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Review Article

## **Pressure Analysis of Heavy Oil Reservoirs under High Viscosity and Pressure-Dependent Properties during Drawdown and Buildup Tests**

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**Abstract:** Heavy oil reservoirs pose distinctive pressure-analysis problems because high viscosity, low mobility, fluid-property nonlinearity, and pressure-dependent rock behavior distort the classical assumptions used in drawdown and buildup test interpretation. This article presents a publication-oriented review and analytical framework for interpreting pressure transient data from heavy oil reservoirs during flowing and shut-in periods. The study synthesizes recent work on pressure transient analysis, tight-oil physical constraints, threshold-pressure-gradient behavior, stress-sensitive permeability, thermal and solvent recovery implications, automated PTA, and integrated pressure-temperature workflows. It argues that heavy-oil well-test interpretation should be treated as a coupled fluid-rock-flow problem rather than as a conventional single-phase Darcy-flow exercise. The article shows how high viscosity delays radial-flow stabilization, increases wellbore-storage dominance, magnifies rate-control error, and can produce derivative signatures that mimic boundaries, skin, or composite reservoirs. It further explains how pressure-dependent viscosity, compressibility, porosity, and permeability affect mobility, storativity, superposition, Horner straight-line behavior, and type-curve matching. A practical workflow is proposed for data screening, diagnostic plotting, model selection, parameter estimation, and uncertainty communication. The article concludes that reliable heavy-oil pressure analysis requires early integration of PVT data, geomechanics, temperature data, rate history, and nonlinear numerical or semi-analytical models, especially when drawdown and buildup tests are used for field-development decisions.

**Keywords:** Heavy Oil Reservoir; Pressure Transient Analysis; Drawdown Test; Buildup Test; Viscosity; Pressure-Dependent Permeability; Well Testing

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## 1. Introduction

Pressure transient analysis remains one of the most useful tools for estimating permeability, skin, boundary behavior, average reservoir pressure, and well productivity, yet its application in heavy oil reservoirs is more difficult than in conventional light-oil systems (Liu et al., 2023). In classical well-test interpretation, the analyst often assumes single-phase slightly compressible flow, approximately constant viscosity, constant permeability, stable rate, and radial-flow development within a practical test duration (Sun et al., 2024). Heavy oil reservoirs violate several of these assumptions simultaneously because mobility is low, viscosity may vary strongly with temperature, pressure, dissolved gas, and shear history, and effective permeability can change with stress and depletion. Recent pressure transient studies increasingly emphasize physical constraints, stress sensitivity, threshold pressure gradients, and model-assisted interpretation for unconventional and low-mobility reservoirs (Juneghani et al., 2025).

The problem becomes more pronounced during drawdown and buildup tests. A drawdown test records bottom-hole flowing pressure while the well produces at a controlled rate, whereas a buildup test records pressure recovery after shut-in (Dastkhan et al., 2022). In a heavy-oil well, the flowing period may be dominated by wellbore storage, multiphase near-wellbore effects, low-mobility pressure diffusion, and rate instability caused by artificial lift limitations. During buildup, pressure recovery may be slow, incomplete, and affected by changing fluid mobility around the wellbore. Consequently, the pressure derivative may fail to show a clean horizontal radial-flow plateau within the available shut-in time, and the semilog plot may generate misleading permeability and skin values if conventional assumptions are imposed (Fair, 2025; Juneghani et al., 2025).

Heavy oil is usually described in operational terms by high density and high viscosity. From a pressure-analysis perspective, however, viscosity is not merely a fluid descriptor; it directly controls mobility, hydraulic diffusivity, the time required for transient pressure propagation, and the size of the pressure drop needed to produce a given rate. When viscosity is high, a relatively small permeability reduction or skin effect can produce a disproportionately large pressure loss. This means that pressure transient data from heavy oil wells must be interpreted with attention to nonlinear mobility, rate-dependent behavior, temperature change, and near-wellbore alteration such as fines migration, sand production, foamy-oil behavior, or thermal stimulation history (Plata et al., 2021; Cartagena-Pérez et al., 2025).

Pressure-dependent reservoir properties complicate the analysis further. As reservoir pressure declines during production, effective stress increases, which can reduce pore volume, porosity, fracture conductivity, or matrix permeability. At the same time, oil viscosity may increase or decrease depending on pressure, gas liberation, temperature, and solvent effects. These changes alter transmissibility during the test itself, meaning that pressure response is no longer governed by a constant-diffusivity equation. Recent models for tight oil and fractured systems show that stress sensitivity and threshold pressure gradient can modify derivative behavior and make flow-regime identification more difficult (Guo et al., 2024; Sun et al., 2024; Tian et al., 2024).

