Oil & Gas Science and Technology – Rev. IFP Energies nouvelles, Vol. 66 (2011), No. 1, pp. 67-80

DOI: 10.2516/ogst2010017

IFP Energies nouvelles International Conference
Rencontres Scientifiques d'IFP Energies nouvelles

Deep Saline Aquifers for Geological Storage of CO_2 and Energy
Stockage géologique du CO_2 et de l'énergie en aquifères salins profonds

Pressure Build-up and Decay in Acid Gas Injection Operations in Reefs in the Zama Field, Canada, and Implications for CO_2 Storage

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Résumé — Variations de pression au cours de l'injection de gaz acides dans le réservoir récifal du champ de Zama, Canada. Implications pour le stockage géologique de CO_2 — Le but de l'article est de comprendre l'accroissement de pression dans le gisement de Zama X2X, utilisé pour le stockage de gaz acide (NO de l'Alberta, Canada), et aussi d'examiner si la baisse de pression, observée ultérieurement, est la conséquence d'une dissipation par un aquifère de grande taille. Le gisement de Zama X2X, d'une extension de 1 km^2 environ, est connecté à quatre autres gisements voisins par l'intermédiaire d'un aquifère commun sous-jacent. L'analyse de la pression à travers tous ces gisements indique un bon niveau de communication hydraulique. La pression initiale de l'accumulation de Zama X2X était d'environ 15 MPa. Pendant la production d'huile, la pression a commencé par décroître, pour se stabiliser vers 10 MPa au début de la décennie 1970. Mais ensuite la pression a repris son ascension, jusqu'à atteindre 26 MPa en 1986. Un nouvel épisode de baisse est alors intervenu et la pression s'est établie vers 22 MPa en 1995, au moment où l'on a commencé à injecter du gaz acide (80 % CO_2 et 20 % H_2S) – l'opérateur, toutefois, injectait ce gaz à des débits et à des pressions en tête de puits qui se situaient en deçà des seuils autorisés par l'Administration. En dépit d'une production significative d'eau et d'hydrocarbures, la pression à Zama X2X est ensuite restée plus élevée que la pression vierge, d'au moins 5 MPa, au point qu'en 1998 les opérations d'injection de gaz furent suspendues. La production d'huile a cependant été maintenue jusqu'en 2002.

Des simulations numériques effectuées avec CMG-IMEX™, assorties d'une analyse de sensibilité, montrent ici que la ré-injection de plus de 1 million de m^3 d'eau dans le gisement voisin de Zama YY, entre 1970 et 1988 puis en 1992-93, est la principale cause du comportement de la pression à Zama X2X. Les deux champs sont en effet connectés hydrauliquement via l'aquifère situé au-dessous de la colonne d'huile. L'analyse de sensibilité indique que la baisse de pression un moment enregistrée à Zama X2X était due à la production de fluides, mais aussi que l'aquifère commun n'est pas d'une dimension suffisante pour permettre une dissipation rapide et complète des effets de pression. Ce cas d'étude illustre toute l'importance, pour la transmission des pressions lors du stockage géologique de CO_2, de la connectivité entre les réservoirs concernés.

Abstract — Pressure Build-up and Decay in Acid Gas Injection Operations in Reefs in the Zama Field, Canada, and Implications for CO_2 Storage — *The objective of this paper is to examine reasons for pressure rise in the Zama X2X pool in northwestern Alberta, Canada, that was used for acid gas disposal, and whether subsequent pressure decay was a result of pressure dissipation into a* *larger aquifer. The Zama X2X pool, approximately 1 km² in size, is connected to four other nearby pools through a common underlying aquifer. Pressure analysis for all the pools indicates that they are in good hydraulic communication. Initial pressure in the Zama X2X pool was approximately 15 MPa. Pressure declined first during oil production, stabilizing at around 10 MPa in the early 1970s, after which started to increase such that it reached 26 MPa in 1986. Subsequently, pressure declined reaching 22 MPa by 1995 just prior to starting injection of acid gas (80% CO_2 and 20% H_2S). The operator injected acid gas at lower rates and wellhead pressures than those licensed by the regulatory agency. Despite significant production of water and hydrocarbons, the pressure in the Zama X2X pool continued to be higher than the initial reservoir pressure by more than 5 MPa, such that disposal operations were suspended in late 1998. Oil production continued all this time until 2002.*

Numerical simulations using CMG-IMEX™ and corresponding sensitivity studies reported in this paper show that disposal of more than 1 million m^3 of water between 1970 and 1988 and again in 1992-1993 in the adjacent Zama YY pool, which is in good hydrodynamic communication with the Zama X2X pool through the aquifer below the oil column, is the main reason for the high pressures observed in the Zama X2X pool. Sensitivity studies indicate that pressure decay in the X2X pool was due to fluid production. The study indicates that while pressure rise has been caused by hydraulic communication between the X2X and YY pools through the common aquifer, the aquifer was not of large volume to allow dissipation of the pressure. In addition to the case study, the implications of pressure communication to geological storage of CO_2 in aquifers are briefly discussed.

INTRODUCTION

Carbon dioxide capture and storage in geological formations is considered to be one of the practical options for reducing atmospheric greenhouse gas emissions. A number of operators in Alberta have implemented acid gas injection into depleted gas and oil pools as a means of disposal and storage of acid gas, which is a mixture of H_2S and CO_2 stripped off produced sour gas before sending the natural gas to markets (Bachu and Gunter, 2005). Significant interest has been expressed in the study of these reservoirs as commercial-scale analogues for geological storage of CO_2 (Bachu and Gunter, 2005; Bachu and Haug, 2005). Currently there are close to 50 acid gas injection operations in western Canada. The authors have studied five of these operations where either breakthrough of the injected gas in producing wells (Pooladi-Darvish *et al.*, 2008a), or significant pressurization was observed.

The Zama Keg River X2X pool in northwestern Alberta *(Fig. 1)* experienced significant overpressuring even before acid gas injection was implemented. The objective of the study presented here was to investigate the cause of the overpressure and the subsequent pressure decline. In particular, we investigate whether the dissipation of pressure after overpressurization is a result of hydraulic connectivity to a large aquifer.

In the following the reservoir architecture and properties are first reviewed. This is followed by a brief review of production/injection history and the ensuing pressure trend. The simulation and associated sensitivity studies, as well as their use for better understanding of the over-pressurization and its dissipation are then presented.

The Zama Keg River X2X pool is an oil pool in the Zama oil field that produces oil from the Zama Member of the Middle Devonian Keg River Formation. The Keg River Formation consists of porous reefal dolostones and is overlain and sealed by tight evaporites (anhydrites) of the Muskeg Formation. There are between 600 and 800 such reefal oil pools in the Zama oil field. The Zama Keg River X2X pool has an area of approximately 106 hectares at the oil-water contact of −1122 mSS, with an estimated original oil-in-place (OOIP) of 751×10^3 m^3.

The structure map created from seismic information indicates that this pool is connected to four nearby pools *(Fig. 1)*. The reservoir pressure data of these pools (particularly the Zama Keg River X2X, YY, P9P pools and the Muskeg BBB pool) show strong pressure interference, providing evidence that there is good hydraulic communication between four of the five pools. The measured pressure data of the Zama Keg River G2G pool (north of the Zama Keg River X2X pool) indicates that it may or may not be in pressure communication with the Zama Keg River X2X pool.

1 RESERVOIR ARCHITECTURE AND PROPERTIES

The Zama Keg River reefs including the Zama Keg River X2X pool are encased in the Muskeg Formation. Figure 1 shows a 3D seismic depth structure map of the Upper Keg River Formation, depicting the topographic highs that mark the Keg River Formation reefs. Figure 2 shows the gross-thickness map of the Upper Keg River. The limiting 40 m thickness contour line in Figure 2 suggests that there is a layer beneath the Keg River reefs that connects the five adjacent reef pools shown in Figure 2.

