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Optimization of Reservoir Shrinkage Volumes: Laboratory and Field Results

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Abstract

This paper reviews a technique to enhance the value of existing oil fields by optimizing the operating temperature and pressure of the surface processing facilities (batteries). Incremental value is added by reducing the shrinkage volume and density of the stock tank oil, which is offset to some extent by reduced gas production volumes and heat content. Improved laboratory equipment and procedures were assembled to model multi-stage separation systems. The experimental and theoretical results determined the optimum operating conditions and an economic evaluation was done which identified outstanding potential economic returns. A post mortem evaluation indicated that the project has performed as expected, with significant increases in both incremental cash flow and field value.

Introduction

With increasing economic pressures placed on the upstream oil industry, one must take advantage of every means possible to extract the greatest economic value from existing oil fields. One prospective means of doing so, where oil shrinkage volumes are reduced by modifying surface facility temperatures and pressures, may hold considerable promise. This method applies best to conventional and light oils with an API gravity of at least 35°.

Background

An obvious method of increasing revenues from an oil-producing property is to maximize the sales liquid volumes and minimize the sales liquid density (while maintaining the appropriate RVP criterion) with respect to unit volume of reservoir fluid produced at the well head. The lighter the oil the more sensitive the oil's shrinkage response will be to the conditions chosen between the well head and the stock tank. For some oils the volume may only shrink by 1% in travelling through the separator train to the stock tank. For lighter oils, however, the shrinkage may be more than 10% and therefore considerable revenue could be realized if this shrinkage could be reduced. Figure 1 shows a typical separation train. For mature waterfloods and miscible floods, the conditions of the Inlet Surge Vessel are usually determined by the volume of fluids being produced since the temperature, in particular, is very difficult to change due to the large volume of water being produced and its relatively high heat capacity. Pressures are more easy to modify but their impact on volumes is usually less important than temperature. In combination, the two may act synergistically however, resulting in considerable shrinkage changes.

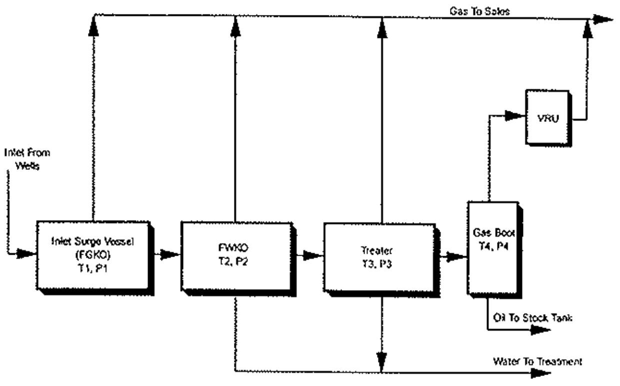

FIGURE 1: Typical surface processing operations.

Two oil systems have been tested in the laboratory using specially designed equipment to measure accurate phase volumes. This will be reviewed in detail along with all the experimental data generated. The scheme was then implemented in the field and detailed economic analyses were performed to determine the impact on cashflow and field net present value.

Laboratory Testing

Figure 2 provides a schematic diagram of the pressure cells used most commonly to measure PVT behaviour of petroleum fluids. The cell is a Ruska-type visual cell with an internal diameter of approximately 3.6 cm (1.4 inches) and a length of about 10 cm (4 inches). With these dimensions, every cm travelled up the cell equates to a volume of about 10.2 cm^3 or every mm travelled corresponds to just over 1 cm^3. This is one deficiency of the cell – the volumes cannot be measured accurately enough using standard techniques such as a cathetometer (telescope with cross hairs mounted on a potentiometer which reads mm travelled). The minimum error associated with reading interfaces is about 1 to 2 mm; a combination of interface curvature and inherent "thickness" of the interface tend to obscure the readings. Therefore if one has a maximum operating volume of about 75 to 80 cm^3 and one can only read interface levels to within 2 mm accurately then the associated error is 2/80 or 2.5 volume %. Most of the time the total volume used is 40 cc (due to the need to cycle gas and to allow for expansion of the total volume due to escaping gas upon depressurization) and therefore the error, at best, is 5 volume %. This inaccuracy, when measuring shrinkage, is large since changes of

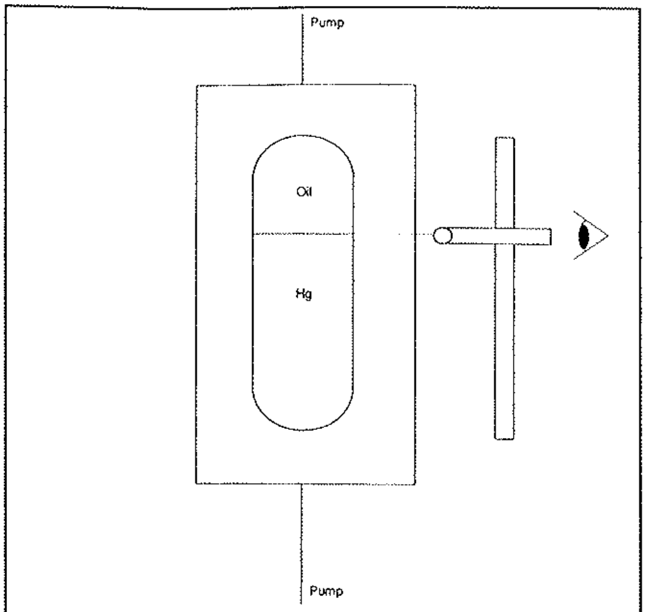

FIGURE 2: Standard PVT equipment.

