Greater Green River Basin Production Improvement Project

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1.   Introduction

The Greater Green River Basin (GGRB) of Wyoming has produced abundant oil and gas out of multiple reservoirs for over 60 years, and large quantities of gas remain untapped in tight gas sandstone reservoirs. Even though GGRB production has been established in formations from the Paleozoic to the Tertiary, recent activity has focused on several Cretaceous reservoirs.   Two of these formations, the Almond and the Frontier Formations, have been classified as tight sands (permeabilities <0.1 millidarcy) and are prolific gas producers in the GGRB. The formations are typically naturally fractured and have been exploited using conventional vertical well technology. In most cases, hydraulic fracture treatments must be performed when completing these wells to increase gas production rates to economic levels. However, hydraulic fracture treatments may not be the most effective method for improving gas production from these tight reservoirs. With the maturation of horizontal drilling technology it has become apparent that horizontal drilling may be particularly well suited to reservoirs where hydraulic fracturing is inefficient either because hydraulic fractures are parallel to natural fracture strike and/or because encasing shales are poor stress barriers to limit excessive hydraulic fracture height growth.

Several horizontal completions have been made in the Almond Formation in the Wamsutter Arch area (i.e. Amoco Champlin 254-B2-H in T20N-R93W), and several more horizontal completions are planned as alternatives to vertical, hydraulically-fractured wells.   The objectives of the GGRB production improvement project, however, were to apply the concept of horizontal and directional drilling to the Second Frontier Formation on the western flank of the Rock Springs Uplift and to compare production improvements by drilling, completing, and testing vertical, horizontal and directionally-drilled wellbores at a common site. The western GGRB area has not been tested with alternative completion technologies, and the laterally extensive marine and

lenticular fluvial reservoirs characteristic of the Second Frontier represent prime candidates for a DOE demonstration project that would compare production improvements by drilling, completing and testing vertical, horizontal and directionally-drilled wells. Developing techniques to more efficiently improve exploitation efficiencies in the Second Frontier has potentially high rewards because the potential recoverable gas resource in the Deep Frontier is large, with gas-in-place ranging from 10 to 25 BCF per 640-acre section.

1.1 Objectives of the project and technical approach

The objective of the Greater Green River Basin (GGRB) production improvement project is to assess the technical and economic feasibility of multiple lateral completion technology in the fluvial and marine sandstones of the deep Second Frontier Formation located in the GGRB, Sweetwater County, Wyoming. This project may help to reduce the technical risks and economic uncertainty standing in the way of increased efficient industry development of this low permeability (tight) gas resource.

Phases I and II of the project involved site characterization and the subsequent drilling of a vertical characterization well through the Second Frontier Formation (Fig. 1-1). Information gained from the vertical well was used to further characterize the geology of the site, reservoir quality, natural fractures, stress directions, and gas productivity in order to evaluate the feasibility of implementing subsequent phases of the project (multiple lateral wellbores). Data from the vertical well was also used in evaluating the potential effectiveness of a hydraulic fracture treatment. Unfortunately, the production rates from the test well were significantly lower than expected, and the reservoir encountered in the well does not appear to warrant further drilling at the current location.

2. Project Description - Phase I

2.1 Regional Geology

The Greater Green River Basin is a composite of several smaller foreland basins, and covers an area of approximately 19,700 square miles. The GGRB is bounded by the Wyoming Overthrust Belt on the west, the Wind River Mountains on the north, the Rawlins Uplift and the Park Range Uplift on the east, and the Uinta Mountains and Axial Basin Arch on the south (Figures 2-1a and 2-1b). Although the GGRB is bounded on the west by the thin-skinned deformation of the Overthrust Belt, the uplifts within the GGRB and their adjacent sub-basins are basement-involved. Most of the structural features within the basin are the result of compressional deformation associated with the Laramide orogeny (Campanian through Maastrichtian). There is evidence that there was earlier movement along the Moxa Arch, perhaps as early as Frontier time (Wach, 1977). Isopach maps and stratigraphic relationships

within the Frontier Formation indicate that parts of southwestern Wyoming and northeast Utah were slightly positive elements during Frontier time.

The Greater Green River Basin of Wyoming is located along the western margin of the Cretaceous Western Interior Seaway which extended from Alaska to Mexico during the Upper Cretaceous (Fig. 2-2). Over 17,000 feet of Upper Cretaceous rocks were deposited during several cycles of relative sea level rises and falls. The sediments that fed the Upper Cretaceous shorelines in southwest Wyoming were derived from the west and northwest as uplifts resulting from the Sevier and Laramide orogenies were eroded.

Isopach maps of the Upper Cretaceous sediments in southwesternmost Wyoming and easternmost Utah show a north-south trending feature in which tens of thousands of feet of Upper Cretaceous sediments accumulated (Fig. 2-3). This geographic area characterized by the remarkably thick package of sediments is interpreted to represent a foredeep. This foredeep apparently formed in response to the loading of the crust caused by the multiple episodes of thrusting associated with the Sevier Orogeny to the west. The foredeep acted as a sediment sink for many of the Upper Cretaceous rocks, and trapped most of the coarse-grained sediment that was being shed off the Sevier Orogeny. The Greater Green River Basin is situated on the easternmost edge of the foredeep, and contains a relatively thin package of Upper Cretaceous rocks compared to the foredeep directly to the west.

