INFERRED PRODUCTION TESTING OF OIL AND GAS WELLS

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ABSTRACT

Production testing with digital electronic devices has been discussed for about 20 years amongst a small group of people. The idea has been implemented a few times with uncertain results. The uncertainty exists because the measurements were done with turbine meters which have uncertain accuracy.

Recent testing has been accomplished by gauging calibrated tanks. We believe these measurements of liquid volumes can be viewed as ‘perfect’. Measurement of gas is done with computerized orifice meters which are known to be accurate as long as the correct orifice size is used.

This paper compares ‘perfect’ production tests made with tank gauges and tests made with imperfect digital-electronic devices. The comparison indicates that the ‘imperfect’ measurements are usable. This raises the important question. What would the oilfield look like if testing with the digital-electronic devices became the norm?

THE TEST PROCEDURE

Production tests were made on three wells at different times. The tests were carefully done. Measurements were discarded if the slightest hint of inaccuracy or uncertainty existed. Eight days of perfect measurements for each well were fashioned into a collection that a Production Accountant might produce using accepted methods. The entire production stream from a well was sent to a heater-treater. The produced oil was sent by the heater-treater to a calibrated oil tank. Produced water was also sent by the heater-treater to a calibrated water tank. Gas was separated and was sent to an inference device and a sales meter. The tanks were gauged at the same time (10:00 AM) each day. Accurate oil and water production and gas production for the day was determined. Accurate watercut was also determined.

Second order effects were considered such as retention of oil and water in the heater-treater. This was determined by the daily movement of the oil-water interface in the sight glass (see Figure 1). From heater-treater dimensions, the liquid volume in bbl/inch was calculated. For example, a 4 ft heater-treater contains a liquid volume of about 0.187 bbl/in. If the oil-water interface moves up 6.5 inches from the previous day, it is reasoned that 1.216 bbl of oil [6.5 (0.187) = 1.216] was pushed into the oil tank. This must be subtracted from the gauged oil production. Since the corresponding volume of water is still in the heater-treater, 1.216 bbl of water must be added to the gauged water production. A similar procedure is used if the sight glass marker goes down from the previous day. Assume the oil-water marker has dropped from the previous day by 3.4 in. This means that 0.636 bbl of water is displaced into the water tank. Thus 0.636 bbl must be subtracted from the gauged water measurement while 0.636 bbl of oil must be added to the gauged oil measurement since the oil is still in the heater-treater. Gas from the well casing is directed to a device that infers the quantity (mcf/d) using repetitive pressure buildup measurements (psi/min). As an extra measure of control, the same casing gas is being measured with a computerized meter run. The close agreement between inferred and measured casing gas is discussed later in the paper. Gas quantities are also read at Gauge-Off time of 10:00 AM. Tubing fluids (oil and water), free gas and gas dissolved in the oil are measured with a special POC which uses the downhole pump as a meter. Gauge-Off time for the special POC is also set at 10:00 AM.

DISCUSSION OF RESULTS

Oil and Water Measurement

We now compare oil and water measurements from tank gauges with measurements made with the inference device (POC). See Table 1 below for Well No. 1. Note how the sum of total fluid from the POC tracks the sum of tank measurements. We multiply each POC total fluid by watercut to determine POC water. For example, POC water is 70.2 (0.820) = 57.6 b. POC oil is 70.2 (1-0.820) = 12.6 b. Locate these numbers on Table 1. Continue this process for the remainder of days. The inferred total fluid is 327.0 b compared to the exact 345.4 b determined from the tank gauges. The error in the inferred value of total fluid is only -5.3 percent. Similarly the error in inferred total water is -5.2 percent. Finally the error in inferred total oil is -5.7 percent. All inferred values are too low. Well No.1 would present a problem to the Production Accountant. Notice how variable its production rate is. On day 7 it produced 94.3 b.fld/d. On day 2, it only produced 19.4 b.fld/d. The reason for this variability is that many zones are commingled into the same wellbore. Different combinations of zones produce different amounts on different days. If the well was production tested on Day 2, it would receive a different allocation from the Production Accountant than if it had been tested on Day 7.

Gas Measurement

Next comes the comparison of gas measurement made with calibrated test meters versus the inference device. See Table 2 below. The gas production is recorded at Gauge-Off time for all wells and all days. Total Gas on Table 2 is measured casing gas plus inferred tubing gas read from the POC. Sales Gas is read from orifice meters owned by the purchasing company. Sales gas is also the total gas produced through the casing and tubing. Note how closely the Total Gas and Sales Gas compare (within 0.46 percent). Note also how closely the inferred gas and measured casing gas compare (within 3.8 percent). It has been noted earlier that the inference device and the computerized meter run are in series (measuring the same gas). This speaks well for the inference method which derives from the equation

$$scf\ /\ \mathrm{min} = 73.729\frac{kV}{zT_b}\frac{dp}{dt} \qquad \ldots 1$$

in which

k = ratio of specific heats
V = annular volume of gas, cu ft
z = gas compressibility
Tb = gas temperature, deg R
dp/dt = pressure buildup, psi/min

For example if the casing is shut in for one minute every 10 minutes and pressure increase is measured, Eq. 1 indicates how many *scf* have passed through the device in the 10 min interval. This rate is then integrated (summed) to give the daily rate, *mcf/d*.

