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Shashank Shekhar

shashankshekhar10031992@gmail.com

The University of Tulsa

Zenefa Rahaman

The University of Tulsa

Alexy Mazarovich

Balmohan G. Kelkar

The University of Tulsa

Chris G. Einchomb

Sunil K. Srivastava

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STACK Play Production Analysis – Canadian and Kingfisher Counties, Oklahoma: Production Performance, Flow Regime Characterization, and Parent-Child Well Interference. A Comprehensive Statistical Analysis of 3,550 Horizontal Wells

Shashank Shekhar^{1*}, Zenefa Rahaman¹, Alexy Mazarovich³,
Balmohan G. Kelkar¹, Chris G. Einchcomb³, Sunil K. Srivastava³

^{1*}Department of Petroleum Engineering, The University of Tulsa,
Tulsa, Oklahoma, USA.

²Department of Petroleum Engineering, The University of Tulsa, Tulsa,
Oklahoma, USA.

³Independent Researcher.

*Corresponding author(s). E-mail(s):

shashankshekhar10031992@gmail.com;

Contributing authors: zeneferahaman@gmail.com;

mazarovichaa@gmail.com; mohan@utulsa.edu;

chris.einchcomb@icloud.com; sksrivastava2003@gmail.com;

Abstract

This study presents a field-scale production analysis of 3,550 horizontal wells in the Sooner Trend Anadarko Basin Canadian and Kingfisher (STACK) play of north-central Oklahoma using monthly production histories from 2008 through 2024. Multi-Segment Arps decline curves were fitted from peak production to reduce early-time ramp-up bias and were evaluated with material-balance-time diagnostics, type-curve validation, EUR estimation, GOR characterization, and decline-corrected parent-child interference screening.

The material-balance-time diagnostics indicate transition away from early transient linear flow after approximately 13–32 months, supporting a segmented decline framework with hyperbolic early-time behavior followed by late-time exponential decline. EUR distributions show that Woodford Shale, WF/Miss.

Combo, and Mississippian intervals provide the strongest recovery performance on a BOE basis, while Oswego remains a lower-EUR but oil-rich target. Parent-child analysis of 17,191 candidate well pairs identifies 2,177 confirmed production-signature anomalies and 1,461 probable communication cases after correcting for expected parent decline. The results show that parent age alone is not protective; infill development should combine decline-corrected screening, formation-specific spacing, true lateral geometry, and pressure-support or prefill mitigation for depleted parent wells.

Keywords: STACK play, unconventional reservoirs, decline curve analysis, material balance time, parent-child interference, hydraulic fracture communication, reservoir engineering

1 Introduction

The Sooner Trend Anadarko Basin Canadian and Kingfisher (STACK) play of north-central Oklahoma is one of the major unconventional resource plays within the Anadarko Basin. The play is characterized by vertically stacked producing intervals, including the Woodford Shale, Mississippian Limestone, Mississippi Lime Less Chester, Oswego Dolomite, WF/Miss. Combo, Meramec, Hunton, Hoxbar, and other minor producing formations. This stacked reservoir architecture creates both development opportunity and reservoir-management complexity because production performance, fracture communication, depletion behavior, and parent-child well interference vary by formation, county, fluid type, completion design, and well spacing.

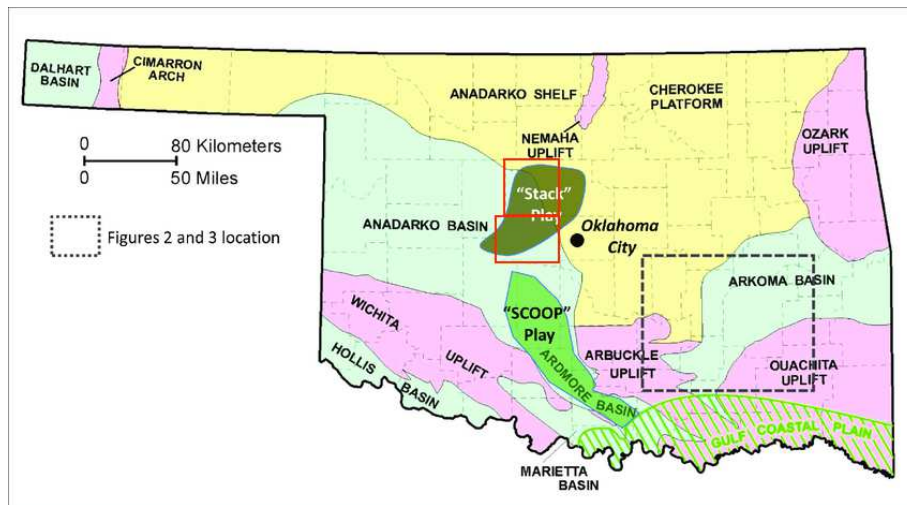


Fig. 1: Location of the STACK play within Oklahoma. The highlighted STACK fairway is shown with Canadian and Kingfisher Counties marked by red boxes.

Figure 1 shows the location of the STACK play within Oklahoma and highlights the Canadian and Kingfisher County study area in red. The two study counties sit on the eastern flank of the Anadarko Basin rather than in its depocentre, which is the reason formation depths in the study area are shallower than basin-center equivalents and why the fluid window shifts from volatile oil in the east toward condensate in the west. The study area includes 3,550 horizontal wells with positive production histories from 2008 through 2024. The dataset contains extensive monthly production records across nine producing formations, principally the Mississippian Limestone (1,302 wells), Woodford Shale (985 wells), Mississippi Lime Less Chester (554 wells), Oswego Dolomite (367 wells), and WF/Miss. Combo interval (178 wells). Canadian County contributes 1,600 wells, while Kingfisher County contributes 1,950 wells.

Unconventional reservoir development in the STACK requires an integrated workflow that can evaluate both well performance and communication risk. Traditional decline-curve analysis remains central to reserves estimation and production forecasting, but unconventional wells commonly exhibit early-time ramp-up, transient flow, long hyperbolic decline periods, and delayed transition toward depletion-dominated behavior. For this reason, this study fits Multi-Segment Arps decline curves [1, 2] from the peak production month rather than from Month 1. This approach reduces artificial ramp-up bias and provides a more representative basis for estimating initial rate, decline behavior, and EUR.

A key component of the workflow is material-balance-time analysis. Log-log plots of monthly rate, q , versus material-balance time, N_p/q , are used to diagnose flow-regime evolution and evaluate the transition away from early transient linear flow. In this study, the material-balance-time diagnostics indicate transition away from early transient linear flow after approximately 13–32 months across the county-formation profiles. Fully developed boundary-dominated flow is generally not established within the first 60 months of production. This supports the use of hyperbolic decline during the early transient-flow period and a later pure-exponential segment for late-time decline behavior, consistent with the scaling behavior reported for fractured tight reservoirs by Patzek et al. [3].

The study also evaluates EUR distributions and fluid character across the STACK. EUR distributions are computed at the P10, P50, and P90 levels for each county-formation pair. Two EUR bases are distinguished: pooled well-level absolute EUR and length-normalized EUR per 1,000 ft of completed lateral. On the pooled well-level basis, Woodford Shale exhibits the highest median EUR, followed by WF/Miss. Combo, Mississippian Limestone, Miss. Less Chester, and Oswego. Because all EUR values are reported on a 6 Mcf/BOE conversion basis, high-GOR intervals such as Woodford, Meramec, and WF/Miss. Combo should be interpreted together with fluid-type and GOR information.

Parent-child well interference is another central challenge in stacked unconventional development. Infill wells can affect older parent wells through direct fracture communication, pressure-depletion effects, geomechanical stress perturbation, or shared drainage. However, raw post-child production loss can be misleading because unconventional parent wells naturally decline steeply even without child-well interference. To address this issue, the present study applies a decline-corrected

production-signature method. For each parent–child pair, observed post-child parent production is compared with the parent well’s expected 12-month production from its pre-child decline trajectory.

A total of 17,191 candidate parent–child well pairs are evaluated within a 6,560-ft surface-location search radius. This radius is used as a conservative screening window, not as a direct fracture-to-fracture communication criterion. The relevant physical length scale for direct fracture interference is governed by hydraulic-fracture half-length and fracture overlap, while the broader search radius also captures softer pressure-depletion and geomechanical associations relevant to infill screening. Sealed-wellbore pressure monitoring in Anadarko Basin stacked-pay settings illustrates why a broad screen is operationally useful but not physically definitive [4]. After requiring both observed pre/post production and a fitted parent decline model, 16,547 pairs are classifiable. The decline-corrected workflow identifies 2,177 confirmed production-signature anomalies, 1,461 probable communication cases, 12,909 no-interference cases, and 644 insufficient-data cases.

The objective of this paper is to provide a practical, field-scale reservoir-engineering framework for STACK development evaluation. The workflow integrates type-curve construction, decline-curve fitting, material-balance-time flow-regime diagnostics, EUR estimation, GOR characterization, and decline-corrected parent–child interference screening. The results are intended to support infill planning, formation-specific spacing decisions, depletion-risk screening, and mitigation strategies such as prefill or pressure support for older depleted parent wells.

2 Location, Wells, and Formation Classification

2.1 Geographic Setting

The STACK play occupies the north-central portion of the Anadarko Basin, one of the most prolific sedimentary basins in North America [7], located in west-central Oklahoma. The study area encompasses two adjacent Oklahoma counties: Canadian County (centered approximately at 35.50°N, 98.00°W) and Kingfisher County (centered approximately at 35.85°N, 98.35°W), together covering roughly 1,809 square miles (Figure 3) [8]. Figure 3 also resolves the spatial organization of development by producing formation: Mississippian Limestone wells are distributed broadly across both counties, Woodford Shale wells concentrate on the Canadian County (southern and western) side of the fairway, and Oswego Dolomite wells form a distinct cluster in the northeastern part of Kingfisher County, consistent with the county-level formation mix in Table 1.

The Oswego is overwhelmingly a Kingfisher objective; a small number of Canadian County completions also target the interval, and these are retained in the county-level statistics. The inset circle denotes the 6,560-ft (2,000-m) parent–child search radius used in Section 6, shown to scale against the well spacing so that the screening window can be visually compared with typical inter-well distances.

The acronym STACK derives from the stratigraphic stacking of productive intervals—Sooner Trend, Anadarko Basin, Canadian and Kingfisher counties—and has emerged since 2013 as one of the most significant unconventional resource plays in the

continental United States. The play lies on the eastern flank of the Anadarko Basin, where formation depths range from approximately 6,000 ft TVD for shallower Oswego targets to more than 19,000 ft TVD for deep Woodford Shale completions. Subsurface temperatures range from roughly 180°F to 270°F across the depth window, and reservoir pressures typically exceed hydrostatic, facilitating prolific initial production rates from hydraulically fractured horizontal laterals. The area benefits from established oil and gas infrastructure, including numerous pipelines, gathering systems and takeaway capacity developed during both the conventional vertical-well era and the modern horizontal period.

Figure 2 presents the aggregate monthly production rate and cumulative BOE for the 3,550-well STACK dataset from 2008 through March 2024, stacked by county. Two distinct quantities are plotted and should not be confused: the aggregate monthly production *rate*, which is the total BOE produced across all wells active in a given month, and cumulative BOE, which is the running sum of all production to date. Because new wells are continually added to the active inventory, the monthly rate rises through the growth phase, peaks, and then declines, whereas cumulative BOE necessarily continues to climb through the end of the record; the curve that increases monotonically to 2024 is therefore the cumulative total, not the monthly rate.

Combined monthly output grew rapidly from near-zero in 2008 to a peak of 13.2 MMboe/month in May 2019—coinciding with the height of the drilling boom when 2,406 wells were simultaneously producing. Canadian County consistently contributed the larger share of monthly output, reflecting its concentration of high-EUR Woodford Shale and Mississippian Limestone wells. The COVID-19 commodity price crash of 2020 caused a 25% reduction in aggregate monthly rates, with the trough reaching 9.9 MMboe/month in mid-2020. Activity recovered to approximately 11.9 MMboe/month by 2022—roughly 90% of the pre-COVID peak—driven by a smaller but more capital-efficient well inventory with longer average laterals. Cumulatively, the 3,550 wells have produced approximately 1,204 MMboe through March 2024, comprising approximately 395 MMbbl of oil and 4,900 Bcf of gas. Canadian County accounts for 714 MMboe (59%) of total cumulative production despite representing only 45% of the well count, underscoring the higher per-well productivity of Canadian County formations—particularly Woodford Shale (median EUR 813 MBOE) and Mississippian Limestone (median EUR 652 MBOE). Kingfisher County contributes 491 MMboe (41%), with its production base more evenly distributed across Mississippian, Miss. Less Chester, and Oswego formations.

The STACK play is situated along the eastern to northeastern flank of the Anadarko Basin, one of the deepest and most structurally complex sedimentary basins in North America. The basin developed as an asymmetric intracratonic foreland basin associated with late Paleozoic Ouachita–Marathon orogenesis and reactivation of the Southern Oklahoma Aulacogen structural system. Regional subsidence related to compressional tectonics along the southern Laurentian margin generated accommodation space exceeding 40,000 ft of cumulative Paleozoic sedimentary fill in the basin depocenter. Structurally, the Anadarko Basin is bounded by the Wichita–Amarillo uplift to the south, the Nemaha uplift to the east, the Central Kansas uplift to the north, and the Las Animas arch to the west. The STACK petroleum system comprises a

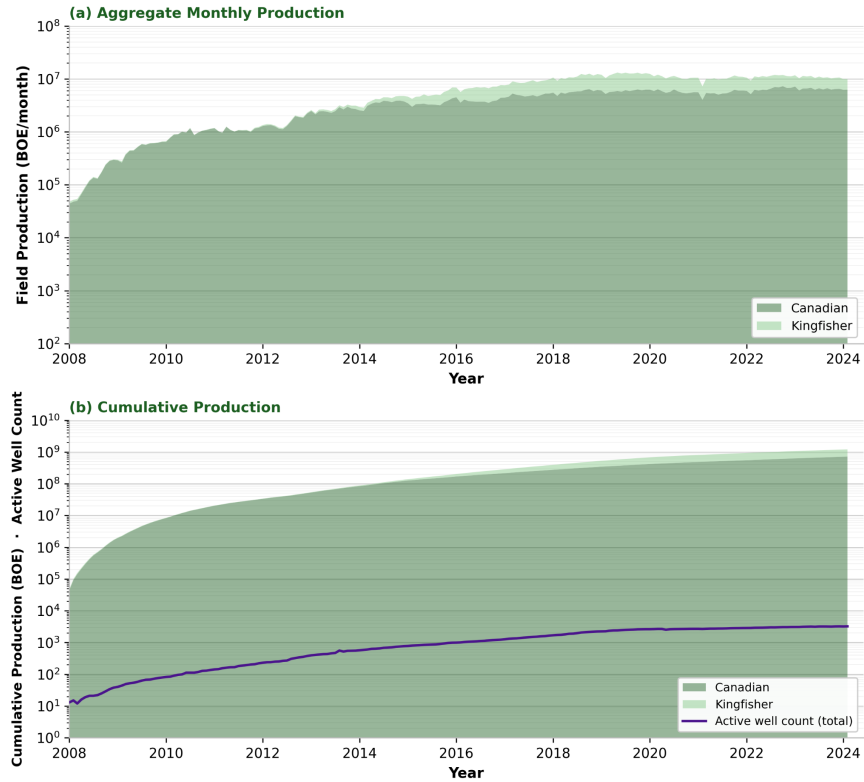


Fig. 2: Aggregate STACK production for Canadian and Kingfisher Counties, 2008–March 2024, stacked by county. The figure shows the total monthly production *rate* summed over all wells producing in each month together with cumulative BOE. The monthly rate grows as new wells are added, peaks at 13.2 MMboe/month in May 2019, dips during the 2020 price collapse, and plateaus near 11.9 MMboe/month thereafter; the curve that increases monotonically through 2024 is cumulative production, not the monthly rate.

vertically stacked succession of Devonian, Mississippian, and Pennsylvanian unconventional reservoirs deposited during repeated transgressive–regressive cycles across a broad epicontinental carbonate ramp developed along the southern midcontinent of Laurentia (Figure 4).

