RANKING THE RESOURCE POTENTIAL OF THE WOODFORD SHALE IN NEW MEXICO

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ABSTRACT

The Upper Devonian Woodford Shale ranges from a thickness of 0 ft to 300 ft and is found at depths of 7,000 ft to 18,000 ft in the Delaware Basin. The Woodford is thermally mature over its entire extent in New Mexico: In the deeper parts of the Delaware Basin it is in the thermogenic gas and condensate window; on the Northwest Shelf and where present on the Central Basin Platform it is in the oil window. Southeastern New Mexico is subdivided into Regions I, II and III based on the intensity of the fracture networks, thermal maturity and Total Organic Carbon (TOC) (Comer 2005).

Miller's (2010) gas shales ranking scorecard used parameters like total organic carbon, vitrinite reflectance, shale thickness, gas-filled porosity, clay content, quartz content, fluid compatibility, natural fracture intensity, tectonic stress and reservoir pressure gradient. The range of the scale of ranking is 0 to 100 points and for reference, the Barnett has 73 points. The better the total points, the better are the prospects of finding shale gas. Each of the regions (Regions I, II and III) were ranked for the prospects of shale gas using Miller's (2010) ranking scorecard and assigned a score of 68, 66 and 48 respectively. The results showed that Region I and II have better chances of finding shale gas. Finally an assessment was made to quantify the volumes of oil and gas in-place using Comer's (2005) Hydrogen mass balance method. The estimated volumes were 36 billion barrels of original oil in-place and 44.5 trillion cubic feet of original gas in-place (New Mexico) in comparison to 119 billion barrels of original oil in-place and 230 trillion cubic feet of gas in-place in the Woodford for the entire Permian Basin (Texas & New Mexico) (Figure 3). The assessment confirms that Woodford shale is a major unconventional source of both oil & gas in New Mexico.

INTRODUCTION

The Permian basin of New Mexico has been a source of oil & gas since 1924. The identification of new potential sources is very important as the region is mature. The USGS recently defined continuous (unconventional) assessment units (AU) in the Permian Basin. Those units were the Spraberry Continuous Oil AU, the Woodford-Barnett Continuous Gas AU, the Delaware-Pecos Basins Woodford Continuous Shale Gas AU, the Delaware-Pecos Basins Barnett Continuous Gas Shale AU, and the Delaware Basin Wolfcamp Shale AU. This paper focuses on the Woodford Shale of New Mexico. The Delaware Basin and Central basin platform has Upper Devonian Woodford Shale that ranges from a thickness of 0 ft to 300 ft and is found at depths of 7,000 ft to 18,000 ft (Broadhead 2010). Other reservoirs within the deep Delaware Basin produce primarily gas from depths of more than 17,000 ft and oil with associated gas from reservoirs shallower than 13,000 ft in the Northwest Shelf and Central Basin Platform. This study is focused on southeastern New Mexico which is subdivided into Regions I, II and III based on the intensity of the fracture networks, thermal maturity and Total Organic Carbon (TOC) (Comer 2005) (Figure 1). The isopach map of Broadhead (2010) for the Woodford Shale is used in this work. The weighted mean average for the thickness of each region was calculated and used in the assessment.

REGIONAL STRATIGRAPHY, LITHOLOGY & DISTRIBUTION

Southeastern New Mexico has a wide variety of rock types, including black shales, black cherts, sandstones, siltstones, and lighter-colored shales (Comer 1991). Black shale is dominant in most places. The Woodford Shale of the Permian Basin is Late Devonian in age (Ellison 1950; Meyer and Barrick 2000; Broadhead 2010) and places the Woodford in the upper part of the Upper Devonian (Figure 2). In the Permian Basin, the Woodford overlays Silurian and Lower Devonian carbonate strata of the Wristen Group and is in turn overlain by Lower Mississippian limestone. Both the Wristen and Thrityone carbonates have been a good source for oil and gas in New Mexico.

In this paper we considered the Woodford Shale as a single unit. Apparent thickness of the Woodford Shale will exceed true thickness by significant amounts where the structural dips are steep on the flanks of some of the Pennsylvanian-age paleostructures. This is thought to be a complication only where there is a large amount of variation in apparent Woodford thickness over a small geographical area perhaps one township. Broadhead (2010) solved this problem and published an isopach map with the true thickness and this true-thickness isopach map was used as one of the base maps in the ranking and estimation of the Woodford Shale.

