Reasonably Foreseeable Development Scenario for Oil and Gas Activities

Carlsbad Field Office, Eddy County, Southeastern New Mexico

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Final Report

submitted

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And last, I would like to express thanks to the U. S. Bureau of Land Management for funding this important project.

Executive Summary

The proposed Reasonably Foreseeable Development (RFD) scenario is to provide the Carlsbad Field Office (CFO) a projection of the potential future oil and gas development activity for the next 20 years (starting in 2023) to assist the BLM's Resource Management Plan. Included are projections for vertical and horizontal wells drilled, future surface disturbance accompanying this development, water production and use, and oil and gas production volumes. The RFD establishes a baseline scenario that can then be used to compare the resource management plan with its alternatives and to analyze the long-term effects that could result from oil and gas activities.

The New Mexico portion of the Permian Basin is well-known for being a highly productive oil and gas region. Recently, a significant increase in production has occurred in response to technology advancements in horizontal drilling and multistage completions unlocking the hydrocarbons in the unconventional reservoirs. Past activity is cyclical, depending on a variety of factors such as commodity price, resource potential, and technology advancements. For BLM planning purposes, projections of future **oil and gas production** is needed. To accomplish, future annual oil and gas production was generated using decline curves from historical production data and then extrapolated into future years to acquire remaining production for existing wells and future production from new well development.

In the short term the trend of increasing oil production is anticipated to continue until 2025. This year (2025) was selected based on current 2022 EIA Energy Outlook reference case projections for oil price peaking in 2025 and then remaining at a relatively stable but lower value afterwards. In the long term the expectation is for new well production to reduce as the resources become less prolific, resulting in a decrease in well development. The average wells spudded on Federal-managed lands from 2011 through 2021 was 617 new spuds per year, thus a short-term prediction of 770 new spuds allow for the continued upward trend in development over the short term. In total, 12,500 wells are predicted to be drilled and completed on Federal lands managed by the BLM in the CFO. The majority (~90%) of this development will be horizontal completions and the main targets will be the unconventional Bone Spring and Wolfcamp plays. Over the 20-year forecast period, cumulative production from existing and new wells on Federal-managed lands is estimated to be 5.4 billion BO, 20.5Tcf gas, and 18 billion BW.

The Federal portion represents 60% of the total activity in the area of interest, thus the total (Federal and non-Federal) well development is projected to be 19,600 of which 90% are horizontal. The total (Federal and non-Federal) historical spuds from 2011 through 2021 average 1,031 per year. In comparison, the total new well spud count is projected to be 1,208 in the beginning of the forecast period, declining to 769 wells at the end of the twenty-year period. Over the 20-year forecast period, cumulative production from existing and new wells for Federal and non-Federal ownership is estimated to be 8.6 billion BO, 33 Tcf gas, and 30 billion BW.

As **water** is limited and thus essential in arid New Mexico for agriculture, domestic consumption, industry, and other beneficial uses, it is important to assess and predict the associated water production and the corresponding use of water in oil and gas development. Water production is estimated to be 30 billion barrels of water over the life of the plan or 1.5 billion barrels per year.

Water production has been increasing with the increasing development of oil in the area, and thus is intrinsically tied to the hydrocarbon production scenario. Water production has averaged approximately 1 billion barrels of water per year over the last twelve years, thus a 50% increase in water production is projected for the RFD time period, capturing the increasing trend observed the last several years.

Most produced water is either injected for enhanced oil recovery or disposed. However, the percent of produced water injected and disposed has been decreasing with time from >90% in 2011 through 2017 to a low of 50% in 2022. The remaining is used by oil and gas development as indirect, direct or ancillary. Gonzalez, et al, 2023 defines direct water use as water used in a wellbore to complete a well, which includes water used for drilling, cementing, stimulating, and maintaining the well during production. Indirect water use is defined as water used at or near the well site, including water used for dust abatement, equipment cleaning, materials washing, worker sanitation, and site preparation. Ancillary water use is defined as all other water used during the life cycle of oil and gas development that is not categorized as direct or indirect, such as additional local or regional water use resulting from a change (for example, population) related to oil and gas development (Valder, et al, 2021). Analysis identified stimulation, specifically hydraulic fracturing, as the major use of produced water, accounting for 99% of the direct water use. On average, 465 thousand bbls of water per well is required for stimulation of a 2-mile horizontal lateral, or a total of 8,137 million bbls will be needed for future oil and gas well development over the twenty-year span.

The additional subsurface development projected in the next twenty years will require associated **surface development** of roads, flowlines and well pads. To acquire the surface disturbance for new development and existing infrastructure was determined from surface disturbance data extrapolated from the U.S.G.S. Vegetation Data (Villarreal, et al. (2023). The total (Federal and non-Federal) existing acreage is approximately 109,000 acres, of which 60% or 65,400 acres is the Federal portion. For the twenty-year period, it is estimated an additional Federal and non-Federal 33,300 acres of disturbance is required (~ 20,000 acres - Federal portion), which includes both vertical and horizontal well development. Combining existing and new development results in the maximum potential disturbance of 142,400 acres or 85,300 acres on Federal-managed lands.

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List of Abbreviations and Acronyms

AAPG	American Association of Petroleum Geologists
AGI	Acid Gas Injection
AOI	Area of Interest
APD	Application to Permit to Drill
BEG	Bureau of Economic Geology, Texas
BLM	U.S. Bureau of Land Management
BO	Barrels of oil
BOPD	Barrels of oil per day
BSCF or BCF	Billion standard cubic feet (gas)
CO_2	Carbon Dioxide
CBP	Central Basin Platform
CFO	Carlsbad Field Office
DOE	U.S. Department of Energy
DOI	U.S. Department of Interior
EIA	U.S. Energy Information Administration
EIS	Environmental Impact Statement
EOR	Enhanced Oil Recovery
EUR	Estimated ultimate recovery
FERC	Federal Energy Regulatory Commission
ft	feet, foot
GB/SA	Grayburg/San Andres
GIS	Geographic Information System
GOR	Gas-oil Ratio, Mscf/STB
Gp	Cumulative gas production
GRI	Gas Research Institute
MBO or mstb	Thousand barrels of oil
MBOE	Thousand barrels of oil equivalent
MBBLS	Thousand barrels of liquid
MBW	Thousand barrels of water
MMSCF	Million standard cubic feet (gas)
MMBO	Million barrels of oil
MMBOPD	Million barrels of oil per day
MMBBLS	Million barrels of liquid
NMOCD	New Mexico Oil Conservation Division
ONRR	DOI Office of Natural Resources Revenue
psi	pounds per square inch (pressure)
RFD	Reasonably Foreseeable Development
RMP	Resource Management Plan
ROW	Right-of-way
SENM	Southeast New Mexico (Eddy and Lea Counties)
SPE	Society of Petroleum Engineers
Tscf	Trillion standard cubic feet of gas

U.S.	United States of America
WAG	Water-alternating-Gas
WOR	Water-oil ratio, bbl/bbl
WRRI	Water Resource Research Institute
WTI	West Texas Intermediate

Introduction

Purpose

The purpose of this update to the Reasonably Foreseeable Development (RFD) scenario is to analyze the known and potential oil and gas resources within the Carlsbad Field Office (CFO) in southeastern New Mexico, and to project the potential future oil and gas development activity for the next 20 years (starting in 2023) based on logical and technical assumptions. To accomplish the projection will require evaluation of historic and current activity to estimate future development potential (including projections for vertical and horizontal wells drilled during the life of the plan-the Carlsbad Resource Management Plan), future surface disturbance, water use for hydraulic fracturing, and oil and gas production volumes. This RFD scenario has been prepared in support of the CFO Resource Management Plan. Previous RFD scenarios for the Pecos District, which included the CFO, were completed in 2012 and 2014. The RFD is unconstrained by management-imposed conditions as it is based primarily on geology and historical exploration and development activity. It provides information to analyze long-term and/or widespread effects that could result from potential exploration and development in a defined area regardless of land ownership or jurisdiction. The RFD establishes a baseline scenario that can then be used to compare the resource management plan with its alternatives and to analyze the long-term effects that could result from oil and gas activities.

The Carlsbad Field Office administers approximately 3.0 million total acres of all Federal mineral ownership types in Eddy, Lea and portions of Chaves County, New Mexico (see Figure 1). For purposes of this work, only Eddy and Lea Counties are evaluated since no oil and gas potential is considered in Chaves County. Currently, 1.9 million acres or 63% of the total acreage is leased. Other portions of oil and gas minerals are state-owned or owned privately and are not subject to the resource management plan. All acreages presented herein are based on geographic information systems (GIS) calculations and should be considered approximate.

Draft Resource Management Plan/Environmental Impact Statement

Chapter 1: Introduction
Planning Area

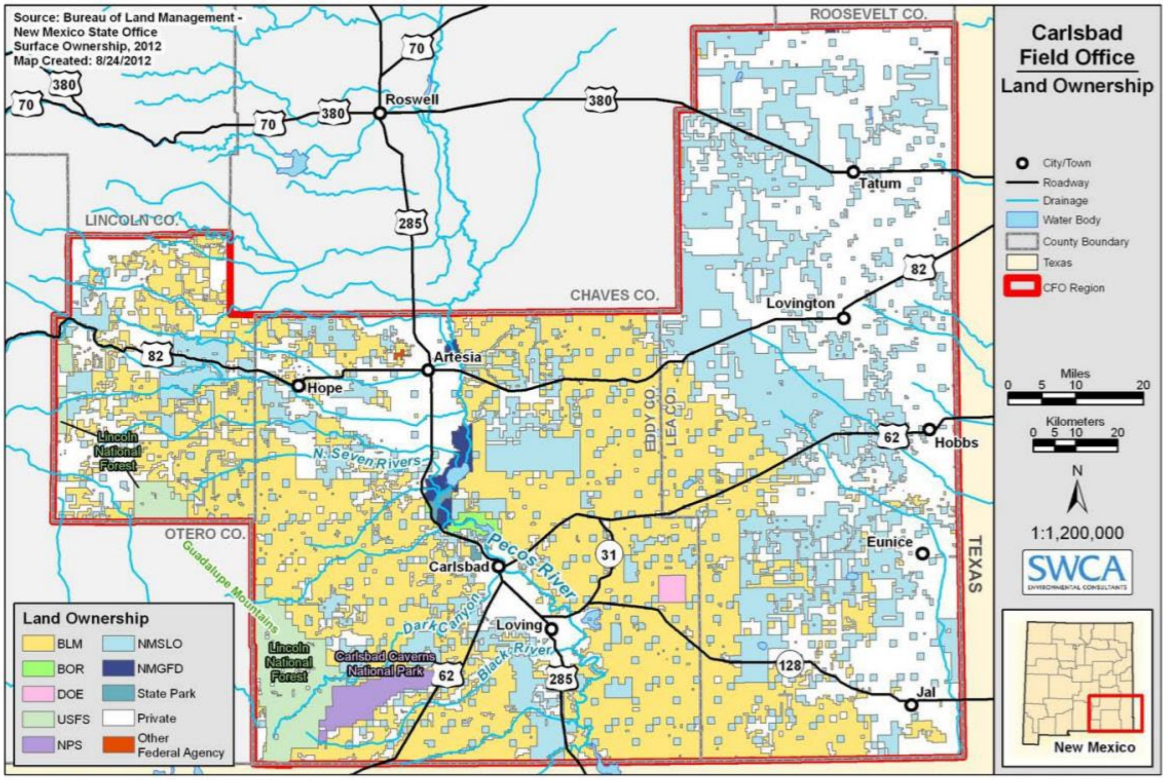

Figure 1-1. **Carlsbad Field Office planning area.**
(NMSLO = New Mexico State Land Office; NMDGF = New Mexico Department of Game and Fish).

