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Perspectives on the Potential Migration of Fluids Associated with Hydraulic Fracturing in Southwest Florida

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Abstract: The variable-density flow model—SEAWAT Version 4, was used to evaluate the hydrogeological conditions associated with hydraulic fracturing (fracking) the limestone oil reservoir in the Lower Cretaceous Sunniland Formation of Southwest Florida. This research contributes to the understanding of the controls on fluid and potential contaminant migration, following high pressure hydraulic fracturing. A hydraulic fracturing treatment used recently in this formation at the Collier-Hogan 20-3H well represents the base case simulation. Multiple stage fracturing using typical stress periods, a modelled fracture zone radius, and various injection rates were tested to evaluate the potential for horizontal and vertical fluid migration in and from the reservoir under dynamic conditions, with TDS used as a tracer. Hypothetical scenarios including preferential vertical pathways between the Sunniland Formation and the Lower Floridan aquifer Boulder Zone were also simulated. Results indicate that injected fluids do not migrate significantly in the lateral and vertical directions beyond the design fractured zone, unless a preferential pathway exists within close proximity to the fractured zone. In a worst-case scenario under the simulated conditions, vertical heads are approximately 580 meters greater than static conditions and fluids associated with hydraulic fracturing vertically migrate approximately 500 meters; therefore, the quality of the deepest sources of drinking water is not compromised. Analytical results from a monitoring well installed in the immediate vicinity of the Collier-Hogan 20-3H well and at the base of the deepest source of drinking water support the conclusion that impacts from hydraulic fracturing fluids have not migrated into the deepest sources of drinking water.

Key words: Hydraulic fracturing, Sunniland Formation, fluid migration.

1. Introduction

Interest in the environmental effects of hydraulic fracturing has become an increasingly important topic associated with the development of oil and natural gas because of the potential risk to the quality of shallow and deep aquifers. Although hydraulic fracturing has been in use since the 1960s, the ability of this technique to significantly enhance recovery of oil and natural gas from low permeability reservoirs and shale, has currently led to its widespread use in the U.S. and other petroleum-producing countries. Hydraulic fracturing is generally an environmentally safe practice because of the geologic conditions under which it is typically employed; however, in some instances hydraulic fracturing has been linked to inadvertent groundwater contamination and other health hazards, for example the fracturing of the Marcellus Shale in Pennsylvania for natural gas potentially resulted in groundwater contamination. In addition, the USGS (U.S. Geologic Survey) has also identified cases of hydraulic fracturing that have potentially resulted in environmental impacts. The USEPA (U.S. Environmental Protection Agency) [1] has summarized the development and potential adverse effects of hydraulic fracturing in a recent publication that identifies the most likely practices that result in groundwater contamination. The USEPA [1] concluded that impact to aquifers from the

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injection of fluids into deep oil reservoirs, and subsequent migration, is not a known major source of groundwater contamination. Several other studies have evaluated the hydrogeologic conditions under which hydraulic fracturing takes place [2-5] and have also concluded that, in general, the vertical migration of injected fluids and natural gas to groundwater aquifers is unlikely [4, 5].

This research contributes to the understanding of the controls on fluid and potential contaminant migration, following high pressure hydraulic fracturing, with the use of the numerical model SEAWAT Version 4 [7] to simulate the hydrogeologic conditions and the effects of hydraulic fracturing in the Sunniland Formation of Southwest Florida. The Lower Cretaceous Sunniland Formation is an oil-producing trend within the South Florida Basin, half of which occurs within the onshore Florida peninsula [8]. The trend is approximately 145 miles (233 kilometers) long and 12 miles (19 kilometers) wide, extending from Sarasota to Dade counties. Production began in 1943, with the eventual discovery of 11 fields through 1984. To date, 120 million barrels have been produced from the formation. The Sunniland Formation occurs at a depth of approximately 12,000 feet (3,657 meters) below land surface, and is composed of 250 feet (76 meters) of limestone, dolomite and anhydrite. Exploration and production continue to date in the Sunniland Formation. A single instance of hydraulic fracturing took place at the Collier-Hogan 20-3H oil well located in Collier County (Fig. 1) in December 2013 that resulted in the immediate termination of further development of this well, due to unapproved extraction methods. To date, adverse effects associated with the migration of fracking fluids have never been documented in Florida. Although hydraulic fracturing has since been banned by numerous local governments, to date, the Florida legislature has not banned the practice.

This study is an assessment of the potential migration of the injected fluids from the reservoir associated with this event and variations of this event that include greater volumes of injectate and injection rates. The conclusions of this study could potentially apply outside of Southwest Florida to assess the behaviour of hydraulic fracturing fluids under generally similar hydrogeologic conditions. However, the hydrogeologic conditions under the Florida platform appear to provide several unique restrictions to the vertical migration of fluids from the Sunniland Formation to drinking water aquifers.

This paper is organized into the following sections: Introduction; Study Area; Hydraulic Fracturing Methods; Numerical Analysis; Results, Discussion; and Conclusions.

2. Study Area

The Sunniland Formation is a Lower Cretaceous sedimentary deposit composed of limestone, dolostone, and anhydrite [9]. The formation consists of an upper tidal shoal and a lower fractured carbonate oil play. Structural elements (Fig. 1) that occupy the Upper Sunniland formation include the Charlotte High, Lee-Collier Swell, and 40-Mile Bend High, from northwest to southeast. The formation is bounded by the Tampa-Sarasota Arch and the Peninsular Arch to the north, and the Pine Key Arch and Largo High to the south. The Florida Escarpment is located approximately 160 to 200 miles west of the Upper and Lower Sunniland formations, respectively. Only subtle structures with no major faults or vertical fractures have been identified onshore to date. However, in the offshore part of the basin, basement fault blocks and other complex structural features potentially exist, especially within the uppermost Jurassic and lowest Cretaceous part of the stratigraphic section [10]. The Sunniland Formation is not known to exhibit any major fractures/faults and was considered as a potential suitable formation for carbon dioxide-sequestration [11].

The general hydrogeology of Southwest Florida (Figs. 2a and 2b), from top to bottom, includes the

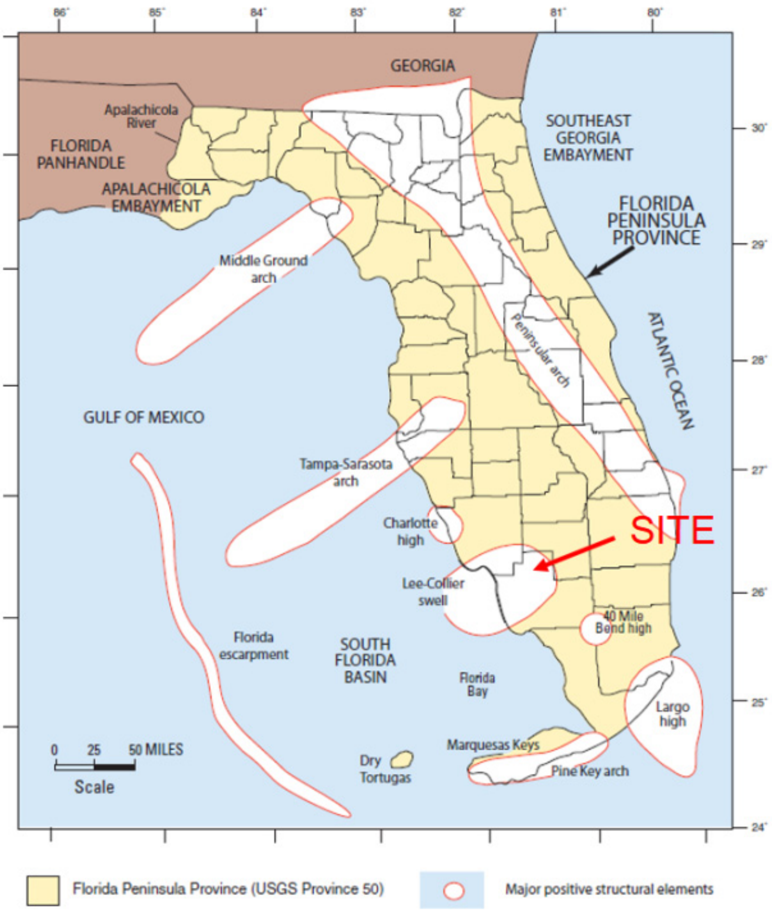

Fig. 1 Structural elements of the Florida Peninsula [6].

