Hydraulic Fracturing in the Permian Basin and the Case for Northern White Sand

Paper Introduction and Executive Summary

Overview: While Permian Basin operators have chosen in-basin sand (IBS) over the last five years, a series of research studies demonstrate that Northern White Sand (NWS), while more expensive upfront, performs better throughout the life of the well, and is almost always the better economic choice. This whitepaper analyses three studies from Rystad Energy and provides an engineering simulation showing how sand attributes and specifications drive superior performance. This whitepaper details the importance of higher sustained conductivity and provides economic analyses of proppant choice. The authors suggest that IBS sand choices result in suboptimal cashflow and moderate long-term profitability.

Brief History and Today's Challenge:

Fracture stimulation in the Permian basin has been practiced for over 50 years and the application and selection of proppants has been well documented. Research in the 1980's led to the development of enhanced strength proppant materials that could be applied at closure ranges from 7000 psi to 10,000 psi, a range where sands are now applied without consideration of conductivity impact. The evolution from polymer laden fluids to slick water was originally undertaken to reduce costs however it was recognized that the conductivity damage associated with polymer residue in the induced hydraulic fracture can reduce conductivity and subsequent productivity. It is recognized in the industry that Northern White sand (NWS) is a superior product to IBS creating improved fracture conductivity and BOE production and associated reserves in the Delaware and Midland basins.

For several decades thousands of wells have been hydraulically fractured in the Permian Basin using a multitude of proppants that have evolved over time for specific application. Over the last 40 years, proppant quality standards, originally from the American Petroleum Institute (API) and later the International Standards Organization (ISO), have been developed to ensure fracturing proppant quality to create adequate and sustainable conductivity in an induced hydraulic fracture. These standards have been developed and followed until the recent horizontal shale boom.

However, since 2018, there has been a near complete switch to IBS in completing oil and gas wells in the Permian Basin without regard for historical proppant selection criteria and the conductivity effects of switching sand types. This switch to IBS has primarily been based on the premise that overall well and field economics are improved due to: i) lower capital costs required for completing the well by sourcing sand needs locally thereby reducing the logistics costs of delivering the sand to the wellsite, and ii) well results using IBS were "good enough" in terms of well production in the first couple years of production to justify the reduced capital requirements upfront to complete the well. The driver of this change was based on the short-term benefits of reduced capital expenditures in the current year while still being in the range of current year production goals with little regard to the long-term impact on field development, overall production, and cumulative free cash flow goals over a five-to-ten-year horizon.

A series of studies completed by Rystad Energy, however, provides clear evidence that the perceived benefits of using IBS to complete wells in the Permian is not accurate and demonstrates the adverse long-term effects of using IBS to complete wells relative to using NWS in both the Midland and Delaware basins. Rystad, a respected energy research firm, evaluated 850 wells in both the Midland and Delaware basins using their global proprietary database. The authors have subsequently performed extensive fracture stimulation modeling to identify the conductivity difference of IBS to that of NWS and provide reasoning behind the Rystad results. These conductivity differences ultimately allow a comparison of economics for each sand type, clearly showing a long-term economic benefit using NWS.

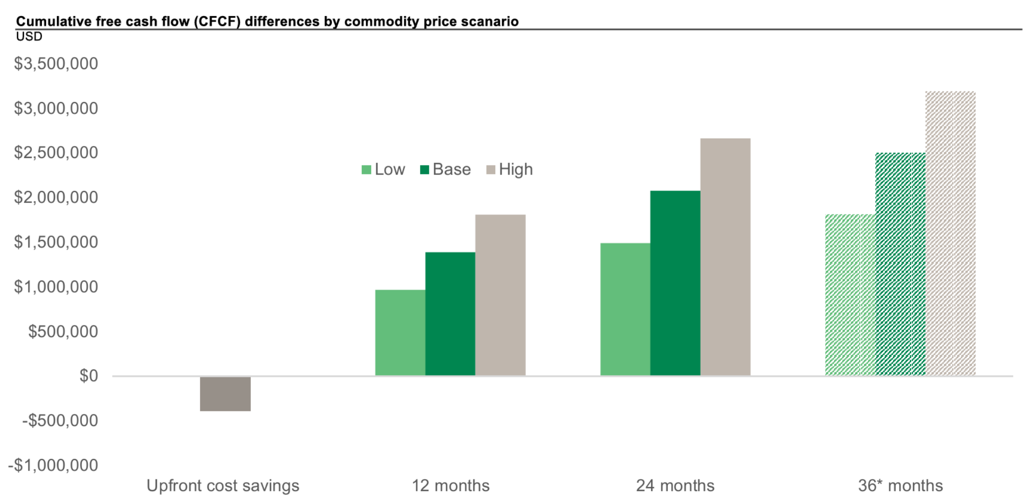
We have taken the Rystad data and done further analysis to demonstrate the conceptual incremental production and economic value that can be created by using NWS in well development over a five to ten-year period compared to using IBS. Our analysis and results are included in the white paper, and some are summarized below. The economic value of NWS over IBS is very compelling.

Our white paper examines the history and development of the proppant selection processes, the effects of fracture conductivity, and reviews recent publications and testing that support the use of NWS for both Midland and Delaware basin applications.

Key findings from the Rystad study and our work are:

- Rystad isolates the effects of In-Basin sands versus that of Northern White Sands and shows a clear relationship between the application of In-basin sands and reduced productivity among a sample of seven different operators who migrated from NWS. The study refutes the ready counter that the lower cost of IBS still makes a better business case, Rystad further modelled three different oil and gas pricing scenarios, showing that NWS generated significant positive cumulative free cash within 12 months of starting well production. The chart below shows this with the example of one Midland operator.

Midland Operator C: Upfront cost savings from in-basin sand wiped out in all cases after one year



- Operator saved ~$389,000 when switching to in-basin sand from NWS.
- Operator lost ~$966,000, $1.4 million and $1.8 million under low, base and high cases, respectively, by the end of year 1 with in-basin sand.
- Operator lost ~$1.5 million, ~$2.1 million and ~$2.7 million under low, base and high cases, respectively, by year 2 in using in-basin sand.

- Our modelling shows that in the Delaware basin, NWS resulted in, on average, 4.5x greater conductivity, compared to IBS. In the Midland basin, NWS had on average 3.4 x improved fracture conductivity over IBS.

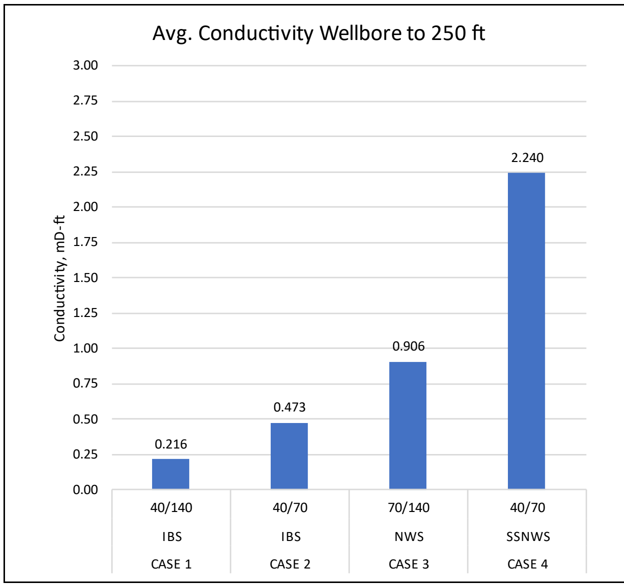


Fig. 1.3 – Average fracture conductivity comparing IBS and NWS in 100 and 40/70 mesh in the Delaware basin.

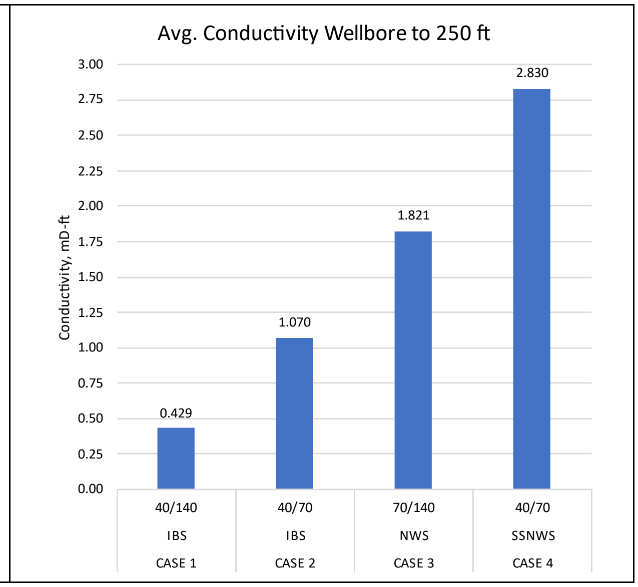


Fig. 1.4 – Average fracture conductivity comparing IBS and NWS in 100 and 40/70 mesh in the Midland basin.

- The production deliverability from NWS material becomes greater over the life of the well.

Table 1 - Cumulative BOE production comparison of IBS and NWS in time and percent uplift of NWS over IBS in the Delaware basin.

	P50 | Cumulative BOE Production					
	40/140 Mesh			40/70 Mesh		
	IBS	NWS	Uplift	IBS	NWS	Uplift
	(Mboe)	(Mboe)	(%)	(Mboe)	(Mboe)	(%)
1-Year	324	337	4.2	396	414	4.5
5-Year	887	964	8.7	1,004	1,063	5.9
	P90 | Cumulative BOE Production					
	40/140 Mesh			40/70 Mesh		
	IBS	NWS	Uplift	IBS	NWS	Uplift
	(Mboe)	(Mboe)	(%)	(Mboe)	(Mboe)	(%)
1-Year	494	520	5.3	613	661	7.8
5-Year	1,341	1,452	8.2	1,525	1,644	7.8

Table 2 - Cumulative BOE production comparison of IBS and NWS in time and percent uplift of NWS over IBS in the Midland basin.

	P50 | Cumulative BOE Production					
	40/140 Mesh			40/70 Mesh		
	IBS (Mboe)	NWS (Mboe)	Uplift (%)	IBS (Mboe)	NWS (Mboe)	Uplift (%)
1-Year	200	209	4.5	239	258	7.9
5-Year	554	584	5.4	621	659	6.1
	P90 | Cumulative BOE Production					
	40/140 Mesh			40/70 Mesh		
	IBS (Mboe)	NWS (Mboe)	Uplift (%)	IBS (Mboe)	NWS (Mboe)	Uplift (%)
1-Year	310	327	5.5	382	408	6.8
5-Year	889	957	7.6	1,013	1,076	6.2

- At 5-yr in the Delaware basin, NWS 100 mesh on average creates 9% more value over IBS 100 mesh for both the P50 and P90 production cases. The NWS 40/70 material on average adds 6% value over IBS 40/70 for the P50 production case and 8% for the P90 well.
- At 5-yr in the Midland basin, the NWS 40/70 material on average adds 6% value over IBS 40/70 for both the P50 and P90 production cases. The NWS 100 mesh on average creates 5% more value over IBS 100 mesh for the P50 case and 8% for the P90 production case.

Table 3 – 5-yr cumulative BOE percent production improvement and net present value added by created with NWS proppant over IBS material.

	Delaware Basin P50 Production Case				Delaware Basin P90 Production Case			
	100 Mesh		40/70		100 Mesh		40/70	
Oil Price	Delta, Δ (%)	Δ NPV ($MM)	Delta, Δ (%)	Δ NPV ($MM)	Delta, Δ (%)	Δ NPV ($MM)	Delta, Δ (%)	Δ NPV ($MM)
$50	9.5	2.908	6.2	2.209	8.7	4.330	8.3	4.730
$75	9.3	4.541	6.2	3.471	8.6	6.675	8.2	7.253
$100	9.2	6.175	6.2	4.733	8.6	9.020	8.1	9.770
	Midland Basin P50 Production Case				Midland Basin P90 Production Case			
	100 Mesh		40/70		100 Mesh		40/70	
Oil Price	Delta, Δ (%)	Δ NPV ($MM)	Delta, Δ (%)	Δ NPV ($MM)	Delta, Δ (%)	Δ NPV ($MM)	Delta, Δ (%)	Δ NPV ($MM)
$50	4.8	0.809	6.4	1.255	8.0	2.457	6.4	2.310
$75	5.1	1.438	6.4	2.075	8.0	3.911	6.4	3.657
$100	5.2	2.067	6.4	2.895	7.9	5.364	6.4	5.005

- The payout term of the additional proppant expenses decreases with higher oil prices and better producing wells.

Table 4 – Payout time, in years, to recover the additional cost of using NWS in the Delaware and Midland basins.

	Delaware Basin P50 Production Case		Delaware Basin P90 Production Case		Midland Basin P50 Production Case		Midland Basin P90 Production Case	
	100 Mesh	40/70	100 Mesh	40/70	100 Mesh	40/70	100 Mesh	40/70
Oil Price	Payout (months)	Payout (months)	Payout (months)	Payout (months)	Payout (months)	Payout (months)	Payout (months)	Payout (months)
$50	14.2	9.8	8.0	4.2	36.6	11.8	16.6	8.3
$75	10.3	6.7	5.3	2.9	19.4	7.4	10.2	5.5
$100	7.7	5.0	4.2	1.9	14.5	5.8	7.4	4.2

We understand that many factors contribute to the overall performance of a completed well in the Permian Basin. However, through the work done by Rystad in combination with the analysis provided in this white paper, we demonstrate significant incremental value for an Oil and Gas Producer in using NWS in its completion program in both the Midland and Delaware Basins. For a producer, using NWS, instead of IBS, to develop a field over the next five to ten years, with a goal to maintain or grow production, less capital should be required over the development period as fewer wells will need to be drilled to meet the targeted production goals, which should result in higher free cash flow and greater value that can be returned to the producer's shareholders.

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April 2023

Abstract

The Permian Basin has a long history of using hydraulic fracture stimulation to enhance oil recovery and long term well performance. Over the last several decades thousands of wells have been hydraulically fractured in the Permian Basin using a multitude of proppants that have evolved over time for specific application. Over the last 50 years, proppant quality standards, originally from the American Petroleum Institute (API) and later the International Standards Organization (ISO), have been developed to ensure fracturing proppant quality to create adequate and sustainable conductivity in an induced hydraulic fracture. These standards have been developed and followed until the recent horizontal "shale" boom. Due to the great demand for proppants with the ever-increasing length of horizontal laterals and fracture stimulation volumes, In-Basin sand mines became operational in 2018. While these mines produce sand with Permian applications, they do not cover all applicable ranges for hydraulic fracturing across the Basin and are known to create less sustainable conductivity at closure ranges of 6000 psi and greater.

Since 2018, there has been a near complete switch to In-Basin sands without regard for historical proppant selection criteria and the conductivity effects of switching sand types. This paper will examine the history and development of these selection processes, the effects of fracture conductivity, and review recent publications and testing that support the use of Northern White Sand (NWS) for both Midland and Delaware basin applications. Further, a study completed by Rystad Energy, a respected energy research firm is summarized outlining the adverse long-term effects of In-Basin sand relative to NWS over some 850 wells in both the Midland and Delaware basins. Finally, extensive fracture stimulation modeling was performed to identify the conductivity difference of In-Basin sands to that of NWS. These conductivity differences ultimately allow a comparison of economics for each sand type, clearly showing a long-term economic benefit using Northern White Sand.

Introduction and Background

Since the first hydraulic fracture treatment was performed, fracturing has become recognized as a key process in the enhancement of petroleum recovery. The first hydraulic fracture treatment utilized river-bed sand and water and the properties of both were initially of no apparent concern. However, over the last 50 years the industry has directed resources toward a greater understanding of the mechanics of the fracturing process. Substantial evolution has taken place in the area of fracturing equipment and products with a focus placed on the ability to carry proppant deep into the formation. In its infancy hydraulic fracturing was thought to increase the drainage area of the subject well without regard for the conductivity of the newly induced hydraulic fracture. The assumption was that any conductivity created in the induced fracture and propped open with sand would be more conductive than the relative permeability of the producing formation. This thought process remained in place for many years as the enhancement and subsequent research related to the fracturing process was focused on the improvement of fracturing fluids and the generation of increased viscosity for greater proppant transport. Fracture fluid research led to the employment of crosslinked fluids, some of which incorporated high temperature tolerant polymers that created enhanced viscosity stability and subsequent damage mechanisms within the proppant pack. This damaging polymer residue was later recognized, leading to the evolution of breaker systems for improved conductivity that eventually lead to low polymer systems and finally to slick water systems coming full circle as the shale age began. In the 1990's experiments with "water fracs" proved that in certain formations proppant concentrations could be dramatically reduced in combination with increased fluid volume and higher injection rates, thus reducing the effects of polymer damage. In addition to the reduction of damage, another by-product of slick water treatments was a substantial decrease in treatment cost. It was observed over time that gelled or crosslinked conventional treatments did not clean up well and that the conductivity created through low concentrations of proppant with greater water volume ultimately produced greater conductivity than induced fractures containing gel damage [(3)(8)].

The development of the Barnett Shale in the 1990's led to the widespread use of economic slick water systems and once they could be economically applied the search began for the next big shale play. However, it must be understood that not all shales behave similarly and possess the same rock properties. The silica-rich Barnett proved to be conducive to slick water hydraulic fracturing due to its brittle nature, mechanical rock properties and mineral composition. This inherent brittleness when fractured hydraulically can create complex fractures with a substantial network of fissure openings. This network of fractures provides an extreme amount of surface area that is not always duplicated by formations that are not really "shale" as classically defined by geologist and may be best described as source rock formations not exhibiting the same ability to create complex fractures thus increasing the need for adequate propped fracture conductivity [(4)].

Slick water systems have not only addressed issues associated with polymer damage, but greatly favor the economics of fracturing and in turn have allowed larger treatment volumes to be employed, further increasing the stimulated reservoir volume of horizontal wellbores. Given that slickwater fracturing has proven to be a cost effective and a viable stimulation technique for low permeability reservoirs, efforts were undertaken to identify potential methods to resolve the associated proppant transport issues encountered when employing slickwater fluids [(5)]. Such efforts eventually lead to the use of smaller mesh proppants to aid with proppant transport. However, the reduced proppant mesh size approach comes with a tradeoff, as the reduced proppant size for transportability is offset by the need to maximize proppant size for optimal well stimulation and optimal stimulation has proven to be directly related to the conductivity of the created proppant pack and its ability to maintain that conductivity over time.

