



Gas-Shale Play With Multi-Trillion Cubic Foot Potential Fact Book

Kent Bowker

Mississippian Barnett Shale, Fort Worth basin, north-central Texas: Gas-shale play with multi-trillion cubic foot potential

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ABSTRACT

The Mississippian Barnett Shale serves as source, seal, and reservoir to a world-class unconventional natural-gas accumulation in the Fort Worth basin of north-central Texas. The formation is a lithologically complex interval of low permeability that requires artificial stimulation to produce. At present, production is mainly confined to a limited portion of the northern basin where the Barnett Shale is relatively thick (>300 ft; >92 m), organic rich (present-day total organic carbon > 3.0%), thermally mature (vitrinite reflectance > 1.1%), and enclosed by dense limestone units able to contain induced fractures. The most actively drilled area is Newark East field, currently the largest gas field in Texas. Newark East is 400 mi² (1036 km²) in extent, with more than 2340 producing wells and about 2.7 tcf of booked gas reserves. Cumulative gas production from Barnett Shale wells through 2003 was about 0.8 tcf. Wells in Newark East field typically produce from depths of 7500 ft (2285 m) at rates ranging from 0.5 to more than 4 mmcf/day. Estimated ultimate recoveries per well range from 0.75 to as high as 7.0 bcf. Efforts to extend the current Barnett play beyond the field limits have encountered several challenges, including westward and northward increases in oil saturation and the absence of lithologic barriers to induced fracture growth. Patterns of oil and gas occurrence in the Barnett, in conjunction with maturation and burial-history data, indicate a complex, multiphased thermal evolution, with episodic expulsion of hydrocarbons and secondary cracking of primary oils to gas

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accomplishments include petroleum system analysis and resource assessments of the Bend arch–Fort Worth basin with particular focus on Barnett Shale, South Florida basin, and the Arabian Peninsula.

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in portions of the basin where paleotemperatures were especially elevated. These and other data imply a large-potential Barnett resource for the basin as a whole (possibly >200 tcf gas in place). Recent assessment by the U.S. Geological Survey suggests a mean volume of 26.2 tcf of undiscovered, technically recoverable gas in the central Fort Worth basin. Recovery of a significant portion of this undiscovered resource will require continued improvements in geoscientific characterization and approaches to stimulation of the Barnett reservoirs.

INTRODUCTION

Unconventional natural-gas reservoirs are an increasing focus of activity in several United States basins. Development of coal-bed methane, tight-gas sand, and gas-shale reservoirs, for example, has brought important successes in production, while also establishing a basis of knowledge and experience that may prove applicable to other geologic provinces, both in North America and elsewhere. These successes have not been fortuitous or haphazard. Instead, they have come about through a combination of scientific study, engineering innovation, new technology, and, in some cases, persistence and risk taking.

All of these factors have had an influence in elevating the Barnett Shale of the Fort Worth basin, Texas, to a major new gas-shale play in North America. The Barnett Shale is an organic-rich, petroliferous black shale of middle–late Mississippian (Osagean–Chersterian?) age, long recognized as a probable source rock for hydrocarbons throughout north-central Texas. Prior to the 1980s, the formation was not a target of exploratory efforts. Instead, such efforts remained focused on Pennsylvanian clastic reservoirs and, to a lesser extent, Ordovician, Mississippian, and Pennsylvanian carbonates. Widespread gas shows and unexpected minor production convinced Mitchell Energy and Development Corp. to pursue the formation as a possible oil-gas productive zone. Initial recoveries from the low-permeability reservoir were largely uneconomical. However, continued geologic and engineering analysis, coupled with more effective completion techniques, led Mitchell to progressively increase well performance and encouraged interest from other operators. By the mid-1990s, drilling established a core productive area, Newark East field, in the northern part of the basin (Figure 1).

Pioneered by Mitchell Energy, the Barnett Shale play is interpreted as a continuous-type natural-gas accumulation in the Fort Worth basin (Schmoker et al., 1996; Pollastro, 2003). At Newark East field, the formation is 300–500 ft (92–152 m) thick and exhibits mild overpressure (0.52 psi/ft) and about 75% gas saturation at depths of 6500–8500 ft (1982–2592 m). Barnett Shale production remains centered in this field, which exceeds 400 mi² (1016 km²) in extent, including parts of several counties in the northern part of the basin (Figure 1). In 2000, Newark East became the largest gas field in Texas in terms of monthly production, a ranking it retained through 2003. Development has established proven reserves of more than 2.7 tcf of gas. Estimates for the total in-place Barnett gas resource are on the order of 200 tcf, with

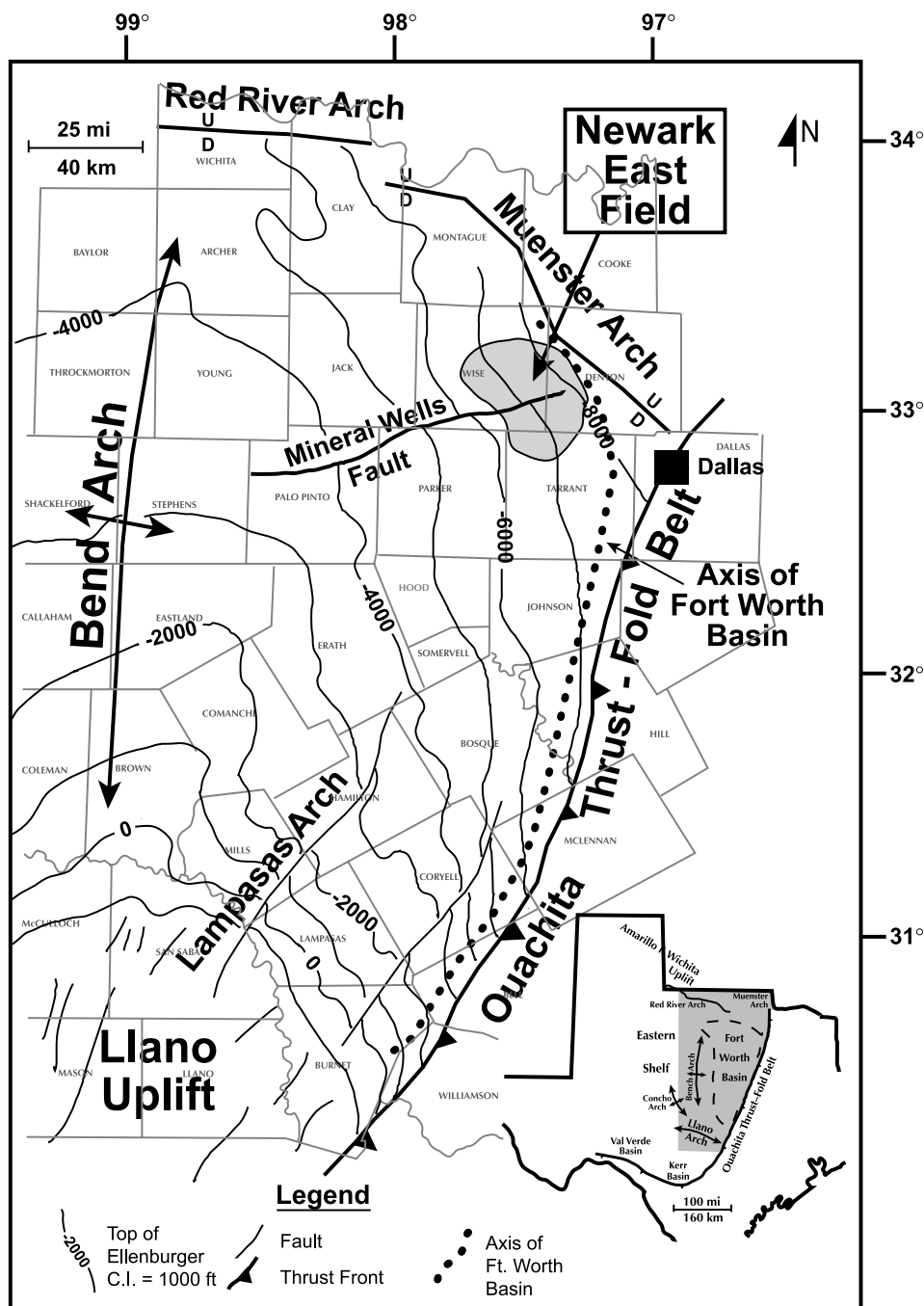


Figure 1. Regional setting and structure contour map of the Fort Worth basin, north-central Texas. Also shown is the location of the Newark East field, the main producing area of the Barnett Shale gas play. Contours are drawn on top of the Ordovician Ellenburger Group (contour interval = 1000 ft [305 m]).

ultimate technically recoverable reserves variably assessed at 3–40 tcf (Schmoker et al., 1996; Jarvie et al., 2004a; Pollastro et al., 2004b).

Compared with other gas-shale plays, the Barnett Shale is unique in several aspects. First, the Barnett produces from greater depths and, therefore, at higher pressures than do other gas-shale reservoirs. Second, Barnett gas is entirely thermogenic in origin and, in large parts of the basin, occurs with liquid petroleum. Third, the Barnett Shale has undergone a complex, multiphase thermal his-

tory, making geochemical considerations central to patterns of productivity. Fourth, natural fractures do not appear essential for production and, in some cases, may even reduce well performance. Overall, these and other factors have presented a set of challenges to geoscientists engaged in reservoir characterization of the Barnett Shale. The evolving knowledge related to development of this play will likely prove valuable to future exploration and production of gas-shale reservoirs elsewhere in the world.

This report offers a brief survey of current knowledge regarding this important new gas-shale play. Until recently, published information on the Barnett Shale was largely confined to a series of vintage reports based on outcrops along the Llano uplift, approximately 120 mi (160 km) south of the current play area (e.g., Cheney, 1940; Plummer, 1950), and a few studies of the Barnett Shale in the subsurface (White, 1948; Turner, 1957; Henry, 1982). Beginning in the 1990s, a small number of reports on the potential gas resources of the formation appeared (D. M. Jarvie and L. L. Lundell, 1991, personal communication; Lancaster et al., 1993; Schmoker et al., 1996; Kuuskraa et al., 1998). Since 2000, however, new data have been published and reviewed (Jarvie et al., 2001; Curtis, 2002; Bowker, 2003; D. M. Jarvie, 2003, personal communication; Pollastro, 2003; Pollastro et al., 2003). It is our intent to summarize and expand on this work by adding recently available information regarding the nature of the Barnett reservoir, its geological framework, productivity, geochemistry, and field characteristics.