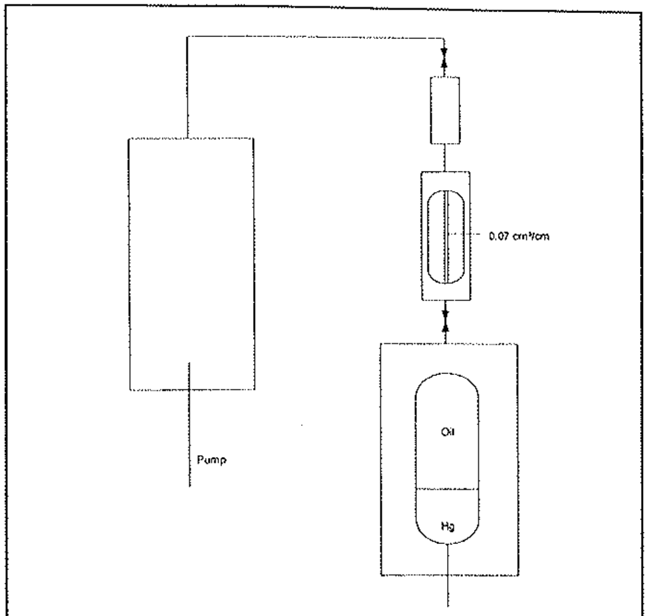

FIGURE 3: Modified PVT equipment.

process conditions may only alter the resulting shrinkage by a maximum of 3.5 to 4% (less for lower GOR oils and more for lighter oils). Therefore standard laboratory techniques cannot be used to examine the impact of separator conditions on shrinkage. The following design was therefore implemented.

Figure 3 shows the modified equipment used for this testing. The main advantage of using this new system is that the accuracy has been improved by about 10 times. The new system relies upon the measurement of the volumes with an additional cell. By watching interfaces in the capillary tube mounted above the visual cell instead of the visual cell directly the volumes can be read to 0.10 cm x 0.07 cm³ / cm or 0.007 cm³. Therefore the limiting factor is the pump reading at ±0.02 cc. The procedure used was the following:

1. Charge the cell with oil at reference temperature and pressure.

TABLE 1: Composition analysis – Oil #1.

Component	Inlet Surge Oil	Inlet Surge Gas	Process Boot
N_2	0.0010	0.0159	0.0268
CO_2	0.0013	0.0200	0.0074
H_2S	–	–	–
C_1	0.0057	0.3065	0.0422
C_2	0.0665	0.4856	0.4027
C_3	0.0394	0.1062	0.2379
i-C_4	0.0113	0.0142	0.0503
n-C_4	0.0312	0.0308	0.1326
i-C_5	0.0159	0.0066	0.0351
n-C_5	0.0232	0.0076	0.0422
C_6	0.0390	0.0066	0.0229
C_7	0.0534	–	–
C_8	0.0814	–	–
C_9	0.0417	–	–
C_{10}	0.0538	–	–
C_{11}^+	0.5352	–	–
GOR (m^3/m^3)	10.8	–	–
MW	182.53	29.7	42.5

TABLE 2: Detailed summary of shrinkage results – Oil #1.

Stage # **	Run #1 (current conditions)		Run #2		Run #3		Run #4	
	T(°C), P(kPag)	Cuml Oil Volume Shrinkage %*	T(°C), P(kPag)	Cuml Oil Volume Shrinkage %*	T(°C), P(kPag)	Cuml Oil Volume Shrinkage %*	T(°C),P(kPag)	Cuml Oil Volume Shrinkage %*
1 - FWKO	59, 516	–	59, 516	–	59, 516	–	59, 516	–
2 - Treater	57, 378	3.58	30, 250	4.24	30, 250 ***30, 250	4.20 6.56	33, 516 33, 516	3.20 2.48
3 - Gas Boot	50, 15.0	6.45	26, 15.0	5.04	26, 15.0	5.52	30, 304 26, 15.0	3.16 6.08
4 - Tanks	24.5, 0.0	9.19	24.5, 0.0	6.20	24.5, 0.0	6.84	24.5, 0.0	8.28
Contract Conditions	15.5, 0.0	9.87	15.5, 0.0	3.31	15.5, 0.0	7.52	15.5, 0.0	8.72
STO Density (kg/m^3)	828 (39.4 API)		827 (39.6 API)		826 (39.8 API)		825 (40.0 API)	
GOR								

* % shrinkage is defined as, $\left[\frac{(\text{oil volume reference} - \text{oil volume at stage})}{\text{oil volume reference}}\right] \times 100\%$ where oil volume reference corresponds to the oil volume at FWKO conditions

** Stage 1 is inlet surge vessel
Stage 2 is treater, stage 3 is gas boot and stage 4 is to tanks

*** Indicates multicontact operation of inlet surge gas with oil at this stage

TABLE 3: Compositional analysis – Oil #2.

