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Well and Inflow Performance Relationship for Heavy Oil Reservoir under Heating Treatment

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Abstract

Well and Inflow Performance Relationship, termed TPR and IPR, respectively have been the unfailing methods to predict well performance. It is further to determine the schemes on optimising production. The main intention of the study is to explore TPR and IPR under heating treatment for heavy oil well. Klamono is a mature field which mostly has depleted wells, it produces heavy oil within 18.5 °API (>0.95 g/cc oil density), and therefore, artificial lifting method is necessary. Sucker Road Pump (SRP) and Electrical Submersible Pump (ESP) are the most deployed artificial lifting method in this reservoir. To boost the heavy oil production, the application of Electric Downhole Heater (EDH) in Well KLO-X1 is being studied. Whole Klamono's production is more than 100,000 bpd within 97-99% water cut. By installing EDH, oil viscosity is decreased hence oil mobility ratio will play a role to decrease water cut. EDH is installed together with the tubing joint to simplify its application in the wellbore. The study shows that EDH application can elevate fluid (mixed oil and brine) temperature. Oil viscosity confirms a reduction from 68 to 46 cP. The gross well production is up to 12.2 bopd due optimising its outflow performance and reducing 97.5 to 96.9% water cut. The field data gives an incremental of 4.9 bopd. The computational results only show an attainment of net oil production up to 8.3 bopd (2 bopd incremental). The EDH works to lessen both density and viscosity as we hypothesised for the mechanism of thermally induced oil production improvement. The evaluation study on its economics aspect exhibits good result that is 1.4 USD/bbl additional profit margin according to field data despite the challenging annual rig rent cost. Following the field data, the expected net income through analytical model revealed that this project is financially promising.

Keywords: IPR heavy oil; TPR heavy oil; Electric Downhole Heater (EDH); flow assurance; heavy oil; Klamono Field; thermal well stimulation; economics analysis.

1. Introduction

1.1 Downhole Heating

Heating oil at downhole conditions by deploying a concentrated resistive heaters was first introduced in 1969 by USSR (now: Russia) and US (Farouq Ali, 1973). This method is one of the well stimulation techniques because it focuses on altering the fluid and rock in the wellbore area.

There are three proposed mechanism of thermal induction in reservoir to improve oil production, which are: lowering viscosity, reducing oil gravity and wettability alteration. Some researches have shown laboratory or field experimental results which thermal-based induction operation can reduce viscosity (Ojeda and Parman, 2013), reduce heavy oil density (Naser et al., 2015) and alter wettability (Weinbrandt et al., 1975; Permadi et al., 2016). Decreased viscosity influences the mobility ratio to increase which means oil will easily flow (See Eq. 1).

$$M = \left(\frac{k_{rw}}{\mu_w} \right)_{S_{w(max)}=1-S_{or}} \times \left(\frac{\mu_o}{k_{ro}} \right)_{S_{w(min)}=S_{wc}} \quad [1]$$

Oil gravity can be regarded as a mechanism due to its ability to segregate with water. Density of liquid is strongly correlated with its viscosity as liquid gets lighter, the liquid will be less viscous (Andrade, 1930). Wettability is a rock characteristic that refers to the interaction between rock and fluid (oil and brine). Taking into account wettability means heat transmission is quite strong to reach the near wellbore rock. Wettability is the manifestation of rock-fluid interaction associated with fluid distribution in porous media (Hascakir et al., 2009). Mathematically, wettability which is measured by contact angle θ can be depicted in capillary number N_C . An important key of fluid flow in porous media is that by altering wettability in such way to increase the capillary N_C or Bond number N_B (in case of considering gravity effect $\Delta\gamma$), the fluid would flow easier (See Eq. 2 and 3 by Pennel et al. (1996); Lenormand et al. (1988)).

$$N_C = \frac{F_d}{F_c} = \frac{3\pi d \mu_{inv} v_{inv}}{\pi d T_s \cos \theta} = \frac{3\mu_{inv} v_{inv}}{T_s \cos \theta} \quad [2]$$

$$N_B = \frac{F_b}{F_c} = \frac{\Delta\gamma \pi d^3 / 6}{\pi d T_s \cos \theta} = \frac{\Delta\gamma d^2}{6 T_s \cos \theta} \quad [3]$$

There has also been a research done on altering capillary number on EOR process (Hakiki et al., 2015). The study found that rock-fluid interaction is also exhibited by relative permeability. Accordingly, the understanding of wettability effect is governed by its relative permeability alteration.

A summary on increasing capillary number to reduce residual fluid saturation is presented in Figure 1. This summary is resumed from various phenomena of fluid flow in porous media, which covers oil, microemulsion and brine flow. Figure 1 portrays the attempt to recover more fluid either oil or brine is achievable by increasing trapping number N_T . The contribution of trapping number can be approached either by capillary number side or Bond number side. Bond number covers the density difference $\Delta\gamma$, fluid bubble size d and both wettability θ and surface tension T_s . Capillary number is increased if the invading fluid (brine or polymer) is introduced, escalating a higher fluid velocity by injecting another invading fluid (water injection), changing wettability or a decrement in interfacial tension. In the discussion of wettability, it must be able to detach more oil from its surface, structural or pore trap.

Figure 1. Capillary desaturation curve (CDC) under stable displacement regime or piston-like displacement. Once buoyancy number N_B is ignored, trapping number N_T would equal to capillary number N_C . Buoyancy number at particular inclination α is only considered in Youssef (2015). All data are abstracted from laboratory results except Al Shalabi (2014) which is from numerical simulation. Normalised residual saturation is expressed as follow $S_n = (S_{or} - S_{or(min)}) / (S_{or(max)} - S_{or(min)})$.

Wettability is inter-correlated with surface tension T_s as equated by Young-Dupre in Eq. 4 (Schrader, 1995). It is obvious that interfacial tension plays the role in producing more oil (Hakiki, 2014; Hakiki et al., 2015). For this reason, there might be a possibility that electrical downhole heating also change both wettability θ and oil-water interfacial tension T_{ow} .

$$T_{os} - T_{ws} = T_{ow} \cos \theta \quad [4]$$

Doubt was raised whether or not thermal recovery affect wettability in better condition in such a way to mobilize more oil (Punase et al., 2014). This was answered by an observation of a negative relation that wettability alteration happened from oil wet to stronger oil-wet by steam (Permadi et al, 2016). Our discussion will concentrate on the flow assurance of heavy oil through tubing in which EDH acts as the intake of tubing. The focus is to apply EDH in Klamono Field, Indonesia. Table 1 is evident that electrical downhole heating is promising. The heater used in this field trial was a resistive type heater (Ohmic heater).

Table 1. Summary of application of Ohmic (resistive) downhole heating in various places.

Author	Year	Field	Initial oil viscosity [cP]	Initial oil density [°API]	Incremental recovery [%]	Incremental production rate [bopd]
Vinsome	1994	Sparky Formation	13,500 (24 °C)	12.15	N/A	56.61
McQueen	2009	California	365.8 (49 °C)	14.3	N/A	12 (liquid)
Vielma	2010	Zatchi Marine Field, Congo	500-1,500 (35.5 °C)	15	≤7.6	-

Ojeda	2013	Venezuela	18,000 (47 °C)	8.1	54	200
Ojeda	2013	California	338 (30-49 °C)	8.5 - 21	11.6*	19.3
Quintero	2014	Zuata Field, Venezuela	14,500 (49 °C)	8.9	50	662. 7
Notes:						
*Average taken from 10 wells.						