Hydrocarbon production is concentrated primarily within the Woodford Shale, Osage, Meramec, Mississippian Limestone composite, and Oswego intervals. The Late Devonian–Early Mississippian Woodford Shale represents the principal source rock of the STACK petroleum system and serves simultaneously as a self-sourced unconventional reservoir. The Woodford was deposited during a major marine transgression under relatively deep, low-energy, oxygen-deficient basinal conditions favorable for preservation of organic matter. Lithologically, the formation consists of siliceous organic-rich black shale containing abundant quartz, subordinate carbonate phases,

● Mississippian (n=1,302) ● WF/Miss. Combo (n=178) ● Hoxbar (n=10) — Secondary Rd
 ● Woodford (n=985) ● Hunton (n=99) ● Other (n=17) — Local Rd
 ● Miss. (Less Chester) (n=554) ● Meramec (n=38) — Primary Hwy — 6,560 ft (2,000 m) Search Radius
 ● Oswego (n=367)

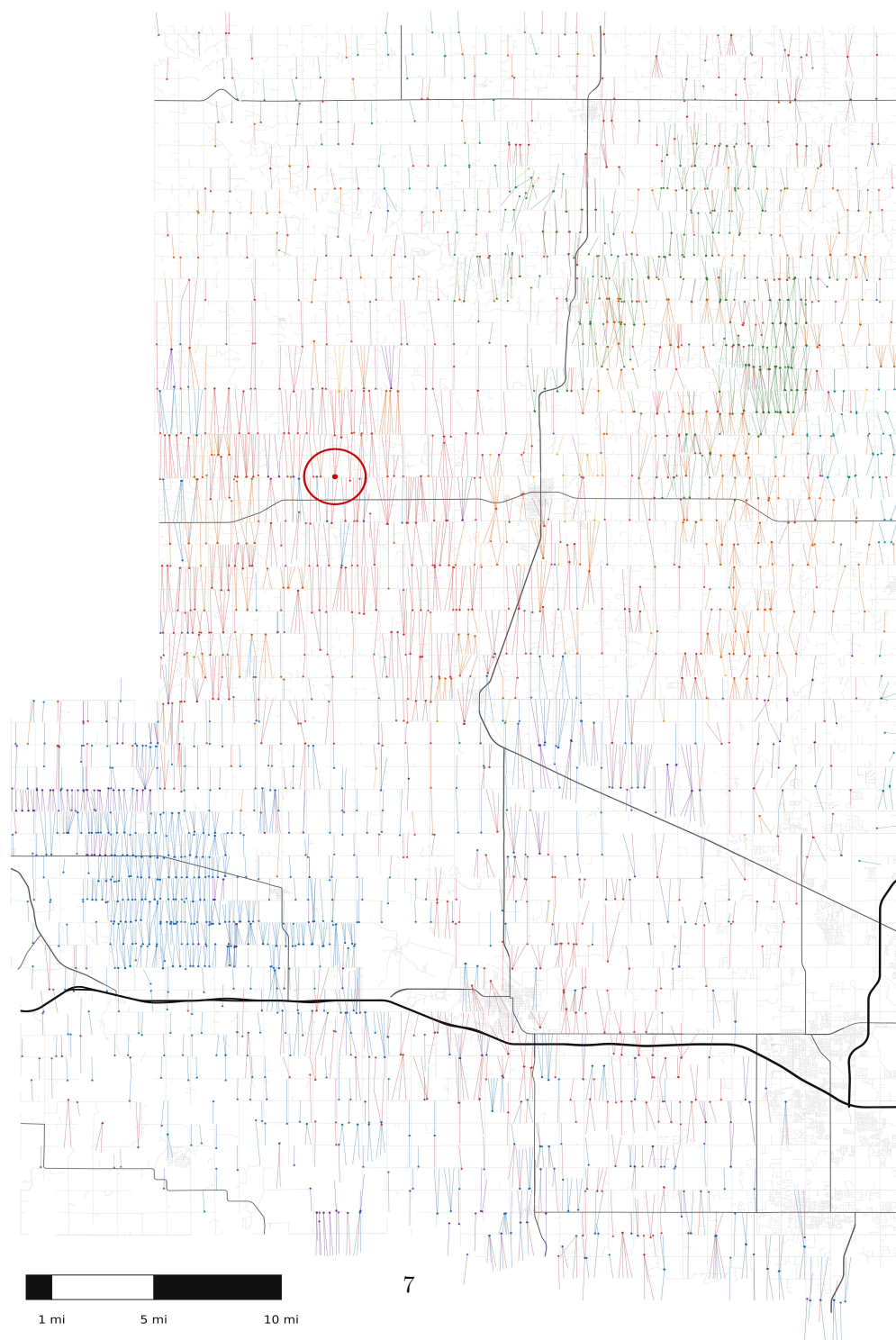


Fig. 3: Map of the STACK study area showing 3,550 horizontal wells across Canadian and Kingfisher Counties, Oklahoma, color-coded by producing formation. The legend identifies nine formation classes.

System	Series	Lithostratigraphic Unit	
Permian (part)	Guadalupian	Whitehorse Group; El Reno Group	
	Leonardian	Sumner Group, Enid Group, Hennessey Group	
	Wolfcampian	Chase Group Council Grove Group Admire Group	Pontotoc Group
Pennsylvanian	Virgilian	Wabaunsee Group Shawnee Group	Ada Group
		Douglas Group	
	Missourian	Lansing Group Kansas City Group	Hoxbar Group
	Desmoinesian	Marmaton Group Cherokee Group	Deese Group
	Atokan Morrowan	Atoka Group Morrow Group/Formation	
Mississippian	Chesterian	Springer Formation Chester Group	Mayes Group
	Meramecian	Meramec lime	
	Osagean	Osage lime	
	Kinderhookian	Kinderhook Shale	
Devonian	Chautauquan	Woodford Shale	
	Senecan Erian Ulsterian	Misener sand	
Silurian	Cayugan Niagaran Alexandrian	Hunton Group	
Ordovician	Cincinnatian	Sylvan Shale; Maquoketa Shale Viola Group/Formation	
	Champlainian	Simpson Group	
	Canadian	Arbuckle Group	
Cambrian	Trempealeauan	Reagan Sandstone	
	Franconian		

Fig. 4: Generalized stratigraphic columns for Devonian through Permian strata in the Anadarko Basin Province. Assessment unit (AU) names and generalized divisions are separated by the horizontal red line into the Pennsylvanian Composite Total Petroleum System (TPS; upper section) and the Woodford Composite TPS (lower section). Italicized blue text and lowercase names indicate informal status. The Devonian Misener Sand was evaluated as part of the Hunton Group AU [24]. Extension of the Morrowan–Atokan AU into the Desmoinesian reflects the uncertain boundary of the Atoka Shale in the southern basin. Modified from Bebout et al. [25] and Henry and Hester [26]. Ages are in millions of years and are based on Haq and Van Eysinga [27] and Gradstein et al. [28]. Abbreviations: Fm., Formation; Gp., Group; Lst., Limestone; lm., lime; Sh., Shale; Ss., Sandstone. Reproduced from U.S. Geological Survey material, which is in the public domain.

pyrite, and variable clay content. Total organic carbon commonly ranges between 4 and 12%, locally exceeding these values in deeper portions of the basin. Thermal maturity increases southwestward toward the Anadarko depocenter, where deeper burial resulted in condensate-rich and dry-gas production windows. Natural fracture development associated with regional tectonic deformation and differential compaction significantly enhances effective permeability within the ultra-low permeability shale matrix.

Overlying the Woodford, the Mississippian Osage and Meramec intervals constitute the primary oil-bearing reservoirs within the STACK fairway. These formations were deposited on a low-gradient carbonate ramp during progressive regression of the Mississippian sea. The Osage interval is characterized by alternating shallow carbonate shelf facies and deeper marine mudstones, whereas the Meramec consists predominantly of interbedded calcareous mudstones, siltstones, wackestones, and argillaceous carbonate facies deposited in cyclic regressive packages. Compared with the underlying Osage carbonates, the Meramec exhibits elevated silica and clay content, producing greater lithological heterogeneity but favorable geomechanical properties for hydraulic fracturing. The upper Meramec intervals are generally considered the most prospective owing to improved porosity preservation, lower calcite cementation, and enhanced hydrocarbon saturation. Sedimentation within the Mississippian system was strongly influenced by differential subsidence across the Anadarko foreland basin and by episodic eustatic sea-level fluctuations. During maximum flooding phases, deposition was dominated by fine-grained basinal mudstones and organic-rich facies, whereas regressive phases promoted accumulation of carbonate shoals, skeletal wackestones, and silty carbonate ramp deposits. This cyclic depositional architecture produced significant vertical and lateral heterogeneity in reservoir quality, mineralogy, and fracability throughout the STACK fairway.

The younger Pennsylvanian Oswego Dolomite forms a shallower oil-prone reservoir developed mainly within Kingfisher County. The Oswego was deposited in shallow-marine to restricted inner-shelf environments during renewed Pennsylvanian subsidence and cyclic carbonate sedimentation. Lithologically, the interval consists predominantly of tight dolomitized carbonates exhibiting relatively low gas-oil ratios and shorter depletion times compared with the deeper Woodford and Mississippian targets. Its comparatively shallow burial depth and favorable oil cut have made the Oswego an economically attractive secondary target during recent STACK development.

Structurally, the STACK area is affected by extensive faulting and fracture development inherited from late Paleozoic compressional tectonics and basement reactivation associated with the Southern Oklahoma Aulacogen. Seismic inversion and ant-tracking analyses indicate widespread structural compartmentalization, particularly within the Osage interval where natural fracture intensity may locally exceed one discontinuity per lateral foot. These fracture systems exert a primary control on hydraulic fracture propagation, reservoir connectivity, pressure communication, and parent-child well interference. Despite matrix porosity commonly remaining within the 1–2% range in the Meramec and Osage intervals, hydrocarbon productivity is substantially enhanced by the interaction between induced hydraulic fractures and pre-existing tectonic fracture networks. Overall, the STACK represents a vertically integrated

unconventional petroleum system formed through the interaction of foreland-basin tectonics, organic-rich marine deposition, Mississippian carbonate ramp sedimentation, and late-stage structural fracturing. The combination of thermally mature source rocks, overpressured tight reservoirs, favorable geomechanical properties, and stacked hydrocarbon-bearing intervals has established the STACK as one of the most prolific unconventional resource plays in the continental United States.

2.2 Well Count and Generational Classification

The full dataset comprises 3,550 horizontal wells with positive production histories, compiled from ShaleXP.com and Oklahoma Corporation Commission (OCC) well records and production data [9–11]. Canadian County contributes 1,600 wells (45.1%) and Kingfisher County 1,950 wells (54.9%). Horizontal drilling commenced in earnest around 2010, with fewer than 50 wells per year recorded before 2012 and peak activity reaching 645 wells spudded in 2018. Well generation is defined chronologically at the lease-pad or spacing-unit level, not as a count of wells on a single physical pad: the first horizontal well to produce on a given tract is designated Generation 1 (Gen-1), with subsequent wells assigned incrementally higher generation numbers. The dataset includes wells through Generation 13, with the bulk of parent-child interference analysis concentrated in Generations 2 through 8 where statistical sample sizes are largest. A summary of well counts by county and formation is provided in Table 1. The Mississippian Limestone is the dominant formation in both counties [12], reflecting its broad areal extent and moderate drilling costs relative to deeper Woodford targets. Woodford Shale wells are concentrated in Canadian County where the formation is thermally mature for liquids-rich gas, whereas Kingfisher County Woodford wells trend drier. The Oswego Dolomite is an exclusively Kingfisher County target representing a shallower, oilier objective that gained prominence after 2015 as operators sought lower-cost, shorter-cycle assets.

2.3 Lateral Length and Completion Statistics

Horizontal lateral lengths have evolved considerably over the study period. Early wells (2010–2014) were predominantly short laterals of 4,000–5,000 ft, reflecting operator learning and lease configuration constraints. The 2020–2021 vintages exhibit the longest median laterals, approaching 9,500–10,100 ft. Median lateral length subsequently declined to approximately 6,200 ft in 2022 and 5,500 ft in 2023, reflecting a change in county, operator, and formation mix. The dataset median lateral length across all vintages is 5,313 ft, with the interquartile range spanning 4,935–9,262 ft. This lateral length inflation is a key driver of observed EUR improvements between early and late vintages and must be normalized to 1,000 ft when comparing formation-level productivities.

Table 1: Well count by formation and county. Counts are taken from the well master table using the revised formation assignment applied throughout the analysis; formation totals and county totals reconcile with the well-population figures reported in Section 2 and with the per-formation counts shown in Figure 3.

Formation	Canadian	Kingfisher	Total Wells	% of Dataset
Mississippian	474	828	1302	36.7
Woodford	913	72	985	27.7
Miss. (Less Chester)	16	538	554	15.6
Oswego	5	362	367	10.3
WF/Miss. Combo	156	22	178	5.0
Hunton	12	87	99	2.8
Meramec	9	29	38	1.1
Hoxbar	10	0	10	0.3
Other	5	12	17	0.5
TOTAL	1600	1950	3550	100.0

3 Geology and Drilling Activity

3.1 Stratigraphic Framework

The STACK play exploits multiple unconventional reservoir intervals within the Paleozoic succession of the Anadarko Basin. The primary producing formations, from deepest to shallowest, are the Woodford Shale (10,000–13,500 ft TVD), Mississippian Limestone (7,000–10,500 ft), Mississippian (Less Chester) (6,500–9,000 ft), Oswego Dolomite (5,900–8,500 ft), WF/Miss. Combo (dual-zone Woodford + Mississippian), Meramec (6,600–9,500 ft), and the Hunton Group (7,000–13,100 ft). Each formation differs in lithology, fluid type, and reservoir energy—characteristics that set the intrinsic ceiling for well performance regardless of completion design. Key reservoir properties are summarized in Table 2; oil gravity distributions are shown in Figure 6.

Figure 6 shows that fluid character is strongly formation-dependent and, within a formation, county-dependent. The Woodford and WF/Miss. Combo intervals produce the lightest fluids (median gravities near 51–55°API), consistent with their condensate-rich, high-GOR character, whereas Miss. (Less Chester) produces the heaviest oil in the dataset (median near 39°API). For the formations present in both counties, Canadian County wells are systematically lighter than their Kingfisher counterparts—for example, the Woodford and WF/Miss. Combo medians are roughly 10°API higher on the Canadian side—reflecting the deeper burial and higher thermal maturity of the Canadian acreage toward the Anadarko depocenter. This gravity contrast reinforces the decision to report decline and EUR statistics separately by county, because it signals a genuine fluid-property difference rather than a completion artifact.

The vertical succession and relative stratigraphic positions are shown in Figure 4. Hoxbar and Meramec (minor formations): Together representing fewer than 50 wells

Table 2: Key reservoir characteristics by formation in Canadian and Kingfisher Counties, Oklahoma. Oil gravity is obtained from well-test records; GOR denotes cumulative produced gas–oil ratio; EUR denotes the median estimated ultimate recovery of the pooled well-level EUR distribution for each formation, computed from the well master table; by construction it lies between the corresponding county medians plotted in Figure 11. Porosity and permeability are not tabulated because STACK formations are ultra-tight and production is fracture-dominated; lateral length and completion intensity govern drainage more strongly than matrix flow.

Formation	Lithology	TVD Range Length (ft)	Median Lateral Length (ft)	Median Oil Gravity (°API)	Oil Median Cum.GOR (scf/bbl)	Median EUR (MBOE)	Fluid Type
Woodford	Siliceous black shale	10,000–13,500	5,098	51	~29,500	813	Gas condensate / volatile oil
Mississippian	Skeletal limestone / carbonate	7,000–10,500	5,580	42	~8,600	652	Retrograde condensate / oil
Miss. (Less Chester)	Carbonate mudstone (shallow)	6,500–9,000	5,030	39	~6,400	417	Oil / retrograde condensate
Oswego	Tight dolomite	5,900–8,500	5,194	43	~1,700	203	Black oil
WF/Miss. Combo	Dual-zone Woodford + Mississippian	7,000–14,000	5,305	54	~25,300	728	Wet gas / volatile oil
Meramec	Calcareous mudstone / wackestone	6,600–9,500	5,064	45	~9,200	618	Volatile oil / condensate
Hunton	Limestone / dolomite carbonate	7,000–13,100	4,962	43	~12,100	255	Dry gas / condensate

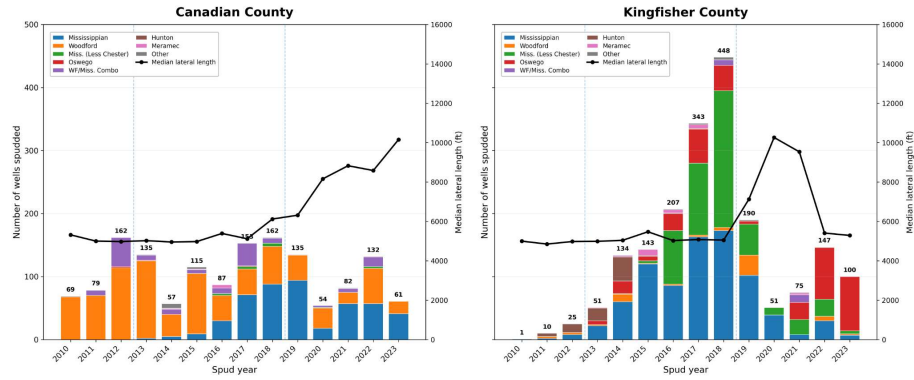


Fig. 5: Annual well spud count by formation for Canadian and Kingfisher Counties, 2010–2023, illustrating three distinct phases of STACK development activity.

in the dataset, these intervals serve as niche exploration targets or opportunistic sidetracks from primary Mississippian/Woodford programs.