The southeastern New Mexico is divided into three regions (Updated from Comer 2005) Region I (Probable), Region II (Possible), and Region III (Local Success). The Woodford Source Rock Characteristics data used in this work is from Broadhead 2005.

METHODOLOGY

This work applies the Miller's gas shale scorecard (Table 3) for ranking the potential unconventional gas areas of Woodford Shale in New Mexico. The gas shale scorecard used geochemical parameters (total organic carbon, vitrinite reflectance, clay content and quartz content), geo-mechanical parameters (natural fracture intensity, tectonic stress and reservoir pressure gradient) and field development parameters (shale thickness, gas-filled porosity and fluid compatibility). After evaluating each parameter for a certain value, there is a score assigned corresponding to that value on a scale of 10. And finally we add the scores for all the ten parameters and rank the reservoir on a scale of 100. The assessment of potential hydrocarbon in-place estimates were accomplished using a hydrogen mass balance methodology (Comer 2005).

GEOCHEMICAL PARAMETERS

TOC – Total Organic Carbon

Total organic carbon consists of data points spanning a range of 1.7 wt % to 4.93 wt % from Broadhead (2010). Miller (2010) gives a higher rank for higher TOC values. This study assigned a score of 8, 6 and 4 for Region I, Region II and Region III respectively (Table 1).

R_o – Vitrinite Reflectance

Vitrinite Reflectance consists of data points spanning a range of 0.55 to 2.02 % from Comer (2005). Miller (2010) gives higher rank for dry gas generation with higher R_o values. This study assigned a score of 6, 8 and 4 for Region I, Region II and Region III respectively (Table 1).

Clay Content (wt %)

Clay Content consists of data points spanning a range of 45 wt % to 60 wt % from Ruppel, S. & Loucks, R., (2007) and Jarvie, D., (2008). Miller (2010) gives higher rank for lower clay content. This study assigned a score of 4, 4 and 4 for Region I, Region II and Region III respectively (Table 1).

Quartz content (wt %)

Quartz content consists of data points spanning a range of 30 wt % to 45 wt % from Ruppel, S. & Loucks, R.,(2007) and Jarvie, D., (2008). Miller (2010) gives higher rank for higher quartz content. This study assigned a score of 6, 6 and 6 for Region I, Region II and Region III respectively (Table 1).

GEO-MECHANICAL PROPERTIES

Natural Fractures Intensity (per 10ft)

Natural Fractures Intensity consists of data points spanning a range of 4 to 9 (per 10ft) from Comer (1991) and 110029-MS. Miller (2010) gives higher rank for higher fracture intensity. This study assigned a score of 8, 6 and 6 for Region I, Region II and Region III respectively (Table 1).

Tectonic Stresses (σ2 versus σ3)

Tectonic stresses consists of data points with values of $\sigma2>\sigma3$ and $\sigma2=\sigma3$ from Comer (1991). Miller (2010) gives higher rank for stresses where $\sigma2=\sigma3$. This study assigned a score of 10, 10 and 6 for Region I, Region II and Region III respectively (Table 1).

Reservoir Pressure gradient (psi/ft)

Reservoir pressure gradient consists of data points spanning a range of 0.4 to 0.7 psi/ft from Lee & Williams (2000). Miller (2010) gives higher rank for higher reservoir pressure gradient. This study assigned a score of 8, 8 and 6 for Region I, Region II and Region III respectively (Table 1).

FIELD DEVELOPMENT PARAMETERS

Shale Thickness (ft)

Shale thickness consists of data points spanning a range of 0 to 300 ft from Broadhead (2010). Miller (2010) gives higher rank for higher thickness reservoirs. This study assigned a score of 8, 6 and 4 for Region I, Region II and Region III respectively (Table 1).

Gas-filled Porosity (Average %)

Gas filled porosity consists of data points spanning a range of less than 2 % to 8 % from Comer (2005). Miller (2010) gives higher rank for higher gas-filled porosity reservoirs. This study assigned a score of 6, 8 and 4 for

Region I, Region II and Region III respectively (Table 1).

