Using Pore System Characterization to Subdivide the Burgeoning Uteland Butte Play, Green River Formation, Uinta Basin, Utah

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ABSTRACT

Over 240 horizontal wells with highly variable production results have been drilled in the Uteland Butte member (UBm) of the lower Green River Formation in the Uinta Basin, Utah. The best wells have each produced more than 300,000 barrels of oil in the first 12 months of production, with conservative Estimated Ultimate Recoveries (EURs) for several wells above a million barrels. Conversely, the poorest UBm wells have initial production rates of less than 10,000 barrels of oil in the first year and will never recoup their drilling costs. Pore pressure, oil viscosity, well length, and well completion are recognized as important controls on well productivity. Less understood, but of equal importance, is the variability in reservoir types across the UBm play. The UBm can be divided into sub-plays by district using the dominant pore systems in each area. We defined four distinct sub-plays within the Uinta Basin: 1) intergranular-dominated porosity, 2) intercrystalline-pore-dominated dolomite, 3) mixed intercrystalline-organic porosity, and 4) organic porosity. Reservoirs in the intergranular-dominated porosity sub-play are mostly present in the form of nearshore siliciclastic and carbonate bars, such as ooid and ostracod shoals, fluvial mouth bars, and nearshore siliciclastic bars. The normal pressure and charge in these reservoirs are due to hydrocarbon migration out of the deeper basin. Source rocks in this sub-play have an average maturity of 0.5 to 0.7 vitrinite reflectance (VRo), too low for mainstage oil generation for these lacustrine shales (Ruble and others, 2001), and produce highly viscous black wax with very low gas-to-oil ratios (GORs). To date, horizontal wells drilled in this sub-play have not been economically successful. The intercrystalline-pore-dominated sub-play consists of thin (<2 to 8+ feet), laterally continuous, high-porosity dolomites that act as the best reservoirs. The reservoir is normally to slightly overpressured and is predominately charged with hydrocarbons that migrated out of the deeper basin. This sub-play was the first to be drilled horizontally, with the dolomite beds being identified as the highest quality targets. The UBm is thick in the intercrystalline-pore-dominated fairway, consisting of over 130 feet of carbonates and black shales, with only a fraction of the interval being high-porosity dolomites. This sub-play has an average VRo of 0.6 to 0.8, still too low for mainstage oil generation in these rocks and produces a migrated black wax with low GORs. The mixed intercrystalline-organic porosity sub-play is largely self-sourced and significantly overpressured. This sub-play has the thickest gross section and is dominated by thin dolomite beds, thicker argillaceous limestones, and thicker shaley beds, with the latter units contributing significant production. Maturities in this sub-play range from 0.8 to 1.0 VRo. This sub-play produces a yellow to gray wax with moderate GORs. Finally, the organic-porosity-dominated sub-play is highly overpressured and completely self-sourced. There is relatively little reservoir-quality dolomite, the limestones are more argillaceous, and the organic-rich carbonate shales are thicker. The productive reservoir in this sub-play consists of organic porosity largely contained in bitumen that has been expelled at lower maturity, then continued to thermally degrade with higher maturity, converting to zones of interconnected organic porosity. Maturities range from 1.0 to 1.2 VRo and the hydrocarbons produced are a bright yellow wax with relatively high GORs. To be economically developed, each of these sub-plays requires individually tailored drilling, completion, and production strategies. By recognizing the important differences these pore systems exert on best development practices and then accurately mapping them across the basin, operators, interest owners, and regulatory agencies can more efficiently plan operations.

INTRODUCTION

Historically, petroleum geologists have identified and ranked oil and gas prospects through mapping a reservoir's original oil in place (OOIP), determined through relatively simple calculations such as water saturation (Sw) and porosity (Phi) (Brinkerhoff and others, 2016). In conventional reservoirs, these measurements prove to be reliable predictors of reservoir productivity. In these plays, an OOIP map can be used to quickly identify "sweet spots," where greater oil in place typically correlates with higher cumulative oil production. Unfortunately, in tight plays, OOIP can mislead operators as to where the highest yielding reservoirs are present due to the complex nature of unconventional reservoirs and the necessity to hydraulically stimulate the rock. A prime example of this is in the Uteland Butte member (UBm) play of the Uinta Basin (figure 1), where historically operators have experienced highly variable production results with little or no relation to calculated oil in place (Johnson and others, 2016). This paper explores the disconnect between gross OOIP and oil production and identifies other reservoir factors that more accurately predict production, namely pore type, pore geometry, and reservoir pressure.

Green River Formation

For many decades, the Green River Formation (GRF) in the Uinta Basin has been the most frequently targeted oil reservoir in Utah (Coal and Picard, 1978; Remy, 1992; Fouch and others, 1994; Morgan and Bereskin, 2003). The GRF consists of up to 6000 feet of lacustrine rocks that were deposited during a roughly 13-million-year period between 55 and 42 Ma (Eocene) (Johnson, 1984; Remy, 1992; Davis and others, 2010; Birgenheier and others, 2019). The Uinta Basin is a Late Cretaceous-Paleogene age, Laramide basin, formed as a deep foreland basin in response to the rising Uinta Mountain range (Johnson, 1985) (figure 2). The deepest part of the basin is immediately south of the Uinta Mountains, with a large, gently north-dipping limb extending to the south. It is this relatively gentle dipping southern limb of the basin that hosts the current GRF horizontal oil plays (figure 3). This study focuses on oil and gas reservoirs within the UBm of the GRF, the first major lacustrine transgression of the formation (Bradley, 1931; Johnson, 1985; Morgan and Bereskin, 2003). The UBm has also been frequently targeted in vertical wells drilled across a large swath of the Uinta Basin (Johnson and others, 2016), along with overlying oil-charged GRF sediments and the underlying Wasatch interval.

The Uteland Butte Member

The UBm was first identified as the Basal Tongue by Bradley (1931) in his seminal article on the GRF. He described a series of interbedded ostracodal limestones, lean oil shale, and blocky marlstones with pelecypods and gastropods, but he failed to notice the prominent dolomites in the outcrops he studied. Osmond (1992) described gas production from the Uinta Basin and informally named this unit as the UBm limestone, after the small gas field in township 10S and range 18E, in the south-central part of the Uinta Basin, where it also produces modest volumes of oil.

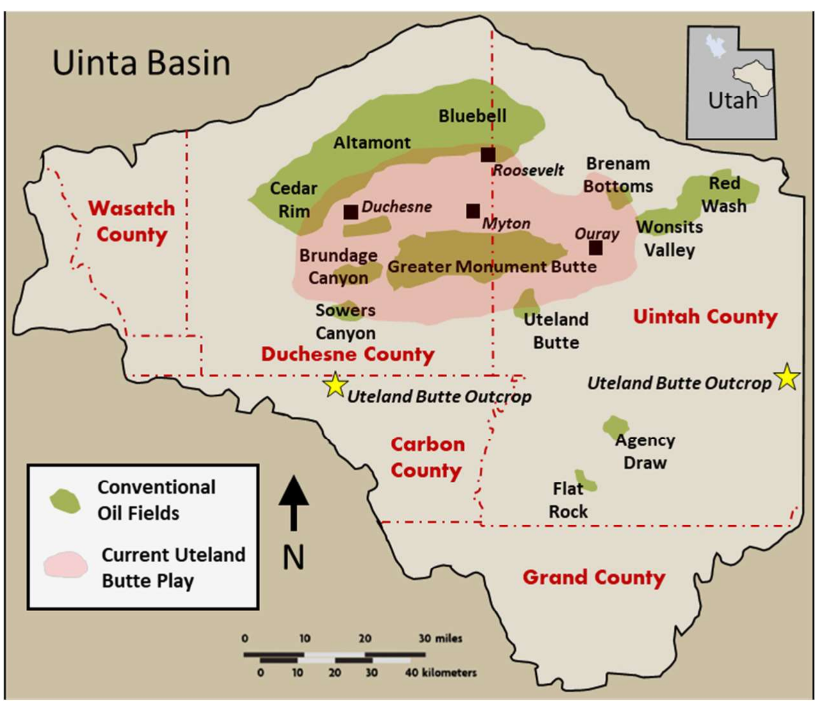


Figure 1. Map of the Uinta Basin in northeastern Utah showing the approximate position of the Uteland Butte play in red. Note that the study area extends over 3300 square miles, incorporates ~2200 vertical well logs and 17 cores. Production from ~500 vertical and horizontal wells was analyzed across the play area. Modified from Brinkerhoff and Woolf (2018).

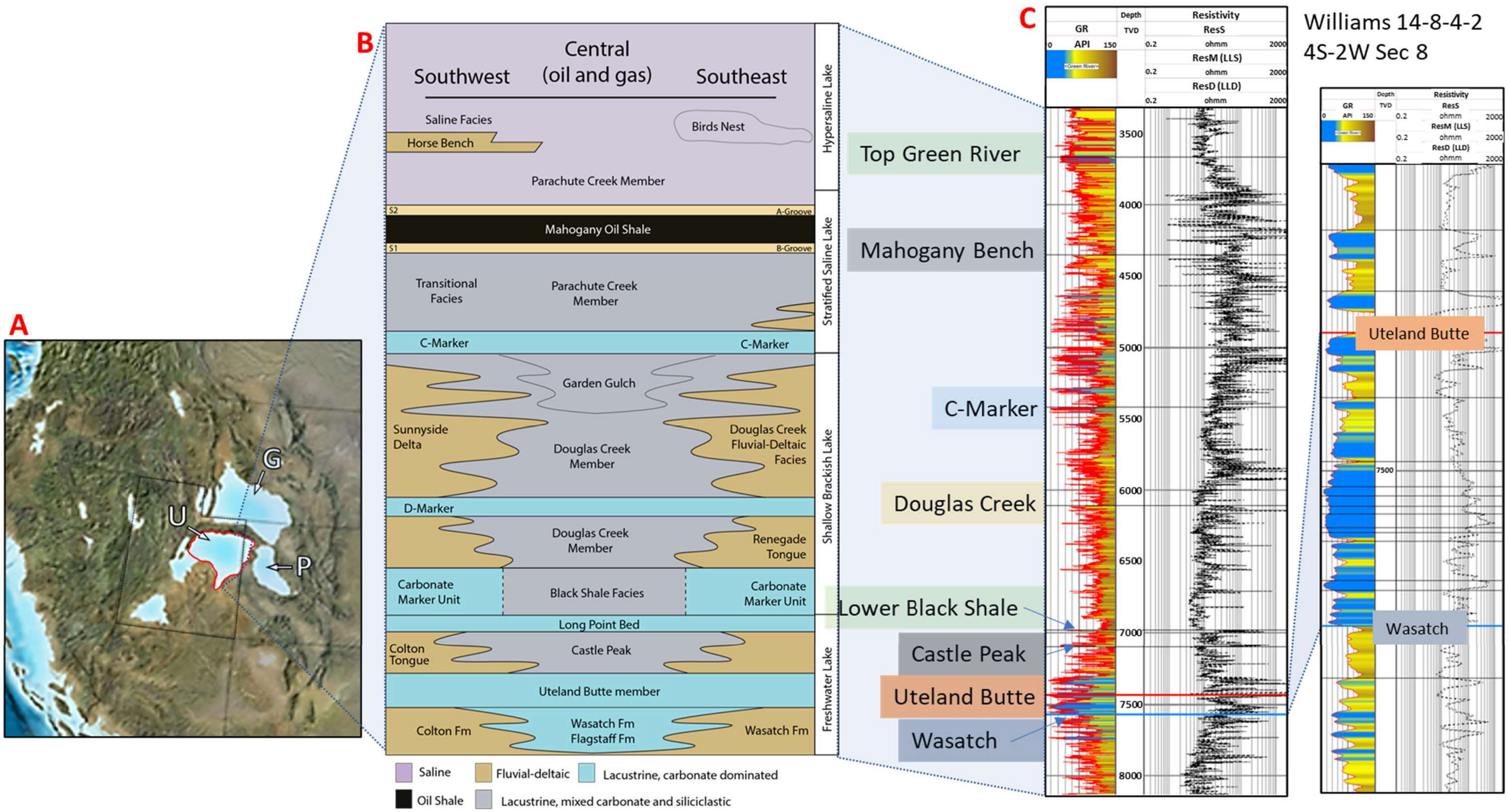


Figure 2. *(A) Paleogeographic map of Utah during the early Eocene (Blakey, 2006). "U" (red outline) is the Uinta Basin portion of Lake Uinta. "P" is Lake Uinta in the Piceance Basin, "G" is ancient Lake Gosiute. (B) Lithostratigraphic subdivision of lower and middle Eocene deposits in the Uinta Basin (modified from Gall and others, 2022). (C) Well log showing the Uteland Butte within the lower Green River Formation. Note that it is the most carbonate-rich (blue color) unit.*

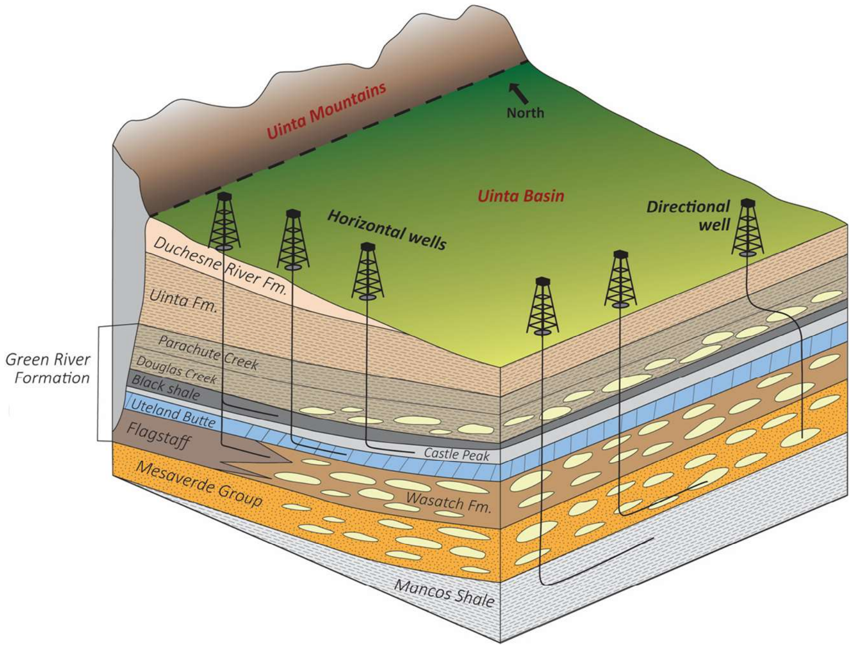


Figure 3. *Schematic of the Uinta Basin showing the Uteland Butte member near the base of the Eocene Green River Formation. Depth to the Uteland Butte member varies from ~5000 ft to the south, to well over 10,000 ft at the northern end of the play.*

This field was named for the eponymous butte 6 miles to the northeast, which is in fact composed of the much younger Uinta Formation (figure 4).