Practices for the Selection of Fracturing Proppants

The American Petroleum Institute published "Recommended Practices for Testing Sand used in Hydraulic Fracturing Operations- First Edition" as API RP 56 in March 1983 and updated December 1995. These recommended practices outline testing to ensure sands maintain the minimum requirements to ensure basic characteristics such as sphericity, roundness, acid solubility, low turbidity, bulk and absolute densities and sand crush resistance, all basic components of performance intended to generate long term conductivity in an induced hydraulic fracture. By 1958 the increase in fracture treatments across the industry had increased to the point that demand warranted additional sources. During this period "brown" sands mined near Brady, Texas were introduced to the domestic market and were routinely applied to reservoir intervals of lower closure stress (< 4000 psi). In the mid 1970's Exxon Production implemented the first high strength proppants that were developed exclusively for deep gas reservoirs. These high strength proppants contained an alumina-silicate clay or ceramic Bauxite (80% Al_2O_3) that was first introduced in 1982. Following the advent of Bauxite, a second introduction of what would be referred to as an intermediate strength proppant (ISP) containing lesser percentages of alumina ore (70% Al_3O_2) was introduced to the industry. Finally, in 1985 the development of the first light weight ceramic was introduced with an alumina ore content around 50%. These ceramic proppants could be applied to reservoir closures ranging from 7000 psi to greater than 10,000 psi and while they proved to be fit for high strength application, they also proved to be costly relative to conventional sand products. The need to apply proppants at higher closure and still maintain the economics of silica-based products lead to the development of resin coated sand (RCS) using a coating of phenolic resin that could be applied to each grain enabling application in areas where closure pressures exceeded standard silicate proppants and where the economics did not justify the expense of ceramic proppants. **Table 1** provides guidelines published in 2000 for the application of fracturing proppants [(6)].

Application of Proppants	
Proppant Type	**Closure Pressure Range (psi)**
Brown Sand	4000
White Sand	6000
Resin Coated Sand (RCS)	8000
Intermediate Strength Proppant (ISP)	>5000 - <10000
High Strength Proppant	>10,000

Table 1 - Closure range of proppants

A great deal of industry research has gone into the development of proppants to ensure the induced fracture maintains the ability to convey the produced fluids over the life of the well. The measurement of this conveyance is known as fracture conductivity. The physical properties of proppants for use in hydraulic fracturing that have an impact on fracture conductivity include the following [(7)]:

- Proppant strength
- Grain size and grain size distribution
- Quantities of fines and impurities
- Roundness & sphericity
- Proppant density

After placement of the proppant during the fracturing process, formation stress acts to hold the proppant in place. If the proppant strength is insufficient the closure stress will crush the proppant. Closure pressure (CP) is defined as bottom hole fracture pressure (BHFP) minus the bottom hole pressure (BHP) of the reservoir and can be expressed by the following equation:

$$CP = (\text{Fracture gradient (psi/ft)} \times \text{Depth (ft)}) - \text{BHP (psi)}$$

The equation for bottom hole fracture pressure can define the effects of closure pressure within the induced fracture over time. In other words, as the bottom hole pressure of the reservoir declines, the closure pressure on the proppant pack increases, thus the original conductivity created during the hydraulic fracture treatment naturally declines throughout the life of the well as bottom hole pressure is drawn down. This relationship of closure stress to that of conductivity is well understood and has been well published within the industry since the advent of the hydraulic fracturing process.

Fracture Conductivity

The evolution of proppants for hydraulic fracturing has been well documented and the application of higher conductive "Ottawa" or Norther White Sand goes back to 1959 [6]. Testing procedures for conductivity and embedment can be found in the early volumes of the Hydraulic Fracturing Monograph Volume 2 by Howard and Fast, circa, 1970. Fracture conductivity defines the conductive path provided by the proppant material to enhance deliverability and provide economic benefit after the well is producing. Traditionally this is measured as the product of created proppant pack permeability and propped fracture width and is reported in millidarcy-feet (md-ft), a key fracture design parameter. The units of permeability are length squared and fracture width is a unit of length. Therefore, fracture conductivity is the volumetric capacity of the induced hydraulic fracture's ability to transmit reservoir fluid [9].

In recent history the API RPs have been superseded by new standards from the International Standards Organization (ISO). ISO 13503-2 was first published in 2006 and is reviewed every five years with the latest confirmation being 2018. Under ISO 13503, API RP 19D is the current industry standard for conductivity testing of proppants used in hydraulic fracturing and was developed to improve the quality of proppants delivered to the well site. It should be noted that "proppants" mentioned in ISO 13503 refers to sand, ceramics, and resin-coated proppants, all having application in hydraulic fracturing historically dependent on the closure stress environment of the subject application/well [7]. This standard of testing which measures the "long term" conductivity of proppants is measured over 50 hours at 250°F at a given stress.

As 50 hours is a woefully short duration for "long term" conductivity testing, a damage factor must be estimated by engineers to apply to production declines for the life of a well based on correlations or experience. Due to absence of any industry published "long term" conductivity testing, Pearson, et.al, (SPE 205272-MS) conducted conductivity testing using the API RP 19D procedures for testing at 250 days. This approximate eight-month test duration was conducted for four proppant types including 40/70 White/Ottawa sand, 40/70 Brown sand, 100 mesh Brown sand and 40/70 Light Weight Ceramic (LWC) to duplicate conditions at 10,000' with a 0.75 psi/ft gradient or Delaware Basin type conditions [10]. The results of this testing at 0.5 lb/ft2 were extrapolated over a 40-year period to show the conductivity differences of the three proppant types and can be seen in Figure 2. The results of this extended time testing follow the anticipated and recommended proppant selection criteria shared earlier. Therefore, it would be expected that Light Weight Ceramics outperform all sand products at 7500 psi closure. The proppant selection science that has been developed over decades of fracture stimulation work didn't cease to become valid when the completion of shale wells and horizontal drilling became prevalent. It should be of no surprise that only the Lightweight Ceramic proppant actually maintains conductivity over the 40 year life of the well. However, the economics associated with massive hydraulic fracture treatments containing manmade Ceramic proppants would ultimately prove uneconomic for most any development play. It has also been outlined that the application of slick water combined with sand enables the economic application of large volume fracture treatments that would not be possible when applying massive volumes of ceramic proppants. Therefore, it is the difference between the conductivities of Northern White Sand (NWS) with that of In-Basin Brown sand (IBS) that should be of greatest interest here.

TIME	0.5 from 1lb PROPPANT LCDF CONDUCTIVITY CALCULATION			
	LWC 40/70 mesh	WS 40/70 mesh	BS 40/70 mesh	BS 100 Mesh
	Conductivity	Conductivity	Conductivity	Conductivity
Years	md-ft	md-ft	md-ft	md-ft
0	300	53	32	8.5
0.5	187	16	10	3.3
1	178	13	7.9	2.9
1.5	172	11	6.8	2.6
2	168	9.5	6.1	2.4
3	163	7.7	5.0	2.2
5	156	5.4	3.7	1.9
10	147	2.3	1.9	1.4
15	141	0.5	0.9	1.2
20	137	0.0	0.1	1.0
30	132	0.0	0.0	0.7
40	128	0.0	0.0	0.6

Table 2 - Calculated Conductivity over 40 years at 7500 psi at 0.5 lb/ft^2 from Pearson, et.al. SPE 205272-MS

In **Table 2** above, the early time conductivity differences between White (Ottawa or Northern White Sand) sand range from 39% to 31% greater than that of in-basin Brown sands in the first five years of production. This difference in conductivity will most certainly equate to a greater decline in well productivity over this same time period and is not an immaterial difference. In-basin sand mines began operations in West Texas in 2018 and produce finer mesh sands (100 mesh, 40/70). The difference in crush resistance of in-basin sands is known to be less than that of NWS and the angularity greater, and it could be said that while these differences are known they are not fully understood as the in-basin sands continue to be utilized or miss applied in areas exhibiting closure pressures exceeding published and historically practiced application parameters. The performance of in-basin Brown sands will in time prove to be inferior to that of NWS due to the difference in the proppant pack conductivity created by each. The good news for the industry is that hydraulic fracturing works and the early time results or initial production (IP) for wells in ultralow permeability and/or low closure reservoirs has proven to be minimal and supported by early time production studies [(11)]. However, it is the longer-term effects after the first year of well life (as BHP declines) that will affect the ability to return greater cash flow that should be considered. Ultimately the associated reserves of the subject well or asset will be compromised and the expectation that unconventional wells at stress levels of several thousand psi will produce their Estimated Ultimate Recovery (EUR) over a period of decades is unlikely to occur [12].

The Wisconsin Industrial Sand Association and the Rystad Study

The frac sand market for Permian reservoirs with closure pressures in the 6000-psi range or greater has long been a dominant market for NWS and has also been the preferred sand option among most all oil companies. However, in 2018 due to the ever-increasing market for frac sands in the growing Permian horizontal plays in-basin Permian sand mines began to open and supply small mesh proppants for fracturing. Understanding that in-basin sands have application, the Wisconsin Industrial Sand Association (WISA), a group of sand producers with significant exposure to the North American onshore oil & gas industry anticipated seeing a shift in the Permian market for low closure applications. However, the application of these sands in closure ranges exceeding 6000 psi was not anticipated and the misapplication of in-basin sands was unexpected. The change in the frac sand market seemed immediate when in-basin sands became available and while WISA expected to lose market share in some capacity it was not prepared for the dramatic and almost total switch that occurred starting in 2018. In December 2019 Rystad Energy released a study commissioned by WISA to study and identify the effects of in-basin sands on well performance relative to that of NWS. Operators working in both the Midland and Delaware basins were identified and using Rystad Energy's global proprietary database, public information, company presentations, industry reports and other general research, the sand types in use for operators in both the Midland and Delaware basins were identified and productivity impacts relative to sand in use were examined. In the 2019 study, four operators in the Midland basin that had previously used NWS and had switched to in-basin sands were identified along with three operators that had done the same in the Delaware basin (**See Figure 1.1**). In all, the study analyzed approximately 800 wells across these seven operators. To review the differences in sand application a methodology was adopted that included three steps:

1. Choose operators with high confidence of sand type.
2. Isolate operator controls for important parameters
    a. Proppant intensity
    b. Lateral length
    c. Fracture design
3. Benchmark well productivity

Once the operators and well sets were identified, a method to capture the effects of proppant degradation and its effect on the associated well economics was created. This chosen method was deemed "Allowable Degradation" and it was defined as the difference between cumulative net cash flow from NWS and in-basin sands. In other words, the sand cost savings of in-basin sands would have to be greater than the loss in production revenue due to lesser productivity associated with a decrease in conductivity of the induced hydraulic fracture over time. In addition, net present value by year verses productivity degradation could also be plotted. It should be noted that production revenue loss must be tied to commodity prices and in 2018 oil prices hovered in the \$40 to \$50/bbl range and therefore Allowable Degradation was calculated at \$40 and \$50/bbl. The results of the 2019 study were mostly inconclusive as the production for most all the operators was less than one year. As the use of in-basin sands in the Permian Basin didn't occur until early 2018 limited impact on well productivity was initially observed for the well sets available and it was determined that it was simply too early to observe degradation effects. Even so, three of the seven operators did show some decline in productivity after the switch to in-basin sands within the first year [13].

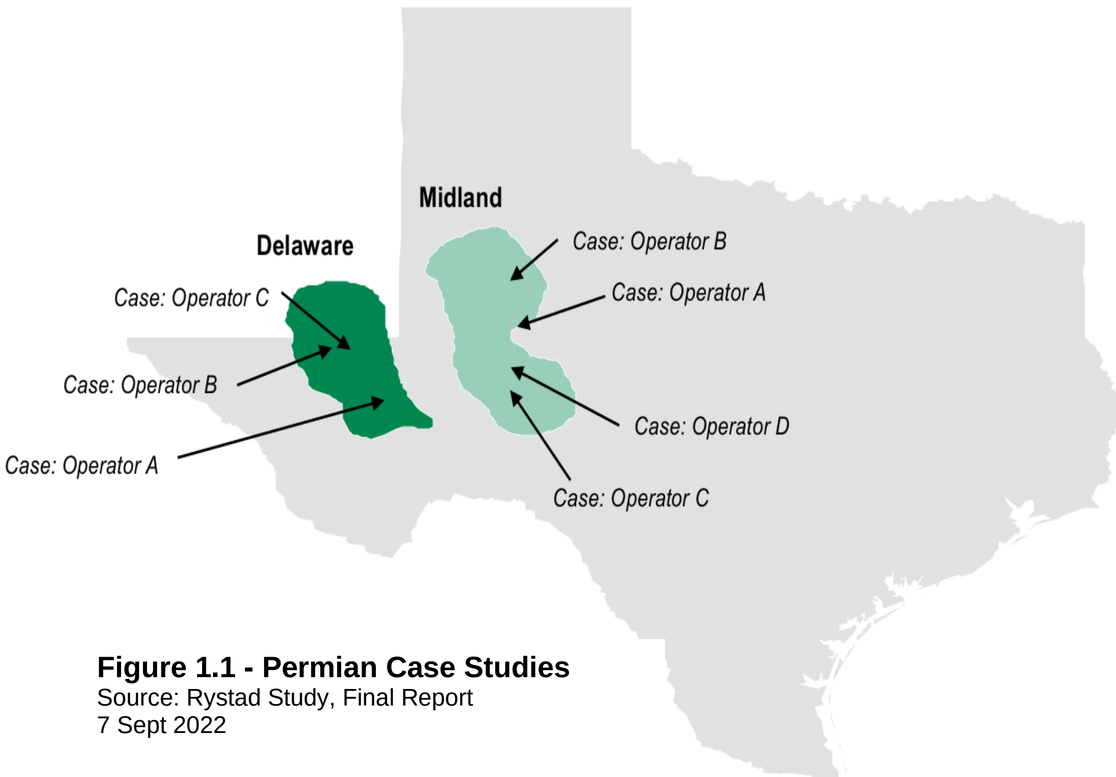


Figure 1.1 - Permian Case Studies
Source: Rystad Study, Final Report
7 Sept 2022

After the original study was released in 2019 an updated version was subsequently published by Rystad in May 2020. Compared to previous iterations of this study, the macro environment had changed considerably as both oil & gas prices remained firmly elevated. The 2020 iteration was an analysis of the same well sets, now with more production history. In the updated study with more production data available the focus was analyzing one-year (IP360) and two-year (IP720) production trends. The final Rystad report is structured in three parts that includes a summary highlighting all the primary findings, methodology description and a case-by-case review.

The primary objective for Permian operators in utilizing in-basin sand is to reduce upfront well costs. Due to these upfront cost savings, in all likely hood operators would only consider the use of NWS should any negative impact from using in-basin sand be greater than the cost savings. Hence the analysis was performed to estimate how big the production impact must be for NWS to provide more value. In other words, estimate the loss of production or the allowed degradation of the in-basin sand wells relative to the upfront cost savings. Before this allowable degradation is even identified, it should be noted that any degradation of well performance will be repeated or increase over time meaning that any loss of production equates to lost reserves and the long-term value of the well or asset is diminished. These lost reserves are coupled with a negative cash flow impact in the first 2-5 years of a given well's life reducing available cash flow for continued drilling operations.

In further review of the Rystad analysis the study compares actual production data against allowable degradation and categorizes the results in three categories:

- No Impact – Operators case studies that do not exhibit any productivity decline following in-basin sand adoption.
- Light Impact – Cases with decline in well productivity that is within the allowable degradation.
- Significant Impact – Clear signs of productivity declines that are greater than the allowable degradation.

Of the seven operators previously described six of the seven cases see productivity declines after switching from NWS to in-basin sand and it should be noted that higher commodity prices along with more production history enhance the impact. Due to higher commodity prices, the value of potentially lost barrels is much higher, and the estimated allowable degradation has gone down significantly across all cases analyzed, generally by more than 50% and as such, smaller productivity declines can wipe out all the cost savings potential compared to previous studies at lower commodity pricing. Referring to the previous categories defined, four of the seven cases are classified as "Significant Impact" following the switch to in-basin sand, while two cases are identified as" Light Impact," however the effect grows when looking at two-year trends and the Light Impact cases approach significance. For all six cases with impact, the whole cost savings from the switch to in-basin sand on a cash basis is gone after two years at $90/bbl and for the four cases with Significant Impact, the upfront cost savings are wiped out even under $50/bbl [(14)].

For all but one of the cases studied, operators are losing out on cash flows following the switch from NWS and of the seven operators studied one case was classified as "No Impact." While the Rystad study is statistically reliable and the results are undeniable there are (as stated previous) applications for in-basin sands, the objective should be to rely on the decades old science of proppant selection especially when completing wells with closure pressures clearly exceeding the limitations of brown sands. The fact that one operator had no impact infers the subject wells may be in a region of lower closure or perhaps other variables exist for this well set. Variables that may impact well production other than fracture conductivity include but are not limited to, lateral length, proppant intensity, target formation, acreage quality and well spacing. That said, the approach used in the Rystad work revolves around case studies by operator and formation that ensure most variables are controlled. Operator cases where variables were in question were not included, such as significant experimentation in well designs or if an operator switched acreage focus at the time of the shift to in-basin sand.

The Rystad study can be reviewed in detail to examine each of the seven cases individually, however the most significantly impacted case has been provided in **Figure 1.2**. The study utilizes three scenarios based on commodity price permutations identified as Low-$70 oil, Base-$90 oil, and High- $110/bbl oil.

