Reducing Economic Risk In Areally Anisotropic Formations With Multiple-Lateral Horizontal Wells

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Abstract
Well orientation is critical to horizontal well performance in areally anisotropic reservoirs. A horizontal well, drilled normal to the direction of maximum permeability, will have higher productivity than one drilled in any other arbitrary direction. Currently, horizontal permeability magnitudes and even indications of direction are rarely measured in the field. Based on well performance modeling and economic evaluation, this study attempts to determine the relative attractiveness of horizontal wells with multiple-laterals. The work exposes the economic risk in ignoring horizontal permeability magnitudes and directions and demonstrates the importance of adequate reservoir testing. A new rationalization for multiple-lateral horizontal wells is the reduction of the economic risk associated with poor reservoir characterization in areally anisotropic formations while increasing the incremental net present value (NPV) over single-horizontal wells.

Introduction
Horizontal wells are proliferating throughout the petroleum industry as a means to increase well productivity and enhance incremental recovery economics. Multiple laterals from the same vertical section provide greater reservoir exposure, soften the risk of economic uncertainty, reduce the number of wells needed to drain a particular reservoir, and speed up the reservoir drainage process. Very importantly, they may also remedy poor production from a horizontal well drilled in the wrong orientation in formations with large areal anisotropy. For a horizontal well drilled without adequate formation evaluation, a second lateral will increase the chance to intersect frequently critical natural fractures.

Traditionally, petroleum engineers have not been too concerned about horizontal permeability anisotropy. For a vertical well this is forgiving because in cylindrical flow the average permeability, \( k_{H} \), is in the horizontal plane and is simply \( \sqrt{k_X k_Y} \). Several studies\(^2\) have shown that large permeability anisotropies in the horizontal plane are common in many reservoirs. Naturally fractured formations, which are generally excellent candidates for horizontal wells, are likely to exhibit horizontal permeability anisotropy. In this situation, two principal horizontal permeabilities can be identified: \( k_{H_{max}} \) and \( k_{H_{min}} \).

The direction to drill a horizontal well is often based on the shape of the presumed drainage area, when instead, the deciding parameter should be the horizontal permeability anisotropy. This becomes increasingly important with increasing permeability anisotropy. Warpinski\(^3\) and Buchsteiner \textit{et al.}\(^4\) note cases where permeability ratios in the horizontal plane are as much as 50:1.

This is an extreme case. However, ratios of 3:1 or 4:1 are common\(^5\). The well trajectory with respect to the permeability directions is then central to the success of the horizontal well project and thus, it is essential to know the preferred permeability direction before drilling a horizontal well. Several means exist for this purpose.

It is also important to evaluate the risk of economic uncertainty when the horizontal permeability components are not known versus the additional costs of performing tests to determine these reservoir parameters.

Using a versatile productivity index model, this paper will demonstrate the advantages of multiple-lateral horizontal wells over conventional single-horizontal well completions in anisotropic formations. The model allows for arbitrary positioning of wells and is useful in evaluating the economics of drilling multiple-lateral horizontal wells for various well
configurations. Economic comparisons are simple once the productivity of multiple-laterals with time is compared with a base case, such as a vertical well or a single-horizontal well. Net present value (NPV) calculations can weigh the discounted incremental benefits of multiple-laterals against the incremental costs of drilling, completing, and stimulating any alternative configuration.

Estimating Directional Permeabilities

Permeability anisotropy and direction can be determined with stress measurements in a vertical pilot before a horizontal well is directed, or by experiments with directional cores obtained in the vertical pilot.

Horizontal well tests or multi-well interference tests are, of course, the best techniques to measure permeability anisotropy. Pressure transient tests at a well are most commonly used to measure permeability magnitudes and directions directly, while interference tests are seldom used in the field.

However, there are many complications associated with analyzing horizontal well transient tests beyond the fact that they are done after the drilling of the horizontal well. One problem is the unavoidable presence of large wellbore storage effects caused by the longer borehole, even with a downhole shut-in. Wellbore storage often masks early-time transient behavior, which inhibits the determination of vertical permeability, the permeability normal to the well, and the damage skin effect.

