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## **The Value Proposition for Applying Advanced Completion and Stimulation Designs to the Bakken Central Basin**

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### **Abstract**

The Bakken boom in North Dakota is currently focused on the Central Basin area where around half of the drilling rigs in North Dakota are now operating. What makes this area different compared to previous areas of Bakken development is that there is only minor structural variation and significantly less naturally induced fracturing as compared to the higher permeability rock facies that exist in the sub-reservoirs of earlier Bakken development such as at the Elm Coulee field in Montana or the Sanish and Parshall fields in North Dakota. As a consequence, the role of the well's completion and stimulation design has a greater significance and impact on well productivity and ultimate recovery.

Different companies have taken very different approaches to well design using either plug and perf or ball and sleeve completions, and a variety of fracture designs with slickwater, hybrid or cross-linked gel fluids and a variety of proppants from 100% natural sand to 100% ceramics. As a consequence, it is not uncommon for different operators to have over a 2 million dollar difference in their AFE's solely because of the differences in approach to the well's completion and stimulation design. The authors have chosen to apply "advanced completion and stimulation designs" which are designed to maximize the reservoir contact area (slickwater and plug and perf) and optimize the conductivity (ceramic proppant at relatively high volumes).<sup>1,2</sup>

In order to benchmark performance of its completion and stimulation program the authors in 2010 developed a production and completion database of all wells completed in the Central Basin using publicly available information from the North Dakota Industrial Commission's records augmented by additional completions information obtained directly from the operators. From an initial dataset of ~30 wells the database has been updated monthly and has now grown to over 1100 wells in the Central Basin from 28 operators. Benchmarking of completion performance has been performed using the above database together with a Petra geological database developed from all publicly available logs in the Central Basin (~500 vertical wells which had been drilled and logged prior to the first Bakken horizontal well).

Benchmarking of performance is somewhat subjective in the Bakken (as well as most reservoirs) due to variations in reservoir quality. Without geological input (reservoir quality), the acquired data were too scattered to achieve meaningful correlations to completion methods unless the area was limited to ensure similar reservoir quality for the wells being evaluated. By narrowing the analysis to very limited areas; this also reduced the input as to the number and type of completion methods being compared.

Multivariate analysis methods, that included geological input, were used to benchmark performance over most of the Williston Central Basin, allowing comparison of the varied completion methods for 28 operators and over a thousand wells. Using multiple parameters an excellent correlation for completion methodology versus reservoir quality was obtained.

While early analysis focused on 30, 60 and 90-day cumulative production; in the past year there have been enough wells to generate performance metrics based on 180 and 365-day cumulative production since over 600 wells have now been on production for at least a year.

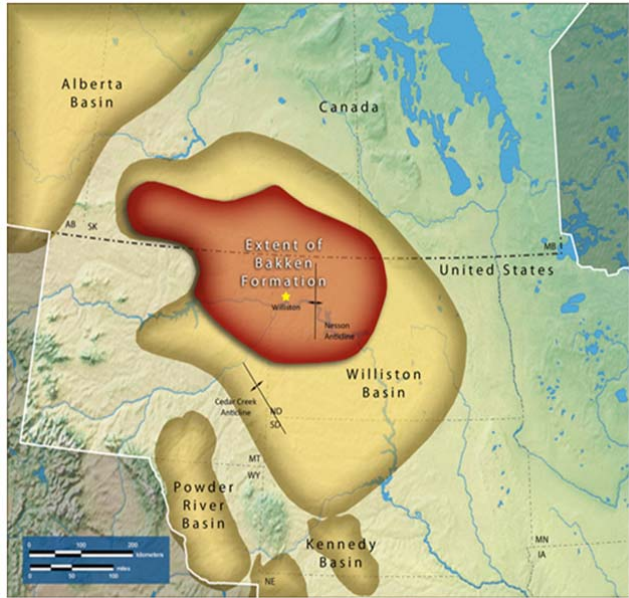
The analysis shows that companies with a greater completion spend are typically paying out the increased spend in 1 to 8 months depending on the area and these wells are still producing at significantly higher rates after one year of production. The declines of these wells also project a significantly greater EUR and hence have lower F&D costs per barrel of oil. This higher performance continues to hold after 365-days of production.

**Introduction**

The Bakken Formation (highlighted in red in Figure 1) is located within the Williston Basin, which spans southern Saskatchewan and Manitoba in Canada as well as North Dakota, South Dakota and Montana in the United States. The majority of the Williston Basin has gentle regional dip with little structural deformation, with the exception of a small number of structural features including the Nesson Anticline and the Cedar Creek Anticline.

The stratigraphic column (Figure 2) shows that the Bakken Formation is Mississippian and Devonian in age. It consists of the Upper, Middle and Lower Members of the formation. The focus of this paper is the Middle Bakken Member. As shown in Figure 3, the Bakken does not outcrop at the surface, making it a completely contained petroleum system. The Bakken petroleum system, which includes the underlying Three Forks Formation, has a top seal in the Lodgepole Formation, and a bottom seal in the Nisku Formation.

Bakken oil saturations are highest in the deep center of the basin where thermal maturity was greatest, and in the stratigraphic traps on the flanks of the basin where better reservoir quality and higher permeability result in improved oil saturation and higher oil-cut production. In the Central Basin area, in general, there is a direct and significant relationship with depth and water cut. That is, the deepest part of the basin centered in north-central McKenzie County where the most intense hydrocarbon generation has taken place, the oil cut is the highest (see Figure 5 and Figure 19).



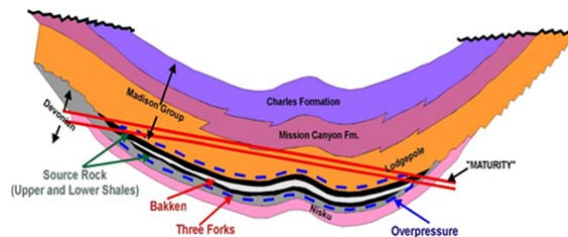
**Figure 1 - Location of the Williston Basin.<sup>3</sup>**

Mississippian	Lodgepole Formation	"False Bakken"
	<b>Bakken Formation</b>	Scallion
Upper		
<b>Middle</b>		
Devonian	Lower (Pronghorn)	
	Three Forks Formation	

**Figure 2 - Bakken stratigraphic chart.**

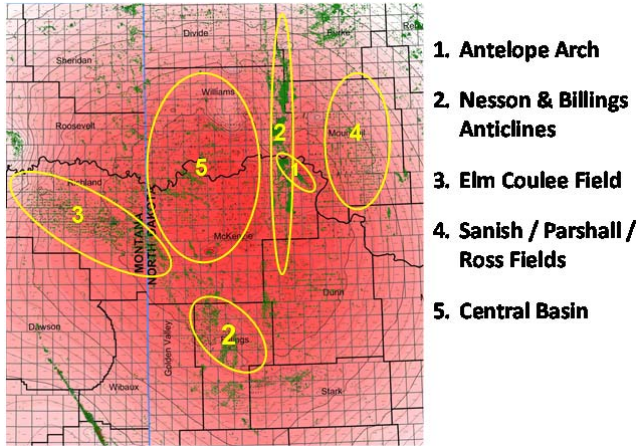
A second period of Bakken vertical well development occurred between 1970 and 1985 with wells drilled along two other structural features; the much larger Nesson and Billings anticlines. Drilling in the same areas occurred during the third period of development (1986 to 1999), which saw the first use of horizontal wells. These wells were typically completed with pre-perforated liners and generally consisted of single fracture treatments, often incorporating diversion materials in an attempt to generate multiple zones of stimulation.

The first Bakken Formation well came on production in 1953 - just two years after first oil production in North Dakota. Drilling took place along the axis of the Antelope Arch – an anticlinal feature in eastern McKenzie County shown as the first development area in Figure 4. Over the next 15 years a total of 42 vertical wells were completed in the Middle Bakken and/or Three Forks formations. Commercial production was dependent on the existence of natural fractures associated with the uplift and could be correlated to the second derivative curvature in the formation.<sup>4</sup>



**Figure 3 - Cross-section of Williston Basin formations.<sup>5</sup>**

The discovery of a high porosity dolomitized carbonate shoal complex within the Middle Bakken at the Elm Coulee Field in Montana ushered in the next period of development in 2000. Horizontal drilling was used with open-hole single stage completions. The first ten wells all had cemented liners and some flowed after perforating without stimulation. The most significant productivity gains over the early years of Elm Coulee development came with the use of uncemented liners, and the drilling of many wells having multiple horizontal legs. Drilling of the dolomitized shoal facies also crossed the state line into North Dakota as shown in Figure 4.

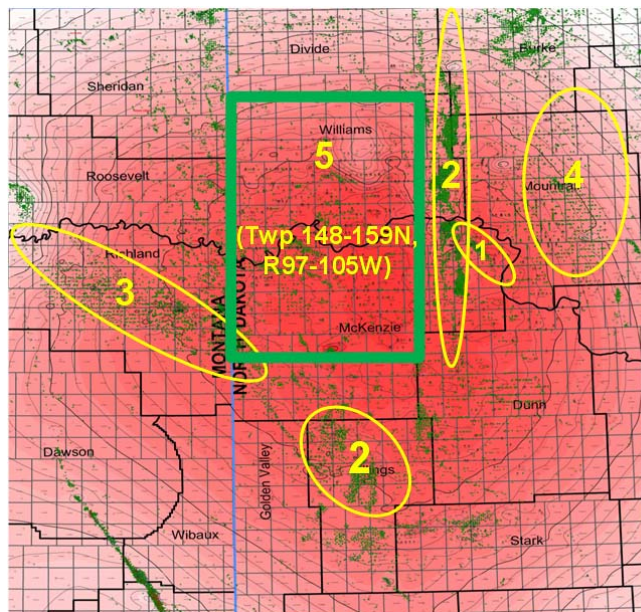


**Figure 4 - Structural Map with the main development areas in the Williston Basin.**

The broader significance of the Elm Coulee development was the realization that very large volumes of oil had been generated in the Upper and Lower Bakken shales and expelled into the Middle Bakken and Three Forks zones. This subsequently led in 2006 to the exploration and finding of higher porosity facies in the Ross, Parshall and Sanish fields on the east side of the Nesson Anticline. Well stimulation of these earliest wells typically involved the pumping of a single stage frac of ~2 million pounds of proppant and one million gallons of cross-linked gel. The first multi-stage fraced well was completed in the Parshall Field in 2007 and this technology was rapidly duplicated in other areas of the Williston Basin such that by 2008 the average stage count per well had reached ~10 fracs.<sup>6,7</sup>

**Overview of Database**

The authors entered the Bakken in 2010 building a final land position of approximately 42,000 acres in the Central Basin. This effort began by developing a focus area for targeting leasing in Williams and McKenzie Counties encompassing 97 townships, 72 miles by 48 miles rectangle internally called the “Green Box” as shown in Figure 5. The initial completion designs were based on a philosophy of applying the most advanced completion methods used for oil resource plays and then refining the completions through benchmarking against other operators in the Central Basin.