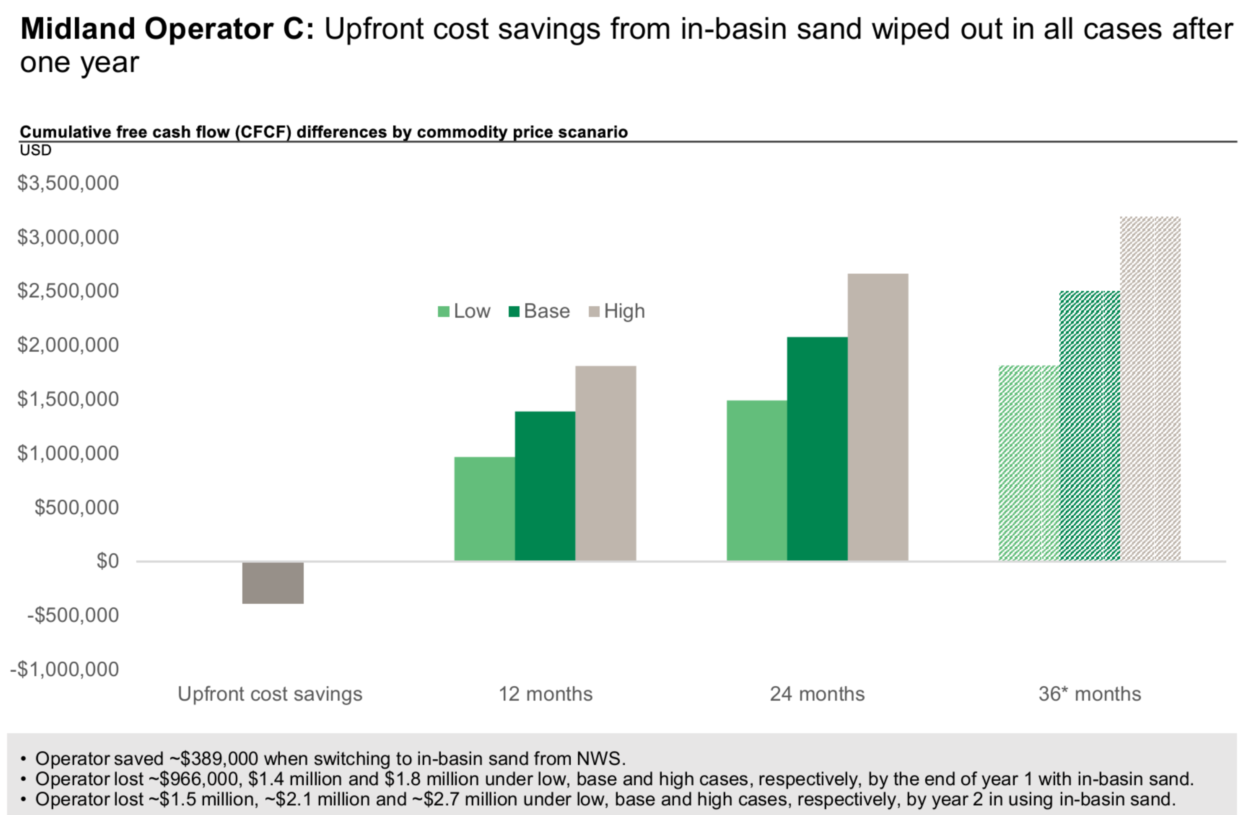


Figure 1.2 - Source: Rystad Study, Final Report 7 Sept 2022

The observation that Permian operators have lost production during the time period captured in the Rystad study is not exclusive to Rystad, the trend has been observed outside the Permian and examined by other entities with no ties to proppant markets. The lost Permian production since the application of in-basin sands captured in the Rystad study, even caught the eye of the Wall Street Journal who published an article March 8, 2023, stating, “Oil production from the best 10% of wells drilled in the Delaware portion of the Permian was 15% lower last year, on average, than top 2017 wells according to data from analytics firm FLOW Partners LLC. Meanwhile, the average well put out 6% less oil than the prior year, according to an analysis of data from analytics firm Novi Labs." The article went on to blame some of the decline on less optimum drilling sites, and while optimum drilling sites most certainly can contribute, it is also logical to assume that the timeliness of this decline can also be attributable to completion methods that now create less conductive fractures [15]. The WSJ article went on to imply that operators would be pushed to drill lower quality wells that would require higher oil prices to attract investment, if this is true, then it is these types of wells that need more than any to have completions that optimize production and sustain it longer. When a pumping service company leaves any Permian location after a muti-million-dollar fracture stimulation treatment the only tangible purchase made by the operator of a given well other than water that must be disposed of, is sand or proppant, would it not stand to reason that this solitary tangible purchase be spent on the highest quality proppant available within economic limits.

Fracture Modeling of Northern White Sand vs. In-Basin Sand

The science associated with hydraulic fracturing proppant selection has been outlined while the Rystad study (and others) have recently shown the real time differences in production results when the science of proppant selection is ignored. To further define the differences in conductivity performance and the associated economics of these differences, hydraulic fracture modeling was conducted for the Wolfcamp A (WCA) formation for both the Delaware and Midland basins. Parametric sensitivities for substituting In-Basin Sand (IBS) and Northern White Sand (NWS) in the 40/140 and 40/70 mesh were performed using a constant pump schedule and for each basin. However, basin specific completion methodology was utilized in the fracture models. The methodology using a common pump schedule, i.e., stimulation volumes, created consistent fracture geometry, per basin, with only variables being proppant type and proppant mesh. As such, propped fracture height and propped fracture half-length were defined at 200 ft and 250 ft respectively to compare insitu proppant performance. Four (4) variable proppant cases were modeled in each basin and defined in **Table 3**. This nomenclature was used throughout all modeling phases of the project. SSNWS denotes proppant performance data for northern white sand provided by Smart Sand. Further, when comparing or discussing results from Case 1, IBS 40/140, and Case 3, NWS 70/140, these cases may be referred to as "100 mesh".

Table 3 – Fracture modeling proppant sensitivities cases.

Basin		Fracture Modeling	
Delaware	Midland	CASE 1	IBS 40/140
		CASE 2	IBS 40/70
		CASE 3	NWS 70/140
		CASE 4	SSNWS 40/70

Tables 4 and **5** list the constant created and propped fracture geometry results, and the reported fracture conductivity and dimensionless fracture conductivity values obtained from the fracture

modeling in the Delaware and Midland basins correspondingly. Fracture conductivity varied by basin because the closure pressure on proppant is different between the Delaware and Midland basins. Generally, in the Delaware basin, NWS resulted in, on average, 4.5x greater conductivity, compared to IBS regardless of mesh size. In the Midland basin, 100 mesh NWS had 4.2x improved fracture conductivity over IBS 100 mesh, while and 40/70 NWS shows 2.6x improved conductivity of 40/70 IBS. The fracture conductivity results are compared further, by basin, in **Figures 1.3** and **1.4**.

Table 4 – Hydraulic fracture geometry and as-pumped conductivity results in the Delaware basin.

Proppant Type Proppant Mesh	CASE 1 IBS 40/140	CASE 2 IBS 40/70	CASE 3 NWS 70/140	CASE 4 SSNWS 40/70	
Total Fracture Height	660	660	660	660	(ft)
Propped Fracture Height	200	200	200	200	(ft)
Created Fracture Half-Length	435	435	435	435	(ft)
Propped Fracture Half-Length	250	250	250	250	(ft)
Fracture Conductivity at Closure	0.216	0.473	0.906	2.240	(mD-ft)
Dimensionless Fracture Conductivity	1.728	3.784	7.248	17.920	(dim)

Table 5 – Hydraulic fracture geometry and as-pumped conductivity results in the Midland basin.

Proppant Type Proppant Mesh	CASE 1 IBS 40/140	CASE 2 IBS 40/70	CASE 3 NWS 70/140	CASE 4 SSNWS 40/70	
Total Fracture Height	448	448	448	448	(ft)
Propped Fracture Height	200	200	200	200	(ft)
Created Fracture Half-Length	555	555	555	555	(ft)
Propped Fracture Half-Length	250	250	250	250	(ft)
Fracture Conductivity at Closure	0.429	1.070	1.821	2.830	(mD-ft)
Dimensionless Fracture Conductivity	3.432	8.560	14.568	22.640	(dim)

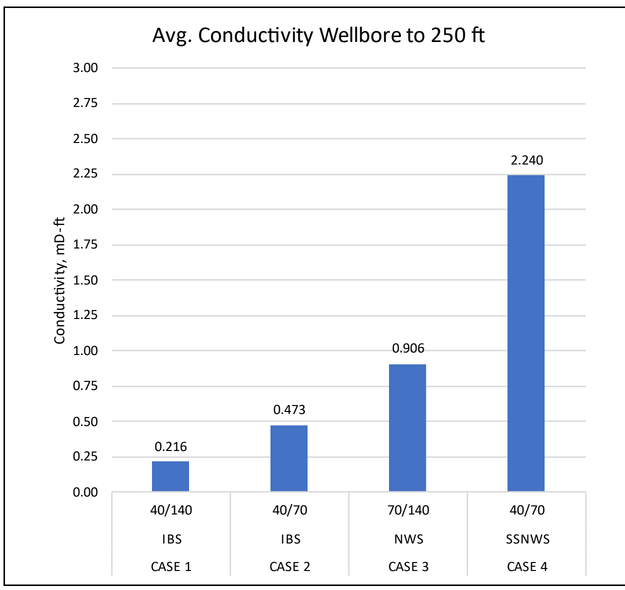


Fig. 1.3 – Average fracture conductivity comparing IBS and NWS in 100 and 40/70 mesh in the Delaware basin.

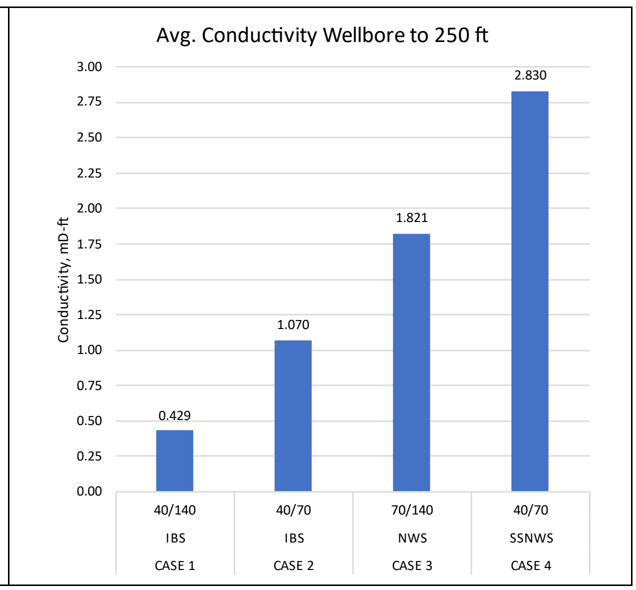


Fig. 1.4 – Average fracture conductivity comparing IBS and NWS in 100 and 40/70 mesh in the Midland basin.

Well production flow rates were forecasted to be 100-years for P50 and P90 wells in the Delaware and Midland basins using the fixed geometry and the variable fracture conductivity determined from the fracture model cases. **Table 6** summarizes the fracture modeling and production forecast cases.

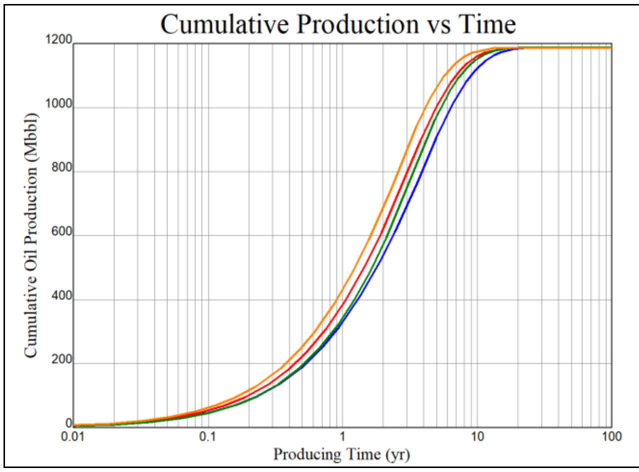
Table 6 – Fracture and production modeling cases.

Basin		Fracture Models		Production Forecast
Delaware	Midland	CASE 1	IBS 40/140	P50
		CASE 2	IBS 40/70	
		CASE 3	NWS 70/140	
		CASE 4	SSNWS 40/70	
Delaware	Midland	CASE 1	IBS 40/140	P90
		CASE 2	IBS 40/70	
		CASE 3	NWS 70/140	
		CASE 4	SSNWS 40/70	

The BOE production differences were compared at 1-, 5- and 10-years as well as the 30-year EUR for the IBS and NWS products in 100 and 40/70 meshes. Generally, in both the Delaware and Midland basins, there are only marginal production differences in the 100 mesh at 1-year, with noticeable difference occurring at 18-months regardless of proppant type. This is a similar result to the Rystad [13] study. The uplift from the 40/70 mesh is marginal at 9 months with noticeable uplift occurring at 1 year. The production deliverability from NWS material becomes greater over the life of the well. **Table 7** and **Figure 1.5-1.6** present the BOE cumulative production at specific times for the Delaware basin and **Tables 8** and **Figure 1.7-1.8** show similar information for the Midland basin.

Table 7– Cumulative BOE production forecast by proppant type and mesh size in the Delaware basin.

			Cumulative BOE Production							
			P50				P90			
	Proppant	Mesh	1-yr	at 5-yr	at 10-yr	EUR	1-yr	at 3-yr	at 10-yr	EUR
			(Mboe)	(Mboe)	(Mboe)	(Mboe)	(Mboe)	(Mboe)	(Mboe)	(Mboe)
CASE 1	IBS	40/140	324	887	1,113	1,188	494	1,342	1,718	1,871
CASE 2	IBS	40/70	337	964	1,150	1,188	520	1,452	1,790	1,872
CASE 3	NWS	70/140	396	1,004	1,161	1,188	613	1,525	1,812	1,872
CASE 4	SSNWS	40/70	414	1,063	1,178	1,188	661	1,644	1,855	1,877



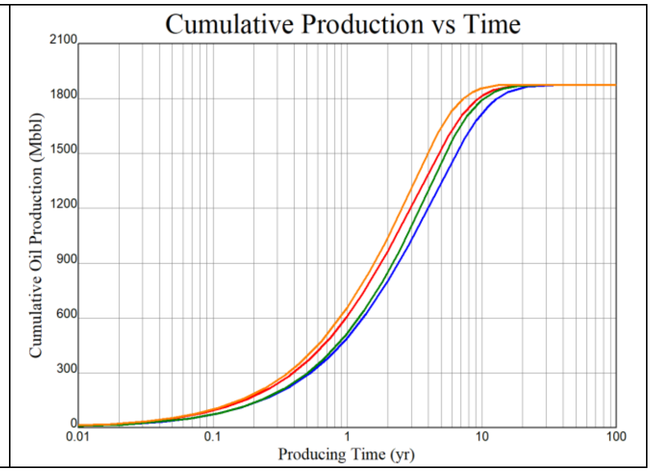
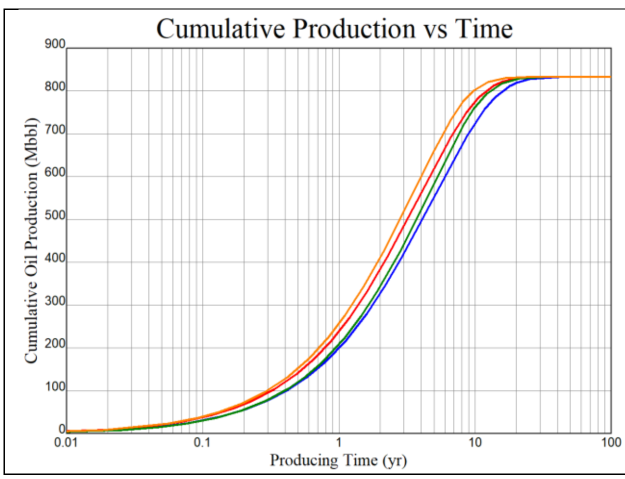


Fig. 1.5 – P50 cumulative BOE production forecast to 100-yr comparing IBS and NWS in 100 and 40/70 mesh in the Delaware basin.

Fig. 1.6 – P90 cumulative BOE production forecast to 100-yr comparing IBS and NWS in 100 and 40/70 mesh in the Delaware basin.

Table 8 – Cumulative BOE production forecast by proppant type and mesh size in the Midland basin.

			Cumulative BOE Production							
			P50				P90			
	Proppant	Mesh	1-yr	at 5-yr	at 10-yr	EUR	1-yr	at 3-yr	at 10-yr	EUR
			(Mboe)	(Mboe)	(Mboe)	(Mboe)	(Mboe)	(Mboe)	(Mboe)	(Mboe)
CASE 1	IBS	40/140	200	554	725	832	310	889	1,187	1,358
CASE 2	IBS	40/70	209	584	762	832	327	957	1,244	1,358
CASE 3	NWS	70/140	239	621	776	832	382	1,013	1,271	1,358
CASE 4	SSNWS	40/70	258	659	803	832	408	1,076	1,305	1,358



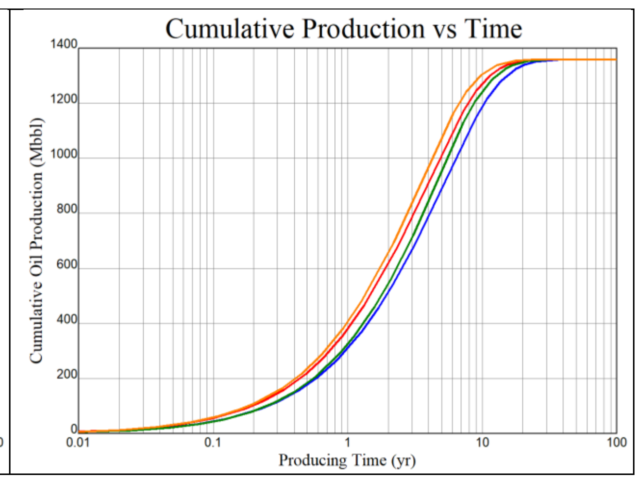


Fig. 1.7 – P50 cumulative BOE production forecast to 100-yr comparing IBS and NWS in 100 and 40/70 mesh in the Midland basin.

Fig. 1.8 – P90 cumulative BOE production forecast to 100-yr comparing IBS and NWS in 100 and 40/70 mesh in the Midland basin.

Economic analysis was performed on the cumulative BOE production forecast in each basin for P50 and P90 wells considering the production benefit seen with the NWS material to estimate 1) the value, measured as Net Present Value (NPV) and 2) the payout required to utilize NWS proppant. Cases assumed oil prices of \$50, \$75 and \$100 USD. **Table 9** summarizes the fracture models, production forecast and economic cases completed for this project.

Table 9 – Fracture models, production forecast and economic cases.

Basin		Fracture Modeling		Production Forecast	Economic Cases
Delaware	Midland	CASE 1	IBS 40/140	P50	$50
		CASE 2	IBS 40/70		$75
		CASE 3	NWS 70/140		
		CASE 4	SSNWS 40/70		$100
Delaware	Midland	CASE 1	IBS 40/140	P90	$50
		CASE 2	IBS 40/70		$75
		CASE 3	NWS 70/140		
		CASE 4	SSNWS 40/70		$100

Utilizing NWS material burdens the operator with additional proppant expense compared to the use of IBS proppant. Using NWS instead of IBS material adds, on average, approximately $340,000 or 42%, additional proppant cost in Delaware and $420,000, or 49% in Midland basin, **Table 10** presents the IBS proppant cost, incremental cost of NWS and total proppant cost for 100 and 40/70 mesh in both the Delaware and Midland basins. Higher costs in the Midland basin are attributed to increased NWS transportation charges over the Delaware basin.

Table 10 – Proppant cost by material and mesh for Delaware and Midland basins.

	Delaware Basin			Midland Basin		
	IBS Proppant Cost	Incremental NWS Proppant Cost	Total Proppant Cost	IBS Proppant Cost	Incremental NWS Proppant Cost	Total Proppant Cost
	($ USD)	($ USD)	($ USD)	($ USD)	($ USD)	($ USD)
IBS 100 mesh	450,000	-	450,000	450,000	-	450,000
NWS 100 mesh	-	360,000	810,000	-	450,000	900,000
IBS 40/70	540,000	-	540,000	550,000	-	550,000
NWS 40/70	-	315,000	855,000	-	385,000	935,000

Table 11 shows the payout, in months, for the added proppant expense of utilizing NWS instead of IBS in the Delaware and Midland basins for P50 and P90 cumulative BOE production cases. As expected, the payout term of the additional proppant expenses decreases with higher oil prices and better producing wells.

Table 11 – Payout time, in years, to recover the additional cost of using NWS in the Delaware and Midland basins.

