Transient Near-Wellbore Thermo-Hydraulic Behavior and Its Influence on Surface-Measured Well Responses

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ABSTRACT Transient behavior in the region surrounding a wellbore is controlled by tightly coupled hydraulic and thermal processes within the reservoir and the well completion. In many production and injection operations, this near-wellbore zone exhibits pressure and temperature dynamics that evolve over time scales comparable to those of surface measurements, and these dynamics influence how surface signals are interpreted. Conventional well test analysis and rate transient analysis approaches often assume isothermal flow and negligible wellbore storage beyond simple lumped representations, which may mask or distort the impact of thermal effects and complex local hydraulics. In addition, distributed and pointwise temperature measurements along the wellbore are increasingly used to infer inflow profiles and reservoir properties, yet the relationship between near-wellbore thermo-hydraulic conditions and surface-measured signals remains intricate. This work examines the transient thermo-hydraulic behavior in the vicinity of the wellbore and discusses how it shapes the pressure and temperature responses recorded at the surface. A coupled description of flow and heat transport is considered, including the roles of rock and fluid compressibilities, heat capacity, thermal diffusion, convection along the wellbore, and localized completion features. By combining physical reasoning, mathematical formulation, and dimensionless analysis, the study outlines key time scales and parameter sensitivities that control the mapping between subsurface dynamics and surface measurements. The discussion highlights conditions under which thermo-hydraulic transients significantly affect surface responses and conditions under which they may be approximated by simpler representations. Implications for interpretation of well tests, production data, and temperature-based diagnostics are considered, together with potential strategies to incorporate thermo-hydraulic coupling into analysis and modeling workflows.

KEYWORDS

1. Introduction

Transient well responses measured at the surface are a core source of information about subsurface properties and operational performance [1]. Pressure, rate, and temperature signals are routinely recorded at the wellhead and used to infer reservoir permeability, wellbore storage, skin factors, boundaries, multiphase behavior, and completion performance. Many of the established analysis techniques rely on relatively idealized models in which the wellbore is treated as a simple boundary condition to a homogeneous reservoir and in which thermal effects are either neglected or represented in a rudimentary manner. As measurement resolution and diagnostic expectations have increased, limitations of these simplifications have become more apparent, especially in settings where near-wellbore thermo-hydraulic behavior exhibits strong transients [2].

The region surrounding a wellbore is characterized by high hydraulic gradients, potential changes in fluid state, and strong contrasts in material properties between the reservoir, the casing and cement, and the fluid in the tubulars. When rates and pressures vary with time, these gradients can drive coupled transport of mass and energy that alters both local and apparent global behavior. Transient heat exchange between the wellbore fluid, the casing, the cement sheath, and the adjacent formation leads to evolving temperature and density distributions that influence pressure losses, effective wellbore storage, and the timing and shape of observed pressure responses at the surface.

Table 1 Key thermo-hydraulic processes in the near-wellbore region

Process	Domain	Primary driver	Main impact on signals
Radial fluid flow	Reservoir	Pressure gradients	Drawdown/buildup, diffusional pressure spreading
Thermal diffusion	Reservoir rock + fluid	Temperature gradients	Slow evolution of near-wellbore temperature
Axial advection	Wellbore	Imposed rate, gravity	Transport of mass and energy along well axis
Wellbore–formation heat exchange	Interface at $r = r_w$	ΔT between T_w and T_r	Cooling/heating of near-wellbore rock and fluid
Completion/damage effects	Near-wellbore zone	Altered k, ϕ, λ_{eff}	Apparent skin and modified local storage

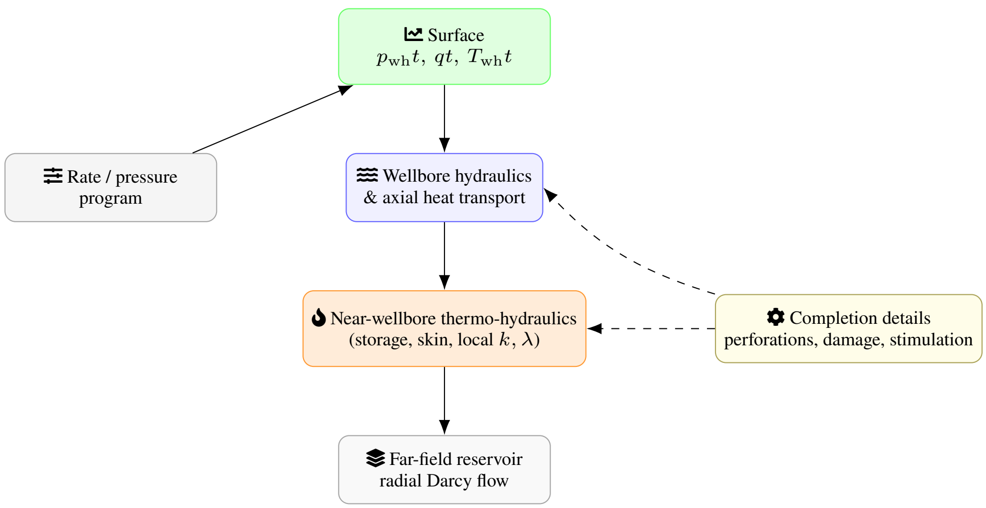

Figure 1 Conceptual structure of the coupled near-wellbore thermo-hydraulic system linking surface rate and pressure control, internal wellbore dynamics, localized completion effects, and radial flow in the far-field reservoir to the measured pressure and temperature responses at the wellhead.

Even in single-phase liquid systems, where large phase-change effects are absent, temperature variations modify fluid viscosity, compressibility, and thermal expansion, and these variations feed back into the hydraulic system [3].

At the same time, surface-measured responses are shaped not only by reservoir flow but also by internal wellbore dynamics, including frictional pressure drop, inertia, and the thermal and hydraulic storage capacity of the wellbore fluid. In classical well test theory, such effects are often condensed into a single wellbore storage coefficient that captures the gross ability of the well to take fluid without immediate change in bottomhole pressure. This representation does not explicitly account for thermal processes, spatial variations along the wellbore, or the distributed nature of storage in the composite system of tubulars, annulus, cement, and formation. In thermally sensitive operations, such as injection of cold water into warm rock or production of hot fluids from cooler surroundings, the approximation of purely isothermal hydraulic storage can lead to discrepancies between modeled and observed behavior.

In addition, distributed temperature sensing and downhole gauges are increasingly deployed, making temperature itself both a diagnostic and a source of coupling in the system. Temperature logs are interpreted to infer inflow profiles, locate zones of crossflow, and estimate thermal properties. However, the temperature profile along the wellbore is governed by an interplay of advective transport along the flow direction, radial heat exchange with the surrounding formation, and localized events such as inflow at perforations or throttling across completions. The near-wellbore thermal field is therefore connected to reservoir fluxes in a manner that is neither instantaneous nor purely local [4]. When only surface measurements are available, these complexities are folded into the pressure and temperature signals that reach the wellhead, complicating inverse interpretation.

