ONE MORE TOOL FOR THE BOX – USING PATTERN ALLOCATION FACTORS DERIVED FROM DARCY'S LAW

Rebecca J. Larkin
Kinder Morgan CO2

ABSTRACT

Balancing injection-withdrawal ratio on a pattern basis is essential in optimizing tertiary recovery projects, where high lease expenses tend to marginalize even the best of candidates. Advances in reservoir modeling techniques provide increasingly reliable predictions of long-term field-wide production response; however, a gap frequently exists in supplying routine or short-term individual well forecasts. This paper describes a simple allocation technique utilizing a modified version of Darcy's equation for linear flow within the setting of a field-wide pattern network. Generated factors allocate actual injection to offset production, calculating idealized production volumes on a gross reservoir barrel basis for comparison to actual production to influence uniform injection-withdrawal. In other words, a check and balance system to assist in guiding operations. Developed over the past several years for use in the SACROC Unit in West Texas, tailoring is possible for other secondary/tertiary recovery projects given field specific conditions.

INTRODUCTION

Primary oil production is all but gone from domestic onshore fields, replaced by ever increasingly complex recovery schemes to extend economic life. This is particularly true in unitized operations with hundreds of wells requiring attention. Field personnel, production engineers, and supervisors need performance feedback on a daily basis to understand well-to-well interactions and maximum operating efficiency. Unfortunately, having a full-blown compositional reservoir simulator complete with a well-constructed geologic model updated on a daily basis to maintain material balance is not today a practical reality, at least not an affordable option for most companies. Stream-tube simulation offers to bridge the feedback gap for those companies who still have research arms able to support the effort. For the rest of us though, the typical alternative remains some form of geometric allocation factoring system with or without adjustment from engineered opinion. While simple in execution, such a system makes volume assignments arbitrarily and as a result, force fits past performance to forecast short-term balance. Throw in the added complication of an energized fluid, such as carbon dioxide, to confuse fluid level interpretation and production equipment sizing becomes a monumental rather than routine task.

However, using readily available software with basic petroleum engineering concepts and field data we normally have, we can calculate a reference volume for each well to approximate an ideal balance and compare it to actual to assist in making those daily adjustments needed to stay on track. First, software can be as simple as a spreadsheet. As a trial, I started with a small project area within the SACROC Unit (Scurry County, Texas) in 1994, using an MS Excel spreadsheet, but as I expanded to encompass more of the Unit, I converted to a relational database (MS Access in this case, but the choice of provider is yours). A database is an excellent repository and reporting tool, can handle the necessary calculations, and best of all, can digitally link to other databases for information. A competent laptop can handle a large number of wells, such as SACROC – so computer expenses can be minimal. Second, the Darcy-Weisbach equation (commonly referred to as Darcy's Law) provides the foundation for us – the bulk of this paper will describe how. Lastly, what do we normally know about our specific field? We know the wells – count, type, status, location/spacing, and depths. Generally, we know what is perforated, what is open hole, what is isolated in each well. At a minimum for each well, we have a porosity log and a curve (gamma ray or spontaneous potential, for example) to correlate to offset wells, and if we actively monitor flood behavior, coverage by injection and/or production profile logs. Since we are responsible for collecting it, we usually have the injection/production fluid volumes for each well. Fortunately, in our case, we also have monthly gas compositions from chromatograph measurements.

Our knowledge of well location allows us to exploit geometry and enhance it utilizing a modified version of the Darcy-Weisbach equation. Pattern geometry establishes a nodal network, each well being a node. This type of relationship is commonly employed by other engineering disciplines; the most familiar analogy is the use of Ohm's

Law in electrical power grids. It provides linearity and connectivity between nodes within the network. Ping a node and see proportional response in the offset nodes. Reservoir heterogeneities prevent exact responses to events, but ask any pumper about the effect on offsets caused by shutting in a good well, and a few cups of coffee later, a causal relationship is readily apparent.

In a single pattern (figure 1), stream tubes develop faster and "tube density" is greater as injector-producer spacing gets tighter. Flow conditions may be described by linear equations (because changes in pressure drop and flow rate are linear and laminar flow exists in porous media having permeability less than 5,000 md) except near wellbore. Extending this to a network of patterns (figure 2), we see that despite the complexity, this network dissects rather simply. Given the number of nodes and the relative spacing between them, ultimately, stream tubes are simply paths of least resistance within the pattern network (figure 3). Definitely an oversimplification, but the objective here is a reference solution for comparison to actual not an absolute to bet the farm upon. How a well relates to other wells within the pattern and to adjacent patterns is key. Continuing, activity level affects flood performance. Inactive wells drop from consideration within days to weeks depending upon permeability (figure 4). Pay conformance, or net pay exposed rather than net pay available, dictates areal sweep efficiency (figure 5).

Regardless of network configuration, in an injector-centered flood pattern, injection is independent pattern to pattern, whereas production is dependent (with the converse being true in producer-centered patterns) yet we must manage each on a small scale. Why? Because of the laundry list of factors we have little or no control over:

- Reservoir pay heterogeneity
- Hydrodynamic factors
    - Elevation
    - Influx
    - Pressure
- Fluid Properties
    - Viscosity
    - Relative Permeability
    - Saturation

Plus, the imperfect nature of the things we think we do control:

- Injection
- Adjacent pattern producer operation
- Management philosophy (everyone is on the same page, right?)

Ironically, borrowing from the hydraulics of nineteenth century European sewage flow through porous media, as developed in the Darcy-Weisbach equation, we can use an approximation to calculate field-wide pattern balance.

DERIVATION OF IDEAL PATTERN BALANCE

Our basic premise is to inject x barrels of reservoir fluid and withdraw x-loss barrels from the offset producers, extending this pattern by pattern field-wide. At SACROC, an estimated ten percent loss of total injectant occurs on average (this value should not be confused with injected carbon dioxide (CO_2) left in situ) based upon empirical data from bottom hole pressure surveys and gas-oil ratios, and rudimentary material balance. Here we calculate a snapshot in time to judge relative performance. The period to obtain this is set as long as three months (with corrected data) to smooth operational variations and as short as 30 days (with daily updated well tests) to gauge changes made. All volumes are converted to gross reservoir barrels to accommodate fluid diversity. The program always uses the latest information through links to existing databases that are maintained independently.

Since we are dealing with a linear pattern network where our interest is in regional well interactions and are not attempting to forecast individual fluid streams, we will stick with the linear equation. Figure 6 illustrates factors that go into the basic equation. As a first consequence of Darcy's Law, we notice that holding all other variables constant, flow rate rises as cross-sectional area increases. In case of fire, a fireman can spray more water than you and your garden hose (figure 7). In the case of a reservoir, productivity is directly related to exposed pay thickness (figure 8). As a second consequence of Darcy's Law, holding all other variables constant, flow rate drops as distance increases (tortuosity being relative among neighboring wells on an individual pattern or small scale). This analogy also applies to electrical circuits (figure 9). Consequences one and second suggest we may tie Darcy to linear network analysis. We know that injection must equal production plus losses to balance voidage and conserve reservoir energy (maintain bottom hole pressure). Meaning,

$$Q_{INJ} = Q_{PROD} - Q_{Losses}$$

Losses are both natural and induced. Induced losses should be minimized; e.g., maintaining injection below parting pressure in each injector to avert short circuiting fluid. Extending this simple relationship to multiple pattern wells yields,

$$\Sigma\, Q_{INJ} = \Sigma\, Q_{PROD} + \Sigma\, Q_{Losses}$$

Water influx should be added to the injection side if present.

