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A Strategic Study and Economics of Optimum Well Design for the Utica Shale

Linda N. Anumele
West Virginia University

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**A Strategic Study and Economics of Optimum Well Design for the
Utica Shale**

Linda N. Anumele

**Thesis Submitted to the College of Engineering and Mineral
Resources at West Virginia University in partial fulfillment of the
requirements for the degree of**

**Master of Science
In
Petroleum and Natural Gas Engineering**

**Ilkin Bilgesu, Ph.D., Chair
Samuel Ameri, M.S.
Daniel E. Della-Giustina, Ph.D.**

Department of Petroleum and Natural Gas Engineering

**Morgantown, West Virginia
2013**

Keywords: Well design, Fracture design, Economic analysis, Utica Shale.

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ABSTRACT

A Strategic Study and Economics of Optimum Well Design for the Utica Shale

Linda N. Anumele

This research seeks to venture into optimal well and fracture design via reservoir modeling, simulation and economic analysis in an attempt to discover, analyze, interpret and present the best ways of maximizing hydrocarbon (natural gas) production from the Utica shale which is a relatively new reservoir.

Furthermore, comparison of natural gas production in deep and thick Utica shale formation sections is studied for various well and fracture designs in conjunction with stimulated reservoir volume analysis and economic analysis in order to achieve an optimal design. The objective of this study is to compare and contrast the gas production from various well and fracture designs in deep and thick Utica formation sections.

This project focuses only on horizontal wells since it has been proven time and again that horizontal wells tend to be more viable in shale when compared to vertical well. Therefore, this project focuses only on how to optimize production from the Utica shale by selecting an optimal horizontal well design.

Hence, this thesis work analyzes the effect of fracture half-length, number of fracture treatments and horizontal wellbore lateral lengths on gas production in these shale wells as well as interpretation and presentation of results. Economic evaluations of various well designs are also analyzed, interpreted and presented.

This research presents also results for the Utica shale play productivity via optimal well & fracture design and detailed economic analysis.

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Chapter I-Literature Review

Shale gas is a natural gas formed and trapped within shale formations. Shale gas has become an increasingly important source of natural gas in the United States over the past decade, and interest has spread to potential gas shale's in the rest of the world. In 2000 shale gas provided only 1% of U.S. natural gas production; by 2010 it was over 20% and the U.S. government's Energy Information Administration predicts that by 2035, 46% of the United States' natural gas supply will come from shale gas. Figure 1 shows the shale gas distribution of the U.S. by play.

Figure 1: Shale plays of the U.S. (<http://www.naturalgaswatch.org/?p=862>)

Some analysts expect that shale gas will greatly expand worldwide energy supply. China is estimated to have the world's largest shale gas reserves. A study by the Baker Institute of Public Policy at Rice University concluded that increased shale gas production in the US and Canada could help prevent Russia and Persian Gulf countries from dictating higher prices for the gas they export to European countries. (Rice Universities, 2009) The Obama administration believes that increased shale gas development will help reduce greenhouse gas emissions through the injection of CO₂ into shale formation.

The Utica Shale is a stratigraphic unit of Middle Ordovician age in the Appalachian Basin. It underlies much of the northeastern United States and adjacent parts of Canada. It takes the name from the city of Utica, New York. The Utica Shale lies under most of New York, Pennsylvania, Ohio, and West Virginia and extends under adjacent parts of Ontario and Quebec in Canada and Kentucky, Maryland, Tennessee, and Virginia in the United States. It occurs in outcrops in the state of New York and parts of the island of Montreal consist of Utica shale, which affected construction of parts of the Montreal metro. It has recently become the target of gas and oil exploration in eastern Ohio and Pennsylvania where it is around 8,000 to 14000 feet deep. In 2011 drilling and permits for drilling in the Utica Shale in Ohio reached record highs. It reaches a thickness of up to 1,000 feet and can be as thin as 70 feet towards the margins of the basin. Ohio is currently the center of most exploration and development of the Utica Shale, though many expect exploration and development to spread into Western and Northwestern Pennsylvania. In 2009, Scheper et. al. history matched production from the Utica shale, deriving values for the parameters associated with the Utica shale reservoir production such as fracture permeability, matrix permeability, fracture porosity and matrix porosity.

The potential source rock portion of the Utica Shale is extensive. In the United States it underlies portions of Kentucky, Maryland, New York, Ohio, Pennsylvania, Tennessee, West Virginia and Virginia. It is also present beneath parts of Lake Ontario, Lake Erie and part of Ontario, Canada. This geographic extent of potential Utica Shale source rock is shown in Figure 2. If the Utica is commercial throughout this extent it will be geographically larger than any natural gas field known today.

Nasar (2011) performed economic analysis on the Coal Bed Methane reservoirs of the Appalachia region of West Virginia and concluded that lateral wells were more economically viable than vertical wells. Also, He Quin (2011) performed parametric and reservoir studies on the sequestration of CO₂ into un-mineable coal seams as well as the production of natural gas from the coal seam and concluded that fracture permeability had the most effect on natural gas production and CO₂ injection. Finally, Steven (2012) elaborated on the importance of shale gas to the economy of the U.S. and Canada as well as how the shale gas in both countries could neutralize Europe's dependence on Russian energy. Newmann (1988) presented a detailed engineering economic analysis.

Historical studies have also been conducted on the Utica shale. Lash (2008) investigated the fracture and stratigraphy of the Appalachian shale of middle and upper Devonian of which the Utica belongs to. More so, the U.S. Department of Energy is currently conducting research on the "Evaluation of Fracture Systems and Stress Fields within the Marcellus Shale and Utica Shale". More economic evaluation of shale was also conducted by Kaiser and Mark (2011), examining the economic viability and sustainability of the Haynesville shale play.

