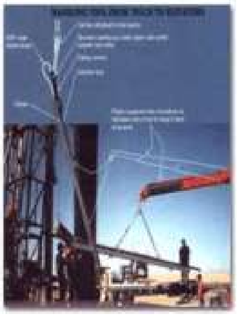
The MxL Downhole Induction Heating System

The MxL Induction Heating System heats the near well bore at the production zone thus decreasing oil viscosity to improve oil mobility both in the zone and at the pump suction. The inductive method of heating transfers the energy directly from the tool to the well casing which, since it is in direct contact with the reservoir rock, transfers the heat efficiently at the lowest possible annulus temperature. Since the tool surface does not have to be at a high temperature there is no tendency for the tool to scale, overheat and burnout. One of these tools has been in almost constant use since 1997 and others have been in service for more than two years. They have been re-deployed from well to well when used as a data gathering system to define production from multi zones and from different levels within a zone.

MxL System Configuration



A MxL Tool Installation

The MxL system is a retrofit system suitable for vertical, deviated or horizontal completions wherein one or more inductors are attached to the bottom of the production tubing in order to heat the production zone.

Electrical power is applied to an Electric Submersible Pump (ESP) cable strapped to the side of the production tubing utilizing a regular ESP power feed through and appropriate tubing hanger at the wellhead. The system utilizes the production casing as an inductively heated element to conduct heat and electrical energy into the production zone.

PCU Power Controls

The Power Conditioning Unit (PCU), computer and power controls are set up so that power to the three inductor sections can be varied to heat the casing through electromagnetic induction in a selective and controllable manner.

The MxL tool's inductors are configured to use 50 to 180 Hz three phase modified output waves from the PCU. Resistance measurements are used to indicate temperature at each inductor section and the PCU shuts down periodically to obtain readings that are indicative of the average inductor section temperature. Additional "signature" readings are also included to measure specific location temperatures and bottom hole pressure and return that information on the supply cables. These signature readings are retained in the logged data for periodic evaluation of the system and if proven to be reliable may be selected as control inputs.

The PCU

The PCU has data logging and controls to set power limits based on the greater of either downhole temperature or maximum KVA, for each of three sections, and to retain operating information for later evaluation. System control interlocks are included to provide high current trip, pump trip, low flow trip and provide an operator controlled output contact to signal if the PCU has tripped off.

Application

Applications include medium light to heavy crude as the benefit depends upon the ratio of unheated to heated oil viscosity and even light oil shows about a 3:1 ratio.

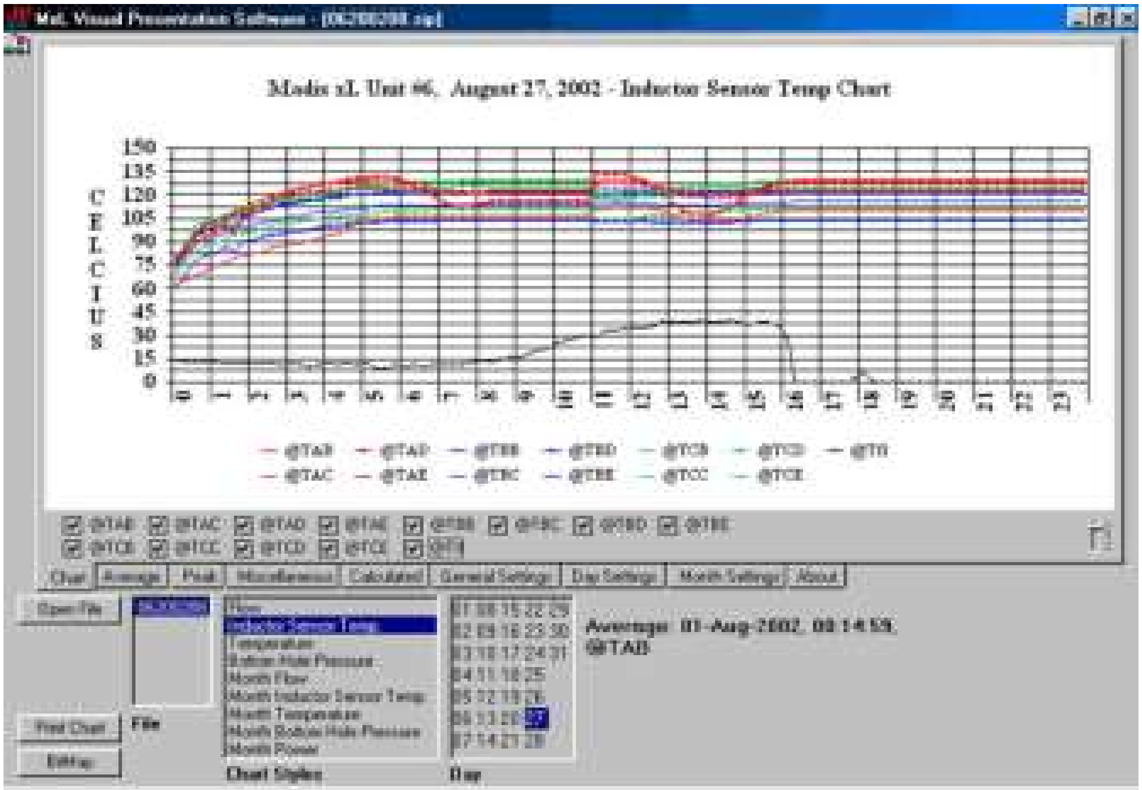
Visual Presentation Software

As the induction tool is equipped with an array of temperature sensors placed along the assembly and one or two pressure sensors, a software package is provided to convert the logged data into graphical form.

The Visual Presentation Software (VPS) opens the .ZIP file downloaded from a PCU, then automatically processes it using a custom DAT file extraction program, which is written specifically to convert PCU .DAT files to TAB delimited .TXT files. The whole process is reduced to a couple clicks of the mouse. Flow rate is also logged, as are the operating conditions at the PCU.

The VPS makes assessment of operations and research work straightforward and understandable. Printout capabilities are built-in to provide graphs for daily or monthly display of operating information. These graphs can be printed or directly exported to a bitmap image and sections of raw data can be printed as needed.

VPS can simultaneously view all records from up to 6 individual PCUs depending upon the speed of the user's computer. The data can be viewed in a graphed format with the option to graph any one datum set against any other. The raw data can also be viewed spreadsheet style.



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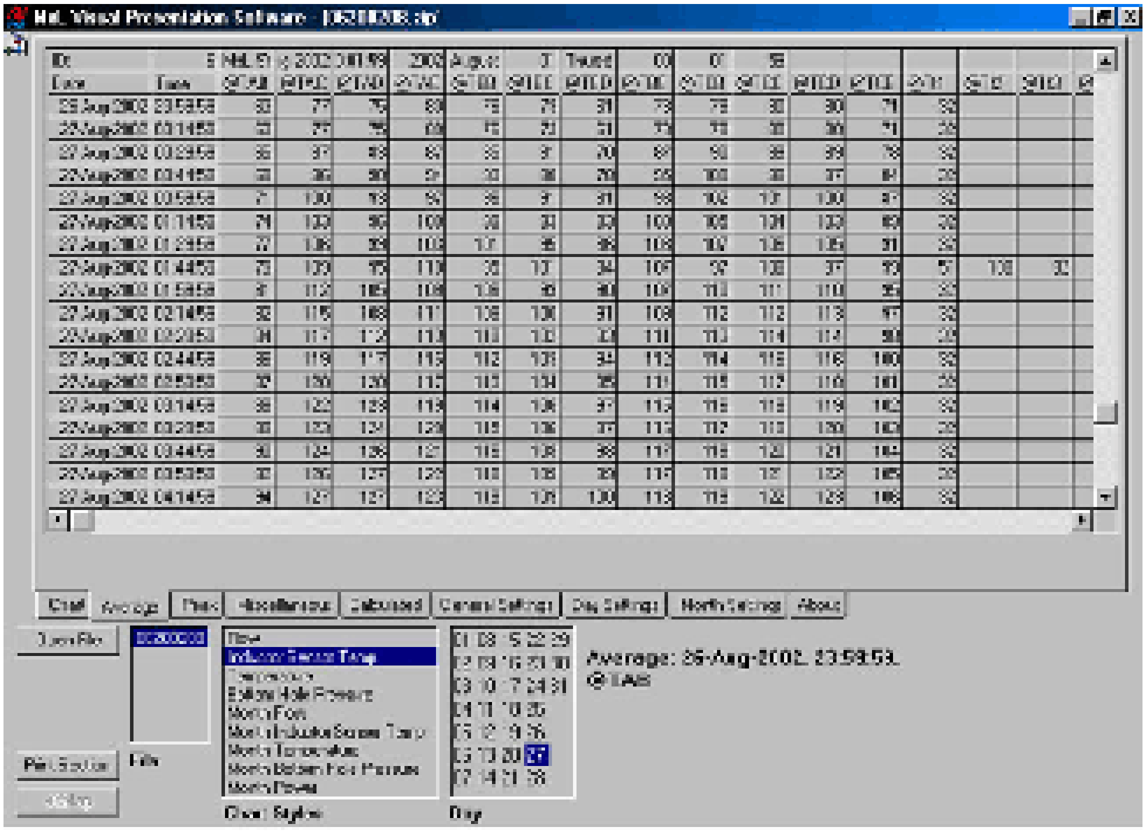
@TAB



This software was written in-house to eliminate the need to use the often changing and usually cumbersome import routines found in many of todays popular spreadsheet/chart applications.