Understanding transient near-wellbore thermo-hydraulic behavior requires a coupled description of mass and energy conservation in both the porous formation and the wellbore. This description involves continuum models grounded in Darcy flow for the reservoir and one-dimensional momentum and energy

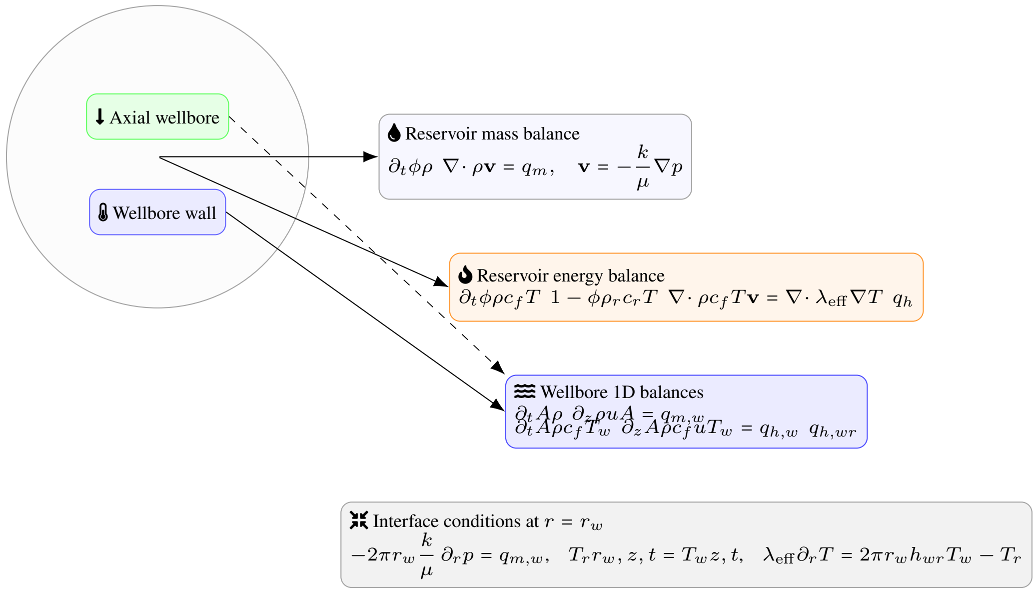

Figure 2 Schematic representation of the coupled domains and governing equations: a radial reservoir around the wellbore with mass and energy conservation, a one-dimensional wellbore model for mass and energy transport, and interface conditions at the wellbore wall that exchange mass and heat between the two systems.

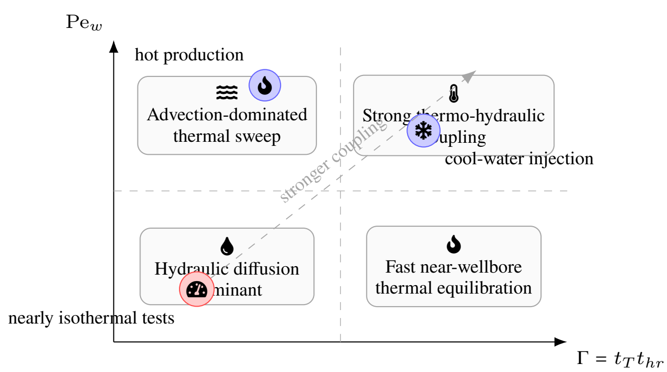

Figure 3 Dimensionless map of thermo-hydraulic regimes in terms of the ratio of thermal to hydraulic diffusion times in the near-wellbore region, Γ, and the wellbore Péclet number, Pe_w. Example operating conditions illustrate where classical isothermal behavior, advection-dominated thermal transport, and strongly coupled thermo-hydraulic responses are expected.

balances inside the wellbore. The coupling occurs through boundary conditions at the wellbore wall, where inflow or outflow of fluid is accompanied by the exchange of thermal energy with the adjacent rock [5]. Thermal diffusion within the formation leads to temperature perturbations that extend outward from the wellbore, while the flow-induced pressure disturbance propagates according to hydraulic diffusivity. Because thermal and hydraulic diffusivities generally differ by several orders of magnitude, the associated time scales can be widely separated, yet the interplay of these processes within the confined near-wellbore region can be nontrivial.

The present discussion focuses on transient phenomena in which both thermal and hydraulic effects play an observable role in the surface responses. The emphasis is on single-phase fluid systems, such as water or light oil, flowing in porous rock with no phase change, although many of the concepts are directly relevant to multiphase cases [6] [7]. The aim is not to provide a complete catalog of all possible phenomena but to articulate a coherent framework within which near-wellbore thermo-hydraulic behavior can be linked to surface measurements. This framework relies on continuum models, dimensionless analysis, and qualitative interpretation of numerically simulated responses to identify the dominant parameters and time scales governing observable effects.

By clarifying the mechanisms through which near-wellbore thermo-hydraulic transients influence surface signals, it becomes possible to assess when classical isothermal well test constructions remain adequate and when an explicitly coupled treatment is desirable. It also becomes possible to delineate regimes in which the near-wellbore region can be represented by effective parameters, such as an apparent skin factor or an effective wellbore storage coefficient, and regimes in which such reduced representations may be misleading [8]. This perspective is particularly relevant for the interpretation of pressure transients in

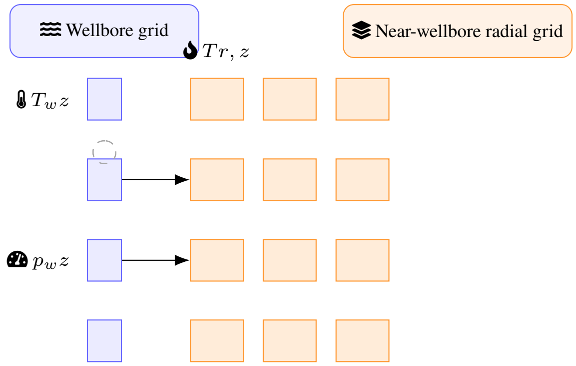

Figure 4 Illustrative finite-volume discretization of the coupled wellbore and near-wellbore reservoir: axial cells along the wellbore are linked to radial cells in the surrounding formation through exchange terms for mass and heat, allowing numerical resolution of steep thermo-hydraulic gradients close to the well.

