RESERVOIR MANAGEMENT SERVICES, INC.
INTEGRATED CONSULTING SERVICES FOR THE PETROLEUM INDUSTRY

Jonah Infill Drilling Project
Evaluation of Directional Drilling

prepared for

EnCana Oil and Gas (USA) Inc.

by
Reservoir Management Services, Inc.

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Attachment 4

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INTRODUCTION

The Jonah Field in the Green River Basin of Sublette County, Wyoming is a major gas resource with approximately 10.5 TCF of original gas-in-place (OGIP) corresponding to a surface area of approximately 21,000 acres. With current well limitations and current surface spacing of 40 acres per well, the projected recovery is expected to be 30% of the OGIP which would leave approximately 4.7 TCF of economically recoverable gas in the reservoir. The projected 30% recovery is low compared to typical recoveries in conventional gas fields of over 80% of OGIP. The objective of infill drilling is to optimize the development of the hydrocarbon resource by increasing the recovery of gas to about 80% of the OGIP.

In low permeability reservoirs in Wyoming and other western states there is a trend to decrease the well spacing in order to increase recovery of the gas resource. Jonah is a low permeability reservoir and the decision to drill more wells at Jonah is based on field performance and detailed technical studies completed by operators. The technical studies include 3D seismic acquisition and interpretation, detailed description of the subsurface rocks that makeup the gas reservoir, flow modeling of the field, acquisition of petrophysical and pressure data, and microseismic/tiltmeter surveys during completion operations.

Jonah is an important gas resource in Wyoming. The field currently produces about 680 MMSCF of gas per day or 248 BCF of gas per year and, as shown on Table 1, is the largest non-coalbed-methane gas field in Wyoming, yielding about 13.5% of the total gas produced in the state.

Top 25 Largest Gas Fields In Wyoming for 2003

FIELD	Gas 2003 MCF	% OF STATE GAS TOTAL	COUNTY
PRB COAL BED	345,998,970	18.86	CAMPBELL / SHERIDAN / JOHNSON
JONAH	247,923,542	13.52	SUBLETTE
FOGARTY CREEK	161,012,934	8.78	SUBLETTE
MADDEN	111,261,366	6.07	FREMONT
PINEDALE (Includes MESA UNIT FIELD)	102,522,360	5.59	SUBLETTE
PAINTER RESERVOIR EAST	72,757,458	3.97	UINTA
WHITNEY CANYON-CARTER CREEK	67,004,736	3.65	LINCOLN / UINTA
LAKE RIDGE	65,466,134	3.57	SUBLETTE
LOST SOLDIER	38,955,320	2.12	SWEETWATER/FREMONT
BRUFF	31,291,864	1.71	LINCOLN / SWEETWATER / UINTA
ECHO SPRINGS	29,732,358	1.62	CARBON / SWEETWATER
WAMSUTTER	27,376,592	1.49	SWEETWATER
STANDARD DRAW	24,071,278	1.31	CARBON / SWEETWATER
WALTMAN	23,845,277	1.30	NATRONA
WILD ROSE	22,398,570	1.22	CARBON / SWEETWATER
TIP TOP	17,503,510	0.95	SUBLETTE
FONTENELLE	13,379,094	0.73	LINCOLN / SWEETWATER
HOGSBACK	13,046,843	0.71	LINCOLN / SUBLETTE
PAVILLION	12,109,148	0.66	FREMONT
WERTZ	12,001,184	0.65	CARBON/SWEETWATER
LABARGE	11,544,751	0.63	LINCOLN / SUBLETTE
PAINTER RESERVOIR	11,220,192	0.61	UINTA
BEAVER CREEK	10,798,737	0.59	FREMONT
BRADY	10,694,488	0.58	SWEETWATER
CHURCH BUTTES	10,521,394	0.57	SWEETWATER / UINTA

Table 1: The 25 Largest Gas Producing Fields in Wyoming in 2003[1]

[1]The Wyoming Oil and Gas Commission," 2003 Wyoming Oil and Gas Statistics".

In terms of energy consumption in Wyoming, Jonah Field gas production is significant. Total annual residential consumption of natural gas for the State of Wyoming in 2002 was 13 BCF (81 MCF per year per household)[2]. Production from the Jonah Field could theoretically supply 3,000,000 households or 19 times the annual residential natural gas requirements for the state of Wyoming. Additionally, Jonah produces about 2,200,000 barrels of condensate (oil) each year, which is equivalent to approximately 9% of the field gas production (1 barrel of oil equals 10,000 standard cubic feet of gas).

Jonah Field was compared to four other sandstone reservoirs in SW Wyoming. Outlines of the five fields are shown on :

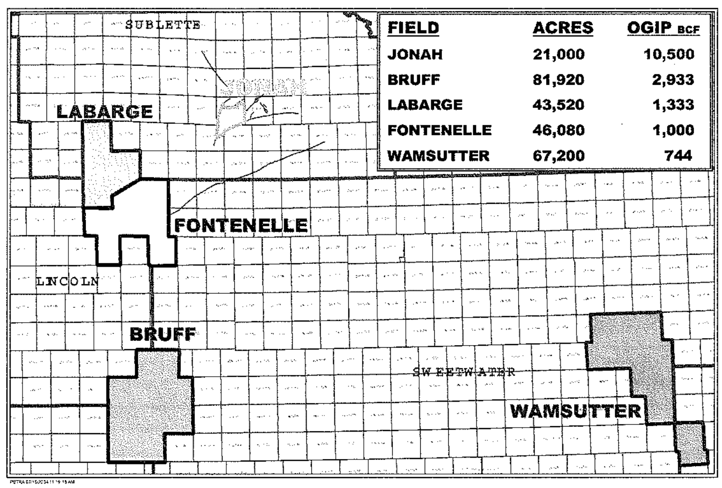

Figure 1: Outline of Jonah and comparison gas fields.

The portion of Jonah Field being proposed for infill drilling, which contains about 10.5 TCF of OGIP under 21,000 acres of surface area, is compared to four other fields from the top 25 gas producing fields in Wyoming. The areas shown for these fields are defined by the Wyoming Oil and Gas Commission (WOGC). Within these areas, the field production, number of wells, and acres were determined from WOGC data. The acres shown in the table on Figure 1 were calculated by multiplying the number of drilled sections within the outline by 640 acres.

A comparison of Jonah with other fields in Sublette and Lincoln Counties is shown in Table 2

Jonah Field Comparisons - Sublette, Lincoln, and Sweetwater Counties, Wyoming.

	ANNUAL VOLUMES			TOTAL	EST. ULTIMATE RECOVERY			OGIP	SURFACE AREA
FIELD	ANNUAL MCF	MCF per Well	ANNUAL BBLS	WELLS	GAS-BCF		Oil-MMBO	BCF	ACRES
JONAH	247,923,542	498,840	2,272,761	497	3000	1	30.0	10,500	21,000
JONAH				3,597	7947	2	79.5	10,500	21,000
BRUFF	31,291,864	70,957	194,943	441	2200	3	15.0	2,933	81,920
FONTENELLE	13,379,094	44,746	20,245	299	750	3	1.6	1,000	46,080
LABARGE	11,544,751	13,566	322,230	851	1000	3	26.0	1,333	43,520
WAMSUTTER	27,376,592	110,389	306,062	325	558	3	6.0	744	67,200

1. Estimated from EnCana's technical studies(no additional wells)
2. Estimated from EnCana's technical studies(proposed action)
3. Estimated from extrapolation of field gas rate vs. cum. gas production(Wyoming Oil and Gas Commission data)

Table 2: Comparison of Jonah and other gas fields in Sublette, Lincoln, and Sweetwater Counties, Wyoming.

[2] American Gas Association; "The Natural Gas Industry in Wyoming",2002.

Table 2 summarizes the comparison of Jonah Field to the other fields. Estimated ultimate gas recoveries were found by extrapolating the plot of field gas production versus cumulative gas production to a limit of 100,000 MCF/Month. Values for Jonah Field were taken from EnCana's technical studies. OGIP for the other four fields is not available and was estimated by assuming an arbitrary recovery factor of 75% of OGIP.

Table 2 shows that Jonah Field is a significant, highly-concentrated, energy source. A comparison of the data on a per-acre and per-well basis is shown in Table 3:

FIELD	OGIP-BCF		EUR-GAS(BCF)		EUR-OIL(STB)	
	Per well	Per Acre	Per Well	Per Acre	Per Well	Per Acre
JONAH(no Action)	21.1	0.500	6.0	0.143	60362	1429
JONAH(proposed action)	2.9	0.500	2.2	0.378	22102	3786
BRUFF	6.7	0.036	5.0	0.027	34014	183
FONTENELLE	3.3	0.022	2.5	0.016	5351	35
LABARGE	1.6	0.031	1.2	0.023	30552	597
WAMSUTTER	2.3	0.011	1.7	0.008	18462	89

Table 3: Comparison of OGIP and EUR: Jonah and some other Wyoming Gas Fields

For the proposed action, Jonah Field contains about 25 times more OGIP and gas reserves per-acre than the other fields. The OGIP and gas reserves per-well are about equal to the other fields. The Jonah oil reserves per-acre (proposed action) are 45 times higher than the other fields. Per-well oil reserves, on average, are about the same as the other fields. OGIP per acre for the fields is shown on Figure 2:

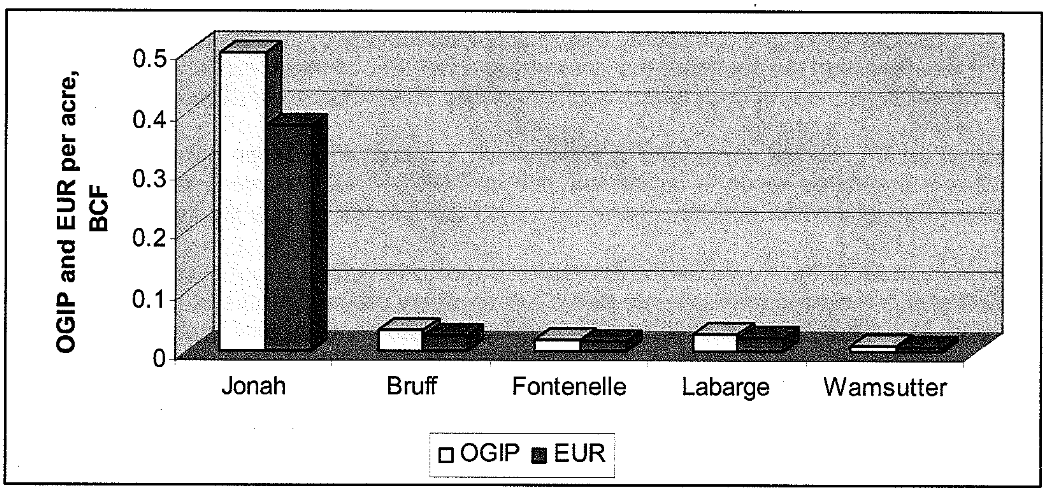

Figure 2: OGIP and EUR per acre for Jonah and comparison fields

Jonah is currently developed on 40 acre surface spacing and with the significant potential of increased gas recovery anticipated from infill drilling, optimized subsurface well spacing in the range of 5 to 10 acres is being considered. In this report, the various well architecture options available for infill drilling at Jonah are outlined and the "waste" associated with these options is quantified. State oil and gas commissions generally have rules addressing "prevention of waste", which in most cases they have defined as:

- Actions that result in irrecoverable loss of natural gas
- Drilling of unnecessary wells

The potential resource waste at Jonah results from incremental costs and lost gas reserves associated with directional drilling relative to vertically drilled wells. In this report, the potential "waste" is quantified based on a review of actual directional well experience at Jonah where 54 directional wells have been drilled and completed as of May 2004.

BACKGROUND

Geological Setting. Jonah Field produces from a thick sequence of rocks that is defined by the intersection of two fault zones which form a wedge-shaped structural block. The updip termination at the southwest end of the field is the apex of the block. The downdip limit is defined as occurring along the structural low between Jonah and the Pinedale Anticline to the northeast.

Within the wedge-shaped Jonah block, overpressure conditions exist in the Lance Formation, whereas the same Lance Formation rocks outside the Jonah compartment appear to contain "normal" pressure (pressure equivalent to a column of water at the same depth). The Wyoming Oil & Gas Conservation Commission has defined the Lance Pool as the stratigraphic interval between the Ericson Sandstone of the Mesaverde Group and the base of Tertiary Fort Union (aka "Bois Marker"). This interval comprises the full range of productive rocks known at Jonah Field. Thickness of this interval ranges from about 3200 ft in the updip (southwestern) corner to about 5100 ft at the downdip extreme. Over the field the vertical depth to the top of the Lance from the surface varies from 7200 ft to 9000 ft.

The gas reservoir at Jonah is described as a combination structural-stratigraphic trap. The bounding fault zones form the lateral trap and the top-seal is comprised of the mudstones that are interbedded with the reservoir sandstones of the Lance. The Lance Formation sandstones are lenticular and discontinuous having been stream-deposited (fluvial), with interbedded siltstones and mudstones deposited outside the stream channels. The 3-dimensional geometry of the sandstones deposited in this fluvial setting and the overprint of faults results in extreme reservoir complexity. It is this geometric complexity that makes full recovery of the gas-in-place impossible on 40-acre well spacing. Additionally, the average permeability of these rocks is very low (0.01 millidarcies) making it more difficult to move gas over long distances within the sandstones.

The Lance at Jonah Field is highly over-pressured. In, general, for a given pore volume, higher initial reservoir pressures result in larger volumes of OGIP. The over-pressure also results in preservation of slightly better porosity relative to Lance sandstones outside the field boundary.

The lenticular nature of the fluvial Lance Formation sandstones created highly complex reservoir architecture and is a significant challenge to the gas recovery process. There is poor connectivity as indicated by difficulty in correlation of individual sandstone bodies between wellbores positioned as close as 5 acre spacing. The poorly connected sandstones mean that relatively close well spacing is required to produce a high percentage of the gas resource.

The Tertiary Fort Union Formation overlies the Lance Pool Interval. The Fort Union is comprised mostly of sandstone, much of which is porous, permeable and normally pressured. The large reservoir pressure difference between the over-pressured Lance and the normally pressured Fort Union is the main source of drilling problems at Jonah and will be discussed In detail later in the report.

Field history. Jonah Field was discovered by Davis Oil Company in 1975 with the drilling of the Wardell Federal #1 well. The discovery well was not economic and in 1992, McMurry Oil Company acquired the field after a total of three wells had been drilled. After testing the first three wells with encouraging results, McMurry Oil drilled the Jonah Federal #1-5 well, which initially produced 3.7 million cubic feet (MMCF) of gas and 40 barrels of oil per day. Initial assessments led to the request by McMurry Oil for a maximum of 497 wells to develop the field on 80 acre spacing over an area of 60,000 acres.

Alberta Energy Company, now EnCana after the merger with PanCanadian, acquired McMurry's interest in Jonah Field in 2000. In June of 2000, the BLM approved 40 acre spacing (497 well pads) over a smaller area corresponding to the core of the field defined by the over-pressured

Lance. The remaining area is in the normally pressured Lance and is excluded from the current environmental impact statement.

As of early 2004, Jonah Field has produced 1,020 BCF of gas (10% of the resource) and 10.2 MM barrels of condensate (oil). Current field production is about 680 MMSCF per day making it the largest non-coalbed-methane gas field in Wyoming. Projected recoveries without infill drilling will be about 30% of the resource. With infill drilling it is anticipated that close to 75% of the resource can be recovered.

Evaluation of infill drilling. More recently, detailed technical studies based on field performance and 3D seismic indicated that significant reserves would not be drained on 40 acre spacing. In 2002 EnCana initiated a pilot infill well program with some wells drilled as close together as 475 ft. The main objectives of this pilot were to gather technical information required to determine the spacing necessary to develop Jonah Field and to evaluate the feasibility of directional drilling.

A good understanding of the drainage areas and their shapes will prevent the drilling of unnecessary wells and will help locate wells to insure that the maximum possible volume of gas is recovered. Microseismic and tiltmeter surveys are being conducted in conjunction with well completion operations to better understand the size and shape of drainage areas associated with individual wells. The operators also constantly evaluate new technologies that might be used to maximize gas recovery. Examples of new technologies being evaluated are:

- New logging technologies such as Cased Hole Dynamic Testing
- Improved fluids utilized for hydraulic fracturing
- VSP seismic technology
- Geocellular interpretation and reservoir modeling

Subsurface Spacing – Waste Considerations. Analysis by EnCana based on pilot infill results, detailed reservoir description and reservoir modeling work, and volumetric analysis, gives the following estimated gas recovery volumes based on several different field development techniques. The results are shown in Table 4:

Field Development Alternative	Additional wells and pads	EUR (Bcf)	Waste Relative to Proposed Action (Bcf)
No Action	0	3,366	(4581)
Proposed Action	3,100 from 16,200 acres of disturbance	7,947	0
Max Development	Unrestricted development	8,191	244
Alternative A	3,100 from 497	6,124	(1824)
Alternative B	1,250 from 1,250	6,657	(1290)
	2,200 from 2,200	7,554	(393)
Alternative C	3,100 from 266 New (16 dis/Sec)	6,302	(1645)
	3,100 from 1,028 New (32 dis/Sec)	7,186	(761)
	3,100 from 2,553 New (64 dis/Sec)	7,876	(71)

Table 4: Anticipated Gas Recovery Volumes for various field development techniques, Jonah Infill Drilling Project, Sublette County, Wyoming, 2004.

Based upon EnCana's current technical understanding of the Jonah Field, original-gas-in-place (OGIP) is currently estimated at 10.5 trillion cubic feet of gas (TCF). Typical recovery factors for deep gas fields range between 75-85% of OGIP. With no further development, it is currently estimated that gas recovery will be approximately 30% of the 10.5 TCF of OGIP leaving 4,581 BCF of potential gas reserves in the ground unrecovered. This constitutes significant waste.

With no new surface locations and limiting the development of the northern third of the field (3100 wells/existing 497 well pads), it is currently estimated that approximately 1,824 BCF of gas would not be recovered, also constituting significant waste.

If the Jonah Field were developed with sixteen surface disturbances per section (40-acre spacing), this would limit development of the lower EUR/well population of the 5, 10 and 20-acre infill program, causing many wells to fall below the economic threshold due to increased directional drilling costs. This waste is significant and is estimated to be approximately 1,645 BCF of gas reserves.

To put this loss in perspective, 2,000 BCF, if produced over 25 years, represents 6 times Wyoming's current annual residential natural gas usage.

WELL ARCHITECTURE OPTIONS

Directional drilling has been proposed as a universally applicable technology for use in reducing surface disturbance that can easily be applied to Jonah Field[3]. This is a misconception resulting from superficial analysis of directional drilling technology applications in development of oil and gas fields.

The evaluation of well architecture options for thick, low permeability gas reservoirs is not a simple matter of stating that drilling multiple wells from a single pad will reduce surface disturbance. Many factors must be considered in order to select the appropriate well type and to evaluate the tradeoffs between vertical and deviated wells. The tradeoffs involve increased cost and potential lost reserves associated with increased risks in the deviated well drilling, completion and production processes. In addition, increased drilling times and higher engine load requirements for deviated wells increase cumulative surface activity, emissions, and environmental impact.

Directional drilling is a well-established technology in the oil and gas industry. However, the technology is not applicable to all situations. The proper application of directional or deviated well drilling must be carefully evaluated for each reservoir and a fit-for-purpose well architecture must be designed for each reservoir or field. For example, at Jonah, the Lance is over-pressured and in directional wells, the bends and inclined section of the borehole is contained within the normally pressured Fort Union above the Lance. Differential sticking caused by moving the drill pipe and casing through the bends of the directional well severely complicates directional drilling at Jonah. The position of the s-shaped well relative to the Fort Union and the Lance is shown on Figure 3:

[3] Amos, J.F.:"WITNESS STATEMENT:Environmental Aspects of Modern Onshore Oil and Gas Development", Testimony to the Committee on Resources of the United States House of Representatives, Subcommittee on Energy and Mineral Resources, September 17, 2003.

