

Determination of the optimal hot water injection volume to enhance oil recovery in extra-heavy oil reservoirs

Jabrayil Eyvazov, Togrul Aslanov, Kamran Aghazada

Abstract. The growing global demand for petroleum and prevailing oil price dynamics have elevated the recovery of heavy oil resources to a matter of strategic importance for the energy sector. Addressing the technical challenges and operational complexities inherent to heavy oil production has been a primary focus of applied petroleum engineering research in recent years. A substantial proportion of hydrocarbon reserves remains unrecovered owing to the characteristically high viscosity of heavy crude oils, which severely impairs their mobility within the reservoir formation. Thermal enhanced oil recovery (EOR) technologies provide a viable pathway for reducing oil viscosity and augmenting oil displacement efficiency through the application of heat to subsurface formations.

Hot water injection constitutes a thermal EOR technique that involves the injection of heated water into hydrocarbon-bearing formations via injection wells. The injected thermal energy reduces the viscosity of heavy oil, thereby improving its mobility and facilitating displacement toward production wells. This study investigates the application of hot water injection in a Middle Eastern reservoir with substantial heavy oil reserves, characterized by an initial oil saturation of 75% and an in-situ heavy oil viscosity of 500 cP. Two-phase immiscible displacement experiments were conducted to evaluate system performance. The primary objective is to identify the optimal injection temperature and hot water slug size – in terms of pore volumes injected – that maximize oil recovery efficiency. The results of several design parameter combinations are analyzed, including hot water floods conducted at various injection volumes and slug sizes. Based on these findings, operational guidelines are established for designing effective hot water injection systems capable of efficiently recovering heavy oil from analogous reservoir conditions. The study also delineates the conditions under which specific design configurations yield superior recovery performance. A critical element of process optimization is the determination of the optimal hot water injection volume that maximizes incremental oil recovery.

Keywords: hot water injection, heavy oil, oil viscosity, enhanced oil recovery (EOR) methods, thermal recovery techniques, optimal injection volume, oil displacement efficiency.

* Corresponding author:

E-mail: jabrayil.eyvazov88@gmail.com

1. Introduction. Upon conclusion of primary oil recovery operations, a substantial fraction of the original oil in place (OOIP) remains unextracted within the reservoir formation. Enhanced oil recovery (EOR) encompasses a broad spectrum of techniques specifically designed to mobilize and produce this residual hydrocarbon resource from partially depleted reservoirs. EOR processes are conventionally classified into three principal categories: thermal methods, chemical methods, and miscible/immiscible displacement methods. Each approach targets a distinct mechanism governing fluid displacement efficiency and aims to address specific reservoir and fluid property limitations that constrain primary and secondary recovery performance.

Thermal recovery methods and their associated operational procedures have been the subject of extensive research within the petroleum engineering literature. The application of heat serves as the fundamental mechanism by which thermal recovery technologies mobilize subsurface hydrocarbons. Among all EOR strategies, thermal recovery methods represent the most widely deployed approach for enhancing production from heavy oil reservoirs, owing to their demonstrated effectiveness in reducing oil viscosity and improving displacement efficiency under a broad range of reservoir conditions.

1.1. Classification of Thermal EOR Techniques. Four distinct thermal injection techniques are recognized in petroleum engineering practice:

- Hot gas injection
- Hot water injection (HWI)
- Steam stimulation (cyclic steam injection)

- Steam displacement (steamflooding)

In-situ combustion – in which the fuel source is the reservoir oil itself and an oxidizing agent (air or oxygen - enriched gas) is injected into the formation – represents an alternative thermal production method. Heat can also be introduced externally by injecting hot fluids such as steam or hot water into the formation. In-situ combustion occurs less frequently than exogenous heat injection methods in field applications.

1.2. Fundamentals and Advantages of Hot Water Injection. Among all thermal injection methods, hot water injection (HWI) most closely resembles conventional cold water flooding in terms of operational simplicity and surface facility requirements. The fundamental concept is straightforward: water is heated at surface facilities and injected into the reservoir formation through designated injection wells. The thermal energy delivered to the formation serves to reduce oil viscosity, and the associated displacement mechanism – combined with the increased oil mobility – facilitates hydrocarbon flow toward production wells.

