THE UNIVERSITY of TULSA

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Tulsa, Oklahoma

PE 4983 – Capstone Design
Final Report
Spring 2020

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Introduction

This project was given to us by Cimarex Energy Company and it begins with a geologist who has found a new unconventional play in the Permian Basin. He believes that this play is analogous to the lower Wolfcamp (C&D) in Culberson County, Texas. An entire township was acquired for $1000 an acre and an obligation schedule is provided which must be satisfied over a 5 year period in order to hold all the leases. We are a 60% working interest owner in each section and we have a 75% 8/8ths net revenue interest. As a team our goal is to propose a 5 year drilling plan that fulfills every obligation, to determine a reasonable spacing, and to provide a recommendation on whether to operate midstream internally or with a third party provider. We are given various parameters such as drilling cost, drilling time, pipeline capacities, oil and gas prices, as well as a myriad of other given data so that we can develop type curves, decline curves, drilling plans and schedules, midstream designs, and economic analysis to be able to create the most profitable outcome at the conclusion of this project. Before the completion of the project we were given a curveball that threw a wrench in our plans and made us adjust various aspects of our drilling and midstream designs.

Executive Summary

Our group was tasked with developing type curves for wells with a lateral length of one and two miles in the lower wolfcamp in Culberson County Texas drilled prior to 2014, a drilling and completions schedule, along with a midstream infrastructure plan to optimize the return on investment. The project has an internal budget of 250 million dollars with a working interest of 60% and a NRI of 45%. The timeframe of the project is five years to develop a township. With a week and a half remaining prior to the final presentation a curveball was introduced stating that only the eastern portion of the section was economic and the oil production was 50% higher than our original type curve. Our group was able to complete this task under budget by 62 million dollars with a discounted ROI of 3.8 non discounted ROI of 5.0 a 3 year payback period an IRR of 371% and a PW 10 of 413 million dollars.

Procedure

General Type Curves, Behavior and Shortising wells:

Cimarex Co. our sponsors instructed us to look at production data until 2014, upon doing so we discovered 71 wells in the wolf camp basin which is our analogous basin for the project. One of the key objectives was to see the analysis between two mile wells and one mile wells. That being said, out of the 71 wells, 7 were two mile wells and 64 one mile wells. In order to have a fair comparison between the two categories (two mile and one mile wells) we had to have a comparable number of wells while not being biased in our selection. Shortlisting the right wells was important because throughout the project our objective was to maximize the production and minimize the cost. In this regard selection of our wells would affect our production, leading to our drilling design and schedule and finally also our midstream design. In conclusion, selecting the wells was something we looked deeply into and the basis were type curves. Below you can see the general type curve for all the 71 wells.

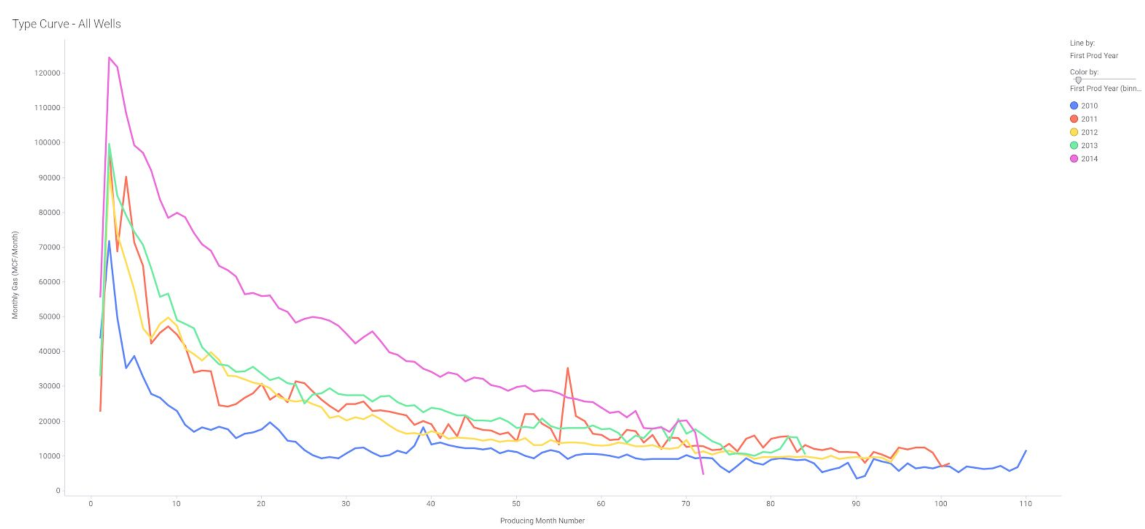


Fig 1 - Type curve All 71 wells

The figure above represents the entirety of the data, and we differentiated the wells by the first production years. Each year represents a different color and we can clearly start to see an increase in the production each year, with the year 2014 being the best type curve and an increase of nearly 32000 Mscf/month from last year i.e 2013. With this information, we began to question why and what is causing this increase in production, which variables are affecting the production and how we can shortlist the wells while maximizing our production. Hence the graphs below represent the variables contributing to production.

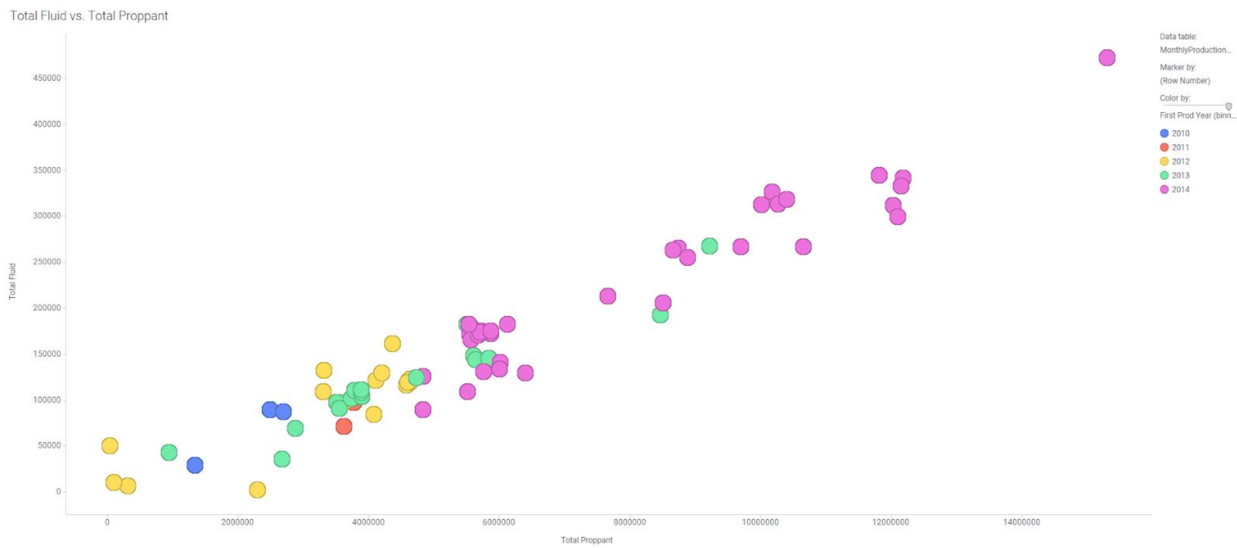


Fig 2-Total proppant vs Total fluid

The graph above represents the total proppant and total fluid relationship. Once again the data is sorted by different colors each representing a different year and we notice more proppant and fluid is being added each year and consequently improving the performance of our production. We wanted to be fair in our selection of the wells and therefore we looked into the concentration of the proppant which is basically just the slope of the graph above. We decided to create a box plot and we were hoping to get a similar concentration for both one mile and two-mile wells. The box plot below represents the mean and median concentrations for both the one mile well and two-mile wells. (units are pounds of sand / bbl of fluid).

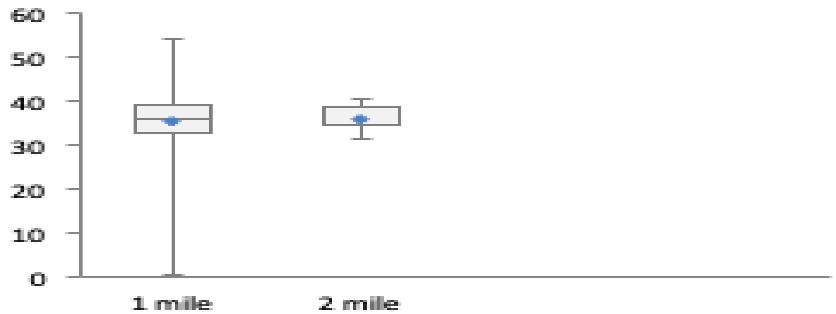


Fig 3 - Box plot Analysis

Column1	1 mile	2 mile
Count	4619	395
Mean	35.52	35.87
SD	8.19	2.97
Min	0.58	31.19
Q1	32.67	34.30
Median	35.94	34.45
Q3	38.84	38.56
Max	53.76	40.34
Bottom	32.67	34.30
2Q Box	3.27	0.16
3Q Box	2.90	4.10
Whisker-	32.09	3.11
Whisker+	14.93	1.78
Offset	0.50	1.50

Table 1

As you can see above the mean and median for both 1 mile well and two miles well is nearly the same and that is what we had expected. That being said, our selection of one mile wells was based on this. We wanted to be fair in our selection process and select the two mile wells that received nearly the same median concentration values of proppant and fluid. We also looked into some other parameters like horizontal length, peak gas, cumulative gas, etc. And graphs for each can be seen below.

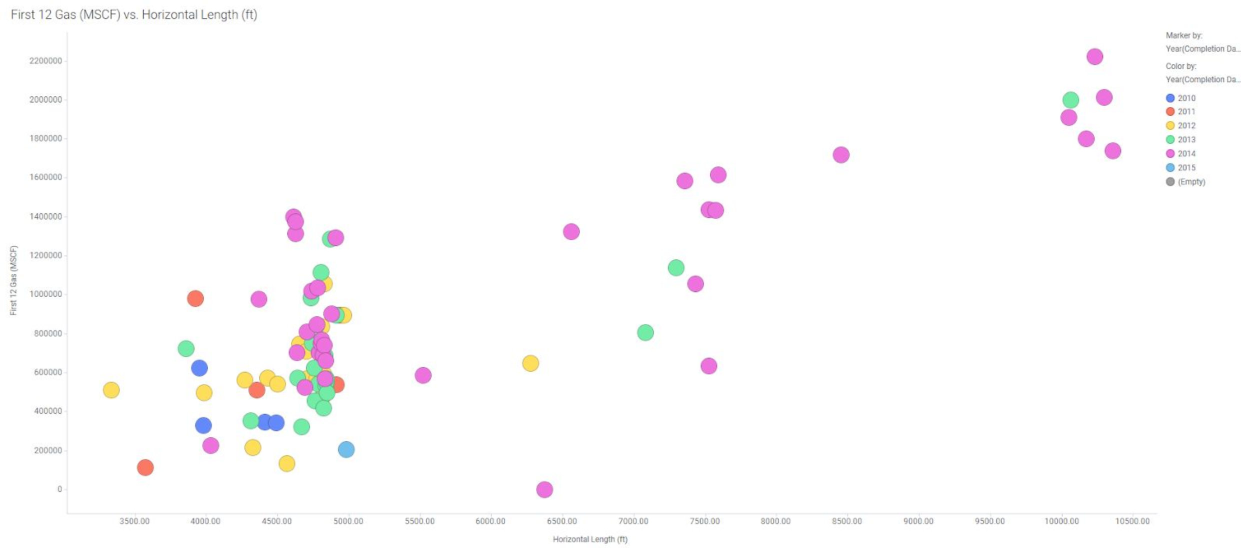


Fig4 - First 12 gas(Mscf) vs Horizontal length (ft)

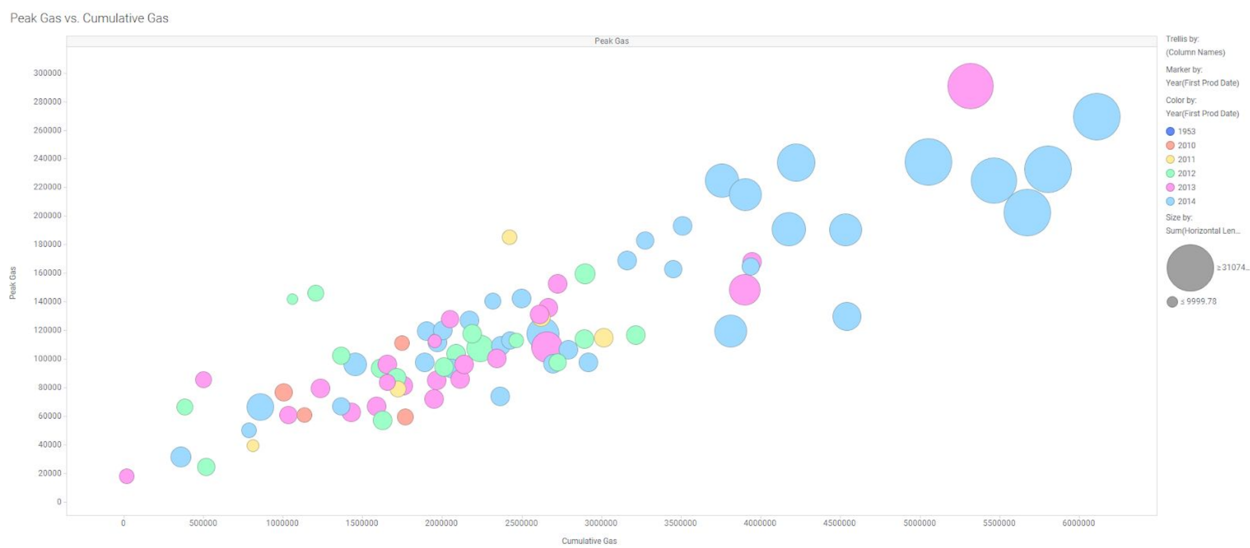
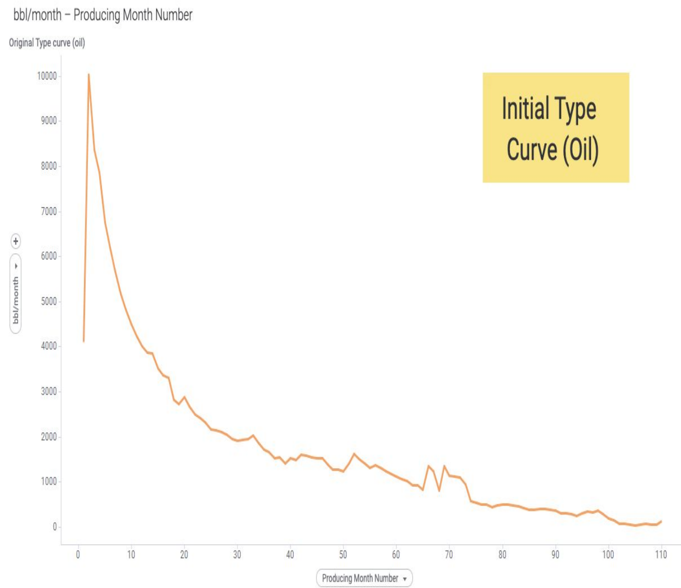


Fig 5 - Peak gas(Mscf/Month) vs cumulative gas(Mscf) vs horizontal length(ft)

We conducted our unbiased selection process of one mile wells and initially shortlisted 16 wells, the names of the wells can be seen below along with the initial type curve for all 1 mile wells.