Component	Inlet Surge Oil	Inlet Surge Gas	Process Boot
N_2	0.0029	0.0258	0.0033
CO_2	0.0006	0.0185	0.0057
H_2S	--	--	--
C_1	0.0044	0.3246	0.0677
C_2	0.0734	0.4393	0.4060
C_3	0.0360	0.1116	0.2299
$i\text{-}C_4$	0.0109	0.0155	0.0474
$n\text{-}C_4$	0.0344	0.0370	0.1267
$i\text{-}C_5$	0.0170	0.0081	0.0331
$n\text{-}C_5$	0.0255	0.0095	0.0405
C_6	0.0398	0.0102	0.0398
C_7	0.0812	--	--
C_8	0.0522	--	--
C_9	0.0392	--	--
C_{10}	0.0489	--	--
$C_{11}{}'$	0.5836	--	--
GOR (m^3/m^3)	11.1	--	--
MW	177.7	30.07	42.6

2. Measure the volume exactly by pushing all the oil at pressure up into the capillary cell. An interface level (equilibrium gas/oil) is read in the capillary tube and the pump reading is recorded. The pump is engaged and all fluid displaced upward until the oil/mercury interface is observed in the capillary tube. The difference in interface location is recorded (gas/oil vs. oil/Hg) and corrected with 0.07 cc/cm cell constant and the pump readings used to calculate the volumes.
3. The fluid is then flowed back into the lower cell and the pressure and temperature altered.
4. Measurement after each stage is made in the same manner.
5. This is continued for as many temperature and pressure stages as required.
6. The same procedure can then be applied to as many oils as desired or to as many different sets of conditions.

Experimental Results

The equipment was used to analyse shrinkage effects on two oil samples. Table 1 presents the compositional analysis of the separator gas and oil for sample #1, and Table 2 presents a detailed summary of these results. The maximum shrinkage measured was 9.87% (which modelled the existing facility operating conditions) while the minimum was 6.56% (run #2). The second test was repeated and the relative error was approximately 1.5% due to wetting effects of the tubing and cylinders involved in the experimental apparatus. This is still significantly better than the 5% error which was associated with standard techniques (one trial was done using conventional measurement and about 15% shrinkage was observed). Analysis of the data indicates the following trends:

TABLE 5: Detailed summary of shrinkage results – Oil #1.

	Shrinkage %			
	Run #1	Run #2	Run #3	Run #4
Experimental	9.87	6.56	7.52	8.72
Theoretical	8.52	7.12	7.26	

1. Treater temperature is a strong determinant in shrinkage reduction.
2. The treater temperature reduction combined with higher pressure tends to reduce shrinkage even more.
3. Reduced gas boot temperature improved shrinkage losses. No pressure changes were implemented in the gas boot.
4. Gas cycling operations are extremely sensitive to cycling pressure and temperature but seem to provide improvement in oil gravity and not shrinkage (run #3 showed some foaming behaviour upon depletion to 16°C and 15 kPag – was not quite equilibrated when the volume was measured). Cycling operations may be effective in some applications but are strongly motivated by the gas compositions available and the conditions at which cycling is implemented. At sufficiently high pressure 516 kPag, as opposed to 250 kPag (in test #3), the cycling swelled the oil but upon subsequent depressurization the oil shrunk even more than in tests #2 and #3.

The error was 1.5% as mentioned before but this was based on 25 cc of total oil volume. With the inherent inaccuracies of the conventional techniques it would have been about 2/25 or 8%. This represented sufficiently accurate data that it was concluded that these trends should be investigated on another oil system.

Table 3 presents the compositions of fluids from oil sample #2 and this was tested for shrinkage in the same equipment. Table 4 details these results. A repeat run was also performed here and the relative error was 0.71% or 0.18 cc absolute volume. In this sequence again a dominant feature was the temperature of the second stage. Thirty degrees Celsius reduced the volatility and some of the components tended to remain in the liquid phase throughout the procedure. The oil density was also decreased from 830 to 823 kg/m^3.

Theoretical Analysis

The permutations of the separator train conditions are too plentiful to perform experimental tests on each one. Therefore an EOS was tuned to the experimental data of Table 2. The

TABLE 4: Detailed summary of shrinkage results – Oil #2.

