SUB-SEISMIC SCALE FAULTS INTERPRETED FROM BOREHOLE IMAGES, CAVE GULCH FIELD, WYOMING

by

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ABSTRACT

With proven reserves of 600 BCF, Cave Gulch field is one of the most significant Rocky Mountain gas discoveries of the past decade. The field is located beneath the Owl Creek Thrust along the northeast flank of the Wind River Basin in central Wyoming. Cave Gulch is a structurally complex reservoir, with production of oil and gas coming mainly from lenticular fluvial sands of the Paleocene Fort Union, and Upper Cretaceous Lance, Meeteetse, and Mesaverde Formations. Additional production occurs from the underlying Mesozoic and Paleozoic units. Well productivity within the field is strongly influenced by faulting. The objective of this integrated study is to determine the occurrence of sub-seismic scale faults using dip-domain analyses of borehole images.

The main data set for this study consists of 5 FMI (Formation MicroImager) logs from Cave Gulch field. Each well log was examined on a computer workstation using Baker Atlas' RECALL/REVIEW software to view borehole images and pick bed boundaries and fractures. Dip domains, or blocks of rock with consistent orientations, were determined using cumulative dip and dip azimuth vector plots. These techniques led to the interpretation of many faults below seismic resolution.

Other evidence of faulting exists. Such evidence includes microfaults, healed and open fractures, a high intensity of parallel fractures, washouts, shows, and seismic faults.

Examination of rotary sidewall cores shows no evidence of deformation bands. No other core was available. 2-D seismic lines extracted from the 3-D seismic volume along lines of well-log cross sections were examined to compare faults observed using borehole images to those seen on the seismic lines. Results indicate that the majority of faulting within the field cannot be imaged using seismic data.

According to this study, wells that encounter the most faulting and related fracturing are associated with decreased production. This is probably caused by fault compartmentalization. Healed fractures, faults, and deformation bands may cause damage zones and decreased production in some areas. Seismic imaging is limited in resolution and borehole image interpretation has defined faulted and fractured zones not discernable by other methods.

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1. INTRODUCTION

Cave Gulch Field, discovered in 1994 in the eastern Wind River basin of Wyoming, represents one of the most significant recent gas discoveries in the Rocky Mountains. Wells in the field produce mainly from a folded section of Upper Cretaceous and Tertiary fluvial sandstones in the footwall of the Owl Creek Thrust. Well productivity is determined by structural position but is complicated by pervasive faulting, partly segmenting the field into a series of compartments.

Due to the subthrust location of the field, detailed interpretation of the reservoir is subject to numerous complications. Seismic imaging at Cave Gulch has proven difficult due to strong lateral velocity variations attributed to relatively shallow granite in the hanging wall of the Owl Creek thrust. In addition, no core has been taken within the field. Without the benefit of core and high resolution seismic, fault interpretation is difficult. 3-D seismic and advanced mapping techniques provide limited information on the faulting and compartmentalization of the reservoir. However, reservoir characterization can occur at many different scales. Borehole images can be used to identify individual fractures of <1mm width to large fault zones with significant offset. Together, these varying scales of investigation yield a more robust and comprehensive model, leading to better reservoir management.

Development at Cave Gulch field brings to fruition years of speculation by many Rocky Mountain geologists. Existing as the proven subthrust play analog, Cave Gulch has spurred renewed interest in exploration along the Laramide uplifts of the Rocky Mountain foreland. Increased understanding of the mechanisms that contribute to the success of this field may benefit future discoveries in similar settings.

1.1 Purpose of Study

> The fundamental goal of structural analysis in the petroleum industry is to develop a 3-D geometrically and kinematically consistent interpretation honoring all data, which can be used to evaluate all aspects of the hydrocarbon system that have been influenced by structural history (Ando, 2001).

Even with technological advances in seismic imaging, complexities related to faulting at the reservoir scale continue to contribute uncertainty and complicate predictions during development and production (Ando, 2001). The main objective of this study is to determine the occurrence of sub-seismic scale faults and related structural features and their effect on production and compartmentalization within Cave Gulch field. The steps used to complete this main objective are:

- Interpret borehole image logs from selected wells in the field.
- Perform dip-domain analyses of image log data using cumulative dip and dip azimuth vector plot techniques.

- Correlate evidence of faulting, fracturing, and fracture density defined on borehole image logs with other data such as washouts, anomalous production, and shows.
- Integrate previous 3-D seismic interpretation with faults defined from borehole image logs.
- Compare interpreted sub-seismic faults with production intervals, communication, structural position, and well performance.

1.2 Research Contributions

This study is an attempt to increase the understanding of faulting and reservoir compartmentalization and provide an improved structural model for Cave Gulch field. Specifically, borehole image analysis and interpretation are the focus of this study. Specific contributions are:

- Dip domain analysis of 4 wells drilled in the shallow Cave Gulch structure led to the identification of 154 sub-seismic scale faults. Faulting is unevenly distributed, with some wells having many more faults than others.
- Borehole image interpretation of these 4 wells resulted in the interpretation of 3,135 open fracture depths and orientations, useful for delineating potential bypassed production zones. In addition, 828 healed fractures and 856 microfaults have been documented.

- Less faulted and fractured areas within Cave Gulch field are associated with increased production. However, perforated intervals do not coincide with the occurrence of zones of open fractures.
- The structural position and proximity to faults of wells within Cave Gulch field are the predominant controls on open fracture orientations.
- Seismic imaging at Cave Gulch resolves only large scale faulting (hundreds of feet of offset). Results from dip domain analysis further refine the current structural model.
- Borehole image interpretation and dip domain analysis can be performed to identify important features that cannot be detected from seismic interpretation or conventional well logs.
- Sub-seismic scale faults are important controls on reservoir production, effectively limiting connectivity to the well bore at Cave Gulch.

2. GEOLOGIC FRAMEWORK

2.1 Location of Study Area

The Wind River basin, located in central Wyoming, is an asymmetric gas-prone Rocky Mountain foreland basin. Covering nearly 8,500 square miles, the basin is one of the least explored in the Rockies. Foreland basins are defined as sedimentary basins that lie between cratons and mountain fronts (Allen et al., 1986). As such, the Wind River basin (Figure 1) is bounded on the east by the Casper Arch, on the south by the Sweetwater Uplift and Granite Mountains, on the west by the Wind River Mountains, and on the north by the Washakie and Owl Creek Mountains (Kuuskraa, 1999). Cave Gulch field is located along the northeastern margin of the Wind River basin in Natrona County, Wyoming (Figure 2).

2.2 Stratigraphy

The stratigraphic units associated with this study include the entire section of the Wind River basin (Figure 3). Production at Cave Gulch field occurs from numerous stacked sandstone pays within the Fort Union, Lance, Meeteetse, Mesaverde, Frontier, Muddy, and Cloverly Formations (Natali et al., 2000). However, the Upper Cretaceous Lance and Tertiary Lower Fort Union Formations are the main focus. Accounting for the majority of production at Cave Gulch, this interval is composed of lenticular, stacked fluvial sandstones with greater than 10% porosity (Montgomery et al., 2001).

2.2.1 Regional Stratigraphy

The stratigraphic sequence in central Wyoming has been well studied and contains numerous reservoir intervals (Figure 3). In the area of the present day Wind River basin, thick successions of metasedimentary rocks that are preserved in the cores of the surrounding mountain ranges record early Precambrian deposition. These rocks, along with granite, gneiss, amphibolites, and felsic and mafic dikes comprise the oldest rocks in central Wyoming. Extensive late Precambrian erosion reduced this area into a broad, nearly level plain (Paylor and Yin, 1993; Keefer, 1965).

In central Wyoming, the Paleozoic Era is represented by a near complete section of passive margin sediments that typically thin to the east. The Cambrian system consists of the Middle Cambrian Flathead Sandstone and Gros Ventre Group, and the Upper Cambrian Gallatin Group. These rocks represent the first advance of Paleozoic seas, which reached a maximum eastward advance during the Late Cambrian. The Flathead Sandstone, which nonconformably overlies Precambrian basement, represents the initial deposits of the transgressive sequence (Burke, 1956). This competent sandstone preserves highly polished slickensides in fault zones within the area. Glauconitic shales, siltstones, and limestones of the Gros Ventre Group conformably overlie the Flathead Sandstone. Dense gray micritic and oolitic limestones of the Gallatin Group conformably overlie the Gros Ventre Group. The Gros Ventre and Gallatin Groups are typically intensely sheared and attenuated in fault zones in central Wyoming (Paylor and Yin, 1993; Barrett, 1989; Cercone, 1989; Keefer, 1965).

