To frac or refrac? Insights from the Bakken*

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Abstract

Publically available data on U.S. frac jobs suggests refrac operations are still relatively modest, but growing (see Figure 1). In 2014 refracs accounted for 1.7% of all U.S. fracturing activity, 2.3% in 2015 and 2.6% by Q1 2016 (Johnson, 2016). For some U.S. Shale / Light Tight Oil (LTO) producers, refracs have become a hot topic again. Are they an overrated niche technology, or can they provide a lower cost alternative to drilling, as the number of high quality drilled uncompleted wells (DUCs) begins to decline?

This article builds on previous work by the author (Nolan, 2015) and summarises the results of a non-proprietary study on Bakken and Three Forks refracs. Wells that started producing after 2008 and had two or more fracs that were more than 12 months apart were identified and investigated. Incremental refrac production to date and estimated ultimate recoverable (EUR) were estimated. A refrac economic model was created and the incremental EUR required to break-even and generate an IRR of 10% determined. The economics of refracs vs fracs are considered.

Refracs

Refracs vary considerably in type and cost, from a small refrac with the aim of reconnecting to the existing completion (a so-called pump and pray) to a massive refrac designed to connect with virgin reservoir. Careful screening and ranking of candidate Drilling Spacing Units (DSU's) for refracing is one of the key aspects in the overall refrac process. What is the goal of the refrac? To remedy DSU's that were poorly completed? Is it to apply improved frac techniques? Or is it to access reservoir not accessed by the original frac? A refrac will involve stopping production, pumping a secondary stimulation treatment, recompleting the well and bringing it back online. A typical horizontal refrac treatment can vary considerably in design, extent, and cost. Many operators are currently quoting completion costs of $2.0-4.0 million (NDPC, 2016a). A recent study by the SPE and Baker Hughes suggests that some simple Bakken wells refracs can cost as little as $1.8 million (Collins, 2015). This study assumes two refrac cost scenarios, $2.5 and $3.5 million. Whatever the refrac type, the commercial objectives remain the same: to increase production, raise the estimated ultimate recoverable (EUR), and improve the overall DSU economics.

Bakken Refracs

Reliable estimates on the number of refracs carried out in the in the Bakken and Three Forks are hard to come by. Rystad (2016) estimate approximately 250 refracs; Primary Vision estimate is around 100 (Johnson, 2016). At the North Dakota Petroleum Council meeting in September 2016 (NDPC, 2016b), one leading operator quoted a total of 94 DSU's having been refraced in the Williston Basin.

A number of analysts have used statistical analysis of production data to determine candidate refrac wells. Determining the number of unsuccessful refracs, with limited or no increase in production, by statistical means is difficult. Well down-spacing, drilling producers closer to one another, can result in the unintentional stimulation of nearby older wells – so-called passive refracturing (Ciezobka et al., 2016). Offset well impacts have been seen up to a half-mile away, varying by shale play, reservoir quality, and presence of natural fractures. Statistically derived estimates of the number of refracs may be overstated as a result of passive refracturing and other types of well intervention.

The North Dakota Industrial Commission (NDIC) (NDOGD, 2016) production does not produce any refrac statistics. A list of all fracs carried out in North Dakota was supplied by NDIC and screened to identify public domain Bakken / Three Forks wells that started producing after 2008 and had two or more fracs that were more than 12 months apart. Eighty-three wells met the criteria. Of the 83 wells, 75 of were verified on FracFocus (2016), the United States national hydraulic fracturing chemical registry database.

The 83 wells with refracs are displayed in Figure 2 on a 12-month oil only production map. Sixty-nine percent of the refracs were performed by Marathon Oil in Dunn County and Southern McKenzie County between 2009 and 2015; 80% of the 83 refracs were performed when WTI oil prices were $75 or higher.

83 Bakken Refracs - Results

The top 5 refracs (by estimated oil only EUR) are also displayed in Figure 2. Figure 3 illustrates the well production for one of these, Jay Sandstrom USA 34-31H. The well started producing in February, 2009, and 12-month production was below expectation--41% of that predicted by the regional 12-month production model. A refrac was performed in June, 2014, and initial production peaked at 21,192 bopm (692 bopd), over twice the peak rate of the initial frac, 9355 bopm (307 bopd). Incremental refrac production is 193 mb,o and future refrac production is estimated to be 68 mbo giving a total incremental refrac EUR of 261 mbo.

Incremental refrac EURs (oil only) were estimated for all 83 wells, and the results are illustrated in Figure 4. The mean incremental oil EUR is 136 mbo. Five wells had no incremental production, 2 of these for refracs that had just been performed; so no production data was available. Figure 5 shows incremental oil only EURs vs 12-month oil only actual vs predicted for the 83 refracs. Wells that have performed below expectation are to the left; refracs with high EURS are to the top in lighter colours. No correlation exists between original well performance and refrac performance.

Bakken refrac data demonstrates a high degree of variation in refrac EUR and the difficulty in accurately predicting refrac reservoir performance. Ruhle (2016) summarised some of the likely explanations for refrac success and failure. Merely selecting a well based on initial completion design or initial performance is a 'naïve approach.' Refrac reservoir performance contrasts with the ability to reasonably predict frac reservoir performance. Work carried in this study has not focused on the reasons for refrac success/failure.

Passive Refracs

Screening of the well data reveals many examples of passive refracs (enhanced production as a result of a frac/refrac from a nearby well). Most passive refracs result in an increase in production and in some cases result in incremental EURs >100 mbo (oil only). Others have initially increased production, and then production has ceased all together. Incremental production from nearby passive refracs has not been included in the single well refrac economic modelling in this study, but it could have a significant impact.