The vertical separation between producing intervals varies from roughly 500 ft between the shallowest Mississippian sub-facies and Oswego to more than 3,000 ft between Oswego and the Woodford. This multi-interval stack architecture enables staggered vertical development (zipper fracs, offset staging) but also creates the formation cross-communication risk that underpins the interference analysis presented in Section 6.

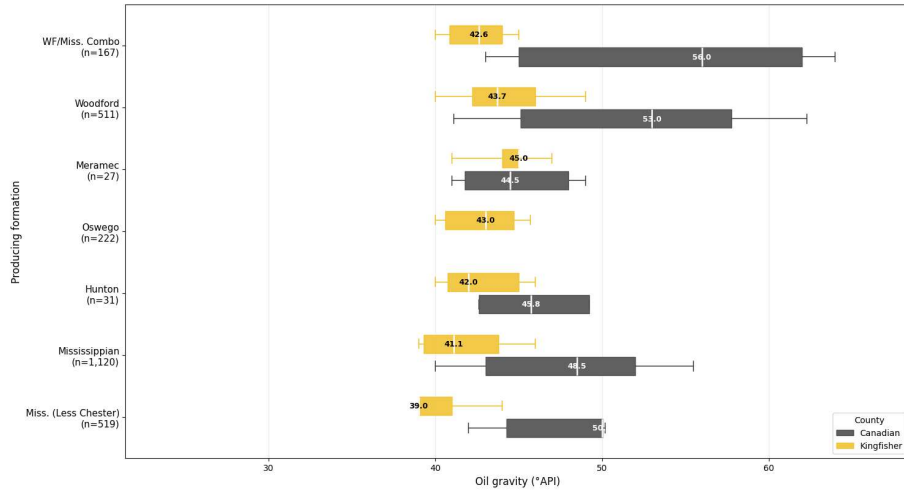


Fig. 6: Oil gravity distribution by formation (°API), Canadian and Kingfisher Counties, OK ($n = 2,597$ wells with gravity data). The box extends from P25 to P75, the vertical line denotes the median, and dots denote outliers. Woodford and WF/Miss. Combo produce the lightest, most gas-rich fluids, whereas Miss. (Less Chester) produces the heaviest oil in the dataset.

3.2 Drilling Activity and Development Phases

Drilling activity in the STACK play exhibits three well-defined phases (Figure 5):

Phase 1 – Exploration and Appraisal (2008–2012): Fewer than 80 horizontal wells were spudded annually, mostly targeting the Mississippian Limestone which was the first interval proven commercially productive by the horizontal drilling campaign. Well designs used short 4,000–5,000 ft laterals with limited perforation stages. EUR performance was highly variable as operators refined landing targets and completion designs. This phase established the geological framework and proof of commercial viability that would trigger the rapid-growth phase.

Phase 2 – Rapid Growth and Peak Activity (2013–2018): Annual spud counts grew from fewer than 200 in 2013 to a maximum of 645 wells in 2018—a more than threefold increase. Multiple formation targets were added simultaneously: the Woodford Shale was delineated as a major liquids-rich gas play after 2014; the Oswego Dolomite entered development in Kingfisher County after 2015; and the WF/Miss. Combo and Miss. Less Chester intervals were proved as commercial targets. Lateral lengths extended toward 7,000–9,000 ft, and completion intensity (proppant volumes, fluid volumes, stage counts) escalated dramatically. This period also generated the majority of parent wells that would later face interference issues from infill drilling.

Phase 3 – Rationalization and Capital Efficiency (2019–2023): Following the 2019 oil price downturn and the 2020 COVID-19 pandemic shock, drilling activity

contracted sharply to 100–200 wells per year, as reported in EIA [13] drilling productivity data. Operators focused capital on tier-1 acreage and longer-lateral programs (9,000–15,000 ft) targeting the Woodford and Mississippian in proven sweet spots. The Oswego maintained a relatively stable infill program in Kingfisher County. Formation mix shifted toward higher-confidence Mississippian and Woodford targets, with minor-formation activity largely suspended. These three phases have important implications for the interference analysis. The large cohort of Gen-1 wells drilled during Phase 2 (2013–2018) provides the parent well inventory that infill Child wells are now intersecting. The median age of parent wells at time of child stimulation has increased steadily as Phase 2 parent wells age, making parent depletion state an important control on the decline-corrected interference response described in Section 6.

4 Production Performance, Type Curves, and Flow Regime Analysis

4.1 Empirical Type Curve Methodology

Monthly production profiles were aggregated for each county-formation pair to produce empirical type curves at the P10 (high productivity, top-decile), P50 (median), and P90 (low productivity, bottom-decile) levels. Wells are included in the type curve calculation only if they have a minimum of 12 months of non-zero BOE production. The P-ranking is established at each calendar month independently, meaning the P50 type curve represents the 50th-percentile well in each production month—effectively a flowing median profile rather than the profile of any single median well.

To remove the strong effect of lateral-length differences between wells, all production is normalized to a per-1,000-ft-of-completed-lateral basis *before* any percentile is computed; the empirical type curves, the fitted initial rates q_{i1} , and the resulting EUR values are therefore all reported in per-1,000-ft units—BOE per 1,000 ft for rates and MBOE per 1,000 ft for EUR (Tables 3 and 4). Length normalization removes the first-order completion-design difference between short early-vintage and long recent-vintage laterals, but it does not remove differences in proppant intensity, stage spacing, or fluid system between vintages; these residual completion-technology effects are retained as a recognized source of within-formation dispersion and are the primary reason the P10–P90 spread is wide. Because length normalization is a linear per-well scaling, ranking wells on a per-1,000-ft basis and, where an absolute type well is required, multiplying the resulting per-1,000-ft percentile profile by a target lateral length is self-consistent; the per-1,000-ft profile is the length-neutral representative form reported here, with the caveat that—because lateral length is itself correlated with vintage and completion intensity—it is a summary statistic rather than a single physical well.

The P10, P50, and P90 percentiles are all constructed by the identical procedure and differ only in the percentile selected. At each production month the length-normalized rates of every qualifying well are ranked, and the 90th, 50th, and 10th percentiles of that monthly distribution define the high-, median-, and low-productivity flowing profiles, respectively (the P10 label denotes the high-productivity,

top-decile case and P90 the low-productivity, bottom-decile case). The decline parameters and EUR values tabulated at each percentile are then obtained by fitting the Multi-Segment Arps model to the corresponding percentile profile using the same peak-anchored workflow described below, so that P10 and P90 are computed by exactly the same method as P50. Because these percentile parameters are marginal percentiles of correlated fitted quantities, they are reported only as descriptive percentile type curves and are not recombined to synthesize intermediate percentiles (see the note to Tables 3 and 4).

A critical methodological refinement applied in this study is fitting Arps [1] decline curves from the peak production month rather than from Month 1. This workflow follows the unconventional decline-analysis and variable-rate diagnostic literature for fractured tight reservoirs [5, 18–23]. Well testing data and aggregate production profiles both confirm that horizontal wells in the STACK play commonly exhibit a ramp-up period of 1–4 months before peak production is achieved, reflecting wellbore clean-up, fracture closure, and fluid segregation effects. Initiating the Arps fit from Month 1 systematically overestimates early decline and underestimates initial productivity for multi-fractured horizontals. By identifying the peak production month in the P50 type curve (typically Month 2) and anchoring the hyperbolic decline fit from that point, we obtain parameter estimates that correctly describe the transient portion of the production profile.

4.2 County-Level Decline Analysis and Type Curve Validation

The STACK play spans two counties with distinct geological and completion characteristics: Canadian County (Woodford-dominated; 1,600 wells total, 1,452 successfully fitted) and Kingfisher County (Mississippian/Oswego-dominated; 1,950 wells total, 1,738 fitted). This county- and target-level separation is consistent with recent Anadarko Basin work showing that stratigraphic target selection influences drilling performance, capital exposure, and drainage behavior [17]. Because reservoir quality, well vintage, and completion intensity differ systematically between the two, all decline-curve and flow-regime analyses are reported separately by county rather than pooled. This avoids aggregation bias where one county’s dominant formation would otherwise skew a basin-wide type curve. Each county is presented with its own set of type-curve, MBT diagnostic, and validation figures below. For each county–formation type curve, cumulative production at month t is computed as

$$N_p(t) = \sum_{\tau=1}^t q(\tau) \Delta t,$$

where $q(\tau)$ is the monthly average BOE rate and Δt is one month. The material-balance-time diagnostic variable is then calculated as

$$t_{\text{MB}}(t) = \frac{N_p(t)}{q(t)}.$$

The diagnostic plot displays $q(t)$ versus $N_p(t)/q(t)$ on log–log axes. Because the horizontal axis is N_p/q rather than calendar or producing month, the vertical transition

marker in the MBT figures is placed at the N_p/q value corresponding to the selected transition month t_s , not at $x = t_s$. Slopes near -0.5 are interpreted as transient linear flow, while slopes approaching -1.0 indicate transition toward depletion-dominated behavior.

Validation methodology: Type-curve R^2 values for rate and cumulative BOE are computed only over the months during which at least 50% of each formation’s wells remain in production (the “50%-coverage window”). Beyond this window the raw P50 reflects only a small number of long-lived survivor wells whose cumulative continues to climb while the population-anchored fitted curve correctly plateaus; scoring against that survivor-biased tail would unfairly penalize the fit. The full 120-month raw data are still displayed in Figures 8 and 10, with the 50%-coverage cutoff marked and the low-coverage tail shown in gray. Formations with fewer than 20 wells in a county (marked †) are flagged as having insufficient sample for robust county-level validation and their statistics are indicative only.

Across all wells, the effective Segment-2 exponential decline rate D_{e2} ($b_2 = 0$) averages approximately 15%/year, calibrated per-well to each well’s own observed late-time decline. By formation the median D_{e2} ranges from 7.1%/year (Meramec) and 13.3%/year (Woodford) up to 21.4%/year (Miss. Less Chester) and 26.9%/year (Oswego); the carbonate-dominated formations decline fastest. These rates are markedly steeper than the 5–7%/year economic terminal declines sometimes assumed for conventional reservoirs, making the resulting EUR estimates conservative. The complete fitted parameters appear in Tables 3 and 4. Three key observations emerge from the formation-scale MBT flow-regime analysis, presented separately by county in Figures 7 and 9:

1. **Observation 1 — Early-time transient linear flow (ELF).** Fitted early-time MBT slopes range from approximately -0.06 to -0.45 (Figures 7 and 9), consistent with bilinear-to-transient-linear flow through the hydraulic-fracture network. Pure transient linear flow yields a theoretical slope of -0.5 ; observed values shallower than -0.5 reflect finite fracture conductivity and vintage mixing at the formation-aggregate level. The early-linear-flow period persists for approximately 13–32 months, corresponding to the fitted Segment 1 to Segment 2 transition months (t_s , Tables 3 and 4), physically supporting hyperbolic Segment 1 behavior, including elevated b_1 values where the aggregate profile remains strongly transient dominated.
2. **Observation 2 — Transition to boundary-dominated flow (BDF).** After the ELF period, late-time MBT slopes steepen toward the boundary-dominated-flow limit of -1.0 (observed values of approximately -0.55 to -0.78), indicating the onset of departure from transient linear flow. The transition months selected from the MBT diagnostic generally align with the Segment 1→Segment 2 transition months used in the decline-curve tables, with the MBT plots serving as the visual diagnostic for selecting the onset of late-time flow-regime evolution. These transition months therefore represent the beginning of late-time flow-regime evolution rather than proof that fully developed boundary-dominated flow has already been reached. This agreement confirms that the segmentation is physically grounded and supports the use of pure-exponential decline, $b_2 = 0$, for Segment 2.

3. Observation 3 — Consistency of the segmented decline framework. The MBT diagnostic is computed from raw production data, but the vertical transition marker plotted in Figures 7 and 9 is placed at the N_p/q coordinate corresponding to the Segment 1→Segment 2 transition month taken from the fitted Multi-Segment Arps model. The marker therefore illustrates where the fitted transition falls on the diagnostic; it is not an independent estimate of that transition, and the agreement between the two should not be read as external validation of the decline model. What the diagnostic does support is the qualitative observation that the aggregate profiles depart from early transient-dominated behavior within the observed window, which is the physical basis for segmenting the decline at all. The $b_1 > 1.0$ values should be interpreted as descriptors of a strongly transient early period rather than as evidence of a particular flow geometry, and the $b_2 = 0$ constraint with D_{e2} calibrated to observed late-time decline is a conservative engineering choice that bounds long-range recovery from below. Both are checked against the raw production profiles in Figures 8 and 10. An independent estimate of the transition—for example a piecewise regression breakpoint fitted directly to the MBT data—would be required to validate the segmentation externally, and is left to future work.

4.2.1 Canadian County

Figure 7 shows the MBT flow-regime diagnostic and Figure 8 shows the raw-vs-fitted validation for both rate and cumulative BOE. Table 3 lists the fitted decline parameters and the EUR distribution. Formations marked † have small sample sizes ($n < 20$) and their statistics should be treated as indicative only. The effective Segment-2 exponential decline rate D_{e2} ($b_2 = 0$) is calibrated to the formation-level observed P50 late-time decline measured from production data, preventing over-estimation of late decline where boundary-dominated-flow data are sparse. Each well fit is validated on both rate and cumulative BOE; 66.5% of 3,191 fitted wells achieve $R^2 \geq 0.70$ on both metrics.

4.2.2 Kingfisher County

Figure 9 shows the MBT flow-regime diagnostic and Figure 10 shows the raw-vs-fitted validation for both rate and cumulative BOE. Table 4 lists the fitted decline parameters and the EUR distribution. Formations marked † have small sample sizes ($n < 20$) and their statistics should be treated as indicative only.

5 EUR Distribution, GOR Profile, and Best-Performing Formations

5.1 EUR Distribution by Formation and County

Estimated Ultimate Recovery (EUR) values in this dataset are derived from the Decline Analysis using the Arps hyperbolic model applied to each individual well’s production history. EUR is reported in BOE (barrels of oil equivalent, converting gas at 6 Mcf per BOE). EUR is computed as each well’s actual cumulative production

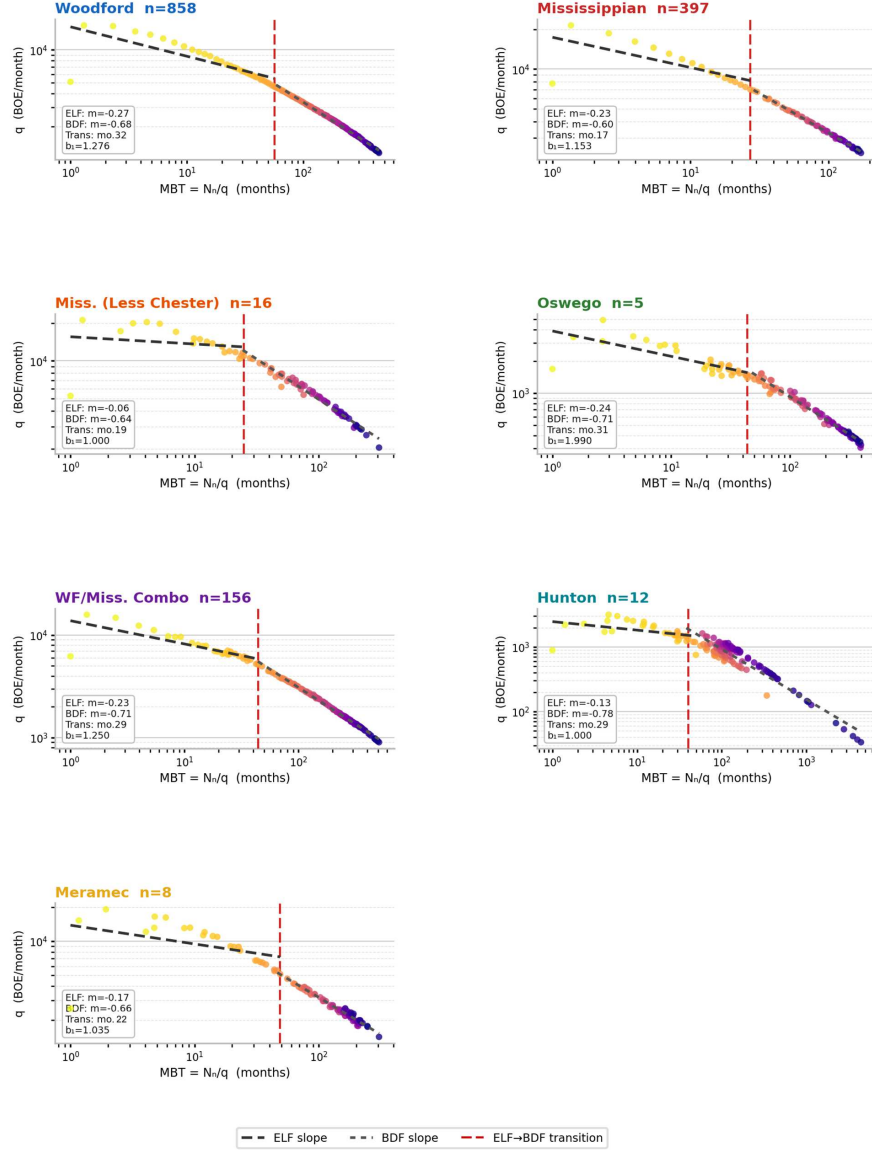


Fig. 7: Canadian County material-balance-time (MBT) log-log flow-regime diagnostic. Each point is an individual-well monthly observation of rate q versus material-balance time N_p/q , colored by producing month (early to late) and pooled by formation (well count n shown per panel). The dashed line is the early-time transient-linear-flow (ELF) reference slope and the dotted line is the late-time boundary-dominated-flow (BDF) reference slope; the fitted ELF and BDF slopes and the b_1 value are annotated in each panel. The red vertical line marks the MBT coordinate N_p/q corresponding to the Segment 1 to Segment 2 transition month t_s taken from the P50 Multi-Segment Arps fit reported in Table 3.