The UBm represents approximately 1+ million years of lacustrine stratigraphy, ~56 Ma, deposited during an early freshwater phase of Lake Uinta (Remy, 1991; Smith, 2007). The unit consists of interbedded dolomites, limestones, marlstones, and dark, calcareous shales (Remy, 1991; Johnson, 2016; Birgenheier and others, 2019; Rueda and others, 2019). The limestones have variable amounts of chert and total organic carbon (TOC) and range from ostracod and ooid grainstones on the lake margins to argillaceous bivalve wackestones. Interbedded with these limestones are carbonate mudstones and laminated, calcareous shales, which have wide variability in TOC. The dolomites often exhibit a microcrystalline fabric with a higher TOC content than the adjacent limestones (Rueda and others, 2019). The carbonates transition into and interfinger with penecontemporaneous siltstones and sandstones along the southern paleolake margin. To put it simply, beds in the UBm have complex and often rapid lateral transitions.

Representing the first major expansion of Lake Uinta as defined by Bradley (1931), the UBm overlies fluvial and alluvial sediments at its farthest reaches, consisting of the Colton Formation on the southwestern margin of the Uinta Basin and the Wasatch Formation east of the modern Green River and on the northern margin (Johnson, 1985; Remy, 1991). Closer to the center of the lake, UBm sediments overlie lacustrine limestones, shales, sandstones, siltstones, coals, and carbonate grainstones that originated in smaller predecessor lakes. These sediments are designated as the upper Wasatch, the Flagstaff Formation, and the Flagstaff Member of the GRF, depending on whose nomenclature is used. In this paper, we refer to the units directly below the UBm as the upper Wasatch, to be consistent with operator terminology. Within the basin center, the upper Wasatch consists

Figure 4. *View to the north of the landform named "Uteland Butte". Its geology has little to do with the stratigraphic unit that shares its name. The butte is made up of the late Eocene Uinta Formation. The Uteland Butte gas field, located about six miles southwest, was named after this prominent landmark. Subsequently, the Uteland Butte member of the lower Green River Formation was named after the gas field.*

of carbonate mudstones, bivalve wackestones, and carbonaceous shales, looking very much like overlying UBm strata. At the margins of the basin, the upper Wasatch grades into and is indistinguishable from the underlying, formally named, Colton/Wasatch Formation. Overlying the UBm, at the margins, are alluvial sandstones and claystones of the informal Wasatch tongue, Colton tongue, or Castle Peak member. Farther into the basin, this interval consists of thin limestones and marginal, deltaic sandstones designated as the Castle Peak interval. In the basin center, this interval largely consists of limestones with thin, hyperpycnal sandstones at the top of the succession (Brinkerhoff and Woolf, 2018).

Due to the lateral facies changes across the ancient lake basin and variability of the adjoining beds in the Wasatch Formation and Castle Peak member of the GRF, stratigraphic delineation of the UBm is difficult. The "Basal Carbonate" of Bradley (1931) roughly corresponds to the UBm on the southern margin of the Uinta Basin. Different researchers put the base of the UBm at various limestone beds, depending on what part of the basin they are focusing on. As deeper limestone beds appear progressively towards the center of the paleolake it becomes difficult to find consensus on where to place the base of the UBm. This paper will use the base defined by Osmond (1992), irrespective of the underlying lithologies (figure 2).

Significantly, the presence of the thin dolomites interbedded within UBm limestone is often a characterizing feature, distinguishing it from limestones in both the underlying upper Wasatch and overlying Castle Peak interval. Except for a few outcrops on the southwestern margin of the Uinta Basin, moving downwards, the first persistent limestone without interbedded dolomite marks the top of the upper Wasatch and the base of the UBm. Going upwards, the first limestone above the last dolomite-rich interval marks the top of the UBm and the base of the Castle Peak (figure 5).

METHODOLOGY

This study examines horizontal wells drilled within the UBm across an area of over 3300 square miles. This dataset consists of geophysical logs from more than 2200 vertical wells, 17 cores, and production data from 500 horizontal and vertical wells. We integrated the borehole logs with the available core data to construct a basin-wide correlation of the UBm. Core analyses and descriptions were divided by stratigraphic zones, classified by lithology and interpreted depositional environments, and then correlated to create facies maps. Log-based interpretations were calibrated through quantitative data from laboratory core analyses from each major identified lithology, including apparent porosity from helium porosimetry and effective porosity from mercury injection capillary pressure measurements (MICP). Core descriptions include visual and analytical observations of porosity character, carbonate grain identification (calcite vs. dolomite), estimation of mineral percentages, and examination of fracture intensity, connectivity, and correlation to lithology. Horizontal UBm wells were identified both by state records and matching wellbore true vertical depths (TVDs) with UBm structure maps. Oil production data was gathered for these wells from the Utah Division of Oil, Gas and Mining website and Enervus (formerly DrillingInfo). Comparative bubble maps were built of both initial production (IP), calculated as the highest 30-day sum, and cumulative production. Lithologic and petrographic core descriptions and capillary pressure data were analyzed to determine the dominant pore types and then correlated with facies maps. Pore-types were then correlated with production results.

Stratigraphy of the Uteland Butte

The focus of this paper is to identify the different effective pore types within the UBm play area and see if they differ across the fairway. The most important factors in determining dominant pore types for the UBm are lithology, TOC content, and thermal maturity. Many researchers have subdivided the UBm into four discrete intervals that correlate across the basin (Vanden Berg and others, 2014; Birdwell and others, 2016; Logan and others, 2016), a convention that we will follow here (figure 5). Prominent shales are labeled A, B, C, and D and sit on top of carbonate intervals named the A, B, C and D benches. Logan and others (2016) built a sequence stratigraphic interpretation of the carbonate benches and intervening shales, with the shales representing lake transgressive system tracts and maximum flooding surfaces, and the carbonate benches representing highstands and falling stage system tracts. Correlation of the stratigraphy to low-order lake level cycles is defensible as the individual shales and benches extend across the ancient lake basin (figure 6).

The carbonates in each bench have variable volumes of dolomite. Laterally extensive dolostone beds have also been informally named within the existing literature as the PZ-1, PZ-1', PZ-2 and the DPZ (Birdwell and others, 2016; Rueda and others, 2019). This paper proposes a slight modification to the scheme in that the PZ-1' and PZ-2 have been re-

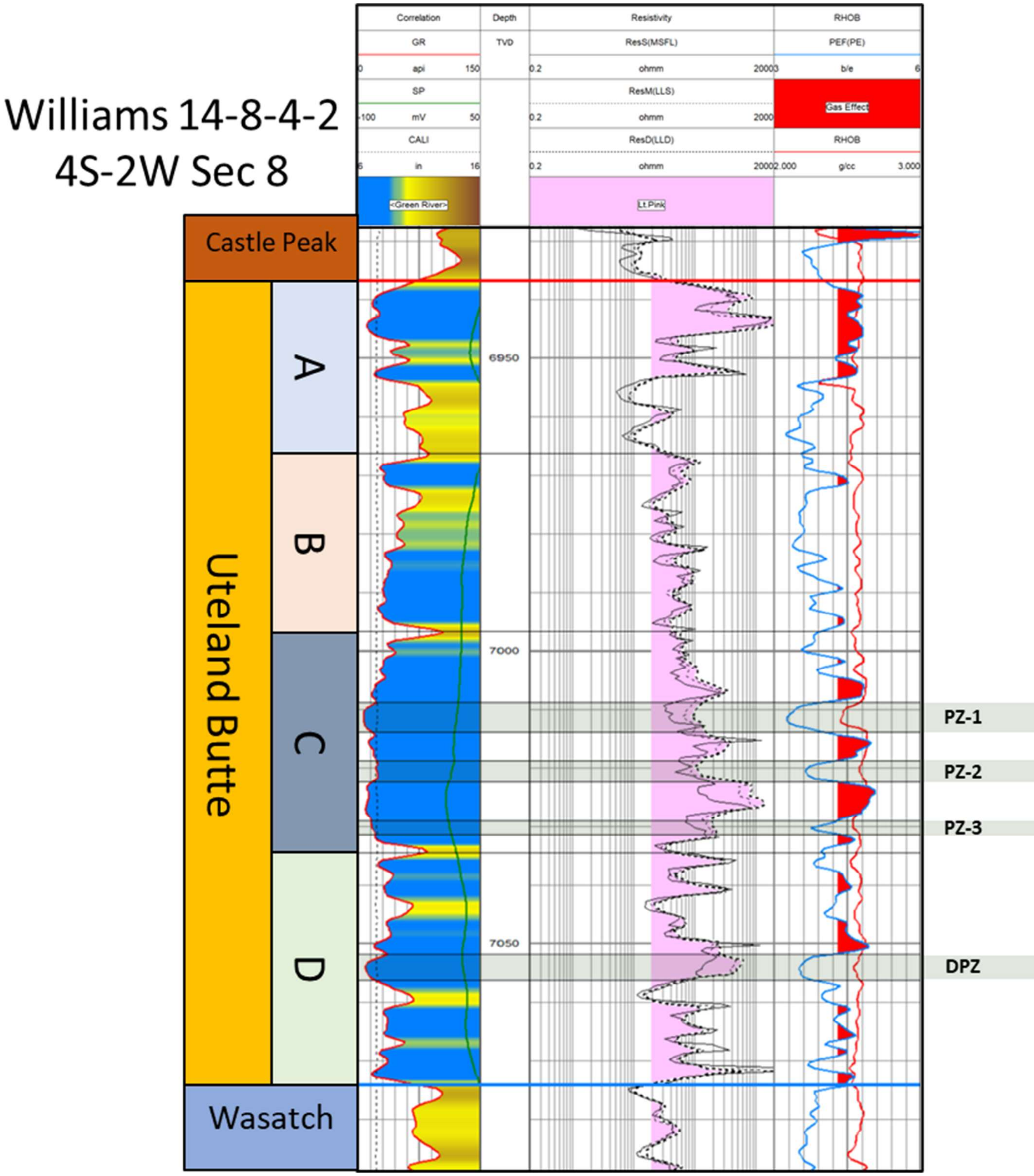


Figure 5. *The Uteland Butte member is conformably bounded at the base by the Wasatch/Colton Formation (or upper Wasatch in more distal areas) and at its top by the Castle Peak interval of the Green River Formation. It is commonly divided into A, B, C, and D benches, divided by laterally extensive organic-rich mudstones. The Uteland Butte is characterized by its high percentage of dolomite, including the high porosity PZ-1, 2, and 3 and the DPZ dolomite beds.*

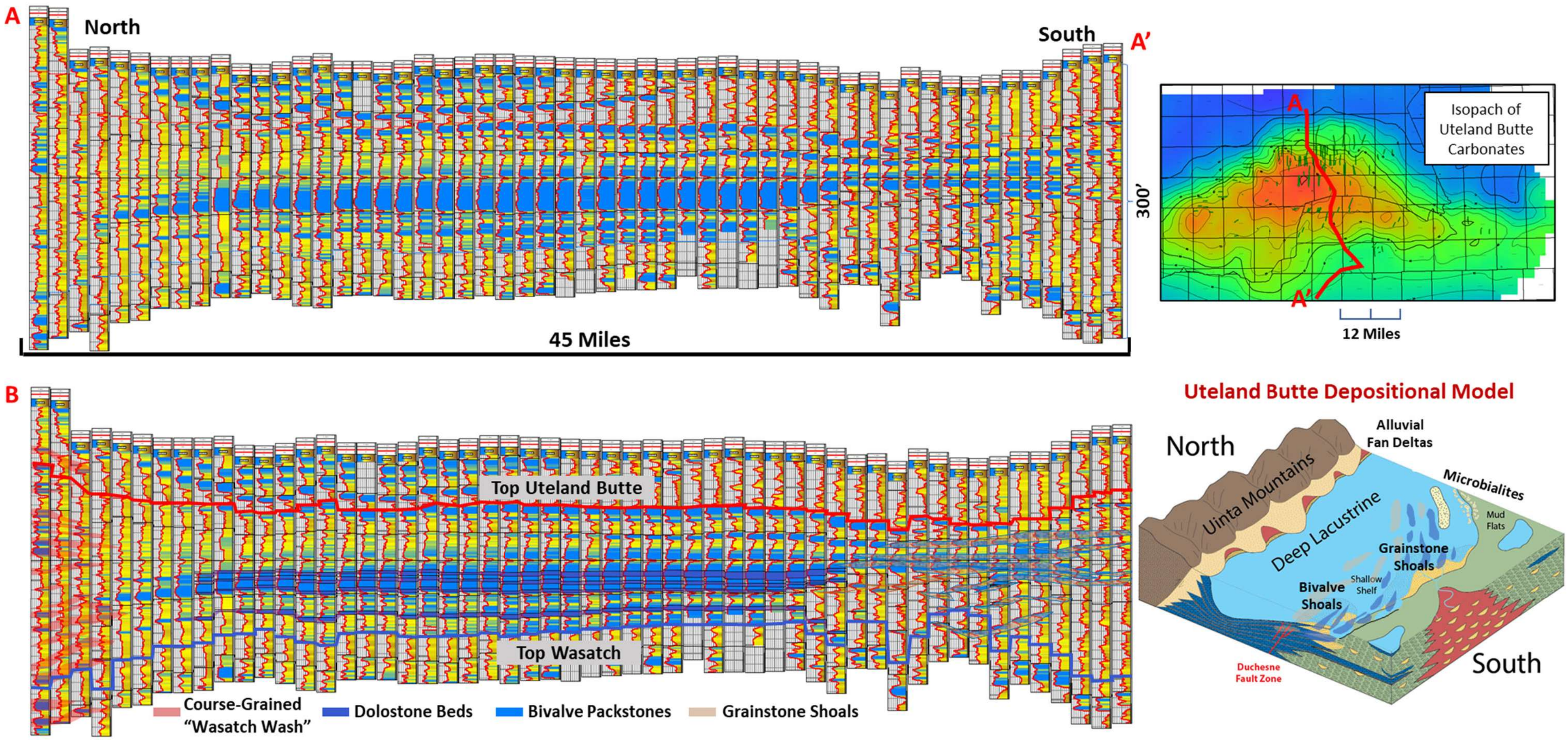


Figure 6. *(A) Cross-section of closely spaced gamma-ray logs from 54 wells spread from north to south across the Uteland Butte fairway. The cross-section has been flattened on the C Shale. Note that the center of the fairway has thick, well-developed carbonates, which pinch out towards the margins. The locations of wells included in the cross-section are highlighted in the isopach map (10-ft contour interval). (B) Lithological interpretation of the same cross-section, with the coarse-grained "Wasatch Wash" noted on the northern end of the section and southern margin consisting of thin grainstone (mostly ostracods) shoals interbedded with marginal lacustrine clastics and deltaics. The center of the system is dominated by thick bivalve packstones and wackestones, plus laterally extensive dolostones. The block diagram shows how paleoenvironments are spatially related (modified from Brinkerhoff and Woolf, 2018).*

named the PZ-2 and PZ-3, respectively (figure 5).

