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Technical challenges in characterization of future CO_2 storage site in a deep saline aquifer in the Paris basin. Lessons learned from practical application of site selection methodology

Le Gallo Y.[a*], Fillacier, S.[a], Lecomte A.[a], Munier G.[a], Hanot F.[b], Quisel N.[c], Rampnoux N.[c], Thomas S.[c]

"a Geogreen, 7, rue E. et A. Peugeot, 92563 Rueil-Malmaison Cedex, France"
"b CDP Consulting, 23 Avenue des Droits de l'Homme, 45 000 Orléans, France"
"c Veolia Environnement Recherche & Innovation SNC, 10 rue Jacques Daguerre, 92500 Rueil-Malmaison , France"

Abstract

To ensure safe behavior during the whole lifetime of the geological storage of CO_2, site selection and its characterization are essential corner stones. This paper presents the different milestones and the results of each step of the site characterization implemented on a potential storage site in the Triassic deep saline aquifer of the Paris Basin. It addresses a well known theory and practical aspects and challenges of the first phase of real site identification carried out by Veolia Environnement and Geogreen.
The initial static and dynamic characterization of the storage complex will mainly rely on available public or proprietary data. Different challenges related to the gathering and validation of existing data are discussed.
The characterization methodology should aim at re-interpreting the available data in order to populate a dynamic model at semi-regional scale of the storage complex.
2D Seismic data reprocessing made it possible to determine the local structure of the storage. Regional structural information must also been considered since industrial scale injection impacts a significant area with respect to overpressure extension. To complete the storage complex description, upper laying structures and aquifers must be adequately described up to the ground level. When elaborating such a 3D model, data consistency at the different scales should be carefully checked.
Facies variations, porosity and both vertical and horizontal permeabilities will control storage capacity and well injectivity. Thus, an extensive log analysis is a major step in the characterization methodology. When available, core samples and flow tests must also be reconsidered to enhance the model quality. Furthermore, petrophysical interpretation of logs will improve site characterization and enable mineral trapping assessment. The consistent re-interpretation of available well logs will ensure proper site characterization in terms of reservoir and containment. Some examples are provided to illustrate the relevance of re-interpretation work.
Building a 3-D geological model is a major integrating step of the available dataset on the area of interest both in terms of structure and heterogeneities at different scales (facies, mineral, petrophysical…). At this stage, the different assumptions should be carefully revisited in light of the available data. The geological uncertainties can then be estimated using a statistical approach, which highlights key petrophysical characteristics of the storage along with main risks that need to be assessed.
The final step in the characterization methodology includes a dynamic assessment of the short term effects on injectivity and capacity, and of long term trapping mechanism. On the short term, potential interference with other sub-surface activities needs to be investigated along with the potential migration pathways (existing wells and faults). Models were elaborated at different scales. A near-wellbore model helped to estimate chemical induced effects. A storage site model helped to estimate overpressure and CO_2 plume behaviors, and a model larger than the storage complex helped to identify migration pathways and constraint boundary conditions. Different assumptions and operational constraints were supposed to ensure the robustness of different injection scenarios. The results of corresponding dynamic simulations are presented and discussed.

"Keywords: CO2 storage; site selection; storage site; storage complex; modeling; injectivity; capacity; characterization"

* Corresponding author. Tel.: +33 -1-47-08-73-51. *E-mail address*: ylg@geogreen.fr

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1. CO_2 site characterization methodology: general workflow and different milestones

Considering the objectives of the Kyoto protocol and managing roughly 100,000 sites throughout the world, including combustion facilities and non-hazardous waste landfills, Veolia Environnement has been conducting research to reduce its greenhouse gas emissions (estimated at about 1/1,000th of worldwide emissions). Considering the different sizes of the facilities managed, and the probable evolution of their emission characteristics, Veolia Environment Research launched an assessment of a geological storage experiment to identify the technological and economical validity of CCS implementation.

A site in the Île-de-France region was identified for a possible CCS pilot project. CO_2 is emitted from a waste-supplied thermal power plant. Veolia Environnement created a partnership with storage engineering specialists Geogreen to carry out the technical feasibility studies.

