

Enhancement of oil and gas production efficiency through expansion of well drainage area

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Abstract. This study investigates the influence of several key reservoir and well parameters on production performance in the context of increasing drainage area across different well types. The primary objective is to quantitatively determine and compare the production operating points of vertical and deviated (directional) wells, recognizing that deviated wells inherently encompass a larger drainage area than their vertical counterparts. A central component of this investigation involves the derivation and comparative analysis of Inflow Performance Relationship (IPR) and Vertical Lift Performance (VLP) curves for both well configurations. These curves are computed using specialized petroleum engineering software (PROSPER), and their intersection point defines the well's production operating point. Since the drainage areas of the two well types differ fundamentally, their respective IPR curves — and consequently their operating points — yield distinct production outcomes.

Furthermore, this research employs sensitivity analysis to evaluate the effect of varying tubing diameter and wellhead pressure on the VLP curves. The results of this sensitivity study elucidate how the production operating point responds to changes in these critical operational parameters across the two well configurations, thereby providing practical guidance for production optimization and well design.

Keywords: IPR (Inflow Performance Relationship), VLP (Vertical Lift Performance), Nodal Analysis, production operating point, drainage area, tubing diameter, wellhead pressure, deviated well, vertical well, PROSPER.

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1. Introduction. The physical drainage area of a well is governed either by impermeable physical boundaries within the reservoir or by no-flow boundaries that arise from interference between adjacent producing wells. During transient flow conditions, however, a well does not drain its entire physical drainage area; consequently, the physical drainage boundaries do not exert a controlling influence on flow characteristics or production performance during this period. Two complementary interpretations of transient flow are particularly useful for the purposes of this study: (1) the distance reached by the pressure transient within the wellbore — as a result of production — remains smaller than the distance from the well to the drainage boundary; and (2) the cumulative fluids withdrawn from the well have been sourced from a region that is smaller than the total distance to the drainage boundary.

It is not uncommon for unconventional wells to reach the end of their economic life while still operating under transient flow conditions, rendering their physical drainage areas largely inconsequential to production performance assessment. In order to apply conventional recovery-estimation methods to evaluate ultimate recovery and recovery factors, it is analytically advantageous to define a transient drainage area — one that is smaller than the physical drainage area and is an explicit function of time.

The two interpretations of transient flow presented above lead to distinct conceptual frameworks: the first gives rise to the concept of the investigation radius, while the second provides the basis for defining an effective transient drainage area. Before elaborating on the concept of transient drainage during transient flow, it is instructive to first review the pertinent literature concerning the drainage areas of horizontal and deviated (directionally drilled) wells.

When a well is produced until the pressure transient reaches all boundaries of the reservoir (boundary-dominated flow), the area enclosed within those boundaries is defined as the drainage area. The boundaries of a well's drainage area may consist of physical barriers such as faults and formation discontinuities, or they may be established by the no-flow boundaries created by adjacent producing wells operating under interference conditions.

The reservoir model employed in this study considers a two-phase system comprising oil and water; however, the fluid system was modeled as entirely oil-saturated for the purpose of simplification. The fluid viscosity model adheres to Newtonian fluid behavior. No artificial lift mechanism is incorporated into the production system, and the well is completed with a protective casing configuration. Furthermore, no sand control measures are implemented in the wellbore.

2. Experimental Methodology. This study was conducted using the PROSPER well performance simulation software. The following data categories were entered as input parameters: PVT (pressure-volume-temperature) data characterizing reservoir fluid properties, petrophysical data describing reservoir rock properties, deviation survey data defining the well trajectory, surface equipment specifications, and downhole equipment configurations. All input parameters were maintained identical for both the vertical and deviated well models, with the sole distinction being that the deviated well was assigned a larger drainage area than the vertical well. Based on these parametric inputs, the software computed the Inflow Performance Relationship (IPR) curve for each well configuration independently, yielding distinct IPR values corresponding to each well type.

2.1. PVT Data and Reservoir Properties. The primary PVT data utilized as model inputs are summarized in Table 1 below.

Table 1. Primary PVT Data of the Reservoir

Parameter	Value
Reservoir Pressure (psig)	3,150
Reservoir Temperature (°F)	200
Oil Gravity (°API)	30
Gas Specific Gravity	0.75
Water Salinity (ppm)	80,000
Water Cut (%)	0
Total GOR (scf/STB)	400

Additional PVT properties measured at 200°F across various pressure levels are presented in Table 2.