A vertical pilot is essential in determining the desirability of drilling a horizontal well. First, a partial penetration drillstem test should be run. This can be accomplished by drilling only partially into the net pay or by drilling through the net pay and then packing off only a small portion of the interval. Spherical flow emerges when a negative one-half slope straight line is seen on the early-time pressure derivative curve. This flow regime, properly interpreted, provides the spherical permeability, \( \sqrt{k_H k_V} \). Next, a second test, conducted with the entire pay thickness open to flow, should provide the horizontal permeability, \( k_H \). Knowledge of the vertical and horizontal permeabilities and the reservoir thickness can determine the desirability of drilling a horizontal well in the tested formation.

Once the decision to drill a horizontal well is made, the next step is to determine the proper well direction. This will be based on the horizontal-to-horizontal permeability anisotropy. Figs. 1 and 2 show that horizontal well direction is important and that a well should be oriented normal to the maximum horizontal permeability direction.

Every reservoir is subject to a stress field, which can be described with three principal stresses: a vertical, \( \sigma_v \), a minimum horizontal, \( \sigma_{\text{min}} \), and a maximum horizontal, \( \sigma_{\text{max}} \). Measurements can identify the maximum and minimum horizontal stress directions, usually coinciding with the maximum and minimum horizontal permeability directions (Fig. 3). Fig. 3 indicates how the horizontal stress components affect the state of fissures in the formation. Fissures perpendicular to the maximum stress direction are compacted, while fissures perpendicular to the minimum stress are left relatively open. Larger fissure widths imply larger permeability along those fissures. This idea illustrates why the maximum and minimum stress components normally coincide with the maximum and minimum permeabilities, respectively.

The measurement of stresses in a vertical pilot hole would be invaluable for the proper steering of a horizontal well.

Warpinski\textsuperscript{2} and Deimbacher et al.\textsuperscript{3} expounded upon the relationship between stress components and permeability components. For example, a hydraulically fractured vertical well would generally intersect the fracture plane longitudinally. The fracture itself is normal to the minimum stress direction, which corresponds to the path of least resistance during fracture propagation. This path also implies that the minimum permeability is normal to the fracture plane.

For an unfractured horizontal well, the principal horizontal stress direction has a large bearing on the principal horizontal permeability direction. The drilling of the horizontal well, its direction and (if it will be fractured hydraulically) the type of fractures it will accept must consider the stress directions.

Economides\textsuperscript{5} discussed several techniques to determine the stress magnitude and direction:

1. A fracture injection test\textsuperscript{6} is the best technique for estimating the closure pressure, which should be very near the minimum stress for a single layer. In almost all cases, this corresponds to the minimum horizontal stress.

2. A four-arm caliper log detects open-hole wellbore eccentricity. Knowing that stresses are compressive in nature, it is relatively easy to conclude that the smaller axis of the ellipse should be normal to the minimum stress. A hydraulic fracture would be along the minimum axis of the wellbore ellipse (Fig. 3).

3. Laboratory analysis of directionally obtained cores is usually quite accurate and very useful. Techniques include:
   - measurements of strain, i.e., the disappearance or appearance of fissures, such as differential strain curve analysis (DSCA) and anelastic strain recovery (ASR)
   - an acoustic technique, i.e., the differential wave velocity analysis (DWVA)

Productivity Model

Predicting the performance of horizontal wells requires a model that can account for both vertical-to-horizontal and horizontal-to-horizontal permeability anisotropies and any reservoir or well configuration, including partial completion.
Economides et al. attempted to resolve these problems by presenting performance relationships for complex well configurations in horizontal wells. Their model accounts for transient and boundary-dominated flow behavior and uses analytical solutions for arbitrarily oriented single- and multiple-horizontal wells as well as vertical and slant wells.

The model requires a list of input parameters:

- Reservoir Data \((x, y, h, k, k_x, k_y, k_z)\)
- Production Data \((\mu, B, \phi, c)\)
- Borehole Trajectory (lengths and directions)
- Well Completion \((r_w, \text{open/closed segments, } s)\)

The transformations developed by Bessona are used for permeability anisotropy with \(k_x, k_y, \text{ and } k_z\) in the \(x, y,\) and \(z\)-directions, respectively and can be found in Ref. 7. Next, the solution technique obtains dimensionless pressures for a point source of unit length within a bounded, no-flow reservoir. For a line source with uniform flux, the solution is integrated for the point sources along any arbitrary well trajectory. Using a line source with constant pressure, the well is split into segments and each segment is treated as a line source with uniform flux. Next, a rate is assigned for each segment so the individual rates sum to one, the solutions are superposed. The pressure at the midpoint of each segment is the same. Careful switching of early- and late-time semi-analytical solutions allows for very accurate calculations of the composite dimensionless pressure for any well configuration.