Our Findings

The ability to dynamically observe temperature and pressure at the production zone has provided valuable information. The most common, and most significant finding is that bottom hole temperature is nearly always lowered during production.

In a well that had been in production for more than a year, we observed that the bottom hole temperature was 8 degrees C below the driller's reported value. That has been typical for all wells but two, one a water-out horizontal and the other at the edge of a steam flood, with the temperature before heat is applied being 4 to 9 degrees C below expected values.

When the MxL system is applied to an existing well, that has reserves and adequate drive pressure, increased production can usually be realized.

MxL Benefits & Highlights

- **Alleviates Sanding-In**
- **Controls Temperature Within The Zone**
- **Determines Flow Response From The Zone**
- **Heats Only The Selected Zone**
- **Increases Oil Mobility**
- **Increases Pump Efficiency**
- **Portable**
- **Reduces Pump Torque**
- **Reduces Water Cut**
- **Remote Controllable**
- **Retrofit Design**

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The Visual Presentation Software (VPS)

The **MxL** Induction Heating System may be configured to communicate via modem, bag phone, spread spectrum radio or similar interface. With such a link the operation can be supervised remotely and data files transmitted to facilitate evaluation of operations at a central location. Two way communications allows the PCU to be controlled through the remote link and to monitor dynamic activities on a second by second basis. The active link is often beneficial as dynamic data often become obscure when viewed on a time averaged data log. A 3 ½" floppy drive is also available, on the PCU, for file transfer and use by field personnel.

To facilitate use of the data files generated by the PCU a **VPS** has been developed to display temperatures, pressures, flow, and power in graphical form for daily and monthly intervals. Trends and individual events are much easier to follow on the graphs and can be printed or bit mapped for email transfer. The software is part of the **MxL** supply and is without restriction on the number of copies in use, within the company, when used in conjunction with their **MxL** system.

Daily Graph

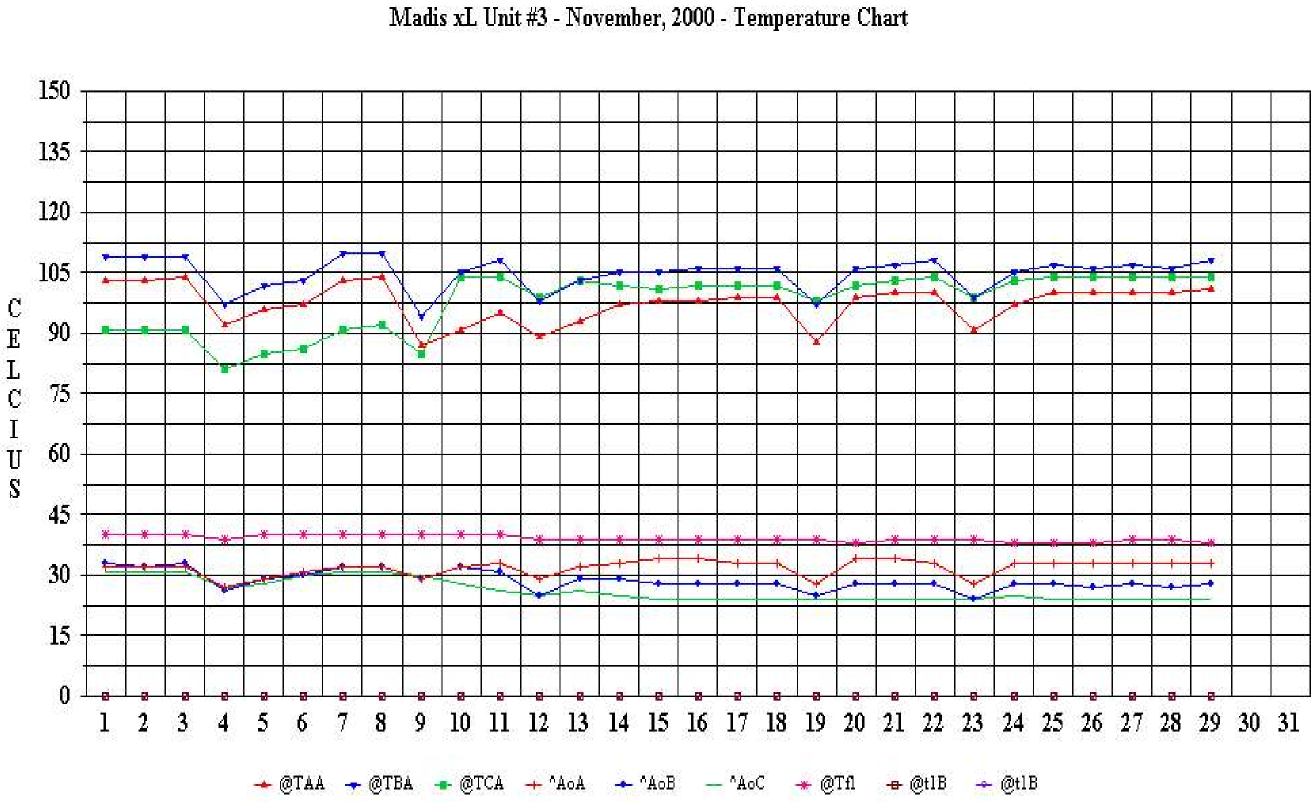
An example of a daily graph is given in "Day 3 Inductor Sensor Temp" which shows values from temperature sensors located along the tool. Sensors "TAB, TAC" are located at the top third of the reservoir "TBB, TBC" near the middle and "TCB, TCC" near the bottom of the zone. Some fluctuation is evident indicating flow variations within the zone. Several methods of operation are possible to help evaluate flow across the zone and we now have up to twelve sensors across the zone to offer greater definition. By setting power at a fixed value the temperature plots readily show localized flow patterns in that they fall when flow increases and rise on decreasing flow. Setting temperature as the limit causes a variation in power, in response to flow variations, which for certain applications is more suitable.

Monthly Graphs

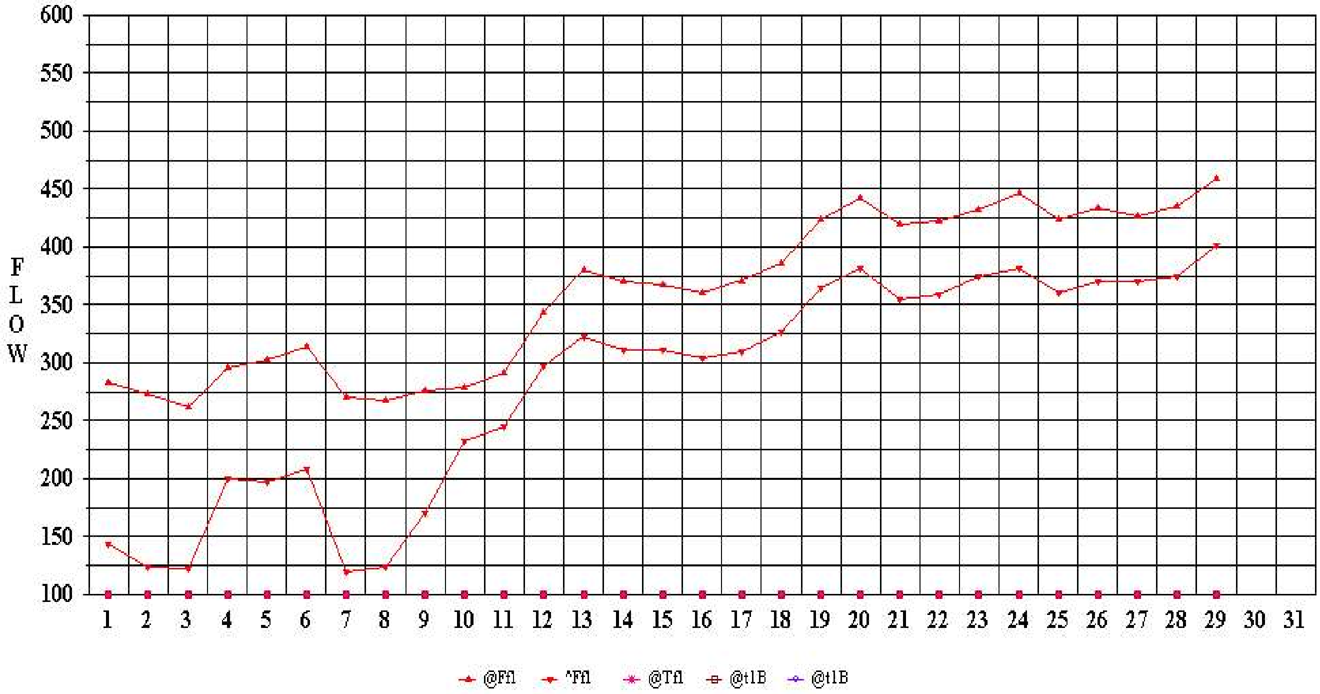
Several monthly graphs are shown and for each of these there are corresponding daily graphs. The graph entitled "Madis xL Unit #3 November, 2000 Inductor Sensor Temperature Chart" has used the built-in customizing features to show additional information in a composite fashion. The values "@t1A,@t1B, PAA, @t1L and @Tfl" were additional data points added to the graph to assist with interpretation.

