CONSTRUCTING A STRATIGRAPHIC FRAMEWORK FOR THE MISSISSIPPIAN BARNETT SHALE: NORTHERN AND CENTRAL FORT WORTH BASIN, TEXAS

by

JOSHUA KEITH KUHN

Bachelor of Science, 2008
The Pennsylvania State University
State College, Pennsylvania

Submitted to the Graduate Faculty of the
College of Science and Engineering
Texas Christian University
in partial fulfillment of the requirements
for the degree of

Master of Science

December 2011

CONSTRUCTING A STRATIGRAPHIC FRAMEWORK FOR THE MISSISSIPPIAN BARNETT SHALE: NORTHERN AND CENTRAL FORT WORTH BASIN, TEXAS

by

Joshua Keith Kuhn

Thesis approved:

____
Major Professor

____

____

____
For the College of Science and Engineering

ACKNOWLEDGEMENTS

I would like to thank Martin Emery, my supervisor at Range Resources and member of my thesis committee, for his extensive contributions of geologic insight and mentoring, Dr. Ken Morgan, my advisor, for his guidance and constructive advice, Dr. Helge Alsleben for providing direction and encouragement throughout my studies as part of my thesis committee, and Dr. John Breyer, for using his substantial knowledge of the Barnett Shale play to assist in my research. The mentoring and combined geologic expertise from the members of my thesis committee provided the insight which helped drive my research. For their contributions of time, guidance, and support, I am truly grateful.

I also would like to thank Range Resources Corporation, Legend Natural Gas, and Premier Natural Resources for supplying geophysical logs, XRD, and geochemical data for my thesis work. My research would not have been possible without the generous contributions from these companies.

Much appreciation is also given to my colleagues at Range Resources Corporation, Magell Candelaria, Toni Eilerts, Rennie Hubnik, and Russ Talley, who engaged in refining my final draft and were always available to lend assistance during my research. Their enthusiasm to provide geologic insight and offer suggestions was tremendously helpful.

I wish to thank the petroleum engineers at Range Resources, especially Nick Christ and Van Collins, for their assistance in reservoir analyses.

Finally, but by no means least, I would like to thank my family for their continued moral support throughout my educational tenure.

TABLE OF CONTENTS

LIST OF FIGURES

INTRODUCTION

Decreasing the United States' dependence on foreign energy and allowing more domestic drilling has become a highly debated issue in the oil and gas industry. Technological advancements in the last twenty years have led to the development of unconventional shale plays, which hold tremendous potential in the United States. In unconventional plays, a single formation may serve as the source, reservoir, and seal unlike most conventional plays where essential elements of the petroleum system are different rock units (Jarvie et al., 2004).

The Barnett Shale play was the first discovered unconventional shale play. Improved understanding of the stratigraphy and reservoir properties of the Barnett Shale in the Fort Worth basin (FWB), Texas, will allow the contained reserves to be exploited more completely and economically (Breyer et al., 2011). Lessons learned from unconventional shale-gas plays like the Barnett Shale may provide further insight to new or undiscovered shale plays. To this end, I am proposing a detailed stratigraphic framework and attempt to regionally assess the Barnett Shale reservoir as a shale-gas play in the northern and central portions of the FWB.

Fort Worth Basin

The FWB in north-central Texas covers an area of about 38,850 km^2 (~15,000 mi^2) (Montgomery et al., 2005) (Figure 1). A relatively shallow trough, it is one of several foreland basins formed during the Paleozoic Ouachita orogeny, a continent-continent collision of Euramerica and Gondwana, which led to the formation of Pangea (Walper, 1982; Thompson, 1988). The axis of this north-south elongated depression is roughly parallel to the Ouachita thrust front, which forms the eastern boundary of the basin. The Muenster and Red River arches form the northern edge of the FWB, and the Llano uplift, a domal structure that exposes Precambrian and Paleozoic rocks, bounds the basin's southern margin (Montgomery et al., 2005). The western extent of the basin shallows over the Bend arch, which formed as a hinge line due to subsidence of the FWB in the early stages of the Ouachita orogeny (Pollastro et al., 2003). The study area of the FWB is located in the most actively developed regions of the Barnett Shale play.

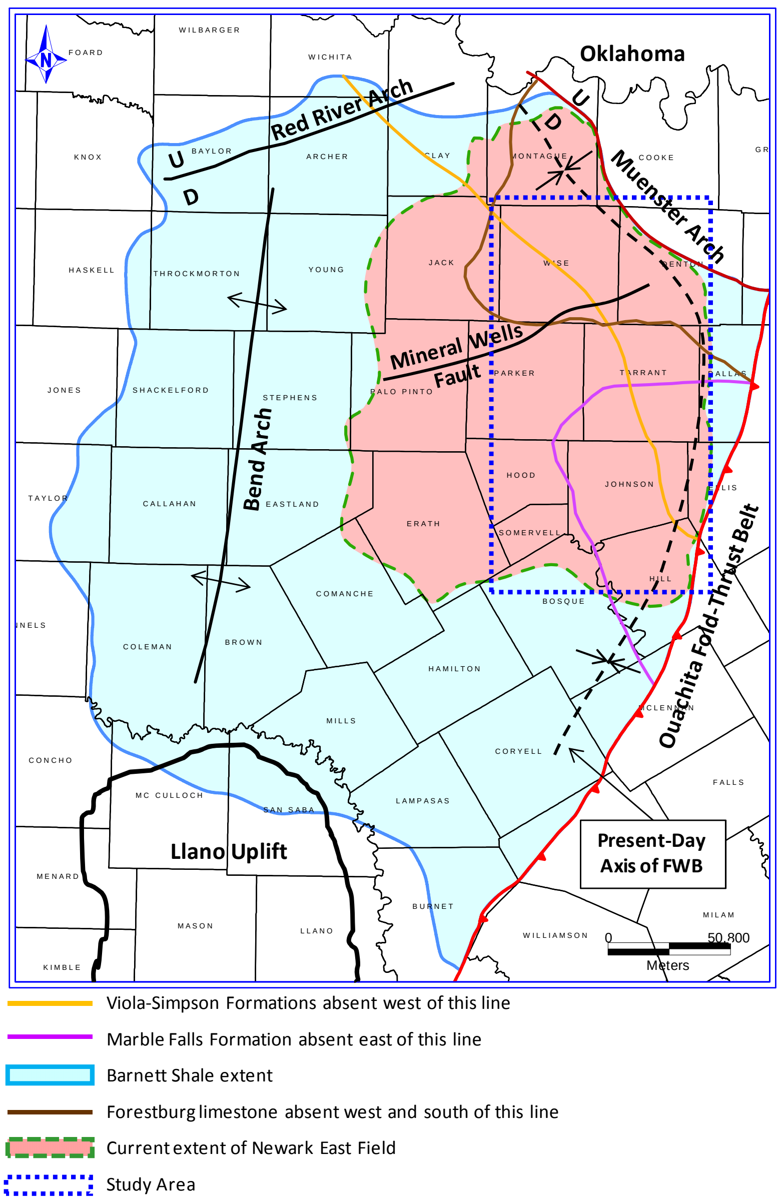


Figure 1. Map showing structures, geographic extent of the Fort Worth basin, and key formations near the core Barnett Shale Newark East field and southern core extension. Modified from Montgomery et al. (2005) and Pollastro et al. (2007).

Geologic History of the Fort Worth Basin

Cambrian-Devonian

The FWB formed as the southern edge of the North American craton changed from a passive margin in the Early Paleozoic (Cambrian) to an active margin in the Late Paleozoic (Pennsylvanian) (Pollastro et al., 2007). Precambrian granite and diorite underlie the sedimentary section (Flippen, 1982). Cambrian rocks in the FWB are comprised of sandstone and shale (Flippen, 1982). During the Early Ordovician, a widespread carbonate platform existed over much of southern Euramerica, or present-day Texas (Turner, 1957; Burgess, 1976). The stable, shallow-marine carbonate platform is referred to as the Ellenburger Group in the FWB and in the Permian basin of west Texas. During the Middle Ordovician, a drop in sea level resulted in an erosional unconformity with prolonged subaerial exposure of the Ellenburger Group (Sloss, 1976; Kerans, 1988; Pollastro et al., 2003). Two separate formations were deposited over the Ellenburger Group, the Simpson Limestone and Viola Limestone (Upper Ordovician). Due to another drop in sea level during the Ordovician, the crystalline limestone and dolomitic carbonates of the Simpson and Viola Formations only exist in the northeastern part of the basin (Montgomery et al., 2005) (Figure 2). After Simpson and Viola deposition, a major erosional event removed all Silurian and Devonian rocks that may have been present in the FWB from the geologic record (Henry, 1982). Subaerial exposure of these carbonates led to karsting of the Ordovician unconformity surface (Sloss, 1976; Kerans, 1988; Pollastro et al., 2003) (Figure 2), predominately in the western area of the FWB where the Simpson and Viola Formations are absent.

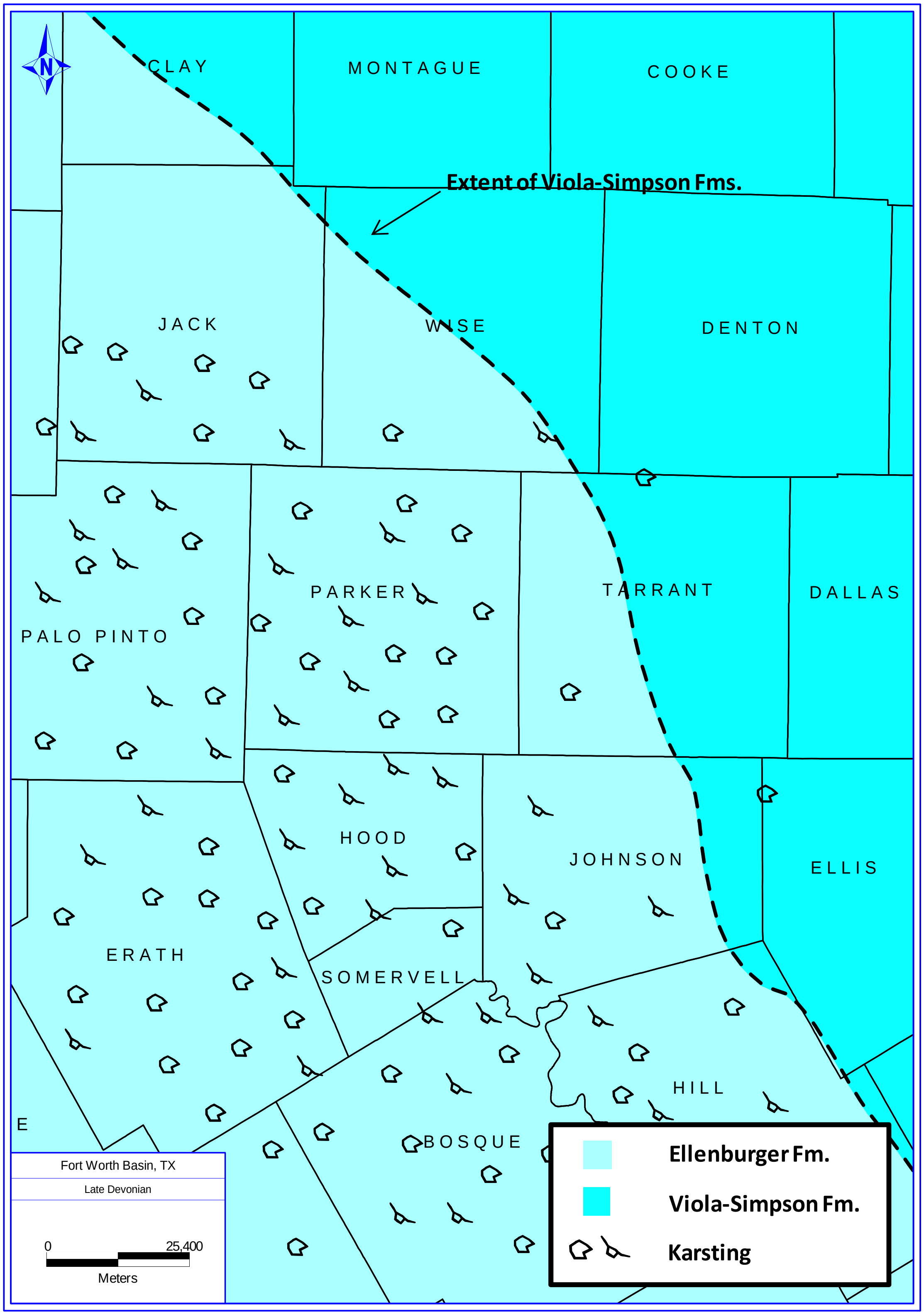


Figure 2. Map of the study area during the Late Devonian showing karst features in pre-Barnett (Ordovician) units.

Mississippian

During the Mississippian, tectonic loading of Gondwana on the Euramerican carbonate platform resulted in the formation of a foreland basin on the southern edge of Euramerica (Gutschick and Sandberg, 1983). Global plate reconstructions by Blakey (2005) suggest that the FWB was the site of a narrow, inland seaway bound to the west by a carbonate shelf and to the south and east by the Caballos-Arkansas island chain (Montgomery et al., 2005) (Figure 3). Poor circulation within the restricted seaway produced an anoxic environment (Montgomery et al., 2005). The foreland basin, flooded by the seaway, created new accommodation space where deep-water clastics were deposited in a sediment-starved, anoxic environment over a 25 million year period (Loucks and Ruppel, 2007). The sediment deposited in the FWB would eventually comprise the black, organic-rich Barnett Shale overlying the pre-Barnett erosional unconformity. Carbonates were also deposited along the western margin of the FWB during the early Mississippian and constitute the Chappel limestone, which consists of crinoidal limestone and local pinnacle reefs up to 91 m (~300 ft) in height (Browning, 1982; Ehlmann, 1982).

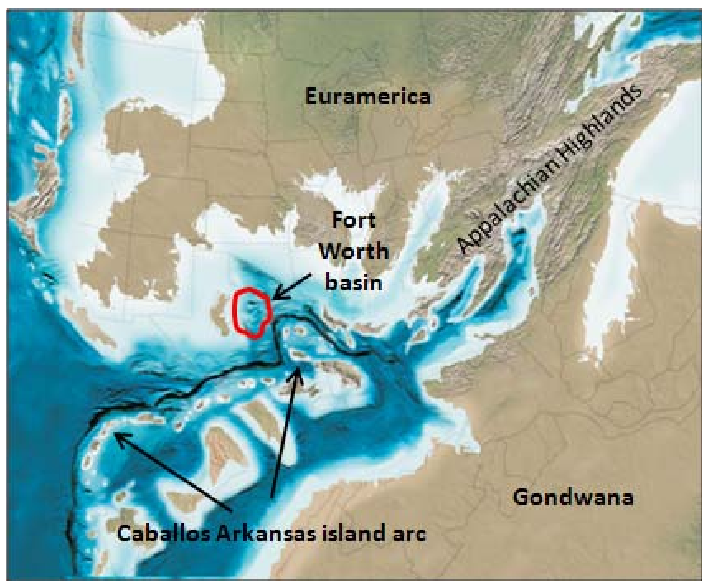


Figure 3. Paleogeographic reconstruction during the Early Carboniferous (Mississippian). Modified from Blakey (2005). During this time, the Rheic Ocean was closing as a result of converging plate margins, and sediment that comprised the Barnett shale was deposited. The Fort Worth basin is outlined in red.

An adjusted sea-level curve constructed for the Mississippian by Ross and Ross (1987) allowed Loucks and Ruppel (2007) to suggest a water depth of 120-210 meters (~400-700 ft) for deposition to be below lowstand storm-wave base. This estimate concurs with Byers (1977), who concluded that water depths must exceed 140 meters (~450 ft) in basinal, anoxic environments where evidence of shelly fauna and bioturbation is minimal and sediment is laminated.

The Forestburg limestone (Mississippian) is an argillaceous lime mudstone (Loucks and Ruppel, 2007) that divides the Barnett Shale into informal upper and lower shale members in the northern region of the FWB. The Forestburg pinches out southward and westward, and where absent the upper and lower Barnett Shale members can no longer be readily differentiated. Compositionally, the Forestburg limestone contains much less silica and TOC than the Barnett Shale, and its origin is still yet to be fully understood. Loucks and Ruppel (2007) suggest that the abundance of carbonate influx into the FWB during Forestburg depositional time may reflect a change in: 1) source area, 2) eustatic sea level, or 3) seawater chemistry.

Pennsylvanian

The first formation deposited over the Barnett Shale was the Marble Falls Limestone (Figure 4), which includes a lower interval of interbedded limestone and gray-black shale and an upper limestone interval (Montgomery et al., 2005). Sea level regression during the Early Pennsylvanian resulted in subaerial exposure of the Marble Falls Formation (Namy, 1974), creating a low-relief erosional unconformity. Throughout the rest of the Pennsylvanian the FWB continued to subside (Pollastro et al., 2003), and clastic sediments shed from the surrounding, rapidly eroding thrusted highlands filled the basin. The clastics, consisting of mostly sand and pebbles derived from the east, comprise the Bend, Strawn, Canyon, and Cisco Groups in the FWB (Walper, 1982) and mark the culmination of the Ouachita orogeny. Besides contributing sediment to the FWB, the Ouachita orogeny also produced the Muenster and Red River arches (Figure 1). These structures are faulted basement uplifts generated during the Ouachita orogeny from reactivation of faults related to the Southern Oklahoma aulacogen (Walper, 1977; 1982).

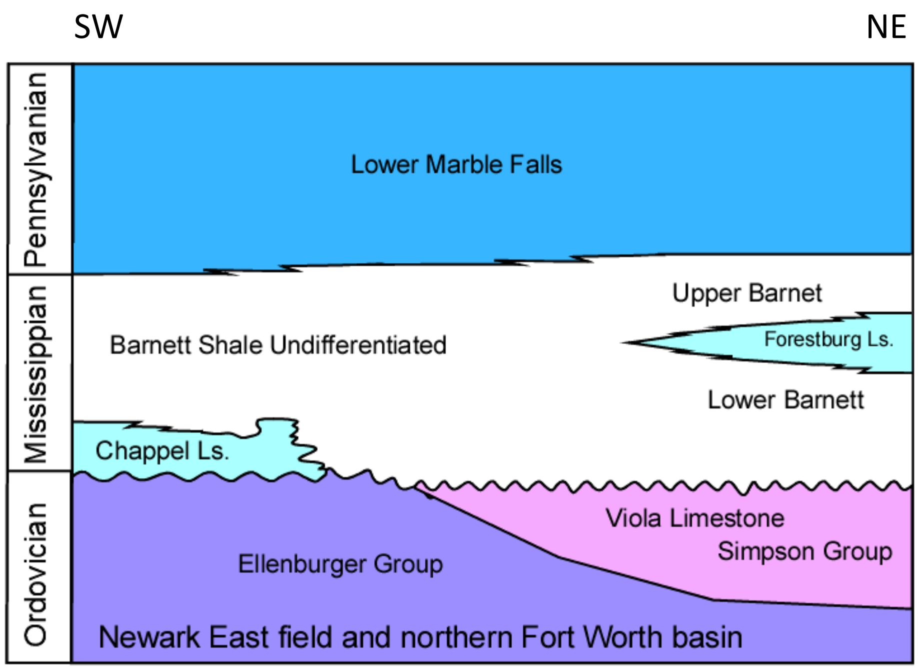


Figure 4. Stratigraphic changes from the southwest towards the northeast regions of the basin. From Monroe and Breyer (2011).

Cretaceous

Pennsylvanian strata are truncated by another erosional unconformity that rests below a thin layer of Cretaceous rocks on the eastern side of the FWB (Flawn et al., 1961; Henry, 1982; Lahti and Huber, 1982). Whether Permian, Triassic, and/or Jurassic strata were present in the FWB is not known, but Henry (1982) and Walper (1982) suggest that much of the Pennsylvanian and possibly Permian rocks were eroded prior to the Cretaceous. Cretaceous rocks comprise the last stratigraphic units deposited in the FWB.

Reservoir Characteristics

The Barnett Shale is dominated by type II oil-prone marine-algal kerogens (Pollastro et al., 2003) sourced from autochthonous organic material deposited within an anoxic, reducing environment (Tissot and Welte, 1984). Organic matter decomposition constitutes the majority of the known porosity in the Barnett Shale (Jarvie et al., 2007). The organic material comprising the complex pore network is pyrobitumen, carbon-rich residue resulting from organic degradation and conversion to hydrocarbons through thermal exposure (Loucks et al., 2010). Low permeability and porosity in the matrix surrounding the organic material minimize hydrocarbon expulsion from the shale (Jarvie et al., 2003). These circumstances present a closed system during hydrocarbon generation, which helps explain why this shale reservoir is over-pressured (Jarvie et al., 2007).

The Barnett Shale is very rich in original organic matter content (Jarvie et al., 2007) and serves as the primary source of petroleum for both conventional and unconventional reservoirs in the FWB (Jarvie et al., 2003; Montgomery et al., 2005). TOC measurements from a less thermally-mature region of Barnett Shale typically yield a higher TOC (wt. %) than those taken from thermally mature, hydrocarbon-bearing regions because less of the organic carbon has been converted to hydrocarbons (Jarvie et al., 2004). The minimum amount of organic material considered a “good risk” baseline for a potential shale reservoir is 2 wt. % TOC (or ~ 4 vol. % TOC) (Jarvie et al., 2004).

