STATE OF ARKANSAS

ASSESSMENT COORDINATION DEPARTMENT

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Bear Chaney
Director

August 31, 2018

All,

The attached is the final report titled Recommendations for Improvement of Arkansas' Oil and Gas Assessed Valuations as prepared by Resource Technologies Corporation (RTC) as required in Professional Services Contract #4600040158.

The report was commissioned as an independent, professional evaluation of our current processes in determining a fair and equitable valuation of the market value of oil and gas mineral rights as prescribed by the Arkansas Constitution.

This report contains evaluations and recommendations from RTC. No actions or decisions have been made regarding any changes or modifications mentioned in the report. AACD is continuing to work with county Assessors, Collectors, County Judges, school district representatives, industry partners, legislators and executive branch staff as to what, if any changes, modifications, or updates may be needed.

AACD will follow all procedures in regards to public meetings if and when any changes to our rules are proposed.

If you have any questions about the report please contact our offices.

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Recommendations for Improvement of Arkansas' Oil and Gas Assessed Valuations

Professional Services Contract #4600040158

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Report Date: June 25, 2018

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1.0 INTRODUCTION

Resource Technologies Corporation (RTC) was engaged by the Arkansas Assessment Coordination Department (ACD) to review and make recommendations for improvement the procedures that the state uses to develop property tax values for active minerals, this report specifically addresses oil and gas well valuation. The goal of the recommendations below is to make the system more market responsive, fair, and equitable

Tax assessment in Arkansas is conducted at the County level. The ACD publishes annual recommendations (in methods and values) to the counties. In general, the system used is based on the income approach to value, wherein the taxable value of a mineral is based on the estimated present worth of an expected future income stream. The Counties assess royalty, working, and operator ownership interests. This procedure, in one form or another, is used by other states, oil and natural gas companies, and banks and is the basis of most texts concerning the valuation of mineral deposits. Therefore, RTC is not recommending a wholesale change in procedure but an improvement of the existing system in line with current staffing levels at the state and County assessment offices.

The income approach is intended to be market responsive, based on current prices, costs, up-to-date financial information, and contemporaneous production data. However, the Arkansas system was developed over the past 30 years for various minerals and has not been significantly updated since its inception. For example, the system for oil and gas was developed in the mid 1980's and has not been updated since. The valuation of gas wells, however, only considers an income stream of one year. This needs to be improved to be more in line with accepted present value methods.

Points of emphasis to the recommendations include:

- Valuation procedures should comply with accepted industry standards, taxing authority requirements, as well as standards established by the International Association of Assessing Officers
- State and County staff could continue the same general methodology (with ACD publishing yearly valuation data), and current vendors updating any valuation database procedures.
- General data (production, commodity pricing, etc.) could be derived from public sources rather than relying on confidential industry reports.

This review is only the first step in the process to any changes to be undertaken by ACD, as a series of stakeholder meeting will follow to develop any changes to the taxation method.

A public meeting was held on May 15, 2018 to present the findings of the initial report dated March 13, 2018. This revised report includes suggestions based on comments from that meeting. The most significant takeaways from the meeting are that:

- Industry participants would like an avenue to submit pertinent data specifically on pricing and expenses.

- County assessors need timely consistent standardized reporting from the industry.
- Division orders are particularly burdensome to the assessors.
- Future stakeholder meetings will be held to refine any taxation changes mad by ACD

Future stakeholder meetings will address these procedures.

1.1 Discounted Cash Flow Analysis as Basis for Market Value

For tax assessment purposes, Arkansas requires all property to be valued at market value. Discounted cash flow (DCF) is the *most* accepted method to value operating mineral properties. All market participants (industry, investors, taxing authorities) use some form of discounted cash flow to value mineral income streams.

Typically, three approaches – cost, market, and income – are available to estimate the value of any property. In one form or another, these approaches are based on the “principle of substitution”. That is, a purchaser of property would typically pay no more for one property than for another of similar utility.

Mineral properties, petroleum producing properties, mining operations, and related operations, are purchased for the production of future income. Willing purchasers and buyers assess the income potential of the property before consummating a transfer of the property. It is the object of an appraisal to mimic or model the behavior of the marketplace.

An oil or gas well is an income producing addition to a property. A yearly income stream is generated in the future by the production and sale of oil/gas until the well is plugged/abandoned. The **Income Approach to Valuation** - capitalization or discounted cash flow of the net income that the well can produce is the appropriate method to value the well.

Depending upon circumstances and the scope of assignment, one or more traditional approaches may not be appropriate or relevant to the assignment. In such cases, a particular approach should be considered but may be excluded from the report, with explanatory comment by the appraiser.

Nearly every text and treatise concerning appraisals recognizes that the existing use (active oil or gas property) may very well be the Highest and Best Use for a property – the market determines the needs and desires that cause properties to be put to specific uses. These documents all recognize the income approach as a valid approach to the appraisal of income producing properties – most state that the comparative sales technique is the most difficult to apply to income properties. All of these texts state succinctly that: income producing properties (as oil and gas wells and related operating facilities) must be appraised by the income approach – as these properties serve only one purpose; the exploitation and depletion of the asset. Calculating the value of a well by discounted cash flow is an accepted method and, in one form or another, is used by other states, oil and natural gas companies, and banks.

In Gentry and O'Neil,[1] a basic text in mineral property appraisals, the authors unequivocally put forward that: ". . . the preferred method for mining property valuation and the one unanimously used in the commercial practice is the income approach." The book states that:

> "Because mines have limited operating horizons and because there are well-established markets for mineral commodities, the income approach is widely used in valuing mineral properties. The approach is used commonly by the mining industry in assessing investment rates of return and determining appropriate purchase prices for mines or mineral prospects."

In discussing the comparable sales approach, Gentry and O'Neil put forward the following:

> "Although this method has been used extensively for estimating the value of residential and agricultural property values, it encounters serious practical problems when applied to mining transactions."

According to the "California Assessors' Handbook,"[2] the method best adapted to valuing mineral producing properties is often an analytical one such as the total property or royalty technique because of the lack of sales data and the shortcomings of the cost approach. Concerning the comparative sales approach, the Handbook states that:

> "Sales prices of mining property constitute the most reliable indicators of value (as they are with all types of property), providing they satisfy arms' length conditions. It is seldom that we are blessed with an ideal sale of a mining property, and when we are it will as often as not fail to lend itself to a value conclusion on any other property because of differences in type of material, state of development, etc."

In the latest revision of the California Assessors' Handbook, Assessment of Mining Properties, it is simply stated that:

> "The properties that are the subject of this handbook are investment properties. They are bought and sold for the income they are capable of generating in the future. As such, they are appropriately valued by the income approach.
>
> The comparable sales method is an important appraisal tool for appraisers. However, the unique nature of many mining properties makes it difficult to apply. Two mineral properties are seldom alike. Mines differ in ore, reserves, size, ore geology, mining depth, cost, ore benefaction, location, salaries, geologic occurrence, waste, markets, local requirements of government agencies, access, etc. Mining properties can change in value rapidly so that a sale would only be valid for comparison purposes very close to its actual sale date. Many mine sales are often part of a larger, more complex sale so that it becomes difficult to extract data on a single property. Finally, it is rare to find sales of comparable mining properties."

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[1] Gentry, Donald W. Dr. and O' Neil, Thomas J. Dr. Mine Investment Analysis, Society of Mining Engineers, American Institute of Mining, Metallurgical, and Petroleum.

[2] Assessor's Handbook: Valuation of Mines and Quarries, Assessment Standards Division, Property Tax Department, California State Board of Equalization, January 1973, page 74 and March 1997.

California's Assessors' Handbook (566) for the Assessment of Petroleum Properties[3] is comprehensive text that discusses oil and gas geology, industry, and production methods before diving into the valuation of oil and gas properties. It describes the income and approach and DCF as:

> **Value is a Function of Income:**
> For the income approach to be appropriate, a property must be of a type that is commonly bought and sold on the basis of its income stream. The benefits that flow from the property must be expressed in terms of money.
>
> **Discounted Cash Flow Analysis:**
> Discounted cash flow (DCF) analysis is a widely used "modern" form of capitalization that derives its validity from one of the most "old fashioned" principles of appraisal: the concept of present value. This concept asserts that present income is more desirable than future income, and that because investors prefer immediate cash returns over future flows, they discount future payments to their present worth.
>
> DCF analysis is defined as the analysis of cash flow projections for each period of time that the property produces income in order to compute the present value of property assuming a certain rate of return or to compute the internal rate of return indicated by serial cash flows.

In "How to determine the value of Oil and Gas Properties and optimizing their values"[4], Hamdy Rashed, discusses oil and gas valuation with an accounting standards and investment approach. He makes it clear that the income approach should be used for producing properties:

> Financial Accounting Standard No. 157 (FAS157) and International Financial Reporting Standard No. 13 (IFRS 13) indicate to three approaches of valuation techniques; Income approach uses the discounted cash flow which is one of the important techniques that is used as value measurement in oil and gas properties for development and production properties and may be reasonably and sufficiently reliable that can be categorized within Level 1 of fair value hierarchy due to availability of market that provide quoted commodity of oil and gas. Market and cost approaches that can be used for exploration properties.
>
> **Valuation of Production and Development Properties:**
> If Company intends to buy oil or gas properties, it needs to estimate cash that will flow in during the life of the property. The first thing that needs to known is the proved reserves that is recoverable from the ground, and needs to know if there is any further initial investment needed after buying the properties, the estimated lifting costs, type of the agreements that is held with landowners or host governments, tax rate, recoverable and non-recoverable costs. All those factors help the Company to estimate the cash flow. But estimating the cash flow is not the final stage, Company needs to consider the time value for the money received over time which the monetary value of cash is decreased due to decreasing the power of purchase. Therefore, the estimated cash flow should be discounted at a specific rate that seller or buyer like to use it as an appropriate rate. Some companies may use weighted average capital costs (WACC), some companies use required rate of return, others may use inflation rate or free-risk rate. But the most appropriate rates are the first two rates. After discounting the cash flow, Companies will have a negotiation for the price that can be affected by other factors such as political and security risks, ability of production, fund needs and other factors that determine the power of buyer and seller in the negotiation. The more positive factors toward the seller, the more power the seller has to negotiate the price to their interest and vice versa.

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[3]California's Assessors' Handbook (566); Assessment of Petroleum Properties, California State Board of Equalization, August 1996, Reprinted January 2015, pages 5-8 through 5-11.

[4]"How to Determine the Value of Oil and Gas Properties and Optimizing Their Values." Hamdy Rashed, CMA, CAPM; Management and Financial Accounting in Oil and Gas Upstream Industry, January 21, 2013.

The most recent publication by the International Association of Assessing Officers (IAAO), Property Assessment Valuation,[5] states that the Hoskold method of capitalization (a modified version of the income approach) is "currently the best-known method for use with mineral properties because it corresponds closely to the conditions that seem to exist when investments are made on mineral deposits. As a mineral deposit is depleted, the recapture provision should provide a return of the investments, enabling the investor to buy another mineral property when the first is depleted."

According to Stermole and Stermole in Economic Evaluation and Investment Decision Methods[6]:

> "Comparable sales often is a poor approach to valuation of natural resource properties. The value of mineral, petroleum, and timber rights varies significantly with sizes of reserves, projected product price at different future points in time related to production, and future salvage value of the assets to name some of the significant parameters to be considered. Usually at least several of these parameters differ significantly for different properties, making comparable sales a very poor approach to valuation of natural resource properties. Different size and quality of natural resource reserves affects the timing and cost of production, which generally makes it imperative to go to discounted cash flow valuation of natural resource investments rather than trying to utilize the comparable sales approach."

Stermole and Stermole teach one of the basic classes in mineral property appraisal and valuation. The course is sponsored by the Colorado School of Mines, a world premier mining College. The book, Economic Evaluation and Investment Decision Methods, is in its fourteenth printing and is used by CSM and also numerous short courses to industry representatives worldwide.

A mineral deposit has virtually no value if it cannot be economically (profitably) developed. The only appropriate analysis available to estimate a deposit's (mineral properties) value is to figure out if the deposit can be economically exploited. Generally, this requires analysis of:

- potential cash flows
- previous cash flows on the property and similarly situated properties
- actual and/or hypothetical royalties
- market conditions
- physical attributes of the deposit and the site.

In Mineral Deposit Evaluation, A.E. Annels, 1991[7], states succinctly that, "In all but a few exceptional cases, an adequate financial return from a mining project is the essential criterion which must be fulfilled before an affirmative decision to exploit is taken. ...The vast majority of mineral exploitation projects are therefore undertaken for financial gain and the

[5] Property Assessment Handbook, Second Edition, International Association of Assessing Officers, 1996, (LOC # 96-075848), page 261.

[6] Stermole, Franklin J. and Stermole, John M., Economic Evaluation and Investment Decision Making, Fourteenth Edition, Colorado School of Mines, Investment Evaluations Corporation, Golden, CO, 2014.

[7] Annels, Alwyn, E., Mineral Deposit Evaluation, Chapman and Hall, London, 1991, pages 306-322.

geological characteristics of the deposit are but one factor of many which collectively determine a project's profitability." Annels lists the following techniques as applicable to the valuation of mineral properties:

- return on capital employed
- payback period
- discounted cash flow – net present value
- discounted cash flow – internal rate of return.

"Geologists include a broad array of materials in the definition of the word "mineral"[8]:

- metallic ores
- nonmetallic industrial minerals
- sand and gravel
- common clay
- petroleum and natural gas..."

Paschall[9] goes on to state that: ". . . a mineral properties appraiser is first, last, and always, a mineral industries economist." Later in the article he states that: "The suspicion may have arisen in the readers mind that only the income approach to value is seriously considered in appraising mineral properties. That suspicion is justified." Paschall states that the only real use of sales information is to provide data necessary to characterize the market and to develop income approach rates and schedules.

According to Stermole and Stermole in <u>Economic Evaluation and Investment Decision Methods</u>[10]:

> "Comparable sales often is a poor approach to valuation of natural resource properties. The value of mineral, petroleum, and timber rights varies significantly with sizes of reserves, projected product price at different future points in time related to production, and future salvage value of the assets to name some of the significant parameters to be considered. Usually at least several of these parameters differ significantly for different properties, making comparable sales a very poor approach to valuation of natural resource properties. Different size and quality of natural resource reserves affects the timing and cost of production, which generally makes it imperative to go to discounted cash flow valuation of natural resource investments rather than trying to utilize the comparable sales approach."

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[8]Paschall, Robert, ASA, The Appraisal of Mineral Producing Properties, ASA VALUATION, American Society of Appraisers, 1974.

[9]Ibid.

[10]Stermole, Franklin J. and Stermole, John M., Economic Evaluation and Investment Decision Making, Thirteenth Edition, Colorado School of Mines, Investment Evaluations Corporation, Golden, CO, 2012.

The essential factors to be considered in the valuation of a working income stream are listed below. The rates used to calculate the present value of the future cash flow are discussed in the following sections.

- Projected number of years of production
- Unit sale price of oil/gas
- Projected annual production/decline rate
- Cost to produce
- Capitalization/discount rate.

In the following text, all these items are discussed with regards to valuing active Arkansans oil and gas properties.

2.0 SUMMARY OF OIL AND GAS WELL VALUATION

Oil and gas shale plays (see **Exhibit 2.0-1)** have revolutionized the energy industry over the past 10 years. The amount of oil and gas produced has disrupted U.S. electricity markets and global oil supplies. It has already led to a couple of oil and gas booms in a short period of time. To put it simply, the U.S. has more natural gas than it knows what to do with.

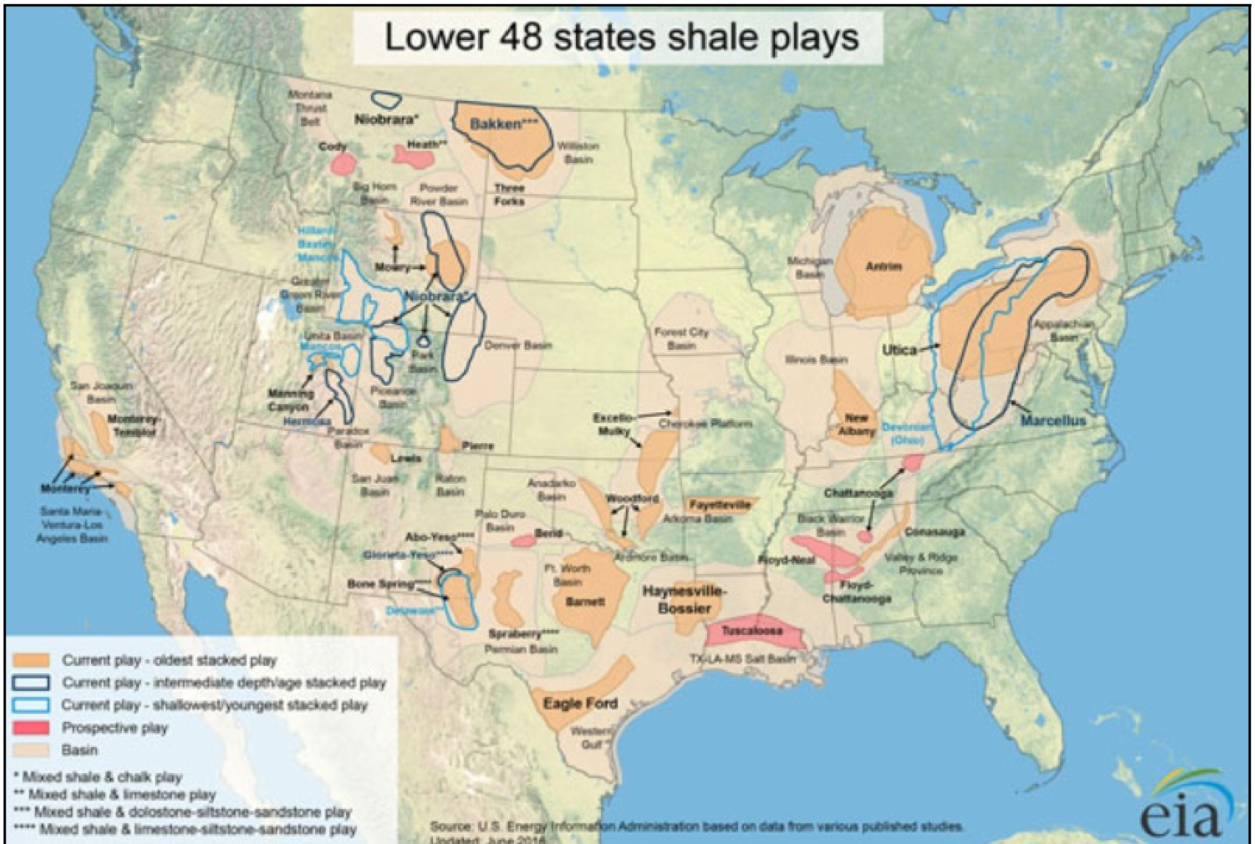


Exhibit 2.0-1: Oil and Gas Shale Plays (EIA)

The Fayetteville Shale, in north-central Arkansas, rapidly developed between years 2007-2010 but has seen an equally rapid a drop in production recently (see **Exhibits 2.0-2 and 2.0-3**). Despite experience from gas production in the Arkoma Basin, the rapid development in the Fayetteville Shale led to challenges on infrastructure, employment levels, and a steep learning curve for area residents and County assessment offices about the oil and gas industry.