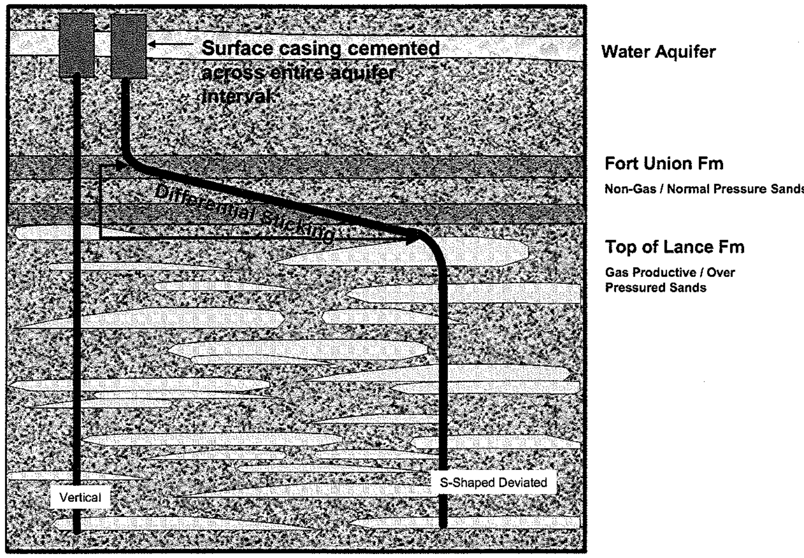

Figure 3: Schematic of S-Shaped directional and vertical wells showing location of differential sticking zone (not to scale - inclined section is 15° maximum).

Directional Well Types. The large number of thin sands distributed over a long interval impacts the selection of the appropriate well configuration. An example cross section at Jonah Field is shown in Figure 4:

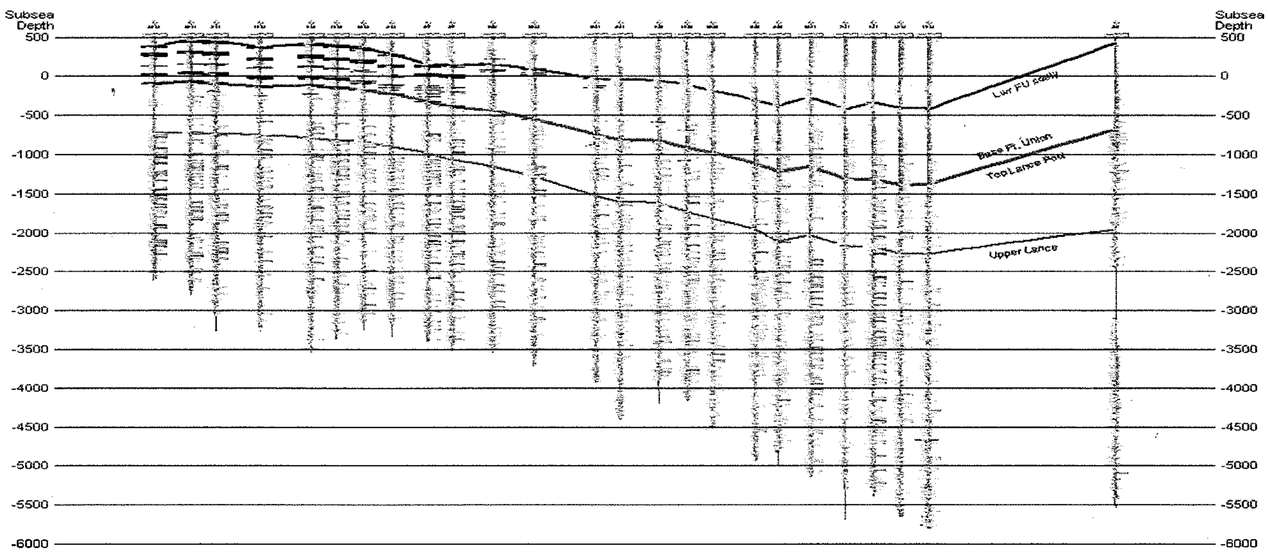

Figure 4: Cross section of the Lance at Jonah Field with potentially productive sands shown in yellow.

The section, which runs from SW to NE shows the structural dip on the top of the Lance. As the top of Lance increases in depth from 7200 ft. to almost 9000 ft., the gross thickness of the reservoir increases from 3000 ft to 5000 ft.

The possible well configurations for Jonah are shown on Figure 5:

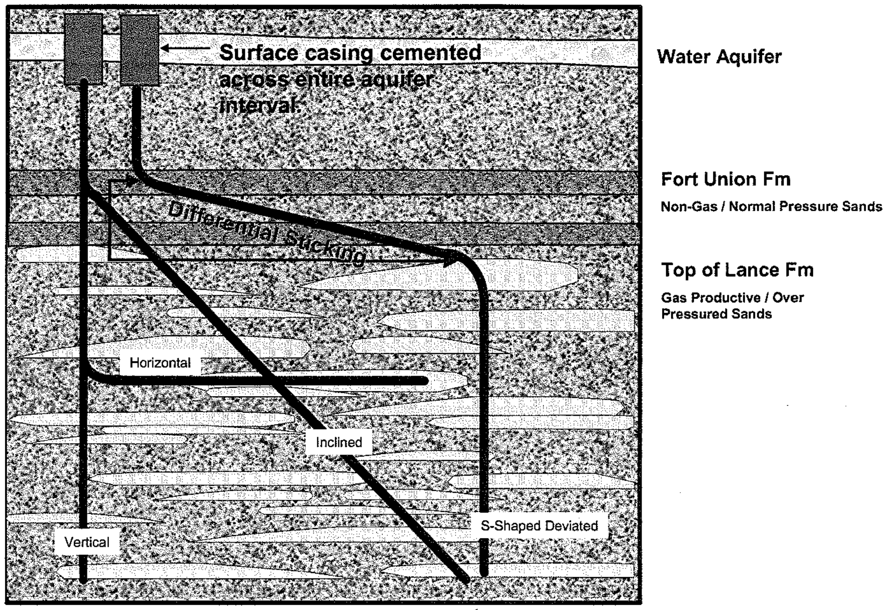

Figure 5: Well type options for Jonah development (not to scale).

Four well types are shown on this diagram: vertical well, s-shaped deviated well, high angle inclined well, and horizontal well.

A vertical well intersects all zones directly under the surface location. All zones of the Lance, including ones partially depleted by offset production, are perforated and hydraulically fractured in up to 10 stages. Drilling and completion operations are based on well-established, low risk technology. This type of well is the most commonly used well in developing thick, multiple zone, low permeability gas reservoirs. A typical well program is to run surface casing to 2500 ft through the surface aquifers then drill the normally pressured Fort Union and the over-pressured Lance with no intermediate casing. Mud weight is increased at the top of the Lance to control pressure and gas flow in the well. The increased mud weight creates a pressure differential (overbalance) across the Fort Union which can cause the drill pipe to stick in the deviated section of the borehole. In vertical wells, drill pipe sticking is generally not a problem.

A horizontal well can be drilled from vertical or high angle inclined wellbores. The horizontal section is deviated from vertical (kickoff point) close to the depth of the target zone and can easily reach lengths of 1500 ft to 3000 ft from the kickoff point. The main problem with this well architecture for the Lance at Jonah is that production is restricted to only one of the potential target zones. Although horizontal wells may drain reserves from a single zone more efficiently than a vertical well completed and hydraulically fractured in the same zone, single zone completions are generally not economic in the Lance. In multizone reservoirs, multilaterals or hydraulic fracturing has been used in some instances to access multiple zones. At Jonah these approaches are not feasible because of the large number of zones distributed over 3000 ft to 4000 ft of gross interval. Horizontal wells are clearly not applicable for development of the Lance at Jonah.

At Jonah, a high angle inclined well would be drilled at 30° to 60° from vertical starting at a 2600 ft kickoff point. This well intersects the reservoir zones at increasing distances from the surface location of the well. There is increased cost associated with drilling time required for the longer, deviated well in addition to increased mechanical risk of directional drilling. A major problem with this type of well is that, based on industry experience, hydraulically fracturing the multiple individual zones is technically difficult due to problems with screenouts. During hydraulic fracturing, sand is carried into a fracture created by high-pressure fluid. If there is a restriction at the wellbore, the sand packs off prematurely (screenout) terminating the fracture treatment. If special, higher-cost technologies are not applied, the frequency of screenouts increases as wellbores are inclined to more than 10° from vertical.

The theoretical reasons for the screenouts in inclined wells are related to fracture initiation problems caused by certain well orientations in the stress field (Hossain[4] and Sankaran[5]). It is critical that the inclined well be correctly oriented in order to have successful hydraulic fracture treatments. However, the stress field is usually poorly defined leading to poor success rates for hydraulic fracturing in inclined wells. Zones that screenout during fracturing are generally not successfully refractured and the reserves are not produced. Orientation in the stress field is not a factor in vertical wells; consequently success rates for hydraulic fracturing are very high.

Finally, the diagonal wellbore on the diagram penetrates approximately the same number of sands the vertical wellbore does. However, the drainage areas are not equivalent as a large wedge-shaped area between the inclined well bores is left undeveloped. This wedge-shaped area on the two-dimensional diagram is actually a very large conical area when looked at in all three dimensions. That conical area would not be drained without the drilling of additional vertical wells.

The s-shaped well is the most common deviated well drilled for field development. A well of this type at Jonah would be kicked off at about 2600 ft and straightened to vertical before entering the first pay zone at about 7150 ft to 8700 ft from surface. From a completion standpoint, this well looks like the vertical well with possible problems working inside a deviated well with two doglegs (bends) in the well path. The main subsurface problem with this well type at Jonah is increased cost associated with directional drilling and mechanical risk due to differential sticking of drill pipe and casing through the normally pressured Fort Union above the Lance.

It is the Lower Fort Union that represents the most significant risk for differential sticking problems during drilling operations. The mud column pressure required to drill the underlying Lance is much higher than the Fort Union formation pressure. This large pressure difference over hundreds of feet in the Fort Union creates conditions where the drill pipe may become attached to the borehole wall (differential sticking) especially where the pipe moves through the bends of the directional wellbore. Directional drilling increases the probability of becoming differentially stuck because where the hole is deviated from vertical, pipe will lay against one side of the borehole instead of hanging near the center of a vertical borehole.

Therefore, the bends in the well paths, located in the Fort Union, increase the possibility of sticking the drill pipe and casing. The end result is increased cost and potential loss of gas reserves. There are some potential solutions to address the problem of differential sticking. These will be discussed in a later section.

In summary, from a reservoir management standpoint, vertical wells with hydraulically fractured, multiple zone completions are the preferred option for efficient recovery of gas reserves at Jonah. S-shaped deviated wells have application to develop gas reserves under areas of the field where surface occupancy is prohibited or not possible because of terrain. Using S-shaped deviated wells for infill development at Jonah in areas where vertical wells can be used involves a tradeoff between reducing surface disturbance and higher per well cost and lost reserves. As spacing is reduced below 40 acres per well, multiple directional wells drilled from a larger single pad reduce the total area of surface disturbance; however, increased cost and resulting loss of reserves associated with directional wells causes waste.

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[4] Hossain, M.K., M.K. Rahman and Sheik S. Rahman;"A comprehensive Monograph for Hydraulic Fracture Initiation from Deviated Wellbores Under Arbitrary Stress Regimes";SPE 54360, Dallas(2000).

[5] Sankaran, S.,Nikolaou, M., and Economides, M.J.: "Fracture Geometry and Vertical Migration in Multilayered Formations from Inclined Wells"; SPE paper 63177, Dallas(Oct 2000).

Maximum Reach. The depth of the top of the Lance from the surface varies from 7000 ft at the SW end of the field to almost 9000 ft at the NE end of the field. The objective is to have the wellbore vertical at the top of the Lance. Given a kick off point, maximum change in the deviation angle (dogleg severity, degrees/100 ft) and a maximum angle of the inclined section of the well, it is possible to calculate the reach of the deviated well versus the depth to the top of the Lance.

Assuming a dogleg severity (rate of bending between the vertical and inclined sections of the directional well) of 1 degree per 100 ft, a maximum inclination of 15 degrees from vertical and a kickoff point of 2600 ft, a typical well design is shown on Figure 6:

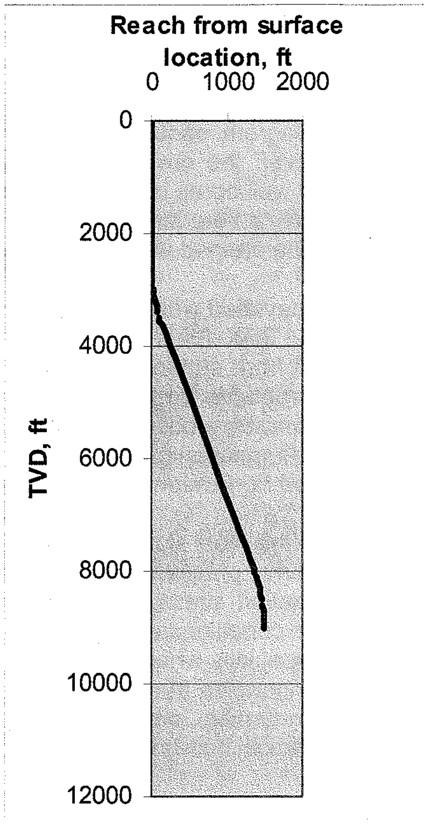

Figure 6: Well path for a typical directional well at Jonah

The maximum reach was calculated, assuming the above deviated-well design parameters and plotted versus the depth to the top of the Lance. The result is shown on Figure 7:

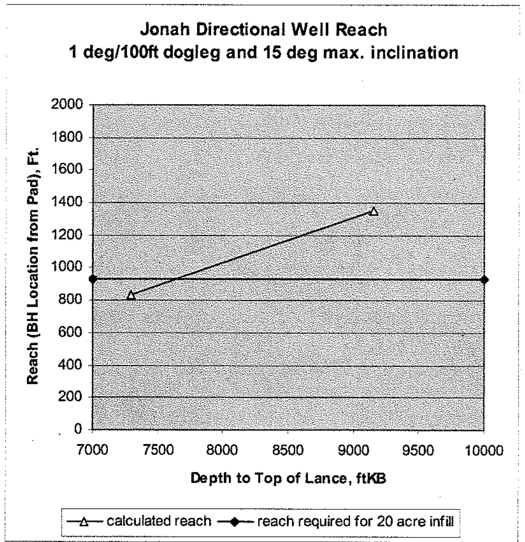

Figure 7: Maximum reach for a deviated well at Jonah for dogleg severity of 1°/100 ft and 15° maximum inclinations in the build section.

From the 40 acre vertical well location, it is possible to achieve 933 ft displacement of the bottomhole location (20 acre location) with an s-shaped well if the top of the Lance is deeper than 7659 ft. For the deepest part of the Lance, a displacement of 1300 ft is possible. With these design parameters it is not possible to reach the adjacent 40 acre location except in the deepest part of the field. A longer reach can be achieved by increasing the inclination angle or by kicking of the deviated section in the surface casing.

Well designs show that a maximum reach of 1500 ft from the surface location can be achieved with inclined sections greater than 15 degrees. The inclination required to reach 1500 ft ranges from 16 degrees for a Lance top at 9193 ft to 31 degrees if the Lance top is at 7500 ft. Therefore, it is possible to reach the adjacent 20 acre locations but not the adjacent 40 acre locations with less than 15 degrees of inclination. However, kicking off in the surface casing interval or increasing the inclination angle above 15 degrees to increase the reach may increase the risk of the directional drilling operation.

DRILLING AND COMPLETION COST

The drilling and completion costs for vertical wells and deviated wells from September 2002 (start of the directional well program) and May 2004 were analyzed to establish the incremental cost of drilling deviated wells. The data were also evaluated to determine how this incremental cost was changing over time as experience was gained in the 54 well directional drilling program.

Drilling Cost. When applying any new sophisticated drilling technology to a field, the costs generally start high and decrease with time as experience is gained and the process is optimized. Figure 8 shows the additional cost of a directional well relative to a vertical well versus the reach of the deviated well. In theory, problems in directional drilling are related to the length and inclination of the deviated borehole section which increase with reach (the distance of the bottomhole location from the surface location).

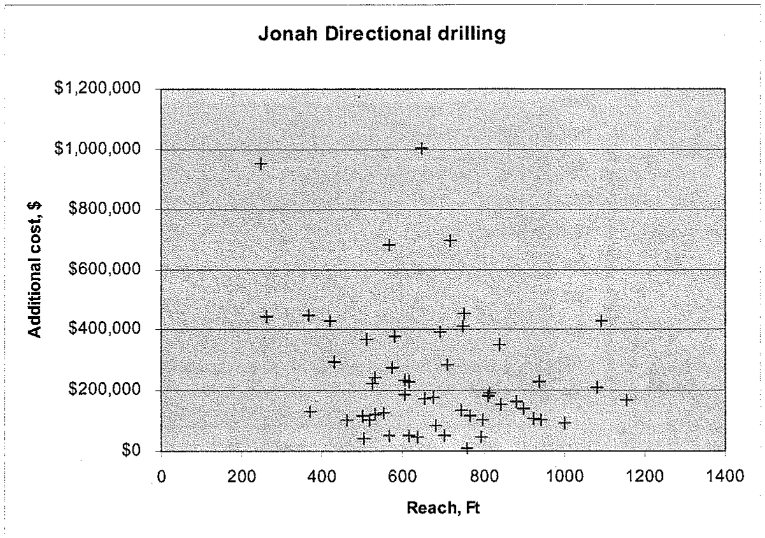

Figure 8: Directional to vertical additional well cost versus reach (distance of bottomhole location from surface location).

Experience to date indicates that there is no correlation between reach and additional well cost. In fact, some of the low reach wells have experienced more problems than longer reach wells. This suggests that other factors are more important in determining the incremental cost.

Generally, for directional drilling, the cost decreases with time as experience is gained. The cost for a directional well will always be higher; however, the additional cost is usually minimized as the number of directional wells drilled increases. Figure 9 shows the additional cost versus time (or number of wells) at Jonah Field.

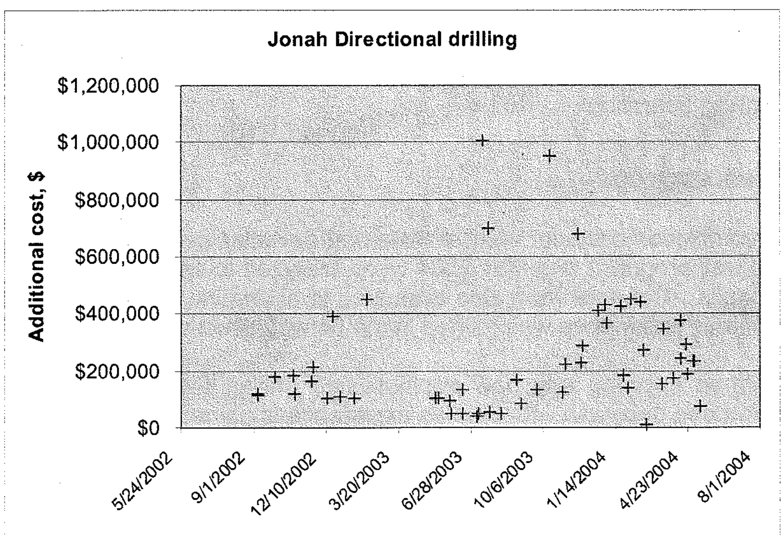

Figure 9: Directional to vertical additional well cost versus time.

