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OPTIMIZING RECOVERY FACTOR IN MULTILAYERS MATURE GAS FIELD, BASED ON DECLINE CURVE ANALYSIS METHODOLOGY

1. FIELD BACKGROUND

The Laslau Mare field is located in the Transylvania Basin, Romania.

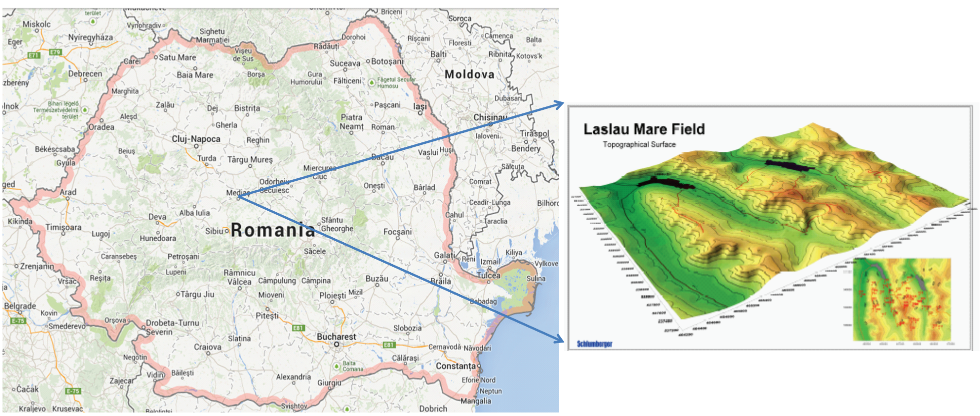

Fig. 1. Field Location

This is a multi-reservoir brownfield, vertically split in 6 reservoirs called "production packages" with different fluid contacts and pressure levels; shale intercalations divide the reservoir layers in several separated sandstone or shaly-sandstone layers; to add complexity the two

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uppers reservoirs have high water production risk and the lower reservoir s have low permeability as tight reservoir. Definitely, this mature gas field is a school where to learn how a diversity of issues with fluids and pressure and technical problems such as: old completions, tubing leaks, casing leaks, wellhead leaks, scale problems, iron incrustation and water loading are managed.

In the figure 2 is displayed on the left side a typical well log with SP and resistivity curves; in the center are shown the average petrophysical parameters such as: net pay expressed in meters, porosity expressed in percentage and permeability expressed in mD, and on the right side the layers, production packages and production zones.

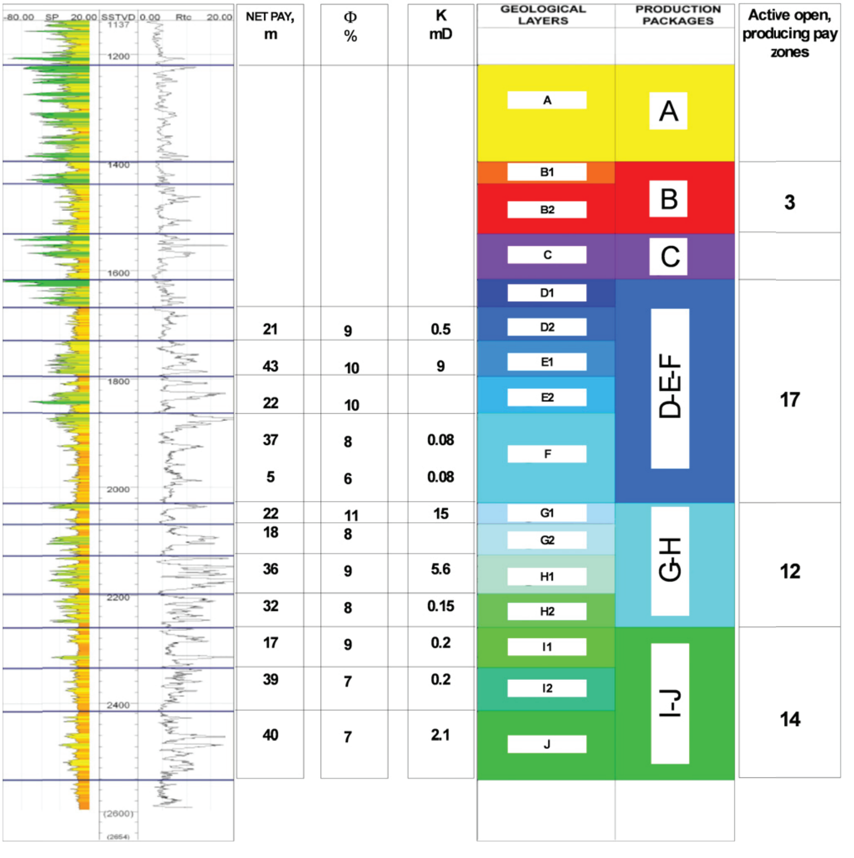

Fig. 2. Field Stratigraphy (multi-layers)

The production began in 1975 and the present recovery factor is estimated around 74%. Seventy wells had been drilled and 49 of them are still active. A new infill well has just been drilled in March and completed in April 2014, 20 years after the last well drilled in the field. The logs and data acquired in the new well allow for a better understanding of the current reservoir conditions and will be useful to update the database and reduce the uncertainty in the forecast profiles.

2. RESERVOIR CHARACTERIZATION

The reservoir rocks are mainly composed of sandstones, having a variable thickness from centimeters up to a few meters, alternating with marl and clay beds with a variable thickness. The average reservoir properties are presented in Table 1.

Table 1
Reservoir Characteristics.

Effective porosity, (%)	6–14
Initial Gas saturation, (%)	53–66
Permeability, (mD)	0.1–15
Net thickness, (m)	7–34
Reservoir temperature, (° C)	56–81

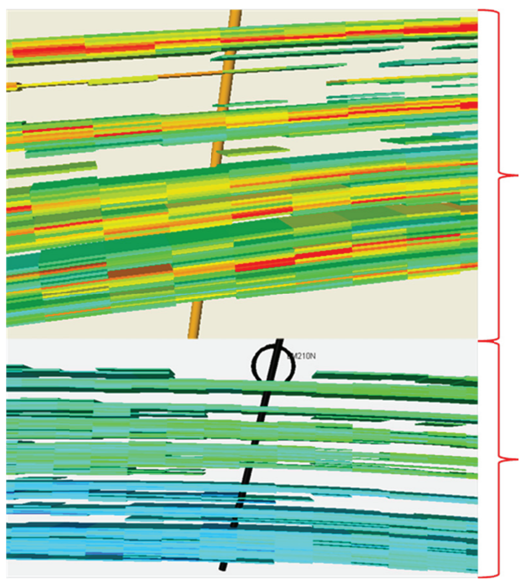

Fig. 3. Reservoirs Stratigraphy (multi-layers)

During the long exploitation period, the dynamic reservoir conditions had changed, and we expect they will continue to change in the future, as the field becomes more mature, negatively impacting gas recovery factor. The negative impact include: decreasing reservoir pressure, reduced gas volume, higher frequency of problems with water loading, scaling, well and facilities aging, and increased operational risk. These problems will become more frequent as the theoretical ultimate gas recovery factor of Laslau Mare field is approaching, requiring more interventions and production optimization work, leading to higher operational costs and investments.

3. DEFINITIONS

The decline curve analysis methodology (DCA) is crucial to optimizing recovery in mature field. Applying DCA on well by well basis allow the identification of the perfect moment to take an action and suggest an intervention on the wells. This reduces the deferred production in the field and allows maintaining a “sustainable” production target.

Hubbert peak theory makes predictions of production rates based on prior discovery rates and anticipated production rates. Hubbert curves predict that the production curves of non-renewing resources approximate a bell curve. Thus, according to this theory, when the peak of production is passed, production rates enter an exponential decline. Brons (1963) and Fetkovich (1983) applied the constant pressure solution to the diffusivity equation to show that the exponential decline curve actually reflects single phase, fluid production from a closed reservoir (i.e. volumetric, pressure-depletion reservoirs). In other words, its meaning was more than just an empirical curve fit.

The decline curve analysis (DCA) in exponential trend lines is considered a suitable technique for this field and will be used to determine the future baseline characteristics.

The decline rate of Laslau Mare field is based on the historical gas production trend line. The average of the last year production rates was agreed as initial gas rate for forecast profiles, and it has been agreed to use the 2013 daily average of 697 Kscm/d (Thousands standard cubic meters per day). Starting date: will be Jan-2014.

For the determination of base-line it is necessary to forecast a case using the decline rate in a period of time where no further activities of any kind are performed in the field from now on. That is:

- “Base Production Maintenance Operations” are carried over.
- No additional production enhancement operations are considered.
- No additional investments (CAPEX) are considered.

4. DCA METHODOLOGY

Production decline-curve analyses (DCA) is one of the oldest but still most widely used tool in the industry for oil and gas reservoir analyses, production forecasting and reserves estimation. The production decline curve shows the amount of oil and gas produced per unit of time for several consecutive periods; if the conditions affecting the rate of production are not changed, the curve may be fairly regular, and, if projected, will provide useful knowledge regarding the future production of the field. Early on, the industry recognized the characteristic decline of oil and gas well performance and attempted to predict its course by fitting empirical equations to the production history. Later it was demonstrated that solution of the diffusivity equation for pressure-depletion conditions of a single phase fluid justifies the exponential decline production performance of a field.

