Productivity Impairment Forecast of Gas Wells in Latin America Due to Condensation

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Petrobras

Background

Gas reservoirs have long exhibited production problems when the pressure and temperature along the porous media and wellbore fall below the dewpoint.

The impact of the depletion strategy of gas fields on the well productivity, liquid and gas recoveries is a topic of increasing interest as deeper, hotter, richer and lower permeability is the reservoir.

There is a need to better understand the factors controlling the drainage and decline of well productivity due to condensation when pressure and temperature fall significantly below the dew point.

Aims

This study was undertaken to review Petrobras experience with gas reservoir performance related to the condensation phenomena.

Methods

Published industry experience along with Petrobras history cases have been evaluated and compared with laboratory experiments and theory.

Results

Condensation

Condensation is due to a pressure and/or temperature decrease below dew point in the wellbore and/or porous media.

Two primary factors are involved in the condensation phenomena (Figure 1):

1. Fluid composition and
2. Pressure and temperature history

The former characterizes the phase envelop and the amount of liquid drop out at different pressures and temperatures. The later defines the conditions which the fluid is expected to experience along the porous media and wellbore. The richer the gas and the lower the original condition of the reservoir pressure and temperature the higher the chances to condensation occur.

Every investigation shall start with a reliable and representative sample of the gas. Black oil representation of the fluid obtained from empirical correlations can not provide the necessary basis to handle the inherently compositional phenomenon. Therefore a compositional approach has to be applied to model condensation.

Downhole single phase sampling or surface gas and liquid sampling with recombination and correspondent gas chromatography and matching to laboratory PVT experiments are the way ahead. Sampling conditions, pressure and temperature, shall always be verified against estimated dew point in order to validate fluid analyses.

Liquid dropout versus pressure and phase envelop are the main fluid characteristics to be accounted for. They can now be framed in the expected pressure and temperature history according to the reservoir depletion and completion strategy.

Condensate will appear as depletion (pressure and temperature decrease) path along the porous media and wellbore intersects the two phase envelop. Otherwise the system is not condensation prone.

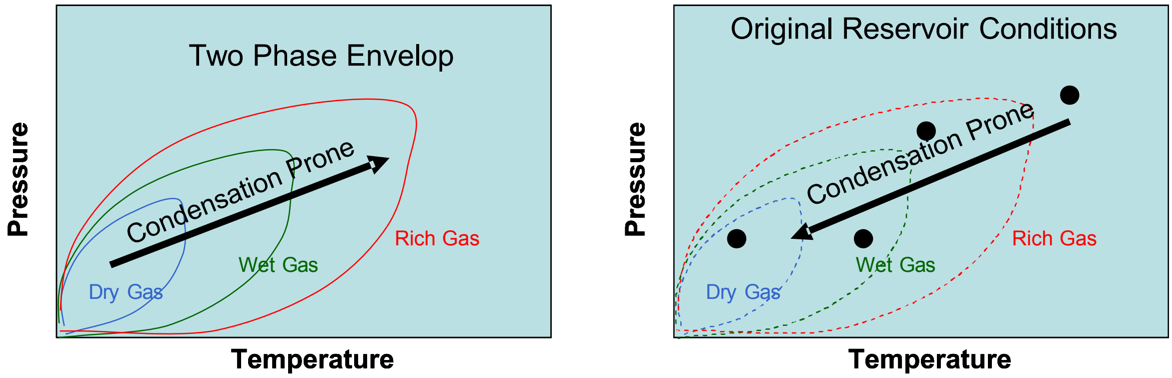

Figure 1 - Primary Factors Involved in the Condensation Phenomena

This paper presents as an example the analyses of a real case (Figure 2) where we assess the impact of the gas quality (poor, lean and rich gases) and pressure and temperature path (in the wellbore and in the porous media) on condensation.

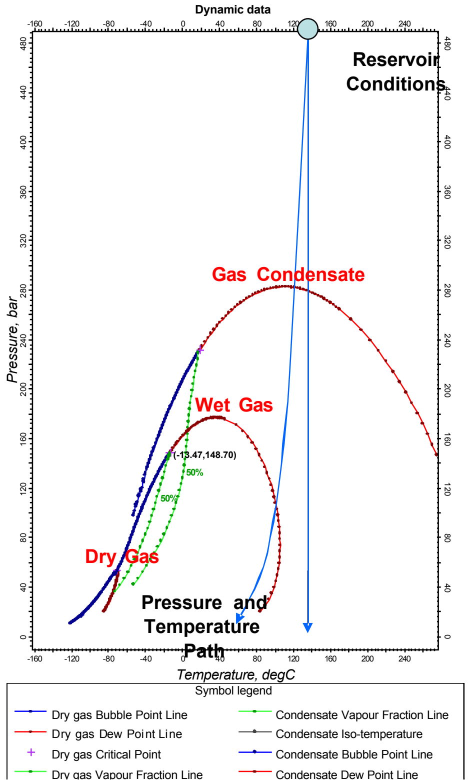

Figure 2 - Impact of the Gas Quality on Condensation

A typical poor gas (dry gas) has a liquid yield less than 10 stb/MMscf. The analysis indicates that in the case of a poor gas there will be no condensation to be handled. In this case, hydrocarbon condensation is not an issue to forecast productivity decline and more simplistic methods than numerical compositional simulation can be applied to forecast liquid and gas recoveries.