Oil Analysis:



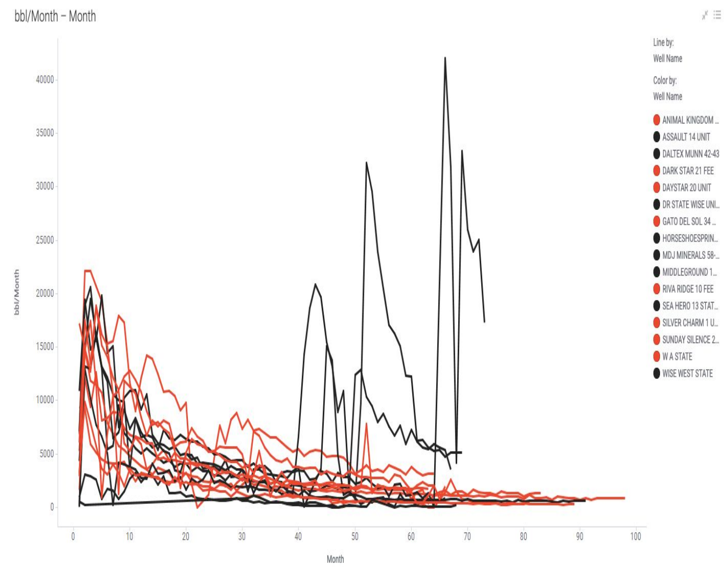
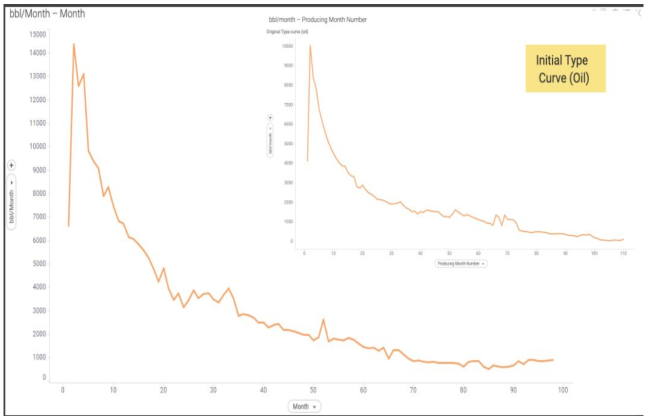


Fig 6 - Bbl/Month - Month (64 one mile wells)

Fig 7 - Bbl/Month - Month (16 wells)

Considering the right proppant selection as well as horizontal length we can see that in fig - 8 we shortlisted 16 wells, but happened to see some unexpected spikes in the production. We were also told that the reservoir is analogous to lower wolf camp and not entire wolf camp basin, therefore the lower the reservoir more gas can be expected due to pressure and the ones in red are our last 8 one mile wells, moving forward from here these 8 one mile wells in red will represent the entirety of our data for one mile wells, See graph below to clearly see our selected 8 one mile wells and resulted in maximizing our oil production, having an additional 4000 bbl/month. All these wells represent the lower wolf camp section and receive similar proppant and fluid concentrations.



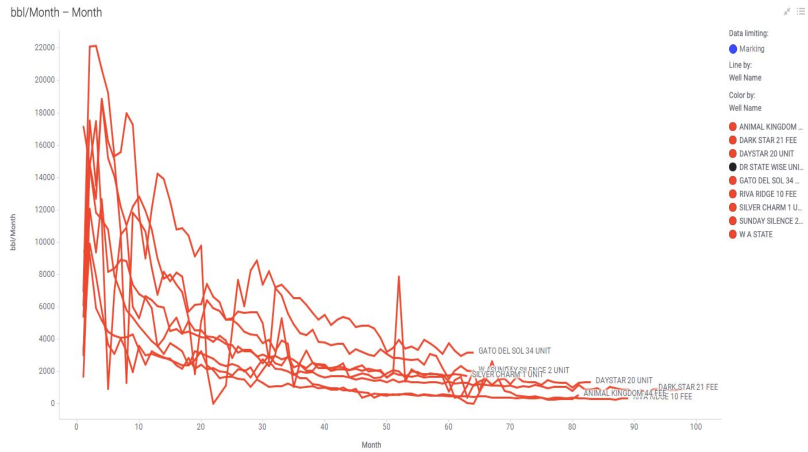


Fig 8   New type curve vs initial type curve

Note: The additional 4000 bbl/month in fig-8

Fig 9 - bbl/Month (Final 8 one mile wells)

Gas Analysis:

For consistency purposes, we conducted a similar analysis for all one mile wells but geared towards gas production, once again resulted in the same 8 wells for one mile wells, and an additional increase in our gas production of nearly 40,000 Mscf/Month. Keeping in mind that these wells are major gas producing wells and therefore have abundant gas but are not very oily.

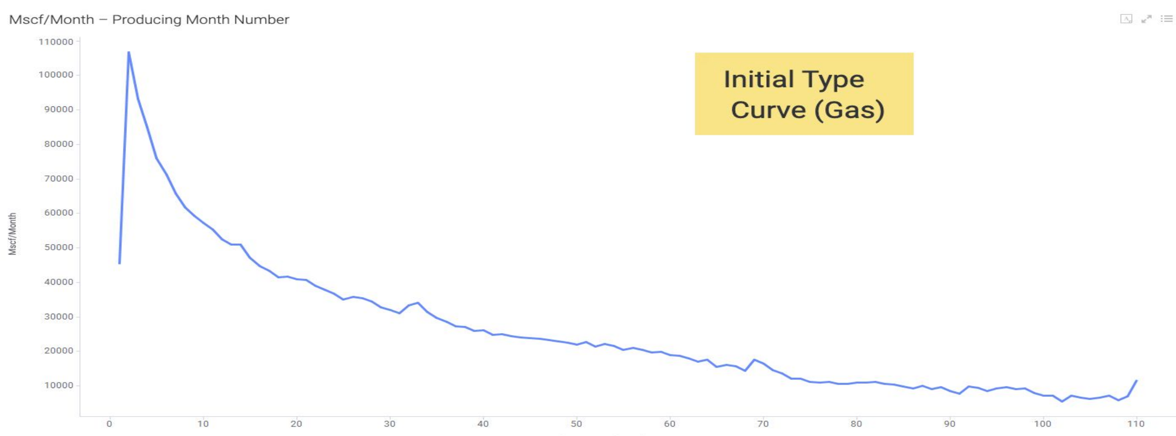
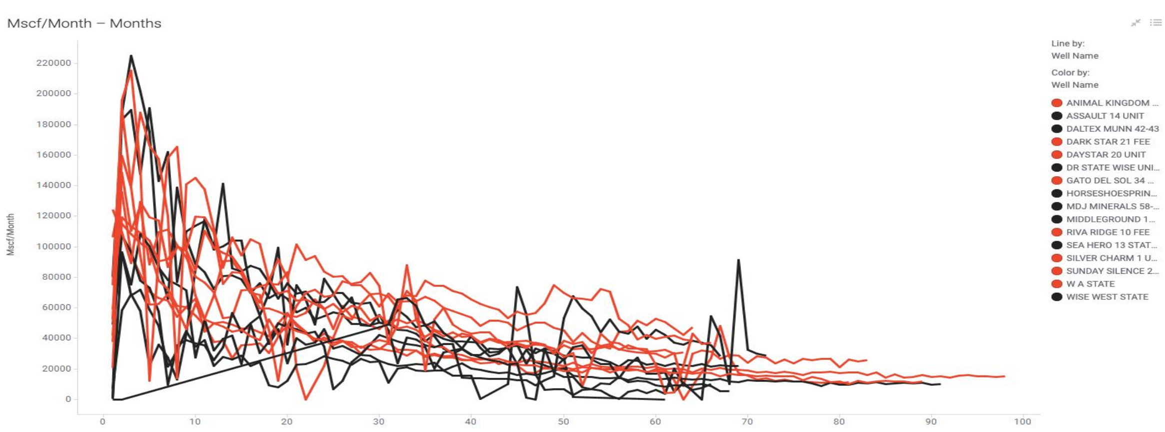


Fig 10 Mscf/ Month - Month (64 one mile wells, above)

Fig 11 - Mscf/Month (16 one mile wells, below)



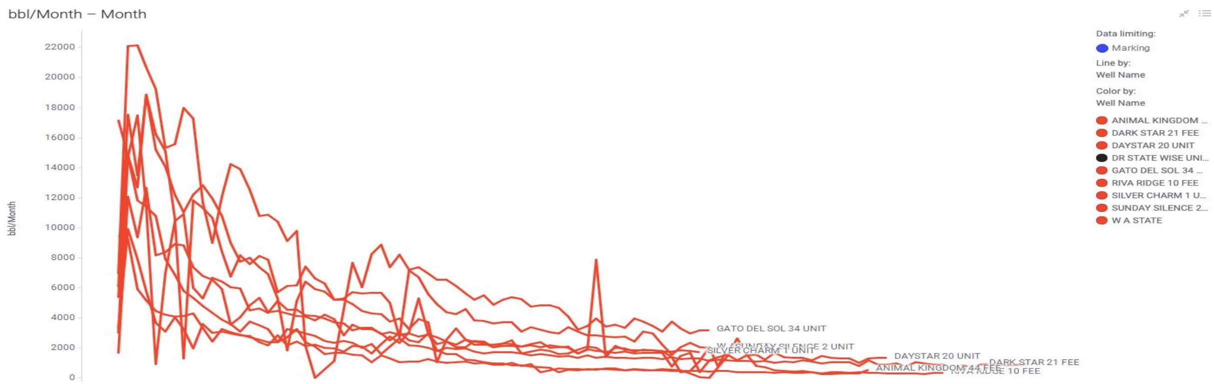


Fig 12 - Mscf /Month (Final one mile wells)

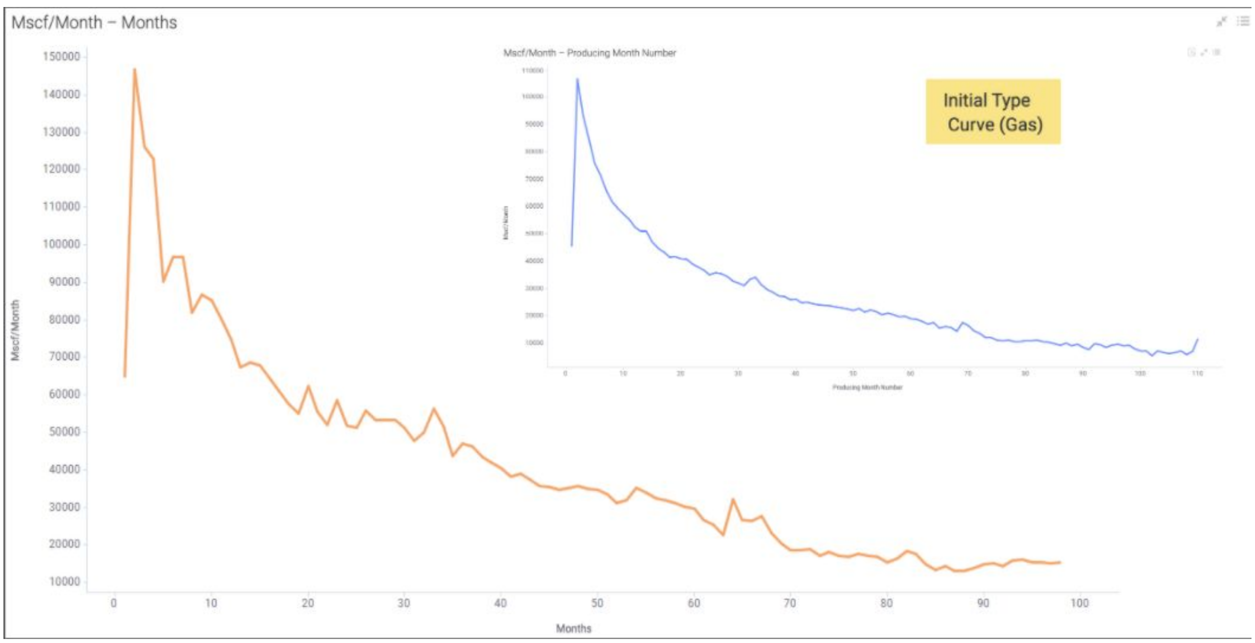


Fig 13 - Mscf/Month (initial vs new type curve)

Note: An additional increase of 40000 Mscf/Month

Decline Curve Analysis:

With our type curves ready, we started to get our decline curve implemented. I coded Vba functions for respective models, hyperbolic, exponential, harmonic and my "combination model" (seen below in blue line). In unconventional plays, the production declines in a weird manner, with the later of the data following exponential decline and majority following the hyperbolic decline. Hence a combination model by numerical optimization of weight (w), assigned to each of the two hyperbolic and exponential functions, was used. I added constraints to parameters like w (0<w<1), a(<2.5), Hyperbolic sum >= combination model sum, etc. Adding constraints was important because we want to avoid unrealistic values and limit our models freedom to fit the data in order to avoid overfitting. We also don't want to add too many constraints because then we will give our model very limited freedom and therefore underfitting the data. See graph below.

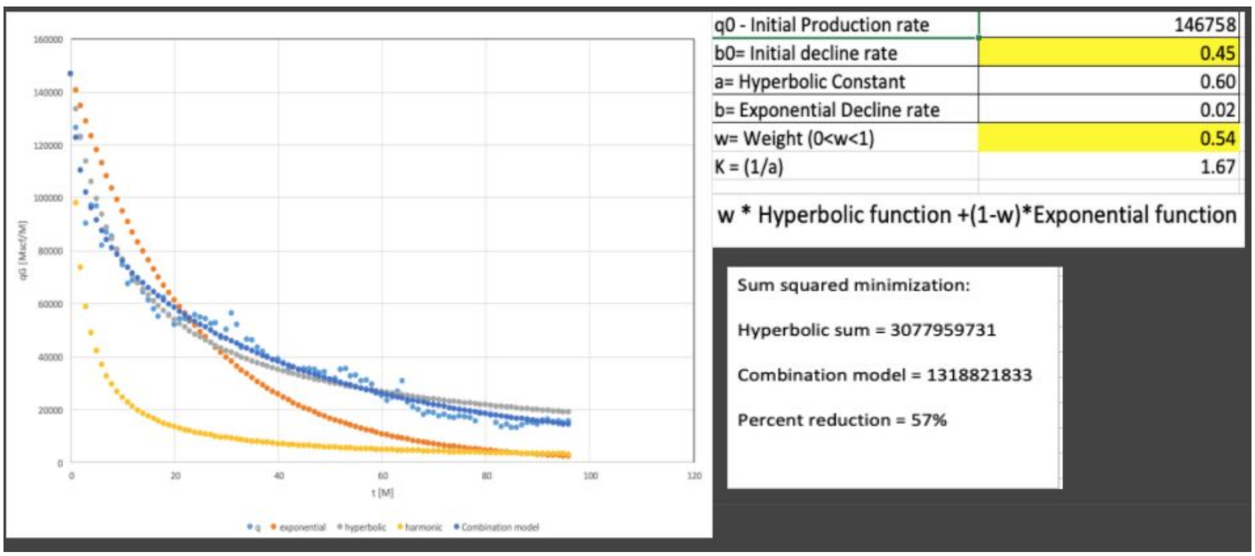


Fig 14- 1 mile Average case Gas decline example

As you can see with my newly made combination model, I was able to fit the data better than hyperbolic by nearly 57 %, hyperbolic being the closest fit out of exponential and harmonic. Above is just an example of the average case 1 mile well. I conducted decline curve analysis for both two mile and one mile wells, with each having three cases, pessimistic, average and optimistic. The graph below shows a decline curve comparison between two and one mile well in cartesian coordinates to see better differences.

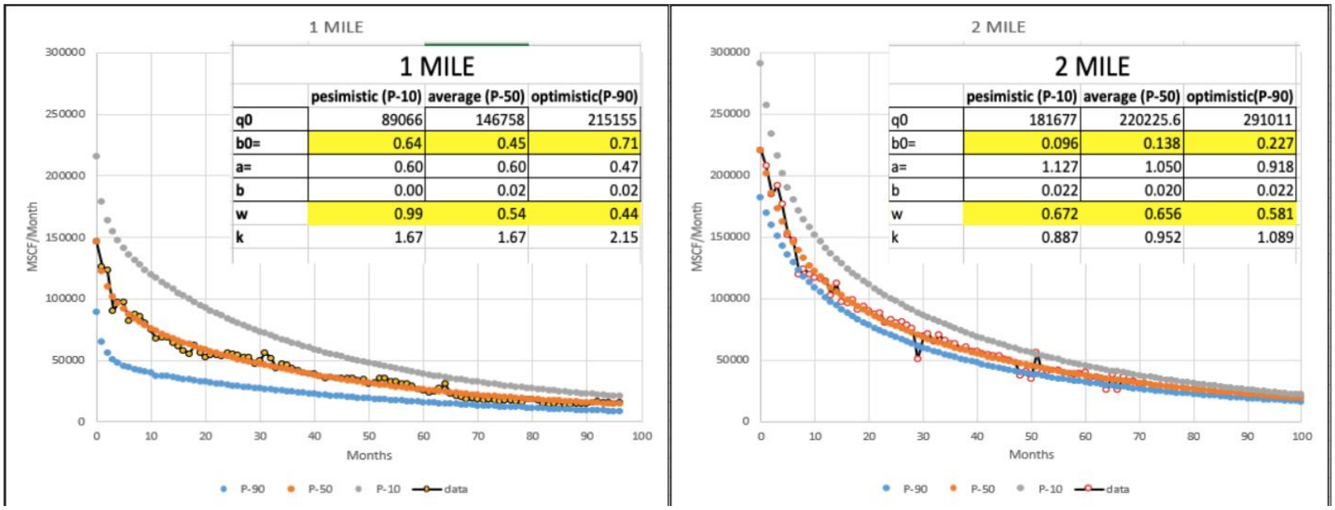


Fig 15 - Gas decline comparison between 1 mile wells and 2 mile wells.