Stage #	1		2		3	
	T(°C), P(kPag)	Cuml Oil Volume Shrinkage %*	T(°C), P(kPag)	Cuml Oil Volume Shrinkage %*	T(°C), P(kPag)	Cuml Oil Volume Shrinkage %*
1 - FWKO	59, 516	--	59, 516	--	59, 516	--
2 - Treater	57, 378	3.04	30, 250	1.96	57, 378	2.64
3 - Gas Boot	50, 15.0	5.96	26, 15.0	2.36	26, 15.0	4.16
4 - Tanks	24.5, 0.0	7.56	24.5, 0.0	4.12	24.5, 0.0	7.60
Contract Conditions	15.5, 0.0	8.24	15.5, 0.0	4.80	15.5, 0.0	8.28
STO Density (kg/m^3)	830 (139.0°API)		823 (40.4° API)		829 (39.2° API)	

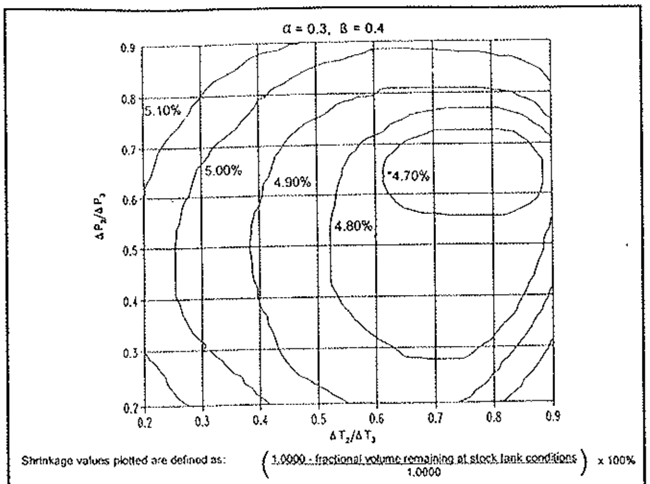

FIGURE 4: EOS shrinkage contour plots as a function of pressure and temperature ratios – Oil #1.

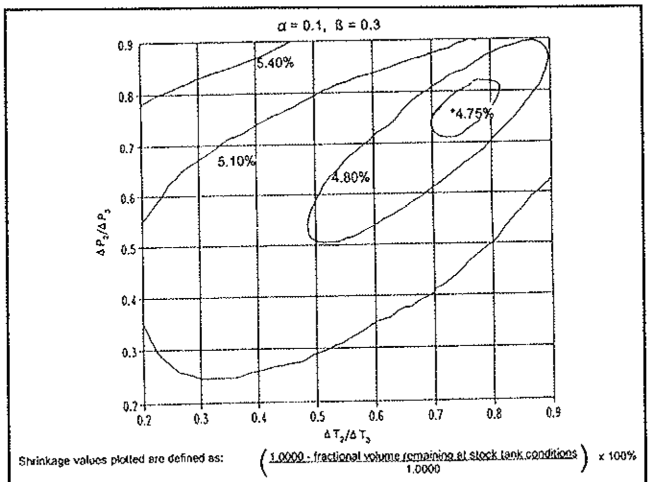

FIGURE 5: EOS shrinkage contour plots as a function of pressure and temperature ratios – Oil #1.

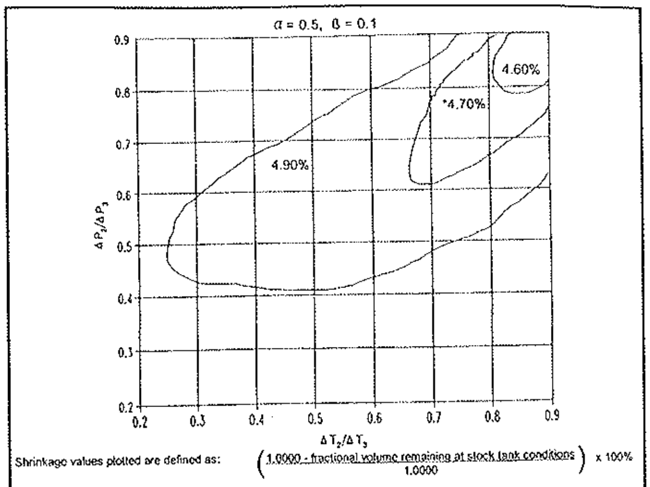

FIGURE 6: EOS shrinkage contour plots as a function of pressure and temperature ratios – Oil #1.