The expected learning curve has been observed at Jonah with technology advancements to the end of 2003 when the additional cost reached a low of about $50,000. However, in 2004 problems and additional costs have increased and demonstrate that directional drilling continues to experience a significant risk. Recently, additional drilling costs are very high ranging from

$200,000 to $400,000 per well. This experience indicates that many factors are influencing the directional drilling results. Some of these factors are:

- depth to the top of the Lance where the mud weight is increased to control the overpressures varies across the field by about 1250 ft
- thickness of the Lance section drilled varies across the field by about 2500 ft
- rig crew experience and quality of the drilling rig and equipment may vary with time
- bit selection and optimization varies by area

From this data it can be concluded that many factors contribute to the mechanical risk of a directional well at Jonah. Therefore, a predictable decrease in the additional cost of a directional well relative to a vertical well over time cannot be expected. Even when some directional wells can be drilled at low additional cost, problems in a following well can result in 5 times the additional cost which significantly raises the average cost of the directional well program. Based on current data, it is expected that the additional cost for a directional well will be in the $200,000 to $400,000 per well range for the current well plan.

Factors Contributing to Additional Cost for Drilling Directional Wells. Several factors may contribute to the increased cost of directional wells at Jonah Field. Experience from the 54 directional wells drilled to date provides some basis for evaluating these factors.

Differential sticking. The 3000 ft to 4000 ft of over-pressured Lance Formation productive interval in the Jonah Field creates both a significant natural gas resource and an operational challenge for recovery of that resource. Directly above the Lance Formation lies the non gas-bearing, lower-pressured Fort Union, comprised mostly of sandstone much of which is porous and permeable. In order to have effective completion and avoid waste, all directional drilling operations must be completed in the Fort Union Formation, resulting in a vertical wellbore at the top of the productive Lance Formation. It is the Fort Union that represents the highest potential for differential sticking while drilling in the over-pressured Lance.

Mud weights required to safely drill the Lance Formation range from 11.0 to 13.0 pounds per gallon, while the Fort Union requires only 8.3 pounds per gallon. While drilling directional wells, this differential pressure requires significant attention to avoid stuck pipe and costly fishing jobs. Experienced rig personnel and above average drilling equipment is required to avoid problems.

Two changes could be made to the drilling program to eliminate most of the differential sticking problems: intermediate casing through the Fort Union or oil based drilling fluid.

Intermediate casing can be run to the top of the Lance where it is necessary to increase mud weight to control the well. Although the intermediate casing would eliminate the differential sticking problems, the estimated additional cost for this option ranges from $600,000 to $700,000 per well.

The high incremental cost for the intermediate casing option results from the significant changes that must be made to the drilling program. In order to run 4 ½" casing to total depth for efficient hydraulic fracturing, the borehole size to the top of the Lance must be increased. Drilling times are longer in the larger hole and additional time and cost are incurred for intermediate casing and the larger surface casing. For this option, crew experience and rig quality requirements would be nearly identical to a vertical well with no intermediate casing string.

Intermediate casing is used on the Pinedale Anticline because reservoir pressure gradients are higher at Pinedale (0.8 psi/ft) compared to Jonah (0.63 psi/ft)[6]. The higher mud weights required at Pinedale increase problems related to differential sticking in the Fort Union. In addition, higher bottomhole pressures require higher strength casing in the upper part of the hole for well control purposes. Because intermediate casing must be run in vertical wells in Pinedale due to a higher

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[6] Charpentier, R.R., Law, B.E., and Prensky, S.E.;"Quantitative Model of Overpressured Gas Resources of the Pinedale Anticline, Wyoming",SPE/DOE 16404.

bottomhole pressure and increased differential pressure between the Fort Union and the Lance/Mesaverde, there is less incremental cost associated with directional wells relative to vertical wells in this case. At Jonah, where the pressure difference is smaller and the bottomhole pressures are lower, it is possible to drill vertical wells without intermediate casing. Therefore, Jonah wells will have a significant additional cost for this option that wells at Pinedale will not have.

The second option being considered for directional drilling in Jonah is changing from water based to oil based drilling fluids with either diesel or synthetic oil. There are two concerns with oil based drilling fluids; the first is cost of the oil and the second is the environmental cost of handling, transporting and disposing of this fluid. A mud plant for recycling of the oil for subsequent wells would be required.

Also, two mud systems would be required, water based for drilling the surface aquifers switching to oil based fluid at the top of the Lance. The estimated additional drilling cost for this option is about $200,000 per well. For this option, crew experience and rig quality requirements would still be a concern. Although the oil based drilling fluid decreases the probability of differential sticking it may not eliminate it.

Well Collisions. As the distance between well locations is decreased in order to reduce the size of the multi-well pads, the risk of collision between the drilling well and existing wellbores increases. EnCana recently experienced a wellbore collision during the drilling of the SHB 20-4 at 700 ft. The estimated cost to remediate the damage (redrill the well) is approximately $168,000. In addition to cost, there is a significant safety risk associated with well collisions. If the integrity of the existing well is lost, then high pressure gas could possibly enter shallow aquifers or the drilling well. High pressure gas entry at this shallow depth could be catastrophic.

Initially, Jonah directional wells on multi-well pads were drilled on 20 ft spacing. It is believed that this spacing significantly reduces the risk of collisions. At 8 ft spacing between wells on the pad (the spacing of the SHB 20-4) it will be necessary to steer the well from surface to avoid collisions. Steering from surface adds to the drilling cost and reduces, but may not eliminate, the risk of collisions. Because of these safety concerns, EnCana plans to return to 20 ft spacing between wells on the multi-well pads.

Gas leaks near the surface. Another problem associated with small multi-well pads, is that the drilling rig is positioned close to earlier completed wells. Where underground gas leaks near the surface occur, there is a serious safety issue for the drilling operation.

A solution for these low-probability, near-surface problems on multi-well pads is to increase the distance between wellheads to increase safety and minimize the risk of gas leaks and well collisions. However, this would increase the size of the multi-well pads and offset some of the surface benefits of directional drilling.

Completion Cost. On average, 10 hydraulic fracturing stages are performed per well working from the bottom of the well to the top of the Lance. Each zone is fractured, back-flowed to recover fracturing fluids (cleanup), and isolated with wireline conveyed plugs for the next stage. During cleanup of the next stage higher in the well, gas flows up through the plugs from the lower zones and provides energy for cleanup. There does not appear to be any problem with this procedure downhole for either vertical or directional wells. However, both vertical and directional wells have experienced problems in the zones where injection/falloff pressure tests are used to measure pressure. In these cases a bridge plug is run to isolate the underlying zone preventing energy from the lower zones from assisting the cleanup. With poor cleanup, sand falls back on top of the bridge plug and a clean-out with a rig or coiled tubing is required.

However, there is an additional cost for directional wells relating to surface layout if a sand clean-out is required. Due to the fact that wellheads at the surface are in close proximity, conventional rig work cannot be performed during the hydraulic fracturing cycle. Coiled tubing is required due to its small footprint. When coiled tubing is used, the incremental completion cost is $70,000.

Openhole Data Acquisition. Data acquisition in new infill wells is important. Good openhole logs and pressure data assist in determining the number and location of infill wells. Data from early infill wells will help define optimum location of later wells and will help insure that no more than the necessary number of wells is drilled to efficiently recover the gas reserves. Pressure data is obtained in cased hole so the problems in acquiring this data are similar for both vertical and directional wells. However, in directional wells without intermediate casing or oil based drilling fluids, there is high risk in obtaining openhole log data. If it is the judgment of drilling supervisors that hole conditions are poor then only a limited number or no openhole logs are run.

The reason for this cautious approach is that if wire line logging tools become stuck and the line parts or keyseats in the bends of the directional well, the tools must be recovered in order to run casing and complete the well. The worst case scenario is a total loss of the well requiring a sidetrack or total redrill.

Recovering stuck logging tools creates a serious safety issue. When the wire line is cut and the drill pipe is stripped over the line to recover the stuck tools, gas entry into the well may be difficult to control. Too much gas entry can cause loss of control of the well.

Total Additional Drilling and Completion Cost. Operator experience after 54 directional wells in Jonah Field has determined that the average increase in costs for drilling and completion ranges from $270,000 to $470,000 as compared to a vertical well. Using oil based drilling fluids will eliminate some of the risk related to differential sticking in the directional wells; however, the estimated total additional cost to drill and complete with these drilling fluids is about $270,000 per well. If oil based drilling fluids eliminate differential sticking problems, then this option gives about the same additional directional well cost as the current program.

Finally, running intermediate casing through the Fort Union is expected to eliminate most of the problems now experienced in directional wells; however, the estimated increased cost of this option ranges from $670,000 to $770,000 per well to drill and complete a directional well from a central pad.

RESERVES LOST DUE TO DIRECTIONAL DRILLING

In the current directional drilling well plan, without oil based drilling fluids or intermediate casing, there is a risk of bypassing gas reserves at the bottom of the Lance if the casing does not reach bottom due to differential sticking. If the casing is set high, then the gas resource below the casing will not be produced.

Casing Set Off Bottom. From Jonah directional well experience, in about 30% of the directional wells, the casing is set an average of 124 ft above the TD (Total Depth) of the well. If casing does not reach bottom, it is cemented high and a decision is made whether or not to run a 2 7/8" liner. The cost to run a liner is about $250,000.

For conditions at Jonah, in addition to the extra cost, cementing the small diameter pipe is difficult and stimulation is less effective.

Casing Stuck on Bottom. The normal practice in a vertical well at Jonah is to reciprocate the casing during cementing to improve the cement bond. In about 75% of directional wells the casing is stuck on bottom so movement during cementing is not possible. Thin cement pumped at high rate is normally used and not being able to reciprocate the casing does not appear to cause any major problem as indicated from cement bond logs. There also does not appear to be any problems with hydraulic fracturing wells that had stuck casing.

The only major issue with cement bond would be at the Lance-Fort Union contact where normally pressured and over-pressured zones would be in communication if the cement bond is poor. If the bond is poor, the interval would be cement squeezed to prevent communication. This situation would lead to increased cost and also lost reserves because the Lance would have to be hydraulically fractured through 2 7/8" tubing to isolate the squeeze perforations. Fracturing through tubing is less efficient than through 4 ½" casing.

In the 54 directional wells drilled to date it has not been necessary to squeeze the top of the Lance.

If casing is stuck on bottom during cementing operations, experience to date indicates that there is no loss of gas resources.

Liquid Loading Effects. Jonah gas production is considered wet, as it also produces gas condensate liquids and water. As reservoir pressure decreases, water content in the gas also increases. These liquids contribute to liquid loading when the gas rate declines to low levels near the end of the producing life.

When liquids accumulate in the well the producing bottomhole pressure increases and can cause early abandonment of the well with loss of gas reserves. Artificial lift such as plunger lift may be used to unload liquids as pressure depletes and reduce the flowing bottomhole pressure.

A review of the petroleum literature suggests that there are no problems particular to directional wells relating to plunger lift. The plunger falls to bottom by gravity so the rate of fall will be slower in directional wells. However, the main disadvantage with plunger lift is that it does not work if there is sand production. In a directional well there may be a tendency for sand to accumulate in the inclined section if the angle is high. If the directional wells at Jonah are producing fracturing sand near the end of the well life, this would prevent the use of plunger lift and result in lost reserves. From the available data it is not possible to quantify this reserve loss.

Waste Attributed to Lost Reserves. The magnitude of the potential reserve loss was estimated by calculating the original gas-in-place in the bottom 400 ft of the hole (including the 150 ft rathole below the base of the Lance). Because gas is compressible, this calculation must be made using actual pressures and not a simple ratio of thickness.

Of the 54 directional wells drilled to May 11, 2004, 16 have failed to set casing on bottom. The average length of hole lost below the float collar (cementing equipment set one joint from the bottom) is 154 ft. When the rathole is added for perforation and stimulation, an average of 275 ft of hole is inaccessible.

The original gas-in-place for the bottom 275 ft of the Lance (including the rathole) was estimated from petrophysical analysis and actual reservoir pressure for 359 wells at Jonah. The gas resource loss per well ranges from 3 MMSCF to 1284 MMSCF with an average of 362 MMSCF. When a 30% probability of setting casing 124 ft high is applied to the 1824 wells to be drilled on 10 acre spacing, assuming an all directional option, the estimated lost gas reserve is 200 BCF.

A new gas field with 200 BCF of recoverable reserves would be considered significant in today's gas market. Also, 200 BCF is over 15 times the annual residential consumption of natural gas in the State of Wyoming.

DIRECTIONAL DRILLING TIMES

Directional drilling is particularly challenging in fields like Jonah where portions of the interval are over-pressured. In addition to increased costs relative to a vertical well, directional drilling requires longer development times and lengthier periods of drilling activity.

In attempting to quantify the increased time associated with directional drilling, it is not possible to directly compare drilling time between vertical and horizontal wells using average numbers. The reach, depth to the top of the Lance, and thickness of the Lance drilled varies throughout the field and these factors must be taken into account. In addition, bit selection, experience gained in drilling directional wells, and the rig being used may impact the drilling time.

Figure 10 shows days versus reach for all directional wells at Jonah.

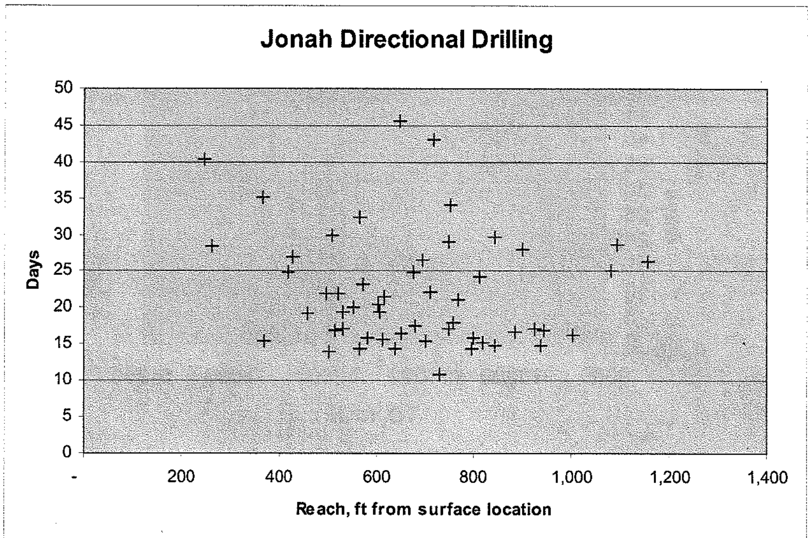

Figure 10: Total days from spud to rig release for Jonah directional wells versus reach.

The data is scattered and there appears to be no strong relationship between drilling days and reach.

Figure 11 shows the total time vs. the start data of the well.

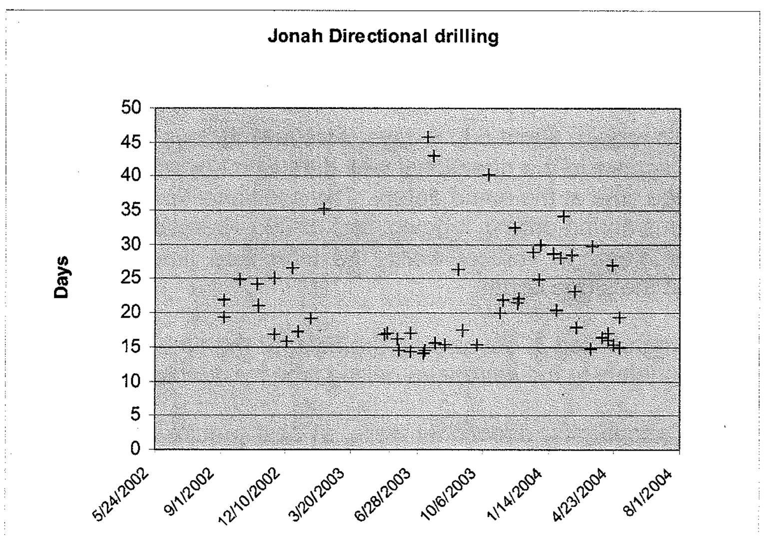

Figure 11: Total days from spud to rig release for Jonah directional wells versus spud date.

The average drilling time in 2004 for a directional well appears to be about the same or slightly higher than the time when directional drilling was started in Jonah in September 2002. As discussed, other factors may be causing this apparent increase.

In order to quantify the incremental time for a directional well, the drilling times for vertical and directional wells drilled since September 2002 were compared a shown on Figure 12.

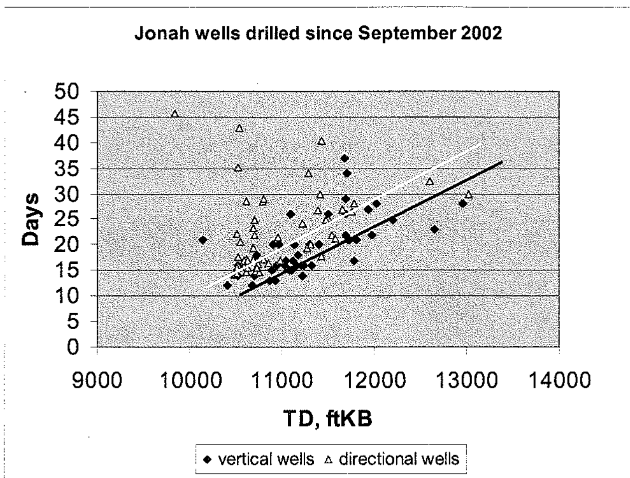

Figure 12: Total days from spud to rig release for Jonah directional and vertical wells versus total depth.

The figure shows days versus total depth drilled (TD). The total depth is a reasonable correlation parameter because:

- The time spent in the heavy mud weight (over-pressured) portion of the hole is a controlling parameter
- The top of the Lance deepens to the NE and the Lance thickens to the NE. The change in thickness (+2500 ft) is much greater than the deepening of the Lance top (+1250 ft)
- The surface elevations vary less than 200 ft for this group of wells.

Observations from this plot follow:

- Directional wells require about 5 to 6 days more drilling days than vertical wells
- There is more scatter in the directional well data with several wells taking 3 times longer than the average time at the same depth. The additional time is due mainly to differential sticking problems during drilling, logging, and casing operations.
- If there are problems in vertical wells, the increased time is only about 50% of the average time at the same depth

The number of rigs being utilized in developing the field, or the time required to develop the field must increase proportionately to the increased drilling time for directionally drilled wells.

Over the range of the above plot, directional wells, at best require 25% longer to drill and case than a vertical well drilled to the same depth. Because of 200% to 300% increase in time in 10% of the directional wells due to differential sticking problems, the average additional time to drill directional wells will be more than a 25% increase.

CONCLUSIONS

1. Jonah Field is a major energy source with about 10.5 TCF of original gas-in-place corresponding to a surface area of approximately 21,000 acres. On 40 acre spacing it is projected that only 30% of this resource will be produced and about 4.6 TCF of potential gas reserves will be unrecovered (difference between 30% and 75% recovery). This lost gas represents significant waste and when averaged over a 25 year period, represents about 15 times the annual residential natural gas consumption in the State of Wyoming.

2. The current incremental cost to drill and complete a directional well over a vertical well is about $270,000 to $470,000.

3. On average, directional wells take at least 5 to 6 days longer than a vertical well drilled to the same depth. The 25% increase in time should be considered in evaluating the impact of directional drilling on the surface operations.

4. Problems are more common in directional wells with 10% of these wells requiring 2 to 3 times longer than average to complete drilling operations. If problems are encountered in vertical wells, the increased time is only about 50% over an average well at the same depth.

5. The expected decrease in average cost difference, between vertical wells and directional wells, has not occurred with experience at Jonah. This is due to the unpredictable and difficult problem of differential sticking in the Fort Union. There is no reason to believe that the directional well costs will approach vertical well costs.