1.2 Klamono Field

Technical screening following the algorithm developed by literature study suggests that Klamono is suited to be treated with immiscible CO₂, steam flood, and polymer (Hartono et al., 2017). Concerning the shallow reservoir and high viscosity, it led to the trial of heat-based EOR or well stimulation to boost the production.

Klamono is an onshore field located in Salawati Basin, in the North-West of Papua Island currently operated by Pertamina EP. This basin is the mature one, with high potential of hydrocarbon, which was proven ever since the first oil well, Klamono-1 (KLO-1) drilled by NNGPM (Nederlandsch Nieuw Guinea Petroleum Maatschappij) in 1936 (Satyana et al., 1999). Figure 2a tells that Klamono Field is located in the East part of Salawati Basin. The reservoir consists of three formations, which are Kais, Sirga and Klasefet Formation under strong water drive force. The New Guinea Limestone Group encompassed of Oligocene to Miocene aged Faumai, Sirga, Kais and Klasafet formations are the key in tertiary strata (See Figure 2b). The major reservoir is Kais carbonates while the source of hydrocarbon is Klasafet shale (Satyana et al., 1999). General reservoir properties are displayed in Table 2. The reason of EDH application is due to its API at 18.5 and viscosity 68 cP (at 52 °C). A crude is categorised as a heavy oil if its API is between 10 to 22 (Pramana et al., 2012).

Table 2. Reservoir, rock and fluid properties of Klamono Field and feature of well KLO-X1.

Parameter	Value	Unit
Reservoir		
Initial pressure (at year of 2011)	171	psi
Bubble point pressure (at year of 2011)	161	psi
Current reservoir pressure	153	psi
Reservoir temperature	55	°C
Oil viscosity (at 52 °C)	68	cP
Brine viscosity (at 52 °C)	0.55	cP
Oil specific gravity	0.95	
Brine specific gravity	0.99	
Initial formation volume factor	1.032	
Current formation volume factor	1.031	
Gas to oil ratio (v/v)	3.3	scf/bbl
Initial water saturation	0.32	
Average permeability	400	mD
Well KLO-X1		
TVD	141	m
MVD	141	m
Tubing inner diameter	2.441	inch

Figure 2. Part (a): Map showing Salawati Basin tectoning setting. Salawati Basin is bounded by Sorong Fault and there exists some faults within SW-NE and SSW-NNE trending, genetically formed as enechelon extension fractures to the Sorong Fault (Satyana et al., 1999). An index map at upper left part indicates that Salawati Basin is in foreland position of Papua Island and nearby the Indo-Australia Plate. Part (b): Stratigraphy map of Salawati Basin (Satyana et al., 1999). Red box points where Klamono Field is, mainly from middle to late Miocene.

Current field gross production is 134,221 blpd with up to 99% water cut (net oil production up to 930 bopd). Peak field production up to 5,972 bopd with 17 total number of production wells was achieved in June 1949. As per 2016, Klamono has 205 total number of wells, consisting of 128 production wells, 21 injection wells, 40 suspended wells and 16 abandoned wells (4 hole problem wells & 12 dry hole wells). Most of them were drilled after 1970 since the Indonesia government started the Production Sharing Contracts (PSCs) policy in 1968. Up to 2011, Klamono’s oil cumulative production is around 41.42 MMSTB from total 93.33 MMSTB OOIP (44.38% of recovery factor). Due to current low reservoir pressure, Klamono wells need an artificial lifting method where out of 128 total production well, 64 wells are sucker rod pump (SRP)-assisted and 64s well are electrical submersible pump (ESP)-assisted well.

The primary candidate for our trial of EDH is well KLO-X1 (See Figure 3). KLO-X1 was drilled on 6 Aug 2007 at 141 m TVD. It could be categorized as a shallow oil well. It is assisted by Sucker Rod Pump. Due to low influx, the well is suspended for a while. The well has been producing since 15 May 2009 at 289 blpd and 5.8 bopd (98% water cut) after respacing job (change of rod spacing at SRP). Current well oil cumulative is approximately 1085 STB (See Figure 3a). Reparation job has been done 4 times those are Feb 2008, Aug 2009, Sept 2011 and Nov 2013.

Figure 3. Part (a): Profile of production history for 7 years of well KLO-X1. Part (b): Profile of pressure and temperature of well KLO-X1. The data is obtained using pressure and temperature gauge (PT Log) at static condition (no flow). This measurement was conducted on 13 March 2015.

The objectives of this paper are, thus, not only to study the fluid behaviour (viscosity and gravity) with respect to the transmitted heat by EDH but also to perform reservoir and tubing performance relationship analysis and field economics evaluation based on the selected well KLO-X1 of Klamono Field, Indonesia.

2. Methods

2.1 Theoretical Approach

There are three main aspects of computations: (i) fluid fraction prediction, (ii) rate computation, and (iii) financial assessment. Part (i) is initiated by predicting wellbore fluid temperature to know the fluid viscosity (See Eq. 5 through 7). The viscosity is then input into fluid fraction model (Eq. 8). Aspect (ii) is to compute the liquid rate corresponding to field data and predicted TPR (Eq. 9 and 10). Aspect (iii) is predicting oil production from oil cut derived from the frame (i) and liquid rate from the frame (ii). A comprehensive economics study is then performed.

As mentioned in the Introduction section, viscosity is critical to the fluid flow of oil. Experimental data is achieved from Fann VG measurement and a set of fitting equations is employed to see how dead oil behaves under a wider temperature range. Possible temperature range must follow what reservoir condition is like and the density is, in fact, pressure dependent (See Figure 3b). Dead oil equation is presented as Eq. 5 (McCain, 1990). Detailed parameters of equation set to compute oil density is presented in Appendices section. A macro tool has been provided to compute the equations set and density of dead oil properties (See Appendix 1 and Figure 4) (Guo, 2007). A rough trend of thermal gradient is projected from the top and bottom well temperature as follows 0.180833 °C/m.

$$\mu_{od} = \left(0.32 + \frac{1.8 \times 10^7}{API^{4.53}} \right) \left(\frac{360}{T + 200} \right)^A \quad [5]$$

Figure 4. **Red curve:** Viscosity profile of oil sample from Klamono Field. Prediction of viscosity is computed using Eq. 5 (See also Appendix 1) indicated by continuous line (-) and the experimental data is performed by Fann VG measurement indicated by ($\square$). **Green curve:** Fractional flow for oil computed by modifying Eq. 8 ($f_o=1-f_w$). This chart is computed based on 6 selected temperature. The value of k_{ro}/k_{rw} is obtained from the history matching of production data, i.e. $f_o=2.5\%$ ($f_w=97.5\%$) at 52°C (from fluid sampling in conjunction of PT Log operation). Point $f_o=2.5\%$ at 52°C points out initial condition before EDH was installed.

Figure 3b shows the reservoir condition 5 days before EDH installation. A simple computation is considered by assuming a radial-horizontal flow into the tubing intake (surrounding of EDH). A constant isobaric specific heat c_p is deployed to take into account heat convection hence these set of equations will prevail in this condition (Equating Eq. 6 and 7, also Appendix 2 (Geankoplis, 1993)).

$$q_s = mc_p(T_{bo} - T_{bi}) \quad [6]$$

$$q_c = h_a A \Delta T_a \quad [7]$$

The mass term in Eq. 6 is derived from oil density times heated volume in the annulus covering the EDH. Unfortunately, it is clueless to assess the volume in the annulus. As a result, the heated volume is acquired by imposing that the volume inside the annulus is equal to gross pipe volume (Pipe ID=2.441 inch, length of pipe=109 m) subtracted by SRP rod volume (Rod OD=0.75 inch, length of rod=106 m). This net volume is below 0.3 m^3 ($\approx 10.6 \text{ cuft}$). This assumption is infused since the reservoir is undergoing assistance by SRP. The fluid comes into tubing via EDH as the intake-hole will fully be controlled by SRP instead of reservoir. That statement is strengthened by its low reservoir pressure, 149 psi.