	Delaware Basin P50 Production Case		Delaware Basin P90 Production Case		Midland Basin P50 Production Case		Midland Basin P90 Production Case	
	100 Mesh	40/70	100 Mesh	40/70	100 Mesh	40/70	100 Mesh	40/70
Oil Price	Payout (months)	Payout (months)	Payout (months)	Payout (months)	Payout (months)	Payout (months)	Payout (months)	Payout (months)
$50	14.2	9.8	8.0	4.2	36.6	11.8	16.6	8.3
$75	10.3	6.7	5.3	2.9	19.4	7.4	10.2	5.5
$100	7.7	5.0	4.2	1.9	14.5	5.8	7.4	4.2

In all cases, the use of NWS proppant adds value to the well. Considering a NPV comparison at 5-yr for the Delaware basin, NWS 100 mesh on average creates 9% more value over IBS 100 mesh for both the P50 and P90 production cases. The 40/70 NWS material on average adds 6% value over IBS 40/70 for the P50 production case and 8% for the P90 well. In the Midland basin the 5-yr comparison of NWS 100 mesh on average creates 5% more value over IBS 100 mesh for the P50 case and 8% for the P90 production case. The 40/70 NWS material on average adds 6% value over IBS 40/70 for both the P50 and P90 production cases. Percent production improvement (delta, Δ) and net present value (Δ NPV) created, at 5-yr cumulative BOE production, by selecting NWS proppant over IBS material is shown in **Table 12**.

Table 12 – 5-yr cumulative BOE percent production improvement and net present value added by created with NWS proppant over IBS material.

	Delaware Basin P50 Production Case				Delaware Basin P90 Production Case			
	100 Mesh		40/70		100 Mesh		40/70	
Oil Price	Delta, Δ (%)	Δ NPV ($MM)	Delta, Δ (%)	Δ NPV ($MM)	Delta, Δ (%)	Δ NPV ($MM)	Delta, Δ (%)	Δ NPV ($MM)
$50	9.5	2.908	6.2	2.209	8.7	4.330	8.3	4.730
$75	9.3	4.541	6.2	3.471	8.6	6.675	8.2	7.253
$100	9.2	6.175	6.2	4.733	8.6	9.020	8.1	9.770
	Midland Basin P50 Production Case				Midland Basin P90 Production Case			
	100 Mesh		40/70		100 Mesh		40/70	
Oil Price	Delta, Δ (%)	Δ NPV ($MM)	Delta, Δ (%)	Δ NPV ($MM)	Delta, Δ (%)	Δ NPV ($MM)	Delta, Δ (%)	Δ NPV ($MM)
$50	4.8	0.809	6.4	1.255	8.0	2.457	6.4	2.310
$75	5.1	1.438	6.4	2.075	8.0	3.911	6.4	3.657
$100	5.2	2.067	6.4	2.895	7.9	5.364	6.4	5.005

DISCUSSION OF RESULTS

Fracture Modeling

Fracture modeling of the four cases; 1) IBS 40/140, 2) IBS 40/70, 3) NWS 40/140, and 4) SSNWS 40/70, was conducted for Wolfcamp A in the Delaware and Midland Basins. The Wolfcamp A formation in the Midland and Delaware basins covers a large geographic area with a significant spread of process and methods from many different completions designs and operators. Experience in these plays provided insight to create general type model inputs including type logs for fracture modeling, rock and reservoir fluid descriptions, and pump schedules. The type logs used in fracture modeling the Delaware and Midland basins are shown in **Figures A.1** and **A.2** respectively. Mechanical rock properties are shown in **Table A.1**. **Table 13** shows the results from public data analysis for basin specific completion and stimulation designs.

Table 13 – Basin specific completion and stimulation designs used in fracture and production modeling.

Fracture Modeling Inputs	Delaware	Midland	
Lateral Length	9,000	10,000	ft
Stage Count	45	50	N
Stage Spacing	200	200	ft
Cluster Spacing	20	20	ft
Clusters (Stage/Total)	10 / 450	10 / 500	N_c/N
Perforations (Stage/Total)	30 / 1,350	30 / 1,500	N_p/N
Mass/Stage	400	400	Mlbm
Proppant Intensity	2,000	2,000	lbm/stg
Fluid/Stage	390	390	Mgal
Fluid Intensity	1,950	1,950	gal/stg
Prop to Fluid Ratio	1.03	1.03	lbm/gal
Temperature	170	160	ºF
Proppant Settling	1.0	1.0	ft/min
Proppant Damage Factor	95	95	%

A generic 400,000 lbm pump schedule, **Figure A.3** was used as a constant for the fracture modeling with the simulation only varying proppant type and mesh sizes described in the four cases. The pump schedule used 2,000 lbm/ft and 1,950 gal/ft. The completion design used 10 clusters spaced 20 ft apart for a stage length of 200 ft. Each stage was shot with 30 perforations at 0.42-inch diameter. A cluster efficiency of 60% was utilized resulting in 6 open clusters in the fracture model.

The fracture conductivity for a propped fracture half-length of 250 ft, was determined for each of the four cases in each basin. This length cutoff was determined from previous extensive modeling efforts performed on the WCA in the Delaware and Midland basins. Representative IBS permeability and conductivity for 40/140 and 40/70 at multiple closure pressures were generated from internal databases. Proppant pack permeability and conductivity behavior for 40/140 NWS was determined using representative values of "St. Peter Sand". Permeability and conductivity values for 40/70 SSNWS were provided by Smart Sand. Long-term conductivity testing profiles for IBS 40/140, IBS 40/70, NWS 40/140 and SSNWS 40/70 are shown in **Figure 1.9**. A closure pressure on proppant of 7,980 psi was used in the Delaware basin fracture modeling and 6,175 psi for the Midland basin.

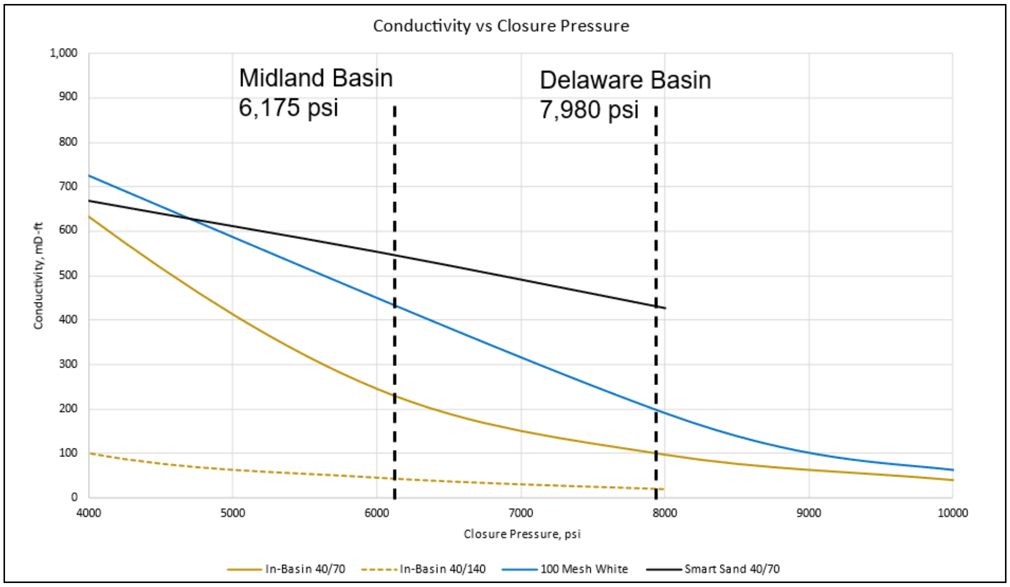


Fig. 1.9 – Fracture conductivity vs closure pressure for each of the four proppants, IBS 40/140, IBS 40/70, NWS 100 and SSNWS 40/70 used in fracture models. The closure pressure on proppant is noted for both the Midland basin (6,175 psi) and Delaware basin (7,980 psi).

The modeled fracture conductivity for the proppant sensitives in the Delaware Basin are shown in Figure 1. When comparing mesh size to different proppant material, the NWS 40/140 (CASE 3) as-pumped conductivity in the fracture is 123% greater than the IBS 40/70 (CASE 1) at the Delaware basin closure pressure. The SSNWS 40/70 (CASE 4) fracture conductivity is 130% greater than the IBS 40/70 (CASE 2). **Table 14** presents the Delaware basin as-pumped fracture conductivity results and percentage differences.

Table 14 – Fracture conductivity percent difference between IBS and NWS materials for the Delaware basin.

	Proppant Type	40/140 Mesh		40/70 Mesh	
		Frac. Cond. (mD-ft)	NWS > IBS (%)	Frac. Cond. (mD-ft)	NWS > IBS (%)
CASE 1	IBS	0.216	123	-	-
CASE 3	NWS	0.906		-	-
CASE 2	IBS	-	-	0.473	130
CASE 4	SSNWS	-	-	2.240	

The Midland Basin fracture conductivity results for the proppant sensitives are reported in Figure 2. The NWS 40/140 (CASE 3) fracture conductivity is 124% greater than the IBS 40/70 (CASE 1) at the Midland basin closure pressure. The SSNWS 40/70 (CASE 4) fracture conductivity is 90% greater than the IBS 40/70 (CASE 2). **Table 15** presents the Midland basin as-pumped fracture conductivity results and percentage differences.

Table 15 – Fracture conductivity percent difference between IBS and NWS materials for the Midland basin.

	Proppant Type	40/140 Mesh Frac. Cond. (mD-ft)	40/140 Mesh NWS > IBS (%)	40/70 Mesh Frac. Cond. (mD-ft)	40/70 Mesh NWS > IBS (%)
CASE 1	IBS	0.429	124	-	-
CASE 3	NWS	1.821		-	-
CASE 2	IBS	-	-	1.070	90
CASE 4	SSNWS	-	-	2.830	

Figures 1.10-1.11 illustrate example summary fracture model graphics for this study using the SSNWS 40/70 case. Figure 8 shows the as-pumped fracture conductivity contour profile and Figure 9 displays the Cartesian fracture conductivity plot indicating the 250 ft cutoff on the abscissa and conductivity value at that point on the ordinate. The fracture conductivity values for the Delaware basin modeling as presented in Table 1 and Figure 1 and similarly the Midland basin conductivity values are shown in Table 2 and Figure 2. The additional seven fracture model summary graphic and Cartesian conductivity plots are presented in **Figures A.4 – A.17** for reference.

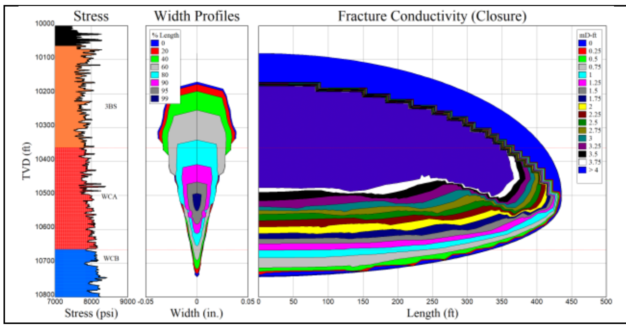


Fig. 1.10 – Fracture conductivity distribution contour profile at fracture closure in WCA for CASE 4, SSNWS 40/70, in the Delaware basin.

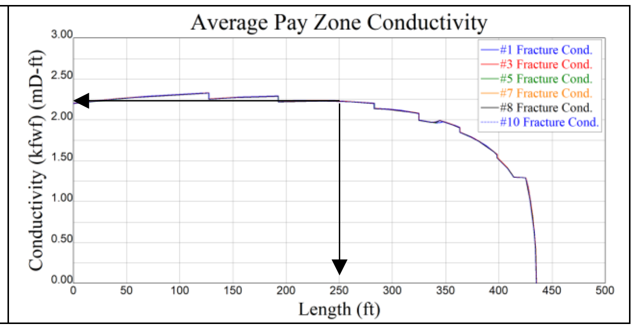


Fig. 1.11 – Fracture conductivity distribution Cartesian profile at fracture closure in WCA with a 250' cutoff noted for CASE 4, SSNWS 40/70, in the Delaware basin.

Production Modeling

Cumulative BOE production forecast was run to 100 years using the variable fracture conductivity, determined from the fracture modeling, for all cases in both the Delaware and Midland basin. In other words, the only variable is the as-placed fracture conductivity with a fixed constant fracture geometry. Additionally, drainage area, dimensionless reservoir aspect ratio, stage count, and open clusters remained constant for each case by basin. Other required inputs for the formation properties were estimated from previous work in both the Delaware and Midland Basin. These include gross pay of 300 ft and net pay of 200 ft for the Wolfcamp A. Additional inputs by basin include oil gravity, gas specific gravity, bubble point pressure, and temperature values were used in the production simulation. All inputs used in production forecasting are presented in **Table A.2.** Additionally, Enverus[15], was used to determine well locations, lateral directional surveys, and production details gathered included true vertical depth, completed lateral length, 12-month cumulative production normalized per 1,000 ft.

The production forecast was calibrated to public data at 1 year, and 30-year EUR. The 12-month cumulative BOE production was evaluated with public data and used to calibrate the production simulations. In the Delaware and Midland basins, all Upper Wolfcamp A wells completed in 2020-2022 in the database were used to create a range of cumulation BOE production results. It is assumed that most wells in the public dataset during these date ranges were completed with IBS products. The EUR for BOE production was determined with the Enverus[16], methodology from public data and used to calibrate the production simulations. A cumulative distribution of 12-month cumulative oil and BOE production and 30-year EUR values are for the Delaware and Midland basin are presented in **Figures A.18 – A.21**, in this order to define P50 and P90 wells in each basin. Two (2) production forecasts cases were created for each basin to model a representative P50 well and P90 well defined by the cumulative frequency distribution. The P50 designation represents that data at that point is greater than 50% of the wells and less than 50% of the wells. Similarly, the P90 designation represents that data at that point is greater than 90% of the wells and less than 10% of the wells in the data set. The P90 point is also known as the P10 value in other analysis, but here the P90 nomenclature was used.

The 12-month cumulative BOE production for P50 well in the Delaware basin was defined at 36 boe/ft and the P90 well was defined at 55 boe/ft. The EUR for P50 and P90 wells in the Delaware basin was 132 boe/ft and 208 boe/ft, respectively. In the Midland basin, P50 and P90 for the 12-month cumulative BOE production was defined at 20 boe/ft and 31 boe/ft respectively. The EUR for P50 well was 83 boe/ft and 136 boe/ft for the and P90 case. The 12-month BOE and EUR cumulative production values were used as approximate IBS 100 mesh calibration points in the production forecasting. Values are summarized in **Table 16.** The average lateral lengths for the Delaware and Midland basins used in this study are 9,000 and 10,000 ft, respectively.

Table 16 - Average BOE 12-month cumulative BOE production, EUR and completed lateral length for the Delaware and Midland basins from public data for P50 and P90 wells.

	P50		P90		
Basin	12-month Cum. BOE Prod. (boe/ft)	EUR (boe/ft)	12-month Cum. BOE Prod. (boe/ft)	EUR (boe/ft)	Lateral Length (ft)
Delaware	36	132	55	208	9,000
Midland	20	83	31	136	10,000

The forecasted BOE production flow rates in the Delaware basin are shown in Figures 3-4 and cumulation production forecast for the Midland basin is shown Figures 5-6. As fracture conductivity increases, either from using NWS material or larger mesh sizes, the simulated BOE production also increases over time. This is the general conclusion from the Rystad study. In both forecasts, the 40/140 cases show minimal production differences at 1-year cumulative production with noticeable separation occurring at approximately 18 months. The 40/70 case follows a similar trend but with noticeable separation between IBS and NWS occurring at 9 months. Both 40/140 and 40/70 cases continue to have separation generally to about 10 years. This is a model constraint in that the fracture geometry for all cases are equal, so drainage area is constant. **Table 17** represents the forecasted BOE production shown in Table 5 in the Delaware basin but also includes the percent “uplift” resulting from the application of NWS.

Table 17 - Cumulative BOE production comparison of IBS and NWS in time and percent uplift of NWS over IBS in the Delaware basin.

	P50 | Cumulative BOE Production					
	40/140 Mesh			40/70 Mesh		
	IBS	NWS	Uplift	IBS	NWS	Uplift
	(Mboe)	(Mboe)	(%)	(Mboe)	(Mboe)	(%)
1-Year	324	337	4.2	396	414	4.5
5-Year	887	964	8.7	1,004	1,063	5.9
10-Year	1,113	1,150	3.3	1,161	1,178	1.5
30-Year EUR	1,188	1,188	0.0	1,188	1,188	0.0
	P90 | Cumulative BOE Production					
	40/140 Mesh			40/70 Mesh		
	IBS	NWS	Uplift	IBS	NWS	Uplift
	(Mboe)	(Mboe)	(%)	(Mboe)	(Mboe)	(%)
1-Year	494	520	5.3	613	661	7.8
5-Year	1,341	1,452	8.2	1,525	1,644	7.8
10-Year	1,718	1,790	4.2	1,812	1,855	2.4
30-Year EUR	1,871	90	0.1	1,872	1,877	0.3

Similarly, **Table 18** represents the forecasted BOE production shown in Table 6 in the Midland basin and percent uplift resulting from the use of NWS.

Table 18 - Cumulative BOE production comparison of IBS and NWS in time and percent uplift of NWS over IBS in the Midland basin.

	P50 | Cumulative BOE Production					
	40/140 Mesh			40/70 Mesh		
	IBS	NWS	Uplift	IBS	NWS	Uplift
	(Mboe)	(Mboe)	(%)	(Mboe)	(Mboe)	(%)
1-Year	200	209	4.5	239	258	7.9
5-Year	554	584	5.4	621	659	6.1
10-Year	725	762	5.1	776	803	3.5
30-Year EUR	832	832	0.0	832	832	0.0
	P90 | Cumulative BOE Production					
	40/140 Mesh			40/70 Mesh		
	IBS	NWS	Uplift	IBS	NWS	Uplift
	(Mboe)	(Mboe)	(%)	(Mboe)	(Mboe)	(%)
1-Year	310	327	5.5	382	408	6.8
5-Year	889	957	7.6	1,013	1,076	6.2
10-Year	1,187	1,244	4.8	1,271	1,305	2.7
30-Year EUR	1,358	1,358	0.0	1,358	1,358	0.0

NPV Modeling

The production forecast provides values from the different proppant sensitives, however, to make a business decision on which proppant adds value, a Net Present Value (NPV) analysis is necessary. NPV analysis considered four well production cases: 1) Delaware P50, 2) Delaware P90, 3) Midland P50 and 4) Midland P90 all at oil prices of $50, $75 and $100 USD for the generated cash flow. With the methodology of setting fracture length constant, the primary variable in the cost differences for each design is the proppant expenses for each scenario. The modeling used a common pump schedule for each basin of 400,000 lbm of proppant. The number of stages in the completed lateral was 45 for Delaware and 50 for Midland basin. The total proppant pumped in each well was 18 MMlbm in Delaware and 20 MMlbm in Midland basin. **Table 19** shows the oil price, stimulation design costs, and most importantly for this study, the spot price of proppant for IBS and NWS in each basin.

Table 19- NPV analysis inputs.

