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**Naturally Fractured Tight Gas Reservoir Detection
Optimization**

**Quarterly Report
January - March 1996**

April 1996

Work Performed Under Contract No.: DE-AC21-93MC30086

For
U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
Morgantown, West Virginia

By
Advanced Resources International, Inc.
165 S. Union Blvd.
Denver, Colorado 80228

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P.O. Box 880
Morgantown, West Virginia 26507-0880

By
Advanced Resources International, Inc.
165 South Union Boulevard
Suite 800
Denver, Colorado 80228

April 1996

QUARTERLY STATUS REPORT
Period of Performance: January 1, 1996 - March 31, 1996
Date of Submission: April 30, 1996

CONTRACT NO.:

DE-AC21-93MC30086

CONTRACTOR:

Advanced Resources International, Inc.
165 S. Union Blvd., Suite 800
Denver, CO 80228

CONTRACT NAME:

Naturally Fractured Tight
Gas Reservoir Detection
Optimization

CONTRACT PERIOD:

09/30/93 - 03/31/97

CONTRACT OBJECTIVE: No Change.

TECHNICAL APPROACH CHANGES: No Change.

FIELD PERFORMANCE TEST PLAN:

The southern portion of the Rulison Field was originally selected as the location for the seismic program. Due to permitting problems the survey was unable to go forward. The permit fee requested by a single landowner both exceeded the total permit fee budget and was regarded as excessive, unreasonable and a dangerous precedent for any future seismic acquisitions. An offer of \$10,000 or roughly \$6/acre was rejected by the landowner with a request to discontinue negotiations because the offer was far too low for further consideration. Typical costs for surface access in the Rocky Mountains are in the \$2.00 to \$3.00/acre range with the original permitting budget based on these values. Considering that the uncooperative landowner controlled over 30% of the site area and was unwilling to accept anything short of extraordinary compensation for surface access, the southern portion of the Rulison Field was eliminated as a candidate for the project site.

The northern Rulison Field has been modeled to determine suitability for the seismic program. The main concern were setbacks necessary to avoid damage to the extensive pipeline gathering system. Modeling indicated that the required 200 foot setback necessary for the dynamite sources did indeed cause the nominal fold to fall below project requirements. The 100 foot setback requirement for vibrator sources has no effect on the optimal source array and therefore provided the required nominal 54-fold P-P. Heloise Lynn reviewed the modeling parameters and concluded that vibrators are high quality seismic sources for the area. She additionally concluded coverage for the planned acquisition are optimal for azimuthal dependent processing. Williams Brothers and Barrett Resources, operators of the gathering system, have requested that the services of Vibra-Tech be available to document that the 100 foot setback was

sufficient to avoid structural damage to the pipeline systems. As matter of courtesy and to avoid potential friction with local operators, Vibra-Tech will be contracted to monitor output vibrations and certify that 100 foot setback are sufficient to prevent pipeline damage.

The survey has been located over an area that contains the best producing, most intensively fractured wells and the worst, least fractured wells. Extreme fracture anisotropy provides optimal conditions for demonstrating azimuthal dependent Amplitude Versus Offset (AVO) fracture mapping capabilities. In addition, due to prolific wells founded in this area, Barrett Resources is committed to further drilling but is hesitant to continue with the development program due to the close proximity of poorly naturally fractured, low volume producers. Interpretation from the seismic survey will be the basis for further drilling by Barrett Resources with the number of wells being contingent upon success of encountering open natural fracture systems.

Western Geophysical surveyed in the 564 vibrator points and 996 receiver stations. Minor modifications from the original pattern were necessary to accommodate difficult terrain. Using Western Geophysical survey design calculation software, fold maps were generated that display total survey fold utilizing 2,000 vertical foot layers at various offset ranges and the oriented offset dependent fold. The orientations are approximately parallel and perpendicular to measured fracture orientations of N70W. Nominal omnidirectional fold exceeds 50-fold with oriented fold exceeds 20-fold within interior of the survey. These fold ranges exceed requirements for processing and interpreting azimuthal dependent AVO. Maps displaying the survey design and modeled offset ranges can be found in Appendix A.

In preparation for the seismic program, Blackhawk Geophysics was contracted to submit the NEPA report. The report was completed and submitted but failed to identify historic cultural sites registered with the State Historical Preservation Office (SHPO). This oversight was a cause for last minute negotiations with SHPO, Bureau of Land Management (BLM), and DOE. Although all issues were ultimately resolved, the project was nearly postponed for four months. Future NEPA reports provided to DOE should include a file search for registered or documented historical sites.

The Western permitting agent was able to rapidly obtain agreement for access to all private lands at an average cost of less than \$2.00/acre. Government owned land included a 80 acre block under the BLM jurisdiction and a 160 acre active land block under joint Garfield County and BLM jurisdiction. Surface access was gained on BLM lands by conducting a Class III block archeological survey. The survey was contracted to Grand River Institute, certified by the BLM to perform such work. Surface access was gained on the Garfield County Landfill by assuring county officials that the operation would have minimal impact and all active landfill areas would be avoided.

Shortly before the seismic crew was due to arrive, we were contacted by SHPO that historical sites existed within boundaries of the survey and that a federal agency would have to take a lead role in protecting the sites. Although the BLM was willing to take lead role, a formal permitting process causing a four month delay would be required. The BLM was willing to forego the formal process and immediately approve surface access if a Class III archeological survey was conducted over portions of privately held lands. Despite the potentially dangerous

precedent of accepting federal jurisdiction on private lands, landowners agreed to allow the archeological survey and as such the BLM issued a surface access permit. Unscheduled work associated with meeting BLM, County and State regulatory agency requirements has caused spending in excess of \$10,000 over the original budget.

The seismic acquisition crew is scheduled to arrive on location by April 7th. The shoot including laying down and picking up all cables will take approximately 14 days contingent upon weather.

3-D BASIN MODELING

1. Three-Dimensional Basins Simulator

The overall development of this fracture prediction simulator has led to new insights into the nature of fractured reservoirs. In particular, we have placed them within the context of recent ideas on basin compartments. These concepts and our overall view of the physico-chemical dynamics of fractured reservoir creation are summarized in the report included as Appendix B entitled "Prediction of Fractured Reservoir Location and Characteristics: A Basin Modeling Approach."

The full three dimensional, multi-process basin simulator, CIRF.B, is operational and is being tested. The incremental stress solver has undergone further improvements and, in particular, optimizations in terms of cash utilization. This solver is now completely integrated in to the overall CIRF.B package and will, therefore, give us the required stress history prediction needed to forecast fractured reservoir location and characteristics.

An improved approach for estimating the history of subsidence at the bottom of the simulation domain has been developed. The method guarantees that the present-day observed shape is preserved at the end of the simulation. The method also decouples the direct relation between sedimentation rate and subsidence history that limits the validity of other approaches.