BLM Carlsbad Field Office 1-4

Figure 1. BLM Carlsbad Field office land ownership map. {Map courtesy of BLM}

In analyzing historical data, production volumes are reported as a total of what the reservoir or well capacity is, independent of ownership. To acquire the federal portion, the federal volumes reported by DOI Office of Natural Resources Revenue (ONRR) were compared to the total production volumes acquired from NMOCD over an eleven-year (2011-2021) time period for Eddy and Lea Counties. Over this time, the federal portion as a percent of the total volume has been increasing for both oil and gas. This suggests more development is occurring on federal lands. To capture this trend, the latest values (Federal portion: 61% gas and 64% oil) were used for the prediction phase of this project.

<u>Data sources</u>

Information presented in this report was compiled from various sources. Historical and current well data (including production volumes) were acquired primarily through the GOTECH system. (http://octane.nmt.edu/gotech/) In addition, specific data was analyzed from Enverus™. Geological data were sourced from New Mexico Bureau of Geology and Mineral Resources reports and various professional publications. Information on water production and use was provided by the U.S.G.S. Water support group. The U.S.G.S. Vegetation group provided surface use associated with oil and gas development. Information regarding price commodity trends was taken from the Energy Information Administration.

Historical Activity

The New Mexico portion of the Permian Basin is well-known for being a highly productive oil and gas region. Recently, a significant increase in production has occurred in response to technology advancements in horizontal drilling and multistage completions unlocking the hydrocarbons in the unconventional reservoirs. Figure 2 shows the increase in monthly oil production for SENM (defined as Eddy and Lea Cos.) since 2011, achieving over 40 MMBO in December 2021 or approximately 1.4 MMBOPD.

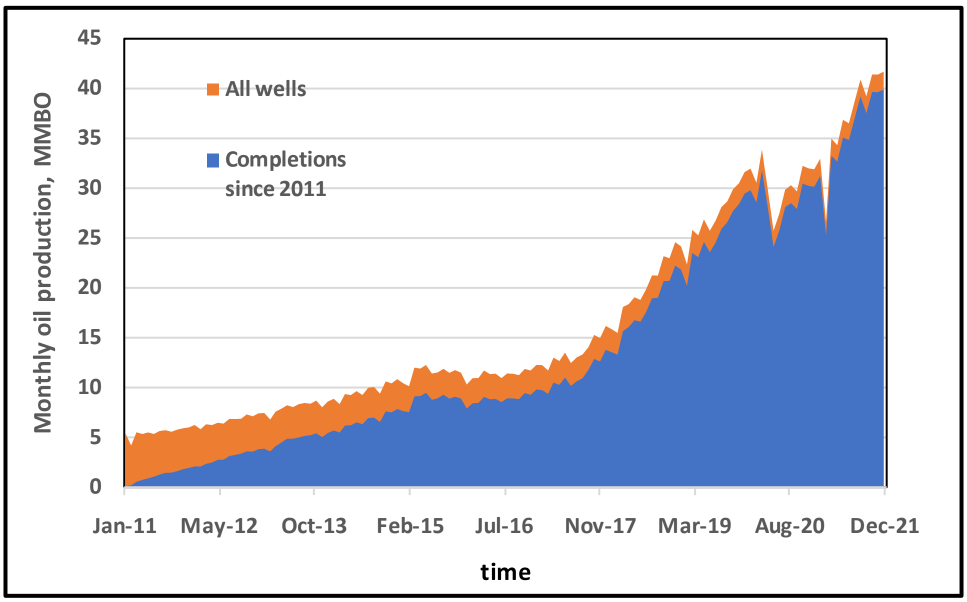

Figure 2. Monthly oil production for all plays in Eddy and Lea Co., SENM (Source: GOTECH/NMOCD)

Recent completions dominate production output, which accounted for approximately 95% of the total oil production in 2021. Remarkably, this high production volume comes from a fraction of the total well's activity. Figure 3 shows total active well count is somewhat constant at 25,000 per year over the eleven-year time period. New well completions since 2011 have steadily inclined to approximately 10,000 at the end of 2021. This increase has been balanced by wells that have been P&A, shutin, or TA and are no longer active.

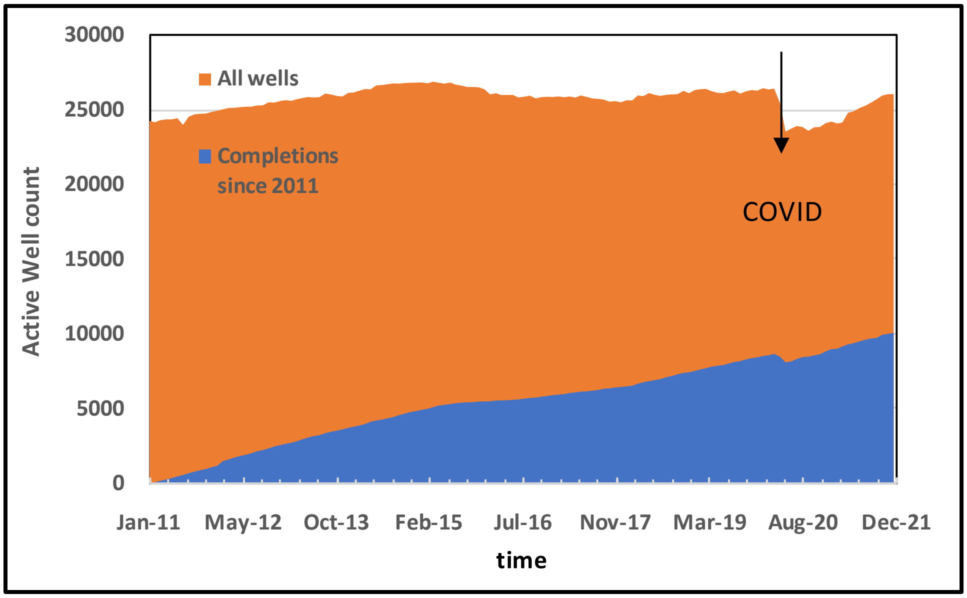

Figure 3. Active well count for all plays in the AOI (Source: GOTECH/NMOCD)

Activity is cyclical, depending on a variety of factors such as commodity price, resource potential, and technology advancements. To identify trends necessary for predictions, further analysis was performed on the recent completions. Shown in figure4 are the annual well completions shown as a bar graph from 2011 through 2021 compared to the WTI spot price (EIA,2022) represented by the solid orange line.

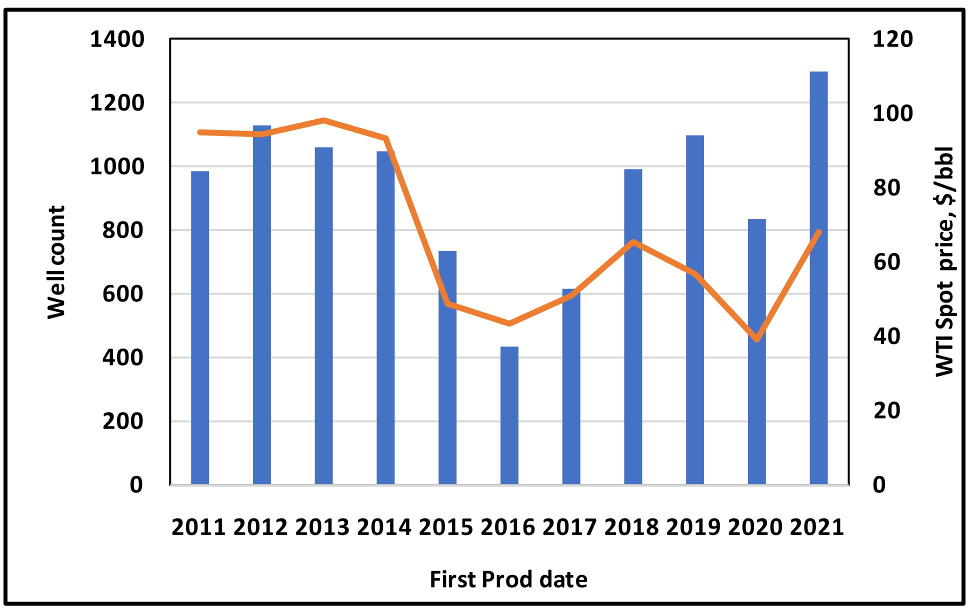

Figure 4. SENM annual well completions {Source: GOTECH/NMOCD} vs WTI Spot price {Source: EIA 2022}

Over this eleven-year time period, a total of 10,195 completions have occurred for an average of 927 completions per year. In 2015-2016, oil prices dropped below $50/bbl and the well completion count swung dramatically lower to 430. Between 2017-2018 oil prices were trending upwards at over $60/bbl resulting in a 132% increase in well completions by 2018. This cycle repeated was again between 2019-2021. The correlation of well activity with oil price is evident and suggests commodity price is a key component to development. In addition to commodity price, technological advancements in horizontal drilling and completions and a better understanding of the complex nature of unconventional reservoirs occurred during this time period. Figure 5 shows the annual well completions separated by well type, i.e., horizontal vs. vertical+ (vertical + directional + other).

