NUMERICAL MODELING OF CO2 INJECTION TEST AT NAGAOKA TEST SITE IN NIGATA, JAPAN

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ABSTRACT

The Research Institute of Innovative Technology for the Earth (RITE) is responsible for the five-year project, “Research and Development of Geological Sequestration Technology for Carbon Dioxide" (RITE,2005, Xue et.al.,2005). The project aims to establish a technology that provides stable, safe and long-term geological sequestration of carbon dioxide emitted from large-scale sources in Japan.

In this project a CO_2 injection test was carried out at Nagaoka in the Niigata prefecture (Figure 1). An injection well and three monitoring wells were drilled at test site and super-critical CO_2 injected into a saline sandstone aquifer at a depth of approximately 1100 meters and a rate of approximately 20 - 40 tones/day. The injection test started in July 2003 and continued until November 2004. Monitoring was begun before injection using the monitor wells and is still continuing.

The main purposes of the Nagaoka experiment are to:

- study the actual behavior of CO_2 in an aquifer,
- test simulation methods by comparing model results with measured data and
- gain a general understanding of the behavior of sub-surface CO_2.

The work described in this paper addresses the progress of the second part of these namely, “test simulation methods by comparing model results with measured data”. To this end, we have developed one and three-dimensional models of the reservoir and carried out a number of simulations. We have used iTOUGH2 (Finsterle, 1999) and ECO2 (Pruess,2005) to determine a number of key reservoir parameters, in particular permeability and residual gas saturation, and ChemTOUGH2 (White, 1995) to investigate likely long-term chemical changes in the reservoir.

As part of the experiment several cross-hole tomography runs were performed. These provide the location of the gas bubble on a plane between two monitor wells. This was found to be in good agreement with the results of the three dimensional simulation of the experiment.

Interestingly, the iTOUGH2 calculation of residual gas saturation found the optimum value was zero although some authors have suggested that a value as high as 0.3 is appropriate. This is an important parameter in determining the long-term fate of sequestered CO2 and we believe this is an important finding.

SUMMARY OF FIELD TEST

Top of reservoir depth at injection well (IW-1) is 1092 m below surface. Thickness of reservoir is 59.2m. Reservoir formation is tilted 15 degrees. Reservoir is constructed four formations from Zone-2 to Zone-5 and Zone-1 is cap rock. Since Zone-2 is most permeable layer, this is main reservoir. Around IW-1, there are three observation wells named OB-2,OB-3 and OB-4. Reservoir thickness around each wells are 59.2m, 59.2m and 56.5m. Figure 2 shows injection and observation wells and reservoir depth.

CO2 injection test was done from July 2003 until January 2005. Reservoir pressure was monitored at IW-1 and OB-4. Figure 3 shows history of injection rate of IW-1 and reservoir pressure of IW-1 and OB-4. Figure 3 shows injection history and pressure monitoring data of reservoir.

On observation wells, several kind of logging were carried out periodically to detect CO2 gas arriving time (Xue et.al.,2005). CO2 gas was detected clearly

at OB-2 and OB-4 by seismic logging. CO2 gas arrived at OB-2 between 232 and 259 days after injection started. It arrived to OB-4 between 324 and 355 days, but it was not detected on OB-3.

Before and after injection, cross hole seismic tomography was carried out. It detected CO2 gas distribution after injection.

MODEL SETUP

Table 1-3 and Figure 4 describe the TOUGH model. Model includes the Zone 2 to 5, but it doesn't include Zone-1. Zone2 is divided to 3 layers and Zone 3 is divided 2 layers. Zone 4 and 5 is composed to one layer.

The Table 2 describes names and location of injection and monitor wells. CO_2 are injected into only top 3 layers, namely Zone 2, Zone 2 Middle and Zone 2 Lower and the fraction of the daily injection amounts are 5.5/12, 5.5/12 and 1/12, respectively. The depths for the monitoring wells are also in top 3 layers.

A simple linear interpolation is used to estimate the CO_2 enthalpy which depends on the pressure (Figure 5).

Boundary conditions for the numerical model are

- No flow at the top and bottom boundaries of the model
- Constant pressure at the edge of the model
- Initially hydrostatic pressure everywhere in the model.

The parameters describing the properties of the reservoir are given in Table 3.

ITOUGH2

iTOUGH2 simulation was performed on Tough model to optimize the parameters to fit the model to the measured data. First 10 iteration of iTOUGH2 simulation gives the parameter changes in rock permeability and relative permeability (Table 4).