2. Data Analysis and Data Base

As an ongoing refinement of the sediment history we are continuously reviewing the well data and related interpretation to be used in the construction of the basin sediment history. Some revisions have been required because of the new algorithm used to delineate the time course of subsidence history. We have started and made great progress in new graphical options in our basin analysis package that allows for "movies". This movie option allows us to understand the more deeply temporal relations that arise during complex three dimensional spatio-temporal evolution of stress fluid flow, hydrofracturing and other properties.

A calibration of our failure criteria for a full suite of relevant rocks has been completed. We are now developing the parameters for the nonlinear viscosity formulation for both the viscosity and the failure criteria. These parameters are being fitted for functions of rock mineralogy and texture.

3. Organic Reaction and Multi-Phase Flow

The three dimensional multi-phase reaction-transport solve has been integrated into CIRB. The required improvements that account for the addition of material due to sedimentation have been accomplished, and testing of the code for the gas/aqueous (two phase) problem are proceeding. This aspect is an important party of fracture prediction. In particular, we will be able to address overpressing through compaction, thermal fluid expansion or methanogenesis.

4. Forecast

Most elements of the subcontract are essentially on schedule. Original goals are being exceeded because of the additional efforts being expended in the three-dimensional, multi-phase model and certain aspects of the sediment history recreation modules. Full simulation of the Piceance Basin has commenced.

Appendix A

SOURCE AND DETECTOR LOCATIONS

Prospect: Rulison Field 3D Survey
 Design: Post Plot Data
 Client: Advanced Resources and
 The Department of Energy
 Area: Garfield County, Colorado

-Post Plot Survey Locations

-No Extra Source Points Added To Program

Plot Area in Cells:

(-33, -16)
 (115, 119)

Cell Size :

X = 110 ft
 Y = 110 ft

Source : X
 Detector: +

Design Compliments of

**WESTERN
 ATLAS**

Western Geophysical

CELL FOLD

Prospect: Rulison Field 3D Survey
 Design: Post Plot Data
 Client: Advanced Resources and
 The Department of Energy
 Area: Garfield County, Colorado

-Post Plot Survey Locations

-No Extra Source Points Added To Program

Azimuth Limits : 18% >84
 None
 Offset Limits : 3% 84
 0-0 ft
 Plot Area in Cells:
 (-33, -16)
 (115, 119)
 Cell Size :
 X = 110 ft
 Y = 110 ft
 Source : X
 Detector: +

Design Compliments of

Western Geophysical

CELL FOLD

Prospect: Rulison Field 3D Survey
 Design: Post Plot Data
 Client: Advanced Resources and
 The Department of Energy
 Area: Garfield County, Colorado

-Post Plot Survey Locations

-No Extra Source Points Added To Program

Azimuth Limits

■ Keep □ Reject

Offset Limits :
 0-0 ft

Plot Area in Cells:
 (-33, -16)
 (115, 119)

Cell Size :
 X = 110 ft
 Y = 110 ft

Source : X
 Detector : +

Design Compliments of

Western Geophysical

CELL FOLD

Prospect: Rulison Field 3D Survey
 Design: Post Plot Data
 Client: Advanced Resources and
 The Department of Energy
 Area: Garfield County, Colorado

-Post Plot Survey Locations

-No Extra Source Points Added To Program

Azimuth Limits

■ Keep □ Reject

Offset Limits :
 0-0 ft

Plot Area in Cells:
 (-33, -16)
 (115, 119)

Cell Size :
 X = 110 ft
 Y = 110 ft

Source : x
 Detector : +

Design Compliments of

Western Geophysical

CELL FOLD

Prospect: Rulison Field 3D Survey
 Design: Post Plot Data
 Client: Advanced Resources and
 The Department of Energy
 Area: Garfield County, Colorado

-Post Plot Survey Locations

-No Extra Source Points Added To Program

Azimuth Limits :
 None

Offset Limits :
 2000-4000 ft

Plot Area in Cells:
 (-33, -16)
 (115, 119)

Cell Size :
 X = 110 ft
 Y = 110 ft

Source : X
 Detector : +

Design Compliments of

Western Geophysical

CELL FOLD

Prospect: Rulison Field 3D Survey
 Design: Post Plot Data
 Client: Advanced Resources and
 The Department of Energy
 Area: Garfield County, Colorado

-Post Plot Survey Locations

-No Extra Source Points Added To Program

Azimuth Limits

■ Keep □ Reject

Offset Limits :
 2000-4000 ft

Plot Area in Cells:
 (-33, -16)
 (115, 119)

Cell Size :
 X = 110 ft
 Y = 110 ft

Source : X
 Detector: +

Design Compliments of

**WESTERN
 ATLAS**

Western Geophysical

CELL FOLD

Prospect: Rulison Field 3D Survey
 Design: Post Plot Data
 Client: Advanced Resources and
 The Department of Energy
 Area: Garfield County, Colorado

-Post Plot Survey Locations

-No Extra Source Points Added To Program

Azimuth Limits

Keep ☒ Reject ☐

Offset Limits :
 2000-4000 ft

Plot Area in Cells:
 (-33, -16)
 (115, 119)

Cell Size :
 X = 110 ft
 Y = 110 ft

Source : X
 Detector : +

Design Compliments of 18%

**WESTERN
 ATLAS**

Western Geophysical

CELL FOLD

Prospect: Rulison Field 3D Survey
 Design: Post Plot Data
 Client: Advanced Resources and
 The Department of Energy
 Area: Garfield County, Colorado

-Post Plot Survey Locations

-No Extra Source Points Added To Program

CELL FOLD

Prospect: Rulison Field 3D Survey
 Design: Post Plot Data
 Client: Advanced Resources and
 The Department of Energy
 Area: Garfield County, Colorado

-Post Plot Survey Locations

-No Extra Source Points Added To Program

Azimuth Limits

■ Keep □ Reject

Offset Limits :
 4000-6000 ft

Plot Area in Cells:
 (-33, -16)
 (115, 119)

Cell Size :
 X = 110 ft
 Y = 110 ft

Source : X
 Detector : +

Design Compliments of

Western Geophysical

CELL FOLD

Prospect: Rulison Field 3D Survey
 Design: Post Plot Data
 Client: Advanced Resources and
 The Department of Energy
 Area: Garfield County, Colorado

-Post Plot Survey Locations

-No Extra Source Points Added To Program

Azimuth Limits

■ Keep □ Reject

Offset Limits :
 4000-6000 ft

Plot Area in Cells:
 (-33, -16)
 (115, 119)

Cell Size :
 X = 110 ft
 Y = 110 ft

Source : X
 Detector : +

Design Compliments of

Western Geophysical

CELL FOLD

Prospect: Rulison Field 3D Survey
 Design: Post Plot Data
 Client: Advanced Resources and
 The Department of Energy
 Area: Garfield County, Colorado