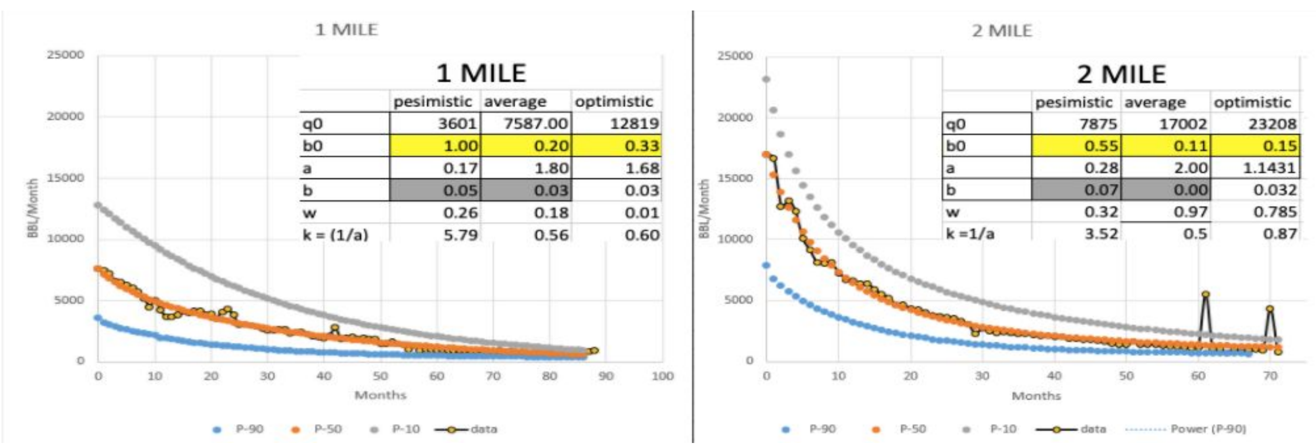


Fig 16 - Oil decline comparison between 1 mile well and 2 mile well

```
Option Explicit

Public Function ExpArpFnc(q0 As Double, b As Double, t As Double) As Double
' q0  :: Initial flow rate [BPD] or [Mscfd]
' b   :: Continuous declain rate [1/d]
' t   :: time [d]
' ExpArpFnc :: Flow Rate following the exponential decline [BPD] or [Mscfd]
' W :: weight

   ExpArpFnc = q0 * Exp(-b * t)

End Function

Public Function HyperbolicArpFnc(q0 As Double, b0 As Double, t As Double, a As Double) As Double
' q0  :: Initial flow rate [BPD] or [Mscfd]
' b0   :: Initial declain rate [1/d]
 ' t   :: time [d]
 ' a :: Hyperbolic Constant [-]

'HyperbolicArpFnc :: Flow Rate following the hyperbolic decline [BPD] or [Mscfd]
 HyperbolicArpFnc = q0 / (1 + b0 * t / a) ^ a
End Function

Public Function Combinationmodel(q0 As Double, b As Double, t As Double, a As Double, W As Double, b0 As Double) As Double

Combinationmodel = (q0 / (1 + b0 * t / a) ^ a) * W + (q0 * Exp(-b * t) * (1 - W))

End Function

Public Function cumulativeProduction(q0 As Double, b0 As Double, a As Double) As Double


If a = 1 Then

cumulativeProduction = q0 / b0 * Log(q0 / q)

Else

cumulativeProduction = q0^(1 / a) / (b0 * (1 - 1 / a)) * (q0^(1 - 1 / a) - q^(1 - 1 / a))
End If

End Function


Function NominalDecline(b0, a, t)
End Function
```

Fig - 17 - VBA code for decline curve analysis

Note: All Initial production values for each case pessimistic, average and optimistic for two mile wells is nearly two times as much as one mile wells for both oil and gas decline. Also decline rate b0 is nearly half for two mile wells than that of one mile well. Clearly two mile wells give nearly twice as much of a production while declining quicker. This is what we had to prove and we successfully proved that in order to maximize our production two mile wells are the best. We can now move on to the next stage of minimizing our cost while performing iteration for our drilling schedule, midstream design and curveball adjustment.

Just so that I am not biased to my decline curve model, we did a quick cross check of our 2 mile average case for gas, oil and water on PhDwin software. And to great satisfaction ended up with almost the same decline curve as above.

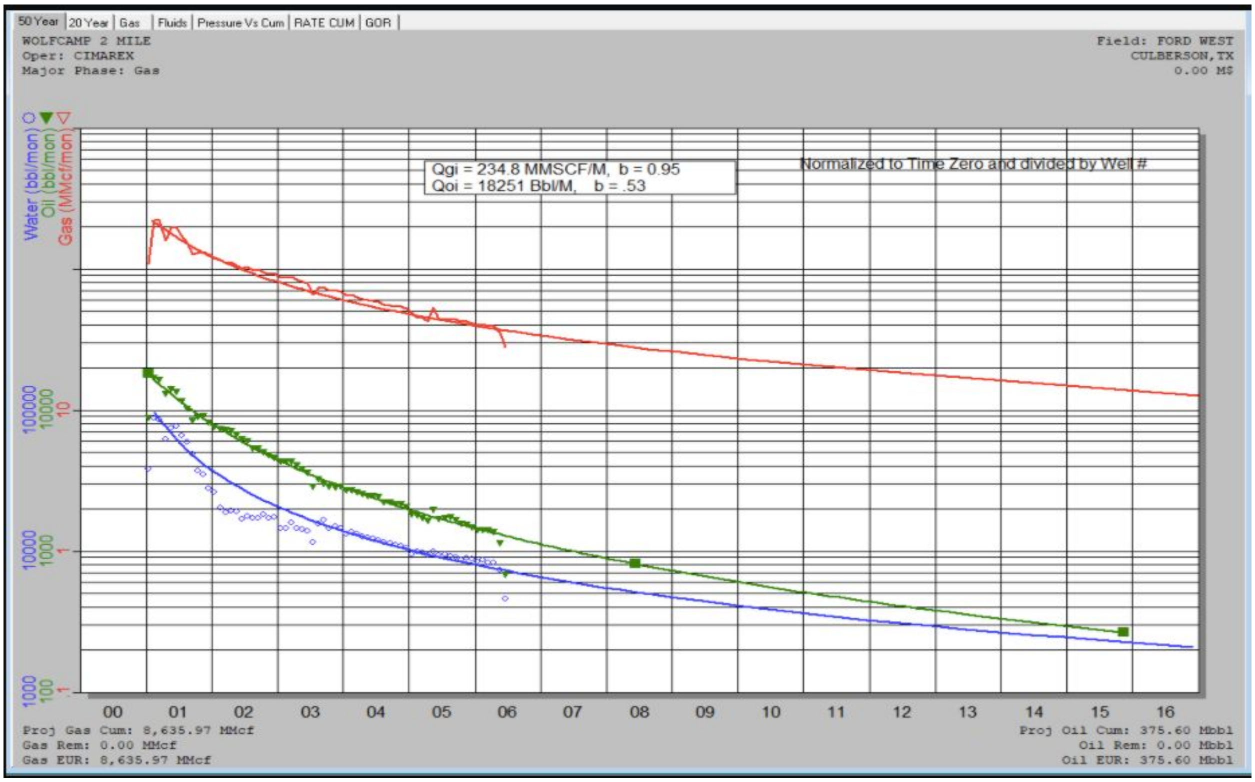


Fig 18 - 2 mile Decline curve on Phdwin

Drilling:

With both the type curves and the decline curves finalized for oil and gas we came to the conclusion that two mile wells produce nearly double the amount of oil and gas as one mile wells do. With that idea in mind we have to decide whether to drill all one mile wells, all two mile wells, or a combination of one and two mile wells. The obvious way to determine which of these methods is best is to analyze the difference in cost between drilling one and two mile wells. By keeping in mind the knowledge that the more wells drilled per pad the cheaper it would cost on a per well basis we came to the conclusion that we should attempt to maximize the number of wells per pad in our drilling plan whether we chose to drill one mile wells or two mile wells. So we formulated tables that included the total cost, cost with working interest deduction, total cost per well, cost with working interest deduction per well, total cost per foot, and working interest cost per foot of one, two, four, six, and eight wells per pad for both the one mile and two mile cases. This side by side comparison table can be seen below.

1 Mile Wells						
# per Pad	Total Cost (M$)	WI Cost (M$)	Total Cost per Well (M$)	WI Cost per Well (M$)	Total Cost/ft	WI Cost/ft
1 Well Pad	6	3.6	6	3.6	$1,136.36	$681.82
2 Well Pad	11.6	6.96	5.8	3.48	$1,098.48	$659.09
4 Well Pad	22.2	13.32	5.55	3.33	$1,051.14	$630.68
6 Well Pad	32.8	19.68	5.47	3.28	$1,035.35	$621.21
8 Well Pad	43.4	26.04	5.43	3.26	$1,027.46	$616.48
2 Mile Wells						
# per Pad	Total Cost (M$)	WI Cost (M$)	Total Cost per Well (M$)	WI Cost per Well (M$)	Total Cost/ft	WI Cost/ft
1 Well Pad	11	6.6	11	6.6	$1,041.67	$625.00
2 Well Pad	18	10.8	9	5.4	$852.27	$511.36
4 Well Pad	35	21	8.75	5.25	$828.60	$497.16
6 Well Pad	52	31.2	8.67	5.20	$820.71	$492.42
8 Well Pad	69	41.4	8.63	5.18	$816.76	$490.06

Fig 19- Cost Comparison Between One and Two Mile Wells

The major tell here is in the cost per foot columns which show that one two mile well is cheaper on a per foot basis than one one mile well is. Another detail that sticks out is the big decrease in cost per foot between one well per pad and two wells per pad. It drops over $100 per foot when drilling multiple wells per pad. So, the takeaway from simply looking at the cost of drilling is that we should maximize the number of two mile wells while also drilling at least two wells per pad. This drilling strategy is also supported by the conclusions reached in the decline curve analysis, so we will only be drilling two mile wells throughout the township. Now that we have our plan of what to drill it is time to determine when and where to drill. A 5 year obligation map was given and must be fulfilled in order to hold the leases.

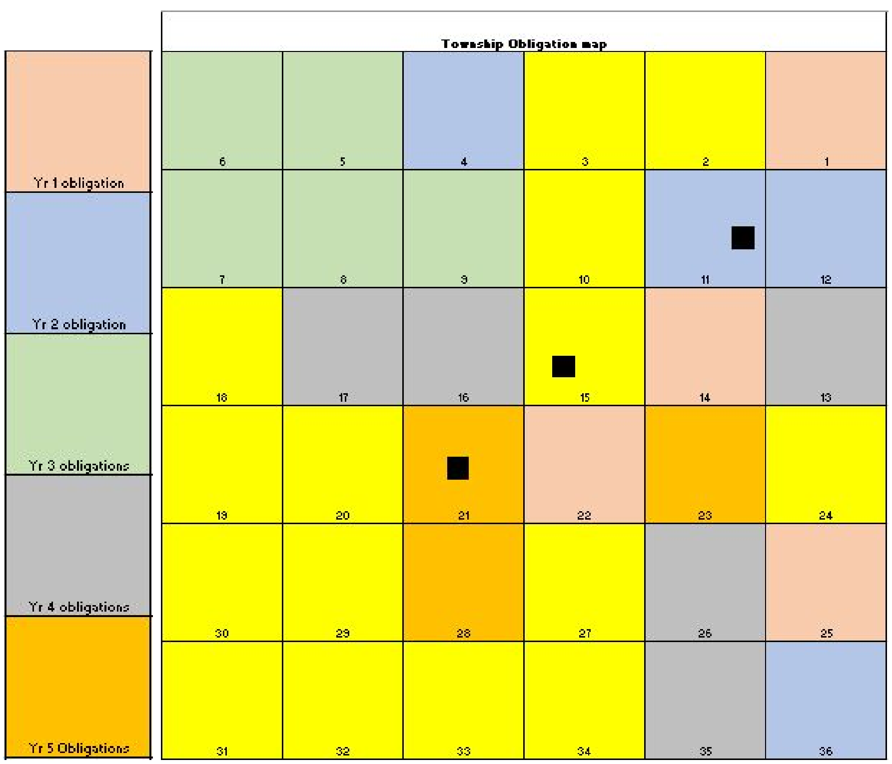


Fig 20- Obligation Map

Each section is colored differently based on its yearly obligation and the yellow sections have no obligation, but drilling can still take place within these sections. As an example, sections 4, 11, 12, and 36 are all year two obligations and drilling must begin or be completed prior to the end of two years in these sections. Before drilling can take place we need to determine the spacing that will be implemented first. By looking at a group of analogous wells in Culberson County we can determine the spacing that was used for the lower Wolfcamp formation. In the image below you will see eight wells that are spaced about 650 feet apart on average. This translates to roughly 8 well per section spacing which we chose to use throughout the drilling plan.

Fig 21- Well Spacing

Another detail that you will notice from this image is that these wells are all oriented north to south which is perpendicular to natural fractures. This allows for a more efficient frac job in the end, so all of our wells will follow this trend. Some final requirements that need to be kept in mind before planning out the entire drill schedule are pooling, drilling back to backs, and drilling near other wells that are being fractured. We are allowed to pool multiple sections together in this project. However, if two sections are pooled together there must be two wells drilled in those sections. Since we are only drilling two mile wells this is especially important because pooling two sections will be required for every well. Another stipulation is that we must allow all wells on a given pad to be drilled before fracturing any of the wells on that pad. This means we can't begin to frac well 1 of a four well pad before well 4 is finished drilling. Lastly, we are forbidden to drill any well within one mile of another well that is currently being fractured. Now that we know all of the obligations, the spacing, and other requirements for drilling we can begin the planning process. We strategically chose to have our pilot to be a four well pad drilled in section 1 on eight well per section spacing. In reality this would allow us to test the spacing over time and then adjustments could be made in the future. Additionally, section 1 is the only section to have two obligations, a year one obligation and a year four obligation. Drilling a four well pad here will fulfill both of these obligations and it would also allow the spacing to be tested. The next few wells are drilled on two well pads in other year one obligations (sections 22 and 25) followed by the first well of a four well pad in section 14 (the last year one obligation) to finish out drilling in year one. Each event such as drilling start, drilling end, frac start, frac end, first production date, and the cumulative cost is outlined for each well in a drill schedule table which can be seen below alongside the entire year one drilling plan. It is important to note that the numbers located on each well correspond to the order of drilling on the drill plan and in the drill schedule.