Individual benches vary in lateral extent across the basin, percentage of carbonate development, faunal diversity, and dominant lithologies. Figure 7 shows the extent of clean carbonate, here consisting of dolomite, micrite and limestone beds, created by summing the total thickness of gamma ray values less than 50 API for each bench. Beginning at the base of the UBm, the D bench (figure 7D) records the initial transgression of the UBm carbonates across the basin. It has high faunal diversity. The southern margin is dominated by shoals of ostracods and mixed siliciclastics from the proto-Sunnyside Delta. In the center of the basin, bivalve and gastropod wackestones and micrites are common, with one thick (up to 8 ft thick) dolostone bed, the DPZ. Most horizontal wells drilled in the UBm have targeted the DPZ, typically attempting to maintain the wellbore in the argillaceous limestones above the DPZ. The C bench (figure 7C) represents the thickest and most extensive carbonate interval of the UBm. It likely represents the widest extent of Lake Uinta during UBm time and contains abundant bivalves and gastropods. Like the D bench, its southern margin is dominated by ostracodal shoals and interbedded siliciclastics, which thicken and coarsen into the proto-Sunnyside Delta. The C Bench contains the PZ-1, PZ-2, and PZ-3, with the PZ-1 being the thickest dolostone and the original target of the earliest horizontal drilling of the UBm. The B bench (figure 7B) records a southward shift of the carbonates as clastics prograded into Lake Uinta from the north. Bivalves and gastropods become less common, with thin (inch scale) interbedded dolomites, micrites, and high TOC mudstones becoming more common. The proto-Sunnyside Delta appears to dissipate as ostracod and oolitic shoals cover the entire southern margin. The A bench (figure 7A) represents the final stage of UBm deposition, with carbonates restricted to the lake center and consisting mostly of grainstone (ostracods) beds and generally having much more restricted faunal diversity and abundance.

The summation of clean carbonates (i.e., GR values lower than 50 API units) of the named UBm benches shows the approximate extent of this Lake Uinta fourth-order highstand (figure 8). The thickest deposits are in the northern one-third of the basin, exceeding 90 feet and pinching out at the lake margins, with a long, gradually thinning southern margin. This demonstrates the foreland nature of the Uinta Basin, with the thickest beds on the northern margin against the rising Uinta Mountains where subsidence was the greatest. Beds gradually thin to the south with increasing distance from the mountains. When all UBm wells are layered on this map (figure 8), it is immediately apparent that these carbonates contain the entire play. Production from these wells is not evenly distributed across the play and does not appear to be correlative with carbonate thickness (figure 8A). Cumulative oil production suggests that the best production appears to be concentrated in the northern part of the play. A bubble map of well IPs further highlights the performance of wells on the northern margin of the carbonate zone (figure 8B).

SUBDIVIDING THE UTELAND BUTTE PLAY BASED ON PORE TYPE

Reservoirs consisting of multiple, thin-bedded lithologies that vary laterally, such as the UBm, are excellent examples of the utility of Darcy's Law, $q=-k/\mu*\Delta p$. For operators, the economic value of a well is the production volume (or volumetric flow, q). The variables in the equation, permeability (k), pressure gradient ($\Delta\rho$) and viscosity of the oil (μ), all vary significantly across the UBm play area. A dolostone that produces prolifically (high flow, q) in the deep part of the basin may not produce much at all (low flow, q) in the southern part of the basin where oil viscosity (μ) is much higher and pore pressure ($\Delta\rho$) much lower. Multiple pore systems exist across the UBm play area (figure 9). The dolomite that occurs in most of the UBm contains the bulk of the intercrystalline porosity. Other pore types, such as the organic porosity that dominates production in the deep basin, only occurs where the UBm has been exposed to sufficient thermal stress. Identification of the dominant pore type by area highlights which reservoirs are being effectively exploited. Conversely, understanding which pore types are not currently being exploited may show where opportunities exist to use better engineering techniques to unlock potential new oil reserves. In a series of lithologies as complex as the UBm, multiple pore types may be productive in each area at some level of flow; however, this paper only attempts to identify and map the dominant (most productive) pore type by area. Since reservoirs rarely end at a discrete line, boundaries are drawn where a distinct pore type becomes more dominant, with the understanding that some gradation occurs at the boundary. In this paper we document four sub-plays in the UBm based on dominant pore types:

1. The intergranular porosity-dominated sub-play along the southern margin.
2. The intercrystalline porosity-dominated sub-play.
3. The mixed intercrystalline-organic porosity sub-play.
4. The organic porosity sub-play along the northern margin in the deepest part of the basin.

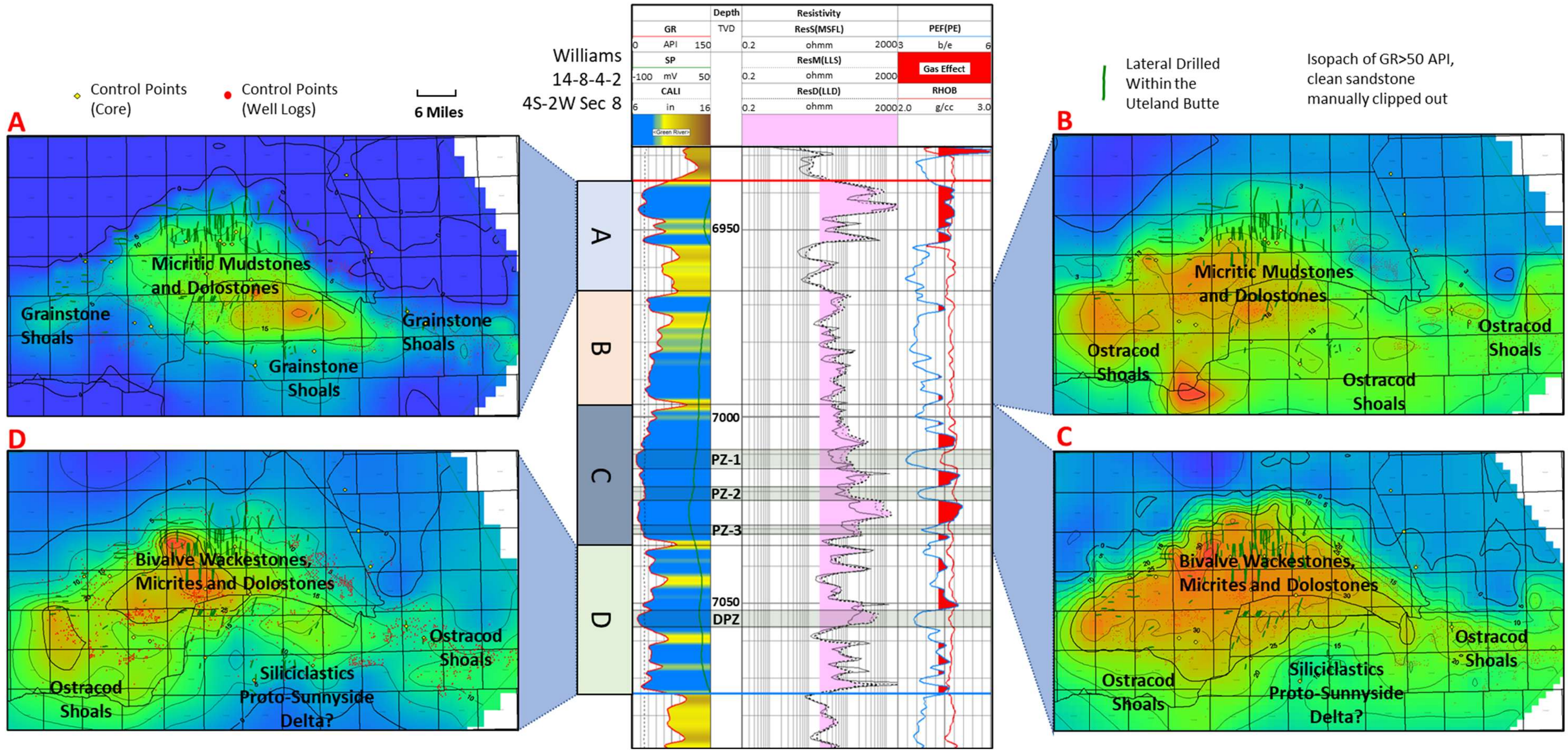


Figure 7. *The Uteland Butte member subdivided with isopach maps of clean (GR<50 API) carbonate. Five-foot contour interval on all four isopach maps. The clean carbonate is used as a proxy for open lacustrine deposition for each respective unit. Basic lithology is identified on each map.*

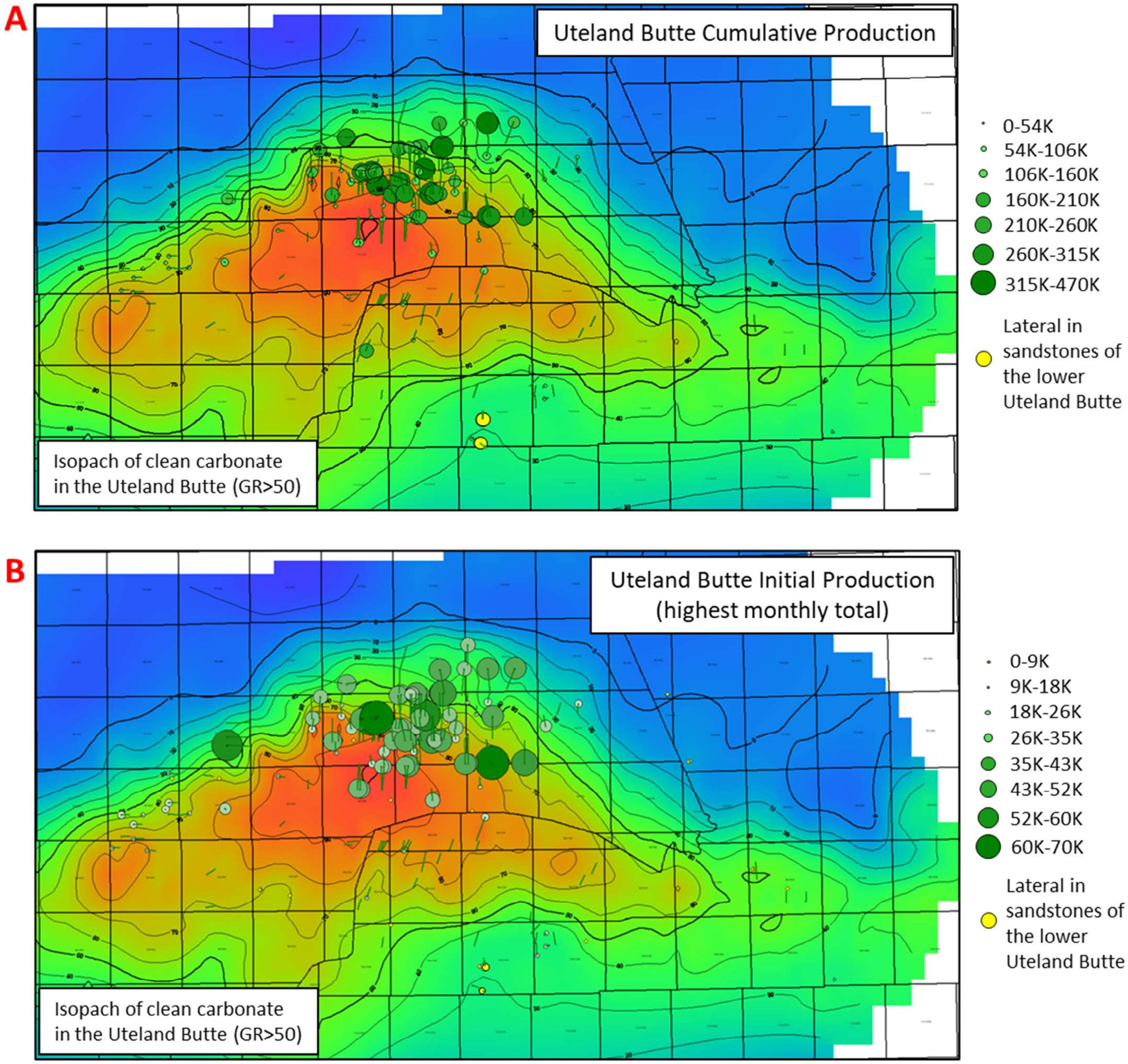


Figure 8. *(A) Cumulative production bubble map for Uteland Butte horizontals overlain on an isopach of clean carbonate in the Uteland Butte (10-foot contour interval). Note how poorly production correlates with Uteland Butte thickness. The longest laterals with the biggest fracs produce the most oil, with total time of production also being an important factor. In general, production improves to the north. (B) Uteland Butte initial production (IP) map calculated as the highest monthly total for each well. Note that the northern tier of wells shows much better IPs than any other area.*

The Intergranular Porosity-Dominated Sub-Play

The grainstone reservoirs in this sub-play were the first UBm interval to be tested horizontally in 1998. Unfortunately, it has been the least economically successful sub-play of the UBm, with productive reservoirs consisting of nearshore deltaic sediments and carbonate grainstone (mostly ostracods, some ooids) bars (figure 10). Horizontal wells in this sub-play are shallow, generally less than 5000 feet TVD and produce a highly viscous, black, sweet, waxy oil with API gravities between 25 and 30. The UBm interval in this sup-play consists of interbedded, TOC-rich shales and argillaceous carbonates, but the zone is thermally immature, with source rock values in the 0.5%–0.7% vitrinite reflectance (VRo) range. The gas-to-oil ratios (GORs) are low (200–3000:1) as much of the dissolved gas was lost along the migration pathway as the oil migrated up dip from the deeper part of the basin to the north. In core samples, only

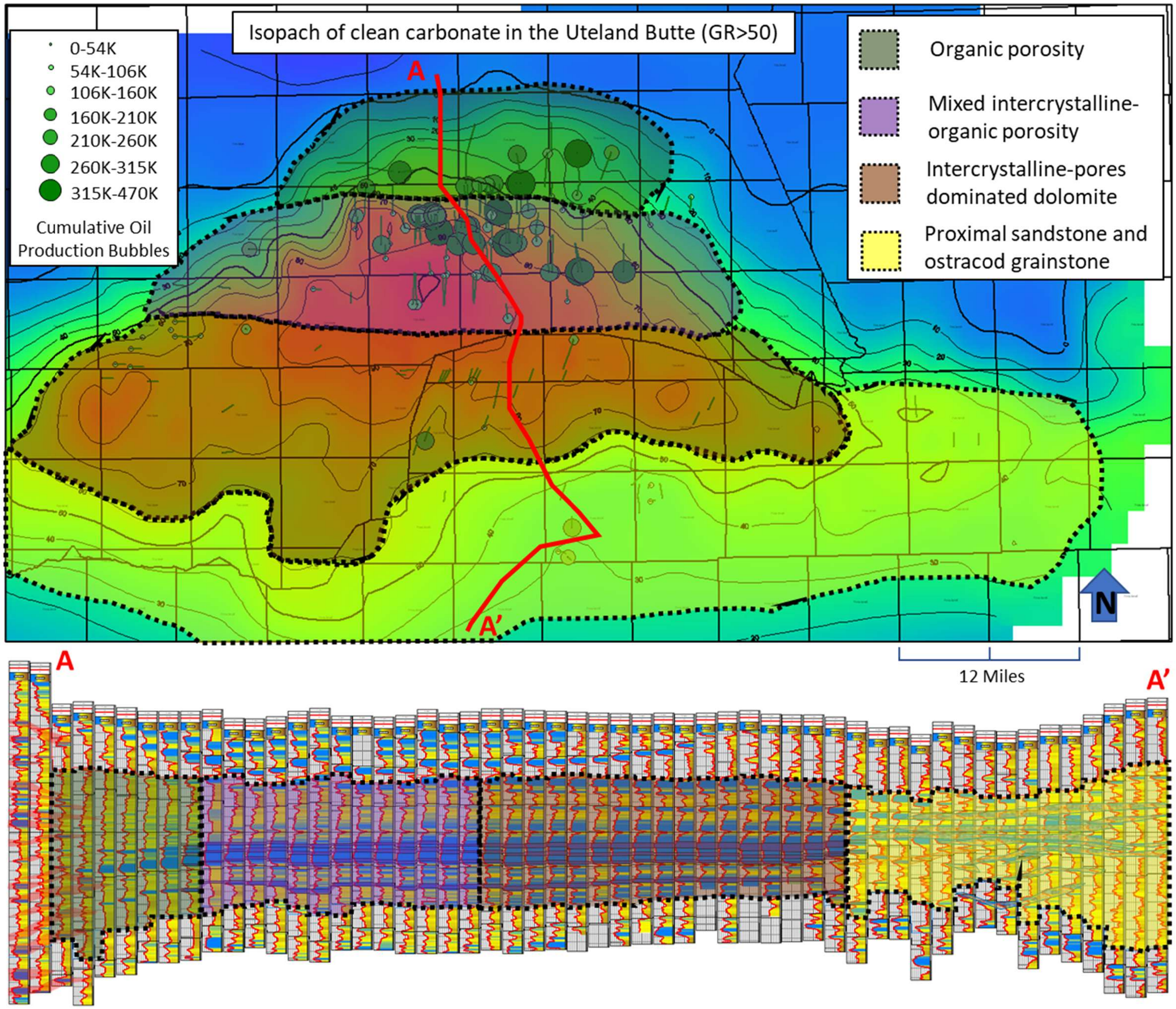


__Figure 9.__ The Uteland Butte member, subdivided by dominant pore type, here defined as the porosity system that contributes the largest volume of fluids in the reservoir (10-foot contour interval). Note that the wells located in the organic and mixed intercrystalline-organic pore types have by far the largest production volumes as shown by the cumulative production bubbles.