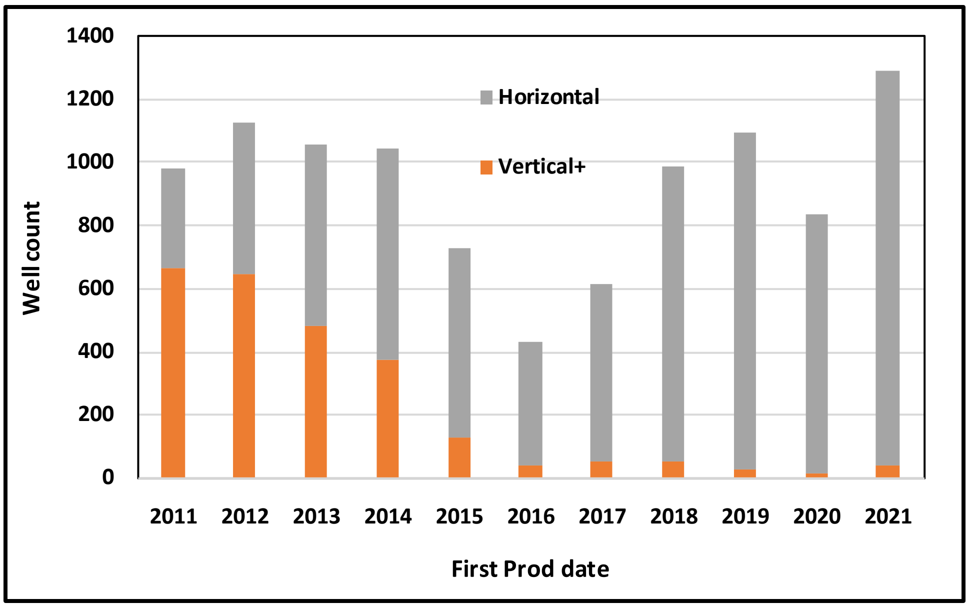

Figure 5. Annual well completions separated by well type; horizontal vs vertical+ {Source: GOTECH/NMOCD}

The increase in horizontal well completions is evident; from a third of all completions in 2011 to 97% in 2021. Horizontal completions over the last four years (2018-2021) have averaged 1000 completions per year.

Not only has the number of horizontal well completions been increasing, but also the lateral length. As shown in Figure 6, the gross perforated interval for horizontal well completions has increased to average 8,500 ft. (approximately 1 ½ miles) lateral length. In this work, the gross perforated interval is defined as the distance from the uppermost to lowermost perforation in the lateral. This distance will be less than the total lateral length and the surface-to-bottomhole distance.

In summary, the well activity and corresponding production strongly correlates with commodity pricing (Fig. 4) and advancements in horizontal drilling and completions (Figs. 5 and 6).

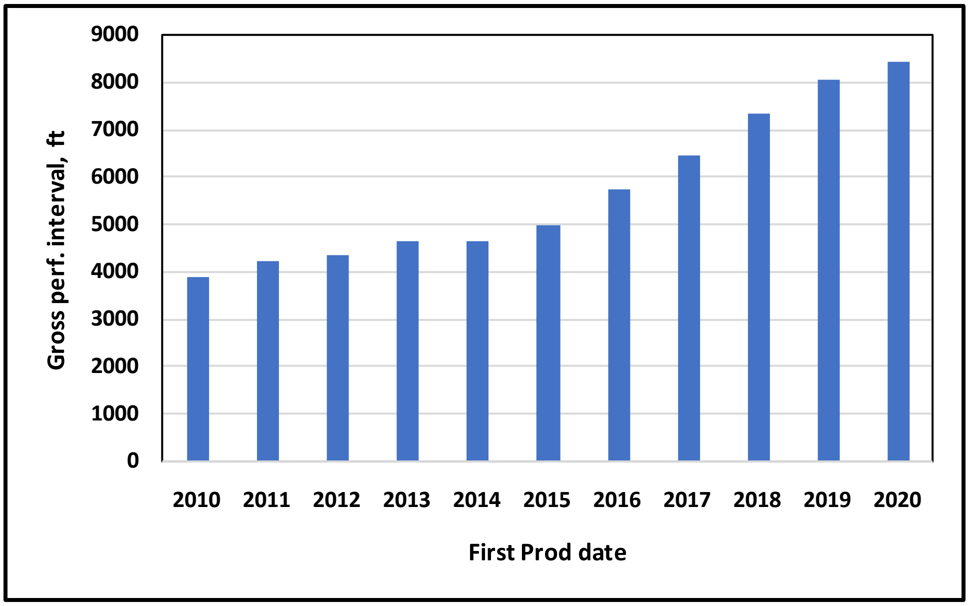

Figure 6. Gross perforated interval for horizontal well completions as a function of date of first production {Source: Enverus}

In the previous RFD and update, historical activity and predicted development was separated into defined plays (Broadhead et al, 2004). Table 1 lists the plays, the 2014 RFD results and recommendations, and the recent (2015 through 2021) activity, well type and activity trend. The scale in the bottom right corner of Table 1, defines the potential in wells per year as defined in the 2012 RFD and 2014 RFD update. The "over" and "under" in the far-right column indicates plays where the prediction overestimated or underestimated the actual activity. The most significant under-prediction was the Wolfcamp play.

	2014 RFD Results and recommendations			Statistics -2015 through 2021				
Minor Play	HC type	Potential	Comments	Average*	% Horiz	Last	Trend	
Abo Platform Carbonate	OIL	High	Additional development, horizontal, waterflooding, EOR	4	25%	2	decline	over
Artesia Sandstone Group	OIL/GAS	Moderate	Mature, shallow targets	3	4%	3	constant-low	over
Gas				2.5		1	decline	
Atoka & Atoka-Morrow	GAS	Low	Infill available, no gas price	1.5	28%	1	decline	
Morrow	GAS	Low	Infill available, no gas price	1	0%	0	decline	
Mississippian	GAS	Low	No gas price					
Woodford	OIL/GAS	Low	High risk, likely re-completions in existing wells					
Delaware Mountain Group	OIL	High	Development, waterflooding, EOR	16	73%	1	decline	over
Deep, mature oil				<1	0%	1	constant-low	
Ellenburger	OIL	Low	Limited resource, mature, deep	0	0%	0	constant-low	
Fusselman	OIL	Low	Limited resource, mature, deep	0	0%	0	constant-low	
Simpson Sandstone	OIL	Low	Limited resource, mature, deep	0	0%	0	constant-low	
Wristen	OIL	Low	Limited resource	<1	0%	1	constant-low	
Leonard	OIL	Very high	Infill and extension drilling of Yeso	66	55%	54	decline	over
Penn				5	27%	1	decline	
Penn - NW shelf	OIL/GAS	Low	Limited extent, mostly gas play					
Penn - Strawn patch reef	OIL/GAS	Low	Limited resource					
San Andres				26	24%	10	decline	
NW Shelf	OIL	Low	Mature, long term EOR-CO2 potential	6	93%	3	decline	
Artesia-Vacuum GB/SA	OIL	High	Mature, long term EOR-CO2 potential	11	5%	5	decline	over
Central Basin Platform	OIL	Moderate	Mature, long term EOR-CO2 potential	9	3%	2	decline	over
Major Play	HC type	Potential	Comments	Average*	% Horiz	Last	Trend	Trend
Bone Spring	OIL	Very high	Development of sands and Avalon, horizontal wells	391	99%	437	steady	
Wolfcamp	OIL/GAS	Moderate	Additional oil development w/horizontal wells	375	96%	595	increasing	under
		Notes				Scale	wells/yr	
		1	*Average completions per year from 2015 through 2021			Low	<25	
		2	% horizontal over the average time period			moderate	25 to 50	
		3	Last - number of wells completed in 2021			High	50 to 100	
		4	trend			Very high	> 100	

Table 1. 2014 RFD results and recent summary statistics separated by play.

In this work, the play nomenclature has been kept consistent with the previous work; however, the plays have been categorized based on their general attributes and similarities.

Major plays include the two dominant plays: Bone Spring and Wolfcamp. As will be seen, these plays are mostly oil-prone, albeit some more gassy than others, almost exclusively completed with horizontal wells, and require significant stimulation.

Minor plays include the Abo platform carbonates, Artesia Sandstone Group, Delaware Mountain Group, Leonard, and all the San Andres. These plays are similar in that all are mostly oil prone, have exhibited limited development from 2015 through 2021, and have a declining trend in development with time.

Gas plays include the Atoka and Atoka-Morrow, Morrow, Mississippian and Penn plays. Production from these plays is mostly if not all gas and as a result heavily dependent on natural gas price.

Deep, mature oil plays are the Ellenburger, Fusselman, Simpson and Wristen plays. All are very mature and depleted, with extremely limited production potential; however, these plays have been excellent candidates for saltwater disposal.

Play Analysis

Major Plays

Included in the major plays category are the Bone Spring and Wolfcamp plays. The magnitude of both plays can be observed in oil production (Figure 7) and in well count (Figure 8) from wells with a first production start date in 2011. Early in this time period, other plays, particularly the Leonard Yeso, dominated in both well count and production. Later (circa 2014-15), the Bone Spring rapidly developed while the other plays remained relatively constant. In 2016, Wolfcamp development began to spike and has continued to increase year over year in response to available acreage for spacing wells providing an opportunity in New Mexico for the increased development. Through 2021, both Bone Spring and Wolfcamp have dominated, accounting for 85% of all oil and gas production from wells completed since 2011, and approximately 65% of all wells completed.