The relative mobility improvement achieved by hot water injection is particularly pronounced for heavy oils, because their viscosity decreases at a substantially faster rate with temperature than does water viscosity. As reservoir temperature increases, the oil-to-water mobility ratio improves favorably, resulting in a more efficient displacement front and higher incremental oil recovery compared to cold water flooding at equivalent injection volumes.

It has been established that the energy content of saturated steam is approximately three times that of hot water at temperatures below 423°F (217°C). Consequently, hot water injection generally achieves lower maximum energy injection rates than steam injection. However, practical field experience has demonstrated that a steam flood followed by a hot water flood can yield greater total oil recovery than a steam flood alone. In such hybrid operations, steam follows the preferential flow channels established by the preceding hot water flood – rather than overriding toward the reservoir crest – thereby contacting previously bypassed oil in the lower portions of the formation.

Conversely, when a steam flood project is converted to hot water injection, the advancing hot water front mobilizes and displaces oil that had been bypassed by the steam phase. This operational strategy reduces fuel consumption, mitigates the risk of formation compaction during steam production, and minimizes the probability of sand production. Additionally, steam in a steamflood project has a tendency to migrate preferentially toward the upper portions of the reservoir due to gravity segregation, resulting in non-uniform volumetric sweep. When hot water is subsequently injected into the thermally affected zone, heat is transferred from the swept region to the unswept portions of the reservoir, thereby recovering thermal energy that would otherwise be stranded.

2. Field Background and Research Methodology

2.1. Field Description and Reservoir Characteristics. This research was conducted with reference to the Western Absheron (Qərbi Abşeron) heavy oil field, located in the South Caucasus petroleum province. The field is classified as a heavy oil reservoir, with in-situ crude oil viscosity ranging between 20 and 28 cP under reservoir conditions. For heavy oil accumulations of this type, thermally enhanced oil recovery methods represent the most appropriate and technically justified production strategy.

Oil is principally recovered from two producing horizons, designated the QA and QD formations. The field currently supports 59 active production wells. A supplementary development program has been planned that includes the drilling of 14 injection wells to support the proposed hot water injection scheme. The primary research objective is to determine the optimal daily hot water injection volume that maximizes oil recovery efficiency, and to this end, a comprehensive sensitivity analysis was performed as a function of injection volume.

2.2. Sensitivity Analysis: Effect of Injection Volume on Daily Oil Production. A series of simulation scenarios was designed and executed in which the daily hot water injection volume was systematically varied across a range of values. The simulation results for daily oil production as a function of hot water injection volume are presented in Figure 1. Each scenario was evaluated under identical reservoir and operational conditions, with the sole variable being the daily hot water injection rate.

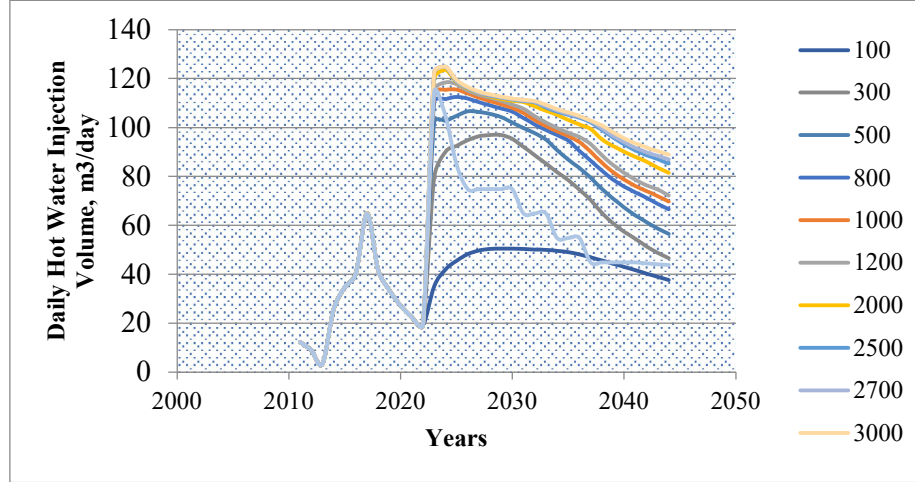


Figure 1. Daily Oil Production Rate as a Function of Hot Water Injection Volume

Table 1.

