THERMAL SURFACE TREATMENT TO PREVENT PARAFFIN AND ASPHALTENE TUBING DEPOSITION

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ABSTRACT

The prevention and mitigation of paraffin and asphaltene deposition in oil and gas wells presents different challenges depending on each well producing fluid chemistry and thermodynamic behavior. There are three big groups of treatment methods commonly used: Chemical, Thermal and Mechanical.

In the case of the chemical mitigation, one of the most widely used treatments, the target chemistry must be tested and validated in representative samples to determine the optimum formulation. This iterative process takes multiple attempts to adjust that often leads to simplify by using the same formulation to specific groups of wells. Additionally, well conditions change over time, which forces to re-assess the treatment, making the optimization process a full-time effort.

The other broad used alternative is the utilization of mass thermal treatments, using hot oil or water, typically inefficient and usually applied as a corrective action instead of a preventive measure. This is still valid due to the cost of using produced water and local hot oil units to do routine hot water circulations until a work over operation is utterly required.

The last option, especially for paraffin, mechanically removing it with scrapers or replace the elements showing issues. Both mechanical and mass thermal mitigation alternatives take time, resources, and loss of consequential production, and overall poor production performance of the well.

Normally the mitigation implemented at a field level has a combination of these techniques, always targeting the fluid, but neglecting its behavior at a tubular surface level.

This work describes the research, development and case studies of a mature technology that uses surface thermal treatment of tubing to minimize paraffin and asphaltene deposition. The technology first developed for heavy oil producers proved its wide application in paraffin with more than 1000 systems installed all throughout South America over the last 20 years.

INTRODUCTION

The heat loss experienced by the fluid while going up the production tubing is detrimental since it causes an increase in viscosity, paraffin precipitation, incrustations, asphaltenes, emulsion stabilization, etc. All these conditions finally reduce the well productivity and increase the operative costs emerging from cleaning jobs, artificial lift premature failure and loss of production.

As an example, in the case of mitigation of paraffin issues, we can mention these conventional treatment methods: varying degrees of wax crystal modifiers, solvents such as xylene or toluene, treated hot water or hot oil applications and tools such as paraffin knives during workovers. The cloud points typically occur from surface to 3000' below surface. Rig time lost due to dealing with paraffin averaged 1-2 days. Worst case scenarios were up to 5-7 days prior to focusing on specific cause for workover. Hot watering, pumping solvent, pulling incrementally over string weights, rod stripping and hacksawing were all common use methods for freeing the rod string and clearing the tubing.

Like in any system, the intervention of a critical step of the process greatly modifies the outcome. This is the case for each mitigation technique used for paraffin, asphaltenes and heavy oil friction (see the case for Crystal Modifiers problem solving process approach in **figure 1**).

The last 20 years GLOBAL TECHNOLOGIES (GT) developed a series of tools that focus on disrupting the deposition process by heating only the inner surface of the tubing in contact with the processed fluid (**Fig. 2**). By avoiding the heating of the whole mass of fluid and focusing only on the interaction of the fluid with the tubing surface, the energy consumption is considerably lower than mass thermal treatments. The generic nature of this treatment will allow it to work with a wide range of fluid compositions and flow rates minimizing the need for new formulations like in the case of chemical treatments when wells change their production behavior over time.

<u>OPERATIONAL CONCEPT</u>

The No-Kalt® is a production tubing heating system. It is installed to the required depth banded to the outside diameter of the tubing just like in the case of electro submersible pump (ESP) cable (**Fig. 3**) but with a much smaller size. The downhole heater is a 3-phase, 380 VAC system with a ground connection (other voltages available too up to 600 V). The heater is surrounded by a metal foil and fluoropolymer jacket to ensure its integrity (**Fig. 4**).

The goal is to warm up the walls of the tubing to obtain a hot laminated film on top of the internal surface, acting as a lubricant directly affecting the behavior of the viscous sublayer in contact with the tubing wall (viscosity dominated layer – **figure 5**). The temperature will be high enough to generate low viscosity, but not so high to produce oil coke or the separation of the lightest elements of the crude, thus avoiding unwanted side-effects. This lubricant effect reduces back pressure and allows for higher flowing rates. Also avoiding paraffin crystals to get attached and grow on inner tubing surface.