The iTOUGH2 corrected permeability give the CO_2 gas arrive time at OB-4 matches with the measured data. Figure 6 shows the gas saturation at OB-4. The measured CO_2 gas arrival time at is in between 325 and 359 days. There is large improvement in iTOUGH corrected simulation which gave the gas arrival time at OB-4 in 337 days. This compares to 294.91 days in Tough model. On other wells, CO2 gas didn't arrive at OB-3. It matches with measured data. Measured CO2 gas arrival time at OB-2 is in 232 and 259 days. It doesn't match with calculation. Thickness of each layers of model is same. But thickness of reservoir aroundOB-2 is wider than OB-4. It is possible to be one of reason of wrong matching. Figure7 shows the measured pressure and residual of its fitted pressure at OB-4. Figure 8 shows gas saturation in vertical slice on the like at 500 days after the injection began.

CHEMTOUGH2

ChemTOUGH (White,1995) is a multi-component reactive flow code based on the porous media multiphase mass and energy flow code TOUGH2 (Pruess,1991). Flows in fractured media may be treated via the MINC formalism (Pruess,1991). ChemTOUGH2 will treat variably saturated multiphase reacting flows including those where boiling us taking place. Bring based on TOUGH2 the discretization of the spatial domain is by the integrated finite difference method, which provides fir modelling of 0-3 dimensional situations. Time stepping is fully implicit and heat and mass calculations are fully coupled with the reactive chemical calculations. Any number of chemical components (in solid, liquid or gas phase) and reactions may be included in the calculations. Reaction types available include; aqueous chemical complexation, redox reactions, gas dissolution – exsoltion and mineral dissolution precipitation. Mineral reactions may be assumed to be either described by a general kinetic rate flow (Lasaga ,1984) or to be in local equilibrium.

ChemTOUGH model has the same specification as TOUGH model except that it has less number of elements (4806 elements). Table 5 and 6 are the provided and simplified chemical composition for the ChemTOUGH simulation.

CHEMTOUGH SIMULATION RESULTS

CO_2 was injected into the Zone 2 at IW-1 for 550 days. After the period of injection, CO_2 within the reservoir was tracked for a total of 550 days.

Contour figures of pH on a vertical slice show the deeper portion of the reservoir has little effect than the shallower regions from injection. The pH near the injection well drops to 4.2 as some dissolved CO_2 reacts with the reservoir fluid to form H^+ and HCO_3^-. The pH also provides a tracer of fluid flow in the reservoir with some low pH fluid being forced through the capping structure and also a plume of low pH fluid travels towards the bottom of the reservoir, probably driven by the density difference between the initial reservoir fluid and the CO_2 saturation fluid near the injection point.

There is a little change in the reservoir mineralogy over the time scale of this simulation but by examining the logarithm of Q/K (where Q is the solubility product and K the equilibrium coefficient) of minerals included in the simulation, we get an indication of which minerals are dissolving or precipitating. A negative value of Q/K implies that the reservoir fluid in undersaturated in the mineral and, it present in the rock matrix, the mineral will dissolve. Conversely, a positive Q/K implies that the mineral will precipitate. Actual dissolution and precipitation rates will depend on the solubility product, reaction rate, reactive surface area and temperature. Figure 12 shows pH and log(Q/K) of selected minerals in vertical slice on the line at 500 days after injection begin.

Anothite is initially undersaturated everywhere and remain this way at 500 days. Although, it appears that anothite is approaching saturation, away from the low pH region of the aquifer.

Calcite is undersaturated in the low pH region about the injection point as is anothite. However, Ca^{+} ions driven by the increased density of CO_2 saturated fluid. As the pH of this fluid increases from interaction with the rock calcite nearly saturates and calcite will begin precipitate. Dawsonite, another mineral likely to be important in CO2 sequestration, remains undersaturated throughout the reservoir and simulation period. Dolomite shows a similar pattern to calcite becoming nearly saturated in the plume beneath the injection point. K-Feldspar dissolves in the low pH region and there is some precipitation of muscovite there and all other minerals remain undersaturated throughout the reservoir.

CONCLUSION

We have developed two models of the Nagaoka CO_2 injection experiment. The first of these (Tough model) uses the simulator TOUGH2/ECO2 and the second uses ChemTOUGH. The results of both models give very similar outcome. The chemical simulation has run for a short period of time, the chemical modelling predicts significant changes in reservoir chemistry near the injection point. However, this model predicts very small changes in reservoir mineralogy over the simulation time period.