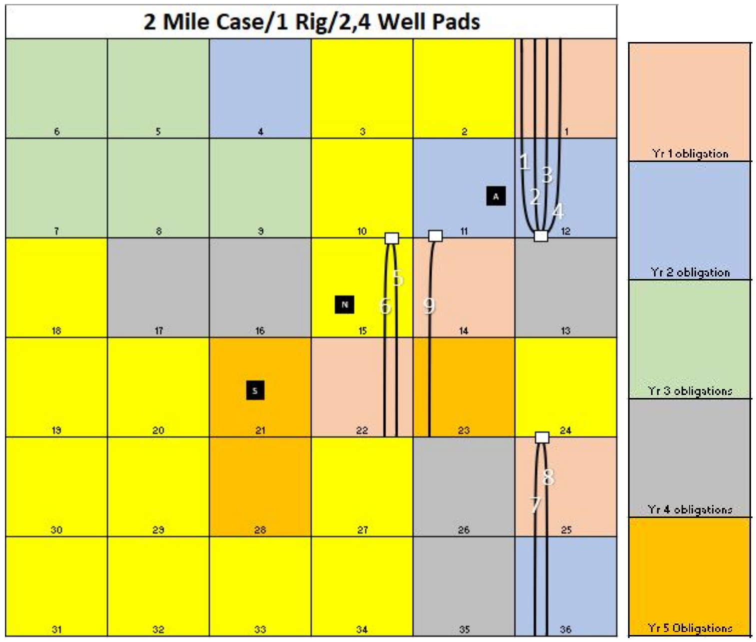


Fig 22- Year One Drill Plan

2 Mile/1 Rig/2,4 Well Pads						
Order	$ (MIL)	Drill Start	Drill End	Frac Start	Frac End	First Prod
1	5.25	0	45	180	194	195
2	10.5	45	90	194	208	209
3	15.75	90	135	208	222	223
4	21	135	180	222	236	237
5	26.4	180	225	270	284	285
6	31.8	225	270	284	298	299
7	37.2	270	315	360	374	375
8	42.6	315	360	374	388	389
9	47.85	360	405	540	554	555

Key
2 Well Pad
4 Well Pad
6 Well Pad
8 Well Pad

Fig 23- Year One Drill Schedule

Moving into year two of drilling, we apply the same ideology going forward. To reiterate, we want to fulfill all obligations, maximize wells per pad, and stay within the requirements given to us. The four well pad that begin at the end of year one was completed to hit a year two obligation, then another four well pad is drilled which satisfies four different obligations (one of which is a year two obligation), and then one well of a future four well pad starts drilling in section 8 to finish off the year.

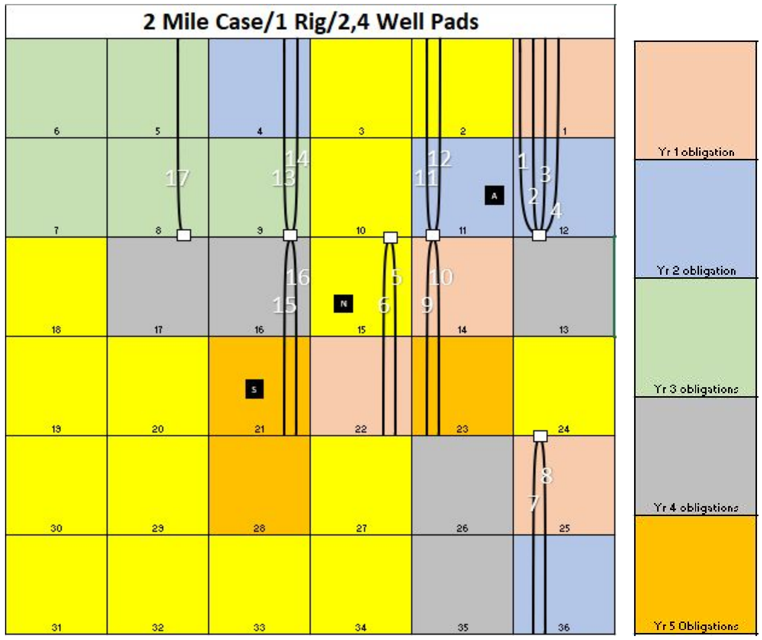


Fig 24- Year Two Drill Plan

2 Mile/1 Rig/2,4 Well Pads						
Order	$ (MIL)	Drill Start	Drill End	Frac Start	Frac End	First Prod
10	53.1	405	450	554	568	569
11	58.35	450	495	568	582	583
12	63.6	495	540	582	596	597
13	68.85	540	585	720	734	735
14	74.1	585	630	734	748	749
15	79.35	630	675	748	762	763
16	84.6	675	720	762	776	777
17	89.85	720	765	900	914	915

Key
2 Well Pad
4 Well Pad
6 Well Pad
8 Well Pad

Fig 25- Year Two Drill Schedule

To begin drilling in year three the four well pad started in section 8 is completed followed by a two well pad in section 7 to hold all of the year 3 obligation leases. Since a lot of the previous wells are drilled in sections with year four and year five obligations there aren't many more obligations to fulfill, so not many wells are required to be drilled in year 3.

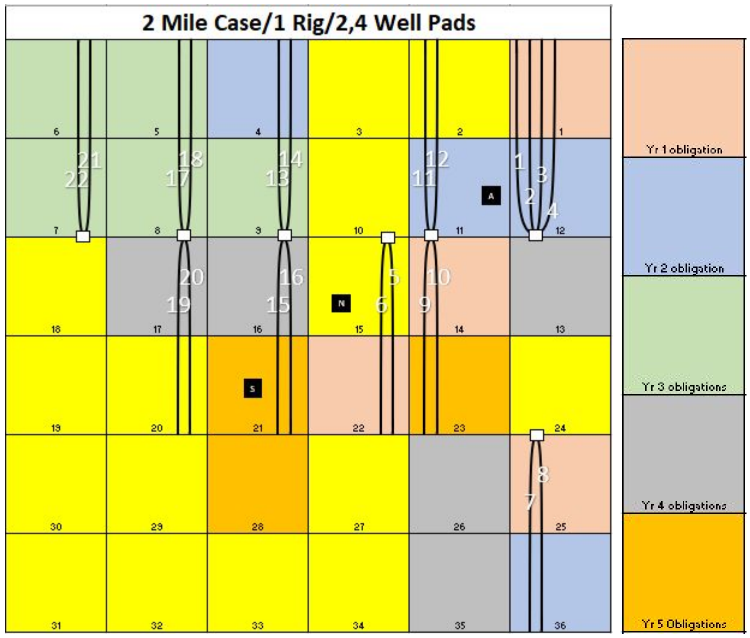


Fig 26- Year Three Drill Plan

2 Mile/1 Rig/2,4 Well Pads						
Order	$ (MIL)	Drill Start	Drill End	Frac Start	Frac End	First Prod
18	95.1	765	810	914	928	929
19	100.35	810	855	928	942	943
20	105.6	855	900	942	956	957
21	111	900	945	990	1004	1005
22	116.4	945	990	1004	1018	1019

Key
2 Well Pad
4 Well Pad
6 Well Pad
8 Well Pad

Fig 27- Year Three Drill Schedule

In the final year of this drilling plan we only have four more sections that have obligations, three of which are year 4 obligations and the other is a year five obligation. With there being plenty of capital left and enough time in the year to complete all remaining obligations, we found it in our best interest to drill three two well pads in order to complete this drill plan. Doing so would allow the final wells to come online faster instead of waiting until year five to drill the last couple wells.

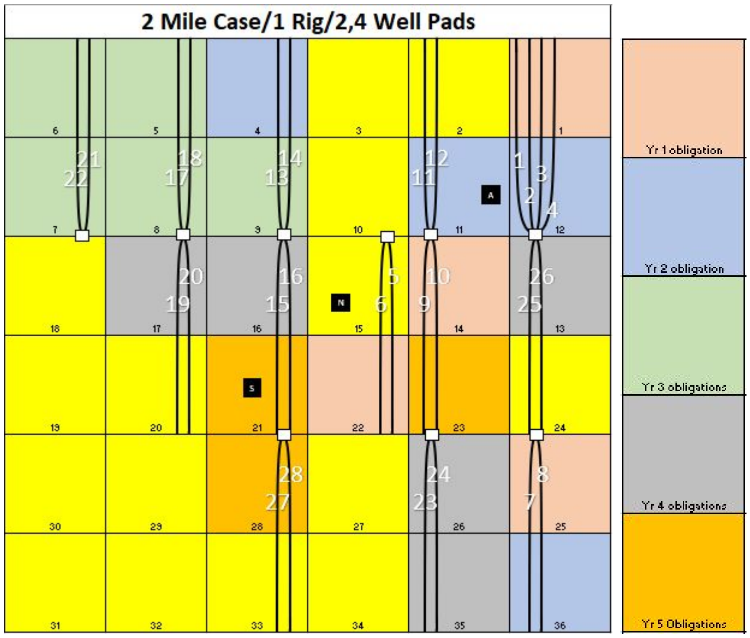


Fig 28- Year Four Drill Plan

2 Mile/1 Rig/2,4 Well Pads						
Order	$ (MIL)	Drill Start	Drill End	Frac Start	Frac End	First Prod
23	121.8	1095	1140	1185	1199	1200
24	127.2	1140	1185	1199	1213	1214
25	132.6	1185	1230	1275	1289	1290
26	138	1230	1275	1289	1303	1304
27	143.4	1275	1320	1365	1379	1380
28	148.8	1320	1365	1379	1393	1394

Key
2 Well Pad
4 Well Pad
6 Well Pad
8 Well Pad

Fig 29- Year Four Drill Schedule

Now that the drilling plan is complete the midstream side can start to unfold. It is important to note that the placement of these wells kept midstream in mind. Some wells are placed closer to processing plants in order to minimize the amount of pipeline required.

Midstream:

One of the objectives of this project is to determine whether to build an internal midstream to serve the new township drilling schedule or let a third party handle it. The trade off would be between the capital cost of building an internal midstream or the higher fees required by the third party. Thus, an economic analysis considering each option is needed to make the decision. The following table shows the fees that go with each option to operate the midstream.

	Internal Midstream	External Midstream
Compression Fees ($/MSCFD/M)	0.25	0.45
Gathering Fees ($/MSCFD/M)	0.5	0.45
Fuel %MSCF/D	5	5.5
Gas Lift at 200 MSCF/D	0.25	0.35

Fig 30- Midstream OPEX Comparison

When designing the internal midstream, minimizing the capital cost must be a priority. The length and sizing of the different pipelines need to be as efficient as possible. To determine the placement and length of the pipeline, a measurement tool in excel was used taking into account the drilling plan to serve as many wells as possible with the same line. The gas processing plants location affects the midstream design, so the chosen plants are based on both fees, commitments, and location.

Plant Name	Location	Fees	Guarantees
Company Awesome	Section 11 (500' FEL, 1500' FSL)	0.5 per mcf to process.	Firm guarantee at 98% Runtime and up to 300 MM/D, Requires 10MM/D per year which increases 10MM/D year over year up to 50MM/D. Will not build without a commitment
Company Shady	Section 21 (2500' FWL, 2000' FSL)	0.52 per mcf to process	No Firm, interruptible only and no commitment. Can take up to 100MM/D
Company Nice	Section 15 (1500' FWL, 1000' FSL)	.46 per mcf to process if you use let them gather and compress, .5/mcf otherwise	Will build to fill

Fig 31- Gas Processing Plants Comparison

Plant Awesome provides the best quality considering the ability to meet the daily required flow rate. However, the downtime must be considered so an alternative plant was considered to cover up. Taking into account all of these parameters, the internal midstream design was done as shown in the map.

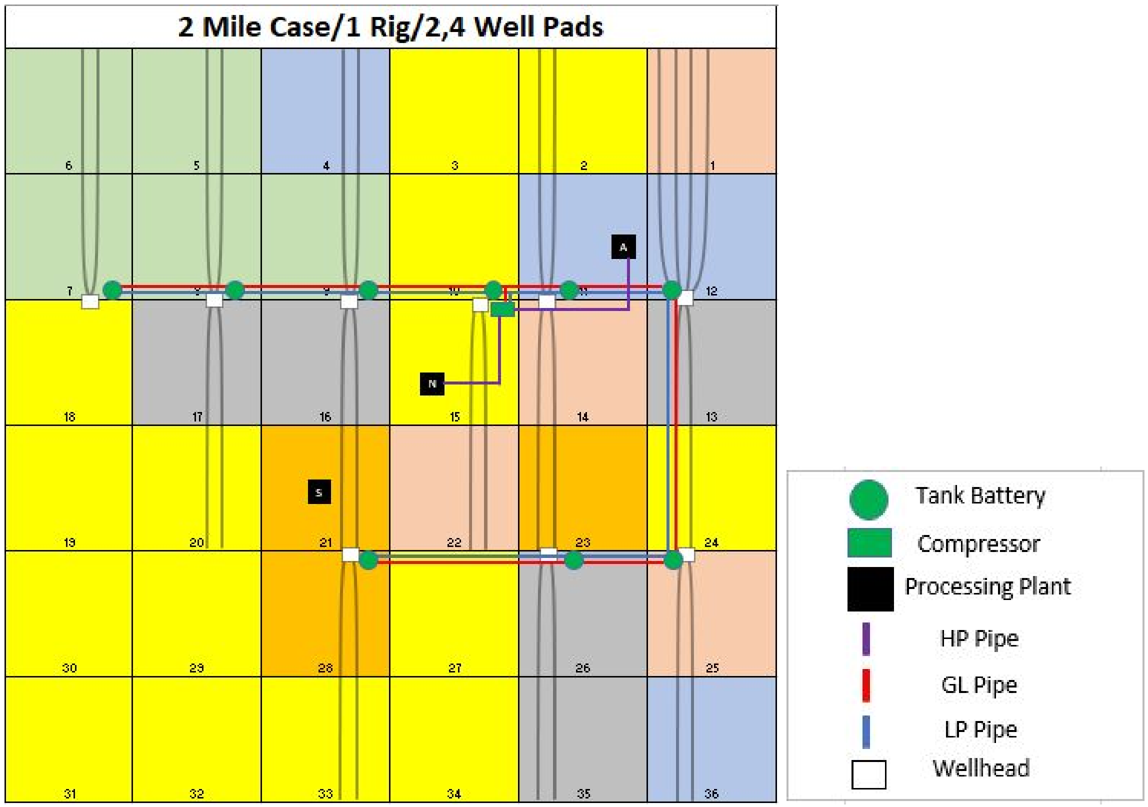


Fig 32- Internal Midstream Design

It can be observed from the map that plants A and N are the most convenient options because of their locations. The compressor is located in the middle of the two plants to cut the costs of the HP pipeline. The low-pressure pipe (LP) runs from the batteries to the compressor while the high-pressure pipe runs from the compressor to the processing plants. The gas lift (GL) moves the gas from the compressor back to the wells when gas lift procedure is required.

The next step in designing the midstream is pipelines sizing. To make the calculations simple, fixed relationships between the size and capacity were given by the sponsor. HP pipe can move 20 MM/D per inch diameter LP can move 5MM/D per inch diameter mile. All pipes cost $160,000 per diameter inch-mile if less than 1 mile and $80,000 if more than 1 mile. An estimation of the maximum daily production considering the timeline at which each well comes online is needed to size the pipes. The next graph shows peak daily production for this drilling schedule. This was done by adding an average decline curve as each well comes online.

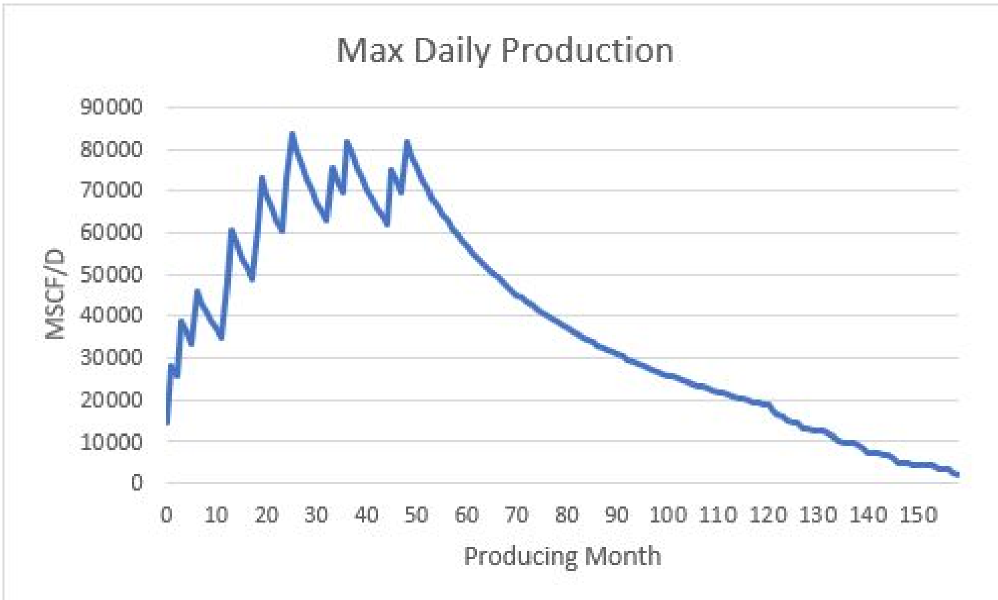


Fig 33- Max Daily Production

A maximum daily production of 83.9 MSCFD is observed from the plot. The LP size needed to accommodate this amount = 83.9 MSCFD / 5 (MSCFD/Inch) = 16.7 Inches. HP and HP size = 83.9 MSCFD / 20 (MSCFD/Inch) = 4.2 Inches. Using nominal sizes, the following table can be constructed.

