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ADVANCED FRACTURE MODELING IN THE UINTA BASIN (UTAH)
FOR OPTIMIZED PRIMARY AND SECONDARY RECOVERY

Final Report
September 1998

December 1998

Performed Under Subcontract No. G4S51729 Contract No.
DE-AC22-94PC91008

TerraTek, Inc.
Salt Lake City, Utah

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National Petroleum Technology Office
U. S. DEPARTMENT OF ENERGY
Tulsa, Oklahoma

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and Secondary Recovery

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Work Performed Under Subcontract No. G4S51729 Contract DE-AC22-94PC91008

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CONTENTS

INTRODUCTION AND PROJECT DESCRIPTION.....	1
Project Objectives.....	2
The long-range objectives for this research.....	2
Technical Approach to Objectives	3
TASK 1 – RESERVOIR CHARACTERIZATION	5
TASK 2 – LABORATORY MATERIAL CHARACTERIZATION.....	5
TASK 3 – FRACTURE REPRESENTATION	5
TASK 4 – PERMEABILITY TENSOR	6
TASK 5 – PRIMARY RECOVERY MODEL	6
TASK 6 – SECONDARY RECOVERY MODEL.....	7
TASK 7 – TECHNOLOGY TRANSFER	7
 SUMMARY OF ACCOMPLISHMENTS	
TASK 1 – RESERVOIR CHARACTERIZATION.....	9
The Duchesne Fault Zone at the Surface	9
Subsurface Structure Revealed	10
TASK 2 – LABORATORY MATERIAL CHARACTERIZATION	11
TASK 3 - FRACTURE REPRESENTATION	11
Hydraulic Fracturing and Production.....	11
Discontinuous Deformation Modeling	11
Summary	12
Finite Element Model	12
Finite Element Mesh and Interface Elements	12
Mechanical Properties of Rock and Faults	13
Regional (Far-Field) Stresses.....	14
Computational Results: Stresses in the Balcron Oil Field.....	15
TASK 4 – PERMEABILITY TENSOR.....	27
Permeability Anisotropy	27
Three-Dimensional Reservoir Modeling and Visualization	28
TASK 5 – PRIMARY RECOVERY MODEL.....	31
Primary Recovery Model.....	31
TASK 6 – SECONDARY RECOVERY MODEL	31
TASK 7 – TECHNOLOGY TRANSFER.....	31
Objectives	31
Component 1: Information Specifically Related to the Uinta Basin	32
Objectives	32
Methodology and Status	32
Component 2: Applicability to Other Reservoirs in the United States.....	33
Objectives	33
Methodology and Status	33
Component 3: Promote Appropriate Methodologies for Evaluation.....	33
Objectives	33
Methodology and Status	33

Component 4: Software and Numerical Methods.....	35
Objectives	35
Methodologies and Status	35
Component 5: Public Domain Information Dissemination	37
Objectives	37
Methodologies and Status	37
Component 6: Identify Future Needs and Required Improvements	37
Objectives	37
Methodology and Status	38

SUGGESTIONS FOR PRESENT AND FUTURE OPERATIONS IN THE DUCHESNE FAULT ZONE	39
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INTRODUCTION AND PROJECT DESCRIPTION

The Uinta Basin in northeastern Utah has long been recognized as the second richest onshore basin in the contiguous United States in terms of hydrocarbons in-place. Despite the prolific abundance of hydrocarbons, recovery is impeded by the nature of the oil, the difficult behavior of these "conventional" reservoirs, and the sporadic deliverability associated with production through natural fractures. How to more intelligently extract these substantial reserves is a goal not only applicable to the Uinta Basin itself, but also to other difficult plays throughout the United States. Fracture systems throughout the United States are being recognized more commonly but are not sufficiently characterized or considered to take full advantage of their presence. In this regard, the Uinta Basin was ideal for the development of advanced, integrated methodology applicable to naturally fractured reservoirs. This is because:

- substantial unrecovered resources are present,
- historical oil production has taken place in the basin since the 1950s,
- primary production has largely been hit-or miss, with recoveries in the 5 to 10% range (Colburn, et al., 1985),
- excellent geologic exposure and structural expression characterize the basin, and
- good, basic geologic information is readily available.

The completed study focused on an area fracture-controlled highly unpredictable, fracture-controlled production near the Duchesne Fault Zone, Uinta Basin, in northeastern Utah. Production is seriously influenced by numerous high-angle faults and associated fractures - represented at the surface by a set of parallel, N80°W-trending lineaments, and intricate fracture patterns in outcrop. Specific production is erratic and secondary recovery design is difficult because well-specific structural characterization and local fracture patterns are poorly understood. Furthermore, numerical models to simulate fluid flow in fractured reservoirs were either overly simplistic (did not adequately account for mechanical contrasts between matrix and fractures) or were extremely complex, requiring volumes of data typically *not* available to the operator.

The contractors proposed implementing advanced geological, geomechanical and reservoir engineering methods to recognize and model the complex fracture networks exhibited at the surface and suggested in the shallow subsurface in the Duchesne Fault Zone. The intended methodology was to be developed in a *data-limited environment*, recognizing that operators in the basin will not have the financial resources or motivation to perform sophisticated and expensive reservoir engineering programs. User-friendly models for permeability, stress, and production using key geological and geophysical data, developed in this study can then be used to determine:

- ✓ economic placement of future operations
- ✓ assessment of recoverable hydrocarbons, and
- ✓ forecasting of primary and secondary recovery.

The project team integrated engineering and geological expertise from diverse organizations:

- *TerraTek, Inc.* – a geological and geomechanical applied research and service company,
- *Department of Geology and Geophysics* from the *University Of Utah*, with recognized expertise in fracture characterization,
- *Reis and Associates* – an independent consulting firm with expertise in formulating reservoir engineering numerical models,
- *Utah Geological Survey*, with substantial experience in Uinta Basin research and hydrocarbon studies, and,
- *E^xponent Failure Analysis Associates* – an internationally recognized leader in the investigation and analysis of engineering and scientific problems.

Project Objectives

The completed study, summarized in this and previous reports, focused on the development of reliable well-siting information using an advanced, multidisciplinary approach to characterizing naturally fractured, economically “difficult” reservoirs. Although the simulations and models developed during this research may still be complex, procedures are available to provide methods for operators who do not possess extensive resources to carry out proprietary studies. Methodology created from characterization and modeling of fractured Uinta Basin reservoirs in the Green River Formation can certainly be applied to numerous other fractured plays in Rocky Mountain basins, as well as to other hydrocarbon reservoirs with subtle tectonic complexity and fracture-enhanced permeability.

The long-range objectives for this research were:

- *To integrate surface geological investigations with available subsurface data pertaining to a pronounced fracture system affecting oil reservoirs in the Uinta Basin, northeastern Utah.*
- *To apply basic and advanced geological, geomechanical, and reservoir engineering data to implement advanced techniques for fractured reservoir characterization along the Duchesne Fault Zone. These approaches focused on the prediction of the variability of permeability and associated stresses throughout a large region, using limited available data.*
- *To model permeability, stress, and production parameters in order to create a geological laboratory with practical, three-dimensional application for potential operators.*
- *To improve efficiency of primary and secondary recovery in fractured reservoirs not only in the Uinta Basin but also in analogous situations elsewhere in the United States.*
- *To develop new predictive models for heterogeneous reservoirs in the presence of crossflow between media. Such models can then be extended to oil recovery from naturally fractured reservoirs during waterflooding.*

Technical Approach to Objectives

As stated in the original proposal, the basis for this research was to implement state-of-the-art geological, geotechnical, and reservoir engineering techniques in order to model the complex fracture networks that characterize the Duchesne Fault Zone. A series of tasks was carried out with the following considerations in mind:

- Most naturally fractured reservoirs will be data-limited. Available data may include basic structural and stratigraphic information, some pressure transient data, minimal logging suites, and some production information.
- Operators will not have the financial resources or motivation to perform extensive and expensive reservoir engineering programs. Even if sophisticated testing is performed, inherent reservoir heterogeneities make interpretation of these data speculative.
- Methods must be developed for economically extending (interpolating and extrapolating) the few measured fracture regimes throughout the entire field to develop stress and permeability maps for well siting.

Individual tasks described below centered on two different areas along the Duchesne Fault Zone experiencing different types of production:

- ✓ fracture production at ~2000 ft from shales with little or no matrix porosity in the Duchesne Field, and,
- ✓ fracture-enhanced production at ~5000 ft from sandstones with some intrinsic porosity/permeability at Pariette Draw (referred to as the Balcron Area).

The flowchart below (Figure 1) graphically presents a series of discrete tasks that were proposed and carried out during the course of this research. A summary of each research task follows. Accomplishments are listed subsequently.

Figure 1. Flow chart of Tasks carried out in this research.

TASK 1 - RESERVOIR CHARACTERIZATION

Participants: *TerraTek, Inc. University of Utah, Utah Geological Survey*

Objective

Consolidate available geological information and generate supplemental field information to adequately characterize the stratigraphic and structural regimes along the Duchesne Fault Zone. Fracture quantification of lithotypes and fracture spacing information were major efforts here.

Deliverables

Improved structural maps of the Duchesne Fault Zone in the Duchesne and Balcron fields that include all recognized faults and associated structures. Through reservoir characterization, all data were directly incorporated into subsequent tasks for the final product.

TASK 2 - LABORATORY MATERIAL CHARACTERIZATION

Participants: *TerraTek, Inc.*

Objective

Determine the mechanical and fluid transport characteristics of intact (matrix) and fractured samples from the Balcron and Duchesne fields for load-deformation modeling, development of the local permeability tensor in the reservoir, primary production forecasting, and analytical representations.

Deliverables

Intact rock properties and naturally fractured rock properties applicable to the modeling effort in Tasks 3, 4, 5, and 6. A particularly important deliverable was an analytical/empirical predictive model for natural fracture deliverability under different normal and shear stress conditions.