ALLOCATION BASED ON TANK GAUGES

The preliminary work has been done. Oil, water and gas production for each well and each day is known, both from tank gauges and inference devices. The task of allocating now confronts us. Allocations are important, particularly to royalty owners, reservoir engineers responsible for creating reserve estimates and stockholders in the company owning the assets.

An Exact Oil Allocation

This is based on tank gauges which should be correct to small fractions of a barrel. This is the justification for calling this allocation 'Exact'. Table 3 below presents this allocation. Run tickets and LACT records can be a valuable check on the amount of oil produced. It is likely that the sum of the run tickets and LACT records will not exactly equal the total produced oil. The reasons for the discrepancy are primarily oil shrinkage in the storage tanks and possibly human factors. Still we believe the allocation based on tank gauges is very precise.

An Exact Gas Allocation

The gas allocation is called exact because it is based on the sales meter. Gas production for all wells is determined (as in Table 2) and the allocation is shown as Table 4. Sales meters are not always correct. As pointed out by co-author Ken Nolen there is a tendency for the gas buyer to neglect downsizing the orifice in the meter run as gas production declines. This makes the meter read too low which decreases the cost of the gas to the buyer.

ALLOCATION BASED ON INFERENCE DEVICES

Oil and water production from the inference device (a special POC) has been determined for each well as typified in Table 1.

Table 7 is very revealing. It shows the actual errors in inferential allocation of oil and gas, well by well. Allocated oil on Well No. 1 is 5.7 b.oil/d low (5.7 percent). A royalty owner would not approve of the error if he knew! Gas allocation is much closer, only 1.5 mcf low (0.45 percent). On Well No. 2, oil is allocated 3 b.oil/d high (6.2 percent). Gas is allocated 12.3 mcf high (8 percent). Finally on Well No. 3, oil is allocated 3.1 b.oil/d high (12.9 percent). Gas is allocated 17.6 mcf high (14.4 percent).

The allocations are not perfect, but they may be as good or better than the Production Accountant can produce with current methods. Well No. 1 would be troublesome for the Accountant. Look at Table 1 again. In the 8 day test period it was measured to produce from 13.9 to 94.3 b.fld/d. The well is vertical with 6 zones being produced into the same wellbore. Daily production is variable because different combinations of zones produce at different times. If the monthly well test was done with the well only producing 13.9 b.fld/d, its allocation would be much too low. Conversely if it was producing at 94.3 b.fld/d, its allocation would be much higher. Down-time is also a problem for the Production Accountant. The well may be shut down for repairs without the accountant being aware. On the other hand, the POC is not troubled by downtime since it controls the well. It knows when the unit is running and when it is stopped. The Accountant is usually required to assume that the well produces the tested amount every day during the accounting period. This is never true in practice.

CONCLUDING REMARKS

Evaluation of Inferred Production Testing should continue. It would be instructive to conduct a head-to-head test between the Production Accountant Method and the Inferred Production Method. A tank battery would be chosen with multiple wells producing to it. A test period would be arbitrarily set. The Production Accountant would get his one well test per period using turbine meters and orifice meters. He will make his usual assumption that the well produces its tested amount each day of the test period. The Inferred production data will be read from the special POC each day. This will measure the oil, water and gas being produced through tubing. The POC will determine oil/water ratio with manually obtained bleeder samples taken each day. The gas inferring device will indicate the amount of casing gas being produced each day. Each method will produce allocations and total oil, water and gas produced during the period. It will not be possible to determine which method produces the best allocations. But it will be possible to declare a winner concerning which method produces the best estimate of total production sold during the period. This can be done with run tickets, water meters, gas sales meters and LACT records.

It is useful to imagine what the oilfield would look like if Inferred Production became the norm. There would be no well test equipment in the tank battery. The wells served by the battery would be tested with inference devices at each wellsite. Wells served by the battery would no longer have individual flowlines from the wells to the battery. Instead each well would have a short flowline to a header in an area near the well. From the header, a single (large) flowline would carry production from several wells in the area to the battery. Farmers and ranchers would like this arrangement. A few trailer mounted test units equipped to measure oil, water and gas would be needed to resolve questionable individual well measurements. Large capital savings would result in tank battery construction.

Further observations concerning gas measurement are pertinent. As pointed out by co-author Rowland Ramos, orifice size in orifice meters is hard to determine and maintain. Incorrect orifice size leads to incorrect gas measurement. Computerized orifice meters can be programmed to reveal the percentage of time that differential pressure is too low or too high to measure accurately. This feature is useful in optimizing orifice size for best accuracy.