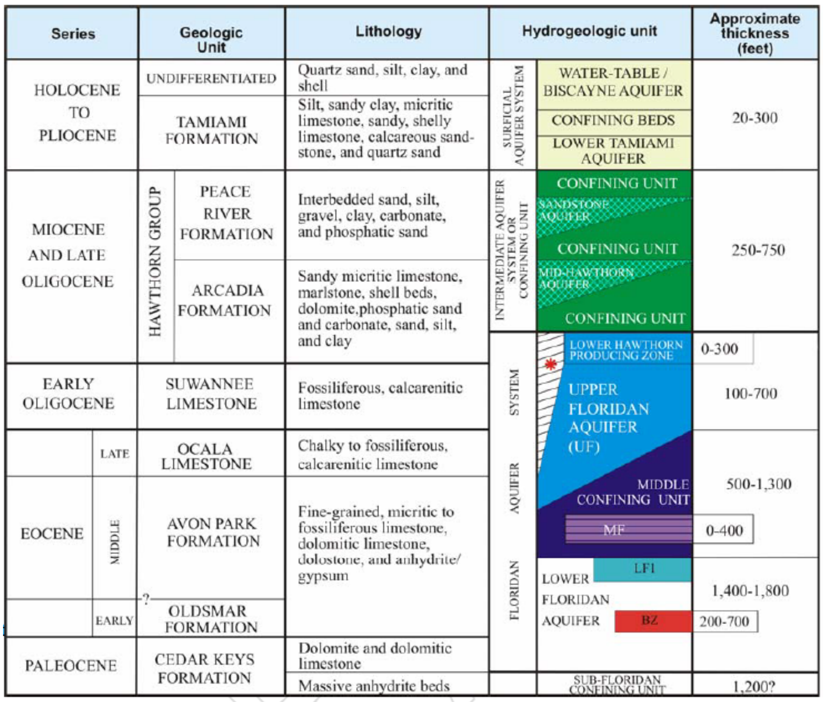

Fig. 2a Stratigraphic and hydrogeologic column of SW Florida [16].

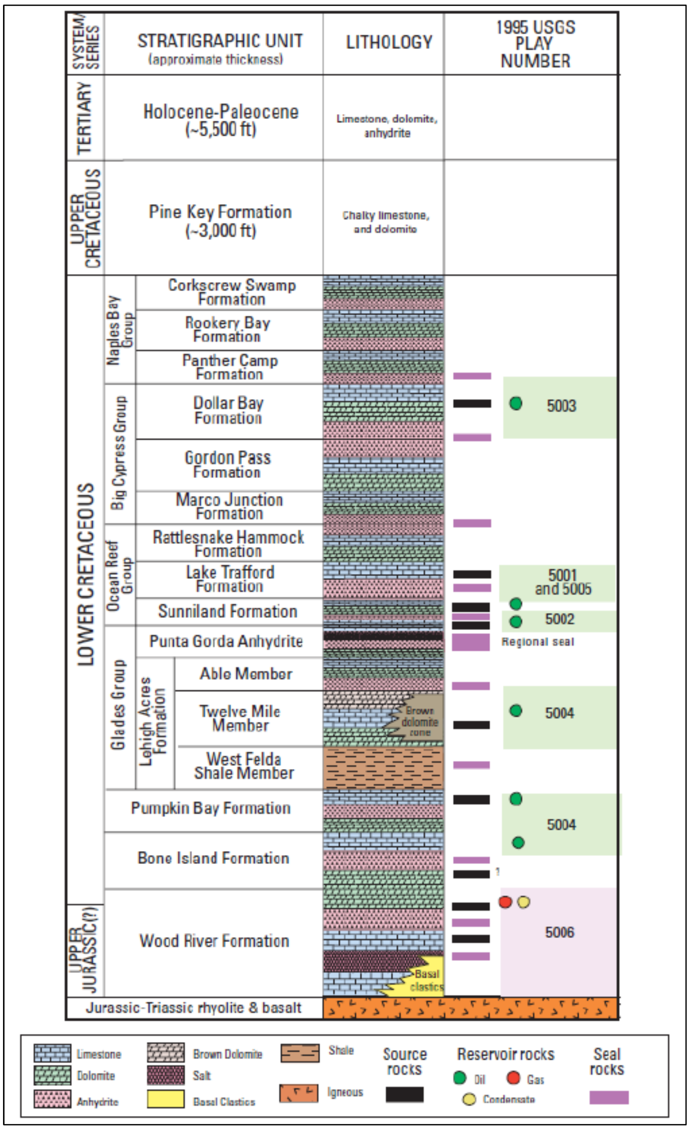

Fig. 2b Stratigraphic column of Southwest Florida [17].

Surficial Aquifer Systems (SAS) and Intermediate Aquifer Systems (IAS), extending to approximately 200 feet (61 meters) below land surface (ft bls), underlain by a confining unit and the underlying UFA (Upper Floridan Aquifer), at approximately 600 ft (183 m) bls, a sequence of Tertiary limestone. The SAS, including the water table aquifer and the Lower Tamiami aquifer, and IAS are the primary sources of drinking water in Southwest Florida. The middle confining unit separates the UFA from the LFA (Lower Floridan Aquifer). The LFA, at approximately 1,900 ft (579 m) bls, consists of micritic to fossiliferous limestone, dolomitic limestone, dolostone and anhydrite/gypsum. The Boulder Zone (BZ), at approximately 2,900 ft (884 m) bls, composed of highly fractured and cavernous dolomite, occurs in the Oldsmar Formation in the lower part of the LFA. The highly permeable BZ is approximately 400 ft (122 m) thick in the study area and is occupied by groundwater with seawater composition, supporting the theory of having a hydraulic connection to the Atlantic Ocean and Gulf of Mexico. According to the Kohout convection theory [12], seawater flows into the Lower Floridan aquifer BZ formation and, in response to the prevailing thermal gradient, flows vertically through the BZ and then flows laterally eastward into the

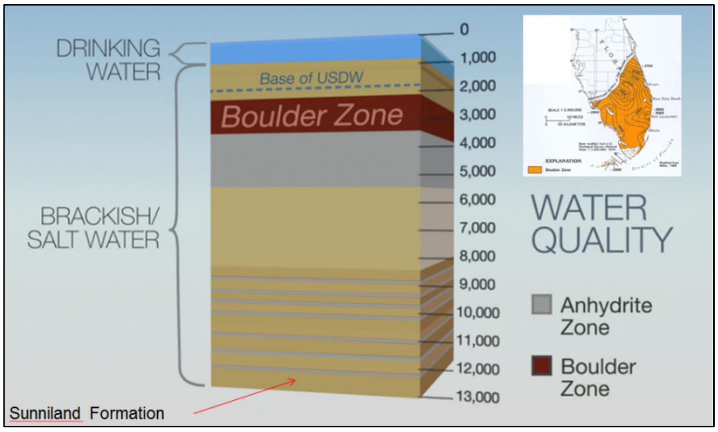

Fig. 3 Water quality characteristics underlying Southwest Florida.