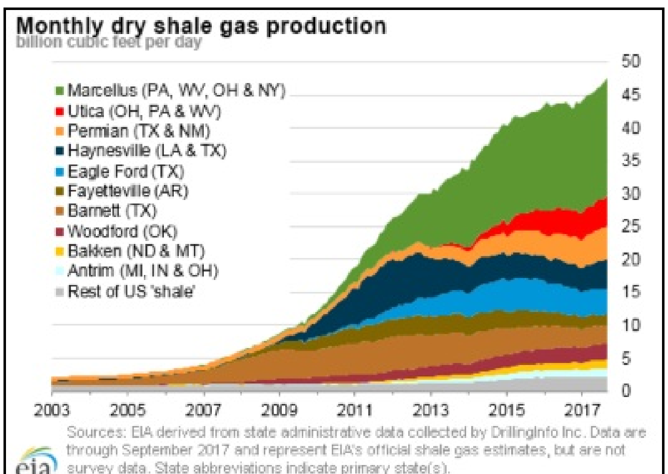


Exhibit 2.0-2: Natural Gas Production

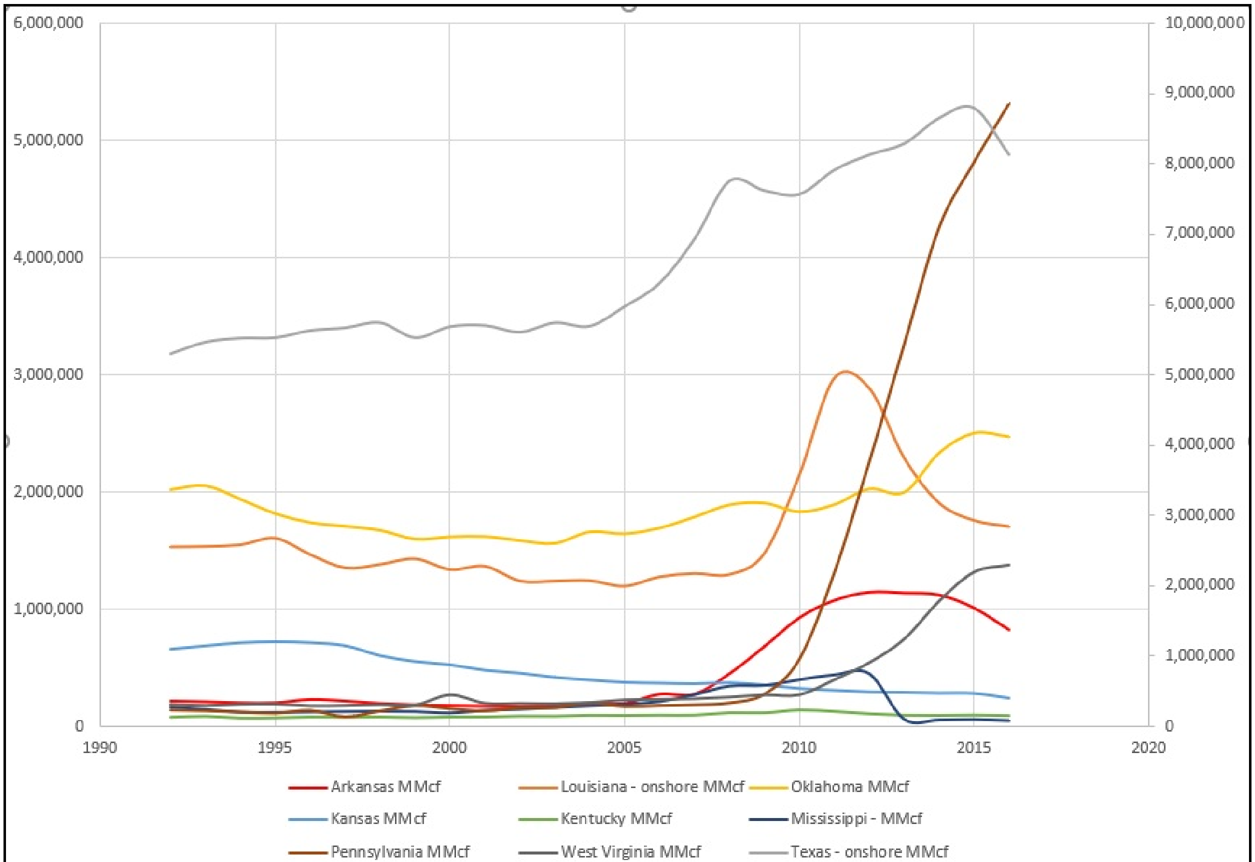


Exhibit 2.0-3: Gas Production (MMcf), Arkansas in Red (Texas scale on right)

Exhibit 2.0-4 shows the top five gas producers in Arkansas since 2014. Even though production has fallen every year, Southwestern Energy dominates the Northern Arkansas gas market. **Exhibit 2.0-5** shows the assessed values in Northern Arkansas since 2014.

Exhibit 2.0-4: Top 5 Gas Producers (Mcf - AOGC)				
Operator	**2014**	**2015**	**2016**	**% of overall Total 2016**
SEECO, LLC (Southwestern Energy)	749,832,929	695,374,693	558,311,483	68.08%
XTO Energy, Inc.	156,570,116	138,762,901	116,416,724	14.19%
BHP Billiton Petroleum (Fayetteville), LLC	140,227,746	109,581,131	89,424,597	10.90%
Stephens Production Company	23,017,878	18,169,914	15,304,300	1.87%
Lime Rock Resources III-A, L.P.	13,422,693	12,164,932	11,411,040	1.39%

Exhibit 2.0-5: Northern Arkansas Assessed Values			
County Name (Basin)	**2014**	**2015**	**2016**
Van Buren (Fayetteville)	$194,920,240	$165,093,370	$145,395,798
Cleburne (Fayetteville)	$114,052,275	$129,559,750	$131,601,358
Conway (Fayetteville)	$138,124,097	$132,171,539	$126,782,242
White (Fayetteville)	$129,160,450	$113,285,540	$108,966,540

Exhibit 2.0-5: Northern Arkansas Assessed Values			
County Name (Basin)	**2014**	**2015**	**2016**
Faulkner (Fayetteville)	$ 37,082,150	$ 37,538,180	$ 52,925,720
Sebastian (Arkoma)	$ 16,146,570	$ 15,628,990	$ 14,472,350
Logan (Arkoma)	$ 15,385,597	$ 13,717,018	$ 12,593,013
Franklin (Arkoma)	$ 11,129,973	$ 9,615,703	$ 10,181,068
Crawford (Arkoma)	$ 2,821,183	$ 3,133,719	$ 2,980,220

The Southern Arkansas oil fields have not been immune either (see **Exhibit 2.0-6**). An oil boom a couple of years ago led industry consolidation, typically out-of-state operators acquiring or merging with long-term local operators. The recent downturn in prices has also lead to volatility to those operators and the Southern Arkansas assessment offices.

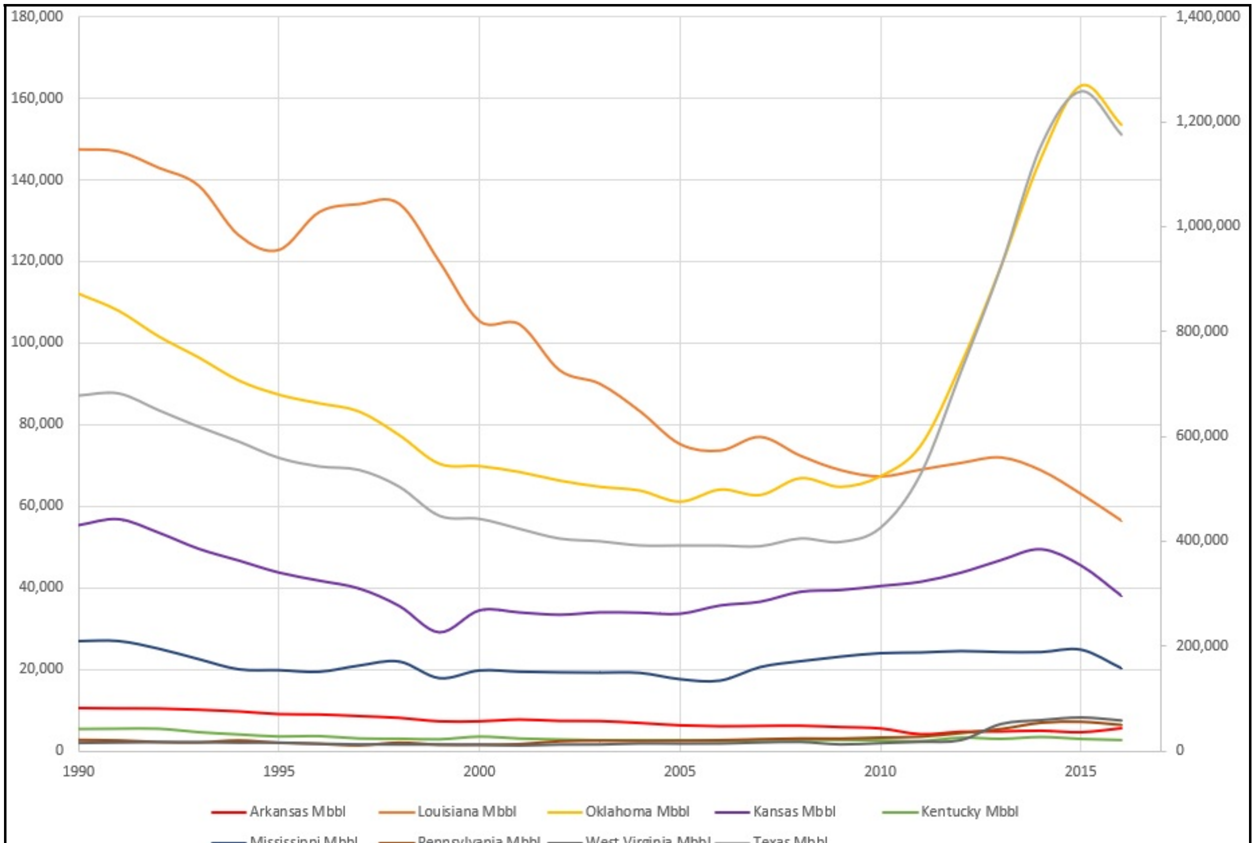


Exhibit 2.0-6: Oil Production (Mbbl), Arkansas in Red (Texas scale on right)

Exhibit 2.0-7 shows the top five oil producers in Arkansas since 2014. As with gas, there is one major producer, Bonanza Creek, although not as dominate as Southwestern Energy. **Exhibit 2.0-8** shows the assessed values in Southern Arkansas since 2014.

Exhibit 2.0-7: Top 5 Oil Producers (BBL - AOGC) Southern Arkansas				
Operator	**2015**	**2016**	**2017**	**% of Total 2017**
Bonanza Creek Energy Resources, LLC	1,028,925	827,195	648,298	46.23%
Petro-Chem Operating Company, Inc.	230,050	213,029	228,210	16.28%
White Rock Oil & Gas, LLC	217,891	201,763	203,805	14.53%
Quanico Oil & Gas, Inc	197,078	184,257	176,846	12.61%
Betsy Production Company, Inc	180,931	158,524	145,049	10.34%

Exhibit 2.0-8: Southern Arkansas Assessed Value			
County Name	**2014**	**2015**	**2016**
Columbia	$78,016,230	$88,190,435	$62,254,800
Union	$53,696,901	$58,523,535	$41,303,247
Ouachita	$15,014,281	$19,589,701	$17,692,164
Lafayette	$12,276,496	$13,098,904	$10,505,556
Miller	$5,274,889	$5,809,858	$5,336,452

Exhibits 2.0-9 through 2.0-11 show the recent gas assessment variables and values in the Fayetteville shale and why it has caused volatility on the tax assessment system. Falling gas production and falling prices since 2013 have led to a dramatic drop in assessed values for the counties.

Exhibit 2.0-9 shows the difference between the 3-year average of the Henry Hub price (ACD) than the actual Henry Hub price from the previous year. This is not uncommon as it reduces volatility to both the taxpayers and tax recipients (school districts being the largest stakeholder for property taxes in Arkansas). Notice how the three year average buffers the yearly changes in the Henry Hub price. Typically, operators do not complain when prices are increasing as the average value will hold down the taxable valuation price. However, operators have appealed the price now that the taxable price is higher than the current price as prices sag.

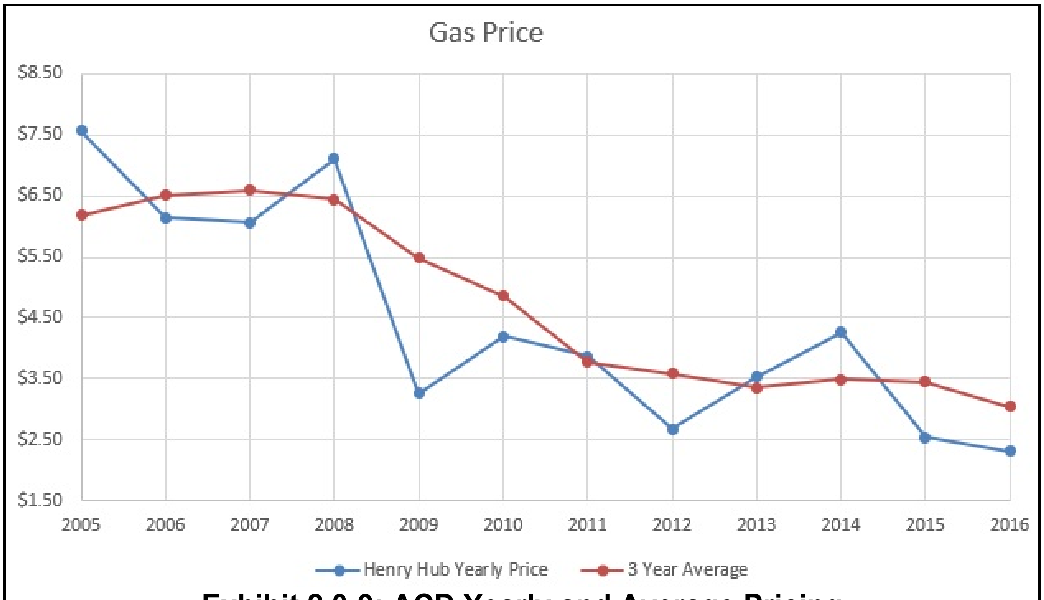


Exhibit 2.0-9: ACD Yearly and Average Pricing

Exhibit 2.0-10 is a graph of the production since 2013 showing declines in all the major Fayetteville Counties. In **Exhibit 2.0-11**, notice the drop in assessed values attributed to falling production and falling prices. Additionally the entire state switched from a five-year cyclical valuation to an annual valuation. In Van Buren and White Counties, the dramatic drop in assessed values is compounded because they were at the end of the cycle. This means they basically had a five year price correction in one year.