2.2 Frontier Formation regional depositional setting

The Frontier Formation in the Greater Green River Basin of Wyoming, Colorado, and Utah consists primarily of sandstone, siltstone, and shale, with minor amounts of coal and conglomerate. These marine and non-marine sediments were deposited along the western margin of the Western Interior Cretaceous Seaway, and record sedimentation into and across a foredeep that was subsiding during Frontier time (Figures 2-2 and 2-3). Previous studies have described the Frontier sediments as fluvial/deltaic deposits associated with wave-dominated deltaic complexes that fed sediments from the rising Sevier highlands in the west to the Cretaceous seaway to the east (Cobban and Reeside, 1952; Reeside, 1955; Hale, 1962; DeChadenades, 1975; Ryer, 1977; Myers, 1977; Winn et al., 1984; Moslow and Tillman, 1986; Moslow and Tillman, 1989; Hamlin, 1992). Molluscan fossils from the marine units indicate that the Frontier was deposited during early Late Cretaceous time (Merewether and Cobban, 1983; Merewether, et al., 1984; Merewether, 1983). The Frontier Formation ranges from several thousand feet thick near Coalville, Utah (Ryer, 1977) to less that 200 feet thick near the northern flank of the Uinta Mountains (Reeside, 1955; Merewether, et al., 1984). The dramatic thickness changes in the Frontier are related to the presence of the foredeep that allowed several thousand feet of Frontier sediments to accumulate due to increased accommodation space. In contrast, the area along the north flank of the Uinta Mountains was a positive element during Frontier deposition, where a relatively thin Frontier package is present.

The Frontier sediments were deposited as a result of the progradation of several wave-dominated deltaic complexes. The Frontier deltas were sourced from the Sevier orogenic belt to the west in

Utah and the Idaho Batholith to the northwest in Idaho. Sediments in the lower part of the Frontier Formation generally prograded to the east-southeast while sediments in the upper part of the Frontier (First Frontier and some of the Second Frontier) prograded to the east-southeast as well as to the south in the northern part of the Greater Green Basin.

The Stratos well targeted the part of the Frontier Formation known throughout the subsurface as the Second Frontier sandstone. Correlations from outcrops on the eastern edge of the Overthrust Belt into the subsurface indicate that the Second Frontier is equivalent to the Oyster Ridge and Dry Hollow members of the Frontier (Fig. 2-4) (Merewether and Cobban, 1983; Merewether, et al., 1984; Merewether, 1983). The Second Frontier is further subdivided in the subsurface into two benches. The second bench (the older of the two benches) of the Second Frontier consists of a coarsening-upward shoreface succession of mudstone, siltstone and sandstone. It is unconformably overlain by the first bench of the Second Frontier which consists of fluvial and estuarine channel-fill sandstones and associated coastal plain mudstones and siltstones. Both sandstone benches were expected to be present in the Stratos location (Fig. 2-5).

2.3   Region of Overpressure in the GGRB

The Upper Cretaceous sedimentary rocks in the GGRB are commonly overpressured, beginning at depths of 8,000 to 12,000 ft. (2438 to 3658 m) (Law and Dickinson, 1985). These rocks can have pressure gradients exceeding 0.9 psi/ft (Law and Spencer, 1091; Spencer and Law, 1981), exhibit low porosities and low permeabilities (<0.1 md), and always contain gas. The overpressured, gas-bearing rocks occur in the deeper parts of the Green River Basin, downdip from the normally pressured, gas and water-bearing rocks (Fig. 2-6). There is no apparent lithologic seal for the gas accumulations; the top of the overpressuring cuts across structural and stratigraphic boundaries (Fig. 2-7). Law et al. (1979, 1980), McPeek (1981), Law (1984), Law and Dickinson (1985), Law et al. (1986), Spencer, 1987, and Law et al. (1989) have attributed the origin of the anomalously high pressures to the accumulation of gas in low permeability reservoirs, at rates greater than it is lost. The position of the top of the overpressuring in the GGRB is related to the level of thermal maturity, organic richness of the gas source rocks, and present-day temperature (Law, 1984). The top of overpressuring occurs at an uncorrected bottom hole temperature of approximately 180° F. (82° C) and a vitrinite reflectance of around 0.8% (ranges from 0.74 to 0.94%).

The Stratos well is located well within the zone in which the Frontier Formation is overpressured. The Frontier Formation is overlain by the Baxter Shale is and underlain by the Mowry Formation, both of which are considered two favorable source bed units. Bottom hole temperatures in the two closest offsets to the Stratos location (the ERG Blue Rim Federal 1-30 and the ERG Blue Rim Federal 1-31) (Fig. 2-8) ranged from 270° to 295° F. The Frontier Formation typically exhibits permeabilities of less than 0.1 millidarcy, and it has been classified as a tight gas sand throughout this part of the Green River Basin. Both of the Blue Rim wells tested significant amounts of gas and no water from perforations in the Second Frontier.

2.4   Natural fracturing

Regional fracture orientations were obtained through numerous measurements taken from Frontier outcrops that surround the Green River Basin. The locations of the outcrops are shown on figure 2-9 and include outcrops from the Oyster Ridge in the Wyoming/Utah Overthrust Belt, the north flank of the Uinta Mountains near Manila, Utah, and Frontier outcrops near Sinclair, Wyoming. The most prominent fracture orientations from the Frontier Formation along the Oyster Ridge outcrop are east, east-northeast, and north; the east-trending fractures are the most numerous. There is more variability in fracture orientations from the north flank of the Uinta Mountains, and there seem to be several common fracture orientations. These include east (75-95 degrees), southeast (110-120 degrees), and northeast (35-55 degrees). There are also scattered north to northeast-trending fractures along the outcrop. Measurements from the east flank of the Greater Green River Basin (Sinclair, WY) are predominantly south-southeast (334 degrees) and east-northeast (70 degrees).

Fracture trends and patterns from the Oyster Ridge outcrop along the eastern margin of the Overthrust Belt were considered to be most analogous to the fracture patterns predicted for the Stratos location for several reasons. The Oyster Ridge outcrop is approximately 50 miles west of the Stratos location and is therefore the closest outcrop to the location. Fractures are known to behave differently between units with differing rock properties, and therefore it is more accurate to compare fractures between rocks with similar lithologic characteristics. The Oyster Ridge and Dry Hollow members of the Frontier are the units that make up the resistant Oyster Ridge Hogback topographic feature, and these two members of the Frontier are equivalent to the Second Frontier sandstones targeted in the Stratos well. Therefore, natural fractures with east, east-northeast, and north-south trends, the most prominent trends in the Oyster Ridge Overthrust outcrop, were predicted for the Second Frontier target in the Stratos well.   The dominant trend of regional lineaments in the area is to the northeast, and the Stratos well was deviated to the north north-west in hopes of crossing northeast-oriented fractures.