TASK 3 – FRACTURE REPRESENTATION

Participants: *TerraTek, Inc., Exponent Failure Analysis Associates*

Objective

Delineate the fracturing infrastructure and stress conditions in the field using Discontinuous Deformation Methods (DDM). From a low-resolution representation of the fields areas, numerically generate a high-resolution representation of the Balcron Area, indicating favorable well locations and natural fracture morphology for use in predictions of deliverability in Task 4.

Deliverables

From the field information on fault/joint systems and far-field stresses calculated for these portions of the Uinta Basin, the Discontinuous Deformation Method generates the stress distribution in each block, which is in itself bounded by designated faults or joints. The stress distribution was then used to designate smaller-scale fractures in the basin blocks (Zheng, 1989). Finally, after small fracture sets were generated in each large block, the DDM model was again utilized to obtain more detailed stress maps including recognition of both normal and shear stresses on fracture surfaces.

TASK 4 - PERMEABILITY TENSOR

Participants: ***University of Utah, TerraTek, Inc.,***

Objective

To consolidate the measured and predicted fracture information for the reservoir into a spatially-varying representation of the permeability tensor; represent permeability sensitivity to varying reservoir pressure.

Deliverables

From a high-resolution representation of the field, consolidate the available fracture information, provide a location-dependent representation of the principal permeabilities (representing permeability anisotropy) and indicate how these permeabilities will vary as a function of reservoir pressure. An operator now has a logical measure of how permeability will vary through the reservoir - in essence, permeability anisotropy coupled with reservoir pressure variability.

TASK 5 - PRIMARY RECOVERY MODEL

Participants: ***Reis and Associates, TerraTek, Inc.***

Objective

To verify a multi-porosity model (formulated by John Reis) specifically developed for prediction of primary recovery in naturally fractured reservoirs.

Deliverables

Include (1) multi-porosity model for prediction of primary recovery from naturally fractured reservoirs, and (2) technology to characterize the fractured reservoir and the fracture system around the wellbore from the pressure transient response.

TASK 6 - SECONDARY RECOVERY MODEL

Participants: *Reis and Associates, TerraTek, Inc.*

Objective

Because secondary recovery is currently adopted in the Uinta Basin, some guidance on sweep efficiency of fractured sandstones would be especially important, not only in known designated waterflood units, but throughout the Balcron Area. The findings would also be instantly applicable to floods in lenticular fractured sandstones throughout the United States. The primary objective of this task was to develop a model for fluid flow in naturally fractured reservoirs in the presence of cross-flow between media.

Deliverables

Include a new waterflooding recovery (secondary recovery) model for naturally fractured reservoirs. This model includes a variety of fracture characterization data in its prediction of waterfront position in a fractured reservoir undergoing secondary recovery.

TASK 7 - TECHNOLOGY TRANSFER

Participants: *TerraTek, Inc., University of Utah, Reis and Associates, Utah Geological Survey, Exponent Failure Analysis Associates*

Objective and Deliverables

Technology transfer of information is an essential component of the research package. In addition to promoting the missions and results of the programs to associates and clients during the normal course of business and through face-to-face exchanges, technology transfer also involved: (1) monthly, quarterly, annual, and final progress reports, as prescribed by BDM; (2) annual reporting in semi-technical trade journals, technically oriented congresses such as SPE meetings and forums, and numerous publications in refereed geologic, engineering, and oilfield journals; (3) oral presentations and poster displays at appropriate technical conferences; and (4) presentation of results at Petroleum Technology Transfer Council workshops.

SUMMARY OF ACCOMPLISHMENTS

Numerous technological and methodological advances of varying scope have developed during the course of the funded research. Some accomplishments simply involve a better qualitative understanding of and approach to the relationship between subtle surface character and subsurface structure and fluid flow. Other avenues of research have yielded discrete numerical or visualization tools for reservoir evaluation, production forecasting, and reservoir management. Both types of data are significant to individuals at all levels of industry involvement who have to contend with economically problematic, structurally complex reservoirs.

The following discussion summarizes the significant accomplishments that have resulted from this multi-phase study, categorized by topic and/or task. Where appropriate, implementation, importance, and applicability to operators in this and other basins are highlighted.

TASK 1 - RESERVOIR CHARACTERIZATION

The Duchesne Fault Zone at the Surface

- Detailed structural maps of the Duchesne fault zone were completed in the two study areas (the Duchesne oil field and the Balcron Area to the east). Maps incorporated extensive lineaments visible on aerial photographs, as well as smaller-scale faults, joints and folds revealed through detailed surface mapping. It was determined that some faults are more laterally continuous than previously determined. This in itself had significant ramifications in the homogeneity of the stress fields predicted by numerical modeling.
- Outcrop studies along the Duchesne fault zone indicated that fracture partitioning within the basin is clearly lithology-dependent. Sandstones of the Uinta Formation contain conjugate joints that dip steeply to the north and south and strike parallel to the fault zone. Fine-grained, lower porosity carbonates contain only vertical fractures and are locally pervaded by joints. Fracture spacing decreases (at the surface) appreciably with proximity to the primary fault zone. *Average fracture spacings within the highly faulted graben in the Balcron area are as small as 1.8 ft.*
- Analogous, fractured reservoir sandstones exposed at the surface are consistently oil-soaked, indicating that hydrocarbon migration may have preceded faulting. Later-formed gilsonite dikes also indicate *two episodes of hydrocarbon migration*. Why is this important? Structural cross-cutting relationships in the field indicate that the fault zone likely characterizes a *paleotectonic* stress environment different from those currently existing - an important consideration in the ultimate delineation of sweets spots.
- In the Balcron area, calcite-cemented gouge, as well as calcite veins and lenses, now seal the walls of the faults, thereby forming barriers to lateral fluid flow. However, intense fracturing in the country rock adjacent to the faults may provide pathways for fluid migration, both along strike and vertical dip.

Subsurface Structure Revealed

- Data acquired from FMS logs from the Duchesne field indicate that open fractures do exist at reservoir depths from 2500 to 3000 feet and that fracture spacings are as small as 1 to 2 inches. Likewise, examination of Formation Micro-Imager (FMI) data from the Balcron test well yielded four major fracture classes: (1) open, well-developed fractures continuous around the wellbore; (2) open, but nonpenetrative fractures, either lithologically bounded or partially healed; (3) mineralized fractures; and (4) drilling-induced fractures. Open natural fractures typically strike between N50°W and N80°W.
- Subsurface cross-sections in the *Duchesne field* currently indicate a maximum of 600 feet of individual displacement across a single fault plane (Groeger, 1997). However, total displacement involving all known faults appears to be negligible. Correlation of well logs and integration with mapped fault traces in the *Balcron area* (Humpback Waterflood Unit) revealed that *vertical offsets due to faulting are up to several tens of feet, but less than 100 feet*. Furthermore, stratigraphic cross-section clearly indicates that four selected marker beds all appear to be affected by faults at depth. Projection of surface features into the subsurface shows *discernible offset of the major producing interval (R5) across modeled faults*.
- If the structural and mineralogical characteristics of normal faults observed at the surface are similar to those at depth, faults can be expected to form low-permeability baffles or barriers that restrict lateral movement of hydrocarbons and injected fluids from one side of the fault to another. Permeability parallel to the fault surfaces could allow vertical migration of fluids, but the faults may now be largely impermeable because of extensive calcite cementation that clogs both intergranular porosity and fault-generated void space between slip surfaces.

TASK 2 - LABORATORY MATERIAL CHARACTERIZATION

Properties were determined from mechanical tests of intact sandstone rock core samples obtained at 5176 feet from the Balcron Federal Well #23-25 (Quarterly Report TR97-6130Q3). Although the mechanical properties testing indicated a Young's Modulus ranging from 3.13×10^6 psi to 4.18×10^6 psi, depending on the applied confining pressure, a lower value of Young's Modulus 2.0×10^6 psi, was used in numerical analyses to account for the increased compliance due to ubiquitous fractures, known to be present.

TASK 3 - FRACTURE REPRESENTATION

Hydraulic Fracturing and Production

- Analysis of hydraulic fracture information gathered from the Balcron producing area indicates that productivity appears to be independent of the volume of fluid and mass of proppant. This observation suggests that primary production is not dominated by conventional porous medium flow and that fracturing is likely the contributing candidate. In addition, several prominent wells had high instantaneous production regardless of the treatment volume. These wells are #9-23, #21-25, and #31-25.
- Several typical treatment stage volumes were simulated using a fully three-dimensional hydraulic fracturing model, based on actual pumped treatments in the Balcron area test well (Equitable Resources #23-24). *Results show that fracture growth is preferentially downward and highest conductivity may be well below the pay zone* (largest volumes of sand are pumped downwards). This would favor the small, high concentration treatments currently being performed, although alternate perforating strategies should be considered. In addition, proppant concentrations in the pay, even for the larger jobs, were less than 0.5 lb/ft², and weighted-average dimensionless fracture conductivities in the pay for three treatments were 4.12, 2.59, and 3.98 (probably low except for long production times).
- Indications from hydraulic fracturing simulations performed during the course of the research are that abnormally high production in some wells cannot be explained by variations in fracturing treatments (although some treatment design improvements were obviously possible). Evaluation of production data in the Balcron area was, therefore, undertaken to see if keys to high production could be identified. No production trends were identified when comparing time-dependent production averages. *However, comparing initial production with effective producing thickness in the R5 pay zone revealed that anomalously high production in three wells (#9-23, #31-25, and #21-25) can be directly attributed to intersection of conductive channels or faults systems. A strong linear trend exhibited by most wells showed a distinct dependency on stratigraphic net producing thickness (Figure 25, Quarterly Report No. 8).*

Discontinuous Deformation Modeling

- Fracturing infrastructure, localized stress conditions, and preferred exploration locations were delineated using the Discontinuous Deformation Method (DDM). The most refined model

incorporates geometrical relationships between mapped faults extending into the subsurface in addition to mechanical properties of fault surfaces and pay zone lithotypes.

