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Introduction

This document contains updated information and maps for the Wolfcamp and Bone Springs plays of the Permian Basin. The geologic features characterized include contoured elevation of the top of the formations (structure), contoured thickness (isopach), paleogeography elements, and tectonic structures (such as regional faults and folds), as well as play boundaries, well location, and initial wellhead production of wells producing from January 2005 through September 2018.

These geologic elements are documented and integrated into a series of maps. The Permian Basin maps consist of layers of geologic and production information that users can view either as separate thematic maps (such as Figure 1) or as interactive layers of the U.S. Energy Mapping System. Data sources include Enverus DrillingInfo Inc. (DI), a commercial oil and natural gas well database; the United States Geological Survey (USGS); Texas ***Bureau of Economic Geology***; EIA reports; peer-reviewed research papers; and academic theses.

Currently, EIA has access to well-level data, including more than 20,000 well logs from the Permian Basin, which we use for map construction. This report contains the Wolfcamp play section, including subsections on the Wolfcamp A maps in the Delaware Basin. EIA will add spatial layers on structure, thickness, and production maps as well as corresponding report sections describing major plays of the Permian Basin in the future as additional maps are created.

Permian Basin

The Permian Basin of West Texas and Southeast New Mexico has produced hydrocarbons for about 100 years and supplied more than 33.4 billion barrels of oil and about 118 trillion cubic feet of natural gas as of September 2018. Implementing hydraulic fracturing, horizontal drilling, and completion technology advancements during the past decade has reversed the production decline in the Permian, and the basin has exceeded its previous production peak, set in the early 1970s. In 2018, Permian Basin production accounted for more than 35% of total U.S. crude oil production and about 9% of total U.S. dry natural gas production. As of 2017, EIA estimates remaining proven reserves in the Permian Basin exceed 8 billion barrels of oil and 27 trillion cubic feet (Tcf) of natural gas, making it one of the largest hydrocarbon-producing basins in the United States and the world (EIA, 2018).

Regional tectonic setting and geologic framework

The Permian Basin is a complex sedimentary system located in the foreland of the Marathon-Ouachita orogenic belt. It covers more than 75,000 square miles and extends across 52 counties in West Texas and Southeast New Mexico. The Permian Basin developed in the open marine area known as the Tobosa Basin in the middle Carboniferous period approximately 325 million-320 million years ago (Galley, 1958). The ancestral Tobosa Basin was formed by an asymmetric structural flexure in the Precambrian basement at the southern margin of the North American plate in late Proterozoic time (Beamont, 1981; Jordan 1981). During consequent phases of basin development, sediments eroded from the surrounding highlands and were deposited in the basin (Brown et al., 1973; Dorobek et al., 1991).

The Permian Basin is now an asymmetrical, northwest- to southeast-trending sedimentary system bounded by the Marathon-Ouachita orogenic belt to the south, the Northwest shelf and Matador Arch to the north, the Diablo platform to the west, and the Eastern shelf to the east (Gardiner, W.B., 1990; Ewing, 1991; Hills, 1985). The basin is comprised of several sub-basins and platforms: three main sub-divisions include the Delaware Basin, Central Basin Platform, and the Midland Basin.

The tectonic history of the Midland and Delaware Basins is mostly affected by uplift of the Central Basin Platform and, to a less degree, by the thrusting of the Marathon-Ouachita orogenic belt. The main phase of the basin differentiation occurred during Pennsylvanian and Wolfcampian time because of the rapid subsidence in the Delaware and Midland Basins and the uplift of the Central Basin Platform, as shown by sudden changes in thickness and lithology of Pennsylvanian to Permian strata. In the fault zone surrounding the Central Basin Platform, Strawn carbonates unconformably overlie lower to middle Paleozoic strata. This alignment is a stratigraphic indicator that the fault zone along the Central Basin Platform perimeter was tectonically active during late Pennsylvanian time. Because of deferential movements of basement blocks, uplift of the Central Basin Platform created differential subsidence and variable basin geometry in the adjacent Delaware and Midland Basins. This stage of tectonic activity lasted until the end of the Wolfcampian time, when the fast deformation and subsidence in the sub-basins stopped. However, basin subsidence continued until the end of the Permian (Oriel et al., 1967; Robinson, K., 1988; Yang and Dorobek, 1995).

The Delaware Basin is bounded to the north by the Northwestern shelf, to the south by the Marathon - Ouachita fold belt, to the west by the Diablo Platform, and to the east by uplifted areas of the Central Basin Platform separating the Delaware and Midland Basins. An echelon pattern of high angle faults with a large vertical displacement are detected along the boundaries of the Central Basin Platform, which itself is an uplifted, fault-bounded structural high that is primarily carbonate in composition and is highly faulted.