-Post Plot Survey Locations

-No Extra Source Points Added To Program

Azimuth Limits : 11% >28
 None
 Offset Limits : 5% 28
 6000-8000 ft
 Plot Area in Cells: 4% 26
 (-33, -16) 4% 24
 (115, 119) 4% 22
 Cell Size : 4% 20
 X = 110 ft
 Y = 110 ft
 Source : X 4% 18
 Detector: + 4% 16
 6% 14
 6% 12
 7% 10
 8% 8
 9% 6
 10% 4
 13% 2
 0

Design Compliments of

Western Geophysical

CELL FOLD

Prospect: Rulison Field 3D Survey
 Design: Post Plot Data
 Client: Advanced Resources and
 The Department of Energy
 Area: Garfield County, Colorado

-Post Plot Survey Locations

-No Extra Source Points Added To Program

Azimuth Limits

■ Keep □ Reject

Offset Limits :
 6000-8000 ft

Plot Area in Cells:
 (-33, -16)
 (115, 119)

Cell Size :
 X = 110 ft
 Y = 110 ft

Source : X
 Detector : +

Design Compliments of

**WESTERN
 ATLAS**

Western Geophysical

CELL FOLD

Prospect: Rulison Field 3D Survey
 Design: Post Plot Data
 Client: Advanced Resources and
 The Department of Energy
 Area: Garfield County, Colorado

-Post Plot Survey Locations

-No Extra Source Points Added To Program

Azimuth Limits

■ Keep □ Reject

Offset Limits :
 6000-8000 ft

Plot Area in Cells:
 (-33, -16)
 (115, 119)

Cell Size :
 X = 110 ft
 Y = 110 ft

Source : X
 Detector : +

Design Compliments of

**WESTERN
 ATLAS**

Western Geophysical

CELL MINIMUM OFFSET

Prospect: Rulison Field 3D Survey
 Design: Post Plot Data
 Client: Advanced Resources and
 The Department of Energy
 Area: Garfield County, Colorado

-Post Plot Survey Locations

-No Extra Source Points Added To Program

Azimuth Limits : 8% >1700
 None

Offset Limits : 1% 1700
 0-0 ft

Plot Area in Cells:
 (-33, -16)
 (115, 119)

Cell Size : 1% 1400
 X = 110 ft
 Y = 110 ft

Source : X
 Detector: +
 2% 1200
 5% 1100
 9% 1000
 8% 900
 12% 800
 11% 700
 19% 600

Design Compliments of 13% 400
 6% 200
 0

**WESTERN
 ATLAS**

Western Geophysical

CELL MAXIMUM OFFSET

Prospect: Rulison Field 3D Survey
 Design: Post Plot Data
 Client: Advanced Resources and
 The Department of Energy
 Area: Garfield County, Colorado

-Post Plot Survey Locations

-No Extra Source Points Added To Program

Azimuth Limits : 2% >15000
 None

Offset Limits : 3% 15000
 0-0 ft

Plot Area in Cells:
 (-33, -16)
 (115, 119)

Cell Size : 10% 12000
 X = 110 ft
 Y = 110 ft

Source : X
 Detector : +

Design Compliments of

Western Geophysical

Appendix B

**Predicting Fractured Reservoir
Location and Characteristics:
A Basin Modeling Approach**

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Bloomington, IN 47405

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Abstract

Phenomena in fracture reservoir genesis and dynamics are reviewed and put in the context of recent developments in compartmentation theory. Preliminary remarks on the compartmentation structure of the Piceance Basin are presented, as this basin is a primary example of one from which petroleum is produced from fractures in otherwise tight reservoirs.

Requirements for a predictive model of fractured reservoir location and characteristics are outlined. A new three dimensional basin simulator having these features is presented and preliminary results are discussed. The use of the predictive model in an integrated remote sensing/modeling exploration strategy is noted, as are future developments and practical issues in the realization of this scheme.

I. Approach

Predicting the location and characteristics of natural fractures is a challenging problem of practical and basic interest. Our approach focuses on the use of three dimensional basin modeling to make these predictions. The specific goals are to place fractured reservoirs within the wider context of basin compartmentation, to delineate the features that a viable basin model must have to make reliable predictions and to give some preliminary examples of the predictions of such a model. We conclude with comments on the future prospects of such models and their integration into a program of remote detection for petroleum exploration.

In this article, we limit the discussion of the wider issue of fracturing to perhaps the most interesting case of enclosed fracture networks. From the standpoint of petroleum, one is not very interested in fracture networks that have good communication with overlying, high permeability strata. Even if such fracture networks had petroleum in the geological past, buoyancy or overpressuring would likely have led to its loss in time. Thus, fracture networks overlain or even completely enclosed by low permeability rock is of greatest interest.

Compartments are, by definition, regions of preserved porosity and permeability enclosed in a three dimensionally-closed shell of very low permeability rock (a seal) (Powley, 1975, 1990; Bradley, 1975; Bradley and Powley, 1994; Ortoleva, 1994a,b, 1996; Ortoleva et al., 1994). As fluids in a compartment cannot readily escape, their interiors are commonly overpressured. The overpressure (of greatest interest in the context of fractures) can be developed via a number of mechanisms, including

- fluid thermal expansion in a subsiding basin;
- compaction (from mechanical or pressure solution);
- clay dewatering and devolatilization of organic rich rocks;
- volume increasing reactions (notably those generating gases); and
- desorption of surface-adsorbed gases.

When the compartment interior attains sufficient overpressure, then fluid pressure can exceed least compressive stress and fracturing can occur within the compartment. As mechanisms generating overpressure are commonplace, it is likely that many fractured reservoirs can be understood as compartments with fractured interiors.

In Section II, the relation of fractured reservoirs and compartments is further developed and factors which affect fractured reservoir genesis, longevity and characteristics are delineated. A preliminary discussion of the compartmentation structure of the Piceance Basin is presented in Section III. Over- and underpressured compartments in the southern part of the basin are observed in this gas-centered, fracture-producing basin. In Section IV the features of a three dimensional basin simulator that accounts for the hydrologic, reaction and mechanical processes needed to predict fractured reservoir location and characteristics is presented. Preliminary simulations of the genesis and evolution of fracture networks is presented in Section V. Future developments and integration of the model into an exploration strategy are outlined in Section VI.

II. Fractures and Compartmentation

A. Fractured Reservoirs/Sweet Spots

Hydrofracturing and tectonic fracturing play essential roles in compartmentation phenomena. Overpressured compartment interiors may have internal hydrologic connectivity maintained through a network of hydrofractures. Indeed, compartment interior pressures are commonly at a critical level for hydrofracture induction. On the other hand, fractures may compromise seals and thereby destroy compartment integrity. In these and other ways, fractures play many complex and sometimes contradictory roles in compartment dynamics.

The petroleum industry has long had an interest in production from formations of low matrix permeability which contain sweet spots due to a network of connected fractures. Without the fractures, these tight sandstone, shale and other reservoirs would be unproducible.