Figure 2: Utica shale gas play
(<http://www.dnr.state.oh.us/tabid/23014/default.aspx>)

The Utica Shale is thicker than the Marcellus, it is more geographically extensive and it has already proven its ability to support commercial production. This research focuses on the area around the New York/Pennsylvania border where the depth is 6000 ft.

Figure 3 below shows a generalized cross-section of the Utica as we move across the border between Ohio and Pennsylvania.

Figure 3: Utica generalized cross-section Ohio to Pennsylvania
<http://www.dnr.state.oh.us/tabid/23014/default.aspx>

Figure 4 below shows a generalized cross-section of the Utica as we move across the border between New York and Pennsylvania.

Figure 4: Utica generalized cross-section New York to Pennsylvania
<http://www.dnr.state.oh.us/tabid/23014/default.aspx>

A useful tool which can enable us to understand the value of the Utica shale is reservoir modeling and simulation in conjunction with parametric sensitivity studies. The reservoir simulation and modeling can guide us in determining the changes that can lead to increased hydrocarbon production in the Utica shale. Furthermore, the potential of the Utica shale can be established through reservoir modeling and simulation. Once a model is built from real geological and physical properties data, numerous runs can be executed by using a reservoir simulator. In each run, a different value can be used for certain parameters to determine the best possible combinations in a well, in order to maximize production.

Figure 5 below displays the Utica shale in Quebec. The darkly colored formation is organic rich Utica shale while the light colored formation is limestone.

Figure 5: Dark organic rich Utica shale formation in Quebec
(<http://www.dnr.state.oh.us/tabid/23014/default.aspx>)

The Figure 6 below shows energy use by sources in the US and production. Roughly a fourth of US energy is produced out of natural gas. The amount of shale gas has increased steadily over the last few years and it is expected that shale gas may deliver up to 45% of total natural gas produced in the US by 2035.

Figure 6: U.S. energy use and production

(<http://www.dnr.state.oh.us/tabid/23014/default.aspx>)

Chapter II-Statement of Problem

This research seeks to find the most optimum way of producing gas from the Utica shale via the means of reservoir modeling and simulation. In this research, production from horizontal wells without fractures will be compared to other horizontal well designs with lateral length varying from 2000 to 6000 ft, in 2000 ft increments as well as fracture half length varying from 300 to 900 ft, in 300 ft increments. In addition, an economic evaluation will be conducted in order to reach a conclusion on the best way to produce from the Utica shale. Previously, limited work has been done on hydraulic fracture optimization. Pinkhouse et. al. (2006) performed research on optimizing hydraulic fracturing performance in Northeastern United States fractured shale formations.

The objective of this research is to maximize gas production from the Utica shale through well design, fracture design and economic evaluation. For this research, commercially available reservoir modeling and simulation software is used to investigate the Utica shale production. In order to build a reservoir model that can accurately simulate an average Utica shale formation, extensive literature review and data collection were initiated. This research seeks to evaluate if it is economically warranted to drill several horizontal well designs which is often expensive in most shale formations.

Once all of the production data are obtained, an economic analysis was conducted to determine the most optimal designs for the wells. All of the modeling and production forecasting are completed utilizing a reservoir simulator.

Analysis was performed in order to understand the effect of well type, lateral length of horizontal wells, effect of single fracture, effect of multiple fractures and the effect of fracture half length on production from the Utica. Finally, economic analysis was performed on the wells and fracture designs in order to select an optimum design.

In order to accomplish the objective of this study, the following procedure will be followed:

- Building a reservoir model which is capable of producing methane (natural gas) from deep and thick shale reservoirs with various well and fracture designs.
- Performing economic analysis on the horizontal well designs in order to identify the best drilling pattern in deep and thick Utica shale reservoirs, and to evaluate the recovery factors.

Model Nomenclature for Reservoir Simulation

To study the effect of well designs on shale gas production from the Utica Shale, reservoir modeling study was conducted. To simulate production data for the Utica Shale wells, CMG software was used, a total of 28 different simulations were conducted. Only one parameter was changed at a time to hold the validity of the effect of the parameter that was investigated, after this is done, comparison was then made to the effects of the changes of lateral lengths, fracture treatments and number of half lengths.

Table 1 below shows the reservoir model designations that were used for this research. 0Xf represents zero fracture treatment while 5Xf represents five fracture treatments. The numbers appearing after Xf indicates the fracture half length. For example, 3Xf300 means a well with 300 ft half length and three fracture treatments. Also, the number preceding 3Xf300 represents the lateral length of the well. For example 2000 3Xf600 refers to a well with 2000 ft lateral, three fracture treatments and a 600 ft half-length.

Table 1: Well designs used in the study.

Well Designation	Lateral length, ft	Half-length, ft	# of frac treatments
2000 0 Xf0	2000	0	0
2000 3 Xf300	2000	3	300
2000 3 Xf600	2000	3	600
2000 3 Xf900	2000	3	900
2000 5 Xf300	2000	5	300
2000 5 Xf600	2000	5	600
2000 5 Xf900	2000	5	900
4000 0 Xf0	4000	0	0
4000 3 Xf300	4000	3	300
4000 3 Xf600	4000	3	600
4000 3 Xf900	4000	3	900
4000 5 Xf300	4000	5	300
4000 5 Xf600	4000	5	600
4000 5 Xf900	4000	5	900
4000 9 Xf300	4000	9	300
4000 9 Xf600	4000	9	600
4000 9 Xf900	4000	9	900
6000 0 Xf0	6000	0	0
6000 3 Xf300	6000	3	300
6000 3 Xf600	6000	3	600
6000 3 Xf900	6000	3	900
6000 5 Xf300	6000	5	300
6000 5 Xf600	6000	5	600
6000 5 Xf900	6000	5	900
2000 10 Xf300	2000	10	300
2000 10 Xf600	2000	10	600
4000 20 Xf300	4000	20	300
6000 15 Xf300	6000	15	300

Chapter III- Approach

Table 2 below shows reservoir parameters obtained for the Utica through history matching. Schepers (2009) designed a reservoir model, assuming various values for reservoir parameters as long as these values were within reasonable range for the Utica. He then obtained production data from a company. Finally, he ran his reservoir model and obtained cumulative gas production curves which were different from those obtained from the companies who were drilling in the Utica.