Most of the high radioactivity measured from gamma ray logs run through the organic-rich Barnett Shale is due to high uranium content (Breyer et al., 2011). The remainder of the gamma ray response is due to the presence of thorium and potassium (Breyer et al., 2011). Organic material deposited in an anoxic environment is reducing due to absence of oxygen and acts as a sorbent for uranium (Lüning and Kolonic, 2003). The amount of uranium precipitated is largely influenced by sedimentation rate (Lüning and Kolonic, 2003). Essentially, longer exposure between organic matter and sea water before burial allows for greater precipitation (Lüning and Kolonic, 2003). During Barnett Shale deposition, preservation of organic matter and slow sedimentation rates permitted substantial uranium precipitation, and, consequently, high gamma ray responses (Lewis et al., 2004).

Montgomery et al. (2005) estimate the Barnett Shale to contain 742 bcm (~26.2 tcf) of technically recoverable gas in the FWB. Effective recovery of hydrocarbons is directly dependent on significant gas storage in the reservoir and the absence of faults and/or karst features penetrating the Barnett Shale (Jarvie et al., 2007). Barnett wells drilled in structurally complex areas are typically poor producers (Bowker, 2007).

Fort Worth Basin Drilling History

The Mississippian Barnett Shale is one the largest known unconventional shale plays in the world, producing more than 158 mcm (5.6 tcf) of gas (Berman, 2009) since the play's discovery in 1981 by Mitchell Energy Company (Martineau, 2007). By 1998, industry perseverance along with technological advances like hydraulic fracturing and horizontal drilling developed the Barnett Shale into an economically successful play (Martineau, 2007) (Figure 5). These drilling and completion techniques were quickly applied to various shale plays across the United States, rendering them economic successes and making the Barnett Shale the key play that initiated the search for additional unconventional oil and gas plays worldwide.

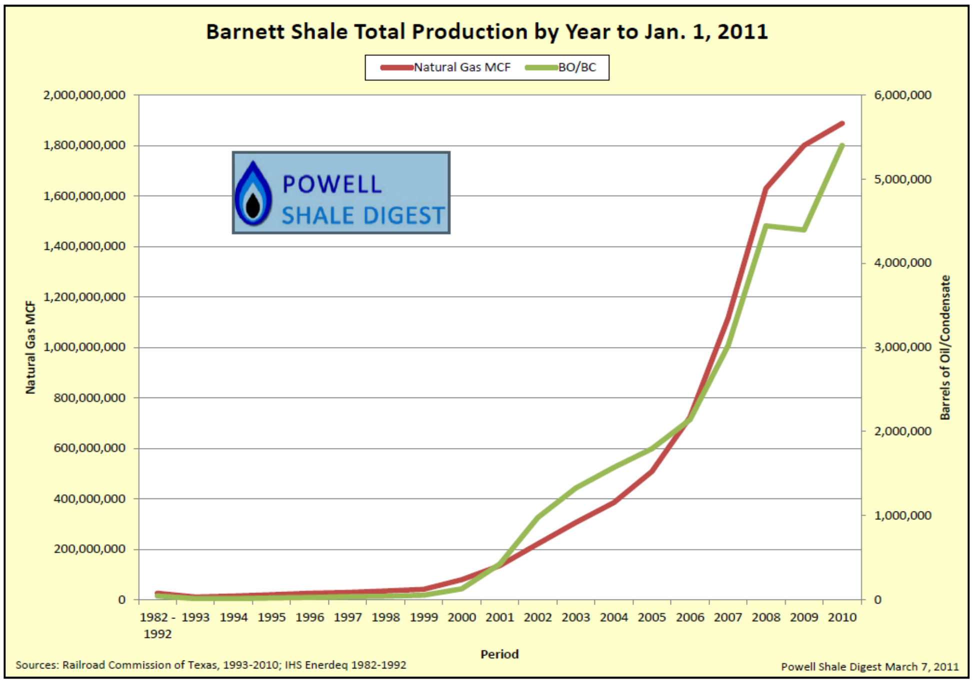


Figure 5. Representation of the increased Barnett Shale production since the play's discovery in the early 1980s. From Powell et al. (2011).

METHODOLOGY

Approximately 200 geophysical logs are used to create chronostratigraphic correlations across the study area, which defines the gross reservoir (see below) and leads to the proposed stratigraphic framework detailed in this study. Basin-wide chronostratigraphic correlations are based on events (i.e. marine flooding surfaces) that are essentially coeval, rather than lithostratigraphic relationships that typically cross time-lines. Once the gross reservoir is defined, stratigraphic relationships throughout the Mississippian-Pennsylvanian section are recognized from geophysical logs. Isopach maps of the gross reservoir and

Barnett Shale are created in order to illustrate regional changes in thickness. Based on these chronostratigraphic relationships, a stratigraphic framework/reservoir model for the Barnett Shale is proposed.

Interpreted chronostratigraphic relationships and core analyses are also used to identify facies belts throughout the gross reservoir on a general scale throughout the FWB due to the geographic size of the study area (~15,000 km^2). The reservoir model is then studied more comprehensively, and various characteristics of the gross reservoir are analyzed. Geophysical logs and X-ray diffraction (XRD) analyses spanning the study area are used to define mineralogic and lithologic trends in the gross reservoir. Rotary sidewall cores from ten wells are also used to identify mineralogic variability throughout the reservoir. Time slice maps are shown to illustrate facies changes across the FWB during deposition of the strata comprising the gross reservoir. The facies belts exhibit the interpreted depositional trends in the FWB during the Mississippian and Early Pennsylvanian.

Geochemical analyses identifying TOC from four cored wells are used to show trends in organic matter of the Barnett Shale reservoir. Organic matter content is compared to spectral gamma ray log responses in an attempt to find correlations between the two and evaluate the gross reservoir based on organic richness. The gross reservoir can be assessed via log analysis, and the amount of public log data collected in the FWB could prove very advantageous as a quick, inexpensive assessment of acreage in the Barnett Shale play.

RESULTS

Chronostratigraphic Relationships

Log analyses were used to define the gross reservoir, which consists of the Barnett Shale and Marble Falls Formation (or stratigraphic equivalent) and is bound by two unconformities. The Morrowan section is included with the Barnett Shale as part of the gross reservoir for two reasons: 1) to help construct the stratigraphic framework and 2) to evaluate shaley intervals for possible contribution to the Barnett Shale reservoir. Type logs and formation tops of the gross reservoir are provided in Figures 6 and 7. The two type logs of the gross reservoir differ in thickness, and some formations are only present in the northern part of the basin. The Marble Falls and Forestburg carbonates present towards the northern extent of the FWB are absent to the south. The formation tops identify correlative log responses used to construct the stratigraphic framework of the gross reservoir and to establish an internally consistent reservoir model for the Barnett Shale play.

Chronostratigraphic regional cross sections spanning the FWB were constructed to identify changes in gross reservoir thickness across the study area (Figures 8 and 9). The gross reservoir thins from north to south and thickens from west to east across the FWB. Identified marine flooding surfaces, further explained and illustrated below in the reservoir model, reveal the relationship between chronostratigraphic trends and depositional environments.

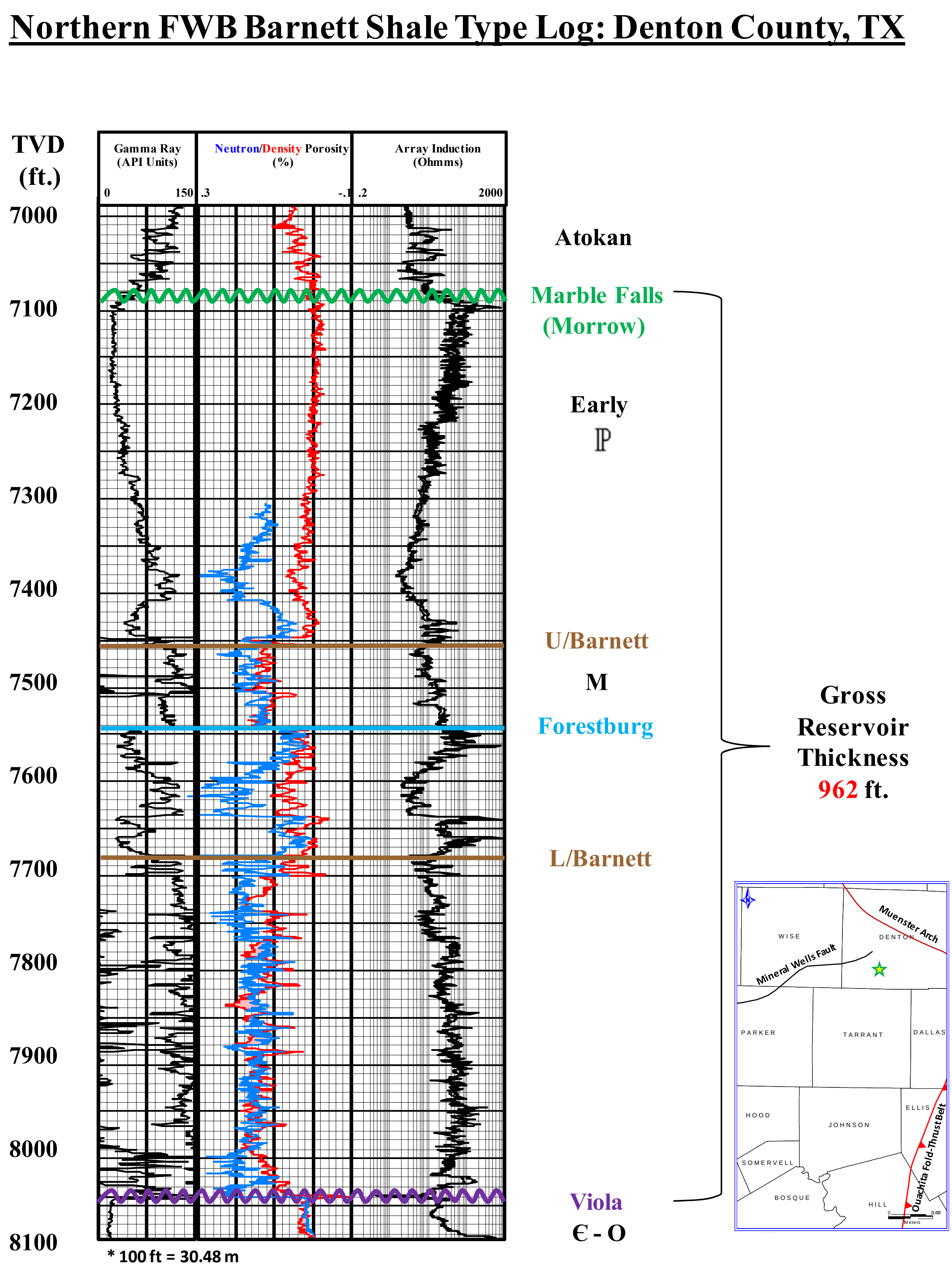


Figure 6. Type log of the gross reservoir illustrating shoaling-upward sequence in the northern FWB.

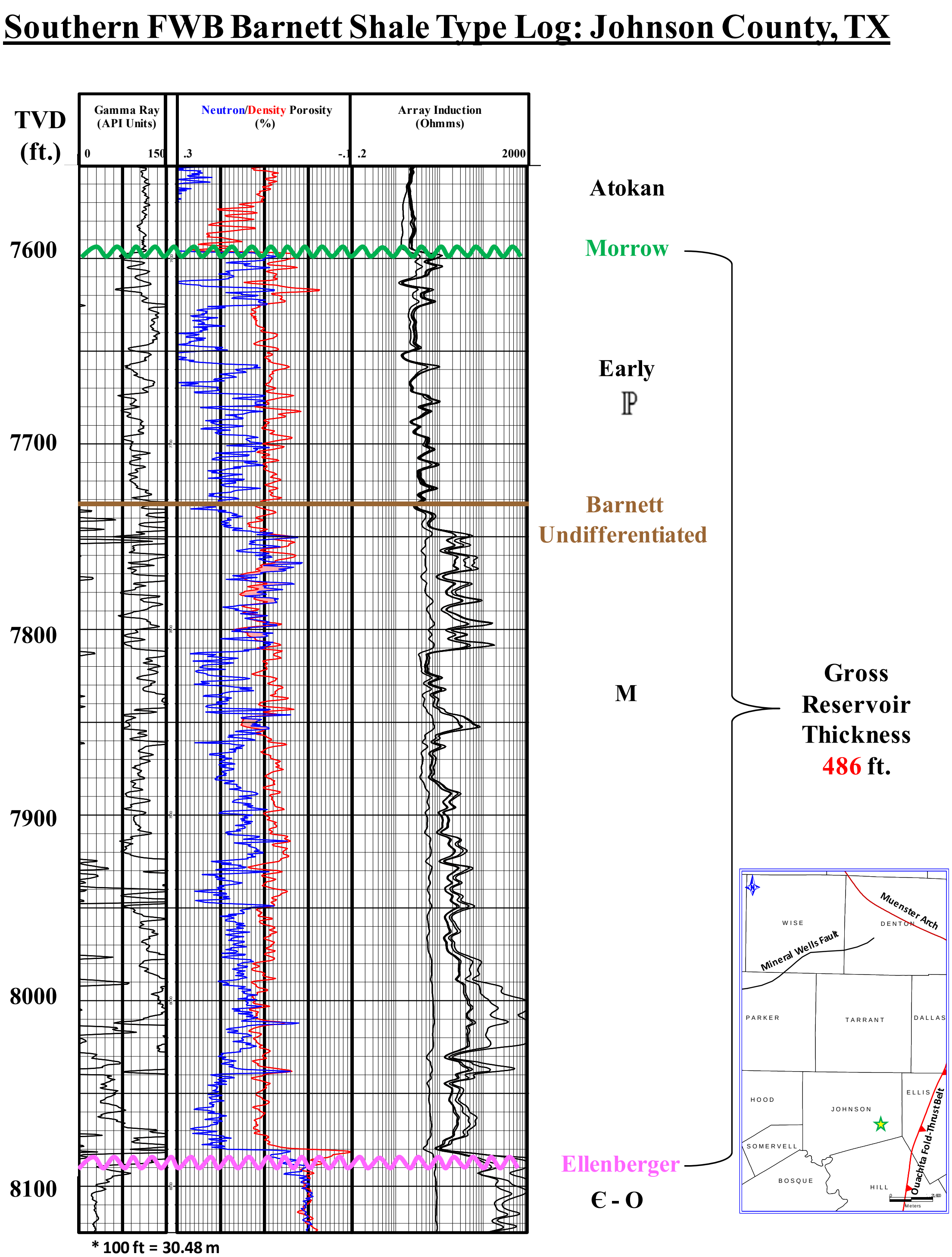


Figure 7. Type log of the gross reservoir illustrating mostly organic rich shale in the southern region of the FWB.

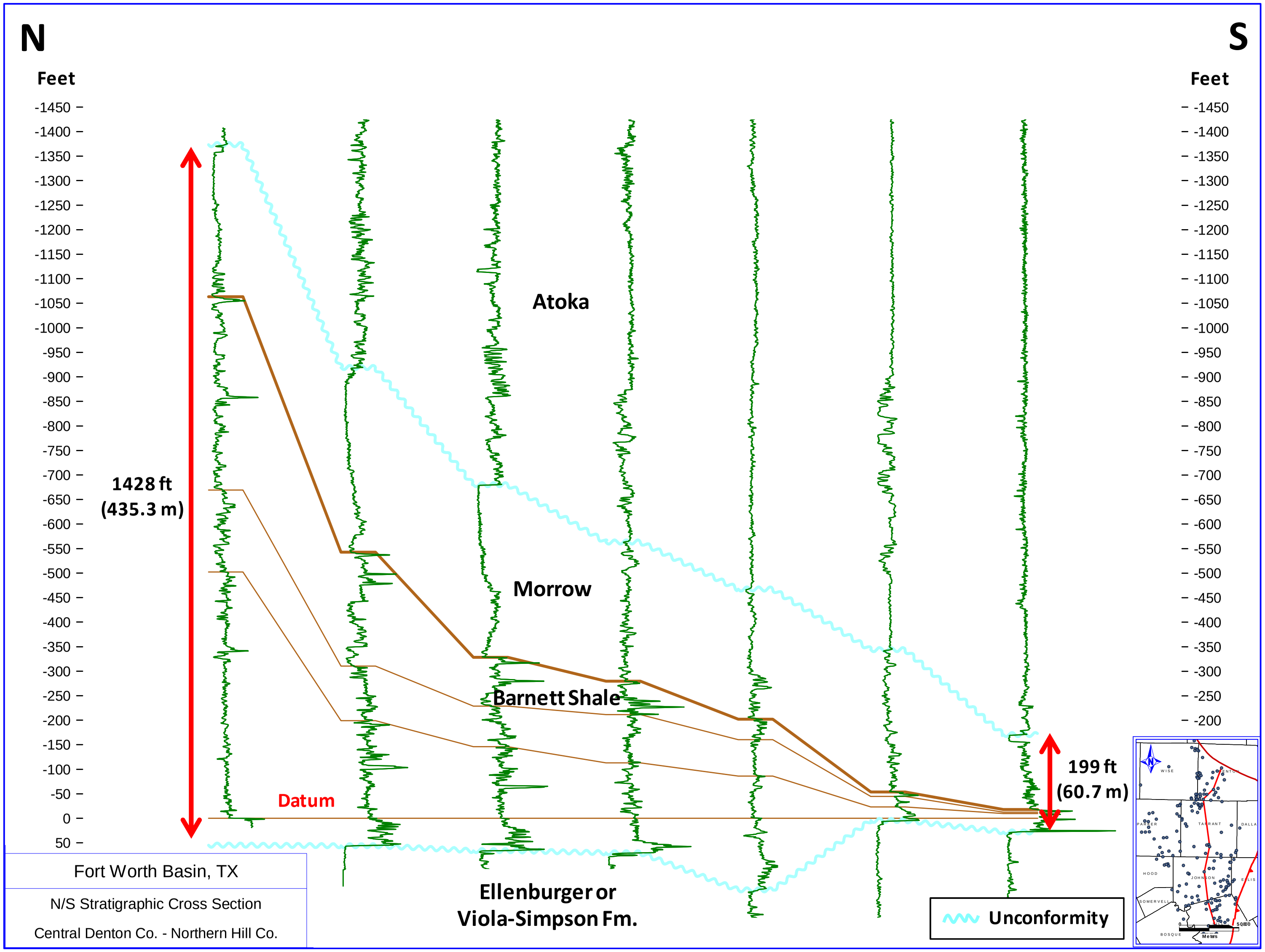


Figure 8. Chronostratigraphic cross section illustrating thinning of the gross reservoir from north to south across the study area (~ 135 kilometers).

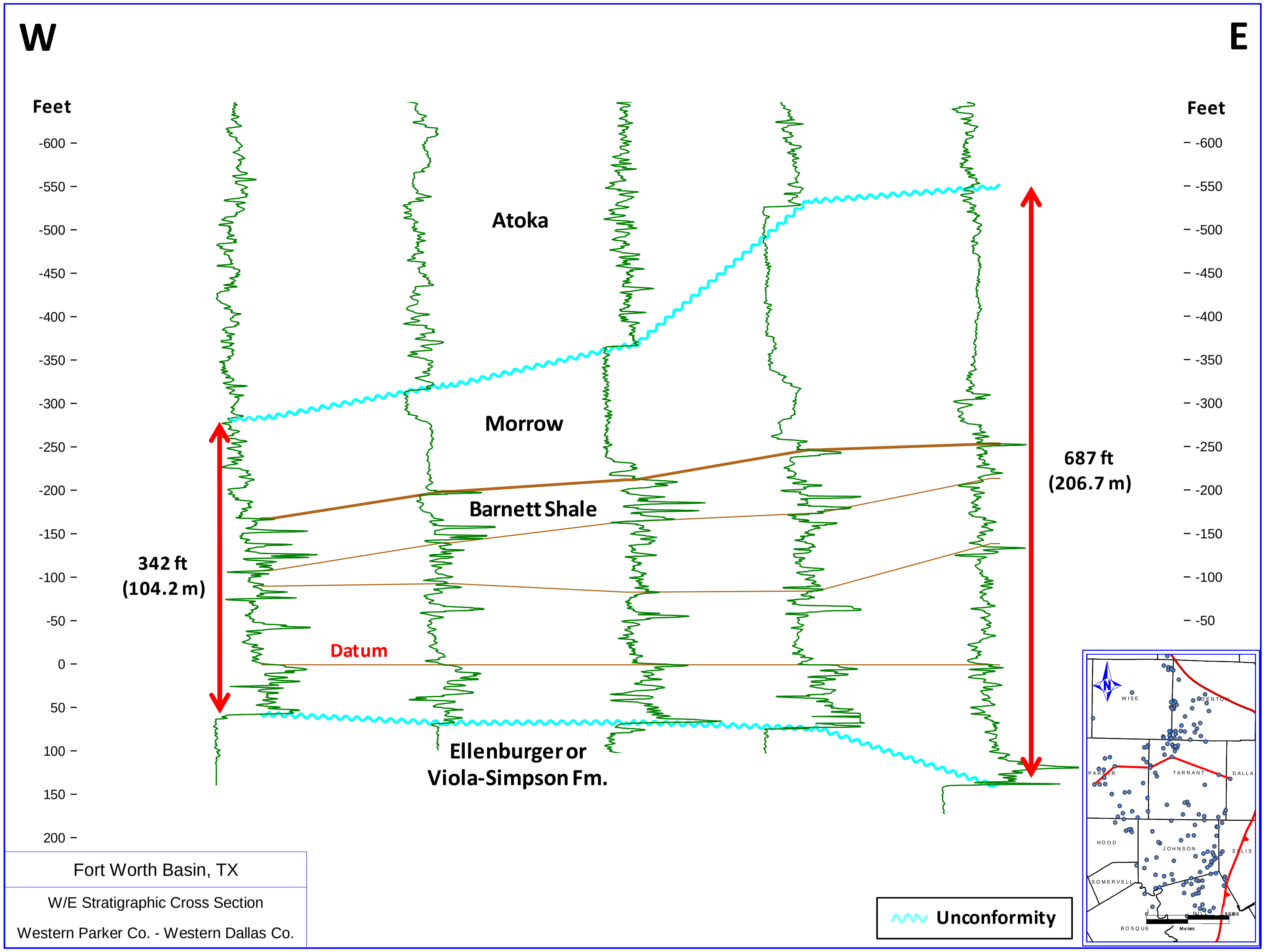


Figure 9. Chronostratigraphic cross section showing thickening of the gross reservoir from west to east across the study area (~ 84 kilometers).