A horizontal fractional flow f_w is adopted for predicting water cut for every selected viscosity. Each viscosity data for a particular temperature is computed using Eq. 5. A fluid temperature change is assumed to happen at near sand-face in which fluid satisfies radial-horizontal flow condition and assuming both oil and brine relative permeability are not changed, in this case, it is still reasonable to further simplify the case (See Eq. 8 and Figure 4).

$$f_w = \frac{1}{1 + \frac{\mu_w k_{ro}}{\mu_o k_{rw}}} \quad [8]$$

A reservoir performance will be pronounced only through IPR model and more deal with near-wellbore activity because of supposing no change in k_{ro}/k_{rw} . Vogel's equation is considered adequate to describe the two phase's inflow performance relationship (See Eq. 9 by Vogel (1968); Guo (2007)). A detailed change of IPR under heating treatment will in-depth be discussed in the of Section 3.1.

$$\frac{Q_L}{Q_{L,max}} = 1 - 0.2 \left(\frac{P_{wf}}{P_r} \right) - 0.8 \left(\frac{P_{wf}}{P_r} \right)^2 \quad [9]$$

The tubing performance relationship is generated by utilising Hagedorn-Brown correlation (Hagedorn and Brown, 1965; Guo, 2007) (See Eq. 10 and Appendix 3).

$$144 \frac{dP}{dz} = \bar{\rho} + \frac{f_F M_t^2}{7.413 \times 10^{10} D^5 \bar{\rho}} + \bar{\rho} \frac{\Delta(u_m^2)}{2g_c \Delta z} \quad [10]$$

2.2 Field Application

The heater EDH installation is joined with producing tubing string at 109 m TVD. The breakdown of instrument specification and temperature regarding EDH application is summarised in Table 3 and Eq. 11. A temperature gradient is retained from the data of pre-installation, 0.180833 °C/m then substitute it by subtracting post-installation bottom-hole well temperature T_{wbh} .

$$\begin{aligned} \frac{\partial T}{\partial z} &= \frac{T_{wbh} - T_{wh}}{\Delta z} \\ T_{wh} &= T_{wbh} - \left(\frac{\partial T}{\partial z} \right) \Delta z \end{aligned} \quad [11]$$

Table 3. Heater specification and PT log-survey and -computation.

Parameter	Value	Unit
Heater specification		
ID Heater	1	inch
Heater length	1.5	m
Required voltage, V	220	V
Required power, P_{req}	4	kW
Heat conduction constant, k (Cr-Ni-steel)	12.8	W/mK
Surface test		
Initial water temperature, T_{wi}	28	°C
Final water temperature, T_{wf}	67	°C
Initial fluid temperature, T_{hi}	28	°C
Final fluid temperature, T_{hf}	74	°C
PT log (before heater installation)		
Bottom-hole well temperature, T_{wbh}	63	°C
Surface well temperature*, T_{wh}	41	°C
Average well temperature**, $\bar{T}_w$	52	°C

Bottom-hole oil temperature [§] , T_{bi}	52	°C
PT log (after heater installation)		
Bottom-hole well temperature [‡] , T_{wbh}	74	°C
Surface well temperature [†] , T_{wh}	49	°C
Average well temperature ^{**} , $\bar{T}_w$	62	°C
Bottom-hole oil temperature [§] , T_{bo}	62	°C
Notes: Pressure-Temperature Log (PT Log) was performed on March 13, 2015. *Measured by using Thermal Imager apparatus. **Computed using arithmetic average of bottom-hole well temperature T_{wbh} and surface well temperature (well head temperature) T_{wh} . [§] Calculated by solving Eq. 6 and 7 (See also Appendix 2). [‡] Supposed to reach the maximum heater temperature as per surface experiment performed prior to installation, $T_{wbh}=T_{hf}$. [†] Calculated using set of equations presented as Eq. 11.		

2.3 Economic Model

The Economic model is done using a single-flow concept to calculate profit margin from net income and cost. Costs consist of two main parameters: rig and fuel daily cost, while income is achieved from net daily oil production sale. Detailed calculation assumptions are disclosed in Table 4. Under pre-installation process, the required investment is annual rig rent of 3,422,374 USD. The other expenses are 346 USD, 50 USD and 58 USD for personnel, maintenance and consumable use respectively. The set of equations for economy analysis (Eq. 12).

$$\begin{array}{l|l}
P = \frac{\sqrt{3}}{1000} \left(\frac{f}{f_i} \right) V I \cos \pi & P_{inj} = \beta Q_w \\
Q_o = (1 - f_w) Q_L & I_D = p_o Q_o \\
Q_w = f_w Q_L & C_D = (P_{con} + P_{inj}) V_f C_f \\
P_{con} = 24P & M_p = I_D - C_D
\end{array} \quad [12]$$

Table 4. Assumptions of economic parameters used in the calculation using Eq. 12.

Parameters	Value	Unit
Crude oil price, p_o	44.25	USD
Fuel cost, C_f	0.849	USD/liter
Fuel consumption, V_f	0.2653	liter/kWh
Power factor, $\cos \pi$	0.85	
Pump energy consumptions, β	0.11	kWh/blpd

The EDH tool consists of two main components, EDH panel and cable. EDH Panel is purchased at 437 USD/set. EDH Cable costs 397 USD/set. The computation of the economics analysis is all converted to US dollar even though there exist some costs or contract that were delivered in Indonesian Rupiah (IDR). The conversion rate was following the rate exchange at mid of January 2015 (12,578 IDR/USD). As presented in Eq. 12, there is a square root of three $\sqrt{3}$, which means multiplication for 3-electrical phase pump and division of 1000 is to convert into kilo watt.

3. Results and Discussion

3.1 Well and Inflow Performance

A published simulation study has shown that recovery will increase as ratio of μ_o/μ_w gets lower (Maini and Okazawa, 1987). The outcome of this research shows that brine viscosity reduction is not as drastic as oil, from 0.55 to 0.47 cP and from 68 to 46 cP, for brine and oil respectively. Detailed comparison results pre- and post-EDH application is shown in Table 5. As seen from the summary, heat treatment lessens brine viscosity as much as 0.08 cP while oil viscosity is reduced by as much as 22 cP. Due to the reduction of mobility ratio ($|\Delta M|=26$, from 124 to 98), the production of oil is higher. Mathematically, this relation can be acquired by combining Eq. 1 and 8 to gain the oil cut relation as below, Eq. 13. Since this paper is not discussing a response on wettability or relative permeability, the rock-fluid interaction will not be considered. Mathematically, the value of k_{ro}/k_{rw} remains constant.

$$f_o = \frac{1}{1 + M} \quad [13]$$

Table 5. Reservoir properties, production & economics prediction summary before and after EDH installation.

Parameter	Before EDH Installation	After EDH Installation	Unit
Fluid temperature	52	62	°C
Oil viscosity	68	46	cP
Water viscosity	0.55	0.47	cP
Oil specific gravity	>0.95 [†]	0.94 [‡]	
Water cut, f_w^*	97.5	96.9	%
Production rate (field data)	253/7.3/246	267/12.2/255	blpd;bopd;bwpd
Production rate** (prediction)	251/6.3/245	261/8.3/253	blpd;bopd;bwpd
Power, P	3.93	5.25	kW
Daily income, I_D	278	362	USD/day
Daily cost, C_D	27	35	USD/day
Profit margin, M_p	251	327	USD/day
[†] Data is obtained using hydrometer at predicted initial bottom-hole fluid temperature T_{bi} . [‡] Data is obtained using hydrometer at predicted final bottom-hole fluid temperature T_{bo} . [*] Data is calculated using Eq. 8 and used to get prediction rate (data with double asterisks ‘**’). All numbers related to economics aspects are derived from predicted production rate (data with double asterisks ‘**’).			