2.5   Stratos site-specific geology

The Stratos prospect was based on finding gas-charged, naturally fractured Second Frontier reservoir sandstones in an overpressured position. Wells closest to the structural axis of the Green River Basin are the deepest and exhibit reservoir temperatures that are more than adequate for natural gas generation. In fact, in deep-basin wells that have tested the Frontier, the formation always gives up some gas. Where pressure data are available, all of the deep-basin Frontier wells exhibit indications of overpressuring. Data from two wells, both of which are located less than one mile from the Stratos location, indicate that the Frontier is overpressured and is gas-productive. The two wells (the ERG Blue Rim Federal #1-30 and #31-1, Sections 30 and 31 of T22N-R106W, drilled in the late 1970's) are situated near the structural axis of the Green River Basin (Fig. 2-10), and rest on a structural saddle within the basin known to operators as the Blue Rim Arch. The structural position of the Frontier Formation at the Stratos site (proposed subsea elevation = -9280 ft.) was proposed be similar to the two Blue Rim wells, and in fact came in at exactly the proposed elevation.

Data from all of the deep basin wells drilled between the Rock Springs Uplift and the Moxa Arch, as well as data from many wells along the crests of both the Moxa Arch and Rock Springs Uplift were incorporated into the study and aided in the interpretation of sequence stratigraphy, depositional architecture and facies analysis, diagenesis, and reservoir characterization of the Frontier Formation. The specific location of the Stratos site was determined after careful examination of all of the available data. The proposed site was considered to be optimal for several reasons, one of which being its proximity to two significant production tests from the Second Frontier.   The Stratos well was drilled in close proximity to two relatively recent Frontier wells (the Blue Rim wells - Fig. 2-8). These two wells had the best production tests out of the Frontier sandstones of any of the deep basin wells. Both of these wells tested gas at rates of over one million cubic feet of gas per day, and one well (the Blue Rim #1-31) actually produced and sold gas to a pipeline at monthly average rates in excess of 500 MCFD. The well had a cumulative production of 145.5 MMCF after nineteen months out of the Second Frontier sandstones. This production was established in a well with a hydraulic fracture treatment considered to be well below optimal and relatively ineffective when compared to current stimulation technology.

Based on detailed core descriptions, subsequent calibration to electric logs, and log correlation of the Frontier Formation from the Moxa Arch, the western flank of the Rock Springs Uplift, and the intervening deep Green River Basin, a series of isopach maps of net feet of pay were constructed for the Second Frontier fluvial sandstones as well as for the Second Frontier marine benches (Figs. 2-11, 2-12, 2-13, and 2-14). Data from the Stratos well have been incorporated into these maps.

The fluvial isopach maps are shown in figures 2-11 and 2-12 and show the net feet of pay encountered within the Second Frontier fluvial interval. The Stratos well encountered 4 feet of fluvial sandstone net pay. Net pay was defined as sandstone that exhibited 6% or greater porosity, 60% or less water saturation, and 40% or less Vshale. The vast majority of the porosity values were calculated from sonic logs while the remainder were calculated from density logs. Water saturations were also calculated from sonic logs, and values for Vshale were calculated from the gamma ray curves.

The fluvial isopach map is somewhat difficult to interpret because there appears to be some thickness of fluvial sand almost everywhere. Some of this is a function of the sparse drilling in the deep basin, and some of it is actually representative of the Frontier fluvial section. Where drilling is closely spaced on the Moxa Arch and Rock Springs Uplift, the well control indicates considerable variability in the thickness of the fluvial sandstones. The unconformity, or sequence boundary, at the base of the Second Frontier fluvial section, can be traced over all of the mapped area and even one hundred miles to the east of the mapped area. In almost all wells in the study area, there is fluvial sandstone sitting on top of the sequence boundary. The Second Frontier fluvial system apparently was deposited as an irregular sheet of wandering river channels, perhaps due to very low accommodation space during the lowstand. In areas where there is more closely spaced well control, such as the Moxa Arch and the Rock Springs Uplift, correlations of channels within the Second Frontier yield a transport direction of east to southeast. These trends are consistent with paleocurrent measurements taken from outcrops of the Dry Hollow member of the

Frontier (equivalent to the subsurface Second Frontier) along the Oyster Ridge at the eastern edge of the Overthrust Belt.

The marine isopach maps (Figs. 2-13 and 2-14) show the general trend of the Second Frontier shoreline and the net pay encountered in the marine sandstone section. Paleocurrent measurements from outcrops along the Overthrust Belt and the north flank of the Uintas indicate north-south to northeast-southwest-trending shorelines. Detailed correlation of individual shoreface successions along the Moxa Arch also indicate approximately north-south or northeast-southwest trends for the Frontier shorelines along almost the length of the Moxa Arch. However, the trends of the shorelines begin to shift around to an east-west trend on the northern part of the Moxa Arch. In fact the shorelines appear to wrap around what is now the deep Green River Basin. This indicates that the present-day deep Green River Basin was also an embayment of some sort during the time that some of the Frontier shorelines were being deposited.

The location for the Stratos well was determined by Union Pacific geotechnical personnel after careful integration of all available data, including electric logs, cores, production tests, pressure data, and seismic data. The location was based primarily on the probability of favorable reservoir sandstone thickness, the location's proximity to two offset wells with known Frontier gas production and good reservoir quality, and structural position within the zone of overpressured Frontier. Although the probability of encountering overpressured gas in the proposed well was high, the risks of this project involved finding adequate reservoir quality and implementing a successful stimulation technology.