Daily Oil Production Rate as a Function of Hot Water Injection Volume

Years	Hot Water Injection Volume, m ³ /day										
	100	300	500	800	1000	1200	2000	2500	2700	3000	3500
2023	135.20	146.06	152.90	157.43	158.85	159.18	160.08	160.23	160.24	160.24	158.78
2024	149.59	177.66	190.78	197.73	200.56	201.97	205.13	205.79	205.84	205.84	198.51
2025	165.60	211.03	228.52	238.71	242.76	245.13	249.19	250.02	250.12	250.18	235.25
2026	182.82	245.20	267.28	279.67	284.61	287.53	291.89	292.83	292.99	293.15	264.99
2027	200.74	280.15	306.16	320.20	325.84	329.18	333.83	334.86	335.04	335.28	292.31
2028	219.08	315.56	344.94	360.32	366.63	370.43	375.32	376.42	376.66	377.04	319.70
2029	237.50	350.96	383.26	399.87	406.81	411.14	416.22	417.51	417.83	418.30	347.02
2030	255.93	386.10	420.85	438.95	446.46	451.32	456.83	458.30	458.68	459.25	374.33
2031	274.32	420.24	457.63	477.35	485.54	490.94	497.21	498.84	499.29	499.96	400.73
2032	292.69	453.27	493.72	514.85	523.72	529.73	537.35	539.30	539.82	540.59	424.46
2033	310.95	484.96	528.92	551.36	560.83	567.41	576.66	579.11	579.85	580.84	448.13
2034	329.13	515.39	562.74	587.06	597.11	604.22	615.34	618.25	619.16	620.39	469.35
2035	347.13	544.58	595.09	622.03	632.65	640.24	653.31	656.87	657.94	659.35	489.36
2036	364.90	572.57	626.18	655.84	667.55	675.69	690.67	695.14	696.35	697.95	509.43
2037	382.23	598.98	655.93	688.07	701.16	710.22	727.30	732.77	734.17	735.78	528.84
2038	399.11	623.58	684.00	718.89	733.22	743.42	762.68	769.48	771.13	772.98	545.21
2039	415.52	646.48	710.57	748.22	763.71	774.98	796.86	805.03	806.92	809.28	561.57
2040	431.50	668.07	735.82	776.47	793.05	805.33	830.24	839.59	841.76	844.68	577.98
2041	446.94	688.45	759.74	803.68	821.27	834.50	862.73	873.09	875.61	879.15	594.35
2042	461.88	707.74	782.59	830.08	848.64	862.76	894.49	905.80	908.72	912.96	610.63
2043	476.33	725.98	804.45	855.58	875.28	890.30	925.38	937.85	941.22	946.18	626.77
2044	490.33	743.38	825.50	880.30	901.17	917.13	955.56	969.39	973.29	978.95	642.86

As illustrated in Figure 1, daily oil production increases progressively with increasing hot water injection volume up to a threshold value of 3,000 m³/day. Beyond this critical injection rate,

however, further increases in injection volume yield diminishing marginal returns, and the production rate begins to decline. This behavior is consistent with the well-established principle that beyond an optimal injection volume, excessive water injection can result in premature water breakthrough, unfavorable mobility ratios, and reduced displacement efficiency.

Table 1.

Annual Oil Production at Various Hot Water Injection Volumes

Hot Water Injection Volume (m ³ /day)	Recovery Performance
500	Below optimal — insufficient thermal energy
1,000	Progressive improvement in recovery
1,500	Continued improvement
2,000	Approaching optimal range
2,500	Near-optimal performance
3,000	Optimal — maximum oil recovery rate achieved
> 3,000	Diminishing returns — production rate declines

Note: Specific annual production values for each injection scenario are presented in the corresponding simulation output figures. The table above summarizes the qualitative performance trend observed across the injection volume range investigated.