Each rate term may be represented in turn by the linear form of the Darcy-Weisbach equation:

$$Q = C * \Delta P * k * A / \mu * L$$

where,

Q = fluid flow rate through container
C = dimensional constant
ΔP = differential pressure between container inlet and outlet
k = permeability of container media to fluid flow
A = cross-sectional flow area of container
μ = viscosity of fluid at container pressure and temperature
L = distance between container inlet and outlet

At this point vital assumptions are necessary to proceed. In a nodal network across porous media, we attempt to control each node, as opposed to controlling the linkage between the nodes. Where we position (drill) each node dictates our potential for success at control. As such, our control is limited to the inlet and outlet nodes in the network, and it should be possible to substitute height (of the inlet/outlet) for area in the case of an injection pattern with multiple producers. Consequently, the permeability-area product should be proportional to the permeability-height product. Furthermore, although not an equal measure, particularly in clay-rich lithologies, readily available porosity data may closely approximate the more appropriate but less measured permeability; therefore, we will assume that we can substitute the porosity-height product for the permeability-height product in this idealized scenario. Bear in mind, if permeability data is available field-wide, it should be used instead. Unlike a simulator, where generalized but known characteristics typically describe a grid, we need to use as much well-specific data for each individual node as possible. Summarizing,

$$k * A \approx k * h \cong \phi * h$$

On a macroscopic level, these substitutions lead to a plausible approximation of Darcy's Law,

$$Q \approx \frac{C * \Delta P}{\mu} * \left(\frac{\phi * h}{L} \right)$$

where,

Q = fluid flow rate (from corrected monthly volumes and daily well tests)
C = dimensional constant
ΔP = differential pressure (measured or assumed)
ϕ = porosity of media (from well logs)
h = height of exposed pay (from perforation/open hole records)
μ = viscosity of fluid (from lab measurements or approximated)
L = distance between inlet and outlet (midpoint of each well in x, y, z directions from bottom hole preferably or surface coordinates; "z" acknowledges the probability that gravity influence exists despite layering)

If losses may be reasonably approximated or assumed, we can sum up the rates within each pattern,

$$\Sigma Q_{INJ} - \Sigma Q_{LOSSES} = \Sigma Q_{PROD}$$

Substituting variables from the approximation of Darcy's Law for each well in a pattern,

$$\Sigma Q_{INJ} \cong C \left[\frac{(\Delta P_1)(\phi_1 h_1)}{\mu_1 L_1} + \frac{(\Delta P_2)(\phi_2 h_2)}{\mu_2 L_2} + \ldots + \frac{(\Delta P_n)(\phi_n h_n)}{\mu_n L_n}\right], \text{ for injectors}$$

And,

$$\Sigma Q_{PROD} \cong C \left[\frac{(\Delta P_1)(\phi_1 h_1)}{\mu_1 L_1} + \frac{(\Delta P_2)(\phi_2 h_2)}{\mu_2 L_2} + \ldots + \frac{(\Delta P_n)(\phi_n h_n)}{\mu_n L_n}\right], \text{ for producers}$$

At this junction, we can choose to treat the pattern analysis as injector- or producer-centered. In a flood as opposed to primary recovery, injection drives production. Control is more feasible on the injectors because the flow stream begins at the surface rather than in the reservoir, as is the case with producers, but the balance can be run in either direction depending on preference. Because of the inherent time lag between injecting a barrel and producing that barrel minus losses, my preference is to define a grid of injector-centered patterns and focus on the production side of the equation. Using accurately measured injection rates on a single-phase fluid (CO_2 or water) makes $\Sigma Q_{INJ\ actual}$ known with a high degree of certainty, thus, we can solve for $\Sigma Q_{PROD\ ideal}$ for comparison to multiphase $\Sigma Q_{PROD\ actual}$.

Unlike other geometric allocation schemes, we add one more caveat to introduce the idea that an optimal pattern throughput rate may be determined rather than merely distributing actual to balance withdrawals. To do so we assume uniform drawdown across each pattern. In other words, if ΔP were constant at any particular point in time across any particular pattern, then:

$$\Sigma Q_{PROD} \cong C' \left[\left(\frac{\phi_1 h_1}{\mu_1 L_1} + \frac{\phi_2 h_2}{\mu_2 L_2} + \ldots + \frac{\phi_n h_n}{\mu_n L_n} \right)\right]$$

As radical as this sounds, how might ΔP be constant?

- Conceptually, if ΔP were constant, flood front advance would tend to be uniform, thereby improving sweep efficiency and consequently pattern performance (figure 10).
- On a small-scale basis, such as a pattern, and over a limited period of time, *composite* μ on the displacing (injection) side of the flood front should vary negligibly interwell under conditions of uniform pressure gradient injecting a non-compressible (water) liquid or supercritical (CO_2) fluid having the behavior of a dense liquid. We cannot assume the same on the displaced (production) side where reduced pressures allow compressible fluids to dominate. More will be said about viscosity later.
- If ΔP is known for each well couplet then, of course, conventional equations can be used as is. However, unlike rate measurements these values are sampled too infrequently in many floods, hence if we assume uniform differential pressure across a pattern as a reference to gauge production volumes, we may improve overall flood efficiency by sizing equipment or controlling withdrawal to steer fluid, so to speak, in the direction of uniformity within each pattern. When actual pressure measurements are available, having an idealized reference is a handy tool for problem recognition in well analysis.

Continuing this line of reasoning, canceling constants and dividing both sides of the above equation by ΣQ_{PROD}, makes it dimensionless and yields production allocation factors that sum to unity for any particular pattern considered,

$$1 = \frac{\phi_1 h_1/\mu_1 L_1}{\Sigma Q_{PROD}} + \frac{\phi_2 h_2/\mu_2 L_2}{\Sigma Q_{PROD}} + \ldots + \frac{\phi_n h_n/\mu_n L_n}{\Sigma Q_{PROD}}$$

Multiplying the production allocation factors by the actual pattern injection (minus losses) yields the target production rate segments for any pattern considered. It follows that the production target of any particular producer is the sum of the injection-driven production segments from all adjacent patterns. This is the fundamental basis of the pattern balancing application (figure 11).

To account for non-pattern well volumes, pseudo-patterns may be created by radially linking injectors and producers together at distances up to 2,000 meters apart. Beyond 2,000 meters, allocation factors approach zero, given local parameters.