Atlantic Ocean and westward into the Gulf of Mexico. The vertical distribution of drinking water and brackish water, BZ, and the base of the USDW (underground source of drinking water), identified by a TDS (total dissolved concentration) of 10,000 milligrams per liter (mg/L), are depicted on Fig. 3.

Underlying the LFA is the sub-Floridan confining unit consisting of Cretaceous to Upper Jurassic sediments composed of cyclic deposits of dolomite, limestone, and anhydrite. The Sunniland Formation occurs within this interval at a depth of approximately 12,000 ft (3,657 m) bls. The Upper Sunniland Formation is a tidal shoal deposit [6], which is the most productive oil reservoir in Southwest Florida. The Lower Sunniland Formation is known as a fractured dark carbonate oil play and has had only one productive well, which was installed in the Lake Trafford Field in 1969 [6].

The Collier-Hogan 20-3H well exhibits construction details in accordance with the Florida Department of Environmental Protection requirements including four cased intervals (Fig. 4) that serve to prevent migration of fluids within the borehole; thereby, protecting aquifers shallower than the base of the USDW. The general well construction details [13] include a 24-inch diameter conductor casing installed to a depth of approximately 250 ft (76 m) bls; 13-3/8-inch diameter surface casing set at 1,600 ft (488 m) near the bottom of the USDW; intermediate 9-5/8-inch diameter casing set at 3,850 ft (1,173 m) and cemented to the base of the Boulder Zone; and 4-1/2-inch diameter production casing set at 12,500 ft (3,810 m) with cement emplaced to 9,300 ft (2,835 m). Seven packers were installed in the horizontal section of the well between MTD (measured total depths) of 12,644 ft (3,854 m) and 16,215 ft (4,942 m) resulting in a fractured interval of 3571 ft (1,088 m). The TVD (true vertical depth) of the well is approximately 11,948 ft (3,642 m).

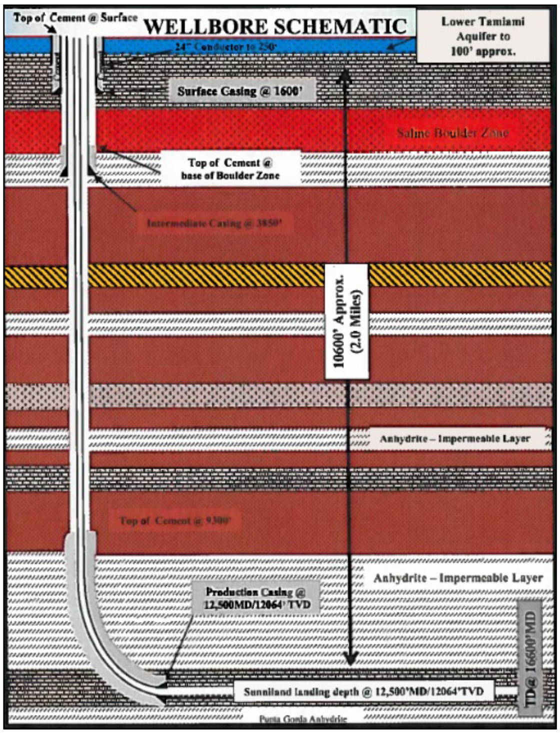

Fig. 4 Oil well construction details.

3. Hydraulic Fracturing Method

The orientation of fractures that develop in response to hydraulic fracturing is a function of the depth of the well and the distribution of the principal components of the stress field. Hydraulic fractures develop or propagate parallel to the principal vertical stress and open parallel to the direction of the least principal horizontal stress. In deep formations, i.e. greater than 2,000 ft, the vertical or overburden stress is greater than the horizontal stress; therefore, the fractures are vertically oriented. The hydraulic fracturing that was conducted at the Collier Hogan 20-3H well was designed with the MFrac3D Simulator by Baker Hughes [13] that predicted fractures 4.378 m (14.364 ft) above the lateral and 17.941 m (58.864 ft) below the lateral for a total of fracture height of 22.319 m (73.228 ft).

A total slurry volume of 691,068 gallons (16,454 barrels) that included 662,298 gallons of water and 637,399 pounds of proppant were used for the fracking treatment. On average, treatment pressures ranged from 8,287 to 8,397 pounds per square inch (psi) and the average injection rate per stage was 597 gallons per minute (gpm). The treatment was conducted in seven (7) stages with the injection time per stage equal to approximately 0.11 days, for a total treatment period of 2.09 days. The treatment procedure on the Collier-Hogan well was performed from December 30, 2013 to January 1, 2014.

4. Numerical Analysis

The SEAWAT Version 4.0 model was used to simulate the flow and mass transport characteristics associated with the natural system and hydraulic fracturing of the Sunniland reservoir in the vicinity of the Collier-Hogan 20-3H well. The SEAWAT model couples MODFLOW-2000 and MT3DMS. The MODFLOW-2000 code solves for the variable density flow field in terms of equivalent freshwater heads using the density determined from the MT3DMS-derived TDS concentrations present in each cell. This version of SEAWAT also includes the effects of salinity and temperature on viscosity, heat transport, and pressure on density. Given these recent modifications, SEAWAT is capable of simulating the hydraulic and geochemical conditions associated with this model.

4.1 Under-pressured and Over-pressured Scenarios

The finite difference grid for the three-dimensional model consisted of a horizontal domain with dimensions of 1005 by 520 meters discretized into 256 columns and 74 rows (Fig. 5). Model construction and parameter values are presented in Table 1. The model consisted of 52 layers (variable thicknesses) with constant head boundaries set up along the west and east sides of the model (Fig. 6). The north and south sides of the model were simulated as "no flow" boundaries. An expanding grid was used with rows and columns increasing from 3.05 meters in the vicinity of the horizontal injection well to 40 meters at the outer edges of the model. Row and column cell dimensions were maintained at 3.05 m in the vicinity of the horizontal well, determined from preliminary simulations, in order to accurately model fluid migration. Qualitative variations in the vertical distribution of hydraulic conductivities are illustrated in Fig. 7. The constant head boundaries ranged from 6.0 meters NGVD (National Geodetic Vertical Datum) for the water table to -710 meters in the Sunniland Formation for under-pressured conditions, based on measured formation pressures obtained from well construction records. A minor westward hydraulic gradient of 0.0001 was set up within each layer of the model. For over-pressured conditions, a hydraulic head of 6.0 meters was assigned to the Sunniland Formation. Due to historic production from the Sunniland Formation, the formation is currently under-pressured or less than the hydrostatic gradient [14]. TDS was assigned to the model, with 500 mg/L to the potable water of the surficial aquifer, 35,000 mg/L to the Boulder Zone, and 270,000 mg/L to the Sunniland Formation.