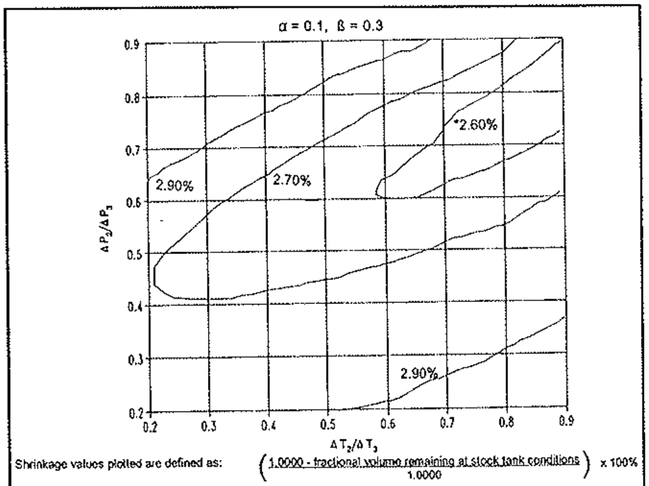

FIGURE 7: EOS shrinkage contour plots as a function of pressure and temperature ratios – heavier, lower GOR oil.

experimental/theoretical comparison is shown in Table 5. The absolute values were not as close as would be possible if volume translation techniques were to be invoked(1). However the relative volumetric changes were representative. Using the EOS, tuned to the experimental data, a number of other parametric runs were performed to determine trends: shrinkage as a function of temperature and pressure of the different unit operations. To be able to portray these trends in a contour plot the pressure and temperature variables were put into dimensionless form, where the maximum temperature (T_1) was that of the current field operating FGKO (59°C – 108.2°F) and the maximum pressure (P_1) was 517 kPag (75 psig). Standard conditions of 15.5°C and 101.325 kPa were the lowest temperature and pressure respectively (T_a, P_a).

Unit	Stage	Pressure	Temperature
FGKO	1	P_1	T_1
Treater	2	P_2	T_2
Gas Boot	3	P_3	T_3
Stock Tank	Stock Tank	P_a	T_a

Define the variables for plotting as

$$\Delta P_{max} = P_1 - P_{a'}, \quad \Delta T_{max} = T_1 - T_a \qquad (2)$$

To generate contour plots as a function of the different temperatures and pressures of the unit operations one must specify

$$P_3 = \alpha \Delta P_{max} + P_a \qquad (3)$$

$$T_3 = \beta \Delta T_{max} + T_a \qquad (4)$$

then

$$\frac{\Delta T_2}{\Delta T_3} = \frac{T_1 - T_2}{T_1 - T_3} \qquad (5)$$

$$\frac{\Delta P_2}{\Delta P_3} = \frac{P_1 - P_2}{P_1 - P_3} \qquad (6)$$

Therefore as $\Delta T_2/\Delta T_3 \rightarrow 1$ $T_2 \rightarrow T_3$ or the treater temperature approaches the gas boot temperature which is defined in Equation (4) by the value of β. So as β is lower, and $\Delta T_2/\Delta T_3$ is larger, the lower the treater temperature. The analogous discussion for pressure is also implicit. Figures 4 through 6 present contour plots for different α, β values. Figure 4 describes the scenario when $\alpha = 0.30$ and $\beta = 0.40$; Gas Boot temperature and pressure are 32.9°C and 155 kPag respectively. Therefore as $\Delta T_2/\Delta T_3$ and $\Delta P_2/\Delta P_3 \rightarrow 1$ the treater temperature approaches 32.9°C and the treater pressure approaches 155.1 kPag according to the numbers given in Table 2. The shrinkage values (predicted) are only different by 0.4% in Figure 4 but the least shrinkage (0.953) is toward the 0.65 to 0.85 $\Delta T_2/\Delta T_3$ region and in the $\Delta P_2/\Delta P_3$ axis between 0.55 to 0.75. Intuitively one may think that a $\Delta T_2/\Delta T_3$ of 1 would be the best since it would correspond to the lowest temperature and therefore the volatility of the components would be minimized. This would be true, however the minimum pressure is lim-

TABLE 6: Economic evaluation based on experimental results – Oil #1, Run #2.

Assumptions:		Before Coolers	After Coolers		
	Oil Volumes	2,000	2,069	m^3/d	3.44% increase
	Production Decline	5%	5%	per year	
	Gas-Oil Ratio	350	329	m^3/m^3	
	Oil Royalty Rate	29%	29%		
	Gas Royalty Rate	20%	20%		
	Variable Gas Processing Cost	$5.50	$5.50	per E^3/m^3	
	Oil Density	828	827	kg/m^3	
	Oil Price	$150.00	$150.16	per m^3	
	Raw Gas Price	$100.00	$99.83	per Em^3	
	Laboratory PVT Studies		$5,000		
	Capital Cost of Coolers	0	$100,000		
	Operating Cost of Coolers	0	$400	per month	

$$275 \quad \frac{m^3 \text{ reduction in gas}}{m^3 \text{ increase in oil}}$$

Incremental Cash Flow (1000$)