Bakken Refrac Economic Model

A Bakken refrac economic model was constructed for a typical 2011 well with a refrac performed in 2016. Decline curves were modelled to determine NPV, IRR and break-even oil prices on a forward-looking basis, assuming flat oil and gas prices. The IP oil and gas rates of the 2016 refrac are varied according to a scalar of the original 2011 rates. Figure 6 shows the production profiles and outputs for the original 2011 well and the refrac. The same decline rates were used for the 2011 well and the 2016 refrac. The scalar and hence refrac IP are varied (using goal search in excel) to determine NPV zero after 20 years production (see Figure 7). This was repeated for the thirty scenarios in total.

The discount rate is 10% in all cases. Incremental Opex (LOE) costs were assumed to be 50% of the 2011 well. Three EUR cases were considered (230, 330 and 430 mboe oil+gas), two refrac costs cases ($2.5 and $3.5 million), and five forward oil price cases (WTI $40, 50, 60, 70 and 80).

Figure 7 shows a summary of the results for a 'base case' as well as the costs, taxes, royalties, depreciation and other production assumptions (similar to those used in the previous analysis). The 30 cases define a range of incremental EUR that a refrac needs to recover to break-even, as illustrated in Figure 8. A base case scenario was considered as: a 430 mboe 2011 well, a $2.5 million refrac cost, and oil at $60 WTI flat. The incremental refrac EUR required to break-even is 100 mbo (oil only).

For the base case to generate an IRR of 10%, the incremental refrac EUR required is 121 mbo (oil only). For a $3.5 million refrac to generate an IRR of 10%, the incremental refrac EUR required is 187 mbo (oil only); 60% of refracs had oil only EURs >121 mbo, and 27% had EURs >187 mbo (see Figure 9).

2016 Refrac vs 2016 Frac Economics

The economics of refracing an average 2011 well in 2016 versus completing a 2015 DUC in 2016 were compared (no drilling costs included). The IP oil and gas rates of the 2016 refrac are varied according to a scalar of the original 2011 rates (630 bopd, 477 mscf/d) in order to achieve the same NPV as the 2016 frac. Using the base case assumptions, an incremental (oil only) refrac EUR of 288 mbo would be required to generate the same NPV as completing an average 2015 DUC in 2016. Only one refrac exceeded this value. Previous work by the author

(Nolan, 2015) outlines the average 2015 DUC production parameters.

Conclusions

Frac/DUC economics are by in large superior to those of refracs. Higher oil prices and lower completion costs will reduce the incremental EUR threshold required to make refracs economically attractive. The inability to accurately predict refrac reservoir performance as opposed to the ability to reasonably predict frac reservoir performance is another key reason as to why refracs are considered niche technology by many operators. Companies with a limited supply of high quality DUCs and a need to reduce capital expenditure may view refracs as a lower cost alternative to maintaining production. The remaining key to transforming refracs from niche to mainstream is the ability to accurately predict refrac reservoir performance.

