JOURNAL OF GEOPHYSICAL RESEARCH, VOL. 109, B11104, doi:10.1029/2003JB002922, 2004

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Dissipation of anomalous pressures in the subsurface

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Received 2 December 2003; revised 11 June 2004; accepted 31 August 2004; published 30 November 2004.

[1] Zones of anomalous pressure, higher and lower than hydrostatic pressure, have been observed in many sedimentary basins around the world. These normally consist of groups of pressure compartments: volumes of higher-permeability rock surrounded on all sides by lower-permeability barriers. Knowledge of the timescales over which these abnormal pressures are maintained and the mechanisms by which they dissipate is critical for understanding how fluids, such as oil and gas, move in the subsurface. Existing analytic solutions investigate pressure dissipation through low-permeability barriers on top of or underneath an isolated pressure compartment. There are no analytic solutions describing pressure dissipation through lateral barriers, such as faults, or investigating the impact of groups of pressure compartments on the rate of pressure dissipation. This paper presents simple analytic models to investigate pressure dissipation through barriers, such as faults, forming the sides of pressure compartments. The timescales are compared with a solution for pressure dissipation through barriers on top of and underneath the compartment. It also investigates analytically the rate of pressure dissipation from groups of pressure compartments. Lateral seal permeabilities of 10^{-19} m^2 may delay pressure equilibration for millions of years provided the compartment has a sufficiently high fluid storage capacity. Factors contributing toward a high fluid storage capacity include a high fluid compressibility (as is the case in hydrocarbon reservoirs) and a high porosity. The grouping of abnormally pressured compartments into "megacompartment complexes" may delay pressure dissipation for hundreds of millions of years. *INDEX TERMS:* 5139 Physical Properties of Rocks: Transport properties; 1832 Hydrology: Groundwater transport; 1829 Hydrology: Groundwater hydrology; 5114 Physical Properties of Rocks: Permeability and porosity; 3210 Mathematical Geophysics: Modeling; *KEYWORDS:* abnormal pressure, permeability, pressure compartments

Citation: Muggeridge, A., Y. Abacioglu, W. England, and C. Smalley (2004), Dissipation of anomalous pressures in the subsurface, *J. Geophys. Res.*, *109*, B11104, doi:10.1029/2003JB002922.

1. Introduction

[2] Fluid pressures, in general, increase with depth due to the increasing overlying fluid column. If the fluid pressure (p, Pa) in a given formation can be calculated from the surface pressure (P_{surface}, Pa), its depth of burial (z, m), and the fluid density (ρ, kg m^{-3}) using

$$p = P_{\mathrm{surface}} + \rho g z, \tag{1}$$

then the formation is said to be normally pressured. However, zones of anomalous pressure, higher and lower than that calculated by equation (1), have been observed in many basins around the world, usually (but not exclusively) at depths greater than 2500 m in thick sedimentary accumulations [e.g., *Bradley*, 1975; *Hunt*, 1990; *Powley*, 1990; *Bradley and Powley*, 1994; *Anissimov*, 2001; *MacArthur et al.*, 2001]. A number of mechanisms have been proposed to explain how these zones are created [see, e.g., *Osborne and Swarbrick*, 1997]. These include rapid erosion or uplift for underpressured reservoirs [see, e.g., *Jiao and Zheng*, 1998] and rapid accumulation of sediments or hydrocarbon generation for overpressured zones [*Martinsen*, 1994; *Michael and Bachu*, 2001; *Wangen*, 2001].

[3] These zones of anomalous pressure normally consist of groups of pressure compartments [*Bradley and Powley*, 1994; *Ortoleva*, 1994; *Ortoleva et al.*, 1995], each pressure compartment being formed from a volume of relatively high permeability rock that is surrounded on all sides by lower-permeability rock and/or faults. Compartments may lie within other compartments (see Figure 1). In some cases, such as the Anadarko Basin, the whole basin may form a "megacompartment" with the interior subdivided into smaller subcompartments. This system has been described

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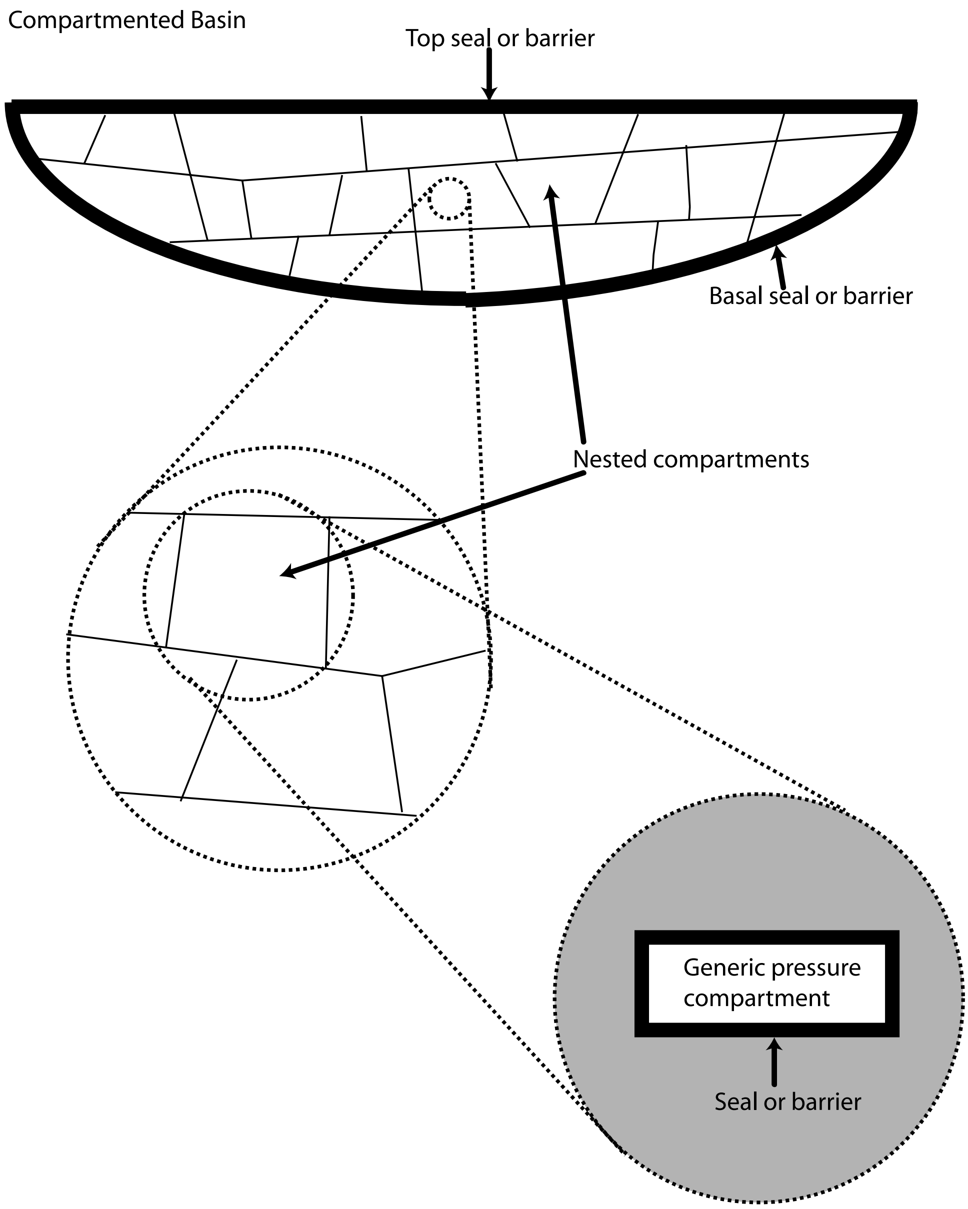

Figure 1. Schematic diagram of a nested hierarchy of pressure compartments or megacompartment complex [*Al-Shaieb et al.*, 1994a, 1994b]. Three levels of compartments are shown, ranging from the basin scale (hundreds of kilometers) to the reservoir scale (kilometers). Each individual pressure compartment may be overpressured to a different extent from its neighbors [after *Ortoleva*, 1994].

as a megacompartment complex [*Al-Shaieb et al.*, 1994a, 1994b]. Different compartments often have different degrees of overpressuring, although the pressure gradient within them is typically hydrostatic. They are usually associated with hydrocarbon accumulations, but it is unclear whether this is solely due to the mechanisms by which the overpressures were generated [*Martinsen*, 1994; *Michael and Bachu*, 2001; *Wangen*, 2001] and maintained over geological timescales or a result of the fact that hydrocarbon exploration is the principal driver for drilling to these depths and then logging fluid pressure.

[4] Determining the timescales over which these abnormal pressures exist, once the mechanism that created them has ceased, is critical for understanding how fluids move in the subsurface. Some authors believe that, provided the three-dimensional (3-D) stress regime is such that no fracturing or faulting occurs, abnormal pressures can be maintained indefinitely by rocks acting as pressure seals, either because they are totally impermeable [*Hunt*, 1990; *Ortoleva*, 1994] or through capillary pressure effects [*Iverson et al.*, 1992, 1994; *Surdam et al.*, 1997; *Bjorkum et al.*, 1998; *Revil et al.*, 1998; *Cathles*, 2001; *Deming et al.*, 2002]. Others postulate that all abnormal pressures are transient [*Bredehoeft and Hanshaw*, 1968; *Hanshaw and Bredehoeft*, 1968]. They make the following arguments:

[5] 1. It is unlikely that the rocks surrounding a pressure compartment (which are normally of sedimentary origin) can ever have absolutely zero permeability, even after undergoing extensive diagenesis. They are better described by *Martinsen* [1994, p. 33] as "low-hydraulic-conductivity

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Table 1. Rock and Fluid Properties Used in the Calculation of Timescales for Pressure Dissipation From Abnormally Pressured Compartments[a]

Properties	Value	Units
k_b, barrier permeability[b]	10^{-22}	m^2
k_c, compartment permeability	10^{-13}	m^2
ϕ_b, barrier porosity	0.05	
ϕ_c, compartment porosity	0.2	
c_b, bulk rock compressibility[c]	10^{-9}	Pa^{-1}
c_w, water compressibility[d]	2×10^{-10}	Pa^{-1}
μ, water viscosity[e]	1.5×10^{-4}	N s m^{-2}

[a]These properties are typical of those encountered in overpressured compartments 3 km below the surface.
[b]Minimum of *Katsube et al.* [1991], *Neuzil* [1994], *Helton et al.* [1997], *Schlömer and Krooss* [1997], *Cosenza et al.* [1999], *Kwon et al.* [2001], *Boving and Grathwohl* [2001], and *Beauheim and Roberts* [2002].
[c]*Lee and Deming* [2002]; at the upper end of shale compressibilities discussed by *Ge and Garven* [1992].
[d]Pure water at 200°C, 100 MPa, *Perry et al.* [1997].
[e]Pure water at 200°C, 100 MPa, *Engineering Sciences Data Unit* [1978].

rocks which continuously allow the flow of fluids across them, but at a reduced rate compared with the flow rates through surrounding rocks.''