Summary

Results are presented of a computational stress analysis for a 2.3-mile by 2.0-mile region of the **Balcron** oil field in the Pariette Draw area, Uintah County. The finite element model described in previous reports was refined and a parametric study was conducted to determine the effects of certain fault properties on the stress state. The computational results indicate that stresses in the region of the fault are not significantly affected by the presence of the fault, with the exception of the fault terminus where stress concentration effects occur. These results are generally consistent with other numerical analyses of the local effects of faults.

Finite Element Model

The finite element model was constructed from the geological model of the **Balcron** oil field in the **Pariette Draw** area of Uintah County. A plan view of this general area, constructed from geologic mapping of predominate fault traces, showing the locations of oil wells in the area is shown in Figure 2. As documented in previous quarterly reports, the major faults are believed to be almost vertical. Therefore, a two-dimensional model representing a horizontal slice of the field has been adequate to estimate the effects of the faults on the stress state.

Finite Element Mesh and Interface Elements

The finite element mesh used is shown in Figure 3. The model consisted of six separate deformable bodies or *blocks*. The finite elements were linear triangle elements. These elements are often referred to as constant strain elements because the components of the strain tensor, ϵ_{xx} , ϵ_{xy} , and ϵ_{yy} , are constant within the element. The elements are approximately 333 feet along the border of each block.

Stress is transferred between blocks using interface elements. The interface elements prevent blocks from penetrating one another, but allow relative sliding and intermittent contact or separation along contact surfaces (Kikuchi and Oden, 1988¹; Hilbert, et al. 1994,² 1995³). The interface elements are based on a *perturbed Lagrange multiplier* method. Lagrange multiplier methods are frequently used in contact mechanics because contact stresses or forces between the bodies can be extracted directly and the impenetrability constraints are satisfied exactly. The perturbed Lagrange multiplier method is an approximate technique for enforcing contact constraints in which some penetration (i.e., overlap) between bodies is permitted. A penalty parameter is used in conjunction with the Lagrange parameter, which may be thought of as representing an *elastic spring* between the bodies. The magnitude of the spring constant is

¹ Kikuchi, N. and Oden, J.T.: Contact Problems in Elasticity: A Study of Variational Inequalities and Finite Element Methods, SIAM, Philadelphia (1998).

² Hilbert, L.B., Jr., Yi, W., Cook, N.G.W., Cai, Y., and Liang, C.P.: "A New Discontinuous Finite Element Method for Interaction of Many Deformable Bodies in Geomechanics," *Proc. 8th Int. Conf. Comp. Meth. Adv. Geomech.*, H.J. Siritwardane and M.M. Zaman, (eds.), Balkema, Rotterdam (1994) 831-836.

³ Hilbert, L.B., Jr., Cook, N.G.W., and Myer, L.R.: 1995, "Numerical Modeling of Highly Jointed and Fractured Media Using Discontinuous Deformation Methods," *Proc. Intl. Congress Rock Mech.*, Vol. III, Balkema, Rotterdam (1995) 1159-1165.

usually taken to be a fraction of the elastic modulus of the deformable bodies. In this work, the spring constant is taken to represent the stiffness of the fault.

Mechanical Properties of Rock and Faults

The deformable bodies are linear elastic and are limited to infinitesimal deformations and small strains. The elastic properties of each of the blocks are identical.

The deformation or stiffness characteristics of the faults were inferred from the literature (Scholz, 1990⁴). A parametric study of the effect of the coefficient of friction was conducted. Friction factors of 0.2, 0.4, and 0.6 were used in separate analyses.

Figure 2. Locations of major faults and wells in the Balcron Field. The finite element model includes the major, longer faults (refer to Figure 3).

⁴ Scholz, C. H.: "The Mechanics of Earthquakes and Faults," Cambridge University Press (1990).

*Figure 3. Refined finite element mesh for the computer model of the **Balcron** oil field. The thick black lines represent fault segments included in the model, beyond these fault segments the interfaces are welded (i.e., cannot slide). The model covers approximately 2.3 miles by 2.0 miles. The thick black lines are the boundaries of the deformable blocks, the segments next to red colored faults are not allowed to slide.*

Regional (Far-Field) Stresses

The objective of this numerical modeling was to estimate the local stress fields surrounding the faults, since the regional stress field is perturbed by the presence of the faults. To accomplish this requires knowledge of the regional stress field. However, the state of tectonic stress in the Uinta Basin is not well understood, as discussed in each of the previous Quarterly Reports. As discussed in previous quarterly reports, regional principal stresses of 5500 psi and 3685 psi in the East-West and North-South directions, respectively, were used because:

- The presence and orientation of the faults comprising in the Duchesne Fault Zone indicate that the maximum principal stress is oriented approximately East-West. Field evidence of (gilsonite emplacements) indicates that the principal stresses have changed direction in the past (Quarterly Report TR96-6130Q2).
- The orientation of fractures at depth is consistent with the orientation of subsurface fractures and faults, as indicated in FMS logs from the Coors Energy Well 13-16D (Quarterly Report TR97-6130Q3).

- Data were obtained from a case study of the Pariette Draw #23-34 Well (Quarterly Report TR97-6130Q4). FMI data indicate that the fracture orientations at depth are consistent with the surface fault and fracture orientations of approximately N70°W to N80°W with a dip of nominally 85°. In this well, hydraulic fractures generated at three depths between 4674 feet and 5351 feet indicate that the minimum principal stress ranges between 3400 psi and 3820 psi. This corresponds to a minimum principal stress gradient of approximately 0.72 psi/ft ±.
- The minimum principal stress was assumed to be consistent with the 3820 psi determined in the Pariette Draw #23-24 well data. The maximum principal stress gradient was taken as 1.0 psi/ft.

Computational Results: Stresses in the Balcron Oil Field

Calculated shear stresses, σ_{xy} , are shown in Figures 4 and 5. If the model was solid (i.e., without faults) and no shear stress, σ_{xy} , was prescribed on the boundaries of the model, there would be no shear stress in the x or y directions within the model. However, the deformable faults can perturb the local stresses and affect the “transmission” of stress across the faults. Furthermore, if the fault is inclined relative to the horizontal in Figure 3 and the shear stress on the fault exceeds the frictional strength of the fault (i.e., locally on the fault $\tau \geq \mu\sigma_n$), the fault may slip and stress concentrations will be generated at the ends of the fault. This is case for the simulation with a friction factor of 0.2, as is shown in Figure 4. During loading of the model, the shear stress exceeds the strength of the fault because of the low friction factor, $\mu = 0.2$, and slip occurs. Thus, a stress concentration is generated at the “kink” in the fault. Fault slip was not predicted to occur in the simulations with factors of 0.4 and 0.6. Significant stress concentrations did not occur at the end of the faults.

Figure 4. Maximum shear stresses in the analyzed region. Shear stresses are important because it is speculated that where the shear stress is high, supplementary fracturing is possible with a consequent increase in permeability.

Figure 5. *Maximum shear stresses in the analyzed region. Shear stresses are important because it is speculated that where the shear stress is high, supplementary fracturing is possible with a consequent increase in permeability. This is similar to Figure 4, with the exception that only the higher stressed areas are represented.*

As is shown in Figures 6 through 8, which present contours of the maximum and minimum principal stresses, the principal stresses are changed from the magnitudes of the applied “far-field” stresses only in the region of the “inclined”⁵ fault which slipped. This result indicates that there is a reorientation of the principal stress field in the neighborhood of the kink in the fault. However, rotation of the principal stress axes is not significant. There is no reorientation of the principal stresses for situations where the friction factors are 0.4 and 0.6. Also, reduction in stresses can be speculated to correlate with increased permeability.

⁵ Inclined to the far-field principal stress directions.

Figure 6. This shows contours of the minimum principal stress (compression is negative). The implications are that the minimum principal stress is reduced in the region immediately to the west of the kink in the fault. With reduced stresses, permeability will be higher. The north-south band of reduced stresses correlates with the higher production in Well 9-23.

Figure 7. This shows contours of the maximum principal stress (compression is negative). The implications are that the maximum principal stress is modified, particularly in the region immediately to the west of the kink in the fault. With reduced/increased stresses, permeability will be higher/lower.

Figure 8. This is an alternate view of Figure 7 (only areas with stress greater than 5300 psi are contoured). It shows contours of the maximum principal stress (compression is negative). The implications are that the maximum principal stress is modified, particularly in the region immediately to the west of the kink in the fault. With reduced/increased stresses, permeability will be higher/lower. A northeasterly band of reduced stresses is indicated.

The differences in stiffnesses between the faults and the host rock were not large enough to result in an extremely large perturbation of the stress field in the local neighborhood of the faults. In addition, the contact elements have no thickness, as would actually be the case with a fault gouge or melange of significant thickness surrounding the fault. Pourjavad 1998,⁶ showed that a significant difference in fault stiffness relative to the host rock was necessary to produce a significant effect of the fault on the local stresses. The differences in stresses are however significant enough to impact production to some extent. To comprehend the combined effect of changes in the maximum and minimum principal stresses, mean stress is determined. Mean stress is the average of the maximum and minimum principal stresses. Mean stress contours are shown in Figures 9 and 10.

⁶ Pourjavad, M., Bell, J.S., and Bratli, R.K.: "Stress Trajectories in the Neighborhood of Fault Zones," paper SPE 47211, *Proc. SPE/ISRM Rock Mech. in Petroleum Engineering*, Vol. 2, Trondheim, Norway (1998) 33-41.

Figure 9. This figure shows contours of the mean stress (the average of the maximum and minimum principal stresses – compression is negative). It shows reduced stresses along the kinked fault and in a north-south band. Reduced mean stress correlates with increased permeability.

Figure 10. This figure shows contours of the mean stress (the average of the maximum and minimum principal stresses – compression is negative). It shows reduced stresses along the kinked fault and also in a north-south band. This figure is identical to Figure 9, with the exception that the range of stresses being contoured has been restricted to highlight the north-south trending area where mean stress is reduced and permeability could be expected to be larger.