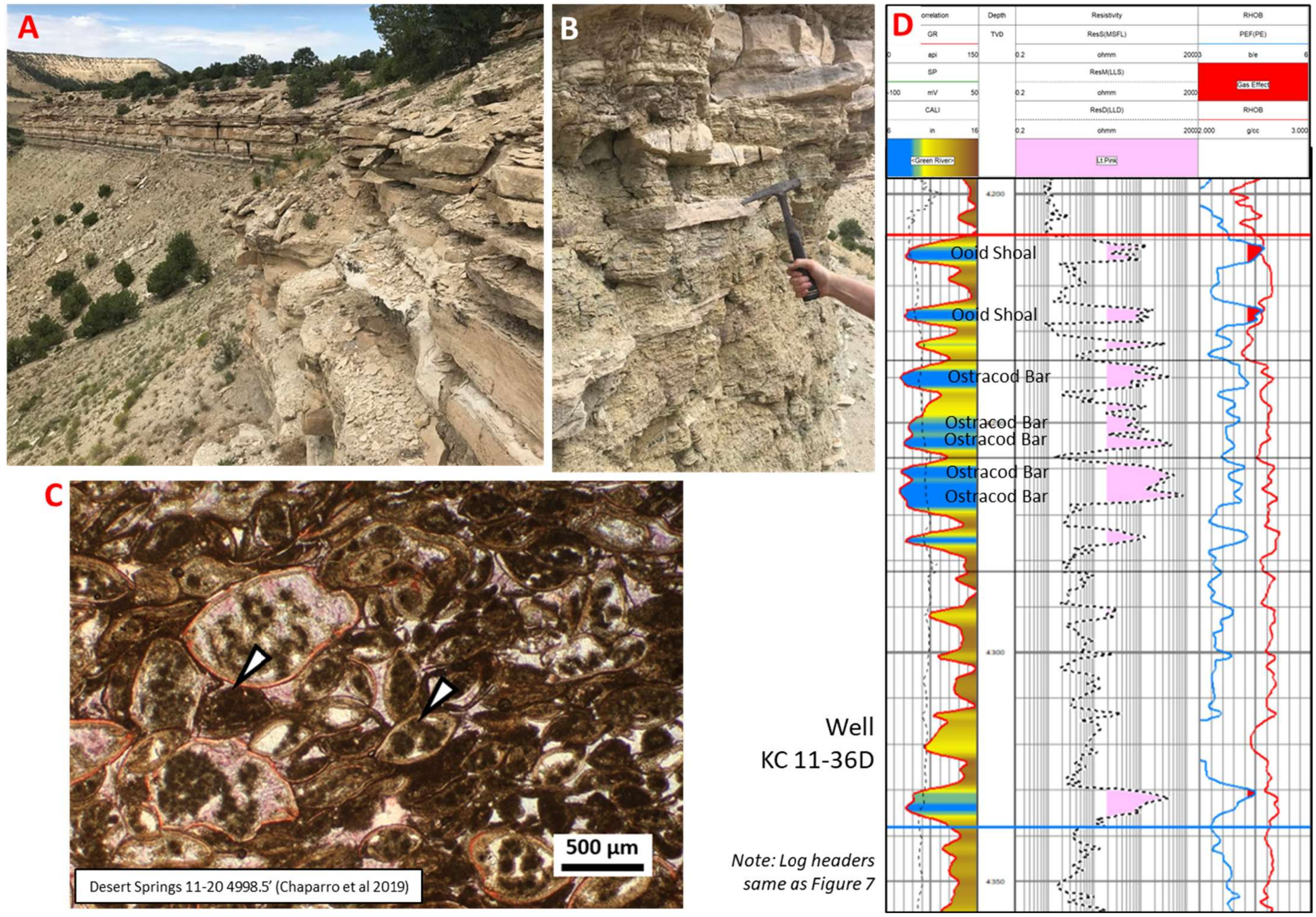


Figure 10. *Examples of the intergranular porosity-dominated sub-play of the UBm. These reservoirs mostly consist of nearshore carbonate bars and siliciclastic deltas. (A) Outcrop of laterally extensive, flat, proximal ostracodal shoals in Hells Hole Canyon, Uintah County, Utah. (B) Outcrop of distal ostracodal shoals pinching out into bivalve wackestones in Hells Hole Canyon, Uintah County, Utah. (C) Thin section of ostracodal grainstone from core. White arrows identify a peloid (left arrow) and an ostracod shell (right arrow). (D) The bars that make up the reservoirs of this sub-play are well defined in well data, showing generally good porosity and oil saturation. These reservoirs produce highly viscous, black, waxy oils with low GORs. To date, wells drilled in this sub-play have not been economically successful.*

the highest permeability rocks are charged with oil. These reservoirs are near bubble point, with GORs rising rapidly after reservoir pressures fall below bubble point.

This sub-play was investigated in the late 1990s and early 2000s by several operators in the Uinta Basin including EOG, Anadarko, Bill Barrett, Newfield, and QEP. The UBm was seen as a possible analogue to the successful G1 shoal development in the Wonsits Valley field in the northeast part of the basin, which has produced over 53 million barrels (bbls) of oil as of 2020 (Morgan and Stimpson, 2017; Utah Division of Oil, Gas and Mining website). The G1 consists of a highly productive oolitic and ostracodal limestone reservoir at the base of the Douglas Creek Member. Discovered in 1962, most of the reserves were exploited in vertical wells, some of which have produced greater than 500,000 bbls of oil. Beginning in 2007, the G1 has been targeted by 35 horizontal wells by longtime Uinta Basin operator QEP. The ostracodal shoals that make up much of the southern margin of the UBm have similarities to the G1 shoal, being relatively thin at 1 to 5 feet thick, laterally extensive, with individual beds in the outcrops at Hells Canyon (east side of the basin) being laterally correlative for miles (figure 10A) and containing moderate porosity at 5% to 15% with excellent permeability (up to 1 mD). These early explorers invested heavily into the sub-play, coring the UBm in five locations and drilling 13 horizontal tests.

The sub-play has been unsuccessful to date due to the high oil viscosity and low pore pressure of the reservoir. A UBm reservoir temperature map (figure 11A) shows that the proximal grainstone and sandstone play is largely outside of the 150°F contour line. A viscosity versus temperature cross-plot for Uinta Basin black wax (figure 11B) shows that the force necessary to push black wax through the reser-

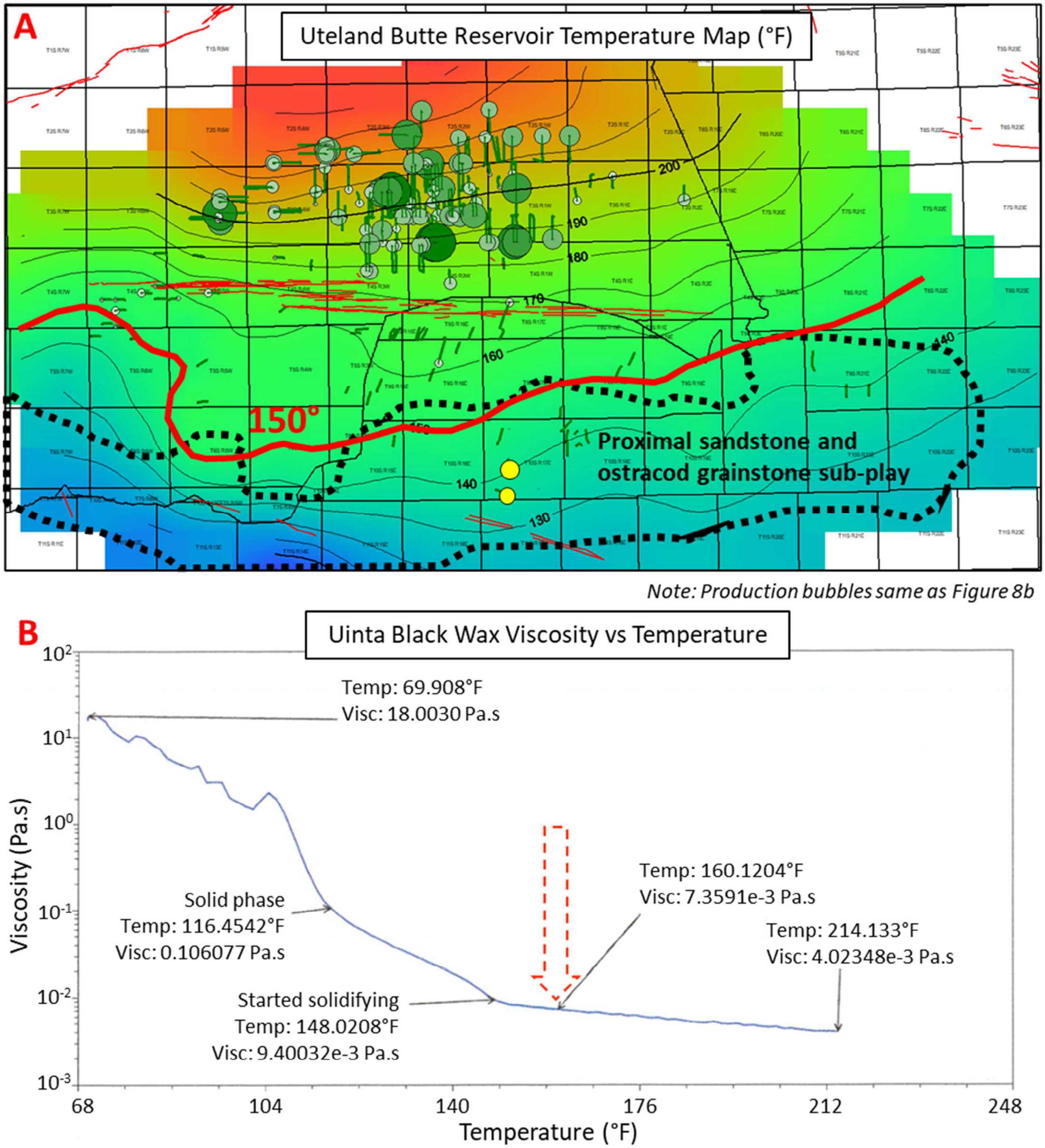


Figure 11. *(A) Reservoir temperature map of the UBm. The dark red line is important as all reservoir rocks south of it are below 150ºF. This would include almost all the proximal sandstone and ostracod grainstone sub-play. (B) Cross-plot of Uinta black wax oil vs. viscosity. In general, the cooler the oil, the higher its viscosity. Note that the Uinta wax has important hinge points where viscosity rapidly begins to rise. At 150ºF there is the beginning of a sharp increase in viscosity. The energy necessary to push black wax through the reservoir increases by an order of magnitude from 150° to 120°F. To produce oil at economic rates at the higher oil viscosity found in this sub-play, either higher reservoir pressure must be induced (higher $\Delta\rho$), or higher permeability (higher k) must be created.*

voir begins to climb rapidly at temperatures under 150°F. Viscosity increases by over an order of magnitude from 150° down to 120°F. Measured reservoir pressures in the proximal grainstones sub-play are normal to slightly under-pressured (figure 12). The average depth and pressure gradient of this sub-play would calculate to about ~2000 psi, which is not nearly enough pressure to produce significant oil production rates at the calculated viscosity. For this sub-play to produce at economic rates, either higher reservoir pressures must be encountered, the reservoir must be heated to lower fluid viscosity, or much better permeability must be created through artificial stimulation.

Intercrystalline-Porosity-Dominated Sub-Play

Farther north into paleo-Lake Uinta, the grainstone reservoirs transition into thin (1–8 feet thick), high-porosity dolomites, and low-porosity bivalve and gastropod packstones. The dolomite reservoirs in this sub-play were targeted early in the play history as operators noted that they had the highest porosities of the UBm play. The entire zone consists of 130 feet of carbonates and thin black shales, with only a small fraction consisting of high-porosity dolomite (figure 13). These reservoirs are normally pressured along the southern boundary of the sub-play and climb to a maximum pore pressure gradient of about 0.6 psi/ft along the northern boundary (figure 12). Most of the hydrocarbons in these reservoirs likely migrated from the basin center based on analysis of oils having markers showing higher heat stress than the bounding shales and argillaceous limestone, which have 0.6% to 0.8% VRo. Oils in the sub-play are black waxes with API gravities in the 28 to 35 range.