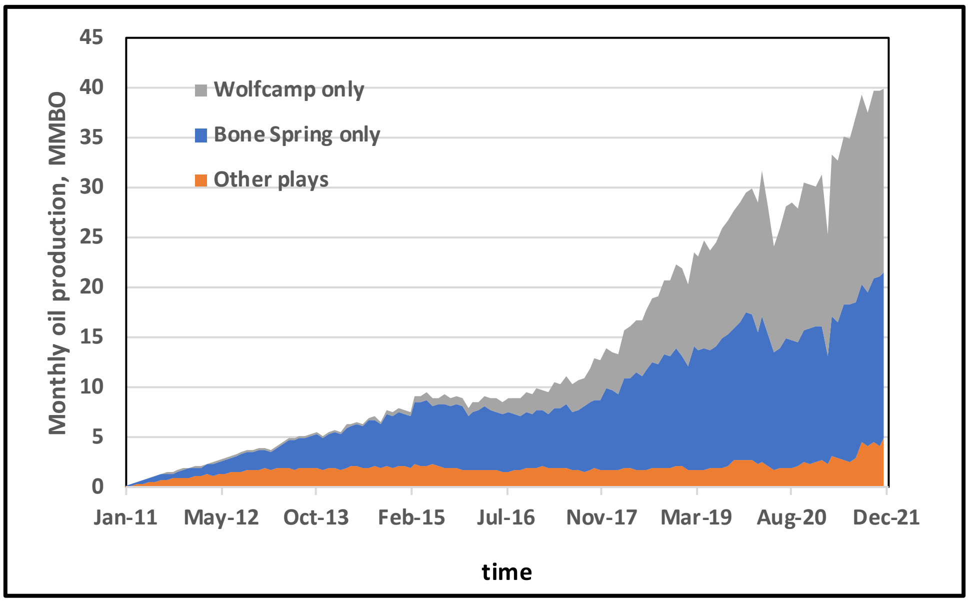

Figure 7. Monthly oil production from wells with first production date of 2011separated by Wolfcamp, Bone Spring and all other plays combined. {Source: GOTECH/NMOCD}

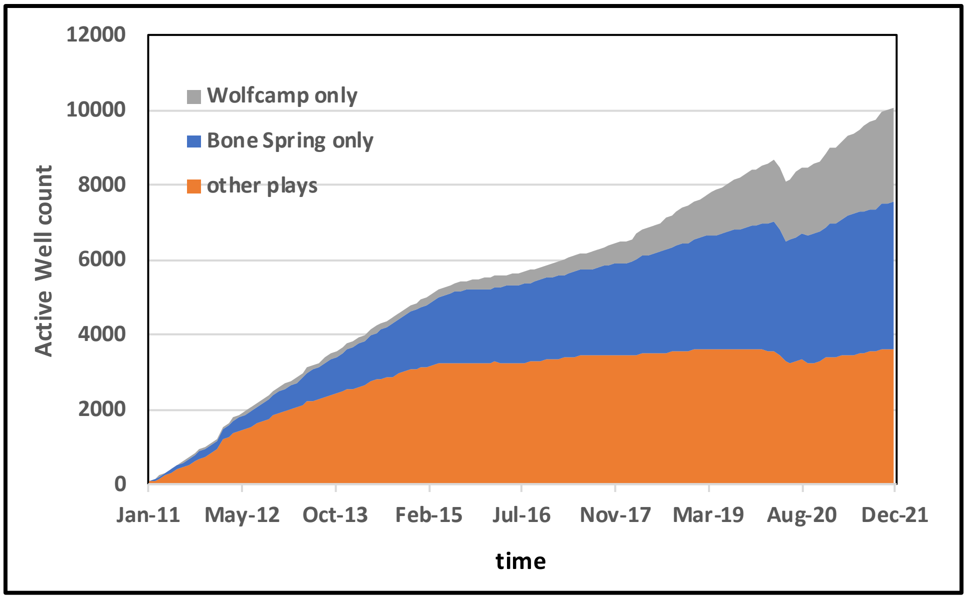

Figure 8. Monthly active well count separated by Wolfcamp, Bone Spring and all other plays combined. {Source: GOTECH/NMOCD}

Minor, Gas, and Deep Mature Oil Plays

Since the level of activity and corresponding production for the other three categories is extremely limited, the data has been combined and is shown in Figures 9 and 10, respectively. Within this group, the Minor plays, mostly the Leonard Yeso play, dominate production and well count.

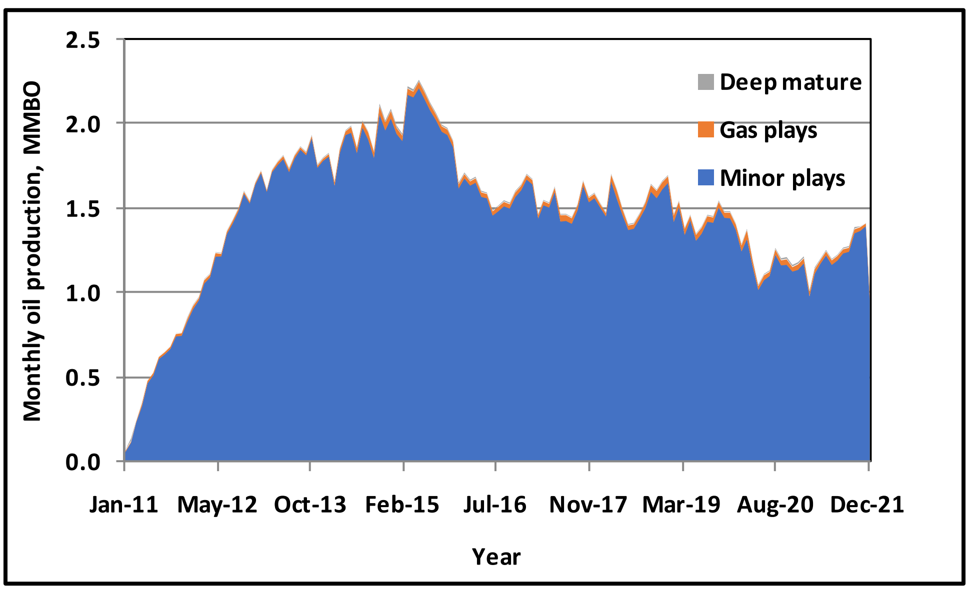

Figure 9. Monthly oil production separated by Minor, Gas, and Deep mature plays. {Source: GOTECH/NMOCD}

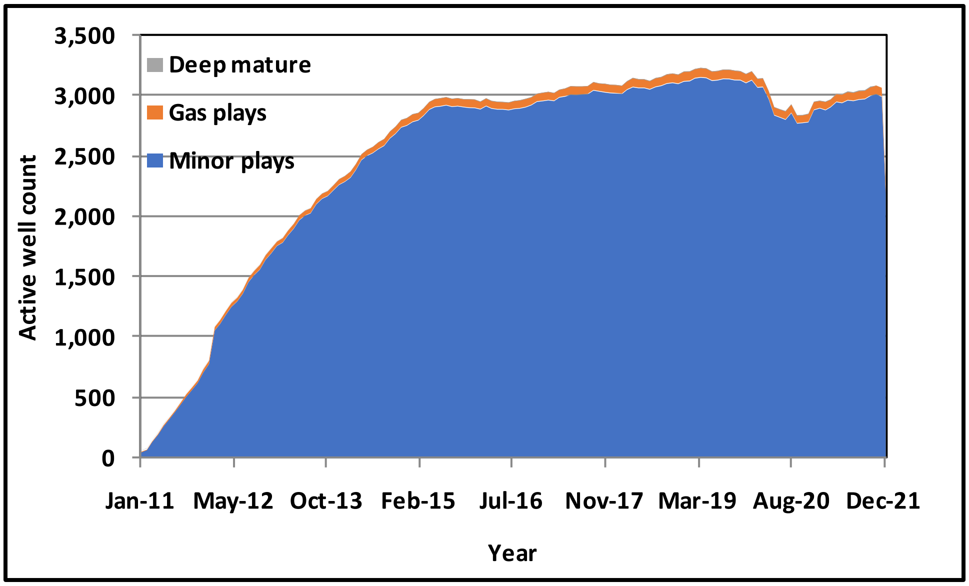

Figure 10. Monthly active well count separated by Minor, Gas, and Deep mature plays. {Source: GOTECH/NMOCD}

Further discussion and details for the plays included in the four categories listed above are presented in the Appendices A through D.

Recent Activity

An indicator of future interest and activity of industry is to review the submitted drilling permits. Subsequently, statistics from NMOCD were compiled and are shown in Figure 11. Unfortunately, the majority of wells (>50%) do not provide a formation on the permit. As expected, the Bone Spring and Wolfcamp dominate the known targets, but again this is not reliable given the number of wells with no formation listed. Typically, the trend of increasing and decreasing intents follow the WTI oil price, but since a significant fraction of the data is missing dependable results could not be acquired.

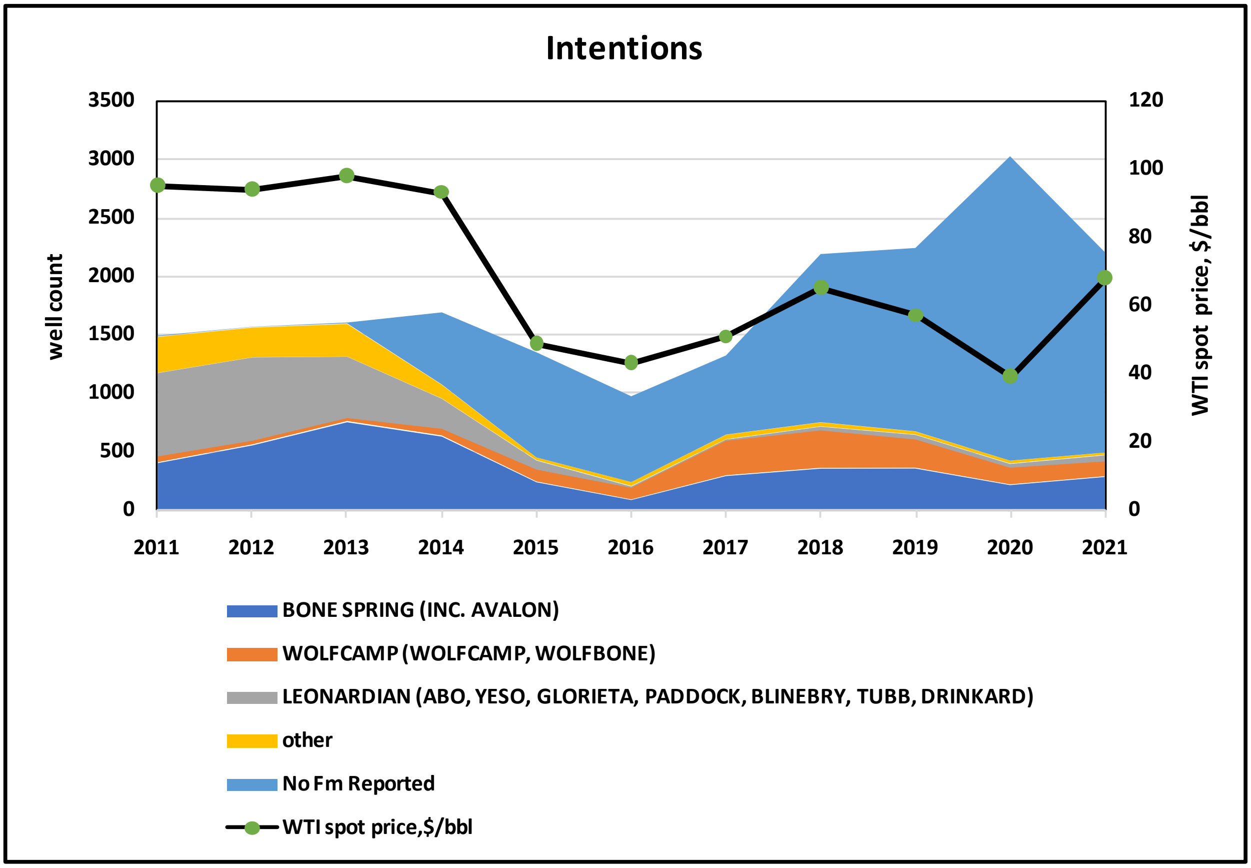

Figure 11. Intents by year and Formation type. {Source: WRRI, NMOCD}

Further analysis adjusted the drilling permits by subtracting the cancellations. Details of this evaluation can be found in (WRRI Report, 2023). Some notable findings are: 20% to 30% of APD's that are filed will eventually be cancelled, average time between the APD report and cancellation is approximately three years, and cancellations increase for plays with higher activity. A final caveat is the significant uncertainty in the data reporting of cancellations.