6. It is believed that differential sticking problems can be significantly reduced in directional wells at Jonah in two ways: 1) running intermediate casing through the Fort Union at approximately $670,000 to $770,000 additional drilling and completion cost per well or 2) changing from water based to oil based drilling fluids at approximately $270,000 additional drilling and completion cost per well. This additional cost is much higher than experienced at Pinedale Anticline where intermediate casing is usually required in vertical wells because of higher bottomhole pressures and higher pressure differences between the Fort Union and the deeper over-pressured intervals.

7. Failure to place casing at the bottom of the well in 30% of the directional wells represents a potential loss of gas reserves of 200 BCF for a 10 acre infill, all-directional option. A gas field with 200 BCF of recoverable reserves would be considered significant in today's market. This lost reserve volume is over 15 times the annual residential consumption of natural gas in the State of Wyoming and represents significant waste.

8. Considering all of the alternatives, the lowest incremental cost of drilling and completing directional wells at Jonah that also provides for acquisition of critical data is $270,000 per well (oil base drilling fluids). In addition to increased cost, oil based drilling fluids have environmental issues relating to handling, transporting and disposing of these fluids.

9. Directional drilling of development wells at Jonah may help control the impact of the footprint of the development on the surface. However, this impact includes not only the size of the disturbed area but also the length of time the development footprint impacts the surface. The additional time and cost, and potential for lost reserves associated with directional drilling may significantly increase the total life of the field.

Comments on the Use of Directional Drilling to Minimize Surface Disturbance in the Jonah Infill Drilling Project and on the Content of <u>Jonah Infill Drilling Project Evaluation of Directional Drilling</u>*

*A document prepared for EnCana Oil and Gas (USA) Inc. by Reservoir Management Services, Inc. (July 16, 2004) and referenced in the Draft Environmental Impact Statement, Jonah Infill Drilling Project, Appendix G, pg. 17.

Attachment 5

Introduction

The application of directional drilling to minimize surface disturbance resulting from the Jonah Infill Drilling Project (JIDP) presents an ideal case for supporting the President's National Energy Policy, which states:[1]

> *"Producing oil and gas from geologically challenging areas while protecting the environment is important to Americans and to the future of our nation's energy security. New technology and management techniques will allow for sophisticated energy production as well as enhanced environmental protection...Smaller lighter drilling rigs, coupled with advances in directional and extended-reach drilling significantly increase protection of the environment... Modular drilling rigs, "slimhole" drilling, directional drilling, and other advances enable: [...]*
>
> - *Production of oil and gas with increased protection to wetlands and other sensitive environments ; [...]*
>
> *Other examples of advanced technology include: [...]*
>
> - *Highly sophisticated directional drilling that enables wells to be drilled long horizontal distances from the drilling site[.]"*

The Secretary of the Interior has stated:[2]

> *"We must also harness 21st Century technology to help our environment. Where we once needed scores of wells to tap underground reserves, today in some areas we can use one hole on the surface to drill for oil in a circle extending seven miles. We can use the resources below ground while we preserve the landscape and habitat above."*

The JIDP Draft Environmental Impact Statement ("Draft EIS") evaluated 5 alternatives that include (to varying degrees) the application of directional drilling for the purpose of reducing surface disturbance:

Alternative B – requires that all future wells be drilled from existing pads which are concentrated in the southernmost three fourths (3/4's) of the JIDP area with a maximum density of 1 well pad each 40 acres.

Alternative E – allows no more than 1 well pad each 40 acres throughout the JIDP area.

Alternative F – allows no more than 1 well pad each 20 acres throughout the JIDP area

Alternative G – allows no more than 1 well pad each 10 acres throughout the JIDP area

BLM's Preferred Alternative – allows 3 different maximum well pad densities each applicable to different parts of the JIDP area. These maximum pad densities are; 1 per 10 acres, 1 per 20 acres and 1 per 40 acres.

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[1] National Energy Policy, May 2001, "Reliable, Affordable, and Environmentally Sound Energy for America's Future: Report of the National Energy Policy Development Group," p. 5.5.
[2] Presentation of Gale Norton, Secretary of the Interior, to the National Newspaper Association (Washington, DC, March 23, 2001)

Comments on the Use of Directional Drilling in the JIDP

The maximum well horizontal displacement necessary to develop the Jonah Field using 40-acre pad spacing (as in Alternative E) is less than 1,000 feet. Approximately 87% of the wells would require a horizontal displacement of 660 feet or less. The average well horizontal is only about 515 ft. An analysis of the directional well profiles necessary to develop the entire Jonah Field using a maximum well pad density of 1 pad per 40 acres is presented in **Appendix A** of this document.

Approximately one third of all wells being drilled in U.S. today are directional or horizontal wells.[3] The drilling of directional wells with 5,000 feet or more of horizontal displacement has been considered routine for over 2 decades. Today, it is increasingly common for directional wells to be drilled with horizontal displacements in excess of 5 miles (over 26,000 feet).

Within Sublette County, Questar is developing the Pinedale Anticline gas field using no more than 4 well pads per section. This requires the drilling of directional wells with horizontal displacements of approximately 1,700 feet.

The drilling and completion of any oil or gas well, vertical or directional, involves risks and uncertainties. Numerous problems or incidents could occur that might result in economic loss, loss of the well, or danger to life and the environment. The engineers, geologists, managers and other professionals that plan, coordinate and execute these operations must be, and usually are, qualified to anticipate and manage these risks.

Compared to vertical wells, the incremental risks associated with the types of directional wells required to develop the Jonah Field using a maximum pad density of 40 acres are minimal and well within industry capabilities to manage. Every oil and gas field is different, but there is nothing about the geology or economics of the JIDP that precludes this modest application of directional drilling from being technically and economically successful. Neither is there any technical or economic aspect of the JIDP that would cause directional drilling from 40-acre spaced pads to result in a significant reduction of recoverable reserves.

Directional drilling should be utilized to the greatest extent practical during the JIDP. Doing so will minimize surface disturbance, habitat fragmentation and disturbance to wildlife. It will minimize hydrological impact caused by run-off and changes in drainage patterns. It will minimize air quality impacts due to reduced dust and truck traffic during pad construction, pad reclamation and rig moves. Air quality impacts during the production phase will be minimized due to the consolidation of surface production equipment on multi-well pads. It will keep the Jonah field from becoming an industrial wasteland and an embarrassment to the citizens of Wyoming and the BLM. It will enable Jonah to stand as an example of the willpower of the citizens of Wyoming and the U.S. Government to demand the practical application of technology and best management practices that permit development of energy resources in a manner that respects and preserves the essence of our precious natural environments and the wildlife that depend on those environments for their very existence.

Directional Drilling technology should be combined with these other key technologies and practices to significantly mitigate environmental impact:

- Closed loop drilling fluid systems to eliminate reserve pits
- Flareless completions
- Drilling rigs that use Tier II diesel engines or natural gas engines
- Emission controls and operating practices that minimize VOC, BTEX and HAPs emissions

[3] Reference Smith International Incorporated (SII) Quality Rotary Rig Count. On the world-wide web at www.smith.com/stats/new

Besides being effective in reducing environmental impact, the application of each of these technologies and practices is easily monitored (an important consideration considering the limited resources of the BLM and the span of decades over which monitoring will be required).

The practical (e.g. economic and technical) limits of directional drilling in Jonah are well beyond the minimal challenges of developing the entire field using 40-acre pad spacing. Therefore, alternatives F, G, and the BLM's Preferred Alternative do not make sufficient use of directional drilling to limit the environmental impact of the JIDP.

Alternative B would require a small but significant percentage of the JIDP wells in the northern part of the field to be drilled with horizontal displacements of approximately 5,000 feet. While technically feasible, there are practical and economic reasons why displacements of that magnitude should not be mandated in Jonah.

For the Final Environmental Impact Statement a new Alternative should be evaluated. This Alternative would be a modification of Alternative B from the Draft EIS. It would allow new pad construction only if there were no existing pads within 1,320 ft of the proposed pad. This would limit pad density to 4 per section (same as Questar is using) in the portions of the JIDP area that, as yet, are still relatively undeveloped.

Of the Draft EIS Alternatives, this leaves Alternative E as being the only practically acceptable Alternative that makes even marginally sufficient use of directional drilling to minimize environmental impacts.

Comments on "Jonah Infill Drilling Project Evaluation of Directional Drilling"[4]

A report titled "Jonah Infill Drilling Project Evaluation of Directional Drilling" was prepared for EnCana Oil and Gas (USA) Inc. by Reservoir Management Services, Inc. (July 16, 2004) and is referenced in the Draft Environmental Impact Statement, Jonah Infill Drilling Project, Appendix G, pg. 17. For the remainder of this commentary, the subject report will be referred to as the "EnCana Report".

The EnCana Report is overtly biased against the application of directional drilling in the JIDP. Its propositions against the use of directional drilling are either totally unsubstantiated or weakly supported; often through the use of ambiguous or misinterpreted data and misleading statements, miscalculations and exaggerations.

The extent to which the contents of this report may have influenced the conclusions of the Draft EIS or the formulation of the BLM's Preferred Alternative is not clear. However to the extent to which it may have had influence, it is necessary to point out why it should not be relied upon as unbiased, substantive or technically accurate evaluation.

For the purposes of this commentary, we will consider that the directional wells in Jonah will be drilled from 40 acre spaced pads. The well profiles required to drill from 40 acre spaced pads are shown in Appendix A to this document. The directional characteristics of these wells are:

- The maximum horizontal well displacement (required on about 12.5% of the wells) is less than 1,000 ft.
- The average well horizontal displacement is about 515 feet.
- The maximum required hole angle is 15 degrees or less.
- All well inclinations are reduced to zero degrees (i.e. vertical) by the top of the Lance Formation.

[4] A document prepared for EnCana Oil and Gas (USA) Inc. by Reservoir Management Services, Inc. (July 16, 2004) and referenced in the Draft Environmental Impact Statement, Jonah Infill Drilling Project, Appendix G, pg. 17.

The only directional wells considered in the Draft EIS that cannot be drilled within these above stated parameters are a relatively small but significant percentage of the wells that would be required under Alternative B. Those wells, with horizontal displacements of a mile or more might be subject to some of the problems discussed in the EnCana Report. But for the most part, those problems are either not applicable or not significant on wells drilled from 40 acre spaced pads.

Following are brief comments on each of the key errors in the EnCana Report. They are numbered and discussed in roughly the order in which they are presented in the report.

1.) Table 4 on Page 9 – Unsubstantiated EUR for all the Draft EIS Alternatives (except the Preferred Alternative) are presented. They show that directional drilling will have a substantial negative impact on JIDP Recoverable Reserves. These are the same EUR numbers used in the Draft EIS. A thorough analysis of these EUR numbers presented in **Appendix C** of this document demonstrates that these EUR numbers are grossly inaccurate.

2.) Page 10 – Claims about the risks of directional drilling are made which are unsubstantiated and unquantified ("increased cost, potential lost reserves...increased risks,... increased drilling times and higher engine load requirements...(increased) surface activity, emissions, and environmental impact'). While there are certainly times when directional drilling could cause all these negative impacts, there are also many times when it does not or when it actually has a positive impact on these parameters. Such loose and unsubstantiated comments do not reflect high professional standards and should be ignored.

3.) Page 10, last paragraph – The description of an over-pressured gas bearing formation (i.e. the Lance) laying below a normally pressured formation (i.e. the Fort Union) and creating potential for differential sticking, is a scenario that exists in the majority of the world's gas wells, both vertical and directional.

4.) Figure 3, page 11 – For a scale drawing of the S-shaped wells required at Jonah, refer to Appendix A of this document. The diagram depicts differential sticking occurring in the inclined part of the directional well, but not in the vertical well. Differential sticking is a common problem that is managed every day in the drilling industry. Differential sticking can and does occur in both vertical and directional wells. Everything else being equal, the potential for differential sticking will increase with hole inclination. But this problem is successfully managed daily on hundreds of high angle directional wells. With a maximum required hole angle of 15 degrees, the problem of differential sticking in Jonah directional wells will be only marginally higher than in Jonah vertical wells.

5.) Page 12 and upper third of page 13 – Horizontal wells and high angle inclined wells are not being considered in any of the Draft EIS Alternatives, therefore the discussion of these in the EnCana Report is irrelevant and will not be commented on here.

6.) Lower two thirds of page 13 - Again, differential sticking is discussed but in vague and unsubstantiated terms that add nothing to new to what was already said in pages 10 and 11 (see comments 2, 3 and 4 above).

7.) Page 14 – All the directional drilling trajectories shown or discussed in the EnCana Report assume a dogleg severity (rate of change in hole inclination) of 1 degree per 100 feet (1^0/100'). This is a very low dogleg severity. By using a low dogleg severity you reduce the amount of horizontal displacement that is possible for a given well depth. It is extremely rare for a directional well to be planned using a dogleg severity of less than 2^0/100'. Roughly 60% of the directional wells drilled worldwide use a dogleg severity of 2^0/100', and nearly all of the other 40% use higher dogleg severities. The EnCana report does not state how many (if any) of the directional wells drilled to date in Jonah have used a dogleg severity of 1^0/100'.

By using a dogleg of 2^0/100' instead of 1^0/100', the maximum attainable horizontal displacement of directional wells with maximum hole inclinations of 15^0 increases by 400 feet over the maximum displacements claimed in the EnCana Report.

As demonstrated in Appendix A to this document, even using the stringent EnCana limitations of 1^0/100' dogleg severity, maximum hole inclination of 15 degrees and the requirement to have the hole angle reduced back to zero degrees (i.e. vertical) by the top of the Lance Formation, approximately 97% of all the JIDP wells drilled from 40 acre spaced pads can reach their required horizontal displacement. The other 3% would require either a slightly higher maximum hole angle (19.6^0 in the extreme case) or a slightly higher dogleg severity (1.35^0/100' in the extreme case).

8.) Page 15 – First Paragraph: *"With these design parameters it is not possible to reach the adjacent 40 acre location except in the deepest part of the field".* Strictly speaking, this is a true statement but it is misleading. From the discussion in comment #7 above and from the calculations shown in Appendix A, it can be seen that using a 40 acre pad spacing, 97% of all wells can be drilled using the EnCana design parameters, the other 3% will require either a slightly high maximum hole angle or a slightly higher dogleg severity.

9.) Page 15 – Second Paragraph: The content of this paragraph (discussions around achieving 1500 feet of horizontal displacement) is out of context. As discussed in comment 7 above and further demonstrated in Appendix A of this document, the conclusion of this paragraph is false (*"Therefore it is possible to reach the adjacent 20 acre locations but not the adjacent 40 acre locations with less than 15 degrees of inclination"*).

10.) Page 15 – Last paragraph: The indirect reference to directional drilling as a "new sophisticated drilling technology" is an overt example of the bias of the EnCana Report.

11.) Page 16 – Figure 8 and first paragraph. Figure 8 merely demonstrates that there is scatter in directional well cost data. Such variation in cost could be expected in the vertical wells also. If, as the EnCana Report contends, most directional well problems are related to their hole inclination, then you would expect to see a direct correlation between "reach" (i.e. horizontal displacement) and cost. Even the EnCana Report observes here that this is not the case. The conclusion therefore is that the prime reason for the data scatter is unrelated to the fact that the wells are directional and therefore, whatever factors are contributing to the data scatter are probably also present in vertical wells.

The only useful conclusion that can be drawn from Figure 8 is that, of the 54 directional wells drilled to date, the average incremental cost over the vertical well average cost is roughly $220,000.

12.) Page 16 - Figure 9 and last paragraph and first third of page 17. The EnCana Report attempts to use Figure 9 to drawn the conclusion that *"...a predictable decrease in the additional cost of a directional well relative to a vertical well over time cannot be expected."* This conclusion is absurd. It says that a learning curve cannot be established and the lessons learned carried over from one well to the next cannot be used to improve performance. If true, this would represent the first documented case in the history of the oilfield of a large infill drilling program where sound engineering, management and operational practices could not be used to establish a learning curve and sustain the benefits of that learning curve throughout the infill drilling program.

The implication is that Figure 9 depicts a reverse learning curve...the more directional wells EnCana drills the worse they get. In practice, reverse learning curves have been known to occur. One cause for reverse learning curves is a "boom mentality". The basis for this mentality is that the drilling is so lucrative that the oil company just wants to drill the wells and get them producing as fast as they can. To heck with taking the time and manpower required to do it right, establish a learning curve, train the drilling crews and identify best practices and lessons learned and carry them forward; applying them from one well to the next.

Prolonged reverse learning curves are the result of failing to apply sound engineering, management and operational practices.

In the bullet points at the top of page 17, the EnCana Report once again recognizes that there are variables unrelated to directional drilling (and therefore also affecting vertical wells) that can influence well cost. One variable that is not mentioned is the rising unit cost of equipment and services used to drill and complete both vertical and directional wells. For example, about 5 years ago the cost of a drilling rig of the type used in Jonah was about $5,000 per day and roughneck wages started around $7.00 per hour. Today, those same rates are in excess of $15,000 per day and $20.00 per hour. In late 2003 / early 2004, those rates were on the rise in Sublette County and likely are a major contributor to the apparent "reverse learning curve" depicted in Figure 9. (The costs would have been going up for vertical wells also. But, if the cost of individual directional wells are being compared to an average cost of vertical wells drilled over a two year time span, the directional well costs will appear to be rising compared to the vertical well costs when in fact the costs of both well types could be moving up in parallel.)

Based on the reasoning presented in the previous paragraph (above), the EnCana Report conclusion (2nd paragraph page 17) that *"Based on the current data, it is expected that the additional cost for a directional well will be in the $200,000 to $400,000 range..."* is misleading.

As discussed in comment 11, the average incremental cost of a directional well is roughly $220,000 (and for a good portion of the wells close to, or under, $100,000). Well costs are showing a rising trend, but the major causes of that trend are unrelated to directional drilling and therefore the same trend is almost certainly occurring in the vertical wells also. The likely causes for the rising cost trend could be one or more of the following:

- One or more of the 4 bullet points at the top of page 17
- A "boom mentality"
- Increases in the unit costs of goods and services

13.) Page 17 – Third paragraph: The discussions on the next two pages of the EnCana Report are introduced with this sentence: *"Several factors may contribute to the increased cost of directional wells at Jonah Field. Experience from the 54 directional wells drilled to date provides some basis for evaluating these factors."* It has already been established that the average incremental cost to drill a directional well at Jonah is roughly $220,000.

14.) Page 17 – Second half of the page. The circumstances that cause the common drilling problem known as "differential sticking" are presented here once again. EnCana is pushing the limits of drilling practices in Jonah by drilling to TD without incurring the cost of setting a string of intermediate casing at the top of the Lance Formation. From a drilling standpoint, there is nothing wrong with this as long as EnCana can successfully get the well and casing to the planned total depth. By pushing this limit however, they do expose themselves to increased risk of drilling and completion problems such as differential sticking. These problems can be encountered in vertical or directional wells. Some problems such as differential sticking can be more prevalent in directional wells, but given that the Jonah Directional wells can be drilled with a low maximum hole inclination of 15^0 or less, any increase in problems compared to vertical wells will be small.

The BLM, EnCana and the citizens of Sublette County have other reasons to be concerned about the plan to develop Jonah without the use of intermediate casing. Without an intermediate casing string there is a strong likelihood that a significant portion of the wells will have communication (i.e. "gas flow") between the high-pressured Lance Formation and the normally pressured Fort Union formation. The problems that this could cause may not manifest themselves right away, but could include one or more of the following:

- Well control problems due to normally pressured Fort Union sands becoming "charged" with gas from the Lance (in the worst case a "blow-out" or "wild well")
- Contamination of the aquifer with completion fluids
- Loss of recoverable gas reserves
- High-pressured gas migrating along the outside of the casing to shallow depths and eventually seeping through the ground to the atmosphere.