DCA techniques have many advantages: they use hard data (production history) which is easy to obtain, they are easy to plot, they yield results on a time basis, and they are easy to analyze with a minimum of assumptions and interpretation. Properly implemented, DCA techniques provide robust results that are widely accepted by the oil and gas industry, certification agencies and financial institutions.

The procedure consists of:

1. Identify a period of time where DCA conditions are technically applicable (i.e. declining production, constant operation conditions, constant number of producers, base maintenance operations).
2. Select the field or well to analyze.
3. Select a forecast graphics to do a DCA.
4. Select a variable and its phase: Average daily gas and gas.
5. Select a history match fit type: Exponential or best fit, setting b=0. Equation 1.

$$\begin{gathered} am = (\ln((1 - da)^{1/12}) \\ \textit{here: am=monthly nominal decline ratew} \\ da = \textit{annual effective decline rate} \end{gathered} \tag{1}$$

6. Select declination rate type: Yearly nominal or monthly nominal.
7. Select the scale type: Semi-log.
8. Fit the extreme point matching with the period of time of interest and allow the software to compute a best fit line that considers all the points in between.

The ideal period to estimate the natural decline is when we don't have incremental production from maintenance or enhancement operations (i.e. we need a declining production), and keep the same number of active wells (e.g. in our database project is managed as completions, because the field has 8 wells that produce from two reservoirs commingled). These two considerations are difficult to find in the recent history of Laslau Mare, due to the fact that in the last seven years were executed many maintenance or enhancement operations.

The methodology to estimate the decline rate is subjective to the software used, as well as to the interpreter, but the subjectivity can be reduced with agreements regarding the parameters to be used during the DCA, e.g., the eight points mentioned before.

The methodology can be applied on well-by-well or field-wide basis, to compare results of procedures. DCA also allows estimating the total decline rate, the mechanical decline rate, and the natural reservoir decline rate.

It is possible to get different decline rates depending on the period of time considered. In the following section these issues are addressed and suggestions are provided for the selection of suitable analyzed intervals.

5. APPLYING DCA METHODOLOGY IN LASLAU MARE FIELD

Gas reservoirs located in Laslau Mare field are produced by depletion drive mode. The produced gas is dry, mainly methane, and the current recovery factor at the end of 2013 is approaching 74 %. Production history is available and very well established. From that point of view, DCA techniques should provide a suitable and straight forward technique for future production forecast.

Results for DCA field-wide basis

The complete gas production history in Laslau Mare Field was considered to make one of the most used DCA graphics. In this regard, all what is required is to plot the field production history over time as showed in figure 4.

For twenty eight years the field was managed by Romgaz. In September 2003, an agreement between Romgaz and SPM Schlumberger was signed, to manage and optimize the production of Laslau Mare brownfield. From the start of this association in 2004, the increase of activity and investment in the field was proven to be very effective by enhancing the field production profile. As a result of the permanent and ongoing operations, production has been increased and/or maintained at high levels, considering the maturity and depletion of the field; for this reason the field production decline cannot be anymore derived for this period. This is because production is either increasing, or declining at a very low rate due to the continuous optimization process set up in the field. For these reasons it became difficult to estimate the decline rate in the last years since end of 2008 (see figure 4).

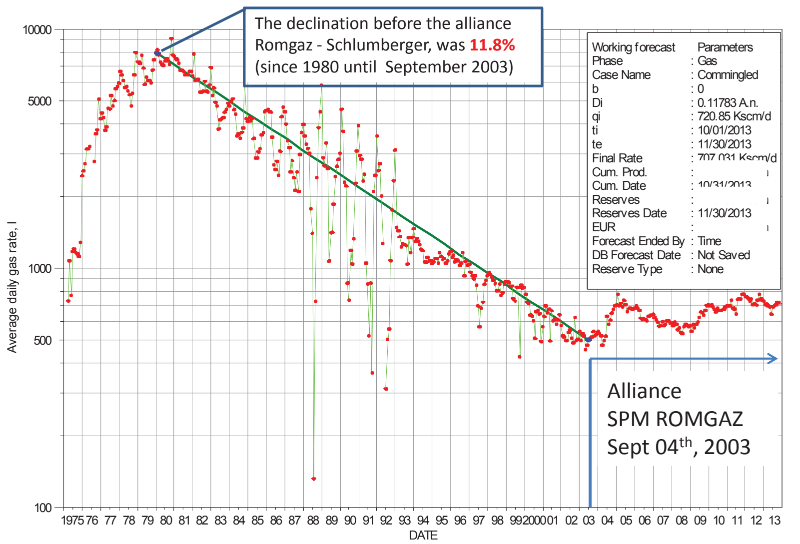

Fig. 4. Gas Production decline rate versus time, Laslau Mare brownfield

Between 1983 and 1994 the production was highly impacted by the seasonal market demand. The gas market demand introduces a kind of noise to the interpretation unless some filtering or re-sampling is applied to the data. For this period no decline was estimated.

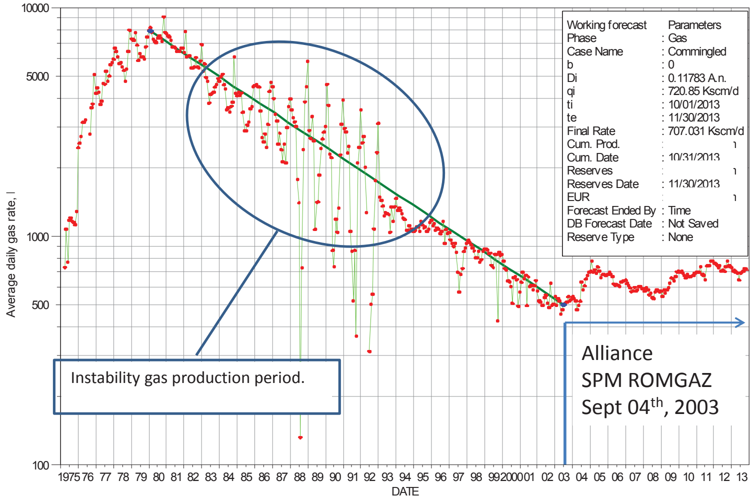

Fig. 5. Gas Production decline rate versus time; unstable gas production period

The period between 1996 and 2003 is characterized by less aggressive outtake due to the fact that the field was not exploited at its full potential. The resulting declination was 10.7% annual nominal. 1995 shows a stable production, so it's difficult to estimate a declination for that year (it wasn't considered for that reason).

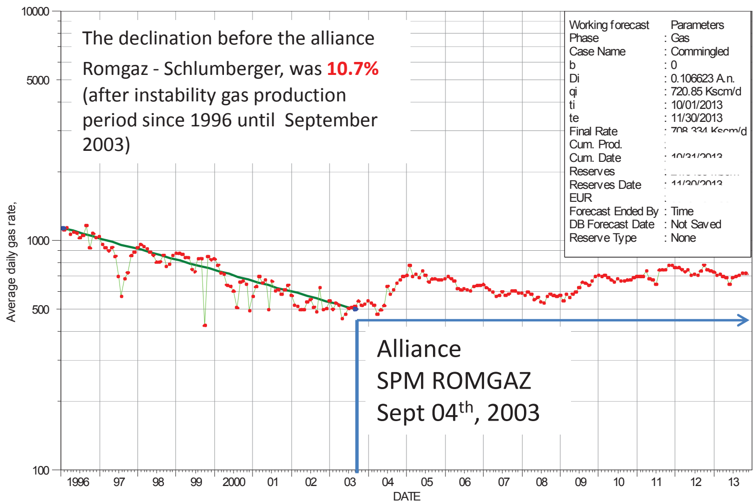

Fig. 6. Gas Production decline rate versus time; seven years before alliance contract

Production period 2005-2008

Between May 2005 and July 2008 there was a recession period in interventions, when the field operations were limited to basic maintenance, without production enhancement operations. Thereby, this period can be defined as “base production maintenance operations” period and can be used to determine a reference decline rate.