A comparison between intents less cancellations and completions are shown in Figure 12. Prior to 2017 the two trends were closely aligned and thus the time to completions was less. The increase difference starting in 2017 suggests industry has developed an inventory of potential locations for future development to be accounted for in the next several years.

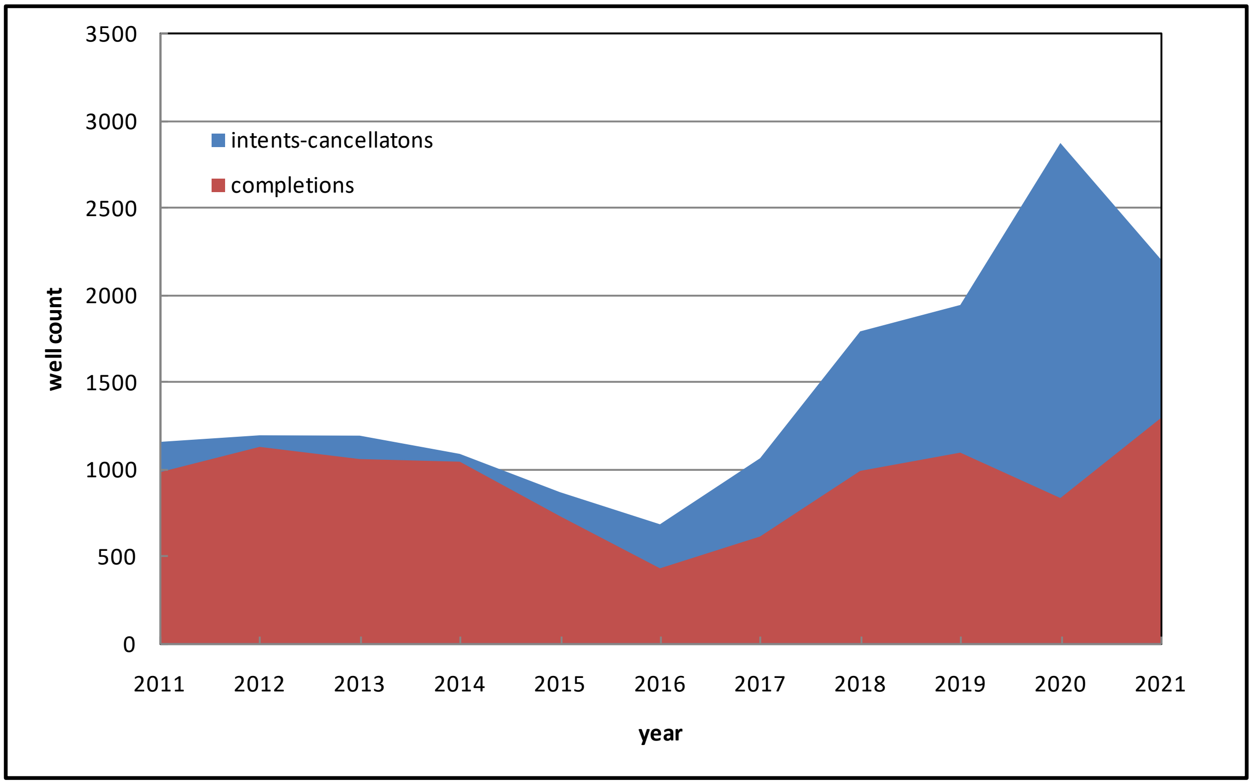

Figure 12. Well intents less cancellations compared to completions for SENM from 2011 through 2021. {Source: NMOCD/GOTECH}

Projections of Future Activity

Factors Impacting Predicted Development

The focus of this project is to predict future development in the Carlsbad Field Office area for twenty years. Specific items required are the number of new wells to be drilled and completed, the estimated ultimate recovery of this activity, the net surface disturbance created by this development and the water balance between production and use. To accomplish this estimate requires numerous assumptions and constraints. To simplify, these factors have been divided into two categories, internal and external. The geologic controls and engineering principles that control development of the resource are internal factors directly related to the resource Items such as shale content, lithology, porosity, permeability, natural fracture intensity and orientation, stress magnitude and orientation are just a few of the geologic parameters that control the extent and productivity of a given well. Engineering principles including completion effectiveness, stimulation and horizontal well design, artificial lift, and optimization also influence well productivity.

To evaluate all the factors and develop a comprehensive model is beyond the scope of this project. Instead, the approach was to use historical well data such as production volumes, number of wells, type of wells, horizontal lateral length, etc.) as a proxy for the factors listed above. That is, production type curves were created and analyzed for various subgroups (plays, reservoirs, well types, etc.). To create these type curves, sufficient subgroup data was appropriately analyzed, and meaningful results obtained. In the area of interest, applying production criteria is considered valid, since the primary activity is the development of the unconventional resources with horizontal wells while the secondary activity the continuing EOR projects.

Another internal factor is the advancement in technology that unlocks and expands the resource. Advancements such as improved reservoir characterization, extending horizontal drilling length and multistage stimulation techniques are three of the most important recent developments. Current well-established technologies are implicitly included in the production type curve analysis. However, the prediction of unknown new technologies to be employed in the future or more importantly their impact, is not feasible. It is also worth noting that undeveloped unconventional resources will require these future technologies to be productive. In the 2012 RFD, two such undeveloped resources that were mentioned as "possible" are the Woodford Shale and the San Andres Residual Oil Zone (ROZ). As of today, neither has been an active target. A third application of technology that is being investigated is EOR processes in unconventional reservoirs using horizontal wellbores. Research and pilot tests are ongoing in the Eagle Ford (Barden et al, 2020) and Bakken Formations (Rassenfoss, 2022).

External factors are defined as those items that are nationwide or global in nature. Factors in this group include commodity prices, economic growth, and market competition from other energy sources. The EIA (2022) has developed a useful and comprehensive methodology to incorporate these factors for their future predictions, and thus was relied upon in this work as the template to account for their impact on development. Details of their methodology and results can be found in EIA (2022, 2023) and thus will not be explained here. As an example of the impact of oil price on activity, Figure 4 illustrates the well-correlated trend of annual well completions to the rise and fall of oil price from 2011 through 2021.

<u>Development Potential</u>

The result of evaluating the activity and production from 2011 through 2021 provides the basis for projecting the reasonably foreseeable development spanning 20 years beginning in 2023. Table 2 lists the estimated potential by play using the scale shown. Also included are metrics from 2015 through 2021 for comparison.

Continued minor well development of 100 wells per year is projected for all plays except Bone Spring and Wolfcamp. These wells will mostly be replacement and infill wells in existing mature plays that are not conducive to horizontal well development. These wells are indicated by the low to very-low potential indicated in Table 2. The Bone Spring and Wolfcamp are the major plays and they each account for 554 horizontal wells per year each. This activity is due to additional development of multiple reservoirs in both plays. As noted in Table 2, both plays have very high potential as indicated.

	Results and recommendations			Statistics -2015 through 2021				
Minor Play	Potential		Comments	Average*	% Horiz	2022$	Trend	
Abo Platform Carbonate	<10	Very low	infill and extension drilling	4	<1%	3	decline	
Artesia Sandstone Group	<10	Very low	Mature, shallow targets	4	<1%		constant-low	
Gas							decline	
Atoka & Atoka-Morrow	<10	Very low	Infill available, no gas price	1	0%	2	decline	
Morrow	<10	Very low	Infill available, no gas price	1	0%	1	decline	
Mississippian			No gas price					
Penn - NW Shelf+Strawn patch reef	<10	Very low	Limited resource, mostly gas play	5	27%	6	decline	
Delaware Mountain Group	10 - 25	Low	Development, waterflooding, EOR	16	73%	7	decline	
Deep, mature oil				<1	0%	1	constant-low	
Ellenburger	<10	Very low	Limited resource, mature, deep	0	0%	0	constant-low	
Fusselman	<10	Very low	Limited resource, mature, deep	0	0%	0	constant-low	
Simpson Sandstone	<10	Very low	Limited resource, mature, deep	0	0%	0	constant-low	
Wristen	<10	Very low	Limited resource	<1	0%	1	constant-low	
Leonard				66		34		
NW Shelf Yeso Subplay	25 - 50	Moderate	Infill and extension drilling of Yeso, horizontal	57	64%	30	decline	
CBP Subplay	10 - 25	Low	Infill - vertical	9	<1%	4	decline	
San Andres				26	24%	33	decline	
NW Shelf	10 - 25	Low	horizontal well development	6	93%	10	decline	
Artesia-Vacuum GB/SA	10 - 25	Low	Mature, long term EOR-CO2 potential	11	5%	10	decline	
Central Basin Platform	10 - 25	Low	Mature, long term EOR-CO2 potential	9	3%	13	decline	
Major Play	HC type	Potential	Comments	Average*	% Horiz	2022*	Trend	Trend
Bone Spring	>100	Very high	Development of sands and Avalon, horizontal wells	393	99%	712	increasing	
Wolfcamp	>100	Very high	Additional oil development w/horizontal wells	339	99%	467	increasing	

Notes

1 *Average completions per year from 2015 through 2021
2 % horizontal over the average time period
3 $ Last - number of wells completed in 2022

Scale	wells/yr
Very low	<10
Low	10 - 25
moderate	25 to 50
High	50 to 100
Very high	> 100

Table 2. Estimation of potential by play.