The aim of this article is to provide a comprehensive technical discussion of pressure analysis in heavy oil reservoirs under high viscosity and pressure-dependent properties during drawdown and buildup tests. The article is structured as follows: the literature review synthesizes recent developments in heavy-oil recovery, transient analysis, pressure-dependent rock and fluid properties, and diagnostic interpretation; the methodology presents an integrated analytical framework; the discussion evaluates drawdown and buildup behavior under nonlinear conditions; and the conclusion presents implications for field practice and future research.

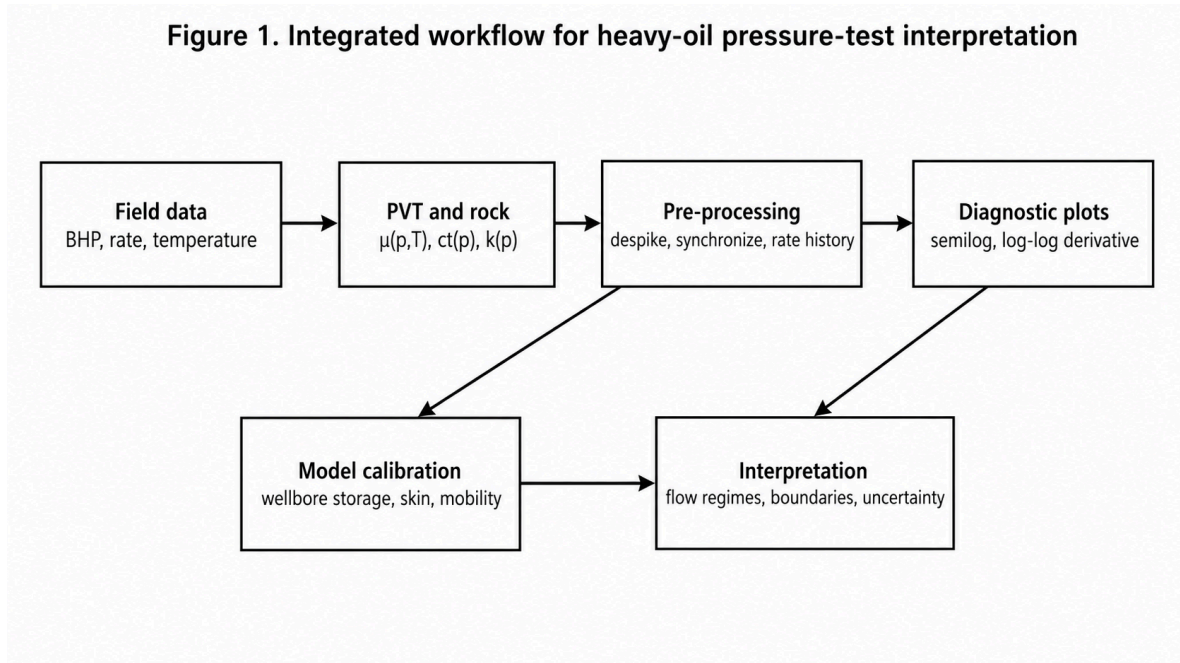
## **2. Literature Review**

### **2.1 Heavy Oil Reservoir Characteristics and Well-Test Implications**

Heavy oil reservoirs are commonly associated with low API gravity, high viscosity, reduced mobility, and sensitivity to temperature and pressure. These characteristics affect primary production, artificial lift design, pressure-test duration, and the interpretation of pressure derivatives. In cold heavy oil production, low mobility causes slow pressure diffusion, while gas exsolution and foamy-oil behavior can make compressibility and mobility time-dependent. Recent heavy-oil recovery literature notes that primary cold production may leave a large fraction of oil in place and those post-primary techniques such as cyclic solvent injection are often considered to improve recovery (Cartagena-Pérez et al., 2025).

For well testing, heavy-oil characteristics translate into longer stabilization periods and greater ambiguity in diagnosing flow regimes. A short drawdown test may reveal only wellbore storage and near-wellbore behavior instead of reservoir-scale radial flow. Likewise, a short buildup may not recover enough pressure to estimate average reservoir pressure reliably. Where sand production, wormholes, or unconsolidated formations are

present, the effective flow geometry may be neither radial nor homogeneous, and classical straight-line methods can produce attractive but physically weak results (Plata et al., 2021; Cartagena-Pérez et al., 2025).



*Figure 1. Integrated workflow for heavy-oil pressure-test interpretation. Source: Author's illustration based on PTA workflow concepts.*

## 2.2 Drawdown and Buildup Tests in Low-Mobility Systems

Drawdown tests are useful for evaluating productivity and near-wellbore pressure losses, but in heavy oil systems they are often constrained by the ability to maintain a constant rate. Rate instability is not a minor operational inconvenience because pressure transient analysis relies on superposition of rate changes. When rate changes are large, frequent, or poorly measured, the estimated skin and permeability may reflect rate-history uncertainty rather than reservoir behavior. Automated PTA workflows have recently been proposed to reduce interpretation time and improve consistency, but heavy-oil analysis still requires engineering judgment because automated pattern recognition may misclassify nonlinear viscosity and stress-sensitive effects as conventional flow regimes (Fair, 2025).