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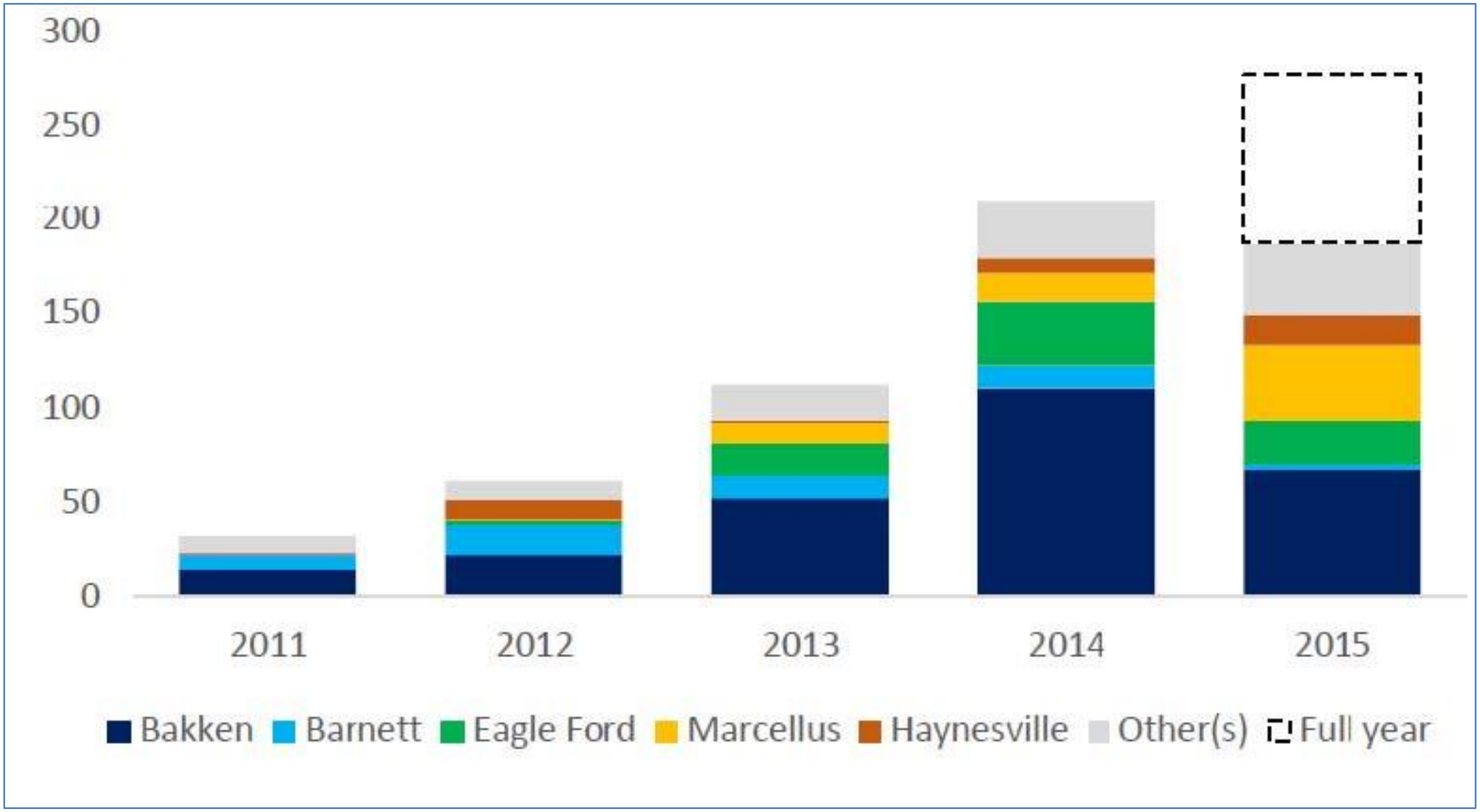
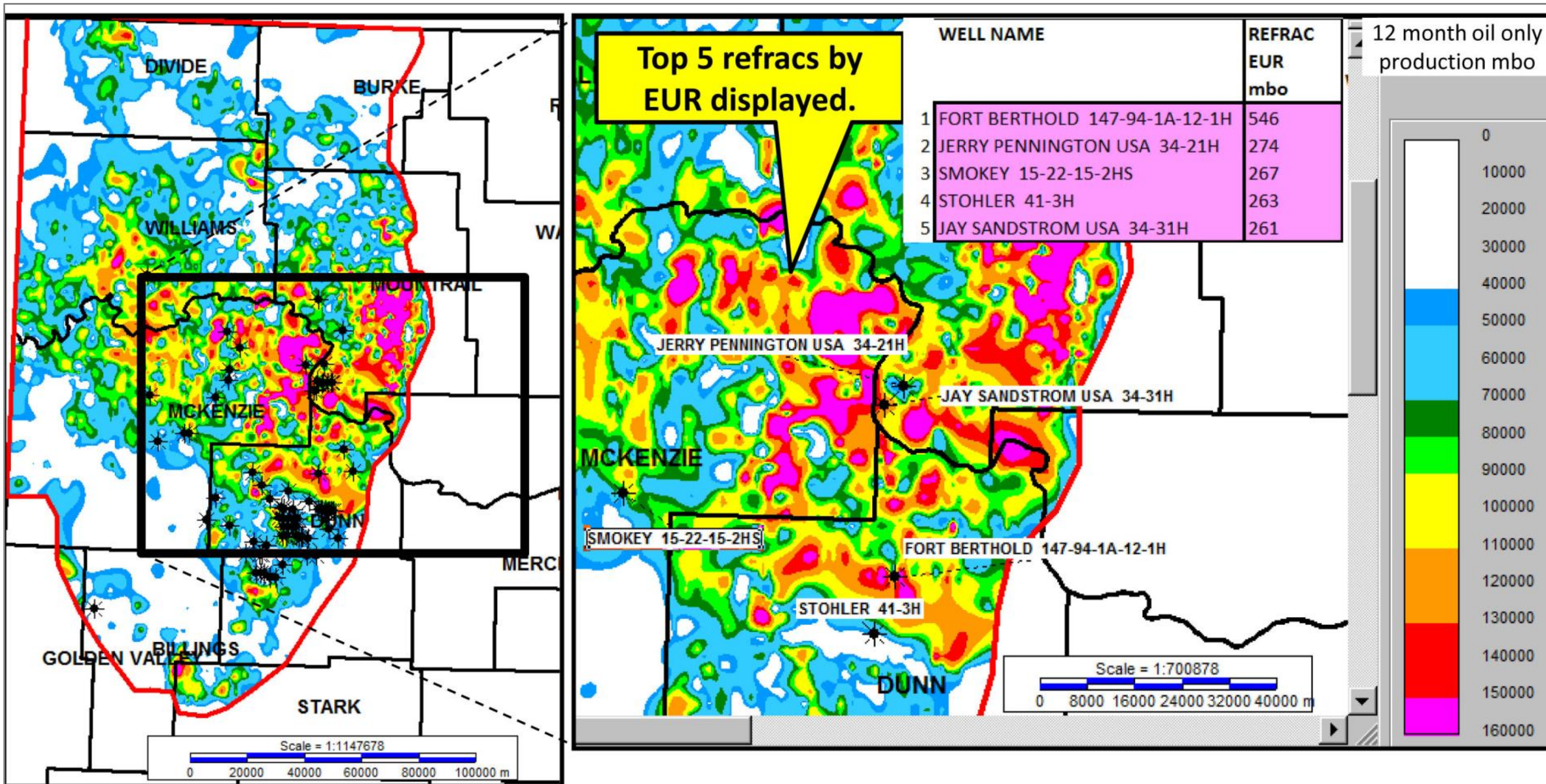
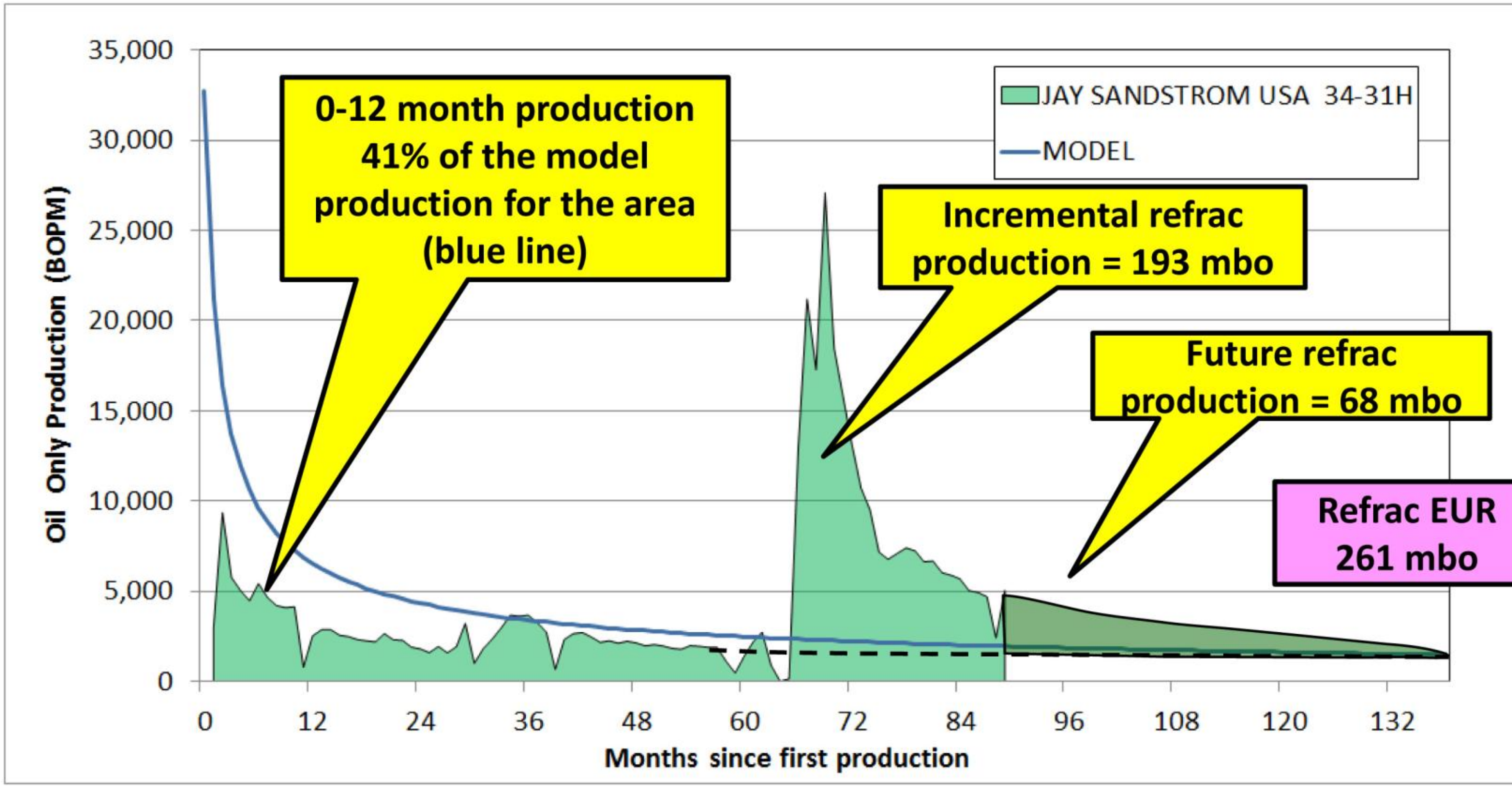