The Midland Basin is bounded to the east by the Eastern shelf through a series of north-south trending fault segments and to the north by the Northwest shelf. Southward, Midland Basin formations thin out into the Ozona Arch, an extension of the Central Basin Platform, which separates the Delaware and Midland Basins.

Regional Stratigraphy

The age of sedimentary rocks underling the Permian system in West Texas to Southeast New Mexico ranges from Precambrian to Pennsylvanian. Typically, the oldest rocks immediately underlie Permian rocks in uplift areas such as the Central Basin Platform and the Ozona Arch. Pennsylvanian rocks are common across the Delaware and Midland Basins and on the Northwestern and Eastern shelves.

Representative stratigraphic sections of all Paleozoic systems are present and reach a maximum combined thickness in excess of 29,000 feet in the Val Verde Basin and in the southern part of the Delaware Basin. The older Paleozoic systems (Cambrian through Devonian) are found in sedimentary rocks accumulated in the ancestral Tobosa Basin, an extensive, stable marine depression. The Tobosa Basin extended through the entire present day Permian Basin region. Pennsylvanian and Wolfcampian times are characteristic of a period of transition, indicated by structural deformation, differential movements, increased clastic sedimentation, and development of contemporary tectonic elements. The Permian time is mostly characterized by a long period of sedimentation ending with cessation of tectonic activity (Oriel et al., 1967; Robinson, K., 1988).

Regional stratigraphic relationships for upper Carboniferous to upper Permian strata in the Permian Basin are shown on a generalized stratigraphic schema (Figure 2) and as three geologic cross sections (Figures 3-5). These cross sections indicate differences in basin geometry and the effects of differential uplift of the Central Basin Platform.

Upper Pennsylvanian and Wolfcampian strata spread across the entire Permian Basin; the thickest accumulations, however, are located in the central and southern parts of the Delaware Basin. As shown on Cross Section A (Figure

3), this stratigraphic interval quickly thins out to the Central Basin Platform, in contrast with the more gradual decrease in thickness toward the western part of the Delaware Basin and eastern part of the Midland Basin.

Upper Carboniferous Pennsylvanian rocks that range in thickness from 0 feet to 3,000 feet generally occur in the depth between 5,000 feet and 15,000 feet. Pennsylvanian formations, including Atoka, Strawn, and Cisco, predominantly consist of limestone, shale, and minor quantities of sandstone and siltstone. An extensive development of reef facies1 accounts for a large percentage of the limestone deposits in shallow peripheral areas of the Delaware and Midland Basins (Dolton et al., 1979; Hills, 1984).

Permian rocks are extremely heterogeneous, generally grading upward from a clastic-carbonate sequence into an evaporate sequence. Guadalupe, Leonard, and Wolfcamp series consist of limestone interbedded with shale and a subjugated amount of sandstones (Oriel et al., 1967; Robinson, K., 1988). The cessation of tectonic activity and the transition to a stable marine basin fill-in stage influenced the depositional environment in Early Permian time. Clastic sediments were deposited in the Delaware and Midland Basins, surrounded by peripheral reefs and carbonate shelves that graded shoreward into evaporitic lagoons.

However, compared to the corresponding strata in the Delaware Basin, upper Cretaceous to upper Permian strata of the Midland Basin are thinner overall with no significant changes in thickness or lithology. Lithofacies within these stratigraphic units are also relatively uniform or alter gradually across the basin with some thickening adjacent to the boundary of the Central Basin Platform. Pennsylvanian to Wolfcampian strata in the peripheral areas of the Midland Basin consist mainly of carbonate facies that grade toward the basin into shale and fine-grained siliciclastic2 facies. In the central part of the basin, thick Wolfcampian shales overlie shallow water carbonates of the Strawn limestone (Oriel et al., 1967; Robinson, K., 1988).

Paleogeography and depositional environment

Paleogeographic reconstructions of the Late Carboniferous (346 Ma3), Middle Pennsylvanian (305 Ma), and Early Permian (280 Ma) exhibited at Figure 6 show present-day New Mexico, Oklahoma, and Texas as one open marine area (Figure 6 c) that developed into a semi-enclosed epicontinental sea (Brown et al.; Blakey, 2011).