Buildup tests can be more reliable than drawdown tests because shut-in eliminates flowing-rate control problems, but the shut-in response in a high-viscosity reservoir may still be slow and diagnostically ambiguous. A buildup test following a long production period can reveal reservoir pressure, skin, and boundary influence if pressure recovery reaches a recognizable regime. However, in heavy-oil wells, recovery may be dominated by

afterflow, wellbore storage, gas segregation, changing temperature, or slow equilibration between high- and low-mobility zones. The recent review by Juneghani et al. (2025) reaffirms the usefulness of buildup analysis for near-wellbore and boundary interpretation while also showing why modern analytical solutions must account for non-ideal reservoir conditions.

### **2.3 Pressure-Dependent Viscosity, Compressibility, and Mobility**

Viscosity is central to heavy-oil pressure analysis because mobility is defined by the permeability-to-viscosity ratio. Even when permeability is constant, a pressure-dependent viscosity introduces apparent mobility changes across the pressure sink around the wellbore. If viscosity increases as pressure declines, the near-wellbore region may become less mobile during drawdown, producing a stronger pressure drop and a derivative trend that can be mistaken for positive skin, composite behavior, or boundary effect. Conversely, gas liberation or solvent contact can reduce effective viscosity and create an apparent mobility improvement that may be misread as stimulation (Liu et al., 2023; Cartagena-Pérez et al., 2025).

Compressibility is also important. The diffusivity equation contains total compressibility, and pressure-dependent compressibility changes storativity during the test. In heavy oil reservoirs, oil compressibility, rock compressibility, solution-gas behavior, and possible foamy-oil mechanisms may interact. If total compressibility is underestimated, pressure diffusion may appear slower than expected, leading the analyst to underestimate permeability or overestimate reservoir size. If compressibility is overestimated, the opposite bias may occur. Therefore, laboratory PVT data and field pressure-volume behavior should be incorporated before interpreting derivative signatures.

### **2.4 Pressure-Dependent Permeability and Stress Sensitivity**

Pressure-dependent permeability occurs when effective stress changes the pore system during depletion or testing. In unconsolidated or weakly consolidated heavy-oil reservoirs, stress sensitivity can be strong because grains, pore throats, and sand-control completions may respond to pressure drawdown. In fractured or naturally fractured reservoirs, fracture conductivity may decline with effective stress. Recent transient-flow studies show that stress sensitivity can produce upward pressure-derivative trends at later times and can complicate the identification of radial-flow regimes (Sun et al., 2024; Tian et al., 2024).

Stress sensitivity is especially relevant when drawdown is aggressive. A high drawdown may temporarily increase rate but can also reduce near-wellbore permeability, mobilize fines or sand, change relative permeability, or create compaction-related productivity loss. When a buildup test is analyzed after such a drawdown, the pressure response may include both reservoir recovery and partial mechanical or fluid redistribution effects. Therefore, the drawdown magnitude should be treated as an interpretive variable rather than merely an operating condition (Guo et al., 2024; Li et al., 2024).

### **2.5 Threshold Pressure Gradient and Non-Darcy Low-Velocity Flow**

Heavy oil can exhibit low-velocity non-Darcy behavior in which a finite pressure gradient is required before flow becomes measurable or approximately Darcy-like. The threshold pressure gradient is more commonly emphasized in tight-oil and low-permeability literature, but the concept is highly relevant to heavy oil because high viscosity increases the pressure gradient required to mobilize fluid. Recent models incorporating threshold pressure gradients show upward pressure-derivative trends and delayed flow-regime recognition, which are also common practical symptoms in heavy-oil tests (Liu et al., 2023; Sun et al., 2024).

The presence of a threshold-like effect changes the meaning of the interpreted permeability. In a purely Darcy system, permeability is a rock property that can be estimated from a radial-flow slope. In a threshold-gradient system, the apparent permeability inferred from a pressure test depends on pressure gradient, rate, and distance from the wellbore. This creates a risk of interpreting an operational mobility limit as a geological permeability reduction. Heavy-oil PTA should therefore separate rock permeability, effective mobility, and flow-initiation pressure gradient whenever possible.

### **2.6 Temperature, Solvent, and Thermal History Effects**

Temperature has a dominant effect on heavy-oil viscosity. Even modest heating near the wellbore can reduce viscosity and alter the pressure response, while cooling during shut-in can increase viscosity and slow pressure recovery. In reservoirs affected by thermal stimulation, steam-assisted processes, cyclic steam stimulation, hot-water injection, or electrical heating, pressure data alone may be insufficient. Temperature transient analysis can complement pressure transient analysis because thermal signals help identify fluid movement, wellbore effects, and formation properties (Dastkhan et al., 2022).