Dolomites in this sub-play are the dominant productive lithology in this reservoir. The PZ 1, 2 and 3, plus the DPZ (figure 6), are laterally continuous throughout the central part of the UBm play, with beds 1 to 8 feet thick and porosities up to 30%, and a maximum permeability of 0.3 mD. The dolomites also host TOC values as high as 10% (Rueda and others, 2019). The PZ-1 was recognized early in the play history as being the thickest of the dolomites with the best developed reservoir quality. There have been 34 horizontal tests in the intercrystalline sub-play to date and results have been generally disappointing (figure 9). Operators typically attempted to keep the lateral

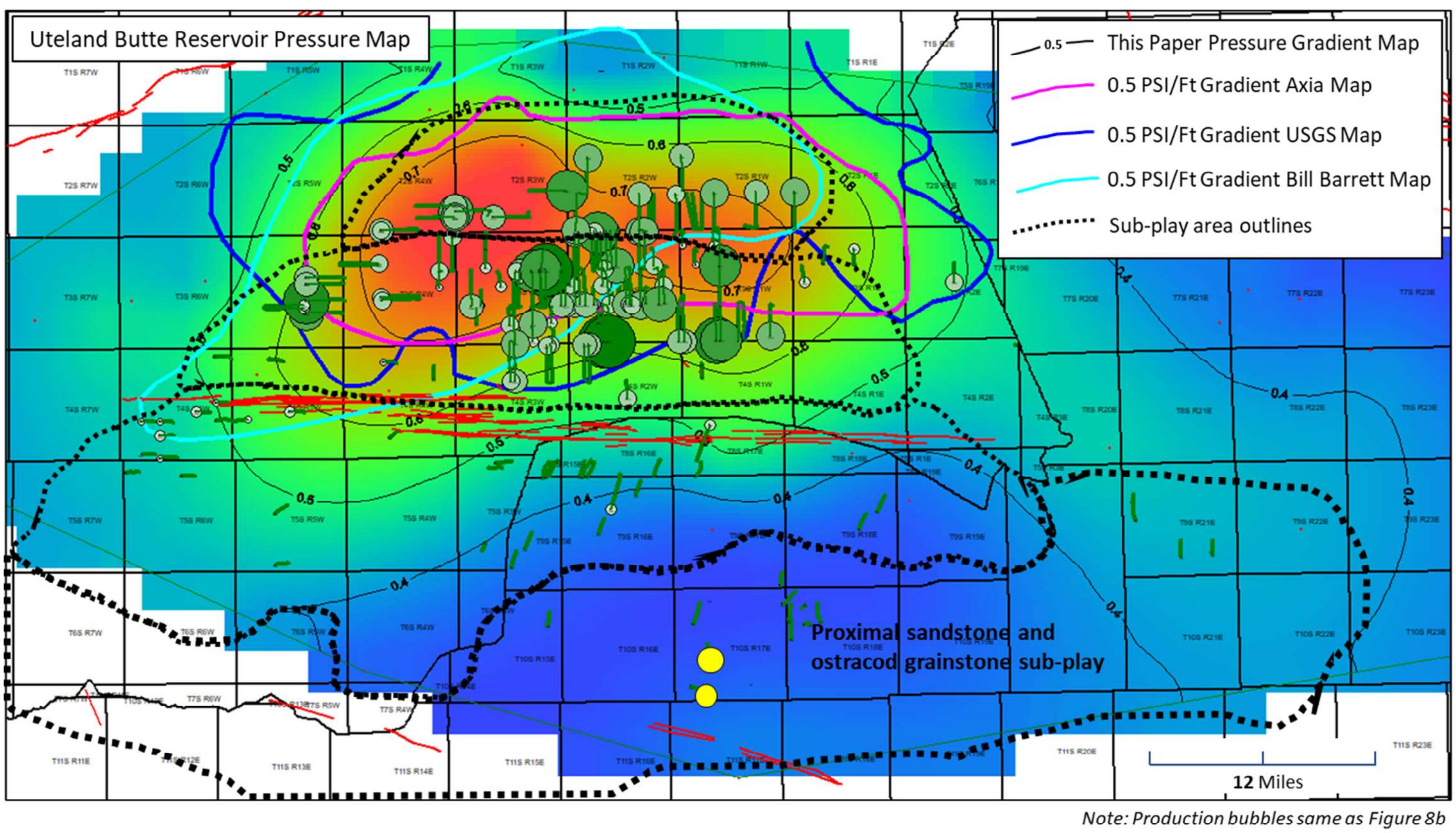


Figure 12. UBm reservoir pressure map, showing the limits of pore pressure from both this study and from maps released by Axia, Bill Barrett Corp., and the U.S. Geological Survey. Note the presence of the Duchesne Fault Zone, often used by operators in the Uinta Basin as the southern limit of significant overpressure in the Green River Formation. The various pressure gradient maps all show that the intergranular porosity dominated sub-play is at normal pressure to under-pressured, while the other UBm sub-plays to the north are at substantial overpressure.

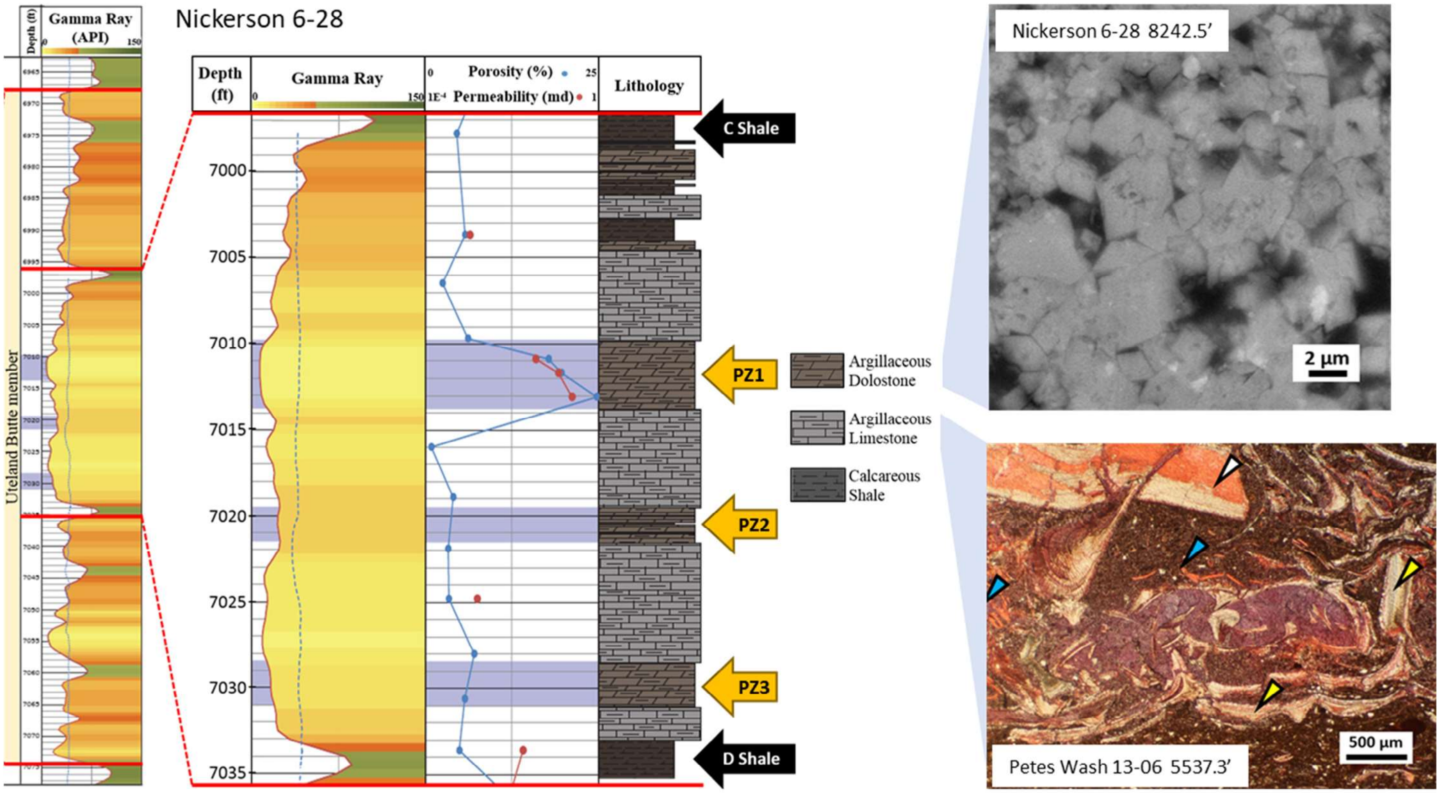


Figure 13. *Intercrystalline-pore-dominated sub-play, with the C bench expanded to show PZ dolomite beds (modified from Rueda and others, 2019). These thin, high porosity dolomites, plus lower porosity bivalve packstones and wackestones, make up the C bench. The dolomite layers are only 1 to 8 ft thick, but they have porosities of up to 30% with maximum permeabilities of ~0.1 mD. The bivalve packstones and wackestones are interbedded with the dolostones and are extensive in the sublittoral lake. They have higher clay volume, lower porosity (~4%) and much lower permeability (~0.001mD).*

wellbores in the PZ-1, which often proved difficult and expensive. Short lateral lengths (~5000 ft), small frac volumes, and limited reservoir capacity of the thin dolomite beds kept these wells from being large producers. Limited oil in place in the high-quality dolomites is the greatest challenge of this sub-play. When all four of the named dolomites are summed, most of the fairway only has about 15 feet of reservoir (figure 14A and B). At only 15 feet of reservoir, it is not surprising that these dolomites only contain a calculated 5–6 million barrels of OOIP per section (figure 14C).

Interbedded within the dolomites are bivalve and gastropod packstone and wackestone. These rocks were deposited extensively in the sublittoral lake. The wackestones have a higher clay content with much lower porosity (~0%–3%) and permeability (~0.001 mD) with typically little or no TOC content (0%–3%). These rocks are not considered effective reservoirs in most of the intercrystalline sub-play. MICP data shows that much higher pressures are needed to force a non-wetting fluid through this rock than the dolomites, which is why oil saturations in packstones and wackestones are generally below 30% in this sub-play (oil saturations are higher in these rocks farther north where more in-situ generation occurs, and pressures are higher).

Given that typical recovery rates in most unconventional plays are less than 5% of OOIP, wells that only recover oil from the main four dolomites are often disappointing. Significant volume of dolomite exists in thinner beds, often only an inch or two thick, throughout the UBm, particularly in the A and B benches, cumulatively hosting two to three times the amount of oil hosted in the PZ's and DPZ beds. These argillaceous reservoirs often have significant concentrations of clay, which significantly impacts the effective porosity. We believe that most of the early tests in this sub-play did not access the hydrocarbons in these thin dolomites because their small frac jobs were only meant to target the PZ beds. To improve results, operators will need to access a higher effective OOIP by finding a way to make adjacent lithologies contribute through either a better frac strategy, identifying better landing zones, or sweet spot targeting. A successful example of these efforts is the GMBU 13-34 9-16-3-9-3H well, which targeted its lateral near the DPZ and stimulated the entire UBm zone with a frac job many times larger than its older offsets (2000 lbs/ft and 2000 gals/ft vs. ~400 lbs/ft and 400 lbs/ft) (frac data available on DOGM website). The resultant production for this well was much

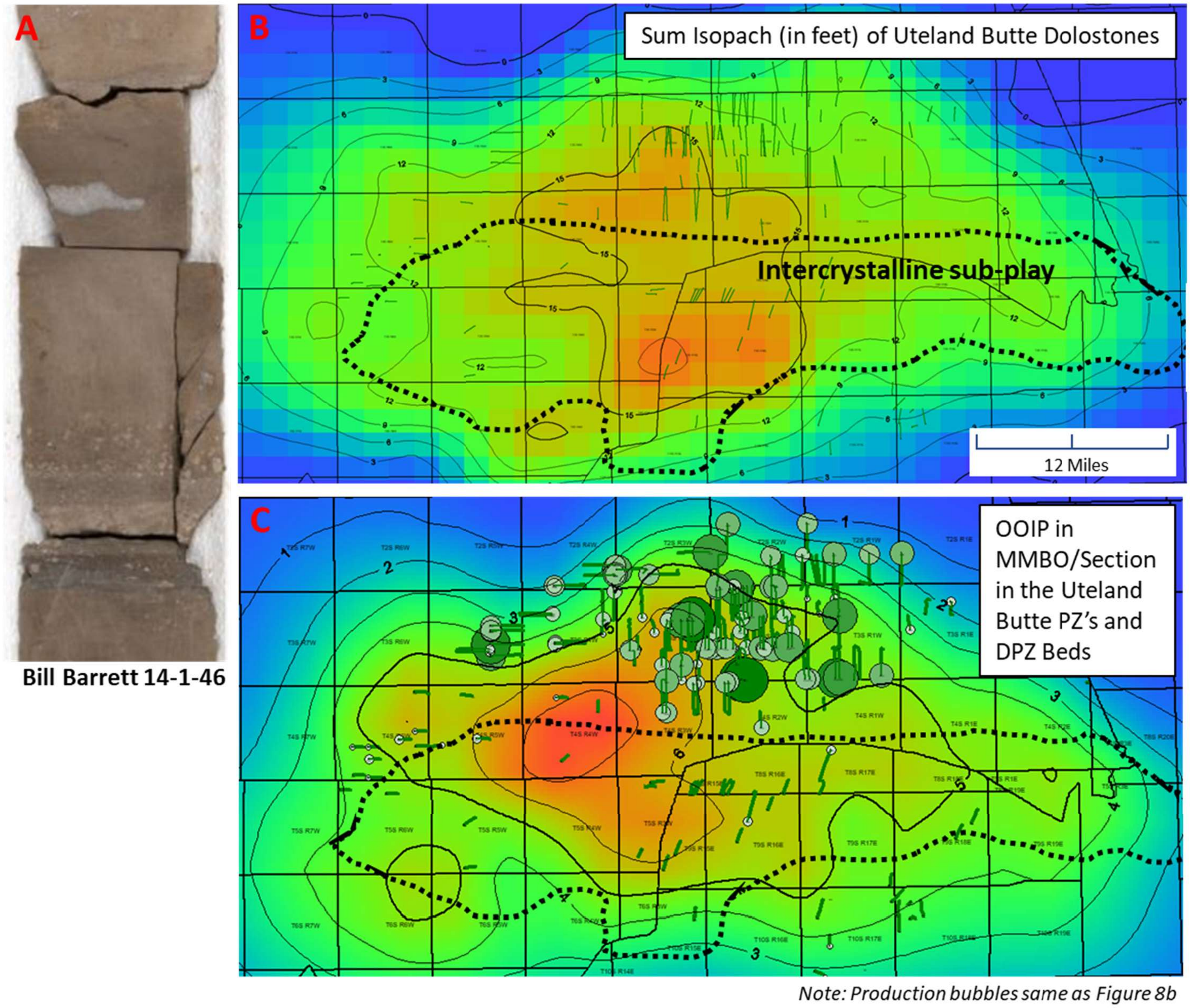


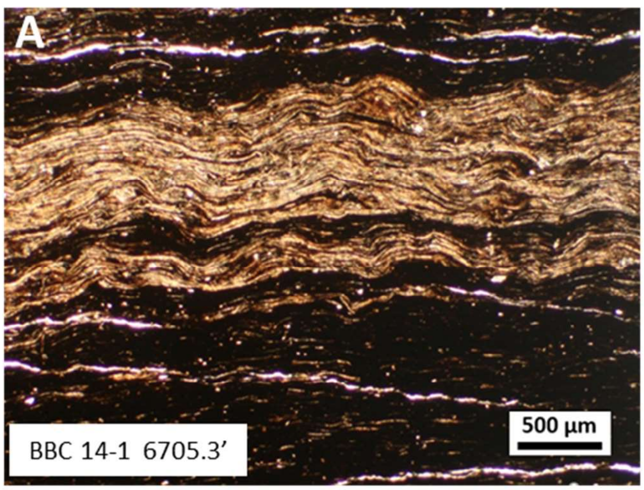
Figure 14. *(A) Sucrosic dolomite in the PZ1 interval from slabbed core. (B) Isopach map of the PZ and DPZ layers summed together (3-foot contour interval). At their greatest summed thickness, these dolostone layers are still less than 20 feet thick. Most of the fairway is between 12 and 15 feet thick. (C) Original oil in place (OOIP) map for the summed dolostones.*

greater than that of its older, offsetting wells, indicating that the disseminated dolomites are contributing at significantly larger volumes.