Figure 7 shows the comparison of measured and simulated pressure at monitor wells, respectively. The results of the iTOUGH2 corrected simulation give a better approximate pressure than Tough model simulation at both wells (IW-1 and OB-4). Together with the Figure 6, the iTOUGH2 corrected model gives supremely better results than that of Tough model. For instance, gas arrival time at OB-4 has improved dramatically, in fact it actually matches with the measured data. Overall, iTOUGH2 simulation was worthwhile and proven to be an invaluable tool in this project.

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Table 1. Model grid setup for Tough model.

Area Name	Area Size	Size of element	Number of elements
Outer area	920 × 960 m	20 × 20 m	2208
Middle area	320 × 320 m	5 × 5 m	4096
			6 layers total: 37824

Table 2. The location and names of wells.

Name	Type	Location (centre)	Dimension	Depth
IW-1	Injection well	(23950,155970)	$1m^2$	-1051.9 m
OB-2	Monitor well	(23991,155972)	$1m^2$	-1062.2 m
OB-3	Monitor well	(23828,155960)	$1m^2$	-1024.4 m
OB-4	Monitor well	(23901,156011)	$1m^2$	-1036.4m

Table 3. Simulated vertical model and its parameters.

Zone	Layer Name	Porosity (%)	Permeability (mD)	Thickness (m)
Zone 2	Zone 2 upper	22.5	3.06	5.50
	Zone 2 middle	22.5	10.70	5.50
	Zone 2 lower	22.5	1.53	1.00
Zone 3	Zone 3 upper	20.4	0.33	10.00
	Zone 3 lower	20.4	0.66	10.00
Zone 4 and 5	Zone 4 and 5	23.4	0.46	25.00

Table 4 Result of iTOUGH2 simulation

Layer Name	Permeability (mD) of Tough model	iTOUGH2 corrected Permeability (mD)
Zone2 upper	3.06	2.92
Zone2 middle	10.70	10.44
Zone2 lower	1.53	1.486
Zone3 upper	0.33	0.33
Zone3 lower	0.66	0.66
Zone4, 5	0.46	0.46
0.61 **(Parameter for relative permeability of TOUGH2 model)**		
0.5372 **(iTOUGH corrected parameter for relative permeability.)**		

Table 5 Measured ground water chemistry.

Species	Concentration (mM)
pH	7.87
Cl^-	95
SO_4^-	0.77
HCO_3^-	4
Na	74
K	6.4
Mg	0.73
Ca	10
Al	4.3×10^{-3}
Si	1.8
Ti	4×10^{-4}
Mn	0.0103
Fe	-0.021
Sr	0.021
Ba	0.01

Table 6 Supplied analysis of reservoir rock composition.

Mineral	Abundance (Weight %)
	Reservoir
Quartz SiO_2	25.7
Feldspar Group	25.6
K-feldspar	(4.9)
Plagioclase(Albite /Anorthite	(20.7)
Pyroxene group(Enstatite /Diopside)	5.0
Mica group	1.2
Muscovite	
Biotite	(>0.9)
Amphibole group	0.3
Hornblende	(0.1)
Chlorite	0.1
Smectite/Illite	0.8
Epidote	0.0
Glass	9.3
Others*	32.0
*: Others include matrix, cement and organic matter	

Figure 1. Location of Nagaoka test site.

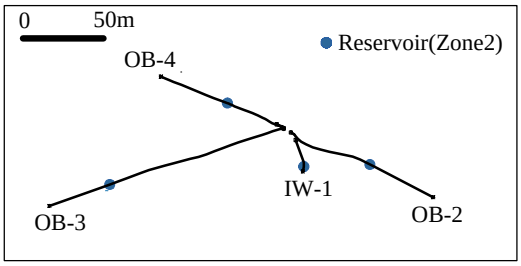

Figure 2a. Injection and observation wells.

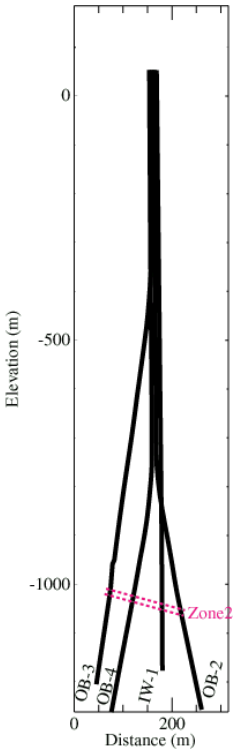

Figure2b Injection and observation wells.