During much of the Pennsylvanian time, the Permian Basin formed as a semi-enclosed depression; however, it was not until the Wolfcampian (Early Permian) that a carbonate shelf and margin developed around the edges of both the Delaware and Midland Basins. These accumulations of carbonates formed after the end of intense tectonic movement and widespread siliciclastic sedimentation, which began during the Early Pennsylvanian. By the early Leonardian, this ramp-type shelf was already developing a series of barriers along its seaward edge, becoming a more distinct rimmed margin. The development of this marginal rim influenced depositional environments on the shelf, creating the intrinsic lateral facial changes observed in the Leonardian and Guadalupian rocks behind the shelf edge. From the late Wolfcampian through Guadalupian (Late Permian), the Midland and Delaware Basins were principally sites of siliciclastic accumulation, whereas the platforms and shelves were sites of intense fine-grained siliciclastic and carbonate accumulation (Oriel et al., 1967; Robinson, K., 1988; Yang and Dorobek, 1995).

Wolfcamp formation

The Wolfcamp Shale, a Wolfcampian-age organic-rich formation, extends in the subsurface in all three sub-basins of the Permian Basin (Delaware Basin, Midland Basin, and Central Basin Platform) and is the most prolific tight oil and shale gas-bearing formation contained within. The Wolfcamp Shale is divided into four sections, or benches, known as the Wolfcamp A, B, C, and D. The Wolfcamp D is also known as the Cline Shale. The most drilled targets to date are the A and B benches.

The four benches of the Wolfcamp formation each display different characteristics in terms of lithology, fossil content, porosity, total organic content, and thermal maturity. Overall, basement tectonics patterns influence Wolfcamp structure and thickness (Gaswirth, 2017).

Structure map of the Wolfcamp formation

USGS estimates undiscovered, continuous, hydrocarbon resources of only the Wolfcamp formation in the Midland Basin to be in excess of 19 billion barrels of oil, 16 trillion cubic feet of natural gas, and 1.6 billion barrels of natural gas liquids (NGL), making it one of the largest hydrocarbon plays in the United States (Gaswirth, et al., 2016). Like other continuous plays, key geologic and technical criteria that control play boundaries and productivity include thermal maturity, total organic carbon (TOC), formation thickness, porosity, depth, pressure, and brittleness.

EIA constructs contoured elevation maps of subsea depth to the top of a geologic formation (also called structure maps) from point-measurement depth referenced to sea level (well observations) for the formation in the subsurface. These elevation measurements provide the third dimension for characterizing the depth or elevation of a reservoir on an otherwise two-dimensional map. Enverus DrillingInfo Inc. provides these stratigraphic picks, or formation depths, based on well log interpretation from 7,730 wells. Subsea depth of Wolfcamp in the Delaware Basin varies from 0 feet in the west to -9,500 feet subsea in the central areas, and in the Midland Basin, it varies from -2,000 feet subsea in the east along the Eastern Shelf to -7,000 feet subsea along the basin axis near the western basin edge.

Thickness map of the Wolfcamp formation

Thickness maps (isopachs) show spatial distribution of the formation thickness across the formation footprint. Thickness values are used, in combination with reservoir petrophysical properties such as porosity and thermodynamic parameters (reservoir temperature and pressure), to calculate resource volumes, such as oil-in-place and natural gas-in-place estimates.

The isopach map for the Wolfcamp formation is constructed from subsurface point measurements from 2,040 individual wells that include both depth to the top and to the base of the Wolfcamp formation.

The Wolfcamp thickness varies between 200 feet to 7,050 feet across the Permian Basin. As the isopach map demonstrates (Figure 8), thickness ranges from about 800 feet to more than 7,000 feet thick in the Delaware Basin, from 400 feet to more than 1,600 feet thick in the Midland Basin, and from 200 feet to 400 feet in the adjacent Central Basin Platform.

Regional stratigraphy and lithology of the Wolfcamp formation

The Wolfcamp formation, deposited during late Pennsylvanian through late Wolfcampian time, is distributed across the entire Permian Basin. The Wolfcamp formation is a complex unit consisting mostly of organic-rich shale and argillaceous carbonates intervals near the basin edges. Depth, thickness, and lithology vary significantly across the basin extent. Depositional and diagenetic processes control this formation heterogeneity. Stratigraphically, the Wolfcamp is a stacked play with four intervals, designated top-down as the A, B, C, and D benches (Gaswirth, 2017). Porosity of the Wolfcamp Formation varies between 2.0% and 12.0% and averages 6.0%; however, average permeability is as low as 10 millidarcies4, which requires multistage hydraulic fracturing.