Organic-Porosity-Dominated Sub-Play

The organic porosity sub-play is along the northern limit of the UBm play, in the deepest part of the basin where UBm carbonates still exist (the mixed intercrystalline-organic porosity subplay is discussed in the next section). Farther north, the interval transitions to coarse clastics (the Wasatch Wash) that eroded off the rising Uinta Mountains (figure 6B). The economic success of this sub-play is tied to high TOC and maturity, and the resultant high reservoir pressures, rather than lithology. Organic porosity is easily the most extensive reservoir pore-type in the deep basin center. This sub-play is highly productive, with 10,000-foot laterals routinely achieving 200,000 bbls of oil in their first year of production (figure 8A). It is highly overpressured and completely self-sourced, being the most thermally mature of any UBm sub-play at 1.0% to 1.2% Vro. These reservoirs are at a 0.65 psi/ft pressure gradient along the southern boundary of the sub-play and climb to a maximum pore pressure gradient of about 0.85 psi/ft in the center of the sub-play (figure 12). Considering the overpressure and self-generation in this sub-play, the GORs of these wells are relatively low at 500 to 700 cf/bbl. The lower GORs in the highest maturity sub-play are related to the higher pore pressure allowing for larger volumes to be produced before the reservoir reaches bubble point. The lower maturity and lower pressured sub-plays to the south reach bubble point relatively soon in the wellbore's life, leading to a much higher average GOR. The organic porosity sub-play has a lower carbonate content and higher clay content than the other sub-plays (figure 15). The reservoir-quality dolomites found in the other sub-plays are almost entirely absent. As the name implies, the productive reservoirs consist of organic porosity, largely contained in bitumen that were expelled at low maturities as the sequence was being buried. The bitumen continued to thermally degrade as thermal stress increased, converting to zones of interconnected organic porosity. The thermal maturity of this sub-play is sufficient to convert bitumens and asphaltenes to paraffins, therefore these oils are bright yellow waxes (figure 16).

The UBm play abruptly terminates to the north as the carbonate and organic-dominated rocks that make up the UBM transition to relatively coarse clastic turbidites and Gilbertian deltas coming off the rising Uinta Mountains, typically labeled as the Wasatch Wash (figure 17). Rapid sedimentation and lower compaction along with faster subsidence at the extreme end of the foreland basin led to a thickening of the section. The associated turbid water column poisoned the carbonate system and diluted the TOC, resulting in deposition of coarse clastic rocks. Due to



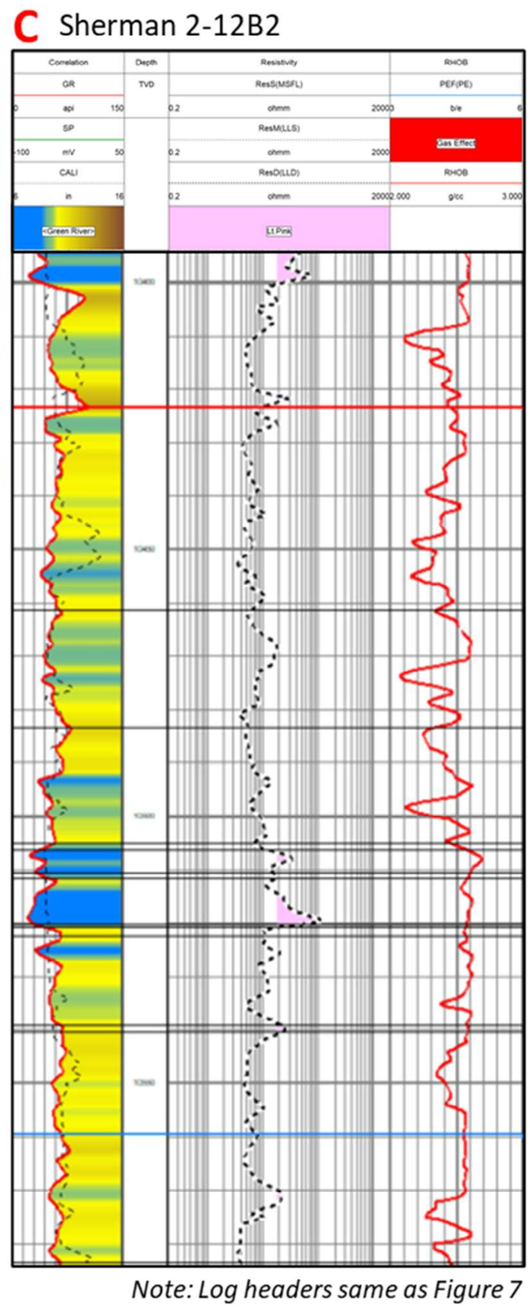
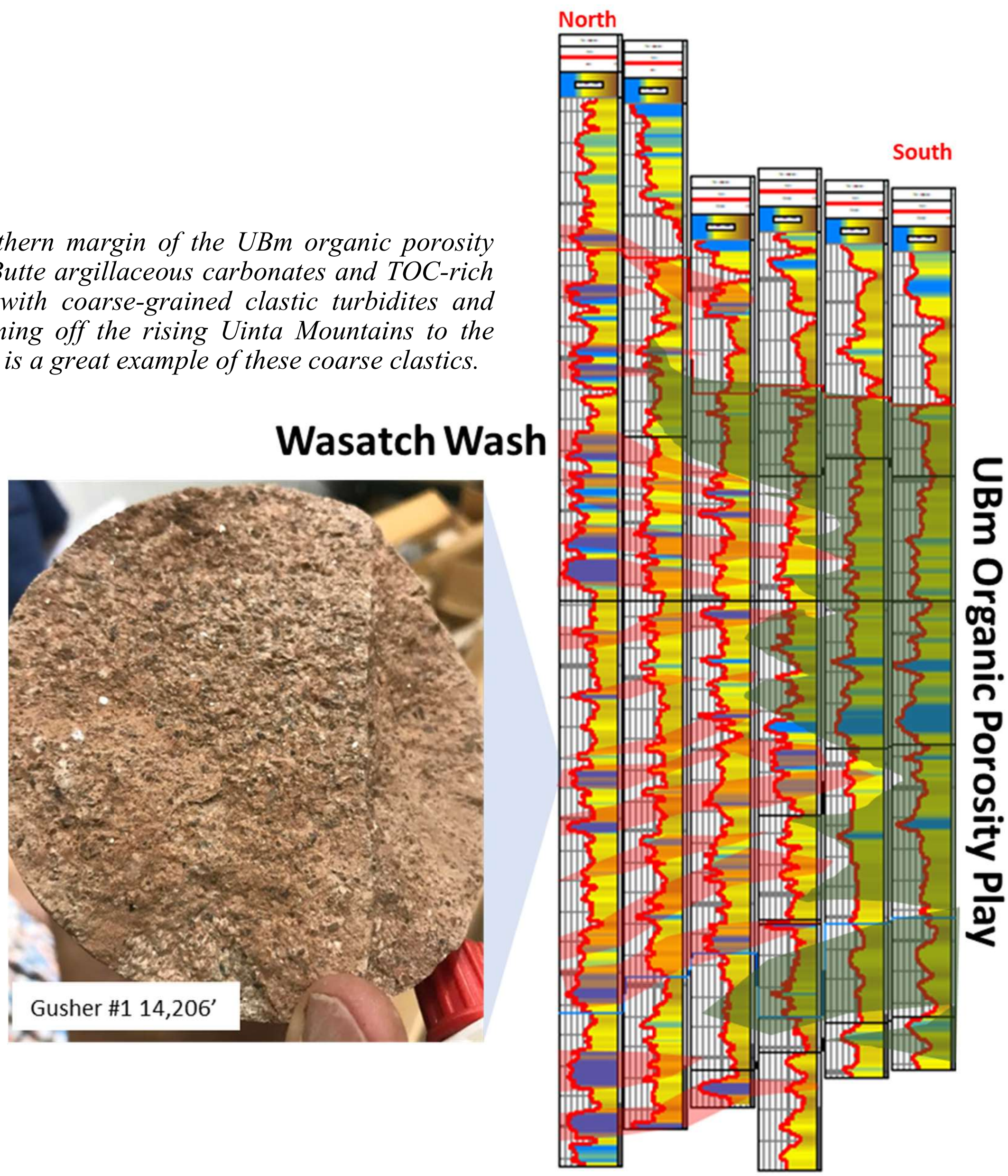


Figure 15. *The organic porosity sub-play of the UBm is tied to TOC richness and thermal maturity (1.0–1.2 Vro) rather than reservoir lithologies. (A) Photomicrograph of organic-rich carbonate mudstone with thin pelecypods. Note the tensile fractures in the more organically rich portion of the sample related to hydrocarbon exhalation and shrinkage. (B) Core from a relatively carbonate-poor but organic-rich part of the Uteland Butte. (C) Log example of the organic porosity sub-play, with thinner, more clay-rich carbonates and almost no reservoir quality dolomites. Note the low RhoB values related to the high TOC.*

Figure 16. *UBm oils, arranged from shallower and less thermally mature (left) to deeper and more thermally mature (right). Oils produced from the UBm play vary by region, from black waxes in the south (shallow) with relatively high fractional volumes of asphaltenes (10%–20%), to bright yellow waxes with almost no asphaltenes in the northern (deep) part of the play.*

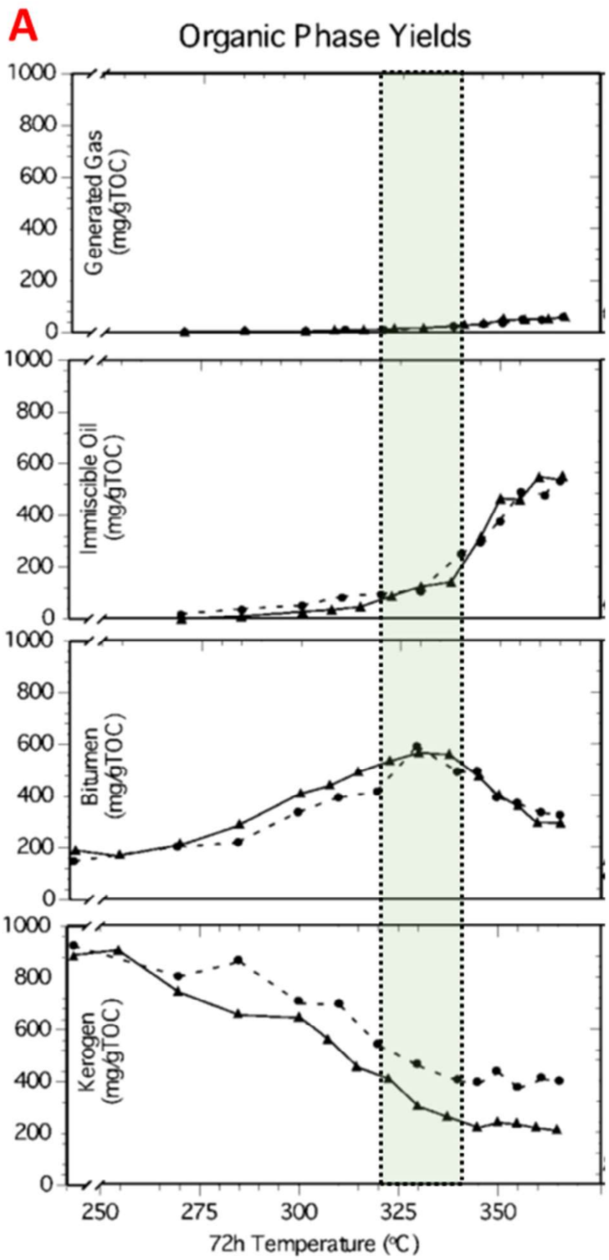
Figure 17. *The northern margin of the UBm organic porosity play where Uteland Butte argillaceous carbonates and TOC-rich shales are replaced with coarse-grained clastic turbidites and Gilbertian deltas coming off the rising Uinta Mountains to the north. The core photo is a great example of these coarse clastics.*



depletion effects tied to permeability issues, horizontal wells testing these strata have been largely unsuccessful. It is not an active play and marks the northern edge of both the UBm play and the organic porosity sub-play.

Ruble and others (2001), working with GRF source rocks, demonstrated the complex evolution of organic phase yields during artificial maturation of Mahogany and Black Shale samples (figure 18A). Kerogen fractional volumes fall with exposure to thermal stress but are not directly converted to oil and gas. Rather the kerogen is first converted to bitumen in a process that is greatly volumetrically expansive (figure 18B). Importantly, as kerogen is converted, the resulting bitumen forces its way into existing porosity, fractures, seams, and can even create hydrofractures. As these masses of bitumen degrade to oil with greater thermal maturity, the resulting organic pores are already in contact with each other, creating large volumes of effective porosity.

The most prominent example of relatively immature expulsion of bitumen from GRF rocks are the many extensive uintaite (a brittle/solid hydrocarbon often commonly referred to as Gilsonite®, a trademarked name) dikes. Boden and Tripp (2012) showed that uintaite is largely composed of low-maturity bitumens that were expelled from high TOC rocks (figure 19). Thin sections from almost any GRF rock show bitumen forcing itself between grains, into small moldic pores, as discreet layers between laminae, and into adjacent pores and vugs. In some cases, the bitumen hydrofractures the rock, filling the resulting fracture. Within UBm sediments, photomicrographs show bitumen invading intercrystalline porosity in dolomites, fractures in bivalve packstones, and vugs in carbonate mudstones.



