SPE 164931

Injection Testing: Gas Storage Field Experience

Eleonora Azzarone, Enzo Beretta, SPE, eni spa e&p division, and Daniele Marzorati, stogit spa.

This paper was prepared for presentation at the EAGE Annual Conference & Exhibition incorporating SPE Europec held in London, United Kingdom, 10–13 June 2013.

Abstract

This work presents the interpretation of the injection testing operations performed on two wells in a gas storage field, located onshore Italy.

These field applications were aimed at setting the most suitable injection rates to allow the reintegration of the reservoir working gas. The injection gas rates were established as a function of the existing surface facilities constraints.

A secondary target was to confirm the areal hydraulic communication between two injection wells. A third well was used as an observation well to assess whether the hydraulic communication could be confirmed within the reservoir.

Two injection tests were conducted injecting methane gas into a depleted gas sands reservoir. All the wells were completed with sand control techniques.

The bottomhole pressure and temperature data were acquired by permanent downhole gauges allowing real time transmission. Memory gauges were used in the observation well to account for interference effects.

Over the sequence of several injection/falloff cycles, the downhole pressure response, observed in both the injection wells, was found to change and evolve over time.

In fact, during the injection history the expansion of the gas in the sand layer was able to displace the reservoir aquifer away. This effect was clearly experienced in the longest falloff phase.

Such a complex dynamic phenomenon can be properly described using 3D numerical simulators. However, a clear understanding was achieved utilising the standard analytical solutions typical of pressure transient analysis.

Introduction

The injection testing technique generally consists of injecting a fluid at a constant rate into the reservoir. The injected fluid must be non damaging and compatible with both the rock and the formation hydrocarbons.

In the case of this field application, observed in well “A” and well “B”, natural gas was selected as the injected fluid into a depleted natural gas bearing formation of a gas storage field. This technique addresses the same objectives as conventional well testing: formation pressure, permeability, boundaries, skin and well deliverability. A falloff period, with the well shut-in, follows the injection phase. The injection phase must be performed in matrix conditions without exceeding the formation fracture gradient.

The main objective of the injection tests was to ensure the evaluation of the injection rates suitable for the working gas reintegration in the field. The gas injection rates were defined honoring the project constraints on the existing surface facilities, i.e. a total volume of methane of 135 MSm^3 to be injected during the first six months and about 300 MSm^3 during the subsequent months until the end of the three year project.

A third well, “C”, was used as an observer during the injection tests performed on the other two wells, with the aim of ascertaining the areal hydraulic communication between the three wells.

The first injector well A and the observer well C are vertical wells, while the second injector well B is a deviated well with a deviation angle of 43°. All the wells were completed with gravel pack sand control techniques.

The bottomhole pressure and temperature data acquisition was achieved by permanent downhole gauges (DPTT) with a real time transmission system for the injection tests on well A and B, and by memory gauges for the monitoring of well C.

The wells’ configuration has been presented in Fig. 1. Some summarizing field information for a quick look view has been gathered in Tab. 1.

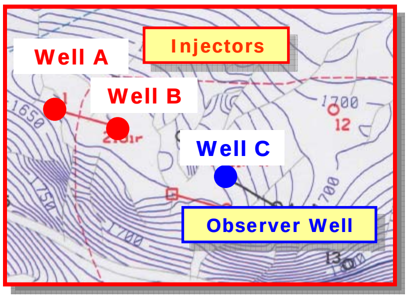

Fig. 1 – Wells' Configuration

Country	Italy
Field	Gas Storage
Wells Names	A, B & C
Wells Types	Injectors (Well A & Well B) Observer (Well C)
Target	Sands
Reservoir / Injected Fluid	Methane/Methane
Wells Completions	Gravel Pack
Gauges Types	Real Time DPTT (Well A & Well B) Memory (Well C)

Tab. 1 – Field General Information

Background

The present field operation involves two injection tests conducted simultaneously from the 1st July 2010 until the 8th March 2011 on two injectors, well A and well B, into a depleted methane sand reservoir, in an onshore Italian gas storage field. The pore pressure gradient was measured at 0.7 bar/10 m at the field reference datum of 1700 m TVD SS, at the beginning of the operations.

The reservoir is characterized by heterogeneous turbiditic sediments mainly composed of Messinian post-evaporitic conglomerates and sands. The lower boundary is a paraconformity and locally shows an onlap termination on the underlying Miocenic shaly-silty marls.

A sequence of 40 - 50 meters of pelitic turbidites represents the last stage of the systems that originated the reservoir and 450 meters of shales (middle-upper Pliocene) guarantees a perfect sealing.

The stratigraphic succession is covered by sediments related to the marine/deltaic progradation and quaternary alluvial plain sedimentation (Fig. 2).

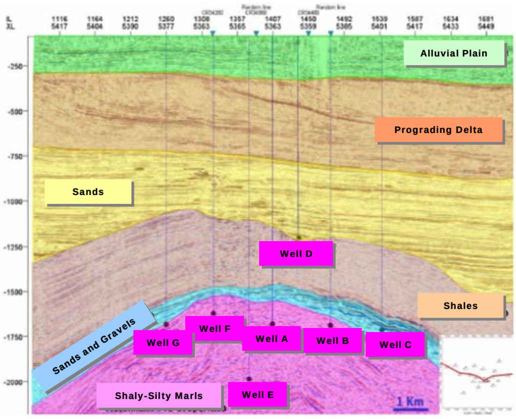

Fig. 2 – Field Geological Cross Section

The reservoir sedimentation is constituted by gravels, sometimes cemented, with inter layers of sands and silts, originated by submarine debris flows. The sequence is characterized in the lower part by medium-fine sands, sometimes silty and cemented, probably due to less dense turbiditic flows. This stratigraphic sequence presents interbedded layers of pelitic turbidites (shaly-silty marls).

The facies succession records an environment depositional evolution characterized by the flooding of the external silicoclastic shelf with the deposition of deep gravitative sediments (sandy-gravelly turbiditic lobes). The later stage shows a pelitic turbidites bacinal sedimentation.

Two kinds of traps characterize the hydrocarbon bearing layers:

- ✓ Stratigraphic trap (A1 - A2 layers).
- ✓ Structural-stratigraphic trap (B1 to B5 and C, D, E1, E2, F layers).

The structural trap consists in a South verging anticline with South flank dislocated by Apennine and Alpine thrust system. This is the result of the tectonic activity related to the South dipping Apennine thrusts (middle Pliocene) and the successive reactivation of older North dipping Alpine thrusts.