Two solutions to differential sticking are presented here; oil base mud and intermediate casing. The report does not disclose if either solution has ever been necessary in Jonah. In any case, if either of these solutions is necessary for a significant number of Jonah directional wells then chances are it is also necessary to apply the solution in a significant number of the vertical wells.

It is significant that the EnCana Report does not present any data on the frequency and severity of stuck pipe incidents in both vertical and directional wells within Jonah.

One of the truest statements of the EnCana Report occurs in the middle of page 17: *"While drilling directional wells, this differential pressure requires significant attention to avoid stuck pipe and costly fishing jobs. Experienced rig personnel and above average drilling equipment is required to avoid problems."* It is a well-known fact among drilling professionals that differential sticking and other stuck pipe problems can be effectively mitigated (in both directional and vertical wells) by drilling crews that are adequately trained and motivated to implement known best practices for avoiding stuck pipe. These mitigating controls cannot be implemented when operating under a "boom mentality". It requires cooperation from the drilling contractor personnel and leadership, resolve and discipline from the operator's managers. The operators managers hold the purse strings, and if they need "experienced personnel and above average drilling equipment", they have the power and the professional obligation to obtain both. If one drilling contractor isn't willing to work cooperatively to develop a solution, then there's always another that is.

<u>There is very little basis for the potential for differential sticking to be used as an excuse against the use of directional drilling in Jonah.</u>

15.) Page 18 – Well Collisions. The potential for well collisions is a realistic concern. But it is a risk that the industry successfully manages every day on hundreds of offshore drilling platforms and onshore multiple well pads around the world. EnCanas' plan to increase the spacing between wellheads to 20 feet is a reasonable response to this risk.

16.) Page 18 – Completion Costs. The report discusses the problem of sand accumulation in the well during the completion operations, but states that the problem occurs in both vertical and directional wells. When a location is crowded with expensive fracturing equipment, there is no room for a conventional drilling rig in any case (vertical wells or directional pad wells). Even if there was room, there is no time to wait on a conventional drilling rig to become available, move to the well and rig-up to perform a clean-out. The use of a highly mobile and small footprint coiled tubing rig is the preferred option. Any additional costs due to this scenario occurring cannot be reasonably attributed to the fact that a well is directional and not vertical.

17.) Page 19 - Open Hole Data Acquisition. A decision to limit openhole wireline logging due to poor hole conditions is one that is often required on both vertical wells and directional wells. Wireline logs are run successfully on high angle (60^0 or more) extended reach directional wells on a daily basis around the world. Because of the low hole angles required by the Jonah directional wells, the chances of getting wireline tools stuck are only marginally greater than in a vertical well.

It is significant that the EnCana Report does not present any data on the frequency and severity of open hole wireline logging tools getting stuck in both vertical and directional wells within Jonah.

18.) Page 19 – Casing set off bottom. Like stuck drilling pipe, this problem is likely to occur nearly as often on Jonah vertical wells as on the Jonah directional wells. It is a problem that can also be mitigated to a large extent by well-trained crews executing well planned casing procedures. It is significant that no data is presented on how often this problem has occurred on vertical wells in the Jonah field.

19.) Page 19 - Casing stuck on bottom. Again, this is a problem that is likely to occur nearly as often on Jonah vertical wells as on the Jonah directional wells. The only "major issue" that the EnCana Report associates with the scenario is the potential need to "squeeze the top of the Lance". The report states however: *"In the 54 directional wells drilled to date, it has not been necessary to squeeze the top of the Lance."* Again, it is significant that the report does not state how often it has been necessary to squeeze the top of the Lance in the vertical Jonah wells drilled to date.

20.) Page 20 – Liquid loading effects. This is not a factor in evaluating directional drilling in Jonah. The EnCana report states: *"A review of the literature suggests that there are no problems particular to directional wells relating to plunger lift."* It also states: *"In a directional well there may be a tendency for sand to accumulate in the inclined section of the well if the angle is high"* Such sand accumulation will not occur in low angle 15^0 directional wells.

21.) Page 20 – Loss of recoverable reserves due to casing being stuck off bottom. The analysis of this scenario and the resulting conclusions are severely flawed. A detailed analysis is presented in **Appendix B** of this document. (Note that this is the same problem addressed by comment #18 above.)

The analysis in Appendix C demonstrates that the EnCana Reports' conclusion that this scenario will cause directional drilling to produce a loss of 200 BCF is overstated by a factor of 8.

22.) Pages 20 to 22 - Directional Drilling Times. The only valid, useful and applicable conclusion that can be derived from the information presented in this portion of the EnCana Report is stated in the middle of page 22: *"Directional wells require 5 to 6 days more drilling days than vertical wells".*

23.) Pages 22 & 23 – Conclusions of the EnCana Report. The Conclusions are numbered 1-9. A brief commentary on each of the EnCana Report conclusions follows:

1.) Unsubstantiated and grossly incorrect (see the analysis in Appendix C of this document)
2.) Misleading. Of the directional wells drilled to date the average incremental cost over a vertical well is roughly $240,000. (As illustrated by Figure 8 of the EnCana Report).
3.) Accurate, but with the establishment of a learning curve there is no reason why the average incremental time required to drill a Jonah directional well can't be reduced to 1 or 2 days over a vertical well.
4.) This is not a significant conclusion, it is an irrelevant observation regarding data scatter.
5.) As discussed in comment #12 above, this conclusion is absurd.
6.) As discussed above in comment #14, these are hypothetical solutions to an unsubstantiated and unquantified problem. If either of these solutions is needed on a significant number of the low angle Jonah directional wells, then chances are they will also be required on a significant number of vertical wells. As stated in the Encana Report: "*...this differential pressure requires significant attention to avoid stuck pipe and costly fishing jobs. Experienced rig personnel and above average drilling equipment is required to avoid problems.*" (Page 17.)

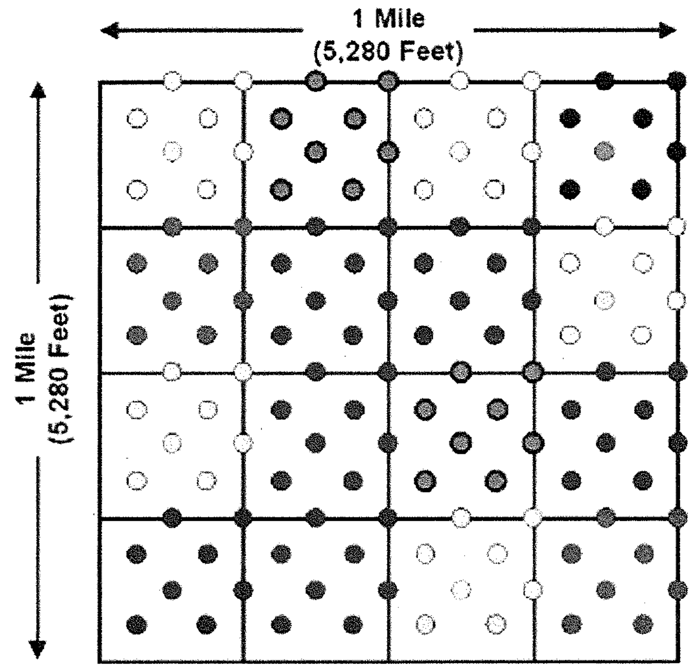
7.) As discussed in comment #21 and as supported by the analysis presented in Appendix B, the prediction that 200 BCF of recoverable reserves will be lost is overstated by a factor of 8.

8.) This conclusion is essentially a restatement of conclusion #6.

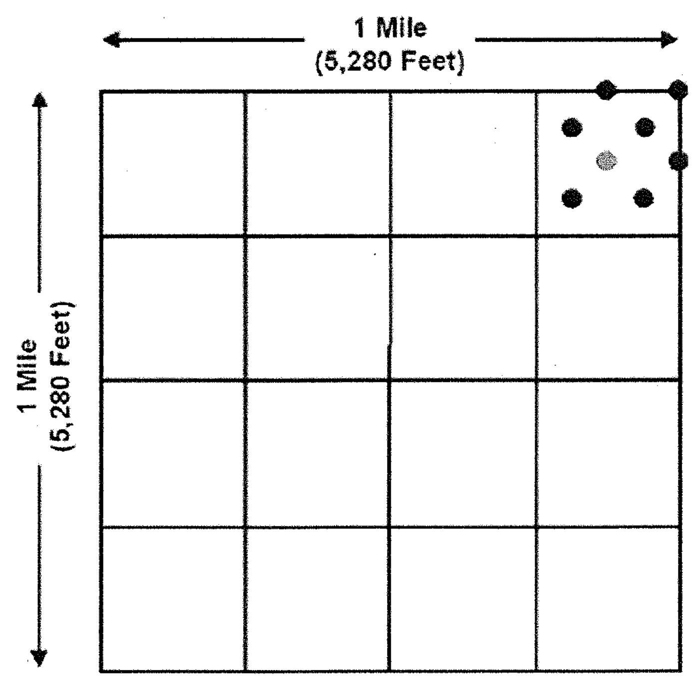
9.) It is true that, even after a learning curve is established and maintained, directional drilling will still take 1 – 2 days longer on average than a vertical well. This will be offset by a per well savings of about 2 days per well in rig moving time. Even if the drilling time difference cannot be reduced to 1-2 days, the environmental benefits of drilling from 40 acre spaced pads far outweigh any potential downside. There is no basis for the statement that *"The additional …cost, and potential for lost reserves associated with directional drilling may significantly increase the total life of the field."*

Appendix A

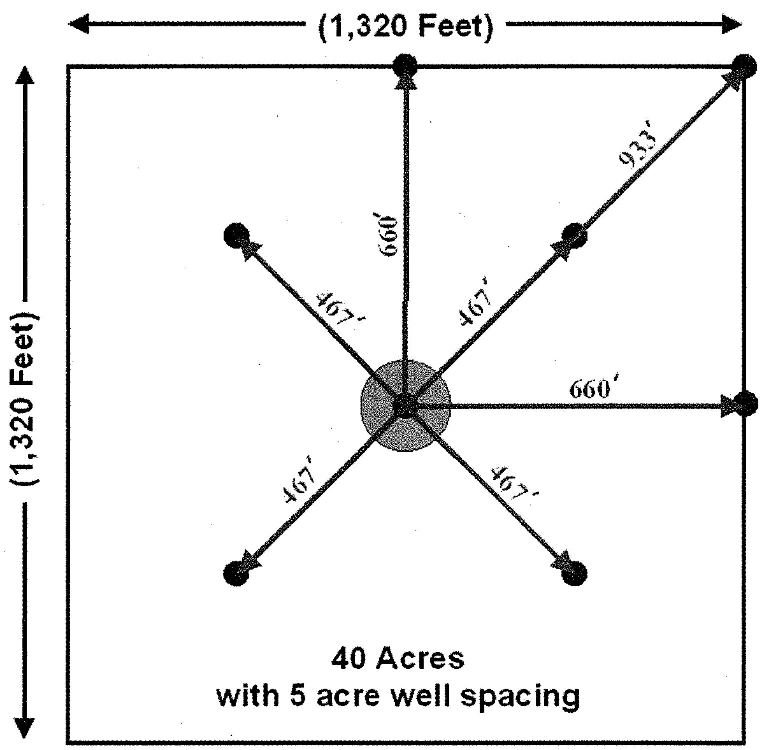
Directional Well Profiles Necessary to Develop the Jonah Field from Multi-well Pads Spaced 1 per 40 acres



128 wells per section = 1 well every 5 acres = 8 wells per 40 acres
The Jonah Field infill drilling area will cover over 32 sections of land
This diagram shows only 1 section

