Consideration of Retrograde Loss in Determining the Optimum Economic Operation of a Gas Condensate Reservoir

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Many reservoirs which are classified as gas reservoirs produce both gas and liquid as the well stream is produced through conventional separation equipment at the surface. These reservoirs may be either wet gas reservoirs or retrograde condensate reservoirs. Both types of reservoirs exist in the ground in the gaseous phase and produce both gas and liquid upon production to the surface. The difference between the two types is that a retrograde reservoir condenses liquid in the reservoir upon reduction in reservoir pressure, whereas, the wet gas reservoir remains in the vapor state in the reservoir throughout pressure depletion. This paper will be concerned only with retrograde condensate reservoirs.

It is not possible to distinguish a wet gas reservoir from a retrograde condensate reservoir from surface producing characteristics, such as gas-oil ratio, tank liquid gravity, etc. From a practical standpoint, however, it may be considered that any reservoir which produces condensate in excess of ten barrels per million cubic feet of separator gas will behave as a retrograde condensate reservoir. On the other extreme, retrograde condensate reservoirs may produce as much as 350 barrels or more of stock tank condensate per million cubic feet of separator gas.

In all but the very rich condensate reservoirs the liquid condensed in the reservoir cannot be produced under normal depletion conditions. In the very rich condensate reservoirs only a very small fraction of this liquid will be produced under depletion conditions. This retrograde liquid loss under extreme conditions may be as high as 75 to 80 per cent of the stock tank liquid originally in place. This loss will have a big effect on the economic projections of production from the reservoir.

A study will be described which will allow the reservoir engineer to determine the extent of the retrograde loss so that decisions may be made as to whether steps should be taken to prevent a loss in reservoir pressure, thus preventing retrograde loss. Data will be developed to determine the liquid and gas yield from the field for both pressure maintenance and pressure depletion conditions through any type of surface processing conditions.

In order to obtain reservoir fluid samples for PVT study, it is necessary to place the well on production and stabilize the production at a constant rate. The production rate will depend primarily on the capacity of the well and should be at a high enough rate to prevent slippage in the tubing. Excessively high production rates should be avoided so as not to create excessive pressure drawdown at the formation face. Once the well has been stabilized it should be tested at a constant rate for 24 hours minimum and preferably 48 to 72 hours. Short-duration tests should be avoided.

Mr. F. O. Reudelhuber discusses testing and sampling of condensate reservoirs in his paper "Separator Sampling of Gas Condensate Reservoirs".[1] It should be realized at this point that the accuracy of the PVT study to be performed and the accuracy of the production and economic projections made from the study depend entirely upon the accuracy of the gas-liquid ratio determination, and the quality of the samples. For this reason persons experienced in testing and sampling for PVT studies should be consulted.

Once the samples are received in the PVT laboratory, they should be physically recombined in the producing gas-liquid ratio after all efforts have been made to refine the producing gas-liquid ratio calculations to as high a degree as is possible.

The essential data to be developed in the fluid study are shown in Tables 1, 2, 3, 4 and 5. Table 1 shows the composition of the separator liquid and vapor and the composition of the reservoir fluid. In Table 2 is the relative volume of the reservoir fluid from reservoir pressure to some pressure approaching abandonment pressure. This includes a determination of the retrograde dew point. Also shown is the deviation factor of the reservoir fluid at the dew point pressure and higher.

The next step in the PVT study (Table 3) is to determine the composition and volume of the produced well stream at various reservoir pressures. The composition of the produced well stream at the original reservoir pressure of 5713 psig is identical to the composition at 4000 psig. The dew point of this reservoir is 4000 psig, and the composition of the produced well stream will not be affected by reservoir pressure except at pressures below the dew point. You will note in Table 3 that below the dew point the produced well stream loses a high percentage of the total pentanes plus as pressure is depleted. This is the effect of the retrograde condensation in the reservoir.

The next step in the laboratory study is to determine the amount of the retrograde condensation in the reservoir at reservoir temperature and various pressures. These data are illustrated in Table 4.