The graph "Madis xL Unit #3 November, 2000 Flow Chart" show increasing production line flow over a period of one month. The upper line represents the rolling average of flow whereas the bottom line represents the rolling average of minimum flow values. A large spread between lines often indicates a pumped-off condition as was the case in this particular instance. As the heat penetrated into the reservoir and flow increased the pump rate was adjusted to suit the increasing flow.

These two graphs show increasing production but they also illustrate some of the workings of that increase. We note a substantial drop in bottom hole pressure "PAA"on the 6th which was likely due to the wellbore temperature rise increasing pump efficiency causing an increased production rate. At that point in time the heat penetration into the reservoir was not sufficient to increase inflow to match the increased pump capacity resulting in a pumped-off well. That is confirmed by a low production rate over the following day, then an increase in bottom hole pressure and then resumption of production. Subsequent increases were accomplished without disruption in production.

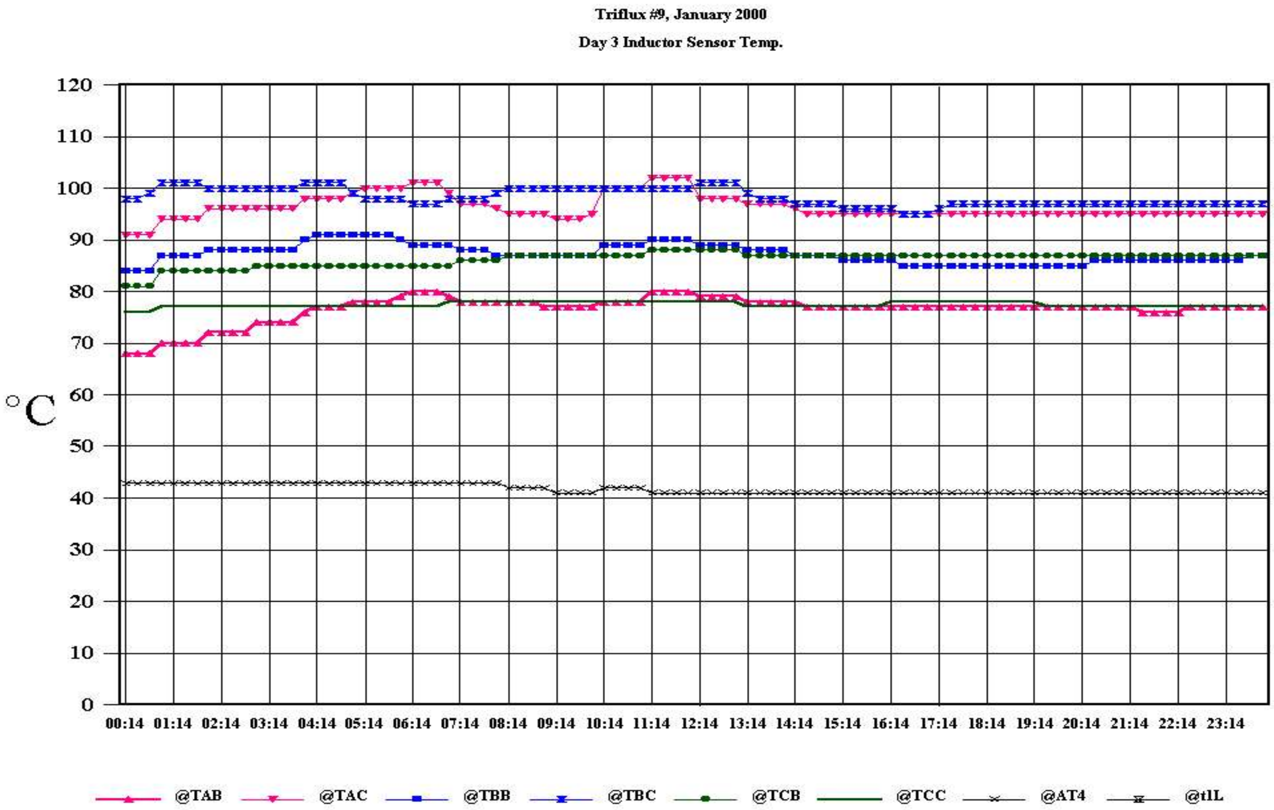


Madis xL Unit #3 - November, 2000 - Flow Chart



Heating during October was intermittent due to grid power supply problems (see "System Number 3" description}caused by an undersized open delta transformer that supplied both the pump and the Induction Heater. We were able to change the PCU transformer taps to limit the 25 KVA system to 4 KVA in order to run both the pump and heater.

The flow graph is from a thermal probe style flow indicator which gives relative flow indication that in this case represents a flow increase from 7 BOD to 21 BOD with no water.



Production Enhancement Projection Service (PEPS)

The surface area through which oil must flow to reach the well diminishes as it nears the wellbore. The following page "TABULATION OF FLOW PATH" shows the surface area and corresponding resistance to flow with respect to distance from the casing. It illustrates that at a substantial distance from the casing a small pressure differential will drive the fluid toward the well and that differential slowly increases as the wellbore is approached to reach substantial values near the wellbore. Nearly half of the pressure difference required, between reservoir and casing pressure, is consumed in the last 50 inches of travel to the wellbore (figure 1 shows this graphically).

Since the pressure required to force oil through the strata is related inversely to the flow area a pressure plot may be drawn to graph the pressure drop with respect to distance from the wellbore given that the other influences remain constant. The influences from permeability, viscosity, casing size, perforations, reservoir thickness, pressure and production rate are used with our **PEPS** pressure profile software to generate profiles used in making projections for a given well. The **MxL** system causes an increase in production by increasing the near wellbore temperature thus reducing the fluid viscosity. To generate a temperature profile our **PEPS** temperature profile software uses tool size, casing size, thermal conductivity, heat capacity, torturous path, porosity, production rate, water cut, reservoir thickness and power level.

TABLULATION OF FLOW PATH AREA AND PERCENT PRESSURE DROP WITH RESPECT TO DISTANCE FROM WELL BORE

Column 1 shows distance from casing to face of cylindrical shell
Column 2 cylindrical shell surface area normal to flow per foot of reservoir thickness
Column 3 ratio of pressure drop at distance to pressure drop near casing at constant viscosity & permeability
Values based on 7 inch Casing 10 Inch increment

Distance from Casing	Relative Surface Area	Relative Resistance to Flow (100 at Casing)
0	1.000	100.000
10	3.857	25.926
20	6.714	14.894
30	9.571	10.448
40	12.429	8.046
50	15.286	6.542
60	18.143	5.512
70	21.000	4.762
80	23.857	4.192
90	26.714	3.743
100	29.571	3.382
110	32.429	3.084
120	35.286	2.834
130	38.143	2.622
140	41.000	2.439
150	43.857	2.280
160	46.714	2.141
170	49.571	2.017
180	52.429	1.907
190	55.286	1.809
200	58.143	1.720
210	61.000	1.639
220	63.857	1.566
230	66.714	1.499
240	69.571	1.437
250	72.429	1.381
260	75.286	1.328
270	78.143	1.280
280	81.000	1.235
290	83.857	1.193
300	86.714	1.153
310	89.571	1.116
320	92.429	1.082
330	95.286	1.049
340	98.143	1.019
350	101.000	0.990
360	103.857	0.963
370	106.714	0.937
380	109.571	0.913
390	112.429	0.889
400	115.286	0.867
410	118.143	0.846
420	121.000	0.826
430	123.857	0.807
440	126.714	0.789
450	129.571	0.772
460	132.429	0.755
470	135.286	0.739
480	138.143	0.724
490	141.000	0.709
500	143.857	0.695

Once the available information is entered we look for a match with Initial Production (IP) and if necessary adjust the permeability to obtain a match for IP conditions or early production reports if the IP values are not usable. The following graphs are then prepared as part of the service.