Fluid Compatibility (with Fresh Water; CST ratio)

Fluid compatibility test with fresh water consists of no data points in New Mexico, so data points are analogous to the Barnett shale in the Permian basin. As a result a value of 2-3 CST ratios from Miller (2010) is used. Miller (2010) gives higher rank for lower CST ratios. This study assigned a score of 6, 6 and 6 for Region I, Region II and Region III respectively (Table 1).

SCORES BY REGION

The summary of all the above analyzed parameter was provided in Table 1. Region I, II & III were ranked as 68, 66 and 48 respectively and region I and II has been identified as having higher chances of finding good gas prospects. Region III was identified as the least productive region for shale gas prospects.

ESTIMATION OF RESOURCE POTENTIAL

The estimations worked out were based on some very important assumptions and focuses on the southeastern part of the New Mexico. The resource potential estimated by Comer (2005) had less data from the Permian basin of New Mexico and his Woodford analysis was based on the Woodford in the Arkoma Basin in Oklahoma. Further, Broadhead (2010) mentioned "several works that have been published about the Woodford in the Permian basin, but most of the data and analysis was done using data from Texas". This work analyzed the Woodford Shale of New Mexico with more data in the New Mexico Woodford and quantified the in-place oil & gas estimates using the Hydrogen Mass Balance Methodology. The mean organic carbon concentrations for the Permian basin is 3.8 wt % (Comer 2010). The Woodford shale contains predominantly oil-prone type II kerogen (Comer and Hinch, 1987; Cardott, 1989; Comer 1991, 1992, 2005; Landis and others 1992; Broadhead, 2010) representing a wide range of thermal maturities from marginally immature to metamorphic (Ro = 0.37 - 4.89%) (Cardott, 1989; Comer, 1992; Broadhead 2010).

The first assumption made by Comer (2005) was that Oil & Gas in the Woodford Shale are indigenous. And because it is indigenous conventional source rock data like Organic Carbon, Organic Hydrogen, Organic Matter type, Thermal Maturity, along with facies volumes (thickness times area) etc., can be used for in-place oil & gas estimation. Some of his other assumptions were that hydrogen from inorganic sources such as water and hydrogen mineral do not appear to result in an increase in hydrogen available for hydrocarbon (HC) generation. Comer also assumed losses of hydrogen from the organic fraction in the form of H_20 and H_2 molecules did not represent large losses of organic hydrogen mass during the main stages of HC generation. And finally, the amount of hydrogen available for HC generation is equivalent to the amount of organic hydrogen present at the onset of the main stage of oil generation.

Comer (2005) first observed that thermal maturation of organic matter results in CH_4 and graphite carbon residue. Thus the volume of hydrogen generated is limited by the amount of hydrogen available in the system. Second, that large amount of waters are eliminated from organic matter by reactions of H- and OH- bearing organic molecules before a source bed enters the oil window. All the organic data in his work represent kerogen that has matured to or beyond the inflection point on the van Kervelen diagram (Broadhead 2010) for Type II kerogen between organic reactions predominantly involving H_20 and Co_2 elimination and those involving hydrocarbon generations. With all of Comer's assumptions and observations, the volume of evolved HCs is estimated using mass balance of organic hydrogen (H_{org}). The units being used are Metric Tons (MT), kilometers (km), weight fraction (wt fraction), barrels (bbl), and cubic feet (ft^3).

Our estimation of oil & gas potential began with gathering essential data (Table 4, Table 5, and Table 6) for the Woodford Shale of New Mexico. E.g.: Reservoir Area (km^2), Average Thickness (km), Reservoir Mass (MT), Mean organic carbon concentration (%), mean organic hydrogen concentration (%) and bulk density (MT/km^3). Southeastern New Mexico has been categorised into 3 regions: Region I (thermal maturity (early oil to oil generation window), high TOC and high fracture intensity); Region II (thermal maturity (wet gas, dry gas & condensate generation), moderate TOC and sparely fractured); and Region III (thermal maturity (oil window), reasonable TOC and local fractures) (Figure 3). As a result, estimation for each region follows a similar methodology to Comer (2005) except that due to the variation in thermal maturity, we needed to use various conversion factors.

Step 1: Reservoir Mass Determination

$$\text{Reservoir Mass (MT)} = \text{Thickness (km)} \times \text{Area (km}^2) \times \text{Density (MT/km}^3) \qquad \text{Eq. (1)}$$

Table 4 gives the reservoir thickness, area, volume, and mass for Woodford Shale of New Mexico. The area of regions I, II & III was calculated using ArcGIS and the corrected Woodford thickness used is obtained from Broadhead (2010). The mean density of Woodford shale is 2.4×10^9 MT/km^3 (Comer and Hinch, 1987; Comer, 2005).