Carbonates of the Middle and Upper Ordovician Bighorn Dolomite form resistant cliffs along the northwestern margins of the basin. Separated by an unconformity from Cambrian rocks below, the Bighorn Dolomite was either not deposited, or removed by erosion in the eastern parts of the basin. Erosion probably continued throughout Silurian time, with deposition recorded again by carbonates and shales of the Devonian Darby Formation in the northwestern parts of the basin (Keefer, 1965).

The Mississippian System in central Wyoming records a period of normal marine sedimentation resulting in the limestones and dolomites of the Madison Formation. Covering the entire basin, the Madison disconformably overlies Devonian through Cambrian rocks from northwest to southeast. Carbonates of the Ordovician Bighorn Dolomite and Madison Formation are structurally competent and deform cataclastically (Paylor and Yin, 1993; Keefer, 1965).

At the end of Madison deposition, all of central Wyoming became emergent and subject to subaerial erosion. A shallow sea spread across the area during the Lower Pennsylvanian, resulting in deposition of the Amsden Formation. Unconformably overlying the Madison and in places filling in the karsted surface, the Amsden is composed of interbedded red shales, siltstones, and dolomites. In exposures in the Owl Creek Mountains, the Amsden Formation is generally missing in fault zones due to attenuation. Conformably overlying the Amsden is the structurally competent Pennsylvanian Tensleep Formation. Composed primarily of medium-grained, cross-bedded sandstones, the Tensleep was deposited in a combination marine-eolian environment. Quartz arenites of the Tensleep are well exposed in fault zones and preserve slickensided surfaces in the Owl Creek Mountains (Paylor and Yin, 1993; Barrett, 1989; Keefer, 1965).

At the onset of Permian time, a north-south trending highland of Pennsylvanian rocks occupied much of central Wyoming. Permian seas slowly encroached from the east and west until the entire area was flooded by Late Permian time. The Permian Phosphoria Formation, which unconformably overlies the Tensleep Formation, records this encroachment with carbonates to the west and red beds and evaporites to the east. In the Owl Creek Mountains, the Phosphoria is typically folded or attenuated in fault zones (Paylor and Yin, 1993; Keefer, 1965).

Overlying and interfingering with the Permian Phosphoria are the marine siltstones and carbonates of the Triassic Dinwoody Formation. Because the Phosphoria and Dinwoody interfinger and are difficult to distinguish, they are often grouped together as the Goose Egg Formation. Conformably overlying the Goose Egg are the red beds, siltstones, and thin limestones of the Triassic Chugwater Formation. The Chugwater is typically attenuated or folded near faults in the Owl Creek Mountains (Paylor and Yin, 1993; Keefer, 1965). With the onset of Jurassic time, continental conditions existed and deposition of the cross-bedded eolian Nugget Sandstone occurred. During the Middle

Jurassic, shallow seas covered much of central Wyoming, resulting in deposition of the carbonates, siltstones, and evaporites of the Gypsum Spring Formation. At the close of the Middle Jurassic, uplift occurred in the east and the marine shales and sandstones of the Sundance Formation were deposited across the truncated edges of rocks from the Jurassic Gypsum Spring, Nugget, and Triassic Chugwater Formations. Before the end of Jurassic time, the seas withdrew and fluvial and lacustrine rocks of the Morrison Formation were deposited. Due to a high percentage of shale, with the exception of the Nugget Formation, the Jurassic section in central Wyoming is considered to be incompetent and ductile (Cercone, 1989; Keefer, 1965).

Unconformably overlying the Morrison Formation are the Lower Cretaceous sandstones, shales, and conglomerates of the Cloverly Formation. Fluvial and lacustrine in origin, rocks of the Cloverly Formation are well cemented and form prominent outcrops in central Wyoming. After the region was again flooded, black marine shales of the Thermopolis and Mowry Formations were deposited. With the gradual shifting of the sea to the east, the regressive sandstones and shales of the Upper Cretaceous Frontier Formation were deposited. The thick marine shales of the Cody Formation were then deposited after the Cody sea transgressed across much of Wyoming. Following a long regression of this sea, the basal sandstones of the Mesaverde Formation were deposited. The uppermost unit in the Mesaverde Formation is the Teapot Sandstone. The Teapot Sandstone, a well-sorted, medium grained channel sand, forms distinctive white resistant ridges in outcrop. Emergence of the area gave rise to the flood-plain and swamp deposits of the overlying Meeteetse Formation. Due to fluctuations of the Cretaceous sea, the Meeteetse Formation intertongues with the marine sands and shales of the Lewis Formation, which represents the end of marine deposition in the basin (Cercone, 1989; Keefer, 1965).

Downwarping of the present day basin axis began during the Late Cretaceous. This accommodated thick packages of clastic sediments that were eroded from the surrounding uplifts. The fluvial sands of the Lance Formation were deposited during this time. The Lance Formation is characterized by numerous fine-grained massive lenticular sands and interbedded shales and coals (Keefer, 1965).

The intensity of Laramide deformation increased during the Paleocene and clastic debris from the flanks of the rising mountain ranges was shed basinward from all sides. Prolific stream systems dominated at this time and deposited the interbedded conglomerates, sandstones, shales, and coals of the Fort Union Formation. During the Late Paleocene, the thick organic black shales of the Waltman Member of the Fort Union were deposited in Waltman Lake. By the close of the early Eocene, basin subsidence and mountain uplift had stopped. However, deposition of red shales and mudstones of the Wind River Formation continued until the middle Miocene. Subsequently, the area underwent thousands of feet of uplift, initiating erosion that continues today. Exhumation has progressed to the point that only rocks of lower Eocene age and older are left in the basin center (Ray and Keefer, 1985; Keefer, 1965).

2.2.2 Local Stratigraphy

Along the axis of the eastern Wind River basin, more than 25,000 ft of sediments have been preserved. 87% of these sediments are comprised of Cretaceous and Tertiary-age rocks (Kuuskraa, 1999). In the study area, Paleozoic and lower Mesozoic deposition occurred in a stable passive margin environment. At the beginning of Lower Cretaceous time, sedimentation reflected foreland basin development related to the eastward-advancing Sevier thrust belt. Rocks of the Cloverly, Thermopolis, Muddy, and Mowry Formations are believed to be sourced from these emerging highlands to the west. The Upper Cretaceous Frontier Formation, Cody Shale, Mesaverde Group, Lewis Shale, and Meeteetse Formation represent the Rocky Mountain foreland basin-fill sediments. Late Cretaceous basement block uplift began, dividing the foreland into a series of intermontane basins. Laramide movements controlled the fluvial deposition of the Lance and lower Fort Union Formations and the fluvial-lacustrine deposition of the upper Fort Union Formation and Waltman Shale. The fluvial sand packages of these units reached their greatest thickness along the developing basin axis. After increased uplift along the Owl Creek and Casper Arch mountain fronts, alluvial fan deposition of the Wind River Formation filled depressions along the basin margin (Montgomery et al., 2001).

At Cave Gulch, nearly the complete section of the Lance and lower Fort Union Formations are gas productive. Minor contributions are added from the upper Meeteetse and Mesaverde Group (Figure 4). Influenced by development of the Wind River basin, both the Lance and Fort Union Formations thicken along the basin axis, just downdip from Cave Gulch field. The axial trough, oriented roughly parallel to the emerging Casper Arch, played a major role in controlling sand deposition and the location of depositional fairways. Variable subsidence and associated uplift of the Casper Arch, combined with strong sediment supply, allowed for the accumulation of a thick sequence of nonmarine reservoir rocks at Cave Gulch (Montgomery et al., 2001).

Based on sedimentological data from the Cave Gulch field area, the Lance and lower Fort Union Formations represent deposition in a combination of high sinuosity (e.g., meandering), medium to low sinuosity (e.g., braided), and smaller cut-and-fill fluvial environments. This interpretation corroborates evidence of the same effect shown in outcrop in the vertical beds at Cave Gulch and other nearby areas of the Wind River basin (Keefer and Johnson, 1993; Phillips, 1983; Keefer, 1965). The Lance and lower Fort Union, the dominant reservoirs in the shallow part of the field, exhibit substantial preserved porosity and permeability. However, fracturing appears to play an important role, significantly enhancing permeabilities. The Lance-lower Fort Union section at Cave Gulch is comprised of numerous lenticular sand packages 25-125 ft thick with greater than 10% porosity over a total interval of 4500-4800 ft. The majority of these reservoirs are in the Lance Formation, which is divisible at Cave Gulch into lower, middle, and upper sections (Montgomery et al., 2001).

