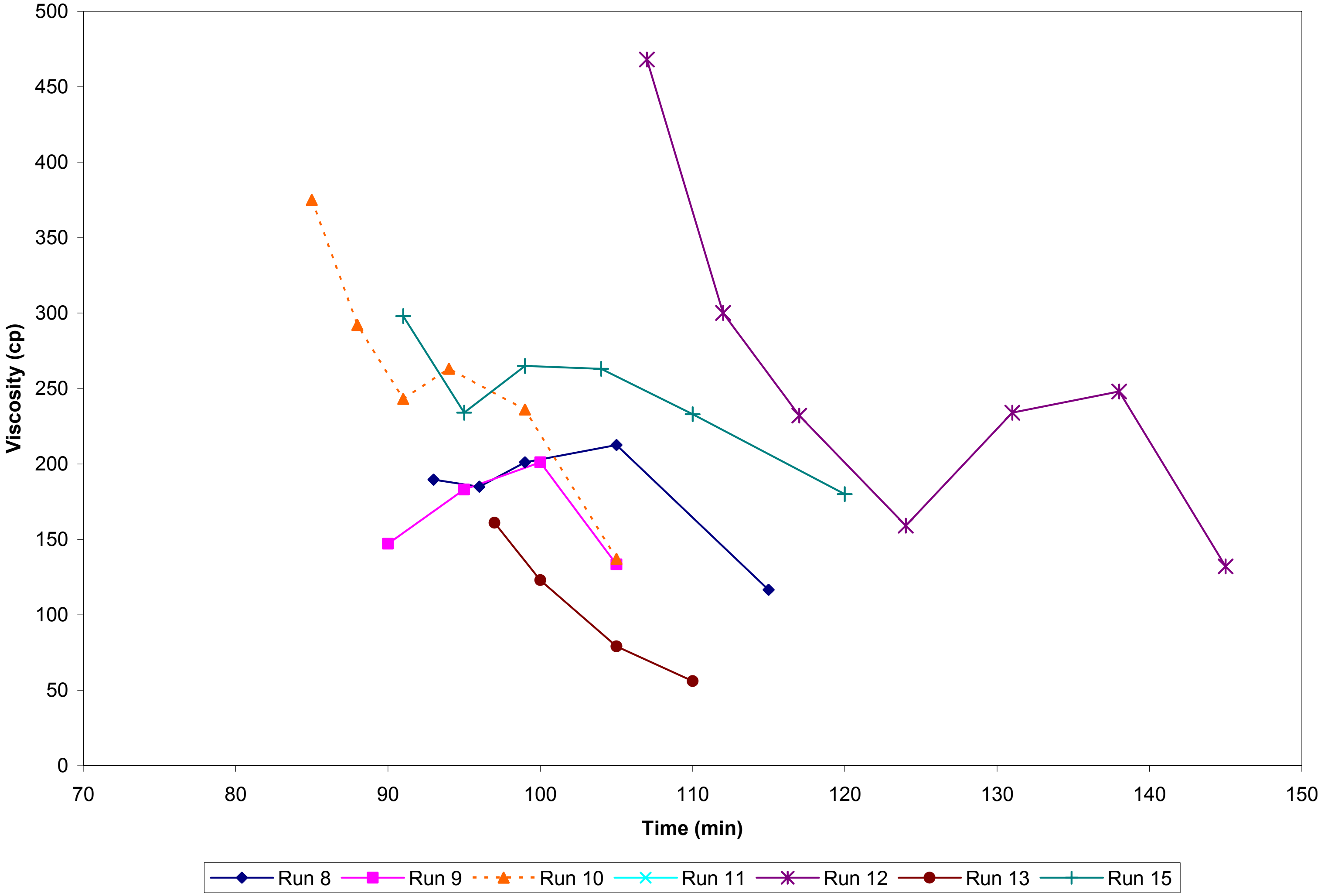

Fig. 4.71— Oil viscosity versus time for all runs.