Pipe Type	Length (mile)	Diameter (in)	Volume (MMSCF/D)	Total Cost	WI Cost
LP	8.565	18	90	$12,333,600	$7,400,160
GL	8.63	5	100	$3,452,000	$2,071,200
HP	2.31	5	100	$924,000	$554,400

Fig 34- Midstream Pipelines Design and Cost

The final step in designing the midstream is to determine the compression and plant connects costs. Compression costs $125,000 per MMSCFD while a plant connection costs $1,500,000.

Midstream Component	# of	Total Cost	WI Cost
Compressors	1	$10,487,500	$6,292,500
Plant Connects	2	$3,000,000	$1,800,000

Fig 35- Compression Costs

Economics:

To streamline the economic evaluation and allow for maximum iterations our group utilized PHDWin to assist with Economic analysis. One group member has had experience with the software through an internship and was able to assist the remainder of the group and instruct the remainder of the group on how to use the program. Many iterations of the economics were completed including all would create an excessively long appendix so for simplicity only the final iteration of the internal and external midstream pre and post curveball were included.

There were several base parameters that were provided by Cimarex that needed to be included. These constraints were: Oil price is to be set at $60/bbl gas gas prices are to be set at $2.00 per wet MCF. Processing fees ranged from $0.46/ Mcf to $0.52 depending on what plant or plants were chosen, all internal plant connections cost $1.5 million. Internal compression cost starts at $125k/MMCF and has an OPEX of $0.25/MCF transported whereas external compression has no initial cost but has a cost of $0.45/MCF external compression burns 5.5% of produced gas where internal compression only burns 5% of produced gas. Gas lift will be required for all wells once production falls below 1MM per day at a flat rate of 200 MCFPD internally it costs $0.25/MCF of lift gas whereas externally it will cost $0.35/MCF. For internal pipelines high pressure lines are capable of transporting 20MMCFPD/ inch of diameter while low pressure lines can transport 5MMCFPD/ inch of diameter and the cost for flowlines are 160k/inch mile for all lines less than one mile and 80k/ diameter inch mile for all lines longer than one mile. Working interest is 60%

and the negotiated NRI is 45%. The internal Capex budget is set at 250 million dollars and is to be spent over the course of 5 years. While the budget is not set to a strict 50 million per year all 250 can not be spent in a single year. The cost to drill, complete, and build facilities for a single one mile lateral well is 7 million dollars; if more than one one mile later well is drilled from the same pad immediately after the previous well and completed with a zipper frac the cost per well is reduced to 6.3 million dollars per well with a base cost of 1 million dollars to construct the pad. Each well takes 37 days to drill and complete, all wells must be drilled and completed before any well can be put online. For a well with a two mile lateral the cost for a single well is 11 million dollars and if the same conditions for drilling multiple one mile wells are met the cost is reduced to 8.5 million dollars with a one million dollar base cost to construct the pad.

These constraints were applied to all of the iterations and the iteration with the best economics was selected as the final iteration. Upon final review our economics could have been improved if we had built facilities and compressor stations to meet the needs of each well as it was drilled instead of constructing the infrastructure at the beginning. Additionally due to the cost of high pressure and low pressure lines being the same for this exercise more high pressure pipe could have been used. Despite these shortcomings we were able to produce high quality economics as follows: under budget by 62 million dollars with a discounted ROI of 3.8 non discounted ROI of 5.0 a 3 year payback period an IRR of 371% and a PW 10 of 413 million dollars.

Curveball:

The curveball was given about a week and a half before final presentations, so we had to adjust quickly and accordingly. The twist was that the west half of the township was not profitable and the east side actually yielded 50% more oil than our model stated. This clearly impacts our drill plan, midstream, and economics in a big way. The first step is to adjust the planned drilling operations. We are given the option to drill in the west half to test if this theory is correct or we can just trust the given information and not have a sunk cost from drilling a dry hole. We elected to trust the information and focus all drilling in the eastern half of the township. In a similar manner to the drill plan before the curveball, we began with a 4 well pad pilot in section 1 to test the spacing and fulfill both of section 1's obligations. Since we have half the area to drill we will now add even more wells per pad with our smallest pad in this plan being a four well pad. With a four well pad taking 180 days to drill it is impossible to meet all four year one obligations using only one rig, so we were required to use two drilling rigs. In the project description using multiple rigs comes with no additional cost. In the year one drill plan below, wells drilled with rig 1 are colored in white while wells drilled with rig 2 are colored in red.

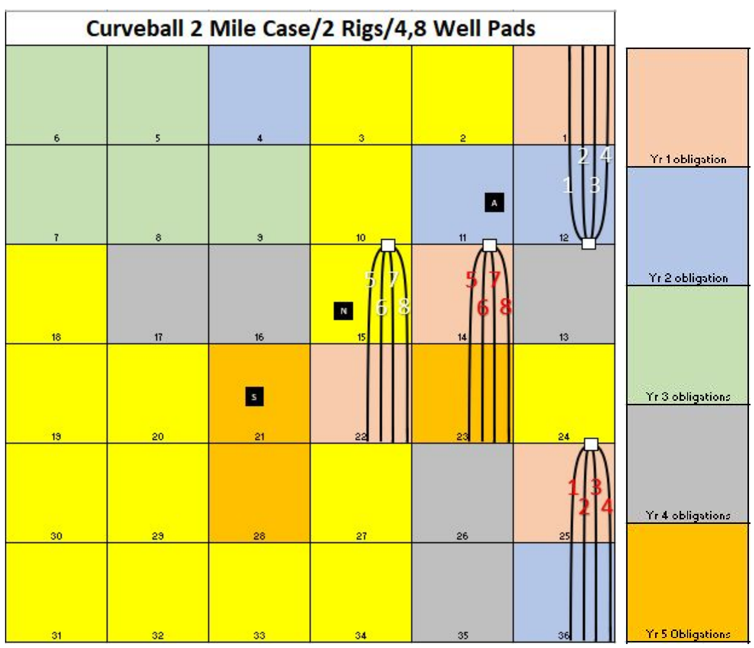


Fig 36- Curveball Year One Drill Plan

One detail to point out is that since the pads on sections 14 and 15 are drilled at the same time they will both finish drilling at the same time. This means there will be no complications with the requirement that wells cannot be drilled within a mile of a well that is currently being fractured and no time will be lost waiting for a frac job to end. The following drill schedule consists of every detail as previous drill schedules, but it now includes which wells were drilled by which rig.

Curveball 2 Mile Case/2 Rigs/4,8 Well Pads							
Order	$ (MIL)	Rig #	Drill Start	Drill End	Frac Start	Frac End	First Prod
1	5.25	1	0	45	180	194	195
2	10.5	1	45	90	194	208	209
3	15.75	1	90	135	208	222	223
4	21	1	135	180	222	236	237
5	26.25	1	180	225	360	374	375
6	31.5	1	225	270	374	388	389
7	36.75	1	270	315	388	402	403
8	42	1	315	360	402	416	417
1	47.25	2	0	45	180	194	195
2	52.5	2	45	90	194	208	209
3	57.75	2	90	135	208	222	223
4	63	2	135	180	222	236	237
5	68.25	2	180	225	360	374	375
6	73.5	2	225	270	374	388	389
7	78.75	2	270	315	388	402	403
8	84	2	315	360	402	416	417

Key
2 Well Pad
4 Well Pad
6 Well Pad
8 Well Pad

Fig 37- Curveball Year One Drill Schedule

Year two of the curveball drilling plan is very simple. Only one eight well pad is drilled in between the two four well pads in sections 14 and 15. In the previous drill plan an eight well pad was not used due to there being little flexibility since it takes 360 days to drill all 8 wells. However, with the curveball there is only one more year two obligation, so we have plenty of time and capital to accomplish drilling this massive pad in the final year two obligation section.

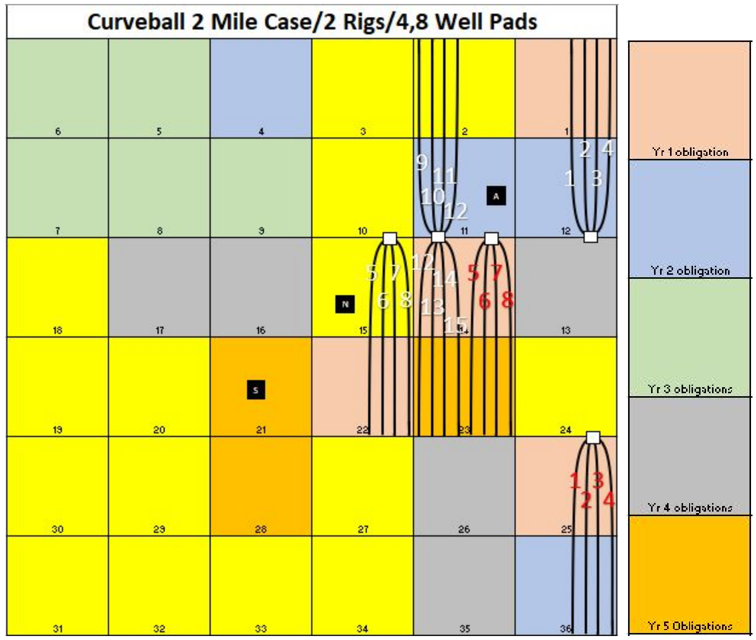


Fig 38- Curveball Year Two Drill Plan

Curveball 2 Mile Case/2 Rigs/4,8 Well Pads							
Order	$ (MIL)	Rig #	Drill Start	Drill End	Frac Start	Frac End	First Prod
9	89.18	1	365	410	725	739	740
10	94.36	1	410	455	739	753	754
11	99.54	1	455	500	753	767	768
12	104.72	1	500	545	767	781	782
13	109.9	1	545	590	781	795	796
14	115.08	1	590	635	795	809	810
15	120.26	1	635	680	809	823	824
16	125.44	1	680	725	823	837	838

Key
2 Well Pad
4 Well Pad
6 Well Pad
8 Well Pad

Fig 39- Curveball Year Two Drill Schedule

In year three an identical strategy was used. Another eight well pad will be drilled since we are trying to maximize the number of wells per pad. There are no year three obligations, so this well can be drilled in the best possible spot. We chose to put it right next to Company Awesome's processing plant in section 12 to save on midstream expenses.

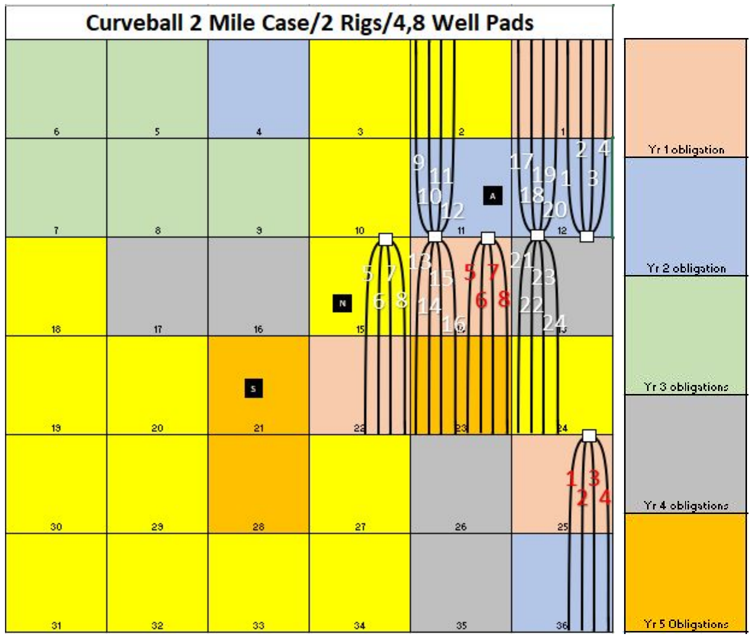


Fig 40- Curveball Year Three Drill Plan

Curveball 2 Mile Case/2 Rigs/4,8 Well Pads							
Order	$ (MIL)	Rig #	Drill Start	Drill End	Frac Start	Frac End	First Prod
17	130.62	1	730	775	1090	1104	1105
18	135.8	1	775	820	1104	1118	1119
19	140.98	1	820	865	1118	1132	1133
20	146.16	1	865	910	1132	1146	1147
21	151.34	1	910	955	1146	1160	1161
22	156.52	1	955	1000	1160	1174	1175
23	161.7	1	1000	1045	1174	1188	1189
24	166.88	1	1045	1090	1188	1202	1203

Key
2 Well Pad
4 Well Pad
6 Well Pad
8 Well Pad

Fig 41- Curveball Year Three Drill Schedule

The fourth and final year of this proposed drill plan consists of one last four well pad to satisfy the remaining two obligations in sections 26 and 35. This pad was also strategically located in the eastern half of the section so the midstream cost can be limited by shortening the required pipelines.

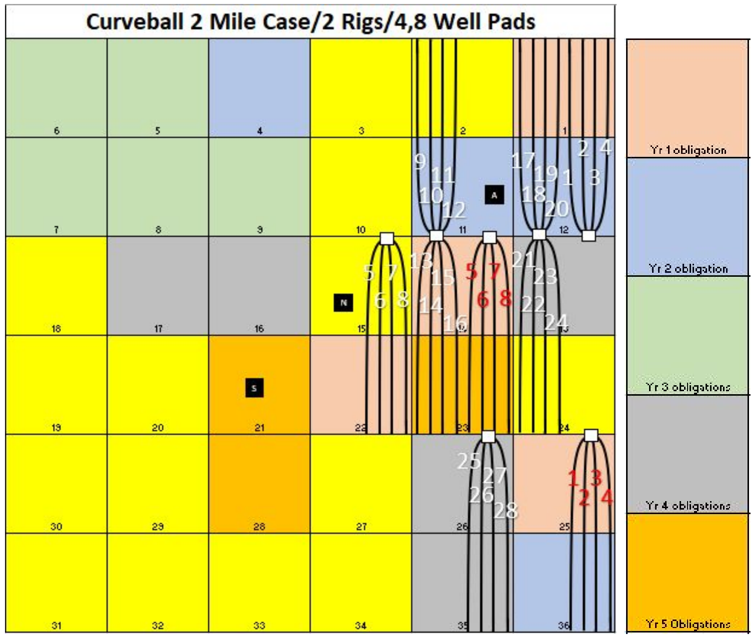


Fig 42- Curveball Year Four Drill Plan

Curveball 2 Mile Case/2 Rigs/4,8 Well Pads							
Order	$ (MIL)	Rig #	Drill Start	Drill End	Frac Start	Frac End	First Prod
25	172.13	1	1095	1140	1275	1289	1290
26	177.38	1	1140	1185	1289	1303	1304
27	182.63	1	1185	1230	1303	1317	1318
28	187.88	1	1230	1275	1317	1331	1332

Key
2 Well Pad
4 Well Pad
6 Well Pad
8 Well Pad

Fig 43- Curveball Year Four Drill Schedule

The same procedure was used to design the midstream for the curveball iteration. Since all the wells are drilled in the eastern side of the township, shorter pipelines were needed to transport the gas.