Facies Analysis

Classification of facies in this study is general due to the size of the study area and scale of the research. The facies analysis relies mainly on correlations between gamma ray logs, identified flooding surfaces, and implementation of Walther's law. XRD data from ten wells and geochemical analyses identifying TOC from four wells were used to supplement classifications of depositional environments from log analyses and help construct a reservoir model. Description of mineralogic variability between facies is explained in further detail below.

Facies Belts

Geophysical logs across the Barnett Shale and Morrowan stratigraphic section, XRD data, and TOC analyses suggest the presence of three different facies belts associated with the gross reservoir interval in the FWB: 1) shelf margin carbonates, 2) slope carbonates, and 3) basinal organic-rich shale (Figure 10). The basinal organic-rich shale facies includes the condensed shale (not identified as a separate facies). The XRD and geochemical data taken from 47 rotary sidewall cores are averaged across each facies to illustrate changes in mineralogic composition and organic content throughout the gross reservoir. Total gas measured from each core is plotted to illustrate changes in gas content relative to stratigraphic interval, TOC, and depth. Transitions from third order sequences (Slatt and Abousleiman, 2011) (orange arrows) are annotated to illustrate episodic shoaling-upward sequences following flooding events throughout deposition of the gross reservoir interval.

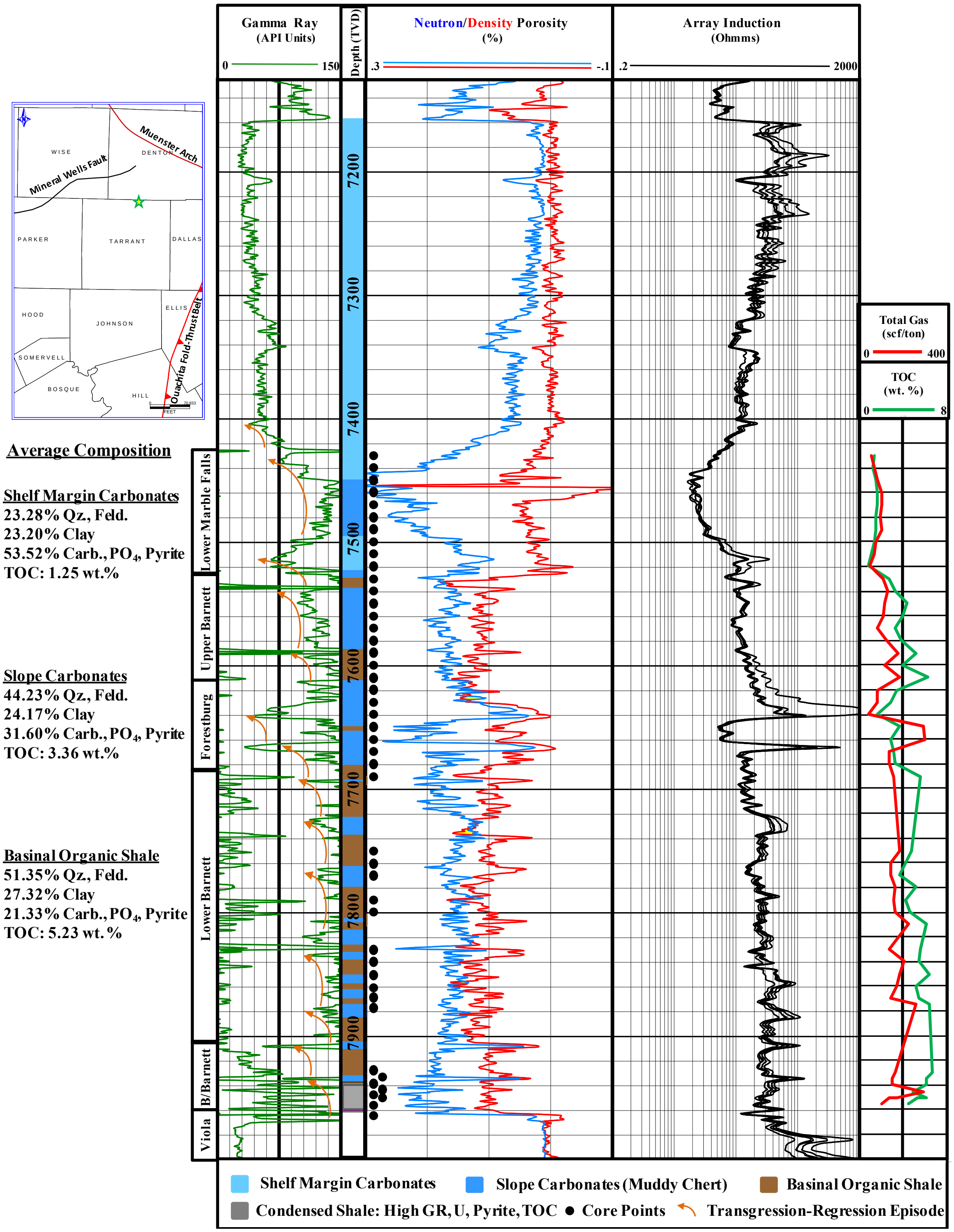


Figure 10. Composite plot relating geophysical logs, facies, and rotary sidewall core data across the gross reservoir interval.

The shelf margin carbonates facies only exists where the Marble Falls Formation is present in the FWB. Low gamma ray response, high carbonate content, and low TOC defines this facies. According to core data, this facies contains the least amount of quartz and feldspar, clay, and TOC of the three identified. Carbonate, phosphate, and pyrite content are highest (nearly all is carbonate). The shelf margin carbonate facies in the Lower Marble Falls is bound by the slope carbonates facies. Shelf margin carbonates associated with the Upper Marble Falls interval are bound by slope carbonates at the base and an erosional unconformity at the top. The only well that contains core data in the Marble Falls Formation is located in north-central Tarrant County.

The slope carbonate facies is present at the end of transgression-regression cycles when bound by the basinal, organic-rich shale facies or at the beginning of a transgression-regression cycle when underlain by shelf margin carbonates. Gamma ray response is less than 100 API units. Average quartz and feldspar, clay content, and TOC are greater than the shelf margin carbonates and less than in the basinal, organic-rich shale facies. Together, carbonate, phosphate, and pyrite composition in the slope carbonates is typically less than that of the shelf margin carbonates and greater than the basinal, organic-rich shale facies.

The organic-rich shale facies is identified at the beginning of transgressive-regressive cycles. The facies is bound by slope carbonates, and gamma ray response is typically greater than 150 API units. The basinal organic shale facies typically contains the greatest amount of quartz and feldspar, clay, and TOC and the least amount of carbonate, phosphate, and pyrite. Gas content is also typically highest in the organic-rich shale.

Mineralogic Variability

While the Barnett Shale is a continuous reservoir that can be mapped across the entire FWB, XRD analyses of core samples taken from the most productive regions of the play (Figure 11) suggest widespread mineralogic variability and complexity in the shale. Ternary diagrams display XRD data from ten Barnett Shale wells, five of which also contain cores from the Morrowan section (Figures 12-22). Quartz and feldspar comprise one ternary end member, clays encompass the second, and carbonate, phosphate, and pyrite incorporate the third. The ternary diagrams of this study indicate a high degree of mineralogic heterogeneity across the FWB but also suggest regional mineralogic similarities and trends.

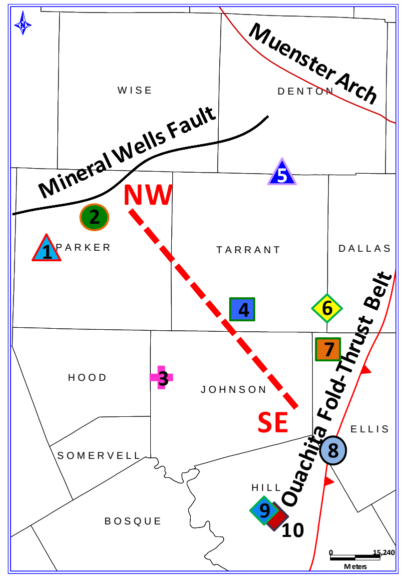
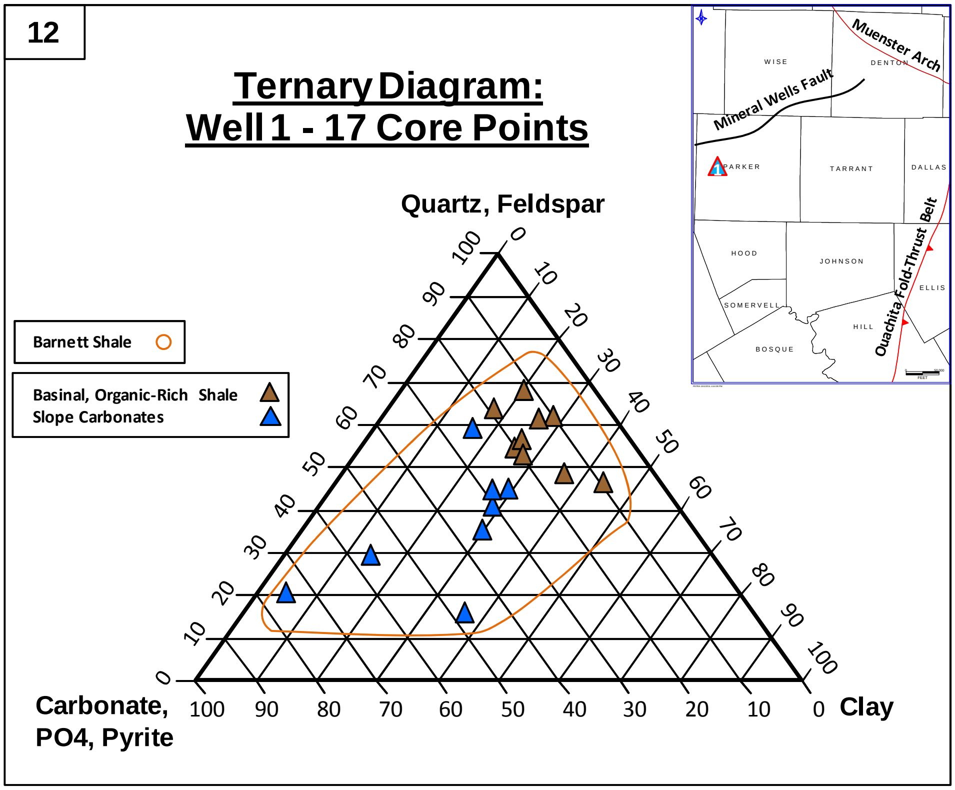


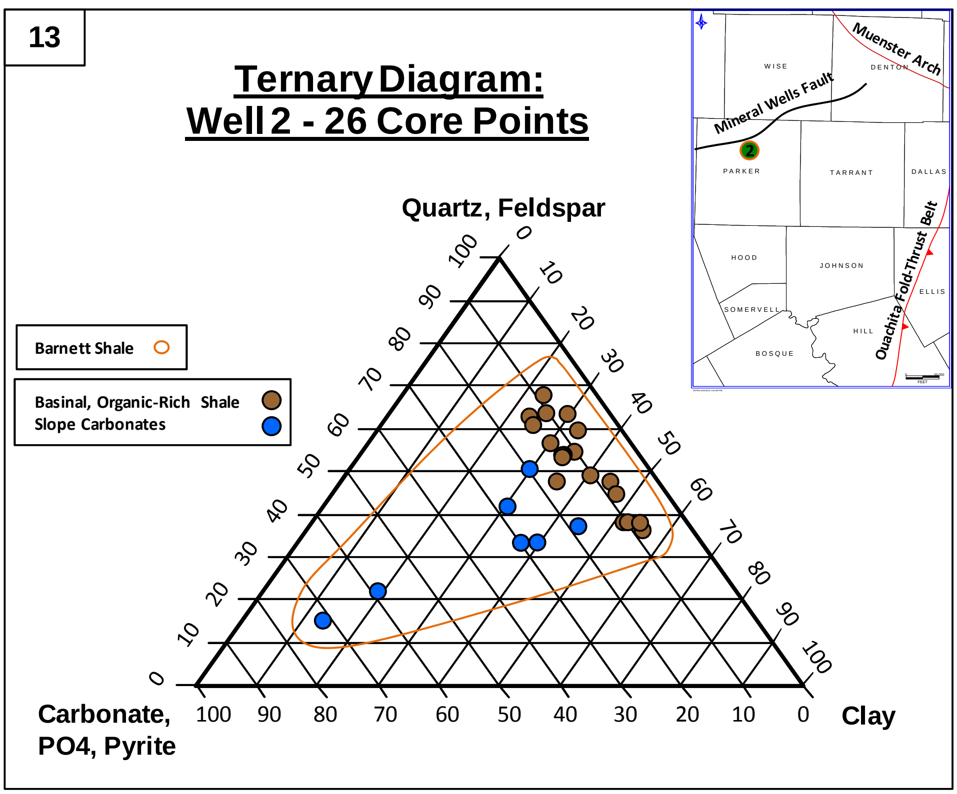
Figure 11. Location map identifying cored wells with XRD data.

The mineralogic composition of wells sampled along the Ouachita thrust front (wells 6, 7, 8, 9, and 10) reveals that the quartz/feldspar and clay content are particularly high in both the slope carbonates and basinal organic shale facies. Cores extracted from slope carbonates and basinal organic-rich shale facies are compositionally very similar in the Marble Falls equivalent and Barnett Shale. Clay content is the dominant composition in three of the five wells (wells 6, 7, and 9). Of these five wells, none of the cores contained greater than 30% of the third end member, carbonate, phosphate, and pyrite.

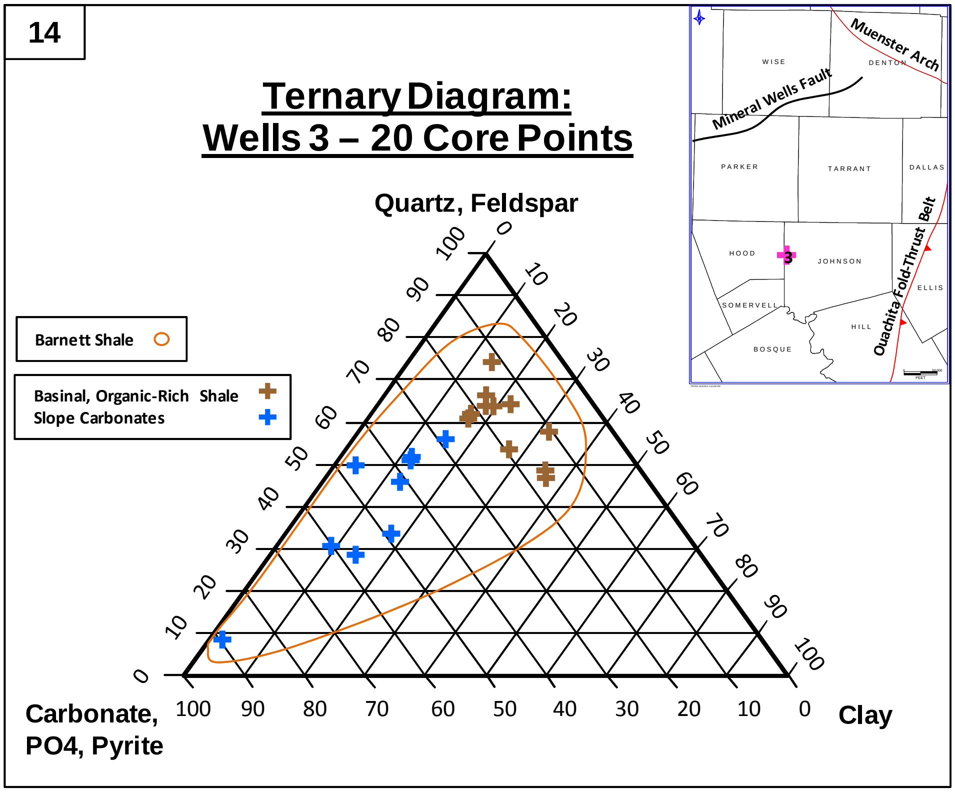
Westward of the five wells sampled along the Ouachita thrust belt, the average clay content decreases, while silica and carbonate mineralogy both increase. The slope carbonates facies is more prevalent in the Barnett Shale in wells 1-5. Mineralogic heterogeneities between slope carbonates and basinal organic-rich shale are also more apparent. With exception to the three wells with high clay content along the Ouachita thrust front, silica (quartz and feldspar) is the dominate mineralogy observed facies comprising the Barnett Shale. Average silica concentrations from cores extracted from the Barnett Shale are highest in western Johnson County (well 3), south-central Tarrant County (well 4), and north-central Tarrant County (well 5).

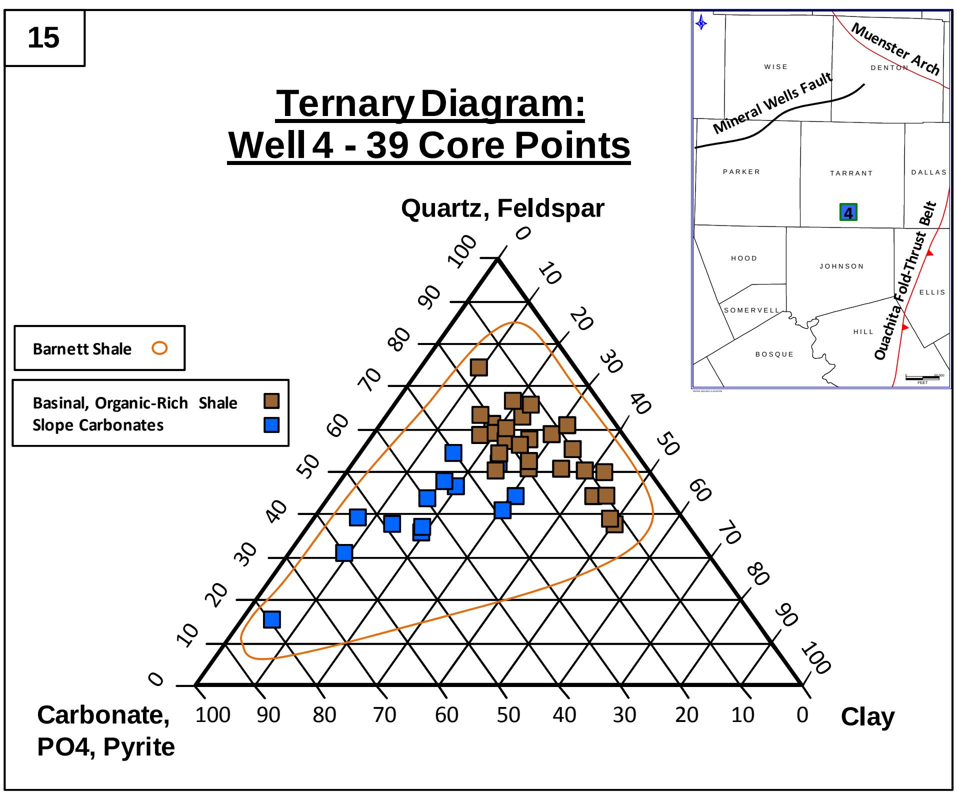
Carbonate, phosphate, and pyrite content is the least dominate group in the Barnett Shale according to XRD data. However the concentration of this group in the gross reservoir, which is mostly attributed to carbonate content, does increase from south/southeast to north/northwest in the FWB. Unfortunately, XRD analyses from the northern extent of the FWB (Wise and Denton counties) were not available for this study. The north-south cross section of the gross reservoir in Figure 8 illustrates how carbonate content in the gross reservoir increases north towards the Muenster arch. A ternary diagram of all 241 core points from the 10 wells is shown in Figure 22. The general compositional trend from carbonate to silica to clay dominance running northwest to southeast is shown in red.