Consequently, a geological model was constructed with the Upper Keg River Formation divided into two layers: Upper Keg River A and B. The A layer at the top constitutes the reef build up and is of better reservoir quality. The Upper

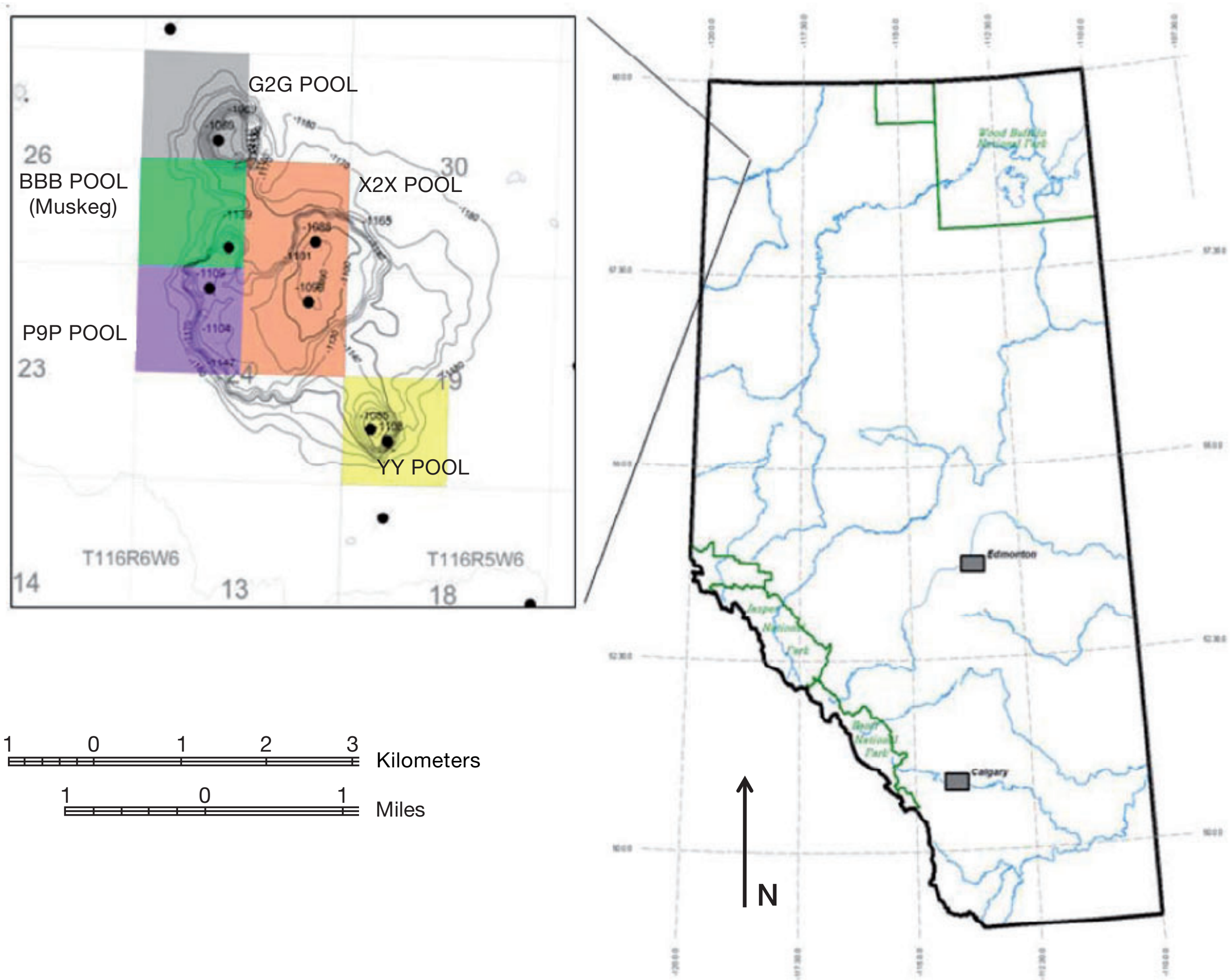

Figure 1

Location of the Zama Keg River X2X pool in northwestern Alberta. The contour lines show the depth to top of the Upper Keg River.

Keg River B layer sits beneath, and covers the whole area of study. A Lower Keg River Formation, which is a regionally tight lime mudstone, underlies these layers. This tight layer is not included in the study.

Figure 2 suggests that four out of the five pools (the exception being the G2G pool) are directly connected through the Upper Keg River A layer with better reservoir quality. Communication with the Zama Keg River G2G to the north is through the B layer (note in *Fig. 2* that the limiting contour line depicts a 40 m thickness).

The five pools have been penetrated by nine wells in total, with three cored wells. The quality and quantity of the information does not allow building a detailed geological model. Instead, a simplified geological model was built, representing the A and B layers of the Upper Keg River. It was felt that this simplified representation is consistent with the objective of this work that is the study of pressures and their communication between the pools where no wells have been drilled. This simplified representation facilitates sensitivity studies presented in the simulation section of this paper.

Using the available core and log information, the two layers of the Upper Keg River where characterized with average porosity, permeability and net-to-gross ratio of 8%, 100 mD, and 80%, respectively, for the A layer, and 4%, 2 mD, and 55%, respectively, for the B layer (ERCB, 2008). The overlying anhydritic Muskeg Formation is extremely tight, with permeability in the order of 10^{-4} mD (10^{-19} m^2) (Bennion and Bachu, 2008). Thus, considering the permeability of the caprock and that of the underlying aquifer, the system can be considered as semi-closed (Zhou *et al*., 2008).

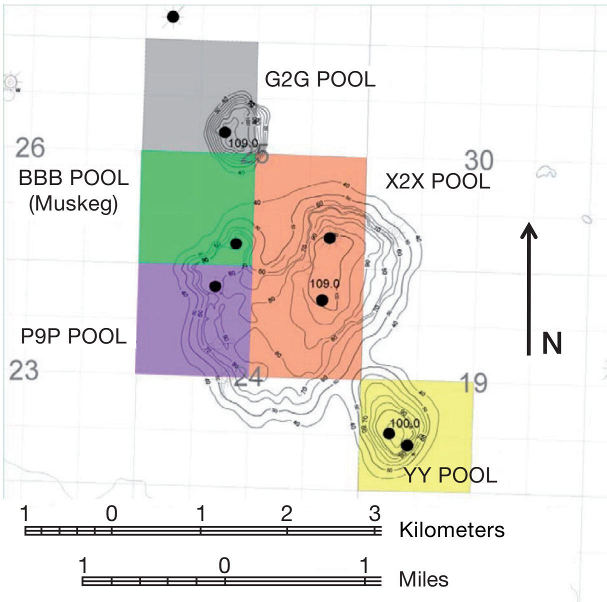

Figure 2

Gross thickness of the Upper Keg River, including the B layer of the Upper Keg River.

2 PRODUCTION HISTORY

This study includes five pools, the Zama Keg River X2X, YY, P9P and G2G, and Muskeg BBB oil pools, which communicate and interfere with each others. Injection and production in the four surrounding pools, and their relations with the behaviour of the X2X pool is reviewed in this section. Table 1 lists the original fluid in place and cumulative production or injection for each of the 5 pools. The data in Table 1 indicate that the Zama Keg River X2X pool is the largest and that the Zama Keg River G2G pool is the second largest. The oil recoveries for the Zama Keg River X2X and G2G pools are 38.8% and 23.8%, respectively.