Heavy oil density gets lighter as saturation pressure-temperature increase, while steam density is found to be heavier under the same condition (Naser et al., 2015). It shows that liquid is more temperature dependent and gas phase is more pressure dependent. The steam gets compressed ($\Delta P > 0 \rightarrow V$ decrease $\rightarrow \rho$ increase) and the oil experiences expansion ($\Delta T > 0 \rightarrow V$ increase $\rightarrow \rho$ decrease). The results of this field trial show diminutive decrement of density ($\Delta \rho = 0.01$ g/cc). This decrement is normal since the increment of fluid temperature approximates 10 °C. It is a good compromise with published data on heavy oil (20 °API) which undergoing reduction of density $\Delta \rho = 0.057$ g/cc for incremental temperature $\Delta T = 15$ °C (Naser et al, 2015).

This research assumes that the reservoir fluid temperature T_{wbh} will reach temperature as high as the

surface fluid-measurement by heater T_{hf} that is at 74 °C. This optimistic temperature is the better option since we do not perform an advance heat transfer along the pipe. The final surface temperature is inversely enumerated from the reservoir fluid temperature $T_{wbh} = 74$ °C and handled by a constant well temperature gradient 0.180833 °C/m for both cases. The gradient is derived from the PT log data at the pre-EDH installations. Then, the surface data of wells was used as an input to get average well temperature $\bar{T}_w$ (See Appendix 2).

Figure 5 displays the initial and final liquid rate are added to 14 blpd (field data). By zooming Figure 5a, the initial and final liquid rates are 251 blpd and 261 blpd, respectively for the prediction data through computation. This study assumes constant productivity index PI at 5 bbl/day/psi.

Figure 5. KLO-X1 inflow and outflow performance. Part (a): Liquid phase inflow and outflow performance is constructed by Eq. 9 and 10, respectively. Outflow performance is conducted by matching pressure & rate based on BHP survey and production test of well. “Before” refers to condition when EDH was just about to install at 18 March 2015 and “After” is showing the condition at 20 March 2015. Part (b): Oil phase inflow performance relationship.

Figure 5b portrays that a shifted IPR due to heating treatment effects: a reduction of water cut and viscosity. There are 3 IPR models presented: Vogel (solution gas-driven reservoir) and general oil flow model derived from diffusivity equation (Guo, 2007). The Guo model shows a normal trend where the heated well curve moves to the right for both liquid and oil phase curve. It has similarity with Vogel IPR from zero rate until 270 blpd.

The reservoir still has dissolved gas with 3.3 scf/bbl GOR even the reservoir pressure is below the bubble point. It is, therefore, still reasonable to use Vogel IPR. In the case of pure heavy oil, a single phase IPR must be deployed. The comparison works with field data employs intersections of well performance (TPR) and Vogel IPR. A matched is set between Vogel IPR and Guo IPR at EDH-treated condition for liquid phase (Figure 5a). A comparison study on flow model in heavy oil reservoir appears in Table 6.

Table 6. A literature study of flow model in the heavy oil reservoir.

Author(s) – Year	Equations as Presented in Paper	Notes
Guo – 2007	$q = \frac{kh(\bar{p} - p_{wf})}{70.6B_o\mu_o \ln\left(\frac{4A}{\gamma C_A r_w^2}\right)}$	<p>Similar form by substituting this term</p> $\ln \frac{r_e}{r_w} = \frac{1}{2} \ln \left(\frac{4A}{\gamma C_A r_w^2} \right) + \frac{3}{4}$

		<p>Therefore, also add skin, (in field units),</p> $q = \frac{kh(\bar{p} - p_{wf})}{141.2B_o\mu_o \left[\ln \frac{r_e}{r_w} - \frac{3}{4} + s \right]}$ <p>Values being used and the justifications in Figure 5: $h=35$ ft, Original perforation is 50s ft. It could be justified that the formation might undergo plugging so that the active perforation is only around 35 ft. $s=5$, The contributing skin is at 5 to obtain matched results between Guo Liquid IPR (after) with Vogel IPR. $r_e=3964$ ft, Drainage radius is obtained from this formula below (in ft).</p> $r_e = \sqrt{\frac{\text{Producing Area}}{\text{Number of wells}}} = \sqrt{\frac{1.57 \times 10^7 \text{ ft}^2}{205}}$ <p>The other parameters refer to Table 2 and Table 5.</p>
Liu <i>et al.</i> – 2011	$q = \frac{2\alpha\pi k k_r h [p_i - p_{wf} - G_o(r_e - r_w)]}{\mu_o T \ln \frac{r_e}{r_w}}$	<p>The r_e acts as a half reservoir $L/2$ since the numerical model is a square reservoir (in Darcy units).</p> $q = \frac{2\alpha\pi k k_r h \left[p_i - p_{wf} - G_o \left(\frac{L}{2} - r_w \right) \right]}{\mu_o T \left[\frac{1}{2} \ln \left(\frac{4A}{\gamma C_A r_w^2} \right) + s + \frac{3}{4} \right]}$ <p>Introducing depletion factor G_o (differential pressure over horizontal distance) from empirical data. It is a case-dependent equation and not pure analytical.</p> $G_o = m \ln T + n$ $m = 0.203 \ln \left(\frac{k}{\mu_o} \right) - 0.199$ $n = -0.94 \ln \left(\frac{k}{\mu_o} \right) + 0.783$
Kumar and Mahadevan – 2012	$q = \frac{2\pi h k}{\left(\ln \frac{r_e}{r_w} - \frac{1}{2} \right)} \frac{1}{(\rho B_o)_{p_{wf}}} \int_{p_{wf}}^{\bar{p}} \frac{k_r \rho}{\mu_o} dp$	<p>Assuming the reservoir area is still cold (no EDH treatment), the oil properties may behave as if at initial condition at a</p>

		<p>location further away from well. It is cold properties at $p=\bar{p}$; It can be cold (initial) or heated properties (final) while $p=p_{wf}$.</p> $q = \frac{2\pi h k}{\left(\ln \frac{r_e}{r_w} - \frac{1}{2}\right)} \frac{(\bar{p} - p_{wf})}{(\rho B_o)_{p_{wf}}} \times$ $\frac{\left(\frac{k_r \rho}{\mu_o}\right)_{\bar{p}} + \left(\frac{k_r \rho}{\mu_o}\right)_{p_{wf}}}{2}$ <p>The equation is reduced to a conventional black oil model (Guo, 2007) by assuming a constant density, viscosity and relative permeability during pressure change from reservoir to wellbore (in Darcy units).</p> $q = \frac{2\pi h k k_r}{\left(\ln \frac{r_e}{r_w} - \frac{1}{2}\right)} \frac{\bar{p} - p_{wf}}{B_o \mu_o}$
Jahanbani and Shadizadeh – 2013	$q = \frac{1}{141.2} \frac{k k_r h}{B_o \mu_o} \frac{(\bar{p} - p_{wf})}{\left[\ln \frac{r_e}{r_w} - \frac{3}{4} + s\right]}$	This equation is same as conventional black oil model by assuming the existence of skin (Guo, 2007).