A stratigraphic cross-section through several adjacent wells illustrates the lenticular nature of the sandstones in the Lance (Figure 5). The lower and middle intervals of the Lance have a higher percentage of sandstone than the muddier, shaleprone upper section. Data from the field indicate that individual sandstones within the Lance range from 10 to 30 ft thick and are separated by thin (5-15 ft) silty shales and mudstones. These sandstone-shale sequences can be stacked into packages up to 100 ft or more in thickness (Montgomery et al., 2001).

Sandstones within the Lance are very fine to fine grained, moderately well sorted, and sublithic in composition. By weight, samples consist of 80-90% quartz, 12-20% rock fragments, and 6-9% clays. Grain size varies from 0.00001 to 0.000025 mm, with slightly larger grains in the middle Lance. Cements within the Lance include authigenic clays, quartz overgrowths, and slightly ferroan dolomite. X-ray diffraction analysis indicates that 31-55% of total clay weight is in the form of kaolinite, with illite/smectite (10-49%), chlorite (13-28%), and smectite (8-14%) making up the remainder. In some samples, however, the illite/smectite component represents the dominant clay fraction (Montgomery et al., 2001).

2.3 Structural Geology and Tectonics

Cave Gulch field is located in the northeast part of the Wind River basin, an asymmetric rhomb-shaped subdivision of the Rocky Mountain foreland. The basin is bound on all sides by Late Cretaceous-Middle Eocene basement uplifts. These surrounding uplifts include the Sweetwater uplift and Granite Mountains to the south, the Wind River Mountains to the southwest, the Owl Creek Mountains to the north, and the Casper Arch to the northeast (Figures 1 and 2).

2.3.1 Regional Tectonic History

The Late Jurassic to Late Cretaceous subduction of the Farallon plate under the North American plate formed the western Cordillera into an Andean-type orogenic continental margin. Plate convergence resulted in horizontal compression and thin-skinned, low angle thrusts of the Sevier Orogeny (Upper Jurassic through Paleocene) in Idaho, Wyoming, and Utah. Continued plate convergence through middle Eocene time generated the basement involved, thick-skinned thrusts of the succeeding Laramide Orogeny (Coney, 1978; Barrett, 1989).

The Laramide Orogeny, beginning in the Campanian and continuing through middle Eocene, overlaps and succeeds the Sevier Orogenic thrust belt to the west. However, with differing modes of deformation and involved stratigraphy, the two phases of mountain building are easily separated. Decollement thrust-belt styles of the Sevier were developed in passive-margin Paleozoic-Mesozoic sediments, whereas Laramide basement uplifts formed in the stable cratonic interior (Coney, 1978).

The development of these dissimilar modes of deformation is attributed to changes in plate movement along the western continental margin. Late Jurassic through Late Cretaceous convergence of the North American and Farallon plates occurred at roughly N 72° E at a rate of 8 cm per year. With the onset of Laramide deformation, the direction of convergence had rotated to N 40° E and subduction had increased to 14 cm per year. This increased rate of convergence coincides with the change from thin-skinned

Sevier deformation to the thick-skinned basement uplifts of the Laramide Orogeny (Coney, 1978; Brown, 1987; Barrett, 1989).

The Wind River basin is typical of the large structural basins that formed in the Rocky Mountain foreland with the onset of the Laramide orogeny. This large continental depression, stretching from the Artic Ocean to the Gulf of Mexico, was later divided into small sedimentary basins by emerging Laramide basement uplifts (Johnson et al., 1996; Kaufmann, 1977). The Wind River basin is asymmetric, with the deepest areas in the northeast corner near the intersection of the Owl Creek Mountains, Bighorn Mountains, and Casper Arch (Figures 1 and 2). The axial trough parallels the Owl Creek thrust, located about 3-5 mi basinward (Ray and Keefer, 1985).

Evidenced by the extreme thickening of sedimentary rocks, Laramide deformation within the Rocky Mountain foreland began during the late Campanian (Late Cretaceous, 80 Ma) with uplift of the Wind River and Washakie Mountains (Figure 6). Emplacement of the Medicine Bow Range and Granite Mountains began during the Maastrichtian. Early Paleocene mountain building included uplift of the Owl Creek Mountains and the Laramie Range. Uplift of the Bighorn Mountains to the north began during the middle Paleocene and continued through the early Eocene. Uplift of the Casper Arch began during the latest Paleocene, thrusting Precambrian granite over Paleozoic strata. Sediments along the north and eastern margins of the basin are commonly vertical to overturned due to intense faulting and folding related to uplift of the Casper Arch (Ray and Keefer, 1985). In addition, secondary structures along the Casper Arch, including

Cave Gulch, were influenced by deformation continuing from the latest Paleocene through the early Eocene. By the end of the Tertiary, the entire Wind River basin had been elevated approximately 5,000 ft, triggering the erosional cycle that continues to this day (Gries, 1983b; Barrett, 1989).

The styles of deformation responsible for the structures seen in the study area and throughout the Rocky Mountain foreland have long been under debate. The mechanics of basement uplifts and faulting, and their relationship with deformation styles in the overlying strata have been the focus of these debates. Until the mid-1980's, arguments had centered around whether vertical or horizontal forces were the dominant structural style. Prucha (1965) and Stearns (1971,1978) proposed that vertical forces of Laramide orogenesis dominated, resulting in their classic high-angle fault and drape-fold interpretations. Proponents of horizontal compression stressed the fact that low-angle reverse faults were involved in the formation of Rocky Mountain basement-involved foreland structures (Berg, 1962; Brown, 1983, 1987). Advancing this argument, Stone (1984) and Erslev (1991) proposed a model involving fault-propagation folding caused by horizontal stresses (Figure 7). Advances in seismic imaging and data from exploration wells that penetrated overthrusted basement have shown the large horizontal displacement thrust-fault geometries on northwest-southeast trends (Figure 8), compatible with predictions for horizontal compression (Brown, 1993).

To explain the variable structural orientations in the Laramide foreland, Gries (1983a) suggested that a rotated regional stress field was responsible for the two main structural trends (east-west and northwest-southeast). Gries postulated the reorientation of the horizontal compressive stress field from northeast-southwest, to north-south during the latter part of the Laramide orogeny. This reorientation allowed for the development of the enigmatic east-west trending mountain ranges in the foreland. Combining sedimentologic data, Gries proposed that the older north-northwest structures were overprinted by younger east-west oriented structures. Within the Wind River basin, the structural pattern of faults and folds is dominantly N 40˚ W, supporting northeast-southwest compression.

In appearance, the east-west trending Owl Creek thrust, bounding the Wind River basin to the north, seems to support north-south compression. However, Paylor and Yin (1993) and Mozler and Erslev (1995) interpreted fault slip data from the area to show that the east-west trending portion of the Owl Creek thrust fault is dominated by left lateral oblique-slip (Figure 9). The northwest-southeast portion, along with similarly oriented structures, is dominated by dip-slip movement. In this model, a single phase of horizontal compression oriented northeast-southwest is assumed to be responsible for the dip-slip and oblique-slip faults and associated folds seen in the study area.

2.3.2 Regional Structure

Cave Gulch field, a complex structural trap, is located just east of the axis of the Wind River basin near the leading edge of the Owl Creek thrust (Figure 2). The Owl

Creek thrust is a major zone of basement-rooted reverse faulting that continuously overrides the northern and eastern margins of the basin, covering as much as 55-60 mi along strike. Interpretations of stratigraphic and structural relationships have placed the timing of this thrust zone predominantly in the Eocene (Keefer, 1965, 1970; Gries, 1983a). More specifically, thrusting along the Owl Creek thrust began after deposition of the Fort Union Formation. Conglomerates eroded from the thrust plate are readily found along the basin margins at the unconformity at the top of the Fort Union. Thrusting along the fault continued through Lower Eocene time, ending prior to deposition of the Lysite Member of the Wind River Formation (Hogle and Jones, 1991). In this thrust, Precambrian granite carried in the hanging wall rests directly over Mesozoic and Paleozoic sediments in the footwall. Displacement along the thrust ranges from 1 to 12 mi horizontally and 2,000 to 30,000 ft vertically with maximum offset at the change in strike orientation (from east-west to northwest-southeast) near the center. Horizontal and vertical displacements at Cave Gulch are 3-4 mi and 18,000 ft, respectively (Montgomery et al., 2001).