FIGURE 1

From the IP match we generate Figure 1 which shows the pressure profile resulting from baseline input values representing the pressure gradient in the early stages of production. The steep pressure gradient, in the near wellbore region, is evident in all pressure profiles

FIGURE 2

If a reasonable amount of production has taken place there frequently is a decline in production. During installation of all but a few of the **MxL** systems we found that the bottom hole temperature was below the reported value and below what the normal thermal gradient would project. We use that information to see if a match can be found when the viscosity in the near wellbore is increased as it would be with a decrease in temperature. Figure 2 shows our pressure profile and production rate for an actual installation that had been in production for several years. The actual rate had declined from 40 to 9 BOD whereas our projection was 12 BOD.

FIGURE 3

Heating creates a temperature that diminishes with distance from the casing to approach ambient reservoir at a distance that expands with time. The amount of power and production rate have the biggest influence on the shape of the temperature profile. The amount of time that heating takes place also has an influence on the profile so usually curves for one, three and twelve months are generated. In several instances the heating was turned off while production continued and we were able to observe a temperature decline with respect to time that was consistent with our projection of heat penetration into the reservoir (see "System Number 8").

FIGURE 4

Temperatures from Figure 3 are used to input the viscosity corresponding to temperature at each distance in the pressure profile program of Figure 1 . Permeability and other factors are held constant and the production rate is adjusted to match the same pressure differential between reservoir and casing. Once that match is established a pressure profile is generated and the same procedure is repeated to find matches for the other time periods. While the temperature profile continues to expand, over time, generally a year is considered to approach steady state conditions which establishes the limit of the projections we make.

GENERAL OBSERVATIONS

The pressure profiles graphically illustrate that because of the near wellbore geometry any viscosity improvement can have an appreciable positive affect on the production rate and conversely if gas expansion, due to production, lowers the near wellbore temperature there can be a considerable decline.

The same benefit is available for light oils and is governed by the same inverse ratio of unheated to heated viscosity that applies to heavy oil. Non-Newtonian fluids such as waxy oils may be altered to Newtonian conditions depending on temperature and cloud point in which case they may respond more favourably than the projections indicate.

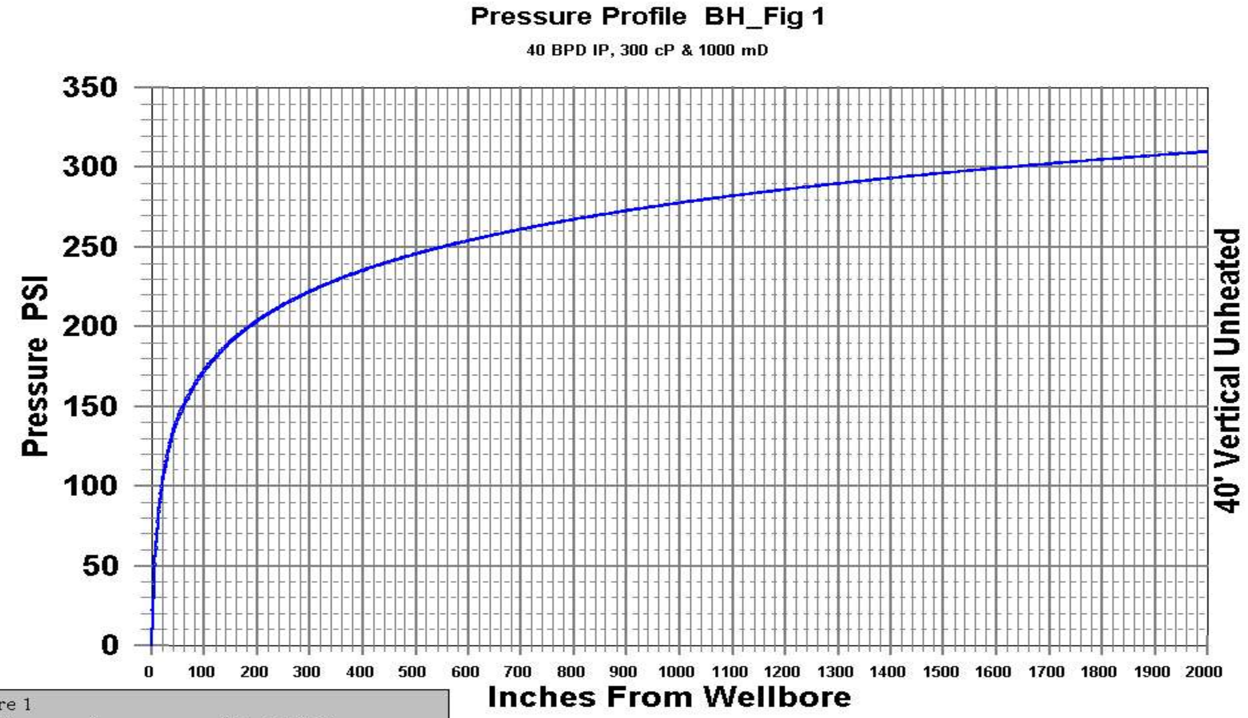


Figure 1
Radial reservoir pressure profile at Initial Production (IP) of 100 BPD gross at 60% Water.

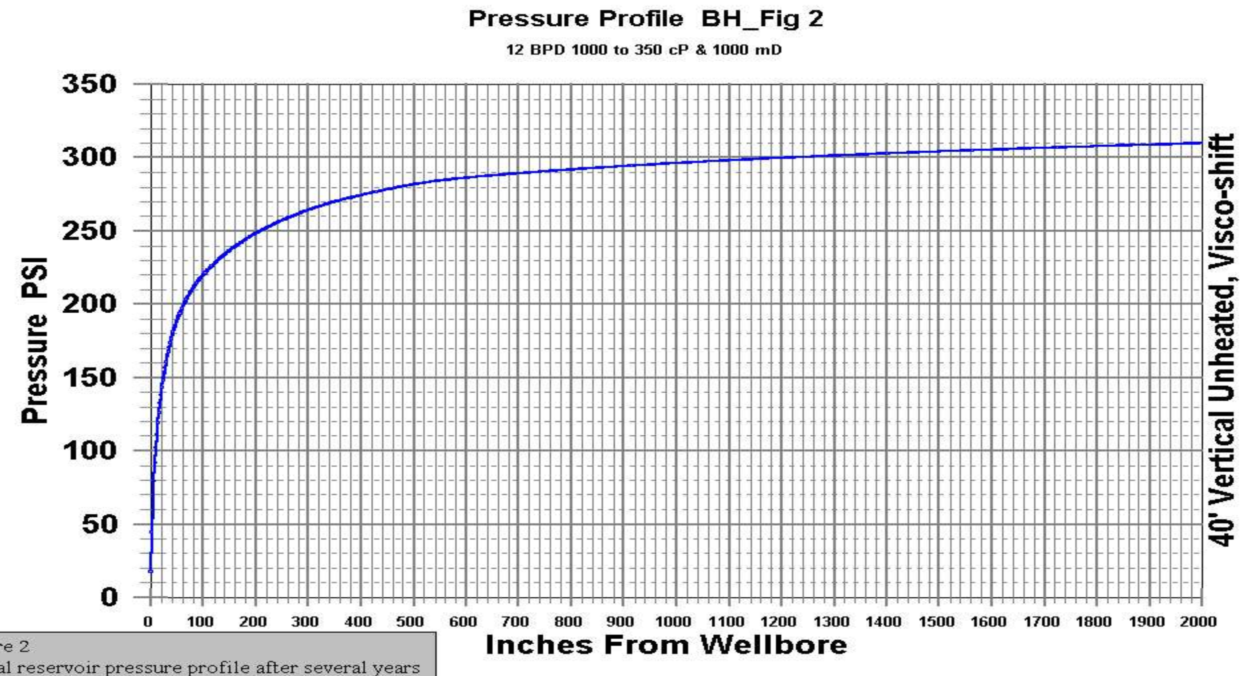


Figure 2
Radial reservoir pressure profile after several years of production. Near wellbore viscosity has increased, the pressure gradient has steepend, resulting in reduced production.