It seems reasonable to place these fractured sweet spots within the context of compartmentation theory. In a sense, a tight formation can constitute both the seal and the compartment interior. Such a fracture-related, intra-bed compartment is suggested in Figure 1. The genesis of such an intra-bed compartment is quite interesting. Suppose the interior is being overpressured. This overpressure can build up there but not near the periphery as the surroundings are, according to the situation of Figure 1, normally pressured. With time, the periphery can become increasingly tight through compaction due to the normal pressure there (elevated pressure represses compaction). However, in the interior, compaction is slowed by overpressure and permeability may be elevated through hydrofracturing. Over time, this permeability contrast between the interior and the surrounding rock can persist or even increase.

The rate of overpressuring plays a key role. If it is large, fractures can extend to the bed periphery and, thereby, internal fluids can be lost along with the potential for interior overpressuring. In time, such a system evolves to a tight, unfractured bed. Thus, as fluid chemistry and rock temperatures can affect overpressuring rate, it is clear that basin stress history

and sedimentary texture, mineralogy and geometry are not the only factors to be considered in predicting the location and characteristics of fractured sweet spots. A fully coupled basin geochemical, hydrologic, mechanical and thermal model and computational simulator is required. Such a simulator is described in Sect. IV.

B. Seal Puncturing

1. Moving Fracture Fronts

The puncture of a seal by fracturing through elevated pore fluid pressure plays a number of roles in compartment dynamics. Compartments can lose fluid through this process. In the case of nested or adjoining compartments, a fracturing of shared seals creates a larger (unified) compartment. Thus seal fracturing can be a mechanism for increasing the spatial scale of compartmentation.

Breaking through a seal by the overpressure it sequesters occurs via a fracture front that sweeps across the seal from the higher pressured side toward the lower pressured surroundings (see Fig. 2). As fractures extend into the seal, they increase fluid pressure there and thereby advance the incursion of fractures. This front may be arrested somewhere within the seal if leakage across the remaining unfractured layer of the seal can keep pace with the influx of fluid from the overpressured region. In this way, the zone wherein the fluid pressure exceeds least compressive stress is contained within the seal and the seal is not completely breached (see Fig. 2).

However, if the rate of overpressuring within the compartment interior is sufficiently large, the fracture front breaks through the seal into high permeability rock in the surroundings. This causes a relatively large fluid loss across the seal and, through fracture healing or closure, the seal can be brought back to viability. Thus one expects that the typical case of a seal enclosing a highly overpressured compartment interiors is that the outer limit of the fractured domain lies somewhere within a region which, due to its small matrix permeability, would otherwise have been a seal.

The advancement of the fracture front into the seal followed by fluid pressure release and fracture healing can repeat if overpressuring is still operating. This repetitive cycle and the notion of migrating seals are addressed in Chen et al. (1990), Dewers and Ortoleva (1994) and Ortoleva (1994a, 1996), and for cyclic methane expulsion from source rock in Ghaith et al. (1990).

2. Fracture Puncturing at High Points of the Top Seal

Fracture-related overpressure breakout through a top seal is favored at the highest point in the seal. Consider a top seal as in Figure 1. The seal is assumed to cap an overpressured compartment. At the high point along the bottom face of this seal, the overpressure is most effective in bringing the total fluid pressure over least compressive stress.

To demonstrate this, note that the depth dependence of the least compressive stress minus hydrostatic fluid pressure generally increases with depth as suggested in Figure 3). Along a vertical line at the high point in the top seal of Figure 1, the overpressure should be roughly as suggested in Figure 3. The overpressure along the line is zero until the top seal is encountered. It rapidly rises above zero with depth through the seal, approaching the compartment interior overpressure as the underside of the top seal is reached from above. Within the compartment the overpressure is roughly constant, assuming this interior has relatively high permeability. In the case suggested in Figure 3, the overpressure curve near point A (away from the top seal highpoint) never reaches least compressive stress minus hydrostatic fluid pressure, and hence no fracture breakthrough is predicted to occur there. However, at the high point breakout can occur. Thus, as overpressure develops, it is seen that breakout should first occur at top seal high points.

The above simple arguments can break down, however. For example, if the seal at the high point is somewhat less efficient than elsewhere, the high point overpressure can be lower and fracturing might be repressed there. In general, any mechanism breaking down the assumption that overpressure is constant along the bottom side of the top seal might lead to the violation of the high point breakout rule. Nevertheless, the high point rule is a general guideline suggesting where expulsion from overpressured source rock was or is favored.

3. A Primary Puncture Represses Neighboring Puncturing

When a given puncture forms, leakage through it lowers pressure in the compartment interior to its sides as fluid flows laterally toward and out the primary puncture. Thus overpressure in regions neighboring a puncture may not develop sufficient levels to induce breakthrough near a primary puncture. In this way, an initial puncture represses the formation of neighboring punctures. The distance over which this repression is effective is expected to increase with increasing compartment interior permeability and decrease with the rate of overpressuring.

C. Flexure

Flexure of brittle layers surrounded by relatively ductile, low permeability ones can lead to compartmentation. Consider such a three-layer package as in Figure 4. As the overall package bends, the top and bottom layers may relieve the tendency towards extensional fracturing by a ductile response involving extension and concomitant thinning. However, the tendency for extension is relieved in the brittle layer by fracturing. If the brittle layer is, say, a tight sandstone, then beyond the region of flexure the central bed serves as a lateral seal. If, finally, the top and bottom layers are seals (say, low permeability shales) then the ensemble constitutes a compartment.

D. Fracture Filling Precipitates

As fractures play a dual role in compartmentation, the filling of fractures by mineral cements or organic solids can foster or destroy compartmentation. A fracture provides a surface on which mineral grains may nucleate and grow subjected to fluid pressure and not the generally higher normal stress at grain-grain contacts in a matrix. Thus there is always a driving force promoting dissolution from grain-grain contacts leading to nucleation and growth within fractures. Overgrowth at the free face of grains neighboring the fracture experiencing pressure solution also competes for these dissolution products. If these free faces are armored with clay or other

coatings, then loss of solutes to free face overgrowth can be less than to fracture cementation. In particular, the fracture faces are made of fresh (broken) faces. Thus, armoring may not play a role at the fracture faces. In this way, fracture infilling by mineral cements can serve to destroy compartment interior hydrologic connectivity.

Fracture filling cements can heal punctured seals (Chen et al., 1994). As fluids exit a compartment through such a puncture, changes in pressure, temperature or composition can cause mineral precipitation within the main flow conduit — the fractures. As flow is focused to these well-localized features, they may deposit much more cements than would have been predicted from an overall flow (mass balance) analysis.

Precipitation of organic solid phases (e.g., asphaltines or paraffins) may also heal punctured seals. On the other hand, through wetting of fracture faces with organic phases, fracture healing can be slowed or inhibited and the nucleation of fracture-filling mineral cements (as from nearby pressure solution or infiltrating fluids) may be repressed. Thus the existence of petroleum in fractures can serve to inhibit intrafracture mineralization and thereby preserve hydrologic continuity within compartments with fractured interiors. Likewise, such cement inhibition by petroleum wetting of mineral grain surfaces may inhibit seal healing and hence allow for the loss of compartment interior fluid pressure.