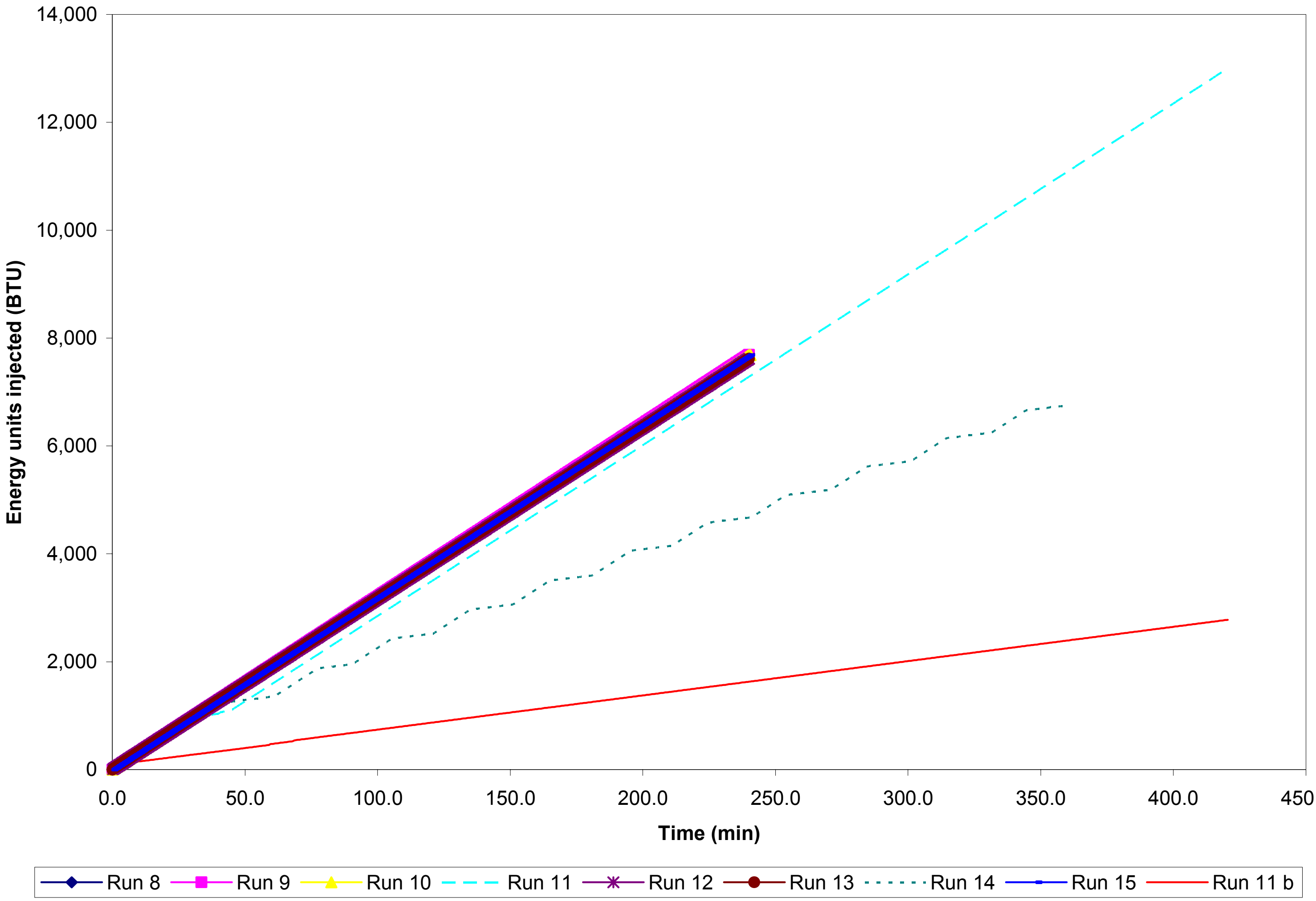

Fig. 4.72— Injection of energy vs. time for all runs.