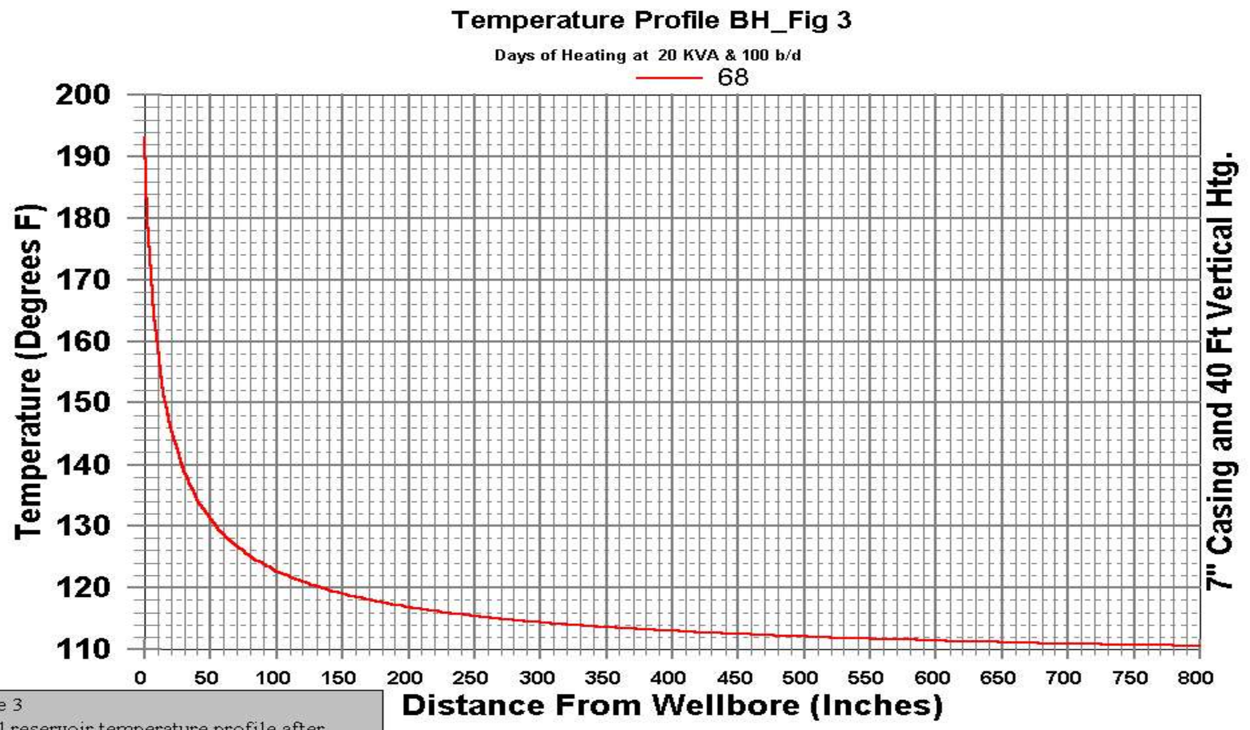


Figure 3
Radial reservoir temperature profile after heating for 68 days with gross production of 100 bbl/ day,

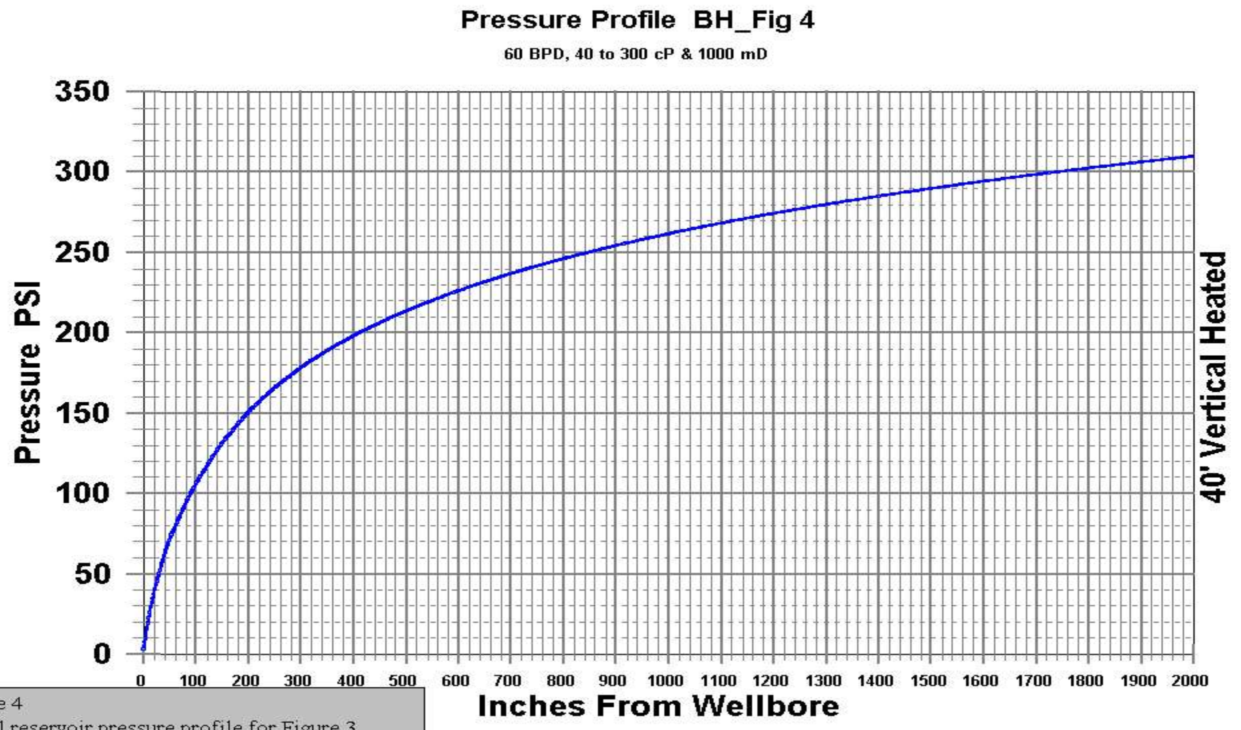


Figure 4
Radial reservoir pressure profile for Figure 3 temperature profile indicating a net oil production increase from 12 to 60 BPD. Actual production increased from 9 to 70 bopd.

MxL INDUCTION HEATER SYSTEM

CASE HISTORIES, RELATED PAPERS AND APPLICATION INFORMATION

SYSTEM NUMBER 1.

Alberta - McLaren channel

Three metres of perforations were added during installation of the heater which resulted in frequent free gas flow thus rendering the primary production values invalid as a base-line. To minimize the influence of the free gas flow we have compared production during the heating regime to that which took place after the tool was removed and the field was put back on production. When the tool was removed we observed that it was installed 24 feet too low so that only 12' of the 40' zone was heated. At the installation we questioned the tally but were assured that the system was in the zone. When the tool was removed, during the next workover in 1999, we examined it and found the electrical values the same as when manufactured and to be in good condition in all other respects.

Before Heating (production after perforations added but before heat was applied)

July 22 to August 20 1997 88 M^3 over 29 days = 3.03 M^3 / day.

Heater Operating 1997

Dates	Total fluids less Load fluid	Net Production M^3	M^3/day
Aug 21 to 31	10	77	7.7
Sept 1 to 30	30	138	4.6
Oct 1 to 31	31	178	5.74
		393	
Production days	71	production per day	393 / 71 = 5.53 M^3 / day

High production was 14 M^3 / day when gas flow subsided for a day or two. We now recognize the pattern of an initial surge, followed by a fall back, then a steady increase. The flush production is caused by a rapid increase in near wellbore fluidity due to the temperature rise. As the volume of oil in the affected zone "drains" a new pressure gradient develops to continue the supply of reservoir fluids. Over time the heated envelope expands until it reaches a steady state condition. At the time we were not able to project the rate of temperature increase and how it would affect production and did not realize that we could expect a continuing increase for eight or nine months before it would level off. We would now project 8 to 9 M^3 /day as the heated production rate.

Heater Off 1998

Field back on production with frequent hot oil loading.

Feb 1 to 28	45.9 + 10.5 - 34	22.4
Mar 1 to 31	105.9 + 9.2 - 7.4	107.7
Apr 15 days	28.7 + 4.3 - 27.3	5.7
May 1 to 31	197 + 8.5 - 13.5	192
June 1 to 30	152 + 5.6 - 29	128.6
July 9 days	39.3 + 1.7 - 15	26
		482.4
Production days	144	production per day 482 / 144 = 3.35 M^3 / day.

SYSTEM NUMBER 2

Middle East, Bahrain - 40' Limestone Rubble Zone

IP of 50 BOD which declined to 10 over 2 years, acid wash briefly returned production to 50 Barrels Oil per Day (BOD). After 6 years of production well yielded 9 BOD and 59 Barrels Water per Day (BWD).

Induction Heating system installed resulting in 60 BOD and 39 BWD. Tubing leak shut well in for six months. Following the work-over first one then a second conductor of the ESP cable shorted so that heating was reduced over 66% of the zone. The production rate dropped to 39 BOD and 39 BWD. The system was installed in 1998 and is still in operation but supply of a new cable and the latest tool configuration, with twelve temperature sensors and one pressure sensor, is in the works. The graph “PRODUCTION PERFORMANCE OF PILOT WELL 480" plots the production history of this well. Four additional wells are in the review stage for installation in 2004.