GT developed a series of heating configurations depending on the need of the well, treating the upper section of the well, below the pump or in the lateral for the case of horizontal wells (see **table 1** for reference). The following case studies are examples of the NK4500 series targeting the top section of the well for a case with paraffin issues and one with high viscosity oil.

<u>CASE STUDIES</u>

Paraffin

- Well#: PP
- Artificial Lift System: rod pumping
- Casing: 9 5/8” 47#
- Tubing: 2 7/8” EUE 6.5#
- Rod String: 1”-7/8”
- Formation interval: 3390-3468ft
- Pump depth: 3440ft
- Gross flow rate: 250 BPD
- NK System installed: NK-4500 (404v)
- Required energy for NK system: 23 KW

The following case study relates to a rod pumping well with continuous production down time due to paraffin issues in a productive region of Venezuela.

This well had a Mean Time Between Failures (MTBF) of 6 months with complete reduction of the tubing flow area, plugged by paraffin (**Fig. 6**). The production rate when in operation was very random and heavily influenced by the behavior of the paraffin deposition on the inner section of the tubing (**Fig. 7**).

In April of 2014, after a year of Temporary Abandonment (TA) due to failures, 2297 ft of heat conveyor (NoKalt 4500) was installed to start evaluating the performance of the system for the first 90 days.

The evaluation of the performance of the first 90days of the heat conveyor installation showed a considerable increase on production rate (70%) (**Fig. 8**) and remarkable stability of it over time. This last effect minimizes stress cycles induced to the overall mechanical system generating a significant reduction in failures extending the MTBF to 18 months.

The other variable affected by the implementation of this technology is the pressure at wellhead, it decreased on a 50% even when production increased.

This field continue the standard utilization of heat conveyors for the most problematic wells before they reach a technical and economical limitations that forced them to shut them down.

Viscous oil

One of the most representative case studies regarding viscous oil was the Well VO from an operator in southern region of Argentina.

- Well#: VO
- Artificial Lift System: Initially on rod pumping and progressive cavity pump (PCP) after solids and high viscosity generated multiple failures.
- Casing: 5 ½" 17#
- Tubing: 2 7/8" EUE 6.5#
- Rod String: 1", 7/8 and ¾" (RP); and 1" (PCP)
- Formation interval: 4600-5300 ft
- Pump depth: 5310 ft
- Gross flow rate: 180 bpd
- NK System installed: NK-4500, 360v.

This well was produced with rod pumping until July 1999, when it stopped producing because of the constant rod and tubing failures. After its last failure, the production engineering team decided to change systems to a PCP pump, which are better designed to handle viscous oil with moderate quantities of solids. The PCP system installed was designed to lift 176 bpd but it failed to deliver since it was worked over 4 times in its first 5 months of operation (**Table 2**). The high torque requirement, generated mainly by viscous friction, was responsible of premature pin breaks and thread over torque of sucker rod connections (**Fig. 9**). In January of 2000, 2624 ft of heat conveyor were installed on this well (**Fig. 10**). The performance of the system was quickly detected by the decrease in pressure and the subsequent increase on production. The simulated new temperature gradient is represented by **figure 11**, it shows the estimated gradient with and without the NoKalt. The increase in the sublaminar temperature has a direct impact on the heavy oil mobility and its viscosity (**Fig. 12**).

Important benefits have been gained since the installation of the heat conveyor, not only associated to failure reduction but to an important increase in production rate (**Fig. 13**). Logs on production, temperature and wellhead pressure can be seen in **Table 3**, in which a wellhead pressure reduction becomes noticeable, even working at higher flow rates.

CONCLUSIONS

- The thermal surface treatment of production tubing demonstrates to be a reliable yet simple to deploy tool to treat viscous oil and paraffin issues in oil and gas wells.
- Production flow rates and equipment load see a quick and significant impact early on the No-Kalt® implementation phase.

- This technology employs a significantly lower amount of energy when compared to other thermal process looking to increase mass (fluid) temperature.
- The system's versatility makes it attractive in comparison to other alternatives due to the wide range of well and fluid conditions that the tool can handle. It can easily re-deploy on different wells as needed.