The owner of the sales meter (the buyer of the gas) has no incentive to optimize orifice size. Early in the life of a well, gas production is high. A ‘large’ orifice is required. To get good accuracy as the well declines, the orifice needs to be downsized. Why? It is measuring too low. The buyer of the gas does not wish to downsize the orifice because it will measure more gas and increase his cost.

We conclude with another thought for consideration. During the 8 day test, the inferring devices measured 625.6 mcf while the sales meters measured a lesser amount of 597.2 mcf (see Table 7). What if the inferring devices were measuring more accurately? We extrapolate the difference of 28.4 mcf (625.6 – 597.2 = 28.4) to one year instead of 8 days and to 10000 wells instead of 3. We compute that an astounding amount of gas (4,319,167 mcf) is being given to the pipeline buyer without payment.

REFERENCE

Gibbs, Sam G., Ramos, Rowland and Nolen, Ken B. (2016): *Inferred Production of Oil and Gas Wells*, Artificial Lift Forum; Midland, Texas: November 2.

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Table 1. Liquid Production, Tank vs POC

Day	Watercut %	Total Fluid (b/d) Tank	Total Fluid (b/d) POC	Water (b/d) Tank	Water (b/d) POC	Oil (b/d) Tank	Oil (b/d) POC
1	82.0	71.5	70.2	58.7	57.6	12.9	12.6
2	67.8	19.4	16.7	13.2	11.3	6.3	5.4
3	81.2	43.0	40.8	34.9	33.1	8.1	7.7
4	67.2	13.9	10.3	9.3	6.9	4.5	3.4
5	56.3	60.3	58.7	34.0	33.0	26.4	25.7
6	73.1	21.5	19.5	15.7	14.3	5.8	5.2
7	67.3	94.3	89.0	63.5	59.9	30.8	29.1
8	77.0	21.5	21.8	16.5	16.8	4.9	5.0
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		345.1	327.0	245.8	232.9	99.7	94.0

Well No. 1

Table 2. Gas Production – Orifice meter vs Inference Device

Day	Total Gas (mcf)	Sales Gas (mcf)	Casing Gas (mcf) INF	Casing Gas (mcf) Meter
1	79.7	74.9	77.6	71.6
2	24.8	28.6	23.1	23.4
3	57.5	62.7	56.1	52.0
4	21.0	19.1	19.2	18.9
5	25.7	24.1	22.5	22.1
6	26.0	43.3	24.0	26.1
7	66.5	33.4	62.1	58.3
8	26.5	43.1	25.1	25.7
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	327.7	329.2	309.7	298.1

Well. No. 1

Table 3. Exact Oil Allocation

Produced (b)	Well
99.7	No. 1
47.8	No. 2
24.0	No. 3

171.5	Total

Produced / Total	Allocation (%)	Well
99.7 / 171.5 = 0.58134	58.134	No. 1
47.8 / 171.5 = 0.27872	27.872	No. 2
24.0 / 171.5 = 0.13994	13.994	No. 3

	100.00	Total

Table 4. Exact Gas Allocation

Gas Produced (mcf)	Well
329.2	No. 1
145.7	No. 2
122.3	No. 3

597.2	Total

Produced / Total	Allocation (%)	Well
329.2 / 597.2 = 0.55124	55.124	No. 1
145.7 / 597.2 = 0.24397	24.397	No. 2
122.3 / 597.2 = 0.20479	20.479	No. 3

	100.00	Total

Table 5. Oil Allocation Based on Inference Device

Oil Produced (b)	Well
94.0	No. 1
50.8	No. 2
27.1	No. 3

171.9	Total

Produced / Total	Allocation (%)	Well
94.0 / 171.9 = 0.54683	54.683	No. 1
50.8 / 171.9 = 0.29552	29.552	No. 2
27.1 / 171.9 = 0.15765	15.765	No. 3

	100.00	Total

Table 6. Gas Allocation Based on Inference Device

Gas Produced (mcf)	Well
327.7	No. 1
158.0	No. 2
139.9	No. 3

625.6	Total

Produced / Total	Allocation (%)	Well
327.7 / 625.6 = 0.52382	52.382	No. 1
158.0 / 625.6 = 0.25256	25.256	No. 2
139.9 / 625.6 = 0.22362	22.362	No. 3

	100.00	Total

Table 7. Produced vs Allocated

Well No.	Prod. Oil (b)	Allocated Oil (b)	Prod. Gas (mcf)	Allocated Gas (mcf)
1	99.7	94.0	329.2	327.7
2	47.8	50.8	145.7	158.0
3	24.0	27.1	122.3	139.9
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Totals	171.5	171.9	597.2	625.6

Figure 1 – Sight glass marker used to determine fluid retention in heater-treater