The productivity index, \(J\), is related to the dimensionless pressure under transient conditions (in oilfield units):

\[
J = q = \frac{k x}{887.22 B \mu} \left( \frac{x}{2 \pi L \sum s} \right)
\]  

(1)

The generalized solution to the dimensionless pressure, \(p_D\), starts with early-time transient behavior and ends with pseudosteady state if all drainage boundaries are felt. At that moment, the dimensionless pressure can be decomposed from a 3-dimensional contribution into one 2-dimensional and one 1-dimensional contribution. The horizontal plane can be characterized with shape factors, while the vertical effects can be accounted for by a vertical skin effect. Thus, under pseudosteady-state flow conditions, \(p_D\) is:

\[
p_D = \frac{x C_H}{4 \pi h} + \frac{x}{2 \pi L} s_z
\]

(2)

where the skin effect, \(s_z\), is (after Kuchuk et al.):

\[
s_z = \ln \left( \frac{h}{2 \pi r_w} \right) - \frac{h}{6L} + s_x
\]

(3)

and \(s_x\), describing eccentricity effects in the vertical direction, is

\[
s_x = \frac{h}{L} \left[ \left( \frac{2 z_w}{2 h} \right)^2 - \frac{1}{2} \right] - \ln \left[ \sin \left( \frac{\pi z_w}{h} \right) \right]
\]

(4)

which is negligible if the well is placed near the vertical middle of the reservoir.

These equations are sufficient for the prediction of any single- or multiple-well configuration, and the general solutions described in the Appendix of Ref. 7 can handle all situations for infinite-acting, mixed, and no-flow boundaries.

**Effect Of Areal Anisotropy**

To illustrate the impact of areal anisotropy, consider a 2000-ft-long single-horizontal well in a 100-ft-thick formation with an index of anisotropy, \(l_a\), equal to 3. The average horizontal permeability is 10-md, but the horizontal permeability magnitudes and directions are uncertain. Four horizontal permeability anisotropy ratios will be examined: 1:1 (isotropic), 5:1, 10:1, and 50:1. The importance of well orientation will be determined by rotating the horizontal well in the horizontal plane. Fig. 4 shows the two well configurations referred to throughout the rest of the paper: a single-horizontal well and a multiple-lateral “cross” configuration. Economic calculations are made using the NPV criterion and the inputs listed in Table 1.

Horizontal well productivity is greatest when the well is drilled normal to the maximum horizontal permeability direction. Fig. 5 shows that for a single-horizontal well drilled in the optimal direction, cumulative production accelerates as areal anisotropy increases. For a given horizontal permeability with increasing areal anisotropy ratio, the reservoir drainage process speeds up, making the high areal anisotropy ratio cases more attractive than the isotropic case. As the deviation from the optimal well direction increases, horizontal well productivity decreases, resulting in a deceleration of cumulative production. Fig. 1 shows the critical importance of well orientation for the highly anisotropic case.

Changes in the areal anisotropy ratio and well orientation have a considerable effect on cumulative production. They also have similar effects on the NPV calculations. Fig. 2 shows three-year NPV’s for a single-horizontal well as the well orientation is rotated in the horizontal plane from the optimal direction \(0^\circ\) to \(90^\circ\). NPV decreases as the horizontal well
orientation deviates from the optimal direction. Similarly, Fig. 6 shows that when single-horizontal wells are drilled in the optimal direction, NPV increases as areal anisotropy increases.

Thus, for wells drilled perpendicular to the maximum horizontal permeability direction, areal anisotropy is favorable, but as the well deviates from this optimal direction, areal anisotropy becomes a detriment. In some instances the success or failure of a horizontal well completion may depend solely on the decision at which direction to drill the horizontal well. There are large ranges of possible economic outcomes when the horizontal permeability magnitudes and directions are not known. These problems are magnified with increasing areal anisotropy. The range of possible economic outcomes will be termed the risk of economic uncertainty.