Figures 9 and 10 demonstrate reduction in mean stress, which probably correlates with increased permeability. Earlier figures have shown areas where high shear stresses could induce supplementary natural fracturing and increased permeability. These two effects have been combined into a permeability indicator ξ :

$$\xi = \frac{\text{Maximum Shear Stress}}{\text{Mean Stress}}$$

Higher values of ξ indicate areas where it is anticipated that permeability will be improved. Contours of this parameter are shown in Figures 11 through 13. Figure 14 superimposes well locations.

Figure 11. This figure shows contours of the newly-defined permeability indicator, ξ . Higher values imply improved permeability because of reduction in mean stress and/or supplementary fracturing associated with increased shear stresses. A north-south trending sweet spot is clearly identified.

Figure 12. This figure shows contours of the newly-defined permeability indicator, ξ . Higher values imply improved permeability because of reduction in mean stress and or supplementary fracturing associated with increased shear stresses. A north-south trending sweet spot is clearly identified. This figure is identical to Figure 11, with the exception that the range of values contoured is restricted to provide more detail in the areas where wells exist. Figure 13 is similar.

Figure 13. This figure shows contours of the newly-defined permeability indicator, ξ . Higher values imply improved permeability because of reduction in mean stress and or supplementary fracturing associated with increased shear stresses. A north-south trending sweet spot is clearly identified. This figure is identical to Figure 11, with the exception that the range of values contoured is restricted to provide more detail in the areas where wells exist. Figure 12 is similar.

Figure 14. Variation of the permeability indicator ξ with position. The producing wells are superimposed. The high production from Well 9-23 is strongly supported because of its proximity to the fault and incorporation in the north-south trending sweet spot (plus there is a relatively thick and clean reservoir section). The lower productivity in Well 11-25 is clearly associated with the lower ξ values. Wells 21-25 and 31-25 also have high production. They are in a zone of modest ξ . The ξ value needs to be combined with reservoir thickness data and permeability measurements to fully characterize the reservoir.

TASK 4 - PERMEABILITY TENSOR

Permeability Anisotropy

- A new computer code was developed in cooperation with S. Brown of Applied Research Associates to model the permeability of deformable fracture networks in two dimensions. This code has the ability to:
 - (1) model and include the stress tensor in either principal or non-principal reference frames, and
 - (2) account for the effects of both shear and normal stresses on fracture aperture, based on a rough, fractal surface model for the fracture walls.
- Data input consists of a file with fracture orientation and trace lengths, the area of the sample domain, the permeability of the rock matrix, and the magnitudes and orientations of the two-dimensional stress tensor. This program was developed using the MatLab™ scripting language.⁷
- A separate computer algorithm was developed for modeling permeability in fractured rocks that contain both faults and joints. This algorithm was developed to model normal fault arrays like those mapped in the Duchesne fault zone. Input data include the dip angle and dip direction of each fracture, the rake of the slip direction and the fault surface (or a code to indicate that the fracture is an isotropic joint), the permeability of the rock matrix, the volume of the modeling domain, and the magnitudes and orientations of the three principal stresses. This program was developed in the MatLab™ scripting language.⁷
- A computer program for modeling and viewing fracture networks in either two-or three-dimensions was developed by K. Mahan and R. Bruhn of the University of Utah. The program provides an interactive tool for visually generating fracture networks based on statistical information acquired from basic surface mapping, remote sensing images, and downhole fracture imaging logs. The program allows the user to enter information on fracture trace length and orientation, displays the data, allows the user to adjust the probability density distribution functions interactively, then generates a simulated fracture network in three dimensions with the appropriate statistical properties. An example of a three-dimensional fracture representation created from this program is presented in Quarterly Report No. 5 (Subcontract G4S51729, October 2, 1997). This program was also developed using the MatLab™ scripting language.⁷

⁷ MatLab™ is a commercially available engineering and science software package that runs on all common types of computers, and is an ideal software platform for technology transfer.

Three-Dimensional Reservoir Modeling and Visualization

To develop strategies for exploration and exploitation, it was recognized that better geologic models and more realistic numerical simulations of fluid flow are essential. This is a challenging prospect in intensely faulted reservoirs because the subsurface structure is complicated by abrupt offsets of producing intervals, heterogeneous fracture swarms, and complex fault patterns. Three-dimensional computer visualization of fault zone and reservoir geology allows geologists and reservoir engineers to quickly visualize the geometry and location of strata and faults, to examine the location of existing and proposed wells relative to these features in the subsurface, and to conveniently consider various drilling and completion schemes. Three-dimensional geologic models also provide constraints on hydrological models of the reservoir.

During the course of this study, a three-dimensional reservoir modeling procedure was developed that incorporates a combination of custom MatLab™ script files, written at the University of Utah, and public domain visualization software. The MatLab™ programs can be used to prepare topographic data, geological measurements, and well log data for input into a three-dimensional visualization package. In this study, the GEOMVIEW (Version 1.6.1) computer code was chosen as the visualization tool.

A prototype reservoir model of the Humpback waterflood unit in the Balcron area illustrates the potential of interactive, three-dimensional computer visualization for evaluating reservoir models that integrate both surface and subsurface data (Figures 15 and 16). In this case, the user can visualize:

- the extent of mapped structures in the subsurface (including the pay zone) and fault geometry,
- topographic expression as related to structural elements,
- well locations in relation to faults and fault-bounded blocks,
- proximity of known fracture zones to perforated pay intervals at depth, and,
- expected fluid flow pathways into and out of wells during secondary recovery (waterflooding).

This refined three-dimensional model can be used by operators to make qualitative assessments of secondary recovery strategies, and to define reservoir model grid blocks for simulation of production and secondary recovery. This type of modeling is critical because operators are presently designing waterflood projects with the assumption that the sandstone bodies are continuous and well connected across the Humpback Unit (Morgan, 1997). This assumption is almost certainly incorrect, based on the evidence for fault offsets of beds. Offsets of several feet to several tens of feet are sufficient to strongly affect the efficiency of waterflooding in the producing sandstones.

Figure 15. This computer-generated, three-dimensional (block) of the Humpback Unit has been updated to include offset carbonate markers (subsurface) in the Green River and Uinta Formations. Also shown are re-interpreted fault traces, digitized surface topography, and locations of wells in the Humpback unit. Projections of fault traces into the subsurface have been modified to create a more realistic fault geometry: south-dipping, antithetic faults truncate against a master north-dipping fault.

Figure 16. *This representation was computer generated and facilitated visualization of fault blocks, well trajectories, markers and pay.*

TASK 5 - PRIMARY RECOVERY MODEL

Primary Recovery Model

- New models for multi-porosity reservoirs were developed that allow the effects of fracture spacing distributions (on pressure transient response) to be quantified. These models divide the matrix into multiple domains and group similar matrix blocks into the same domains. *Unlike existing multi-porosity models that require complex Laplace transform or an infinite series solution before they can be used, these models give direct solutions in the time domain that can be easily programmed into a commercial spreadsheet. This solution allows simple and rapid calculations of the pressure transient behavior when a distribution of fracture spacings is incorporated.*
- Results from the primary recovery model indicate that the differences between the pressure transient responses of the double-, triple-, and quadruple-porosity models were so small that field data cannot be used to differentiate between them. The simpler double-porosity models probably provide as much reliable data as the more complex multi-porosity models. Use of the more complex multi-porosity models is probably not justified.

TASK 6 - SECONDARY RECOVERY MODEL

A model was developed for predicting fluid flow in naturally fractured reservoirs in the presence of cross-flow between media, to simulate the injection of water into objective reservoir zones during secondary recovery. The model was designed to simulate fluid flow in a series of reservoir blocks.⁸

TASK 7: TECHNOLOGY TRANSFER⁹

Objectives

There were six components in the Marketing Program. These are shown in Figure 17. The individual components are discussed separately.

⁸ Additional information is provided in Appendix A.

⁹ Abstracted from Quarterly Report TR98-6130Q8, June 1998.

Figure 17. Components of Ongoing Technology Transfer Program.

Component 1: Information Specifically Related to the Uinta Basin

Objectives

To continue to familiarize local producers (Uinta Basin operators) with the DOE-funded technology program and to emphasize how the specific findings and the approaches can be applied in their particular situations.

Methodology and Status

This objective is being undertaken in four different ways.

- All contractors are promoting the program, results and philosophies during the *normal course of business*. For example, TerraTek interacts with many of the producers in the Uinta Basin. These individuals are informed of the progress of the project, the key developments and the considerations that should be applied to their specific reservoirs.
- Presentation of the results in local and national *forums*. To date, TerraTek is scheduled to provide presentations in two workshops. These are:
 - ✓ Fractured Reservoirs Workshop – West Texas Geological Society, October 16, 1998, Midland, Texas
 - ✓ DOE Technology Transfer Workshop, October 28, 1998, Socorro, New Mexico
- TerraTek summarizes recent developments for programs such as this in its *Web Site* (www.terratek.com). For example, TerraTek's technical presentation on the program in the Uinta Basin at the latest national AAPG Meeting is incorporated into its Web Page. This presentation could be provided to BDM in HTML format. The presentation is highlighted in Appendix B.

- ***Publications*** have been an integral part of the Technology Transfer Program all along. Appendix C summarizes the publications to date and indicates planned future publications.

Component 2: *Applicability to Other Reservoirs in the United States*

Objectives

To continue to familiarize producers (throughout the United States) of the DOE-funded technology program and to emphasize how the specific findings and the approaches can be applied to their particular situations (reservoirs or plays).

Methodology and Status

The methodologies and findings are applicable to other fractured reservoirs. As with Component 1, this is being indicated to producers using four approaches:

- Promotion of the program, results and philosophies during the ***normal course of business***. TerraTek interacts with many producers who have fractured reservoirs in other parts of the United States. These individuals are informed of the progress of the project, the key developments and the considerations that should be applied to their specific reservoirs.
- Presentation of the results in local and national ***forums***. To date, TerraTek is scheduled to provide presentations in two workshops. These were indicated above. The workshop scheduled in Midland (October 16, 1998) will emphasize methodology of studying fractured reservoirs and its application to similar reservoirs in Texas Basins.
- TerraTek summarizes recent developments for programs such as this at its ***Web Site***, (www.terratek.com). This has been discussed previously (refer to Appendix B). Internet communication remains an important method for technology transfer.
- ***Publications*** have been an integral part of the Technology Transfer Program all along. Appendix C summarizes the publications to date and indicates planned future publications.

