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Geomechanical Analysis and Decision Analysis for Delta Pressure Operations in Gas Storage Reservoirs

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Abstract

One of the most cost-effective ways to increase deliverability and working gas capacity in gas storage reservoirs is to operate at higher pressure (increased delta pressure). A common practice in the U.S. and Canada has been to operate gas storage reservoirs at pressures less than or equal to original reservoir pressure due to concerns for caprok integrity, fracturing, faulting, and gas loss. However, original discovery pressures do not always represent the maximum short-term pressure capacity for the formation. In many instances the pressure can be safely increased by a substantial margin if the geomechanical behavior and stress conditions of the reservoir and overburden is well characterized. The economic viability of such operations can be evaluated through quantitative decision analysis, taking into account and balancing economic benefits, conversion costs, and any additional risk costs. This paper describes step-by-step processes to evaluate both the technical feasibility and the economic feasibility for delta presssure operations at gas storage reservoirs.

Introduction

Maximum safe operating pressures for a reservoir depend on several geomechanical factors, including in-situ stresses, stresses induced by local and global pressure changes in the reservoir, and the mechanical properties of the reservoir and overburden material. The typical practice in North America has been to operate gas storage reservoirs at levels at or below original reservoir pressure due to concerns about caprock integrity, fracturing, faulting, and gas loss. However, current approaches for choosing maximum operating pressure limits with respect to initial discovery pressure are often overly conservative. This leads to under-utilization of existing storage resources and consequent competitive restrictions on particular projects. In many instances the pressure in a gas storage reservoir can be safely increased if the geomechanical behavior of the reservoir and overburden is well characterized.

Figure 1 presents a summary of gas storage reservoir operating conditions compiled by the AGA in 1993. About 60% of reservoirs are operated at pressure less than or equal to discovery pressure, while about 40% of reservoirs are operated at very slight to moderate delta pressure conditions. The current application of delta pressure conditions at gas storage reservoirs is somewhat random, however, rather than based on local geomechanical conditions. For example, one appropriate geomechanical control on maximum safe operating pressure is the burial depth and *in situ* stress. Figure 2 presents a summary of the ratios of maximum operating pressures to depth, as reported by the AGA survey of gas storage operators in 1993. This graph is symbol-coded with respect to those reservoirs operating at delta pressure conditions (shown with squres) and those operated at normal pressure conditions (shown with diamonds).

Many of the reservoirs operating at normal pressure conditions are also operating at relatively low pressure magnitude relative to overburden stress, and are therefore good candidates for delta pressure operations. Simply increasing the operating pressure for these reservoirs to hydrostatic pressure levels would add about 700Bcf of working gas capacity to the 2700 Bcf working gas capacity total for those reservoirs included in the AGA survey.

Geomechanical Analysis Process

Two basic geomechanical processes limit maximum operating pressures in gas storage reservoirs. They are: the tensile fracture pressure for the reservoir; and the stresses at which faulting or mechanical damage may be induced in the reservoir or caprock and overburden formations.

Figure 3 presents a step-by-step process to assess the technical feasibility of delta pressure operations at any gas storage reservoir. The basic process involves estimating the current rock strength and reservoir stress values with the best available data, calculating induced stresses due to pressure cycling, and then comparing the induced stresses to the estimated limiting strength and stress values. The most accurate estimation techniques for the mechanical properties and stress are those encountered first in the diagram (towards the left).

The specific steps taken for a field will depend on the available data and the desired solution accuracy. These design steps may be summarized as follows:

1. Determine the mechanical properties of the reservoir and caprock;
2. Determine the *in situ* stresses and reservoir fracture pressures;
3. Evaluate fracture pressure variations with position and with reservoir pressure;
4. Evaluate caprock stresses induced by pressure cycling with geomechanical modeling;
5. Compare stresses induced by pressure cycling with estimated strength properties and with estimated *in situ* stresses and reservoir fracture pressure; and,
6. If they are the same order of magnitude, then more detailed analyses and field verification are recommended.

The first stage in such an assessment is to characterize the geomechanical properties of the reservoir and overburden based on the best available data. The second stage in assessing delta pressure potential is to analyze stresses induced by gas storage operations in the caprock and overburden with geomechanical models.

<u>Determining Material Properties</u>

The most accurate estimation techniques for mechanical properties and stress are those encountered first in the process diagram (towards the left) shown in Figure 3. Rock stiffness and strength properties should ideally be measured in the laboratory on core samples and reservoir stresses should ideally be measured at several locations in the field with hydraulic fracture tests. However, because in many cases there is little core data or direct stress measurement data available, initial assessments often tend to rely on estimates of mechanical properties and reservoir stresses derived from correlations from other fields of similar lithology and depth.

When core measurements are not available for reservoir formation material, stiffness and strength properties must be estimated from available geophysical log data and lithology correlations from the literature. Rock stiffness properties are primarily determined from acoustic logs; and it is best when both compressional velocity and shear velocity data is recorded and they can be calibrated against core data. Empirical correlations are then used to relate rock strength properties to the stiffness properties or velocities, often with additional clay content and/or porosity dependencies. A few empirical correlations are available in the literature to estimate compressive or shear strength from rock stiffness values (see for example, Tixier et al, 1973; Coates and Denoo, 1981; Gatens et al, 1990; Schlumberger, 1987; Vernick et. al, 1993), but it is important to use correlations for materials of similar lithology. Because of the inherent large uncertainty in these properties, the analysis results (which scale with stiffness properties) are only qualitative in nature, and should be recognized as order of magnitude type estimates.