The simulation results demonstrate that the optimal daily hot water injection volume for the Western Absheron field is 3,000 m³/day. At this injection rate, the maximum daily oil production rate is achieved. This finding indicates that a well-defined injection volume threshold exists, beyond which the incremental benefits of additional hot water injection are outweighed by adverse displacement dynamics, including increased water cycling, thermal dilution, and unfavorable sweep efficiency.

3. Discussion

3.1. Mechanisms Governing Optimal Injection Volume. The existence of an optimal hot water injection volume is a consequence of competing physical mechanisms operating within the reservoir. At sub-optimal injection rates, the thermal energy delivered to the formation is insufficient to reduce oil viscosity to levels that enable effective displacement, resulting in poor sweep efficiency and low recovery. As injection volume increases toward the optimal threshold, viscosity reduction improves progressively, mobility ratio becomes more favorable, and the displacement front advances more uniformly through the reservoir.

Beyond the optimal injection volume, however, the thermal front moves faster than the oil bank, leading to early thermal breakthrough at production wells. Excessive injection rates can also result in unfavorable pressure gradients that promote channeling through high-permeability streaks, bypassing significant volumes of oil in less permeable zones. Additionally, the energy efficiency of the process degrades as an increasing proportion of the injected thermal energy is produced without contributing to oil displacement.

3.2. Design Parameters Influencing Hot Water Injection Performance. The overall effectiveness of a hot water injection program is governed by a complex interplay of reservoir characteristics and operational design parameters. The primary factors influencing hot water injection performance include the following:

- Oil recovery factor and residual oil saturation distribution within the reservoir
- Well spacing geometry and the pattern of injection and production wells
- Daily hot water injection rate and total cumulative injection volume
- Injection water temperature and associated thermal energy content
- Reservoir permeability distribution and heterogeneity
- In-situ oil viscosity and its temperature-dependence
- Reservoir geometry, structural configuration, and net pay thickness

Understanding and optimizing these parameters – both individually and in combination – is essential to the design of an economically and technically efficient hot water injection project. Sensitivity analysis, as employed in this study, provides a systematic and rigorous methodology for quantifying the relative importance of each parameter and identifying the combination of design variables that yields the highest recovery performance.

4. Conclusions. Heavy oil has long been recognized as one of the world's most significant unconventional hydrocarbon resources, owing to its vast reserve volumes and the growing global demand for petroleum. However, the inherently high viscosity of heavy crude oil – governed by reservoir properties such as permeability, reservoir pressure, and in-situ oil viscosity – presents substantial technical challenges to efficient production. Hot water injection represents a technically appropriate and commercially viable thermal EOR technology for recovering heavy oil from reservoirs with characteristics similar to those studied in this investigation. The principal conclusions of this research are as follows:

1. The optimal daily hot water injection volume for the Western Absheron heavy oil field has been quantitatively determined to be 3,000 m³/day. Below this threshold, increasing injection volume produces a consistent and progressive improvement in daily oil production, attributable to enhanced viscosity reduction and improved oil-to-water mobility ratio.

2. Beyond the optimal injection volume of 3,000 m³/day, further increases in hot water injection rate yield no additional improvement in oil production rate, and in some scenarios result in a measurable decline in recovery performance. This confirms the existence of a well-defined optimal injection volume beyond which the displacement process becomes increasingly inefficient.

3. The sensitivity analysis demonstrates that hot water injection is a highly effective thermal EOR strategy for extra-heavy oil reservoirs, provided that injection parameters are carefully optimized. Suboptimal injection volumes result in insufficient thermal energy delivery, while excessive injection leads to premature breakthrough and reduced volumetric sweep efficiency.

4. The findings of this study provide a quantitative basis for the design and operational planning of hot water injection programs in analogous heavy oil reservoirs, and underscore the critical importance of injection volume optimization as a central element of thermally enhanced recovery project design.

5. Future work should investigate the combined effects of injection temperature, well spacing geometry, and reservoir heterogeneity on recovery performance, as well as the potential economic benefits of hybrid thermal strategies combining hot water flooding with steam injection phases.

Conflict of interest

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

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