NPV Assumptions	Delaware	Midland	
Oil Price	50 | 75 | 100	50 | 75 | 100	$/bbl
Share of Cost | Share of Revenue	100 | 85	100 | 85	%
Currency Escalation Rate	0	0	%
Drilling Cost	3,500,000	3,500,000	$/well
Cost/bbl Completion | No Prop	0.12	0.12	$/gal
Stimulation Cost no Proppant	2,106,621	2,340,690	$/well
In-Basin 40/140	50.0	45.0	$/ton
In-Basin 40/70	60.0	55.0	$/ton
White 100 Mesh	90.0	90.0	$/ton
White 40/70	95.0	93.5	$/ton
In-Basin 40/140	450,000	450,000	$/well
In-Basin 40/70	540,000	550,000	$/well
White 100 Mesh	810,000	900,000	$/well
White 40/70	855,000	935,000	$/well

Three oil price/cash flow scenarios were evaluated at $50, $75, and $100 to assess the payout difference of each design and net present value. In determining the payout, the net price difference in the cost of NWS over IBS was used. **Figure 1.12** shows the proppant cost to complete a well in the Delaware Basin and the resulting difference to use either NWS 100 Mesh or 40/70. In this scenario, the NWS 100 Mesh is $360M more than IBS 40/140 ($450M) while the NWS 40/70 is $315M more than the IBS 40/70 ($540M). These values were shown in Table 8. Similarly, in the Midland Basin, IBS is slightly cheaper than in the Delaware basin. The difference, as seen in **Figure 1.13**, to use NWS 100 Mesh is $450M more than IBS 40/140 ($450M) and NWS 40/70 is $385M more than the IBS 40/70 ($550M). These values for the Midland basin were also shown in Table 8.

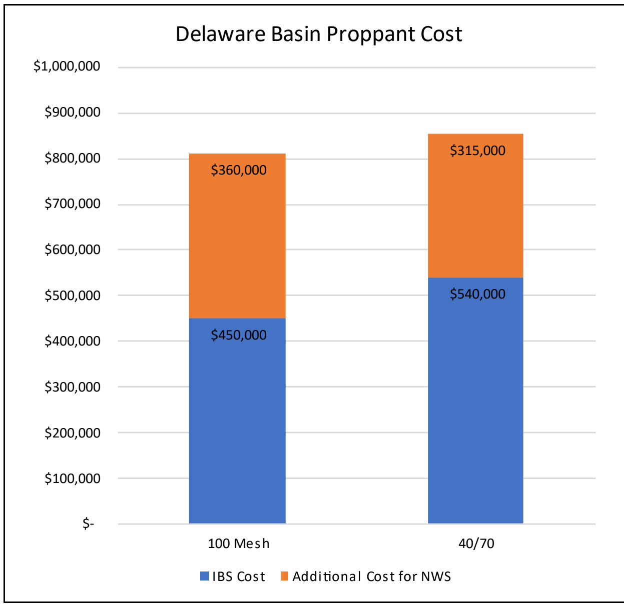


Fig. 1.12 – Average total proppant cost for the Delaware basin for IBS 100 and 40/70 mesh and the additional expense of replacing IBS with NWS 100 and 40/70 mesh material.

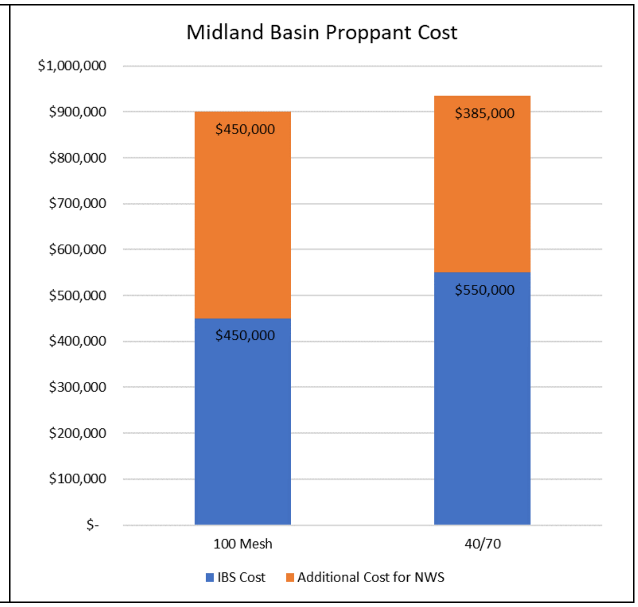


Fig. 1.13 – Average total proppant cost for the Delaware basin for IBS 100 and 40/70 mesh and the additional expense of replacing IBS with NWS 100 and 40/70 mesh material.

The forecasted cumulative BOE production was used to determine the Share NPV to the operator and determine the payoff time required for the additional cost of NWS. The Share NPV is assumed to be 85%. The Share NPV results are reported in 1-, 2-, 3-, 5-, and 10-year intervals. The Delaware Basin P50 production forecast is shown in **Table 20** and the P90 production forecast is presented in **Table 21**.

Table 20: Delaware Share NPV for P50 cases.

$50	100 Mesh			40/70		
Year	IBS, $MM	NWS, $MM	Difference, $M	IBS, $MM	NWS, $MM	Difference, $M
1	7.4	7.7	210	10.4	10.9	440
2	15.9	16.9	1,019	20.2	21.4	1,220
3	22.0	24.0	2,008	27.0	29.1	2,069
5	30.5	33.4	2,908	35.4	37.6	2,209
10	39.1	40.4	1,286	41.1	41.5	422
$75	100 Mesh			40/70		
Year	IBS, $MM	NWS, $MM	Difference, $M	IBS, $MM	NWS, $MM	Difference, $M
1	14.2	14.7	495	18.7	19.5	818
2	26.9	28.6	1,709	33.3	35.3	1,988
3	36.1	39.3	3,193	43.6	46.8	3,261
5	48.8	53.3	4,541	56.2	59.6	3,471
10	61.6	63.8	2,109	64.7	65.5	791
$100	100 Mesh			40/70		
Year	IBS, $MM	NWS, $MM	Difference, $M	IBS, $MM	NWS, $MM	Difference, $M
1	21.0	21.7	781	27.0	28.2	1,196
2	37.9	40.3	2,398	46.5	49.2	2,755
3	50.1	54.5	4,377	60.1	64.6	4,452
5	67.1	73.2	6,175	76.9	81.7	4,733
10	84.2	87.1	2,932	88.3	89.5	1,160

Table 21: Delaware Share NPV for P90 cases.

$50	100 Mesh			40/70		
Year	IBS, $MM	NWS, $MM	Difference, $M	IBS, $MM	NWS, $MM	Difference, $M
1	14.6	15.4	736	19.6	21.3	1,726
2	27.6	29.2	1,643	34.4	37.2	2,776
3	36.9	39.5	2,597	44.5	48.3	3,773
5	49.6	53.9	4,330	57.3	62.0	4,730
10	64.3	67.0	2,772	68.2	69.7	1,528
$75	100 Mesh			40/70		
Year	IBS, $MM	NWS, $MM	Difference, $M	IBS, $MM	NWS, $MM	Difference, $M
1	25.0	26.3	1,284	32.5	35.2	2,747
2	44.4	47.1	2,645	54.7	59.0	4,322
3	58.4	62.4	4,076	69.8	75.6	5,817
5	77.4	84.0	6,675	89.0	96.2	7,253
10	99.4	103.8	4,340	105.4	107.8	2,440
$100	100 Mesh			40/70		
Year	IBS, $MM	NWS, $MM	Difference, $M	IBS, $MM	NWS, $MM	Difference, $M
1	35.3	37.1	1,832	45.4	49.1	3,768
2	61.2	64.9	3,646	75.0	80.9	5,867
3	79.8	85.4	5,554	95.1	103.0	7,866
5	105.2	114.2	9,020	120.7	130.5	9,770
10	134.6	140.5	5,900	142.6	146.0	3,370

The resulting Share NPV shown above (Delaware basin) are presented graphically for all four proppant types, by oil price, for the P50 cash flow scenarios in **Figures A.22 – A.24** and shown again by proppant types and oil price for the P90 cash flow scenarios in **Figure A.25 – A.27. Figures 1.14** and **1.15** show the data above including all four proppant types and all three oil prices for the P50 100 mesh and 40/70 cases respectively and **Figures 1.16** and **1.17** show the results for the P90 100 mesh and 40/70 cases.

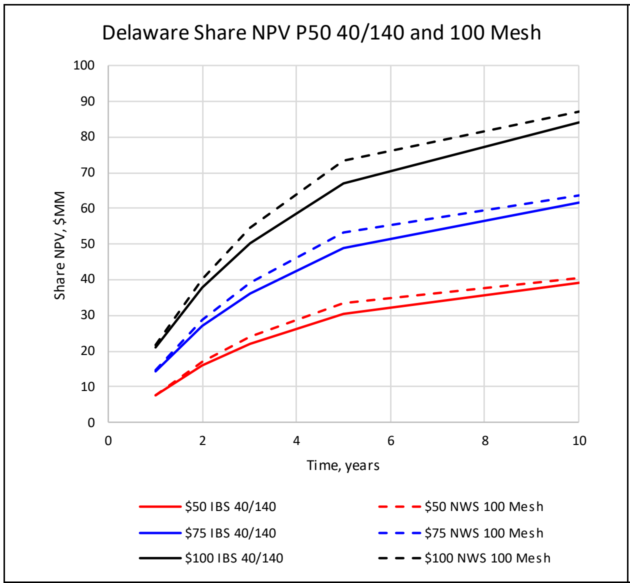


Fig. 1.14– Share NPV for Delaware Basin P50 cases of 40/140 and 100 Mesh.

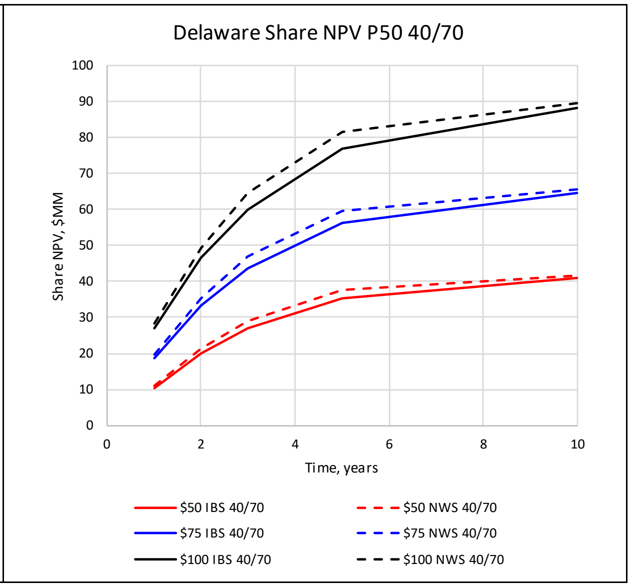


Fig. 1.15 – Share NPV for Delaware Basin P50 case of 40/70.

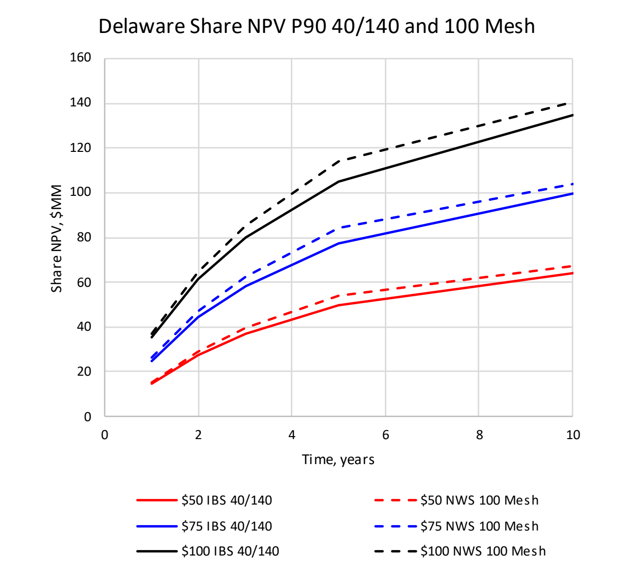


Fig. 1.16 – Share NPV for Delaware Basin P90 cases of 40/140 and 100 Mesh.

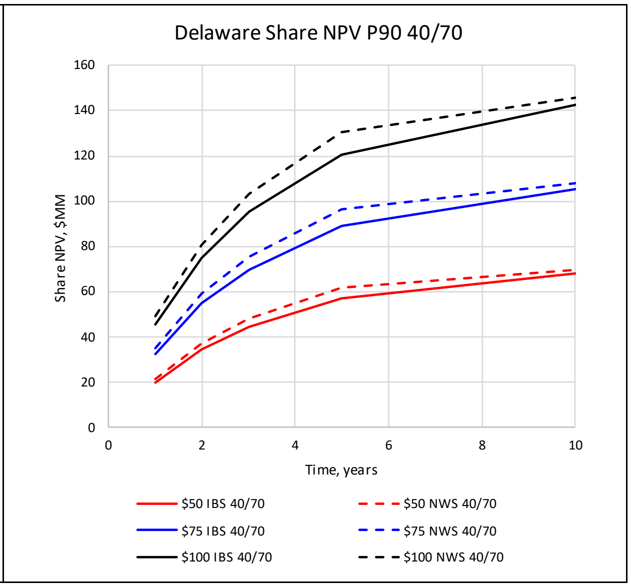


Fig. 1.17 – Share NPV for Delaware Basin P90 case of 40/70.

The Share NPV runs were used to determine the payoff for each case of NWS 100 mesh and the NWS 40/70. The payoff is the time required to have the proppant cost of NWS covered by the additional revenue generated. This comes from the separation in the Share NPV curves resulting from the separation in cumulative BOE production curves. The payout for the Delaware basin P50 and P90 wells is shown in **Figures 1.18 and 1.19** which were originally presented in Table 9 at oil prices of $50, $75, and $100 USD**.** As expected, the payout time decreases with increasing commodity prices. The P90 wells will have a shorter payout time than the P50 cases as there is greater production (better wells) to offset the additional costs of the NWS.

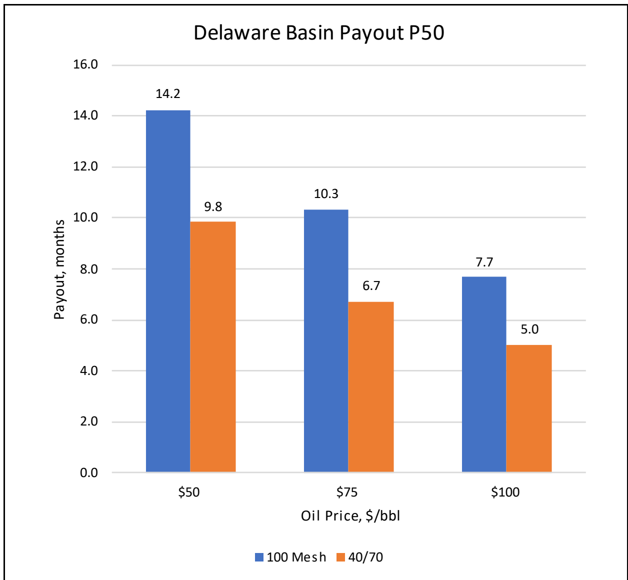


Fig. 1.18 – Estimated time, in months, to pay out the additional proppant cost of NWS 100 and 40/70 mesh over IBS 100 and 40/70 mesh in the Delaware basin for P50 well production case at oil prices of $50, $75 and $100 USD.

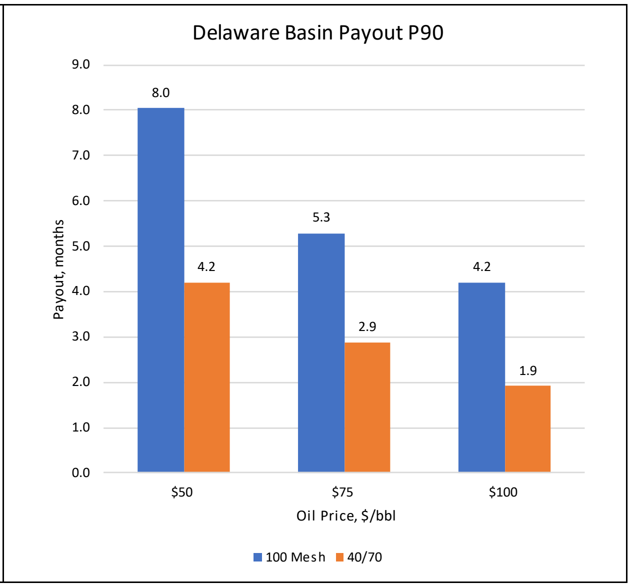


Fig. 1.19 – Estimated time, in months, to pay out the additional proppant cost of NWS 100 and 40/70 mesh over IBS 100 and 40/70 mesh in the Delaware basin for P90 well production case at oil prices of $50, $75 and $100 USD.

Considering the Midland basin cases, the forecasted cumulative BOE production was used to determine the Share NPV of 85% to the operator and determine the payoff time required for the additional cost of NWS. The results are reported in 1-, 2-, 3-, 5-, and 10-year intervals. The Midland basin P50 production forecast is presented in **Table 22** and the P90 production forecast is shown in **Table 23**.

Table 22: Midland Share NPV for P50 cases.

$50	100 Mesh			40/70		
Year	IBS, $MM	NWS, $MM	Difference, $M	IBS, $MM	NWS, $MM	Difference, $M
1	2.1	2.0	-67	3.7	4.1	410
2	7.4	7.7	251	9.7	10.5	786
3	11.4	11.8	445	14.0	15.0	981
5	16.8	17.6	809	19.6	20.8	1,255
10	23.7	24.8	1,149	25.7	26.5	808
$75	100 Mesh			40/70		
Year	IBS, $MM	NWS, $MM	Difference, $M	IBS, $MM	NWS, $MM	Difference, $M
1	6.3	6.4	124	8.7	9.5	806
2	14.3	14.9	601	17.8	19.2	1,372
3	20.2	21.1	893	24.2	25.9	1,663
5	28.4	29.8	1,438	32.5	34.6	2,075
10	38.6	40.6	1,949	41.8	43.2	1,404
$100	100 Mesh			40/70		
Year	IBS, $MM	NWS, $MM	Difference, $M	IBS, $MM	NWS, $MM	Difference, $M
1	10.5	10.8	315	13.8	15.0	1,203
2	21.2	22.1	951	25.9	27.8	1,957
3	29.1	30.4	1,341	34.4	36.7	2,346
5	39.9	42.0	2,067	45.5	48.4	2,895
10	53.6	56.4	2,749	57.8	59.8	2,001

Table 23: Midland Share NPV for P90 cases.