VISCOSITY AND OPERATIONS

Viscosity is especially important to take into consideration in an alternating CO_2-water (WAG) flood because mobility ratio, or the ratio of displacing to displaced fluid viscosity, changes from injectant cycle to cycle within a pattern. Additionally, offset patterns may be on alternate injectants because of differences in processing rates between patterns, availability of injectant supply or wellbore conditions that alter planned WAG schedules. Unfortunately, injectant quality may also be inconsistent within a field, usually because of non-floating distribution systems and/or multiple entrance streams. In any event, every effort should be made to know viscosity distribution through time - no small order to accomplish. However, given the choices we make operationally can lessen the severity of an unfavorable mobility ratio. Theoretically, the better the mobility ratio - the greater the oil recovery possible both before and after breakthrough.

Operationally, debate exists within the industry whether or not to pump-off producing wells. Conventional wisdom demands we pump-off to maximize drawdown and make more oil. In a waterflood, particularly at fill-up, excessive gas production is rarely an issue if we do. Such is not the case in a CO_2 flood. Pressure drop below saturation pressure liberates free gas. Excessive CO_2 breakthrough generally results in freezing (gas hydrates) and premature shut-in or need for workover to squeeze off the offending zone(s). Flowing wells are always more efficient when gas breaks out at or near the surface rather than down hole. Pumping equipment pumps liquid not gas as a rule; down hole gas separation has physical limits, therefore, it is better to keep gas in solution regardless of producing mechanism. Theoretically, the fluid level maintained over the pump should be oil, making corrosion inhibition of submerged tubular goods a potential benefit of not pumping down a well. Obviously, fluid to surface is undesirable though as excessive backpressure will choke production. To achieve miscibility between CO_2 and hydrocarbon, reservoir pressure must be above minimum miscibility pressure (MMP), which is typically above saturation pressure. Maintaining miscibility from injector to producer should be the ideal scenario to minimize stranding of hydrocarbon. This gives us a choice:

- we may pump-off, release free gas, create substantial pressure drop and maximize short term production rates;
- we may hold high fluid levels above the pump, keep all gas in solution, but move very little fluid; or,
- we can establish a pump intake pressure intermediary between the first two possibilities to minimize free gas at the wellbore yet sustain economic production rates (Figure 12).

In my opinion, the last choice is the best option. From a reservoir engineering viewpoint, establishing a middle ground may mitigate convective dispersion on the high rate end and molecular diffusion on the low rate end. Whichever option we choose, we usually can reasonably regulate bottom hole producing pressure with our design of pump intake pressure in combination with surface choke setting and/or variable motor speed controller. Flowing wells tend to be self-regulating, in that natural flow only occurs when bottom hole pressure is sufficient to overcome the hydrostatic head of a full column of liquid – usually ensuring bottom hole single-phase flow. Continuous flow early in the WAG cycle life may be maintained by proper choke setting in combination with separator system design. Designing separation to conserve energy through staged pressure surface facilities, usually justified to reduce overall required stages of compression needed, also assists the effort to keep gas in solution as long as possible.

The pattern balancing application assumes uniform differential pressure across each pattern; however, knowledge of bottom hole conditions at one end or the other is needed to establish a viscosity value for use in solving for either Σ $\mathbf{Q_{PROD}}$ or Σ $\mathbf{Q_{INJ}}$. Again, keeping reservoir pressure at or above MMP from injector to producer should minimize the stranding of product. In a CO_2 flood, MMP is relative to the quality of injectant; hence, it tends to increase with time if methane (C_1H_4) is present and decrease with hydrogen sulfide (H_2S) content (note that I am advocating the deadly toxin H_2S for any reason). Saturation pressure is also a moving target with time as reservoir fluid composition metamorphoses. Therefore, the dynamics of our flow streams recommend that compositions be routinely determined; this will also indirectly answer the question of what differential pressure magnitude is desirable.

The viscosity of water is a constant for all practical purposes, so we exert minimal influence on performance as long as we inject clean water. CO_2 viscosity is considerably less than that of oil, causing an unfavorable mobility ratio regardless of conditions. To get as favorable a mobility ratio as possible, besides injecting water between CO_2 cycles, we can try to reduce oil viscosity as low as possible while raising CO_2 viscosity as high as possible without the expense of additives. SACROC oil viscosity (figure 13) is lowest near or slightly above the bubble point. Original reservoir temperature at discovery averaged 130 deg F. If we choose to limit free gas entry, oil viscosity near the bubble point does not vary significantly from saturated levels. However, viscosity rises dramatically as pressure decreases, liberating gas and adversely affecting fluid flow. If we hold enough backpressure to restrict generation of two-phase fluid at the sand face we can mitigate most of the viscosity variation and the resulting negative effect on mobility ratio.

Monthly, technicians sample and analyze by gas chromatograph each producing well to track response, both in terms of CO_2 breakthrough and flood-induced compositional change. Gas composition ranges widely on surface samples from producing wells taken over a one-year period between October 2002 and September 2003. Averaging the compositions in 5% increments of CO_2 cut then plotting the distribution of it versus percentage of samples (figure 14) shows a preponderance of the producing cuts between 70 and 95% CO_2 gas. Filtering the histogram to a manageable yet representative number of bins is shown in figure 15. Downhole production profiles provide insight into producing temperatures. Figure 16 (number of surveys in parenthesis) covers surveys over the last two years and suggests rising producing temperature in the neighborhood of the original temperature. While not immediately explainable as subsequent decreasing injection temperatures suggest conflict, production rates have been increasing recently leaving the possibility that some of the apparent raise may be from increased friction. The effect of tailpipe used mostly in open hole is not yet discernible. In any event, producing bottom hole temperatures currently appear to range from 120 to 135 deg F in the wells surveyed. Plotted NIST14-derived viscosities over this range versus likely bottom hole pressures (figures 17 through 20), suggest the following:

- the effect of composition on viscosity increases with pressure and temperature during conditions normally thought to be supercritical
- two-phase behavior exists below the supercritical region (presumably natural gas liquid drop out); exhibiting significant differences between liquid and vapor phase viscosities
- at different compositions, viscosity difference in the supercritical region is a maximum of 0.027 cP at the highest pressure and a maximum of 0.0095 cP near saturation; suggesting that a close approximation may be sufficient in estimating producing gas viscosity particularly producing near the saturation pressure
- mobility ratio decreases as viscosity increases with increasing pressure and temperature; knowledge of composition also increases in importance
- just as with oil, optimal bottom hole producing pressure appears to be near saturation pressure to maximize benefit to mobility.

NIST14 (National Institute of Standards and Technology Standard Reference Database 14) is downloadable for a nominal fee but alas is written in MS-DOS. NIST23 is also available now, is MS-Windows-based, but costs more. In a simple nodal analysis, use of a more sophisticated equation of state would be overkill.

