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Technical & Legal Considerations in Implementing an Exploration and Development Plan or What do We do Now?

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TECHNICAL & LEGAL CONSIDERATIONS IN IMPLEMENTING AN EXPLORATION AND DEVELOPMENT PLAN

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Considerations in Implementing an Exploration and Development Plan or "What Do We Do Now?"

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The following is a commentary on the exploration and development planning of the theoretical Arbuckle and Spiro drilling prospect, which is the subject of the Natural Resources Law Institute this year. The below described description ties to an outline and tables that follow the text.

<u>Prospect review</u> Look at available well data and analogous well data and estimate reserves by well and area. Look at minimum and maximum rock and fluid properties to obtain a most likely and best case scenario for reserves and economics for the prospect area and the first well to be drilled. Base participation decision on economic parameters that build in risk and allow ample profit margin. Use common sense. Is it reasonable and based on analogous information? Prepare pre-drill economics. Use costs and prices that are based on actual cases were available. Use current prices and use lower prices to account for worst-case scenario. Examine available infrastructure to determine costs for additional facilities to get the product to market. Pick location based on geologic data and best chance to make a successful first well. The location pick can also be influenced by proximity to an existing pipeline or some topographic concern. This prospect includes the Spiro Sandstone at a depth of 9,500 feet and the Arbuckle Limestone at a depth of 13,500 feet. An examination of available data shows that the Arbuckle initial well should recover between 1.6 BCF and 6.5 BCF based on drainage area. This is a fractured limestone and the productive area will be determined based on well performance. The prospect well drainage area has been estimated to be between 80 and 320 acres. The total prospect area based on pre-drill geology shows a potential productive area of 10,200 acres and estimated recoverable reserves of 206 BCF of gas. The Spiro Formation is deltaic sandstone in this area that encounters east-west running faults in the prospect area. The Spiro initial well should recover between 1.7 BCF and 3.3 BCF based on drainage area. This sandstone productive area will be determined by stratigraphic sand quality and fault boundaries. The productive area for the prospect well is estimated to be between 160 and 320 acres. The total prospect area based on pre-drill geology shows a potential productive area of 13,800 acres and estimated recoverable reserves of 142 BCF of gas. The first well will recover all costs including land and pipeline if minimum reserves from either zone are found with minimum pricing. If both zones are found to be productive, even with minimum reserves and pricing, the well will yield an acceptable rate of return. This reserve and economic exercise demonstrates that this prospect has the chance to very profitable.

<u>Drill a successful first well</u> First, determine where and how to complete the well based on well data to include logs, drilling mud log and any tests, and analogy to offset wells. The well completion procedure should include adequate tests of the encountered zones.

Revise geology from pre-drill geology if it changes. Decide whether to compete well dually or as a single completion. This will be based on ability to produce dually and economics. If a single completion is made, it may be necessary to drill a twin to the original well if other zones are encountered that need to be produced sooner than later. This is based on economics, field rules and partner preference. The geology is still not definitive in that you have one subsurface control point but if it ties to 3-D seismic, it may further define the productive limits or help with development.

Drill an unsuccessful first well Do not panic. Evaluate all log and test data to determine if an additional well is warranted. If you have 19,200 acres leased then one well may not condemn the acreage.

Future Development Once successful wells have been drilled than development strategies need to be formulated. Spacing patterns and drilling and production unit size need to be determined. Given the depth of our theoretical prospect, the unit size will most likely be 640-acre governmental section units. Field rules including well spacing will need to be established by application with the Arkansas Oil and Gas Commission six months after the completion of a new pool well or after the drilling of three wells, whichever comes first. Field rules will need to be set up for two reservoirs being the Spiro and the Arbuckle. In picking new well locations, consideration must given to new well performance and revised geology and 3-D seismic results. Generally, development will be step outs from wells drilled. Once some successful wells have been drilled, some operators may wish to drill a well to define the productive limits of the field. Pipeline design will be a dynamic situation in insuring there will be adequate pipeline capacity to account for field development plans. Economic analyses should be current with wells as they are drilled, as well as future estimates for up to date development plans. Since they are two active zones being developed some well twinning may be necessary. This can be determined based on economic analysis by comparing drilling two wells separately or completing the Spiro after the Arbuckle depletes. Depending on the situation, the present value may be much higher if two wells are drilled because the rates have been accelerated. Development is also dependent on well costs and pricing. This may change through the life of a field. Another consideration in field development will be increased well density. The Arbuckle wells on 640 acre spacing may not be adequate to drain the total unit due to the tight nature of the limestone. This is an economic exercise and is determined from current unit well performance, costs, and pricing. Density drilling in the Spiro may also be necessary if geologic boundaries prevent a single unit well from draining the unit area.

Considerations in Implementing an Exploration and Development Plan or "What do we do now?"