Solvent processes add another layer of complexity. CO<sub>2</sub> or hydrocarbon solvent can swell the oil, reduce viscosity, alter relative permeability, and change phase behavior.

Recent reviews of cyclic solvent injection in post-CHOPS heavy-oil reservoirs emphasize that solvent-fluid interaction and reservoir deformation remain challenging to model at field scale (Cartagena-Pérez et al., 2025). For pressure analysis, this means that tests performed before, during, and after solvent exposure cannot be interpreted as if the reservoir fluid were unchanged.

### **2.7 Modern Analytical, Semi-Analytical, and Numerical PTA Approaches**

Modern PTA increasingly combines analytical solutions, derivative diagnostics, numerical inversion, and constrained optimization. Conventional analytical solutions are still valuable because they provide transparent relationships among pressure slope, permeability, skin, storativity, and boundary behavior. However, heavy-oil reservoirs often require semi-analytical or numerical models because pressure-dependent viscosity, permeability, and compressibility are difficult to represent with a single closed-form solution. The 2025 review of analytical PTA solutions highlights the continued importance of analytical methods while documenting the expansion of models for more complex reservoir conditions (Juneghani et al., 2025).

Recent tight-oil and fractured-reservoir models are useful analogues for heavy oil because they address nonlinear flow, physical constraints, stress sensitivity, and derivative interpretation. Liu et al. (2023) proposed a workflow for early-time transient-pressure interpretation under physical constraints; Sun et al. (2024) incorporated threshold pressure gradient and stress sensitivity in a fractured horizontal well model; and Guo et al. (2024) considered low-velocity non-Darcy effects in shale oil reservoirs. Although these studies are not heavy-oil specific in every detail, their treatment of non-ideal mobility is directly relevant to heavy-oil drawdown and buildup interpretation.

### **2.8 Knowledge Gap**

The main knowledge gap is not the absence of pressure transient methods but the limited integration of heavy-oil fluid behavior, stress-dependent rock properties, and practical drawdown-buildup test design into a single interpretation framework. Many field interpretations still rely on conventional Horner plots or type-curve matches even when viscosity, permeability, and compressibility are pressure-dependent. Recent literature provides pieces of the solution, including physical constraints, stress-sensitive models, automated PTA, and pressure-temperature integration, but field analysts require a practical synthesis that connects these developments to heavy-oil operations (Dastkhan et al., 2022; Fair, 2025; Juneghani et al., 2025).

### 3. Methodology and Analytical Framework

This article adopts a conceptual analytical methodology based on synthesis of recent literature and petroleum-engineering pressure-test principles. The proposed framework assumes that heavy-oil pressure analysis should begin with data validation, continue through diagnostic plotting, and end with model calibration under explicit uncertainty. The workflow is not a replacement for reservoir simulation; rather, it is a disciplined procedure for avoiding common interpretive errors when drawdown and buildup data are affected by high viscosity and pressure-dependent properties.

The first step is data conditioning. Bottom-hole pressure, wellhead pressure, production rate, liquid level, temperature, artificial-lift operating data, and shut-in records should be synchronized on a common time basis. Heavy-oil wells often have unstable rate measurements and significant wellbore storage; therefore, rate averaging must be performed carefully. Any periods of pump-off, gas interference, separator instability, or gauge drift should be flagged before derivative computation. This step is consistent with modern PTA practice, where interpretation quality depends strongly on pressure-rate history integrity (Fair, 2025; Juneghani et al., 2025).

The second step is property modeling. The analyst should construct pressure-dependent functions for viscosity, total compressibility, and permeability using PVT reports, core tests, correlations, or calibrated field data. A simple first-pass representation may use piecewise linear or exponential relationships, such as viscosity as a function of pressure and temperature and permeability as an exponential function of effective stress. These functions should be tested in sensitivity cases rather than treated as exact inputs because laboratory conditions rarely reproduce the full reservoir flow history.

The third step is diagnostic analysis. Semilog plots, log-log pressure derivative plots, rate-normalized pressure, and pressure-rate convolution should be used together. In heavy-oil reservoirs, a single diagnostic plot is rarely adequate. A derivative slope that appears to indicate boundary influence may instead reflect pressure-dependent permeability, threshold-gradient behavior, or changing viscosity. Similarly, a delayed derivative plateau may reflect low diffusivity rather than the absence of radial flow. The analyst should compare drawdown and buildup derivatives because the same reservoir should not produce contradictory properties unless the flow path or fluid state changes between test periods.