Table 2 Summary of governing equations for coupled flow and heat transport

Equation	Domain	Form	Role in model
Mass conservation	Reservoir	$\frac{\partial \phi\rho}{\partial t} \;\; \nabla\cdot\rho\mathbf{v} = q_m$	Controls pressure and flux in porous medium
Darcy's law	Reservoir	$\mathbf{v} = -\frac{k}{\mu}\nabla p$	Relates pressure gradients to volumetric flow
Energy balance	Reservoir	$\frac{\partial}{\partial t}\phi\rho c_f T \;\; 1-\phi\rho_r c_r T \;\; \nabla\cdot\rho c_f T\mathbf{v} = \nabla\cdot\lambda_{\text{eff}}\nabla T \;\; q_h$	Describes thermal storage and transport in rock–fluid system
Wellbore mass balance	Wellbore	$\frac{\partial A\rho}{\partial t} \;\; \frac{\partial \rho u A}{\partial z} = q_{m,w}$	Captures axial flow and influx/outflux along the well
Wellbore momentum	Wellbore	$\frac{\partial p}{\partial z} = -\rho g - \frac{f}{2D}\rho u\lvert u\rvert$	Links pressure gradient to hydrostatic and frictional effects
Wellbore energy	Wellbore	$\frac{\partial A\rho c_f T_w}{\partial t} \;\; \frac{\partial A\rho c_f u T_w}{\partial z} \;\; = \;\; q_{h,w} \;\; q_{h,wr}$	Governs evolution of wellbore temperature profile

wells subject to substantial temperature variations, for the design of diagnostic tests in injection wells, and for the development of analysis methods that combine pressure and temperature data.

2. Physical Processes Governing Near-Wellbore Thermo-Hydraulic Transients

The near-wellbore region is subject to several coupled physical processes that jointly determine its transient response. The first is radial fluid flow in the porous formation toward or away from the wellbore under changing bottomhole pressure or imposed rate conditions. In a single-phase, slightly compressible system, this radial flow can be described on the reservoir scale by a diffusion-type process governed by hydraulic diffusivity [9]. Close to the wellbore, geometric and property heterogeneities, damaged or stimulated zones, and completion features can cause deviations from ideal radial behavior, but the underlying relation between pressure gradients and volumetric flux remains rooted in Darcy's law.

Simultaneously, the formation rock and the pore fluid participate in heat exchange with the wellbore. At the simplest level, the formation is a semi-infinite medium that conducts heat radially in response to a temperature difference between the wellbore wall and the undisturbed far-field temperature. Heat is stored in both the solid matrix and the fluid, and thermal diffusion tends to smooth temperature gradients over time [10]. The thermal diffusivity of the composite medium sets a characteristic time scale for the decay of temperature perturbations in the vicinity of the wellbore. Unlike hydraulic pressure, which propagates rapidly through the pore space even under low fluid velocities, temperature disturbances are limited by molecular conduction with comparatively slow diffusion rates.

Within the wellbore, the fluid flows along the vertical or inclined axis of the well under the influence of imposed rates, gravity, and frictional resistance. The thermal state of this fluid evolves through advection of internal energy along the flow path,

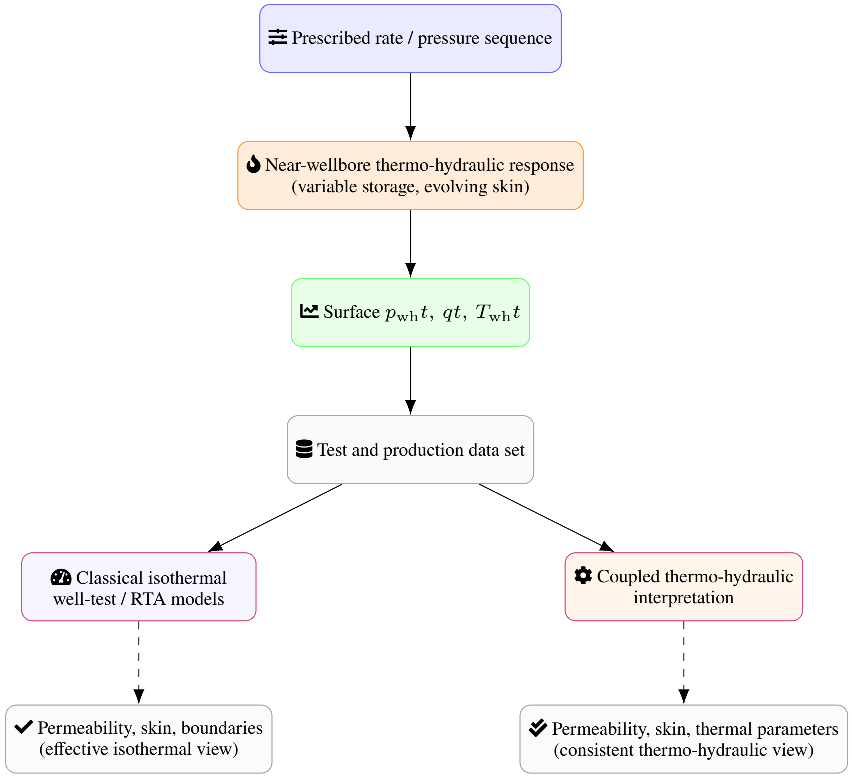

Figure 5 Schematic interpretation workflow linking imposed rate or pressure histories, near-wellbore thermo-hydraulic dynamics, and surface measurements to two classes of analysis models: classical isothermal approaches and explicitly coupled thermo-hydraulic treatments that can jointly constrain hydraulic and thermal parameters.

heat exchange with the formation through the wellbore wall, and potentially internal sources or sinks such as Joule–Thomson cooling or heating, viscous dissipation, and mixing at junctions or perforations [11]. Because the axial flow transports both mass and energy, the thermal profile in the wellbore reflects a balance between local radial heat exchange and longitudinal advection. At high flow rates, advection tends to dominate, leading to relatively uniform axial temperature gradients determined by the net radial heat flux. At lower flow rates, the fluid has more time to equilibrate thermally with the surrounding rock, and near steady-state conditions may emerge over certain depth intervals.

In many practical situations, the fluid entering or leaving the wellbore from the formation has a temperature that differs from that of the wellbore fluid at that depth [12] [13]. When cold water is injected into a warm reservoir, for example, the injected fluid cools the formation around the wellbore, creating a transient thermal front that migrates outward over time, while the heat flux from the formation warms the wellbore fluid as it moves upward. Conversely, in hot production wells, the fluid may be cooled as it ascends through cooler overburden rock. The net effect is that the temperature at the wellhead at a given time and rate reflects not only current operating conditions but also the history of thermal exchange along the well and in the near-wellbore region.

Hydraulic and thermal processes are coupled because fluid properties depend on temperature and pressure [14]. Density variations induced by temperature changes modify hydrostatic pressure distribution and can alter the effective wellbore storage. Viscosity changes affect frictional pressure losses and thus influence the pressure gradient along the well. Compressibility and thermal expansion together determine how much fluid volume is stored per unit pressure and temperature change in the wellbore and in the formation. In systems where these property variations are modest over the range of interest, linearization about a reference state yields a tractable description of the coupling [15]. When variations are larger, nonlinear feedback may become significant.

