Simple Groundwater Modeling of Transport Pathways in Unconventional Natural Gas Plays

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ABSTRACT: Groundwater modeling using MODFLOW-2000 has suggest that vertical flow of contaminants from the Marcellus Shale and other deep shale natural gas plays can occur within time frames of interest to water resources managers, if proper conditions are met (Myers 2012). These conditions include an upward vertical gradient and a pathway, which could include fractures or improperly abandoned wells. Subsequently published data has also documented the presence of pathways between the Marcellus formation and shallow aquifers (Warner et al. 2012). However, the modeling included potential oversimplifications including ignoring imbibition, whether the flow is Darcian, the effect of boundaries, and potential multiphase flows. Consideration of these assumptions as presented on this poster shows that the modeling is accurate and the simplifications are appropriate.

HYPOTHESIS

Fluids released from the Marcellus Shale or other deep nonconventional shale formations due to hydraulic fracturing (fracking) could move vertically to shallow aquifers or surface discharge points.

NECESSARY CONDITIONS

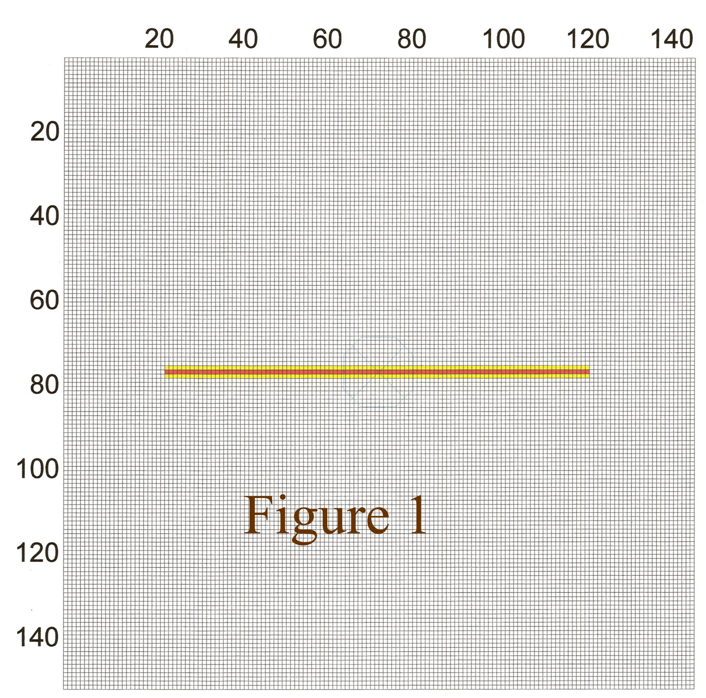
1. Upward vertical gradient.
2. Pathway for fluid transport through the overburden. Pathways include fractures, abandoned wells, or simple advection.

MODEL STRUCTURE FROM MYERS (2012)

150 rows and columns, 3 m square cells, 50 layers with ten 3-m thick layers for the shale. See the plan view below (Figure 1) and a cross section to the right (Figure 3).

IMBIBITION

MODFLOW does not simulate the losses that would occur if fracking fluids become bound due to capillarity in the bulk media. However, a primary assumption is that the contaminants get out of the shale, either through out-of-formation fractures, natural fractures, or well leaks. Potential imbibition does not obviate the modeling results but is an issue to consider for some of the transient modeling. Data on the amount and processes controlling imbibition is clearly needed.



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DARCIAN FLOW

Darcy's Law accurately describes groundwater flow as long as the relationship between specific discharge and hydraulic gradient is linear (Bear 1979) with a slope equal to conductivity. Darcy's law is valid where viscous flow predominates, or in the range between microscopic and turbulent effects.

Where microscopic flow predominates, Darcy's law would not be valid. For shale, this would be the laboratory scale of a permeameter. In shale, and other consolidated rock, conductivity within samples too small to include fractures is extremely low and may legitimately not be considered to be Darcian flow.