The fourth step is model calibration. Candidate models should include conventional radial flow, composite mobility, wellbore storage and skin, pressure-dependent permeability, threshold pressure gradient, and boundary effects. A model should not be accepted simply because it fits pressure data; it should also be consistent with PVT behavior, production history, completion design, reservoir geology, and operational constraints. Recent physical-constraint approaches support this philosophy by reducing parameter non-uniqueness during early-time interpretation (Liu et al., 2023).

The final step is uncertainty reporting. Heavy-oil pressure-test results should be presented as ranges rather than single deterministic values. Permeability, skin, average reservoir pressure, drainage radius, and boundary distance should be reported with sensitivity to viscosity, compressibility, stress sensitivity, rate history, and test duration. This is important because field-development decisions based on a single fitted permeability can be misleading when property dependence is strong.

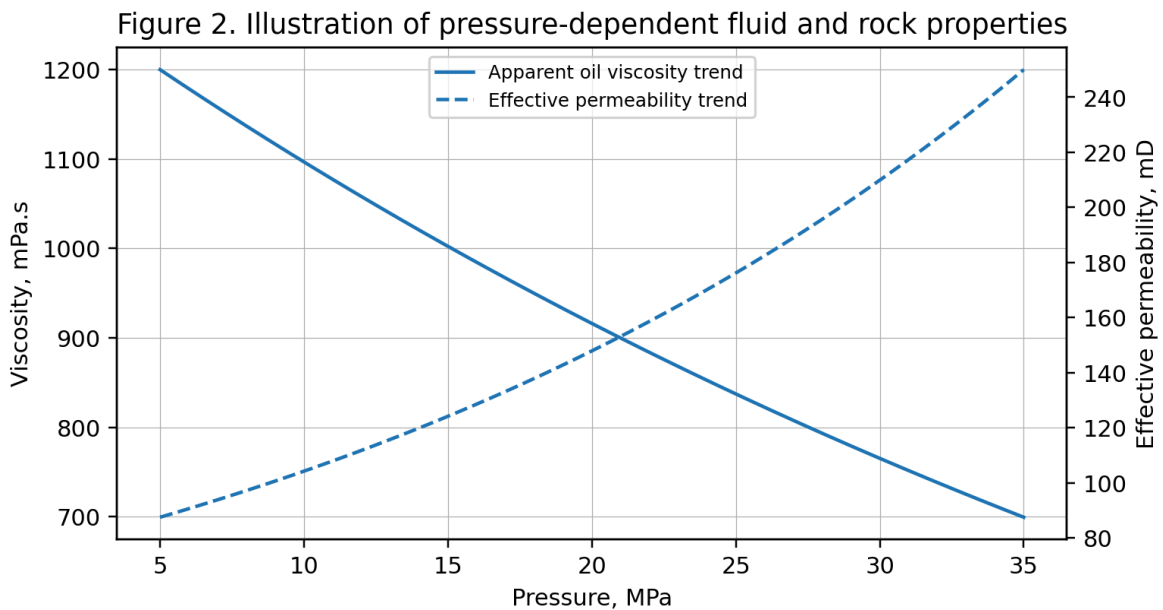


Figure 2. Pressure-dependent viscosity and effective permeability trends. Source: Author's conceptual illustration.