Another important aspect of near-wellbore behavior is the presence of completion and damage features that create hydraulic skin. A damaged zone with reduced permeability and altered porosity may also possess different thermal properties, including thermal conductivity and heat capacity, relative to the undisturbed formation. Likewise, stimulation treatments that increase permeability and modify pore structure can alter thermal transport characteristics [16]. These changes can make the near-wellbore region a distinct thermo-hydraulic domain with its own characteristic time scales and storage capacities. When a pressure disturbance is imposed, the system responds with an initial period in which near-wellbore conditions control the behavior, followed by a period dominated by the larger reservoir. In the presence of thermal coupling, this evolution includes changes in local temperature that influence the effective hydraulic properties in the near-wellbore zone and, in turn, the shape of the pressure response.

The surface-measured pressure and temperature signals result from the integration of these processes along the well [17]. For a

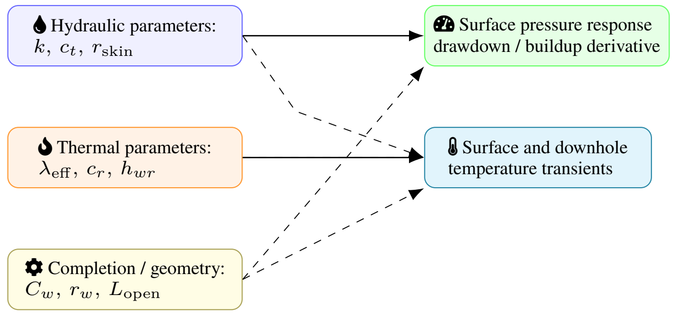

Figure 6 Qualitative sensitivity structure between parameter groups and observables: hydraulic properties have strong influence on surface pressure responses and moderate impact on temperature, thermal properties primarily govern observed temperature transients but also modify apparent hydraulic behavior, and completion or geometric features affect both pressure and temperature via their control of storage and local thermo-hydraulic coupling.

Table 3 Thermophysical property dependencies and their hydraulic consequences

Property	Symbol	Dependence	Main consequence
Density	$\rho p, T$	Linearized via c_p, β	Modifies hydrostatic head and effective storage
Viscosity	μT	Typically decreases with T	Alters frictional pressure drop and effective mobility
Total compressibility	c_t	Function of rock and fluid	Sets hydraulic diffusivity α_h
Thermal conductivity	λ_{eff}	Composite rock–fluid value	Controls rate of radial heat penetration
Heat capacity	ρc (rock, fluid)	Material specific	Determines thermal storage and damping of T transients

given change in surface rate or pressure, the initial response may be dominated by wellbore fluid compressibility and by the inertia of the flowing column, with limited immediate contribution from reservoir flow. As time progresses, reservoir influx or outflow adjusts to the imposed conditions, and the pressure at the sandface evolves. The thermal state adjusts more slowly, as heat diffuses radially and is advected axially. The degree to which the surface response is sensitive to near-wellbore thermodynamics depends on the relative magnitudes of hydraulic and thermal storage and on the ratio of their characteristic time scales to the observation window [18].

When measurement periods are short relative to thermal time scales, the system can be approximated as isothermal, and the dominant effects arise from hydraulic storage and inertial dynamics. When the observation period is long, thermal equilibration along the wellbore and into the near-wellbore rock may approach quasi-steady conditions, and surface measurements primarily reflect longer-range reservoir behavior. The most complex regime occurs when the observation window is comparable to the thermal time scales in the near-wellbore region and the wellbore, so that evolving temperature fields contribute to variations in density, viscosity, and storage that influence pressure transients and temperature signatures measured at the wellhead.

3. Formulation of Coupled Flow and Heat Transport

A mathematical formulation of the coupled thermo-hydraulic problem provides a basis for analyzing how near-wellbore processes influence surface responses [19]. For the porous reservoir, consider a single-phase fluid saturating a rigid rock matrix. The local conservation of mass can be written as

$$\frac{\partial}{\partial t}\left(\phi\rho\right)\ \nabla\cdot\left(\rho\mathbf{v}\right) = q_m, \tag{3.1}$$

where ϕ is porosity, ρ is fluid density, $\mathbf{v}$ is Darcy velocity, and q_m is a source term representing mass injection or production per unit bulk volume. Darcy's law relates the velocity to the pressure gradient as

$$\mathbf{v} = -\frac{k}{\mu}\nabla p, \tag{3.2}$$

where k is the permeability and μ is dynamic viscosity [20]. The dependence of ρ and μ on pressure and temperature introduces thermo-hydraulic coupling into the mass balance.

Table 4 Dimensionless groups characterizing coupled thermo-hydraulic behavior

Group	Definition	Physical meaning	Regime when $\gg 1$
Hydraulic time scale	$t_{hr} = L_r^2 \alpha_h$	Time for pressure diffusion over L_r	Slow hydraulic equilibration
Thermal time scale	$t_T = L_r^2 \alpha_T$	Time for heat diffusion over L_r	Persistent thermal gradients
Time-scale ratio	$\Gamma = \alpha_h \alpha_T$	Relative speed of pressure vs. heat diffusion	Thermal transients outlast pressure if $\Gamma \gg 1$
Axial Péclet	$\mathrm{Pe}_w = \rho c_f u_0 L_w \lambda_w$	Advection vs. axial conduction in wellbore	Temperature transported mainly by flow
Radial Biot	$\mathrm{Bi}_r = h_{wr} L_r \lambda_{\text{eff}}$	Interface vs. radial conductive resistance	Strong coupling between wellbore and rock
Thermal expansion	$\Theta = \beta \Delta T$	Strength of density change due to ΔT	Significant impact on hydrostatics and storage

Table 5 Characteristic time scales relevant to surface measurements

Time scale	Expression	Dominant process	Interpretation for tests
Hydraulic diffusion	$t_{hr} = L_r^2 \alpha_h$	Pressure equilibration in near-wellbore reservoir	For $t \ll t_{hr}$, response dominated by wellbore storage
Thermal diffusion	$t_T = L_r^2 \alpha_T$	Radial heat penetration in rock	For $t \sim t_T$, evolving T modifies apparent skin and storage
Axial advection	$t_{aw} = L_w u_0$	Transport of temperature along wellbore	Sets delay between downhole and surface T signatures
Global test duration	t_{test}	Operational	Position relative to t_{hr}, t_T, t_{aw} selects regime (isothermal vs. coupled)

It is convenient to linearize density with respect to pressure and temperature around a reference state p_0, T_0. Let ρ_0 be the density at the reference state, c_p the isothermal compressibility, and β the volumetric thermal expansion coefficient. A first-order relation can be expressed as [21]

$$\rho \approx \rho_0 \left[1 \;\; c_p \left(p - p_0\right) - \beta \left(T - T_0\right)\right]. \tag{3.3}$$

Similar linearizations can be introduced for viscosity if required. Substituting Darcy's law and the density relation into the mass conservation equation yields a diffusion-type equation for pressure, coupled to temperature through the density and viscosity dependencies.