3.0   Project Description - Phase II: Drilling, Testing, and Completion of the Vertical Characterization Well

The UPRC Stratos Federal #1 (SE 1/4 of Sec. 24-T22N-R107W, Sweetwater Co., WY) was drilled through the Second Frontier to a total depth of 16,250 ft (See wellbore diagram in Fig. 3-1.). In order to facilitate the fracture characterization portion of this project, the wellbore was deviated, thereby increasing the probability of intersecting one or more vertical fractures during drilling. Maximum deviation from vertical was 12°, resulting in the core point being 106.15' N23° E5° from the surface location (Figs. 3-2 and 3-3).

3.1   Sedimentological interpretation of the Second Frontier

Oriented cores were taken through both the fluvial and marine sandstone benches of the Second Frontier. Eight gross feet and four net feet (porosity>6% and water saturation<60%) of fluvial channel sandstones and approximately forty gross feet and 19 net feet (porosity>6% and water saturation<60%) of marine sandstones were encountered in the well. Core porosities ranged from 3.3 to 7.3% in the fluvial sandstones and from 3.5% to 11.4% in the marine sandstones. The unstressed horizontal permeabilities to air ranged from <0.01 millidarcies to 0.25 millidarcies in the fluvial sandstones and from <.01 to 0.1 millidarcies in the marine sandstones. Special core analyses revealed that permeabilities decreased on the order of one magnitude after the application of confining pressures up to 4000 psi. Permeabilities also decreased an additional one order of magnitude as water saturations (Sw) were increased to 40% in comparison to normal dry unstressed routine permeabilities.

The Frontier Formation was cored from 15,990 to 16,100.5 ft, recovering 110.5 feet of core. The cored interval contains both fluvial and marine sandstones typically found in the Second Bench of the Second Frontier sandstone as well as the sequence boundary that separates the two facies. (See figure 3-4 for a complete core description.) Core #1 is from 15,990 ft to 16,039 ft and consists of coastal plain fluvial mudstones and stacked active channel fill sandstones. The channel sandstones are eight feet thick, and ten feet of coastal plain fluvial mudstones separate the channel sandstones from the underlying sequence boundary and marine sandstones. The sequence boundary that separates the coastal plain fluvial sediments from the lower shoreface marine sediments is not preserved in the core. In fact, the break between cores #3 and #4 coincides with the contact between fluvial and lower shoreface marine sediments.

Coastal plain fluvial deposits - The coastal plain fluvial sediments of the Second Frontier are composed of both mudstones and sandstones (15,990 ft to 16,039 ft). The mudstones are typically dark gray to black, organic-rich, and silty with thin silt and very fine-grained sandstone interbeds. The mudstones are locally rooted and occasionally contain wood clasts. The fluvial sandstones are fine to medium-grained and exhibit sharp and locally scoured bases. Internally, the sandstones contain small scale trough cross-stratification with abundant mudstone chips and carbonaceous laminations.   Bedding plane orientations were measured by TerraTek for the fluvial interval between 16,021 and 16,029 ft. Their dip azimuth plot indicates that bedding generally dips to the east, although some beds dip to the northeast and southeast (Fig. 3-6). This indicates that transport within the fluvial channels was generally to the east.

Marine deposits - The marine deposits of the Second Frontier (16,039 ft to base of core) consist of the following lithofacies: burrowed to bioturbated mudstones and siltstones; muddy, bioturbated very fine-grained sandstones; relatively clean very fine-grained, bioturbated sandstones; clean, massive to hummocky cross-stratified, very fine-grained sandstones; and massive fine-grained sandstones that contain some shell debris and are occasionally graded. The base of the core is composed of several incomplete coarsening-upward cycles of burrowed to bioturbated mudstones and muddy siltstones. These sediments are interpreted to represent deposition in an offshore transition environment. These units grade gradually upward into a muddy sandstone that coarsens upwards and gradually becomes cleaner toward the top of the

unit; it is thoroughly bioturbated by *Ophiomorpha, Planolites, Teichichnus*, and occasionally *Asterosoma.* This sandstone is interpreted to represent deposition by storms in a lower shoreface environment. This unit is capped by a two-foot thick, sharp-based, fine-grained massive sandstone that contains shell debris and graded bedding. Directly on top of the fine-grained sandstone is a two-foot thick, very-fine-grained sandstone that is highly contorted by soft-sediment deformation. Capping the contorted unit is another one to two-foot thick fine-grained massive sandstone. The two thin massively bedded sandstone bodies are interpreted to represent slurry deposits. The contorted sandstone between the two massive beds was probably deposited by storms in a lower shoreface environment, and was subsequently disturbed shortly after deposition to produce the contorted bedding. A thin, one-foot thick, shaley sandstone that is thoroughly bioturbated lies directly on top of the uppermost fine-grained massive sandstone unit. This thin shaley sand is interpreted as a transgressive event. It is capped by a sharp-based, very fine-grained, hummocky cross-stratified sandstone that is interpreted as a lower shoreface sandstone. The sandstone is occasionally burrowed by *Ophiomorpha*, and becomes more massive near the top of the unit. This sandstone is abruptly overlain by coastal plain fluvial mudstone, and the contact between the two units is interpreted as a major sequence-bounding unconformity, or a sequence boundary.