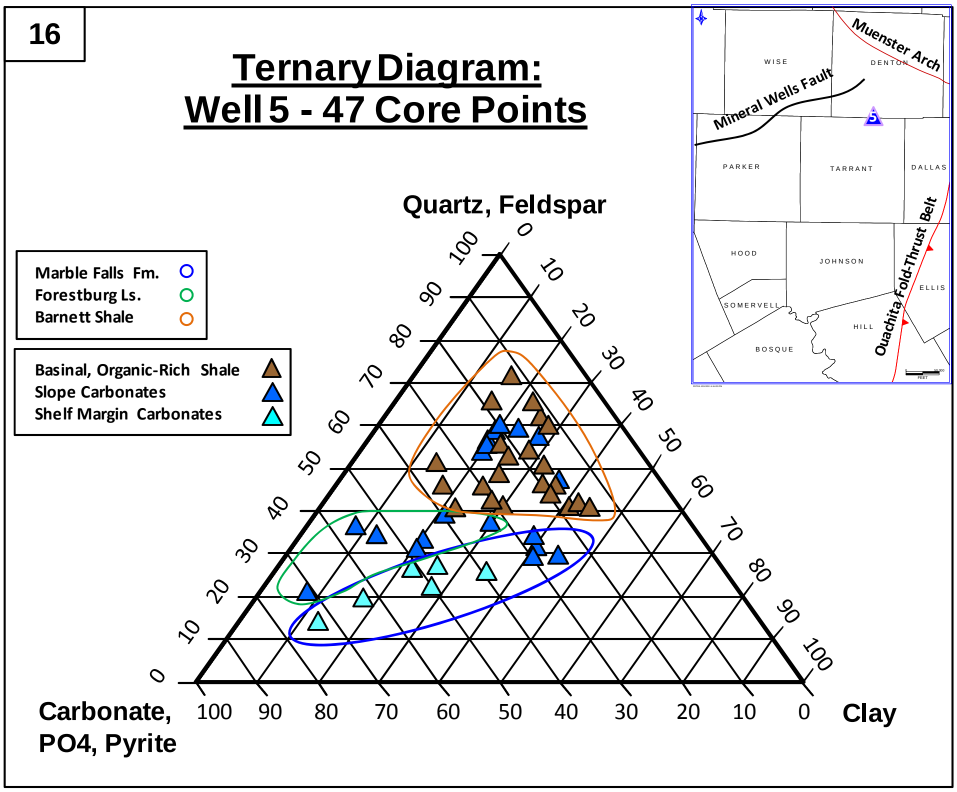


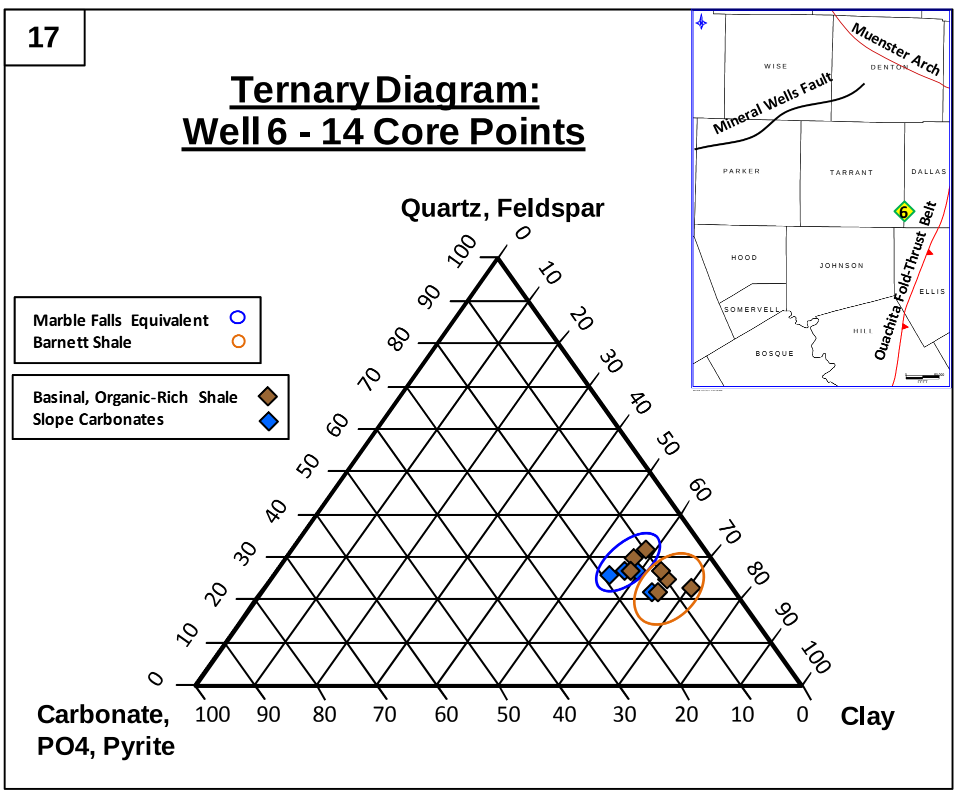
Figures 12. & 13. Mineralogic ternary diagrams of the Barnett Shale from two wells in Parker County.



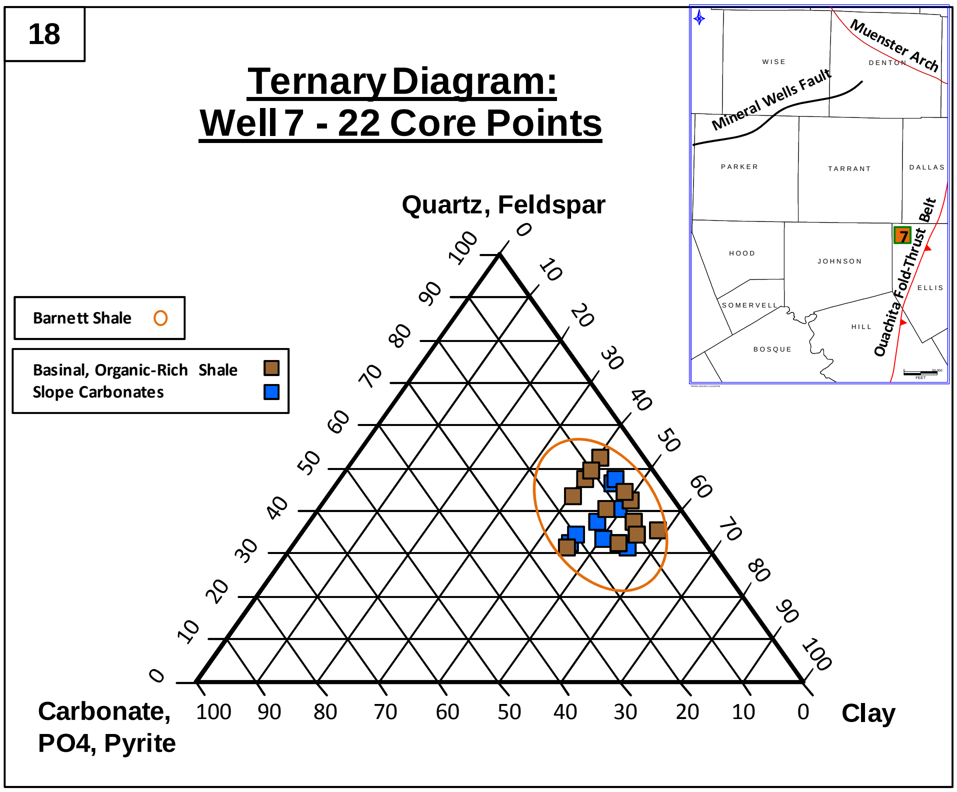


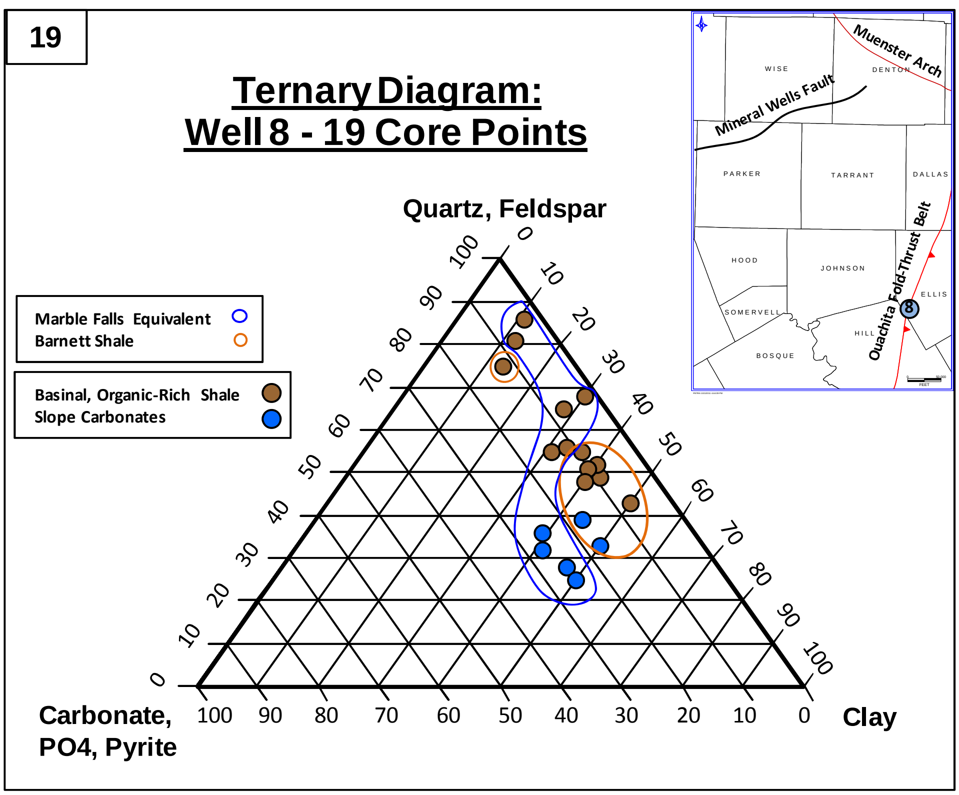
Figures 14. & 15. Ternary diagrams showing mineralogic composition of the gross reservoir from wells in western Johnson and south-central Tarrant counties.



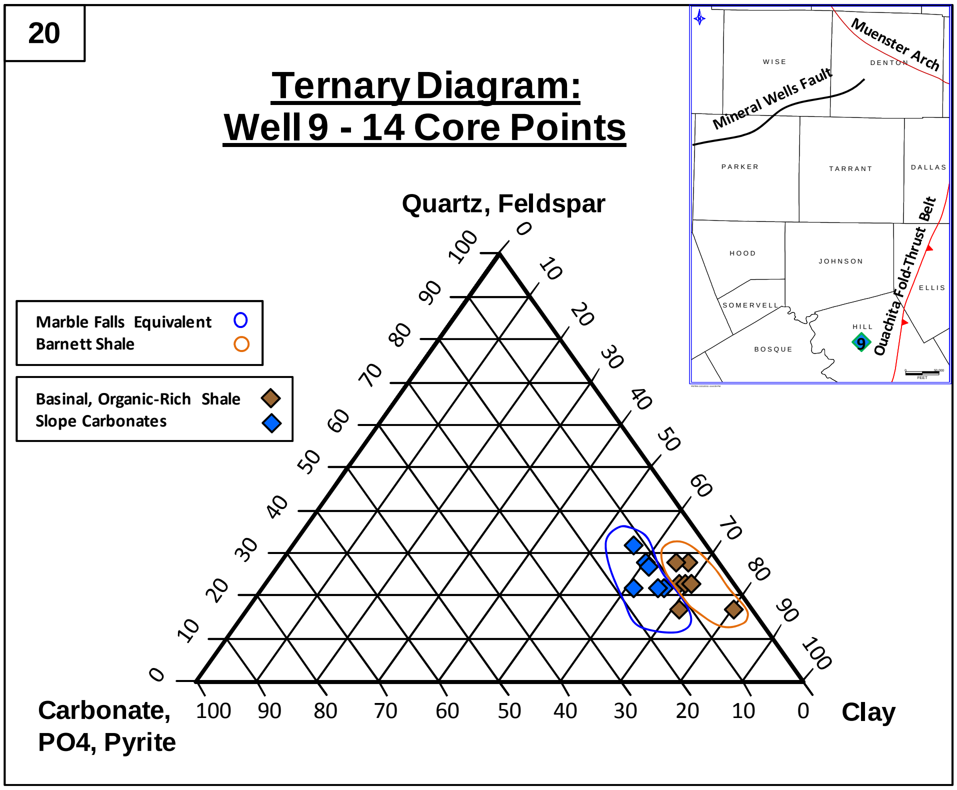


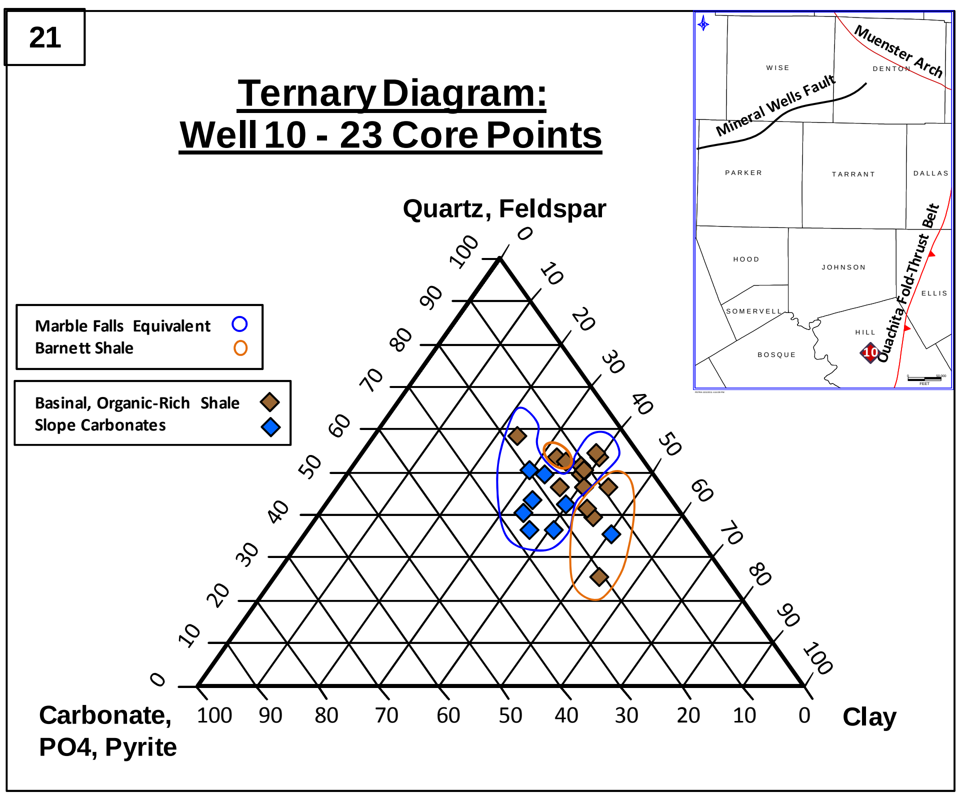
Figures 16. & 17. Ternary diagrams showing mineralogic composition of the gross reservoir from north-central and southeastern Tarrant County.





Figures 18. & 19. Mineralogic ternary diagrams of the gross reservoir from wells in northwestern and southwestern Ellis County.





Figures 20. & 21. Ternary diagrams showing mineralogic composition of the gross reservoir from wells in northern Hill County.

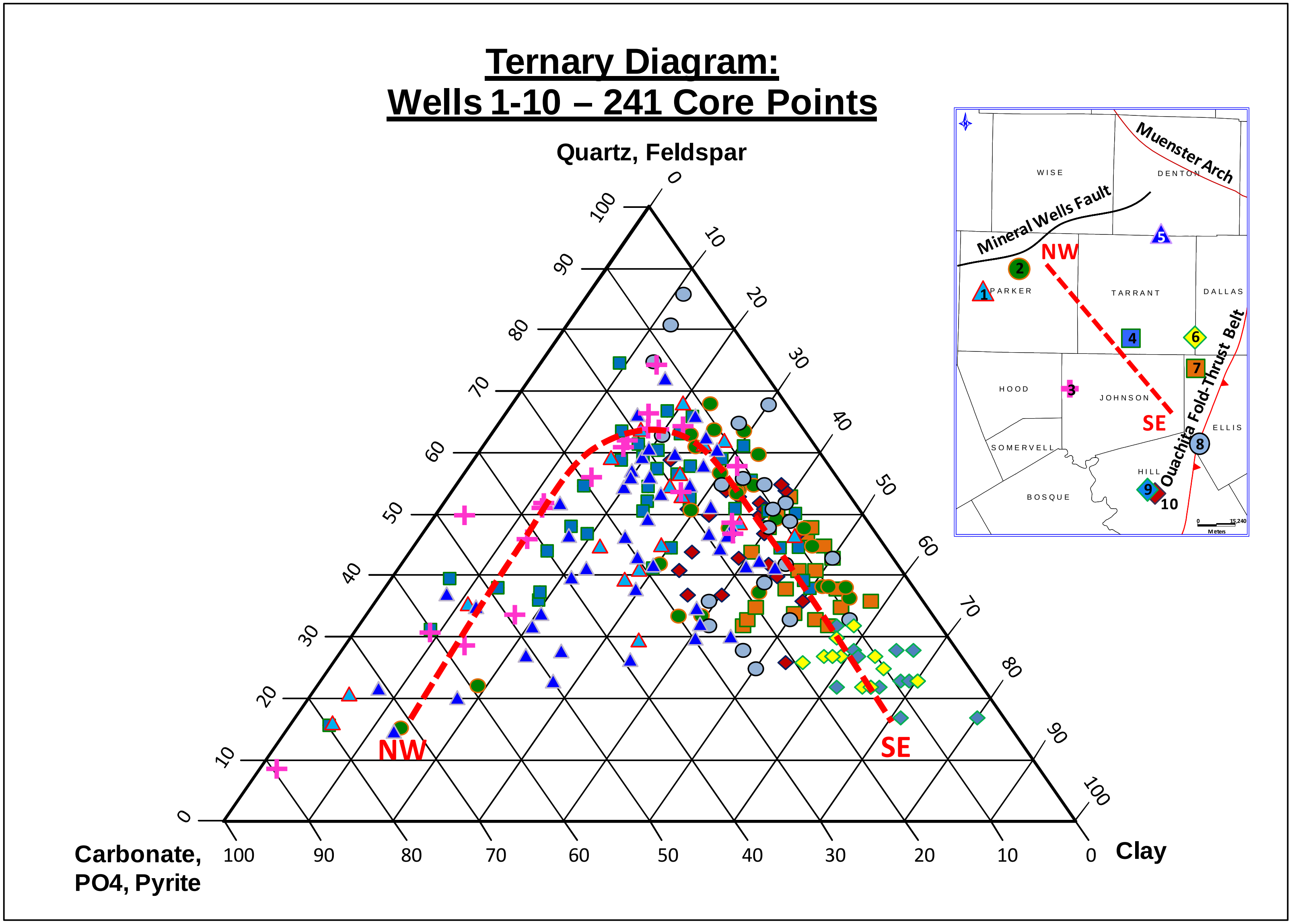


Figure 22. Ternary diagram of all 241 core points illustrating regional shifts in dominant mineralogic composition from northwest to southeast across the FWB.

Reservoir Model

The proposed reservoir model of the Mississippian-Morrowan section extends from central Denton County to southwestern Ellis County (Figure 23). This model is generalized due to the scale of the cross section (approximately 120 km). The diagram depicts a maximum flooding surface (mfs) as the top of a transgressive systems tract (TST) where an erosional unconformity in the platform carbonate sequence (base of TST) is overlain by high gamma ray shale on the cross section. This flooding surface not only represents the datum for each cross section, but also the first Mississippian deposits of sediment and organic material that comprise the basal Barnett Shale overlying older Paleozoic strata (Ellenburger or Viola-Simpson Formations).

A second order highstand systems tract (HST) representing Mississippian to Early Pennsylvanian deposition (excluding the basal Barnett Shale) overlies the TST. Third order sequences are present within the second order HST. The sequences are defined by high gamma ray shale overlain by “decreasing-upward” gamma ray. General sequences are marked by the mfs in the reservoir model. The Morrowan section above the Barnett Shale marks the top of the HST where sea level fell, resulting in another erosional unconformity. The episodes depositing the organic shale strata above the mfs are interpreted as minor transgressions during larger-order progradation.

According to the reservoir model, the basinal, organic-rich shales facies are more prominent towards the southern fringe of the FWB. In the northern region of the FWB the slope carbonates are overlain by shelf margin carbonates, the Upper and Lower Marble Falls. The shelf margin facies thin southward from Denton County until grading into slope carbonate deposits overlying organic-rich shale.

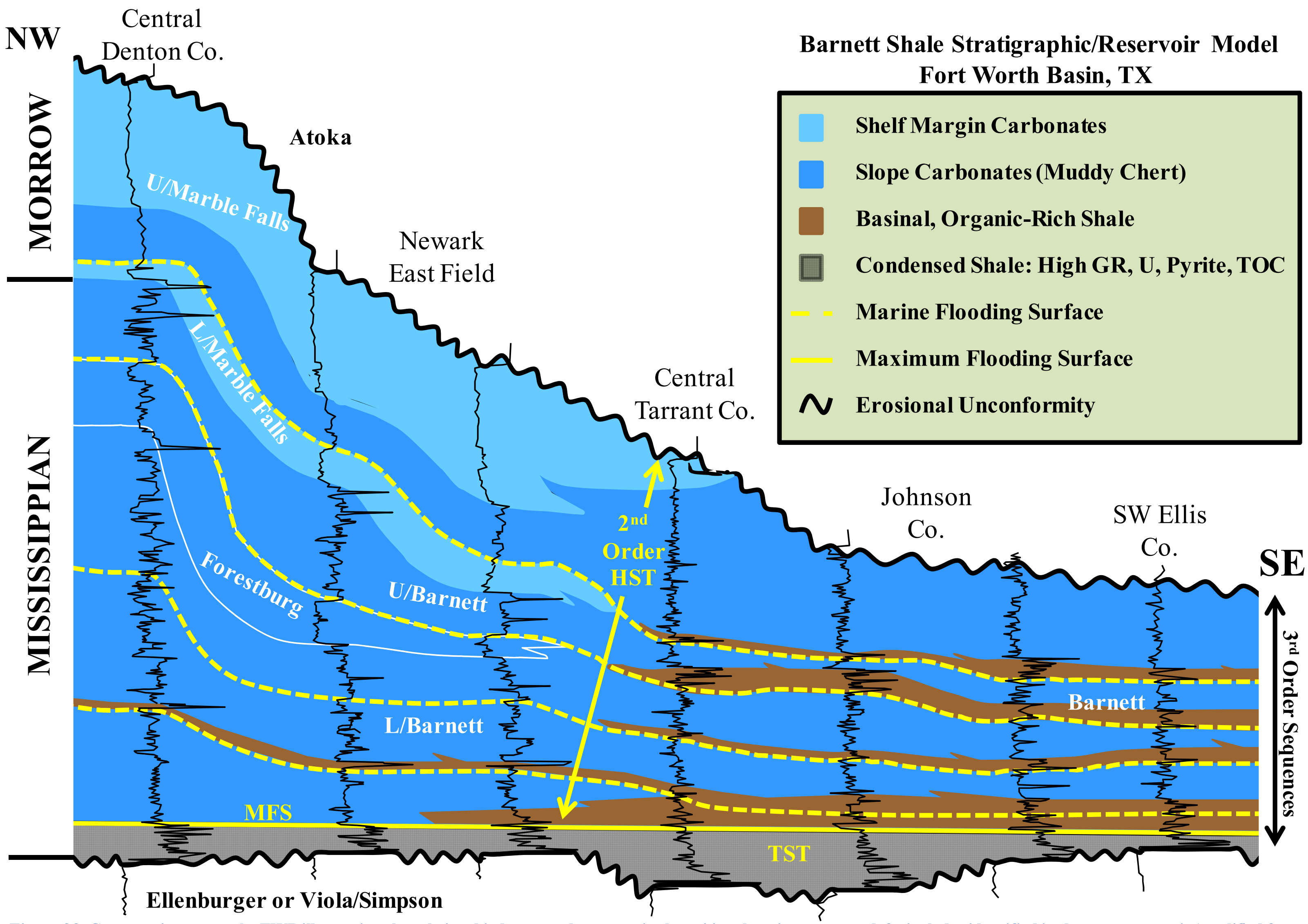


Figure 23. Cross section across the FWB illustrating the relationship between the reservoir, depositional environment, and facies belts identified in the gross reservoir (modified from Emery, 2009). Abbreviations include: GR (gamma ray), U (uranium), HST (highstand systems tract), MFS (maximum flooding surface), and TST (transgressive systems tract).