Outline

I. Prospect Analysis

1. Geology
   - A. Determine well and project area minimum and maximum productive limits
   - B. Verify rock and fluid properties
     - i. available data
     - ii. analogous wells

2. Reserves
   - A. Determine well and project minimum and maximum productive limit reserves
   - B. Determine drive mechanism
     - i. Analogous well and field
   - C. Make certain reserves are reasonable based on analogous wells

See Table I (Rock and Fluid Properties and Reserve Data – Arbuckle)
See Table II (Rock and Fluid Properties and Reserve Data – Spiro)

3. Economics
   - A. Determine current drilling and completion costs including cost to pipeline
   - B. Prices
     - i. Use current NYMEX pricing adjusted for margin to get to field paid prices as maximum price
     - ii. Use best worst-case scenario as minimum price
     - iii. Determine oil and gas quality from analogous wells to make price adjustments if necessary
   - C. Lease operating costs
     - i. Account for future anticipated costs such as compression and water disposal
   - D. Interest ownership
     - i. Determine potential ownership in well and project and account for any reversions
   - E. Schedule future production
     - i. Schedule based on offset or analogous well performance
     - ii. The date of first production should be as correct as possible with initial rate based on analogous wells
     - iii. Make certain the capital costs includes all costs for which you are responsible including land, drilling and completion and cost to market
   - F. Economic Analysis

i. Apply costs and pricing to scheduled production with appropriate interest data

ii. Review results including rate of return and profit to investment ratio

See Table III (Economic Analysis – Arbuckle and Spiro Pre-drill)

II. Post Drill Analysis

1. Geology
   - A. well and project area based on new well data
   - B. Rock and fluid properties
     - i. new well data

2. Reserves
   - A. Determine well and project productive limit reserves based on new well data

3. Economics
   - A. Determine current drilling and completion costs including cost to tanks and pipeline
   - B. Prices
     - i. Use current NYMEX pricing adjusted for margin to get to field paid prices as maximum price
     - ii. Use best worst-case scenario as minimum price
     - iii. Determine oil and gas quality from well data to make price adjustments if necessary
   - C. Lease operating costs
     - i. Account for future anticipated costs such as compression and water disposal
   - D. Interest ownership
     - i. Determine potential ownership in well and project and account for any reversions
   - E. Schedule future production
     - i. Schedule based on offset or analogous well performance
     - ii. The initial rate should be based on new well test data
     - iii. Make certain the capital costs includes all costs for which you are responsible including land, drilling and completion and cost to market
   - F. Economic Analysis
     - i. Apply costs and pricing to scheduled production with appropriate interest data

III. Future Development

1. Development Plan
   A. Spacing Pattern
      i. Field rules
      ii. Prudent spacing pattern
      iii. Lease provisions
      iv. Must maximize economics and recovery
   B. Monitor new well performance
      i. Pressure data
      ii. Production
   C. Propose additional wells
      i. Pick location to maximize development and minimize risk
         a. Examine up to date geology
         b. Place well at best location to test multiple formations
      ii. Must be flexible to change plans to conform to drilling results

2. Reserves
   A. Determine based on new well data

3. Economics
   A. Determine current drilling and completion costs including cost to tanks and pipeline
      i. Include additional infrastructure costs as development wells are drilled
   B. Prices
      i. Use current NYMEX pricing adjusted for margin to get to field paid prices as maximum price
      ii. Use best worst-case scenario as minimum price
      iii. Determine oil and gas quality from wells drilled to make price adjustments if necessary
   C. Lease operating costs
      i. Account for future anticipated costs such as compression and water disposal
      ii. Refine costs with actual costs as more wells are drilled
   D. Interest ownership
      i. Determine potential ownership in well and project and account for any reversions
   E. Schedule future production
      i. Schedule based on offset wells drilled
      ii. The initial rate should be based on new well test data
      iii. Make certain the capital costs includes all costs for which you are responsible including land, drilling and completion and cost to market
      iv. Examine rate acceleration cases where multiple formations are productive See Table IV (Economic Analysis - Rate Acceleration Case)

F. Economic Analysis

i. Apply costs and pricing to scheduled production with appropriate interest data

ii. Review results including rate of return and profit to investment ratio

Table I
Rock and Fluid Properties and Reserve Data
Arbuckle Formation - Prospect Analysis

	Undrilled Well Minimum	Undrilled Well Maximum	Potential Area
Zone	Arbuckle	Arbuckle	Arbuckle
Depth, feet	13,500	13,500	13,500
ROCK AND FLUID PROPERTIES			
Reservoir Pressure, psia	9,450	9,450	9,450
Pressure Souce	.7 * depth	.7 * depth	.7 * depth
Reservoir Temperature, deg F	273	273	273
Compressibility Factor	1.348	1.348	1.348
Gas Gravity	0.650	0.650	0.650
Porosity, %	8.0	8.0	8.0
Water Saturation, %	30	30	30
Gas-In-Place, MCF/AF	809	809	809
Recoverable Gas-In-Place, MCF/AF	404	404	404
, %	50%	50%	50%
VOLUMETRIC DATA			
Area, acres	80	320	10,200
Average Thickness, feet	50	50	50
Volume, acre-feet	4,000	16,000	510,000
Gas-In-Place, MMCF	3,237	12,946	412,657
Recoverable Gas-In-Place, MMCF	1,614	6,456	205,801

Table II
Rock and Fluid Properties and Reserve Data
Spiro Formation - Prospect Analysis
Page 1

	Undrilled Well Minimum	Undrilled Well Maximum	Potential Area West
Zone	Spiro	Spiro	Spiro
Depth, feet	9,500	9,500	9,500
ROCK AND FLUID PROPERTIES			
Reservoir Pressure, psia	4,418	4,418	4,418
Pressure Souce	.465 * Depth	.465 * Depth	.465 * Depth
Reservoir Temperature, deg F	218	218	218
Compressibility Factor	0.973	0.973	0.973
Gas Gravity	0.650	0.650	0.650
Porosity, %	15.0	15.0	15.0
Water Saturation, %	30	30	30
Gas-In-Place, MCF/AF	1,061	1,061	1,061
Recoverable Gas-In-Place, MCF/AF	689	689	689
, %	65%	65%	65%
VOLUMETRIC DATA			
Area, acres	160	320	3,800
Average Thickness, feet	15	15	15
Volume, acre-feet	2,400	4,800	57,000
Gas-In-Place, MMCF	2,547	5,094	60,489
Recoverable Gas-In-Place, MMCF	1,655	3,310	39,301