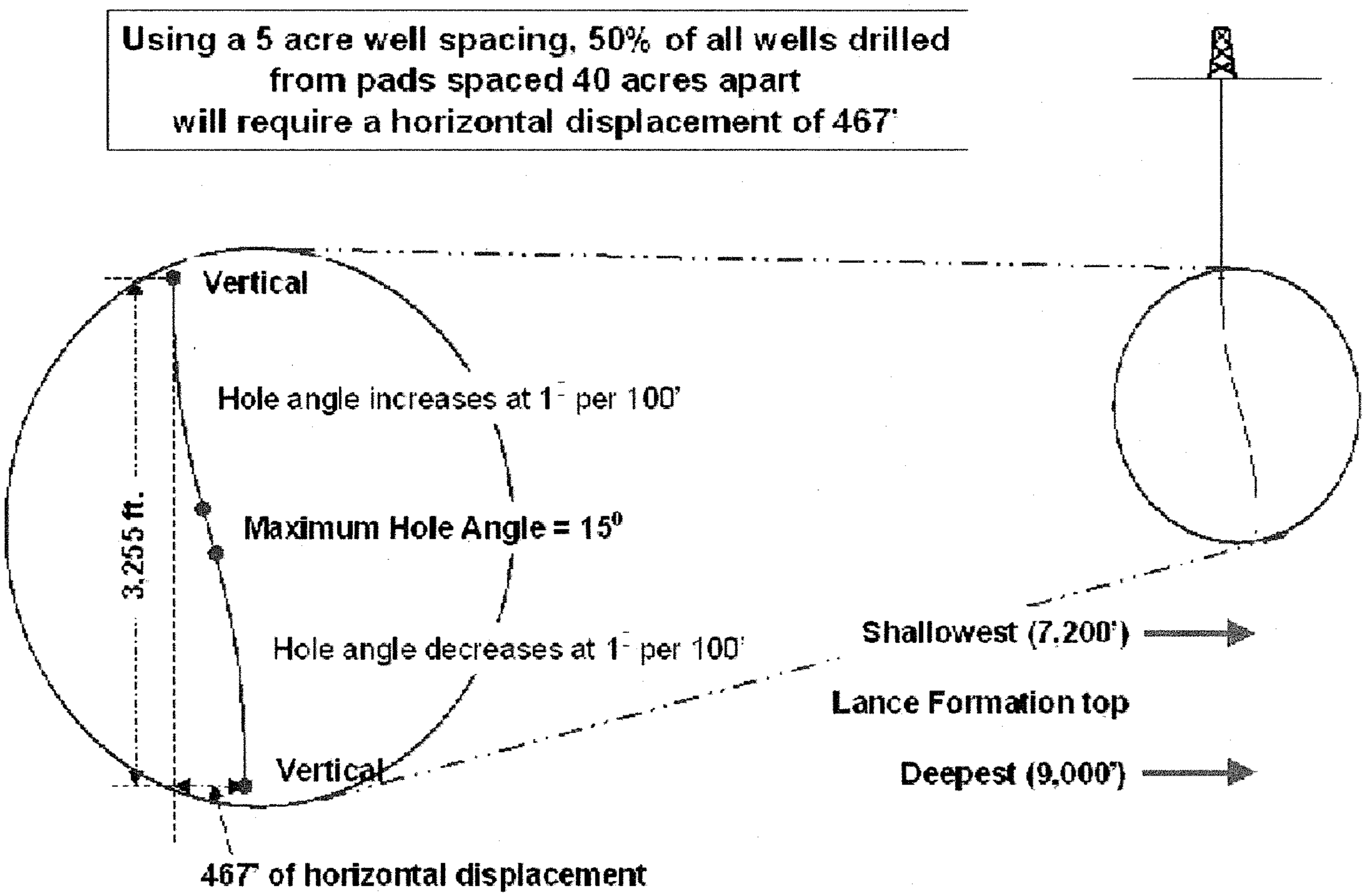


Lets take a closer look at the 8 wells in one 40 acre section

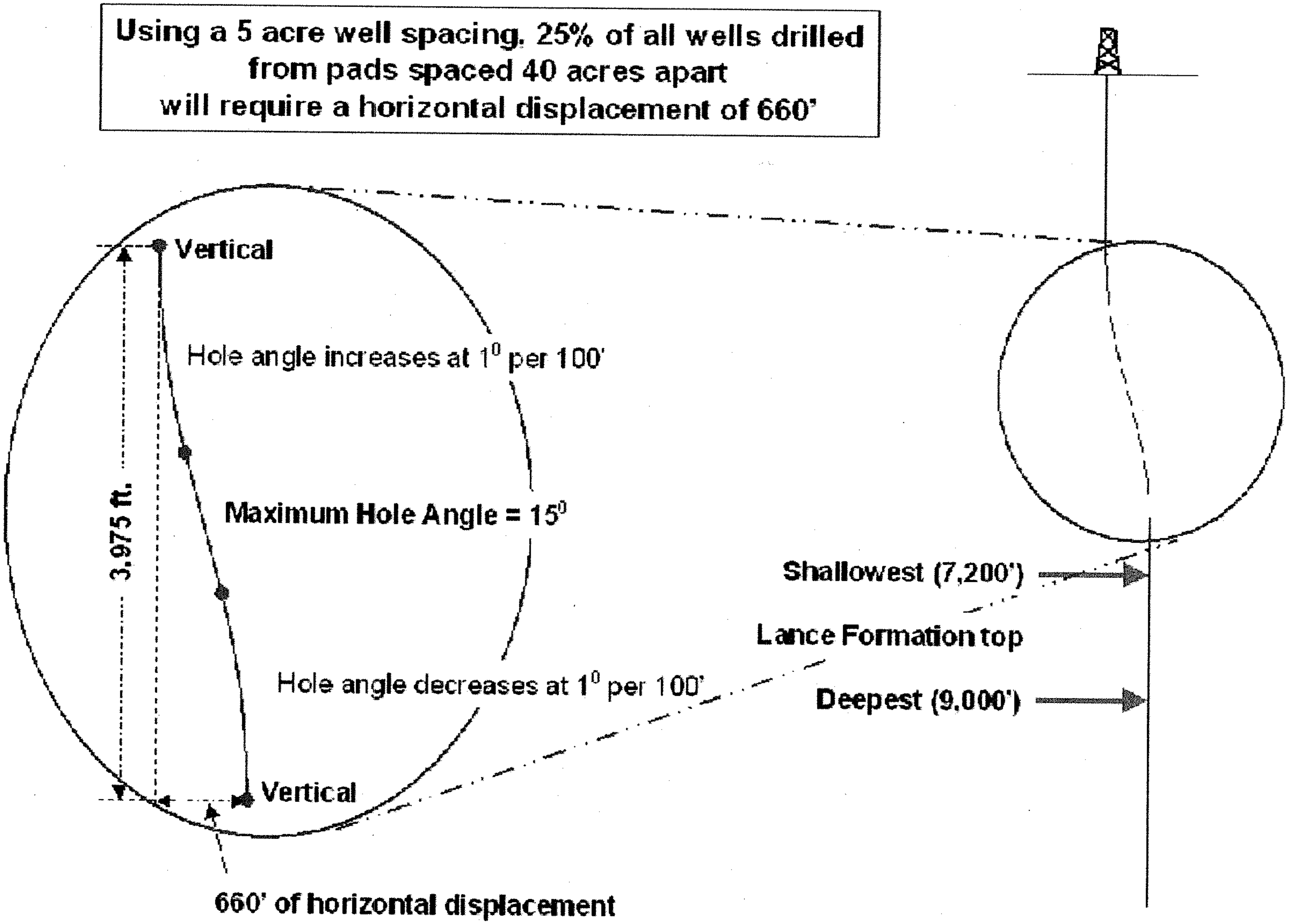


# wells	Displacement
1 (12.5%)	0 ft.
4 (50%)	467 ft.
2 (25%)	660 ft.
1 (12.5%)	933 ft.
8 (100%)	

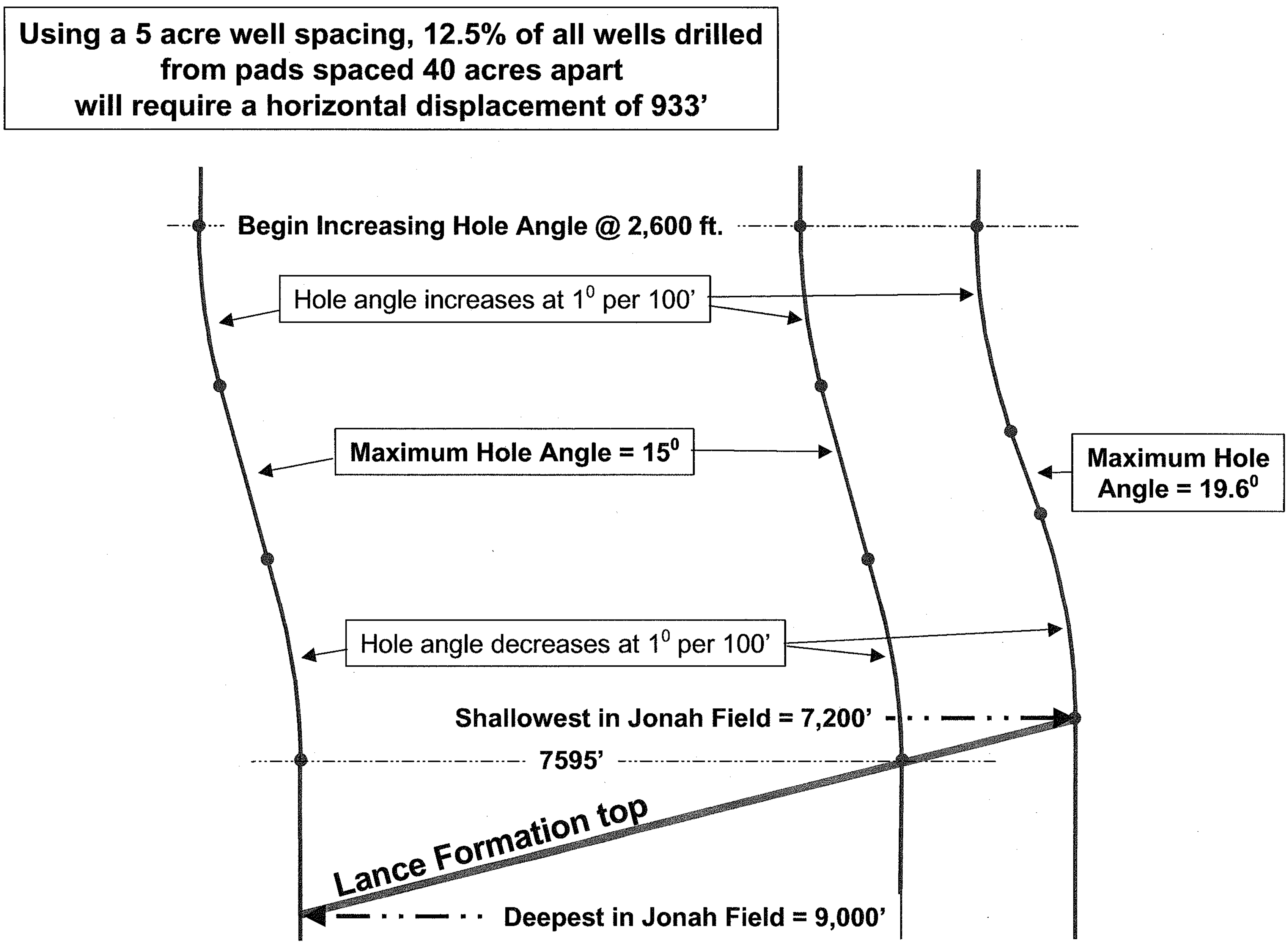
Average Well Displacement = 515 ft.



Scale Profile of a 12,000' deep well



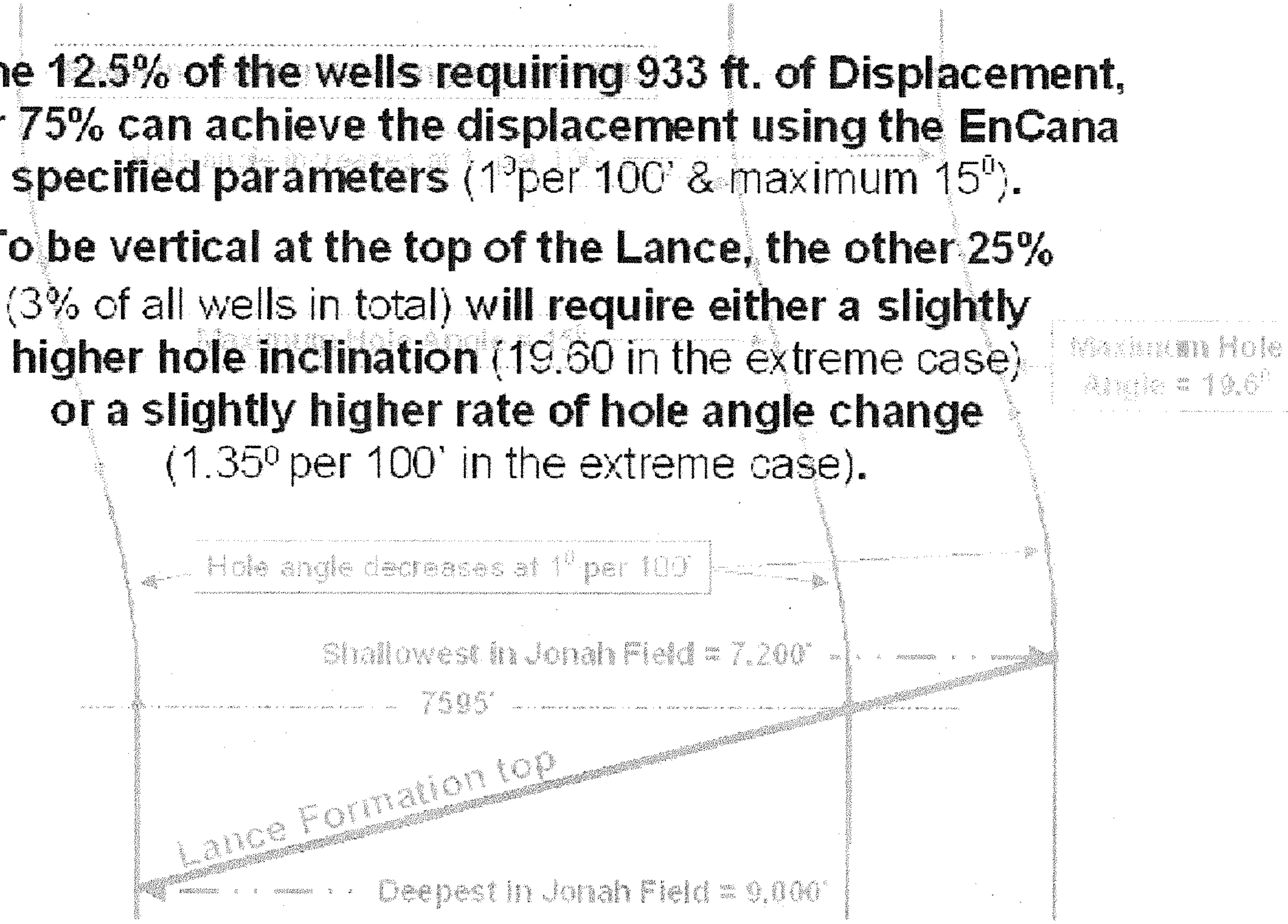
Scale Profile of a 12,000' deep well


Using a 5 acre well spacing, 12.5% of all wells drilled
from pads spaced 40 acres apart
will require a horizontal displacement of 933’
Begin Increasing Hole Angle @ 2,600 ft.
Hole angle increases at 1⁰ per 100’
Maximum Hole Angle = 15⁰
Maximum Hole Angle = 19.6⁰
Hole angle decreases at 1⁰ per 100’
Shallowest in Jonah Field = 7,200’
7595’
Lance Formation top
Deepest in Jonah Field = 9,000’

Using a 5 acre well spacing, 12.5% of all wells drilled
from pads spaced 40 acres apart
will require a horizontal displacement of 933'

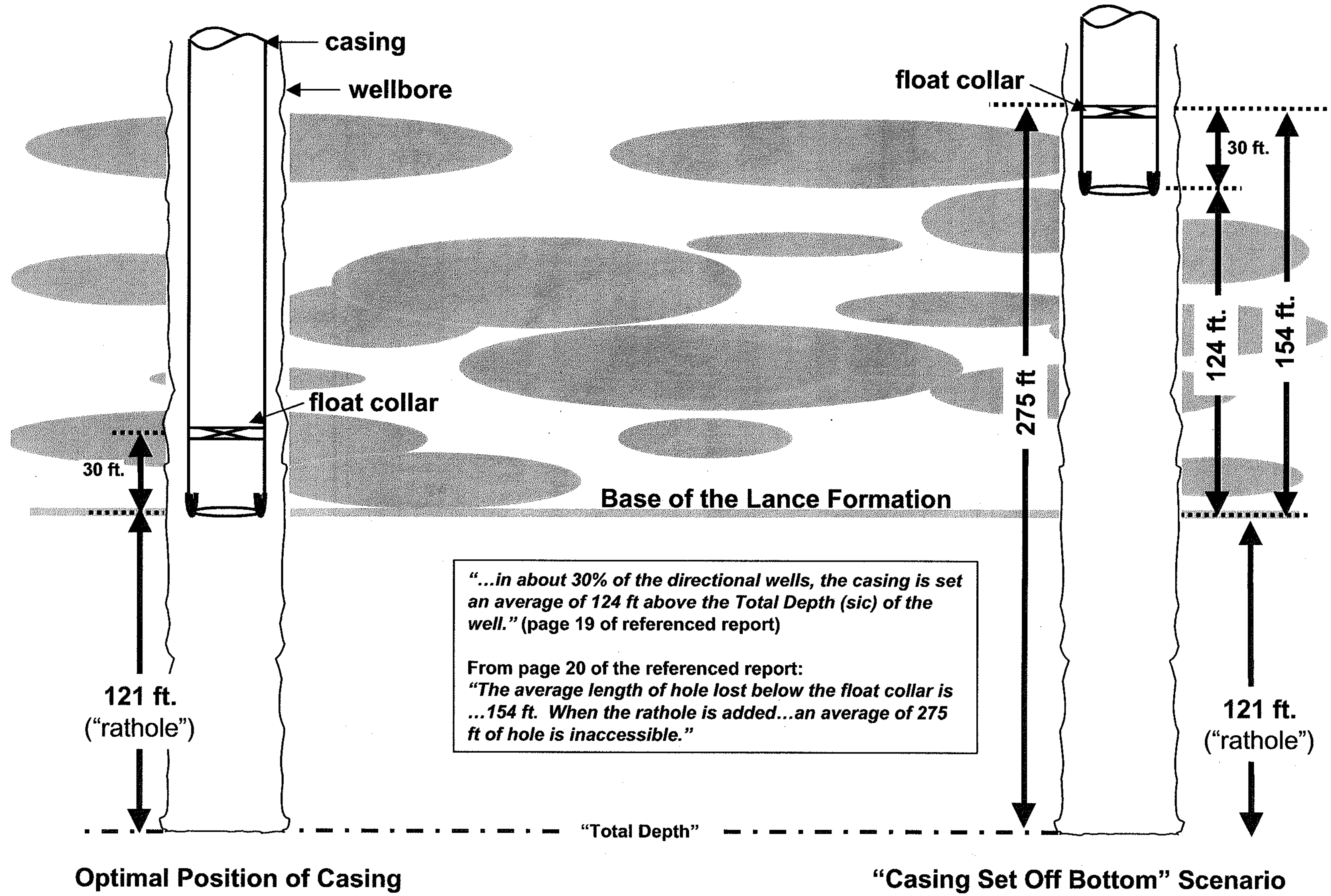
Of the 12.5% of the wells requiring 933 ft. of Displacement, over 75% can achieve the displacement using the EnCana specified parameters (1^0 per 100' & maximum 15^0).

To be vertical at the top of the Lance, the other 25% (3% of all wells in total) **will require either a slightly higher hole inclination** (19.60 in the extreme case) **or a slightly higher rate of hole angle change** (1.35^0 per 100' in the extreme case).

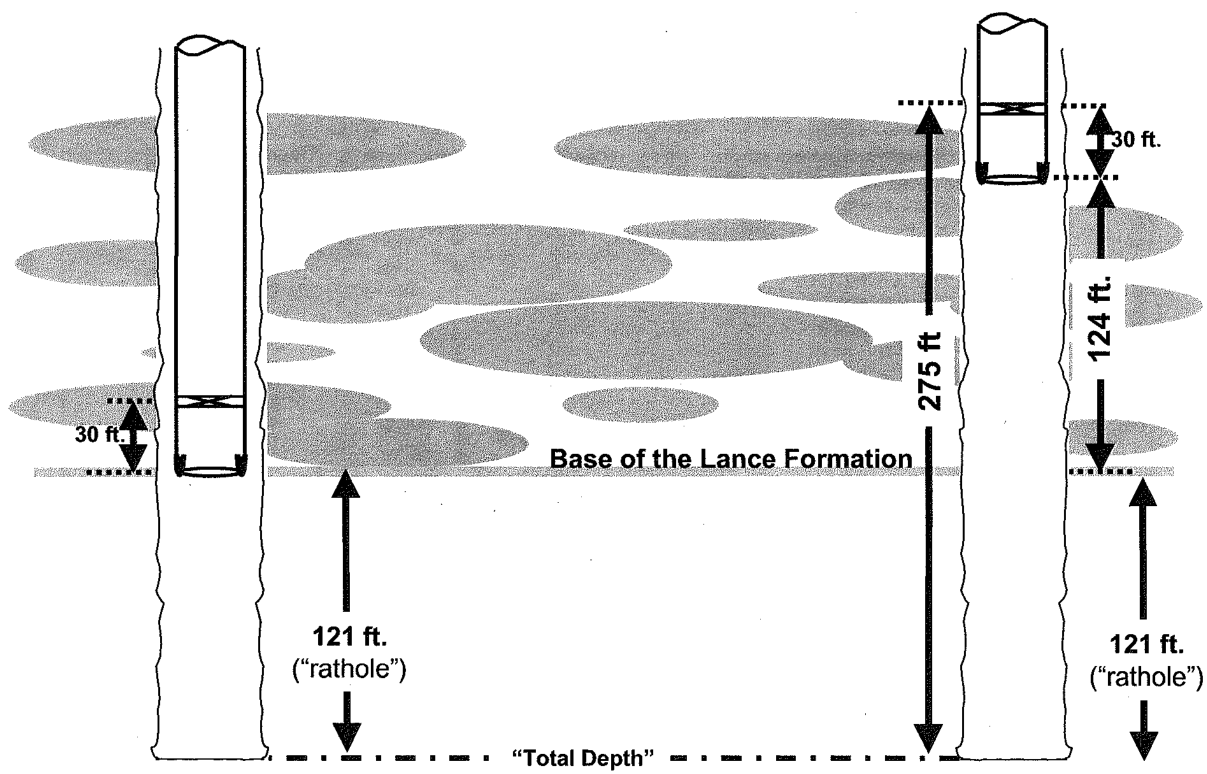


Appendix B

Analysis of the Impact of the Casing Stuck off Bottom Scenario on Recoverable Reserves

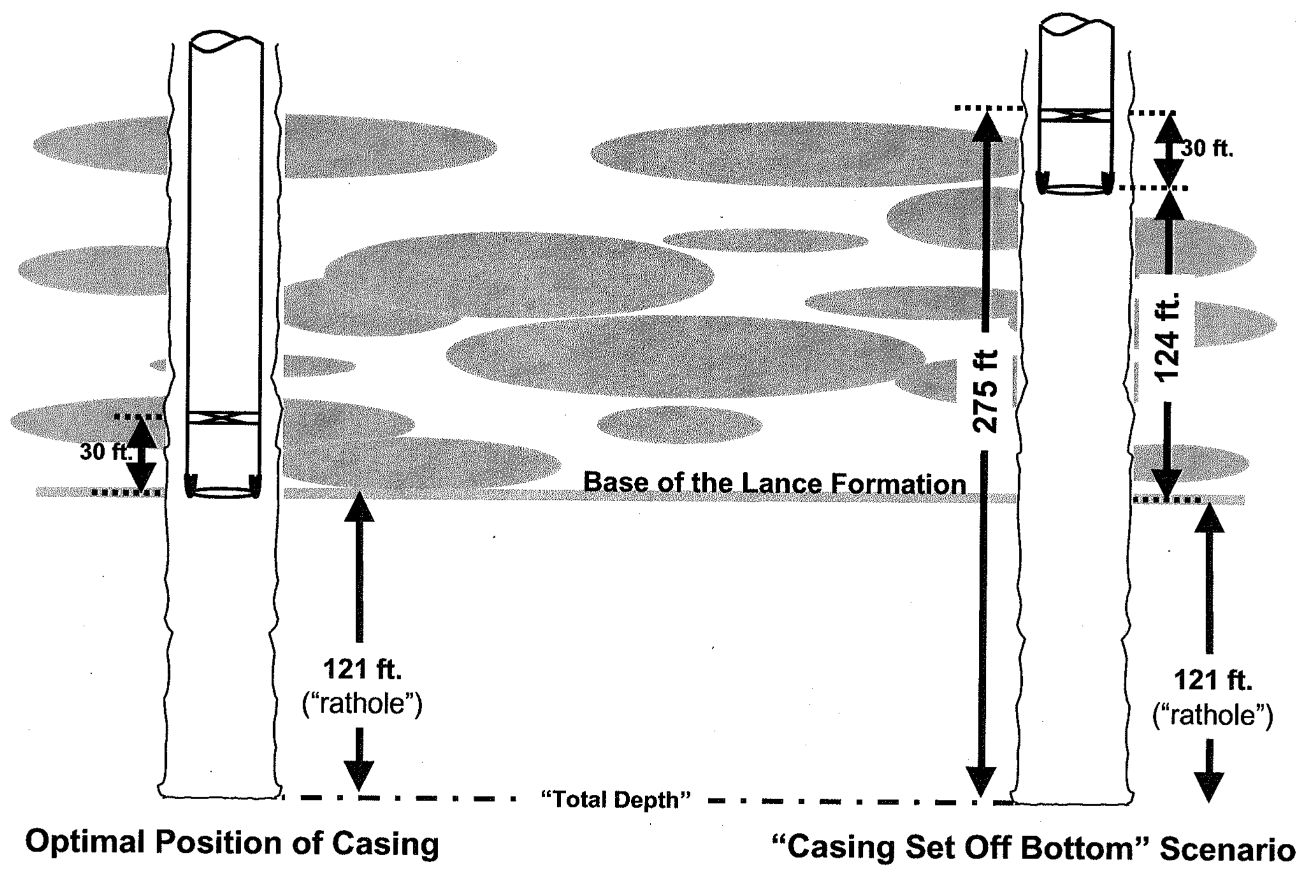

casing
wellbore
float collar
30 ft.
121 ft.
("rathole")
Base of the Lance Formation
"...in about 30% of the directional wells, the casing is set an average of 124 ft above the Total Depth (sic) of the well." (page 19 of referenced report)
From page 20 of the referenced report:
"The average length of hole lost below the float collar is ...154 ft. When the rathole is added...an average of 275 ft of hole is inaccessible."
float collar
275 ft
30 ft.
124 ft.
154 ft.
121 ft.
("rathole")
"Total Depth"
Optimal Position of Casing
"Casing Set Off Bottom" Scenario

The referenced report (page 20) concludes that, based on this "casing set off bottom" scenario, and *"The original gas in place for the bottom 275 feet of the Lance (including the rathole) (sic) was estimated... When a 30% probability of setting casing 124 ft. high is applied to the 1824 wells to be drilled on 10 acre spacing, assuming an all directional option, the estimated lost gas reserve is 200 BCF"*