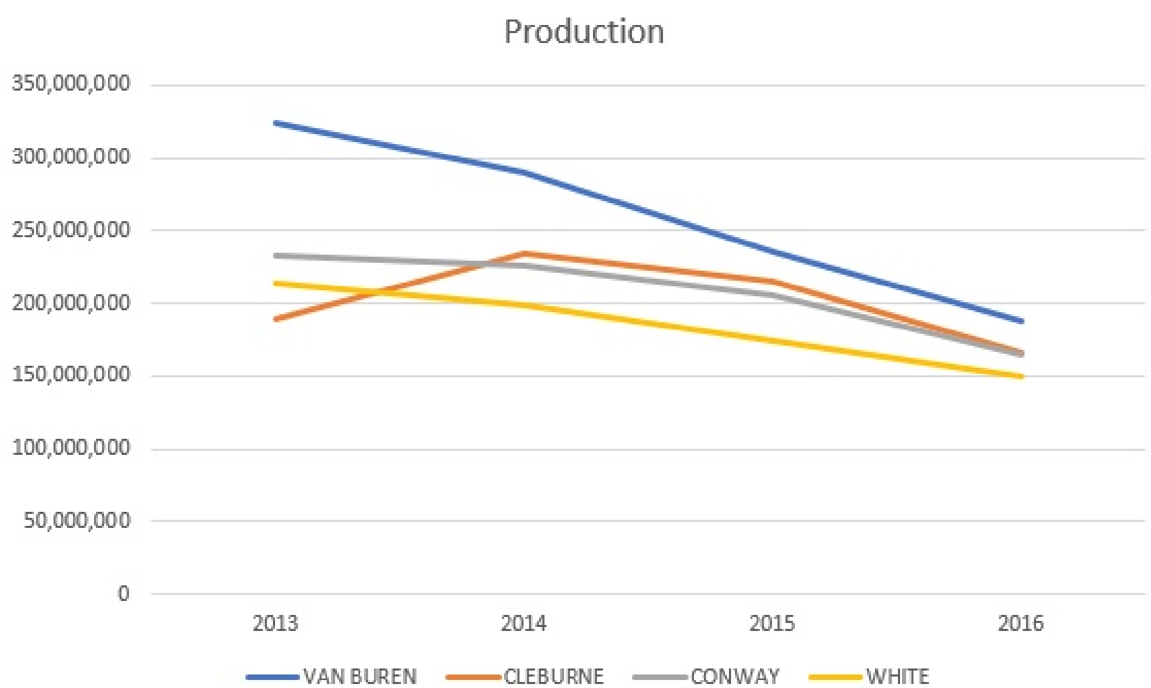


Exhibit 2.0-10: Gas Production in the Fayetteville Shale

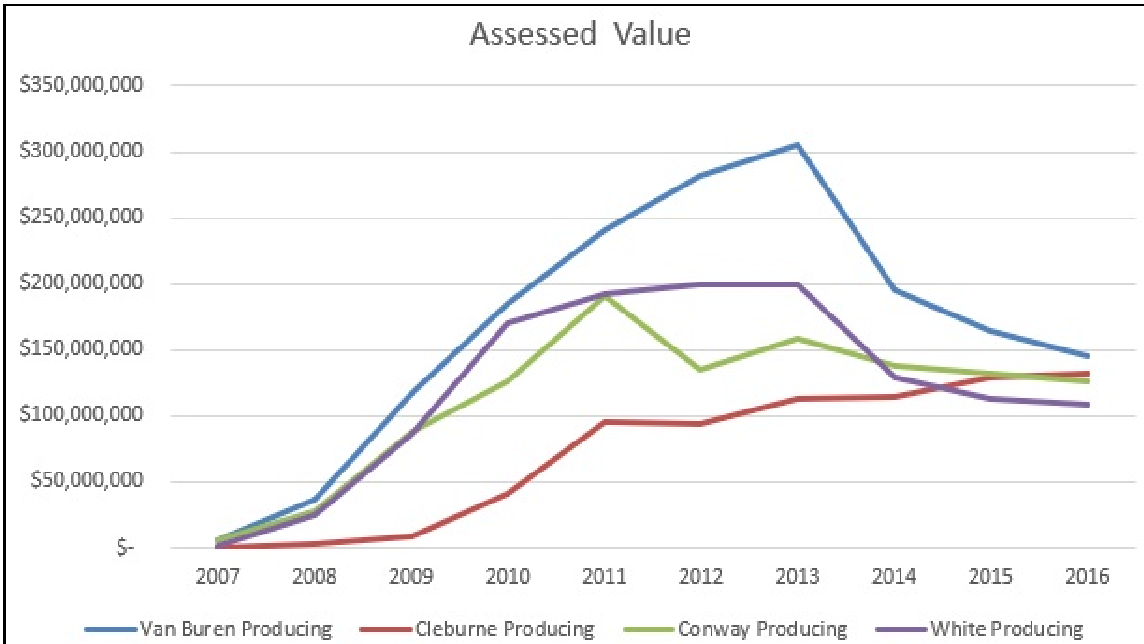


Exhibit 2.0-11: Assessed Value

2.1 Oil and Gas Taxes in the U.S.

Many states tax oil and gas either as a severance tax or property tax or both (see **Exhibit 2.1-1**). Severance taxes appear more common than ad valorem taxes but many states do assess property taxes to active oil and gas.

Exhibit 2.1-1: Summary of States' Oil and Gas Valuation		
State	**Severance**	**Ad Valorem**
Alaska*	depends on production	equipment and flowlines
Arkansas	1-5% (depends on production)	minerals and equipment
Idaho*	2.50%	equipment and flowlines
Kentucky	4.5%	minerals
Louisiana*	12.50%	surface equipment
Montana*	depends on production	equipment and flowlines
North Dakota*	5.00%	none
Oklahoma	7.00%	equipment
Pennsylvania	none	none
Texas	7.5% Gas/4.6% Oil and Condensate	minerals and equipment
Utah*	5.00%	minerals and equipment
Virginia	1.00%	minerals, equipment and flowlines
West Virginia	5.00%	minerals
Wyoming*	6.00%	GPT and equipment
**2016 Oil and Gas Taxation Comparison prepared for: State of Idaho, Idaho Department of Lands (2017) by Covenant Consulting Group*		

2.2 Common Methodologies

Exhibit 2.1-1, above, shows which states tax oil and gas. Below is a summary of how some states do the actual calculation to value an oil and gas well for ad valorem tax purposes. All of the states use a variation of the income approach/discounted cash flow to value oil and gas wells. Factors considered are:

- Unit sale price of the oil/gas
- Royalty rate (usually each owner's interest is reported by operator)
- Cost to produce
- Projected annual production
- Projected number of years of production
- Year when the production will begin (most states don't use the approach until production has started)
- Capitalization/discount rate.

- **Arkansas:**
    - Present Value of discounted cash flow
        - Price: 3-year average
        - Production: as reported to AOGC
        - Discount Rate: 15%, not updated
        - Decline Rate: 0.70 for new oil wells; 0.80 for stripper wells; n/a for gas
        - Income Stream Length: Gas - 1 Year; Oil - 14 Years
        - Expenses: 13%.

- **Texas:**
  - Present value of discounted cash flow (see **Exhibit 2.2-1**)
    - Price: Current price, escalates moving forward in the income stream
    - Discount rate: Updated yearly by State Comptroller, 16.7% for 2016
    - Decline Rate: 0.80
    - Income Stream Length: Texas stops the income stream when expenses are greater than income from well, usually 7-8 years in examples
    - Expenses: As reported by operator, escalates with time.

Discount Cash Flow Method
(Working Interest Portion Only)

Year	(1) Net Oil Production (bbls)	(2) Oil Price ($/bbls)	(3) Gross Income ($)	(4) Op Exp + SevTaxes ($)	(5) Net Income ($)	(6) Discount Factor @ 16.7%	(7) Discounted Cash Flow ($)
1	31,938	$ 19.75	$ 630,776	$ 159,015	$ 471,761	.925688	$ 436,703
2	25,550	20.54	524,797	159,341	365,456	.793220	289,887
3	20,440	21.36	436,598	160,692	275,906	.679709	187,536
4	16,352	22.22	363,341	162,946	200,395	.582441	116,718
5	13,081	23.10	302,171	165,982	136,189	.499093	67,971
6	10,465	24.03	251,474	169,733	81,741	.427671	34,958
7	8,372	24.99	209,216	174,115	35,101	.366471	12,863
						Subtotal	$ 1,146,636
				Salvage	$ 10,000	.339238*	3,392
						Total	$ 1,150,028

* End of year seven factor = $1/(1+.167)^7$

Exhibit 2.2-1: Texas Cash Flow Example

- **West Virginia**
  - Yield Capitalization Method
    - Price: 3-year weighted average of each well's net receipts reported to state
    - Production: 3-year weighted average of each well's net receipts reported to state
    - Discount Rate: Updated yearly, 15.8% for 2018
    - Decline Rate: Calculated for each formation, updated every 5 years (see **Exhibit 2.2-2**)
    - Income Stream Length: Capitalized
    - Expenses: Published yearly, updated every 5 years (see **Exhibit 2.2-3**)
    - Value includes equipment.

Central:Braxton, Clay, Fayette, Nicholas, Webster				
Code	Formation	Year 1	Year 2	Year 3 +
12	Alexander, Benson	-0.31	-0.20	-0.10
14	Benson	-0.48	-0.08	-0.08
16	Benson, Balltown+	-0.45	-0.16	-0.12
17	Gordon +	-0.30	-0.07	-0.07
18	Big Injun	-0.34	-0.13	-0.13
19	Big Injun, Big Lime	-0.36	-0.13	-0.13
22	Big Lime	-0.34	-0.34	-0.13
26	Ravencliff	-0.40	-0.40	-0.25
93	4th Sand	-0.42	-0.32	-0.08
94	50 Foot	-0.34	-0.26	-0.07
95	Injun/Weir	-0.51	-0.26	-0.09
96	Maxton	-0.70	-0.27	-0.08
109	Trenton/Deeper *	-0.41	-0.22	-0.09
110	Marcellus *	-0.41	-0.22	-0.09

Exhibit 2.2-2: WV Decline Rate

Industry Operating Expense Survey and Results

This component was determined through a review of responses to a survey distributed by the State Tax Department to producers of all oil and natural gas wells producing in West Virginia and through use of other market data.

GAS

- % Working Interest Expenses for Typical Producing Well = 45%
- Maximum Operating Expenses = $5,000
- Coal Bed Methane, Vertical Wells Expenses = $9,000

OIL

- % Working Interest Expenses for Typical Producing Well = 35%
- Maximum Operating Expenses = $5,750
- Maximum Enhanced Operating Expenses = $9,000

MARCELLUS/UTICA

- % Working Interest Expenses for Vertical Producing Well = 30%
- Maximum Operating Expenses = $30,000

- % Working Interest Expenses for Horizontal Producing Well = 20%
- Maximum Operating Expenses = $175,000

Exhibit 2.2-3: WV Oil and Gas Expenses

- **Kentucky**
  - Present value of discounted cash flow
    - Price: Each well's net receipts reported to state
    - Production: Each well's net receipts reported to state
    - Discount Rate: 15.35%, to be updated yearly
    - Decline Factor: 0.96 - to represent a well's decline in database calculations, current production is multiplied by 0.96 to estimate next

year's production. The process is repeated 12 times for the length of the income stream.

- Income Stream Length:12 years
- Expenses: 35% for gas, 45% for gas net income valued.
- Capped at $20,000

2.3 Improvements to Arkansas Methodology

RTC has identified the following areas that can be improved and maintained by the state and individual counties that will lead to a more accurate and equitable mass appraisal:

- Division Orders
- Valuation of Gas Wells
- Valuation of Oil Wells
- Oil and Gas Equipment.

Our research shows that changes to the current system can make the assessment market responsive and adhere to accepted valuation procedures but still operate within the given reporting, staffing, and database procedures. This will allow for an accurate assessment of each ownership interest in the well but also allows for collection of data that is already familiar to County staff and computer systems.

3.0 DIVISION ORDERS

While not directly related to valuation, the delivery of division orders (partial interest ownership) causes significant problems to County assessment staff. In fact, in interviews with assessment offices, usually the entire session was spent discussing division orders.

If no other recommendations from this report is taken, we cannot stress enough that the delivery of division orders must change. **Exhibit 3.0-1** is a summary of our recommendations to update to division order.

<table>
<tr><th colspan="3">Exhibit 3.0-1: Recommendations for the Update of Division Orders</th></tr>
<tr><td rowspan="3">Problems</td><td colspan="2">Late arriving division orders</td></tr>
<tr><td colspan="2">An inordinate amount of County time typing division orders into CAMA systems</td></tr>
<tr><td colspan="2">Yearly data entry of 100,000s division (partial ownership) orders</td></tr>
<tr><td colspan="2">Solutions</td><td>Notes</td></tr>
<tr><td colspan="2">Discontinue use of division orders. County would send 100% of tax bill to well operator. Operator and owners would reconcile taxes depending on lease terms.</td><td>Tax Bill is 100% of gross (after expenses are removed)</td></tr>
<tr><td colspan="3">If division order billing is continued, we suggest the following:

- A statewide due date of April 1st to County assessors. If late, as a penalty, the well will be billed at 110% of the assessed value to the operator.
- A requirement that data files are in a standard format compatible for direct digital import with CAMA systems.</td></tr>
</table>

3.1 <u>Oil and Gas Leasehold Interest</u>

If common ground cannot be reached on division orders, our research shows that Arkansas law may make it possible to send 100% of the tax bill to the operator The typical argument for maintaining division orders and sending tax bills to individual royalty/working owners is that it maintains a record of ownership.

However, an oil or gas lease is not a traditional "lease" in the landlord/tenant sense. Rather, it is a conveyance of real estate (the mineral rights estate), which when production is obtained (Arkansas only taxes producing wells) creates a fee simple determinable interest in the lessee. The lessor's reservation of a royalty under an oil and gas lease creates an estate in land and not a personal property interest. The royalty payment itself to the lessee, whether in cash or in-kind, is personal property.

In other words, when the lessee (operator) starts production, they have created a new property estate which is taxable. The royalty payment to the lessor constitutes personal property. There is no attempt to "return" the property (gas) to the lessor after a period of rental - for all intents and purposes, an oil and gas lease, after production has started, is a sale.

Leases have been considered a method of transfer of ownership by industry, courts, and financial institutions. Minerals are frequently severed (sold) apart from the fee estate of land as a mineral estate. Leases are bought and sold and used for basis for mortgages. Case in point, Southwestern Energy recently issued a press release indicating they are "Actively pursue strategic alternatives for the Fayetteville Shale E&P and related midstream gathering assets;"[11]. This is interpreted to mean that Southwestern's Fayetteville Shale assets are on the market to be sold with a major portion of the assets being leases held by Southwestern Energy.

This has been the major tenant in coal, oil, and gas lease cases and the understanding in mortgages. This has been the finding of all the prior court decisions -- a mineral lease is the sale of the mineral because the lease allows for the total depletion of the asset. Some leases may have special conditions restricting or limiting but most allow for the total exhaustion of the asset - they are considered to be a sale. Arkansas case law is in agreement with this view[12]:

> ***LEASEHOLD INTERESTS***
> *The rule in Arkansas, prior to 1982, was that a leasehold interest (that interest held by a lessee) was in the nature of an easement. The Arkansas Supreme Court held in 1965 that an "oil and gas lease does not of itself constitute constructive severance of the two estates (surface and mineral), but conveys only an interest and easement in the land itself and no title passes until the oil and gas are reduced to possession." Garvan v. Kimsey, 239 Ark. 295, 297, 389 S.W.2d 870 (1965). Thus, the lessee has no title to the minerals until they are actually in his possession.*
>
> *The Arkansas court seems to have abandoned the view that leases grant only an easement. In Hillard v. Stephens, 276 Ark. 545, 637 S.W.2d 581 (1982), in discussing a gas lease the court stated "The gas lease constitutes a present sale of all the gas in place at the time such lease is executed; and as the gas leaves the well head, the entire ownership thereof is in the lessee...."*
>
> *Where the leasehold interest (working interest) in a common lease or mineral venture is owned by multiple parties under a joint operating agreement, the designated operator has a "fiduciary duty" to the non-operators. Texas Oil & Gas Corporation v. Hawkins Oil & Gas, Inc., 282 Ark. 268, 668 S.W.2d 16 (1984). A fiduciary is a person who undertakes to act in the interest of another person. As a fiduciary, the operator in an oil and gas prospect, has a duty of utmost fair dealing and good faith to the non-operators. The operator may not act selfishly or in his own.*
>
> ***ROYALTY INTEREST***
> *In Arkansas, as elsewhere, a royalty interest is a right to a share of the mineral produced accruing to the owner of the royalty. The royalty interest before production is part of the land and, therefore, subject to conveyance but becomes personal property when produced. Shreveport-El Dorado Pipe Line Co. v. Bennett, 172 Ark. 804, 290 S.W. 929 (1927). The royalty owner typically has no right to explore or develop minerals, or to execute leases. A conveyance reserving to the grantor the right to execute oil and gas leases and receive a bonus for execution generally creates a nonparticipating royalty interest in the grantee. In most instruments, it is entitled "Non-Participating Royalty Deed."*

This means, for all intents and purposes, the execution of a gas lease is a sale. Arkansas does not tax non-producing mineral estates even if they are leased so all taxes are based on producing minerals. Therefore, we suggest removing the requirement to

[11] Southwestern Energy Announces Plans to Reposition Portfolio to Increase Shareholder Value; News Release, February 8, 2018.

[12] The Arkansas Leasing Manual (2008) Charles A. Morgan, pg 8-9.

submit division orders. As the owner of the entire mineral estate, the tax burden is the producer's sole responsibility.

4.0 AD VALOREM VALUATION OF GAS WELLS

Exhibits 4.0-1 and 4.0-2 show production in the Fayetteville and Arkoma Basins.