A representative lean gas (wet gas) has a liquid yield around 25 stb/MMscf. Whenever it is taken into consideration no hydrocarbon liquid saturation will be experienced in the porous media but some hydrocarbon condensation will happen in the wellbore as temperature decreases. Liquid deposition will not occur in the porous media as the reservoir temperature will always stay above the dew point temperature. However, liquid drop out will occur inside the wellbore as a consequence of the thermal loss all the way up from the perforations to the surface facilities.

Common rich gas (gas condensate) has a liquid yield greater than 60 stb/MMscf. In this case, significant amount of liquid drop out will occur in the wellbore as well as in the porous media. In this case, production of gas below the dew point will cause condensation to occur which creates a hydrocarbon liquid saturation in the reservoir.

Condensation in the Wellbore

When condensation occurs in the wellbore, if the natural energy of the gas flow is not enough to prevent liquid falling back, cumulative liquid loading at the bottom of the wellbore may pose a back-pressure effect at the sand face. That will reduce productivity and eventually may halt the production.

At a high energy condition, a gas well experiences a flow regime of annular-mist flow where the gas is the continuous phase and the tubing walls are coated with a liquid film. At a decreasing energy, a gas wells experiences some parts with a slug-annular transient flow regime. Further decrease causes some slugs to occur with some liquid fall back. Finally the gas well experiences a misty regime in the upper zone, annular in the middle and bubble regime in the bottom (Figure 3).

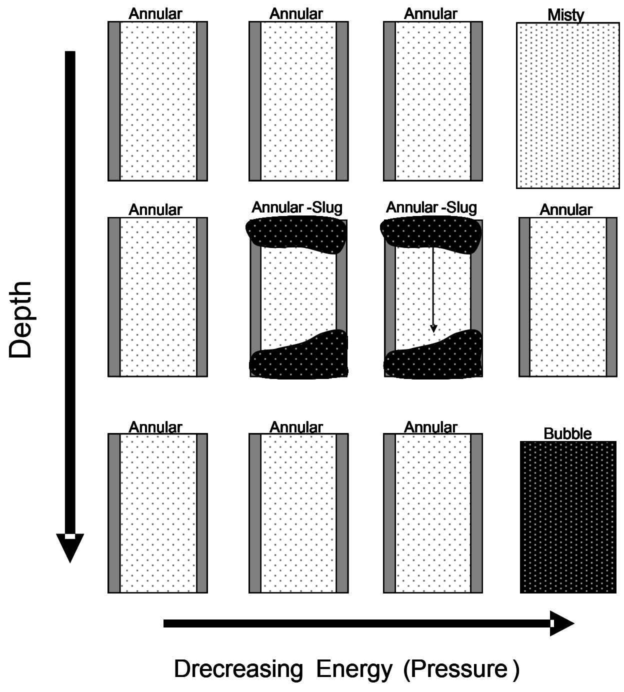

Figure 3 – Flow Regimes in Vertical Gas Wells

In the literature, most results indicate an upper zone with increasing gas fluid gradient (>0.1 psi/ft), a middle zone with typical dry gas gradient (<0.02 psi/ft), and a bottom zone with an liquid phase gradient (0.3 to 0.4 psi/ft).

The first accounts for an increasing holdup under a misty regime as result of the low temperatures. The second is justified by liquid slippage along the wall, annular regime, and the later is explained by a liquid column accumulated with the gas phase passing through it in a bubble regime.

This paper presents as an example a real downhole survey (Figure 4) that involves pressure, temperature and fluid gradient profile along the wellbore. The analyses indicate different gradients and flow regimes in three different zones of the wellbore:

1. Upper zone: Increasing gas gradient (increasing holdup) under a misty flow regime
2. Middle zone: Constant gas gradient under a annular flow regime and
3. Bottom zone: Liquid gradient under a bubble flow regime.