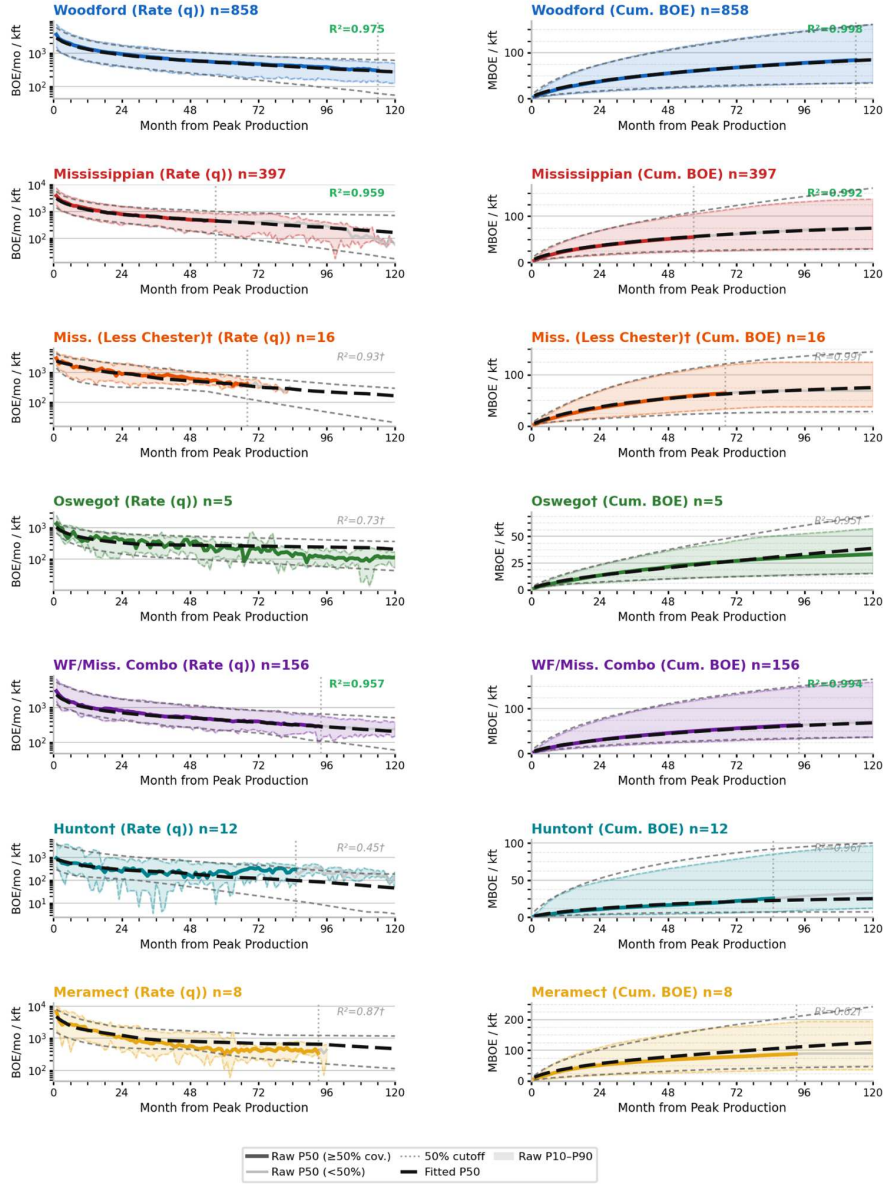


Fig. 8: Canadian County type-curve validation showing the raw data in color and fitted P10, P50, and P90 curves as black dashed lines. Production rate is shown on a logarithmic scale on the left, and cumulative BOE is shown on the right over the full 120-month period.

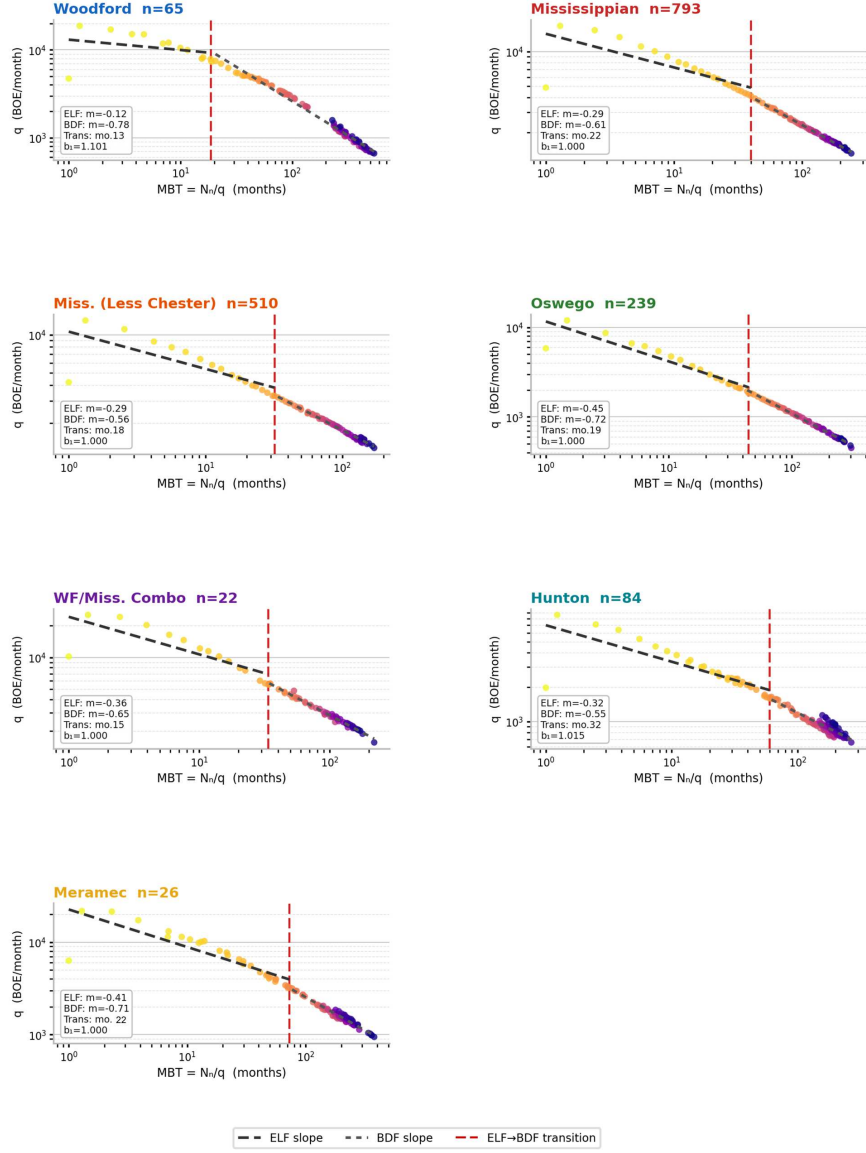


Fig. 9: Kingfisher County material-balance-time (MBT) log-log flow-regime diagnostic. Each point is an individual-well monthly observation of rate q versus material-balance time N_p/q , colored by producing month (early to late) and pooled by formation (well count n shown per panel). The dashed line is the early-time transient-linear-flow (ELF) reference slope and the dotted line is the late-time boundary-dominated-flow (BDF) reference slope; the fitted ELF and BDF slopes and the b_1 value are annotated in each panel. The red vertical line marks the MBT coordinate N_p/q corresponding to the Segment 1 to Segment 2 transition month t_s taken from the P50 Multi-Segment Arps fit reported in Table 4.

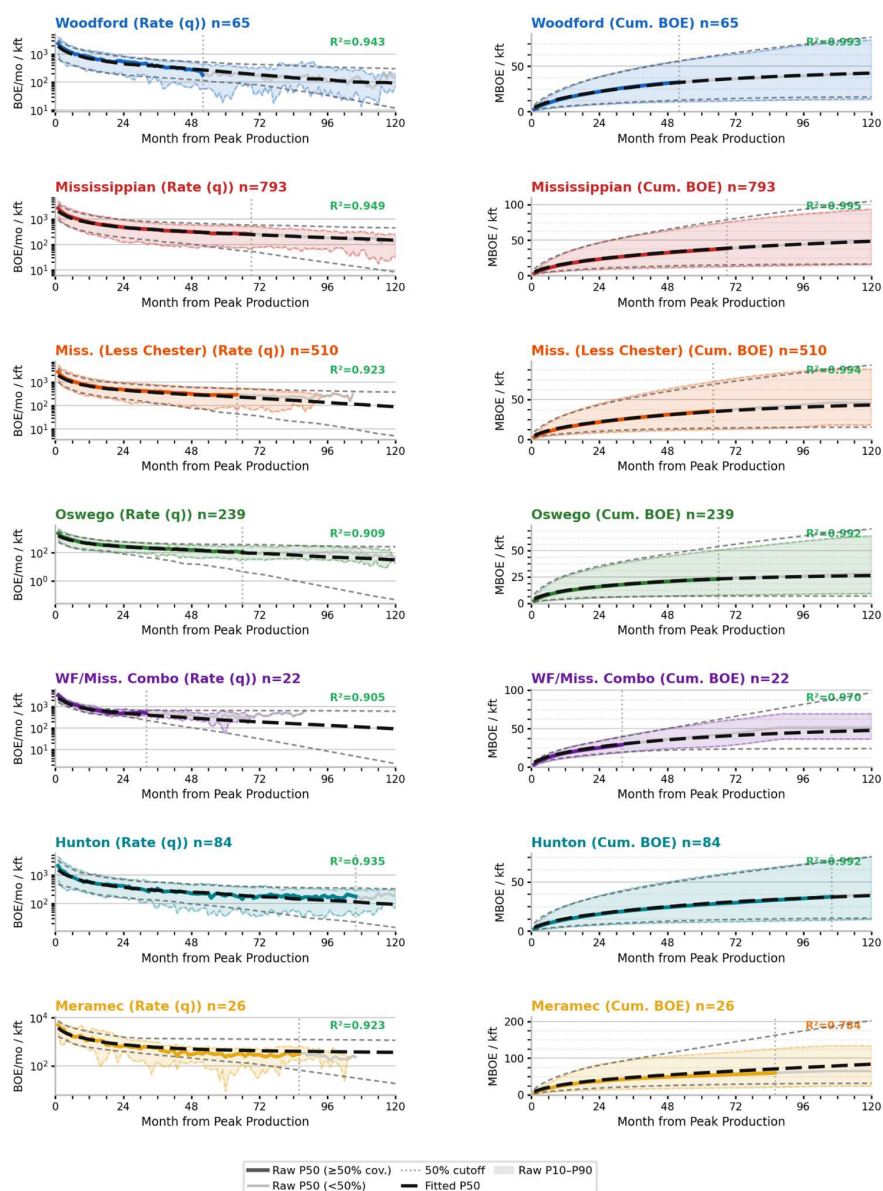


Fig. 10: Kingfisher County type-curve validation showing raw data in color and fitted P10, P50, and P90 curves as black dashed lines. Production rate is shown on a logarithmic scale on the left, and cumulative BOE is shown on the right over the full 120-month period.

Table 3: Canadian County—P10/P50/P90 Multi-Segment Arps decline parameters, EUR, and validation statistics by formation. Bold rows represent the P50 type curve. P10 denotes the high-productivity case, P50 the median case, and P90 the low-productivity case.

Formation	Percentile	q_{i1} (BOE/mo/kft)	D_{i1} (yr ⁻¹)	b_1	t_s (month)	D_{e2} (yr ⁻¹)	EUR (MBOE/kft)	Cutoff (month)	R_q^2	$R_{N_p}^2$
Woodford	P10	7,276	5.28	1.99	35	0.319	234	114	0.966	0.923
	P50	3,461	2.16	1.28	32	0.131	114	114	0.975	0.998
	P90	1,446	0.73	1.00	28	0.036	48	114	0.848	0.800
Mississippian	P10	7,691	6.33	1.99	28	0.460	300	57	0.953	0.934
	P50	3,776	2.90	1.15	17	0.210	96	57	0.959	0.992
	P90	1,649	0.99	1.00	14	0.010	41	57	0.891	0.849
Miss. (Less Chester) [†]	P10	5,062	4.89	1.99	28	0.551	143	68	0.962	0.989
	P50	2,640	2.27	1.00	20	0.220	88	68	0.926	0.991
	P90	1,744	0.22	1.00	19	0.090	50	68	0.923	0.972
Oswego [†]	P10	2,414	8.51	1.99	34	0.175	127	120	0.844	0.637
	P50	1,245	3.87	1.99	31	0.093	62	120	0.728	0.947
	P90	800	1.45	1.11	28	0.036	20	120	0.844	0.637
WF/Miss. Combo	P10	6,555	5.37	1.99	32	0.304	204	94	0.973	0.975
	P50	2,894	2.12	1.25	29	0.146	86	94	0.957	0.994
	P90	1,406	0.84	1.00	26	0.036	44	94	0.906	0.658
Hunton [†]	P10	4,145	5.43	1.96	32	0.448	118	85	0.813	0.990
	P50	868	1.31	1.00	29	0.251	35	85	0.452	0.963
	P90	364	0.50	1.00	26	0.041	12	85	0.606	0.988
Meramec [†]	P10	9,500	9.09	1.99	30	0.314	335	93	0.884	0.981
	P50	6,946	1.76	1.04	22	0.081	179	93	0.872	0.621
	P90	1,738	0.58	1.00	17	0.010	77	93	0.884	0.907

q_{i1} : Segment-1 initial production rate normalized per 1,000 ft; D_{i1} : Segment-1 initial decline rate; b_1 : Segment-1 hyperbolic exponent; t_s : Segment-1 to Segment-2 transition month; D_{e2} : effective Segment-2 exponential decline rate with $b_2 = 0$; EUR: estimated ultimate recovery normalized per 1,000 ft of completed lateral (MBOE/kft), computed by the same per-well length-normalization used for q_{i1} ; Cutoff: 50%-coverage cutoff month; R_q^2 and $R_{N_p}^2$: rate and cumulative-production validation statistics. P50 R^2 values are type-curve validation statistics over the coverage window. P10 and P90 R^2 values are median individual-well DCA validation statistics from wells whose fitted q_{i1} lies within the q_i -similar band around the tabulated P10/P90 q_{i1} value; if fewer than five wells fell within the $\pm 10\%$ band, the closest five wells by q_{i1} were used. P10, P50, and P90 are marginal percentiles of the well-level fitted parameters and should not be combined independently to construct synthetic percentile type curves because the fitted parameters are correlated. The EUR column follows the same convention: it is the P10/P50/P90 of the well-level EUR distribution, obtained by computing EUR for each well and then ranking those values. It is therefore not reproducible by integrating the parameters printed in the same row, and no such reproduction is intended. b_1 values reported as 1.99 in the P10 rows sit at the optimizer's upper bound, indicating strongly transient-linear behavior in the high-productivity tail. [†] County-formation sample size below 20 or q_i -band support limited; results are indicative only.

to date—including the first producing month—plus the Arps forecast beyond the last recorded month; anchoring the decline fit at the peak month removes ramp-up bias from the *fitted parameters* but discards no early-time produced volume, so first-month production is fully included in the reported EUR. Tables 3 and 4 summarize the P10, P50, and P90 decline parameters and EUR values by formation for Canadian and Kingfisher Counties, respectively. The formation-level EUR distribution is shown in Figure 11. Two features are worth noting. First, the P10–P90 spread within a single formation routinely exceeds a factor of five, which is wider than the spread between formation medians; formation choice therefore explains less of the variance in well outcome than position within a formation does. Second, the county split is visible within formations as well as between them, which is the empirical basis for reporting decline and EUR statistics separately by county throughout this study.