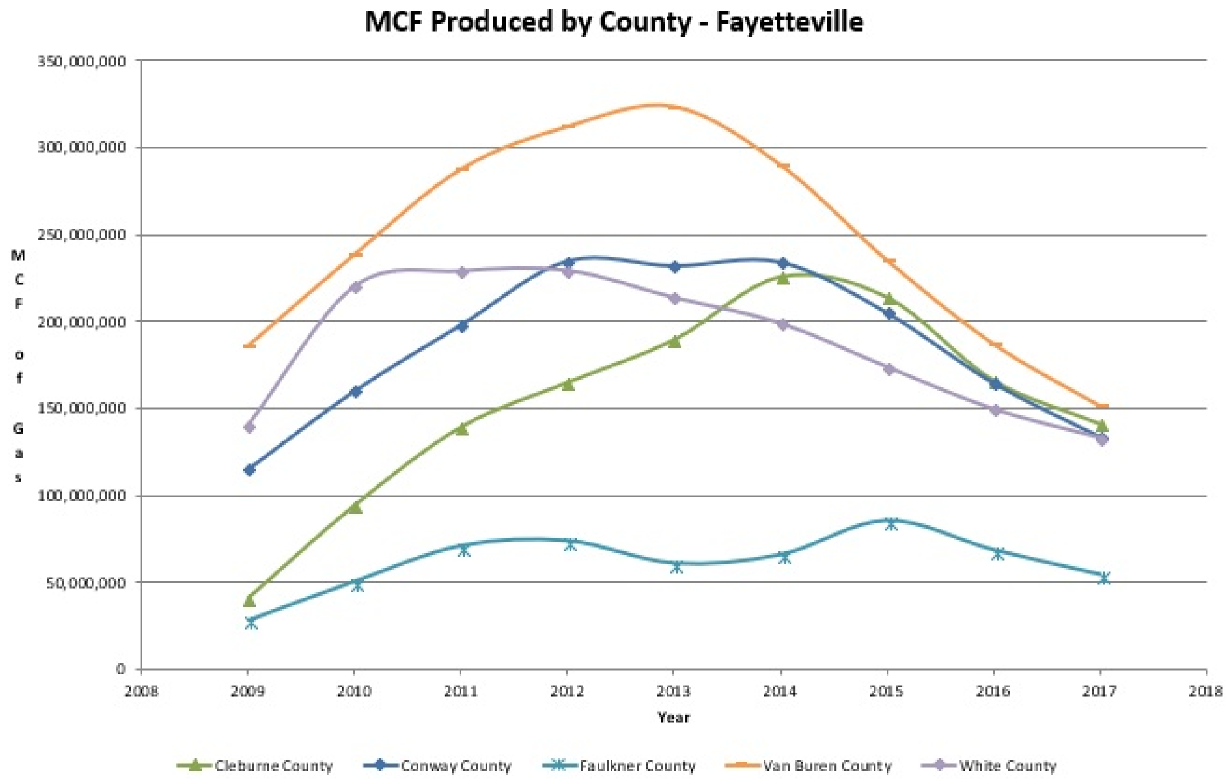


Exhibit 4.0-1: Production in the Fayetteville Shale

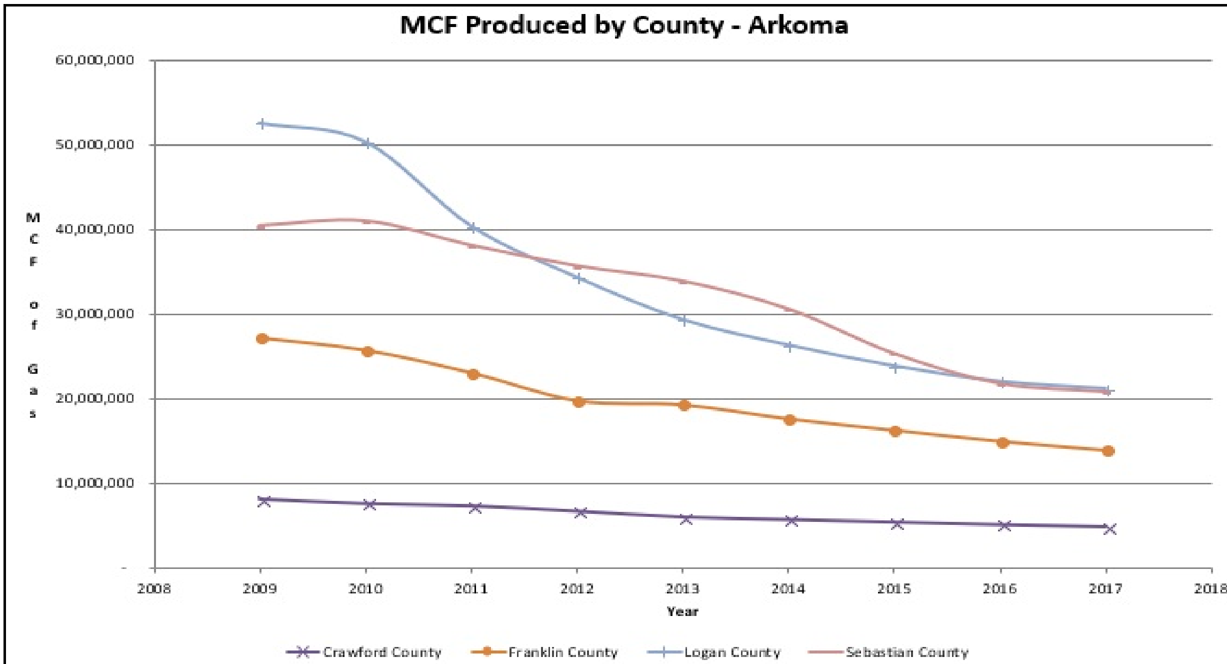


Exhibit 4.0-2: Production in the Arkoma Basin

Exhibit 4.0-3 is a summary our recommendations to update the valuation of gas wells.

Exhibit 4.0-3: Recommendations to update the valuation of gas wells	
Issues	3-year average pricing (2016 last available data for January 1, 2018 tax bills)
	1-year income stream valuation (KY uses 12; WV uses 40; AR uses 14 for Oil, TX uses economic life)
	Expenses on a percentage basis
Suggestions	**Notes**
Move to a present worth valuation with multiple years of income	Currently: A one year income stream is used. The three-year average price (see below) is used to calculate value of one year of production. Production trends describing future years of production beyond year 1 are not accounted for.
Income Stream Length: 10 years	10 years is suggested as it represents a fair and equitable valuation method compatible with current wellife.
Production: from AOGC	Currently Used
Price: 3-year weighted average of the Henry Hub Spot price	ACD currently uses the straight average of the last three years. This method has been accepted in court. Moving to a weighted average will make the system more market responsive.
Deductions: $1 per MCF per well for expenses	Can be updated yearly - typical production costs publically reported by operators[13] A market participant survey should be considered at future stakeholder meetings to calculate average statewide production and transportation costs to arrive at a wellhead price. Appropriate documentation to substantiate costs should also be discussed.
Decline Factor: <u>Fayetteville per well age</u> Years 1-2: 0.58 Years 3-4: 0.76 Years 5+: 0.85 <u>Arkoma per well age</u> Years 1-2: 0.55 Years 3-4: 0.79 Years 5+: 0.89	(See Section 4.4) Should be updated periodically, especially if a significant number of new wells are drilled.
Discount Rate: 14.96%	To be updated yearly based on current economic factors (Appendix A)

[13]Southwestern Energy Company, Form 10-K, (2016) United States Securities and Exchange Commission.

The discussions in the sections below explain how and why the recommended variables were chosen. While it is recognized that not every well will fit the model, for a mass appraisal with over 13,000 active wells, these values represent a realistic, fair, and equitable method to arrive at the assessed value for the entire state. As a mass appraisal, there is no intention of providing site or well-specific evaluations. Some wells may end before 10 years and some may produce profitably for more than 10 years. Similarly, some wells will have a greater decline factor than 90% of the previous years' production especially new wells allowed to flow at natural formation properties. However, most wells' production is influenced more by today's current gas market rather than geological properties.

4.1 Income Stream Length

It is well settled that a gas well should be valued considering multiple years of discounted cash flow as a well will produce income until it is plugged. Traditionally, a gas wells' life has been dictated by the natural decline of gas flow that the reservoir formation can achieve. However, RTC and ACD have separately determined that most wells' production is influenced more by today's current gas market rather than geological properties and flow is limited by the operator (See Section 4.4).

A review of the current active wells in Northern Arkansas (see **Exhibits 4.1-1 and 4.1-2**) shows a significant number of wells producing gas longer than the 10-year mark. The numbers drop after 2007 (10 years old) and significantly drop after 2002 (15 years old) but this is probably more a reflection of when the Fayetteville shale wells were drilled rather than well productivity. For the mass appraisal of the state, we suggest an income stream length of 10 years. It appears most wells produce for at least 10 years, and it is prudent to limit the income stream rather than extending the predicted life to 30 or more years because some wells may be closed sooner. Valuing wells to 10 years captures 75% of the value compared to 30 years at a 15% discount rate. A one-year income stream captures 13% of the total value.

Exhibit 4.1-1: Wells with Production in 2016

Year Drilled	Count
2001	57
2002	43
2003	264
2004	288
2005	269
2006	467
2007	636
2008	899
2009	992
2010	908
2011	906
2012	774
2013	625

2014	608

Exhibit 4.1-2: Wells Per Operator

OPERATOR	Count
SEECO, Inc. (SWN)	3971
XTO Energy, Inc.	1874
BHP Billiton Petroleum (Fayetteville), LLC	954
Stephens Production Company	705
Forest Oil Corporation	482
Hanna Oil and Gas Company	210
Foundation Energy Management, LLC	210
Eagle Rock Mid-Continent Operating, LLC	100

It must be noted that every state's method to value wells (a decline rate to an end of life), **assumes no new production/reserves** will come on line to replace the production. That is, only currently active production is valued in the overall income stream. This means, after 10 years, the state is assumed to have **no gas production** - overall valuation is underestimated. However, valuing wells that are yet to be drilled is probably not within the realm of ad valorem taxation. It is a trade off because on the other hand since it is recalculated every year all remaining wells are assumed to offer 10 years of remaining life which may overestimate the value of some individual wells.

4.2 <u>Gas Pricing</u>

While one year pricing makes the value more market responsive, it makes the value more volatile. The SEC requires publically traded oil and gas companies to report value and proven and probable reserves based on the average price from the previous year. However, as the oil and gas market has been volatile over the last 10 years (see **Exhibit 4.2-1**), yearly swings up and down probably don't represent the long-term value of the asset. Currently, ACD uses the average of the last three years Henry Hub average, as it is a publically accessible data source. We suggest using a three-year weighed average of the Henry Hub spot price. This will make the assessed value more market responsive while retaining appropriate value for in-place gas reserves at active wells for taxing bodies (see **Exhibit 4.2-2**).

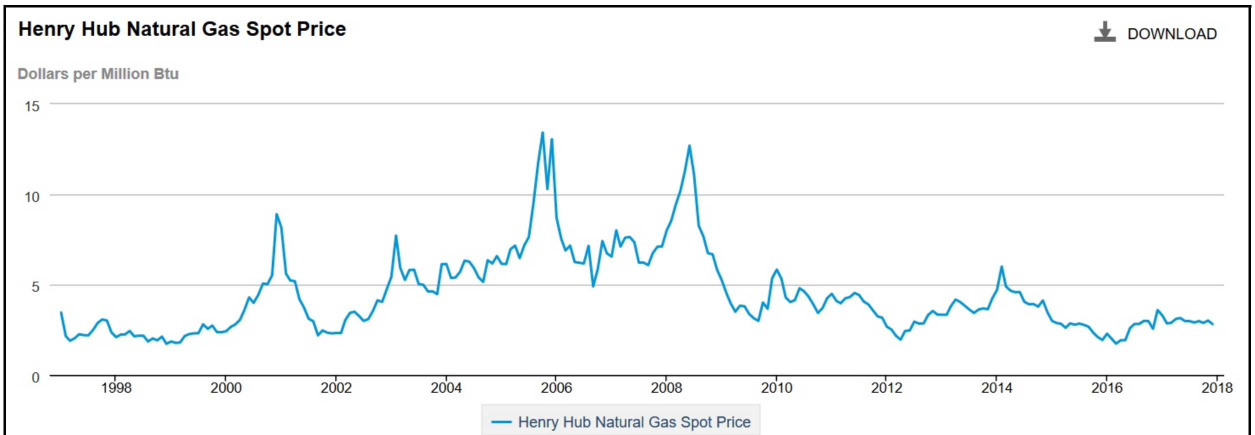


Exhibit 4.2-1: Henry Hub Spot Price

Exhibit 4.2-2: ACD Average Market Pricing (Tax Year 2017-2013)			
Calendar Year	**Henry Hub Average Price**	**3 Year Average**	**3 Year Weighted Average (suggested)**
2016	$2.31	$3.04	$2.71
2015	$2.54	$3.44	$3.28
2014	$4.26	$3.49	$3.75
2013	$3.53		
2012	$2.67		

4.3 Decline Factor

Throughout this report we refer to “Decline Factor”: this is the factor used to predict the yearly decline of an oil or gas well. The Decline Factor is multiplied by previous years’ production to estimate next year’s production. Most state taxing authorities use this method for calculation purposes. This differs slightly from the development of a “Decline Rate/Curve” traditionally used by the industry where a harmonic or hyperbolic decline curve is fitted to the natural formation characteristics of the reservoir. For the mass appraisal of wells across an entire state, this difference is insignificant.

Additionally, as stated above we don’t believe wells are being produced to the formation properties but rather production is restricted at the well head; **Exhibit 4.3-1** shows a histogram of the Decline Factor for Northern Arkansas gas wells which shows this. The vast majority of wells exhibit a decline factor of 0.80-0.90 with the weighted average (by production) at 0.96. For the valuation, RTC suggests using an annual decline factor distributed by well age and basin (more below).

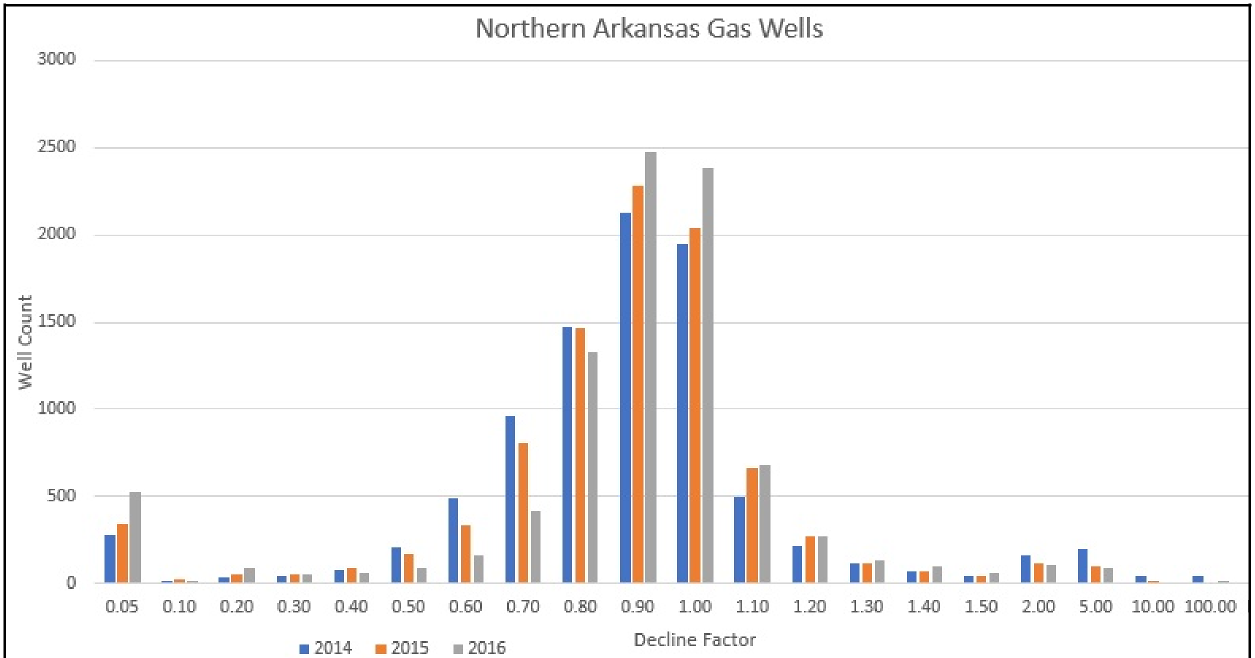


Exhibit 4.3-1: Most Common Decline Factor is 0.80-0.90

4.3.1 Fayetteville Shale

An examination of recent wells drilled in Van Buren County found that it is appropriate to assign specific decline factors based on the age of the well. **Exhibit 4.3.1-1** shows that the number of wells drilled in the Fayetteville have declined significantly since 2014. However, when the market returns, decline factors for new wells, which is typically much greater than older wells, should be used in the valuation.

Exhibit 4.3.1-1: Wells Drilled	
Year	**Count**
2017	1
2016	24
2015	198
2014	502
2013	563
2012	718
2011	831
2010	873
2009	838
2008	685
2007	416
2006	112
2005	44
2004	8

Exhibit 4.3.1-2, on the following page, shows the ranked distribution of decline factors, per well age, for wells drilled in Van Buren County since 2009. **Exhibit 4.3.1-3** shows the average and median of each age and our suggested decline factor. We suggest grouping years 1-2, 3-4, and 5+. As stated above, this does not affect the valuation very much as most wells are already older than 5 years, it will prove useful when there is an up-tick in well spuds.

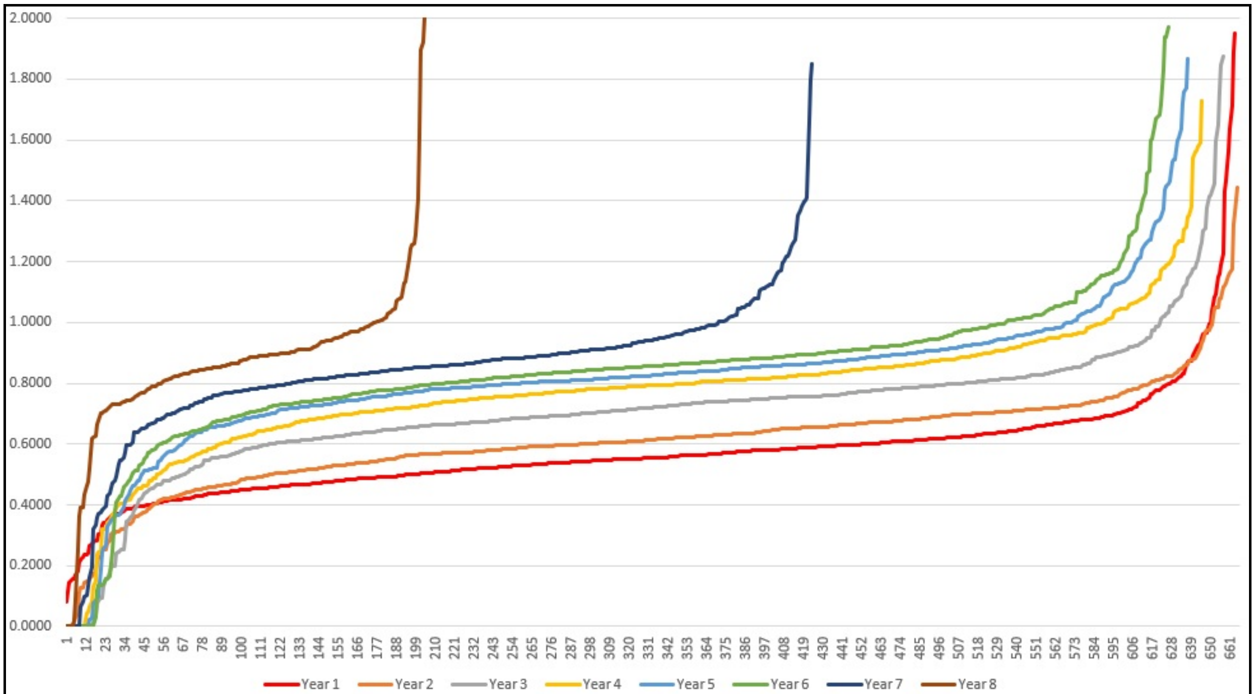


Exhibit 4.3.1-2: Decline Factor by Well Age

Exhibit 4.3.1-3: Suggested Fayetteville Shale Decline Factor								
Well Age	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Average	0.5810	0.6162	0.7205	0.8052	0.8368	0.8691	0.8537	0.8972
Median	0.5543	0.6149	0.7197	0.7911	0.8216	0.8512	0.8576	0.8800
	0.58		0.76		0.85			

4.3.2 Arkoma Basin

Similar to the Fayetteville Shale, there should be different decline factors based on well age in the Arkoma Shale. **Exhibit 4.3.2-1** shows the number of wells drilled in the Arkoma Shale. Notice the significant drop since 2009. Additionally, production data was only available back to 2009 but it was still enough data to arrive at decline factors when the market returns and more wells are drilled.