On the basis of a preliminary site selection study, detailed studies were carried out considering new dataset, in order to confirm that the selected site was adequate, and revise its capacity. The study aimed at characterizing the site and assessing its capacity for large scale injection: CO_2 source is a biogas plant generating about 0.1 Mt/y of CO_2. The site preselection study showed that a regional area, the lateral extension of which includes the CO_2 source plant, was adequate in terms of global static capacity. In order to minimize transportation and land ownership issues, the investigations focused on geological layers underneath the plant itself. Site characterization implies an important seismic reprocessing and significant geological and production data integration. The applied methodology can be summed up in the following way:

- Reprocessing of about 300 km of 2D seismic data to better highlight faults and geometry of the target reservoir (Triassic sandstone) and of upper laying formations.
- Well logs petrophysical interpretation: this analysis was carried out on 15 wells (proprietary and public domain). Interpretation covers the whole sedimentary column and is detailed for Triassic and Dogger levels where log acquisition has historically been important, due to past oil exploration in the Paris basin.
- Geological model at semi-regional scale, locally refined: all available data from wells on water-bearing levels upper laying Triassic sandstone and its caprock, as well as all regional maps were taken into account in the semi regional model (50x50 km). A local sub-model (17x14 km) of the storage complex was used in the dynamic simulation of injection. A geostatistical approach constraint by wells' data was used to populate the model with facies and properties.
- Dynamic model: Several injection scenarios were investigated from pilot to industrial scale to assess capacity and injectivity of the storage site. CO_2 plume migration and the different trapping mechanisms were modelled. The main risks were identified and the pressure and plume potential induced effects were assessed.
- Geochemical analysis: long-term geochemical behaviour of the system showed a stability of the rock in relation to CO_2 injection in spite of necessary simplifying hypotheses.
- Geomechanical analysis: Based upon of the dynamic simulation results, a mechanical stability analysis of the structure and faults was carried out for the different storage scenarios.

This paper will review the key issues and technical challenges of each step of the characterization workflow

2. Practical implementation of the site characterization methodology: storage site validation in the Triassic deep saline aquifer of the Paris Basin

The Paris Basin is part of a large intracratonic bowl of about 140,000 km^2 which includes the London Basin and part of Belgium. Faults existing in the Paris Basin are to a great extent of Hercynian age and have for the most part been reactivated by major tectonic events (Alpine and Pyrenean orogenesis mainly). These faults had a key role in oil migration and trapping. In addition, geological history of the basin is reflected by many transgression-regression cycles. The basin is a multilayer reservoir-cap rock system with mainly sandstone reservoirs and one major limestone reservoir (Figure 3). Hydrogeological synthesis was carried out to describe water-bearing formations, their main characteristics and water pressure regime in the vicinity of the site.

2.1. Challenges related to the gathering and validation of existing data.

A minimal dataset (standard well logs, drilling reports) for all oil exploration wells, along with 10 years old 2-D seismic profiles are publicly available in France. Data collection was the utmost concern at start of the study and required discussions with a local oil concession operator. This step was essential to the study success and one shall take care not to underestimate it in terms of delay. Final dataset was then made of existing data available in the area, with 2D seismic profiles, all available well data from the mentioned local oil producer (drilling reports, reservoir structural maps, well logs, production tests …), and public domain data (see Figure 1).

2.2. Seismic reprocessing to determine geological and fault structure.

Reprocessing of 34 2-D seismic lines (303 km, Figure 1) which were recorded in the 80^{ths} and from 10 different surveys with different quality of initial records was carried out. Initial quality of the existing data was poor and a particular pre-processing was performed to insure consistency between surveys. As static corrections are of primary importance in the Paris basin, a laterally consistent multi-layered model of the whole tertiary cover was built for corrections calculation. The whole dataset was then harmonized through a suitable deconvolution [1], and seismic velocity analyses were performed in 3 iterations with an increasing lateral density (2 km, 1 km and 500 m for the last one). Estimation and application of residual static corrections were run after each velocity analysis. A post-stack migration in the F-X domain was then applied (operator length of 24 ms), and DMO velocities were smoothed over 50 CDP. Band-pass filtering and AGC were carried out after migration. The time interpretation was tied at 3 wells with the help of their synthetic seismograms, and depth conversion was calibrated at 38 wells. 8 horizons were picked, and this interpretation highlighted several local faults and structures at Triassic level, which made it possible to refine location and interpretation of faults taken from regional studies. Unfortunately, this reprocessing did not make it possible to analyze lateral variations of facies at reservoir level, due to the overall quality of field seismic data.