Component 3: *Promote Appropriate Methodologies for Evaluation*

Objectives

To emphasize (to operators) methods that will assist in identifying fracture systems in their fields, with an emphasis on how these systems will impact production.

Methodology and Status

For example:

- ***The University of Utah:***

Practical methods for evaluating the characteristics of fracturing in faulted reservoirs were a major focus of this project. Emphasis was placed on methods that can be implemented efficiently in the field by geologists, and on visual techniques that can be implemented using typical office and laboratory computers.

- ✓ **Field Methods:** There is a vast body of literature detailing fracture sampling methods for which outcrops are used as reservoir analogs (e.g., La Pointe and Hudson, 1985). The University of Utah evaluated these methods in the Duchesne fault zone, and found that the most practical and useful information was the spacing, trace lengths, orientation and type of filling material. The nature of natural exposures limits the quantity and completeness of outcrop data, which in turn limits the utility of sophisticated statistical algorithms for characterizing fracture data. During this study we developed and extended fracture modeling programs that allow the operator to interactively create fracture networks that are both statistically and visually similar to those seen in the field. We streamlined data input by developing methods for acquiring photographic images of fracture networks, and transposing the images into digital format suitable for interactive computer modeling. *These codes are available in a form suitable for use with MatLabTM, a commercial engineering and scientific analysis system that runs under all major computer operating systems (UNIX, Macintosh, and PC).*

- ✓ **Fracture Permeability Models:** Highlights of this work were the development of computer codes to model fracture permeability in two- and three-dimensions for networks of fractures that respond to changes in the stress field (Brown and Bruhn, 1998), and for networks containing both joints and faults (Bruhn et al., 1997). The new algorithm developed by Brown and Bruhn (1998) incorporates the effects of both normal and shear stresses on permeability of fractures in a network. Important results are that changes in the stress tensor can create large and non-intuitive changes in the permeability of the fracture network, including both the magnitudes and directions of the principal permeability axes. The algorithm developed by R.L. Bruhn and discussed in Bruhn et al. (1997) treats faults as anisotropic features with directional permeability dictated by fault surface morphology. Joints are treated as hydraulically isotropic features. *This work illustrated the importance of discriminating between joints and faults in fracture networks because the anisotropy introduced by fault structure may cause significant changes in permeability that will not be detected in other fracture permeability computer codes.*

- ✓ **Reservoir Visualization and Fluid Transport Characterization:** Visualization of the structure of the reservoir is an important first step in developing strategies for both primary and secondary production. We evaluated three-dimensional computer models that incorporate surface topography, surface mapping, and subsurface logging data to generate reservoir models in three-dimensions. *Three-dimensional models of the Humpback Unit in the eastern Duchesne fault zone were generated using GEOMVIEW, a public domain software program that allows the user to interactively rotate and "fly through" the modeled reservoir on the computer screen.* The resulting models are extremely useful, because they allow the geologist to present reservoir data in a manner that is quickly assimilated by a variety of personnel, including reservoir engineers and managers.

➤ *Exponent Failure Analysis Associates* is stressing (to producers) that:

- ✓ To design effective secondary recovery programs and to understand the mechanics of a reservoir, operators must estimate the stress field in the area of the well. However, most operators cannot or do not consider the local effects of faults and fractures. *The computational methodologies used during this project, to determine the effects of discontinuities, will continue to be presented to operators.*
- ✓ Operators are beginning to use computational geomechanics in their reservoir analysis investigations. *This project is being used to demonstrate the importance of deformation of the reservoir rock and overburden/underburden and in particular, the effects of faults and fractures.*

Component 4: Software and Numerical Methods

Objectives

Indicate specific numerical or visualization tools that can be effectively used for reservoir evaluation, production forecasting and reservoir management.

Methodologies and Status

Certain important tools have been used or validated during the course of this project. These include:

➤ *The University of Utah:*

The following software was either developed or modified and extended as part of this project:

- ✓ ***FMOD2D, FMOD3D:*** These programs provide interactive modeling of fractures in two-dimensions (FMOD2D) and three-dimensions (FMOD3D) using data from field and subsurface measurements.
- ✓ ***FRFK2D, FRFK3D:*** Computer codes that model fracture permeability using modifications of the Representative Element Volume (REV) models of Oda et al., 1987.
- ✓ ***Oda2d:*** A computer code created by S.R. Brown and R.L. Bruhn (Brown and Bruhn, 1998) to model the effects of normal and shear stress on a network of deformable fractures.
- ✓ ***PAFN:*** A computer code written by R.L. Bruhn and discussed by Bruhn et al., 1997, which treats compound fracture networks comprised of joints and faults.
- ✓ ***Fracture Modeling Utilities:*** A group of computer programs which are used to estimate the statistical properties of fracture networks.

All of the above computer codes are the intellectual property of the author or authors, and are available in the public domain. The codes are written in the MatLab™ scripting language, and require use of the commercial MatLab™ product (The MathWorks, Inc.) which runs on UNIX, Macintosh and IBM-compatible computers.

➤ *Exponent Failure Analysis Associates:*

- ✓ Methods of contact mechanics were incorporated into computational geomechanics software during dissertation research at the University of California at Berkeley. This software was used to construct a model of the faulted Uinta Basin and to simulate the effects of faults on the regional stresses in the basin.
- ✓ Simulations of the Basin as an assemblage of deformable blocks have been performed to determine the effects of the faults on the regional stress field.
- ✓ Contour plots of the variation of stress as a function of location in the field have been used to investigate the effects of the faults on the local and regional stresses.
- ✓ Investigations are continuing to determine the relationships between well production, computed stresses, and the proximity of wells to faults.
- ✓ The effects of faults on the regional stresses is important and non-trivial. However, operators have rarely modeled oil and gas bearing basins considering these effects.

➤ *Reis and Associates:*

- ✓ A new pressure transient analysis model was developed that explicitly allows a realistic fracture spacing (matrix blocks size and shape) distribution to be included in the model (Reis, 1966a). This new model assumes that all matrix blocks can be grouped into one of a number of matrix domains. Each domain can have different properties, sizes, and shapes, but all matrix blocks within a particular domain are assumed to be identical. Traditional dual porosity models assume only one matrix domain. This new model gives complete analytical expressions for the pressure transient response for up to three matrix domains (quadruple porosity reservoirs) and can be extended to an arbitrary number of matrix domains by numerically determining the roots of a higher-order polynomial equation.
- ✓ A method for utilizing measured fracture spacing data in the new pressure transient model was developed (Reis, 1966b). This model assumes that the fracture spacing distribution can be modeled by either a log-normal or a negative exponential distribution. This approach gives the equivalent shape factor for each of the matrix domains.
- ✓ The new pressure transient model was demonstrated by applying it to typical fractured reservoir properties (Reis, 1966b). For the data used, it was determined that including multiple matrix domains had an effect on the predicted pressure transient response, but that the effect was relatively small. It was concluded that, in the presence of normal formation heterogeneities, traditional dual porosity models provided a good model for the reservoir behavior and the complexity of adding multiple matrix domains may not be warranted.
- ✓ Existing and new analytical models for capillary imbibition of water into oil-saturated matrix blocks in both one- and multi-dimensions were developed and converted to a common set of parameters. These models were then tested against existing laboratory data to determine their validity. The strengths and weaknesses of these models were identified (Reis, 1997a and 1998).
- ✓ New models for the advance of water down individual fractures and through fracture

networks (equivalent porous medium) in the presence of capillary imbibition into the associated matrix blocks were developed (Reis, 1997b and 1998). These models allow realistic fracture spacing distributions to be used for the matrix block sizes and shapes by utilizing the matrix domain concept previously developed for the new pressure transient analysis model (Reis, 1998).

- ✓ A new approach to evaluating waterflooding in naturally fractured reservoirs that uses fracture spacing data from the field, imbibition data from the laboratory, and the new models developed in this study was successfully demonstrated.

Component 5: Public Domain Information Dissemination

Objectives

The work program has applications outside of the petroleum industry. These include the general geotechnical and environmental disciplines. Where appropriate, the relevant information will be made available to these disciplines.

Methodologies and Status

The objective would be accomplished as follows:

- During the *normal course of business*, all parties involved in this work, some more than others, have contact with individuals from organizations involved in non-petroleum applications. Relevance of the project and its findings would be indicated to these individuals. Hydrologic and contaminant flow in fractured aquifers (for the environmental industry) is one such application.
- **Publications:** A good example is E^xponent Failure Analysis Associates' abstract for the 1999 Rock Mechanics Meeting in Vail, Colorado. Many of the attendees will be from other geomechanics disciplines.
- **Internet Presentations:** As examples:
 - ✓ E^xponent Failure Analysis Associates has a diverse client base that includes forensic engineering in the areas of civil engineering, mechanical engineering, biomechanics, and many other areas. Situations for non-petroleum applications that have been promoted to potential E^xponent clients have been landslide causation, mining and mineral extraction, and subsidence induced by groundwater withdrawal. E^xponent maintains a website (<http://www.exponent.com>) in which they are incorporating examples of the simulations of the Uinta Basin performed during this project.

Component 6: Identify Future Needs and Required Improvements

Objectives

Solicit continuing research money from various agencies, consortiums or individual organizations to do site-specific evaluations, using the team that has developed in this project.

Methodology and Status

➤ *TerraTek, Inc.:*

- ✓ TerraTek is currently the lead contractor on an industrial consortium evaluating produced water reinjection. An essential component is geomechanical modeling. Concepts and protocols learned from the Uinta Basin project are being incorporated.