Exhibit 4.3.2-1: Wells Drilled by Year - Arkoma	
Year	**Count**
2017	1
2016	2
2015	3
2014	23
2013	23
2012	37
2011	39
2010	95
2009	151
2008	247

Exhibit 4.3.2-1: Wells Drilled by Year - Arkoma	
Year	**Count**
2007	266
2006	265
2005	265
2004	268

Exhibit 4.3.2-2 shows the decline factor, per well age, for wells drilled in the Arkoma since 2009. **Exhibit 4.3.2-3** shows the average and median of each age and our suggested decline factor. We suggest grouping years 1-2, 3-4, and 5+. As stated above, this does not affect the valuation very much as most wells are already older than 5 years, it will prove useful when there is an up-tick in well spuds.

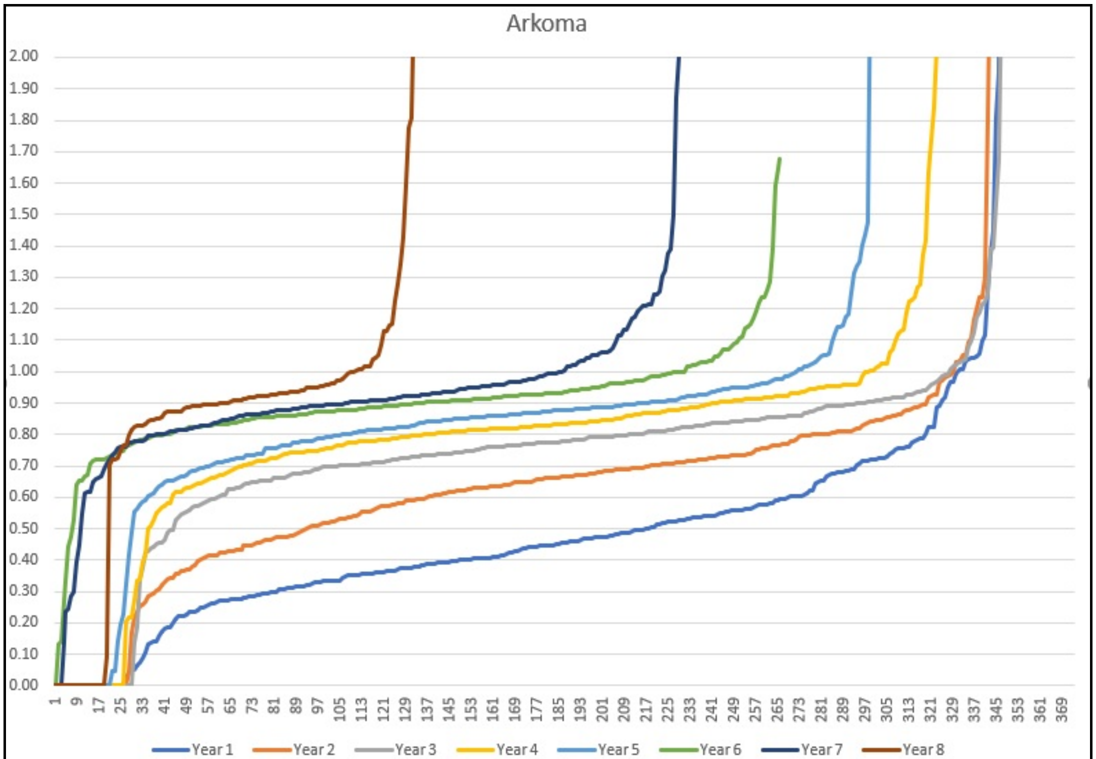


Exhibit 4.3.2-2: Decline Factor by Year

Exhibit 4.3.2-3: Suggested Arkoma Decline Factor								
Well Age (Yr)	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**
Ave	0.4851	0.6609	0.7217	0.7715	0.8071	0.8961	0.9019	0.8339
Median	0.4412	0.6508	0.7694	0.8182	0.8524	0.9003	0.9066	0.9097
	0.55		0.79		0.89			

4.4 Expenses

Oil and gas wells require a minimum cost to operate. Generally, this ranges from $20,000 to $48,000 per year and depends on production level. Theoretically, wells producing less revenue than the minimum cost to operate are typically shut-in. For example, at $3.00/MCF, a well would have to produce a least 7,000 MCF to be profitable. However, a review of well production in Northern Arkansas show a full 14% of gas wells are operating below this threshold. Therefore, we do not suggest that the State model the economic life of a well to closure but rather have the operator report when the well is closed, or no production for the year.

Southwestern Energy, responsible for almost 70% of the Northern Arkansas gas market, is also the only publically listed U.S. company operating in the area. An examination of production expenses from Southwestern Energy's publically available documents shows costs remained constant at less than $1/MCF even as other operational data changed significantly (see **Exhibit 4.4-1**).

Exhibit 4.4-1: Southwestern Energy Data (2016 Annual Report - Fayetteville Shale)

Year	Realized Price ($/MCF)	Production Costs ($/MCF)	Production (Bcfe)	Gross Production Value (1-Year)	Reserves (Bcfe - Total)	Market Cap (Ycharts)	Well Spuds
2016	1.80	0.87	375	$348,750,000	2,997	$5.46B	4
2015	2.12	0.91	465	$562,650,000	3,281	$2.60B	155
2014	3.86	0.92	494	$1,452,360,000	5,069	$9.62B	465

At the meeting discussing the results of this report, gas operators suggested that a $1 per MCF production was too low and didn't represent transportation well to arrive at a true wellhead price. We suggest a survey should be periodically sent to all operators to collect data on common deductions. This can be discussed at future stakeholder meetings.

Expenses that can be typically deducted for real estate taxing purposes should only be only ordinary expenses which are directly related to the maintenance and production of natural gas and/or oil:

- labor and lease operations
- maintenance
- abandonment/environmental expenses.

Deductible expenses do not include extraordinary expenses, depreciation, ad valorem taxes, capital expenditures, or expenditures relating to maintenance vehicles or other tangible property not used exclusively for the production of gas.

5.0 AD VALOREM VALUATION OF OIL WELLS

Oil production in southern Arkansas started in the 1920's and has been relatively steady for the last 30 years (see **Exhibit 2.0-4**). **Exhibit 5.0-1** shows production since 2009, and **Exhibit 5.0-2** shows recent production by company from 2014-2017.

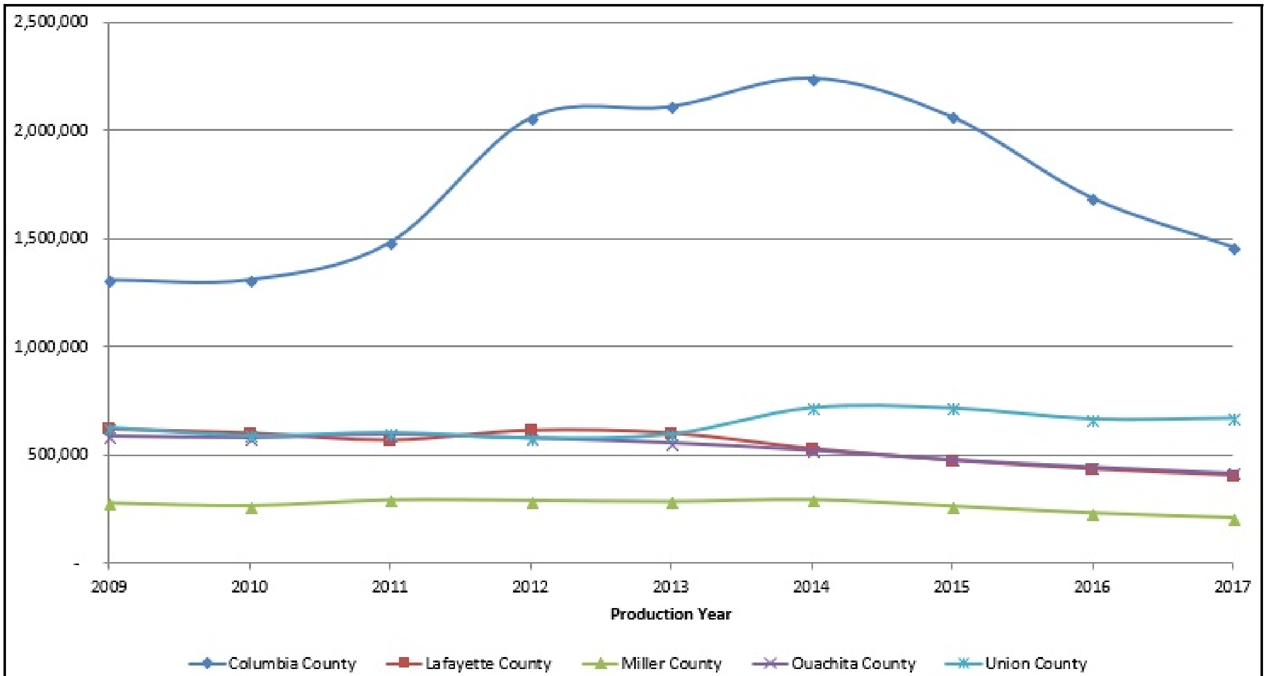


Exhibit 5.0-1: Southern Arkansas Oil Production by County

Exhibit 5.0-2: Top 15 Oil Producers				
Operator	**2014**	**2015**	**2016**	**2017**
Bonanza Creek Energy Resources, LLC	1,335,403	1,028,925	827,195	648,298
Petro-Chem Operating Company, Inc.	242,758	230,050	213,029	228,210
White Rock Oil & Gas, LLC	232,833	217,891	201,763	203,805
Quanico Oil & Gas, Inc	216,152	197,078	184,257	176,846
Betsy Production Company, Inc	212,483	180,931	158,524	145,049
Enerco Operating Corporation	108,627	112,295	102,756	94,247
Breitburn Operating, LP	128,534	136,497	94,248	89,463
Weiser-Brown Operating Company	80,049	76,927	71,625	57,447
Urban Oil & Gas Group, LLC	77,890	76,397	62,183	57,116
C12: Arkansas Oil, LLC	71,581	62,044	57,778	46,386
The Blackbird Company	37,837	40,767	39,829	39,178
ArklaTx Operating Company, Inc	53,908	50,505	42,089	37,591
Four R Operating Company, LLC	50,417	42,847	33,643	32,804
Red Oak Operating, LLC	51,616	42,077	33,393	32,126
Shuler Drilling Company Inc	24,747	26,711	24,527	25,164

Exhibit 5.0-3 shows the most common current active operators in southern Arkansas. **Exhibits 5.0-4 and 5.0-5** show wells drilled since 2010, notice the significant drop in new wells since 2014.

Exhibit 5.0-3: Current Active Wells per Operator	
Operator	**Well Count**
Bonanza Creek Energy Resources, LLC (Chapter 11)	291
ArklaTx Operating Company, Inc	224
Langley, Jerry Oil Company LLC	160
LBOC, LLC	113
Webb Brothers Well Service, Inc.	109
McGowan Working Partners, Inc.	94
Four R Operating Company, LLC	90
Quantum Resources Management, LLC	77

Exhibit 5.0-4: Wells Drilled Since 2010								
Company	**2017**	**2016**	**2015**	**2014**	**2013**	**2012**	**2011**	**2010**
ArklaTx	1	2	2	10	2	3	1	13
Bonanza Creek	0	0	0	52	49	50	35	15
Langley, Jerry Oil Company LLC	0	0	3	17	29	13	21	13
Enerco Operating Corporation	0	0	0	4	7	10	7	1
Breitburn Operating, LP	0	0	5	9	0	0	0	0
Four R	0	0	0	2	1	2	3	4
Quanico Oil & Gas, Inc	1	0	0	6	6	2	0	0

Exhibit 5.0-5: Wells Drilled Per Year			
Year	**Count**	**Decade**	**Count**
2017	2	2000s (includes 2009)	349
2016	7	1990s	141
2015	18	1980s	631
2014	154	1970s	519
2013	167		
2012	125		
2011	116		
2010	82		
2009	50		

Exhibit 5.0-6 is a summary our recommendations for the update of oil wells.

Exhibit 5.0-5: Recommendations to Update the Valuation of Oil Wells	
Issues	Multiple arbitrary valuation break points based on production, static discount rate, and decline factor
	Some confusion about at what age stripper wells begin
Solutions (same procedure as gas)	**Notes**
Move to a continuous present valuation of a producing income stream	Will eliminate multiple valuation break points depending on the production of a well and will harmonize production in unitized fields. Actual production will be used rather than midpoints of a production range.
Income Stream Length: 10 years	Down from 14 to match gas
Production: from AOGC	Currently used
Price: 3 year weighed average of Arkansas market price BBL (Lion Oil)	ACD currently tracks Arkansas market pricing
Deduction of ~ $8.00 per BBL per well for expenses[14]	Current expenses are $10,000 + 10% of the working income. Other deductions can be taken for water floods and enhanced recovery. Bonanza Creek Energy, while bankrupt, is the largest publically traded company in the Southern Arkansas Fields and the only source of production costs A participant survey should be considered at future stakeholder meetings to calculate state wide averages of production costs to arrive at a other deductions to the oil price. Additional deductions may include water floods Appropriate documentation to substantiate costs should also be discussed.
Decline Factor: South Arkansas Oil Wells per well age: Years 1-2: 0.59 Years 3-4: 0.70 Years 5+: 0.85	To be updated yearly, see **Exhibit 5.2-1** - switch to stripper well status not necessary.
Discount Rate: 14.96%	To be updated yearly (see Appendix A).

[14]United States Securities and Exchange Commission, Form 10-K, (2016) Bonanza Creek Energy, pg 38.

5.1 Previous Method

The previous method used discounting to arrive at an assessed value based on well production. Wells were assigned into one of seven categories based on the production of the well. **Exhibit 5.1-1** shows how all wells with production between 5.1 and 10 BBLs per day are valued. The production starts with an average of 7.55 and declines each year (Decline Factor of 0.80, “Decline” column). The “Income” column, the discounted income, is calculated per year based on a 15% discount rate. From there, the expenses are removed and the value is disturbed among working and royalty interests.

Exhibit 5.1-1: Example Valuation for Wells producing 5.1 to 10 BBLs per day									
2017 - LEVELS OF OIL WELLS- CALCULATION OF ASSESSED VALUES FOR VARYING PRODUCTION									
BASE PRICE PER BBL:				$52.14					
DISCOUNT RATE USED:				15.0%					
EXPENSE RATE USED				$10,000 PLUS 10% OF GROSS INCOME					
PRESENT WORTH OF FUTURE PRODUCTION									
PRODUCTION BBL/DAY: 7.55					5.1 to 10 BBLs				
Decline	**YR**	**INCOME**	**7/8 INC**	**EXPENSE**	**7/8 NET**	**DISC**	**7/8 P/W**	**1/8 INC**	**1/8 P/W**
6.04	1	114,948	100,579	20,058	80,521	0.9325	75,087	14,368	13,399
4.83	2	91,958	80,463	18,046	62,417	0.8109	50,612	11,495	9,321
3.87	3	73,567	64,371	16,437	47,934	0.7051	33,798	9,196	6,484
3.09	4	58,853	51,497	15,150	36,347	0.6131	22,286	7,357	4,511
2.47	5	47,083	41,197	14,120	27,078	0.5332	14,437	5,885	3,138
1.98	6	37,666	32,958	13,296	19,662	0.4636	9,116	4,708	2,183
1.58	7	30,133	26,366	12,637	13,730	0.4031	5,535	3,767	1,519
1.27	8	24,106	21,093	12,109	8,984	0.3506	3,149	3,013	1,056
1.01	9	19,285	16,874	11,687	5,187	0.3048	1,581	2,411	735
0.81	10	15,428	13,500	11,350	2,150	0.2651	570	1,929	511
0.65	11	12,342	10,800	11,080	0	0.2305	0	0	0
0.52	12	9,874	8,640	10,864	0	0.2004	0	0	0
0.42	13	7,899	6,912	10,691	0	0.1743	0	0	0
0.33	14	6,319	5,529	10,553	0	0.1516	0	0	0
						PRESENT WORTH TOTALS:	216,171		42,856
		7.55	BBL PRODUCTION LEVEL						
		NET WI	**RATIO**	**TOTAL**	**PER BBL**	**WI**	**AV BBL**		
		216,171	20%	43,234	5,726	0.8750	6,544		
		NET RI	**RATIO**	**TOTAL**	**PER BBL**	**RI**	**AV BBL**		
		42,856	20%	8,571	1,135	0.1250	9,082		

There are a number of issues with this method. There is no reason to assign wells into seven production categories; each well can be valued based on the exact production from the well. Decline factors should be based on well age, not by production at the well (0.70 - 0.80). That the discount rate between the old method and this report, 15%, is happenstance. The discount rate should be calculated periodically, to account for market changes.

Additionally, when multiple wells are pooled, the overall value is less than if the wells were valued individually. This is because the current system varies the decline factor with production levels rather than age of the well. Wells with production above 10 barrels per day have a decline factor of 0.70 for the first few years. All other wells have a decline factor of 0.80. When the wells are pooled, the higher summed production leads to a 0.70 decline factor instead of 0.80.

5.2 Oil Pricing

ACD uses the three-year average of yearly Lion Oil (*http://www.lionoil.com*) pricing. Again, this is a public data source that can be accessed by ACD, County Assessment Offices and Market participants. **Exhibits 5.2-1 and 5.2-2** show changes in the oil market over the past few years.