Table II
Rock and Fluid Properties and Reserve Data
Spiro Formation - Prospect Analysis
Page 2

	Potential Area Central	Potential Area East	Total Potential Area
Zone	Spiro	Spiro	Spiro
Depth, feet	9,500	9,500	9,500
ROCK AND FLUID PROPERTIES			
Reservoir Pressure, psia	4,418	4,418	4,418
Pressure Souce	.465 * Depth	.465 * Depth	.465 * Depth
Reservoir Temperature, deg F	218	218	218
Compressibility Factor	0.973	0.973	0.973
Gas Gravity	0.650	0.650	0.650
Porosity, %	15.0	15.0	15.0
Water Saturation, %	30	30	30
Gas-In-Place, MCF/AF	1,061	1,061	1,061
Recoverable Gas-In-Place, MCF/AF	689	689	689
%	65%	65%	65%
VOLUMETRIC DATA			
Area, acres	6,000	4,000	13,800
Average Thickness, feet	15	15	15
Volume, acre-feet	90,000	60,000	207,000
Gas-In-Place, MMCF	95,510	63,673	219,672
Recoverable Gas-In-Place, MMCF	62,054	41,369	142,723

Table III
Economic Analysis
Arbuckle and Spiro Formations
Prospect Analysis

Formation	Spiro		Spiro		Arbuckle		Arbuckle		Arrbuckle/Spiro		Arrbuckle/Spiro	
Reserve Case	Minimum		Maximum		Minimum		Maximum		Minimum		Maximum	
Price Case	$4.00/MCF	$6.00/MCF	$4.00/MCF	$6.00/MCF	$4.00/MCF	$6.00/MCF	$4.00/MCF	$6.00/MCF	$4.00/MCF	$6.00/MCF	$4.00/MCF	$6.00/MCF
Gross Reserves, MCF	1,655.00	1,655.00	3,310.00	3,310.00	1,614.00	1,614.00	6,456.00	6,456.00	3,269.00	3,269.00	9,766.00	9,766.00
Net Reserves, MCF	1,241.25	1,241.25	2,482.50	2,482.50	1,210.50	1,210.50	4,842.00	4,842.00	2,451.75	2,451.75	7,324.50	7,324.50
Gas Revenue, $M	4,965.00	7,447.00	9,930.00	14,895.00	4,842.00	7,263.00	19,368.00	20,052.00	9,807.00	14,710.00	29,298.00	43,947.00
Net Severance Tax, $M	10.00	10.00	20.00	20.00	10.00	10.00	39.00	39.00	20.00	20.00	59.00	59.00
Net Investment, $M	1,200.00	1,200.00	1,200.00	1,200.00	1,500.00	1,500.00	1,500.00	1,500.00	1,750.00	1,750.00	1,750.00	1,750.00
Net Pipeline Cost, $M	500.00	500.00	500.00	500.00	500.00	500.00	500.00	500.00	500.00	500.00	500.00	500.00
Net Land Cost, $M	1,920.00	1,920.00	1,920.00	1,920.00	1,920.00	1,920.00	1,920.00	1,920.00	1,920.00	1,920.00	1,920.00	1,920.00
Lease Expense, $M	435.00	435.00	870.00	870.00	315.00	315.00	1,262.00	1,262.00	750.00	750.00	2,229.00	2,229.00
Compression and Transportation, $M	579.00	579.00	1,158.00	1,158.00	565.00	565.00	2,260.00	2,260.00	1,144.00	1,144.00	3,418.00	3,418.00
Net Cash Flow, $M	321.00	2,804.00	4,262.00	9,227.00	32.00	2,453.00	11,888.00	21,572.00	3,723.00	8,627.00	19,422.00	34,071.00
Present Worth @ 10%, $M	(276.00)	1,731.00	2,069.00	5,492.00	(386.00)	1,687.00	6,394.00	12,476.00	1,426.00	4,714.00	7,105.00	13,645.00
Payout, Years	4.83	2.08	2.88	1.76	5.00	1.66	1.92	1.39	5.71	1.81	2.04	1.36
ROI	1.10	1.77	2.20	3.55	1.00	1.63	4.03	6.50	1.89	3.07	5.66	9.17
ROR, %	5.00	46.00	34.00	82.00	1.00	58.00	73.00	162.00	24.00	68.00	73.00	162.00