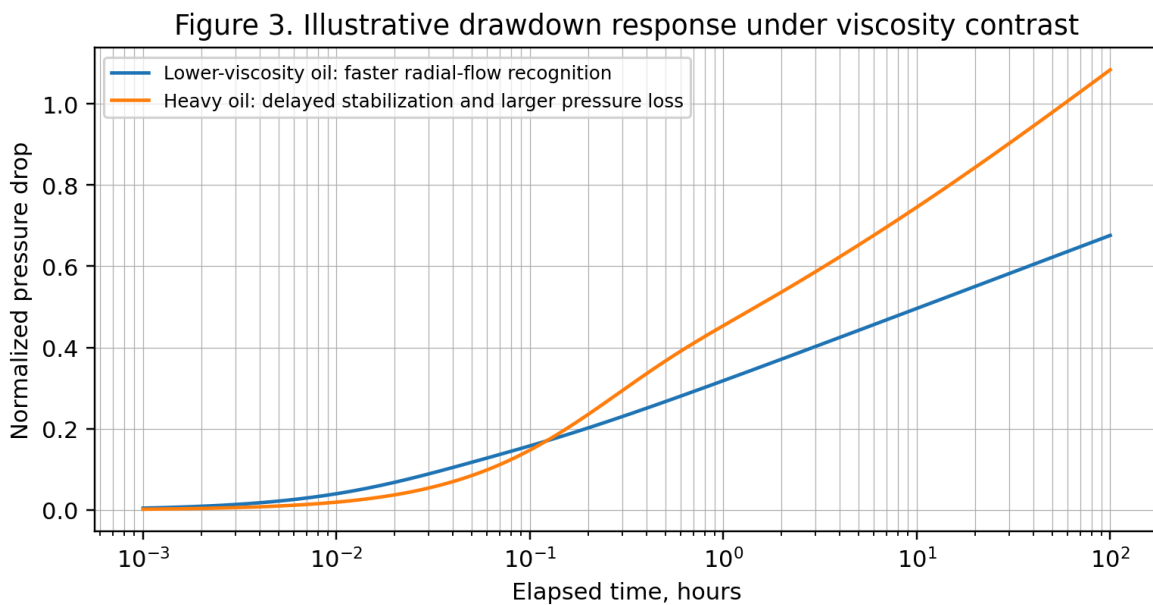
## 4. Results and Discussion

### 4.1 Effect of High Viscosity on Drawdown Pressure Behavior

During drawdown, high viscosity increases the pressure gradient required to sustain production. For a given permeability and rate, the pressure drop is proportional to viscosity; therefore, a heavy-oil well can show a large pressure decline even when reservoir permeability is not exceptionally low. The practical implication is that pressure loss should

not immediately be interpreted as severe formation damage. A high skin estimate from a conventional drawdown plot may be an artifact of using an inappropriate viscosity, ignoring near-wellbore temperature, or neglecting pressure-dependent mobility.

High viscosity also delays the propagation of pressure disturbance away from the wellbore. Hydraulic diffusivity is inversely related to viscosity and compressibility; therefore, heavy oil slows the development of infinite-acting radial flow. In short tests, the derivative may remain in a transition regime, and analysts may be tempted to force a radial-flow line. This can underestimate permeability and overestimate skin. A better practice is to design longer tests or use early-time workflows with physical constraints when operational constraints prevent long shut-ins or long stabilized drawdowns (Liu et al., 2023).



*Figure 3. Illustrative drawdown response under viscosity contrast. Source: Author's conceptual illustration.*

#### 4.2 Effect of High Viscosity on Buildup Pressure Recovery

In buildup testing, the well is shut in and bottom-hole pressure recovers toward reservoir pressure. In heavy-oil wells, recovery is often slow because the low-mobility fluid cannot redistribute pressure quickly. Wellbore afterflow may persist for an extended period, especially if the wellbore contains gas-liquid mixtures, rod-pump equipment, or thermal gradients. As a result, early buildup data may reflect wellbore mechanics more than formation response.

The Horner method can still be useful as a screening tool, but its assumptions must be checked. If viscosity and permeability change during the production period or shut-in period, the Horner straight line may not represent a constant-mobility reservoir. The extrapolated pressure may be biased, and the slope-derived permeability may be an apparent effective mobility. Buildup interpretation should therefore be linked to the preceding drawdown history, because the pressure sink created during drawdown determines the initial condition for pressure recovery (Juneghani et al., 2025).

### **4.3 Pressure-Dependent Properties and Apparent Flow Regimes**

Pressure-dependent viscosity and permeability can create apparent flow regimes that mimic conventional signatures. If effective permeability declines with pressure drawdown, the derivative may trend upward at late time, resembling a sealing boundary or reduced reservoir volume. If viscosity decreases near the wellbore because of heating or solvent contact, the derivative may trend downward, resembling improved mobility or a composite reservoir with higher inner-zone permeability. These signatures must be tested against independent temperature, PVT, and completion data before geological conclusions are drawn (Dastkhan et al., 2022; Sun et al., 2024).

The combined effect of viscosity increase and permeability decrease is especially severe. Both effects reduce mobility near the wellbore during drawdown. The pressure derivative may show no stable plateau, and the model match may require high skin, low permeability, or finite boundary assumptions. However, the physical explanation may be dynamic mobility loss rather than fixed reservoir architecture. A robust interpretation should therefore run matched cases with constant properties and pressure-dependent properties to determine how much of the response is caused by nonlinear properties.