For energy conservation in the porous medium, consider a local averaged balance that accounts for conduction in both solid and fluid, advection of internal energy with the fluid, and possible heat sources or sinks. A commonly used form is [22]

$$\frac{\partial}{\partial t}\left(\phi \rho c_f T \;\; 1 - \phi \rho_r c_r T\right) \;\; \nabla \cdot \left(\rho c_f T \mathbf{v}\right) = \nabla \cdot \left(\lambda_{\text{eff}} \nabla T\right) \;\; q_h, \tag{3.4}$$

where c_f is fluid specific heat, c_r is rock specific heat, ρ_r is rock density, λ_{eff} is an effective thermal conductivity of the saturated medium, and q_h is a volumetric heat source term. The left-hand side includes temporal storage of thermal energy in fluid and rock and advective transport of thermal energy by the moving fluid, while the right-hand side includes conductive heat transport and source contributions.

In the near-wellbore region, the above equations hold in the formation outside the wellbore. The wellbore itself can be modeled as a one-dimensional conduit aligned with coordinate z along the well axis. Assuming cross-sectionally averaged quantities, the mass balance in the wellbore can be written as [23]

$$\frac{\partial}{\partial t}\left(A\rho\right) \;\; \frac{\partial}{\partial z}\left(\rho u A\right) = q_{m,w}, \tag{3.5}$$

where A is the cross-sectional flow area, u is the average axial velocity, and $q_{m,w}$ represents mass inflow or outflow per unit length of well, which couples the wellbore to the formation. The corresponding momentum balance may be simplified to a steady

Table 6 Numerical modeling components and typical discretization choices

Component	Spatial discretization	Temporal treatment / notes
Radial pressure in reservoir	1D radial finite volume or finite difference	Implicit diffusion; tridiagonal or banded linear system
Radial temperature in reservoir	1D radial with upwind for advection	Implicit/semi-implicit; central differences for conduction
Axial wellbore flow	1D along z; nodes at perforations and completion changes	Algebraic momentum or transient; coupled to mass balance
Axial wellbore temperature	1D along z with upwind or flux-limited schemes	Explicit or implicit; includes source $q_{h,wr}$ from rock
Wellbore–reservoir coupling	Source terms at shared nodes	Nonlinear in p, T; solved via iterative updates of $\mathbf{A}\mathbf{x}^{n1} = \mathbf{b}\mathbf{x}^{n}$

relation between pressure gradient, frictional losses, and gravity when inertial effects are small on the time scales of interest, yielding

$$\frac{\partial p}{\partial z} = -\rho g - \frac{f}{2D}\rho u|u|, \tag{3.6}$$

where g is gravitational acceleration, D is hydraulic diameter, and f is a friction factor.

The energy balance in the wellbore is written in terms of a cross-sectional average temperature T_w and velocity u. Neglecting kinetic energy variations, a representative form is [24]

$$\frac{\partial}{\partial t}\left(A\rho c_f T_w\right) \ \frac{\partial}{\partial z}\left(A\rho c_f u T_w\right) = q_{h,w} \ q_{h,wr}, \tag{3.7}$$

where $q_{h,w}$ represents any internal heat sources or sinks per unit length, and $q_{h,wr}$ denotes heat exchange between the wellbore fluid and the surrounding formation. A commonly used closure for this exchange assumes a convective heat transfer coefficient h_{wr} between the wellbore fluid and the wellbore wall area, leading to

$$q_{h,wr} = 2\pi r_w h_{wr}\left(T_r - T_w\right), \tag{3.8}$$

where r_w is wellbore radius and T_r is the rock temperature at the wellbore wall.

Coupling between the wellbore and the formation occurs through boundary conditions at the wellbore radius. For the reservoir pressure, the boundary condition at $r = r_w$ relates the radial flux to the wellbore inflow per unit length, often expressed as

$$-2\pi r_w \frac{k}{\mu}\frac{\partial p}{\partial r}\Big|_{r=r_w} = q_{m,w}, \tag{3.9}$$

with a sign convention that positive $q_{m,w}$ denotes flow into the wellbore. For temperature, continuity of temperature at the interface is imposed, such that [25]

$$T_r r = r_w, z, t = T_w z, t, \tag{3.10}$$

while the radial heat flux in the rock at the wellbore wall balances the convective exchange term in the wellbore energy equation.

To connect the reservoir and wellbore systems with surface measurements, a boundary condition at the wellhead is specified. In a rate-controlled scenario, the volumetric or mass flow rate at the wellhead is prescribed as a function of time, and the surface pressure adjusts accordingly. In a pressure-controlled scenario, the surface pressure is imposed and the rate becomes an unknown [26]. The linkage between the bottomhole pressure at the sandface and the surface pressure is mediated by the integrated effects of hydrostatic head, frictional losses, and any thermal contributions to density and viscosity along the well. In a single-phase liquid case with modest property variations, the relation can be approximated by integrating the momentum equation along the wellbore, using the density and viscosity fields determined from the temperature and pressure profiles.

For analytical and numerical tractability, additional simplifications are often introduced. These include assuming constant rock properties, neglecting advective energy transport in the reservoir relative to conduction, and representing the wellbore heat transfer coefficient as a function of local flow conditions [27]. Under such approximations, the governing equations reduce to coupled diffusion equations for pressure and temperature in the reservoir, a one-dimensional advection–conduction equation for the wellbore temperature, and algebraic or differential relations for the wellbore pressure. The resulting model retains the key features of thermo-hydraulic coupling while admitting analysis of characteristic time scales and parametric sensitivities.

4. Dimensionless Analysis and Characteristic Time Scales

Dimensionless analysis provides insight into the relative importance of different processes and the time scales over which they influence surface-measured responses. To nondimensionalize the reservoir equations, consider a characteristic length scale L_r, taken here as a multiple of the wellbore radius or as a representative near-wellbore region thickness, and a characteristic pressure scale Δp [28]. Introduce dimensionless variables

$$r_D = \frac{r}{L_r}, \quad t_D = \frac{t}{t_{hr}}, \quad p_D = \frac{p - p_0}{\Delta p}, \tag{4.1}$$

Table 7 Model parameters with strong influence on surface responses

Parameter	Primarily affects	Qualitative impact on surface signals
Permeability k	Hydraulic diffusivity, inflow rate	Changes timing and magnitude of drawdown/buildup
Total compressibility c_t	Reservoir storage	Alters early-time slope and apparent wellbore storage
Thermal conductivity λ_{eff}	Rock heat diffusion	Controls rate of equilibration of near-wellbore temperature
Heat transfer coefficient h_{wr}	Wellbore–rock thermal coupling	Modifies amplitude of surface T transients and density profile
Wellbore roughness / friction f	Axial pressure losses	Shifts relation between sandface and surface pressure
Open interval length	Distribution of exchange along well	Changes weighting of zones in combined pressure and temperature response
Damage/stimulation (skin)	Near-wellbore k, λ_{eff}	Alters apparent skin, local storage, and transient T effects

where t_{hr} is a characteristic hydraulic diffusion time, defined as

$$t_{hr} = \frac{L_r^2}{\alpha_h}, \quad \alpha_h = \frac{k}{\phi \mu c_t}, \tag{4.2}$$

with c_t the total compressibility of the reservoir fluid–rock system. For pressure diffusion in the reservoir, the dimensionless radial equation in an isothermal approximation reduces to a standard radial diffusivity equation for p_D as a function of r_D and t_D.