E. Cleating

Cleats are fracture-like partings usually cited for coals. They are generally believed to be a result of a material contraction associated with the loss of mass from an organic-rich matrix due to the escape of volatized components.

The origins of cleating can be understood in terms of incremental stress theory (see also Sect. III.B). Let $\underline{\dot{\epsilon}}$ be the total rate of strain, $\underline{\dot{\epsilon}}^f$ be the contribution of fracturing to $\underline{\dot{\epsilon}}$ and $\dot{\Omega}$ be the relative rate of volume decrease from devolatilization (i.e., the time derivative of the natural

logarithm of rock volume). Neglecting elastic response and ductile yield, incremental stress theory (see also Sect. III.B) implies

$$\underline{\dot{\epsilon}} = \underline{\dot{\epsilon}}^f + \frac{1}{3} \dot{\Omega} \underline{I} \quad (\text{II.G1})$$

for unit tensor $\underline{I}$. For vertical (z) shortening, without horizontal fractures, this implies

$$\frac{\partial u_z}{\partial z} = \frac{1}{3} \dot{\Omega} \quad (\text{II.G2})$$

for rock deformation vertical velocity u_z . As $\dot{\Omega} < 0$ this shows that a horizontal bed undergoing devolatilization will shorten, as expected. However, friction with over- and underlying beds will make horizontal rock motion negligible. Hence $\dot{\epsilon}_{xx} = \dot{\epsilon}_{yy} \approx 0$. With this

$$\dot{\epsilon}_{xx}^f = -\frac{1}{3} \dot{\Omega} \quad (\text{II.G3})$$

and similarly for $\dot{\epsilon}_{yy}$. Thus the devolatilization-induced contraction is taken up by fracture opening (cleating). In this way, generation of petroleum in very organic-rich beds can induce the formation of a fractured zone (compartment interior or sweet spot) that can house the petroleum.

III. Basin Modeling for Fracture Prediction

A. Overview

The complex network of coupled reaction, transport and mechanical (RTM) processes underlying the genesis and dynamics of fractures and compartments suggested above puts reliable prediction of their location and characteristics outside the realm of simple approaches. In particular, we believe that one must turn to a quantitative basin model capable of integrating all the relevant geological factors and the equations describing RTM processes. As reservoirs are fundamentally three dimensional in nature, the starting point of fractured reservoir theory should be three dimensional also.

The CIRF.B simulator is designed for full three dimensional modeling of a sedimentary basin. CIRF.B (chemical interaction of rock and fluid simulator for basin analysis) accounts for the full range of RTM processes commonly believed to be operating in a basin. CIRF.B development was funded and guided by the petroleum industry, the Gas Research Institute and the U.S. Department of Energy (Maxwell and Ortoleva, 1994; Qin and Ortoleva, 1994; Sonnenthal and Ortoleva, 1994; Ortoleva, 1994a, 1996).

The external influences such as sediment input, sealevel, thermal and tectonic effects operate at the basin boundaries. Within the basin the RTM processes are at work modifying the sediment chemically and physically to arrive at petroleum, mineral and potable water reserves and other basin features.

The CIRF.B approach for predicting the location and characteristics of petroleum reservoirs and other basin features is based on our novel basin model and computer simulation algorithms. CIRF.B provides a platform for integrating all available geological data into basic scientific case study or an exploration or reservoir development strategy under the umbrella of the laws of physics and chemistry.

Available information can be divided into geological data and the physico-chemical laws and associated parameters. The former give the information that makes a simulation tailored to a specific basin. The physico-chemical information gives our model the power to predict resource location and characteristics and other features of the evolving basin.

CIRF.B simulations show the windows of time during which formations along a putative migration pathway were open and not closed due to compaction, formation collapse or cementation. Similarly, CIRF.B predicts whether formations bounding likely reservoirs form in time (before the reservoir became charged with petroleum) or if the sealing rock was breached due to natural fracturing or permeability-enhancing diagenetic reactions. It also can be used to predict reservoir producibility by estimating fracture network characteristics and effects on permeability due to diagenetic reactions. These considerations can be made in a completely self-consistent way through the inclusion of a multi-phase, organic and inorganic, reaction-transport module. Calculations of all effects are done fully self-consistently so that all cross-coupling between processes is accounted for. The determination of temperature is affected by transport which is affected by the changes of porosity that changes due to temperature-dependent reaction. The rate of kerogen decomposition depends on temperature which in turn depends on thermal transport that is affected through fluid buoyancy, thermal conductivity, capillarity and relative permeability on the content of organic material. Similar coupling relations between the full set of RTM processes is accounted for.

Other basin simulators lack the CIRF.B predictive power because they use statistical correlations. For example, they predict porosity based on a formula relating it to mineralogy and depth. However, porosity evolves due to the detailed stress, fluid composition and pressure and thermal histories. These histories are different for every basin. Thus a simple correlation of porosity and depth and lithology type does not exist in principle. CIRF.B avoids such problems by actually solving the fully coupled rock deformation, fluid and mineral reactions and fluid transport problem. While there are thousands of sedimentary basins that the statistical correlations must account for, the calibration required for our physico-chemically based approach involves less

factors and, unlike the statistical approach, can be calibrated in principle. In short, the laws of physics and chemistry clearly hold in all basins and, furthermore, capture the individual personality of every basin. Statistical approaches can only hope to capture the average personality — i.e., can only predict a stereotypical basin's evolution.

To explain the interplay of geological and physico-chemical information in making CIRF.B predictions, consider one time step in its forward modeling as illustrated in Figure 5. The purpose of the incremental evolution step is to advance the state of the basin from a time t in the past to a later time $t + \delta t$. In the simulator, two distinct operations are taking place simultaneously during this time interval δt . The geological information is used to 1) fix the input/output of energy and mass at the basin boundaries and 2) impose, through the tectonic history, the strain history (i.e., overall deformation) at the basin boundary. On the other hand, the physico-chemical processes determine the evolution in time during δt of the spatial distribution of the local state variables. The latter include stress, fluid properties, mineralogy, porosity, permeability, fracture characteristics and temperature.

The CIRF.B geological input data is divided into four categories as shown in Figure 5. The tectonic data gives the change in the lateral extent and the shape of the basement-sediment interface during δt . As suggested in Figure 5, this data provides the conditions at the basin boundary needed to calculate the change in the spatial distribution of stress and rock deformation within the basin. This latter physico-chemical calculation is carried out by a stress module that solves equations based on incremental stress rock rheology and force balance.