CHAPTER V

PROPANE COST ESTIMATE

5.1 Factors Affecting Propane Cost

The residential and commercial sector consumes almost half the propane sold in the U.S. each year (**Fig. 5.1**) [30]. As you would expect from this, the propane cost is highly affected by the supply and demand within this sector.

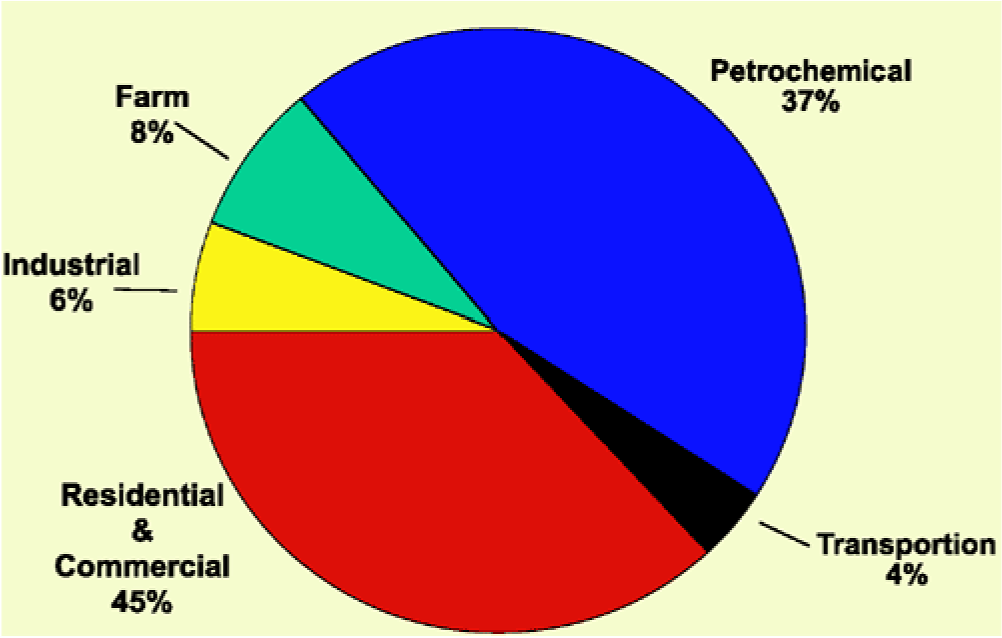

Fig. 5.1— Propane demand displayed by sector.

While propane is produced year-round, residential demand for propane is highly seasonal. This seasonality causes inventories to increase when demand is low and decrease when demand is high, as in the winter months. Additionally, while the demand for natural gas continues to grow for large-scale users, such as power generators, its supply remain relatively constant. This unmet demand pushes the price of natural gas—and thus propane—up. Colder temperatures during the winter months increase the demand for propane, which reduces supplies and raises prices. Propane marketers try to forecast the demand, but predictions of long-term weather trends are difficult.

Because propane is derived from both crude oil and natural gas, its price parallels the prices of those energy sources. It is especially sensitive to the cost of crude oil, since propane competes mostly with crude oil-based fuels for heating (**Fig. 5.2**).[31]