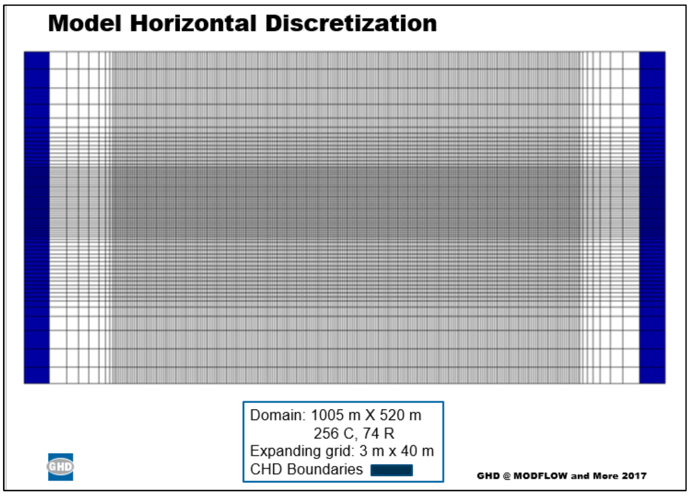

Fig. 5 Plan view of finite difference grid discretization.

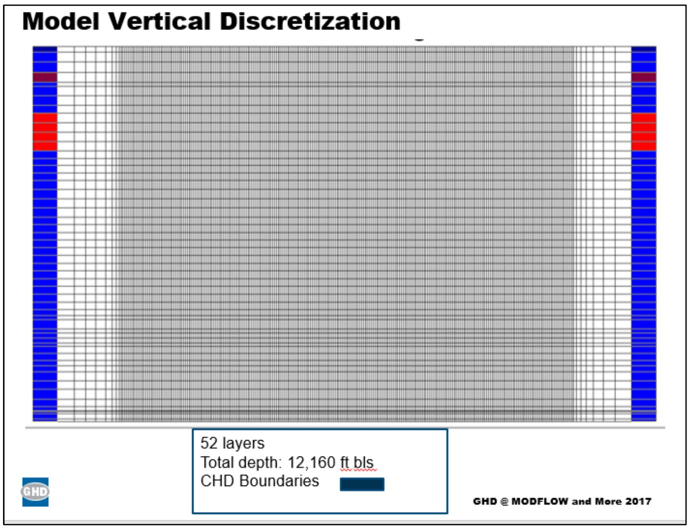

Fig. 6 Cross-sectional view of finite difference grid discretization.

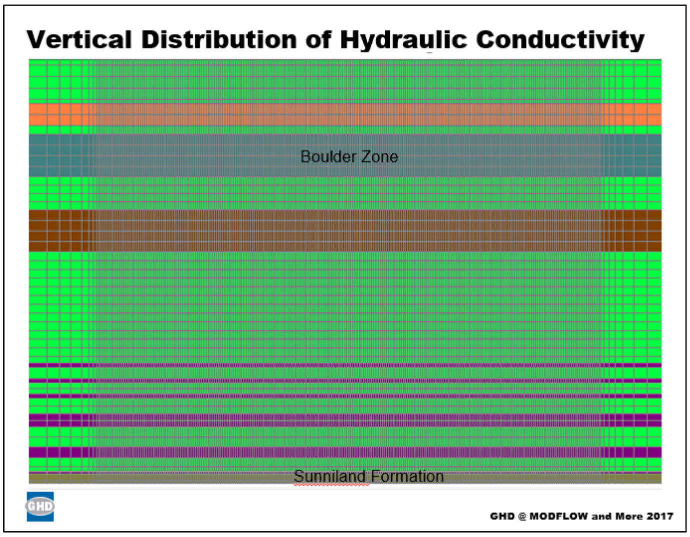

Fig. 7 Model cross-sectional view of hydraulic conductivity distribution.

Table 1 Model construction and input parameter values.

Input parameters	Units	Values
Number of columns (NCOL)		256
Number of rows (NROW)		74
Number of layers (NLAY)		52
Δx (DELR)	m	3.05 to 40
Δy (DELC)	m	3.05 to 40
Δz (DZ)	m	7 to 100
Horizontal hydraulic conductivity (Kh)-anhydrite	m/d	3.32E-05
Vertical hydraulic conductivity Kv)-anhydrite	m/d	3.32E-05
Horizontal hydraulic conductivity (Kh)-limestone	m/d	2.80E+01
Vertical hydraulic conductivity Kv)-limestone	m/d	2.80E+01
Horizontal hydraulic conductivity (Kh)-Sunniland Fm	m/d	8.30E-01
Vertical hydraulic conductivity Kv)-Sunniland Fm	m/d	8.30E-01
Horizontal hydraulic conductivity (Kh)-Boulder Zone	m/d	5.54E+03
Vertical hydraulic conductivity Kv)-Boulder Zone	m/d	5.54E+03
Horizontal hydraulic conductivity (Kh)-Cedar Keys	m/d	1.40E-04
Vertical hydraulic conductivity Kv)-Cedar Keys	m/d	1.40E-04
Horizontal hydraulic conductivity (Kh)-Avon Park	m/d	1.10E-01
Vertical hydraulic conductivity Kv)-Avon Park	m/d	1.10E-01
Horizontal hydraulic conductivity (Kh)-Fracture	m/d	2.80E+02
Vertical hydraulic conductivity Kv)-Fracture	m/d	2.80E+02
Specific storage (Ss)	m^{-1}	1e-4 to 1e-6
Porosity (θ)	ND	0.2 to 0.35
Longitudinal dispersivity (αL)	m	1
Transverse dispersivity (αT)	m	0.1
Heat capacity of the solid (CPsolid)	J/(kg°C)	835
Density of the solid (ps)	kg/m^3	2710
Bulk density (pb)	kg/m^3	1761
Thermal conductivity of solid (kTsolid)	W/(m°C)	3.59
Bulk thermal conductivity (kTbulk)	W/(m°C)	2.547
Diffusion coefficient (Dm_salinity)	m^2/d	1.00E-10
Bulk thermal diffusivity (Dm_temp)	m^2/d	0.150309621
Heat capacity of the fluid (CPfluid)	J/(kg°C)	4183
Thermal conductivity of water (kTfluid)	W/(m°C)	0.61
Distribution coefficient for salinity (Kd_salinity)	m^3/kg	0
Distribution coefficient for temperature (Kd_temp)	m^3/kg	2.00E-04
Reference density (ρ_0)	kg/m^3	1000
ōρ/ōC		0.7
Reference concentration for density ($C\rho_0$)	kg/m^3	0.5
ōρ/ōT		-0.375
Reference temperature (T_0)	°C	24
Temperature range	°C	24 to 100
Temperature gradient	°C/km	20.5
Reference viscosity	Kg/(ms)	0.001
ōμ/ōC	m^2/d	1.92E-06
Reference concentration for viscosity (Cμ0)	kg/m^3	0.5
ōρ/ōP	kg/m^4	4.46E-03
TDS	kg/m^3	0.5-275

Representative values of TDS were assigned to the Floridan aquifer and a linear gradient was used between the Boulder Zone and the Sunniland Formation. Temperatures ranged from 24 to 100 degrees centigrade, with a gradient of 20.5 °C/kilometer assigned to the model.

Density ranged from 1,000 to 1,181 kg/m^3 ($\delta\rho/\delta T$ -2.40 kg/(m^3 ºC). Viscosity varied throughout the model according to $\delta\mu/\delta C$ = 1.92 × 10^{-6} m^2/d. Density and salinity varied according to the relationship, $\delta\rho/\delta C$ = 0.7. The density-pressure slope was set at 4.46E^{-3} kgm^4. Hydraulic conductivities were assigned to the models as: anhydrite - 3.3240E^{-5} m/day; limestone/dolostone - 2.8E^{+1} m/day; Sunniland Formation - 8.3E^{-1} m/day (pre-fracture); > 8.3 m/day (post-fracture); Boulder Zone dolomite - 5.54E^{+3} m/day; Cedar Keys Formation -1.4E^{-4} m/day; Avon Park Formation - 1.1E^{-1} m/day; and fault/fracture - 280 m/day. The diffusion coefficient was set at 1E^{-10} m^2/day. Specific storage ranged from 1E^{-4} to 1E^{-6} per meter and porosity ranged from 0.35 to 0.2. All other terms and values used in the models are consistent with this type application of the model and can be found in the SEAWAT model documentation [7].