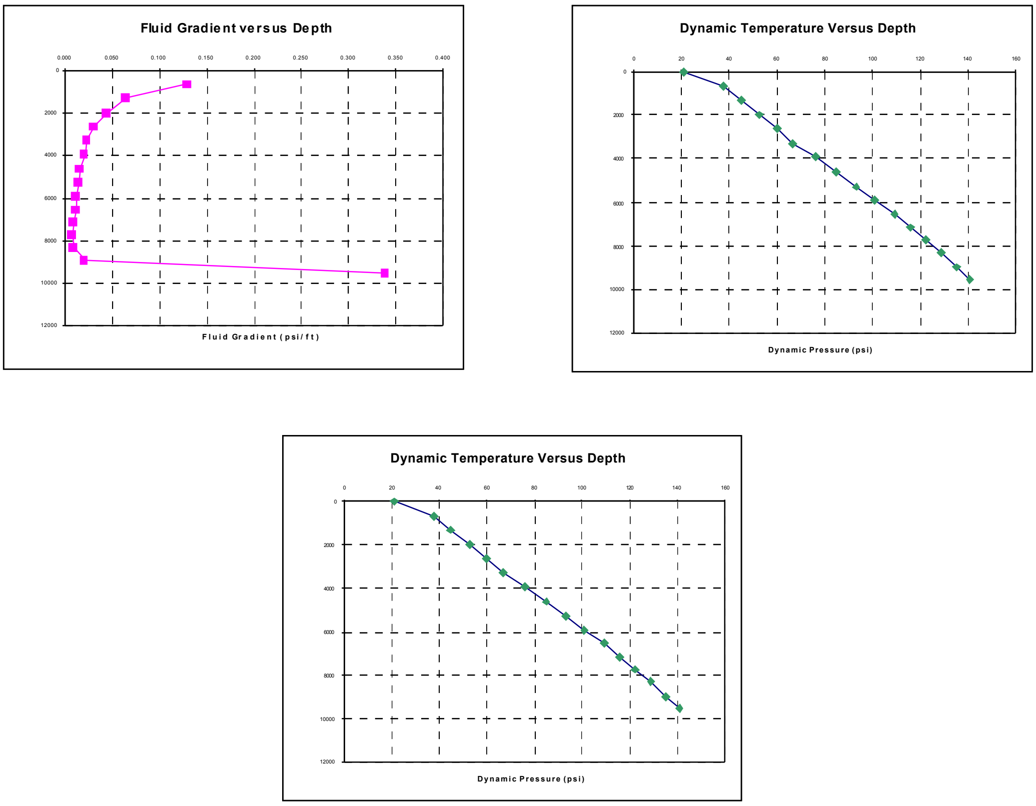

Figure 4 – Downhole Survey Example in Vertical Well

Liquid falling back can take several forms and their composition is not constrained to hydrocarbons. Liquids can be the result of the reservoir pressure dropping below dew point, coning or aquifer support. Water in liquid phase may also occur due to water vaporization in the wellbore and/or in the reservoir as function of the compositional equilibrium between vapour and liquid phases in the porous media with the pressure drawdown or depletion.

Liquid loading in gas wells happens because of the inability of the gas flow to remove the liquid phase from the wellbore. When gas flows below a minimum flow rate, determined by the inherent tubing and reservoir performances, the liquid phase accumulates in the wellbore. This minimum flow rate is the minimal gas flow rate required to naturally and continuously lift the liquid phase from the wellbore and prevent back pressure.

Simple reservoir models coupled with a compositional and thermal transient wellbore model allows matching downhole and surface transient data from gas wells in order to investigate the productivity impairment caused by condensation inside the wellbore.

They show that natural vertical flow will cease when the reservoir pressure approaches a certain value under certain wellhead premises. Below such a pressure, liquid back flow starts and a liquid phase will be accumulated, generating an additional back-pressure in the sand face that will eventually halt production.

The onset of liquid loading, critical flow velocity, can also be estimated based on analytic methods, such as Turner Droplet Model or Coleman Equation, valid for misty flow regime. As an example in real cases experienced by Petrobras, minimum estimated flow rates from Turner-s drop removal model indicates liquid loading conditions will likely exist in well producing less than 350 Mscfd at representative surface conditions.

Once the problem is forecasted, two main types of actions can be pursued: to avoid or to remediate the drawback.

The former comprises:

1. Using a small size string diameter to sustain a gas velocity above the critical one
2. Heating the upper part of the wellbore to avoid liquid condensation
3. Insulation to prevent liquid condensation in the upper part of the wellbore
4. Comingle multizones

Practical experiences show that liquid loading, liquid blockage between formations, interference and crossflow may cause inefficient production of wells with multiple open formations to one wellbore. Heating and insulation are not cost effective most of the time. A small size string diameter has an important impact on high gas production rates.

The remediation option involves the gas well deliquification which aims to produce the liquids artificially in order to help the gas to flow unobstructed again. Reduction or elimination of the additional wellbore backpressure caused by the liquid gradient zone play a key role in boosting gas well productivity and extending the lifetime of the field.

Applying deliquification technologies will lead to higher gas production rates in the short-tem and extended field lives until wells are fully depleted in this way securing the future of gas supplies form mature gas assets.

The coupled reservoir wellbore transient model may also help to investigate cost efficient artificial lift methods to reduce or eliminate back-pressures and extending the lifetime of a gas field.