Cave Gulch field is located at the northeastern terminus of the Waltman Arch, a pre-Laramide asymmetric fold, where it is overridden by the Owl Creek thrust (Figures 2 and 10). Thinning of numerous formations across the crest of the fold suggest that displacement occurred periodically from the Pennsylvanian to the Tertiary. The north-northeast trending arch obliquely converges with the Owl Creek thrust and is truncated to the west by a high-angle, basement-rooted reverse fault with approximately 2,000 ft of vertical offset (Figure 11). The Waltman arch also has a left-lateral slip component that may reflect reactivation during Laramide orogenesis. The arch, which is over 20 mi in length, extends across the basin to the southwest of Cave Gulch and serves as a trap for hydrocarbons produced at Cooper and Wallace Creek fields (Montgomery et al., 2001).

Production at Cave Gulch occurs from the subthrust anticline developed along the northeastern terminus of the Waltman arch (Figures 11 and 12). Wells within the field actually drill through vertical and overturned reservoir rocks in the hanging wall of the Owl Creek Thrust. Due to a location at the oblique convergence of two significant structural features, complex folding and faulting occur throughout the field. Montogomery et al. (2001) suggested that the structural complexity at Cave Gulch is the result of a rotation of the major compressive stress during the early Tertiary, claiming that Paleozoic and Mesozoic structural elements appear to be tectonically overprinted by younger Tertiary influence. However, the aforementioned work by Mozler and Erslev (1995) and Paylor and Yin (1993) suggests that a single phase of southwest-northeast directed compression of the Laramide could also be responsible.

2.3.3 Local Structure

Examination of 3-D seismic data, integrated with subsurface well control, has led to the interpretation of the Cave Gulch structure as a subthrust footwall anticline. The location of the anticline is controlled in part by the Waltman arch and the Waltman fault 1-2 mi to the west (Figure 10). The structure at Cave Gulch is divided into a shallow and deep unit based on production strategies implemented to overcome the differences in structural style between the two levels (Figure 13). Overall, the crest of the Cave Gulch anticline migrates to the south-southwest moving upsection (Montgomery et al., 2001).

The structure at Cave Gulch is associated with the Cave Gulch thrust, a secondary basement fault with 2,500-3,000 ft of vertical throw. This thrust splays into the Paleozoic-Mesozoic section, terminating in the lower part of the Cody shale (Figure 14). The Upper Cretaceous section at Cave Gulch is cut by numerous high-angle reverse faults with vertical displacements ranging from 50-700 ft (Figure 15). Montgomery et al. (2001) suggested that these faults are of several generations because they cut to varying levels stratigraphically. However, these faults could also represent a lateral slip component of a single phase of faulting.

The numerous east-west trending reverse faults in the shallow section bound the crest of the anticline and segment the Cave Gulch structure into several separate culminations (Figures 15, 16). Reservoir rocks in this fault zone are cumulatively offset 700 ft (down to the north) and display marked production differences along this trend. Illustrated in Figure 15, on the upthrown side of the footwall master fault, the Waltman #1, Waltman #16, and the Cave Gulch #1 wells are excellent producers with per well reserves estimated to be > 10 BCF. To the north, on the downthrown side, the Cave Gulch #9 well drilled a small, fault-bounded reservoir compartment in the Lance and Fort Union, and rapidly depleted its reservoir. In addition, the Cave Gulch #4 is a marginal producer (Montgomery et al., 2001).

2.4 Field History

Cave Gulch field was discovered in 1994 upon completion of the Cave Gulch Federal Unit #1 well by Barrett Resources Corporation, now Williams Production. The well produces gas from the Tertiary Fort Union and Cretaceous Lance Formations and had an initial rate of 9.7 MMCFD and 117 BCPD (Dea et al., 1998). Through September of 1999, the well had produced more than 10 BCFG (Natali et al., 2000). Interestingly enough, this prospect, which prompted the discovery of significant gas reserves (500 BCF –1 TCF), was delineated years ago. Information defining the prospect had been in existence since 1959 (McPeek et al., 1997 and 1998). Lawrence A. McPeek of Thomasson Partner Associates, Inc., first recommended the prospect in 1971. McPeek et al. (1997, 1998) suggested that the 35-year discovery delay may be attributed to reliance on early interpretations of subthrust 2-D seismic data, suspect due to velocity variations within the sediments and Precambrian granite.

These strong lateral variations in velocity beneath the Owl Creek thrust were well documented in the seismic models of Skeen and Ray (1983). Large velocity variations of 7,000 ft/sec to 20,000 ft/sec over a distance of 2 mi (Natali et al., 2000) cause significant "pull-ups." This makes interpretation of time-migrated seismic data a difficult task. This "pull-up" effect is readily apparent in the deeper reflectors, causing them to appear to dip in the opposite direction of true dip and migrating the crest of the structure as much as 1 mi to the northeast of its true location. To eliminate this problem, check-shot surveys have been acquired during development of the field and used to progressively update a detailed velocity model. The 3-D volume, acquired after drilling the Cave Gulch #1 discovery well, has, in turn, been re-interpreted after numerous poststack depth migrations. The vertical seismic profile shown in Figure 17 illustrates the problem of accurately interpreting the structure at Cave Gulch. Fault location and geometry are correct in this section, however, there is also a depth pull-up to the north. This anticlinal high disappeared after several iterations of the velocity model. In reality, the structure more closely resembles what is shown in Figure 15 (Skeen and Ray, 1983; Natali et al., 2000; Montgomery et al., 2001).

Due to the seismic pitfalls, placement of the discovery well relied heavily on dipmeter information from three nearby wells. The Waltman #1 well in SW Section 31, T37N-R86W, had cumulative production in excess of 12 BGFG and bedding dips to the southwest. This well was drilled by Chevron in 1959 and completed in the Lance and Fort Union at depths of less than 10,000 ft (Montgomery et al., 2001). The marginal Waltman #3 and the Bullfrog #1-6, which is non-productive in shallow horizons, encountered northwest and south dips, respectively (Figure 18). This information combined with available 2-D seismic mapping (Figure 19) gave rise to the interpretation of a subsurface structural closure, later confirmed by the Cave Gulch #1 discovery well (Natali et al., 2000). This well, drilled to 6,095 ft, encountered 481 ft of pay over a 2,200 ft interval in Lance and lower Fort Union reservoirs. Initial production was 9.7 MMCF of gas and 117 BBL of condensate per day and the well had produced over 13.5 BCF of gas by the end of 2000 (Montgomery et al., 2001).

During acquisition of a 21.5 mi^2 3-D seismic survey of the area (Figure 20), two 40-acre offsets (Cave Gulch #4 and #9) to the discovery well were drilled (Figure 19). Even though the operator was aware of the velocity variations, structural complexity within the field precluded any success in these two wells. Reasons for their poor performance were not clear until depth-migration of the 3-D seismic data volume. To overcome the seismic "pull-up" problems and accurately model subsurface velocities, Barrett Resources acquired check-shot surveys in several existing wells to the north and south, in the Cave Gulch #4 well, and in many subsequent wells. The Cave Gulch #4 was drilled to test a separate structural high 250 ft updip from the Cave Gulch #1. In fact, the Cave Gulch #4 was actually out of the plane of the 2-D section (Figure 19), and was drilled into a downthrown fault block. The Cave Gulch #9 drilled into what was later found to be a fault sliver, producing 12 MMCFGPD initially. This well quickly drained the small compartment. The Cave Gulch #7 became the first successful offset to the discovery well due to Barrett's rigorous application of the iterative velocity model used in the depth migration of the 3-D volume (Natali et al., 2000). The integration of geologic data from all relevant wells with the aforementioned techniques has resulted in an improved understanding of local structure and successful field development in all productive horizons (Montgomery et al., 2001).

As of late 2000, Cave Gulch field included more than 50 active wells and encompassed an area of 2.75 mi^2. These wells produce from reservoirs in the Fort Union (Paleocene), Lance, Meeteetse, Mesaverde, Frontier, Muddy, Cloverly (all Cretaceous), and Morrison/Sundance Formations (Jurassic). Potential from subsidiary intervals and the deeper Tensleep and Madison units remains likely but are yet to be developed. A large hydrocarbon column within the field suggests that intervals above an as yet undetermined porosity and permeability threshold have a high probability of being gas charged. Approximate drilling depths for the field average 5,000 ft to the top of the Lance, 17,000 ft to the Frontier, 19,000 ft to the Cloverly, and 21,000 ft to the Madison (Montgomery et al., 2001).