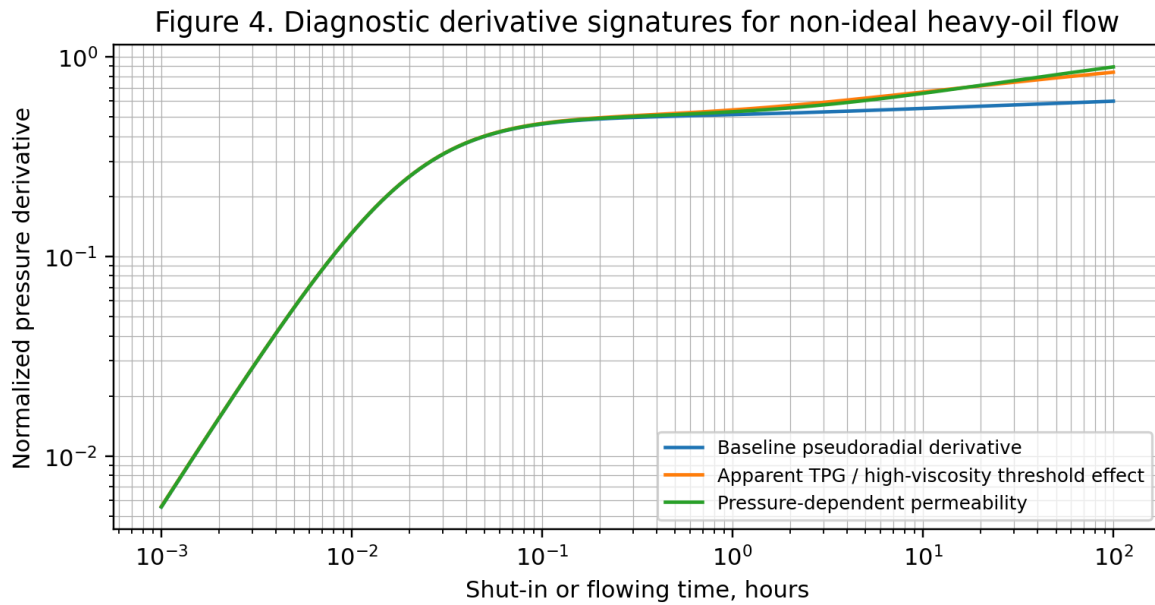


Figure 4. Diagnostic derivative signatures for non-ideal heavy-oil flow. Source: Author's conceptual illustration.

#### 4.4 Skin, Wellbore Storage, and Near-Wellbore Alteration

Skin is a lumped parameter representing additional pressure drop near the wellbore. In heavy-oil reservoirs, skin is often not a single stable quantity. It can include completion damage, sand-control restriction, fines migration, emulsion blockage, temperature-induced viscosity change, altered saturation, gas blockage, or wormhole development. Treating all these mechanisms as a single constant skin may be convenient but can be misleading for operational decisions.

Wellbore storage is also more persistent in heavy-oil tests because the wellbore system may contain compressible gas, pump equipment, and viscous fluids. A long wellbore-storage period masks formation response and prevents early recognition of radial flow. If the test ends before storage effects decay, permeability and skin estimates may be non-unique. The analyst should identify whether storage behavior is normal, changing, or multiphase, and should consider pressure-temperature data where available (Dastkhan et al., 2022).

#### 4.5 Drawdown Test Design for Heavy Oil Wells

A heavy-oil drawdown test should be designed around achievable rate stability and expected diffusivity. The test duration should be estimated using preliminary permeability, viscosity, compressibility, and wellbore-storage values. If the expected radial-flow time is longer than the operational test window, the test objective should be revised. It may be

more realistic to estimate near-wellbore mobility and productivity index than to claim reservoir-boundary detection.

The drawdown rate should be selected carefully. Excessive drawdown may create sand production, gas liberation, compaction, or mobility loss. Very low drawdown may produce pressure changes too small for reliable derivative analysis. A multi-rate sequence can help separate rate-dependent skin from reservoir transmissibility, but only if rates are accurately measured and maintained. In heavy-oil wells, the operational design is therefore inseparable from the interpretation model.

#### **4.6 Buildup Test Design for Heavy Oil Wells**

A buildup test should follow a sufficiently long and well-documented production period. The preceding rate history should be stable or at least accurately recorded for superposition. Shut-in should be rapid and complete; partial shut-in or leakage through lift equipment can distort the pressure response. Because recovery is slow, the shut-in duration should be long enough to move beyond wellbore storage and afterflow. If production loss is a concern, short buildup tests can be supplemented by repeated tests and integrated with production data.

Gauge resolution and placement are important. Heavy-oil pressure changes may be large during drawdown but slow during late buildup; therefore, gauge drift and temperature compensation matter. Downhole gauges are preferred where possible. If only surface data are available, wellbore hydraulics and multiphase column effects must be corrected before reservoir interpretation.

#### **4.7 Practical Interpretation Workflow**

A practical workflow begins by plotting raw pressure and rate versus time to identify operational events. The next step is pressure derivative calculation using appropriate smoothing that does not erase real flow-regime features. The analyst should then compare diagnostic plots with property-sensitivity models. Constant-property interpretation should be used as a baseline, but pressure-dependent viscosity and permeability should be introduced before final conclusions are drawn.

The interpretation should reconcile drawdown and buildup results. If drawdown indicates very high skin but buildup suggests moderate skin, the difference may reflect rate-dependent or pressure-dependent effects. If buildup permeability is lower than drawdown permeability, stress sensitivity or shut-in cooling may be involved. If neither test

shows radial flow, the conclusion should state that the test did not reach diagnostic conditions rather than forcing a conventional answer.