[6] 2. The chances of a system that is several kilometers or tens of kilometers long and wide, and possibly hundreds of meters thick, remaining completely sealed in three dimensions over periods of hundreds of millions of years are remote.

[7] Simple analytic solutions for pressure dissipation [*Neuzil*, 1986; *Deming*, 1994; *He and Corrigan*, 1995] through a homogeneous barrier of thickness H (m) predict that the timescale T for pressure dissipation (in seconds) is given by

$$T \sim \frac{H^2 c_r \mu}{k}, \tag{2}$$

where c_r is the bulk rock compressibility (Pa^{-1}), μ is the fluid viscosity (N s m^{-2}), and k is the barrier permeability (m^2). Using typical barrier and water properties for the depths at which overpressured compartments are encountered (see Table 1), a 100 m thick barrier will allow abnormal pressures to dissipate completely within 1 Myr.

[8] However, there are abnormally pressured basins, such as the Anadarko Basin in southwestern Oklahoma [*Gilbert*, 1992; *Al-Shaieb et al.*, 1994a, 1994b; *Corrigan et al.*, 1998; *Lee and Deming*, 2002] and the Precaspian Basin in Kazakhstan [*Anissimov*, 2001], which have apparently not experienced new over pressuring as a result of compaction or hydrocarbon generation for tens of millions for years. Thus, if equation (2) is correct, abnormal pressures can only be maintained over such long periods if average barrier permeabilities are less than 10^{-24} m^2 (10^{-9} mdarcy) [*Deming*, 1994; *Lee and Deming*, 2002], which is lower than any barrier permeability yet measured. Alternatively, compartments need to be surrounded by barriers whose thickness is greater than 1 km.

[9] *Luo and Vasseur* [1997] investigated pressure dissipation from a more realistic model of a compartment, consisting of a thick high-permeability sand topped by a lower-permeability barrier (Figure 2). They obtained the approximate solution

$$T \sim \frac{c_{cb} H_c H_b \mu}{k_b}\left(1 + \frac{c_{bb} H_b}{3 c_{cb} H_c}\right), \tag{3}$$

where c_{cb} is the bulk compressibility of the compartment rock (Pa^{-1}), c_{bb} is the bulk compressibility of the barrier rock (Pa^{-1}), H_c is the thickness of the compartment (m), H_b is the thickness of the barrier (m), and k_b is the permeability of the barrier (m^2). They also predicted that abnormal pressure should dissipate within 1 Myr. However, their solution was only approximate and assumed that the fluid compressibility was negligible.

[10] More recently, *Muggeridge et al.* [2005] obtained an exact solution for the change in fluid pressure with time in the model pressure compartment shown in Figure 2:

$$\frac{p - P_H}{P_I - P_H} = \sum_{n=1}^{n=\infty} \frac{2\left(\alpha_n^2 + R^2\right) e^{-C\alpha_n^2 t} \sin(\alpha_n z / H_b)}{\alpha_n\left[\left(\alpha_n^2 + R^2\right) + R\right]}, \tag{4}$$

where $p(z, t)$ (Pa) is the pressure as a function of thickness z (m) in the barrier ($z = 0$ is the bottom of the barrier and $z = H_b$ is the boundary between the top of the barrier and the abnormally pressured compartment) and time t (seconds), α_n are the roots of the transcendental equation $\alpha_n \tan(\alpha_n) = R$, which is the ratio of the storage capacity of the barrier to that of the compartment and is given by

$$R = \frac{2 H_b \phi_b c_b^e}{H_c \phi_c c_c^e}, \tag{5}$$

where the superscript e denotes an effective compressibility (discussed in section 2), and C is the reciprocal of the time constant for pressure diffusion in the barrier and is given by $k_b/(\mu \phi_b c_b^e H_b^2)$. This solution reduces (1) to equation (1) when the compartment permeability approaches that of the barrier and (2) to the solution of *Luo and Vasseur* [1997] when the

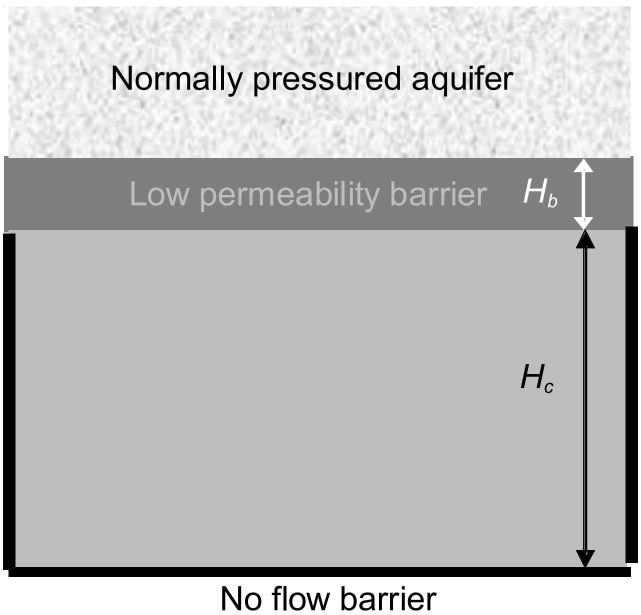

Figure 2. Schematic of model pressure compartment for which *Luo and Vasseur* [1997] obtained an approximate analytic solution. The thickness of the high-permeability sand is much greater than that of the low-permeability barrier. Previous analytic solutions did not consider the effect of the high-permeability sand on the rate of pressure dissipation from the compartment.

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compartment permeability and thickness are both much greater than the barrier thickness and permeability.

[11] However, even these solutions neglected the possibility of pressure dissipation through the lateral boundaries of the compartment. Furthermore, they only considered isolated pressure compartments, whereas most abnormally pressured compartments are found in groups or megacompartment complexes.

[12] The purpose of this paper is to examine, using simple analytic models, the effect of pressure dissipation through compartment edges and how stacking or grouping such pressure compartments together (as is typical in many basins) alters the time taken for pressure to dissipate. We show that for isolated pressure compartments, very low permeabilities at the edges of the compartment are required to maintain abnormal pressures over geological timescales. However, in the case of hydrocarbon reservoirs the increased compressibility of oil and gas, combined with the compartmentalized nature of most overpressured basins, makes it likely that abnormal pressures will take hundreds of millions years to dissipate using measured values of seal permeability. There is thus no need to invoke complete pressure sealing, via capillary pressure or any other mechanism, to explain the existence of anomalous pressures in the subsurface for hundreds of millions of years after those pressures were first generated.

2. Approach

[13] Our approach is to use simple analytic solutions to investigate the rate of pressure dissipation from simplified models of a pressure compartment or compartments via Darcy flow. We assume that the compartment is not subject to heating, cooling, or vertical movement. If this is the case, then the only way that this abnormal pressure can dissipate is via fluid flow into or out of the compartment to equalize pressures.

[14] First, we derive the pressure diffusion equation. Although this is described in many engineering textbooks [e.g., *Dake*, 1978], it is helpful to describe it again here so we can review the simplifying assumptions made in its derivation. Consider a volume of porous rock filled with a fluid with density ρ (kg m^{-3}) and viscosity μ (N s m^{-2}). The rock has permeability k (m^2) and porosity ϕ. This volume V_b of porous rock is made up of a volume V_s of solid mineral plus a volume V_p of pore space (all measured in m^3). Applying mass conservation, the rate of change of mass within the volume V_b is controlled by the net rate of mass flowing in or out of that volume:

$$\frac{1}{V_b}\frac{\partial(\rho V_p)}{\partial t} = \nabla\cdot\rho\mathbf{v}, \tag{6}$$

where $\mathbf{v}$ is the Darcy velocity (m s^{-1}) which is given by

$$\mathbf{v} = -\frac{k}{\mu}(\nabla p + \rho\mathbf{g}), \tag{7}$$

p is the fluid pressure (Pa) and $\mathbf{g}$ is the acceleration due to gravity (m s^{-2}). Substituting equation (7) into (6), we get

$$\frac{1}{V_b}\frac{\partial(\rho V_p)}{\partial t} = -\rho\nabla\cdot\left[\frac{k}{\mu}(\nabla p - \rho\mathbf{g})\right], \tag{8}$$

where we have assumed that fluid density does not change with location; that is, there are no compositional variations and the system is isothermal. Differentiating the left-hand side of equation (8) gives

$$\begin{aligned}\frac{1}{V_b}\frac{\partial(\rho V_p)}{\partial t} &= \frac{1}{V_b}\left(\rho\frac{\partial(V_b - V_s)}{\partial t} + V_p\frac{\partial\rho}{\partial t}\right)\\ &= -\rho(c_b - (1-\phi)c_s)\frac{\partial p}{\partial t} - \phi\rho c_f\frac{\partial p}{\partial t},\end{aligned} \tag{9}$$

where c_b is the bulk rock compressibility, c_s is the compressibility of the solid rock fraction, and c_f is the compressibility of the fluid (all describing changes in volume as a function of pore pressure and measured in Pa^{-1}). Equation (9) describes the fact that change of fluid mass in the rock volume V_b with time is controlled by pore space compressibility ($c_b - (1-\phi)c_s$) and the fluid compressibility c_f. For a fuller discussion of the compressibility of porous rocks as a function of pore and confining pressures the reader is referred to *Zimmerman et al.* [1986]. Substituting equation (9) into equation (8) and canceling ρ gives

$$\left\{-[c_b - (1-\phi)c_s] + \phi c_f\right\}\frac{\partial p}{\partial t} = -\frac{k}{\mu}\nabla\cdot(\nabla p - \rho\mathbf{g}), \tag{10}$$

where we have assumed that (1) the rock is homogeneous so k is independent of position and (2) the fluid viscosity μ is also independent of position. This last assumption is consistent with the assumption above that fluid density does not change with position.