Determining In-Situ Stress

The preferred technique to determine *in situ* stresses is through hydraulic fracture stress measurements (see for example, Haimson, 1993). If hydraulic fracture measurements are not available, then the analyst should review any available leak-off and borehole breakout data. Extended leak-off test data, if carefully measured, can often be used to provide reasonable estimates of minimum stress values (Kunze and Steiger, 1992). Another useful stress estimation technique is measurement and analysis of borehole breakouts from vertical wells to provide stress directions (Plumb and Hickman, 1985; Zoback et al, 1985), and from deviated wellbores to constrain stress magnitudes (Aadnoy, 1990; Peska and Zoback, 1995).

The final option is to review regional stress data and lithology/depth correlations for the area. Extensive work has been done in measuring and tabulating stress fields worldwide (Zoback et al, 1989). To a great extent, the global orientation of stress patterns and their relative magnitudes are consistent with the directions of tectonic forces that are acting at present. Although map consulting is a necessary step in the process, reliance on regional stress maps should be restricted to reservoirs in areas that are not heavily folded or faulted, or where local impacts such as local hydrothermalism, salt domes, local vulcanism, and so on, have not acted.

Analyzing Stresses Induced by Pressure Cycling

Pressure cycling in a gas storage reservoir modifies the reservoir volume both vertically and laterally, and this causes flexure in the overburden, expansion of the reservoir rock relative to the rock around it, and other effects. Normal and shear stresses are altered, and this affects the stress conditions along natural discontinuities or planes of weakness, such as bedding planes and joints. During pressurization, lateral stresses increase adjacent to the reservoir formation, but decrease above and below, giving rise to shear stresses at the interface. During pressure depletion the opposite occurs.

To evaluate stresses in the reservoir and caprock induced by gas pressure cycling, a geomechanical model needs to be assembled for the field. This model is then used to investigate reservoir caprock interface shear and horizontal stresses arising from lateral expansion and contraction of the gas storage zone. Isopach and structure data is used to define the geometry of the model. Input data for the model can be collected from a hydraulic fracture report, stress constraint studies based on borehole breakout of the region, and estimates of elastic modulus and strength properties from the literature.

Stresses induced by pressure cycling in gas storage reservoirs may be estimated by applying the nucleus of strain concept from continuum mechanics, described by B. Sen (1950) and Geertsma (1973). The volumetric strain at a point, caused by a local change in pore pressure, is treated as a center of dilation in an elastic half space and is equivalent to the change in reservoir pressure times the material compressibility.

Stresses induced in the reservoir and caprock by gas pressure cycling can also be analyzed with several numerical modeling techniques currently available for geological materials (see Bruno et al, 1998). These include finite element methods, finite difference methods, and boundary and discrete element methods. The use of numerical models is justified when heterogeneous material property data is available for the overburden, or when the analysis is to be carried out beyond the elastic regime to evaluate slip and material failure. For example, figure 4 presents a geomechanical model used to estimate stress changes induced by pressure cycling in a deep gas storage reservoir.

The geomechanical review and model simulation results should then be examined for the following:

1. Do local pressure values exceed the current fracture gradient in the area, based on measurements or stress estimates?
2. Of what magnitude are the induced shear stresses due to pressure cycling?
3. Are the induced shear stresses small relative to the estimated matrix rock strength and the field shear stresses?
4. Are the shear stresses induced in the overburden enough to cause potential faulting and bedding plane slip?
5. Can lowering the minimum pressure in the field also induce shear stresses which may be of concern?

Decision Analysis Process

Once the technical feasibility for delta pressure operations at a field is established, the decision for increasing maximum operating pressures at a gas storage reservoir will then depend on both potential benefits and potential risks, with estimates of associated uncertainties and costs. This is best determined through a quantitative risk and decision analysis process. A quantitative assessment of benefits, risks, and uncertainties provides an operator with information for:

1. Ranking the value and expected return on investment of the delta pressure project against other investment opportunities;
2. Evaluating consequences of possible loss to determine potential insurance requirements; or,
3. Defining the critical uncertainty parameters and the potential value of collecting additional data to reduce this uncertainty.

A decision analysis process for evaluating delta pressure operations has been developed and applied by Terralog Technologies and Radian International for the Gas Research Institute (deWolfe et al, 1999). The process is comprised of three key steps:

1. Estimating likelihood of loss events;
2. Evaluating Consequences; and
3. Comparing economic benefits and risks.

<u>Loss Likelihood</u>

The first step in the decision process is to estimate the likelihood that delta pressure operation might lead to a loss of gas, storage capacity, or other asset value. This loss might come about due to:

- reservoir fracturing;
- reservoir faulting;
- excess permeation or spillover; or
- well casing mechanical damage.