BIBLIOGRAPHY & REFERENCES

1) SPE 69435. Use of a Heat Conveyor Increases Capacity of Artificial-Lift System in Viscous Oil Wells. A. Eloff, and G. Gómez Cavieres, and J. Milathianakis, and E. Gordillo, and E. Gonzalez, Repsol-YPF. 2001
2) SCPSC 2018. MITIGATING PARAFFIN BUILDUP IN UPTON COUNTY, TEXAS – HARNESSING INNOVATIVE TECHNOLOGY TO PREVENT PARAFFIN BUILDUP FROM CAUSING AND CONTRIBUTING TO WELL FAILURES. Matt Berkebile, Diamondback Energy
3) Depositional Behaviour of Highly Macro-Crystalline Waxy Crude Oil Blended with Polymer Inhibitors in a Pipe with a 45-Degree Bend. SPE Offshore Europe Conference and Exhibition, Aberdeen, UK. Nura Makwashi, Delcia Barros, Doglin Zhao, LONDON SOUTH BANK UNIVERITY

TABLES

1) Table with all NK series and their technical specifications.

NK SERIES	NK 4500	NK 7500 T	NK 7500
Location within the well	Upper section of the well (top 3000ft)	Below the pump or close to formation	Lateral section of the well to better condition de fluid to go through the pump
Power Requirements	Low	Medium	High
Type of well	Vertical or Horizontal	Vertical or Horizontal	Horizontal
Installation type	Tubing strapping	Tubing strapping	Encapsulated
Slim hole Limitations	NO	NO	NO

2) Well VO: Historical Workover interventions

WELL VO- Historical WO interventions	
Date	Reason
2/26/99	Fishing of Packer
8/25/99	Pump change
8/30/99	Change of lift system
9/8/99	Pump change
9/18/99	Pump change
11/19/99	Fishing of sucker rod
12/3/99	Fishing of sucker rod

3) Well VO: Historical production parameters.

WELL VO- PRODUCTION CONDITIONS						
Date	Temp. °C	Liquid bbl/d	% Water	Oil bbl/d	Regimen R.P.M	Pressure psi
3/25/00	47	105	30	74	131	198
3/26/00	47	96	30	67	131	198
3/27/00	47	94	30	66	131	198
4/1/00	48	70	30	49	131	150
4/7/00	50	93	30	65	131	150
4/12/00	46	111	40	67	155	150
4/15/00	46	111	47	58	155	140
4/29/00	50	104	35	67	155	160
5/2/00	50	105	35	68	155	160
5/23/00	42	113	57	49	155	160
5/24/00	42	138	43	79	182	120
6/1/00	40	120	42	69	182	120
6/6/00	42	136	40	81	182	120
6/8/00	42	159	40	95	238	120
6/14/00	42	151	34	101	238	120
6/21/00	42	135	22	105	238	180
7/26/00	42	126	15	107	238	240