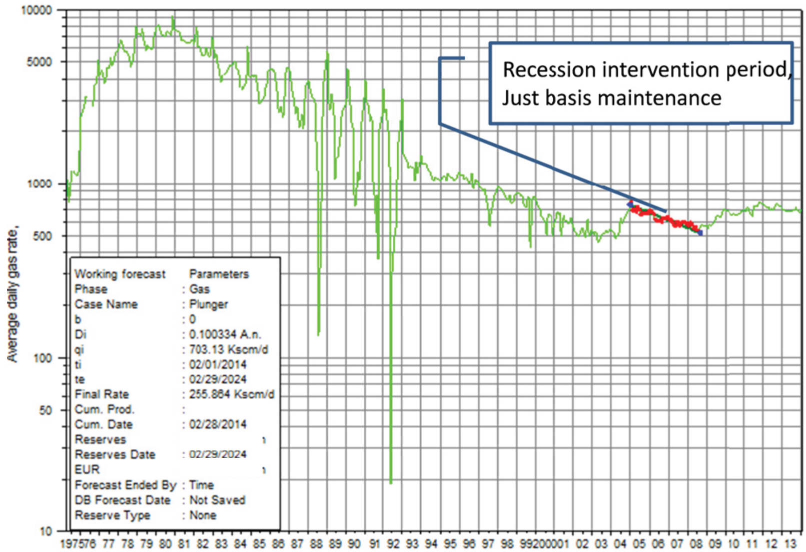

Fig. 7. Decline rate during base production maintenance operations period: 2005 -2008

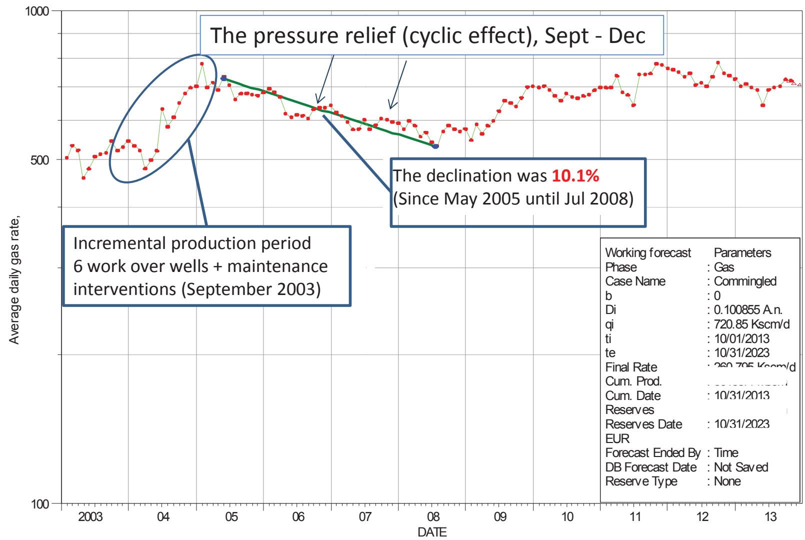

Fig. 8. Gas production decline rate - detailed period 2005 to 2008

During this period of time the decline rate was 10% as we can see in the figure 7. This trend line was useful to validate the decline rate calculated in different periods of time that had been showed before.

It is worth noting that the surface network pressure impacts the production behavior and this is imposed by the national grid intake pressure, highly influenced by the gas market demand.

It is also useful to compare the decline rates of different periods of time and this way evaluate the change of the gas volume mobility and relative permeability on the decline rate.

Recent period: August 2008-YTD

Since August 2008, many production optimization operations and interventions have been executed, making the decline analysis difficult due to their impact on the production trend.

The table below shows the type of interventions during this period of time.

Table 2

Well operations classified by intervention type

Intervention type	Quantity
Acidizing	46
Kick off	61
Velocity String	4
Compression	5
Work over	22

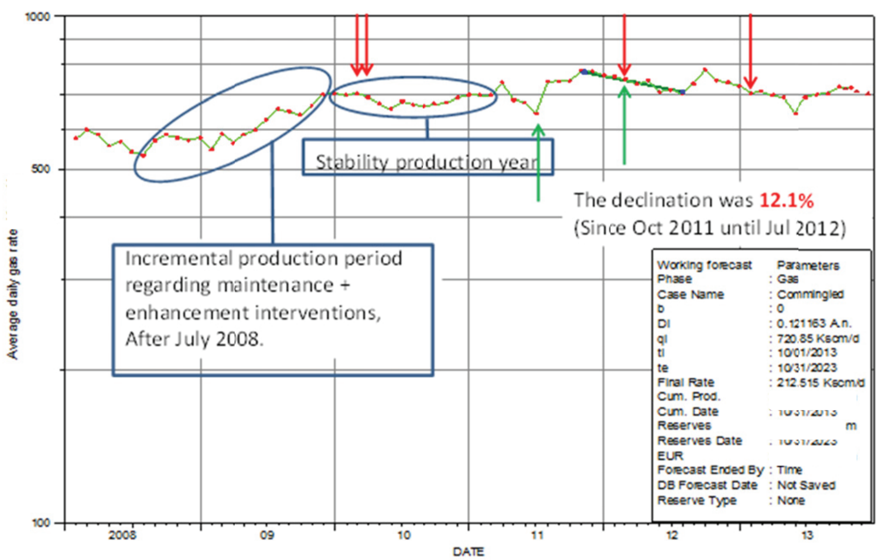

Fig. 9. Gas production decline rate - detailed period 2008 to 2013

Between August 2008 and December 2009 the production was constantly increasing due to the well interventions executed. In 2010 the gas production looks mostly flat, as a result of the previous field operations and the continuing production optimization.

During the first six months of 2011, the gas production started decreasing, but this period of time was short and is not enough to use to determine a decline. At the end of 2011, the gas production started increasing due to seasonal pressure variations, production enhancement operations, and especially due to the WO operation in well LM-X05. This well accounted for ~10% of the field when started producing after the WO, but declined at ~60% initial year.

Since October 2011 until August 2012 the gas production started decreasing due to low market demand, corresponding to a decline rate 12.1% as shown in figure 9.

The field production was affected by some events during the past 4 years. Some examples with higher impact in the production behavior are:

- Negative Impact:
  LM_X35 (- 8,5 Kscm/d) salt precipitation; Feb 2010.
  LM_X27 (-30 Kscm/d) casing leaks; Apr 2010.
  LM_X12 (-30 Kscm/d) casing leaks; Feb 2012.
  LM_X07 (-10 Kscm/d) casing leaks; Jan 2013
- Positive Impact:
  WO LM_X05 (60 Kscm/d) Jun 2011.
  Deepening LM_X20 (20 Kscm/d) Feb 2012.
  Deepening LM_X43 (08 Kscm/d) Jul 2012.
  Acidizing and compression effect Aug 2012.

After July 2012, the gas production was increasing due to the positive impact of the above mentioned optimization operations. The gas production trend between September 2012 and June 2013 was used to calculate another declination percentage and the resulting decline rate was 11.9% (see figure 10).

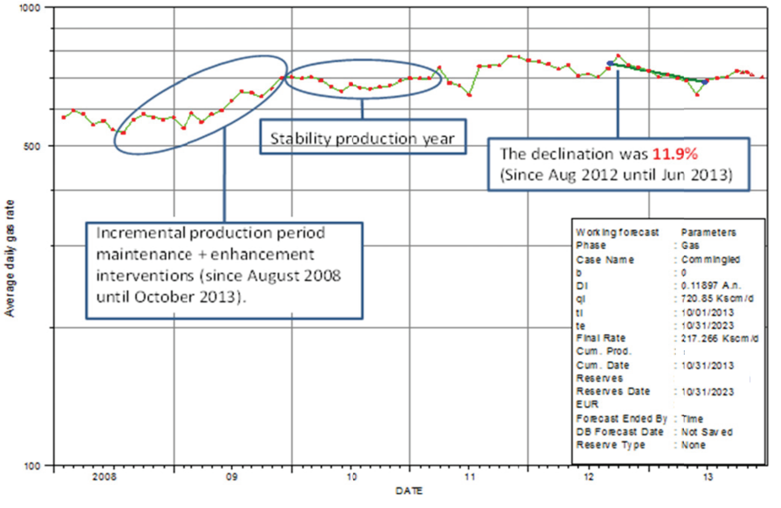

Fig. 10. Gas production decline rate, period 2012 to 2013

A field DCA that includes all the producing wells for a long time, describe the total decline of the reservoir. The total decline has two components one of them is the mechanical decline and the other is the natural reservoir decline.

Results for well-by-well DCA

Another kind of analysis is called well-by-well approach. Applying DCA methodology, the new procedure consists in evaluating each producer well separately, in case of the commingled wells by completion or reservoir. At the end, all the monthly gas production rates are put together to obtain a curve that would represent the natural decline rate of the field, estimated with exponential trendline.

This procedure would take more time to analyze in some cases, depending on the number of producer wells, and is also more complex - it generates as many DCA graphics as the number of wells producing in the field.

The procedure consists of:

1. Select the completion well.
2. Select a forecast graphics to do a DCA.
3. Select a variable and its phase: Average daily gas and gas.
4. Select a history match fit type: Best fit.
5. Select a method: by user (b=0)
6. Select declination rate type: Yearly nominal.
7. Select forecast type: Exponential.
8. Select a limit range and set in X axis: from 20050501 to 20080801
9. Select the scale type: Semi-log.

This type of analyses was performed for 52 wells, some of which are commingled, translating in 57 completions to analyze. They were classified in 4 groups:

1. Decreasing gas rate,
2. Flat gas rate,
3. Lack of data,
4. Increasing gas rate.

One example of each are presented in figures 11 to 14.