**Figure 5 - Central Basin Study Area.**

The State of North Dakota (North Dakota Industry Commission) provides excellent well and completion information to the public. Log, core, lateral length and survey data are available through the state along with the standard well production information. The Well Completion Reports (Form 6) provide information for the completed interval, stimulation stage count, fluid/proppant volumes, proppant type, and maximum treating rate and pressure.<sup>8</sup>

More detailed completion data were obtained through partners, working interest ownership of wells operated by others, public presentations (SPE, SEC filings, Industry Conferences, etc.) and personal contacts. This completion information primarily includes:

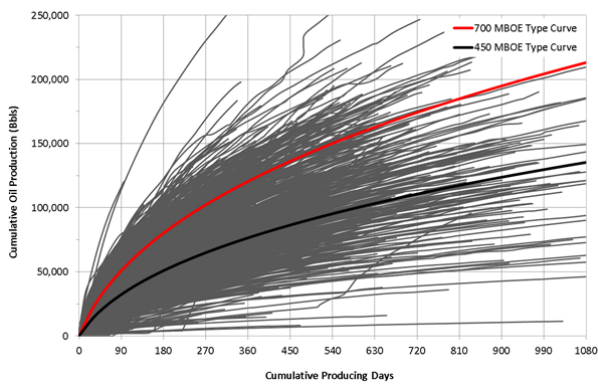
- 1) Open-hole swell packers or cemented
- 2) Plug and perf (PNP) or ball and sleeve (BS)
- 3) Type stimulation fluid (Slickwater, Gel, Hybrid)
- 4) Size proppant
- 5) Type proppant (sand, resin coated, ceramic)

**Data Analysis**

To date, 1,185 wells are in the Central Basin completion database. The database was quality controlled to remove a small number of wells identified as having mechanical failures or where only part of the lateral was stimulated. The first month’s production is the highest 30 days of production which removes issues and differences in how companies initially bring wells on, and flowback reporting issues. This can be significant for the early time analysis. The completion parameters in the database include: operator, gross pay thickness, lateral length, number of stages, proppant volumes, fluid type and volumes, type and size proppant, maximum treating rate and pressure, type completion (PNP or BS) and liner placement (open-hole swell packers or cemented lateral).

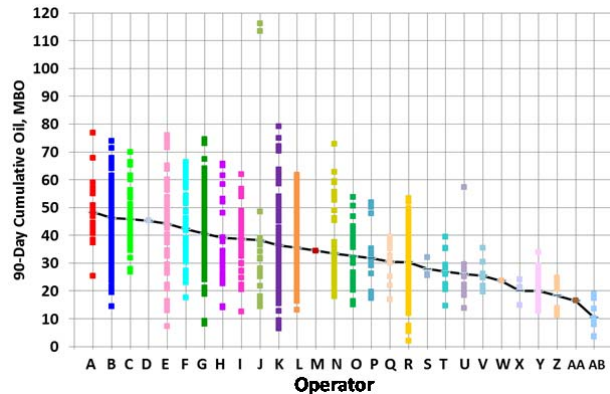
**Bi-Variate Analysis**

The initial completion design and early optimization efforts were done through relatively simple bi-variate analysis. Figure 7 is the cumulative oil production for all wells in the Central Basin and Figure 6 is a bubble map color coded by operator for 90-day cumulative oil production. As can be seen, there is a high variability in the production performance across the Central Basin which is very typical for resource type plays.

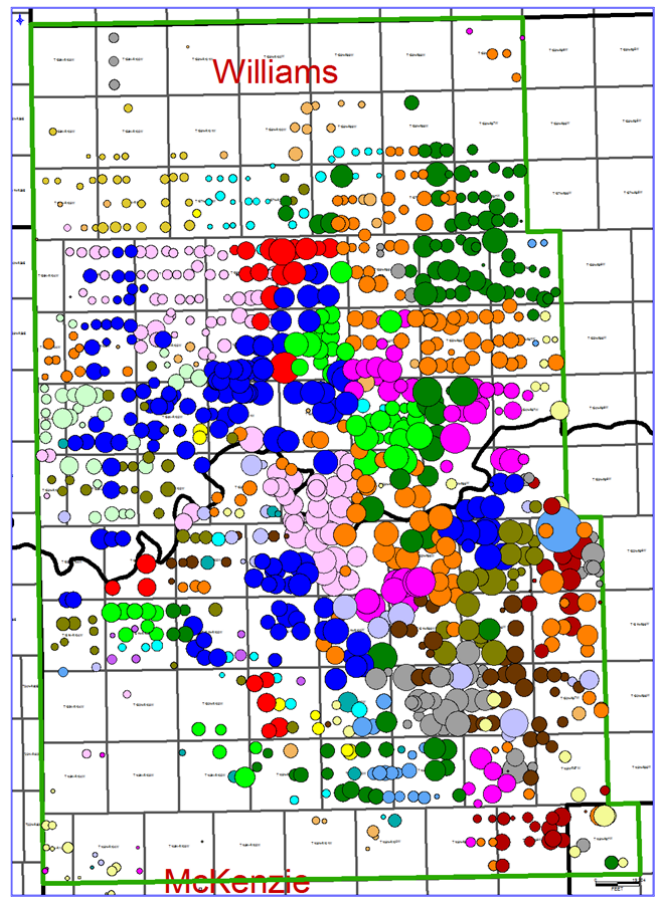


**Figure 7 - Central Basin Cumulative Oil Production.**

Based on the mean 90-day cumulative production the 28 operators in the Central Basin were ranked in Figure 8 with markers for each completion giving a range for the performance. Note there is a 5X difference in mean cumulative production from the highest performing operator to the lowest.



**Figure 8 - Central Basin 90-Day Cumulative Oil Production by Operator.**



**Figure 6 - Central Basin Bubble Map of 90-Day Cumulative Oil Production.**

The 90-day cumulative production versus stimulation parameters “Lateral Stage Length” and “Proppant Volume per Lateral Length” are shown in Figure 9. The trend indicates increased performance with more proppant and shorter stage lengths (more stages); however, the correlation is relatively poor with  $R^2$  values less than 0.1 over the entire Central Basin area.

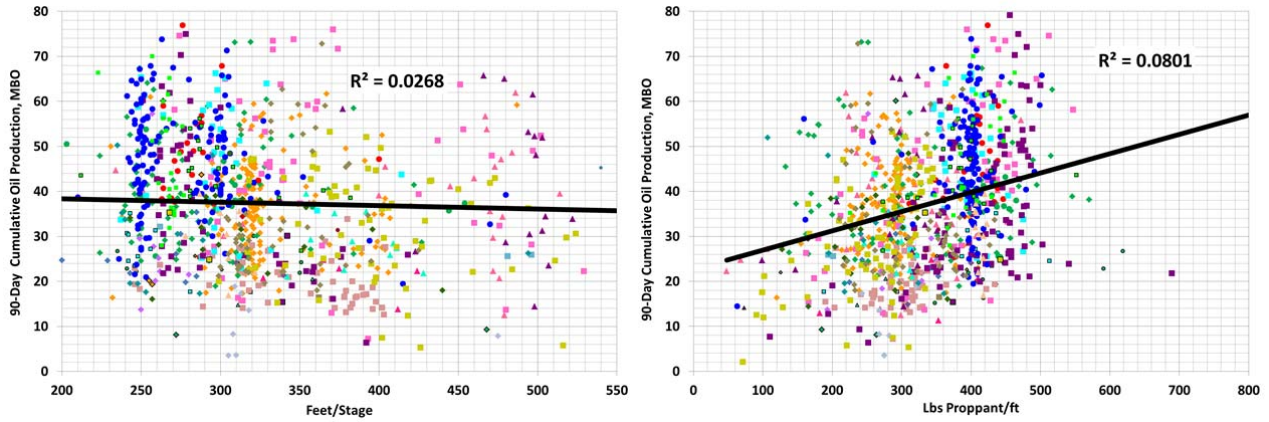


Figure 9 - Central Basin Bi-Variate 90-Day Cum Oil vs. Lateral Stage Length and Proppant Volume Lateral Length.

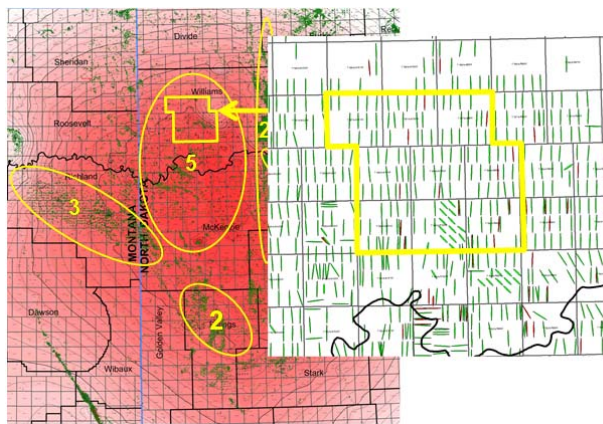


Figure 10 - Study Area 1 with 114 wells in T155-157N, R99-101W.

Improved correlations were generated in a number of studies by limiting the area of investigation. As an example, Study Area 1 (Figure 10) spans 9 townships including 114 wells. As shown in Figure 11 (Bubble Map) and Figure 12 (cumulative production), there is still a wide variation in well performance.