The Stratigraphic trap derives from the pinch-out terminations of the hydrocarbon bearing layers on the flanks of the anticline. These pinch-out terminations are the result of a gravitative sandy-gravelly deposition.
The seismic lines (NNE – SSW), in the central part of the field, show the double vergent structural context, Apennine and Alpine thrust systems, (Fig. 3), while the Apennine thrusts disappear proceeding towards the NW (Fig. 4).

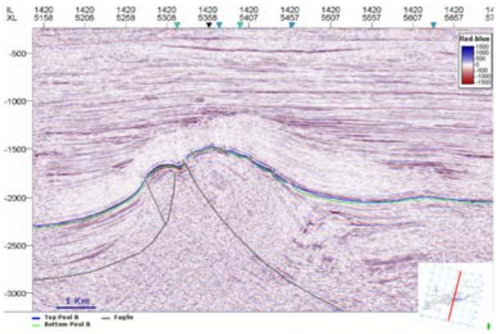

Fig. 3 – NNE-SSW Seismic Line - Double Vergent Structure

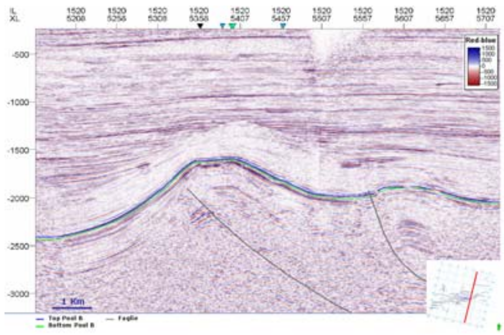

Fig. 4 – NNE-SSW Seismic Line - Alpine Thrust System

The wells' completion sketches and their general information have been respectively illustrated in Fig.5, Fig. 6 and Fig. 7 and reported in Tab. 2, Tab. 3 and Tab. 4.

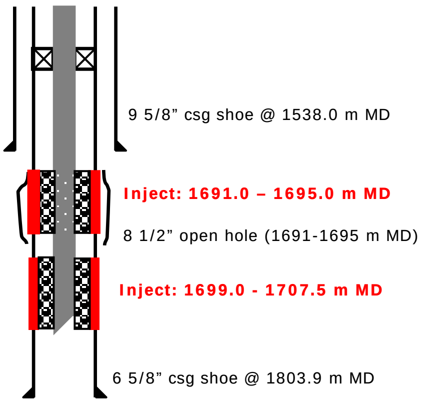

Fig. 5 – Well A: Completion Sketch

Well Type	Vertical – Injector
Intercepted Layers	B1, B2, B3 & B4
Injected Intervals	1691 – 1695 m MD (B1) 8 ½" OH **Gravel Pack** 1699 – 1707.5 m MD (B2) 6 5/8" CH **Gravel Pack**
Test String	2 7/8" Tbg
DPTT Depth	1657.22 m MD (1583.72 m TVD SS)
RT Elevation	73.5 m
TD	2001 m MD (1927.5 m TVD SS)

Tab. 2 – Well A: General Information

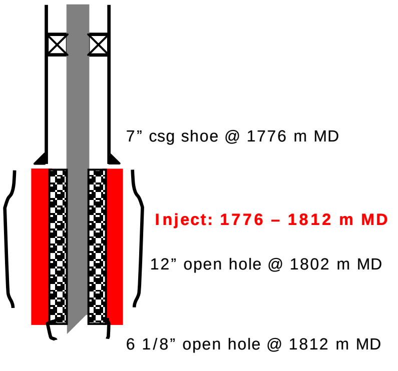

Fig. 6 – Well B: Completion Sketch

Well Type	Deviated (~ 43°) – Injector
Intercepted Layers	B1, B2, B3, B4 & B5
Injected Intervals	1776 – 1802 m MD (B1, B2 & B3) 12" OH 1802-1812 m MD (B3 & B4) 6 1/8" OH **Gravel Pack**
Test String	3 1/2" Tbg
DPTT Depth	1740.91 m MD (1577.4 m TVD SS)
RT Elevation	68.3 m
TD	1850 m MD (1725 m TVD)

Tab. 3 – Well B: General Information

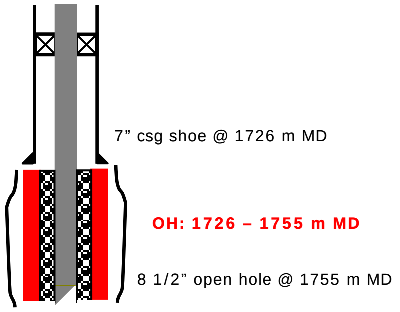

Fig. 7 – Well C: Completion Sketch

Well Type	Deviated (~ 2.6°) – Observer
Intercepted Layers	B1, B2, B3, B4 & B5
Open Hole Interval	1726-1755 m MD (B1, B2, B3 & B4) (1722.5-1751.5 m TVD) 8 1/2” OH Gravel Pack
Test String	5” Tbg
DPTT Depth	1721.57 m MD (1652.97 m TVD SS)
RT Elevation	65.1 m
TD	1755 m MD (1751.5 m TVD)

Tab. 4 – Well C: General Information

Injection Tests

Series of alternate injection and shut-in/falloff phases were performed. The injection tests on both the wells A and B ended with a very long shut-in period of the wells lasting nearly 73 days.

In well A (Fig. 8), an average gas rate of about 200000 Sm^3/d was injected which led to a total injected cumulative gas volume equal to 24.3 MSm^3, coupled with a significant repressurization of the system of around 31 bar.
The initial reservoir static pressure was measured at 120.5 bara, at the reference datum depth, by the initial static gradient survey carried out before the test (Fig. 9).