Table 2. Matched PVT Data at 200°F

Pressure (psig)	GOR (scf/STB)	Oil FVF (rb/STB)	Oil Viscosity (cP)
1,500	237	1.138	1.34
2,000	324	1.178	1.15
2,500	400	1.214	1.01
3,000	400	1.207	1.05
4,000	400	1.198	1.11

2.2. Well System Equipment Configuration. The equipment section of the system model is subdivided into five principal sub-sections:

- Deviation survey measurement

- Wellhead equipment specifications
- Downhole equipment configuration
- Geothermal gradient profile
- Average heat capacity parameters

The deviation survey datum can be defined at any reference point, including the wellhead, seabed, platform deck, or mean sea level. The critical requirement is that all downhole equipment descriptions are referenced consistently to the selected datum origin. It is important to note that the wellhead depth does not necessarily coincide with the datum origin. Any deviation between these two reference points will influence the pressure gradient calculations for the mixed-phase flow arriving at the surface. The contribution of each lateral section and its corresponding impact on the downhole pressure drop is incorporated into the IPR model calculations.

Table 3. Deviation Survey Data for Vertical (lower) and Deviated (upper) Wells

Measured Depth (m)	True Vertical Depth (m)	Cumulative Displacement (m)	Inclination Angle (°)
0	0	0	0
1,665	1,665	0	0
1,680.23	1,680	2.64	9.97
1,696.78	1,695	9.63	25.00
1,714.10	1,710	18.29	30.00
1,733.68	1,725	30.87	40.00
1,757.52	1,740	49.40	51.01
1,900	1,775	187.52	75.78
2,500	1,775	787.52	90.00
2,700	1,775	987.52	90.00

Downhole equipment encompasses all components situated between the wellhead and the completion interval, including production tubing strings, casing strings, tubing joints, subsurface safety valves (SSSVs), and associated accessories. Consistent with the deviation survey reference framework, this sub-section provides a complete description of all downhole equipment from the wellhead datum to the completion point.

Table 4. Downhole Equipment Specifications

Equipment Type	Measured Depth (m) [Vert./Dev.]	Inner Diameter (in)	Roughness (m)
Christmas Tree	0	N/A	1.52E-05
Tubing	260	3.5	1.52E-05
SSSV	N/A	2.875	1.52E-05
Tubing	1,750 / 2,100	3.5	1.52E-05
Casing	1,800 / 2,700	7.0	1.52E-05

The geothermal gradient represents the rate of temperature increase per unit depth and is considered independent of the well's flow rate. When employing the approximate temperature prediction method, the geothermal gradient is entered as a function of measured depth. PROSPER internally converts measured depth to true vertical depth and applies a true vertical depth-based temperature gradient throughout its calculations.

Table 5. Perforation Intervals for Vertical and Deviated Wells

Perforation Interval	Vertical Well	Deviated Well
Measured Depth (m)	1,750–1,800	2,100–2,700
True Vertical Depth (m)	1,750–1,800	1,775–1,775

Table 6. Reservoir Parameters

Parameter	Value
Horizontal Permeability (md)	200
Net Pay Thickness (m)	50
Drainage Area (acres)	200
Reservoir Top Depth (m)	1,750
Vertical Permeability (md)	20

3. Nodal Analysis of Oil and Gas Wells. Nodal analysis — formally defined as a systematic approach to the optimization of oil and gas well production systems — is employed to conduct a comprehensive evaluation of the entire production system. This methodology enables the optimization of individual components within a producing well, as well as the collective performance of all wells operating within a given production system. As an integrated systems analysis technique, nodal analysis provides a rigorous framework for simultaneously evaluating reservoir inflow performance and wellbore/surface outflow performance.

3.1. Objectives of Nodal Analysis. The principal objectives of nodal analysis are as follows:

1. Determination of the production flow rate achievable by an existing oil or gas well, accounting for the well's geometric configuration and completion-imposed constraints (natural first flow).
2. Identification of the flow conditions — which may be time-dependent — under which the well will experience loading or flow cessation.
3. Selection of the economically optimal timing for artificial lift installation and facilitation of the most suitable lift method selection.
4. Optimization of the overall production system to achieve the most economically justified target flow rate.
5. Diagnostic evaluation to identify individual system components that unnecessarily restrict the achievable flow rate.
6. Facilitation of rapid identification — by operating and engineering personnel — of potential avenues for production rate enhancement.