The final portion of the PVT study which should be performed is a calculation procedure. It is at this point that the PVT study may be tailored to fit the exact needs of the operator. The amount of sales gas and stock tank liquid recovered from a condensate reservoir is not only a function of the reservoir fluid composition but is also a function of how the well stream is processed at the surface. For the purposes of this illustration, it was assumed that three-stage separation was used at the wellhead at pressures of 500, 50 and 14.7 psia, all at 70° F. These conditions should be set at the conditions in use in the field or at conditions that the reservoir engineer might wish to evaluate.

A unit volume reservoir of 1000 MSCF of gas in place at the dew point pressure was chosen for the basis of these calculations. Using equilibrium ratios and the composition of a reservoir fluid at the dew point pressure, it was calculated that the unit volume reservoir contained 135.7 barrels of stock tank liquid, 757.87 MSCF of primary separator gas, 96.68 MSCF of second-stage gas, etc. See column 1 in Table 5.

Using the produced volume percentages measured during the depletion study, Table 3, the volumes of the produced well stream between pressure decrements were calculated. Using these volumes and their respective compositions, the amount of stock tank liquid which would be produced from this unit volume reservoir was calculated for each pressure decrement. The stock tank liquid production figures shown are cumulative. A total of 35.1 barrels of stock tank liquid is indicated to be produced at the abandonment pressure of 605 psig. This compares with the total of 135.7 barrels originally in place at the dew point pressure. The loss in stock tank liquid due to retrograde condensation is the difference between 135.7 barrels initially in place and 35.1 barrels produced to the abandonment pressure of 605 psig, or a total of 100.6 barrels. The calculations also show the recovery of primary separator gas, second-stage gas and stock tank gas as a function of reservoir pressure.

Recovery calculations for a depletion drive reservoir follow:

I. *HYDROCARBON PORE SPACE*

Given: Depletion drive reservoir	12,500	Acre-Feet
12,500 Acre-Feet	x 7758	Bbls/Acre-Foot
Porosity = 10%	x 0.10 x (1-0.30)	
Connate Water = 30%	= 6.788 (10^6)	Bbls of Hydrocarbon Pore Space

II. *CUMULATIVE RECOVERY*—Production by Expansion from Original Reservoir Pressure to the Dew Point Pressure. (Basis Two-Stage Separation at 500 psia and 50 psia at 70 degrees F.)

A. *In-Place Reserves at Original Reservoir Pressure (5713 psig)*

Well Stream (Obtain data from Table 2)	6.788 (10^6)	Bbls Pore Space
	x 1.591	MSCF Well Stream/Bbl Pore Space
	=10,800	MMSCF

Stock Tank Liquid (Factor obtained from Table 5 — tabulated under heading of "Initial in Place")	10,800	MMSCF Well Stream
	x 135.7	Bbls STO/MMSCF Well Stream
	=1,466,000	Bbls
Primary Separator Gas (Factor obtained from Table 5)	10,800	MMSCF Well Stream
	x 757.87	MSCF Sep. Gas/MMSCF Well Stream
	= 8185	MMSCF
Second Stage Separator Gas (Factor obtained from Table 5)	10,800	MMSCF of Well Stream
	x 96.68	MSCF Second Stage Gas/MMSCF Well Stream
	= 1044	MMSCF
B. *In-Place Reserves at Dew Point (4000 psig) Well Stream* (Obtained factor from Table 2)	$6.788\ (10^6)$	Bbls Pore Space
	x 1.424	MSCF Well Stream/Bbl Pore Space
	= 9666	MMSCF
Stock Tank Liquid (Factor obtained from Table 5)	9666	MMSCF Well Stream
	x 135.7	Bbls STO/MMSCF Well Stream
	= 1,312,000	Bbls
Primary Separator Gas (Factor obtained from Table 5)	9666	MMSCF Well Stream
	x 757.87	MSCF Sep. Gas/MMSCF Well Stream
	= 7326	MMSCF
Second Stage Separator Gas (Factor obtained from Table 5)	9666	MMSCF Well Stream
	x 96.68	MSCF Second Stage Gas/MMSCF Well Stream
	= 934	MMSCF
C. *Cumulative Recoveries at Dew Point Well Stream*	10,800	MMSCF in place @ 5713 psig
	-9666	MMSCF in place @ 4000 psig
	= 1134	MMSCF Produced
Stock Tank Liquid	1,466,000	Bbls in place @ 5713 psig
	- 1,312,000	Bbls in place @ 4000 psig
	= 154,000	Bbls Produced
Primary Separator Gas	8185	MMSCF in place @ 5713 psig
	- 7326	MMSCF in place @ 4000 psig
	= 859	MMSCF Produced
Second Stage Separator Gas	1044	MMSCF in place @ 5713 psig
	-934	MMSCF in place @ 4000 psig
	= 110	MMSCF Produced

III. CUMULATIVE RECOVERY — Production Below the Dew Point. (Basis Two-Stage Separation at 500 psia and 50 psia at 70 degrees F.)