GEOLOGIC SETTING

The Fort Worth basin is a shallow, north-south–elongated trough encompassing roughly 15,000 mi² (38,100 km²) in north-central Texas (Figure 1). It is one of several foreland basins associated with the late Paleozoic Ouachita orogeny, a major event of thrust-fold deformation resulting from collisional tectonics during the formation of Pangea (Walper, 1982; Thompson, 1988). Other basins in this trend include the Black Warrior, Arkoma, Kerr, Val Verde, and Marfa basins (Flawn et al., 1961).

The Fort Worth basin is a wedge-shaped, northward-deepening depression. Its axis trends roughly parallel to the Ouachita structural front, which bounds the basin to the east (Figure 1). A northern margin is formed by fault-bounded basement uplifts of the Red River and Muenster arches. These basement features have been interpreted to be part of the northwest-striking Amarillo–Wichita uplift trend, created when basement faults associated with the Oklahoma aulacogen were reactivated during Ouachita compression (Walper, 1977; 1982). Westward, the Fort Worth basin shallows against a series of gentle positive features, including the Bend arch, Eastern shelf, and Concho platform (Figure 1). To the south, the basin is bounded by the Llano uplift, a domal feature that exposes Precambrian and Paleozoic (Cambrian–Pennsylvanian) rocks.

Preserved fill in the Fort Worth basin reaches a maximum of about 12,000 ft (3660 m) in the northeast

corner, adjacent the Muenster arch. Deposits consist of about 4000–5000 ft (1200–1500 m) of Ordovician–Mississippian carbonates and shales; 6000–7000 ft (1800–2100 m) of Pennsylvanian clastics and carbonates; and, in the eastern parts of the basin, a thin veneer of Cretaceous rocks (Flawn et al., 1961; Henry, 1982; Lahti and Huber, 1982; Thompson, 1988). Stratigraphic relationships and burial-history reconstructions suggest that a significant thickness of upper Pennsylvanian and possibly Permian strata was eroded prior to incursion of Early Cretaceous seas (Henry, 1982; Walper, 1982; D. M. Jarvie, 2003, personal communication).

Structures in the Fort Worth basin include both major and minor faulting, local folding, fracturing, and karst-related collapse features. Thrust-fold structures are interpreted to exist in the easternmost parts of the basin (Walper, 1982) and involve or override Mississippian and older deposits. Major basement reverse faults, possibly with a component of strike-slip displacement, define the southern margin of the Red River–Muenster arch (Flawn et al., 1961; Henry, 1982).

Local fault blocks are present in the northern basin (Montague County), based on isopach patterns of Mississippian (Barnett) rocks (Henry, 1982). An important structural feature in this area is the Mineral Wells fault (see Figure 1), a prominent northeast-southwest structure more than 65 mi (104 km) in length that bisects the Newark East field. The origin of the Mineral Wells structure is not well understood because it does not appear directly related to either the Muenster–Red River arch or the Ouachita front. Proprietary seismic data suggest that the Mineral Wells fault is a basement feature that underwent periodic rejuvenation, particularly during the late Paleozoic. Studies have shown that the fault exerted significant control on the deposition of Atokan conglomerates (Thompson, 1982), and that it also directly influenced depositional patterns and thermal history of the Barnett, as well as hydrocarbon migration in the northern Fort Worth basin (Pollastro, 2003).

In addition, minor high-angle normal faults and graben-type features are present in many parts of the basin (see, for example, Reily, 1982; Williams, 1982). The changing orientation of these structures argues for a relationship to several major tectonic elements. In the northern basin, for example, as evidenced by high-density well control in Boonsville and Newark East fields, many normal faults trending northeast-southwest, parallel or subparallel to the Mineral Wells fault system exist. In the central basin area, fault trend changes to north-south and appears related to the Ouachita structural front to the east. The southern half of the basin contains a series of northeast-trending normal

faults and intervening horstlike arches associated, in part, with the Llano uplift (Browning, 1982).

Macroscopic natural fractures related to fault trends have been observed in conventional cores taken from wells that penetrate the Barnett Shale, particularly in the northern half of the basin. These natural fractures, as observed in core, are nearly always healed with carbonate cement. Recent three-dimensional seismic study of a portion of the northern basin has revealed small-scale faulting and local subsidence related to karst development and solution collapse in the Ordovician Ellenburger Group (Hardage et al., 1996). The effects of such collapse are present in Mississippian strata and in overlying formations as young as the middle Pennsylvanian (Strawn).

STRATIGRAPHY AND LITHOLOGY

Generalized stratigraphy of the Fort Worth basin is shown in Figure 2. The total Paleozoic section can be roughly divided into three intervals, reflective of tectonic history: (1) Cambrian–Upper Ordovician platform strata (Riley–Wilberns, Ellenburger, Viola, Simpson), deposited on a passive continental margin; (2) middle–upper Mississippian strata (Chappel Formation, Barnett Shale, and lower Marble Falls Formation), deposited during the early phases of subsidence related to tectonism along the Oklahoma aulacogen; and (3) Pennsylvanian strata (upper Marble Falls Formation, Atoka, etc.), representing the main phase of subsidence and basin infilling related to the advancing Ouachita structural front. The lower Paleozoic section is capped by a regional unconformity. Silurian and Devonian strata are absent in the basin. Uppermost Mississippian and lowermost Pennsylvanian deposits appear conformable but may include disconformities in some areas (e.g., proximal to the Muenster arch) (Flippin, 1982; Henry, 1982).

The top of the Ellenburger Group is an erosional surface commonly characterized by solution-collapse features. Overlying Upper Ordovician Viola and Simpson rocks are confined to the northeastern part of the basin and consist mainly of dense, crystalline limestone and dolomitic limestone. These strata dip generally eastward beneath the sub-Mississippian unconformity and thin to a zero edge along a northwest-southeast line through Wise, Tarrant, and northeasternmost Johnson counties (Bowker, 2002). This zero edge of the Viola–Simpson constitutes a crucial stratigraphic boundary because south and west of it, Mississippian rocks rest directly upon karsted, potentially water-bearing Ellenburger carbonates.

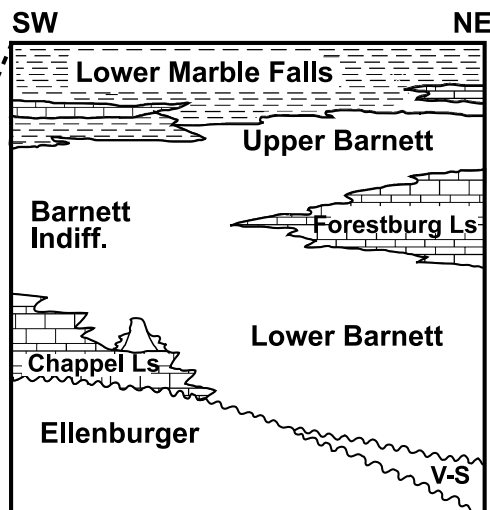
Mississippian deposits consist of an alternating series of shallow-marine limestones and black, organic-rich shales. Precise definition of the complete Mississippian section remains difficult because of the lack of sufficient diagnostic fossils. This report follows current industry practice, which places the lower part of the Marble Falls Formation in the Chesterian–Meramecian stage and assigns the Barnett Shale and Chappel Formation units to the Osagean (Figure 2). The Marble Falls Formation typically includes an upper limestone interval and a lower portion consisting of interbedded dark limestone and gray-black shale, sometimes referred to as the Comyn Formation. Shale of the lower Marble Falls Formation differs from the more organic, highly radioactive shale of the underlying Barnett Shale. Well data indicate that the Marble Falls Formation thins rapidly south of Newark East field and is absent in the east-central part of the Fort Worth basin (Bowker, 2003; Pollastro, 2003). The total Mississippian section is thickest just south of the Muenster arch, where the Barnett Shale is more than 1000 ft (305 m) thick and contains significant limestone (Pollastro, 2003) (Figure 3). West of the basinal axis, along the flanks of the Bend arch, the Barnett Shale thins over the Chappel carbonate platform (Figure 3). The Chappel consists of crinoidal limestone and local pinnacle reefs up to 300 ft (92 m) in height, several of which have been proven productive of hydrocarbons (Browning, 1982; Ehlmann, 1982).

The stratigraphy and lithology of the Barnett Shale change across the basin. To the northeast, where it is especially thick, the Barnett Shale contains a significant proportion of limestone, which diminishes rapidly to the south and west. These limestones appear to have been deposited in a series of debris flows into the deeper part of the basin from a source to the north (Bowker, 2002). In the area of the Newark East field, the Barnett Shale is divided into lower and upper intervals by a carbonate unit informally known as the Forestburg limestone. Proximal to the Muenster arch, the Forestburg limestone is 200 ft (60 m) or more thick, but thins rapidly south- and westward to a feather edge in southernmost Wise and Denton counties. The limestone does not exhibit consistent porosity development and is not considered an exploration target. Where the Forestburg unit is absent, a single, undifferentiated Barnett Shale interval is interpreted on logs and maps. As indicated by Figure 3, the Barnett Shale thins to the northwest over the Chappel shelf and to the south and west along the Llano uplift and Bend arch. In the northern part of the Fort Worth basin, thicknesses average about 250 ft (76 m) thick. The regional extent of the Barnett Shale in the basin is controlled by the Red River–Muenster arch

SYSTEM AND SERIES		STAGE	GROUP or FORMATION
CRETACEOUS	LOWER	COMANCHEAN	
PERMIAN		OCHOAN - GUADALUPIAN	
		LEONARDIAN	
		WOLFCAMPIAN	☼ CISCO GROUP
PENNSYLVANIAN		VIRGILIAN	● CISCO GROUP
		MISSOURIAN	● CANYON GROUP
		DESMOINESIAN	● ● ● ☼ STRAWN GROUP
		ATOKAN	☼ ● BEND GROUP
		MORROWAN	● MARBLE FALLS LIMESTONE
MISSISSIPPIAN		CHESTERIAN-MERAMECIAN	● ☼ BARNETT SHALE
		OSAGEAN	● CHAPPEL LIMESTONE
ORDOVICIAN			● VIOLA LIMESTONE
			● SIMPSON GROUP
			● ELLENBURGER GROUP
CAMBRIAN	UPPER		WILBERNS - RILEY - HICKORY FORMATIONS
PRE-CAMBRIAN		GRANITE - DIORITE - METASEDIMENTS	