Most common artificial lifting methods are (Alipour-Kivi, G, Bugacov, A., Khoshnevis, B., and Ershaghi, I., 2006, Rodriguez, A. and Schott, R., 2008 and Brady, C. and Morrow, S.,1994):

1. Cycling: well is shut-in to let it build up pressure and then open it.
2. Venting: well is open with a minimum wellhead pressure.
3. Surface compression: well head pressure is reduced to a minimum.
4. Swabbing: liquid is removed mechanically using a swab cup.
5. Plunger lift: piston driven
6. Jet pump (downhole and surface)
7. Surfactant injection (liquid, soapsticks and foamers)

Simulation results show that each of the above methods is suitable for specific ranges of wellbore and reservoir characteristics. Practical experience in Petrobras shows that cycling, venting, swabbing and surface compression are not effective at a long run. Plunger lift and jet pump are not cost effective in low permeability low transmissibility reservoirs. Soapsticks has been the most successful method. Applying such a method can maintain significantly lower backpressures and increase well productivity for a long time.

Condensation in the Porous Media

Hydrocarbon condensation in the porous media may occur in the whole reservoir due to a long depletion strategy or can be restricted to the vicinity of the well due to the local drawdown. That will depend on the pressure and temperature history that the fluid is expected to experience with time as a consequence of well spacing, completion strategy, absolute permeability, thickness, porosity and overall hydrocarbon volume.

Gas fields that are submitted to an exhaustive drainage plan by either a small well spacing or high production rates are prone to significant reservoir depletion. Low absolute permeability and thickness leads to significant pressure drawdown in the vicinity of the well.

These situations associated with a lean or rich gas can lead to a hydrocarbon condensation process in the reservoir that may result on considerable productivity impairment and consequent recovery loss. In the case of severe pressure decline conditions, significant productivity decline can also be experienced associated with lean gas condensate.

Published industry experience, laboratory data, simple analytical and complex numerical simulations flow models investigate the phenomenon and suggest that this overall process may reduce gas well productivity, liquid and gas recovery (Hichman, S. and Barree, R., 1985; Afidick, D,, Kaczorowski, N. and Srinivas, B., 1984 and Almarry, J., 1995).

Two main factors in the condensation phenomenon in the porous media are involved in the condensation phenomena:

1. Reservoir Transmissibility – K.h (Figure 5)
2. Pore throat size distribution - relative permeability and critical condensate saturation (Figure 6).

Reservoir Transmissibility K.h

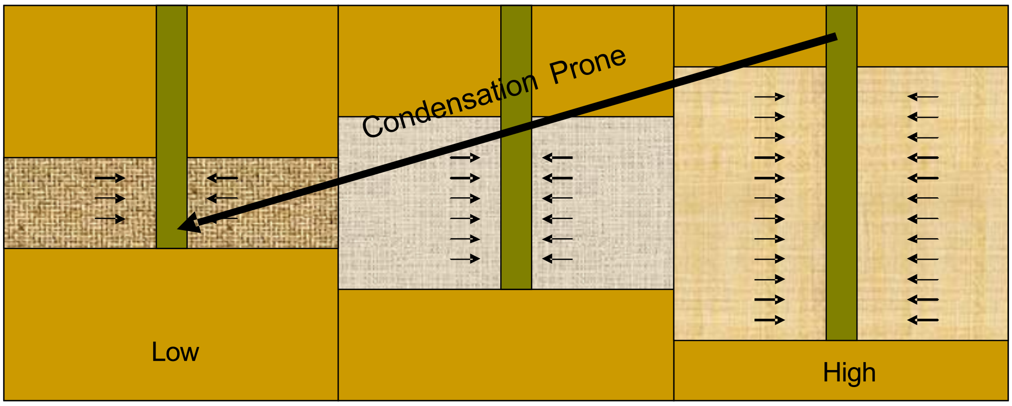

Figure 5 – Impact of Reservoir Transmissibility on Condensation

Most examples of severe productivity loss relate to moderately gas condensate fluid in low pressure reservoirs with transmissibilities within a range of less than 100 md-ft. The strength of the gas flow that discharges the liquid will mostly depend upon the reservoir energy and quality: pressure, permeability and thickness

Lower reservoir transmissibilities lead to a significant pressure drawdown in the vicinity of the wellbore and therefore to an expressive hydrocarbon condensation.