Possible future applications include:

- ✓ Maximizing development in fractured hydrocarbon reservoirs in the Rocky Mountain region and throughout the United States; specifically, other oil plays, tight gas or fractured gas plays, and fractured shale-gas reservoirs in structurally disturbed basins,
- ✓ Fluid-flow studies in the environmental industry; specifically, water or contaminant flow in fractured and structurally complex aquifers,
- ✓ Site evaluation for the geotechnical industry; specifically, sites characterized by fracture networks or fault systems, and,
- ✓ Mining development strategies in fractured/faulted deposits; e.g., tunnel stability, stress concentrations, subsurface fault distributions, and the extent of mineralization.

➤ *E^xponent Failure Analysis Associates:*

- ✓ The Ekofisk field in the North Sea (Phillips Petroleum) is an example of a petroleum reservoir whose behavior is governed in part by faults and fractures, much as the Uinta Basin. E^xponent has been discussing the use of the computational methods used in this program with Ekofisk operators.
- ✓ There is considerable expanding interest in computational geomechanics for faulted reservoirs. Future improvements to the current computational methods (used in this project) are incorporation of plasticity capabilities for weak-rock reservoirs and extension of the methods to three dimensions from the current two-dimensional implementation.

➤ *Reis and Associates:*

- ✓ Dr. Reis has been formulating imbibition concepts for use in improved saturation determination from logs.

Suggestions for Present and Future Operations in the Duchesne Fault Zone

- Conventional logging analysis alone is inadequate for forecasting potential reservoir performance. Both fracture production and fracture-enhanced production have been established in the Green River Formation through the study of oriented core and imaging logs. Conjugate shears and extensional fractures have been proven to affect both the Uinta and underlying Green River Formations.
- The predominant fracture orientation in the fault zone trends N80°W, with supplementary gilsonite trends also present. Local permeability tensors, developed from detailed outcrop mapping of fractures, strongly indicate significant permeability anisotropy, with preferential permeability paralleling the major fault system. Wells literally straddle all known fault traces. From a primary recovery standpoint, this has led to certain prolific wells, as well as disappointments. *Also, based on inferred fault sealing properties, secondary recovery efforts could prove catastrophic if injectors and producers are not situated in the same structural block.*
- Avoid surveying new well locations without regard to the surface structure, and take advantage of subtle structural highs associated with mapped faults and fault-related folds. Beds dip more steeply proximal to some fault planes.
- *East-west 40-acre offsets may already be pressure-depleted. A 40-acre spacing may be adequate in the north-south direction but an 80- or 160-acre spacing may be more appropriate in an east-west sense. This is very important.*
- Hydraulic fracturing may initially propagate nonparallel to the dominant fault trend, but can ultimately be captured in a barren east-west oriented regime. In the vicinity of the predominant east-west striking features, east-west propagation is likely. Away from these features, oblique propagation is possible for some distance. Methods will need to be developed to refine hydraulic fracture design in the proximity of projected downhole faulted zones.
- Initiate horizontal drilling ventures in a northeast direction.

APPENDIX A
Secondary Recovery Model

APPENDIX A

Secondary Recovery Model

SECONDARY RECOVERY

(Final Report)

***Research and Development of Advanced Fracture Modelling
in the Uinta Basin (Utah) for Optimized Primary and
Secondary Recovery***

TerraTek, Inc.

by

***John C. Reis
Reis and Associates***

August 30, 1998

TABLE OF CONTENTS

1.0 Introduction.....	1
2.0 Imbibition Data in Laboratory	1
3.0 Equations for Field Imbibition.....	2
4.0 Field Imbibition Times	4
5.0 Water Advance in Reservoir	5
6.0 Conclusions.....	7
7.0 Project Summary.....	7
References.....	9

LIST OF TABLES

Figure 1. Imbibition Data from Uinta Field Sample.....	11
Figure 2. Dimensionless Imbibition Data from Uinta Field Sample	11
Figure 3. Modified Imbibition Ratio, X_R^*	12
Figure 4. Areal Coverage of Waterflood Project, Average Fracture Spacing = 2.6 ft.....	12
Figure 5. Areal Coverage of Waterflood Project, Average Fracture Spacing = 8 ft.....	13

LIST OF FIGURES

Figure 1. Imbibition Data from Uinta Field Sample.....	11
Figure 2. Dimensionless Imbibition Data from Uinta Field Sample	11
Figure 3. Modified Imbibition Ratio, X_R^*	12
Figure 4. Areal Coverage of Waterflood Project, Average Fracture Spacing = 2.6 ft.....	12
Figure 5. Areal Coverage of Waterflood Project, Average Fracture Spacing = 8 ft.....	13

1.0 Introduction

In this report, the waterflood recovery potential for the naturally-fractured oil fields in the Uinta Basin is evaluated. First, imbibition data measured in the laboratory on representative rock samples are described. Second, the imbibition models previously developed are modified to be more easily used with the laboratory data by separating the petrophysical properties from the matrix block dimensions. Third, field measurements of fracture spacings are discussed and used to characterize the expected imbibition rates during a waterflood project. Fourth, the measured data are combined with the previously developed models to characterize how rapidly water travels through the reservoir in the presence of capillary imbibition into the matrix blocks.

2.0 Imbibition Data in Laboratory

Imbibition data from several rock samples from the Uinta Basin were received from TerraTek. One of these samples was from a producing formation being studied through this project. The relevant properties of this sample are provided in Table 1. The shape of the sample was virtually cubic.

The imbibition properties of this sample were measured by TerraTek using the following method. The sample was first cleaned and then resaturated with an unspecified oil. The initial oil saturation was 100%. The sample was then suspended in water having an unspecified composition and its weight was recorded as a function of time. As water spontaneously imbibed into the sample and replace oil, the suspended weight changed through Archimedes principle. This weight change was then combined with the fluid densities, grain density, and porosity information to yield the water saturation as a function of time. These data are shown in Fig. 1.

From Fig. 1, it can be seen that the maximum recovery from this sample is about 12% of the pore volume. This is a relatively low fractional recovery for naturally fractured reservoirs. Recoveries for highly water-wet formations are typically 40% of the pore volume (Reis, 1992). This relatively low cumulative volume of water imbibed indicates that the sample was not highly water-wet. The time for imbibition to come to completion was on the order of 1000 minutes. This is a very slow imbibition rate relative to strongly water-wet samples reported in the literature for samples of a similar size (see references in Reis, 1998). This slow imbibition rate also indicates that the formation may not be strongly water-wet. This low total volume imbibed and slow imbibition rate was confirmed through a second imbibition test on a different sample.

It is not known whether this imbibition behavior is representative of the formation or if the wettability of the samples had been altered. If this low recovery is representative of the formation, this will significantly impact the ultimate recovery by waterflooding from these fields and will need to be considered in the economic analysis of any waterflooding projects.

The imbibition data shown in Fig. 1 were converted to the dimensionless form utilized in the previous reports. The conversion of the imbibition values was conducted by dividing the cumulative imbibition fraction (% pore volume) by the same fraction after an infinite time. The

conversion of the time values was conducted by first determining the fractional volume of water imbibed (volume imbibed divided by the volume imbibed after an infinite imbibition time) at the time when the imbibition fronts first reached the centerline of the matrix block, e.g., the centerline time. This fractional volume is given by (Reis, 1998):

$$F_{early} = 1 - \frac{L_x^2 - 2L_xL_y - 2L_xL_z + 6L_yL_z}{12L_yL_z}, \quad (1)$$

where L_x , L_y and L_z are the matrix block dimensions.

Knowing the fraction of water imbibed at the centerline time, the centerline time was then obtained from the imbibition data. The dimensionless time was then calculated by dividing the actual time by the centerline time. The centerline time for the representative sample is also given in Table 1.

The normalized (dimensionless) imbibition data are shown in Fig. 2. Also shown is the exponential model previously reported (Reis, 1998). It can be seen that the sample follows the exponential model behavior very well.

3.0 Equations for Field Imbibition

In this section, the imbibition models previously reported (Reis, 1998) will be used to develop an equation for the imbibition rate into the matrix blocks in the field. It is assumed that the matrix blocks in the lab and field have similar capillary pressure and relative permeability characteristics and only differ in size and shape.

In the previous report (Eq. 2.2.24, Reis, 1998), the following expression was obtained for the normalized cumulative imbibition volume for the exponential model:

$$\frac{Q_w}{Q_\infty} = 1 - \exp \left\{ -\ln \left(\frac{1}{F_{late}} \right) \frac{t}{t_{cl}} \right\}, \quad (2)$$

where F_{late} is the cumulative volume of water imbibed during the late time period, e.g., after the centerline time,

$$F_{late} = \frac{L_x^2 - 2L_xL_y - 2L_xL_z + 6L_yL_z}{12L_yL_z}, \quad (3)$$

and the centerline time is given in terms of the petrophysical properties as (Eq. 1.4.48, Reis, 1997a)

$$t_{CL} = \frac{\left(\frac{\mu_w}{k_{rw}} + \frac{\mu_o}{k_{ro}}\right) \phi \Delta S_w L_x^2}{4kP_{c,i}} \left[\frac{3}{16a_2} \left(1 - \frac{32}{27}a_1 + \frac{4}{3}a_2\right) \right], \quad (4)$$

where

$$a_1 = 1 + \frac{L_y}{L_x} + \frac{L_z}{L_x}, \quad (5)$$

and

$$a_2 = \frac{L_y L_z}{L_x^2} + \frac{L_y}{L_x} + \frac{L_z}{L_x}. \quad (6)$$

Eq. 4 can be is rewritten as

$$t_{CL} = \beta \frac{\phi \Delta S_w L_x^2}{4} \left[\frac{3}{16a_2} \left(1 - \frac{32}{27}a_1 + \frac{4}{3}a_2\right) \right], \quad (7)$$

where

$$\beta = \frac{\left(\frac{\mu_w}{k_{rw}} + \frac{\mu_o}{k_{ro}}\right)}{kP_{c,i}} \quad (8)$$

Using the measured values for the centerline time and the matrix block dimensions, the parameter β was calculated for the matrix block using Eq. 7. This parameter is also listed in Table 1.