The simulated hydraulically fractured zone was assigned to layer 52 with a length of 545 meters, width of 15.25 meters, and depth of 23 meters (Fig. 8). The modeled horizontal well length is approximately half of the Collier Hogan 20-3H, which should amplify the potential effects of plume injection and migration. Modelling the decreased well length significantly reduces simulation run times, without adversely affecting the modelling results. The base case simulation represents under-pressured conditions with fluid injection rates that are consistent with the hydraulic fracturing event. An additional simulation representing over-pressured conditions was run with similar injection rates over the hydraulic fracturing period. Since hydraulic fracturing can be performed using higher volumes of injectate, additional simulations were run representing under and over-pressured conditions with injection rates two and four times the base case simulation. TDS is used in the models as a tracer to track and evaluate potential plume migration. Injection was simulated with pumping wells set up in 175 cells injecting 136 m3/day (base case), 272 m3/day (2 x base case) and 544 m3/day (4 x base case) to identify the potential differences in migration characteristics. The total volumes injected during the three previous scenarios are 662,298 gallons (2,506,798 liters), 1,324,596 gallons (5,013,596 liters, and 2,649,192 gallons (10,027,192 liters) respectively. A potential vertical fracture/fault (3.05 × 3.05 m) extending from layer 51 to layer 37 was then set above the center of the horizontal well to simulate a hypothetical anomalous hydraulic preferential pathway. Hydraulic conductivity of this preferential flow path was set at 280 m^3/day, which is consistent with faults [4]. Backflow was simulated at 30% of the injected volume to occur over 30 days and production was simulated at 160 barrels per day for 10 years into the future, which was anticipated and consistent with production in the formation.

The flow system was solved using the Pre-conditioned Conjugate Gradient Package. The advection component of the transport equation was solved using the Total-Variation Diminishing option. Dispersion, reaction and sources/sinks terms were solved using the Generalized Conjugate Gradient solver with the Slice-Successive Over-relaxation Package for pre-conditioning. Seven equal sections of the horizontal well were sequentially assigned 0.11 days of injection followed by 0.22 days of inactivity representing the first 13 stress periods. Subsequently, the models were run for an additional 107 stress periods of 30 days each, for a total of 120 stress periods.

5. Results and Discussion

The model simulation exhibiting the initial flow system and TDS distribution (Fig. 9) is consistent with the distribution of constant head and concentration

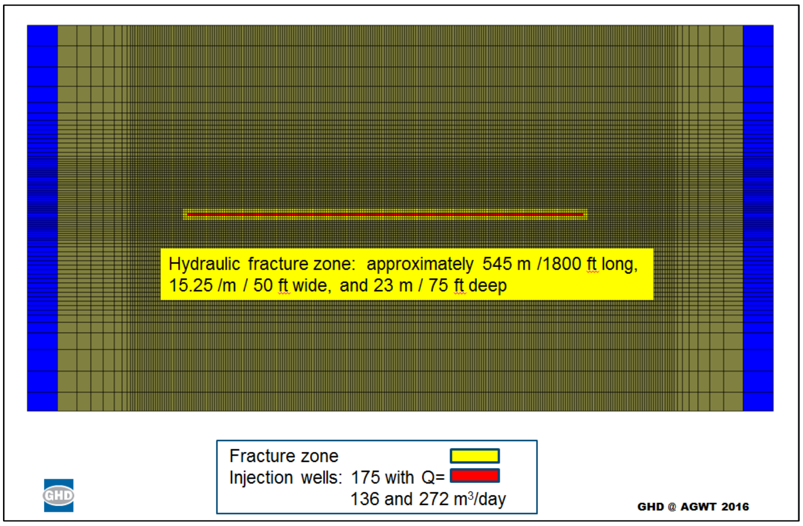

Fig. 8 **Horizontal discretization, horizontal well and hydraulic fracture zone configuration.**

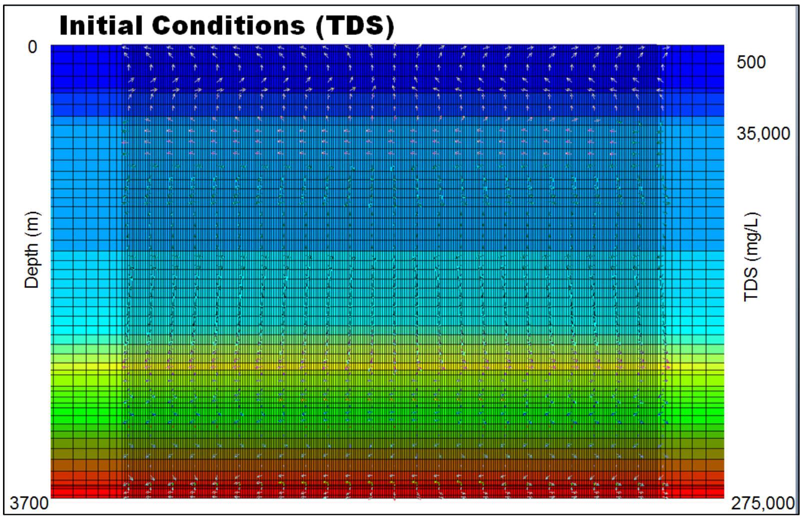

Fig. 9 **Initial TDS conditions and flow system.**

boundaries, depicting upward flow in the Floridan aquifer, horizontal flow in the Boulder Zone, and downward flow between the Boulder Zone and the Sunniland Formation.

The hydraulic head distribution of the base case model (without a fracture/fault) after stage 7 of the injection period exhibits a significant increase in head (approximately 400 m), which is generally restricted to the near vicinity of the horizontal well (Fig. 10).

The TDS distribution after stage 7 in this same simulation exhibits a decrease in TDS concentration in the immediate vicinity of the horizontal well, due to the injectate fluid, with lateral migration restricted to the permeable zone created by the hydraulic fracturing and no vertical migration. The hydraulic head distribution of the model (with a fracture or fault) after stage 7 of the injection period (Fig. 11) shows a similar increase in head (approximately 400 m) compared to the base case simulation. After 90 days, the TDS concentration in the area affected by the rising plume is approximately 207 mg/L and, after 360 days, the TDS concentration has increased to 225 mg/L and the diameter of the impacted area has also increased. In layer 47 of this simulation, it is evident that the injectate has migrated to this layer after 90 days by the range of TDS concentrations, 231 to 254 mg/L. After

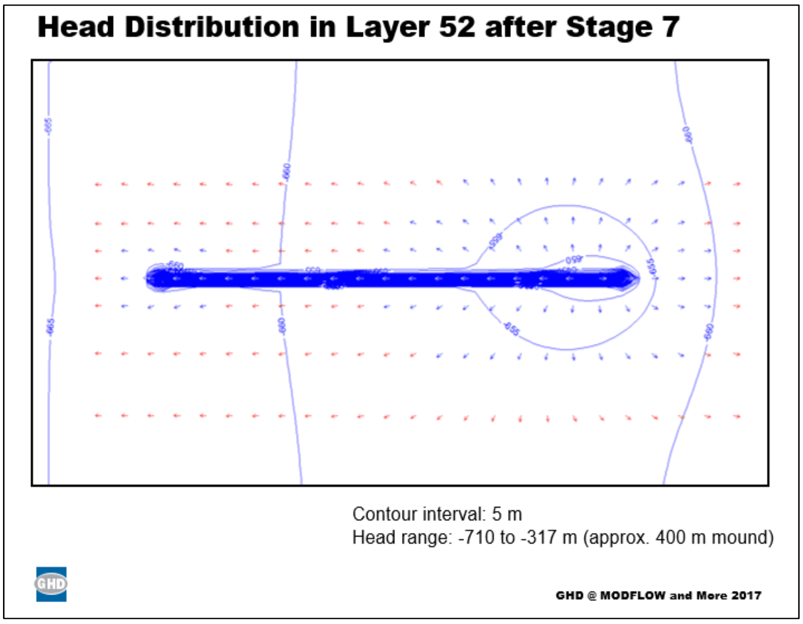

Fig. 10 Hydraulic head distribution in layer 52 after stage 7.