Fractures are tensile cracks formed in the reservoir or overburden when the gas pressure exceeds the minimum in-situ confining stress. The likelihood of this occurring will depend on the amount of delta pressure, the natural confining stresses, and the caprock strength. For gas to be displaced from the reservoir, the fracture must propagate far enough through the relatively impermeable caprock to establish communication with another porous formation (collector zone) or the surface. The likelihood that fractures in overburden strata would allow gas escape to the atmosphere would be higher in shallow reservoirs, in reservoirs with thin caprock, and for reservoirs with no collector zones in the overburden. These relative influences are summarized in Table 1.

Excess pressure increase or pressure decline in a reservoir can sometimes induce faulting along newly formed or pre-existing fault planes. Faulting will produce gas loss only if the slippage opens a communication pathway to an overlying collector zone or to the surface sediments. The likelihood faulting depends on the present-day stress state, the structural geology of the formation, and reservoir geometry. Relative influences are summarized in the Faulting Loss column of Table 1.

Excess permeation can occur when gas pressure is sufficient to drive gas laterally or vertically across a low permeability so that it becomes unrecoverable in subsequent production cycles. A spillover loss can occur when the gas reservoir contacts groundwater downdip on the structure, displaces that water below a natural saddle point, and escapes into an adjacent structural trap.

Mechanical loss can occur due to well casing damage, or well cement damage. Gas might then migrate vertically to a higher collector zone or to the surface. Well casing damage is sometimes related to reservoir faulting.

For specific reservoir parameters, the qualitative likelihood factors in Table 1 can be used to generate a more quantitative likelihood estimate by assigning order of magnitude severity scores to various conditions. A strong or high likelihood of loss is given a severity score of 100, a moderate likelihood is given a severity score of 10, and a low likelihood is given a severity score 1. An illustrative example is presented in Table 2. The total likelihood score for each loss event mechanism is the sum of the individual category scores.

The likelihood scores for each category may then be converted to absolute order-of-magnitude propability. An example is provided in Table 3. These probability values can subsequently be used in an event tree to determine the consequences and risk cost for various loss events.

Table 3. Relative Risk Scores and Order-of Magnitude Probabilities

Relative Ranking Score Value	Loss Event Probability Order-of-Magnitude Value
greater than 500	10^{-1}
301 – 500	10^{-2}
201 – 300	10^{-3}
101 – 200	10^{-4}
Less than 100	10^{-5}

For our example case, therefore, the probabilities would be:

Fracture	10^{-3}	(score = 256)
Faulting	10^{-3}	(score = 265)
Perm/Spillover	10^{-2}	(score = 346)
Mechanical loss	10^{-2}	(score = 346)

Evaluating Loss Consequences

The consequences of a loss depend on the loss event mechanism, the corresponding quantity of gas released, potential degradation of the reservoir for future storage, and possible legal and regulatory consequences. The quantity of gas released depends on the aperture size of the geological pathways created by the loss event. The availability of the reservoir for future storage depends on whether the damage is reparable or irreparable. The decision about whether or not to proceed with an investment in delta-pressuring for a given reservoir involves consideration of safety, environmental and business impacts, and economic benefits.

Each individual company must establish its own criteria for assessing the level of acceptable risk and returns. An approach used here, that allows consequences to be translated into economic terms, assigns monetary values to all consequences. An event tree summarizing loss probability, consequences, and costs can be constructed as shown in Figure 5. Probability and cost values from one example are inserted in Figure 5 for illustrative purposes. Specific costs must be determined on a site-by-site basis.

When a reservoir is pressurized, one or more of the four gas loss mechanisms can occur with a given probability, or no loss will take place (the most likely scenario). The likelihood of each occurring, as discussed in the previous section, is the expressed as a probability along each event path.

Each possible loss event can produce different physical consequences with associated costs. In our example we list seven loss categories and costs. These are: gas inventory loss, gas sales loss, asset value loss, repair costs, legal costs, regulatory costs, and other potential business loss costs. The costs are a function of the nature of the event and are generally proportional to the initial reservoir size and well density, and to local market value of the gas. For example, fracture or faulting loss will result in both short-term inventory and gas sales loss as well as potential permanent damage to the storage asset. Spillover loss or mechanical damage to a well, however, does not impair the long-term value of the reservoir asset.

The resulting risk cost is equal to the probability of an event occurring times the costs of that event if it occurs. Total risk cost is the summation of all event paths (i.e., the summation of all risk costs listed in the far-right column of Figure 5).

Economic Analysis

A complete economic analysis for delta pressure operations must take into account and compare three factors:

1. The risk-cost for potential gas loss;
2. The costs for conversion to delta pressure operations;
3. The economic benefits of delta pressure operations.

The costs of conversion include the capital investment for changes in facility equipment (i.e., pipelines, compressors, wellheads, etc…) and any additional operating and maintenance costs which might be attributable to the increased pressure (such as additional safety equipment and procedures, for exampley).

The benefits of delta pressure operations include the direct profits from increased gas sales and deliverability increase, as well as the increased asset value derived from the increase in storage capacity. These will depend on the specific reservoir and upon local market conditions. Our analysis of several case studies, however, indicates that the economic benefits of delta pressure operations generally far outweigh both the risk cost and associated conversion costs.