Table 4: Kingfisher County—P10/P50/P90 Multi-Segment Arps decline parameters, EUR, and validation statistics by formation. Bold rows represent the P50 type curve. P10 denotes the high-productivity case, P50 the median case, and P90 the low-productivity case.

Formation	Percentile	q_{i1} (BOE/mo/kft)	D_{i1} (yr ⁻¹)	b_1	t_s (month)	D_{e2} (yr ⁻¹)	EUR (MBOE/kft)	Cutoff (month)	R_q^2	$R_{N_p}^2$
Woodford	P10	3,981	6.79	1.99	28	0.498	125	52	0.977	0.955
	P50	2,438	3.06	1.10	13	0.153	59	52	0.943	0.993
	P90	901	1.55	1.00	10	0.010	29	52	0.830	0.662
Mississippian	P10	5,278	8.30	1.99	25	0.420	181	69	0.945	0.955
	P50	2,690	3.34	1.00	22	0.138	67	69	0.949	0.995
	P90	1,212	1.38	1.00	19	0.010	23	69	0.838	0.958
Miss. (Less Chester)	P10	5,346	10.20	1.99	28	0.552	156	64	0.954	0.936
	P50	2,712	4.02	1.00	18	0.214	57	64	0.923	0.994
	P90	1,276	1.67	1.00	15	0.010	19	64	0.841	0.808
Oswego	P10	5,063	13.61	1.83	27	0.975	107	66	0.969	0.914
	P50	2,420	5.23	1.00	19	0.272	31	66	0.909	0.992
	P90	840	1.99	1.00	16	0.010	11	66	0.791	0.966
WF/Miss. Combo	P10	4,511	5.29	1.64	26	0.655	269	32	0.992	0.890
	P50	3,400	3.57	1.00	15	0.211	47	32	0.905	0.970
	P90	1,887	2.38	1.00	12	0.012	29	32	0.903	0.852
Hunton	P10	4,500	6.22	1.99	35	0.378	146	106	0.973	0.912
	P50	2,013	2.81	1.02	32	0.110	51	106	0.935	0.992
	P90	495	0.79	1.00	28	0.010	19	106	0.731	0.996
Meramec [†]	P10	8,141	7.02	1.62	30	0.504	243	86	0.942	0.978
	P50	5,057	2.71	1.00	22	0.071	129	86	0.923	0.784
	P90	1,689	0.63	1.00	17	0.010	34	86	0.776	0.941

q_{i1} : Segment-1 initial production rate normalized per 1,000 ft; D_{i1} : Segment-1 initial decline rate; b_1 : Segment-1 hyperbolic exponent; t_s : Segment-1 to Segment-2 transition month; D_{e2} : effective Segment-2 exponential decline rate with $b_2 = 0$; EUR: estimated ultimate recovery normalized per 1,000 ft of completed lateral (MBOE/kft), computed by the same per-well length-normalization used for q_{i1} ; Cutoff: 50%-coverage cutoff month; R_q^2 and $R_{N_p}^2$: rate and cumulative-production validation statistics. P50 R^2 values are type-curve validation statistics over the coverage window. P10 and P90 R^2 values are median individual-well DCA validation statistics from wells whose fitted q_{i1} lies within the q_i -similar band around the tabulated P10/P90 q_{i1} value; if fewer than five wells fell within the $\pm 10\%$ band, the closest five wells by q_{i1} were used. P10, P50, and P90 are marginal percentiles of the well-level fitted parameters and should not be combined independently to construct synthetic percentile type curves because the fitted parameters are correlated. The EUR column follows the same convention: it is the P10/P50/P90 of the well-level EUR distribution, obtained by computing EUR for each well and then ranking those values. It is therefore not reproducible by integrating the parameters printed in the same row, and no such reproduction is intended. b_1 values reported as 1.99 in the P10 rows sit at the optimizer's upper bound, indicating strongly transient-linear behavior in the high-productivity tail. [†] County-formation sample size below 20 or qi-band support limited; results are indicative only.

EUR variability is high within each formation, with P10-to-P90 spreads commonly exceeding 5–7 $\times$. Canadian County Woodford and Oswego both exhibit broad EUR distributions, although the underlying causes differ. Woodford variability is primarily associated with thermal-maturity gradients, reservoir-quality variation, and completion intensity, whereas Oswego variability reflects localized differences in dolomitization, porosity preservation, and cementation.

5.2 EUR Trend Versus Vintage Year

Median EUR per well has improved substantially across all formations from the 2012–2014 vintage to the 2017–2019 peak. The most dramatic improvement is observed in the Woodford Shale, where median EUR approximately doubled between 2013 and

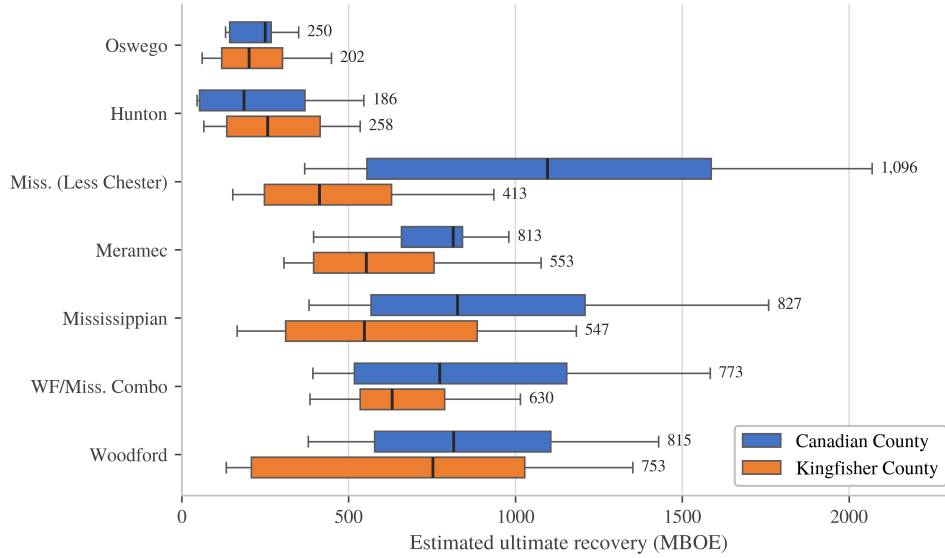


Fig. 11: EUR distribution by formation and county. Boxes span the P25–P75 interquartile range, whiskers span P10–P90, and the vertical line within each box is the median; the value printed beside each box is that median in MBOE. County–formation groups with fewer than five wells are omitted. Canadian County Miss. (Less Chester) ($n = 16$), Meramec ($n = 9$) and Oswego ($n = 5$) rest on small samples and are indicative only. Medians reconcile with the pooled values in Table 2.

2018, driven by lateral length extension from approximately 4,500 ft to approximately 8,500 ft and by optimized completion designs incorporating tighter stage spacing (200–250 ft) [14]. The Mississippian Limestone shows a more moderate improvement, reflecting a combination of longer laterals and better landing zone targeting within the Meramec and Osage sub-intervals. The post-2019 cohort shows normalized EUR per 1,000 ft of lateral that is broadly comparable to the 2018–2019 vintage, suggesting that completion efficiency has approached a plateau. Absolute EUR remains strongly influenced by lateral length; however, the decline in median lateral length after 2021 means that continued year-over-year increases in per-well EUR should not be assumed.

Figure 12 summarizes the corresponding P50 EUR trend by completion vintage for the major Canadian and Kingfisher County formations. The trend should be read with the lateral-length history in Figure 14 alongside it, because the two move together: much of the apparent vintage improvement through 2020 tracks lateral extension rather than any change in rock quality or completion efficiency. The most recent vintages carry the least production history and the largest forecast component, so late-vintage points are the least reliable in the series and should not be extrapolated.

Figure 14 provides the corresponding lateral-length trend by spud year. The 2020 peak near 10,100 ft and the subsequent retreat to roughly 5,500 ft by 2023 confirm that extended-reach drilling was a temporary program feature rather than a settled design standard. Because absolute EUR scales with contacted lateral, this reversal is

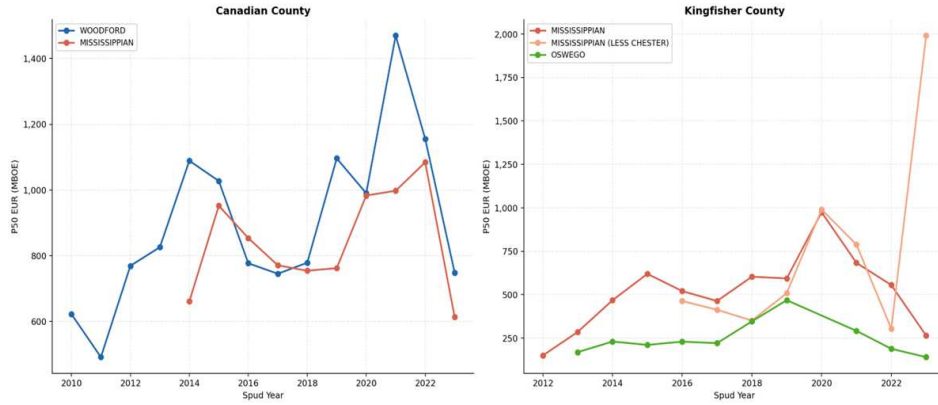


Fig. 12: P50 full-cycle BOE EUR trend by completion vintage for major Canadian and Kingfisher County formations. The figure shows that the strongest vintage-related gains occur during the 2017–2020 development period, although late-vintage values should be interpreted with caution where sample sizes are small.

the principal reason absolute per-well EUR must be normalized to a per-1,000-ft basis before formations or vintages are compared.

5.3 GOR Characterization and Fluid Regime by Formation

Figure 13 shows the evolution of cumulative GOR by formation and spud year. The formation ordering is stable across the entire period, which indicates that the GOR differences reflect fluid character set by burial depth and thermal maturity rather than any artefact of completion vintage. This matters for the EUR rankings reported below, because a 6 Mcf/BOE conversion credits high-GOR intervals with barrel-equivalent volumes that carry lower realised value per BOE than oil-weighted intervals. The annual median trends and P25–P75 interquartile bands highlight persistent differences in fluid character among formations and illustrate temporal changes associated with field maturation. The formations separate into a clear and stable ordering that mirrors the fluid-type assignments in Table 2: the Woodford and WF/Miss. Combo intervals maintain the highest cumulative GOR throughout (medians in the tens of thousands of scf/bbl, reflecting their condensate-rich to wet-gas character), the Mississippian and Miss. (Less Chester) intervals occupy an intermediate band, and the Oswego sits lowest (a few thousand scf/bbl), consistent with its black-oil character. Overlaid on these formation offsets is a broadly declining GOR trend for most formations across later spud years, indicating that more recent completions in a given interval have produced at somewhat lower gas–oil ratios—consistent with a shift toward oilier landing zones and sweet spots during the capital-efficiency phase rather than with any change in the underlying rock. Formation–year groups containing fewer than five wells are omitted to reduce small-sample instability. Best-performing formations by EUR and key reasons:

1. **Woodford Shale (median EUR 813 MBOE):** Ranks first due to thermally mature, naturally fractured source rock with high TOC, significant overpressure,

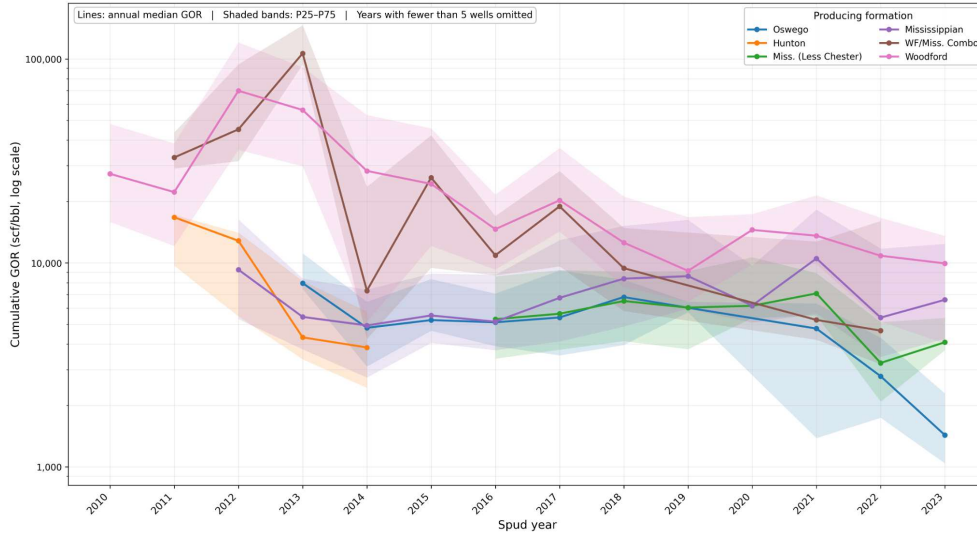


Fig. 13: Annual cumulative gas–oil ratio (GOR) trends by formation. Lines represent the median GOR for each spud year, while shaded bands indicate the P25–P75 interquartile range. The vertical axis is logarithmic, and formation–year groups containing fewer than five wells are omitted to reduce small-sample instability.

and maximum benefit from extended-reach laterals. Canadian County Woodford wells exceed Kingfisher counterparts due to deeper burial and higher thermal maturity. High GOR ($>30,000$ scf/bbl) reflects condensate-rich production that boosts BOE equivalent.

2. **WF/Miss. Combo (median EUR 728 MBOE):** Dual-zone completions access two productive intervals simultaneously, combining Woodford gas production with Mississippian oil, yielding the highest composite BOE per wellbore in the dataset. These completions are harder to allocate between zones but are economically compelling in high-productivity acreage.
3. **Mississippian Limestone — Canadian County (median EUR 652 MBOE):** Benefits from the deepest Mississippian burial in the study area, higher reservoir pressure support, and the longest average laterals in the dataset (approximately 7,200 ft median for post-2015 completions). The Meramec sub-interval within the Mississippian composite class is particularly productive where calcite cementation is low.
4. **Oswego Dolomite (median EUR 203 MBOE, lowest among major formations):** Despite lower absolute EUR, the Oswego commands operator interest due to its oil-rich character ($\text{GOR} < 3,500$ scf/bbl), shorter production tails, and lower well costs relative to deep Woodford completions, yielding competitive F&D costs. It also exhibits the lowest interference susceptibility (see Section 6).



Fig. 14: Median completed lateral length by spud year in Canadian and Kingfisher Counties, Oklahoma, from 2010 to 2023. The shaded band represents the P25–P75 interquartile range. Median lateral length remained near 5,000 ft through 2018, increased sharply to approximately 10,100 ft in 2020, and subsequently declined toward approximately 5,500 ft by 2023, indicating a temporary shift toward extended laterals rather than a uniform long-term increase.