Table III
Economic Analysis
Arbuckle and Spiro Formations
Prospect Analysis

Formation	Spiro		Spiro		Arbuckle		Arbuckle		Arrbuckle/Spiro		Arrbuckle/Spiro	
Reserve Case	Minimum		Maximum		Minimum		Maximum		Minimum		Maximum	
Price Case	$4.00/MCF	$6.00/MCF	$4 00/MCF	$6.00/MCF	$4 00/MCF	$6.00/MCF	$4.00/MCF	$6.00/MCF	$4.00/MCF	$6.00/MCF	$4.00/MCF	$6.00/MCF
Gross Reserves, MCF	1,655.00	1,655 00	3,310.00	3,310 00	1,614.00	1,614.00	6,456.00	6,456.00	3,269.00	3,269.00	9,766.00	9,766.00
Net Reserves, MCF	1,241 25	1,241 25	2,482 50	2,482 50	1,210 50	1,210.50	4,842.00	4,842.00	2,451.75	2,451.75	7,324 50	7,324.50
Gas Revenue, $M	4,965 00	7,447 00	9,930 00	14,895.00	4,842.00	7,263.00	19,368 00	20,052.00	9,807.00	14,710.00	29,298.00	43,947.00
Net Severance Tax, $M	10.00	10 00	20 00	20.00	10.00	10.00	39.00	39.00	20.00	20.00	59.00	59.00
Net Investment, $M	1,200 00	1,200 00	1,200 00	1,200 00	1,500 00	1,500.00	1,500 00	1,500 00	1,750.00	1,750.00	1,750 00	1,750 00
Net Pipeline Cost, $M	500 00	500 00	500 00	500 00	500 00	500.00	500.00	500.00	500.00	500.00	500.00	500 00
Net Land Cost, $M	1,920 00	1,920 00	1,920 00	1,920 00	1,920 00	1,920 00	1,920 00	1,920.00	1,920 00	1,920.00	1,920 00	1,920.00
Lease Expense, $M	435 00	435 00	870 00	870 00	315 00	315 00	1,262 00	1,262 00	750 00	750.00	2,229.00	2,229 00
Compression and Transportation, $M	579 00	579 00	1,158 00	1,158 00	565 00	565 00	2,260 00	2,260 00	1,144 00	1,144.00	3,418.00	3,418 00
Net Cash Flow, $M	321 00	2,804 00	4,262 00	9,227 00	32 00	2,453 00	11,888 00	21,572.00	3,723.00	8,627 00	19,422.00	34,071.00
Present Worth @ 10%, $M	(276 00)	1,731 00	2,069 00	5,492 00	(386 00)	1,687 00	6,394 00	12,476 00	1,426.00	4,714.00	7,105.00	13,645.00
Payout, Years	4 83	2 08	2 88	1 76	5 00	1 66	1 92	1 39	5 71	1 81	2 04	1 36
ROI	1 10	1 77	2 20	3 55	1 00	1 63	4 03	6 50	1 89	3 07	5 66	9.17
ROR, %	5 00	46 00	34 00	82.00	1 00	58 00	73.00	162.00	24 00	68.00	73 00	162.00

LEGAL CONSIDERATIONS IN IMPLEMENTING AN EXPLORATION AND DEVELOPMENT PLAN

The geologist has decided where he wants to drill the next well. He has hit ten in a row, so management has issued a standing order: Give the geologist whatever he wants.

Prices are at an all-time high, so everyone in the chain of command, from the top to the bottom, is pushing to get wells drilled and connected as quickly as possible.

The land department says everything is ready to go, from a title standpoint.

Since you are the low man on the totem pole, the following order lands on your desk: Get this well drilled, connected, and producing, ASAP.

You have never worked in Arkansas before. Where do you start?

I. Step One: Get to Know the Staff at the Arkansas Oil and Gas Commission

When the Arkansas Oil and Gas Commission (the "AOGC" or "Commission") was created in 1939, it was given exclusive jurisdiction over the "production and conservation of oil and gas." A.C.A. § 15-71-110. As a practical matter, this means that you will never drill, complete, and produce a well in the State of Arkansas unless and until the Commission says you can. Since the staff at the Commission is primarily responsible for enforcing the Commission's Rules and Regulations, it follows that the first thing you need to do is a no-brainer – go to the offices of the Arkansas Oil and Gas Commission (El Dorado and Fort Smith) and get to know the staff.

The good news is that the staff at the Commission is very easy to work with. All of us have had experience dealing with government bureaucrats. It is probably safe to say that, as a general rule, government employees enjoy a reputation right up there with used car salesmen and lawyers. The staff at the Arkansas Oil and Gas Commission, on the other hand, is just the opposite. My experience with the staff at the Arkansas Oil and Gas Commission, without exception, has been excellent. They return phone calls promptly, they go out of their way to help you, they are patient in explaining the procedures, and they are open to putting substance over form, when it is appropriate. In short, the staff at the Arkansas Oil and Gas Commission is your best friend, and you should take advantage of it.

The Commission also maintains a good web site. All of the Commission rules and forms can be found on the site.

II. <u>Step Two: Determine Whether the Proposed Well is at a "Legal" Location.</u>

The Commission rules require that wells be drilled at certain locations (i.e., a "legal" location). If the proposed well is not located at a "legal" location (i.e., it is located at an "exceptional" location), it will be necessary to secure Commission approval before the well can be drilled at the exceptional location. You must therefore determine whether or not the proposed well is located at a "legal" location, and if it is not, go through the process of securing Commission approval to drill the well at an exceptional location.

A. <u>Determine whether the proposed well is located within an area for which field rules have been established by the Arkansas Oil and Gas Commission.</u>

Once oil or gas is discovered, the Commission adopts "field rules." Rule B-38; A.C.A. § 15-72-302. The theory is that the field rules will allow the orderly development of the pool/reservoir, in a manner which maximizes the recovery of the resource for the benefit of all. As a practical matter, there are two aspects of field rules which impact the drilling of the proposed well. First, the field rules establish the size of drilling units within the field. Second, the field rules establish setback requirements (i.e., how far the well must be located from unit boundary lines, in order to be at a "legal location"). Rule B-3.

If you conclude that the proposed well is located in an area for which field rules have been adopted, you should also confirm that the field rules are applicable to the target depths/formations. In most cases, the field rules govern all depths and all formations, and the boundaries of the field and the units within the field are determined by surface legal descriptions. There are instances, however, in which the field rules are specific to certain zones/formations, which may not include the zones the geologist is looking for. If the field rules do not apply to the target zone, the well will be treated as a "wildcat" (see Section II D. below).