Figure 1 – Number of refractured horizontal wells by play, as of August 2015



WELL NAME	Operator	FIRST PROD. (FP) DATE	FRAC FOCUS?	REFRAC (RF) DATE	Years (FP-RF)	WTI OIL PRICE $	12M OIL ACTUAL mbo	12M OIL MODEL mbo	ACTUAL/ MODEL %	INCREMENTAL REFRAC PROD. mbo	FUTURE REFRAC PROD. mbo	REFRAC EUR mbo
FORT BERTHOLD 147-94-1A-1	MARATHON OIL COMPANY	01/07/2010	N	07/10/2011	1.27	86.3	1	75	1%	546	0	546
JERRY PENNINGTON USA 34-2	MARATHON OIL COMPANY	01/06/2009	Y	06/07/2014	5.10	103.6	45	65	70%	166	108	274
SMOKEY 15-22-15-2HS	MARATHON OIL COMPANY	01/12/2011	Y	20/04/2013	1.39	92.0	13	71	18%	223	45	267
STOHLER 41-3H	MARATHON OIL COMPANY	01/01/2008	Y	17/07/2014	6.54	103.6	50	46	108%	132	132	263
JAY SANDSTROM USA 34-31H	MARATHON OIL COMPANY	01/02/2009	Y	28/06/2014	5.40	105.8	53	129	41%	193	68	261

Figure 2. Bakken 12 month oil only production map +83 refracs



NDIC WELL ID	WELL NAME	Operator	FIRST PROD. (FP) DATE	FRAC FOCUS?	REFRAC (RF) DATE	Years (FP-RF)	WTI OIL PRICE $	12M OIL ACTUAL mbo	12M OIL MODEL mbo	ACTUAL/ MODEL %	INCREMENTAL REFRAC PROD. mbo	FUTURE REFRAC PROD. mbo	REFRAC EUR mbo
17771	JAY SANDSTROM USA 34-31H	MARATHON OIL COMPANY	01/02/2009	Y	28/06/2014	5.40	105.8	53	129	41%	193	68	261

Figure 3. Profile for Jay Sandstrom USA 34-31H oil only production. Twelve-month production was 41% of that predicted by the regional 12-month production model. Total Refrac EUR = 261 mbo (fifth largest).