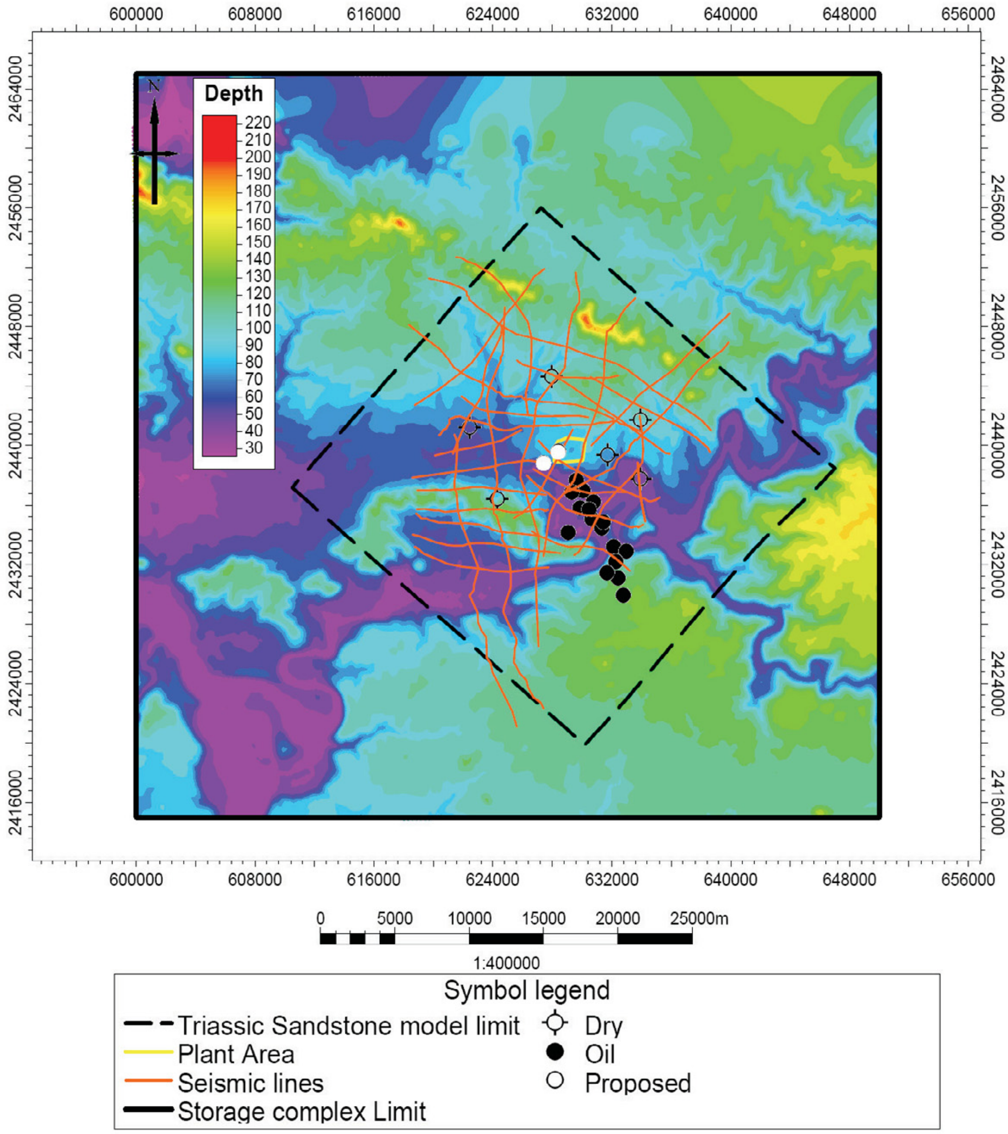

Figure 1 Area of interest with reinterpreted seismic lines, available and proposed wells, and areas of semi-regional (50x50 km) and storage complex (17x14 km) models

2.3. Initial static and dynamic characterization of the storage complex

One initial step in the site characterization study focuses on the interpretation of available well logs acquired in 15 wells. Beyond facies, porosities and saturation determination, mineralogical volumes were computed as illustrated in Figure 2. As most exiting logs were oil-industry oriented, Triassic and Dogger units were well characterized. For other layers (like Liassic shales which are the cap-rock of Triassic reservoirs, and other beds), the log interpretation had to be coupled with an analytical approach and lead to the quantification of porosity only. The log interpretation enables a good identification of best reservoir levels when associated with a geological synthesis of the storage complex. Comparisons between core and log porosities confirm the quality of the interpretation. This work provided further detailed information on the petrophysical characteristics and the lithology of the target reservoir.