Now that we see the viscosity data for oil and gas is most favorable near saturation pressure, we need to ration them reasonably along with water for use in our idealized equation. The magnitude of viscosity difference is remarkable - water viscosity is 2.5 times that of oil, oil is 15 times that of gas. Because each well has experienced a different production history, variation exists in the compositional profile well to well. The simplest direct indication we have of that difference is in the monthly volume data; while this data may not represent the total zonal profile at play, it does reflect the summation of active flow path(s). Admittedly, using an approximation of actual composite viscosity is less than ideal, but it does preserve the network relationship between the nodes. Modeling near saturation pressure, we will use the known formation volume factors to convert oil and water to reservoir barrels than adjust the remaining gas. Granted, actual pressure probably is unknown and may be significantly different from that of saturation, but this conversion allows us to keep composition intact and relative to our previous assumptions. From reservoir barrels, we can proportion viscosity as a percent of total volume. Over the relatively small temperature span at the log profiles suggest, gas viscosity variation is only 0.0015 cP from average across all compositions. If the temperature span is known to be greater, a pseudo-temperature can be estimated from surrounding profile temperatures using a kriging or similar method and additional viscosities calculated. Under extreme conditions that occur during severe breakthrough, very cool temperatures guarantee two-phase flow and not only complicate our calculations but make operations difficult (figure 21).

Looking at the injection side of the equation, CO_2 viscosity conversely becomes higher as pressure rises, which is convenient for our purpose. Figure 22 shows the actual range of CO_2 injectant compositions converted to viscosity over an observed range of surface pressures and temperatures over a same one-year period referenced above at SACROC, using NIST14 to generate viscosities based on composition. Viscosities are relatively uniform across the observed compositions, but vary substantially with pressure and temperature, even though all points appear to be above the supercritical point (for pure CO_2 that is 87.8 deg F and 1,071 psia). Our injectant viscosity increases with increasing pressure and decreasing temperature as expected. Knowing these values suggest we should attempt to inject cold, high pressure CO_2 for best possible mobility ratio. Seasonal temperature variation makes this difficult – CO_2 flooders are familiar with seasonal injectivity woes – but maintaining surface wellhead pressure to keep CO_2 supercritical is a must. Accurate surface data is necessary to define $\Sigma\ \mathbf{Q_{INJ}}$; however, we need viscosity data at bottom hole pressure and temperature conditions to solve for $\Sigma\ \mathbf{Q_{INJ}}$ if we choose to use $\Sigma\ \mathbf{Q_{PROD}}$ as a given. Figures 23 and 24 (number of surveys in parenthesis) show the average recent profile log temperatures. Both CO_2 and water average injection temperatures have declined recently, whereas, production temperature appears to be increasing as mentioned. Figure 25 shows the wide range of viscosities that project for bottom hole conditions using NIST14. We currently do not have a good correlation for bottom hole injection pressure given surface pressure, temperature and distribution system composition based upon measurements made in recent years. An internal study currently in progress may provide a corollary, or may indicate we need continuous bottom hole measurements to answer this question. Given the measurements available at present, solving for $\Sigma\ \mathbf{Q_{PROD}}$ is easier than solving for $\Sigma\ \mathbf{Q_{INJ}}$.

Knowing bottom hole injection pressure will help ensure that we keep both injectants injecting at the same pace, which will stabilize reservoir pressure and aid flood management. However, a more fundamental issue remains. Generally, floods have more producers than injectors – producers are revenue centers whereas injectors play a supporting role that is harder to quantify from an accounting standpoint. If we require the injectors to support maximum drawdown by the producers, which may happen when we assume $\Sigma\ \mathbf{Q_{PROD}}$ is given, production outruns injection before long and ultimately is starved. Rarely will a Vogel IPR curve suggest less production than that provided by injection. The quick fix is usually to over-inject to match withdrawals. Again, before long excessive injection exceeds fracture pressure, short-circuiting through the reservoir, and ultimately bypassing reserves. In the instance where we deliberately choose to restrict injection, for example, if an offset producer loses capacity because of mechanical or wellbore damage or facility limitation, we can scale off under-injected perforations and lose injectivity that is expensive to reestablish once production capacity is restored. Conservation of energy instructs we maximize injection below parting pressure and let it drive production. Over time, when flooding most reservoirs, production is purely a function of injection, and lives and dies by it. My apologies to the accountants.

IDEAL VERSUS ACTUAL IN PRACTICE

Having described the methodology at length, where is the utility in this model? It is simple in construction yet accounts for changes in known parameters on a timely basis. It is updatable daily if needed to generate production targets for operations personnel to use in balancing pattern voidage. Unlike a typical geometric allocation, where voidage may still be balanced pattern-wide with a combination of excessive and insufficient drawdowns, this model relates physical properties of each producer to its offsets to derive an optimum allocation pattern-wide to balance actual injection. A snapshot from a recent report is included as table 1. Note that some patterns are doing well while others need further attention; this is a tool not a rule. Actual volumes are compared to idealized ones to uncover anomalies. For example, if actual production is greater than target production, this suggests that drawdown is excessive and the excess is quantified. High HC GOR, possibly high WOR, and probably low liquid level in pumping wells are confirming indicators. If actual production is less than target production, conversely suggests that drawdown is insufficient. Low HC GOR, possibly high WOR, and probably high liquid level in pumping wells confirm this. Of course, like any software application, wellbore problems if ignored or unknown skew the model (figure 26); however, the more different actual is from ideal, the more likely parameters are not what we think they are, giving us a starting point for further investigation.

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ACKNOWLEDGEMENT
I would like to thank Kinder Morgan for permission to publish this paper. I especially thank the operations personnel at the SACROC Unit for providing enlightenment not found in most textbooks.

Table 1

Recent Page from Report

Well	3 months Ideal Prod	3 months Actual Prod	Diff	Exception	30 days Ideal Prod	30 days Actual Prod	Diff	Change	Date	Type	Oil	Water	Gas	GOR	TGOR	WOR	AF	[illegible]	TP	TbgP	CsgP	LineP	Remarks
71-6	2,252	3,144	892	Over Produced	2,072	4,313	2,241	Worse	[illegible]	FH	20	3014	2821	1149	141050	150	Y	53	Yes	750	0	600	[illegible]
71-6	1,815	873	-941	Under Produced	1,938	983	-954	Worse	[illegible]	FH	113	459	801	1397	7088	4	Y	40	Yes	400	0	250	[illegible]
71-7	4,596	2,744	-1,852	Under Produced	4,157	2,797	-1,360	Improving	[illegible]	SH	70	2470	498	1109	7114	35	Y	84	No	575	575	575	[illegible]
71-8	2,237	876	-1,361	Under Produced	1,994	820	-1,174	Improving	[illegible]	SH	82	560	313	1109	3817	6	Y	84	No	560	550	500	DR
72-6	3,869	3,221	-648	Under Produced	3,666	3,227	-439	Improving	[illegible]	SH	74	2379	1650	3016	22297	32	Y	84	No	600	540	550	[illegible]
72-6	1,114	2,882	1,768	Over Produced	982	2,636	1,654	Improving	[illegible]	SH	184	1072	2880	1984	15652	5	Y	95	No	900	590	530	[illegible]