TABLE 1

Original fluids in place and cumulative production and injection of each pool (ERCB, 2008)

Pool name	BBB	G2G	P9P	X2X	YY
Discovery year	1995	1968	1983	1968	1967
OOIP (10^3 m^3)	15.7	591	199	751	184
OGIP (10^6 m^3)		42	3	54	15
Cumulative oil prod. (10^3 m^3)	1.32	140.7	20.1	291.2	58.2
Cumulative gas prod. (10^6 m^3)		20.0	1.5	28.1	3.8
Cumulative water prod. (10^3 m^3)	3.34	99.5	4.9	588.8	68.0
Oil recovery (%)	8.4%	23.8%	10.1%	38.8%	31.7%
Cumulative gas injection (10^6 m^3)		19.6		72.2	
Cumulative water injection (10^3 m^3)					1330.2

Figure 3 shows the production from the X2X pool. Oil production from the X2X pool started in 1968. A significant increase in water cut was experienced in the early 1980's. Production continued until 1995, when one of the two producers in the pool was turned into an acid gas injection well. Oil recovery by this time is estimated at approximately 38.3% (with an additional 0.5% since acid gas injection).

As the production data in Figure 3 suggest, the amount of water produced is twice as much as the produced oil. It is thought that the primary oil recovery in the X2X pool was influenced by the significant water injection that was going on in the YY pool, 400 m southeast of the Zama Keg River X2X Pool since 1970. Figure 4 shows the history of water injection. By the time water disposal stopped in 1993, the cumulative water injected was 1.330 × 10^3 m^3, many times the OOIP in the YY pool.

The history of acid gas injection is shown in Figure 4, which shows that acid gas was injected in the Zama X2X pool between May 1995 and February 1998 at an average injection rate of between 40 × 10^3 m^3/day (early on) and 140 × 10^3 m^3/day. The cumulative injected acid gas is 72.2 × 10^6 m^3, approximately 30% more than the original solution-gas-in-place. The acid gas injection was concurrent with oil production, until acid gas breakthrough in 1998. Incremental oil recovery as a result of acid gas injection was approximately 0.5%.

Among the other 4 pools, acid gas has also been injected in the G2G pool. This started in 2006, after injection and production had ceased in the X2X pool. As shown in Figure 4, the average acid gas injection rate in the G2G pool is approximately 30 × 10^3 m^3/day. The cumulative injected acid gas to January 2008 is 19.6 × 10^6 m^3.

3 PRESSURE HISTORY

The measured reservoir pressure histories of the individual pools are plotted in Figure 5, depicting a hydrostatically pressure reservoir at an initial pressure of approximately 15 MPa. (Throughout this paper, use of the term "initial pressure" is in reference to pressure at the time of discovery). Measurements shown in Figure 5 indicate that pressure declined during the first few years of oil production, before it stabilized at around 10 MPa during early and mid 1970's. This is followed by a long period of significant pressure rise to more than 50% above the initial pressures in 1987. The rise in pressure until its peak in 1987 corresponds with the water injection period in the YY pool, which amounts to many times the OOIP in the YY pool. A significant reduction in reservoir pressures is evident between 1987 and 1992, when there is no water injection. There is a second period of pressure increase to approximately 22 MPa in 1995 just before the start of acid gas injection. This also corresponds to a period of water injection in the YY pool. For most of their history, the pressure of the 5 pools has been above their initial value.

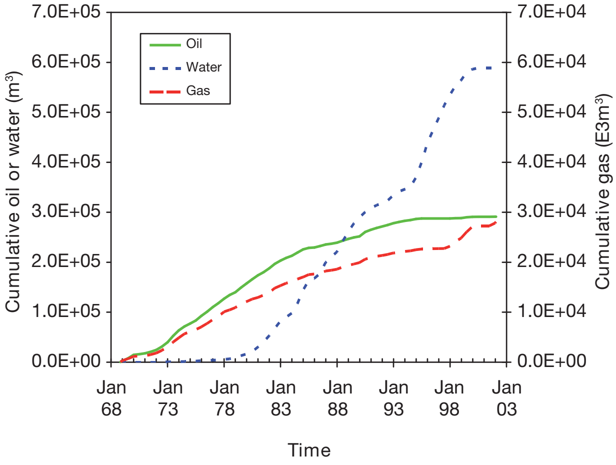

Figure 3

Production history of the Zama Keg River X2X pool.

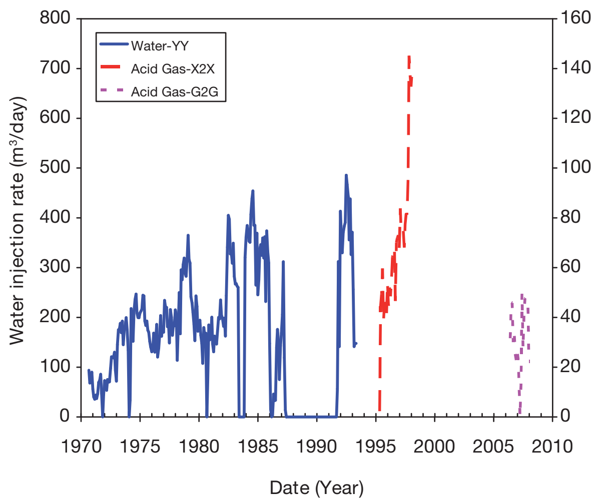

Figure 4

History of water injection in the Zama Keg River YY Pool (1970 to 1993), acid gas injection in Zama Keg River X2X pool (1995 to 1998), and acid gas injection in Zama Keg River G2G pool (2006 to 2008).

A careful review of pressures in Figure 5 suggests that, with the exception of the G2G pool, the pressures of the other pools follow a similar trend. All these four pools were overpressured before the start of acid gas injection in the X2X pool in 1995. The pressure data indicate that the Zama Keg River X2X, YY and P9P, and Muskeg BBB pools have strong connections. The pressure communication between the four pools is consistent with the gross-thickness map of the layer A of the Upper Keg River formation depicted in Figure 2.

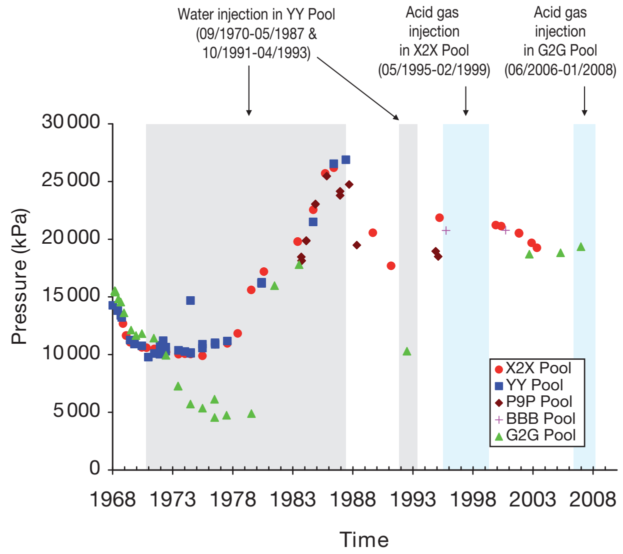

Figure 5

Reservoir pressure history of the Zama Keg River X2X, YY, P9P and G2G, and Muskeg BBB pools.

The reservoir pressure of the Zama Keg River G2G pool does not follow as closely those of the other pools, particularly in the 1970's. However, since the mid-1980's, the pressure in this pool approached that of other pools and shows significant overpressuring. The overall behavior of pressure in the G2G pool suggests a weak communication between this and the other pools. The geological model presented earlier indicates that the Zama Keg River G2G pool does not directly connect to the other pools through the A layer of the Upper Keg River Formation; instead communication is through the underlying lower-quality B layer.

The correlation between reservoir pressures and acid gas injection is not as clearly evident. Acid gas, containing 20% H_2S and 80% CO_2, was injected into the Zama Keg River X2X pool starting in May 1995, which continued until June 1999. A reservoir pressure of 21.9 MPa was measured just prior to the acid gas injection in March 1995. During the acid gas injection period, fluids were produced from the producing well in the X2X pool resulting in a pressure decline of approximately 600 kPa. Large volumes of water were produced to facilitate reduction in reservoir pressure (average water oil ratio of 52). However, this was not sufficient to lower the reservoir pressure to its initial value. Acid gas injection at a pressure above the initial reservoir pressure could increase risk of leakage. In February 1998, the acid gas broke through the producing well, which subsequently produced only intermittently. The well was ultimately shut-in in 2002, when pressure was still significantly higher than the initial value.