● Oil Reservoir
☼ Gas Reservoir

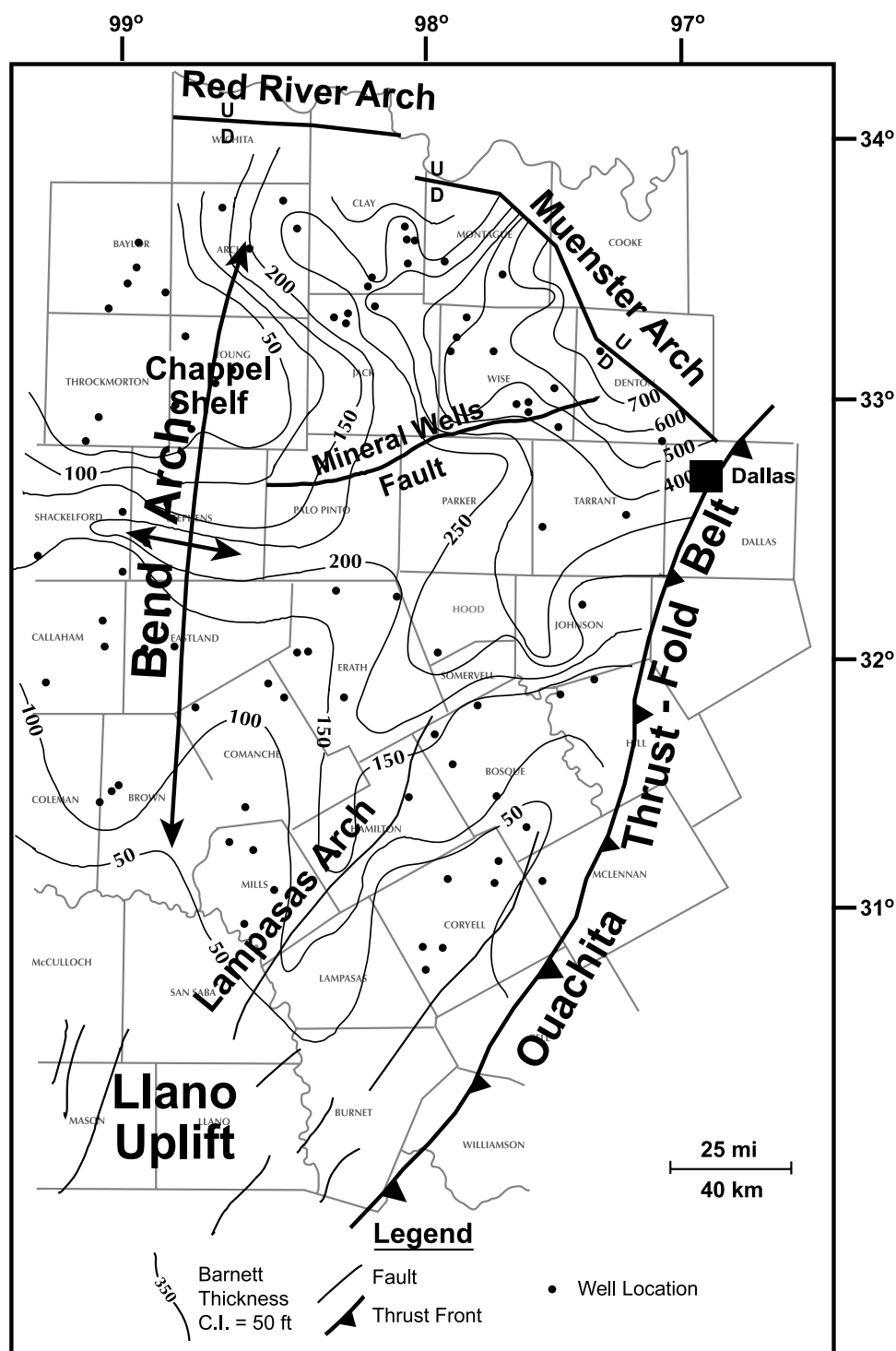
Figure 2. Generalized stratigraphic column, Fort Worth basin. Expanded section shows more detailed interpretation of Mississippian stratigraphy. V-S refers to Viola-Simpson interval. Modified from Pollastro (2003).



and the Ouachita structural front to the north and east, respectively, and by erosional pinch-out or a facies change to the west, on the Eastern shelf.

Pennsylvanian strata above the Marble Falls Formation can be broadly classified as consisting of regressive clastic deposits, representing a range of westward-prograding environments, and transgressive carbonate bank deposits (Cleaves, 1982; Thompson, 1988). Terrigenous clastics were derived from source areas to the north and east, where uplift was associated with the main phases of the Ouachita orogeny, involving the Muenster arch

and Ouachita fold and thrust belt. Sediment loading and basin encroachment by westward-advancing thrust-fold deformation resulted in a progressive westward shift of depocenters (Thompson, 1988). Lower Pennsylvanian deposits consist of Atokan conglomerates, sandstones, shales, and thin limestones reflective of marine, marginal-marine, and continental settings (Thompson, 1982). Depositional patterns in lower Pennsylvanian (Atokan) strata indicate that the arch was an active sediment source prior to major uplift of the Ouachita orogen (Lovick et al., 1982). Tectonism along



the Muenster arch likely involved rejuvenation of older, deep-seated basement faults, associated in part with the Oklahoma aulacogen (Flawn et al., 1961; Walper, 1977, 1982). Widespread conventional oil and gas production in the Fort Worth basin is associated with deltaic, fluvial, and carbonate bank deposits of Pennsylvanian age.

BARNETT SHALE: DETAILED CHARACTER

Lithologically, the Barnett Shale consists of siliceous shale, limestone, and minor dolomite. In general, the formation is relatively rich in silica (35–50%, by volume) and poor in clay minerals (<35%). Where exposed along

the Llano uplift, in Llano, Lampasas, and San Saba counties, the formation is 30–50 ft (9–15 m) thick and highly petroliferous (Cheney, 1940; Plummer, 1950). Northward, the Barnett Shale thickens progressively, reaching more than 400 ft (122 m) in the Newark East field and more than 1000 ft (305 m) just south of the Muenster arch (Figure 3). In the subsurface, hydrocarbon-bearing siliceous shale forms a significant part of the formation. The basal zone of the Barnett Shale in the central and eastern parts of the basin commonly contains a thin (<10 ft; <3 m) zone of highly phosphatic material, mainly apatite (Bowker, 2002). In some areas, abundant pyrite has been identified in Barnett drill cuttings (Flippin, 1982).

Organic content is highest in clay-rich intervals (3–13%; average ~3.2% by weight in cuttings; D. M. Jarvie, 2003, personal communication) and is also high in silica-rich intervals, which comprise the primary producing facies of the Barnett Shale. Such intervals are generally more abundant in the lower Barnett interval but are significant in the upper Barnett Shale as well. According to Bowker (2002), the average composition of this facies (by volume) is as follows: 45% quartz (mostly in the form of altered silica-rich radiolarian tests); 27% illite, with minor smectite; 8% calcite + dolomite; 7% feldspar; 5% organic matter; 5% pyrite; and 3% siderite, with trace amounts of native copper and phosphatic minerals. North and northeast of the Newark East field, the proportion of carbonate material in the Barnett Shale increases significantly (Bowker, 2002). In the western parts of the Fort Worth basin, fine-grained calcareous material is fairly abundant in the lower Barnett Shale because of wave and current distribution of debris from Chappel reefs (Henry, 1982). Isopach and facies patterns suggest that the Mineral Wells fault was a subtle but active feature during Barnett Shale deposition.

Type logs from the northern and southern Newark East field are shown in Figure 4. As indicated, the upper Barnett is picked at the base of an interbedded limestone-shale zone, forming the lower portion of the Marble Falls Formation. The Forestburg limestone is 200 ft (61 m) thick in the Star of Texas Energy Services 2 Oates Star well (Wise County) and thins southward to less than 10 ft (3 m) in the Star of Texas Energy Services 1 Sotel, near the southern edge of the Newark East field in Tarrant County. Distinctive aspects of Barnett Shale log response include high radioactivity and high resistivity. However, conventional log analysis for reservoir identification and characterization is largely inapplicable to the Barnett.

Basic reservoir characteristics of the Barnett productive intervals have therefore depended mainly on core

analysis. Such analysis indicates that productive, organic-rich parts of the formation have average porosities of 5–6% and permeabilities of less than 0.01 md and even in the nanodarcy range. Average pore-throat radii for this facies are less than 0.0005 μm (Bowker, 2003). Water saturations average about 25% in these intervals but increase rapidly with an increase in carbonate content, suggesting that expulsion of hydrocarbons from these organically rich intervals resulted in a drying of the reservoir (Bowker, 2003).

The Barnett Shale is known to be naturally fractured. Detailed studies of core recovered from the Mitchell Energy 2 T. P. Sims (Wise County), however, and observations on core samples from other wells indicate that most fractures are wholly or largely sealed with calcite (CER Corporation, 1992). In the area of Newark East field, mineralized fractures have a northwest strike (azimuth 100–120°), approximately parallel to the faulted southern boundary of the Muenster arch and an average dip of 74° to the southwest. Microfractures may exist in the formation (Bowker, 2003), but this possibility has not yet received systematic study.

GEOCHEMICAL CONSIDERATIONS

The Barnett Shale represents an unconventional hydrocarbon play, where critical petroleum system elements, source, reservoir, and seal coincide in the same formation. Hydrocarbon distribution, saturation levels, and productivity in the Barnett Shale are complex and strongly dependent on geochemical factors such as original organic richness, patterns of thermal maturity, and burial history (D. M. Jarvie, 2001, personal communication). In addition, analyses of gas content in the Barnett, using data from desorption and adsorption studies, have proven essential to assessing the total hydrocarbon in place and undiscovered resource of the formation, both within the current play area and elsewhere in the basin (Bowker, 2003; Pollastro, 2003; Jarvie et al., 2004a, b; Pollastro et al., 2004b).