To get an average decline rate for this scenario should add up the monthly gas production rate from each well. The exponential trend obtained represents the average decline rate. Depending on the wells selected, the decline rate would be the total decline, mechanical decline or reservoir decline. E.g. if we include all wells, the resulting curve could offer the option to estimate the total decline; if we select instead the wells with mechanical issues, the curve resulting could offer the option to estimate the mechanical decline, and if we exclude the wells with mechanical issues, the obtained curve could offer the option to estimate the natural reservoir decline.

Our target was to get a total decline discarding only the completions with increasing gas rate and the resulting curve is showed in the figure 15.

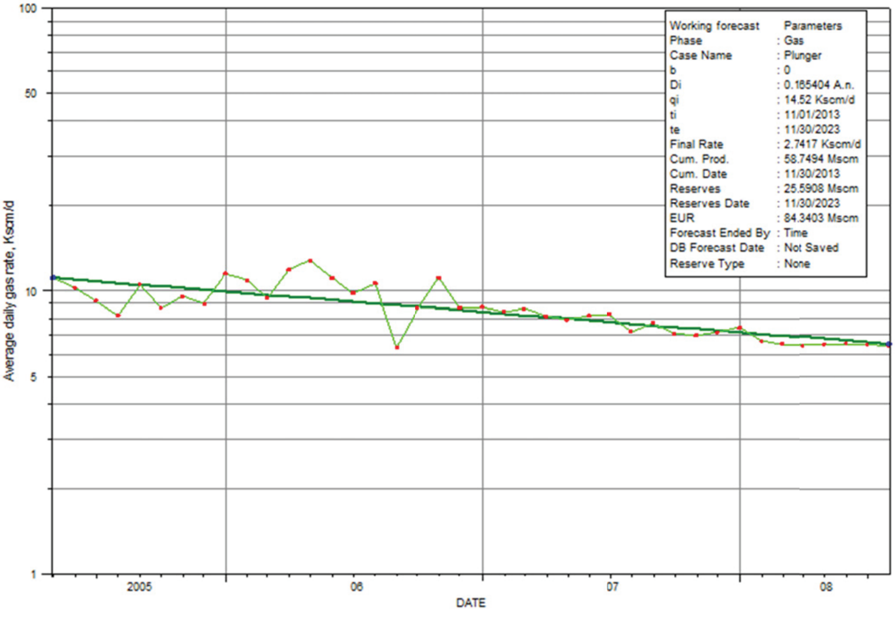

Fig. 11. Decreasing gas rate type decline for period 2005 to 2008

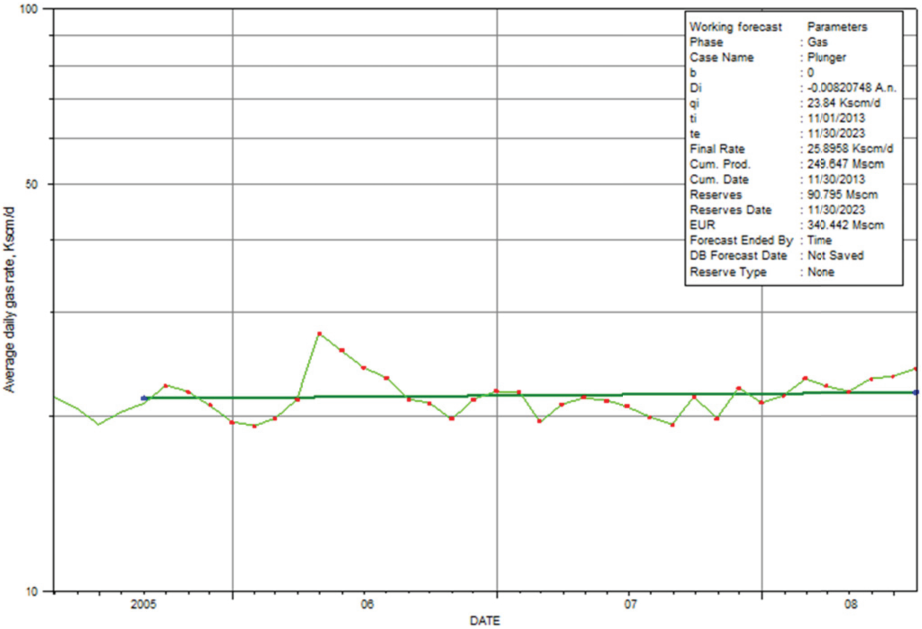

Fig. 12. Flat gas rate type decline for period 2005 to 2008

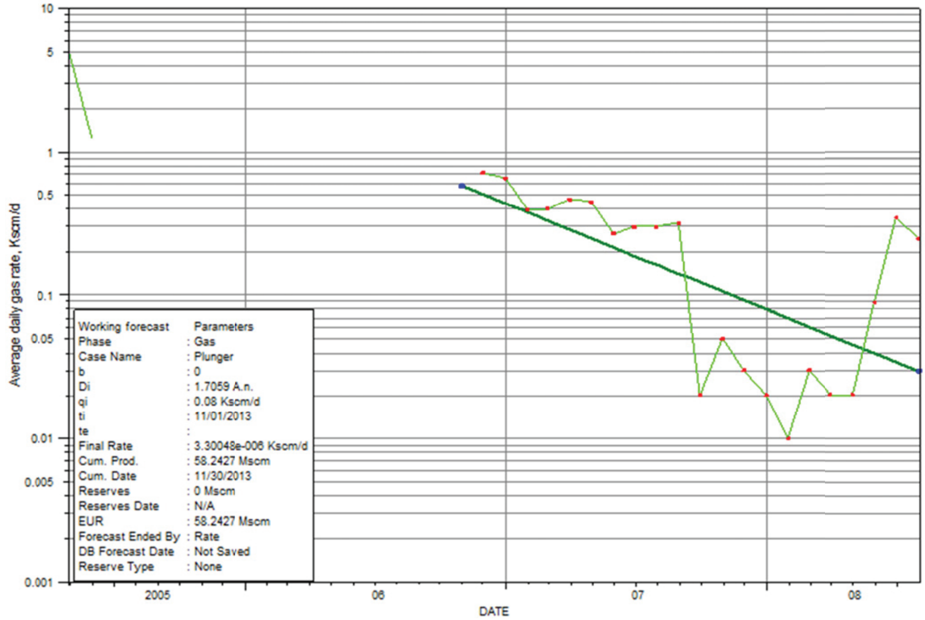

Fig. 13. Lack of data type decline for period 2005 to 2008

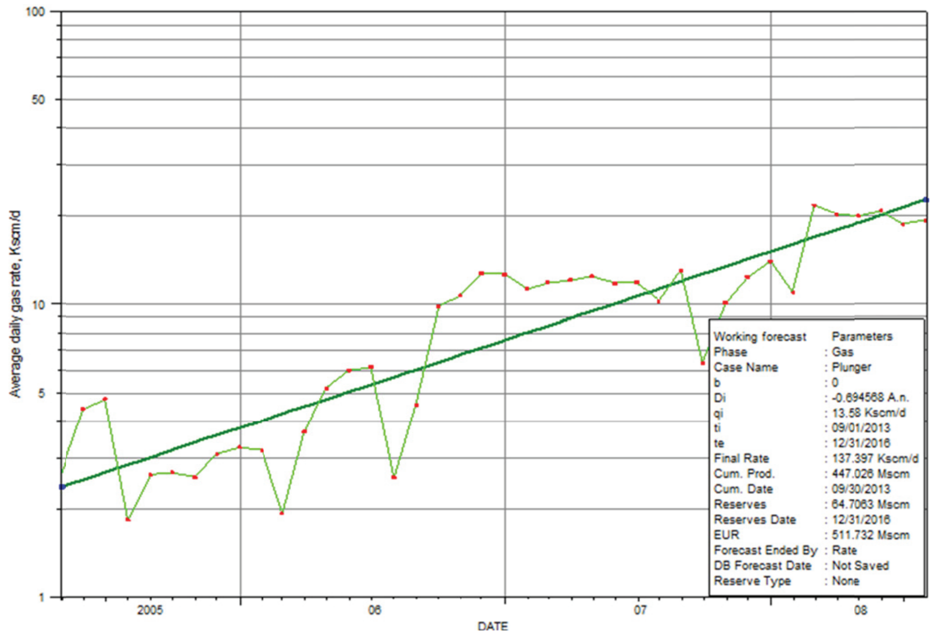

Fig. 14. Increasing gas rate type decline for period 2005 to 2008

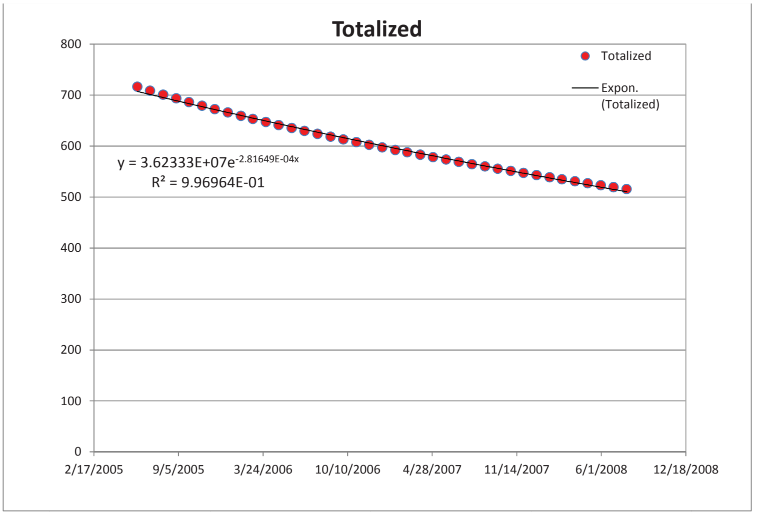

Fig. 15. Result of well-by-well DCA in Laslau Mare field, period 2005 to 2008

Table 3

Decline rate in Laslau Mare Field, period 2005-2008

	Exponential	Cumulative Production Volume
Decline Rate, %	**10.3%**	**11.58%**

The decline rate was 10.3% using a conventional exponential function, and 11.6% using another method to get the decline rate, called "cumulative production volume".