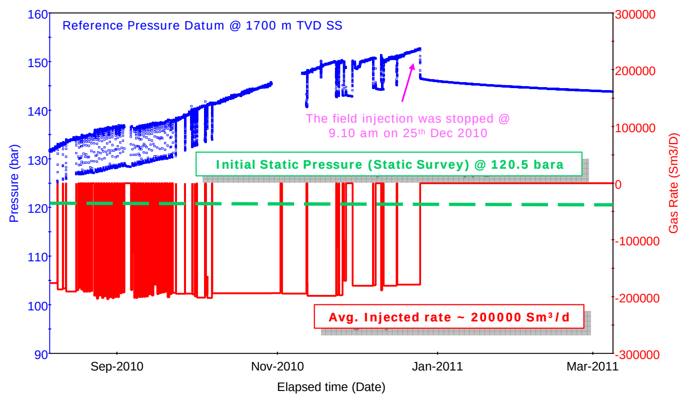

Fig. 8 – Well A: Injection Test Sequence

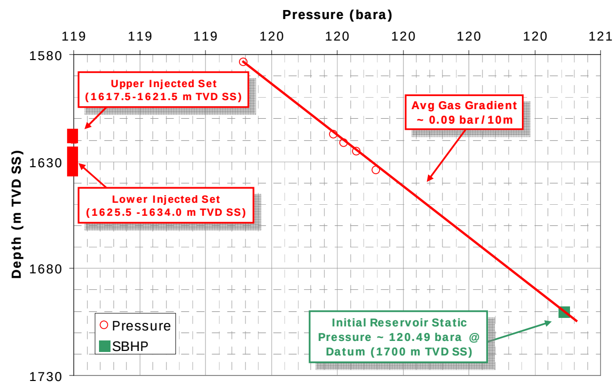

Fig. 9 – Well A: Static Survey

For the well B case (Fig. 10), the average injected gas rate was set at about 700000 Sm^3/d, with a total injected cumulative gas volume of nearly 89.4 MSm^3, with a considerable system repressurization of about 28 bar, as in the previous case.
The initial reservoir static pressure, measured by the initial static gradient survey before the test, was 120.9 bara, at the same reference datum depth (Fig. 11).

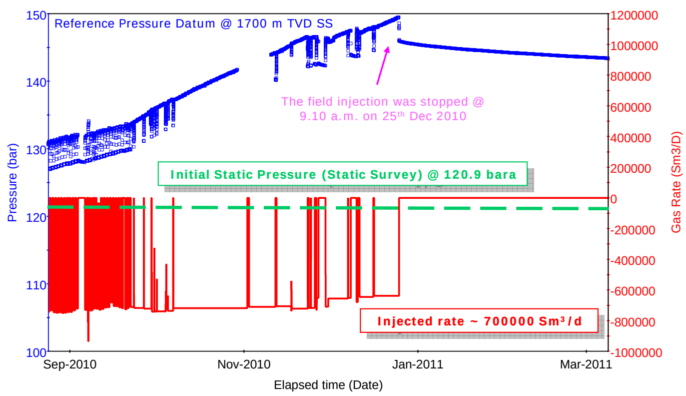

Fig. 10 – Well B: Injection Test Sequence

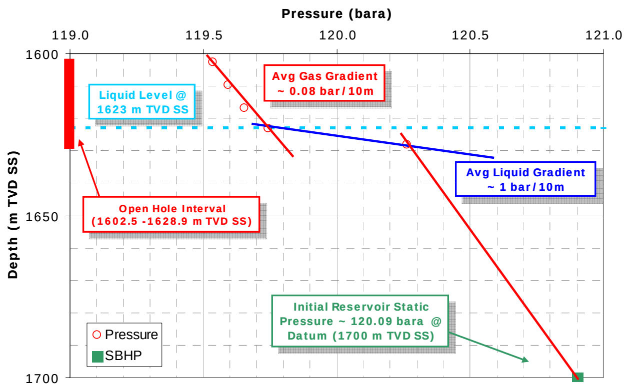

Fig. 11 – Well B: Static Survey

Conventional Interpretation Workflow

The interpretations of both the injection tests performed on well A and well B were initially carried out following the usual "conventional interpretation workflow", as depicted in Fig. 12.

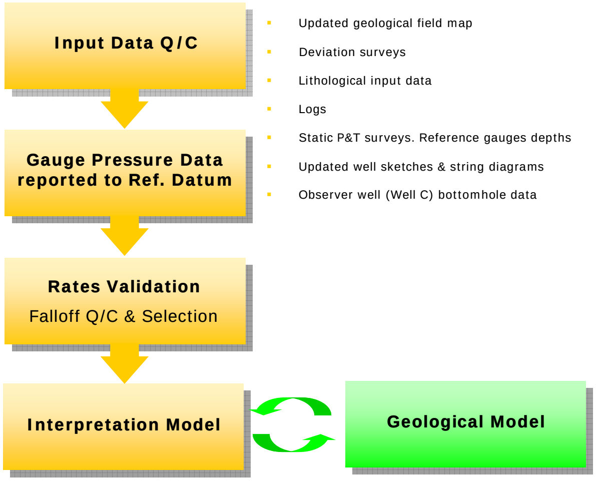

Fig. 12 – Conventional Interpretation Workflow

The quality check on the available petrophysical input data, the PVT characteristics of both injected and reservoir fluids and the acquired bottomhole pressures measured at the permanent gauges' depths was accurately accomplished. All the bottomhole pressures were corrected and referred to the field reference datum depth (1700 m TVD SS).
The validation of the gas injected rates followed, with the selection of the most reliable falloff, recognised to be the last one of both injection tests (Fig. 13 and Fig. 14).

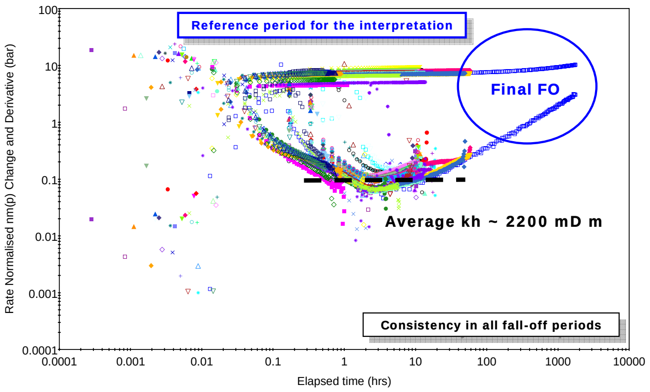

Fig. 13 – Well A: Rates Validation (All Falloff Periods)

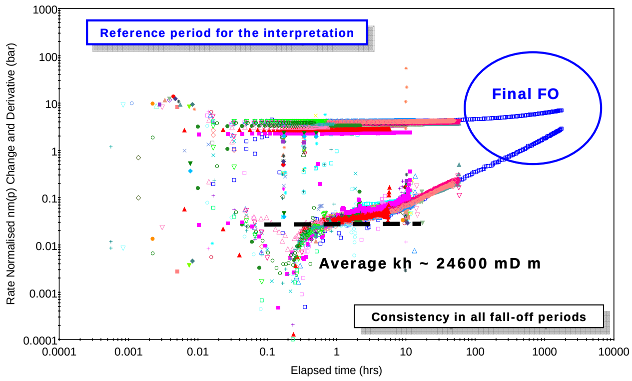

Fig. 14 – Well B: Rates Validation (All Falloff Periods)

The bottomhole pressure data have been interpreted with a simulation model which has been then validated by and compared to the current geological model of the storage field, achieving the following major interpretation results:

- ✓ Estimate of reservoir pressure and temperature
- ✓ Evaluation of the average reservoir properties and well parameters within the test duration (kh, k and skin)
- ✓ Identification of the late time effects

For both wells, the following interpretation model was initially assumed to match the actual data:

- ✓ Early Time: Partial Penetration
- ✓ Middle Time: Homogeneous
- ✓ Late Time: Open Ended Rectangle

But the assumed "Open Ended Rectangle" for the late time effects interpretation allowed only the match on the BHP data of the last falloff period, without succeeding in the simulation of the entire pressure history response of the overall injection test (Fig. 15 and Fig. 16).