Substituting Eq. 7 into Eq. 2 yields the following expression for the cumulative volume of water imbibed into the matrix block:

$$\frac{Q_w}{Q_\infty} = 1 - \exp \left\{ - \frac{4 \ln \left(\frac{1}{F_{late}} \right)}{\phi \Delta S_w L_x^2 \left[\frac{3}{16a_2} \left(1 - \frac{32}{27}a_1 + \frac{4}{3}a_2\right) \right] \beta} t \right\}. \quad (9)$$

Eq. 9 predicts the imbibition behavior for any size matrix block in the field as long as β is measured on representative samples in the laboratory.

4.0 Field Imbibition Times

Fracture spacing measurements were made on representative outcrops in the Uinta Basin (TerraTek, 1997a and 1997b). Table 2 summarizes fracture data in the formation that is associated with the imbibition data. This data corresponds to Well 9-32 (McLennan, 1998).

The fractures for this formation are assumed to be controlled by normal faults associated with a graben. The primary fracture set is parallel to the faults. Although there are orthogonal fractures observed in outcrops (in plan view), those secondary fractures are thought to be surface features associated with desiccation and are not believed to be present at depth (McLennan, 1998). The beds above and below the formation are assumed to be impermeable. Thus, there is one fracture set having the measured fracture spacings with the fractures in the other two directions having an infinite spacing. Thus, the fracture network in the reservoir is essentially a one-dimensional system.

Two average fracture spacings for the primary fracture set will be modeled. The first average spacing will be the measured average fracture spacing observed in the outcrops of 2.6 ft. The second average spacing will be assumed to be equal to the bed thickness of 8 ft. This latter spacing will be used because there is evidence that the average spacing in some formations is approximately equal to the bed thickness (Nelson, 1985). The bed thickness of the outcrop where the fracture spacings were measured was not reported.

For an average primary fracture spacing of 2.6 ft, the expected imbibition behavior for the average matrix block from Eq. 2 will be

$$\frac{Q_w}{Q_\infty} = 1 - \exp\{-0.00095t\} , \quad (10)$$

where t is in days, with

$$F_{late} = 0.5 , \quad (11)$$

and

$$t_{CL} = 727 \text{ days} \quad (12)$$

For an average primary fracture spacing of 8 ft, the expected imbibition behavior for the average matrix block will be

$$\frac{Q_w}{Q_\infty} = 1 - \exp\{-0.0001t\} , \quad (13)$$

where

$$F_{late} = 0.5 \quad , \quad (14)$$

and

$$t_{c,L} = 6820 \text{ days} \quad (15)$$

This analysis has shown that the time for the imbibition fronts to reach the centerline of the matrix blocks in the formation associated with Well 9-23 is on the order of two years for an average fracture spacing of 2.6 ft and 20 years for a spacing of 8 ft. This is considered to be a long time for imbibition to come to completion in matrix blocks in the field. This long time will necessitate an appropriate water injection strategy for an economically successful waterflood project.

5.0 Water Advance in Reservoir

The areal sweep of the injected water can be determined from the following equation (Reis, 1998):

$$A(t) = \frac{q_{w,inj} \left(\frac{\mu_w}{k_{rw,m}} + \frac{\mu_o}{k_{ro,m}} \right)}{H k_m P_{e,l,m}} \left[\frac{(\chi_1 R_2^* + \chi_2 R_1^*)}{R_1^* R_2^*} + \frac{k_m P_{e,l,m}}{\left(\frac{\mu_w}{k_{rw,m}} + \frac{\mu_o}{k_{ro,m}} \right) \phi_m \Delta S_{w,m}} t \right] + \left[\frac{1}{(\chi_1 R_1^* + \chi_2 R_2^*)} - \frac{(\chi_1 R_2^* + \chi_2 R_1^*)}{R_1^* R_2^*} \right] \exp \left\{ - \frac{R_1^* R_2^*}{(\chi_1 R_1^* + \chi_2 R_2^*) \left(\frac{\mu_w}{k_{rw,m}} + \frac{\mu_o}{k_{ro,m}} \right) \phi_m \Delta S_{w,m}} t \right\} \quad (16)$$

Using Eq. 8, Eq. 16 can be rewritten as

$$A(t) = q_{w,inj} \left[\frac{\beta (\chi_1 R_2^* + \chi_2 R_1^*)}{H} + \frac{1}{H \phi_m \Delta S_{w,m}} t \right] + \frac{\beta}{H} \left[\frac{1}{(\chi_1 R_1^* + \chi_2 R_2^*)} - \frac{(\chi_1 R_2^* + \chi_2 R_1^*)}{R_1^* R_2^*} \right] \exp \left\{ - \frac{R_1^* R_2^*}{(\chi_1 R_1^* + \chi_2 R_2^*) \beta \phi_m \Delta S_{w,m}} t \right\} \quad (17)$$

The values of χ and R^* can be determined using the method reported by Reis (1998). χ_i are the user-specified volume fractions for the two matrix domains and R_i^* are the modified imbibition ratios obtained from the following equation (Reis, 1998):

$$R^* = \exp \left\{ 1.45 X_{R^*} + 2 \ln \left(\frac{1}{\langle L_x \rangle} + \frac{1}{\langle L_y \rangle} + \frac{1}{\langle L_z \rangle} \right) \right\} \quad , \quad (18)$$

where X_{R^*} is determined from Fig. 3 at the midpoint of each domain volume fraction selected. It is noted that R^* has units of inverse length squared and β has units of time per length squared.

Eq. 17 was evaluated for the two average fracture spacings using a variety of matrix domain sets. Three triple porosity reservoirs were used, with the volume fractions for the matrix domains of 0.25 and 0.75, 0.5 and 0.5, and 0.75 and 0.25, respectively. One double porosity reservoir was also evaluated having only a single matrix domain. The water swept area was also evaluated for a nonfractured reservoir using a simple material balance with the measured porosity and change in water saturation. The relevant values for use in Eq. 17 are summarized in Tables 3 and 4 for the two average fracture spacings, respectively.

The water swept area was then evaluated using an injection rate of 300 barrels of water per day (Equitable Resources Energy Company, 1998) and is shown in Figs. 4 and 5 for an average fracture spacing of 2.6 and 8 ft, respectively.

These figures show that the swept area increases linearly with time late in the injection project. This occurs when imbibition into the matrix blocks around the injection well has come to completion. At that time, a steady-state condition occurs with three zones in the reservoir. Ahead of the leading edge of the waterfront, the fractures are oil-saturated and no water is imbibing into the matrix. Behind the waterfront, the fractures contain a mixture of oil and water and imbibition is occurring into the matrix blocks. Behind this imbibition zone is an expanding region around the wellbore where imbibition is complete and the fractures are entirely water-saturated. When this third zone has been established, the water swept zone calculated by Eq. 17 then increases linearly with time, e.g., the exponential term has decayed to zero.

The difference between the fracture models and the nonfractured model after a long time is the area of the second zone in which imbibition is occurring. The swept area for the fractured models is greater than that of the non-fractured model because water will penetrate faster through the fracture network when imbibition is incomplete behind the water front. The differences between the fracture models after a long time reflects the different times required for imbibition to come to completion because of the different matrix block sizes assumed for the different domains.

It is noted that these models for the swept area are not valid for very early times and the finite swept areas predicted at time zero are not real (see Reis, 1997b). The early-time bias becomes insignificant after a time of roughly one-half of the centerline time, e.g., Eqs. 12 and 15. At that time, however, there is not a significant difference between the fracture models.

The additional complexity of modeling the reservoir as a triple porosity formation relative to a double porosity formation does not appear to be justified because of the similarity of the swept areas for the different models. A similar conclusion was previously obtained for the effect of multiple matrix domains on pressure transient analysis (Reis, 1996).

This analysis of the water swept area has indicated that the effects of imbibition are long-lasting, e.g., it takes a long time for imbibition to come to completion in the matrix blocks. Because of this, it is expected that the water will advance through the reservoir to production wells before imbibition reaches completion in the matrix blocks around the injection well. Thus, a significant amount of oil is expected to be recovered after water breakthrough.

To optimize oil recovery, the water injection rate will need to be reduced after breakthrough to minimize the costs of water handling. The injection rate, however, will need to remain high enough to balance the water loss to imbibition, which is equal to the oil production rate for a confined well pattern.

6.0 Conclusions

This analysis of the waterflood potential for naturally fractured reservoirs in the Uinta Basin has yielded the following conclusions:

1. The formation is not strongly water-wet, indicating a relatively low recovery potential for waterflooding. This conclusion is based on laboratory imbibition studies that revealed a change in water (and oil) saturation of only 12% for spontaneous capillary imbibition as well as a relatively slow imbibition rate. Because changes in wettability from the field to laboratory are not unusual, it is recommended that those laboratory tests be repeated and their results confirmed before any decisions based on those tests are made.
2. The time for imbibition to come to completion within matrix blocks in the reservoir is estimated to be on the order of years. This conclusion is based on the measured laboratory imbibition rate corrected to field conditions using the models for the effect of matrix block size developed in this study and the measured fracture spacing data.
3. Because of the slow imbibition rate, imbibition is not expected to reach completion in the matrix blocks around the injection well before water breaks through at the production wells. A significant volume of oil is expected to be produced after water breakthrough.

7.0 Project Summary

This project was funded to develop methods to improve oil recovery in naturally fractured oil reservoirs in the Uinta Basin. Dr. Reis served as a subcontractor to TerraTek and provided reservoir engineering services to the project. These services included developing a number of new models for the analysis of naturally fractured reservoirs. The key results from this three year study include:

1. A new pressure transient analysis model was developed that explicitly allows a realistic fracture spacing (matrix blocks size and shape) distribution to be included in the model (Reis, 1966a). This new model assumes that all matrix blocks can be grouped into one of a number of matrix domains. Each domain can have different properties, sizes, and shapes, but all matrix blocks within a particular domain are assumed to be identical. Traditional dual porosity models assume only one matrix domain. This new model gives complete analytical expressions for the pressure transient response for up to three matrix domains (quadruple porosity reservoirs) and can be extended to an arbitrary number of matrix domains by numerically determining the roots of a higher-order polynomial equation.