Facies time-slice maps illustrate interpreted facies across the FWB during the Early Mississippian, Middle Mississippian, and Early Pennsylvanian (Figures 24, 25, and 26). The largest accumulation of organic-rich sediment blanketed the entire FWB during the first major transgression in the Early Mississippian. It is important to note that the basal Barnett Shale (illustrated by this major transgression) is the only interval that can be consistently correlated throughout the entire study area. Facies time-slice maps during the Middle Mississippian and Early Pennsylvanian indicate depositional and erosional extents of the Forestburg limestone and Marble Falls Formation, respectively. The three maps correspond to the reservoir model shown in Figure 23.

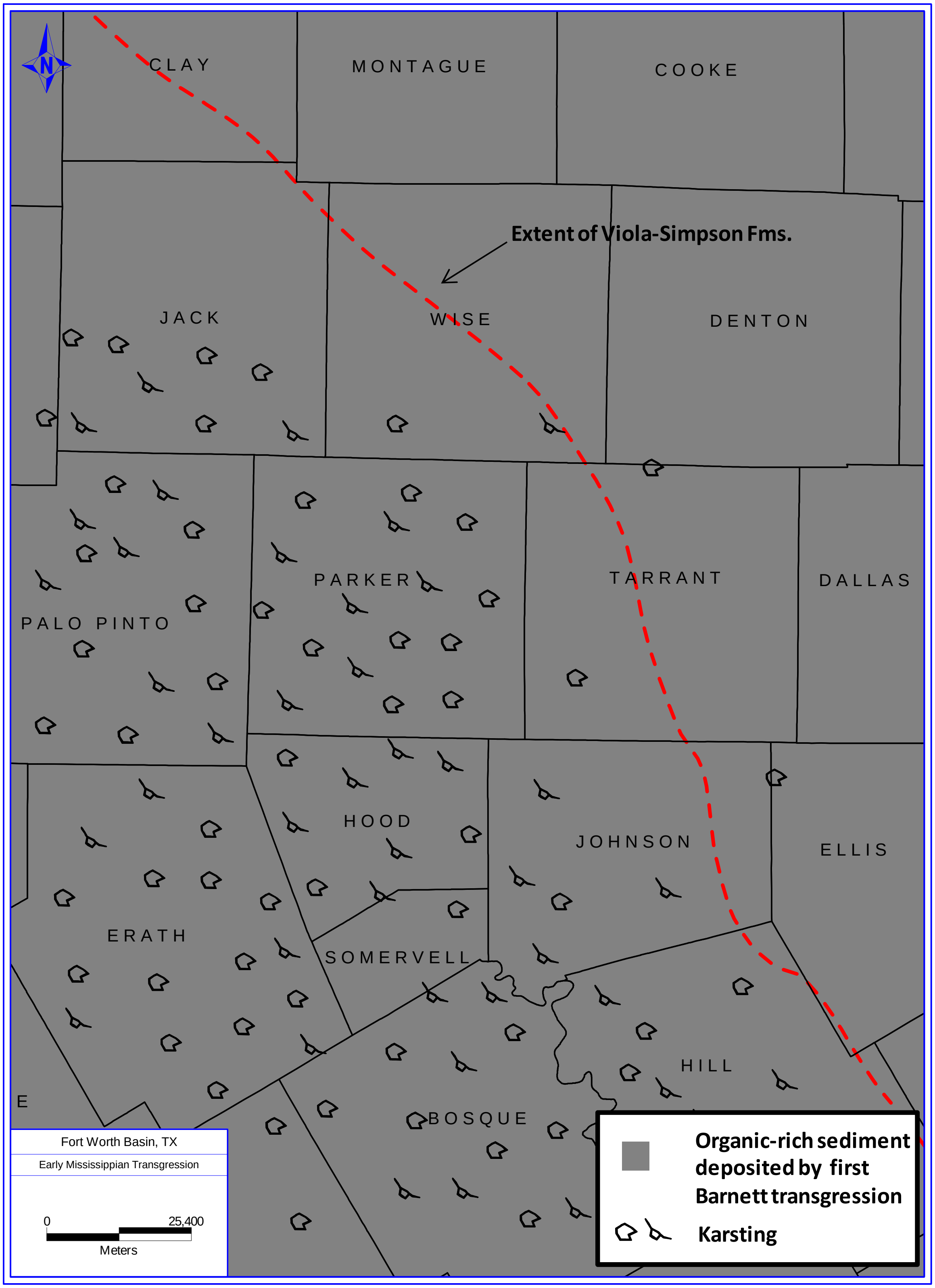


Figure 24. Early Mississippian time slice facies map illustrating first major transgression that lead to Barnett Shale deposition over the underlying Ellenburger or Viola-Simpson carbonates.

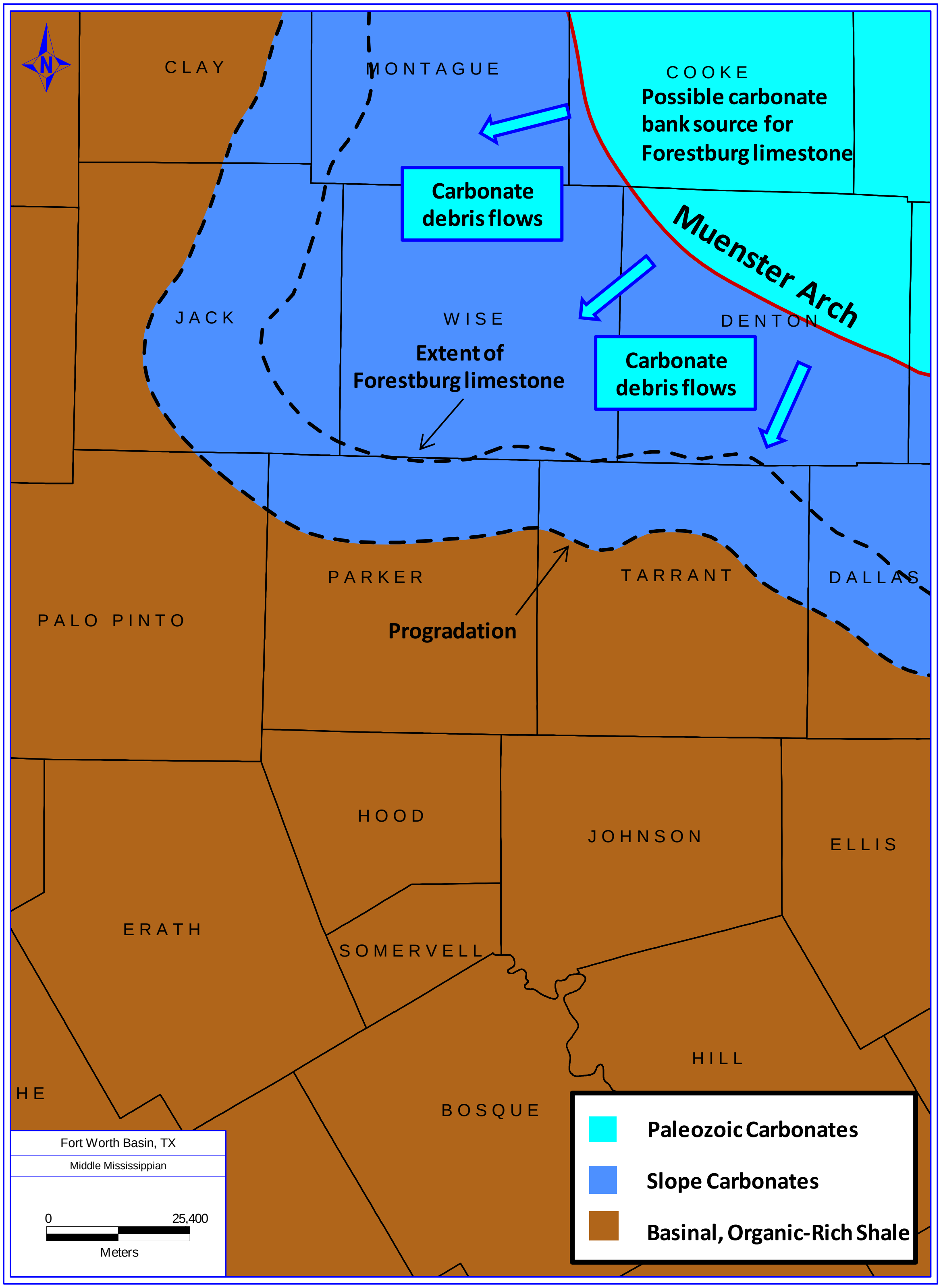


Figure 25. Middle Mississippian time slice facies map illustrating maximum progradation during Forestburg limestone deposition and the uplift of the Muenster arch.

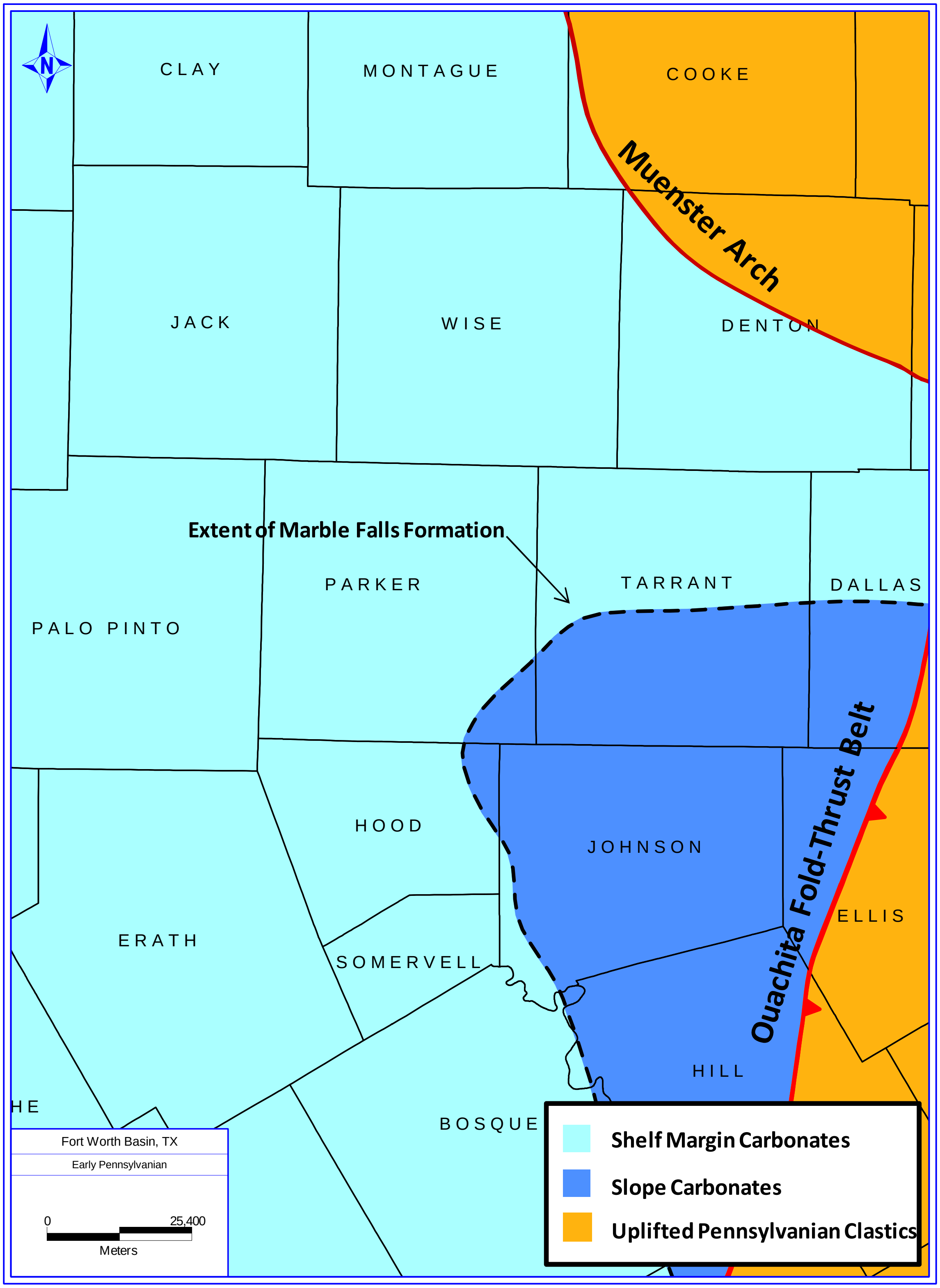


Figure 26. Early Pennsylvanian time slice facies map illustrating maximum progradation of the Marble Falls Limestone and the active uplift of the Muenster arch and Ouachita fold-thrust belt.

Reservoir Thickness

In the case of the FWB, the thickness of the gross reservoir generally increases with depth of the carbonates underlying the Barnett Shale (Ellenburger Group or Viola-Simpson Formations) (Figure 27). The Barnett Shale is deepest along the eastern and northeastern sides of the FWB proximal to the Ouachita fold-thrust belt and Muenster arch.

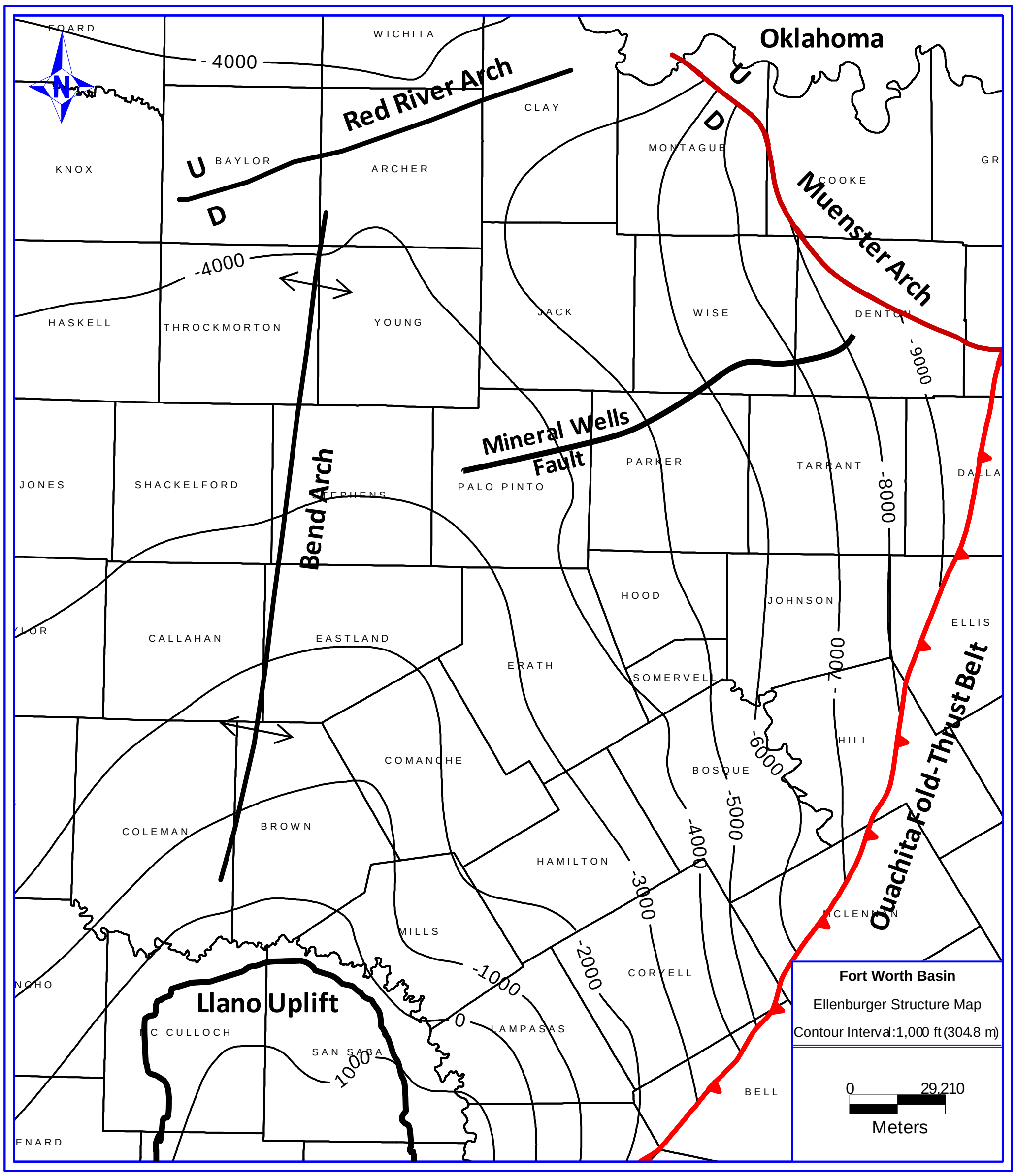


Figure 27. Ellenburger Group structure map illustrating the depths of the Paleozoic carbonates underlying the Barnett Shale (modified from Monroe and Breyer, 2011).

Thicknesses of the Barnett Shale and the gross reservoir follow similar trends as both are thickest in northern Johnson, Tarrant, Wise, and Denton counties where the Ellenburger Group is deepest (Figures 28 and 29). As the depth to the Paleozoic carbonates decreases towards the northwestern, western, and southern regions of the FWB, the thicknesses of these two intervals decrease.

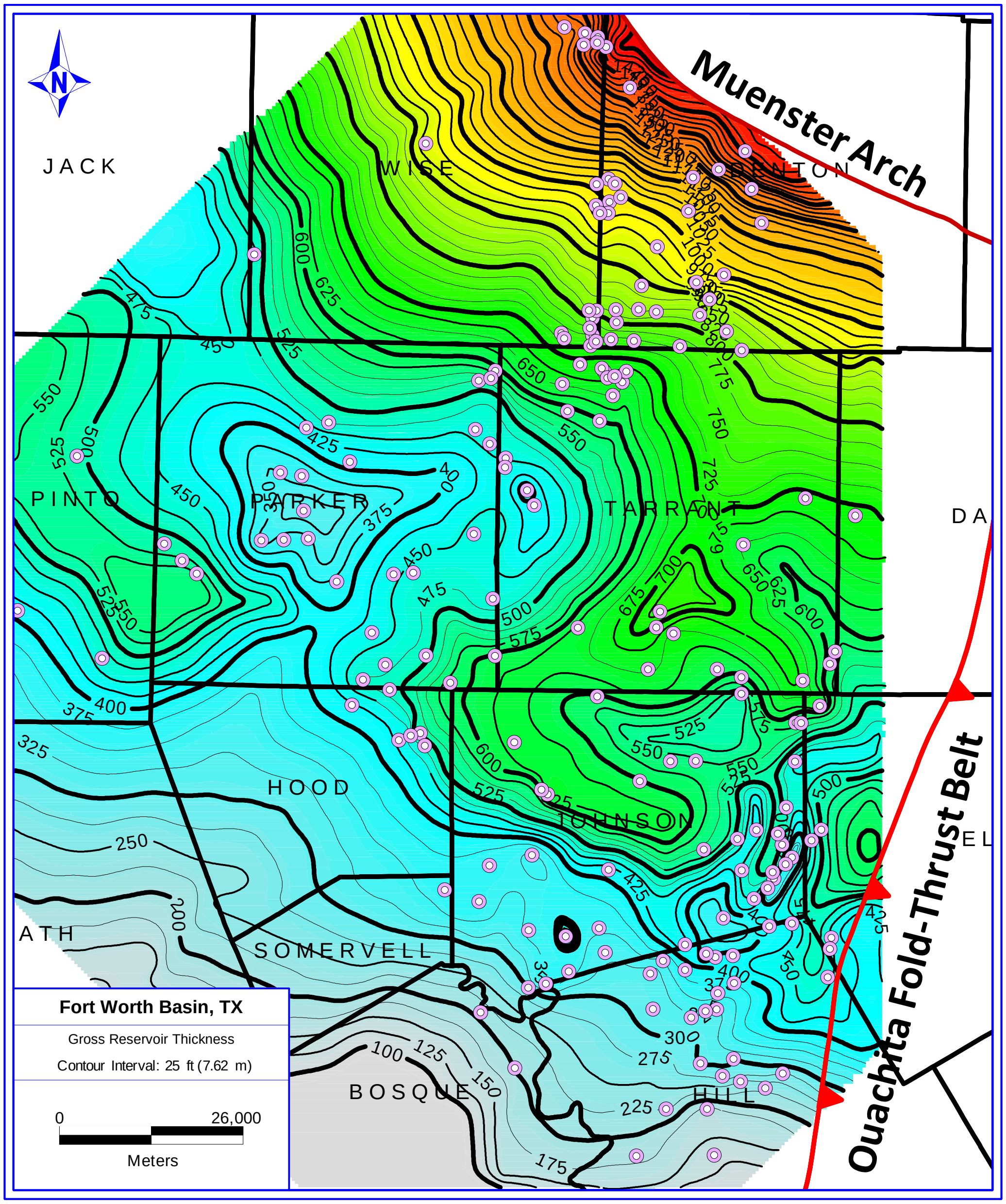


Figure 28. Isopach map created from pilot-hole well logs demonstrating thickness variability of the gross reservoir (Morrow – base of Barnett Shale).