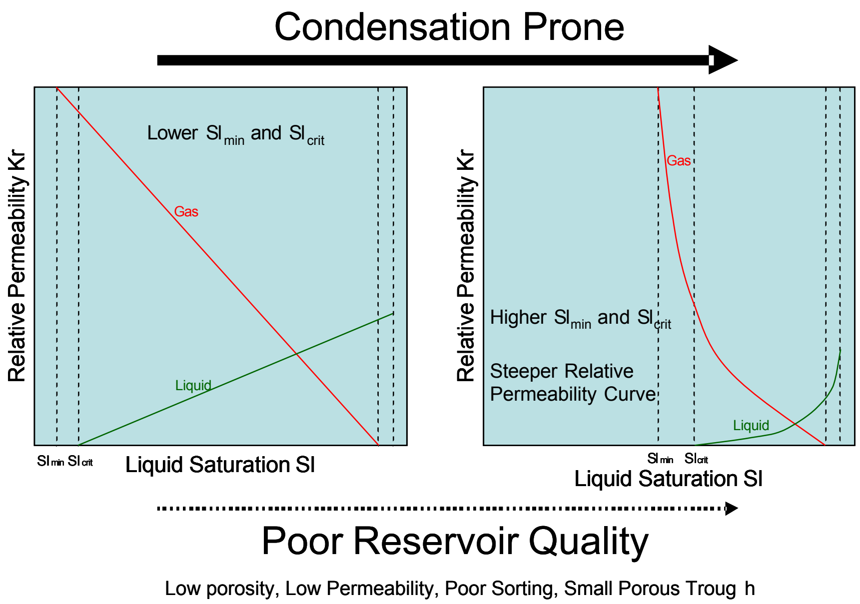

Figure 6 – Impact of Reservoir Quality on Condensation

Pore throat size is closely related to the relative permeability curve and critical liquid saturation (the minimum liquid saturation which the liquid phase starts flowing).

Poorly sorted and low pore throat size and porosity will lead to a steep gas relative permeability curve and high critical liquid saturation. Steep gas relative permeability curve implies a significant relative and effective permeability reduction with liquid saturation and a resultant severe productivity decline.

The formation of liquid condensate will reduce the reservoir relative gas permeability, since the liquid will occupy parts of the volume in the porous media that previously were used for gas flow. Liquid formed above the critical saturation is subjected to shear forces of the gas production that will immediately transport it to the wellbore and the relative gas permeability is therefore not significantly reduced.

A high critical liquid saturation leads to a great liquid accumulation before the liquid phase is allowed to flow. While the liquid saturation increases steady without liquid flow the steep gas relative permeability curve leads to drastic effective permeability reduction and consequent productivity decline. In the other way around, low critical saturations allow the liquids to be dragged by a strong gas flow throughout the porous.

Several authors have published laboratory derived gas condensate relative permeability data with a range of critical hydrocarbon saturations of 10% in high permeability sands to 30% in low permeability sands (Fang,F, Firoozabadi, A. Abbaszadeh, M. and Radke, C., 1996 and Kewen, L and Fioroozabadi, A. 2000). Critical gas saturation is often of the order of 1 to 5%. Some works point out that wettability may play a key role in the in the critical saturation.

Relative permeability curve experiments in low permeability sandstones can take months and are usually not performed for development purposes. Theoretical ones, such as Corey, with empirical exponents and end points are usually applied.

This paper presents as an example a real case (Figure 7) where the original pressure and temperature reservoir condition lies just above the fluid dewpoint.

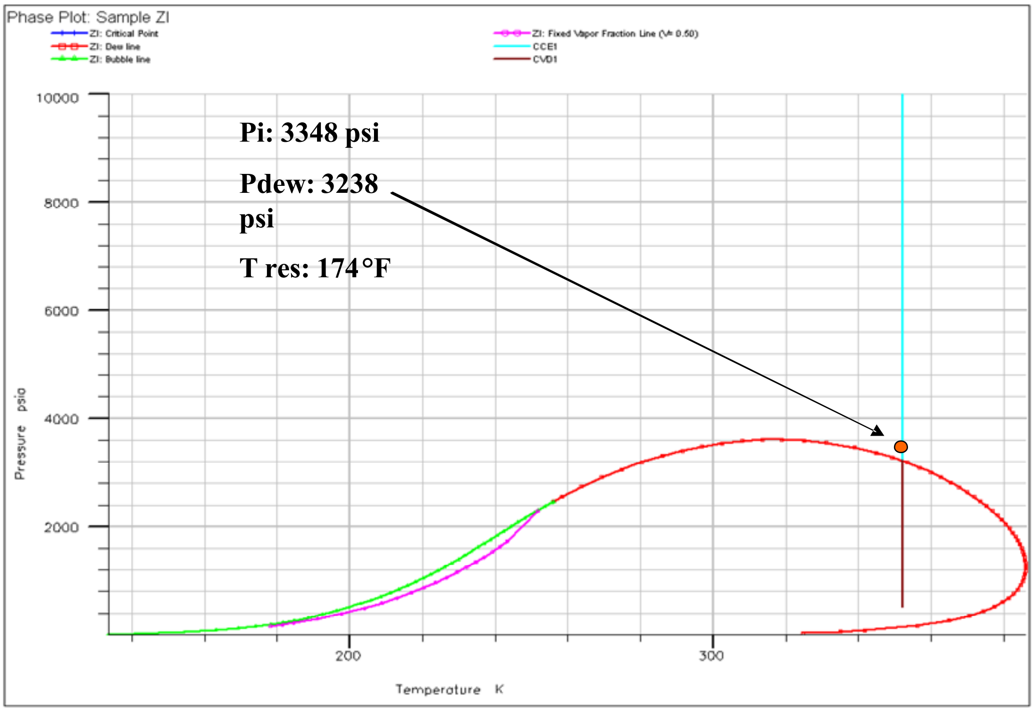

Figure 7 – Example of a Gas Reservoir just above Dewpoint

The figure illustrates that the expected pressure depletion path will intersect the phase envelop, hydrocarbon will condensate and liquid saturation will appear in the porous media.