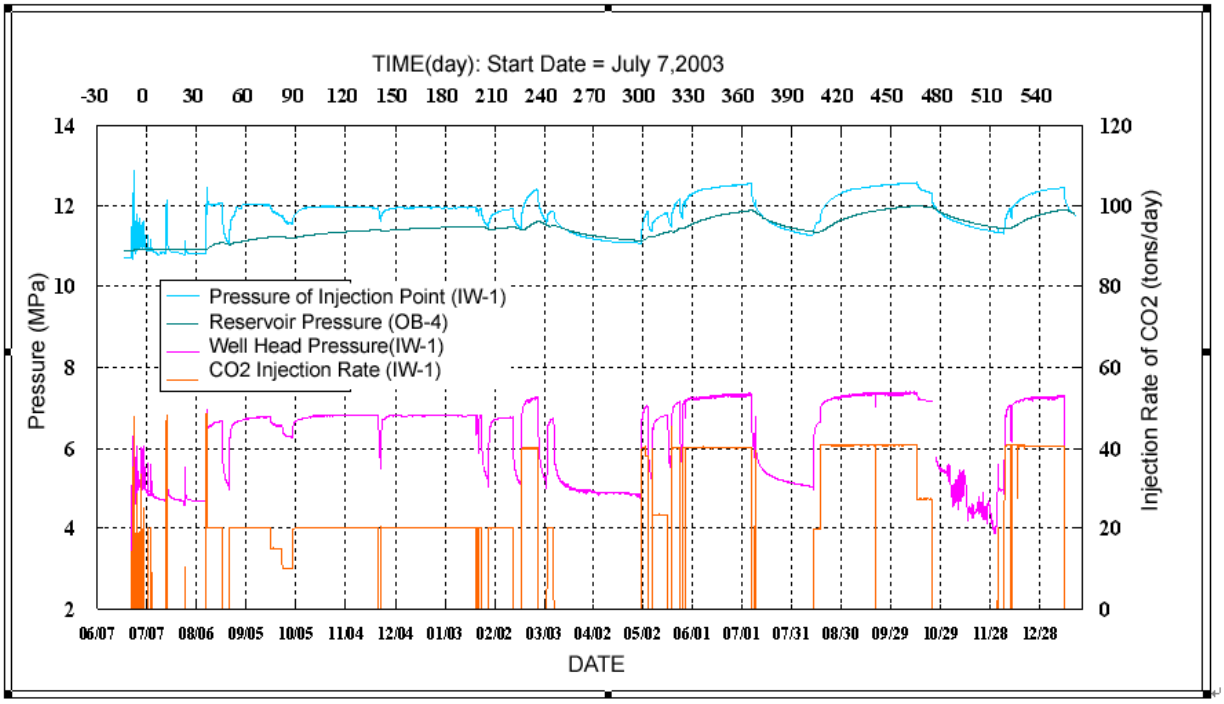

Figure 3 CO2 Injection history and reservoir pressure monitoring data.

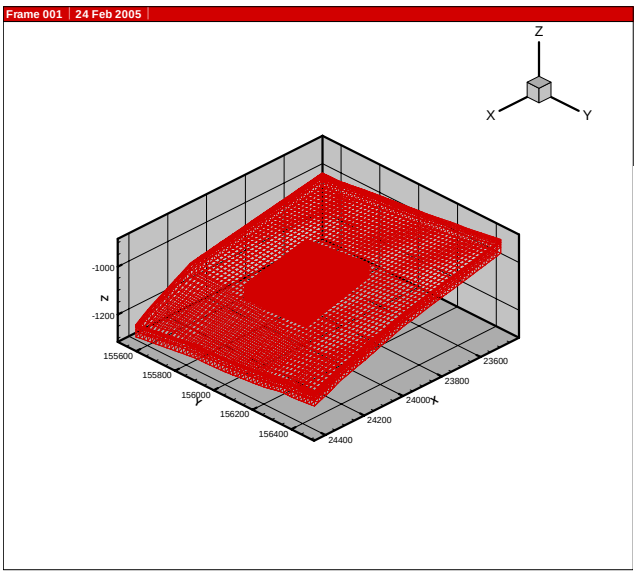

Figure 4. Grid mesh of Tough model

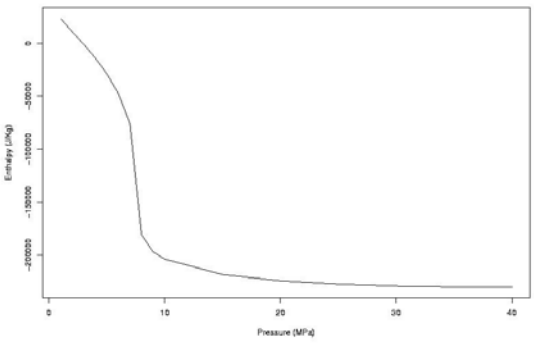

Figure 5. Enthalpy of CO2 against pressure.