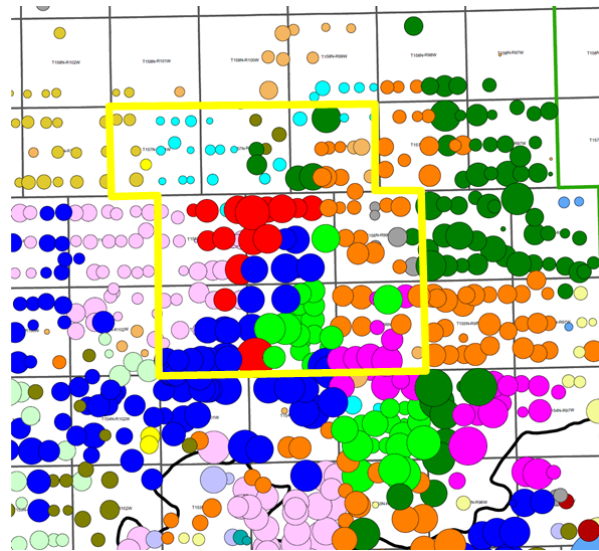


Figure 11 - Study Area 1 Bubble Map 90-Day Cumulative Oil Production.

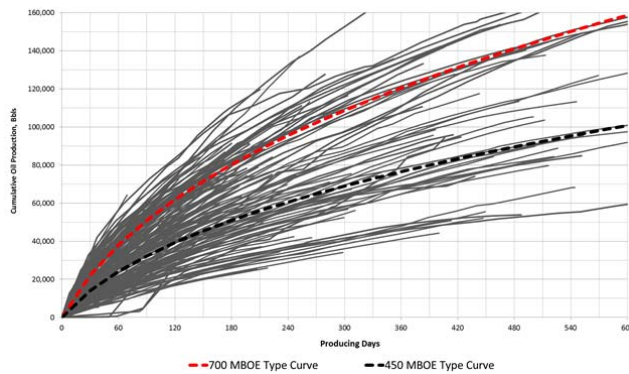


Figure 12 - Study Area 1 Cumulative Oil Production.

An evaluation of stage performance was conducted for this area. Figure 13 breaks down the number of wells that fall within three ranges for the number of stimulation stages. Figure 14 is the average for wells with 18-29, 30-34 and 35-48 stages; there is a 40% increase in production for the 30-34 stage group over the 18-29 stage group, with another 13% increase for going to 35 stages or more. This is a simple analysis that looks only at stage count, without considering other completion and reservoir parameters.

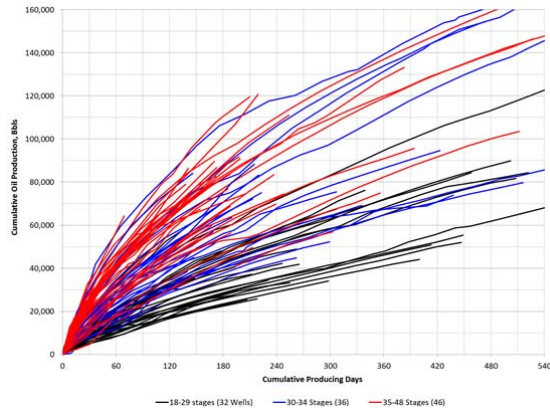


Figure 13 - Study Area 1 Cumulative Oil Production.

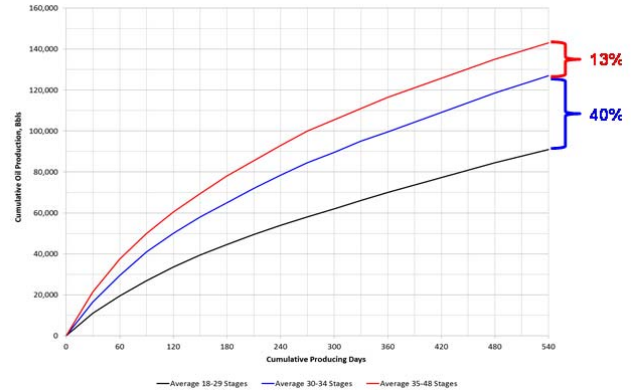


Figure 14 - Study Area 1 Stage Performance.

Scatter plots for the number of stages, color coded by operator, and amounts of proppant pumped (Figure 15) show a clear trend for better performance with more stages and more proppant.

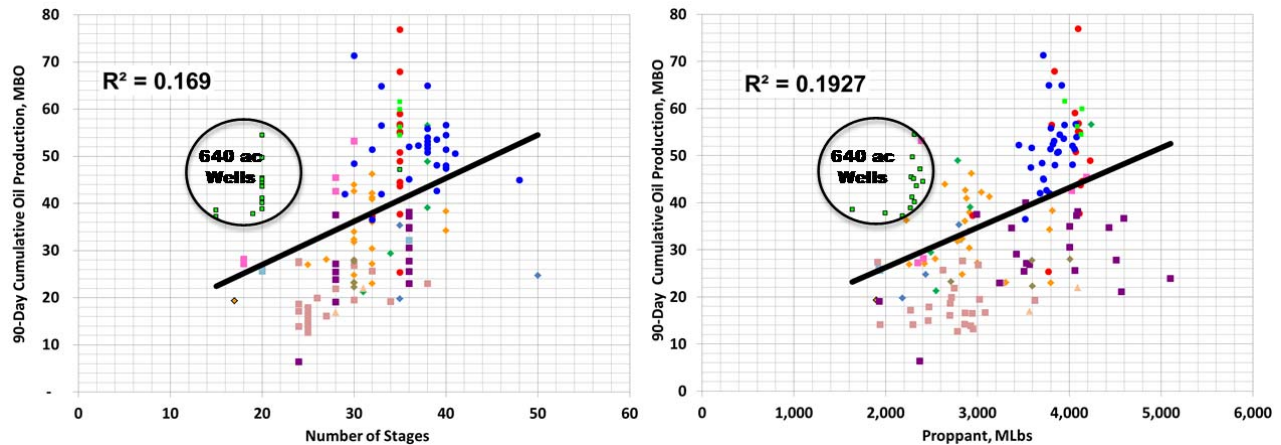


Figure 15 - Study Area 1 90-Day Cum Production versus Stage Count and Proppant Volume.

### Multivariate Analysis

As our database grew both in the number of sample points and input variables it became apparent that more advanced multivariate analysis techniques were needed. This also allowed more easily incorporating geological attributes and eliminating inter-dependencies between completion parameters and their impact on production. These tools provided the ability to quickly evaluate the completion performance versus numerous variables to determine those with the greatest impact on production, and to graphically map these results. One of the most surprising early findings was that cumulative water cut was the best indicator of reservoir quality and its co-linear correlation with a number of geological inputs. Once this was incorporated into the analysis we achieved very high levels of correlation between significant parameters, and there was no longer a need to narrow the analysis to small areas when comparing completion techniques.

For this study, a multi-variate, non-linear regression technique was utilized. Unlike linear regression, where the response variable is assumed to be a linear combination of the predictor variables, in this technique the response variable is the sum of

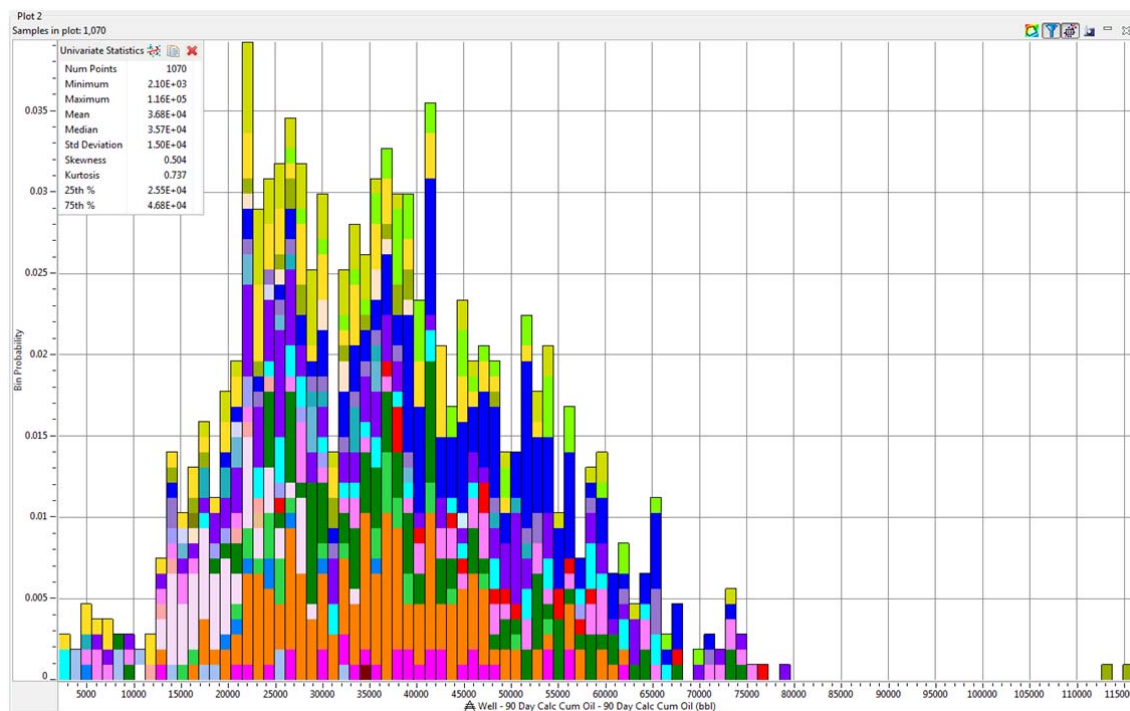
transformations of the predictor variables. The algorithm solves for the optimal transformation of each predictor variable based on the provided data and within the context of the other predictor variables in the model. The user specifies the types of transformations that can be applied to each predictor variable: linear, monotonic, higher order, or periodic. For this study, each variable was limited to linear and monotonic transformations as none of the variables were expected to have higher order or periodic relationships with well performance.