Year	Oil Revenue		Gas Revenue	Royalties		Operating Costs		Capital	Cash Flow	PV Cash Flow (12% DCF)
	Volume Increase	Density Adjustment		Oil	Gas	Oil	Gas			
1	3,767	117	(734)	1,092	(147)	10	(38)	100	2,132	2,132
2	3,578	111	(697)	1,038	(129)	5	(36)	0	2,125	1,898
3	3,400	105	(663)	986	(133)	4	(34)	0	2,019	1,609
4	3,230	100	(629)	937	(126)	4	(33)	0	1,918	1,366
5	3,068	95	(598)	890	(120)	4	(31)	0	1,822	1,159
Total	17,042	528	(3,321)	4,942	(664)	27	(172)	100	10,017	8,164

ited to 155 kPag and therefore the pressure driving force is still substantial downstream of the treater. Therefore the treater temperature lower than about 36°C ($\Delta T_2/\Delta T_3$ of > 0.88) is counter effective. If the pressure had been lower (smaller α) then the optimal $\Delta T_2/\Delta T_3$ ratio would have been higher. Figure 5 shows the same relationship but with smaller α. The best shrinkage response occurs at higher $\Delta T_2/\Delta T_3$ ratio. Comparing Figures 5 and 4 shows that an α of 0.3 provides a better shrinkage value than $\alpha = 0.10$ even though the temperature is lower in the latter case ($\beta = 0.3$ instead of 0.40). Figure 6 provides a similar comparison which states that as one depressurizes and cools very quickly the optimal $\Delta T_2/\Delta T_3$ and $\Delta P_2/\Delta P_3$ ratios are in the 0.85 to 1 region. The upshot of this is that if the treater pressure for this oil is higher ($\alpha > 0.10$) then the treater temperature does not have to be lower than 40°C; the pressure is still high enough that the pressure will drive the gas off upon further reduction no matter what the treater temperature. The same can be generated for other α and β values.

Figure 7 shows the same for a heavier oil and the overall shrinkage was less as well as the dependence on unit conditions. The same was also observed for a very light oil where overall shrinkage was on the order of 7%. It must be emphasized that each shrinkage optimization analysis is unique for each oil and that to best exploit this application, the oils should be examined specifically.

TABLE 7: Economic evaluation based on experimental results – Oil #1, Run #2.

Assumptions:		Before Coolers	After Coolers		
	Oil Volumes	2,000	2,028	m^3/d	1.40% increase
	Production Decline	5%	5%	per year	
	Gas-Oil Ratio	350	341	m^3/m^3	
	Oil Royalty Rate	29%	29%		
	Gas Royalty Rate	20%	20%		
	Variable Gas Processing Cost	$5.50	$5.50	per E^3/m^3	
	Oil Density	828	823	kg/m^3	
	Oil Price	$150.00	$150.48	per m^3	
	Raw Gas Price	$100.00	$99.83	per Em^3	
	Laboratory PVT Studies		$5,000		
	Capital Cost of Coolers	0	$100,000		
	Operating Cost of Coolers	0	$400	per month	

$$275 \quad \frac{m^3 \text{ reduction in gas}}{m^3 \text{ increase in oil}}$$

Incremental Cash Flow (1000$)

Year	Oil Revenue		Gas Revenue	Royalties		Operating Costs		Capital	Cash Flow	PV Cash Flow (12% DCF)
	Volume Increase	Density Adjustment		Oil	Gas	Oil	Gas			
1	1,533	350	(325)	445	(65)	10	(15)	100	1,084	1,084
2	1,456	333	(309)	422	(62)	5	(15)	0	1,130	1,009
3	1,384	316	(294)	401	(59)	4	(14)	0	1,073	855
4	1,314	300	(279)	381	(56)	4	(13)	0	1,020	726
5	1,249	285	(265)	362	(53)	4	(13)	0	969	616
Total	6,936	1,585	(1,472)	2,011	(294)	27	(70)	100	5,276	4,291

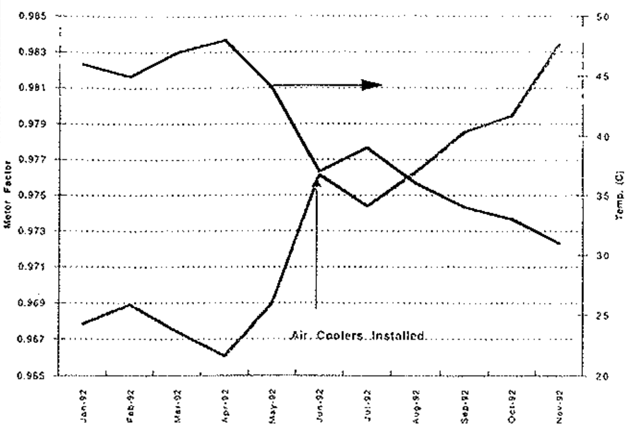

FIGURE 8: Oil #1 – sales oil meter data.

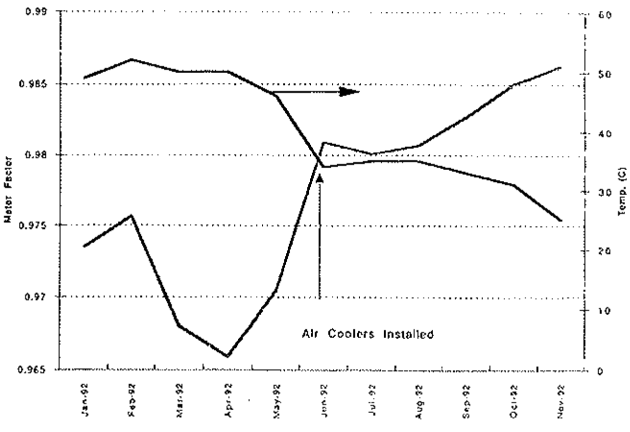

FIGURE 9: Oil #2 – sales oil meter data.