Table 2: Parameters via deterministic approach-History matching.

http://www.spe.org/events/lacpec/2009/en/technical/documents/123057_Karine_Schepers.pdf

Reservoir Parameters	Units	Value
Thickness	ft	400
Elevation	ft	4000
Initial Pressure Gradient	psi/ft	0.30
Reservoir Temperature	F	80
Matrix Porosity	%	5
Fracture Porosity	%	0.60
Matrix Permeability ($K_x=K_z$)	mD	$5 \cdot 10^{-4}$
Fracture Permeability ($K_x=K_z$)	mD	$3 \cdot 10^{-3}$
Permeability Anisotropy	-	5
Initial Water Saturation	%	0
Matrix Block Size	ft	10
In-situ Langmuir Volume	scf/t	52
Langmuir Pressure	psia	375
Gas Saturation	%	100
Fluid Parameters		
Gas Gravity		0.55
Water Viscosity	cp	0.86
Water Formation Volume Factor	RB/STB	1.01
Water Density	lbm/cuft	62.3
Gas Composition	%CH ₄	100
Matrix Relative Permeability Curves (Corey function)		
Irreducible Water Saturation	%	0
Residual Gas Saturation	%	0
Maximum Gas Relative Permeability	v/v	1
Maximum Water Relative Permeability	v/v	1
Corey Exponents (water and gas)	v/v	1
Fracture Relative Permeability Curves (Corey function)		
Irreducible Water Saturation	%	0
Maximum Gas Relative Permeability	v/v	1
Maximum Water Relative Permeability	v/v	1
Residual Gas Saturation	%	0
Corey exponent (water and gas)	v/v	1
Well Parameters		
Wellbore Radius	ft	0.27

Consequently, he kept changing the values of his reservoir parameters, within the reasonable range, until his gas cumulative production curve matched with those of the company. This method of finding out reservoir parameters/properties is called history matching. For this research, a reservoir model will be built using data obtained from literature review and research.

In this research, a Cartesian grid, totaling 5000 grid blocks (100 x 50) was used. A dual porosity/dual permeability shale gas reservoir model was built with a 6000 ft depth and a net thickness of 300 ft. The model was designed as a homogeneous shale gas reservoir. With fracture width was set at 0.001 ft. Runs were conducted for a period of 30 years.

Figures 7, 8, 9 and 10 below show the Utica shale reservoir models in 2D as well as four horizontal wells drilled in the middle of a Cartesian grid. Figure 7 shows a well with 2000 ft lateral length, ten frac treatments and 600 ft half-length which is represented by 2000 10Xf600. Similarly, figures 8, 9 and 10 represent wells with designs 4000 20Xf300, 6000 15 Xf300 and 4000 9Xf900 respectively. The descriptions of these wells can be found on Table 1.

Figure 7: Well design with 2000 ft lateral and 10 fracture treatments of 600 ft half lengths.

Figure 8: Well design with 4000 ft lateral and 20 fracture treatments of 300 ft half lengths.

Figure 9: Well design with 6000 ft lateral and 15 fracture treatments of 300 ft half lengths.

Figure 10: Well design with 4000 ft lateral and 9 fracture treatments of 900 ft half lengths.

Figure 11 shows the horizontal well design used to represent a 4000 ft lateral with 20 treatments of 300 ft fracture half lengths.

Figure 11: Well design with 4000 ft lateral and 20 fracture treatments of 300 ft half lengths.

Figure 12 represents 3D representation of well design with 2000 ft lateral and 3 fracture treatments of 900 ft half lengths. Figure 13 shows the 3D representation of well design with 4000 ft lateral and 3 fracture treatments of 900 ft half lengths and figure 14 shows 3D representation of well design with 6000 ft lateral and 3 fracture treatments of 900 ft half lengths.

Figure 12: 3D representation of well design with 2000 ft lateral and 3 fracture treatments of 900 ft half lengths.

Figure 13: 3D representation of well design with 4000 ft lateral and 3 fracture treatments of 900 ft half lengths.

Figure 14: 3D representation of well design with 6000 ft lateral and 3 fracture treatments of 900 ft half lengths.

Figure 15 below shows the well design for a horizontal well with 6000 ft lateral and 5 fracture treatments of 900 ft fracture half length.

Figure 15: Well design with 6000 ft lateral and 5 fracture treatments of 900 ft half lengths.

Note the reservoir model designs above are just a few of many which will not be shown in this paper. The model pictures above have just been shown to boost the reader's understanding of the general orientation and location of the wells in addition to the general orientation of the fracture treatments and design. Finally, Appendix B shows the reservoir pressure distribution for 0, 10, 20 and 30 years for select reservoir models that were built and used in this research as shown from Figure Appendix 1 to Appendix 16.

Chapter IV-Economic Analysis

This part of the research uses economic analysis as a basic financial tool to investigate various well designs in the Utica shale, the result of which shows either a profit or loss for the given well design. In order to determine the economic feasibility, a cash flow model is constructed for all simulation runs. The Net Present Value (NPV) was used to determine the economics of well design for the Utica shale reservoir.