The analytical results have good agreement with the field data oil rate, with 0.8% and 2.3% relative error with respect to the field data, pre- and post-EDH installation respectively. It gains 10 blpd rises after EDH was installed on the 2nd day after installation (See Figure 6). The comparison of field and prediction data as revealed in Figure 6 shows that prediction has a pessimistic trend. It might be due to higher volume exhibiting heat exchange via convection than it should be. The computation of temperature is carried out at the static condition of heat transfer along the tubing (gross pipe length $L_{pipe}=109$ m). According to Eq. 6 (also See Appendix 2), the volume considered is the entire liquid along inside the tubing.

It is difficult to verify how much volume in the annulus is heated by EDH. As mentioned in the Methods section, the volume being heated equals to be the one inside the tubing because the pump is more accounting for the flow of liquid instead of the reservoir performance itself. The calculation results in Figure 6 is derived from the intersection points between well inflow performance or IPR with respect to outflow or tubing performance relationship (TPR) in Figure 5a.

Figure 6. Well KLO-X1 production performance. Actual production are collected from well production test data. Prediction data are computed by inflow versus outflow performance relationship. The continuous line (—) represents field data and dashed line (--) refers to prediction data computed. The vertical red line indicates the date of EDH installation.

3.2 Economics Analysis

A major consideration in downhole heating is wellbore power transmission and associated power loss (Sahni et al., 2000). The heater demands a higher power supply i.e. 4 kW than what is being supplied, 1.32 kW. Yet, it is also paramount to see how much energy is consumed for each produced oil for this heat treatment.

The amount of energy would be associated with money spent for investment and operation of the downhole heating set. The itemised production profile and economics evaluation is summarised in Table 5. The output states that predicted profit margin is 76 USD/day, accordingly better than before EDH usage ($\Delta M_p = 76$ USD/day). The daily-consumed energy depends on the power transmission, thus it affects the daily operating cost C_D (see Table 5).

The additional oil rate accelerates around 4.9 bopd on the 2nd day after installation, which boost the income at roughly 217 USD/day compared to no EDH adoption. Theoretically, the income was anticipated to step-up only 88.5 USD per 2 additional bopd. Prior to profit considerations, the value of predicted profit margin must be evaluated, those are 251 USD/6.3 bopd (≈ 39.8 USD/bopd) and at 327 USD/8.3 bopd (≈ 39.4 USD/bopd), before and after installation respectively. This USD/bopd value is assigned into a variable called x ($=M_p/Q_o$).

The result shows a reduction of x at 0.4 USD per produced barrel ($\Delta x = -0.4$ USD/bbl). A comprehensive simulation is demonstrated for a whole year application of EDH by assuming a 25% annual decline rate from each well and a fixed initial rate at $q_o = 8.3$ bopd after 2 days installation processes. The comparison was also carried out for a case of no EDH application at a fixed initial rate at $q_o = 6.3$ bopd for each well experiencing 25% decline rate too. The detailed calculation is presented by Eq. 14 to 15 in case of no EDH (with constant $x = 39.8$ USD/bbl) and Eq. 16 to 18 in case of adopting EDH.

The equations used to calculate the annual profit of field P_A is calculated by summation of each well annual profit for all 64 SRP-aided wells (i denotes well counter). The well profit per barrel is denoted by $x_{t,i}$ and remain constant during a particular duration of well i . The daily oil rate q_o is declined at $d_r=0.0684932\%$ (converted from 25% annually) for a whole year of operating duration.

$$P_{A_{without}} = \sum_{i=1}^{64} \left(\sum_{t=1}^{365} x q_{o_t} \right) = 64x \sum_{t=1}^{365} q_{o_t} \quad [14]$$

$$q_{o_{t+1}} = q_{o_t} - q_{o_t} d_r; q_{o_1} = 6.3 \quad [15]$$

$$P_{A_{EDH}} = \sum_{i=1}^{64} \left(\sum_{t=1}^{365} x'_{t,i} q'_{o_{t,i}} \right) \quad [16]$$

$$q'_{o_{t+1,i}} = \begin{cases} q_{o_{t,1}} - q_{o_{t,1}} d_r; q_{o_{1,1}} = 8.3, & 1 \leq t \leq 365, i = 1 \\ q_{o_{t,i}} - q_{o_{t,i}} d_r; q_{o_{1,i}} = 6.3, & 1 \leq t \leq 2(i-1), i \geq 2 \\ q_{o_{t,i}} - q_{o_{t,i}} d_r; q_{o_{t=2i-1,i}} = r_q q_{o_{t=2i-2,i}}; r_q = \frac{8.3}{6.3}, & 2i-1 \leq t \leq 365, i \geq 2 \end{cases} \quad [17]$$

$$x'_{t,i} = \begin{cases} 39.4, & 1 \leq t \leq 365, i = 1 \\ 39.8, & 1 \leq t \leq 2(i-1), i \geq 2 \\ 39.4, & 2(i-1) < t \leq 365, i \geq 2 \end{cases} \quad [18]$$

In case of no EDH, $t=365$ days (1 year) within constant x . In the case of using EDH, it is vital to judge that the well is able to operate on the 2nd day of installation processes (1 day for rig movement and 1 day for putting the EDH set into wellbore). Supposing rig will move around the field to install EDH in a series, the total operating EDH is summation of 365, 363, 361 days and so on following the number of wells. Before EDH is applied, the rate is assuming no-EDH case i.e. initiated at 6.3 bopd then it will be shifted at ratio $r_q=8.3/6.3$ of a-day-before installation's rate. Bouncing back to 8.3 bopd/6.3 bopd ratio shows that this simulation results are optimistic, where it disregards the installation day required for the first well, and that it works immediately on the days of installation. The cost of rig renting also starts on the first day of usage to install EDH.

The simulation exploiting analytical models assuming Eq. 14 through 18, details shown in Appendix 4 (consists of . Rate calculation in case of no EDH installed. The results shown are truncated for 1st to 13th day at Well #1 to #5. The computation of rate at t days is following Eq. 15. Units are in bopd. Rate at 6.3 bopd is predicted data. Table 7 through Table 10) and Appendix 5 (consists of Table 11 through Table 14). The results show that by heating the fluid, the annual field profit margin could reach up to 6.5 million USD. It must, however, subtract the rig rent cost of about 3.4 million USD annually. As results, the net profit margin would be 3.1 million USD.

The field could achieve 5.2 million USD of net profit margin from natural flow. For sure, it is a rough prediction because even though no EDH is installed, there might be some additional costs to execute a work over service in each well. The results that EDH installation is still better as it adds more income (adding more than 1.3 million USD) but the rig investment is not economically reasonable. It could be paid off if the profit margin is secured at $x=54.8$ USD/bbl daily ($\Delta x=15.0$ USD/bbl). The minimum $x=54.8$ USD/bbl is assumed at the oil rate-independent case. Thus, EDH installation is not economically worth applying following the prediction data due to rig cost.

This estimation was, in fact, not performed as the basis of feasibility study prior to performing EDH installation. The computation data was used to evaluate the performance of EDH theoretically. A considerable amount of investment will be required to run EDH for all wells in the field.

The real field observations yield a profit margin of 296 USD/7.3 bopd (≈ 40.5 USD/bopd) and 511 USD/12.2 bopd (≈ 41.9 USD/bopd), before and after installing EDH respectively. It succeeds in driving more $\Delta x = 1.4$ USD per daily barrel produced oil according to the field data. It could be paid off if the profit margin can guarantee $x = 41.0$ USD/bbl daily ($\Delta x = 0.5$ USD/bbl). The minimum $x = 41.0$ USD/bbl is assumed at the oil rate-independent case. It is acceptable to have a decrement in profit margin per barrel as long as the oil rate is comparable. The analogue computation using field data is quite optimistic and promising since it has an improved rate of 12.2 bopd/7.3 bopd ratio r_q times the latest rate before installation.