The next type of geological data is that affecting fluid transport, pressure and composition. This fluid data includes sealevel changes, recharge conditions and the composition of fluids injected from the ocean and meteoric sources. This history of boundary input data is then used by the hydrologic and chemical modules to calculate the evolution of the spatial distribution of fluid pressure and composition within the basin. These physico-chemical calculations are based on single- or multi-phase flow in a porous medium and of fluid phase molecular species conservation of mass (i.e., the reaction-transport equations). The physico-chemical equations draw on internal

data banks for permeability-rock texture relations, relative permeability formulae, chemical reaction rate laws and reaction and phase-equilibrium thermodynamics.

The spatial distribution of heat flux imposed at the bottom of the basin is another geological input/control. This data as well as the temperature imposed at the top of the sediment pile (i.e., climate and ocean bottom temperature) is used to evolve the spatial distribution of temperature within the basin during the time interval δt . This evolution is computed using the equations of conservation of energy and formulae and data for mineral and rock thermal properties (conductivities and specific heats).

The sedimentation data provides the detailed textural characteristics such as grain size, shape, mineralogy, mode and carbon content (i.e., inorganic and organic texture) of the sediment being deposited during δt . The physico-chemical laws and data are used to calculate the change of the spatial distribution of texture within the basin during δt . These physico-chemical calculations involve the rate laws and data for free face grain chemical kinetics, pressure solution and grain rotation or breakage, grain nucleation and the laws of kerogen chemical kinetic transformation. Also used are the laws of fracture nucleation, extension, aperture dynamics and the kinetics of cement infilling.

All this geological input data and the physico-chemical calculations are integrated in CIRF.B to uniquely give it the power to predict the present-day internal state of the basin. The physico-chemical laws translate the boundary constraints (geological data) into a prediction of the changes of internal basin state that took place during δt . The incremental time advancement is repeated until the evolution of the basin internal state, from the inception of the basin (or other chosen initial state) to the present, is computed.

The above procedure can only be considered useful in a practical context if the required geological data is the same or less than that presently used in exploration and resource development. In fact, all the geological data noted above is in common usage. It is derived from well log analysis, seismic data, general basin tectonic history re-creation studies, vitrinite reflectance and other temperature indicators, stress and strain indicators, core analysis and

production data. In work in progress, we are developing methods for the input of geological data in the form of well logs, seismic data, core analysis and other "raw" data. Most of the physico-chemical data is available in data banks or the literature.

An important perspective is that the physico-chemical computations provide another way of integrating the presently-used geological data. In a real sense these calculations put constraints on the interpretation of this geological data. For example, an interpretation of the geological data without the benefit of our model is subject to some assumptions on the relative timing of events; estimates of the times of these events could be made more reliably when they are predicted based on the known rates of the underlying physico-chemical processes.

Like any analysis of the geological data (including those presently used in other approaches) our model-based data integration and predictions are subject to some uncertainties. These are of three types:

- variations among the interpretations of the geological data;
- incomplete physico-chemical phenomenologies or required data; and
- numerical inaccuracies in the simulation algorithms.

All these discrepancies must be addressed in evaluating our or any predictions. Our simulator itself provides an important tool for analysis of the above potential errors. By carrying out sensitivity studies, one can determine the contributions of uncertainties in the various factors. To accomplish this one needs to vary the less well-constrained geological and the physico-chemical data and those parameters controlling the numerical accuracy (time and space step, convergence criteria for iterative algorithms, etc.).

Clearly there is a variety of feedback loops that exist in the network of basin RTM processes. Fracturing plays a key role in many of these feedback loops as it depends on a number of effects (stress, fluid pressure, and mineral infilling reactions) and, in turn, modulates these effects. Thus predicting the timing of the development of petroleum and its emplacement in quality reservoirs (and similarly for water and mineral resources) requires a fully coupled model and simulator. In CIRF.B, the solver modules of Figure 5 are not run independently. Rather, the system of fully

coupled equations are solved iteratively for each time step advancement so that all cross coupling relationships between processes are accounted for. This full self-consistency of our RTM simulator gives it the unique character needed to make the predictions required for fundamental and applied basin research.

B. Incremental Stress Computation

Key elements of abnormal pressure generation and preservation are compaction and fracturing. These processes depend strongly on basin stress. Thus good estimates of stress distribution and its history are required to predict mechanical and chemical compaction and fracturing, essential aspects of compartment and seal genesis, structure and dynamics. As fracturing occurs when fluid pressure exceeds least compressive stress by rock strength, estimates of the time of creation, growth, healing or closure as well as orientation of fractures rely on estimates of the stress distribution and its history. In turn, resulting fracture permeability can affect overpressure through escape of fluids from overpressured zones or the creation of economic petroleum reserves in otherwise tight reservoirs. For these and other reasons, the ability to estimate the history of the distribution of stress within a basin from available data on its overall tectonic and sedimentary history is a key element of a predictive model of compartments and seals and their implications for fractured or other reservoir location, fluid pressure, heterogeneity and producibility.

A rock rheological model has been developed in CIRF.B based on incremental stress theory. This approach allows one to include fracturing and pressure solution naturally into a unified theory that also accounts for elastic and viscous/plastic mechanical rock response. This rheology combined with the force balance condition allows for the calculation of rock deformation and stress and their distribution in space and evolution over time. The stress solver is based on a moving, second order finite element discretization and efficient iterative solution approaches.

The incremental stress rheology used to integrate all the strain mechanisms has the generic form

$$\underline{\dot{\epsilon}} = \underline{\dot{\epsilon}}^{el} + \underline{\dot{\epsilon}}^{in} + \underline{\dot{\epsilon}}^{ps} + \underline{\dot{\epsilon}}^{fr} + \underline{\dot{\epsilon}}^{misc}. \quad (\text{III.A1})$$

Here $\underline{\dot{\epsilon}}$ is the rate of strain while the terms on the RHS give the specific dependence of the contributions to $\underline{\dot{\epsilon}}$. These are poroelasticity (el), continuous inelastic mechanical (in), pressure solution (ps), fracturing (fr) and miscellaneous (misc) processes such as clay dewatering and cleating. Expressions for each term used in CIRF.B are from the literature or our earlier work.

The boundary conditions implemented in CIRF.B are indicated in Figure 5. They allow for a prescribed tectonic history at the bottom and sides of the basin. This data is input as a history of rock velocity at these boundaries. At the simulation domain sides the vertical component of tangential shear is set to zero. This avoids artificial interference with the natural dynamics of compaction and fracturing there. Normal stress at the top of the basin is set to ocean bottom or atmospheric pressure. Tangential shear on the top is set to zero to simulate the fluid-sediment interaction there.

The above boundary conditions allow for the full range of tectonic scenarios to which a basin is subjected. These include complex histories of subsidence and lift, compression or extension and the variation of these effects with map-view position along the basin periphery and basement-sediment interface. These features make the CIRF.B three dimensional stress solver a unique tool, powerful enough to address the important problems of basin deformation and the interplay of rock deformation, hydrology and geochemistry needed to analyze and predict naturally fractured reservoir phenomena.