Comparison of the Stratos Federal #1-24 and the Blue Rim wells - The UPRC Stratos Federal #1-24 was drilled only 4100 feet to the northwest of the ERG Blue Rim # 1-30 (Fig. 3-4), yet the two wells exhibit some important variations in reservoir quality within the Second Frontier sandstones. The stratigraphic relationship between the Stratos Federal # 1-24 and the two Blue Rim wells is shown on figure 3-7, and core descriptions of the Stratos #1 and the Blue Rim #1-30 are included as figures 3-4 and 3-5, respectively. The cross-section shows that the Blue Rim #1-30 contains approximately 14 feet of fluvial sandstone while the Stratos Federal #1-24 contains 8 feet of fluvial sandstone. However, the most important distinction is that all of the fluvial sandstone in the Blue Rim #1-30 exhibits porosity greater than 6% while the fluvial sandstone in the Stratos Federal #1-24 contains only four feet of porosity greater than 6 %. The Stratos Federal #1-24 marine sandstones are cleaner than the muddier, more bioturbated Blue Rim marine sandstones, and apparently the Blue Rim wells are located on a more distal part of the Second Frontier marine shelf. Unfortunately, the cleaner marine sandstones appear to contain more quartz cementation than the muddier lower shoreface sandstones, and therefore exhibit lower porosities overall. The Blue Rim #1-30 contains over 20 feet of marine sandstone with electric log porosities of 6-10%. However, routine core analysis indicates that there are only 10 feet of sandstone with porosities 6% or greater in the marine sandstones of the Blue Rim well. Routine core analysis shows that the Stratos Federal #1-24 contains 35 feet of marine sandstone with greater than 6% porosity. In summary, the Blue Rim well contains 10 more feet of fluvial sandstone with porosities of 6% or greater while the Stratos well contains 25 more feet of marine sandstone with porosities of 6% or greater.

Figure 3-8 compares porosity-feet (porosity value multiplied by number of feet) and permeability-feet (permeability value multiplied by number of feet) between the Stratos #1-24 and the Blue Rim #1-30 wells. The Second Frontier sandstone consists primarily of three lithofacies (fluvial, clean marine and bioturbate marine), and the permeability and porosity values for each lithofacies are shown on figure 3-8. Note that the Blue Rim #1-30 exhibits higher values in the fluvial section,

but the Stratos well exhibits much higher values in the marine sandstones. However, a comparison of total permeability-feet and porosity-feet between the Stratos Federal #1-24 and the Blue Rim #1-30 shows that the Stratos Federal # 1-24 actually exhibits higher values in both categories (Fig. 3-9). Despite exhibiting lower porosity-feet and permeability-feet values, the ERG Blue Rim Federal #1-30 had an initial production rate of 378 MCFD after breakdown as compared to the initial production rate of 20 MCFD for the Stratos Federal #1 (Fig. 3-10).

The Stratos Federal #1-24 appears to contain a somewhat similar distribution and amount of porosity in the Second Frontier as the other Blue Rim well (the ERG Blue Rim Federal #1-31). Note however, that the porosity information is based solely on the comparison of electric logs because the ERG Blue Rim Federal #1-31 was not cored. The Blue Rim #1-31 contains six feet of fluvial sandstone with 6% or greater porosity (as compared to four feet in the Stratos), and the Blue Rim #1-31 contains eighteen feet of marine sandstone with 6% or greater porosity as compared to 35 feet in the Stratos well. There is also a zone in the Blue Rim #1-31 located between the fluvial and marine sandstones that could be interpreted as either fluvial or marine from the electric logs. (It has been interpreted to be fluvial on the stratigraphic cross-section - Figure 3-7.) This zone contains an additional five feet of 6% or greater porosity. The Blue Rim #1-31 well had an initial production after breakdown of 817 MCFD as compared to the Stratos initial production rates of 20 MCFD.

A possible explanation for the discrepancy in flow rates between the three wells is that the fluvial sandstone is a better reservoir than the marine; therefore, the reason that the Stratos well did not perform well is because the Stratos contains less fluvial sandstone than the two Blue Rim wells. However, it is not apparent from the core analyses nor from petrographic analyses why the fluvial sandstone would be a better reservoir. The porosities and permeabilities in the better marine sandstones are comparable to those of the fluvial sandstones, and the petrographic work indicates similar diagenetic histories for the two sandstones. The answer may involve a subtle distinction in the distribution and/or size of pore throats which would require additional detailed mercury injection capillary pressure analyses to be performed for both lithofacies in both wells.

The anomaly between the apparently comparable reservoir qualities yet vastly different production rates between the Stratos and the Blue Rim wells could also suggest, as predicted, that natural fractures play a critical role in gas productivity, and that for some reason, the Stratos well is not well connected to a natural fracture system that has enhanced the performance of the Blue Rim wells.

Another possible explanation for the low rates in the Stratos well is that some of the perforations in the Stratos well are not open, and that there is not good communication between the formation and the wellbore. The latter has been proposed by Integrated Petroleum Technologies, Inc. after their analysis of some of the post-breakdown, pressure buildup data. UPRC is currently considering performing an acetic/hydrochloric acid treatment on the Stratos well in order to ensure that all of the perforation tunnels are open.

Another possible explanation for the difference in production rates between the Blue Rim wells and the Stratos well is that a lower sandstone bench of the Frontier (the Fourth Frontier) was

perforated, acidized, and fracture stimulated along with the Second Frontier zone in both of the Blue Rim wells. This zone is approximately six to eight feet thick, and is interpreted as a marine shoreface sandstone in the lower Frontier. Previous technical evaluation of this zone indicated that it was probably not the main contributor to the production in the Blue Rim wells; therefore the decision was made not to drill to the depths needed to encounter the sandstone. However, since this zone was not penetrated in the Stratos well, the possibility remains that some of the gas production in the Blue Rim wells is coming from this lower sandstone.

3.2   Diagenesis

Porosity in the reservoir is a combination of primary intergranular porosity and secondary porosity created by the dissolution of feldspar and chert grains. The fluvial sandstones can be classified as sublitharenites to litharenites, with extensive silica cementation occluding much of the porosity (Figs. 3-11 and 3-12). The marine sandstones are primarily sublitharenites; however, these sandstones contain much more feldspar and generally less chert than the fluvial sandstones. The best porosity and permeability in the marine section occurs not in the cleanest lower shoreface sandstone, but in a slightly muddy, thoroughly bioturbated lower shoreface sandstone. The presence of detrital mud within the bioturbated sandstone has precluded the extensive precipitation of quartz overgrowths and therefore preserved a greater amount of primary intergranular porosity. Both calcite and dolomite cements are present in some of the marine sandstone samples, with values ranging from 1 to 8%.