An analogue computation is tested in the basis of field data's profit per produced oil ($x = 40.5$ and 41.9 USD/bbl) and after installation rate ratio $r_q = 12.2/7.3$. This analogy only substitutes the post-installation initial rate and profit per barrel x . It yields 9.7 and 6.3 million USD, before and after subtracted by rig rent cost respectively. No-EDH installation field produces only 6.1 million USD. The 9.7 million USD can pay off the rig rent cost. Therefore, there is an additional 0.2 million USD of profit margin. Therefore, it can be concluded that this project is economically viable.

4. Concluding Remarks

Application of an electric downhole heating (EDH) or resistive (Ohmic) heating in the case study in Klamono shallow heavy oil field well KLO-X1 positively improves the production. Experimental and simulation study results show:

1. Heat transfer from EDH to fluid in the wellbore resulted in a slight oil density reduction as 0.01 cP per $\Delta T = 9$ °C. It satisfies the condition of one of the proposed mechanisms.
2. Viscosity reduction could increase oil mobility passing water mobility thus decreasing water cut of produced liquid from 97.5 to 96.9%. A viscosity reduction mechanism is thus realized.
3. The field data of flow assurance through the tubing is proven to improve well production from 253 to 267 blpd; equals to increasing oil from 7.3 to 12.2 bopd.
4. EDH application is predicted to give an income gain up to 88.5 USD/day for additional 2 bopd, analytically. The economics study employing prediction data reveals that EDH installation is not financially favorable due its high rig rent cost.
5. On the contrary with the 4th conclusion, the actual data from field holds a positive economics result that the EDH installation might be financially feasible by assuming an optimistic oil rate i.e. holding rate ratio $r_q = 12.2/7.3$ every starting post-installation phase.

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Nomenclature

M	=	Mobility ratio []
k_{rw}	=	Water relative permeability []
μ_w	=	Water viscosity [cP]
μ_o, μ_{od}	=	Oil viscosity or dead oil viscosity [cP]

k_{ro}	=	Oil relative permeability []
N_C	=	Capillary number []
F_d	=	Drag force [N]
F_c	=	Capillary force [N]
d	=	Fluid bubble size [m]
μ_{inv}	=	Invading fluid viscosity [cP]
v_{inv}	=	Invading fluid velocity in porous media [m/s]
T_s	=	Surface or interfacial tension [mN/m]
θ	=	Contact angle [rad]
N_B	=	Bond number []
F_b	=	Buoyancy force [N]
$\Delta\gamma$	=	Gravity different, $(\rho_o - \rho_w)g$ [N/m ³]
S_{or}	=	Residual oil saturation []
T_{ow}	=	Water-oil interfacial tension [mN/m]
T_{os}	=	Solid-oil interfacial tension [mN/m]
T_{ws}	=	Solid-water interfacial tension [mN/m]
API	=	API oil gravity []
T	=	Temperature of dead oil [°C], [°F]
f_o	=	Oil cut []
f_w	=	Water cut []
c_p	=	Isobaric fluid calor capacity, crude oil has 2090 [J/kg/K], 0.5 [btu/lbm/°F]
q_s	=	Specific heat [J]
m	=	Fluid mass [kg], [lb]
T_{bo}	=	Final bottom-hole fluid temperature [°C], [°F]
T_{bi}	=	Initial bottom-hole fluid temperature [°C], [°F]
q_c	=	Convection heat [J]
h_a	=	Fluid convection coefficient [J/s.m ² .K], [btu/hr.ft ² . °F]
A	=	Area [ft ²]
ΔT_a	=	Temperature average for convection process [°C], [°F]
Q_L	=	Liquid rate [blpd]
P_{wff}	=	Flowing bottom-hole pressure [psi]
P_r	=	Reservoir pressure [psi]
z	=	Depth [ft]
$\bar{\rho}$	=	In-Situ average fluid density [lb _m /ft ³]
f_F	=	Fanning friction factor []
M_t	=	Total mass flowrate [lb _m /d]
u_m	=	Mixture velocity [ft/s]
g_c	=	Unit conversion factor, 32.17 [lb _m ft/lb _f s ²]
Δz	=	Elevation increase [ft]
T_{wbh}	=	Bottom-hole well temperature [°C], [°F]
T_{wh}	=	Surface well temperature (well-head) [°C], [°F]
P	=	Power [kW]
f	=	Operating frequency [Hz]
f_i	=	Ideal operating frequency, 50 Hz
V	=	Electrical voltage [V]
I	=	Electrical current [A]
$\cos \pi$	=	Power factor []
Q_o	=	Oil rate [bopd]

Q_w	=	Water rate [bwpd]
P_{con}	=	Daily consumed energy required by producing well [kWh]
P_{inj}	=	Daily consumed energy for injecting brine [kWh]
β	=	Pump energy consumption [kWh/blpd]
I_D	=	Daily income [USD]
p_o	=	Indonesian Crude Price, ICP, 44.25 [USD/bbl]
C_D	=	Daily cost [USD]
V_f	=	Consumed fuel [liter/kWh]
C_f	=	Fuel cost [USD/liter]
M_p	=	Profit margin [USD]
h	=	Reservoir thickness [ft]
$\bar{p}$	=	Average reservoir pressure [psi]
γ	=	$e^\gamma = 0.781073015$, Euler's constant $\gamma = 0.577216$ []
C_A	=	Dietz reservoir shape factor for square shape with a well in the middle, 30.8828 []
r_e	=	Drainage radius [ft]
r_w	=	Well radius [ft]
B_o	=	Formation volume factor [bbl/stb]
s	=	Skin factor []
α	=	Mathematical constant, 0.01 []
G_o	=	Depletion factor on horizontal distance [psi/ft]
L	=	Reservoir length [ft]
P_A	=	Annual field profit margin, subscript: "without" means no EDH installed; "EDH" means using EDH [USD]
i	=	Well counter from 1 st to 64 th well []
t	=	t -th day [day]; Day counter from day 1 to 365 []
q_o, q'_o	=	Oil rate production from each well [bopd]
d_r	=	Decline rate of well at daily basis []
x, x'	=	Profit margin per barrel oil produced at daily basis, M_p/Q_o [USD/bbl]
r_q	=	Rate ratio of before and after of EDH installation []
N_{Re}	=	Reynold number []
D_i	=	Inside diameter [m ²], [ft ²]
v	=	Fluid velocity in pipe [ft/s]
ρ	=	Fluid density [kg/m ³], [lb/ft ³]
N_{Pr}	=	Prandtl number []
k	=	Heat conductivity [J/s.m.K], [btu/hr.ft. °F]
N_{Nu}	=	Nusselt number []
D_{pipe}	=	Inner diameter of pipe [inch]
L_{pipe}	=	Tubing length [m]
T_w	=	Average well temperature [°C], [°F]
y_L	=	Liquid fraction []
ρ_L	=	Liquid density [lb _m /ft ³]
ρ_G	=	In-situ gas density [lb _m /ft ³]
u_{SL}	=	Superficial velocity of liquid phase [ft/s]
u_{SG}	=	Superficial velocity of gas phase [ft/s]