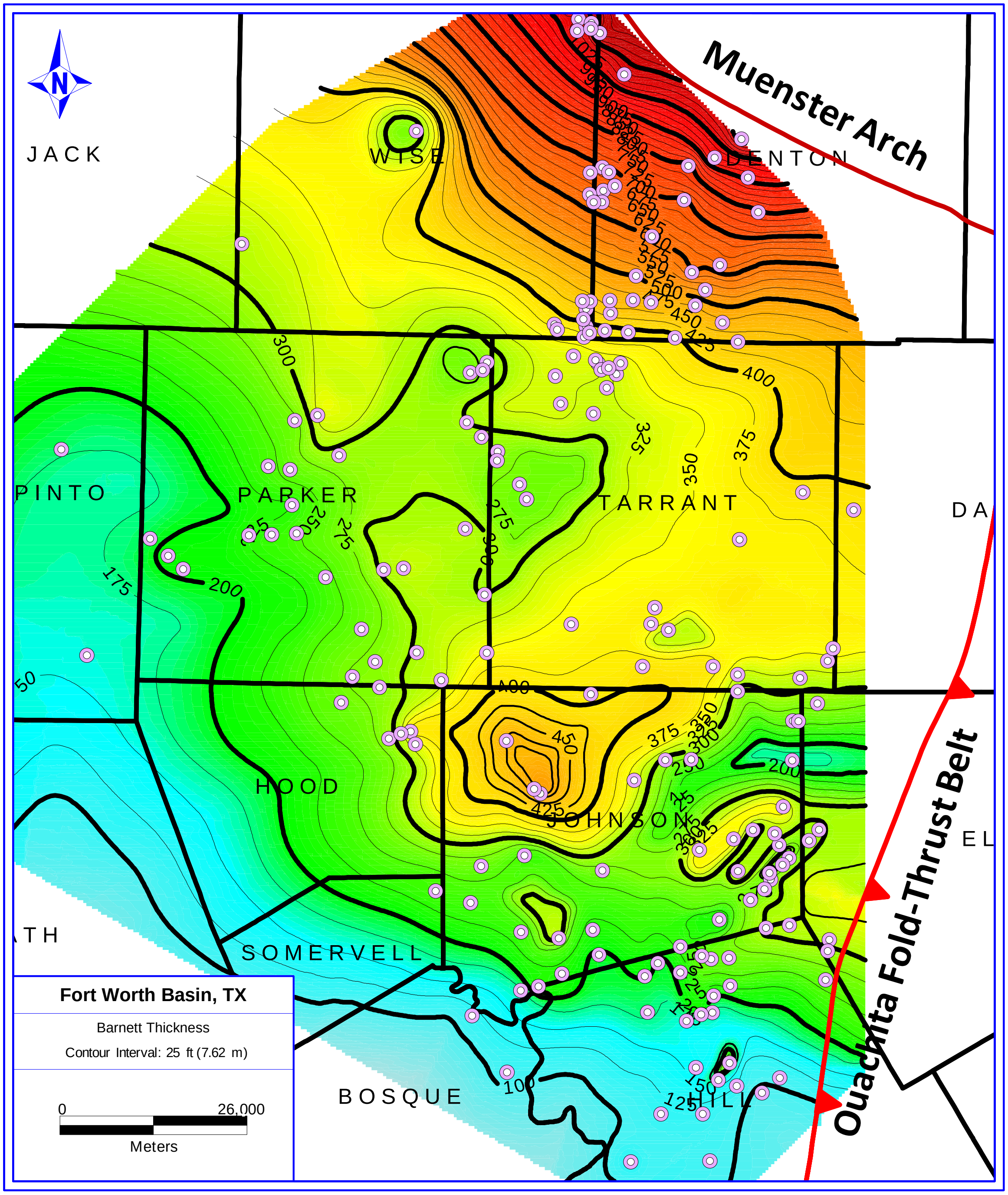


Figure 29. Isopach map generated from pilot-hole well data illustrating variable Barnett Shale thickness.

Assessing unconventional reservoirs using only gross lithofacies isopach maps is inadequate. Although mapping reservoir thickness is important, additional data add insight to comprehension of a complex reservoir like the Barnett Shale. Recognition of the reservoir potential across the FWB requires more data including but not limited to mineralogic variability, organic matter content, and geochemical characteristics. Addition of such data supports chronostratigraphic correlations and contributes to the overall evaluation of a shale play.

Net Reservoir Thickness

Thick, organic-rich intervals of the gross reservoir contribute to hydrocarbon generation and storage. Identifying the net thickness of the reservoir with respect to these organic-rich intervals is essential to regionally quantify the gross reservoir across the FWB. Gamma ray logs and geochemical analyses from cores extracted from the gross reservoir can be used to aid in this identification. Most of the gamma ray activity is due to uranium content (Breyer et al., 2011), and a positive relationship between the two should exist if the two are linked. Uranium content in shale plays like the Barnett also suggests preserved organic material, from which hydrocarbons may be derived (assuming thermal maturation).

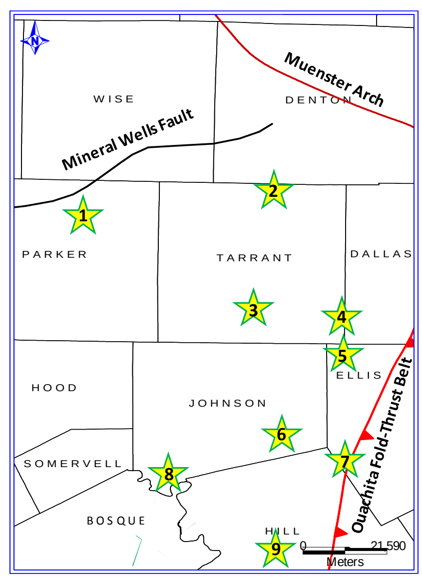
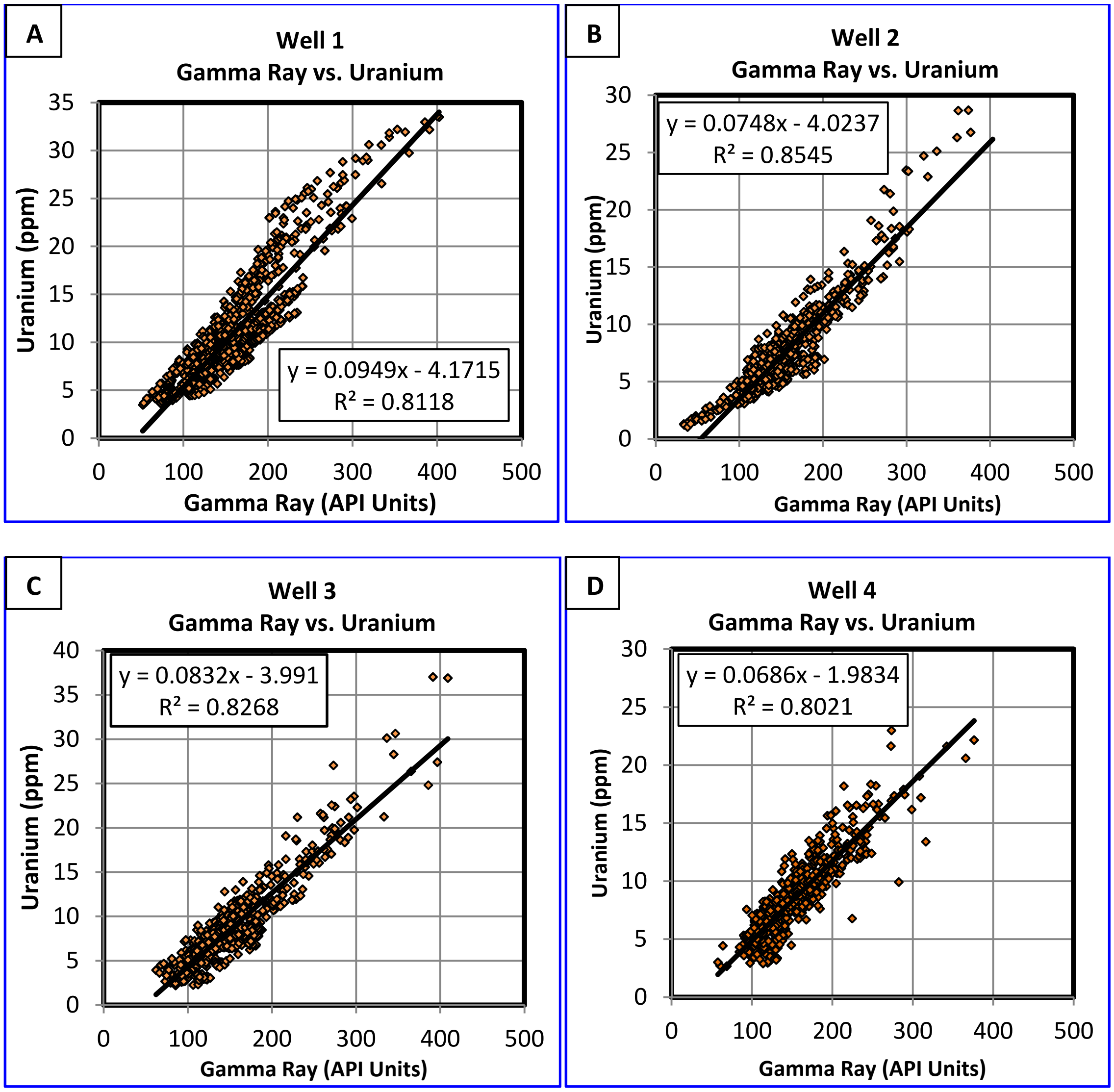


Figure 30. Map identifying wells used to compare gamma ray and uranium across the gross reservoir.

Using data obtained from standard gamma ray and spectral gamma ray logs from nine Barnett Shale pilot holes drilled in Parker, Tarrant, Ellis, Johnson, and Hill counties (Figure 30), a strong correlation exists between uranium content and gamma ray response. Cross plots of uranium (ppm) vs. gamma ray yield (API units) from the nine wells illustrate this positive relationship (Figure 31). R squared values range from 0.80 - 0.93.



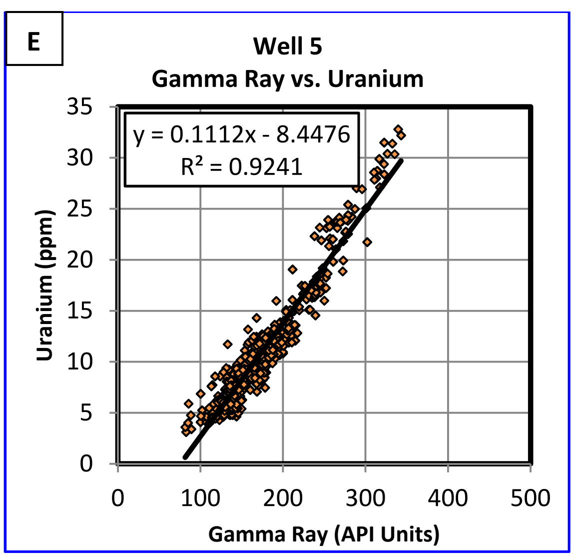


Figure 31A-E. Positive relationship between gamma ray response and uranium concentration from wells in the northern region of the study area: A) north-central Parker County, B) north-central Tarrant County, C) south-central Tarrant County, D) southeastern Tarrant County, and E) northwestern Ellis County.

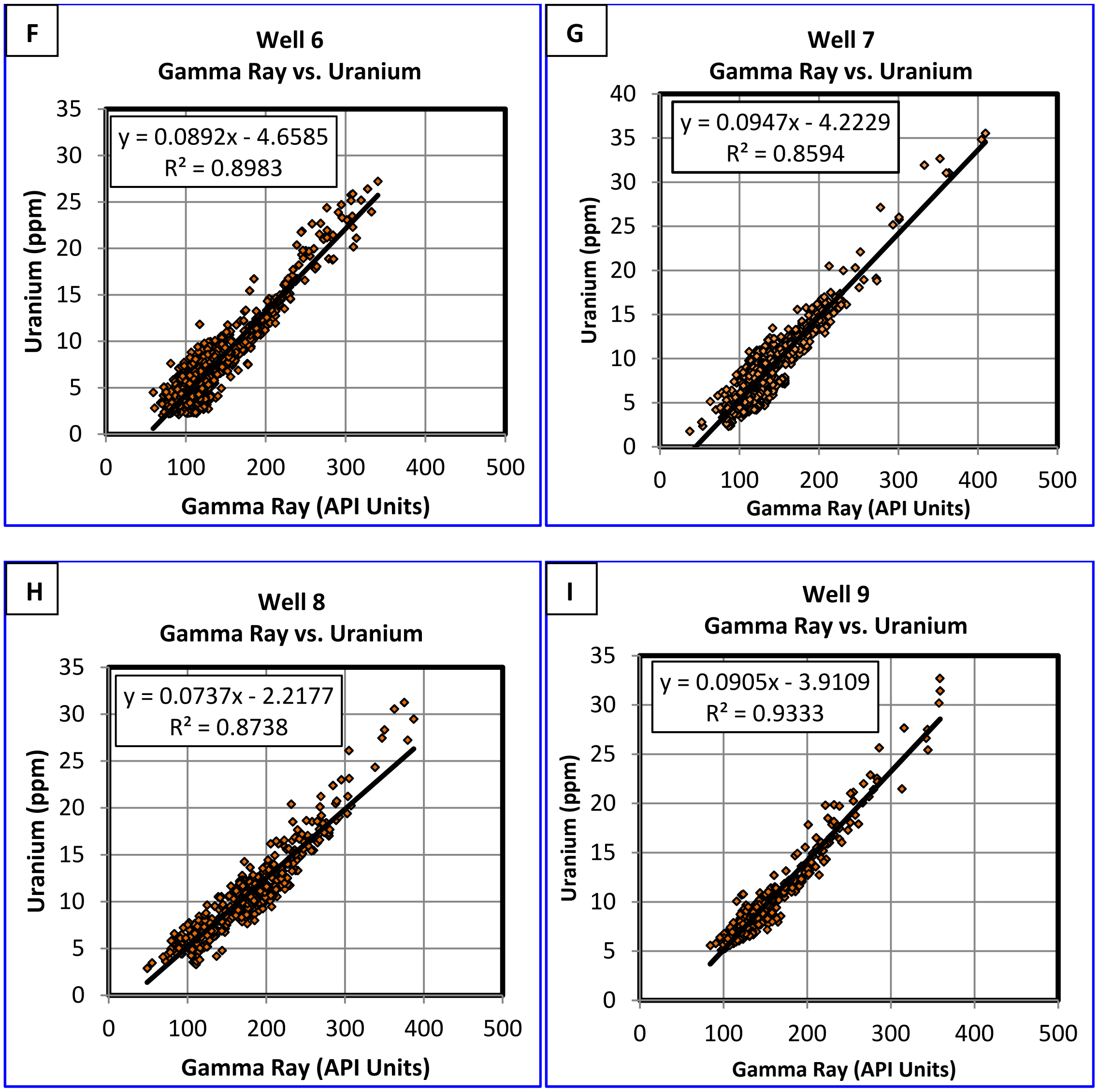


Figure 31F-I. Positive correlation between gamma ray response and uranium concentration from wells in the southern region of the study area: F) southeastern Johnson County, G) southwestern Ellis County, H) southwestern Johnson County, and I) and northern Hill County.

Four of the nine wells (2, 3, 5, and 7) above contained core data from which TOC was derived using geochemical analyses. A strong relationship between uranium and TOC does not exist in these wells (Figures 32-35). Cross plots between uranium and TOC % vol. data appears to scatter without a strong correlation; however, the data are relatively consistent in one important sense. Most core samples that contain 3-5 parts per million (ppm) uranium in the cores are also greater than ~ 4 vol. % (or ~2 wt. %) TOC, which is the baseline organic material considered a “good risk” in potential shale reservoirs (Jarvie et al., 2004). Any data points below 4 vol. % TOC are not considered source rocks in this study. Note that this lower limit for economic hydrocarbon generation does not apply to shales that source conventional reservoirs. This only pertains to unconventional plays where the target reservoir is the shale source rock itself.

Wells 2 and 7 include cores from the Marble Falls and Marble Falls stratigraphic equivalent. While all cores extracted from the Marble Falls in well 2 are not considered source rocks due to low TOC, eleven of the thirteen cores taken from the Marble Falls stratigraphic equivalent in well 7 are considered “good risk” due to their TOC. For this reason, the Morrowan section (Marble Falls Formation or stratigraphic equivalent) in the FWB was added to the Barnett as part of the identified gross reservoir.

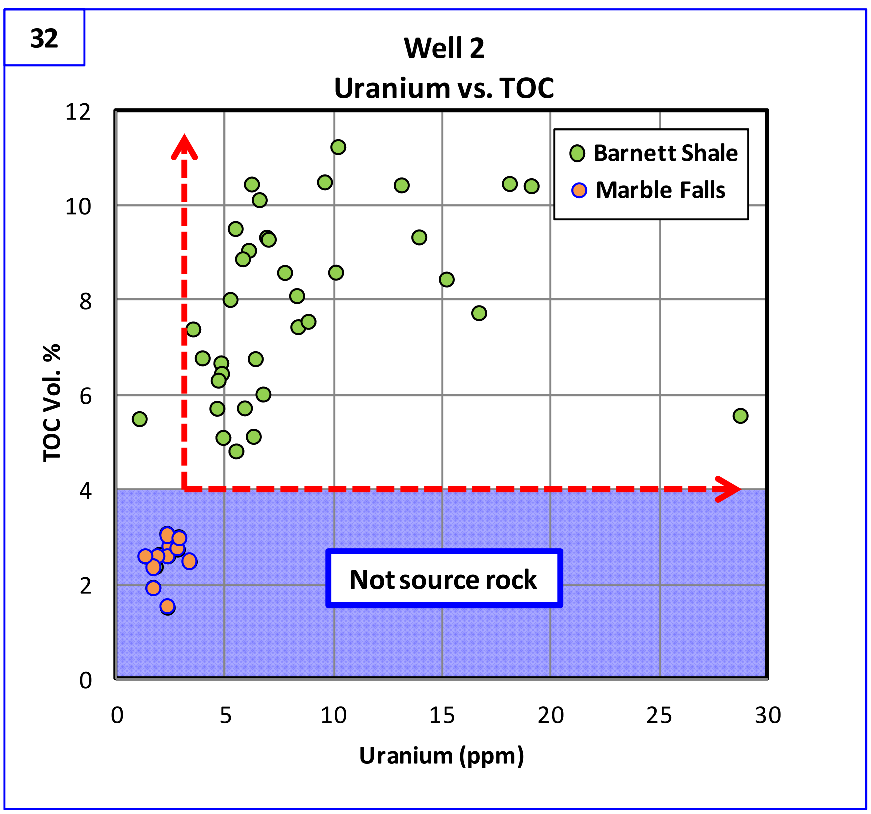
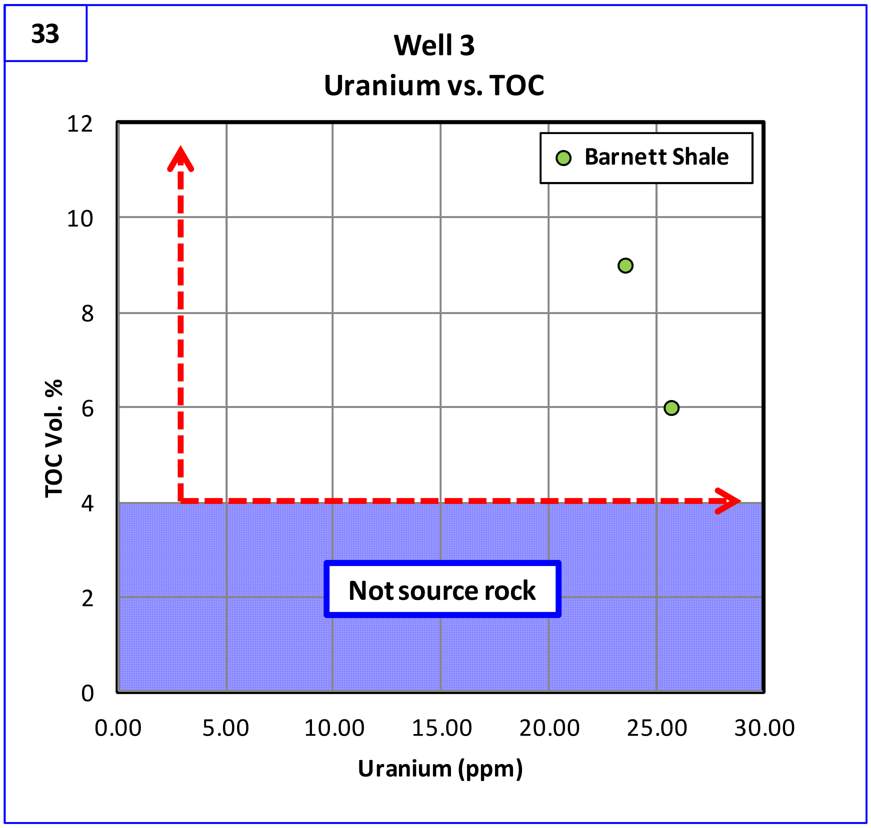
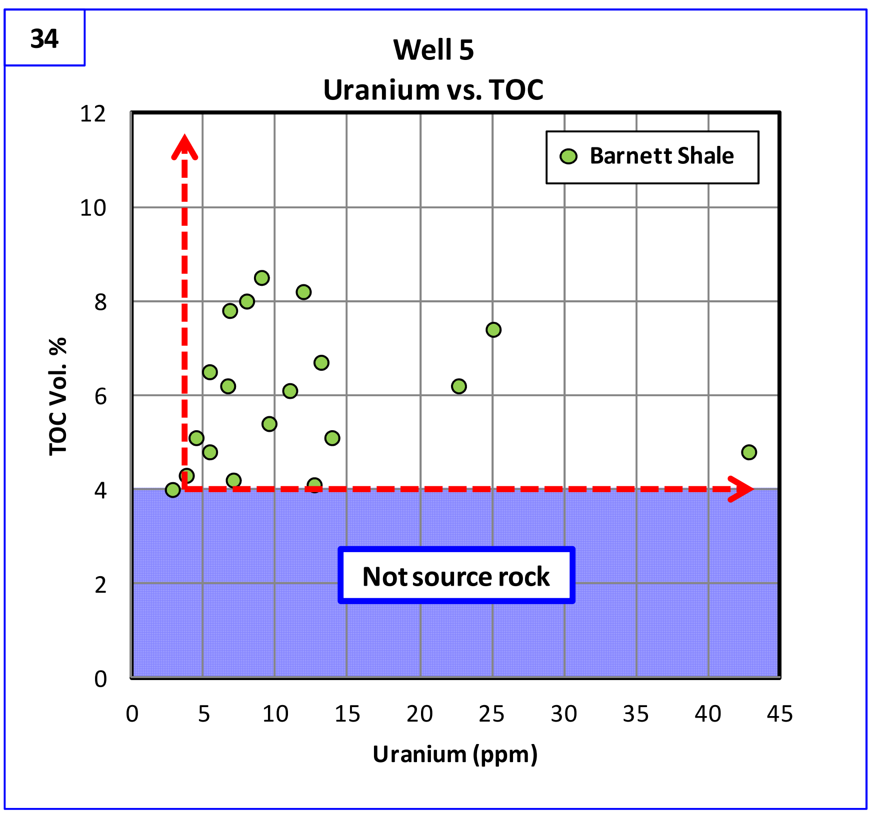


Figure 32. Comparison between TOC and uranium content from a well located in north-central Tarrant County.