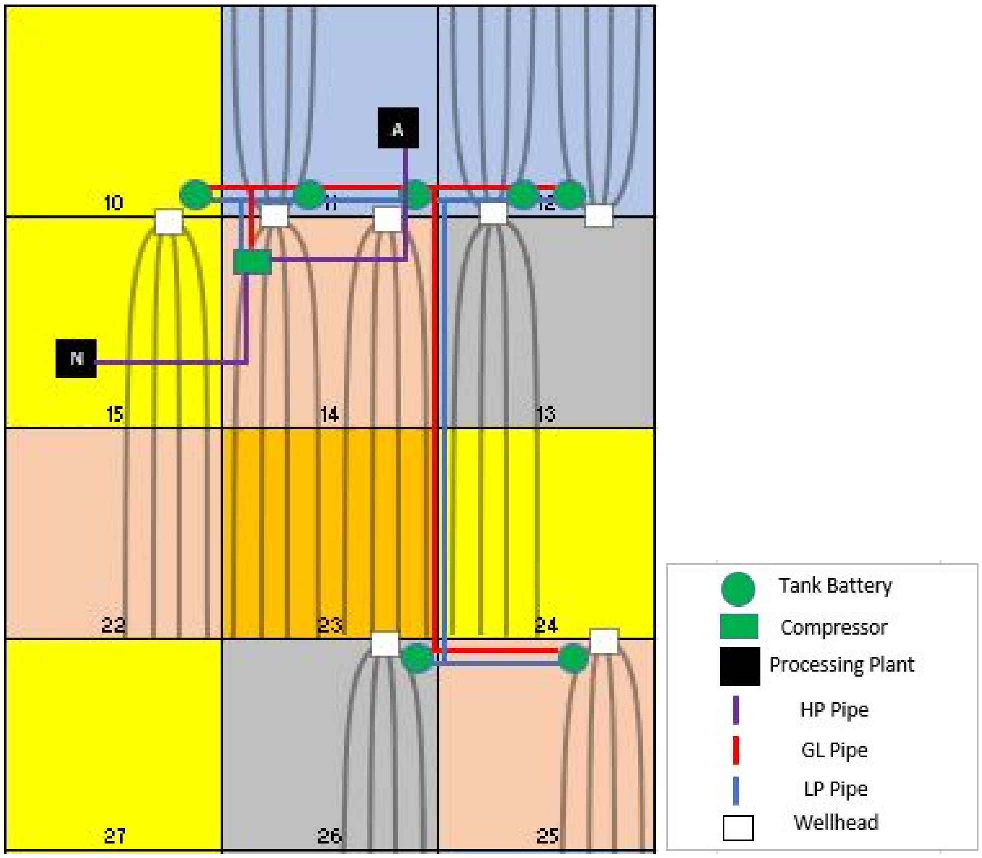


Fig 44- Internal Midstream Design Map

Again, the compressor is located between plants A and N. The new maximum daily production is 126.96 MMSCFD as can be seen in the graph below. That is a result of having 36 wells compared to 28 wells in the original iteration.

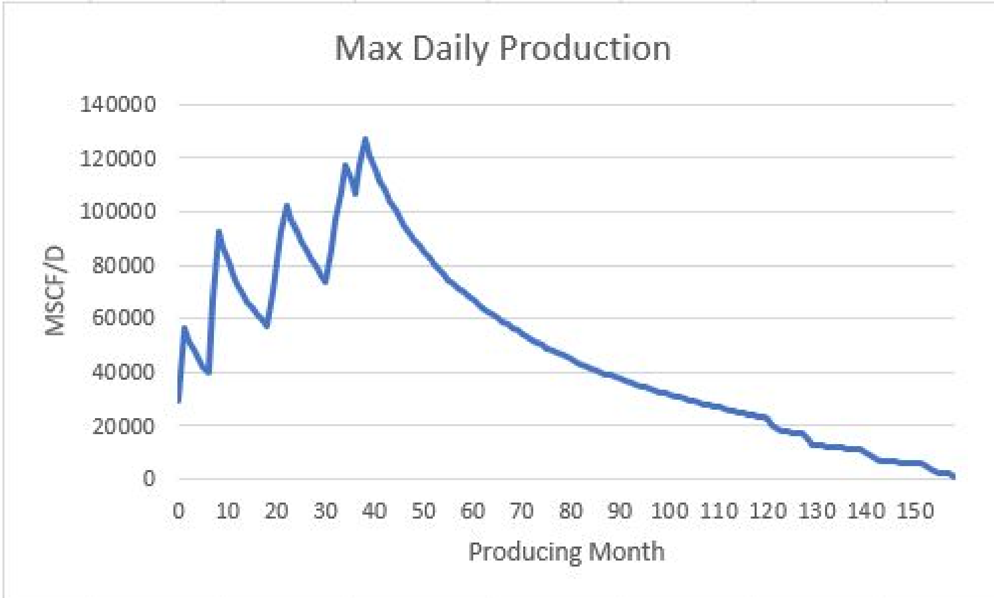


Fig 45- Maximum Daily Production (Curveball)

The specifications and costs of the new pipelines needed for this iteration are shown in the table below.

Pipe Type	Length (mile)	Diameter (in)	Volume (MMSCF/D)	Total Cost	WI Cost
LP	4.58	30	150	$10,992,000	$6,595,200
GL	4.62	8	160	$2,956,800	$1,774,080
HP	2.3	8	160	$1,472,000	$883,200

Fig 46- Pipelines Design and Costs (Curveball)

Compression costs have gone up as we have higher amounts of gas produced while the cost for the plant connections is the same.

Midstream Component	# of	Total Cost	WI Cost
Compressors	1	$15,870,250.00	$9,522,150.00
Plant Connects	2	$3,000,000.00	$1,800,000.00

Fig 47- Compression and Connections Capital Cost

Results and Discussion

In conclusion, we analyzed our type curve in multiple different ways, in order to select wells that behave nearly the same, wells that receive nearly the same total proppant which culminated into eight one mile wells and seven two mile wells for a comparable discussion. We saw an additional increase of 40,000MSCF/Month in the eight one mile wells selected and 4000 bbl/Month for oil. With eight one mile well and seven two mile wells , we arrived at a comparable number of wells and conducted the decline curve analysis. From the decline curve analysis we found that two mile wells produce nearly twice as much but declines faster. Which makes sense, because it gives us more oil and gas and therefore decline is faster. In short we came with an answer that in order to maximize our production we will be drilling all two mile wells as it produces more - as you read the report below - and the cost per foot per well for a two mile well is lower than one mile well. Hence, maximizing our production and minimizing our cost.

Drilling:

After completing the entire drill plan before the curveball a final drill schedule was compiled. Included in the final drill schedule seen below is the cumulative cost along with the day in which drilling starts and ends, the day in which fracturing starts and ends, and the first production date for each well. The final row of this table consists of the remaining budget, the time when all wells are online, and the footage drilled across all wells.

2 Mile/1 Rig/2,4 Well Pads						
Order	$ (MIL)	Drill Start	Drill End	Frac Start	Frac End	First Prod
1	5.25	0	45	180	194	195
2	10.5	45	90	194	208	209
3	15.75	90	135	208	222	223
4	21	135	180	222	236	237
5	26.4	180	225	270	284	285
6	31.8	225	270	284	298	299
7	37.2	270	315	360	374	375
8	42.6	315	360	374	388	389
9	47.85	360	405	540	554	555
10	53.1	405	450	554	568	569
11	58.35	450	495	568	582	583
12	63.6	495	540	582	596	597
13	68.85	540	585	720	734	735
14	74.1	585	630	734	748	749
15	79.35	630	675	748	762	763
16	84.6	675	720	762	776	777
17	89.85	720	765	900	914	915
18	95.1	765	810	914	928	929
19	100.35	810	855	928	942	943
20	105.6	855	900	942	956	957
21	111	900	945	990	1004	1005
22	116.4	945	990	1004	1018	1019
23	121.8	1095	1140	1185	1199	1200
24	127.2	1140	1185	1199	1213	1214
25	132.6	1185	1230	1275	1289	1290
26	138	1230	1275	1289	1303	1304
27	143.4	1275	1320	1365	1379	1380
28	148.8	1320	1365	1379	1393	1394
Remaining Budget	101.2	Time (YR)	3.82	Total Ft Drilled	295,680	

Fig 48- Final Drill Schedule

Another visualization of what occurs over the course of the drilling operations is the following table which breaks down the spending in each year and the number of wells drilled in a particular year.

	Cost (MIL $)	WI Cost (MIL $)	Wells Drilled
Year 1	79.75	47.85	9
Year 2	70	42	8
Year 3	44.25	26.55	5
Year 4	54	32.4	6
Total	248	148.8	28

Fig 49- Annual Drilling Breakdown

Midstream:

The internal midstream design before the curve ball Is shown in the table below. The table includes the cost of each pipeline in addition to compression capital and plant connections.

Capital Expense	Total Cost	WI Cost
LP	$12,333,600	$7,400,160
GL	$3,452,000	$2,071,200
HP	$924,000	$554,400
Compressor	$10,487,500	$6,292,500
Plant Connects	$3,000,000	$1,800,000
Total	$30,197,100	$18,118,260

Fig 50- Internal Midstream Capital Cost

It can be observed that the capital cost for building the internal midstream is high which is mainly due to the large low pressure pipe size. One of the ideas that was applied in the early iterations is having the LP line increase in size gradually in the direction of the compressor as more wells join the stream. However, the sponsor advised us to use one size as a reality application.

Economics:

After completing several iterations of drilling schedules and midstream designs using the same constraints as before the curveball we were able to achieve the following economics: under budget by 62 million dollars with a discounted ROI of 3.8 non discounted ROI of 5.0 a 3 year payback period an IRR of 371% and a PW 10 of 413 million dollars. This is an average increase over the pre curveball scenario in all parameters of around 30%. This is due to the increased oil recovery and the decrease in cost per well as there was capital to drill wells on larger pads decreasing the effect of the one million dollar base cost to build the pad.

Curveball:

After adjusting to the new information regarding the productivity within this township our drilling strategy changed a lot, but it still operated on the same principles outlined in the first drill plan/schedule. With half the area to work and a 50% increase in oil production, we knew it was beneficial to increase the density of wells in our plan. In this curveball drilling plan we added eight more wells than before and also used only four and eight well pads as opposed to only two and four well pads used previously. This did end up using more of the $250 million budget, but the cost per well decreased from $5.314 million per well to $5.219 million per well which is nearly a 2% decrease. When spending millions of dollars 2% really starts to add up.

Curveball 2 Mile Case/2 Rigs/4,8 Well Pads							
Order	$ (MIL)	Rig #	Drill Start	Drill End	Frac Start	Frac End	First Prod
1	5.25	1	0	45	180	194	195
2	10.5	1	45	90	194	208	209
3	15.75	1	90	135	208	222	223
4	21	1	135	180	222	236	237
5	26.25	1	180	225	360	374	375
6	31.5	1	225	270	374	388	389
7	36.75	1	270	315	388	402	403
8	42	1	315	360	402	416	417
1	47.25	2	0	45	180	194	195
2	52.5	2	45	90	194	208	209
3	57.75	2	90	135	208	222	223
4	63	2	135	180	222	236	237
5	68.25	2	180	225	360	374	375
6	73.5	2	225	270	374	388	389
7	78.75	2	270	315	388	402	403
8	84	2	315	360	402	416	417
9	89.18	1	365	410	725	739	740
10	94.36	1	410	455	739	753	754
11	99.54	1	455	500	753	767	768
12	104.72	1	500	545	767	781	782
13	109.9	1	545	590	781	795	796
14	115.08	1	590	635	795	809	810
15	120.26	1	635	680	809	823	824
16	125.44	1	680	725	823	837	838
17	130.62	1	730	775	1090	1104	1105
18	135.8	1	775	820	1104	1118	1119
19	140.98	1	820	865	1118	1132	1133
20	146.16	1	865	910	1132	1146	1147
21	151.34	1	910	955	1146	1160	1161
22	156.52	1	955	1000	1160	1174	1175
23	161.7	1	1000	1045	1174	1188	1189
24	166.88	1	1045	1090	1188	1202	1203
25	172.13	1	1095	1140	1275	1289	1290
26	177.38	1	1140	1185	1289	1303	1304
27	182.63	1	1185	1230	1303	1317	1318
28	187.88	1	1230	1275	1317	1331	1332
Remaining Budget	62.12	Time (YR)	3.65	Total Ft Drilled	380160		

Fig 51- Curveball Final Schedule

This annual spending table does indicate that the cost of drilling in year one is very expensive, but over the remaining years it reduces considerably. We also knew that the midstream pipelines were not going to cost as much since we are only operating in half the township, so using more capital in drilling wasn't a problem.

	Cost (MIL $)	WI Cost (MIL $)	Wells Drilled
Year 1	140	84	16
Year 2	69.07	41.44	8
Year 3	69.07	41.44	8
Year 4	35	21	4
Total	313.13	187.88	36

Fig 52- Curveball Annual Drilling Breakdown

The internal midstream cost for the curveball case is around 13.5% higher than the original iteration. This is expected because of the increase in the number of wells which needs larger pipelines. However, the increase is not that big when compared to the production increase as a result of using shorter pipes.

Capital Expense	Total Cost	WI Cost
LP	$12,333,600	$7,400,160
GL	$3,452,000	$2,071,200
HP	$924,000	$554,400
Compressor	$10,487,500	$6,292,500
Plant Connects	$3,000,000	$1,800,000
Total	$30,197,100	$18,118,260

Fig 53- Internal Midstream Capital Cost (Curveball)

Conclusion

We were tasked with developing two type curves (one for two mile laterals one for one mile laterals) for the lower wolfcamp wells in culberson county texas that were drilled before 2014. Developing a drilling and completions schedule along with a midstream plan to transport the produced gas to one or a combination of three available processing plants. We were to do this in a way that produced economic returns, fulfilled the yearly drilling obligations and stayed under the 250 million dollar internal budget. We were also given a curveball a week and a half prior to the final presentation. This required us to change our type curves, drilling schedule, and midstream proposal. We were able to accomplish all of this and propose the drilling schedule previously mentioned. Our midstream recommendation is to use the infrastructure built by company Nice as this resulted in best economics. The economics that we generated produced the following returns: under budget by 62 million dollars with a discounted ROI of 3.8 non discounted ROI of 5.0 a 3 year payback period an IRR of 371% and a PW 10 of 413 million dollars. While the proposal that we generated is likely not the absolute best due to the time constraint of the curve ball and the near infinite possible combinations of midstream designs and drilling schedules we feel that the objective of the project was met and the economic returns are satisfactory.

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Minin, A., Guerra, L., & Colombo, I. (2011, January 1). Unconventional Reservoirs Probabilistic Reserve Estimation Using Decline Curves. International Petroleum Technology Conference. doi:10.2523/IPTC-14801-MS

Appendices

Internal Midstream Total Economics

Date : 05/01/2020 1:45:52PM
Partner : All Cases

Total

ECONOMIC SUMMARY PROJECTION

Cimarex Project
Custom Selection
Discount Rate : 10.00
As of : 04/01/2020

Est. Cum Oil (Mbbl) :	**0.00**
Est. Cum Gas (MMcf) :	**0.00**
Est. Cum Water (Mbbl) :	**0.00**

Year	Oil Gross (Mbbl)	Gas Gross (MMcf)	Oil Net (Mbbl)	Gas Net (MMcf)	Oil Price ($/bbl)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Misc. Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF (M$)
2020	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021	369.56	4,682.14	277.17	3,511.60	60.00	2.00	23,653.40	0.00	4,582.75	1,883.06	55,318.20	-38,130.62	-33,684.06
2022	1,234.96	16,937.49	926.22	12,703.12	60.00	2.00	80,979.50	0.00	16,355.23	6,486.33	31,650.00	26,487.95	-12,371.20
2023	1,751.58	25,515.14	1,313.68	19,136.36	60.00	2.00	117,093.81	0.00	24,493.20	9,423.57	36,750.00	46,427.04	21,162.15
2024	1,612.65	25,697.40	1,209.49	19,273.05	60.00	2.00	111,115.32	0.00	24,486.79	8,980.74	21,600.00	56,047.79	58,370.52
2025	1,488.53	25,439.40	1,116.40	19,079.55	60.00	2.00	105,143.14	0.00	24,237.91	8,571.78	21,600.00	50,733.45	88,935.87
2026	1,076.21	21,021.79	807.16	15,766.34	60.00	2.00	79,962.24	0.00	19,965.26	6,591.77	0.00	53,405.21	118,481.58
2027	701.97	16,187.43	526.48	12,140.58	60.00	2.00	55,870.03	0.00	15,423.06	4,670.93	0.00	35,776.04	136,460.22
2028	503.20	13,270.64	377.40	9,952.98	60.00	2.00	42,549.84	0.00	12,795.21	3,598.31	0.00	26,156.32	148,403.38
2029	379.67	11,213.52	284.75	8,410.14	60.00	2.00	33,905.21	0.00	11,020.32	2,895.06	0.00	19,989.83	156,697.83
2030	298.81	9,736.16	224.11	7,302.12	60.00	2.00	28,050.73	0.00	9,780.81	2,415.12	0.00	15,854.79	162,677.40
2031	242.06	8,604.12	181.54	6,453.09	60.00	2.00	23,798.80	0.00	8,820.51	2,063.99	0.00	12,914.30	167,104.60
2032	201.01	7,727.61	150.76	5,795.71	60.00	2.00	20,637.06	0.00	8,077.13	1,801.38	0.00	10,758.55	170,456.87
2033	169.01	6,976.45	126.76	5,232.34	60.00	2.00	18,070.33	0.00	7,415.49	1,586.47	0.00	9,068.37	173,025.10
2034	144.64	6,364.59	108.48	4,773.44	60.00	2.00	16,055.58	0.00	6,876.17	1,416.81	0.00	7,762.61	175,023.63
Rem.	1,008.92	53,851.55	756.69	40,388.66	60.00	2.00	126,178.61	0.00	69,207.12	11,301.22	0.00	45,670.26	7,317.83
Total 33.2	**11,182.79**	**253,225.43**	**8,387.09**	**189,919.07**	**60.00**	**2.00**	**883,063.59**	**0.00**	**263,536.96**	**73,686.54**	**166,918.20**	**378,921.89**	**182,341.46**
Ult.	**11,182.79**	**253,225.43**											