#### **4.8 Implications for Reservoir Management**

Accurate pressure analysis affects reservoir management decisions such as artificial-lift sizing, drawdown policy, stimulation planning, thermal or solvent pilot design, and infill-well placement. If permeability is underestimated because viscosity effects are ignored, the operator may overinvest in stimulation. If skin is underestimated because pressure-dependent permeability is ignored, the operator may apply excessive drawdown and damage the reservoir. Therefore, heavy-oil PTA should be connected directly to production strategy.

For enhanced recovery projects, pressure tests can monitor mobility changes before and after steam, solvent, or water injection. However, the analyst must recognize that the reservoir after stimulation is not the same system as before stimulation. Viscosity, saturation, relative permeability, compressibility, and stress state may all change. Pressure-test interpretation should therefore be tied to time-lapse reservoir characterization rather than treated as a one-time static measurement.

#### **5. Conclusion**

Pressure analysis of heavy oil reservoirs during drawdown and buildup tests requires a broader interpretation philosophy than conventional constant-property PTA. High viscosity reduces mobility, slows pressure diffusion, extends wellbore-storage dominance, and increases the pressure drop required to sustain production. Pressure-dependent viscosity, compressibility, and permeability further distort diagnostic signatures and can cause derivative behavior that resembles boundaries, skin, or composite reservoirs even when the underlying cause is nonlinear mobility.

The central conclusion is that heavy-oil pressure-test interpretation should not rely solely on straight-line plots or unconstrained type-curve matching. Instead, the analyst should integrate PVT data, temperature history, rate-quality control, stress-sensitive permeability models, and uncertainty analysis. Drawdown and buildup data should be interpreted together because the drawdown period establishes the pressure and mobility distribution that controls the buildup response. Where radial flow is not reached, the limitation should be stated clearly and the test should be used for near-wellbore mobility or productivity assessment rather than overextended reservoir characterization.

For field practice, heavy-oil well tests should be designed with longer durations, better rate stabilization, high-quality downhole gauges, and explicit pressure-dependent property models. For research, future work should focus on coupled thermal-fluid-geomechanical PTA models, field validation of threshold-gradient behavior in heavy oil, pressure-temperature transient integration, and machine-learning tools constrained by physics rather than by pattern recognition alone. Such developments will improve the reliability of drawdown and buildup tests as decision tools for heavy-oil reservoir development.

*Table 1. Common interpretation risks and mitigation strategies in heavy-oil PTA*

<b>Interpretation risk</b>	<b>Likely heavy-oil cause</b>	<b>Recommended mitigation</b>
No clear radial-flow plateau	Low diffusivity, prolonged storage, pressure-dependent mobility	Extend test duration; compare drawdown and buildup; use constrained model
Excessive apparent skin	High viscosity, completion restriction, gas blockage, emulsion or sand-control loss	Separate mechanical skin from viscosity effect; verify PVT and completion data
Upward late-time derivative	Stress-sensitive permeability, threshold-gradient behavior, boundary effect	Run sensitivity cases before assigning boundary interpretation
Inconsistent drawdown and buildup permeability	Rate instability, changing viscosity, shut-in cooling, afterflow	Use full rate history and pressure-temperature integration
Misleading average reservoir pressure	Incomplete buildup, property variation, multiphase redistribution	Report pressure range and uncertainty; avoid over-extrapolation

## 6. Recommendations

Operators should plan heavy-oil drawdown and buildup tests using expected hydraulic diffusivity rather than using generic test durations. Preliminary viscosity, permeability, compressibility, wellbore-storage, and artificial-lift constraints should be used to estimate whether radial flow can be observed within the available testing window.

Well-test interpretation should include pressure-dependent property sensitivity as a routine step. At a minimum, the final report should compare constant-property and

pressure-dependent-property matches and explain how viscosity, compressibility, and permeability assumptions affect permeability, skin, and average reservoir pressure.

Pressure and temperature data should be acquired together whenever possible. Temperature transients are valuable in heavy-oil reservoirs because viscosity is temperature-sensitive and because thermal history can explain pressure signatures that would otherwise be misinterpreted as geological boundaries or skin changes.

The final PTA report should distinguish fixed reservoir properties from apparent test-derived mobility. For heavy oil, apparent mobility may be rate-dependent, pressure-dependent, and temperature-dependent; therefore, reporting a single permeability without assumptions and uncertainty can mislead reservoir-management decisions.

Field teams should avoid excessive drawdown during testing unless the objective is specifically to evaluate drawdown tolerance. High drawdown may induce sand production, gas liberation, fines movement, compaction, or stress-sensitive permeability loss, which can compromise both the reservoir and the interpretation.

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