Table 2 shows the risk of economic uncertainty for single-horizontal wells for various anisotropy ratios. In the isotropic reservoir, the NPV is independent of the well orientation, but as the horizontal anisotropy ratios increase, the risk of economic uncertainty grows. In fact, the range of possible NPV’s rises to over $2 million in the most anisotropic case. Not only do the high anisotropy cases have the most positive economic potential when drilled correctly, they also have the potential to lose the most when orientated incorrectly.

New Approach Using Multiple-Lateral Horizontal Wells

Previous work has shown that horizontal wells with multiple-laterals increase productivity and incremental NPV in low- to moderate-permeability reservoirs over single-horizontal well completions. This study will extend that work by showing the impact of well orientation in areally anisotropic reservoirs and presenting a new application using multiple-laterals in risk management, while still increasing productivity and incremental NPV.

Using the same analytical simulator discussed earlier, Remanto and Economides presented a series of parametric studies for a range of reservoir permeabilities and permeability anisotropies for various multiple well configurations. The authors examined three magnitudes of permeability and three magnitudes of horizontal anisotropy: \( k_h=0.1, 1, \text{ and } 10 \text{-md} \), \( k_l=k_h, 0.1k_h, \text{ and } 0.01k_h \), and \( k_l=0.1k_h \). The \( k_h \) value was used as the basis for the calculations, while \( k_l \) values were varied to account for various horizontal anisotropy ratios and to determine the effects of increasing areal anisotropy. The vertical permeability was left constant.

Remanto and Economides examined four well configurations: (1) a 2,000-ft horizontal well along \( k_l \), (2) a 2,000-ft horizontal well along \( k_h \), (3) a “cross” configuration of four laterals which form the equivalent of two 2,000-ft wells intersecting orthogonally at the reservoir middle, and (4) a “star” configuration with eight laterals which form the equivalent of four 2,000-ft wells intersecting at 45° angles at the reservoir center. In summarizing their results, they found that multiple-laterals in low- to moderate-permeability reservoirs can produce with higher production rates and, therefore, with higher cumulative productions at early times compared to single-horizontal wells. They also found that multiple-laterals in higher-permeability reservoirs have reduced incremental benefits.

Both high- and low-permeability reservoirs exhibit productivity improvements with multiple-laterals during transient conditions. However, once pseudosteady state is reached, the increase in productivity index is diminished. Multiple wells in the same drainage area will interfere with each other. Although high-permeability formations see larger absolute productivity increases, they also experience interference effects earlier. Therefore, the relative economic benefit of multi-well configurations in high-permeability reservoirs begins to diminish quickly, while low permeability formations exhibit interference effects much later and relative economic benefits are both higher and prolonged.

Consider a case study comparing single-horizontal completions to a multiple-lateral “cross” configuration in areally anisotropic reservoirs. The study involves four horizontal anisotropy ratios: 1:1 (isotropic), 5:1, 10:1, and 50:1, and shows the effect of well orientation by rotating both configurations within the horizontal plane. For the single-horizontal well, rotation of 90° displays all possibilities; this example looks at 0°, 30°, 45°, 60°, and 90°. The “cross” configuration needs to be rotated only by 45°; the study includes 0°, 15°, 30°, and 45°.

The economic base case is a 2,000-ft-long single-horizontal well that is oriented in the optimal direction, perpendicular to the direction of maximum horizontal permeability. The reservoir has a horizontal permeability equal to 10-md with an index of anisotropy equal to 3. The thickness is 100-ft.

The dimensionless time and dimensionless rate are defined as:

\[
\tau_D = \frac{0.000264 \frac{k_t}{\phi \mu c r x_c^2}}
\]

and

\[
q_D = \frac{887.22 q B \mu}{k x_0 \Delta p}
\]

Figs. 7 to 13 show the advantages of multiple-lateral horizontal wells, the effect of areal anisotropy, and the types of reservoirs in which they are most useful. Fig. 7 graphs dimensionless production rate as a function of dimensionless time. Case D is a well drilled normal to the minimum permeability, whereas Case E is a well drilled normal to the maximum permeability. Cases F and G are for the “cross” and
“star” configurations, respectively. This illustration shows that multiple-lateral wells have higher productivities at early time. However, as time advances the productivity advantage decreases, until at pseudosteady-state, they vanish. Cases D and E in Fig. 7 show the effect of well orientation on productivity for single horizontal wells. Fig. 8 illustrates the effect of well orientation in more detail. At early time, the highest productivity results when the well is drilled in the optimal direction. As the well direction deviates from the optimal direction, the productivity decreases. The productivity advantage lasts until pseudosteady-state is reached but diminishes as the curves converge at pseudosteady-state. At late time, productivities diverge due to the depletion of the reservoir.