Eco. Indicators

Return on Investment (disc) :	2.411
Return on Investment (undisc) :	3.270
Years to Payout :	3.87
Internal Rate of Return (%) :	98.81

Present Worth Profile (M$)

PW	**5.00% :**	**255,879.51**	**PW**	**20.00% :**	**101,775.58**
PW	**8.00% :**	**207,757.48**	**PW**	**30.00% :**	**60,973.84**
PW	**10.00% :**	**182,341.46**	**PW**	**40.00% :**	**37,832.70**
PW	**12.00% :**	**160,925.15**	**PW**	**50.00% :**	**23,739.05**
PW	**15.00% :**	**134,590.79**	**PW**	**60.00% :**	**14,719.63**

Internal Midstream Single Well Economics

Date: 05/01/2020 1:45:52PM	**ECONOMIC PROJECTION**	**Case :** Well Pad 1 {Well #002}
Partner : All Cases	**Cimarex Project**	**Type :** LEASE CASE
Retrieval Code :	**Custom Selection**	**Field :** Ford West
Reserve Cat. : Proved Undeveloped	**Discount Rate :** 10.00	**Operator :** Cimarex
Location :	**As of :** 04/01/2020	**Reservoir :**
Archive Set : default		**Co., State :** Culberson, TX
		API No. :

Est. Cum Oil (Mbbl) : 0.00
Est. Cum Gas (MMcf) : 0.00
Est. Cum Water (Mbbl) : 0.00

Year	Oil Gross (Mbbl)	Gas Gross (MMcf)	Oil Net (Mbbl)	Gas Net (MMcf)	Oil Price ($/bbl)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Misc. Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF (M$)
2020	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021	75.80	965.53	56.85	724.15	60.00	2.00	4,859.19	0.00	945.35	387.00	5,250.00	-1,723.17	-1,594.86
2022	102.01	1,490.93	76.51	1,118.20	60.00	2.00	6,827.06	0.00	1,424.84	549.58	0.00	4,852.64	2,342.53
2023	55.33	979.39	41.50	734.55	60.00	2.00	3,958.90	0.00	924.91	323.69	0.00	2,710.30	4,338.88
2024	35.04	728.91	26.28	546.68	60.00	2.00	2,670.08	0.00	688.41	221.28	0.00	1,760.39	5,516.60
2025	24.17	576.67	18.13	432.50	60.00	2.00	1,952.70	0.00	547.92	163.73	0.00	1,241.05	6,270.94
2026	17.77	477.27	13.33	357.95	60.00	2.00	1,515.76	0.00	457.58	128.38	0.00	929.80	6,784.55
2027	13.65	406.62	10.24	304.97	60.00	2.00	1,224.18	0.00	394.15	104.60	0.00	725.42	7,148.77
2028	10.86	354.78	8.14	266.09	60.00	2.00	1,020.69	0.00	356.13	87.90	0.00	576.66	7,411.95
2029	8.81	312.92	6.61	234.69	60.00	2.00	865.73	0.00	321.93	75.08	0.00	468.72	7,606.35
2030	7.32	280.37	5.49	210.28	60.00	2.00	749.75	0.00	293.43	65.43	0.00	390.90	7,753.73
2031	6.18	253.84	4.63	190.38	60.00	2.00	658.77	0.00	270.01	57.81	0.00	330.94	7,867.15
2032	5.30	232.41	3.98	174.31	60.00	2.00	587.30	0.00	250.92	51.81	0.00	284.57	7,955.80
2033	4.58	212.96	3.44	159.72	60.00	2.00	525.65	0.00	233.76	46.59	0.00	245.31	8,025.26
2034	4.01	195.93	3.01	146.95	60.00	2.00	474.41	0.00	218.93	42.21	0.00	213.28	8,080.16
Rem.	28.51	1,572.96	21.39	1,179.72	60.00	2.00	3,642.54	0.00	2,092.03	327.04	0.00	1,223.47	201.03
Total 29.1	**399.34**	**9,041.50**	**299.51**	**6,781.12**	**60.00**	**2.00**	**31,532.73**	**0.00**	**9,420.32**	**2,632.13**	**5,250.00**	**14,230.28**	**8,281.20**
Ult.	**399.34**	**9,041.50**											

Major Phase :	Gas		
Initial Rate :	223,713.00	Mcf/month	
Abandonment :	4,737.94	Mcf/month	
Initial Decline :	58.976	%/year	b = 0.95
Initial Ratio :	0.082	bbl/Mcf	
Abandon Ratio :	0.018	bbl/Mcf	
Abandon Day :	05/05/2049		

Eco. Indicators

Return on Investment (disc) :	2.783
Return on Investment (undisc) :	3.711
Years to Payout :	2.04
Internal Rate of Return (%) :	181.32

	Initial	**1st Rev.**	**2nd Rev.**
Working Interest :	0.60000000	0.00000000	0.00000000
Revenue Interest :	0.75000000	0.00000000	0.00000000
Rev. Date :			

Present Worth Profile (M$)

PW	**5.00% :**	**10,594.72**	**PW**	**20.00% :**	**5,502.88**
PW	**8.00% :**	**9,097.78**	**PW**	**30.00% :**	**3,899.36**
PW	**10.00% :**	**8,281.20**	**PW**	**40.00% :**	**2,868.44**
PW	**12.00% :**	**7,575.13**	**PW**	**50.00% :**	**2,161.38**
PW	**15.00% :**	**6,678.59**	**PW**	**60.00% :**	**1,654.79**

External Midstream Total Economics

Date : 04/30/2020 10:21:37PM
Partner : All Cases

ECONOMIC SUMMARY PROJECTION

Total

Cimarex Project
Custom Selection
Discount Rate : 10.00
As of : 04/01/2020

Est. Cum Oil (Mbbl) : **0.00**
Est. Cum Gas (MMcf) : **0.00**
Est. Cum Water (Mbbl) : **0.00**

Year	Oil Gross (Mbbl)	Gas Gross (MMcf)	Oil Net (Mbbl)	Gas Net (MMcf)	Oil Price ($/bbl)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Misc. Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF (M$)
2020	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021	369.56	4,682.14	277.17	3,511.60	60.00	2.00	23,653.40	0.00	5,004.14	1,883.06	38,280.00	-21,513.81	-18,971.64
2022	1,234.96	16,937.49	926.22	12,703.12	60.00	2.00	80,979.50	0.00	17,879.60	6,486.33	31,650.00	24,963.57	1,114.71
2023	1,751.58	25,515.14	1,313.68	19,136.36	60.00	2.00	117,093.81	0.00	26,789.56	9,423.57	36,750.00	44,130.68	32,966.04
2024	1,612.65	25,697.40	1,209.49	19,273.05	60.00	2.00	111,115.32	0.00	26,799.56	8,980.74	21,600.00	53,735.02	68,633.16
2025	1,488.53	25,439.40	1,116.40	19,079.55	60.00	2.00	105,143.14	0.00	26,527.46	8,571.78	25,200.00	44,843.90	95,627.88
2026	1,076.21	21,021.79	807.16	15,766.34	60.00	2.00	79,962.24	0.00	21,857.22	6,591.77	0.00	51,513.25	124,128.16
2027	701.97	16,187.43	526.48	12,140.58	60.00	2.00	55,870.03	0.00	16,879.93	4,670.93	0.00	34,319.17	141,375.37
2028	503.20	13,270.64	377.40	9,952.98	60.00	2.00	42,549.84	0.00	14,008.29	3,598.31	0.00	24,943.24	152,765.27
2029	379.67	11,213.52	284.75	8,410.14	60.00	2.00	33,905.21	0.00	12,079.94	2,895.06	0.00	18,930.21	160,620.52
2030	298.81	9,736.16	224.11	7,302.12	60.00	2.00	28,050.73	0.00	10,738.43	2,415.12	0.00	14,897.18	166,239.25
2031	242.06	8,604.12	181.54	6,453.09	60.00	2.00	23,798.80	0.00	9,696.40	2,063.99	0.00	12,038.41	170,366.41
2032	201.01	7,727.61	150.76	5,795.71	60.00	2.00	20,637.06	0.00	8,891.41	1,801.38	0.00	9,944.26	173,465.15
2033	169.01	6,976.45	126.76	5,232.34	60.00	2.00	18,070.33	0.00	8,164.34	1,586.47	0.00	8,319.53	175,821.42
2034	144.64	6,364.59	108.48	4,773.44	60.00	2.00	16,055.58	0.00	7,569.94	1,416.81	0.00	7,068.84	177,641.43
Rem.	944.57	50,184.09	708.43	37,638.07	60.00	2.00	117,781.65	0.00	69,155.95	10,545.51	0.00	38,080.20	6,318.87
Total **31.1**	**11,118.44**	**249,557.98**	**8,338.83**	**187,168.48**	**60.00**	**2.00**	**874,666.63**	**0.00**	**282,042.16**	**72,930.82**	**153,480.00**	**366,213.65**	**183,960.29**
Ult.	**11,118.44**	**249,557.98**											

Eco. Indicators

Return on Investment (disc) :	2.582
Return on Investment (undisc) :	3.386
Years to Payout :	3.74
Internal Rate of Return (%) :	158.13

Present Worth Profile (M$)

PW	**5.00% :**	**252,935.54**	**PW**	**20.00% :**	**107,223.65**
PW	**8.00% :**	**207,909.01**	**PW**	**30.00% :**	**67,748.99**
PW	**10.00% :**	**183,960.29**	**PW**	**40.00% :**	**45,029.21**
PW	**12.00% :**	**163,688.26**	**PW**	**50.00% :**	**30,962.84**
PW	**15.00% :**	**138,640.47**	**PW**	**60.00% :**	**21,786.71**

External Midstream Single Well Economics

Date: 04/30/2020 10:21:37PM
Partner : All Cases
Retrieval Code :
Reserve Cat. : Proved Undeveloped
Location :
Archive Set : default

ECONOMIC PROJECTION

Cimarex Project
Custom Selection
Discount Rate : 10.00
As of : 04/01/2020

Case : Well Pad 1 {Well #002}
Type : LEASE CASE
Field : Ford West
Operator : Cimarex
Reservoir :
Co., State : Culberson, TX
API No. :

Est. Cum Oil (Mbbl) : 0.00
Est. Cum Gas (MMcf) : 0.00
Est. Cum Water (Mbbl) : 0.00

Year	Oil Gross (Mbbl)	Gas Gross (MMcf)	Oil Net (Mbbl)	Gas Net (MMcf)	Oil Price ($/bbl)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Misc. Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF (M$)
2020	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021	75.80	965.53	56.85	724.15	60.00	2.00	4,859.19	0.00	1,032.25	387.00	5,250.00	-1,810.06	-1,669.97
2022	102.01	1,490.93	76.51	1,118.20	60.00	2.00	6,827.06	0.00	1,559.02	549.58	0.00	4,718.46	2,158.69
2023	55.33	979.39	41.50	734.55	60.00	2.00	3,958.90	0.00	1,013.06	323.69	0.00	2,622.16	4,090.18
2024	35.04	728.91	26.28	546.68	60.00	2.00	2,670.08	0.00	754.01	221.28	0.00	1,694.79	5,224.06
2025	24.17	576.67	18.13	432.50	60.00	2.00	1,952.70	0.00	599.82	163.73	0.00	1,189.15	5,946.88
2026	17.77	477.27	13.33	357.95	60.00	2.00	1,515.76	0.00	500.54	128.38	0.00	886.85	6,436.78
2027	13.65	406.62	10.24	304.97	60.00	2.00	1,224.18	0.00	430.75	104.60	0.00	688.82	6,782.64
2028	10.86	354.78	8.14	266.09	60.00	2.00	1,020.69	0.00	391.30	87.90	0.00	541.49	7,029.80
2029	8.81	312.92	6.61	234.69	60.00	2.00	865.73	0.00	354.41	75.08	0.00	436.24	7,210.74
2030	7.32	280.37	5.49	210.28	60.00	2.00	749.75	0.00	322.98	65.43	0.00	361.35	7,346.98
2031	6.18	253.84	4.63	190.38	60.00	2.00	658.77	0.00	297.18	57.81	0.00	303.78	7,451.09
2032	5.30	232.41	3.98	174.31	60.00	2.00	587.30	0.00	276.15	51.81	0.00	259.33	7,531.88
2033	4.58	212.96	3.44	159.72	60.00	2.00	525.65	0.00	257.25	46.59	0.00	221.82	7,594.70
2034	4.01	195.93	3.01	146.95	60.00	2.00	474.41	0.00	240.88	42.21	0.00	191.32	7,643.95
Rem.	26.20	1,441.18	19.65	1,080.88	60.00	2.00	3,340.81	0.00	2,049.93	299.89	0.00	990.98	169.30
Total 27.0	**397.03**	**8,909.72**	**297.77**	**6,682.29**	**60.00**	**2.00**	**31,230.99**	**0.00**	**10,079.56**	**2,604.97**	**5,250.00**	**13,296.46**	**7,813.26**
Ult.	**397.03**	**8,909.72**											

Major Phase :	Gas		
Initial Rate :	223,713.00	Mcf/month	
Abandonment :	5,653.62	Mcf/month	
Initial Decline :	58.976	%/year	b = 0.95
Initial Ratio :	0.082	bbl/Mcf	
Abandon Ratio :	0.018	bbl/Mcf	
Abandon Day :	03/23/2047		

Eco. Indicators

Return on Investment (disc) :	2.682
Return on Investment (undisc) :	3.533
Years to Payout :	2.06
Internal Rate of Return (%) :	169.88

	Initial	1st Rev.	2nd Rev.
Working Interest :	0.60000000	0.00000000	0.00000000
Revenue Interest :	0.75000000	0.00000000	0.00000000
Rev. Date :			

Present Worth Profile (M$)

PW	**5.00% :**	**9,970.23**	**PW**	**20.00% :**	**5,190.06**
PW	**8.00% :**	**8,577.84**	**PW**	**30.00% :**	**3,665.15**
PW	**10.00% :**	**7,813.26**	**PW**	**40.00% :**	**2,682.67**
PW	**12.00% :**	**7,149.57**	**PW**	**50.00% :**	**2,008.68**
PW	**15.00% :**	**6,303.74**	**PW**	**60.00% :**	**1,526.13**

Curveball External Midstream Single Well Economics

Date: 05/01/2020 4:36:10PM	**ECONOMIC PROJECTION**	**Case :** Well Pad 1 {Well #002}
Partner : All Cases	**Cimarex Project**	**Type :** LEASE CASE
Retrieval Code :	**Custom Selection**	**Field :** Ford West
Reserve Cat. : Proved Undeveloped	**Discount Rate :** 10.00	**Operator :** Cimarex
Location :	**As of :** 04/01/2020	**Reservoir :**
Archive Set : default		**Co., State :** Culberson, TX
		API No. :

Est. Cum Oil (Mbbl) : 0.00
Est. Cum Gas (MMcf) : 0.00
Est. Cum Water (Mbbl) : 0.00