$$Y=3.62E+07*EXP(-2.816e-04*X) \tag{2}$$

We use the best fit trend to sum up the gas production rate by month, from May 2005 until Jul 2008, according to ROMGAZ requirement. Afterwards, the best fit trend lines by well were exported to Excel and were summed up and, as was mentioned before, a decline was estimated for the total using an equation for exponential function.

6. REDEVELOPMENT STRATEGY FOR MATURE GAS FIELD BASED ON DCA

In a mature field as Laslau Mare, is recommended to apply the DCA methodology monthly, focusing on the most recent decreasing production period of each well, to identify the production enhancement opportunities in order to improve the ultimate gas recovery factor per well.

As was mentioned in Result for DCA field-wide basis section, estimating the decline rate in the last years is important for a realistic forecast, to propose operations in the wells, and for a better understanding of how the gas production modifies the reservoir conditions.

The well-by-well DCA methodology was also applied in the most recent production period in each well, to determine the current decline rate in Laslau Mare Field (see some examples of these DCAs in the following figures: 16-18). The periods analyzed for the wells are not the same, because the wells have different production behavior depending on: operation type (compression, soaping, acidizing, kick-off, etc.), producing formation, time of execution and national grid pressure control.

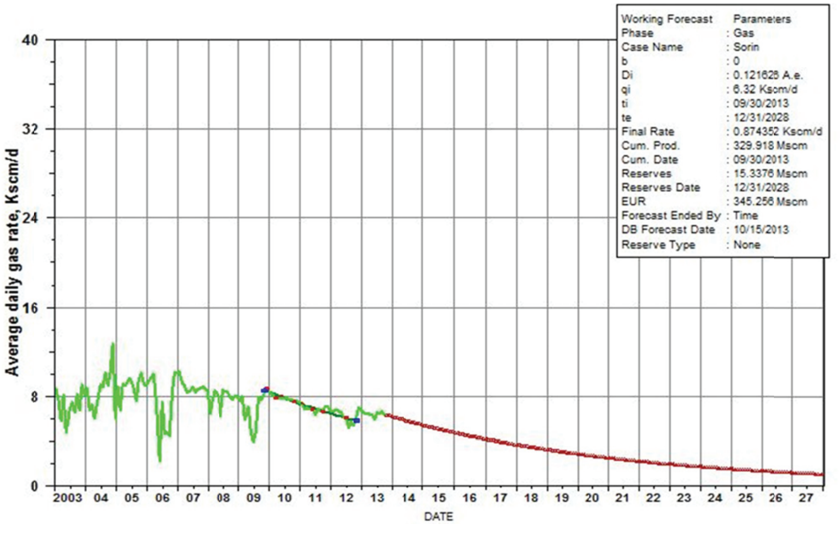

Fig. 16. DCA for LM_X1, D E F Reservoir

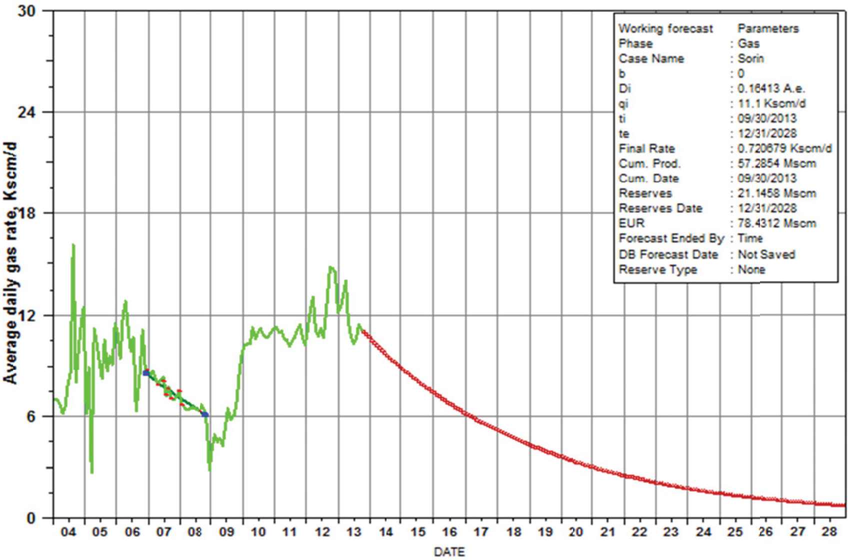

Fig. 17. DCA for a well in G-H Reservoir

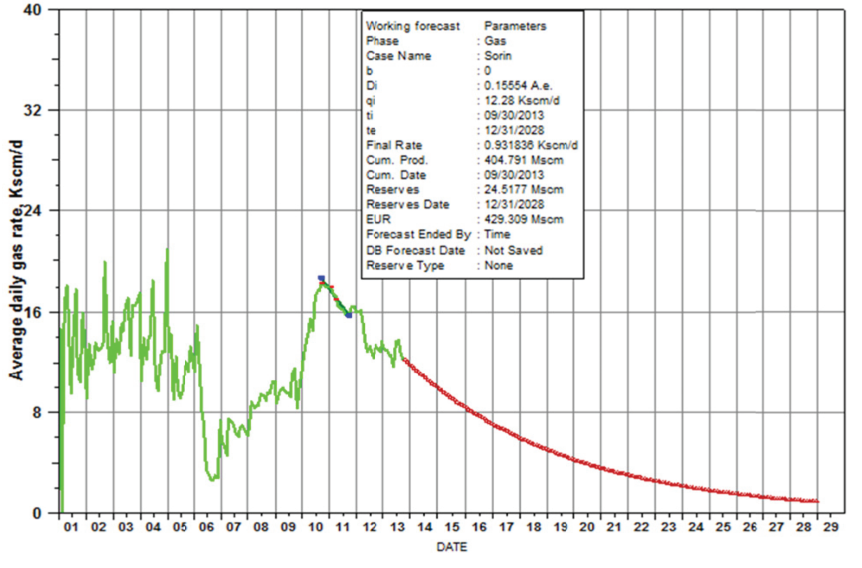

Fig. 18. DCA for a well in I-J Reservoir

The gas production forecast by well are located in Appendix A. The forecast was generated from November 2013 to December 2028.

The monthly production forecast resulting for each well was summed up to obtain a forecast profile for the field (see figure 19).

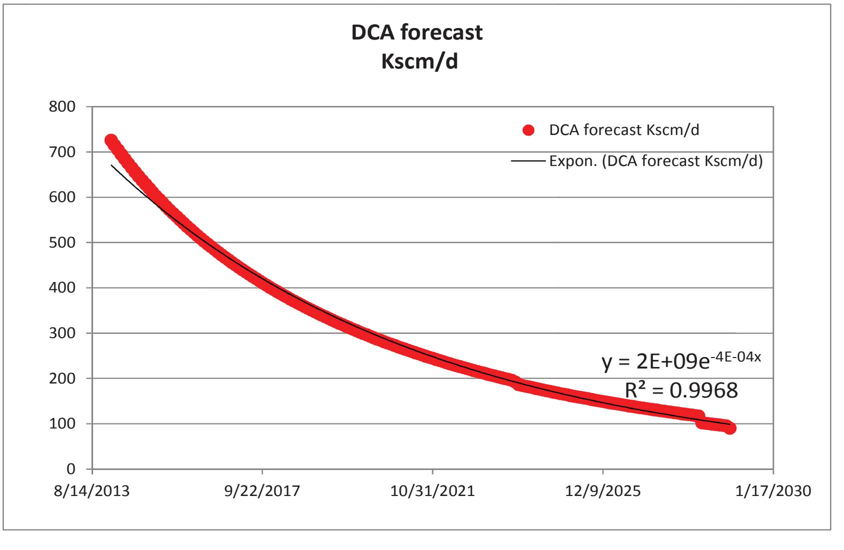

Fig. 19. Result of DCA well by well in Laslau Mare field

From the exponential equation results that the decline rate for Laslau Mare Field in the most recent period is 12.8%.

Using the forecast of the DCA methodology, a redevelopment strategy was designed for Laslau Mare field for the next years, to improve the gas production recovery factor.