Organic Content

Organic richness and composition in the Barnett Shale indicate that the unit has excellent oil- to mixed oil-gas-prone source rock potential at low to moderate thermal maturity (Jarvie et al., 2003). Organic content varies with lithology, being the highest in clay-rich

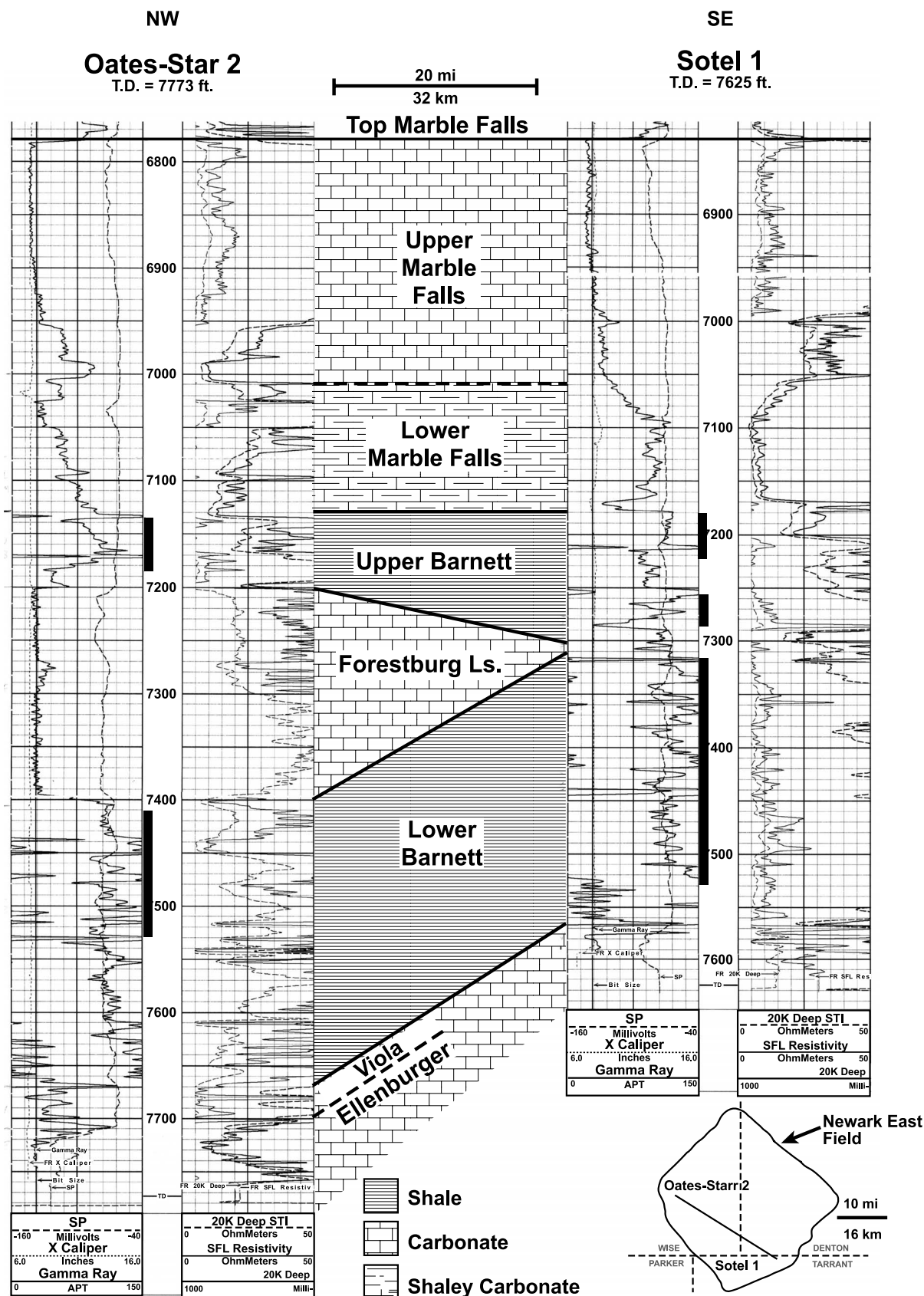


Figure 4. Log cross section, Newark East field, showing typical response and interpreted generalized lithology through the Mississippian–Ordovician interval. Perforated intervals are indicated by vertical black bars. Cross section location is indicated on the map.

intervals, and differs significantly between mature subsurface samples and immature outcrop samples. In the central and northern parts of the Fort Worth basin, well samples from highly mature, silica-rich intervals average 3.3–4.5% total organic content (TOC, by weight), whereas immature outcrop samples, taken from the southern margins of the basin in Lampasas County, show TOC values that range up to 11–13% (Jarvie et al., 2001).

Laboratory maturation studies strongly imply that such differences partly reflect conversion of organic matter to hydrocarbons in the subsurface. Table 1 presents data on low-maturity samples taken from the Explo Oil, Inc. 1 Mitcham (Brown County), showing the change in various geochemical parameters with progressive simulated maturation (D. M. Jarvie and L. L. Lundell, 1991, personal communication). Data were derived from a single aliquot of Barnett Shale heated to the selected temperatures shown, with the aliquot sampled after each heating event to obtain the measured values. As indicated by Table 1, the remaining generation potential (milligrams of hydrocarbon per gram of source rock) and hydrogen index values suggest that as much as 85–90% conversion of hydrocarbon potential at a starting vitrinite reflectance (R_o) value of 0.62% has occurred by the time T_{max} exceeds about 450°C and R_o is above 1.0 (D. M. Jarvie and L. L. Lundell, 1991, personal communication; Jarvie et al., 2003). In addition, Table 1 indicates a total reduction in TOC by 36.3%, implying that TOC values at the start of generation can be back-calculated using the equation $TOC_{original} = TOC_{present} / (1 - 0.363)$ (Jarvie et al., 2003). Applying this equation to samples from other wells in the central basin area suggests that original TOC values were in the range of 5–12%.

Maturation and Burial History

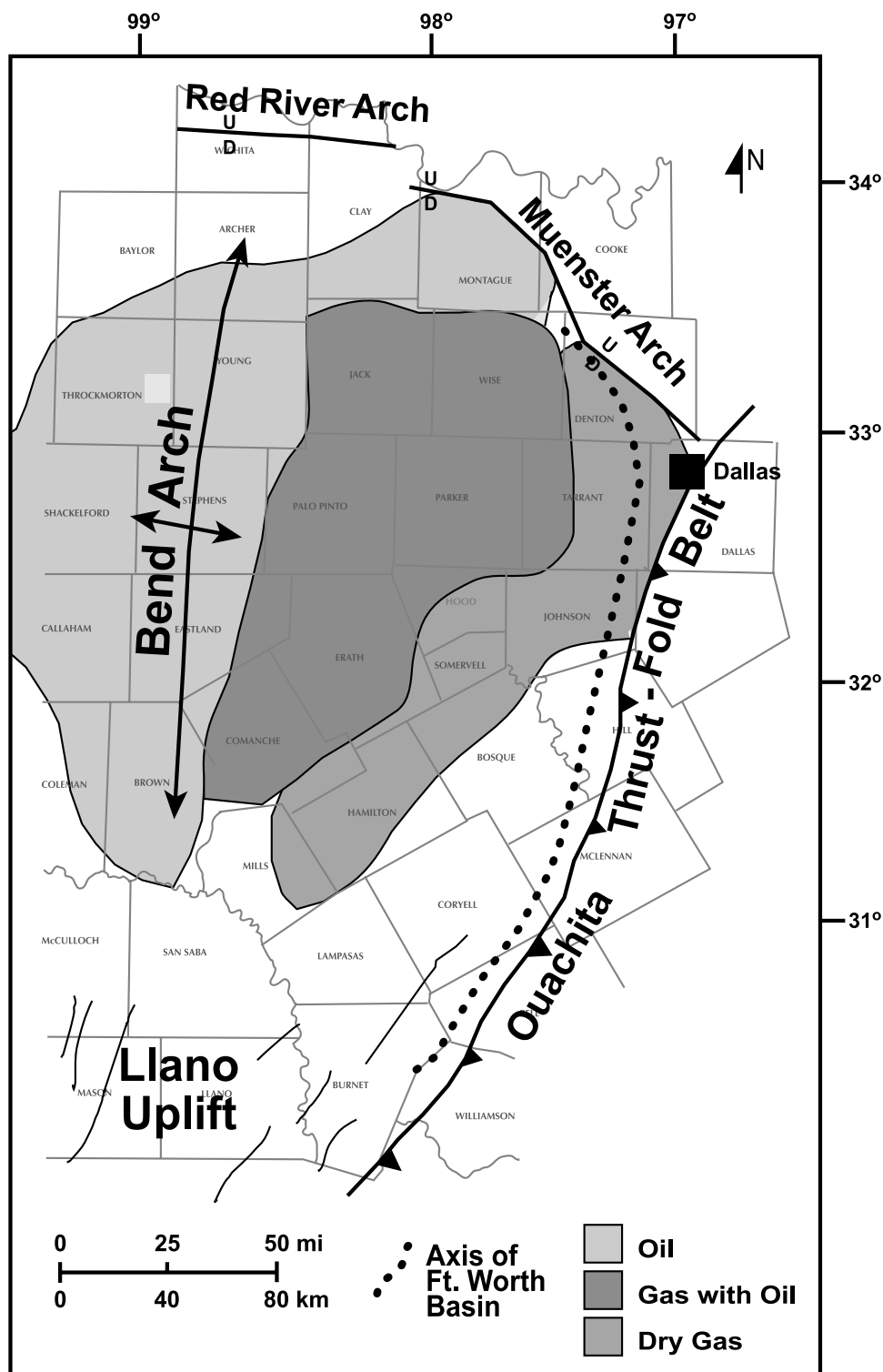
Large-scale generation and migration from Barnett Shale source rock is confirmed by recent geochemical analyses of oils and gas samples from a wide range of Paleozoic reservoirs in north-central Texas (Jarvie et al., 2001; Jarvie et al., 2003; R. J. Hill, D. M. Jarvie, R. M. Pollastro, K. A. Bowker, B. L. Claxton, 2004, personal communication). Such analyses have employed fingerprinting, carbon isotope, and biomarker data to establish correlations between Barnett Shale organic matter and oils in Ordovician (Ellenburger Group and Viola Limestone), Mississippian (Chappel Formation and Barnett Shale), and Pennsylvanian (Atokan, Strawn, and Canyon) reservoirs. These correlations show that the Barnett Shale is the source rock for the great majority of oil historically produced in the Fort Worth basin and on the adjacent Bend arch.