Total organic carbon content of the Wolfcamp formation

Large amounts of organic material that accumulated in the deep, poorly oxygenated areas of the Delaware and Midland Basins later converted to hydrocarbons. Analytical results from well core samples indicate that TOC content in the Wolfcamp formation ranges from less than 2.0% to 8.0% (Ward, et al., 1986; Kvale and Rahman, 2016). Wolfcamp lithological facies vary significantly across the Permian Basin. The carbonate turbidites5 originated from the Central Basin Platform, whereas the siliciclastic -dominated turbidites derived from the surrounding highlands. The carbonate turbidites display TOC values ranging from 0.6% to 6.0%, whereas the siliciclastic turbidites generally exhibit less than 1.0%. The interbedding, non-calcareous mudstones contain as much as 8.0% TOC. Analytical results of oil samples produced from Wolfcamp reservoirs also demonstrate that these oils were generated from mostly marine type II kerogens with a contribution from type III kerogens (Kvale and Rahman, 2016; Gupta et al., 2017). Known good source rocks typically contain mostly 2.0% TOC or higher. As such, the Wolfcamp formation has sufficient TOC content compared with other low permeability plays.

Wolfcamp play boundaries

In the Delaware Basin Wolfcamp play, boundaries are controlled by the main tectonic features of the Permian region (Figures 9 and 10). The play boundaries are outlined to the south by the Marathon-Ouachita fold and thrust belt, to the north by the Northwest shelf, and to the west by the Diablo Platform, and the southern play boundary traces the western margin of the Central Basin Platform. The changes in depth and thickness along the play boundaries reflect the amount of differential movements that set off subsidence within the Delaware Basin and the uplift of the surrounding highlands. EIA's analysis of the well log and productivity suggests the best reservoir quality corresponds to the Upper Wolfcamp areas with the following characteristics:

Thickness is more than 1,000 feet Subsea depth to the formation top is more than 3,000 feet Neutron porosity ranges from 4.0% to 8.0% Density ranges from 2.60 g/cm3 to 2.85 g/cm3 Estimated total organic carbon ranges from 1.0% to 8.0% Deep resistivity ranges from 10 Ohm-meter to 80 Ohm-meter Wolfcamp formation benches

Most of the current drilling activities in the Delaware and Midland Basins target Upper Wolfcamp (A and B benches) rather than Lower Wolfcamp (C and D benches), which is more natural gas prone and more mature. The Upper Wolfcamp sections are comprised of two main facies: shallow water fine-grained calcareous turbidites5 that are often interbedded with dolomite and deep-water turbidites and mudstones that represent the distal accumulation (Thompson et al., 2018; Gupta et al., 2017). Distal turbidites and mudstones of Upper Wolfcamp are the thickest and have the best reservoir quality.

Structure and thickness maps of Wolfcamp A in the Delaware Basin

EIA constructed the Wolfcamp structure map in the Delaware Basin from subsurface point measurements (well observations) of the depth to the formation top. These stratigraphic picks include well log interpretations from 2,020 wells drilled in the Delaware Basin. Subsea depth of Wolfcamp in the Delaware Basin varies from 0 feet in the west to -9,500 feet in the Central Basin areas (Figure 9).

EIA constructed the Wolfcamp A thickness map from subsurface point measurements from 1880 wells that include both depth to the top and to the base of the Wolfcamp A bench. Thickness ranges from about 100 feet to more than 700 feet thick in the Delaware Basin.

Structure and thickness maps of Wolfcamp B in the Delaware Basin

EIA constructed the Wolfcamp structure map in the Delaware Basin from subsurface point measurements of the depth to the formation top. These stratigraphic picks include well log interpretations from 1,422 wells. Subsea depth of Wolfcamp B in the Delaware Basin varies from 0 feet in the west to -10,000 feet in the Central Basin areas.

EIA constructed the Wolfcamp B thickness map based on stratigraphic picks from 1193 wells that include both depth to the top and to the base of the Wolfcamp B bench. Thickness ranges from about 150 feet to more than 1800 feet thick across the Delaware Basin, except in the southeast area, where Wolfcamp B is more than 4000 feet thick.

Bone Spring formation

The Leonardian (Middle Permian) Bone Spring formation of the Delaware Basin extends in subsurface under southeastern New Mexico and a part of West Texas. The Leonardian Bone Spring formation is characterized by a succession of calcareous, siliciclastic, and carbonaceous marine deposits associated with significant production of oil, condensate, and dry gas in the Delaware Basin.