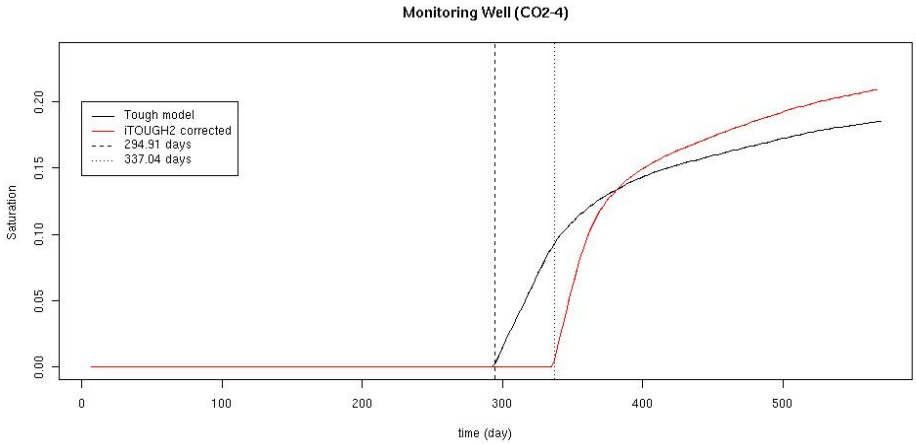

Figure 6 Gas saturation at monitoring OB-4

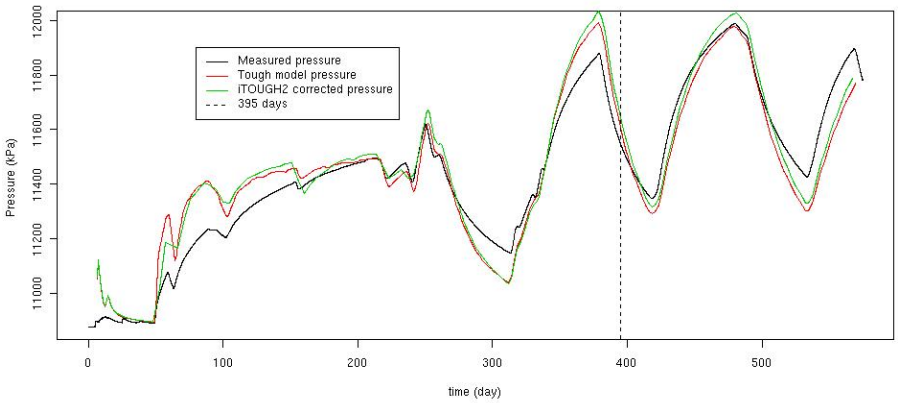

Figure 7 Compared pressure at monitor well (CO2-4).

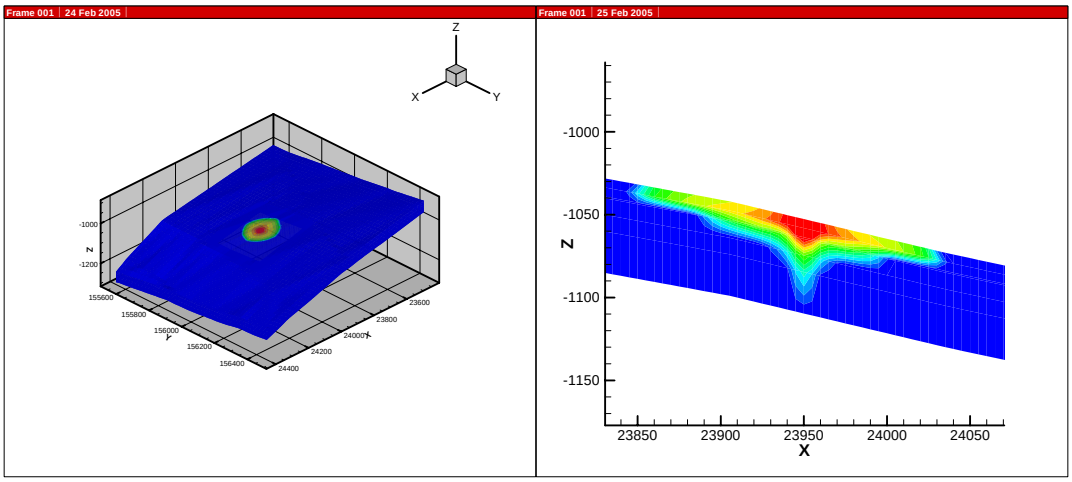

Figure 8. CO_2 saturation and its cross section at 500 days.