Note: Ideal Production = Actual Injection - Losses (assumed to be 10%)

Tuesday, December 28, 2004 *Inj Tests: Date/Status/BWID Target/BCO2ID Target/AF/CK/TP/CP/LP/WJ/Remark* *TP = Tailpipe* *Page 12 of 49*

Pattern Stream Tubes

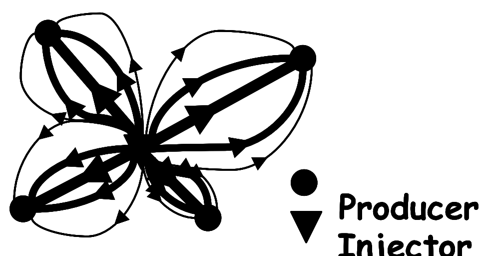


Figure 1

Pattern Network

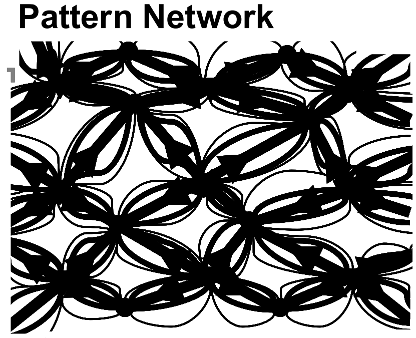


Figure 2

Simplified Network

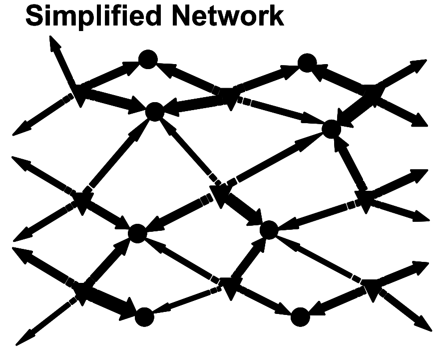
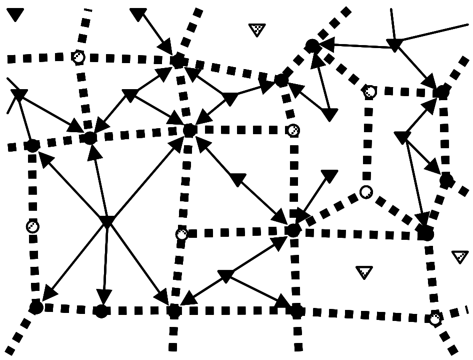


Figure 3

Well Status



Pay Conformance

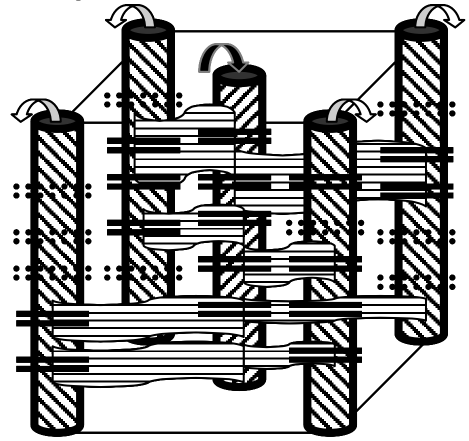


Figure 4

Figure 5

Fundamentals: Darcy's Law

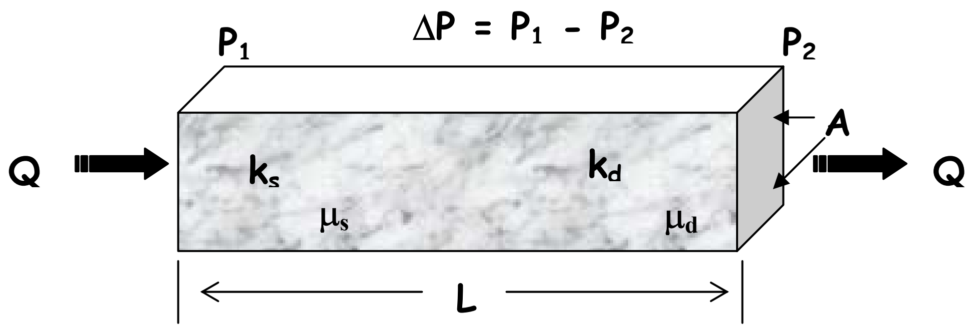
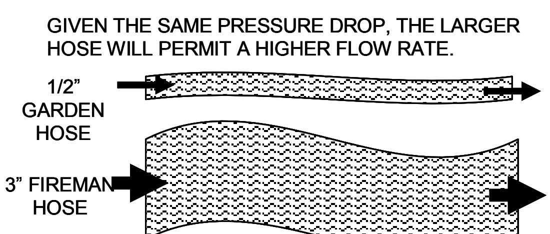
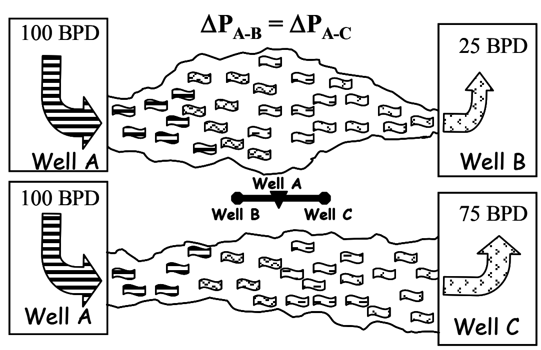


Figure 6

Flow Rate Vs Area



Darcy's Law Applied to Reservoir Behavior



Outlet geometry affects production rate (zero losses assumed).