Step 2: Gathering Organic Fraction Data from Core Samples

Table 5 has data from the organic fraction used in the assessment (Comer 2005). These values were taken from the analyses of isolated, solvent extracted kerogen in the two Woodford Shale Cores with the lowest thermal maturity; these cores were recovered from two wells in Oklahoma (Comer, 1991 and 2010). Each region has been assigned a certain value of Present and Immature C_{org} (%), Horg (%), & Vitrinite Reflectance (R_o %) respectively.

Step 3: Converting the organic fraction from core sample to Whole rock.

Data from the Anadarko Basin was used for the analogous facies of the Woodford in the Permian basin. Kerogen data are converted to whole rock data by recognizing that the ratio of C_{org} to H_{org} in kerogen is the same as the ratio of C_{org} to H_{org} in whole rock using the relationship as below.

$$(C_{org}/H_{org})\text{ kerogen} = (C_{org}/H_{org})\text{ whole rock} \qquad \text{Eq. (2)}$$

Step 4: Calculating the Total hydrocarbon mass H_{org} (MT) using wt fraction of the whole rock

Initial Immature H_{org} MT is calculated by multiplying the immature H_{org} (%) (Table 6) and the Reservoir Mass (Table 4). Similarly the residual H_{org} MT is calculated by multiplying the Present H_{org} (%) (Table 6) and the Reservoir Mass (Table 4).

$$\text{Immature } H_{org} \text{ Mass (MT)} = \text{Reservoir Mass (MT)} \times \text{Immature } H_{org} \text{ (wt fraction)} \qquad \text{Eq. (3)}$$

$$\text{Residual } H_{org} \text{ Mass (MT)} = \text{Reservoir Mass (MT)} \times \text{Present } H_{org} \text{ (wt fraction)} \qquad \text{Eq. (4)}$$

And finally the Total mass of hydrocarbon H_{org} (MT) is the difference between the Immature H_{org} (MT) and the Residual H_{org} (MT).

$$\text{Total Organic Hydrogen } H_{org} \text{ (MT)} = \text{Immature } H_{org} - \text{Residual } H_{org} \qquad \text{Eq. (5)}$$

Step 5: C_{org} Mass Determination

Values for the immature C_{org} in table 6 are derived from the mean organic carbon concentration observed in each region adjusted using the mean organic carbon concentration in the two immature cores, the difference between the immature and observed level of thermal maturity, and the degree of dilution by the clastic sediment.

$$C_{org} \text{ Mass (MT)} = \text{Reservoir Mass (MT)} \times \text{Immature } C_{org} \text{ (wt fraction)} \qquad \text{Eq. (6)}$$

For example in Region I, the initial C_{org} mass of 19.71×10^9 (MT) is equal to the reservoir mass of 239.84×10^9 (MT) times the mean C_{org} weight fraction of 0.0822 in immature shale.

Step 6: Total Natural Gas Co-Generated (Gas MT):

The amount of natural gas co-generated with oil during thermal maturation of low to moderate maturity marine black shale is estimated based on data from literature (table 5). For thermal maturities between 0.4 and 0.9% R_o, the saturated light hydrocarbons content more than two orders of magnitude mostly in the range of 1×10^{-4} MT/MT C_{org} to 1×10^{-2} MT/MT C_{org} (Schaefer and Leythaeuser, 1983; Comer). For those regions where Woodford Shale is in the Oil Window, the total mass of natural gas is estimated using the initial mass of C_{org} in immature shale (Table 8) and the published ratio where

$$\text{(Oil Window) Gas (MT)} = \text{Gas (MT/MT } C_{org}) \times C_{org} \text{ (MT)} \qquad \text{Eq. (7)}$$

In Region I, the mean vitrinite reflectance of Woodford shale is 0.55% and by analogy with Mesozoic marine black shale, the gas concentration is on the order of 1×10^{-4} MT/MT C_{org} (Comer 2005). Also for Region III, where the mean vitrinite reflectance is 1.09% R_o, the gas concentration value of 1×10^{-2} MT/MT C_{org} (Comer 2005) was used. But for Region II, where there is a thermogenic gas generation ($R_o\,\% > 2$), there is no published ratio that can be used. So, the total natural gas co-generated in MT is calculated using the total volume of Generated Gas (ft^3) (from Step 9) divided by the volume occupied by a metric ton of natural gas (5×10^4 ft^3/MT).