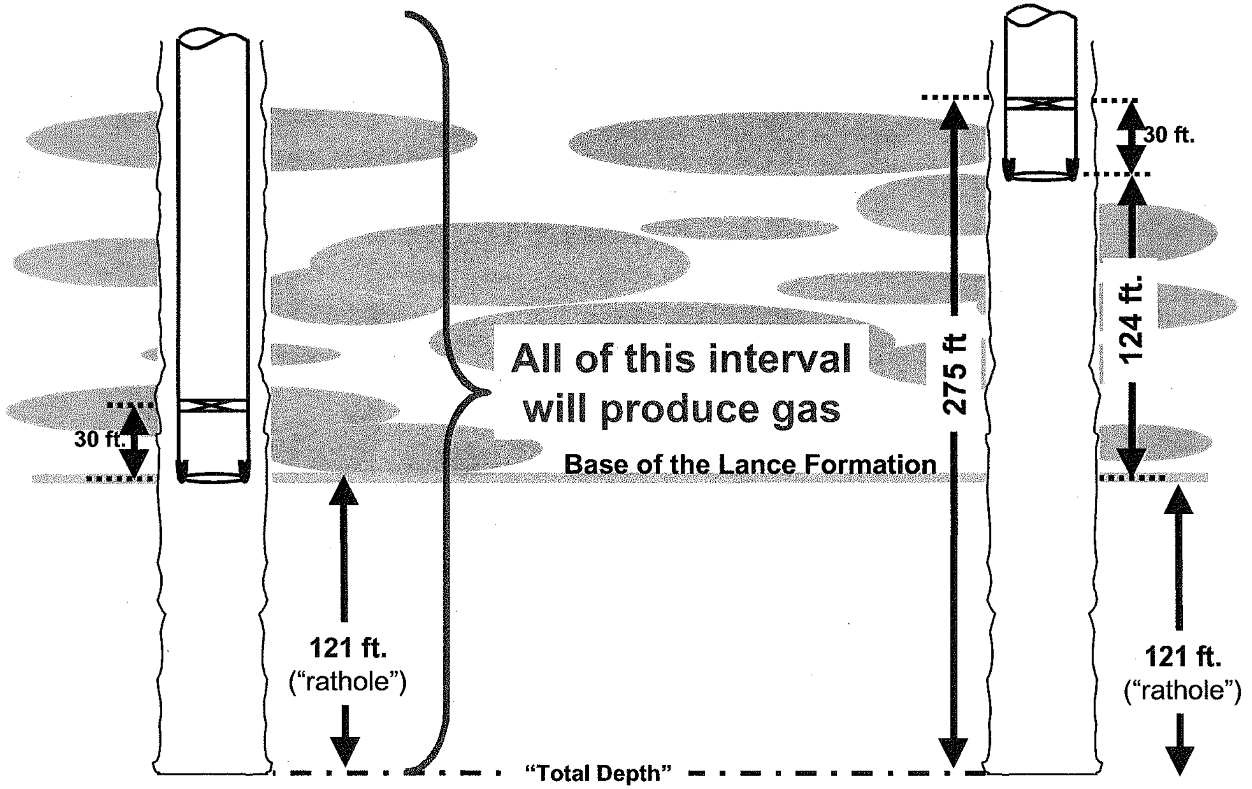


Optimal Position of Casing **"Casing Set Off Bottom" Scenario**

This number of 200 BCF lost reserves is grossly overstated because the logic used to derive the number is flawed on at least three counts which should be obvious to even the non-expert reader .

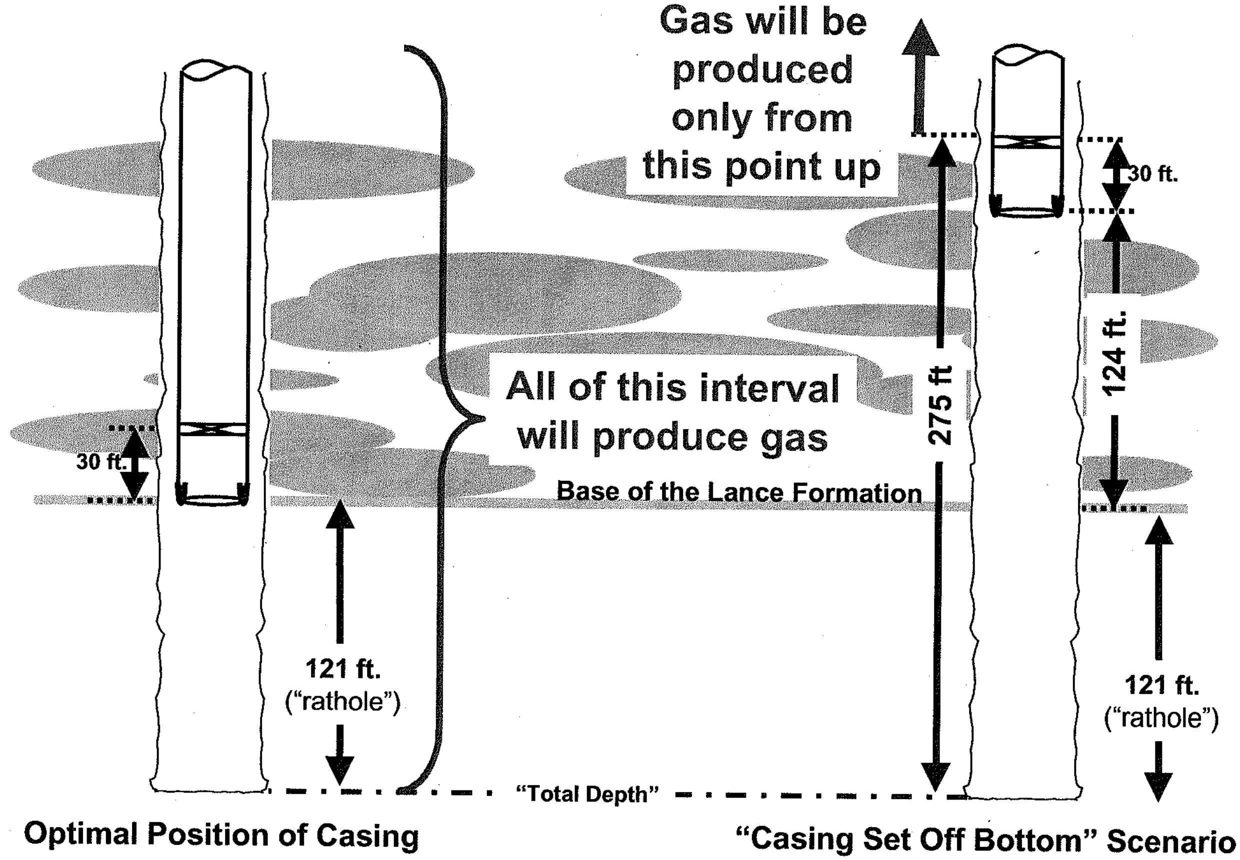


For the Optimal Case, the logic of the referenced report assumes that gas will be produced throughout the entire lance interval, including the 121 feet of rathole below the bottom of the casing and also for the 30 feet of Lance formation that is below the float collar.

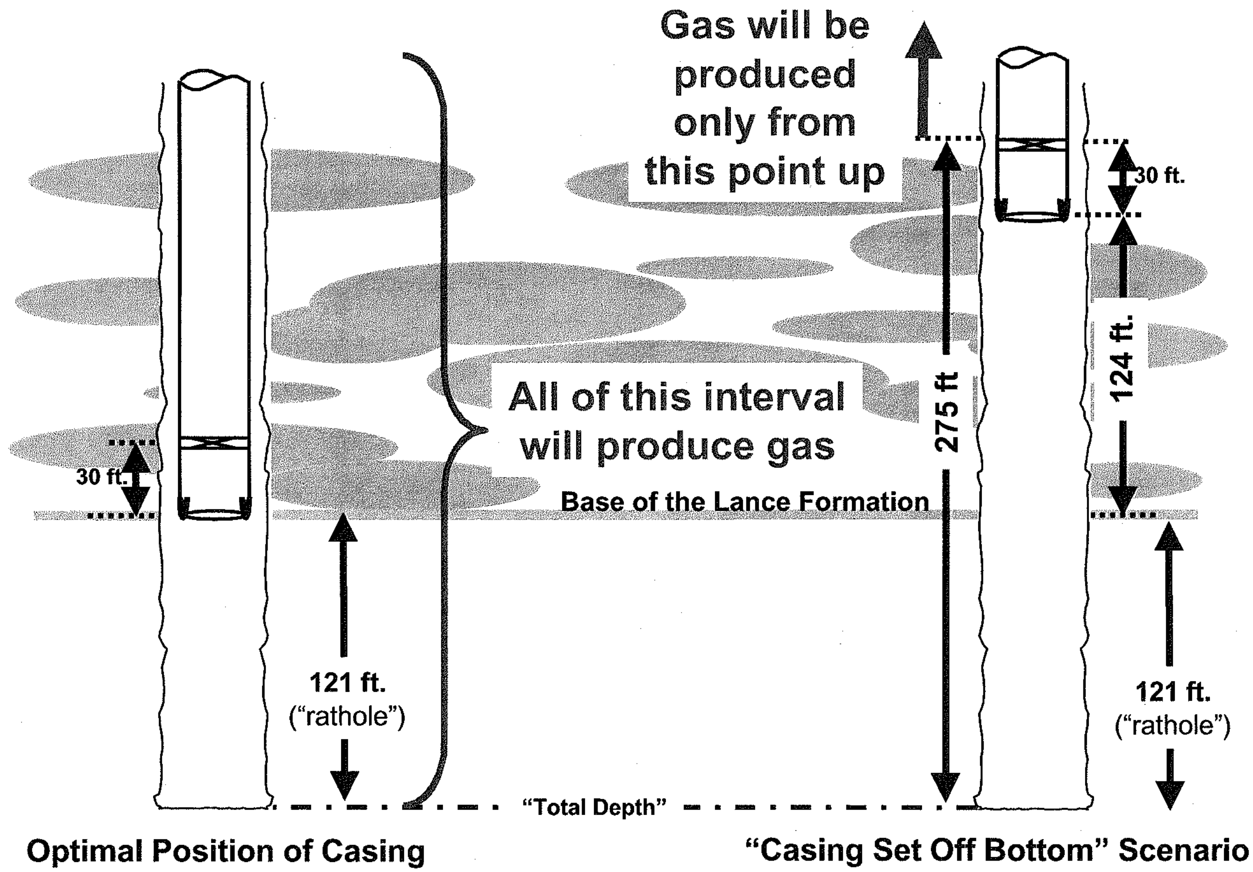


Optimal Position of Casing **"Casing Set Off Bottom" Scenario**

For the Casing set off bottom case, the logic of the referenced report assumes that gas will be produced <u>only</u> from the portion of the Lance interval which is <u>above</u> the float collar. The referenced report was not consistent in it's application of assumptions. The "casing stuck off bottom scenario" did not receive the benefits of the assumptions used in "Optimal" case; i.e. when casing was stuck off bottom, it was assumed that there would be <u>no</u> production from the open hole interval below the casing <u>or</u> from the 30 feet of Lance formation below the float collar.



Using this flawed comparison between the Optimal case and the Casing Set Off Bottom case, the report assumes that 275 ft. of producing interval will be "lost" if the casing is stuck 124 feet "off bottom". The actual loss is 124 feet and therefore the actual loss of gas is less than half the estimated 200 BCF.



There are two other counts in which the report's analysis and conclusion concerning the "casing set off bottom" scenario are flawed:

1.) The report assumes that all the gas in the lower 275 ft. of Lance will be lost on the 30% of the wells in which casing is set off bottom. For these wells, this equates to "*an average of 362 MMSCF*" per well (page 20). At <u>today's</u> gas prices this represents $2,000,000 of production. On Page 19 however the report states that the problem of casing set off bottom can be remedied by spending $250,000 to "*run a 2 7/8" liner.*" Why wouldn't you spend $250,000 to recover these "lost" reserves that are worth $2,000,000?

The report indicates that "fracturing" through the 2 7/8" liner is not as effective as fracing through the 4 1/2" casing. No indication is given of what fracturing efficiency can be expected with this remedy, but if we assume a low efficiency of only 50%, this would <u>further</u> reduce the estimated "lost reserves" by half...bring the original 200 BCF figure to about 50 BCF.

2.) Without stating so, and without offering any data on vertical well problems with running casing, the report analysis is based upon the assumption that the "casing set off bottom" scenario does not occur at all for vertical wells. If this scenario has occurred on 30% of all directional wells, then it seems likely that it is occuring on a significant number of vertical wells also. If we assume that 15% of vertical wells experience the same scenario, then the "lost" reserves due to directional drilling are further reduced by half...bringing the original 200 BCF figure to about 25 BCF. This amounts to 3 /10ths of 1 percent of the total EUR of Encana's Proposed Action.

Appendix C

Analysis of the JIDP Draft EIS Conclusions Concerning Reductions in Recoverable Reserves due to Directional Drilling

1.0 Introduction

A stated BLM objective concerning the further development of the Jonah Field is to "optimize natural gas recovery"[5]. To the degree that any of the Alternatives analyzed in the Draft EIS are shown to have a significant negative impact on gas recovery, they will be considered undesirable from the standpoint of this objective.

The Draft EIS recognizes that the use of directional drilling in the Jonah Field will reduce the amount of new ground disturbance required by EnCana's Proposed Action by as much as 80%[6]. However, based largely on "information" provided by EnCana, the Draft EIS also concludes that directional drilling will have a significant negative impact on natural gas recovery in the Jonah Field. The Draft EIS concludes that each of the Alternatives evaluated will result in "Unrecovered (Gas) Volumes"[7] proportional to the percentage of directional wells.

The Draft EIS cites[8] two factors that cause directional drilling to reduce recoverable reserves:

Factor #1 – Production from the lower 1,000 feet of the Lance formation will be lost on 10% of the directional wells because those wells will not reach their planned total depth.

Factor #2 – An unspecified number of the 3,100 planned wells assumed to be in the "lower EUR / Well population"[9] will remain "undeveloped" because the incremental costs of directional drilling will make them "uneconomic".

It is impossible that these two factors could cause the "Unrecovered Gas Volumes" claimed in the Draft EIS. This fact will be clearly demonstrated in the following pages with analysis that incorporates comparisons between Encana's Proposed Action and Alternative E.

The Draft EIS Alternative E will permit EnCana to drill all their planned wells from well pads spaced 40 acres apart. Alternative E will reduce new surface disturbance that would result from EnCana's proposed action by over 60%[2]. Under Alternative E, approximately 95% of the future wells will be directionally drilled.

The Draft EIS erroneously concludes that the gas recovery from all future wells drilled under Alternative E will be 36% less than from all future wells drilled under EnCana's Proposed Action[10].

2.0 Analysis of Factor #1

The basis of Factor #1 is the assumption that 10% of all directional wells that might be drilled as part of the Jonah Infill Drilling Project (JIDP) will be unsuccessful in setting production casing at a depth that is within 1,000 feet of the planned total depth of the well. This assumption is contrary to the overwhelming experience of the oil and gas industry, and is presented in the Draft EIS without

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5 From a public presentation by BLM manager Carol Kruse – Pinedale March 23, 2005

6 DEIS, page 2-33, Table 2.12 (To determine the amount of "new" disturbance for any Alternative, subtract the "No Action" surface disturbance from the surface disturbance stated for the Alternative of interest.)

7 Appendix G, page 14, Table 2.3

8 Appendix G, page 14, Table 2.3, footnote #3

9 Page 10, Jonah Infill Drilling Project Evaluation of Directional Drilling. Prepared for EnCana Oil and Gas (U.S.A.) Inc., by Reservoir Management Services Inc.

10 DEIS, page 2-33, Table 2.12 (To determine the gas recovery from future JIDP infill wells, for any Alternative, subtract the "No Action" gas recovery from the gas recovery stated for the Alternative of interest.)

supporting documentation[11]. However, for the sake of demonstrating the gross errors in the Draft EIS conclusions regarding the impact of directional drilling on recoverable gas reserves, we will assume here that the underlying assumptions of Factor # 1 are reasonable.

Within the Jonah Field, the depth of the top of the Lance Formation (which is the formation containing the gas), ranges from 3,200 ft. to 5,100 ft.[12]. Therefore, the average thickness of the Lance is 4,150 ft.

If the loss of recoverable reserves was directly proportional to the ratio of the thickness of the Lance Formation lost on the 10% of the wells assumed to be impacted by Factor #1 (1,000 ft.) to the total average thickness of the Lance (4,150 ft.), then the expected loss would be 24.1% of the resources on 10% of the directional wells.

$$1{,}000 / 4150 = 24.1\%$$

The actual loss is somewhat greater however. This is because the amount of gas per foot of Lance Formation increases with depth. This happens because pressure in the formation increases with depth and natural gas is compressible. Therefore, losing production from the lowest 1,000 feet of Lance Formation is more detrimental than losing 1,000 ft. of production higher in the formation.

Using Jonah formation pressure data from a document that is referenced by the BLM in the Draft EIS[13], basic engineering calculations were used to estimate the effect of Lance formation pressure on recoverable gas volumes. These calculations indicate the actual loss of recoverable reserves to be approximately 44% per well on the 10% of the directional wells assumed to be subject to Factor #1.

In conclusion, if 95% of the future wells in Jonah were directionally drilled (as in Alternative E), and if 10% of those directional wells experienced a loss of 44%, the overall loss of the entire Jonah Infill Drilling Project due to Factor #1 would be 4.2% of the recoverable reserves that would otherwise be recovered under EnCana's Proposed Action.

$$44\% \times 10\% \times 95\% = 4.2\%$$

A report authored by an EnCana consultant and referenced in the Draft EIS[14] recognizes that when casing is stuck off bottom, remedial actions can be taken that will allow much of the otherwise lost gas to be recovered. Although the report concludes that these remedial actions

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[11] The casing stuck off bottom scenario is discussed (and misrepresented) in pgs.19 and 20, Jonah Infill Drilling Project Evaluation of Directional Drilling. Prepared for EnCana Oil and Gas (U.S.A.) Inc., by Reservoir Management Services Inc. Here, it states that on 30% of the directional wells drilled in Jonah to date, casing was set high by an average of 124 feet. Any analysis of the effect of this problem on recoverable reserves must also quantify the frequency with which the problem occurs on vertical wells. The referenced report concludes erroneously that setting casing 124 feet high will result in loss of production from the lower 275 feet of Lance.

[12] Page 8, Jonah Infill Drilling Project Evaluation of Directional Drilling. Prepared for EnCana Oil and Gas (U.S.A.) Inc., by Reservoir Management Services Inc.

[13] Page 17, Jonah Infill Drilling Project Evaluation of Directional Drilling. Prepared for EnCana Oil and Gas (U.S.A.) Inc., by Reservoir Management Services Inc.

[14] Page 19, Jonah Infill Drilling Project Evaluation of Directional Drilling. Prepared for EnCana Oil and Gas (U.S.A.) Inc., by Reservoir Management Services Inc.

may not be economically feasible in all cases, it is reasonable to assume that the remedial actions would be taken on a significant percentage of the wells subject to Factor #1. Therefore, even assuming that the underlying assumptions of Factor #1 are reasonable, it is likely that the actual losses would be significantly less than 4.2%.

2.1 Factor #1 Conclusion

The Draft EIS projects that gas recovery from future wells drilled under Alternative E will be 36% less than under EnCana's Proposed Action. The analysis just presented demonstrates that a loss of no more than 4.2% can be attributed to Factor #1.

$$36\% - 4.2\% = 31.8\%$$

The remaining 31.8 % loss of gas reserves projected by the Draft EIS under Alternative E must be attributed to Factor #2.

3.0 Analysis of Factor #2

The analysis of Factor #2 will involve the investigation two questions:

Question #1 – In order to produce a 31.8% reduction in recoverable gas reserves, what percentage of the vertical wells planned under EnCana's Proposed Action would be assumed to become uneconomical under the directional drilling requirements of Alternative E?