Workover Plan:

The gas production associated to these operations was estimated considering the current production potential area.

Table 4

Summary of workover candidates per year

OPORTUNITIES TO DO WO WELLS IN THE NEXT YEARS, BASED ON DCA FROM OFM.															
Well	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
LM_X1	1														
LM_X2	1														
LM_X3	1														
LM_X4	1														
LM_X5	1														
LM_X6	1														
LM_X7									1						
LM_X8		1													
LM_X9															
LM_X10								1							
LM_X11													1		
LM_X12											1				
LM_X13				1											
LM_X14															1
LM_X15							1								
LM_X16							1								
LM_X17									1						
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LM_X19													1		
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LM_X21											1				
LM_X22						1									
LM_X23		1													
LM_X24		1													
LM_X25					1										
LM_X26															1
LM_X27		1													
LM_X28						1									
LM_X29					1										
LM_X30										1					
LM_X31		1													
LM_X32											1				
LM_X33	1														
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LM_X35											1				
LM_X36												1			
LM_X37								1							
LM_X38					1										
LM_X39					1										
LM_X40							1								
LM_X41														1	
Candidates	7	5	0	1	4	2	3	2	2	2	5	2	2	1	2

Re-perforation Plan:

For some wells, the production is limited because of flowing problems (i.e. scale deposit, obstructions, etc.). When they are in areas with high or moderate gas potential, quick and easy remedial actions are suggested, such as re-perforation operation. The objective is to recover the gas production in the shortest time, maximizing the NPV in the reservoirs.

Table 5

Re-perforation candidates

Infill Wells	D - E - F	G - H	I - J	Comments
LMX_7			X	1st option: Through tbg. re perforation 2" guns. 2nd option : WO with RIG.
LMX_41	X			Csg. Leak, (snubbing candidate) 1st Option: pull out tbg. and set a packer. 2nd option: Through tbg. inflatable packer.
LMX_20	X			1st option: Through tbg. re perforation 2" guns. 2nd option : WO with RIG. 3rd option: complete to VI packages.
LMX_13	X			Evaluate with saturation log (PNN). Pull out the tbg. above the intervals perforated. Option: Could be re perforation.
LMX_38		X		As a commingle with XIII XIV. Well produces 15Kscm/d.
LMX_16	X			Reperforate in VIIIb

Side-Track Plan:

Some wells had been abandoned or temporary suspended for long periods in Laslau Marefield due to technical issues. This kind of situation is common in a brownfield because of facilities aging and/or wells mechanical problems, such as parted tubing, stuck tubing, fish inside the wellbore, casing leak, etc. When the wells are in areas with high or moderate remaining gas volumes, they are suggested to be Side-tracked, in order to recover the gas production in these areas of the reservoirs.

Table 6

Side Track candidates for next year

Infill Well	D - E - F	G -H
LMX_12	X	
LMX_25	X	
LMX_3		X

Infill Program:

The infill candidates are selected in areas where there are high or moderate remaining gas volume and didn't have many active wells around.

Table 7

Infill candidates for next years

Infill Wells	VIII IX X	XI XII	XIII XIV
LM13_1	X	X	X
LM13_2	X	X	X
LM13_3	X	X	X
LM13_4	X	X	X
LM13_5	X	X	
LM13_6	X	X	
LM13_7	X	X	
LM13_8			X
LMX_43	X	X	
LMX_12	X		
LMX_25	X		
A10	X		
LMX_42		X	X
LMX_44		X	X
201SW		X	
A1		X	X

The next figures show the infill and side track candidates locations for the upper reservoirs, plotted in red color on the map.

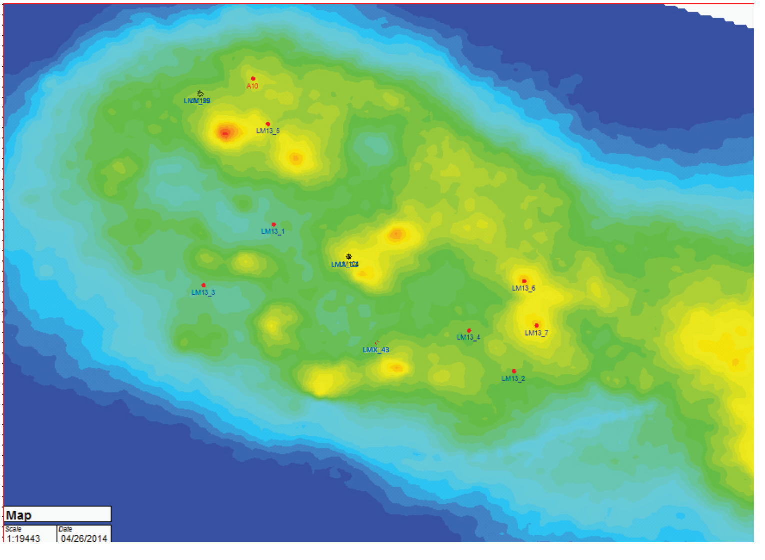

Fig. 20. Locations map of infill and side track candidates in D-E-F reservoir

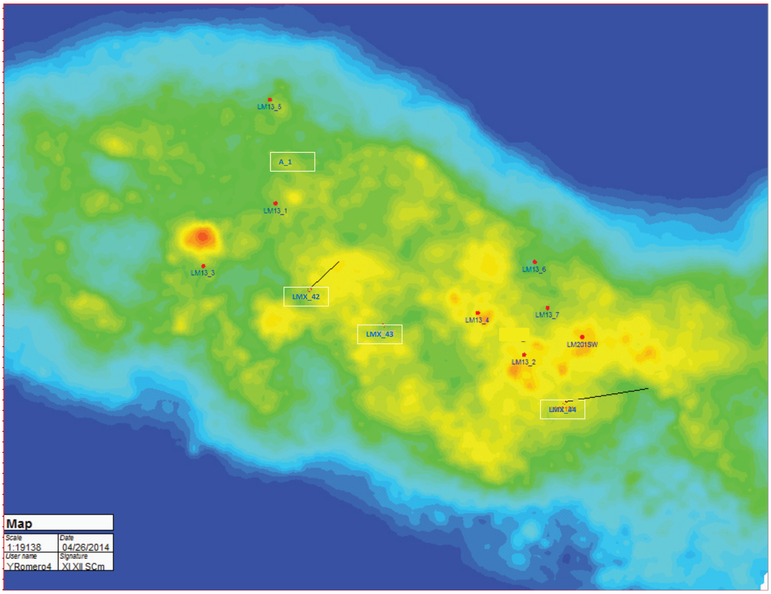

Fig. 21. Locations map of infill and side track candidates in G-H reservoir

The next figure shows the infill and side track candidates locations for the deeper reservoirs, plotted in green and purple colors on the map.

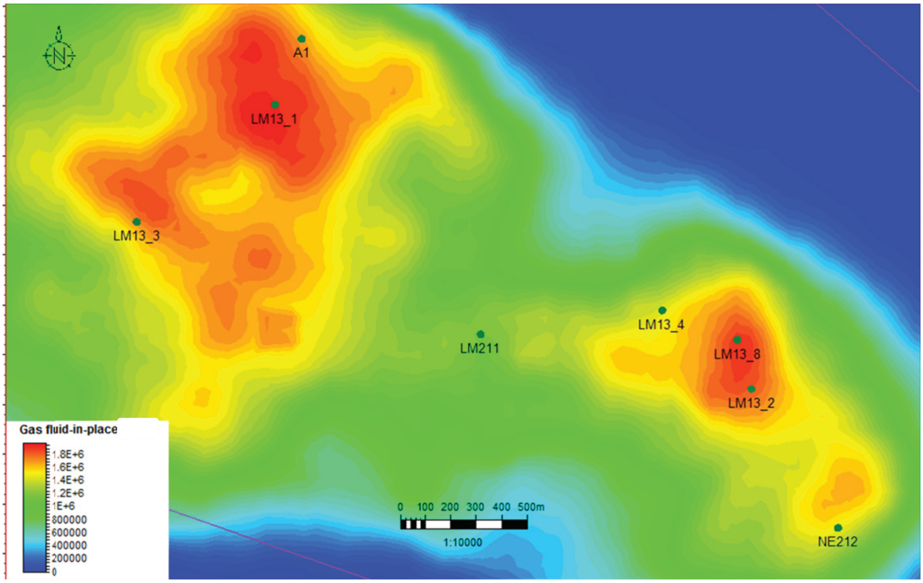

Fig. 22. Locations map of infill and side track candidates in I-J reservoir

Data acquisition Program:

Table 8

Candidates for acquisition data by reservoirs

Build Up Test	Reservoir Static Pressure	PLT
LMX_42 (G-H / I-J)	LMX_25 (D-E-F)	LMX_42 (G-H / I-J)
LMX_43 (D-E-F / G-H)	LMX_52 (G-H)	LMX_43 (D-E-F / G-H)
LMX_44 (G-H / I-J)	LMX_29 (G-H)	LMX_44 (G-H / I-J)
LMX_11 (I-J)	LMX_5 (A-B-C)	
LMX_35 (I-J)	LMX_7 (D-E-F)	
LMX_1 (D-E-F)	LMX_34 (G-H)	
LMX_8 (D-E-F)		
LMX_6 (D-E-F)		
LMX_29 (G-H)		

All of these candidates have been delivered to Laslau Mare SPM Schlumberger team for the feasibility study. The forecast for them are showed in the next figures 23 to 25.