C. Other Modules

In CIRF.B texture, stress, fluid phase and composition, temperature and fractures are coevolved in time to preserve all the coupling of the underlying processes. Some of these modules are briefly described as follows.

A reservoir is defined by its spatial distribution of porosity and permeability. These factors are dictated by matrix texture (grain size, shape and packing) and fracture density, geometry and connectivity. In CIRF.B these properties are evolved via the texture evolution modules. The fracture nucleation, lengthening and aperture kinetics are based on subcritical, hydrofracture theory.

The textural description and kinetics model used in CIRF.B is the mean contact model (Park and Ortoleva, 1996). In that model the grains of a given mineral are all assumed to be of the same size and shape — i.e., are represented by the average or mean grain of that mineral. The mean grain of mineral i ($i=1,2,...M$) of the M mineral system is represented by a set of four lengths. The lengths are used to keep track of growth/dissolution of various facet types (contacts of various orientations and free faces).

The theory underlying the multi-phase reaction-transport approach implemented in CIRF.B is discussed in more detail in Chang and Ortoleva (1996) and Ortoleva (1996). Transport is via the black oil model. Formulae and data for relative permeability and capillary pressure, and equations of state, are taken from published literature and in-house industrial reports. The formulation implemented allows for the transport and spontaneous creation or disappearance of up to four phases (gas, aqueous, oil and CO₂-dominated) under the assumption that all processes transferring molecules between phases are at phase exchange equilibrium. Both rapid (equilibrated) intraphase reactions and finite rate (kinetic law determined) intra-phase and fluid-rock reactions are accounted for. A simple organic kinetics of kerogen thermal decomposition into organic fluid species is also implemented while a more comprehensive model based on a new kinetic formulation calibrated using published experimental data is under development (and will be implemented by late 1996).

Sedimentary history is automatically constructed from petrology and age data at prescribed well sites. Seismic cross sections can also be used. A number of novel graphical features allow for the viewing and editing of this computer-generated history. Basement heat flux, sea level and overall basin deformation histories may also be specified in CIRF.B.

D. Illustrative CIRF.B Simulation

Much of the development of CIRF.B was done using a simple test case inspired by research on the Anadarko Basin. The simulation shows a basin-wide compartment (megacompartment) as suggested in Figures 6-9 (Maxwell and Ortoleva, 1994). An early epoch of relatively rapid infilling lasted about 14 m.y. The basin sediment history is indicated by the schematic crosssection of Figure 6. Isosurfaces of overpressure (Fig. 7) and fracture radius (Fig. 8) are also shown. The region of overpressure varies with time over the history of the basin. In this simulation, overpressure starts in the lower shale formation (meant to mimic a Devonian shale) such as the Woodford Formation of the Anadarko Basin. A higher lying fine-grained material evolves into a top seal that eventually caps the overpressure.

Overpressuring mechanisms active in this simulation are pressure solution-mediated compaction and fluid thermal expansion. The mineralogy is restricted to quartz. The hydrology is single phase (water) and temperature is determined by the solution of the energy conservation equation for a prescribed basement heat flux. A temperature isosurface is seen in Figure 9. Note the elevated temperature in the fault region and at the periphery, both manifestations of the fluid escaping the lowest formation centrifugally. The lowest formation is meant to mimic the Hunton Formation. Its fractured nature eventually allows it to become normally pressured. It is often observed that deep in the basin, below the compartment zone, the formations are normally pressured (as pointed out by Powley, 1990 for onshore U.S. basins).

IV. Fracturing and Compartmentation in the Piceance Basin

A. Observations

According to Powley (1990), many on-shore U.S. basins contain a three-tiered structure of pressure regimes. A shallow normally pressured regime is separated from a compartmented regime by a relatively flat top seal that can traverse stratigraphy. The compartmented regime generally supports overpressure (although underpressured compartments in uplifted/ended areas are known). Below the compartmented zone usually lies a normally pressured regime separated from the compartmented zone by a seal that tends to follow stratigraphy. In the Anadarko Basin, for example, this basal seal follows the Woodford shale (Al-Shaieb et al., 1994a,b).

An attempt was made to delineate pressure compartmentation in the Piceance Basin using sparse pressure data and some general notions of basin hydrology. The following procedure was used to develop a basin-wide pressure data set. A Gaussian formula was used to interpolate data given as a set of shut-in pressure values at selected points (x,y,z) in the basin and the known pressure (1 atm) along the top surface of the basin.

A preliminary picture is seen in Figure 10 in terms of a pressure isosurface of 145 bars. Normal pressure increases at about 100 bars/kilometer. Roughly below the surface shown is the basin-wide zone of overpressure.

Let $\sigma_L (> 0)$ be least compressive stress and p be fluid pressure. Then the quantity ψ ,

$$\psi = p - \sigma_L, \quad (\text{IV.1})$$

indicates potential for fracture networks. The domain $\psi > 0$ indicates the spatial location of viable fractures.

At this writing, no least compressive stress (σ_L) measurements across the basin were available. For illustrative purposes, take the typical value of .35 times overburden. Assuming a

constant rock density of 2.3 gm/cc, σ_L is roughly 105 bars $\times$ depth in kilometers. The resulting $\psi=0$ isosurface corresponding to the pressure as in Figure 10(a) within which fractures are likely ($\psi>0$) is seen in Figure 10(b).

A more accurate description of the compartment structure and, in particular, fracture sweet spots, in the Piceance Basin awaits more complete fluid pressure and stress data. In particular, one would like to correlate these with the structure of formations and with gas production data. The challenge is to analyze and interpret this data with both remote sensing and basin evolution/fractured reservoir prediction models.

Finally, a key issue in the Piceance Basin is whether observed fractures are from overpressure as suggested above or from flexure or other "tectonic" origin. Clearly, if σ_L is sufficiently low, as for flexure (Subsection II.D), then ψ can be positive even though p is normal. Thus, predicting fracturing requires a model of stress, fluid pressure and, as suggested in Section II, the diagenetics of fracture filling precipitation, factors accounted for in our CIRF.B basin simulator.

B. Preliminary Piceance Basin Modeling

A preliminary simulation of the Piceance Basin is shown in Figure 11. The focus was the southern half of the basin due to data availability. Twenty-nine wells were used for constructing the sediment history via the CIRF.B sedimentation module which interpolates the sediment properties and sedimentation rate in time and space. The sediments were composed of quartz, K-feldspar and muscovite in different proportions. A noflux boundary condition for the pressure equation was assumed for the bottom and all sides of the basin, while hydrostatic boundary conditions were used for the top.