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Appendices

Appendix 1

Dead oil properties formula (McCain, 1990)

$$\gamma_o = \frac{141.5}{^\circ API + 131.5}$$

$$\rho_o = \frac{62.4\gamma_o + 0.0136R_s\gamma_g}{0.0972 + 0.000147 \left[R_s \sqrt{\frac{\gamma_g}{\gamma_o}} + 1.25T \right]^{1.175}}$$

$$\mu_{od} = \left(0.32 + \frac{1.8 \times 10^7}{API^{4.53}} \right) \left(\frac{360}{T + 200} \right)^A$$

$$A = 10^{\frac{0.43 + 8.33}{API}}$$

$$a = R_s(2.2 \times 10^7 R_s - 7.4 \times 10^{-4})$$

$$c = 8.62 \times 10^{-5} R_s$$

$$d = 1.10 \times 10^{-3} R_s$$

$$e = 3.74 \times 10^{-3} R_s$$

$$b = \frac{0.68}{10^c} + \frac{0.25}{10^d} + \frac{0.062}{10^e}$$

$$\mu_{ob} = 10^a \mu_{od}^b$$

$$\mu_o = \mu_{ob} + 0.001(p - p_b)(0.024\mu_{ob}^{1.6} + 0.38\mu_{ob}^{0.56})$$

Appendix 2

Heat transfer and capacity formula (Geankoplis, 1993)

Definition of dimensionless number which are: Reynold, Prandtl, and Nusselt.

$$N_{Re} = \frac{D_i v \rho}{\mu}$$

$$N_{Pr} = \frac{c_p \mu}{k}$$

$$(N_{Nu})_a = \frac{h_a D}{k}$$

$$(N_{Nu})_a = 1.86 \left(N_{re} N_{pr} \frac{D}{L} \right)^{\frac{1}{3}} \left(\frac{\mu_b}{\mu_w} \right)^{0.14}$$

Those dimensionless numbers are adapted for compute convection heat constant h_a .

$$h_a = 1.86 \frac{k}{D} \left(N_{re} N_{pr} \frac{D}{L} \right)^{\frac{1}{3}} \left(\frac{\mu_b}{\mu_w} \right)^{0.14}$$

Heat transfer considered from convection process is to increase m oil sampel temperature from T_{bi} to T_{bo} .

$$q_s = mc_p(T_{bo} - T_{bi})$$

$$m = \frac{\pi \rho}{4} (D_{pipe}^2 L_{pipe} - D_{rod}^2 L_{rod})$$

$$q_c = h_a A \Delta T_a$$

$$A = \pi D_{pipe} L_{pipe}$$

$$\Delta T_a = \frac{(\bar{T}_w - T_{bi}) + (\bar{T}_w - T_{bo})}{2}$$

$$\bar{T}_w = \frac{T_{ws} + T_{wbh}}{2}$$

Equating specific heat q_s with respect to the convection heat q_c yields the final oil temperature T_{bo} as follow.

$$T_{bo} = \frac{\frac{h_a A}{2} (2\bar{T}_w - T_{bi}) + mcT_{bi}}{\frac{h_a A}{2} + mc}$$

Appendix 3

Hagedorn-Brown correlation ([Hagedorn and Brown, 1965](#)).

$$144 \frac{dP}{dz} = \bar{\rho} + \frac{f_F M_t^2}{7.413 \times 10^{10} D^5 \bar{\rho}} + \bar{\rho} \frac{\Delta(u_m^2)}{2g_c \Delta z}$$

$$\bar{\rho} = y_L \rho_L + (1 - y_L) \rho_G$$

$$u_m = u_{SL} + u_{SG}$$

Appendix 4

Detailed simulation of economics aspects using predicted data.

Table 7. Rate calculation in case of no EDH installed. The results shown are truncated for 1st to 13th day at Well #1 to #5. The computation of rate at t days is following Eq. 15. Units are in bopd. Rate at 6.3 bopd is predicted data.

Well #	1	2	3	4	5
Days					
1	6.3	6.3	6.3	6.3	6.3
2	6.296	6.296	6.296	6.296	6.296
3	6.291	6.291	6.291	6.291	6.291
4	6.287	6.287	6.287	6.287	6.287
5	6.283	6.283	6.283	6.283	6.283
6	6.278	6.278	6.278	6.278	6.278
7	6.274	6.274	6.274	6.274	6.274
8	6.270	6.270	6.270	6.270	6.270
9	6.266	6.266	6.266	6.266	6.266
10	6.261	6.261	6.261	6.261	6.261
11	6.257	6.257	6.257	6.257	6.257
12	6.253	6.253	6.253	6.253	6.253
13	6.248	6.248	6.248	6.248	6.248

Table 8. Rate calculation in case of installing EDH. The results shown are truncated for 1st to 13th day at Well #1 to #5. The computation of rate at t days is following Eq. 17. Units are in bopd. The highlighted yellow means the effect of EDH performance i.e. bounced back at 8.3/6.3 ratio (predicted data). It is assumed to take 1 day rig moving and 1 day installation.

Well #	1	2	3	4	5
Days					
1	8.3	6.3	6.3	6.3	6.3
2	8.294	6.296	6.296	6.296	6.296
3	8.289	8.294	6.291	6.291	6.291
4	8.283	8.289	6.287	6.287	6.287
5	8.277	8.283	8.283	6.283	6.283
6	8.272	8.277	8.277	6.278	6.278
7	8.266	8.272	8.272	8.272	6.274
8	8.260	8.266	8.266	8.266	6.270
9	8.255	8.260	8.260	8.260	8.260
10	8.249	8.255	8.255	8.255	8.255
11	8.243	8.249	8.249	8.249	8.249
12	8.238	8.243	8.243	8.243	8.243
13	8.232	8.238	8.238	8.238	8.238

Table 9. Daily profit calculation in case of no EDH installed. The results shown are truncated for 1st to 13th day at Well #1 to #5. The computation of profit at t days is following Eq. 14 to 15. Units are in USD. This computation is employing $x=39.8$ USD/bbl. This x value is derived from prediction data rate as presented in Figure 6 and Table 5. Referring to Table 5, $M_p=251$ USD is the maximum profit margin before installing EDH.

Well #	1	2	3	4	5
Days					
1	\$ 251	\$ 251	\$ 251	\$ 251	\$ 251
2	\$ 250.57	\$ 250.57	\$ 250.57	\$ 250.57	\$ 250.57
3	\$ 250.40	\$ 250.40	\$ 250.40	\$ 250.40	\$ 250.40
4	\$ 250.23	\$ 250.23	\$ 250.23	\$ 250.23	\$ 250.23
5	\$ 250.05	\$ 250.05	\$ 250.05	\$ 250.05	\$ 250.05
6	\$ 249.88	\$ 249.88	\$ 249.88	\$ 249.88	\$ 249.88
7	\$ 249.71	\$ 249.71	\$ 249.71	\$ 249.71	\$ 249.71
8	\$ 249.54	\$ 249.54	\$ 249.54	\$ 249.54	\$ 249.54
9	\$ 249.37	\$ 249.37	\$ 249.37	\$ 249.37	\$ 249.37
10	\$ 249.20	\$ 249.20	\$ 249.20	\$ 249.20	\$ 249.20
11	\$ 249.03	\$ 249.03	\$ 249.03	\$ 249.03	\$ 249.03
12	\$ 248.86	\$ 248.86	\$ 248.86	\$ 248.86	\$ 248.86
13	\$ 248.69	\$ 248.69	\$ 248.69	\$ 248.69	\$ 248.69

Table 10. Daily profit calculation in case of installing EDH. The results shown are truncated for 1st to 13th day at Well #1 to #5. The computation of profit at t days is following Eq. 16 through 18. Units are in USD. Since the yellow highlighted cells and below, the computation uses $x=39.4$ USD/bbl. The green highlighted cells are employing $x=39.8$ USD/bbl. Both these x value are derived from prediction data rate as presented in Figure 6 and Table 5. Referring to Table 5, $M_p=251$ USD is the maximum profit margin before installing EDH and $M_p=327$ USD is the maximum profit margin after installing EDH.