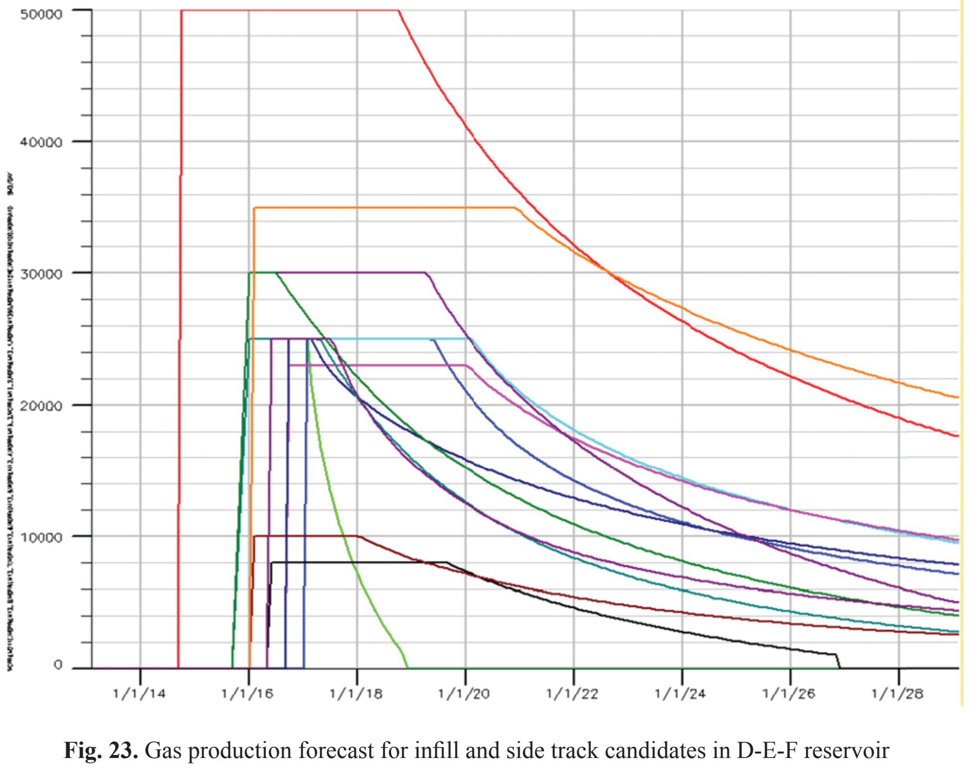

Fig. 23. Gas production forecast for infill and side track candidates in D-E-F reservoir

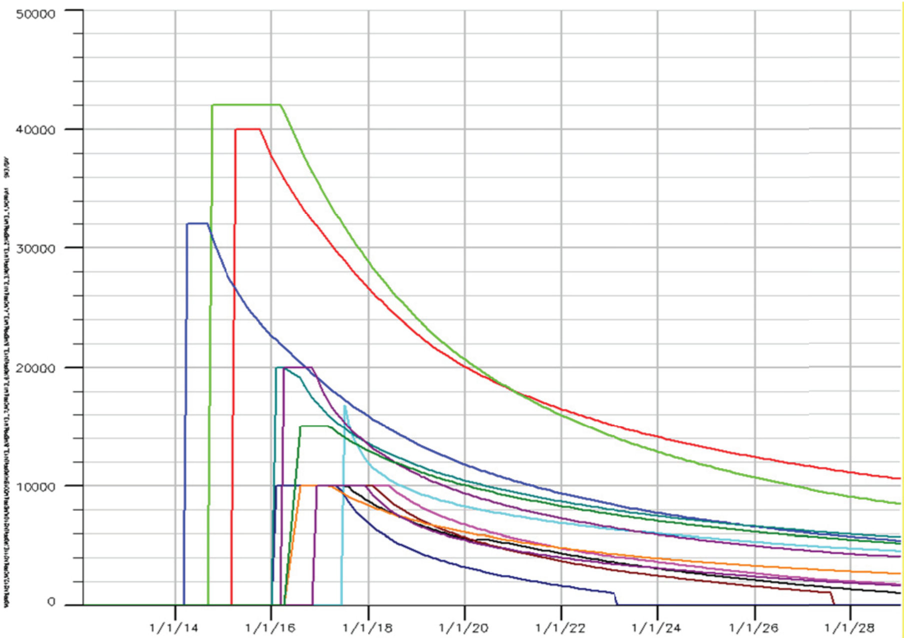

Fig. 24. Gas production forecast for infill and side track candidates in G-H reservoir

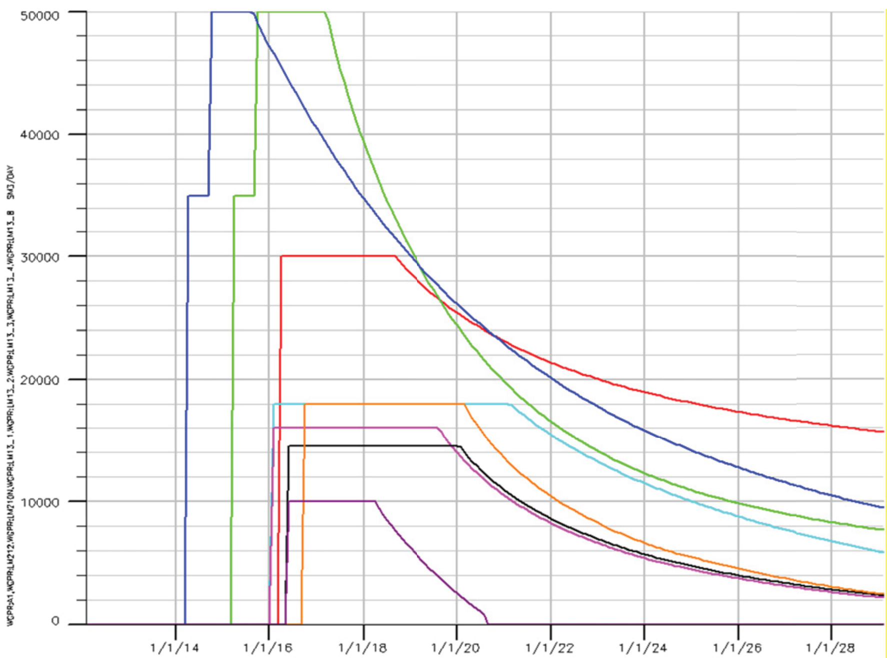

Fig. 25. Gas production forecast for infill and side track candidates in I-J reservoir

Based on the last 3 figures, the best candidates for next year should be: LM13_2, A1, LM13_1, LM13_5, LM13_4 and A10. Combining the reservoirs in that form:

1. LM13_2 (D-E-F with I-J),
2. A1 (G-H with I-J),
3. LM13_1 (G-H with I-J),
4. LM13_5 (D-E-F with G-H),
5. LM13_4 (D-E-F with I-J),
6. A10 (D-E-F).

7. OPTIMIZING RECOVERY FACTOR DURING THE MANAGEMENT FOR BROWNFIELD REDEVELOPMENT

The redevelopment strategy showed in this paper describes the conservative number of operations till December 2028.

The incremental cumulative gas production represents 28% of the remaining gas volume and 5% of the gas volume in place.

Laslau Mare has a recover factor of 74 %. If the proposed redevelopment strategy is adopted and implemented, the recovery factor would increase by 5 % (see table 9).

The table 9 shows the recovery factors split in percentages by reservoir.

Table 9

Cumulative gas production and optimization recovery factors by reservoirs

	OGIP	Cumulative OFM Feb 2014	Remaining Volumes Feb 2014	Cumulative Dec 2028	Rf 2014	Rf 2028	Theor. Rf abandon
	5	5	4	0	73%		
D-E-F	**46**	**47**	**40**	**46**	**76%**	**80%**	**91%**
G-H	**32**	**34**	**22**	**26**	**79%**	**83%**	**91%**
I-J	**17**	**14**	**31**	**28**	**60%**	**68%**	**92%**
	0	0	3	0	4%		
Total	100	100	100	100	74%	79%	

The redevelopment strategy proposed is focused on the reservoirs D-E-F, G-H and I-J. The original gas in place (OGIP) in the second column is expressed in percentage for data confidentiality reason. The third column represents the cumulative gas production for February 2014 and is expressed in percentage as well; the total of 100% represents 74% of the OIGP. The forth column shows remaining volumes in February 2014, and is also expressed in percentage; the total of 100% represents the remaining 17% of the OGIP. The fifth column represents the incremental cumulative gas production for this redevelopment strategy. The sixth column represents the current recovery factor (RF) for Laslau Mare field and the seventh column is the recovery factor resulting from the proposed work plan until

December 2028. The gain obtained from applying and implementing the DCA methodology is increasing the recovery with 5% of the OGIP in 14 years. The remaining gas volume at abandonment, after the theoretical recovery factor is reached, is 9%.