2.4. Static assessment of storage capacity

To fully integrate all available data and evaluate the impact of CO_2 injection on the reservoir and above aquifers, a geological model larger than the storage complex is built. This model of semi regional size (50x50 km) includes the targeted reservoirs (Triassic sandstones) and the whole sedimentary column (Figure 3). Such extended model is necessary to avoid boundary numerical artefacts in the dynamic modelling but requires merging different data at different scales. Indeed, integrating all the available data and considering different scales represents a real and unusual challenge. The regional information must be consistently combined with the local (reservoir) information for each aquifer unit and fault. Each horizon (unit top and base) within the sedimentary pile has to be built, from basement to the surface level, and of course match at wells. A digital elevation model (DEM) is input to properly integrate outcrops as they will locally influence hydrology of some aquifers. Regional maps for the whole Paris basin (large scale data) are used to constrain the structural model where no seismic lines or wells data are available (small scale data). The further from the injection point, the coarser the model definition is. To complete the database, hydro geological data from fresh water or geothermal reports are integrated in the model.

Using the structural framework set up by this large model, a local storage site model is built, focusing on the Triassic sandstone and its complex stratigraphic setting, at a very fine scale. Using a suitable geological analogue extensively studied [2], it is possible to establish the geological characteristics of the reservoir and its main parameters. A geostatistical approach may then be used to model facies, porosity and permeability. The properties populations are also constrained by regional property trend maps, interpreted well logs and core measurements. Mineral composition of the rock reservoir may be determined from core and well log interpretation and associated with facies. They can then be applied using the facies distribution in between wells.

Several possible realizations of the model of Triassic sandstones are then computed to assess the uncertainty and highlight the key petrophysical features of the model. It is then possible to estimate the storage static capacity (pore volume) which was suitable for the foreseen injection operation.

2.5. Dynamic assessment of short term effects (storage injectivity).

The dynamic simulations of the storage site were performed on a 240 km^2 3D block (17x14 km) with an average thickness of about 160 m. These simulations aim at assessing possible impacts associated with the development of the CO_2 plume and interference with neighboring oil production activities. Different injection scenarios were considered to assess the reservoir injectivity. The base case scenario aimed at an industrial injection of about 0.1 Mt/y for 30 years.

The flow model focused on Triassic is vertically refined to better reproduce the heterogeneities of the formation. The targeted reservoir level was a salt water bearing formation isolated from the neighboring oil field, thanks to log interpretations. Relative permeabilities and capillary pressure must be assumed as no data is available at this stage of the study. Thus, conservative assumptions were followed to maximize the impact and spread of the CO_2 plume for the different injection scenarios, especially on the choice of the flow properties of different units. Due to limitations of the simulation software, the neighboring oil field must be assumed either as an aquifer or as a gas field to enable compositional modeling and CO_2 dissolution in water. To maximize the potential impact of injected CO_2, model boundaries are assumed to be closed and the faults are assumed to be fully transmissible. To assess the impact of the injection, the pressure of the aquifer must be estimated since the neighboring oil production has altered the aquifer pressure, which is then no longer at hydrostatic conditions. The corresponding pressure drop also enhances the CO_2 migration towards the oil field[1]. Since on the oil concession, the drilling of producing wells was carried out on several years, production test data clearly showed the isolation of some sub-layers in terms of hydraulic units. Several hypotheses using these tests trends were then investigated.

[1] One shall note that production inside a reservoir layer shall create preferred CO_2 pathways from the injection well to the depleted area.