B. <u>Producing Units: Increased Density and the "Rule of One"</u>

If the proposed well is located in a producing unit, another problem arises. Arkansas subscribes to an unwritten law described by Dorsey Ryan as the "rule of one." The rule of one, as it is applied in Arkansas, prohibits two wells, in the same unit, from producing oil or gas that could be produced from one well. To illustrate by example, envision a situation in which two wells have been drilled in the same unit, both at a legal location. One was drilled in the 1960s, and is producing at a rate which is barely commercially productive. The second well was drilled recently, for the purpose of testing deeper zones, but encountered the zone from which the first well is producing. The second well is capable of producing gas from such zone at a tremendously higher rate. The two wells are in communication; stated differently, gas (or oil) that flows to one well bore could also flow to the other well bore. In Arkansas, the second well will not be allowed to produce as long as the first well is still producing.

Whether or not the "rule of one" makes sense is a matter which has been debated on more than one occasion. Nevertheless, it is the law in Arkansas, even if it is not written down anywhere. You should therefore confirm that the geologist has not proposed a well which will, if successful, produce from a formation/reservoir that another well in the unit is already producing. If it is, you need to tell the geologist and your boss that even if you drill the best well you've ever drilled, the Arkansas Oil and Gas Commission will not let you produce it, unless and until the other well has been shut in or plugged and abandoned. As a practical matter, this means that whoever controls the first well will insist that you buy the well at a premium price, and/or insist on a significant portion of the new well, as a condition to any agreement that the second well be allowed to produce.

Although the "rule of one" still applies, two recent developments merit mention. First, in the 2003 legislative session, the statutes were modified so that it is now clear that the Commission has authority to permit true increased density (i.e., the hypothetical described above). See generally, A.C.A. § 15-72-302, 303, and 304. The Commission has not, however, taken advantage of this authority. In fact, the Commission recently denied an application (unanimously) in this exact situation. The fact remains, however, that the Commission clearly has statutory authority to depart from the "rule of one" (i.e., to allow increased density wells).

Second, the Commission has, in recent years, authorized multiple wells within drilling units in some fields to produce from the same zone. For pooling purposes, the existing drilling units have been retained, but for spacing purposes multiple wells (as close as 560 feet between well bores), producing from the same zone/formation, have been permitted. The theory is that the wells are either separated by faults or the sand is so tight that the wells are not in communication, thus honoring and preserving the sanctity of the "rule of one." Nevertheless, it is an improvement, as the Commission had previously only allowed one well per zone per drilling unit, with rare exception.

C. <u>What happens if the proposed well is located in an area for which field rules have been adopted, but the proposed well is not at a "legal" location?</u>

For purposes of this discussion, assume that the applicable field rules establish drilling units consisting of uniform governmental sections, and that a legal location is at least 1,320 feet from the section lines. If the proposed well is going to be located closer than 1,320 feet to the section lines, you will need to ask the Arkansas Oil and Gas Commission for approval of an exceptional well location (Rule B-3).

The process of seeking Commission approval is a simple one. A.C.A. § 15-71-111(f) provides that "any interested person shall have the right to have the Commission call a hearing for the purpose of taking action in respect to any matter within the jurisdiction of the Commission by making a request therefor in writing. Upon the receipt of any request, the Commission shall promptly call a hearing thereon, and, after the hearing, and with all convenient speed and in any event within thirty days after the conclusion of the hearing, shall take such action with regard to the subject matter thereof as it may deem appropriate." Asking the Commission to approve an exceptional well location is therefore as simple as writing a letter to the Commission, explaining what it is you want, and sending the Commission a filing fee of $500.00.

The Commission has also adopted a streamlined process for administrative approval of some exceptional location requests. As a general rule, if the well is located at a distance which exceeds one-half of the established setback, the Commission staff may approve the application administratively (Rule B-40). For example, in this hypothetical, if the proposed well is to be located 660 feet or more from the section line, it would fall within the administrative location exception procedures. There is a form which needs to accompany the letter, if the well meets the criteria for administrative approval.

Regardless of whether the proposed well location qualifies for administrative approval or must be considered by the full Commission, notice of the application will be given to all interested parties (i.e., the units that are encroached upon), and the application will be placed on the docket for the next Commission hearing.

As a practical matter, even in those cases where the proposed location will not qualify for administrative approval, the Commission rarely denies the request. There are limits, however. For example, in the hypothetical under discussion, if the proposed well was located on the section line, or very near it, the Commission would not approve it.

Assuming the application for approval of an exceptional location is granted, the approval will be conditioned on a reduction in the allowable. Stated differently, when the Commission sets the allowable (the maximum rate at which the well can produce), it will reduce the allowable in proportion to the encroachment on the unit line, as compared to what would be allowed if the well were drilled at a legal location. Rule D-16. The theory is that this ensures that the offsetting units are treated fairly. In the real world, however, the way the Commission enforces the rule renders it essentially irrelevant. The Commission only compares the actual production with the allowable production on an annual basis. Rule D-16. Most wells decline rapidly. Thus, a well can produce at its maximum rate, and be well over the allowable initially, but by the end of the year be well within the allowable, on an average basis. Statistically, only a few percent of the wells, if they are allowed to produce at the maximum they are capable of producing, will exceed the reduced allowable specified in the exceptional location process, on an annual basis. The end result is that, as a practical matter, in the vast majority of cases, there is no penalty or drawback for drilling a well at an exceptional location, other than jumping through the hoops from a paperwork standpoint.

One other aspect of the exceptional location process merits mention. If an exceptional location application is approved, operators in the offsetting units will be given a co-equal right to drill wells at an exceptional location.