SUMMARY AND DISCUSSION

The objectives of this project has been to investigate and summarize the geomechanical processes associated with gas storage operations and to provide some practical guidelines and tools for increasing maximum pressure limits in order to improve short-term deliverability and working gas storage capacity in existing reservoirs. A step-by-step protocol is presented for evaluating delta pressure options at gas storage reservoir.

In addition to geomechanical limits on gas storage operations, however, there are also economic and risk factors to consider. The risk cost for delta pressure operations can be evaluated by analyzing the likelihood of loss events for specific reservoir situations, and by estimating the costs associated with all possible loss events. This risk cost, combined with direct costs related to conversion to delta pressure operations, can then be compared to the economic benefits associated with increased storage capacity and deliverability.

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Table 1. Likelihood Ranking Tool Qualitative Structure

		Fracture Loss	Faulting Loss	Permeation and Spillover Loss	Mechanical Loss event
1.0 Pressure State					
Delta-pressure Magnitude Factors		Likelihood of loss event			
less than or equal to 1.25		low	low	low	low
between 1.25 and 1.5 inclusive		med	med	med	med
greater than 1.5		high	high	high	high
Desired max/depth:					
less than or equal to 0.625		low	low	low	low
between 0.625 and 0.75 inclusive		med	med	med	med
greater than 0.75		high	high	high	high
Desired min / depth :					
< current min/depth and greater than or equal to 0.375		low	low	low	low
< current min/depth and between 0.375 and 0.25 inclusive		med	med	med	med
< current min/depth and less than 0.25		high	high	high	high
> current min/depth		low	low	low	low
2.0 State of Stress					
Desired max pressure/ min in-situ stress					
less than or equal to 0.5		low	low	low	low
between 0.5 and 0.75 inclusive		med	med	med	med
greater than 0.75 or unknown		high	high	high	high
Regional Stress Conditions:					
Normal stress orientation		low	low	low	low
Strike-slip stress orientation		med	med	med	med
Thrust-fault orientation		high	high	high	high
Local seismic history (region categories)					
Low activity		low	low	low	low
Moderate activity		med	med	med	med
High activity		high	high	high	high
3.0 Reservoir Properties					
Collector Zone:					
Multiple collector zones		low	low	low	low
One collector		med	med	med	med
No collector zones		high	high	high	high
Fault Boundaries					
None		low	low	low	low
One		low	med	med	med
More than one		low	high	high	high
Caprock Thickness					
Thickness >= 100 ft		low	low	low	low
10 < Thickness < 100 ft		med	med	med	low
Thickness < = 10 ft		high	high	high	low
Caprock Strength					
Strong		low	low	low	low
Moderate		low	med	low	med
Weak		low	high	low	high
Reservoir Heterogeneity					
Low		low	low	low	low
Moderate		med	med	med	low
Significant		high	high	high	low
Ratio Lateral Dimension / DBS					
Less than or equal to 1		low	low	low	low
Between 1 and 10		med	med	low	med
Greater than or equal to 10		high	high	low	high
Ratio Thickness / DBS					
Less than or equal to 0.1		low	low	low	low
Between 0.1 and 0.5		med	med	low	med
Greater than or equal to 0.5		high	high	low	high

Table 2. Illustrative Example of Likelihood Evaluation

	Input Data								
1.0 Pressure State									
Formation depth	2500	ft							
Discovery pressure	800	psi							
Current max pressure	800	psi							
Current min pressure	400	psi							
Current max pressure/discovery	1								
Current max pressure/depth	0.32								
Current min pressure/ depth	0.16								
Current delta-pressure (+)	0	psi							
Current delta-pressure (-)	-400	psi							
Current delta-pressure (+)/depth	0	psi/ft							
Current delta-pressure (-)/depth	-0.16	psi/ft							
Desired max pressure	1400	psi							
Desired min pressure	500	psi							
Desired max pressure/discovery	1.75								
Desired max pressure/depth	0.56								
Desired min pressure/depth	0.2								
Desired delta-pressure (+)	600	psi							
Desired delta-pressure (-)	-300	psi							
Desired delta-pressure (+)/depth	0.24	psi/ft							
Desired delta-pressure (-)/depth	-0.12	psi/ft							
Delta-pressure Magnitude Factors		Influence	**Fracture**	Influence	**Faulting**	Influence	**Perm/spill**	Influence	**Mech**
Desired Maximum Pressure / Discovery Pressure:	1.75	factor	**Loss**	factor	**Loss**	factor	**Loss**	factor	**Loss**
Less than or equal to 1.25	0	1	0	1	0	1	0	1	0
Between 1.25 and 1.5 inclusive	0	10	0	10	0	10	0	10	0
Greater than 1.5	1	100	100	100	100	100	100	100	100
Desired Maximum Pressure/ Formation Depth:	0.56								
Less than or equal to 0.625	1	1	1	1	1	1	1	1	1
Between 0.625 and 0.75, inclusive	0	10	0	10	0	10	0	10	0
Greater than 0.75	0	100	0	100	0	100	0	100	0
Desired Minimum Pressure / Formation Depth :	0.2								
< current min/depth and greater than or equal to 0.375	0	1	0	1	0	1	0	1	0
< current min/depth and between 0.375 and 0.25 inclusive	0	10	0	10	0	10	0	10	0
< current min/depth and less than 0.25	0	100	0	100	0	100	0	100	0
>= current min/depth	1	1	1	1	1	100	100	100	100
CATEGORY SCORE	**606**		102		102		201		201