Development of the field has been concentrated in the lower Fort Union and Lance reservoirs. Wells in these units have been drilled on 40 acre spacing in the central part of the field and commonly have net pay intervals that range from 250-1,000 ft. Per well reserves range from 2-25 BCF and average 7.5 BCF. Reserves for the entire Fort Union and Lance interval is on the order of 300-400 BCF. Fracture stimulation is usually required due to restricted permeabilities. Commonly, 3-6 sands are perforated for every 50-300 ft of gross pay interval. Gas quality from these two reservoirs is exceptional, at 1,130 BTU/MCF for the Lance and 1,040 BTU/MCF for the Fort Union (Montgomery et al., 2001).

Deeper development in the field is incomplete but recent wells in the Frontier and Muddy show excellent potential with initial production rates of 10 MMCF and 38 MMCF per day, respectively. Overpressuring is common below the Cody Shale, which may be a factor in the preservation of porosity at these depths. Based on the considerable success at the nearby Madden field (25 mi northwest), prospectivity of the Madison reservoir is also likely to be high (Montgomery et al., 2001).

3. ANALYSIS AND INTERPRETATION OF BOREHOLE IMAGE LOGS

3.1 Introduction to Borehole Images

The Formation MicroImager (FMI), successor to the Formation MicroScanner (FMS), is a high-resolution microresistivity imaging tool (Figure 21). Evolving from the dipmeter, the FMI tool has an array of 24 closely spaced electrodes with insulated backings mounted on four conducting orthogonal pads. Four similar laterally and vertically offset flaps are mounted to each pad allowing the FMI to provide approximately 80% coverage of the borehole wall in an 8.5 inch diameter hole (Ekstrom et al., 1987; Safinya et al., 1991; Prosser et al., 1999).

The electrodes of the FMI, which are each 0.2 in in diameter, are arranged in two rows 0.15 in apart (Figure 22). The electrodes are pressed against the borehole wall and the amount of current emitted from each electrode is recorded along with depth, tool azimuth, and inclination to provide borehole orientation to the images (Bourke, 1989; Prensky, 1999). The arrangement and small size of the sensors allows changes in rock resistivity in the well bore to be sampled at a resolution of 0.1 x 0.1 in horizontally and vertically by the FMI tool. More conductive materials are assigned darker tones and more resistive materials are light colored (Safinya et al., 1991; Prensky, 1999).

After processing, the data collected by the FMI tool provides eight 2.75 inch-wide strips of microresistivity images spaced in pairs at 90°. The strips are presented two-dimensionally in the form of an unrolled cylinder (Figure 23) separated along true north (Prensky, 1999; Prosser et al., 1999).

The high-resolution of the FMI tool enables qualitative identification and quantitative analysis of planar features such as bedding and fractures. During normal drilling conditions, drilling muds are forced into openings such as fractures in the borehole wall. The conductivity contrast between the mud in these openings and the adjacent rock is readily apparent on FMI images. Sensitive to resistivity contrasts in rocks (caused primarily by fluids) and capable of resolving small features due to sensor size and arrangement, microresistivity devices such as the FMI are ideally suited for reservoir and fracture characterization.

3.2 Available Data

Ten borehole image logs from five wells were interpreted in this study (Table 1) and served as input for bedding and fracture analysis. These image logs are Schlumberger's FMI (Formation MicroImager) logs. Figure 24 shows the location of these wells. The Cave Gulch #3, 10, 11, and B-5 wells have FMI coverage over the shallow Cave Gulch structure, focusing on lower Fort Union and Lance intervals. The Cave Gulch #4-19 deep was logged in the deeper Cave Gulch structure, with the Frontier, Muddy, and Cloverly Formations as the focus.

Well Name	FMI Coverage Interval(s)	Totals (ft)
Cave Gulch #3	1,107-7,650; 8,586-9,052	7,009
Cave Gulch #10	5,156-9,344	4,188
Cave Gulch #11	1,090-3,366; 3,267-6,698; 6,567-9,633	8,773
Cave Gulch #B-5	874-5,798; 5,760-9,414	8,578
Cave Gulch #4-19 deep	17,036-18,180; 18,250-18,787	1,681

Table 1. List of Cave Gulch wells and recorded FMI log data intervals interpreted in this study. Total recorded interval is 30,229 ft.

3.3 Borehole Image Log Processing

Processing and interpretation of the FMI logs was performed using Baker Atlas' RECALL/REVIEW software. Prior to image generation, magnetic declination and accelerometer corrections were performed. The resistivity responses of the many electrodes of the FMI were then processed together as a matrix. This matrix corresponds to the vertical and horizontal intervals between the microresistivity curves (0.1 in for the FMI) (Rider, 1996). After processing, static and dynamic-normalized images were created. Static images utilize a consistent contrast setting for the entire well, whereas dynamic images display variable contrast throughout, enhancing the appearance of bedding and structural features (Figure 25). For this study, image interpretation involved simultaneous investigation of both static and dynamic image types.

3.4 Borehole Image Log Interpretation

Due to the two-dimensional presentation of FMI images in the form of an unrolled cylinder, planar features such as bedding and fractures that intersect the borehole at an angle other than horizontal appear as sinusoidal features (Figure 23C). The amplitude of the sine curve is a function of dip magnitude with the tangent to the slope being the actual dip angle. Dip azimuth corresponds to where the low point of the sine wave crosses the borehole (Figure 23C).

In practice, each FMI log was examined on a computer workstation, viewing both static and dynamic images and manually fitting sine curves to bed boundaries and fractures. In order to create cumulative dip plots, an ASCII file containing dip type, depth, dip azimuth, dip magnitude, gamma ray value, and dip quality was output for each well (Table 2). In this study dip quality values, a confidence factor, were all 1.00 because no dips were of the computed variety.

DIPTYPE	DEPTH	AZIM	DIP	GR	QUAL
BED BOUNDARY	911.1181	16.53	62.50	64.31	1.00
BED BOUNDARY	911.7114	17.81	63.88	62.08	1.00
BED BOUNDARY	913.4914	17.82	70.96	60.84	1.00
BED BOUNDARY	914.2331	20.39	73.29	61.75	1.00

Table 2. Example of data output in ASCII file format for each well after bedding analysis has been performed. Data is from Cave Gulch #B-5 well. Gamma Ray (GR) values were assigned to the exact depth of each bed boundary by linear interpolation.

Dip domain analyses were performed to identify faults larger than microfaults, which have offsets measured in cm. Dip domains, or blocks of rock with consistent orientations, were determined using cumulative dip and dip azimuth vector plots. Cumulative dip plots were constructed to identify dip domains of consistent dip magnitude and dip azimuth vector plots were created to identify dip domains of similar dip azimuth. A cumulative dip plot (Hurley, 1994) is a graph of sample number (a function of depth) vs. cumulative dip magnitude. Samples are color-coded by dip direction. Vector plots are projections in the horizontal plane that are made by creating and plotting oriented unit vectors for each observed bedding plane. Inflection points between dip domains are commonly faults, usually occurring on scales at or below seismic resolution. However, in stratigraphic horizons with significant cross bedding, unconformities, or soft-sediment deformation, dip-domain boundaries can occur because of stratigraphic or sedimentologic reasons.

Variations in dip related to faulting were distinguished from stratigraphic or sedimentologic changes by constructing cumulative dip plots and vector plots for shale beds (Hurley, 1994) and comparing dip variations with evidence of fractures and microfaults in borehole-image displays. Bed boundaries picked included sand-sand, sand-shale, and shale-shale interfaces. The elimination of stratigraphic and sedimentologic controls on dip variations was accomplished by assigning gamma-ray values to each bed boundary dip and dip azimuth determination (tadpole), and then removing all “sandy” data points that fell below a certain gamma-ray cutoff. A gamma ray cutoff value of either 80 or 100 (API units) was used for the wells in this study. This number, which varied depending on the sand to shale ratio, was adjusted to provide a reasonable number of sample points over the interval sampled (Figure 26). This technique relies on the assumption that most shales were deposited as horizontal layers. Therfore, they should be representative of structural dip. Dip domain boundaries between shaly intervals are probably caused by faulting. The plots represented here were created for the purpose of analyzing structural features. Therefore, they consist of only shale bedding orientation data.