6 Parent–Child Well Interference Analysis

6.1 Decline-Corrected Methodology

Parent–child interference is evaluated with a decline-corrected production-signature method. The workflow is positioned within prior parent–child and multiwell depletion studies, but uses only production histories and fitted decline forecasts so that it can be applied consistently across the full public STACK dataset [15, 29]. For each child well classified as Generation 2 or later, candidate parent wells are identified within a 6,560-ft (2,000-m) surface-location search radius, provided that the parent first produced before the child well’s first-production date. The child first-production date is used as the stimulation proxy because detailed stimulation dates are not consistently available in the public production records. The underlying well inventory and monthly production histories are compiled from ShaleXP.com and Oklahoma Corporation Commission (OCC) well and production records [9–11]. The formal classification is based on the decline-corrected expected-rate ratio,

$$I_{12} = \frac{\bar{q}_{\text{obs,post},12}}{\bar{q}_{\text{forecast,post},12}},$$

where $\bar{q}_{\text{obs,post},12}$ is the observed average parent-well rate during the 12 months after the child first-production month, and $\bar{q}_{\text{forecast,post},12}$ is the parent well’s expected average rate over the same 12-month window in the absence of a child event. The expected rate is obtained from the parent well’s fitted Multi-Segment Arps decline curve, normalized to the observed pre-child production level:

$$\bar{q}_{\text{forecast,post},12} = \bar{q}_{\text{obs,pre},12} \left(\frac{\bar{q}_{\text{DCA,post},12}}{\bar{q}_{\text{DCA,pre}}} \right).$$

Here $\bar{q}_{\text{DCA,pre}}$ and $\bar{q}_{\text{DCA,post},12}$ are model-predicted parent rates over the pre-child and post-child windows. This normalization removes the parent well’s expected natural decline before assigning an interference class. The original post/pre ratio is retained only as a descriptive audit metric and is not used for the final classifications, figures, tables, or development recommendations. The decline-corrected classes are defined as follows:

1. **Confirmed Production Anomaly:** $I_{12} \leq 0.80$, indicating observed parent production at least 20% below the decline-forecast expectation.
2. **Probable Communication:** $0.80 < I_{12} \leq 0.95$, indicating observed production 5–20% below the decline-forecast expectation.
3. **No Interference:** $I_{12} > 0.95$.
4. **Insufficient Data:** the parent well lacks required observed pre/post production data or lacks a fitted decline model suitable for estimating expected post-child production.

The class labels describe the strength of a statistical production-signature anomaly and not a directly observed physical mechanism. A “Confirmed Production Anomaly” is a confirmed deviation of observed parent production from its own decline-forecast expectation; it does not, by itself, establish a hydraulic-fracture connection, distinguish direct fracture communication from pressure-depletion or geomechanical interference, or rule out non-offset causes of underperformance such as the price-driven curtailment discussed in Section 6.2. The thresholds (0.80 and 0.95) are engineering screening cut-offs rather than physically derived boundaries; their effect on the reported rates is bounded by the fact that the confirmed-plus-probable population is defined by the single cut-off $I_{12} \leq 0.95$. Using this decline-corrected classification, 2,177 pairs were classified as confirmed interference signatures, 1,461 as probable communication, 12,909 as no interference, and 644 as insufficient data.

6.2 Pairing Radius and Screening Assumptions

The 6,560-ft search radius is used as a broad screening window rather than as a claim of direct fracture-to-fracture contact. As discussed in the Abstract, the length scale for direct fracture interference is set by the propped fracture geometry—approximately 4,000 feet tip-to-tip for the measured ~2,000-ft single-wing half-lengths, or 4,000–5,000 feet once a survey-uncertainty margin is added. We note that pseudo-steady-state (boundary-dominated) flow is a within-well phenomenon, established when the drainage regions of adjacent fractures along a single well begin to interfere, and is distinct from the well-to-well communication screened by this radius. The 6,560-ft

radius is intentionally set beyond this direct-interference scale so that the screen also admits the pressure-depletion and geomechanical associations that may be relevant for brownfield infill, acquisition screening, and refracturing decisions, while remaining an outer screening bound rather than a physical communication limit. Distance-based results should be interpreted as associations with surface-location proximity; future work using complete directional surveys could refine the analysis with true lateral-to-lateral spacing.

The parent well must precede the child well by more than 180 days and no more than 1,798 days. The lower bound ensures that a pre-child production baseline exists, while the upper bound reflects the observable lead-time range in the available 2008–2024 production window. For parents younger than 12 months, the available pre-child producing months are used for the pre-window average. The post-child window spans the 12 calendar months after child first production.

A known confounder of the I_{12} ratio is field-wide production that is driven by commodity price or takeaway conditions rather than by offset stimulation. As documented in Section 2.1, aggregate STACK output fell approximately 25% during the 2020 COVID-19 price collapse as operators curtailed and shut in wells for economic reasons. Because a large fraction of child wells came online during the 2019–2023 development phase, many post-child windows overlap this curtailment period. The parent well’s fitted Multi-Segment Arps forecast represents unconstrained natural decline and does not model price-driven shut-ins; a parent that was voluntarily curtailed in 2020 will therefore show observed production below its decline forecast and can be classified as a Confirmed Production Anomaly even when no offset well affected it. This mechanism biases the confirmed count *upward* for pairs whose 12-month post-child window intersects 2020. Two mitigations partially limit the exposure: normalization to the observed pre-child rate (which absorbs a well’s own baseline level) and the requirement of a fitted decline model. Neither removes a broad, synchronous, price-driven rate reduction. The confirmed counts reported here should therefore be read as an upper bound during the 2020-overlapping cohort, and a recommended extension is a macro-control sensitivity in which the 2020 curtailment months are excluded from, or detrended within, the post-child window before I_{12} is computed. The parent-age, formation-pair, and distance patterns reported below are internally consistent and are unlikely to be produced by curtailment alone, but the absolute confirmed rate for price-affected cohorts is expected to decrease under such a control.

6.3 Overall Decline-Corrected Interference Results

Table 5 summarizes the decline-corrected parent–child production-signature classification. Using the decline-corrected classification, 2,177 of the 17,191 candidate parent–child pairs were classified as confirmed interference signatures (12.7%), 1,461 pairs were classified as probable communication (8.5%), 12,909 pairs were classified as no interference (75.1%), and 644 pairs were assigned to the insufficient-data category (3.7%). Thus, confirmed and probable production-signature interference accounts for 3,638 pairs, or 21.2% of the candidate parent–child pair population. The observed-versus-expected validation shown in Figure 15 confirms that these classifications

Table 5: Decline-corrected parent–child production-signature classification.

Classification	Pairs	% of all candidates
Confirmed Production Anomaly	2,177	12.7
Probable Communication	1,461	8.5
No Interference	12,909	75.1
Insufficient Data	644	3.7
Total	17,191	100.0

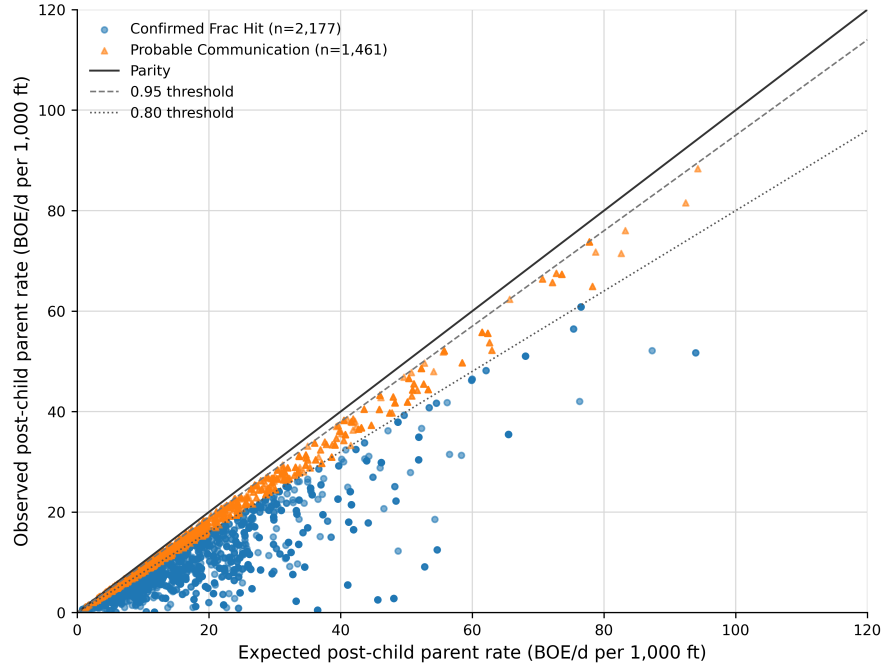


Fig. 15: Observed versus expected post-child parent production for confirmed and probable decline-corrected interference cases, normalized by parent completed lateral length. The expected post-child rate is derived from the parent well’s pre-child decline behavior, while the observed rate is the actual 12-month average parent production after child-well stimulation. Both axes are reported as BOE/d per 1,000 ft. The diagonal line represents observed production equal to expected production. The 0.95 and 0.80 lines define the probable-communication and confirmed-interference thresholds, respectively.

are based on deviation from expected parent decline rather than on raw post-child production loss alone.

To evaluate how confirmed interference cases relate to relative child–parent well performance, child/parent EUR ratio and child/parent initial-rate ratio were calculated for all 2,177 confirmed decline-corrected interference pairs after normalizing both EUR and initial rate by completed lateral length. Figure 16 displays the central ratio range from 0.1 to 10 on both axes for readability; 1,892 of the 2,177 confirmed pairs fall within this display window. The remaining 285 confirmed pairs fall outside the plotted ratio range and are excluded only from the display, not from the confirmed-interference count.

The scatter in Figure 16 is centered near the (1,1) point, with the highest local density in the region where both the length-normalized EUR ratio and the length-normalized initial-rate ratio lie between roughly 0.5 and 2. In other words, for most confirmed pairs the child and parent wells are of broadly comparable length-normalized quality, and confirmed interference is not confined to pairs in which the child strongly out-performs or under-performs the parent. The cloud shows a weak positive association between the EUR ratio and the initial-rate ratio—pairs in which the child has the higher initial rate also tend to have the higher EUR—which is expected because both quantities scale with well quality. The practical implication is that relative child–parent well quality is a poor stand-alone discriminator of confirmed interference: a strong offset production signature can occur whether the child is a better or a poorer well than its parent, so screening should rely on the decline-corrected signature and depletion state rather than on expected relative well quality.

As an additional raw-production validation, first-12-month cumulative BOE was calculated directly from the monthly production histories for both wells in each confirmed parent–child pair and normalized by completed lateral length. The resulting parent/child first-12-month BOE per 1,000 ft ratio provides a time-normalized and length-normalized comparison of early well productivity that is independent of DCA extrapolation. The normalized calculation is preferable to an unnormalized 12-month BOE ratio because parent and child wells may have different completed lateral lengths.

Figure 17 shows the parent/child first-12-month BOE per 1,000 ft ratio as a function of parent-well age at the time of child stimulation. Figure 18 shows the same raw-production ratio as a function of parent–child spacing distance.

A ratio above unity indicates that the parent well had higher length-normalized first-12-month production than the associated child well, whereas a ratio below unity indicates that the child well had higher length-normalized first-12-month production. Across every parent-age bin in Figure 17, the median ratio lies above unity (approximately 1.1–1.7), indicating that within confirmed pairs the parent well typically delivered higher length-normalized first-12-month production than its child. The median does not increase monotonically with parent age—it is highest for intermediate-age parents (around 18–24 months) and comparable at the youngest and oldest bins—so the early parent-versus-child productivity gap is not explained by parent age, and the wide interquartile ranges (spanning parity in every bin) confirm that individual pairs vary substantially. Figure 18 shows the same ratio against spacing distance: the median again stays above unity across all bins and declines only gently, from roughly 1.6 at the closest spacing to about 1.2 beyond 6,000 ft. This mild attenuation is in the direction expected if closer wells share more drainage volume, but it is

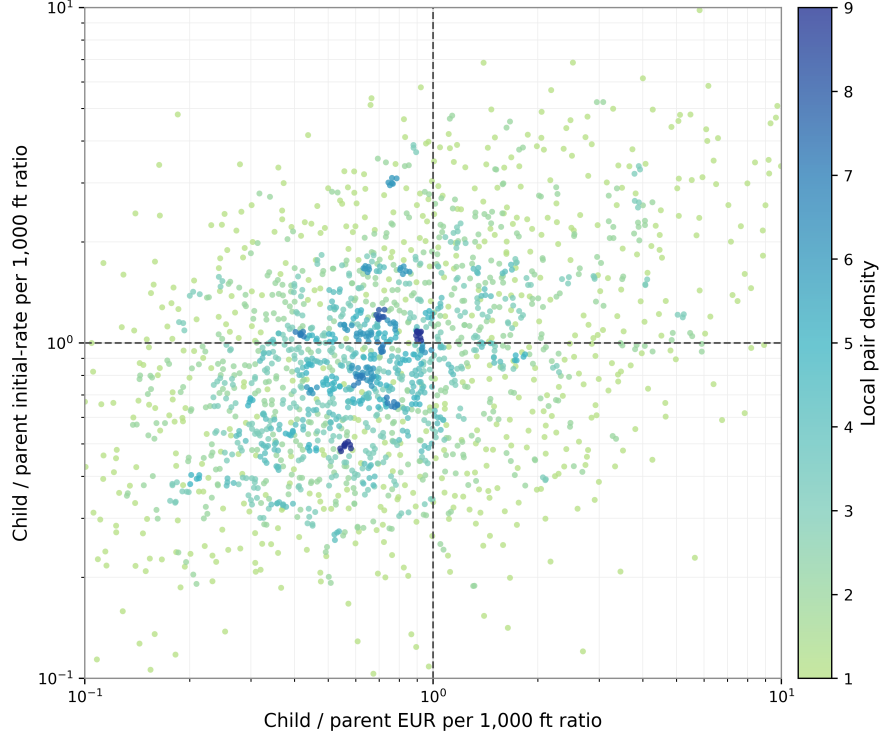


Fig. 16: Length-normalized child/parent EUR ratio versus length-normalized child/parent initial-rate ratio for confirmed decline-corrected interference pairs. EUR and initial-rate values were normalized by completed lateral length before calculating child/parent ratios. Ratios were calculated for all 2,177 confirmed pairs by joining the pair-level interference table with well-level DCA-derived EUR and initial-rate estimates. The figure displays the central ratio range from 0.1 to 10 on both axes for readability; 1,892 confirmed pairs fall within this plotting window, while 285 confirmed pairs fall outside the plotted range.

weak and, as noted in Section 6.2 and the Limitations, is measured on surface-location distance rather than true inter-lateral spacing, so it should not be read as a quantitative spacing law. Taken together, both panels show that in confirmed pairs parents out-produced children early on, with only a weak dependence on parent age or surface spacing.

Figure 19 and Figure 20 provide complementary length-normalized EUR-ratio summaries by parent age and spacing distance. These plots use the same confirmed decline-corrected pair population but focus on ultimate recovery per 1,000 ft rather than first-year production per 1,000 ft. On the EUR basis, the pattern is consistent with the first-12-month results but expressed as a child/parent ratio, so the informative direction is reversed: the median child/parent EUR ratio lies *below* unity in

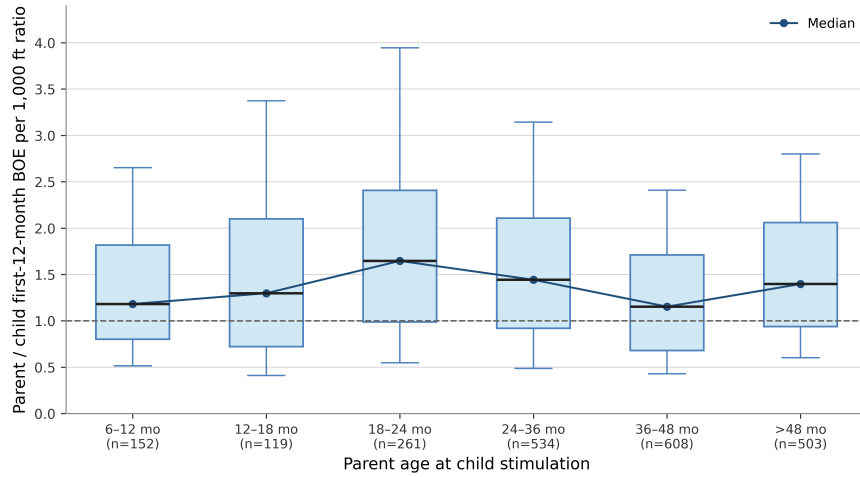


Fig. 17: Parent/child first-12-month BOE per 1,000 ft ratio for confirmed decline-corrected interference pairs as a function of parent-well age at child stimulation. First-12-month BOE was calculated directly from raw monthly production histories and normalized by completed lateral length. Boxes indicate the interquartile range, whiskers indicate the P10–P90 range, the line within each box indicates the median, and the dashed line denotes parity between parent and child first-12-month production per 1,000 ft.

essentially every bin. In Figure 19 the median ranges from near parity for the youngest parents (6–12 months) to roughly 0.55–0.65 for parents in the 18–48-month range, indicating that in confirmed pairs children ultimately recover less per 1,000 ft than their parents, with the deficit largest where the parent had a moderate head-start rather than at the extremes of parent age. Figure 20 shows the same ratio against spacing distance: the median is essentially flat near 0.65–0.8 across all distance bins, with no monotonic trend, echoing the distance-bin confirmed rates in Table 8 and reinforcing that surface-location distance alone does not order interference severity. Because these ratios are computed only over the confirmed subpopulation, they characterize the outcome of pairs already flagged as interfering and should not be read as a basin-wide child-well penalty; nonetheless, the consistent sub-unity EUR ratio is the ultimate-recovery counterpart of the early-time production gap in Figures 17 and 18, and together they indicate that the confirmed production signature persists from first-year rate through to estimated ultimate recovery.