Step 7: Total mass of organic hydrogen that exits as natural gas (H_{gas})
For Region I, the total mass of natural gas is determined by multiplying the total amount of natural gas (MT) times the weight fraction of hydrogen (0.25 for methane). In Region III, The total mass of organic hydrogen that exits as natural gas (H_{gas}) is calculated by multiplying the resulting mass of gas by the weight fraction of H_{org} in gas where

$$H_{gas}\ (MT) = Gas\ (MT) \times H_{org}\ (wt\ fraction) \qquad \text{Eq. (8)}$$

For Region II, the process is a bit different. H_{gas} is determined as a difference of Total Hydrocarbon H_{org} (MT) and Total mass of Hydrogen in oil H_{oil} (Step 8).

Step 8: Total mass of hydrogen contained in Crude Oil (H_{oil})
For regions I & III, the total mass of hydrogen contained in Crude Oil (H_{oil}) is the difference between the total mass of H_{org} in Hydrocarbons (Table 7) and the mass of hydrogen in gas (H_{gas}). But for Region II where the thermogenic gas exists a different approach was used. The Total amount of oil (Eq. 9) generated (Table 9) which is the total hydrocarbon H_{org} (MT) divided by 2×10^{-2} was calculated and if 30% of this is expelled, the difference between total Hydrocarbon H_{org} and the Oil Expelled would result in H_{oil}.

$$H_{oil} = (\text{Total Hydrocarbon } H_{org} - \text{Oil Expelled}) \times 2 \times 10^{-2} \qquad \text{Eq. (9)}$$

Step 9: Volumes of Oil & Gas Generated and Expelled
The oil volume generated in Region I, Region II & Region III was calculated using total hydrocarbon H_{org} (MT) and converting it into barrels using the conversion of 1unit of hydrogen mass per barrel of crude oil as 2×10^{-2} MT/bbl. The resulting relationship is shown in Eq. 10. The oil volume expelled in Regions I, II & III was taken as30% of the oil volumes generated in each region after Comer and Hinch (1987) and Comer (2005)

$$\text{Oil Volume (bbl)} = \text{Hydrocarbon } H_{org}\ (MT) / 2.0\ X10^{-2}\ (MT/bbl) \qquad \text{Eq. (10)}$$

The gas volume generated in Region I was calculated by dividing H_{gas} (total amount of natural gas (MT) times the weight fraction of hydrogen (0.25 for methane)) by the mass of hydrogen per in a cubic foot of natural gas (5×10^{-6} MT/ft^3). However, for Region II & Region III, the gas volume is calculated by equations 10 & 11. The volume of gas produced by thermal cracking 1 barrel of crude oil is 3000 ft^3/bbl (Comer 2005). The gas volume expelled in Regions I, II & III is 80% (Comer and Hinch, 1987; Comer, 2005) of the gas volumes generated in each region.

$$\text{Gas Volume } (ft^3) = \text{Oil Volume (bbl)} \times 3000\ (ft^3/bbl) \qquad \text{Eq. (11)}$$

The final estimation of in-place oil & gas is achieved by calculating the difference between the volumes generated and volumes expelled. For Region II where Woodford Shale is in the gas window, it is assumed that all of the indigenous oil has cracked to gas.

RESULTS

Increased data density and quality for the New Mexico Woodford shale data was gathered from various published data since 1990 and used for ranking the Woodford Shale on the Miller Shale Scale. The Woodford was divided into three regions based on the intensity of the fracture networks, thermal maturity and Total Organic Carbon (TOC). Ranking and estimated potential gave highest gas resources to Region II. Estimated volumes for the Woodford Shale in New Mexico were 36 billion barrels of original oil in-place and 44.5 trillion cubic feet of original gas in-place compared to 119 billion barrels of original oil in-place and 230 trillion cubic feet of gas in-place in the Woodford in the entire Permian Basin (Texas & New Mexico).