$50	100 Mesh			40/70		
Year	IBS, $MM	NWS, $MM	Difference, $M	IBS, $MM	NWS, $MM	Difference, $M
1	6.7	7.0	256	9.6	10.4	722
2	15.3	16.1	855	19.5	20.8	1,306
3	21.7	23.1	1,405	26.5	28.2	1,738
5	30.7	33.1	2,457	35.9	38.2	2,310
10	42.6	44.6	1,977	46.1	47.2	1,072
$75	100 Mesh			40/70		
Year	IBS, $MM	NWS, $MM	Difference, $M	IBS, $MM	NWS, $MM	Difference, $M
1	13.2	13.8	610	17.7	18.9	1,275
2	26.1	27.6	1,507	32.4	34.6	2,152
3	35.6	38.0	2,331	42.9	45.7	2,799
5	49.1	53.1	3,911	57.0	60.6	3,657
10	67.1	70.3	3,191	72.4	74.2	1,800
$100	100 Mesh			40/70		
Year	IBS, $MM	NWS, $MM	Difference, $M	IBS, $MM	NWS, $MM	Difference, $M
1	19.7	20.7	963	25.7	27.5	1,828
2	36.9	39.0	2,160	45.4	48.4	2,999
3	49.6	52.9	3,259	59.3	63.2	3,861
5	67.6	73.0	5,364	78.1	83.1	5,005
10	91.5	95.9	4,405	98.6	101.1	2,529

The resulting Share NPV shown above (Midland basin) are presented graphically for all four proppant types, by oil price, for the P50 cash flow scenarios in **Figures A.28 – A.30** and shown again by proppant types and oil price for the P90 cash flow scenarios in **Figure A.31 – A.33.** **Figures 1.20** and **1.21** show the data above including all four proppant types and all three oil prices for the P50 100 mesh and 40/70 cases respectively and **Figures 1.22** and **1.23** show the results for the P90 100 mesh and 40/70 cases.

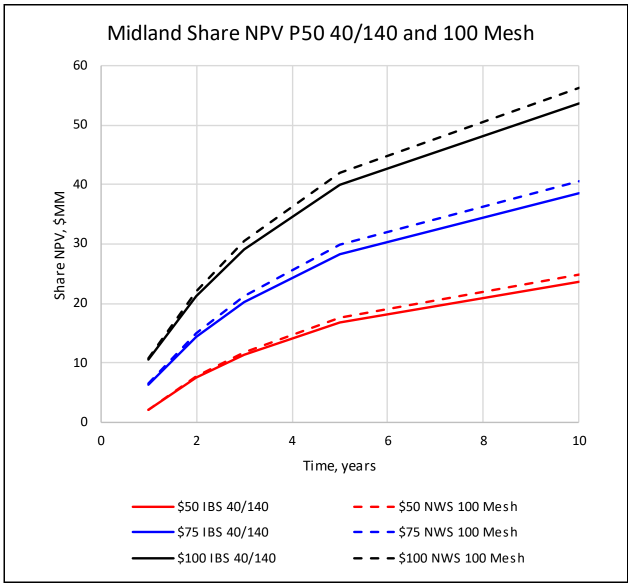


Fig. 1.20 – Share NPV for Midland Basin P50 case of 40/140 and 100 Mesh.

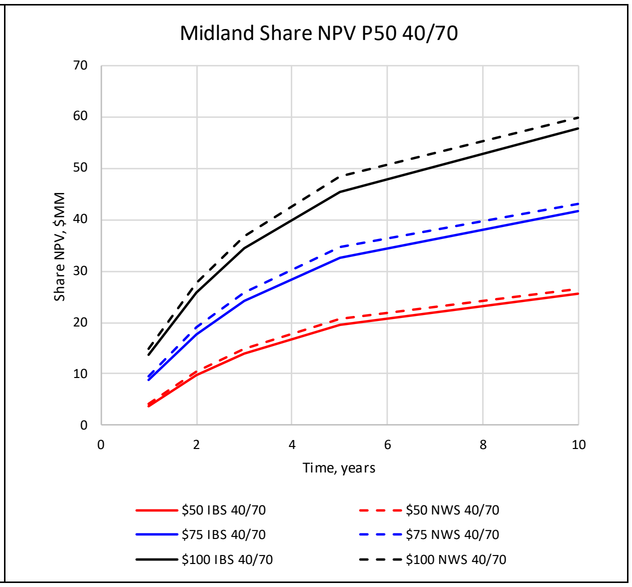


Fig. 1.21 – Share NPV for Midland Basin P50 case of 40/70.

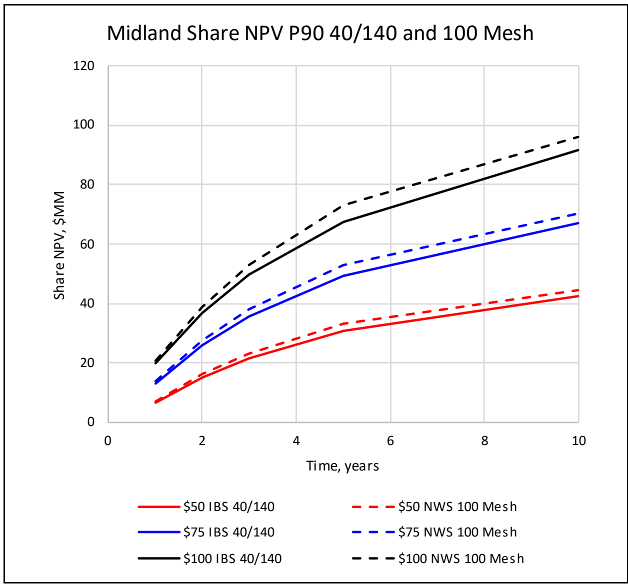


Fig.1.22 – Share NPV for Midland Basin P90 case of 40/140 and 100 Mesh.

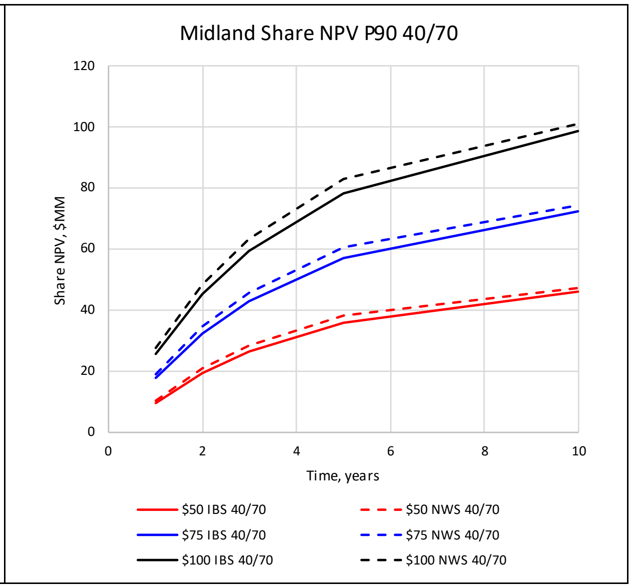


Fig. 1.23 – Share NPV for Midland Basin P90 case of 40/70.

The Share NPV runs were used to determine the payoff for each case of NWS 100 mesh and the NWS 40/70. The payout for the Midland basin P50 and P90 cases are shown in **Figures 1.24** and **1.25** originally presented in Table 9 at oil prices of $50, $75, and $100 USD**.** As expected, the payout time decreases with increasing commodity prices. The P90 wells will have a shorter payout time than the P50 cases as there is greater production to offset the additional costs of the NWS.

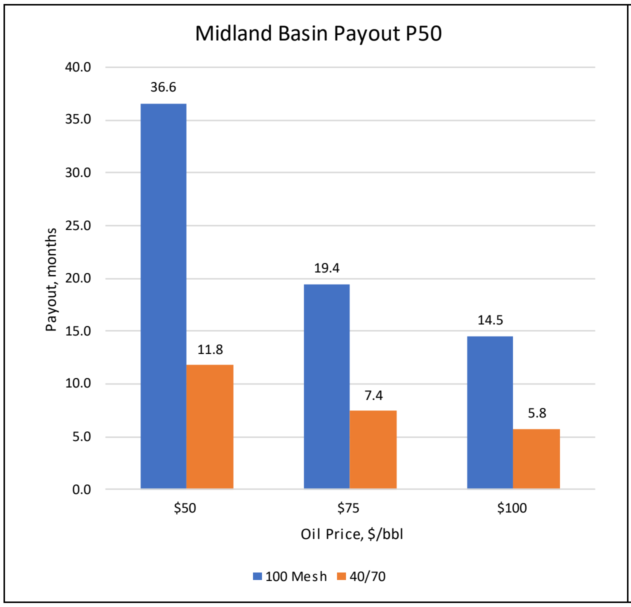


Fig. 1.24 – Estimated time, in months, to pay out the additional proppant cost of NWS 100 and 40/70 mesh over IBS 100 and 40/70 mesh in the Midland basin for P50 well production case.

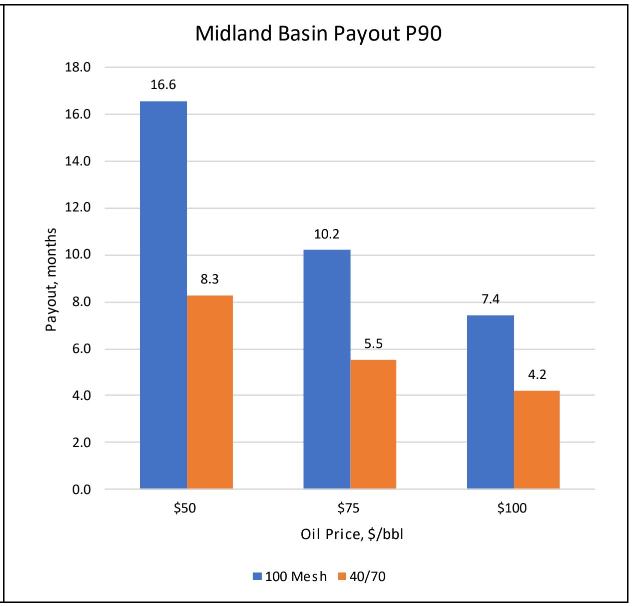


Fig. 1.25 – Estimated time, in months, to pay out the additional proppant cost of NWS 100 and 40/70 mesh over IBS 100 and 40/70 mesh in the Midland basin for P90 wells.

Conclusions

- Fracture stimulation in the Permian basin has been practiced for over 50 years and the application and selection of proppants has been well documented.
- RPI and ISO standards for proppants have been in place since the early 1980's.
- Research in the 1980's led to the development of enhanced strength proppant materials that could be applied at closure ranges from 7000 psi to 10,000 psi, a range where sands are now applied without consideration of conductivity impact.
- The evolution from polymer laden fluids to slick water was originally undertaken to reduce costs however it was recognized that the conductivity damage associated with polymer residue in the induced hydraulic fracture reduced conductivity and subsequent productivity.

- It is recognized in the industry that NWS is a superior product to IBS creating improved fracture conductivity and BOE production and associated reserves in the Delaware and Midland basins.
- Early time cash flows in the first 2-5 years of well life can be diminished with the use of In-basin sands thus limiting an operator’s cash for continued drilling operations.
- Recent technical publications have undertaken studies to identify and extrapolate the long-term negative effects produced by the reduced conductivity created by In-basin sands at closure ranges where white sands or man-made proppants have been historically applied.
- Rystad was commissioned by WISA to study the effects of In-Basin sands verses that of Northern White Sands and the conclusions draw a clear relationship between the application of In-basin sands and reduced well productivity after seven different operators made the switch from NWS.
- Fracture modeling of NWS and IBS resulted in a 4.5x greater conductivity of NWS compared to IBS regardless of mesh size in the Delaware basin. In the Midland basin, NWS 100 mesh had 4.2X improved fracture conductivity over IBS 100 mesh, and NWS 40/70 shows 2.6X improved conductivity of IBS 40/70.
- The production deliverability from NWS material becomes greater over the life of the well.
- At 5-yr in the Delaware basin, NWS 100 mesh on average creates 9% more value over IBS 100 mesh for both the P50 and P90 production cases. The NWS 40/70 material on average adds 6% value over IBS 40/70 for the P50 production case and 8% for the P90 well.
- At 5-yr in the Midland basin, the NWS 40/70 material on average adds 6% value over IBS 40/70 for both the P50 and P90 production cases. The NWS 100 mesh on average creates 5% more value over IBS 100 mesh for the P50 case and 8% for the P90 production case.
- An oil price of $75 USD will payout the additional cost of NWS proppant in P50 wells in 10 months and 7 months for P90 wells in the Delaware basin and 5 months and 3 months for the NWS 40/70. In 5 years, the additional value generated with NWS 100 mesh is 4.5 MMUSD and 3.5 MMUSD for the NWS 40/70 for the P50 case. The additional value generated with NWS 100 and 40/70 mesh is 6.7 MMUSD and 7.3 MMUSD, respectively for the P90 case.
- In the Midland basin, an oil price of $75 USD will payout the additional cost of NWS 100 Mesh proppant in P50 wells in 19 months and 10 months for P90 wells and 10 months and 6 months for the NWS 40/70. In 5 years, the additional value generated with NWS 100 mesh is 1.4 MMUSD and 2.1 MMUSD for the NWS 40/70 for the P50 case. The additional value generated with NWS 100 and 40/70 mesh is 3.9 MMUSD and 3.7 MMUSD, respectively, for the P90 case.

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Appendix

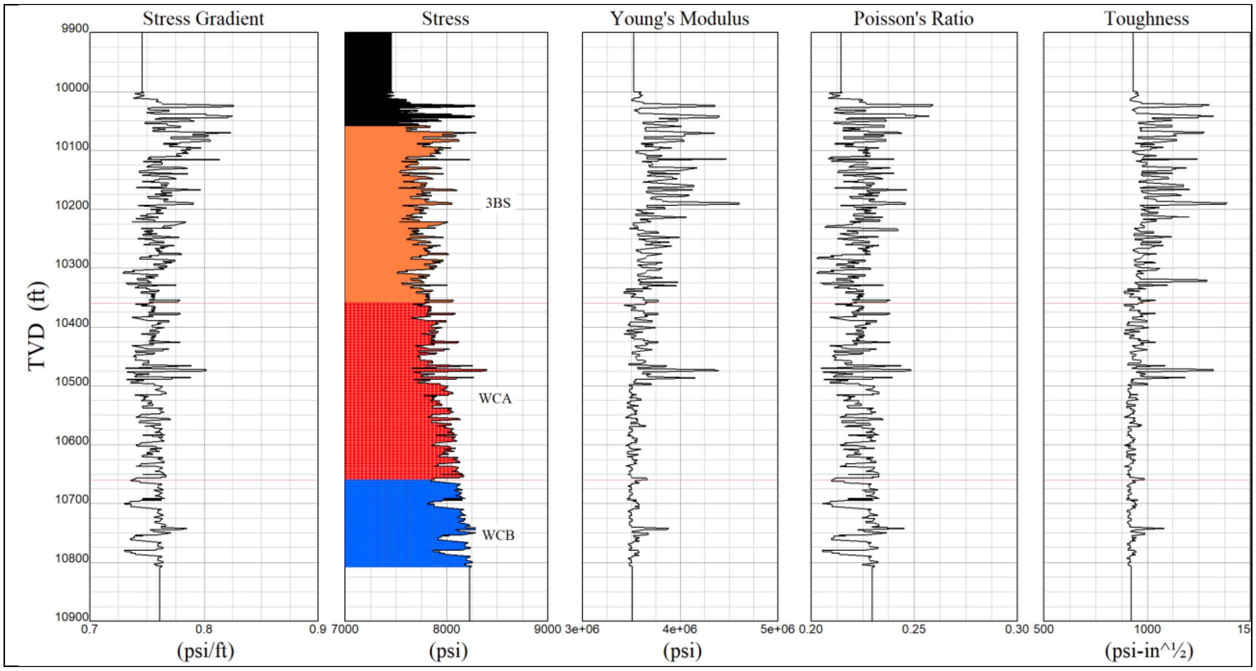

Fig. A.1 – Mechanical rock properties used for the WCA Delaware basin fracture modeling.

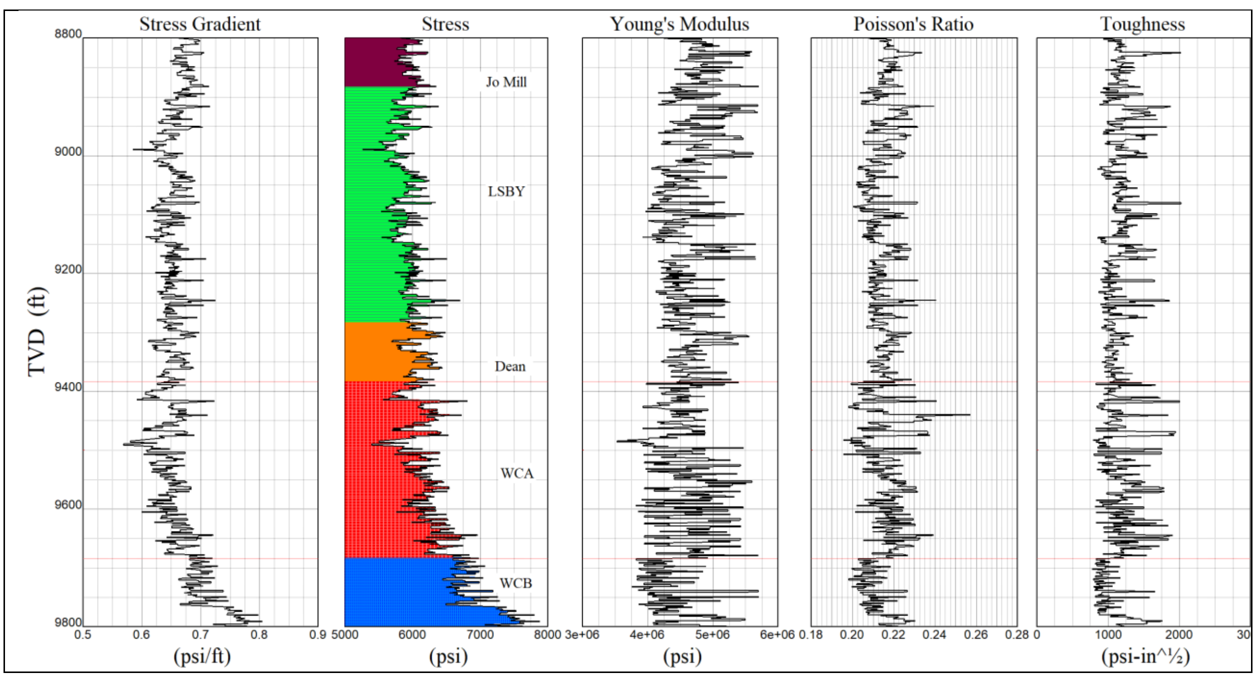

Fig. A.2 – Mechanical rock properties used for the WCA Midland basin fracture modeling.

Table A.1 - Formation properties from type log used for fracture modeling.