[15] As the mineral compressibility of the rock is generally negligible compared with the bulk rock compressibility for overpressured and therefore undercompressed formations, we can rewrite equation (10) in terms of the hydraulic head p (which, like *Luo and Vasseur* [1997], we shall hereafter refer to simply as overpressure) as

$$c_e\phi\frac{\partial p}{\partial t} = \frac{k}{\mu}\left(\nabla^2 p\right), \tag{11}$$

where c_e (the effective system compressibility) is given by

$$c_e = \frac{c_b}{\phi} + c_f. \tag{12}$$

Most, if not all, previous workers in this area seem to have assumed that the compressibility of the fluid in the pore space is negligible compared with that of the rock, in which case $c_e = c_b/\phi$. However, we shall see that this is not necessarily the case. At pressures and temperatures (200°C, 100 MPa) typical of these overpressured compartments, pure water has a compressibility of 2×10^{-10} Pa^{-1} [*Perry et al.*, 1997], while most sedimentary rocks have a bulk compressibility between 10^{-9} and 10^{-11} Pa^{-1} [*Ge and Garven*, 1992] and a porosity between 5 and 20%. Clearly, water is much less compressible than rocks at the upper end of this range (typically shales); however, it has the same order of magnitude compressibility as rocks at the lower end of the range (typically consolidated sandstones). Oil and gas are significantly more compressible than water; furthermore, in some circumstances, such as the geological

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sequestration of carbon dioxide, formation water may have sufficient volumes of gases dissolved in it that its compressibility also becomes significant.

[16] Equation (12) is the general equation describing pressure dissipation within a porous media. It can be seen that it is a nonlinear diffusion equation as, in principle, the fluid and rock compressibility, fluid viscosity, and porosity may all change with pressure. Here we solve this equation analytically by making the following simplifying assumptions:

[17] 1. Flow is single phase.

[18] 2. Flow is one-dimensional.

[19] 3. The compressibility of the mineral rock is negligible.

[20] 4. The fluid is slightly compressible (not gas), i.e., the compressibility does not vary significantly with pressure.

[21] 5. Rock properties (bulk compressibility, permeability, porosity, compartment and barrier thickness) only vary slowly with pressure.

[22] 6. There are no sources or sinks (e.g., active charge of hydrocarbon or pressure depletion from adjacent communicating compartments, hydrocarbon production from the compartment).

[23] 7. The composition of the fluid does not change with position and the system is isothermal. This means that mass transfer via osmosis can be ignored and that density and viscosity do not change with position. It also means that fluid flow via convection is ignored.

[24] In this case, equation (12) becomes a linear diffusion equation, and we can then take advantage of the large literature describing the solution of the transient heat conduction or diffusion equations for a range of boundary conditions, most of which is summarized by *Carslaw and Jaeger* [1959]. It should be noted that these analytic solutions are unlikely to be quantitatively accurate when describing large pressure drops in systems containing gas and/or large quantities of shale, both of which have pressure-dependent compressibilities.

[25] We examine three simple models and compare their behavior with a simple base case model. The base case model consists of a rectangular reservoir compartment completely sealed on all sides by zero permeability rock. One half of the compartment is initially at pressure P_1 (Pa) and the other initially at pressure P_2 (Pa) (Figure 3). We compare the timescales for pressure equilibration within this base case model with model 1, which consists a compartment made up of a single homogeneous sand, in which pressure is dissipated only by flow through the barriers at top and bottom (the model investigated by *Luo and Vasseur* [1997] and *Muggeridge et al.* [2005]); model 2, which consists of a compartment containing a single homogeneous sand, in which pressure is dissipated only by flow through low-permeability barriers at the edges, with negligible flow through the top and bottom seals; and model 3, which consists of a megacompartment complex made up of alternating layers of homogeneous higher-permeability rock and lower-permeability barriers, in which pressure is dissipated by vertical flow through the low-permeability barriers. These models are illustrated schematically in Figure 4.

[26] Models 1 and 2 allow us to determine the relative importance of pressure dissipation through the top and bottom of an isolated pressure compartment and the edges. Model 3 is used to investigate how the rate of pressure dissipation changes when compartments are grouped together and also to see how abnormal pressures change between compartments over time.

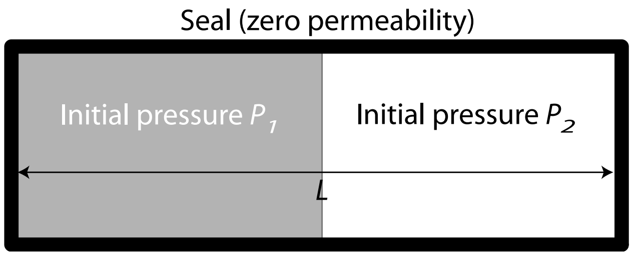

Figure 3. Schematic of base case model: A sealed compartment half at initial pressure P_1 and the other at initial pressure P_2.

3. Base Case

[27] This model represents a completely sealed, water-filled compartment and is used to examine how quickly pressure can equilibrate within a given compartment. One half of the compartment is initially at pressure P_1 Pa, and the other half is initially at pressure P_2 Pa (Figure 3). Using the equation given by *Carslaw and Jaeger* [1959. p. 101], the timescale for pressure to equilibrate is given approximately by

$$T_{\mathrm{base}} \approx \left[\ln\left(\frac{\pi}{2}\right) - \ln\left(\frac{\delta P}{\Delta P}\right)\right] \frac{L^2 \phi c_e \mu}{k\pi^2}, \tag{13}$$

where T_{base} is the time (seconds), δP is the pressure difference criterion that deems the system to be in equilibrium (Pa), $\Delta P = P_1 - P_2$ is the initial pressure difference (Pa), and L is the length of the compartment (m).

[28] If we assume that pressure equilibrium exists once $\delta P/\Delta P = 0.01$, then the time for pressure equilibration is more easily approximated by

$$T_{\mathrm{base}} \sim \frac{1}{2} \frac{L^2 \phi c_e \mu}{k}. \tag{14}$$

Thus, for a water-filled pressure compartment 10 km long, using the properties given in Table 1, the time for pressure equilibration is ~5 years. Clearly, pressure equilibrates very quickly in high-permeability sands. Indeed, the time taken for pressure to equilibrate across a typical compartment thickness of 100 m is less than 5 hours, so hydrostatic equilibrium is established almost instantly in such units compared with typical geological timescales. We shall assume this is the case in the following analyses.

4. Model 1: Leakage Through Top and Bottom Barriers

[29] This model (see Figure 4a) represents a single pressure compartment that is laterally extensive and completely sealed at the edges. The top and bottom of the compartment are formed by relatively thin barriers of low-

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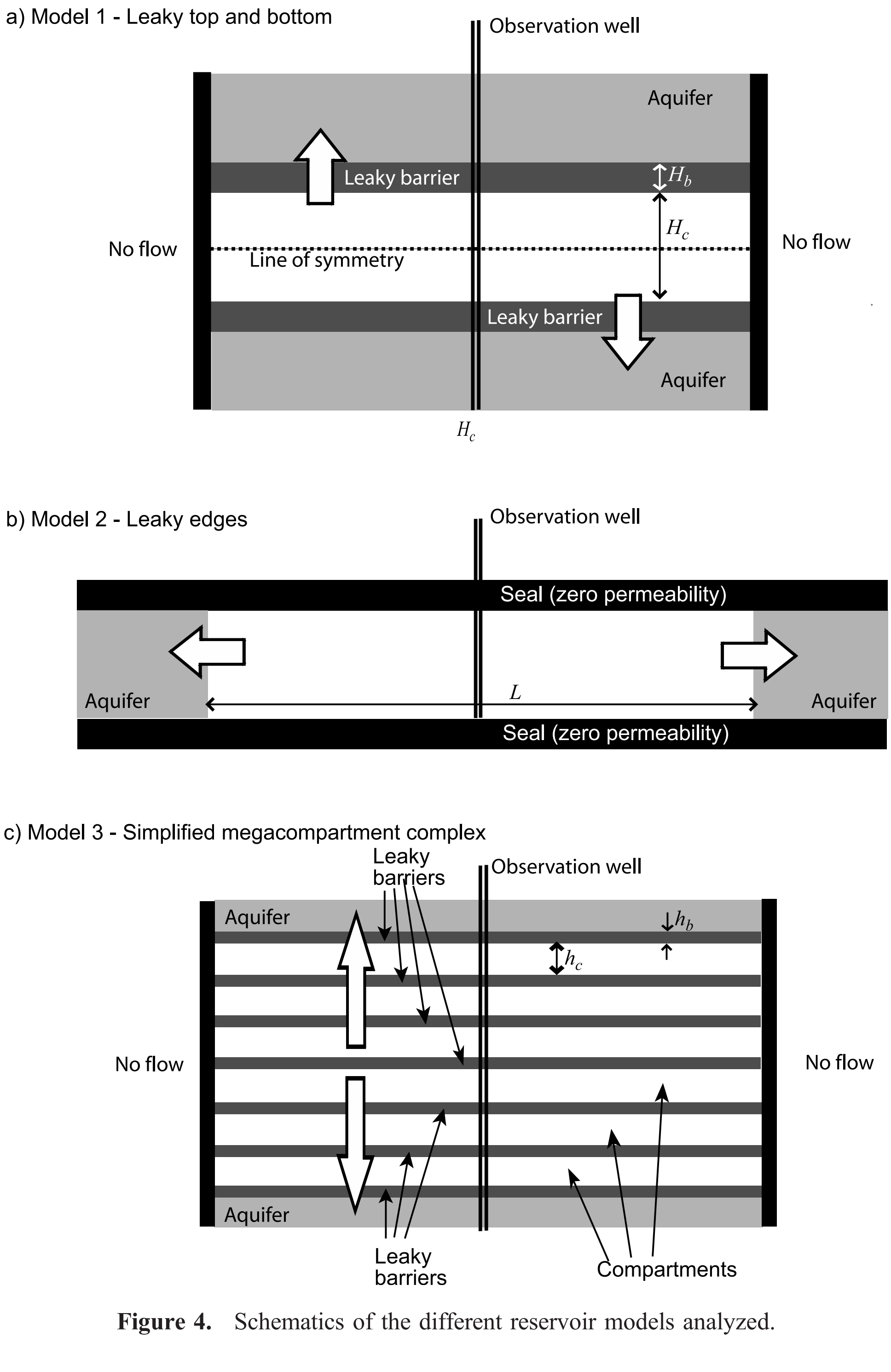