Patterns of production of Barnett-sourced hydrocarbons imply maturation differences from east to west across the Fort Worth basin. The generalized map of Figure 5 indicates a westward change from dry gas and mixed gas-oil in the Fort Worth basin to oil on the Bend arch and Eastern shelf. Within the gas window, this westward decrease in maturity is accompanied by an increase in gas wetness and, therefore, in heating (Btu) content (D. M. Jarvie, 2003, personal communication). However, the patterns given in Figure 5 do not reflect present-day depths of the Barnett Shale source rock, which are maximal along the basinal axis, close to the Muenster arch. In some cases, for example, in Hood and Erath counties, production of dry gas is mainly west of the structurally deeper portions of the basin, suggesting a complex thermal history.

Table 1. Change in Barnett Shale Geochemical Parameters as a Result of Laboratory Maturation*

Rock-Eval T_{max} (°C)	Vitrinite Reflectance (% R_o)	TOC (wt.%)	Remaining Potential (S_2) (mg HC/g rock)	S_2 Transformation Ratio (TR) (%)	Hydrogen Index (HI) (mg HC/g TOC)	HI TR (%)
432	0.62	5.21	19.80	0	380	0
435	0.67	4.53	13.45	32	297	22
437	0.71	4.11	10.27	48	250	34
443	0.81	3.77	5.88	70	156	59
455	1.03	3.41	1.81	91	53	86
470	1.30	3.32	1.36	93	41	89

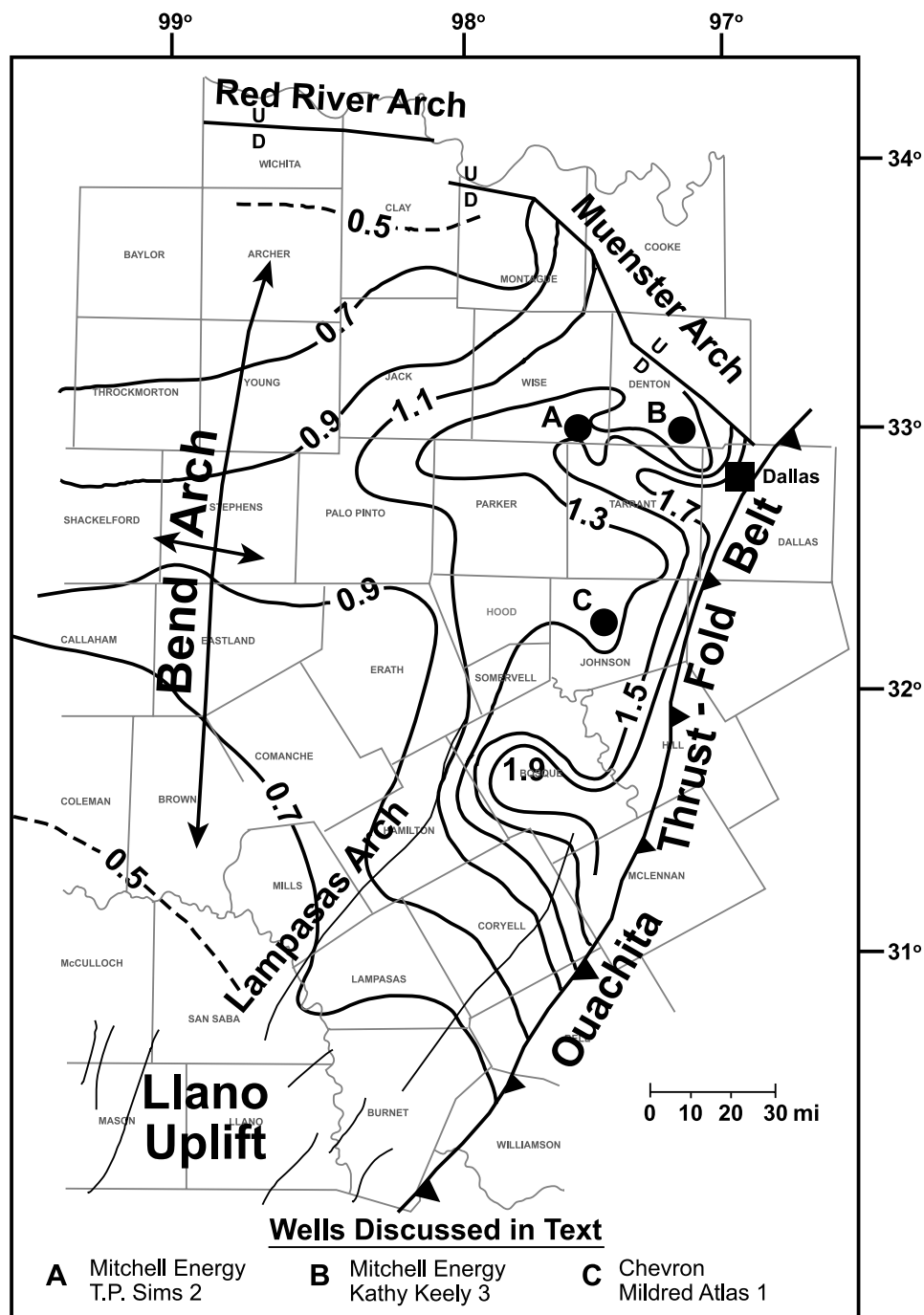
*Data from D. M. Jarvie and L. L. Lundell (1991, personal communication) and D. M. Jarvie (2003, personal communication).



Maturity indicators and burial-history reconstructions also support the interpretation of a multiphase thermal history for the Barnett Shale in the Fort Worth basin, involving hydrothermal events associated with the Ouachita structural front and the Minerals

Wells fault system (Bowker, 2003; Pollastro, 2003; Pollastro et al., 2004a). The distribution of measured vitrinite reflectance values, shown by the isoreflex- tance map of Figure 6, cannot be explained by present-day burial depth. Instead of a consistent decrease in

Figure 6. Isoreflectance map, Fort Worth basin and Bend Arch region. Contour interval $R_o = 0.2\%$. Data from Humble Geochemical Services, Inc. Map interpretation modified from Pollastro et al. (2004a).



maturity to the south and west, as would be implied by current overburden, the patterns of Figure 6 include (1) a decrease in maturity levels on the Bend arch both to the north and south of an east-west trend from Shackelford to Palo Pinto counties; (2) a maturity increase directly associated with the Ouachita structural front; and (3) local increases and decreases in maturity related to intrabasin structures of various orientation.

Burial-history reconstructions further highlight the complexity of thermal history in the Fort Worth basin. An example from Eastland County, in the west-central part of the basin, is shown in Figure 7. This reconstruction suggests three main stages in the thermal history of the Barnett Shale: (1) an initial stage of rapid subsidence and burial in the Pennsylvanian–Permian; (2) a second stage, encompassing the Late Permian–Early

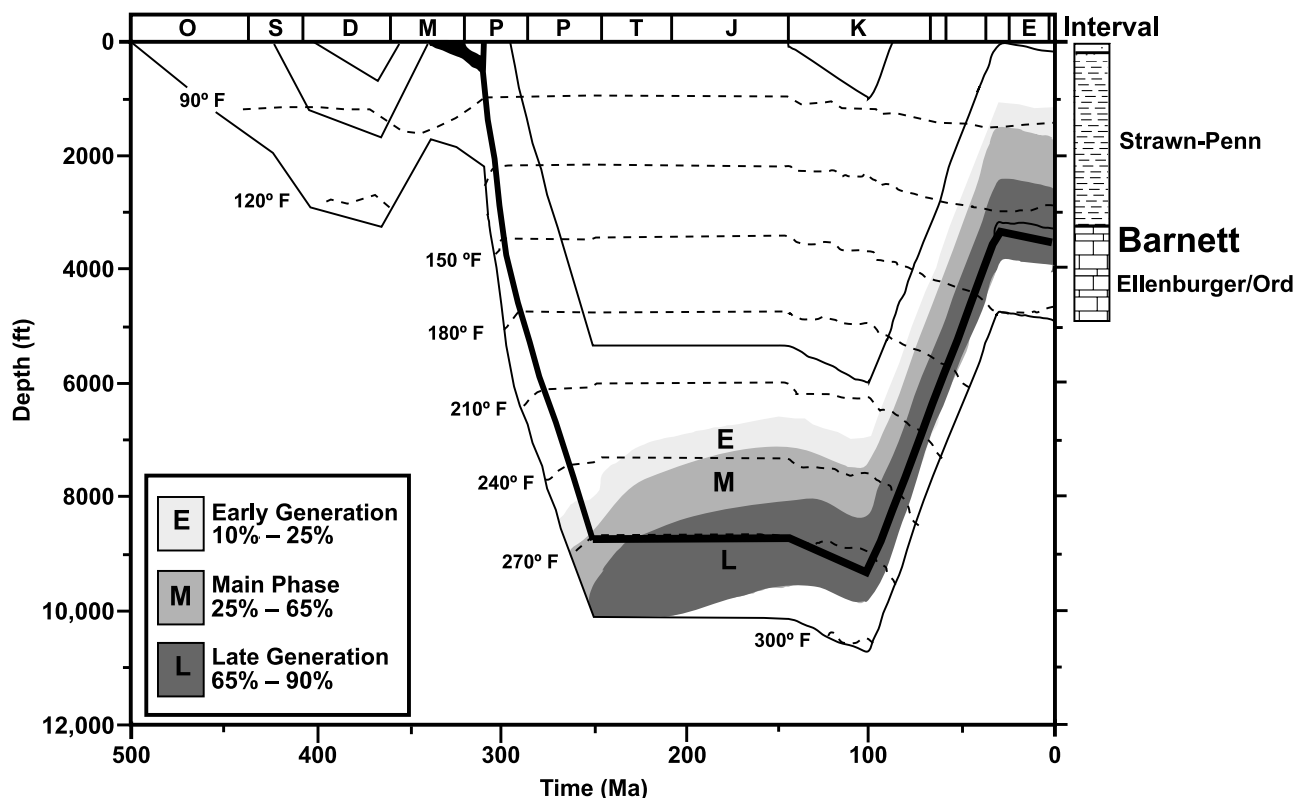


Figure 7. Burial-history reconstruction for individual wells in Eastland County (southeastern Fort Worth basin). Modified from Jarvie et al. (2001).

Cretaceous, when the Barnett Shale remained at elevated temperatures, punctuated by a brief episode of increased burial during the middle–Late Cretaceous; and (3) a third stage determined by uplift and removal of overburden in the Late Cretaceous–Tertiary. Based on this reconstruction, Jarvie et al. (2001) interpreted a generalized maturation scheme for Barnett Shale source beds to include a primary phase of oil and gas generation, possibly with some secondary cracking of oil, depending on maximum paleotemperatures during the first episode of subsidence, and a secondary phase, predominantly of gas generation from cracking of oil, during the later period of burial.