The current RF of 74%, the remaining producible volumes of 17% and the abandonment volume of 9% s um up to 100% of the OGIP for Laslau Mare Field.

8. CHALLENGES

The challenges to increase the ultimate gas recovery factor are:

1. Ability to develop smaller opportunities in each reservoir, in particular securing existing base and improving the economics by smaller risk interventions.
2. Recognizing the exploitation opportunities for all remaining reserves, identifying best practice and applying lessons learnt to improve the recovery factor.

9. ADVANTAGES

1. When the quality of the production and pressure data is not adequate to do a detailed reservoir simulation model, the DCA methodology is the best.
2. Reliable redevelopment of a mature field.
3. Easy understanding, high applicability, low costs, internationally standardized procedure (oil & gas industry).
4. Style, fast and furious reservoir analysis.
5. This methodology can reduce answer time reproducing similar results.

10. CONCLUSIONS AND RECOMMENDATIONS

The DCA methodology can help optimizing the recovery in mature fields, integrating information gathered during completions into the interpretation workflow. The methodology can be applied well-by-well or by field, to compare the results between both procedures.

The DCA methodology is known for decline rates estimation such as: total decline rate, mechanical decline rate and reservoir decline rate, although could go further than that, helping to visualize opportunities in the field. Based on that, it could help designing exploitation strategies in conventional and unconventional gas reservoirs, in order to maximize the recoverable reserves.

How to do it? Generating a DCA forecast for each well, should be easier to identify the wells with higher decline rate or the wells there are dying, After generating a list of these wells, could be evaluated what type of intervention would be the best according to the production potential, the drainage area and the remaining gas volume; the options could be:

workover, reperforation, side track, propellant stimulation, Wavefront stimulation, snubbing, multistage fracture, soaping etc. Based on the evaluations, is feasible to propose a redevelopment strategy program for the next 10 years, to accelerate the recovery of gas in place, through better understanding of the current reservoir conditions.

The DCA methodology allow geoscientists, engineers, and managers to work together to enhance the production of mature gas fields. Brown fields management require geoscience teams to work more closely with production and drilling teams, to plan well interventions and production enhancement operations.

The DCA can be considered a subjective methodology. Even so, this is an easy method to be applied on the historical production data of a field.

For longer a period of time (ex. 1980-2003) the average decline of Laslau Mare field was 11.7%. On shorter time intervals, the decline can vary between 10.7-12.8%. This shows the importance of properly selecting the period to be analyzed and understanding the field and production conditions that can influence the wells behavior.

After 2004, due to the operations executed in the field, the production does not show a clear decline, making this period more difficult to analyze. Due to this reason, the decline analysis was done on shorter periods of time:

DCA field-wide basis

1. Between May 2005 and July 2008, the decline was 10.1%, this period is considered the less affected period, because there was just the basic maintenance in the field.
2. Between October 2011 and July 2012, the estimated rate of decline was 12.1%, and between September 2012 and June 2013, the decline was 11.9%. These time periods of almost 1 year are considered to have also reliable decline rates.

DCA well-by-well

1. Between May 2005 and July 2008, the decline was 10.3%.
2. In the most recent period (October 2011 and October 2013), the decline rate was 12.8%.

The results of all scenarios presented show an increasing decline rate from 10.0% to 12.8% (see table 10).

Table 10

Decline rate comparison, increasing over time

	Scenarios	2005-2008 Field	2005-2008 well by well	20010-2013 well by well
Decline rate,%	3 completions	10.0	10.3	12.8

The decline rates estimated today for a future period of time are mostly reference values, due to the fact that an increase in the number of the drainage points would result in an acceleration of the production.

The reservoirs conditions have changed during the field life and are continuing to change in the future, as the field becomes more mature, negatively impacting the field productivity. These reservoir conditions are referring to: decreasing reservoir pressures, reducing gas volumes, more frequent problems with water loading, scaling, tubing and casing leaks, increasing operational risk, etc. These problems will become more frequent as we get closer to the theoretical recovery factor of the field and will require more interventions and production optimization work, leading to higher operational costs and investments.

The production acceleration will result in a higher decline in the future; for this reason, it is considered that the natural field decline in the case of "base maintenance operations" will be around 12%.

Finally our recommendations are:

1. The DCA methodology is the most appropriate approach in mature fields where historical pressure data are missing.
2. The DCA methodology should be applied in mature fields as an alternative for fast and reliable analysis, before other methodologies that required more time for analysis.
3. The specialist should be a reservoir engineer with wide technical background, for best understanding of the wells selection part.
4. A thorough well analysis should be performed prior to generating a DCA for specific wells.
5. The DCA methodology is easy to use. Junior engineers should be coached by a reservoir engineer with more expertise.

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APPENDIX A

Table 11

Decline rate resume for Laslau Mare Field by well

WELL	Reservoir	Decline Rate, %	Period
LMX_7	D - E - F	12.4	Nov 2009 to Oct 2013
LMX_9	I -J	8.4	Oct 2008 to Oct 2013
LMX_53	G - H	15.2	Oct 2012 to Apr 2013
LMX_29	G - H	32.5	Nov 2008 to Sep 2009
LMX_54	I -J	6.1	Apr 2011 to Oct 2013
LMX_52	G - H	19.9	May 2012 to Aug 2013
LMX_55	G - H	8.3	Aug 2005 to Oct 2013
LMX_10	I -J	8.9	Apr 2009 to Mar 2011
LMX_30	G - H	9.1	Mar 2011 to Apr 2012
LMX_56	I -J	9.2	Mar 2011 to Apr 2012
LMX_32	D - E - F	5.4	Jan 2012 to Apr 2012
LMX_31	G - H	16.6	Jun 2006 to Dec 2008
LMX_33	G - H	25.3	Oct 2011 to Feb 2012
LMX_11	I -J	20.9	May 2012 to Oct 2013
LMX_6	D - E - F	7.0	May 2011 to Oct 2013
LMX_34	G - H	17.6	Oct 2006 to Oct 2008
LMX_12	G - H	20.2	Sep 2012 to Jan 2013
LMX_13	I -J	24.8	Sep 2012 to Jun 2013
LMX_35	I -J	15.8	Sep 2010 to Oct 2013
LMX_14	I -J	5.6	Dec 2009 to Oct 2013
LMX_46	I -J	13.7	Nov 2009 to Feb 2010
LMX_57	G - H	7.0	Jan 2010 to Oct 2013
LMX_15	I -J	18.8	Sep 2012 to Feb 2013
LMX_58	G - H	8.8	Jul 2005 to Aug 2008
LMX_59	D - E - F	11.8	Sep 2012 to Mar 2013
LMX_16	G - H	8.5	Oct 2011 to Oct 2013
LMX_3	I -J	9.7	Jun 2006 to Oct 2013
LMX_17	D - E - F	16.9	Oct 2012 to Apr 2013
LMX_18	G - H	15.8	Sep 2008 to Jun 2010
LMX_19	I -J	23.2	Apr 2011 to Jun 2013
LMX_36	I -J	8.8	Mar 2011 to Sep 2012
LMX_20	G - H	13.9	Jan 2010 to Feb 2011
LMX_21	I -J	12.7	Oct 2004 to Oct 2013
LMX_8	B	15.3	Jul 2011 to Oct 2013
LMX_31	I -J	15.9	Oct 2012 to Feb 2013
LMX_22	B	25.3	Nov 2009 to Oct 2013
LMX_60	B	6.5	Oct 2007 to Feb 2011
LMX_23	D - E - F	25.3	Mar 2013 to Oct 2013
LMX_38	B	37.3	Feb 2007 to Apr 2008
LMX_51	D - E - F	11.2	Apr 2009 to Sep 2012
LMX_24	I -J	26.6	Oct 2012 to Jul 2013
LMX_39	D - E - F	39.2	Feb 2010 to Dec 2010
LMX_61	D - E - F	9.3	Oct 2012 to Oct 2013
LMX_40	D - E - F	27.1	Oct 2006 to Apr 2007
LMX_41	D - E - F	20.9	Jul 2011 to Oct 2012
LMX_62	D - E - F	7.3	Oct 2006 to Mar 2010
LMX_63	D - E - F	7.3	Dec 2012 to Oct 2013
LMX_25	D - E - F	18.5	Dec 2012 to Oct 2013
LMX_64	D - E - F	8.4	Oct 2004 to Oct 2013
LMX_65	D - E - F	11	Nov 2009 to Jul 2010
LMX_26	D - E - F	8.6	Feb 2008 to Oct 2013
LMX_27	B	9.3	Jul 2011 to Jul 2013
LMX_5	D - E - F	11.5	Dec 2009 to Mar 2011
LMX_4	D - E - F	9.6	Jul 2007 to Jun 2008
LMX_28	D - E - F	20.9	Aug 2010 to Oct 2013