The major factors affecting the economics of Utica shale reservoirs are as follows:

- Natural Gas Price
- Drilling Cost
- Completion Cost
- Royalty
- Interest Rate
- Operating cost

Along with the fact that the price of gas is projected to increase at some point in future, however, to predict the prices in the coming years is very difficult due to many factors impacting the market. Thus, several gas prices were used to cover the anticipated price range, namely \$3.5, \$4.0 and \$5.0 per MSCF. The drilling cost includes the cost of various lateral length designs for horizontal wells with same vertical depth. The completion cost includes completing and fracturing a well and it is based on half length of the fracture and number of fracture treatments. The operating cost is based on the monthly cost of operating the well.

Table 3 shows the drilling cost by well design for the selected cases used in this study. Table 4 shows the completion cost for a single fracture treatment based on the half length of the fracture treatment. Table 5 lists the value of other economic parameters used in the calculations.

Table 3: Drilling cost by Well Design.

Horizontal Well Design (Drilling)	Cost \$
2000 ft lateral	3,000,000
4000 ft lateral	5,000,000
6000 ft lateral	7,000,000

Table 4: Completion cost by Well Design.

Frac Half Length Well Design (Completions)	Cost \$
300 ft	130,000
600 ft	175,000
900 ft	220,000
0	0

Table 5: Economic Parameters.

Economic Parameters	Value
Operating cost, \$ per month	1,600
Gas Prices \$/SCF	3.5, 4.0, 5.0
Interest Rate, %	15
Royalty, %	12.5

The equation 1 below shows the formula used in the calculation of NPV values where i is the interest rate, t is the time period and R_t is the cash flow.

$$NPV(i, N) = \sum_{t=1}^N \frac{R_t}{(1+i)^t} \dots\dots\dots \text{Equation 1}$$

A fixed interest rate of 15% was used in this study.

Table 6 below shows a sample economic analysis of NPV calculation for a 2000 ft long horizontal well with three fracture treatments of 600 ft half-length for a period of 30 years. Gas revenue is based on the yearly gas production obtained from the reservoir model. Three different gas prices were considered with 12.5% royalty. All calculations are based on pre- tax value, due to the changes in tax rates used by different states.

Table 6: NPV analysis for 2000 ft lateral horizontal well with three fracture treatments and 600 ft fracture half length in the Utica after 30 years.

DATE	Yearly Production SC	Revenue, \$	Revenue after royalty, \$	Well Design Cost, \$			Cash flow, \$ (after expenses)	NPV @ 15%	
				Operating	Drilling	Completions		Discount factor	Discount cash flow, \$
oct 1-2012			0		3,000,000	525,000	(3,525,000.00)	1.0000	(3,525,000.00)
oct 1-2013	407982656	1,427,939.30	1249446.884	19,200.0			1,230,246.88	0.8696	1,069,779.90
oct 1-2014	286451584	1,002,580.54	877257.976	19,200.0			858,057.98	0.7561	648,815.10
oct 1-2015	238730688	835,557.41	731112.732	19,200.0			711,912.73	0.6575	468,094.18
oct 1-2016	214060288	749,211.01	655559.632	19,200.0			636,359.63	0.5718	363,840.68
oct 1-2017	194926592	682,243.07	596962.688	19,200.0			577,762.69	0.4972	287,250.17
oct 1-2018	180718848	632,515.97	553451.472	19,200.0			534,251.47	0.4323	230,971.65
oct 1-2019	169299200	592,547.20	518478.8	19,200.0			499,278.80	0.3759	187,697.39
oct 1-2020	160251520	560,880.32	490770.28	19,200.0			471,570.28	0.3269	154,157.16
oct 1-2021	151780864	531,233.02	464828.896	19,200.0			445,628.90	0.2843	126,675.54
oct 1-2022	144854528	506,990.85	443616.992	19,200.0			424,416.99	0.2472	104,909.39
oct 1-2023	138793984	485,778.94	425056.576	19,200.0			405,856.58	0.2149	87,236.12
oct 1-2024	133784832	468,246.91	409716.048	19,200.0			390,516.05	0.1869	72,990.24
oct 1-2025	128619776	450,169.22	393898.064	19,200.0			374,698.06	0.1625	60,898.91
oct 1-2026	124294912	435,032.19	380653.168	19,200.0			361,453.17	0.1413	51,083.69
oct 1-2027	120366336	421,282.18	368621.904	19,200.0			349,421.90	0.1229	42,942.03
oct 1-2028	117088512	409,809.79	358583.568	19,200.0			339,383.57	0.1069	36,268.15
oct 1-2029	113465600	397,129.60	347488.4	19,200.0			328,288.40	0.0929	30,506.49
oct 1-2030	110415616	386,454.66	338147.824	19,200.0			318,947.82	0.0808	25,772.62
oct 1-2031	107585280	376,548.48	329479.92	19,200.0			310,279.92	0.0703	21,801.92
oct 1-2032	105230848	368,307.97	322269.472	19,200.0			303,069.47	0.0611	18,517.63
oct 1-2033	102476544	358,667.90	313834.416	19,200.0			294,634.42	0.0531	15,654.13
oct 1-2034	100163840	350,573.44	306751.76	19,200.0			287,551.76	0.0462	13,285.06
oct 1-2035	97988352	342,959.23	300089.328	19,200.0			280,889.33	0.0402	11,284.57
oct 1-2036	95936512	335,777.79	293805.568	19,200.0			274,605.57	0.0349	9,593.15
oct 1-2037	93996288	328,987.01	287863.632	19,200.0			268,663.63	0.0304	8,161.37
oct 1-2038	92158208	322,553.73	282234.512	19,200.0			263,034.51	0.0264	6,948.15
oct 1-2039	90412800	316,444.80	276889.2	19,200.0			257,689.20	0.0230	5,919.08
oct 1-2040	88752640	310,634.24	271804.96	19,200.0			252,604.96	0.0200	5,045.48
oct 1-2041	87171328	305,099.65	266962.192	19,200.0			247,762.19	0.0174	4,303.26
oct 1-2042	86125824	301,440.38	263760.336	19,200.0			244,560.34	0.0151	3,693.61
								Total NPV, \$	649,096.81

CHAPTER V- Results and Discussion

The results below show how cumulative production is affected by lateral length, frac half-length and number of fracture treatments. Notably, the analysis below generally shows the trend in cumulative production with respect to changes in lateral length, frac half-length or number of fracture treatments. For example, Figure 16 shows the effect of well lateral length on cumulative production and it is evident that as lateral length increases from 2000 ft to 6000 ft, cumulative production increases; however, the amount of increased gas production by each well length is not linearly related to lateral length size. The actual cumulative gas production values from each well design are listed in Table 7.