4 ANALYSIS OF PRESSURE AND PRODUCTION

Review of the pressure information in the preceding section indicated that the degree of communication between the G2G and other pools is not as good as that among other pools. To explore this degree of communication, a simple analysis is presented in this section. Figure 6 shows the Cumulative Voidage Replacement Ratio (CVRR) *versus* time (CVRR is the ratio of the cumulative volume of fluid injected into the reservoir to that produced, both evaluated at initial reservoir conditions). Two cases were considered. In one case, the production from the G2G pool was excluded (shown using a dashed-line), while in the other case production of G2G was accounted for (solid line). Material balance concepts would suggest that in the absence of aquifer influx or efflux, the reservoir pressure should approach the initial pressure when CVRR reaches one.

As results in Figure 6 indicate, the solid line is consistent with this theoretical argument. Since 1980 the CVRR remains continuously above 1, consistent with the overpressuring of all the pools. This observation seems to suggest that the five pools communicate among themselves, however communication to a larger aquifer beyond their boundaries is weak or absent. This will be further explored during the sensitivity studies.

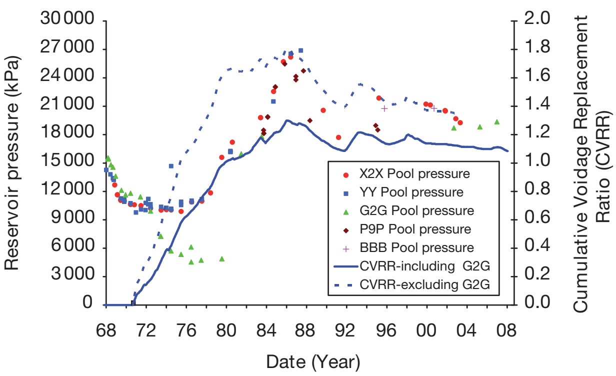

Figure 6

Cumulative Voidage Replacement Ratio (CVRR) *versus* time for the Zama Keg River X2X, YY, G2G and P9P, and Muskeg BBB pools.

5 NUMERICAL SIMULATION

As mentioned earlier, the focus of this work is the study of over-pressurization and hydraulic communication through aquifers. If the necessary data were available to allow detailed fluid characterization, then use of a compositional simulator would have allowed modeling of miscibility, and tracking the location of the injected acid gas. However, such fluid data were not available. Moreover, in this study the distribution of the fluids was not of interest. Analysis of the pressure and production measurements in the previous sections suggested that over-pressurization is most likely related to water injection in the YY pool, and that reservoir pressure actually declined by a few hundred kPa since acid gas injection started. Moreover, of interest in this work is the role of the regional aquifer in affecting the pressure. Overpressurization because of natural or induced water flow can be accurately modeled using a black oil simulator. Appropriate corrections were made to the volume of the injected acid gas so that its volume at reservoir conditions is correctly estimated. Furthermore, sensitivity studies were conducted to examine the effect of acid gas injection on the conclusions of this study.

With this in mind, the CMG-IMEX™ black oil simulator was used in this study (CMG, 2007). This simplified approach was partly forced by unavailability of detailed compositional information, but also it was felt that this choice is consistent with the simplified geological characterization and with the objectives of the study, *i.e.* study of pressure transmission.

In the following, the input parameters are described followed by the results of the history match and the sensitivity studies.

5.1 Model Description and Input Parameters

As described earlier, the structure map was obtained from a seismic survey, and parameters such as the Net to Gross Ratio and porosity were determined from the available well log and core data (ERCB, 2008). Figure 7 shows the top of the structure and locations of the five pools. It is interesting to note that the high point of structure in the Zama Keg River P9P pool has not been penetrated by any well.

Permeability of the B layer of the Keg River is much lower than that in the reef (2 *vs* 100 mD). In Figure 7, note that the low between the G2G and other pools constrains the communication to the B layer of the Upper Keg River formation, while communication between the other pools is through the A layer. Figure 8 shows the initial fluid distribution in the different pools.

Consistent with the production gas-oil-ratio, a solution gas-oil ratio of 70 m^3/m^3 was considered. The bubblepoint pressure of the oil in public records is consistent with that given by Davison *et al*. (1999) and is the range of 11 to 12 MPa. A value of 11 MPa was assumed. Using these data, the oil and gas PVT curves used in the numerical model were estimated from the Standing correlations (Craft and Hawkins, 1959). For the pressure range above 15 MPa, the gas formation volume factor (B_g) of *in-situ* solution gas have been replaced by the formation volume factor of acid gas with 80% H_2S and 20% CO_2 in order to model the acid gas during injection period. This allows the correct estimation of the volume of the acid gas at reservoir conditions. The PVT curves are shown in Figures 9 to 11. While the modification of gas formation volume factor goes a long way in correcting for the approximations that the black-oil simulator introduces, other effects such as the miscibility of acid gas in oil

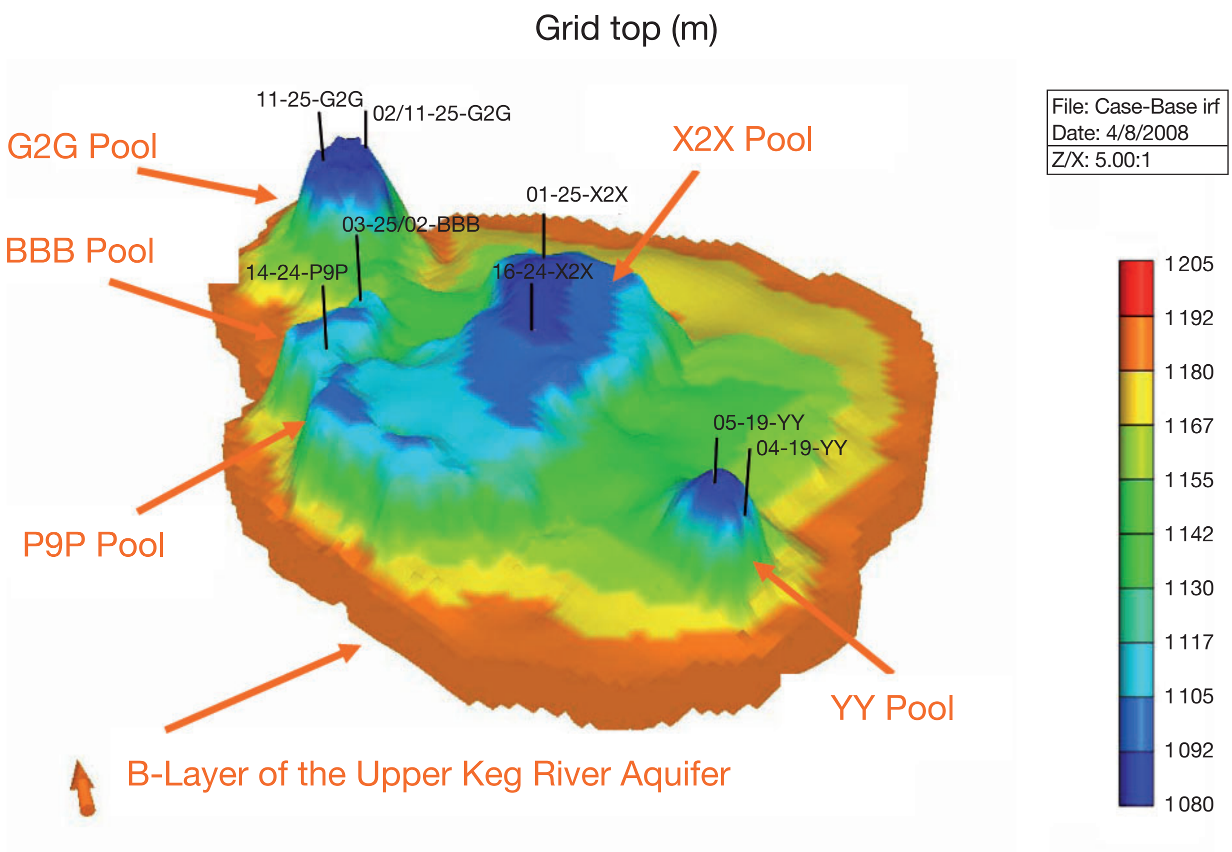

Figure 7

3-D view of the structure top. Note that communication between the G and other pools is through the B layer only, while other pools have some of the A layer among them. The arrow in the bottom left corner in this and other figures shows the North direction.

and solubility of acid gas in the aqueous phase were not modeled in the black-oil simulator. The importance of the acid gas injected on the conclusions of this study is examined in the sensitivity studies.