Figure 7

Figure 8

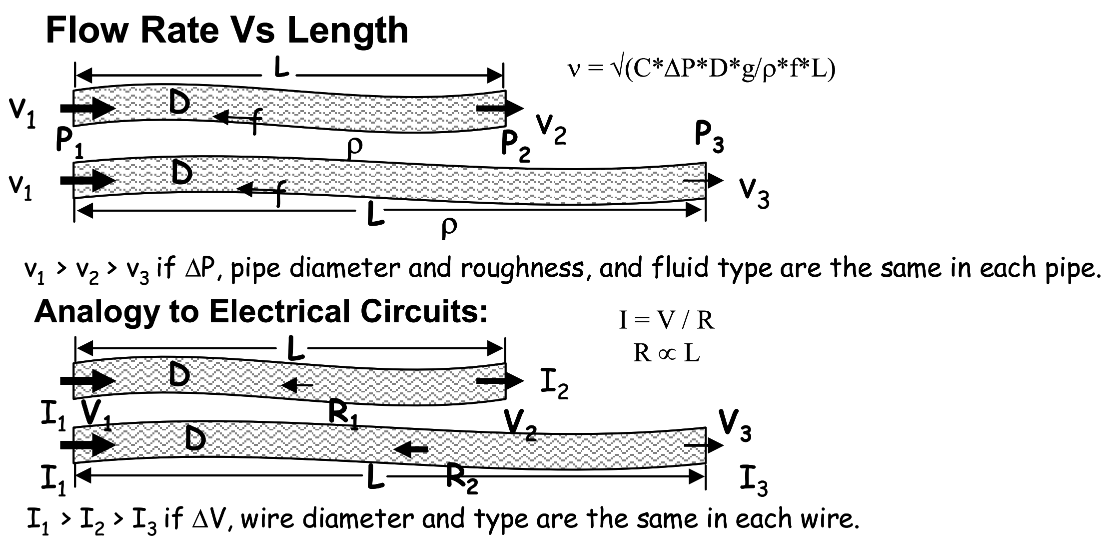


Figure 9

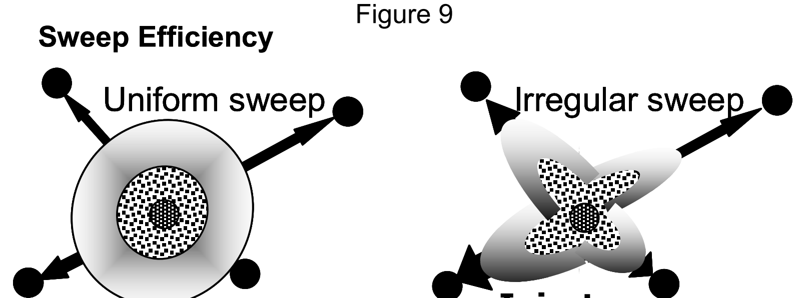


Figure 10

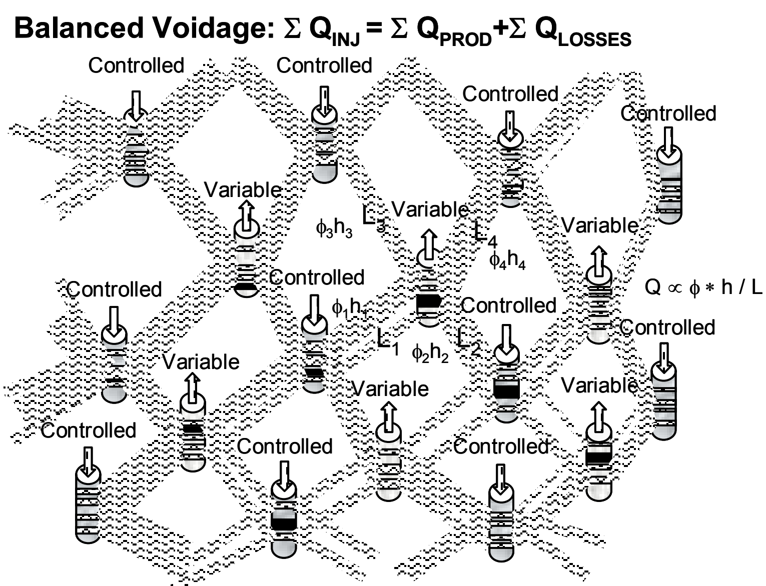


Figure 11

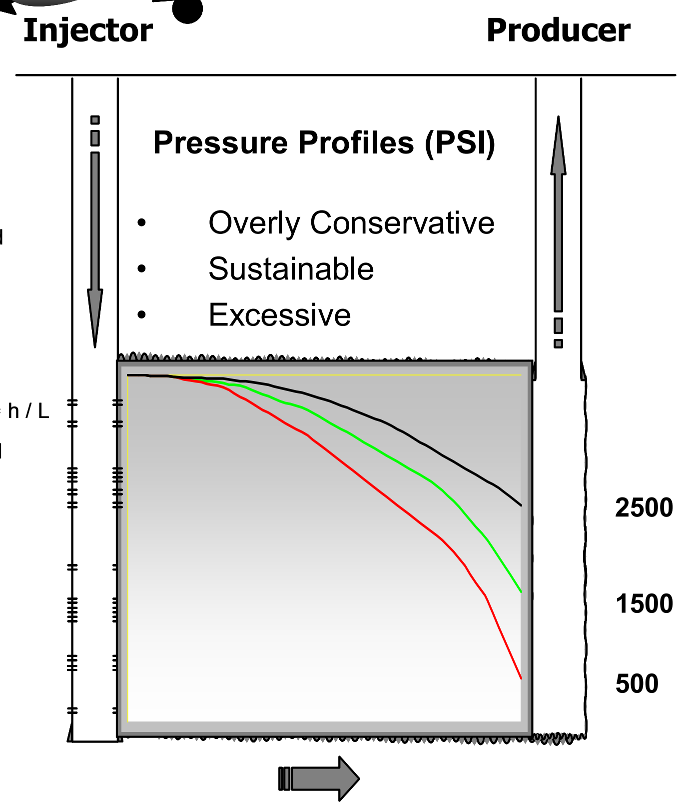


Figure 12

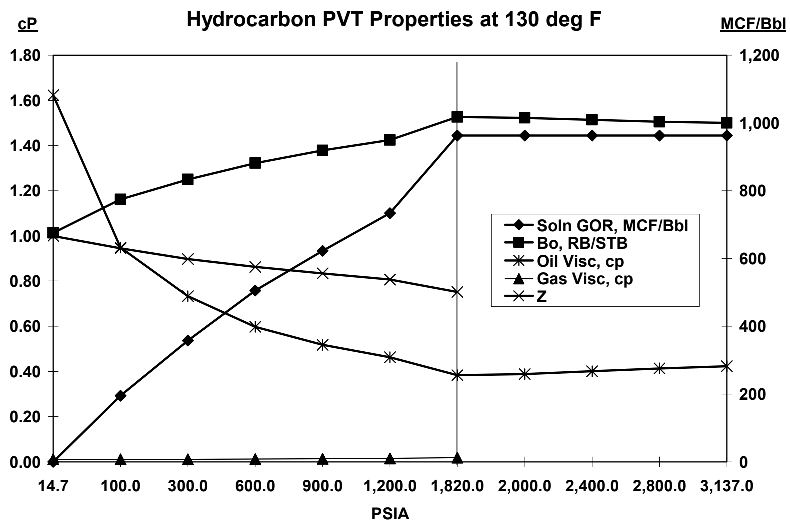


Figure 13

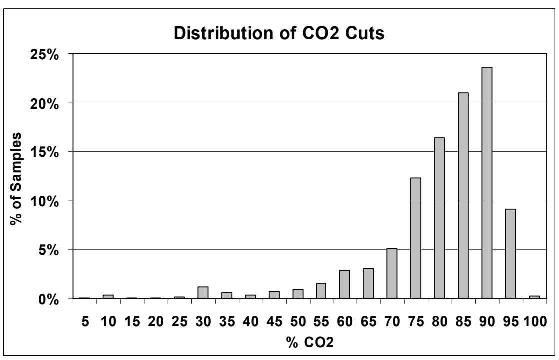


Figure 14