Table 2. Illustrative Example of Likelihood Evaluation (continued)

2.0 State of Stress									
Minimum Stress Known? (1=yes, 0=no)	1								
Minimum in-situ Stress	2000								
Desired Max Pressure/ Min Stress	0.7								
Less than or equal to 0.5	0	1	0	1	0	1	0	1	0
Between 0.5 and 0.75 inclusive	1	10	10	10	10	10	10	10	10
Greater than 0.75 or unknown	0	100	0	100	0	100	0	100	0
Regional Stress Conditions:									
Normal stress orientation	0	1	0	1	0	1	0	1	0
Strike-slip stress orientation	1	10	10	10	10	10	10	10	10
Thrust-fault orientation	0	100	0	100	0	100	0	100	0
Local Seismic History									
Low activity	1	1	1	1	1	1	1	1	1
Moderate activity	0	10	0	10	0	10	0	10	0
High activity	0	100	0	100	0	100	0	100	0
CATEGORY SCORE	84		21		21		21		21
3.0 Reservoir Properties									
Largest Lateral Dimension, LD, ft	15000								
Reservoir Thickness, ft	10								
Caprock Thickness, ft	15								
Collector Zone:									
Multiple collector zones	0	1	0	1	0	1	0	1	0
One collector	0	10	0	10	0	10	0	10	0
No collector zones	1	100	100	100	100	100	100	100	100
Fault Boundaries									
None	1	1	1	1	1	1	1	1	1
One	0	1	0	10	0	10	0	10	0
More than one	0	1	0	100	0	100	0	100	0
Caprock Seal									
Thickness >= 100 ft	0	1	0	1	0	1	0	1	0
10 < Thickness < 100 ft	1	10	10	10	10	10	10	1	1
Thickness < = 10 ft	0	100	0	100	0	100	0	1	0
Caprock Strength									
Strong	0	1	0	1	0	1	0	1	0
Moderate	1	1	1	10	10	1	1	10	10
Weak	0	1	0	100	0	1	0	100	0
Reservoir Homogeneity									
Low	0	1	0	1	0	1	0	1	0
Moderate	1	10	10	10	10	10	10	1	1
Significant	0	100	0	100	0	100	0	1	0
Ratio Reservoir Lateral Dimension / Formation Depth	6.00								
Less than or equal to 1	0	1	0	1	0	1	0	1	0
Between 1 and 10	1	10	10	10	10	1	1	10	10
Greater than or equal to10	0	100	0	100	00	1	0	100	0
Ratio Reservoir Thick / Depth	0.004								
Less than or equal to 0.1	1	1	1	1	1	1	1	1	1
Between 0.1 and 0.5	0	10	0	10	0	1	0	10	0
Greater than or equal to 0.5	0	100	0	100	0	1	0	100	0
CATEGORY SCORE	514		133		133		124		124
TOTAL SCORE	1204		256		265		346		346

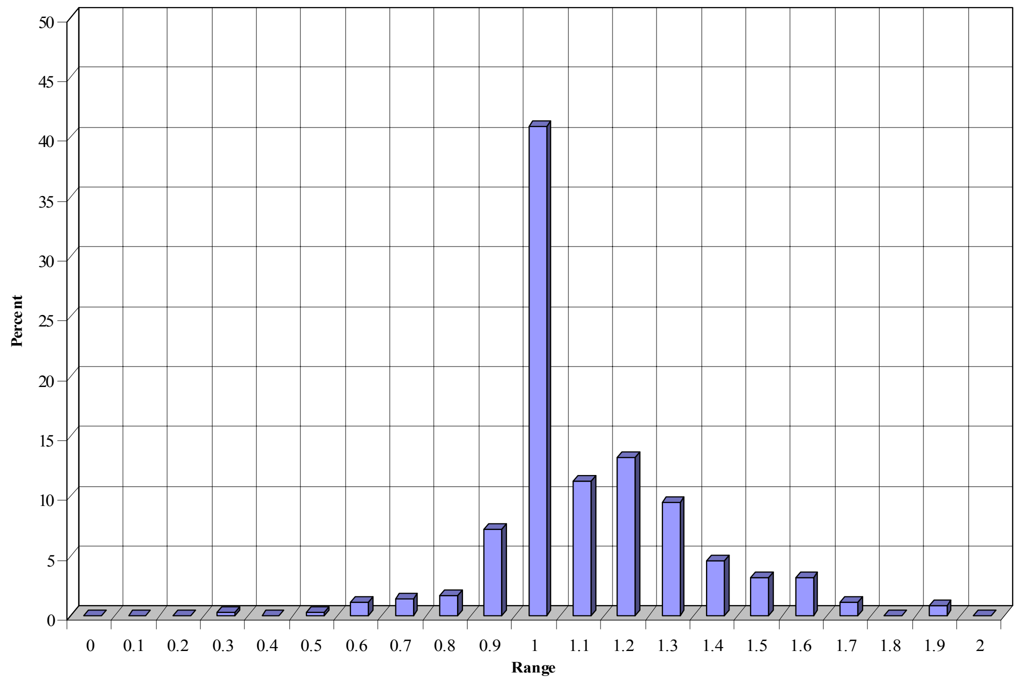

Figure 1. Gas reservoir operating pressure compared to discover pressure (AGA, 1993)