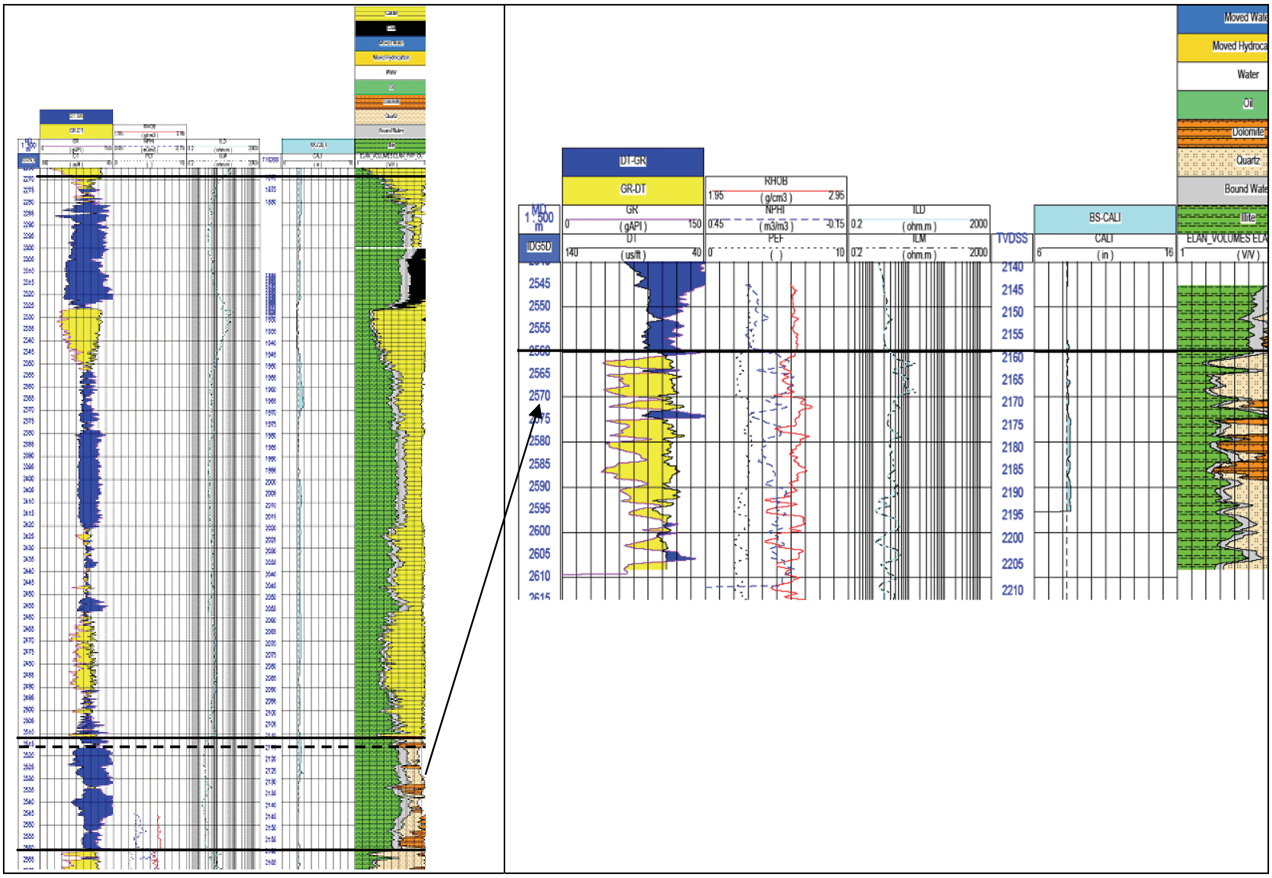

Figure 2 Typical petrophysical interpretation of the overburden and target storage (left), and zoom on the target storage (right)