Table 7: Cumulative gas production for different well designs

Analyzed Well Designs	Cumulative Gas Production SCF
2000 3 Xf300	2,914,683,136.00
2000 3 Xf600	4,283,884,800.00
2000 3 Xf900	5,348,584,448.00
2000 5 Xf300	3,821,350,400.00
2000 5 Xf600	5,881,631,232.00
2000 5 Xf900	7,525,968,384.00
2000 10 Xf300	4,525,214,720.00
2000 10 Xf600	7,049,180,672.00
4000 3 Xf300	3,927,911,936.00
4000 3 Xf600	5,301,746,688.00
4000 3 Xf900	6,369,676,288.00
4000 5 Xf300	5,014,160,896.00
4000 5 Xf600	7,292,295,168.00
4000 5 Xf900	9,071,793,152.00
4000 9 Xf300	6,824,958,464.00
4000 9 Xf600	10,486,311,936.00
4000 9 Xf900	13,424,247,808.00
4000 20 Xf300	8,599,832,576.00
6000 3 Xf300	4,887,753,728.00
6000 3 Xf600	6,261,260,288.00
6000 3 Xf900	7,329,083,904.00
6000 5 Xf300	5,978,297,344.00
6000 5 Xf600	8,266,182,144.00
6000 5 Xf900	10,051,795,968.00
6000 15 Xf300	10,146,748,416.00

Effect of Lateral Well Length on Cumulative Gas Production

Figure 16 shows the cumulative gas production from three horizontal wells with 2000 ft, 4000 ft and 6000 ft laterals for a period of 30 years.

Figure 16: Comparison of cumulative gas production from three different lateral wells with no fracture treatments.

As can be seen from the plot, the horizontal well with the longest lateral 6000 ft 96907207808 MSCF produces more gas followed by the horizontal well with 4000 ft lateral and 66666076928 MSCF more with 2000 ft lateral 34828655600 MSCF. These lengths increase in the wellbore increases the gas production. However the cumulative gas production should justify the cost of extra length.

Effect of Number of fracture treatments on 2000 ft lateral horizontal well with 300 ft half length.

Figure 17 shows the effect of number of fracture treatments on cumulative natural gas production on a 2000 ft lateral horizontal well.

Figure 17: Comparison of cumulative gas production with different number of fracture treatments on 2000 ft lateral well with 300 ft half length.

Three different fracture treatments of 3, 5 and 10 were increased as shown in the figure above, the well with the most number of fracture treatments (10) has the highest cumulative production for a period of 30 years followed by the wells with 5 and 3 fracture treatments respectively with half-length being constant at 300 ft.

Effect of Number of fracture treatments on 2000 ft lateral horizontal well with 600ft half length.

Figure 18 shows the effect of number of fracture treatments on cumulative natural gas production on a 2000 ft lateral horizontal well.

Figure 18: : Comparison of cumulative gas production with different number of fracture treatments on 2000 ft lateral well with 600 ft half length.

Similar to results with 300 ft fracture half length, the cumulative gas production was 4,283,884,800MMSCF, 5,881,631,232 MMSCf and 7,049,180,672 MMSCF for 3, 5 and 20 treatments respectively.

Effect of Fracture Half Length on 2000 ft Lateral horizontal well with 3 fracture treatments

Figure 19 shows the effect of half-length sizes on cumulative natural gas production on a 2000 ft lateral horizontal well with three fracture treatments.

Figure 19: Comparison of cumulative gas production with different fracture half Length on 2000 ft Lateral well with 3 fracture treatments.

As shown in the figure above the cumulative production for a period of 30 years increased from 2,914,683,136 MMSF to 5,348,448 MMSCF when fracture half length increased from 300 ft to 900 ft.

Effect of Fracture Half Length on 2000 ft Lateral horizontal well with 5 fracture treatments

Figure 20 shows the effect of half-length sizes on cumulative natural gas production on a 2000 ft lateral horizontal well with five fracture treatments.

Figure 20: Comparison of cumulative gas production with different Fracture Half Lengths on 2000 ft Lateral well with 5 fracture treatments

As shown in the figure above, the well with the longest fracture half-length (900 ft) has the highest cumulative production for a period of 30 years followed by the wells with 600 and 300 ft fracture treatments respectively with fracture treatment being constant at three.

Effect of Number of fracture treatments on 4000 ft lateral horizontal well with 300ft half length

Figure 21 shows the effect of number of fracture treatment on cumulative natural gas production on a 4000 ft lateral horizontal well. For all cases shown in Figure 21, the fracture half length of 300 ft was used.

Figure 21: Comparison of cumulative gas production with different Number of fracture treatments on 4000 ft lateral well with 300 ft half length

The cumulative production for a period of 30 years increases from 3,927,911,936 MMSCF to 6,824,958,464 MMSCF when the number of fracture treatments increases from 3 to 9. Further

increase in the number of treatments to 20 increases the cumulative gas produced to 8,599,832,576 MMSCF at end of 30 years.

Effect of Number of fracture treatments on 4000 ft lateral horizontal well with 600ft half length

Figure 22 shows the effect of number of fracture treatment on cumulative natural gas production on a 4000 ft lateral horizontal well.