Figure 4. Schematics of the different reservoir models analyzed.

permeability rock. These low-permeability barriers are also laterally continuous. They may consist of low-permeability shale, a series of diagenetic bands of low permeability [see, e.g., *Qin and Ortoleva*, 1994], a tight limestone, or other very low permeability rock. The pressure compartment itself consists of a layer of homogeneous and relatively high permeability rock. Thus pressure dissipation is only through the top and bottom barriers.

[30] The solution for pressure dissipation from this compartment model has already been obtained by *Luo and Vasseur* [1997] (see equation (3)). Figure 5 compares the predicted timescales for pressure dissipation in a typical reservoir compartment as a function of barrier permeability, using their model, with the timescales for pressure dissipation obtained when only the barrier properties are considered (the solution of *He and Corrigan* [1995] is chosen for this purpose as it is the most pessimistic of the different solutions in the literature (see *He and Corrigan* [1995] or *Muggeridge et al.* [2005] for further discussion)). This calculation used the compartment and fluid properties given in Table 2 and assumed a barrier a porosity of 5%. The range of barrier permeabilities investigated is consistent

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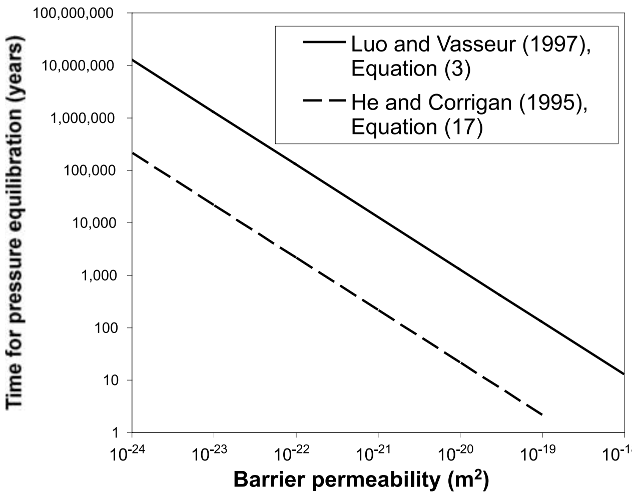

Figure 5. Time for pressure to dissipate from a reservoir compartment 150 m thick topped by a barrier 15 m thick (other properties given in Table 2) as a function of the barrier permeability. It can be seen that the timescale based purely on the properties of the barrier [*He and Corrigan*, 1995] is 2 orders of magnitude quicker than the solution including the compartment properties (equation (3)).

with those given in the literature [*Katsube et al.*, 1991; *Neuzil*, 1994; *Helton et al.*, 1997; *Schlömer and Krooss*, 1997; *Cosenza et al.*, 1999; *Kwon et al.*, 2001; *Boving and Grathwohl*, 2001; *Beauheim and Roberts*, 2002; *Lee and Deming*, 2002].

[31] It can be seen that it may take 10 Myr for pressure to dissipate completely from our model reservoir compartment if the barrier permeability is 10^{-24} m^2 (10^{-12} darcies). This is 2 orders of magnitude longer than we would predict if we only considered the barrier properties. However, this permeability is very much at the lower end of barrier permeabilities; furthermore, some abnormally pressured compartments are believed to have existed for tens or hundreds of millions of years. Thus, although the solution of *Luo and Vasseur* [1997] shows that pressure may dissipate much more slowly than originally thought from reservoir-scale compartments surrounded by relatively thin barriers, it does not explain how abnormal pressures can exist in such compartments over geological timescales.

5. Model 2: Leaky Edges

[32] Having examined the rate of pressure equilibration through top and bottom barriers of a water-filled compartment, we shall now examine the rate of pressure dissipation when we allow fluid flow through the edges of the compartment.

5.1. No Barrier at Edges

[33] In this model the compartment is sealed top and bottom but is in communication with a constant pressure aquifer at the compartment edges (see Figure 4b). Flow is thus 1-D, from the center of the compartment to the edge and is not affected by gravity. The middle of the compartment is penetrated by a vertical observation well at a distance $L/2$ from the edges of the compartment. The compartment has a constant thickness H_c (m) and an effective compressibility of c_c^e (Pa^{-1}). The compartment rock has a permeability k_c (m^2) and a porosity ϕ_c. The pressure in the aquifer is always P_H (Pa).

[34] For a rectangular reservoir compartment that only leaks fluid through two opposite sides (see Figure 6b) the

Table 2. Reservoir Rock and Fluid Properties Used in the Calculation of Timescales for Pressure Dissipation Through the Edges of an Abnormally Pressured Compartment[a]

	Base Case Value	Sensitivities
Compartment permeability, m^2 (millidarcies)	10^{-13} (100)	10^{-15} (1) 10^{-14} (10) 10^{-13} (100)
Compartment porosity, fraction	0.2	
Shale thickness, m (feet)	15 (50)	
Compartment thickness, m (feet)	152 (500)	
Shale length, m (feet)	1520 (5000)	1,520 (5,000) 3,050 (10,000) 6,100 (20,000) 12,200 (40,000)
Gap length, m (feet)	30 (100)	0.03 (0.1) 0.3 (1) 3 (10) 30 (100) 300 (1000)
Gap permeability, m^2 (millidarcies)	5×10^{-14} (50)	1×10^{-17} (0.01) 1×10^{-16} (0.1) 1×10^{-15} (1) 1×10^{-14} (10) 1×10^{-13} (100)
P_I, MPa (psi)	28.4 (4100)	
P_0, MPa (psi)	27.6 (4000)	
δP, Pa (psi)	6920 (1)	
Fluid compressibility, Pa^{-1} (psi^{-1})	5×10^{-10} (3×10^{-6})	
Fluid viscosity, N s m^{-2}	0.8×10^{-3}	
Formation compressibility, Pa^{-1} (psi^{-1})	5.8×10^{-10} (4×10^{-6})	

[a]Model 2, see Figure 4b.

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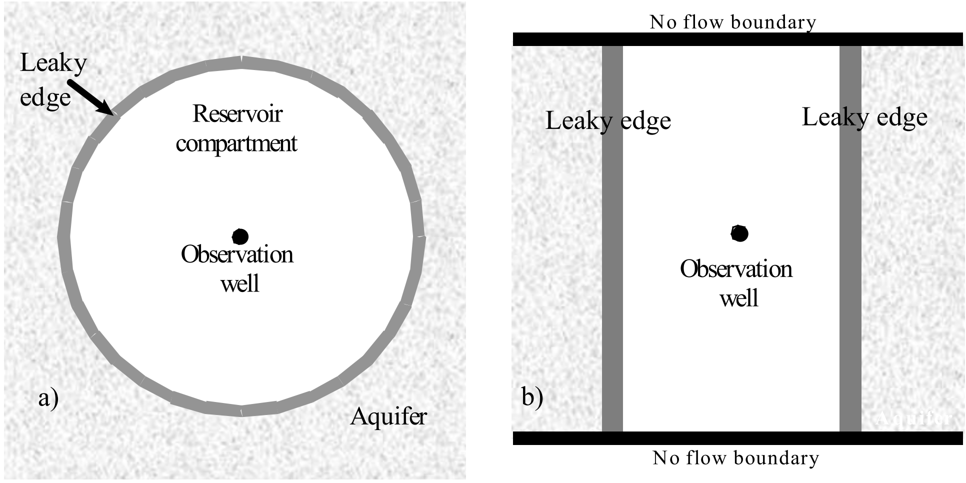

Figure 6. Areal view of reservoir compartment with leaky edges for (a) circular geometry and (b) linear geometry.

pressure behavior at the observation well versus time is given by *Carslaw and Jaeger* [1959, p. 100]:

$$\frac{p - P_H}{P_I - P_H} = 1 - \frac{4}{\pi}\sum_{n=0}^{\infty}\frac{(-1)^n}{2n+1}\exp\left[-\frac{(2n+1)^2\pi^2 t}{4}\right], \qquad (15)$$

where p is the pressure at the observation well as a function of time (Pa), P_H is the hydrostatic (final) pressure within the compartment (Pa), and P_I is the initial pressure in the compartment (Pa). For a circular compartment that leaks fluid around its circumference (see Figure 6a) the pressure behavior versus time at the observation well is given by [see *Carslaw and Jaeger*, 1959, p. 199]

$$\frac{p - P_H}{P_I - P_H} = 1 - 2\sum_{n=1}^{\infty} e^{-\beta_n^2 t}\frac{J_0(0)}{\beta_n J_1(\beta_n)}, \qquad (16)$$

where $t = Tk_c/4L^2 c_c^e \phi_c \mu$, J_0 and J_1 are Bessel functions, and β_n are the roots of $J_0(\beta_n) = 0$.