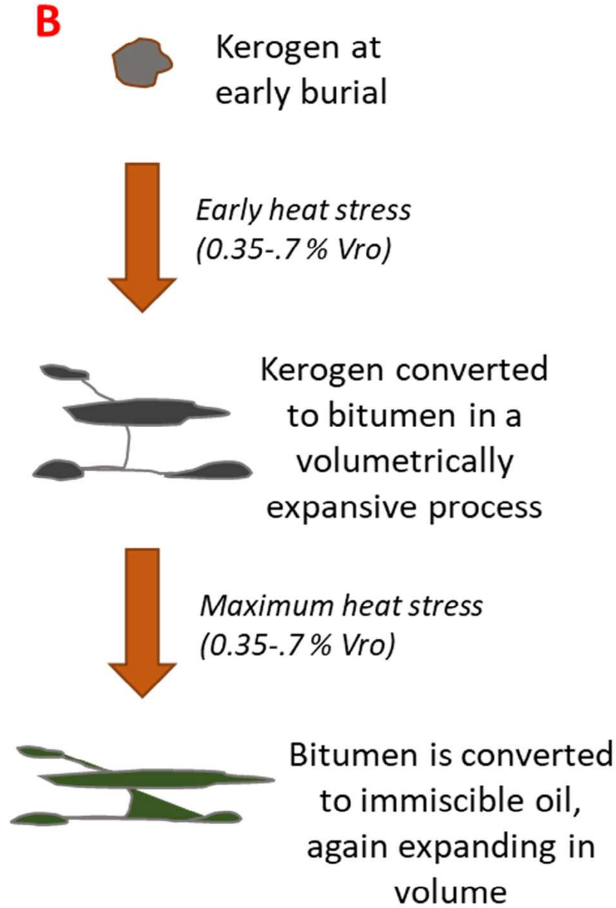


Figure 18. *(A). Ruble and others (2001) demonstrate the complex evolution of kerogen to oil in Green River rocks, with progressive thermal stress. (B) With further burial and additional heat stress, the bitumen begins to be converted to oil, with large volumes of the oils generated remaining within the newly created organic porosity within both the original kerogen and the bitumen. Deeper burial of sediments forces the bitumen to thermally degrade to oil, converting to zones of interconnected organic porosity.*

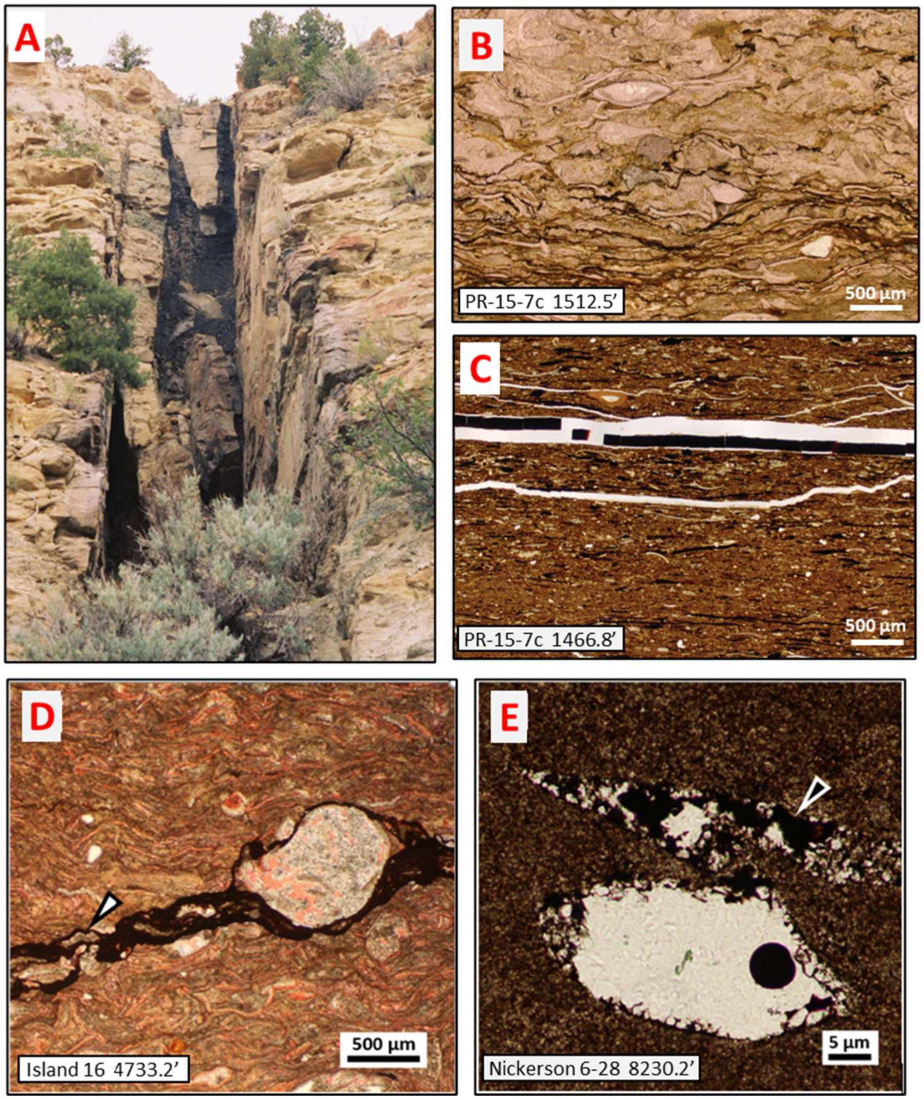


Figure 19. *Example of bitumen being generated during early burial and intruding the surrounding matrix or hydrofracturing the rock. (A) Photo of the Dragon uintaite vein. (B–D) Photomicrographs of Green River sediments with bitumen filling pores, vugs, mats, and fractures. (E–F) Photomicrographs from Rueda and others (2019) with significant bitumen deposits within UBm rocks.*

The two-stage maturation process for GRF source rocks leads to large volumes of connected organic porosity, which is filled with in-situ generated oil. Mapping these volumes of oil requires that the interpreter first identify TOC richness. We began with cores having TOC data, then modified a Schmoker curve (Schmoker, 1993) by empirically matching it to the core TOC data. This leads to a reasonable correlation between our log-calculated TOC values and core-derived values in the UBm interval (figure 20A). The TOC curve values can then be summed to give a TOC richness of the UBm. Mapping this TOC richness shows that the northern part of the UBm play has the high TOC content, particularly where the carbonate volume falls (figure 20B). To calculate TOC porosity from TOC volume percentage, a conversion factor is needed. We took MICP porosity data and paired it with TOC data from sample splits in GRF rocks with negligible interparticle porosity (figure 21A). Measurements of various rocks with differing TOC volumes at a constant thermal maturity allowed us to calculate a TOC-porosity (Phi-TOC) conversion equation from the average slope of the data points (PhiTOC[] = 1.4174*TOC[] - 0.0045). This process was repeated on rocks of different thermal maturities, allowing us to estimate a maturity conversion factor (figure 21C).

Frac modeling from internal company sources suggests that modern frac jobs are effectively stimulating ~200 vertical feet of the UBm section, including the upper ~30 feet of the underlying upper Wasatch to the bottom ~20 feet of the overlying Castle Peak. Including the complete stimulated vertical section in the summed TOC volume and then converting to Phi-TOC and the maturity conversion factor allows us to estimate the volumes of in-place oil in the TOC porosity sub-play (figure 22). The OOIP volumes for TOC hosted porosity range from 0 barrels per section in the immature portions of the play to over 30 million bbls per section in the center of the organic porosity sub-play. Calculated organic porosity-hosted oil volumes correlate well with measured reservoir pressures (figure 12) and production volumes (figure 8). Most of the Uinta Basin operators utilize managed pressure flowback techniques to avoid damage caused

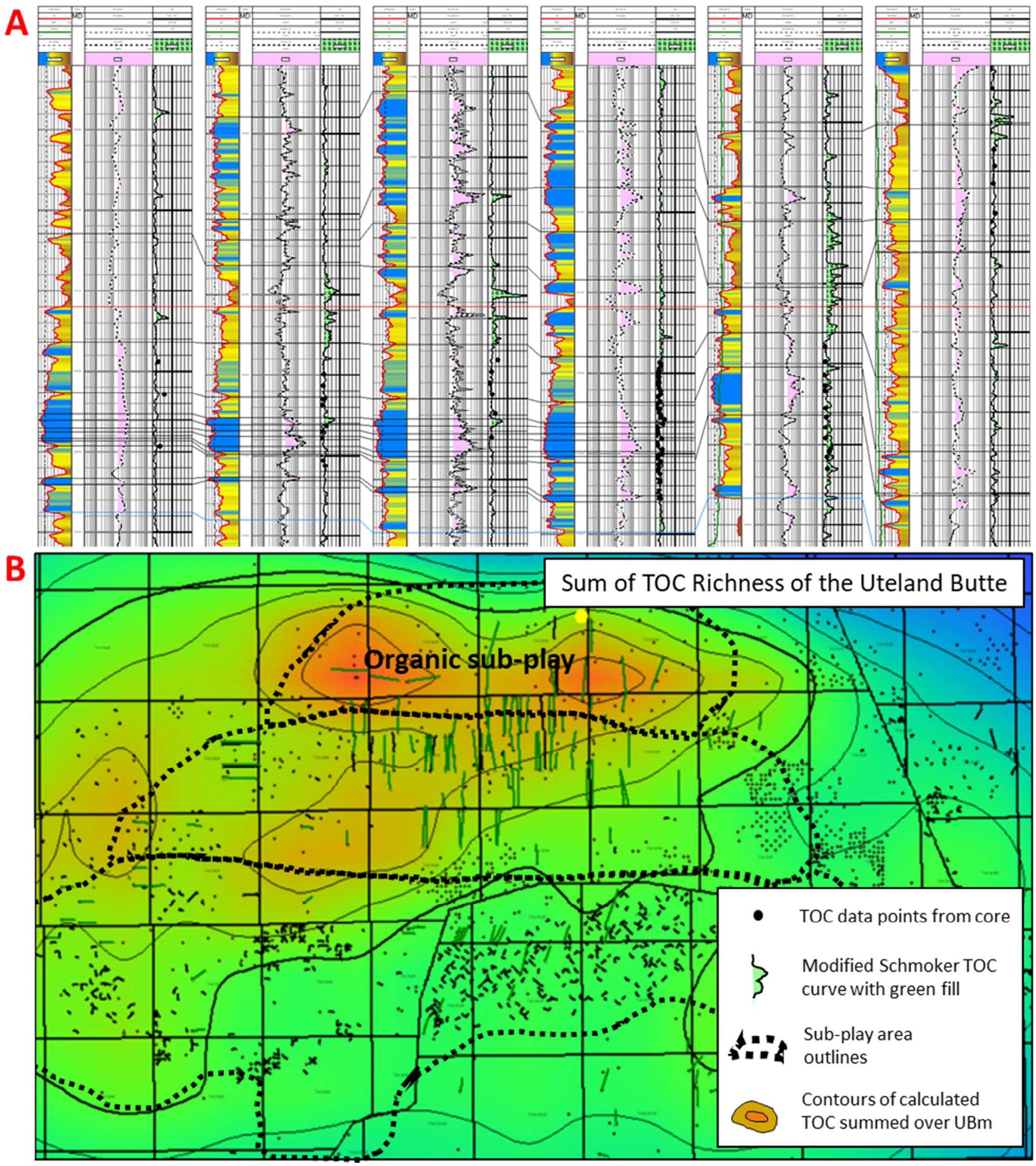


Figure 20. *Mapping the UBm organic porosity fairway begins by creating a TOC model. (A) Plotting TOC points from publicly available core data on logs and empirically matching them to a modified Schmoker TOC curve allows the interpreter to calculate the total volume of TOC in the UBm play. (B) Mapping the summed TOC richness across the Uinta Basin shows that the area of highest TOC enrichment is in the organic porosity sub-play. The area of richer TOC matches where carbonate fractional percentage falls.*

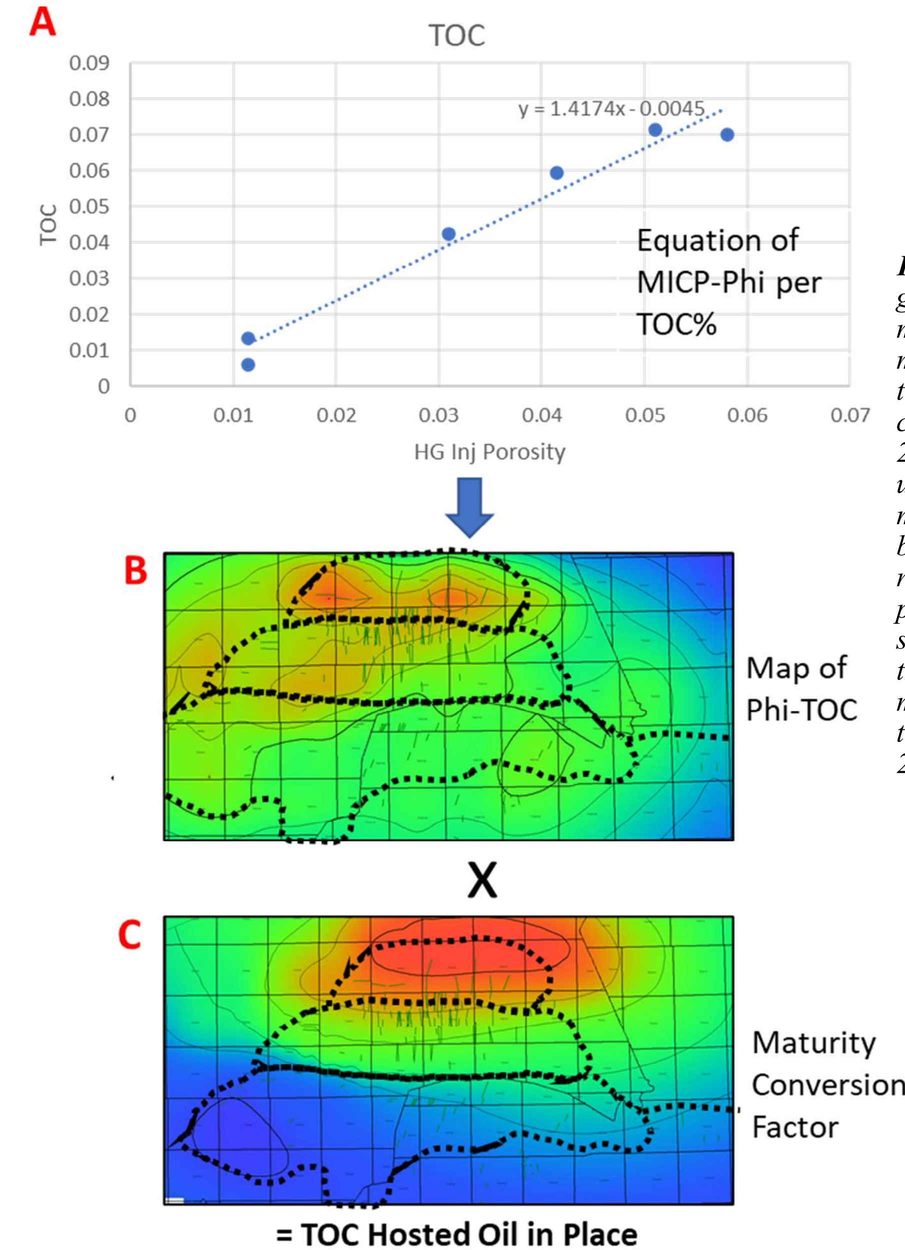


Figure 21. *Process used to calculate organic porosity. (A) Capillary pressure measurements cross-plotted against core-measured TOC in rocks with little interparticle porosity. (B) Phi-TOC map calculated from TOC map in figure 20B. (C) A conversion factor must be used to account for the variable thermal maturity across the UBm play. This can be done by repeating the above process in rocks with a known thermal maturity and plotting the ratio of effective porosity versus that of the standard and mapping these ratios. Multiplying the conversion map against the Phi-TOC OOIP results in the actual organic hosted OOIP (figure 22).*

by aggressive flowback. These operators believe that near wellbore damage can be mitigated by effectively monitoring and controlling initial rates and pressures (i.e., choking back production at IP). Because of this, IP is not always a good indicator of Estimated Ultimate Recovery (EUR). The original operator of many of these horizontal wells has put EURs in the 1–2 million bbls of oil range. Future development of the organic porosity sub-play will involve pushing development closer to the Wasatch Wash on the northern margin of the sub-play, where carbonate development of the UBm is lowest but pressure and total OOIP volumes are highest (figure 22). Most recently, newer frac techniques such as increased sand loading, higher pump rates and increased percentage of 100 mesh proppant sand have shown promise of further improving well results here.