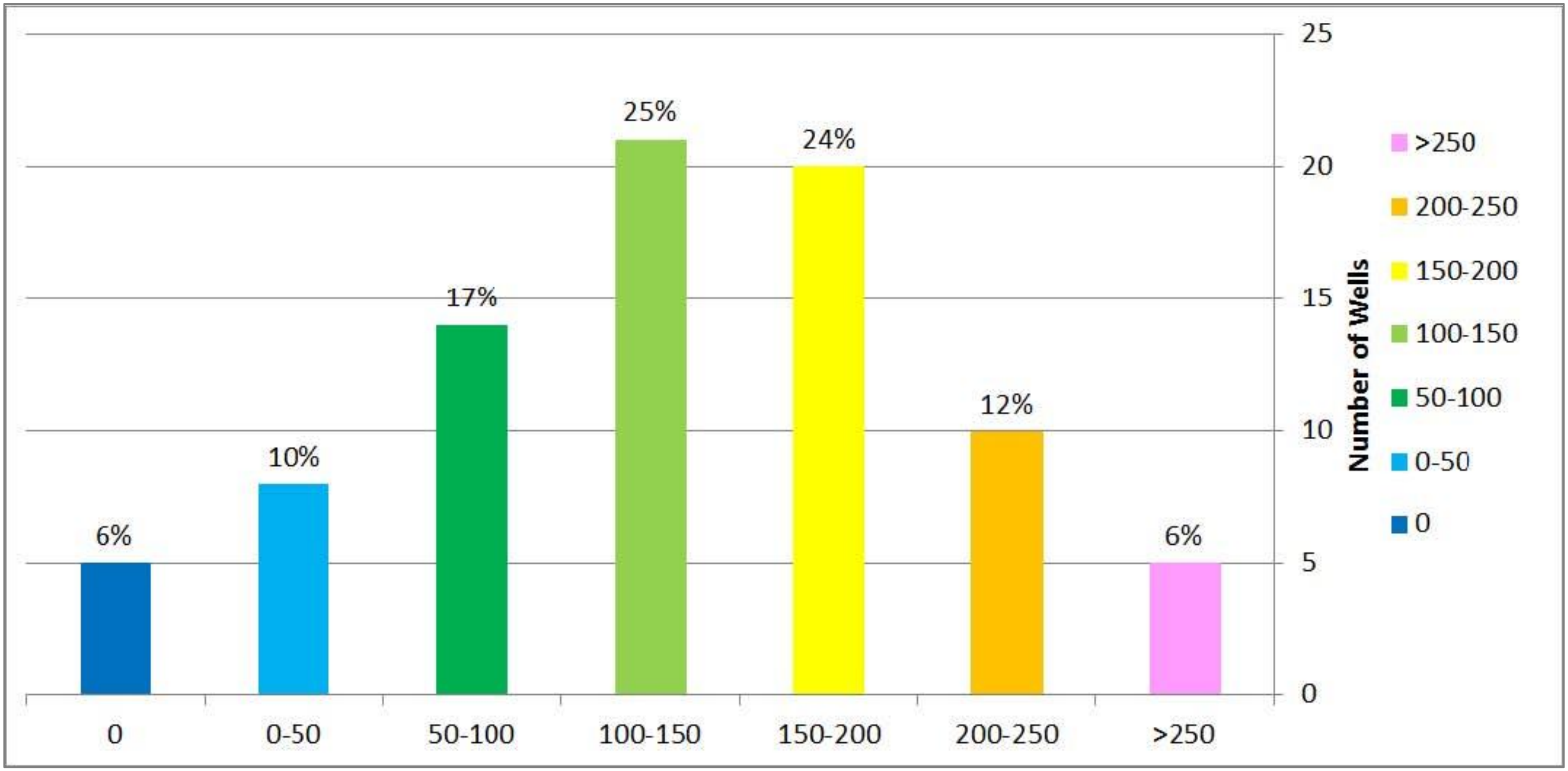


Figure 4. Distribution of incremental oil only EURs for the 83 refracs. Five wells had no incremental production; two of these are for refracs that had just been performed, and no production data was available.