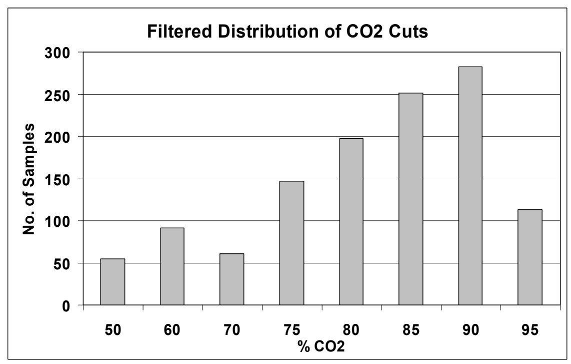


Figure 15

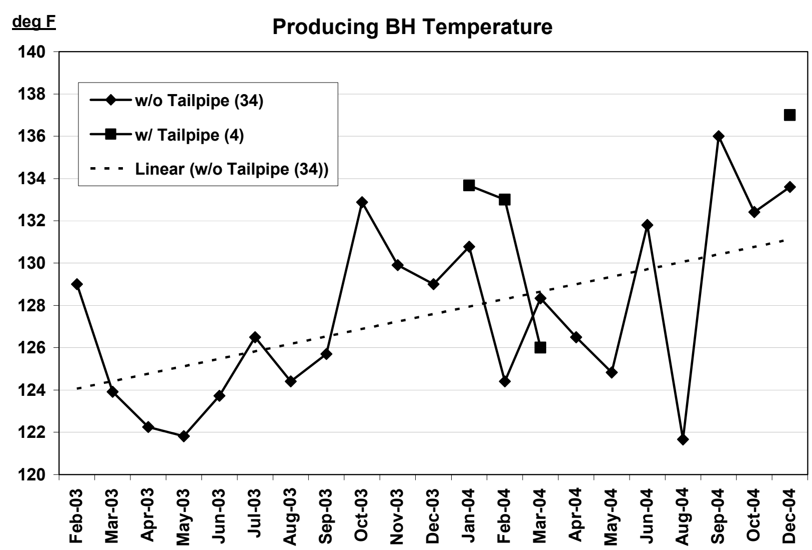


Figure 16

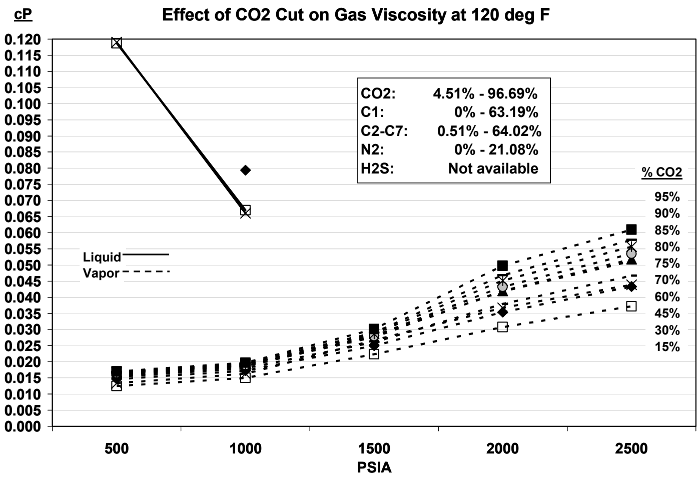


Figure 17

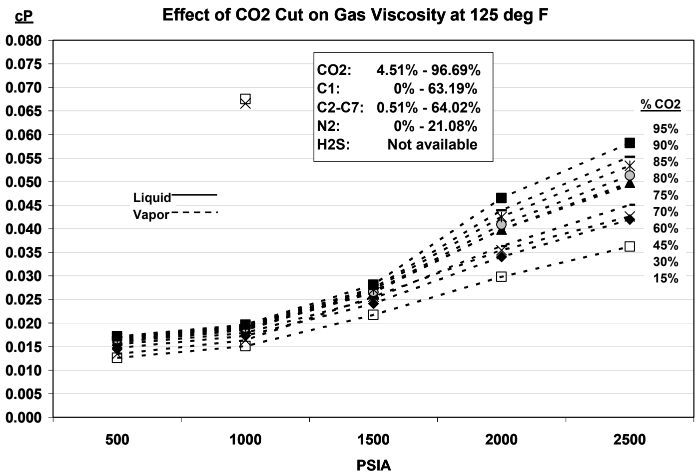


Figure 18

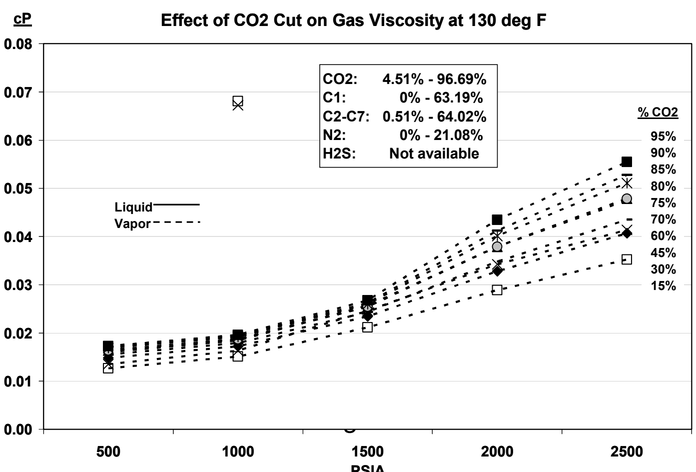


Figure 19

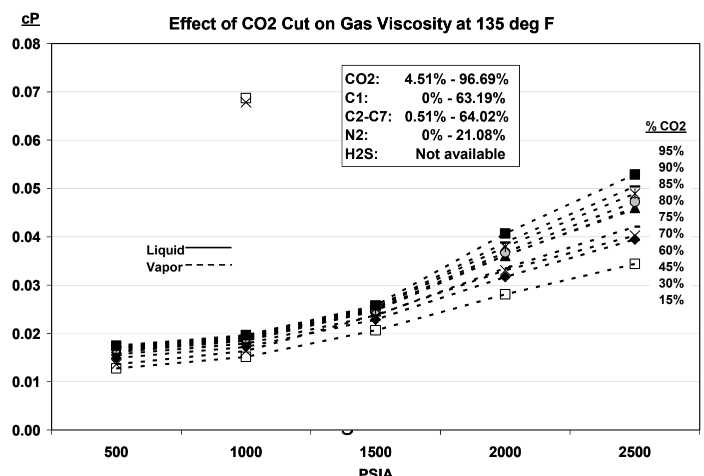


Figure 20

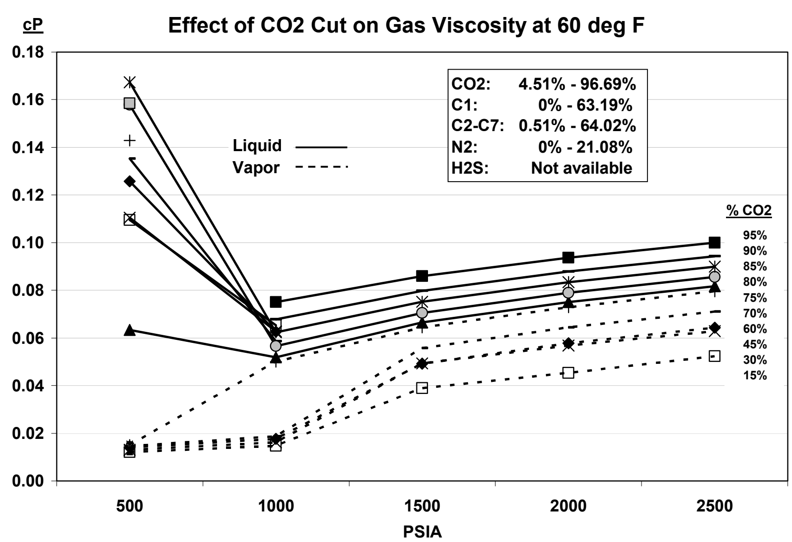