Economic Analysis

The experimental and theoretical results show the potential for increasing oil production volumes and reducing oil densities by modifying the processing temperatures and pressures in the battery. The costs involved would be the laboratory PVT studies, the capital and operating costs of Air Coolers and the reduction in gas revenues due to reduced gas production volumes and heat content. An economic evaluation was required to determine the potential economic gain of a project of this nature.

A detailed economic analysis was undertaken for one battery using: i) experimental results from run #2 of the tests performed on Oil #1 as shown in Table 2 and, ii) theoretical results as shown in Table 5. For run #2, the oil is cooled from 59°C to 30°C at approximately 250 kPag. The experimental results show the oil volumes will increase by 3.31% while the theoretical results indicate a 1.4% increase. The experimental results show the oil density reduced from 828 to 827 kg/m^3 while the theoretical results indicate a 828 to 823 kg/m^3 reduction. Further EOS modelling indicated that the gas production is reduced by 275 m^3 for every m^3 increase in oil volumes. The assumptions used in the economic runs, along with a five year cash flow projection, are shown in Table 6 (experimental results) and Table 7 (theoretical results). The following points are noted:

Oil Densities:

- a reduction of \$0.16/m^3 is factored into the oil price for every kg/m^3 of crude oil density in excess of 825 kg/m^3, up to 875 kg/m^3 (2).
- the increase in price is applied to all production from the battery.
- oil royalties do not increase because royalty rates are calculated using par prices and paid in kind.

Oil Volumes:

- increasing the oil volume after the treater does not increase battery operating costs.
- incremental oil royalties must be paid.

Gas Volumes:

- reduced gas volumes result in lower gas revenues, royalties and gas processing costs.

Air Coolers:

- laboratory PVT work estimated to be \$5000, installed capital cost estimated at \$100,000, operating costs (power to operate fans) estimated at \$400/month.

The results show a potential increase in before tax cash flow of some \$2.1 million/year using the experimental results and \$1.1 million/year using the theoretical results. The experimental results (Table 6) show dramatically higher incremental oil revenues than the theoretical results (Table 7) due to the larger volume increase, which is offset to some extent by the smaller density adjustment.

The economic results for Oil #2 were very similar to Oil #1. It should be noted, however, that the experimental results on Oil #2 showed an oil density reduction of 830 - 823 kg/m^3.

The main conclusion that can be drawn from the economic analysis is that the lighter components of the oil are more valuable in solution with the oil than as a gas. The reasons for this are the relative prices of oil and gas, gas fuel/flare losses and the costs of transporting and processing gas. The major reason however, is the relative prices of oil and gas. For oil priced at \$150/m^3 with a heating value of 33.5 GJ/m^3, the gas equivalent value would be \$4.48/GJ. Natural gas typically sells in the \$1.00 - \$1.50/GJ range.

Field Case Implementation

Air Coolers were installed in the batteries representing Oils #1 and #2 in the summer of 1992. The optimum physical location of the coolers based on the experimental results would be just before the treater. However, due to concerns over the treater separation efficiency at lower temperatures and the possibility of wax/asphaltene precipitation, the coolers were placed after the treater, but before the pressure control valve. Therefore, the pressure at which the oil is cooled in the field installations is just slightly less than the operating pressure of the treater (350 kPa).

With almost 6 months of data since the coolers were installed, a post mortem evaluation of the effectiveness of air coolers was done. In summary, the following was noted;

Oil and Gas Volumes

It was not possible to directly measure the increased oil volumes and reduced gas volumes through the battery as a result of cooling. The measurement accuracy of the oil, gas and water volumes into the battery and the normal daily fluctuations in field production volumes made it extremely difficult to identify the small volume changes (+3% for oil, -%5 for gas) due to reduced oil shrinkage. However, it was possible to track the factors applied by the pipeline company to the metered sales oil volumes to derive the actual sales volumes on which revenue is paid. The meter factor is predominantly a correction factor to reflect the fact that the sales oil is not shipped to the pipeline company at contract sales temperature (15°C). The calculation of the factor is taken from Tables 53A and 54A of the "Manual of Petroleum Measurement Standards, Chapter 12 – Calculation of Petroleum Quantities" published by the American Petroleum Institute. A summary of the required calculations, before and after coolers, is given below.