The transformation functions determined for each of the predictor variables are shown in a graphical display and are interpretable by the user. Based on the model's solution, the transformation functions illustrate how each predictor variable relates to well production when isolated from the other predictor variables. For example, the model can determine the relationship between the horizontal length of the well and 90-day cumulative oil production when all other predictor variables are held constant to their average values. If horizontal length is the only parameter that can be changed, the model illustrates how these changes will impact well performance.

The non-linear regression technique was selected instead of other multi-variate techniques, like neural networks, because of the interpretability of the model results, the simplicity of the technique, and the ability of the user to specify prior information into the model. The non-linear regression technique is transparent and the graphical displays of the transformation functions applied to each predictor variable makes it possible to interpret the model results. In contrast, neural networks have "hidden-layers" and even though the model results may have high correlation coefficients, it is not possible to interpret many of the model parameters. For this reason, neural networks are often described as "black boxes". The non-linear regression technique finds simple linear, monotonic, higher order, or period functions. Neural networks are free to find any higher order polynomial functions that best fit the data, but this extreme flexibility results in relationships that are less likely to be real and physical. Finally, the non-linear regression technique allows the user to provide prior information to the model by specifying the type of function that can be applied to each predictor variable. This specification of prior information is not possible with a neural network model.

Figure 16 is a histogram for the 1,070 completions with 90-day production from 28 operators in the Central Basin.

The first step of the analysis focused on the geological attributes. Figure 17 shows the correlation for 90-day cumulative production versus the Middle Bakken depth, Gross Middle Bakken thickness and Water Cut. It was found that thickness had a very low correlation, so this variable was removed from the model. However, both depth and water cut had a high level of correlation. The lower section of the figure is a map for each attribute. Figure 18 shows that water cut and MB depth are very closely related, which can also be seen in the maps of Figure 17. Due to their close relationship, MB depth was removed from the model since water cut had a higher correlation.



**Figure 16 - Central Basin Histogram of 90-Day Cum Oil Colored by Operator.**

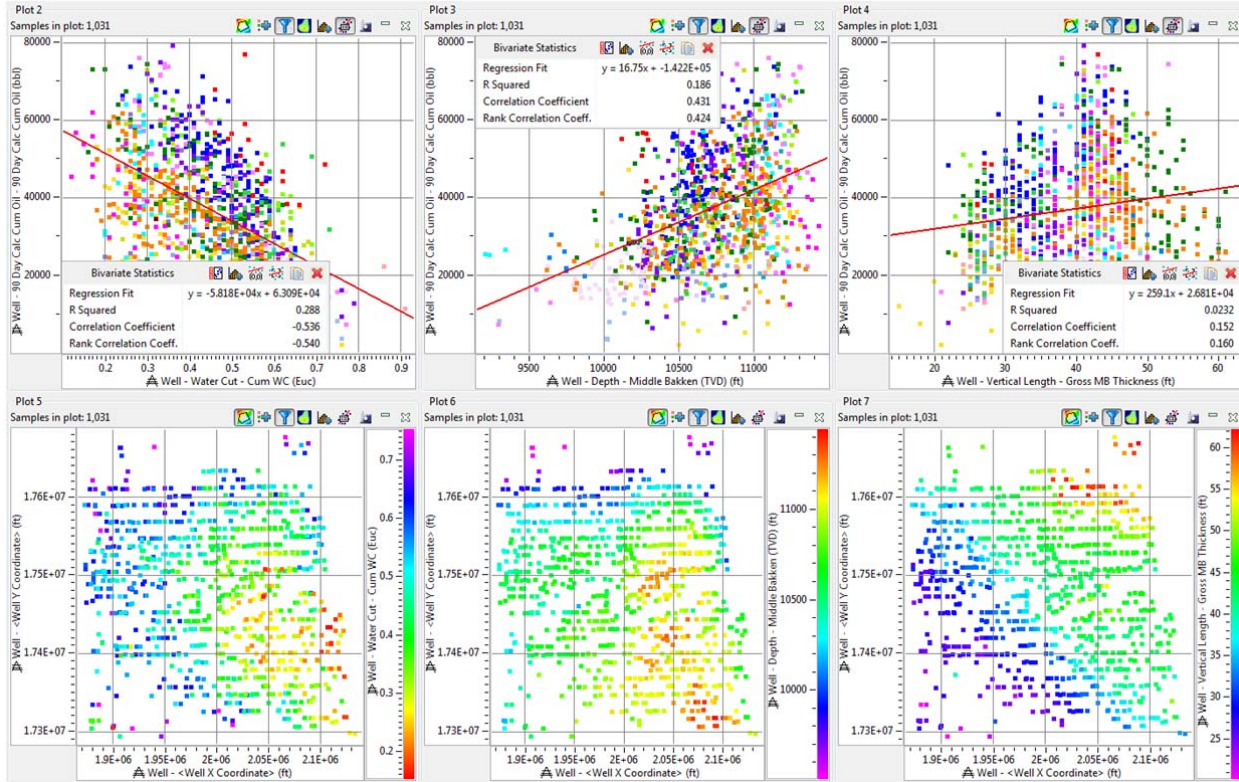


Figure 17 - 90-Day Cum Oil vs. Geologic Attributes.

In the central part of the Williston Basin, water cut from Middle Bakken production is a function of thermal maturity, oil migration, and oil expulsion. In the deepest parts of the Central Basin, the rate of oil expulsion is thought to be greater than oil migration. This results in increased pore pressures in the reservoir closest to the source rock to accommodate the increase in volume from oil expulsion. Formation water is driven up-dip while oil migrates to replace it. The lower Middle Bakken water cut regions of the Central Williston Basin are over-pressured, thermally mature reservoirs that have generated greater amounts of hydrocarbons in place than higher water cut regions. This geologically explains the close relationship that water cut has to true vertical depth and pressure and that not only do the lower water cut areas produce more oil, but they will have higher pressure. The other benefit of using cumulative water cut as a performance predictor is that it is readily available and an accurately measured parameter.

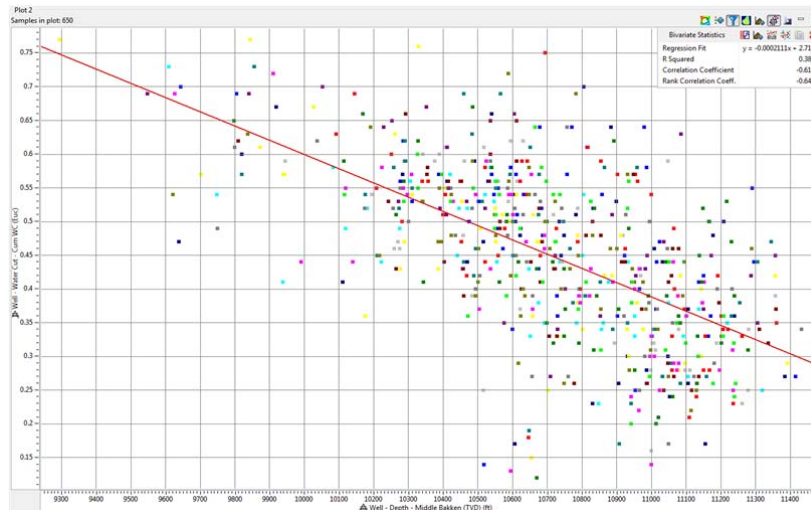


Figure 18 - Middle Bakken TVD vs. Water Cut.



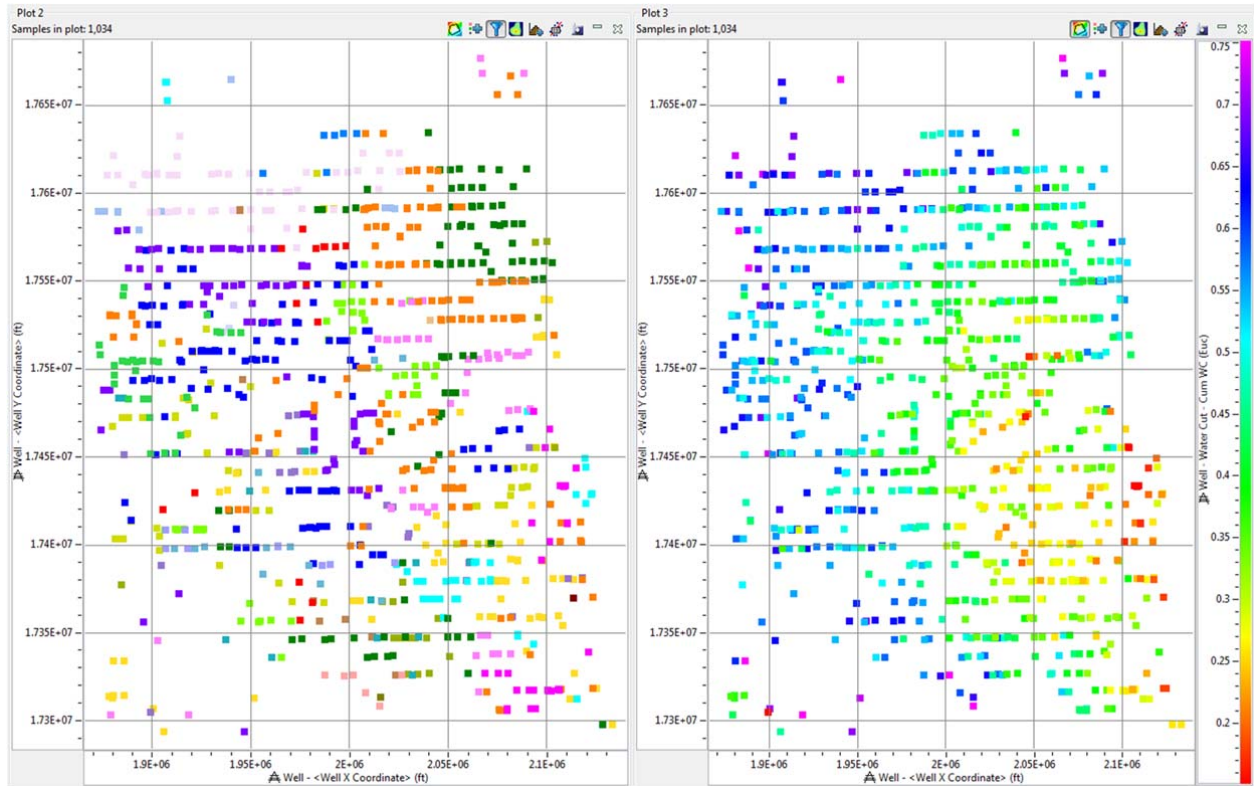


Figure 19 - Central Basin Operators and Water Cut.