3.4.1 Quality of Borehole Images

The 5 FMI logs interpreted in this study can be classified in terms of quality. Overall, the shallow logs from the Lance and Lower Fort Union section of the field are of excellent quality. These include the logs from the Cave Gulch #10, 11, and B-5 wells. Although still of fair quality, the logs from the #3 well are not quite as good. Coincidentally, the first FMI logs interpreted were from the Cave Gulch #4-19 deep well. FMI coverage in this well consists of an upper 1,144 ft logged interval of Upper Cretaceous Frontier and a lower 537 ft logged interval of Lower Cretaceous Muddy, Cloverly, and Morrison Formations. These log intervals are within the deeper Cave Gulch structure (Figure 14), starting at a depth of 17,036 ft. At these depths and formation pressures, heavier oil-based muds were used while drilling. The FMI tool, however, works best in water-based muds. Nevertheless, the logs from the #4-19 well were run in oil-based muds and their quality is considerably less than the other wells. Since this well concerns the deeper structure (and has also been plugged and abandoned) the Cave Gulch #3, 10, 11, and B-5 wells, drilled on the shallow structure, are the focus of this study.

3.4.2 Picking Dips

Computed dips were initially investigated, however, manual dips allowed for a higher degree of data accuracy. Therefore, manual dip picking was performed for all five wells, totaling over 30,000 ft of examined section. Bedding boundaries were delineated with a green sine wave and dips ranged from <1° to 84°. Bed boundaries were determined based on amplitude contrasts of static and dynamic amplitude images of the FMI logs (Figure 27). The interactive display of both image types and manual interpretation of these images made it possible to obtain results in a more reliable way. In addition, changes in the color palette and interval of display were used to vary the resolution and alter contrast to enhance bedding and structural features.

In addition to bed boundaries, planar features such as open and healed fractures, microfaults, and scours were also delineated. Figures 28, 29, 30, and 31 present FMI images of open fractures, healed fractures, microfaults, and scours. Open fractures and healed fractures were interpreted with red and yellow sine waves, respectively. Fractures commonly have different dip and azimuth orientations than bedding. Open fractures (Figure 28), commonly filled with conductive drilling muds, are easily differentiated from healed fractures, which show characteristic high resistivity traces. In mineral filled healed fractures (e.g. calcite cement in a sand/shale sequence) electrical imaging tools such as the FMI will show a "halo effect" caused by the change in resistivity (Figure 29) (Thompson, 2000). Scours, indicated by light blue sine waves, represent erosional events that cut into underlying bedding surfaces. The scour shown in Figure 31 is easily recognized by the sharp lithological contrast and the stratal terminations against the scour surface.

3.4.3 Cumulative Dip Plots

Cumulative dip plots (Hurley, 1994) have been shown to be useful in the identification and subdivision of stratigraphic and structural dip domains (Prosser et al., 1999). In this study, cumulative dip plots were used to help determine the depths of faults. Interpretation of dip trends was the first essential step in structural interpretation of dip data, allowing the depth of faults cutting the well bore to be accurately positioned.

Cumulative dip azimuth plots are a graph of sample number (a function of depth) vs. cumulative dip magnitude (Figure 32). Samples are color-coded by dip direction. The ASCII file containing bedding feature information is organized in a spreadsheet and sorted by depth. Each dip, starting with the shallowest, is assigned a sequential number. Magnitudes for each data point are summed sequentially and plotted against sample number, resulting in a cross plot where inflection points separate blocks of rock with consistent orientations (i.e., dip domains). Sample number is used in place of depth due to the irregular distances between interpreted bed boundaries. Depth plotting could create false inflection points.

These plots yield straight-line segments and inflection points, which correspond to abrupt or subtle changes in dip magnitude within the section. In addition, color-coding each sample based on the four compass quadrants allows for further corroboration in the interpretation of dip domains. Cumulative dip plots help to identify zones where dip remains constant and as such, changes provide evidence of structural boundaries. Figure 32 is the cumulative dip plot for the Cave Gulch #B-5 well (top interval) where 10 inflection points represent interpreted faults at the depths given. Not only do these inflection points correspond to changes in dip magnitude, but they also commonly correspond to changes in dip azimuth, represented on these plots by changes in color. Cumulative dip plots for shale beds were made for each FMI interval in all five of the studied wells and are included in the appendices.

3.4.4 Dip-Azimuth Vector Plots

Dip azimuth vector plots, or vector plots, are projections in the horizontal plane that are made by creating and plotting oriented unit vectors for each observed shale bedding plane. Each vector points in the dip direction of the corresponding bed. When vectors are plotted end-to-end from deepest-to-shallowest reading, inflection points that occur between straight-line segments can be used to define tops and bottoms of dip domains. Inflection points are commonly interpreted as faults.

Figure 33 illustrates a dip azimuth vector plot for shale beds of the Cave Gulch #B-5 well (top interval). There are 28 dip domains on this plot, 10 of which correspond to the same depth intervals interpreted from the cumulative dip plot for the same data. However, dip domains defined from cumulative dip and vector plots do not always match. This is because some inflection points have changes in dip azimuth, but not dip magnitude, and vice-versa. Dip azimuth vector plots for shale beds were prepared for each FMI interval in all five of the studied wells and are included in the appendices.

3.4.5 Structural Dip Removal

The result of interpretation of cumulative dip plots and vector plots yields depths that separate dip domains. Using the assumption that shale beds were originally deposited as horizontal layers, dip domains interpreted from shale-bed cumulative dip and vector plots represent structural dip. By rotating the structural dip out of all tadpole measurements, paleo-transport directions in sandstones can be inferred.

To accomplish this task, the depths separating each dip domain were used to define intervals for the creation of equal-area data projections on Schmidt plots within the Recall/Review software. Figure 34 shows Schmidt plots of dip domain data from Cave Gulch #B-5 (top interval). A mean dip and dip azimuth is automatically calculated for all poles and for a cone of 10° drawn about the mean pole (Table 3). Tables listing these data for every FMI log can be found in the appendices. The means computed from the data included in the cone of 10° are used for all later calculations because they are less representative of outliers. Outliers can result from fault drag, sedimentary structures, slumps, and errors in interpretation.

After mean dip magnitudes and dip azimuths are obtained for each shale structural domain, they are subtracted from all dip data. Separated by the interpreted dip domain depths, the corresponding mean dip and dip azimuth values are rotated out of each depth interval (domain) leaving tadpoles representing depositional dip and direction (Figure 35).

3.4.6 Paleocurrent Orientations

Once structural dip removal has been performed, dip data is output in ASCII format and sorted to remove all rotated dips below 5°. This is done to reduce scatter in the resulting rose diagrams of depositional dip orientations. The depositional dip orientations are then plotted as tadpoles on the paper log copies. These dip tadpoles, representative of paleo-transport direction, are grouped into 10 ft intervals and their orientations are plotted on dip azimuth rose diagrams. These rose diagrams give mean paleocurrent directions for each 10 ft interval (Figure 36). Structural dip removal was performed and paleocurrent orientations were determined for each well investigated in this study, with the resulting data plotted to rose diagrams and saved as TIF files for each well on CD-ROM.

Paleocurrent directions varied greatly for each well and depth interval. This could be a reflection of the fluvial depositional environment, wherein the direction of sand deposition changes rapidly in respect to evolving channel meanders. The complicated structure at Cave Gulch could also mask paleocurrent direction interpretations.

3.4.7 Structural Features

The interpretation sequence used to derive accurate structural information from the FMI log data was an iterative process involving several techniques. The following steps were involved in determining fault depths: 1) Identification of structural dip domains from dip trends on cumulative dip azimuth plots and dip azimuth vector plots. 2) Detailed examination of faulted intervals on borehole images. This step is particularly useful as detailed image examination of these intervals, paying close attention to fault related features such as microfaults, fractures, fault drag, and washout, can help to most accurately define fault (fault zone) depths.

Approximately 20% of faults interpreted from dip domain analyses were found on both cumulative dip and corresponding vector plots. However, nearly every fault interpreted corresponded to fractures, microfaults, and/or washouts on borehole images. Faults were interpreted where high fracturing zones occurred associated with 2 dip domains as depicted in Figure 37. In this Figure, a fault at 5,678 ft separates east dipping beds above from the west-southwest dipping beds below.

After FMI interpretation was completed and dip-domain analysis was performed, the resulting fault interpretations were integrated into two structural cross sections illustrated in Figures 38 and 39. In these cross sections, reservoir stratigraphic zones are shown along with inflection points interpreted from cumulative dip and vector plots.