A word on directional wells and horizontal wells is also appropriate. For directional wells, approval of an exceptional location must be secured for both the surface location and the anticipated bottom hole location. In addition, a bottom hole survey, showing the location of the midpoint of the perforations, must be provided to the Commission as part of the process of setting the allowable, and the allowable will be based on the actual location of the perforations as the well was actually completed. Of course, for the reasons stated, the allowable really doesn't matter, but the process will be followed nevertheless. As to horizontal well bores, the entire length of the horizontal well bore, as well as the surface location, must be at a legal location, or approval of an exceptional location must be secured.

D. **What if the proposed well is located in an area for which field rules have not been established?**

If the proposed well is not located in an area for which field rules have been established, it is treated as a wildcat well. Under the Commission rules, a "wildcat" well must be located 280 feet from ". . . any property, unit or division line within a governmental section" (Rule B-3). This rule doesn't make a lot of sense, and there is some movement toward getting the rule changed. Also, there is some question as to what the rule really means. Some argue that the mention of "property" lines refers to surface property boundaries. At the other extreme, it is argued that "property" lines refers to leasehold property lines. Thus, if an entire section has been leased, and all of the leases have pooling clauses, and the leases have been pooled, then in theory there are no "property" lines other than the section lines, for purposes of applying this rule.

To be on the safe side, if the well is not located at least 280 feet from all ". . . property, unit, or division lines . . ." you should go through the process of seeking approval of an exceptional location.

E. **What if the proposed location is on the line between two established units?**

The Commission has, on occasion, approved an application to drill a well on the boundary line between two existing units. To my knowledge, however, this has only occurred in situations where the working interest owners in both units have reached an agreement and have filed a joint application. The application has asked for the creation of a special unit, applicable only to the proposed well, which consists of both units, with one-half of the production allocated to the working interest owners in one unit and one-half to the working interest owners in the other unit. Also, the "rule of one" continues to apply. Thus, if the proposed well targets a zone that is already producing in one or both units, the Commission will not approve it unless there is proof of separation from both well bores. In short, it's possible, but difficult.

III. Step Three: Decide who's in charge

Drilling a well is kind of like riding on a bus. A whole lot of people can ride, but only one can drive. The next step is therefore the selection of the operator.

A. Identify the Candidates

The process of selecting an operator necessarily begins by identifying the candidates. Anyone who has the right to drill is legally qualified to act as operator. Technically, this means that Mr. and Mrs. Smith, retired grandparents with no oil and gas experience whatsoever, who happen to own surface and minerals in a 40-acre tract and who have not executed a lease, would be legally qualified to act as operator. At first glance, this seems absurd -- surely there must be rules, statutes, and regulations that require some sort of qualification or expertise in the oil and gas business. As far as I can tell, however, this is not the case. As long as you own the right to drill, you are legally qualified to act as operator. You have to file a Form 1 (Organization Report) (Rule B-13) with the Arkansas Oil and Gas Commission (name, rank, and serial number information), and you have to file a bond (Rule B-2). Nowhere, however, is there any requirement that the operator prove that he has the requisite experience and qualifications.

I must confess I was surprised at this. It seems to me that just like we require plumbers, electricians, engineers, and so forth to secure licenses, by first establishing that they are qualified to perform the work, I would have thought that there would be rules and regulations imposing similar requirements before a person is considered qualified (i.e., "licensed") to drill and operate a well. Apparently, however, this is simply not the case in Arkansas. If you own the right to drill, file a couple of forms, post a bond, and pay a fee, you can start digging a hole in your back yard with a shovel, if you want to.

Setting aside the legal prerequisites (who has the right to drill), there is also the question of defining the boundaries of the proposed unit. Stated differently, you have to define the area (the unit) in which the well will be drilled, in order to identify the persons and parties who possess the right to drill a well in the unit. The answer to this question depends, in the first instance, on whether or not the proposed location falls within an area for which the Arkansas Oil and Gas Commission has previously established field rules. If the location is within an established field, then the field rules will specify the unit's size and configuration. A.C.A. § 15-72-302 (b); Rule B-38.

If the proposed location is not included within an established field, the Commission has authority to integrate an exploratory unit (including the establishment of the proposed unit boundaries). A.C.A. § 15-72-302. In order for the Commission to have authority to establish an exploratory unit, the applicant(s) must own at least 50% of the right to drill within the proposed unit. A.C.A. § 15-72-302 (e)(2).

Finally, there is the possibility of a situation in which the proposed well is not within an established field, and the applicant does not own 50% of the right to drill. In this scenario, the well is a true wildcat. All that is required to drill the well is the right to drill on the drillsite tract. A.C.A. § 15-72-306. If the well is successful, the party drilling the well must apply to the Arkansas Oil and Gas Commission for the establishment of field rules, before the well can be produced (Rule B-38). The process of establishing the field rules will also determine the unit size and boundaries. Once field rules (and unit sizes) have been decided, the Commission is then empowered to select an operator, if the parties in the newly formed unit cannot reach an agreement. A.C.A. § 15-72-304 (c). As a practical matter, this situation rarely occurs, for the simple reason that the party who chooses to drill a well under such conditions takes 100% of the risk, but faces the possibility that the other owners in the unit, once one is established, will have a "free look," and in addition, may potentially be designated as operator.

Once the unit boundaries have been determined, identifying the parties who are qualified to act as operator is straightforward – anyone who owns minerals in the unit (if unleased) and anyone who owns leases in the unit (if the mineral owner is leased) are potentially qualified to act as operator.