Fig. 9 illustrates the effect of permeability magnitude on productivity increases in multiple-laterals. This figure plots the cumulative production ratio vs time and shows how productivity advantages last much longer in low-permeability reservoirs. The cumulative production ratio is the ratio of the production from the multiple-lateral well over the production of the base case for a single-horizontal well oriented in the direction perpendicular to the maximum permeability. This figure is for the “cross” configuration. Therefore, at early time, we would expect the “cross” configuration to produce twice the amount of the base case. Fig. 9 shows that this is true. The cumulative production ratio is constant at a value of 2 at early time for all three cases and then begins to decrease over time until they eventually converge at a value of 1. Production ratios for wells in the high-permeability formations begin to decrease earlier than those in low-permeability formations. The productivity advantage lasts much longer in the latter.

Fig. 10 shows that, for all permeability orientations the cross configuration in anisotropic formations is better than for the isotropic case. This demonstrates that for the cross configuration, the productivity is always greater than the isotropic case regardless of well orientation, where the single-horizontal well is much better when drilled correctly — but worse when drilled incorrectly. Fig. 11 graphs production rate vs time, showing that high-permeability formations pose much higher increases in production wherever multiple-laterals are used but, once again, the benefits disappear much sooner than in low-permeability formations. Of course, the decision to drill multiple-laterals must be made on a reservoir-by-reservoir basis where permeability and completion costs have been accounted for to determine the incremental economic benefits over single-horizontal wells or other completion options.

Fig. 12 is a 3-dimensional graph that shows the effects of well orientation on NPV as a function of increasing anisotropy and deviation for a single horizontal well. As the figure shows, the NPV in the isotropic case is independent of well orientation. As the anisotropy ratio increases, if the wells are drilled correctly, there are increases in NPV from the isotropic case; however, as the well deviates from the optimal direction, the net-present-value decreases, until at 90° the NPV decreases with increasing horizontal anisotropy.

Although all the cases shown have the same ultimate cumulative production, drilling a well in the optimal direction will increase the production rate at early times and result in a higher NPV than any other well orientation. Poor well orientation results in delayed recovery. As well orientation deviates from this optimal direction, production rates at early time decrease, slowing down the increase in cumulative production, and thereby decreasing the NPV. Increasing anisotropy ratios results in increasing the range of possible economic outcomes, depending upon the direction the horizontal well is drilled.

Fig. 13 shows another 3-dimensional graph of NPV as a function of well orientation and increasing areal anisotropy for the “cross” configuration. For this case, the isotropic case is once more independent of well orientation. Another similarity is that the NPV increases as the areal anisotropy ratio increases. However, in this case, as the well is rotated in the reservoir, the NPV decreases almost imperceptibly. In fact, regardless of well orientation, NPV increases with increasing areal anisotropy ratios.

Table 3 shows that multiple-lateral horizontal wells have a much lower risk of uncertainty than single-horizontal wells with well orientation in areally anisotropic reservoirs. For the three anisotropic cases, the decrease in the risk of uncertainty ranges from approximately $1 million in the 5:1 case (reduced by a factor of 37) from $935,000 to $25,000; and $2 million in the 50:1 case (reduced by a factor of 13) from $2,123,000 to $159,000.

These data have shown that horizontal wells can reduce the risk of uncertainty resulting from not knowing the horizontal permeability magnitudes and directions in areally anisotropic reservoirs. The incremental economics of single- and multiple-lateral horizontal wells over the selected base case appears in Figs. 14 and 15. Fig. 14 shows the incremental NPV for the single-horizontal well with increasing areal anisotropy and various well orientations over the single-horizontal-well base case. For single-horizontal wells, the positive incremental NPV’s are moderate when the well is drilled in the optimal direction, and the negative incremental NPV’s are relatively larger when drilled incorrectly.

Fig. 15 shows the incremental NPV for the “cross” configuration over the single well base case. Once again, the increases in incremental NPV are moderate; however, regardless of well orientation and areal anisotropy ratio, the incremental NPV is positive for the cross configuration. This would confirm that the multiple-lateral configuration is the most attractive completion in this reservoir.