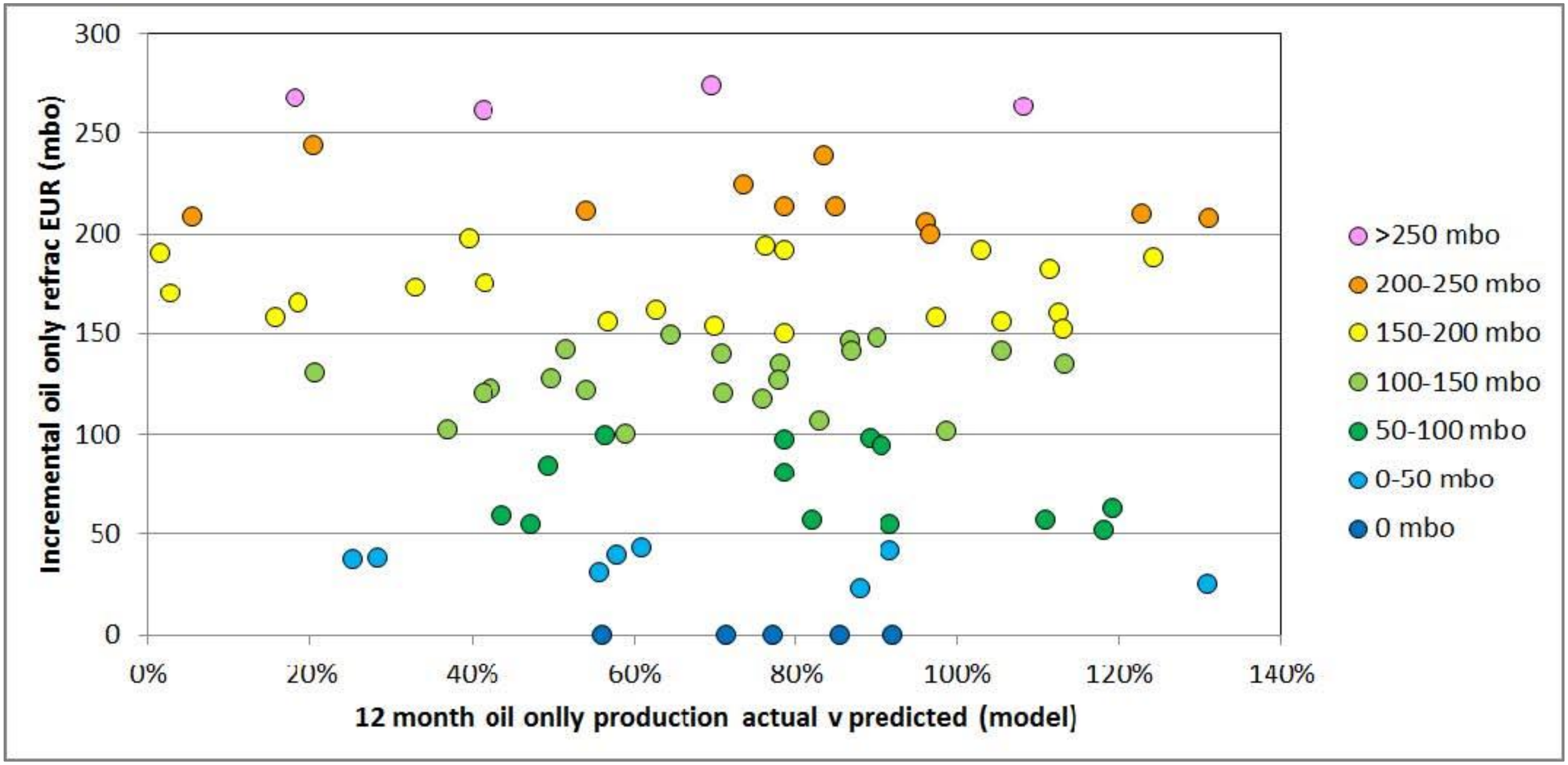


Figure 5. Incremental oil only EURs vs 12-month oil only actual v predicted for the 83 refracs. Original wells that have performed below expectation are to the left; refracs with high EURS are to the top in lighter colours. No correlation exists between original well performance and refrac performance.

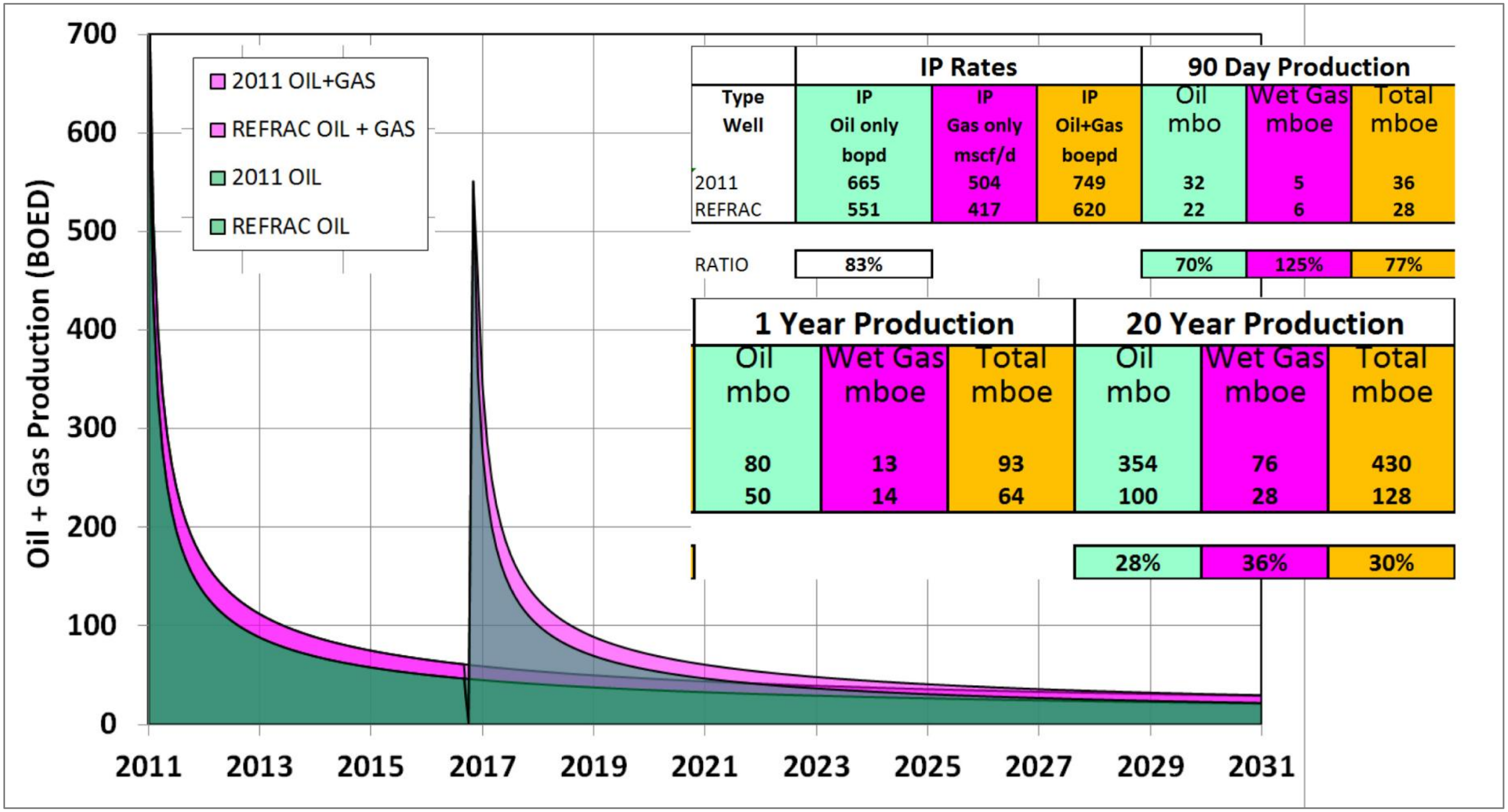
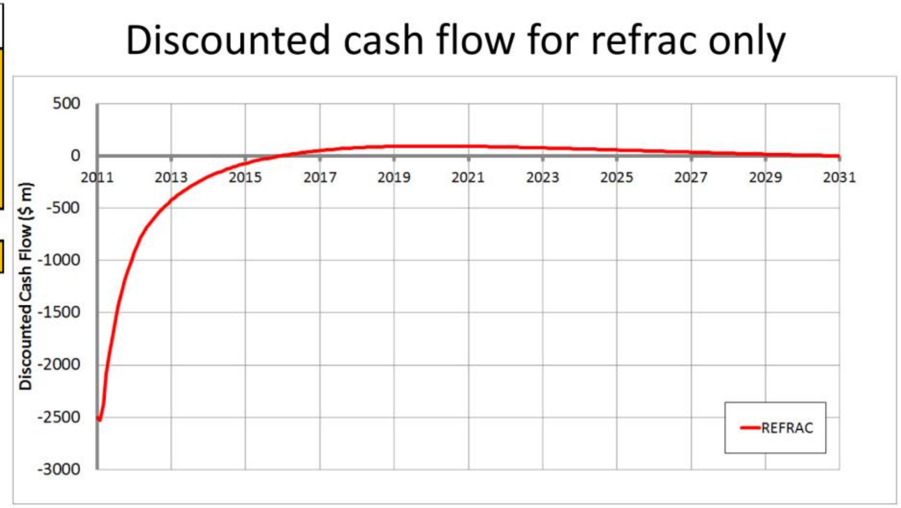