In general, paleotemperatures were much higher in the Fort Worth basin than at present. For example, Figure 6 strongly suggests that thermal history was influenced by hydrothermal heating associated with the advancing Ouachita thrust front (Bowker, 2003; Pollastro et al., 2004a); by movement along the deep-seated Mineral Wells fault; and by unspecified structures extending northwestward from the Ouachita front. Hot fluids generated by Ouachita thrusting could have been forced through karsted, porous Ellenburger Group carbonates

into the overlying Mississippian section. This possibility is supported by other forms of evidence, including the presence of saddle dolomites in both the Ellenburger Group and Chappel Formation and also exotic minerals, including native copper, in Barnett Shale core samples.

Thermal maturity data, in conjunction with oil and gas geochemical analyses, indicate that the Barnett Shale has undergone multiple heating events and episodic expulsion of hydrocarbons, with gas derived both from kerogen cracking and secondary cracking of oil. Gas and oil occurrence in the Barnett Shale are dependent on thermal maturity levels but may be influenced by other factors as well. Late-stage uplift during the Tertiary, causing pressure and temperature decreases, is likely responsible in some measure for the dual-phase hydrocarbon system observed in Newark East field. Seals in the basin, including the Barnett Shale itself, must have been leaky, given the wide distribution of Barnett Shale oils in underlying and overlying formations. Episodic expulsion of hydrocarbons from the Barnett Shale may have formed a fabric of microfractures in the rock during peak phases of generation.

Gas Content

An important parameter in unconventional natural gas plays is gas content or gas yield per mass of rock. Gas in shale reservoirs is stored in two basic ways: by sorption and by compression of free gas in natural fractures or other available macroporosity. Sorption refers to gas that is stored in adsorbed and absorbed states. Adsorbed gas is held on the surfaces of solid material, either organic matter or minerals, in the reservoir. Physical controls on adsorption include the type of solid sorbent, temperature, and the rate of gas diffusion. Absorbed gas, however, exists in a dissolved state, e.g., as solution gas in liquid petroleum, and is controlled by pressure and temperature conditions. With regard to the Barnett Shale, it has proven difficult to determine precisely the disposition of these two states in productive parts of the reservoir. Therefore, this article employs the more general term sorbed gas to refer to all nonfree gas in the Barnett reservoir.

Determination of sorbed gas content in the Barnett Shale reservoir (total adsorbed + absorbed gas) has relied on desorption studies of core and cuttings samples. Onsite and laboratory desorption tests have been performed on core samples recovered both by conventional and pressure coring equipment. In all recent cases, appropriate adjustment has been made, particularly in the case of cuttings samples, to restore gas that may have escaped during drilling and maceration of samples for analysis.

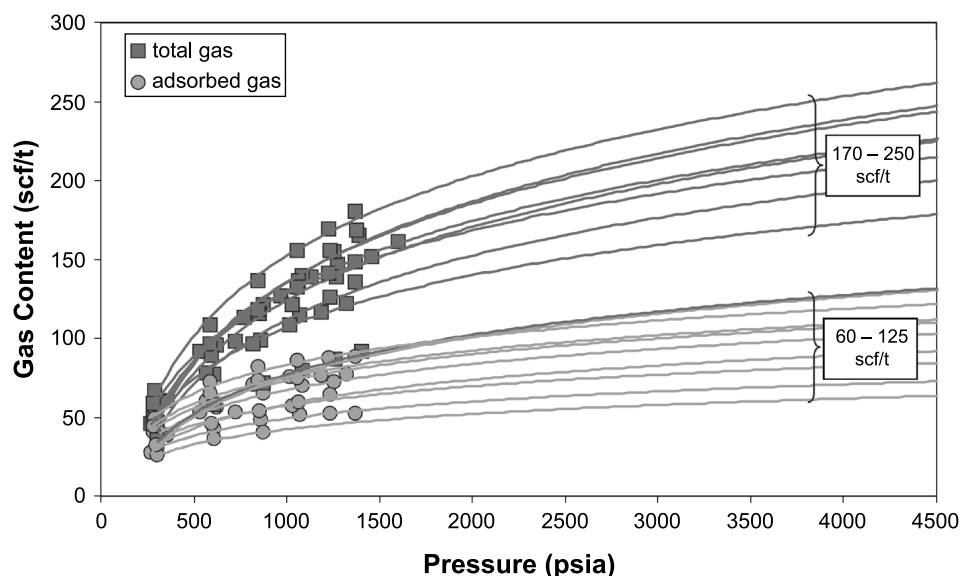
Several recent publications have presented gas content figures for the Barnett Shale (Bowker, 2003; D. M. Jarvie, 2003, personal communication; Mavor, 2003; Jarvie et al., 2004a, b). Bowker (2003) includes results of

canister desorption of core samples from the Chevron 1 Mildred Atlas, Johnson County, south of Newark East field. These results include an adsorption isotherm (in reality representing the total sorbed gas content as a function of pressure), suggesting that at reservoir conditions common in Newark East field (3000–4000 psi), the sorbed gas content of the Barnett Shale should be 105–115 scf/t (standard cubic feet)/t. These values are considerably higher than those determined by earlier laboratory analysis (~40 scf/t; Lancaster et al., 1993), which now appear to have been hampered by inadequate testing apparatus.

The higher values are confirmed by other recent work. For example, in the Mitchell Energy 3 Kathy Keel well (Denton County; redesignated as the K. P. Lipscomb 3), Barnett Shale gas content was determined to be 120 scf/t at an average present-day TOC of 5.2% (Mavor, 2003; pressure not given). In this case, the sorbed gas was estimated to comprise 61% of the total gas-in-place volume, 196.7 scf/t.

Similar values are indicated by the methane isotherms of Figure 8, based on data reworked for the T. P. Sims 2 well (Wise County) (Gas Research Institute, 1991; D. M. Jarvie, 2004, personal communication). The isotherms cover both adsorbed and total gas and show reasonable agreement with the results of the Mildred Atlas and Kathy Keele wells. The sorbed gas component ranges from 60 to 125 scf/t or 35–50% of total gas content (170–250 scf/t) at a reservoir pressure of 3800 psi. Average values include 85 scf/t for sorbed gas and 105 scf/t for free gas, accounting for roughly 45 and 55% of the average total gas (190 scf/t), respectively.

Figure 8. Adsorption isotherms for Barnett Shale core samples recovered from the Mitchell Energy 2 T. P. Sims well, Wise County. Ranges in gas content of 170–250 and 60–125 scf/t for total and adsorbed gas, respectively, are indicated for a reservoir pressure of 3800 psi.



These data imply, in general, that the Barnett Shale has a much higher gas content than other gas-shale reservoirs in the United States currently undergoing development (Hill and Nelson, 2000), and more specifically, that a large portion of the total Barnett Shale resource exists as free gas in the reservoir.

NEWARK EAST FIELD

Gas production from the Barnett Shale is mainly centered in the Newark East field, which encompasses much of western Denton County, eastern Wise County, and the northwestern part of Tarrant County. The field underlies, in part, the older Boonsville field that produces gas from overlying Pennsylvanian (Atokan and Strawn) clastics. Initial drilling in Newark East during the early 1980s also intended to test development locations in Boonsville field.

Within the limits of Newark East field, the Barnett Shale averages 400 ft thick (137 m) and is slightly overpressured at 0.52 psi/ft. The depth to top of the formation ranges from about 6900 to 7500 ft (2104 to 2287 m). Porosities in productive zones average about 6%, with permeabilities ranging from microdarcys up to 0.01 md. Vitrinite reflectance values are in the range of 1.3–2.1%, increasing toward the east-southeast. Gas-to-oil ratios increase in this same direction, reflecting higher maturities, with higher Btu (~1300) wet gas predominant in the western part of the field and lower Btu (~1000) drier gas in the eastern part. Production is established both in the upper and lower portions of the Barnett Shale (see Figure 4), with 75% or more of the gas derived from the thicker, lower Barnett. In the northern part of the field, where the lower Barnett Shale is greater than 450 ft (137 m) thick, up to five distinct pay zones are separated by limestones or calcareous shales. To the south, these zones become less distinct, and a large section of the lower Barnett Shale is completed as a single productive zone (see Figure 4).

As of January 2004, more than 2340 wells had been drilled in Newark East. At that time, the field was producing on the order of 800 mmcf of gas/day, with cumulative production of 0.8 tcf. More than 220 bcf were produced in 2003. Wells have been drilled on 55-ac spacing; however, data are accumulating in support of downspacing to 27 ac and possibly less in some areas of the field. Although most locations to date have been drilled vertically, a growing proportion is horizontal wells. This approach to drilling the Barnett Shale, using

single laterals, is being pursued as a means to increase well productivity in Newark East and to establish commercial production in other areas of the basin.

Artificial stimulation is required to yield commercial rates of gas flow in the Barnett Shale. Early completions used energized foam and gel fluids, with large volumes of proppant (1 million lb). Beginning in the late 1990s, stimulations using water and small amounts of proppant (50,000 lb sand) were successfully employed, at much reduced cost and improved well performance. Productivity has been further enhanced by restimulation, which can increase the estimated ultimate reserves of existing producers by 25% or more.

Successful stimulation in Newark East has depended on the presence of upper and lower lithologic barriers that contain induced fractures and prevent incursion of water from overlying and underlying formations. These barriers include the Marble Falls above and Viola–Simpson carbonates below. Where present in significant thickness, the Forestburg limestone also serves to confine induced fractures in the lower and upper Barnett. The Viola–Simpson, in particular, prevents stimulated fractures in the more highly productive lower Barnett Shale from contacting the water-bearing, karsted, and naturally fractured Ellenburger Group. In some parts of the Fort Worth basin, the Viola–Simpson also contains water-bearing zones that complicate Barnett Shale completions. In addition, faults that affect the lower Paleozoic and Mississippian section are capable of acting as water conduits into the Barnett.

PRODUCTION

Vertical and horizontal producers exist in the Barnett Shale play and exhibit somewhat different characteristics but similar overall patterns. Vertical wells account for the great majority of production to date, particularly in Newark East field. Initial rates of production in this field for vertical wells range from 0.5 to more than 2.0 mmcf/day. Estimated ultimate reserves for these wells are typically on the order of 1.0–2.5 bcf but have been as high as 7.0 bcf. Single restimulations have added an average of 0.5 bcf of reserves per well. Multiple recompletions on early Barnett Shale wells are now common.