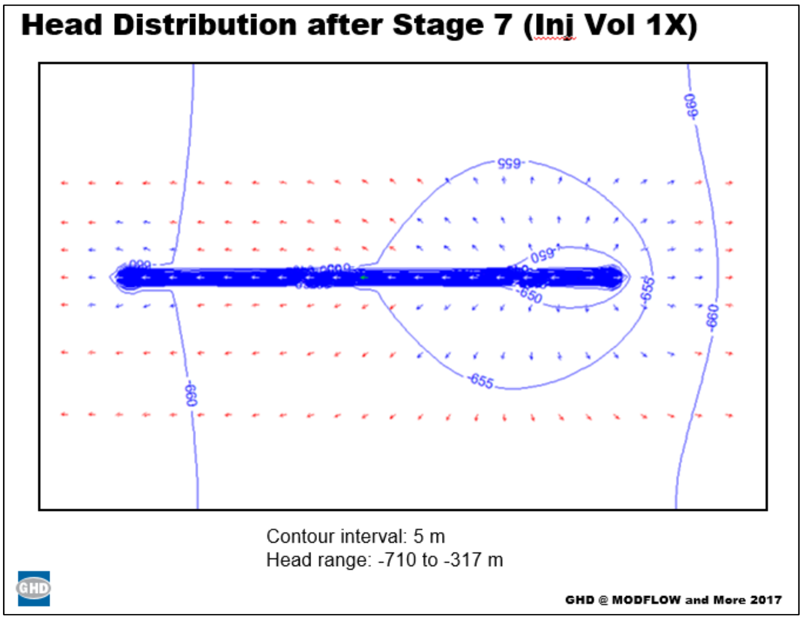

Fig. 11 Hydraulic head distribution in layer 52 after stage 7 (with fracture/fault).

360 days, the range of TDS concentrations has generally decreased from 194 to 229, in the vicinity of the ascending plume. The vertical extent of the plume extends to layer 44 with a plume exhibiting TDS ranging from 225 to 257 mg/L.

The distribution of TDS after 360 days exhibits the maximum vertical extent of the injected plume in layer 44 for both (base case and 2x) under-pressured conditions, a vertical distance of approximately 460 meters. The plume continues to migrate horizontally, although vertical migration has essentially ceased. The vertical and lateral distributions of TDS in the model are exhibited in Fig. 12 and 12a. These figures exhibit the vertical and lateral migration of the plume, with the largest plume diameter shown in layer 44. The increased plume diameter in layer 44 is likely due to

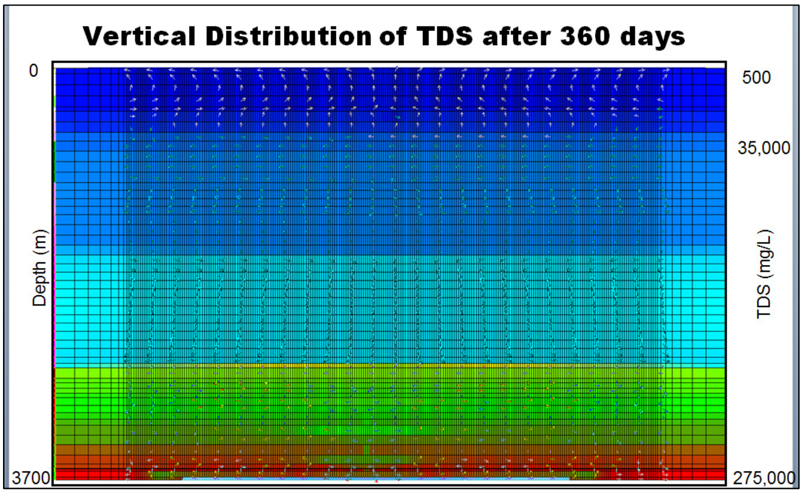

Fig. 12 **TDS distribution after 360 days showing the vertical extent of injected fluids plume in layer 44.**

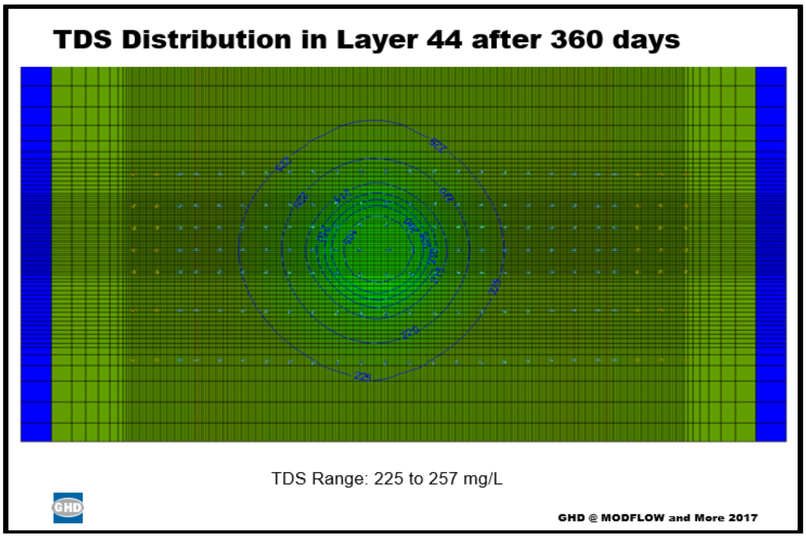

Fig. 12a **TDS distribution after 360 days showing the lateral distribution of injected fluids plume in layer 44.**

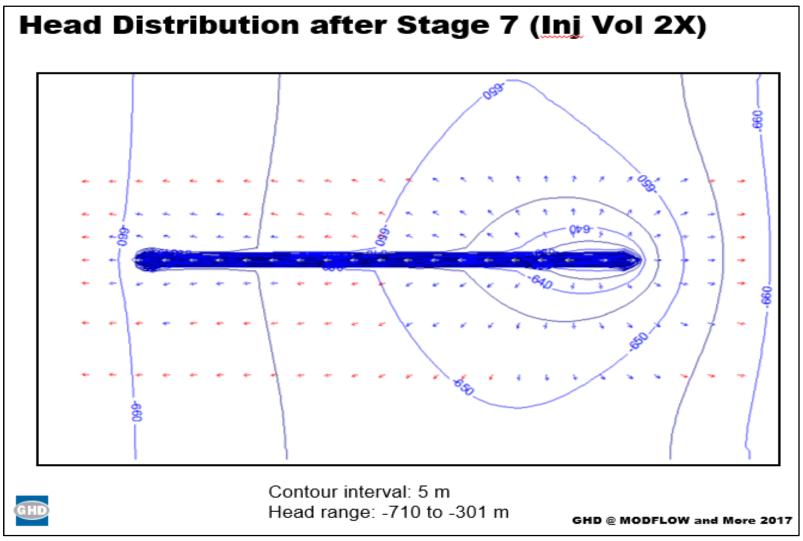

Fig. 13 **Hydraulic head distribution in layer 52 after stage 7 (with fracture/fault and injection volume 2x).**

spreading in response to advection related to the residual pressure field soon after injection; however, late time migration is likely due to the hydraulic gradient.