Year	Oil Gross (Mbbl)	Gas Gross (MMcf)	Oil Net (Mbbl)	Gas Net (MMcf)	Oil Price ($/bbl)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Misc. Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF (M$)
2020	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021	113.69	965.53	85.27	724.15	60.00	2.00	6,564.44	0.00	1,078.10	508.08	5,250.00	-271.73	-339.91
2022	153.02	1,490.93	114.76	1,118.20	60.00	2.00	9,122.12	0.00	1,621.96	712.53	0.00	6,787.64	5,168.08
2023	82.99	979.39	62.24	734.55	60.00	2.00	5,203.66	0.00	1,048.23	412.06	0.00	3,743.37	7,925.61
2024	52.56	728.91	39.42	546.68	60.00	2.00	3,458.35	0.00	776.96	277.25	0.00	2,404.14	9,534.14
2025	36.26	576.67	27.19	432.50	60.00	2.00	2,496.48	0.00	616.13	202.34	0.00	1,678.01	10,554.15
2026	26.66	477.27	20.00	357.95	60.00	2.00	1,915.65	0.00	512.89	156.77	0.00	1,245.98	11,242.47
2027	20.47	406.62	15.36	304.97	60.00	2.00	1,531.27	0.00	440.52	126.41	0.00	964.34	11,726.67
2028	16.28	354.78	12.21	266.09	60.00	2.00	1,264.93	0.00	399.31	105.24	0.00	760.37	12,073.72
2029	13.21	312.92	9.91	234.69	60.00	2.00	1,063.89	0.00	361.11	89.15	0.00	613.63	12,328.24
2030	10.97	280.37	8.23	210.28	60.00	2.00	914.33	0.00	328.70	77.11	0.00	508.51	12,519.97
2031	9.27	253.84	6.95	190.38	60.00	2.00	797.76	0.00	302.09	67.68	0.00	427.99	12,666.65
2032	7.96	232.41	5.97	174.31	60.00	2.00	706.62	0.00	280.37	60.28	0.00	365.97	12,780.67
2033	6.87	212.96	5.16	159.72	60.00	2.00	628.75	0.00	260.89	53.90	0.00	313.96	12,869.57
2034	6.02	195.93	4.51	146.95	60.00	2.00	564.66	0.00	244.07	48.61	0.00	271.97	12,939.59
Rem.	44.76	1,648.59	33.57	1,236.45	60.00	2.00	4,487.05	0.00	2,471.35	390.29	0.00	1,625.41	261.08
Total 30.5	**600.98**	**9,117.13**	**450.74**	**6,837.85**	**60.00**	**2.00**	**40,719.96**	**0.00**	**10,742.69**	**3,287.71**	**5,250.00**	**21,439.55**	**13,200.67**
Ult.	**600.98**	**9,117.13**											

Major Phase :	Gas	
Initial Rate :	223,713.00 Mcf/month	
Abandonment :	4,212.41 Mcf/month	
Initial Decline :	58.976 %/year	b = 0.95
Initial Ratio :	0.122 bbl/Mcf	
Abandon Ratio :	0.026 bbl/Mcf	
Abandon Day :	10/02/2050	

Eco. Indicators

Return on Investment (disc) :	3.842
Return on Investment (undisc) :	5.084
Years to Payout :	1.78
Internal Rate of Return (%) :	429.94

	Initial	1st Rev.	2nd Rev.
Working Interest :	0.60000000	0.00000000	0.00000000
Revenue Interest :	0.75000000	0.00000000	0.00000000
Rev. Date :			

Present Worth Profile (M$)

PW	5.00% :	16,429.93	PW	20.00% :	9,240.50
PW	8.00% :	14,345.87	PW	30.00% :	6,889.68
PW	10.00% :	13,200.67	PW	40.00% :	5,339.27
PW	12.00% :	12,204.57	PW	50.00% :	4,250.15
PW	15.00% :	10,930.47	PW	60.00% :	3,451.52

Curveball External Midstream Total Economics

Date : 05/01/2020 4:36:10PM
Partner : All Cases

ECONOMIC SUMMARY PROJECTION

Total

Cimarex Project
Custom Selection
Discount Rate : 10.00
As of : 04/01/2020

Est. Cum Oil (Mbbl) :	**0.00**
Est. Cum Gas (MMcf) :	**0.00**
Est. Cum Water (Mbbl) :	**0.00**

Year	Oil Gross (Mbbl)	Gas Gross (MMcf)	Oil Net (Mbbl)	Gas Net (MMcf)	Oil Price ($/bbl)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Misc. Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF (M$)
2020	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021	840.50	7,424.37	630.38	5,568.28	60.00	2.00	48,959.28	0.00	8,241.31	3,799.07	54,660.00	-17,741.10	-15,997.27
2022	2,806.16	26,372.18	2,104.62	19,779.14	60.00	2.00	165,835.33	0.00	28,895.29	12,921.50	36,750.00	87,268.54	53,875.97
2023	3,047.04	30,775.46	2,285.28	23,081.60	60.00	2.00	183,279.85	0.00	33,459.01	14,351.60	41,640.00	93,829.24	122,055.59
2024	3,824.23	39,525.45	2,868.18	29,644.09	60.00	2.00	231,378.71	0.00	42,986.28	18,147.25	56,958.00	113,287.18	196,609.01
2025	2,715.00	32,421.78	2,036.25	24,316.33	60.00	2.00	170,807.85	0.00	34,831.01	13,537.70	0.00	122,439.14	271,156.82
2026	1,686.75	24,028.23	1,265.06	18,021.17	60.00	2.00	111,946.18	0.00	25,690.67	8,993.41	0.00	77,262.11	313,879.94
2027	1,166.37	19,177.24	874.77	14,382.93	60.00	2.00	81,252.30	0.00	20,559.86	6,603.12	0.00	54,089.32	341,055.71
2028	863.17	16,017.51	647.38	12,013.13	60.00	2.00	62,869.03	0.00	17,390.98	5,160.46	0.00	40,317.58	359,463.41
2029	664.43	13,691.14	498.32	10,268.35	60.00	2.00	50,436.07	0.00	15,160.90	4,176.53	0.00	31,098.65	372,366.38
2030	530.14	11,980.71	397.61	8,985.53	60.00	2.00	41,827.37	0.00	13,553.44	3,490.90	0.00	24,783.03	381,712.96
2031	433.75	10,648.08	325.32	7,986.06	60.00	2.00	35,491.08	0.00	12,351.68	2,983.06	0.00	20,156.34	388,622.93
2032	362.95	9,604.90	272.21	7,203.68	60.00	2.00	30,740.18	0.00	11,305.55	2,600.37	0.00	16,834.27	393,868.28
2033	307.00	8,700.44	230.25	6,525.33	60.00	2.00	26,865.72	0.00	10,394.16	2,285.94	0.00	14,185.63	397,885.81
2034	263.99	7,955.88	197.99	5,966.91	60.00	2.00	23,813.42	0.00	9,650.46	2,036.83	0.00	12,126.12	401,007.80
Rem.	1,921.49	69,394.81	1,441.12	52,046.10	60.00	2.00	190,559.40	0.00	101,001.98	16,548.39	0.00	73,009.03	11,529.25
Total 33.6	**21,432.99**	**327,718.18**	**16,074.74**	**245,788.64**	**60.00**	**2.00**	**1,456,061.78**	**0.00**	**385,472.58**	**117,636.13**	**190,008.00**	**762,945.07**	**412,537.05**
Ult.	**21,432.99**	**327,718.18**											

Eco. Indicators

Return on Investment (disc) :	3.778
Return on Investment (undisc) :	5.015
Years to Payout :	3.00
Internal Rate of Return (%) :	370.69

Present Worth Profile (M$)

PW	**5.00% :**	**546,359.20**	**PW**	**20.00% :**	**258,753.06**
PW	**8.00% :**	**459,312.37**	**PW**	**30.00% :**	**175,624.42**
PW	**10.00% :**	**412,537.05**	**PW**	**40.00% :**	**125,467.99**
PW	**12.00% :**	**372,582.92**	**PW**	**50.00% :**	**93,007.67**
PW	**15.00% :**	**322,629.67**	**PW**	**60.00% :**	**70,917.85**

Curveball Internal Midstream Single Well Economics

Date: 05/01/2020 4:40:55PM
Partner : All Cases
Retrieval Code :
Reserve Cat. : Proved Undeveloped
Location :
Archive Set : default

ECONOMIC PROJECTION

Cimarex Project
Custom Selection
Discount Rate : 10.00
As of : 04/01/2020

Case : Well Pad 1 {Well #002}
Type : LEASE CASE
Field : Ford West
Operator : Cimarex
Reservoir :
Co., State : Culberson, TX
API No. :

Est. Cum Oil (Mbbl) : **0.00**
Est. Cum Gas (MMcf) : **0.00**
Est. Cum Water (Mbbl) : **0.00**

Year		Oil Gross (Mbbl)	Gas Gross (MMcf)	Oil Net (Mbbl)	Gas Net (MMcf)	Oil Price ($/bbl)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Misc. Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF (M$)
2020		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021		113.69	965.53	85.27	724.15	60.00	2.00	6,564.44	0.00	991.20	508.08	5,250.00	-184.84	-264.80
2022		153.02	1,490.93	114.76	1,118.20	60.00	2.00	9,122.12	0.00	1,487.78	712.53	0.00	6,921.82	5,351.92
2023		82.99	979.39	62.24	734.55	60.00	2.00	5,203.66	0.00	960.09	412.06	0.00	3,831.51	8,174.30
2024		52.56	728.91	39.42	546.68	60.00	2.00	3,458.35	0.00	711.36	277.25	0.00	2,469.74	9,826.68
2025		36.26	576.67	27.19	432.50	60.00	2.00	2,496.48	0.00	564.23	202.34	0.00	1,729.91	10,878.21
2026		26.66	477.27	20.00	357.95	60.00	2.00	1,915.65	0.00	469.94	156.77	0.00	1,288.94	11,590.24
2027		20.47	406.62	15.36	304.97	60.00	2.00	1,531.27	0.00	403.93	126.41	0.00	1,000.93	12,092.80
2028		16.28	354.78	12.21	266.09	60.00	2.00	1,264.93	0.00	364.14	105.24	0.00	795.54	12,455.88
2029		13.21	312.92	9.91	234.69	60.00	2.00	1,063.89	0.00	328.62	89.15	0.00	646.12	12,723.86
2030		10.97	280.37	8.23	210.28	60.00	2.00	914.33	0.00	299.15	77.11	0.00	538.07	12,926.72
2031		9.27	253.84	6.95	190.38	60.00	2.00	797.76	0.00	274.92	67.68	0.00	455.15	13,082.71
2032		7.96	232.41	5.97	174.31	60.00	2.00	706.62	0.00	255.13	60.28	0.00	391.21	13,204.58
2033		6.87	212.96	5.16	159.72	60.00	2.00	628.75	0.00	237.40	53.90	0.00	337.44	13,300.13
2034		6.02	195.93	4.51	146.95	60.00	2.00	564.66	0.00	222.12	48.61	0.00	293.93	13,375.80
Rem.		47.01	1,734.22	35.26	1,300.66	60.00	2.00	4,716.91	0.00	2,426.58	410.34	0.00	1,879.99	293.45
Total	**32.3**	**603.24**	**9,202.76**	**452.43**	**6,902.07**	**60.00**	**2.00**	**40,949.82**	**0.00**	**9,996.60**	**3,307.76**	**5,250.00**	**22,395.47**	**13,669.25**
Ult.		**603.24**	**9,202.76**											

Major Phase : Gas
Initial Rate : 223,713.00 Mcf/month
Abandonment : 3,617.45 Mcf/month
Initial Decline : 58.976 %/year b = 0.95
Initial Ratio : 0.122 bbl/Mcf
Abandon Ratio : 0.026 bbl/Mcf
Abandon Day : 07/30/2052

Eco. Indicators

Return on Investment (disc) :	3.943
Return on Investment (undisc) :	5.266
Years to Payout :	1.77
Internal Rate of Return (%) :	451.31

	Initial	1st Rev.	2nd Rev.
Working Interest :	0.60000000	0.00000000	0.00000000
Revenue Interest :	0.75000000	0.00000000	0.00000000
Rev. Date :			

Present Worth Profile (M$)

PW	**5.00% :**	**17,058.27**	**PW**	**20.00% :**	**9,553.32**
PW	**8.00% :**	**14,867.14**	**PW**	**30.00% :**	**7,123.89**
PW	**10.00% :**	**13,669.25**	**PW**	**40.00% :**	**5,525.03**
PW	**12.00% :**	**12,630.44**	**PW**	**50.00% :**	**4,402.84**
PW	**15.00% :**	**11,305.41**	**PW**	**60.00% :**	**3,580.18**

Curveball Internal Midstream Total Economics

Date : 05/01/2020 4:40:55PM
Partner : All Cases

ECONOMIC SUMMARY PROJECTION

Total

Cimarex Project
Custom Selection
Discount Rate : 10.00
As of : 04/01/2020

Est. Cum Oil (Mbbl) :	**0.00**
Est. Cum Gas (MMcf) :	**0.00**
Est. Cum Water (Mbbl) :	**0.00**

Year	Oil Gross (Mbbl)	Gas Gross (MMcf)	Oil Net (Mbbl)	Gas Net (MMcf)	Oil Price ($/bbl)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Misc. Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF (M$)
2020	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021	840.50	7,424.37	630.38	5,568.28	60.00	2.00	48,959.28	0.00	7,573.11	3,799.07	73,080.00	-35,492.91	-31,718.31
2022	2,806.16	26,372.18	2,104.62	19,779.14	60.00	2.00	165,835.33	0.00	26,521.80	12,921.50	36,750.00	89,642.04	40,074.40
2023	3,047.04	30,775.46	2,285.28	23,081.60	60.00	2.00	183,279.85	0.00	30,689.22	14,351.60	41,640.00	96,599.03	110,286.58
2024	3,824.23	39,525.45	2,868.18	29,644.09	60.00	2.00	231,378.71	0.00	39,428.99	18,147.25	56,958.00	116,844.47	187,207.34
2025	2,715.00	32,421.78	2,036.25	24,316.33	60.00	2.00	170,807.85	0.00	31,913.05	13,537.70	0.00	125,357.09	263,529.32
2026	1,686.75	24,028.23	1,265.06	18,021.17	60.00	2.00	111,946.18	0.00	23,528.13	8,993.41	0.00	79,424.65	307,446.92
2027	1,166.37	19,177.24	874.77	14,382.93	60.00	2.00	81,252.30	0.00	18,833.91	6,603.12	0.00	55,815.27	335,489.04
2028	863.17	16,017.51	647.38	12,013.13	60.00	2.00	62,869.03	0.00	15,917.73	5,160.46	0.00	41,790.84	354,568.51
2029	664.43	13,691.14	498.32	10,268.35	60.00	2.00	50,436.07	0.00	13,855.25	4,176.53	0.00	32,404.29	368,012.70
2030	530.14	11,980.71	397.61	8,985.53	60.00	2.00	41,827.37	0.00	12,367.18	3,490.90	0.00	25,969.29	377,806.27
2031	433.75	10,648.08	325.32	7,986.06	60.00	2.00	35,491.08	0.00	11,242.88	2,983.06	0.00	21,265.15	385,096.03
2032	362.95	9,604.90	272.21	7,203.68	60.00	2.00	30,740.18	0.00	10,285.59	2,600.37	0.00	17,854.23	390,658.97
2033	307.00	8,700.44	230.25	6,525.33	60.00	2.00	26,865.72	0.00	9,455.60	2,285.94	0.00	15,124.19	394,942.14
2034	263.99	7,955.88	197.99	5,966.91	60.00	2.00	23,813.42	0.00	8,778.91	2,036.83	0.00	12,997.67	398,288.40
Rem.	2,002.27	72,504.16	1,501.70	54,378.12	60.00	2.00	198,858.25	0.00	98,295.37	17,272.87	0.00	83,290.02	12,807.44
Total 35.5	**21,513.76**	**330,827.53**	**16,135.32**	**248,120.65**	**60.00**	**2.00**	**1,464,360.63**	**0.00**	**358,686.71**	**118,360.60**	**208,428.00**	**778,885.32**	**411,095.84**
Ult.	**21,513.76**	**330,827.53**											

Eco. Indicators

Return on Investment (disc) :	3.495
Return on Investment (undisc) :	4.737
Years to Payout :	3.07
Internal Rate of Return (%) :	226.22

Present Worth Profile (M$)

PW	**5.00% :**	**550,211.11**	**PW**	**20.00% :**	**253,103.70**
PW	**8.00% :**	**459,543.68**	**PW**	**30.00% :**	**168,584.42**
PW	**10.00% :**	**411,095.84**	**PW**	**40.00% :**	**118,001.02**
PW	**12.00% :**	**369,858.96**	**PW**	**50.00% :**	**85,519.11**
PW	**15.00% :**	**318,488.03**	**PW**	**60.00% :**	**63,593.00**