As the representative elemental volume (REV) increases, the volume is more likely to include fractures so that the conductivity becomes larger (Bear 1979) and the proportion of media and fractures becomes relatively constant and the hydrogeologic parameters also becomes constant.

Three types of flow can occur within the REV – porous, fracture or a double porosity or combined flow behavior. Devonian shale exhibits fracture flow (Schulze-Makuch et al. 1999), and there is an upper limit to the volume scale at about 10^7 m^3. Figure 2 shows that as volume (and fractures) increase in pre-fracked Devonian shale, the relative conductivity also increases.

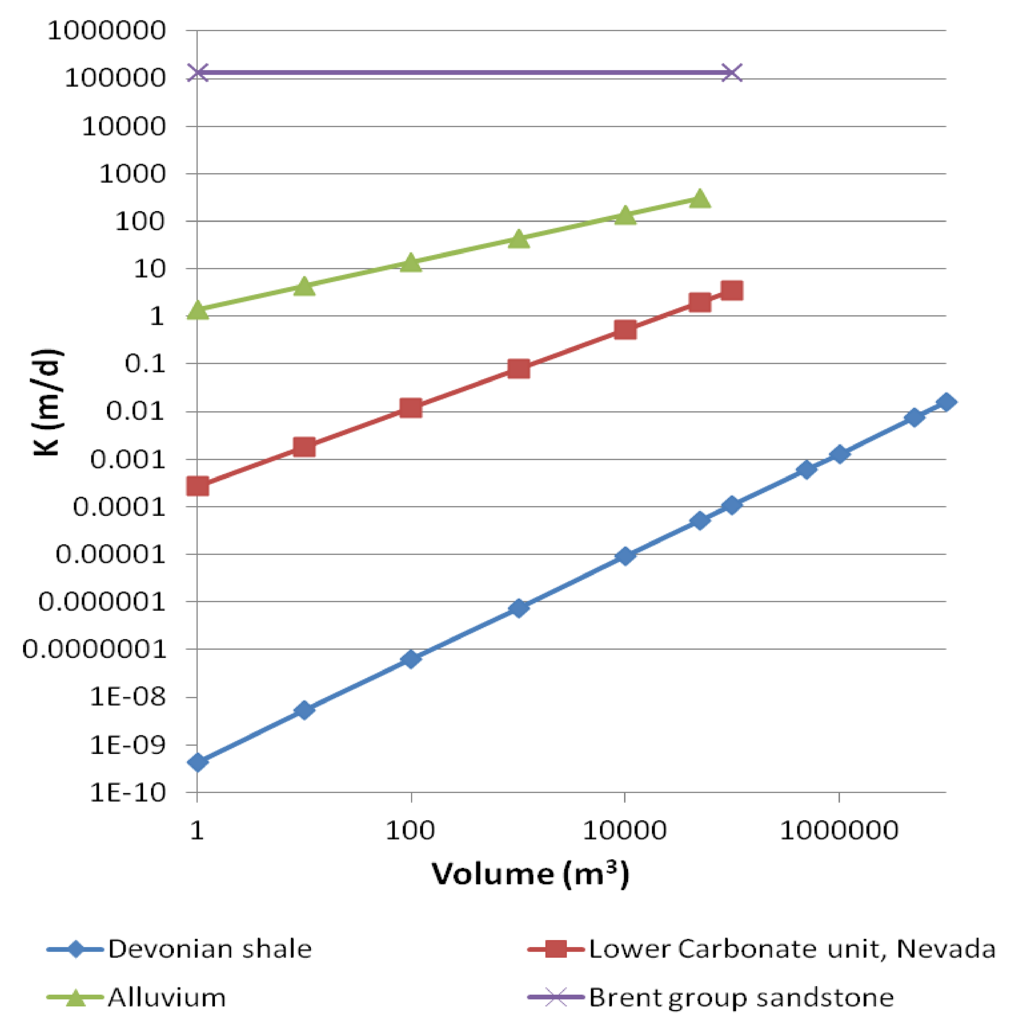

Figure 2: Hydraulic conductivity/ scale relationship for various materials, after Schulze-Makuch et al. (1999).