[35] In both cases, for all but early time we can ignore all terms in the summations except the first and we get a time for pressure equilibration of

$$T_{2R} \sim -\frac{1}{\pi^2}\frac{L^2 c_c^e \phi_c \mu}{k_c}\ln\left\{\frac{\pi}{4}\frac{(p - P_H)}{(P_I - P_H)}\right\} \qquad (17)$$

for the rectangular compartment and a time of

$$T_{2C} \sim -\frac{1}{5.8}\frac{4L^2 c_c^e \phi_c \mu}{k_c}\ln\left\{0.625\frac{(p - P_H)}{(P_I - P_H)}\right\} \qquad (18)$$

for the circular compartment. Both solutions are almost identical to our base case solution (equation (13)) with small differences (less than an order of magnitude) in the constants. Hereafter we shall only consider the behavior of a rectangular compartment. The solution for the rectangular compartment is also the solution proposed by *He and Corrigan* [1995] to model the rate of pressure dissipation from a low-permeability barrier (replace $L/2$ by the barrier thickness H_b and use barrier values for compressibility, porosity and permeability).

[36] We investigated the implications of our analysis for pressure dissipation in a rectangular model pressure compartment whose properties were typical of those encountered in a hydrocarbon reservoir. The purpose of this investigation was to determine the timescales for pressure equilibration for an overpressured or underpressured reservoir compartment adjacent to other normally pressured compartments and the influence of the compartment properties on these timescales. We compared the predictions of our analytic solution (equation (17)) with those obtained using a reservoir simulator [*Killough et al.*, 1997]. The reservoir simulator was used to check that the assumptions used to derive the mathematical model were reasonable (for example, was it reasonable to neglect vertical flows in determining the timescales for pressure equilibration in this model?).

[37] A schematic of the model pressure compartment is illustrated in Figure 7. It represents a single reservoir compartment 3050 m long and 150 m thick, separated from an underlying aquifer by a laterally extensive shale. The shale itself was sealing, but there were gaps at either end of the shale through which fluid could leak from the overpressured reservoir into the aquifer to equalize pressures. All

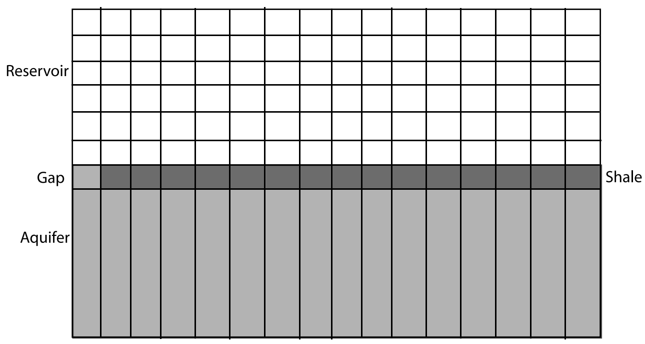

Figure 7. Schematic of simulation model used to validate the time to pressure equilibration in a reservoir compartment with leaky edges (equations (8) and (9), model 1).

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the other compartment boundaries are completely sealing. The compartment thickness (H_c) was much less than the distance from the observation well to the gap (L/2) so that the time taken for pressure to equilibrate vertically in the compartment was much less than the time taken for pressure to equilibrate horizontally. This ensured that the pressure distribution within the compartment was essentially 1-D along the compartment from the observation well to the compartment edge. In this case, equation (17) is valid.

[38] An x-y model was used in the simulation to eliminate the need to correct pressure to a reference depth, thus simplifying the interpretation of the results. The simulation model consisted of 102 grid blocks (including 1 grid block for each gap) in the x direction and 12 grid blocks in the y direction. Both shale and aquifer were modeled with 1 grid block in the y direction, while the sand had 10 grid blocks in this direction. The constant pressure beneath the shale was achieved by giving the "aquifer" grid blocks a large pore volume.

[39] The main simplification compared with a real reservoir compartment was that the compartment was filled completely with one fluid of negligible compressibility. In reality, of course, it may contain oil, water, and gas. In this case, multiphase flow effects would complicate the analysis. The fluid compressibility may also become an issue (see section 7). The properties and the sensitivities investigated are summarized in Table 2. The initial level of overpressure in the compartment is quite small (100 psi, or 690 kPa); however, inspection of equation (17) shows that it is only a function of the relative pressure drop. Pressure was said to have equilibrated when there was a remaining overpressure of 1 psi (6.9 kPa), which is equivalent to the resolution of a pressure log.

[40] Figure 8 compares the timescales for pressure equilibration predicted by equation (17) with those predicted by the reservoir simulator as a function of shale half length and compartment permeability. It can be seen that abnormal pressures will dissipate through a compartment's edges very quickly. Over (or under) pressures could not be maintained in such a leaky compartment over geological timescales (~1 Myr). Even over basin-scale distances of order 100 km, the time constant for pressure equilibration, from equation (17), is 1200 years, assuming a 152 m gap and a compartment permeability of 10^{-13} m^2 (100 mdarcy). These results show that a pressure compartment must have a barrier or seal at the edges as well as at the top and bottom if abnormal pressures are to persist over periods of 1 Myr or more.

5.2. Low-Permeability Barrier at Edges

[41] In this section we consider the situation when the compartment's edges are bounded by lower-permeability barriers, e.g., a leaky fault. These low-permeability barriers have a width H_b (m) and a permeability k_b (m^2). As before, the initial pressure in the compartment is P_I (Pa). Again, we shall assume that pressure equilibrates instantly across the thickness of the compartment so again flow is 1-D along the compartment. In this case the time for the pressure in the rectangular compartment to equilibrate with the aquifer is given by

$$T_1 = -\frac{1}{\alpha_1^2}\frac{L^2\mu c_c^e\phi_c}{4k_c}\ln\left\{\frac{\delta P}{P_I - P_H}\frac{R(R+1)+\alpha_1^2}{2R\sec\alpha_1}\right\}, \qquad (19)$$

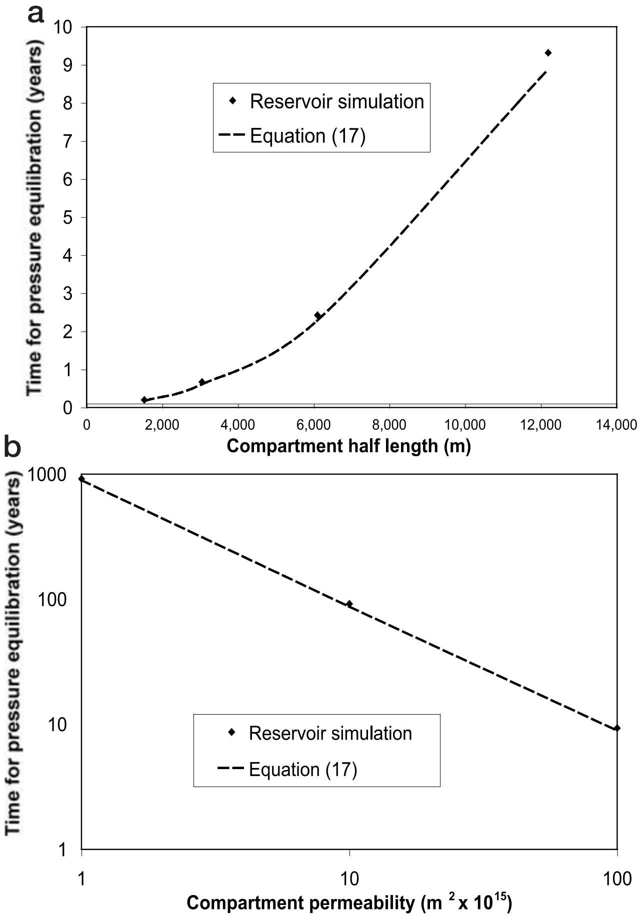

Figure 8. Timescales for pressure dissipation through the edges of an abnormally pressured compartment (model 1) predicted by analytical solution (equation (17)) and reservoir simulation, showing the influence of (top) shale half length and (bottom) compartment permeability on time for pressure to equilibrate.

where α_1 is the first root of the transcendental function

$$\alpha_1 \tan\alpha_1 = R$$

and $R = k_bL/2k_cH_b$. This solution is derived from that given by *Carslaw and Jaeger* [1959, p122, equation (12)], for large times.

[42] Physically, R is the ratio of flow rate leaving the compartment to the flow rate within the compartment away from the observation well. Thus the solution can be further adapted to the case where either (1) the compartment's thickness varies with distance from the observation well, i.e., its thickness at the observation well is different from that at its edges (Figure 9a) or (2) the barrier at the edge is sealing except for a small gap of low permeability (as may be the case with a leaky fault, Figure 9b). In this case the ratio of the flow rate leaving the compartment to that within the compartment is also controlled by the ratio l/H_c, where the thickness of the compartment (size of the gap in a sealing fault) at the edges is l (m) and its mean thickness is H_c (m) (Figure 9). The ratio R is now defined by $R = k_bLl/2k_cH_bH_c$.

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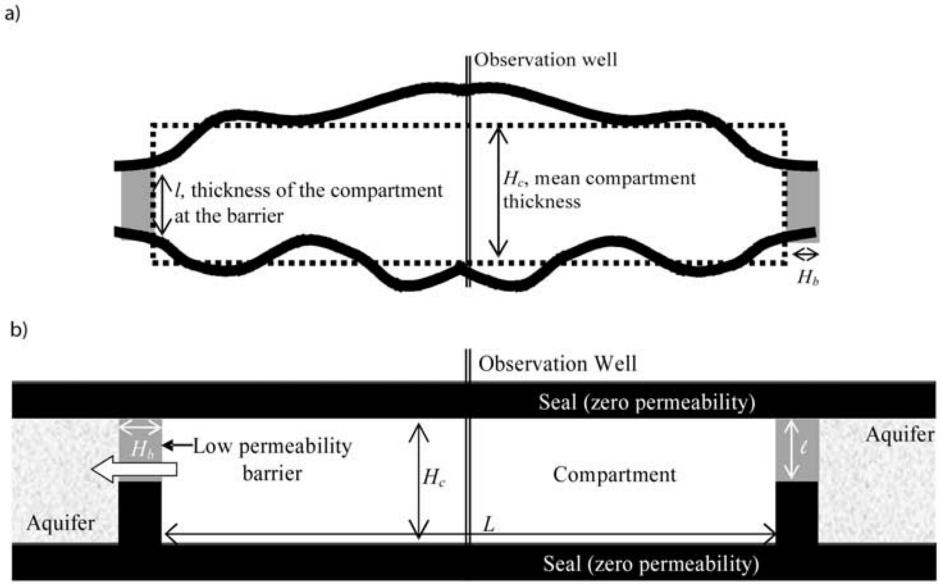

Figure 9. Schematic diagrams of abnormally pressured compartment with sealing top and bottom barriers and low-permeability barriers at the edges. (a) Compartment thickness, which varies with distance from the observation well. That is, its thickness at the observation well is different from that at its edges. (b) Barrier at the edge, which is sealing except for a small gap of low permeability (as may be the case with a leaky fault).