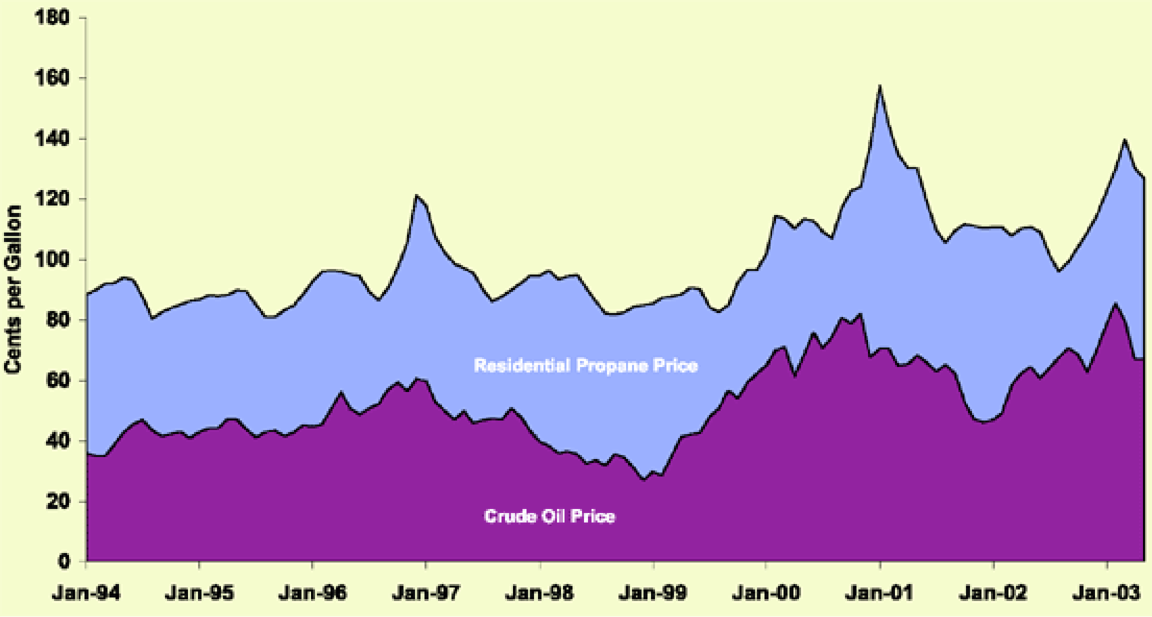

Fig. 5.2— Propane price compared to crude oil price.

In addition, propane prices are influenced by the proximity of the customer to propane supplies. In an area such as the Gulf Coast, customers are closer to major supplies and therefore may pay less. In areas farther from major supplies customers will probably pay a premium to compensate for the transportation costs.

Propane prices are also influenced by the propane distribution system. As with all energy sources, prices are influenced by the systems required to transport the energy source from where it is produced to where it is used, whether through pipelines or power grids. Temporary difficulties transporting propane from production source to its distribution facilities in various regions include weather, transportation bottlenecks at trains or ports, and pipeline repairs.

5.2 Expected Cost Associated with Injecting Propane in an Oilfield

In this study, we have gathered information specifically for the San Ardo field in California, operated by ChevronTexaco. This is a large, mature field where steam flooding has been used for many years. The company is investigating the possibility of doing a steam-propane test well in this area.

A typical steam injection well in San Ardo operates at about 1,600 barrels per day of cold water equivalents (BPDCWE) during its first two years of operation. Then the rate is lowered to 1,200 BPDCWE, and eventually 800 BPDCWE. Assuming 5:100 propane:steam ratio this early injection scheme translates into approximately 28,000 pounds of propane per day (**Eq. 1**). With today's propane price of \$1.35 per gallon, the associated cost would be about \$9,000 per day (**Eq. 2**).

$$5\% \times 1{,}600\ BPDCWE \times 5.6145\ {}^{ft^3}\!/_{BBL} \times 62.4\ {}^{lbs}\!/_{ft^3} = 28{,}030\ lbs/day \ \ldots\ldots\ldots\ldots\ldots(1)$$

$$28{,}030\ {}^{lbs}\!/_{day} \times 0.2404\ {}^{gal}\!/_{lb} \times 1.35\ {}^{\$}\!/_{gal} = 9{,}096\ {}^{\$}\!/_{day} \ \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(2)$$

This is a significant amount, so recycling of the gas will be necessary. It is expected that recycling can be done by drying the produced gas and re-injecting it directly. No processing beyond this is thought to be needed.