3.3   Fracture characterization and analysis of in-situ stresses

The accurate prediction of the orientation of any naturally-occurring or induced fractures present in a reservoir is critical in optimizing the drilling and completion of both vertical and horizontal wells. This is especially true for formations such as the deep, overpressured Second Frontier where it is thought that natural fractures are vital factors in enhancing the permeability of otherwise very tight reservoirs. Since the orientations of natural fractures are commonly parallel to the maximum horizontal stress (S_{Hmax}) azimuth, determination of this azimuth has become important in evaluating naturally fractured reservoirs (Fig. 3-13). Estimates of S_{Hmax} can be obtained from the analysis of both core and well log data. Description of macrofractures in oriented core, analysis of microfractures, wellbore breakout analysis, anelastic strain recovery, and other core-based methods were all used to determine

the direction of S_{Hmax} in the Stratos Federal # 1. The results of each technique are summarized in the following sections.

3.31 Characterization of macrofractures in core

Macroscopic natural fractures are relatively isolated in the Stratos core. The lack of abundant macrofractures was disappointing but not surprising. The Second Frontier was also cored in the offsetting ERG Blue Rim #1-30, and only one thin zone of calcite-filled macrofractures was detected in that core (16,123 ft on core description - Fig. 3-5). In the Stratos core, three relatively short, calcite-filled fractures are oriented ENE to WSW while three longer fractures filled with dark gouge are oriented NE-SW. One partially open fracture is also oriented NE-SW. Formation MicroScanner (FMS) logs show a lack of significant natural fracturing in the reservoir near the vertical wellbore.

3.33   Preliminary analysis of microfractures

Microfractures, those natural fractures that are generally not visible to the unaided eye (microns to millimeters in size), can be used to determine the relative timing of fracturing and to infer the orientation of larger macrofractures (Laubach, in press). However, many of these microfractures typically go undetected in even detailed petrographic analyses because the fractures are completely filled with quartz that is in optical continuity with the host-rock quartz. Most of these microfractures are only faintly visible to invisible using conventional optical techniques; however the use of photomultiplier-based electron beam-induced luminescence (scanned CL) imaging has dramatically improved the resolution of these features. This is because the cathodoluminescence of detrital quartz grains is different from that of the diagenetic quartz that lines the natural fractures, even though the quartz may be in optical continuity. The scanning microscope also allows for much greater magnification of the sample than is possible with standard petrographic microscopes.

Three thin sections from the Stratos core were sent to the Bureau of Economic Geology at the University of Texas at Austin for scanned CL microscopy, and the preliminary results are presented here and in Appendix D. Work is ongoing with this project and should yield some interesting information upon completion. At the time of this report, preliminary study indicates that quartz-lined, opening-mode fractures are widespread in the three samples. The dominant strike of the highest reliability microfractures is west-northwestward (280°). There is also a subsidiary northeast striking component to the data; this northeast trend is clearest in areas that have few of the west-northwest-trending fractures. Figure 3-14 (Photos a through d) illustrates some of oriented microfractures. Figure 3-15 is a plot of the orientation of the strikes of all the microfractures measured from a thin section of the fluvial sandstone (16027 ft). It is important to note that although there is a strongly preferred orientation in the areas of the thin sections that have been studied, the actual areas that have been analyzed represent less than one percent of each thin section.

3.34   Core-based methods for estimating in situ stress conditions

Introduction - As previously discussed, the determination of in situ stress orientations and magnitudes is a critical component of natural fracture analysis because it is these parameters which presumably control the orientation and aperture of natural fractures in formations at depth. In order to establish the stress regime present in the Frontier in the Stratos Federal #1 wellbore, Union Pacific Resources contacted Sandia National Laboratories to discuss core-based methods for determining in situ stress orientation and magnitude in this well. These discussions led to an effort by both Sandia National Laboratories and Terra Tek to apply Anelastic Strain Recovery (ASR) to core retrieved from the Stratos well. One ASR (anelastic strain recovery) sample analyzed by Terra Tek yielded a maximum horizontal strain azimuth of N64.7°E, roughly consistent with the fractures encountered in the core. However, Sandia felt that the ASR results obtained from the Stratos core were essentially null, probably because of the time required to retrieve core from 16,000 ft.

Since the ASR results were disappointing, further discussions with Sandia led to the use of other approaches for the determination of in situ stress orientations. These analyses were applicable to "old" core and used measurements of the anisotropy of elastic wave speeds and anisotropic, non-linear strains exhibited by core subjected to hydrostatic stress. Stress magnitudes were estimated using Differential Strain Curve Analysis (DSCA) and Differential Wave Velocity Analysis (DWVA), both of which rely on determining the pressure required to close relaxation cracks. A summary of the results will follow; the two detailed reports provided by David Holcomb and Robert Hardy of Sandia National Laboratories are located in Appendix E.

Procedure - Six whole core samples were sent from Terra Tek in Salt Lake City, Utah to Sandia National Laboratories in Albuquerque, New Mexico. The samples were trimmed to approximately 10 centimeters (4 inches) in length using a diamond cutoff saw and water coolant. The core samples were then stored in plastic bags with no control on moisture content. Orientation of the master scribe was determined from the orientation survey conducted during the coring.

Methods - The methods involved measuring velocities and amplitudes for several types and amplitudes of elastic waves, including compressional, shear, and cross-polarization shear waves to detect birefringence. Velocity and strain measurements (Differential Strain Curve Analysis and Differential Wave Velocity Analysis) were done on the six samples to a maximum pressure of 190 MPa (27,500 psi). The crack strain tensor was also determined. The orientation survey done during coring was presumed to be correct since there were no indication of problems. It was assumed that the axis of the core was vertical.