In the Bone Spring formation, main depositional processes are defined as a variety of gravity-driven sediment flows that resulted in turbidites5 with some pelagic layers. Distal flows deposited fine-grained silty shales often with carbonate cements. More proximal flows produced an accumulation of turbiditic silts and fine-grained sandstone and shales along with pelagic shales. Carbonate cementation is often presented across observed lithologies (Montgomery, 1997). The Bone Spring formation had produced hydrocarbons from conventional wells long before it became an unconventional target. These conventional wells targeted sandy layers within the Bone Spring interval. During the past decade, the Bone Spring formation has been developed as an unconventional play. In its 2018 report, the U.S. Geological Survey (USGS) estimated undiscovered, continuous, hydrocarbon resources in the Delaware Basin Bone Spring and Avalon assessment units as follows: 14 billion barrels of oil, 32 trillion cubic feet of natural gas, and 2.3 billion barrels of natural gas liquids; and 2.7 billion barrels of oil, 27.5 trillion cubic feet of natural gas, and 2.8 billion barrels of natural gas liquids, respectively (Gaswirth et al., 2018).

Regional stratigraphy and lithology of the Bone Spring formation

The Bone Spring formation directly underlies the Brushy Canyon formation of the Delaware group (Guadalupian) and overlies the Wolfcamp formation. The Bone Spring formation consists of alternating carbonate and sandstone layers representing the slope and basinal equivalent of Abo-Yeso and Wichita-Clear Fork carbonate accumulated along the Northern Shelf margin (Montgomery, 1997).

Subdivisions of the Bone Spring include members, labeled respectively, from the top to bottom: Bone Spring Lime, Avalon, Frist Bone Spring Carbonate, Frist Bone Spring Sand, Second Bone Spring Carbonate, Second Bone Spring Sand, Third Bone Spring Carbonate, and Third Bone Spring Sand. In this succession, the upper unit of each member is represented by carbonate, and lower unit is represented by sandstone, historically called sand. In addition, the Avalon shale was identified in the First Bone Spring Carbonate. The Avalon is divided further into three informal intervals: Lower Avalon, Middle Avalon, and Upper Avalon. Lower and Upper Avalon are generally considered to be mudstone-rich intervals separated by the more carbonate-rich Middle Avalon (Montgomery, 1997).

In this study, a generalized stratigraphic schema (Figure 4) includes the following subdivisions of the Bone Spring formation from top to bottom: Avalon, Frist Bone Spring, Second Bone Spring, and Third Bone Spring. The Leonardian Bone Spring formation of the Delaware Basin shows a distinct transition from slope to basin floor deposits. These rocks were primarily deposited by slope and deepwater re-sedimentation of carbonate and clastic detritus delivered from carbonate-dominated platforms surrounding the Delaware Basin. The formation is divided into thick successions of carbonate and clastic members that reflect the history of relative sea level fluctuation during the Leonardian time. The siliciclastic sediments were transported to the basin during relative sea level lowstands. However, the effects of sea level on sedimentation and facial distribution can be complex, so a drop in the sea level can shift carbonate development basinward (Saller, et al., 1989).

Reservoirs in the Bone Spring are the product of complex interactions among depositional processes, diagenesis, and structural deformation. Main basin structures at the Bone Spring level are a result of differential movements on basement blocks during the Permian period. Structural features began to develop in the Pennsylvanian time, when the Central Basin Platform was raised. Tectonic activity, including reactivation of basement faults, continued but decreased during the Permian period so that by the end of the Leonardian time (top of Bone Spring) and into the early Guadalupian series (lower Brushy Canyon), structure development continued to influence the depositional environment.

Total organic carbon content of the Bone Spring formation

The Bone Spring formation is a hybrid shale-oil system with high total organic carbon source rocks interbedded with organic-poor sandy layers. Shale members contain some organic matter, but the total organic carbon (TOC) content is usually on the lower end for a typical source rock, about 1% to 5%. Geochemical data indicated TOC from Bone Spring formation samples ranges from 0.99% to 4.17%, and the residual hydrocarbons left in the rock range from 0.26 milligram/gram (mg/g) to 1.38 mg/g. Measured vitrinite reflectance6 from the selected samples averages 0.62 %Ro. This value is at the low end of the oil generation window. Analytical results show that most of the samples are oil prone Type II kerogen7, which is primarily marine organic matter (Jarvie et al., 2001; Jarvie, 2017; Stolz et al., 2015).

Bone Spring and Avalon play boundaries

By the 1980s, the Bone Spring formation had become a major conventional target with wells targeting mostly sandstone members (Jackson et al, 2014). The Bone Spring formation had not been a prolific conventional reservoir, but by the year 2000, more than 65,000 million barrels (MMb) of oil were produced from the Bone Spring play. With the introduction of hydraulic fracturing and horizontal drilling, production has increased considerably, and it is now one of the fastest-developing unconventional plays in the United States. Between 2008 and 2019, more than 4,000 horizontal wells had been drilled in the Bone Spring formation.