Well test data has proven to be reliable and practical to identify the existence of condensation. The analysis of a short term modified isochronal test (Figure 8) confirms the identification of a first radial flow at short time and a second one at longer times. That would suggest a condensate ring near the well and further on an area with gas.

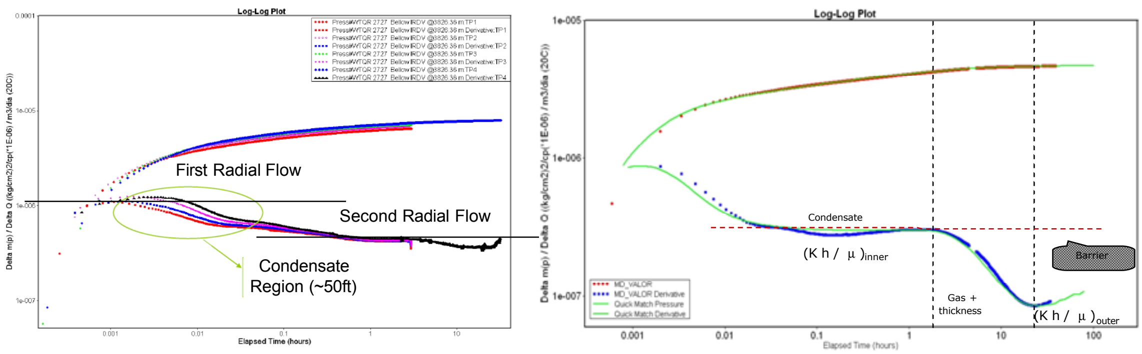

Figure 8 – Example of Condensate Identification and Gas Relative Permeability Reduction

As long as the hydrocarbon liquid saturation does not reach the critical saturation the phase is immobile and the gas production can not take it out from the porous media to the wellbore. During this period the gas relative permeability will keep on falling as liquid saturation increases. The gas relative reduction can be estimated by the mobility ratio of the inner and outer zones identified in the well testing.

As soon as the hydrocarbon liquid saturation reaches the critical saturation, the hydrocarbon liquid phase turns mobile, the gas production starts removing liquids in the porous media towards the wellbore and relative permeability stops reducing

This paper presents as an example a real case study of hydrocarbon liquid saturation calculation using a compositional numerical simulation.

Figure 9 shows the decrease of hydrocarbon liquid saturation with time as the gas production removes the liquids from the porous media to the wellbore.

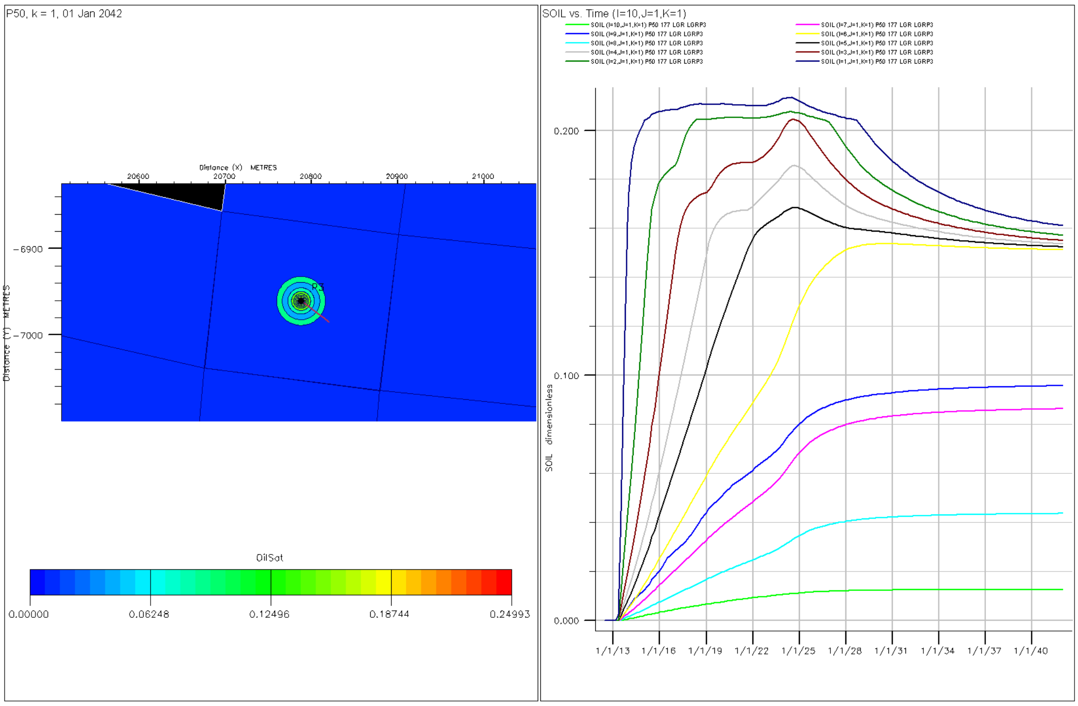

Figure 9 – Example of Numerical Calculation of Liquid Saturation with Time

Figure 10 depicts the decrease of hydrocarbon liquid saturation along the radial system as the reservoir pressure reaches values above the dewpoint pressure.