[43] The following assumptions underlie this solution:

[44] 1. The barriers are thin compared with the thickness of the compartment (i.e., $H_b \ll H_c$), so the pressure gradient across them is approximately linear and their storativity is negligible compared with that of the compartment

[45] 2. The thickness of the compartment is very much less than its length (i.e., $H_c \ll L$, so the system is approximately 1-D)

[46] 3. The thickness of the compartment at the edge is smaller than the length of the compartment (i.e., $l \ll L$)

[47] Figure 10 compares the predictions of our analytic solution for a compartment bounded by a low-permeability barrier (equation (19)) with those obtained for the case when there is no barrier at the edges (equation (17)) and also using a reservoir simulator [*Killough et al.*, 1997] as a function of compartment thickness at the edge (l) and barrier permeability. Again, the sensitivities investigated are shown in Table 2. There is excellent agreement between equation (19) and the simulator for all cases, but as might be expected, equation (17) is only accurate when the barrier permeability is equal to that of the compartment and the compartment edge thickness is greater than or equal to the mean compartment thickness.

[48] It can be seen from Figure 10 that pressure dissipates from the compartment in less than 100 years even when the width of the gap l is reduced to 1 cm. The compartment needs to be bounded at the edge by a low-permeability barrier in order for abnormal pressures to exist over longer periods of time. In this case a 30 m barrier, 15 m thick would need to have a permeability of the order of 1 ndarcy (10^{-21} m^2) in order to maintain anomalous pressures in the compartment over a period of 1 Myr. This permeability is well within the range of measurements for caprock permeability [*Katsube et al.*, 1991; *Neuzil*, 1994; *Helton et al.*, 1997; *Schlömer and Krooss*, 1997; *Cosenza et al.*, 1999; *Kwon et al.*, 2001; *Boving and Grathwohl*, 2001; *Beauheim and Roberts*, 2002; *Lee and Deming*, 2002] but at the lower end of measured values for fault permeability [*Matthai and Roberts*, 1996; *Ngwenya et al.*, 2000; *Fisher and Knipe*, 2001; *Shipton et al.*, 2002; *Harris et al.*, 2002; *Forster et al.*, 2003; *Ngwenya et al.*, 2003; *Takahashi*, 2003]. Moreover, it assumes that the barriers at the top and bottom of the compartment are completely sealing. We have already seen in section 4 that pressure will dissipate from this compartment through top and bottom barriers of permeability 10^{-21} m^2 in approximately 100,000 years (Figure 5). Thus it appears that the properties of barriers at the edge of a compartment may have as great an influence on rates of pressure dissipation as the top and bottom barriers. This is principally due to the fact that they are typically much thinner (~10 m) than the top and bottom barriers.

6. Model 3: A Simplified Megacompartment Complex

[49] This model is a simplified representation of a series of stacked, abnormally pressured compartments, separated by thin low-permeability barriers. The megacompartment complex consists of $2n$ compartments (see Figure 4c) interleaved between $2n + 1$ barriers. Each compartment is h_c (m) thick and each barrier is h_b (m) thick. Hence the total thickness of the system is $2n(h_c + h_b) + h_b$. The topmost and the lowermost barriers are in contact with a system that is at hydrostatic pressure at all times. As in the single-compartment model (model 1) the pressure in each compartment varies with time but is constant across its thickness. We assume each barrier is sufficiently thin that the effect of its storage capacity on the rate of

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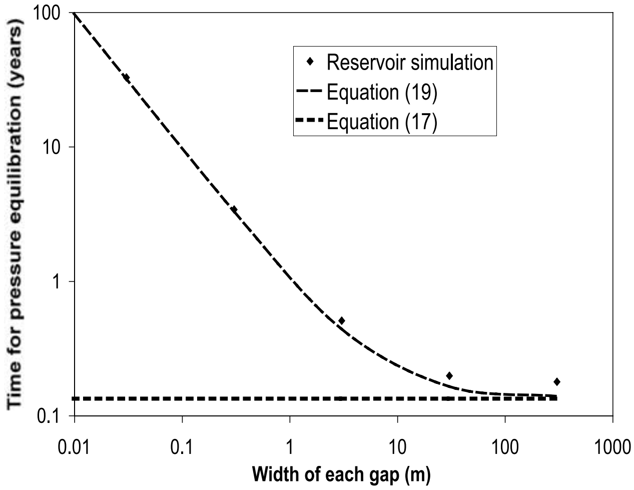

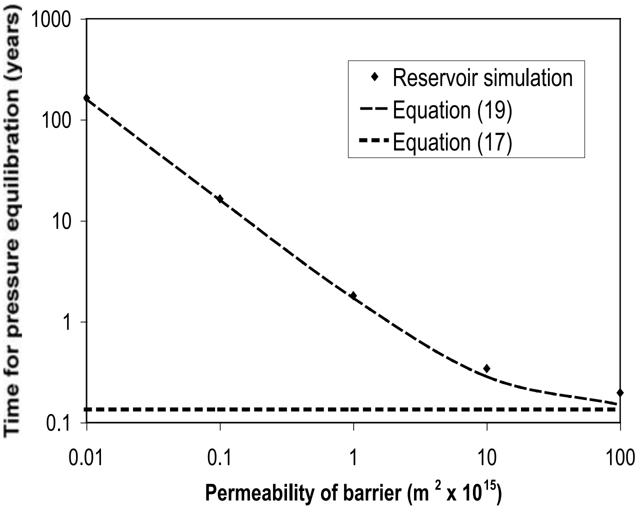

Figure 10. The timescales for pressure dissipation through the edges of an abnormally pressured compartment (model 2) predicted by analytical solutions and reservoir simulation, showing the influence of (top) gap width and (bottom) barrier permeability on time to pressure equilibration. It can be seen that there is excellent agreement between equation (19) (which models the properties of the gap) and reservoir simulation. In contrast, equation (17) (which assumes gap properties are the same as those of the compartment) is increasingly inaccurate.

pressure dissipation is negligible. There is thus a linear pressure drop across each barrier.

[50] In this case the timescale for pressure equilibration is given approximately by

$$T_3 \approx -\frac{4}{\pi^2}\frac{n^2 h_c h_b \phi_c c_c^e \mu}{k_b}\ln\left(\frac{\pi}{4}\frac{\delta P}{P_I - P_H}\right). \quad (20)$$

The derivation of equation (20) is summarized in Appendix A.

[51] Alternatively, we can treat such a megacompartment as a homogeneous volume with an effective vertical permeability (K_{eff}) given by the harmonic mean of the individual compartment and barrier permeabilities:

$$\frac{n(h_c + h_b)}{K_{\mathrm{eff}}} = n\left(\frac{h_c}{k_c} + \frac{h_b}{k_b}\right).$$

If the barriers have a very much lower permeability than the compartments, then we can write

$$K_{\mathrm{eff}} \approx \frac{(h_c + h_b)}{h_b} k_b. \quad (21)$$

Substituting this permeability into equation (17), we get a timescale for pressure equilibration of

$$T_3 \approx \left\{\ln\left[\frac{\pi}{4}\frac{\delta P}{(P_I - P_H)}\right]\right\}\frac{4n^2(h_c + h_b)h_b\phi c_b^e \mu}{k_b \pi^2}. \quad (22)$$

If $h_c \gg h_b$, this reduces to equation (20).

[52] We can use our multiple-layer solution to compare the behavior of a simple supercompartment (model 1) with that formed of multiple stacked compartments separated by thin barriers (>10) (a simplified megacompartment complex). Obviously, the two compartments have the same total thickness, $H_c + H_b = n(h_c + h_b)$. Following the derivation given in Appendix B, we find that the ratio of the timescale for pressure dissipation from our megacompartment (model 3) to that from a single compartment (model 1) is

$$\frac{T_3}{T_1} \approx \frac{4}{\pi^2} n\mathrm{NTG} \quad (23)$$

assuming that the net to gross (NTG, the ratio of compartment thickness to the total thickness of compartment and barrier) is close to 1 (approximately greater than 0.9).

[53] It can be seen that the effect of multiple thin barriers within an overpressured basin is to increase the time for pressure to dissipate. The timescale is linearly dependent on the number of layers. We can also compare our estimate for the timescale for pressure equilibration in a stack of compartments with equation (17) (the formula proposed by *He and Corrigan* [1995]) to estimate the timescale for pressures to equilibration across a barrier of thickness h_b). In this case we get

$$\frac{T_3}{T_1} \approx \frac{n^2 h_c \phi_c c_c^e}{h_b \phi_b c_b^e}. \quad (24)$$

Thus the actual timescale for pressure equilibration in a megacompartment complex ($n \gg 1$) with a high net to gross ($h_c \gg h_b$) is likely to be at least 3 orders of magnitude greater than that predicted by equation (17) for high net-to-gross environments. It increases as the square of the number of layers and the ratio of the average compartment thickness to the thickness of the barrier.