The hydraulic head distribution of the model (with a fracture/fault), with injection twice the base case model, after stage 7 of the injection period shows that increase in head (approximately 409 m) exhibits a greater head (by approximately 10 m) and head distribution around the horizontal well, compared to the distribution using half of the injection rate (Fig. 13). The cross-sectional TDS distributions after 360 (Fig. 14) and 720 days are generally similar to those exhibited by the base case models with a fracture/fault, with increased spreading due to the additional volume of injected fluid. The vertical extent of plume migration generally occurs in layer 44, which is a distance of approximately 460 m, although minor migration into layer 42 is evident.

The hydraulic head distribution of the model (with a fracture/fault), with an injection volume four times the base case model (Fig.15), after stage 7 of the injection period exhibits a maximum head difference

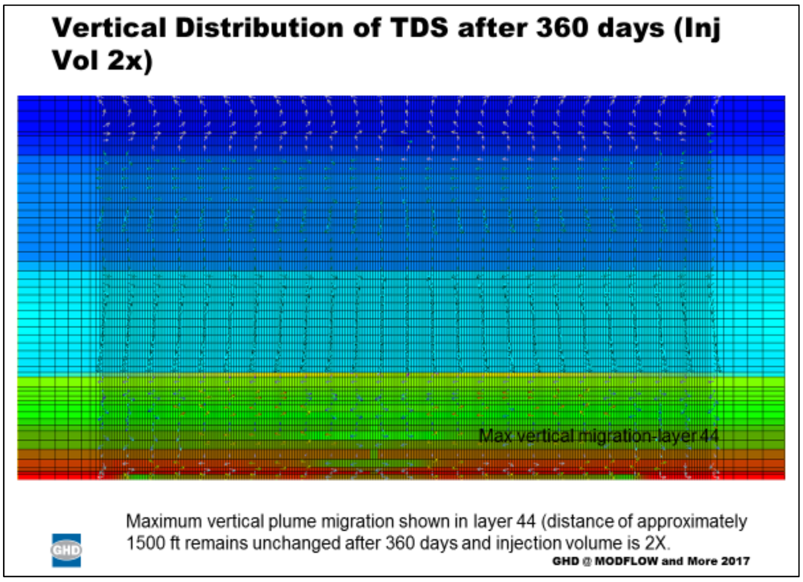

Fig. 14 TDS distribution after 360 days showing the vertical extent of injected fluids plume in layer 44 (with fracture/fault and injection volume 2x).

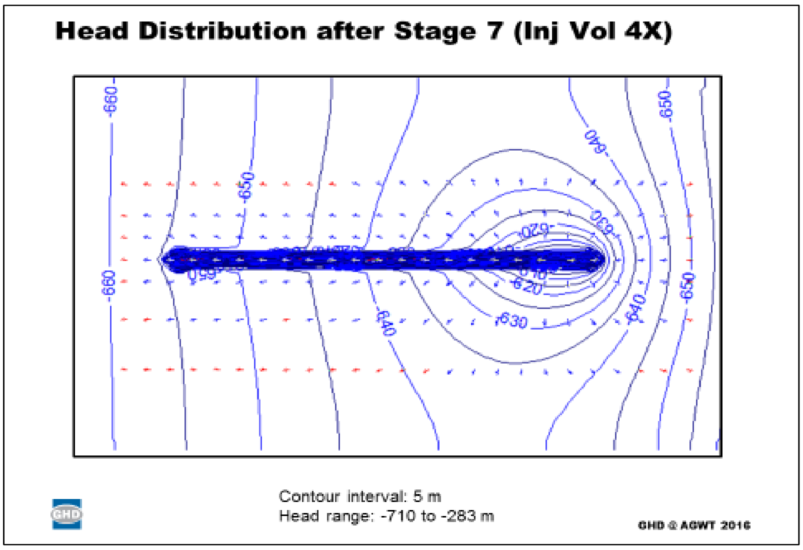

Fig. 15 Hydraulic head distribution in layer 52 after stage 7 (under-pressured with fracture/fault and injection volume 4x).

of 427 m. The TDS distribution is generally similar to the preceding scenario using under-pressured conditions and twice the base case injection rate after seven years, with the exception that the amount of fluids that migrate is greater, as exhibited by Fig. 16. Although most of the mass resides between model layers 52 and 44, minor evidence of migration indicates that the plume has broken through to layer 42.

The hydraulic head distribution of the model (with a fracture/fault), with injection twice the base case model, and under over-pressured conditions, after stage 7 of the injection period (Fig. 17) exhibits hydraulic heads ranging from -70 to 270 m, a difference of 340 m. In this scenario, the heads are distributed about the centrally-located fracture/fault instead of the east end of the well, which is the location of the last stage of the hydraulic fracturing event. Apparently, the fracture is an opening to the

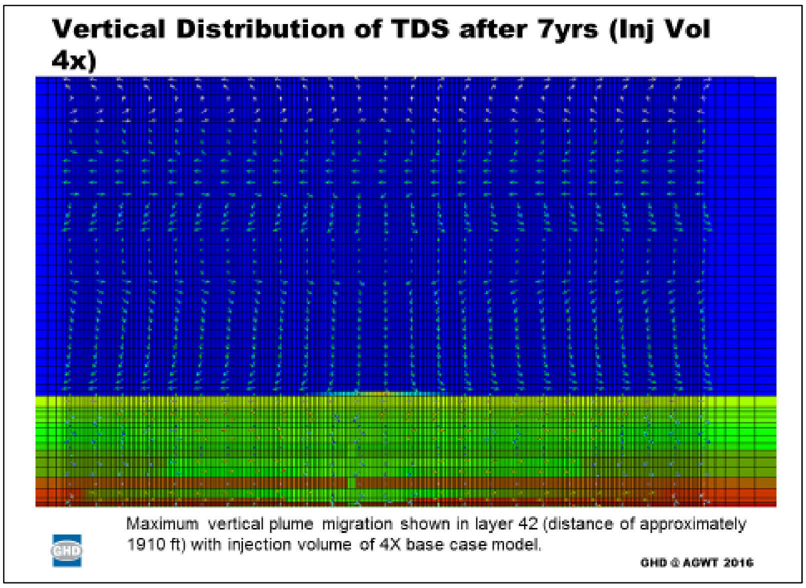

Fig. 16 TDS distribution after 7 years showing the vertical extent of injected fluids plume in layer 44 ((with fracture/fault and injection volume 4x).