SYSTEM NUMBER 3

Montana - Waxy Light Oil -

At time of Heater installation the well was producing 7 BOD and required frequent hot oiling. The electricity supply on the lease limited power for the 25 KVA Heater to approximately 4 KVA. If the pump load increased fuses at the grid transformer would and did blow. Within a month of installation our flow log “Madis xL Unit #3 -November, 2000 Flow Chart” shows an increase of about three time the initial production. While no field production reports were provided on one field trip the pumper confirmed that production had hit 21 BOD. During installation a pump suction pup was not installed which forced all of the oil to flow through our Side-Outlet-Sub cable port which caused cable and tool damage such that the tool had to be removed and repaired.

SYSTEM NUMBER 4

Alberta - Strat. Test Well - no return on swab.

No results, operation of system was not monitored and tool burned out. The system was selected, purchased and operated by a third party, even though we had advised that we considered it unlikely to be economic.

SYSTEM NUMBER 5

Alberta - Deviated Well - Lindbergh. Several years of foamy oil production. Four month test.

This well showed a cyclical production pattern with flow peaking at 50 to 70% over average for 24 to 36 hours every 7 to 10 days. At the time our Production Enhancement Projection Software (PEPS) was only partially developed so we were not aware that during the early stages of heating a flow surge can “drain” the near wellbore reservoir. The pressure gradient then re-adjusts and drives more fluid but in the meantime the annulus fluid level has dropped giving the appearance of a “pumped-off” well. In a heavy oil six to nine months may be required for a steady gradient to develop during which time the flow will increase and new oscillatory patterns will take place until a steady state flow is achieved. By inspection of the flow graphs it would appear that a stable flow rate of 9 to 10 M^3/day could be expected.

The Production information given prior to installation of the tool showed an average of 4.5 M^3/d and the Pumper log for May 1st to 16th averaged 4.9 M^3/d gross fluids if the loading fluid is subtracted.

May 1 - 16

Gross Production	128.4
Load Oil	50
Net Production	78.4

Gross Daily Production 78.4 / 16 = 4.9 M^3/d

Heater installed

May 20 - 31	Average Daily Production	6.45 M^3/d
June to October	Average Daily Production	7.25 M^3/d
September	Average Daily Production	7.31 M^3/d

Field averages for water cut were assigned to post heater installation results and typically there is a reduction in water cut. If we assume that the absolute water volume remained constant before and during the heating test then the comparison is:

Constant Water Volume	15% of 4.9 = 0.735
Initial Oil Volume	85% of 4.9 = 4.165
Heated Oil Volume	7.31 - 0.735 = 6.57
Incremental Oil Increase	100(6.57 - 4.165) / 4.165 = 57.7%

The production level was increasing toward the end of the test which is consistent with our **PEPS** although at the time we could only model the temperature profile.

SYSTEM NUMBER 6

Bakersfield - Steam Flood -

Heater installed in a well that supposedly was not affected by the steam flood however bottom hole temperature was 110 to 115° C at time of installation. After waiting for a month the temperature had not dropped which indicated that the steam had swept by the well. Power was turned on to demonstrate that the system could heat and control but no production effects were noted.

SYSTEM NUMBER 7

Egypt - Limestone - Depleted Well- Gravity Drainage

Heater installed in a 4 BOD well with little drive pressure. The well had been pumped-off for some time. Loading the well with hot oil indicated that production was only coming from the lowest perforations. It was concluded that the upper perforations had choked-off and without drive pressure little production gain could be expected. The system was relocated to other wells to monitor flood operations.

SYSTEM NUMBER 8

Alberta - Glauconite - High Water-cut Horizontal

Probe Style Heater, approximately 500' long, installed in open hole horizontal that was producing at 99.9% water at approximately 1000 BPD. From the tool's instrumentation we were able to determine the water flow pattern and the effect from near by injectors. We were able to use that information and the tool instrumentation to complete a wax injection that sealed part of the water flow and briefly decreased the water-cut to 78%. After about a year and a half of operation the Heater system was turned off, but the pumping continued and we monitored the temperature decline in the heated reservoir temperature which showed that considerable heat penetration had taken place as it took six weeks for the temperature to drop to the normal ambient bottom hole temperature. This observation was of immense assistance by way of verifying our **PEPS** program as well as to confirm heat does indeed penetrate into the reservoir counter to fluid flow.

Alberta - Glauconite - Moderately High Water-cut Horizontal.

The Probe Style Heater was lengthened to 180 M, by adding spacers, and then moved to an existing 810 M open hole horizontal well number 103. The top of the heater is located 50 M beyond the casing, there are two 25 M spacers between the heating sections which leaves 512 M of unheated hole beyond the tool or stated another way the heater covers only 20% of the horizontal hole. The reservoir is approximately 14 M thick, bottom water drive, with the hole in the top 1 to 2 M of the pay zone. While a lower hole location would better suit thermal stimulation it is probably typical of the wells available for retrofit.

There is no base line with which to compare heated and unheated production as the wells produce into a group line and the metering at each well is not considered accurate or repeatable. At the beginning of 2003 the purchase of a portable test trailer enabled periodic production figures to be acquired as the trailer is moved from well to well. The MxL heater system has now been in operation for thirty months and production at 27 BOD and 83% water-cut, at 50% power, has been determined by using the test unit as given in “2003 Water Cut”. As a comparison we note that the wells surrounding 103, which are not heated, have all watered-out as shown in the above referenced plot.

Power was increased, on January 22, 2004, to 85% of rated capacity and as a result the wellbore temperature is now approaching 95 C and the flow-line temperature has risen 4 C. At the low power setting the toe section of the MxL tool ran about 10 C below the middle and heel sections indicating that there is substantial flow from beyond the tool. Increasing the power increased the temperature differential to 15 C indicating that the flow rate from beyond the tool has not changed. The heel section has always had a higher flow rate, per unit length, as indicated by the tendency to run a few degrees cooler than the middle section but it now runs a few degrees warmer indicating that the flow pattern may be changing.

Our projections show that approximately a month will be required for significant results to take place because of the higher power input. The next step will be determining conditions at zero power after the heat has dissipated.

SYSTEM NUMBER 9

Saskatchewan - Channel Sand - Old Well with No Production.
Vertical well with good static reservoir pressure but no production. Viscosity of 150,000 cP and no solution gas drive project an IP of 0.5 BOD without heating. By observing the fluid level rise in the annulus after eight weeks of heating we determined that the inflow had increased to 3 BOD. Our projection was that at one year the flow would only increase to 6 to 10 BOD which would not provide an economic return.

Vandalism damaged the system and ended the test so we were unable to continue logging after the heating ended in order to determine a cool down rate.

SYSTEM NUMBER 10

Saskatchewan - Test - Major Oil Company
Confidential with only information available reported as “two to three fold increase in production”.

Heating a reservoir can increase both production and recovery. Light, waxy and heavy crudes have improved mobility as the temperature increases. In the late 80's and early 90's we observed that electrical heating frequently increased production two and three fold but the systems were fragile, usually required a special completion and were prone to premature failure.

After reviewing the available systems Madis called upon it's background, in the metal producing industry with respect to induction furnaces and heating systems, to develop an Induction Heating System. The result (the MxL system) is a retrofit heater that is suspended from the pump suction, across the production zone, and a control cabinet that automatically holds temperatures in each portion of the zone to preset values. The system also displays and records temperatures across the zone as well as bottomhole pressure. The systems are robust with two years of shop testing followed by nearly seven years of field operation.

The following papers provide a history of developments that have taken place with respect to electrical reservoir heating:

SPE 68220 FIELD PILOT TEST OF THERMAL STIMULATION OF RUBBLE RESERVOIR USING DOWN HOLE INDUCTION.

V. C. Babu Sivakumar

Description of Induction Heater System installation together with production information.

- Production of 12 to 18 API , 350 cP at 40° C, oil is from the shallow rubble limestone in Bahrain.
- Initial oil production of 50 BOD commenced in 1991 and declined rapidly to less than 20 BOD. Several remedial actions including acid washes brought temporary increases but by 1997 the production was less than 9 BOD with water cut in excess of 60%.
- installation of an Induction Heating System in 1997 immediately increased the oil production to about 70 BOD and lowered the water cut to the low 30% range.
- The electrical power was turned off, as an experiment, and the production soon dropped back to unstimulated values and quickly returned to the high values on restoration of power.
- Information given showed a bottom hole temperature of 114° F , at time of drilling, but readings returned from the Induction tool were 94°F at the time of installation.
- On repairing a tubing leak the ESP cable was damaged such that electricity was unavailable to 33% of the tool and that decreased production to approximately 40 BOD.

SEVENTH UNITAR CONFERENCE MANUSCRIPT No. 061 BEIJING ELECTRICAL INDUCTION HEATING USING THE TRIFLUX SYSTEM. H. L. Spencer, R.E. Isted.

A synopsis of available electrical wellbore heating methods is presented and the Madis (Triflux)Induction System history is described.