[54] Figure 11 shows the pressure profiles with depth predicted for the stacked compartment model after 250 Myr when (1) the compartments are represented explicitly and (2) the compartments are represented by a thick homogeneous layer with an effective permeability calculated from the compartment and barrier permeabilities. We have used the pressures calculated from equation (A4) and added these onto the hydrostatic pressure gradient to give the overall pressure profile. These calculated values are superimposed upon data measured in the Anadarko Basin and given by *Lee and Deming* [2002]. The parameters used to obtain

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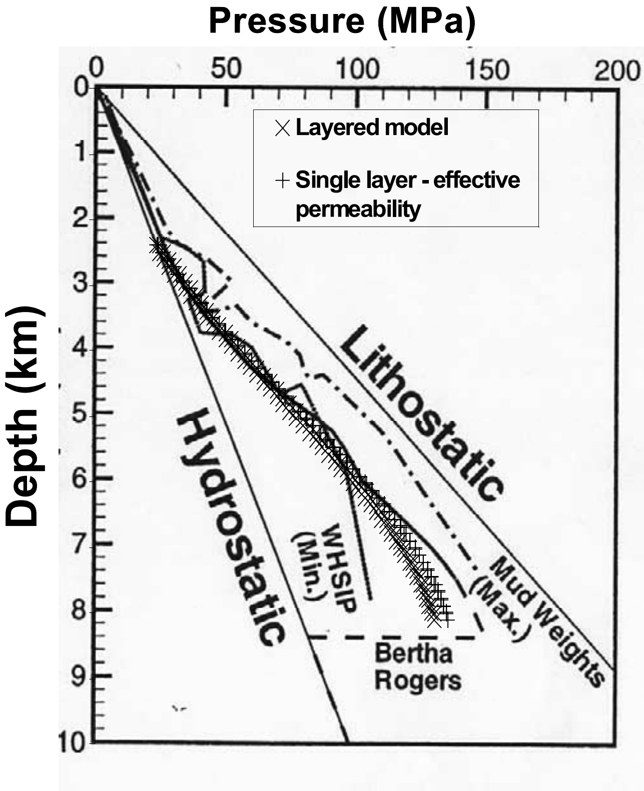

Figure 11. Comparison of pressure profile predicted by multiple-layer model after 250 Myr of pressure dissipation with that obtained using analytic solutions for a single layer and an effective permeability. The data are superimposed on pressure profiles measured in the Anadarko Basin and published by *Lee and Deming* [2002].

these profiles are given in Table 3. The compartment porosity, effective compressibility, fluid viscosity, and barrier permeability are all taken from the values for the Anadarko Basin, first published by *Lee and Deming* [2002] as is the proportion of barrier to sand (10%). The average thickness of each compartment is assumed to be 100 m, so the average thickness of the barriers is 10 m. The compartment thickness was based upon data of *Al-Shaieb et al.* [1994b]. They observe that the Anadarko Basin contains three distinct levels of compartments. Level 1 is the overall megacompartment complex. Level 2 compartments consist of field sized units between 122 and 183 m thick, and level 3 compartments consist of the individual reservoirs nested within the level 2 compartments. These units have thicknesses varying between 2 and 30 m thick.

[55] It can be seen that the stacked compartment/barrier model gives a reasonable match to the observed pressure behavior even though it is quite simplistic. Both predicted and observed overpressures increase with distance from the top and bottom barriers of the basin, suggesting that the abnormal pressure profile is transient. Of course, our model does not predict the exact pressure variation with depth at any given locality because real sedimentary basins are not formed of a uniform stack of compartments and barriers. Nor does it consider pressure dissipation through the edges of compartments. However, it demonstrates that a normal sedimentary sequence of compartments and barriers can delay the dissipation of abnormal pressures over hundreds of millions of years due to the combined effects of the storage capacity of the compartments and the low permeability of the barriers. In this example, barriers as thin as 10 m can retard the dissipation of abnormal pressures provided there are sufficient numbers of them, interleaved between thicker higher-permeability compartments.

7. Discussion: Hydrocarbon Reservoirs

[56] We have shown that abnormal pressures may take hundreds of millions of years to dissipate through thin, low-permeability barriers. Such barriers can slow the rate of pressure dissipation sufficiently provided we consider abnormal pressures on the basin-scale rather than in isolated reservoir-scale compartments. However, as well as making simplifying assumptions about the geology of abnormally pressured compartments, our models assume that the compartments are filled with a single, slightly compressible fluid. In reality, of course, the majority of abnormally pressured compartments are hydrocarbon reservoirs which contain at least two fluids (oil and/or gas as well as water). In these cases, it is possible that our analyses are no longer valid.

[57] We shall first consider a compartment containing oil and water, both of which are slightly compressible fluids (compressibility does not change significantly with pressure). We shall neglect the fact that gas dissolved in the oil may come out of solution as pressure decreases. Migrating oil has displaced the majority of the water from the reservoir over time and is trapped there by capillary pressure effects [*Baker*, 1959; *Schwolter*, 1979; *Tissot and Welte*, 1984]. The reservoir barriers have much smaller pores than the reservoir sand and remain filled with water. In a normally pressured reservoir it is typically assumed that the water has drained downward into an underlying aquifer which is in hydraulic communication with the surface. However, in the case of an overpressured reservoir, either the displaced water remains in the reservoir as a small aquifer at the base that is also trapped within the reservoir or it has left the reservoir (which suggests that at least initially there was flow out of the compartment). In both cases the larger pores in the compartment contains water in the form of films on the pore walls and trapped in crevices with connected oil filling the centre of the pore. The smaller pores in the compartment are still filled with water. This remaining, or connate, water saturation is usually of the order of 20%.

Table 3. Data Used to Calculate the Pressure Profile for a Series of Vertically Stacked Pressure Compartments and Compared With Those Observed in the Anadarko Basin in Figure 11

Parameter	Value
Number of layers	40
h_c, m	100
h_b, m	10
Compartment porosity ϕ_c	0.15
Effective compressibility c_{eff}, Pa^{-1}	10^{-9}
Barrier permeability k_b, m^2	10^{-23}
Effective permeability k_{eff}, m^2	1.1×10^{-22}
Time, years	250×10^6

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[58] For simplicity, we shall consider a reservoir compartment consisting solely of oil and connate water. At some point, since the compartment filled with oil, it has become abnormally pressured. Now the only mechanism by which pressure can dissipate is via fluid flow into (in the case of underpressured compartments) or out of (in the case of overpressured compartments) the compartment. Conventional wisdom suggests this is not possible as the oil is trapped (or there would not be a reservoir) and the connate water saturation in the reservoir is so low that the water does not form a continuous phase and hence cannot flow either.

[59] However, there is significant evidence that water saturation never decreases to the point where it cannot flow [*Morrow and Melrose*, 1991]. Although the pore walls of the larger pores may become partially oil-wet over time, there still exists a continuous water phase connecting the water-filled smaller pores via films and water-filled crevices in the surface of the larger oil-filled pores [*Dullien et al.*, 1986, 1989; *Tuller and Or*, 2001; *Laroche et al.*, 2004]. If this is true, then there is pressure continuity between the hydrocarbon reservoir and the overlying caprock through the water films. Any abnormal pressures will dissipate over time via the slow leakage of the water phase from the reservoir through the caprock.

[60] The effect of oil filling most of the compartment's pore space is twofold: (1) the permeability of the compartment to water flow is very much reduced and (2) its effective compressibility is increased because oil is relatively compressible compared with water and rock and will expand to fill the volume left as the water leaks away. We shall consider the effect of each of these changes to the compartment properties in turn.

7.1. Reduced Compartment Permeability to Water

[61] On the basis of the work of *Tuller and Or* [2001], a plausible value for the relative permeability of water at the typical water saturations found in hydrocarbon reservoirs is 10^{-6}. Hence the permeability of a 10^{-13} m^2 (100 mdarcy) sand to water flow is approximately 10^{-19} m^2. This is at the higher end of the measured range of top and bottom barrier permeabilities of 10^{-18} to 10^{-24} m^2 [*Katsube et al.*, 1991; *Neuzil*, 1994; *Helton et al.*, 1997; *Schlömer and Krooss*, 1997; *Cosenza et al.*, 1999; *Kwon et al.*, 2001; *Boving and Grathwohl*, 2001; *Beauheim and Roberts*, 2002; *Lee and Deming*, 2002]. Thus for top and bottom barriers it may be more appropriate to use equation (17), treating the compartment as a continuous thickness of low-permeability rock rather than a volume of higher-permeability rock surrounded by low-permeability barriers. In this case the timescale for pressure dissipation in the compartment (neglecting the compressibility effects discussed in the next section) will be increased from 1 year (see Figure 5, assuming a barrier permeability of 10^{-19} m^2) to 10 Myr (by extrapolation of Figure 8). If, however, the barrier permeability is 10^{-20} m^2 or less, then equation (3) will be valid and timescales for pressure dissipation will be unchanged from those given in Figure 5.

[62] A compartment permeability of 10^{-19} m^2 is similar to the lowest measured fault permeabilities [*Matthai and Roberts*, 1996; *Ngwenya et al.*, 2000; *Fisher and Knipe*, 2001; *Shipton et al.*, 2002; *Harris et al.*, 2002; *Forster et al.*, 2003; *Ngwenya et al.*, 2003; *Takahashi*, 2003]. Thus pressure dissipation via edge barriers from a compartment containing oil and water is best modeled with equation (17). For the model reservoir compartment described in Table 2, this value of compartment permeability results in a time for pressure equilibration of 10 Myr (again by extrapolation of Figure 8). Therefore the reduced permeability to water flow within the compartment may increase the timescales for pressure dissipation significantly, even when increased compressibility due to the presence of oil or gas is neglected.

7.2. Increased Effective Compressibility

[63] The effective compressibility of a formation containing both oil and water is given by

$$C_{\text{eff}} = c_w + \frac{c_o(1 - S_{wc}) + (c_b/\phi)}{S_{wc}}, \tag{25}$$

where c_o is the oil compressibility (Pa^{-1}), c_w is the water compressibility (Pa^{-1}), c_b is the bulk rock compressibility (Pa^{-1}), and S_{wc} is the connate (initial) water saturation (fraction). Expression (25) is similar to that used by petroleum engineers to estimate oil recovery via pressure depletion in an under saturated oil reservoir above the bubble point [*Dake*, 1978]. The oil compressibility term is obtained by assuming that the oil behaves like part of the rock matrix. It cannot flow and change the pore space available for water as it expands or contracts as pressure changes.