The value in this figure are representative of values that could be used for groundwater and transport modeling for the Marcellus shale and other overburden layers.

BOUNDARY CONDITIONS

The upper constant head (CH) boundary was changed to a drain boundary
Shale and overburden K = 0.001 and 0.1 m/d, respectively
Storage coefficient = 0.0001 and 0.001 for overburden and fracked shale
Steady state simulation with the drain boundary caused a vertical flux equal to 2.0 m^3/d, 5% higher than w CH bounds

General head boundaries (GHBs) established a 1 m head drop over 850 m (slope approximately 0.0012) with a conductance equal to the product of the layer thickness and conductivity to cause horizontal flow.

At steady state, the vertical flux through the shale from the lower constant head boundary was 2.02 m^3/d, but the flux through the drain on the top layer increased to 5.97 m^3/d. The vertical gradient diverted some of the horizontal flow upward toward the drain. Horizontal inflow to and outflow from the domain equaled 78.0 and 74.1 m^3/d, showing that the vertical flow may be a small proportion of the total flux.

Figure 3 shows a time series of vertical pressure changes analogous to those shown by Myers (2012) with a horizontal component superimposed due to an instantaneous change in properties (due to fracking).

Initially, the majority of the flow is horizontal similar to the steady state solution for pre-fracking conditions (Figure 3a). The changes to a more horizontal component to the 1550 m contour (Figure 3b and 3c) and the addition of 1550.5 and higher contours (Figure 3c through 3h) show the adjustment from the steady state, pre-frack, head drop across the shale of almost 30 m to a lesser drop of about 27 m necessary for a two-order of magnitude increase in K due to fracking.

Flow through the shale adjusts quickly from 2.0 to more than 100 m3/d due to changed K in the shale just above the boundary. The flow through the shale displaces some of the horizontal flow through model cross-section (Figure 4). A 100 m3/d flux is less than 0.2 m/y over the 450 m square domain.

MULTIPHASE FLOW

Fluids in the shale exist in at least two phases, methane gas and brine. The primary affect of the brine would be to reduced the effective primary permeability for water flow. If fractures control the flow through the system, the gas phase would have little effect hydrogeologically away from the well bores.