Figure 19 is a map showing operator on the left (color coded) and water cut on the right (reservoir quality). The operators with the best performance in the Central Basin are not located in the best reservoir quality areas (Figure 20).

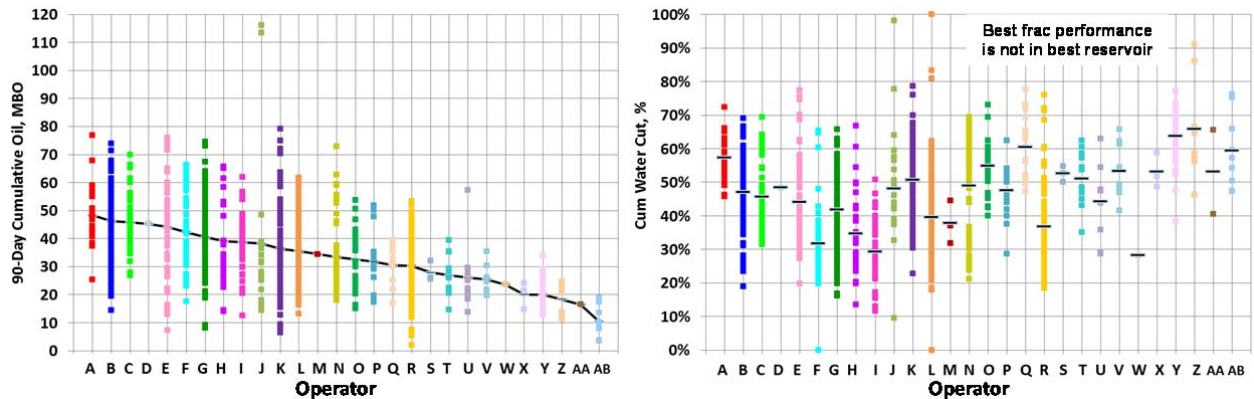


Figure 20 - Operator Ranking by Mean 90-Day Cumulative Oil Production and Cumulative Water Cut.

Wanting to capture the influence of multiple completion parameters along with the reservoir description, various combinations of input parameters were analyzed. As previously indicated, water cut unexpectedly emerged as the strongest contributor for 90-day cum production with an  $R^2$  of 0.25. Since there are a number of 640-acre wells, along with mostly 1,280-acre wells, it was important to include lateral length as well as to decouple as many of the completion parameters as possible. Instead of incorporating number of stages, total proppant and total fluid, the parameters of ft/stage, lbs proppant/ft and bbls/ft were utilized instead. Finally, the type proppant used varies widely by operator from 100% natural sand to 100% ceramic proppant, so percent natural sand became the final parameter.

Data were available for the great majority of the wells, except for the % sand. Deciding to use this parameter reduced the dataset from 1070 wells to 655, but was necessary since previous studies had showed that type of proppant was a significant contributor to both completion cost and production performance.<sup>1</sup> The model indicates an R<sup>2</sup> of 0.14 for 90-day cum production, which is a stronger correlation than any other parameter, excluding water cut.

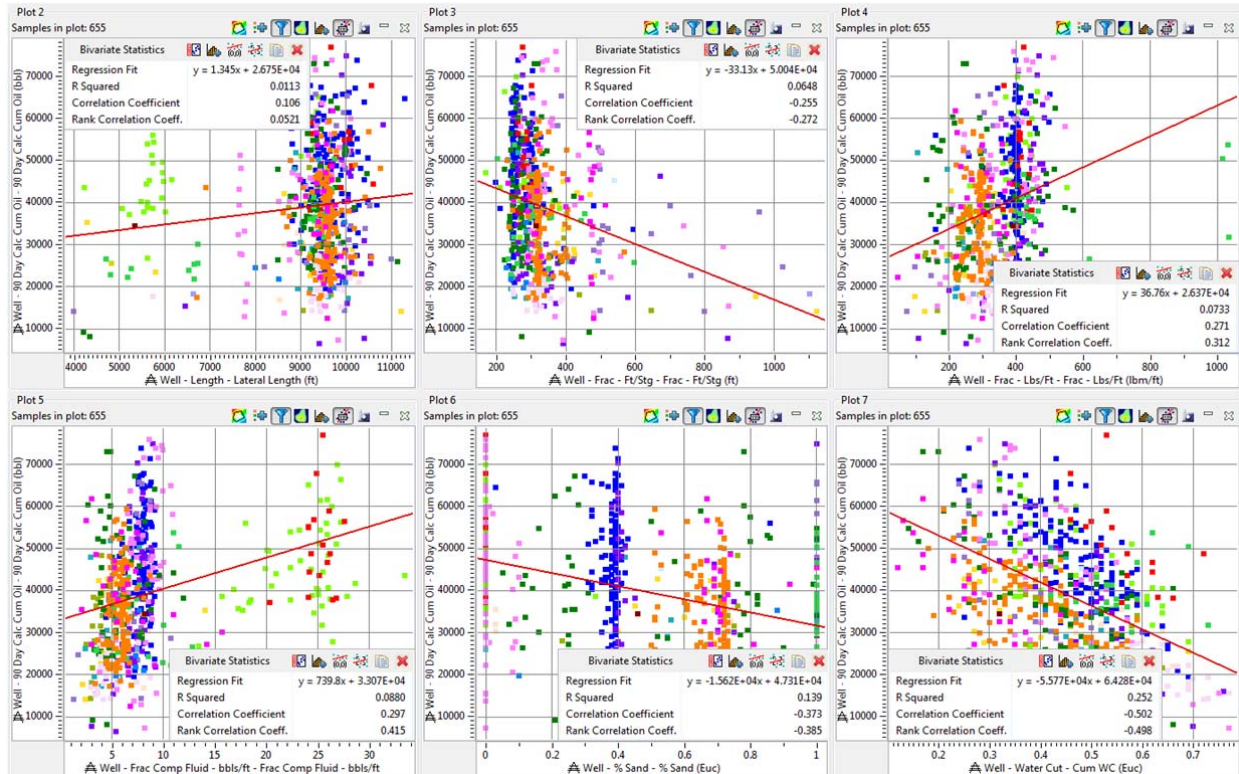


Figure 21 – Central Basin Bi-variate Crossplots of Input Data Colored by Operator.

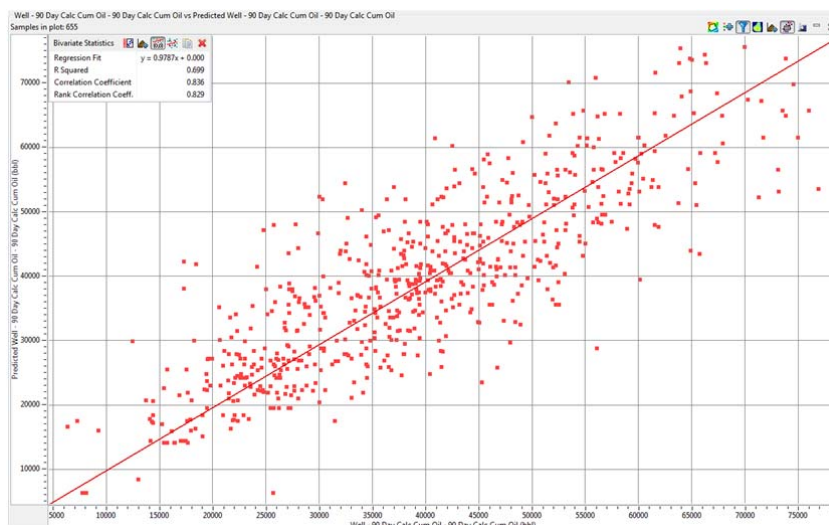
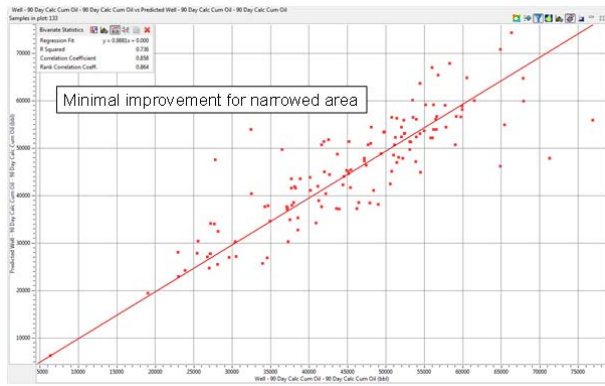


Figure 22 – Central Basin 90-Day Cum Oil Analysis Multivariate Stats Predicted vs. Actual.

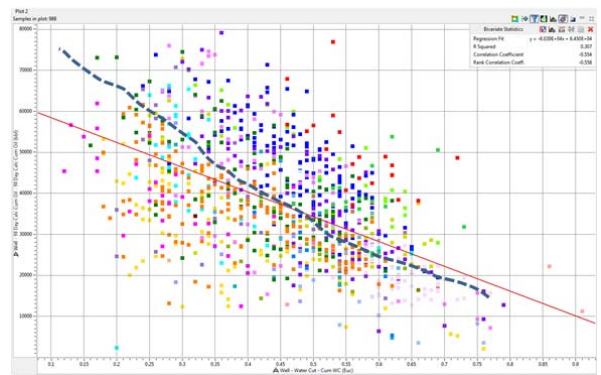
When the multivariate model used the described parameters, the correlation for calculated 90-day cumulative production versus actual cum production was very high with an R<sup>2</sup> of 0.70 (Figure 22).