Development potential maps were created to visually represent the overall potential for the area of interest. Figure 13 represents a conglomeration of these potential maps. In the high potential region outlined in Figure 13, an approximate estimate of 11 additional wells per section is projected over the RFD lifespan. Activity in this region is anticipated to be horizontal well development with an average 2-mile lateral length in the Wolfcamp and Bone Spring plays. In the moderate region, 5 new wells per section is projected and is based on a mix of Wolfcamp, Bone Spring and other plays. Again, mostly horizontal development. The low potential region is projected to have minimal development and thus less than one new well per section, composed of a mix of horizontal and vertical development. Individual play potential maps can be found in the Appendices.

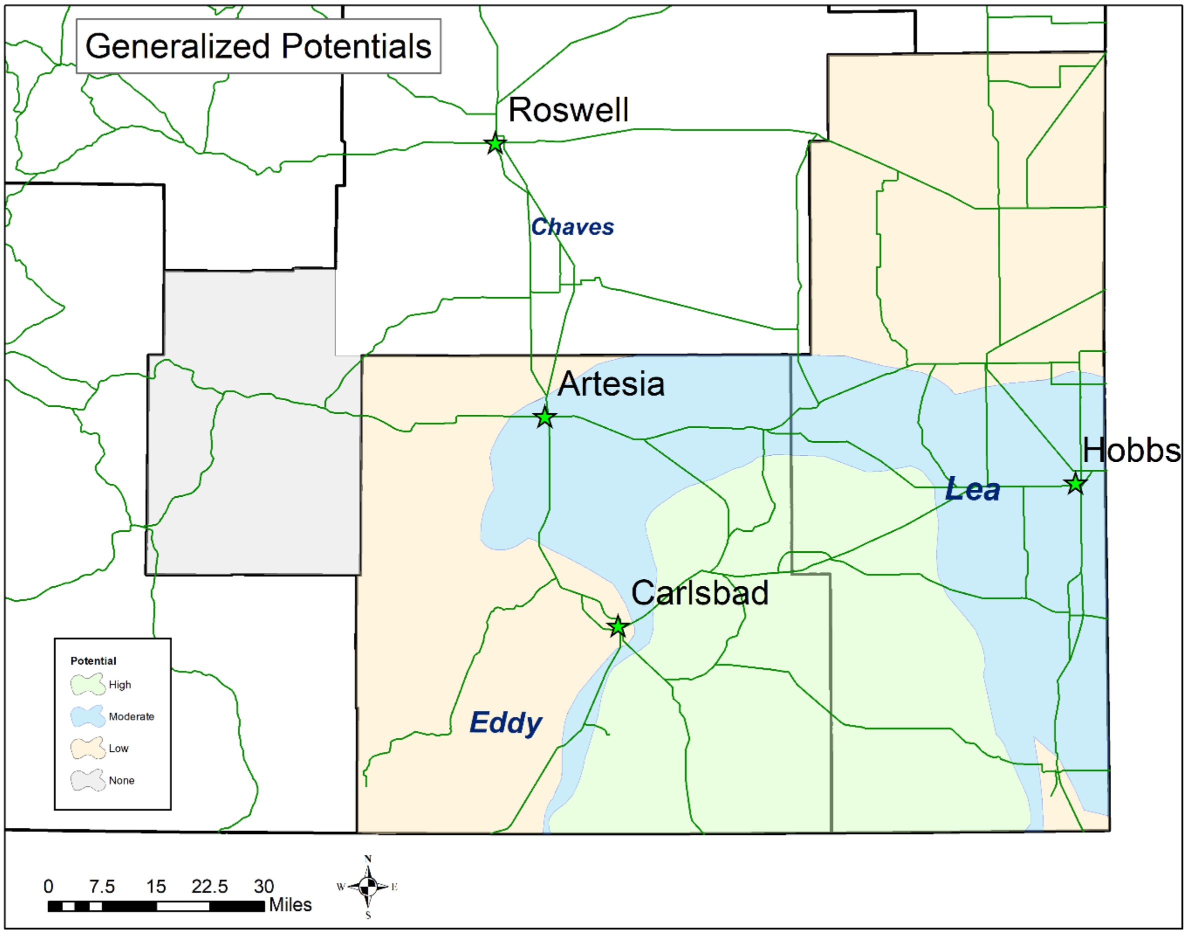

Figure 13. Conglomeration of all development potential maps for all plays. {GOTECH/NMOCD}

Estimated Future Oil and Gas Production

For BLM planning purposes, projections of future oil and gas production were created by analyzing historical production data and constructing decline curves that forecast future volumes for the next 20 years. Figure 14 shows a comparison in decline curve predictions between the RFD SE NM and the EIA's SW U.S. projections. The two trends (RFD of SENM only and the EIA estimate of Southwest U.S.) are remarkably similar until 2039 where the predictions deviate. Since the EIA estimate is for the entire Southwest region, it is hypothesized that this difference reflects an increase in development from another region outside of Southeast New Mexico.

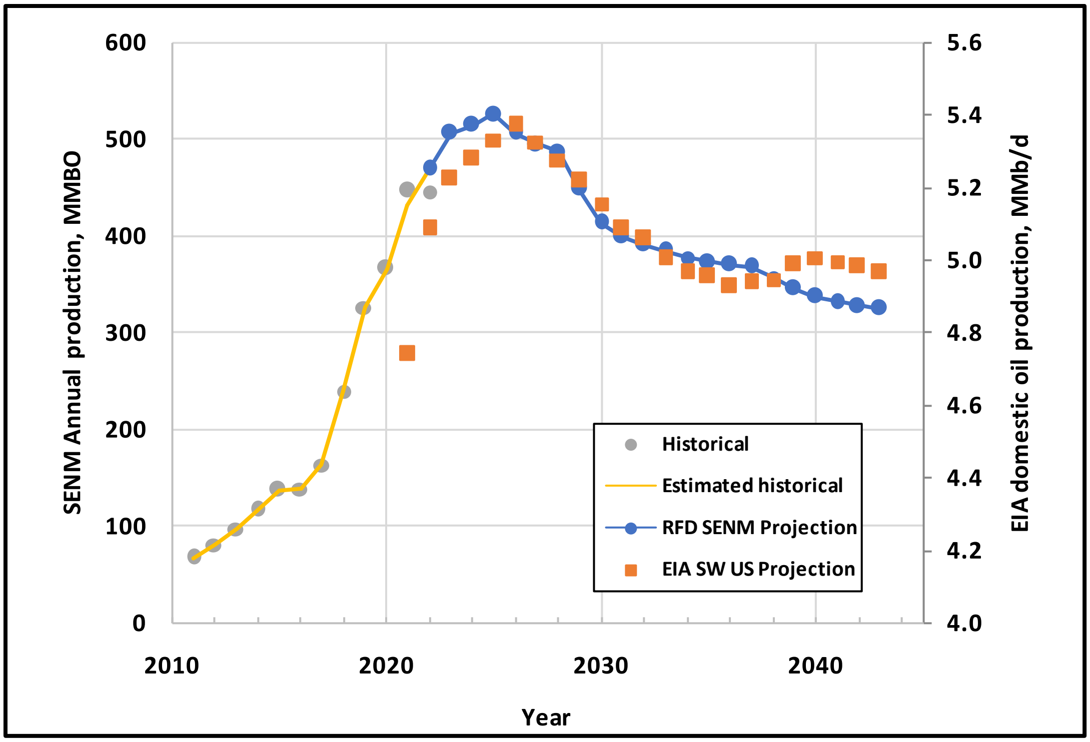

Figure 14. Historical and projected oil production for SENM {Data Sources: GOTECH/NMOCD, EIA 2022}

In the short term the trend of increasing oil production is anticipated to continue until 2025. This year (2025) was selected based on current 2022 EIA Energy Outlook projections for oil price peaking in 2025 and then remaining at a relatively stable but lower value afterwards. In the long term the expectation is for oil production to decline as reservoirs become less prolific. This also leads to a corresponding decrease in new well starts and lease development. The Federal portion of the historical number of spuds added per year from 2011 through 2022and the predicted new spuds are shown in Figure 15. Observing the dependency of the magnitude of historical spuds to commodity price, confirms the influence of price on activity level. The average from 2011 through 2021 (Note: 2022 data was ignored in this analysis) is 617 new spuds per year, and thus a short-term prediction of 770 new spuds allows for the continued upward trend in development over the short term. Over the 20-year forecast period, cumulative production from existing and new wells is estimated to be 5.4 billion BO, 20.5Tcf gas, and 18 billion BW.

The Federal portion is approximately 60% of the total spuds per year; thus, the total (Federal and non-Federal) historical spuds are 1,031 and the projected new spud count is 1,208. Over the 20-year forecast period, cumulative production from existing and new wells is estimated to be 8.6 billion BO, 33 Tcf gas, and 30 billion BW.

Footnote: Spud in this context refers to a well that is recorded as actually beginning the drilling process. This is different from the completion values provided in much of this report which is related to the actual first production of a well.