<u>FIGURES</u>

FIGURE 1: MECHANISM OF CHEMICAL TREATMENT USING CRYSTAL MODIFIERS TO ADRESS PARAFFIN ISSUES

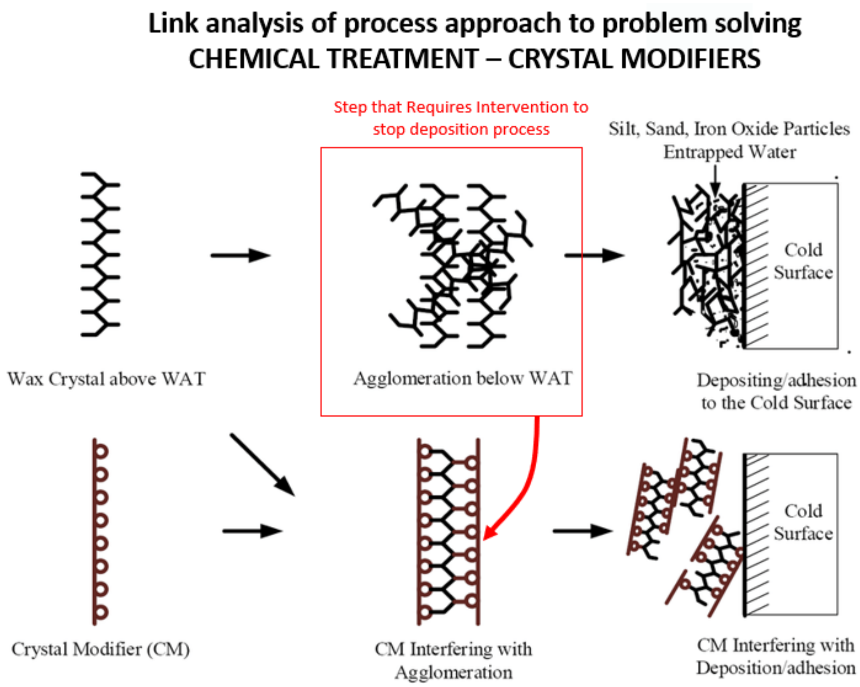


FIGURE 2: MECHANISM OF SURFACE THERMAL TREATMENT TO ADRESS PARAFFIN ISSUES

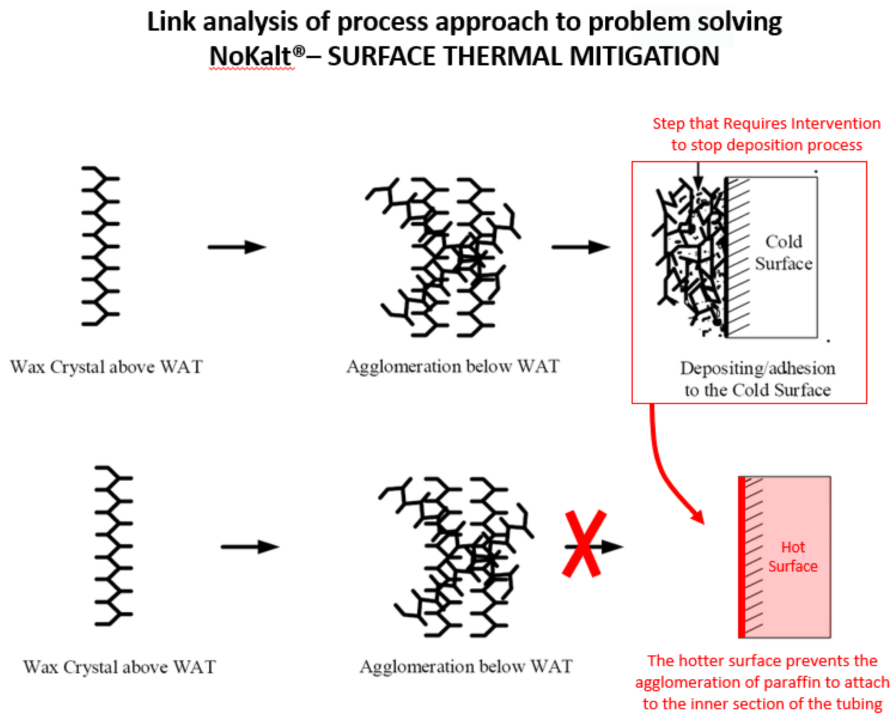


FIGURE 3: TYPICAL WELLHEAD CONFIGURATION OF A NO-KALT INSTALLATION

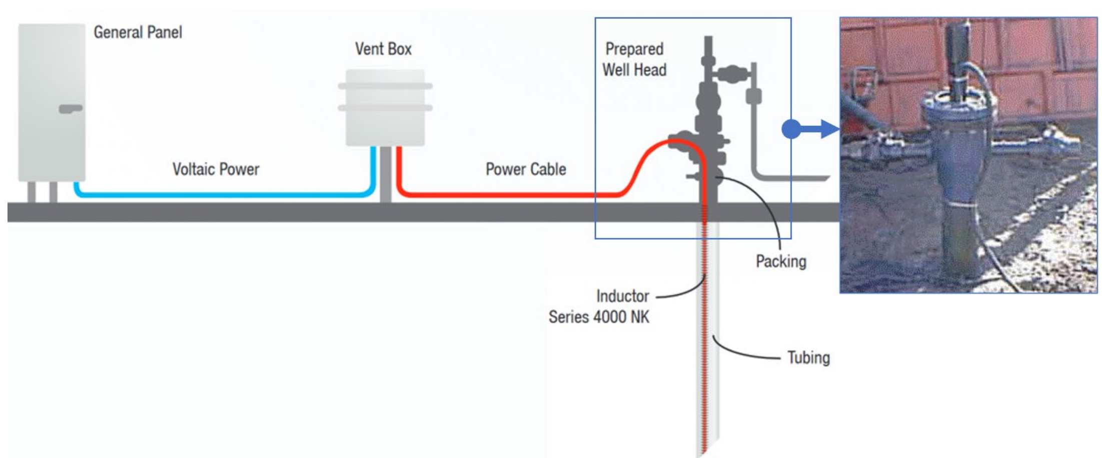


FIGURE 4: TYPICAL DOWNHOLE CONFIGURATION OF A NO-KALT INSTALLATION

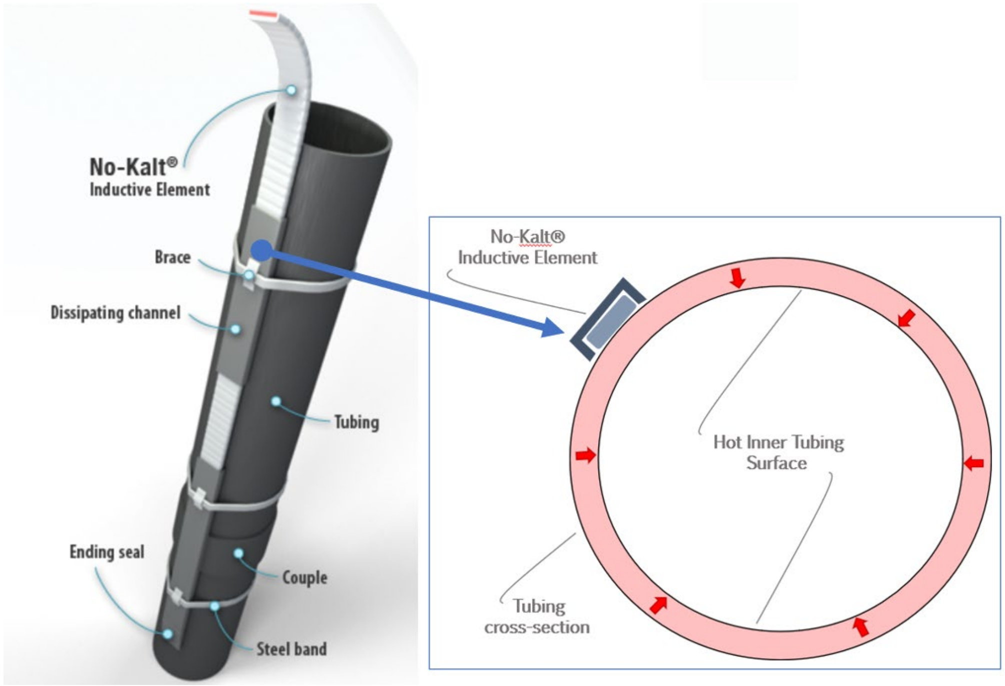