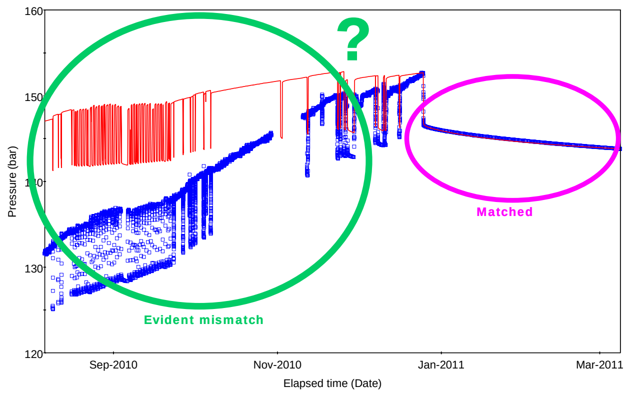

Fig. 15 – Well A: Open Ended Rect. Pressure History Match

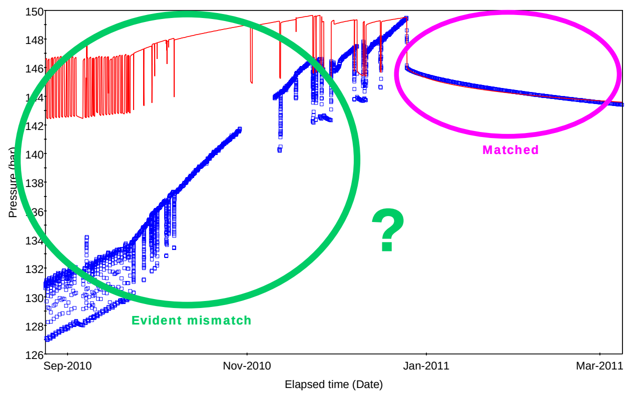

Fig. 16 – Well B: Open Ended Rect. Pressure History Match

This evident mismatch of the system was related to the particular reservoir behaviour. In fact, as a consequence of the injection phase, which lasted a number of months, the reservoir pressure response was found evolving in time in a way that it was not possible to simulate the entire pressure history.

As a result, a decision was made to change the conventional interpretation workflow in favour of a more suitable unconventional approach to this field experience.

The entire test was then recalibrated and a "dedicated simulation strategy" was introduced to understand better the reaction of the injected system.

Dynamic Evolution of the System: Dedicated Simulation Strategy

A dedicated simulation strategy has been adopted to explain this apparently anomalous dynamic evolution. It comprised two subsequent steps regarding the "short time" and the "long time" effects.

1. "Short Time" Interpretation Phase. In the falloff response selected for the interpretation, there is not yet sufficient time to push significantly the surrounding aquifer away from the well. The injected gas volume accumulates into the reservoir and contributes to the charging of the system. Thereby an "apparent closed system rectangle" model has been imposed to reproduce the entire pressure history, except for the final falloff pressure trend.

2. "Long Time" Interpretation Phase. The falloff response selected for the interpretation reflects a system which evolves over time, since the injected gas volume increases and starts expanding, thus displacing the aquifer away. As a consequence, the "open ended rectangle" was chosen as the most likely model able to match the falloff response only, but not the complete injection pressure history. In this perspective, the distances of some boundaries detected by the model are clearly time dependent.

Therefore a series of barriers, characterised by different physical meanings, has been recognised.

Regarding the injector well A, through the evolution over time of the two assumed different models (Fig. 17 and Fig. 18), the conclusions were as follows:

- ✓ The first boundary (d_1) resulted to be caused by the dynamic interaction established between the injectors A and B.
- ✓ The second boundary (d_2) intercepted the structural fault toward the Southern direction.
- ✓ The third boundary (d_3) is coherent with the field porosity limit recognised lying along the Western direction.
- ✓ The forth boundary (d_4) defines the gas expansion Northward where the aquifer is present.

It is important to underline that only the first and the forth boundaries are time dependent. According to the current geological model the other two barriers are representative of real geological features.

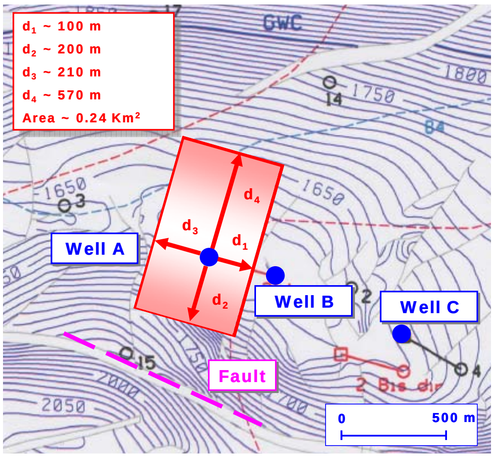

Fig. 17 – Well A: Closed System – Short Time Response

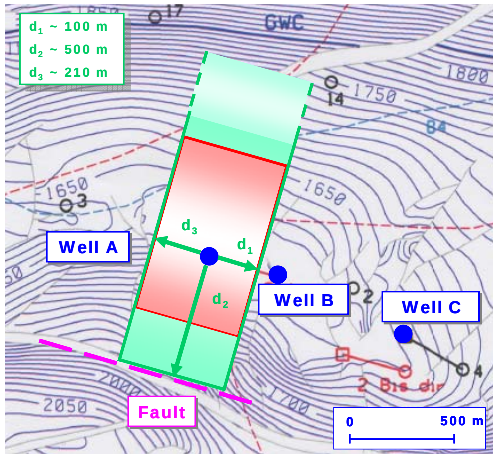

Fig. 18 – Well A: Open Ended System – Long Time Response

Concerning the injector well B (Fig. 19 and Fig. 20):

- ✓ The first boundary (d_1) also resulted by the dynamic interaction between the injectors A and B.
- ✓ The second boundary (d_2) intercepted the same structural fault toward the Southern direction.
- ✓ The third boundary (d_3) is consistent with the field porosity limit being present along the Eastern direction.
- ✓ The forth boundary (d_4) defines again the gas expansion Northward where the aquifer is positioned.