The Bone Spring formation is a very attractive unconventional target because it has many pay zones, high TOC, and large formation thickness (average of 3,000 feet). In the mid-2000s, much of the exploration was in the Wolfbone interval, where the well is landed at the base of the Third Bone Spring Sandstone so that both the Bone Spring and underlying Wolfcamp formations can be stimulated. However, many horizontal wells are often stacked to target other intervals in the First, Second, and Third Bone Spring members. Starting in 2012, Avalon shale was designated as an emerging unconventional play. In the Bone Spring formation, interval porosity for productive wells varies from 8% to 20% in the sand layers and from 1% to 4% in the mud layers, but all layers have very low permeability at an average of less than a few millidarcies (Jackson et al, 2014). Recent advances in completion techniques have increased the oil recovery factor to as high as 34%.

The Bone Spring formation has been described as a hybrid shale oil system with organic-rich source rocks alternated with organic-lean reservoir intervals (Jarvie et al., 2001; Jarvie, 2017). The Bone Spring formation consists of interbedded siliciclastic, carbonate, and shale rocks of up to 4,000 feet. The formation is divided into different larger sandstone and carbonate intervals with the sandstone members in the base of each interval labeled as the First, Second, and Third Bone Spring. In addition, the Avalon shale was identified within the First Bone Spring Carbonate.

The Bone Spring play produces oil and associated gas from carbonate debris flows and turbidite5 reservoirs throughout the 3,500-foot section, where organic-rich layers of shale or carbonate are interlaminated with organic-lean sandstone or carbonate layers (Dutton et al, 2005). The reservoirs of the Avalon shale play consist of hundreds of feet of dark, organic-rich siliciclastic mudstones interbedded with carbonate-rich turbidite deposits. The reservoir quality of this unconventional hydrocarbon system is generally controlled by carbonate content. Increased carbonate content is related to lower productivity than in neighboring mudstones. The lowest reservoir quality is associated with mainly grainy carbonate facies, and the highest reservoir quality is associated with siliceous mudstones. Accordingly, the better reservoirs are found where muddy deposits are thickest and dominate carbonate debris flows (Montgomery, 1997; Walsh, 2006; Hurd et al., 2018).

In the Bone Spring and Avalon plays of the Delaware Basin, boundaries are constrained by the main tectonic features of the Permian region (Figures 9 and 10). The play boundaries are outlined to the south by the Marathon-Ouachita fold and thrust belt, to the north by the Northwest shelf, and to the west by the Diablo Platform, and the southern play boundary traces the western margin of the Central Basin Platform. The changes in depth and thickness along the play boundaries reflect the amount of differential movements that set off basement sinking within the Delaware Basin and the uplift of the surrounding platforms.

EIA's analysis of the well log and productivity suggests the best reservoir quality corresponds

(1) to the Bone Spring areas with the following characteristics

Thickness is more than 1,000 feet Subsea depth to the formation top is more than 1,500 feet Neutron porosity ranges from 4.5% to 16.5% Density ranges from 2.54 grams per cubic centimeter (g/cm3) to 2.70 g/cm3 Estimated total organic carbon ranges from 1.0% to 8.0% Deep resistivity ranges from 15 ohmmeter to 75 ohmmeter (2) and to the Avalon areas with the following characteristics

Thickness is more than 150 feet Subsea depth to the formation top is more than 500 feet Neutron porosity ranges from 4.0% to 17% Density ranges from 2.52 g/cm3 to 2.70 g/cm3 Estimated total organic carbon ranges from 4.0% to 8.0% Deep resistivity ranges from 15 ohmmeter to 75 ohmmeter Bone Spring formation members

The Avalon, First Bone Spring, and Second Bone Spring intervals are widespread throughout the entire Delaware Basin, but they exhibit maximum development along the basin's northern slope. Along the margin of the Central Basin Platform, they are silty and clay rich. In contrast, during deposition of the Third Bone Spring, a depocenter was located in the northeastern part and in the central part of the Delaware Basin next to the Central Basin

Platform. Structural, thickness, and facies analysis indicate a similar northern source for many carbonate-debris flow units (Montgomery, 1997; Stolz et al., 2015).

Structure and thickness maps of Bone Spring-Avalon

The Avalon shale play consists of organic-rich mudstones interbedded with fine-grained carbonate strata. EIA constructed Avalon Bone Spring structure and thickness maps in the Delaware Basin from subsurface point measurements (well observations) of the depth to the formation top and base. These stratigraphic picks include well-log interpretations from 520 wells. Subsea depth of Avalon in the Delaware Basin ranges from 0 feet in the west to -5,500 feet in the eastern part of the basin in areas next to the Central Basin Platform (Figure 13). The Avalon ranges from 50 feet to 500 feet thick.