Figure 21

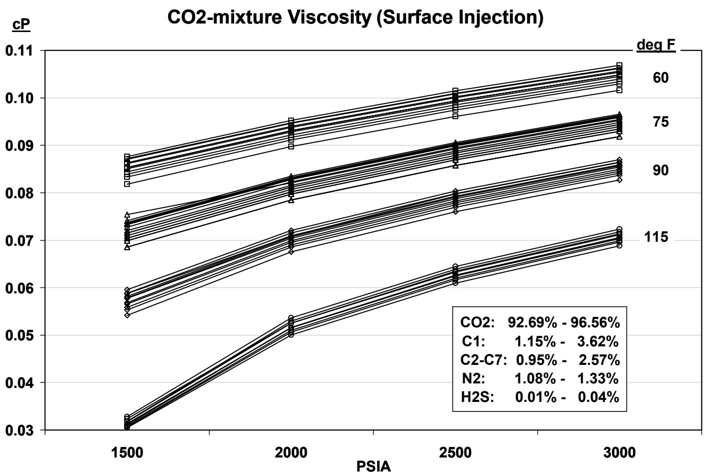


Figure 22

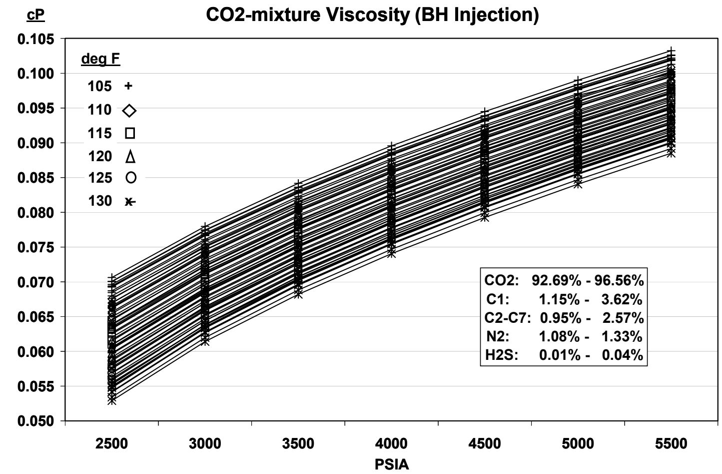


Figure 25

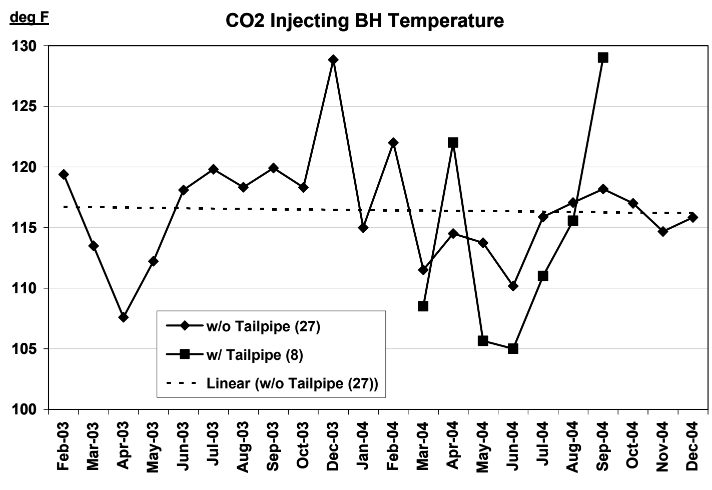


Figure 23

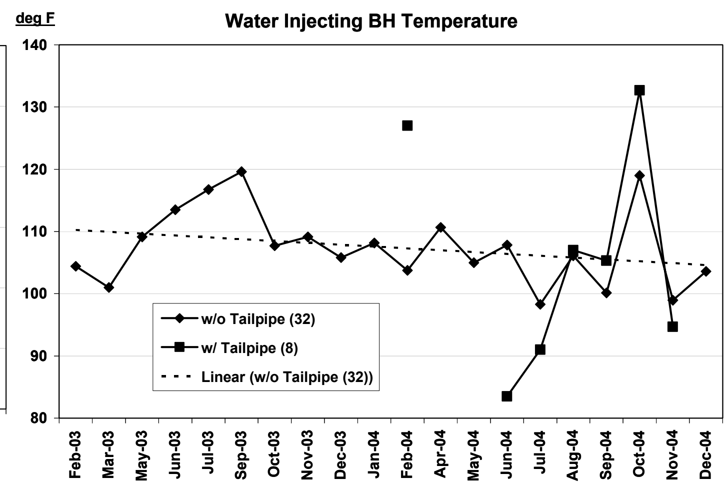


Figure 24

Examples of downhole problems that (any) computer application can't fix

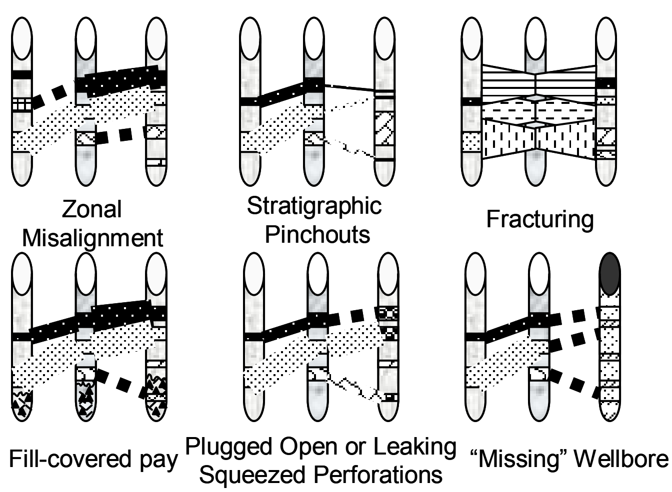


Figure 26