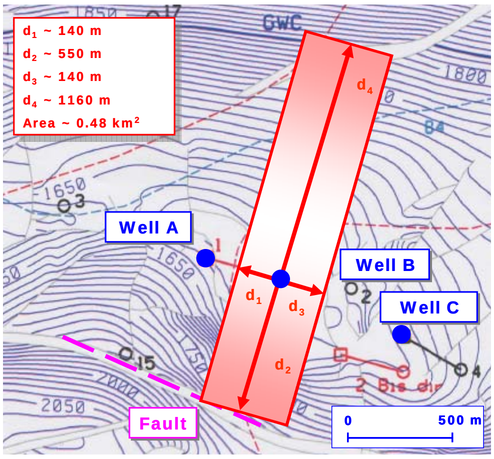

Fig. 19 – Well B: Closed System – Short Time Response

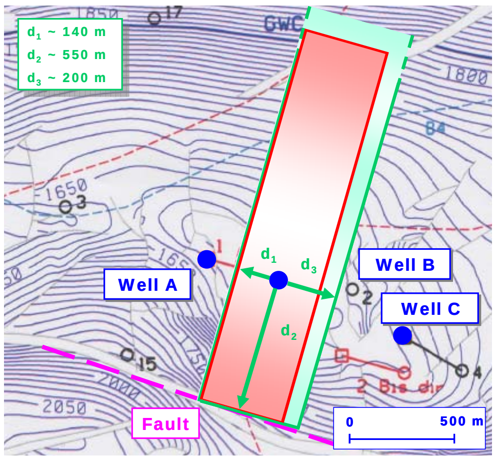

Fig. 20 – Well B: Open Ended System – Long Time Response

By symmetry, the first and forth limits can be thought of as dynamic barriers.

Substantially, the gas injection through the two injectors wells would preferentially develop toward the South-North axis zone. This seems to be coherent with the best lithological properties recognised in the depositional sands trend.

However, it is important to point out that the complexity of such a system cannot be properly described with the analytical well testing software. Therefore the use of a 3D reservoir simulation package is needed to study adequately the overall static and dynamic issues.

Interpretation Results

The petrophysical input data and the PVT properties used in the interpretation process have been listed in the following Tab. 5 and Tab. 6.

Petrophysical Parameters	
Net Pay Thickness	22 m
Total Perforated Interval	12.5 m
Average Porosity	21 %
Average Water Saturation	20 %
Well Radius	0.108 m
PVT Properties	
Initial Reservoir Pressure	120.5 bara (*)
Reservoir Temperature	57 °C (*)
Ref. Datum Depth	1700 m TVD SS
Gas Specific Gravity (air=1)	0.56
Gas Formation Volume Factor	0.008 Rm^3/Sm^3
Gas Viscosity	0.015 cP
Gas compressibility	8.9 E^{-3} bar^{-1}
Total System Compressibility	7.2 E^{-3} bar^{-1}

(*) From static profile performed before the injection test

Tab. 5 – Well A: Input Data

Petrophysical Parameters	
Net Pay Thickness	41 m
Open Hole Interval	36 m MD
Average Porosity	21 %
Average Water Saturation	20 %
Well Radius	0.152 m
PVT Properties	
Initial Reservoir Pressure	120.9 bara (*)
Reservoir Temperature	57 °C (*)
Ref. Datum Depth	1700 m TVD SS
Gas Specific Gravity (air=1)	0.56
Gas Formation Volume Factor	0.008 Rm^3/Sm^3
Gas Viscosity	0.015 cP
Gas compressibility	8.9 E^{-3} bar^{-1}
Total System Compressibility	7.2 E^{-3} bar^{-1}

(*) From static profile performed before the injection test

Tab. 6 – Well B: Input Data

The "short time" interpretation matching for both wells has been shown in Fig. 21 and Fig. 22. The pertinent interpretation results have been presented in Tab. 7 and Tab. 8. The closed system model allows only the match of the entire pressure history except the final falloff.

On the other hand, the "long time" injection tests simulations have been illustrated in Fig. 23 and Fig. 24, with the main results in Tab. 9 and Tab. 10. The open ended system model still allows a satisfactory match only of the final falloff (73 day duration), but does not fit the overall pressure history response.