Since the Woodford shale in New Mexico has had no gas production at the time of this paper, most of the parameters have been used from either Woodford Shale of the Permian Basin or from the analogous Woodford Shale of Oklahoma. The Woodford shale in New Mexico is found at great depths which contribute to its lack of production. However, this assessment strongly indicates that the Woodford Shale has high potential future potential as an unconventional oil & gas resource in New Mexico.

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Table 1
Ranking Score Card of the Woodford Shale of New Mexico

Parameters	Ranking on the Shale Scale			Data Source
	Region I	Region II	Region III	
Total Organic Carbon (TOC) – wt %	8	6	4	Broadhead (2010) & ComerRI(2005)
Vitrinite Reflectance (Ro) - %	6	8	4	Broadhead (2010) & ComerRI(2005)
Shale Thickness - ft	8	6	4	Broadhead (2010) & Comer (2005)
Gas-Filled porosity (Ave)	6	8	4	S Ruppel & Robert Loucks (2007)
Clay content (wt %)	4	4	4	S Ruppel & Robert Loucks (2007); Dan Jarvie(2008)
Quartz content (wt %)	6	6	6	S Ruppel & Robert Loucks (2007)
Fluid compatibility (Fresh Water; CST ratio)	4	4	4	Randall S.”Randy” Miller (2010); Dan Jarvie(2008)
Natural Fracture Intensity (per 10 feet)	8	6	6	John B. Comer (1991)
Tectonic stress (σ2 versus σ3)	10	10	6	John B Comer (1991)
Reservoir pressure gradient (psi/ft)	8	8	6	Randall S.”Randy” Miller (2010)
Total Score	**68**	**66**	**48**	

Table 2
Reference Barnett Ranking Scorecard (Source: Randy Miller 2010)

Parameters	Scale (0-10)
Total Organic Carbon (TOC) – wt %	6
Vitrinite Reflectance (Ro) - %	7
Shale Thickness - ft	10
Gas-Filled porosity (Ave)	6
Clay content (wt %)	8
Quartz content (wt %)	8
Fluid compatibility (Fresh Water; CST ratio)	6
Natural Fracture Intensity (per 10 feet)	6
Tectonic stress (σ2 versus σ3)	10
Reservoir pressure gradient (psi/ft)	6

Table 3
Set of Parameters and their range of scores assigned

1. Total Organic Carbon (TOC)					
Range of Values	< 1.0	1-3	3-6	6-9	>9
Assigned Score	0	4	6	8	10
2. Vitrinite Reflectance (Ro)					
Range of Values	< 0.5	0.5-1.0	1.0-1.5	1.5-2.0	> 2.0
Assigned Score	0	4	6	8	10
3. Shale Thickness					
Range of Values	< 50	50-100	100-200	200-300	> 300
Assigned Score	2	4	6	8	10
4. Gas-Filled porosity (Ave)					
Range of Values	< 2	2-4	4-6	6-8	>8
Assigned Score	0	4	6	8	10
5. Clay content (wt %)					
Range of Values	> 60	45-60	30-45	15-30	< 15
Assigned Score	2	4	6	8	10
6. Quartz content (wt %)					
Range of Values	< 15	15-30	30-45	45-60	> 60
Assigned Score	2	4	6	8	10
7. Fluid compatibility (Fresh Water; CST ratio)					
Range of Values	> 4	3-4	2-3	1-2	< 1
Assigned Score	2	4	6	8	10
8. Natural Fracture Intensity (per 10 feet)					
Range of Values	< 1	1-3	4-6	7-9	> 9
Assigned Score	2	4	6	8	10
9. Tectonic stress (σ2 versus σ3)					
Range of Values	σ2>>σ3		σ2>σ3		σ2=σ3
Assigned Score	3		6		10
10. Reservoir pressure gradient (psi/ft)					
Range of Values	< 0.4	0.4-0.5	0.5-0.6	0.6-0.7	> 0.7
Assigned Score	2	4	6	8	10

Table 4
Data used for calculating Reservoir Mass

Woodford Shale of New Mexico	Thickness (km)	Area (km2)	Volume (km3)	Density (MT/km3)	Mass (MT x 10^9)
Region I	0.030	3331.12	99.93	2400000000.00	239.84
Region II	0.043	5806.55	252.20	2400000000.00	605.28
Region III	0.015	22200.21	341.04	2400000000.00	818.49