Figures 33. & 34. Cross plot of TOC and uranium content from south-central Tarrant County and northwestern Ellis County.

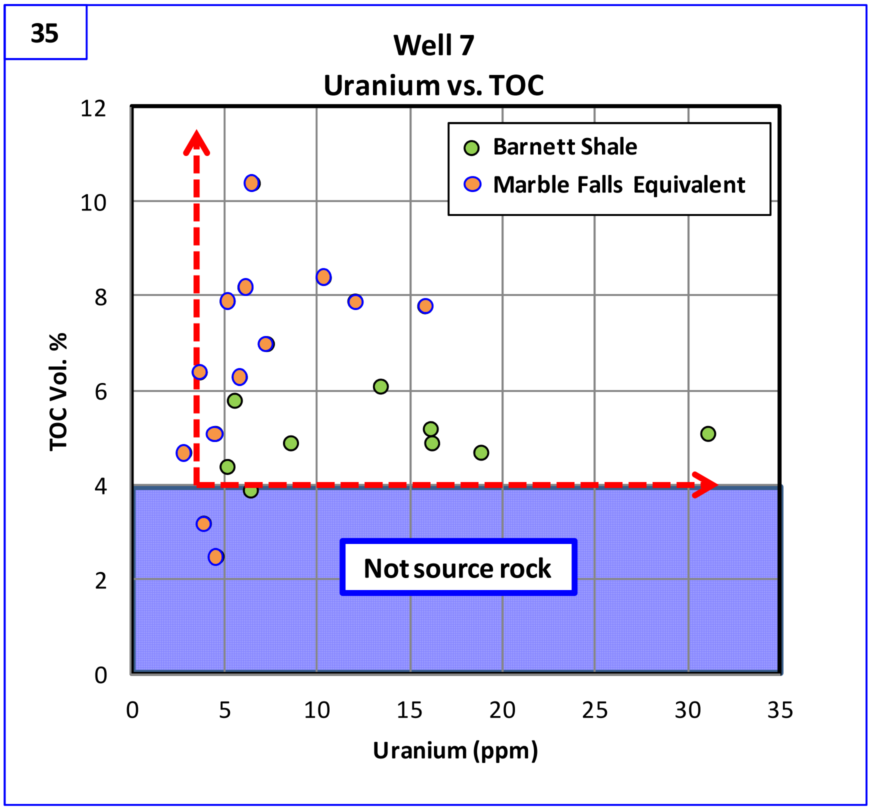


Figure 35. TOC and uranium comparison using core and log data from a well in southwestern Ellis County.

Another positive relationship between uranium content and gamma ray response is noted. At approximately 100 API units, the uranium content in the four wells from Tarrant and Ellis counties generally plots above 3-5 ppm. Therefore, gamma ray responses > 100 API units relates to ≥ 4 vol. % TOC. This relationship was used to calculate net reservoir thickness from gamma ray logs run across the gross reservoir in order to isolate the organic-rich shale intervals.

The greatest net gamma ray thickness using a > 100 API unit cutoff throughout the entire gross reservoir is in southeastern Tarrant County (Figure 36). The majority of Tarrant County contains wells with over 100 net meters (350 feet) of gamma ray greater than 100 API units, which by this line of reasoning suggests that this region contains the highest amount of shale with greater than 4 vol. % TOC. Northern Johnson, northeastern Ellis, and southwestern Denton counties also contain thick intervals of high net gamma ray shale. When applying this gamma ray threshold, the net thickness of the gross reservoir decreases radially from southeastern Tarrant County to the northern, western, and southern regions of the FWB.

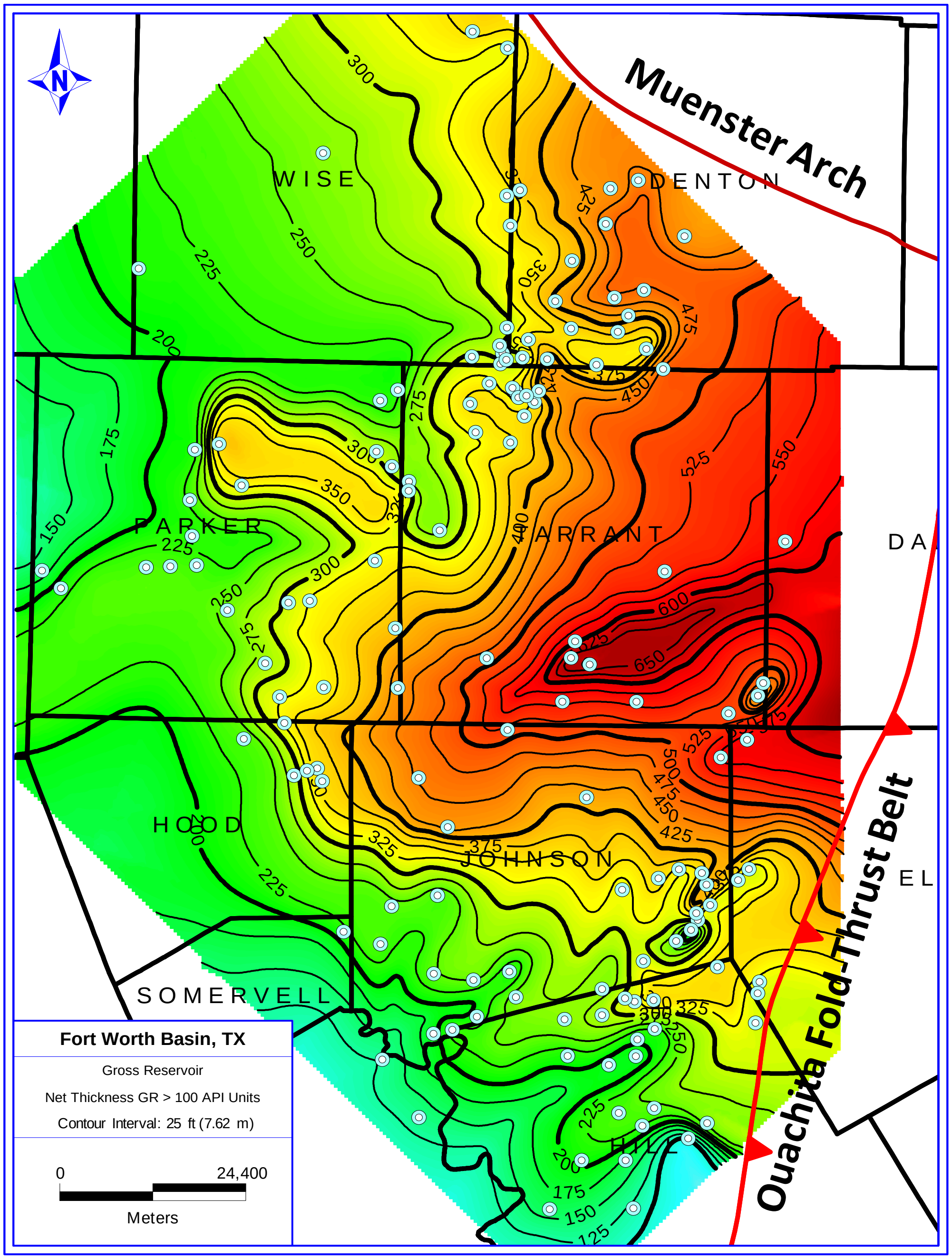


Figure 36. Isopach map illustrating variations in net thickness of gamma ray greater than 100 API units throughout the gross reservoir.

The isopach of net gamma ray >100 API units for Barnett Shale (Figure 37) demonstrates a similar trend to the gross reservoir isopach of gamma ray >100 API units. Tarrant, northwestern Johnson, and southwestern Denton counties contain the greatest thickness of high gamma ray shale, and, consequently, greatest concentration of TOC. As in the gross reservoir, the TOC-rich intervals in the Barnett Shale also thin from the Denton, Tarrant, and Johnson counties to the northern, western, and southern extents of the FWB.

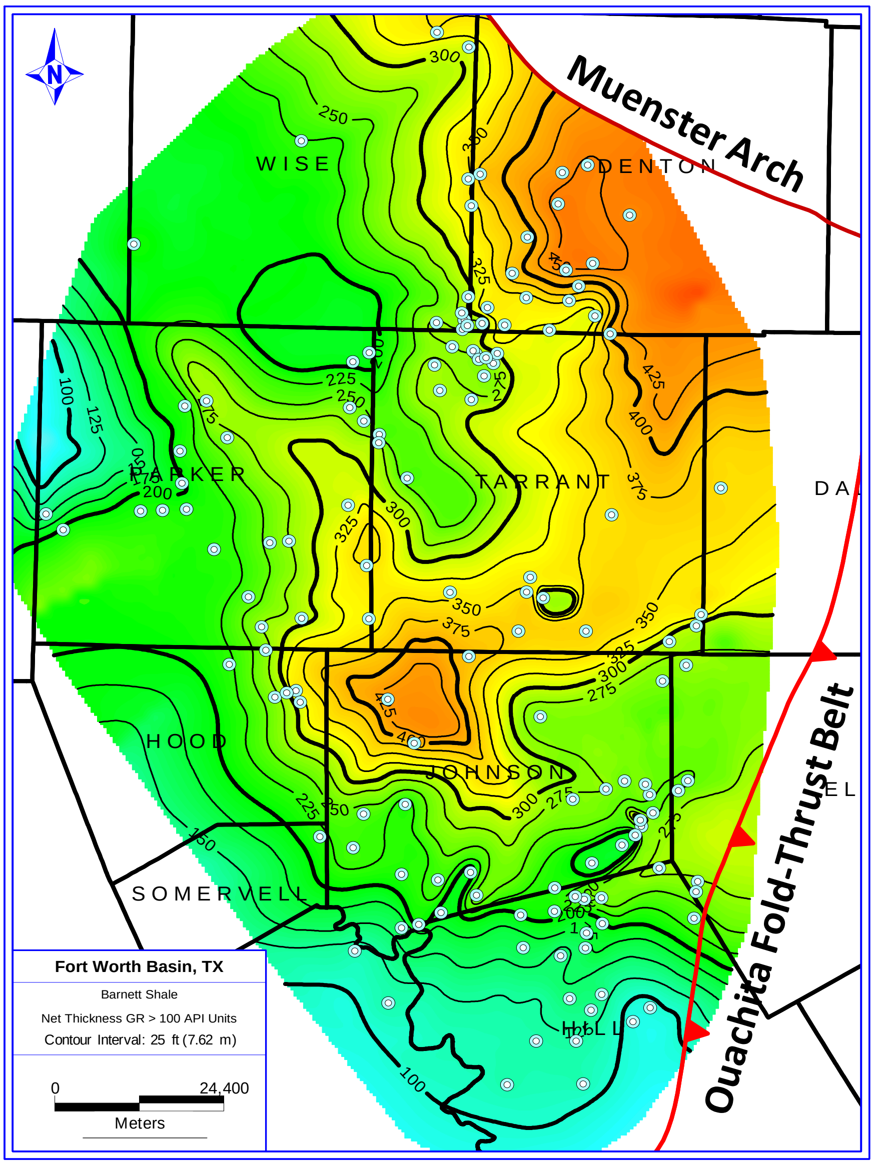


Figure 37. Isopach map illustrating net thickness of gamma ray greater than 100 API units in the Barnett Shale.

While the gross reservoir is thickest to the north along the Muenster arch, applying the >100 API unit gamma ray threshold in this area reveals that the reservoir contains the same net thickness of organic-rich shale as in northern Johnson County where the gross reservoir thickness is 20% as great. The formula below was used to calculate overall organic richness in the gross reservoir on a per-county basis. Once the organic richness was calculated for each well, an average organic richness for each county was computed (Figure 38).

$$\textit{Organic Richness} = \frac{\textit{Net GR Thickness} > 100 \textit{ API Units}}{\textit{Gross Reservoir Thickness}} \qquad \text{(Eq.1)}$$

Organic richness increases across the basin from northwest to southeast where the organic composition appears to be highest along the Ouachita fold-thrust belt. Coincidentally, the southern and eastern extents of the FWB also contain the highest clay content recorded in XRD analyses of the gross reservoir. XRD analyses and geophysical log data confirm a more carbonate-rich reservoir towards the north/northwestern extent of the FWB and a more clay-rich reservoir towards the east/southeast along the Ouachita fold-thrust belt. Thinning of the gross reservoir and karsting of the pre-Barnett carbonates are both prevalent along the west, southwest, and southern extents (Figure 39).

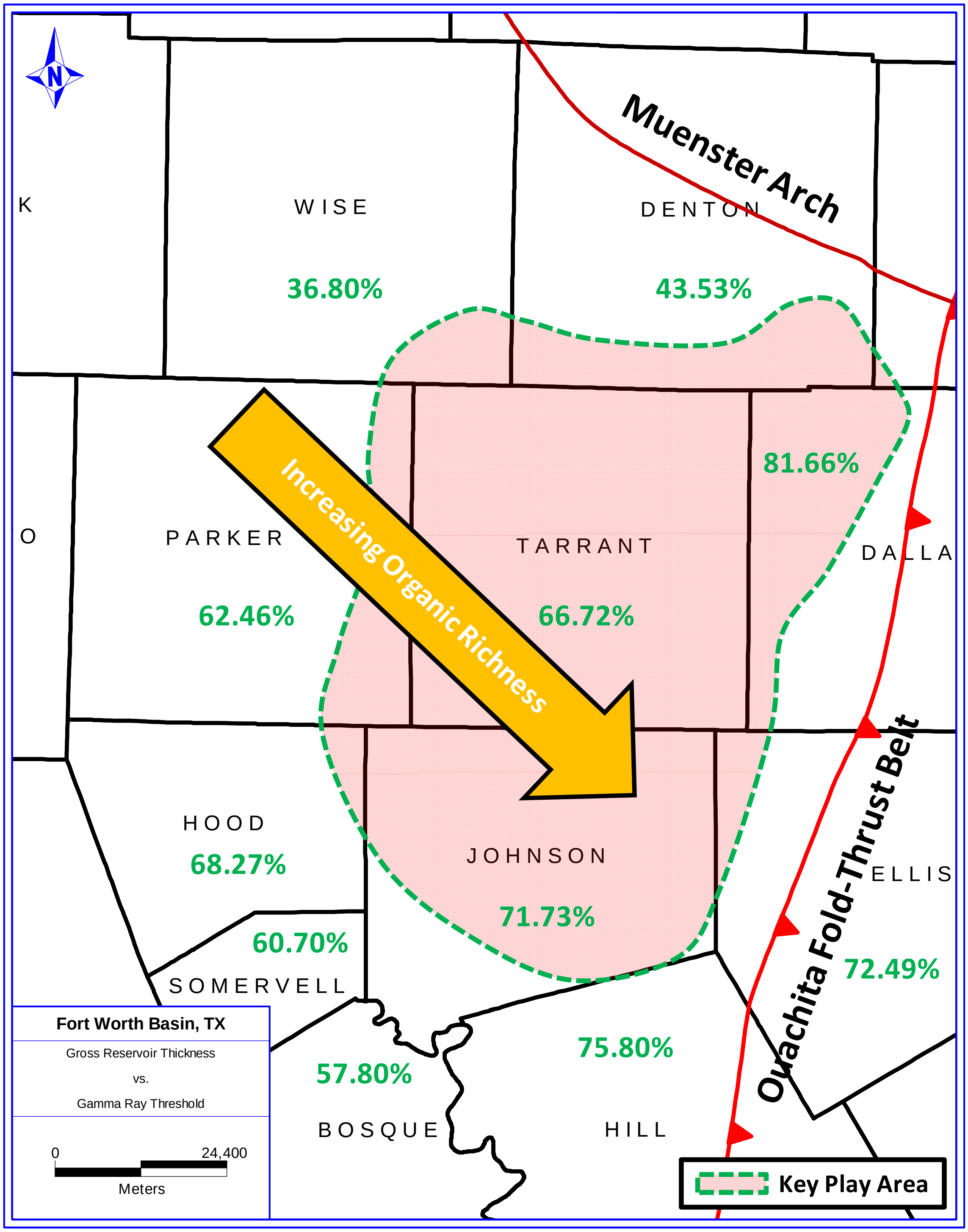


Figure 38. The organic-richness (net ft gamma ray > 100 API units) associated with the gross reservoir increases in a northwest-to-southeast direction across the FWB.

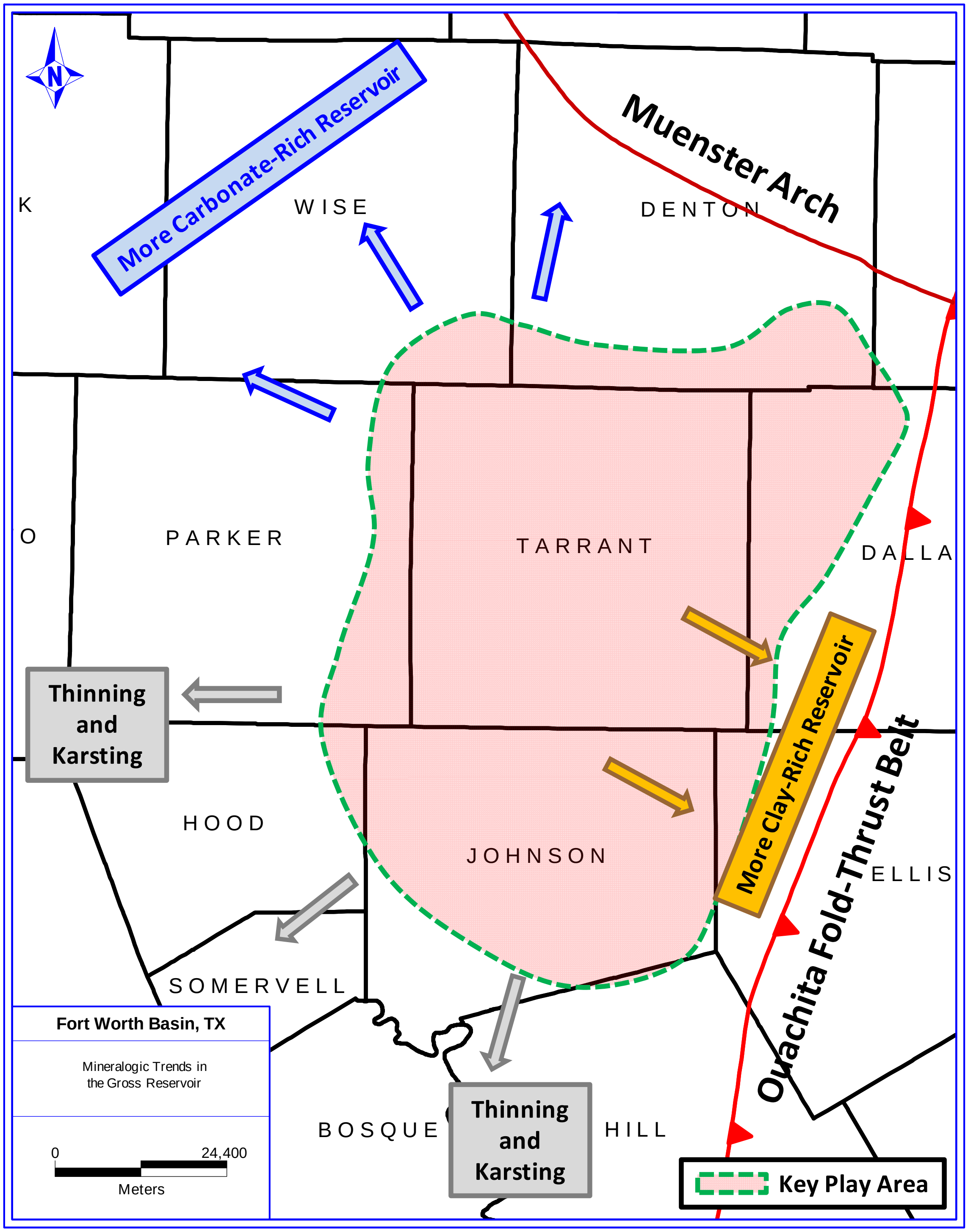


Figure 39. Illustration of key mineralogic changes within the gross reservoir with respect to the area of key Barnett Shale drilling activity.