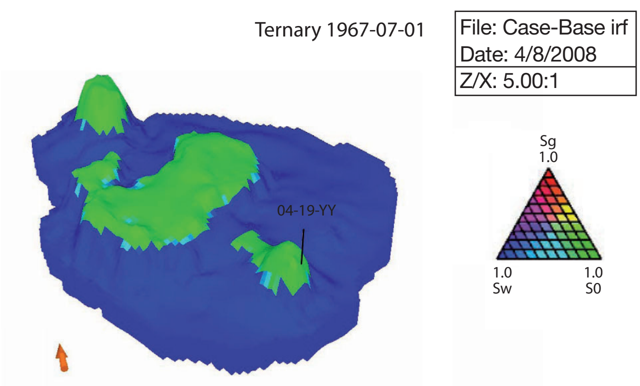

Figure 8

3-D view of initial fluid distribution.

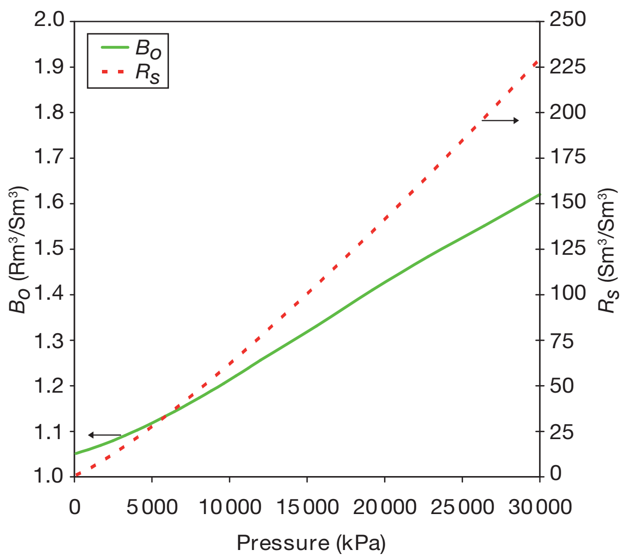

Figure 9

Variation of oil formation volume factor (B_o) and solution gas oil ratio (R_s) with pressure.

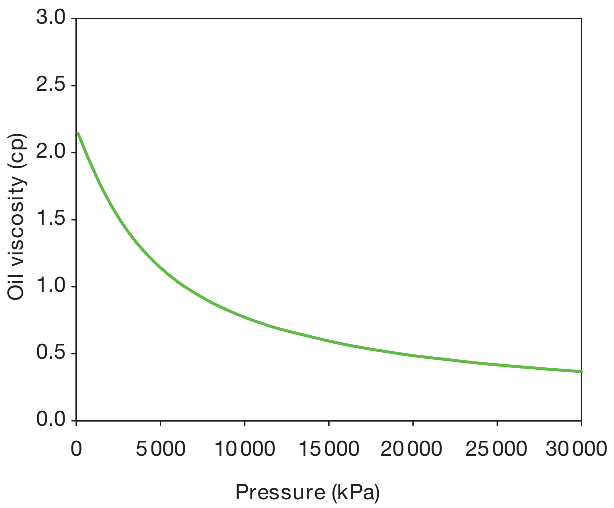

Figure 10

Variation of oil viscosity with pressure.

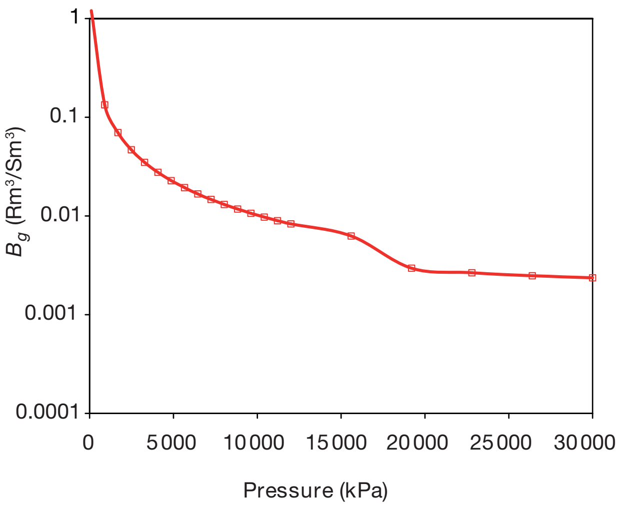

Figure 11

Variation of gas formation volume factor (B_g) with pressure.

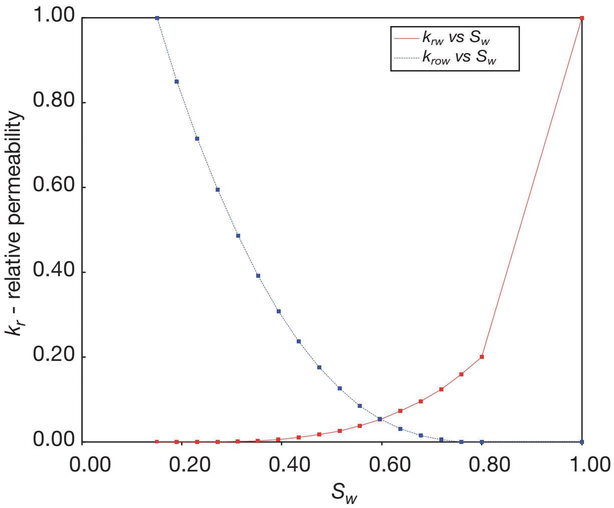

Figure 12

Water relative permeability (k_{rw}) and oil relative permeability (k_{row}) curves as a function of water saturation (S_w) used in numerical simulations.

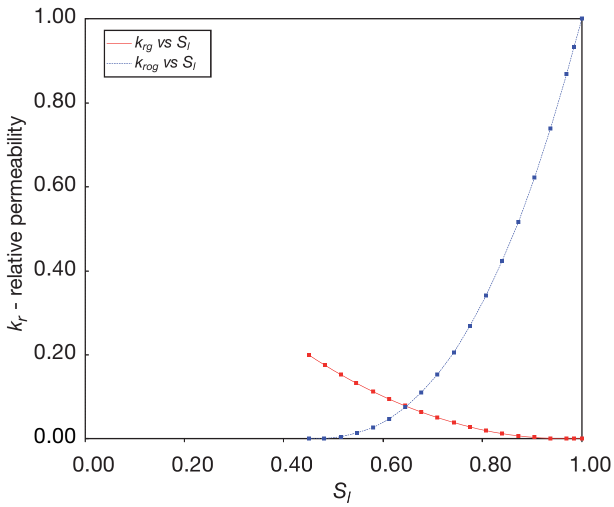

Figure 13

Gas relative permeability (k_{rg}) and oil relative permeability (k_{rog}) curves as a function of liquid saturation (S_l) used in numerical simulations.

Upon initialization, the original fluid-in-place values were in general agreement with values reported by Davison *et al*. (1999). In the absence of any measurements, Corey-type relative permeability curves were chosen, and the end-points were varied to obtain a match. Figures 12 and 13 show the relative permeability curves used in the history-matched case.