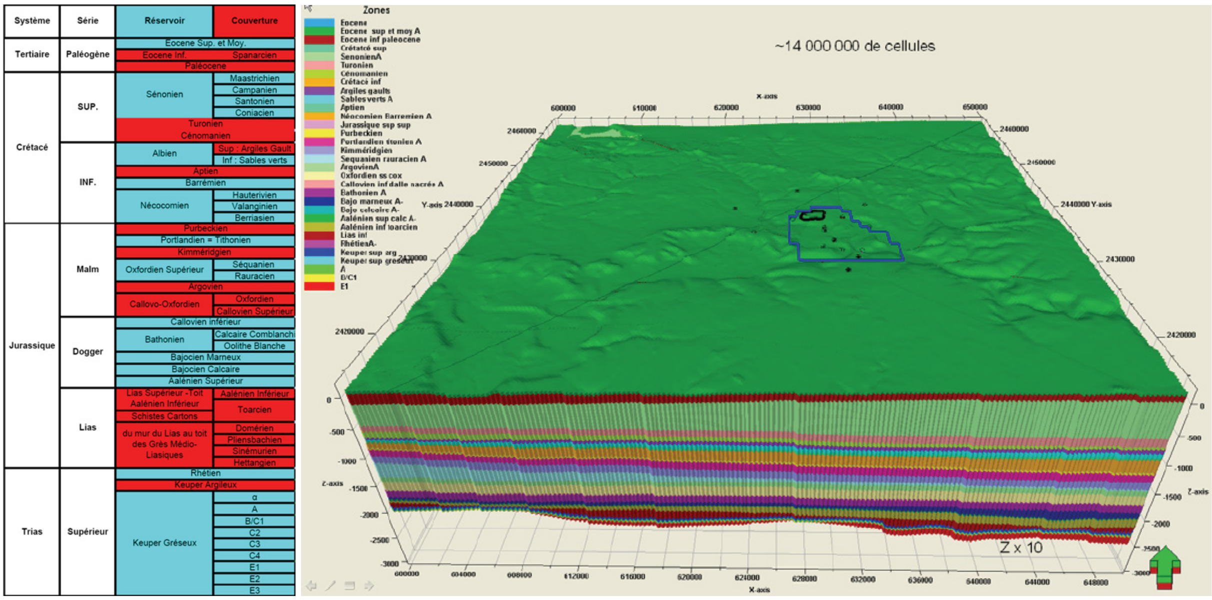

Figure 3 Sedimentary column of the storage complex from storage target to surface. Red color indicates a caprock character while the blue one indicates a reservoir. Right hand side is a 3D view of the corresponding geological model. Black dot indicates the wells used for static and dynamic analysis, while the blue line indicates the location of the neighboring oil production concession.

At the end of CO_2 injection, the plume extension is confined to the immediate vicinity of the injection well: free CO_2 remains within about 2 km from the injection well in all investigated scenarios. The CO_2 plume is then laterally very close to the oil field (Figure 4) but remains confined in the water-bearing reservoir which is isolated vertically from oil-bearing reservoirs, because of the continuity of a shale interbed. Therefore, fluid interaction may be negligible. Similarly, the CO_2 dissolved in the water phase (Figure 4) remains within 2.5 km around the injection well for all investigated scenarios and do not contact the oil-bearing layers. The overpressure created by injection (Figure 4) reaches about 20 bars, which is well within design limits as the aquifer is initially depleted due to the oil production. The maximum overpressure occurs within a short distance (less than 0.5 km) from the injection well and declines quickly away from it. Despite the large model size, as illustrated in Figure 4, the pressure disturbance reaches the boundary of the model. Even though the boundary condition will influence the pressure computation [3], the level of pressure increase at the boundary is less than 5 bars i.e. less than 2 % of the initial pressure. The negligible numerical bias induced by the boundary condition will not alter the CO_2 plumes either dissolved or free as the computation domain is already significantly larger than the plume extension.

In the base case, it is then possible to consider industrial injections (0.1 Mt/y for 30 years) without interference between injected CO_2 and the near-by oil reservoir. However, pressure interference may be expected with the oil field, beyond eight years of injection as illustrated in Figure 5. Smaller injection rate, e.g. 0.02 Mt/y during 30 years, do not pose any difficulty of interference in pressure nor in CO_2 plume development.