Formation Properties	Delaware	Midland	
TVD	10,500	9,500	ft
Min Horizontal Stress Gradient	0.76	0.65	psi/ft
Min Horizontal Stress	7,980	6,175	psi
Young's Modulus	3.56	4.58	MMpsi
Poisson's Ratio	0.223	0.217	-
Fracture Toughness	950	1,200	psi-ft$^{1/2}$
Reservoir Pressure Gradient	0.69	0.49	psi/ft
Reservoir Pressure	7,245	4,655	psi

FRACTURE DESIGN PUMP SCHEDULE

WELL NAME	In-Basin Sand				
LOCATION		Stage Spacing: 200 (ft)	Pad Percentage 5%	9,288	Total Water Required for Job (bbls)
FORMATION	WCA	Fluid Design: 1,951 (gal/ft)	100 Mesh Percentage 50%	390,115	Total Water Required for Job (gals)
OPERATOR	Generic	Proppant Design: 2,000 (lbm/ft)	40/70 Natural Percentage 50%	400,000	Total Proppant Required for Job (lbm)
API		lbm / U.S gal Design: 1.03 (lbm/gal)	30/50 Natural Percentage 0%		
AFE					

									CLEAN VOLUMES			SLURRY VOLUMES			STAGE
									STAGE		TOTAL	STAGE		TOTAL	TIME
STAGE		FLUID	PROPPANT	RATE	CONC.	PROP SG	STG MASS	TOTAL MASS	GALS	BBLS	GALS	GALS	BBLS	GALS	(minutes)
1	LOAD	Slickwater	-	20	0.00	2.65	0	0	1000	24	1000	1000	24	1000	1.19
2	ACID	15% HCl	-	20	0.00	2.65	0	0	1000	24	2000	1000	24	2000	1.19
3	PAD	Slickwater	-	65	0.00	2.65	0	0	20000	476	22000	20000	476	22000	7.33
4	PROP	Slickwater	Varies	90	0.25	2.65	10000	10000	40000	952	62000	40453	963	62453	10.70
5	PROP	Slickwater	Varies	90	0.50	2.65	20000	30000	40000	952	102000	40906	974	103359	10.82
6	PROP	Slickwater	Varies	90	0.75	2.65	30000	60000	40000	952	142000	41359	985	144718	10.94
7	PROP	Slickwater	Varies	90	1.00	2.65	40000	100000	40000	952	182000	41812	996	186530	11.06
8	PROP	Slickwater	Varies	90	1.25	2.65	50000	150000	40000	952	222000	42265	1006	228795	11.18
9	PROP	Slickwater	Varies	90	1.50	2.65	50000	200000	33333	794	255333	35598	848	264393	9.42
10	PROP	Slickwater	Varies	90	1.50	2.65	60000	260000	40000	952	295333	42718	1017	307111	11.30
11	PROP	Slickwater	Varies	90	1.75	2.65	70000	330000	40000	952	335333	43171	1028	350282	11.42
12	PROP	Slickwater	Varies	90	2.00	2.65	70000	400000	35000	833	370333	38171	909	388453	10.10
13			-	90		2.65	0	400000		0	370333	0	0	388453	0.00
14			-	90		2.65	0	400000		0	370333	0	0	388453	0.00
15			-	90		2.65	0	400000		0	370333	0	0	388453	0.00
16			-	90		2.65	0	400000		0	370333	0	0	388453	0.00
17			-	90		2.65	0	400000		0	370333	0	0	388453	0.00
18			-	90		2.65	0	400000		0	370333	0	0	388453	0.00
19			-	90		2.65	0	400000		0	370333	0	0	388453	0.00
20			-	90		2.65	0	400000		0	370333	0	0	388453	0.00
21			-	90		2.65	0	400000		0	370333	0	0	388453	0.00
22			-	90		2.65	0	400000		0	370333	0	0	388453	0.00
23			-	90		2.65	0	400000		0	370333	0	0	388453	0.00
24			-	90		2.65	0	400000		0	370333	0	0	388453	0.00
25	FLUSH	Slickwater	-	90		2.65	0	400000	19782	471	390115	19782	471	408235	5.23
							TOTAL	400000		TOTALS	390115	408235	9720		111.9

CASING INFORMATION				
OD / ID/Drift (in)	GRADE / WT (lb/ft)	MD (ft)	PBTD (ft)	CAPACITY (bbl/ lin.ft)
5.500 / 4.670	P-110 / 23.00 lb/ft	21,100		0.021186

Completed Lateral Length			Stages	Clusters	Diameter	SPF	Holes
	MD (ft)	Displace (bbl)					
First	11000	233	50	10	0.42	3	30
Last	21000	445					
Mid	16000	339					
$Length_{Perf}$	10000						

Fig. A.3 – Pump schedule used for both the Delaware and Midland basins. Cases 1-4 were modeled in the fracture simulator to obtain insitu fracture conductivity.

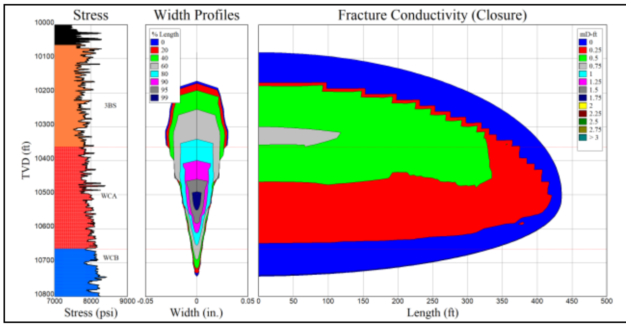

Fig. A.4 – Fracture conductivity distribution contour profile at fracture closure in WCA for CASE 1, IBS 40/140, in the Delaware basin.

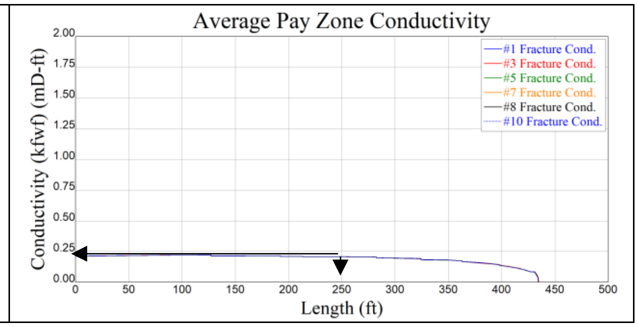

Fig. A.5 – Fracture conductivity distribution Cartesian profile at fracture closure in WCA with a 250' cutoff noted for CASE 1, IBS 40/140, in the Delaware basin.

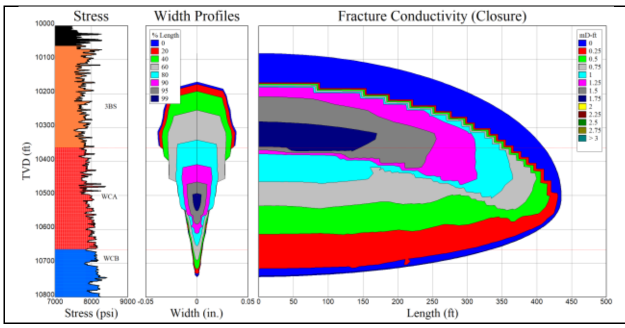

Fig. A.6 – Fracture conductivity distribution contour profile at fracture closure in WCA for CASE 2, IBS 40/70, in the Delaware basin.

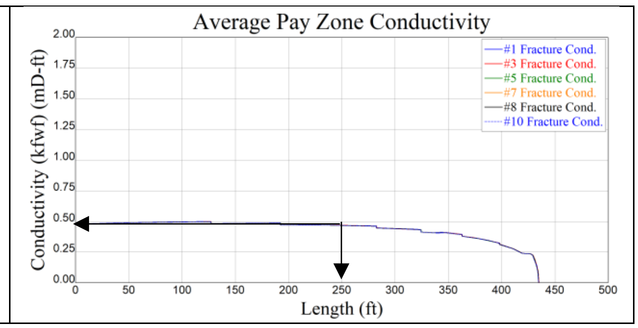

Fig. A.7 – Fracture conductivity distribution Cartesian profile at fracture closure in WCA with a 250' cutoff noted for CASE 2, IBS 40/70, in the Delaware basin.

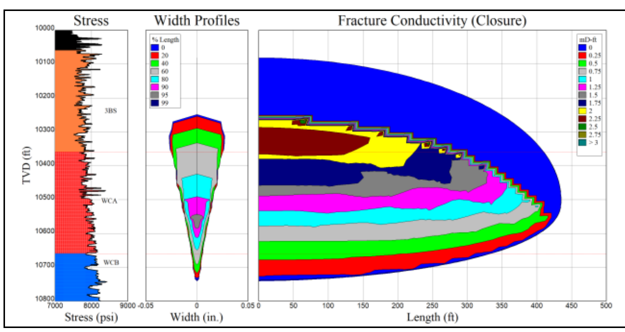

Fig. A.8 – Fracture conductivity distribution contour profile at fracture closure in WCA for CASE 3, NWS 40/140, in the Delaware basin.

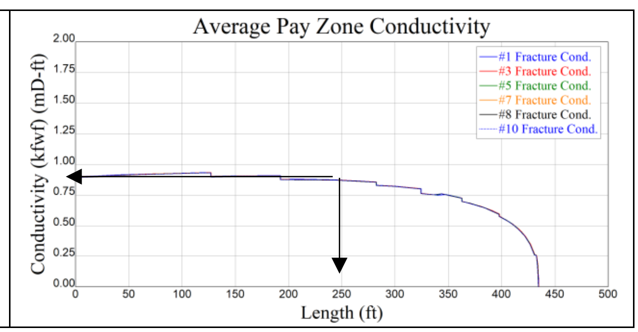

Fig. A.9 – Fracture conductivity distribution Cartesian profile at fracture closure in WCA with a 250' cutoff noted for CASE 3, NWS 40/140, in the Delaware basin.

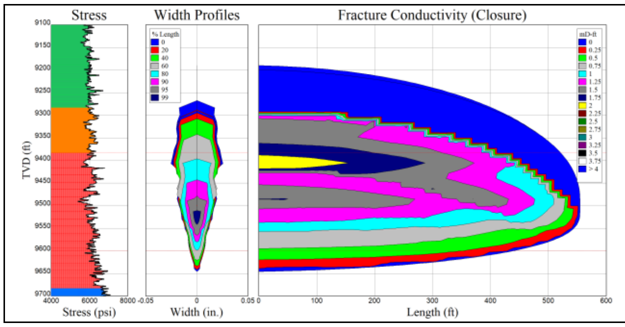

Fig. A.10 – Fracture conductivity distribution contour profile at fracture closure in WCA for CASE 1, IBS 40/140, in the Midland basin.

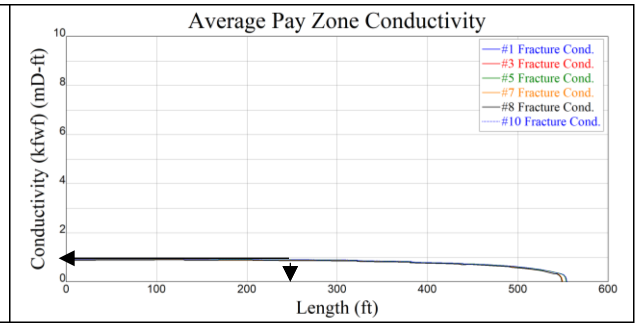

Fig. A.11 – Fracture conductivity distribution Cartesian profile at fracture closure in WCA with a 250' cutoff noted for CASE 1, IBS 40/140, in the Midland basin.

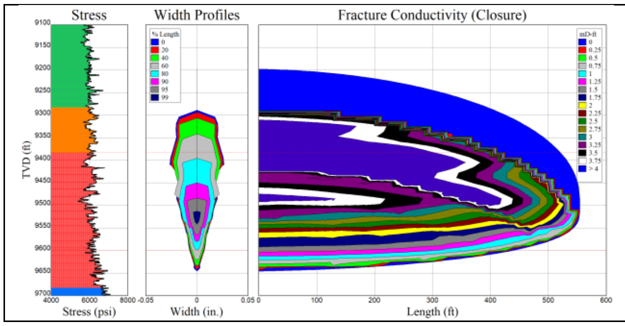

Fig. A.12 – Fracture conductivity distribution contour profile at fracture closure in WCA for CASE 2, IBS 40/70, in the Midland basin.

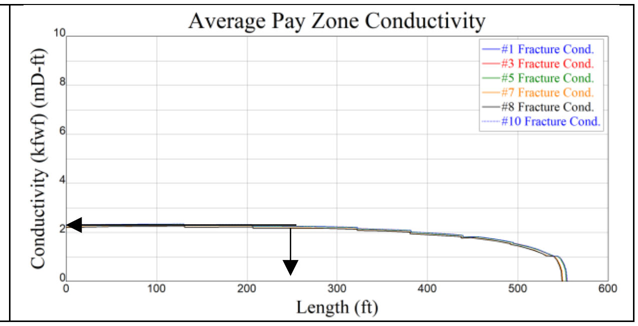

Fig. A.13 – Fracture conductivity distribution Cartesian profile at fracture closure in WCA with a 250' cutoff noted for CASE 2, IBS 40/70, in the Midland basin.

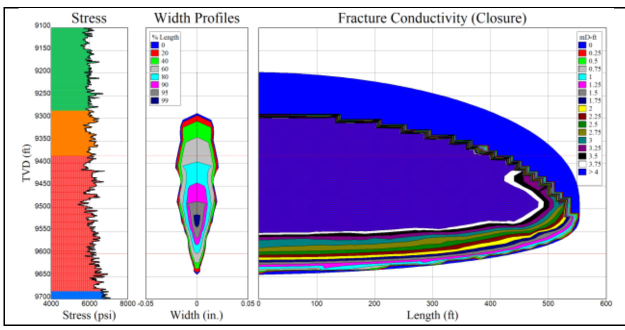

Fig. A.14 – Fracture conductivity distribution contour profile at fracture closure in WCA for CASE 3, NWS 40/140, in the Midland basin.

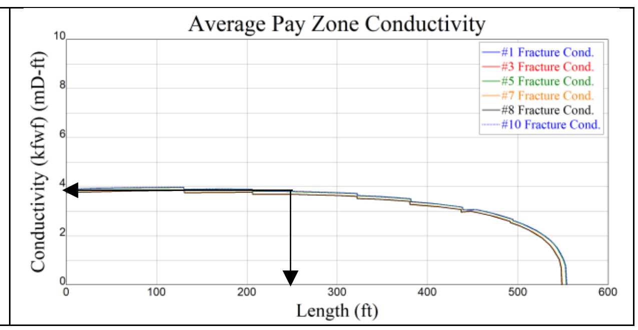

Fig. A.15 – Fracture conductivity distribution Cartesian profile at fracture closure in WCA with a 250' cutoff noted for CASE 3, NWS 40/140, in the Midland basin.

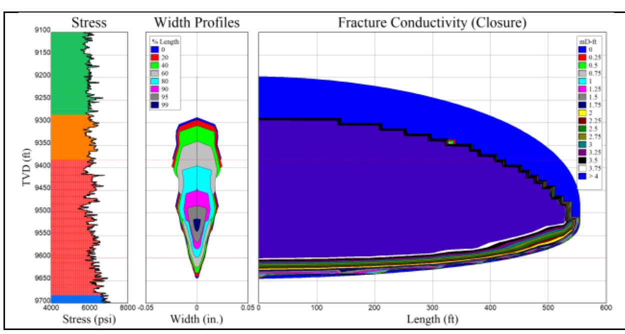

Fig. A.16 – Fracture conductivity distribution contour profile at fracture closure in WCA for CASE 4, SSNWS 40/70, in the Midland basin.

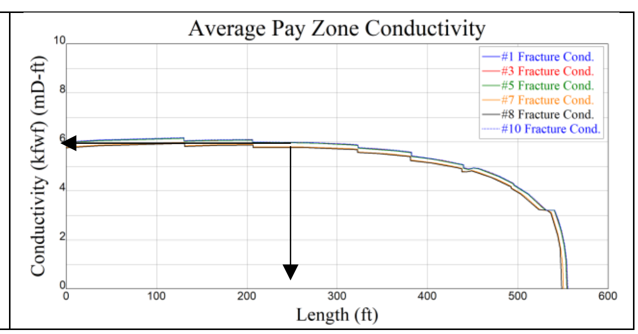

Fig. A.17 – Fracture conductivity distribution Cartesian profile at fracture closure in WCA with a 250' cutoff noted for CASE 4, SSNWS 40/70, in the Midland basin.

Table A.2 - Production forecast modeling inputs.

Production Forecast Assumptions	Delaware	Midland	
Gross Pay	300	300	ft
Net Pay	200	200	ft
Oil API	46	40	API
Gas SG	0.7	0.9	-
Porosity	7.5	6.3	%
Formation Volume Factor	1.2	1.2	RB/STB
Bubble point	2,000	2,000	psi

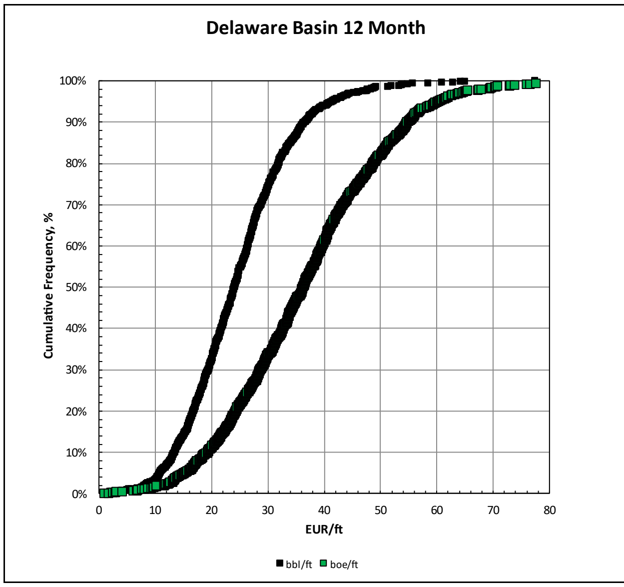

Fig. A.18 – Cumulative frequency distribution of 12-month cumulative oil and BOE production for the Delaware basin.

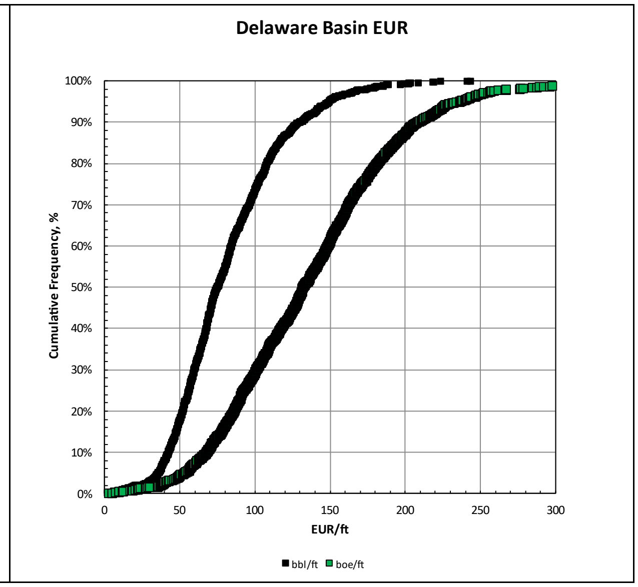

Fig. A.19 – Cumulative frequency distribution of 30-year oil and BOE EUR for the Delaware basin.