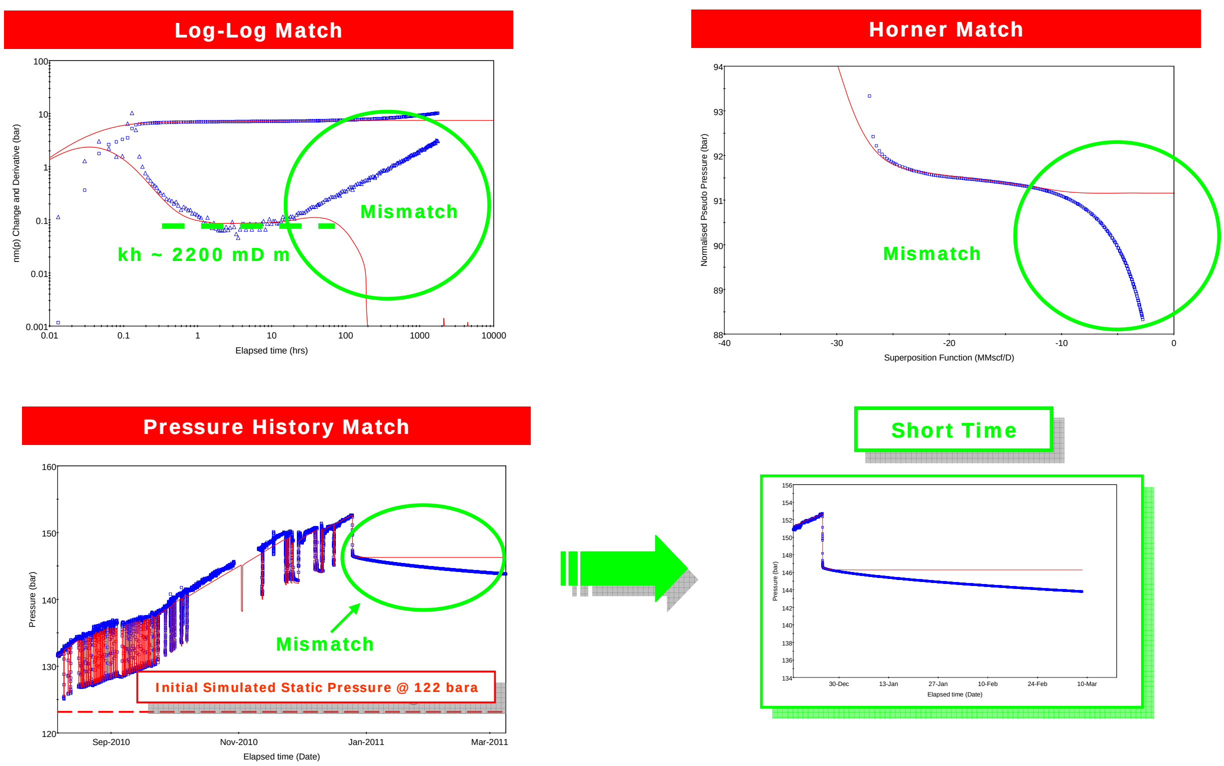

Fig. 21 – Well A: Closed System – Short Time Response Matching

MODEL	
Early Time:	Partial Penetration
Middle Time:	Homogeneous
Late Time:	Closed System (Rectangle)

Initial Reservoir Pressure @ 1700 m TVD SS		122 bara
Initial Pore Pressure Gradient		0.7 bar/10 m
Total Injected Volume @ 25th December 2010		24.3 MSm^3
Final Measured Pressure @ 1700 m TVD SS		152.6 bara
kh		2200 mD m
$\mathbf{k_{xy}}$		100 mD
$\mathbf{S_t}$		29
$\mathbf{k_z / k_{xy}}$ **(Estimated Injection Interval,** $\mathbf{h_w}$ **= 6 m)**		0.1
$\mathbf{S_m}$		5
Closed System (A ~ 0.24 Km²) :	$\mathbf{d_1}$	100 m
	$\mathbf{d_2}$	200 m
	$\mathbf{d_3}$	210 m
	$\mathbf{d_4}$	570 m

Tab. 7 – Well A: Closed System – Main Results

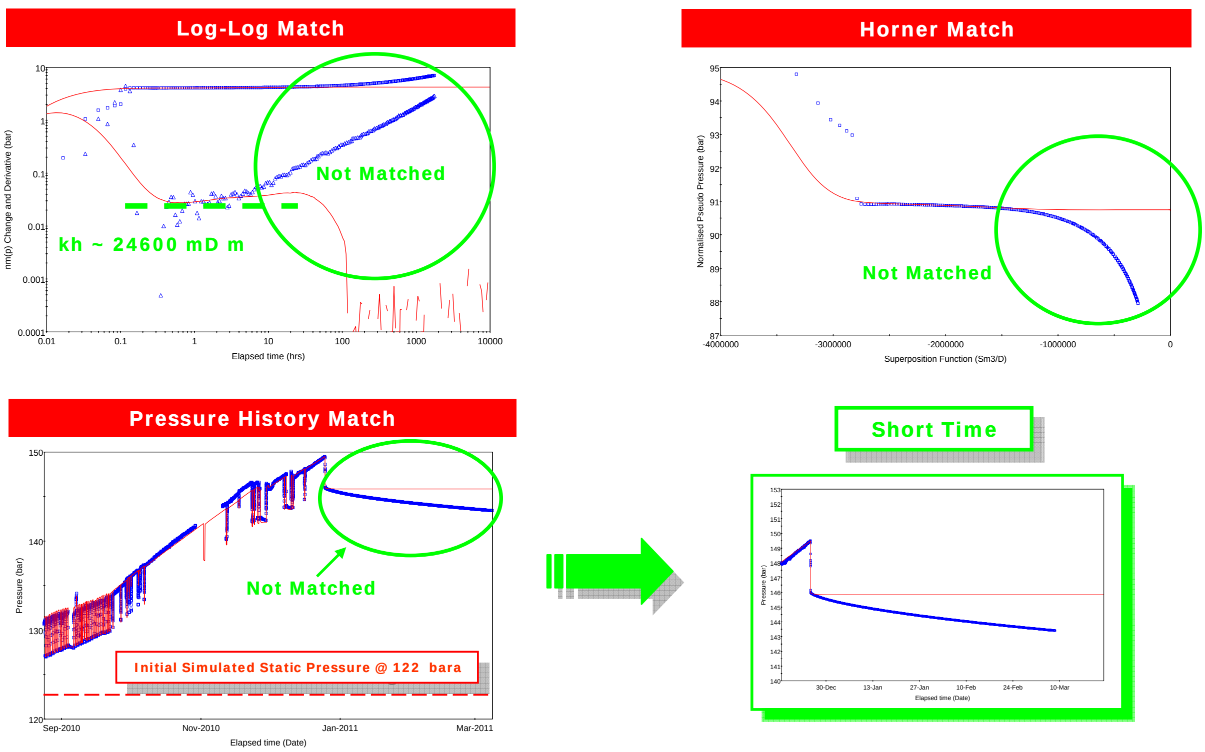

Fig. 22 – Well B: Closed System – Short Time Response Matching

MODEL	
Early Time:	Partial Penetration
Middle Time:	Homogeneous
Late Time:	Closed System (Rectangle)

Initial Reservoir Pressure @ 1700 m TVD SS		122 bara
Initial Pore Pressure Gradient		0.7 bar/10 m
Total Injected Volume @ 25th December 2010		89.4 MSm^3
Final Measured Pressure @ 1700 m TVD SS		149.5 bara
kh		24600 mD m
k_{xy}		600 mD
S_t		56
k_z/k_{xy} (Estimated Injection Interval, h_w = 20 m)		0.1
S_m		25
Closed System (A ~ 0.48 Km^2):	**d_1**	140 m
	d_2	550 m
	d_3	140 m
	d_4	1160 m