Table 4 shows a comparison of the ranges of incremental NPV with increasing areal anisotropy between a single-horizontal well and a “cross” configuration multiple-lateral well.
Clearly, not only are multiple-lateral horizontal wells attractive in low-permeability reservoirs, but they are also beneficial in moderate-permeability reservoirs in reducing the risk of uncertainty associated with areally anisotropic reservoirs and in increasing the incremental NPV over single-well completion options.

Also, drilling a horizontal well normal to the direction of maximum permeability results in increased well productivity. For a given horizontal permeability, the highest productivity and NPV comes from the most anisotropic reservoirs when drilled correctly. Horizontal well direction becomes critical with increasing areal anisotropy. NPV decreases as deviation from the optimum well direction increases. Choosing the correct direction to drill a horizontal well can result in the economic success or failure of a project.

Poor reservoir characterization (unknown directional permeabilities) results in a high risk of uncertainty. The new application for multiple-lateral horizontal wells, developed in this study, can reduce the risk of uncertainty and improve incremental economics.

Conclusions

This study found that drilling a single-horizontal well normal to the direction of the maximum permeability results in increased well productivity over any other arbitrary direction. Horizontal well direction becomes critical with increasing areal anisotropy. For a given horizontal permeability, the highest productivity and NPV come from the most anisotropic reservoirs when single-horizontal wells are oriented correctly. NPV decreases as deviation from the optimal direction increases; therefore, there is a large risk of uncertainty associated with drilling a single-horizontal well without an idea of the permeability component magnitudes and directions. Choosing the correct direction to drill a horizontal well can effect greatly the economic success or failure of a project.

To improve well productivity and incremental economics, multiple-lateral horizontal wells should be considered along with additional reservoir testing to reduce the risk of economic uncertainty associated with poor reservoir characterization. They can also be used to remedy single-horizontal wells that have been drilled incorrectly.

Nomenclature

- $B_o$ = Formation volume factor, bbl/STB (resm$^3$/m$^3$)
- $C_H$ = Geometric shape factor
- Costs = Total costs for drilling, completing, and stimulating well, $\$$
- c_i$ = Total compressibility, psi$^{-1}$ [Pa$^{-1}$]
- $h$ = Formation thickness, ft [m]
- $i$ = Discount rate, fraction
- $J$ = Productivity index, STB/psi [m$^3$/s/Pa]
- $k_H$ = Average horizontal permeability, md [m$^2$]
- $k_{H,\text{max}}$ = Minimum horizontal permeability component, md [m$^2$]
- $k_{H,\text{min}}$ = Maximum horizontal permeability component, md [m$^2$]
- $k_v$ = Vertical permeability, md [m$^2$]
- $k_x$ = Permeability in the $x$-direction, md [m$^2$]
- $k_y$ = Permeability in the $y$-direction, md [m$^2$]
- $k_z$ = Permeability in the $z$-direction, md [m$^2$]
- $k$ = Average permeability, md [m$^2$]
- $\bar{k}$ = Average permeability, md [m$^2$]
- $L$ = Length of horizontal section, ft [m]
- $n$ = Number of years
- $N_p$ = Cumulative oil production, STB [m$^3$]
- $NPV$ = Net present value
- $OOIP$ = Original oil in place, Bbl [resm$^3$]
- $\Delta P$ = Differential pressure, psi [Pa]
- $p_D$ = Dimensionless pressure, psi [Pa]
- $p_i$ = Initial reservoir pressure, psi [Pa]
- $\bar{p}$ = Average pressure in drainage volume of well, psi [Pa]
- $p_{wfi}$ = Average flowing bottomhole pressure, psi [Pa]
- $q$ = Total production rate into a horizontal well, STB/d [m$^3$/s]
- $r_w$ = Wellbore radius, ft [m]
- $s$ = Skin due to damage
- $s_e$ = Eccentricity skin
- $s_v$ = Vertical skin effect
- $x$ = Reservoir length, ft [m]
- $y$ = Reservoir width, ft [m]
- $z_w$ = Distance of well from middle of reservoir, ft [m]
- $\sigma_v$ = Vertical stress component, psi [Pa]
- $\sigma_{H,\text{min}}$ = Minimum horizontal stress component, psi [Pa]
- $\sigma_{H,\text{max}}$ = Maximum horizontal stress component, psi [Pa]
- $\mu_o$ = Viscosity, cp [Pa-s]
- $\phi$ = Porosity, fraction
- $\sum s$ = Summation of damage skin, turbulence skin, and other pseudoskin factors
- $\Delta S$ = Yearly incremental revenue, $\$