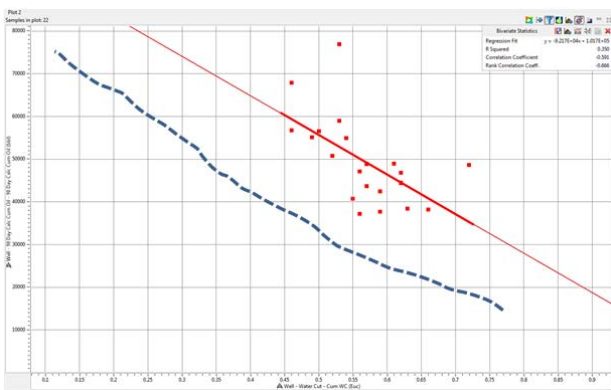
**Figure 23 - Study Area 1 90-Day Cum Oil Analysis Multivariate Stats Predicted vs. Actual.**

To evaluate improvement for narrowing the area, this same analysis was performed for the 9 township Study Area 1 (Figure 23). Greatly reducing the area only improves the correlation to an  $R^2$  of 0.74. Minimal improvements to the model were found by narrowing focus area indicating that the water cut attribute is a valid indicator for reservoir quality.

Figure 24 shows the various operators (color coded) and the “Average Designed Well” (blue dashed line) using average completion parameters. As can be seen, each operator generally groups at similar distances to the average well as the water cut changes.



**Figure 24 - Central Basin Operator 90-Day Production vs. Water Cut.**



**Figure 25 - Operator A 90-Day Production vs. Water Cut.**

Since completion methods vary widely from operator to operator, we looked at the 12 operators with over 40 completions each in the Central Basin. Figure 25 is for Operator A (top 90-day performance). As can be seen this performance is high relative to the average completion over the range of water cuts.

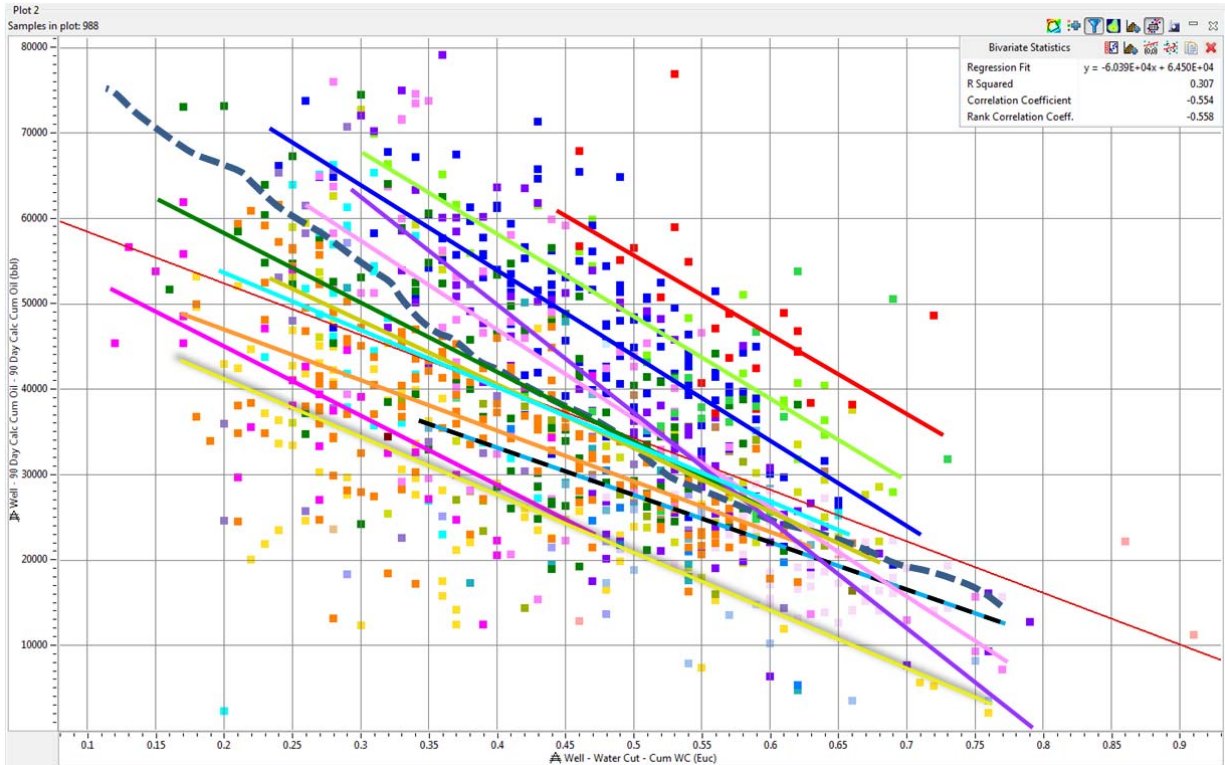


Figure 26 - All Operators 90-Day Production vs. Water Cut.

Figure 26 shows the 12 primary operators in the Central Basin. All the operator lines trend similarly; however, clear and consistent performance differences can be seen between operators. These differences are attributed to completion methodology.

To further refine the analysis the authors focused on 6 operators (or groups of operators) where we had a detailed understanding of the completion designs and the designs have remained relatively unchanged over the time frame for the analysis. This completion information and the estimated total frac cost (frac stimulation, hardware, wireline, water and time) for each type of completion is shown in Figure 27. The total remaining completion, drilling and production costs are \$6-7 million; the total drill and equip cost for Operator A&C's wells is \$10.7 million. As can be seen there is a significant difference in completion methods as well as cost.

Operator	Color Code	Number Wells	Liner	Av. No. Stgs	Comp. Type	Frac Type	Av. lbs/ft	Av. bbls/ft	Av. % Sand	Av. % Ceramic	Est. Total Frac Cost, M\$	Cost Savings Relative to A&C Comp., M\$
A&C	[Red]	45	SP	35	PNP	SW	396	25.1	0%	100%	\$4,205	\$0
B	[Blue]	144	SP	34	PNP	Hybrid	395	7.9	38%	62%	\$3,040	\$1,165
E	[Pink]	56	Cmt	25	PNP	Gel	353	7.8	0%	100%	\$3,020	\$1,185
L	[Yellow]	157	SP	30	PNP	Gel	288	5.7	68%	31%	\$2,335	\$1,870
Y&T	[Black]	68	SP	28	BS	Gel	300	6.1	83%	15%	\$2,280	\$1,925
R	[Green]	76	SP	25	PNP	Gel	264	6.5	100%	0%	\$1,880	\$2,325

Swell Packer	SP
Cemented Liner	Cmt
Plug and Perf	PNP
Ball and Sleeve	BS
Slickwater	SW
XL Gel	Gel
Hybrid Slickwater/Gel	Hybrid

Figure 27 - Select Operator "General" Completion Method and Estimated Cost

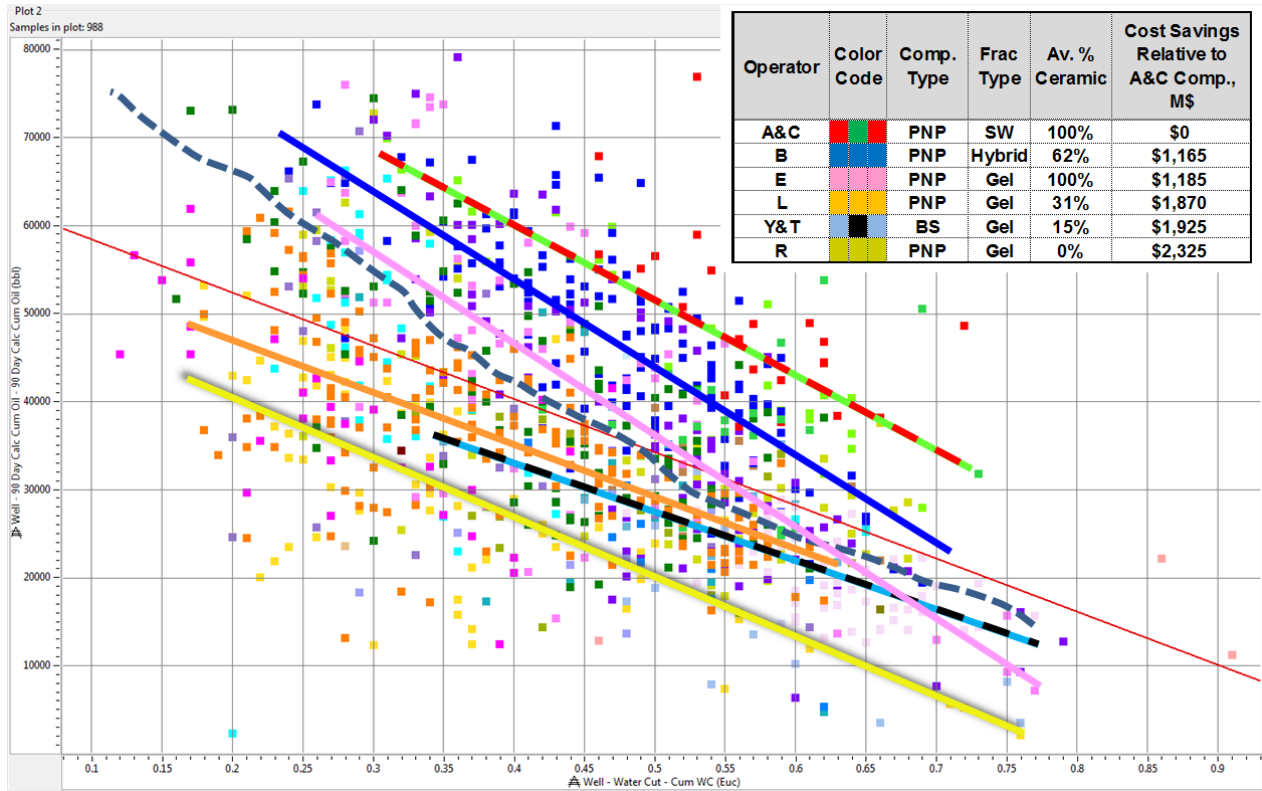


Figure 28 - Central Basin Operator 90-Day Production vs. Water Cut.

Figure 28 shows the performance lines for the 6 completion methods identified. Relative benefits can be clearly seen. The slickwater frac, plug and perf, and 100% ceramic completions outperform other completions across the range of water cuts for the first 90-days of production.