Structure and thickness maps of First Bone Spring

EIA constructed First Bone Spring structure and thickness maps in the Delaware Basin based on stratigraphic picks from 650 wells. Subsea depth of First Bone Spring in the Delaware Basin varies from 0 feet in the west to -6,000 feet in the eastern part of the basin in areas next to the Central Basin Platform. Thickness ranges from about 250 feet to more than 1,200 feet thick across the Delaware Basin, except in the northwest area, where the First Bone Spring is more than 2,000 feet thick.

Structure and thickness maps of Second Bone Spring

EIA constructed Second Bone Spring structure and thickness maps in the Delaware Basin by using subsurface point measurements from 720 wells. The subsea depth of Second Bone Spring in the Delaware Basin ranges from 0 feet in the west to -7,000 feet in the eastern part of the basin in areas next to the Central Basin Platform. The Second Bone Spring ranges from 250 feet to more than 1,000 feet thick.

Structure and thickness maps of Third Bone Spring

EIA constructed Third Bone Spring structure and thickness maps in the Delaware Basin based on stratigraphic picks from 1,050 wells. Subsea depth of Third Bone Spring in the Delaware Basin ranges from 0 feet in the west to -7,500 feet in the eastern part of the basin (Figure 19). Thickness ranges from about 200 feet to more than 1,200 feet thick across the Delaware Basin, except the northwest area and the area in the middle part of the basin next to the Central Basin Platform, where the First Bone Spring exceeds 2,000 feet and 1,000 feet thick, respectively.

Delaware Mountain Group

The Delaware Mountain Group in west Texas and southeast New Mexico consists of organic rich siltstones and fine-grained sandstones deposited in slope to basin environments during Early Permian (Guadalupian) time. Delaware Mountain Group strata represent up to a 4500-foot-thick succession of marine deposits in the Delaware Basin (Gardner, 1997b).

The Delaware Mountain Group is divided, from top to bottom, into the Bell Canyon, Cherry Canyon, and Brushy Canyon formations. The cyclic interbedding of sandstones with organic-rich siltstones in the Delaware Mountain Group reflects changes in relative sea level. During highstands in relative sea level, sandy sediments were enclosed within a broad shelf while organic-rich siltstones accumulated on the basin floor (Meissner, 1972; Gardner, 1992, 1997).

Regional stratigraphy and lithology of the Delaware Mountain Group

The Guadalupian-age Delaware Mountain Group of the Delaware Basin consists of stratigraphically cyclic, mixed siliciclastic and carbonate slope to deep-sea deposits. It overlies the thick carbonate interval of the Bone Spring formation and underlies the Castile formation.

During Early Permian (Guadalupian) time, a broad carbonate platform surrounded the basin to the north. At times of sea level drop and platform rise, siliciclastic sediments moved through the shelf and were deposited as major submarine fan successions in the basin to form the Delaware Mountain Group represented from the top to bottom by Bell Canyon, Cherry Canyon, and Brushy Canyon complexes (King, 1948; Kerans et al., 1992, 1993; Gardner and Sonnenfeld, 1996).

Each of these depositional complexes includes three major facies1: (1) submarine-canyon siliciclastic2 channel fills; (2) slope deposits consisting of isolated sandstone bodies enclosed in thick sequences of interbedded sandstone and siltstone, and (3) basin-floor accumulations of laterally extended, siliciclastic sediment sheets cut by erosive-based multistory channel systems.

Dark, organic carbon-rich siltstones occur generally as beds from 0.3 feet to more than 7 feet thick throughout gravity-flow successions and represent sediment-starved suspension deposits (Gardner and Sonnenfeld, 1996).

The cyclic interbedding of sandstones with organic-rich siltstones in the Delaware Mountain Group depositional system reflect recurrent changes in relative sea level. During highstands in relative sea level, sands accumulated within a wide shelf. Thin sheets of organic-rich siltstones were deposited on the basin floor by the slow accumulation of marine algal material and airborne silt. During succeeding lowstands in relative sea level, the carbonate shelf emerged and sands were carried to the basin floor. The absence of channels on the shelf and the textural properties of the sands, including the lack of detrital clay-sized material, are believed to illustrate that wind was an important agent in bringing the sands to the shelf margin. During sea level lowstands, dunes popped up on the shelf break, and eolian sands were carried into the basin by turbidity currents. Paleogeographic reconstructions show that the sands arrived to the basin from the Northwest shelf and Central Basin platform (Fisher and Sarnthein 1988; Gardner, 1992, 1997a,b; Barton and Dutton, 1999; Gardner and Borer, 2000).