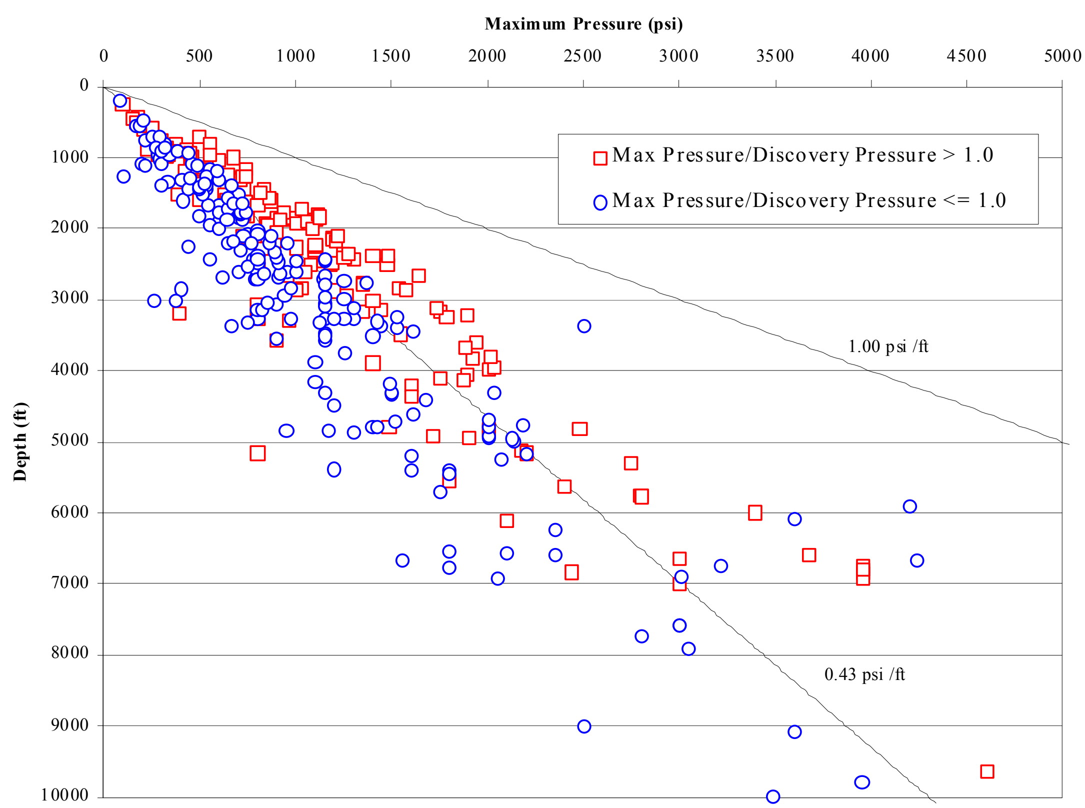

Figure 2. Gas reservoirs operated at normal and delta pressure conditions (AGA, 1993)