DISCUSSION

Chronostratigraphic correlations between gamma ray logs run through the gross reservoir interval are used to define a sequence stratigraphic framework for Mississippian to Early Pennsylvanian strata deposited in the FWB based on marine flooding surfaces representing events in geologic time. This relationship implies that the northern and western margins of the FWB ringed by carbonate platforms are age-equivalent to the organic-rich basinal facies that are the Barnett Shale.

Facies belts spanning the entire study area are defined using relationships between strata in the cross sections, carbonate facies models, Walther's Law, and previous work dedicated to depositional environments of strata in the FWB. Due to the scale of the study the facies belts identified in the gross reservoir are general. However, the relationships between facies belts reflect the depositional environments and history of Mississippian to Early Pennsylvanian strata in the FWB. Three facies belts are identified in the gross reservoir interval: 1) shelf margin carbonates, 2) slope carbonates, and 3) basinal, organic-rich shales.

The shelf margin facies belt represents the Upper and Lower Marble Falls Formation in the gross reservoir. Gamma ray logs and XRD data indicate that the Upper and Lower intervals of the Marble Falls Formation are predominately limestone and carbonate rich. The Marble Falls Formation was deposited in a high energy, well-oxygenated shallow water environment and contains evidence of bioturbation (Farrar, 2007). TOC is low in the shelf margin facies and is most likely attributed to degradation from organisms and deposition in oxygenated waters. Further defining this facies, Keir (1979) describes shelf facies associated with the Marble Falls Formation near the Llano Uplift. Based on previous studies, gamma ray logs, and XRD data, the Marble Falls Formation is classified as a shelf margin facies in the FWB.

The basinal, organic rich shale facies is prevalent in the Barnett Shale. This facies yields a high gamma ray response (>150 API units) from geophysical logs due to high uranium content and is typically rich in TOC based on geochemical analyses in this study. High uranium and TOC are indicative of an anaerobic environment of deposition, which is typical of shales deposited in restricted basins. The basinal organic-rich shale facies represents marine transgression.

The slope carbonates facies belt was defined using carbonate facies models and Walther's Law. Carbonate facies models illustrate that deposition between shelf margin carbonates and basinal shales down-dip from carbonate shelves are slope carbonates (Handford and Loucks, 1993). Implementing Walther's Law, a vertical sequence of facies should represent the series of depositional environments lying adjacent to one another. Therefore, deposition above and below shelf margin facies and basinal, organic-rich shale facies should be slope carbonates assuming there is not a gap in the sedimentary record. The slope carbonates facies typically contains more carbonate than the basinal, organic-rich shale facies and less carbonate than that shelf margin carbonates facies.

The proposed reservoir model is consistent with sequence stratigraphic framework studies performed by Slatt and Abousleiman (2011) on other North American shale plays and Emery (2009). The base of the transgressive systems tract (TST) onlaps over an erosional surface (Ellenburger Group) and is comprised of a condensed shale section represented by high gamma ray response in the basal Barnett Shale. The top of the TST corresponds to the maximum flooding surface and represents the datum in chronostratigraphic cross sections used to construct the reservoir model. Third order sequences are represented by high gamma ray responses (>150 API units) overlain by decreasing-upward gamma ray signatures (Slatt and Abousleiman, 2011). These gamma ray patterns represent marine flooding surfaces followed by regression.

The incursions of deeper-water sediments that divide the slope carbonates facies are keyed by transgressions (flooding surfaces) in third order sequences during second order highstand. The most organic-rich sediment is found in two places: 1) the transgressive systems tract that comprises the basal Barnett Shale and 2) down-dip (basinward) of the shelf margin carbonates to the north and west where anaerobic conditions preserved organic material. In general, the organic-rich sediments are distributed at the base of the upward-shoaling mega-sequence identified as the gross reservoir. Intervals of organic-rich sediments diminish upwards due to overall progradation during highstand, resulting in an asymmetrical distribution (decreasing upward) of TOC and gas in place (GIP) across the entire gross reservoir.

The gross reservoir is thickest in the northern region of the FWB against the Muenster arch, but most of the stratigraphic section is predominately carbonate. Cross sections indicate that stacked, organic-rich intervals, which are present in the southern regions of the basin (Hill, Tarrant, Parker, Johnson, Hood, and western Ellis counties), continue to become separated northward by progressively thickening carbonate sequences.

An increase in accommodation space was present during the Mississippian towards the northern extent of the FWB; however, organic-richness of the Barnett Shale tends to decrease northward while carbonate content increases significantly. The northern extent of the basin is interpreted to represent shelf margin and slope carbonate facies within the proposed depositional model. Prograding carbonate tongues extend southward from the north basin margin indicating that basinal, anoxic conditions were not as prevalent towards the northern extent of the FWB as they were to the south where much of the organic material accumulated in the basinal facies.

A decrease in accommodation space coincident with a facies change alludes to the decrease in organic-richness in the Barnett Shale towards the Bend arch at the western extent of the FWB. Towards the Bend arch, the Barnett section thins and shallows structurally, and interfingers or transitions via facies change with local pinnacle reefs of the Chappel carbonate platform. Little evidence exists for thick, organic-rich deposits along this western flank of the FWB during the Mississippian.

In the Barnett Shale, high TOC corresponds to high gas content and porosity. While there is not a direct relationship between gamma ray response and TOC, uranium content appears to link the two when a gamma ray threshold is implemented. This threshold of 100 API units relates to greater than or equal to ~4 vol. % (or ~2 wt. %) TOC in the Barnett Shale based on TOC, gamma ray, and spectral gamma ray data from pilot-hole wells. The 4 vol. % TOC is important since this was determined the lower limit for economic hydrocarbon generation in shale-gas plays (Jarvie, 2004). Applying the gamma ray threshold assists in detecting changes in net thickness of the organic-rich gross reservoir across the FWB.

The organic richness of the gross reservoir increases southward from Denton and Wise counties, most likely due to deeper water, more organic-rich, less carbonate-rich deposition and sedimentation. According to this study, organic composition in the gross reservoir is highest along the present-day axis of the FWB in front of the Ouachita fold-thrust belt. This organic-richness distribution reveals the increased basinward presence of the organic shale facies described in the reservoir model. Thick, organic-rich Barnett Shale sections provide higher organic porosity and gas saturation in the reservoir. High gamma ray response is directly related to high organic content. Therefore, gamma ray can be used as a tool to help assess reservoir quality (as a function of organic richness) in the Barnett Shale. Recognition of this association is key. This technique will eliminate the less or non-productive intervals of the established gross reservoir like the slope carbonates facies belts present in the northern region of the FWB. Instead, this method focuses on the organic-rich intervals of the gross reservoir responsible for hydrocarbon generation and storage, mainly the basinal, organic shales facies belt.

Geophysical log data and XRD analyses indicate that mineralogic composition of the gross reservoir is highly variable throughout the FWB. Silica, carbonate, and clay content each dominate regionally. The identified facies belts, mineralogic content of the facies belts, and geophysical logs demonstrate a general mineralogic trend in the gross reservoir from the northwest to southeast corners of the study area. According to geophysical logs and XRD data, carbonate content dominates the gross reservoir in Denton and Wise counties and decreases southward. Silica content increases throughout Tarrant and northern Johnson counties but decreases to the south towards Hill County and eastward toward the Ouachita fold-thrust belt where clay content increases in composition of the gross reservoir. This trend in mineralogic composition of wells cored along the Ouachita fold-thrust belt may be related to deep, basinal deposition, where the predominate source was most likely distal, possibly from hemipelagic plumes or deep marine “snow” containing mostly clay minerals.

The northwest to southeast trend appears consistent with current depositional models where finer-grained sediment is deposited further basinward (Handford and Loucks, 1993). Increased silica content towards the center of the basin could have resulted from deceased organisms with silica components (radiolarians, diatoms, sponge spicules) being transported down the slope into the basin via debris flows or through suspension settling (Bowker, 2003).

Preserved organic matter and fine-grained sediment deposited in basins are indicative of anoxic conditions and are typically deposited down-dip of carbonate shelves or platforms where pervasive degradation from benthic organisms or oxidation is greatly diminished. While depositing organic shales up-dip onto shelf margin carbonates is possible, the increase in carbonate composition in the gross reservoir towards the northern extents of the FWB suggests less organically-rich sediment deposition.

CONCLUSIONS

Chronostratigraphic cross sections constructed from approximately 200 pilot hole define the stratigraphic framework of the gross reservoir. Cross section correlations indicate that sediment comprising the gross reservoir in the FWB was deposited during marine transgression followed by second order highstand aggradation and progradation. Gamma ray patterns, XRD data, and TOC analyses from core data identify three facies belts present in the proposed reservoir model: 1) shelf margin carbonates, 2) slope carbonates, and 3) basinal, organic-rich shale. While each of the facies belts are important during construction of the reservoir model, identifying the basinal, organic-rich shales are most integral for regional assessment of the Barnett Shale reservoir.

Thick organic-rich intervals of the Barnett Shale are key for hydrocarbon generation and storage. Gamma ray responses > 100 API units indicate organic-rich shale containing ≥ ~ 4 % vol. TOC. According to the reservoir model, the thickest accumulations of organic-rich shale in the gross reservoir are present in Tarrant, northern Johnson, and northwestern Ellis counties. Isopach maps of the net reservoir indicate that thickness of organic-rich intervals associated with the gross reservoir decrease radially from southeastern Tarrant County.

BIBLIOGRAPHY

Berman, A., 2009, Lessons from the Barnett Shale suggest caution in other shale plays: www.aspousa.org . 5 Feb. 2010.

Blakey, R., 2005, Paleogeography and geologic evolution of North America; images that track the ancient landscapes of North America: *http://jan.ucc.nau.edu/rcb7/nam.html*. 23 Feb. 2010.

Bowker, K. A., 2003, Recent developments of the Barnett Shale play, Fort Worth basin: *West Texas Geological Society Bulletin*, v. 42, no. 6, p. 4-11.

Bowker, K. A., 2007, Barnett Shale gas production, Fort Worth basin: Issues and discussion: *American Association of Petroleum Geologists Bulletin*, v. 4, p. 523-533.

Browning, D. W., 1982, Geology of the North Caddo area, Stephens County, Texas, in Martin, C. A. ed., Petroleum geology of the Fort Worth basin and Bend arch area: *Dallas Geological Society*, p. 315-330.

Breyer, J. A., Bunting, P. J. Monroe, R. M., and Steed, M. B., 2011, Stratigraphic and geographic variation in depositional facies in a continuous shale gas reservoir: The Barnett Shale (Mississippian), Fort Worth basin, north-central Texas, in Breyer, J. A., ed., Shale Reservoirs—Unconventional Wisdom: *American Association of Petroleum Geologists*, Special Publication, in press.

Burgess, W. J., 1976, Geologic evolution of mid-continent and Gulf Coast areas; plate tectonics view: *Gulf Coast Association of Geological Societies Transactions*, v. 26, p. 132-143.

Byers, C. W., 1977, Biofacies patterns in euxinic basins: A general model, in H. E. Cook and P. Enos, eds., Deep-water carbonate environments: *SEPM Special Publication*, v. 25, p. 203-219.

Ehlmann, R. B., 1982, La Pan field— Clay County, Texas, a field study, in C. A. Martin, ed., Petroleum geology of the FortWorth Basin and Bend Arch area: *Dallas Geological Society*, p. 331-352.

Emery, M., Mature shale play – Barnett Shale, Fort Worth basin, TX. *Range Resources Corporation Techfest*. Hilton DFW Lakes Executive Conference Center, Grapevine, TX. 4-5 May 2009.

Farrar, K. M., Stratigraphy of the Marble Falls interval (Pennsylvanian), Jack and Wise counties, Texas. MS thesis. Texas Christian University, Fort Worth, Texas, 2010.

Flawn, P. T., Goldstein A. Jr., King P. B., and Weaver C.E., 1961, The Ouachita system: University of Texas at Austin: *Bureau of Economic Geology*, Publication 6120, 401 p.

Flippin, J. W., 1982, The stratigraphy, structure, and economic aspects of the Paleozoic strata in Erath County, North-Central Texas, in Martin, C. A. ed., Petroleum geology of the Fort Worth Basin and Bend arch area: *Dallas Geological Society*, p. 129-155.

Gutschick, R., and Sandberg C., 1983, Mississippian continental margins on the conterminous United States, in Stanley, D. J. and Moore, G. T. eds., The shelf break: Critical interface on continental margins: *SEPM Special Publication*, v. 33, p. 79-96.

Handford, C. R., and Loucks, R. G., 1993, Carbonate depositional sequences and systems tracts – Responses of carbonate platforms to relative sea-level changes, in Loucks, R.G., Sarg, J.F., eds., Carbonate sequence stratigraphy. *American Association of Petroleum Geologists Geology Memoirs*, v. 53, p. 3-41.

Henry, J. D., 1982, Stratigraphy of the Barnett Shale (Mississippian) and associated reefs in the northern Fort Worth Basin; in Martin, C. A., ed., Petroleum geology of the Fort Worth Basin and Bend arch area: *Dallas Geological Society*, p. 157-178.

Jarvie, D. M., Claxton, B. L., Henk, F., and Breyer, J. A., 2001, Oil and shale gas from the Barnett Shale, Fort Worth basin, Texas [abs.]; *American Association of Petroleum Geologists*. Program and Abstracts, p. A100.

Jarvie, D. M., Hill, R. J., Pollastro, R.M., Claxton, B. L., Bowker, K.A., Evaluation of hydrocarbon generation and storage in the Barnett Shale, Ft. Worth basin, Texas. *Ellison Miles Geotechnology Institute/Petroleum Technology Transfer Council*. Brookhaven College, Farmers Branch, TX. 22-23 June 2004.

Kerans, C., 1988, Karst-controlled reservoir heterogeneity in Ellenburger Group carbonates of West Texas: *American Association of PetroleumGeologists Bulletin*, v. 7, p. 1160-1183.

Kier, R. S., 1979, Deposition of the Marble Falls Formation [abs.]; *American Association of Petroleum Geologists*. Program and Abstracts, p. 479.

Lahti, V. R., and Huber W. F., 1982, The Atoka Group (Pennsylvanian) of the Boonsville field area, north-central Texas, in Martin, C. A., ed., Petroleum geology of the Fort Worth basin and Bend arch area: *Dallas Geological Society*, p. 377–400.

Loucks, R. G. and Ruppel, S. C., 2007, Mississippian Barnett Shale: Lithofacies and depositional setting of a deep-water shale-gas succession in the Fort Worth basin, Texas: *American Association of Petroleum Geologists Bulletin*, v.91, no. 4, p. 579-601.

Lüning, S., and Kolonic, S., 2003, Uranium spectral gamma-ray response as a proxy for organic richness in black shales: Applicability and limitations: *Journal of Petroleum Geology*, v. 26, no. 2, p. 153-174.

Martineau, D. F., 2007, History of the Newark East Field and the Barnett shale as a gas reservoir: *American Association of Petroleum Geologists Bulletin*, v. 91, no. 4, p. 399-403.

Monroe, R. M., and Breyer, J. A., 2011, Shale wedges and stratal architecture, Barnett Shale (Mississippian), southern Fort Worth basin, Texas, in Breyer, J. A., ed., Shale Reservoirs—Unconventional Wisdom: *American Association of Petroleum Geologists*, Special Publication, in press.

Montgomery, S. L., Jarvie, D. M., Bowker, K. A. and Pollastro, R. M., 2005, Mississippian Barnett Shale, Fort Worth basin, north-central Texas: Gas-shale play with multi-trillion cubic foot potential: *American Association of Petroleum Geologists Bulletin*, v. 89, no. 2, p. 155-175.

Pollastro, R. M., Ronald, J. H., Jarvie, D. M., and Mitchell, E. H., 2003, Assessing undiscovered resources of the Barnett– Paleozoic total petroleum system, Bend arch– Fort Worth basin province, Texas: *American Association of Petroleum Geologists Southwest Section Convention*, Fort Worth Texas, March 1-5, 2003, 18 p.

Pollastro, R.M., Jarvie, D. M., Ronald, J. H., and Adams, C. W., 2007, Geologic framework of the Mississippian Barnett Shale, Barnett-Paleozoic total petroleum system, Bend arch-Fort Worth basin, Texas: *American Association of Petroleum Geologists Bulletin*, v. 91, no. 4, p. 405-436.

Ross, C. A., and Ross, J. R. P., 1987, Late Paleozoic sea levels and depositional sequences, in Ross, C. A. and Haman, D., eds., Timing and deposition of eustatic sequences: Constraints on seismic stratigraphy: *Cushman Foundation for Foraminiferal Research Special Publication*, v. 24, p. 137-149.

Slatt, R.M., and Abousleiman, Y., 2011, Multi-scale, brittle-ductile couplets in unconventional gas shales: Merging sequence stratigraphy and geomechanics. Houston, TX. *American Association of Petroleum Geologists Annual Convention and Exhibition*. 10-13 April.

Sloss, L. L., 1976, Areas and volumes of cratonic sediments, western North America and eastern Europe: *Geology*, v. 4, p. 272-276.

Texas Railroad Commission, 2011, Barnett Shale production by year to Jan. 1, 2011, *Powell Shale Digest*.

Thompson, D. M., 1988, Fort Worth basin, in Sloss, L. L. ed., The geology of North America: *Geological Society of America*, v. D-2, p. 346-352.

Tissot and Welte, 1984, Petroleum formation and occurrence. Springer-Verlag, New York, 699 p.

Turner, G. L., 1957, Paleozoic stratigraphy of the Fort Worth basin: *Abilene & Fort Worth Geological Societies*, Joint Field Trip Guidebook, p. 57-77.

Walper, J. L., 1977, Paleozoic tectonics of the southern margin of North America: *Gulf Coast Association of Geological Societies Transactions*, v. 27, p. 230-239.

Walper, J. L., 1982, Plate tectonic evolution of the Fort Worth basin, in Martin, C. A., ed., Petroleum geology of the Fort Worth basin and Bend arch area: *Dallas Geological Society*, p. 237-251.

VITA

Joshua Kuhn was born May 20, 1985 in Pittsburgh, Pennsylvania. Son of Keith and Patricia Kuhn, Josh also has a twin brother, Ben, and two older sisters, Abbie and Christy. A graduate of Riverside High School in 2004, Joshua received a Bachelor of Science degree with a major in Geosciences from The Pennsylvania State University in 2008. After graduation, Joshua began a summer internship with Range Resources Corporation in May, 2008 and signed on to work as a full time geologist in August, 2008.

In Fall 2009, Joshua started his graduate work at Texas Christian University. While obtaining his Masters of Science degree in Geosciences, he continued to work with Range Resources Corporation gaining oil and gas experience in the Fort Worth, Permian, and Appalachian basins. Joshua is currently a member of AAPG, GSA, FWGS, and the Geology Club at Texas Christian University.

ABSTRACT

CONSTRUCTING A STRATIGRAPHIC FRAMEWORK FOR THE MISSISSIPPIAN BARNETT SHALE: NORTHERN AND CENTRAL FORT WORTH BASIN, TEXAS

by Joshua Keith Kuhn
Department of Geology
Texas Christian University

Thesis Advisor: Ken Morgan, Director of the School of Geology, Energy, and the Environment

Sediment comprising the gross reservoir (Barnett base-Morrowan top) was first deposited over Paleozoic strata during marine transgression, followed by highstand aggradation and progradation. Chronostratigraphic cross sections illustrate relationships between flooding events and facies belts in the gross reservoir. The reservoir model supports mineralogic trends identified in the gross reservoir that grade from carbonate to silica to clay-rich in a northwest/southeast orientation across the Fort Worth basin. Facies analyses identify organic richness associated with the gross reservoir increases south/southeast away from the Newark East field. Gamma ray response in the Barnett Shale > 100 API units indicates ≥ ~4% vol. TOC, the basal limit accepted for commercial production in unconventional shale reservoirs. High TOC indicates greater porosity and hydrocarbons present in the Barnett Shale. Based on organic richness, mineralogic composition, and geochemical considerations, southeastern Tarrant, northern Johnson, and northwestern Ellis counties contain the best reservoir qualities for gas generation and accumulation.