5.2 Results of History Match

Use of the input data described above allowed a reasonable match of the pressures (and overpressurization) in all pools except the G2G pool. Three modifications were made to improve matching pressures of the G2G pool. These modifications in the G2G pool included:

– the bubble point pressure and solution gas oil ratio were modified to 12 MPa and 66 Sm^3/Sm^3,

– the porosity, permeability and net-to-gross ratio in the A layer were multiplied by a factor of 1.25, and

– a permeability barrier (0.1 mD) in the B layer of the Upper Keg River (aquifer) on the two sides of the communication pathway between the Zama Keg River G2G pool and the other pools was introduced.

Neither zero permeability nor a permeability of 1 mD resulted in a match of pressure in the Zama Keg River G2G pool. This indicates the small degree of communication that exists between the Zama Keg River G2G pool and the other pools through the B layer of the Upper Keg River aquifer.

These modifications were necessary in order to obtain a better history match of reservoir pressure and produced gas-oil ratio in the G2G pool. Properties in other pools remained unchanged. The results of the history-matched case (called Base Case) are shown in Figure 14.

While the historical oil production rates are used as well constraints, the measured values of producing Gas-Oil-Ratio (GOR), water cut and reservoir pressure are compared with model results (symbols are the historical data and lines are the results of model). As results in Figure 14 show, the overpressurization of the pools is captured by the model. In this study, the cumulative produced water is significant; 1.6 times of the cumulative produced oil. The match of water production and gas production is crucial for matching of the reservoir pressure.

The model results indicate that, consistent with the pressure measurements, the hydraulic communication among the Zama Keg River X2X, BBB, P9P and YY pools is excellent among the reefs. Overpressuring was observed in every pool. Consistent with the measured data, the model pressure in the Zama Keg River G2G pool showed significant departure from the others, nevertheless it too exhibited overpressurization after significant water was injected in the Zama Keg River YY pool.

The Base model included an analytical Fetkovich-type aquifer (CMG-IMEX, 2007), which was attached at the boundary of the B layer of the Upper Keg River formation shown in Figure 7. This is meant to model the extent of the Keg River aquifer beyond what is shown in Figures 2 and 7. Along with the B layer included in the model, we

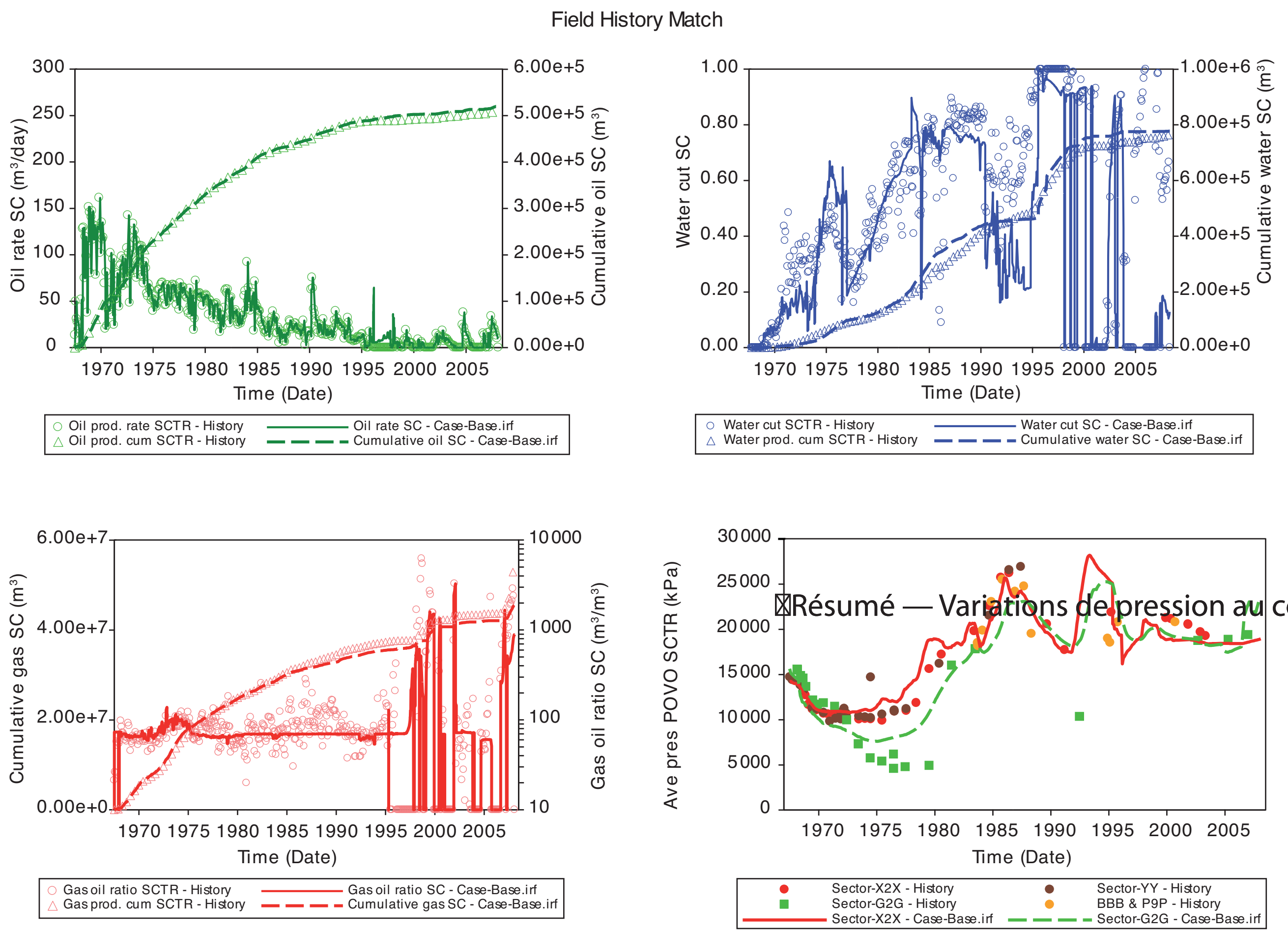

Figure 14

History match of Base Case – counterclockwise from top left to top right: plots of oil rate and cumulative production, GOR and cumulative gas production, reservoir pressure, and water cut and cumulative water production. The open and solid symbols show the measured data, and the lines are the model results. In the lower-right plot, the solid and dashed lines show the model pressure of the Zama X2X and G2G pools, respectively. The pressures of YY, BBB and P9P are in close agreement with that of X2X; only that of X2X is shown. In all other graphs, the dashed line indicates the cumulative values, while the solid line either indicates oil rate, or ratio of gas and water rates to oil.

will refer to this as the underlying Keg River aquifer. A small aquifer size and a low permeability of 0.05 mD were needed to match the history, indicating that the pressure support from the aquifer is weak. The sensitivity of the pressure match to the aquifer properties is examined later in this paper. Table 2 lists the aquifer parameters that allowed a match.

TABLE 2

Parameters of the analytical Regional Keg River aquifer

Parameter	Value
Thickness (m)	40
Porosity (fraction)	0.04
Permeability (mD)	0.05
Inner influx radius (m)	1600
Influx angles	360º
Ratio of outer/inter radius	1.5

The measured pressure after the acid gas injection could not be matched if the formation volume factor of *in-situ* solution gas was used. Use of *in-situ* gas properties resulted in a much higher reservoir pressure, because the reservoir volume of 1 m^3 of acid gas (at standard conditions) is only half the reservoir volume of 1 m^3 solution gas (at the same conditions). However, by using the formation volume factor of acid gas instead of that of the original solution gas, a reasonable match was achieved.

Figure 15 shows the saturation distribution at the end of history matching. Acid gas has contaminated a large area of the Zama Keg River X2X pool. The results indicate that some mobile oil may be left within the Muskeg BBB and Zama Keg River P9P pools.

6 SENSITIVITY STUDIES

To investigate the causes of the pressure increase and decline, the effect of the aquifer parameters and production history on the pressure match was investigated. For example, reservoir pressure declined after 1987 when water injection in the Zama Keg River YY pool was stopped. Two reasons may have contributed to the decline in pressure:

- dissipation of pressure through the underlying aquifer, and
- continued production.