Results - The following statements summarize the results of the above analyses:

- The velocity and strain anisotropy data indicate, with two exceptions, that the in situ stress was oriented as expected, with one principle axis in the vertical and the other two in the horizontal. However, the principal stress in the vertical direction was not usually the maximum compressive stress, as is generally the case. The maximum horizontal stress (σ_H)

was indicated to be at 10° east of north between 16,025 and 16,038 ft. The data indicate that σ_H then rotates to about 35° east of north at 16,050 ft.

- All of the data indicate that the maximum horizontal effective stress is close to (and possibly larger than) the vertical effective stress. From Differential Wave Velocity Analysis, the effective stress state was (σ_H, σ_h, σ_Z) = (67,53,60) MPa (σ_H = maximum horizontal stress, σ_h = minimum horizontal stress, σ_Z = vertical stress). The small differences between the stress magnitudes are not conducive to fracturing.

- Since the estimated effective stress state for the Frontier was (σ_H,σ_h, σ_Z) = (67,53,60 MPa) where σ_H = maximum horizontal stress, σ_h = minimum horizontal stress, σ_Z = vertical stress, then the stress state is interpreted as extensional ($\sigma_1 \approx \sigma_2 > \sigma_3$). If this is the case in the Frontier, the ductility of the formation would be decreased under extensional conditions, increasing the likelihood of fracturing; however, the strength of the rock could increase under these conditions, making fracturing more difficult.

- The more severe constraints on possible fracture orientations also decrease the amount of fracturing that would be expected.

3.44   Wellbore Breakout Analysis from Four-Arm Caliper Data

Wellbore breakout data obtained from oriented 4-arm caliper tools have been widely used to determine the current stress directions in a wellbore, and wellbore breakout analysis have been typically regarded as one of the more reliable methods for estimating in situ stress configurations. Wellbore breakouts occur when the stress concentrations near the wellbore exceed the strength of the rock. This results in an elliptical wellbore where the elongations are aligned parallel to the minimum horizontal stress. The relationship between wellbore breakout, maximum and minimum horizontal stress, natural fractures, and other features is summarized in figure 3-13. A detailed analysis of the wellbore breakout data from the entire Frontier Formation in the Stratos wellbore has been performed by Union Pacific Resources, and the results are shown in figure 3-16.

The four-arm caliper data from the Stratos well were analyzed in detail from 15,495 to 16,170 ft (Figure 3-16). This interval encompasses the entire Frontier Formation; and the zone of interest, the Second Frontier sandstone, is situated at approximately 15,990 to 16,100 ft. For 60 feet above the Second Frontier sandstone, the borehole is essentially round and gives no indication of any breakouts. For 13 feet of fluvial sandstone in the Second Frontier, the direction of breakout is 88.7°, yielding an orientation of North 1.3° West for maximum horizontal stress (S_{Hmax}). The data yields a 275.4° breakout direction for the eleven feet of non-marine mudstone that separates the fluvial sandstone from the marine sandstones; this yields a direction of North 5.4° East for S_{Hmax}. The remainder of the wellbore through the rest of the Second Frontier sandstones (all marine) is essentially round, giving no indication of any breakouts and therefore no indication of S_{Hmax}. In summary, the wellbore breakout data yield an essentially north-south direction for maximum horizontal stress though the fluvial sediments of the Second Frontier, but do not give any indication of S_{Hmax} in the marine sediments.

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Note that the orientation of S_{Hmax} changes considerably as one moves uphole in the Stratos well. (See figure 3-16.) From 15,495 to 15,579 ft (84 feet), the data show either no breakouts or breakouts that trend in a generally northeast direction. There is then a 10-foot zone from 15,581 to 15,591 ft that exhibits a 288.8° (west-northwest) breakout direction, followed by an interval from 15,595 to 15,608 ft that shows breakouts trending in a more northwest direction. That zone is followed by approximately 385 feet that show either no wellbore breakouts or breakouts that trend in a west-northwest direction.

3.5   Well log analysis

Two important factors for improving production in any area are an understanding of the reservoir and the accuracy of the parameters used in planning the completion of a well. In deep, ultra-tight reservoirs, the economics of drilling and completing a well are frequently marginal and the completion methods can economically "make or break" further development of a field. If there is no further development of a field due to poor initial development, then there is a loss of production and a waste of natural resources. Ways of trimming completion costs include extrapolating data from comparable reservoirs, modeling pre-completion pressure and flow tests and adjusting the size of completion accordingly, and lastly, substituting wireline data for core data. An effort has been made in the Stratos well to address this last methodology of improving production in the Frontier formation by obtaining the necessary parameters to efficiently and accurately plan development through the use of modern well logging techniques.

In planning the logging package for this project, the information sought was broken down into two groups. The standard logging suite of Neutron/Density and Resistivity logs provided the usual porosities, saturations, and lithologies. Since the Frontier formation was to be cored and tested extensively as part of the Statement of Work in the DOE contract, the decision was made to examine the correlation between the core tests and a more complex Hi Tech logging suite. It was anticipated that the data from these additional logs could provide a comparison of fracture identification, permeability, thin bed identification, and could aid in planning the eventual completion and even help predict the outcome of that completion. Good comparison between log and core data leads to confidence in future testing and development using only log data and thereby cutting costly coring operations in cases where coring is not feasible.