Horizontal producers have been drilled in Newark East field and in surrounding areas to the south, east, and west, with all of these wells fracture stimulated. In Newark East, horizontal wells have exhibited initial rates of production ranging from 1.5 to 8.1 mmcf/day; outside

the field, rates have varied from 1.0 to 3.0 mmcf/day. Reserves for these wells range widely, but average about 2.5 bcf.

Production for both vertical and horizontal Barnett Shale wells shows rapid initial decline, followed by progressive flattening over time. Restimulation has been performed on an increasing number of older (vertical) wells in Newark East (Figure 9), especially those completed prior to the late 1990s when water-based stimulations were introduced. This technique, moreover, is now also being applied routinely to younger wells, those that have been producing for several years. In many cases, flow from restimulation has increased to initial rates or, in some instances, to superior levels of production than the well had previously experienced. The approach has also been applied successfully to wells in which production had become subeconomic. Such results suggest that multiple restimulation may be profitable in certain wells.

In the case of Figure 9, the original stimulation involved the lower Barnett Shale only and employed approximately 1,000,000 gal (3,785,411 L) of gel-based fluid and 200,000 lb (90,718 kg) of proppant. For the restimulation, both upper and lower Barnett Shale intervals were treated with approximately 620,000 gal (2,346,954 L) of water and 54,000 lb (24,493 kg) of 20/40 sand. As of May 2004, the well had produced

0.76 bcf, with 0.52 bcf (68%) of this total attributable to the restimulation.

Total production for Newark East field has climbed steadily since the late 1980s (Figure 10). As shown in Figure 10, the most rapid increase occurred after 1999, when improved completion practices (water stimulations), addition of the upper Barnett Shale as a target zone, and restimulation were all implemented, the latter two of these improvements having been instituted as a direct result of high gas content determinations. Most wells completed or recompleted using the new water-stimulations approach have only been producing for a few years. Thus, there is insufficient production history at present to make detailed predictions regarding long-term well and field performance.

HORIZONTAL DRILLING IN THE BARNETT SHALE

The long-term future of the Barnett Shale play in the Fort Worth basin may be determined, in part, by the success of horizontal drilling. At the time of this writing, such drilling represents a recent application of advanced technology to the play. Although more than 150 horizontal wells have been completed in the Barnett, the great majority of these have been drilled since 2002;

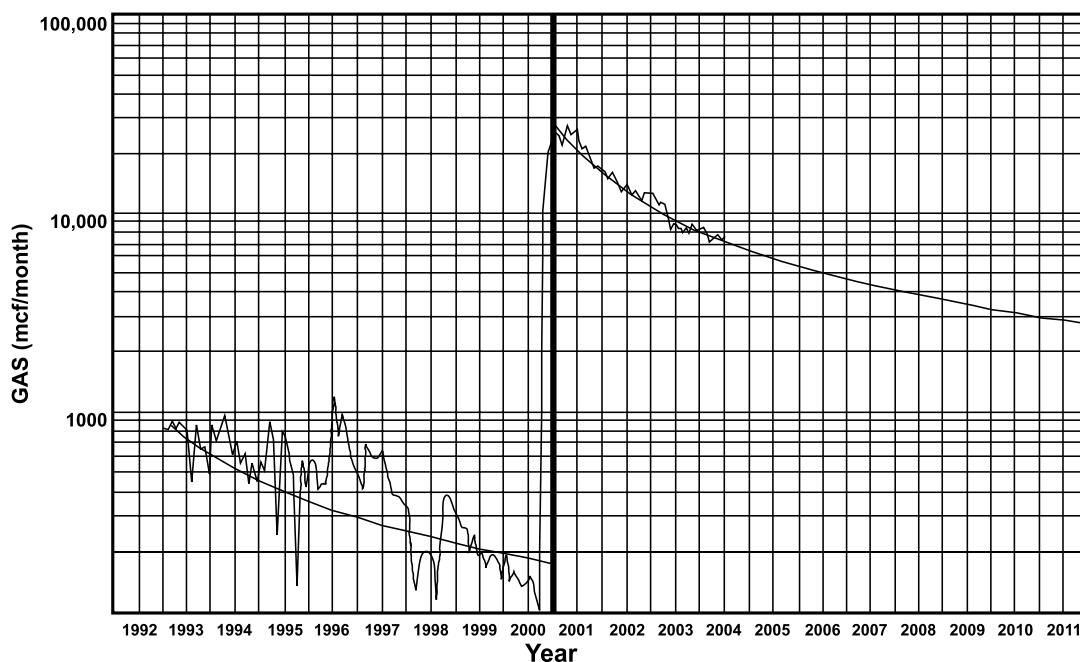


Figure 9. Typical production history for an older well in Newark East field, showing low rates of flow and flattening decline, followed by a sharp increase in production because of restimulation using newer, water-based treatment. Well is the Mitchell Energy 2 Boyd Townsite. Estimated ultimate recovery for this well is on the order of 0.85 bcf.

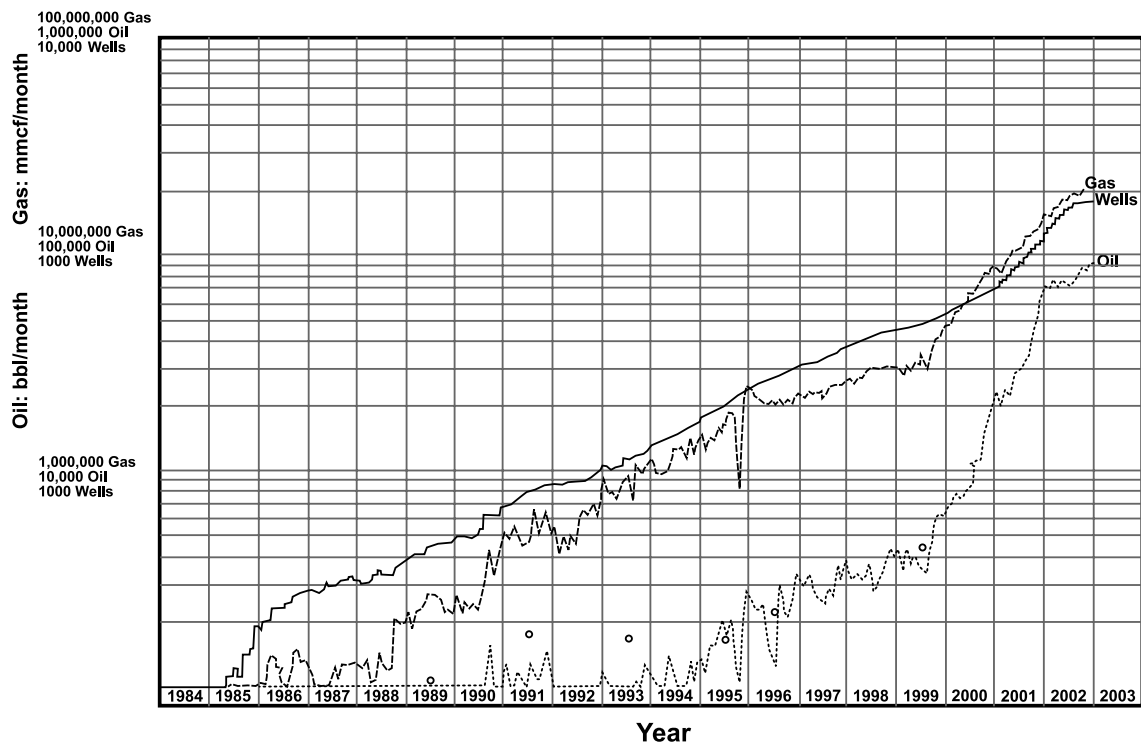


Figure 10. Graph showing growth in hydrocarbon production and number of wells in Newark East field. Data are current through the end of 2002.

thus, there is insufficient production history to support any final estimates regarding the ultimate potential of this approach to developing the Barnett Shale reservoir. However, results to date, combined with data from the mapping of induced fractures in the Barnett Shale, support several important preliminary conclusions.

Horizontal wells will not produce unless stimulated. Fracture mapping in Newark East field, using a combination of tiltmeter (surface and downhole) and microseismic techniques, has indicated that stimulated vertical wells drain a long, narrow section of reservoir averaging about 3000×500 ft (915×152 m) (Fisher et al., 2002). With this information, operators postulated that a horizontal well drilled perpendicular to the induced fracture direction will, when stimulated, be able to drain several parallel sections of reservoir, thus expanding the overall drainage area. Early production results appear to bear out this assumption. Initial rates of gas flow from horizontal wells in Newark East field have been typically two to three times those of vertical wells. Nearly all these horizontal attempts have involved single laterals drilled in the lower Barnett interval. Ongoing evaluation is being performed to determine optimal placement of the borehole in this part of the Barnett stratigraphic section.

Completion procedures differ according to the presence of lithologic barriers to vertical fracture growth. Where such barriers exist, operators typically do not cement the production string in the hole and may stimulate the well either in a single stage or in multiple stages. In areas where lithologic barriers are absent or where there is some question as to their ability to contain fracture growth (e.g., where they are thin or faulted), production casing is cemented in place, and a multiple-stage stimulation is performed. In all cases, water-based treatments are used. Treatment volumes range from 750,000 to more than 2,000,000 gal (2,839,058 to more than 7,570,822 L) per stage, depending on the length of the horizontal lateral, which has varied from 500 to more than 3500 ft (150 to more than 1070 m).

Operators report two main reasons for applying horizontal technology to the Barnett Shale. The first reason, as indicated above, is that stimulated laterals increase production significantly in the core area of Newark East field. The second reason relates to the observation that, in areas where lithologic barriers to induced fracture growth are thin or absent, stimulations in horizontal wells tend to remain in the target interval of the Barnett reservoir much better than do those in vertical wells. Why this should be the case is not yet

understood, but the phenomenon has considerable implications for future development of the Barnett Shale play. As operators test, analyze, and improve stimulation methods for horizontal wells in the play, larger portions of the basin will likely open to development.