2. A method for utilizing measured fracture spacing data in the new pressure transient model was developed (Reis, 1966b). This model assumes that the fracture spacing distribution can be modeled by either a log-normal or negative exponential distribution. This approach gives the equivalent shape factor for each of the matrix domains.
3. The new pressure transient model was demonstrated by applying it to typical fractured reservoir properties (Reis, 1966b). For the data used, it was determined that including multiple matrix domains had an effect on the predicted pressure transient response, but that the effect was relatively small. It was concluded that in the presence of normal formation heterogeneities, traditional dual porosity models provided a good model for the reservoir behavior and the complexity of adding multiple matrix domains may not be warranted.
4. Existing and new analytical models for capillary imbibition of water into oil-saturated matrix blocks in both one- and multi-dimensions were developed and converted to a common set of parameters. These models were then tested against existing laboratory data to determine their validity. The strengths and weaknesses of these models were identified (Reis, 1997a and 1998).
5. New models for the advance of water down individual fractures and through fracture network (equivalent porous medium) in the presence of capillary imbibition into the associated matrix blocks were developed (Reis, 1997b and 1998). These models allow realistic fracture spacing distributions to be used for the matrix block sizes and shapes by utilizing the matrix domain concept previously developed for the new pressure transient analysis model (Reis, 1998).
6. A new approach to evaluating waterflooding in naturally fractured reservoirs that uses fracture spacing data from the field, imbibition data from the laboratory, and the new models developed in this study was successfully demonstrated through this report.

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Reis, J. C., "Primary Recovery," progress report for project Research and Development of Advanced Fracture Modelling in the Uinta Basin (Utah) for Optimized Primary and Secondary Recovery, submitted to TerraTek, June 30, 1996a.

Reis, J. C., "Primary Recovery," progress report for project Research and Development of Advanced Fracture Modelling in the Uinta Basin (Utah) for Optimized Primary and Secondary Recovery, submitted to TerraTek, Sept. 30, 1996b.

Reis, J. C., "Secondary Recovery," progress report for project Research and Development of Advanced Fracture Modelling in the Uinta Basin (Utah) for Optimized Primary and Secondary Recovery, submitted to TerraTek, June 30, 1997a.

Reis, J. C., "Secondary Recovery," progress report for project Research and Development of Advanced Fracture Modelling in the Uinta Basin (Utah) for Optimized Primary and Secondary Recovery, submitted to TerraTek, Sept. 30, 1997b.

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TerraTek, "Advanced Fracture Modeling in the Uinta Basin (Utah) for Optimized Primary and Secondary Recovery," Quarterly Report submitted to BDM-Oklahoma, Inc., Sept. 1997a.

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Table 1. Properties of Laboratory Sample

<i>Description</i>	<i>Very fine-to- fine-grained, cross-bedded sandstone</i>
Porosity (%)	11.64
Change in Saturation (%)	11.18
Dimension 1 (mm)	26.37
Dimension 2 (mm)	26.72
Dimension 3 (mm)	29.06
Centerline Time (min)	454
β (min/mm ²)	2060

Table 2. Fracture Spacing Data

	<i>Well 9-23</i>
Pay Thickness (ft)	8
Fracture Spacing (ft)	2.6

Table 3. Matrix Domain Data, Average Fracture Spacing = 2.6 ft

<i>Property</i>	<i>Matrix Domain Set 1</i>	<i>Matrix Domain Set 2</i>	<i>Matrix Domain Set 3</i>	<i>Double Porosity</i>
χ_1	0.25	0.5	0.75	1
χ_2	0.75	0.5	0.25	0
$X_{R^*,1}$	0.30	0.47	0.67	1
$X_{R^*,2}$	1.28	1.82	3.00	-
R_1^* (ft ⁻²)	0.23	0.30	0.40	0.64
R_2^* (ft ⁻²)	0.96	2.1	11.65	-

Table 4. Matrix Domain Data, Average Fracture Spacing = 8 ft

<i>Property</i>	<i>Matrix Domain Set 1</i>	<i>Matrix Domain Set 2</i>	<i>Matrix Domain Set 3</i>	<i>Double Porosity</i>
χ_1	0.25	0.5	0.75	1
χ_2	0.75	0.5	0.25	0
$X_{R^*,1}$	0.30	0.47	0.67	1
$X_{R^*,2}$	1.28	1.82	3.00	-
R_1^* (ft ⁻²)	0.025	0.032	0.0426	0.069

R_2^* (ft ²)	0.10	0.23	1.26	-
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Figure 1. Imbibition Data from Uinta Field Sample

Figure 2. Dimensionless Imbibition Data from Uinta Field Sample

Figure 3. Modified Imbibition Ratio, X_{R^*}

Figure 4. Areal Coverage of Waterflood Project, Average Fracture Spacing = 2.6 ft

Figure 5. Areal Coverage of Waterflood Project, Average Fracture Spacing = 8 ft

APPENDIX B
Internet Opportunities

APPENDIX B

Internet Opportunities

The following three figures illustrate three segments of a technical poster presentation available for viewing at www.terratek.com/whatnew. This presentation was given at the Annual Meeting of the American Association of Petroleum Geologists (A.A.P.G.) held in Salt Lake City, Utah on May 17-20, 1998. The site is organized so that the technical abstract is viewed first, after which the reader/visitor can select one of three poster segments. The reader can then "double click" on any of the poster elements to view it in more detail. Index buttons are available on every screen and allow the viewer to go back to the poster segment, jump to a new poster segment, or view the next detailed image in sequential order. This internet presentation was created at TerraTek using HTML.

Figure B-1. Segment 1 of the technical poster presented at the Annual Meeting of A.A.P.G. (May 1998). Each element of this segment can be viewed at www.terraviva.com/whatnew.

Figure B-2. Segment 2 of the technical poster presented at the Annual Meeting of A.A.P.G. (May 1998). Each element of this segment can be viewed at www.terratek.com/whanew.

Figure B-3. Segment 3 of the technical poster presented at the Annual Meeting of A.A.P.G. (May 1998). Each element of this segment can be viewed at www.terratek.com/whatnew.

APPENDIX C
Publications

APPENDIX C

Publications

The following is an abbreviated list of relevant publications:

1. Bereskin, S.R., Bruhn, R.L., Marin, B.A., Walters, M.C. and Reinschmidt, K.K.: "The Importance of Surface Geology to Subsurface Production - A Partial Answer to Willy-Nilly Drilling in Mature Basins (Examples from the Uinta Basin, Utah, U.S.A.)," *Abstracts with Program*, American Association of Petroleum Geologists Annual Meeting, Salt Lake City, UT, May 17-28, 1998.
2. Bereskin, S.R., Walters, M.C., Marin, B.A., Bruhn, R.L. and Groeger, A.Y.: "Kinematic Evolution of Structures Influencing Hydrocarbon Migration and Production in Economically Unpredictable Reservoirs: Duchesne Fault Zone, Uinta Basin," *Fractured Reservoirs: Practical Exploration and Development Strategies*, T.E. Hoak (ed.), Rocky Mountain Association of Geologists Symposium (1998).
3. Bereskin, S.R., Bruhn, R.L., Groeger, A., and Marin, B. A.: "Correlation of Fractured Surface Exposures to Aberrant Oil Production Along the Duchesne Fault Zone, Northeastern Utah," *Natural Fracture Systems in the Southern Rockies*, J.C. Close and T.A. Casey (eds.), Four Corners Geological Society, Durango, Colorado (1997).
4. Brown, S.R. and Bruhn, R.L.: "Permeability of Anisotropic Fracture Networks," *Journal of Geophysical Research* (1998) Vol. 103, 2489-2500.
5. Bruhn, R.L., Bering, D., Bereskin, S.R., Magnus, C. and Fritsen, A.: "Field Observations and Analytical Modeling of Fracture Network Permeability in Hydrocarbon Reservoirs," *Intl. J. Rock Mech. & Min. Sci.* (1997) Vol. 34, no. 3-4, paper no. 041.
6. Bruhn, R.L., Bering, D., Bereskin, S.R., Magnus, C. and Fritsen, A.: "Field Observations and Analytical Modeling of Fracture Network Permeability in Hydrocarbon Reservoirs," *Abstracts with Program*, U.S.R.M. Annual Conference, New York, New York (1997).
7. Groeger, A. Y.: *Structure and Geomorphology of the Duchesne Graben, Uinta Basin, Utah*, unpublished M. S. thesis, The University of Utah, Department of Geology and Geophysics (1997).
8. Morgan, C.: "Duchesne Oil Field, T. 4 S., R. 4 and 5 W., UBM, Duchesne County, Utah," Utah Geological Survey Oil and Gas Field Study 16 (1997).
9. Morgan, C.: "Bridgeland and South Myton Bench Oil Fields, T. 4 S., R. 2 and 3 W., UBM, Duchesne County, Utah," Utah Geological Survey Oil and Gas Field Study 17 (1997).
10. Morgan, C.: "Humpback Secondary-Recovery (Waterflood) Unit, T. 8 S., R. 17 E., Salt Lake Base Line, Uintah County, Utah," Utah Geological Survey Oil and Gas Field Study 18 (1997).
11. Reis, J.C.: "Effect of Fracture Spacing Distribution on Pressure Transient Response in Naturally Fractured Reservoirs," *Journal of Petroleum Science and Engineering* (June 1998) Vol. 20, 31-47.
12. Reis, J.C.: "Analytical Models for Capillary Imbibition: One-Dimensional Matrix Blocks," manuscript in preparation; to be submitted for publication, *In-Situ* (1998).
13. Reis, J.C.: "Water Advance in a Fracture in the Presence of Capillary Imbibition into Adjacent Matrix Blocks," accepted for publication, *In-Situ* (1998).

14. Reis, J.C.: "Analytical Models for Capillary Imbibition: Multi-Dimensional Matrix Blocks," manuscript in preparation, to be submitted 1998.
15. Reis, J.C.: "Water Advance in Fracture Networks in the Presence of Capillary Imbibition into Matrix Blocks," manuscript in preparation, to be submitted 1998.