Abandonment Pressure Assumed to be 605 psig

A. Well Stream in Place at Dew Point (4000 psig) = 9666 MMSCF

B. Cumulative Recoveries at 605 psig
(Recovery factors obtained from Table 5)

Stock Tank Liquid	9666	MMSCF Original Well Stream
	x 35.1	Bbls STO/MMSCF Original Well Stream
	= 339,000	Bbls
Primary Separator Gas	9666	MMSCF Original Well Stream
	x 685.02	MSCF Separator Gas/MMSCF Original Well Stream
	= 6621	MMSCF
Second Stage Separator Gas	9666	MMSCF
	x 37.79	MSCF Second Stage Separator Gas/MMSCF
	= 365	MMSCF

IV. TOTAL RECOVERABLE RESERVES — Basis Two-Stage Separation at 500 psia and 50 psia at 70 degrees F.

A. *Stock Tank Liquid*	Production to Dew Point	=	154,000 Bbls
	Production below Dew Point	=	339,000 Bbls
	Total	=	493,000 Bbls
B. *Primary Separator Gas*	Production to Dew Point	=	859 MMSCF
	Production below Dew Point	=	6621 MMSCF
	Total	=	7480 MMSCF
C. *Second Stage Separator Gas*	Production to Dew Point	=	110 MMSCF
	Production below Dew Point	=	365 MMSCF
	Total	=	475 MMSCF

The calculations indicate a total recovery of 493,000 barrels of stock tank condensate when the reservoir is produced from the original reservoir pressure to an abandonment pressure of 605 psig. This compares with an original in-place figure of 1,466,000 barrels of stock tank condensate or a recovery percentage of 33.6 per cent. Approximately two-thirds of the stock tank condensate originally in place was lost, due to retrograde condensation. It should be observed at this point that retrograde condensation was not a factor until the reservoir pressure reached 4000 psig. At that pressure the stock tank condensate in place was 1,312,000 barrels. It was at this point that retrograde condensation began to take its toll, and a recovery percentage below 4000 psig was only 25.8 per cent. The retrograde loss is 973,000 STB. The abandonment pressure chosen for these calculations is quite low for a reservoir with this original pressure. It is only necessary to point out at this point that had the abandonment pressure been raised to a higher pressure, the recovery would have been decreased.

Retrograde condensation can be prohibited by maintenance of the reservoir pressure at or above the dew point pressure. The most common method of pressure maintenance in a gas condensate reservoir is gas injection, commonly referred to as cycling. This process involves reinjection of produced gas, and usually additional make-up gas, to replace reservoir voidage. When the reservoir pressure is maintained at or above the dew point pressure, the producing gas-liquid ratio should remain at the original value until the injection gas breaks through to the producing wells. There will be no retrograde loss and the stock tank liquid recovery from the reservoir will be the total originally in place adjusted for the conformance factor and displacement efficiency. The conformance factor will depend largely upon reservoir characteristics, well placement, injection pattern and reservoir rock uniformity. The displacement efficiency of a gas displacing a gas condensate reservoir fluid will be high and will approach 100 per cent.

Assuming that the reservoir is pressure depleted from the original reservoir pressure to 4000 psig and pressure maintained at that point, and assuming a combination conformance and displacement efficiency factor of 70 per cent, the total condensate recovery would be 1,072,000 STB. This is a recovery percentage of 73.1 per cent and an increase of 579,000 STB over pressure depletion recovery.

The discussion to this point has been primarily concerned with the effect of retrograde condensation upon the production of stock tank liquid. Calculations have been presented to determine stock tank liquid recovery for both pressure depletion and pressure maintenance methods of operation. In an actual field problem it will probably be necessary to refine these calculations even further to include the plant products recoverable from the separator products. Note in Table 5 that the total plant products in terms of propane, butanes and pentanes-plus are furnished for the initial in-place situation as well as for the pressure depletion conditions. Calculations similar to those presented above can be made for the recovery of these products for both pressure depletion and pressure maintenance.