It is noteworthy that a substantial number of oil and gas wells worldwide have not been optimized to achieve efficient target production rates. Indeed, many wells may have been completed in configurations that preclude attainment of their maximum production potential. System analysis is applicable to both naturally flowing wells and wells operating under artificial lift conditions, and provides valuable insight at the initial completion design stage. Even with limited data availability, a qualitative evaluation of anticipated well behavior can be obtained by screening multiple completion scenarios. This approach proves particularly useful in the analysis of producing wells, enabling the identification of flow restrictions and opportunities for productivity enhancement.

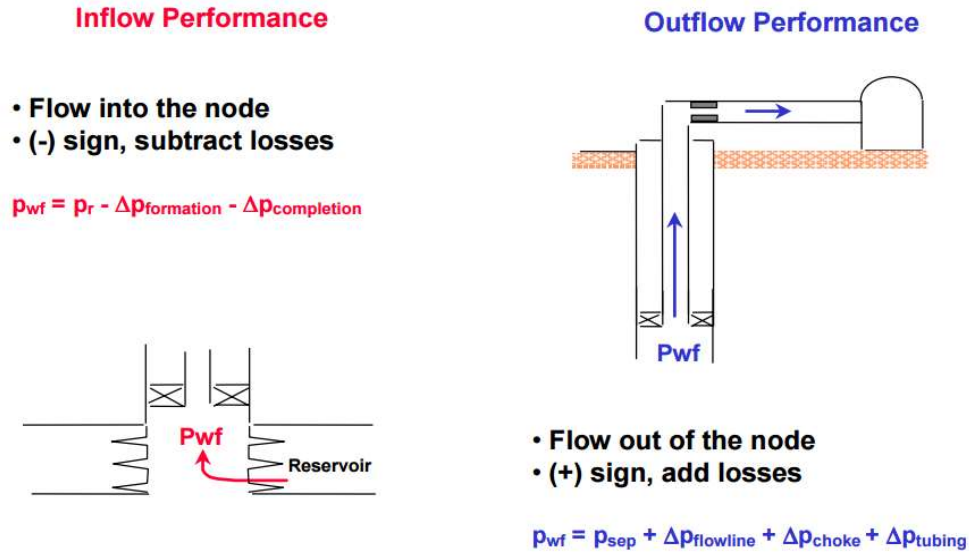


Figure 1. Schematic Representation of Inflow and Outflow Performance Relationships

3.2. Typical Applications of Nodal Analysis. Primary applications of nodal analysis include the following:

- Flow rate estimation and production capacity assessment
 - Tubing string sizing and selection
 - Flowline and surface pipeline sizing
 - Wellhead pressure optimization and surface choke sizing
 - Evaluation of the effects of reservoir pressure depletion
 - Identification and quantification of flow restrictions
- Additional specialized applications include:*
- Sizing of subsurface safety valves (SSSVs)
 - Optimization of perforation density and shot phasing
 - Gravel pack completion design
 - Artificial lift system design and selection
 - Optimization of injection gas-liquid ratio for gas lift operations
 - Evaluation of the effects of reduced wellhead pressure or compression installation
 - Assessment of well stimulation treatment effectiveness

4. Results and Discussion. Following the determination of the IPR curves for both well configurations, the corresponding VLP (Vertical Lift Performance) parameters were entered into the PROSPER model to compute the tubing performance curves. A sensitivity analysis was subsequently conducted by varying the wellhead (first node) pressure and tubing internal diameter across a range of specified values. Based on these parametric variations, the software identified the distinct production operating points corresponding to each parameter combination.

The IPR curve computed from the input parameters clearly demonstrates that the production performance outcomes differ between the vertical and deviated wells. As established by nodal analysis theory, the intersection of the IPR and VLP curves defines the well's production operating point — the stabilized flow rate and corresponding bottomhole flowing pressure at which the well operates under steady-state conditions. Since the drainage areas of the two well configurations differ fundamentally, their operating points are inherently distinct. This study further characterizes the sensitivity of the production operating point to variations in tubing diameter and wellhead pressure for both well types.