The effect of aquifer parameters and continued production on the model results are investigated in the following.

6.1 Effects of Aquifer Characteristics

6.1.1 No Analytical Aquifer

Figure 16 shows the comparison between the measured and model pressures with and without the analytical aquifer. The calculated reservoir pressure without the aquifer, starting in 1987 is significantly higher than the measured historical pressure. The implication of these results is explained after the sensitivity of the results to a strong aquifer is presented next.

6.1.2 Strong Analytical Aquifer

To further explore the effect of the aquifer on pressures, a case with a stronger analytical aquifer was run. In this case, the aquifer radius was 5 times the reservoir radius, in contrast to the ratio of 1.5 in the Base Case. Furthermore, a permeability of 1 mD was used instead of 0.05 mD in the Base Case. Figure 17 illustrates the sensitivity of reservoir pressure to this strong aquifer. As the departure between the solid line and the symbols in Figure 17 shows, starting in approximately 1971 and during the early oil production period, the calculated reservoir pressure is much higher than the measurements, while the level of simulated overpressuring after 1983 is reduced significantly.

As expected, a strong aquifer provides more pressure support during primary production. However, later on when water is injected in the YY pool, a larger and more permeable aquifer would not lead to a large over-pressurization because more reservoir fluid could flow out into the aquifer.

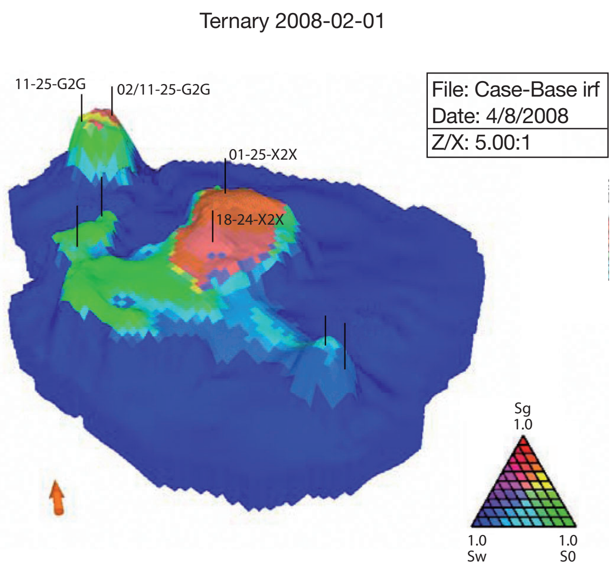

Figure 15

Saturation distribution map at the end of history matching.

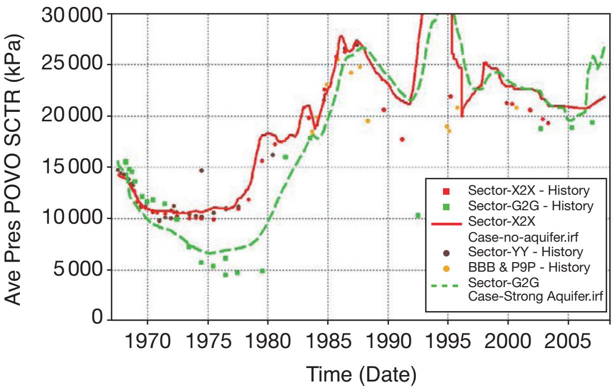

Figure 16

Comparison between the historical measurements and the model without the analytical aquifer. The solid symbols show the measured data, and the lines are the model results. The solid and dashed lines show the model pressure of the Zama X2X and G2G pools, respectively.

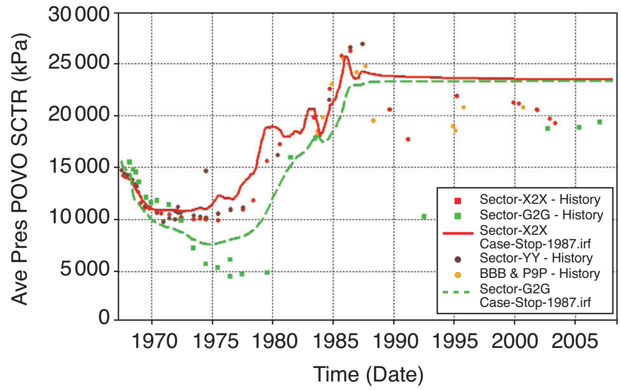

Figure 18

Sensitivity of pressure to production – assumed no production after water injection. The solid symbols show the measured data, and the lines are the model results. The solid and dashed lines show the model pressure of the Zama X2X and G2G pools, respectively.

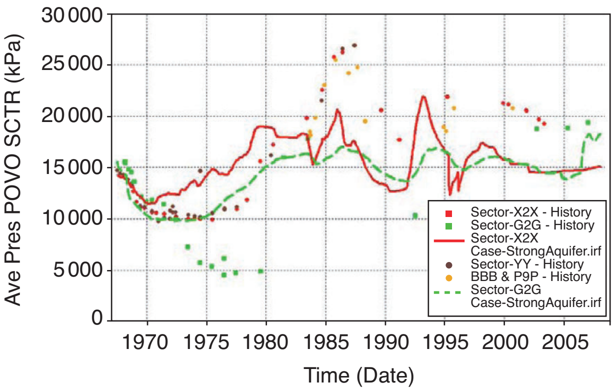

Figure 17

Comparison between the historical measurements and the model with a strong analytical aquifer. The solid symbols show the measured data, and the lines are the model results. The solid and dashed lines show the model pressure of the Zama X2X and G2G pools, respectively.

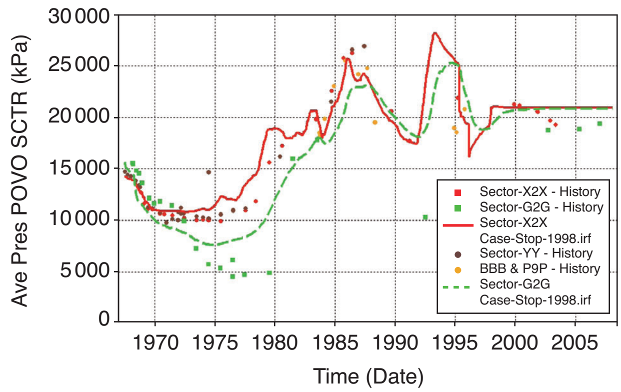

Figure 19

Sensitivity of pressure to production – assumed no production after acid gas injection. The solid symbols show the measured data, and the lines are the model results. The solid and dashed lines show the model pressure of the Zama X2X and G2G pools, respectively.

6.2 Effects of Production History

6.2.1 No Production after Water Injection

As shown in Figure 5, pressure in the X2X pool declined after 1987, when water injection in the YY pool was stopped. To investigate whether the cause of the pressure decline after water injection in the YY pool was stopped in 1987 is the communication through the aquifer or continued production, a simulation case was run in which all the injection and producing wells were shut off after that time. Figure 18 shows the results of the simulation and indicates that the pressure would not have declined if there was no production from the reservoirs. These results, and the previous ones, demonstrate that the reservoir pressure decline was caused by production from the pools, not by the existence of the weak underlying aquifer.

6.2.2 No Production after Acid Gas Injection

To investigate whether the cause of pressure decline after 1998, when acid gas injection in the Zama Keg River X2X pool ceased, is communication through the aquifer or continued production, a simulation run was carried out with all the wells shut in after acid gas injection ceased in 1998.

Results shown in Figure 19 indicate that, with no production, the calculated pressure remained constant. This result suggests again that the water layer and analytical aquifer underlying the reservoir did not lead to any significant dissipation of reservoir pressure. On the contrary, the result indicates that actual reservoir pressure declined due to production.