B. Selecting the Operator

After the list of candidates has been finalized, there are two ways to select an operator. First, the parties can decide for themselves. Second, the Oil and Gas Commission has the authority to designate an operator. A.C.A. § 15-72-304. In the vast majority of cases, the Oil and Gas Commission, if asked to select an operator, will give operations to the party owning the largest percentage of the unit, although there are instances in which the Commission, for a variety of reasons, has declined to designate the majority owner as operator. One *caveat* is in order, however. If the parties are in agreement, they can designate anyone, including a person who does not own the right to drill, as the operator. If the Commission is designating the operator, however, the Commission may only designate a person or party who actually possesses the right to operate (i.e., an owner).

C. Producing Units Governed by Existing Joint Operating Agreements

The foregoing discussion involves situations in which the well will not be drilled in a producing unit. If the proposed well is going to be drilled in a producing unit, there will always be a joint operating agreement which governs the relationship between the parties, and the joint operating agreement will specify a method for selecting the operator of the proposed well. Again, however, there is a *caveat*. If the unit was originally established by an integration in front of the Arkansas Oil and Gas Commission, the integration order always specifies a joint operating agreement form. A.C.A. § 15-72-304. Historically, however, in such situations the joint operating agreement covered only the well which was being integrated. It did not cover unit rights outside the well bore of the integrated well. Thus, for any parties who did not voluntarily sign the joint operating agreement, but who were instead deemed parties to the joint operating agreement by virtue of the integration order, selection of an operator (absent agreement) would be up to the Oil and Gas Commission as part of an integration process. This problem has been remedied in recent years by the adoption of a general rule of procedure that integration orders, as to working interest owners and joint operating agreements, are applied on a unit-wide basis, both for the borehole of the integrated well and for all future wells, so long as the unit is a producing unit. Nevertheless, it is possible that the unit will be subject to two operating agreements – one for integrated parties and one for everyone else – or by an operating agreement for some parties and nothing for others.

D. Joint Operating Agreements

The relationship of the parties who participate in the drilling of a well will always be governed, one way or the other, by a joint operating agreement (or agreements). A detailed analysis of the terms of joint operating agreements and the art of negotiating joint operating agreements is outside the scope of this paper. It is sufficient to note here that the joint operating agreement will govern the relationship between the parties who participate in the drilling of the well.

IV. Step Four: Confirm that you have surface rights for the drill site.

Just because the Land Department says you are good to go from a title standpoint does not necessarily mean that you have surface rights for the drill site. Your next step should therefore be confirming that you do in fact have surface rights.

A. Land Owners

Mineral owners who also own surface rights have become increasingly sophisticated in negotiating leases with "no surface use" clauses. Once the geologist has specified the well location, you should therefore examine the lease (or leases) to ensure that you have surface rights at the proposed location. I note in this regard that it is an open question in the State of Arkansas whether or not the Arkansas Oil and Gas Commission has power and authority, as part of the integration process, to compel a surface owner to permit operations on his land, against his will. I am of the opinion that the Commission does not have this authority, and that unless you have secured surface rights from a mineral owner, the only way you can use the surface for drilling operations is if you are successful in securing an agreement with the surface owner.

B. Notice to Surface Owner

Before drilling operations can be commenced, there is a statutory requirement in Arkansas that notice be given to the surface owner, by certified mail. A.C.A. § 15-72-203. The statute does not specify how much notice must be given. In addition, the statute does not give the surface owner any rights. In other words, the statute essentially accomplishes nothing, other than to let the surface owner know what is coming. If the operator has secured from the mineral owner the right to use the surface to explore for oil and gas, there isn't anything the surface owner can do to stop the process, so the statutory requirement of notice amounts to nothing more than a courtesy. Nevertheless, it must be complied with.

C. Governmental Agency Approvals

You should also confirm whether or not the proposed location is within an area which has been condemned by the Corps of Engineers for flowage easements. Many locations in the Arkansas River Valley are subject to Corps of Engineers flowage easements. If the proposed location is within the Corps of Engineers flowage easement, approval must be secured from the Corps of Engineers, which is always an interesting process.

If by chance the geologist wants you to drill at a location which the Corps of Engineers holds fee title, start thinking Act of Congress. It is all but impossible to secure Corps of Engineers approval for a well located on land for which the Corps of Engineers holds fee title.

In some cases, you may also have to secure approval from the Arkansas Historical Preservation Society.

V. Step Five: Permitting the Well – Notice of Intent to Drill

The process of actually drilling the well begins with the filing of a notice of intent to drill with the Arkansas Oil and Gas Commission. AOGC Form 2; Rule B-1; A.C.A. § 15-72-205. If the operator has not previously done so, the operator is required to file a Form 1 (Organization Report) with the Commission. This form simply provides name, rank, and serial number information. It is also necessary to post a bond. Rule B-2. The amount of the bond is $3,000.00 per well, or in the event an operator operates multiple wells in the state, $25,000.00 for 1-25 wells, $50,000.00 for 26-100 wells, and $100,000.00 for more than 100 wells. The notice of intent to drill must be accompanied by a filing fee of $300.00. Finally, a certified lease plat, showing the exact location of the proposed well, must be submitted with the notice.

Upon receipt of the $300.00 fee, Form 1, the notice of intent to drill, proof of financial responsibility, and the plat, the Commission staff examines the notice for the purpose of confirming that the proposed well is at a legal location. Assuming it is, the Commission staff will issue a permit to drill. If the proposed well is not in a legal location, a permit to drill will not be issued until the Commission, after notice and hearing, has authorized the issuance of a permit to drill at an exceptional location.