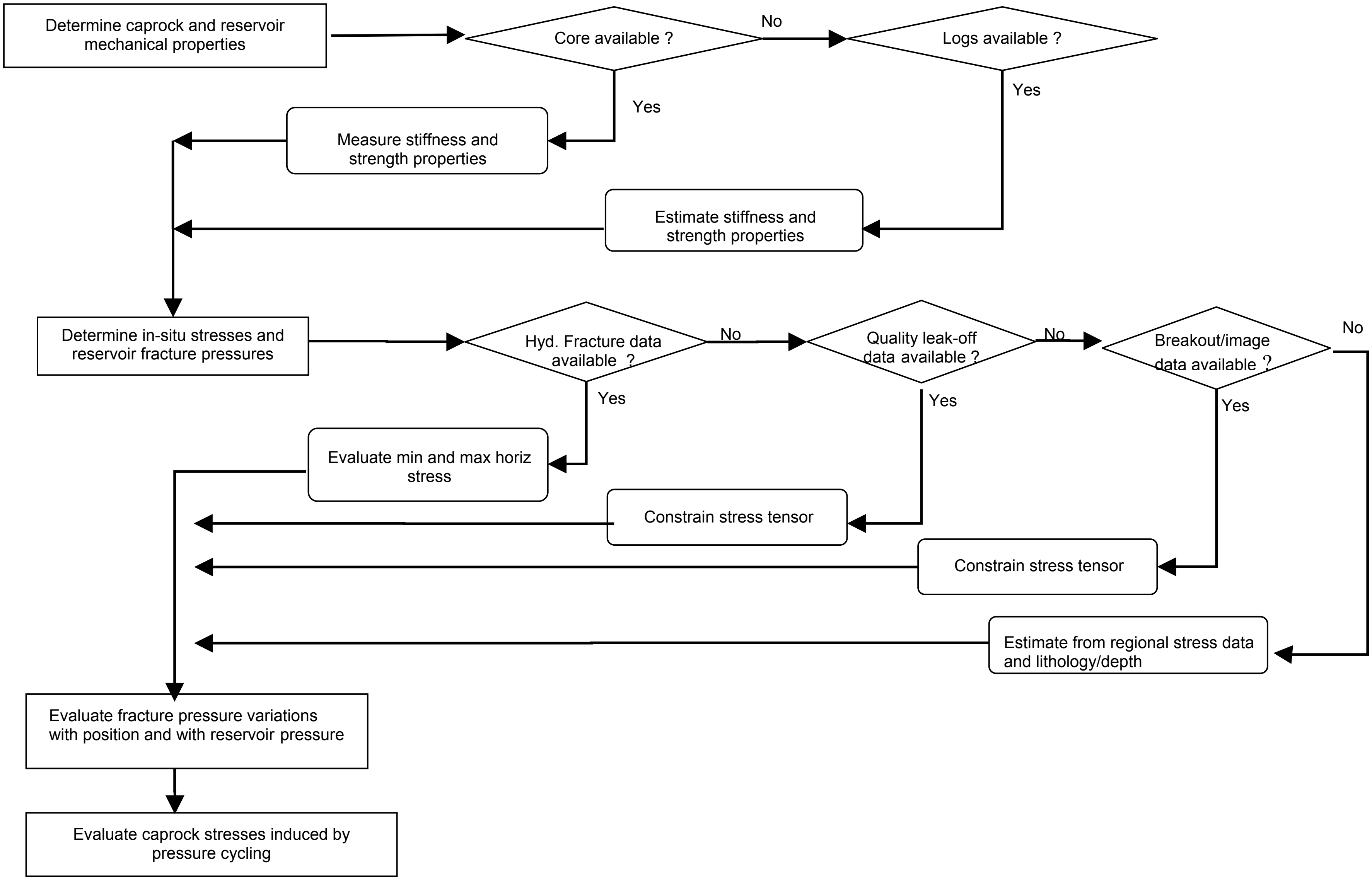

Figure 3. Step-by-step process to evaluate geomechanical limits for delta pressure operation