Unfortunately, this well was not an ideal candidate for the more Hi Tech logging suite since the reservoir at this location contained very few natural fractures, very little pronounced bedding, and very few hydrocarbon shows or other characteristics which the logs were designed to identify. Core analysis verified the lithology, porosity and fluid saturations as determined by the standard log interpretation. Quantitative log-derived permeability is suspect in the Stratos well due to possible geologic alterations that may have destroyed the porosity-to-permeability relationship, but the CMR, Neutron/Density and APS neutron profile all indicated low permeability and poor fluid invasion. The lack of fractures as seen in the core was confirmed by the ARI, FMI and DSI. The calipers from these same three logs also pointed to a NE-SW stress direction, although it is not a strong trend. The rock mechanics values calculated from the DSI also provided a good Poisson's ratio match to that computed from lithology.

To summarize, there is sufficient correlation between log-derived data and core-derived data from the Stratos well that in future Frontier tests, less expensively obtained log data could be reasonably substituted with some confidence for core data. Of course, additional comparisons of fractures and bedding between cores and logs would increase the confidence in these interpretations.

4.0 Completion and testing of the Stratos Federal #1-24

As part of Phase II of this DOE contract, the vertical wellbore in Stratos was to be thoroughly tested and evaluated. Since the objective of the project was to reduce technical risks and the economic uncertainty impeding development of the deep Frontier in the Green River Basin, UPR teamed with GRI (contract 5094-210-3021) to develop testing and completion procedures under the auspices of their "Emerging Resources in the Greater Green River Basin" study. The GRI contract included using IPT (Integrated Petroleum Technologies, Denver, Colorado), a company composed of petroleum engineers specializing in completion optimization, to provide an independent evaluation of the testing performed by GRI and its contractors.

UPR's contract included the following requirements for the testing and evaluation of Stratos based upon the assumption that the physical properties of the Frontier formation at this location would warrant hydraulic fracture stimulation:

- Cased-hole Stress Testing
- Pre-Frac Well Testing
- Mini-Frac
- Main "Moxa-Type" Frac

IPT proceeded with the analysis of the Stress Testing and Pre-Frac Well Testing. The results of these tests along with the various core and well log analyses demonstrated that the Second Frontier in the Stratos #1-24 did not exhibit reservoir properties that would obviously warrant the further expense of hydraulic fracture stimulations. However, complications during testing have led to questions concerning the validity of the testing results (electrical and mechanical difficulties, packer leakage problems, water sitting on formation, etc.).

Cased Hole Stress Testing - Cased hole Stress Tests are used to determine closure stress for reservoir rock and its surrounding formations. The contrasts in minimum closure stresses between layers of rock determine the fracture height growth and overall fracture geometry as a result of a hydraulic fracture treatment. While modeling what happens during a fracture treatment is difficult at best and subject to great debate, it is generally agreed that accurate determination of minimum closure stress is critical in optimizing any hydraulic fracture treatment.

Although four intervals were perforated for Cased hole Stress Tests (the shales bounding the reservoir and the fluvial and marine reservoir intervals) only the shales were tested due to problems with testing. There were three PI/SI (pump in / shut in) tests performed in the marine shale below the bottom of the Frontier. These tests had increasing ISIP's (initial shut-in pressures) with each successive pump in. This is an indication that the fracture geometry, both

near the wellbore and/or far-field, is becoming progressively more complex. The upper bound for the closure stress of the lower shale is 1.0 psi/ft or 15,800 psi. There were also three PI/SI tests for the shale above the Fluvial Frontier section. These tests had repeatable, consistent ISIP's which suggest that the fracture geometry is not as complex as that in the lower marine shale. This shale had an upper bound of the closure stress of 0.9 psi/ft or 14,300 psi.

Because no stress tests were performed on the Frontier pay intervals, the closure stress for the Frontier was estimated to have a gradient of 0.85 psi/ft or to be 13,700 psi. These values were used to model the breakdown treatment analysis using FRACPRO$^{®}$. The history match of the breakdown treatment showed a created fracture length of 78 feet with 6 far-field hydraulic fractures being created. Unfortunately, the pressure data recording stopped before the reservoir pressure could decline sufficiently to confirm the closure pressures of the bounding shales.

Pre-frac well testing - Following the breakdown with KCl water, there followed an eight day flow period, followed by a two week pressure buildup. Analysis of the buildup showed a reservoir pressure of 11,900 psi or a gradient of 0.74 psi/ft and a conductivity (kh) of 0.036 md-ft which translates to a permeability of 0.0012 md with a net pay of 30 ft. This permeability is low compared to core analysis and may be explained by several factors. Downhole shut off leaks created disturbances in the pressure transient several times during the buildup test. The formation had a 4000 ft water column sitting on it throughout the flow period since it was not "cleaned up" or swabbed dry after the breakdown treatment. This water could have been drawn into the formation by capillary pressure and reduced effective permeability. This water could also be imbibed reducing the permeability further. Another point raised by IPT is that fresh water breakdowns do not necessarily achieve good communication between the wellbore and the formation since they do not significantly affect cement. It is possible that not all the perforations have been opened.

IPT concluded that the productivity of the Stratos well could be enhanced by a hydraulic fracture treatment. However, using the test data, which is somewhat suspect, they estimate gas rates of only a few hundred MCFPD as a result. Some of the doubts concerning the results of previous tests could be addressed by further testing, i.e. acidizing to clean up the perforations. Rate step-down testing to determine the difference between near wellbore tortuosity and perforation fraction would be helpful in a hydraulic fracture design. Extending the post-breakdown observation of closure pressures would also help to confirm the results of the Stress Tests.

5.0   Results and Recommendations

The Second Frontier sandstones were perforated from 16,000 to 16,060 ft with 4 JSPF. The perforated interval includes both the fluvial and marine sandstones. Initial gas production after a 50 barrel 3% KCl water breakdown was approximately 20 MCFD with a flowing tubing pressure of 38 psi, a much lower rate than predicted after comparison to two offset wells with similar reservoir characteristics. The well is currently shut-in, pending further evaluation and a potential hydrochloric/acetic acid treatment that would be used to clean up existing near-wellbore damage.

Acknowledgments

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