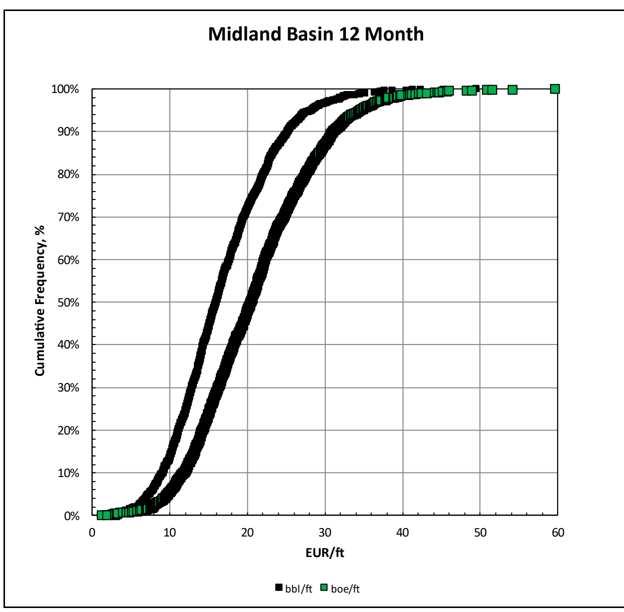

Fig. A.20 – Cumulative frequency distribution of 12-month cumulative oil and BOE production for the Delaware basin.

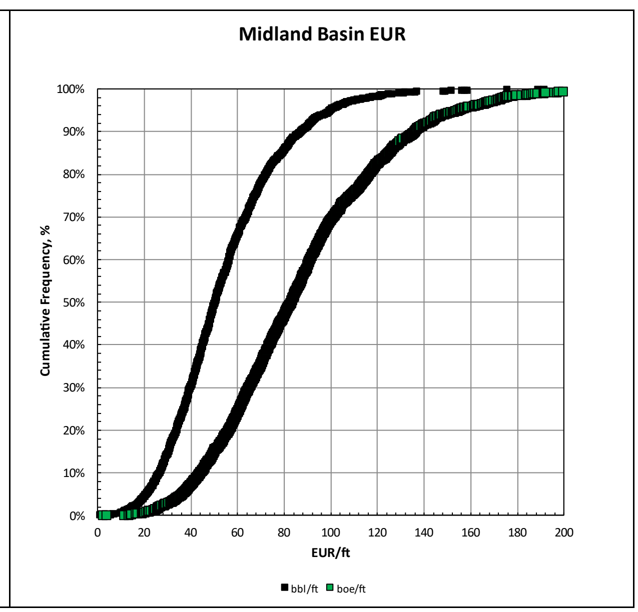

Fig. A.21 – Cumulative frequency distribution of 30-year oil and BOE EUR for the Delaware basin.

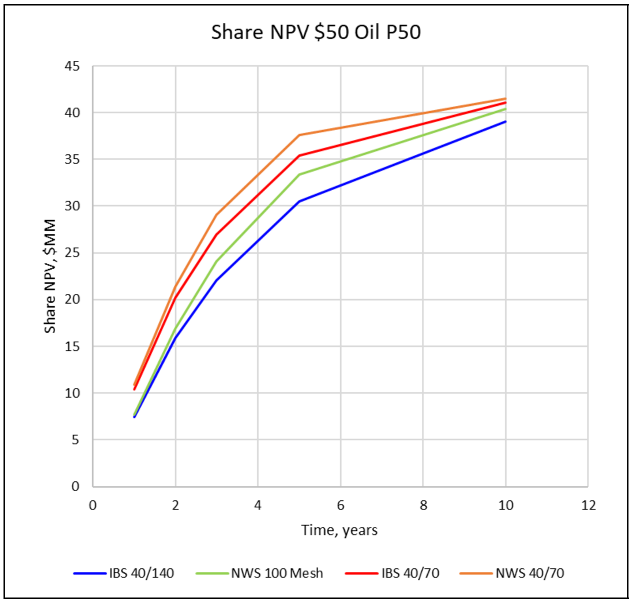

Fig A.22 – Share NPV for Delaware Basin P50 scenario for the four proppants in $50 cash flow scenario.

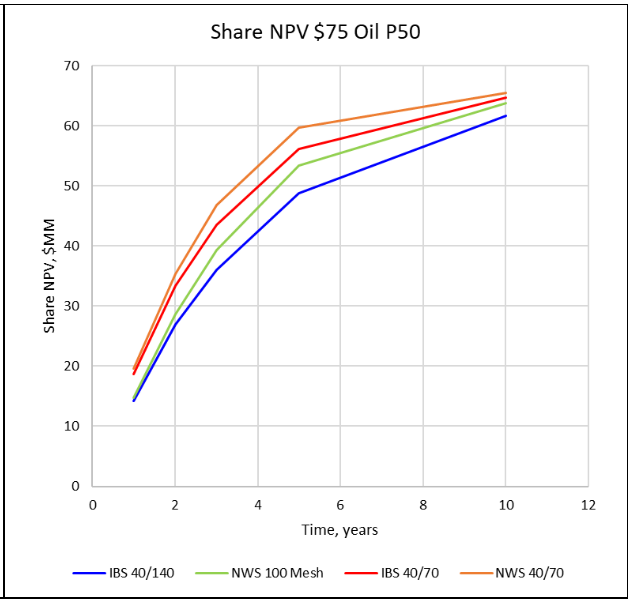

Fig A.23 – Share NPV for Delaware Basin P50 scenario for the four proppants in $75 cash flow scenario.

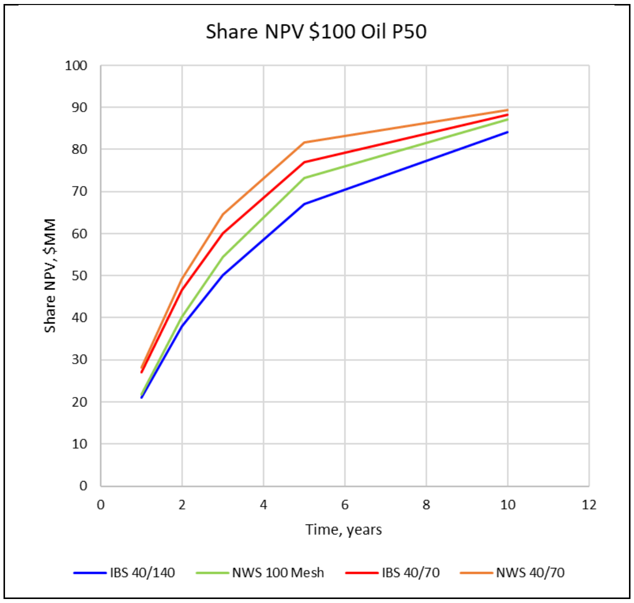

Fig A.24 – Share NPV for Delaware Basin P50 scenario for the four proppants in $100 cash flow scenario.

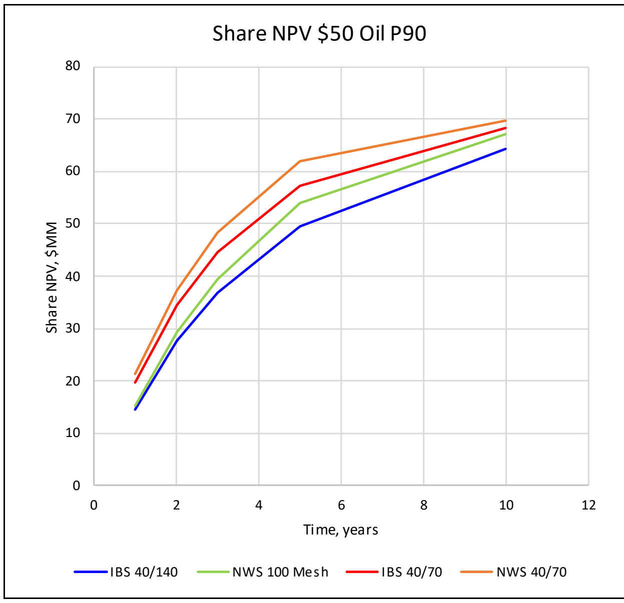

Fig A.25 – Share NPV for Delaware Basin P90 scenario for the four proppants in $50 cash flow scenario.

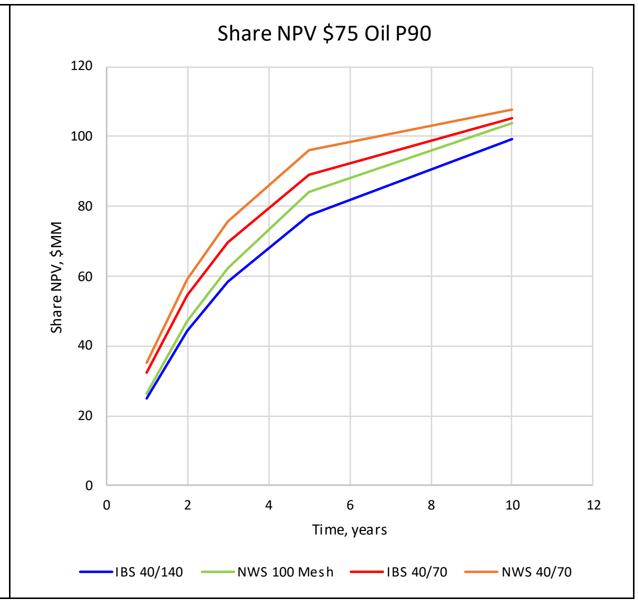

Fig A.26 – Share NPV for Delaware Basin P90 scenario for the four proppants in $75 cash flow scenario.

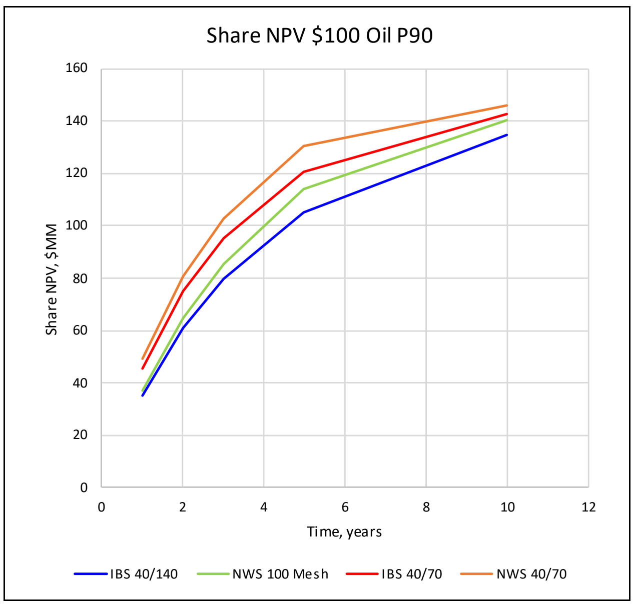

Fig A.27 – Share NPV for Delaware Basin P90 scenario for the four proppants in $100 cash flow scenario.

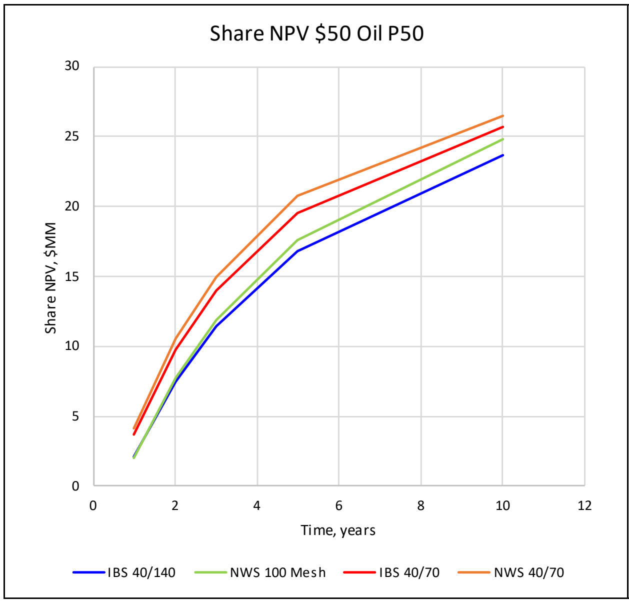

Fig A.28 – Share NPV for Midland Basin P50 scenario for the four proppants in $50 cash flow scenario.

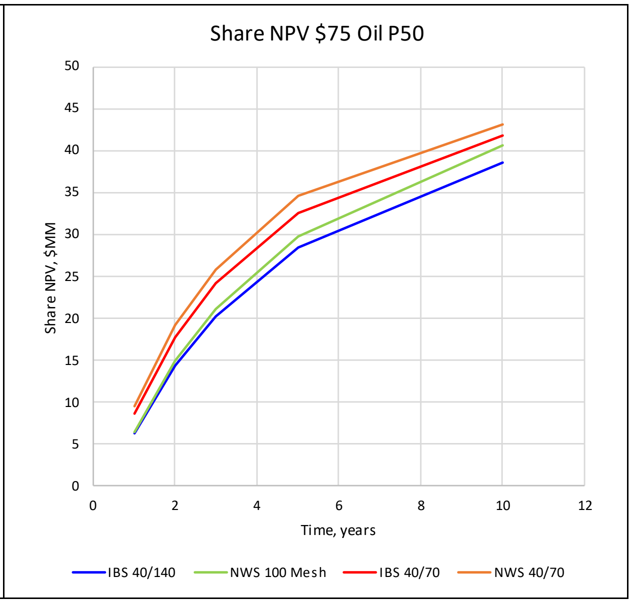

Fig A.29 – Share NPV for Midland Basin P50 scenario for the four proppants in $75 cash flow scenario.

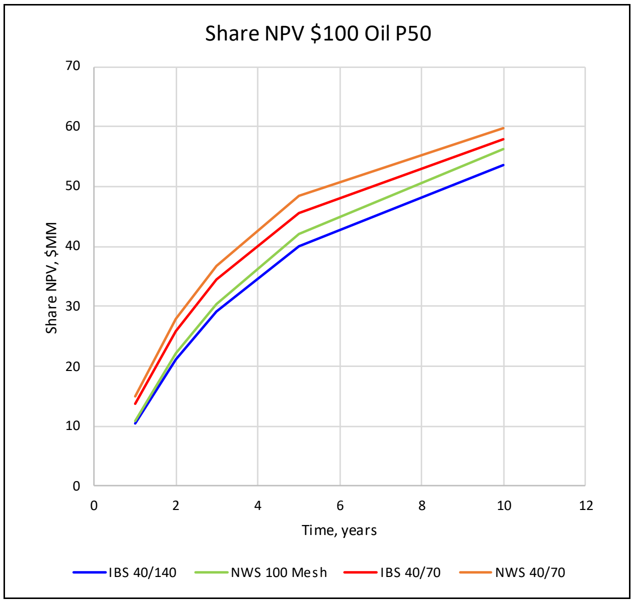

Fig A.30 – Share NPV for Midland Basin P50 scenario for the four proppants in $100 cash flow scenario.

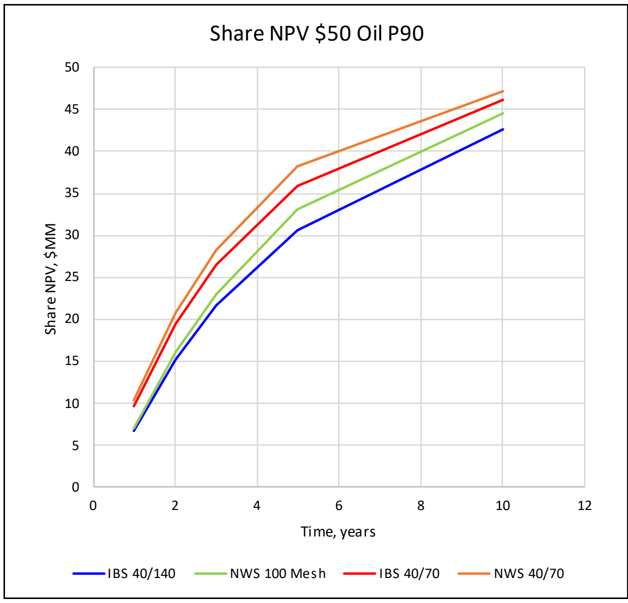

Fig A.31 – Share NPV for Midland Basin P90 scenario for the four proppants in $50 cash flow scenario.

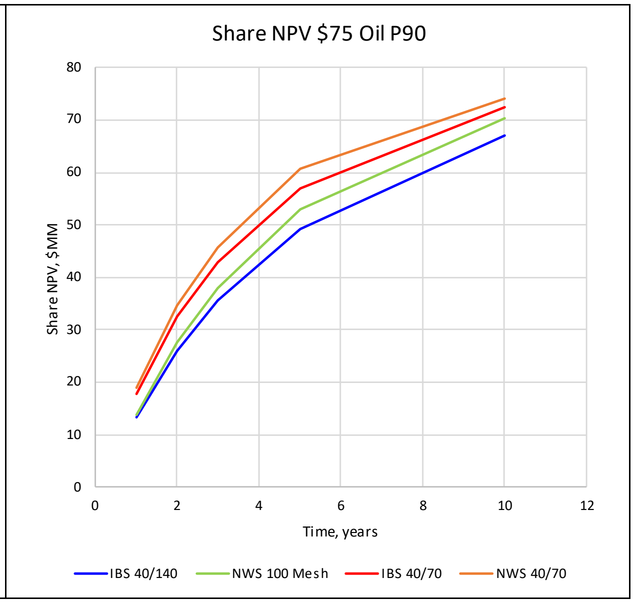

Fig A.32 – Share NPV for Midland Basin P90 scenario for the four proppants in $75 cash flow scenario.

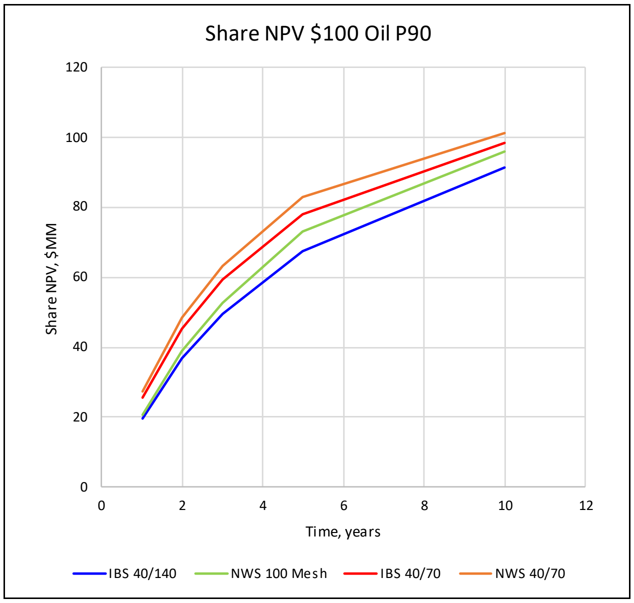

Fig A33 – Share NPV for Midland Basin P90 scenario for the four proppants in $100 cash flow scenario.