Figure 22: Comparison of cumulative gas production from Effect of Number of fracture treatments on 4000 ft lateral well with 600 ft half length

As shown in the figure above, the well with the most number of fracture treatments (9) has the highest cumulative production for a period of 30 years followed by the wells with 5 and 3 fracture treatments respectively with half-length being constant at 600 ft.

Effect of Number of fracture treatments on 4000 ft lateral horizontal well with 900ft half length

Figure 23 shows the effect of number of fracture treatments on cumulative natural gas production on a 4000 ft lateral horizontal well when a fracture half length of 900 ft is used

Figure 23: Comparison of cumulative gas production with different Number of fracture treatments on 4000 ft lateral well with 900 ft half length

When the number of treatments increases from fracture from 3 to 5 then to 9, the cumulative gas production values at the end of 30 years period increases from 6,824,958,464 MMSCF to 9,071,793,152 MMSCF and then to 13,424,247,808 MMSCF respectively.

Effect of Half-length on 4000 ft lateral horizontal well with 3 fracture treatments

Figure 24 shows the effect of half-length sizes on cumulative natural gas production on a 4000 ft lateral horizontal well with three fracture treatments.

Figure 24: Comparison of cumulative gas production with different Fracture Half Length on 4000 ft Lateral well with 3 fracture treatments

As shown in the figure above, the well with the longest fracture half-length (900 ft) has the highest cumulative production for a period of 30 years followed by the wells with 600 and 300 ft fracture treatments respectively with number of fracture treatment being constant at three.

Effect of Half-length on 4000 ft lateral horizontal well with 5 fracture treatments

Figure 25 shows the effect of half-length treatment on cumulative natural gas production on a 4000 ft lateral horizontal well with five fracture treatments.

Figure 25: Comparison of cumulative gas production from Effect of Fracture Half Length on 4000 ft Lateral well with 5 fracture treatments

As shown in the figure above, the well with the longest fracture half-length (900 ft) has the highest cumulative production for a period of 30 years followed by the wells with 600 and 300 ft fracture treatments respectively with number of fracture treatment being constant at five.

Effect of Half-length on 4000 ft lateral horizontal well with 9 fracture treatments

Figure 26 shows the effect of half-length treatment on cumulative natural gas production on a 4000 ft lateral horizontal well with nine fracture treatments.

Figure 26: Comparison of cumulative gas production from Effect of Fracture Half Length on 4000 ft Lateral well with 9 fracture treatments

As shown in the figure above, the well with the longest fracture half-length (900 ft) has the highest cumulative production for a period of 30 years followed by the wells with 600 and 300 ft fracture treatments respectively with number of fracture treatment being constant at nine.

Effect of half-length on 6000 ft lateral horizontal well with 3 fracture treatments

Figure 27 shows the effect of half-length treatment on cumulative natural gas production on a 6000 ft lateral horizontal well with three fracture treatments.

Figure 27: Comparison of cumulative gas production from Effect of Fracture Half Length on 6000 ft Lateral well with 3 fracture treatments

As shown in the figure above, the well with the longest fracture half-length (900 ft) has the highest cumulative production for a period of 30 years followed by the wells with 600 and 300 ft fracture treatments respectively with number of fracture treatment being constant at three.

Effect of half-length on 6000 ft lateral horizontal well with 5 fracture treatments

Figure 28 shows the effect of half-length treatment on cumulative natural gas production on a 6000 ft lateral horizontal well with five fracture treatments.

Figure 28: Comparison of cumulative gas production from Effect of Fracture Half Length on 6000 ft Lateral well with 5 fracture treatments

As shown in the figure above, the well with the longest fracture half-length (900ft) has the highest cumulative production for a period of 30 years followed by the wells with 600 and 300ft fracture treatments respectively with number of fracture treatment being constant at five.

Effect of number of frac treatments on 6000 ft lateral horizontal well with 300 ft half length

Figure 29 shows the effect of number of fracture treatment on cumulative natural gas production on a 6000 ft lateral horizontal well.

Figure 29: Comparison of cumulative gas production from Effect of Number of fracture treatments on 6000 ft lateral well with 300 ft half length

As shown in the figure above, the well with the most number of fracture treatments (15) has the highest cumulative production for a period of 30 years followed by the wells with 5 and 3 fracture treatments respectively with half-length being constant at 300 ft.

Pressure Distribution

The pressure distributions at 0, 10, 20 and 30 years are shown in Figures 30, 31, 32 and 33, respectively for a horizontal well with 2000 ft lateral and five 900 ft half-length fracture treatment. Pressure distributions for other well designs used in this study are given in Appendix.

Figure 30: Initial Pressure Distribution

Figure 31: Pressure Distribution after ten years of gas production.

Figure 32: Pressure Distribution after twenty years of gas production.

Figure 33: Pressure Distribution after 30 years of gas production.

Economic Analysis Results

Table 8 shows the summary of the economic analysis with a gas price of \$3.5/MSCF for well designs used in this study. The horizontal well with 4000 ft lateral, and fracture half-length of 900 ft with nine fracture treatment was the most economical with an NPV value of \$7,039,826.53 at the end of 30 years compared to NPV value of \$2,932,917.37 for a design with a longer lateral length of 6000 ft with 15 fracture treatments. The results show that the effect of fracture half-length has more impact on gas production from the Utica shale based on NPV values.