Figure 6. Modelled production profile for 2011 well and 2016 refrac. Refrac vs 2011 IP ratio varied to achieve NPV0 or IRR 10%.

	IP Rates			20 Year Production		
Type Well	IP Oil only bopd	IP Gas only mscf/d	IP Oil+Gas boepd	Oil mbo	Wet Gas mboe	Total mboe
2011	665	504	749	354	76	430
REFRAC	551	417	620	100	28	128
RATIO	83%			28%	36%	30%

IP ratio varied by goal search to achieve NPV0 or IRR 10%



Type Well	OIL PRICE $	NPV $mm	IRR %	Payout years	CAPEX $m	OPEX $m	PROD. TAXES $m	INCOME TAXES $m	CAPEX $/bbl	OPEX $/bbl	PRODUCTION TAXES $/bbls	INCOME TAXES $/bbl	TOTAL COSTS $/bbl
REFRAC	60	0.00	0.0%	5.00	2500	1321	426	357	23.9	12.6	4.1	3.4	44.0

Commodity Prices

Oil Price	60
ND WH / WTI	0.89
ND WH - WTI Differential	6.6
ND WH Oil Price	53
Henry Hub gas Price ($/mcf)	2.80
ND WH / HH	0.80
Realised gas price ($mcf)	2.24
NGL realisation	40%

Costs

DUC Capex ($mm)	
Refrac Capex ($mm)	2.5
Refrac Opex %	50%
Opex ($/bbl)	10.7
Opex ($/month)	8000

Royalty and Taxes

Royalty	18.0%
Production Taxes (%)	8.7%
Income Tax Rate	35%

Financials

Discount rate (%)	10%
Cost Inflation (%)	0.0
Monthly discount	0.83%

Depreciation Structure

% Intangible Drilling Costs	60%
% Tangible Drilling Costs	30%
% UOP Drilling Costs	10%

Well Type Curve Parameters

See table opposite

GOR and NGL Parameters

Initial GOR scf/bbl	
GOR increase / year	
GOR plateau scf/bbl	
Gas shrinkage	35%
NGL yield (bbls/mmscf)	120
MCF to BOE conversion	0.167

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Figure 7. 2016 Refrac economic model – summary.