FIGURE 5: IDENTIFICATION OF VISCOUS SUBLAYER, THE PREDOMINANT VISCOUS LAYER, AT THE EDGE OF THE TUBING WALL

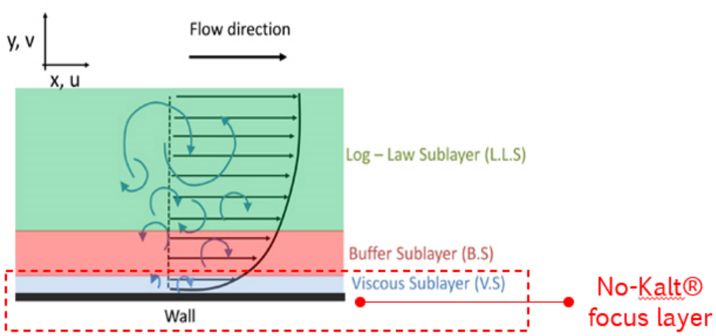


FIGURE 6: TYPICAL ISSUES WITH HEAVY PARAFFIN ON WELL PP

FIGURE 7: WELL PP: OIL PRODUCTION PLOT SHOWING DOWN TIME DUE TO CLEANING AND ERRATIC OIL PRODUCTION

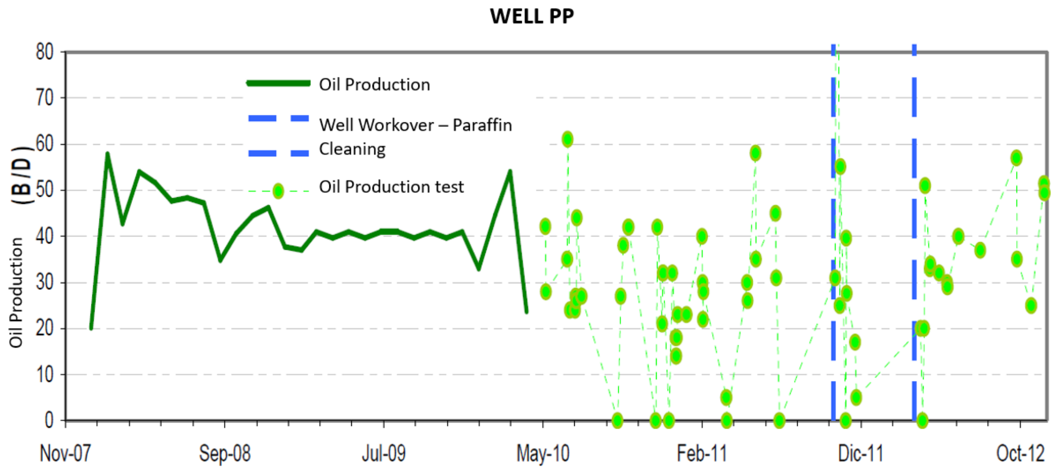


FIGURE 8: WELL PP: HISTORICAL WELL OIL PRODUCTION SHOWING THE INCREASE ON OIL PRODUCTION AFTER NOKALT IMPLEMENTATION

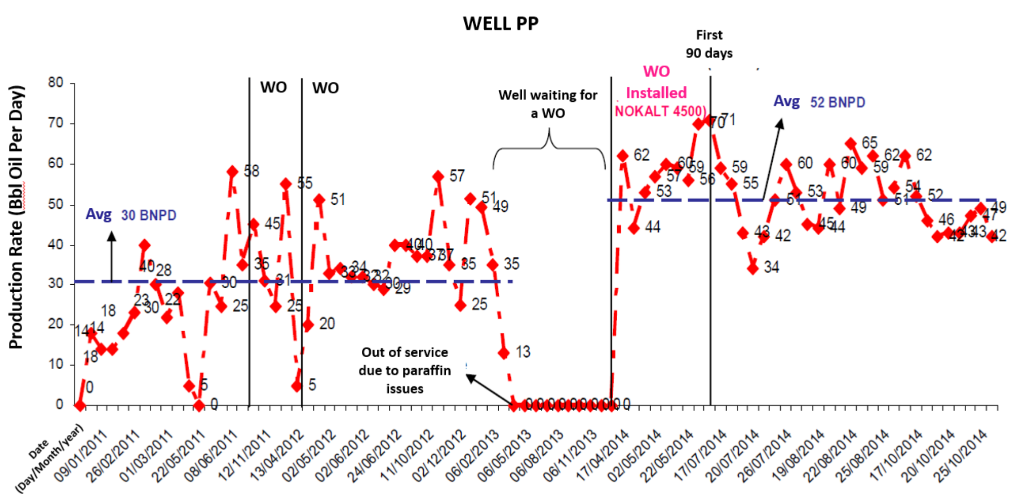