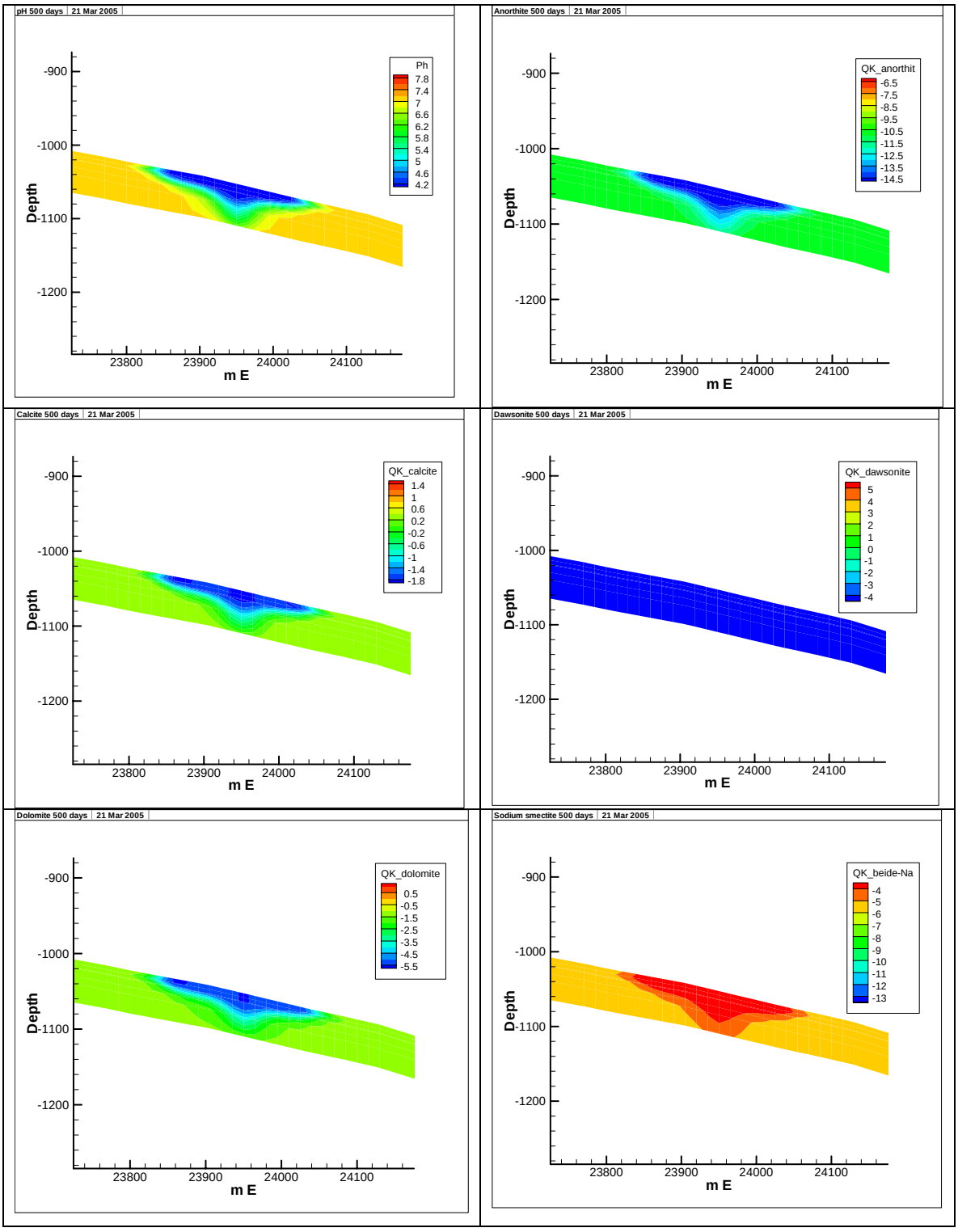

Figure 9. pH plot and log(Q/K) plots of selected minerals.