Longer term performance was also evaluated for up to 365-days. Figure 29 shows the performance over time for the 28 operators in the Central Basin. For the most part the early high performance holds over time. This plot also highlights differences in operator flowback strategies.

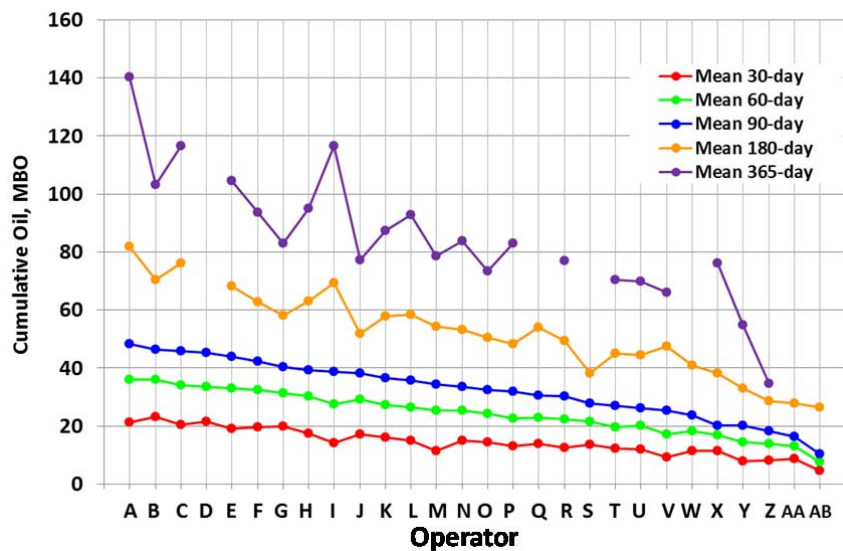
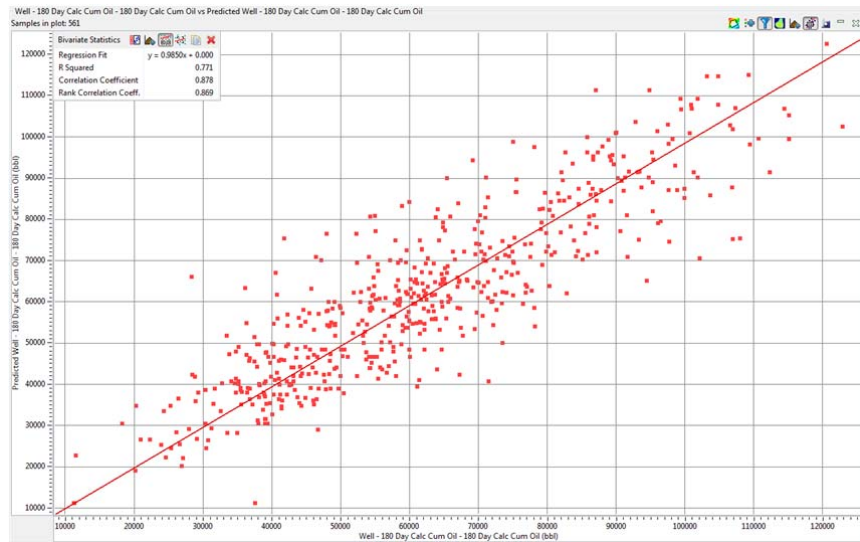


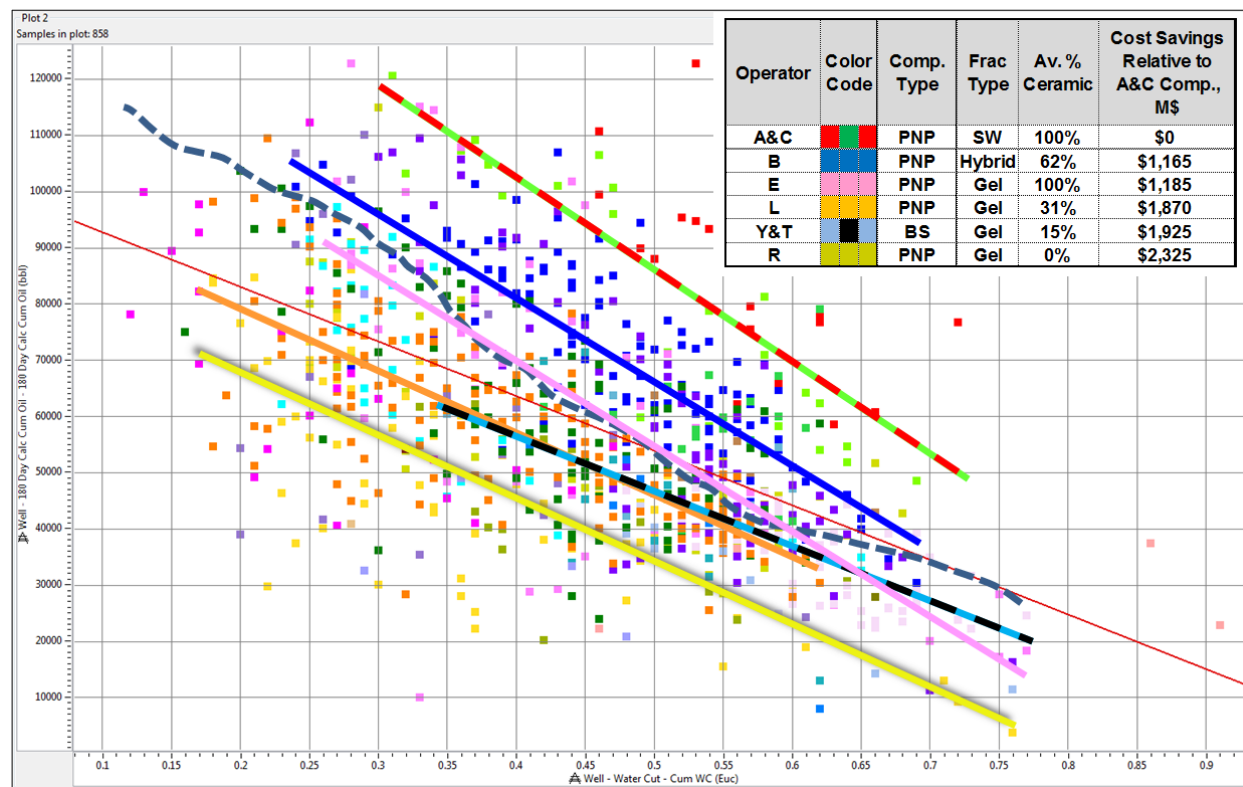
Figure 29 - Operator Performance by Cumulative Oil Production.

The same multivariate analysis was performed for the 561 wells in the database with 180-day production. The correlation between predicted and actual 180-day cumulative oil production improved to an  $R^2$  of 0.77.



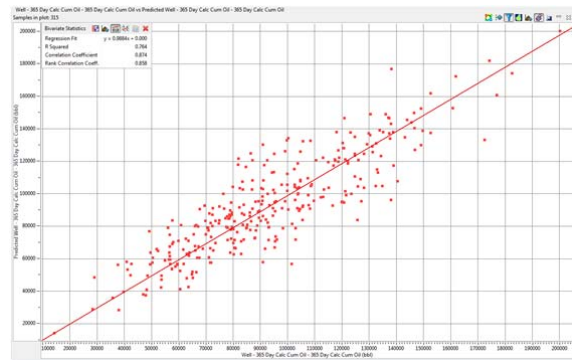
**Figure 30 - Central Basin 180-Day Cum Oil Analysis Multivariate Stats Predicted vs. Actual.**

Figure 31 shows the 180-day performance lines for the 6 completion methods identified. The previous trends seen in the 90-day data continue to hold.

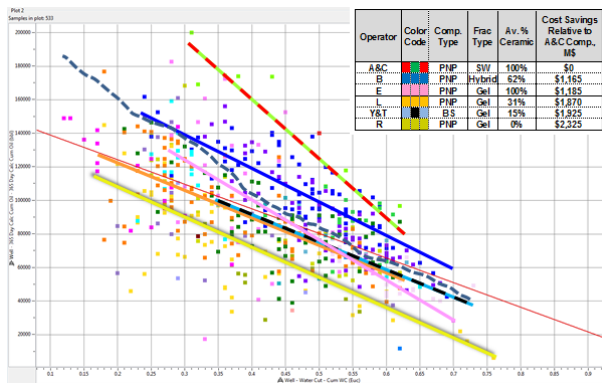


**Figure 31 - Central Basin Operator 180-Day Production vs. Water Cut.**

The analysis was then performed for the 315 wells in the database with 365-days of production. Figure 32 shows the correlation with an  $R^2$  of 0.76 – very similar to the 180-day correlation.



**Figure 32 - Central Basin 365-Day Cum Oil Analysis Multivariate Stats Predicted vs. Actual.**



**Figure 33 - Central Basin Operator 365-Day Production vs. Water Cut.**

The performance by completion method continued to have a similar trend as previously seen, indicating that the relative performance is holding up for at least a year.

**Multivariate Analysis Discussion**

At this point the 180-day data probably best represents the actual long-term performance for the different completion techniques. The 90-day data is heavily influenced by differences in the various operators’ philosophies for bringing the wells on line and also in the flowback. This difference in flowback is seen clearly in Figure 29 where Operators C and I restrict production early in the well life. Operator B performs very aggressive flowbacks.