Under some conditions, it may be desirable to investigate the economics of dispensing with lease separation and processing the entire well stream through a plant. The figures at the bottom of Table 5 detail the plant products initially in place as well as those which would be recovered by pressure depletion from the unit volume reservoir. It should be remembered in making the calculations regarding plant products that the figures presented in Table 5 are based on 100 per cent plant efficiency and should be modified for the efficiency of the plant being considered.

CONCLUSIONS

A description is given of a laboratory study and associated calculations to determine the effect of retrograde condensation upon the yield from a gas condensate reservoir under pressure depletion conditions. The laboratory study may be tailored to fit the separation conditions in use in the field or to conditions anticipated for the future. A variety of conditions may be considered for comparative purposes. Figures are also presented to calculate gasoline plant recovery either in conjunction with lease separation or for the case where the entire well stream is processed. These depletion recoveries may then be compared to those for pressure maintenance to determine the method of operation in the field to yield the maximum economic return.

REFERENCE

1. Reudelhuber, F. O.: Separator Sampling of Gas Condensate Reservoirs, *Oil & Gas Jour.*, June 21, 1954, pp. 138-140.

TABLE 1

Hydrocarbon Analyses of Separator Products and Calculated Well Stream

Component	Separator Liquid Mol Per Cent	Separator Gas Mol Per Cent	Separator Gas GPM	Well Stream Mol Per Cent	Well Stream GPM
Hydrogen Sulfide					
Carbon Dioxide	Trace	0.22		0.18	
Nitrogen	Trace	0.16		0.13	
Methane	7.78	75.31		61.92	
Ethane	10.02	15.08		14.08	
Propane	15.08	6.68	1.832	8.35	2.290
iso-Butane	2.77	0.52	0.170	0.97	0.317
n-Butane	11.39	1.44	0.453	3.41	1.073
iso-Pentane	3.52	0.18	0.066	0.84	0.306
n-Pentane	6.50	0.24	0.087	1.48	0.535
Hexanes	8.61	0.11	0.045	1.79	0.734
Heptanes plus	34.33	0.06	0.028	6.85	3.904
	100.00	100.00	2.681	100.00	9.159

Properties of Heptanes plus

	Separator Liquid	Separator Gas	Well Stream
API gravity @ 60° F.	46.6		
Specific gravity @ 60/60° F.	0.7946		0.795
Molecular weight	143	103	143

Calculated separator gas gravity (air = 1.000) = 0.735
Calculated gross heating value for separator gas = 1295 BTU
per cubic foot of dry gas @ 14.696 psia and 60° F.

Primary separator gas collected @ 300 psig and 62 °F.
Primary separator liquid collected @ 300 psig and 62 °F.

Primary separator gas/separator liquid ratio 4428 SCF/Bbl @ 60° F.
Primary separator liquid/stock tank liquid ratio 1.352 Bbls @ 60° F./Bbl
Primary separator gas/well stream ratio 801.66 MSCF/MMSCF
Stock tank liquid/well stream ratio 133.9 Bbls/MMSCF

TABLE 2

Pressure-Volume Relations of Reservoir Fluid at 186° F.
(Constant Composition Expansion)

Pressure PSIG	Relative Volume	Deviation Factor Z
6000	0.8808	1.144
5713[1]	0.8948	1.107*
5300	0.9158	1.051
5000	0.9317	1.009
4800	0.9434	0.981
4600	0.9559	0.953
4400	0.9690	0.924
4300	0.9758	0.909
4200	0.9832	0.895
4100	0.9914	0.881
4000[2]	1.0000	0.867**
3905	1.0089	
3800	1.0194	
3710	1.0299	
3500	1.0559	
3300	1.0878	
3000	1.1496	
2705	1.2430	
2205	1.5246	
1605	2.1035	
1010	3.5665	

*Gas formation volume factor = 1.591 MSCF/Bbl.
**Gas formation volume factor = 1.424 MSCF/Bbl.
[1]Reservoir pressure
[2]Dew point pressure

TABLE 4

Retrograde Condensation During Gas Depletion at 186° F.