Exhibit 5.2-1: Examples of Lion Oil Pricing

	Arkansas	Arkansas	Arkansas	North LA	East Texas
Jan 1, 2011	$87.25	$82.50	$70.75	$87.25	$87.25
Jan 4, 2012	$100.75	$95.00	$81.25	$100.75	$98.50
Jan 1, 2013	$91.50	$87.00	$78.00	$91.50	$91.50
Jan 1, 2014	$92.25	$89.50	$77.25	$92.25	$95.00
Jan 1, 2015	$47.75	$44.75	$36.75	$47.75	$47.75
Jan 5, 2016	$29.25	$28.25	$22.27	$29.25	$30.25
Jan 1, 2017	$45.50	$39.00	$45.50	$46.00	$48.50
Jan 3, 2018	$55.00	$54.00	$50.00	$55.00	$55.25

Exhibit 5.2-2: U.S. Crude Futures - CLN8 Nymex - WSJ

The average (three-year) pricing for Southern Arkansas was over $80/BBL between 2012-2016 which led to increased assessed values (see **Exhibit 5.2-3**). However, the oil price dropped from $82.73 to $39.81 from 2014 to 2015 leading to a significant reduction in assessed value (see **Exhibit 5.2-4**). The 2016 assessed value to BBL was $70.70. As with the natural gas valuation, it is suggested to move to a three-year weighed average for the assessed price.

Exhibit 5.2-3: Oil Pricing				
Calendar Year	**Lion Oil Yearly AR Average**	**3 Year Average**	**3 Year Weighted Average (Suggested)**	**Bonanza Creek Energy**
2016	$33.89	$52.14	$44.00	$35.42
2015	$39.81	$70.70	$62.41	$40.98
2014	$82.73	$86.48	$85.74	$81.95
2013	$89.57			
2012	$87.13			

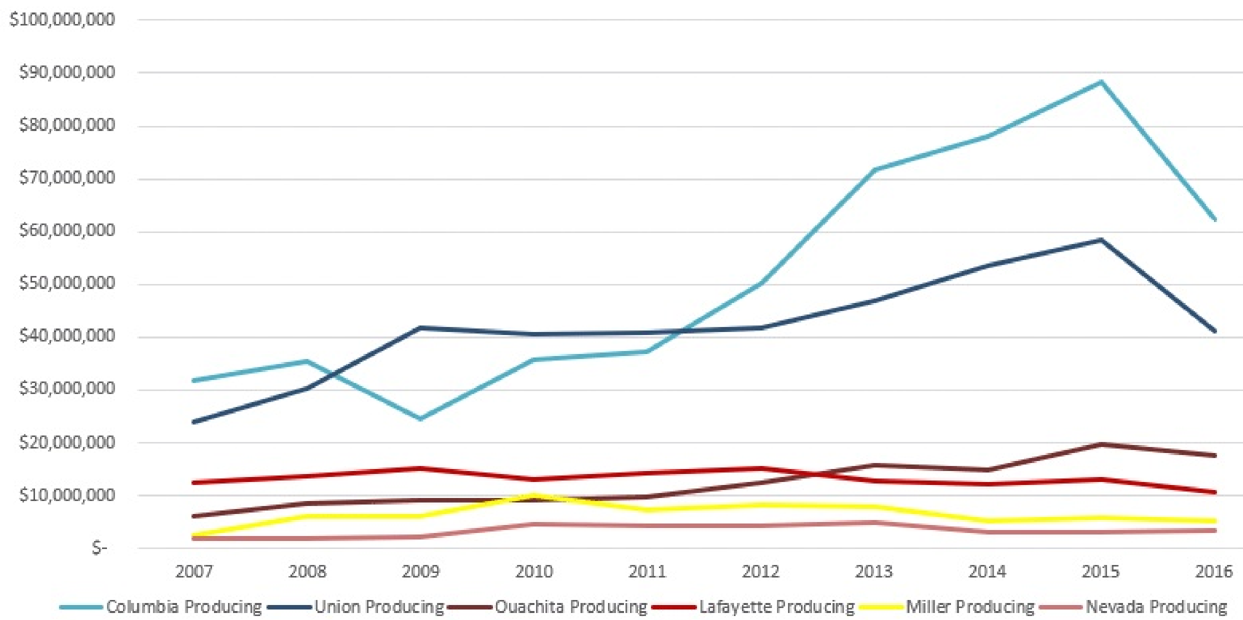


Exhibit 5.2-4: Southern Arkansas Assessed Value (Active Oil)

Exhibit 5.2-5 shows the yearly average oil price and the average three-year price. Notice that in an ascending market, the price is to the operators advantage. Only recently, with the declining market, has the three-year average price been greater than the yearly price.

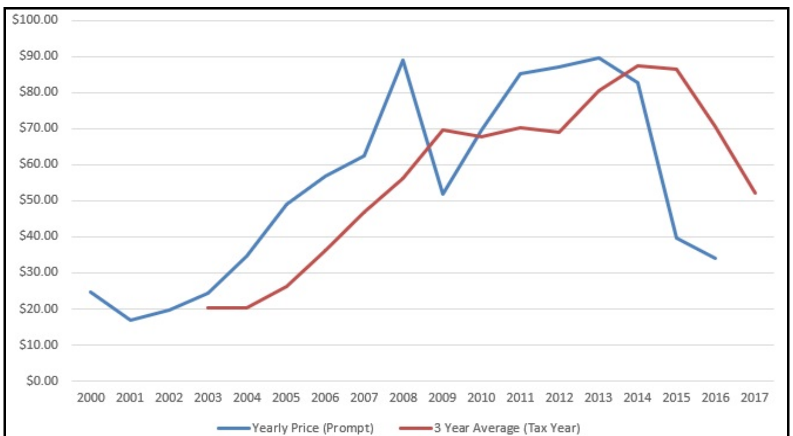


Exhibit 5.2-5: Yearly Oil Price Compared to 3yr Average

5.3 Deductions

Deductions to the oil price are important as they can reflect the price at the well head. The only publically traded company in southern Arkansas reported production costs around $8.00 per BOE. Bonanza Creek operates both in Colorado and Arkansas, and the production costs are averaged across both operating areas. Additionally, Bonanza Creek filed for bankruptcy in January 2018 but are still in operation[15].

Exhibit 5.3-1: Bonanza Creek Operation Data, SEC From 10-K 2016			
	2016	**2015**	**2014**
Oil:			
Total Production (MBbls)	4,309.90	6,072.30	5,618.70
Wattenberg Field (CO)	3,470.70	5,029.60	4,486.40
Dorcheat Macedonia Field (Columbia County, AR)	750	923.2	1,025.60
Average sales price (per Bbl), including derivatives (4)	$39.68	$62.10	$84.00
Average sales price (per Bbl), excluding derivatives (4)	$35.42	$40.98	$81.95
Natural Gas:			
Total Production (MMcf)	11,906.30	14,110.90	15,316.10
Wattenberg Field	9,574.80	11,020.80	11,372.70
Dorcheat Macedonia Field	2,331.40	3,090.50	4,030.60
Average sales price (per Mcf), including derivatives (5)	$1.88	$2.01	$5.16
Average sales price (per Mcf), excluding derivatives (5)	$1.88	$1.82	$5.11
Natural Gas Liquids:			
Total Production (MBbls)	1,491.10	1,675.90	260.6
Wattenberg Field	1,354.30	1,489.90	16.8
Dorcheat Macedonia Field	136.8	186	243.8
Average sales price (per Bbl), including derivatives	$12.39	$9.49	$49.14
Average sales price (per Bbl), excluding derivatives	$12.39	$9.49	$49.14
Oil Equivalents:			
Total Production (MBoe)	7,785.40	10,100.00	8,365.60
Wattenberg Field	6,420.80	8,356.30	6,398.60
Dorcheat Macedonia Field	1,275.40	1,624.20	1,874.70
Average Daily Production (Boe/d)	21,271.70	27,671.20	22,919.30
Wattenberg Field	17,543.40	22,894.10	17,530.50
Dorcheat Macedonia Field	3,484.50	4,450	5,136.30
Average Production Costs (per Boe) (3) (2)	$7.25	$7.56	$8.66

Bonanza Creek defines *"Production costs" as:*

> Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the

[15] Press Release - Bonanza Creek Energy Announced First Quarter 2018 Financial Results and Operational Update, May 8, 2018, (Accessed Wall Street Journal).

cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are (a) costs of labor to operate the wells and related equipment and facilities; (b) repairs and maintenance; © materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities; (d) property taxes and insurance applicable to proved properties and wells and related equipment and facilities; and (e) severance taxes.

A Wall Street Journal Survey[16] from 2016 showed total expenditures over $20 per barrel, but production costs were only about a quarter of that, and actually less than what Bonanza Creek reported.

	U.S. Shale	**U.S. Non Shale**
Gross Taxes	$6.42	$5.03
Capital Spending	$7.56	$7.70
Production Costs	$5.85	$5.15
SGA & Trans	$3.52	$3.11
Total	$23.35	$20.90

However, at the presentation, Southern Arkansas producers reported significantly higher expenses than reported by Bonanza Creek. **Exhibit 5.3-2** shows the data provided at the meeting for twelve wells in southern Arkansas. The total average expenditure per barrel is $21.42 but it is not known what the expenditures entail. Expenses that can be typically deducted for real estate taxing purposes should only be ordinary expenses which are directly related to the maintenance and production of natural gas and/or oil. The expenses do not include extraordinary expenses, depreciation, ad valorem taxes, capital expenditures, or expenditures relating to vehicles or other tangible personal property not permanently used in the production of natural gas or oil.

Exhibit 5.3-2: Expenditures per Well

Sample Well #	Expenditures	BBLs	$/ton
1	$109,620	7,890	$13.89
2	$30,437	2,180	$13.96
3	$43,303	2,885	$15.01
4	$173,335	10,297	$16.83
5	$101,362	6,020	$16.84
6	$124,456	6,545	$19.02
7	$450,920	22,410	$20.12
8	$195,620	8,015	$24.41
9	$229,037	7,030	$32.58
10	$118,639	2,467	$48.09
11	$20,432	409	$49.96
12	$53,126	904	$58.77
Ave	$1,650,287	77,052	$21.42

[16] "Barrel Breakdown" April 15, 2016, Wall Street Journal News Graphics.

There is a significant difference between $8 and $21 per barrel for a total deduction. The table above can serve as a starting point for future stakeholder meetings and the need for operator data in the process. The expenses that operators should report still needs to be discussed. Additional deductions may include water floods Appropriate documentation to substantiate costs should also be discussed.

5.4 Oil Decline Factor

Exhibit 5.4-1 shows a histogram of decline factor in oil wells from Columbia and Union Counties. The average decline factor was less volatile than currently used (0.70 or 0.80). The mode was actually 0.90 - 1.00, meaning year to year, most oil wells don't produce that much different volume of oil. In fact, a significant number of wells produced more oil than the year before indicating production is more market dependant than geologically determinative. We suggest using 0.95 for the decline factor of oil wells. The high number of wells in the 0.01 range represent wells with active status; wells that did not produce are not valued as there is no production.

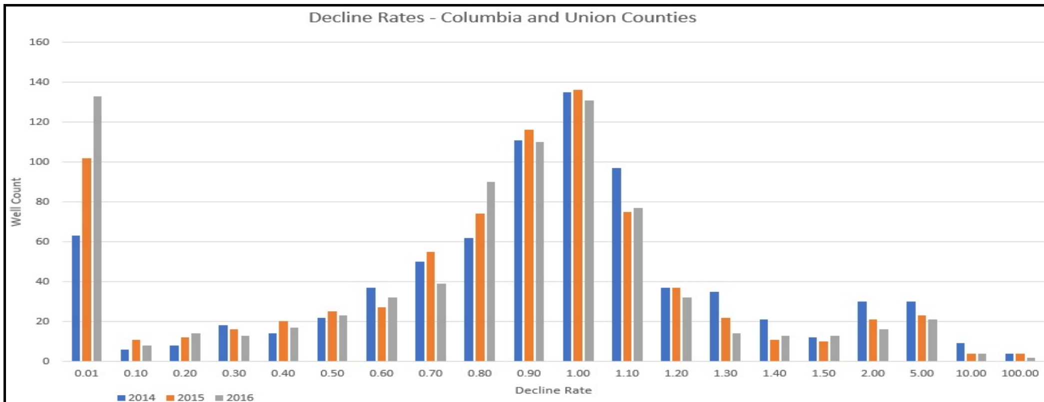


Exhibit 5.4-1: Oil Decline Factor

The exhibit above shows long-term decline for all the wells in southern Arkansas. A more detailed analysis was performed on wells spud since 2009 to determine decline rates of recently drilled wells. Since 2012, there have not been that many wells drilled, but this should make the valuation of newer wells more accurate moving forward and when more wells are drilled if the market improves.

Exhibits 5.4-2 and 5.4-3 show the year to year decline factor for wells spud from 2009 to 2014. This analysis show that, as expected, the decline factor in years 1 and 2 are much greater than years 3 and 4, which, in turn, is much greater than the long term discount rate (below). There were not enough wells 5 and 6 years old to develop a credible long-term decline factor (Exhibit 5.4.3).

Exhibit 5.4-2: Average and Median Decline Factor by well age 2009- 2014

	Year 1	Year 2	Year 3	Year 4
Average	0.66	0.63	0.67	0.68
Median	0.59	0.59	0.68	0.72
	0.59		0.70	

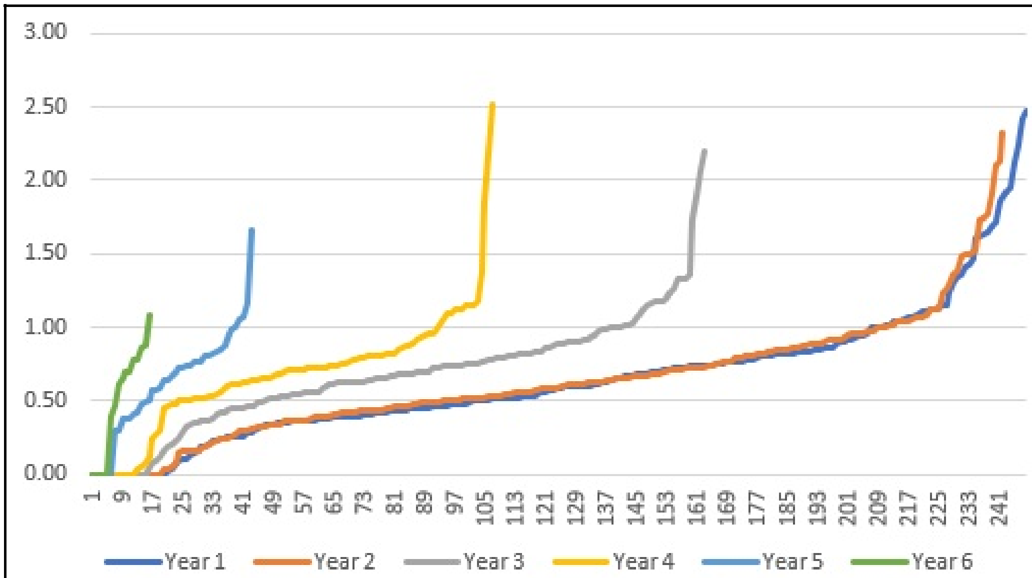


Exhibit 5.4-3: Decline Factor by Well Age, 2009-2014

Exhibits 5.4-4 and 5.4-5 show the decline factor since 2009 of <u>all wells </u>operating in Southern Arkansas. This analysis was used to find the long-term discount rate, as the vast majority of wells in Souther Arkansas are older than five years (**Exhibit 5.0-5:**) The long-term decline factor is 0.85.

Exhibit 5.4-4: Decline Factor All Wells								
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Average	0.83	0.95	1.04	0.99	0.87	0.86	0.81	0.90
Median	0.84	0.89	0.90	0.87	0.81	0.81	0.80	0.85
	0.85							

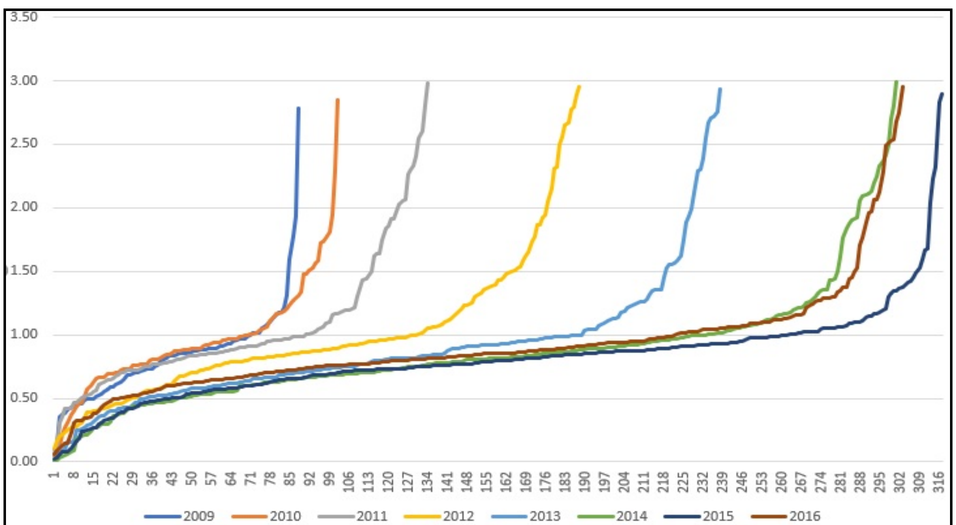


Exhibit 5.4-5: Decline Rates, All Wells 2009-2016

6.0 BUSINESS EQUIPMENT USED IN THE PRODUCTION OF MINERALS

Typically, a comprehensive DCF valuation of the working interest is an estimate of the total enterprise value of any given oil and gas operation: all of the components of the oil and gas well contribute to the total value. The appraiser must value the whole of the real estate interest. Each component of an oil and gas operation is not valued independently but rather as a whole so as to allow for a proper allocation of the overall market value to the real estate The equipment is one of component of the total value.

Other examples of components may include (all my not be taxable in Arkansas):

- mineral reserves
- land
- in-place permits
- machinery and equipment
- intangible interests

However, right now equipment is valued as personal property and in-place oil and gas is real estate. Additionally, Arkansas does not value gas wells using a DCF so the entire enterprise value not accounted for. The suggested methodology will eventually capture the entire value, but it will take a number of years because the assessed value on real property can only increase by 10% per year. Therefore, until the entire DCF can be valued, we suggested leaving the current system of valuing equipment in-place.