Table 5
Data from the Organic Fraction used the Assessment

(Oklahoma Woodford analogous to New Mexico Woodford Shale)						
Woodford Shale of New Mexico	**Present Corg (%)**	**Immature Corg (%)**	**Present Horg (%)**	**Immature Horg (%)**	**Present Ro (%)**	**Immature Ro (%)**
Region I	82.00	82.20	7.72	7.74	0.55	0.39
Region II	90.50	82.20	4.38	7.74	2.02	0.39
Region III	85.60	82.20	6.08	7.74	1.09	0.39

Table 6
Whole rock data used in the Assessment

Woodford Shale of New Mexico	**Present Corg (%)**	**Immature Corg (%)**	**Present Horg (%)**	**Immature Horg (%)**
Region I	7.80	8.00	0.73	0.75
Region II	4.20	5.80	0.20	0.55
Region III	3.60	4.00	0.26	0.38

Table 7
Distribution of Hydrogen Mass Estimated

Woodford Shale of New Mexico	**Initial Immature Horg MT x 10^9**	**Residual Horg MT x 10^9**	**Total Hydrocarbon Horg MT x 10^9**
Region I	1.80	1.75	0.048
Region II	3.33	1.21	2.12
Region III	3.11	2.13	0.98

Table 8
Initial mass distribution

Woodford Shale of New Mexico	**Corg MT x 10^9**	**Gas MT x 10^9**	**Hgas MT x 10^9**	**Hoil MT x 10^9**
Region I	19.71	0.0020	0.00049	0.047
Region II	35.11	4.45	1.48295	0.635
Region III	32.74	0.33	0.00085	0.981

Table 9
Estimated Volumes of Generated, Expelled & Original In-Place Oil & Gas

	Generated		**Expelled**		**Original In-Place**	
Woodford Shale of New Mexico	**Oil MMbbl**	**Gas BCF**	**Oil MMbbl**	**Gas BCF**	**Oil MMbbl**	**Gas BCF**
Region I	2398.40	98.57	719.52	78.85	1678.88	19.71
Region II	105924.74	222441.96	31777.42	177953.56	0	44488.39
Region III	49109.44	2.55	14732.83	2.04	34376.61	0.51

Table 10
Comparison of Volumes of Original In-Place Oil & Gas to Comer's (2005) Assessment

	Original In-Place (Woodford Shale - Study Area)		**Original In-Place (Woodford Shale - Total Permian basin)**	
	Oil Billion bbl	**Gas Trillion ft^3**	**Oil Billion bbl**	**Gas Trillion ft^3**
Region I	1.68	0.019	35	.11
Region II	0	44.49	0	220
Region III	34.38	0.00051	84	9.0
Total	**36.06**	**44.6**	**119**	**229.11**

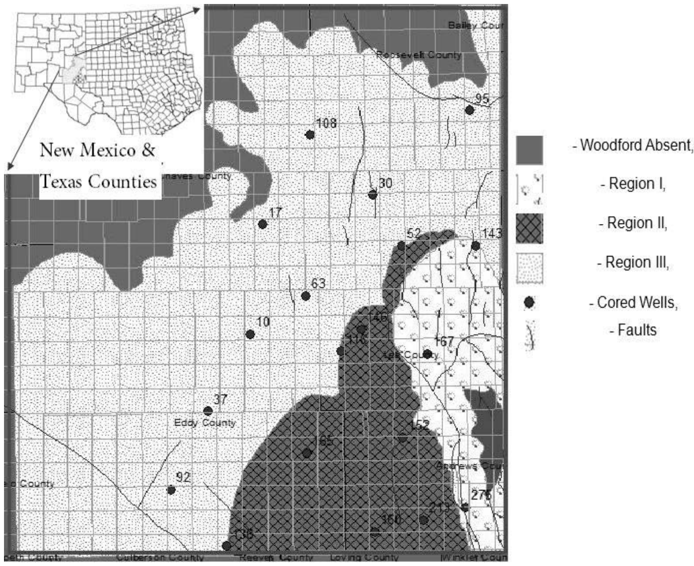
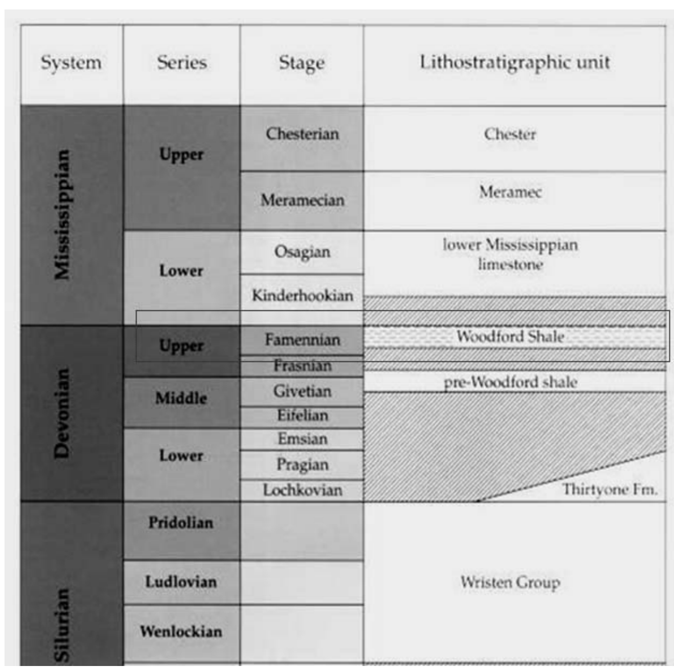