References


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**Table 1 - Net Present Value Inputs**

<table>
<thead>
<tr>
<th></th>
<th>Price of Oil</th>
<th>Discount Rate</th>
<th>Single-Horizontal Well Costs</th>
<th>&quot;Cross&quot; Horizontal Well Costs</th>
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<td>$15/STB</td>
<td>25%</td>
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<td>$1,750,000</td>
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**Table 2 - Risk of Economic Uncertainty With Increasing Areal Anisotropy**

<table>
<thead>
<tr>
<th>Areal Anisotropy Ratio</th>
<th>Total Range of NPV ($1000)</th>
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<tr>
<td>1:1</td>
<td>0</td>
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<tr>
<td>5:1</td>
<td>935</td>
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<tr>
<td>10:1</td>
<td>1,315</td>
</tr>
<tr>
<td>50:1</td>
<td>2,123</td>
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**Table 3 - Reducing the Risk of Economic Uncertainty With Multiple-Lateral Horizontal Wells Compared to Single-Horizontal Wells**

<table>
<thead>
<tr>
<th>Areal Anisotropy Ratio</th>
<th>NPV Ranges (Single) ($1000's)</th>
<th>NPV Ranges (&quot;Cross&quot;) ($1000's)</th>
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<tbody>
<tr>
<td>1:1</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>5:1</td>
<td>935</td>
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<tr>
<td>50:1</td>
<td>2,123</td>
<td>159</td>
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**Table 4 - Reducing the Risk of Economic Uncertainty With a "Cross" Configuration Compared to a Single-Horizontal Well**

<table>
<thead>
<tr>
<th>Areal Anisotropy Ratio</th>
<th>Incremental NPV Ratio (Single)</th>
<th>Incremental NPV Ratio (&quot;Cross&quot;)</th>
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</thead>
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<tr>
<td>1:1</td>
<td>1.07</td>
<td>1.09-1.11</td>
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<td>5:1</td>
<td>0.74-1.13</td>
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<tr>
<td>10:1</td>
<td>0.62-1.19</td>
<td>1.13-1.21</td>
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<tr>
<td>50:1</td>
<td>0.34-1.28</td>
<td>1.13-1.21</td>
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Figure 1  Poor Well Orientation Slows Down the Reservoir Drainage Process on Cumulative Production for a Single-Horizontal Well.

Figure 2  Net Present Value for a Single-Horizontal Well Decreases as Well Direction Deviates From the Optimal Orientation.
Figure 3  Conceptual Relationship Between Stress and Permeability Components.

Figure 4  Horizontal Well Configurations for this Study.

Figure 5  Increasing Areal Anisotropy Speeds Up Reservoir Recovery for a Single-Horizontal Well Drilled in the Optimal Direction.
Figure 6  Net Present Value Increases as Areal Anisotropy Increases for a Given Horizontal Permeability as a Single-Horizontal Well is Drilled in the Optimal Direction

Figure 7  Dimensionless Production Rate vs Dimensionless Time for Horizontal-to-Horizontal Permeability Anisotropy, \( k_y = 0.1 k_x \) (Cases D, E, F, and G)
Figure 8 - Dimensionless Production Rate vs Dimensionless Time for Various Single-Well Orientations (10:1 Anisotropy Ratio)

Figure 9 - Cumulative Production Ratio for Real Time for the “Cross” Configuration, $k_y/k_x = 10$.
Figure 10  Cumulative Production Ratio for Real Time for the "Cross" Configuration (10:1 Anisotropy Ratio)

Figure 11  Production Rate for Horizontal-to-Horizontal Permeability Anisotropy, $k_x=0.1k_y$ (Cases D, E, F, G).
Figure 12  Effect of Well Orientation on Net Present Value in Areal Anisotropic Reservoirs (Single Horizontal Well)

Figure 13  Effect of Well Orientation on NPV in Areal Anisotropic Reservoirs ("Cross" Configuration)
Figure 14  Incremental Net Present Value Ratio Compared to the Single-Horizontal Well Base Case (Single-Horizontal Well)

Figure 15  Incremental Net Present Value Ratio Compared to the Single-Horizontal Well Base Case ("Cross" Configuration)