To facilitate interpretation of fracture and microfault orientation data obtained from image analysis of each well, three plotting techniques were used: 1) Schmidt plots, 2) rose diagrams, and 3) fracture density histograms. Figure 40 presents fracture and microfault orientation data plotted on equal-area lower hemisphere Schmidt projections for the Cave Gulch #B-5 well. The poles of each fracture plane and microfault were plotted and contoured in order to determine the total number of fracture sets and the vector means for strike azimuth and dip magnitude. Figure 40 represents stereonets of all fractures and microfaults plotted together, and separated into hanging wall and footwall components. The orientation data shown in Figure 40 was further subdivided into healed fractures, microfaults, and open fractures, above and below the Owl Creek thrust, and plotted separately in Figures 41, 42, and 43 in order to discern differences in structural feature type. For example, the majority of healed fractures interpreted (85%) were limited to the hanging wall of the Owl Creek thrust (Figure 41). In addition, open fractures orientations below the Owl Creek thrust vary depending on structural location of the well within the field. In Figure 43 open fracture orientations below the thrust closely mirror that of the Northern Owl Creek thrust shown in Figure 9. The appendices contain these plots for all wells.

Strike azimuth rose diagrams were also created to illustrate the mean fracture orientations for each well. Figures 40, 41, 42, and 43 show the corresponding strike azimuth rose diagrams for all fractures and microfaults on the adjacent Schmidt plots for the Cave Gulch #B-5 well. Strike azimuth rose diagrams were plotted on structural contour maps obtained from seismic interpretation in order to observe the relation of fracturing with seismically derived faults (Figures 44 and 45). Fracture sets in the Lance and Meeteetse intervals are consistent with the orientation of the seismically derived faults.

Fracture density histograms were created for each well using fracture data obtained from FMI log interpretation. The plots show reservoir zonation and include faults interpreted from dip-domain analysis as illustrated in Figure 46. In this figure, the fracture density histogram plots the number of fractures contained in 100 ft intervals vs. depth. This example shows high fracture density associated with the Owl Creek thrust and other fault zones. The Middle Fort Union and the Lower Lance intervals also contain abundant fractures. These intervals also have the highest log porosity and net sand. The majority of production in this well is also from the Lower Lance interval. Fracture density histograms for each well are included in the appendices.

Fracturing at Cave Gulch field is pervasive with orientations consistent with nearby faults. However, variations in fracture density occur corresponding to structural position of the well. Figure 47 presents fracture and microfault densities for entire wells along with stratigraphic zonation of the reservoir on the Lance interval structure map. Here all fracture density histograms illustrate the number of fractures contained in 50 ft intervals vs. depth. Fracture density varies with each well, relating to structural position, proximity to major faults, and variations in lithostratigraphy.

4. INTEGRATED ANALYSIS

4.1 Available Data

A 3-D seismic interpretation made by Barrett Resources Corporation (now Williams Production) was examined in order to establish a structural framework for the field. Data used in this study consisted of seismic sections examined to compare faults interpreted from dip domain analysis with those interpreted within the 3-D volume. This comparison was done on a workstation at Williams. However, due to permissions related to the joint ownership of the seismic volume with ChevronTexaco, the figures presented here are all taken from published literature. These figures are representative of the 3-D volume in terms of resolution and applicability to this study.

The 21.5 mi^2 3-D survey was acquired by Northern Geophysical in late 1994, immediately after drilling of the Cave Gulch discovery well. However, due to the vertical beds at the surface, imaged area in the subsurface is only 6 mi^2. Bin spacing was 110 ft x 110 ft with 20 pound dynamite shots spaced at 60 ft intervals as the source (Natali et al., 2000).

Production data was also used in this analysis, consisting of perforated interval depths, and initial and monthly production rates of gas, oil, and water. This data was combined with structural diagrams to highlight reservoir zones in the field.

4.2 3-D Seismic

Two seismic sections are used to illustrate the structural framework of Cave Gulch field. Structural position of the interpreted intervals is shown along with reservoir zonations. Faults interpreted from the 3-D seismic volume are displayed next to those interpreted from dip-domain analysis for comparison.

Figures 49 and 50 are north-south and east-west seismic cross sections (depth migrated) showing the major footwall reverse fault that bisects the reservoir (location map shown in Figure 48). Overlays are provided on each of these figures to show interpreted seismic stratigraphy and seismic-imaged faults, as well as faults interpreted from dip domain analysis. As illustrated in these two seismic lines, many more faults were interpreted from dip domain analysis than those resolved within the 3-D seismic volume. In fact, virtually all faults interpreted from dip domain analysis, with the exception of the Owl Creek thrust, were not resolved by the 3-D volume.

Major seismic-imaged faults have similar orientations as associated sub-seismic scale faults and fractures. These faults and fractures may affect reservoir performance and are not readily apparent utilizing standard interpretation techniques. For example, the numerous faults (upper Lance) interpreted from dip domain analysis in well #B-5

(Figure 49) suggest that the seismic-imaged fault just to the north (terminating in the middle Lance) may continue as a fault splay as shown in Figure 51. The orientation of associated microfaults and fractures corresponds to this interpretation.

4.3 Production Data

Structural diagrams illustrating reservoir zonation and perforation intervals for the field were used to analyze and interpret the production data. The structural position of the wells with respect to the perforated intervals is a critical control on flow rates and estimated ultimate recoveries (EUR's). Wells in the central part of the field, on the crest of the Cave Gulch structure, tend to have lower decline rates and higher EUR's than those on the flanks. Wells depicted on the cross sections of Figures 52 and 53 exemplify this pattern. The Cave Gulch #3 well, located near the crest, has produced in excess of 5.6 BCF over 6 years, whereas the nearby #10 well, drilled 15 months later and 200 ft downdip, has only produced 1.14 BCF over 5 years (Figure 52). Similarly, the #B-5 well (Figure 53), which is south of the crest, has only produced 0.08 BCF to date (Dan Anderson, personal communication, 2002). The importance of structural position continues to the north of the major footwall fault that divides the field. The Cave Gulch #11 well, in a relatively unfaulted portion of the field, has produced 5.93 BCF (over approximately 6 years) at its crestal location along the northeastern terminus of the Waltman arch (Figure 53).

Initial production rates for these wells and others in the field mirror this trend, with wells high on the structure also having the highest initial flow rates. Faulting throughout the structure also plays a role, with fault splay compartments having limited production as demonstrated by the #9 well discussed in Chapter 2. Production rate decline curves for oil, gas, and water for the #3, 10, 11, and B-5 wells, shown on Figures 54, 55, and 56 respectively, illustrate the importance of structural position in the field. These were examined to compare production rates with the occurrence of faults and fractures interpreted from borehole images and dip domain analysis. The low production rates of the B-5 well, as compared with the other three, may not be a function of its structural position alone. The 525 feet perforated in the B-5 well (Figure 53) is considerably less than the 1,471 feet in the nearby #3 well. In addition, the well did not undergo the same extensive multi-stage stimulations that were performed in the #3, 10, and 11 wells (Dan Anderson, personal communication, 2002).

Pay distribution in the Fort Union and Lance was also examined in terms of controls on production. Figures 57 and 58 are structure contour maps at the top of the Lance interval with pay isopach data highlighted for the Fort Union and Lance respectively. Pay was defined by Williams as thickness of sandstone with more than 10% log porosity and more than 40 ohmm resistivity. Significant methane shows (chromatograph readings) correspond with these log cutoffs (Montgomery et al., 2001). Figure 59 shows the thickness of chromatograph readings and corresponding reservoir zonations for the #3, 10, 11, and B-5 wells.

Pay in the lower Fort Union (Figure 57) is thickest at the crest of the structure and is truncated by the footwall reverse fault that bisects the field. To the north of this fault, the formation is nonproductive and may be breached by the Owl Creek thrust. Pay in the middle Lance (Figure 58) is also thickest on the crest of the structure, however, 200 ft of pay exists north of the footwall reverse fault and the total area with significant pay thickness (>100 ft) is considerably larger than that of the Fort Union shown in Figure 57. Montgomery et al. (2001) suggested that this is due to better reservoir quality and fracture enhancement in the middle Lance.

4.4 Interpretation

Figure 60 shows the aforementioned production data with diagrams of the wells with faults interpreted from dip domain analysis. Perforation intervals are shown along with the number of healed and open fractures and microfaults (interpreted from image analysis) encountered. This was done in order to establish a relationship between production rates and the location of perforated intervals with respect to faulting/fracturing in the well.

Seemingly at odds with the possible reasons for the poor performance of the #B-5 well mentioned previously, perforations in the well encountered the most open fractures. However, this well is the furthest down-dip from the structural crest and also has the most sub-seismic scale faults interpreted from dip domain analysis (63 in total). The well also encountered the least amount of pay (Figures 57 and 58) and had the lowest overall thickness of chromatograph readings (Figure 59).