Well #	1	2	3	4	5
Days					
1	\$ 327	\$ 251	\$ 251	\$ 251	\$ 251
2	\$ 326.80	\$ 250.57	\$ 250.57	\$ 250.57	\$ 250.57
3	\$ 326.57	\$ 326.80	\$ 250.40	\$ 250.40	\$ 250.40
4	\$ 326.35	\$ 326.57	\$ 250.23	\$ 250.23	\$ 250.23
5	\$ 326.12	\$ 326.35	\$ 326.35	\$ 250.05	\$ 250.05
6	\$ 325.90	\$ 326.12	\$ 326.12	\$ 249.88	\$ 249.88
7	\$ 325.68	\$ 325.90	\$ 325.90	\$ 325.90	\$ 249.71
8	\$ 325.46	\$ 325.68	\$ 325.68	\$ 325.68	\$ 249.54
9	\$ 325.23	\$ 325.46	\$ 325.46	\$ 325.46	\$ 325.46
10	\$ 325.01	\$ 325.23	\$ 325.23	\$ 325.23	\$ 325.23
11	\$ 324.79	\$ 325.01	\$ 325.01	\$ 325.01	\$ 325.01
12	\$ 324.56	\$ 324.79	\$ 324.79	\$ 324.79	\$ 324.79
13	\$ 324.34	\$ 324.56	\$ 324.56	\$ 324.56	\$ 324.56

Appendix 5

Detailed simulation of economics aspects using field data.

Table 11. Rate calculation in case of no EDH installed. The results shown are truncated for 1st to 13th day at Well #1 to #5. The computation of rate at t days is following Eq. 15 with rate adjustment. Units are in bopd. Rate at 7.3 bopd is field observation data.

Well #	1	2	3	4	5
Days					
1	7.3	7.3	7.3	7.3	7.3
2	7.295	7.295	7.295	7.295	7.295
3	7.290	7.290	7.290	7.290	7.290
4	7.285	7.285	7.285	7.285	7.285
5	7.280	7.280	7.280	7.280	7.280
6	7.275	7.275	7.275	7.275	7.275
7	7.270	7.270	7.270	7.270	7.270
8	7.265	7.265	7.265	7.265	7.265
9	7.260	7.260	7.260	7.260	7.260
10	7.255	7.255	7.255	7.255	7.255
11	7.250	7.250	7.250	7.250	7.250
12	7.245	7.245	7.245	7.245	7.245
13	7.240	7.240	7.240	7.240	7.240

Table 12. Rate calculation in case of installing EDH. The results shown are truncated for 1st to 13th day at Well #1 to #5. The computation of rate at t days is following Eq. 17 with rate adjustments. Units are in bopd. The highlighted yellow means the effect of EDH performance i.e. bounced back at 12.2/7.3 ratio (field observation data). It is assumed to take 1 day rig moving and 1 day installation.

Well #	1	2	3	4	5
Days					
1	12.2	7.3	7.3	7.3	7.3
2	12.192	7.295	7.295	7.295	7.295
3	12.183	12.192	7.290	7.290	7.290
4	12.175	12.183	7.285	7.285	7.285
5	12.167	12.175	12.175	7.280	7.280
6	12.158	12.167	12.167	7.275	7.275
7	12.150	12.158	12.158	12.158	7.270
8	12.142	12.150	12.150	12.150	7.265
9	12.133	12.142	12.142	12.142	12.142
10	12.125	12.133	12.133	12.133	12.133
11	12.117	12.125	12.125	12.125	12.125
12	12.108	12.117	12.117	12.117	12.117
13	12.100	12.108	12.108	12.108	12.108

Table 13. Daily profit calculation in case of no EDH installed. The results shown are truncated for 1st to 13th day at Well #1 to #5. The computation of profit at t days is following Eq. 14 to 15 with some rate and x adjustments. Units are in USD. This computation is employing $x=40.5$ USD/bbl. This x value is derived from field observation data rate as presented in Figure 6. Calculating from Figure 6 using Eq. 12, $M_p=296$ USD is the maximum profit margin before installing EDH.

Well #	1	2	3	4	5
Days					
1	\$ 296	\$ 296	\$ 296	\$ 296	\$ 296
2	\$ 295.45	\$ 295.45	\$ 295.45	\$ 295.45	\$ 295.45
3	\$ 295.25	\$ 295.25	\$ 295.25	\$ 295.25	\$ 295.25
4	\$ 295.04	\$ 295.04	\$ 295.04	\$ 295.04	\$ 295.04
5	\$ 294.84	\$ 294.84	\$ 294.84	\$ 294.84	\$ 294.84
6	\$ 294.64	\$ 294.64	\$ 294.64	\$ 294.64	\$ 294.64
7	\$ 294.44	\$ 294.44	\$ 294.44	\$ 294.44	\$ 294.44
8	\$ 294.24	\$ 294.24	\$ 294.24	\$ 294.24	\$ 294.24
9	\$ 294.03	\$ 294.03	\$ 294.03	\$ 294.03	\$ 294.03
10	\$ 293.83	\$ 293.83	\$ 293.83	\$ 293.83	\$ 293.83
11	\$ 293.63	\$ 293.63	\$ 293.63	\$ 293.63	\$ 293.63
12	\$ 293.43	\$ 293.43	\$ 293.43	\$ 293.43	\$ 293.43
13	\$ 293.23	\$ 293.23	\$ 293.23	\$ 293.23	\$ 293.23

Table 14. Daily profit calculation in case of installing EDH. The results shown are truncated for 1st to 13th day at Well #1 to #5. The computation of profit at t days is following Eq. 16 through 18. Units are in USD. Since the yellow highlighted cells and below, the computation uses $x=41.9$ USD/bbl. The green highlighted cells are employing $x=40.5$ USD/bbl. Both these x value are derived from field observation data rate as presented in Figure 6. Calculating from Figure 6 using Eq. 12, $M_p=296$ USD is the maximum profit margin before installing EDH and $M_p=511$ USD is the maximum profit margin after installing EDH.

Well #	1	2	3	4	5
Days					
1	\$ 511	\$ 296	\$ 296	\$ 296	\$ 296
2	\$ 510.83	\$ 295.45	\$ 295.45	\$ 295.45	\$ 295.45
3	\$ 510.48	\$ 510.83	\$ 295.25	\$ 295.25	\$ 295.25
4	\$ 510.13	\$ 510.48	\$ 295.04	\$ 295.04	\$ 295.04
5	\$ 509.78	\$ 510.13	\$ 510.13	\$ 294.84	\$ 294.84
6	\$ 509.43	\$ 509.78	\$ 509.78	\$ 294.64	\$ 294.64
7	\$ 509.08	\$ 509.43	\$ 509.43	\$ 509.43	\$ 294.44
8	\$ 508.73	\$ 509.08	\$ 509.08	\$ 509.08	\$ 294.24
9	\$ 508.39	\$ 508.73	\$ 508.73	\$ 508.73	\$ 508.73
10	\$ 508.04	\$ 508.39	\$ 508.39	\$ 508.39	\$ 508.39
11	\$ 507.69	\$ 508.04	\$ 508.04	\$ 508.04	\$ 508.04
12	\$ 507.34	\$ 507.69	\$ 507.69	\$ 507.69	\$ 507.69
13	\$ 506.99	\$ 507.34	\$ 507.34	\$ 507.34	\$ 507.34