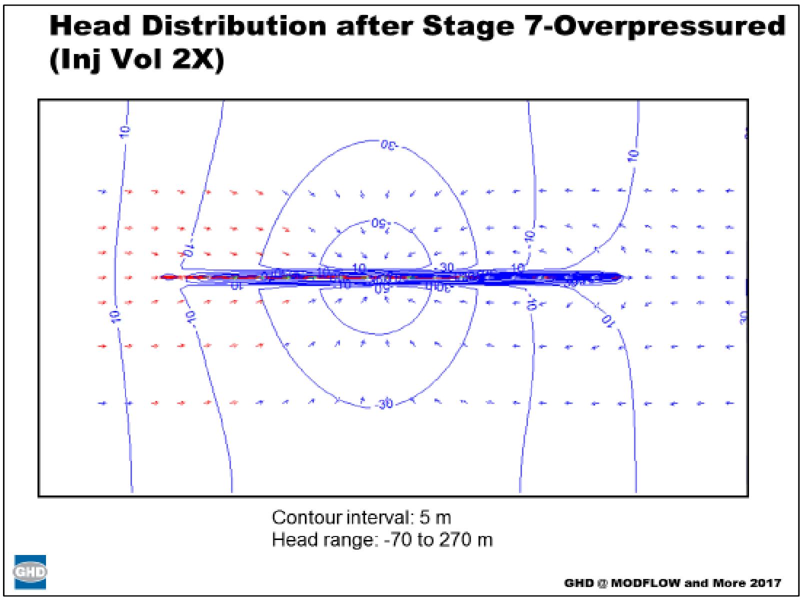

Fig. 17 Hydraulic head distribution in layer 52 after stage 7 (over-pressured with fracture/fault and injection volume 2x).

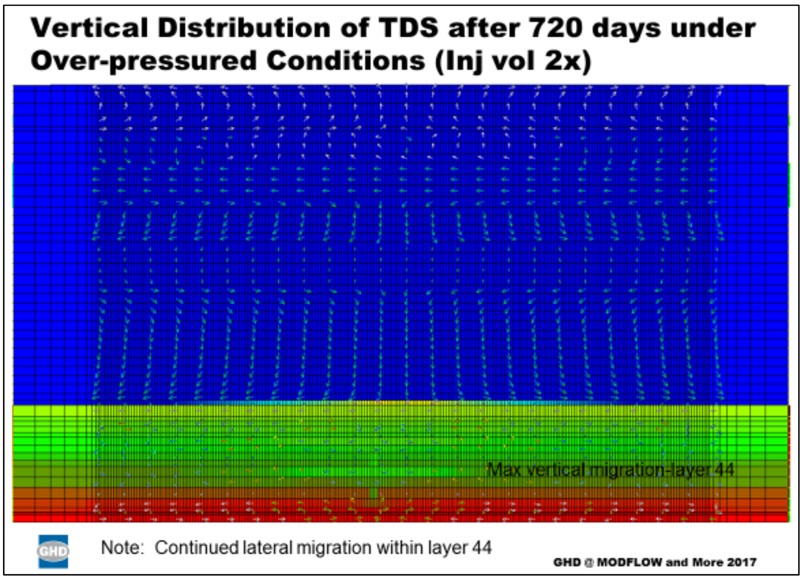

Fig. 18 TDS distribution after 720 days showing the vertical extent of injected fluids plume in layer 44 (over-pressured with fracture/fault and injection volume 2x).

very low formation pressure of layer 51 causing a hydraulic sink and the injected fluids to migrate to this low-pressure part of the well. The vertical distribution of TDS through time after 90, 360 and 720 days is generally similar to the preceding scenario using under-pressured conditions and twice the base case injection rate, where the vertical extent of the plume generally occurs in layer 44.

The results of these simulations consistently exhibit several similarities, regardless of the operating conditions associated with the hydraulic fracturing scenarios. The hydraulic heads generated during the hydraulic fracturing simulations are approximately 400 m for under-pressured conditions and 340 m for over-pressured conditions. This head difference appears to be the result of the difference in pressure of the high-density reservoir water column associated with each scenario, i.e. under over-pressured conditions the water column is approximately 12,000 ft (3,657 m). In all of the simulations, the lateral head distributions exhibit very high horizontal hydraulic gradients indicating that the high fracturing pressures are generally restricted to the immediate vicinity of the fractured zone. Another consistency is the TDS concentration distributions in the reservoir following hydraulic fracturing. Similar to the head distributions, all of the simulations exhibit variations in TDS concentrations that occur in the immediate vicinity of the fractured zone with background TDS concentrations occurring immediately beyond the fractured zone after hydraulic fracturing. With increasing time to approximately greater than seven years, the TDS plume grows beyond the fractured zone in the vicinity of the fracture/fault, as fluids migrate to the fault. Beyond the vicinity of the fracture/fault, the TDS plume does not migrate far from the fractured zone. The rapid reduction in the pressure field and TDS distribution beyond the fractured zone is generally attributed to fracture mechanics, losses to the formation (leak off), and backflow, which was set at 30% of the injection volumes for all of the models and simulations. The fracture length is determined by the mass balance between leakoff and flow into the fracture [15]. The vertical extent of fluid migration in all cases generally terminates at model layer 44, which is equivalent to a distance of approximately 460 m, beyond which lateral spreading is dominant. With increasing injection volumes, the volume of fluids that migrate from the injection zone into the overlying formations increases with most of the mass generally maintained in model layers deeper than layer 44, although the results do indicate some migration into layer 42. Since TDS was used as a tracer to track fluid migration and the constituents of the plume, these modeling results indicate that any regulated constituents in the plume will not migrate beyond the distance attained by the TDS plume.

When evaluating the potential effects of injecting the volumes of fluid for these various scenarios, it should be considered that the volumes are distributed over a model distance of 545 meters. The actual length of the horizontal well is approximately twice this length or 1,090 meters (3,576 feet). Therefore, a significantly larger volume of the injectate is in contact with reservoir brine with a TDS concentration of 270,000 mg/L, compared to a vertical well used for ASR (Aquifer Storage Recovery) that would potentially have the base case volume injected into a few hundred feet of the Floridan aquifer, eventually creating a freshwater zone about the injection zone. Prior to creating the freshwater zone in a brackish formation used for ASR, much water is lost to the formation. Similarly, much of the low TDS injected water used for hydraulic fracturing should rapidly experience an increase in TDS resulting in reduced buoyancy.

6. Conclusions

This study, based on the application of a numerical model incorporating site-specific hydrogeologic and fluid injection parameters, demonstrates that the injected fluid from hydraulic fracturing does not have the potential to migrate into the USDW (Underground Source of Drinking Water) that occurs in the Lower Floridan aquifer. The vertical migration of the injected solution is restricted from migrating into drinking water aquifers as a result of the following conditions:

- the presence of low permeability formations composed of clay, anhydrite, limestone and dolomite overlying the reservoir;
- very high salinities and increasing density with depth;
- downward hydraulic gradient associated with under-pressured conditions;
- general absence of naturally occurring faults in the Sunniland Formation and sub-Floridan confining unit;
- without a fracture or fault exhibiting a preferential flow path, vertical migration from the reservoir does not occur;
- with presence of a fracture/fault, vertical migration is limited to approximately 460 meters;
- presence of the Boulder Zone and associated Kohout convection, potentially restricts migration into the USDW;
- horizontal plume migration is restricted to near vicinity of the hydraulic fracture zone.

The deep monitoring well installed at the base of the USDW, in the vicinity of the Collier-Hogan 20-3H oil well, has not exhibited any impacts related to the injected fluids to date, supporting the conclusion that such fluids are not capable of migrating through the various hydrogeological barriers between the reservoir and the USDW over the short periods of high pressure hydraulic fracturing events or longer periods of post fracturing residual migration due to buoyancy of the injected fluids. These results are in agreement with the general conclusion, based on an extensive body of evidence compiled by the USEPA, that impacts to aquifers have not been found to result from the migration of the fluids associated with hydraulic fracturing of deep formations.

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