7 DISCUSSION

The work shown in this paper suggests that in the presence of sufficient injection or production, the pressure history may be analyzed to quantify aquifer properties. Here, a case study was presented where the common underlying aquifer between two structures allowed pressure rise in both (when fluid was injected in one), but the limited size of the aquifer did not allow dissipation of the overpressuring resulting from injection. This is not a general conclusion. For example, within the same family of Zama pools, the large aquifer connected to the Zama Z3Z pool allowed partial pressure dissipation. The history of the Z3Z pool is briefly described below to emphasize the need for case-by-case understanding of communication in aquifers (more detail is given in Pooladi-Darvish *et al*., 2008b).

Pressure in the Zama Z3Z pool declined from 15 MPa at discovery to 3 MPa at the end of primary oil production in 1986. Pressure recovered to 6 MPa during the period between 1986 and 1998 when the reservoir was shut in. Injection of acid gas between March 1998 and December 2000 led to pressure build-up that reached 22 MPa prior to suspension of injection in January 2001. Subsequently, pressure decayed to 17 MPa by August 2002 and further to 16 MPa in November 2003. In 2004 the operator started an acid gas miscible flood to recover additional oil (acid-gas enhanced oil recovery), during which pressure in the reservoir decreased further because of production, reaching 13 MPa in 2006. History matching of pressure behaviour, oil and gas production and acid gas injection for the Zama Z3Z pool required assigning a relatively large aquifer size of low permeability (0.2 md). Sensitivity analysis indicated clearly that the pressure rise during the 12 years between the cessation of oil production in 1986 and the start of acid gas injection in 1998, was due to pressure support from the underlying aquifer. Similarly, the modeling study suggested that the dissipation of the overpressuring during the period between suspension of acid gas injection in 2000 and start of enhanced oil recovery operations in 2004, was also through the connected aquifer. A similar case of pressure transmission between reefal oil pools through an underlying aquifer, induced by oil production rather than water injection, was reported previously for Leduc reefs in the Rimbey-Meadowbrook trend in the central Alberta (Hnatiuk and Martinelli, 1967), but there is a significant difference between that case and the cases reported here, namely that the underlying aquifer in the case of the Leduc reefs is of very large areal extent and has high permeability as a result of dolomitization.

The two cases of pressure rise and decay in carbonate reefs as a result of injection of fluids and of hydrodynamic communication between different sites through an underlying aquifer underlie the importance of proper hydrodynamic assessment of future CO_2 storage sites, be they deep saline aquifers or depleted hydrocarbon reservoirs underlain by a common aquifer. Although the geological setting and characteristics of the individual sites in this case led to the initial assumption of separate closed systems, the observations in the field and the analysis presented here demonstrate that these systems are in reality semi-closed, allowing pressure transmission and fluid displacement through the underlying aquifer, even if it has low permeability (in this case 0.05 mD, or 5×10^{-17} m^2). In fact, Zhou *et al*. (2008) consider that if the underlying and overlying units have permeability in the order of 10^{-17} m^2, the system is open. In the case presented here we consider the system as being semi-closed because the overlying caprock has permeability in the order of 10^{-19} m^2, and the underlying unit is of limited areal extent. Even in the case of aquifers of extremely large areal extent ("infinite aquifers"), which normally are considered to be open systems (Zhou *et al*., 2008), the permeability of the underlying and overlying seals (caprocks) is very important in allowing pressure dissipation, as shown in the case of the Mt. Simon aquifer in the Illinois Basin by Birkholzer and Zhou (2009). The challenge in such cases of hydraulic communication will be determination of hydraulic connectivity and associated permeability distribution.

Given the volumetric, spatial and temporal size of future CO_2 storage operations, the examples presented in this paper illustrate the fact that, even if a stratigraphic trap in a deep saline aquifer is filled only to the spill point, CO_2 storage in that particular trap may affect pressures, injectivity and storage capacity in other structural traps at considerable distance from the CO_2 injection site with which the former are, nevertheless, in hydrodynamic communication. While pressure communication between accumulations through underlying aquifers is understood within the petroleum industry, the size of CO_2 storage projects (which are potentially much larger than hydrocarbon production operations) would further increase both the effect of such hydrodynamic communications and importance of its correct characterization, as shown by Birkholzer and Zhou (2009).

Implications of pressure communications to geological storage of CO_2 are of significant importance and include:

- pressure increase in hydrocarbon reservoirs that are in communication with the aquifer over distances of many tens of kilometers,
- pressure interference effects among multiple injectors such that there would be a diminishing return in increase in total injectivity with increasing number of injectors,

- pressure increase over long distances, such that design of more than one storage project in a common aquifer will have to consider the presence of the other storage projects, as shown by Birkholzer and Zhou (2009).

In the case study presented in this paper, fluid production was the cause of reduction in pressure. Similarly, fluid production from aquifers could be potentially used for management of pressure effects associated with CO_2 storage in aquifers.

In the case of deep saline aquifers continuing with or in contact with shallow groundwater aquifers, as in the case of the Mt. Simon aquifer in the Illinois basin, or of aquifers in the Gulf Coast, Texas, the impact of large scale CO_2 storage on shallow groundwater aquifers may be minimal (Nicot, 2008; Birkholzer and Zhou, 2009). However, this obviously is predicated on the existence of a significant distance between the CO_2 storage site and the groundwater aquifer. In some cases large-scale CO_2 storage at multiple sites may raise the pressure in the shallow groundwater aquifer and lead to brine displacement into the groundwater aquifer in the order of 10 s mm/yr, as shown for the Tokyo Bay area by Yamamoto *et al*. (2008).

SUMMARY AND CONCLUSIONS

Disposal of acid gas in depleted oil and gas reservoirs and deep saline aquifers at close to 50 sites in western Canada is a commercial-scale analogue to future CO_2 storage in geological media. Acid gas is a mixture of H_2S and CO_2 that is separated, using an amine-based process, from natural gas produced from sour gas reservoirs. Acid gas is injected in western Canada since 1990 with no leakage incidents, however, in four cases acid gas injected in depleted oil or gas reservoirs broke through at producing wells, and in two cases injection of acid gas in depleted oil reservoirs in small individual carbonate reefs in the Zama oil field in northwestern Alberta was associated with overpressuring that led the provincial regulatory agency to first suspend and subsequently rescind these two operations. Both these reefs, overlain by tight anhydrites, are underlain by the Keg River carbonate aquifer of variable characteristics and strength that affected pressure rise and/or decay in these disposal reefs. Analysis of reservoir history and reservoir simulations of oil production and acid gas injection were used to identify the causes of pressure build-up and subsequent decay in these two reefs:

- The Zama Keg River X2X reservoir pressure was significantly above its initial reservoir pressure (of 15 MPa) prior to start of acid gas injection. The reservoir was overpressured (at 25 MPa) due to the significant amount of water injection in the Zama Keg river YY Pool, the two being connected through an underlying aquifer;
- There is excellent hydraulic communication among Zama Keg River X2X, YY and P9P, and Muskeg BBB pools, and some communication with the Zama Keg River G2G pool. All these pools became overpressured as a result of injection in the Zama Keg River YY pool;
- During acid gas injection (and subsequent to its termination) reservoir pressure remained above the initial reservoir pressure, but it never exceeded the previously reached maximum pressure of 25 MPa;
- The decline in pressure when water injection in the YY pool was stopped in 1987, or when acid gas injection in the X2X was stopped in 1998, was due to fluid production. A simple analysis based on voidage-replacement-ratio and the sensitivity studies suggest that the aquifer underlying the pools is small and of low permeability, not allowing significant dissipation of the high pressures in the pools;
- The cases exemplified in this paper, although for comparatively small injection rates and volumes compared with future CO_2 storage operations, underlie the effects of pressure transmission between injection sites that otherwise may seem to be isolated from each other or at sufficient distance for pressure effects to be absent or negligible.

ACKNOWLEDGEMENTS

The authors wish to thank Doug Nimchuk of Apache Canada Ltd. for providing the seismic maps and other geological information and useful discussions, and Natural Resources Canada (NRCan) which funded the study.

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Final manuscript received in July 2010
Published online in March 2011