Economic Analysis with \$3.5/Mscf

Table 8: Summary of Economic Analysis Price of Gas = \$3.5/Mscf

Gas Price = \$3.5/MSCF				
Lateral length, ft	Number of treatments	Fracture half length,ft	Total NPV, \$	AVG ROR, %
2000	0	0	-1313110.822	-43.77
2000	3	300	-559701.1245	-16.51
2000	3	600	649,096.81	18.41
2000	3	900	1,388,293.53	37.93
2000	5	300	450,606.55	12.35
2000	5	600	2,410,458.97	62.21
2000	5	900	3,618,444.86	88.25
2000	10	300	1,736,143.60	40.38
2000	10	600	4,778,157.30	90.59
4000	0	0	-1633070.837	-32.66
4000	3	300	-1735570.464	-32.20
4000	3	600	-526320.9004	-9.53
4000	3	900	213,180.09	3.77
4000	5	300	-669702.5101	-11.85
4000	5	600	1,345,811.67	22.91
4000	5	900	2,582,285.00	42.33
4000	9	300	75,192.44	1.08
4000	9	600	4,868,368.69	74.04
4000	9	900	7,039,826.53	100.86
4000	20	300	4,342,500.75	57.14
6000	0	0	-2037433.61	-29.11
6000	3	300	-3350292.899	-45.34
6000	3	600	-2261986.501	-30.06
6000	3	900	-1005694	-13.13
6000	5	300	-995694	-13.02
6000	5	600	129,429.50	1.64
6000	5	900	1,364,679.00	16.85
6000	15	300	2,932,917.37	32.77

Figure 34 compares NPV obtained for each well and fracture design at a gas price of \$3.5/MSCF. The well with 4000 ft lateral, 900 ft of fracture half-length and nine fracture treatments appears to have the highest NPV. There were 17 designs with positive NPV while 11 designs yielded negative NPV values.

Figure 34: NPV by well design at \$3.5/Mscf gas price

Figure 35 lists Rate of Return (ROR) values by well and fracture design at a gas price of \$3.5/Mscf. The wells with 4000 ft lateral and 900 ft of fracture half-length and nine fracture treatments has the highest rate of return of 100% over a period of 30 years.

Figure 35: Rate of Return by well design at \$3.5/Mscf gas price

Economic Analysis with \$4/Mscf

Table 9 summarizes the economic analysis with a gas price of \$4/MSCF for well designs used in this study. The horizontal well with 4000 ft lateral, and fracture half-length of 900 ft with nine fracture treatment was the most economical with an NPV value of \$9,060,668.44 at the end of 30 years compared to NPV value of \$4,648,486.54 for a design with a longer lateral length of 6000 ft with 15 fracture treatments. The results show that the effect of fracture half-length has more impact on gas production from the Utica shale based on NPV values.

Table 9: Summary of Economic Analysis Price of Gas = \$4/Mscf

Gas Price = \$3.5/MSCF				
Lateral length, ft	Number of treatments	Fracture half length,ft	Total NPV, \$	AVG ROR, %
2000	0	0	-1054117.109	-35.14
2000	3	300	-137363.1696	-4.05
2000	3	600	1,263,405.90	35.84
2000	3	900	2,127,487.86	58.13
2000	5	300	1,054,417.03	28.89
2000	5	600	3,326,391.23	85.84
2000	5	900	4,739,089.38	115.59
2000	10	300	2,616,459.37	60.85
2000	10	600	6,157,332.18	100.63
4000	0	0	-1134071.413	-22.68
4000	3	300	-1195499.558	-4.05
4000	3	600	205785.66	3.72
4000	3	900	1,070,215.36	18.91
4000	5	300	59778.1	1.06
4000	5	600	2,394,612.48	40.76
4000	5	900	3,840,621.00	62.96
4000	9	300	1,101,086.62	15.77
4000	9	600	6,521,145.19	99.18
4000	9	900	9,060,668.44	129.81
4000	20	300	6,066,581.83	79.82
6000	0	0	-1310486.01	-18.72
6000	3	300	-2755182.341	-37.28
6000	3	600	-1492117.885	-19.83
6000	3	900	-37069.5	-0.48
6000	5	300	-27069.5	-0.35
6000	5	600	1,290,929.00	16.39
6000	5	900	2,734,785.00	33.76
6000	15	300	4,648,486.54	51.94

Figure 36 shows NPV values by well and fracture design at a gas price of \$4/Mscf. There were 19 designs with positive NPV while nine designs with negative NPV values.

Figure 36: NPV by well design at \$4/Mscf gas price

Figure 37 compares Rate of Return values by well and fracture design at a gas price of \$4/Mscf. ROR values range between 5% and 129.8%.

Figure 37: Rate of Return by well design at \$4/Mscf gas price

Based on the results of the NPV values above, when the price of gas used in the economic analysis is increased from \$3.50 to \$4.0 per MSCF, two cases or designs become economical while they were uneconomical with \$3.5/Mscf. These two designs are 4000 ft lateral length with 3 fracture treatments and 600 half-length and 4000 ft lateral length with 5 fracture treatment and 300 half length.

Economic Analysis with \$5/Mscf

Table 10 summarizes the economic analysis with a gas price of \$5/MSCF for well designs used in this study. The horizontal well with 4000 ft lateral, and fracture half-length of 900 ft with nine fracture treatment was the most economical with an NPV value of \$13,102,352.25 at the end of 30 years compared to NPV value of \$8,079,624.88 for a design with a longer lateral length of 6000 ft with 15 fracture treatments.