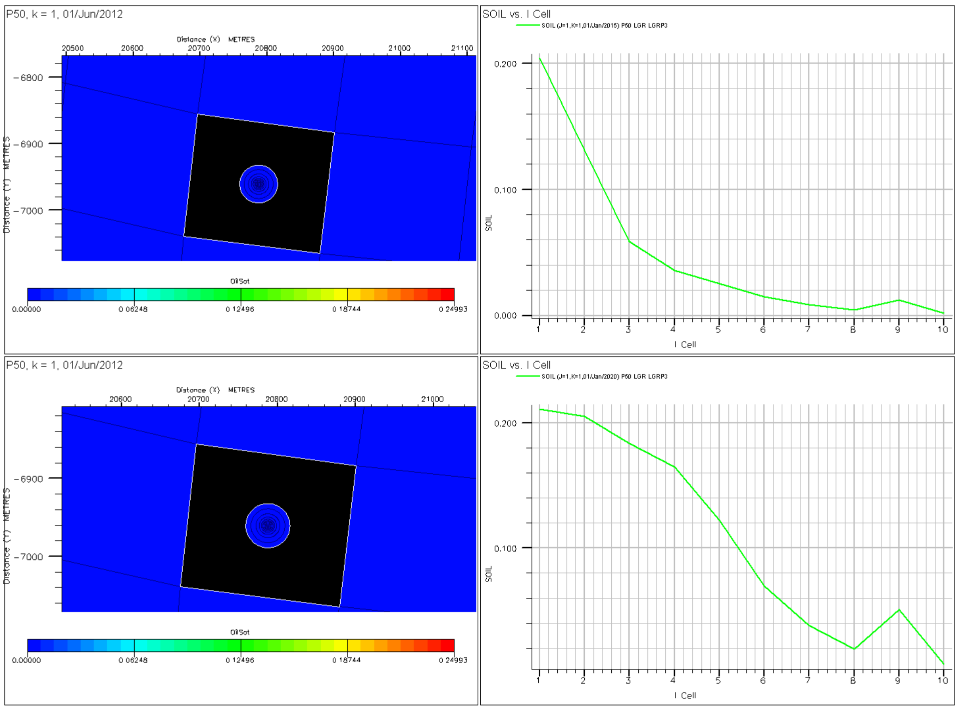

Figure 10 –Numerical Calculation of Liquid Saturation with Radial Distance

Gas condensate reservoirs have long displayed production problems when the pressure in the reservoir drops below the dewpoint pressure. Several authors documented the productivity impairment of a gas well (Afidick, D,, Kaczorowski, N. and Srinivas, B. 1984; Barnum, R. Brinkman, F. Richardson, T. and Spillette, A.,1995 and Hichman, S. and Barree, R., Productivity Loss in Gas Condensate Reservoirs, SPE 14203, 1985).

Once condensation in the reservoir is identified and characterized the following actions may be taken into consideration:

1. To account the productivity impairment in the forecast of gas and condensate production curve
2. To look for processes to prevent or reduce the formation of liquids within the reservoir such as (Ahmed, T. , Evans J. , Kwan , R., Viviam T. 1998, Garzon, F. Al-Anazi,H, Leal, J. and Al-Faifi, M., 2008):
   a. Gas cycling process to reduce the liquid dropout by vaporization
   b. Pressure maintenance schemes to keep the reservoir pressure at or above the dewpoint pressure.
   c. Huff`n Puff method for decreasing liquid dropout. This process could be a viable option in the near wellbore region when sufficient volume is injected before the maximum liquid dropout is reached.
   d. Hydraulic fracturing
   e. Inhibited diesel treatment

This paper presents as an example the real case study of production forecast (Figure 11) where productivity impairment from hydrocarbon condensation is accounted by means of compositional numerical simulation and compared with the correspondent black oil model. The results show a reduction of the ultimate recovery factor of a gas condensate field.