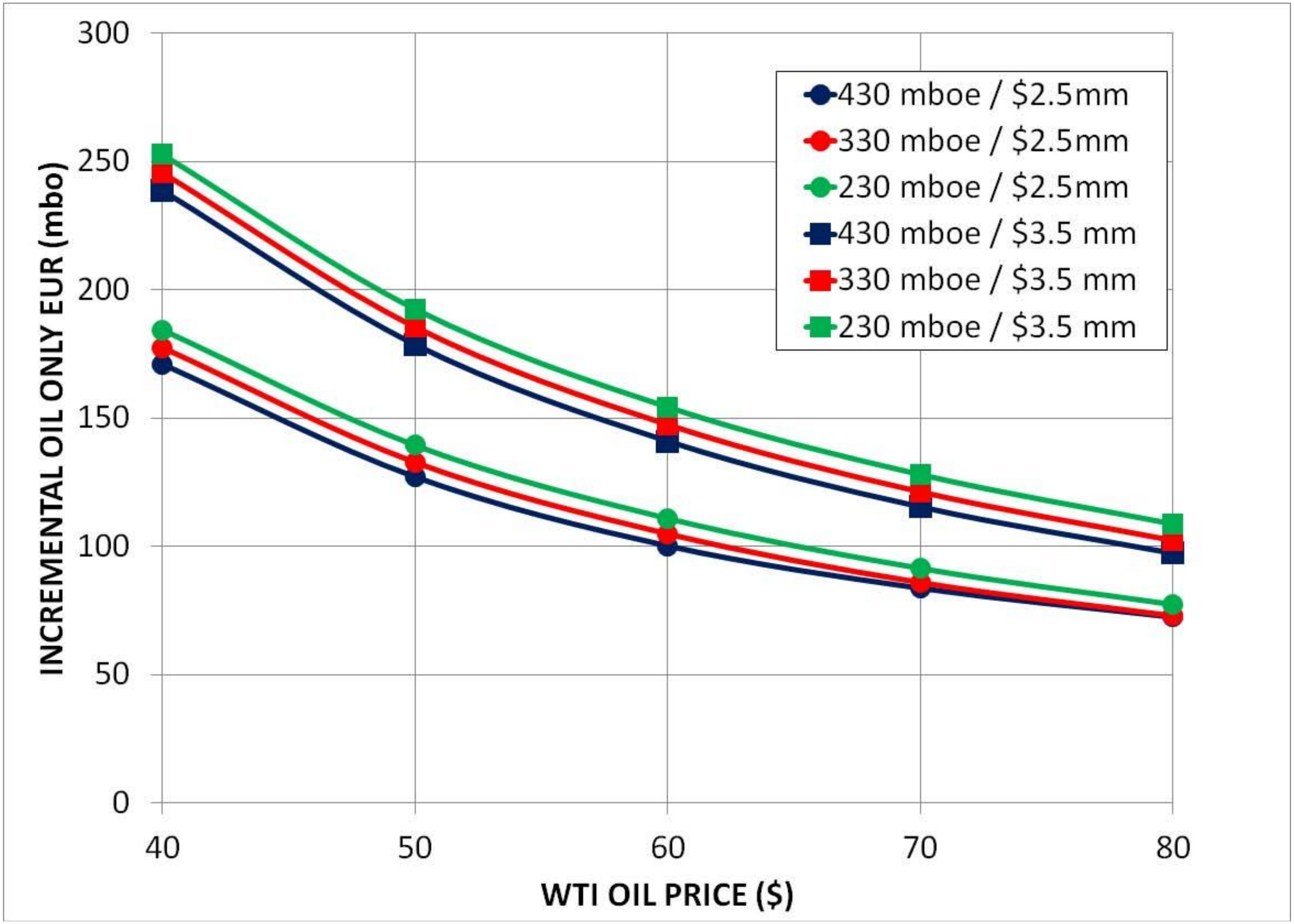

Figure 8. Incremental refrac EURs (oil only) required to break-even. Three 2011 EUR cases were considered (230, 330 and 430 mboe oil + gas), two refrac cost cases ($2.5 and $3.5 million), and five forward oil price cases (WTI $40, 50, 60, 70 and 80). Thirty cases define a range of incremental EUR that a refrac needs to recover to break-even.

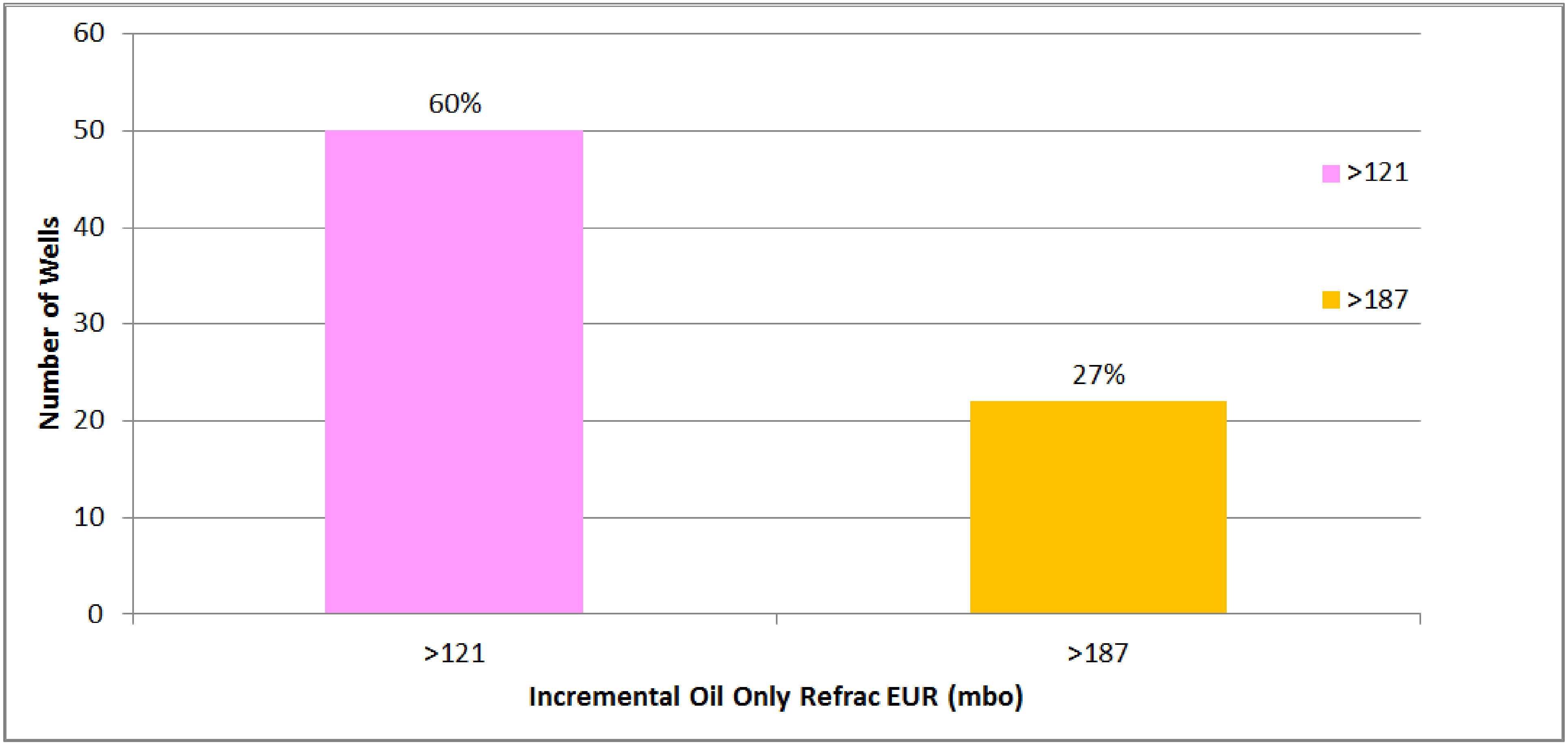

Figure 9. Incremental refrac EURs (oil only) required to generate an IRR of 10%. Base case assumptions – see Figure 7 for details. For the base case to generate an IRR of 10%, the incremental refrac EUR required is 121 mbo (oil only). For a $3.5 million refrac to generate an IRR of 10%, the incremental refrac EUR required is 187 mbo (oil only). Sixty percent of refracs had oil only EURs >121 mbo, and 27% had EURs >187 mbo.