The corresponding thermal problem involves a thermal diffusivity

$$\alpha_T = \frac{\lambda_{\text{eff}}}{\phi \rho c_f \;\; 1 - \phi \rho_r c_r}, \tag{4.3}$$

and a characteristic thermal time t_T defined by

$$t_T = \frac{L_r^2}{\alpha_T}. \tag{4.4}$$

The ratio of thermal to hydraulic time scales for a chosen L_r is

$$\Gamma = \frac{t_T}{t_{hr}} = \frac{\alpha_h}{\alpha_T}. \tag{4.5}$$

Typical parameter values in water-saturated rock can lead to Γ significantly less than or greater than unity, depending on permeability, fluid viscosity, and thermal properties. When Γ is much less than one, hydraulic diffusion is slower than thermal diffusion, and pressure equilibration in the near-wellbore region takes longer than thermal equilibration. When Γ is much greater than one, temperature equilibrates more slowly than pressure, and thermal transients persist longer than hydraulic transients in the near-wellbore region [29].

To characterize thermal convection in the wellbore, a Péclet number can be introduced. Consider an axial length scale L_w along the well and a characteristic velocity u_0. The axial Péclet number is

$$\text{Pe}_w = \frac{\rho c_f u_0 L_w}{\lambda_w}, \tag{4.6}$$

where λ_w is an effective thermal conductivity in the wellbore [30]. When Pe_w is large, axial advection of heat dominates conduction, and temperature variations are transported primarily by flow. When Pe_w is small, conduction and radial exchange may dominate, leading to more uniform axial temperature profiles over the length scale L_w.

Radial heat exchange between the wellbore and the formation can be characterized by a Biot-type number that compares the convective heat transfer at the wellbore wall to conductive resistance in the surrounding rock. For a characteristic radial length L_r and a convective coefficient h_{wr}, a Biot number can be defined as

$$\text{Bi}_r = \frac{h_{wr} L_r}{\lambda_{\text{eff}}}. \tag{4.7}$$

When Bi_r is small, the dominant thermal resistance lies at the wellbore wall, and the rock near the wall tends to remain closer to its initial temperature. When Bi_r is large, the interface is efficient at transferring heat, and temperature perturbations penetrate more readily into the formation over the length scale L_r.

The storage capacity of the wellbore relative to the reservoir can be encapsulated by dimensionless storage numbers. A hydraulic storage ratio can be defined as

$$S_h = \frac{C_{w,h}}{C_{r,h}}, \tag{4.8}$$

where $C_{w,h}$ is an effective hydraulic storage coefficient of the wellbore and $C_{r,h}$ is the hydraulic storage capacity of the near-wellbore reservoir region per unit length of well. Under

Table 8 Interpretation scenarios influenced by thermo-hydraulic coupling

Situation	Risk if coupling is neglected	Suggested treatment
Large ΔT injection (cold into warm rock)	Misattribution of T-induced viscosity/density changes to skin or k	Use coupled model or time-varying effective storage/skin
Long-duration tests	Ignoring slow thermal equilibration	Assess t_{test} vs. t_T; include thermal diffusion when comparable
Poorly insulated wells	Underestimating hydrostatic variation	Include T-dependent density in wellbore pressure integration
DTS-based inflow profiling	Misreading T anomalies as purely zonal flow changes	Interpret T with axial advection and radial heat exchange
Shut-in and restart events	Misinterpreting transient anomalies as connectivity changes	Attribute short-lived features to reinitiated thermal transients when consistent

Table 9 Qualitative regimes of near-wellbore behavior based on time-scale ordering

Regime	Time-scale relations	Interpretation simplification
Nearly isothermal storage dominated	$t_{\text{test}} \ll t_T, t_{\text{test}} \lesssim t_{hr}$	Classical wellbore storage + skin sufficient
Coupled transient near-wellbore	$t_{\text{test}} \sim t_T, t_{\text{test}} \sim t_{hr}$	Need explicit thermo-hydraulic model for early/mid times
Thermally relaxed, hydraulically transient	$t_{\text{test}} \gg t_T, t_{\text{test}} \lesssim t_{hr}$	Thermal effects lumped into quasi-steady effective parameters
Fully equilibrated near-wellbore	$t_{\text{test}} \gg t_T, t_{\text{test}} \gg t_{hr}$	Responses dominated by far-field reservoir behavior

linearized compressibility, the wellbore hydraulic storage can be approximated as [31]

$$C_{w,h} \approx A c_f \rho_0, \tag{4.9}$$

while the reservoir storage per unit length over a radial domain $r_w < r < r_e$ is

$$C_{r,h} \approx 2\pi \int_{r_w}^{r_e} r\, \phi c_t \rho_0 \, dr. \tag{4.10}$$

The ratio S_h determines whether early-time pressure responses are dominated by wellbore or reservoir storage. A similar thermal storage ratio can be defined to compare the thermal capacity of fluid in the wellbore to that of the rock and fluid in the near-wellbore formation.

Coupling between thermal and hydraulic behavior introduces additional dimensionless groups [32]. The influence of temperature on density can be quantified through a dimensionless thermal expansion parameter

$$\Theta = \beta \Delta T, \tag{4.11}$$

where ΔT is a characteristic temperature difference in the system. When Θ is small relative to unity, density variations due to temperature changes are small, and hydrostatic contributions remain close to those predicted with constant density. When Θ is sizable, temperature changes can significantly alter hydrostatic pressure and effective wellbore storage, contributing to observable differences in surface pressure responses [33].

The combination of these dimensionless numbers yields different regimes of behavior. When Pe_w is large, Bi_r moderate to large, and Γ significantly greater than one, near-wellbore thermal fields can evolve slowly relative to hydraulic pressure but have strong axial coupling through advection, making temperature signatures at the wellhead reflect a history of radial heat exchange. When Pe_w is large but Bi_r small, the wellbore fluid may be only weakly coupled to the formation, and surface temperature reflects primarily the imposed inlet conditions and internal wellbore dynamics. When Γ is of order unity, hydraulic and thermal transients in the near-wellbore region occur over comparable time scales, and pressure responses may be influenced by evolving temperature-dependent properties.