- The authors had observed favourable production response from electrical downhole heating and premature failure of those systems.
- Madis, a manufacturer of Power Conditioning Units used by a well heating system supplier, participated in the startup and early operation of many systems that developed downhole problems. Madis undertook a study to look at the features and detractions of the available methods.
- The resistance probe style heater, because of film heat transfer coefficients at the element and again at the casing, has limited heating capability otherwise it can foul and burn out. Secondly it passes much of its heat output, directly to the produced fluid in the annulus rather than to the reservoir.
- The formation resistive heating system which passes electrical energy through the conate water requires a special completion and is prone to premature failure of the downhole components. Selection of the electrode is critical and since the downhole characteristics often change during production the method is not as flexible as one would like.
- Microwave has very shallow penetration into the reservoir and requires elaborate wave guides and has special completion requirements.
- The Madis MxL system (formerly Triflux) is explained. Recapping it is a retrofit system with three independent temperature control zones with an array of temperature and pressure sensors that can be configured for vertical or horizontal wells. The system operates under closed loop control so as to adjust power output in accordance with temperatures. Production increases of two to three fold are common and in one case (SPE 68220) approached an eight fold increase. That system is still in operation some six years after installation.

A TEST OF THE ELECTRIC HEATING PROCESS AS A MEANS OF STIMULATING THE PRODUCTIVITY OF AN OIL WELL IN THE SCHOONEBEEK FIELD.

CANADIAN INSTITUTE OF MINES, 1993
S. A. Rice, A.L. Kok and C. J. Neate.
A test of the formation resistance heating method in the Netherlands in a waxy reservoir.

- Primary oil production 13 M^3 with 35 % water cut. The oil is waxy with a cloud point close to the 40° C reservoir temperature and a viscosity of 160 cP at 40° C and 8500 kPa.
- At 60 KVA, bottom hole temperature of 54° to 60° C, oil production abruptly increased to 30 M^3 suggesting that a wax skin had melted out. Increasing power did not further improve the production rate.

PETROLEUM ENGINEER, October 1973. WELL STIMULATION BY DOWNHOLE THERMAL METHODS. S. M. Farouq Ali.

- More than 100 wells, in Russia, California and Montana which were equipped with wellbore probe style resistance heaters. The heater consists of a 2 1/2" slotted pipe containing resistance elements which is hung below the pump suction.
- Heating will be largely convective from the element to the fluid and from the fluid to the casing which causes high temperatures at the element surface as power requirements increase.
- Because of thermal convection to the wellbore fluids the highest temperature will be at the top of the element thus a great deal of the heat is lost in the produced fluids without affecting the reservoir.
- Even though the method is limited by channelling of fluid flow, by two thermal film transfer coefficients and by limited element temperature reasonable production responses of from 56 to 186% increase were reported.
- Most of the wells initial production was in the 12 to 20 BOD range.
- Early fire-flood, hot water heaters, downhole gas-air burners and the formation resistance methods are mentioned.

5th Unitar/UNDP International Conference on Heavy Crude and Tar Sands, Caracas, Venezuela February, 1991. VISCO-SKIN EFFECT IN HEAVY OIL RESERVOIRS
Bruce C. W. McGee, Phillip Sigmund, H.L. Spencer.

- The case described is in the Lloyd minster area. The reservoir resistance electric heating systems that they were supplying increased the production rate two or three fold in a matter of one or two days. Simulations showed that the temperature rise in the reservoir in that short time interval would only affect the near wellbore region leading to the conclusion that production develops a skin near the casing which was termed "visco-skin".
- The electric resistance heating system is described.
- The viscosity of heavy oil with solution gas is described, in Figure 3, based on the work of Katz, Houpeurt and Thelliez.
- Heated production to primary production was found to have more than a two fold increase.

JCPT April 1995, Volume 34, No.4 Electromagnetic Stimulation of Lloyd minster Heavy oil reservoirs: Field Test Results. R. J. Davison.

- Case histories of two field tests using reservoir resistance electric heating to stimulate heavy oil production from the Sparky formation. Northminster A8-6 showed a production increase from 10 M^3 per day to 20 M^3 per day over a period of a few days.
- Lashburn A1-11 showed a production increase from 5 M^3 per day to 8 or 9 M^3 per day for a few days.
- Shorting of the downhole systems curtailed operation at both locations.

SPE 62550 ELECTROMAGNETIC HEATING METHODS FOR HEAVY OIL RESERVOIRS

Akshay Sahni, Mridul Kumar and Richard B. Knapp.
Discussion of means of applying electrical energy to heat a reservoir.

- Two wells form the connection path for electrical energy to flow through the conate water of the reservoir. A simulation is presented.
- High frequency electrical heating is reviewed and the parameters given.
- The completion methods for this method are elaborate, difficult and fragile.
- Penetration depths of heating are small.

Heating the reservoir electrically avoids preferential heat flow in zones of lowest permeability which is the case with steam. With the MxL system the amount of heat distributed over three portions of the production interval can be individually adjusted to suit fluid inflow. The highest temperature is near the casing thus ensuring that the lowest viscosity is in the near wellbore region where it will be most beneficial.

We are frequently asked to explain how heat can move out into the reservoir with oil moving toward the casing. The simple answer is that only about 10% of the flow path is radially toward the casing while the other 90% is taken going around sand grains, reservoir rock, to the perforations or similar impediments. Any flow that is at an angle to the radial direction increases heat transfer. As an example a horizontal well, producing at approximately 1000 BPD and heating at 50 KVA for approximately a year proved that heat was being stored in the reservoir. The wellbore temperature declined from 50° C to 35° C over a period of six weeks after the heat was turned off and the well continued to pump at 1000 BPD. The decline, at that time, was so slow that we ceased data logging even though the original reservoir temperature was 30° C. The real significance of this observation is that the slow cool down verifies that substantial heat had transfered into the reservoir during fluid inflow. In fact when we cancel out the heat lost in the produced fluids we find that a producing reservoir will, within the normal range to 5 bbl/Ft, transfer more heat than at stagnant conditions.

We have found the following papers to be of assistance in understanding and quantifying the results from different installations:

- **SPE 20070 Mechanics of Bubble Flow in Heavy Oil Reservoirs** M. R. Islam & A. Chakma Gathers-up data from Arrhenius, Berry, Brown, Dumore, Elkins, Gibbs, Hagerdorn, Hunt, Kennedy, Levart, Olson, Smith, Stewart, Ward and Wieland to define reservoir flow characteristics. production is dependent on number of bubbles produced due to pressure decline. They are micro-bubbles that do not coalesce to impede flow (Smith & Ward).
- Lab vs field inconsistencies attributed to effect rate of pressure decline has on bubble size with faster decline in lab, finer bubbles, having better recoveries than observed in the field.
- It is not clear if interpretation should be recovery, rate or both. Figure 10 shows the effect decline rate has on oil recovery as %IOIP. Figure 13 shows % recovery for microbubbles at 20% vs conventional 15% for continuous gas injection.
- Dumore found that dispersion of gas bubbles in cores remained as disconnected agglomerations of gas bubbles whereas free gas was in a network of channels.
- tests of oil flow and micro-bubble methane gas were run through capillary and packed sand core. Oil viscosity ranged from 10 to 5000 cP. None of the graphs showed the pressure drop value for zero gas fraction but by using laminar flow piping pressure drop formulae the generated values fit the curve reasonably well out to 0.3 volume fraction (VF). At 0.1VF the measured value was 65% of theoretical crossing over at 0.25 VF. Mixture viscosity is given by $\mu = \mu_L{}^{f} {*} \mu_g{}^{(1-f)}$ where f is the liquid

volume fraction at a pressure of 600 kPa. With such a low system pressure the differential pressure across the capillary tube, at the low gas fractions (higher viscosity), may have influenced the calculated viscosity.

- Hagerdorn and Brown equation for viscosity vs liquid volume fraction is verified.
- relative permeability curves for gas oil mixtures are given in figure 14.

SPE JCPT March 2003 Volume 42 No. 3

A Case Study of Foamy Oil Recovery in the Patos-Marianza Reservoir, Driza Sand, Albania D.B. Bennion, M Mastmann, M. L. Moustakis.

- Viscosities for insitu 11 API oil as related to pressure and GOR are given.
- This testing is based on re-constituted oil rather than dispersing micro-bubbles in a flowing stream
- Comparisons are given for the effect rate of pressure reduction has on viscosity.
- Depletion rate formation volume factor and pressure relationship are given.
- Solution gas oil ratios are graphed against pressure.
- Observation is made that oil viscosity impedes coalescing of gas bubbles which causes an expandable mobile oil characteristic.

SPE 78968 THE EFFECT OF CLAY FRACTION ON HEAVY OIL DEPLETION TEST

L. Andarcia, A. M. Kamp, M. Huerta, G. Rojas.

Gas bubble nucleation sites, size and phase distribution are studied with respect to clay fraction.