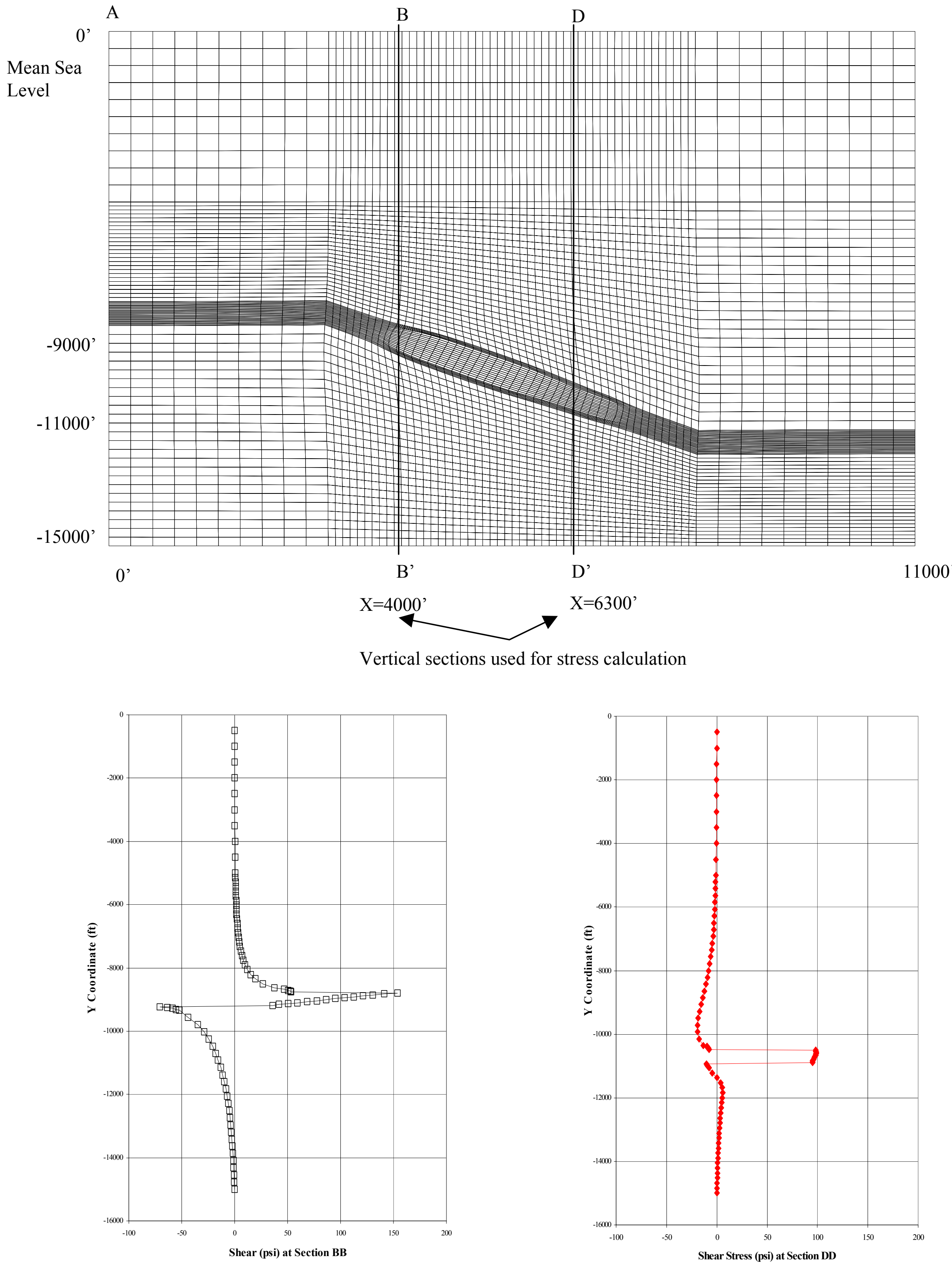

Figure 4. Geomechanical models for gas reservoirs (top figure with displacements magnified 1000 times) can be applied to evaluate stresses induced by gas pressure cycling

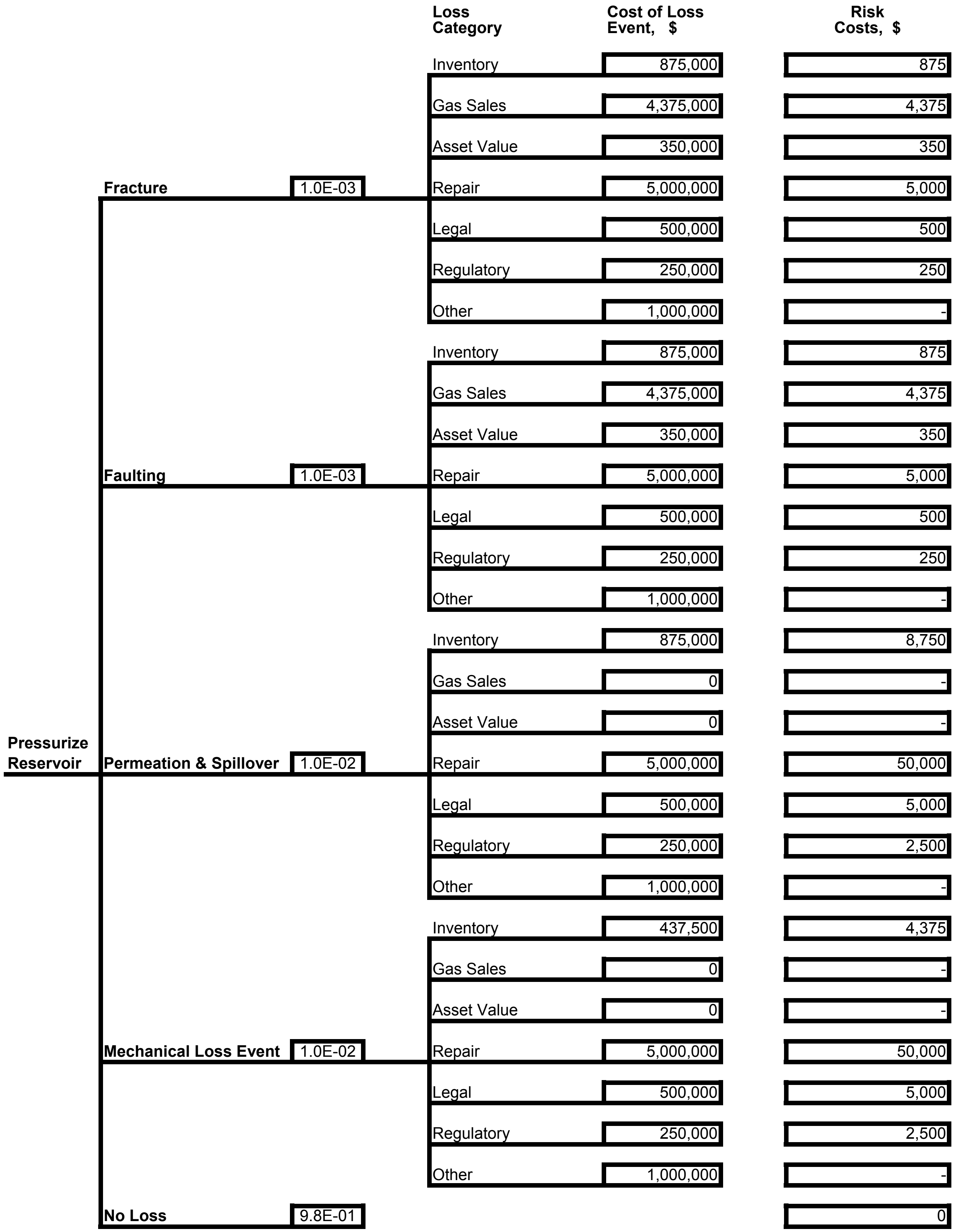

Figure 5. Event tree to evaluate risk costs for loss mechanisms