Pressure PSIG	Retrograde Liquid Volume Per Cent of Hydrocarbon Pore Space
4000*	0.0
3500	3.3
2900	19.4
2100	23.9
1300	22.5
605	18.1
0	12.6

*Dew point pressure

Properties of Zero PSIG Residual Liquid

Gravity : 47.5 °API @ 60° F.
Density : 0.7897 gms/cc @ 60° F.
Molecular weight: 140

TABLE 3

Depletion Study at 186 °F.

Hydrocarbon Analyses of Produced Well Stream - Mol Per Cent

	Reservoir Pressure - PSIG							
Component	5713*	4000**	3500	2900	2100	1300	605	0
Carbon Dioxide	0.18	0.18	0.18	0.18	0.18	0.19	0.21	
Nitrogen	0.13	0.13	0.13	0.14	0.15	0.15	0.14	
Methane	61.72	61.72	63.10	65.21	69.79	70.77	66.59	
Ethane	14.10	14.10	14.27	14.10	14.12	14.63	16.06	
Propane	8.37	8.37	8.25	8.10	7.57	7.73	9.11	
iso-Butane	0.98	0.98	0.91	0.95	0.81	0.79	1.01	
n-Butane	3.45	3.45	3.40	3.16	2.71	2.59	3.31	
iso-Pentane	0.91	0.91	0.86	0.84	0.67	0.55	0.68	
n-Pentane	1.52	1.52	1.40	1.39	0.97	0.81	1.02	
Hexanes	1.79	1.79	1.60	1.52	1.03	0.73	0.80	
Heptanes plus	6.85	6.85	5.90	4.41	2.00	1.06	1.07	
	100.00	100.00	100.00	100.00	100.00	100.00	100.00	
Molecular weight of heptanes plus	143	143	138	128	116	111	110	
Specific gravity of heptanes plus	0.795	0.795	0.790	0.780	0.767	0.762	0.761	
Deviation Factor - Z								
Equilibrium gas	1.107	0.867	0.799	0.748	0.762	0.819	0.902	
Two-phase	1.107	0.867	0.802	0.744	0.704	0.671	0.576	
Well Stream produced-Cumulative per cent of initial		0.000	5.374	15.438	35.096	57.695	76.787	93.515
GPM from Smooth Compositions								
Propane plus	9.218	9.218	8.476	7.174	5.171	4.490	5.307	
Butanes plus	6.922	6.922	6.224	4.980	3.095	2.370	2.808	
Pentanes plus	5.519	5.519	4.876	3.692	1.978	1.294	1.437	

* Original reservoir pressure.
** Dew point pressure.

TABLE 5

Calculated Cumulative Recovery During Depletion

Cumulative Recovery per MMSCF of Original Fluid	Initial in Place	Reservoir Pressure—PSIG 4000*	3500	2900	2100	1300	605	0
Well Stream -- MSCF	1000	0	53.74	154.38	350.96	576.95	767.87	935.15
Normal Temperature Separation**								
Stock tank liquid-barrels	135.7	0	6.4	15.4	24.0	29.7	35.1	
Primary separator gas -- MSCF	757.87	0	41.95	124.78	301.57	512.32	685.02	
Second stage gas--MSCF	96.68	0	4.74	12.09	20.75	27.95	37.79	
Stock tank gas--MSCF	24.23	0	1.21	3.16	5.61	7.71	10.40	
Total "Plant Products" in Primary Separator Gas-Gallons***								
Propane	1198	0	67	204	513	910	1276	
Butanes (total)	410	0	23	72	190	346	491	
Pentanes plus	180	0	10	31	81	144	192	
Total "Plant Products" in Second Stage Separator Gas -- Gallons***								
Propane	669	0	33	85	149	205	286	
Butanes (total)	308	0	15	41	76	108	159	
Pentanes plus	138	0	7	19	35	49	69	
Total "Plant Products" in Well Stream -- Gallons***								
Propane	2296	0	121	342	750	1229	1706	
Butanes (total)	1403	0	73	202	422	665	927	
Pentanes plus	5519	0	262	634	1022	1315	1589	

* Dew point pressure

** Recovery Basis: Primary separation at 500 psia and 70° F.,
Second stage at 50 psia and 70° F.
Stock tank at 14.7 psia and 70° F.

*** Recovery assumes 100 percent plant efficiency.