[64] Using a typical initial water saturation of 20%, a water compressibility of 2×10^{-10} Pa^{-1} (typical of pure water at 200°C and 100 MPa), an oil compressibility of 2.2×10^{-9} Pa^{-1}, a porosity of 15%, and a bulk rock compressibility of 10^{-10} Pa^{-1} (the compartment is typically less compressible than the barrier) gives an effective compressibility of $\sim 10^{-8}$ Pa^{-1}. This is an order of magnitude greater than the value used in our previous calculations, resulting in a factor of 10 increase in the time taken for pressure to dissipate from a single pressure compartment filled with oil and water whether via top and bottom barriers or through the edges, compared with the time taken for a compartment filled completely with water.

[65] We note, however, that we have assumed that the water saturation is approximately constant in equation (25), despite the fact that water is leaving the reservoir. This changing effective compressibility with time may invalidate our calculations as our analytic solutions to equation (11) are only valid if the effective compressibility c_e is approximately constant. Using our calculated value of effective compressibility in the definition of compressibility,

$$c = -\frac{\Delta V}{V}\frac{1}{\Delta P}, \tag{26}$$

where $\Delta V/V$ is the fractional change in volume for a change in pressure ΔP (Pa), we see that for a change in pressure of 50 MPa (the maximum overpressure currently observed in the Anadarko Basin, Figure 11) we obtain a fractional change in water volume of 0.5. Thus the effective compressibility calculated in equation (25) doubles as the connate water saturation changes from 0.2 to 0.1. Nevertheless, our calculations still provide an order of magnitude estimate for the timescales involved. Furthermore, this slow reduction in connate water saturation (20% to 10% in

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250 Myr) also supports the data of *Morrow and Melrose* [1991] that irreducible (i.e., immobile, because the water no longer forms a continuous phase in the pore space) water saturation rarely occurs in hydrocarbon reservoirs.

[66] We can apply the same analysis to gas reservoirs, again assuming that pressure equilibration occurs via water film flow [*Laroche et al.*, 2004]; however, it will be even more approximate in this case as gas compressibility is highly dependent on pressure. Nevertheless, we can still estimate order of magnitude timescales for pressure dissipation. Replacing the oil compressibility in equation (25) with a gas compressibility of 3×10^{-8} Pa^{-1}, we obtain an overall effective compressibility for the system of 10^{-7} Pa^{-1}. This is 2 orders of magnitude greater than the value used in our calculation of the timescales for pressure equilibration in an isolated compartment using equation (3) and shown in Figure 5. Thus a barrier of permeability 10^{-23} m^2 and 15 m thick may prevent abnormal pressures dissipating from a 150 m thick gas reservoir for tens of millions of years. Similarly, for the idealized megacompartment calculations illustrated in Figure 1, based on data in Table 3, the top and bottom barriers need only have a permeability of $\sim 10^{-21}$ m^2 for pressure to dissipate over a period of 250 Myr. This value is much closer to values typically measured in the laboratory for barriers [*Katsube et al.*, 1991; *Neuzil*, 1994; *Schlömer and Krooss*, 1997; *Kwon et al.*, 2001; *Lee and Deming*, 2002].

[67] In summary, our calculations show that overpressures can exist in oil-water (and gas-water) reservoirs over geological timescales without the need to invoke completely impermeable barriers or capillary sealing. The combined effect of the increased effective compressibility of the compartment and the reduced compartment permeability to fluid flow is to increase the timescales for pressure equilibration by several orders of magnitude. The water remaining in the reservoir after hydrocarbons have migrated into the compartment will flow through the reservoir caprock over a period of hundreds of millions of years until the pressures are equilibrated. In the process the remaining water saturation may decrease by a half, in our example from 20% to 10%.

8. Conclusions

[68] We have used simple analytic solutions to investigate the rate of pressure dissipation via Darcy flow in abnormally pressured compartments surrounded by thin low-permeability barriers. Although all the examples investigated considered are overpressured compartments, the analytic solutions are equally valid for underpressured systems as they are purely functions of the ratio of initial and final pressure differences.

[69] The timescales for pressure dissipation through relatively thin barriers, such as faults, at the compartment edges have been compared with those for pressure dissipation through top and bottom barriers. These analytic solutions show that there is no reason to invoke complete pressure sealing in order to explain the existence of anomalous pressures in hydrocarbon reservoirs or sedimentary basins over geological timescales (tens to hundreds of million years). Top and bottom barrier permeabilities as high as 10^{-19} m^2 combined with edge barrier permeabilities of 10^{-19} m^2 may sustain abnormal pressures as a result of the combined effects of (1) nested pressure compartments (a megacompartment complex, as defined by *Al-Shaieb et al.* [1994a, 1994b]) within a basin, (2) the low permeability to water flow in an oil-filled compartment, and (3) the high effective compressibility of hydrocarbon reservoirs in which the oil or gas is trapped by capillary forces but the connate water is free to move through films and crevices within the compartment rock pores.

[70] The analytic solutions predict timescales for pressure dissipation consistent with those generally accepted for the Anadarko Basin. Furthermore, the pressure profile with depth predicted by the analytic solution for a stacked sequence of compartments and barriers shows remarkable agreement with that observed in the Anadarko Basin. The analytic solutions also explain why pressure gradients within compartments may be hydrostatic even though the absolute pressure is greater than hydrostatic pressure and is slowly dissipating through the barriers around the compartment.

Appendix A: Analytic Solution for Stacked Compartments

[71] We consider a sedimentary system consisting of $2n$ compartments (as shown in Figure 4c) interleaved between $2n + 1$ barriers. Each compartment is h_c m thick and each barrier is h_b m thick. Hence the total thickness of the system is $2n(h_c + h_b) + h_b$. The topmost and the lowermost barriers are in contact with a normally pressured sedimentary system. The pressure in each compartment varies with time but is constant across the thickness of the compartment while we assume a linear pressure drop across each barrier. In other words, the storativity of each barrier is neglected.

[72] Now consider the ith compartment. The pressure versus time behavior in this compartment is characterized by the relationship

$$h_c \phi_c c_c \frac{dP_i}{dt} = \frac{k_b}{\mu} \frac{(P_i - P_{i-1})}{h_b} - \frac{k_b}{\mu} \frac{(P_{i+1} - P_i)}{h_b}, \qquad \text{(A1)}$$

which can be rewritten as

$$\frac{h_b h_c \phi_c c_c^e \mu}{k_b} \frac{dP_i}{dt} = (2P_i - P_{i-1} - P_{i+1}). \qquad \text{(A2)}$$

By analogy with finite difference representations of differential equations, this is approximately the same as

$$\frac{h_b h_c \phi_c c_c^e \mu}{k_b} \frac{\partial P_i}{\partial t} = \frac{\partial^2 P_i}{\partial i^2} \qquad \text{(A3)}$$

for large i. The boundary equations for this system are constant hydrostatic pressure at the top and bottom boundaries: $P_{(i=0)} = P_H$ and $P_{i=2n+1} = P_H$. As in the single compartment case the initial pressure in all the compartments is P_I. The solution to this equation and boundary conditions can be found on page 100, *Carslaw and Jaeger* [1959]. Rewritten in our terminology, this solution is

$$\frac{\delta P}{(P_I - P_H)} = \frac{4}{\pi} \sum_{m=0}^{\infty} \frac{(-1)^m}{2m+1} \exp\left[-(2m+1)^2 \pi^2 t/4\right] \cdot \cos \frac{(2m+1)\pi\{(i-n)/n\}}{2}, \qquad \text{(A4)}$$

where $t = k_b T/(n^2 h_c h_b \phi_c c_c^e \mu)$.

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[73] As we are interested in the late time solution at $i = n$ (the middle of the stack of compartments), we can concentrate on the $m = 0$ term of the summation. In this case the timescale for pressure equilibration is given by

$$T_3 = -\frac{4}{\pi^2}\frac{n^2 h_c h_b \phi_c c_c^e \mu}{k_b}\ln\left(\frac{\pi}{4}\frac{\delta P}{P_I - P_H}\right). \quad \text{(A5)}$$

Appendix B: Comparison With Single-Compartment Case

[74] Taking the ratio of equations (A5) and (3) and neglecting the pressure term, we get

$$\frac{T_3}{T_1} \approx \frac{4}{\pi^2}\frac{n^2 h_c h_b}{H_c H_b}. \quad \text{(B1)}$$

Now the total thickness, γ, of the single and multiple layer compartments is constant and given by

$$\gamma = H_c + H_b = n(h_c + h_b) \quad \text{(B2)}$$

(remember we need only consider half the system, by symmetry).

[75] Hence we can rewrite equation (B1) as

$$\frac{T_3}{T_1} \approx \frac{4}{\pi^2}\frac{n^2((\gamma/n) - h_b)h_b}{(\gamma - H_b)H_b}. \quad \text{(B3)}$$

Now $h_b = H_b$ so equation (B3) becomes

$$\frac{T_3}{T_1} \approx \frac{4}{\pi^2}\frac{n(\gamma - nh_b)}{(\gamma - H_b)}. \quad \text{(B4)}$$

If we assume that H_b is small compared with the overall compartment thickness, then we can write

$$\frac{T_3}{T_1} \approx \frac{4}{\pi^2}\frac{n(\gamma - nh_b)}{\gamma}, \quad \text{(B5)}$$

where $(\gamma - nh_b)/\gamma$ is the ratio of the total thickness of compartment to the total thickness of the system which in essence is the net-to-gross of the compartment.

[76] **Acknowledgments.** Part of this work was funded by BP Exploration. The manuscript has benefited from the thoughtful reviews by several individuals, and we thank them all for their time and effort.

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