Figure 1 - Regions used for assessment of the Woodford Shale potential in the Southeastern New Mexico. (Updated study area using Broadhead 2010 & Comer 2005).



System	Series	Stage	Lithostratigraphic unit
Mississippian	Upper	Chesterian	Chester
		Meramecian	Meramec
	Lower	Osagian	lower Mississippian limestone
		Kinderhookian	
Devonian	Upper	Famennian	Woodford Shale
		Frasnian	
	Middle	Givetian	pre-Woodford shale
		Eifelian	
	Lower	Emsian	
		Pragian	
		Lochkovian	Thirtyone Fm.
Silurian	Pridolian		Wristen Group
	Ludlovian		
	Wenlockian		

Figure 2 - Startigraphic Unit of the Woodford Shale in New Mexico (Source: Broadhead 2010)

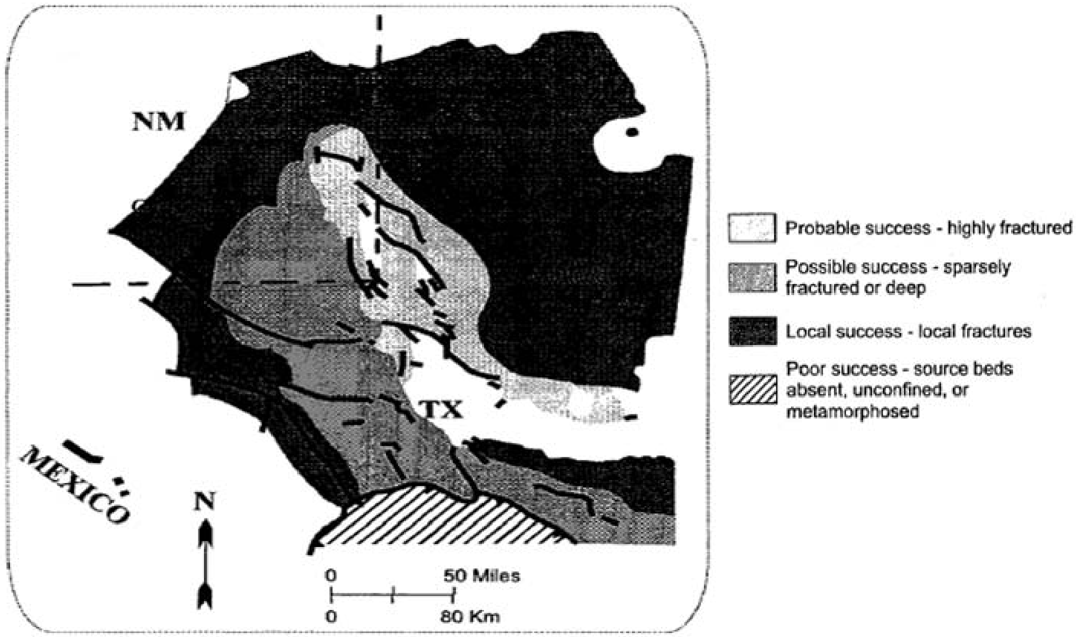


Figure 3 - Assessment for the Permian Basin (Comer 2005)