6.4 Parent Well Age Effect

Table 6 reports the decline-corrected confirmed-rate trend by parent-well age. Parent age remains important, but its interpretation changes after normal decline is removed. The corrected confirmed rate increases from 3.3% for 6–12-month parents to 23.6% for parents older than 48 months. This trend indicates that older depleted parents

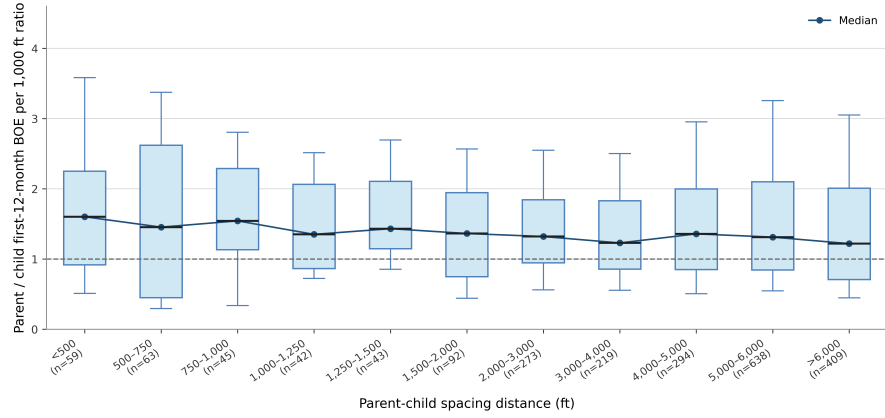


Fig. 18: Parent/child first-12-month BOE per 1,000 ft ratio for confirmed decline-corrected interference pairs as a function of parent-child spacing distance. First-12-month BOE was calculated directly from raw monthly production histories and normalized by completed lateral length. Boxes indicate the interquartile range, whiskers indicate the P10-P90 range, the line within each box indicates the median, and the dashed line denotes parity between parent and child first-12-month production per 1,000 ft.

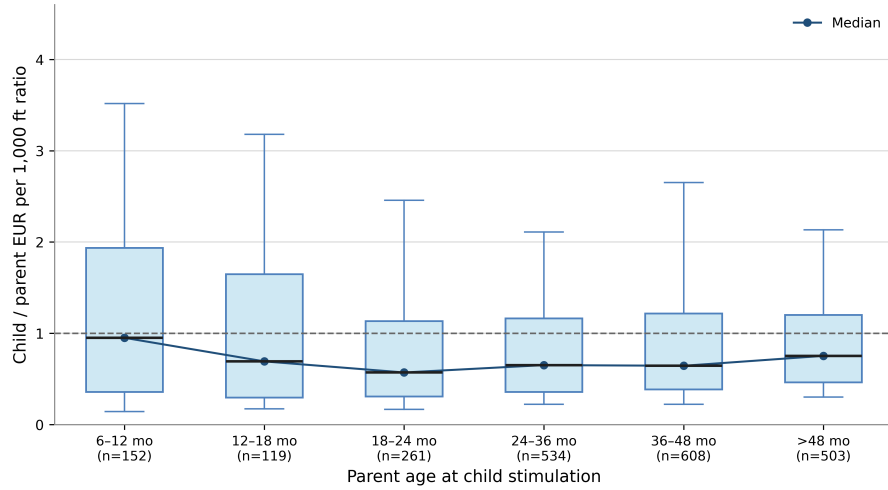


Fig. 19: Length-normalized child/parent EUR ratio for confirmed decline-corrected interference pairs as a function of parent-well age at child stimulation. EUR values were normalized by completed lateral length before calculating child/parent ratios. Boxes indicate the interquartile range, whiskers indicate the P10-P90 range, the line within each box indicates the median, and the dashed line denotes parity between child and parent EUR per 1,000 ft.

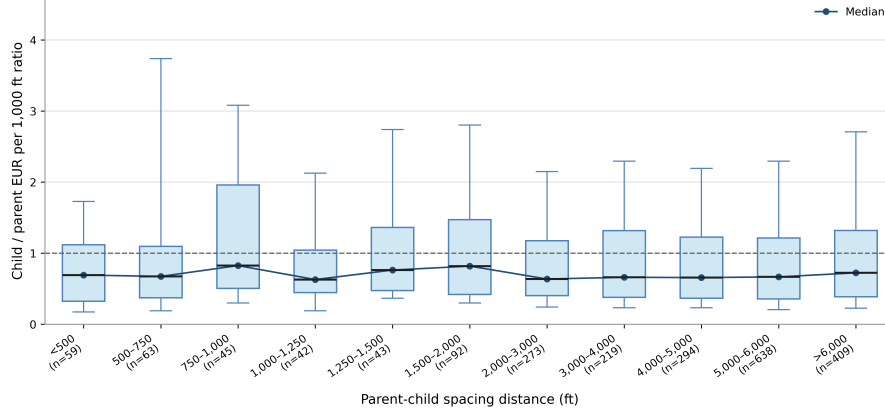


Fig. 20: Length-normalized child/parent EUR ratio for confirmed decline-corrected interference pairs as a function of parent-child spacing distance. EUR values were normalized by completed lateral length before calculating child/parent ratios. Boxes indicate the interquartile range, whiskers indicate the P10–P90 range, the line within each box indicates the median, and the dashed line denotes parity between child and parent EUR per 1,000 ft.

Table 6: Decline-corrected confirmed production-signature rate by parent-well age.

Parent age	Classifiable	Confirmed	Rate (%)
6–12 mo	4,665	152	3.3
12–18 mo	2,308	119	5.2
18–24 mo	1,963	261	13.3
24–36 mo	2,798	534	19.1
36–48 mo	2,686	608	22.6
>48 mo	2,127	503	23.6

are more likely to show anomalous post-child underperformance relative to their own expected decline path. Parent age should therefore be treated as a depletion-risk proxy, not as a simple protective waiting period. Figure 21 summarizes the decline-corrected confirmed and confirmed-plus-probable production-signature rates by parent-well age. The two series rise together and stay approximately parallel, which is the useful observation: because the broader confirmed-plus-probable series shows the same age trend as the narrower confirmed series, the trend cannot be an artefact of where the 0.80 classification threshold happens to fall. Both series rise monotonically with parent age and are close to parallel: the confirmed rate climbs from 3.3% to 23.6% while the confirmed-plus-probable rate climbs from 7.3% at 6–12 months to 37.0% beyond 48 months. The persistence of the trend in the broader confirmed-plus-probable series confirms that the age effect is not an artifact of the specific 0.80 confirmed threshold.

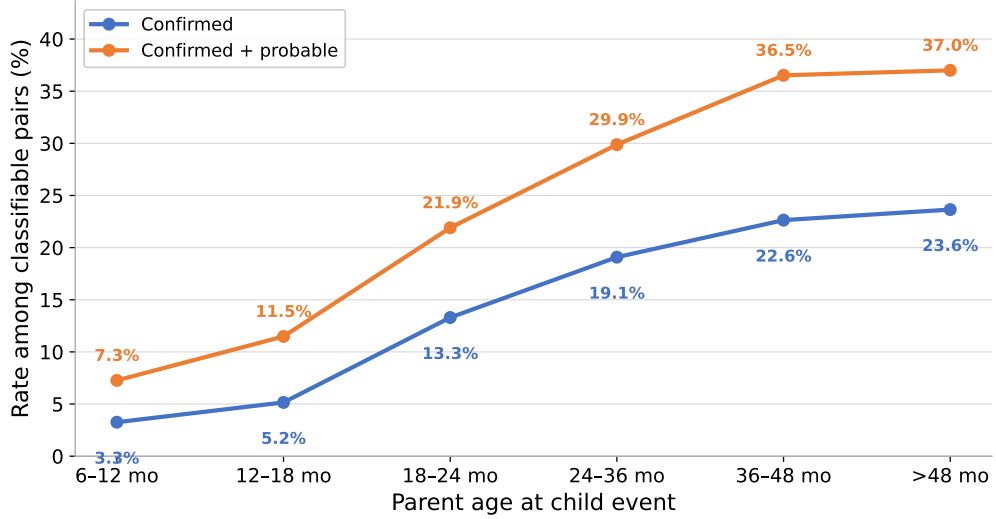


Fig. 21: Decline-corrected confirmed and confirmed-plus-probable production-signature rates by parent age. Rates are calculated over classifiable pairs only.

6.5 Time-Difference Trend and Percentage-Difference Metric

Two additional analyses examine the parent–child time difference and the choice of interference metric more directly. Both are motivated by the observation that, once a parent’s own decline is removed, the interference signature is governed primarily by how depleted the parent is at the time of child stimulation. Figure 22 shows the number of Confirmed Production Anomalies as a function of parent age at child stimulation, evaluated under four cumulative surface-location search radii (1,500, 3,000, 4,500, and 6,000 ft). Confirmed hits concentrate in older parents at every radius: the count rises with parent age through the 36–48-month bin, and although a wider radius admits more candidate pairs—and therefore more confirmed hits—the age distribution is preserved across all four radii. The parent-age concentration is thus a property of the depletion state rather than an artifact of the chosen screening radius, which reinforces the treatment of the 6,560-ft radius as a screening bound rather than a physical communication limit.

Figure 23 examines the same effect using a *percentage* difference taken relative to the observed rate, defined as $(\text{expected} - \text{observed}) / \text{observed}$, so that positive values denote underperformance (interference). To isolate the interference response from the general population, the distribution is restricted to pairs that carry an interference signature—the 2,177 Confirmed Production Anomaly and 1,461 Probable Communication pairs—and non-interfering pairs are deliberately excluded, because the large No-Interference population sits near zero and carries a forecast-anchoring artifact for young parents that otherwise dilutes the blended median and obscures the depletion signal. The two interference classes are shown in separate panels—panel (a) Confirmed Production Anomaly and panel (b) Probable Communication—each with its vertical

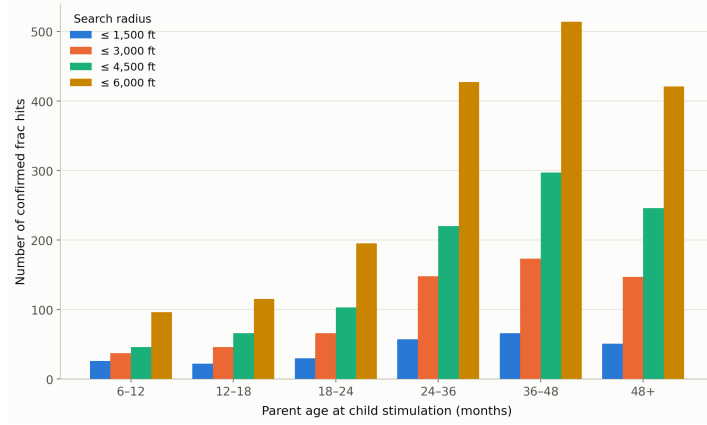


Fig. 22: Number of Confirmed Production Anomalies as a function of parent age at child stimulation, evaluated under four cumulative surface-location search radii (1,500, 3,000, 4,500, and 6,000 ft). Confirmed hits concentrate in older parents at every radius; a wider radius adds candidate pairs but preserves the parent-age distribution, indicating that the age effect reflects parent depletion state rather than the choice of screening radius.

axis scaled to the full P10–P90 range of its own data, so that the two classes remain individually legible and directly comparable across parent age despite their very different severity magnitudes. A percentage basis referenced to observed production is preferred to an absolute BOE difference because parent rates decline steeply with age: an absolute gap shrinks as the parent depletes and would understate late-time interference, whereas the observed-referenced percentage does not. This metric moves in the same direction as the classification ratio $I_{12} = \bar{q}_{\text{obs,post},12} / \bar{q}_{\text{forecast,post},12}$ used elsewhere in the paper.

The severity trend lives in the Confirmed Production Anomaly class: its median underperformance rises with the parent–child time difference, from about 36% for 6–12-month parents to 55%, 64%, and 91% through the 24–36-month bin, remaining near 67–79% beyond 36 months—the expected signature of accumulating depletion, where a larger parent–child time gap corresponds to a larger percentage underperformance. The Probable Communication class, by contrast, remains a flat band near 12–15% at every parent age; this is a consequence of its definition ($0.80 < I_{12} \leq 0.95$), which admits only a 5–20% underperformance window and therefore cannot express a strong age trend by construction. Consistent with Table 6, parent age thus acts on both dimensions of the interference response: the *incidence* of confirmed interference rises with parent age—from 3.3% at 6–12 months to 23.6% beyond 48 months—and, among confirmed pairs, the *severity* of the percentage underperformance rises as well.

6.6 Formation and Distance Controls

Table 7 reports the decline-corrected production-signature results by child formation. Corrected interference risk varies by formation. Child wells in Mississippian,

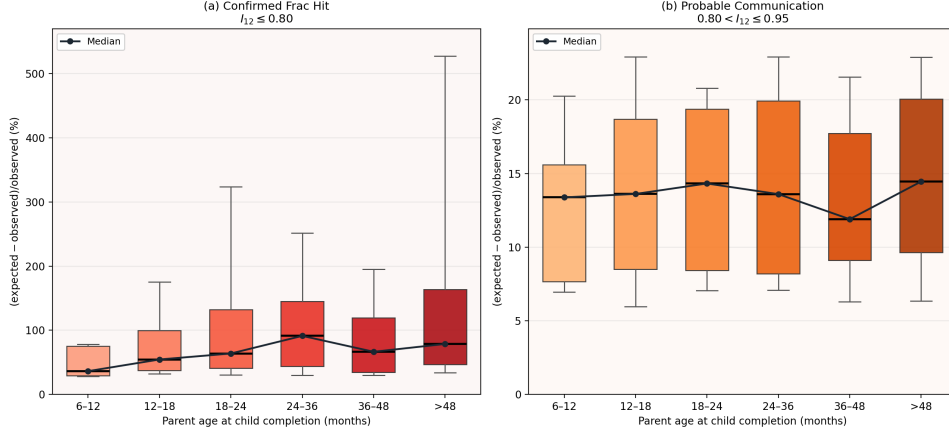


Fig. 23: Parent underperformance relative to its own decline forecast, (expected – observed)/observed, by parent age at child stimulation, for the two interference classes shown in separate panels: (a) Confirmed Production Anomaly ($I_{12} \leq 0.80$) and (b) Probable Communication ($0.80 < I_{12} \leq 0.95$). Non-interfering pairs are excluded so that the depletion signal is not diluted by the near-zero No-Interference population. Each panel’s vertical axis is scaled independently to the full P10–P90 range of its own class, keeping both classes legible despite their different severity magnitudes. Positive values denote production below the forecast (interference). Boxes span the P25–P75 interquartile range, whiskers span P10–P90, and the overlaid line marks the median. In panel (a) the median severity rises with the parent–child time difference—from about 36% for 6–12-month parents to a peak near 91% at 24–36 months and 67–79% beyond—the expected signature of accumulating parent depletion. In panel (b) the Probable class remains a flat 12–15% band at every parent age, a consequence of its narrow classification window rather than an absence of an age effect. The incidence of confirmed interference rises with parent age in parallel (Table 6).

Table 7: Decline-corrected production-signature results by child formation. Rates are computed over classifiable pairs only.

Child formation	Total pairs	Classifiable	Confirmed	Probable	Confirmed rate (%)	Communication rate (%)
WOODFORD	5,587	5,369	703	465	13.1	21.8
MISSISSIPPIAN	4,402	4,333	717	412	16.5	26.1
MISS. (LESS CHESTER)	2,784	2,708	384	230	14.2	22.7
OSWEGO	3,246	2,997	233	292	7.8	17.5
WF/MISS. COMBO	735	723	109	44	15.1	21.2
HUNTON	108	108	6	4	5.6	9.3
MERAMEC	66	63	11	0	17.5	17.5
OTHER	263	246	14	14	5.7	11.4

WF/Miss. Combo, Miss. (Less Chester), and Woodford intervals show moderate corrected confirmed rates, whereas Oswego and Hunton show lower confirmed rates. This supports the interpretation that formation pairing, vertical position, depletion state, and pressure communication jointly control the observed production response.

Table 8: Decline-corrected production-signature results by surface-location distance.