Question #2 – Given the economics of the Jonah Field, is the answer to Question #1 reasonable, or even possible?

3.1 Investigation of Question #1 related to Factor #2

To answer Question #1, it is necessary to estimate how the overall population of future wells will contribute to the total gas recovery from the Jonah Infill Drilling Project (JIDP).

The amount of gas that a well is expected to produce throughout its lifetime is called the well's Expected Ultimate Recovery or "EUR". The Draft EIS projects that the total EUR from all future wells drilled under EnCana's Proposed Action is 4,581 BCF[15]. Assuming that this production will come from 3,100 wells (EnCana's projected maximum number of wells), the average well EUR under the Proposed Action is 1.477 BCF / well.

Average JIDP well EUR ("Proposed Action") = 4,581 BCF / 3,100 wells = 1.477 BCF / well

When infill drilling within an oil or gas field, a wide range of well performance can be expected. However, most wells will have EUR's that are relatively close to the average EUR. Relatively few wells will have EUR's that are either significantly higher or significantly lower than the average EUR.

To answer Question #1, a graph was made of "JIDP Well EUR Percentile" versus "JIDP Cumulative EUR Percentage". To create this graph, all the JIDP wells were ordered according to their Expected Ultimate Recovery. If a well has EUR Percentile of 72.6%, that means its EUR is greater than 72.6% of all the wells.

[15] DEIS, page 2-33, Table 2.12 (To determine the gas recovery from future JIDP infill wells, for any Alternative, subtract the "No Action" gas recovery from the gas recovery stated for the Alternative of interest.)

If all the JIDP wells had EUR's that were nearly equal, then the wells in lowest 10 percentile (i.e. 0% to 10%) would contribute nearly the same percentage to the "JIDP Cumulative EUR" as the wells in the highest 10 percentile (i.e. 90% to 100%), and the graph would resemble a straight line as shown in **Figure 1**.

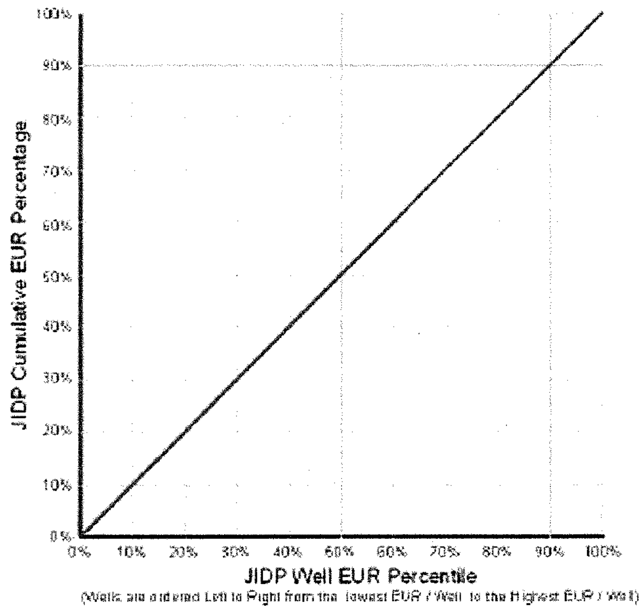

Figure 1

However, as discussed above, the JIDP wells can be expected to have a wide range of EUR's. Therefore, a curve with a shape similar to the one shown in Figure 2 is more realistic. The curve in **Figure 2** represents the case where the lowest performing two thirds (i.e. 66 percentile and lower) of the well population is contributing only 50% of the total JIDP gas recovery.

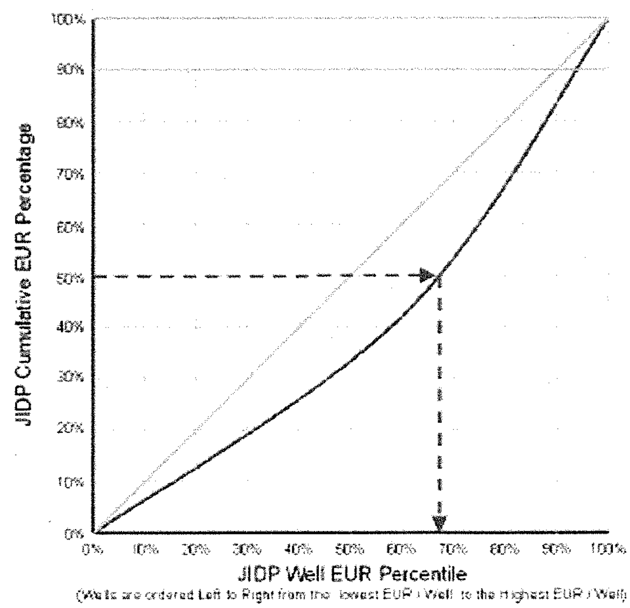

Figure 2

Because the Draft EIS does not contain sufficient information to support its conclusions, an educated guess must be made as to the exact shape of the curve that best represents the expected EUR performance from the JIDP wells under EnCana's Proposed Action.[16] This uncertainty is illustrated by **Figure 3**.

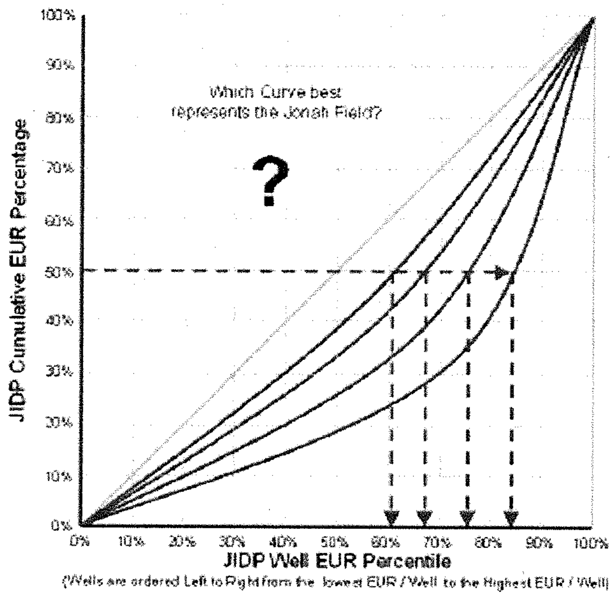

Figure 3

This analysis will assume that the most representative curve is the one shown in Figure 2. The answer to Question #1 can now be determined by reading the graph as shown in **Figure 4**.

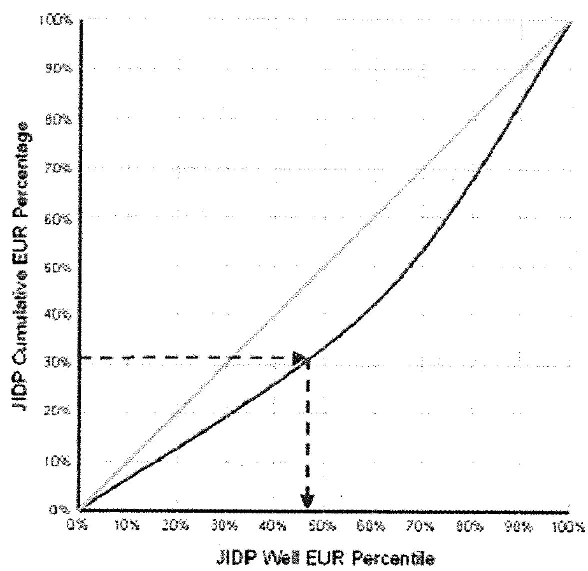

Figure 4

[16] No analysis can be made concerning the effect of well economics on recoverable reserves without analyzing the range of well EUR's in a manner similar to the one presented here. However, no evidence of such an analysis is presented in the DEIS.

3.2 Answer to Question #1 related to Factor #2

In order to produce the 31.8% reduction in recoverable gas reserves, approximately 47% of the vertical wells planned under EnCana's Proposed Action would have to be assumed to become uneconomical under the directional drilling requirements of Alternative E.

3.3 Investigation of Question #2 related to Factor #2

Question #2 can now be restated to be more specific:

> *"Given the economics of the Jonah Field, is it reasonable, or even possible, that approximately 47% of the wells planned under EnCana's Proposed Action could be assumed uneconomic if subjected to the directional drilling requirements of Alternative E?"*

To answer Question #2, it is necessary to evaluate the economics of the Jonah Infill Drilling Project. The project economics were evaluated for two scenarios using cost data provided in the Draft EIS:

1.) EnCana's Proposed Action
2.) Alternative E

These evaluations are summarized in Table 1 and Table 2 respectively.

To the degree possible, the economic evaluations are based on the assumptions or data provided in the Draft EIS.[17] The evaluations indicate that the vertical average well profitability under EnCana's Proposed Action will be approximately $4.5 million per well. If the wells are drilled directionally in accordance with Alternative E, the average well profitability is predicted to be approximately $4.0 million per well.

The predicted difference in well profitability between the two scenarios is approximately $500,000 per well. Therefore, if a vertical well to be drilled under EnCana's Proposed Action was predicted to produce a profit margin of $500,000 or less, then it would also be predicted to be "uneconomical" if subjected to the directional drilling requirements of Alternative E.

Based upon the results of the economic analysis, Question #2 can be restated once again:

> *"Given that the average well profitability under EnCana's Proposed Action is approximately $4.5 million, is it reasonable, or even possible, that approximately 47% of the wells could have a profit margin of $500,000 or less?"*

Although the average profitability of wells drilled under EnCana's Proposed Action is estimated to be approximately $4.5 million, the profitability of individual wells will fall within a range that is centered on this average number. The range of well profitability results from varying gas recovery per well and differences in costs incurred in drilling and completing each well. Most wells will produce a profit that is relatively close to the estimated average well profit. Relatively few wells will have profits that are either significantly higher or significantly lower than the average well profit. This distribution of well profitability is illustrated by **Figure 5**.

[17] DEIS, Pages 411 & 412, Tables 4.12 & 4.13

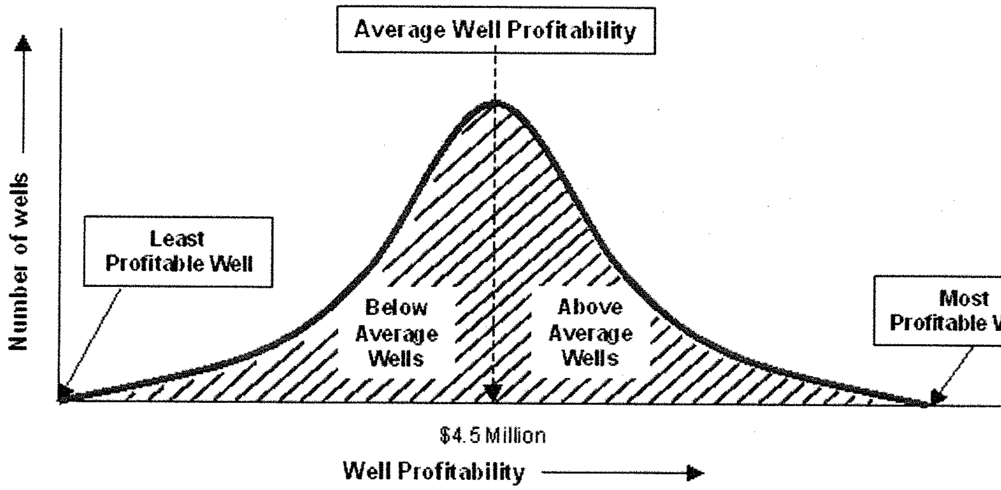

Figure 5
Distribution of Individual Well Profitability under EnCana's Proposed Action

Given this normal distribution of well profitability, only a very small percentage of the wells drilled under EnCana's Proposed Action could be expected to have a profitability of $500,000 or less. The probability of any given well having profitability equal to, or less than, a particular dollar amount is proportional to the ratio of the area under the curve and left of the dollar amount to the total area under the curve. In Figure 6, it can be seen that the shaded area to the left of $500,000 is very small in relation to the total area under the curve.

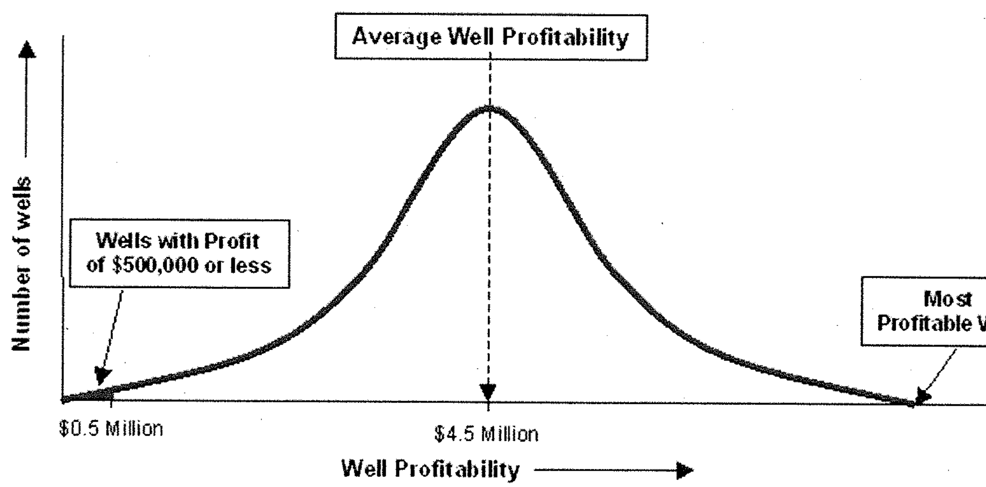

Figure 6

3.4 Answer to Question #2 related to Factor #2

It is statistically impossible that more than a couple percent of the wells planned under EnCana's Proposed Action could be expected to have a profit margin of $500,000 or less.

3.5 Factor #2 Conclusion

No more than about 2% of the 3,100 wells planned under EnCana's Proposed Action can be reasonably projected to have a profit margin low enough ($500,000 or less) to cause them to become uneconomical under the directional drilling requirements of Alternative E. Because these uneconomical wells will be from the "lower EUR / well population"[18], the resulting loss of gas reserves will be even less than 2%.

4.0 Over-all Conclusion

This analysis demonstrated the following facts:

1.) The Draft EIS conclusions concerning reductions in recoverable reserves due to directional drilling are grossly inaccurate.
2.) The Draft EIS claim that two factors (a frequent inability to drill and case the lower 1,000 feet of Lance formation and well economics) will cause Alternative E to lose 36% of the gas reserves that would otherwise be recoverable under EnCana's "Proposed Action" is statistically impossible.
3.) In no case could the these two factors result in a loss of more than about 6.5% and even that number is a significant stretch.

[18] Page 10, Jonah Infill Drilling Project Evaluation of Directional Drilling. Prepared for EnCana Oil and Gas (U.S.A.) Inc., by Reservoir Management Services Inc.

Table 1

Jonah Infill Drilling Project

Economic Evaluation[1] under EnCana's Proposed Action

	Total JIDP under Proposed Action	Average Well under Proposed Action (assuming 3100 wells)	Draft EIS Reference or Assumptions
Income			
Gross Natural Gas Production	4,581 BCF	1.477 BCF	Table 2.12 (7947 BCF - 3,366 BCF= 4,581 BCF)
Net Natural Gas Production (after Royalty)	4,008 BCF	1.293 BCF	12.5% Federal Royalty
Gross Condensate Production	44 million bbls	14,194 bbl	Table 2.12 (76 mmbbls - 32 mmbbls = 44 mmbbls)
Net Condensate Production (after Royalty)	38.5 million bbls	12,419 bbl	12.5% Federal Royalty
Natural Gas Income	$23.807 Billion	$7,679,677	Assumed $5.40 / mmbtu and 1.1 mmbtu/mcf ($1 less than current Opal prices)
Condensate Income	$1.540 Billion	$496,774	Assumed $40.00 per Barrel ($15 less than current prices)
Total Income	**$25,347,000,000**	**$8,176,452**	
Direct Costs (Vertical Well)			
Drilling	$2,026,079,400[2]	$653,574[2]	Table 4.13
Completion	$4,752,641,000	$1,533,110	Table 4.13
Total Direct Costs	**$6,778,720,400**	**$2,186,684**	
Production Costs			
$.32 per mcf	**$1,282,560,000**	**$413,729**	From Table 4.12 (includes the cost of producing the associated condensate)
Plug, Abandon & Reclaimation			Plug, Abandon & Reclaimation costs are estimated - no costs provided in the DEIS
Plug and abandon well	**$93,000,000**	**$30,000**	
Land surface reclaimation	**$162,000,000**	**$52,258**	Esitmated at $10,000 per acre of new disturbance (16,200 acres under "Proposed Action"[3])
Taxes & Royalties			
Wyoming Mineral Severance Tax	**$1,520,820,000**	**$490,645**	6 % of Production Value (net of Royalties)
Sublette County Property Tax	**$1,495,473,000**	**$482,258**	5.9% of Production Value (net of Royalties)
Net Earnings Before Income Tax	**$14,014,426,600**	**$4,520,783**	

Notes:

1 Using Draft EIS data for production volumes, new surface distrubance acreage, and drilling, completion and production costs

2 Assumed "Conventional Well" (i.e. "vertical well") drilling cost from Draft EIS Table 4.13

3 From Table 2.12 (Proposed Action Disturbance Acreage minus No Action Disturbance Acreage)

Table 2

Jonah Infill Drilling Project

Economic Evaluation[1] under Alternative E

	Total JIDP under Alternative E	Average Well under Alternative E (assuming 3100 wells)	DEIS Reference or Assumptions
Income			
Gross Natural Gas Production	4,389 BCF	1.416 BCF	Assumes that Production is decreased by 4.2% due to "Factor #1"[2]
Net Natural Gas Production (after Royalty)	3,840 BCF	1.239 BCF	12.5% Federal Royalty
Gross Condensate Production	42.2 million bbls	13,613 bbl	Assumes that Production is decreased by 4.2% due to "Factor #1"[2]
Net Condensate Production (after Royalty)	36.9 million bbls	11,903 bbl	12.5% Federal Royalty
Natural Gas Income	$22.800 Billion	$7,354,839	Assumed $5.40 / mmbtu and 1.1 mmbtu/mcf ($1 less than current Opal prices)
Condensate Income	$1.476 Billion	$476,129	Assumed $40.00 per Barrel ($15 less than current prices)
Total Income	**$24,276,000,000**	**$7,830,968**	
Direct Costs (Directional Well)			
Drilling	$2,781,270,400[3]	$897,184[3]	Table 4.13
Completion	$4,752,641,000	$1,533,110	Table 4.13
Total Direct Costs	**$7,533,911,400**	**$2,430,294**	
Production Costs			
$.32 per mcf	**$1,228,800,000**	**$396,387**	From Table 4.12 (includes the cost of producing the associated condensate)
Plug, Abandon & Reclaimation			Plug, Abandon & Reclaimation costs are estimated - no costs provided in the DEIS
Plug and abandon well	**$93,000,000**	**$30,000**	
Land surface reclaimation	**$63,860,000**	**$20,600**	Esitmated at $10,000 per acre of new disturbance (6,386 acres under Alternantive E[4])
Taxes & Royalties			
Wyoming Mineral Severance Tax	**$1,456,560,000**	**$469,858**	6 % of Production Value (net of Royalties)
Sublette County Property Tax	**$1,432,284,000**	**$462,027**	5.9% of Production Value (net of Royalties)
Net Earnings Before Income Tax	**$12,467,584,600**	**$4,021,802**	

Notes:

1 Using Draft EIS data for new surface distrubance acreage, and drilling, completion and production costs

2 Decrease is relative to the "Proposed Action" production. "Factor #1" is based on the unsubstantiated Draft EIS assumption that 10% of all directional wells will lose production from the lower 1,000 ft. of Lance formation

3 Assumed "Directional Well" drilling cost from Draft EIS Table 4.13

4 From Table 2.12 (Alternative E Disturbance Acreage minus No Action Disturbance Acreage)