BARNETT PLAY: LIMITING FACTORS

Although a large portion of the Fort Worth basin appears to be prospective for Barnett Shale gas production, full development beyond the borders of Newark East field will need to overcome several limiting constraints imposed by geological and geochemical factors. These factors include the following:

1. Erosional pinch-out of the Viola–Simpson section (lower barrier to hydraulic fracture growth) along a northwest-trending line through easternmost Johnson, western Tarrant, and central Wise counties, placing lower Barnett Shale directly on the karsted, potentially water-bearing Ellenburger Group and therefore creating the potential for water incursion after stimulation.
2. Increasing presence of porous, water-wet zones in the Viola–Simpson interval northwest of Newark East field, i.e., in northwestern Wise County. This also places the lower Barnett Shale immediately above wet carbonates, increasing the possibility of water incursion.
3. Depositional pinch-out of Marble Falls Formation (upper barrier to hydraulic fracture growth) along an east-west line through northern Dallas and central Tarrant counties. Stimulation of the upper Barnett Shale south of this line runs the risk of fracturing into overlying mixed gas-water-bearing Pennsylvanian clastics.
4. Decreasing maturity levels in the western and northern parts of the basin, where the Barnett Shale is in the oil window. Permeability constraints make producing commercial volumes of gas with black oil more difficult than gas or gas with condensate.
5. Higher maturity levels and much increased drilling depths in the easternmost part of the basin, proximal to and possibly beneath, the leading edge of the buried Ouachita thrust and fold belt. Increased drilling costs, higher bottomhole temperatures, and lower heat content (drier) gas negatively affect economics in this area.

Several of these factors may be compensated by improved completion practices, specifically those able to confine stimulated fractures or production to prospec-

tive portions of the Barnett Shale itself. The need for such practices is widely recognized among operators active in the Barnett Shale play. Continued innovation in this area, possibly in conjunction with horizontal drilling, should unlock considerable new potential both within and beyond the limits of Newark East field.

It should be stressed that the influence of natural fracture systems on Barnett Shale productivity is not well understood. Whereas certain parts of Newark East field are more productive than others, the reasons for this are unclear. Core study and patterns of production suggest that macrofractures can adversely affect well performance in many cases because apertures are heavily mineralized with calcite and thus form barriers to fluid flow. Wells located on structural highs, for example, adjacent local faults or in sites surrounded by karst-related collapse, where fracturing would be expected, commonly exhibit poorer production compared to wells sited where the Barnett Shale is flat-lying and undisturbed. Wells close to identified faults, in particular, commonly exhibit reduced production levels and increased water production. However, if present to a significant degree, microfractures may influence productivity in a positive manner (Bowker, 2003), for example, by storing significant amounts of free gas. Such microfracturing has been interpreted as a result of maturation and expulsion (Jarvie et al., 2001; Adams, 2003; Jarvie et al., 2003). More detailed study of microfractures appears needed.

BARNETT SHALE GAS RESOURCE POTENTIAL

The combined evidence of laboratory analysis, maturation studies, subsurface mapping, and observed productivity patterns confirms that the Barnett Shale is thermally mature and hydrocarbon bearing over a large portion of the Fort Worth basin and Bend arch. Recent assessments suggest a total prospective area as large as 28,000 mi² (72,520 km²) (Pollastro, 2003). Borders to this area include regional tectonic features to the north, east, and south (Red River arch, Ouachita structural front, Llano uplift, respectively) and facies changes in the Barnett Shale west of the Bend arch, along the Eastern shelf.

Within this total area, the Barnett Shale is interpreted to contain a giant (multi-tcf), continuous-type gas accumulation over a section of the Fort Worth basin roughly 7000 mi² (18,100 km²) in size, corresponding to the gas window outlined by the 1.1% vitrinite reflectance contour (Figure 11; light shading) (Pollastro et al., 2004a, b). The most prospective portion of this

interpreted accumulation is a 1800-mi² (4700-km²) area in the northeast corner of the basin (Figure 11, dark shading). Prospectivity is deemed to be especially high in this area because of several factors: (1) both over- and underlying barriers to vertical fracture growth are present; (2) the Barnett Shale is especially thick (>350 ft; >107 m); (3) Barnett Shale TOC values in clay-rich intervals average 3.5% or greater; (4) R_o in the Barnett Shale equals or exceeds 1.3%; and (5) T_{max} values are above 450°C (Bowker, 2003; D. M. Jarvie, 2003, personal communication; Pollastro et al., 2004a, b).

Booked reserves for the Barnett Shale are currently on the order of 2.7 tcf. Ongoing assessments are

being performed by operators in the current play and by the U.S. Geological Survey. Early published estimates of undiscovered, technically recoverable gas in the Barnett Shale ranged from 3.2 tcf (Schmoker et al., 1996) to 10 tcf (Kuuskraa et al., 1998). More recently, the U.S. Geological Survey completed a resource assessment of the Bend arch–Fort Worth basin province and estimated a total mean undiscovered shale gas resource of 26.2 tcf and 1 billion bbl of natural gas liquids for the two areas of Figure 11 combined.

Unofficial figures provided by Devon Energy propose an average gas-in-place estimate of 142.5 bcf/mi² (55 bcf/km²) for the entire Barnett Shale interval in the northern Fort Worth basin (Devon Energy, 2003).

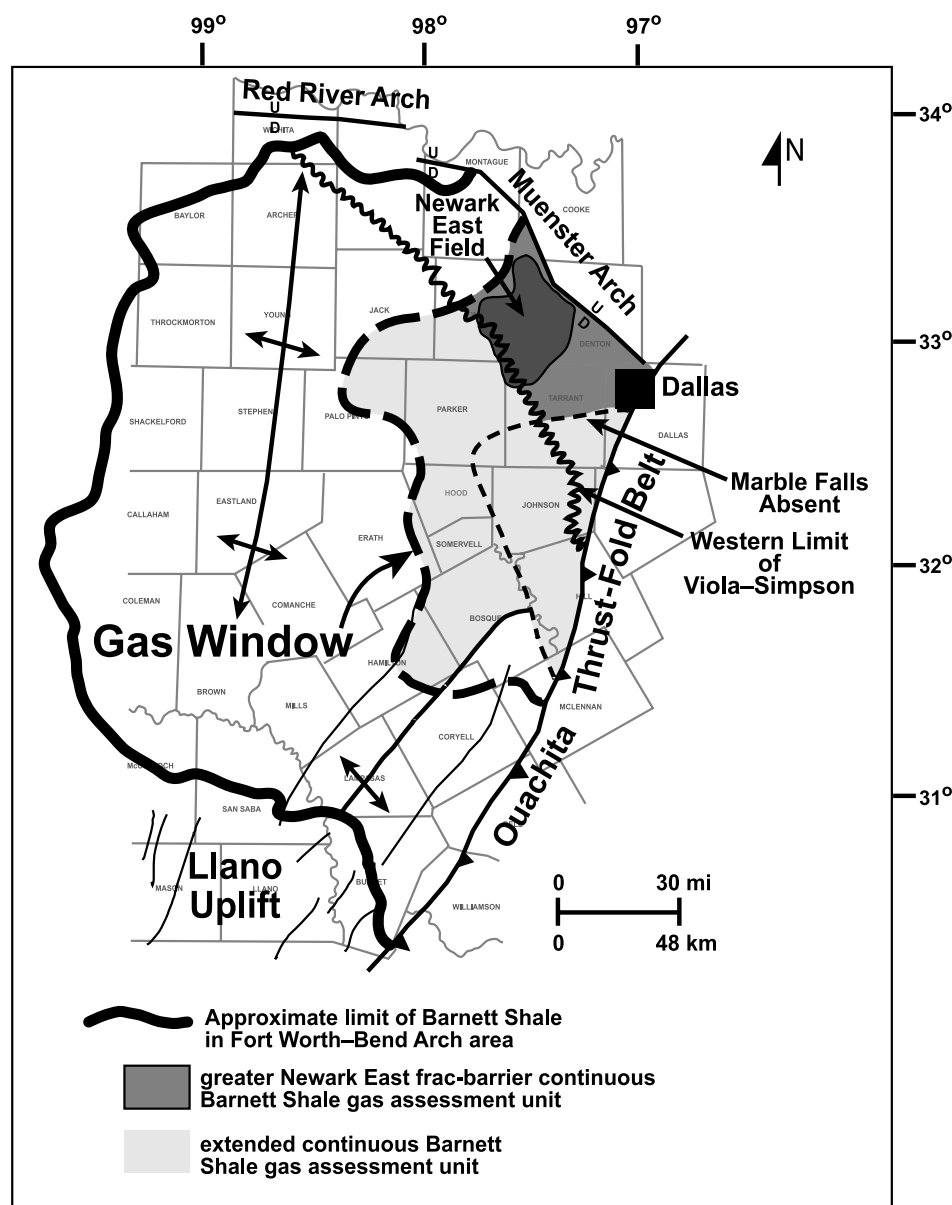


Figure 11. Map outlining high-potential areas for Barnett Shale gas production in the Fort Worth basin. Lighter shading corresponds to the area interpreted to contain the larger portion of a continuous-type gas accumulation in the Barnett. Darker shading indicates subset of that accumulation where limestone barriers exist to contain stimulated fractures in the formation (highest potential area, given current technology). Modified from Pollastro (2003).

This would suggest a gas-in-place resource of 57 tcf for Newark East field (400 mi²; 1036 km²) and 256.5 tcf for the most prospective part of the basin.

CONCLUSIONS

The Barnett Shale of the Fort Worth basin is source and reservoir to a world-class unconventional gas play that has developed rapidly since the mid-1990s. Whereas the play has thus far remained confined to one part of the basin, mainly in the vicinity of Newark East field, the ultimate potential of the Barnett Shale appears large, regional in extent. Current knowledge indicates that defining especially prospective areas in this larger domain can be achieved through the mapping of thickness, organic richness, thermal maturity, gas content, and lithologic (reservoir quality) data.

Development of the Barnett Shale play has depended on a combination of geological, geochemical, and engineering study. Geological analysis has identified and, to a certain extent, characterized reservoir portions of the Barnett Shale. Geochemical data have proven essential to explaining Barnett Shale potential and observed patterns of productivity. The role of engineering is apparent from improvements in completion techniques, particularly the introduction of water-based, low-proppant stimulation and the use of restimulation, both of which have greatly aided play economics.

Future expansion of the play will require continued advances in all these areas. Major challenges include explaining and predicting detailed patterns of higher production, as well as establishing commercial production south and north of Newark East field, in areas where lithologic barriers to induced fracture growth are absent, and in the western, oil-prone parts of the basin. Various combinations of horizontal drilling, multistaged completions, and new stimulation approaches may be required to meet these challenges.

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