Distance bin (ft)	Classifiable	Confirmed	Confirmed rate (%)
<500	531	59	11.1
500–1,000	599	108	18.0
1,000–1,500	603	85	14.1
1,500–2,000	513	92	17.9
2,000–3,000	1,476	273	18.5
3,000–4,500	2,057	361	17.5
4,500–6,560	10,768	1,199	11.1

Table 8 reports the decline-corrected results by surface-location distance bin. The distance-bin results do not support a simple monotonic spacing rule when surface-location distance alone is used. This is expected because the screening radius is based on surface-hole coordinates rather than directional-survey-derived minimum lateral spacing. Distance is therefore retained as a screening variable, while final operational interpretation should combine spacing with formation pair, parent age, depletion state, and well geometry.

Figure 24 compares the decline-corrected confirmed and confirmed-plus-probable communication rates by child and parent formation. Reading the two panels together is more informative than either alone, because a formation can carry a high rate as a child while carrying a low rate as a parent; that asymmetry points to depletion state and vertical position rather than to any intrinsic property of the interval itself. Read by child formation, the ordering matches Table 7: Mississippian children carry the highest corrected rates (16.5% confirmed, 26.1% confirmed-plus-probable), Woodford, Miss. (Less Chester), and WF/Miss. Combo children fall in an intermediate band (roughly 13–15% confirmed), and Oswego and Hunton children are lowest (below 8% confirmed). Read by parent formation—the view the figure adds beyond the child-formation table—the same conservative picture holds among large-sample parents (Woodford, Mississippian, and Miss. (Less Chester) parents cluster near 12–15% confirmed and 20–26% confirmed-plus-probable, while Oswego parents are lowest at about 5%), with one apparent outlier: Meramec-as-parent shows a much higher rate (above 50% confirmed). That cell rests on a small parent population and should be read as a small-sample screening flag rather than a robust rate, consistent with the sample-size cautions in the Limitations and in Figure 25. Figure 25 then shows the corresponding formation-pair matrix used to evaluate within-formation and cross-formation interference risk.

The decline-corrected formation matrix shows that several high-rate cells involve modest sample sizes and should be treated as screening indicators rather than stand-alone development rules. Among large-sample pairings, corrected within-formation rates are moderate: Mississippian–Mississippian pairs show a 17.3% confirmed rate ($n = 2,525$), Woodford–Woodford pairs show 14.6% ($n = 4,241$), and Miss. (Less Chester)–Miss. (Less Chester) pairs show 14.2% ($n = 1,091$). The corrected matrix therefore supports a conservative interpretation: formation pair and depletion state

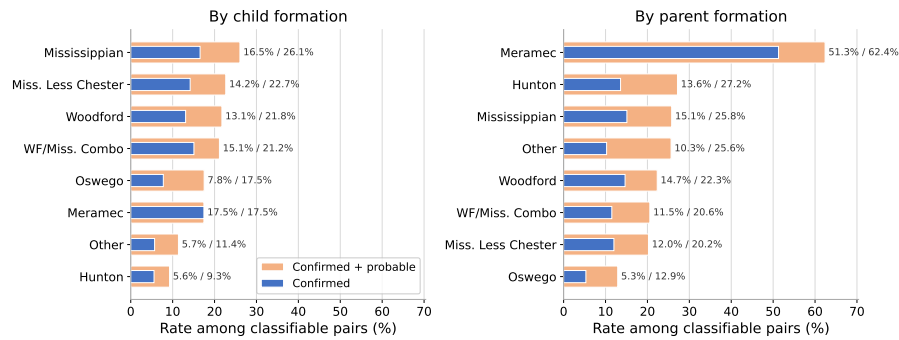


Fig. 24: Decline-corrected formation-level communication rates by child formation and parent formation. Dark bars show confirmed rates; light bars show confirmed-plus-probable communication rates. Rates are computed over classifiable pairs only.

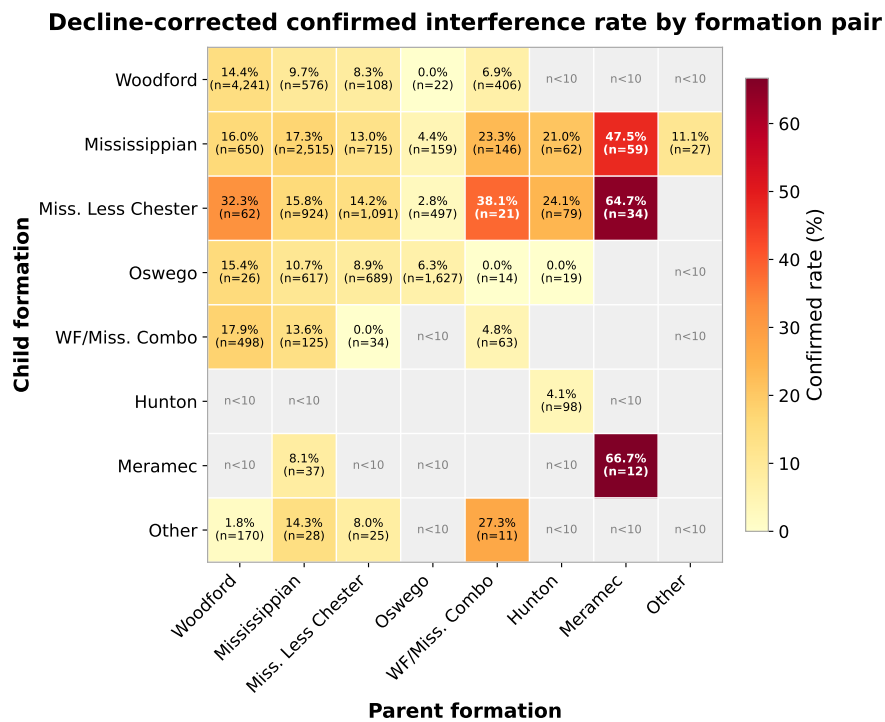


Fig. 25: Decline-corrected formation cross-interference matrix. Rows represent child formations and columns represent parent formations. Cell values show the percentage of valid parent-child pairs classified as confirmed interference after comparing observed post-child parent production against the parent well's expected decline forecast. Cells containing fewer than 10 valid parent-child pairs are not interpreted.

influence interference risk, but the final rates are substantially lower than a raw post/pre screen would imply.

7 Observations and Discussion

The decline-corrected analysis changes the interpretation of the interference component of the study. The principal result is not that parent-child effects disappear, but that only a subset of the raw post-child production drops remain anomalous after the parent well's expected decline is removed. The corrected workflow identifies 2,177 Confirmed Production Anomalies and 1,461 Probable Communication pairs out of 17,191 candidates, corresponding to a combined confirmed-plus-probable rate of 22.0% among classifiable pairs. This is a more defensible measure of anomalous parent underperformance than the original post/pre ratio because it controls for the steep natural decline typical of unconventional wells. The corrected parent-age trend is also more physically interpretable. Young parents can show large raw post/pre drops because early-life decline is naturally steep. Once that expected decline is removed, anomalous underperformance becomes more concentrated in older parent wells. This behavior is consistent with depletion-driven pressure sinks and geomechanical stress perturbations becoming more important as parent wells mature. The operational implication is that elapsed parent age should not be used as a simple waiting-period rule. It should be combined with parent decline state, formation pair, surface or lateral spacing, and mitigation options such as prefill or pressure support. The formation results indicate that interference is not uniform across the STACK. Formation pair, vertical separation, pressure depletion, and rock-fluid system all contribute to the corrected response. Within-formation pairings remain important because they are more likely to share the same pressure-depletion volume and fracture network. Cross-formation pairings with large vertical separation generally have lower corrected rates, although local natural fracture systems and stacked completion designs can still create communication pathways. The broad 6,560-ft search radius remains useful as a screening tool because it captures not only direct fracture hits, but also softer pressure and depletion effects that matter for infill planning and asset evaluation. However, the corrected distance-bin analysis also shows that surface-location distance alone is not a sufficient predictor. Directional surveys, true lateral-to-lateral spacing, landing interval, depletion state, and parent well performance should be incorporated before making well-level completion or refracturing decisions. The production-signature approach is consistent with tracer-based field evidence from Banerjee [6], which shows that parent depletion can control communication severity and that prefilling depleted parents can reduce communication. The statistical method used here cannot directly observe the hydraulic pathway, but it provides broad-field evidence across 17,191 candidate pairs and multiple STACK formations.

7.1 Limitations

The results above should be read subject to the following limitations, several of which bound the interference conclusions in particular.

Macroeconomic confounding of the interference classifier.

As detailed in Section 6.2, the I_{12} ratio compares observed post-child parent production against an unconstrained decline forecast that does not model price-driven curtailment. Post-child windows overlapping the 2020 COVID-19 shut-in period can therefore be misclassified as Confirmed Production Anomalies, biasing the confirmed count upward for the 2019–2023 child cohort. Absolute confirmed rates for price-affected cohorts are best treated as upper bounds pending the macro-control sensitivity recommended in Section 6.2.

Surface-location rather than lateral-to-lateral spacing.

All distance results use surface-hole coordinates. In a long-lateral, stacked play, surface separation is a weak proxy for true inter-lateral spacing, and the non-monotonic distance response in Table 8 is consistent with this proxy error rather than with an absence of spacing dependence. Distance-based rates should be used only as a screen, and directional-survey minimum lateral spacing is required before any spacing rule is inferred.

Production-signature, not physical, confirmation.

The classifier identifies statistical anomalies in produced rate. It cannot separate direct fracture communication from pressure-depletion or geomechanical interference, and it cannot confirm a hydraulic connection. The “Confirmed” label should be read accordingly (Section 6.1).

BOE aggregation convention.

EUR is reported on a 6 Mcf/BOE basis, which flatters high-GOR formations. The Woodford, Meramec, and WF/Miss. Combo EUR rankings partly reflect condensate-rich gas volumes rather than oil-equivalent economic value; ranking against oil-weighted formations such as Oswego is therefore not on a like-for-like value basis.

Formation-aggregate flow-regime diagnostics.

The MBT diagnostics are computed on formation-aggregate type curves that superimpose wells of differing vintage and lateral length. This aggregation smears individual-well flow-regime signatures and is the most likely reason observed early-time slopes (-0.06 to -0.45) are shallower than the -0.5 transient-linear theory. The diagnostic supports the qualitative flow-regime interpretation and the segmentation timing but is not a well-level measurement of the linear-flow slope.

Boundary-pinned high-productivity parameters.

The $b_1 = 1.99$ values in the P10 rows of Tables 3 and 4 are optimizer-boundary results at the transient-linear limit rather than interior optima, and the corresponding high-productivity EURs inherit that boundary behavior.

Point estimates without uncertainty bounds.

The reported interference rates, including the formation-pair matrix cells, are point estimates. Several matrix cells with elevated rates (for example, Meramec–Meramec

at 66.7%, $n = 12$, and Miss. Less Chester–Meramec at 64.7%, $n = 34$) rest on small samples where the sampling error is large. Cells with fewer than 10 pairs are already suppressed, but bootstrap confidence intervals on the confirmed rates—especially for cells below roughly 50 pairs—would materially strengthen the formation-pair interpretation and are recommended for future work. Large-sample within-formation rates (Woodford–Woodford $n = 4,241$; Mississippian–Mississippian $n = 2,525$) are correspondingly more robust.

8 Conclusions and Recommendations for Future Horizontal Well Development

8.1 Principal Conclusions

This study of 3,550 horizontal STACK wells in Canadian and Kingfisher Counties, Oklahoma, yields the following principal conclusions:

- The STACK dataset, compiled from ShaleXP.com and OCC production records, provides a basin-scale view of production performance across nine formations and two counties without pooling all wells into a single average type curve.
- The formation-aggregate q versus N_p/q flow-regime diagnostic indicates departure from early transient linear flow after approximately 13–32 months, matching the fitted Segment 1 to Segment 2 transition months across the county–formation Multi-Segment Arps fits, while fully developed boundary-dominated flow is generally not established within the first 60 months. This supports the use of a hyperbolic Segment 1 and a later pure-exponential Segment 2 in the Multi-Segment Arps workflow.
- Arps decline parameters fitted from the peak production month avoid Month-1 ramp-up bias and provide a more physically consistent basis for EUR estimation. The effective Segment-2 exponential decline rate is calibrated from observed late-time behavior rather than imposed as a generic economic terminal decline.
- The Woodford Shale, WF/Miss. Combo, and Canadian County Mississippian intervals remain the highest-EUR development targets. Oswego has lower absolute EUR but retains strategic value because of its oil-rich fluid character, shallower depth, shorter depletion timeline, and lower corrected interference tendency.
- The final interference analysis is based on the decline-corrected ratio I_{12} , not on the raw post/pre ratio. Of 17,191 candidate pairs, 16,547 are classifiable; 2,177 pairs (12.7% of all candidates) are Confirmed Production Anomalies and 1,461 pairs (8.5%) are Probable Communication. These labels denote statistical production-signature anomalies rather than directly observed fracture connections, and the absolute confirmed rate for child cohorts whose post-child window overlaps the 2020 price-driven curtailment should be treated as an upper bound pending the macro-control sensitivity described in Section 6.2.
- The corrected parent-age trend increases from 3.3% confirmed at 6–12 months to 23.6% beyond 48 months. This monotonic pattern is internally consistent and is unlikely to be an artifact of curtailment alone, indicating that older depleted parents require more screening and mitigation, not less.

- Formation cross-interference rates are lower and more conservative after decline correction. Large-sample within-formation pairings such as Mississippian–Mississippian, Woodford–Woodford, and Miss. (Less Chester)–Miss. (Less Chester) remain important, but the corrected rates are moderate rather than uniformly high.
- Surface-location distance is useful for broad screening but is not sufficient as a stand-alone spacing rule. True lateral geometry, formation pair, vertical separation, parent depletion state, and pressure-support options must be considered together.

8.2 Recommendations for Future Horizontal Well Development

Recommendation 1 — Use decline-corrected parent screening before infill stimulation.

Do not interpret parent age alone as protective. Older, depleted parent wells should be screened using decline-corrected production forecasts, recent production trends, GOR behavior, and offset-child timing before additional infill completions are planned.

Recommendation 2 — Apply formation-specific spacing and sequencing.

Maintain larger spacing and more conservative sequencing for high-risk within-formation pairs. Cross-formation development can be lower risk where vertical separation is large, but formation-specific risk should be checked against the corrected matrix before finalizing pad designs.

Recommendation 3 — Use prefill or pressure-support mitigation for depleted parents.

Where parent wells are mature, pressure-depleted, or located near planned child completions, evaluate prefill or pressure-support options before stimulation. This recommendation is supported by the decline-corrected age trend and by tracer-based evidence reported by Banerjee [6].

Recommendation 4 — Treat the 6,560-ft radius as a screening window, not a final spacing rule.

The broad radius is useful for identifying potentially affected offsets, acquisition risk, and refracturing candidates. Final engineering decisions should use directional surveys and true inter-lateral spacing where available.

Recommendation 5 — Preserve the flow-regime-based decline framework for reserves work.

Use formation-specific transition timing from the q versus N_p/q diagnostic rather than forcing an early exponential switch. Premature switching can understate long-tail unconventional recovery.

Recommendation 6 — Match capital allocation to formation behavior.

Prioritize Woodford, WF/Miss. Combo, and Canadian County Mississippian for higher-EUR development, while considering Oswego for oil-weighted, shorter-cycle

opportunities. In all cases, parent–child risk should be evaluated with the decline-corrected workflow before infill development. Together, these recommendations define a revised STACK development framework in which decline analysis, flow-regime diagnostics, formation performance, and decline-corrected parent–child screening are integrated into a single decision workflow. Future extensions could combine this physics-guided workflow with data-driven reservoir analytics while preserving the decline-corrected interpretation used here [16].

Data Availability

The well-header and monthly production data analyzed in this study were compiled from Oklahoma Corporation Commission well records and production data, supplemented with commercially licensed ShaleXP.com well and production records. Derived datasets generated during this study—including the formation mapping, fitted decline-curve parameters, type-curve statistics, EUR summaries, and parent–child production-signature classifications—are available from the corresponding author on reasonable request, subject to the licensing restrictions attached to the commercially sourced records.

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Competing Interests

The authors declare no competing interests.

Author Contributions

Shashank Shekhar carried out the data analysis and analysis design, the decline-curve modeling, the parent–child screening, the methodological framing, and the figure preparation, and drafted the manuscript. Zenefa Rahaman carried out the statistical review and contributed to manuscript preparation. Alexy Mazarovich contributed the geological interpretation and reservoir-context review. Balmohan G. Kelkar provided reservoir-engineering supervision, decline-analysis review, and technical interpretation. Chris G. Einchcomb contributed industry review and technical manuscript review. Sunil K. Srivastava contributed technical review and manuscript editing. All authors reviewed and approved the final manuscript.

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