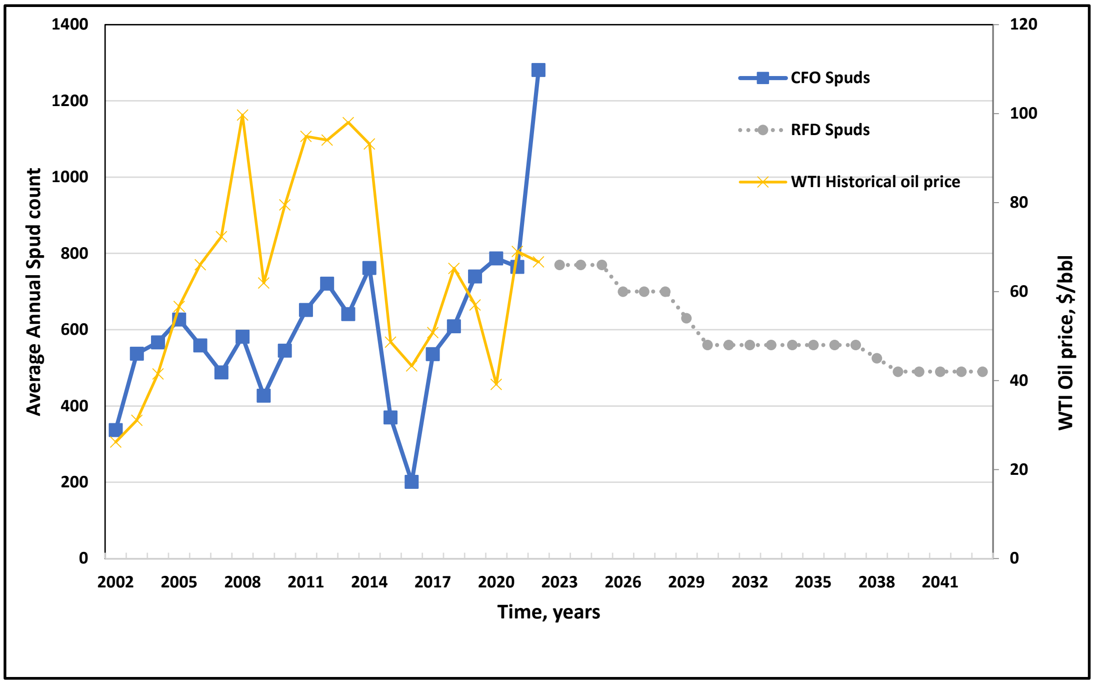

Figure 15. Historical and projected spuds on Federal lands. {Data Sources: CFO spuds from BLM, Oil price from EIA}

Estimated Surface Disturbance

Oil and gas development projected in the next twenty years will require associated surface development of roads, flowlines and well pads. To acquire the surface disturbance requirements for new development, disturbance caused by existing infrastructure was estimated and is shown in Table 3.

Surface disturbance data were extrapolated from the U.S.G.S. Vegetation Data (Villarreal, et al. (2023). The pad polygons for each of the New Mexico Oil and Gas Conservation Division well points were derived from classified 1-meter National Agriculture Imagery Program (NAIP) Imagery from 2020. The process is based on a threshold classification of the red band aimed at mapping the bright soil of the disturbed pad. The classified NAIP imagery was filtered in GIS to simplify the geometry of the polygon and fill in the gaps. Therefore, the data approximates the true size of the pad, and represents the disturbed area dominated by bright soil that is visible from aerial imagery, and not the disturbed areas that have been reclaimed or vegetated. In cases where areas around the pad were reclaimed/revegetated the true disturbance area may be underestimated. The total existing acreage is approximated to be 109,000 acres as of the end of 2020.

Year/status	Wells (n)	Pads (n)	Total pad area (ac)	Average pad size (ac)	Average area per well (ac)	Total area roads (ac)	Road area per pad (ac)	Total area disturbed (ac)
pre-2000	26,089	21,881	38,344	1.8	1.47	22,472	1.03	60,816
2001-2005	3,673	3,127	5,984	1.9	1.63	1,843	0.59	7,827
2006-2010	4,025	3,427	7,445	2.2	1.85	1,902	0.56	9,347
2011-2015	5,092	3,792	11,288	3.0	2.22	2,029	0.54	13,317
2016-2020	4,507	1,580	6,672	4.2	1.48	1,157	0.73	7,829
P&A		6,519	9,931	1.5				
Totals*	43,386	40,326	79,664	2.0	1.84	29,403	0.73	109,067

Table 3. Estimated surface disturbance at the end of 2020 from existing wells. (Federal and non-Federal combined)

*The Plugged and Abandoned pads were inferred from the data based on the SPUD year value of '9999' or '0.' The totals of surface disturbance area were included in the totals in Table 3 because the reflectance values indicate interim or unsuccessful reclamation.

Table 3 breaks down surface disturbance into summary statistics in five-year increments to include the surface disturbance associated with access roads to well pads. It includes well count, pad count, average acres per pad, average acres per well, average acres or road per pad, and total acres disturbed. The road data was interpolated based on previous work that determined that average access road width was 5 meters – thus road segment lengths were multiplied by 5 and converted to acres.

The surface disturbance for new well development is shown in Table 4. For the twenty-year period, it is estimated an additional 33,300 acres of disturbance is required, which includes both vertical and horizontal well development. Note the trend in Table 3 is an increasing number of wells per pad, with 3 wells/pad the latest value for the 2016-2020 group. Therefore, 3 wells per pad was used for the projection. Combining existing and new development results in the maximum potential disturbance of 142,400 acres.

Year/status	Wells (n)	Pads (n)	Total pad area (ac)	Average pad size (ac)	Average area per well (ac)	Total area roads (ac)	Road area per pad (ac)	Total area disturbed (ac)
Projected vertical wells	2,000	2,000	3,500	1.8	1.47	2,000	1.00	5,500
Projected horizontal wells(3 wells/pad)	17,600	5,867	23,467	4.0	1.50	4,400	0.75	27,867
Totals*	19,600	7,867	26,967	3.4	1.38	6,400	0.81	33,367

Table 4. New surface disturbance over the life of the plan (2023-2043)(Federal and non-Federal combined)

Not accounted for in the future surface disturbance is the reclamation for sites where wells are P&A. On average, from 2011 through 2021, 650 wells were plugged and abandoned each year (NMOCD, GIS database). Percent of wells plugged by formation has changed through time. A decade ago, Artesia Group wells were the biggest proportion of wells being plugged, gradually decreasing in proportion through time. Their place has been taken by Delaware and Bone Spring wells. The past two years have seen an increase of Wolfcamp wells being plugged as well.

Estimated Water Production and Use

As water is limited and thus essential in arid New Mexico for agriculture, domestic consumption, industry and other beneficial uses, it is important to assess and predict the associated water production and the corresponding use of water in oil and gas development. A holistic approach was taken with regards to the mass balance between the production of water to the end use of water. This preliminary framework is defined as the "water balance".

As a starting point, water production and injection data since 2011 were compiled and analyzed for trends. Figure 16 exhibits water production and injection combined from Eddy and Lea Counties from 2011 through 2022(note that 2022 is a partial year of data). Injection includes both water injection for enhanced oil recovery and saltwater disposal. As can be seen from the figure, most of the water is being disposed and/or injected. No attempt was made to differentiate between the two for this project.

In 2017 the difference in water production and injection/disposal begins to increase and this difference rapidly expands in subsequent years. This timing also coincides with the increase in horizontal completions for oil and gas development (see Figure 5).

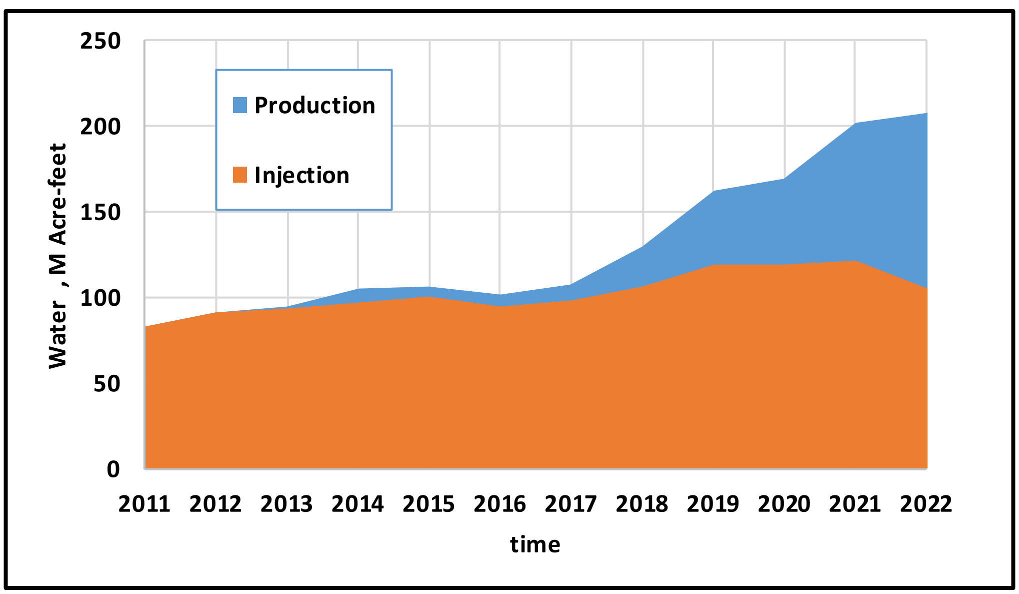

Figure 16. Water production and injection for SENM, Eddy and Lea Counties. Note: 2022 is a partial year of data. {Source: GOTECH}. 7758 bbl = 1 acre-foot

Many factors can account for this difference, from recent recycling efforts (reference) to estimates of use for oil and gas development. One such estimate by the U.S.G.S. (Gonzalez, et al, 2023) provides data for three segments of water use by oil and gas development: indirect, direct and ancillary. Direct water use is defined as water used in a wellbore to complete a well, which includes water used for drilling, cementing, stimulating, and maintaining the well during production. Indirect water use is defined as water used at or near the well site, including water used for dust abatement, equipment cleaning, materials washing, worker sanitation, and site preparation. Ancillary water use is defined as all other water used during the life cycle of oil and gas development that is not categorized as direct or indirect, such as additional local or regional water use resulting from a change (for example, population) related to oil and gas development (Valder, et al, 2021).

Data for Lea and Eddy Counties was analyzed over an eleven-year time period (2011 through 2021) for each segment and the results are shown in Figure 17. The significant rise in water use in 2017 is in response to the increase in direct water use. Data for components of direct water use (i.e. cementing, drilling, and stimulation) are provided by the U.S.G.S. data release (Gonzalez, et al, 2023) and thus were reviewed to identify the major contributor to this increase. Stimulation, specifically hydraulic fracturing, accounts for 99% of the direct water use and thus is the driver of the overall increase in water use for oil and gas development.