5. DISCUSSION

This chapter summarizes the results obtained from the analysis methods described in Chapters 3 and 4. Faulting/fracturing and structural position have been shown to be the predominant control on well performance at Cave Gulch field and as such the results presented here concentrate on image-interpretation derived structure(s).

5.1 Seismic and Sub-seismic Scale Faults

Complex structural elements and less than ideal seismic imaging promote the importance of incorporating all available data to support the structural interpretation. FMI image interpretation and dip domain analysis of 4 wells led to the identification of 154 faults in the shallow Cave Gulch field structure (Figures 38 and 39). These faults were compared with seismic data. With the exception of the Owl Creek thrust, all were found to be below seismic resolution, or sub-seismic in scale (Figures 49 and 50). However, these interpreted faults can be integrated with the seismic data to allow existing fault interpretations to be expanded and defined with increased confidence as shown in Figure 51.

Seismic and sub-seismic scale faults are related to decreased production in the studied wells. The #3 and #11 wells, which encountered the least amount of faulting, also have the highest production rates. Alternately, the #10 and #B-5 wells are associated with heavily faulted intervals and have lower production rates.

Dip domain analysis, utilizing cumulative dip and dip azimuth vector plots, can assist in planning for completion and perforation. One can either avoid or specifically target fault blocks or zones of open fractures. If these techniques were utilized at Cave Gulch, prior to perforation, fault zones could have been completely avoided, possibly maximizing production potential beyond present levels. In addition, with an early aggressive tie-in of image analysis data with the seismic interpretation, a more robust structural model for the field could have been realized, possibly reducing risk during development.

5.2 Fracture Orientation and Fracture Density

Results obtained from fracture interpretation and dip domain analysis are summarized on Table 4. This table lists the number of fractures, microfaults, and sub-seismic scale faults for each reservoir interval. The Lance, the main reservoir in these wells, is highlighted.

Fracture and microfault orientations locally mirror those of nearby seismic-imaged faults (Figures 40-45). Open fracture orientations vary within the field, depending on proximity to larger scale faults and reservoir zones (Figures 44 and 45).

Open fractures are a very important structural control on reservoir performance. Stresses relating to the northwest-southeast trending Owl Creek thrust are the primary control in the hanging wall, with most fractures following this trend. In the footwall, at reservoir level, the occurrence and orientations of fractures and microfaults varies with proximity to larger structures. These larger structures include the east-west trending seismic-imaged faults that bisect the field and the numerous sub-seismic faults interpreted from dip domain analysis.

Paleocurrent orientations obtained after structural dip removal do not show obvious trends. Structural deformation may contribute to the variable nature of the results.

6. CONCLUSIONS AND RECOMMENDATIONS

6.1 Conclusions

1) Dip domain analysis of 4 wells drilled in the shallow Cave Gulch structure led to the identification of 154 sub-seismic scale faults. Faults are unevenly distributed, with some wells having many more faults than others.

2) FMI image interpretation of these 4 wells resulted in the interpretation of 3,135 open fracture depths and orientations, useful for delineating potential bypassed production zones. In addition, 828 healed fractures and 856 microfaults have been documented.

3) Areas with less faulting and fracturing are associated with increased production. However, perforated intervals do not coincide with the occurrence of zones of open fractures.

4) Open fracture orientations within the field vary, depending on structural position and proximity to faults.

5) Seismic imaging at Cave Gulch resolves only large scale faulting (hundreds of feet of offset). Results from dip domain analysis can further refine the current structural model.

6) FMI image interpretation and dip domain analysis can be performed to identify important features that cannot be detected from seismic interpretation or conventional well logs.

7) Paleocurrent orientations varied with depth, showing no discernable trend. This may be a function of the structural complexity within the field.

8) Sub-seismic scale faults are important controls on reservoir production, effectively limiting connectivity to the well bore at Cave Gulch. If dip-domain analysis is performed before perforations are chosen, faulted intervals could be completely avoided.

6.2 Recommendations

With the shallow structure at Cave Gulch almost completely developed, application of the results from this study need to be shifted to strategies involved in the development of deeper targets. Because porosity decreases with depth at Cave Gulch, adequate production will depend more heavily on the occurrence of open natural fractures as the deeper targets are tested. This is where image analysis could have the greatest benefit as drilling costs and risks increase with depth. Performing dip domain analysis before choosing perforations would help avoid faulted zones not detected by seismic interpretation. Open fractures are easily visible on FMI images and interpretation could help identify zones of open fractures that are not discernable on other logs.

In addition, with the success at Cave Gulch, many companies are actively pursuing their own exploration programs in subthrust regimes. This play environment does not lend itself to high-resolution seismic imaging due to high variations in velocities and high dip magnitudes. Therefore, the use and practice of interpreting borehole images will have increased importance.

6.3 Future Work

FMI logs at similar depths (Table 5) exist from 6 additional wells in the field (Figure 61). Image interpretation and dip domain analysis should be performed for the remaining wells. Application of the techniques described previously to these logs would help expand the existing results.

WELL NAME	**FMI INTERVALS**			**TOTALS**
	(feet)			(feet)
Cave Gulch #2	3,978-9,738			5,760
Cave Gulch #6	940-1,860	9,330-9,560		1,150
Cave Gulch #7	6,212-7,310	8,300-9,300		2,098
Cave Gulch #13	1,190-2,810	4,100-6,710	8,000-9,300	5,530
Cave Gulch #4-30	670-10,190			9,520
Cave Gulch #B-4	697-9,846			9,149

Table 5. List of remaining Cave Gulch wells and recorded FMI log data intervals. Locations of wells shown in Figure 61. Total recorded interval is 33,207 ft.

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APPENDIX A: WELL #B-5

Figure 1: Cumulative dip plot for shale beds #B-5 (low)

Figure 2: Dip azimuth vector plot for shale beds #B-5 (low)

Figure 3: Schmidt plot dip domains for #B-5 (low)

APPENDIX B: WELL #3

Figure 1: Cumulative dip plot for shale beds #3 (low)

Figure 2: Cumulative dip plot for shale beds #3 (top)

Figure 3: Dip azimuth vector plot for shale beds #3 (low)

Figure 4: Dip azimuth vector plot for shale beds #3 (top)

Figure 5: Schmidt plot dip domains for #3 (low and top)

Figure 6: Schmidt plots and rose diagrams for #3 well

Figure 7: Healed fractures for #3 well

Figure 8: Microfaults for #3 well

Figure 9: Open fractures for #3 well

Figure 10: Fracture density histogram for #3 well

APPENDIX C: WELL #10

Figure 1: Cumulative dip plot for shale beds #10 well

Figure 2: Dip azimuth vector plot for shale beds #10 well

Figure 3: Schmidt plot dip domains for #10 well

Figure 4: Schmidt plots and rose diagrams for #10 well

Figure 5: Healed fractures for #10 well

Figure 6: Microfaults for #10 well

Figure 7: Open fractures for #10 well

Figure 8: Fracture density histogram for #10 well

APPENDIX D: WELL #11

Figure 1: Cumulative dip plot for shale beds #11 (low)

Figure 2: Cumulative dip plot for shale beds #11 (middle)

Figure 3: Cumulative dip plot for shale beds #11 (top)

Figure 4: Dip azimuth vector plot for shale beds #11 (low)

Figure 5: Dip azimuth vector plot for shale beds #11 (middle)

Figure 6: Dip azimuth vector plot for shale beds #11 (top)

Figure 7: Schmidt plot dip domains for #11 (low)

Figure 8: Schmidt plot dip domains for #11 (middle)

Figure 9: Schmidt plot dip domains for #11 (top)

Figure 10: Schmidt plots and rose diagrams for #11 well

Figure 11: Healed fractures for #11 well

Figure 12: Microfaults for #11 well

Figure 13: Open fractures for #11 well

Figure 14: Fracture density histogram for #11 well

APPENDIX E: WELL #4-19

Figure 1: Cumulative dip plot for shale beds #4-19 (low)

Figure 2: Cumulative dip plot for shale beds #4-19 (top)

Figure 3: Dip azimuth vector plot for shale beds #4-19 (low)

Figure 4: Dip azimuth vector plot for shale beds #4-19 (top)

Figure 5: Schmidt plot dip domains for #4-19 (low and top)

Figure 6: Schmidt plots and rose diagrams for #4-19 well

Figure 7: Healed fractures for #4-19 well

Figure 8: Microfaults for #4-19 well

Figure 9: Open fractures for #4-19 well

Figure 10: Fracture density histogram for #4-19 well