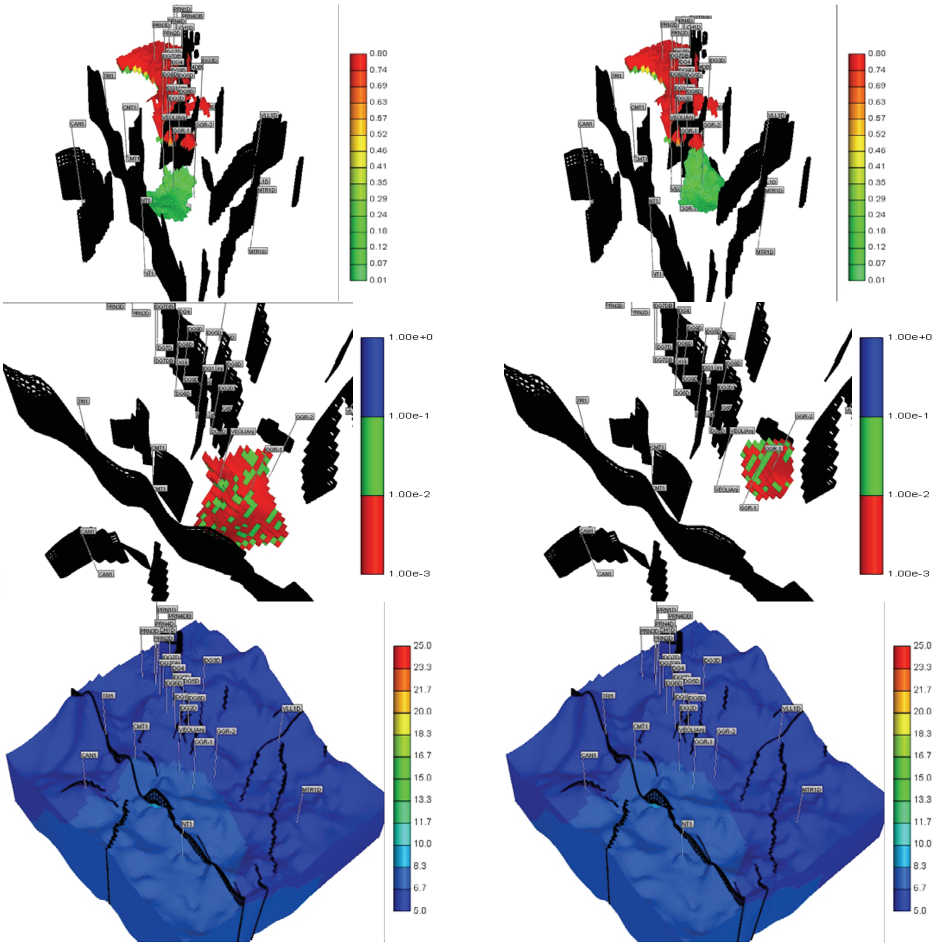

Figure 4 Plume migration at the end of CO_2 injection (0.1 Mt /y for 30 years) using Well-1 (left column) on a flat zone or Well-2 (right column) down dip of a structure. Gas saturation (Top), fraction of CO_2 dissolved in the water (Middle), Overpressure (Bottom) at the end of the injection. The gas saturation above 0.7 corresponds to the neighboring field. The black vertical planes represent the faults assumed to be conductive in this scenario.

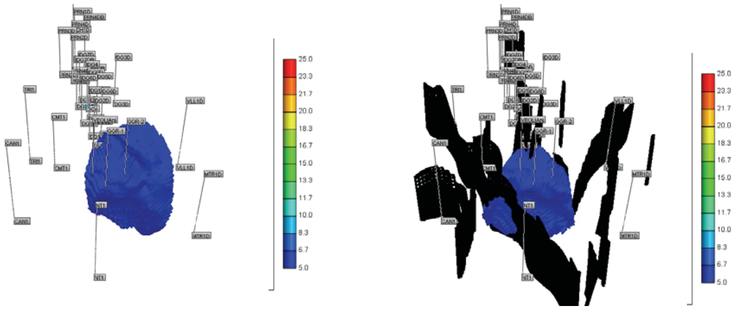

Figure 5 Beginning of pressure interference with the oil production activities after 8 years of CO_2 injection (0.1 Mt /y for 30 years) with Well-1 (left) or Well-2 (right)

2.6. Trapping mechanism and the long term behavior

The trapping mechanisms will have different relative kinetics and importance during and after injection. In the previously described dynamic simulations, the main focus was on injectivity and capacity estimate when structural and solution trapping are dominant (see Table 1). However, depending on the location of the injection well, significant changes in the migration and trapping may be induced (Figure 4 and Table 1): Well-1 is centered on a relatively flat part of the reservoir gently raising towards a fault, whereas Well-2 is on the flank of a local closed structure, which is a satellite of the main oil field. Figure 4 illustrates the different plume migrations and enhancement of trapping mechanisms. In the case of injection in Well-2, most of the CO_2 is trapped in the local structure, i.e. limited migration. In the case of injection in Well-1, the CO_2 migration is not constraint and tends towards the fault. Consequently, the solution trapping is enhanced in the case of Well-1 (Figure 6). In both cases, capillary trapping has a low impact compared to solution trapping (Table 1) since modeling focused on the injection period. The relative inefficiency of the former is a direct consequence of the petrophysical assumptions to maximize the plume extension: limited hysteresis effect is assumed.

Table 1 CO_2 trapping at the end of the injection (0.1 Mt/y during 30 years)

	End of injection	
Trapped CO_2	Well 1	Well 2
structural	71%	76%
capillary	1%	5%
solution	28%	19%

Geochemical simulations are carried out on a representative model in the near-well bore region using the geological model scale and the computed mineral distribution. No significant mineral trapping is predicted in the sandstone reservoir. However, some calcite-dolomite transforms (calcite dissolution and dolomite precipitation) were predicted which resulted in negligible porosity decrease. A more detailed study would be required to assess other potential impacts on the formation.

From the dynamic simulation, a geomechanical analysis was performed to assess the possible fracturation pressure and the fault reactivation. The fault stability criteria uses a semi-analytical "Reservoir Stress Path" method [4,5]. However, estimating the different in-situ stress components was a paramount task given the lack of data. Thus, a sensitivity analysis was performed trying to evaluate the fault reactivation potential. Given the lack of information on the fault configuration which by interval was normal or reverse, some configuration may present reactivation risks. Thus a data acquisition programme is specified to estimate in-situ stress conditions. Such data acquisition would ideally take place during drilling of the first well (site exploration and confirmation program).