Tab. 8 – Well B: Closed System – Main Results

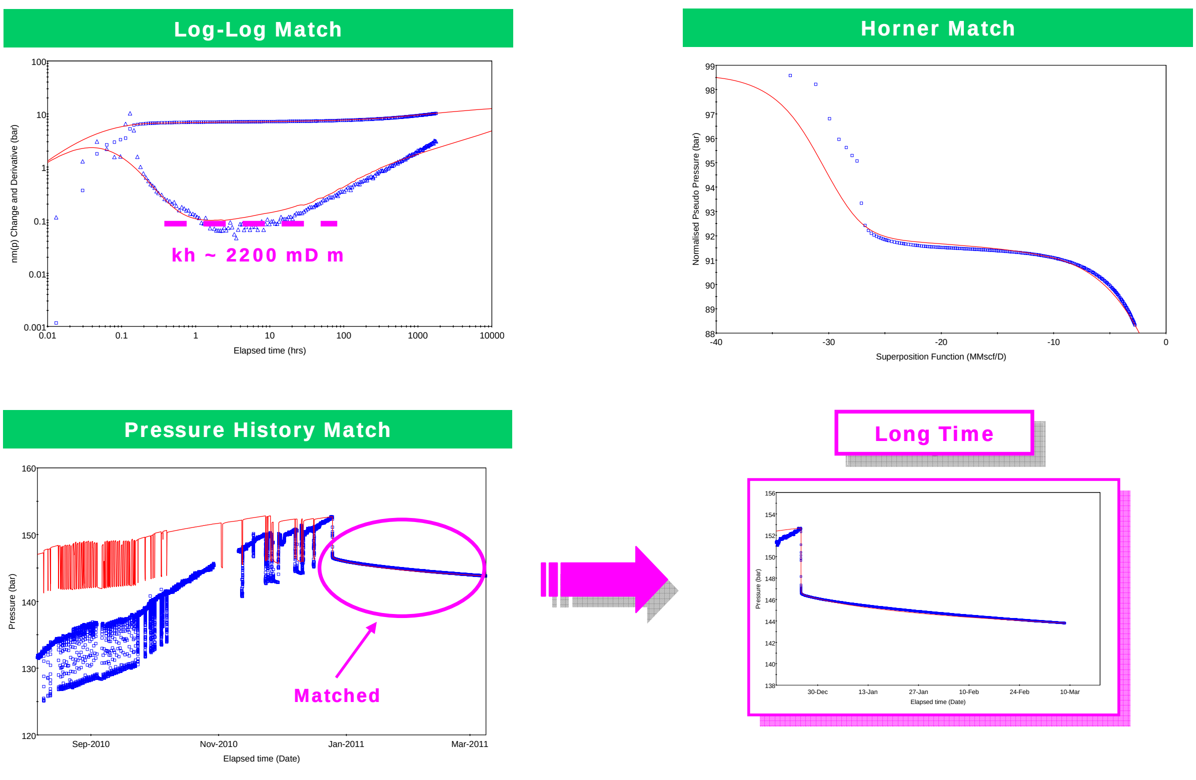

Fig. 23 – Well A: Open Ended System – Long Time Response Matching

MODEL	
Early Time:	Partial Penetration
Middle Time:	Homogeneous
Late Time:	Open Ended Rectangle

kh		2200 mD m
k_{xy}		100 mD
S_t		29
k_z / k_{xy} (Estimated Injection Interval, h_w = 6 m)		0.1
S_m		5
Open Ended Rectangle:	**d_1**	100 m
	d_2	500 m
	d_3	210 m

Tab. 9 – Well A: Open Ended System – Main Results

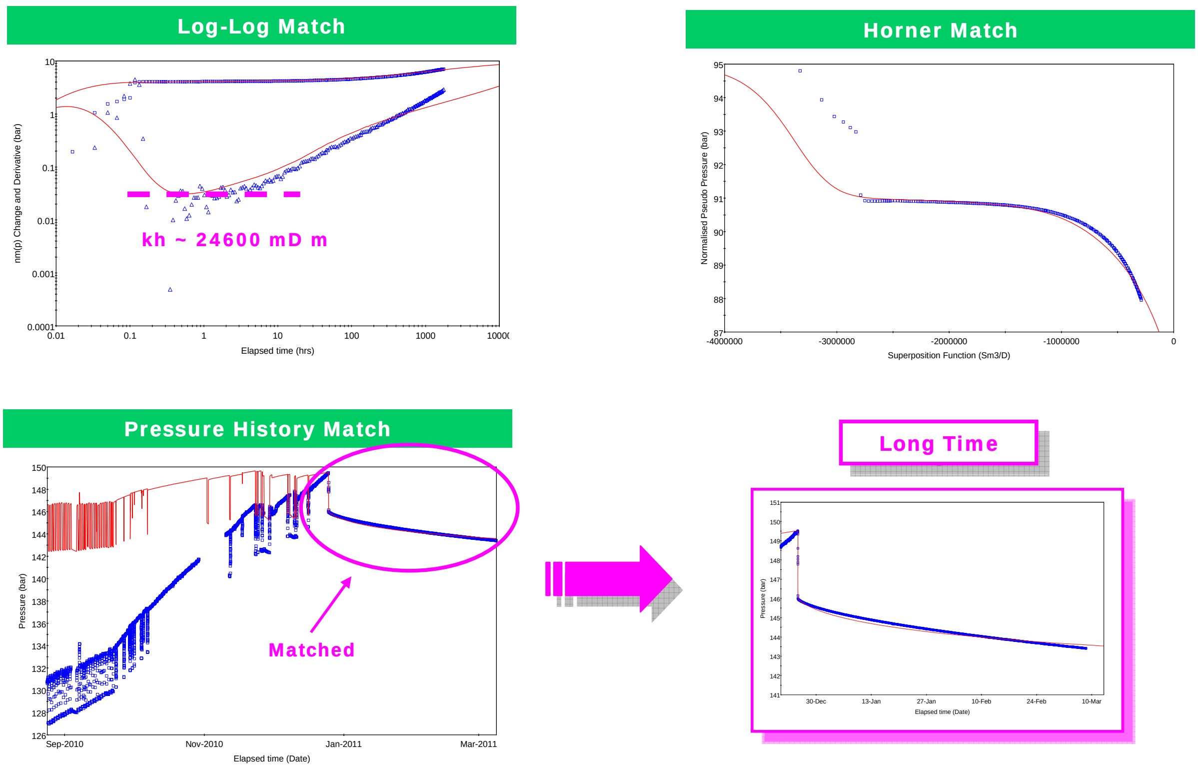

Fig. 24 – Well B: Open Ended System – Long Time Response Matching

MODEL	
Early Time:	Partial Penetration
Middle Time:	Homogeneous
Late Time:	Open Ended Rectangle

kh		24600 mD m
k_{xy}		600 mD
S_t		~ 60
k_z / k_{xy} (Estimated Injection Interval, h_w = 20 m)		0.1
S_m		25
Open Ended Rectangle:	**d_1**	140 m
	d_2	550 m
	d_3	200 m

Tab. 10 – Well B: Open Ended System – Main Results

In well B, the static pressure profile (Fig. 11) indicated the presence of a liquid level (i.e. brine) in the wellbore at the start of the injection phase. As a result, only the upper 20 m of the open hole interval were capable to receive the injected fluid. This wellbore scenario would justify the partial penetration model assumption.
No liquid presence was detected in well A (Fig. 9). A partial penetration model was anyway suspected since only the upper perforations set was assumed as the active zone for injection. The presence of sand control screens made the execution of the PLT not feasible.