4.1. Sensitivity Analysis: Wellhead Pressure (Deviated Well)

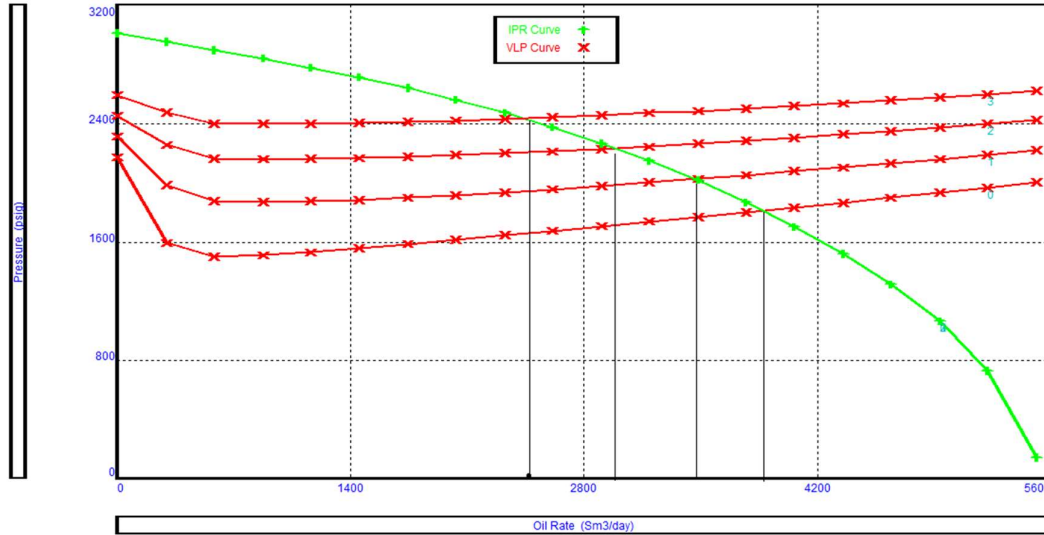


Figure 2. IPR/VLP Curves for the Deviated Well at Various Wellhead Pressures

Figure 2 illustrates the production response of the deviated well as a function of increasing wellhead (tubing head) pressure. The VLP curves at each pressure level are represented by distinct colored lines, while the red curve represents the baseline VLP at a wellhead pressure of 275.4 psig, yielding an estimated production operating point of 3,878 m³/day. This operating point corresponds to the stabilized flow rate and associated bottomhole flowing pressure achieved when a steady-state flow condition is established between the reservoir and the wellbore.

The sensitivity results demonstrate a consistent inverse relationship between wellhead pressure and the estimated production operating point – as wellhead pressure increases, the operating flow rate decreases correspondingly. The specific results are summarized as follows:

- Case 0 — Wellhead pressure: 275.4 psig → Operating point: 3,878 m³/day
- Case 1 — Wellhead pressure: 420.4 psig → Operating point: 3,465 m³/day
- Case 2 — Wellhead pressure: 565.5 psig → Operating point: 2,968 m³/day
- Case 3 — Wellhead pressure: 710.5 psig → Operating point: 2,443 m³/day