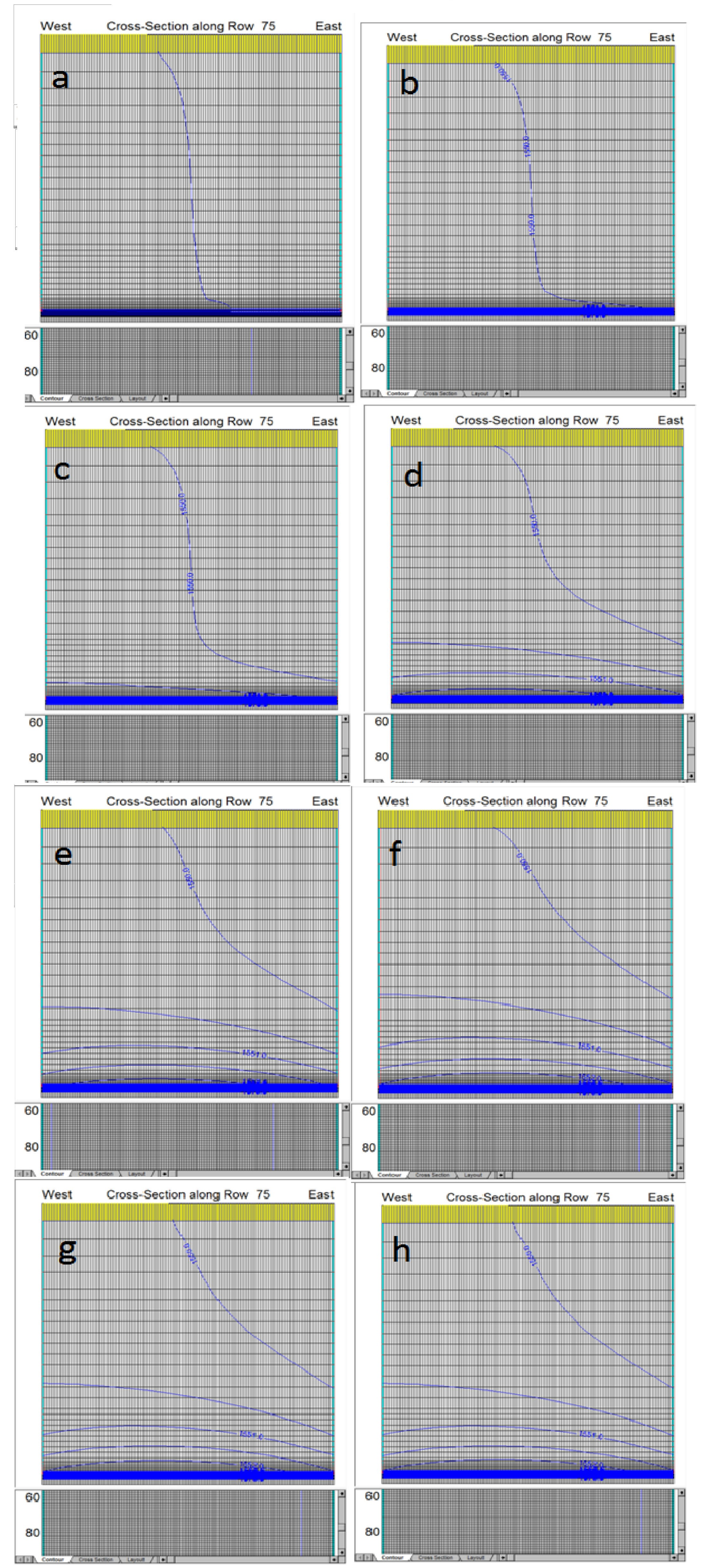

Figure 3: Potentiometric surface at 0.12 (a), 0.96 (b), 9.3 (c), 61 (d), 153 (e), 584 (f), 14,670 (g) and 36,500 days (h), respectively, after the start of the simulation.

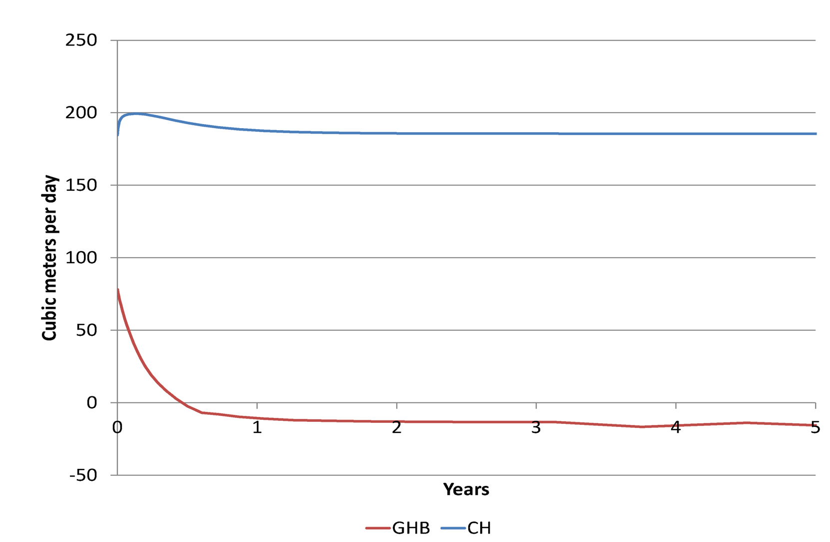

Figure 4: Horizontal flow through the model (GHB) and discharge through the shale (CH).

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