The total commingled permeability thickness product (kh), was estimated at 2200 mD m for well A, with a resulting gas average permeability evaluated in 100 mD.
In well B, the associated kh was evaluated in about 24600 mD m, one order of magnitude larger than that calculated in well A. The huge difference in values supported the high degree of areal heterogeneity present in the geological environment. The average gas permeability was estimated at 600 mD, consistent with a previous injection test performed in December 1998.

As far as the well damage is concerned:

- ✓ A mechanical skin of 5 has been calculated for the well A. However, the impact of the geometrical skin, associated with the partial penetration effect, resulted in about 80 % of the total skin (30).
- ✓ In well B, the total skin of 60 was still a combination of the mechanical damage (25) and the partial penetration component, estimated in excess of 50 %.

At “short times”, the area affected by the gas injection has been estimated at 0.24 km^2 for well A and at 0.48 km^2 for well B. The dynamic barrier, caused by the interaction between the two wells, has been clearly investigated for both wells: at a distance respectively of 100 m to the East for well A and of 140 m to the West for well B. Furthermore, the well A intercepted a porosity limit in the Western direction set at a distance of nearly 210 m.
In well B, the injected gas reached the structural fault present toward the South direction at a distance of approximately 550 m.

At “long times”, also the injected gas in well A expanded toward the South direction until reaching the same structural fault. The well B reached, at a distance of 200 m, the porosity limit which limited the gas expansion to the East.

Based on the dynamic response of both wells, the injected gas would tend to expand towards the preferential South-North direction, pushing the surrounding aquifer away.

Interference Test

A third well, namely C, set at a distance of about 650 m away from the well B, was used as observer well during the interference test (Fig. 25).

The petrophysical input data set, introduced for this well, has been reported in Tab. 11. The bottomhole pressure response, recorded by memory gauges from 3rd August 2010 to 1st March 2011, clearly confirmed the areal hydraulic communication between the three wells of the field (Fig. 26).

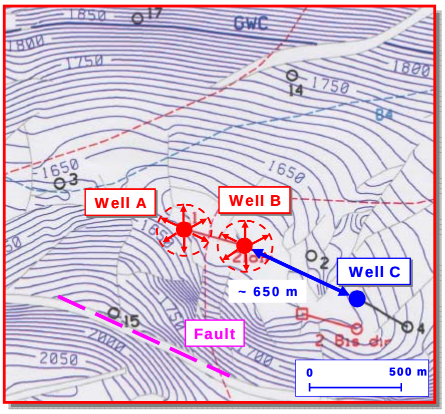

Fig. 25 – Injectors vs Observer Wells

Petrophysical Parameters	
Net Pay Thickness	24 m
Open Hole Interval	29 m MD
Average Porosity	21 %
Average Water Saturation	20 %
Well Radius	0.108 m

Tab. 11 – Well C: Petrophysical Input Data

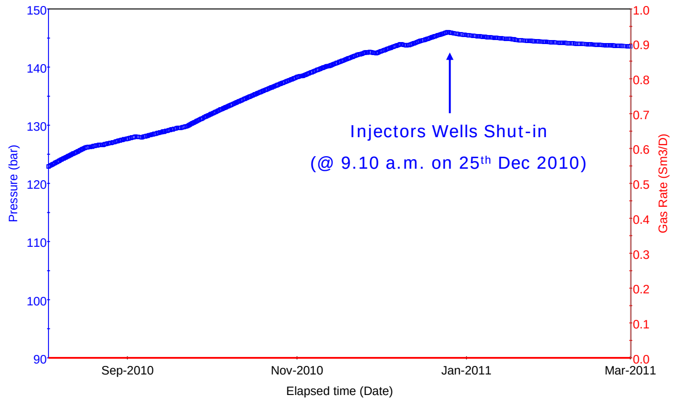

Fig. 26 – Well C: BHP History

Conclusions

The main conclusions have been summarised as follows:

- The pressure response of the wells during the injection history was recognised as changing and evolving over time since the injected gas expanded, thus displacing the surrounding aquifer away from the well. This effect was clearly experienced in the final longest falloff phase.
- The complexity of the reservoir dynamic behaviour should be described in detail by 3D numerical simulators. However, the utilised approach based on standard analytical solutions clearly discriminates between the actual geological features and the time dependent pseudo-barriers associated with the expansion of the gas/aquifer system.
- The total permeability thickness product (kh) on well A was evaluated in 2200 mD m. In well B it was estimated to be approximately ten times larger (kh ~ 24600 mD m). The average gas permeability of the system resulted in 100 mD and 600 mD respectively.
- In both the cases, the injectivity was significantly reduced by huge skin, with values of 30 and 60 respectively. The total well damage was caused by a combination of mechanical and geometrical components.
- The areal hydraulic communication between wells A, B and C was confirmed by the interference test conducted between the injection wells A and B and the observation well C.

Acknowledgements
The authors wish to thank stogit spa for giving permission to publish the data presented in this paper.

Nomenclature

BHP	Bottomhole Pressure
CH	Cased Hole
DPTT	Downhole Pressure and Temperature Transmitter
MD	Measured Depth
OH	Open Hole
PLT	Production Logging Tool
PVT	Pressure Volume Temperature
TVD SS	True Vertical Depth Sub Sea

References

1. Bourdet, D. 2002. *Well Test Analysis: The Use of Advanced Interpretation Models*, First Edition, 426. Elsevier Science B. V.
2. Chierici, G.L. 1989. *Principi di Ingegneria dei Giacimenti Petroliferi*, Vol. 1 & 2, Third Edition, 425 & 568. eni spa.

Conversion Factors

bar x 1.0*E+05	= Pa
cP x 1.0*E-03	= Pa s
°C (°C + 273.15)	= K