	As Is	**After Cooling**
Sales Oil Temperature (°C)	50	30
Sales Oil Pressure (kPag)	0	0
Measured Density	804	804
Density @ 15°C (Table 53A)	829	823
Density Price Adjustment	(\$0.64/m^3)	0
Volume Correction to 15°C (Table 54A)	0.9689	0.98635

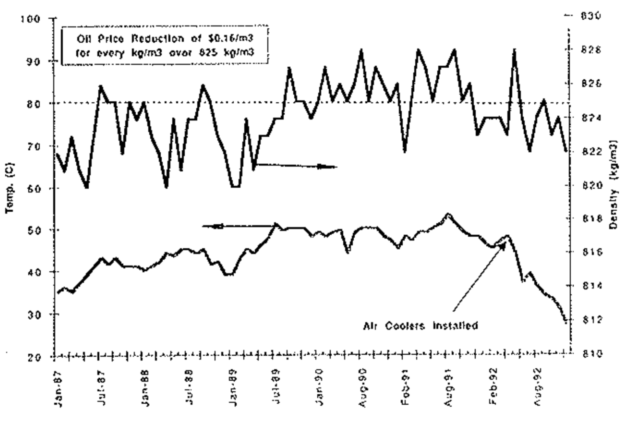

FIGURE 10: Oil #1 – sales oil temperature and density.

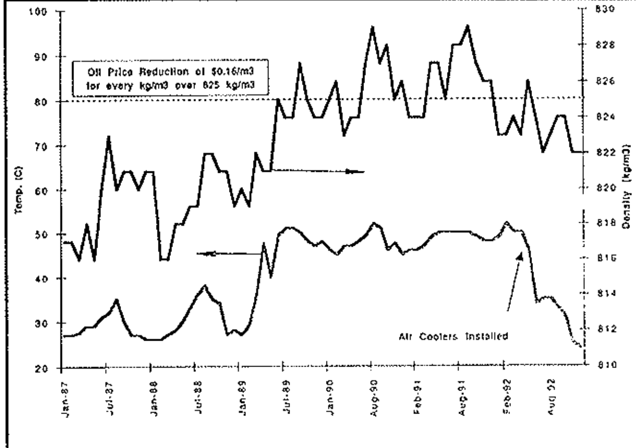

FIGURE 11: Oil #2 – sales oil temperature and density.

A plot of the meter factor and sales oil temperature with time are shown for Oil #1 (Figure 8) and Oil #2 (Figure 9). As the sales oil temperature was decreased, the meter factor increased as predicted above.

Oil Density

The plot of sales oil density and temperature with time are shown for Oil #1 (Figure 10) and Oil #2 (Figure 11). It is noted that temperature and density are on increasing trend with time. The main reason for increasing facility operating temperature is the increase in the volume of water produced and then re-injecting it into the field. The variation in temperature and density follows the seasons, with higher values in summer and lower values in winter. With the installation of the coolers in the middle of 1992, the sales oil temperature and density dropped dramatically. If the oil temperature can be kept below 30°C, it seems very unlikely that the oil density will exceed 825 kg/m^3 and invoke the density price penalty ($0.16/m^3 per kg/m^3 over 825 kg/m^3). If the density adjustment was the only change to occur (no volume change), it is estimated that the before tax cash flow would increase by approximately $300,000 per year. However, because the oil density reduction matched the experimental and theoretical predictions, the light ends of the oil must have been prevented from flashing off into the gas stream by the installation of air coolers. If that mass transfer did not occur, it seems reasonable to assume that the oil volume shrinkage was also reduced as predicted by experimental and theoretical analysis.

Conclusions

1. Equipment has been modified to provide more accurate shrinkage measurements.
2. Differences in shrinkage as a function of separator train pressure and temperature have been measured to be as high as 3.31 and 3.44 volume % for two different oils.
3. For the oils used herein, gas cycling to minimize shrinkage in the separation process did not appear to be very effective.
4. The data were matched with an EOS and trends were then inferred from many theoretical calculations. The lower the treater pressure the greater the effect of temperature on reducing shrinkage.
5. Due to the complexity of the different oil/gas mixtures shrinkage optimization must be performed on every oil that shows promise.
6. In general, oils with an API greater than 30° are candidates for shrinkage optimization efforts.
7. The lighter components of the oil are more valuable in solution with the oil than as a gas.
8. For large batteries, significant increases in cash flow and field net present value can be achieved by the optimization of facility operating conditions.
9. The reduction in oil density was the only evidence that could be found to verify the process in the field.

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Brent Thomas holds a doctorate in Chemical Engineering. He has worked on enhanced oil recovery applications for the last yen years, including gas injection, chemical flooding, solids precipitation and thermal applications. He is presently Vice President of Hycal Energy research Laboratories Ltd.

Xue Zhou Long obtained a B.Sc. in Petroleum Engineering from East China Petroleum Institute in Shangdon Province in 1983. Since that time he has worked in the area of PVT analysis (both experimentally and theoretically). Since 1991 he has been involved in research and development related to fluid phase flow, multi phase equilibria, and EOS modelling. He is presently completing the requirements for his Master of Science degree from the faculty of Chemical and Petroleum Engineering at the University of Calgary.