4.2. Sensitivity Analysis: Wellhead Pressure (Vertical Well)

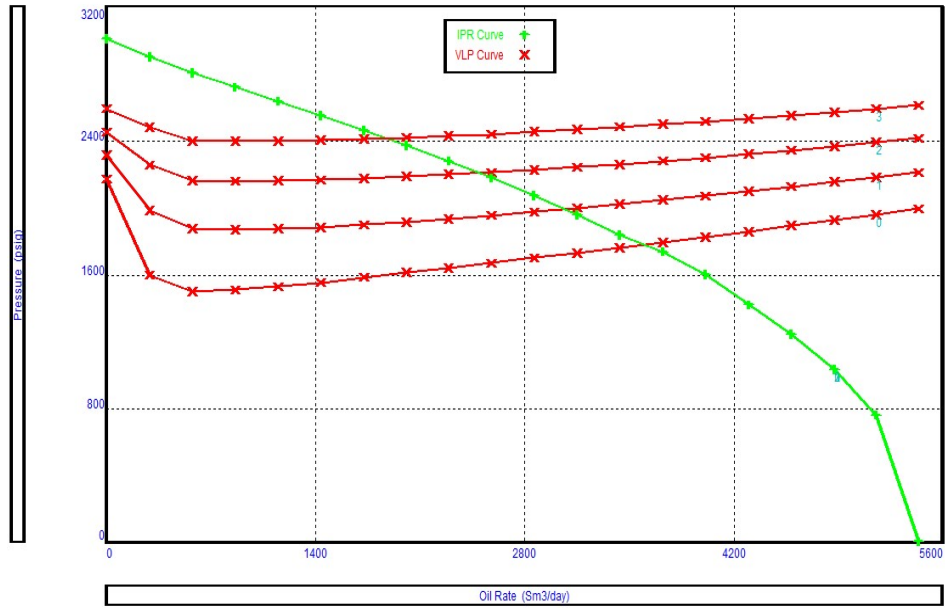


Figure 3. IPR/VLP Curves for the Vertical Well at Various Wellhead Pressures

Figure 3 presents the analogous wellhead pressure sensitivity results for the vertical well configuration. At the baseline wellhead pressure of 275.4 psig, the estimated production operating point for the vertical well is 3,598 m³/day — lower than that of the deviated well at the same pressure, reflecting the smaller drainage area of the vertical well. The results confirm that increasing wellhead pressure similarly reduces the production operating point for the vertical well configuration, as follows:

- Case 0 — Wellhead pressure: 275.4 psig → Operating point: 3,598 m³/day
- Case 1 — Wellhead pressure: 420.4 psig → Operating point: 3,066 m³/day
- Case 2 — Wellhead pressure: 565.5 psig → Operating point: 2,478 m³/day
- Case 3 — Wellhead pressure: 710.5 psig → Operating point: 1,862 m³/day

4.3. Sensitivity Analysis: Tubing Diameter (Deviated Well)

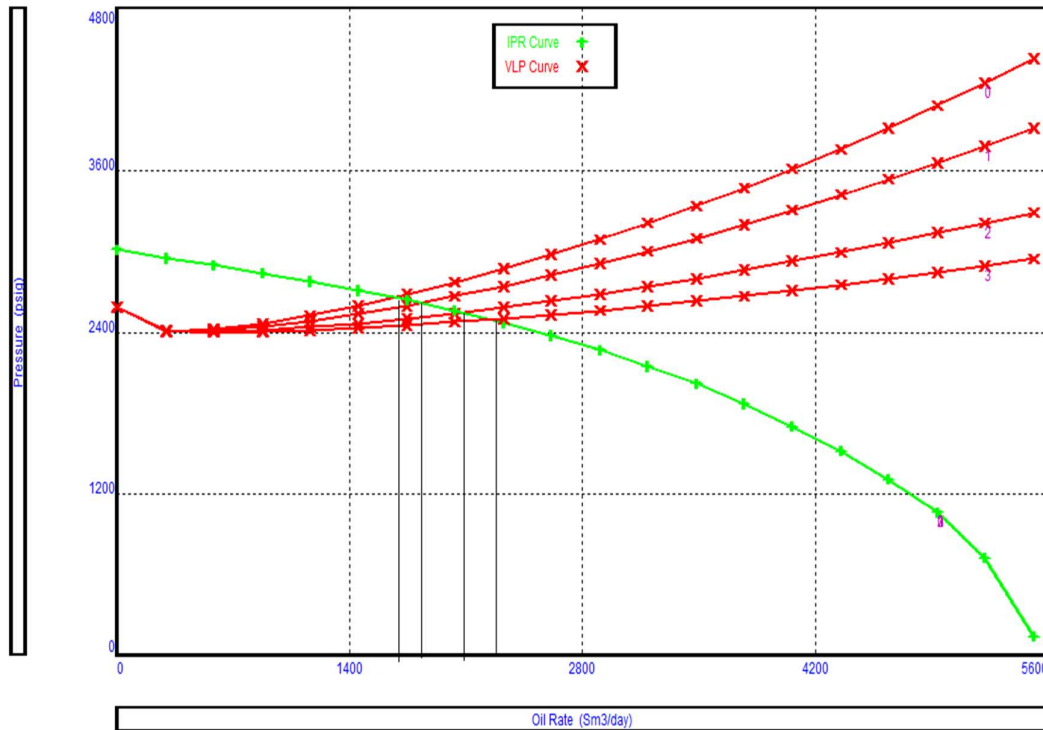


Figure 4. IPR/VLP Curves for the Deviated Well at Various Tubing Diameters

Figure 4 illustrates the production response of the deviated well as tubing internal diameter is progressively increased. The baseline case (Case 0) employs a tubing diameter of 3.75 inches, yielding an estimated production operating point of 1,673 m³/day. The results demonstrate that increasing the tubing diameter produces a consistent positive effect on the production operating point — a physically expected outcome attributable to the reduction in frictional pressure losses within the tubing string as diameter increases. The full sensitivity results are as follows:

- Case 0 — Tubing diameter: 3.75 in → Operating point: 1,673 m³/day
- Case 1 — Tubing diameter: 4.00 in → Operating point: 1,813 m³/day
- Case 2 — Tubing diameter: 4.50 in → Operating point: 2,100 m³/day
- Case 3 — Tubing diameter: 5.00 in → Operating point: 2,226 m³/day

4.4. Sensitivity Analysis: Tubing Diameter (Vertical Well)

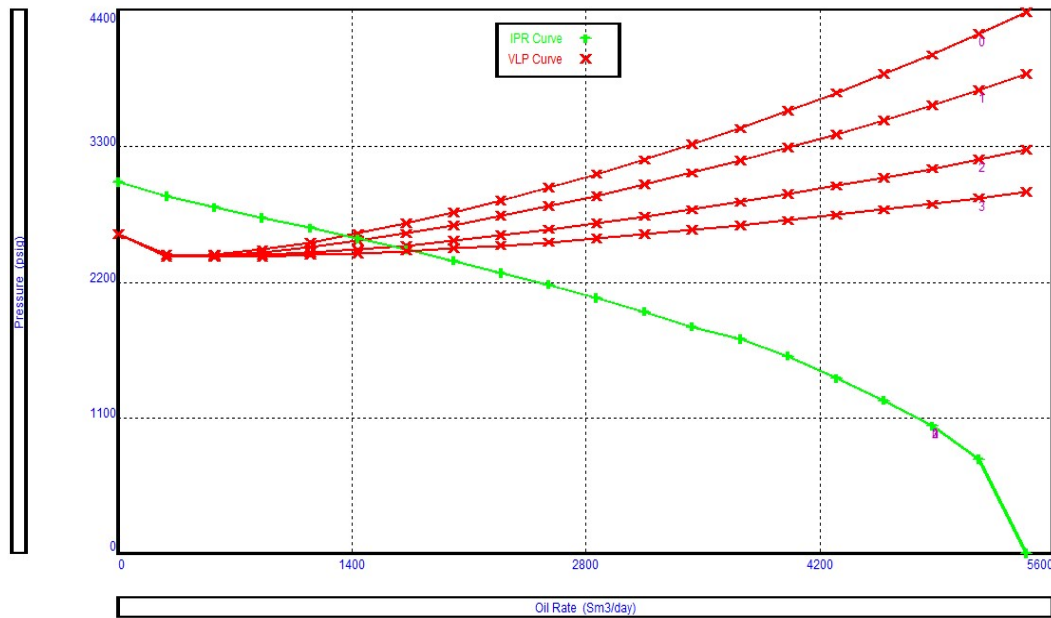


Figure 5. IPR/VLP Curves for the Vertical Well at Various Tubing Diameters

Figure 5 presents the tubing diameter sensitivity results for the vertical well. The baseline case with a tubing diameter of 3.75 inches yields a production operating point of 1,365 m³/day — again lower than the corresponding deviated well value, consistent with the smaller drainage area of the vertical well. Increasing the tubing diameter produces a qualitatively identical positive effect on production performance, as detailed below:

- Case 0 — Tubing diameter: 3.75 in → Operating point: 1,365 m³/day
- Case 1 — Tubing diameter: 4.00 in → Operating point: 1,477 m³/day
- Case 2 — Tubing diameter: 4.50 in → Operating point: 1,645 m³/day
- Case 3 — Tubing diameter: 5.00 in → Operating point: 1,723 m³/day

5. Conclusions. This study has successfully demonstrated the production performance differential between vertical and deviated well configurations when PVT data and petrophysical parameters are held constant. The key findings and conclusions are as follows:

1. The deviated well encompasses a significantly larger drainage area relative to the vertical well, which directly translates into a higher production operating point as determined through nodal analysis.

2. The intersection of the IPR and VLP curves — as computed by PROSPER — consistently confirms that the production operating point of the deviated well exceeds that of the vertical well under equivalent operational conditions, demonstrating the production advantage conferred by the larger drainage area of the deviated well configuration.

3. The sensitivity analysis reveals that increasing tubing diameter yields a positive effect on oil production rates in both well types, attributable to the reduction in frictional pressure drop within the production string.

4. Conversely, increasing wellhead pressure exerts a detrimental effect on production performance in both the deviated and vertical well configurations, as it shifts the VLP curve and consequently reduces the production operating point.

5. The primary conclusion of this investigation is that oil production from the deviated well is substantially greater than that from the vertical well under identical reservoir and operational conditions, confirming the production efficiency advantage of deviated well completions in

Conflict of interest

The authors declare that they have no conflict of interest in relation to this research

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