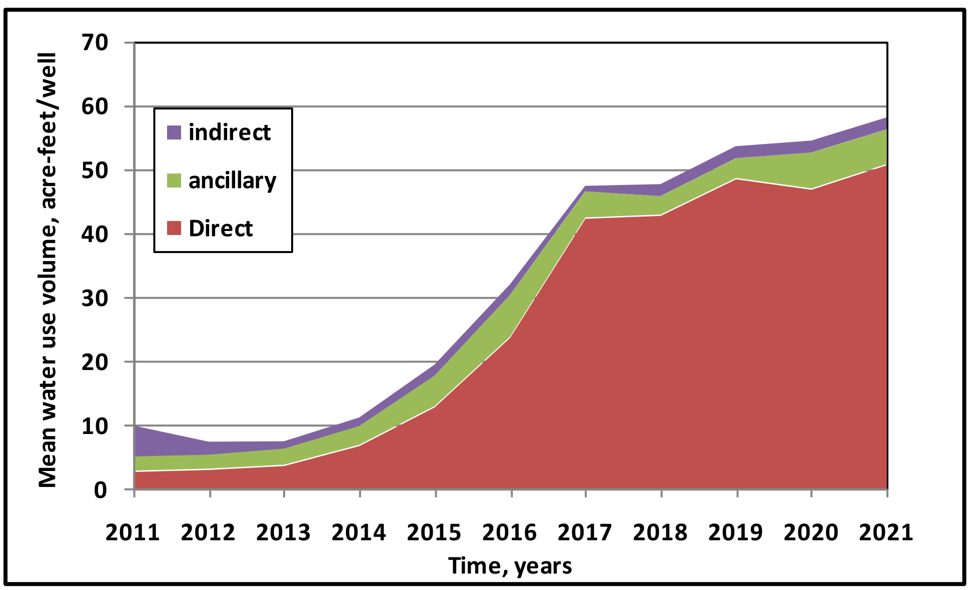

Figure 17. Indirect, direct and ancillary mean water use per well for Eddy and Lea Counties combined from 2011 through 2021. {Source: Gonzalez, et al, 2023}

Figure 16 was modified to include the estimate of water use for hydraulic fracturing in Eddy and Lea Counties combined and the results are shown in Figure 18. The difference between water production and water use by injection/disposal plus stimulation is remarkably small, except for 2022, however no stimulation volumes were available for 2022 and analyzed for that year since data is still being updated and reported. In summary, this comparison is very preliminary and requires more detailed analysis to improve our understanding of the water balance issue. However, two important trends recognized and necessary for the prediction phase are future water production and stimulation water use.

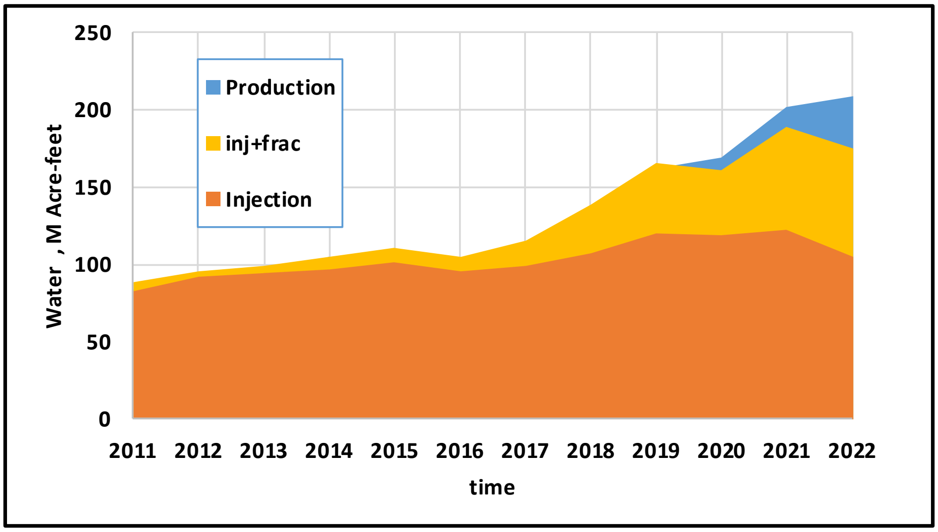

Figure 18. Water production, injection and stimulation water use for SENM, Eddy and Lea Counties. Note: 2022 is a partial year of data. {Sources: GOTECH, Gonzalez, et al, 2023}

Horizontal well completions are dominating oil and gas development, and thus this trend is expected to continue in the future prediction phase. Simultaneously, the average lateral length has been increasing since 2011 (See Figure 6) to approximately 1 ½ to 2 miles. Subsequently, the estimate for lateral length in the prediction is to average 2 miles. Data was extracted from the U.S.G.S. data release {Gonzalez, et al, 2023} to determine stimulation water use for longer laterals. The data was limited to only wells with lateral lengths greater than 10,000 ft. Results in Figure 19show an increase in stimulation water use to approximately 6 acre-feet per 1000-foot lateral length or 60 acre-feet per well. Also shown is the number of longer lateral wells has been increasing. The decreases in 2020 and 2021 are assumed to be due to limited data. Subsequently, for the purposes of future oil and gas well development, 60 acre-feet of water per well will be required for stimulation.

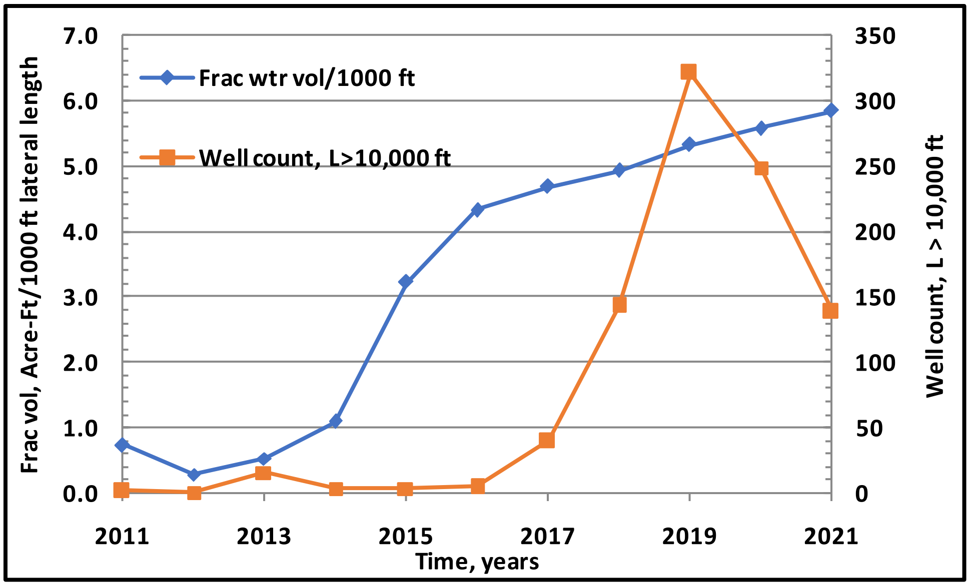

Figure 19. Stimulation water volume per 1000 ft of lateral and number of wells with lateral length greater than 10,000 ft. {Source: Gonzalez, et al, 2023}

A recent trend has shown an increase in using produced water for stimulation, replacing the use of fresh water. Water use data compiled by industry and reported on the NMOCD website began in September 2020. Figure 20 illustrates the increasing trend in using produced water as a percent of total used in hydraulic fracturing up to March 2023. Approximately 3000 wells are included in this data, with two-thirds (~2000 wells) considered to be the Federal portion.

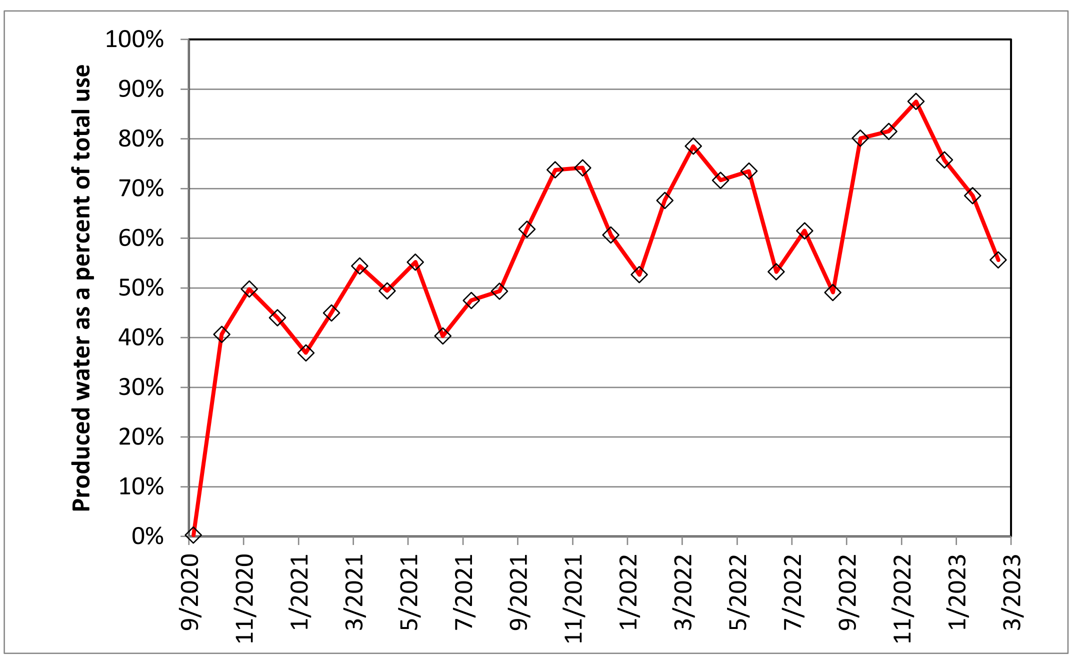

Figure 20. Percent of produced water used in hydraulic fracturing in SENM. {Data source: NMOCD}

Forecasted water production was based on historical WOR values for the Wolfcamp and Bone Spring Formations and decline analysis for the remaining plays. Furthermore, the applied WOR values varied between remaining production of existing wells and production from new wells. In all cases, the WORs were assumed constant throughout the 20 –year time period. This assumption is a simplification and should be considered as such. It is supported by observed historical trends in the Wolfcamp and Bone Spring formations, (Further discussion can be found in both plays) but a complete analysis of modeling water production was not attempted in this work.

The estimated cumulative water production for the 20-year period beginning in 2023 is 30 billion barrels of water or 1.5 billion barrels of water per year. In comparison, over the last twelve years (2011-2022), water production has averaged approximately 1 billion barrels of water per year, with an increasing trend with time. Thus a 50% increase in water production is projected for the RFD time period and captures the increasing trend observed in the last several years.

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Appendices (Attachment 1)

A. Major Plays: Bone Spring and Wolfcamp

B. Minor Plays

C. Gas Plays

D. Deep, Mature Oil Plays

E. Annual Summary of Forecast Data