VI. Step Six: Master Service Contracts

In most cases, the actual drilling of the well, construction of pipelines, etc., will be done by contractors selected by the operator. Just as the joint operating agreement has evolved into an essentially standard document, so too have master service contracts. As with the joint operating agreement, a detailed discussion of the terms of the master service contracts, and the various options that are available, is beyond the scope of this discussion. It is sufficient to note that such relationships should always be governed by a written contract, and that care should be taken in reviewing the documents, and selecting optional provisions, before the contracts are signed.

VII. Step Seven: Drilling the Well

The Arkansas Oil and Gas Commission has adopted a number of rules which govern the nuts and bolts of drilling, completion, and plugging of wells. Also, there are a number of statutes that apply. A detailed discussion of these rules and statutes is outside the scope of this paper, as they primarily concern engineering/technical issues. I note, however, that the rules and statutes do make one thing clear – if you screw it up (i.e., a blowout, the reserve pit leaks, etc.), you have to clean it up.

VIII. Step Eight: Connecting and Producing the Well

Once a well is completed, the next problem is getting the gas or oil to the market. Although in some cases oil producers have the option of transporting production in trucks, all gas producers and many oil producers will have to construct a pipeline. The second issue to be addressed, once a means of getting the gas or oil to market has been determined, is the measurement of the production and the accounting for sales and payment of proceeds (primarily royalties).

A. Pipelines

There are three ways to secure authority to build a pipeline. First, the terms of the lease(s) may include a clause authorizing the use of the surface for the construction of pipelines. Second, easements can be negotiated with surface owners. Third, in some cases a pipeline company having eminent domain powers may be able to exercise its eminent domain authority for the purpose of condemning a pipeline right-of-way to the well.

Given the three options just described, building a pipeline pursuant to lease rights is obviously the easiest. Once you have decided on a pipeline route, you should therefore examine the leases to determine whether or not the leases give you the right to build pipelines on the leased lands. There are a couple of shortcomings to this option, however. First, this option only gets you to the unit boundary. Second, there is a substantial question whether or not an Arkansas Oil and Gas Commission order of integration would include authority to use the surface for any purpose, including pipelines.

If the lease(s) does not include surface rights, or if the pipeline has to be built across lands lying outside the unit boundary, the next option is a private agreement with the surface owner. The drawback to this option is the fact that you have no ability to force the surface owner to do anything. In most cases, however, it comes down to a question of money – if your checkbook is big enough, you can get a pipeline easement.

The third alternative is the last resort. Condemnation statutes always require a good faith effort to negotiate a deal with the landowner, so as a practical matter you will have to exhaust the second alternative anyway. Also, the condemning authority will almost certainly insist on building the pipeline with its own personnel/contractors, at its own price, and will retain ownership (and therefore control) after the pipeline is built, which is usually not the preferred solution. Nevertheless, if it's a choice between the condemnation option and no pipeline at all, condemnation is a legitimate option.

One final point concerning pipelines. Three regulatory agencies potentially have jurisdiction over pipelines – the Arkansas Oil and Gas Commission, the Arkansas Public Service Commission, and the Arkansas Department of Environmental Quality. For purposes of this paper, I simply note that all three agencies may potentially play a role from a regulatory standpoint when it comes to pipelines. Also, a discussion of the safety specifications which must be complied with (depth. material strength/thickness size. testing and reporting requirements. warning signs. etc.) is not addressed in this paper.

B. Commission Approval/Well Allowables

Once the well is ready to produce, the Commission must set an allowable before actual production can commence. The operator is required to file a Well Completion and Recompletion Report (Form 3), a Producer's Certificate of Compliance (Form 4). electrical logs and surveys, and related service company reports. The Commission will then test the well (Rules D-2, 3, 4. 5. 6). and set an allowable (Rule D-16 (4)).

C. Measuring/Accounting/Payment

Once a means of transporting the gas or oil to market has been established. and an allowable has been established, gas or oil will be produced and sold. The process of producing and selling the gas or oil gives rise to several obligations on the part of the producer.

The producer is required to measure the production. and to account for the production to the Arkansas Oil and Gas Commission. A.C.A. § 15-74-201. *et seq.*, and 301. *et seq.* See also Rules C-2, D-7. 8.

For gas wells, the operator is responsible for collecting and distributing the 1/8 royalty pool, and any party who sells gas is responsible for remitting the 1/8 royalty to the operator for distribution to the royalty pool. A.C.A. § 15-72-305.

Proceeds resulting from the sale of oil or gas must be distributed within six months after the date of first sale, and thereafter no later than sixty days after the end of the calendar month within which the production was sold. A.C.A. § 15-74-601. The penalty for not making timely payments is interest at the rate of 12% per annum. In addition, for willful violation, the Commission can impose additional interest at the rate of 14% per annum (i.e., the 12% for late payment plus 14% for willful violation, or a 26% interest rate), and attorneys' fees.

If a participating working interest owner owns no more than 5% of the well and is not regularly engaged in the oil and gas industry, the operator (or its designee) is obligated to market such party's gas along with the operator's gas. A.C.A. § 15-74-605.

A.C.A. § 15-74-701, *et seq.*, specifies a number of requirements that apply to payment of royalties. In essence, the statutes impose on the working interest owners and downstream pipelines/purchasers what is for all practical purposes a fiduciary obligation to give the royalty owners exactly the same deal that they are getting. Failure to do so potentially exposes such parties to treble damages, lease forfeiture, and fines imposed by the Arkansas Oil and Gas Commission of up to $100,000.00. The statutes also give the Arkansas Oil and Gas Commission authority to investigate failure to pay and account for royalties, and to not only impose fines but to also suspend 8/8 of the production until such time as any deficiencies in royalty payments have been corrected.

A.C.A. § 15-74-101 specifies the information which must be contained in division orders.