Total organic carbon content of the Delaware Mountain Group

Throughout its thickness, the Delaware Mountain Group contains organic carbon-rich siltstone beds, while dominant facies are arkosic8 sandstones. Sediment texture ranges mainly between coarse silt and very fine-grained sand, while shales are uncommon. Finer-grained intervals, those that are several percent organic carbon, are correctly identified as siltstones. Siltstones represent organic-rich facies (up to 46% total organic content [TOC]) with an average 2.0%-2.5% TOC) and organic-poor facies with average 0.5% TOC (Thomerson and Asquith, 1992; Sageman et al., 1998; Wegner et al., 1998; Dutton et al., 1999).

Organic matter in slope and basin-floor facies of the Delaware Mountain Group has been reported to include a mixture of Type II and Type III kerogen7, implying both algal and terrestrial components contributed to deposits of siliciclastic material. Quantity and quality of preserved organic matter are controlled by changes in the sediment accumulation rate, which affect organic matter inputs to the sediment, as well as the balance between sea-floor processes of preservation vs. degradation (Hays and Tieh, 1992).

Delaware play boundaries

The history of hydrocarbon exploration in the Permian Basin includes many instances of re-discovered opportunity. In the last decade, such occurrences have expanded on unconventional reservoirs in a number of Permian formations, including Delaware Mountain Group, where new discoveries are related to the low permeable organic-rich siltstone intervals. In August 2019, the Delaware Mountain Group produced more than 27,000 barrels per day (b/d) of oil and 82 million cubic feet per day (MMcf/d) of natural gas from 3,400 wells (including 2,950 vertical, 320 horizontal, and 130 directional).

The Delaware Mountain Group has been the target of three major periods of drilling effort with 11,400 wells (including 10,440 vertical, 740 horizontal, and 220 directional) installed through a century-long history of exploration and production. Development of the Delaware Mountain Group began with the shallowest zones in the Texas portion of the Delaware Basin. During the 1950s through 1980s, the upper and middle intervals known as Bells Canyon and Cherry Canyon formations were the focus of exploration within the Delaware Mountain Group. A second major phase of activity, in the deeper Brushy Canyon and lower Cherry Canyon formations, took place during the 1990s and 2000s in Texas and New Mexico. Until 2010, most of the hydrocarbon production has been from multiple sandstone layers, separated by organic siltstone and limestone intervals. By the year 2010, more than

375 million barrels (MMb) of oil had been produced from the Delaware Mountain Group. The section also produced 1.3 trillion cubic feet (Tcf) of natural gas during the same period.

A third major phase of activity in the Delaware Mountain Group took place within the last decade and is related to unconventional reservoir development. Through the last 10 years, activity has been extended to cover organic-rich low-permeable stacked siltstone layers with continuing development of conventional sandstone reservoirs. Starting in 2010 and through 2019, the Delaware Mountain Group generated about 160 MMb of oil and 0.4 Tcf of natural gas from 3,170 wells, where about 45% of crude oil and 20% of natural gas production were extracted from low permeability reservoirs.

The Delaware Mountain Group has been identified as a hybrid oil system with organic-poor sandstone reservoirs alternated with thin intervals of organic-rich siltstone (Jarvie et al., 2001; Jarvie, 2017). The Delaware Mountain Group consists of interbedded siliciclastic2 and carbonate rocks up to 4,500-feet thick. Hydrocarbon source beds are thin, organic-rich siltstones that settled on the basin floor between periods of turbidite activity.

Analysis of reservoir parameters and productivity distributions across the formation footprint indicates the best reservoir quality is represented by Delaware Mountain Group areas with the following characteristics:

Thickness is more than 1,000 feet Subsea depth to the formation top ranges from 1,200 feet to -2,600 feet Neutron porosity ranges from 3.5% to 16.5% Density ranges from 2.50 grams per cubic centimeter (g/cm3) to 2.68 g/cm3 Estimated total organic carbon ranges from 1.0% to 15.0% Deep resistivity ranges from 12 ohmmeter to 35 ohmmeter Structure and thickness maps of the Delaware Mountain Group

The Delaware Mountain Group play consists of interbedded sandstones with organic-rich siltstones. EIA constructed Delaware Mountain Group structure and thickness maps in the Delaware Basin from subsurface point measurements (well observations) of the depth to the formation top and base. These stratigraphic picks include well-log interpretations from 3,200 wells for the formation top and from 1,830 wells for the formation base. Subsea depth of the Delaware Mountain Group ranges from 2,800 feet in the west in the areas adjacent to the Diablo Platform to -2,600 feet in the eastern part of the Delaware Basin in the depocenter9 area. The Delaware Mountain Group ranges from 200 feet to 4,500 feet thick.

(U.S. Energy Information Administration)

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