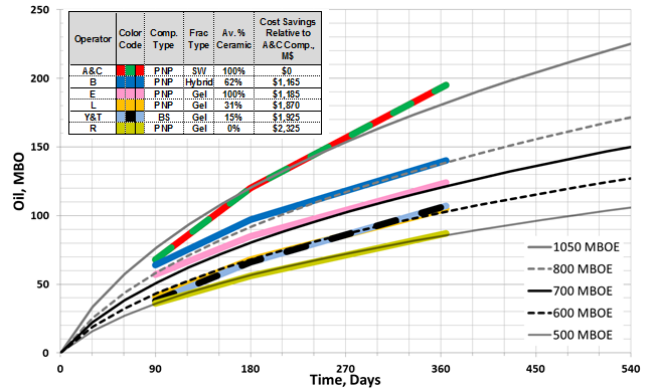
For the 180-day data the following observations can be made:

- 1) The advanced completions of Operators A&C are 100% better than Operator R in the best (low water cut) areas and 4X better for the high water cut areas. Operator R employs a very low cost completion method, no ceramic proppant, and lower volumes of proppant, and low rate, small volume gel fracs.
- 2) Operator B utilizes hybrid slickwater/gel stimulations with ~60% ceramic proppant and underperforms the advanced completions by 20%.
- 3) Operator E’s completion method includes 100% ceramic proppant with gel and underperform by roughly 40% over all the water cut range, indicating a benefit for the larger high rate slickwater volumes of the advanced completion design and negative impact of having a cemented liner.
- 4) Comparing Operators L and Y&T, there appears to be minimal benefit for using the plug and perf technique with low rate gel stimulations.
- 5) Operator R’s total drill and equip cost is about \$9 million versus just under \$11 million for Operators A&C. For the roughly 20% increase in total well cost, Operators A&C’s advanced completions deliver 100% to 400% more oil in the first 180-days. In the poorer reservoir areas (70% WC), production from Operator R’s completions is 12 MBO in the first 180-days versus 53 MBO for Operators A&C, a difference of 41 MBO, worth \$3.7 million. This difference increases to 63 MBO in the better reservoir areas (30% WC) adding \$5.6 million to the first half-year’s revenue.

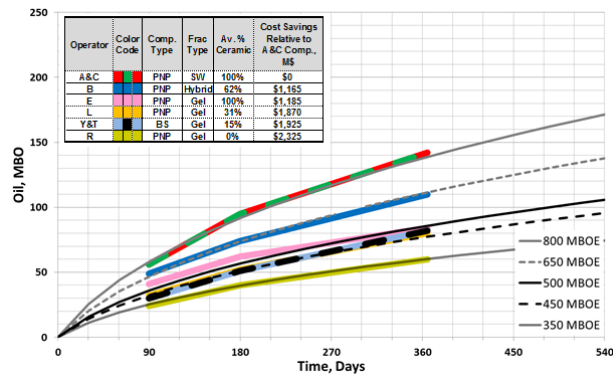
The 365-day dataset is still fairly limited over the full range of water cuts and completion types. The authors believe at this point it is too early to base too many conclusions on this smaller dataset; however, the general trends hold for this longer production period. The advanced completions appear to be performing even better in the higher reservoir quality areas, but possibly the benefits are not as much in the poorer areas. As more production data become available the longer term benefits will become better defined.

**Economics/Benefit Analysis**

Economics were run for the 6 completion methods previously outlined. For the economics, the cost for each completion method was estimated and the drilling costs were assumed to be the same. The incremental completion cost is fully loaded and accounts for differences (frac stimulation, hardware, wireline, water and time) in the various completion methods.



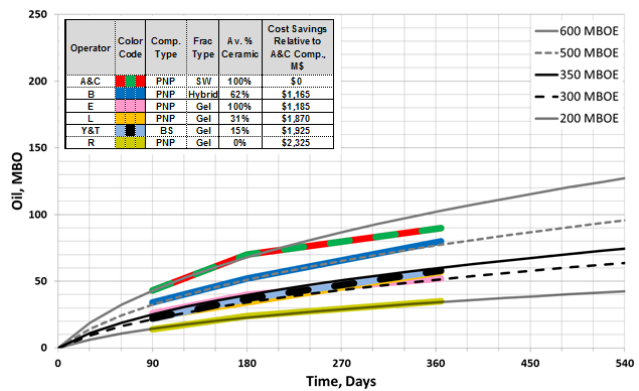
**Figure 34 - Central Basin EUR by Completion Technique 30% Water Cut Areas.**



**Figure 35 - Central Basin EUR by Completion Technique 45% Water Cut Areas.**

Full economics were run using the incremental production streams relative to the higher performing, but higher cost advanced completions. These were performed for the high quality areas (30% water cut), mid-range (45% water cut) and lower reservoir quality (60% water cut) with results summarized in Figure 37.

The authors developed type curves for wells in the Central Basin and continued to refine them as more production data become available. From these type curves, an average initial decline (Di) and b factor was determined. To determine the exponential decline (De) (terminal decline), a full-field study of Elm Coulee was conducted since these wells have extended production histories. Each type curve is shown in Figure 34, Figure 35 and Figure 36 and has consistent Di, b and De factors, with only the initial rates being varied. As can be seen, the modeled 90, 180 and 365 data match the type curves very well. These type curves for 30%, 45% and 60% water cuts provided the production stream input for the economics model.



**Figure 36 - Central Basin EUR by Completion Techniques 60% Water Cut Areas.**



Operator	Color Code	Number Wells	Liner	Av. No. Stgs	Comp. Type	Frac Type	Av. lbs/ft	Av. bbls/ft	Av. % Sand	Av. % Ceramic	Est. Total Frac Cost, M\$	Cost Savings Relative to A&C Comp., M\$
A&C		45	SP	35	PNP	SW	396	25.1	0%	100%	\$4,205	\$0
B		144	SP	34	PNP	Hybrid	395	7.9	38%	62%	\$3,040	\$1,165
E		56	Cmt	25	PNP	Gel	353	7.8	0%	100%	\$3,020	\$1,185
L		157	SP	30	PNP	Gel	288	5.7	68%	31%	\$2,335	\$1,870
Y&T		68	SP	28	BS	Gel	300	6.1	83%	15%	\$2,280	\$1,925
R		76	SP	25	PNP	Gel	264	6.5	100%	0%	\$1,880	\$2,325

		30% WC								
		Production					Economics			
Operator	90 day Cum, MBO	180 day Cum, MBO	365 day Cum, MBO	EUR, MBOE	MBO Loss versus A&C Comp @ 365 days	EUR Loss vs A&C Comp, MBOE	PV 10 Loss vs A&C Comp., M\$	Months to Payout added cost for A&C Comp.	Cost for added BOE, \$/BOE	
A&C	68	120	195	1050	0	0	-	-	-	
B	64	97	140	800	55	250	\$5,979	2	\$ 4.66	
E	57	85	124	700	71	350	\$8,813	1	\$ 3.39	
L	41	68	105	600	90	450	\$10,988	2	\$ 4.16	
Y&T	38	66	107	600	88	450	\$10,933	2	\$ 4.28	
R	36	56	87	500	108	550	\$13,390	2	\$ 4.23	

		45% WC								
		Production					Economics			
Operator	90 day Cum, MBO	180 day Cum, MBO	365 day Cum, MBO	EUR, MBOE	Loss versus A&C Comp @ 365 MBO	EUR Loss vs A&C Comp, MBOE	PV 10 Loss vs A&C Comp., M\$	Months to Payout added cost for A&C Comp.	Cost for added BOE, \$/BOE	
A&C	56	95	142	800	0	0	-	-	-	
B	49	74	110	650	32	150	\$2,864	7	\$ 7.77	
E	41	62	84	500	58	300	\$6,865	2	\$ 3.95	
L	32	52	80	450	62	350	\$7,525	3	\$ 5.34	
Y&T	30	51	82	450	60	350	\$7,471	3	\$ 5.50	
R	24	40	60	350	82	450	\$9,754	3	\$ 5.17	

		60% WC								
		Production					Economics			
Operator	90 day Cum, MBO	180 day Cum, MBO	365 day Cum, MBO	EUR, MBOE	Loss versus A&C Comp @ 365 MBO	EUR Loss vs A&C Comp, MBOE	PV 10 Loss vs A&C Comp., M\$	Months to Payout added cost for A&C Comp.	Cost for added BOE, \$/BOE	
A&C	43	70	90	600	0	0	-	-	-	
B	34	52	80	500	10	100	\$1,220	19	\$11.65	
E	26	40	52	300	38	300	\$5,951	2	\$ 3.95	
L	23	34	57	350	33	250	\$4,084	8	\$ 7.48	
Y&T	22	37	58	350	32	250	\$4,030	8	\$ 7.70	
R	14	24	35	200	55	400	\$7,196	5	\$ 5.81	

**Assumptions:**  
 NRI = 80%  
 Oil Price = \$90/BO  
 BFIT Economics  
 Payout Based on Incremental Cash Flow

Swell Packer	SP
Cemented Liner	Cmt
Plug and Perf	PNP
Ball and Sleeve	BS
Slickwater	SW
XL Gel	Gel
Hybrid Slickwater/Gel	Hybrid

Figure 37 - Central Basin Economic Analysis by Completion Type and Water Cut.

Based on this analysis, the advanced completions give exceptional value, paying out in many cases in just a few months and except for the one comparison to hybrid partial sand fracs at high water cuts, the payout is significantly less than a year.

## Conclusions

- 1) Benchmarking resource play performance is complicated. Over relatively small areas production performance can vary dramatically making simple evaluations difficult.
- 2) Reservoir quality matters. Benchmarking without taking this into account can be very subjective and weighed heavily to preconceived ideas.
- 3) Completions matter. Higher cost advanced completion techniques can be very economically attractive when properly applied.
- 4) Multivariate analysis tools are very helpful for objectively looking at large datasets, once a sufficiently large dataset is obtained. Being able to incorporate larger areas and more data removes much of the subjectivity sometimes placed in comparative analysis.
- 5) The value for developing completion databases and benchmarking well performance cannot be overstated. Determining and applying the right completion techniques to the right reservoir can more than double the value of an asset and is one of the primary drivers for making an asset economical.
- 6) Advanced completion designs creating large reservoir contact areas (fractures and fracture networks) and effectively connecting the contacted area back to the wellbore (conductivity) is highly profitable across the Central Basin. In the poorer reservoir quality areas, the advanced completions were the difference for the area being economically developed.
- 7) Spending an additional \$1-2 million per well for advanced completions may seem high; however, this is only 10-20% of the total well cost. For most of the cases looked at, the benefits for the advanced completions add multiple millions of dollar in the first year and the additional costs are paid out in just a few months.
- 8) The use of water cut as the primary indicator of reservoir quality was a significant finding of this study. Once the relationship was found, it correlated well to the geological resource model used for the Bakken in the Williston Central Basin. Cumulative water cut is readily available for all wells and easily incorporated into the model.

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