FIGURE 9: WELL VO: SUCKER ROD PIN FAILURES DUE TO GALLED THREADS AND OVER TORQUE

FIGURE 10: WELL VO: HEAT CONVEYOR CHEMATIC INSTALLATION

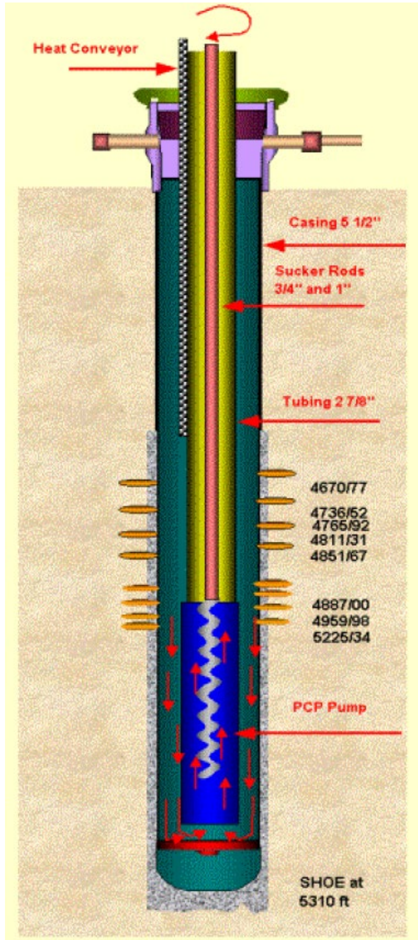
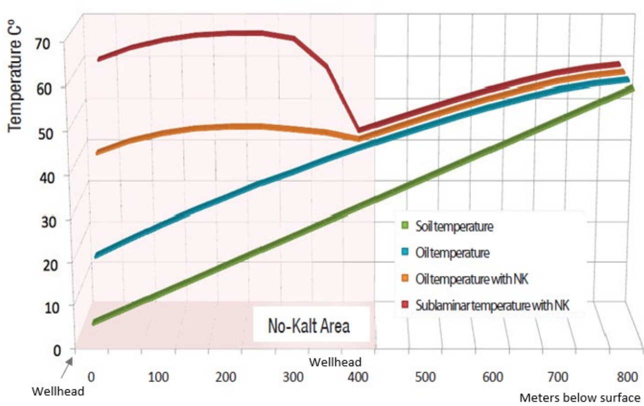


FIGURE 11 (LEFT): GEOTHERMAL AND FLUID TEMPERATURE GRADIENT FOR WELL VO, **FIGURE 12** (RIGHT) VISCOSITY PROFILE FOR OIL FROM WELL VO,



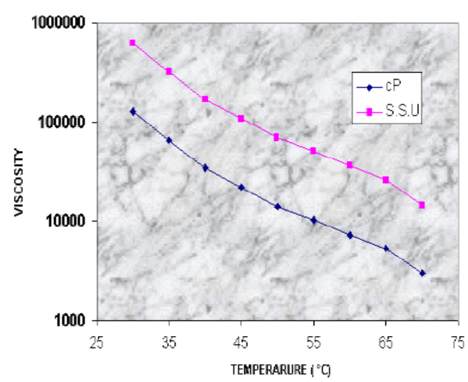
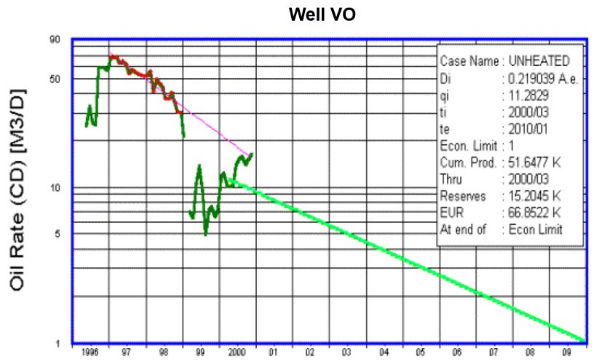
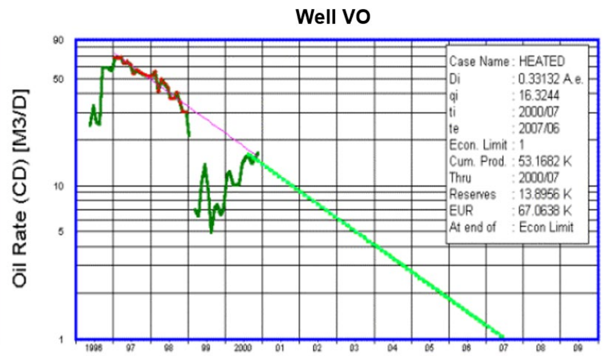


FIGURE 13: A) LEFT: PRODUCTION FORECAST ESTIMATION WITHOUT NOKALT, B) RIGHT: PRODUCTION FORECAST WITH NOKALT


Well VO
Oil Rate (CD) [M3/D]
Case Name : UNHEATED
Di : 0.219039 A.e.
qi : 11.2829
ti : 2000/03
te : 2010/01
Econ. Limit : 1
Cum. Prod. : 51.6477 K
Thru : 2000/03
Reserves : 15.2045 K
EUR : 66.8522 K
At end of : Econ Limit


Well VO
Oil Rate (CD) [M3/D]
Case Name : HEATED
Di : 0.33132 A.e.
qi : 16.3244
ti : 2000/07
te : 2007/06
Econ. Limit : 1
Cum. Prod. : 53.1682 K
Thru : 2000/07
Reserves : 13.8956 K
EUR : 67.0638 K
At end of : Econ Limit