- Gas relative permeability decreases as clay fraction increases which likely indicates that gas remains “trapped” within the liquid phase creating internal drive rather than external drive from the gas component.
- Increasing clay fraction increases the gas nucleation sites thereby enhancing the internal drive characteristics.

HEAVY OIL RESERVOIR MECHANISMS

SEMINAR by M. Metwally of PANCANADIAN PETROLEUM LIMITED Oct. 1995

- Several case histories in the Lloyd minster area.“The observed primary production of many heavy oil reservoirs is many folds the production predicted by Darcy's model”.
- During early production considerable amounts of sand is produced.
- Injection test indicated that an two fold increase in permeability combined with an open fracture of 60 M described a well after producing 39,000 M^3 of fluid and 560 M^3 of sand.
- Tracer surveys showed that communication between wells at flow velocities of 7 M/min. were repeatedly measured.
- Sand production rate characterized.
- Foamy oil pressure rebound is described as pressure decline causes generation and expansion of gas within the foam. Time dependent rates is characterized.
- Pressure drop from flow within a horizontal well is given.
- Foamy oil mobility and pressure rebound and increased permeability as a result of sand production are the main attributes for higher than projected heavy oil production.

SPE 79081 PVT and Viscosity Measurements for Lloyd minster-Aberfeldy and Cold Lake Blended Oil Systems Ted W. J. Frauenfeld, Geral Kissel Shibing (Wendy) Zhou.
Pressure Volume and Temperature relationships aimed for Vapex operations with limited information on Methane.

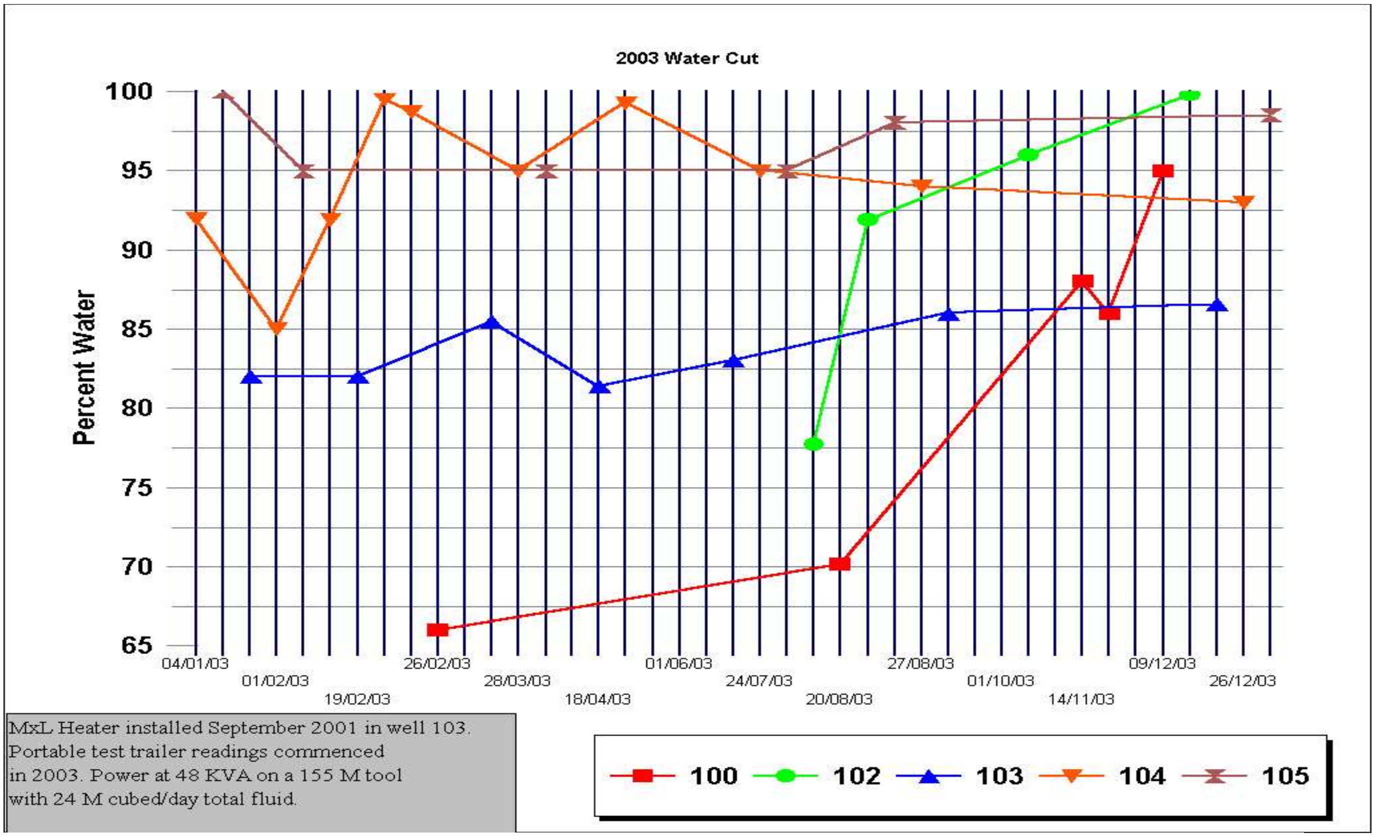
VISCOSITY, DENSITY AND GAS SOLUBILITY DATA FOR OIL SAND BITUMEN SATURATED WITH N_2, CO_2, CH_4, CO_2, AND C_2H_6.
Anil K. Mehrota and William Y. Svrcek U of C.
Experimental data for Wabasca bitumen and gas saturated bitumen are given and contrasted to other bitumens.

- Compositional analysis for Athabasca, Peace River and Wabasca bitumen is given.
- Viscosity for dead- bitumen is given for Peace River, Athabasca, Wabasca and Marguerite.
- Viscosity, density and solubility at pressures from 2.9 to 10 Mpa and temperatures from 23 to 110° C are given for the above mentioned saturated bitumens. Values are for reconstituted oils without micro bubbles.
- This data would be applicable for external drive pressures.

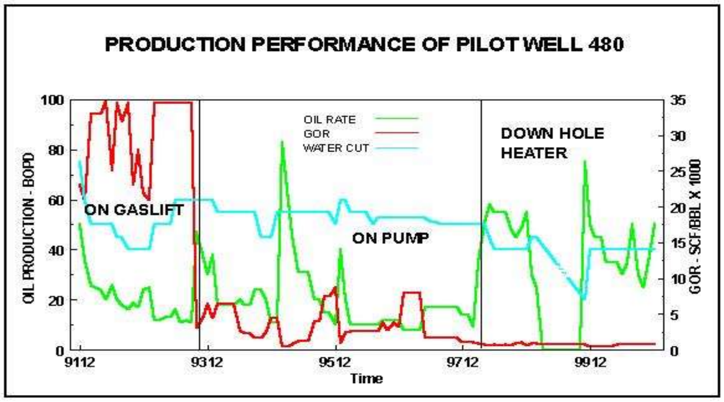
PRODUCTION AND OUR APPLICATION.

- Our Production Enhancement Projection Software (PEPS) is used to assess candidate wells, MxL system requirements and project the expected increase in production.
- The PEPS consists of a spreadsheet that shows a temperature profile and one that shows a pressure profile.
- Heating power, oil and water flow, well and reservoir geometry, thermal transfer values and days of heating are inputs that generate a temperature profile with respect to distance from the casing. Data from installations are used to back-check our projections.
- Inputs for the production profile consist of well and reservoir geometry, reservoir pressure, porosity and permeability, oil viscosity and water cut. If historical production data are available we compare projections with actual as the program is designed make a projection based on a specific difference.
- The basic production equation $Q_f = k A (P1 - P2) / \mu L$

  is used to match historical data and then the values of μ that are appropriate for the temperatures, as shown on the temperature profile, are entered at the appropriate distance to generate a pressure profile specific to the heated conditions.
- When a foamy oil reservoir is heated it tends, for the first few months, to surge and drop back to primary values on a seven to ten day cycle. The interval time and surge tend to flatten out at the increased flow rate over time. Bahrain on the other hand jumped from 9 to 70 BOD in less than a week with very little surging. The absolute water volume and fluid level did not change appreciably.
- PEPS consists of a spread sheet module that displays the pressure profile and a module that displays the temperature profile with reference to distance from the wellbore.
- primary production, reservoir and oil characteristics as provided by the owner form the input for projections.



MxL Heater installed September 2001 in well 103.
Portable test trailer readings commenced
in 2003. Power at 48 KVA on a 155 M tool
with 24 M cubed/day total fluid.



Heater installed March 98. Out of service May 99 due to tubing leak. Work-over October 99 to place system back in service. ESP cable damaged resulting in no power to the top third of Heater. Well shut-in 2004 due to tubing leak. Work-over is planned at which time a newer style Madis MxL heater with twelve temperature sensors and a bottom hole pressure sensor will be installed.