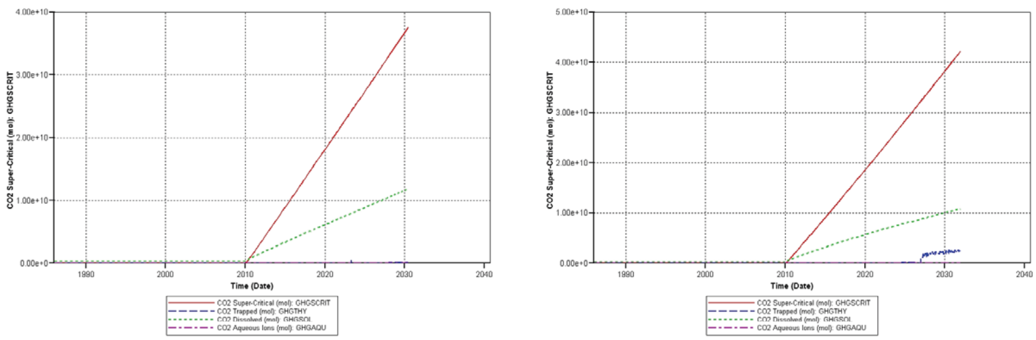

Figure 6 CO_2 inventory at the end of injection (0.1 Mt /y for 30 years) using Well-1 (left) on a flat zone or Well-2 (right) down dip of a structure

2.7. Surface and operational constraints

When considering drilling in Ile de France area, a key concern will be surface constraints (round-the-clock access road, high voltage electric lines, railroad tracks, airplane corridors, utilities…) along with disturbance to the neighbours during drilling operation (noise level, restricted night operations…) and administrative authorisation (heavy equipment route, acceptable overpasses and bridges). Additionally, and because volumes to be injected are reasonable (even in the industrial case), injection wells should be designed as vertical as possible, allowing to assume less risk to the casing set and cement jobs operations, and therefore minimizing potential risk of CO_2 leakage at the well site itself. Unfortunately, given overall surface related constraints, the surface location of wells shows only a few options. This is the reason why Well-2 requires a deviation of about 1km for a depth of about 2.26km (average deviation of about 24°) to reach its target which will increase the potential risks and cost. On the other hand, Well-1 may be drilled vertically but with large scale injection, the CO_2 plume may migrate towards the major Bray regional fault. The fault hydraulic properties need therefore further investigations.

3. Conclusions

When implementing a geological storage characterization study, several issues must be addressed. One of the key factors of future success for a utility company is to build an appropriate geoscientist expert team and initiate collaboration with historical local oil producer, the reservoir data owner. However, integrating oil and gas data, knowledge and engineering experience proved to be a corner stone to build the storage complex and the regional scale models. Then, assessing the capacity, injectivity and confinement of the CO_2 storage site will require re-interpretation. Some of the data may be very old and will require specific processing. The information gained linked to public study on suitable analogue will improve the understanding of the storage complex. Resolving inconsistencies between the different data sources (local vs. regional) and data quality (estimated/interpreted vs. measured) represents a real challenge. Then the different interpretation and hypothesis must be evaluated to assess the key uncertainty and hypothesis.

When estimating capacity, it is necessary to establish a conceptual model of the geological setting of the target reservoir. It is then possible to understand the storage organisation. A suitable geological model of the storage complex is elaborated without overlooking data availability and quality. Geostatistical methods can then be used to estimate the most appropriate and the uncertainty of the structural and petrophysical models.

When estimating injectivity, some key flow properties such as petrophysical parameters or capillary pressure must once again be assumed as no data may be available. Consequently, the dynamic results combined with uncertainty assessment can estimate the impact of the CO_2 injection both in terms of pressure and CO_2 plume. The selected site was successfully characterized and could withstand an industrial injection despite its proximity to a neighbouring oil field production. However, further qualification of the lateral extension and confinement of the shale interbeds is necessary. The pressure interferences with the oil production are likely and their impact should be further investigated.

Data scarcity would limit geochemical and geomechanical analysis as it proves to be difficult to obtain water composition and stress status of the target storage, even current pressure may be difficult to estimate.

The legal framework and status of the CO_2 storage, the medium and long-term guarantees and the local social acceptance issues must also be considered when characterizing a potential CO_2 storage site.

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