AmeriGas is the largest supplier of propane in California as well as the United States. All the cost estimates are provided here after consultation with their California branch. For the pilot well large semi-portable tanks will be put up and refilled by 10,000 gallon trucks as needed. If the whole field was to be put on propane injection bigger, more permanent solutions would be appropriate.

CHAPTER VI

SUMMARY, CONCLUSIONS AND RECOMMENDATIONS

6.1 Summary

7 runs where performed to investigate the effects of injecting propane with hot water compared to steam. Different temperature ranges where used, from undersaturated steam to low quality steam to superheated steam. The injection rate was kept constant at 3.5 cc/min (cold water equivalent), along with a constant backpressure of 20 psig.

6.2 Conclusions

1. Steam-propane injection seems to accelerate start of production. The propane does not have the same effect when used with hot water, or water alternating steam. Pure steam injection accelerate oil production more than these two other methods.
2. Steam-propane injection achieves higher oil recovery than pure steam injection. This is contrary to what has been found earlier, and could be related to injection rates.
3. 70% steam quality with propane gives better results than hot water with propane (albeit the uncertainties in steam quality estimate). The propane does not seem to have the same beneficial effect on oil when used with hot water that it has when used with steam.
4. When steam is superheated it does not make a difference to the injection process if it is by 1ºC or 15ºC. The amount of heat injected does not change much above saturation temperature. For temperatures below saturation temperature though the difference is bigger. When injecting hot water the energy put into the cell is about 1/5 of what you inject with superheated steam in the same amount of time.

5. The steam travels faster in the reservoir, releasing its heat far into the matrix. The hot water –being more mobile than steam - moves more slowly, filling all voids and losing heat on its way.

6.3 Recommendations

It has been established that steam-propane injection lowers the boiling point of the light to intermediate fractions. If this effect can be achieved while injecting steam-propane through the early parts of the run - and then switching to pure steam for the remainder, cost can be significantly lowered.

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APPENDIX A

CALCULATION OF FLUID SATURATION AND PORE VOLUME

This is a sample calculation of fluid saturation and pore volume inside the cell. These calculations were made for run no. 12:

Cell dimensions:

Diameter, d_{cell}	2.9134	in			
Height, h_{cell}	27.126	in			
Volume, V_{cell}	180.83	cu in	=	2963.3	cu cm

Input data:

Sand density, ρ_s	2.65	g/cu cm			
Oil density, ρ_o	20.7	°API	=	0.93	g/cu cm

Weight of mixture prepared:

Weight of sand, W_{sand}	5141	g
Weight of water, W_{water}	226	g
Weight of oil, W_{oil}	443	g
Weight of mix, $W_{mix} = W_{oil}+W_{water}+W_{sand}$	5810	g
Weight of tools and bowl, W_{tools}	999	g
Weight of tools+mix left after adding to cell, W_{left}	1790.0	g

Weight of mixture in cell:

Weight of mix in cell, $W_{m\_cell} = W_{mix}+W_{tools}-W_{left}$	5019.0	g
Weight of sand in cell, $W_{s\_cell} = (W_{m\_cell} * W_{sand})/W_{mix}$	4441.1	g
Weight of water in cell, $W_{w\_cell} = (W_{m\_cell} * W_{water})/W_{mix}$	195.2	g
Weight of oil in cell, $W_{o\_cell} = (W_{m\_cell} * W_{oil})/W_{mix}$	382.7	g

Volume in cell

Volume of sand in cell, $V_{s\_cell} = W_{s\_cell}/ \rho_s$	1675.9	cu cm
Volume of water in cell, $V_{w\_cell} = W_{w\_cell}/ 1$	195.2	cu cm
Volume of oil in cell, $V_{o\_cell}= W_{o\_cell}/ \rho_o$	411.6	cu cm
Porosity = $(V_{cell}-V_{s\_cell})/V_{cell}$	1287.4	%
Volume of pores in cell, Vp_cell = Porosity * V_{cell}	1287.4	cu cm