The simulation started at 75.9 m.y. ago. As the simulation proceeded, new sediments were added at the top of the basin according to the lithologies and sedimentation rate interpolated by CIRF.B to exist at that particular time. The basin is shown in Figure 11(a) after 18 m.y. of

sedimentation and diagenesis. There was no significant overpressure in the domain at that time. After 38.6 m.y., overpressure developed in the basin (Fig. 11b-d) due to compaction and thermal expansion. The location of the overpressure was strongly influenced by the spatial distribution of permeabilities (Fig. 11e). Overpressure is preserved beneath the low permeability bed (seal) corresponding to the finer grain formations (Wasatch) (Fig. 11e). The simulation also indicates that the overpressure was dynamically maintained. If there had been no continuous compaction and heating, the overpressure could have rapidly dissipated because the overpressured domain contacts conduits in the southern and western parts of the basin (Fig. 11e). Finer-grained beds compacted much more than the coarse-grained lithologies. The porosity of the finer-grained beds (Mancos Formation, Cameo Coal units) in the bottom part of the basin was reduced to about 3%. The locations which possibly have natural fractures are those where fluid pressure is significantly greater than the least compressive stress, as indicated in Figure 11(f).

V. Future Prospects

The application of a coupled basin diagenetic, hydrologic, mechanical model to petroleum exploration holds great promise for the future. This type of modeling is an important complement to remote sensing activities in two fundamental ways. The modeling can be of assistance in guiding the selection of seismic surveys. It can also be used to aid in interpreting features detected by the latter.

Only a comprehensive model such as CIRF.B can serve these purposes in the context of fractured reservoir exploration. As noted in this article, the existence and viability of a fracture network depends very sensitively on the three factors — hydrology, chemistry and mechanics. Furthermore, these factors must be coevolved over geological time to predict the present internal state of the basin (notably, the location and characteristics of fractured reservoirs). Decoupled models for basin hydrology or chemistry or mechanics cannot reliably address these problems. Mechanics requires fluid pressure through effective stress rheology. Mechanics affects permeability through fracturing and, finally, mechanics and hydrology are affected by diagenetic chemistry through mineral dissolution/precipitation and organic fluid phases or rock mechanical and flow characteristics. In short, the complex basin dynamics proceeds through a series of tightly coupled hydrologic, chemical and mechanical processes.

The success of the unique CIRF.B code as a practical tool for fundamental and applied basin studies depends strongly on two issues. First, the CIRF.B model is based on a number of rock rheologic, transport and chemical reaction rate laws. Thus, reliable prediction depends on a careful validation and calibration of these laws. Notable examples are the dependence of rock failure criteria and nonlinear viscosity parameters, as well as permeability, relative permeability and capillary pressure on texture. Also, the parameters of the pressure solution and fluid phase chemical reaction rates on texture and fluid chemistry must be verified and calibrated. These activities are presently ongoing in our laboratory.

A basin simulation is only as accurate as the assumptions on sea level and overall tectonic, sedimentary and thermal histories. However, these factors play a role in any exploration strategy. The basin model provides a platform for integrating these factors under the constraint of the laws of physics and chemistry. Furthermore, the fully integrated basin model can be used to evaluate the sensitivity of, for example, the location and characteristics of fractured reservoirs on various, least well constrained factors. Thereby an effort can be focused on determining the key data required for reliable predictions.

A final consideration is a practical aspect of comprehensive basin modeling — i.e., the computational requirements. A typical exploration study involves a simulation on the 100 million year time frame. Our experience with CIRF.B is that a typical simulation of modest mineralogical sedimentary and chemical complexity takes about .1 CPU day per million years on a single R8000 Silicon Graphics Incorporated processor. However, the algorithms we have developed are very parallelizable. Thus, we expect to reduce simulation times to a few days or less. Also, in the next few years, single processor speeds should increase by a factor of two or more. Thus, modest and even more complex models should run in acceptable lengths of time.

In conclusion, we expect that CIRF.B should soon play a very critical role in exploration and field development analysis. This is only made possible because of its comprehensive physical, chemical and geological features and the fully coupled coevolution of all processes in three spatial dimensions.

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Figure 1

Figure 2

Figure 3

Figure 4

Figure 5

Figure 6

(a)

(b)

Figure 7

(a)

(b)

Figure 8

(a)

(b)

Figure 9

Figure 10(a)

Figure 10(b)

Figure 11(a)

Figure 11(b)

Figure 11(c)

Figure 11(d)

Figure 11(e)

Figure 11(f)

Figure Captions

Figure 1 This fractured sweet spot resides within an otherwise tight lense. When the fracture network does not extend out into the normally pressured surroundings, the ensemble may constitute a compartment. Seal puncturing by fracturing usually first takes place at highpoints (see Subsection II.B2).

Figure 2 Schematic profiles of fluid pressure and fracture length illustrating the partial rupture of a seal.

Figure 3 This figure suggests that fracturing should be most likely to cause seal breaching at a highpoint (see Fig. 1).

Figure 4 Flexure of a brittle tight sandstone sandwiched between two ductile layers to develop into a compartment whose lateral seals are due to the unfractured tight rock (UFR).

Figure 5 Conditions at boundary of basin simulation domain allow for imposition of ocean bottom normal pressure p_o and no shear at the top ($\underline{\tau}$ being a tangent vector and $\underline{n}$ being a normal vector). At the bottom the tectonic history fixes the evolution of the deformation velocity $\underline{u}$. On the sides (lightly shaded) the horizontal deformation velocity (u_x, u_y) is imposed, to allow for specification of epochs of basin compression or extension; the vertical component of shear is set to zero to allow for the natural compaction dynamics to take place there.

Figure 6 Schematic basin cross-section used for modeling study.

Figure 7 25 bars overpressure at (a) 50 and (b) 100 m.y.

Figure 8 0.5 cm fracture radius at (a) 50 and (b) 100 m.y.

Figure 9 Temperature of 80°C at (a) 50 and (b) 100 m.y.

Figure 10(a) Isosurface of 145 bars fluid pressure developed from shut-in pressure data in the southern half of the Piceance Basin. The upper and lower surfaces delineate an overpressured, basin-scale compartment.

Figure 10(b) Flow chart showing how the interplay of geologic data and physico-chemical (i.e., reaction-transport-mechanical) process modules evolve the basin over a computational time interval δt .

Figure 11 $\psi=0$ isosurface associated with Fig. 4 containing likely zone of fracturing (see Section III).

Figure 12 (a) Slices showing the volume fraction of quartz in the formations after 18 m.y. of sedimentation and diagenesis. The maximum dimension of the basin is $119.4 \times 69.2 \times 1.986$ km. Note (1) vertical distance is exaggerated 8 times and the viewpoint is the southwest corner of the basin for all the frames of Figure 12; and (2) light gray represents small value and dark gray represents high value in all the frames showing slices. (b) Isosurface of 50 bar and (c) of

90 bar overpressure after 38.6 m.y. of simulation; (d) slices of overpressure after 38.6 m.y.; (e) slices of permeability. Note the relationship between the location of overpressure (Fig. 12d) and the distribution of permeability. (f) Isosurface of $\psi=10$ bars as a prediction of fractured areas.