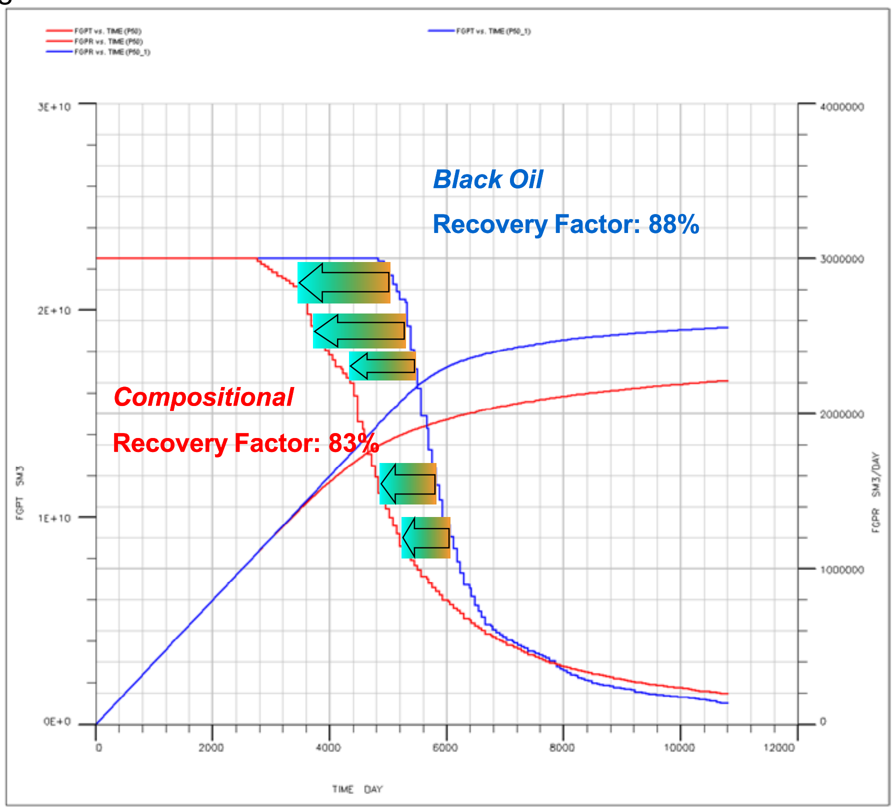

Figure 11 – Example of Production Forecast with Productivity Impairment

The impact of the condensation in the reservoir performance is particularly severe not only in low permeability low thickness reservoirs where a significant pressure drawdown can occur in the vicinity of the well but also in exhaustive pressure depletion where the whole reservoir pressure lies below the dewpoint.

An interesting real case experienced by Petrobras is the one where a naturally fractured reservoir with a very low permeability is exhaustively depleted without a significant impact on productivity impairment. In this dual porosity case, the high permeable fractures allows the mobile hydrocarbon liquids that appear with the pressure below the dewpoint to be shortly removed (low critical saturation) without a significant impact or reduction in the gas relative permeability. Moreover, the gas condensation in the very low matrix and consequent gas relative permeability reduction does not affect the overall permeability that heavily relies on the fracture permeability (not affected) and on the highly effective system of natural fractures that connects the matrix.

This paper presents as an example a real case of numerical simulation study (Figure 12) where the ultimate recovery of black oil and compositional modelling leads to similar results.

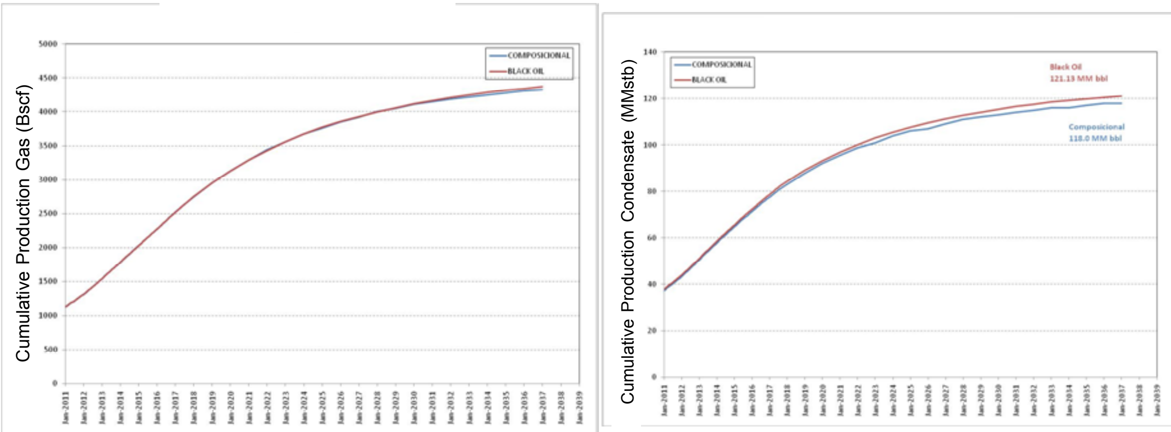

Figure 12 – Example of Production Forecast in a Dual Porosity Model

Summary/Conclusions

A comprehensive review and summary of published literature (history cases, laboratory experiments and theory) has been undertaken, evaluated and compared with Petrobras experience in Latin America.

The results indicate an important impact of condensation in the wellbore and a mild one in the porous media. The last one is usually predicted and accounted for, the former is remediated with artificial lift methods such as soapsticks.

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