Table 10: Summary of Economic Analysis Price of Gas = \$5/Mscf

Gas Price = \$5/MSCF				
Lateral length, ft	Number of treatments	Fracture half length,ft	Total NPV, \$	AVG ROR, %
2000	0	0	-536129.6844	-17.87
2000	3	300	707312.74	20.86
2000	3	600	2,492,024.08	70.70
2000	3	900	3,605,876.53	98.52
2000	5	300	2,262,037.98	61.97
2000	5	600	5,158,255.74	133.12
2000	5	900	6,980,378.43	165.25
2000	10	300	4,377,090.92	101.79
2000	10	600	8,915,681.92	170.70
4000	0	0	-136072.5639	-2.72
4000	3	300	-115357.7451	-2.14
4000	3	600	1669998.78	30.23
4000	3	900	2,784,285.90	49.19
4000	5	300	1518739.33	26.88
4000	5	600	4,492,214.10	76.46
4000	5	900	6,357,293.00	104.22
4000	9	300	3,152,874.98	45.17
4000	9	600	9,826,698.19	149.46
4000	9	900	13,102,352.25	187.71
4000	20	300	9,514,743.99	125.19
6000	0	0	143409.19	2.05
6000	3	300	-1564961.224	2.05
6000	3	600	47619.35	0.63
6000	3	900	1900180	24.81
6000	5	300	1910180	24.97
6000	5	600	3,613,928.00	45.89
6000	5	900	5,474,998.00	67.59
6000	15	300	8,079,624.88	90.28

Figure 38 compares NPV obtained for each well and fracture design at a gas price of \$5/Mscf. The well with 4000 ft lateral, 900 ft of fracture half-length and nine fracture treatments appears to have the highest NPV. There were 24 designs with positive NPV while 4 designs yielded negative NPV values.

Figure 38: NPV by well design at \$5/Mscf gas price

Figure 39 compares Rate of Return values by well and fracture design at a gas price of \$5/Mscf. ROR values range between 2% and 188%.

Figure 39: Rate of Return by well design at \$5/Mscf gas price

Based on the results of the NPV values above, when the price of gas used in this study is increased from \$4.0 to \$5.0 per MSCF, five cases or designs become economical while they were uneconomical with \$4.0/Mscf.

Summary of Economic Analysis

Figure 40 compares the NPV values for each well design used in this study for three different gas prices, namely \$3.5, \$4 and \$5 per MSCF. There were two designs that became economical at \$4/MSCF. With further price increase to \$5/MSCF three additional designs became economically attractive.

Figure 40: NPV by well design at \$3.5/Mscf, \$4/Mscf and \$5/Mscf gas price

Figure 41 compares the Rate of Return values for each well design used in this study with three price scenarios.

Figure 41: Rate of Return by well design at \$3.5/Mscf, \$4/Mscf and \$5/Mscf gas price

From figure 40, it is clear that at \$5 per MSCF of gas, all well designs appear to have a higher NPV than at \$3.5 and \$4 per MSCF of gas. However, even \$5/MSCF is not economical alternative when some of the well designs are considered in this study.

Chapter VI- Conclusion

In this research, modeling studies were conducted for the purpose to understand the impact of design parameters such as lateral length of horizontal wells, fracture half lengths and number of fracture treatments on natural gas production from the Utica shale. A total of 28 cases with different designs were considered in this study.

Based on the runs conducted in this study, the horizontal well design with a lateral length of 4000 ft and 900 ft fracture half-length with nine fracture treatments produced the highest cumulative gas over the period of 30 years (13,424,247,808 SCF) followed by the well design with a lateral length of 4000 ft and 600 ft fracture half-length with nine fracture treatments (10,486,311,936 SCF) as shown in Table 10. Also based on this study, the fracture half-length is found to have more impact on gas production than the lateral wellbore length.

Additionally, the economic analyses based on NPV were conducted for all well designs. The results show the well designs with a horizontal lateral length of 4000 ft and 900 ft fracture half-length with nine fracture treatments was the most economical regardless of the gas price considered in this study. The second most economical well was the horizontal design with a lateral of 4000 ft and 600 ft fracture half-length with nine fracture treatments. The economic ranking of well designs remained the same when future gas prices of \$4 and \$5 were used.

Out of 28 cases studied, 17 designs had positive NPVs with \$3.5/MSCF whereas 11 cases were determined to be uneconomical. With \$4/MSCF, 19 designs had positive NPVs while nine cases

were determined to be uneconomical. When gas price of \$5/MSCF is used, 24 cases had positive NPVs and four cases were determined to be uneconomical. Furthermore it is discovered that NPV values with \$5.0/Mscf has 5 cases or designs that are economical while they were uneconomical with \$4.0/Mscf.

Based on the models designed in this study, there were no boundary effects for the duration of runs.

Chapter VII- Recommendation

The following recommendations are presented for further study of gas production from the Utica Shale:

- To expand this study by adding alternate fractures half lengths and number of fractures.
- To further expand this study with horizontal multi well field studies.
- To study the impact of Stimulated Reservoir Volume (SRV) on gas production based on well designs.

Chapter VIII- Reference

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APPENDIX- Pressure Distributions

Pressure distribution after 0, 10, 20 and 30 years of production for selected wells are included in this appendix.

Figure Appendix 1: Initial pressure distribution for well 4000 20Xf300

Figure Appendix 2: Pressure distribution after 10 years for well 4000 20Xf300

Figure Appendix 3: Pressure distribution after 20 years for well 4000 20xf300

Figure Appendix 4: Pressure distribution after 30 years for well 4000 20Xf300

Figure Appendix 5: Initial pressure distribution for well 6000 15xf300

Figure Appendix 6: Pressure distribution after 10 years for well 6000 15xf300

Figure Appendix 7: Pressure distribution after 20 years for well 6000 15xf300

Figure Appendix 8: Pressure distribution after 30 years for well 6000 15xf300

Figure Appendix 9: Initial pressure distribution for well 2000 5Xf900

Figure Appendix 10: Pressure distribution after 10 years for well 2000 5Xf900

Figure Appendix 11: Pressure distribution after 20 years for well 2000 5Xf900

Figure Appendix 12: Pressure distribution after 30 years for well 2000 5xf900

Figure Appendix 13: Initial pressure distribution for well 4000 9Xf600

Figure Appendix 14: Pressure distribution after 10 years for well 4000 9Xf600

Figure Appendix 15: Pressure distribution after 20 years for well 4000 9xf600

Figure Appendix 16: Pressure distribution after 30 years for well 4000 9xf600