Eventually, it will still be necessary to value oil and gas equipment because it is assessed as personal property; and the value subtracted from the total enterprise value for the real property assessment.

In Arkansas, by law (Arkansas Statutes 26-3-201 and 26-26-903), every person/business is asked to self-report a list of personal property (cars, boats, etc.) and real property they own to be assessed. Similarly, businesses are asked to report the same as Business Personal Assessments. For oil and gas operations, the following, basically all equipment onsite up to the wellhead should be reported for assessment:

Personal Property:

- Christmas trees, pump jacks, well components, line heaters, wellhead/ suction/vacuum compressors
- separation and dehydration equipment
- gathering lines and production lines
- artificial lift equipment and their power sources
- electrical power systems that are easily removed
- compressors that are easily moveable and located in the field (between the wellhead and booster stations)
- everything inside the casing of a well including but not limited to, tubing, pipe, pumps, rods, gas-lift equipment, and packers inside the casing
- meters
- machinery, equipment, and fixtures that are attached components of processing or manufacturing facilities, items that are free standing or which

are bolted down but are readily removed without damage are tangible personal property (TPP)
- compressors at compressor stations other than leased compressors,

Real Property:
- pump stations, booster stations
- storage facilities – tanks, standing alone or in batteries
- casing (in place)
- enhanced production-injection and recovery systems which cannot be moved, intact
- vapor recovery systems
- production platforms with supports permanently embedded in the sea bed
- water disposal systems (same guidelines as storage facilities)
- gathering lines that are totally underground except for road or water crossings, etc.
- underground storage facilities.

Another good source to see all possible oil and gas equipment is from the Arkansas Department of Finance and Administration[17].

Generally, the distinction between personal and real property is how easily the equipment can be moved[18]. Personal property is taxed in Arkansas (cars, boats, etc), and oil and gas personal property should be as well. Real property that adds value to overall property should be included in the ad valorem assessment of the whole parcel.

To assess the personal and real property equipment and fixtures assembled on an oil and gas site, ACD currently recommends County Assessors use Oklahoma's Business Personal Property Valuation Schedule for Petroleum. While the entire document is titled "personal property" some fixtures are better defined as real property (underground storage tanks, for example).

The Oklahoma document directly discusses storage tanks, piping, and compressors. It references other valuation sources (Hadco to value oil and gas production and exploration equipment[19], Marshall and Swift for piping). These materials are competent and comprehensive data sources and we see no reason to change this suggestion. Otherwise, the State/County would be spending time repeating their efforts while chasing the same sales data on a yearly basis.

As discussed above, oil and gas operators should report all equipment (real or personal) up to the wellhead. Past the wellhead, ACD suggests $1 foot valuation for well casing. We see no reason that the well casing should be treated differently than other real property onsite and should be listed by the operator to be taxed in accordance with 26-26-903. Casing is better suited to be valued as real property. Casing is mentioned in the

[17] https://www.dfa.arkansas.gov/images/uploads/exciseTaxOffice/AllowableMarketingCosts.pdf

[18] Audit Procedures for Oil and Gas Well Servicing, Texas Comptroller of Public Accounts.

[19] http://www.hadcointernational.com/

Oklahoma document for Petroleum, but there is no value is listed. However, Marshal and Swift does address well casing (Section 14, Page 41). The average value for Oil and Gas wells is $130/per foot of depth.

6.1 Minimum Equipment Value

In the absence of a credible report from an operator verifying the equipment onsite, the county assessor should assign a value to the equipment that is known to be necessary for oil and gas production. **Exhibit 6.1-1** shows a typical Fayetteville Shale gas pad; wellheads, flowlines, separators, storage tanks, and entrance into a regional network can all be seen. The well pad area is removed from the surface assessment but the value of the equipment should be added back into the assessment. The value can be calculated as a function of the depth and number of wells on the lease. It should be noted, this does not include the cost to drill and complete the well on the equipment left in-place.

For simplicity and to encourage accurate reporting by operators, it is suggested that assessors assign a value of least $1,000,000 per pad to model the value of the equipment onsite. If the wells cannot be differentiated by pad, $1,000,000 per well is suggested.

Exhibit 6.1-1: Typical Fayetteville Shale Gas Pad

The discussion below shows some of the research used to develop the estimated equipment value. It is recognized that every well is different, and this value may be high for some plays. However, this value is only to be used in the absence of a self-reported list onsite by operators.

Source 1: OGOC, an Oil and Gas services company from Longview, TX, has an example of well drilling and completion on their website[20]. While every well is different, it is a good example of all the stages needed from drilling to completion to production onsite to produce oil and gas as well as the associated costs.

In this example, the well was 13,150 feet, cost $3.2 million to drill and complete, and contains $982,250 worth of equipment onsite for production.

AFE - Drilling & Completion

Operator:	ABC Exploration, LP	Prepared By:	RDR	Tax Rate	
Well Name:	Example #1-H	Field:	Expl	Depth:	13,150 '
Legal:		Parish/County:	Harrison	Days:	22
Contractor:	Nabors ???	State:	TX	Spud Date:	TBA

Well Program

Casing	Hole Size	Casing Size Weight, & Grade	Depth	Drilling Fluid	Formation Evaluation
Conductor		14" 3/8" Wall Welded	80 '		
Surface	12 1/4	9 5/8" 36 ppf J/K-55 STC	2,850 '	Spud	None
Intermediate	8 3/4	7" 29 ppf N-80 BTC	7,900 '	LSND	Triple Combo
1st Liner					
2nd Liner					
Production	6 1/4	4 1/2" 11.6 ppf P-110	13,150 '	LSND	LWD

Costs

Code	Item	Item Cost per Unit	Days/Units	Drilling Cost	Days/No.	Completion Cost	Total Cost
				8300		8500	
Capitalized Intangible Drilling & Completion Costs							
100	**Site Preparation & Maintenance**			**135,000**			**135,000**
	Permits & Surveys	7,500	1	7,500			7,500
	Location, Roads, Pits	75,000	1	75,000			75,000
	Water/Water Well/Plugging	7,500	1	7,500			7,500
	Conductor/Mousehole Installation	25,000	1	25,000			25,000
	Site Restoration & Land Use	20,000	1	20,000			20,000
	Wellsite Security						
	Roustabouts & Labor						
110	**Title Opinion**						
120	**Drilling/Completion Rig**			**557,000**			**557,000**
	Mob/Demob	150,000	1	150,000			150,000
	Rig Rental	18,500	22	407,000			407,000
	Top Drive & Mousehole						
	Additional Crew/Oil Base pay						
130	**Engineering & Supervision**			**78,100**		**15,000**	**93,100**
	Wellsite Supervision	3,000	22	66,000	5	15,000	81,000
	Engineering & Geology						
	Rig Supervisor Camp	400	22	8,800			8,800
	Communications	150	22	3,300			3,300
	Field/Office Supplies						
140	**Fuel**	4,500	22	**99,000**			99,000
150	**Well Evaluation**			**45,900**		**7,500**	**53,400**
	Open Hole Logging	25,000	1	25,000			25,000
	Cased Hole Logging	7,500			1	7,500	7,500
	Mud Logging	950	22	20,900			20,900
	Core Analysis						
	Drill Stem Testing						
	Fluid Analysis						
	Production Testing						
160	**Casing Services**			**20,000**		**10,000**	**30,000**
	Casing Crews & Rental Tools	10,000	2	20,000	1	10,000	30,000
	Roustabouts & Cleaning						
	Thread Specialist						
170	**Cementing Services**			**70,000**		**35,000**	**105,000**
	Primary Cementing	35,000	2	70,000	1	35,000	105,000
	Remedial Cementing						
	Loss Circulation						
	Squeeze Packers & Cementers						
	Kick-Off Plugs						
180	**Drilling Tools**			**49,000**		**15,000**	**64,000**
	Drill Bits	40,000	1	40,000			40,000
	Core Bits						
	Stabilizers/Reamers	1,500	5	7,500			7,500
	Performance Motors	15,000			1	15,000	15,000
	Turbines						
	Shock Subs	500	3	1,500			1,500
190	**Drilling/Completion Fluids & Services**			**102,300**		**13,500**	**115,800**
	Fluids & Services	4,500	22	99,000	3	13,500	112,500
	Shaker Screens	150	22	3,300			3,300
200	**Equipment Rentals**			**13,120**		**19,000**	**32,120**
	Shale Shaker						
	Mud Cleaner						
	Centrifuge	350	7	2,450			2,450
	Transfer Pumps						
	Steam Cleaners						
	Wear Bushing	35	22	770			770
	Rentals - Surface						
	Rentals - Subsurface						
	PVT/Flo-Show	350	22	7,700			7,700
	BOP Rental						
	Forklift	100	22	2,200			
	Hydraulic Choke	4,000			4	16,000	16,000
	Tankage (Frac Tanks)	15			200	3,000	3,000
210	**Drill String**			**32,500**			**32,500**

[20] https://www.ogoc.com/documents/Example-1-H-AFE.pdf

AFE - Drilling & Completion

	Drill Pipe	2,500	7	17,500			17,500
	Drill Collars						
	Drill Pipe Protectors	100					
	Inspections & Repair	7,500	2	15,000			15,000
	Corrosion Control						
220	**Environmental**			**4,400**		**35,000**	**39,400**
	Solid Waste Disposal	200	22	4,400			4,400
	Brine & Water Disposal	750			20	15,000	15,000
	Cuttings Haul-off & Disposal						
	Closed Loop Services						
	Reserve & Flare Pit Closure					20,000	20,000
	Spill Cleanup						
230	**Miscellaneous**	250	22	**5,500**	10	**2,500**	**8,000**
240	**Specialty Tools & Services**			**86,500**		**4,500**	**91,000**
	Directional & MWD Services	10,000	7	70,000			70,000
	Well Surveying (SS,EMS,Gyro)	7,500	1	7,500			7,500
	Fishing Tools and Services						
	Sidetrack: Whipstock,Mills,Service						
	Coring Services						
	Safety (H2S)						
	Control Of Well						
	BOP NU & Testing Services	3,000	2	6,000	1	3,000	9,000
	Wellhead Technician	1,500	2	3,000	1	1,500	4,500
250	**Trucking & Transportation**	650	22	**14,300**	10	**6,500**	**20,800**
260	**Welding**	1,000	2	**2,000**	1	**1,000**	**3,000**
270	**Production Services**					**1,685,000**	**1,685,000**
	Stimulation	200,000			8	1,600,000	1,600,000
	Perforating						
	Wireline Services -BP,cement, lubricators, cranes						
	Slickline Services						
	Coil Tubing & Nitrogen Services	60,000			1	60,000	60,000
	Misc. Rental Equipment						
	Pressure Testing Services						
	Facilities Construction	25,000			1	25,000	25,000
300	**Contract Labor**						
310	**Plug and Abandonment**						
400	**OEE Insurance**	**4**	**13150**	**52,600**			**52,600**
500	**Overhead Allocation**	1,000	22	22,000	5	5,000	27,000
Total Intangible Cost				**$1,389,220**		**$1,854,500**	**$3,243,720**
Tangible Drilling & Completion Costs				**8400**		**8600**	
100	**Casing**			**275,050**		**411,700**	**686,750**
	Conductor Casing	40	80	3,200			3,200
	Surface Casing	21	2850	59,850			59,850
	Protection Casing	27	8000	212,000			212,000
	1st Drilling Liner						
	Production Casing	18			13150	236,700	236,700
	Stim Sleeves and Packers	175,000			1	175,000	175,000
110	**Production Tubing**					50,000	50,000
	Tubing	6			8000	50,000	
	Pups and cross-overs						
120	**Subsurface Equipment**			**10,000**		**20,000**	**30,000**
	Liner Hanger & Packer						
	Production Packer, Anchor, Seals, Pump	20,000			1	20,000	20,000
	Cementing Equipment	10,000	1	10,000			10,000
	Gas Lift Mandrels & Valves						
	Pumps						
	Bridge Plugs						
130	**Wellhead Equipment**	**15,000**	**1**	**15,000**	**3**	**45,000**	**60,000**
140	**Production Equipment**					**127,000**	**127,000**
	Tank Battery	9,000			3	27,000	27,000
	Compressors						
	Pump Unit & Stuffing Box	80,000			1	80,000	80,000
	Fluid Meters & run						
	Production Skid - separator, heater treater, de-hy	20,000			1	20,000	20,000
	Treatment Units						
150	**Miscellaneous Equipment**					**28,500**	**28,500**
	Surface Lines/Gathering System					7,500	7,500
	Line Pipe						
	Sucker Rods	3			8000	21,000	21,000
Total Tangible Cost				**$300,050**		**$682,200**	**$982,250**
				Drilling		**Completion**	**Total**
Total Cost				**$1,689,270**		**$2,536,700**	**$4,225,970**
Contengencies							
AFE Cost				**$1,689,270**		**$2,536,700**	**$4,225,970**
W.I. Share		100.00%		**$1,689,270**		**$2,536,700**	**$4,225,970**

Source 2: EIA published a study of oil and gas equipment costs in 2009[21]. Drilling techniques have changed since then especially with non-conventional gas resources. Note the paradigm shift in gas equipment costs. The values from the study probably only represent a well head and some gathering lines (no need to separate liquids and store them and only one wellhead). Still, the report is instructive for conventional oil and gas wells, assuming a 10-well lease can represent a pad. The following tables show the results of the study:

Table 1: Equipment Costs for 10-Well Oil Lease in 2009

Depth:	**2,000-ft**	**4,000-ft**	**8,000-ft**	**12,000-ft**
Mid-Continent	$1,123,700	$1,605,900	$2,519,500	$2,972,700
South Louisiana	$1,276,800	$1,701,200	$2,165,600	$3,376,700
South Texas	$1,166,700	$1,601,800	$2,005,000	$3,300,900
West Texas	$1,114,800	$1,570,000	$2,612,100	$2,978,600
Rocky Mountains	$1,178,400	$1,633,700	$2,584,400	$3,033,100
US Average	$1,315,800	$1,752,900	$2,520,600	$3,264,200
Additional cost for Secondary Recovery in West Texas	$5,187,400	$10,198,800	$23,697,100	

Table 3: Equipment Costs for a 1 well Gas Lease in 2009

Depth:	**2,000-ft**	**4,000-ft**	**8,000-ft**	**12,000-ft**	**16,000-ft**
Producing 50 Mcf/d					
Mid-Continent	$35,200	$35,200			
North Louisiana	$34,700				
US Average	$34,600	$34,600	$44,100		
Producing 250 Mcf/d					
Mid-Continent	$37,400	$48,600	$81,100	$103,400	
North Louisiana	$34,700	$48,600	$80,000		
US Average	$35,000	$53,400	$82,200	$105,000	
Producing 500 Mcf/d					
Mid-Continent		$46,300	$80,000	$101,100	$114,000
North Louisiana		$48,400	$79,100	$100,200	
US Average		$62,000	$80,500	$101,400	$108,400
Producing 1 MMcf/d					
Mid-Continent				$114,000	$114,000
North Louisiana				$113,200	$113,200
US Average			$112,900	$112,700	$112,900
Producing 5 MMcf/d					
Mid-Continent					$137,500
North Louisiana					$136,400
US Average				$136,100	$136,100

[21] EIA Costs.

Table 3: Equipment Costs for a 1 well Gas Lease in 2009					
Depth:	**2,000-ft**	**4,000-ft**	**8,000-ft**	**12,000-ft**	**16,000-ft**
Producing 10 MMcf/d					
North Louisiana					$168,200

Notes from the study:

The costs provided in this report are for representative lease operations with equipment and operating procedures designed by EIA staff engineers. Costs are estimated for representative 10-well oil leases producing by artificial lift; 1 flowing gas well per gas lease; or 10-well coal bed methane leases dewatering by artificial lift. The design criteria took into account the predominant methods of operation in each region. Individual items of equipment were priced by using price lists and by communicating with the manufacturers or suppliers of the items in each region. The leading supply, service, and contracting companies (active in one or more of the regions) were contacted every year (1976 through 2009) for local June prices for their component of equipment or operating function. The objective of this process is to acquire prices that are representative for each region. The annual operating costs measure the change in direct costs incident to the production of oil and gas and exclude changes in indirect costs such as depreciation and ad valorem and severance taxes.

Costs were determined for new equipment. Tubing costs are included for the oil wells but not for the gas wells. Care must be exercised when combining these equipment costs with drilling costs to obtain total lease development and equipment costs because most drilling and completion cost estimates also include tubing costs. Drilling and completion costs are not included for producing wells, but are included for secondary recovery injection wells.

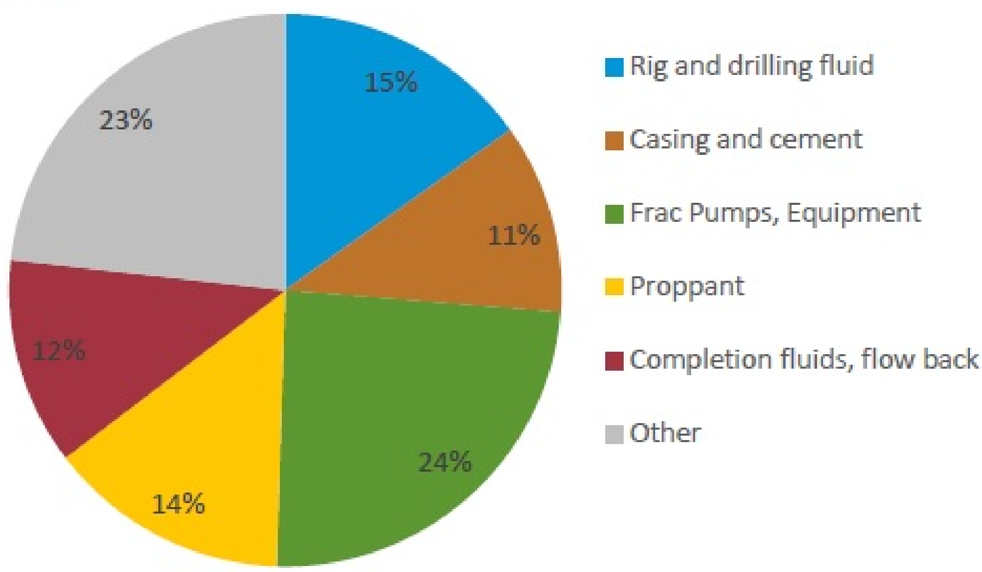
Items Tracked
Table 8 indicates the more significant cost items tracked from year to year, beginning in most cases with the year 1976. Freight and taxes are also a part of the equipment cost, as is the labor to install the equipment. Maintenance costs include replacement costs of some of the more common wear items.