Time scales relevant to surface measurements can be estimated by inserting representative physical parameters into the expressions for t_{hr}, t_T, and the axial advection time in the wellbore, t_{aw}, where

$$t_{aw} = \frac{L_w}{u_0}. \tag{4.12}$$

If the typical test duration or monitoring period is much shorter than both t_T and t_{aw}, the system appears nearly isothermal and axially well mixed, and classical well test models may suffice. When the test duration is intermediate, such that t_{aw} is small but t_T is comparable, surface temperature and pressure can exhibit significant transient evolution linked to near-wellbore thermal changes. For very long tests, both hydraulic and thermal fields in the near-wellbore region may approach quasi-steady profiles whose effect on surface responses can be represented by effective parameters.

5. Numerical Modeling Strategies and Sensitivity Analysis

While dimensionless analysis clarifies the roles of various parameters and scaling, quantitative assessment of surface responses in specific settings typically relies on numerical modeling of the coupled thermo-hydraulic system [34]. The governing equations in the reservoir and wellbore form a coupled system of partial differential equations that can be discretized using finite volume, finite difference, or finite element methods. The spatial domain includes the radial direction in the reservoir around the wellbore and the axial direction along the well, while time evolution is tracked over the period of interest.

A practical approach is to adopt a radial–axial grid in which the reservoir is discretized in radius and the wellbore in depth. At each axial location corresponding to a perforated interval or an open segment of the well, the wellbore and reservoir variables are coupled through source terms representing mass and energy exchange [35]. In the reservoir, the radial diffusion equations for pressure and temperature are solved using implicit or semi-implicit time-stepping schemes to maintain stability at reasonable time steps. Implicit discretization of the pressure diffusion equation is straightforward, as it leads to a linear system of equations with a tridiagonal or banded structure in one-dimensional radial grids. The thermal equation, which includes both conduction and the advective term associated with Darcy velocity, can be handled using upwind or higher-order schemes for the advective term and central differences for the conductive term.

In the wellbore, the mass and energy equations are discretized along the axial coordinate [36]. Depending on the flow regime and the importance of inertia, one may adopt an algebraic relation for pressure gradient derived from steady momentum balance or include the transient inertia term to capture rapid dynamics. For the energy equation, explicit or implicit time stepping may be used, with the convective term handled by upwind or flux-limited schemes to avoid spurious oscillations. The coupling between axial and radial directions through the boundary conditions at the wellbore wall introduces nonlinearities, particularly when fluid properties are temperature dependent, and these nonlinearities can be managed with iterative solution strategies at each time step.

The fully coupled system can be arranged in a block-structured algebraic form, where the unknown vector includes reservoir pressures and temperatures at all radial grid nodes, as well as wellbore pressures and temperatures at all axial nodes [37]. A linearized system at each time step may be written symbolically as

$$\mathbf{A}\mathbf{x}^{n1} = \mathbf{b}\mathbf{x}^{n}, \tag{5.1}$$

where $\mathbf{x}^{n1}$ collects the unknowns at the new time level, $\mathbf{x}^{n}$ the values at the previous time level, $\mathbf{A}$ is a Jacobian or coefficient matrix arising from implicit discretization, and $\mathbf{b}$ is a right-hand side that depends on the previous state and possibly on nonlinear corrections. Iterative linear solvers can be employed to solve the resulting system, with preconditioning techniques used to accelerate convergence when the system is large or ill-conditioned.

Sensitivity analysis can be conducted by systematically varying parameters in the model and examining the impact on surface pressure and temperature responses. Relevant parameters include reservoir permeability and porosity, rock and fluid compressibilities, thermal conductivity and heat capacity, wellbore geometry and roughness affecting friction, and the heat transfer coefficient between the wellbore and the formation [38]. Operational parameters such as flow rate, test duration, and the magnitude and timing of rate changes are also essential, as they determine the characteristic time scales excited by the test.

One common observation from such analyses is that changes in thermal properties can influence surface responses even when pressure behavior in the reservoir remains nearly unchanged. For example, increasing the effective thermal diffusivity of the near-wellbore formation tends to accelerate the equilibration of rock temperature with wellbore temperature, thereby altering the transient density distribution in the wellbore fluid. This can modify the effective wellbore storage as a function of time and thus change the early-time shape of the surface pressure response in a rate-controlled test [39]. The sensitivity of surface pressure to thermal properties is often most pronounced in scenarios with large imposed temperature differences between the injected or produced fluid and the initial formation temperature.

Conversely, variations in hydraulic parameters such as permeability and total compressibility primarily influence the timing and magnitude of pressure diffusion in the reservoir. Changes in permeability affect the rate at which reservoir flux adjusts to imposed wellbore conditions. In a rate-controlled test, lower permeability leads to larger and more persistent drawdown at the sandface, which may enhance local cooling or heating due to changes in inflow temperature and heat exchange [40]. When combined with temperature-dependent viscosity, a feedback loop can arise: pressure drawdown increases inflow rate from segments with lower skin, which modifies the local temperature field and thus the viscosity, further affecting the flux distribution.

The heat transfer coefficient between the wellbore and the formation controls the strength of coupling between axial and radial temperature fields. Larger coefficients lead to more rapid equilibration between the wellbore fluid and the rock, making surface temperature more sensitive to changes in formation temperature in the near-wellbore zone. When the coefficient is small, the wellbore behaves more thermally isolated, and surface temperature tends to reflect the thermal state of the injected or produced fluid more directly [41]. Sensitivities of surface pressure to this coefficient are indirect, arising through property changes linked to temperature.

Numerical experiments that vary the length of the open interval, the distribution of perforations, and the presence of near-wellbore damage or stimulation show that these features can imprint characteristic signatures on surface responses. For example, a high-permeability stimulated zone with enhanced thermal conductivity can act as a buffer that stores thermal energy and modifies the apparent wellbore storage over intermediate times. Conversely, a low-permeability damaged zone with reduced thermal conductivity may extend the duration over which surface pressure reflects local transients rather than far-field reservoir behavior [42].

An important aspect of numerical modeling is the resolution of the near-wellbore region. Because gradients in pressure and temperature are steep near the wellbore, fine radial discretization is needed to capture the correct fluxes and thermal exchange. Coarse grids may smear these gradients and lead to underestimation or overestimation of storage and transfer effects. Grid refinement studies help identify resolutions beyond which further refinement yields negligible changes in predicted surface responses [43]. Time-step selection must balance accuracy with computational cost; smaller time steps resolve rapid early-time transients, while larger steps suffice once the system has evolved into slower dynamics.

6. Implications for Interpretation of Surface-Measured Well Responses

The coupled thermo-hydraulic behavior of the near-wellbore region has several implications for the interpretation of surface-measured pressure and temperature responses. In many classical well test analyses, early-time pressure drawdown or buildup behavior is attributed to wellbore storage and skin, with the assumption that thermal effects can be neglected. Under this framework, a simple model with a constant wellbore storage coefficient and a constant skin factor is fitted to the data, and deviations are interpreted in terms of reservoir heterogeneity or boundaries [44]. When near-wellbore thermal transients are significant, however, the effective wellbore storage may vary with time in a way that departs from the classical model, and the apparent skin factor inferred from pressure derivative behavior may be biased.