Saturations

Water saturation, $S_w = V_{w\_cell}/V_{p\_cell}$	15.16%
Oil saturation, $S_o = V_{o\_cell}/V_{p\_cell}$	31.97%
Gas saturation, $S_{air} = 100\% - S_w – S_o$	52.86%

APPENDIX B

CALCULATION OF STEAM QUALITY AND ENTHALPY

These are the calculations used for calculating steam quality and heat injected into the reservoir. The example below is for run #14:

Properties

Average expected injection pressure, P_i	25	psig	39.7	psia
Saturation temperature at P_i, T_{sat}	265.3	Fahrenheit	129.6243	celsius
Average superheated Cp for this T,				
Cp_s	0.5			
Cp for water, Cp	1			

We want to go 50ºFC above saturation temperature when we are superheated and 50ºF below when we inject hot water (ΔT). This is to ensure we are in the saturated region for as short a time as possible. The heat calculations are as follows:

$$H_c = 91 \times \mathrm{P}_{\mathrm{i}}^{0.2574} \qquad (3)$$

$$H_w = T_{water} - 32 \qquad (4)$$

$$H_{sv} = 1{,}119 \times \mathrm{P}_{\mathrm{i}}^{0.01267} \qquad (5)$$

$$H_s = Cp\_s \times \Delta T + H_{sv} \qquad (6)$$

$$L_{v\_sat} = H_{sv} - H_c \qquad (7)$$

$$L_{vs} = H_s - H_c \qquad (8)$$

As we can see from the calculation of H_s, if we are at superheated steam quality further increases in temperature only yields about 0.5 Btu/lbm injected per ºF.

Heat calculations:

Enthalpy of Condensate, H_c	208.39	Btu/lbm
Enthalpy of water when undersaturated, H_w	183.32	Btu/lbm
Enthalpy of steam vapour, H_{sv}	1165.58	Btu/lbm
Enthalpy of steam when superheated, H_s	1190.58	Btu/lbm
Latent heat of vaporization at Ts, L_{v_sat}	957.19	Btu/lbm
Latent heat of vaporization when superheated, L_{vs}	982.19	Btu/lbm

We are injecting hot water 70% of the time and then superheated steam for 30% of the time. If we do this in 30 minute cycles it translates into 21 minutes of hot water injection followed by 9 minutes of superheated steam

From this we can calculate f_s (**Eq. 9**):

$$f_s = 70\% \times H_w + \frac{(1-70\%)\times(H_c+L_{vs})-H_c}{L_{v\_sat}} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(9)$$

This is how we arrive at the desired steam quality in run 14. By changing the fraction of time we inject hot water as opposed to steam we can manipulate the steam quality to where we want it.

VITA

THOMAS NESSE

Permanent address:
Kroken 8
4340 Bryne
NORWAY
(+47) 950 25 280
thomas@jkn.no

Education

2002 – 2004	2 year M.S. Petroleum Engineering, Texas A&M University
1999 – 2002	3 year B.S. Petroleum Engineering, Stavanger University College
1998 – 1999	1 year compulsory military service, Haslemoen
1995 – 1998	Bryne Videregående skole, almennfaglig linje (High school)

Work experience

2002	Internship at Baker Oil Tools, Workover Systems
1999 – 2002	Part-time salesman at Spaceworld Stavanger (electronics store)
1994 – 1999	Part-time job at Brødrene Kverneland AS, Bryne (auto dealership)

Honors and Activities

2002	Fulbright Foundation for educational exchange (Scholarship)
2001 –	Member of the Society of Petroleum Engineers
1997 – 2001	Leader of “Bryne Innebandyklubb” (Floor-hockey club)

Other Skills

1998	Forklift drivers license