Mixed Intercrystalline-Organic Porosity Sub-Play

The area between the intercrystalline sub-play and the organic porosity sub-play, as its name suggests, produces from both types of reservoirs. The mixed sub-play is mature enough to be largely self-sourced with significant overpressure (0.55 psi/ft to 0.8 psi/ft gradients) (figure 12). It has the thickest gross section, with the PZ and DPZ dolomites retaining significant volume at 2 to 5 feet thick, thick bivalve wackestones, and significant organic-rich shales (figure 9). The organic porosity with argillaceous carbonates and shales contribute substantially to the sub-play's production. Thermal maturity varies from 0.8% to 1.0% Vro, and as might be expected with the higher exposure to thermal stress, produces a yellow to light gray

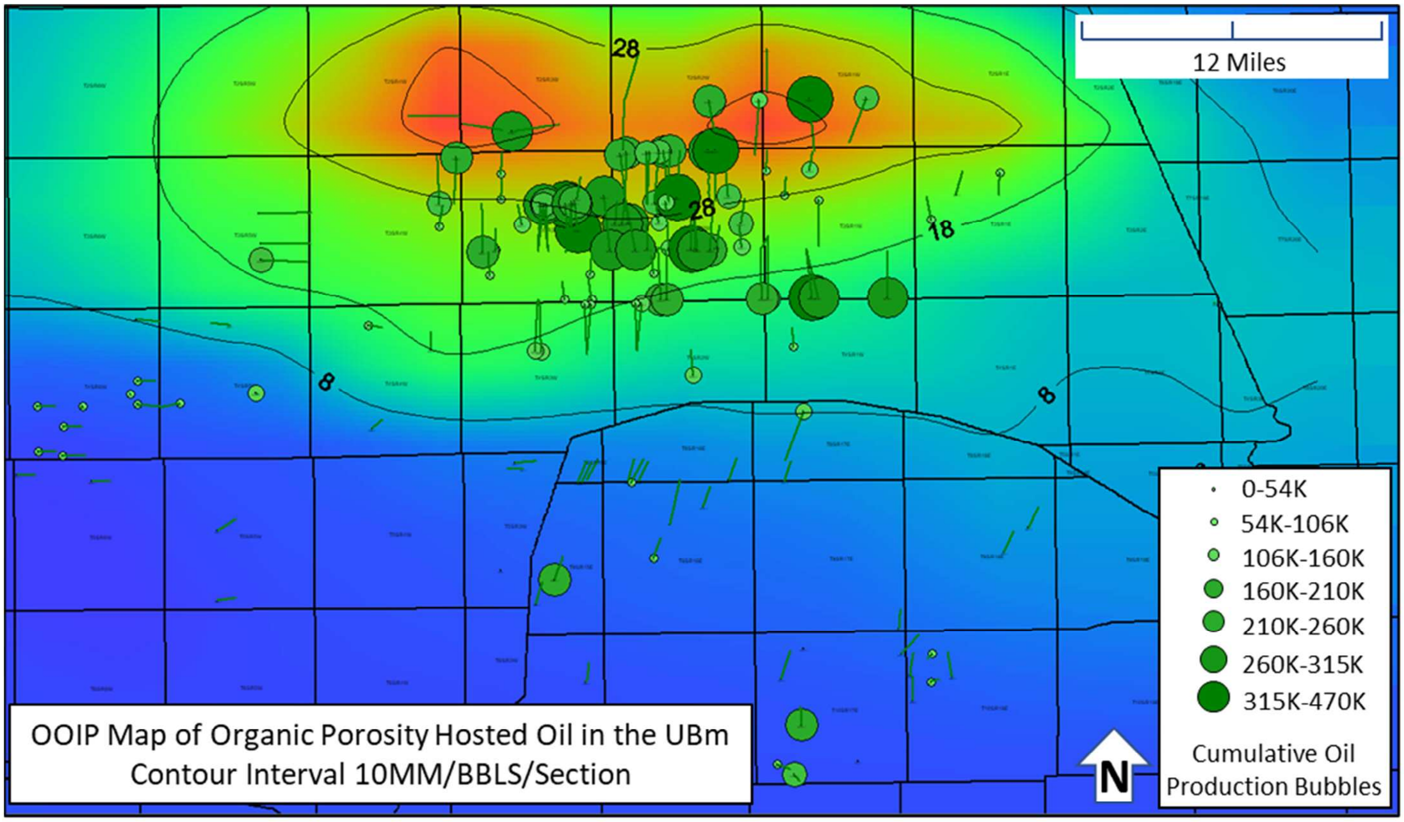


Figure 22. *Map of OOIP in UBm organic pores. Frac modeling suggests that at current designs, operators are stimulating the upper 30 feet of the Wasatch and the bottom 20 feet of the Castle Peak. This OOIP map includes these intervals to better correlate with production bubble maps. The calculated organic porosity OOIP map correlates well with the UBm pore pressure maps (figure 12) and UBm production bubbles.*

wax. GORs vary from relatively high at the southern margin of the play where intercrystalline reservoirs dominate and bubble points are reached at relatively low pressures, to relatively low at the northern margin where organic porosity reservoirs dominate production.

The two different pore types present in this sub-play, the organic porosity and the intercrystalline porosity, combine to produce strong well results (figure 23). Summing the oil-in-place for the organic porosity sub-play with the oil-in-place for the intercrystalline porosity sub-play gives a good approximation for oil-charge available in this sub-play. As the geology in this sub-play is very laterally consistent, well results tie more closely to engineering inputs in this area than to the local geology. Frac fluid and proppant volumes, together with lateral length closely correlate with production (figure 24). Wells in this sub-play with large fracs are routinely reaching EURs of ~1 million bbls of oil or more.

CONCLUSION

Production results in the larger UBm play are directly impacted by the effective pore systems in the targeted reservoirs. Historically, an incomplete understanding of which pore systems are best suited to produce significant volumes in different parts of the play have led to inefficient lateral targeting and ineffective frac strategies. A better understanding of what constitutes the most effective pore systems in the sub-plays that have yet to achieve economic success, namely the proximal intergranular and intercrystalline dominated sub-plays, will be critical for their future development. Relating the pore systems to changes in pore pressure, reservoir temperature, and local bubble point can give operators the tools they need to design the most effective targeting and completion practices. Currently no operator is targeting the proximal intergranular sub-play, but with higher oil prices and a recognition of the large, if slowly produced, cumulative volumes from the few wells drilled in this sub-play may spark renewed attention. The hurdles of high fluid viscosity and low pore pressures could likely be ameliorated with frac jobs designed to greatly improve reservoir connectivity through high sand loading and tighter stage spacing. The intercrystalline sub-play is already seeing greatly increased attention in 2021, with improved frac rate and sand loading greatly improving well results. We expect this trend to continue, with the intercrystalline sub-play finally achieving full economic status in the near future.

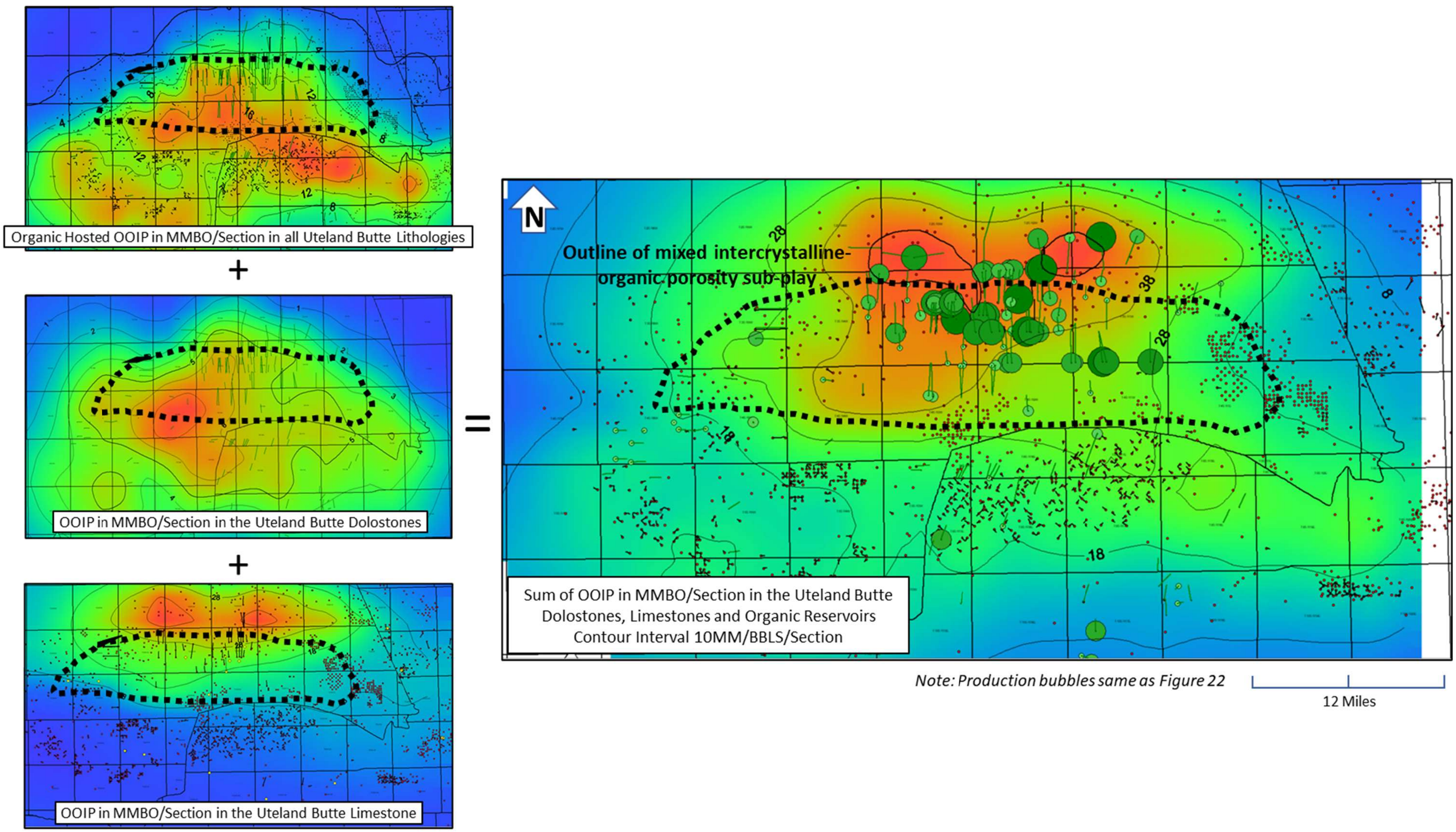


Figure 23. *The mixed intercrystalline-organic porosity sub-play has the most complex porosity system. To generate a total OOIP map for this sub-play, inputs include the OOIP maps from figure 14C (dolostone OOIP) and figure 22 (organic porosity OOIP) plus an OOIP hosted in UBm limestones. All three of these pore types contribute at the pore pressures found in this sub-play.*

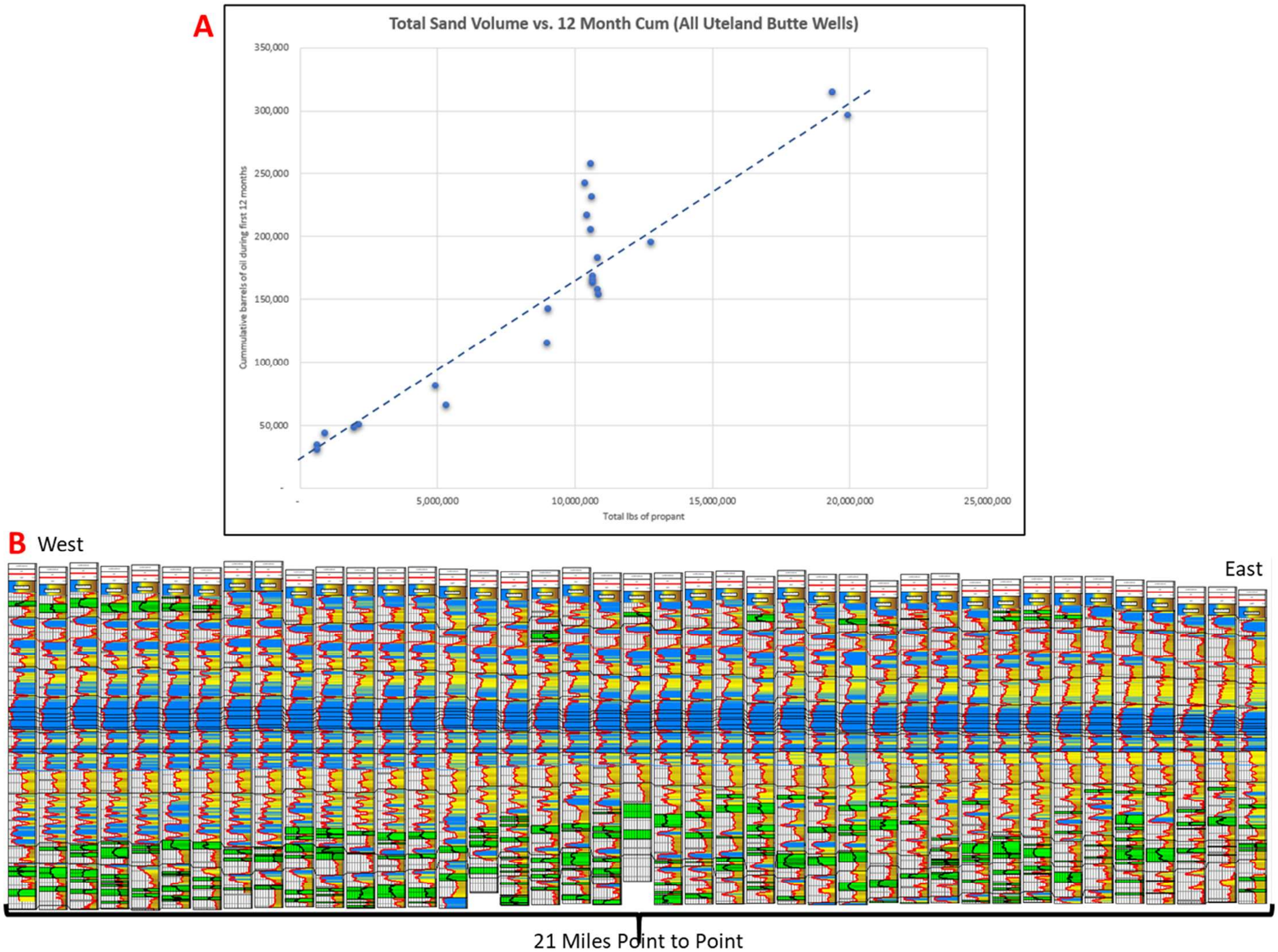


Figure 24. *(A) Cross-plot of total proppant in UBm laterals drilled as the initial wells in their respective spacing units ("held by production" [HPB] wells) in the mixed intercrystalline-organic porosity sub-play versus first 12 months cumulative oil production. HPB wells were used to eliminate parent-daughter effects. Note the tight correlation of production results with frac size. In general terms, the UBm is too tight to produce without a hydraulic frac, and this plot shows, irrespective of lateral length, that the more UBm rock that is hydraulically stimulated, the better production will be. (B) Closely spaced GR logs from 41 wells from the western part of the mixed sub-play to the east, demonstrating the low stratigraphic variation of this play.*

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