Consider a rate-controlled drawdown test in which cool fluid is produced from a formation initially at a higher temperature. As production commences, the fluid entering the wellbore near the sandface may be warmer than the fluid ascending in the well, especially if the latter has equilibrated partially with cooler overlying formations. The resulting temperature gradients along the wellbore influence the density distribution, and as the system evolves, heat exchange alters these gradients [45]. The effective hydrostatic pressure difference between the sandface and the surface depends on the integrated density profile, which not only evolves over time but also depends on local thermal transients in the near-wellbore rock. If analysis methods neglect these variations and assume a constant density, the relation between bottomhole and surface pressure can be misrepresented, leading to errors in inferred reservoir parameters.

Similarly, in injection wells where cold water is injected into a warmer formation, the near-wellbore region can experience substantial cooling, which increases water density and reduces viscosity. These changes can modify local flow resistance and storage, altering the shape of the pressure response [46]. When interpreted with isothermal models, such responses might be attributed to changes in permeability or skin, when in fact they result from temperature-dependent properties. The temporal evolution of the thermal field means that the apparent skin factor could decrease or increase over the course of the test, not because of physical changes in the formation structure but because of the changing local temperature conditions.

Surface temperature measurements are often used qualitatively to infer flow behavior along the well. However, the relationship between surface temperature and reservoir inflow or outflow is filtered through near-wellbore thermo-hydraulic processes [47]. For instance, a transient increase in surface temperature following a rate change might be interpreted as an increase in inflow from deeper, warmer zones, but the same signal could arise from altered heat exchange in the near-wellbore region without a significant change in zonal contributions. Disentangling these effects requires models that account for the thermal inertia of the rock and the wellbore and for the evolving coupling between flow and heat transfer.

In some situations, the influence of near-wellbore thermo-hydraulic behavior on surface responses may be sufficiently small that classical analysis is adequate. This is more likely when the temperature difference between the injected or produced fluid and the formation is small, when fluid properties are only weakly temperature dependent over the range encountered, and when the test duration is short compared to the thermal time scale of the near-wellbore region [48]. Under such conditions, the near-wellbore zone can be approximated as isothermal, and thermal effects may be absorbed into effective parameters with minimal impact on inferred reservoir properties.

In contrast, when temperature differences are large, test durations are long, or the wellbore is poorly insulated, thermo-hydraulic coupling can have a measurable impact on pressure responses. In such cases, analysis strategies that combine pressure and temperature data may provide additional constraints. For example, simultaneous fitting of pressure and temperature transients at the surface to a coupled thermo-hydraulic model can help distinguish between thermal effects and purely hydraulic changes [49]. The temperature signal can be sensitive to thermal parameters such as rock heat capacity and thermal conductivity, which are weakly constrained by pressure alone, while pressure remains more sensitive to permeability and compressibility.

Another implication arises in the context of rate transient analysis, where long-term production data are interpreted to infer permeability, drainage area, and boundary conditions. Over extended periods, thermal equilibration processes may reach a quasi-steady state in which vertical and radial temperature gradients stabilize. In this regime, the influence of thermal coupling on incremental changes in pressure may become less pronounced, and isothermal approximations may regain validity [50]. However, operational changes such as shut-ins and restart events can reinitiate thermal transients, temporarily altering surface responses. Recognition of these episodic influences helps avoid misinterpretation of anomalies as evidence of changes in reservoir connectivity or well performance.

The use of distributed temperature sensing along the well adds another layer of complexity and opportunity. Temperature profiles can reveal localized inflow or outflow zones, but their quantitative interpretation requires an understanding of how heat is transported both axially and radially [51]. A zone that appears as a temperature anomaly at the surface may correspond to a cumulative effect of many small contributions along the well, modulated by near-wellbore thermal behavior. Integrating DTS data with pressure and flow measurements through coupled models offers a path to more robust inflow profiling and reservoir characterization.

From a practical standpoint, one approach to dealing with near-wellbore thermo-hydraulic effects is to identify conditions under which they can be lumped into effective parameters and to quantify the uncertainty introduced by such lumping. For example, if a coupled model indicates that thermal effects can be represented over a given test duration by a time-dependent effective wellbore storage coefficient, then classical well test analysis could be extended by allowing storage to vary according to a precomputed or empirically fitted function [52]. Alternatively, analytical or semi-analytical models that approximate the key features of thermo-hydraulic coupling could be used to derive corrections to apparent skin or storage inferred from simpler analyses.

7. Conclusion

The transient thermo-hydraulic behavior of the near-wellbore region plays a role in shaping the pressure and temperature responses measured at the surface. The coupling of mass and energy conservation in the reservoir and the wellbore leads to a system in which pressure and temperature fields evolve together under the influence of hydraulic diffusion, thermal diffusion, axial advection, and property variations with pressure and temperature. The near-wellbore zone, which may be altered by damage or stimulation and which experiences steep gradients in both pressure and temperature, acts as an intermediate domain that filters and modifies the signals transmitted between the far-field reservoir and the surface.

A continuum formulation based on Darcy flow in the reservoir and one-dimensional flow and heat transport in the wellbore provides a framework for analyzing these phenomena. Linearization of fluid properties around a reference state yields coupled diffusion equations for pressure and temperature, with boundary conditions that connect the reservoir and wellbore through mass and heat fluxes at the wellbore wall. Dimensionless analysis highlights the roles of hydraulic and thermal diffusivities, Péclet and Biot numbers, and storage ratios in determining the relative importance and time scales of the various processes. Numerical modeling enables quantitative assessment of how changes in thermal and hydraulic parameters, completion features, and operational conditions manifest in surface pressure and temperature responses [53].

The implications for interpretation of surface-measured responses are context dependent. In cases where temperature differences are modest and test durations are short relative to thermal time scales, classical isothermal models with constant wellbore storage and skin may adequately capture the essential behavior. When temperature differences are large, wells are poorly insulated, or tests extend over time scales comparable to thermal equilibration in the near-wellbore region, thermo-hydraulic coupling can influence the apparent storage and skin factors inferred from pressure data and can alter the relation between surface and bottomhole measurements. In such cases, incorporating thermo-hydraulic models into analysis workflows can help distinguish between effects arising from near-wellbore thermal dynamics and those due to reservoir properties [54].

Combined interpretation of pressure and temperature data, including distributed measurements when available, offers a means to constrain both hydraulic and thermal parameters. By accounting explicitly for near-wellbore thermo-hydraulic processes, such interpretations can provide a more consistent view of inflow behavior, reservoir properties, and well performance. The level of complexity required in any specific application depends on data quality, operational conditions, and diagnostic objectives. Nevertheless, recognizing the potential influence of transient near-wellbore thermo-hydraulic behavior on surface-measured responses is important for designing tests, selecting appropriate models, and assessing the robustness of inferred reservoir characteristics [55].

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