Table 8: Items tracked for Oil, Gas, or Coal Bed Methane Lease Equipment and Operating Costs	
Automobile Costs	Oil transfer pumps
Communications costs - land	Oilfield chemicals
Communications costs - offshore	Oilfield maintenance - land
Electric lease power	Oilfield maintenance - marine
Electric motors and controllers	Packers
Electric labor - field	Perforating
Electric materials - field	Pipe coating
Fences	Plastic tanks
Field structures - small	Pumping engines - gas
Fishing tools	Pumping motors - electric
Miscellaneous fittings	Pumping unit bases
Gas compressors	Pumping units
Gas lift equipment	Slick line work - offshore
Gas sales meters	Speciality tubing
Gross national product deflator	Submersible pumps
Helicopter service	Submersible hydraulic pumps

Table 8: Items tracked for Oil, Gas, or Coal Bed Methane Lease Equipment and Operating Costs	
Hot oil service	Sucker rods
Insulation	Tubular goods - lease
Insurance - offshore	Tublar goods - well
Labor statistics - oil field	Tugs and barges
Labor - clerical	Valves, pumps, misc. - land
Labor - supervisory	Water filter cases
Labor - technical	Water filters
Large engine for hydraulic pumping	Water injection pumps
Lease processing and storage equipment	Well costs - secondary recovery
Lubricants	Well servicing - land
Marine food services	Well servicing - offshore
Natural gas prices	Wellheads

Source 3: More recently, the EIA commissioned IHS to do a study[22] of upstream oil and gas costs. The report is a comprehensive investigation of costs from drilling to exploration in multiple plays. The following images from the report show the breakdown of each stage of the well, and total estimated costs:

Figure 2 Percentage breakdown of cost shares for U.S. onshore oil and natural gas drilling and completion

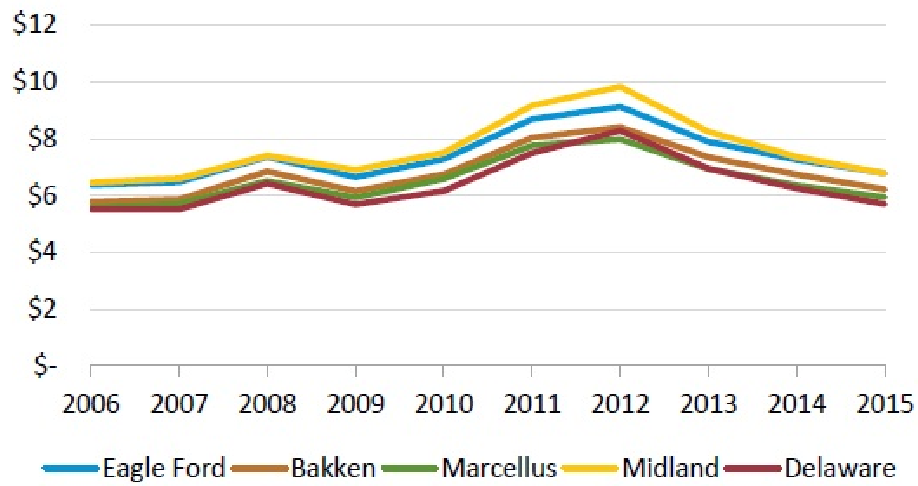


Source: IHS *Oil and Gas Upstream Cost Study commissioned by EIA*

[22] Trends in U.S. Oil and Natural Gas Upstream Costs, IHS Oil and Gas Upstream Cost Study Commissioned by EIA March 2016.

Figure 3. Average well drilling and completion costs for the 5 onshore plays studied follow similar trajectories

Cost by year for 2014 well parameters
$ million per well



Note: Midland and Delaware are two plays within the Permian basin, located in Texas and New Mexico
Source: IHS *Oil and Gas Upstream Cost Study commissioned by EIA*

Findings from the IHS report:

Cost Distribution:

1. *Drilling – Within onshore basins drilling comprises about 30-40% of total well costs. These costs are comprised of activities associated with utilizing a rig to drill the well to total depth and include:*
   a. *Tangible Costs such as well casing and liner, which have to be capitalized and depreciated over time, and*
   b. *Intangible Costs, which can be expensed and include drill bits, rig hire fees, logging and other services, cement, mud and drilling fluids, and fuel costs.*

2. *Completion – Within onshore basins completion comprises 55-70% of total well costs. These costs include:*
   a. *Well perforations, fracking, water supply and disposal. Typically this work is performed using specialized frack crews and a workover rig or coiled tubing and include:*
   b. *Liners, tubing, Christmas trees and packers, and*
   c. *Frack-proppants of various types and grades, frack fluids which may contain chemicals and gels along with large amounts of water, fees pertaining to use of several large frack pumping units and frack crews, perforating crews and equipment and water disposal.*

3. *Facilities – Within onshore basins facilities construction comprises 7-8% of total well cost. These costs include:*
   a. *Road construction and site preparation,*
   b. *Surface equipment, such as storage tanks, separators, dehydrators and hook –up to gathering systems, and*
   c. *Artificial lift installations.*

4. *Operation – These comprise primarily the lease operating expenses. Costs can be highly variable, depending on product, location, well size and well productivity. Typically, these costs include:*
   a. *Fixed lease costs including artificial lift, well maintenance and minor workover activities. These accrue over time, but are generally reported on a $/boe basis.*
   b. *Variable operating costs to deliver oil and natural gas products to a purchase point or pricing hub. Because the facilities for these services are owned by third party*
   c. *midstream companies, the upstream producer generally pays a fee based on the volume of oil or natural gas. These costs are measured by $/Mcf or MMbtu or $/bbl and include gathering, processing, transport, and gas compression.*

(1) Rig related costs are dependent on drilling efficiency, well depths, rig day rates, mud use and diesel fuel rates. Rig day rates and diesel costs are related to larger market conditions and overall drilling activity rather than well design. Rig related costs can range from $0.9 MM to $1.3 MM making up 12%to 19% of a well's total cost.

(2) Casing costs are driven by the casing markets, often related to steel prices, the dimensions of the well, and by the formations or pressures that affect the number of casing strings. Within a play, well depths are often the most variable characteristic for casing with ranges of up to 5,000 feet. Operators may also choose to run several casing strings to total depth or run a liner in lieu of the final casing string. Casing costs can range from $0.6 MM to $1.2 MM, making up 9% to 15% of a well's total cost.

(3) Frack pumping costs can be highly variable, but are dependent on horsepower needed and number of frack stages. The amount of horsepower is determined by combining formation pressure, rock hardness or brittleness and the maximum injection rate. Pumping pressure (which includes a safety factor) must be higher than the formation pressure to fracture the rock. Higher pressure increases the cost. The number of stages, which often correlates with lateral length, is important since this fracturing process, with its associated horsepower and costs, must be repeated for each stage. These total costs (for all stages) can range from $1.0 MM to $2.0 MM, making up 14% to 41% of a well's total cost.

(4) Completion fluid costs are driven by water amounts, chemicals used and frack fluid type (such as gel, cross-linked gel or slick water). The selection of fracking fluid type is mostly determined by play production type, with oil plays primarily using gel and natural gas plays primarily using slick water. Water sourcing costs are a function of regional conditions relating to surface access, aquifer resources and climate conditions. Water disposal will normally be done by re-injection, evaporation from disposal tanks, recycling or removal by truck or pipeline, each with an associated cost. Typically about 20-30 percent of the fluids flow back from the frack and require disposal. Operators typically include the first 30-60 days of flow back disposal in their capital costs. These costs can range from $0.3 MM to $1.2 MM making up 5% to 19% of well's total cost.

(5) Proppant costs are determined by market rates for proppant, the relative mix of natural, coated and artificial proppant and the total amount of proppant. Proppant transport from the sand mine or factory to the well site and staging make up a large portion of the total proppant costs. Operators use more proppant when selecting less costly proppant mixes, which are comprised of mostly natural sand as opposed to artificial proppants. A higher mix of artificial proppants has often been used for very deep wells experiencing high formation pressures. Overall the amount of proppant used per well is increasing in every play. These costs can range from $0.8 MM to $1.8 MM making up to 6% to 25% of the well's total.

This report estimates costs at every stage of the well. The equipment that stays onsite to maintain production is installed among the different stages, and is shown as "tangible" costs. Assuming a typical well in an unconventional gas well now costs $6 million to drill and complete, at least 1/6 of those costs are easily distributed to the tangible costs.

Again, oil and gas operators are required to report personally property at the will site. The above research is intended to give an idea of the values placed in well pads. In the absence of operator reported data, we suggest assigning a value of at least $1,000,000 per pad which contain horizontal wells, and $250,000 for conventional vertical wells.

APPENDIX A-1: Development of Oil and Gas Discount Rate

One of the primary economic factors in oil and gas property appraisals is the discount rate used to compute the present value of the likely future income stream. The process of discounting converts the value of cash projected to be received in the future to the current price investors would pay for the right to receive the income. This appraisal method is widely used throughout the oil and gas industry and, in fact, is the basis for the scheme used by ACD to annually assess the value of oil and gas property throughout the State.

Each year, the valuer should calculate a discount rate based on current market conditions (overall mean weighted average cost of capital (WACC) of a sample of petroleum companies). However, the discount rate in Arkansas has not been updated recently.

There are three generally accepted methods for estimating a discount rate:

- WACC Studies
- Market Survey Methods
- Oil and Gas Property Sales Analysis.

Currently, there are a number of states and other publically available sources that use the above methods to publish yearly data on oil and gas company financials that can form the basis of the yearly ACD discount rate for oil and gas. These sources are:

1. The Texas Comptroller of Public Accounts Property Tax Assistance Division (PTAD) compiles a comprehensive annual study of discount rates to be applied to oil and gas values as well as their methodology (*2017 Property Value Study - Discount Rate Range for Oil and Gas Properties*, and *Manual for Discounting Oil and Gas Income*)[23, 24]. Texas discusses four separate discount rate sources and methods:

    a. WACC Method: PTAD compiled a WACC study based on 18 oil and gas companies (see **Exhibit A-1)**. The study, published in September 2017, showed a range of 13.7 to 20.46 with an average of 14.64 used as a WACC.

Exhibit A-1: Company Financial Data Used for PTAD WACC Study

Company Name	Total Capital (000)	Total Equity (000)	Total Long-Term Debt (000)	Equity % Of Capital	Debt % Of Capital	Beta Factor	After Tax Cost of Equity, %	Before Tax Cost of Equity, %	Cost Of Debt %	Before Tax WACC %
Anadarko	$53,716,176	$38,435,176	$15,281,000	71.55	28.45	1.55	12.12	18.65	4.70	14.68
Apache	$32,627,036	$24,083,036	$8,544,000	73.81	26.19	1.45	11.52	17.73	4.22	14.19
Cabot	$12,386,434	$10,865,904	$1,520,530	87.72	12.28	1.05	9.12	14.04	5.62	13.00
Chevron	$257,916,305	$222,630,305	$35,286,000	86.32	13.68	1.15	9.72	14.96	3.01	13.32
Cimarex	$14,224,978	$12,737,039	$1,487,939	89.54	10.46	1.50	11.82	18.19	4.37	16.74

[23] https://comptroller.texas.gov/taxes/property-tax/docs/96-1166.pdf.

[24] https://comptroller.texas.gov/taxes/property-tax/docs/96-1703.pdf.

Exhibit A-1: Company Financial Data Used for PTAD WACC Study

Company Name	Total Capital (000)	Total Equity (000)	Total Long-Term Debt (000)	Equity % Of Capital	Debt % Of Capital	Beta Factor	After Tax Cost of Equity, %	Before Tax Cost of Equity, %	Cost Of Debt %	Before Tax WACC %
Conoco Phillips	$88,222,684	$62,036,684	$26,186,000	70.32	29.68	1.35	10.92	16.81	4.50	13.15
Devon	$34,039,410	$23,885,410	$10,154,000	70.17	29.83	1.65	12.72	19.57	4.65	15.12
Encana	$15,621,020	$11,423,020	$4,198,000	73.13	26.87	1.65	12.72	19.57	5.20	15.71
Energen	$6,122,187	$5,594,744	$527,443	91.38	8.62	1.60	12.42	19.11	5.15	17.91
EOG	$65,284,160	$58,304,381	$6,979,779	89.31	10.69	1.45	11.52	17.73	3.37	16.19
Exxon Mobil	$403,330,480	$374,398,480	$28,932,000	92.83	7.17	0.95	8.52	13.11	3.27	12.41
Hess	$26,451,230	$19,716,230	$6,694,000	74.54	25.31	1.60	12.42	19.11	5.62	15.68
Marathon	$21,250,570	$14,661,570	$6,589,000	68.99	31.01	1.75	13.32	20.50	4.95	15.68
Murphy	$7,783,403	$5,360,653	$2,422,750	68.87	31.13	1.55	12.12	18.65	5.34	14.51
Noble	$23,506,170	$16,495,170	$7,011,000	70.17	29.83	1.40	11.22	17.27	4.48	13.45
Occidental	$64,255,622	$54,436,622	$9,819,000	84.72	15.28	1.15	9.72	14.96	3.21	13.16
Pioneer	$33,290,219	$30,562,219	$2,728,000	91.81	8.19	1.45	11.52	17.73	3.70	16.58
Range	$12,300,692	$8,491,880	$3,808,812	69.04	30.96	1.15	9.72	14.96	5.56	12.05
TOTAL	$1,172,328,782	$994,118,529	$178,169,253	1,424.22	375.62	25.40	203.22	312.65	80.92	263.55
ENTRIES				18	18	18	18	18	18	18
AVERAGE				79.12	20.87	1.41	11.29	17.37	4.50	**14.64**
STANDARD DEVIATION				9.57	9.57	0.23	1.38	2.13	0.87	1.66

b. The Society of Petroleum Evaluation Engineers (SPEE) conducts an annual opinion poll market survey *(https://secure.spee.org/store)* (Market Survey). The survey is available for a fee. It is also included in the PTAD publication. It is based on responses from petroleum company executives, industry consultants, and energy banks concerning property acquisitions and divestitures. The survey provides perspectives into the discount rates used to analyze properties in the market. In 2016, the SPEE surveyed 32 sources showing a WACC range of 9.0 to 15.70 with an average of 11.20.

c. The only substantive publically available survey of oil and gas property sales and net income was completed by R.J. Miller and Associates in 2006 for the California Independent Petroleum Association. It is also included in the PTAD publication. It involved more than 250 western U.S. producing oil and gas sales that occurred between 1998 and 2006. While the survey is dated, it is still considered by various agencies including the Texas Comptroller.

d. PTAD also reviewed their appraisals of almost 6,000 individual properties as PTAD will vary discount rates for individual properties based on a number of factors from the base discount rate. The average discount rate was 17.26 with a range from 16.36 to 18.16.

2. The West Virginia Department of Tax and Revenue/Property Tax Division publishes an annual Weighted Average Cost of Capital (WACC Method) report for all species of property including producing oil and gas. The report is a band of investments that relies more on U.S. financial data overall than individual data. For 2017, the State used a value of 15.80 for a WACC.

3. Duff and Phelps produces summary reports for major industry sectors (WACC Method). The most recent Duff and Phelps report shows a range of 8.6 to 12.8 with a segment average of 10.10. This report is based on the analysis of 32 publically traded oil and gas companies.

4. Aswath Damodaran -The Stern School of Business, New York University publishes a series of online data sets *(http://pages.stern.nyu.edu/~adamodar/)*. The data sets are updated quarterly and have been available since 1998. The data is separated by industry with companies for industry sectors listed within the database. Of interest is the set "Cost of Capital by Sector (U.S.)". The 2017 data to be used for 2018 valuations shows an estimated WACC of 12.09 based on the following (WACC Method):

Industry Name:	Oil/Gas (Production & Exploration)
Number of Firms:	331
Beta:	1.26
Cost of Equity:	8.80%
E/(D+E):	70.47%
Std Dev in Stock:	78.88%
Cost of Debt:	6.91%
Tax Rate:	2.18%
After-tax Cost of Debt:	5.25%
D/(D+E):	29.53%
Cost of Capital:	12.09%

By including 330 companies, this statistic is a much broader review of the industry than those reviews with narrow focus limited to Exploration and Production. The wider the view, the lower the overall likely risk.

The ACD process is meant to be a mass appraisal; there is no intention of providing site or well-specific evaluations. The ACD does not collect the well-specific data needed to undertake a detailed evaluation including adjustments of the discount rate based on the property. Therefore, a straight forward process of annually gathering typical rates used throughout the national industry is most appropriate.

Additionally, RTC suggests (as with PTAD) to add two percentage points to the overall mean WACC to establish the base discount rate for each oil and gas property to account for:

1. the inherent risk associated with oil and gas production from an individual property rather than a company-wide portfolio of producing properties
2. additional smaller oil and gas companies operating in the state in addition to the above studies

Exhibit A-2 shows the 2017 calculation of the discount rate that can be used for tax year 2018:

Exhibit A-2: ACD Discount Rate Calculation			
Source	**Average**	**Min**	**Max**
Texas Comptroller Study - Calculated WACC (18 companies)	14.64	12.05	17.91
SPEE (32 companies) (via Texas Comptroller)	11.70	9.00	15.70
West Virginia	15.80	N/A	N/A
Duff and Phelps (138 companies)	10.57	8.60	12.80
Damodaran (331 companies)	12.09	N/A	N/A
Average	**12.96**		
Additional 2 Percentage Points	**14.96**		

A yearly review of these sources by ACD can be used to update the discount rate used for oil and gas valuations in the future.